Benton PUD – Who/Where are We?
Benton PUD – Who/Where are We?

Service Connections: 55,725
- 939 Square Miles
  - Kennewick
  - Finley
  - Benton City
  - Prosser
- Irrigated Agriculture (24% of MWh)
- DOE Hanford – Minor Presence
Retail Load Shape – Very Summer “Peaky”

System Peak Hourly Load

Summer: 437 MW (2020)

Annual Power Supply Requirement w/ losses ≈ 210 aMW
BPUD Generation Resources

- **Natural Gas CCCT**
  - 50 MW Capacity Resource
  - Runs When Economic

- **Small Hydroelectric**
  - 3.7 MW
  - 0.92 aMW

- **Packwood Lake Hydro**
  - Capacity 27.5 MW
  - Terminates w/ 2 year notice

- **Wind Power**
  - 18 MW
  - 5.4 aMW

- **Columbia Generating Station**
  - Capacity 1,207 MW
  - Included in BPA Generation Portfolio

- **FREDERICKSON**
  - Capacity 250 MW
  - Contract Expires 2022

- **WHITE CREEK**
  - Capacity 205 MW
  - Contract Expires 2027

- **NINE CANYON**
  - Capacity 90 MW
  - Contract Expires 2030

- **FEDERAL COLUMBIA RIVER POWER SYSTEM DAMS**
  - Capacity 22,000+ MW
  - Contract Expires 2028

- **Columbia River System Operations EIS**
  - Reduced allocation by 8 aMW

- **BPA Slice/Block Contract**
  - 2.85% of FCRPS
  - 192 aMW Firm Tier 1
Current Fuel Mix and Net Power Costs

Benton PUD’s power supply is over 90% clean

- 76.8% Hydroelectric
- 10.0% Nuclear
- 4.6% Regional Power Market
- 5.2% Wind
- 1.6% Natural Gas
- 1.7% Other

Net Power Cost = $80 to $90 million annually

Realized costs depend on:
✓ water for hydro
✓ shape of runoff
✓ load
✓ power market prices
### Power Supply Cost by Source

#### Description | Amount
--- | ---
BPA Power | $60.9
BPA Transmission | 11.8
Gross Frederickson* | 17.3
Renewables & Other | 11.7
Ancillary & Net Conservation | 3.2
**Gross Power Supply** | **$104.9**

**Less:**
- Secondary Market Sales | (22.5)
- Transmission Sales | (0.9)
**Net Power Expense** | **$81.5**

#### Pie Chart
- **BPA Power**: 58.1%
- **Renewables & Other**: 11.1%
- **Frederickson***: 16.5%
- **Ancillary & Net Conservation**: 2.7%
- **BPA Transmission**: 11.3%
- **Net Conservation**: 0.3%

### Notes
* Gross cost excludes the estimated secondary market sales from Frederickson (energy & gas) of $13.2 million resulting in net Frederickson costs of $4.1 million, which is 5.0% of net power expense.

* Usually, net seller on annual basis
  - Hydro & Frederickson NG Plant
  - Buys down gross power costs

---
BPUD Load vs. BPA Resources: Monthly 2019-2021

- Summer energy deficits are typical
- Winter deficits possible
- Surplus Annual Energy in good water years
Capacity Needs – Daily Peak Hour Heatmap

Without existing or new capacity contracts

Significant and frequent summer deficits and periodic winter deficits

200 MW Deficit

200 MW Surplus
BPUD – Summer Peak Hour Capacity Deficits

90% of summer days have had capacity deficits
Daily access to dependable capacity is critically important

“Averages are the enemy of reliability planning”
Managing Capacity Deficits: Existing Approach

BPA Slice/Block Contract
+20-Year Process

Physical Load/Resource Balance

Financial Hedges Forward Contract Agreement

50 MW Call Option: Frederickson CCCT Contract Expires 2022

Unspecified Market Purchases
The District will continue to monitor the regulatory environment and modify its resource strategy as necessary.

