MEMORANDUM

TO: Power Committee

FROM: Ben Kujala and John Ollis

SUBJECT: Scenario Findings and Further Modeling Results

BACKGROUND:

Presenter: Ben Kujala and John Ollis

Summary: The committee has had many presentations on the scenario analysis for the 2021 Power Plan. In this presentation we will review all the scenarios and discuss what we’ve learned from the various analyses. We will also share any final modeling results.

The scenario analysis will be included in the draft of Section 5 that is anticipated to be ready for committee review at the June 30th webinar.
Scenario Findings and Further Modeling Results
Full fathom five thy father lies;  
Of his bones are coral made;  
Those are pearls that were his eyes:  
Nothing of him that doth fade,  
But doth suffer a sea-change  
Into something rich and strange.  
Sea-nymphs hourly ring his knell:  
Ding-dong.  
Hark! now I hear them,—ding-dong, bell.

William Shakespeare - The Tempest
JULY 2019
Scenario Approach Presented to Committee
What has changed in the region since the 7th Plan?

• Coal retirements:
  • Colstrip 1 & 2 retired by end of 2019
  • Valmy 1 retired by end of 2019
  • Discussion of retirement of Bridger 1 & 2 in Idaho Power and PacifiCorp draft IRPs
  • Oregon SB1547 no coal by wire 2030 provisions
  • Washington utility exit from coal by 2025 has an uncertain impact on Colstrip 3 & 4 in addition to uncertainty about fuel supply

• Clean Energy Targets & RPS:
  • California moved to 60% RPS and 100% clean
  • California, Colorado, Maine, Nevada, New Mexico, New York and Washington have all passed laws aimed at getting 100 percent of their electricity from carbon-free sources by midcentury¹
  • Oregon increased RPS to 50%

What has changed in the region since the 7th Plan?

• Natural gas fired generation:
  • Enbridge pipeline + Jackson Prairie maintenance + Unusually cold March + DC scheduled maintenance lead to price spikes
  • Unlikely to expand in Washington
  • Corporate goals make it less likely to be pursued as a resource by Idaho Power and Avista
  • Portland General does not indicate in drafting IRP that natural gas generation is being pursued
  • California unlikely to expand natural gas fired generation after SB 100
What has changed in the region since the 7th Plan?

• Bonneville contracts:
  • Concerns about Bonneville competitiveness have subsided a bit after market prices hit $1000 but still remains a topic of discussion
  • Capacity and flexibility from the hydro system likely to be critical to a future without many natural gas fired generation additions

• Markets:
  • Expansion of the EIM has been rapid
  • Bonneville exploring entry in 2022

• Better understanding of climate change on hydro generation
Why do we develop scenarios?

• 4(e)(2) The plan shall set forth a general scheme for implementing conservation measures and developing resources

• “Certainty about the future does not come from the technical sophistication of the methods used to create a forecast. Instead, it comes from the flexibility and confidence one has in the number and types of resources available to meet any given condition. As times and conditions change, so must the region's plans.” – First Power Plan (1983)
Where we anticipate describing scenarios

Section 1: Executive Summary and Introduction
Section 2: Demand Forecast
Section 3: Forecast of Regional Reserve Requirements and Reliability
Section 4: Energy Conservation Program
Section 5: Resource Development Plan
  • Resource strategy (generation and conservation)
  • Analysis of Alternative Resource Strategies
  • Input and Analysis:
    • Existing resources and retirements
    • Economic and Financial Assumptions
    • Electricity and Fuel Price Forecasts
    • Transportation forecast
    • End-use natural gas forecast
    • Conservation resources (supply curves)
    • New generating resources potential
    • New demand response resources potential
Section 6: Forecasts of Power Resources Required to meet BPA’s Obligations
Section 7: Recommendation for Amount of Power BPA Should Acquire
Section 8: Analysis of Cost-Effective Methods for Providing Reserves
Section 9: Recommendations for Research and Development
Section 10: Methodology for Determining Quantifiable Environmental Costs and Benefits for Cost Effectiveness
Section 11: Fish and Wildlife Program
Building the 2021 Power Plan

Starting Point

Baseline Conditions
- Existing system, policies
- Include SCC for new resources in WA
- Add SCC to final cost (NPV) of all scenarios as a damage cost

Scenario Analysis
- Optimize BPA’s resource portfolio
- Early retirement of coal gen
- GHG cost tipping points
- Paths to decarbonization
- Inc. reliance on extra-regional markets for RA
- Organized markets for energy and capacity
- Test robustness of energy efficiency

Qual. + Quant. Analysis

Develop a resource strategy
Optimize Bonneville’s resource portfolio

- Study Bonneville’s competitiveness
- Examine changes in how Bonneville might acquire resources and sell power
- Look for strategies that benefit Bonneville and its customers
Early retirement of coal generation

• Examine implications of early retirement of all regional coal plants – and to some extent the rest of the West

• Study resulting greenhouse gas emissions and reliability
Greenhouse gas cost tipping points

- Look at adding a regional price for greenhouse gas emissions in addition to existing policies
  - Explore thresholds where the resource strategy changes based on responding to the carbon price
Paths to decarbonization

• Look at potential approaches to reducing greenhouse gas emissions both in the electric sector and in other economic sectors

• Quantify how emissions in the electric sector can be reduced and how that will net out with emissions in the other economic sectors like transportation and end-use of natural gas

• Explore the practical limits of how far emissions can be reduced, e.g. a percentage relative to 1990 emissions, and how quickly that reduction can be achieved
Increasing our reliance on extra-regional markets

• Test relying more on resources outside our region being available when the region has an adequacy need

• Examine the depth of the supply as well as the ability to deliver the power to the region
Organized markets for energy and capacity

