2019 Electric Integrated Resource Plan

Technical Advisory Committee Meeting No. 2 Agenda

Tuesday, November 27, 2018
Conference Room 130

Topic	Time	Staff
Introductions and TAC 1 Recap	9:30	Lyons
Modeling Process Overview	9:40	Gall
Generation Resource Options	10:10	Gall
Break	11:00	
Home Heating Technologies Overview	11:15	Lienhard
Lunch	12:00	
Resource Adequacy and Effective Load Carrying Capability	1:00	Gall
Electric IRP Key Assumptions	1:45	Gall/Lyons
Break	2:30	
2019 IRP Futures and Scenarios	2:45	Gall/Lyons
Adjourn	3:30	

2019 Electric IRP
TAC Meeting Introductions and Recap

John Lyons, Ph.D.
Second Technical Advisory Committee Meeting
November 27, 2018

Integrated Resource Planning

The Integrated Resource Plan (IRP):

- Required by Idaho and Washington every other year
- Guides resource strategy over the next two years
- Current and projected load & resource position
- Resource strategies under different future policies
  - Generation resource choices
  - Conservation / demand response
  - Transmission and distribution integration
  - Avoided costs
- Market and portfolio scenarios for uncertain future events and issues

Technical Advisory Committee

- The public process piece of the IRP – input on what to study, how to study, and review of assumptions and results
- Wide range of participants in all or some of the process
- Open forum while balancing need to get through all of the topics
- Welcome requests for studies or different assumptions.
  - Time or resources may limit the studies we can do
  - The earlier study requests are made, the more accommodating we can be
  - January 2019 at the latest to be able to complete studies in time for publication
- Planning team is available by email or phone for questions or comments between the TAC meetings

TAC #1 Recap – July 25, 2018

- Introduction
- TAC Expectations and Process Overview
- 2017 IRP Acknowledgments and Policies
- Avista's Demand and Economic Forecast
- 2017 Action Plan Updates
- 2019 IRP Draft Work Plan
- Hydro One Merger Agreements
- Meeting minutes are available on the IRP web site at https://www.myavista.com/about-us/our-company/integrated-resource-planning

Today's Agenda

- 9:30 – Introductions and TAC 1 Recap, Lyons
- 9:40 – Modeling Process Overview, Gall
- 10:15 – Generation Resource Options, Gall
- 11:00 – Break
- 11:15 – Home Heating Technologies Overview, Lienhard
- 12:00 – Lunch
- 1:00 – Resource Adequacy and Effective Load Carrying Capability, Gall
- 1:45 – Key Assumptions, Gall and Lyons
- 2:30 – Break
- 2:45 – Futures and Scenarios, Gall and Lyons
- 3:30 – Adjourn

TAC 3 Topics

- TAC 3 on Wednesday, February 6, 2019
- Natural Gas Price Forecast
- Electric Market Forecast
- IRP Transmission Planning Studies
- Distribution Planning within the IRP
- Existing Resource Overview (Colstrip, Lancaster, and other resources)
- Final Resource Needs Assessment

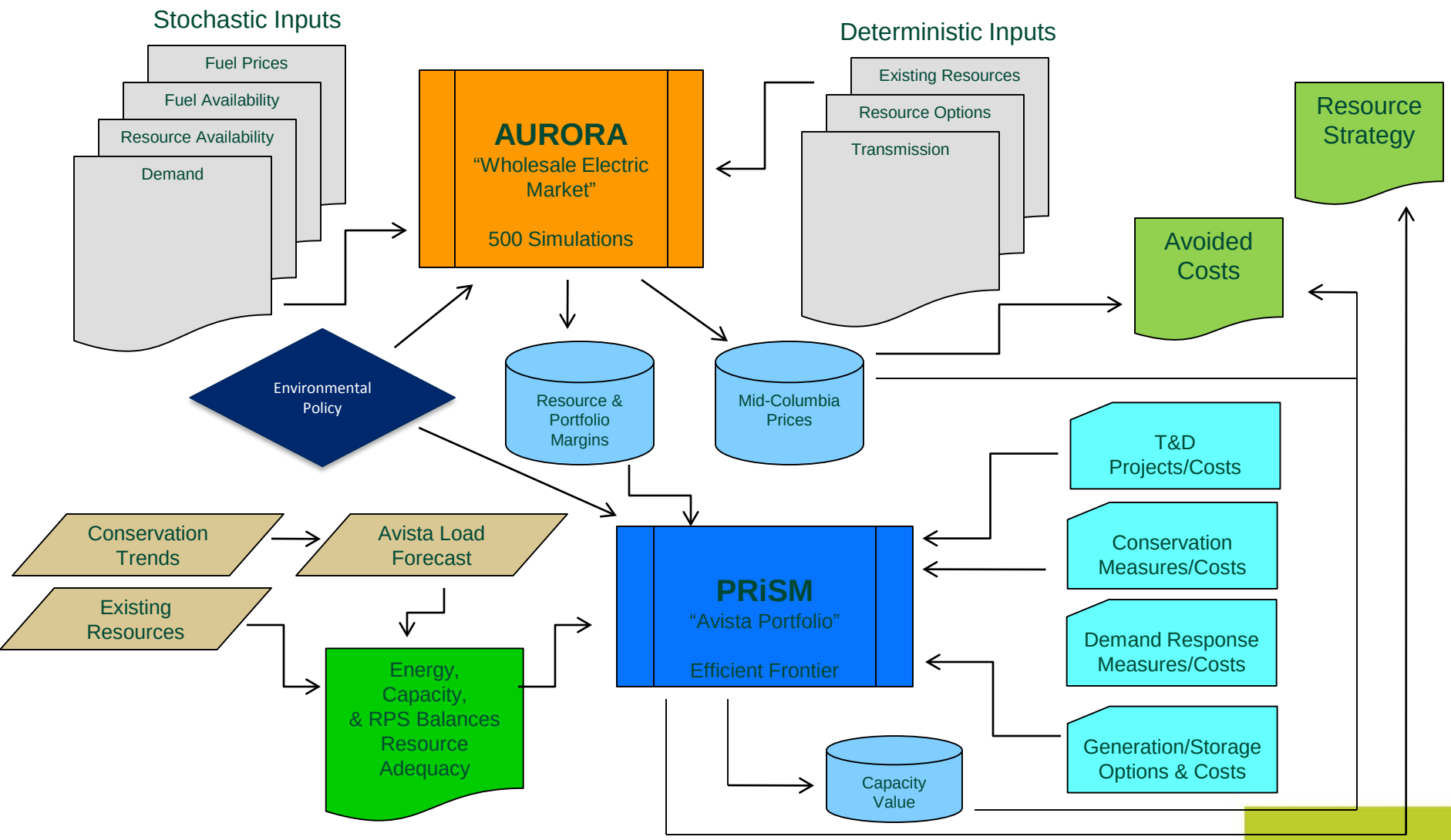
2019 IRP Modeling Process Overview

James Gall, IRP Manager
Second Technical Advisory Committee Meeting
November 27, 2018

IRP Modeling Process

- The purpose of this discussion is to help you understand the steps and process associated with the analysis of the IRP.
- This presentation outlines the steps to develop the plan along with a high level discussion of how the tools and methods are used.

2019 IRP Modeling Process



Electric Market Modeling

- 3rd party software- EPIS, Inc./Energy Exemplar
- Electric market fundamentals- production cost model
- Simulates generation dispatch to meet load and allows for system constraints

Inputs:

- Regional loads*
- Fuel prices*
- Fuel availability*
- Resources (availability*)
- New resources costs
- Transmission

*Stochastic input

Outputs:

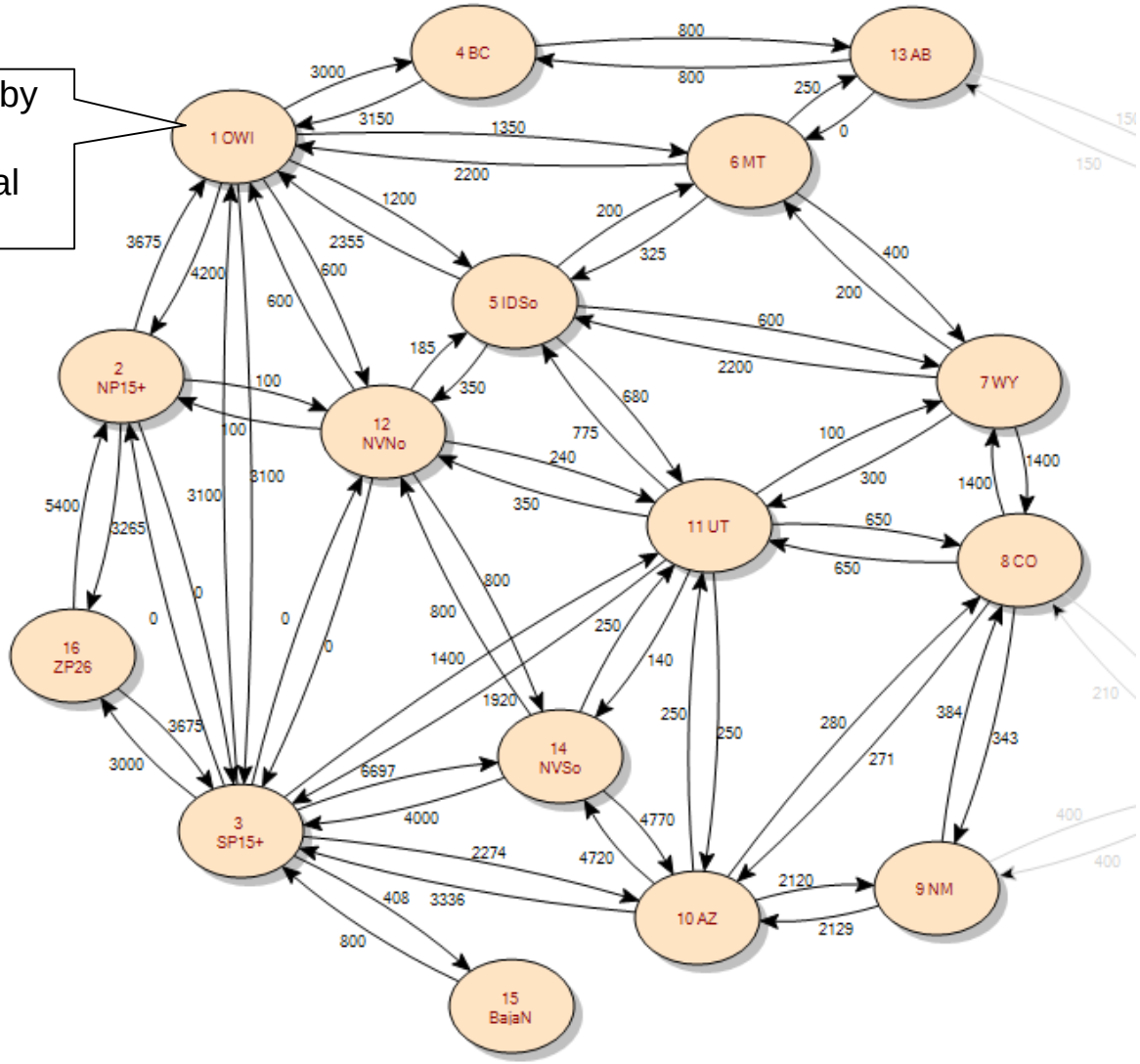
- Market prices
- Energy mix
- Transmission usage
- Emissions
- Power plant margins, generation levels, fuel costs
- Avista's variable power supply costs

Aurora Modeling Changes from 2017 IRP

- Use Epis/Energy Exemplar latest database vs. Avista's proprietary database
- Updates to the Epis database will include:
  - Avista specific characteristics (load/generation/fuel)
  - Fuel prices
  - Regional hydro conditions (80-year record)
  - Adjustments to allow market prices to go negative
  - Load shape changes (electric vehicles/rooftop solar)
  - Known regional resource retirements
  - Split Northwest area between WA, OR, and ID (TBD)

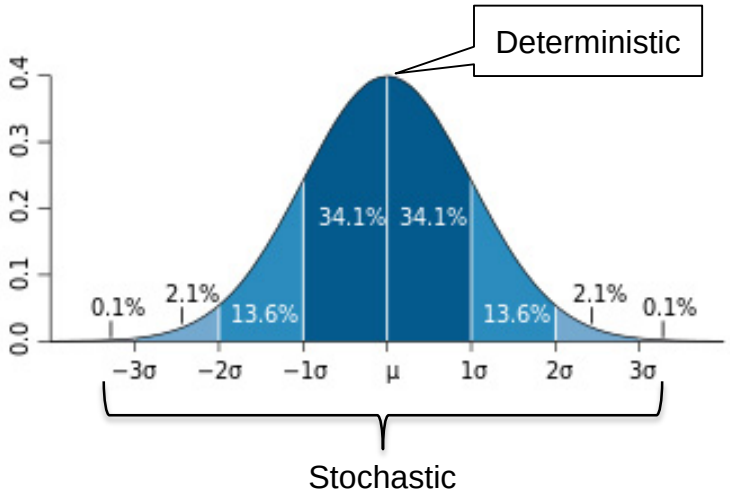
Aurora Load Area Topology

Potential split by state due to environmental policies



Stochastic vs. Deterministic Analysis

- Deterministic analysis forecasts for a specific set of inputs.
  - Easy to understand
  - Works great for sensitivity analysis of specific changes
- Stochastic analysis forecasts for a range of inputs.
  - Range (or distribution) of results
  - Works great to understand risks of the inputs with variation



PRiSM- Preferred Resource Strategy Model

- Internally developed using Excel based linear/mixed integer program model (What's Best & Gurobi)
- Selects new resources to meet Avista's capacity, energy, and renewable energy requirements
- Outputs:
  - Power supply costs (variable and fixed)
  - Power supply costs variation
  - New resource selection (generation/conservation)
  - Emissions
  - Capital requirements

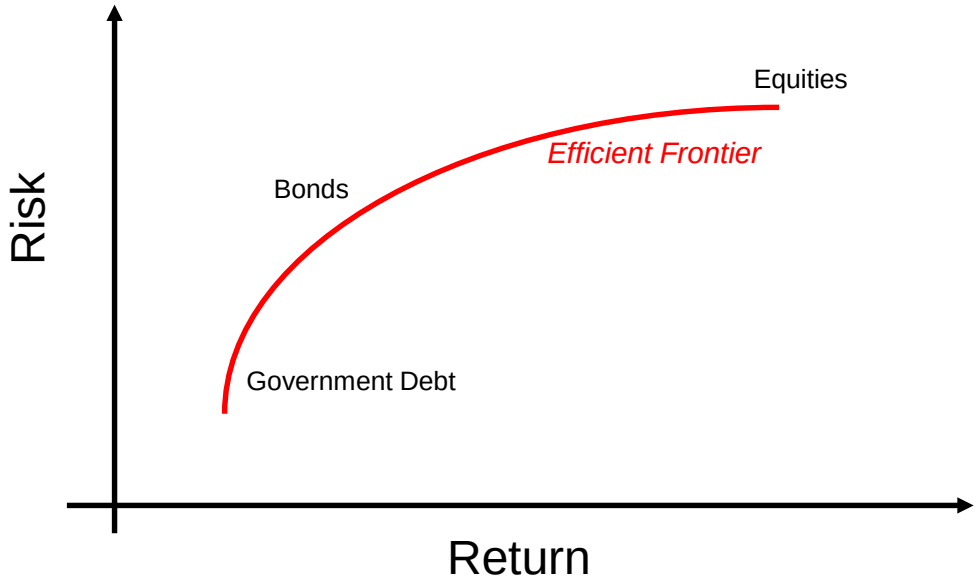
PRiSM

- Find optimal resource strategy to meet resource deficits over planning horizon
- New for the plan: Split Avista's resources and loads
  - City of Spokane
  - Idaho
  - Washington
- Model selects its resources to reduce cost, risk, or both.
- Objective Function:
  - Minimize: Total Power Supply Cost on NPV basis (2020-2058)
  - Focus on first 20 years of the forecast
  - Subject to:
    - Risk level
    - Capacity need +/- deviation
    - Energy need +/- deviation
    - Renewable portfolio standards
    - Resource limitations, sizes, and timing