- The District will closely monitor proposed Washington State carbon initiatives and/or legislation and develop an analysis of the timing, impacts, and magnitude of any resulting carbon regulation.
- The IRP continues to identify the District’s summer capacity deficits as an item to closely monitor as the region’s coal plants are retired.
- Develop a tactical plan for the future purchase of capacity products from the market that addresses timelines, products, counterparties, etc.
- **Monitor the Council’s LOLP studies** and consider longer term (3-5 year capacity products) in periods where the LOLP increases above 5%. See Chapter 7: Capacity Requirements, Energy Storage, and Demand Response for more detail about the possible actions listed below:

- **Monitor regional utilities plans to construct dispatchable resources**. If plans to build lag what is recommended in their current IRPs, consider longer term capacity products.
Capacity Planning Strategy: LOLP > 5%

➢ “The earlier retirement of the Jim Bridger 1 coal plant increases the 2024 reference case LOLP from 8.2 percent to 12.8 percent and increases the 2026 LOLP from 17 percent to 26 percent.”

➢ “Regardless of the analytical tool used to assess power supply adequacy, it is safe to say that the region will be facing a huge resource gap over the next decade.”
Capacity Planning Strategy: Another Warning

“PRESSURE ON SUMMER IS MOUNTING”
Capacity Planning Strategy: Another Warning

PacNW Existing Resources
2018

- Nameplate GW
  - Coal: 10.9
  - Gas: 12.2
  - Biomass & Geothermal: 0.6
  - Nuclear: 1.2
  - Demand Response: 0.6
  - Hydro: 35.2
  - Wind: 7.1
  - Solar: 1.6
- Total Nameplate Generation: 69.1
- Total Firm Generation: 14.4
- Total Supply: 73.5
- Capacity Surplus/Deficit: 1.2

- Effective GW
  - Coal: 10.9
  - Gas: 12.2
  - Biomass & Geothermal: 0.6
  - Nuclear: 1.2
  - Demand Response: 0.3
  - Hydro: 33.2
  - Wind: 7.1
  - Solar: 1.6
- Total Effective Generation: 66.7
- Total Firm Generation: 14.4
- Total Supply: 71.5
- Capacity Surplus/Deficit: 1.2

PacNW Near to Mid-Term Capacity Need Top-Down Forecast

- Multiple regional assessments point to a near-term shortfall of winter-peaking physical capacity in the Northwest region
  - Shortfall grows to ~5,000-10,000 MW over next 10 years

- ~7 GW need by 2025
- ~10 GW need by 2030

Key differences are driven by FFR requirements, capacity costing methodologies, and resource additions (see appendix for comparison of key assumptions)
- E3 and NWPPCC are truly “top-down” stochastic views, while PNWCC and BPA are closer to regional “bottom-up” analyses of utility RFPs.
- E3 study based on 2018 and 2020 RECAP data, modeling, shaped between those years based on forecasted coal-retirement schedules. This study updated previous analysis to include coal retirements from PacifiCorp’s 2019 Data RFP. E3’s need does not incorporate any planned additions.
Capacity Planning Strategy: Defining Event

- Winter 2019 Mid-C Price Spike
- Mid-C Day Ahead Price Spike
- $800/MWh
- $50/MWh
Power market volatility: Will summer look like winter soon?

Extreme prices impacted BPUD $6M over budget for short duration event
2019 Power Market Spike: What would this look like without coal?

Many Natural Gas Power Plants Idle
$160/MMBTU
>$1,000/MWh

2000 MW to Canada
2000 MW from California
1900 MW from Montana

Northwest Deep Freeze Low Hydro

Coal-Fired Power Plant Status

<table>
<thead>
<tr>
<th>Plant Name</th>
<th>Capacity MW</th>
<th>March 1 to 6 Power Production MW</th>
<th>Retirement Year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Centralia (1/2)</td>
<td>1,340</td>
<td>500 – 1,250</td>
<td>2020/2025</td>
</tr>
<tr>
<td>Boardman</td>
<td>585</td>
<td>475</td>
<td>2020</td>
</tr>
<tr>
<td>Colstrip</td>
<td>2,094</td>
<td>2,000</td>
<td>2019 (614 MW)</td>
</tr>
</tbody>
</table>
Capacity Planning Strategy: CETA Impacts