- Look at the impact on the cost of new resources
- Estimate changes to adequacy and reserve requirements
Test robustness of energy efficiency

• Test increasing and decreasing the supply and uptake of energy efficiency

• Examine impacts on regional cost and risk
How we created the recommendation

1. Brainstorm all staff created ideas in small groups
2. Combined similar ideas into 37 different potential scenarios
3. Staff voted with 6 yes and 2 no dots at offsite meeting
4. The following week, staff reviewed transcription of brainstorm and eliminated 13 scenarios
5. The remaining 24 scenarios were then ranked based on difficulty
6. Scenarios that were determined to be too difficult to complete were dropped and scenarios with substantial overlap were combined to get to 16
7. Each staff selected 5 scenarios in priority order from the 16 and 6 scenarios were clearly at the top, the 7th (Increasing our reliance on extra-regional markets for resource adequacy) was marginal but after discussion was included
Primary connection to high-Level themes

GHG Emissions
- Early retirement of coal generation
- Greenhouse gas cost tipping points
- Paths to decarbonization
- Optimize Bonneville’s resource portfolio

Resource Adequacy
- Increase reliance on extra-regional markets
- Early retirement of coal generation
- Organized markets for energy and capacity
- Test robustness of energy efficiency
- Optimize Bonneville’s resource portfolio

Market Expansion
- Organized markets for capacity and energy
- Optimize Bonneville’s resource portfolio
- Test robustness of energy efficiency

Bonneville
- Optimize Bonneville’s resource portfolio
January & February 2020
Further Refined Scenarios Scope
Early Retirement of Coal Generation

• Examine implications of early retirement of all regional coal plants – and to some extent the rest of the West

• Study resulting greenhouse gas emissions and reliability

• Plan implications:
  • Basis for comparison of emission reductions for other scenarios
  • Informs the Resource Development Plan
  • Examine impacts on cost-effective methods for providing reserves
## Proposed In-Scope

<table>
<thead>
<tr>
<th>Coal Plant Unit</th>
<th>Announced/Existing Retirement Date (EOY)</th>
<th>Baseline Conditions*</th>
<th>Scenario: Early Retirement (EOY)</th>
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<tbody>
<tr>
<td>Colstrip Unit 1</td>
<td>2019</td>
<td>Retired</td>
<td>Retired</td>
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<tr>
<td>Colstrip Unit 2</td>
<td>2019</td>
<td>Retired</td>
<td>Retired</td>
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<td>Boardman</td>
<td>2020</td>
<td>Retired</td>
<td>Retired</td>
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<tr>
<td>Centrailia 1</td>
<td>2020</td>
<td>Retired</td>
<td>Retired</td>
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<td>North Valmy 1</td>
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<td>2021</td>
<td>2021</td>
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<tr>
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<td>North Valmy 2</td>
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<td>2025</td>
<td>2025</td>
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<tr>
<td>Jim Bridger 1</td>
<td>2023</td>
<td>2023</td>
<td>2022</td>
</tr>
<tr>
<td>Jim Bridger 2</td>
<td>2028**</td>
<td>2028</td>
<td>2026</td>
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<tr>
<td>Colstrip 3</td>
<td>2027**</td>
<td>2037</td>
<td>2025</td>
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<tr>
<td>Colstrip 4</td>
<td>2027**</td>
<td>2037</td>
<td>2025 (WA Legislation)</td>
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<tr>
<td>Jim Bridger 3</td>
<td>--</td>
<td>2037**</td>
<td>2026</td>
</tr>
<tr>
<td>Jim Bridger 4</td>
<td>--</td>
<td>2037**</td>
<td>2026</td>
</tr>
</tbody>
</table>

* Baseline conditions – announced retirement date or expected end-of-useful life estimate
** PAC and IPC still working out details of the accelerated retirement of Bridger 2, dates could be considered tentative. PAC announced in its 2019 IRP preferred portfolio that the most cost-effective strategy for PAC would be to end its involvement in Colstrip 3 and 4 in 2027. PAC is only 10% owner in these units so clearly this is not a formal retirement announcement, rather an indication of current analyses and discussions between owners to come. Jim Bridger 3 and 4 are currently assumed to operate until the end of their useful life, indicated as 2037 in the PAC 2019 IRP.
Change Reliance on Extra-Regional Markets for Resource Adequacy

• Test relying on availability of resources outside our region when the region has an adequacy need
  • Examine the ability to deliver the power to the region
• Informs conversations regarding:
  • The Council’s resource adequacy standard
  • Those considering differing market depths
  • Efforts to pool resource adequacy
  • Forecast of regional reserve and reliability requirements
  • Resource development plan
Proposed In-Scope

• Change Adequacy Reserve Margin / Planning Reserve Margin for the region
• Examine if incremental market reliance impacts Associated System Capacity Contribution of new resources
• **Potentially** examine impacts of wind and solar generation external to the region on available power for meeting regional peak load and the interaction of new and existing resources in the region with these external market dynamics
• Examine transmission limitations and outage likelihoods
Analyze the Bonneville Portfolio

- Portfolio Analysis:
  - What is the Bonneville Portfolio?
  - Why should the Council analyze it?
  - What is the impact of the 2028 end of the regional dialogue contracts?
Proposed In-Scope

- Bonneville load based on expected obligation
  - Hourly forecast prior to 2028
  - Hourly forecast post-2028 including:
    - Higher obligation (e.g. all current customers plus 15 to 20%-ish)
    - Medium or persistent obligation
    - Lower obligation (e.g. reduce subscription by 35%-ish)
  - Proportional assumptions or parameters to represent above high watermark obligations and the expected weekly/daily/hourly shape (flat or otherwise) of that obligation
- Bonneville commercial contracts from 1+ to 20 years out - e.g. locked in power purchases whether tied to a resource or just a contract for delivery of unspecified power
  - Includes Bonneville’s share of Canadian Entitlement
Proposed In-Scope

• Bonneville Load to Market Price Correlation - Intra-quarterly correlations used in RPM - e.g. should the hours where Bonneville’s load is high be the same hours with high Mid-C prices?

