REVIEW DRAFT
Energy Vision for the Columbia River

March 8, 2013

Prepared by the Columbia River Inter-Tribal Fish Commission

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1. Introduction and Prologue: Visions of the Columbia River

The *2013 Energy Vision for the Columbia River* identifies actions that can save Northwest ratepayers more than $1.3 billion per year, reduce damage to salmon and other fish and wildlife in the Columbia Basin, reduce emissions that are causing climate change, and make BPA more resilient to changes that could affect its financial health. It emphasizes a diverse and reliable energy resource mix that will lower energy costs, and will help to recover abundant, harvestable salmon and resident fish.

This section describes the tribes' energy vision and summarizes the goals and recommendations. Section 2 provides background on balancing fish and wildlife protections and energy production, the issues that led to the *2003 Energy Vision for the Columbia River*, and the progress in implementing the 2003 recommendations. Section 3 provides the recommendations for the 2013 Energy Vision for the Columbia River. Three appendices provide more detail.

1.1 A Tribal Vision

The Yakama, Nez Perce, Umatilla, and Warm Springs tribes each secured, by treaty, rights to take fish that pass their usual and accustomed fishing places. Numerous federal court decisions have affirmed these rights.[1] The four tribes founded CRITFC in 1977 to help them protect the member tribes' treaty rights to take salmon. For the tribes and CRITFC to accomplish their mission, salmon and Pacific lamprey populations need to be rebuilt. The dams on the Columbia and Snake rivers continue to be the main deterrent to anadromous fish restoration.

The people of the Yakama, Nez Perce, Umatilla, and Warm Springs tribes have always shared a common understanding—that their very existence depends on the respectful enjoyment of the Columbia River Basin's vast land and water resources. Indeed, their very souls and spirits were and are inextricably tied to the natural world and its myriad

[1] E.g. Sohappy v. Smith, 302 F.Supp. 899 (D.Or. 1969), aff'd, United States v. Oregon, 529 F.2d 570 (9th Cir. 1976); Washington v. Washington State Commercial Passenger Fishing Vessel Ass'n, 443 U.S. 658 (1979); United States v. Winans, 198 U.S. 371 (1905); Confederated Tribes of the Umatilla Indian Reservation v. Alexander, 440 F.Supp. 553 (D.Or. 1977).

inhabitants.[2] Among those inhabitants, none were more important than the teeming millions of anadromous fish enriching the basin's rivers and streams.

Despite some differences in language and cultural practices, the people of these tribes shared the foundation of a regional economy based on salmon. To the extent the resource permits, tribal people continue to fish for ceremonial, subsistence, and commercial purposes employing—as they always have—a variety of technologies.

Today, perhaps even more than in the past, the Columbia River treaty tribes are brought together by the struggle to save the salmon and by shared spiritual traditions such as the first salmon feast.

- From *Wy-Kan-Ush-Mi Wa-Kish-Wit,* The Spirit of the Salmon Plan of the Nez Perce, Umatilla, Warm Springs, and Yakama tribes, 1996.[3]

A Tribal Energy Vision for the Columbia River

An *Energy Vision for the Columbia River* was originally prepared in response to the energy crisis of 2001. That year Federal agencies curtailed hydro power operations designed to protect migrating salmon in response to drought conditions and manipulation of newly deregulated electricity markets. Resulting salmon mortalities were high. The Bonneville Power Administration also cut fish and wildlife programs to address its financial problems.

CRITFC adopted the original in 2003. It called for a series of actions to avoid another energy crisis and lift some of the burden of the region's energy supply from the Columbia River. A decade later, we look back on actions that were taken and propose new actions.

One of the most important aspects of restoring salmon and ensuring their resiliency to withstand energy and environmental catastrophes like that which occurred in 2001 is the continued investment of the region in fish and wildlife protection, mitigation, and enhancement. In this regard, the Bonneville Power Administration is an unrivaled leader.[4] This plan does not address discrete fish mitigation measures. Rather it is a vision for a long-term regional energy system that places a lesser burden on the Columbia River.

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[2] In our stories, the Celilo Falls are the remains of the dam built by the five Swallow Sisters to block salmon from returning upriver. Coyote tricked the sisters, destroyed the dam, and the resulting flood left the falls and the rocky, contorted riverbed downstream. As punishment for keeping salmon from the people, Coyote ordered swallows to fly up the river each spring to announce the return of salmon. To this day, the migration of swallows marks the spring salmon migration.

[3] This report is a companion to CRITFC's *Wy Kan Ush Mi Wa Kish Wit (Spirit of the Salmon) Plan for Columbia River Anadromous Fish Restoration*.

[4] In 2008, the Commission and three of its member tribes signed a ten-year Fish Accords Agreement with BPA guaranteeing funding for discrete actions. The Accords provide funding for a significant number of projects to rebuild fish and wildlife.

The Columbia River is an integral part of the Northwest and West Coast power system. Power generated from these rivers has been so cheap to electricity users and such a dominant part of the power system that it has been used to provide energy, capacity, ancillary services, system stability, and more. However, the low-dollar cost of hydropower does not fully reflect the huge economic, cultural, and environmental costs that have been incurred by tribes and others.

These tribes based their living on resources of the rivers, including fish, wildlife, and water quality for thousands of years prior to the construction of the hydropower system. The costs to tribes of development of the Northwest's hydropower system represent a classic case of "negative externalities." Because tribal non-market resources have not been "priced", they often have been treated in energy planning as if their cost were zero and their availability limitless. They are not. Treating them in such a way is economic malpractice. More importantly it does not recognize the trust and treaty obligations that the United States carries with regard to the tribes.

By careful energy planning and appropriate action, the region can use the river to supply energy services in a manner that better supplies ecological services such as fish, wildlife, and water quality and reduces costs to ratepayers.

New challenges faced by energy planners that have come to light in the last decade. Our understanding of climate change has advanced significantly. State of the art climate models predict changes in the annual cycle of Columbia River flows and regional temperatures. New fossil-fired generators will exacerbate climate change; the recommendations for energy efficiency and renewable resources in this *Energy Vision for the Columbia River* would reduce the need for power plants that emit greenhouse gases and reduce costs to consumers.

The 2003 *Energy Vision for the Columbia River* described solutions to address the conflict between peak power production and Columbia Basin salmon. Against the backdrop of fish problems associated with serving peak loads, the plan identified less harmful and less expensive ways to provide electricity for peak loads. A win-win combination. Our *2013 Energy Vision for the Columbia River* builds on the recommendations made in 2003. The 2003 *Energy Vision for the Columbia River* provided more information on the Columbia and Snake River hydroelectric system, the Columbia Basin salmon resources, and the role of the Columbia River Treaty Tribes, including their interest in salmon restoration and energy. For a copy of that report go to: http://maps.critfc.org/tech/tev.pdf.

1.2 Goals of the 2013 Energy Vision for the Columbia River

Appropriate planning of regional resources can provide the Northwest with a robust energy system that withstands most unknown future events and keeps costs stable, while protecting fish and wildlife. This *Energy Vision for the Columbia River* has four goals

1. Reduce the stress of new and changing energy demands on the Columbia River's fish and wildlife resources.

2. Lessen the demand for fossil-fuel generation that contributes to climate change.

3. Serve the energy demands of consumers more cheaply than they are served today to better capture the value of the Columbia River for the Northwest.

4. Provide increased protection for ratepayers and fish and wildlife against unanticipated events, such as those the region faced in 2001.

1.3 Summary of 2013 Recommendations

Section 3 of the *Energy Vision for the Columbia River* describes the recommendations to reduce ratepayer costs and improve the survival of fish and wildlife. The recommendations are summarized below. For more information on the economic, energy, and engineering rationale for the recommendations please see Appendix A and C.

- Reduce peak demands on the system (See Section 3.1)
    - Implement time-of-use pricing of power to reflect the full cost of generating and distributing power at different times of the day and year.
    - Implement programs to store power off peak to serve on-peak loads.
        - In water heaters;
        - In existing and added mass in buildings; and
        - In electric vehicles controlled to use off-peak power.
    - Implement fuel switching where appropriate

- Expand programs to improve energy efficiency (See Section 3.2)
    - Secure all cost-effective conservation
    - Ensure that utilities meet the Northwest Power and Conservation Council's energy-efficiency targets.
    - Expand low-income programs.
    - Expand commercial building programs.

- Meet the renewable performance standards established by states. (See Section 3.3)
    - Develop wind energy.
    - Develop solar energy.
    - Develop a comprehensive plan to site renewable resources

- Site strategically located resources (See Section 3.4).

- Take additional actions to address emergencies and dry year strategies (see Section 3.5)

- Improve ecological function for fish and wildlife and reduce flood control costs as part of the review of the Columbia River Treaty. (see Section 3.6)

2. Background

2.1 Balancing Fish and Wildlife and Electricity Production

The day-to-day and seasonal operations of the hydroelectric system to meet peak and seasonal electricity loads cause fluctuations in river levels that continue to kill salmon and other important fish species. While changes in operations have lessened the frequency and severity of these occurrences, their effects are still significant.

Hydropower is used to serve peak loads because dams can react to demand by quickly putting more or less water through the turbines that generate electricity. Serving peak loads with hydropower kills millions of juvenile salmon every year. During certain times of the year, so much water is drawn down to generate electricity that salmon redds (gravel nests where salmon lay eggs) are uncovered or dewatered and their eggs die. Daily fluctuations change river water levels and juvenile fish that feed and live near the shore can be stranded and die when water levels are reduced. Migration of fish is interrupted when flows decrease at night because there is less demand for electricity and therefore less water moving through the reservoirs behind the dams. Fluctuations in reservoirs hurt resident fish by dewatering habitat and food supplies and reducing nutrients in the reservoirs.

Additionally, the water held behind storage dams for power generation would, under natural conditions, be in the river aiding the swift and timely downstream migration of young salmon. Saving this water for winter and summer energy production alters the natural (or normative) river conditions that aid juvenile salmon migration and would help in the restoration of fish to harvestable levels.

The recommendations in this *Energy Vision for the Columbia River* are designed to reduce these problems while also saving money for ratepayers. The Northwest electricity system has relied on the Columbia Basin dams to serve peak loads. The assumption has been that running more water through the generators is a low-cost way to meet the peak. These assumptions have ignored the other costs of serving peak loads. BPA currently charges between 2.8 and 3.7 cents per kilowatt hour for wholesale power in high load hours. Our analysis shows that the costs of transmitting and delivering peak electricity are more than 25 times higher than the generation cost of the peak energy.

As described in more detail in Appendix A, the cost of delivering (transmission and distribution only) the highest 15 percent of peak energy to consumers ranges from 79 cents to $1.19 per kilowatt-hour. The average retail consumer pays about 8 cents per kilowatt-hour for delivered electricity, so these peak delivery costs are more than ten times higher than the total-average electricity costs. The cost of serving the very highest peak load range from 80 to 120 dollars per kilowatt-hour—a thousand times higher than average consumer costs.

All these costs get melded together so consumers do not clearly see the effects. CRITFC estimates that reducing peak energy use could save consumers $800 million per year in planned expansions of the transmission and distribution system. The details of this analysis can be found in Appendix A.

2.2 Background and Purpose of 2003 Energy Vision for the Columbia River

The *2003 Energy Vision for the Columbia River* adopted by CRITFC made a number of recommendations to strengthen BPA's financial health so emergency operations, like those experienced in 2001, would never be needed again.

In 2001, several events combined to create a crisis in the Northwest. In early 2001, BPA committed to serving about 3,300 megawatts of load beyond its power supply. Low water conditions that year, in combination with the manipulation of the California power market caused power costs to serve this additional commitment to soar. A BPA report found that the additional cost was $3.9 billion.[5] This caused large rate increases for Northwest ratepayers.

These increased costs created a risk that BPA would not be able to repay its annual debt to the U.S. Treasury. In 2001, BPA and Corps of Engineers made a number of decisions to increase power production and cut costs, including a decision to eliminate river flows and spills at dams to protect salmon and to reduce funding for fish and wildlife projects designed to mitigate for damages caused by the Federal dams. The 2001 river actions resulted in significant losses of juvenile salmon. In 2001, just 6% of juvenile steelhead survived their in-river migration from Lower Granite Dam on the Snake River to Bonneville Dam; in most years the survival rate is 40% to 70%.

2.3 Progress in Implementing the 2003 Energy Vision for the Columbia River

This section summarizes the progress that has been made over the past ten years in implementing the recommendations in the 2003 *Energy Vision for the Columbia River*. Appendix B provides a detailed report card.

Emergency Response Plan: BPA has made changes in its rate structure that allow it to increase revenue to address emergencies. BPA's changes did not implement all of the CRITFC recommendations, but BPA has assured the tribes that it will not reduce fish and wildlife operations or funding in the future.

[5] *What Led to the Current BPA Financial Crisis? A BPA Report to the Region*, April 2003.

Dry Year Strategy: The Federal Action Agencies are working to implement provisions of the FCRPS Biological Opinion.

Acquire 1000 megawatts of reserves to meet fish and wildlife obligations: The Northwest Power and Conservation Council's Draft Sixth Power Plan Mid-Term Assessment reports that one 200 megawatt rapid response power plant had received a site certificate and three rapid response plants totaling 810 megawatts are in the permitting process. These plants are not designated to meet fish and wildlife operations, but could provide power during shortages.

Reduce peak loads: The *2003 Energy Vision for the Columbia River* called for programs to reduce peak loads by 1,000 megawatts by 2013. The analysis in Appendix B shows that total peak loads have increased since 2003. A number of utilities are participating in pilot projects to address peak loads and the shape of loads and two utilities, PacifiCorp and Idaho Power, exercise control over more than 5 percent of their peak loads, totaling nearly 1,000 megawatts of demand response.

Use pricing to reduce peak loads: BPA's tiered rates will send clear prices signals on the costs of meeting additional load growth as utilities use more power than their low-cost Tier 1 allocation; additional power needs will be at the much higher Tier 2 rates. BPA rates also reflect on and off-peak and seasonal costs. This may provide an incentive for utilities to move to time-of-day pricing, but there has been little progress to date.