- Effectively eliminates investments in new dispatchable generation (natural gas) by Washington utilities
- Increased sense of urgency to consider securing forward physical capacity from existing inventory
- New capacity must come from wind, solar, batteries and demand response
Capacity Planning Strategy: BPUD Takes Action

✓ Request for Proposals Issued
  ▪ October 2019 & September 2020
  ▪ Ultimate goal to cover capacity deficits of: **150 MW** July/August HLH & **50 MW** Winter HLH
  ▪ Three or five-year terms (Fall 2022 through Fall 2028)

✓ Solicited Marketers, Independent Power Producers, Utilities
  ▪ **No direct responses from utilities**
  ▪ 4 combined total responses to both RFPs

✓ Signed contract
  ▪ 75MW heavy load hours (HLH) July/August
  ▪ 25MW HLH December/January/February
  ▪ Term: December 2022 through August 2025
Capacity Planning Strategy: NWPP RA Program

- Highly supportive of effort – Great people & minds

- Qualifying Capacity Contribution (QCC) for each resource
  - Wind and Solar Effective Load Carrying Capability (ELCC)
  - E3 Study for 2018 Expanded Northwest Resource Mix
    - Wind ELCC = 7%
    - Solar ELCC = 12%
  - NWPP will assign monthly QCC by zones (critically important)

- Replacing thousands of megawatts of dependable coal capacity will require tens of thousands of megawatts of wind and solar
  - $ investments in the tens of billions
  - Project development, permitting and construction time
  - What about new transmission lines?
  - Land use issues (NIMBY)

- Will RA program deliver new generation resources in time to avoid blackouts?
  - LOLP already too high
Solving capacity deficits with “energy resources” like wind and solar presents significant challenges

How will Benton PUD access QCC credits from wind and solar without buying all-year, long term energy we don’t need?

- 150 MW @ ELCC = 15% requires 1,000 MW Investment (CapX > $1 billion)
  - Wind @ 30% C.F. = 300 aMW of annual energy
  - Solar @ 20% C.F. = 200 aMW of annual energy

Hard to believe seasonal QCC credits will be available for purchase from existing natural gas or hydro

- Studies have already shown need for new natural gas
- 7 month forward showing means next summer season capacity must be procured by October 31st of prior year (before water year has begun)
- BPUD initial seasonal capacity RFPs provide some indication (but we are a small player & were early)
Benton PUD Path Forward

**BPA Contract:**
- Post 2028 Contract Discussions

- Frederickson Contract Expires

**CETA Requirement:**
- No Coal

- Seasonal Capacity Contract
  - About half-way covered

- Additional Seasonal Capacity Contracts?
  - Explore Other Options; including demand response

**BPA Contract Expiration & New Resources**
- "Re-shape" hydro product?
- Advanced Nuclear?

**CETA Requirement:**
- Carbon Neutral 80/20 Rule

- 100% Carbon Free Resources

- Post 2028 Contract Discussions
Final Thoughts

- Hard to accept double digit LOLP % and an increasingly fragile northwest grid
  - In part to reduce Washington state electricity sector GHG emissions by an amount representing 0.35% of national inventory

- Commerce should consider report to legislature prior to January 1, 2024
  - NWPP RA analysis should answer many questions
    - Including potential role for natural gas
    - It would be best to start the debate sooner than later

Pray for Rain and Mild Weather

“Murphy’s law predicts that the next low water year in the PNW will arrive in 2025 as peak coal plant retirement occurs and the PNW IRPs defer decisions on construction of new resources waiting for the next cost reduction in carbon free capacity.”

Randy Hardy and Larry Kitchen, July 2019
Questions?
Preliminary Pacific NW Resource Adequacy Assessment

ANNUAL RESOURCE ADEQUACY MEETING
Utilities and Transportation Commission &
Department of Commerce
May 11, 2021

John Fazio
NW Power and Conservation Council
Adequacy Standard and the Power Plan

• **Adequacy assessment as an early warning**
  The Council annually assesses the adequacy of the power supply over the next 3 to 5 years to gauge whether new resources and/or demand-side measures are needed and whether utility plans address those needs.

