Northwest **Power** and
Conservation Council

Council Meeting
May 4, 2015
Portland, Oregon

Council Chair Phil Rockefeller called the meeting to order at 1:33 p.m. All members were in attendance.

Rockefeller first introduced his new policy assistant, Kendall Farley.

Reports from Fish and Wildlife, Power and Public Affairs committee chairs

Council Member Bill Bradbury, Chair of the Fish and Wildlife Committee, reported that the meeting opened and was dominated for two hours by the ISAB density dependence report. A highlight from the report is that the region can try to develop opportunities to harvest surplus hatchery fish more effectively. They pointed to the Colville selective fishing project as an example. If they can do so, they can decrease density effects. In addition to more selective harvest, we still need to address habitat and carrying capacity. Improving riparian habitat over the length of the river helps survival, but that takes time. So it's not an instant, quick fix. The return of marine derived nutrients — mostly salmon coming back to spawn — can help stimulate tree growth, which then creates riparian habitat. The ISAB cited a study that showed that closing off the marine nutrients from a system had the effect of stunting tree growth.

There was a lively debate on Fish and Wildlife's cost-saving effort. The Fish and Wildlife Committee will ask the Council at the next Council meeting for BPA to reserve a $3 million placeholder to be used to fund emerging priorities that were identified in the latest Fish and Wildlife Program amendment. The catch is that we have to identify the sources of savings between now and September. If unable, to do so, they will try for Fiscal Year 2017.

Allan Evans, of Real Time Research, and Dan Ropey, of Oregon State, presented results that measure bird predation on salmon populations. They count all the PIT tags that end up on some islands that birds use. The count helps them figure out how many fish were consumed. They can now more accurately count cumulative losses of certain fish species consumed due to terns, cormorants and California gulls that have gone underreported in the past. In 2014, 35 percent of upper Columbia steelhead smolts were lost to bird predation. It's a depressing figure, but there is some hope. We're in a major process of moving terns out of the estuary and off islands in the mid and upper Columbia, by squeezing them into smaller habitat and out of the Columbia Basin entirely.

BPA gave an update on the posting of annual progress reports for research, monitoring and evaluation projects. It's changing to a scientific journal format — they're shorter, more user-friendly reports, with sections that focus on policy and lessons learned. BPA has increased policy report responses by four times its previous rates. Now the reports have been integrated so you don't have to sift through four or five reports to find out about actions in some areas of the program.

Council Member Pat Smith, Chair of the Power Committee, reported on regional electricity sales revenue trends. Looking at a seven-year history, energy sales remained stable throughout all sectors, while the economy grew by 2 percent annually. Retail electricity revenues grew faster than sales of electricity at 1.7 percent of the annual growth rate after inflation. We're seeing a growing gap between public utilities and IOUs average revenues per unit of electricity sales. In 2013, the IOUs average revenues were $86 per MWh compared to $74 per MWh in 2007. In contrast, public utility average revenues were $61 per MWh, the same as they were in 2007. IOU average revenue per MWh increased by 2 percent per year since 2007, while publics remained flat. A couple reasons mentioned was the IOUs' inclination to raise rates more often, and there's a larger industrial load in rural areas at a lower rate, which also impacts the revenue gap.

Second, BPA gave a presentation on demand response efforts. They mentioned that it was a Sixth Northwest Power Plan directive to engage in this research. They started with pilot projects with 20 utilities on a small scale over four years. The idea was to use demand response to help wind integration, balance loads and defer transmission upgrades and build outs.

There were three demonstration projects: a Port Angeles Paper Mill has a 30 MW demonstration project. It is trying to get 90 minutes of demand response relief. A second project is with Energy Northwest, a 35 MW project that started February 2015. It's an aggregate approach to demand response, lumping smaller projects together, and trying to get to 90 minutes of demand response relief for winter peak. It ends January 2016. The third project is being done by EnerNOC, which is trying to shave winter peak with a 13-25 MW proposal. EnerNOC is the largest commercial demand response aggregator. A third party was brought in, and it's very complicated with lots of parties, transactions and contracts. It is looking for up to 90 minutes of demand response help. Most of these projects involve fairly fast ramp rates, within 10 minutes. That demonstration project ends April 27. That approach to aggregating demand response is what BPA sees as the future, which could reach 100-200 MW levels.

The third agenda item was a review of the region's electricity needs assessment. This is a 20-year timeframe looking at load growth and matching it to existing resources. We know we have coal retirements in 2025. Using the loss of load probability, we look at what the gap is going to be. It was emphasized that the benefit of doing this is that it prevents overbuilds. It's an accurate way to match loads with resources.

Another agenda item was the scenario results. We resolved a minor disagreement between the Systems Analysis Advisory Committee (SAAC) and Generation Resources Advisory Committee over what a peaker model is. The SAAC likes the simple cycle, because it is cheaper, and the GRAC want reciprocating engine because it has more flexibility. Staff suggested a compromise is to use an Aero derivative combustion turbine that isn't as expensive and has flexibility.

Last on the agenda for the Power Committee, we got back into demand response, and had a presentation on resource portfolio model (RPM) outputs. We learned that the RPM likes demand response. It likes it because of cost and because of the relatively short time frame in which it becomes available. In the model, demand response is available in April 2016, versus a gas peaker, which wouldn't be available until 2018. I'd emphasize that the model is looking at technical feasibility. It's not looking at institutional transactional barriers – the types of things that are hard to put together. It's going to involve some policy issues. Staff has gone to the region and looked at utility integrated resource plans (IRPs), to see what they're doing on demand response, and many utilities such as PacifiCorp are looking at it,.

Council Member Jennifer Anders, Chair of the Public Affairs Committee, said the committee met in Helena and they are putting together an electronic version of the 2014 Fish and Wildlife Cost Report. Today they will meet and will get an update on the August Congressional staff tour, which takes place August 18-20. The agenda also includes looking at draft copies of the 2015 Pocket Guide and 2014 Fish and Wildlife program summary.

1. Presentation on Northwest Regional Forecast by Pacific Northwest Utilities Conference Committee

Before delving into a summary of PNUCC's latest Northwest Regional Forecast, Executive Director Dick Adams pulled out a copy of the Regional Forecast from March 1952.

"I'm sharing this because I like data," Adams said. "Looking back in 1952, this post-war era report was sent to the Federal Power Commission. Sixty-five years ago loads were a quarter of what they are today (4,000 MWa compared to about 20,000 MWa today). Aluminum smelters were developed in the Northwest because of abundant and cheap hydropower. Loads were increasing rapidly and projections were based on a 4.25 percent growth rate."

Fast forward, the region is now looking at fairly flat load growth of just 0.6 to 0.8 percent, and those numbers are net of energy-efficiency savings, Adams said.

Adams said not to let the overall flat load growth tell the story for the whole region. “There are individual utilities and 25 different stories,” he said. “In a large utility, with energy-efficiency programs and new standards, we might see flat growth. But we also have a small utility with a new data center facing a 3.5 percent annual load growth in the next five years.”

Adams reminded the Council about the testimony it heard from smaller utilities in Eugene and Montana in the last two months. “One size doesn’t fit all, whether it’s a load forecast or resource development,” he said.

PNUCC produces its Northwest Regional Forecast each year, compiling data provided by utility integrated resource plans and it captures smaller utilities’ data from BPA. “We shrunk our forecasts from 20 years to 10,” he said. “While info was interesting, it didn’t tell the story about the NW Power System.”

