Northwest Power and Conservation Council

November 14 and 15, 2017
Coeur d'Alene, Idaho

Minutes

Tuesday, November 14

Council Chair Henry Lorenzen called the meeting to order at 1:32 p.m. All Members were in attendance.

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

Fish and Wildlife Committee

Committee Chair Jennifer Anders reported on five items:

1. The committee received an update on Idaho sockeye by Idaho Fish and Game. They discussed the Springfield hatchery startup. They're pleased with the facility and believe it is producing high-quality smolts. They also discussed smolt outmigration survival and mitigation strategies to deal with certain stressors they found, including water chemistry, which impacts sockeye survival.

2. There was an update on the upcoming research review process. Staff discussed a three-phase approach to reviewing research. First, they will compile and inventory all research work in the basin. An initial inventory is almost complete. Second, they will share the information with managers. The third step is to have a review by the Council to identify any issues from the inventory, and make recommendations for next steps.

3. A white sturgeon workshop will be held next door. Lynn Palensky discussed the workshop. White sturgeon is listed as an emerging priority in the Council's Fish and Wildlife Program. The goal is to foster and maintain a network of sturgeon biologists and researchers, to conserve and increase white sturgeon populations. The workshop begins tomorrow after meeting. Sixty participants have signed up.

4. There was a presentation by Tony Grover, Fish and Wildlife Division director, on adult anadromous fish, including where returning salmon and steelhead go. He may present this to the full Council in future.

5. There was a presentation on Upper Salmon integrated rehabilitation assessment process. Some representatives from Idaho talked about this assessment, which uses previous monitoring and evaluation efforts to estimate existing habitat capacity, and it identifies habitat improvement process to address capacity deficiencies. This process can be applied throughout the region and help address some of the frustration among policymakers over links between habitat improvements and increased salmon returns.

Power Committee
Committee Chair Tom Karier reported on four topics:

1. The committee reviewed the update and framework for a paper on the value of conservation. Staff has been working on it for a few months at the behest of the committee. Karier said they want to identify precisely the value to individual utilities and to BPA utilities as a group, both in the past and going forward. Now the paper has a schedule for vetting. It will be an interesting, innovative paper that provides an assessment of conservation and its values.

2. They looked at a decision on whether to collect conservation supply potential by end use or by specific application. If you're looking at an application, it might be attic insulation, for example. They would assess how much savings you get from that and what is the potential savings for attic insulation in the region. Another approach is look at heating systems as an end use, and look at all of the technologies simultaneously, including attics, windows and other measures more comprehensively. They reviewed the pros and cons, and they decided to continue to look at unit applications. But they will seek to expand their capability to take a more comprehensive look at key measures such as high-efficiency lighting.

3. There was a presentation on recent hurricanes' impact on natural gas prices. It turns out that the impact is less and less. After the 2005 and 2008 hurricanes along the Gulf Coast, prices spiked for several months. That didn't happen in 2017. That is partly due to the fact that the Northwest is less dependent on natural gas from the Gulf Coast, and because the region's supplies are in surplus due to fracking and other reasons.

4. The committee looked at the power system values of conserved irrigation diversions. The Council was asked to provide and encourage funding for measures that would save energy and water through more-efficient irrigation practices. In trying to value that, it would save in pumping costs and leave more water in the river that could generate power. A discussion in the power committee made it clear that not all the water stays in the river. Junior water rights holders and others extract some. That still has to be

factored in. Karier said he thought they would release the paper for comment at this meeting, but they will do some more work and bring it back before the Council.

Public Affairs Committee
Committee Chair and Council Member Jim Yost had no report and the committee did not have a meeting. He said he wants to produce a good product when they do have a meeting, but he doesn't know when that will be.

1. Update on Columbia Basin Trust activities and current initiatives
Member Anders introduced representatives from the Columbia Basin Trust, located in Canada. She said the Trust is as close to anything the Council has to a sister organization. In 2000, the Council and Trust negotiated a memorandum of understanding and have exchanged visits every year.

Rick Jensen, Trust chair, and Johnny Strilaeff, Trust CEO and president, described the Trust's funding and priorities. Jensen said the Columbia Basin Trust was started in 1995 to recognize and address some of the impacts of dams built to control water for power generation in the east and west Kootenays, and up to the north. A promise was made by the provincial government that the reservoirs would be like majestic Swiss lakes, Jensen explained. What actually happened was that there was both a benefit and a cost. There were 12 communities lost, 2,500 residents were displaced, 150,000 acres were flooded, river systems were forever changed, fish and wildlife habitat were lost, and there has been lost indigenous archaeology history. Ongoing land issues have occurred due to fluctuating reservoirs. This resulted in the creation of the Trust.

The Trust was formed by a group of people in the basin, across the political spectrum, which wanted to press upon the province recognition of the hydro system's impacts. Local governments, the five region districts and the Ktunaxa Nation Council formed the Columbia River Treaty. The intent was to form a trust that would share in the downstream benefits. The Trust received a $321 million endowment. It won't receive further funds and the Trust manages the endowment. It has dual accountability to the residents and to the province. It is a government-owned organization with a high level of autonomy. A board of directors governs the Trust. It works in a large area with a limited population of 180,000 people.

Jensen discussed the Trust's organization, mission, vision and geographic range. It manages plants, generates revenue and delivers benefits to the region. Its largest investment is in four hydro projects, which have a combined installed capacity of 800 MW, enough to supply 279,000 homes. The most recent project was completed in 2015 — the Waneta expansion.

Strilaeff said the Trust has a significant portfolio of regional investments in business and real estate. It has ownership of eight communities, providing 800 living suites for seniors. The book value of the Trust's assets is about $740 million, and they generate $60 million in revenue. More than $51 million is going back to communities in programing initiatives and additional investment. They have about 60 active programs and another 10 under development.

Three programs that resonate with the Council's interest include the Accelerate Kootenays EV charging station program, preventing the spread of aquatic invasive species and furthering salmon reintroduction dialogue.

The Accelerate Kootenays program has 53 EV charging stations installed not only to support local use, but to provide electric charging capability on main highway routes. They anticipate the program will require further funding and expansion.

Aquatic invasive species are a critical concern. According to Strilaeff, experts say it's a matter of when, not if they get into local waters. It now administers 10 boat inspection and decontamination stations. Last year, 35,000 inspections took place and found 24 watercraft with adult invasive mussels. Strilaeff said he's heartened that they're detecting some, but they are probably missing some too.

Strilaeff said that Canada has fallen behind U.S. in having a dialogue about reintroducing salmon into the Upper Columbia River. "We don't have a policy, but it's a priority for communities and First Nations tribes in our region," he said. A couple months ago, the Trust convened a dialogue on this topic in Vancouver, B.C. It included representatives from First Nations and utilities.

Jensen discussed the desire for continued meetings with the Council, the sharing of information and other collaborative efforts.

Member Anders asked if the presence of non-native species is also a concern. Strilaeff replied it is and that the Trust is providing funding to fight Northern Pike, for example.

Member Karier asked about invasive mussels. "Of the 24 vessels you found, were they found crossing borders?" he asked. "Where did they originate?" Strilaeff replied that two were from New York, a dozen from the provinces and one from Michigan. Twenty-two of the 24 were identified in advance and 12 self-reported.

Jensen added that the further north, the colder it is, which is less friendly to mussels. He also said that one female mussel could produce up to a million offspring a year. We need to petition the U.S. to keep their mussels in their states, he said.

