2021 Electric Integrated Resource Plan

Appendix A – 2021 Technical Advisory Committee Presentations and Meeting Minutes

2021 Electric Integrated Resource Plan
Technical Advisory Committee Meeting No. 1 Agenda
Thursday, June 18, 2020
Virtual Meeting

Topic	**Time**	**Staff**
Introductions	9:00	
TAC Expectations and Process Overview	9:05	Lyons
2020 IRP Acknowledgement	9:45	Lyons
Break	10:15	
CETA Rulemaking Update	10:30	Bonfield
Modeling Process Overview	11:00	Gall
Lunch	12:00	
Generation Options	1:00	Hermanson
Break	2:00	
Highly Impacted Communities Discussion	2:15	Gall
Adjourn	3:30	

2021 Electric IRP
TAC Expectations and Process Overview

John Lyons, Ph.D.
First Technical Advisory Committee Meeting
June 18, 2020

Updated Meeting Guidelines

- IRP team is working remotely, still available by email and phone for questions and comments
- Some processes are taking longer remotely
- Adding stakeholder feedback form to the IRP website – posted with responses
- Researching best way to share other IRP data
- Virtual IRP meetings on Skype until back in the office and able to hold large group meetings
- TAC presentations and notes will still be posted on IRP page

Virtual TAC Meeting Reminders

- Please mute mics unless speaking or asking a question
- Use the Skype chat box to write out or let us know you have a question or comment
- Respect the pause
- Please try not to speak over the presenter or a speaker who is voicing a question or thought
- Remember to state your name before commenting for the note taker
- This is a public advisory meeting – presentations and comments will be recorded and documented

Integrated Resource Planning

The Integrated Resource Plan (IRP):

- Required by Idaho and Washington* every other year
  - Covering timing of 2020 and 2021 IRPs in next presentation
- Guides resource strategy over the next twenty + 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 involved in all or parts of the process
  - Ask questions
  - Help with soliciting new members
- 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 number or type of studies
  - Earlier study requests allow us to be more accommodating
  - **August 1, 2020** is the study request deadline
- Planning team is available by email or phone for questions or comments between the TAC meetings

2021 Electric IRP TAC Schedule

- TAC 1: Thursday, June 18, 2020
- TAC 2: Thursday, August 6, 2020 (Joint with Natural Gas TAC)
- TAC 3: Tuesday, September 29, 2020
- TAC 4: Tuesday, November 17, 2020
- TAC 5: Thursday, January 21, 2021
- Public Outreach Meeting: February 2021
- TAC agendas, presentations and meeting minutes available at: https://myavista.com/about-us/integrated-resource-planning

2021 IRP Key Dates – Work Plan

- Identify Avista's supply resource options – May 2020
- Finalize natural gas price forecast – June 2020
- Finalize demand response options – July 2020
- Finalize energy efficiency options – July 2020
- Update and finalize energy and peak forecast – July 2020
- Finalize electric price forecast – August 2020
- Transmission and distribution studies due – August 2020
- Determine portfolio and market future studies – August 2020
- Due date for TAC study requests – August 1, 2020
- Finalize PRiSM model assumptions – September 2020
- Simulate market scenarios in Aurora – September 2020
- Portfolio analysis and reliability analysis – October 2020
- Present portfolio analysis to TAC – November 2020

2021 IRP Public Data Release Schedule

- Supply Side Resource Options – June 2020
- Conservation Potential Study Data – July 2020
- Demand Response Potential Study Data – July 2020
- Peak & energy Load Forecast – July 2020
- Wholesale Natural Gas Price Forecast – August 2020
- Wholesale Electric Price Forecast – September 2020
- Transmission Interconnect Costs – September 2020
- Existing Resource Data – September 2020
- Annual Capacity Needs Assessment – November 2020

2021 IRP Key Document Dates

- Filed 2021 IRP Work Plan April 1, 2020
- Internal IRP draft released at Avista on December 4, 2020
- External draft released to the TAC on January 4, 2021
- Comments and edits from TAC due on March 1, 2021
- Final editing and printing – March 2020
- Final IRP submission to Commissions and TAC on April 1, 2021

Today's TAC Agenda

9:00 – Introductions

9:05 – TAC Expectations and Process Overview, Lyons

9:45 – IRP Acknowledgement, Lyons

10:15 – Break

10:30 – CETA Rulemaking Update, Bonfield

11:00 – Modeling Process Overview, Gall

Noon – Lunch

1:00 – Generation Options, Hermanson

2:00 – Break

2:15 – Highly Impacted Communities Discussion, Gall

3:30 – Adjourn

2020 Electric IRP Acknowledgement Update

John Lyons, Ph.D.
First Technical Advisory Committee Meeting
June 18, 2020

Normal Acknowledgement Process

- Avista's electric IRP previously submitted to Idaho and Washington Commissions every other August in odd years
- Commissions set periods for public comments and meetings
- Acknowledgements issued detailing IRP outcomes, comments and expectations for the next IRP
- Normally, we provide details about the acknowledgments in this meeting

How The IRP Changed

- Expectations and passage of the Clean Energy Transformation Act (CETA) in 2019 led to six month IRP extensions
  - February 28, 2020 in Idaho in AVU-E-19-01 Order No. 34312
  - Washington further extended until April 1, 2021
  - Two IRPs in two years

Idaho

- AVU-E-19-01 (https://puc.idaho.gov/case/Details/3633)
- Requests from the Mayor of Sandpoint, Idaho, Idaho Forest Group, Idaho Conservation League and Embodied Virtue for the IPUC to hold a public hearing in North Idaho
- IPUC set a deadline of August 19, 2020 for public comments about the IRP with Avista replies due September 2, 2020
- Will update the TAC on future comments and acknowledgement
- Ongoing discussions with Commission Staff and ICL concerning several aspects about modeling, Colstrip and the impact of CETA on Idaho customers

Washington

- Submitted the 2020 IRP to the Washington UTC
- Washington Commission temporarily suspended issuing IRP acknowledgement letters in UE-180738 Order 02 until December 31, 2020
- Progress filed report filed on October 25, 2019 to accommodate CETA rulemaking
  – Commission cannot legally acknowledge an IRP without meeting certain CETA guidelines which still need to have rulemaking completed
- Next draft electric IRP must be submitted by January 4, 2021 and final 2021 electric IRP must be submitted by April 1, 2021
- No specific requirements or expectations from an acknowledgment letter from the 2020 IRP

Washington

- 2021 IRP expectations are going to focus on the results of CETA rulemaking

Some Washington UTC requests on the work plan include:

- Provide opportunity for stakeholder input on the CPA before finalizing the options
- How equity issues required under CETA will be incorporated in the IRP (TAC 1 and TAC 2)
- Extending participation beyond the TAC through some form of public outreach at a higher level before the end of the IRP process (February 2021)
- Concerns over draft CEIP being included in the IRP
- Provide a general outline of when Avista will provide data or files for stakeholder review and comment deadlines (first presentation today)

DRAFT

Clean Energy Transformation Act (CETA)

Overview and Implementation Status

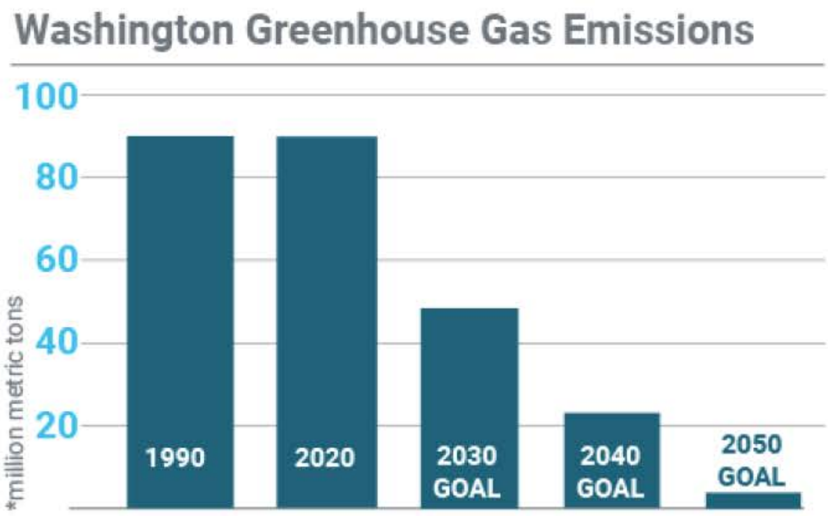
Shawn Bonfield, Sr. Manager Regulatory Policy & Strategy

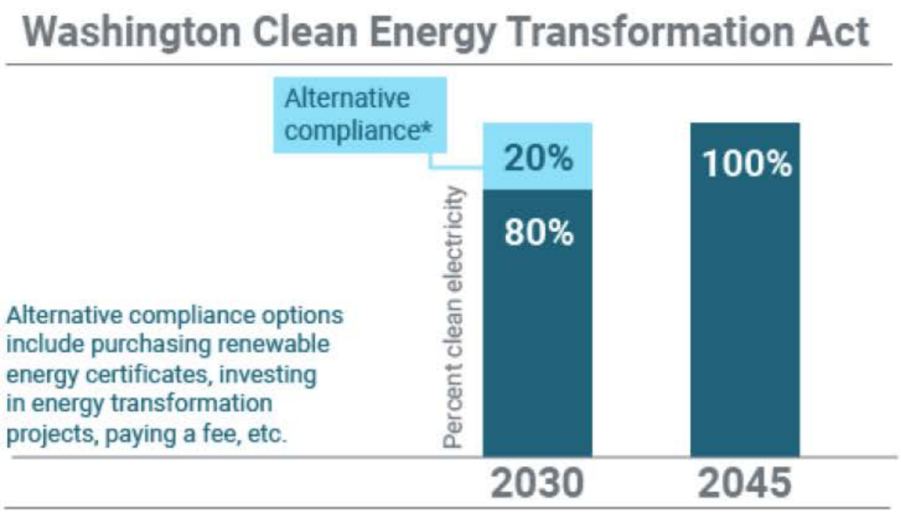
First Technical Advisory Committee Meeting

June 18, 2020

CETA: A Brief Overview

- Senate Bill 5116 – passed by legislature in 2019
- Applies to all electric utilities in WA and sets specific milestones to reach required 100% clean electric supply
- By 2025 – eliminate coal-fired resources from serving WA customers
- By 2030 – electric supply must be greenhouse gas neutral,
- By 2045 – electric supply must be 100% renewable or be generated from zero-carbon resources



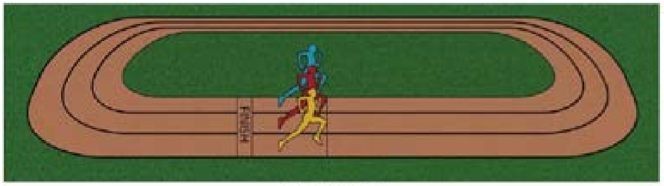


Source: WA Department of Commerce

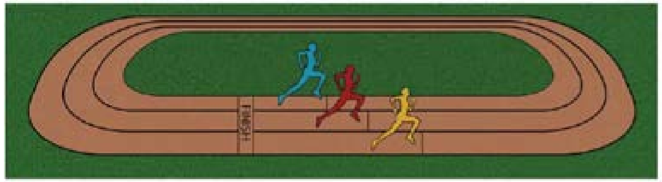
CETA: Additional Details

Utilities must:

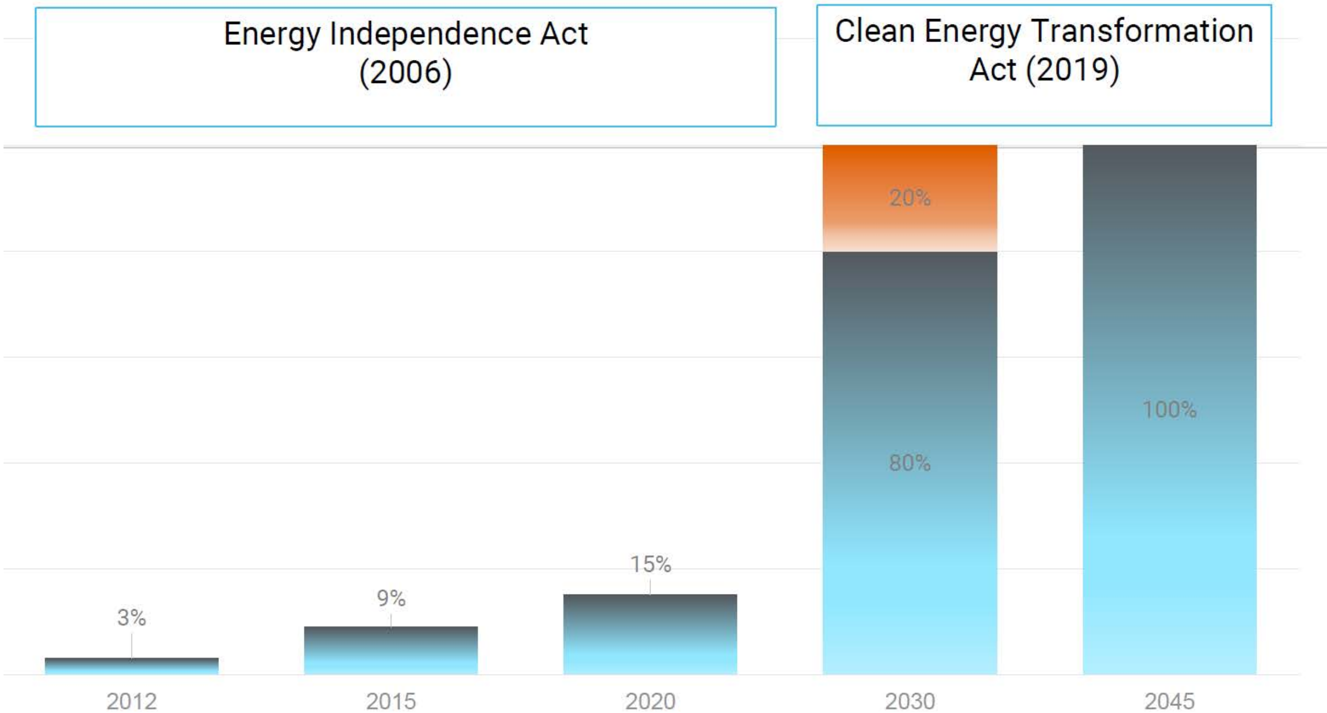
- Ensure the equitable distribution of energy and nonenergy benefits and reduction of burdens to vulnerable populations and highly impacted communities
- Ensure long-term and short-term public health and environmental benefits and reduction of costs and risks
- Ensure energy security and resiliency
- Make progress toward and meet the standards of the law:
  - While maintaining and protecting the safety, reliable operation, and balancing of the electric system
  - At the lowest reasonable cost



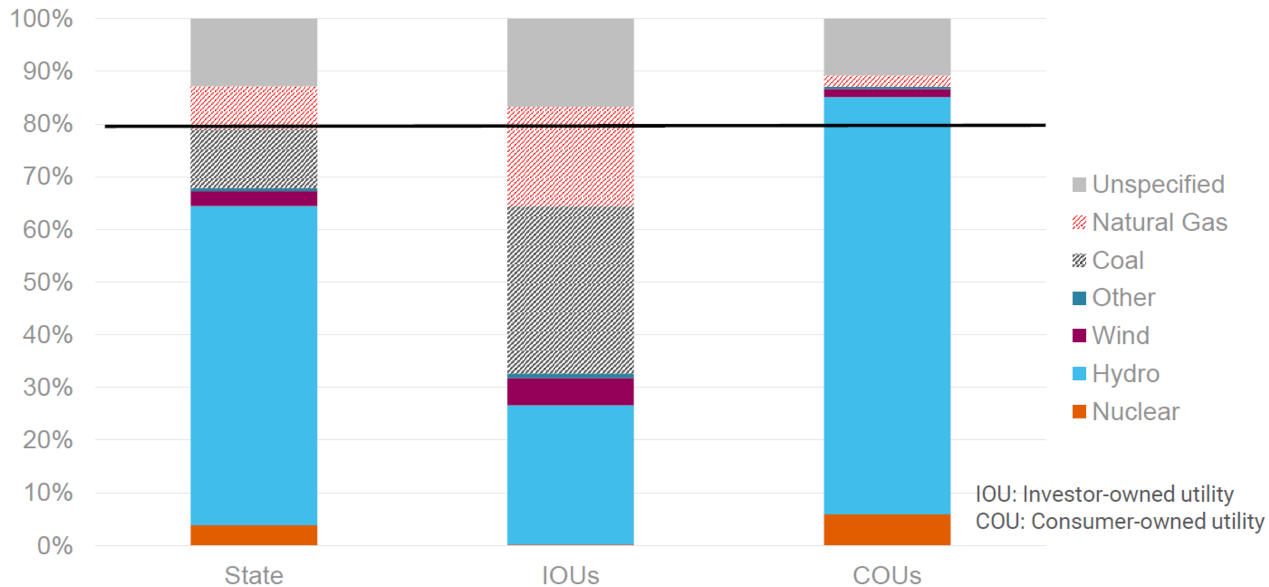
EQUALITY



EQUITY



WA utilities' existing resource mix



Source: WA Department of Commerce

Key dates

Dec 2020	Agencies complete initial rules
Jan 2022	Utilities submit 1st clean energy implementation plans (2022-2025)
Jun 2022	Agency rules on market transactions and double-counting
Dec 2025	Deadline to remove coal from portfolios
Jan 2026	2nd CEIP submitted (2026-2029)
2030	GHG Neutral standard takes effect
2045	100% Clean Electricity standard takes effect

Source: WA Department of Commerce

UTC CETA Implementation Plan UE-190485 (Closed)

- Phase 0 – overall implementation plan
  - Process timeline and scope of issues
- Phase I - August 2019 to January 1, 2021
  - Elements that must be complete by January 1, 2021 as required by Section 10 of SB 5116
  - Publish the social cost of carbon on UTC's website by September 15, 2019
  - Initiate dockets for various rulemakings relating to CETA implementation
- Phase II – January 1, 2021 to June 30, 2022
  - Rulemakings with deadlines after January 1, 2021
  - Amend IRP rules to incorporate Cumulative Impact Analysis
  - Carbon and Electricity Markets Rulemaking

Social Cost of Carbon
U-190730 (Closed)

- New section added to chapter 80.28 RCW, outlining cost of greenhouse gas emissions resulting from the generation of electricity and use of natural gas, the UTC must adjust the social cost of carbon to reflect the effect of inflation.

- Social Cost of Carbon published on UTC website in September 2019:
  - https://www.utc.wa.gov/regulatedIndustries/utilities/Pages/SocialCostofCarbon.aspx

Energy Independence Act (EIA) Rulemaking – UE-190652

- E2SSB 5116: Amending WAC 480-109, Energy Independence Act (EIA) rules
  a. Streamline E2SSB 5116 with EIA rules. (§ 10(3))
  b. Discuss equitable distribution of benefits.
  c. Discuss low-income definition, if needed. (§ 2(25))
  d. Discuss energy assistance need definition, if needed. (§ 2(16))
  e. Consider incorporating low-income energy efficiency target.
  f. Incorporate updates to hydro eligibility and tracking. (§ § 28 and 29)

Status: Written comments due on draft rules July 6th. Rule adoption hearing set for July 28th.

Clean Energy Implementation Plan (CEIP) Rulemaking UE-191023

- E2SSB 5116: New Chapter, Clean Energy Implementation Plans (CEIPs)
  a. Provide guidelines for Clean Energy Implementation Plans. (§ 6)
  b. Discuss equitable distribution of benefits. (§ 4(8))
  c. Develop incremental cost methodology at the beginning of the rulemaking. (§ 6)
  d. Address reporting and compliance, and the penalty process. (§ 9(1)(a))

Status: First draft of rules released May 5, 2020 with comments due June 2, 2020. Second set of draft rules to be released in July timeframe.

Electric IRP Updates Rulemaking UE-190698

- E2SSB 5116 and EHB 1126: Amending WAC 480-100-238, Electric Integrated Resource Plans (IRP)
  a. Update inputs to IRPs (e.g., hydro eligibility and tracking;4 resource adequacy; distributed energy resources principles from EHB 1126; and demand response).
  b. Update structure of IRPs.
  c. Update public involvement process.
  d. Update outputs of IRP Clean Energy Action Plans. (§ 14(2))
  e. Incorporate the social cost of carbon into IRPs. (§ 14(3)(a))
  f. Refine the development of avoided costs to reflect E2SSB 5116 and social cost of carbon.
  g. Develop resource value test based on review of E2SSB 5116 and social cost of carbon.
  h. Discuss equitable distribution of benefits. (§ 4(8))
  i. Discuss assessment informed by cumulative impact analysis, as needed. (§ 14(1)(k))
  j. Amend IRP rules to incorporate the Cumulative Impact Analysis complete by Department of Health workgroup. (ch. 288, § 14(11))
  k. Incorporate distributed energy resources elements from EHB 1126. (ch. 205, § 1)

Status: Development and preparation of draft rules ongoing.