• **Incorporating adequacy into the power plan**
  The amount of required surplus generating capability above expected load (based on the 5% LOLP standard) is used as a minimum threshold to develop the power plan’s resource strategy.
Assessing Resource Adequacy

- Simulate the power supply’s operation
  - Chronological hourly simulation of all resources for one year
  - Run many simulations with different future conditions
  - Record all hours when load is not served

- Calculate the probability of load not being served
  - Count number of years with at least one shortfall
  - Annual LOLP is the probability a future year will have at least one shortfall
  - LOLP = Number of years with a shortfall / Number of simulations

- Set a limit on the probability of not serving load
  - Council’s adequacy standard limits LOLP to 5 percent
  - Power supply is adequate if the likelihood of one or more shortfalls in a year is less than or equal to 5 percent
LOLP is not the probability of a blackout

<table>
<thead>
<tr>
<th>Resource</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generating Resources</td>
<td>Resources dedicated to serving PNW load, whether inside or outside the region</td>
</tr>
<tr>
<td>Conservation Programs</td>
<td>Cost effective energy efficiency measures, appliance and housing codes and standards</td>
</tr>
<tr>
<td>Market Supplies</td>
<td>In-region and out-of-region wholesale short-term market supplies</td>
</tr>
<tr>
<td>Standby Resources</td>
<td>Small (usually expensive) generators or demand buy-back agreements</td>
</tr>
<tr>
<td>Emergency Actions 1</td>
<td>More expensive non-declared resources or demand cut-back provisions</td>
</tr>
<tr>
<td>Emergency Actions 2</td>
<td>Utility or governor’s calls for energy conservation</td>
</tr>
<tr>
<td>Emergency Actions 3</td>
<td>Rolling black outs or brown outs</td>
</tr>
</tbody>
</table>

LOLP = Likelihood of taking emergency actions, not necessarily curtailment.
Why is the adequacy assessment different now?

• **Climate change**
  - Forward looking temperature and river flow projections instead of historical
  - **Better representation** of expected future conditions
  - Captures seasonal shifts in load and hydro generation, which affect adequacy

• **WECC-wide resource buildout**
  - State clean air laws and policies are driving high acquisition of renewable resources
  - **Increases market supply with daily periods of inexpensive energy**
  - Affects PNW resource dispatch and can reduce future resource need for adequacy

• **New (and improved) adequacy model**
  - 17 BA areas, WECC resources & loads, unit commitment, fuel accounting, dynamic reserves
  - **Individual hydro project hourly simulation**, more accurate representation of flexibility
  - Dynamic representation market supply and price
## Announced Coal Plant Retirements by 2025

### Coal Plant Retirement Schedule

<table>
<thead>
<tr>
<th>Coal Plant</th>
<th>Capacity (MW)</th>
<th>Retire Date (EOY)</th>
<th>Total MW Retired</th>
</tr>
</thead>
<tbody>
<tr>
<td>N Valmy 1</td>
<td>127</td>
<td>2021</td>
<td>127</td>
</tr>
<tr>
<td>Bridger 1</td>
<td>530</td>
<td>2023</td>
<td>657</td>
</tr>
<tr>
<td>N Valmy 2</td>
<td>134</td>
<td>2025</td>
<td></td>
</tr>
<tr>
<td>Centralia 2</td>
<td>670</td>
<td>2025</td>
<td>1461</td>
</tr>
<tr>
<td>Bridger 2</td>
<td>530</td>
<td>2028</td>
<td>1991</td>
</tr>
<tr>
<td>Total</td>
<td><strong>1,991</strong></td>
<td></td>
<td><strong>1,991</strong></td>
</tr>
</tbody>
</table>

### Cumulative MW of Retired Nameplate Capacity

**Expected coal-fired generating capacity to be retired between now and 2025**

- 2020: 0 MW
- 2021: 127 MW
- 2022: 127 MW
- 2023: 127 MW
- 2024: 657 MW
- 2025: 1461 MW
- 2027: 1461 MW
- 2028: 1461 MW
- 2029: 1991 MW

---

THE 2021 NORTHWEST POWER PLAN
## Preliminary Resource Adequacy Assessment

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<th>Annual LOLP (percent)</th>
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<td>16.1%</td>
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### Key Findings
- The existing power supply is not adequate
- Utilities are aware of the **imminent risk** and are planning accordingly
Preliminary Resource Adequacy Assessment