Compared to PNUCC’s 1980 report, hydropower capability is now 1,500 MW lower. The operating capabilities have changed, constraints have changed and, while the flows are the same, there are more conditions on how the hydro plants can be operated and their reservoirs drawn. In compiling generating resource data, PNUCC only tracks plants committed to meeting NW loads.

Clean, renewable hydro remains the big dog, Adams said, as it has the largest responsibility for meeting winter peak capacity. The region has some nuclear and coal, and natural gas is a growing segment. Wind has some impact, but very little winter capability, and the region is starting to see reportable information on solar generation.

Over the years, the region has focused on energy planning, due to hydro, Adams explained, but current information suggests that there’s a winter capacity need of growing importance, especially with Boardman going offline at the end of 2020. A gap between generation and need is moving the region from energy planning to capacity planning, Adams said. “We need more discussion on planning margins and how to pick one that fits the needs of the Northwest.”

Adams listed the factors that affect utility actions:

- **Policies** – an example is Washington’s’ I-937 policy. They will drive what utilities will drive and contract for. Might be a local governing board, such as Snohomish’s PUC board with a policy that anything developed will be local and carbon free. Policies drive what utilities will acquire and contract.
- **Risk**: what exposure does a utility have? If a utility has potential high load growth due to server farms, etc., that creates a risk.
- **Need** – Supply and demand — what’s needed to keep the lights on.
- **Cost** – What’s the best way to meet all these objectives in a least-cost fashion?

Other factors include load profile (summer or winter peaking?), resource mix, policy direction, new resource options of generations that are available, and transmission access (which can become a key component to individual utilities trying to decide what to do next).

Adams said that he found the Council's dialogue around demand response valuable, but that the Power Committee meetings have left him with a lot of questions. He said that PNUCC is consulting with utilities to hear how they value demand response, how they develop it, how they assessed its potential and the barriers they found.

"It feels like it's a frontier that needs more attention," Adams said. "But there are so many questions we need to address, including how often can these winter loads be interrupted? What are the conditions under which the utility can reserve that right? Is there a recovery period? We need to know more about the characteristics of this load. There may be all kinds of characteristics that are glossed over, and that's the next step in understanding this demand side resource."

Council Member Henry Lorenzen commented, "It struck me about demand response whether it's retail or wholesale. Will a signal be given by local utility or by the balancing authority to the system as a whole? That's two different types of demand response and there's a lot of work to be done to pan that out."

Adams replied, "For what purpose will you use it? Is it for the utility, for a balancing area activity or to reduce the demand charge from your provider?"

Looking at energy efficiency, PNUCC's forecast tallies up about 900 MWa in utility program savings looking out over five years. The potential savings from market transformation is about 50-60 MWa per year, while the savings from new federal standards and momentum savings are tougher to pin down.

"We know how our load forecasts have been changing over time, and then I looked at conservation forecasts and, if there's a pattern there, I can't see it," Adams said. "These forecasts need to be reevaluated on a regular basis."

On the generation side, going out five years, a few utilities are acquiring generation. Almost 1000 MW of nameplate capability will come online to meet Northwest loads in the next few years. There is some small hydro (Grant PUD is upgrading some turbines, Snohomish has a few, 6 MW projects they're pursuing), solar (Idaho Power and PacifiCorp), wind (Idaho Power) and natural gas (PGE's Hardy project combined cycle turbine – a 450 MW plant).

Adams said that the Public Utility Regulatory Policies Act (PURPA) drives Idaho Power's solar acquisitions. "It's not driven by an energy need or state policy, but because they have requirement to acquire it," he said. "PacifiCorp has some solar too, but I don't know their reason for acquiring it."

The primary takeaways for the Northwest power industry are:

- All utilities are different and are addressing different needs.
- Winter peak is the focus in the West and summer peak in the East.
- Energy efficiency is still a priority
- Utilities are exploring new opportunities – such as demand response.

Adams concluded his presentation by praising the Council for diving deep into scenarios for the Seventh Plan. "I still believe that the scenarios, the *what ifs* and policy propositions are of the highest value," he said. "What would it take for the region to reduce carbon by 50 percent or to zero? What about if we retired all existing coal plants? With the data you have and brainpower that sits around table, these are the most interesting parts of your Seventh Plan."

The tough part, Adams observed, is translating it all into policy answers, not just distributions and net present value. "You're poised to do that kind of work, and I think it needs to get done," he said.

Council Member Tom Karier took the opportunity to thank Adams for all his work with his impending retirement from PNUCC:

"I want to thank Dick Adams for his contribution to this industry and to the Council over the years," Karier said. "Dick has been the executive director of PNUCC since I've been on the Council, and he has been doing this since before I arrived. He's been a wonderful resource. He's the director of this small, highly influential group, and his retirement will be a loss to the intellectual capital of the region. Thank you for helping us over the years."

2. Council decision on Final 2020/2021 Adequacy Analysis Report

John Fazio, Council's staff senior power systems analyst, brought to the Council the adequacy assessments for 2020 and 2021. Back in 2011, the Council adopted a methodology to assess the adequacy of the Northwest's power supply. The assessment provides an early warning if resource development fails to keep pace with demand growth. The Council assesses resource adequacy every year, examining the ability of the power supply to meet regional demand five years out.

The Council's maximum threshold for loss-of-load probability (LOLP) is set at 5 percent. This means that the power system has a 5 percent chance of having a shortfall sometime during the year being examined.

For 2019, the assessment came in at 6 percent, which is a little inadequate. The current adequacy assessment for 2020 shows a LOLP of five percent, just at the Council's adequacy threshold. It turns out that the load forecast has come down quite a bit — 310

MW lower than what was used for the 2019 assessment.

The biggest change on the resource side is that Big Hanaford is no longer in use, which is 250 MW not in the assessment. There also were adjustments for hydro constraints in light of the Biological Opinion. When everything is put together, the LOLP is 4.8 percent, rounded off to 5 percent. So looking forward five years, the region is adequate, but just barely.

By 2021, however, after the planned retirements of the Boardman and Centralia-1 coal plants(1,330 MW nameplate), the LOLP rises to a little over 8 percent, and would lead to an inadequate supply without intermediate actions. Some combination of new generation and load reduction programs will be used to bridge the gap assuming 1,600 MWa of energy efficiency savings are acquired as expected.

The Resource Adequacy Advisory Committee had the following recommendations for the 2020/21 Assessment:

- Add lines to LOLP Table to add firm imports and intertie capacity, and add studies with different combinations.
- Give an indication of LOLP error – due to statistical effects (see, games, etc.), and roughly + or minus 0.5% LOLP.

The expected case is 2500 MW of import availability during the winter, Fazio explained our intertie limit from south to north is 3400 MW. The historical transfer capability from south to north, 95 percent of the time, is 3400 MW. Once in a while it goes up to 4500. The RAAC wanted to see a study on what happens with 4500 of transfer capability.

Member Karier said, “I’m concerned about that 4500 on the intertie, because has to be available all the time, not just when you need it. That seems unrealistic. What’s the likelihood of it?”

