PNUCC REPORT
Council

Northwest Power and Conservation Council
January 14 – 15, 2014

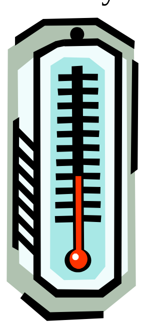
The Council, meeting in Portland, heard a debrief on system operations and power markets during the December 2013 cold snap and got a glimpse of the upcoming federal Environmental Protection Agency rules on existing coal plant emissions. The region is on track to meet the conservation targets in the Sixth Power Plan, and BPA is conducting a Network Open Season to help shape its transmission future. The Council's current officers, Chair Bill Bradbury and Vice- Chair Jennifer Anders, were re-elected. Next meeting: February 11-12 in Portland.

In This Issue

The Agenda

Low Temps Heat Up Gas and CA Issues

The December cold spell was a one in five-year event, according to Jerry Rust of the Northwest Power Pool. Water conditions make a lot of difference in how the region can respond to extreme cold, he said, and in 2013, the most recent water year, the region was at 96 percent of normal. Several factors impact reliability, including load, generation, weather, and constraints, which is the ability of the transmission system to deliver generation to load, Rust said.



He set the stage with demographics about the NWPP and statistics on water conditions over the past three years. Rust also pointed out the impact of Renewable Portfolio Standards in Washington, Oregon, and Montana, and the renewable generation installed in the Northwest: 17 megawatts of solar, 908 MW of biomass, 38 MW of geothermal, and 11,000 MW of wind. The installed capacity of wind generation in the NWPP area nearly doubled from 2010 to 2014, he said, growing from 6,671 MW on June 1, 2010 to 10,903 MW on July 31, 2013, with a January 31, 2014 forecast of 11,403 MW.

The NWPP watches several factors to assure system reliability, including extreme winter weather conditions, precipitation, and the economy, Rust said. For every degree F below normal, the peak demand increases by 300 MW in the NWPP area, he said. Below-normal precipitation impacts future energy availability, and recovery or decline in the economy affects load, Rust said.

During the December 2013 cold snap, NWPP load peaked at 66,700 MW at 5 p.m. December 9, he reported. The BPA load was 9,730 MW at the peak, BC Hydro and the Alberta Electric System Operator were both at 10,830 MW, and the PacifiCorp total, West and East, was 11,480 MW. At the time, the region was importing 3,500 MW of generation from the desert Southwest, Rust said. BPA was generating 15,400 MW, part of which was being used by other entities, he explained. There was plenty of water available, and the situation gives "a perspective on what water means to the system," Rust added. The generation needed isn't just load, it's also reserve requirements; currently, the reserve requirement calls for an average 2,500 to 4,500 MW of additional generation, he said.

The Puget Sound area requires monitoring during high loads, Rust pointed out. There is a constraint in that area – "we transfer a lot of power in and out of Puget Sound" – and it can become unstable with increasing loads and generation transfers, he said. The NWPP has established a trigger point to heighten awareness of the issue, Rust explained. The Puget Sound trigger point is 8,140 MW and the highest load during the recent cold spell was 7,612 MW, so there are no issues, he said.

In the end, there were no problems within the NWPP area in December, Rust said. Operators anticipated the situation and were well prepared, he said. The event was short and there were no significant transmission or generation outages during the event, "always a big plus," Rust concluded.

The Gas Perspective

Northwest Pipeline's Mike Rasmuson said the company has served the region for over 50 years. The pipeline is a "bi-directional system" with access to domestic and Canadian gas supplies, and it interconnects in the Rocky Mountains with seven interstate pipelines. Between December 5 and December 9, 2013, daily gas prices at Sumas jumped from about $4 per decatherm (Dth) to over $10, he reported. The nominations for gas at two of the company's compressor stations, Roosevelt and Plymouth South, exceeded their design capacity in December, Rasmuson said.