Member Lorenzen said mussels are more prolific where there's more calcium. What about Canada's water? Strilaeff said he was unsure of the science about that. Jensen said they do have the technology to fight them, so they'll be able to learn and not make some of the same mistakes.

Member Booth noted that the conference in Spokane in 2014 was quite successful. He attended it and asked if there are plans for another. Jensen agreed it was very successful. He said there are some preliminary talks about a conference in Canada in 2018-2019.

2. Update on Idaho Fish and Wildlife issues

Jeff Allen, office director and policy analyst, introduced Virgil Moore, director, Idaho Department of Fish and Game. It was Moore's fourth appearance before the Council and he is the only person to serve as director for two different states – Oregon and then Idaho. He had just returned from a successful moose-hunting trip.

Moore said the work they do involves Council collaboration and some national-scale collaboration. He discussed Grizzly bear delisting in the Yellowstone ecosystem at the end of July. Grizzly bear management has been turned over to states. They are working hard to develop a tri-state plan with Idaho, Montana and Wyoming to guide management of the bears. There will be some court challenges, but he said their management plans are rock-solid, and have had peer review. There are no plans for an open hunting season. The states need to get together and review the mortality that is allocated. It's no different than calculating mortality for fishing stocks, he said. That work will take place this winter. Then they will see if there's any desire to move forward with a regulated hunting season. Idaho will have a very limited opportunity and, if granted, would be a "once in a lifetime" situation, similar to moose, goat and sheep.

The Selkirk Mountains aren't set up for delisting the bears. But the Northern Continental Divide population in Montana is the next area up for consideration. Managing the bears has been a success, Moore said.

Wolverine management is another area of success. In 2013, the U.S. Fish and Wildlife Service (USFWS) proposed rule to list as wolverines as threatened. An Idaho Fish and Game management plan was developed and ultimately, it wasn't warranted for listing. Climate change was seen as a major impact in the lower population. Wolverines also move about, he said. They're now going back through a status review of wolverines. Some habitats are in Montana and Wyoming. The review was a rigorous, collaborative science approach. That work is still being evaluated.

He talked about sage grouse management. A 2015 USFWS status review determined that ESA protection not warranted. With the changing administration, Secretary of the Interior Ryan Zinke ordered the plans reviewed. Idaho Governor Otter objected to some aspects of the plans. Moore said some things were tacked on in D.C. such as sagebrush focal areas and mining withdrawals. They have since brought together a task force to put together a plan to address the needs of the birds. Working through the WGA (Western Governors' Association) Moore said they'd meet Secretary Zinke's 45-day review period for his order. Some states will have amendments, some won't. They will focus on outcomes and how they get there will be different in each state.

Working with the legislature, IDFG received approval to raise resident fees by 20 percent, effective 2018. They haven't had an increase since 2005. There is a stipulation that any resident buying in 2017 could "price lock" license and tag costs. IDFG gets no general funds. It gets 35 percent of its budget from mitigation funds through BPA, Idaho Power, Avista, etc. The rest is from license buyers.

Looking at 2017 fall steelhead management, this year it was late and they thought it would be a reduced run. There was a director-issued closure. They closed harvest, but allowed catch and release. It was surprisingly controversial. A lot of wild fish advocates looked to use this to make a case for what's happening with wild steelhead in Idaho, Moore said. Even though the numbers came back up, they were concerned we were going to have incidental take impacts on our wild steelhead. After staff reviewed it, they proposed opening the season. He said the issue alerted him to the fact that the steelhead and wild Chinook issues being dealt with by the coastal states have crept upriver. For example, Washington doesn't allow you to lift fish out of the water, Moore said. Advocates wanted those rules in place. They wanted to eliminate the use of bait. We can't find a biological foundation for those, those are social rules, he said. Moore said they have a six-year fish management plan that will be reviewed in 2018, and those social issues can be addressed during that time. Advocates wanted escapement goals for wild steelhead streams. We don't know enough about those wild streams to put hatchery fish in them, he said. We don't allow sport fishing in those streams during the steelhead season because there are no hatchery fish in them. We have kept those areas that way since 1973. One of the legacies in Idaho is a rich tradition of control areas. I'd like to get to a point where we can execute wild fisheries on steelhead. I don't know if we'll get there or not, he said.

Moore highlighted two projects:

1. Kootenai River – Since 1979, they have sponsored research on white sturgeon. Working with the Kootenai tribe, they have been evaluating the stagnant population of burbot.

2. Lake Pend Oreille fish recovery program – They have a stagnant population of fish. They haven't seen successful natural recruitment since the dam went in, and they're working to find a way to improve that.

Lake Pend Oreille fishery has a success story with its kokanee restoration.

He discussed lake trout suppression efforts, using commercial fishing and netting after just using bounties wasn't enough. The effort ended with few fish reaching spawning size. If properly conducted, predator management can work, he said, but you have to do it on a large scale. They had funding from Avista to hire commercial fishermen from the Great Lakes.

Albeni Falls Wildlife mitigation is another collaborative effort in the panhandle. The Clark Fork Delta Restoration of a wetland is another project they're proud of. They're close to a final agreement on the Albeni Falls Wildlife Mitigation program. Member Booth has been a part of the effort.

Moore described IDFW collaborative efforts:

Downstream collaboration efforts include:

- US vs. Oregon
- Columbia River Systems Operations EIS
- Recovery Planning of Snake River Chinook, steelhead and sockeye
- ESA compliance – HGMP effort with NOAA
- Columbia Basin Partnership – NOAA's goal-setting effort and activities.

Council/BPA collaboration includes:

- Fish program priorities
- Long-term O&M – hatcheries and screens
- Adult salmon and steelhead objectives
- Research plan update
- Albeni Falls Dam mitigation agreement
- Accord (MOU) conversations
- Portfolio efficiency conversations

National Scale Collaboration:

- Association of Fish and Wildlife Agencies – Moore is AFWA president for 2017-18. Key AFWA issues include supporting Secretary Zinke's order to increase opportunities for sportsman for hunting, fishing and trapping. They are also working to strengthen the partnership with the new administration to increase participation in hunting, shooting sports, angling and boating, which are also recruitment, retention and reactivation.

They are collaborating with a new entity known as the Blue Ribbon Panel, which recommends dedicating $1.5 billion annually from energy and mineral resource development on federal lands into the wildlife conservation and restoration program, also known as Pittman/Robertson Act. This would occur under the proposed HR 5650 Recovering America's Wildlife Act, which would amend the Pittman/Robertson Act. He discussed what offsets might have to occur to get this moved forward.

Moore also talked about Idaho's work to update its state wildlife action plan.

Moore also mentioned chronic wasting disease. The disease is in Montana and Wyoming. It hasn't crossed into Idaho yet. Much like the Quagga mussels, it's right at our door, he said.

They're updating their management strategies. It's indicative of the challenges they face because nothing is static. It will require more collaboration between the states.

Member Lorenzen expressed interest in chronic wasting disease. "Many years ago, when I served on Oregon Fish and Wildlife, I first became aware of it," he said. "Has there been any further progress on determining on how it's spread?" Moore replied that progress has been made. The prions that are shed combine into soil and can be transferred in many ways. The vectors by which they get moved around are many. Previous strategies were to kill everything around where it's detected. That may not be the tactic to use. Now they're looking at different, more contemporary strategies. Wyoming has an expanding population, and it is concerning that it's moved from eastern Wyoming to the Idaho border.