Ben Kujala, staff system analysis manager, explained that on the transmission system, there’s a lot of power going the other way. “You can buy back through it,” he said. “Transmission ratings go up in cold weather. I don’t think you can say 3400 MW is super likely. It’s a conservative number. A lot goes into available transportation capability. The 3400 MW figure is conservative, but it’s realistic.”

Fazio said that BPA looked at 2021. “If we lose Boardman and Centralia 1, the nameplate is 1330 MW, but winter capacity is just under 1200 MW, so that’s what we need to replace.”

Load growth is forecasted at 40 MW between 2020-21. This is because of anticipated Sixth Plan energy efficiency savings.

But the Council is more interested in the generic question of what if the coal plants were out the entire year? BPA ran the study and the LOLP was 8.3 percent, and 1150 MW would be required to bring it down to 5 percent.

To get to 5%:

Gas-fired turbines	1.15 GW
Solar PVs	12.7 GW
Wind	10 GW (could only get the LOLP down to 6.9%) More wind didn't help.

Fazio said he is not recommending these actions, but rather is just showing what it would take to fill the gap. "How to fill the gap is not the scope of the assessment, that's for the power plan," he said.

RAAC recommendations:

- Review the LOLP metric.
- Account for intertie outages – we don't do this now, because the intertie is up 100 percent of the time.
- Review load shapes in more detail – the difference between resource adequacy loads, which have energy efficiency built in, and frozen efficiency loads, which do not.
- Research "market friction."
- Research gas supply limitations.
- Continue to work on 3-node analysis.
- Review hydro dispatch and recommend changes, if needed. The way we do it now, it's very difficult to do a 3-node analysis.

Staff is asking Council to release the executive summary, along with the technical appendix.

Bradbury asked the definition of a 3-node analysis. Fazio replied that Genesys has two nodes: east and west. But Southern Idaho is not quite like either, so it becomes a node.

Council Member Jim Yost asked if they could look over the document that evening and move on it in the morning.

3. **Remarks by Elliot Mainzer, Administrator, Bonneville Power Administration**

Chair Rockefeller welcomed Mainzer to the Council, stating that it was his second appearance. "Last time, you focused on human resources crisis management, the abrupt change of leadership and other things that fell into your lap. Hopefully now those are receding in the past.

"Last March when I was here, I probably still had that deer in the headlights look," Mainzer said. "It's amazing what 14 months will do. We have our Human Resources restored, have a full set of executives, a General Counsel and we feel very positive about where things are," he said. "I believe this is a historical period for the industry. It's game on."

Speaking without prepared remarks, Mainzer pointed to what he termed "transformational" events in the industry. He believes that some fairly significant changes will come out of the carbon conversation, which "has huge implications for the industry in terms of ranging units of transmission, voltage stability, and infrastructure that we develop or may not develop."

He said that the market design changes occurring in California — the creation of the new energy imbalance market with PacifiCorp, CAISO, and the other utilities — should not be underestimated in terms of its impact on the West.

"I've been engaged with entities in California, trying to figure out how to accommodate that change while managing impacts on transmission system," Mainzer said. "It raises some big questions about where the Northwest is heading."

Another California variable is the famous "duck curve." What does it mean for the Interconnection and wholesale prices? What does it mean to see a transformation in how power is priced on peak and off peak, spreads changing, and huge ramps and demands for new flexible machinery … and how will adjacent markets be impacted? How can we position ourselves in the NW to interact with that and potentially benefit in some ways?

On the technology side, incredible change is taking place. Mainzer said he is interested in Tesla's announcement about battery storage technology and how that evolves. It poses profound questions for all of us who are building infrastructure and who manage the transmission grid.

"We're making an enormous investment in transmission infrastructure," he said. "Starting in 2008, we built the McNary-John Day line, and we're in the advanced stages of construction of the Big Eddy-Knight Line, the Central Ferry-Lower Monumental, and we're permitting a couple of others. We're in a period of significant investment in the high-voltage grid. We're making a multi-$100 million investment strengthening the DC Interties in California and we're investing in reliability and flexibility. We're accommodating a huge amount of renewables on the grid. Last year, we invested $500 million and we're investing the same amount this year."

On the power side, BPA is spending at least $200–250 million a year in sustained investments in the hydro system. The largest amount is at Grand Coulee. With an average age of 55 years, "we're the classic story of aging infrastructure," he said. "But we're sitting on assets of unimaginable value. We have a shared stewardship responsibility to continue to invest in them."

Mainzer spoke of BPA's 2007 Wind Integration Action Plan that he authored, and expressed pride that a lot of its 16 action items have been ticked off the list. "It's hard to believe that we're close to 5,000 MW of wind on Bonneville's grid," he said. "Last year, I was proud to get the 15-minute, interhour scheduling up and running. We had some growing pains, but on the federal Hydro system, not only is existing capacity doing a great job on the integration side, we've been augmenting short-term balancing purchases, and helping grow markets for third-party supplies of this capacity on the supply and demand sides."

We also have been learning a lot about energy efficiency, he said. BPA's team, Richard Genece and his crew, met Sixth Plan targets handily and completed them below budget. "I see energy efficiency at the heart of what the Northwest is about," Mainzer said. "We need to continue leveraging that resource. There has been some concern in the energy efficiency community about our recent move from capital to expense."

On the cost side, they are at a high-water mark in their working relationship with Energy Northwest. The transformation of that asset has been nothing short of astounding, he said. "I look at what Mark Reddemann has done with this team. It's a model of management excellence. To be able to work with them on extremely valuable transactions around refinancing our regional cooperation debt will save hundreds of millions of dollars in interest expense over the life of those deals. It's done in a way we're not just punting debt out into the future and extending the weighted average maturity of our portfolio. These are classic, win/win debt optimization strategies."

Mainzer mentioned the Pacific NW Smart Grid demonstration project in Spokane, where there were a "remarkable number of learnings by participating utilities," from Portland's lithium ion batteries in Salem, to Montana's hot water program.

In addition, Mainzer said BPA has consolidated a key initiative around integrated demand side management. "Obviously, our energy efficiency is at the core of it, but we're now looking at a multifaceted load management strategy, which includes efficiency and conservation, but also takes a look at utilities with peaking loads in winter, and how to take a bite out of that on the demand side," he said. They want to figure out how to extract flexibility from variable loads and variable generation that can complement the scarce hydro capacity for renewables integration.

He mentioned that he had his first year of work on the Biological Opinion, and he's getting to understand the Fish and Wildlife program. "It's unbelievable how much work has been done across the region on habitat and hydro," he said. "Not everyone thinks we've achieved everything we should there, but I think it's an incredible accomplishment. I'm hopeful that we get to a more stable outcome this time around. We'll roll up our sleeves and see what post-2018 looks like."

On the Columbia River Treaty, "I won't say much today, because whenever I talk about that, I get into trouble. The big issue is still proceeding and I will keep region posted as we have material developments. It's a key issue that impacts the region in a lot of different ways."

Talking again about market design, Mainzer mentioned BPA's work with the Northwest Power Pool. "We struggled a bit in last year, to determine what true north looks like," he said. "When PacifiCorp joined CAISO, it changed the dynamic of the conversation and added complexity to the value proposition. We put out an RFP to see if we could get a market operator to operate a Northwest SCED (security constrained economic dispatch). One bidder from the SW Power Pool was higher than we anticipated. We had an offer from CAISO, and its model is just not appealing to our core constituents. So we're stuck in the middle right now, looking at how to advance the conversation."

