Northwest Power and Conservation Council
Resource Strategies Advisory Committee
March 12, 2015

Henry Lorenzen, NPCC, opened the meeting.

Draft 7th Plan Scenarios Proposed for Testing
Tom Eckman

Eckman opened by presenting an overview of the resources being considered for the draft 7th Plan and the Council's scenario analysis process. He stated that in addition to energy efficiency the Regional Portfolio Model (RPM) will select from solar PV, wind and gas fired combined cycle and reciprocating engine generation. Jim Gaston, Energy Northwest, stated that the availability of Small Modular Reactors (SMR) will change over the course of the plan and wondered if there was a reason to exclude from analysis. Tom Eckman, NPCC, answered that SMRs are germane to scenario 3B (the role of new technology in achieving maximum carbon reductions) but there are no plans to model them in the RPM since they are not currently commercially available technology.

Eckman then presented a summary of the scenarios being proposed for analysis.

Slide 18 Scenarios 1A & 1B

Nancy Hirsh, NW Energy Coalition, asked why the council would run scenario 1A and not just use scenario 1B as a baseline. Terry Morlan, consultant to NPCC, stated that by comparing the two you could get a good idea on how the model deals with uncertainties. Eckman stated that it would be good to compare scenario 1A which has no uncertainty with other production-costing models like Aurora that assume perfect foresight (i.e., no uncertainty) to see whether the RPM builds similar resources so as to gain confidence in the model's logic.

Chris Robinson, Tacoma Power, supported running scenario 1A and 1B.

Dick Adams, PNUCC, also supported running both scenarios (1A and 1B) as a test of the model before it has to run other, more complicated scenarios.

Jeff Harris, NEEA, asked for clarification on the acronyms: MATS and haze. Eckman answered that MATS stands for the Environmental Protection Agency's (EPA) Mercury and Air Toxics regulation and haze also refers to another EPA air quality regulation, both of which affect existing and new generating facilities.

Rachel Shimshak, Renewable NW, asked which coal plants will be retiring. Eckman answered that the plants in the generating data base include Boardman, Centralia and Corette in Montana. Doug Howell, Sierra Club, stated that Corette is not in the Council's portfolio. He stated that the five in the portfolio are: Boardman, TransAlta, Colstrip, Jim Bridger and North Valmy. Eckman said yes those are the ones we model and we do not model Corette. He said even though these plants are the standard input assumption to RPM we have the option to model others. In addition, Council staff has some questions later on about whether the PacifiCorp share of Jim Bridger is dispatched to meet Northwest loads...

Travis Kavulla, Montana PSC, asked how you ascertain an uncertainty cost in the modeling run. Eckman answered that the two parameters the model uses to select “least cost/least risk” resource strategies are both derived from the calculation of net present value (NPV) system cost across all of the futures tested in the model. System *cost* is the average NPV of a resource strategy across all futures. System *risk* is measured by calculating the average NPV of a resource strategy in the 90th percentile (i.e. the 10% of the futures with the highest NPVs).

Kavulla asked if the purpose of these scenarios is to derive a risk premium and put a price on it. Eckman answered that it will give us an idea of what we have to build into the system to reduce the risk of high cost outcomes, and that that cost could be considered the premium that’s required to mitigate risk.

Morlan pointed out that because scenario 1A has no uncertainty it will show no risk by the measure used by the Council because it only tests one future. He continued by saying that 1B and other scenarios will have risks that can be compared to 1A, but that 1A isn’t a realistic baseline since the future is uncertain.

Lorenzen stated when he first joined the Council he thought when we discussed risk we were referring to the risk of outage, but has since learned that that the RPM model looks at financial risk. Eckman added that the RPM now includes logic that requires that each resource strategy provide a minimum level of resource adequacy for both capacity and energy. This requirement is generated using the assumptions adopted by the Resource Adequacy Advisory Committee (RAAC) through the use of the Council's GENESYS model.

