2020 Avista Natural Gas IRP

Technical Advisory Committee Meeting
June 17, 2020
2020 Natural Gas IRP schedule


• **TAC 2: Thursday, August 6, 2020:** Market Analysis, Price Forecasts, Cost Of Carbon, demand forecasts and CPA results from AEG, Environmental Policies, fugitive emissions

• **TAC 3: Wednesday, September 30, 2020:** Distribution, Avista’s current supply-side resources overview, supply side resource options, renewable resources, overview of the major interstate pipelines and projects, and sensitivities and portfolio selection modeling.

• **TAC 4: Wednesday, November 18, 2020:** Review assumptions and action items, final modeling results, portfolio risk analysis and 2020 Action Plan.

• **TAC 5: February 2021:** TAC final review meeting (if necessary)
Agenda

- TAC meeting expectations
- 2020 IRP process and schedule
- Actions from 2018 IRP
- Winter of 2018-2019 review
- Demand
- Demand Forecast Methodology
- Weather Analysis
- Weather Planning Standard
- Procurement Plan
- Resource Optimization benefits
- Energy efficiency update
Avista’s IRP Process

• Comprehensive analysis bringing demand forecasting and existing and potential supply-side and demand-side resources together into a 20-year, risk adjusted least-cost plan

• Considers:
  – Customer growth and usage
  – Weather planning standard
  – Demand-side management opportunities
  – Existing and potential supply-side resource options
  – Risk
  – Public participation through Technical Advisory Committee meetings (TAC)
  – Distribution upgrades

• 2018 IRP filed in all three jurisdictions on August 31, 2018 and acknowledged
The Natural Gas System
1. Avista’s 2020 IRP will contain an individual measure level for dynamic DSM program structure in its analytics. In prior IRP’s, it was a deterministic method based on Expected Case assumptions. In the 2020 IRP, each portfolio will have the ability to select conservation to meet unserved customer demand. Avista will explore methods to enable a dynamic analytical process for the evaluation of conservation potential within individual portfolios.

2. Work with Staff to get clarification on types of natural gas distribution system analyses for possible inclusion in the 2020 IRP.

3. Work with Staff to clarify types of distribution system costs for possible inclusion in our avoided cost calculation.

4. Revisit coldest on record planning standard and discuss with TAC for prudency.

5. Provide additional information on resource optimization benefits and analyze risk exposure.

6. DSM—Integration of ETO and AEG/CPA data. Discuss the integration of ETO and AEG/CPA data as well as past program(s) experience, knowledge of current and developing markets, and future codes and standards.

7. Carbon Costs – consult Washington State Commission’s Acknowledgement Letter Attachment in its 2017 Electric IRP (Docket UE-161036), where emissions price modeling is discussed, including the cost of risk of future greenhouse gas regulation, in addition to known regulations.

8. Avista will ensure Energy Trust (ETO) has sufficient funding to acquire therm savings of the amount identified and approved by the Energy Trust Board.
9. Regarding high pressure distribution or city gate station capital work, Avista does not expect any supply side or distribution resource additions to be needed in our Oregon territory for the next four years, based on current projections. However, should conditions warrant that capital work is needed on a high pressure distribution line or city gate station in order to deliver safe and reliable services to our customers, the Company is not precluded from doing such work. Examples of these necessary capital investments include the following:

- Natural gas infrastructure investment not included as discrete projects in IRP
- Consistent with the preceding update, these could include system investment to respond to mandates, safety needs, and/or maintenance of system associated with reliability
- Including, but not limited to Aldyl A replacement, capacity reinforcements, cathodic protection, isolated steel replacement, etc.
- Anticipated PHMSA guidance or rules related to 49 CFR Part §192 that will likely require additional capital to comply
- Officials from both PHMSA and the AGA have indicated it is not prudent for operators to wait for the federal rules to become final before improving their systems to address these expected rules.
- Construction of gas infrastructure associated with growth
- Other special contract projects not known at the time the IRP was published
- Other non-IRP investments common to all jurisdictions that are ongoing, for example:
  - Enterprise technology projects & programs
  - Corporate facilities capital maintenance and improvements

An updated table 8.4 for those distribution projects in Oregon:

- Location
  - Klamath Falls, OR
  - Sutherlin, OR

10. Avista will work with members of the OPUC to determine an alternative stochastic approach to Monte Carlo analysis prior to Avista’s 2020 IRP and share any recommendations with the TAC members.
That Could Never Happen!

Gas Supply Winter 2018-2019
Enbridge Pipeline Rupture

Pipeline ruptured October 9th

- 2.4 Bcf off the system
- Jackson Prairie Storage - down
- **NWP Roosevelt** compressor maintenance
- Within 24 hours, 50% of demand came off
- Moderate temperatures across Pacific NW
- Average gas prices < $3/Dth
- Gas rebate deferral balances growing

Source: NWGA 2017 Annual Outlook
Winter 2018-2019 Outlook

Winter 2018 - 2019 Firm Customer Load
Contract Capacity relative to Forecasted Peak Day, February 15th