Storage of power to use at other times: There are no regional programs to meet this recommendation. Several utility pilot programs under the Smart Grid are testing promising technology that could meet this important objective.

Secure all cost-effective energy efficiency: Since 1978 the region has acquired 5,000 average megawatts through energy efficiency programs at a cost that is less than half the cost of new gas-fired resources. These energy efficiency programs saved the regions consumers $3.1 billion in 2011. These programs also reduced 2011 carbon emissions by 19.8 million metric tons. Regional utilities met or exceeded the Council's conservation targets between 2005 and 2011. This is significant progress; however, projections for saving in 2012 through 2014 decline by 15 percent from the levels in 2011. The conservation targets can be expanded to include all cost-effective improvements and more needs to be done.

Develop renewable resources: The region has approximately 7,300 megawatts of wind power capacity. At a normal capacity factor of 30%, this translates into an energy producing capability of about 2,200 average megawatts—about 14 percent of the average energy generation in the Northwest. Photovoltaic power (PV) installations do not yet make up a significant contribution to the region power system. However, due in part to community based programs in Oregon; the Energy Trust has installed about 20 megawatts of PVs in Oregon alone since the *2003 Energy Vision for the Columbia River* was published.

3. Recommendations for the *2013 Energy Vision for the Columbia River*

This section describes the recommendations for the *2013 Energy Vision for the Columbia River*. They reduce costs for consumers, improve the survival of fish and wildlife, and reduce carbon emissions. The region should take an active role in promoting and monitoring the implementation of these recommendations. The region's energy future is promising and CRITFC sees potential benefit for the region's energy system and the ecosystem in additional actions to reduce the burden of the region's energy system on the Columbia River and its tributaries.

3.1 Reduce peak demand

Controlling energy demand during times of peak energy usage needs to be a priority for the region. There are quantifiable benefits to doing so (see Appendix A for details). For the electrical system, lower demand on peaks translates into fewer capital resources that are needed to serve loads. The grid can serve the same total energy needs with fewer generating plants and a smaller investment in transmission and distribution lines over time if peaks are lowered. Line losses and ancillary services can be reduced with lower demand, as well.

Adopting technologies that allow for peak load control may have significant advantages for fish passage. Once in place to control peak loads, it is a small step to use them to shape loads on a continual basis. Shaping loads could then translate into shaping the river. A strong recommendation in this report is to use pilot projects to shape peak loads and to test whether we can shape the river to allow for more effective spill when fish require it.

As we acquire the general ability to control loads, we can envision a time when loads can be shaped at all times to allow appropriate levels of spill for fish migration through the river system. We should be able to get to this point at costs that are considerably less to the power system than in the past.

3.1.1. Using pricing to reduce peaks.

While there has been some progress, more needs to be done to provide consumers with an accurate price signal for the cost of electricity at different times of the day and different months of the year. CRITFC calls on utilities and utility commissions to implement time of day and time of year pricing for all consumers based on the total costs of serving electricity needs.

3.1.2. Storage of Power to Use at Other Times

Storage of low-cost power to serve loads at other times is one important way to reduce peak loads. CRITFC recommends an expansion of the Smart Grid pilot projects, and urges BPA and utilities to give priority to storage of power in enlarged hot water heaters and in thermal mass placed in residential and commercial buildings. Other storage opportunities should be explored, including ice storage on a diurnal basis.

Hot Water Heaters as Energy Storage Mechanisms.

Time of day water heating technology is commercially available. Water pre-heated during light load hours, e.g. in the middle of the night, can last through the morning peak use period and more. This technology can be used in today's hot water heaters, and can be made more effective in replacement tanks, by increasing the size of the water tanks, and equipping them with a mixing valve to address potential scalding. If hypothetically, all 3 million tanks in the Pacific Northwest were converted to known energy shaping technologies, this action alone would create an equivalent energy peaking capability of about 4,500 megawatts through the four-hour morning peak energy demand period.

The ultimate efficacy of this storage strategy rests on its costs, and the number of units converted, but the potential is large. Our assumptions in this analysis are described in Appendix C.

Space Heating and Cooling Stored in Buildings.

Similar to storing heat in water for later use, heating and cooling effects can be stored in building mass, including mass that may have been added for this specific purpose. The technique of using thermal mass (e.g. properly located rocks, concrete, or other material) to store heat and cold is ancient, but has gone out of style. Adding mass to residential buildings is being tested in regional pilots. Storage of heating and cooling in buildings to meet these needs through peak periods has theoretical possibilities for around the clock applications that are similar to hot water storage.

Commercial buildings generally have a high mass, so they can be pre-heated and pre-cooled by using off peak energy prior to the buildings being occupied in the morning. The potential for saving on transmission and distribution, generation, line losses, and ancillary services is very large.

Web-based thermostat controls can enable existing buildings to store energy for heating and cooling. These controls allow a utility dispatcher to pre-heat and pre-cool buildings thereby shifting the power consumption to an off-peak period. This is an example of using the thermal mass already in the building as a storage medium. Once the platform that enables these web-based controls is in place, all energy devices using these controls could be operated for energy management purposes.

Electric Cars

Electric cars and plug-in hybrid cars could be a win-win-win for consumers, the environment, and salmon if auto manufacturers build in timers that control when the cars charge. If timers are not incorporated, electric cars can make things much worse for consumers, the power system, and salmon.

Electric cars can significantly reduce greenhouse gases and other air pollution and reduce dependence on foreign oil. If owners charge their car batteries during off-peak periods (for example, between 10 pm and 5 am), these cars will not contribute to peak loads and will provide a base load that would be served by hydropower when energy supplies are often in excess of demand. Rather than "turning the river off" during light load hours, increased night-time flows can help migrating salmon.

The Energy Vision for the Columbia River recommends that all electric and plug-in hybrid cars come equipped with a timer that allows the owner to charge the car during off-peak hours. If electric car manufacturers do not cooperate, utilities should develop incentive programs or standards of service requirements for timers on electric car recharging systems. Utility rate structures that reflect the true cost of electricity at different times of the day will provide further incentives for the owners to use the timers.

3.1.3 Fuel switching away from electricity uses that serve peak loads.

The Northwest Power and Conservation Council completed a study of fuel switching in January 2012 entitled *Direct Use of Natural Gas: Economic Fuel Choices from the Regional Power System and Consumer Perspective*, see Council document 2012-1.

The Council study found that about 23% of households would reduce total regional cost by converting either a space heating appliance or a water heating appliance to gas. The Council found that most of these opportunities occur for water heating, which accounts for 80 percent of the potential benefits.

The Council study concluded that the overall effects of conversions on electricity use, natural gas use, and carbon emissions would be small. Across all households, regional electric loads would decrease by about 340 average megawatts, while net natural gas use increases by about 1 percent.

The Council also concluded that the benefits for consumers would be roughly equivalent between choosing electricity or gas where the conversions made economic sense for the electricity system.

The Council concluded that "policy intervention is not currently necessary to ensure that selection of space and water heating systems found to be least cost/risk from the regional perspective are chosen by consumers. There is general alignment between the systems that are economically preferred from a regional perspective and those that are most economical from the 'average' regional consumer's perspective."

The Council study undervalued the economic and environmental benefits of reducing electricity peak loads to serve water heaters. The Council, BPA, and utilities should evaluate the full cost savings from reducing peak loads. If fuel switching can cost effectively reduce peak loads, BPA and utilities should work with natural gas suppliers to develop incentives for consumers to convert to natural gas.

3.2 Energy efficiency resources

Energy efficiency programs reduce both peak demands and year-round energy needs. Energy efficiency has been proven as a reliable resource in the Northwest with costs that are less than half the cost of new gas-fired power plants. These programs save consumers money and reduce the emissions of pollutants that cause climate change.

Energy efficiency continues to be the resource of choice for the region in the Northwest Power and Conservation Council's 6th Power Plan, adopted in February, 2010. The Council estimates that over 6,000 average megawatts of conservation can be acquired cost-effectively over the 20-year planning horizon of the plan. Conservation represents about 85% of the region's power needs in the 20-year plan.

The region has made good progress in achieving the Council's conservation targets in recent years; however, the Council has reported that the projections for saving in 2012 through 2014 will decline by 15 percent from the levels in 2011. The Council's conservation targets do not include all cost-effective improvements and more needs to be done.

The Northwest has been a leader in conservation acquisition since 1980. Most of the conservation we have done is what can be referred to as "technical" conservation. That is, we have improved building codes, and we now use more efficient lights and appliances to run our homes and factories. There is much more to be done in improving the technical efficiency of all energy using devices.

The region has not focused on what can be referred to as "behavioral" efficiency. Behavioral efficiency can be as simple as turning out lights when they are not being used. We believe that the amount of energy that can be saved by changing behavior may be greater than what we have saved by improving the efficiency of energy using better products.

The Smart Grid addresses behavioral controls by allowing the adoption of technology within buildings that can control loads to be only what is needed, or alternatively what individuals are willing to forego in exchange for compensation from the utility. For example, at the right level of compensation some people might be willing to adjust their thermostats up or down a degree or two, saving power and capacity on the electricity grid. Many commercial buildings are operating as though they are occupied continuously. This situation is exacerbated by triple net leasing, wherein nobody takes responsibility for how much energy is used. The potential for energy savings is large. [6]

3.2.1. Secure all cost-effective energy efficiency

The Northwest Power and Conservation Council's studies show that the cost to utilities of efficiency programs is $18 per megawatt hour. This is less than half of the cost of new generating resources. These resources would minimize the region's costs of meeting additional electric energy demands and meeting needs associated with salmon restoration measures. According to the Council, the region has saved 5,000 megawatts since 1978 through energy efficiency programs, codes, and standards. These energy efficiency programs saved the regions consumers $3.1 billion in 2011.

We believe that the region can and should surpass the conservation targets in the Northwest Conservation and Electric Power Plan. There is a great deal of business incentive and public interest in energy efficiency that did not exist in prior decades. Customers are asking for green certifications and business are routinely marketing products with zero carbon foot prints.

The 2011 conservation savings were 277 megawatts, 57 megawatts ahead of the 2011 target and about equal to the 2014 target. The Obama administration has made appliance efficiency a very high priority and is moving aggressively forward with rulemaking proceedings. Whirlpool has indicated that it is prepared to cease production of "dumb" appliances by 2014. Oregon and Washington are poised to upgrade energy efficiency codes. Conservation budgets are increasing at private utilities. Significant portions of ARRA (federal stimulus) funding was geared to energy efficiency. BPA has adopted tiered rates where new loads must be served at market costs, not a melded rate. And, BPA has issued an RFP to develop industrial conservation potential.

Other analysis indicates that the Council has significantly underestimated the amount of conservation in the past. We reviewed two papers that addressed this issue. The first, a paper entitled: *Beyond Supply Curves*, by Fred Gordon and Lakin Garth of the Energy Trust of Oregon and Tom Eckman and Charles Grist of the Northwest Power and Conservation Council indicates that new technologies, which are often impossible to forecast, can significantly increase the amount and reduce the cost of energy efficiency measures. For example, the high efficiency windows that were in the 2005 Council Plan are 12 percent more efficient than the assumptions used in the Council's 1983 plan. Costs have also become more competitive as an efficient technology comes into common use. The paper shows the costs of compact fluorescent lamps has dropped from the $12 per bulb assumed in the 1991 plan to $3 assumed in the 2005 plan.

The second paper, by David Goldstein of the Natural Resources Defense Council, describes the methodologies that are "excessively conservative if the goal of

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[6] Tom Foley is a board member of PowerMand, a company that provides tools to remotely control HVAC use in buildings. We have seen savings in building as high as 50% of the total energy use, by simply operating HVAC systems to take account of unoccupied times.

policymakers is to meet aggressive climate change emission reduction goals." The paper documents the systematic biases that result in low potentials in energy efficiency. These include: 1) subjecting efficiency measures to a criterion of proof beyond a serious doubt; 2) assuming arbitrary realization factors less than 100 percent due to questions about social acceptance of energy efficiency; 3) implicit assumptions that a lack of research on the cost or feasibility of a measures means that is it excluded for a study; 4) a failure to consider system integration; 5) assumptions that once known efficiency measures are implemented, technological progress ceases and no further improvements are possible; and 6) reliance on projected costs of efficiency without looking at realized costs, which whenever data has been available has always been lower.

All of these considerations signal that the conservation estimates in the current Northwest Conservation and Electric Power Plan are likely to be too conservative. Unfortunately, there are significant costs associated with overly conservative conservation estimates. We offer the following example focusing on only one of the conservative assumptions made by the Council.

The Council has de-rated the available conservation by 15 percent. The Sixth Power Plan "assumes that no more than 85 percent of the technically feasible and cost-effective savings can be achieved[7]. De-rating the amount of energy efficiency that is achievable by 15 percent represents approximately 1,000 average megawatts of low cost power that are not included in the conservation targets. A simple calculation of the value (marginal resource costs minus cost of conservation[8] multiplied by 1000 average megawatts) shows that the value of this additional conservation is approximately **<u>$500 million per year</u>**. If we assume these savings are phased in over the life of a 20 year power plan; the additional savings could total **<u>$5 billion by 2030</u>**. Given this significant value, the Council should include these savings and region's utilities should secure this cost-effective conservation.

We are also concerned by the approach the Council has taken in the Draft Sixth Power Plan Mid-Term Assessment on the implementation of the conservation targets. Figure 1 below is taken from a presentation made to the Council in the preparation of the mid-term assessment. The good news is that the region's energy efficiency programs exceeded the targets in 2010 and 2011. The bad news is the savings were projected to decline in 2012 through 2014.

The Council concluded that the total of over performance and under performance was likely to meet the medium range of the conservation targets and therefore the region was on track. A better position would have been to acknowledge that the targets were too low and call on the region to continue to build on its progress.

There are economic consequences to the Council's conservative position. If the region achieved the savings shown in the blue bars for 2012 through 2014, it would save

[7] Sixth Power Plan at page 4-15.
[8] Sixth Power plan at page 10-4.

approximately 200 megawatts more that the medium range target. This would reduce the need for more expensive power plants and save consumers about $18 million per year.