Slide 19 Scenarios 2A-2C – Carbon Emissions Limits

Tom DeBoer, Puget Sound Energy, asked if you set a regional carbon limit how do you determine which generating units dispatch and what is built. Eckman answered that RPM model dispatches based on lowest cost first. So that in any scenario where we raise the cost of carbon until emissions are reduced to the target level, we can then look at the model results showing the dispatch levels of individual or groups of plants as well as what resources were added to replace them and meet load growth. Eckman said that the RPM models regional dispatch so it is not designed to determine individual state compliance options with EPA proposed 111(d) emissions limits. However, he said the states could add their four plans together and compare it to this information to determine whether a regional plan would result in lower cost or more flexibility.

Eckman stated that for Scenario 2A, the staff was proposing to use the EPA "mass-based" targets for 2030 that cover both affected and new generating plants. He said that these targets are the most consistent with the tracking of carbon emissions in the RPM. Tony Usibelli, Washington Energy Office, asked about whether the modeling would be designed to meet both the intermediate values and the final 2030 values, since the intermediate values are lower than the 2030 due to the inclusion of new plants added to satisfy load growth. He asked if the model accounts for that. Eckman stated that we will attempt to model both the intermediate and final targets and will be tracking the carbon emissions in metric tons on an annual basis.

Kavulla stated unlike the rate-based approach, the final carbon target is higher than the intermediate ones. Eckman agreed. Kavulla then stated that he is not sure this approach will have much value for states concerned with 111(d) because it sets a different carbon price for every state. He concedes that a region-wide approach would be the most economically efficient but also the most politically unlikely approach.

Kavulla continued, that the EPA integrated planning model produced implied dollar per ton carbon prices for each state. He stated you could infer an implied carbon price from that. He said other states could game the denominator by adding scrubbers to comply with MATS. He said the model isn't building the least-cost resources but building to comply with 111(d) so why not choose that balkanized approach where each state takes actions to meet its goal. That is how states will probably comply with this rule. Eckman stated his preference would be to constrain the model by limiting the total mass of emissions to satisfy the EPA's targets. We are only using price because the current version of the RPM does not have the logic to limit physical emissions directly.

Kavulla encouraged the Council to think about showing the Net Present Value of a regional portfolio using a balkanized approach. Eckman asked how we could do that. Kavulla suggested running a scenario where there are more renewables in Montana, adding more production costs to thermals in WA and what the other states choose and see what happens. Eckman agreed that it is worthy of asking the states what they will attempt without the existence of a final rule.

Shimshak stated that the EPA is scheduled to have a final rule by the end of the summer and asked if the Council could plug in that answer. Eckman stated that it won't be in time for the Draft Plan as it is scheduled to be adopted in September, which is likely the timeframe that EPA will publish a final rule. Shimshak stated that it seems close enough to run a scenario that demonstrates the final rule's impact.

Lorenzen stated that the Council's analytical work doesn't finish once the plan is out and adopted. He stated that it is not a regulatory plan to bind anyone but is meant to guide and once the Staff has time we could look at this. Shimshak agreed but wondered if you could include the final rule as a scenario when it comes out. Eckman said yes it might be possible to include it in the Final Plan, but not in the Draft Plan due to timing issues.

Pat Smith, NPCC Montana, stated that he raised the same question. Eckman stated that he understands the importance but the timing is difficult. He conceded that the Council's current schedule calls for adopting a final plan by the end of this year and that including an analysis of the final 111(d) rule would be possible. However, our lawyers get nervous when there are major changes between Draft and Final that the public has not had the opportunity to comment on. If the analysis of the final 111(d) rule resulted in major changes from Council's draft 7th Plan, we might have provide another opportunity for public comment.

Mike Jones, Seattle City Lights, asked do you use an expected value or a range of carbon values when picking carbon costs. Eckman answered that's the difference between 2B and 2C. Scenario 2B will use the expected social cost of carbon in every future while in Scenario 2C both the cost of carbon and its price will vary randomly in each future.

Howell stated that the range in scenario 2C is the same as the Sixth Plan and asked if the Council is sticking with that. Eckman said yes. Howell asked for the rationale behind that range. Eckman answered that the Council believes that this will allow a comparison to the results of the Sixth Plan and that since the final EPA rule will not be settled that these values represent a reasonable range of uncertainty.