Efficient Frontier Concept

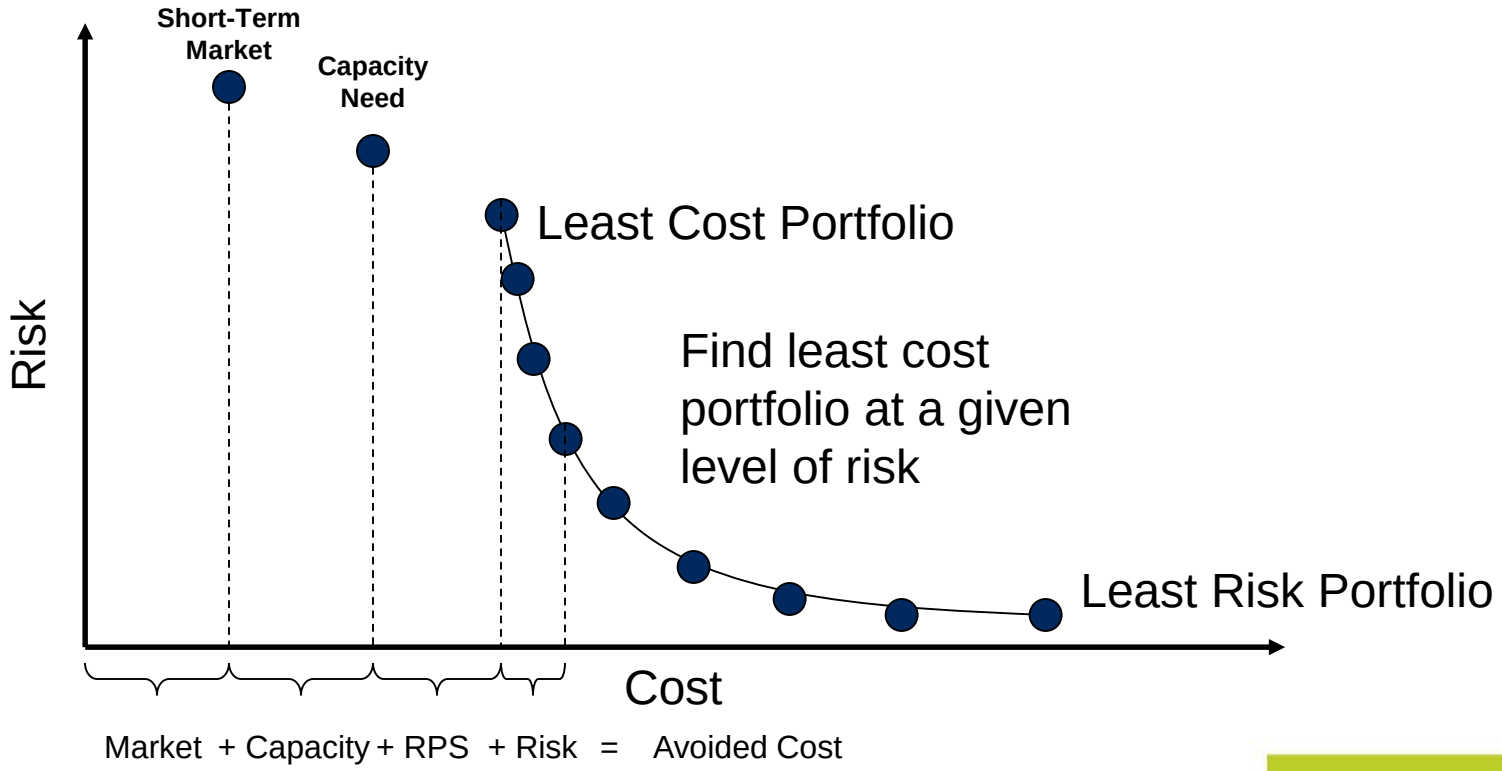
- Does not find the optimal portfolio, only the optimal portfolio for a given level of risk.
- Used in investment finance for portfolio management.

Stock vs. Bond Example



Efficient Frontier

- Demonstrates the trade off of cost and risk
- Avoided Cost Calculation



2019 Electric IRP
Generation Resource Options

James Gall,
Second Technical Advisory Committee Meeting
November 27, 2018

Overview & Considerations

- The assumptions discussed are “today’s” estimates and will likely have periodic revisions.
- Resource costs vary depending on location, equipment, fuel prices, and ownership; while IRPs use point estimates, actual costs will be different.
- Avista retained Black & Veatch to review the renewable and storage resource assumptions as part of the Hydro One merger agreement.
- Certain resources will be modeled as purchase power agreements (PPA) while others will be modeled as Avista “owned”. These assumptions do not mean they are the only means of resource acquisition.
- No transmission or interconnection costs are included at this time.
- Natural gas prices used “today” will be revised with the “final” assumption in January 2019.
- An Excel file will be distributed with all resources, assumptions and cost calculations for TAC members to review and provide feedback.

Proposed Natural Gas Resource Options

Peakers

- Simple Cycle Combustion Turbine (CT)
  - Aero and frame units
  - Smaller units 44 MW to 80 MW
  - Larger units up to 245 MW
- Hybrid CT
  - 92 MW
- Reciprocating Engines
  - 9 MW to 18 MW units with up to 10 engines

Baseload

- Both modern and advanced Combined Cycle CT (CCCT) will be evaluated
  - Smaller options 158 MW to 308 MW (3x2, 1x1)
  - Larger options 324 MW to 480 MW (1x1)
- Large 2x1 technology not modeled

Natural gas turbines are modeled using a 30-year life with Avista ownership

Renewable Resource Options

All Purchase Power Agreement (PPA) Options

Wind

- On-system wind (101 MW)
- Off-system wind (101 MW)
- Montana wind (101 MW)
- Off shore wind (100 MW)
  - Share of a larger project

Solar

- Fixed PV array (5 MW AC)
- On-System Single Axis Tracking Array (100 MW AC)
- Off-system Single Axis Tracking Array (100 MW AC) located in southern PNW
- On-System Single Axis Tracking Array (100 MW AC) with 25 MW 4 hour lithium-ion storage resource

Other “Clean” Resource Options

- Geothermal (20 MW)
  - Off-system PPA
- Biomass (100 MW)
  - i.e. Kettle Falls 3
- Nuclear (100 MW)
  - Off-system PPA share of a larger facility

Storage Technologies

Lithium-Ion

- Assumes: 88% round trip efficiency (RTE), 10-year operating life
- Assumes Avista ownership
- 5 MW Distribution Level
  - 4 hours (20 MWh)
  - 8 hours (40 MWh)
- 25 MW Transmission Level
  - 4 hours (100 MWh)
  - 8 hours (200 MWh)
  - 16 hours (400 MWh)
  - 40 hours (1,000 MWh)

Updates to storage costs are likely as additional information becomes available

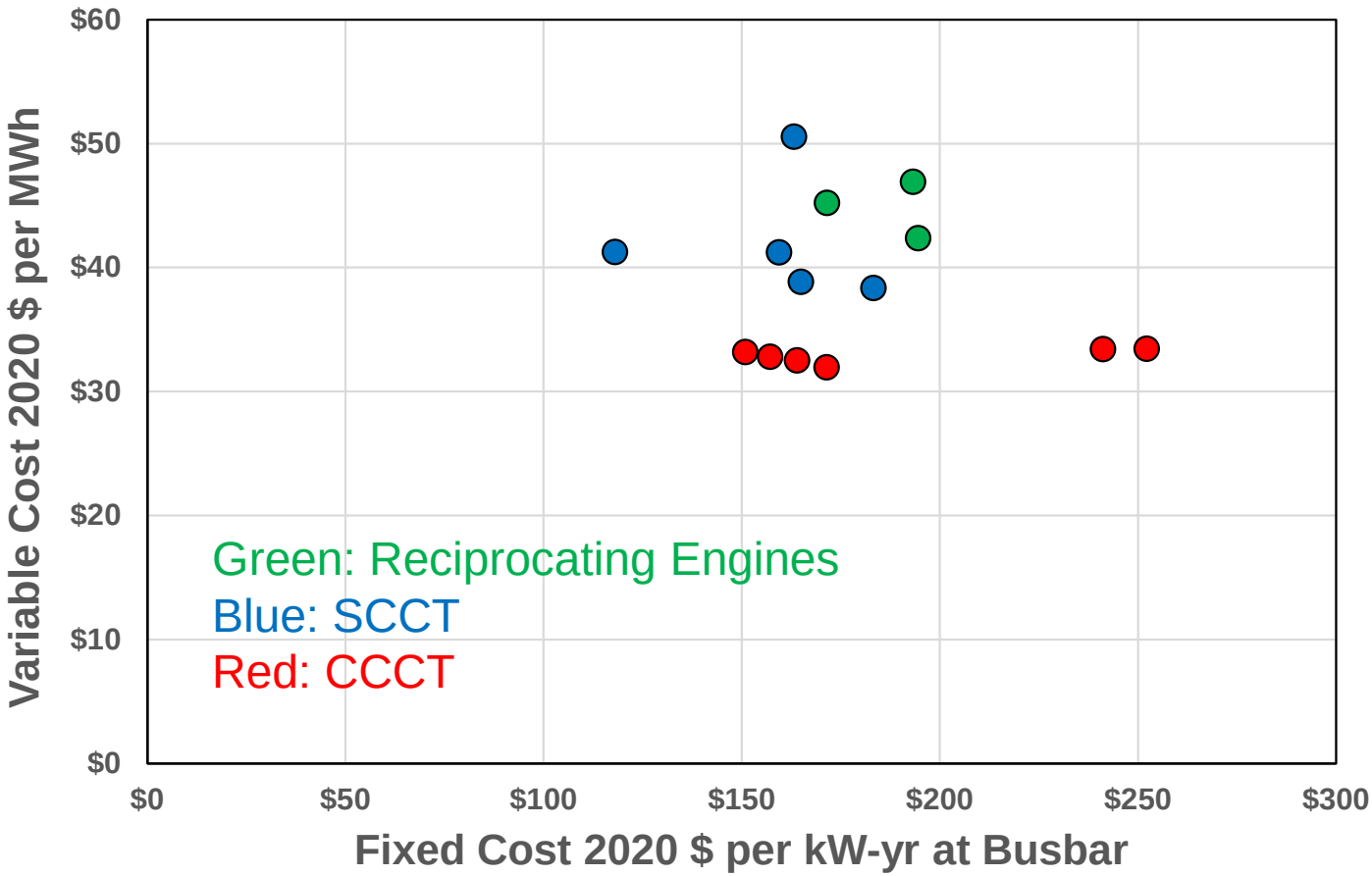
Other Storage Options

- Assumes 20 to 30-year life and Avista ownership
- 25 MW Vanadium Flow (70% RTE)
  - 4 hours (100 MWh)
- 25 MW Zinc Bromide Flow (67% RTE)
  - 4 hours (100 MWh)
- 25 MW Hydrogen Fuel Cell (varies)
  - 4 hours (100 MWh)
  - 16 hours (200 MWh)
  - 40 hours (1,000 MWh)
- 25 MW Liquid Air (65% RTE)
- Liquid Air (retrofit natural gas CT)
  - 12.7 MW (59 MWh)
  - 78 MW (700 MWh)
- 100 MW Pumped Hydro
  - Share of larger project
  - 16 hours of storage
  - PPA assumption

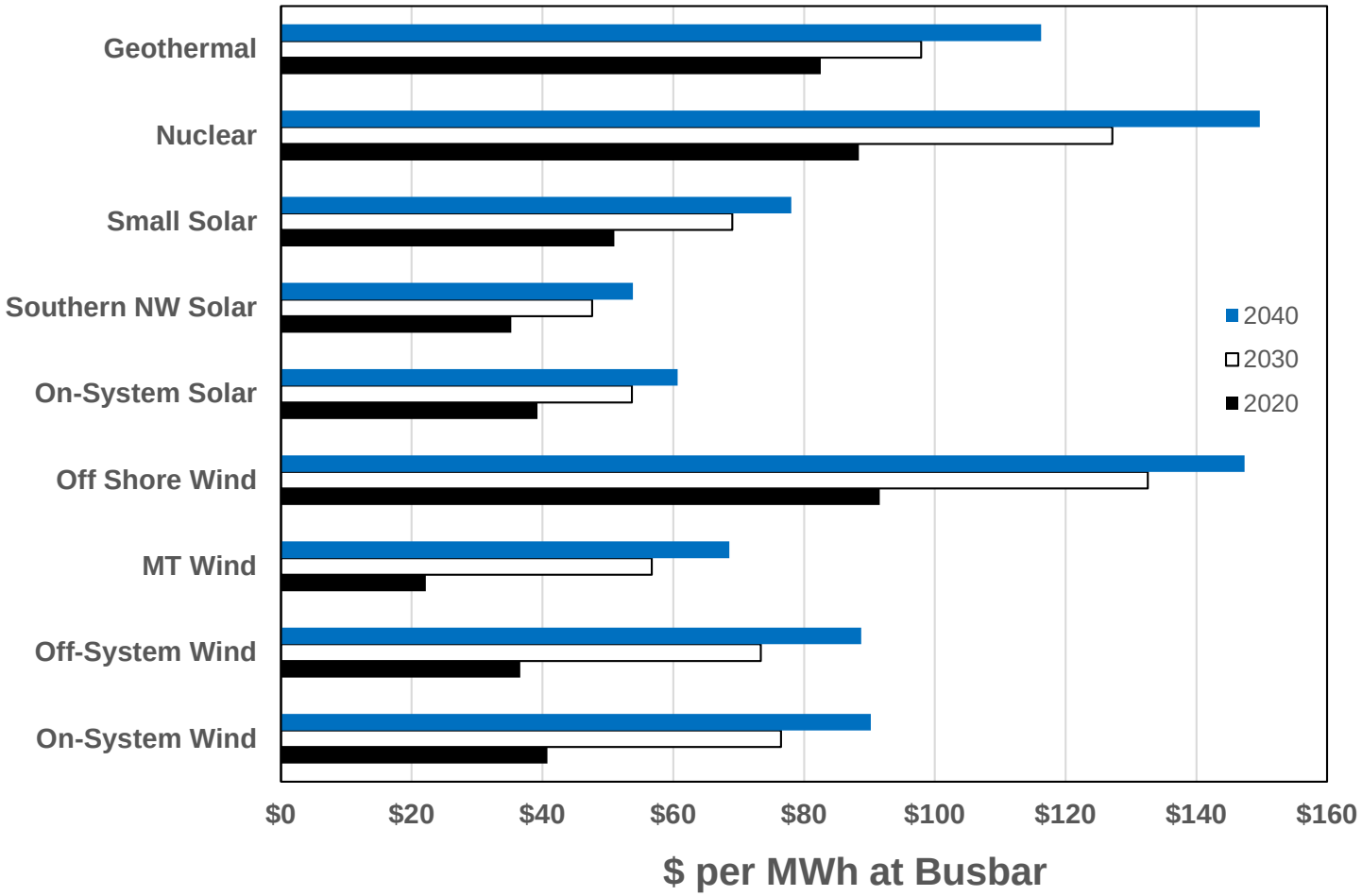
Resource Upgrades

- **Northeast** *[natural gas peaker]*
  - 7.5 MW using water injection
- **Rathdrum CT** *[natural gas peaker]*
  - 5 MW by 2055 uprates
  - 24 MW add supplemental compression
  - 17 MW (summer), 0 MW (winter) Inlet Evaporation
- **Kettle Falls** *[biomass]*
  - 12 MW by repowering with larger turbine during replacement
- **Post Falls Redevelopment** *[hydroelectric]*
  - 8 MW, 4.5 aMW with larger modern units
- **Long Lake 2nd Powerhouse** *[hydroelectric]*
  - 68 MW, 12 aMW with additional powerhouse located at the current "cutoff" dam
- **Monroe Street/Upper Falls** *[hydroelectric]*
  - 80 MW, 27 aMW with additional powerhouse located in Huntington Park
- **Cabinet Gorge** *[hydroelectric]*
  - 110 MW, 18 aMW using the "bypass" tunnels to capture runoff spill