• Bonneville market reliance limits - what is the amount of market power that is available to BPA to meet seasonal energy and capacity needs?
  • Should be consistent with post-2028 obligation levels
Proposed In-Scope

• Bonneville’s transmission to market - beyond adequacy what is the maximum transmission that should be used for marketing opportunities when both purchasing and selling power?

• Bonneville-specific existing resource parameters – aggregate for RPM
  • Hydro – federal not regional
  • Columbia Generating Station
  • Wind PPAs
  • Anticipated Hydro Upgrades
  • Other?

• State RPS / clean policy parameters - should Bonneville acquire resources to facilitate customer utility compliance with state policies?
Proposed In-Scope

- Bonneville-specific market greenhouse gas emissions rate
- Bonneville-specific generating resource potential and cost (with BPA-specific debt assumptions)
- Bonneville EE Supply Curves
- Bonneville DR Supply Curves - assuming Bonneville can arrange a contract for any DR potential in a customer utility that would be dispatched for Bonneville needs
Proposed In-Scope

- Bonneville ASCC assumptions – potentially using federal GENESYS
- Existing System Revenue Requirement—what is the current Bonneville portfolio revenue requirement?
- Debt Balance and Payments
  - What is the current debt and forecast payments?
  - How would new acquisitions be financed and what would be the impact to Bonneville debt?
Test robustness of energy efficiency

- Test increasing and decreasing the supply and uptake of energy efficiency
- Examine impacts on regional cost and risk
Proposed in-scope

• Test increasing EE supply and examine the impacts on portfolio cost
  • Use differing ramp rates reflecting accelerating/decelerating EE acquisition
  • Increase/decrease maximum achievable EE in 20-year horizon
  • Add in emerging EE measures to see impact of additional EE in later years or include >100% ramp rate on existing EE to emulate emerging tech

• Test varying the capacity contribution of EE
  • Change kW impact or load profile to see value of capacity contribution; potentially as a modifier to the ASCC

• Test the interaction between the availability of EE and the availability of DR
  • Modify potential and/or modify elasticity between EE and DR, as DR availability is tied to EE ramp rates
Organized / limited markets for energy and capacity

- Look at the impact on the cost of new resources
- Estimate changes to adequacy and reserve requirements
Proposed in-scope

- Change in Generating Resource Potential available to the region—in an organized market transmission would not limit the resource options available to the region

- Change in Wheeling Charges—these charges are based on charges to get in and out of balancing authorities and existing markets

- Change in market price caps—markets would implement price caps which could limit the value resources like DR get in the market. (CAISO uses $1000 a MWh)

- Adjust regional Planning Reserve Margin (PRM)—simple adjustments to look at the impact of markets on reducing the resources needed for adequacy
Proposed in-scope

- Adjust market availability in GENESYS – probably most of the impact would be on the Adequacy Reserve Margin
- Change the peak hour of EE supply curves to match WECC-wide peak versus regional peak
- Change the supply curve ramp rates and maximum potential to reflect market signal for capacity from EE and DR
  - Increase program participation rates with increased marketing/incentive costs by utilities
Greenhouse gas cost tipping points

• Look at adding a regional price for greenhouse gas emissions in addition to existing policies
• Explore thresholds where the resource strategy changes based on responding to the carbon price
Proposed in-scope

- Test a range of greenhouse gas prices for inside and outside the region
  - Market prices could impact the uptake of energy efficiency depending on how much is acquired in the baseline conditions
- Expand generating resource reference plant options / potential to give additional depth resources that do not emit greenhouse gases
- Examine change in retail price of electricity based on a carbon tax passed through to consumer
- Test for sufficient reserves and examine resources used to supply reserves
Paths to decarbonization

• Look at potential approaches to reducing greenhouse gas emissions both in the electric sector and in other economic sectors

• Quantify how emissions in the electric sector can be reduced and how that will net out with emissions in the other economic sectors like transportation and end-use of natural gas

• Explore the practical limits of how far emissions can be reduced, e.g. a percentage relative to 1990 emissions, and how quickly that reduction can be achieved
Proposed in-scope

- Natural Gas Price and related emissions
  - Change in wholesale price based on reduced demand
  - Reduce upstream methane emission reductions
  - Test price based on blending natural gas to reduce emissions intensity of natural gas fuel
  - Estimate impact of fuel switching on the retail price of natural gas

- Regional Transportation fuel consumption
  - Transportation fuel switching – test increase EV adoption
  - Increase gasoline efficiency – increase CAFÉ standards to 80 MPG or 100 MPG by 2050
  - Increase in alternative delivery methods (Policies to reduce miles travelled)
  - Evaluate alternative fuels (hydrogen, biofuel)
Proposed in-scope

• Consumption of Natural Gas (End-use)
  • Natural gas retail price increase—reflecting emissions cost to consumers may impact consumer choice
  • Reduce greenhouse gas intensity of natural gas fuel – e.g. RNG blending
  • Evaluate alternative fuels (hydrogen, biofuel) for industrial processes

• Generating Resources
  • Accelerated retirements – coal and natural-gas-fired generation
  • Added resources – offshore wind, SMR, enhanced geothermal, etc.
  • Increased potential of non-GHG-emitting resources (i.e. conventional geothermal and pumped storage)
Proposed in-scope