Figure 1. Achievement of Conservation Saving in the Sixth Power Plan

After 30 years of experience, there are ample results in the Pacific Northwest to demonstrate that improving energy efficiency can reliably save energy at less than half the cost of supplying additional energy from new power plants that burn coal or natural gas. We also know that the Council's targets have been conservative. New technology has repeatedly made conservation more cost effective than estimated by the Council. Finally, the Northwest Power Act calls for energy conservation to be developed as a resource ahead of traditional resources.[9]

For all these reasons, the Council should increase its conservation targets and work with BPA and utilities to try to exceed them.

3.3.2. Ensure that utilities achieve the targets

We recommend that the Council, at a minimum, incorporate its conservation targets into Model Conservation Standards (MCS) pursuant to Section 4(f)(1) of the Northwest Power Act.

Many utilities in the Northwest are national leaders in implementing energy efficiency programs. We applaud their efforts. Some utilities have not embraced this proven, low-cost resource. These utilities are costing everyone in the region money because more

[9] 16 U.S.C. § 839; 126 Cong.Rec. H9848 (Rep. Pritchard) ("[The Act] treats energy conservation as a resource, making it the top priority in meeting the region's energy needs. *NRIC and Yakama Nation v. Northwest Power Planning Council,* 35 F.3d 1371, 1378 (9th Cir. 1994).

expensive resources are being purchased to make up for the lost conservation in utility areas that do not meet the targets.

If some utilities do not make good progress on achieving the MCS, the Council should recommend a surcharge of 10 percent on the power these utilities purchase from BPA. Section 4(f) (2) of the Northwest Power Act authorizes the Council to recommend a surcharge of 10 to 50 percent for utilities that do not achieve the model conservation standards in Section 4(f) (1). The 1983 and 1986 Power Plans recommended imposition of a surcharge for utilities that did not meet the MCS. The 1986 surcharge was set at 10 percent. This was well below the cost imposed on other utilities and Northwest ratepayers for failing to achieve the savings, but even at the minimum level it energized utilities to pass state building codes and implement other conservation programs.

We also recommend that utilities have a safe harbor from a surcharge. For example, a utility could avoid the surcharge if it had: 1) well designed programs in place in all sectors; 2) offered funding to cover all the cost to the consumer of the energy-efficiency improvements; 3) had an effective public education program so all customers were aware of the programs; and 4) had committed sufficient funds to implement all requests for these services. CRITFC is seeking other criteria for safe harbor provisions that would effectively protect utilities that are making best efforts to achieve the targets.

3.2.3. Expand Low-income weatherization programs

Tribal communities include many low income people. For example, the percentage of families living below the poverty level on the Yakama Reservation is 42 percent—four times higher than the average for non-tribal families in the State of Washington. The winter unemployment rate is over 70 percent on the Reservation. The per capita income on the reservation is $5,700 per year. This is less than half the average for non-tribal communities.

As a result, much of the housing on reservations is substandard. Yet many weatherization programs will not pay for the basic repairs needed for the energy savings to be effective. For example, BPA has rejected all of the houses that Yakama Power, the Yakama Nation tribal utility, proposed for weatherization because these houses did not meet BPA's qualifications. Many of these substandard houses are occupied by elders and the neediest members of the tribe.

This situation would appear to be at odds with the spirit, if not the letter, of the Environmental Justice policies of the United States and the U.S. Department of Energy. Executive Order 12898 (February 11, 1994). We encourage the BPA, the region's utilities and the Council to support an environmentally just approach to implementing energy and efficiency development in the Pacific Northwest for accessing low-income weatherization.

3.2.4. Commercial Buildings

Energy efficient commercial buildings are also a source of great potential savings. Energy efficient lighting and appliances, of course, are a source of savings. But the biggest gains are related to heating, ventilation, and air-conditioning (HVAC).

Because HVAC systems are complicated, they need continuing attention to remain efficient and tuned to the tasks for which they are designed. All new buildings should go through a building certification process to assure that they are operating as they were designed and to assure that the operation is efficient.

Most commercial buildings rely on programmable thermostats that are not being maintained. Many buildings are operated as though occupied continuously. Better scheduling can result in 30-40% savings in many of these buildings. With Smart Grid technologies and strategies that enable one to essentially dispatch loads behind customers' meters, these savings can now be more easily captured. We recommend a concerted regional effort to do so.

3.3 Renewable resources

3.3.1. Wind Generation

Utilities and BPA should continue to aggressively pursue wind, and the associated efforts to integrate wind power.

The Northwest has been a leader in the adoption of wind power. Wind power is a relatively low-cost source of power today, and it offers insurance against escalating prices in the future, because the "cost of fuel" is free. However, the intermittent production of wind power, and the difficulty in predicting when the wind will blow presents a problem with integrating wind into the system. Integration of wind is exacerbated under high-water, high-wind, and low-load scenarios. BPA has led a regional effort to better integrate wind into the system. We believe that wind integration will be improved by use of various storage mechanisms discussed previously in this report.

3.3.2. Solar Generation

The region should expand its efforts to promote solar energy. This could include support for cooperatives that can purchase photovoltaic panels at lower cost bulk rates and provide technical assistance to homeowners. Oregon has had made good progress using these techniques.

Solar power production is mostly confined to summer months. In a winter-peaking system like that in the Northwest, it might seem counter intuitive to pursue solar production. However, because the wholesale market for power extends throughout the west coast, the market price of power is higher in the summer than it is in the winter, even in the Northwest. Solar power production in the Northwest during summer frees up power to be sold in the west coast market at relatively high costs.

Solar power comes with the same integration problems that affect wind, and it comes with the same benefits of cost certainty throughout the life of the system. The capital costs of solar power have decreased over time, and they are likely to continue to decrease in the future. Further, much of the solar production in this region will be from photovoltaic systems sited behind customers' meters. In this case, line losses and ancillary services to get the power to the load are miniscule. Also, the intermittency problem of solar power is diminished somewhat, because small photovoltaic systems will be spread over wide areas of the region. Passing clouds will affect only a small portion of the total number of installations at any moment. Thus, predictability of solar will be enhanced. For these reasons, it makes sense to pursue solar power in the Northwest.

3.3.3. Develop a Comprehensive Plan for Siting Renewable Resources

CRITFC recommends that the region prepare a thoughtful plan for where renewable resources should be developed, and where they should not, and to provide expeditious siting with clear and uniform standards across all political subdivisions.

Such a plan could take a programmatic approach considering reasonably foreseeable impacts associated with such development. The plan could assess renewable resource sites and prioritize their potential for development. Potential esthetic, wildlife, and cultural resource impacts, all of which may bear upon site selection, and related issues, such as the need for new transmission, could be examined. Two recent examples demonstrate what a plan could address.

In October 2012, the Department of the Interior completed such a plan for development of solar energy on public lands in six western states. The Programmatic Environmental Impact Statement (PEIS) for solar energy development provides a blueprint for utility-scale solar energy permitting in Arizona, California, Colorado, Nevada, New Mexico and Utah by establishing solar energy zones with access to existing or planned transmission, incentives for development within those zones, and a process through which to consider additional zones and solar projects.

The Solar PEIS establishes an initial set of 17 Solar Energy Zones (SEZs), totaling about 285,000 acres of public lands, that will serve as priority areas for commercial-scale solar development, with the potential for additional zones through ongoing and future regional planning processes. If fully built out, projects in the designated areas could produce as much as 23,700 megawatts of solar energy, enough to power approximately 7 million American homes. The program also keeps the door open, on a case-by-case basis, for the possibility of carefully sited solar projects outside SEZs on about 19 million acres in "variance" areas. The program also includes a framework for regional mitigation plans, and to protect key natural and cultural resources the program excludes approximately 79 million acres that would be inappropriate for solar development based on currently available information.

In January of 2013, the Department of the Interior completed a plan for renewable resource development in Arizona. The Restoration Design Energy Project (RDEP) is an initiative to identify lands that may be suitable for the development of renewable energy. The RDEP Record of Decision and Approved Resource Management Plan Amendments establish 192,100 acres of renewable energy development areas on BLM land throughout Arizona. These areas are near transmission lines or designated corridors, close to population centers or industrial areas, and in areas where impacts on water usage would be moderate. These lands also have few known resource impacts or have been previously disturbed, such as retired agriculture properties. These areas are available for solar or wind energy development. In addition, the Plan establishes the Agua Caliente Solar Energy Zone on 2,550 acres in western Arizona.

There are several examples in the Northwest that point to the advantages of a comprehensive plan to guide the development of new renewable resources. The need for such comprehensive planning was highlighted in a separate concurring opinion in the Whistling Ridge wind development proceeding before the Washington Energy Facility Site Evaluation Council in 2011. *Whistling Ridge Energy Project, Washington EFSEC Order No. 868 (October 6, 2011)***.**

In the context of hydroelectric facilities, the Ninth Circuit Court of Appeals observed, in considering the proposed development of numerous small hydroelectric facilities, that:

> Congress' commitment to coordinated study and comprehensive planning along an entire river system before hydroelectric projects are authorized is a central feature of the Federal Power Act. This concern is reflected in the legislative histories of the Federal Power Act and its precursors. The General Dam Act of 1910 "provided that there should be a comprehensive plan for the development of a river and waterway system; that each particular dam project should be given consideration not only with a view to the locality where constructed but with reference to the entire water system of which it constituted a part...."

National Wildlife Federation v. Federal Energy Regulatory Commission, 801 F.2d 150, 1507 (9th Cir. 1986). This particular conflict and similar conflicts over siting small hydro development led to a regional policy establishing "protected areas" where project development is discouraged.[10]

The region would greatly benefit from a comprehensive planning process that would guide renewable resource development for wind, geothremal and solar technologies to favorable locations and outcomes for regional fish and energy needs.

3.3.4. Other Renewable Resources

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[10] Northwest Power and Conservation Council, Fish and Wildlife Program. For more information and for the formal Protected Areas provisions, see the Basinwide Habitat Strategies on Protected Areas (Section II(D)(1)(e)) and Appendix B to the Council's 2009 Columbia River Basin Fish and Wildlife Program.

We focused on wind and solar above, but other renewable resources either at specific sites or with technological breakthroughs may also be cost effective. Geothermal energy and biomass have been used successfully where the right conditions exist. And wave power, although in its infancy, may be cost effective in the not too distant future. Where these resources show promise, the promise should be explored, and implementation should be pursued when and where analyses show them to be ready for commercial production.

3.4 Strategically Sited Resources.

CRITFC recommends that BPA and the regions utilities develop a plan to strategically site generating resources. Strategically sited resources include those resources at loads, those that are sited within the grid to relieve congestion, and siting that protects fish, wildlife and other environmental values.

Moving some generation closer to loads will eliminate much of the planned costs for expanding the transmission and distribution system. Interconnection standards[11] will have to be developed by utilities that allow for the safe operation of these local generators. Distributed generation will have to be deployed in sufficient numbers to eliminate the need for backup generation and transmission and distribution capacity.

In addition, generation closer to loads allows for the use of otherwise wasted heat, a byproduct of combustion. We have not included these additional dollar savings in our calculations, as it not clear what percentage of them will derive from reduced electricity use. But the dollars are real savings to the end-users of power and are not insignificant.

Resources in the category of distributed generation include fuel cells, varying sizes of small gas-fired units, net-metered small renewable resources, and small wind farms. Owners of net-metered small renewable resources, including solar photovoltaic applications, can sell power back to the local utility at retail prices. Small wind farms of two to ten machines can be placed strategically within the grid and not necessarily where the wind is the greatest, but where the combination of strategic placement and the wind resource yields the highest benefit to the electricity system. This benefit would show up as income to the wind developers and savings in transmission and distribution construction.

In some cases it may be cheaper to transport fuels for distributed generation close to loads than it is to transport the equivalent amount of electricity. For example, transportation gains of gas over electricity come from fewer losses in conversion, fewer losses in transmission, and in lower capital costs.

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[11] FERC has a NOPR to make interconnection standards simple and uniform throughout the country. See Standardization of Small Generator Interconnection Agreements and Procedures Advance Notice of Proposed Rulemaking, Docket No. RM02-12-000, issued August 16, 2002

3.5 Additional Actions to Address Emergencies and Dry Year Strategies

3.5.1. BPA rate case

We continue to recommend that BPA increase its probability of repaying the Treasury on time and in full, thus reducing the chances that BPA would get into a position where it might have to choose between meeting fish obligations and deferring a payment to the Treasury. The tribes recommend that BPA's Treasury payment standard should be forward looking so BPA can adjust rates when it experiences added costs or lower revenues rather than waiting until its Treasury payment probability is reduced. The tribes also recommend that BPA expand the circumstances that could trigger the emergency provisions, and increase the amount it could collect in these circumstances.

3.5.2. Dry Year Strategies:

Fully implement the measures called for in the FCRPS Biological Opinion. As a part of that implementation, the following strategies should be analyzed, and implemented if they are feasible:

- Secure an additional 1 million acre-feet of Canadian water.
- Reshape the current 1 million acre-feet of Canadian water
- Add a high-priority 200 kcfs May McNary flow requirement in dry years
- Add more water to the second half of April.
- Maintain the Alternative-1 flow reductions in dry years even if the forecast improved (because Alternative 1 raised flow targets in later months if the forecast improved)
- Expand the modeling changes beyond the driest 20th percentile years.

As part of the dry year strategy, additional Non-Treaty Storage actions should be analyzed and implemented if they are feasible:

- Draft 500,000 acre-feet in the 15% driest years (68.5 million acre-feet), or release 250,000 acre-feet in the first 15% year, and if next year is also dry (15%) draft another 250,000 acre-feet in that year
- Refill full amount in the 40% or better years (87.5 million acre-feet) or refill 250,000 acre-feet in 35% or better years (86.1 million acre-feet)
- Always refill reservoirs during the following year or at least refill within 2 years
- A combination of the above.

3.6 Columbia River Treaty

Background: The Columbia River Treaty was ratified by the United States and Canada in 1964. The purposes were to maximize hydroelectric power production and provide flood control. Ecosystem function, including protection of fish and wildlife and other tribal trust resources are not currently a purpose of the Columbia River Treaty. The

Treaty has no end date. The first chance to terminate or amend the Columbia River Treaty occurs in 2014. This provides an opportunity to make needed revisions to the Treaty.