Forecasted Peak Day: 347,228 Dth

<table>
<thead>
<tr>
<th></th>
<th>Dth/day</th>
</tr>
</thead>
<tbody>
<tr>
<td>Winter 2018-2019 - Firm Capacity</td>
<td>145,000</td>
</tr>
<tr>
<td>Winter 2018-2019 - No Sumas Capacity</td>
<td>145,000</td>
</tr>
<tr>
<td>Historical Actual Peak 1/5/2017</td>
<td>145,000</td>
</tr>
<tr>
<td>5-Year Average Dec-Jan-Feb</td>
<td>145,000</td>
</tr>
</tbody>
</table>

Legend:
- AECO
- Rockies
- Sumas
- JP-Storage
Historical Winter Firm Customer Load

Total System Firm Customer Load

Forecasted Peak Day: 347,228

Winter '18 - '19 Blended Temps

20 Yr Avg Historical - Blended

Actual '18 - '19 - Blended

*Avg. weather
Operation Flow Order (OFO)

- **Northwest Pipeline (NWP) Operational Flow Order**

An OFO is declared to provide the needed displacement on NWP’s system to meet firm commitments. When scheduled quantities exceed physical capacity, NWP is in a potential OFO situation. In other words,

**Avista must flow gas from west to east.**
# US Storage

**Working gas in underground storage, Lower 48 states**

<table>
<thead>
<tr>
<th>Region</th>
<th>03/08/19</th>
<th>03/01/19</th>
<th>net change</th>
<th>implied flow</th>
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<tbody>
<tr>
<td>East</td>
<td>262</td>
<td>311</td>
<td>-49</td>
<td>-49</td>
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<tr>
<td>Midwest</td>
<td>287</td>
<td>338</td>
<td>-51</td>
<td>-51</td>
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<tr>
<td>Mountain</td>
<td>66</td>
<td>73</td>
<td>-7</td>
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<tr>
<td>Pacific</td>
<td>102</td>
<td>112</td>
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<td>South Central</td>
<td>469</td>
<td>557</td>
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<td>Salt</td>
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<tr>
<td>Nonsalt</td>
<td>340</td>
<td>377</td>
<td>-37</td>
<td>-37</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>1,186</strong></td>
<td><strong>1,390</strong></td>
<td><strong>-204</strong></td>
<td><strong>-204</strong></td>
</tr>
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</table>

**Historical Comparisons**

<table>
<thead>
<tr>
<th>Year ago (03/08/18)</th>
<th>5-year average (2014-18)</th>
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<tbody>
<tr>
<td>Bcf</td>
<td>% change</td>
</tr>
<tr>
<td>320</td>
<td>-18.1</td>
</tr>
<tr>
<td>354</td>
<td>-18.9</td>
</tr>
<tr>
<td>94</td>
<td>-29.8</td>
</tr>
<tr>
<td>170</td>
<td>-40.0</td>
</tr>
<tr>
<td>607</td>
<td>-22.7</td>
</tr>
<tr>
<td>186</td>
<td>-30.6</td>
</tr>
<tr>
<td>420</td>
<td>-19.0</td>
</tr>
<tr>
<td>1,545</td>
<td>-23.2</td>
</tr>
</tbody>
</table>

Totals may not equal sum of components because of independent rounding.

569 Bcf below 5 yr avg
JP Storage Levels

Avista – 1.0 bcf
Puget – 2.2 bcf
Nwp – 3.5 bcf
Reduction of withdrawal capability by approx. 200-300 MMscfd
Avista withdrawal ability < 90 MMscfd (JP demand 50 – 90 MMscfd)
Enbridge Capacity Cuts
Pipeline Entitlements

• Entitlements are used to balance demand
  – Entitlement tolerances are tiered
    • 13%, 8%, 5%, 3% depending on severity of issue
  – Overrun entitlement
    • Total demand must not exceed nominations by the prescribed level
    • Example: Avista nominates 150,000 Dth on pipeline, demand must be AT MOST 169,500 Dth

– Entitlement penalties
  • Greater of $10.00/ dth or 4x the highest midpoint price in region
Historical and Current Winter Loads

**Total System Firm Customer Load**

**Forecasted Peak Day: 347,228 Dth**

- **5 Year Min-Max**
- **2018-2019 Forecasted Peak Day (2/15)**
- **5-Yr Avg**
- **Sumas/JP Sourced**
- **2018-2019**
Planning Outcomes changes

- In order to reduce the risk around not being able to serve load on a peak day with late winter weather Avista is moving its peak day from 2/15 to 2/28 for the WA/ID and La Grande.
Avista’s Demand Overview

Tom Pardee
Manager of Natural Gas Planning
Service Territory and Customer Overview

- Serves electric and natural gas customers in eastern Washington and northern Idaho, and natural gas customers in southern and eastern Oregon
  - Population of service area 1.5 million
    - 385,000 electric customers
    - 360,000 natural gas customers

- Has one of the smallest carbon footprints among America’s 100 largest investor-owned utilities

- Committed to environmental stewardship and efficient use of resources

<table>
<thead>
<tr>
<th>State</th>
<th>Total Customers</th>
<th>% of Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Washington</td>
<td>170,000</td>
<td>47%</td>
</tr>
<tr>
<td>Oregon</td>
<td>103,000</td>
<td>29%</td>
</tr>
<tr>
<td>Idaho</td>
<td>87,000</td>
<td>24%</td>
</tr>
<tr>
<td>Total</td>
<td>360,000</td>
<td>100%</td>
</tr>
</tbody>
</table>
Klamath Falls