Member Anders said that recently, the Columbia-Snake River Irrigators Association put out a policy statement paper accusing the Council of mismanaging Idaho stocks listed under the ESA. "We worked hard with Idaho and other FW entities to try and prevent devastation in 2015, which was a significant drought year," she said. "Is there anything we should have done? Might have done? Were we remiss in that regard?"

Moore replied that the question gets at the complication of management on a day-to-day basis. He said he now has the benefit of hindsight. Since 2016, they have had an agreed-upon bypass in terms of operating on smolts in March and April. Generally, when the criteria are right, they begin transporting in May. In 2015, they had unprecedented low flows. There wasn't consensus among the management entities on how to proceed. Therefore, they reverted to the standard operating protocols they had. "Did we make a mistake?" he asked. "I'm not going to second guess the managers trying to determine that. That diversity of expertise we had there has to be respected."

Moore said they have learned that they could have benefitted those fish with transport. Hopefully managers will reach consensus in a quicker period of time so it could be implemented, he said. "Were we negligent? Did we ignore the data? I think everything was known to the managers, but there was that lack of uncertainty about that early transport window, even with these kinds of flows. There was not a consensus operational way to move forward with that."

He said he won't go into the merits of the legal action by the Irrigators Association. That will be up for the courts to determine.

Member Guy Norman asked about recently delisted grizzly bears. "Moving forward, is there a tri-state compact or formal process for managing the future of the grizzly bears in terms of regulations or hunting, or are states making their own assessments?" he asked.

Moore replied that there is a formal agreement among the states describing the criteria that has to be addressed annually by the members who signed it. It is part of the delisting agreement. Each state, once it determines that there's an available mortality for human use, will make a decision independent of each other. Wyoming has more depredation and social issues associated with grizzly bear expansion. But he said they have to manage those forest carnivores so they maintain the societal tolerance in the area they're responsible for. Outside of the greater Yellowstone area, they're still listed. He said they'd be lucky if they have one or two animals a year available for harvest in Idaho.

The meeting recessed at 2:59 p.m.

Wednesday, November 15

Chair Lorenzen called the meeting to order at 9:00 a.m.

3. Implications of the California solar surplus on West Coast power markets

Ben Kujala, Power Division director, introduced Randy Hardy:

Randy obviously has a very long resume in the industry. He has been doing consulting for many years, has been closely following California, and has a very strong perspective. And he has come to share it before the Council. Among the many accomplishments he has is that as a former BPA administrator, he's been in the hot seat and has understood the regional relationship in a very direct way. So it is my pleasure to turn it over and let Randy share with the Council his perspective which, as a continuing thought leader in this region with a strong understanding of our dynamic in this region, as well as how we relate to the California market and the California entities.

Hardy:
Thank you, Ben, and thank you, Mr. Chairman. I would start by thanking you for inviting me. I'm happy to share whatever knowledge I may or may not have with the Council and with others. In my current consulting capacity, working with clients or BPA, I view that as one of my roles to try to help talk about policy tradeoffs and policy choices that decision-makers have, whether that's Elliot at Bonneville or other utilities, the Power Council or whatever. Ben mentioned my 10 years at (Seattle) City Light. One of my first jobs in this region was the head of PNUCC. I worked very closely with Dan Evans, Roy Hemingway, and the initial Council in the early 80s. That contributed very much to my education as a beginning professional in this industry. I appreciated that time and I certainly learned a lot. That was a pretty formative time for our industry.

What I wanted to talk about today in a nutshell is what's going on in the California energy business, and how that might affect the Northwest and WECC as a whole. It's a fascinating social experiment that's occurring down there. Because California is probably 40 to 50 percent of the total WECC load, it inevitably will have major ramifications for what happens up here.

California passed, in 2011, a 50 percent RPS. Three IOUs are well on their way toward achieving that goal. They're currently at 30 percent of their power supply being supplied by renewables, and they have to reach 50 percent by 2030. That's the framework within which decisions are being made. The reality of the resource acquisition in California is that all wind that is possible to acquire, has been acquired. There are other wind sites in California, but they're all transmission constrained.

So the only renewable resource you have to get from the current 30 percent to 50 percent is solar. And you're already dramatically surplus in solar, so they're just going to make that worse. And that's just procurement of utility-scale solar. In addition to that, you have rooftop solar that's growing even faster than utility solar. California has by far the most generous net metering policies in the United States. So, if you have an income of $50,000 or greater, you'd be crazy not to put solar on your house. The tax incentives – both state and local – and the fact that you get the retail rate from the IOU when you sell it back to them, make installation of rooftop solar extremely attractive, and the PUC has made it pretty clear they won't revisit changing those policies until 2019 or 2020 at the earliest, if then.

You have a situation where you have flat or declining load growth in California. And you're growing solar at 2 GW per year. That's a combination of utility-scale solar and rooftop solar. And the percentage of what is rooftop and what is utility is changing. So the utility-scale acquisitions are slowing somewhat, and the rooftop is increasing because of net metering incentives. That's the situation that currently exists in California. One of the first consequences that will have for us as well as for others within WECC is that if you continue to acquire more solar to get to 50 percent, and continue to enlarge the solar surplus on one hand; and then on the other hand you have fracking, which is going to keep natural gas prices low as long as it continues, we're probably are looking at 10 to 15 years of power prices that are below 30 bucks. Now, I've been around this industry for 40 years. Predicting the future is a perilous endeavor, as you all probably understand better than anybody. But the factors are clearly there. Unless fracking is somehow discontinued, or California somehow abandons its march to a 50 percent RPS — neither of which seem very likely to me — you're going to have this enormous surplus that is going to force wholesale prices quite low, ironically, while retail rates go up, because all the solar costs you have with RPSs will continue to flow through to retail rates.

It's already had significant implications for Bonneville and for the hydro-based utilities in the region (Seattle City Light and the public generators) because they've lost an enormous amount of their traditional secondary sales. The combination of low gas prices and the solar surplus has severely reduced spring hydro surplus sales. So you're spilling a lot more, and what you are selling, you're not getting the prices for that you historically obtained. That creates a considerable rate pressure for Bonneville and for all of the primarily hydro-based utilities in the region, and a comparable challenge.

What the solar surplus does in California is it creates two problems for the state:

The first is a midday surplus problem. In the utility industry, literally for 70 to 80 years, you've had a concept of heavy load hours and light load hours. Heavy load hours are from 6 a.m. to 10 p.m., with a peak at 1 to 2 p.m., or maybe 3 or 4 p.m. Light loads are 10 p.m. to 6 a.m.

The low load time in California is now 2 p.m. There is no more heavy-load hour/light-load hour paradigm. It's completely reversed. The peak load tends to be in the evening, when the sun goes down. Your evening activities are still placing a fair amount of load on the grid. So, that paradigm has completely changed. What you have is an ever-growing midday solar surplus. In the spring, loads are at their lowest, because you're not running air conditioners like summertime and you don't need heating for winter because the winter's essentially over.