Purchase of Electricity (PoE) Rulemaking UE-190837

- E2SSB 5116: Amending WAC 480-107, Resource Acquisition (Requests for Proposals, or RFP)
  a. Incorporate existing work on RFPs from Docket U-161024.
  b. Ensure that the E2SSB 5116 standard is met in construction and acquisition of property and the provision of electric service. (§ 5)
  c. Incorporate resource adequacy considerations. (§ 6(2)(a)(iv))
  d. Discuss equitable distribution of benefits. (§ 6(1)(c)(iii))

Status: Second round of draft rules issued June 1, 2020 with comments due June 29, 2020.

Carbon & Electricity Markets Workgroup UE-190760

- E2SSB 5116: With the Department of Commerce, initiate a Carbon and Electricity Markets Workgroup for regular discussions to inform Phase II rulemaking.
- Define requirements for load met with market purchases. (ch. 288, § 13)

Status: Workgroup to hold four educational workshops to set a base of understanding. Second workshop scheduled for June 10, 2020. Public work sessions to begin in Fall 2020 with rulemaking complete June 30, 2021.

Department of Commerce Rulemakings

- Thermal Renewable Energy Credits – applies to all utilities
- Reporting and demonstration of compliance – applies to all utilities
- CEIP for consumer-owned utilities – ensure alignment with UTC rules
- Cost methodology for rate impact – applies to all utilities

Rules effective January 1, 2021

Department of Ecology Rulemakings

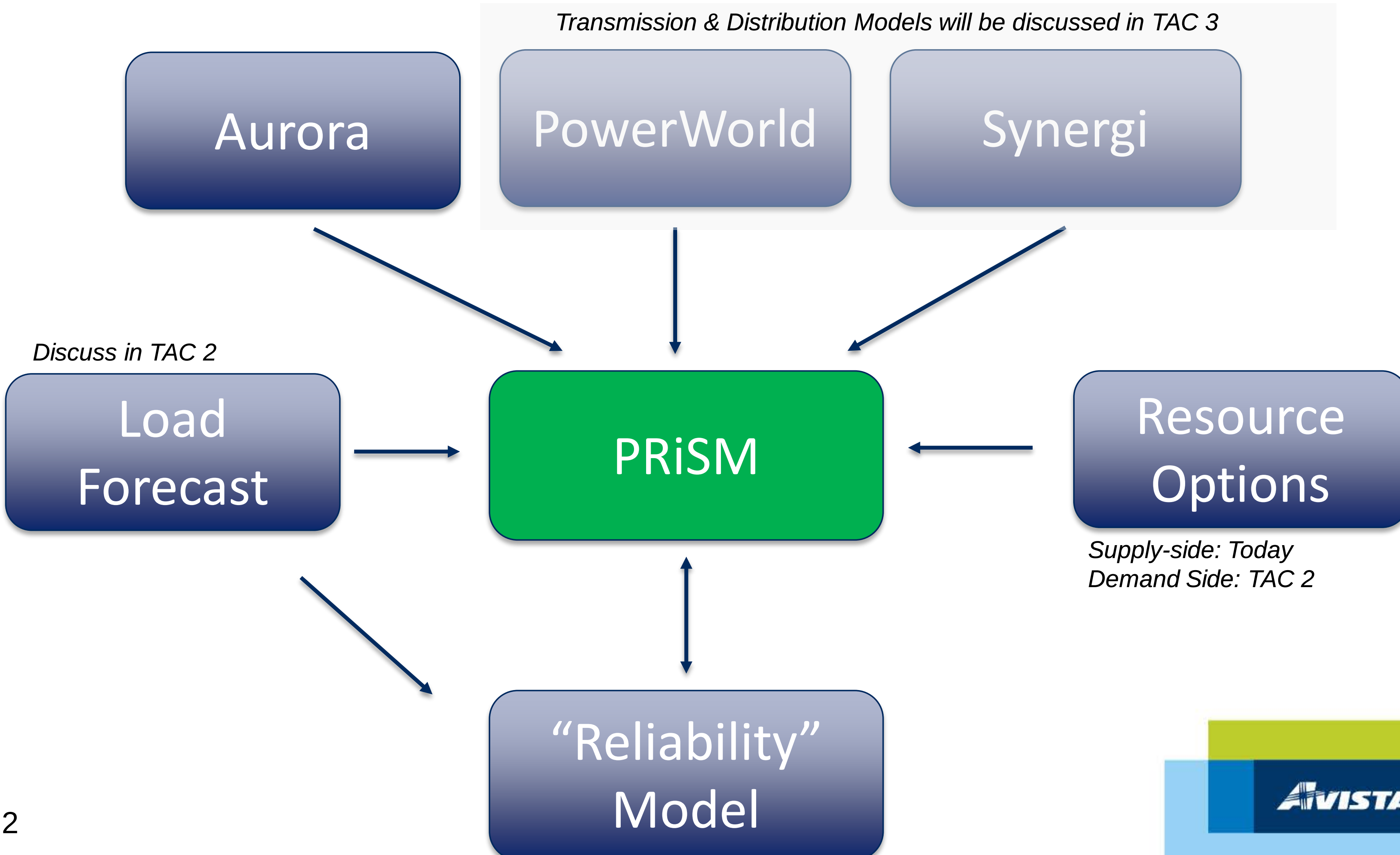
- Ecology is starting rulemaking for Chapter 173-444 WAC, Clean Energy Transformation Rule to implement parts of the Clean Energy Transformation Act assigned to Ecology. The rulemaking will:
  - Establish a process to determine what types of energy transformation projects may be eligible to meet the Clean Energy Transformation Act.
  - Establish a process and requirements to develop standards, methodologies, and procedures to evaluate energy transformation projects.
  - Provide greenhouse gas emission factors for electricity.

- Timeline
  - Spring 2020 – develop and prepare rule language
  - Summer 2020 – public hearing and comment
  - December 2020 – adopt rule
  - January 2021 – rule effective

2021 Electric IRP
Modeling Process Overview

James Gall, IRP Manager
First Technical Advisory Committee Meeting
June 18, 2020

IRP Planning Models



Aurora

- Electric Market- Production Cost Model
- Developed by Energy Exemplar
- Industry standard and widely used in the Pacific Northwest
- Avista started using software for the 2003 IRP
- Simulates generation dispatch to meet load allowing for system constraints

Inputs:

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

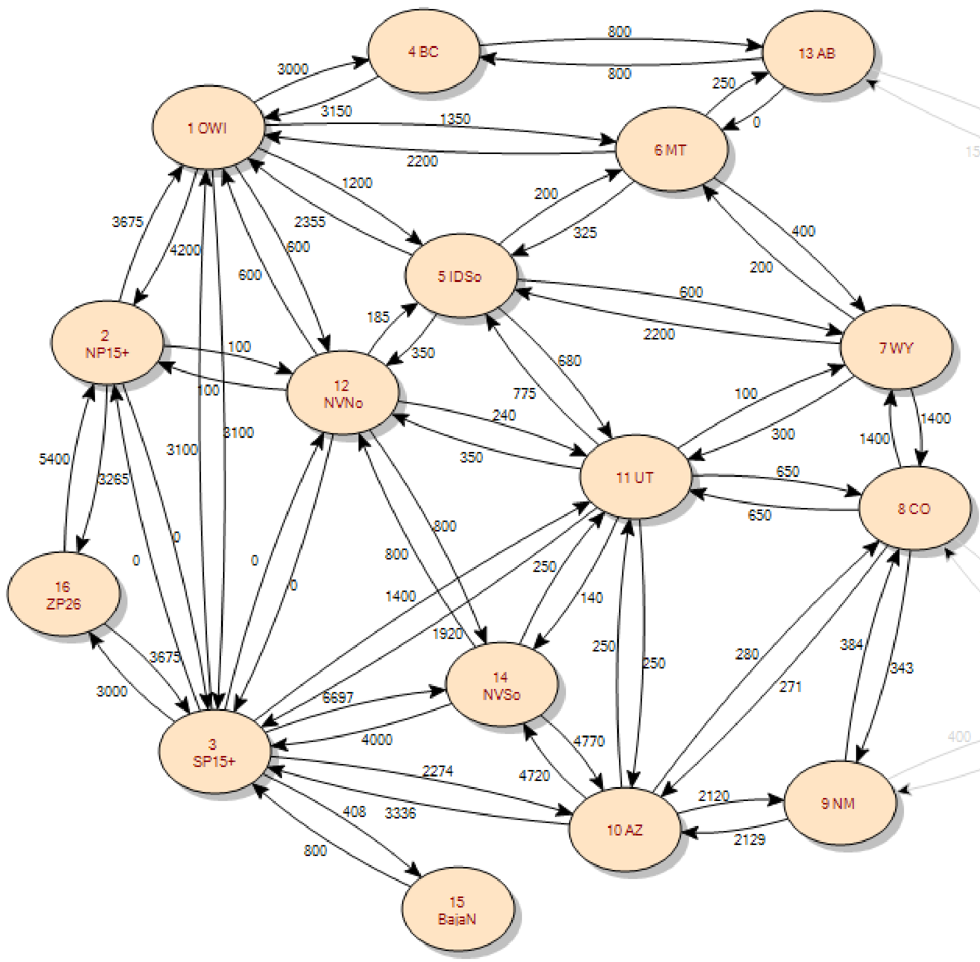
Outputs:

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

*Stochastic input

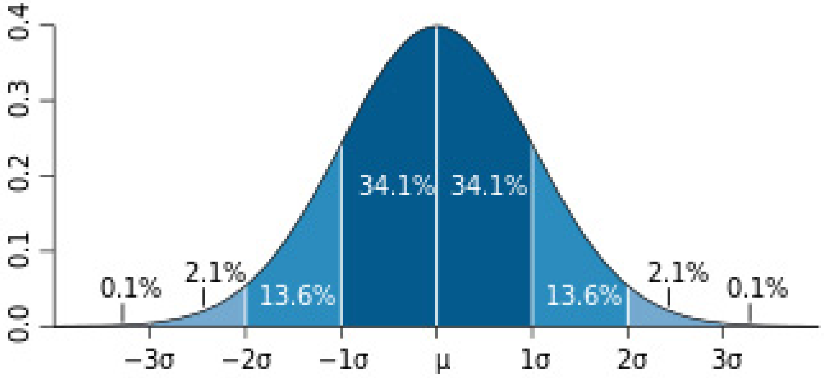
Aurora Pricing Methodology

- Each area contains a load and resources.
- Aurora dispatches resources to meet the load for each hour.
- Resource dispatch is dependent on fuel availability (wind, solar, hydro) and economic dispatch of the resource (fuel price).
- The model includes resource outages for maintenance and forced outage.
- For each location and hour, the model estimate a wholesale electric price using the marginal resource to serve the load.



Stochastic vs. Deterministic Analysis

- Deterministic analysis forecasts for a specific set of inputs.
  - Easier 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
- Avista uses mean value of stochastic analysis for its Expected Case scenario.



Aurora Model Assumptions

- Forecast will start with the 2020 IRP
  - Uses latest available database from Energy Exemplar
- Proposed database changes
  - Natural gas prices (TAC 2)
  - Include new resource additions and announced retirements
  - Include known state/province environmental laws; including adjustments for oversupply events
  - Review inputs for load and new resources options
    - EV/rooftop solar forecast
    - New resources cost
  - Add proprietary Avista system information
  - Add stochastic distribution of regional hydro, natural gas, wind, and loads
- Avista will discuss non-confidential modeling changes in TAC 3
- All other Aurora assumptions are default values

Aurora Run Process

- Once inputs are finalized (July 2020)
- Run Long Term "LT" study to estimate new resource additions for the full hourly study
- Test reliability under 500 simulations of varying hydro, load, forced outage, and wind conditions for future year (i.e. 2035)
- Update LT study to reflect any "need" for new resources and validate regional reliability
- Run deterministic study
- Run stochastic study (500 simulations, each hour for 2022-45)
- Run scenarios

What Aurora Outputs are used?

- Resource dispatch for Avista existing resources and resource options
  - Estimate profitability of each supply and demand side resource
  - Estimate dispatch for REC calculation for CETA
- Value the cost to serve Avista's load
- Estimate the emissions associated with supply side and storage resources
- Estimate regional emission rates for savings for energy efficiency resources
- Gain understanding of the region market
- Data is used to populate PRiSM Model

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

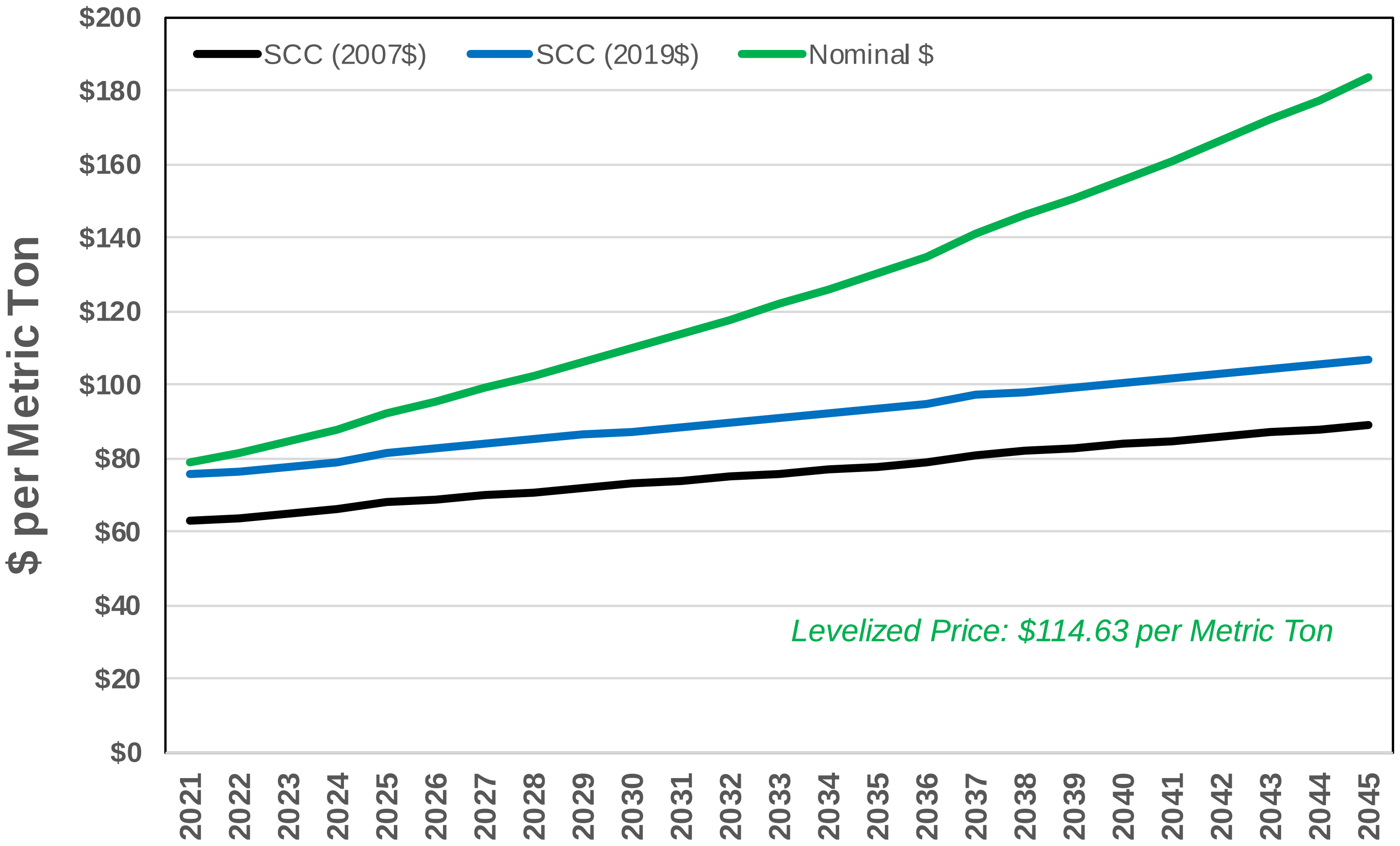
What’s new with PRiSM for this IRP

- New resources may be added to either WA, ID, or combined customer requirements.
- Existing resources will be allocated to each state using the PT ratio (~65% WA and ~35% ID).
- States may sell RECs between states.
- Washington’s former share of Colstrip units will be assigned to new “shareholder” portfolio after 2025.

Social Cost of Carbon (SCC)

- Social cost of carbon will be applied for new resource options for Washington customers; including
  - "Resulting" dispatch of natural gas resources from Aurora forecast of future real-time operations.
  - upstream emissions associated with natural gas drilling and transportation used to run facility.
  - manufacturing, construction, and operation of all resources (using NREL study).
  - storage and market resources will include estimate based on the average emissions rate of the region.
  - energy efficiency resources will use the hourly marginal emission rate of the region and reduction.
  - SCC will not be used for biomass/geothermal resources
- SSC prices will not be included for Idaho customers; although Avista could study this as a scenario

Social Cost of Carbon Prices



- Social cost of carbon dioxide in 2007 dollars using the 2.5% discount rate, listed in table 2, technical support document: Technical update of the social cost of carbon for regulatory impact analysis under Executive Order No. 12866, published by the interagency working group on social cost of greenhouse gases of the United States government, August 2016.
- Adjust to 2019$ using Bureau of Economics GDP
- Adjust to Nominal $ using 2.11% annual inflation rate

Issues not finalized

- Prices of REC transfer between states
  - Avista acquires new qualifying resources to meet Washington's portion of the law, although it may transfer RECs between Idaho and Washington for the 20% portion of CETA
- How to count REC's toward meet the "80%" portion of CETA
  - Must bundled RECs only qualify if meeting Avista WA state load each hour?
  - Serve any WA state load or any utility load?
  - Avista needs clarification from WUTC

What is Reliability Planning

- Estimate the probability of failure to serve all load
  - Avista’s reliability target is 95% of all simulations serve 100% of load and reserve requirments
- Model randomizes events
  - Hydro, weather (load, wind, resource capacity), forced outages
- Typically large sample size 1,000 simulations
- Can be used to validate if a portfolio is reliable
  - Estimate the required planning reserve margin (PRM)
  - May be used to estimate peak credits for new resources (ELCC)
- Gold standard: regional wide program with enforced requirements to each utility
  - Set required methodology, planning margin, and resource contribution based on regional model

Reliability Modeling

- 2020 IRP included ELCC analysis for a new resource alternatives and Avista Preferred Resource Portfolio for the year 2030
- Avista sees areas to improve in reliability modeling
  - Quantity of future years
  - Create ELCC curve for new resources
  - Study all portfolio’s reliability requirements
  - Improve model speed
    - Single year study takes 3 days
  - Create dynamic capability with PRiSM

Options to Address Reliability Modeling

Option	Pros	Cons
Continue using existing model (ARAM- excel model with solver)	• Results reliable for Avista system • Fully developed • Potential for modest speed improvements • Control intellectual property	• Slow • Limited to two processes • User data/knowledge intensive
Build custom professional software	• Likely faster speed • Reliable results • Potential to integrate with PRiSM	• Time to implement • Cost
Adapt Aurora	• User knowledge • Cost • Flexibility • Data management • Parallel processing limit by machines	• Slow (cost to speed up-Gurobi) • Hydro logic- results in higher LOLP • May only work for LOLH • Storage logic is slow
New Genesis Model (Power Council)	• Regional standard • Addresses regional market availability issues • Strong hydro logic • New technology	• Regional focus • Model in progress; not available for this IRP
Purchase Software/Hire Consultant	• Flexibility • Data management • Reliable results ?	• Cost • Implementation time • Risk
Regional Resource Adequacy Market	• Clear requirements for load and resources on a regional basis • Best case scenario	• Market in development not ready for this IRP • May have to make estimates for future years

Reliability Next Steps

- Continue testing Aurora application with Gurobi to understand speed improvements and result improvements
- If we use ARAM
  - Remain with single year study (2030 or 2035)
  - Use 2020 IRP ELCC estimates
  - Estimate ELCC curves for key resources (wind/ storage)
  - Conduct study for each portfolio- may result in different planning margins
  - Move to using RA logic for next IRP if a regional program is developed
- Aurora option may expand options to additional forecast years and ELCC studies
- Update progress with TAC once solution is finalized

Data Availability Proposal

- **Aurora**
  - Model requires licensing agreement with Energy Exemplar
  - Avista specific data is confidential
  - Model results will be retained by Avista
  - Avista will provide summary level results for all studies (i.e. regional prices, regional emissions, regional dispatch)
- **PRiSM**
  - All files will be available, includes annual data for each of 500 simulations for Avista resources and load
  - Requires What's Best and Gurobi license to solve, but results are fully visible
- **Load Forecast**
  - Models are confidential; models includes specific customer information and confidential data
  - Monthly energy and peak data will be available by state, along with break down between new +/- loads (i.e. rooftop solar, electric vehicles, and natural gas)
  - Full discussion of process will be covered in TAC 2
- **Resource Costs**
  - Supply-side resources spreadsheet will be available with all calculations
  - Demand-side resources; measure list and costs will be public for energy efficiency and demand response.
- **Transmission & Distribution**
  - All models and data are confidential
  - Avista will provide cost and requirements for resource integration as provided in prior IRPs
  - Full discussion of process will be covered in TAC 3
- **Reliability Planning**
  - Availability will depend on modeling solution
  - Results will be retained and available

2021 Electric IRP
Generation Resource Options

Lori Hermanson, Senior Power Supply Analyst
First Technical Advisory Committee Meeting
June 18, 2020

Overview & Considerations

- The assumptions discussed are “today’s” estimates – likely to be periodically revised
- IRP supply-side resources are commercially available technologies with potential for development within or near Avista service territory
- Resource costs vary depending on location, equipment, fuel prices and ownership; while IRPs use point estimates, actual costs will be different.
- 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 are 2020 IRP prices and will be revised with the “final” assumptions
- An Excel file will be distributed with all resources, assumptions and cost calculations for TAC members to review and provide feedback.