The weather event that was forecast for December 6-10 was widespread geographically and hit markets throughout the country, he continued. We saw it as a 20-year weather event, Rasmuson added. In preparation, Northwest declared a Stage II Entitlement for the system north of Kemmerer (Wyoming), which means a customer can't take more than 8 percent above what has been ordered without a penalty, he explained.

There is a drop in gas supply when we have a cold snap, and "we are tied to Jackson Prairie storage," Rasmuson stated, referring to the company's gas storage site in western Washington. During the December event, withdrawals from Jackson Prairie fluctuated during the day, peaking on December 6 at 972,000 Dth, which is below the maximum allowed withdrawal, he explained.

It helped that it was early in the season, Rasmuson added. There can be problems with deliverability later in the season; had it been February, for instance, the situation would have been completely different, he stated.

The gas load for power generation exceeded firm contracts for much of December, but the delivered gas did not reach the company's historical peak, Rasmuson reported. Over December 5-7, Northwest Pipeline experienced its third largest load ever, he said. "People are depending on non-firm capacity," and long-term, they may be in trouble doing this, Rasmuson stated.

In summary, advanced planning allowed Northwest Pipeline to meet all of its firm obligations, he stated. The power generation load stayed above contracted levels throughout December, Rasmuson reiterated. "Northwest is trying to serve markets with non-firm capacity, but that may not be possible long term," he said. In order to continue to meet these power generation levels on a contractual peak day, our system will have to be expanded, Rasmuson wrapped up.

<u>December by the Numbers</u>

Jessica Zahnow, a reporter for Argus US Electricity, briefed the Council on how generation performed and how electricity prices responded in December. There was a wide range of temperatures on the system during the December event, as low as minus 18 degrees F on Northwestern Energy's system in Montana to 21 degrees F in Seattle, she noted.

With regard to generation, hydro met the native load from December 7 to December 9, but wind "wasn't doing much," producing 1,400 MW at the a.m. peak on December 9 and about 800 MW at the p.m. peak that day, Zahnow reported. According to transmission line loadings, the region was a net importer on December 9, with about 1,400 MW being delivered over the California-Oregon Intertie at the a.m. peak and 1,000 MW at the p.m. peak; about 500 MW was coming into the region on the DC Intertie, she said.

Overall, "there were no major issues," reported, according to Zahnow. We heard from others that the forecasting was good going into Monday so systems were prepared and "a nice shot of rain before the cold hit" helped out, she said.

When the Northwest load peaked, "prices went up significantly," but there was no major price disruption, Zahnow continued. The Mid-C price was highest on January 6 for January 9 delivery, topping out at over $80 per MWh, she said. The off-peak price swing was a bigger event, Zahnow noted, indicating "the market is as concerned about off-peak as peak prices." A wide range in prices indicated uncertainty following the peak, and the market reacted for a few days afterwards, she pointed out.

With regard to the Mid-C day-ahead trades December 9, the off-peak volumes were not remarkable, which could indicate there was not a lot of wind to move, Zahnow said. Year over year, the Mid-C peak volume is down 35 percent in December and the off-peak volume is down 70 percent, she pointed out. Most likely there is not as much water to move this year, but I want to look at a longer trend line to see what is happening, Zahnow added.

Northwestern Energy set a record in December for imbalance, she continued. For a utility that serves 72 percent of its load with purchases, that represents exposure, Zahnow added. The imbalance price reached its 2013 high of $104.15 per MWh on December 9, she reported.

Electricity prices were up but gas prices were up more, Zahnow said. Gas prices made some generation unprofitable, and highly efficient combined cycle units fared best, she added.

The gas issues in California were noteworthy, Zahnow stated. Among the issues, SoCalGas was short of supply for interruptible power customers and asked the California Independent System Operator (CAISO) to step in and curtail generation, she said. Generators in Southern California were upset because they felt SoCalGas didn't want to pay higher gas prices when there was no physical constraint on its system, Zahnow explained. The CAISO report was unclear about whether there was a physical constraint or SoCalGas was avoiding the spot market, she said.