Natural Gas Fixed & Variable Costs



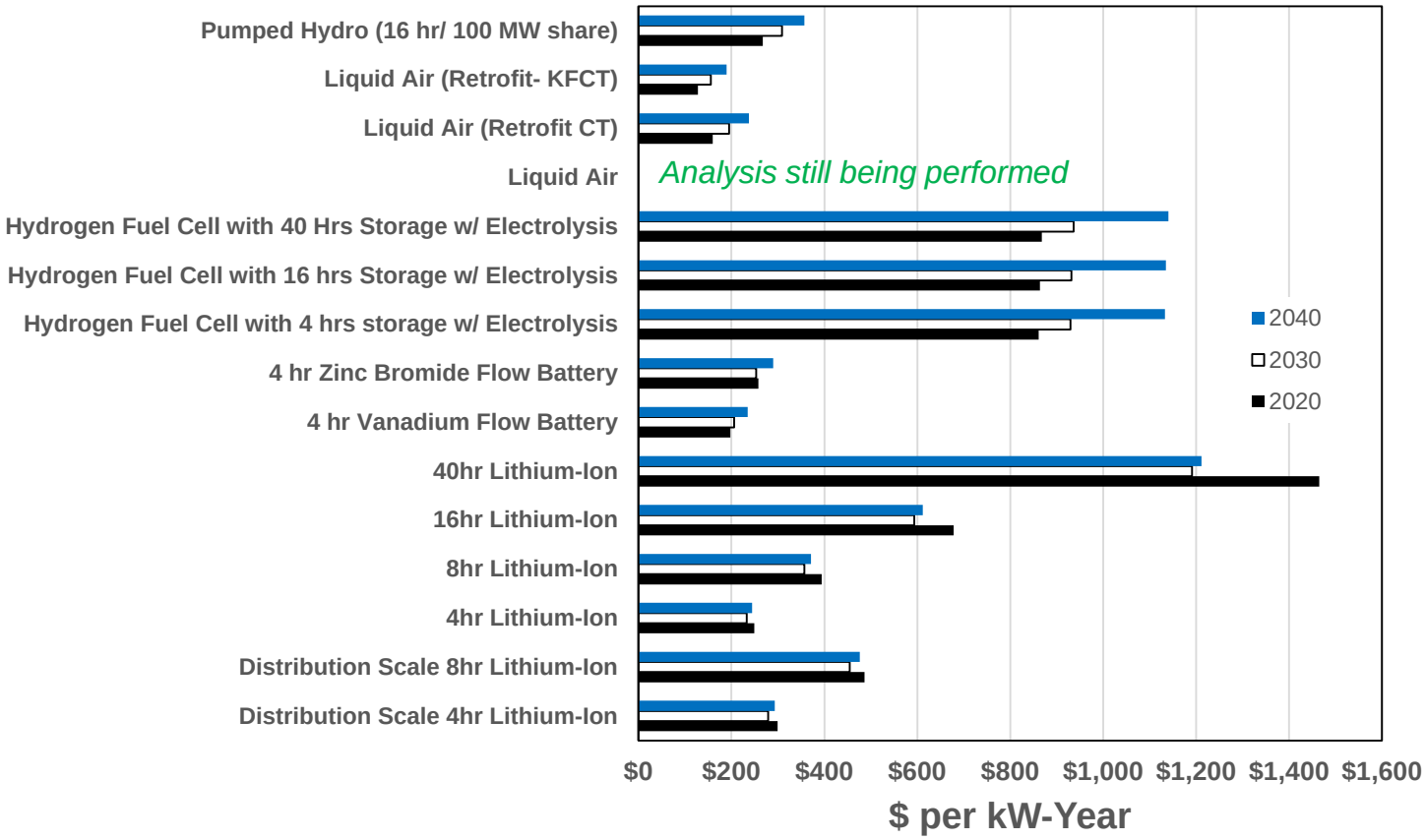
PPA Resource Cost Analysis



Prices include utility loading such as variability integration and revenue taxes

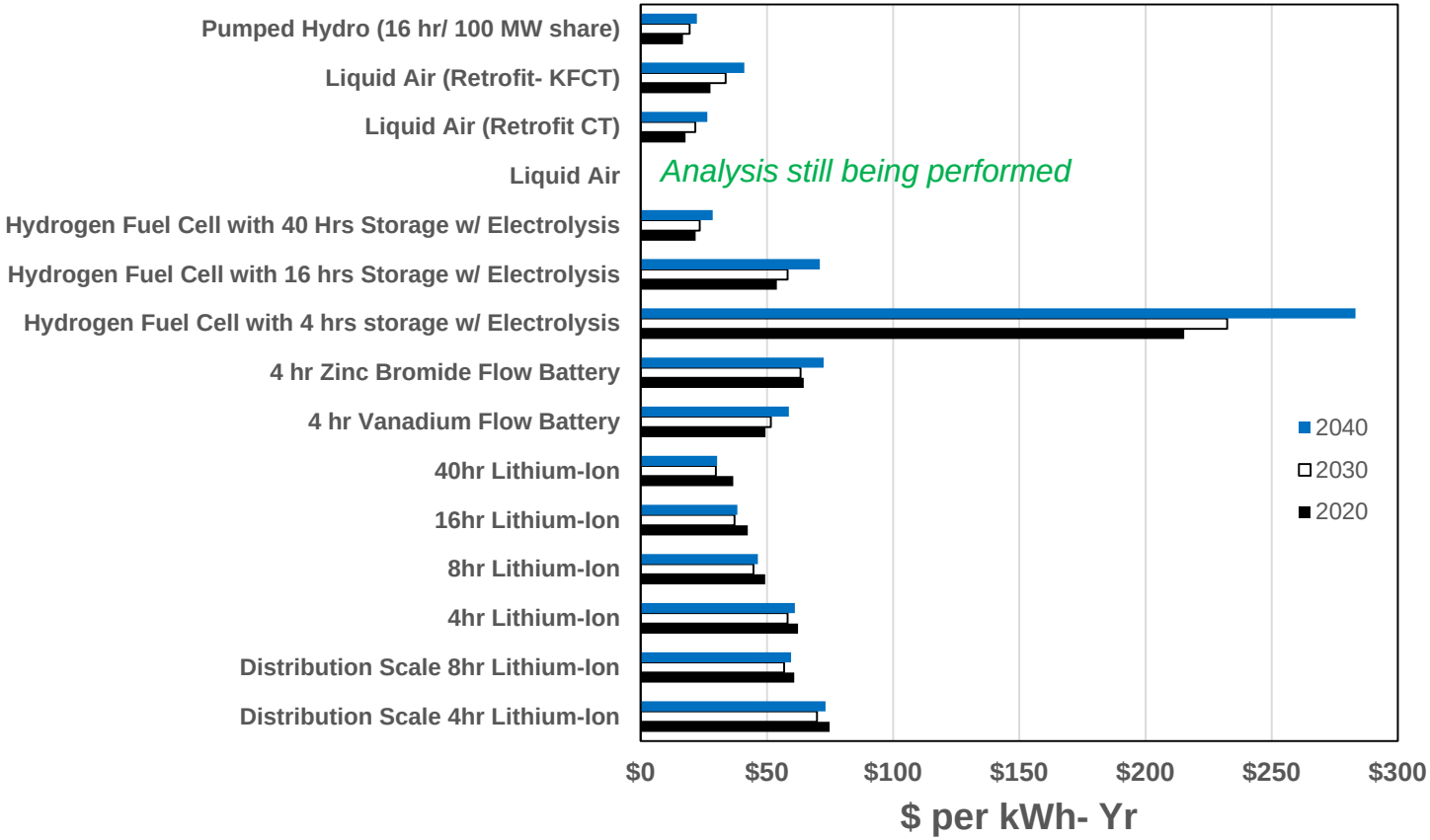
Storage Costs

Capacity based cost analysis

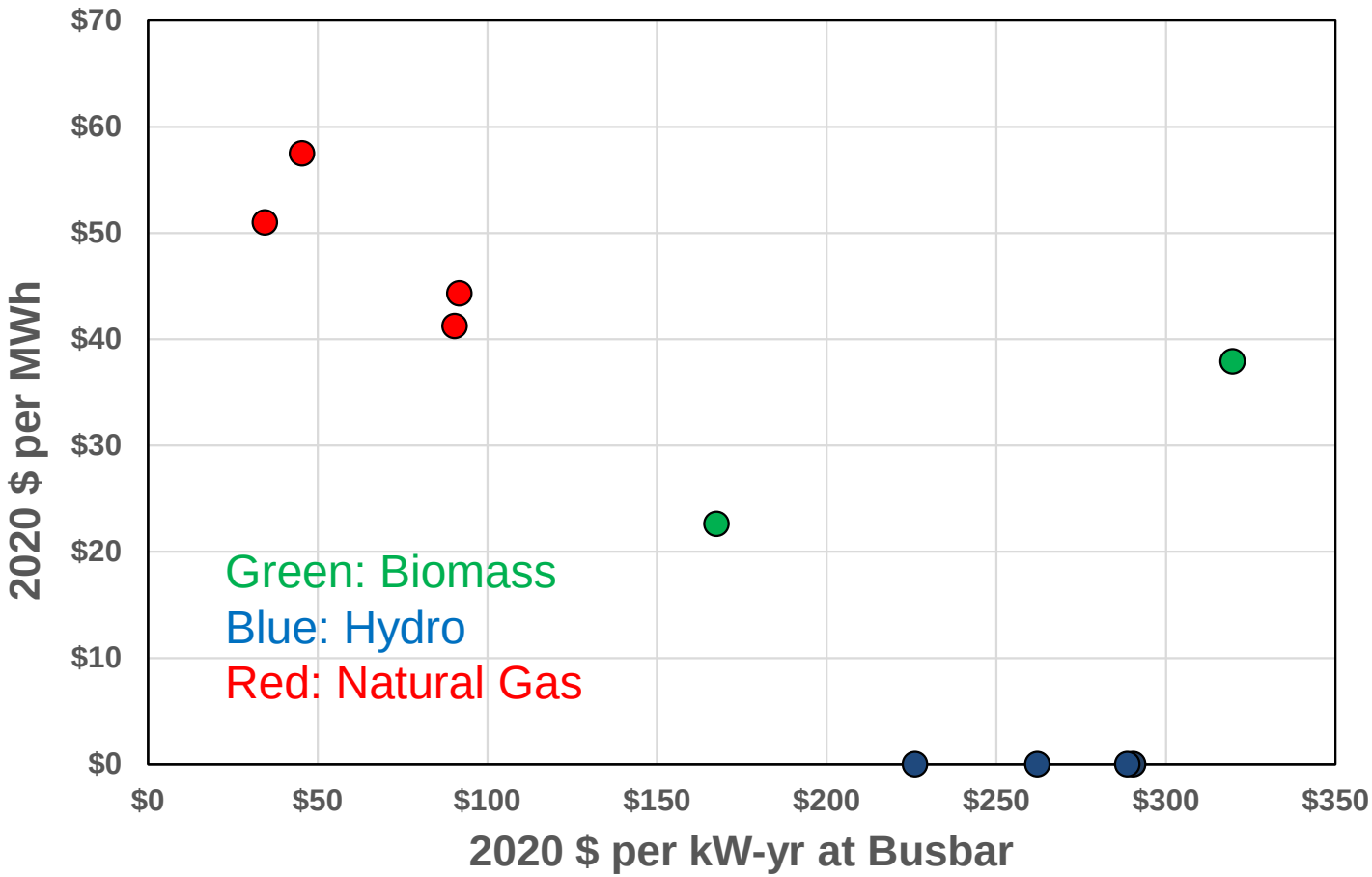


Storage Costs

Energy based cost analysis



Facility Upgrade Cost Analysis



Other Power Purchase Options

- Market Power Purchases
  - Firm purchases
  - Real-time
- Mid-Columbia Hydro
  - Renegotiate slice contracts from Mid-C PUDs
- Acquire existing resources from IPPs
- Renegotiate Lancaster PPA
- BPA
  - Block surplus contract: up to 7-year term at BPA “cost”
  - NR Energy Sales: $78.94 MWh
  - After 2028, other potential options when current Regional Dialog contracts expire

Review Excel Sheet

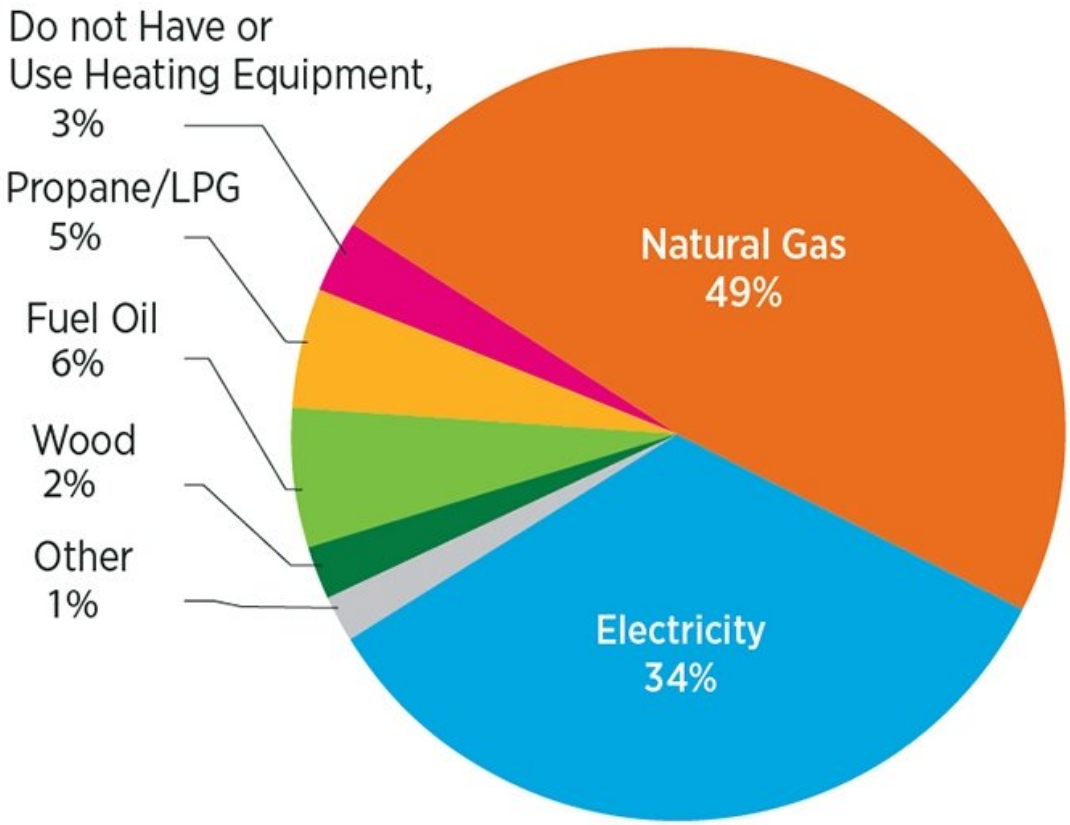
Home Heating Technologies Overview

Tom Lienhard, Chief Energy Efficiency Engineer
Second Technical Advisory Committee Meeting
November 27, 2018