Last April and May there were significant amounts of negative pricing and curtailments. What happens is prices go to zero, and then they go below zero. Negative pricing means you pay the buyer to buy it — kind of a novel concept, but that's what happens. With a tax credit, it makes sense to pay up to about $20 MWh and still run the plant, because you're still getting the tax credit. Particularly with the production tax credit, you only get the credit if you generate. So that's another dynamic. But that will continue to grow. You're going to continue to have increased negative pricing. Each of the IOUs has their own supply curve. They'll pay up to a certain point, and it depends upon the particular PPA they have with each individual solar provider, and then they'll curtail when no longer economic to do that. What you'll have is increasingly massive curtailments, not just in the spring, but they'll eventually spread year-round.

If you can imagine this, somewhere in the 2020-2022 time frame, you will reach in California a no-net load proposition. What's the load when you subtract out the solar and wind? It will be zero at some times in the year. What will we do in those circumstances? Talk about a brave new world. We're in a completely different place than we've ever been. You can solve that up to a point with massive solar curtailments, and that's probably what is going to increasingly occur. And what the California ISO is worried about is that at some point it will produce a political reaction. It's hard to know what that political reaction is given that the politics in California are more complicated and less predictable than what we experience here in the Northwest.

So that's part of the dynamic you're looking at: The midday solar surplus continues to grow, it will continue to increase negative pricing and curtailments.

Member Henry Lorenzen: Can you explain curtailments?

Hardy: You trip the breaker and the solar plant is shut down. It's a little more complicated than that, but not much. You simply turn off with wind and solar. They're essentially "must-run resources," but when you have to keep the grid in balance, and then they get curtailed.

The irony of this is you curtail so many megawatt hours of solar, which means you have to build that much more solar to make the 50 percent, which exacerbates further the midday surplus problem. So you’re in this “chase your tail” proposition that’s just crazy, but that’s where we are.

One of the political dynamics you have in California — and this is a Hardy judgment, I won’t attribute it to anyone else — is you have, from the governor on down, in the legislature, you have officials who voted for this 50 percent RPS, who are very reluctant to acknowledge that it has some significant problems associated with it. Because in the next primary, your opponent may just pop up and point those out. This is kind of that classic line from Reagan in the 80s that: “If there is no solution, there is no problem.” That’s essentially what’s being practiced by the elected officials in California, in my view. That complicates the dynamic of trying to find a solution.

The other problem is that when the sun goes down and you still have the same, basic load. You just don’t have solar generating to meet that load. So you have up to a 15,000 MW ramp that you have to cover in a three-hour period, from 6 p.m. to 9 p.m. That’s an enormous ramp. And that’s a challenge in and of itself. And you meet it, at least right now, mostly with gas-fired resources in California. But the problem is that most of those resources were procured pursuant to the CPUC resource acquisition requirements for the California IOUs that have been in place for many, many years. Most of the resources used to meet that are a variety of combustion turbines, or combined-cycle units, that were procured many, many years ago. What you need are modern, more flexible resources — not just gas resources, but hydro — that can respond, not just in an hourly ramp, but also in a five-minute, 15-minute ramp period.

The CAISO’s so-called flex capacity stack, which is the group of resources that it uses to meet this ramp, 40 percent of those so-called flexible-capacity resources are long-start resources. You have to fire them up the day before to meet a five-minute increment the next day. To put it mildly, the CPUC resource acquisition priorities are completely misaligned with what the CAISO needs. Yet, in California, you can’t change that without the CPUC, and the ISO, and the CEC (which is the agency that procures and sites for new resources) to change their procurement priorities. That looks unlikely to happen anytime in the near future.

Not only getting the three agencies together is a bureaucratic challenge, but also you’ve got another dynamic going on in California that is severely complicating this. And that is you have the creation of what are called Community Choice Aggregators. These are individual communities, typically within a particular county, except they have no association with county government, who can form and go sign a power purchase agreement with Calpine, Exelon, NRG or some other marketer to procure resources independent of the IOUs. In part because of all these policies that IOUs have to pay for, California IOU rates are the highest in the nation. So there’s a lots of incentive to form a community aggregator. You still have to use the IOU wires, but get your power supply independent of the host IOU, whether that’s PG&E or SoCal Edison or to a lesser extent, San Diego Gas & Electric. Also, the CPUC doesn’t have regulatory authority, or complete regulatory authority, over these entities. So what reliability standards, if any, they have to meet, and how their procurement is governed is a complete jumble at this stage.

So the dynamic that this is creating in California, is you have the CPUC completed distracted by trying to figure out how does it regulate the Community Choice Aggregators, and not paying much attention, in my view, to these operational issues that are occurring. And you have the California IOUs who are desperately worried that they're going to lose a bunch of load. So they don't want any extra costs that could become stranded costs. They don't want to change the resource procurement priorities, and be required by the CPUC to acquire new, fast-acting gas resources to help meet the ramp. They just want status quo until this whole penetration of Community Choice Aggregators can be sorted out. To give you an example, PG&E, which is probably the most exposed, thinks that five years from now, they'll have half of their load. PG&E is the largest utility in the country. That's an amazing phenomenon. You have the CCA formation distracting some of the key players, or motivating them in ways that are counter to solving the solar surplus problem, and that is not something that is likely to change in the near future.

Back to my comment that if there is no solution, there is no problem, you have elements in the legislature who are in denial that there is a problem. That the duck curve that you've heard about — that the belly of the duck is when the solar surplus occurs in midday — is all just a big hoax. So it is not a great environment. I certainly wouldn't want to be Steve Berberich, who is the head of the CAISO, right now. Because they're the only agency that is actually trying to solve the problem. Everybody is off doing other things, some of it explainable and some of it not.

Then, to layer on top of the politics of all this, you have the labor interests in California, who don't want to acknowledge the problem. And they don't want to procure any out-of-state resources. They want an all-solar path to 50 percent and they want it all to be in state so they can generate as many jobs as possible. And they have a stranglehold, in my view, on the California State Legislature. Who knows where it will lead? The signs aren't encouraging that it will lead to solving problems. So that's the physics of the issue and the politics that are complicating this.

One pretty straightforward solution would be to simply access Northwest hydro. Hydro is by far the most flexible resource that you can use. All you do is open a wicket gate and you've got it. And the CAISO's problems with the evening ramp in particular are not just a 3-hour problem. To give you some idea, the ramp at its maximum is 15,000 MW. But it's growing each year, because you're adding 2,000 MW of solar each year. That's just going to get worse. Right now, a single hour of the three-hour ramp is often more than 50 percent of the entire three-hour ramp. A single, 15-minute period of each hour is often more than 50 percent of the hourly ramp. A single, five-minute period of the 15-minute market is often more than 50 percent of the 15-minute ramp. So you've got not only a three-hour exponential ramp, you also have an enormous variability of several thousand megawatts within each hour and even within each 15-minute and to some extent, each five-minute period. So you need resources that can really move and move quickly all over the place.