Outlook Since Last IRP

- Natural gas small CT – 4.4%
- Natural gas CCCT - 5.8%
- Solar – 8%
- Wind – 0.3%
- Lithium Ion Storage – 8%

Gas turbines 2022 vs 2020; others are 2022 vs 2022

Proposed Natural Gas Resource Options

Peakers

- Simple Cycle Combustion Turbine (CT)
  - Aero and frame units
  - Smaller units 44 MW to 84 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 option 249 MW (3x2)
  - Larger options 311 MW to 587 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 (100 MW)
- Off-system wind (100 MW)
- Montana wind (100 MW)
- Offshore 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
- May model alternative solar with smaller battery configurations

Other "Clean" Resource Options

- Geothermal (25 MW)
  - Off-system PPA
- Biomass (25 MW)
  - i.e. Kettle Falls 3 or other
- Nuclear (100 MW)
  - Off-system PPA share of a mid-size facility
- Renewable Hydrogen
  - Fuel Cell (25 MW)
  - Natural Gas Turbine Retrofit

Storage Technologies

Lithium-Ion

- Assumes: 88% round trip efficiency (RTE), 10-year operating life
- Assumes Avista ownership
- 5 MW Distribution Level
  - 6 hours (30 MWh)
- 25 MW Transmission Level
  - 4 hours (100 MWh)
  - 8 hours (200 MWh)
  - 16 hours (400 MWh)

Other Storage Options

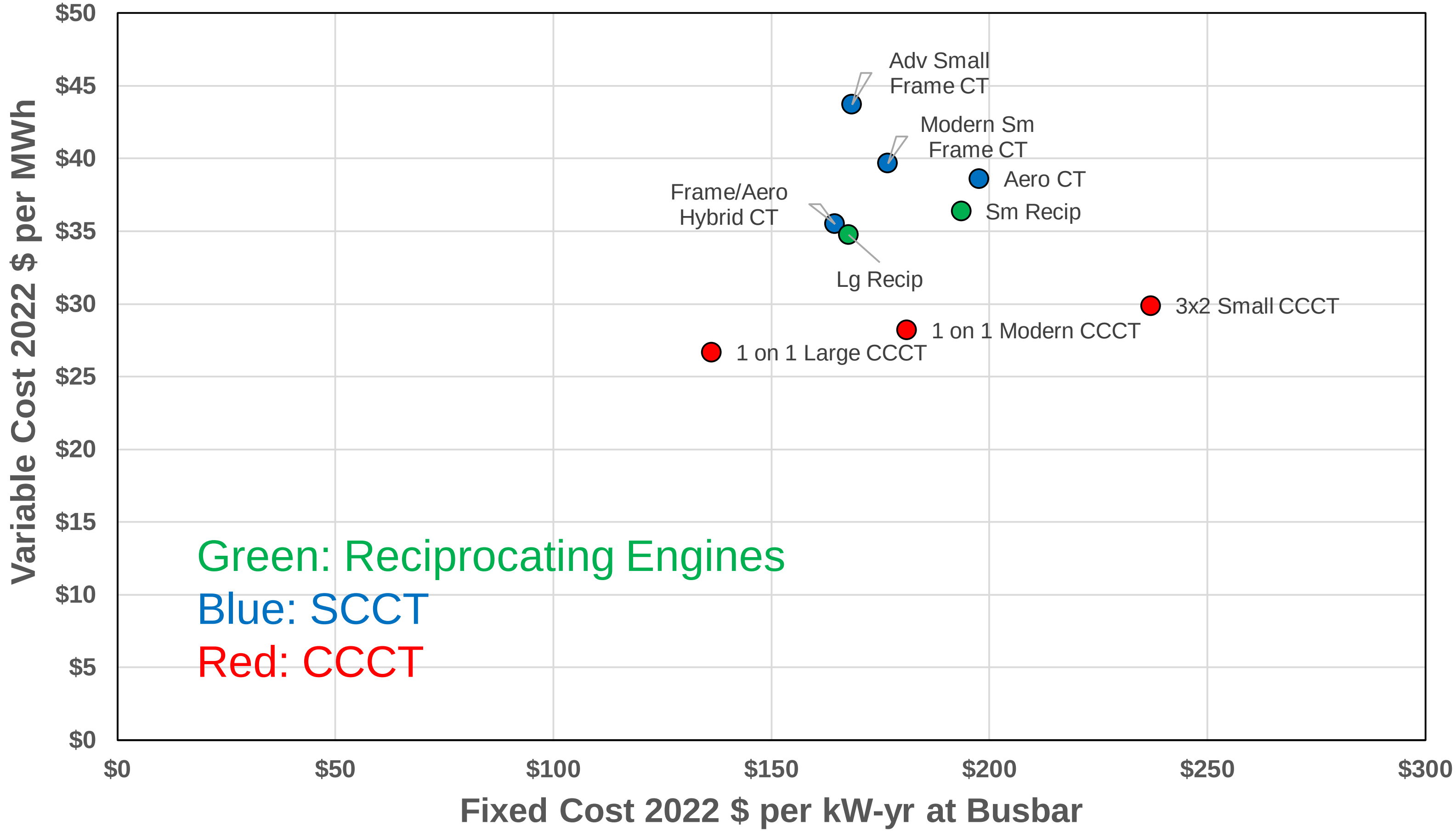
- Assumes 20 to 30-year life and Avista ownership
- 25 MW Vanadium Flow (70% RTE)
  - 4 hours (100 MWh)
- 25 MW Zinc Bromide Flow (67% RTE)
  - 4 hours (100 MWh)
- 25 MW Liquid Air (60-70% RTE)
- 100 MW Pumped Hydro
  - Share of larger project
  - PPA assumption

Updates to storage costs are likely as additional information becomes available

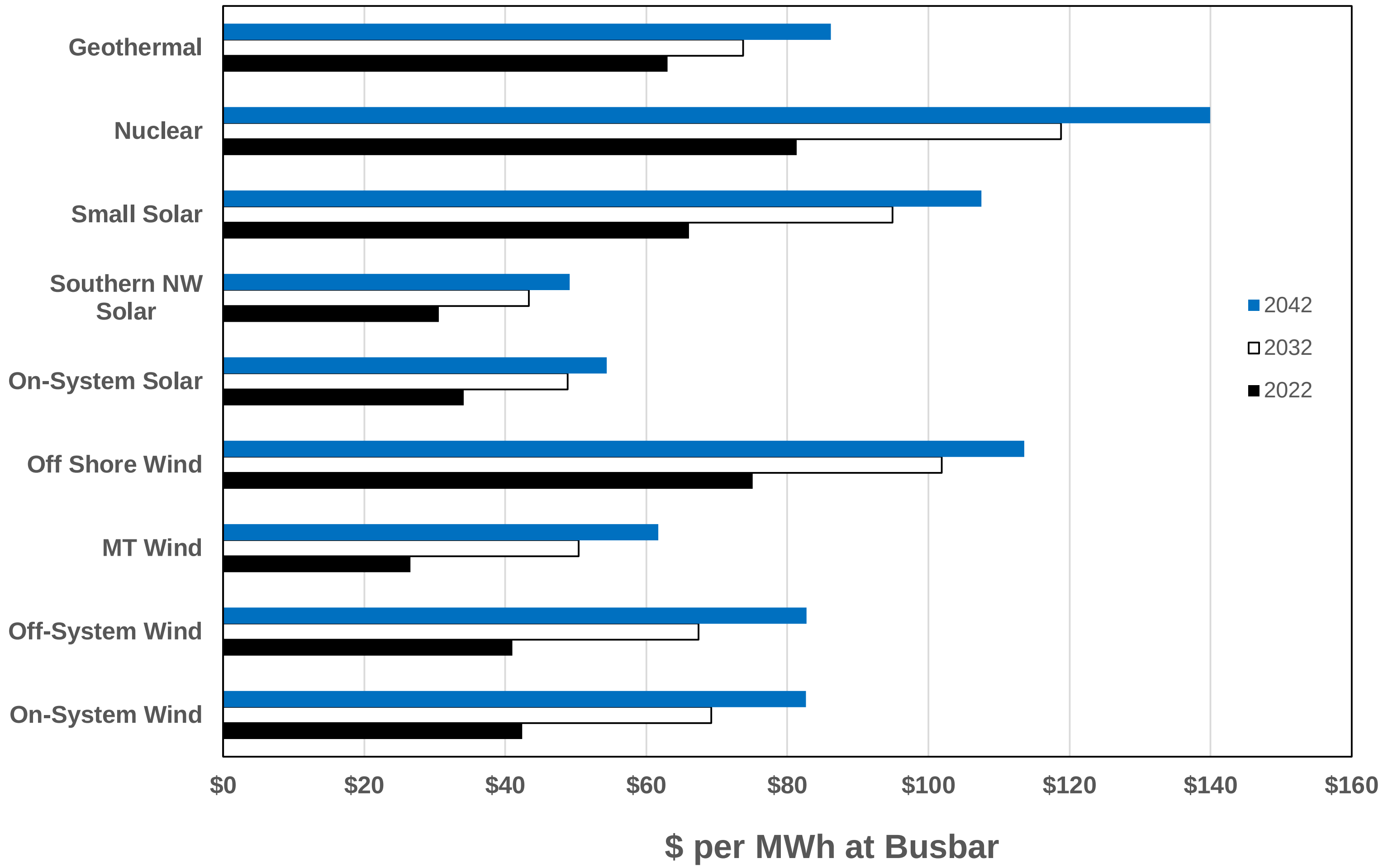
Resource Upgrades

- **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
- **Long Lake 2nd Powerhouse** *[hydroelectric]*
  - 68 MW, 12 aMW with additional powerhouse located at the current “cutoff” dam
- **Cabinet Gorge** *[hydroelectric]*
  - 110 MW, 18 aMW using the “bypass” tunnels to capture runoff spill