• Load Forecast
  • Increase behind-the-meter solar and battery penetration (net zero homes)
  • Increase standards
  • Increase alternative fuels penetration – hydrogen & biofuel
  • Acquire EE outside electric load (e.g. in natural gas end-use)
  • Test no new gas/oil/coal consumption for residential and commercial sectors
  • Increase efficiency of use for both electricity and natural gas
  • Implement economy-wide consumer GHG pricing - test $50 & $100 per ton CO2e
Proposed in-scope

- California
  - Fuel switching of load outside region—new and/or replace on burnout
  - Estimate electrical loads as a result of deep-decarbonization
- EE
  - Increased units from fuel switch
  - Increase availability a la EE Robustness
  - Increased availability from emerging technologies
  - Update with aggressive retrofits
Proposed in-scope

• DR
  - Events based on highest GHG emission hours?
  - Increased potential from increased units/loads
  - Update potential based on changes in units and load forecast

• Greenhouse Gas Sink
  - Need supply curve, costs, and limitations
  - Inventory of potential policy initiatives
  - Supply curve is proxy for other reductions (expensive, not the first measure)
Proposed in-scope

• Estimate System Adequacy Requirements (GENESYS)
  • Optimize Hydro & Regional Generation based on GHG emissions
  • Review adequacy based on retirements and markets outside the region

• Forecast Electricity Price (AURORA) & RPM
  • WECC-wide carbon tax or carbon cap, restrict new resource options
  • Expand 100 percent clean (accelerate)
  • Dispatch based on GHG emissions
  • Possible Time-Of-Use rate structure study
November 2020 to February 2021
First Look at Baseline Conditions
- Wholesale Electricity Price Forecast Challenges & Impacts
- Leaving the 7th Plan Behind
What are baseline conditions?

• Baseline conditions are a basis for comparison when developing scenarios

• Baseline conditions are assumptions that are common between 2 or more scenarios

• Baseline conditions are **not**:
  • Business as usual
  • Most likely scenario
  • Default forecast
  • Recommended regional resource strategy
Adequate system throughout WECC, but due to renewable energy curtailment does not meet clean requirement in every year.

For comparison, WECC nameplate capacity installed in 2021.
Close to 180 GW build from SB 100 draft work, biggest difference BTM solar and out of state wind.
Arizona and New Mexico backfilling for significant coal retirements and building for California and New Mexico clean policy
Nevada, Wyoming, Colorado, and Utah backfilling for significant coal retirements provide some diversity to the CA and Desert SW builds.
All but 4 GW of natural gas builds in Alberta or Baja CA. Both have fairly immediate needs and limited resource and transmission options.
Fixed costs more than **6 times** production costs for WECC, NWPP fixed and production costs stay similar.
Prices by 2041 have persistent negative pricing seasonally for many hours mid-day.
Market Price Conclusions

More Price Spread in RPM
• RPM also looks at different gas price scenarios
• Those simulations are still running...

Daily Price Shape is Important
• Net peak driving prices more than peak.
• Resources that must run midday will be competing with extremely low market prices
• Maintaining reserves and ramping capability while undergoing persistent negative price periods could be a challenge for the WECC, and by the end of the study the NW.
• Resources with ramping capability with low must-run requirements will be more and more valuable.
• Hydro conditions still the major driver of price variability at Mid-C.
Avoided Market Emissions Rate Decreases Over Time
Unexpected Energy Efficiency Results

• Early analysis showed Energy Efficiency playing a very different role in the portfolio than previous plans
• Results were contrary to staff expectations coming in way below where we thought they would be
EE in 2021P World

• Renewables are competing directly with EE
  • No carbon emissions
  • Low cost with additional benefits (ITC and RECs)
  • Interruptible

• Low market prices that are decreasing over time reduce value of EE as a hedge
  • Only first couple bins of EE show negative long-term energy value (when CO2 prices are included)

• EE as an incremental build resource is less desirable than a immediate build generation resource
Renewables Stand Out

- Early on the role of renewables in the portfolio showed the sea change in policy and prices
- Renewables value in the plan analyses stood out because of:
  - Impact on reducing emissions
  - RECs and Clean Policy
  - Interruptibility
  - Levelized cost of energy
Comparing 2021P Energy Efficiency with 7th Plan Generation Resources Costs (examples)

- Combustion turbine costs highly dependent on gas prices and dispatch
- Solar costs vary widely depending on location
# Generation Resources: Seventh Plan vs 2021 Plan

<table>
<thead>
<tr>
<th></th>
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</thead>
<tbody>
<tr>
<td>Combined Cycle Combustion Turbine (Gas)</td>
<td>$1,220</td>
<td>$1,100 - $1,300</td>
<td>$1,150</td>
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<tr>
<td>Simple Cycle CT (Gas) (Frame)*</td>
<td>$859</td>
<td>$500 - 650</td>
<td>$550</td>
</tr>
<tr>
<td>Reciprocating Engine</td>
<td>$1,382</td>
<td>$1,250 - $1,450</td>
<td>$1,250</td>
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<tr>
<td>Wind</td>
<td>$2,382</td>
<td>$1,500 - $1,700</td>
<td>$1,450</td>
</tr>
<tr>
<td>Solar PV</td>
<td>$1,792 (Low cost); $2,566</td>
<td>$1,350 - $1,500</td>
<td>$1,350 (E. Cascades); $1,465 (W. WA)</td>
</tr>
<tr>
<td>Geothermal</td>
<td>$4,575</td>
<td>--</td>
<td>$5,400</td>
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<td>Pumped Storage</td>
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<td>$2,300</td>
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<tr>
<td>Battery (4 hrs)</td>
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<td>Solar + Battery</td>
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<td>$2,568</td>
</tr>
</tbody>
</table>

Solar and Geothermal receive the 10% Investment Tax Credit (ITC) - not included in the capital cost assumptions above

* Price difference also reflects a change in the reference plant technology class
Draft 2021 Plan – LCOE Estimates of Select New Generating Resources*

*Based on draft 2021 plan generating resource reference plants (size, configuration, technology, location, etc.) and financial assumptions in MicroFin
Comparing Energy Efficiency with 2021P Generation Resources Costs (examples)

Net Levelized Cost (2016 $/MWh)

Energy (aMW)

<0 <10 <20 <30 <40 <50 <60 <70 <80 <90 <100 <110 <120 <130 <140 <150 <160 <170 <180 <190 <200

Solar
Wind
CCCT 60% CF
SCCT 20% CF
Adequacy & Needs – Changing Perspective

- Market Prices change import / export behavior
- Economics drive adequacy!
- Economics drive adequacy!
- Economics drive adequacy!