Home Heating Systems

- Delivery method
  - Radiation
  - Convection
  - Forced Convection
- Number of controlled heating segments
- Fuel used for heating the fluid
  - Electricity
  - Natural Gas
  - Other
- Efficiency of fuel delivery
- Heating load of the residence

Home Heating Systems in US



Household Heating Systems: Although several different types of fuels are available to heat our homes, nearly half of use natural gas. | Source: Buildings Energy Data Book 2011

Delivery Method

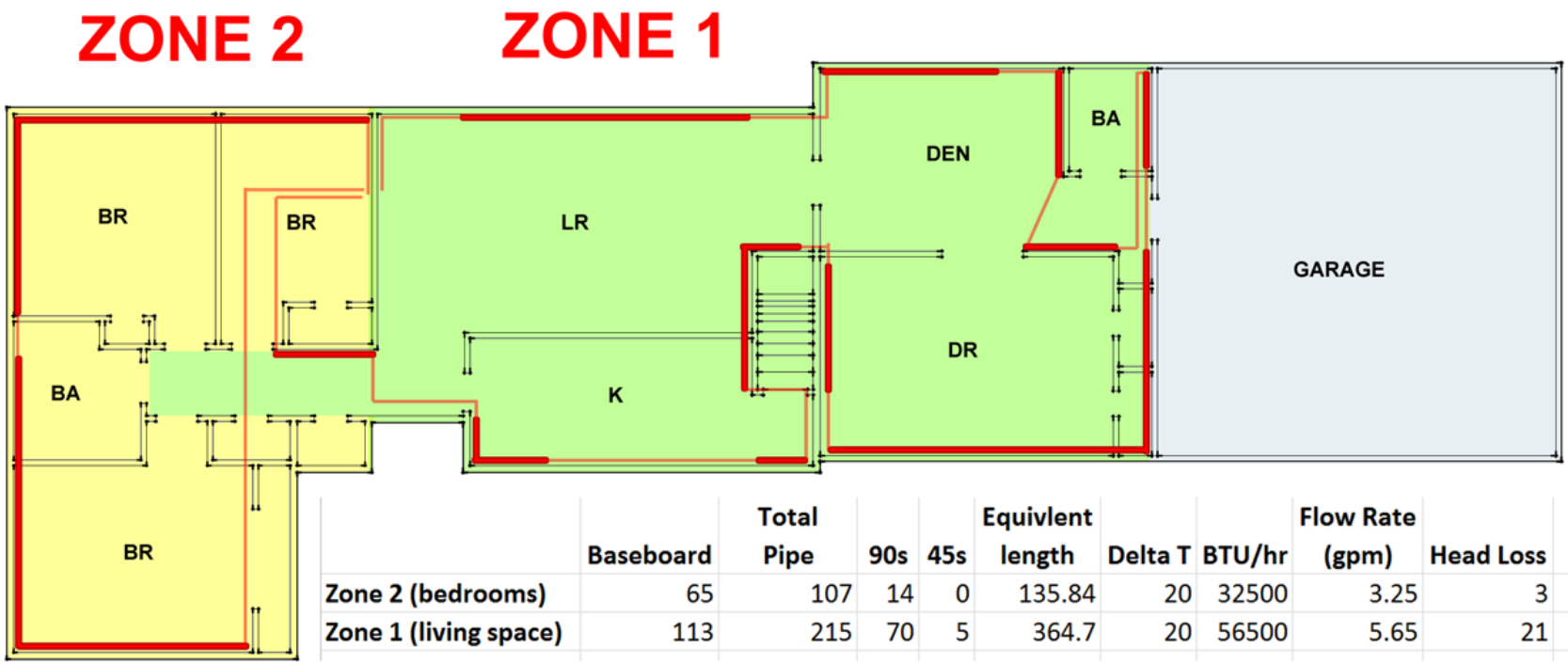
- Radiation – heated by radiant energy. Radiant floor heating can use 40% of the energy of convective heating systems.
- Baseboard or fluid registers on the outer portions of the home cause natural convection.
- Furnaces and fans in heaters create forced convection.

Zoning

- Increasing number of controlled zones decreases amount of heat needed. When two or more areas can be kept at different temperatures based on need or occupancy, savings may occur.

- Home furnaces controlled by single thermostat cannot benefit from zoning. Attempts to zone a forced air system often reduce heating efficiency and have a greater impact on air source heat pumps.

Zoning



	Baseboard	Total Pipe	90s	45s	Equivlent length	Delta T	BTU/hr	Flow Rate (gpm)	Head Loss
Zone 2 (bedrooms)	65	107	14	0	135.84	20	32500	3.25	3
Zone 1 (living space)	113	215	70	5	364.7	20	56500	5.65	21

Fuel Used to Heat the Transfer Fluid

- Radiant surfaces can be fueled by any source.
  - Electric use electric resistance coils.
  - Transfer liquids can be heated by electricity, natural gas or any other fuel.
- Forced and natural convection systems can be fueled by natural gas, electric elements, heat pump, wood, or any other fuel.
- Low carbon future could use dual fuel sources.

Fuel Delivery Efficiency

- Natural gas limited to 98% efficiency when exhausting combustion product outside. Natural gas heat pumps with a coefficient of performance (COP) around 1.5 under development.

- Electricity has a low threshold of 100% efficient with resistive electric, although an air source heat pump backed by resistance can operate below 100% during defrost and low temperatures. Electric heat pumps can approach an annual COP of 4, depending on outside temperature, soil type and heat pump type.

Fuel Delivery Efficiency– cont.

- Ground source heat pump
  - Highest performing units
  - Utilize stored energy of the sun in the earth to transfer heat

- Highest performing air source heat pumps are ductless units
  - Perfectly coupled between interior and exterior units.
  - CO_2 heat pumps being tested in the US do not have the exterior temperature issues that other air source heat pumps have with efficiency degradation due to cold weather (NW CO_2 Pilots)

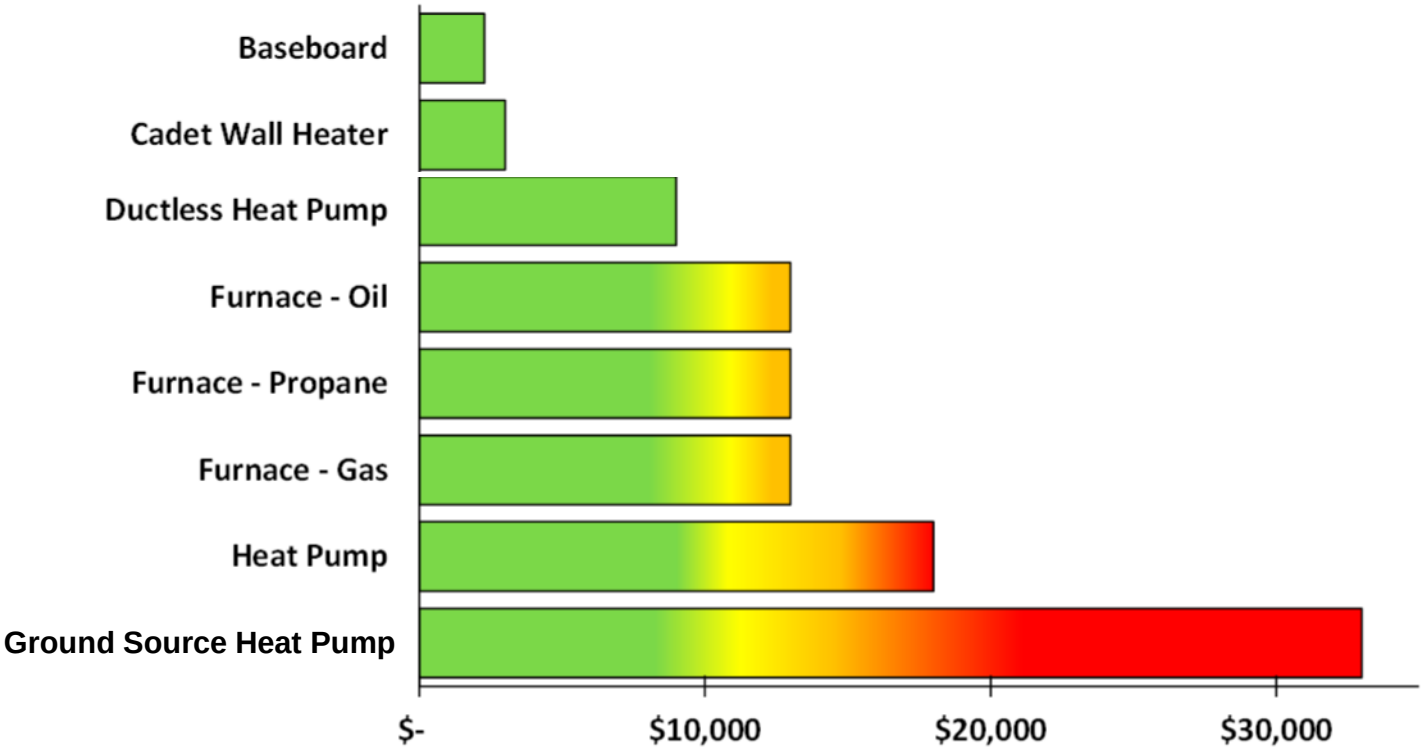
Fuel Delivery Efficiency – cont.

- Lowest efficiency fuel is wood
  - An average of 50% of the heat makes it into the space.
  - If the damper is left open on a chimney flue, the house will evacuate the heat inside after the fire goes out through the stack affect.
  - One of the best home audit measures is to plug the flue of unused fireplaces to reduce lost heat.

First Cost of Technologies

- Ground source heat pumps add $10,000 to $20,000 to a home budget if feasible.
- In-floor radiant systems add $10,000 to $15,000 to normal forced air system in new construction.
- Full home multi-head zoned ductless units can be $10,000 to $30,000 above baseline natural gas systems.

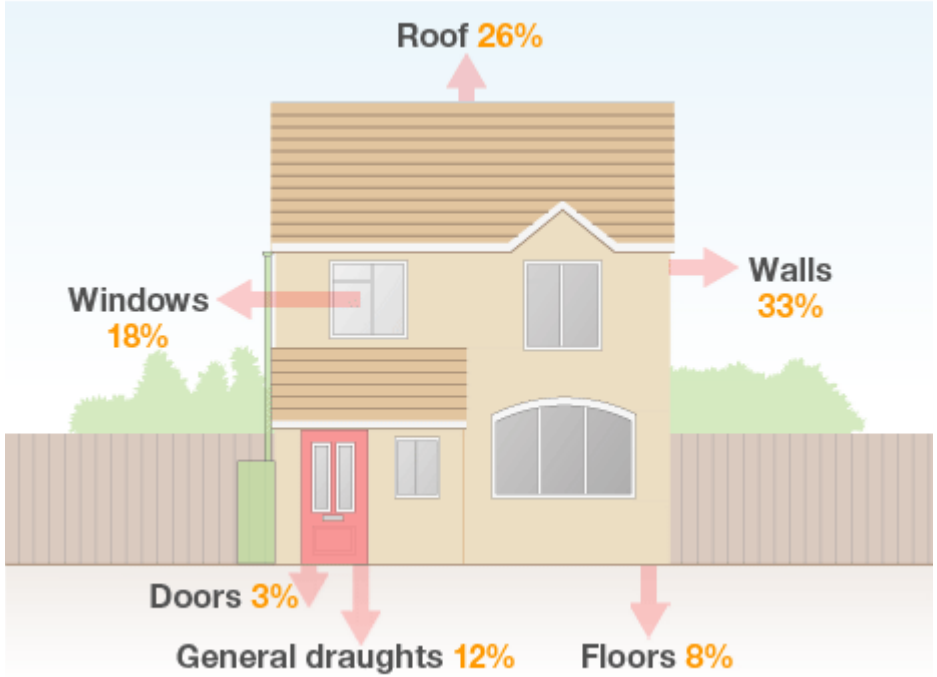
First Costs


Baseboard
Cadet Wall Heater
Ductless Heat Pump
Furnace - Oil
Furnace - Propane
Furnace - Gas
Heat Pump
Ground Source Heat Pump
$-
$10,000
$20,000
$30,000

Home Heating Needed

- **Size:** smaller is better
- **Insulation:** more is better
- **Location and installation of ductwork:** inside is better
- **Infiltration:** none is better, need Energy Recovery Ventilator
- **Number of people:** more is better
- **Humidity:** some is better than none

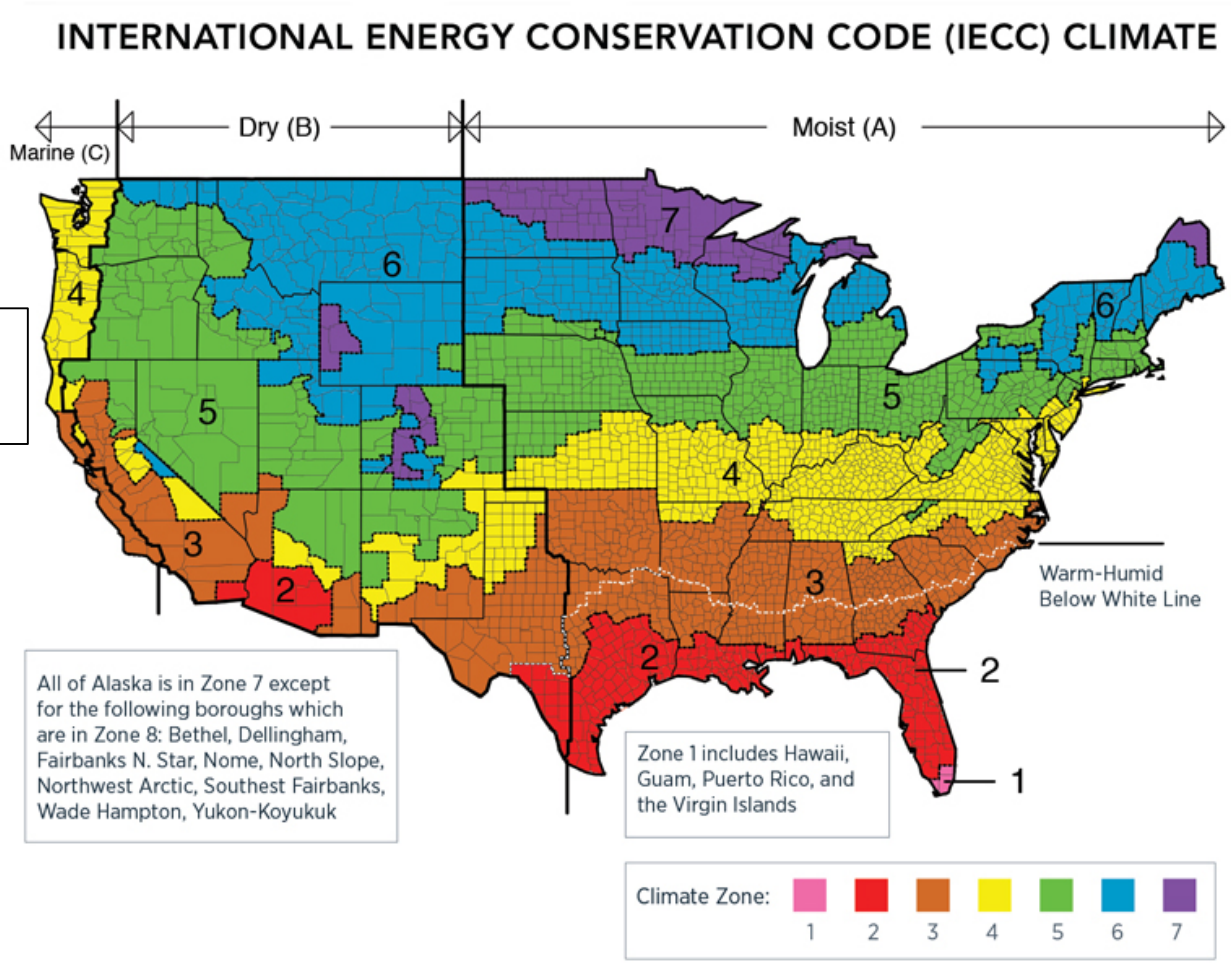
Home Heat Loss



Source: Energy Saving Trust

Climate Zones

RTF identifies zones 4, 5 & 6 zones 1, 2 & 3



https://basc.pnnl.gov/images/iecc-climate-zone-map

Home Heat Loss Calculation

- Most loss from conduction through envelope and infiltration/exfiltration through cracks.