"California can become a big issue," Zahnow said. Some unpredictable situations can develop that could affect the Northwest, she added.

Zahnow recapped her presentation stating that power markets did not show extreme signs of scarcity during the cold spell, but eyes are on Northwestern Energy and its imbalance situation. She reiterated that California and the ISO-pipeline interaction could play a role when the Northwest is importing electricity from the south.

Jim Yost asked what will happen when Boardman and Centralia are replaced with combined-cycle gas plants. There is plenty of gas supply, but the question is whether there is pipeline capacity, Rasmuson responded. Customers already hold all the firm capacity on our system; we are fully subscribed and any new load will require new capacity, he added.

What would have happened if the cold snap had been later? Pat Smith asked. The Northwest isn't contracting firmly for gas supply, and we can't necessarily get more gas across the border from Canada, Rasmuson explained. We could be short of gas to meet the load if we can't bring gas into Jackson Prairie, he said. Customers need to have firm rights, Rasmuson reiterated.

When market prices increase, are utilities holding their generation in reserve rather than taking it to the market? Yost asked. Utilities tend to hold a little back to assure they can meet load when they know a cold spell is coming, Rust replied. Contingency reserves are a requirement to assure a utility can maintain service to its load if a facility is lost, and utilities have to carry a minimum amount to address those contingencies, he said. Look at how much load has grown in the Northwest and how many power plants have been built, Rust pointed out. The Northwest load often takes the generation we have installed, he added.

What about Independent Power Producers? Yost asked. Are they contracting with utilities to firm up load so energy isn't going into the market? he asked. Staffer Charlie Black said utilities are purchasing the merchant plants. There are a few merchant plants in the region that don't have generation committed via a long-term contract, he said, but those plants are bidding to fill utilities' requests for proposal. As time has gone on, merchant plants have been purchased by utilities and put into service to meet native load, Black stated.

While the overall NWPP peak is growing at 1.5 to 2 percent per year, the Pacific Northwest footprint within the NWPP shows no upward trend in peak or energy loads, he pointed out. This raises important questions we will be talking to the Council's Power Committee about, Black said. Are we seeing little demand growth on the system due partly to energy efficiency? It's an interesting question, he concluded.

Cloud Over Coal Plants

Former Council member Angus Duncan, chair of Oregon's Global Warming Commission, briefed the Council on "the latest wicked problem that is coming our way" in the form of Section 111(d) of the Clean Air Act (CAA). The major climate change initiatives of the Obama Administration are auto fuel-economy standards, which are doubling by 2025, and an "obscure section" of the CAA that enables the Environmental Protection Agency to develop regulations that apply to emissions from existing power plants, he said.

Regulators will have to understand better how the electricity system works if we are to end up with rules that will not be disruptive, Duncan said. "That will require heavy lifting on our part and on the part of EPA," he added.

EPA concluded it could regulate greenhouse gases under the CAA and determined the gases were hazardous pollutants, Duncan explained. EPA initially focused its rulemaking on new power plants, he said. The rules were probably useful even though there aren't new coal plants being built that would conflict with the law, Duncan said.

Last year, President Obama asked the EPA to develop regulations under the CAA for greenhouse gases, he continued. About 37 percent of the electricity generated in the United States is from coal, down from over 50 percent 10 years ago, Duncan said. He pointed out that most old coal plants are already off the system, but new and middle aged plants remain.

As a region, we are 18 to 20 percent reliant on coal, Duncan said, adding that for Oregon, it's 34 percent. Some states are over 90 percent reliant on coal, and "they will have a hard time" under the rules, he predicted. The regulations differ dramatically from state to state and region to region, Duncan said, and "EPA has no choice, it has to do this."

With regard to the schedule, EPA has to promulgate rules by the middle of 2015, which means drafts will be needed by the middle of 2014, he continued. States will have to develop their own compliance plan or one will be imposed in 2016, Duncan said, adding that "it is a rigorous schedule to get where we need to go."