![Chart showing Needs: Peak and Energy with notes on peak adequacy issues in 2023 (primarily winter) and increasing lower price WEC market supply by one fraction plant time period leads to less adequacy issues.]

Prior Analysis

This work has been refined.
January to June 2021
Scenario Analysis Results and Vetting
Robustness of EE Scenario
Relative Rate of Acquisition
2021P draft

![Graph showing achievable technical potential (aMW) over program years with different lines for High EE, Baseline, and Low EE.]
Robustness of EE – Early Findings from Ramp Rate Variations

• RPM is acquiring EE at similar costs to baseline
  • High cost bins early to meet adequacy need
  • Low cost bins later as renewables flood market and market price drops

• More findings will be presented at Feb Council meeting

<table>
<thead>
<tr>
<th>EE Level</th>
<th>2027 Acquisition</th>
<th>2041 Acquisition</th>
<th>Portfolio Cost (NPV)*</th>
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<tbody>
<tr>
<td>Low</td>
<td>342 aMW</td>
<td>1157 aMW</td>
<td>$46.2B</td>
</tr>
<tr>
<td>Baseline</td>
<td>524 aMW</td>
<td>1501 aMW</td>
<td>$46.4B</td>
</tr>
<tr>
<td>High</td>
<td>1606 aMW</td>
<td>2856 aMW</td>
<td>$51.4B</td>
</tr>
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*does not include adequacy penalties
Robustness of EE

- Increases in EE acquisition didn’t reduce overall costs
- Many changes tested reduced acquisition, few increased it
Conclusions

• The amount of EE acquired is surprisingly sensitive to how the supply curves are assigned to bins and to how quickly the bins ramp

• Adequacy needs can drive higher EE acquisition but this tends to happen when other options have been exhausted in the current RPM setup

• System costs are extremely low, most of these NPVs translate to approximately 2 to 3 billion 2016 $ fixed annual payment – the region currently spends around 14 billion 2016 $ per year which includes some costs captured in these NPV figures
  • A similar calculation for the Seventh Plan scenario including the social cost of carbon translated to a 4.5 billion 2012 $ fixed annual payment
Early Retirement of Coal Scenario
Proposed Coal Retirement Scenario: 2021 Power Plan

• Purpose: to analyze effect on resource strategies of 100% coal retirements in the region/WECC
  • What does this do to emissions, system cost?
  • What are the replacement resources?
  • How to maintain adequacy and reliability?

• High level parameters –
  Retire all coal by
  • 2027 for Region
  • 2030 for WECC
Region Assumptions: Retire all coal units by 2027

<table>
<thead>
<tr>
<th>Coal Plant Unit</th>
<th>Nameplate Capacity (MW)</th>
<th>Announced/Existing Retirement Date (EOY)</th>
<th>Baseline Conditions*</th>
<th>Scenario: Early Retirement (EOY)</th>
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<tbody>
<tr>
<td>Colstrip Unit 1</td>
<td>358</td>
<td>2019</td>
<td>Retired</td>
<td>Retired</td>
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<tr>
<td>Colstrip Unit 2</td>
<td>358</td>
<td>2019</td>
<td>Retired</td>
<td>Retired</td>
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<tr>
<td>Boardman</td>
<td>601</td>
<td>2020</td>
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<td>Retired</td>
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<tr>
<td>Centralia 1</td>
<td>730</td>
<td>2020</td>
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<td>Retired</td>
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<tr>
<td>North Valmy 1</td>
<td>277</td>
<td>2019**/2021</td>
<td>Retired</td>
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<tr>
<td>Centralia 2</td>
<td>730</td>
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<td>2028***</td>
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EOY = End of Year
* Baseline conditions – announced retirement date or expected end-of-useful life estimate
** Idaho Power ended it’s participation in North Valmy 1 in 2019
*** PAC and IPC still working out details of the accelerated retirement of Bridger 2, date could be considered tentative.

Accelerated coal unit retirement
Coal Unit Retirements: Baseline Conditions vs. Early Retirement

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The graph shows the comparison between baseline conditions and early retirement scenarios for coal units through the end of each year from 2021 to 2042.
WECC Assumptions:
Retire all coal units by 2030

WECC Coal Units in Operation - By State/Province

All coal units assumed retired by 2030; retirement is varied from 2025-2029

Updated 7/10/20
Emissions Drop By 38% in 2030 and by 39% in 2045
Early Coal Retirement - 474 GW Nameplate
More Builds in a Coal Retirement Scenario

Observations:
1. Less solar early, more late, more solar plus battery.
2. Builds of offshore wind and storage deferred to later in study
3. Proxy clean resource builds in first year available.
Retiring Coal Earlier Leads to Increased Resource Needs

• Additional resource needs in 2027 and 2031 relative to the baseline conditions

• Retirements external the region drive more renewables – but the difference to the region is likely not big because the baseline conditions build already represents a renewable saturated market
Early Coal Retirement didn’t result in more EE acquired
Regional emission drop-off in line with retirements
Increased Market Reliance
Increased Market Reliance Results

Increasing the regions reliance on the external market:

• Eliminates all regional needs due to adequacy*
• Decreases residential bills on average by 1.7%
• Decreases the no penalty NPV by 13.1%
• Substantial changes in resource builds tend to be in Demand Response and thermal resources
Winter Example: Increasing Market Reliance Reduces Deficits Directly
Increasing Reliance on the External Market
Reduced Renewable Builds

• Limiting our reliance on other regions generally means we build more resource, this results was not surprising.
Increasing Reliance on the External Market
Also Slightly Reduced EE Acquired

• Also not surprising and consistent with similar results from the 7th Plan
Greenhouse Gas Tipping Points
1. Planning reserve margins are met consistently
2. Clean/RPS Policies met until 2030
3. Gas stays on the margin more often.