He said there's an effort underway to see if there's a bridge strategy to keep the region focused and together, or perhaps they have to look at long-term security constrained economic dispatch alternative. "People are a little fatigued and want to see some action, so we'll stay engaged," he said.

"The Council will want to pay attention to this," Mainzer asserted. "It gets down to what is the future of the Northwest operating environment? What will be the level of alignment and integration versus fragmentation, and how will we adapt to those scenarios?"

This past year, BPA has been grappling with the implications of the Seventh Plan. "What we're focused on internally is the question of Bonneville's long-term sustainability," he said. "I come from a strategic background and I try to take the long view. Big decisions were made in the 60s around the Columbia River Treaty and the Interties, which have been the backbone of our operating environment. Some decisions we make today will have those lasting impacts, so we need to take the long view. Everything we do — from energy efficiency, fish and wildlife mitigation, low-income assistance and technology innovations — are enabled by one thing: our ability to be cost competitive today. That falls apart if not running a viable organization, so I'm concerned about long-term cost structure of BPA."

Mainzer said BPA has had four rate increases in the last eight years, and it's going into a close-to-7 percent increase on the power side and 5.5 to 6 percent increase on the transmission side for the 2016-17 rate period. He said they are investing heavily in the system, there's increased O&M on the hydro system, greater investment in fish and wildlife, and in the residential exchange.

The real question is where things are going over longer term. He said BPA has put a lot of effort into refreshing its long-term rate forecasting capability. "We are putting a tremendous amount of work into capital portfolio management," Mainzer said. "Our cap program last year and this year is $1 billion and the forecast is $9.7 billion of investment over the next decade. It's about being really efficient in how we manage that capital and allocating it between all asset categories: power transmission, fish and wildlife, energy efficiency, IT and facilities."

BPA's investment planning with the Bureau of Reclamation and Army Corp of Engineers is done as efficiently as possible. It has created a new position of Hydro Investment Coordinator, and will develop a 20-year, asset investment strategy for the FCRPS.

They plan to take another look at their budgeting processes after they had some feedback that they could be more granular in the way we build our budgets. There's a major effort underway to look at long-term financial sustainability, to keep their balance sheet as strong as possible, and to keep rates competitive.

Right now, BPA's preference rate is $31.50 per MWh. But the wholesale power market is about $25. People are saying that wholesale prices could be going up with carbon pricing, etc., but only a small fraction of revenues fluctuate as a function of wholesale prices, about $300 million per year, so they can't bank on that.

Mainzer said that going into this 2016-17 rate period, BPA moved its energy-efficiency program from capital to expense. "I was presented with the opportunity to take $1.3 billion off the books and $500 million in interest expense, without imperiling our ability to meet energy efficiency targets, so it was an opportunity I had to take," he said. "I acknowledge it happened quickly and in a perfect world it should have had more dialogue."

Council Member Henry Lorenzen commented, "A concern I have is that BPA and its customers view conservation as a cost and expenditure. I don't see a great emphasis on promoting and marketing the benefits of it, and the impact it has on rates."

"I have sympathy for utilities dealing with the operational and cost-realities of their communities," Mainzer replied. "I'm not as interested in cutting costs, but how do you unleash the value in most efficient ways possible? The driver is trying to mend the cognitive dissonance we have in the Council and utilities facing a different reality. We need to bridge that gap."

Member Karier commented, "It's a great proposition to work on that. There's a lot of discussion and ideas on how BPA should design its rate structure. You deserve a lot of credit, taking over for BPA at a low point. You mentioned about 15 different major issues you're addressing. It's an impressive list. I suggest that, when you think about 2028, consider the advantages of a lower public load. The higher it is, the more the challenge it is for BPA."

"You also mentioned the capacity for peak issues and integration in several contexts. Energy efficiency can play a major role in addressing that issue too. Each MW of energy efficiency can provide 2 MW of capacity. We need to nail that down. The region hasn't done those studies in 35 years. Right now region's doing nothing and that will cost us long term. Let's scale it in a way it's affordable."

"On the Treaty, we're missing an opportunity," Karier continued. "We're stalemated. The region isn't infighting, but it's not exactly pulling together; and it has to in order to pull the State Department along. There are different factions, fighting to fix the entitlement, others for the reintroduction of fish above Grand Coulee. Let's get those both of them. Maybe we can introduce fish above Grand Coulee and get relief on the entitlement, which is an exorbitant payment for very few benefits."

Member Yost added, "I know you have a difficult problem. Tom asks you to do these things, and I'm asking you not to do either one of them. I had a similar experience growing potatoes: I invested $2 in growing a crop of potatoes, and sold them for $1. I was told we'd have to double our production to break even. So you're faced with the same situation. You have $31 invested in energy and you're selling it for $25. Either you reduce expenses, or you increase price to make budget. You do have to look at where to go long term, and this is not a good place to be for the region. We may be the cheapest energy providers, but the way the situation is going, we won't be there very long. We're spending way too much money. Mitigation and energy efficiency are great, but we need to figure out where to spend our money. I think you should start with group of folks having discussions."

Member Smith commented that he's interested in the Northwest Power Pool and the decision coming in the fall. "Can you elaborate the bridge scenario and what that looks like right now?" he asked. "I would emphasize Tom's comment on the treaty. Governor Bullock spoke before the Council last month talked about concern over moving forward."

"We feel the sense of urgency too," Mainzer answered. "On the Power Pool – last March, we found ourselves in a fragmented situation, between the higher-priced, but conforming offer from the Southwest Power Pool, versus the lower-priced challenged governance model from CAISO. Puget then said they'd explore joining CAISO. People were fatigued.

"We've been aiming for the fences going for a Northwest SCED. Maybe we could go for lower-risk, lower-cost alternatives. There's been an agreement among members to take a look at that. We formed scrum teams, groups of strongest subject matter experts taking a look at these, taking a look at the 15-minute market BPA developed. Can we automate that and make it more liquid, faster and effective?"

He said that another group is looking at ACE diversity interchange, sharing short-term diversity in the automatic generation control signal. The idea is to build toward a regulation, reserve-sharing program — some form of balance capacity sharing, that wouldn't involve a centralized market operator that would be FERC jurisdictional?

"I feel it's important to keep the SCED option on the table and finish the due diligence," Mainzer concluded. "There's been tremendous design and regulatory work and that went into that, including the development of a request for declaratory order from FERC on the big regulatory questions and issues around resource sufficiency and adequacy. As BPA's administrator, my allegiance is to the Northwest. I want to give Northwest utilities the best chance of controlling their own destiny, and build off our legacy of operational coordination of the Power Pool since 1942. But people are going to make business decisions. If things fragment, we'll have to figure out how to adapt to that."

Council Member Bill Booth asked Mainzer to identify some cost-side opportunities.

"The first is BPA's asset investment program," Mainzer noted. "We spend $750 million a year on hydro and transmission assets. We need to make sure that our core, sustained expansion investments are being made as efficiently as possible. We need to increase the availability of the turbines, which gets to the revenue side. It's about being good stewards of our revenue dollars."

Another area is BPA's internal operating costs, including the efficient deployment of its workforce. Another cost is the $550 million per year BPA spends on fish and wildlife. "Are we getting the best bang for our buck from those dollars?" he asked. "It's a tricky conversation, but it's something we have to talk about. How do we provide some stability? We can't live in a period of constant escalation."