<table>
<thead>
<tr>
<th></th>
<th>Res</th>
<th>Com</th>
<th>Ind</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average demand</td>
<td>2,628</td>
<td>1,352</td>
<td>44</td>
</tr>
<tr>
<td>Customers</td>
<td>15,192</td>
<td>1,787</td>
<td>6</td>
</tr>
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</table>
Roseburg

Average 2019 Temp Fahrenheit 55
La Grande

<table>
<thead>
<tr>
<th></th>
<th>Res</th>
<th>Com</th>
<th>Ind</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand</td>
<td>1,371</td>
<td>896</td>
<td>116</td>
</tr>
<tr>
<td>Customers</td>
<td>6,794</td>
<td>943</td>
<td>3</td>
</tr>
</tbody>
</table>

Average 2019 Temp Fahrenheit 47
Medford

<table>
<thead>
<tr>
<th></th>
<th>Res</th>
<th>Com</th>
<th>Ind</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average demand</td>
<td>9,312</td>
<td>5,939</td>
<td>62</td>
</tr>
<tr>
<td>Customers</td>
<td>56,354</td>
<td>7,038</td>
<td>14</td>
</tr>
</tbody>
</table>

Average 2019 Temp Fahrenheit 55
Idaho

Average demand:
- Res: 16,872
- Com: 9,668
- Ind: 800

Customers:
- Res: 77,804
- Com: 9,164
- Ind: 89

Average daily use (Dth)

Average 2019 Temp Fahrenheit 47
Washington

<table>
<thead>
<tr>
<th></th>
<th>Res</th>
<th>Com</th>
<th>Ind</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand</td>
<td>32,792</td>
<td>19,999</td>
<td>810</td>
</tr>
<tr>
<td>Customers</td>
<td>155,069</td>
<td>14,980</td>
<td>130</td>
</tr>
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</table>

Average 2019 Temp Fahrenheit 47
OR Daily Demand Profiles

Graphs showing daily demand profiles for Medford, Roseburg, Klamath Falls, and La Grande, with Dekatherms on the y-axis and Avg. Temp (F) on the x-axis.
WA-ID Daily Demand Profiles

Idaho Demand

WA Demand
Demand Forecast Methodology
Temperature & Degree Days

<table>
<thead>
<tr>
<th>Temp (°F)</th>
<th>Degree Days</th>
</tr>
</thead>
<tbody>
<tr>
<td>100</td>
<td>35</td>
</tr>
<tr>
<td>90</td>
<td>25</td>
</tr>
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<td>80</td>
<td>15</td>
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<td>70</td>
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<td>65</td>
</tr>
<tr>
<td>-10</td>
<td>75</td>
</tr>
<tr>
<td>-20</td>
<td>85</td>
</tr>
</tbody>
</table>
Weather

• NOAA 20 year actual average daily HDD’s (2000-2019)
• Peak weather includes two winter storms (5 day duration), one in December and one in February
• Planning Standard
• Sensitivity around planning standard including
  – Normal/Average
  – Monte Carlo simulation
## Base Coefficients

<table>
<thead>
<tr>
<th>Planning Area - Residential Class</th>
<th>2 year</th>
<th>3 year</th>
<th>5 year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Roseburg (Oregon)</td>
<td>0.041949146</td>
<td>0.040148823</td>
<td>0.03765259</td>
</tr>
<tr>
<td>Medford (Oregon)</td>
<td>0.04748832</td>
<td>0.047701223</td>
<td>0.04716918</td>
</tr>
<tr>
<td>La Grande (Oregon)</td>
<td>0.069994892</td>
<td>0.068986632</td>
<td>0.073506326</td>
</tr>
<tr>
<td>Klamath Falls (Oregon)</td>
<td>0.035881027</td>
<td>0.034536108</td>
<td>0.033843554</td>
</tr>
<tr>
<td>Idaho</td>
<td>0.048375922</td>
<td>0.046698825</td>
<td>0.046092068</td>
</tr>
<tr>
<td>Washington</td>
<td>0.047248771</td>
<td>0.046575066</td>
<td>0.047525773</td>
</tr>
</tbody>
</table>

*Base Coefficients

*Historic Data - July and August Average
# Heat Coefficients

<table>
<thead>
<tr>
<th>Planning Area - Residential Class</th>
<th>2 Year</th>
<th>3 Year</th>
<th>5 Year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Roseburg (Oregon)</td>
<td>0.008829</td>
<td>0.008046</td>
<td>0.00699</td>
</tr>
<tr>
<td>Medford (Oregon)</td>
<td>0.00639</td>
<td>0.0065</td>
<td>0.006068</td>
</tr>
<tr>
<td>La Grande (Oregon)</td>
<td>0.006223</td>
<td>0.007297</td>
<td>0.00665</td>
</tr>
<tr>
<td>Klamath Falls (Oregon)</td>
<td>0.005284</td>
<td>0.005268</td>
<td>0.004902</td>
</tr>
<tr>
<td>Idaho</td>
<td>0.006445</td>
<td>0.006344</td>
<td>0.005896</td>
</tr>
<tr>
<td>Washington</td>
<td>0.006307</td>
<td>0.006313</td>
<td>0.005957</td>
</tr>
</tbody>
</table>

*Avg. of monthly heat coefficient

*Historic Data – adjusted by price elasticity and DSM*
Demand Modeling Equation – a closer look

SENDOUT® requires inputs expressed in the below format to compute daily demand in dekatherms. The base and weather sensitive usage (degree-day usage) factors are developed outside the model and capture a variety of demand usage assumptions.