EPA will develop guidelines for the best system of emissions reduction, which will be a "safe harbor for states," he said. If a state has a plan that is different from the guidelines with equal or better outcomes, EPA will approve it, Duncan said. But if it doesn't meet the guidelines, EPA will develop a plan for the state, he said.

In the Northwest, we have plants in one state that serve loads in another, and we have to make sense of that within the CAA 111(d) construct, Duncan went on. EPA has signaled it is open to flexible solutions and to systems solutions, but it is unclear what the systems solution will be, he said. Duncan pointed out complications involved with a coal plant that serves loads several states away or a plant that has shared ownership. We need to figure out what flexible solutions there are that can accommodate the system architecture and pattern of ownership, he stated.

In terms of flexible solutions, the easiest are to close a plant or limit its production, Duncan said. Carbon capture and storage do not seem economic on a retrofit basis, he added. We can explore whether there are ways for utilities to mix and match plants, use energy efficiency that permits plants to ramp down, or introduce renewable energy plants into the system, Duncan suggested.

A Least-Cost Solution

In addition, there is the question of what combination is the least cost solution, he continued. How do the states interact to come together to develop a least-cost solution? How do we come up with collaborative options for state-by-state plans? Duncan asked.

One option might be state-by-state bilateral agreements that focus on a specific utility, he said. For example, Oregon and Montana could wrap a plan around Montana coal generation that serves Oregon and back down the generation and emissions, Duncan said. That approach would take a lot of bilateral agreements, but it might be easier than a true regional solution, he added.

We have to think about the distributive affects, too, Duncan went on. Within Oregon, for example, the effects of a carbon reduction strategy could be dramatically different depending on the utility and its resources; customers would be at different levels of risk, he said. There will also be effects on low-income customers, the industrial mix, and urban and rural differences that have to be addressed, Duncan pointed out.

In the Sixth Power Plan, "the Council did groundbreaking work" to develop regional resource portfolio scenarios that comply with the Oregon, Montana, and Washington greenhouse gas goals, he said. The Council ran models and came up with an interesting proposition of how to achieve the least-cost compliant system and the costs were interestingly manageable, Duncan said. To meet the 2020 goals, customers were looking at a 2 percent increase in their annual cost of electricity, he stated.

We need the Council to do a similar analysis, using plausible scenarios, of how to comply with Section 111(d) and what it would do to the region, Duncan said. It wouldn't be exact for any utility, but it would provide a framework for the most cost-efficient way to meet the law, he said.

The Global Warming Commission will be providing a venue for a utility regulators roundtable to look at options for structuring a least-cost regional response that would ameliorate distributive affects, Duncan said. The Council could have "a slot at the microphone" to talk about the Sixth Power Plan analysis and what the Council could look at to provide the least-cost context, he said. Such an analysis will probably be part of the Seventh Power Plan, Duncan said. Can we move it up in the analytic queue to inform the EPA about an optimal regional solution? he asked.

Henry Lorenzen pointed out that the Department of Environmental Quality regulates emissions from plants in Oregon. Why is the analysis different just because the product is transmitted on electrical lines? he asked. The analysis could be done that way, but most of the costs would land on the producer states, Duncan responded. By the time these rules apply, Oregon will have no coal and Washington will have very little, he said.

But aren't the costs, which are approved by the Public Utility Commission, allocated to the delivered power? Lorenzen asked. The issue will be our collective ability to come up with a least-cost solution, Duncan said. Some solutions would advantage one state over another, he added.

Phil Rockefeller said it would be useful as a baseline for the Council to get a joint submission two dozen states made to EPA in response to the regulations. The submission had general principles and support for a system wide approach, he said.

Those comments support flexibility and defining systems so they are large enough and diverse enough to offer the opportunity for lower-cost solutions, Duncan responded. The Pacific Northwest is distinctive in how separated the generation is from load and the situation invites a different kind of flexibility, he said. We will try "to do a carve-out" with EPA, Duncan said.