CAISO just last week took the first step, albeit a modest one, to address the ramp issue. They have in their initiatives catalog for 2018, which came out last week, an initiative to look at a day ahead, 15-minute market capacity product. They'll develop this during 2018 and presumably put this into effect in 2019. That's the first time CAISO will be paying for capacity in its 20-year history. That's a step in the right direction. If you have a capacity payment that gives Northwest hydro providers more time and more assurance that they can get the financial returns they need to sell. It doesn't make a lot of difference in Q2, because the capacity comes with all the energy associated with runoff. In Q3, it's up and down depending on temperatures, but it makes a big difference in Q4 and Q1, where you essentially face discretionary decisions of do I sell or do I store? If Bonneville and Powerex Seattle and the PGP group can get an actual capacity payment, chances are they can bid into the day-ahead market to do that, which they can't now. They'll at least get some Northwest hydro. That's a modest step, but at least it's moving in the right direction. Ultimately you have to change your Resource Adequacy policies to procure more flexible resources , some of which could very well be hydro. I would commend to you some of the PGP studies that have been done— I'm sure Ben has copies of them — both on carbon pricing in the region and Chelan did one a couple months ago that looked at if you substituted 1500 MW of Northwest hydro instead of California thermal to meet the evening ramp, you would save about a half-million tons of CO2 per year. It's not just cost effective; it actually helps them with their goal of reducing CO2 emissions. But again, you have the labor interests and others that don't want anything out of state, so there's political opposition to that, and it requires, at least in some circumstances, multiagency approval — which is hard for the CAISO to get, given that everybody is going in a different direction.

So that's the basic circumstance. What will that produce for the Northwest? Continued, low, power prices. Bonneville is already well-above market. Bonneville's basic wholesale rate is $35. The market, a 10-year strip on a raw Mid-C price is probably $25, but that's not the right comparison because it doesn't include transmission or reserves. It's not a fully delivered product. But when we add those in, the fully delivered product price is more like $30 for a "market purchase" versus $35 for where Bonneville's rate is. And Bonneville's rate is going to continue to creep up. Bonneville is above market. Fortunately Bonneville has take-or-pay contracts, which don't expire until 2027.

I was the one who lived through the last crisis in 1995, where we had the same problem, albeit a much more temporary one. We woke up one day in April 1995, after deregulation, and our wholesale rate was $28, and Enron was offering five-year contracts to our public and DSI customers at $15 to $17. That's a problem. We broke all kinds of political china and got a lot of help from Senator Hatfield. Fortunately we were able to stabilize that and avoid missing a Treasury payment. In the process, we amended all of our contracts to make them take-or-pay.

Elliot's got stability in the near term. But he's got to start thinking now that, if we're correct, and low power prices are going to continue, do I start to take steps now, anticipating that come 2027, if I'm still in this circumstance, I'm going to have some pretty dramatic diversification. That's certainly what happened when I went through this thing in 1995. You've got to look at that and you have two choices: One is to sit and wait two to three years to see if the California market develops sufficiently, where you can sell big quantities of hydro capacity and other products to get the revenue return that you need to make up for some of the losses you've incurred and keep your rate in check. Or, do you do some long-term deals now if you have some "surplus power" that you can sell to one of the Northwest IOUs or maybe one of the marketers.

There are some interesting strategic choices that the agency will face in the next five years. That's the kind of circumstance: continued low power prices, implications come 2027 (or probably earlier than that for Bonneville) and, of course, financial pressure across the board, which will leak into other areas such as fish and wildlife, and other kinds of things because it's one budget that the agency is struggling with to be financially stable and to make decisions that are politically sustainable.

So you'll have those kinds of choices and continued financial pressure on Bonneville on one hand, but then you'll have a whole bunch of operational choices. By 2020, you'll have daily reversals of flow on the intertie. That hasn't happened in 25 years. That hasn't happened since the early 1990s, when I was administrator, and we did seasonal exchanges — earlier than that in the 1980s, when I ran Seattle City Light, we did seasonal exchanges. That's one of the main reasons why the Pacific intertie was built. It was to dispose of the spring runoff hydro surplus and do seasonal exchanges, to take advantage of the seasonal diversity between California and the Northwest. You send power south in the summer to help run California air conditioners, and you get back load in the winter when their load isn't has high and you need it for winter heating loads. You'll have the same thing happening here, except it will be daily instead of seasonally. You'll send power south in the evening to help California with the evening ramp, and it will come back the next midday. It's not happening now because the solar surplus is not yet severe enough. In addition to all these other quirks, California has a $10 export fee. There's a lot of reasoning behind that, but ultimately that will have to go. Because when you have negative prices, all you're doing is taxing your own consumers another $10/MWh. So one would think that wouldn't stay around that long. But you have those kinds of complications and those kinds of operational challenges. So when you have daily reversals of flow on the intertie, I can't tell you how that will affect flows on the Bonneville transmission network, except it will. And whether you'll have congestion in spots where you've never had it before, or maybe it will help. But you have a whole range of transmission issues (in addition to the South of Allston congestion that Bonneville is struggling with right now) that will start to occur.

What are the solutions going forward?

The CAISO had its symposium about a month ago in mid-October. The CAISO board put out a white paper that was their view of the trends in the industry. I'm sure Ben has it or could get you a copy of it. I suggest you read it. It gives you a very good view of what's going on in California. It identifies trends, which are general industry trends, not unique to California: More decentralized power procurement, less use of gas, more penetration of renewables, and a list of eight different things. Then there are proposed potential solutions. It’s a fascinating mix in the solutions section of the paper of very detailed and very practical things that can be done, like acquire more flexible capacity and access out of state resources. So you can procure Wyoming wind or Northwest wind that has a load shape typically generating in the evening and the winter that compliments California solar load shape in ways that get you to 50 percent, but minimizes the cost of it and doesn’t exacerbate solar problem. That’s prevented by other California legislation. And regionalization: expand the CAISO to be a regional ISO, if you will. Again, that would help significantly, but here are significant governance challenges that are in the way of that. So it has a set of solutions that are quite detailed and on the mark.

Then it has another set of solutions that I would charitably call aspirational (others would call them unicorn chasing) that are much more problematic. There is a heavy reliance on utility-scale storage. That’s coming, but in the next five years, I don’t think so. With a wind resource, if you get viable utility-scale storage for two to three hours, you can turn a 30 percent capacity factor wind plant into 70 to 80 percent capacity. With solar you need something overnight. You need 12-14 hours … we’re 10 years away from that. There was an excellent article in this week’s Clearing Up California Energy Markets that S&P put out saying that commercially significant large-scale energy storage is 10 years away, and the logic for that. I would agree with that. We’ll get there, but it is not easy. You do have viable storage, or will have shortly, at the residential level. Tesla’s Power Wall technology coupled with the solar panels is a good example of that. But that is behind the meter, it’s disaggregated and you have no way to control it. It benefits the individual consumer, but it’s not going to help you without massive changes in the distribution systems, which even if you could accomplish them, are many years away before CAISO has any kind of meaningful control.

So you have a heavy reliance on storage technologies, which don’t yet exist in any commercially viable form, and the second thing is an assumption that you’ll have four million EVs on the street by 2030 in California. I think the current figure is 300,000. Good luck with that. That will really help. Not only will you have four million EVs on the street, you’ll have the ability to precisely control when they charge and when they don’t charge. That’s a degree of control that’s pretty unique, even for California. You can incentivize people to do certain things. But having that many of these in the first place, and then being able to control when they do and don’t charge for the benefit of the electric grid (as opposed to consumer preferences), that’s a social experiment that will be interesting to watch. You have a category of things that are already there that you would need to solve the problem. A more realistic set of measures would probably be … not to posit a full-scale CAISO expansion — that will eventually happen, but that’s more of a five-to-10 year away proposition due to all the concerns about governance, and the some of the issues associated with Bonneville being part of that. If the problem gets bad enough, you could certainly increase your access to Northwest and other resources fairly dramatically. You have an EIM that’s functioning pretty well right now, that helps, but that’s only a five-minute market. One of the reasons why California is going to look at a 15-minute market day-ahead capacity product is because to transact in the five-minute market, you need what’s called dynamic transfer capability on the Intertie. There’s only 400 MW of DTC on the Pacific intertie. It might go to 600. If you go to the 15-minute market, you have the full, 4,800 MW of Pacific Interties you can use. With the five-minute market, you can only use 400 MW. So if you're going to address your evening ramp problem, you need full access to the full value of the Intertie. Probably in a couple of years, Bonneville will change its practices to get 15-minute scheduling on the DC, so the full 7,900 MW of Pacific Intertie will be available to the 15-minute market. Those are solutions. If you get rid of the export fee, if you rely more heavily on hourly and 15-minute market transactions out of state, and if you get rid of the legislative mandate of the category of renewables that effectively prevents much renewable importation from out of state, you'd go a long way.