Table 3.2 Basic Demand Formula

<table>
<thead>
<tr>
<th># of customers × Daily base usage / customer</th>
</tr>
</thead>
<tbody>
<tr>
<td>Plus</td>
</tr>
<tr>
<td># of customers × Daily weather sensitive usage / customer</td>
</tr>
</tbody>
</table>
1. Expected customer count forecast by each of the 6 areas
2. Use per customer coefficients – 5 year, 3 year or last 2 year average use per HDD per customer
3. Current weather planning standard
Weather Analysis
Z-Stat

- Compare one period to another
- Shows how far from the average the data point falls
Spokane Dec-Jan-Feb Temperature Anomaly Histogram

Z-statistic

Frequency

1951/52-1980/81 Reference Period
2001/02 - 2018/19 Period
Summary

• Avista’s warmer climate locations, Roseburg and Medford, continue to see a shift in temperatures vs. the reference period

• The colder weather climate locations, Klamath Falls, La Grande, Spokane (ID, WA), have maintained the general shape and remain consistent vs. the reference period
Weather Planning Standard
Weather Standard

• Has the potential to significantly change timing of resource needs
• Significant qualitative considerations
  – No infrastructure response time if standard exceeded
  – Significant safety and property damage risks
• Current Peak HDD Planning Standards
  – WA/ID 82
  – Medford 61
  – Roseburg 55
  – Klamath 72
  – La Grande 75
### Wind Chill Chart

**Temperature (°F)**

<table>
<thead>
<tr>
<th></th>
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</tr>
</thead>
<tbody>
<tr>
<td>5</td>
<td>36</td>
<td>31</td>
<td>25</td>
<td>19</td>
<td>13</td>
<td>7</td>
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<td>6</td>
<td>-1</td>
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<td>-22</td>
<td>-29</td>
<td>-36</td>
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<td>-67</td>
<td>-74</td>
<td>-81</td>
<td>-88</td>
<td>-95</td>
<td></td>
</tr>
</tbody>
</table>

**Frostbite Times**

- 30 minutes
- 10 minutes
- 5 minutes

**Wind Chill (°F)**

\[
\text{Wind Chill (°F)} = 35.74 + 0.6215T - 35.75(V^{0.16}) + 0.4275T(V^{0.16})
\]

Where, \( T = \) Air Temperature (°F), \( V = \) Wind Speed (mph)

Effective 11/01/01
Wind chill effects

• Wind on homes causes two effects. One is wind chill on the exterior of the building and the other is infiltration increases due to the pressure difference caused by wind blowing past the home.

• The greatest effect of wind on heating is low humidity in the home which makes the customers feel like the temperature is 64 degrees when they have the thermostat set at 72 if their humidity is lower than 10% Relative Humidity.
Weather Peak Planning Day alternative

- Coldest Average Day, each year, for the past 30 years combined with a 99% probability

<table>
<thead>
<tr>
<th>Area</th>
<th>Coldest on Record</th>
<th>99% Probability Avg. Temp</th>
<th>99% Probability Avg. Temp &amp; Wind Chill*</th>
</tr>
</thead>
<tbody>
<tr>
<td>La Grande</td>
<td>-10</td>
<td>-11</td>
<td>-23</td>
</tr>
<tr>
<td>Klamath Falls</td>
<td>-7</td>
<td>-9</td>
<td>-16</td>
</tr>
<tr>
<td>Medford</td>
<td>4</td>
<td>11</td>
<td>9</td>
</tr>
<tr>
<td>Roseburg</td>
<td>10</td>
<td>14</td>
<td>16</td>
</tr>
<tr>
<td>Spokane</td>
<td>-17</td>
<td>-12</td>
<td>-26</td>
</tr>
</tbody>
</table>

*this was done with the recent 20 years of data combined with windspeed for example purposes*
Risks

• Using wind chill effects combined with a 99% probability produces some drastic changes in peak day planning and may require a large amount of capital to meet those design criteria.

• Utilizing a 99% probability means there is a 1 in 100 event where Avista may not be able to meet the demand.
Risk around moving WA and ID peak day temps (1,000 simulated futures run)

Draws 1 - 200

Draws 201 - 400

Coldest on Record Peak Days
(82 HDD’s, or -17 Avg. Temp Fahrenheit)
“Flat Demand” Risk

Figure 1.9 Flat Demand Risk Example

- **Demand**
- **Years**: 1, 2, 3, 4, 5, 6, 7, 8, 9, 10
- **Resources**
- **Initial Demand**
- **Revised Demand**
Avista Weather Recommendation

• Utilize coldest day for each of the past 30 years with a 99% probability supply can be fulfilled

<table>
<thead>
<tr>
<th>Area</th>
<th>99% Probability Avg. Temp</th>
</tr>
</thead>
<tbody>
<tr>
<td>La Grande</td>
<td>-11</td>
</tr>
<tr>
<td>Klamath Falls</td>
<td>-9</td>
</tr>
<tr>
<td>Medford</td>
<td>11</td>
</tr>
<tr>
<td>Roseburg</td>
<td>14</td>
</tr>
<tr>
<td>Spokane</td>
<td>-12</td>
</tr>
</tbody>
</table>
Procurement Plan
Hedging Objectives and Goals

Mission

To provide a diversified portfolio of reliable supply and a level of price certainty in volatile markets.