Gregg Carrington, Chelan PUD, asked how the model handles "seams" issues (i.e. in-region resources that might be sold to California or vice-versa). Eckman answered we do try to represent known contracts in the RPM so we have some idea from resource owners where they sell their output. Carrington stated that he makes Mid-C, price-based decisions and if the price of carbon is higher in California it's going to California. Eckman stated that the RPM uses economic dispatch logic, which it imposes on the full system, so surplus power goes to the highest bidder. Eckman stated that scenario 2A has California pricing in it because it changes our pricing. Morlan added that there are also intertie assumptions and constraints in the model.

Adams stated he thinks scenario 2A should be moved down to the bottom of the priority list.

Jason Eisdorfer, OR Public Utility Commission, pointed out that if 111(d) changed too much the EPA will have to start all over again. Adams stated that there are a lot of elements to the draft but would rather focus on scenarios with different levels of carbon reduction. Eckman stated that EPA published a target and that is certain in the draft rule.

Smith pointed out that the staff has scenario 2A as their eighth priority. Eckman stated that it's eight out of 15 and explained that if we do 2C, which is high-ranking, we will get a lot of information about how to get to EPA levels.

Eckman moved to scenario 2B and referenced Slide 26. Staff is proposing to use the Interagency Work Group on the Social Cost of Carbon's estimate of damage cost at a three percent discount rate shown on the table on slide 26. Usibelli stated that Washington settled on a 2.5% discount rate and offered to share their rational. Eckman accepted the offer and stated that it is simple to put different values in the system for testing sensitivities.

Kavulla stated that it may be simple but it isn't a likely or accurate description of the consequences of the public policies that are driving carbon reduction in the US. He also noted that it seems like a high bookend. Eckman stated that 3A is the high bookend. Kavulla stated that in comparison to IOUs' carbon forecasts these seem high. Eckman said this is the damage cost not the risk cost. Kavulla said that the cost of the damage a ton of carbon dioxide produces is not equal to the cost to avoid its emission. That would be lower. Eckman agreed, stating that the reason for picking damage cost as a limit is that if it costs less to avoid the emissions than the cost of damage from those emissions then public policy should try to do that. On the other hand, from a public policy perspective, if the cost of mitigating carbon emissions is greater than the damage cost, then limiting mitigation cost to damage cost seems the appropriate goal.

Scott Corwin, Public Power Council, said that 2B seems reasonable. Hirsh stated that she likes this scenario because it uses a cost number that's been used by the Federal government, it takes away the risk factor and creates certainty.

Slide 20 Scenarios 3A & 3B

Shimshak asked if the model takes geographic distribution into account when it looks at renewable resources. Eckman said not really as the model uses a quarterly time step so, while we are mindful of integration, flexibility and balancing differences across the system the RPM is not designed to model at this level of granularity. Eckman added that they do model east and west differently but primarily due to transmission and gas pipeline constraints. Shimshak called that a big caveat.

Jim Gaston, Energy NW, stated that UAMPS is pushing forward on SMRs in Idaho. He said they have over 600 staff members and are over 50%

done with design and the first module will be done in 2023. Gaston felt that SMR is real and moving and urges the council to recognize it under the 3B scenario. Eckman stated that many generating technologies will be used to fill that box including Smart Grid and batteries but there is still not a good cost estimate.

Harris asked if emerging technology includes emerging deployment methods of technology we already have i.e. an emerging deployment like heat pump water heaters. Eckman answered yes as long as we are not building out the full economic potential of any resource.

Hirsh asked why storage is in the emerging technology bucket as it is more than emerging and suggested changing it. Eckman stated he is open to it and that the cut line between what is commercially available and what is emerging technology is a judgment call. Hirsh asked for a reconsideration of what is emerging technology. Eckman said that technologies that are out to $300 per MWh are all in the cue and stated that battery storage is the most likely candidate for consideration at this point,

Lorenzen stated he sees the model's shortcoming in load following. Eckman agreed stating that it would be modeled as an adjunct to a variable resource.