That's not something that requires a regional ISO. That could be done tomorrow. The impediments are California's own regulatory impediments, the export fee and the lack of capacity payments, in particular. There are solutions, or at least movement toward solutions, but they are ones that are not politically available right now.

I'd end by saying something I've said many times before: This industry is in the midst of enormous technological change. You've seen that, you've heard that. One vignette unrelated to California illustrates that best. Seattle has, by almost every account, the most commercial construction downtown of any city in the United States. Go up the Space Needle and count the cranes. There were about 20 the last time I counted. Commercial load is 40 percent of Seattle City Light's capability. And it's growing. You have more construction going on to create more load, and yet Seattle City Light's loads are going down. And the reason they're decreasing is LED lights and more sophisticated HVAC system controls. That tells you something about where loads are going generally. You all are the premier load forecasters in the region. I was telling Steve Crow earlier to look at the LED light penetration and what conclusions can we draw. PGE still thinks they're going to have 1 to 1.5 percent load growth in Portland, which has an enormous effect on the South of Alston transmission problem. I'm not so sure. But that's an area with the conservation targets you've set and your load forecasting, where the Council could make a unique contribution that is very germane to sizing this problem. But in any case, those are the kinds of changes that are occurring. We're in the midst of an enormous amount of change, and it's a fascinating time to be involved in the industry, but the outcome of that, given where California is or isn't, will have an effect on all of us.

There are interim solutions that will help. Currently, they're largely precluded by politics in California. But as the problem gets worse, and the renewable curtailments get more pronounced, I think that will change.

Another thing that's lurking out there is you have a significant chance of a major reliability event in California in the next five years. If that happens, since I'm the guy who caused the last event in California back in 1996 that will change things in a hurry. The problem is, when that occurs, people will be far more interested in finger pointing than they are in solutions. It provides a motivation, but what the solution that comes out of that is anyone's guess. Having lived through one of those, I don't wish that on anybody. But there are significant risks that it could happen again.

With that I'll be happy to answer any questions.

Member Bill Booth: For me, you really put the California situation in a perspective that was very easy to understand. I know it's much more complex. This region, because of our hydro resources, is in decent condition and would logically be a solution for California to help in the evening with that quick ramp up. Is the current intertie transmission infrastructure set up to handle the five to 15-minute surge into California? Or would it take additional infrastructure. We're also seeing a large increase in solar in this region, some states have solar goals as well. In Coeur d'Alene, I get radio ads for rooftop here where it's a cloudy, wet climate. Do you see the same problem developing here?

Hardy: To answer your first question, yes and no. The EIM only transacts in the five-minute market with whatever excess transmission capability is available. You only have 400 MW of DTC, on the AC portion of the intertie that's available for those kinds of transactions. So there are real severe limits for the EIM for the five-minute market. But for the 15-minute market and hourly market, you have the whole intertie capability … with the exception that we don't yet have 15-minute scheduling on the DC, but that will come. You have the whole 7,900 MW of the intertie for hourly transactions. And you have the whole AC (the 4,800 MW) and then in two or three years, the DC that will be available for 15-minute transactions. All of which would help if you had a bidding system in California that would pay for capacity. That's the problem. CAISO offers a capacity payment, say it expands … it implements the day-ahead product and then it expands it to an hourly product. This would have to be a set of transactions outside the normal bidding framework, which is a significant challenge for them. Ultimately, you clearly have the capacity to do that. If the problem gets severe enough, by far the easiest thing for you is to access that existing Northwest hydro capacity. And you have plenty of sellers: Powerex, Seattle, Bonneville, the public generators and, frankly, the IOUs.

Idaho Power and Avista are still predominantly hydro-based utilities. Between Hells Canyon, Noxon and Cabinet Gorge, they have significant hydropower capability. But the IOUs can also use their thermal capability. Let me give you a vignette that illustrates what can be done: Right now, PacifiCorp was the first participant in the CAISO EIM. The way they're operating their coal plants is amazing. They're doing this in the five-minute market right now. When the midday surplus comes, they back off to 20 percent. And when the evening ramp comes, they ramp it up to 90. They're printing money. And they're operating coal plants in a way we never dreamed was possible. But they're doing that. Eventually, due to lower power prices, those plants are going to be retired in the mid-to-late 2020s. But that's the kind of operation you'll find with the IOUs and their thermal. And that's the kind of operation you'll find with those publics and IOUs that have hydro projects with significant storage — Powerex, Seattle, Avista, Idaho, and Bonneville to a lesser extent, because fish constraints have essentially removed most of the operational flexibility that Bonneville has. They can still sell some hydro. But the challenge you have, and why you need a capacity payment, is even when you have storage, you need to set up your system three or four days ahead of time. You need to take actions on a Monday to deliver something on a Friday. A cubic foot of water out of Grand Coulee doesn't pass Bonneville until a day later. So you need a fair amount of lead-time to set up your hydrosystem, which the five-minute market does not provide you. That's why capacity payments are important. It not only gives you more money per se, it allows you to set up your hydrosystem in advance to maximize the amount you can deliver to California. So it's better for you, but it's also better for the ISO because they get more of the most flexible resource that's available on the West Coast.

So that's the answer. Outside of five-minute market, yes. Within the five-minute market, very limited capability. You can theorize about Bonneville joining the EIM, but aside from the politics, BPA has two-to-four years' worth of transmission automation work to do before it can even think about joining the EIM. So it's a moot point. Not that they aren't thinking about it, but there's a huge amount of transmission automation work and IT work that would have to take place before they would be remotely capable of participating in the EIM. I've lived through this. That's the physical reality of that system.

Relative to your question about solar, I'm not an expert in Oregon, Idaho and Washington solar, but what I've seen of the data, it's mostly PURPA projects. I doubt that much of that will come to pass. With rooftop, it's a different animal. It just depends on what your net metering policies are, and what the incentive structure at the state and federal level are, and that could well move. The fact that you have this enormous penetration of solar in California, which will keep prices low, I doubt that you'll see much utility-scale solar that will actually come to pass. And you have plenty of projects. But having consulted for a few of these folks, it's the same with the large wind companies. They come to you and they have lots of data. This is probably more so with the wind folks, but it's the same dynamic with solar. They have 10 years' worth of wind data for a particular site. Talked with GE or Siemens, and they have the latest turbine design and everything else. But they haven't thought about transmission. Suddenly, they come in there and say they're ready to go, and you find out they have to build new transmission and that's a 10-year project. In real estate it's location, location, location. For renewables it's transmission, transmission, transmission. By and large, the smaller guys don't think about that until the last minute, and they can't do it. The short answer to your question is I don't see much utility-scale solar anywhere in the Northwest. Some PURPA projects have already gotten through the Idaho Power and Idaho PUC conundrum, but I just don't see that happening much elsewhere because the California prices have so depressed the prices you can get for most large projects, and the transmission issues you typically have of interconnecting to Bonneville. I doubt there will be much penetration.