If there are no amendments to the Columbia River Treaty, a significant change in river operation will significantly damage fish and wildlife beginning in 2024. After 2024, the Canadians will no longer have an obligation to provide flood control and the United States must use all the storage facilities in the United States before calling on any flood control from Canada. The U.S. will also have to pay Canada for the flood control. If there are no changes to the Columbia River Treaty, the revised flood control operations begin automatically in 2024.

Based on the analysis prepared by the U.S. Entity (BPA and the Corps of Engineers) this change in flood control would have significant effects on resident fish and cultural resources in the Grand Coulee, Hungry Horse, Libby, and Dworshak reservoirs; refilling the deep draw downs in theses reservoirs will reduce the spring freshet for salmon migration. The tribes are concerned about the adverse impacts to resident fish and tribal resources in these reservoirs and reductions in migration flows for salmon and steelhead.

It is also possible that the flood control operations could change operations of the upper Yakima River storage dams (including Keechelus, Little Kachess, and Cle Elum lakes), and other storage reservoirs that could be drawn down significantly in late winter-early spring to prepare for the spring runoff.

The 15 Columbia Basin Tribes[12] have developed a common views document and are working together to avoid these damaging changes in flood control operations. The Columbia Basin tribes are also working with the U.S. Entity and Northwest states to explore ways to modify the treaty to improve conditions for salmon, steelhead and resident fish and reduce flood control costs. Before the treaty's 50-year control of the river gives way to a new era, a progressive regional recommendation must be put forth that reflects the evolution of societal values that has occurred since 1964. A modernized treaty should provide equally for ecosystem requirements, hydropower operations and flood-risk management. Equal consideration of improved spring migration of salmon, seasonal flushing of the estuary, resident fish requirements and salmon passage at all historic locations are all needs of the Columbia River basin to include in a new treaty. The elements of this energy vision are intended to complement a modernized Columbia River Treaty.

[12] The Burns Paiute Tribes, the Coeur d'Alene Tribe, the Confederated Salish and Kootenai Tribes of the Flathead Reservation, the Confederated Tribes of the Colville Reservation, the Confederated Tribes of the Umatilla Indian Reservation, the Confederated Tribes and Bands of the Yakama Nation, the Confederated Tribes of the Warm Springs Reservation of Oregon, the Cowlitz Indian Tribe, the Kalispel Tribe of Indians, the Kootenai Tribe of Idaho, the Nez Perce Tribe, the Fort McDermitt Paiute Shoshone Tribes, the Shoshone Bannock Tribes of the Fort Hall Reservation, the Shoshone Paiute Tribes of the Duck Valley Reservation, and the Spokane Tribe, with support from the Columbia River Inter-Tribal Fish Commission, Upper Columbia United Tribes and the Upper Snake River Tribes tribal organizations, have been working together to consider the effects and alternatives related to the Columbia River Treaty.

CONCLUSION

In this report, we have defined a set of strategies and resources that will serve loads more cheaply than they are served today, provide better protection against unforeseen events, and be much healthier for the region's fish and wildlife resources. Our vision can be implemented without raising rates in the Northwest. In fact, over the long-term we believe that our vision contains a more robust set of resources and will lead to lower prices for power. We also know that it will not be achieved without convincing key regional players such as BPA and the NWPCC that it is superior to the current system. We will ask them to use their vastly superior resources and unsurpassed technical resources to analyze the efficacy of our vision to meet tribal and regional needs.

Appendix A. Analysis of Meeting Peak Demands

A.1 Introduction

Background Discussion

Historically, regulated utilities have priced power at the average cost of delivering that power to consumers; they have not varied the cost much by time of day or season of the year. But, power has more value when the demand for it is high and less when the demand for it is low. It also costs more to deliver power when demand is high because of additional, often higher-cost generators being called upon, higher line losses, and congestion in the transmission grid. Consumer electric rates that are the same throughout the day and throughout the year lead to economic distortions of resources were overlooked for a long time because the price of power was very low. This is no longer the case.

The value of the river system is distorted by this type of pricing strategy when hydropower operations on the river are designed to follow loads as they ramp up and down. These fluctuations in river flows kill millions of young salmon every year. Higher prices when loads are high would dampen the peaks and the need for using the river system to follow them. In the *2003 Tribal Energy Vision*, we called for a transition to time-of-day pricing of electricity.

From an economic allocation of resources perspective the ideal pricing strategy would be to price power at its full cost at all times, with costs fluctuating throughout the day. Full costs would cover the cost of generating the power and the costs of the transmission, distribution, and support systems to deliver it. This pricing strategy would, over time, reduce costs and reduce the damage of river operations on fish and wildlife.

Current Use of the Hydropower System Hurts Salmon and Consumers

The day-to-day and seasonal operations of the hydroelectric system to meet peak electricity loads cause fluctuations in river levels that continue to kill salmon and other important fish species. The recommendations in this *Energy Vision for the Columbia River* are designed to reduce this problem while reducing costs for ratepayers. As described in more detail in below, the cost of delivering (transmission and distribution only) the highest 15 percent of peak energy to consumers ranges from 79 cents to $1.19 per kilowatt-hour—the average consumer pays about 8 cents per kilowatt-hour for delivered electricity, so these peak delivery costs are more than ten times higher than the total-average electricity costs. The cost of serving the highest peak loads range from 80 to 120 dollars per kilowatt-hour—a thousand times higher than average consumer costs. These high costs are melded into every consumer's electric bill. Reducing peak loads would also save an estimated $800 million per year in planned expansions of the transmission and distribution system.

Hydropower is used to serve peak loads because dams can react to demand by quickly putting more or less water through the turbines that generate electricity. Serving peak loads with hydropower kills millions of juvenile salmon every year. During certain times of the year, so much water is drawn down to generate electricity that salmon redds (gravel nests where salmon lay eggs) are uncovered or dewatered and their eggs die. Daily fluctuations change river water levels and juvenile fish that feed and live near the shore can be stranded and die when water levels are reduced. Migration of fish is interrupted when flows decrease at night because there is less demand for electricity and therefore less water moving through the reservoirs behind the dams. Fluctuations in reservoirs hurt resident fish by dewatering habitat and food supplies and reducing nutrients in the reservoirs.

Additionally, the water held behind storage dams for future power generation — for example, for summer peak loads to provide air conditioning — would, under natural conditions, be in the river aiding the swift and timely downstream migration of young salmon. Saving this water for summer energy production alters the natural (or normative) river conditions that aid juvenile salmon migration and would help in the restoration of fish to harvestable levels.

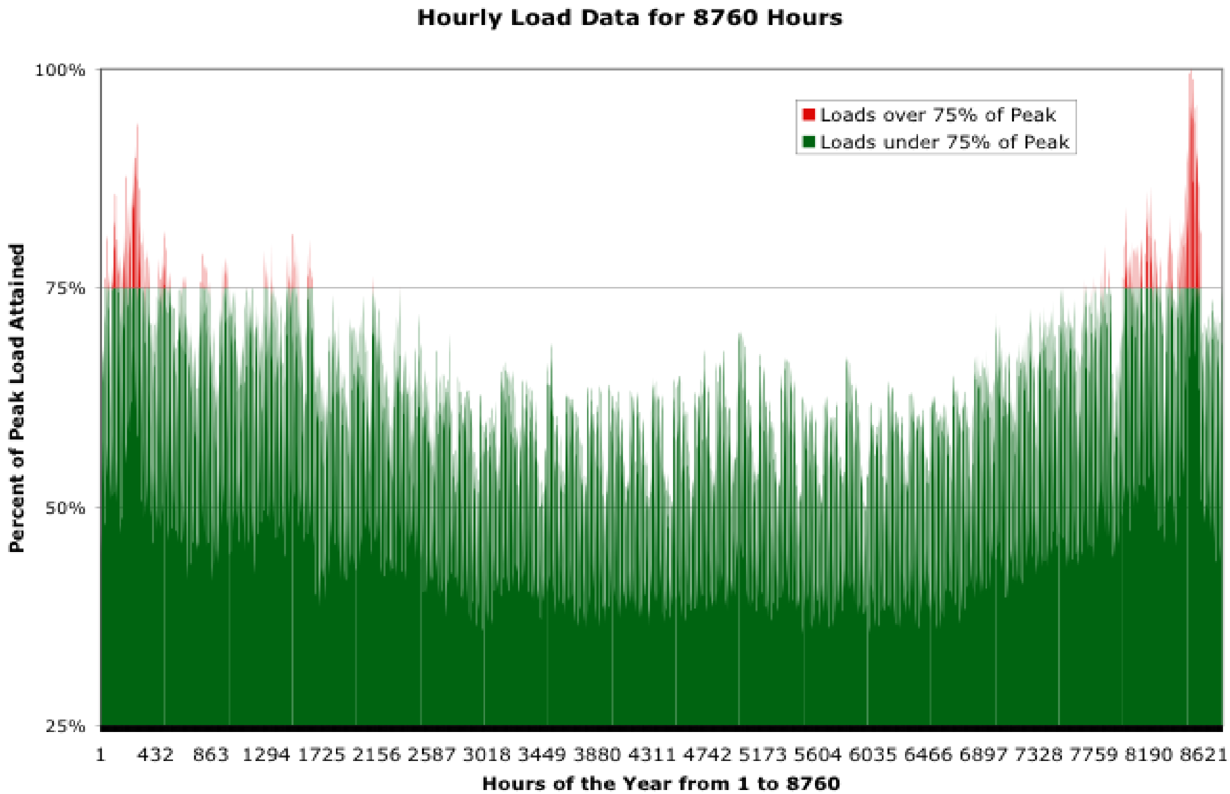
While changes in operations have lessened the frequency and severity of these occurrences, their effects are still significant.

A.2 The Costs of Serving Hourly and Seasonal Peak Loads

The hydroelectric system is used to serve peak loads because output from dams can be increased and decreased instantaneously by increasing or decreasing the amount of water going through the turbines.

In the Columbia River hydropower system, as is customary in most power systems, transmission and distribution lines were built to serve the highest peak load (the maximum amount of electric energy required during certain periods of time). Peak usage occurs infrequently and for short periods of time. Yet more than 25% of all capital in place, including generation capacity, transmission, and distribution is there to serve loads that occur about 6% of the time. Figures A1 and A2 below show the infrequent occurrence of the highest peak loads.

Figure A1. Hourly loads as a percentage of peak



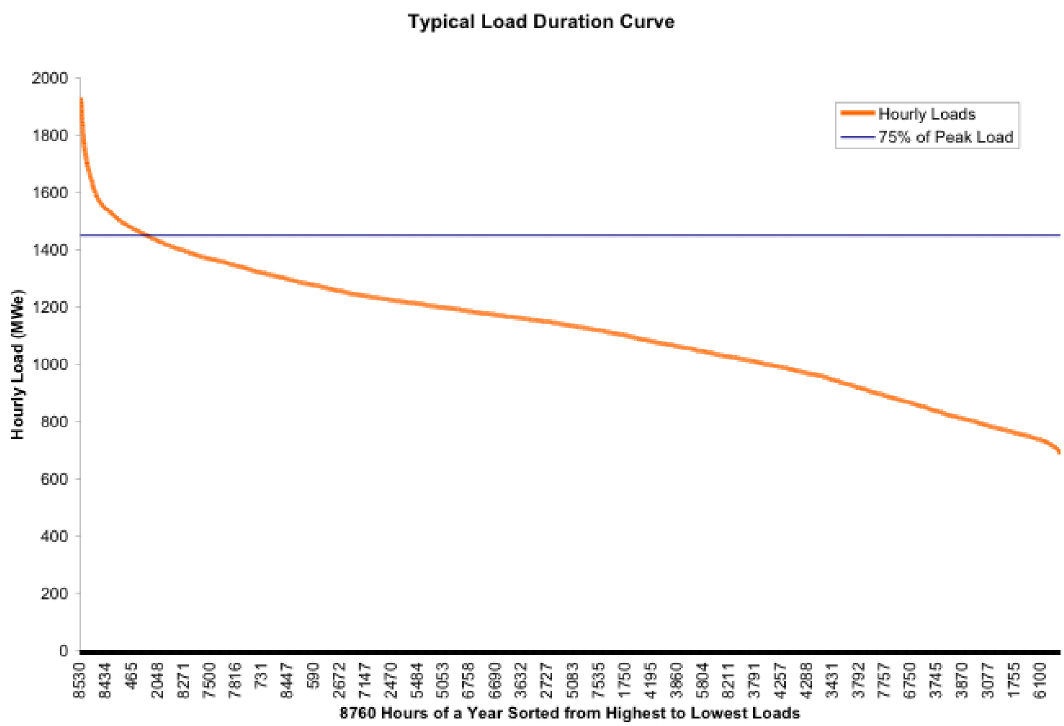
Proponents of using the hydropower system to follow peak loads argue that it is the lowest-cost option and that the fish killed in the process are an acceptable tradeoff. However, it is a myth that using the hydropower system in this way is a low-cost way to meet peak loads. The myth has been perpetuated by average-cost pricing of transmission and distribution systems. That is, all loads pay the same price for transmission and distribution, regardless of whether the transmission and distribution system is partially or fully loaded at time of use. Serving peak loads from any central station, distant plant (including hydropower) is expensive; it is far more expensive than other similarly reliable ways to meet peak loads.

Consider Figure A2, which contains a load duration curve for a typical northwest utility. The load duration curve is a simple structure that plots peak loads for each of the 8,760 hours in a year.[13] The loads, shown along the vertical axis, are sorted from highest to lowest-load hour; shown along the horizontal axis, the hour with the highest load is at the left of the horizontal axis and the hour with the lowest load is at the right of the horizontal axis. An arbitrary line has been drawn horizontally at 75% of the highest peak hourly load. To serve power needs in a conventional power system, a utility has to build or contract for transmission to serve its highest load, and it also must have an adequate distribution system to meet that peak load. A typical rate for transmission in this region ranges from $24 to $30 per kilowatt per year. That is, if a utility needs to transmit a kilowatt from a generator to load, it pays $24 to $30 per year, regardless of how many

[13] For purposes of understanding, a sample load duration curve is derived in the Appendix.

hours the kilowatt is transmitted. If transmitted for only one hour, the cost is $24 to $30 per kilowatt-hour!