• Avista cannot predict future market prices, however we use experience, market intelligence, and fundamental market analysis to structure and guide our procurement strategies.
• Avista’s goal is to develop a plan that utilizes customer resources (storage and transportation), layers in pricing over time for stability (time averaging), allows discretion to take advantage of pricing opportunities should they arise, and appropriately manages risk.
Oversight and Control

**Risk Management Committee (RMC)**
- Comprised of Executive Officers & Sr. Management
- Responsible for the Risk Management Policy
- Provides oversight and guidance on natural gas procurement plan

**Natural Gas Supply**
- Monitors and manages the Procurement Plan on a daily basis
- Leads in the annual Procurement Plan review and modification

**Strategic Oversight Group (SOG)**
- Cross functional group consisting of:
  - Credit, Electric/Gas Supply, Rates, Resource Accounting, Risk
  - Co-develops the Procurement Plan
- Meets regularly

**Commission Update**
- Semi-Annual Update
- New Procurement Plan is communicated semi-annually in the fall and spring
- Intra-year changes communicated to staff on an ad-hoc basis
Comprehensive Annual Review of Previous Plan

Review conducted with SOG includes:

- Mission statement and approach
- Current and future market dynamics
- Hedge percentage
- Operative Boundary
- Resources available (i.e. storage and transportation)
- Hedge windows and quantity (how many, how long)
- Storage utilization
- Analysis (volatility, past performance, scenarios, risk)
A Thorough Evaluation of Risks

- Load Volatility
  - Seasonal Swings

- Legislation
  - Does it impact our plan?

- Foreign Currency
  - What’s our exposure?

- Price
  - Cash vs. Forward

- Market Liquidity
  - Is there enough?

- Counterparty
  - Who can we transact with?
AECO Daily Volatility

$ per DTh

Max-Min

Actual
Natural Gas Procurement Plan vs. System Demand
November 2019 through October 2020

*As of 10/9/2019
Plan Overview

Dynamic Window Hedge (DWH) Plan

- Manages hedges based on average volumetric load
- Firm local distribution customers only
- **Delivery Periods:** Hedges up to 3 years out into the future from the prompt month in monthly and/or seasonal timeframes
- **Supply Basins:** Windows will use VAR as a way to determine the best basin for a hedge. (AECO, Rockies, Sumas).

Risk Responsive Hedging Tool (RRHT)

- Manages all hedges in the portfolio based on a financial position
  - Transport optimization hedges
  - Storage optimization hedges
  - LDC hedges from the DWH program
- Incorporates the financial value at risk (VaR) as a daily position based on current firm supply side assets combined with price volatility at each futures market basin.
# Dynamic Window Hedging

## May 8, 2020

<table>
<thead>
<tr>
<th>Physical Positions</th>
<th>Dynamic Window Hedging</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Window</td>
</tr>
<tr>
<td></td>
<td>Hedging Threshold</td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td>Load Estimate</td>
<td>Completed Hedges</td>
</tr>
<tr>
<td>Dth/Day</td>
<td>Dth/Day</td>
</tr>
<tr>
<td>June-20</td>
<td>-33,221</td>
</tr>
<tr>
<td>July-20</td>
<td>-29,585</td>
</tr>
<tr>
<td>August-20</td>
<td>-29,623</td>
</tr>
<tr>
<td>September-20</td>
<td>-37,700</td>
</tr>
<tr>
<td>October-20</td>
<td>-84,793</td>
</tr>
<tr>
<td>Nov20-Mar21</td>
<td>-169,784</td>
</tr>
<tr>
<td>Apr21-Oct21</td>
<td>-52,143</td>
</tr>
<tr>
<td>Nov21-Mar22</td>
<td>-175,136</td>
</tr>
<tr>
<td>Apr22-Oct22</td>
<td>-52,700</td>
</tr>
<tr>
<td>Nov22-Mar23</td>
<td>-177,251</td>
</tr>
</tbody>
</table>

**Active Hedge Window 04/09/20 - 05/20/20**

*Expiration Date, 5/20/2020*
Risk Responsive Hedging Tool

![Risk Responsive Hedging Diagram]

- Hedged %: 20.00%
- Price @ 2 Sigma: $1.06
- Operative Boundary: $3.50

![Potential Price @ 2 Sigma Diagram]

- Price @ 2 Sigma ($/DTh)
- Boundary ($/DTh)
Optimization
Avista Gas Supply Asset Optimization

• Storage Optimization.
  o Utilize Avista owned portion of Jackson Prairie storage facility
  o Maintain a peak day capability in order to serve needed demand from the facility during a peak event.
  o Optimize excess capacity through arbitrage between daily prices and forward months as well as between different forward months.

• Transport Optimization.
  o Avista owns transport capacity sufficient to serve peak day load. Unused capacity is optimized by purchasing/selling gas at different hubs to capture locational price spreads.
Storage Optimization Examples

• Day ahead market arbitrage with forward month
  Purchase: daily sumas 75,000 dth for $1.45/dth.
  Sale: 75,000 dth October 2020 Sumas for $2.48/dth.
  Realized arbitrage value: $1.03*75,000 = $77,250

• Arbitrage between different forward months
  Purchase: Q3 2020 sumas 225,000 dth for $1.81
  Sale: Q1 2021 sumas 225,000 dth for $3.47
  Realized arbitrage value : $1.66*225,000 = $373,500
Transport Optimization

- Transport Capacity in excess of Avista core load can be optimized to reduce customer costs.