Let's Get Credit for Efficiency

Tom Karier said the schedule for the Council's final analysis on carbon would be difficult to move up. But we can work with you to get what we can earlier, he said. This is an opportunity for the Northwest to put its interests forward, Karier said, adding that the Council hasn't done much in the past on issues like distributive effects.

He added that equity with other regions is a consideration. We want to make sure we are rewarded and not penalized for our years of energy efficiency, Karier stated. The question is where the costs land to move to a carbon-free environment, he said. Has EPA signaled if it is looking for a specific level of carbon reduction? Karier asked.

That is "a tea-leaf exercise," but emissions are within the same framework as the rules promulgated last year, which is to meet the emissions of a high-efficiency gas plant, Duncan responded. If we structure ourselves as a system in the Northwest, we can average things on a system basis; if emissions meet the threshold, the system would be okay, he explained. It depends on how we define the system and what EPA thinks is acceptable, Duncan added.

Are they looking at a level of emissions reduction? Karier said. EPA is inviting comments on defining the level, Duncan said. An important point is the selection of a baseline, he added. Depending on how that is done, we get credit for energy efficiency or we don't, Duncan said.

EPA will offer draft guidelines later this year and a final rule in 18 months, he recapped. We don't need a final regional least-cost solution now, but by the middle of next year, we do, Duncan said.

In the electricity sector, emissions are regulated as point source, but Angus is suggesting a system approach, Black clarified. The question is how to apply a system solution that may cross state boundaries, he said. To get states to participate in the process, the solution needs to deliver a net benefit to the states, Black said. The Council's regional analytical model is being redeveloped and will not be available until the first quarter 2015, he confirmed.

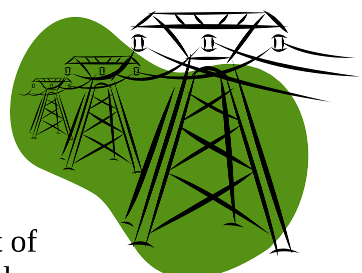
Lorenzen asked if EPA would look for a system rather than point-source approach. All signals from EPA are that they want to see a system strategy, Duncan replied. They need the least-cost way to get the maximum emission reductions, he said. There will almost certainly be legal challenges to whatever they come up with, Duncan said, adding that the best system is a national cap and trade. EPA wants the most reduction with the least cost and least legal risk, he said.

This region is among cleanest if not the cleanest in the nation, Bill Booth said. Since the planned closure of Boardman and Centralia has been achieved, how about an approach that says this region is the cleanest and has done its share, he proposed. The Colstrip plant is important to Idaho and Washington and produces power that is low cost, even below the cost of conservation, Booth said. Doesn't it make sense to say this region is very clean and has met its goal? Is it worth going after the closure of Colstrip? he asked.

EPA will look at plant-by-plant production and set an emissions level, and we will have a decision about which plants to back down, Duncan answered. The point is to reduce emissions, he said. As long as the net consequence meets EPA guidelines, they are inviting us to come back with solutions, Duncan stated. We will have to reduce emissions and meet the threshold EPA sets as though each plant is reaching its greenhouse gas goal, he elaborated. We have the opportunity to come up something better than applying "a meat ax" to each plant, Duncan said.

Pat Smith asked if there is a chance the Council could do some least-cost analysis. This presents opportunities for creative thinking about a system approach, he added.

NOS Feeds BPA Transmission Plans



Bob King of BPA briefed the Council on BPA's transmission planning process, describing a long list of considerations. To plan, we need to know what people want to do on the transmission system, he said. Transmission permitting and construction takes a long time, often 10-plus years for a 500-kV line, King said, so planning has to start early.

