PNUCC REPORT Council

Northwest Power and Conservation Council

May 6-7, 2014

At the Council meeting in Boise, PNUCC's Dick Adams and Shauna McReynolds introduced the Power Committee to the intricacies of the Northwest Regional Forecast. The Council adopted the 2019 Resource Adequacy Assessment with a 6 percent Loss of Load Probability and talked about ways the gap will be filled. Other hot topics at the meeting included the Northwest Energy Efficiency Alliance's latest business plan and the economics of the Columbia Generating Station. Next Meeting: June 10-11 in Missoula.

In This Issue

The Agenda

The Power Committee Meets the NRF

PNUCC executive director Dick Adams explained that the Northwest Regional Forecast (NRF) is a compilation of utility forecasts and Integrated Resource Plans. Two main purposes of the NRF, he said, are measuring the need for additional power supply and conservation in the region, and finding out what future resources are on utilities' drawing boards.

The first NRF was published in 1952 as a report to the Federal Power Commission, and it projected a 4.5 percent load growth rate, Adams noted. Looking at forecasts from 1962 to today, there are several take-away messages, he said. One is the growth in the use of natural gas, Adams stated, pointing out that today 8,500 MW of generation in the Northwest depends on natural gas. Another is the explosion of wind generation from 0 MW to over 8,000 MW in the last 10 years, driven by policy changes, he said. Energy efficiency is a priority in utility activities, and the amount of savings coming from codes and standards is growing, Adams added.

PNUCC deputy director Shauna McReynolds said the NRF lets us know “how we are doing and what we need to do today to make sure we will be okay tomorrow.” This year’s NRF headlines, she said, are: meeting peak need is our focus; energy efficiency is a priority; demand-side management resources are playing a greater role in the system; and more natural gas and wind projects are on the horizon.

McReynolds explained the measures the NRF uses to forecast energy needs and said on an annual energy basis, the region “is looking good.” The NRF also shows the region is doing pretty well with summer peak electricity needs, but that more attention needs to be paid to how the region will meet winter peak demand, she said.

Pat Smith asked about the statement that most utilities plan on 5 percent or less of the capability of their wind projects being available to meet peak demand. Some utilities count on zero percent from wind, and some use a 10 percent factor – they base these estimates on their experience, McReynolds said.

Adams pointed out that the Council’s power plan looks at the region, and its load forecast is not the same as what the NRF captures. Overall, the 2014 NRF shows an annual growth rate of 0.9 percent for the next 10 years, with conservation and other factors contributing to this trend toward slower growth in load, he noted.

But each utility is unique, and load growth rates vary greatly due to a number of factors, including load profile, resource mix, policy priorities, and new resource options, Adams said. Some utilities project zero growth over the next five years, some foresee growth over 3 percent, and Grant PUD told us recently they expect a 15 percent annual growth rate, as a result of data centers and other manufacturing facilities moving in, he added.

Conservation is a high priority for Northwest utilities, and the NRF shows over the next five years that utilities expect to achieve a cumulative annual savings of 900 aMW from their conservation programs, McReynolds said. Conservation will also contribute to a 1,300 MW reduction in winter peak demand, she added.

Demand response is becoming more important, and the NRF identifies agreements available to reduce peak demand by 90 MW in winter and almost 600 MW in summer, McReynolds noted. This year’s NRF reports for the first time on how efficiency programs are helping reduce peak hour needs in the region, she said.

Henry Lorenzen asked how the need for future generation can be balanced with achieving enough conservation so “you don’t have to build so much generation.” In some cases, flexibility needs may not be able to be met through traditional conservation programs, McReynolds replied.

Should we focus more on conservation in light of the projected need for generation? Lorenzen asked. If a utility is focused on meeting peak need, you are likely to see an increase in demand response programs that focus on reducing peak load, replied Adams. The challenge is how to take current energy efficiency programs and rethink them, rather than just do more of the same programs, he added. The “real gift” are programs that help utilities meet peak needs, Adams said.

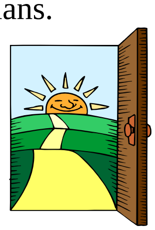
In the past, utilities have had a reluctance to embrace conservation because it drives rates up, but the acquisition of conservation is more cost-effective than constructing new resources, and the question is how to balance the two, Lorenzen said. There tends to be a reluctance to aggressively spend money for conservation, and I’m struggling with that, he stated.