- Optimization can be done in either the daily or forward markets

Example:

Purchase: 30,000 dth AECO for $2.00/dth

Sale: 30,000 dth Malin for $2.30/dth

Realized cost reduction to customers: $0.30*30,000 = $9,000
Risks

• Operational Flow Orders:
  o NW Pipeline may require the use of JP storage gas to satisfy OFO’s.
  o May require additional purchases from market to replace storage inventory.

• Unplanned maintenance:
  o Unexpected reductions to pipeline capacity or reduced access to storage may limit optimization activity

• Damage or failure of infrastructure
2020 Natural Gas IRP
Energy Efficiency

Ryan Finesilver – Energy Efficiency Planning and Analytics Manager
First Technical Advisory Committee Meeting
Team Roles

Planning & Analytics Team

Applied Energy Group (AEG)

Gas Supply

ACP
CPA
IRP

Oregon DSM Programs
Alphabet Soup

- CPA: Conservation Potential Assessment
- IRP: Integrated Resource Plan
- AEG: Applied Energy Group
- IPUC: Idaho Public Utility Commission
- TRC: Total Resource Cost Test
- UCT: Utility Cost Test
- UTC: Utilities and Transportation Commission

The CPA within the IRP is done by AEG and as per the UTC, is according to the TRC but the IPUC requires the UCT.
Who Energy Efficiency Serves

Three Jurisdictions
- Washington
- Idaho
- Oregon (ETO except for Low-Income)

Multiple Customer Segments
- Residential
- Industrial/Commercial
- Low-Income Residential

The Company’s Infrastructure
- Aids in reducing overall capacity
- Defers capital investments
Energy Efficiency Funding – Natural Gas

Tariff percentage of customer bill by state:

- Washington: 3.7%
- Idaho: 2.6%
- Oregon: 4.3%

$8.4 Million Annual Funding (2019)
WA Gas Targets to Actual Savings

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Business Plan Target</strong></td>
<td>637,042</td>
<td>602,010</td>
<td>567,653</td>
<td>620,310</td>
<td>719,451</td>
<td>726,128</td>
<td>937,402</td>
</tr>
<tr>
<td><strong>IRP Target</strong></td>
<td>1,310,000</td>
<td>1,287,000</td>
<td>737,000</td>
<td>489,110</td>
<td>612,830</td>
<td>725,180</td>
<td>936,350</td>
</tr>
<tr>
<td><strong>Actual</strong></td>
<td>615,418</td>
<td>919,892</td>
<td>548,756</td>
<td>1,046,356</td>
<td>736,985</td>
<td>504,113</td>
<td></td>
</tr>
</tbody>
</table>
## ID Gas Targets to Actual Savings

<table>
<thead>
<tr>
<th>Year</th>
<th>Business Plan Target</th>
<th>IRP Target</th>
<th>Actual</th>
</tr>
</thead>
<tbody>
<tr>
<td>2014</td>
<td>0</td>
<td>456,000</td>
<td>0</td>
</tr>
<tr>
<td>2015</td>
<td>0</td>
<td>228,000</td>
<td>0</td>
</tr>
<tr>
<td>2016</td>
<td>232,737</td>
<td>114,000</td>
<td>189,295</td>
</tr>
<tr>
<td>2017</td>
<td>219,272</td>
<td>197,640</td>
<td>245,747</td>
</tr>
<tr>
<td>2018</td>
<td>252,712</td>
<td>246,440</td>
<td>247,756</td>
</tr>
<tr>
<td>2019</td>
<td>321,120</td>
<td>320,830</td>
<td>278,922</td>
</tr>
<tr>
<td>2020</td>
<td>436,405</td>
<td>421,270</td>
<td></td>
</tr>
</tbody>
</table>
OR Energy Trust Gas Targets to Actual Savings

- Energy Trust did not deliver programs for Avista in 2014-2015.

<table>
<thead>
<tr>
<th>Year</th>
<th>Savings Goal</th>
<th>IRP Target</th>
<th>Actual</th>
</tr>
</thead>
<tbody>
<tr>
<td>2014</td>
<td>31,574</td>
<td>318,332</td>
<td>34,708</td>
</tr>
<tr>
<td>2015</td>
<td>318,332</td>
<td>349,520</td>
<td>340,738</td>
</tr>
<tr>
<td>2016</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2017</td>
<td>349,520</td>
<td>294,720</td>
<td>409,128</td>
</tr>
<tr>
<td>2018</td>
<td>360,682</td>
<td>384,599</td>
<td></td>
</tr>
<tr>
<td>2019</td>
<td>360,682</td>
<td>384,599</td>
<td></td>
</tr>
</tbody>
</table>
Energy Efficiency
Business Planning

CPA → Target → Business Plan
Conservation Potential Assessment (CPA)

• Primary Objectives
  – Meet legislative and regulatory requirements
  – Support integrated resource planning
  – Identify opportunities for savings; key measures in target segments

• Key Deliverables
  – 20-year conservation potential
  – Individual measures
  – IRP target
Conservation Potential Assessment