Corwin asked how you cut the line between what is considered commercially available technology and what is not when you redo the Plan every five years. Eckman answered that the intent of these judgments is to avoid mistakes in the next five years, that is, it’s a “no regret policy.”

Jones stated that the region’s biggest question is how we integrate renewables into the portfolio to get to desired carbon levels but is hearing that the model can’t answer that. Eckman stated that we can test flexibility in the GENESYS model to see if the resource strategy provides adequacy. Jones asked if we lose implied value of a flexible resource that can accommodate integration. Eckman stated that we will discover that in GENESYS. Jones stated that GENESYS only looks at portfolios that pass the first test. Eckman concluded by saying the RPM is a strategic risk assessment model, and was not designed to model power system operations.

Morlan brought attention to how the Council is considering capacity in the RPM by using GENESYS to define the constraints that resource strategies selected by the RPM must satisfy. He offered to provide more information to the Committee should members be interested.

Stefan Brown, PGE, commented on Shimshak’s and Jones’s comment stating that GENESYS doesn’t address integrating wind or solar. Shimshak addressed Jones’s question stating that the models the Council uses can’t address operational issues and doesn’t get the most efficient response. She noted that the staff received a briefing on a 2030 low carbon analysis from California. She stated that there was an offer for them to follow on the Council’s work but it would require the Northwest power pool to provide the within hourly information. She noted that there is funding on the table but the region would have to contribute data and more funding.

Eckman stated that the Council was not set up to deal with power systems operational issues, such as intermittent resource integration at the hourly or sub-hourly level.

Jones re-asked his question: it's not what questions the model is answering but are we asking the right questions. He said utilities are trying to integrate more variable resources not the next capacity product. He said this model asks do we have enough capacity and bulk energy as opposed to can we integrate future resources. There was agreement in the room. Eckman noted that he is sensitive to this issue and that staff is working on an approach to flexibility and balancing, but that it will not involve modeling these in the RPM.

Kavulla asked if different wind resources have different capacity contributions in GENESYS and the RPM. Eckman said Montana wind resources are assumed to operate at a higher capacity factor than Columbia Basin wind, so that they would likely have greater capacity value. Kavulla brought up that there is one resource adequacy standard applied across all scenarios and said resource adequacy changes depending on how the market is configured (MISO). He asked what would be the value of the efficient market scenario where you change the resource adequacy by assuming diversity benefits. Eckman said that's doable and that the modeling already embeds a 5% LOLP as a constraint. He then said he's asked John Fazio, NPCC, to develop LOLP values for alternative assumptions about extra regional sales and purchases.

Kavulla ask whether GENESYS computes a region-wide LOLP. Eckman said yes. Brown said this is one of his hot button issues that he has incorrectly referred to as “market friction.” He said in the real world utilities are conservative and hold on to their reserves. Brown then said that GENESYS looks at a regional LOLP not a BA LOLP.

Kavulla said there must be a way for the plan to get at this question. Brown said there is and he asked his trading floor how they treat the excess of their expected loads. He said if we get answers from all of the BAs in the region it may be included in GENESYS but getting the answer is tricky.

Morlan stated that you can’t model the actual market but it is addressed in the adequacy forum by reducing the assumptions of availability and transmission to levels that people are comfortable with.

Kavulla proposed a 1C scenario where you take the base case plus uncertainties and then not change anything in the RPM but change it on the GENESYS side and free up transmission constraints to allow a simulacrum of efficiency. Eckman said the way the Council does it now is by giving different capacity and energy reserve requirements to the RPM as a constraint.

John Prescott, PNGC Power, commented that the model assumes that energy generated at one place can be used at another. He said that gets to the bottom line of the true value of the Plan itself. He said that the Plan is of little value in developing IRPs. He said the real value is in all of the scenarios as they will help guide the IRPs he produces.