No Gas Build Limitations - 264 GW Nameplate
1. Planning reserve margins are mostly met
2. Clean/RPS Policies met until 2037
### Solar and Solar Plus Storage Build Comparisons

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### GHG Price Comparisons

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## Battery and Pumped Storage Build Comparisons

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## Wind and Gas Build Comparisons

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<td>2045</td>
<td>51,481</td>
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Buildout Discussion

• No gas build limit buildout has 67 GW of gas at the end of the study, and overall build is 165 GW less than baseline.
• Buildout with GHG pricing in the dispatch WECC-wide is 33 GW larger than the baseline, and leans even more on solar and short duration storage.
• Both sensitivities are almost as adequate as the baseline, but the no gas build limitations sensitivity does not achieve clean policies as often.
By 2027:
Baseline - 500 aMW
WECC-wide SCC - 300 aMW
No SCC - 175 aMW
Removing the Social Cost of Carbon reduced the renewables build.

2027 Renewable Build ranges from 3500 to 5150 MW.
Targeted DR that reduces GHG emissions and costs gets bought in all futures
Including the Social Cost of Carbon in the dispatch reduces emissions.
Demand Response Re-Binning Sensitivity

Reduce peak emissions by changing binning strategy
Observations on Demand Response and 2021 Power Plan Fundamentals

• Demand response in 7th Power Plan was part of the resource strategy primarily to meet adequacy needs.
• Due to the effects of changing price fundamentals in the October 2019 AURORA price forecast and recent history, the decision was made early on to change the definition of on-peak in the Regional Portfolio Model to best capture intraday price variability
  1. From hour ending 700 to 2200 on-peak aligned with traditional heavy load hours
  2. To hour ending 1900 to 2200 on-peak aligned with evening ramp when sun goes down.
Reconfiguring Bin 1 for Sensitivity

- Sensitivity test – Changing bin designation by dispatchability
  - Dispatchability to meet daily variation is important. DR products that could be dispatched more frequently would have more value; namely **Demand Voltage Reduction** (DVR) and **Time Of Use** (TOU) programs
  - Assumption – DVR and TOU could be dispatched 4 hours **every** peak day (M-Sa 6pm-10pm)
  - Re-create bin 1 so that it only contains DVR and TOU, all former bin 1 products are now grouped with bin 2
  - Since these programs often are used persistently without dispatch cost, consider dispatch cost as 0$/MWh
High-level Results

• Reduces cumulative Greenhouse Gas Emissions by 1.4 MMT
• Reduces system cost by 1.87% and residential bills by 0.1%
• No substantive change in EE, Renewable, or Thermal builds from the baseline
• Substantial increase in DR build relative to baseline conditions
Significant Increase in Average DR Build from Baseline Conditions
High Level Takeaway

• Low fixed cost demand response programs which can be used often at little cost with no change in customer experience can be designed to be effective at not just meeting adequacy needs but also
  1. Reducing energy costs associated with meeting peak times
  2. Reducing emissions associated with meeting peak times

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Markets for Energy and Capacity
Scenario Description

- Examine the impact on the resource strategy of organized or limited markets under different fundamental, structural and regulatory assumptions.

- We will also estimate changes to adequacy, market and reserve requirements where appropriate.

**Organized markets**
- One planning reserve margin AND zero wheeling costs (or a single wheeling cost)

**Limited markets**
- Examine effects of limits on gas builds
- Examine a market built outside the region without considering planning reserve margins
- Examine effects of limits/higher costs on renewable builds due to limits on firm transmission rights
1. Planning reserve margins are missed nearly immediately primarily in California.
2. Clean/RPS Policies met until 2030
3. Prices are low in non-NWPP regions, but volatile
Limited Markets:
WECC-wide Renewable Curtailments increase to 27.2 aGW
Higher prices means more thermal units are committed, which positions the regional fleet better for adequacy issues.
Organized Market (preliminary results)

1. Planning reserve margins are met consistently, but system not adequate
2. Clean/RPS Policies met until late 2020s
3. WECC Prices drop

Simulated market starts in 2021
Organized Markets:
WECC-wide Renewable Curtailments increase to 13.1 aGW
No Gas Build Limitations

1. Planning reserve margins are met consistently
2. Clean/RPS Policies met until 2030
3. Gas stays on the margin more often.

No Gas Build Limitations-264 GW Nameplate
Caveats About Market Studies

• Baseline build is adequate throughout study, all the rest of the builds are less adequate.
  • Adequate in the context of AURORA means minimal or zero load control events.