**Technical Potential**
- Theoretical upper limit of conservation
- All efficiency measures are phased in regardless of cost

**Achievable Technical Potential**
- Realistically achievable, accounting for adoption rates and how quickly programs can be implemented
- Does not consider cost-effectiveness of measures

**Achievable Potential**
- Includes economic screening of measures (cost effectiveness)
- Sets our conservation target
Business Planning Process

- Conservation Potential Assessment
- Business Planning
- Annual Conservation Plan
- EM&V
- Adaptive Management
- Annual Conservation Report
Business Planning Process

CPA
- Sets overall Savings Goal
- Identifies Measures

Avista Programs
- Consult with our existing programs
- Add new measures to existing programs

Update and Evaluate
- Update existing savings values
- Test for Cost-Effectiveness (TRC/UCT)

Feedback and Modify
- DSM Program Managers
- Engineers
- Industry Trends
- Other Parties

Energy Efficiency Advisory Group
### Incentive Setting

#### Cost-Effective Test

<table>
<thead>
<tr>
<th>Utility Cost Test (UCT)</th>
<th>Total Resource Cost (TRC)</th>
<th>Must have a B/E ratio of 1.0 or Higher</th>
</tr>
</thead>
</table>

#### Decide Incentive Level

<table>
<thead>
<tr>
<th>$3 per Therm</th>
<th>70% of CIC</th>
<th>CE Impact</th>
<th>Portfolio Alignment</th>
</tr>
</thead>
</table>
Significant Costs and Benefits

COSTS

- Administration
  (e.g., program design, development, operations, maintenance, overhead, customer service, marketing & outreach, sales, IT infrastructure, customer education, program evaluation, measurement & verification)
- Measure (Capital) Costs
  (equipment costs incurred by the utility and participants)
- Incentives
- Revenue Loss
  (bill reductions)
- Participant Costs
  (Other than capital costs – value of service lost & transaction costs)

BENEFITS

- Avoided Costs
  (complex)
- Tax Credits
  (currently available for DG only)
- Market/Reliability Benefits
- Non-energy benefits
- Incentives
- Bill reductions

From Cost-effectiveness training (3/6/15) Powerpoint
http://www.cpuc.ca.gov/General.aspx?id=5267
Energy Trust’s Resource Assessment Model

• What is a resource assessment model?
  o Energy Trust’s version of a Conservation Potential Assessment
  o Model that provides an estimate of energy efficiency resource potential achievable over a 20-year period
  o ‘Bottom-up’ approach to estimate potential starting at the measure level and scaling to a service territory

• Energy Trust uses a Model that calculates Technical, Achievable and Cost-Effective Achievable Energy Efficiency Potential
  o Final program/IRP targets are established via a deployment forecast in a separate tool

• We provide a 20-year energy efficiency forecast for utility IRPs about every two years.
Energy Trust’s Resource Assessment Model is “Living Model”

- Energy Trust makes continuous improvements to the model
- Measures in the model are updated on an ongoing basis to reflect changing market conditions and savings estimates
- Emerging technologies are added to the model as data availability and product viability allows
- Cost-effective potential may be realized through programs, market transformation and/or codes and standards
- Under discussion: use of a “large project adder” to account for large, unexpected projects
# Energy Trust Resource Assessment Model Inputs

<table>
<thead>
<tr>
<th>Measure Level Inputs</th>
<th>Utility ‘Global’ Inputs</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Measure Definition and Application:</strong></td>
<td><strong>Customer and Load Forecasts</strong></td>
</tr>
<tr>
<td>• Baseline/Efficient equip. definition</td>
<td>• Used to scale measure level savings to a service territory</td>
</tr>
<tr>
<td>• Applicable customer segments</td>
<td>• Residential Stocks: # of homes</td>
</tr>
<tr>
<td>• Installation type (RET/ROB/NEW)*</td>
<td>• Commercial Stocks: 1000s of Sq.Ft.</td>
</tr>
<tr>
<td>• Measure Life</td>
<td>• Industrial Stocks: Customer load</td>
</tr>
<tr>
<td><strong>Measure Savings</strong></td>
<td><strong>Avoided Costs</strong></td>
</tr>
<tr>
<td><strong>Measure Cost</strong></td>
<td><strong>Customer Stock Demographics:</strong></td>
</tr>
<tr>
<td>• Incremental cost for ROB/NEW measures</td>
<td>• Heating fuel splits</td>
</tr>
<tr>
<td>• Full cost for retrofit measures</td>
<td>• Water heat fuel splits</td>
</tr>
<tr>
<td><strong>Market Data (for scaling)</strong></td>
<td></td>
</tr>
<tr>
<td>• Units per site</td>
<td></td>
</tr>
</tbody>
</table>
Energy Trust 20-Year IRP EE Forecast Flow Chart

**Data Collection and Measure Characterization**

**Measure Level Inputs**
- Baseline and Efficient Equipment
- Measure Savings
- Incremental Costs
- Market Data Density/Saturation/Suitability

**Utility 'Global Inputs'**
- Load Forecasts by Sector
- Customer Counts/Building Stocks
- Customer Stock Demographics
- Utility Avoided Costs ($/Therm Saved)