There are utilities like Grant PUD that are growing dramatically and can use hydro to meet their needs, and there are other utilities that have growing demand and need power, but they don't have hydro resources, said staffer Charlie Black. The question is how we do energy efficiency when there are loads growing in one area, and energy efficiency opportunities are located in a different area, he stated.

The Council has had great success with its conservation targets, and as we look forward, moving energy efficiency up faster as a region may be a better way to go than building new gas plants, Tom Karier said. We could try to find ways for faster growing areas to purchase from those that are not growing, he suggested.

In the last five years, the utility industry has met and exceeded the power plan's conservation targets, noted Adams. We've been quite successful, he added. Annually, $400 million is being invested in energy efficiency, and "that's a home run," Adams said. He recommended the Council invite some utility representatives to a future meeting to talk further about their differing needs, programs, and plans.

2019 Adequacy Report Goes Out the Door



Staffer John Fazio briefed the Council on the final Resource Adequacy Assessment for 2019, noting that the Council adopted an adequacy standard of 5 percent maximum allowable loss of load probability (LOLP) in 2011. In 2012, he noted, the Council adopted an adequacy assessment for 2017 with a LOLP of 7 percent.

Key elements of the assessment involve what we assume for generating resources in the region, including independent power projects, as well as what we assume about power imports from California, Fazio explained. We hired Energy GPS to conduct a study of California's power situation, and it shows there is a substantial amount of surplus in California, even when you take into account the shutdown of the San Onofre project and the loss of once-through-cooling generating resources, he noted. The assessment assumes up to 2,500 megawatts (MW) are available to be imported from California, Fazio said.

He went over what has changed since the Council's 2017 assessment. The changes include a 260 aMW increase in net load growth, which incorporates 700 aMW in energy efficiency savings, Fazio reported. There is also an increase in Southwest imports of 800 MW, 670 MW of new gas generation, 260 MW of new wind, reductions in standby energy and winter capacity, and an increase in standby summer capacity, he stated. These new assumptions brought the assessment from 7 percent in 2017 to 6 percent in 2019, Fazio said. The results assume the Council's annual energy efficiency savings target of 350 aMW is achieved between 2017 and 2019, he added.

In 2021, after the Boardman and Centralia 1 coal plants are retired, the LOLP rises to 11 percent, Fazio reported. There are a variety of actions to bring the 2019 and 2021 power supplies into compliance with the Council's 5 percent LOLP standard, and that discussion will take place in conjunction with the Council's next power plan, he said. Fazio noted that PNUCC's 2014 NRF shows utilities are planning new resources through 2024 that would total about 1,800 MW. And there seems to be quite a bit of surplus California power in the winter the Northwest could call on "if we can find a way to get it up here," he added.

The assessment puts a limit of 2,500 MW on California imports, but could that number go higher? Smith asked. Black said it could go up, but that part of the issue is market-related. In the past, Northwest and California utilities did seasonal exchanges, but after market changes in

California, when those interregional agreements expired, they were not renewed, he noted. We have identified a real opportunity for such capacity agreements to happen again, and it would get back to more use of what the Interties were built for in the first place, Black told the Council. California entities are assuming that the surplus solar energy identified in the "duck chart" will be moved to the Northwest, he added.

This assessment shows a LOLP of greater than 5 percent, noted Council Chair Bill Bradbury. He asked about adopting an assessment of 6 percent, higher than the desired standard. The purpose of the assessment is to look forward five years, said Black. If we are above the 5 percent threshold, it indicates something needs to be done in the next five years, he added. Utilities have told us they are planning generating and other resource programs that would get us under the threshold, Black said.

After the Council passed a motion approving the assessment, Karier noted some issues that require additional discussion. One is the opportunity for higher levels of imports from California, especially with the predictions of a solar surplus in the summer, he stated, adding "we can tee that up in the power plan." Another issue is the fact we have low energy prices, but don't have adequacy in the Northwest – that's a dilemma, Karier said.