Figure A2. Hourly load duration curve



Distribution costs are estimated to be three times transmission costs. Thus, the total cost of transmission and distribution can range from $80-$120 per kilowatt per year. Given this information, consider the line in Figure 1 at 75% of peak load. Loads at this level and above occur about 600 hours per year. If the cost of transmission and distribution to simply deliver energy to that portion of load at 75% of peak is $80-$120; the per-kilowatt cost is 13 to 20 cents![14] The peak hour of the year (1 hour at 100% of peak—the extreme left edge of the graph) has a delivery cost of $80-$120 per kWh**!**[15]
Table A1 shows the delivery costs per kWh for other loads that occur in the range of one to 600 hours per year. For example, loads at 85% of peak or higher, occur only 101 hours in a year, at a delivery cost of $.79 to $1.18 per kilowatt-hour.[16]

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[14] $80-$120 kW/year divided by 600 hours per year equals 13-20 cents.
[15] Some will argue that T&D costs are sunk (the capital cost has been made and cannot be recovered) and the variable cost of more throughput (e.g., more power sold) is zero. There are two reasons why this is not the case. First, in the short term for non-transmission owning utilities, transmission costs are not sunk; they simply "rent" space on the lines. Second, in the long term, all T&D owners have planned expenditures at some time in the future. The planned expenditures have not been occurred, and delaying them, perhaps indefinitely, is worth a lot of money.
[16] Note that these costs do not include the cost of energy, which has been over $1,000 per megawatt hour on peak as recently ago as 2001. Costs have come down dramatically since then to a range of $30-$50 per megawatt hour

Table A1. Costs of Transmission and Distribution to Serve Infrequent Loads

Number of Hours	Percentage of Peak Yearly Load	Range of Transmission and Distribution Costs	
		$80/kWh	$120/kWh
1	100	$80.00	$120.00
21	95	$ 3.81	$ 5.71
43	90	$ 1.86	$ 2.79
101	85	$ 0.79	$ 1.19
209	80	$ 0.38	$ 0.57
600	75	$ 0.13	$ 0.20

The book value of transmission in the region is roughly $10 billion.[17] Thus, over $2.5 billion (25% of $10 billion) worth of transmission is being employed less than 6% of the time. Using the 3 to 1 ratio of distribution investments to transmission investments we used above, this means that over $7.5 billion worth of distribution is being used less than 6% of the time. Or, in sum, over $10 billion worth of capital invested in transmission and distribution sits idle for over 8100 hours per year.

Serving peak loads (e.g., those above 75% of peak load) with any resource is extremely costly to the power system and serving peak with hydroelectric power is devastating to salmonids and the aquatic environment on which salmon and other species depend. Even without considering the huge costs imposed on fish and wildlife from raising and lowering river levels to serve peak loads, alternative means of serving these loads are cheaper than buying power and transmitting it from distant generators.

There are a number of benefits associated with controlling demand at peak. For the electrical system, lower demand on peaks translates into fewer capital resources that are needed to serve loads. The grid can serve the same total energy needs with fewer generating plants and a smaller investment in transmission and distribution lines over time if peaks are lowered. Line losses and ancillary services can be reduced with lower demand, as well.

Importantly, lower peak demands also help fish in the river. The river is ramped up and down to follow peak loads, and in so doing, smolts (juvenile fish) have been stranded on

[17] The book value of BPA's transmission is about $5.5 billion (BPA Annual Reports), up from about $4.5 billion in 2001. Avista, Idaho Power Company, Montana Power Company, PacifiCorp, and Puget Energy Services combined had about $3.8 billion of book value in their transmission systems in 2001 (See FERC Form 1 data for 2000.) In 2003, we estimated that other utilities in the region not under FERC's jurisdiction make up another $.15 billion to get us to our estimate of $8.5 billion. Adding the additional $1 billion of BPA investment to the estimate used in the 2003 *Energy Vision* would total $9.5 billion. Other utilities have made investments also. Because the analysis here is only used to show the order of magnitude of transmission costs on partially filled lines, we have rounded up to $10 billion, to reflect other investments that have been made.

banks along the river, and redds (where salmon lay their eggs) have been dried out. Reducing peak loads will limit the number of hours in a year when the rivers have to be ramped up to meet peak demand, thereby, saving fish.

Looking forward, as we acquire the general ability to control loads, we can envision a time when loads can be shaped at all times to allow appropriate levels of spill and flow for fish migration through the river system. And, we should be able to get to this point at costs that are considerably less to the power system than in the past.

A.2.1 Capital Cost Savings Identified

Suppose future peak loads could be lowered, for example to 75% of current peak load[18]. These loads would not have to be eliminated overnight because the transmission system, albeit stressed, has and can continue to serve regional loads at today's levels. Peak loads could be reduced on the transmission system gradually by using the resource options described below. The peak load reduction could be designed to avoid planned transmission investment upgrades that are being driven by the need to serve growing peak loads. This schedule would allow the region to ensure that these actions are carefully planned and implemented correctly.[19]

With peaks at 75% of today's peaks, the capital earmarked for transmission and distribution upgrades to serve peak load growth could be available to invest in alternative technologies to serve peak loads. The savings would be committed to load management, conservation, clean distributed generators to serve those loads, and clean gas-fired or renewable central station resources sited strategically within the transmission and distribution system. These energy plants and strategies would be used to serve peak loads and to serve off-peak loads whenever market prices exceeded the variable costs of operating the specific plants and implementing the load management strategies.

The magnitude of planned transmission and distribution investments that could be eliminated or delayed is significant. As previously mentioned, a rough estimate of the book value of transmission used to serve regional load is about $10 billion. Because the book value has been depreciated and it was funded by low-cost government debt for the most part, the replacement cost of the transmission system would be much higher. In the 2003 *Energy Vision for the Columbia River* we assumed it would be $17 billion dollars. An inflation rate of 2% over the last 10 years would bring replacement value to about $20 billion.

Since the region's transmission system is now constrained during many hours, new investment will be needed to serve loads if load shapes do not change. The region would need to invest about 1% of the total value of the system per year to keep up with load

[18] In keeping with the theme of this report, this is not a prediction of what might happen soon, but rather a vision of what could be done with a regional focus.
[19] This is the goal of BPA as it revamps its transmission planning function, using the Round Table as an advisory group. The Round Table did not meet for several years, but reconvened in April, 2011.

growth.[20] Thus, about $200 million per year will have to be invested in transmission to serve peak load growth.[21]

Book value and replacement value of distribution systems in the region has been estimated at roughly three times that of transmission. Many of the actions we include in our plan will also save distribution investments. Distribution investments are also often very costly from a social perspective because they entail digging up city streets. Large capital costs are incurred along with social costs and economic losses associated with time lost in traffic jams and other even greater displacements.[22] The savings from deferring investments would be great and would allow for even more generation to be built, if necessary. If the region were to do away with transmission investments to meet load growth, it could also do away with the corresponding investment in distribution systems. Thus, an additional $600 million savings per year (three times that of transmission) could be realized through forgone investment in distribution.

A.2.2 Energy Costs

Historically, energy costs have fluctuated widely. In 2001, not long before we published the initial draft of the *Energy Vision*, prices in the Northwest spiked to as high as $1,000 per megawatt hour ($10 per kilowatt hour). In the spring of 2001, futures for summer power were selling for 50 cents/kWh. Utilities and BPA were buying power at 20-50 cents per kilowatt hour and selling power to end users at less than 2.5 cents per kilowatt hour. That reality left BPA with an acute financial problem, which had implications for the protection of fish and wildlife.

The risk of fluctuating prices still exists from a range of catalysts, such as disruptions in power production or the transmission system. The 2013 *Energy Vision for the Columbia River* has been designed with the recognition that we cannot predict future price excursions, and that prices could spike again; however, the recommendations in this report should help constrain future price volatility.

A.2.3 Transmission and Distribution Costs

Transmission and distribution costs have several components[23]. One is the capital cost of the installations, and a second is the cost imposed by congestion on the grid. At many times of the day, season, and year, constraints exist on parts of the transmission and distribution system. Historically, BPA and other utilities have dispatched resources to move power around these constraints. The costs of doing this have been melded into

[20] Based on an assumption of a 2% growth in peak loads. BPA had scheduled over $2 billion between 2002 and 2006. Only about $1 billion of that amount appears to have been spent.
[21] Of course, there will also be capital investment to maintain existing wires. This will be true for the distribution system also. That investment is separate from the investments to serve new load growth and generation interconnections addressed here.
[22] Reduced access to commercial ventures is an example.
[23] Here we ignore line losses associated with T&D.

average costs that in turn have been included in an average total power cost. The value of the resources used to get around transmission constraints is not transparent.

The end user has not paid the true cost of using either the transmission or distribution systems. As we noted previously, the cost of transmission and distribution to serve peak loads is enormous, but these costs are spread over all ratepayers and all hours of the year. If the true costs of transmission capital and congestion were charged to end users, much of the crisis experienced in 2001 would have been averted because peak loads would have been lowered[24]. From an economic perspective, too much transmission is built to serve peak loads that are greater than they would have been if users paid the true price of the delivered peak power.

Today there are still calls for more transmission construction.[25] If one assumes that the trend toward deregulated markets continues, investors who build additional transmission will be at risk. Higher prices for energy and delivery at peak would drive users to look for other innovative ways to serve their peak loads, including shifting those loads to off-peak times when the prices of energy and delivery are lower. The advent of Smart Grid technologies and strategies that will enable devices behind customers' meters to compete with generation and transmission will exacerbate this movement. If this occurs, which we think it will, much of that new investment could easily be stranded.

A.2.4 Climate Change Costs

One of the goals of the *Energy Vision for the Columbia River* is to reduce the need for fossil-fuel generation that adds greenhouse gases to the atmosphere. Studies have shown that climate change in the Northwest will result in less snow pack; this will cause further changes in the amount and timing of river flows that move away from the natural conditions that previously supported abundant, health salmon populations; these climate changes will further reduce salmon survival.

Natural gas plants are often used to meet peak loads so the strategies to reduce those loads will reduce the need for the plants and the amount of time that existing plants operate. Natural gas-fired generators cost more to build and operate than the energy efficiency and other strategies identified in this *Energy Vision for the Columbia River*. Implementing those strategies will reduce the need for new fossil-fired resources. This will also reduce ratepayer costs and greenhouse emissions.

A.2.5 Other Environmental Externalities

Starting in the early 1980s, utility planners and their regulators have struggled with how to account for the unregulated environmental damage resulting from development of generating plants and other utility related activities. For most of the history of electric power, the costs of environmental harm were assumed to be zero.

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[24] Prices shot up because during peak loads generation was not always available to meet loads. This had the effect not only of increasing prices, but also led to rolling brown outs in parts of the West.
[25] BPA's book value of transmission stands at $5.5B today versus $4.5 in 2001.

One approach has been to include an imputed cost into the planned costs of generators in Integrated Resource Plans (IRPs). But, the imputed costs are rough estimates, because we do not know the actual costs. There are other, perhaps more effective, mechanisms that have been employed.

With respect to climate change and the effect on it of generating plants, Oregon has taken a different approach. Plants built in Oregon are limited to a set level of CO_2 emissions. Above that, generation owners either have to mitigate for the excess emissions or pay a sum per unit of excess emissions into a non-profit Climate Trust. The Climate Trust will then embark on programs to limit CO_2 emissions in the cheapest way available. So far the Climate Trust has dedicated over $10 million to projects[26] that prevent or mitigate the emission of CO_2 and other greenhouse gases.

The Bonneville Environmental Foundation (BEF) has been working with BPA for over a decade on a "Green Tags" program that lets government agencies, corporations, and energy producers purchase the green power attributes of qualifying wind, geothermal, solar, or biomass resources. The Bonneville Environmental Foundation is marketing Green Tags to large retail purchasers, government agencies, corporations, and others. The proceeds go toward creating additional revenue to expand renewable resource development.

The most well known trading mechanism to control pollution is the United States' sulfur dioxide (SO_2) emission reduction program, operated through Title IV of the Clean Air Act. Administered by the EPA, the primary goal of the program is to reduce annual SO_2 emissions by 10 million tons below 1980 levels over the life of the program. The Act also calls for a 2 million ton reduction in oxides of nitrogen (NO_X) emissions by 2000. The SO_2 and NO_X programs together constitute the EPA's Acid Rain Program. The Acid Rain Program has been extremely effective. Since 1990, total SO_2 emissions have decreased for 17.3 million tons to 5.7 Million tons in 2009. NO_x emissions have gone from 6.7 million tons to 2.0 million tons over that same time period[27].

In brief, this emissions trading mechanism involves distributing permits to SO_2 emitters that allow them to emit a certain amount of SO_2. Permits may be bought, sold or banked. Emitters wishing to emit more than the level of their permits must purchase permits from

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[26] The Climate Trust's current $10.6 million portfolio consists of 20 projects (all in the U.S. except one in Ecuador) that are expected to mitigate more than 2.6 million tons of GHG reductions. This portfolio contains diverse projects from many economic sectors including a balanced mix of forest restoration and preservation, cogeneration, transportation, material substitution, renewable energy and fuel replacement projects. Projects include the Cool Climate Concrete program that reduces emissions associated with concrete production, the Fuels for Schools program that reduces emissions by switching from fossil fuels to pelletized fuel, and Low-Carbon Farms that reduce methane emissions and produce a reliable source of renewable energy on dairy farms.

[27] EPA: Acid Rain and Related Programs: 2009 Highlights: 15 Years of Results | 1995 to 2009

other permit holders or else reduce their current emissions. At the end of each year, each emitter must hold an amount of permits at least equal to its annual SO_2 emissions.