Regarding energy efficiency, Mainzer stated that he wasn't as interested in cutting costs, "but how do you unleash the value in most efficient ways possible? The driver is trying to mend the cognitive dissonance that we have in the Council, and utilities that are facing a different reality. We need to bridge that gap."

He said BPA has a $35 million increase in O&M because of aging assets. Right now, the average availability on the hydro system is quite low because of maintenance on the third powerhouse at Grand Coulee.

Member Booth said that some flexibility has been seen in capital versus expense, which has helped to reduce those costs. They are setting up an annuity on the fish mitigation parcel. "On the capital versus expense decision, are your guidelines internal? Or are you under strict federal requirements? Is there greater opportunity for more flexibility in using that capital expense? That might help us out, particularly with the Fish and Wildlife Program."

Mainzer replied that, as a self-financing entity under the Transmission Act, they have $7.7 billion of federal borrowing authority. "We've tapped out more than $5 billion of that," he said. "We are constantly looking at how to maintain our access to that borrowing authority and have enough liquidity to manage risk, cover annual operating expenses, pay Treasury, etc. We've been aggressively looking for third parties to finance capital and take debt load off the system. We're financing half of transmission program through lease financing, only using 50 percent of our borrowing authority on the transmission program."

He said that a couple years ago, they did $340 million of customer prepays. Several customers paid us in advance for their power through 2028, which is money we didn't have to go request from the debt markets.

"The constraint is around how much current access to capital we have, and maintaining long-term access," Mainzer said. "We're in a borrowing cycle right now, which is another variable. Now we're trying to work around the constraints of the $7.7 billion. Will we need more borrowing authority? It's something we're paying attention to."

Wednesday, May 6

Council Chair Phil Rockefeller called the meeting to order at 9:00 a.m.

NORTHWEST POWER AND CONSERVATION COUNCIL
MOTION
TO APPROVE THE RESOURCE ADEQUACY ASSESSMENT FOR 2020 AND 2021.
.

That the Council approve the Resource Adequacy Assessment for 2020 and 2021, as presented by staff [with changes adopted by the Members at today's meeting].

Language of the executive summary was edited.
Member Booth moved to approve the Resource Adequacy Assessment for 2020 and 2021 as presented. Member Bradbury seconded.
No discussion.
Motion carried unanimously.

Member Karier thanked Council staffer John Fazio and the Resource Adequacy Advisory Committee. Quite a few people in the region participated in this, he said. We provide a public service of what the system will be five years out. A lot of people rely upon us to keep the lights on. Do we need to take a closer look at the drought and low snowpack, and are we at risk this coming year?

Fazio replied that the Council will hear from staffer Jim Ruff later on that issue. But the question will arise, what is the power status? The short answer is that while we have less-than-average hydro, we're still above the critical hydro. Because we can't store the run off, we base our resources on the driest years. This year, we're ranked 66 out of 80, which is not near our driest year. Question isn't whether we'll meet our demands, but rather secondary hydro revenues. Revenues will be down, but we'll be adequate.

Member Karier asked if it will have an impact price market? Fazio said it probably will.

4. Update on Columbia Basin Water Transaction Program (CBWTP)

Lynn Palensky, staff program development manager, introduced Scott McCaulou, Columbia Basin Water Transaction Program; and Chris Furey, Bonneville Power Administration. The CBWTP represents $5 million of the Council's Fish and Wildlife program, which has been in place since 2003.

Furey explained that in the Columbia Basin, there's a perception that it is a lush, green area, whereas in the east, it is a dry, arid environment. It's an important limiting factor for agriculture and fish. CBWTP is working to restore streams where the water is needed, such as the Okanagan.

Part of why we have the situation is a relic of 19th century western water law of prior appropriation. The first in time, first in right could pull water out of a stream.
The dynamic is such that when flows are low, like in summer and August, the total water ceded can exceed natural flow of the stream. All the irrigators can legally dry up the stream. But by using different transactional mechanisms, you can increase flow in the river.

Member Karier commented that, in Washington, if you don't use your water right, you can lose it.

Furey replied that, "In the month of August, there's a situation where not all the water is being used all the time. With the use or lose component, there's a five-year general statute for that state.

Chair Rockefeller said it's 23 in state of Washington.

Furey said there's plenty of work for attorneys in those circumstances. It's generally challenging for water rights to be lost. When water rights are examined, they could be abandoned or relinquished.

Chair Rockefeller followed, "What is the priority position for inflow water? Are you acquiring water rights to put those back in the stream?

Furey said, "We're trying to secure water that will result in wet water in the stream. There might be a class of water rights where we could expect that water to be in the stream. There are other water rights more junior, which may or may not be in the stream. In general, we're focusing on more senior water rights."

Some of the regulatory context for establishing the CBWTP came through the Northwest Power Act, Endangered Species Act, state instream water right laws, and the Biological Opinion.

Back in 2001-02, the Council and Bonneville came together and talked about what water transactions could be and came out with an RFP to set up a program. Part of the program is creating incentives for water rights holders. They have a set of water transaction tools:

Leases
Perm acquisition
Forbearance
Diversion reduction
Minimum flow
Reverse auction
Source switch
Conserved water
Stored water

Member Bradbury asked what the definition of forbearance is.
Furey: A water right user voluntarily would not use water for a period of time. Generally use that on a short-term basis. It's site specific, transaction specific, and it's a part of a tool box.

Member Smith asked what the definition of a reverse auction is.
Furey said it's not commonly used, but a reverse auction is a tool where a water trust can say they're seeking to secure water rights. Water rights' owners can go to market and say what they'd release the water for. It's been a limited tool, and helps with price setting.

McCaulou said that a reverse auction occurred in the Upper Yakima and Upper Columbia.

Furey said that since 2003, the program secured 1.1 million acre-feet of water. A total of 136 streams and 1,500 miles of streams have benefitted. There have been 439 funded transactions, and 200 this year. The program has invested $40 million, with 50 percent cost-share transactions. There are now more than 1,400 partnerships with landowners.

McCaulou explained the CBWTP's structure. It has seven, core, nonprofit partnerships:

- Clark Fork Coalition
- Deschutes River Conservancy
- The Freshwater Trust
- Trout Unlimited - MT Water Project
- Trout Unlimited - WA Water Project
- Walla Walla Watershed Management Partnership
- Washington Water Trust

It has state partnerships with:

- Idaho Department of Water Resources
- Montana Water Resources Division

- Oregon Water Resources Department
- Washington Department of Ecology

These entities oversee water rights in their states.

CBWTP's Fish Accord Partners:
- Idaho Office of Species Conservation
- Confederated Tribes of the Colville Reservation
- Confederated Tribes of the Umatilla Indian Reservation

There are probably hundreds of other entities that work with CBWTP.

Its internal process includes a proposal process, and they are evaluated against a set of scientific criteria. We're primarily talking about Chinook and salmon, as well as some trout. Once those proposals are received, they go through ranking and legal review, and then before the Council. Then we wait for state administrative agencies to issue final orders and certificates that can enforce the water rights in the stream.

We have a large portfolio of transactions that have gone through the process: 439. There are 217 active transactions, which is a number of transactions over a vast geography.

McCaulou explained its monitoring process to make sure that the agreements in place are being honored.