We need to know where renewable resources are going to be developed and what generating resources they will displace, he explained. Most of the region's load is west of the Cascades, but the higher quality wind and solar potential is on the east side, King pointed out. And the demand for Northwest exports to California is uncertain due to changing policies, he added.

"It boils down to a word: information," King stated. Information is important and the more we know early on, the better we can address the needs, he said.

King explained BPA's transmission "flowgates" and a division of the system into three major geographic areas. Puget Sound south to Portland is a major load corridor, where growth is occurring, he said. It's a major point of congestion on the system, King added. A second area east of Portland on the Columbia River, referred to as Lower Columbia, has seen a tremendous growth in renewable projects and there are lots of transmission requests to satisfy, he continued. Farther east is a third area, referred to as the Lower Snake, where lots of renewable projects are also going in, King said. The challenge is to know where the power is heading from the projects, he said.

A number of recent transmission upgrades provide increased capacity west out of the Lower Snake and Lower Columbia areas, King reported. Most existing interconnection stations in the Lower Columbia are full, so any new large generation projects would require additions, he said.

BPA began a "network open season" (NOS) in 2013 during which anyone with need for transmission capacity can get in a queue with the request, King explained. A "cluster study" is key to coming up with the best plan of service given the requests received, he said. We can't do projects on a one-by-one basis so we focus on the cluster study to come up with preliminary plans, King said.

BPA took a break from the NOS in 2012 to tighten up the process and got back to it in 2013, he added. Right now, the cluster study has been done for the 2013 process, and BPA is in the project definition stage, King said. Up next is a business evaluation step, which is followed by a decision on proceeding with an environmental study agreement, he said.

BPA had 18 executed and funded cluster study agreements in 2013 for 3,473 megawatts of transmission service requests, King continued. BPA extended the cluster study by 120 days at the end of December to address additional issues, he said. BPA is trying to conduct the NOS on a 12-to-24-month cycle that tracks with regional planning, King said.

Lorenzen asked how BPA sets up the projected rate for a transmission request. King said it depends on whether the plan of service involves a cost that will be rolled into the network. If so, service on the line will receive the published tariff rate, he said. But if there will be more than a minimal impact on costs, we recommend an incremental rate, King explained.

How are you addressing pancaked rates? Lorenzen asked. BPA offers a short-distance discount, but much depends on the plan of service, King replied. If a new interconnection causes a build that would impact others, we establish an incremental rate, he said.

In response to a question about the volume of NOS requests, King said "the mix is always different." The reason BPA stepped back from offering NOS in 2012 was that we got commitments early on in the previous process but found the certainty wasn't there for some projects, he explained. This time, we'll ask for the commitment in stages as we get closer to going forward with a project, King said, adding that less that 5 percent of the requests come through in the end.

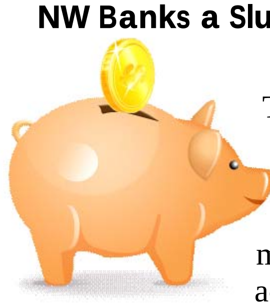
Rockefeller asked about BPA's statement that it will work to improve the efficiency and lower the cost of integrating renewables. The rate case is where "the rubber meets the road" on costs, King responded. We are seeing pressure on rates, and "segmentation" of the system will be contentious, he said. We are committed to a public process to discuss the issues, King said. It is important to keep the Northwest's transmission system together, he added.

"It's important to have a system that recognizes opportunities for renewables," Rockefeller stated. BPA tries to sit in the middle and see both sides, King said. Lorenzen pointed out that the transmission costs can be an incredible strain on small co-ops and rural customers.

BPA operates on the principle of cost causation and tries to find a balance between cost causation and rate shock, King stated. "We try to get the costs into the right bucket," he said. Rockefeller asked if there is some "socialization" of transmission costs, and King said there is.

Black pointed out that similar transmission rate issues have been around for a number of years and remain difficult. BPA would not have the latitude to give special treatment to renewables, he added. That would be considered discriminatory by the Federal Energy Regulatory Commission, Black said.