• Baseline build meets RPS and Clean constraints until late 2030’s with current REC price forecast, the rest of the builds have significant risk of missing clean targets persistently.
  • Higher prices enforcing clean credit than RECs
  • Load shifting to time of clean energy use
### Solar and Solar Plus Storage Build Comparisons

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## Battery and Pumped Storage Build Comparisons

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## Wind and Gas Build Comparisons

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1) Emissions rate starts a little higher in summer, but goes lower than baseline
2) On-peak avoided emissions rate stays around emissions rate of combined cycle gas units.
3) Off-peak avoided emissions rate goes lower than the baseline late in the study. (Less thermal units providing flexibility due to large battery build)
Resource Strategy Results
High-level Take-aways

- Renewable builds are not sensitive to the different external market assumptions
- Energy efficiency acquisition does change based on different external market assumptions
- Electricity prices and residential bills do not substantially diverge based on external market assumptions
- Interactive effects with external markets are better captured by GENESYS - dynamic hydro is a big part of the picture
Energy Efficiency Acquisition Comparison

Baseline Conditions has more energy efficiency acquired than all other market scenarios.
Renewable builds do not vary much based on changes to external markets.

In 2027 build ranges from around 4850 to 5200 MW.
Analyze the Bonneville Portfolio
Analyze the Bonneville Portfolio

• What Resources are Required to Meet or Reduce the Administrator’s Obligation?

• Portfolio costs are one factor of many that the Council will consider and balance as it formulates recommendations on amounts of power to acquire to the Bonneville Administrator

• Much of the information needed for this analysis we expect to be supplied under the existing December 2017 agreement on 4(c)(9) information sharing with Bonneville
Estimated impact of EE on BPA’s load obligation

Using the TRMbd Workbook with this adjustment we see EE changes the BPA obligation to serve load under the Regional Dialogue contracts anywhere from around 70% up to 92% based on how much EE acquired, on average EE changed the BPA obligation by 80.9%.

I.e. for 10 aMW of EE purchased from the supply curves, we estimate BPA’s load is reduced by 8.09 aMW.
Components of Bonneville Adequacy Reserve
Margin Load Calculation

Not all of Bonneville’s load is impacted by temperature
The load that is impacted by temperature is expected to decline over time.
Energy Need with Updated Loads

Maximum seasonal energy needs can range up to 350 aMW
2021 Plan Updated BPA Forecast
By 2027, 150 aMW EE without restrictions, 200 aMW with restrictions

Adding 500 aMW of load in 2028 increases EE to about 235 aMW acquired by 2027, whereas decreasing load by 500 aMW in 2028 decreases EE to around 135 aMW acquired.
Renewables build for both cases but much more substantially without restrictions and when adding 500 aMW of load after 2028.
Curtailment follows the size of the renewable build.
Updated DR TOU and DVR bin for DR acquired up to 300 MW
Challenges with Bonneville in RPM

• **Renewable builds likely overstated** - agent-based logic applied to an individual utility rather than the region overstates the forecast errors the “agent” would make and does not capture the partition

• **Load risk model doesn’t capture slice or subscription-like load dynamics** – fixed this load in the adequacy calculations but the cost impacts on the portfolio would be different with this logic implemented

• **Portfolio is more sensitive to REC forecast** – when RECs are included resource decisions change, the higher the REC price the more likely adding more renewables and less EE would reduce costs

• **No fidelity on hydro spill** – Bonneville adding renewables could impact hydro spill in ways that are not possible to capture in RPM

• **Assumes Bonneville’s contracts with customer utilities continue in a similar form**
Conclusions

• Bonneville has future needs which can be filled by EE, renewables, or some combination of the two

• Having all customer utility contracts end at the same date makes planning for resource acquisition and/or managing contract risk difficult
  • If obligation is added to the portfolio post-2028, adding resource before 2028 lowers portfolio cost
  • If obligation is removed post-2028, reducing resource acquisition before 2028 lowers portfolio cost

• Better fidelity on market interaction with Bonneville would likely reduce resource needs below what we see currently in the models and could change the value of renewable resources
Pathways to Decarbonization
Introduction

To combat climate change - the states of Oregon and Washington have set goals and limits on future greenhouse gas emissions from their respective states:

- **Oregon**
  - 45% below 1990 levels by 2035
  - 80% below 1990 levels by 2050

- **Washington**
  - 45% below 1990 levels by 2030
  - 70% below 1990 levels by 2040
  - 95% below 1990 levels by 2050
  - And net zero emissions

For the **2021 Power Plan** - in order to form a more comprehensive understanding of expected regional emissions - we expanded our forecasting out past the power sector to include the use of fuels for transportation, the home, the business and industry.

The **Paths to Decarbonization Scenario** is an investigation into methods that can reduce greenhouse gas emissions from the **entire economy** - both energy related & non-energy related.
## Baseline Conditions Emissions

### Emissions in Million Metric Tons CO₂ Equivalent (MMTCO2E)

<table>
<thead>
<tr>
<th>Year</th>
<th>Transportation</th>
<th>Industrial, w/o Agric</th>
<th>Residential/Commercial</th>
<th>Electric Sector</th>
</tr>
</thead>
<tbody>
<tr>
<td>1990</td>
<td>62</td>
<td>24</td>
<td>16</td>
<td>46</td>
</tr>
<tr>
<td>2005</td>
<td>78</td>
<td>21</td>
<td>20</td>
<td>54</td>
</tr>
<tr>
<td>2041</td>
<td>109</td>
<td>18</td>
<td>24</td>
<td>17</td>
</tr>
<tr>
<td>2050</td>
<td>119</td>
<td>17</td>
<td>27</td>
<td>19</td>
</tr>
</tbody>
</table>

![Graph showing emissions over time for different sectors](image)
Results

Demand for Electricity (aMW)

<table>
<thead>
<tr>
<th>Year</th>
<th>REF</th>
<th>ELEC Only</th>
<th>H2T</th>
</tr>
</thead>
<tbody>
<tr>
<td>2020</td>
<td>60</td>
<td>63</td>
<td>63</td>
</tr>
<tr>
<td>2025</td>
<td>161</td>
<td>332</td>
<td>332</td>
</tr>
<tr>
<td>2030</td>
<td>336</td>
<td>1,246</td>
<td>1,436</td>
</tr>
<tr>
<td>2035</td>
<td>603</td>
<td>2,475</td>
<td>3,570</td>
</tr>
<tr>
<td>2040</td>
<td>993</td>
<td>3,771</td>
<td>8,367</td>
</tr>
<tr>
<td>2045</td>
<td>1,524</td>
<td>4,954</td>
<td>16,934</td>
</tr>
</tbody>
</table>