2014 accomplishments:

- New transactions funded – 49 (one of largest to date in single year).
- New water protected instream – 31,232 acre feet
- New protected water instream – 156 cubic feet per second
- Habitat benefitted by new streamflows– 416 stream miles, which is about the distance from Boise to Portland.

McCaulou outlined successes in Idaho's Lemhi River, Oregon's Catherine Creek, Washington's Nile Creek and Montana's Dry Cottonwood Creek.

Member Karier commented that he has followed the project over many years, and he only wishes that we had created a similar one for purchasing the habitat, in order to help fish populations directly. "We need to establish the science that shows this helps fish populations directly. We need to prioritize our evaluations and research going forward to measure benefits."

Member Booth remarked that this program is about the best thing the Council can do, one of the best in the toolbox. "When you open a fish screen that has been spawning habitat, you obviously create a new habitat," he said. "Because the Council has some oversight over the final approval of the transactions, we have an opportunity to look at this more holistically in terms of density. As long as it can be done and water rights can be retained, it's a win/win. Can you get me a rundown of where you are in your funding, how much you're spending and if you are you under constraints in the future?"

Chair Rockefeller asked how they decided which watersheds to focus upon. "I assume it's based on state-identified needs and Biop-related needs," he said. "What are your priorities? Also what about the sourcing of water rights you're pursuing? I've heard concerns in Washington – not in relations to your transactions – but about dewatering stretches of rivers by acquiring rights, and then severing and moving them; leaving property owners in the watershed without rights, and their land not as economically valuable as in the past. Do you make sure that the rights you acquire will stay in watershed?"

McCaulou replied, "As a matter of policy, no, the water rights aren't required to stay in the watershed." He said that they only get final approval and pay for the transaction only after it goes through the state administrative process. The state transfer process takes into account changes in water flows that might have impact on other water rights holders. The state administrative process typically looks at third-party impacts to other water rights holders and to fish. Often times, water rights are reduced to mitigate the impact. More broadly we don't see a lot of transfers taking place moving water rights outside of the system. Our projects try to keep it in the system. We're not targeting.

Member Rockefeller asked, "I understand you're not targeting, when you go for a source, are you looking within the basin for available water rights, or do you go broader?

McCaulou said typically they wouldn't look to satisfy a flow restoration target with water from outside the basin, and he can't think of an occurrence where that would happen.

Furey said that comes into play with the Office of Columbia River in Washington where they issue new, out of stream uses, where they have to secure upstream water rights to affect downstream water rights. It's not related to the CBWTP.

Bill Maslen from the audience commented, "I want to spotlight this project as highly successful program across all boundaries. It's collaborative and, for all its successes, it looks at continuous improvements. It's a good model to look at for other programmatic approaches."

Member Smith echoed Member Booth's praise for the program and asked about quarterly solicitations and how CBWTP screens what gets funded.

McCaulou said, "We do have priorities with the BiOp and other factors. Each state has identified flow-limited streams that they want restored. We're not trying to restore the mainstem of the Columbia. But we make sure we're working in the right places and we look at the reliability of the water right. We want to make sure we're working with rights with the sufficient priority, that in times of drought, when fish need it the most, we will have something to show for it. We want to make sure will have success and that transactions are consistent with market conditions.

Member Lorenzen asked what the general range of costs is.

McCaulou said that it varies dramatically. For a permanent acre foot of water, it ranges between $300 to $2,500 per acre foot. Furey added that in California, they're paying that amount for one year.

Staffer Palensky concluded by saying that the groups meet once a year, compare notes and talk about specific issues. The next meeting is in Wenatchee, Washington, in the Okanogan Basin during the third week of September.

5. Discussion of Scenario Analysis Results

The Resource Portfolio Model estimates the regional costs and risks associated with pursuing different resource development strategies in the Seventh Plan. Staff members Tom Eckman, power division director, and Ben Kujala, system analysis manager, focused on the outputs of two of the 14 scenarios in a presentation to the Council.

Current Policy scenario (1b) assumes that all existing emissions requirements and current assumptions about the variability of future gas prices, population growth, employment growth, load forecasts, hydro conditions, and carbon policies stay in place for the next 20 years.

Carbon Risk scenario (2c) looks at a range of carbon costs on a random basis between $0 and $100 a ton. The prices are imposed at random starting in 2016 and 2035. It identifies least-cost and least-risk solutions.

Staff looks at the results in terms of the

- Distribution of net system cost
- Distribution of conservation development
- Distribution of RPS resource development
- CO2 emissions without carbon risk uncertainty
- Discussion of gas capacity resource and demand response

RPM results disclaimers: Staff is still working on the long-term capacity expansion model on inputs and assumptions, including which combustion turbine technology to use or which peaking system to use, and the pace of demand response. They are still refining inputs. All results are preliminary, every future is a different outcome and they are averages.

Member Anders commented, “You said these are preliminary results. Are you calibrating this model or what’s the goal?”

Eckman replied that as we test various strategies, we uncover inputs that drive the results. These are driven by demand response and what turbine is used for peaking. We want to test agreement on assumptions that drive the model. We’re testing the model and testing the results to see which are the most sensitive inputs.

Kujala added that, by running these, we’re getting some context for conversations around demand response and turbines. When we add the carbon price to the model, to do the least-cost thing, it takes up most of the activity to minimize risk as well.

Lorenzen asked what risk means in this context. In least cost, it’s a dollar amount. What’s risk?

Kujala explained that risk is defined in many ways. “We have 800 futures,” he said. “With least cost, you’re talking about minimizing cost over all futures. With risk you’re looking at the top 10 percent most expensive futures, and you’re trying to minimize the cost in those futures.

“In the Sixth Plan, there was a greater emphasis on market. This time we’re looking at building for reliability to keep the lights on. The market won’t pay you to keep the lights on, so we’re bearing a cost to keep the lights on versus making money to do so. By end of the study, you do have some scenarios where you make money.”

Eckman said that the wholesale market has lots of generation available in the West.

“We’re tracking how much conservation contributes to the peaking capacity needs of the system,” he said. “We’re looking at the winter peaking capacity, and the conservation shape contributes from 150 to 200 percent. In 2021, we were around 1,000 MW, and here, we’re at the 1,500 MWa range.

“When we look at minimizing cost, in the 1b case, we’re being more adaptable. In the least risk strategy, we’re using a more predictable conservation strategy.”

He said that in high market cases, we’re building conservation. In lower markets, we build less conservation, on the order of a couple hundred MW. It’s more varied in the least cost case and more predictable in the least risk.

Under the least cost scenario without the carbon price, we have a higher renewable bill because we did less conservation.

“Where I don’t have a carbon problem, I only build for need or price,” Eckman explained. “When carbon is added, it shows that it’s better to build the conservation, so you’re ready for the prices when they come. The carbon risk addition requires a different strategy for the future.”

Kujala said that in a Renewable Portfolio Strategy build, in all cases, building conservation is predictable for an overall lower bill. But you need a lot more energy for RPS. If you look at 1,000 MW, you’re building a lot more wind to meet that standard.

Member Booth wondered how adequacy is addressed in this type of model. “You assume about 30% availability for wind, what about solar?” he asked.

Kujala said that it’s more seasonal, about 26 percent on average. You get more in the summer than in winter.