Member Lorenzen: You mentioned the DC intertie, is that capacity 7,900 MW, or is that combined AC and DC?

Hardy: That's combined AC/DC. The DC is 3,100, and to go to 3,220 here in another year, and the AC is 4,800. There is a possibility you can increase the DC capacity to 3,800, but that involves raising all the towers on the California end and completely reconfiguring the southern temrinal, and that's about a $1 billion project for another 600 MW — probably not something that's going to happen real soon.

Member Lorenzen: You mentioned that there's a potential for Northwest wind to complement California solar. Is that constrained in any way by the Intertie?

Hardy: No. Intertie space is completely allocated out. Avangrid is one of my clients, the biggest wind developer in the Northwest. They have plenty of intertie capacity. They can build more wind and sell to California, but the problem you've got now is you have three categories of renewables. It's very restrictive. The only renewables out of state that a provider can sell into California is in real time, within the hour. That's pretty difficult to do. I think eventually the Californians will have to get rid of those three categories. That's a legislative decision in their part. But the labor interests don't want that to happen because then you go out of state, and losethe jobs, and you all can extrapolate the political implications of that. But ultimately that would have to happen and, if that happened, just like pre-2010, with the 20 percent RPS, you saw a lot of wind development up here. The whole Shepherds Flat is sold to SoCal Edison, that's 850 MW. You'd see similar developments, in my view. You might see more Montana wind that would come, but you have to resolve come intertie constraints there first. But that tends to be a better wind resource. But typically that involves two or three wheels, and the pancaked wheels eat up the 40 percent capacity factor advantage over the 35 percent Gorge wind pretty quickly. But you'll probably see a mix of Montana, Gorge and Lower Monumental wind. You might see some Wyoming wind, but that would involve construction of a several billion-dollar transmission line that I think is more problematic. But you probably would see some New Mexico wind, because you do have existing transmission capability, particularly with the retirements of coal plants at Four Corners. You could see some significant New Mexico wind, that's pretty good wind and would have a transmission path to get to Southern California.

Member Lorenzen: Oregon also has a 50 percent renewable standard. It may not be the same as California's. Do you anticipate that Oregon will face some of the similar issues that California is facing?

Hardy: I would hope not. If you're smart about it and you're PacifiCorp, because you have service territory all over, you can go acquire Wyoming wind and get that to count. Wyoming wind tends to be nighttime peaking and winter peaking. PGE, I would expect, would primarily look at Northwest wind resources. They've looked at that, they're looking at Montana wind, both of which have load shapes that tend to complement, rather than exacerbate, the California solar surplus. So I would expect that would be the approach that the IOUs would take.

Member Tom Karier: The Council is particularly concerned about Bonneville's financial situation now and especially in 10 years. As you said, if things continue with low prices, and they continue to carry the large debt burden that they have today and other costs, they're potentially facing bankruptcy as a government agency. And that's not what the Northwest needs or should have. The ways out of it are more markets, better markets for Bonneville. Not just more sales, but at a better price. I'm just skeptical that California will help us out in any way. The idea that we're waiting for them to set up the right market, that we'll be able to sell our hydro and get the actual value of it in energy and capacity might be overly optimistic that they'll do that for us. I'm thinking about the day-ahead capacity markets. Obviously capacity markets are what we need. But don't we need something longer that provides more assurance at a higher price? We need a six-month, or a six-year capacity market and assurance. If we're just dumping in capacity a day ahead, we're just dumping in surplus energy again, and not going to get the full value. Should we be thinking about that? Can we design markets or pressure markets to serve our needs, rather than California designing markets that represent their needs?

Hardy: Yes, is the short answer. I did not mean to suggest waiting for California to develop a market was the only solution, or even a desirable solution. I was trying to sketch conceptually the two pathways that you've got here, recognizing that they are not mutually exclusive. I think further developments will occur in California because it's inevitable that the solar surplus will create the need to do that. And Californians will not accept the massive renewable curtailments that will be the eventual consequence of just letting things continue the way they are. But that isn't alone sufficient. You need to do that; you need to take advantage. Elliot has done a good job of working with Steve Berberich and the CAISO. But for Bonneville's urging, I don't think the CAISO would have even started to look at the 15-minute market. That's largely Elliot personally doing that. Now there was a lot of support from PGP, Powerex, Seattle and lots of other hydro providers, but 80 percent is Elliot himself lobbying with Berberich to make him understand hydro. That being said, you do need to look at longer-term transactions with Northwest IOUs or with marketers. BPA has the legal authority to do a five-year power sales contract purchase with an IOU, and a seven-year ability to do it with a marketer. And you could do either one of those, and you could make it evergreen and roll it forward. And you could sell — this is Randy Hardy's view not Elliot's — you could do a five year contract with a Northwest IOU, or a seven-year contract with a Northwest marketer, and get something greater than 35 bucks for it. You could make it a fully dispatchable hydro product. That's the key. You could provide the operational flexibility that would make that $35 worth paying. Even though the market is below $30, that is just for a basic block of energy. That's doable in my view. I know that's one of the things that Bonneville is starting to look at. Part of the challenge is it has to be surplus, because public power has a call via the preference clause, but you may have some ability to carve out "surplus power" prior to the contracts expiring and people diversifying.

I'll give you an example: In the last couple of months, Bonneville went through a major exercise with Cowlitz PUD for the NORPAC load. NORPAC is shutting down 100 MW of its paper processing, supposedly to modernize and come back in a year or two. Whether that ever happens, who knows? But if they don't come back, there's 100 MW. And if you have flat load growth, there's 100 MW you could sell to somebody else for a better price. You've got things like that, where I think you could define some amount of surplus power that you would be able to sell on a longer-term basis.

Member Karier: Couldn't Bonneville identify even more of that through its energy efficiency programs and demand response? It could augment that.

Hardy: Yes, energy efficiency will help in the course of your own load forecasting and conservation work. If you could forecast forward what LED lights will do, relative to what your load forecast is going to do. Right now, I don't think BPA has fully sold out its Tier One power. It probably has contractually. But the reality operationally, is that loads are continuing to be flat or declining for the most part, and I think the effect of those new technologies will increase over the next 10 years in ways that create more surplus you could sell.

Member Karier: I like idea of working with Northwest IOUs rather than waiting for California to give us a break.

Hardy: I'm not suggesting waiting for California. BPA is still in court over the 2001 energy crisis. I worked for the California Department of Water Resources during that time. Bonneville saved their ass. They would have had twice the number of curtailments had Steve Wright not been willing to do the two-for-one environmental exchanges. The Californians who were there at the time recognized that. The lesson learned from that is that the California attorney general is a separately elected official. He doesn't get points or kudos for supporting out-of-region providers, he sues them. And if you have a problem with California, that same exact dynamic will happen again. So your caution is well taken.

Member Jim Yost: The situation we have in the Northwest now is do we remove the four Lower Snake River Dams and we have transmission constraints from Bridger west, with two major transmission lines under consideration and development. But even though Idaho Power has 480 MW of solar, it's difficult to find transmission pathways to move it to California, even though we do move some south and west. We're transmission restrained. PG&E can't even replace Boardman coal with a gas-fired plant. So if you take out the Snake River dams, I don't know if we can replace them with gas, unless we line them up on the Idaho border.