Tailpipe Emissions (kTonne CO2e)

<table>
<thead>
<tr>
<th>Year</th>
<th>REF</th>
<th>ELEC Only</th>
<th>H2T</th>
</tr>
</thead>
<tbody>
<tr>
<td>2020</td>
<td>74,257</td>
<td>74,232</td>
<td>74,232</td>
</tr>
<tr>
<td>2025</td>
<td>77,084</td>
<td>76,156</td>
<td>76,156</td>
</tr>
<tr>
<td>2030</td>
<td>79,874</td>
<td>75,034</td>
<td>74,750</td>
</tr>
<tr>
<td>2035</td>
<td>82,964</td>
<td>72,803</td>
<td>71,112</td>
</tr>
<tr>
<td>2040</td>
<td>86,256</td>
<td>70,756</td>
<td>63,325</td>
</tr>
<tr>
<td>2045</td>
<td>89,879</td>
<td>70,240</td>
<td>49,332</td>
</tr>
</tbody>
</table>

ELEC Only - electrification changes only - no H2
Where Does This Leave Us for Emissions from Energy Use in the Northwest?

GHG Emissions from Energy used in Residential, Commercial, Industrial, Agriculture and Electric Utilities

<table>
<thead>
<tr>
<th>Year</th>
<th>1990</th>
<th>2005</th>
<th>2041 Baseline</th>
<th>2041 PTD</th>
<th>2050 Baseline</th>
<th>2050 PTD</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Energy Sectors</td>
<td>148</td>
<td>174</td>
<td>169</td>
<td>105</td>
<td>182</td>
<td>90</td>
</tr>
</tbody>
</table>
Decarbonization Looking at Energy Sector Falls Short of Targets

80% Reduction from 1990 Emissions for Regional Energy Sector Just Under 30 Bcf
Partial Decarbonization

What if we see some but not all impacts on the electric sector?

1. Started with Early Coal Retirement Scenario
2. Removed all natural gas resource options
3. Added SMRs as an option
4. Increased loads consistent with electrification of new buildings and light-duty EV reaching 100 percent of sales by 2030
5. Run through RPM

NOTE: this does not represent a system that meets current state goals
Increased Load for Partial Pathways to Decarbonization Analysis

Regional Load (aMW)

Baseline vs Partial PTD
EE Ramps with Load - 1160 by 2027
Substantial Increase in Renewable Build
Average DR Acquired

Substantial DR Builds to Support Adequacy

Baseline	Early Coal Retirement	PTD - Partial Decarb

THE 2021 NORTHWEST POWER PLAN
Late Storage Build to Support Adequacy
GHG Emissions remain low even with load growth.
Substantial Increase in Residential Bills
Moving renewable surplus to market creates more exports
Conclusions

• Increased EE tends to be really aggressive after the first decade
• Increasing load pushes renewables up
• No options for natural gas pushes storage and DR and a single geothermal plant into resulting strategy
• Reserves likely need to be adjusted to account for additional renewables – operability of the system is unclear
Energy Efficiency

- Competition and markets, both present and future, have altered the value proposition for EE
- The supply is more expensive and there are more alternative resources
- Accelerating EE doesn’t result in a less expensive system
- Supply curves miss drivers that in retrospect are important like timing of the savings and resiliency
- EE is a fixed position in a portfolio, you get flexibility on the pacing of investment and build but don’t have flexibility to curtail which does not work well with negative priced markets
Renewables

• Clean policies throughout the West are incredibly aggressive and impact the results substantially
• Solar is cheap and seems likely to saturate the Western electric grid regardless of decisions made in the region
• Overbuilding and curtailment are projected to grow going forward
• Market structure makes a big difference on the amount of renewables needed to achieve policy goals and maintain adequacy
• Renewables are part of a least-cost solutions for the regional resource strategy regardless of the assumptions made about emissions limitations and/or pricing
Thermals

• Coal in the generation stack still is the substantial driver in regional emissions
• Adding gas resources with renewables doesn’t necessarily increase emissions
• Limiting new natural gas resources substantially increases the assumed renewable resource build
• Low capacity factors in almost every run shows challenging economics for thermals going forward
Markets

- Organized markets can substantially reduce the capital cost needed to achieve policy goals
- Limited markets have big implications throughout the Western electric grid and would impact regional economics, but don’t move regional adequacy substantially
- Every market structure tested is substantially impacted by forecast solar builds with organized markets showing the lowest impact
Adequacy

- Resource adequacy is much more dynamic than expected – with a changing interaction with the external market being anticipated in every scenario tested.
- Operational challenges are more likely to drive adequacy results than a lack of physical resources.
- Hydro flexibility and assessment is fundamental to adequacy results.
- Loss of Load Probability under improved assessment methods does not equate to either the size or severity of needs – it does not well delineate adequacy risks in a system with high renewable penetration.
- How reserves are held determines system adequacy and can substantially change results under different assessments.
- Capacity needs and reserve needs are not independent and to an extent exchangeable – this is particularly true with EE which can reduce the need to hold reserves.
Hydro Generation

• Markets will likely push hydro operations to ramp more as solar generation penetration increases in the Western electric grid.

• Flexibility in the region is likely a plant-by-plant consideration – substantially more focus needs to be spent on understanding operations under forecast future markets and water conditions.

• Expected operations need to be considered as part of the next fish & wildlife program to see if they cause concern or provide opportunities.
Questions?