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Key Findings

- The existing power supply is not adequate
- Utilities are aware of the imminent risk and are planning accordingly
- Region may need as much as **1,600 MW of capacity by 2023** (winter need)
## Preliminary Resource Adequacy Assessment

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<td>1.7%</td>
</tr>
<tr>
<td>Estimated firm capacity needed for adequacy</td>
<td></td>
<td>1600 MW</td>
</tr>
<tr>
<td>With additional reserves (but no new resources)</td>
<td></td>
<td>9.0%</td>
</tr>
</tbody>
</table>

### Key Findings

- The existing power supply is not adequate
- Utilities are aware of the imminent risk and are planning accordingly
- Region may need as much as 1,600 MW of capacity by 2023 (winter need)
- Increasing balancing reserves in 2023 may be a cost-effective way to temporarily reduce the need for additional resources
- **Need drops off** significantly by 2025 primarily because expected increases in market prices result in a greater number of **thermal unit commitments**
RA Advisory Committee Questions/Comments

1. The **needed capacity for adequacy seems low** relative to the capacity lost from expected coal plant retirements.

2. Can adequacy be maintained without conventional thermal resources?

3. How much can reutilization of thermal resources really help (e.g., increasing balancing reserves and unit commitment)?

4. Is the flexibility of the hydro system being overestimated, and are non-power hydro constraints being met?

5. Why are the classic and redeveloped GENESYS model LOLP results so different?
1. Resource need vs. Retired Capacity

• Retired capacity (2019-25) is 2,276 MW yet resource need is only 1,600 MW.
• Power supply was adequate in 2019 (i.e., LOLP < 5%) and thus had surplus capability that would lessen the amount of needed resource.
• Expected increase in the WECC-wide market supply can help. Even though hourly imports are capped, imports can occur over more hours.
• Better utilization of hydro storage (within operating constraints) can defer new resource acquisition.
• Better utilization of thermal resources (e.g., unit commitment and increasing reserves) can also defer new resources.
2. Are conventional thermal resources needed

- Concern that acquiring only renewable resources will lead to problems since they cannot be dispatched.
- Increasing market supply and better utilization of existing resources can lessen the amount of needed resource.
- Acquiring renewable resources will increase the need for additional balancing reserves but analysis shows that (at least for now) the existing system has sufficient flexibility to cover the increased risk.
- It’s unlikely that the power plan will only include renewable resources.
- Retirements are scheduled over a long period (16 years), which should provide sufficient time for better storage technologies to be developed.
3. Thermal Resource Utilization

• Can reutilization of existing thermal plants defer some of the need for new resources
• Thermal plants are generally not committed for dispatch unless prices are sufficiently high. If they aren’t committed, they cannot help during shortfall events.
• As market prices rise, more units are likely to be committed, which should improve adequacy (as seen in 2025).
• Requiring higher balancing reserves forces more thermal resources to commit and allows them to be available during shortfall events.
• However, increasing reserve requirements comes at a cost because resources may then operate “out of the money” for long periods of time.

• The CAISO “flexiramp” product was proposed to address similar issues

4. Hydroelectric System Flexibility

• Is the model overestimating the flexibility of the hydro system and are non-power constraints being met?

• GENESYS simulates the hourly operation of individual hydro projects and implements monthly and hourly operating constraints provided hydro owners.

• Fine tuning the parameters to achieve a realistic hourly operation has been difficult and required extensive review by stakeholders. While not perfect, the current simulation has generally met with stakeholder approval.

• GENESYS does its best to meet all operating constraints, but it should be noted that in real life, not all constraints can be satisfied simultaneously.