As for energy efficiency, maybe we are being "a little too complacent," he stated. BPA staff has told us they don't know what our targets are, and we need to talk with them about that, Karier said. If we had more energy efficiency, we wouldn't have to build any new plants by 2019, he added. If we can consider building new gas plants, we can consider raising the energy efficiency targets in the short term, Karier said.

He also recommended additional analysis of the situation at Wanapum Dam. The dam may be in low production through next winter, with effects on other hydro projects, Karier said.

NEEA Adapts and Offers Options

Jim West, chair of the Northwest Energy Efficiency Alliance (NEEA) board, told the Council NEEA's draft budget and five-year business plan "have morphed." We now have a smaller budget and we've decided to offer choices that utilities can opt for or not, he said.

We issued a revised draft business plan April 14, NEEA executive director Susan Stratton reported. It responds to the needs of existing NEEA funders, achieves savings, supports our core work, accounts for increased local utility investments and capabilities, identifies ways to collaborate more productively, and minimizes overlaps between NEEA and utility activities, she stated. Our proposed five-year budget range is $145 million to $169 million, Stratton said. Our current budget is $188 million, and we expect to come in around $180 million, she added.

We are now offering funders up to 15 percent in optional activities, Stratton noted. We have reduced our strategic markets from six to four, she reported. We took out irrigated agriculture because utilities told us it didn't have broad applicability across the region, and we made commercial real estate an optional program, Stratton noted.

We now plan to ask our regional portfolio advisory committee to vote on whether NEEA should include a new initiative, she said. We have built in visibility and some nice checks and balances with this new process, and we'll be watching it closely and review it after a year, West added. Stratton said NEEA will hold a special meeting in June for the board to take action on the final business plan and budget.

We've tried to understand the changes you've made in the plan, Karier stated, adding the Council thinks scanning and strategic market analysis are key NEEA activities and the budget should reflect that. There was a need for NEEA to respond to the concerns of its funders, and it's good your board rolled up its sleeves and did what was necessary to satisfy the funders, Bill Booth said.

Scrutinizing CGS by the Numbers

Robert McCullough summarized a study McCullough Research did in 2013 for the Physicians for Social Responsibility on the future cost-effectiveness of continuing operation of the Columbia Generating Station (CGS). His study concludes that operating and maintaining CGS on an ongoing basis would be more costly than closing the plant and replacing it with firm power supplies procured from the wholesale market, according to a Council handout.

With changes in natural gas prices and the growing availability of renewable energy, the landscape has changed, and the bottom line is that market competition is crushing plants like CGS, McCullough said. He pointed out Dominion Resources closed the Kewaunee nuclear plant for economic reasons because they couldn't find a market, even though the plant was not outdated.

CGS' location is a problem because, McCullough said, the plant is surrounded by zero marginal cost resources and there isn't enough load in the area. He said the cost of operating a nuclear plant is high compared with the low market prices available today. Unlike coal and natural gas units, nuclear units consume $90 million a year in additional capital expenditures, and aging plants cost more to maintain every year, McCullough stated.

He said the Comprehensive Review, organized by the Northwest governors, adopted a "market test" BPA and Energy Northwest accepted, but that CGS has failed the test since 2009. McCullough recommended verifying provisions of the 1971 Project Agreement to see if the BPA Administrator has the power to terminate CGS; BPA issuance of an RFP on behalf of Energy Northwest for 1,130 MW of replacement power; and that after the replacement contract is implemented, decommissioning of the plant start in May 2015. If the plant had been closed in 2012, and BPA had been buying "the same energy" at Mid-C market prices, there would have been a 10.67 percent reduction in BPA wholesale rates, he said.

Because of its nuclear fuel arrangements, CGS has "the dirtiest fuel in the industry for years to come," McCullough continued. If we are really interested in fighting global warming, we should call up BC Hydro and try to purchase some of the output from their hydro projects, he said. BC Hydro is building a new major dam, Site C, and is considering upgrading other hydro facilities like Mica, McCullough added.

If you replaced CGS with a long-term contract, what is the probability you could get a contract comparable to the output of the CGS? Lorenzen asked. The key is to do an RFP, and "if it fails, don't invite me to your Christmas party, but if it succeeds, I expect a present," McCullough replied.