In the first years of this century, leaders from the City of Chicago and from the automotive, chemical, commercial real estate, environmental services, electric power generation, electronics, forest products, municipal, pharmaceutical, and semiconductor industries have joined to form a North American voluntary private sector program to reduce and trade greenhouse gases. The Founding Members of the Chicago Climate Change (CCX®) set up a voluntary cap-and-trade program for reducing and trading greenhouse gas emissions. In an unprecedented voluntary action, these entities made legally binding commitments to reduce their emissions of greenhouse gases by four percent below the average of their 1998 to 2001 baseline by 2006, the last year of the pilot program. There are 6 exchanges affiliated with CCX operating around the world. A recent review of the CCX website shows that trading is occurring on a regular basis, although we weren't able to determine how effective the program has been in reducing CO_2 emissions. Meanwhile, the US government continues to debate the question of moving forward with an effective energy strategy, including a mechanism to reduce climate change gasses in the atmosphere.

A.3 Lower Cost Alternatives to Serve Peak Loads

The Northwest can serve peak loads and/or lessen peak loads more efficiently. There are several resource options that will be far less expensive than using the hydropower system in tandem with transmission sized to meet peak loads. Some, alternatives such as load management (discussed below) have little or no cost. Each of these resource options will take pressure off of the transmission and distribution system as well as the river system.[28]

A.3.1 Load Management

Load management, as the term is used here, refers to behavioral changes in energy usage, such as turning off lights, lowering thermostats, and shifting some electricity using functions to off-peak hours. The changes can be achieved through manual means or through the use of automated equipment using computers and controls. For example, weather and market prices can be used as inputs into automated computer- driven equipment that allow for automatic adjustments and more efficient use of energy.

Load management can be broken down further into programmatic activity driven by utilities or public purpose entities and those driven by market mechanisms. Load management in response to market forces would require the region's utilities and regulators to adopt electricity rates that recognize the full cost of delivered power throughout the year.

[28] It is well known that the transmission system is experiencing constraints. Considerable investment is needed in a business-as-usual scenario.

Programmatic Load Management: Utilities entered the 2001 energy crisis with little or no programmatic experience in affecting the behavioral side of energy use. Because of the immediate need to reduce purchases, especially during peak hours, utilities bought back power from some of its larger customers. BPA and other utilities asked its customers not to use power because of high market prices and bought the power back at a multiple of what it was sold for. Direct Service Industries (primarily aluminum companies), possessing contracts enabling them to resell power, closed down production and made large profits by selling power purchased from BPA at about $23 per megawatt hour at market prices of up to $1,000 per megawatt hour. Because it essentially pays people not to produce, buyback can only be a near-term solution.[29]

However necessary this buyback program might have been during the 2000-2001 crises, it achieved only what could have been achieved more smoothly with better-designed programs and prices made available to end-using customers. This is still true today.

With better foresight and more time to plan, utilities might have worked with customers to install load management equipment that could be operated by the utility remotely or by customers on request from the utility to shed load. Contract terms could have included lower rates for more utility control of loads or might have contained a fixed percentage of credit for each kWh not consumed. The size of the credits would be based on market prices and flexibility.

With long-term economic incentive to control peak loads, more innovative approaches to programmatic load management would almost certainly be developed by consumers of power or entrepreneurs developing new technologies.[30]

Price-Driven Load Management:

The cost of supplying power changes diurnally and seasonally, sometimes dramatically. This fact was reflected in BPA's 2001 wholesale power rates, which charge for high-load hours (HLHs) and low-load hours (LLHs) by month of the year. However, BPA's prices, which are designed only to recapture its costs, do not approach the value of power on the market. We are not proposing that BPA or any utility in the region change its rates in the near term to reflect market prices. We do believe that BPA's rates should reflect the true cost[31] of serving loads. BPA's shift to tiered rates in October 2011 begins to send price signals about the cost of building resources to serve new loads, but these new rates do not address the costs of peak loads.

[29] This can be a recipe for high inflation—incomes are maintained, but no product is being produced.
[30] See the brief discussion of venture capital money in the Preface.
[31] Here we mean to include all costs of delivering power into the rates to make the components of rates more transparent. For example, ratepayers know little about congestion, line losses, ancillary services needed to bring power from generators to customers' meters. They should, if we are ever to effect changes in how they use power.

With better-designed rates, new technology would have been put in place over time, and the stress on the river and the transmission and distribution systems would have decreased.

A.3.2 Conservation

Conservation will save energy and lower peak loads. Existing and enhanced conservation efforts are an important part of this *Energy Vision for the Columbia River*. Many of these measures, embodied in standards will be paid for by consumers and not the electric industry. Conservation measures will reduce pressure on the river and the transmission and distribution systems and are cheaper than the delivered cost of power using conventional means. Some of the many opportunities to save are summarized below.

Insulation: Insulation in walls and ceilings save more energy when temperatures are severe (hot or cold), when loads are peaking in the Northwest and/or prices are peaking on the West Coast. Typical home weatherization programs save 30 percent of the energy use and cost less than half as much as new generating power plants. The net result would be more comfort, lower power costs, and lower transmission and distribution costs.

Energy Efficient Lighting: Energy efficient lighting saves electricity at costs that are less than five percent of the cost of new power plants. This technology saves more energy on hot summer days when prices on the West Coast are peaking, because the reduced waste heat from efficient lights reduces the stress on air conditioning systems. In the winter, efficient lights save more energy because of the greater number of hours of darkness. Thus, efficient lights make sense year round.

Assuming that a compact fluorescent lights (CFLs) can sell for as little as $1.50 per bulb[32] and save 50 watts of power over each of the 10,000 hours of its expected life. That calculates out to about 0.3 cents per kilowatt-hour saved. Electricity rates are about 8 cents per kilowatt hour. The savings are about 7.7 cents per kWh. Thus, over the 10,000 hours of the CFL's life, the savings to the ratepayer are about $770. Using the same assumptions, 20 lights operating throughout the peak period would save 1 kilowatt of capacity and would cost $30, with no fuel costs. The capital costs of gas-fired generators to serve peak loads range from $600 to $1,110 per kilowatt; the cost of fuel and operations and maintenance expenses further increases the cost of electricity from these plants.

Light emitting diodes (LEDs) are now being produced commercially. Although expensive at this time, costs will come down, and it is likely they will start replacing CFLs, because they will ultimately be a less costly source of light with much longer lifetimes. LEDs are projected to last up to 50,000 hours. Longer lives mean lower labor costs to replace worn out light bulbs. Residential LED lights are included in Energy Trust of Oregon's programs today. Each light cost about $50, and the Trust's incentive is

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[32] The region's utilities have subsidized bulb purchase well below this price in the past. As the rebates have diminished costs have stabilized.

$20. As LEDs mature they will be lower cost than the CFLs, which were shown in the previous paragraph to be highly cost-effective when compared to current electricity rates.

Energy Efficient Appliances: More energy-efficient appliances save energy while also reducing air conditioning loads. Like efficient lights, they add less heat to the living spaces. Replacing 15-year-old refrigerators with Energy Star refrigerators typically will save about 630 kilowatts per year and 0.072 kilowatts of on-peak capacity.[33] Replacing one million of these older refrigerators would save 72 megawatts of electricity, on peak[34]. There are several million refrigerators in the Northwest that are 15-years old or older. Conservation measures embodied in new appliances, retrofits of buildings, lights, motors, etc. are typically half or a third of the cost of power generated at central station plants and shipped over wires. Peak loads are much more costly to serve, up to $100/kWh (See Section 2.2, Table 3.)

Battelle Northwest[35] has been working with appliance manufacturers to develop chips for smart appliances that will adjust to grid frequency fluctuations, and ultimately, to voltage instabilities instantaneously as the chip detects needs in the transmission and distribution system.

Industrial Conservation: Industrial conservation measures are harder to specify, because of the uniqueness of each industrial process. Nonetheless, some of the biggest potential gains come from industrial customers. When industrial customers are planning system changes in their plants, it is especially important to have programs at the ready that can be customized to meet the needs of customers and save energy for the customers and the region. While one of the authors of this report was serving as Chairman of The Energy Trust of Oregon, much of the industrial conservation was being purchased for as little as one cent per kilowatt hour, or about seven cents less than the average electricity rate in the region.

Commercial Buildings: Energy efficient commercial buildings are also a source of great potential savings. Energy efficient lighting and appliances, of course, are a source of savings. But the biggest gains are related to heating, ventilation, and air-conditioning (HVAC).

Because HVAC systems are complicated, they need continuing attention to remain efficient and tuned to the tasks for which they are designed. New buildings should all go through a building certification process to assure that they are operating as they were designed and to assure that the operation is efficient.

Most commercial buildings rely on programmable thermostats that are not being maintained. Many buildings are operated as though occupied continuously. Better scheduling can result in 30-40% savings in many of these buildings. With Smart Grid

[33] Energy Star is a certification program conducted by EPA to help consumers make choices about efficient appliances.
[34] This analysis has not been updated from the 2003 report; the benefits would be similar.
[35] Personal communication with Battelle and BPA staff interested in this technological advance.

technologies and strategies that enable one to essentially dispatch loads behind customers' meters, these savings can now be more easily captured.

We have mentioned a few opportunities for saving energy. Other agencies, such as the Northwest Power and Conservation Council, the Northwest Energy Efficiency Alliance, and state energy offices have ongoing programs and details on opportunities to save energy.

The Council's estimate of available conservation below 7 cents per kilowatt hour (2006$) is about 5,000 average megawatts. About 2,500 average megawatts of that total is below 2.5 cents per kilowatt hour. Both ends of this range are below the price of delivered power today, which is about 8 cents per kilowatt hour. The price of delivered power will likely continue to rise.

A.3.3 Strategic Plant Siting

Often plants are sited distant from load because of a local fuel source, such as mine-mouth coal plants, gas pipelines, and better wind resources or because plants were easier to site in rural communities. These plants are dependent on transmission to move power to population or load centers. Some plants were sited remotely from loads because of size or for environmental reasons such as pollution, noise, etc. But, today's gas-fired generators are smaller, more efficient and cleaner than plants of the past. Small gas turbines are quiet and clean, and can be sited near industrial areas that use a lot of energy.

Solar photovoltaic panels, serving a dual purpose of siding or roofing for buildings and power generation, may be ideal for reducing peak loads because power is generated during daylight hours, which coincides with normal peak demand in the summer. Cities, and areas in the region like southern Idaho that rely on air conditioning and irrigation often see peaks in the summer, although the region as a whole is still winter peaking.

Under the category of strategically-sited plants, we will first discuss distributed generation, which typically constitutes small plants sited within the distribution system, usually on the customers' side of the meter. We will then discuss other generation sited strategically within the network of transmission lines. This category of plant is located so as to lower the cost of transmitting power by both limiting the amount of transmission congestion and shortening the transmission distances to load.

A.3.4 Distributed Generation

Distributed generation consists of relatively small power plants, including wind and gas-fired plants, located close to where the electricity is used. Distributed generation sited within industrial complexes and residential and commercial buildings will take pressure off of the transmission and distribution system, the hydropower system, and fish and wildlife. Interconnection standards have been devised by utilities that allow for the safe operation of these local generators[36]. Distributed generation will have to be deployed in sufficient numbers to eliminate the need for backup generation and transmission and distribution capacity.

Generation sited closer to loads will allow for the use of waste heat from the generation process to be utilized for process heat, space heating, or hot water heating. In most generating resources, many of which are sited remote from load, this heat is wasted. There are many technologies that can be deployed in this way.[37] Using the waste heat will increase efficiencies of conversion from a best of 50% for central-station generators to as high as 85% if all of the waste heat can be used.[38] There is no reason why distributed generation should not be a big player in the power system within a few years.

Currently, there are no technological barriers to distributed generation that cannot be overcome. All that is needed now is the resolve to make it happen. With the appropriate numbers and locations of distributed generation, the region can achieve major transmission capacity savings, increase the conversion efficiencies from fuels to usable energy, and save fish by running the river at more normal flow regimes. Distributed generation will not be cost effective everywhere. Cost effectiveness will depend on the specific conditions encountered at the site.

For the longer term (perhaps 10 years), there are other options on the horizon. Fuel cells have been used as backup resources in situations where high reliability is needed. And fuel cells are being manufactured to power camping equipment and cell phones. If these smaller resources prove their worth, it may be a small step from here to imagine having each appliance with its own generator, and having the wiring in buildings as the only distribution system.

A.3.5 Conventional Generation Strategically Placed within the Grid

The region has delayed investments over the last decade to keep electricity rates low. Because of this, the transmission system, as previously mentioned, is under stress and congested along many of its pathways. Lower cost generators sometimes are kept from serving some loads by these transmission constraints. Loads downstream of certain constraints must often be served by higher cost resources delivered through other, non-constrained pathways to the load. With strategic siting of new, efficient plants, including wind generators, the cost of congestion can be lowered. As with distributed generation above, it may be cheaper to strategically site new plants than to build transmission upgrades to solve congestion.

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[36] In 2002, FERC issued a NOPR to make interconnection standards simple and uniform throughout the country. See Standardization of Small Generator Interconnection Agreements and Procedures Advance Notice of Proposed Rulemaking, Docket No. RM02-12-000, issued August 16, 2002.

[37] *Combined Heat & Power: A Federal Manager's Resource Guide Final Report Prepared for: U.S. Department of Energy Federal Energy Management Program*, Washington, DC. Prepared by: Aspen Systems Corporation Applied Management Sciences Group 2277 Research Boulevard Rockville, MD 20850 March 2000

[38] See above note.

A.3.6 Electric Vehicles

The advent of electric vehicles offers both a challenge and an opportunity to the electric utility system. Electric vehicles, if they are charged during the day, and especially on peak hours of the day, could significantly increase the problems that this *Energy Vision for the Columbia River* paper tries to address. On the other hand, if electric vehicles are charged off-peak, they could help alleviate problems associated with high-water and/or high-wind events, and in general help in the integration of renewable resources with the grid.

They may also play a role in providing ancillary services to the grid, by allowing some of the stored power to be used strategically when the grid needs support. In this way electric vehicles could help to make the grid more stable and more reliable.