Natural Gas Fixed & Variable Costs



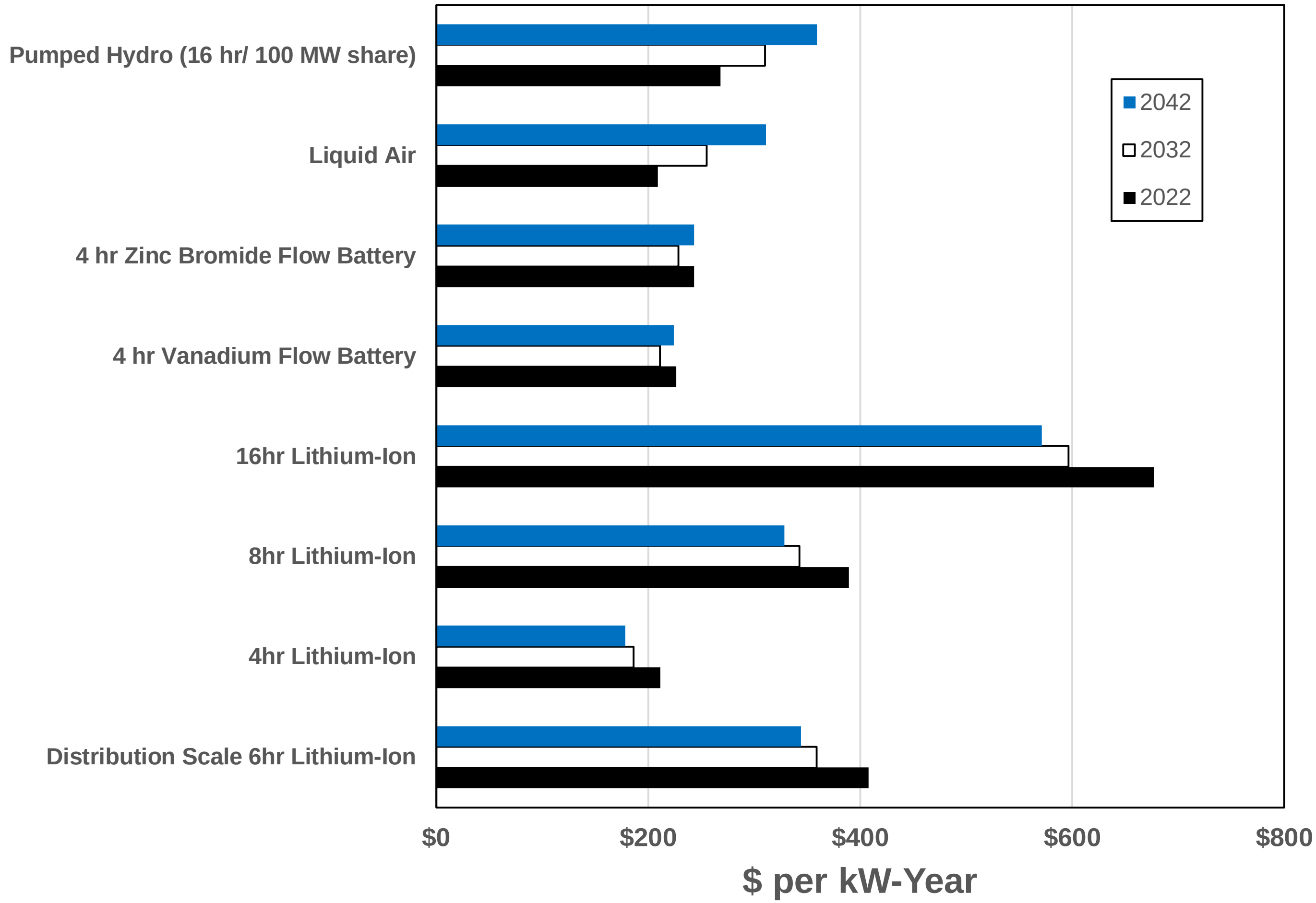
PPA Resource Cost Analysis



Prices include utility loading such as variability integration and revenue taxes

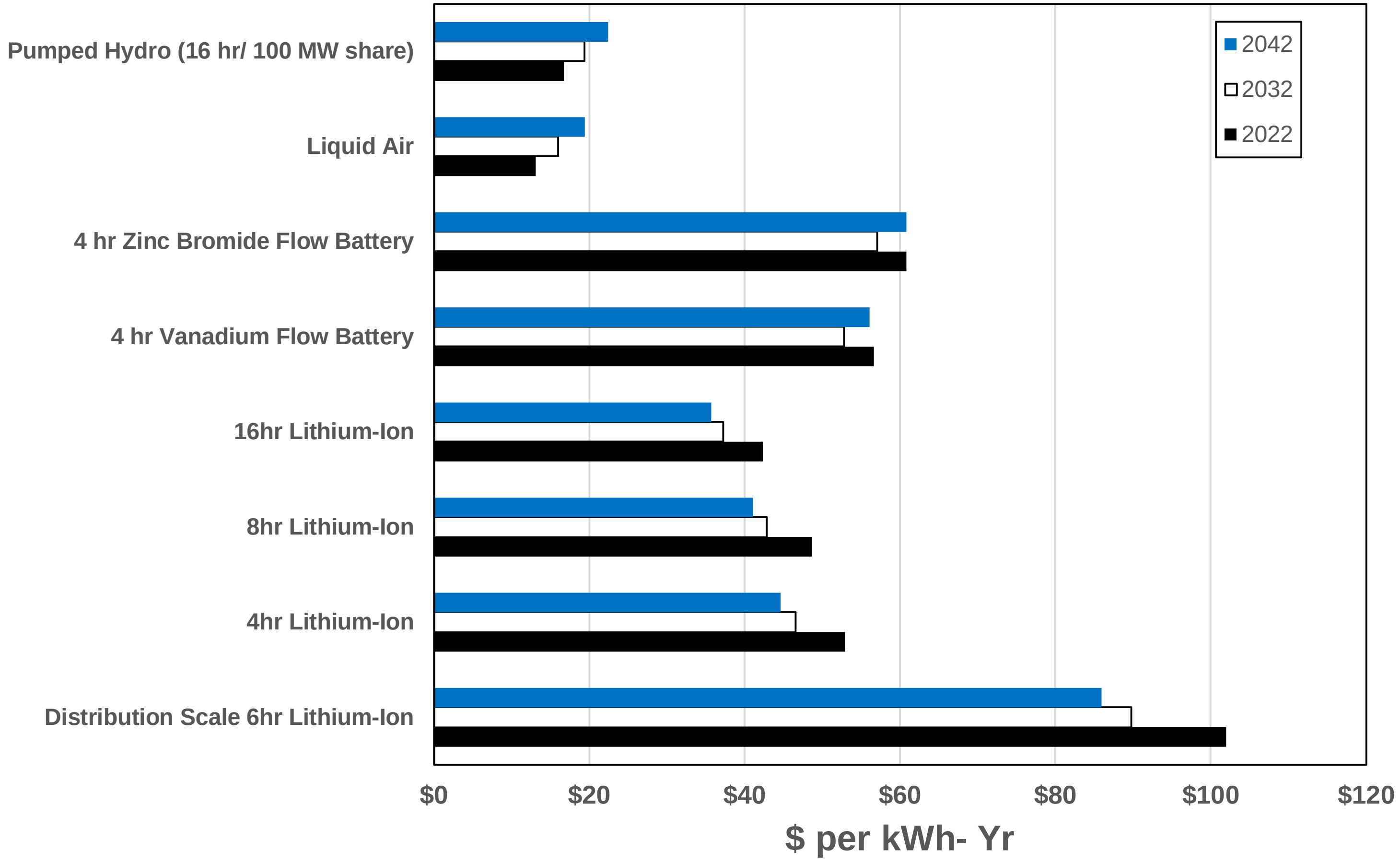
Storage Costs

Capacity based cost analysis

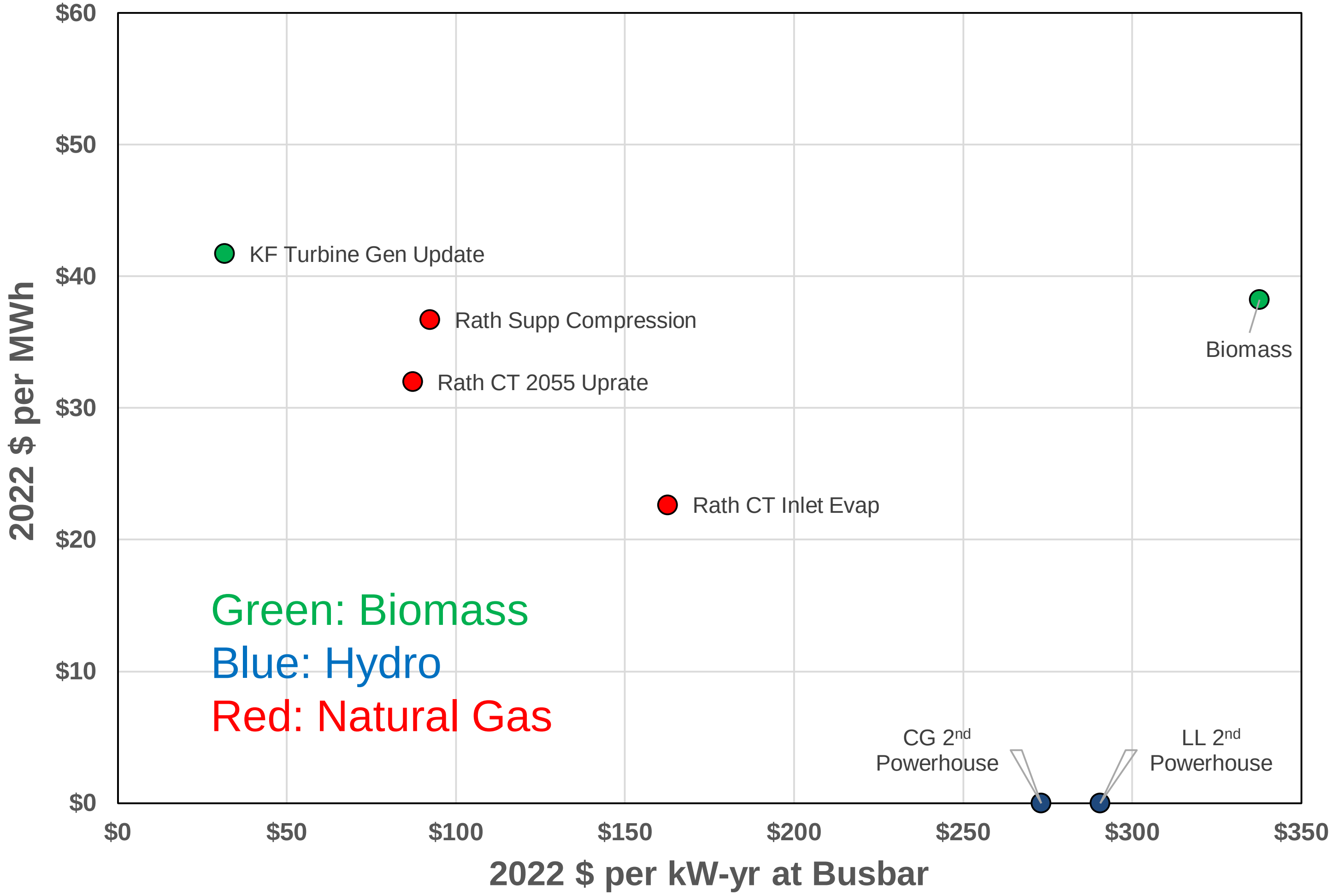


Storage Costs

Energy based cost analysis



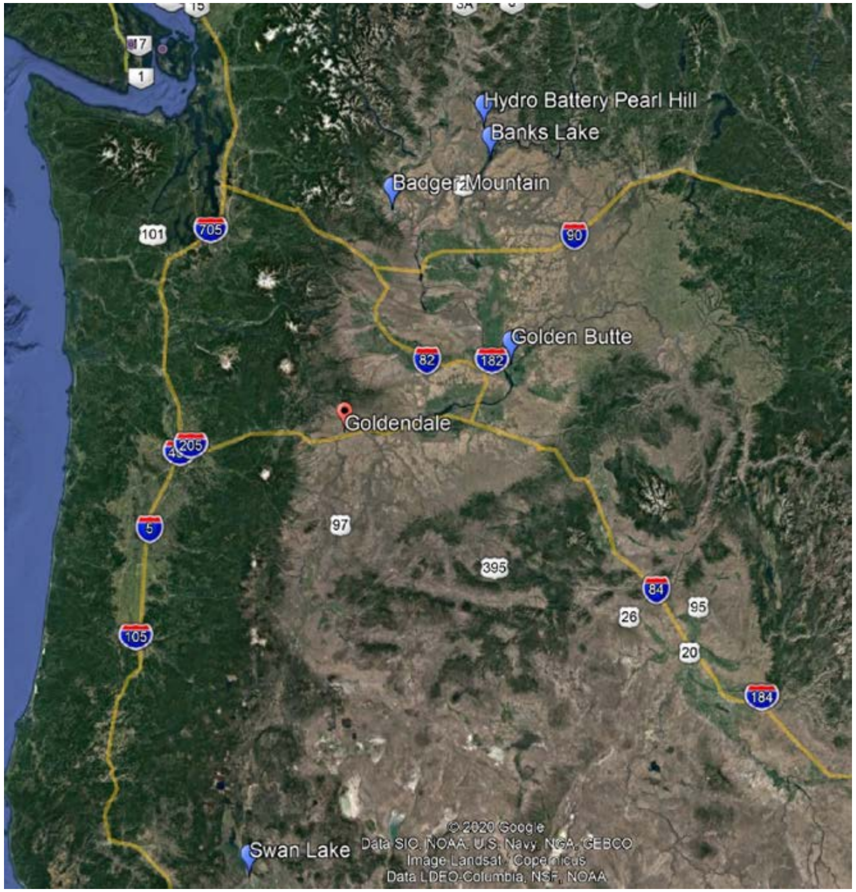
Facility Upgrade Cost Analysis



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 Dialogue contracts expire

Other Items for TAC Input



- Pumped hydro
  - Model specific projects vs. generic options
- Hydrogen Technologies (still researching)
  - Fuel cell
  - Gas turbine retrofit
- Will consider other resource options subject to TAC input

Review Excel Sheet

2021 Electric IRP
Washington Vulnerable Populations & Highly Impacted Communities

James Gall, IRP Manager

First Technical Advisory Committee Meeting

June 18, 2020

CETA: Section 1

(6) The legislature recognizes and finds that the public interest includes, but is not limited to:

- The equitable distribution of energy benefits and reduction of burdens to vulnerable populations and highly impacted communities;
- long-term and short-term public health, economic, and environmental benefits and the reduction of costs and risks;
- and energy security and resiliency.

It is the intent of the legislature that in achieving this policy for Washington, there should not be an increase in environmental health impacts to highly impacted communities.

Definitions

(23) "Highly impacted community" means a community designated by the department of health based on cumulative impact analyses in section 24 of this act or a community located in census tracts that are fully or partially on "Indian country" as defined in 18 U.S.C. Sec. 1151

(40) "Vulnerable populations" means communities that experience a disproportionate cumulative risk from environmental burdens due to:

> (a) Adverse socioeconomic factors, including unemployment, high housing and transportation costs relative to income, access to food and health care, and linguistic isolation; and
>
> (b) Sensitivity factors, such as low birth weight and higher rates of hospitalization.

How Avista Reaches These Communities Today

- Low income assistance
- Senior/disability rate discount
- Project share
- Energy efficiency programs
- Energy fairs and workshops
- Corporate and Avista Foundation giving
- Energy home audits
- Prevention of wood smoke part of energy efficiency analysis
- Wildfire mitigation program
- Public access to hydro facilities
- Park development
- Neighborhood engagement when developing projects

- Tribal hiring
- Energy pathways program
- Tribal settlements
- Hydro relicensing outreach
- Wildlife land purchases

IRP Requirements (Section 14)

(k) An assessment, informed by the cumulative impact analysis conducted under section 24 of this act, of: Energy and nonenergy benefits and reductions of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits, costs, and risks; and energy security and risk;

Sec. 24. By December 31, 2020, the department of health must develop a cumulative impact analysis to designate the communities highly impacted by fossil fuel pollution and climate change in Washington. The cumulative impact analysis may integrate with and build upon other concurrent cross-agency efforts in developing a cumulative impact analysis and population tracking resources used by the department of health and analysis performed by the University of Washington department of environmental and occupational health sciences. [https://www.doh.wa.gov/CETA/CIA]

How Will Avista Address These New Requirements?

- Gain perspectives from advisory group(s) for additional requirements or from new rules
- Identify and engage highly impacted communities & vulnerable populations
  - Advisory groups
  - Encourage representatives to either participate in existing advisory groups or potentially create a new advisory group to address the community impacts.
- Create baseline data
- Estimate benefits/impacts from IRP

Identifying Communities or “Customers”

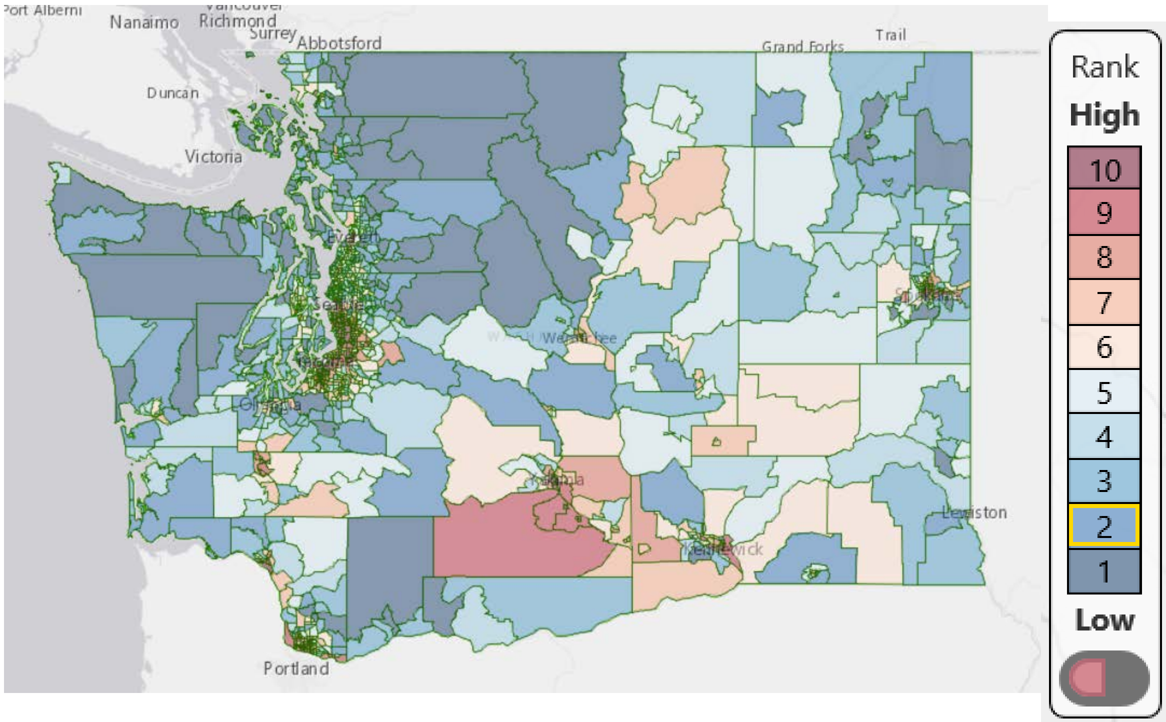
Highly Impacted Communities

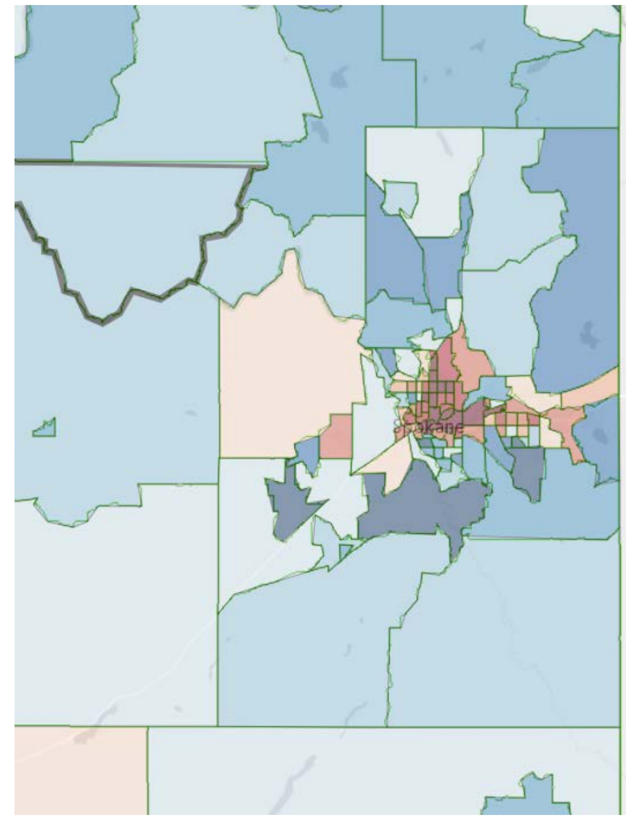
- Cumulative Impact Analysis
- Tribal lands
  - Spokane
  - Colville
- Locations should be available by end of 2020
  - State held workshops in August & September 2019

Vulnerable Populations

- Use Washington State Health Disparities map
  - What is disproportionate on a scale of 1 to 10?
  - Avista proposes areas with a score 8 or higher in either Socioeconomic factors or Sensitive population metrics
- Should we include other metrics to identify these communities?

Environmental Health Disparities Map

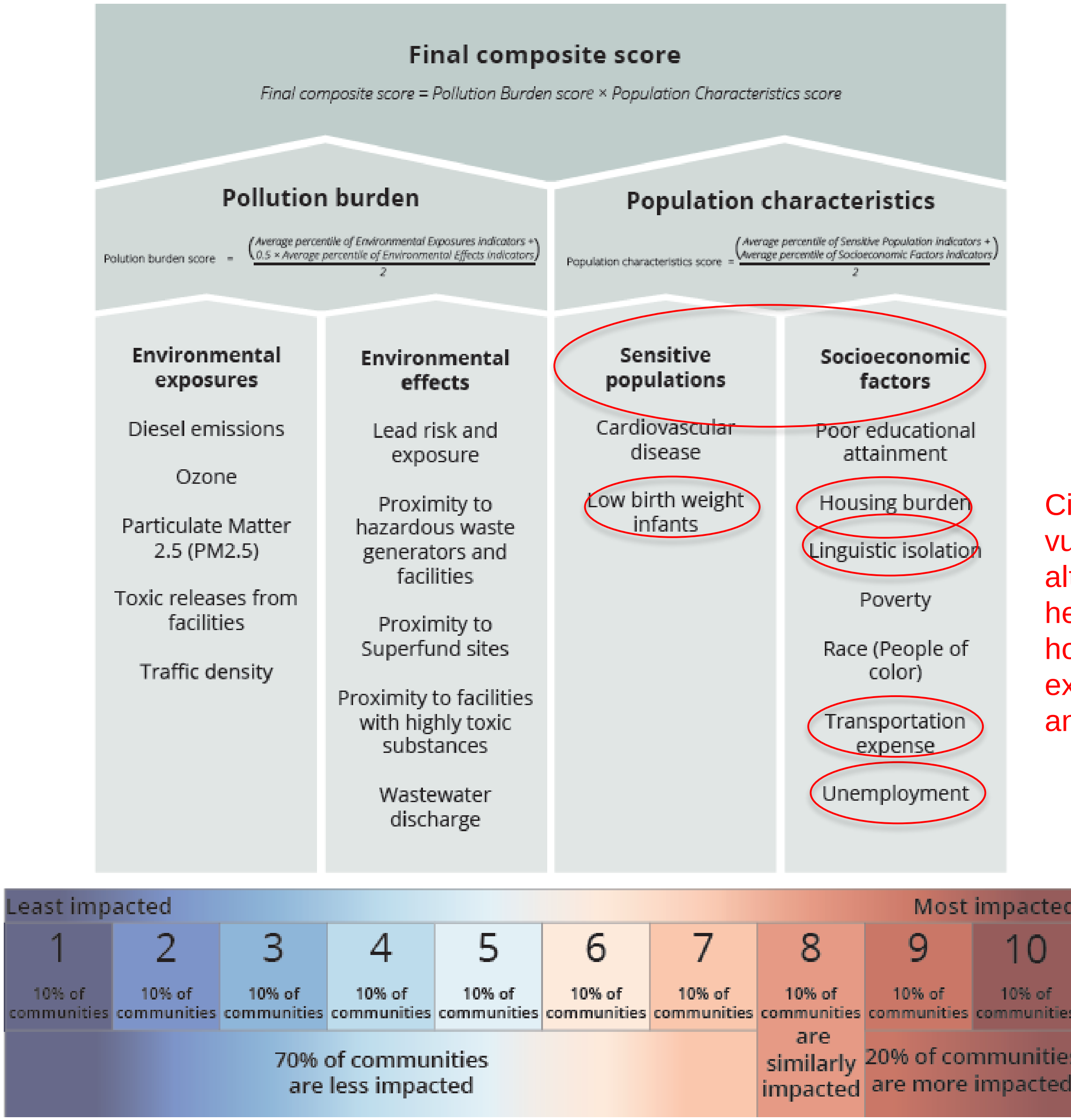




https://fortress.wa.gov/doh/wtn/wtnibl/

Data by FIPS Code

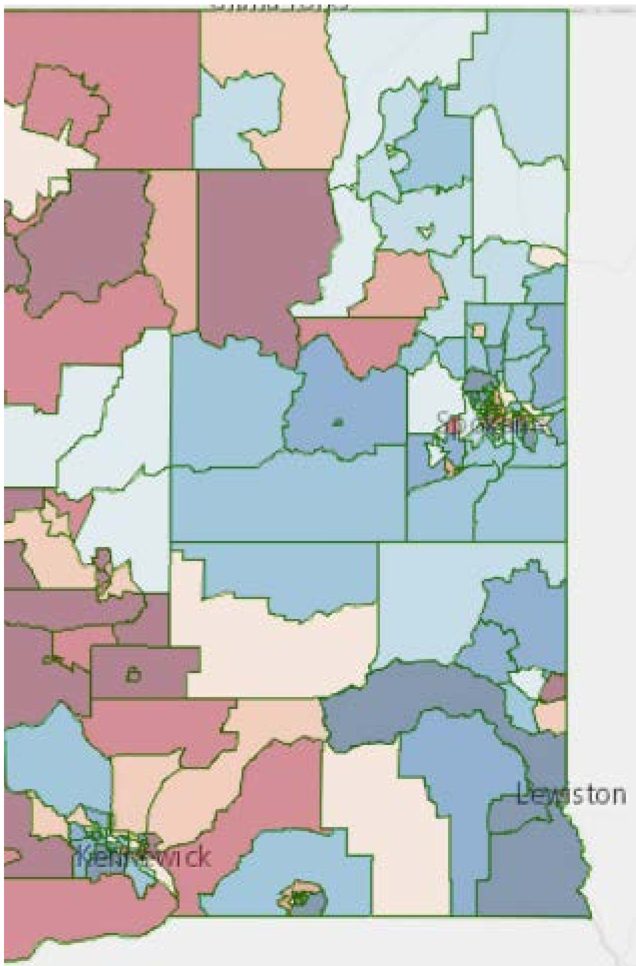
Environmental Health Scoring

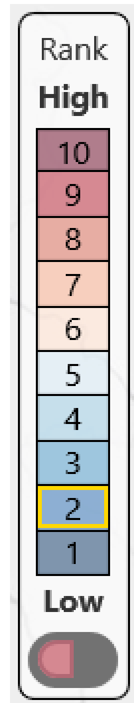


Circle areas match definition of vulnerable population, although access to food & health care, higher rates of hospitalization are not expressively included but are an indication of poverty