Scenarios 4A- 4D Slide 21

Gaston stated that he supports looking at scenario 4A. He further stated that San Onofre Nuclear Generating Station (SONGS) was brought down by a technical problem as was another plant in Florida. He suggested terming 4A as being driving by a technical issue. Eckman stated that was the intent.

Hirsh asked about the word “unexpected” in scenario 4A saying it implies an emergency situation. She wondered if that was perhaps a different exercise. She called it important to run and supports running but wondered if it should be part of the long term resource plan. Eckman stated the futures include discontinuities that affect load but considering what happened to SONGs the staff thought it was worth looking at discontinuities that affect resource availability.

Howell asked why scenario 4A and 4B are both looking at non-GHG emitting resources when other resources such as coal may also be lost. Eckman answered there could be other generation off line that has GHG and that’s why we’re asking for public comment.

Lorenzen asked how the scenario analysis would change if we remove the word non-GHG. Eckman answered we would have to drop out a coal or gas block of comparable size and look at the effect. He said you will see a difference in greenhouse gas emissions and locational impacts. Howell stated that recent history suggests a broader look.

Jones asked if the purpose of this scenario is to gauge regional reliability and uncertainty or to look at our ability to meet greenhouse gas requirements. Eckman stated both. Jones replied that if its greenhouse gas requirements then we should take out non-GHG plant. Howell agreed.

Brost questioned the words “unexpected” in 4A and “anticipated” in 4B saying that both these examples are non-GHG-emitting resources. He felt they could be combined and scenario 4B gets into politics that could be avoided. Eckman said the fishery interest groups asked specifically to look at 4B. He continued by saying 4A could be articulated as carbon-based or non-carbon based.

Howell asked what the intent of “over 1000 MW” was. Eckman stated that it needs to be material enough resource to matter in the system.

Morlan stated that the real question is if something like that happened how the region’s resource strategy would change.

Mark Gendron, BPA, referred to Prescott’s comment, saying the value is looking at a wide range of scenarios. He called it a scenario worthy of considering and likes the way it is characterized.

Scenarios 5A & 5B Slide 22

Shimshak asked if there is a difference between roof top and centralized PV. Eckman answered not particularly as both have the solar load shape; however, distributed solar potential avoids transmission and distribution system losses.

Kavulla stated that scenario 5A lowers electricity prices creating fewer exports and more imports. Eckman stated that the Aurora model would probably assume 50% RPS met in CA with solar and see what that does to the mid-C price and use that as the calibration point for electricity prices and load shape in the RPM.

Howell asked if the Council considered a scenario where there is a massive penetration in the Northwest, kind of like a “mini-duck” phenomena. He then asked if this is a ramp rate issue or a price issue. Eckman answered that this is a price issue but ramp rates will play a role.

Howell re-asked his first question: is the duck neck issue isolated to the California model. Eckman stated that scenario 3A pushes the limits of solar in this region so in that scenario we need to be clear about what might be happening elsewhere in the WECC.

Adams stated that the coarseness of the models would not allow a within-day ramp rate even if the Northwest built 5000 MW of solar. Eckman agreed, but stated that his staff and the System Analysis Advisory Committee will be reviewing the results this scenario to assess its potential operational implications.

Kavulla feels this scenario is worth doing as California is definitely heading in that direction. He stated that he is on an ISO advisory committee and “his breath is taken away” by how serious they are.

DeBoer stated that scenario 5B is useful to do as we get capacity constraints going on.

Corwin asked if there is a baseline set of transmission system assumptions. Eckman said the RPM has limits on imports and exports based on the current AC and DC interties with the southwest.

Morlan asked if scenario 5B was to test reliance on Southwest markets as opposed to price excursions as price excursions are already reflected in the wide range and variability of electricity prices in the model. Eckman stated that it’s both.

Scenario 6A & 6B Slide 23

Carrington asked if it makes sense to do the sensitivity analysis and then make the decision. Eckman answered possibly but we already know from a load perspective how much difference it makes at the high end.

Prescott liked the idea of both scenarios being a sensitivity analysis, especially 6B with the migration issue because so much could change (we could all go to Canada.)