- $E_L = UA(T_{in}-T_{out})$
  - U is thermal conductivity,
  - A is the surface area of the home, and
  - T_{in} is temperature inside and T_{out} temperature outside

- 1,000 ft^2 home with 8 foot ceilings has an area of 3,760 ft^2. If the average R value is 25, it has a U factor of .04 BTU/hr*ft^2*F.

Cost of Heat Loss – Example

- If average outdoor temperature during the heating season is 42° and the set point is 72°, then the hourly heat loss is 4,512 BTU/hour
  - .04*3,760*30 = 4,512 BTUs or 3,248,640 BTU's per month. That is 951 kWh with electric resistance heat, about 560 kWh with an air source heat pump, and about 33 therms.
- At Avista's current rates, losses would be $95 for resistance heat, $56 for a heat pump, and $30 for natural gas.
- This is for a very small home with very good insulation in Northwest climate zone 4 ignoring heat gain from humans or solar.

Heating Degree Days (HDD)

- Difference between 65° and outside temperature measured in days.
- 6,800 HDD: Spokane average of a 38° difference between 65° and outside over 6 month heating season.
- 4,700 HDD: Seattle average of a 29° difference between 65° and outside over 6 month heating season.
- Heat pumps operate in their wheelhouse in Seattle and below optimum in Spokane.

Fuel Cost

- Natural Gas heat is 1/3 the cost per BTU compared to electricity.
  - The average electric home costs more to operate than a natural gas home in climate zones 2 and 3 at Avista's current gas and electric prices.
- Avista's electric peak often occurs at the coldest point in December, so electric homes highest consumption coincides with our highest load.
  - This includes net zero homes which don't produce during our winter peak.

Questions

Resource Adequacy and Effective Load Carrying Capability

James Gall, IRP Manager

Second Technical Advisory Committee Meeting

November 27, 2018

Why Does Resource Adequacy Matter?

- Helps determine how much new capacity our customers need.
- Informs “us” how much capacity we rely on from our neighbors.
- Provides insight on how certain resource help provide reliable capacity.

We discovered this type of analysis requires a lot of process time, specific locational assumptions for renewable resources, and is an “art” rather than a specific science.

Loss of Load Probability (LOLP)

- LOLP is the current regional measurement for resource adequacy.
- Measures probability of a resource adequacy deficiency over a one year time period.
- No regulatory body enforces a particular resource adequacy standard or metric.
- This is a great measure of probability of reliability, but…according to the NPCC…
  - *"No measure of magnitude*
  - *No measure of duration*
  - *No measure of frequency within the year*
  - *Two scenarios with same LOLP can have vastly different curtailment magnitude and duration"*

Reliability Metrics Options

What we are modeling for?

- Events not serving all load and reserve requirements due to insufficient resources/market availability

Metrics

- LOLP: Loss of Load Probability
  - Number of draws with an event (probability of a draw with an event)
- LOLH: Loss of Load Hours
  - Hours with events / iterations (time in hours)
- LOLE: Loss of Load Events
  - Days with events / iterations (time in days)
- EUE: Expected Unserved Energy
  - Average MWh not served during an event (Magnitude)
- ELCC: Effective Load Carrying Capability
  - Percentage of resource capacity equal to CTs

Model Assumptions & Challenges

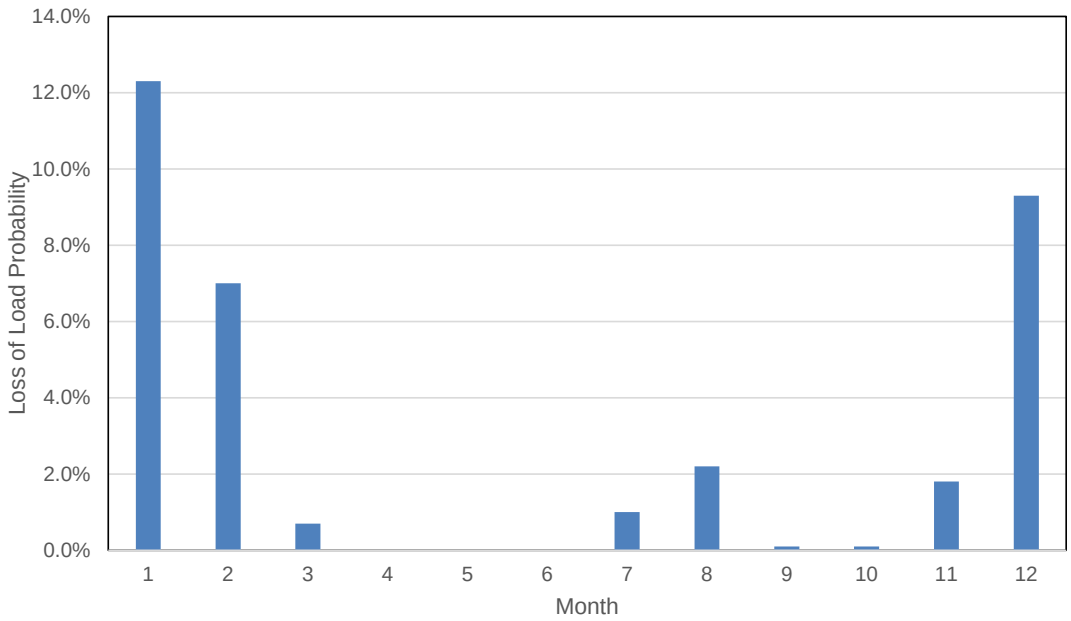
The Model

- Built in Excel with What's Best optimizer
- 1,000 simulations
- Randomizes:
  - Forced outages
  - 80 years of hydro data
  - 128 years of weather data (load & generation)
- Challenges:
  - Time: three days to run per study, to date over 70 studies since April have been completed.
  - Randomization: may not get same results with same assumptions.
  - This is becoming more of an "art" then a "science"

The Key Assumptions

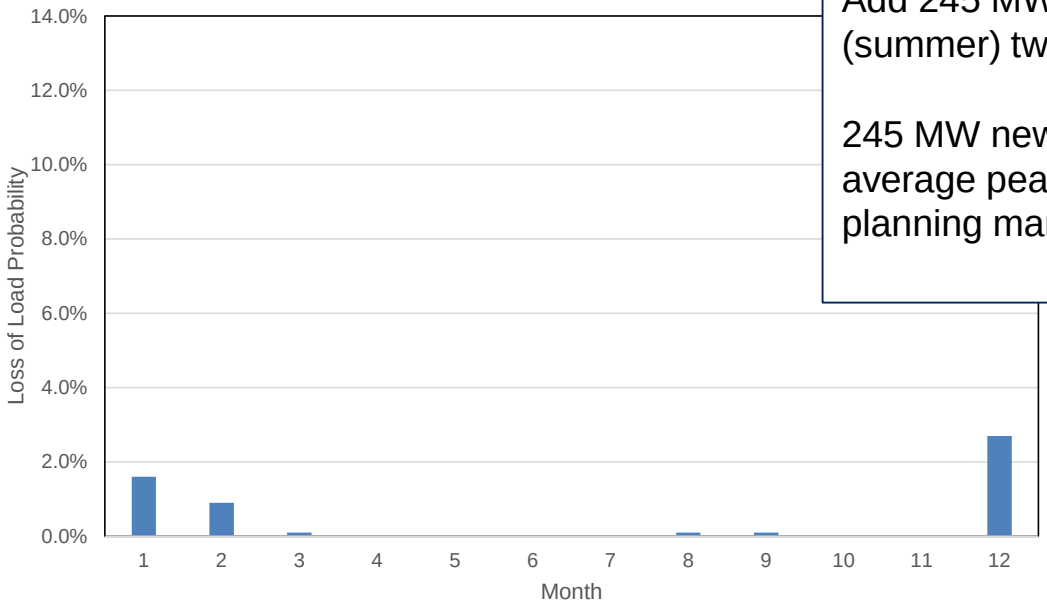
- 2030 load and resources
- Average peak load: 1,778 MW (Winter), 1,636 MW (Summer)
- Average hourly load: 1,081 MW
- Major resource changes from today: No Lancaster, less Mid-C, no WNP-3 contract
- Off-peak market purchases limited to 1,000 MW
- On-peak market purchase limited to 400 MW
- When daily temps > 84 and < 4 degrees Fahrenheit, market purchases are limited 250 MW

Without resource additions, what is our reliability metrics in 2030?



- LOLP: 27.9%
- LOLH: 18.29
- LOLE: 1.41
- EUE: 3,430 MWh

How much capacity is required to be at 5% LOLP?

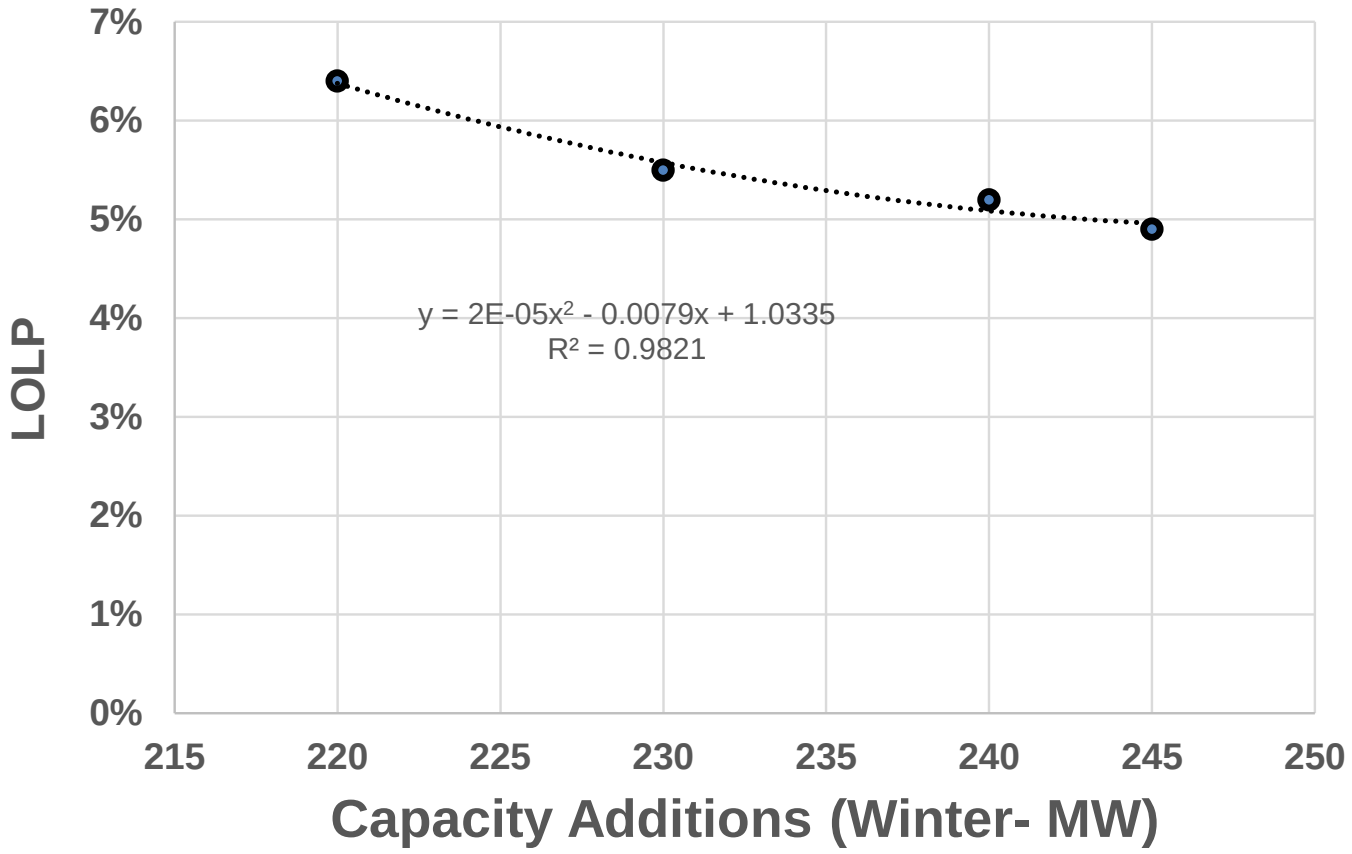


Add 245 MW (winter) / 182 MW (summer) two unit CT

245 MW new gen / 1,778 MW average peak load = 13.8% planning margin

- LOLP: 4.9%
- LOLH: 1.85
- LOLE: 0.16
- EUE: 318.7 MWh

LOLP at Different Levels of Capacity Additions



Does Wind Improve Reliability?

- Wind can improve reliability, but not equal to a CT
- Location diversification improves capacity credit!
- Studies to date include two studies:
  - Case 1: NW Wind
  - Case 2: Montana Wind

Case 1: NW Wind

- 1st study: exclude Palouse Wind

Case	LOLP	LOLH	LOLE	EUE
Reference case	4.9%	1.85	0.16	319
Palouse Wind excluded	5.5%	1.86	0.17	307

- 2nd study: decrease CTs by 25 MW and add more wind until 5% LOLP is achieved

Case	LOLP	LOLH	LOLE	EUE
Reference case	4.9%	1.85	0.16	319
Reference case -25 MW CT	6.4%	2.16	0.20	359
+ 300 MW wind	5.5%	1.80	0.15	296
+ 400 MW wind	5.5%	1.72	0.14	256
+ 500 MW wind	5.4%	1.70	0.14	280
Reference case -15 MW CT	5.5%	1.93	0.17	319

1) 5% LOLP never achieved
2) other metrics improve with more wind
3) Suggest ELCC for NW wind: 15/300= 5%

- Concerns:
  - How will other NW projects with less correlation to Palouse change this result?

Case 2: Montana Wind

- Reduce CTs by 25 MW, add wind until 5% LOLP is maintained

Case	LOLP	LOLH	LOLE	EUE
Reference case	4.9%	1.85	0.16	319
Reference case -25 MW CT	6.4%	2.16	0.20	359
+ 60 MW MT wind	4.9%	1.49	0.13	249
+ 70 MW MT wind	4.9%	1.39	0.12	203
+ 100 MW MT wind	4.1%	1.18	0.10	205

ELCC for MT Wind: 25/60= 42%

- Concerns:
  - Low temperature cut outs, wind turbines must curtail when temperatures are below -30 Celsius (-22 F)
  - All Montana wind regimes may not be the same
  - Earlier analysis showed 30% capacity contribution with alternate data
  - Avista needs to perform more studies including larger reduction in capacity deficit positions

Does Solar Improve Reliability?

- Solar studies are performed similar to wind, but use an earlier version of the model
- CT reductions:
  - 76 MW Winter
  - 56 MW Summer
- Never get to 5% LOLP!
- Summer LOLP reduces to zero in high cases
- Conducted a new reference case with 20 MW less CT winter capacity to arrive at a 5.8% LOLP
- ELCC is 2.2% (20 / 900)

Case	LOLP	LOLH	LOLE	EUE
Reference	5.0%	1.75	0.15	254
Reference – 76 MW CTs	9.4%	3.73	0.30	689
300 MW	7.8%	2.71	0.22	440
600 MW	7.6%	2.29	0.21	353
900 MW	5.8%	2.14	0.18	350
Reference – 20 MW CT	5.8%	1.75	0.17	327

Does Demand Response (DR) Improve Reliability?