Appendix B. Report Card on Implementation of the 2003 Energy Vision for the Columbia River

Progress Since 2003

Over the last ten years, the Bonneville Power Administration (BPA) has taken a number of steps to allow it to adjust electricity rates to meet fish and wildlife needs in future emergencies; while progress has been made, this update identifies additional actions to avoid problems in the future.

This section reviews the progress that has been made in implementing the original 2003 recommendations. It shows some progress has been made, but many of the actions that would have saved money for consumers and improve the survival of fish and wildlife have not been implemented.

B.1 Emergency Response Plan

The *2003 Energy Vision for the Columbia River* recommended actions to address potential shortages and higher costs: 1) rate adjustment mechanisms to deal with changing circumstances; 2) emergency plans and dry-year strategies; and 3) adding additional generation to deal with emergencies. BPA has made progress on two of the three recommendations

BPA Rate Adjustment Mechanisms: During the 2001 crisis, BPA's revenues fell to the point where the agency was concerned that it would not be able to meet its annual payment to the U.S. Treasury to repay the costs of the Federal dams and transmission system. As a result, BPA reduced river flows and spills for salmon and reduced funding for its fish and wildlife restoration program.

CRITFC and the Yakama Nation were parties in the BPA rate case and raised concerns in formal testimony and briefs that BPA was not adequately budgeting for implementation of its fish and wildlife responsibilities and needed mechanisms to adjust its rates to deal with financial emergencies. As a result, BPA has adopted two rate adjustment mechanisms that allow it to trigger a rate increase if the probability of repaying the Treasury falls below 95 percent during the two-year rate period. BPA also adopted an emergency provision that would allow it to immediately increase rates if actions to implement the Federal Columbia River Power System (FCRPS) biological opinions or related litigation increased its costs and reduce its probability of making its Treasury payment to less than 80 percent a year.

While these changes were a positive step in providing BPA tools to address financial problems, the tribes also recommended that BPA increase it probability of repaying the Treasury to reduce the chances that BPA would get into a position where it might defer a payment to the Treasury. The tribes also recommended that the standard should be forward looking so BPA could adjust rates when it experiences added costs or lower revenues rather than waiting until its Treasury Payment Probability was reduced. The tribes also called for BPA to expand the circumstances that could trigger the emergency provisions, and increase the amount it could collect in these circumstances; BPA declined to make these changes, but has assured the tribes that it will not reduce fish and wildlife operations or funding in the future.

BPA Emergency Plans and Dry Year Strategy: Flow management during dry years is often important to maintaining and improving habitat conditions for ESA-listed species. It is also important for the region's energy supply. RPA 14 of the 2008 FCRPS Biological Opinion describes dry water year operations. A dry water year is defined as the lowest 20th percentile years based on the Northwest River Forecast Center's (NWRFC) averages for their statistical period of record (currently 1971 to 2000) using the May final water supply forecast for the April to August period as measured at The Dalles. Under the Biological Opinion, the Action Agencies will complete the following activities to further the continuing efforts to address the dry flow years:

- Within the defined "buckets" of available water (reservoir draft limits identified in RPA Action 4), flexibility will be exercised in a dry water year to distribute available water across the expected migration season to optimize biological benefits and anadromous fish survival. The Action Agencies will coordinate use of this flexibility in the Regional Forum TMT.

- In dry water years, operating plans developed under the Treaty may result in Treaty reservoirs being operated below their normal refill levels in the late spring and summer, therefore, increasing flows during that period relative to a standard refill operation.

- Annual agreements between the U.S. and Canadian entities to provide flow augmentation storage in Canada for U.S. fisheries needs will include provisions that allow flexibility for the release of any stored water to provide U.S. fisheries benefits in dry water years, to the extent possible.

- BPA will explore opportunities in future long-term Non-Treaty Storage agreements to develop mutually beneficial in-season agreements with BC Hydro to shape water releases using Non-Treaty Storage space within the year and between years to improve flows in the lowest 20th percentile water years to the benefit of ESA-listed species.

- The Action Agencies have convened a technical workgroup to scope and initiate investigations of alternative dry water year flow strategies to enhance flows in dry years for the benefit of ESA-listed ESUs. The Hydro Technical Team for Dry Year Strategy Study has met several times

- When seasonal average flows at McNary are expected to be less than 125 kcfs (which is likely to occur in about 1 out of 70 years), the Regional Forum Technical

Management Team may consider, to the extent that regional power emergency operations allow flexibility at McNary Dam, the use of transport and the elimination of voluntary spill or other available means to limit impacts to juvenile survival and adult returns.

In 2011, BPA and BC Hydro negotiated terms for a new Non-Treaty Storage Agreement. The Agreement includes storage releases in dry water years to increase flows for improving the survival of juvenile salmon. While the size of this dry water account is not the amount desired, due to BC hydro's concern, it is a start demonstrating recognition of the dry year concerns of the tribes and others. The Agreement would also allow for additional water releases in dry years by mutual agreement by both BPA and BC Hydro. Strategies to deal with dry years will also benefit from the generating reserves and other measures recommended in the *2003* and *2013 Energy Vision for the Columbia River*.

Acquire 1000 megawatts of Reserves to Ensure that the Region can meet its Fish and Wildlife Obligations: The 2003 *Energy Vision for the Columbia River* argued that in order to fulfill fish obligations the region should have adequate electricity resources to fulfill energy requirements at all times. The argument then and now is simple: if there are not enough resources to meet obligations at all times, then the obligation cannot and will not be met and the region will reduce protections for salmon to meet electricity needs.

Since 2001, the region has installed more than 5,400 megawatts of wind power capacity. At a normal capacity factor of 30%, this translates into an energy producing capability of about 1,620 average megawatts. However, wind cannot always meet peak needs. When an emergency arises, the wind may not be blowing. Although CRITFC sees the need to add more wind energy production, other emergency resources will still need to be in place to fulfill obligations to the fish in the river.

Some individual utilities have developed backup reserves at customers' sites. For example, PGE has about 200 megawatts of generators at the ready to be used in limited emergencies. These generators are owned by customers, but are serviced and dispatched by PGE. We are seeking comments on how many resources have been added by individual customers and will include this information in the final version of the *Energy Vision for the Columbia River*. We will emphasize continuing attention to assuring that resources are sufficient to meet fish obligations.

B.2 Reduce peak demand

In the 2003 *Tribal Energy Vision for the Columbia River*, we called for a set of actions to reduce peak energy use. Chart B1 shows that peak loads have increased since 2003. Peak loads are rising for a combination of reasons. During the last decade while new houses became more efficient, they also were bigger, and bigger efficient houses use more power than smaller, inefficient ones. Also, while the energy use per person has declined about 3 percent, the region's population has grown by about 15 percent. As peak loads grew the region did not implement a strategy to reduce peak energy use.

Figure B1. Northwest Peak Hourly Loads 2001 through 2009

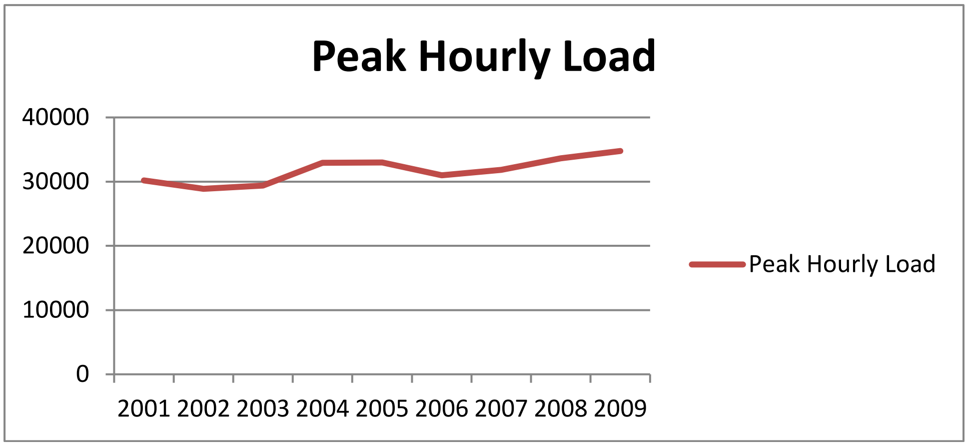

Figure 3. Peak Hourly Load (megawatt hours per hour) in years 2001 through 2009
Source: Northwest Power and Conservation Council

The good news is that the region is now engaged in many pilot projects to address peak loads, and the shapes of loads in general. Much of the work was co-funded from the American Recovery and Reinvestment Act of 2009 (ARRA). An additional catalyst to the recent attention to peak loads and loads in general is that in 2011 BPA began charging a higher rate (Tier II pricing) for all power it sells to its customers above their allocated share of the resources under BPA's control.

The largest pilot effort in this region is the Regional Smart Grid Pilot Project being managed by Battelle and BPA. This project, together with several smaller pilot projects and utility-specific programs, are exploring technologies and programs for load management.

Table B1 displays the utilities/cities that are engaged in Smart Grid activities. The Table also identifies whether the effort is a pilot or ongoing program, and whether is in the Regional Smart Grid Pilot project, a utility's own pilot, or supported by BPA. Most of the efforts are engaged in load shaping through demand response or storage of power.

Table B1. Northwest Utilities Engaged in Demand Response Pilots or Ongoing Programs

	Utility	*Regional Smart Grid Pilot*	*Utility Specific Pilot Project*	*Ongoing Program*	*Pilot with BPA*
1	*Seattle City Light/Univ. of Wash.*	√			

2	*Peninsula Light Co.*	√			
3	*PGE*	√			
4	*Lower Valley Energy*	√			
5	*BPA*	√			
6	*City of Ellensburg*	√			
7	*Avista*	√			
8	*Flathead Electric Coop*	√			
9	*Northwestern*	√			
10	*Milton Freewater*	√			
11	*Benton PUD*	√			
12	*Idaho Falls Power*	√			
13	*Central Lincoln PUD*		√		
14	*Tacoma*		√		
15	*Seattle City Light*		√		
16	*Snohomish PUD*		√		
17	*Idaho Power Co.*			√	
18	*PacifiCorp*			√	
19	*City of Port Angeles*				√
20	*Mason County #3*				√
21	*Central Electric*				√
22	*Kootenai Electric*				√
23	*Emerald PUD*				√
24	*Orcas P&L*				√

An important point about these efforts to control the shape of peak loads is that it may reduce the demand for peaking the flow of the rivers. The operational flexibilities produced by peak load management yield greater opportunities for river operations that are compatible with the needs of affected species. We will address this idea more fully in Section 4.0 of the paper.

B.2.1 Using pricing to reduce peaks.

BPA's tiered rates will send clear prices signals on the costs of meeting additional load growth as utilities use more power than their low-cost Tier 1 allocation, additional needs will be at the much higher Tier 2 rates[39]. BPA rates also reflect on and off-peak and seasonal costs. This may provide an incentive for utilities to move to time-of-day pricing, but there has been little progress to date.

There is also progress in the Regional Smart Grid Program that might help in establishing effective and transparent prices. An important piece of the regional smart grid pilot is the development of a "transactive signal" that will eventually be able to show the approximate value of power at any place on the grid at any instant It will be some time before the signal itself will contain enough information to show with any degree of certainty the real cost of providing this power.[40] This information will be valuable as we develop programs to reduce peak loads, even if we do not incorporate it directly into pricing strategies.

Other pricing strategies have been used successfully here and in other regions. They include:

- Block rates wherein the price of power increases as a user moves from the first block of power used to the next block. These rates may have several blocks representing the first 100 kilowatt hours per month, the second 100 kilowatt hours per month, and so forth. A special block rate may contain a life-line rate, a low rate for the essentials, but with higher rates as use increases beyond essential needs.

- Time of use rates that are based on the time of day and the season. These rates are based on historical load shapes and are used to discourage use of power during periods of high demand.

B.2.2. Incentive programs to affect the timing of energy consumption and reduce peak, including reduction of 1000 megawatts of peak reduction by 2013

The region has not made progress in achieving the goal of reducing peak demands by 1000 megawatts. However, a pilot project by Seattle City Light suggests future progress.

[39] Port Angeles announced that BPA's proposed rates would increase demand charges from a range of $1.30 to $2.30 per kilowatt hour to a range of $8 to $10 per kilowatt-hour.[39] This is a significant increase.

[40] Some organized markets like those served by the PJM regional transmission organization (www.pjm.com) use Location Marginal Prices (LMP), which is an approximation of the real cost of delivering power to any given node in the grid. The transactional signal being developed in the Northwest pilot will eventually carry information that will approximate an LMP.

Seattle City Light has conducted a successful pilot on commercial buildings; using only a handful of commercial buildings over four summer and four winter events, this pilot program achieved winter and summer reductions in demand of 730 kilowatts and 481 kilowatts per building, respectively, and energy savings in those same seasons of 8,763 kilowatt hours and 7,005 kilowatt hours. The average cost of the controls per kilowatt reduction was $76 for winter and $108 for summer; significantly less than the cost to generate and transmit an additional kilowatt.

B.2.3. Storage of Power to Use at Other Times.

Storage of low cost power to serve loads at another time has made progress in the region recently. Several of the pilot projects mentioned in Section 3.1.2 above related to the Smart Grid are testing storage mechanisms. The most interesting of these are storage of power in enlarged hot water heaters and in mass placed in residential buildings. Storing power for later needs can help the system ride through peak requirement periods, and it can probably help to shape electricity loads and river flows on a 24/7 basis. With these pilots in place there may be an opportunity to see if they can be used to do 24/7 shaping when needed. Since the technologies will already be in place to shape loads around peak condition, it would be very low cost to shape loads at all times when needed to assist fish migration.

CRITFC will monitor the results of these pilot projects to get information on the cost effectiveness of storage in buildings.

B.3. Energy efficiency resources

Secure all cost-effective energy efficiency: In the 2003 *Energy Vision for the Columbia River*, we strongly supported the acquisition of all cost-effective conservation. The region as a whole has done well in this regard. In the period from 2001 through 2009, the region acquired through utility programs and state and federal codes about 2,380 average megawatts of conservation. This represents the annual output of about 5 coal plants.[41]

Energy efficiency continues to be the resource of choice for the region in the Northwest Power and Conservation Council's 6th Power Plan, adopted in February, 2010. The Council estimates in the Plan that over 6,000 average megawatts of conservation can be acquired cost-effectively over the 20-year planning horizon of the plan. Conservation represents about 85% of the region's power needs in the 20-year plan.