• Because the redeveloped GENESYS dynamically assesses the value of water based on a forecast of future conditions, it utilizes reservoir storage more effectively than the classic GENESYS.
5. Redeveloped vs. Classic GENESYS

<table>
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<tr>
<th>Annual LOLP (percent)</th>
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<th>2025</th>
</tr>
</thead>
<tbody>
<tr>
<td>Redeveloped GENESYS (baseline WECC buildout, 0 EE 2023, 400 aMW 2025)</td>
<td>16.1%</td>
<td>1.7%</td>
</tr>
<tr>
<td>Classic GENESYS (200 aMW EE 2023, 400 aMW 2025)</td>
<td>15.7%</td>
<td>22.6%</td>
</tr>
</tbody>
</table>

Comparing LOLPs directly doesn’t provide much insight due to different model complexities:

- New GENESYS models 17 BA areas in the PNW
- Simulates individual hydro plants hourly
- Unit commitment
- Dynamic market assessment and pricing
- Dynamic allocation of all reserves
- Dynamic assessment of the value of water

- Classic GENESYS models 2 areas
- Simulates aggregate hydro hourly
- No unit commitment
- Fixed market size and price
- Fixed hydro reserves only
- Fixed value of water in reservoirs

- In 2025, the classic GENESYS shows a higher LOLP primarily due to limited hours of import and less optimal utilization of hydro storage. Increasing hours of import to match those in the new model and extended use of hydro storage reduce the classic model LOLP to 1.2%. 
5. Redeveloped vs. Classic GENESYS

<table>
<thead>
<tr>
<th>Firm Capacity Needed for Adequacy (MW)</th>
<th>2023</th>
<th>2025</th>
</tr>
</thead>
<tbody>
<tr>
<td>Redeveloped GENESYS resource need</td>
<td>1,600</td>
<td>0</td>
</tr>
<tr>
<td>Classic GENESYS resource need</td>
<td>1,250</td>
<td>850</td>
</tr>
</tbody>
</table>

• Because the effect on LOLP of adding an increment of new capacity differs between models (due to differences in complexity) a comparison of resource need is better.

• Resource need is firm capacity need and is not the same as nameplate capacity.

• Effective load carrying capacity must be used to properly size new resource additions.
Preliminary Adequacy Assessment Summary

• These results are preliminary and are still under review by the Council and its advisory committees.

• By 2023, the PNW power supply will no longer meet the Council’s adequacy standard and will need an estimated 1,600 MW of added firm capacity (or some combination of firm capacity and increased reserves) to maintain adequacy.

• After 2023, and despite additional coal plant retirements, adequacy can be maintained with minimal capacity additions because of the expected high level of WECC-wide resource buildout and the opportunity to better utilize the PNW hydro system and thermal resource fleet.

• While these findings are robust across many scenarios, the inherent uncertainty in the projected WECC buildout and the likelihood of accelerated loads due to electrification programs could significantly increase the probability of shortfalls. To offset this risk, it may be appropriate to include additional resource and demand-side actions to the power plan’s resource strategy.
BPA’s Power Services
2020 Resource Program Summary

Project team
James Vanden Bos, Power Planning and Forecasting
Torsten Kieper, Power Planning and Forecasting
Jessica Aiona, Energy Efficiency Planning and Evaluation
Tom Brim, Distributed Energy Resources

Introduction
In support of Bonneville’s 2018-2023 Strategic Plan, Power Services’ 2020 Resource Program provides analysis and insight into long-term, least-cost power resource acquisition strategies. To accomplish this, the Resource Program examines uncertainty in loads, water supply, resource availability, natural gas prices, and electricity market prices to develop a least-cost portfolio of resources that meet Bonneville’s obligations.

Key Take-Aways:
- This is a refresh of the 2018 Resource Program – with updates to some main inputs
- BPA’s needs look lower in 2020 than in 2018 (broadly across metrics)
- **BPA no longer shows a capacity need** during the planning horizon, as measured by its 18-hour capacity metric
- **Demand Response**, in light of the lack of capacity needs and upward cost adjustments, is **not currently being selected**
- Results continue to show **energy efficiency** as the **least-cost** way of meeting future resource needs
- Caveats: modeling incorporates the 125% total dissolved gas (TDG) flex spill operation, but not all of the CRSO EIS Preferred Alternative impacts and does not include a soon-to-be executed long-term capacity sale

Inputs
The 2020 Resource Program (2020RP) builds on the inputs and methodology used for the 2018 Resource Program (2018RP). Some inputs have been updated to reflect new information or program accomplishments. These are discussed in more detail below.