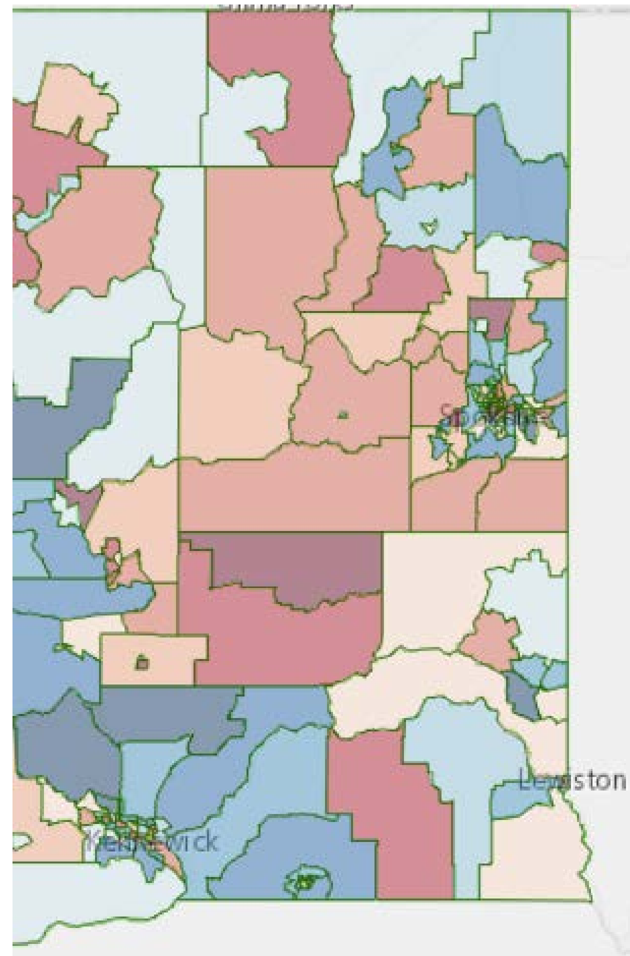
Eastern Washington Communities

Socioeconomic Factors

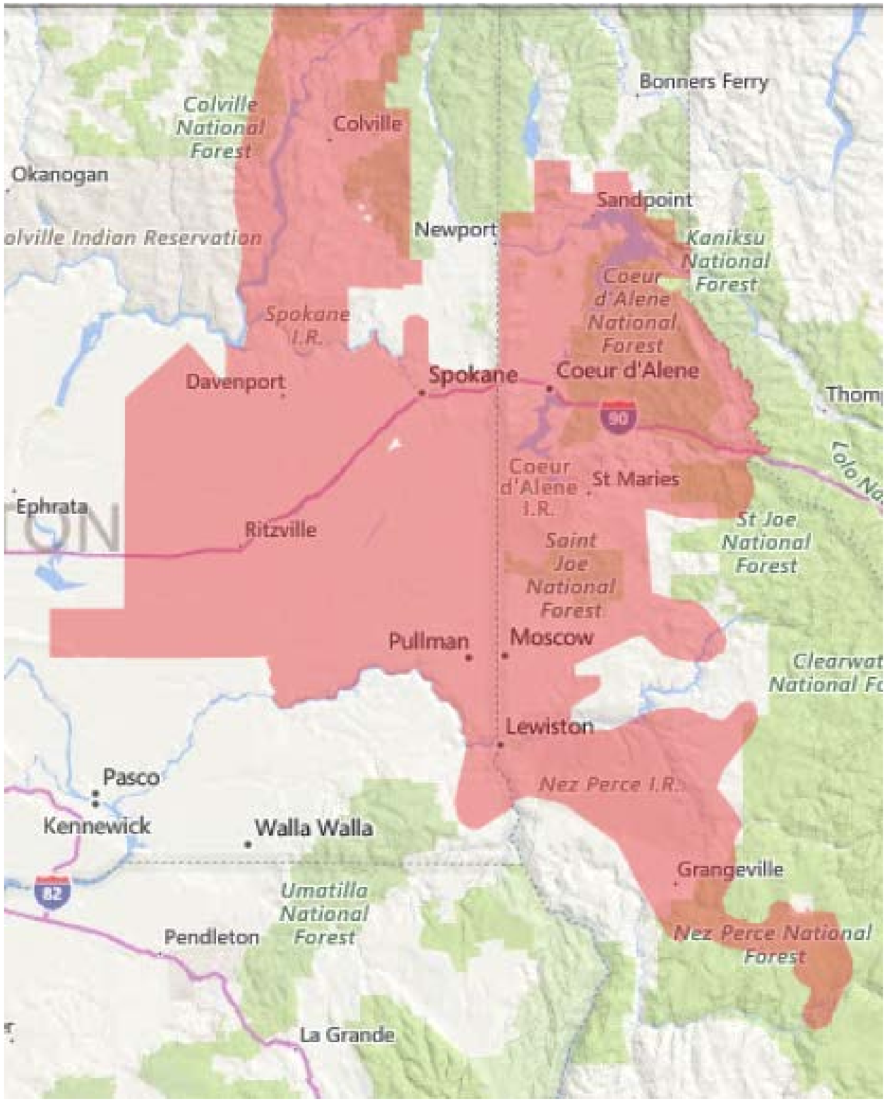




Sensitive Populations



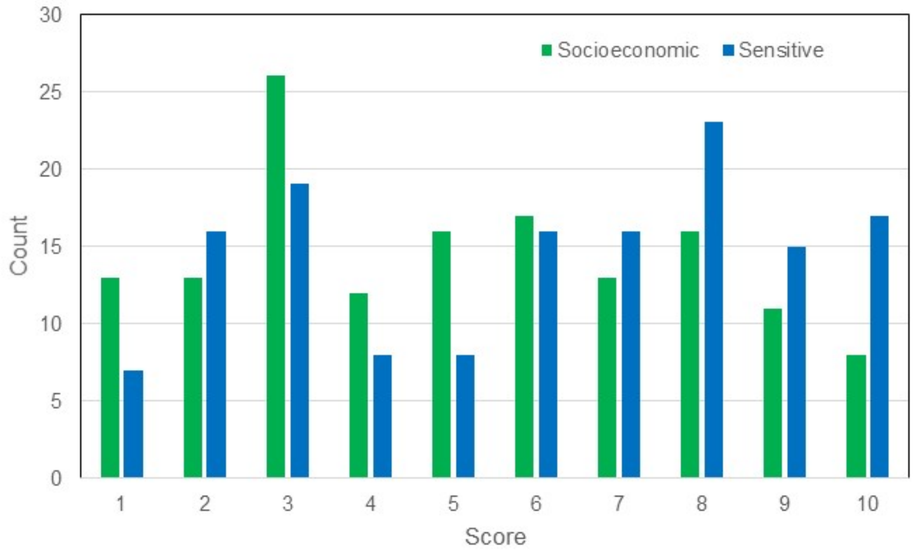
Avista Electric Service Territory



Data Analysis of Vulnerable Populations

Avista has 145 communities identified

- 35 (24%) have an 8 or higher for Socioeconomic Factors
- 55 (38%) have an 8 or higher for Sensitive Populations
- 67 (46%) are considered vulnerable



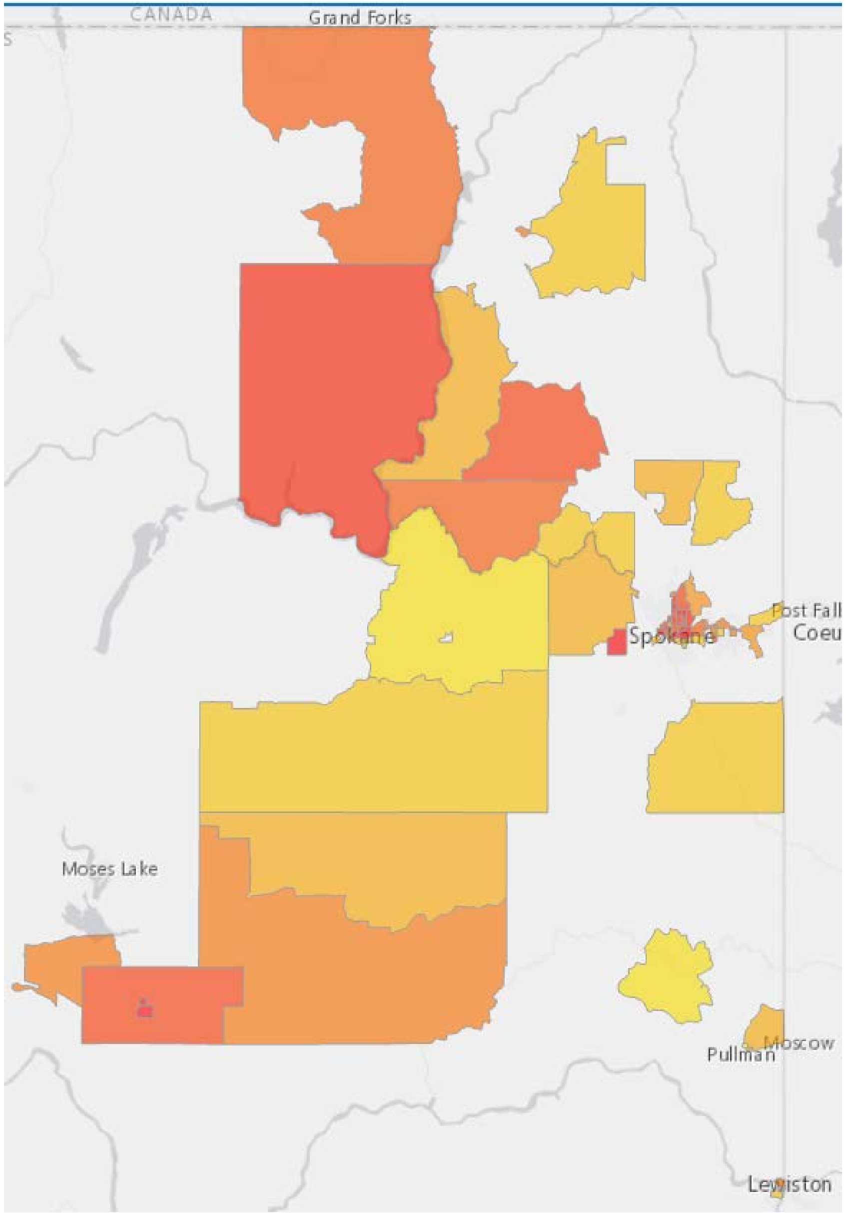
	Socioeconomic	Sensitive
Avista (Mean)	5.1 (5 median)	6.0 (6 median)
State (Mean)	5.4 (5 median)	5.2 (5 median)
Avista (Stdev)	2.67	2.83
State (Stdev)	2.88	2.88

Selected Vulnerable Populations

Vulnerable Populations

Sensitive Pop + Socioeconomic Factors Rank

- ≤9
- ≤10
- ≤12
- ≤13
- ≤14
- ≤15
- ≤16
- ≤17
- ≤18
- ≤20



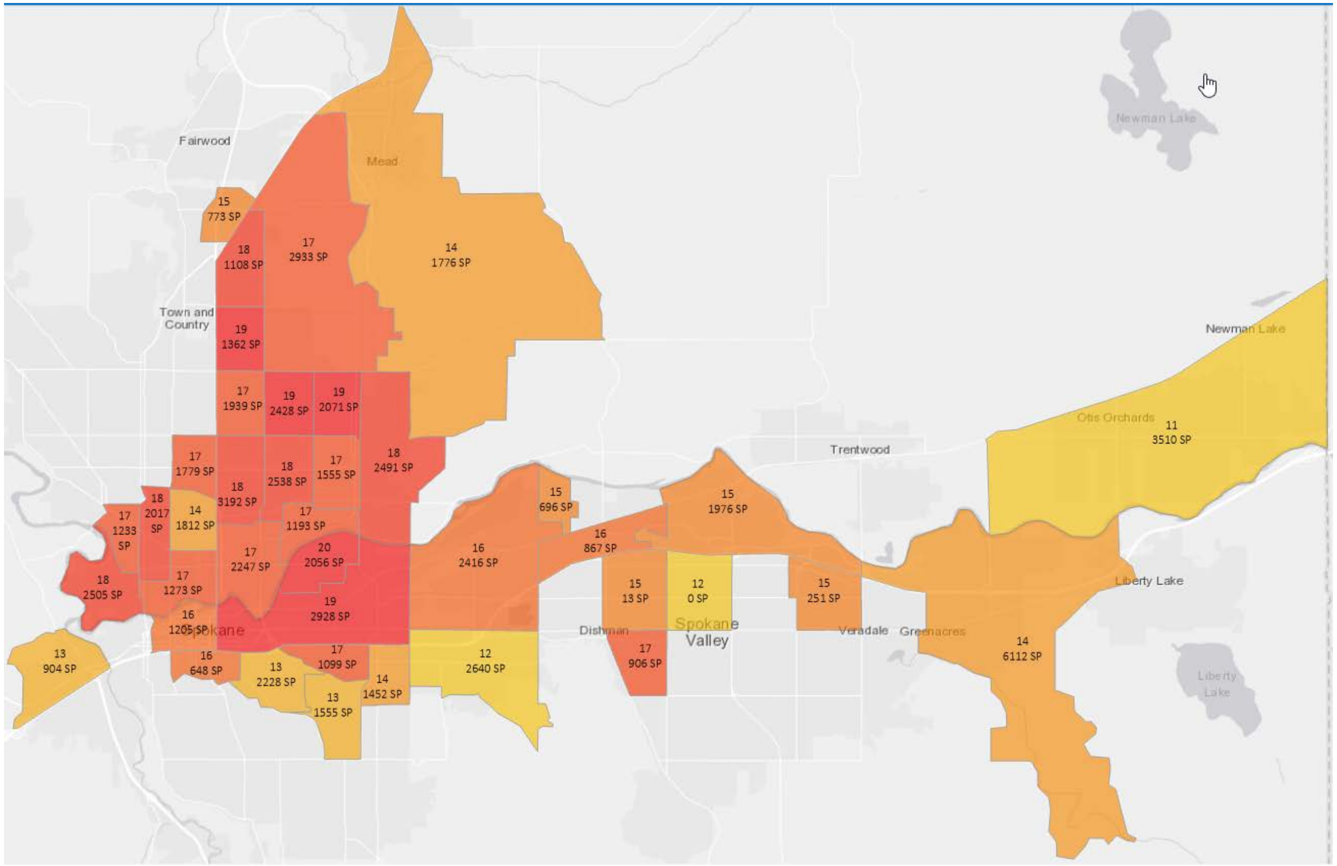
Data is shown by combined score

Spokane Area "Avista" Vulnerable Populations

Vulnerable Populations

Sensitive Pop + Socioeconomic Factors Rank

- ≤9
- ≤10
- ≤12
- ≤13
- ≤14
- ≤15
- ≤16
- ≤17
- ≤18
- ≤20



Data is shown by combined score

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IRP Metrics

Metric	IRP Relationship
Energy Usage per Customer	• Expected change taking into account selected energy efficiency then compare to remaining population. • EE includes low income programs and TRC based analysis which includes non-economic benefits.
Cost per Customer	• Estimate cost per customer then compare to remaining population. • How do IRP results compare to above 6% of income?

Preference	• Should the IRP have a monetary preference?
	    • For example- should all customers pay more to locate assets (or programs) in areas with vulnerable populations or highly impacted communities?
	    • If so, how much more?

IRP Metrics

Metric	IRP Relationship
Reliability • SAIFI: System Average Interruption Frequency Index • MAIFI: Momentary Average Interruption Frequency Index	• Calculate baseline for each distribution feeder and match with communities • Estimate benefits for area with potential IRP distribution projects • Compare to other communities as baseline • May be more appropriate in Distribution plan rather than IRP
Resiliency: • SAIDI: System Average Interruption Duration Index • CAIDI: Customer Average Interruption Duration Index • CELID: Customer's Experiencing Long Duration Outages	
Resource Analysis	• Estimate emissions (NO_X, SO_2, PM2.5, Hg) from power projects located in/near identified communities • Identify new resource or infrastructure project candidates with benefit to communities; i.e. economic benefit, reliability benefit • Identify how resource can benefit energy security

TAC Input

- What other metrics can we provide in an IRP to show vulnerable populations and highly impacted communities are not harmed by the transition to clean energy

Attendees: TAC 1, Thursday, June 18, 2020 Virtual Meeting on Skype:

Shawn Bonfield (Avista), Terrance Browne (Avista), Logan Callan (City of Spokane), Teri Carlock (IPUC), John Chatburn (Idaho Governor's Office of Energy and Mineral Resources), Corey Dahl (Washington State Office of the Attorney General), Thomas Dempsey (Avista), Chris Drake (Avista), Annabel Drayton (NW Energy Coalition), Michael Eldred (IPUC), Nancy Esteb (Renewable Energy Coalition), Chip Estes, Rachelle Farnsworth (IPUC), Ryan Finesilver (Avista), Damon Fisher (Avista), Grant Forsyth (Avista), James Gall (Avista), Annie Gannon (Avista), Amanda Ghering (Avista), Dainee Gibson (Idaho Conservation League), Kate Griffith (Washington UTC), Vlad Gutman-Britten (Climate Solutions), Leona Haley (Avista), Jared Hansen (Idaho Power), Lori Hermanson (Avista), Kevin Holland (Avista), Kristine Holmberg (Avista), Tina Jayaweera (Northwest Power and Conservation Council), Clint Kalich (Avista), Kevin Keyt (IPUC), Kathleen Kinney (Biomethane, LLC), Scott Kinney (Avista), Dean Kinzer (Whitman Co. Commissioner's Office), Erik Lee (Avista), John Lyons (Avista), James McDougal (Avista), Matt Nykiel (Idaho Conservation League), Tom Pardee (Avista), Jørgen Rasmussen (Solar Acres Farm), John Ross, John Rothlin (Avista), Jennifer Snyder (Washington UTC), Dean Spratt (Avista), Jason Thackston (Avista), Marissa Warren (Idaho Governor's Office of Energy and Mineral Resources), Amy Wheeless (NW Energy Coalition), and 13 Guests who did not identify themselves.

Questions and comments are identified by speaker when possible and text in *italics* records the responses by the presenters.

TAC Expectations & Process Overview

John Lyons: A new stakeholder feedback form will be added to the IRP website. Slides from this meeting will be posted on the IRP website next week. The generation resource options spreadsheet was emailed earlier this week. Avista is also considering different options for meetings and sharing of TAC materials, but we will continue to post meeting notes on the website. We will attempt to record these meetings.

John Lyons: Washington now requires an IRP every 4 years with an update after two years. Washington law (Clean Energy Transformation Act or CETA) does not allow for the Commission to acknowledge an IRP without all of the CETA requirements and rulemaking in place, moving the next IRP out until 4/1/21. The 2021 IRP will be modeling 2021 through 2045 (for CETA). Avista welcomes requests for additional studies by August 1, 2010, but earlier is better for accommodating any requests. The dates of future TAC meetings are in the presentation and posted on the IRP web site.

2020 IRP Acknowledgement – John Lyons

IRP acknowledgement means the filing has met the rules for IRPs in both states. It includes comments about topics to include or build upon in the next IRP. Acknowledgement does not provide rate recovery, but is a component of rate recovery. If a new resource wasn't chosen in the IRP, we have more explanation required what it was not identified in the IRP. Because of the extension for the 2020 IRP, we do not have acknowledgements to review in this meeting. The Idaho Commission is accepting comments from the public through August 19, 2020 with replies due from the Company by September 2, 2020. A key area of expected concern is how Avista will develop an IRP that accommodates Washington's CETA requirements, but not adversely impact Idaho customers. Washington suspended acknowledgement letter through December 31, 2020, but provided some comments on the work plan including providing an opportunity for stakeholder input on the conservation potential assessment (CPA) before finalization, extending participation to a broader public audience, and providing a timeline of IRP data and when it will become available.

CETA Rulemaking Update – Shawn Bonfield

CETA applies to all electric utilities in Washington. It requires 100% clean energy, the elimination of coal from serving Washington customers by 2025, greenhouse gas neutral by 2030 and at least 80% clean, and 100% renewable or generated from zero-carbon resources by 2045. CETA also requires equitable distribution of energy and non-energy benefits and to ensure public health and environmental benefits. Avista is well above the 15% renewable standard required under the Energy Independence Act (I-937). Avista is about 60% clean/renewable today. 2020 is a big year for CETA rulemaking: Phase 0 included the overall implementation plan. Phase 1 (August 2019 – January 1, 2021) includes the already published the Social Cost of Carbon (https://www.utc.wa.gov/regulatedIndustries/utilities/Pages/SocialCostofCarbon.aspx) for use in resource planning and the CPA, and the initiation of other required rulemaking dockets. Concurrent EIA draft rules are about done and hopefully will be adopted next month. Other areas include the CEIP – how utilities will look at compliance and penalty processes; IRP updated rulemaking – July timeframe; Purchase of Electric (impacts RFPs) draft rules June 1 with comments due end of June with a workshop mid-July; Department of Ecology rulemakings will identify greenhouse gas emission factors; and plenty of other rulemaking activity at the Department of Commerce, the UTC and other agencies.

Jennifer Snyder: Thank you. You covered it well. We (Washington UTC) appreciate any comments and participation in the CETA rulemaking process.

Modeling Process Overview – James Gall

James Gall: Aurora in an electric market cost model that is used to simulate the Western Interconnect. It is the industry standard model in the Northwest. Avista implemented Aurora in 2003 and uses it for IRP and rate cases. The inputs include regional loads, fuel prices, resource availability, new resource costs, transmission, and system constraints. Outputs include market prices, energy mix, transmission usage, emissions, power plant margins, generation levels, fuel costs and variable power supply costs to serve loads by year. Market price forecast helps us develop a purchase/sales strategy. The model dispatches to meet hourly loads in each area and tries to match supply with demand or loads and resources. Market price is based on the price for the last, or marginal, plant to turn on for that hour.

Matt Nykiel (Slide 3): I have a better understanding of Aurora after participating in the last IRP. For slide 3 inputs and following, I'd like a general understanding of what inputs are public and private in Aurora. *We'll cover some here and there is a slide later that cover more. The database from EPIS is proprietary and they use it for all of their clients who are Aurora license holders. It is largely based on publically available information from EIA, EPA, etcetera, but we can't release it per our license. There are adjustments for Avista including data that will be changed to reflect our contracts, pricing, and operational requirements and how we operate our resource which are proprietary. We'll describe more alter in the presentation.* Thank you.

James Gall: Deterministic studies are single point estimates with median hydro and expected loads. They are easy for scenario analyses. Stochastic studies use the expected case or preferred portfolio providing a range of results. The model runs 500 times with different inputs in order to understand risk or volatility. Avista uses the mean value of stochastic analysis for its expected case. Stochastic studies provide better representation of expected value of resources. The model assumptions start from 2020 IRP. We use the same database available from Energy Examplar today; then update natural gas prices, new resources and retirements, include new laws, review load/resource assumptions for EVs, rooftop solar, new resource costs, add Avista proprietary system info and stochastic distribution of regional hydro, natural gas, wind and loads. We will provide what's not confidential. The Aurora run process-request input will need to be done ASAP, finalize inputs, run long term studies to estimate new resource additions and will show results at next TAC. We will test under 500 simulations and test a future year – 2035. The deterministic run tests reasonableness. The stochastic run takes 3 weeks to run the scenarios. It is a very tight timeline. The outputs will show how profitable each of the resources are to understand dispatch under CETA. This helps us value the cost to serve, estimate emissions, understand changes to the regional market such as volatility, emissions, etc., and the data used for PRiSM.