NW Banks a Slug of Savings



The region exceeded the 2012 conservation target set in the Council's Sixth Power Plan, achieving 253 average megawatts (aMW) of savings, according to a survey condu cted by the Regional Technical Forum (RTF). The RTF survey gathers data annually on conservation savings and expenditures in the region, staffer Gillian Charles told the Council.

The launch of last year's survey was delayed while improvements were made to the data collection system, she explained, noting that Council staff is still working with BPA and utilities to make the process better. The survey is a big effort that involves a lot of people and it is voluntary, Charles said. In the 2012 survey, the RTF coordinated with PNUCC to collect information on utilities' projected savings and expenditures for 2013 to 2015. This will help to see whether the region is on track to meet the conservation target in the Sixth plan, she said.

While there was a drop in the number of utilities responding to the survey, down from a high of 98 in 2010 to 80 in 2012, the share of the regional load covered is 100 percent, Charles continued. The Council gathers data from the Northwest Energy Efficiency Alliance (NEEA) and BPA for utilities that do not respond directly, she explained.

"What looked like mission impossible was not so impossible," Charles said, noting that the target for 2012 was 240 MW. The region has exceeded the target set in the power plan every year since 2005, with the high being 277 aMW in 2011, when BPA's spending on energy efficiency went over budget, she pointed out.

Since 2005, Northwest utilities have acquired over 1,700 aMW of conservation savings, staffer Tom Eckman stated. That exceeds the total load of Seattle, he added. There has been a shift since 2008 in where savings are being achieved, Eckman said. Savings in the commercial and industrial sector are growing relative to the residential sector, he pointed out.

The region's investment in energy efficiency topped $350 million in 2012, Eckman reported, noting that of the $5.35 billion spent nationally on energy efficiency, the Northwest represents 7 percent. NEEA continues to contribute significant efficiency savings in the region, about 20 percent of the aggregate, he continued. A fair amount of the NEEA savings in recent years is attributable to increased efficiency in televisions, Eckman added.

The average levelized cost of conservation remains low and was about $18 per MW-hour in 2012, he said. In 2007 and 2008, utilities flooded the region with compact fluorescent light bulbs at very low cost, Eckman explained. There are higher-cost measures coming into the mix, but the average is still low, he said.

In looking at the survey's projections for future achievements and investments, it's clear that the tally by 2015 will be over 2,000 aMW, he said. We should easily achieve the target in the Sixth plan, and "the question is how much we'll exceed it," Eckman added.

He went on to point out how much the region invests in energy efficiency per person, $28.02 in 2012, which is nearly double the U.S. average of $16.17. The Pacific Northwest also invests about twice the share of its retail electricity revenues in efficiency compared to the rest of the nation, 3.3 percent in 2012 compared to 1.63 percent, Eckman reported. Efficiency has met nearly 60 percent of the load growth in the region since 1980, he added.

Since 1978, the region has produced over 5,300 aMW of savings, with two-thirds attributed to utility and BPA programs, and one-third a result of state codes and federal standards, Eckman reported. That is enough electricity to power the entire state of Oregon, he said. Efficiency saved the region's electricity customers nearly $3.23 billion and lowered carbon emissions by an estimated 20.8 million metric tons in 2012, Eckman said.

Energy efficiency was the region's second-largest resource in 2012, displacing coal in the resource stack, he said. Savings from energy efficiency since 1978 is nearly equal to the annual firm energy output of the six largest Columbia River dams, Eckman said. “We’ve stretched the Northwest’s hydro resource,” he wrapped up.

What is your confidence the savings persist? Rockefeller asked. To the extent we have expired measures, the savings are reduced, Eckman responded. Some measures expire and they are displaced, he added. Where we know a measure won’t persist, we have made an adjustment, Eckman said.

The achievements are a great success, Karier said. This has been done at a phenomenally low cost, has reduced carbon emissions, and set an example for others in the nation, even though this region has low-cost electricity, he said. We need to think about how to build momentum for the future, Karier stated.