- Demand response temporarily reduces load for a period of time
- Studied three scenarios compared to “CT” reference case
  - 25 MW, 4 hour reduction up to 10 times per year
  - 25 MW, 8 hour reduction up to 10 times per year
  - 25 MW, 16 hour reduction up to 10 times per year

Case	LOLP	LOLH	LOLE	EUE
Reference case	4.9%	1.85	0.16	319
Reference case -25 MW CT	6.4%	2.16	0.20	359
4 hour duration	6.1%	1.99	0.18	338
8 hour duration	5.7%	1.87	0.16	316
16 hour duration	5.6%	1.67	0.15	282
Reference case -15 MW CT	5.5%	1.93	0.17	319

  - Proposed ELCC:
    - 4 hour: 8% (2 MW / 25 MW)
    - 8 hour: 60% (15 MW / 25 MW)
    - 16 hour: 64% (16 MW / 25 MW)

Does Storage Improve Reliability?

- Storage moves energy, but doesn't create energy!
  - Storage can lose 10% to 50% of the energy it stores
  - Study assumes 90% round trip efficiency (i.e. Lithium-ion technology)
  - Storage requires the ability to add additional energy to the system from another source to add significant capacity value
  - Higher storage penetration may lead to less capacity contribution

Storage Results

Case	LOLP	LOLH	LOLE	EUE
Reference case	4.9%	1.85	0.16	319
Reference case -25 MW CT	6.4%	2.16	0.20	359
25 MW, 4 hour storage	5.8%	2.13	0.19	352
25 MW, 16 hour storage	5.7%	2.04	0.17	315
25 MW, 40 hour storage	5.6%	1.92	0.17	387
25 MW, 4 hour storage, w/ 50 MW solar	5.6%	1.96	0.18	330
50 MW, 4 hour storage, w/ 50 MW Solar	5.3%	1.95	0.17	302
50 MW, 4 hour storage, w/ 100 MW Solar	5.2%	2.23	0.19	379

Avista proposes to use the following capacity credits for low capacity additions
4 hour: 56% (14 MW / 25 MW)
16 hour: 52% (13 MW / 25 MW)
40 hour: 48% (12 MW / 25 MW)

A third party analysis estimates 10% capacity credit results without new energy resources. With new energy resources its between 12% and 60%

Resource Combination Analysis

What if we remove new “CTs” and planned our system with non-traditional resources

Case	LOLP	LOLH	LOLE	EUE
No new resources	27.9%	18.3	1.41	3,430
Reference case (add 245 MW CT)	4.9%	1.85	0.16	319
Add: 200 MW MT wind, 155 MW NW wind, 50 MW DR, 125 MW 6 hour storage, and 250 MW solar	6.3%	2.43	0.20	429
Add: 200 MW MT wind, 245 MW NW wind, 50 MW DR, 150 MW 6 hour storage, and 350 MW solar	4.8%	2.40	0.17	487
Exclude Colstrip from portfolio & no new resources	75.8%	106.8	8.43	21,265
Add: 400 MW MT wind, 400 MW NW wind, 100 MW DR, 200 MW 6 hour storage, and 500 MW solar	13.2%	5.46	0.45	1,174

Third Party ELCC Analysis

Slides not included at this time for distribution or webcast

2019 Electric IRP Key Assumptions

James Gall, IRP Manager
John Lyons, Senior Resource Policy Analyst
Second Technical Advisory Committee Meeting
November 27, 2018

Existing Forms of Carbon Regulation

- Indirect: Renewable resource additions, higher RPS
- Carbon tax: British Columbia
- Direct regulation: Affordable Clean Energy Rule
- Cap and trade: AB 32 in California
- State mandates: Oregon SB 1547 and emissions performance standards

Renewables

- Renewables drive emissions lower, but may be indirect to the location of the renewable generation's location
- RPS standards in each state (large utility goals shown below)
  - WA: 15% by 2020 (100% clean proposals)
  - OR: 50% goal by 2040
  - CA: 45% by 2023, 50% by 2026, 60% goal by end of 2030, and 100% by 2045 (SB 100)
  - NV: 25% by 2025 (50% by 2030, needs another yes vote in 2020)
  - AZ: 15% by 2025 (50% by 2035 failed in Nov. election)
  - NM: 20% by 2020
  - CO: 30% by 2020 (Higher proposals expected)
  - MT: 15%
- Consumer Driven Renewables
  - Rooftop solar
  - Large commercial direct investment
  - Green tariffs (jurisdictional and organizational)

Direct Regulation

Washington SB 6001- Emissions performance standard limits "baseload" generation to 930 lbs of CO_2 per MWh for new resources or contracts five years or longer

Affordable Clean Energy Rule (ACE) – August 2018 replacement proposal for the Clean Power Plan

1. Defines the "best system of emission reduction" (BSER) for existing plants as on-site, heat-rate efficiency improvements;
2. Provides "candidate technologies" for states to establish standards of performance for their plans;
3. Updates the New Source Review (NSR) permitting program to encourage efficiency improvements at existing plants; and
4. Aligns regulations under CAA section 111(d) to give states time and flexibility to develop their own plans.

Carbon Regulation and Taxes

- AB 32 in California
  - 1990 levels by 2020 and 80% below 1990 levels by 2050
  - Typically modeled as a “price” adder due to economy-wide trading system, using minimum price
- Oregon
  - Coal to Clean: coal can no longer serve Oregon loads after 2030/2035
  - Cap and trade program expectations in next legislative session
- Washington 100% Clean Proposals
- Affordable Clean Energy Rule
- Canadian Carbon Taxes
  - British Columbia: $30/metric ton (Can$)
  - Alberta: $30/metric ton (Can$)

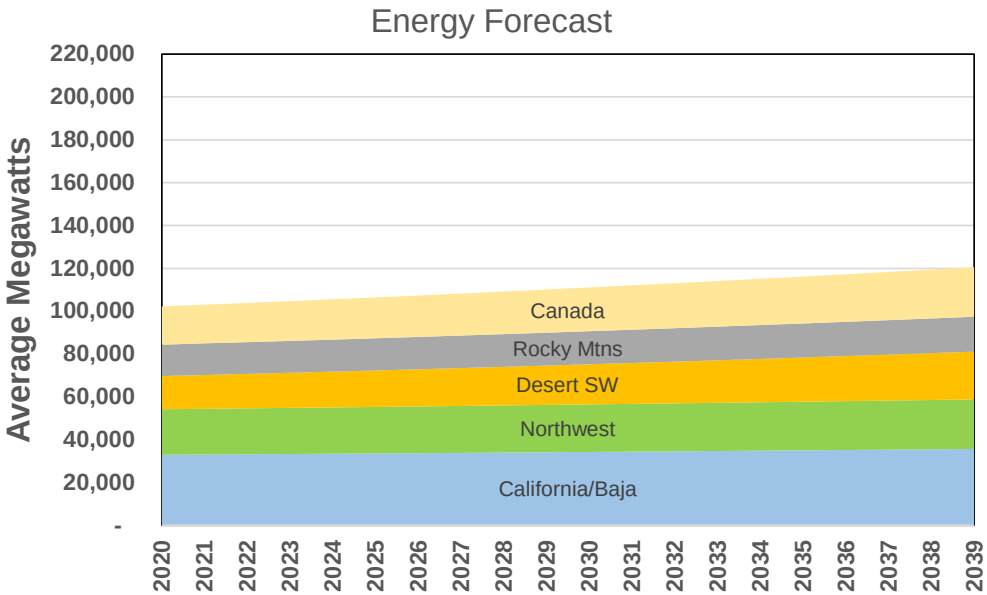
Aurora Inputs

- Regional loads
- Fuel prices
- Hydro levels
- Wind variation
- Environmental constraints
- Resource availability
- Transmission

Regional Loads

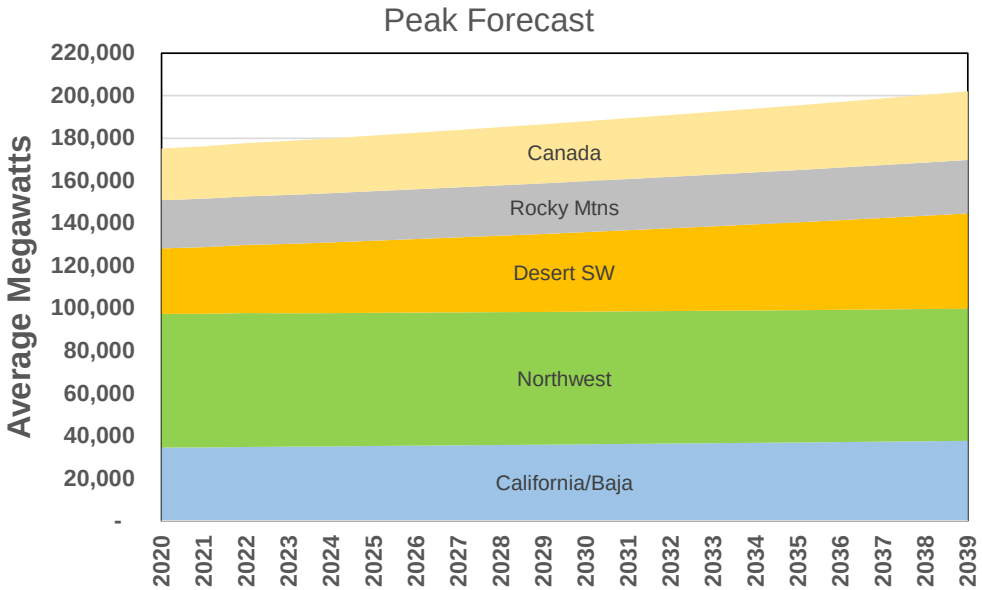
- Forecast load growth for all Western Interconnect regions
- Consider both peak and energy growth
- Use latest load forecast from Epis
- Stochastic modeling simulates load changes due to weather and considers regional correlation of weather patterns
- Economically driven load changes are difficult to quantify and are usually picked up as IRPs are published
- Peak load is increasingly more difficult to quantify as “Demand Response” programs may cause data integrity issues
- Energy demand forecasts need to be net of conservation, electric vehicle forecasts, and behind the meter generation

Energy & Peak Forecast



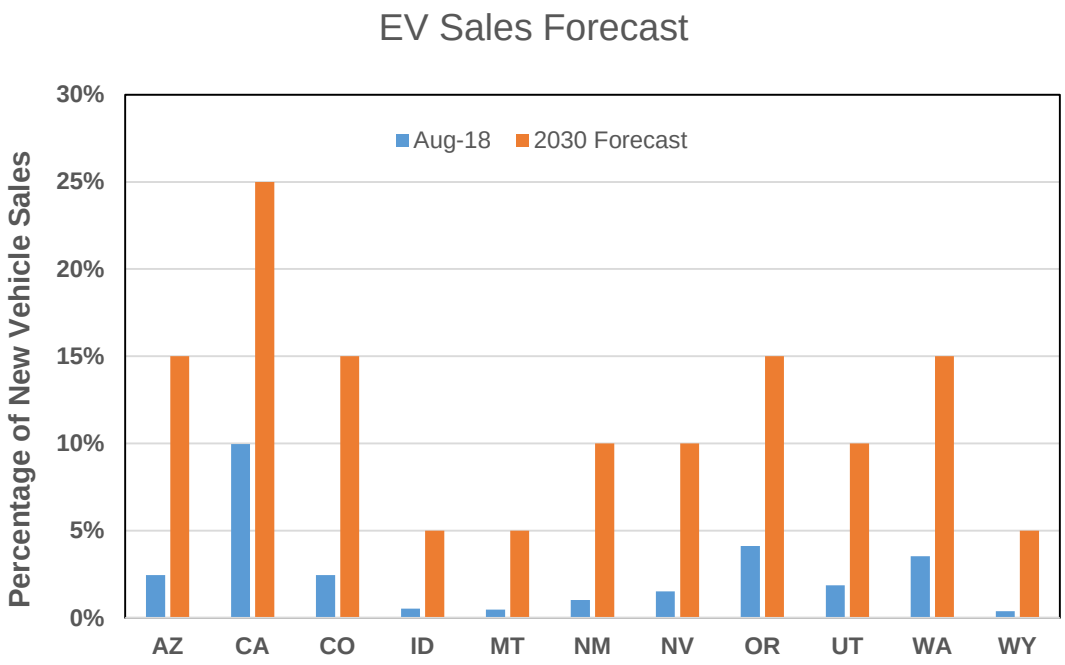
Energy	AAGR	Change
Canada	1.32%	↓
Rocky Mtns.	0.53%	↑
Desert SW	1.84%	↑
California	0.40%	↑
Northwest	0.42%	↓
Total	0.83%	↓

Peak	AAGR	Change
Canada	1.44%	↓
Rocky Mtns.	0.52%	↑
Desert SW	1.89%	↑
California	-0.06%	↓
Northwest	0.44%	↓
Total	0.72%	↓



Electric Vehicles (EV)

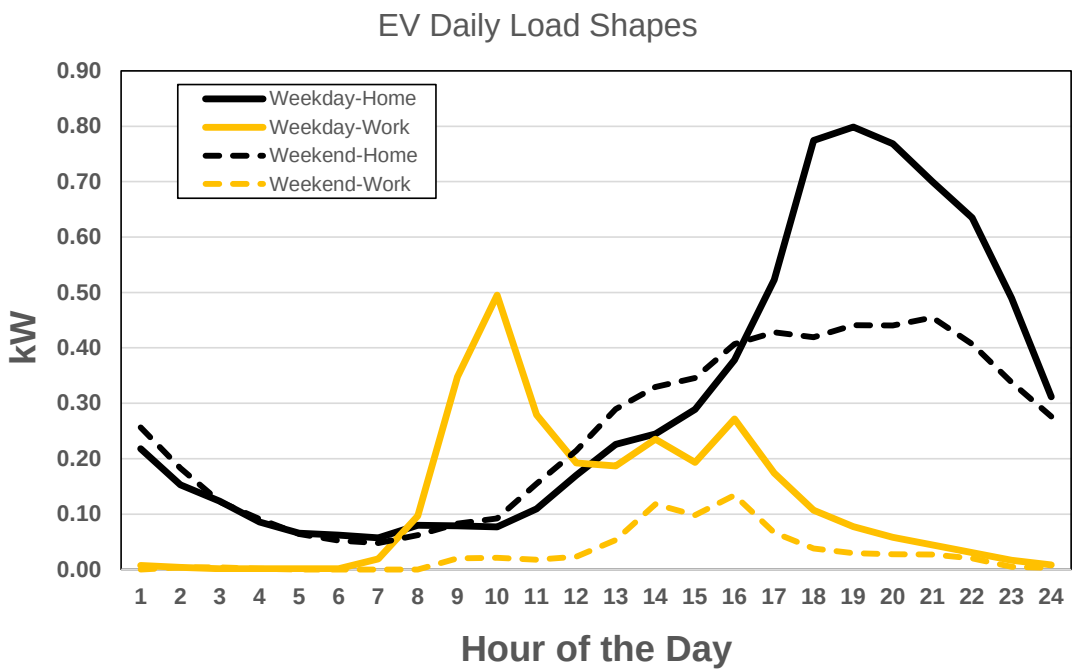
- Current load shapes have low EV penetration, but by 2030, load shapes will differ due to EV and behind the meter solar
- EV percentage of new vehicle sales forecast by 2030
- After 2030, EV growth equals traditional vehicle growth (half of population growth)



http://evadoption.com/ev-market-share/ev-market-share-state/

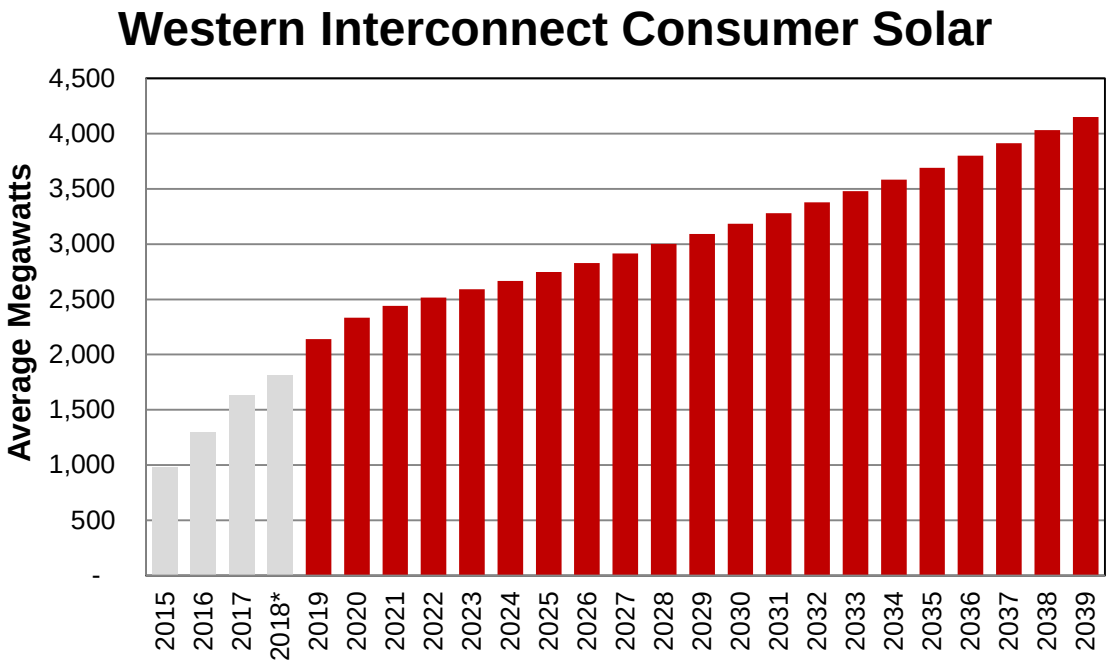
EV Load Shaping

A combined hourly load shape for EV's will be combined using Avista EV load data from its Pilot Project