Smart Grid technologies and strategies will open the door to additional conservation, as discussed in Section 4.

[41] For example, the net capacity of the Boardman coal plant is about 580 megawatts, and it operates at about an 80% capacity factor, producing about 460 average megawatts of power. This plant is facing closure in within the next five to ten years.

B.4. Renewable Resources

Wind generation: Since 2001, the region has installed 5,400 megawatts of wind power capacity. At a normal capacity factor of 30%, this translates into an energy producing capability of about 1,620 average megawatts—about 12 percent of the average energy generation in the Northwest.

Solar Photovoltaic Installations: Photovoltaic power (PV) installations do not yet make up a significant contribution to the region power system. However, due in part to community based programs in Oregon, the Energy Trust has installed about 20 megawatts of PVs in Oregon alone since the previous *Energy Vision for the Columbia River* was published.

Additional Progress

There have been other actions since the 2003 Energy Vision for the Columbia River that have helped improve the survival of fish and wildlife. This section summarizes those activities.

Columbia Basin Accords: BPA and the three of the CRITFC tribes have signed a 10-year agreement to implement fish and wildlife projects. On May 2, 2008, BPA, the U.S. Army Corps of Engineers (Corps) and the U.S. Bureau of Reclamation (Reclamation), (the "Action Agencies") and the Confederated Tribes of the Warm Springs Reservation of Oregon, the Confederated Tribes of the Umatilla Indian Reservation, the Confederated Tribes and Bands of the Yakama Nation, and the Columbia River Inter-Tribal Fish Commission (CRITFC) developed a Memorandum of Agreement (MOA) through good faith negotiations.

The MOA addressed direct and indirect effects of construction, inundation, operation and maintenance of the Federal Columbia River Power System and Reclamation's Upper Snake River Projects, on fish resources of the Columbia River Basin. The Action Agencies and the Tribes (collectively referred to in the MOA as the Parties) intend that this MOA provide benefits to all the Parties to the MOA.

The MOA provides significant benefits, including increased habitat acquisition and improvement for ESA-listed and unlisted fish; continued and expanded restoration efforts for lamprey and mussels; expanded monitoring of fish status to provide evidence of restoration progress and results; funding for increased hatchery production; measures that enable fall Chinook harvest; and continued and expanded enforcement of the Tribe's fishing regulations.

The MOA commits the Action Agencies and signatory Tribes to work together in good faith to fully implement the M. The MOA identifies a number of specific projects and includes funding commitments for their implementation. The Tribes support BPA's incorporation of these costs in the final rate case proposal.

Fish protections in Federal Court orders and FCRPS Biological Opinions: The environment encountered by juvenile and adult salmon during their migration through the FCRPS and mainstem Columbia River has seen numerous changes since the publication of the last *Energy Vision for the Columbia River* in 2001. These changes include both structural improvements and operational changes and stem primarily from revised Biological Opinions on the FCRPS (2004 and 2008) and court ordered operations associated with litigation over those Biological Opinions. Under the 2008 Biological Opinion, the operations and structural improvements are designed to achieve dam passage performance standards of 96% per dam passage juvenile survival for spring migrants and 93% per dam passage survival for summer migrants. Following are the most significant structural and operational changes that have been made since 2001:

Bonneville Dam

- Corner Collector installation and using Power House 2 as primary power house
- New flow deflectors and new spring and summer spill patterns and volumes
- Modifications to the Power House 1 sluiceway to improve fish passage efficiency

The Dalles Dam

- Spillwall construction and modified spill pattern

John Day Dam

- Construction of two Top Spill Weirs
- 24 hours spill program; testing 30 or 40% spill for both spring and summer
- Much improved avain wires to reduce tailrace avian predation

McNary Dam

- Construction of two Top Spill Weirs
- 24 hours spill program 40% for spring and evaluating both 40 and 60% in the summer

Ice Harbor

- Installed one RSW and tested new 24 hours spill program comparing 45 kcfs/spill to the gas cap at night versus 30% spill
- Relocated juvenile outfall bypass to improve tailrace egress for bypass

Lower Monumental

- Installed one RSW and tested new 24 hours spill program with spill levels set to the total dissolved gas standard

Little Goose Dam

- Installed new Top Spill Weir and tested new 24 hours spill program of 30% spill

Lower Granite Dam

- Installed one RSW; implemented 24 hour spill program of 21 kcfs spill

Spilling water at mainstem dams is essential for passing juvenile salmon and is required by the aforementioned federal court orders and Biological Opinions. The differences in spill operations from 2001 to current are highlighted in the following table. Both planned and actual 2001 operations are shown since 2001 ended up being a low-flow year and operations moved to zero spill.

Dam	2001 Planned	2001 Actual	2010 Actual
Bonneville	75 kcfs daytime/Spill to the Gas Cap at Night (usually range 110-140 spill range)	50 kcfs spill 24 hours	Spring: 100 kfs 24 hours. Summer: 85 kcfs until July 20 then 75 kcfs during the day; Spill to the Gas Cap at Night (95-150 kcfs range). Also evaluated 95 kcfs 24 hours in 2010
The Dalles	40% spill	30% spill	40% spill
John Day	0 daytime spill 60% at Night. Also test 30% spill 24 hours	0 Spill (two weeks of minimal over generation spill)	Evaluation either 30% or 40% spill 24 hours
McNary	0 daytime spill; Gas Cap spill at night (range 120-140 kcfs)	0 spill	Spring: 40% spill 24 hours; Summer: 50% spill 24 hours (have also evaluated 40% and 60%)
Ice Harbor	45 kcfs daytime spill and Gas Cap spill at night (90-110 kcfs)	0 spill	45 kcfs daytime; Gas Cap at night (90-120 kcfsc), also evaluated 30% 24 hours a day.
Lower Monumental	0 spill during the day; Gas Cap spill at night (35-45 kcfs)	0 spill	Spring: Gas Cap spill 24 hours (27-45 kcfs); Summer: lower of 17 kcfs or gas cap
Little Goose	0 spill during the day; Gas Cap spill at night (35-40 kcfs)	0 spill	30% spill 24 hours a day
Lower Granite	0 spill during the day; Gas Cap spill at night (35-50 kcfs)	0 spill	Spring: 21 kcfs spill 24 hours a day; Summer: 19 kcfs 24 hours a day

Additional Dworshak salmon flows in Nez Perce Water Rights Settlement: In 2005, the Nez Perce Tribe entered into a water rights settlement with the State of Idaho and the

Federal government. One of the components of the settlement provided the Tribe with the right to manage 200,000 acre-feet of water stored in the Dworshak reservoir to improve the migration of salmon. The agreement with the Corps of Engineers also sets up a yearly planning and implementation process for using the water.

Dam removal since 2003.

There are numerous aging small hydropower dams throughout the Pacific Northwest whose contribution to the power grid is minimal, but whose contribution to fish destruction is great. Over the past decade several of these dams were removed, or slated for removal, allowing for rehabilitation of river systems and reintroducing former fish habitat back to the region.

2007 Bull Run Hydroelectric project (Marmot Dam and Little Sandy Dam) on the Sandy River: At the time of removal, Marmot dam was the largest concrete dam ever removed. The project was constructed in 1906 and supplied power to Portland, but blocked all fish access to its upper 7 miles.

2009 Hemlock Dam on Trout Creek: The Hemlock dam was built Trout Creek in 1935 as an irrigation dam for local agriculture. While not used for power production, it blocked fish passage as well as contributed to serious high heat issues in the creek.

2010 Powerdale Dam on the Hood River: Completed in 1923, the 6 mw PacificCorp project was removed in late 2010.

2011 The Elwha River: The National Park Service has selected a contractor to remove two dams on the Elwha River on the Olympic Peninsula of Washington. Removal begins in September 2011. Salmon populations are expected increase from 3,000 to more than 300,000 as five species of Pacific salmon return to more than 70 miles of river and streams that are currently blocked by the dams, most of which is protected inside Olympic National Park.

2011 Condit Dam: FERC issued the surrender order for the Condit dam on the White Salmon River, a tributary of the Columbia River, for its removal in October 2011. PacifiCorp is working to address the FERCC Order. Removal of this dam will increase access to 32 miles of salmon spawning habitat.

Klamath Basin Restoration and Hydroelectric Settlement Agreements: In 2010 representatives of 45 organizations, including Federal agencies, California and Oregon, the Klamath Tribes, Karuk Tribe, and Yurok Tribe, Klamath and Humboldt counties, irrigators and conservation and fishing groups have agreed to a comprehensive solution for the Klamath Basin. While not in the Columbia Basin, this process was a model for collaboration among a wide range of interests.

The Klamath Basin Restoration Agreement is intended to result in effective and durable solutions which will: 1) restore and sustain natural fish production and provide for full participation in ocean and river harvest opportunities of fish species throughout the Klamath Basin; 2) establish reliable water and power supplies which sustain agricultural uses, communities, and National Wildlife Refuges; and 3) contribute to the public welfare and the sustainability of all Klamath Basin communities. More information on the Klamath settlement agreements is available at: klamathcouncil.org.

Appendix C. Calculating The Benefits of Hot Water Storage Technologies

During the winter morning peak, hot water heaters draw about 1.5[42] kilowatts, on average per unit. The cost of a new high-volume tank with a mixing valve and communications installed is in the $1,200 to $1,500 range. Typical electric water heaters cover a wide range of prices, but a reasonable average is about $650 installed. Therefore, we are left with an incremental cost of between $550 and $850 for the tank with larger volume and the controls installed. This analysis assumes that the tanks are charged at night with low-cost or zero-cost power, that they are called upon 1,000 hours per year to serve peak load, and that they deliver 1.5 kilowatt hours in each of the 1,000 hours, or 1,500 kilowatt hours per year to peak loads. Annualized-incremental cost[43] of the new hot water tank is between $50 and $115 depending on the incremental costs and whether the tank lasts 15 years or 30 years[44]. The cost per megawatt hour delivered at peak is then between $33.59 and $57.50. If hot water tanks draw as little 0.9 kilowatts on peak instead of 1.5 kilowatts, incremental costs per megawatt hour delivered on peak would range from $55.98 to $127.78 per megawatt hour.

To these estimates we have to add the cost of charging the tanks at night. When there is excess power from hydro and wind, the market cost of power would be at or below zero. But let's assume that one has to pay $20[45] per megawatt hour for energy to charge the water heaters at night. This raises the incremental costs of the new water heaters to a range of $53.59 and $77.50 per megawatt hour, if the assumption that the tanks can supply 1.5 kilowatts on average during peak periods is true. If tanks only supply 0.9 kilowatts on peak, the costs would then be $75.98 to $147.78 per megawatt hour.

The cost of a generating plant used to serve peak load is between $140-$158per megawatt hour in 2011 dollars[46] delivered to a customer's meter. Clearly, the hot water storage strategy, under the range of assumptions included in this analysis compare favorably with the costs of serving the peak loads with stored energy in the tanks. Since the tanks are at the load, they save on the transmission and distribution costs.

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[42] The number 1.5 kWe on average through the peak morning period is not firm. It was arrived at through discussions with other folks, and is an educated guess. This number is critical to the analysis. Hopefully, we will get updated numbers from the demonstration programs being conducted throughout the region.

[43] This assumes a capital recovery factor of .0910 for a 30 year tank life and .135 for a 15 year life, consistent with what the NWPCC used for estimating the annualized costs of peaking plants in the 6th Power Plan for the region.

[44] The analysis uses Investor Owned Utility based funding to allow comparison with peaking plants whose costs were estimated by the NWPCC in the Sixth Power Plan.

[45] A review of NWPCC projections using the Aurora pricing model shows over 2,000 hours per year at less than 2 cents per kWh, with 1291 of those at less than 1 cent per kWh. Thus, the 2 cent per kWh assumption used here is a conservatism to making the case for the hot water heating storage strategy.

[46] From NWPCC Sixth Power Plan, Appendix I adjusted from 2006 to 2011 dollars.

The cost of conversion of an existing tank is about $500[47]. Assuming the converted tank has 15 years left before it is retired, the $500 would cost about $67.50 per year. Using the 0.9 kilowatt assumption the cost per kilowatt is $75. At 1.5 kilowatts, the costs is $45 per kilowatt. Adding the $20 per megawatt hour costs boosts the cost to a range of $87.50 to $65 per megawatt. Again the conversion costs are clearly competitive with peaking plants.

Note that we have compared the entire cost of water heaters storage specifically against a peaking plant that would be used to serve the same peak load. But, water heaters used for storage in this way can provide other benefits to the grid. They can be used for load balancing as well, for example. When there is too much load on line and there are water heaters that are not fully charged that excess load can be all or in part used to heat water to maximum temperature. When there is less power than load, charged water heaters can be turned off and be made to coast. Balancing of loads and resources is very valuable. We have not attempted to put a price on this value here.

This technology may also help integrate wind into the region's energy system. In the pilot projects mentioned in Section 3, both existing and new very efficient water heaters are being deployed, and the water temperature will be increased to an average temperature of 170 degrees Fahrenheit. Because of stratification of temperatures in the tanks, the hot water tanks can be drawn down over a day to an average temperature of 90 degrees, which would leave 100 degree water at the top of the tanks. Each of the tanks will be transformed in this way to a "battery" containing about 10 kilowatt hours of stored energy. These hot water tanks would be able to maintain the appropriate temperature through an entire day, and then be charged again at night with low-cost off peak power. The hot water tanks would be able to absorb a significant amount of off-peak power to recharge, including excess night-time wind and hydroelectric power. As power operations in 2011 have shown, this has become serious issue for the Northwest. Wind machines were curtailed due to lack of night-time loads. The curtailments cost wind machine owners considerable money, as federal tax credits for wind are based on production.

[47] There are concerns that raising the temperature of existing tanks could shorten the lives of the tanks. This is an issue that should be addressed and monitored in the regional pilots. This estimate comes from a conversation with a Minnesota utility staff person, who has been installing these types of heaters for years.