Council chair Bill Bradbury asked about costs going forward, and Eckman said the region has not exhausted measures under $40 per MWh, but some of the savings have been captured by standards. There is still potential, he said.

Smith asked if changes in BPA’s program will impact savings. The changes will improve the administrative structure, Eckman responded. There will be a discussion in the course of the rate case about the appetite utilities have for more investment, he said. The current 25 percent cost-share with utilities is being met according to BPA’s program review, Eckman added.

We are probably in good shape for achieving 200 to 250 aMW per year, Yost stated. But not all years are equal and this should be looked at as a five-year target, he said. Also keep in mind that this level of achievement “is paid for by someone,” Yost said. “It is not free; there is a cost to conservation and it comes out of someone’s pocket,” he said. We also need a contribution from technology to continue the achievements, Yost said. “This is not just about cranking up the spending,” he stated; there have to be technology improvements.

Engaging on the Seventh Plan

Black described the activities and proposed schedule for developing the Council’s Seventh Power Plan. Advisory committees are up and running, and we are actively engaged with the region through them, he reported.

A new group, the Resource Strategies Advisory Committee, holds its first meeting this week, Black said. The committee has 34 members and will be chaired by Henry Lorenzen, he said, adding that all Council members are invited to attend. The committee roster is “a who’s who” in Northwest energy and it should be very helpful to the Council, Bradbury commented.

Staff is working on redevelopment of the Regional Portfolio Model (RPM), which is used for strategic risk analysis and developing an overall strategy for the plan, Black continued. The Council issued a request for proposals for software development in December and about 30 individuals participated in a pre-bid conference, he said. We will report back in February on the responses we receive and hope to have a vendor recommendation in March or April, Black said.

Other steps in preparing for the Seventh plan include writing issue narratives like those done for the mid-term assessment, Black said. We have more symposiums planned, including one in March on the change in demand growth for electric utilities, he added. We are also working on forecasts and other inputs and assumptions for the plan, Black reported, adding that the Genesys model will be used for developing a picture of resource adequacy, both for energy and capacity.

Staff is working on issues like balancing and resource integration, Black went on. We are also developing an approach for the region to make policy propositions for us to test, such as Governor Inslee's "glide path" to reduce carbon emissions and the associated price tag, he said

The schedule calls for having a new RPM available in the first quarter of 2015, Black said. A draft plan with a public comment period would follow, and plan approval would occur by the end of 2015, he stated.

The Council must also develop an environmental methodology ahead of the plan, Black went on. We'll propose a methodology for Council approval, he said. Staff wants your suggestions on how to make this plan useful, Black concluded.

End Notes

Kootenai Assessment Continued. The Council voted unanimously to approve a $735,462 annual budget for an assessment of "operational losses" in the Kootenai River and floodplain begun in 2002. Project sponsors, the Kootenai Tribe of Idaho and the Montana Department Fish Wildlife and Parks, reported to the Council on their work and described the Index of Ecological Integrity developed to assess the impact of operations. The operational losses are in addition to those for Libby Dam construction and inundation.

Big Numbers for F&W Amendments. The Council's Fish and Wildlife (F&W) Committee has tackled 480 recommendations to amend the F&W program. The recommendations came from a range of interests, including agencies, tribes, and utilities, as well as 350 from individuals, with most of those specific to protected areas and the Skykomish River. Two work groups are addressing the issues of toxics and research, monitoring, and evaluation. A draft F&W program could be out in April.

Remand Response. The Council voted to release Appendix P from the Sixth Power Plan for comment. The move responds to a September 2013 Ninth Circuit Court decision that remanded the Sixth plan to the Council for "the limited purpose" of allowing public comment on its methodology for determining quantifiable environmental costs and benefits. Comments are due March 5. The Council will subsequently decide whether it would have done anything differently in the Sixth plan as a result of the comments.

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