Member Booth said, “So you’re saying that there’s adequate resources to bring in, as opposed to a presentation yesterday that shows we have a shortfall of 1,000 MW between 2020-22.”

Kujala replied that it’s hard to compare the two analyses. This is an input into the RPM. We’ve tried to consistently have a shortfall in the RPM to meet the 5 percent strategy.

Eckman said that it is an energy chart. “We have a capacity limitation,” he said. “If we go to capacity, we don’t see wind or solar available on peak, in the late afternoon in the winter. So it really doesn’t solve our capacity problem.”

Current Policy scenario (1b) observations:

- Least-cost strategy already has low risk.
    - Additional risk reduction comes at a high cost relative to the reduction in risk.
- Adequacy and RPS drives resource builds.
    - The planning period starts not meeting adequacy standards in many of the futures.
- Economic builds are few and far between.
    - Economic builds occur in less than 1 percent of the futures in the least cost resource strategy.
- Demand response is optioned because it has a shorter lead time than generation options, small incremental resource size and low cost.
- Thermal build options selected for adequacy seem related to retirements of Boardman and Centralia.

- REC banking delays the need for constructing renewables until well past the action plan period.

Carbon Risk scenario (2c) observations:

- Least cost strategy already has low risk.
  - Similar to Scenario 1b, reduction in risk comes at a relatively high cost.
- In the least cost strategy the thermal options selected are all combined cycle gas plants, no gas peaking plant is selected.
- Demand response still plays a major role in the resource strategy.
- Conservation by the end of the study supplies around 80 percent of the capacity added to the system.

A comparison of the two scenarios revealed:

Conservation

- Action plan period has 50 to 70 aMW more conservation purchased under the carbon risk scenario when comparing least cost strategies.
- Over the 20-year study, the carbon risk scenario has around 500 MWa more conservation when comparing least-cost strategies. We'll also be seeing some differences in the ramping of energy efficiency.

Member Karier asked if the model is hitting the maximum amount of conservation. Eckman said yes, in the near time in the lower-cost bins. Other scenarios ramp up and down to change those constraints.

Thermal Resources

- Thermal Options
  - In the carbon risk scenario, more efficient combined cycle combustion turbines are selected rather than peaking units.
  - In the carbon risk scenario, economic builds increase significantly, which is likely based on market price impacts of a CO_2 tax.
- Existing Dispatch
  - Existing units with associated carbon emissions have a much lower dispatch over the planning period.

Member Lorenzen commented that demand response is a desirable resource, and within our region we have different balancing authorities. In each, there are different generation mixes where demand response might be more or less desirable. To what extent will that create problems?

Kujala said that can’t really be captured. Demand response might be a cheap resource, but it might be hard to get because of the way it’s set up.

Eckman said if we have a generalized finding — and it looks like it’s attractive — it depends when and where it’s needed. But it doesn’t necessarily mean it can be deployed where it needed, because every one of them takes time to negotiate.

Carbon Emissions

- Under both scenarios, carbon emissions are significantly reduced.
    - Average carbon emissions under the current policy scenario are approximately 15 percent below EPA 111(d) proposed 2030 limits.
    - Average carbon emissions under the carbon risk scenario are approximately 40 percent below EPA 111(d) proposed limits.
    - However, 90th percentile emissions exceed EPA’s proposed limits in under both scenarios. What is driving 111(d) is the announced retirements of existing plants, more than anything else,” Eckman said. “We already have policies in place to reduce emissions.”

Eckman said that staff is still refining inputs into the long-term capacity expansion model on inputs and assumptions, such as which combustion turbine technology or peaking system to use, and the pace of demand response. He said staff has several more scenarios on the docket: the next set is 4c and 4d, where they model a faster and slower pace of conservation.

Member Yost asked if the carbon reductions in 1b are the results of plant closures, instead of price. Eckman said, yes, primarily. “There’s no carbon price beyond today’s policies. The Boardman and Centralia closures are driving the reductions, and as we expand the system leaning on energy efficiency, that continues to defer further thermal generation into the system, which keeps the emissions flat.”

Member Karier said that the power committee had an interesting presentation from BPA about their demand response pilot program. They’re getting out and trying to buy some demand response and see how it works. They’ve done it through different venues. There’s a certain problem that needs to be addressed for a certain number of hours per year, when we are just short of capacity. At that point, either you could have built a peaking gas plant and let it sit there until you need it a few hours a year — or you write contracts with businesses that they’ll turn things off for a few hours a year, with relatively no real investments. That’s going to be a key issue – how much should the region do and what’s feasible? The rest of the country has done more of this. But you don’t know until you start knocking on doors.

Before the Council took a short break, staff policy analyst Chad Madron announced updates to the Council's Seventh Power Plan website, including links to the latest webinars.

6. Briefing on hydrologic conditions, water supply forecasts and drought declarations for the Columbia River Basin

Jim Ruff, manager, mainstem passage and river operations, shared the April 20 water supply reports issued by the Natural Resources Conservation Service (NRCS) and NOAA's Northwest River Forecast Center. The reports' summary states that there is widely varying precipitation across the Columbia River Basin which, when combined with higher than normal temperatures, combine to result in an early spring runoff from a meager mountain snowpack across the basin.

April water supply forecasts have continued to deteriorate. While British Columbia, western Montana, north-central Washington and the headwaters of the Snake have near to slightly below normal runoff forecasts, the forecasts for the lower Snake River, southern Idaho, and eastern and western Oregon and Washington are mostly well below average. Water supply forecasts are low enough that drought declarations have been declared in numerous counties and watersheds in Idaho, Oregon and Washington.

Chair Rockefeller commented that some have said we don't have precipitation problem, we have a snowpack problem.

Ruff said this year is a dress rehearsal for climate change. He then ran through snowpack forecasts for the different Northwest states. In summary, the report states that the winter conditions of 2015 did not provide enough cold weather fronts necessary to build and sustain basin snowpacks to normal or beyond. The overall snowpack conditions in the Columbia Basin are dismal, except in the high elevation northern and eastern portions of the basin, such as the Rocky Mountains. With much below average snowpacks as of April 1st, chances are good that summer runoff will be much below normal in many tributaries of the Columbia River Basin.

Looking at the region's drought conditions, Ruff said that the central and eastern parts of Idaho are experiencing significant drought conditions. In Oregon, the south central and eastern regions have significant drought, to the point that drought emergencies have been declared in seven counties and five watersheds. In Washington, the 2015 runoff is the lowest in the past 64 years.

The May-June-July temperature outlook in the Northwest shows a higher likelihood of warmer-than-normal temperatures all along the west coast and up to Alaska, due to a warmer sea anomaly.

The warmer temperatures in the Pacific Ocean are due to a condition called “the Blob,” which is 1,000-feet wide and 30-feet deep. The marine ecosystem is turning unfavorable, and seabirds and seal pups are washing up on shore. The food web has been disrupted with less nutrient-rich water.

Ruff doesn’t anticipate power shortages, just water supply shortages. Out-migrating fish will face warm and below average stream flows together. The big question is, what will be the cumulative effect on salmon?

7. Presentation by Energy Trust of Oregon

Tom Eckman introduced Margie Harris, executive director of the Energy Trust of Oregon (ETO), as an anchor tenant on energy efficiency in the region going back several decades. The ETO has done an outstanding job of bringing energy efficiency to the Northwest, working with PacifiCorp, NW Natural, PGE, Cascade Energy and others.