Matt Nykiel (Slide 7): You mentioned long-term study. Is this what Avista thinks how the region will meet demand? Is this Avista's interpretation or is it based on other utilities that have their own IRPs? *That's a good question. It's multiple ways. We* *typically have not utilized other utility's IRPs since they only cover a portion of the area and could be dated. Some utilities don't do IRPs. We look at the region of load obligations, the current resource mix, and state requirements. The model selects new resources for most cost effective for those load areas given our cost assumptions. We have also looked at other studies, consultant data for storage and small renewables. This is a fairly industry standard approach.*

James Gall: PRiSM is where all of the models come together from an input perspective to make resource decisions. It is internally developed. We input resource needs and options. The model will select resources that meet needs based on constraints. 'What's Best' is the solver function – min/max of a variable to optimize the value with unlimited variables/constraints. What's Best plus Gurobi speeds up optimization especially when considering so many inputs such as energy efficiency. The outputs include the power supply costs (fixed + variable) and variation; selection of new resources, etc. We design the model to add new resources to serve Washington, Idaho or combined customer requirements. We will split our resource cost using the P/T ratio [35% Idaho and 65% Washington]. States may sell RECs to help recover customer costs.

James Gall (Slide 10): The last IRP showed that Colstrip was not cost-effective past 2025. We will reevaluate Colstrip in this plan as no decision has been made. After 2025, since we're splitting by state in PRiSM for the resource balance, Idaho will still receive its 35% share of Colstrip unless it's determined that it will be retired. There is an option to retire in Colstrip in 2025 or in the future.

Vlad Gutman-Britten: Does the future year on the chart incorporate potential climate change? *Typically impacts include from climate change include load and hydro. We are open to for 2045 about how climate change impacts these forecasts*

John Lyons: Grant [Forsyth] picks these changes up in his load forecast.

Grant Forsyth: I try to look at how temperatures change. The approach is a moving average for weather. People can ask more about that during my presentation in the next TAC meeting [August TAC].

James Gall (Slide 11): The Social Cost of Carbon (SCC) is required for Washington under CETA. We will run the model to get the expected amount of emissions for each resource. This is for long-term not short-term resources. We will calculate emissions from short-term resources and may cover those at a future TAC. We will not include SCC for biomass or geothermal since those resources are specifically outlined in law, or for Idaho, but we could consider including for Idaho as a scenario if the TAC wants.

James Gall (Slide 12): SCC pricing – 2007 $ and discounted 2.5% (on the lower range). Will use the green line in the chart which starts at $80 per ton. We move prices from 2007 to 2019 and inflate based on our annual inflation rate of 2.11%.

James Gall: (Slide 13): Issues Not Finalized. We may transfer RECs between states, but must determine the price to transfer RECs at. We will need input on if we need to consider transferring more than 20% if there is an economic benefit. How do we count RECs toward the 80%? Will this be hourly or over the four-year compliance period? If we receive no clarification, we will need to make assumptions to model the IRP. This may be the biggest rulemaking from CETA that the UTC needs to resolve, hopefully in early fall, so it can be modeled correctly for this IRP.

James Gall (Slide 14): Reliability planning. We estimate probability of failure to serve all load to a regional standard of 5%. To evaluate whether a portfolio is reliable – PRM (planning reserve margin) is the percentage above the expected load measured by the coldest day of each month averaged by that temperature, load requirement, plus planning margin. This helps us understand how much we can rely on certain resources. The gold standard would be a region wide program with enforced requirements for each utility. Currently, the region is looking at moving toward this model, but probably not in time for this IRP. So, we need to decide how much time we invest in this issue now. ELCC (Electric Load Carrying Capability) – improvement by focusing on additional years, sampling every 5 years, peak credits or peak types. As you add intermittent resources peak value declines. We haven't ran an ELCC for each resource to determine how much the peak contribution reduces over time.

James Gall (Slides 15 – 17): Reliability study models to consider. ARAM model is used currently and is customized (not for this IRP). Aurora has ability to dispatch hydro – not as good when the system is stressed leading to over acquisition. Genesis is an option for the future. We can purchase software/hire consultant – this is costly and not currently being looked at. Regional Resource Adequacy Market – could be used for a future option. Two areas of focus are ARAM and Aurora – likely our current model with a single year and possibly scenarios, but we can't commit to every year, use 2020 ELCC (peak credits) scenario on resource adequacy. We will keep the TAC updated throughout the process.

James Gall (Slide 18): Data availability – proposal, we are interested in feedback for. Avista-specific data and Energy Exemplar database is proprietary, prices, regional emissions, not dispatch (confidential), high level results including PRiSM, won't be able to make inputs and resolve (requires license), big change from prior IRPs, load forecast models are confidential because of customer-specific information. We will provide monthly energy/peak results by state, resource costs (you already received); demand-side data will include a list of energy efficiency programs available, may not be fully available in July/August so we may have a short, 1-hour workshop when that data becomes available. DR programs and their potential. Transmission/distribution models are confidential and will be a TAC 3 discussion. Reliability – ARAM requires a license so you can't input and resolve, but we are researching to ensure we can make it available.

Michael Eldred: I have a question of how you are testing for reliability. *LOLP in 2035, 500 times in that year. The percent probability load not met. The goal is 95% meeting in all times. In most cases it does. If results are grossly inadequate and outside the margin of error, we rerun the study. Does that help?* Yes, thank you.

Matt Nykiel: LT study, when Avista is looking over a range of resources is it taking into account things like customer owned generation over time as roof top solar reduces demand on IOUs? *Good question. Slide 6 specific adjustment made to model. We will present assumptions in the market price meeting. Definitely an area we will have to consider.*

Matt Nykiel: Recall that was an analysis for Avista, but how meeting regional WECC loads but in area. *Yes, we look at both inside Avista and outside the service territory. Looking to point to the right spot in the last IRP. Typically not a lot of discussion. It is a small but important input. Will definitely talk about it in the next TAC.*

James Gall: I appreciate the better interaction on these questions.

Tina Jayaweera: I'm interested in more about emissions savings in energy efficiency and demand response. *DR is challenging and depends on program – some reduce and some shift loads, and the likelihood of a DR program being called on based on program design could be a challenge. Energy efficiency typically uses an hourly profile of savings compared to hourly emissions from Aurora – possibly could run a scenario to see how emissions change by the hour. We can do this for the deterministic but not all 500 runs. Could show incremental savings.*

Dainee Gibson: A lot of CETA requires the model to be able to split differences geographically. Can Aurora split it by state or does it apply to the entire service territory? *Sure. We could split it by state, but it doesn't model the physics well. Now we talk about region as a whole. The OWI bubble in Aurora can't split by state really well, since the system doesn't recognize state boundaries. Avista in PRiSM is where we talk about how we split resources by state from a resource planning perspective.*

Kevin Keyt (Slide 10): I understand the 65/35 split historically, but it appears incremental legislation in Washington may split differently. *Maybe the model equals 65/35 for existing resources and the split of new resources are an output of the model.* I don't want to volunteer you for a bunch of runs, but want to understand how it might change. *We may shift from a cost to a load balance.*

Vlad Gutman-Britten: CETA requires 100% in 2045, but Avista corporate goal is 100% by 2027. How do you account for that? *Excellent question. If cost effective, we will do it. Will run a scenario to meet the goal and it becomes a management decision on reaching 2027 and 2045 goals to set the strategy going forward based on the cost to customers. Last IRP, we were 90% clean without additional costs beyond CETA. At that time, management was not willing to put that additional cost on customers for the remaining 10 percent.*

Matt Nykiel: In PRiSM, are there parameters that require Avista service territory to meet the goal in 2027 and 2045 for the entire service territory? Carbon neutral by 2027 and 2045 is not meaningful if not cost effective from the get go. I don't understand the goal if it doesn't have an impact

Jason Thackston: Good question and the point is appreciated. I appreciated the way James answered. What we said, and are still committed to, is affordability and reliability. We are still committed to those goals, but reliability will not be sacrificed and the goal is subject to affordability by the impact on customers' bills. We always look at cost-effective, but trying to be more holistic. Does that help?

Matt Nykiel: I'd like to learn more.

Terri Carlock: To clarify, you will run the full system to meet that commitment and looking at the costs separately for both states to decide whether you implement in both states and the Commissions will each review. *That is a fair and correct summary. Still need guidance by states before we can fully state how we model.*

Vlad Gutman-Britten – Are you selling REC between states? *About ready to talk about that. If 20% REC only or bundled. Idaho to Washington for Rulemaking is still being considered relative to this and bundling so I can't answer specific questions on how we'll be modeling until the rulemaking is more final. We will likely try to simulate REC sales similar to our last plan*.

Vlad Gutman-Britten: So Idaho would have a higher fossil fuel content than Washington? *Correct.*

Matt Nykiel (Colstrip): What does it mean to have a shareholder portfolio? One question, I don't understand why if Units 3 and 4 are uneconomic, why is the Washington share only going to shareholders? *Need to model it to decide where it goes. We are redoing same analysis so the Idaho portion only serves their load. If the model chooses 2025, or another date, to close for economics. The shareholder portfolio is because it can't be in Washington rates after 2025 under CETA, but if it is still operating, we still have to sell off or consume those megawatt-hours.*

Jason Thackston: Correct me if what I say is incorrect. There are two outcomes. One. Assume all same as last IRP, after 2025 Colstrip is not in the portfolio because it is not economic. Two. Very extreme. Everything doubles and Colstrip is way in the money, it should still be in the portfolio beyond 2025, but it is not viable in Washington. It would still be, absent a decision to shut down the plant. Nuance in Washington State the model has to reflect.

Matt Nykiel: That's helpful. Thank you.

Terri Carlock: What shareholder portfolio costs would be associated for any costs extending the life of the plant? *Washington depreciation done in 2025 for Colstrip. Any other O&M, capital, or fuel at that time will be on shareholders. Washington will still cover their shutdown costs for the time it was on their system.*

Matt Nykiel (Slide 10 – PRiSM): I don't mean to belabor the point, first bullet point, does it respect state guidelines? How will the model in practice split up new resource? *We don't have all the answers regarding specific actual operations. From a modeling* *perspective for adding or subtracting resources we continue to operate as a whole system. Operations is as a single system. From a clean energy perspective, we can assign whether or not power is clean, etcetera on an accounting basis not a physics basis. Accounting rather than an engineering basis.* Appreciate more discussion in the future.

Terri Carlock: Same for market purchases? *Still rules to come. I hope regulating bodies don't rush it because of lasting impacts of the decision.*

Jennifer Snyder: Are you including social cost of carbon on new construction and operation of new or existing resources? *Just new, but there are there processes at the generation site that add to emissions. Trucks for hauling fuel at Kettle Falls and other equipment, trucks to maintain wind farms. NREL has some older studies estimating these types of emissions as well.*

Matt Nykiel: SCC is a reflection of the understanding of GHG cost not being internalized by facilities that emit them. Is Avista incorporating this cost due to the legal requirements not because Avista is acknowledging that GHG have a cost that's not being internalized? *Its Avista's understanding of a cost just as a legal operation, not as a corporate entity. Makes sense. One way to interpret it.*

Jason Thackston: I'm not sure I'm the best one to answer, but generally speaking you have captured it for Washington legislation and Washington feedback.

Tina Jayaweera: Upstream value for emissions? *Next TAC meeting, but Avista gas line rights are very different than the distribution side. We source our gas mostly from Canadian sources so we're focusing on the emission for the gas we're sourcing.*

Jennifer Snyder: Issues not finalized, what date do you need clarification by for RECs/CETA? *REC transfers by September [2020] at the latest. Earlier is better. If not clarified by then, we would run multiple scenarios or possible outcomes.*

Matt Nykiel: Bundled RECs, can Avista transfer energy plus RECs associated with that? *Multiple interpretations of the options. Power, REC, power plus REC or separate the two and combine with others. The way bundled or not is the difference for Washington CETA in different contexts. Depending on how WUTC rules, we could have to way overbuild because of REC needs. Treat as I-937 or actually serve instantaneously.*

Rachelle Farnsworth: So can you tell more on how and why it is Washington establishing the price of REC transfers between states? *Hopefully I didn't say that. Washington sets the requirement for how many RECS are required. Then it is a question of what price is needed to meet Washington law. I.e., the price is $20 so the model says build for Idaho to sell to Washington. Price matters depending on outcome in model. Much as last time, if economic to build for state and take advantage of the market if available. Three examples at different prices: example price of a REC at $20, Idaho should build a project to sell to Washington. If valued at $0, Idaho wouldn't build.*

We wouldn't want to see the model build based on resources to sell to Washington, but would build the least cost to take advantage of the market.

Kevin (IPUC) – have you defined requirements for Reliability modeling (document would be helpful)? James - slide 14 95% of simulations serve 100% load and reserve requirements; don't want to start down the path of buying new software if the regional market is coming soon

Kevin Keyt (Slide 14): Have you defined requirements for reliability models and decision making? *95% LOLP of simulations serve 100% of load requirements and we look at other metrics too. In terms of software development and modeling tool, we want to produce some confident results. There is a cost to maintain/operate a reliability model. Timeline is short for this plan, so we don't want to go too far if a resource market overseer is coming. Maybe the new Genesis model. Maybe a new overseer. Don't want to have to scrap a new model in a year or two.*

Modeling Process Overview Continued After Lunch Break – James Gall

Matt Nykiel: I appreciate the transparency. I notice it in the slides already. For Aurora, I'd like to understand Colstrip inputs better. If Units 3 or 4 continues to be uneconomic for Idaho from modeling, how would the Idaho share go into a shareholder portfolio? *Aurora gives a price forecast valuing resources not by ownership. Dispatch the plant with a heat rate and fuel costs that influence market price if economic to run. If PRiSM is not cost effective, do we retire or close the plant? If it goes out, need to decide how – if closed or sold. PRiSM more utility based.*

Matt Nykiel: Make sure the model is looking at price to meet minimum take obligations. If it becomes uneconomic for Idaho, does the IRP consider where that minimum energy goes? *If it goes out of the Idaho portfolio, it jumps from planning to action. If we remove it from Idaho, Idaho no longer bears the expense. We reevaluate it at every IRP cycle. Nothing changes here from how we model in last IRP*

Matt Nykiel: Mentioned earlier it accounts for shut down, forced outages and needed repairs. Unit 4 is expected to need repairs to the super heater. Does the model account for those expected repairs? This can affect ownership issues not agreed to under sections of the contract. *I can't and maybe shouldn't comment on a contract. It includes expected and potential repairs.*

Generation Resource Options – Lori Hermanson

James Gall: We are seeking feedback from the TAC about if we should model generic or specific resources regarding pumped hydro storage.

Jennifer Snyder: Don't have rates impact now. But lean towards specific projects if data available.

Terri Carlock: Doesn't pumped hydro storage depend on scale?

James Gall: A generic resource would need an assumption for duration and cost. Hybrid concept we used last time. But some projects have attributes with lower or higher costs. We got comments last time from some TAC members. We modeled one specific pumped hydro resource and some TAC members thought we should have modeled others. Then what about specific wind and solar projects? That means we are doing an RFP in an IRP.

Kathleen Kinney: I have some sources on renewable hydrogen gas you can email me about. *We will email you. Renewable natural gas will be discussed in the next TAC meeting.*

Amy Wheeless: I acknowledge the conundrum. Did you reach out to the renewable hydrogen alliance? *We did not. We used Black & Veatch last time. Also had comments from a vendor on gas turbine retrofits for hydrogen gas.*

Matt Nykiel (Slide 3): Can you explain what in the analysis that caused gas prices to increase. *2020 is an estimate of 2022. Mostly inflation and the price of gas. They are effectively the same.*

Matt Nykiel (Slide 10): What is the northwest for solar? Southern Idaho? Are we looking at Idaho? *Southern Idaho or Oregon with a BPA wheel to get to Avista. We are indifferent on location, this is showing the costs and benefits of solar in a better location.*

Jørgen Rasmussen: Is liquid air storage included? *Yes, see slide 7, we are modeling it again. It was selected in the last plan.*

Thomas Dempsey: We will be reviewing the liquid air energy storage costs further in this plan.

Review of spreadsheet with resource costs and operating characteristics:

James Gall: I've been involved with half a dozen RFPs. Prices vary widely and will be different than the generic modeled prices. We are really seeking input on these costs and assumptions.

Vlad Gutman-Britten: Environmental burdens are a wider scope, not just greenhouse gas emissions.

Washington Vulnerable Populations and Highly Impacted Communities – James Gall

James Gall: Vulnerable populations consider socioeconomic factors and income sensitivity factors. Avista already recognizes that nearly half of our territory is low income and we are economically involved in our communities. This part of CETA is currently in the rule-making process. We hope the TAC and other advisory groups will help guide us in how to address these new requirements. It is possible a new advisory group is needed or we may get more participants in the current TAC or another group.

We need to gather more data and better understand our baseline – where are they at today? The Washington State disparities map rates each census tract between 1 and 10 for socioeconomic factors which seems to align with the proposed rules. We are proposing score of 8 or higher to be considered vulnerable or impacted. We will overlay this on our service territory, noting that Idaho is not subject to CETA. There are overlapping service territories with other utilities in some of the vulnerable areas. Average use per customer – two sets and compare how they change over time. We use that information to estimate how costs can change over time. Whether or not customers have more than 6% of their income goes toward energy. Should the IRP have a monetary preference for these areas, no preference, or no additional preferences?

Reliability/Resiliency metrics are available by feeder. We can show this at a future TAC meeting and compare to the remaining areas. There is a challenge for how this relates to the IRP. For Resource analysis, we can estimate emissions from our facilities located near or removed from these areas. If a new resource, we can discuss how those may change in those areas. Energy security is challenging. The grid works together for the benefit of all customers, not necessarily for certain populations.

Kate Griffith: Regarding DOH map. The state Environmental Justice Taskforce is working on guidance as the mapping tool is being developed among other tasks. They have regular meetings. More info is here: https://healthequity.wa.gov/TheCouncilsWork/EnvironmentalJusticeTaskForceInformation.

Vlad Gutman-Britten: Note that the tracts aren't categorized in a population weighted way, so the three most impacted deciles of tracts may not correspond to the three most impacted deciles of people.

Jennifer Snyder (Slide 7): No good updates to add [concerning the identification of highly impacted communities or vulnerable populations].

Amy Wheeless: How do you define community? *Identified by census tract, so each colored area in Slide 10 is a community.*

Vlad Gutman-Britten: It would be helpful to understand how community compares to population and customer share and load share. *Excellent questions. We're going to get to that in metrics.*

Shawn Bonfield (Slide 14): What do the figures on the map represent? *The numbers are census tracts and the darker shaded areas are more vulnerable.*

Kate Griffith: Do you have a sense for the particular sensitivity factors in Spokane? I apologize, I mean the issues they face such as low birth rates, etc. *I don't know that information.*

Vlad Gutman-Britten: The Department of Health map provides component scores, in addition to the rolled up score. *Thank you.*

Amy Wheeless: Some of the CAP [Community Action Partnership] agencies may be able to provide more qualitative information.

Vlad Gutman-Britten: Yes, monetary preference and extra inducements are important and would go toward equalizing going forward since they haven't received these resources in the past. Equity is worthwhile to perform and pursue. How much is required? Think about what will be necessary for success.

Kate Griffith: How is Avista working to contact and engage with these communities around planning? Have you started reaching out to these groups or communities? *We need direction. Are these separate advisory groups. We have had some participation in the past on the TAC from tribes and SNAP. They are not always able to attend. We need to reach out to public officials in these areas and need more outreach and opportunities to include these groups. More to come on this.*

Jennifer Snyder: What metrics make sense? It would be helpful to have more representation from these groups for these particular committees to understand what issues to address.

Corey Dahl: I'll second conducting outreach. What does it look like? How to address equity? The company has both an obligation to select the lowest cost resource, but a need to comply. Example off the top of my head not sure if real. Natural gas generation facility goes offline and is replaced with solar benefits to the surrounding community, but also benefits of transmission. But jobs are lost.

Jennifer Snyder: What type of long- and short-term public health benefits have you looked at? Potentially for DSM and supply-side resources? *Example, wood smoke in energy efficiency. Including things from a TRC point of view. Concentrate on emissions with existing generation. Are there others?*

Jennifer Snyder: There are things we didn't take into consideration prior to CETA, but we should. There are a lot of health benefits in some jurisdictions. Not in Washington yet, but new things not taken into account before CETA.