Why are capital costs increasing at nuclear plants? Smith asked. As the plants get older, their parts need replacement, like hip replacements for old people, McCullough replied. Phil Rockefeller asked if BPA has the legal authority to issue an RFP on behalf of

Energy Northwest. I would get the RFP's portfolio of resources approved by the Council, BPA, and Energy Northwest and have Energy Northwest operate the virtual plant, replied McCullough. If BPA operated it, we would have to replay the entire rate case, he added.

Why would BPA want to do the RFP? Rockefeller asked. Rate reduction would be a pretty good incentive, replied McCullough. Why would BPA not want to do it? Rockefeller asked. Inertia and fear, replied McCullough.

IHS Makes the Case for CGS

Lawrence Makovich of IHS CERA presented the results of an economic assessment of CGS his firm did last year at the request of Energy Northwest. That report concludes that continuing to operate and maintain CGS on an ongoing basis is cost-effective, according to a Council handout.

If you want to give consumers the electricity they want, when they want it, at predictable prices, you can't do it all with wind power, Makovich said. CGS is part of cost-effective baseload generation in the Northwest regional power system, and continued operation of the plant provides $1.6 billion in benefits to power consumers, compared to closing CGS and replacing its power, he stated.

Until replacement resources could be built, spot market purchases would have to be made, and the future delivered price of natural gas to the Northwest is hard to predict, Makovich noted. The delivered price of natural gas to the Northwest exhibits multi-year cycles, strong seasonality, and periodic price spikes, he added.

The long-run marginal cost of power supply in the Northwest is greater than $60/MWh, Makovich said. Mid-C wholesale prices reflect the short-run marginal costs of power supply that typically average around half the long-run marginal cost, he stated. The spot market is not the proper benchmark to judge the viability of an existing generation asset, Makovich said. Our study found it was less expensive to continue to run CGS than to replace its power between 2014 and 2043, plus continued operation of the plant prevents 3.6 million metric tons in annual carbon emissions, he told the Council.

The Northwest states have the lowest electricity rates in the country, and when the cost of electricity rises, the burden falls disproportionately on low-income individuals, Makovich stated. Low power prices give the Northwest a comparative advantage, and electricity costs are one of a number of important things that determine competitiveness, he said.

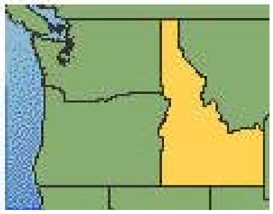
If you close nuclear plants that are economical to run, then you will have power prices that are higher and more variable than they need to be, Makovich stated. There are already indications that the loss of the San Onofre nuclear plant is increasing emissions and costs in California, he added.

Lorenzen asked what a long-term contract to replace CGS would look like. A large investment has been made in CGS, and the plant provides energy, capacity, and emissions benefits, replied Makovich. To be comparable, an RFP should be for a 30-year supply, with 1,000 MW of capacity that is available 90 percent of the time, and also provide energy and emissions benefits, at a price that can't be escalated by natural gas prices, he said.

Collateral of $1 billion should also be required in case of a default, Makovich added. Loads of people enter into these contracts and default on them, he said. If you write an RFP with a 30-year commitment, I'd be surprised if you could get something more economical than what you've got, Makovich stated.

What about securing power from Canadian hydro facilities? Smith asked. You are talking about trade that involves treaties and about building transmission between the Northwest and Canada, replied Makovich. I don't think you can do that and come up with a cost of 5.5 cents/kWh for 30 years, he said. Plus, you would have to add exchange rate risk to it, Makovich stated.

What Energy Issues Top Idaho's Agenda?



John Chatburn, director of the Idaho Governor's Office of Energy Resources (OER), made a presentation on his office's activities, noting that the OER was created by Governor Otter in 2007. Our charges include coordinating energy planning and policy development in the state, coordinating comments on federal energy issues, serving as Idaho's clearinghouse for energy information, representing the state in regional and national energy forums, and coordinating the Idaho Strategic Energy Alliance (ISEA), he said. The ISEA involves state agencies, utilities, and private sector representatives to explore and vet energy ideas in Idaho, Chatburn noted.