**Technical Energy Efficiency Potential**
All technically available energy efficiency potential in service territory

**Achievable Energy Efficiency Potential**
85% of Technical Potential is achievable due to market barriers

**Cost-Effectiveness Screen**
Measures are screened for cost-effectiveness using the TRC Test

\[ \text{Total Resource Cost Test (TRC)} = \frac{\text{Benefits}}{\text{Costs}} \]

**Cost-Effective Achievable Energy Efficiency Potential**
Measures with TRC Ratio > 1.0 included in Cost-Effective Achievable Potential

**Deployment of Cost-Effective Achievable EE Potential**
Exogenous of the RA Model - Energy Trust works internally with programs and uses NWPPC council methodologies to determine acquisition rates of CE Potential
Energy Trust Forecasted Potential Types

- Not Technically Feasible
- Market Barriers
- Not Cost-Effective
- Program Design & Market Penetration
- Final Program Savings Potential

Technical Potential

Achievable Potential (85% of Technical Potential)

Cost-Effective Achievable Potential

Calculated within RA Model

Developed with Programs & Market Information
Energy Trust Cost-Effectiveness Screen For RA Modeling

- Energy Trust utilizes the Total Resource Cost (TRC) test to screen measures in the model for cost effectiveness

| TRC = | Measure Benefits | Total Measure Cost |

- If TRC is > 1.0, it is cost-effective and the resources is included in cost-effective achievable potential

- Measure Benefits:
  - Avoided Costs
    - Annual measure savings x NPV avoided costs per therm or kWh
  - Quantifiable Non-Energy Benefits
    - Water savings, etc.

- Total Measure Costs:
  - The customer cost of installing an EE measure (full cost if retrofit, incremental over baseline if replacement)

- Some gas measures are forced into the model if they have exceptions from the OPUC under the criteria established via UM 551
Energy Trust Deployment

- The RA model results represent the maximum savings potential in a given year.
- Ramp rates are an estimate of how much of that available potential will come off Avista’s system in a given year.
- Energy Trust ramp rates are based on NW PCC methods and ramp rates, but calibrated to be specific to Energy Trust.
Energy Trust Final Savings Projection Methodology

Energy Trust calibrates the first five years of energy efficiency acquisition ramp rates to program performance and budget goals.

**Years 1-2**
- Program forecasts – they know what is happening short term best

**Years 3-5**
- Planning and Programs work together to create forecast

**Years 6-20**
- Planning forecasts long-term acquisition rate to generally align NWPCC
Energy Trust Ramp Rate Overview

- Total RA Model cost-effective potential is different depending on the measure type.
  - **Retrofit measure savings** are 100% of all potential in every year, therefore must be distributed in a curve that adds to 100% over the forecast timeframe (bell curve)
  - **Lost opportunity measure savings** are the savings available in that year only and deployment rates are what % of that available potential rate can be achieved – results in an s-curve

- Generally follows the NWPCC deployment methodology
  - 100% cumulative penetration for retrofit measures over 20-year forecast
  - 100% annual penetration for lost opportunity by end of 20-year forecast (program or code achieved)
  - Hard to reach measures or emerging technologies do not ramp to 100%
Energy Trust Ramp Rate Examples

![Graph showing Retrofit Curve and Lost Opportunity Curve over years]

- **Retrofit Curve % adoptions**
  - Year 1-2: 0%
  - Year 3-4: 1%
  - Year 5-6: 2%
  - Year 7-8: 3%
  - Year 9-10: 4%
  - Year 11-12: 5%
  - Year 13-14: 6%
  - Year 15-16: 7%
  - Year 17-18: 8%
  - Year 19-20: 9%
  - Year 21: 10%

- **Lost Opportunity % adoptions**
  - Year 1-2: 0%
  - Year 3-4: 1%
  - Year 5-6: 2%
  - Year 7-8: 3%
  - Year 9-10: 4%
  - Year 11-12: 5%
  - Year 13-14: 6%
  - Year 15-16: 7%
  - Year 17-18: 8%
  - Year 19-20: 9%
  - Year 21: 10%

- **Legend**
  - Orange: Retrofit Curve
  - Blue: Lost Opportunity Curve
Avista’s OR IRP Savings Targets Influence Annual Energy Trust Savings Goals and Budgets

• The savings forecasts that Avista incorporates into their IRPs is a reference point for setting annual Energy Trust savings goals and budgets

• Likewise, the Energy Trust savings goals from the last budget cycle inform the early years of the next IRP forecast

• This results in a cycle of iterative updates to savings projections based on the most recent market intelligence

• In addition, Energy Trust’s measure development process uses the Utility Cost Test to screen measures for cost-effectiveness
  – This test sets an upper bound on the incentive that can be offered and this factors into the budget process
Questions?
2020 Natural Gas IRP schedule


• **TAC 2: Thursday, August 6, 2020:** Market Analysis, Price Forecasts, Cost Of Carbon, demand forecasts and CPA results from AEG, Environmental Policies, fugitive emissions

• **TAC 3: Wednesday, September 30, 2020:** Distribution, Avista’s current supply-side resources overview, supply side resource options, renewable resources, overview of the major interstate pipelines and projects, and sensitivities and portfolio selection modeling.

• **TAC 4: Wednesday, November 18, 2020:** Review assumptions and action items, final modeling results, portfolio risk analysis and 2020 Action Plan.

• **TAC 5: February 2021:** TAC final review meeting (if necessary)