James Gall: One other is interplay of gas and electric service territory.

Amy Wheeless: The past few slides spurred a lot of thoughts. I'm not really involved with the CETA rulemaking. Great questions to bring forward. Seek potential future and get cost benefits.

James Gall: Can look at distribution or opportunities that might be higher cost, but see what those costs might be. The topic will come up again to show some of these metrics. Let John [Lyons] or myself know of any thoughts you have.

Kate Griffith: Are these the metrics you're planning to bring into the CEIP? *So far. We may have additional metrics later with input. Meaningful and calculable metrics for a more useful set of data.*

Kate Griffith: You mentioned quantifiable, but non quantifiable is also a big piece of this so I'd be interested to hear more about incorporation of less measurable equity measures. *We are looking for any ideas we can look at.*

Meeting adjourned.

2021 Electric Integrated Resource Plan

Technical Advisory Committee Meeting No. 2 Agenda

Thursday, August 6, 2020

Virtual Meeting- 9:00 AM PST

Topic	Time	Staff
Introductions & IRP Process Updates	9:00	Lyons
Natural Gas & RNG Market Overview	9:30	Pardee
Break	10:45	
Natural Gas Price Forecast	11:00	Brutocao
Lunch	11:30	
Upstream Natural Gas Emissions	12:30	Pardee
Break	1:30	
Regional Energy Policy Update	1:45	Lyons
Natural Gas and Electric Coordinated Study	2:15	Gall/Pardee
Highly Impacted & Vulnerable Populations Baseline Analysis	3:00	Gall
Adjourn	3:45	

2021 Electric and Natural Gas IRPs TAC Introductions and IRP Process Updates

John Lyons, Ph.D.

Second Technical Advisory Committee Meeting

August 6, 2020

Updated Meeting Guidelines

- Gas and electric IRP teams working remotely, but still available by email and phone for questions and comments
- Some processes are taking longer remotely
- Virtual IRP meetings until back in the office and able to hold large group meetings
- TAC presentations, notes, work plans and past IRPs are posted on joint IRP page for gas and electric: https://www.myavista.com/about-us/integrated-resource-planning

Virtual TAC Meeting Reminders

- Please mute mics unless speaking or asking a question
- Use the Skype chat box to write questions or comments or let us know you would like to say something
- Respect the pause
- Please try not to speak over the presenter or a speaker who is voicing a question or thought
- Remember to state your name before speaking for the note taker
- This is a public advisory meeting – presentations and comments will be recorded and documented

Integrated Resource Planning

- Required by Idaho, Oregon and Washington* every other year
- Guides resource strategy over the next twenty + years
- Current and projected load & resource position
- Resource strategies under different future policies
  - Resource choices
  - Conservation measures and programs
  - Transmission and distribution integration for electric
  - Gas distribution planning
  - Gas and electric market price forecasts
- Scenarios for uncertain future events and issues
- Key dates for modeling and IRP development are available in the Work Plans

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 involved in all or parts of the process
  - Ask questions
  - Help with soliciting new members
- 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 number or type of studies
  - Earlier study requests allow us to be more accommodating
  - **August 1, 2020** was the electric study request deadline
- Planning teams are available by email or phone for questions or comments between the TAC meetings

2020 Electric IRP Meetings – IPUC

- AVU-E-19-01 https://puc.idaho.gov/case/Details/3633
- Telephonic public hearing on August 5, 2020
- August 19, 2020 comment deadline, September 2, 2020 response
- Overview of topics discussed at July 9, 2020 virtual public workshop:
  - Moving away from coal
  - Cost impacts for Idaho customers from Washington laws
  - IRP procedural questions about acknowledgment of the IRP
  - Climate change questions and timing of actions
  - Colstrip: decommissioning, other owners, cost sharing with Washington
  - Consideration of social costs/externalities and public health
  - Support for clean energy and Commission authority to require it
  - Resource timing
  - Risks considered in the IRP: economic, qualitative and climate
  - Idaho versus Montana wind locations
  - Maintaining Idaho RECs
  - Climate change law applicability and lawsuits

2021 Natural Gas IRP TAC Schedule

- TAC 1: Wednesday, June 17, 2020
- **TAC 2: Thursday, August 6, 2020 (Joint with Electric TAC)**
- TAC 3: Wednesday, September 30, 2020
- TAC 4: Wednesday, November 18, 2020
- TAC 5: February 2021 – TAC final review meeting if necessary
- Natural Gas TAC agendas, presentations and meeting minutes available at: https://myavista.com/about-us/integrated-resource-planning

2021 Electric IRP TAC Schedule

- TAC 1: Thursday, June 18, 2020
- **TAC 2: Thursday, August 6, 2020 (Joint with Natural Gas TAC)**
- Economic and Load Forecast, August 2020
- TAC 3: Tuesday, September 29, 2020
- TAC 4: Tuesday, November 17, 2020
- TAC 5: Thursday, January 21, 2021
- Public Outreach Meeting: February 2021
- TAC agendas, presentations and meeting minutes available at: https://myavista.com/about-us/integrated-resource-planning

Process Updates

Economic and load forecast delay

- Special meeting 1:00 – 3:30 pm PST on Tuesday, August 18 or Wednesday, August 19, 2020 to cover the forecasts

AEG Conservation Potential Assessment and Demand Response Studies – delayed from TAC 2

- AEG has developed baseline assumptions, market profiles and energy/gas use per customer
- Market data has been collected and compiled
- Measure Assumption development is complete
- Compiled 2021 Power Plan Assumptions
- Measure List is in-process and is expected to be available mid-September
- CPA discussion with TAC – September TAC meeting.

AVISTA

Today's TAC Agenda

9:00 – Introductions & IRP Process Updates, Lyons

9:30 – Natural Gas & RNG Market Overview, Pardee

10:45 – Break

11:00 – Natural Gas Price Forecast, Brutocao

11:30 – Lunch

12:30 – Upstream Natural Gas Emissions, Pardee

1:30 – Break

1:45 – Regional Energy Policy Update, Lyons

2:15 – Natural Gas and Electric Coordinated Study, Gall/Pardee

3:00 – Highly Impacted & Vulnerable Populations Baseline Analysis, Gall

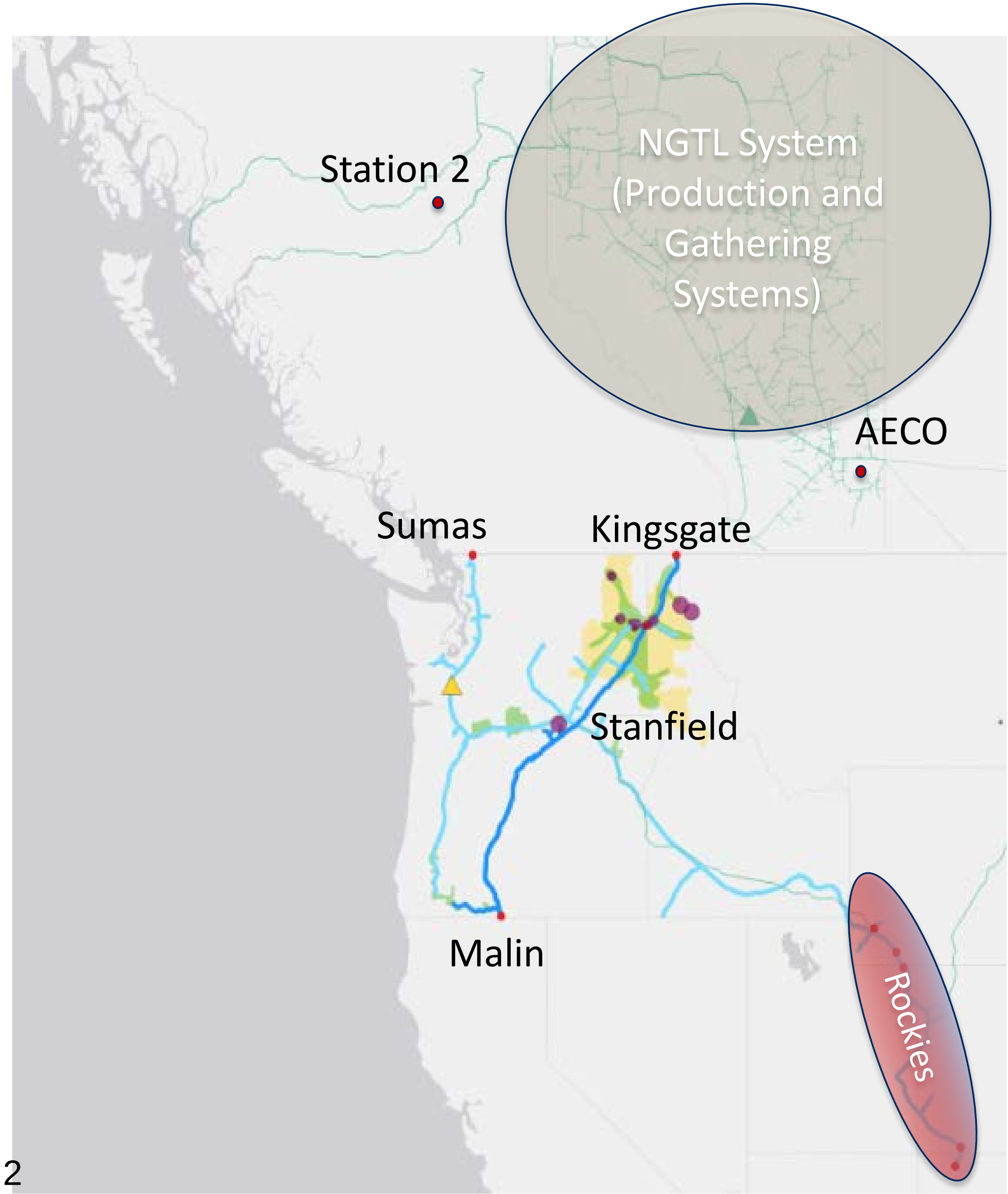
3:45 – Adjourn

Natural Gas Market Overview

Tom Pardee, Natural Gas Planning Manager
Second Technical Advisory Committee Meeting
August 6, 2020

Units

	Common Gas Units		
	1 Bcf	1 Dth	1 Therm
kWh	302,062,888	293.001	29.300
MWh	302,063	0.293	0.029



Avista Electric Territory

Avista Natural Gas Territory

Electric Power Plants

Gas Transmission Network

Northwest Pipeline

Receipt Point

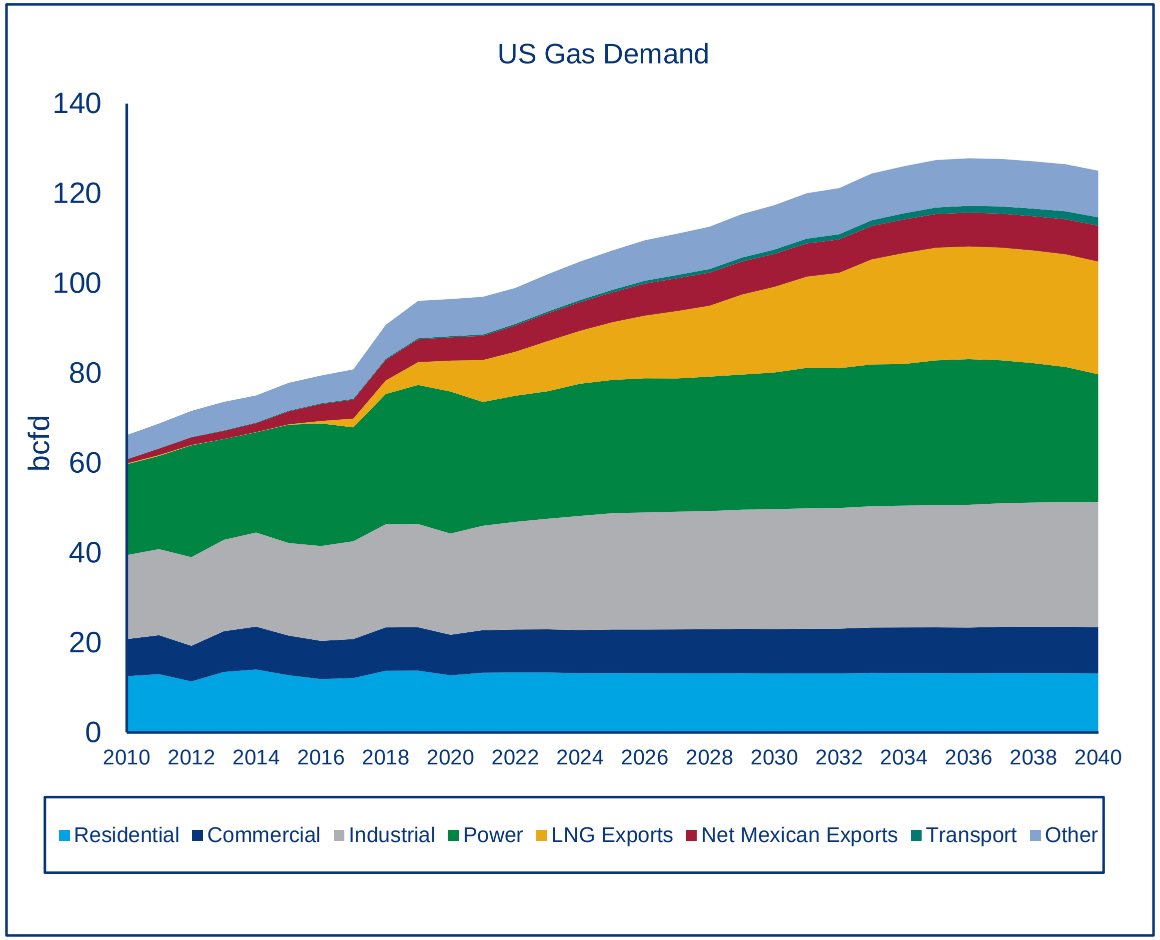
Jackson Prairie Storage (LDC Owned)

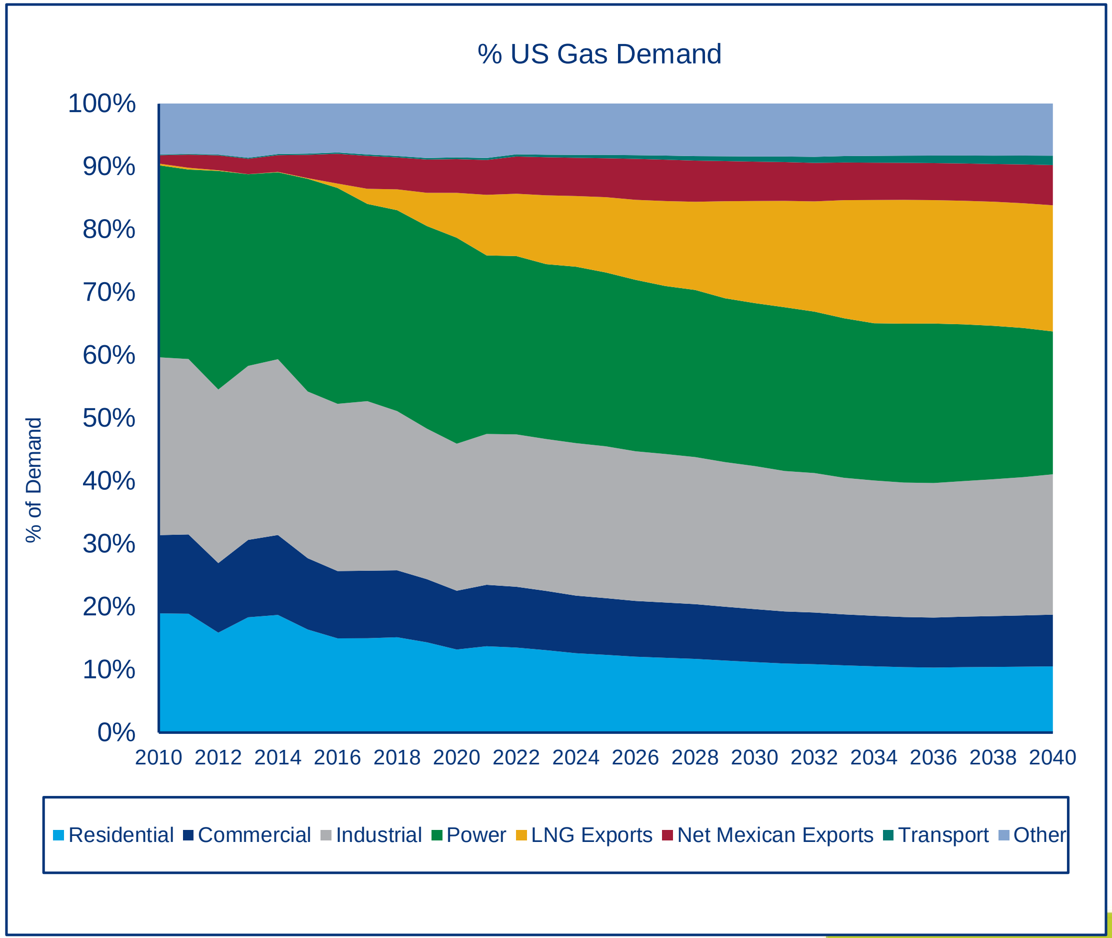
Avista’s Supply

- Natural Gas LDC Side
  - – 10% contracted from US supply basins
  - – 90% contracted from Canadian supply basins