Harris said hopefully we can talk about some of the solutions to what we’ve been hearing. ETO is an independent, mission-driven, nonprofit organization. It was begun by the Oregon Legislature in 1999, and is funded by customers of gas and electric utilities. Our purpose is to build a clean energy future with efficiency and renewable energy investment. Every day, we help customers take actions to lower their energy costs, boost our economy and protect our natural resources.

When we began, we started with Pacific Power and PGE. Over time, it has expanded to NW Natural and Cascade customers. We represent 73 percent of electricity users and 87 percent of gas customers. We’ve built a clean energy power plant fueled by 346 aMW of energy savings. We’ve also generated 112 MW of renewable generation that we’ve supported.

We’ve served a half-million homes, which are saving $1.7 billion on their bills. Since 2002, we’ve invested $968 million. For every dollar we invest, we get $3 in return. Ten million tons of carbon has been avoided through 2013, which is a side benefit of our efficiency and renewable investments.

We update our strategic plan every five years. Some of the challenges we see is that, while we’re seeing economic recovery in our state, it’s uneven. In southern Oregon, there are lots of economic challenges. A requirement of ETO is that all energy efficiency investments have to be cost effective. Therefore we’ve eliminated some weatherization measures on the gas side because they’re no longer cost effective. On July 1, 2015, we’ll look at eliminating some measures all together. In our 14 years, 85 percent of homeowners we try to reach have already taken some action. So there’s saturation and maturation in the market. What remains to be done is more challenging and expensive to reach customers who have yet to participate, such as renters, multifamily, smaller businesses and rural customers. All of that is target of our strategic planning. We have a long history of offering tax credits for efficiency and renewables, and those are changed and, in the case of renewables, eliminated. We expect future energy savings to be harder to acquire.

Our approach to setting goals and our budget is that we work collaboratively with utilities to update their integrated resource plans (IRPs). We work on how much savings we can acquire that they have identified and at what cost. That determines the tariff filings. Once the tariff goes through, it identifies our resource requirements and budgets. It’s a unique approach, but it aligns us with the utilities’ least-cost planning. We tend to go above what the IRP is suggesting because we know there will be new projects and technologies that will be within our reach.

We have long-term and five-year goals. It’s not very accurate beyond three to five years. Cross cutting strategies refer to program efforts that cross both efficiency and renewables. Our internal cost management focus is making productivity gains.

We’re stabilized, we have exceeded our goals in the last five years and have doubled our output. We’re now seeing an evenness, replenishing the savings we had the year prior. See that we’re going in the direction similar to your Seventh Plan.

Our renewable goal is lower than it has been historically, due to the economic case. There’s a lot of emphasis on solar, which generates half of our renewable energy, and we’ve lowered those costs by 60-70 percent.

Where we’re focusing to meet our efficiency goals, is we’re a customer-focused organization that emphasizes how services are provided, and we’re focused on expanding participation:

We are getting more sophisticated on where the gaps are in our service delivery. We’re identifying where we have opportunities. We are emphasizes different kinds of customers that have potential for acquiring new savings. That focus is yielding good results. Not only did our customer rates increase, but we have good experience to design programs for target audiences.

Our customer satisfaction rates reached a record high last year, we had a 98 percent satisfaction rate with customers we worked with, and 96 percent overall.

In year one of our five-year plan, we have taken what we’ve learned at the Northwest Energy Efficiency Alliance (NWEEA), where we shared strategic energy management best practices. These are operations and maintenance strategies that have achieved a quarter of overall industrial savings last year. It’s a good employee engagement strategy.

We had growth last year of 34 percent in new construction buildings that have enrolled in our programs. There's an emphasis on multifamily and half are outside the Portland area.

In new construction, we have an energy performance score to compare the energy output of a house to a comparable house. It also compares the carbon output of the house. The real estate community is behind this, and we're representing builders who are dealing with more stringent regulations. About 34 percent of the homes are using this score.

We're also focused on emerging technologies, to pilot activities before we go to scale. We pay close attention to whatever the Council identifies.

Lighting is a classic market transformation play with LEDs. We put in four million bulbs last year. We have Living Wise program, where fourth-grade students take bulbs home. It engages them in energy efficiency.

We're open to new opportunities, such as indoor agriculture, swapping out more efficient mobile homes. It's tricky because we're an IOU-based program. Also, we've been approached to run a rebate program for electric vehicles.

If 111(d) regulations come out this summer, it opens the door to more energy efficiency and renewable development. Currently, SB844 opens the door for gas companies to recoup their investments in carbon reduction, such as oil-heated home conversions to natural gas. In Portland, there's a new, commercial disclosure mandate for commercial building energy usage, and we'll be involved in implementing that requirement.

Chair Rockefeller praised the ETO's work and lamented that Washington doesn't have anything like it.

Member Karier asked if ETO can take capacity into account in cost-effective calculations and targeting energy efficiency.

"Not as yet," Harris replied. "It's come up, talking about the intersection between energy efficiency and the smart grid. If an electric vehicle program goes into place, and we're involved in that, it gives us access to customer and storage for Pacific Power's or PGE's purposes. There's nothing specific, not part of our technical scope, but if here's something we could do to help the utilities, we're interested in making that part of our scope."

Chair Rockefeller expressed interest in Harris' comments on mobile homes. Do you have lessons on how to deliver equitable benefits to all? Could you talk to our staff?

We're not tasked with the same mandate, but the model is pay to play. We work with affordable housing developers as much as possible to make them as efficient as possible. Also we have a strong referral system from utilities and state officials working with low income to make sure they have access to all the programs available, either ours or other agencies, caps. There are many dimensions. We also work with Habitat for Humanity and work with putting solar on those.

8. Council Business

Northwest Power and Conservation Council Motion to Approve the Minutes of the April 6-7, 2015, Council Meeting

Booth moved that the Council approve for the signature of the Vice-Chair the minutes of the April 6-7, 2015, Council Meeting held in Helena, Montana. Bradbury seconded. Motion passed unanimously

Northwest Power and Conservation Council Motion to Approve the Release of Fiscal Year 2017 and Fiscal Year 2016 Revised Budget for Public Comment

Booth moved that the Council approve the release of the Council's draft Fiscal Year 2017 Budget and Fiscal Year 2016 Revised Budget for public comment until July 1, 2015, as presented by staff.

Sharon Ossman, administrative division director, said the draft budget will be released, they will take oral comments at the June meeting, and summarize comments at the July meeting with a goal of finalizing the budget in July or August. It then will be submitted to Bonneville.

Motion passed unanimously.

Northwest Power And Conservation Council Motion to Approve a Regional Portfolio Model Software Support Contract with Navigant Consulting, Inc.

Booth moved that the Council approve entering into a continuing software support contract with Navigant Consulting, Inc. for an amount not to exceed $50,000 and for a period ending September 30, 2015, as presented by staff. Anders seconded.

Eckman explained that the proposed contract is for a maintenance agreement with Navigant to be on call above and beyond what they're currently contracted for. The Council might need them to help with work to fix what we've done wrong with their device. Staff will probably come back to you with a new contract at end of this fiscal year. The time period is June through the end of September, not to exceed $50,000.

Motion passed unanimously.

Adjourned at 11:45 a.m.

Approved June 10, 2015

_/s/ Bill Booth
Vice-Chair

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