Gendron asked what the relative impact is on load growth between the two effects on demand. Eckman answered that the temperature change is smaller by a factor of 3 or 4. He says the biggest impact of the temperature effects is that they are forecast to reduce winter peak loads below summer peak loads. Under the current load forecast without the temperature change assumptions winter peak loads and summer peak loads are nearly equal by 2035.

Usibelli asked for explanation why scenario 6A is a low modeling effort while 6B is a high modeling effort. Eckman explained that the current data on river flows that are supposed to represent the impact of climate change model have known errors. He said that a new version is coming out, but not until next year. Therefore, there's significantly more staff work involved in reasonably representing what the hydro-system impacts might be going forward.

John Saven, NRU, stated that these are a reasonable set of alternative assumptions. He stated that he is strongly inclined to deal with both scenarios as sensitivities rather than building them into the base.

Corwin agreed considering that temperature assumptions are already built in. Eckman reminded him that there are some built in but not to the degree we see in climate change projections. Corwin said that server farms could show up and change load and other factors are just as uncertain. Why embed this particular uncertainty in all scenarios.

Jones agreed that a sensitivity study is a better choice. Hirsh agreed.

Conservation Resources
Charlie Grist, NPCC

Harris asked if there is a graph for the summer peak given the findings on temperature changes. Grist said he will make one after they wrap up on March 27th.

Tom Eckman opened the floor for questions
Slide 32
Hirsh stated that her group re-prioritized the scenarios and offered to send it. Eckman accepted her offer and asked for a thumbnail for the group to discuss now. Hirsh stated that she would move 2B, 2A and 3A to the top five. She would drop 6A down. Eckman said if its sensitivity it shows up at the back end.

Adams stated he would like to reconvene the group to see what the studies are telling us. He wonders what people will be more interested in: Net Present Value? Carbon? Change in seasonal flow? Adams suggested meeting sooner rather than later. Adams suggested April or May for a next meeting. Eckman suggested late May.

Jones asked for early feedback from 1A and 1B. Eckman said results could be presented to the Council and we will make them available to you at the same time. He said Morlan could include results in his memos to the group.

Lorenzen suggested meeting again 60 days out with information flowing out in the interim. Eckman gave an overview of what would be sent out. Eckman stated that a doodle poll will go out and suggested attending webinars of Council meetings.

RPM Input Matrix

Eckman noted that the materials included a matrix describing the key inputs to the RPM and their level of effects on the model's results.

Lorenzen thanked the RSAC. Smith echoed Lorenzen's comments and stated the power committee may have meetings every two weeks and invited people to plug in.

Attendees On-Site

Tom Eckman	NPCC
Henry Lorenzen	NPCC
Terry Morlan	Consultant to NPCC
Jason Eisdorfer	OR Public Utility Commission
Mark Gendron	BPA
Stan Price	NEEC
Mike Jones	Seattle City Lights
Dick Adams	PNUCC
Jim Manion	WS Power
Scott Corwin	Public Power Council
Tom DeBoer	Puget Sound Energy

Doug Howell	Sierra Club
Stefan Brown	PGE
Dave Hagen	Clearwater Power Company
John Prescott	PNGC Power
John Saven	NRU
Nancy Hirsh	NW Energy Coalition
Gregg Carrington	Chelan PUD
Chris Robinson	Tacoma Power
Travis Kavulla	Montana PSC
Rachel Shimshak	Renewable NW
Pat Smith	NPCC Montana
Jim Gaston	Energy NW

Attendees via Go-To-Meeting

Colleen Peterson	Clark PUD
Dan James	PNGC
Gillian Charles	NPCC
Sandra Hirotsu	NPCC
Jeff Harris	NEEA
Kevin Smit	NPCC
Rick Rozanski	
Roger Gray	EWEB
Steve Andersen	EES Consulting
Steve Klein	Snohomish PUD
Tina Jayaweera	NPCC
Tom Haymaker	Clark PUD
Tom Karier	NPCC
Tomas Morrissey	PNUC

Tony Usibelli	Washington Energy Office
Ed Brost	Franklin PUD

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