Load Forecast
An updated frozen efficiency load forecast was developed to inform the needs in the 2020RP (Graph 1). Compared to 2017, annual load in the updated load forecast declined due to the termination of the Alcoa DSI contract, Pacific Northwest Generating Cooperative’s election to self-supply a greater portion of its load and an overall decline in BPA’s Priority Firm Tier 1 Load forecast.

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1 The frozen efficiency load forecast was developed at BPA in 2017, and consists of a Statistically Adjusted End Use (SAE) load forecasting model. The primary benefit over BPA’s traditional econometric load forecast is that the frozen efficiency load forecast does not presume future incremental energy efficiency savings are automatically acquired. Without this presumption, loads are higher, and BPA is able to consider whether or not to pursue energy efficiency savings based on need, cost, and other factors.
Graph 1: Needs Assessment Obligations forecast for use in 2018RP and 2020RP

### Needs Assessment
The 2020RP also included an updated Needs Assessment (NA), which incorporated: 125% TDG, flex spill, early spill cessation assumptions, new spill calculations, and the 200MW capacity sale to Portland General Electric. With these new assumptions on resources and obligations, combined with the load forecast, average energy needs (per the P10 Monthly HLH metric) decreased on average by 120 aMW over the 2022-2026 timeframe and 440 aMW from 2027-2031. Formerly, the months with the highest average needs were January and February, but this has shifted to April in the new NA because higher spill operations and the wide range of uncertainty surrounding April weather and streamflow combinations. Finally, the 18-hour capacity metric no longer shows a capacity deficit due to the beneficial impacts of early spill cessation.

### Market Prices
The forecast of market prices used in the 2020RP’s optimization model shows a significant decline in average electricity prices from the 2018RP to 2020RP, largely due to declining regional gas prices, increasing renewable resource penetration and modeling improvements that better capture the impacts of increasingly stringent renewable portfolio standards. In the 2018RP the average Mid-C price was $36.50/MWh over the 2020-2039 study horizon. In the 2020RP, the Mid-C price is $23.60/MWh over the 2022-2031 study horizon. The change to a 10-year study horizon also puts downward pressure on average prices. All else being equal, a lower average market price can be expected to drive fewer resource acquisitions compared to the 2018RP. Additionally, on average across all 3200 price iterations, HLH/LLH price inversions occur as soon as April 2023, occur in March-November in 2028, and every month but January in 2031 (the last year of analysis).

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2 The P10 HLH energy metric utilizes the stochastic analysis conducted by BPA’s Needs Assessment. In this study, many different combinations of potential future load and resource scenarios are combined to create unique combinations where BPA either has enough energy to serve its heavy load hour load obligations, on a monthly basis, or does not. The P10 HLH metric goes to the 10th percentile of this distribution (looking at the bad outcomes for BPA) and determines, by month, whether BPA is surplus or deficit resources required to meet load. If BPA is surplus, at the P10, then BPA considers itself not to have an energy need in that month. If BPA is deficit in any month, then the size of the deficit becomes BPA’s energy need, for that month, to solve for in the Resource Program.

3 While April shows a large deficit at the 10th percentile, it flips to a surplus at the 24th percentile, and the surplus grows from there.
**Market Availability**

BPA assumes a limited amount of energy purchases will be available from the Mid-Columbia trading hub to help meet its energy needs. This assumption of availability is calculated monthly, in AURORA, for the duration of the study period, and is unchanged from the 2018RP. If in any month the optimization model has a need for energy remaining after purchasing its full monthly allowance from the spot market, the model will fill any gaps in those months by adding incremental resources to the least-cost portfolio. In the 2018RP, BPA’s monthly needs occasionally exceeded BPA’s monthly market purchase limit. In the 2020RP this is no longer the case – in the 2020RP, BPA’s share of the market exceeds BPA’s forecasted energy needs in every month. This is illustrated for a representative year, FY 2025 (Figure 1). The practical impact of this is the model will never be forced to acquire a resource because it never runs out of assumed market depth. Further, this means that, to acquire a resource to meet BPA’s needs, that resource must be cheaper than the market, otherwise the model will simply choose to serve the need with market purchases.