Rooftop Solar

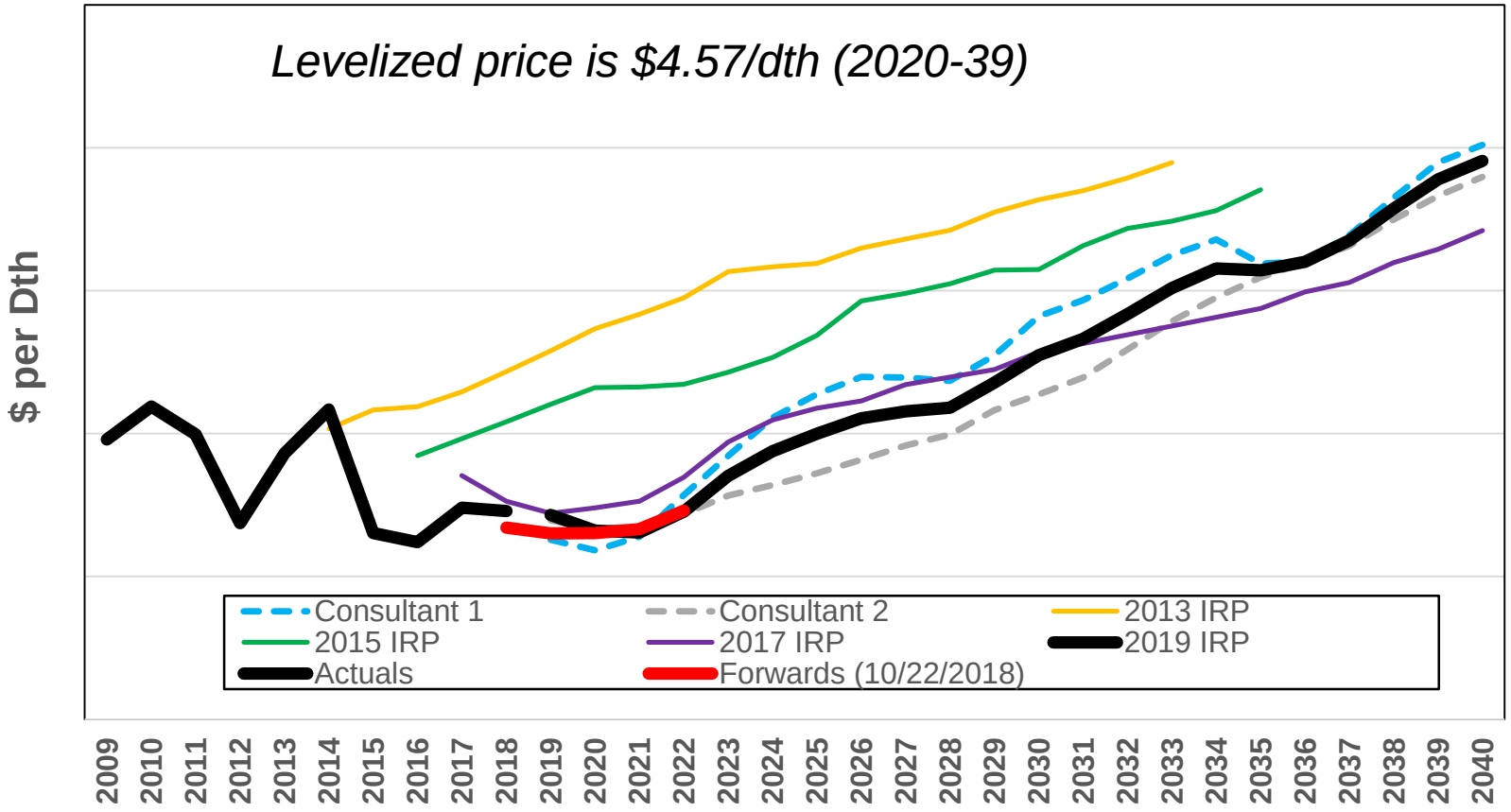
- Rooftop solar impacts future load growth and changes its hourly profile
- Future rooftop solar growth depends on policy choices
- Assumes 20-30% growth, before leveling off to 3% long run growth in 2020s



Natural Gas Prices

- Natural gas prices among the most difficult inputs to quantify
- A combination of forward prices and consultant studies will be used for this IRP. This work should be complete by December 2018 (i.e. deterministic forecast)
- 500 different prices using an auto regressive technique will be modeled, the mean value of the 500 simulations will be equal to the deterministic forecast
- A controversial input for these prices is the amount of variance within the 500 simulations
  - Historically prices were highly volatile, recent history is more stable
  - Final variance estimates consider current market volatility and implied variance from options contracts

Henry Hub Natural Gas Prices *



* Based on methodology described above, **<u>to be updated</u>**

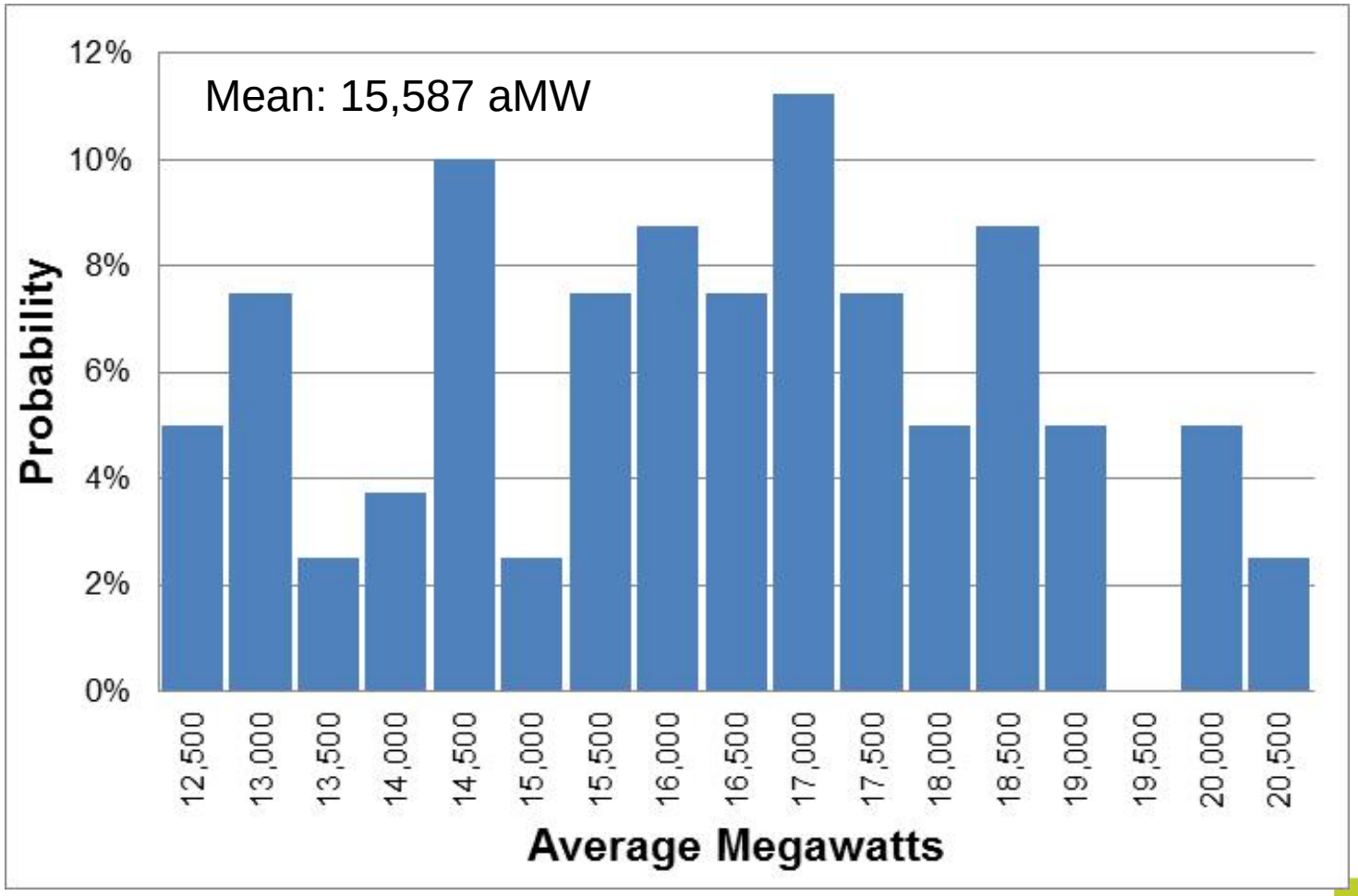
Coal Prices

- Decreased demand for US based coal with lower natural gas prices and state and federal regulations, but potential exports may stabilize the industry
- Western US coal plants typically have long-term contracts and many are mine mouth
- Rail coal projects incur diesel price risk
- Prices will be based on review of coal plant publically available prices and EIA mine mouth and rail forecasts, currently the price escalator is ~2.5%
- Colstrip Fuel Prices will be discussed at the February TAC meeting with final fuel forecasts

Hydro

- 80 years of hydro conditions are used for the Northwest states, British Columbia and California provided by BPA
  - Hydro levels change monthly
  - Aurora dispatches the monthly hydro based on whether its run-of-river or storage
- For stochastic studies the hydro levels will be randomly drawn from the 80-year record
- Columbia River Treaty could change regional hydro patterns, but until there is a new treaty, no changes will be included

Northwest State Hydro Volatility

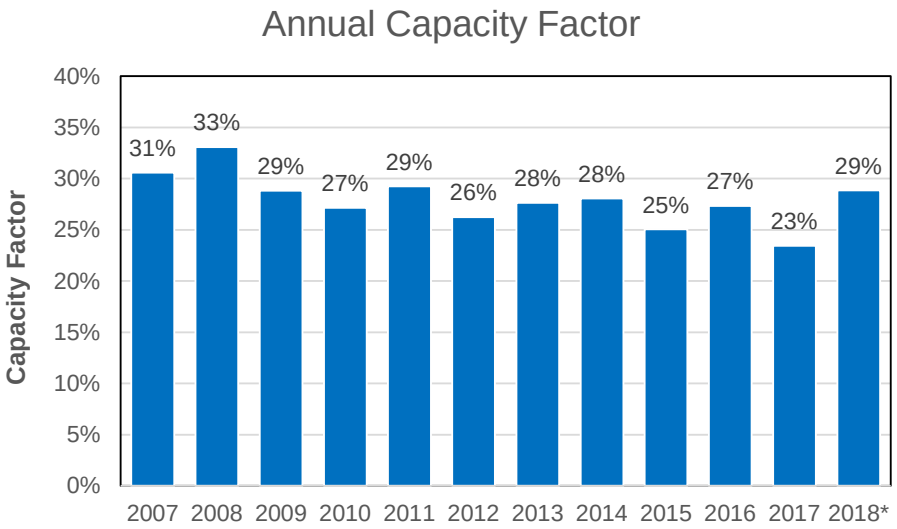


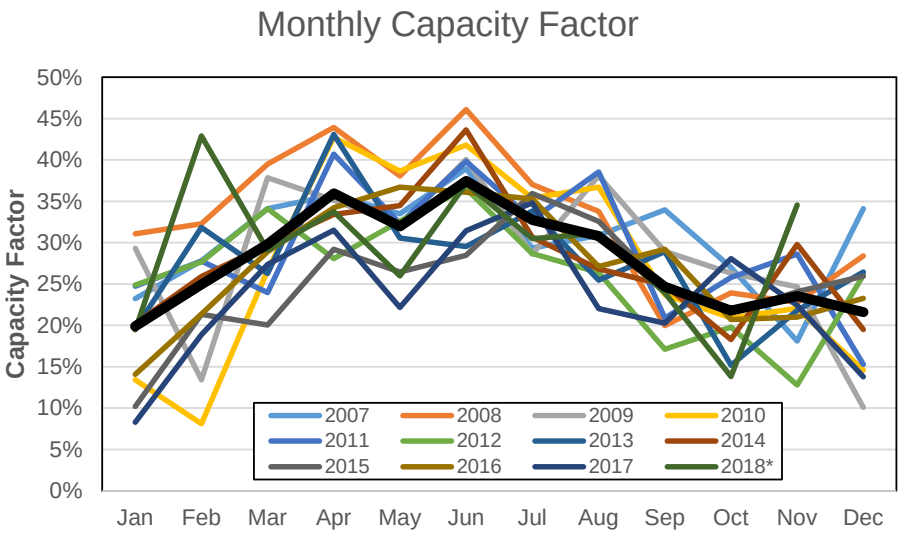
Wind

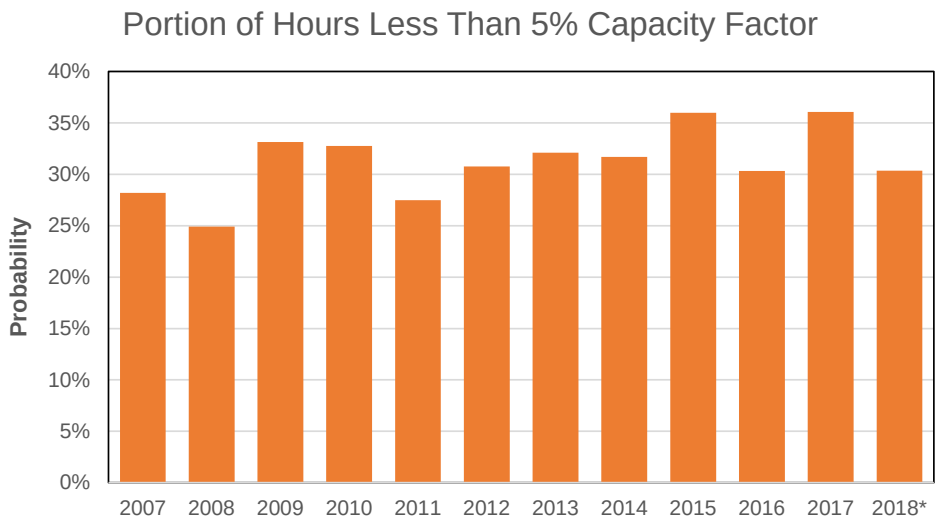
- Modeling technique
  - Autoregressive technique to simulate output in similar to reported data available from BPA, CAISO, and other publically available data sources- also considers correlation between regions
  - For stochastic studies several wind curves, will be drawn from to simulate variation in wind output each year for each of the 500 draws