Hardy: I've tried to make a practice in my 20 years of consulting to stay away from fish issues, because it's just so depressing. All I'd observe is the factoid that's often ignored when you talk about taking out the Snake River dams, is yeah, they only provide five percent of the region's energy, but they also provide 16 percent of region's generation capacity. That's why they're important, and that's what you're going to need. We're awash in energy, thanks to the California solar problem. It's capacity that we need and taking those dams out, the capacity replacement (unless someone invents the next, great storage technology) is going to have to be a CT. So you're going to end up with more combustion turbine construction to replace them regardless. It underlines the importance of trying to keep those facilities, at least in the midterm, until some of this stuff sorts itself out.

Let me offer another, quasi-political observation. Again, this is something Ben should provide you. PGP has just done a really interesting study. E3, a consulting firm out of California did it for them, looked at a cap and trade system for the Northwest versus a 50 percent RPS, versus a no-new gas scenario. A 50 percent RPS is twice the cost for half the savings of a cap and trade system. So if your goal is carbon reduction, you want cap and trade or a carbon tax. You don't want RPS. RPS hurts things. It especially hurts the Northwest. If you do a cap and trade, you actually raise the prices for existing hydro, which is an advantage to Bonneville and others financially. And no new gas doesn't do a damned thing. You get virtually no CO_2 savings, or a miniscule amount of CO_2 savings for about the same cost as if you did cap and trade. You could read the study and make your own judgments. It's a very interesting piece of work relative to some of the choices, particularly Washington State, will have.

Member Karier: That confirms the results in our Seventh Power Plan too.

Hardy: I'm sorry I'm not as familiar with that. Whether Governor Inslee listens or not, we'll see. It was just a very interesting piece of work, especially since it complements what you've already concluded in the Seventh Power Plan. That's the kind of guidance policymakers need when they're looking at the tradeoffs. As California is dramatically illustrating, an RPS is a very inefficient and costly way of getting to carbon reduction. And ultimately, whether you even get there, is a good question. Because if the EVs don't come in and save your ass, what you're going to end up with, when the older CTs get retired, is you're going to have to build all kinds of single-cycle units to meet your evening ramp. You may actually increase CO_2 in California with that kind of an outcome. Crazy, but that's where you can go if you're not careful.

Member Lorenzen: Ben, can you get access to that study?

Kujala: We're still working with PGP on the scheduling, but we're going to have them present directly to the Council. It's in a future Council meeting.

Member Lorenzen: Do you have access to the study? Is that a printed study?

Hardy: It was posted last week on their website. If I could leave you with two thoughts: Read the PGP study. There's a stack of things from a summary to extremely detailed, so you can pick your level of specificity. Read the CAISO issue paper that they prepared for the symposium. Those two things will give you a really good view of both what works and doesn't work in the Northwest, and the California view of the world. And you can draw your own implications for what that means for us.

Member Lorenzen: Ben, can you get the site for that? Randy, thank you very much. It's a pleasure to have someone with your knowledge to come talk to us and spend an hour of your time.

Hardy: It's a pleasure. The reason I do this is I've been around awhile. I'm in my early 70s. I keep doing this because it's fun, given all the changes going on. I view my role here as not just doing good for my clients, but trying to help the region out. Whether that's Bonneville or you all or other regional institutions to at least help focus the trade off choices for the policymakers. The agreement I have with all my clients is I'll help you out with what you want, but I will look for win/win solutions for you and BPA in particular. Seventy or 80 percent of the time I can do that, and the other 30 percent you're on your own. Fortunately, I have a group of clients who accept that as a going-in condition. As long as I can continue to do that, that's fine.

4. Council decision on use of cost savings for fish hatchery and fish screen O&M purposes

Mark Fritsch briefed the Council on the Fish and Wildlife Division's O&M strategic planning effort. It approved and initiated actions on its screens and hatchery program. Part of that assessment, through the contract engineering firm, they identified beneficial and essential elements to address aging infrastructure. Staff initiated a request to prioritize essential elements. They received responses from five of 14 screening sponsors on essential needs. The intent is to address these needs in fiscal year 2018.

The O&M subcommittee approached cost savings workgroup seeking $320,000 for hatcheries and $150,000 for screens. This was taken to the Fish and Wildlife Committee in August and now it is requesting Council approval.

Member Lorenzen said this issue has come up before. There was a discussion on whether this requires a full Council vote. It was indicated that these matter would be infrequent and in the future, we will continue to have them come before the Council. If they become more frequent, we can decide if we want it to go to another level.

Member Karier thanked staff and Council members on their good work. First, it sets priorities on what we should be funding out of cost savings. I think Member Anders and Member Booth picked up on that assignment and developed the cost savings to fund this, and identified the priority needs for the hatcheries and screens, and worked though this methodically. It's a good accomplishment.

Member Guy Norman said he reiterates what Member Karier said. The process is well thought out, Council staff and Bonneville were involved, and we have a good product here.

Northwest Power and Conservation Council Motion to Recommend Bonneville Fund O&M Improvements at Fish Hatcheries of Up to $324,000 and at Fish Screens of Up to $150,000

Member Booth moved that the Council recommend that Bonneville implement O&M improvements at fish hatcheries in an amount up to $324,000 and at fish screens in an amount up to $150,000, as presented by staff and recommended by the Fish and Wildlife Committee.

Member Anders second.
Motion carries without objection.

Council Business

Northwest Power and Conservation Council Motion to Approve the Minutes of the October 10-11, 2017, Council Meeting

Member Booth moved that the Council approve for the signature of the Vice-Chair the minutes of the October 10-11, 2017 Council Meeting held in Portland, Oregon.

Member Bradbury second.
Motion carries without objection.

Motion to Support Development of Understanding with Bonneville on Bonneville's Provision of Power Data Necessary to Support the Council's Power Planning Responsibilities under the Power Act

Member Lorenzen said the final item of the day, a motion to approve release for public comment of the draft power system value of conserved irrigation diversions white paper, has been set over. So there is one additional item of business from Kujala relating to a Bonneville data request.

Kujala said that staff is preparing for the Eighth Power Plan, and they need information from BPA about any augmentation of the hydrosystem, anything that adds energy, and any big contracts. Staff is seeking approval from the Council to enter into a Memorandum of Understanding on what information they need.

Member Bradbury said he appreciates Ben for checking with the members on this. He looked over the memo and thinks it looks great.

Member Karier agreed with Member Bradbury. He added that in the past, they didn't always get this information in a timely manner, due to a misunderstanding or a lack of agreement. The right solution is to talk with BPA and come to an agreement.

Member Lorenzen said, "It gives me two months to make great mischief if this is approved."

Member Booth acknowledged Kujala's work, and marveled at his ability to cram so many words into a one-sentence motion.

Member Booth moved that the Council authorize staff to work with Bonneville staff to finalize a letter that both the Council Chair and a Bonneville executive will sign expressing the two agencies' understanding as to when Bonneville will provide information to the Council on power acquisitions and hydropower generation improvements, information that the Council needs to support its power planning responsibilities under the Northwest Power Act.

Member Bradbury second.

Motion carries without objection.

There was no public comment

Chair Lorenzen adjourned the meeting at 10:21 a.m.

Approved December ___, 2017

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Vice-chair