The ISEA is working on an update of Idaho's Energy Plan, has completed new reports on baseload and energy efficiency, and developed fact sheets and other materials to provide information to the public, he said. Chatburn gave an update on three transmission projects in Idaho. The Bureau of Land Management (BLM) has delayed a decision on segments 8 and 9 of the Gateway West transmission project, he noted. We are working with BLM to review potential routes for those segments and hope to have recommendations to them by the end of this month, Chatburn reported.

BLM has again delayed the draft EIS on the Boardman to Hemmingway transmission line, and we now hope to see it by the end of the summer, he said. BPA is releasing a draft supplemental EIS this month for the Hooper Springs transmission line in southeast Idaho, which will examine a new route that has local support, Chatburn added.

As for federal regulations, OER is providing comments on the sage grouse EIS, monitoring EPA's development of carbon emission standards for existing power plants, and coordinating Idaho's comments to EPA about the Wyoming regional haze rule, he reported. We are also working with BLM on regulations for hydraulic fracturing on federal and Indian lands, Chatburn said. Idaho received a grant from the U.S. Forest Service to establish a team to look at developing biomass and combined-heat-and-power projects to boost rural communities with depressed economies, he stated.

Industrial energy efficiency is a top issue for Governor Otter, Chatburn noted. We have completed industrial energy-savings assessments at five industrial facilities and identified over $1.2 million in annual energy-savings measures, he reported.

We are deeply involved in residential and commercial energy efficiency efforts and participate in the Idaho Energy Code Collaborative, Chatburn noted. We are working with BPA and Boise State University to assess the acceptance of energy codes in Idaho and with the University of Idaho's Integrated Design Lab to provide energy-saving assessments for government facilities, he added.

In Idaho, our legislature did not enact a Renewable Portfolio Standard, but you see from this presentation that, rather than using the top-down approach, using a bottom-up approach with grass-roots efforts produces quite positive results, Booth said. A recent American Wind Energy Association report noted that only three states have a higher percentage of electricity provided by wind than Idaho, added Chatburn. One of our big issues is access to federal land, he stated. All of our renewable projects are on private or state lands, and it's a struggle to find ways to move energy from projects on private land across federal land, Chatburn said.

Snake River Fall Chinook's Amazing Comeback Story

Staffer Jeff Allen kicked off a panel presentation on 2013 Snake River fall chinook returns by saying "this is a comeback story of epic proportion." The Snake River fall chinook program "was born in anger and frustration" and we were all geared for litigation, but then through the *U.S. v. Oregon* process, we were able to strike an agreement, Dave Johnson of the Nez Perce Tribe said. Senator Mark Hatfield found the money to get this program started, and it has worked, he added.

Jay Hesse, a fisheries researcher for the Nez Perce Tribe, reported that total Snake River fall chinook returns to Lower Granite Dam were 75,846 in 2013, compared to 575 in 1990. In 2013, there were 20,222 natural-origin fall chinook adult returns, compared to 78 in 1990, a 260-fold increase, he noted.

We have a highly coordinated and integrated hatchery program, involving the states of Washington, Oregon, and Idaho, the Nez Perce and Umatilla Tribes, U.S. Fish and Wildlife Service, NOAA Fisheries, Corps of Engineers, BPA, and Idaho Power, Hesse said. We are forecasting 70,000 total fall chinook returns at Lower Granite in 2014, about half natural-origin and half hatchery fish, he added.

This is an innovative and successful effort, stated Karier. What are the prospects for re-introduction of fish above Hells Canyon Dam? he asked. The Tribe fully supports re-introduction above Hells Canyon, but the question is when, replied Johnson. It needs a lot of work, and one thing we are watching is what's being done as part of Idaho Power's relicensing effort for Hells Canyon, he added.

This is a very impressive presentation, and it's a tribute to the perseverance and collaboration of all the parties involved, said Booth.

End Notes

Draft F&W Program Ready for its Close-up. Staffer Patty O'Toole reported the draft F&W program was posted on the Council's website on May 7, with a comment period scheduled to end July 9. Public hearings on the draft will be held in each state, beginning in Astoria on May 29 and concluding July 8 in Portland.

Morlan to the IEAB. The Council appointed Terry Morlan, former head of the Council's Power Division, to a four-year term on the Independent Economic Analysis Board.

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