- Oversupply modeling technique
  - RECs and PTC's have caused wind facilities to economically generate in oversupply periods in the Northwest- particularly in the spring months
  - Wind is modeled in Aurora as a negative marginal cost, allowing for the model to simulate negative prices

NW Wind Capacity Factor History







Source: https://transmission.bpa.gov/business/operations/wind/

Western Interconnect Coal Retirements

Plant	Units	State	Summer Capacity (MW)	Retirement Year	Committed or Proposed	Fuel Conversion
Apache Station	2	Arizona	175	2017	Committed	Natural gas
Hardin	1	Montana	107	2018	Proposed	
Naughton	3	Wyoming	330	2018	Proposed	
Navajo	1 to 3	Arizona	2,250	2019	Committed	
Centralia Complex	1	Washington	670	2020	Committed	
Centralia Complex	2	Washington	670	2025	Committed	
Cholla	4	Arizona	380	2020	Proposed	Natural gas
Boardman (OR)	1	Oregon	585	2021	Committed	
North Valmy	1	Nevada	254	2021	Proposed	
Colstrip	1 & 2	Montana	614	2022	Committed	
Comanche	1	Colorado	325	2022	Proposed	
Nucla	1-3, ST4	Colorado	100	2022	Proposed	
San Juan Generating Station	1 & 4	New Mexico	847	2022	Proposed	
TS Power Plant	ST	Nevada	218	2022	Proposed	
Cholla	1 & 3	Arizona	387	2025	Proposed	
Comanche	2	Colorado	335	2025	Proposed	
Craig (CO)	1	Colorado	428	2025	Committed	
Intermountain	ST1 & ST2	Utah	1,800	2025	Proposed	Natural gas
North Valmy	2	Nevada	268	2025	Proposed	
Dave Johnston	1 to 4	Wyoming	762	2027	Proposed	
Jim Bridger	1	Wyoming	531	2028	Proposed	
Naughton	1 & 2	Wyoming	357	2029	Proposed	
Hayden	1 & 2	Colorado	446	2030	Proposed	

The price forecast simulation may find additional coal retirements in the later half of the study period

Initiative 1631

- 2018 Carbon Emissions Fee Measure
  - $15 per metric ton of carbon emissions fee on January 1, 2020
  - Increase fee $2 per year until state emissions goals met
  - Direct proceeds to various programs and projects to improve carbon emissions
- Failed with 56.55% voting against the measure
  - Avista counties 67% voting against
- Will update TAC and modeling for new legislation in the upcoming Washington session

City of Spokane 100% Renewable Goal

- Spokane City Council adopts aspirational goal to have the city served with all renewable power by 2030 (August 2018)
- Committee will be formed to scope and define this ordinance
  - Net renewable or something else?
  - How it will be ramped in?
  - Implications and help for low income and other at risk groups?
  - Rate issues

2019 IRP Futures and Scenarios

James Gall, IRP Manager
John Lyons, Senior Resource Policy Analyst
Second Technical Advisory Committee Meeting
November 27, 2018

IRP Modeling Plan for Environmental Policies

- No expected case due to potential policy uncertainty
- Three futures used rather than an expected case + scenarios
- Alternative futures and scenarios can also be studied, but will need to be minimal due to resource constraints
- Proposed Futures (500 simulations each)
  1. Existing policies & trends
  2. Social Cost of Carbon
  3. Clean Resources

Existing Policies & Trends

Major future assumption change is a greenhouse gas price distribution with:

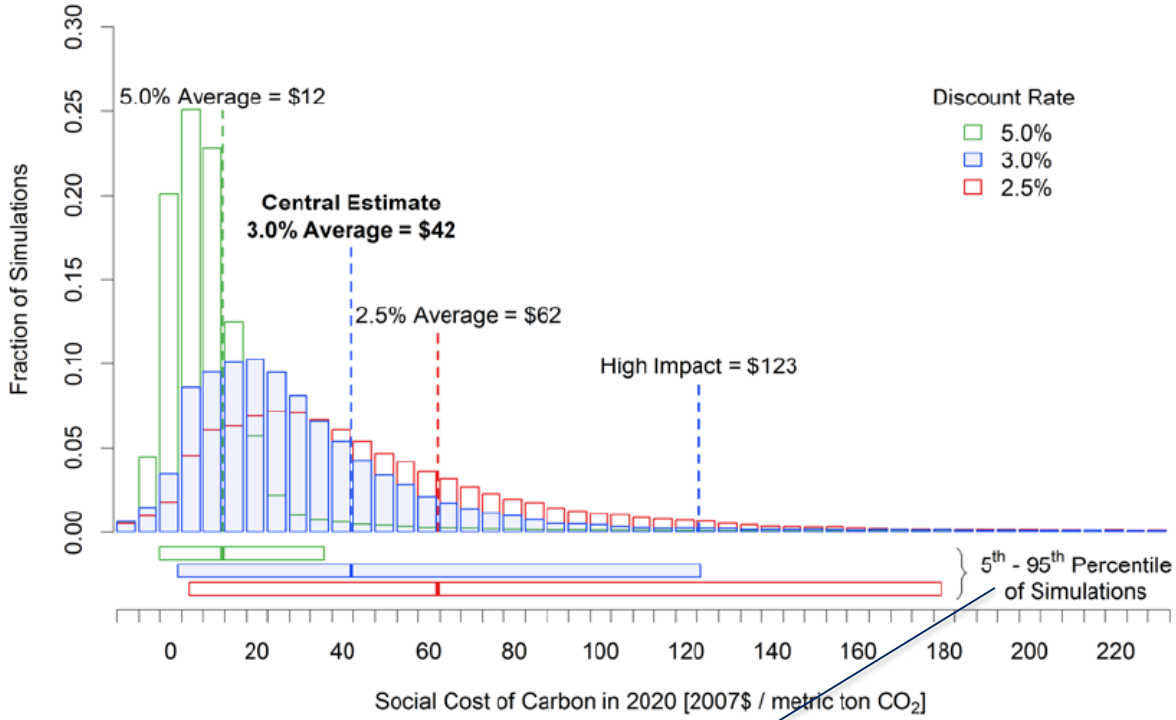
- 1/3 probability of no pricing
- 1/3 probability of $10/metric ton (2018$) escalating at 2.5% year
  - Begins in 2025
  - Applies to all of Western Interconnect resources
- 1/3 probability of cap and trade of 20% below 1990 levels
  - 20% goal by 2030
  - 40% goal by 2040
  - Applies to all of Western Interconnect
  - An implied CO_2 price will be a result of each study

Social Cost of Carbon (SCC)

- No CO_2 cost penalties for dispatch, the SCC will be included as a cost in resource and energy efficiency acquisitions
- Pricing will be a distribution of costs from the Interagency Working Group on Social Cost of Carbon (Aug 2016)
  - 1/3 probability of 5.0% discount rate pricing distribution (90th Confidence Level)
  - 1/3 probability of 3.0% discount rate pricing distribution (90th Confidence Level)
  - 1/3 probability of 2.5% discount rate pricing distribution (90th Confidence Level)
- SCC will be applied to the Washington portion of load service for Avista resource portfolios

Social Cost of Carbon Pricing Distribution From

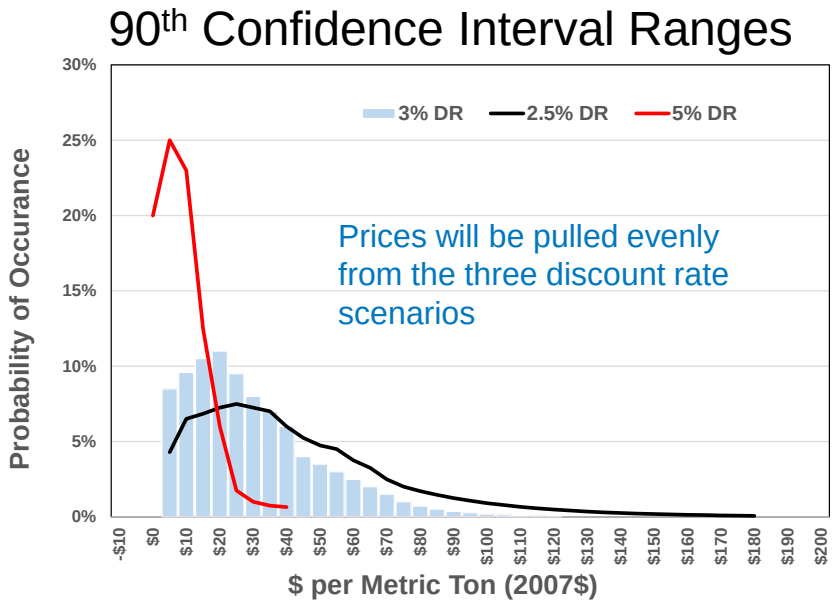
Figure ES-1: Frequency Distribution of SC-CO_2 Estimates for 2020[3]

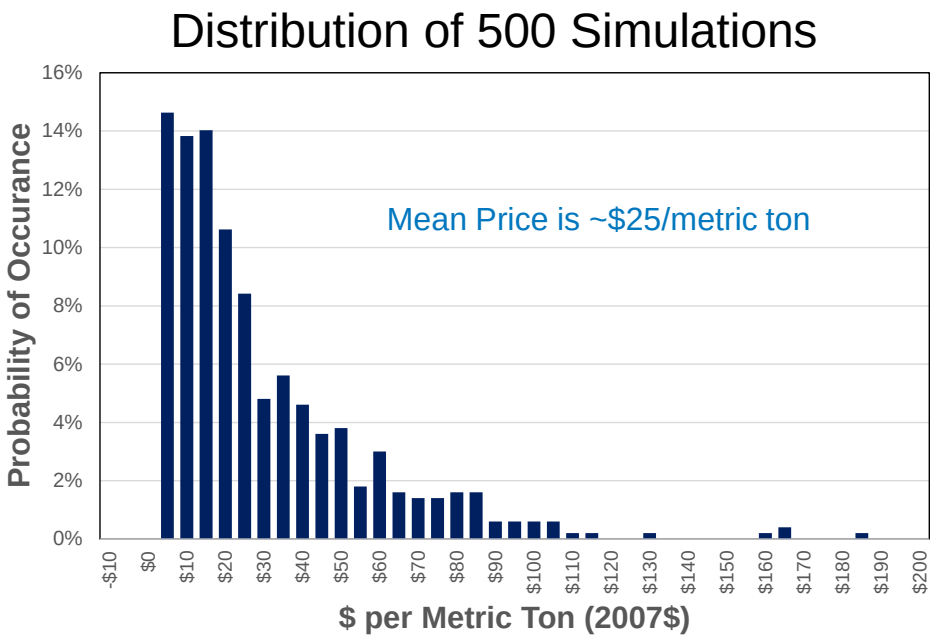


Use 90th confidence interval for each of the three distributions for the 500 simulations

Social Cost of Carbon

Confidence Interval





Clean Resource Future

- Washington: 100% of load met by “clean” resources on a “net” basis
  - 80% by 2030, 90% by 2040, and 100% by 2050
  - Qualifying resources can be sourced from anywhere in the Western Interconnect
  - Up to 20% of resources can be “RECs” from outside of the region or alternative compliance
  - Price cap of $5 per metric ton ($2018) beginning in 2030 and 1% revenue requirement for portfolio modeling
- Oregon cap and trade
  - 20% below 1990 levels by 2030
  - 50% below 1990 levels by 2040
  - 80% below 1990 levels by 2050

Additional Scenarios

Aurora Studies

- High natural gas prices (deterministic)
- Low natural gas prices (deterministic)
- Social Cost of Carbon (stochastic)
- High Colstrip fuel cost (deterministic)
- Colstrip shutdown (stochastic)

PRiSM Studies

- Study from each of the Aurora cases
- Colstrip closes in 2027
- Colstrip closes in 2035
- High cost to retain Colstrip (with low gas)
- Low and high load growth, alternative load cases (i.e. electrification, EV, behind the meter generation, power-to-gas, etc.)
- Lancaster continues
- High cost to retain Colstrip
- Colstrip fuel prices
- Conservation TRC vs. UCT
- Tipping point scenarios

High and Low Natural Gas Prices

- Deterministic studies to show the impacts of consistently lower or higher natural gas prices than the expected price forecast
- Low case will have existing price levels and not increase
- High case level TBD – more details forthcoming at February 2019 TAC meeting

Social Cost of Carbon

- Differs from the future discussed earlier by including the price for dispatch for all plants in the Western Interconnect
- Will include the same prices as discussed in the SCC future

Colstrip Basic Assumptions

- Avista's share of fuel, O&M, and capital investment costs
- Increased common costs due to shut down of units 1 & 2 in 2022
- Selective catalytic reduction (SCR) – 2027 and 2028, includes capital costs, ammonia and fixed and variable O&M to reduce NO_x
- Enhanced mercury controls
- Coal Combustion Residuals (CCR's)
  - Coal dry ash handling (2022) and long term storage
- Smart Burn combustion controls installed in 2017
- Water management
- Depreciation schedule shortened to 2027 per merger agreement
- Additional details on the specifics will be provided in TAC 4

Colstrip Scenarios

- Retire Colstrip Units #3 and #4 in 2027 as an alternative to SCR investment
- Retire Colstrip Units #3 and #4 in 2035 as an alternative to SCR investment
- Colstrip fuel prices increase 30%
- High cost to retain Colstrip case (next slide)

High Cost to Retain Colstrip Case

- This case answers questions about several higher cost issues impacting Colstrip's compliance cost
- This scenario uses assumptions in the three futures, except:
  - EPA expands regional air quality programs and rules to the western U.S. such as CASPR and NAAQS requiring SCR installation on Units #3 and #4 at an earlier date (End of 2023)
  - Units #1 and #2 shut down earlier than announced, increasing the amount of shared costs cover by Units #3 and #4 (End of 2019)
  - MACT PM/MATS RTR compliance problems. Dry system required to remove particulates and reduce water use (End of 2023)
  - No enhancement to existing SO_2 scrubbers as no current regulation drives reduction levels beyond current plant emissions
  - Higher Colstrip fuel costs
  - Low natural gas cost environment
  - Specific cost details will be provided in TAC 4

Load Growth Scenarios

- High and low load growth scenarios due to economic changes in the service territory
- Potential load study scenarios
  - High EV penetration case (120,000 EVs by 2045)
  - Behind-the-meter generation (10% penetration by 2030)
  - Fuel switching electric to natural gas
  - Fuel switching natural gas to electric

Lancaster Continues

- Lancaster PPA currently ends October 2026
- PPA has an option to extend the contract 5 years at a negotiated price
- Implications of extending the PPA or purchasing the plant beyond the current end of the PPA

Alternative Energy Efficiency Evaluations

- All cases will model cost effectiveness of energy efficiency using the total resource cost (TRC) in Washington and the utility cost test (UCT) in Idaho
- This scenario tests both methods of evaluation

Tipping Point Analyses

- Estimates the cost reduction or operating characteristics needed to change the resource strategy
  - Are there any assumptions that need to be tested to find the cost tipping point?
  - Past studies have included capital costs for solar and storage