**Figure 1: Bonneville's Needs vs. Market Purchase Limits in FY 2025**

![Graph showing Bonneville's Needs vs. Market Purchase Limits in FY 2025](image)

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**Resources**

The resource categories considered in the 2020RP are the same as those considered in 2018, but include updates to resource costs and savings shapes, where applicable. These updates are detailed below.

- **Renewable Resources:** Wind and solar capital costs decreased by approximately $200/kW (to $1,366/kW fixed cost for a 2025 build date) and $50/kW (to $1,242/kW fixed cost for a 2025 build date), respectively, before tax credits are applied.

- **Natural Gas Turbines:** Capital and variable costs for natural gas plants are unchanged from the 2018RP ($1,047/kW fixed cost for a 2025 build date).

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4 Note that, for its planning purposes, April is divided in half due to the substantially different weather, streamflow, and operational requirements across the month. The two points above April in the graph represent the measures of heavy load hour energy need for the two halves, April I and April II.
- Market Purchases: Average Mid-C prices declined over the study horizon from the 2018RP to the 2020RP.
- Energy Efficiency (EE): Supply curves from the 2018 Conservation Potential Assessment were updated to account for 90aMW of planned EE acquisitions and 56 aMW of expected market transformation and momentum savings over the 2020-2021 time period.
- Demand Response (DR): Updates to assumptions and corrections to the levelized cost calculations for DR resources increased the cost of DR resources in the 2020RP relative to 2018. All else being equal, increases in the cost of DR resources will tend to reduce the amount of DR selected by the model.

**Preliminary Results**

Given these updates, the results of the 2020RP lean toward slightly lower amounts of EE acquisition than in 2018, with the least-cost portfolio shedding a few of the more expensive EE bundles. This follows from the lower needs, eliminated capacity metric and lower market price forecast. Also as a result of these changes, EE is the only resource selected in any of the relevant portfolios. A comparison of the EE acquisitions from the 2020RP and 2018RP are shown in Table 1 below. The first 2 years’ cumulative total amount of EE selected in the least cost portfolio is one of the inputs used to determine how many average megawatts of EE BPA will programmatically pursue in the ensuing rate case – in this instance, in BP-22.

**Table 1: EE Acquisition of Least-Cost Portfolio in 2020RP and 2018RP**

<table>
<thead>
<tr>
<th></th>
<th>2020 Cumulative Savings (aMW)</th>
<th>2018 Cumulative Savings (aMW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Portfolio 1</td>
<td>111</td>
<td>121</td>
</tr>
</tbody>
</table>

**Considerations**

The 2020RP was developed using the most up-to-date information available at the time. However, some developments that occurred after the finalization of the NA could potentially influence BPA’s needs and thus the least-cost resource selections in the Resource Program. The most significant of these developments are an update to, or elimination of, the Hourly Operations System Scheduler (HOSS) tool (resulting in changes to the NA metrics and/or their calculations), the impact of the Columbia River System Operations Environmental Impact Study Preferred Alternative, and an impending 5-year capacity sale to an external party. The influence of these developments on BPA’s NA and Resource Program are uncertain at this time, though they are all anticipated to exert directionally upward pressure on BPA’s needs metrics. Potential impacts can be assessed, in part, with future sensitivity analysis.
Water Year Rank at The Dalles (Jan-Jul)

Selected Years Average: 104.4 MAF

Water Year 2021
Jan-Jul (MAF): 82.2

TEA Forecast (05/18/2021): 62.1 MAF
Load vs. BPA Resources (Forecast as of 05/25/2021)

Note: Benton PUD actual and forecasted load includes transmission losses. Forecasted deficits are typically covered through the use of financial hedges approved by the Risk Management Committee members and the physical deficit is covered with Day Ahead and Real-time purchases made by The Energy Authority (TEA).

Slice Generation Comparison
Jun-Jul-Aug 2021

Three-Month Outlook
Temperature Probability
0.5 Month Lead
Valid JJA 2021
Made 20 May 2021

EC Means Equal
A Means Above
N Means Normal
B Means Below

Three-Month Outlook
Precipitation Probability
0.5 Month Lead
Valid JJA 2021
Made 20 May 2021

EC Means Equal
A Means Above
N Means Normal
B Means Below