- Electric Side
  - – 100% contracted from Canadian supply basins

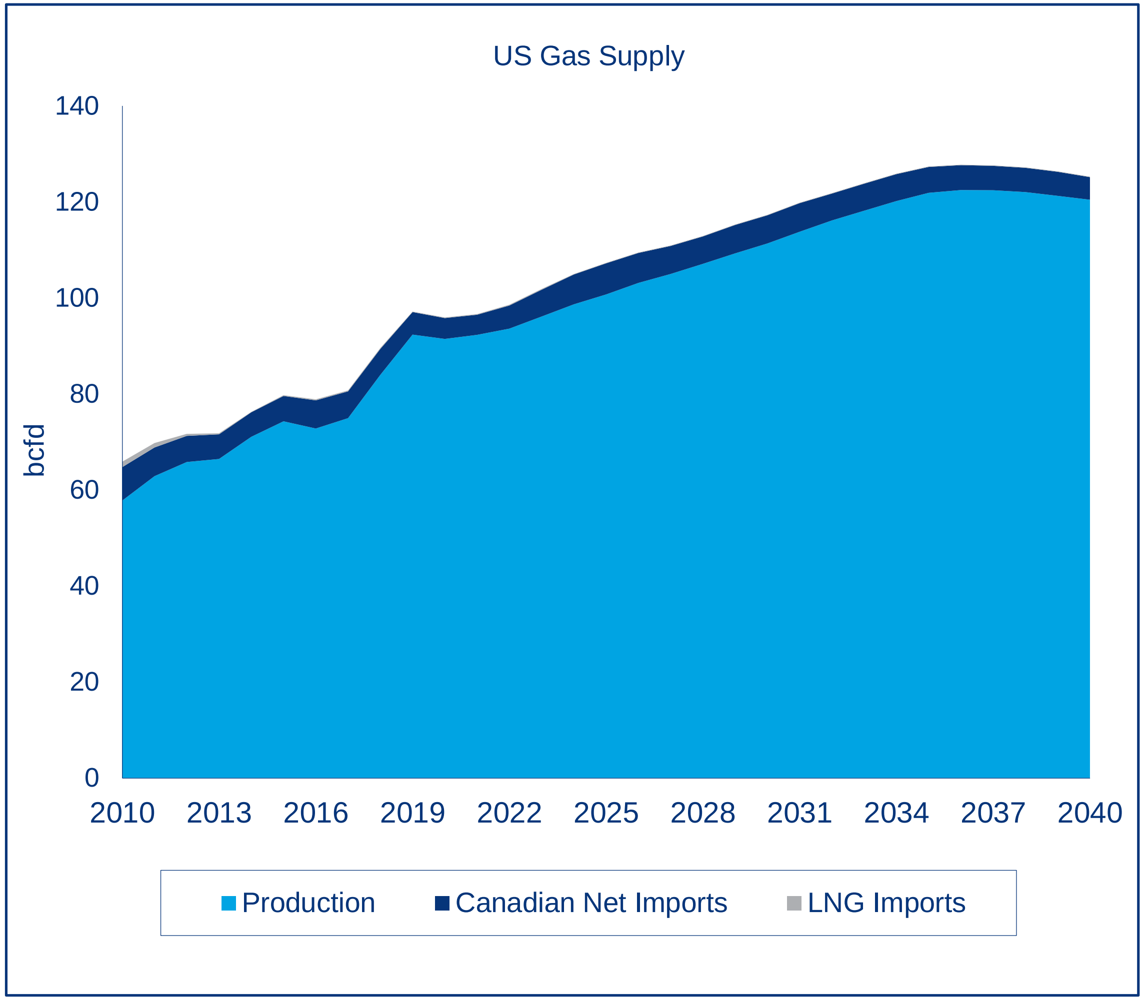
US Demand

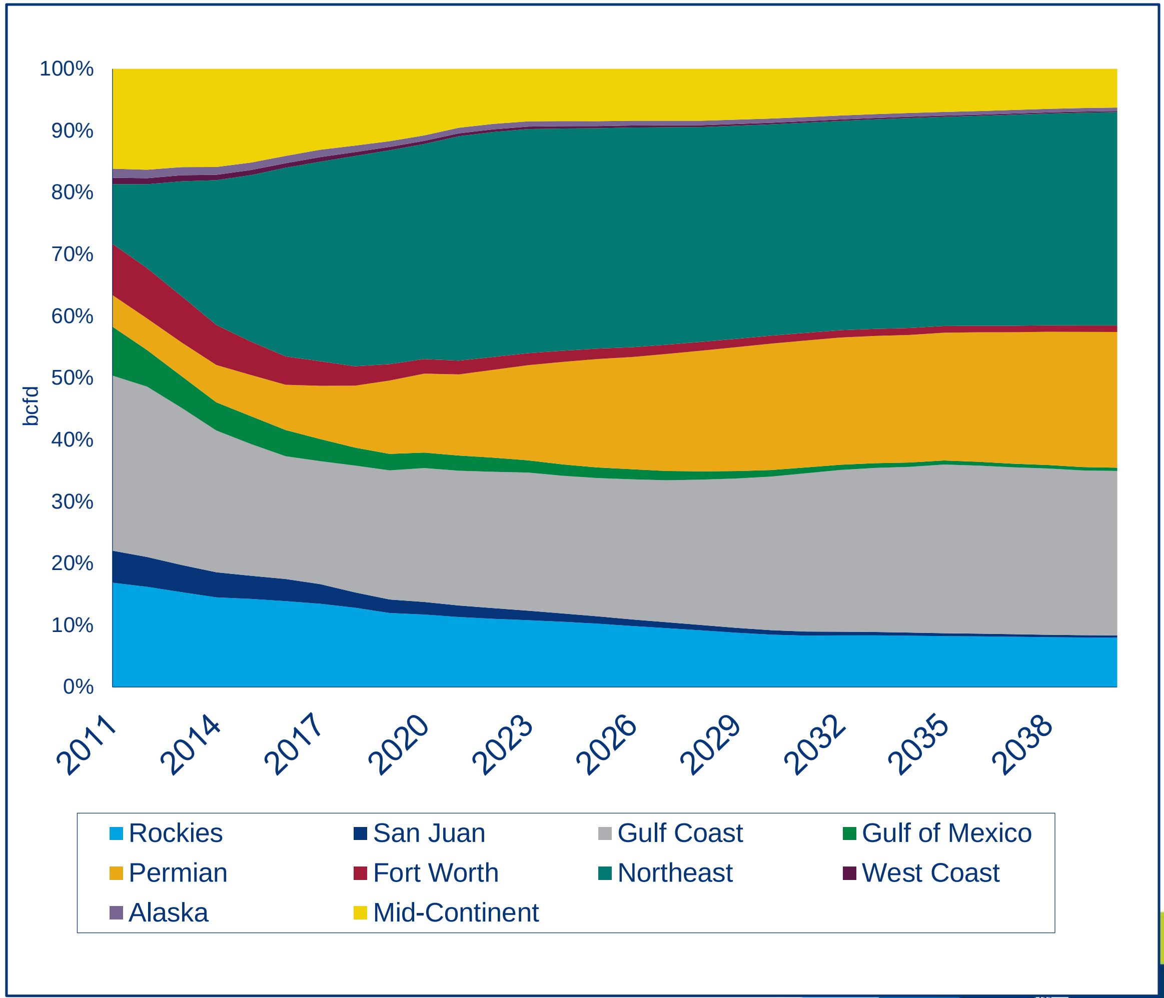




Source: Wood Mackenzie

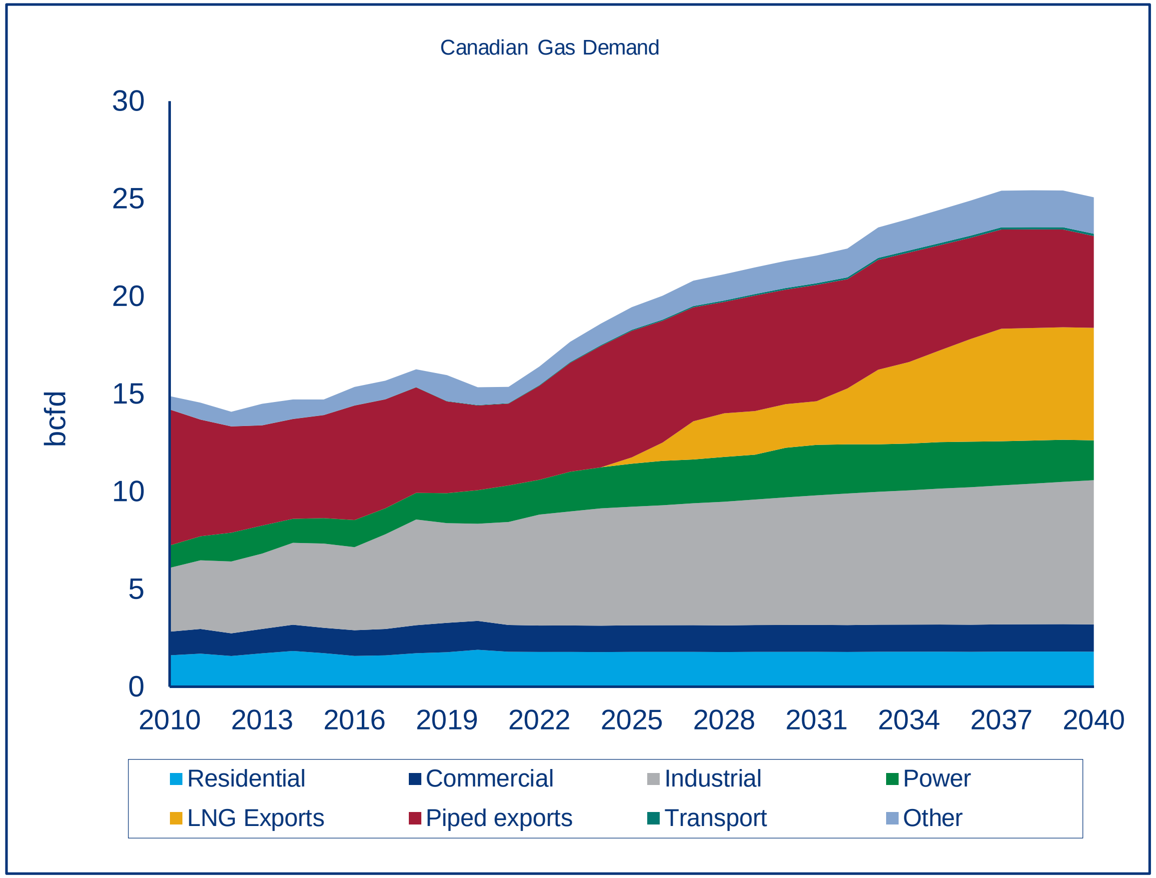
US Supply

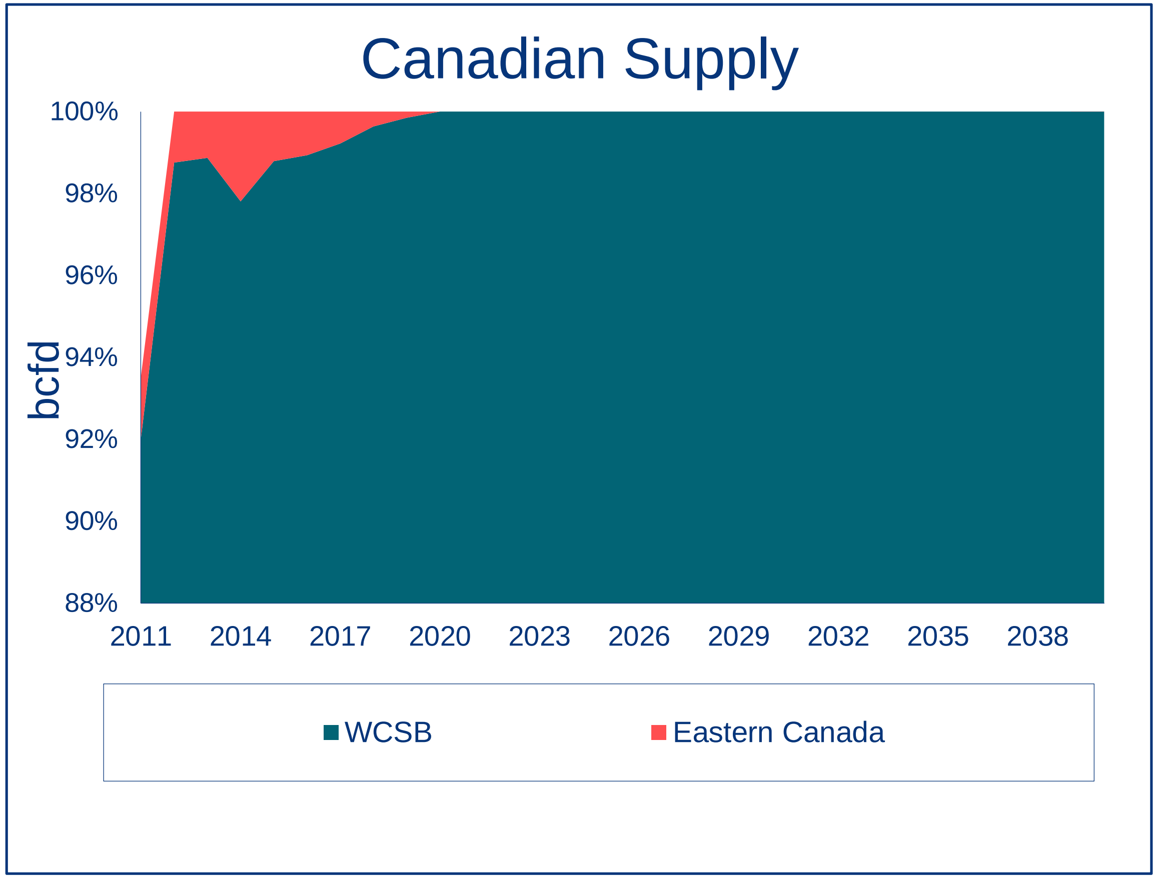




Source: Wood Mackenzie

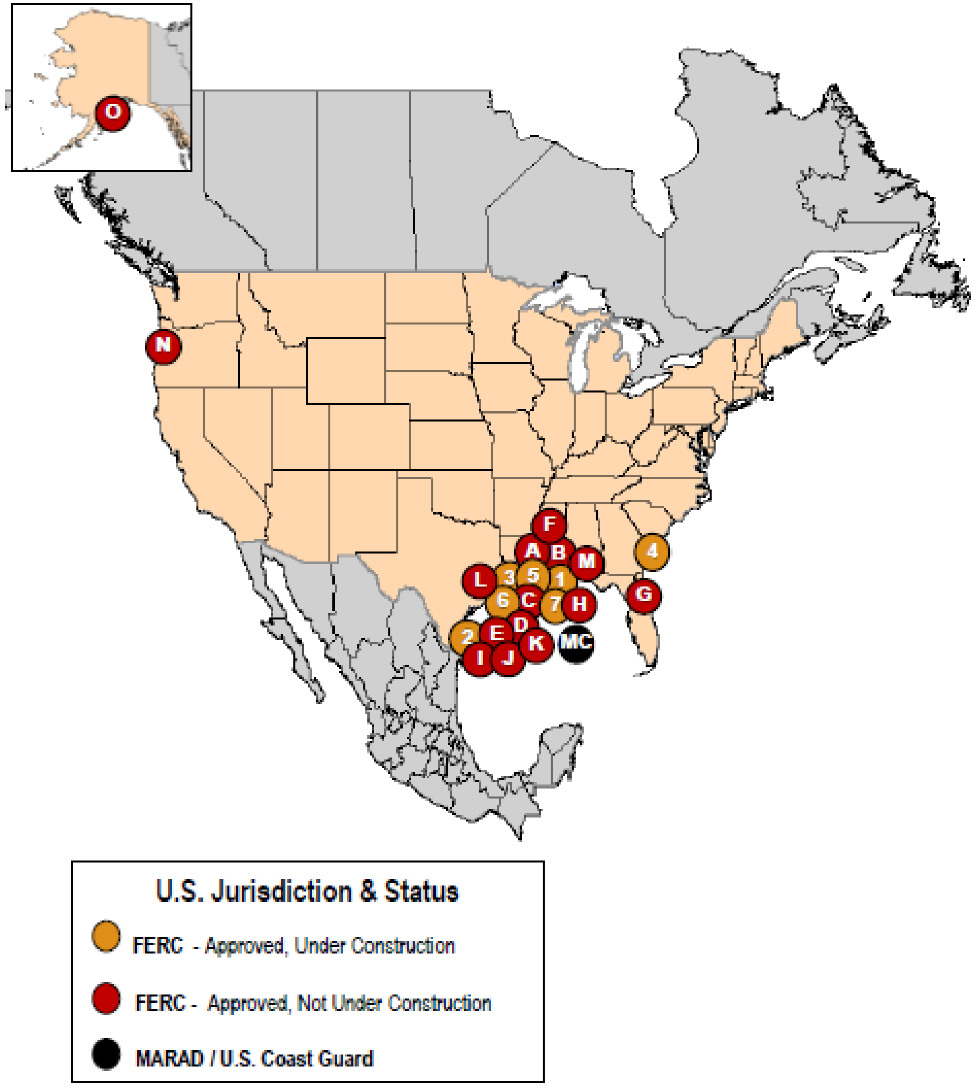
Canadian Supply and Demand





Source: Wood Mackenzie

North American LNG Export Terminals
Approved, Not Yet Built



Export Terminals

UNITED STATES

APPROVED - UNDER CONSTRUCTION - FERC

1. **Hackberry, LA:** .71 Bcfd (Sempra–Cameron LNG Train 3) (CP13-25)
2. **Corpus Christi, TX:** 0.72 Bcfd (Cheniere–Corpus Christi LNG Train 2) (CP12-507)
3. **Sabine Pass, LA:** 0.7 Bcfd Train 6 (Sabine Pass Liquefaction) (CP13-552)
4. **Elba Island, GA:** 140 MMcfd (Southern LNG Company Units 7-10) (CP14-103)
5. **Cameron Parish, LA:** 1.41 Bcfd (Venture Global Calcasieu Pass) (CP15-550)
6. **Sabine Pass, TX:** 2.1 Bcfd (ExxonMobil – Golden Pass) (CP14-517)
7. **Calcasieu Parish, LA:** 4.0 Bcfd (Driftwood LNG) (CP17-117)

APPROVED – NOT UNDER CONSTRUCTION - FERC

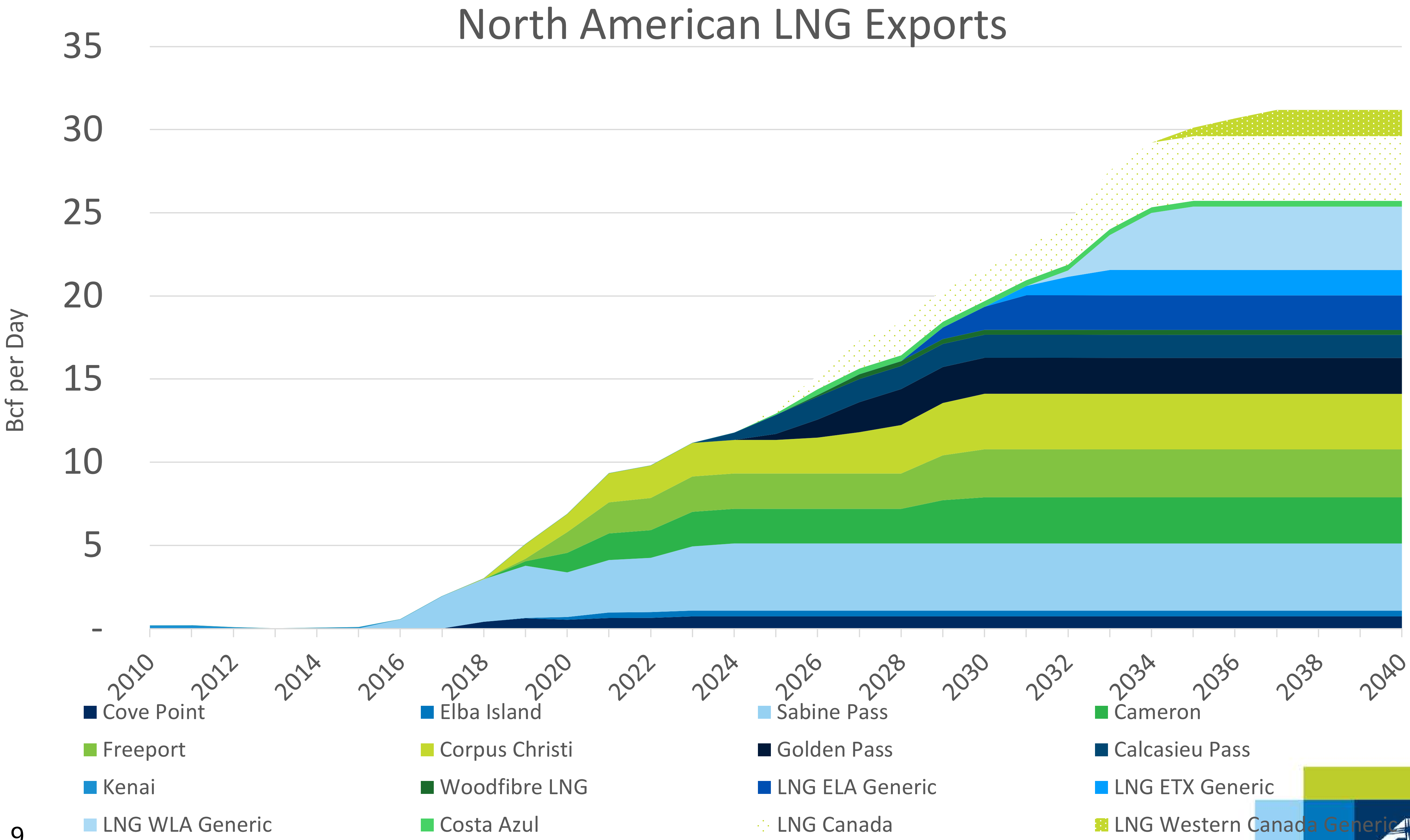
A. **Lake Charles, LA:** 2.2 Bcfd (Lake Charles LNG) (CP14-120)
B. **Lake Charles, LA:** 1.08 Bcfd (Magnolia LNG) (CP14-347)
C. **Hackberry, LA:** 1.41 Bcfd (Sempra - Cameron LNG Trains 4 & 5) (CP15-560)
D. **Port Arthur, TX:** 1.86 Bcfd (Port Arthur LNG Trains 1 & 2) (CP17-20)
E. **Freeport, TX:** 0.72 Bcfd (Freeport LNG Dev Train 4) (CP17-470)
F. **Pascagoula, MS:** 1.5 Bcfd (Gulf LNG Liquefaction) (CP15-521)
G. **Jacksonville, FL:** 0.132 Bcf/d (Eagle LNG Partners) (CP17-41)
H. **Plaquemines Parish, LA:** 3.40 Bcfd (Venture Global LNG) (CP17-66)
I. **Brownsville, TX:** 0.55 Bcfd (Texas LNG Brownsville) (CP16-116)
J. **Brownsville, TX:** 3.6 Bcfd (Rio Grande LNG – NextDecade) (CP16-454)
K. **Brownsville, TX:** 0.9 Bcfd (Annova LNG Brownsville) (CP16-480)
L. **Corpus Christi, TX:** 1.86 Bcfd (Cheniere Corpus Christi LNG) (CP18-512)
M. **Sabine Pass, LA:** NA Bcfd (Sabine Pass Liquefaction) (CP19-11)
N. **Coos Bay, OR:** 1.08 Bcfd (Jordan Cove) (CP17-494)
O. **Nikiski, AK:** 2.63 Bcfd (Alaska Gasline) (CP17-178)

APPROVED – NOT UNDER CONSTRUCTION – MARAD/Coast Guard
MC. Gulf of Mexico: 1.8 Bcfd (Delfin LNG)

CANADA
For Canadian LNG Import and Proposed Export Facilities:

https://www.nrcan.gc.ca/energy/natural-gas/5683

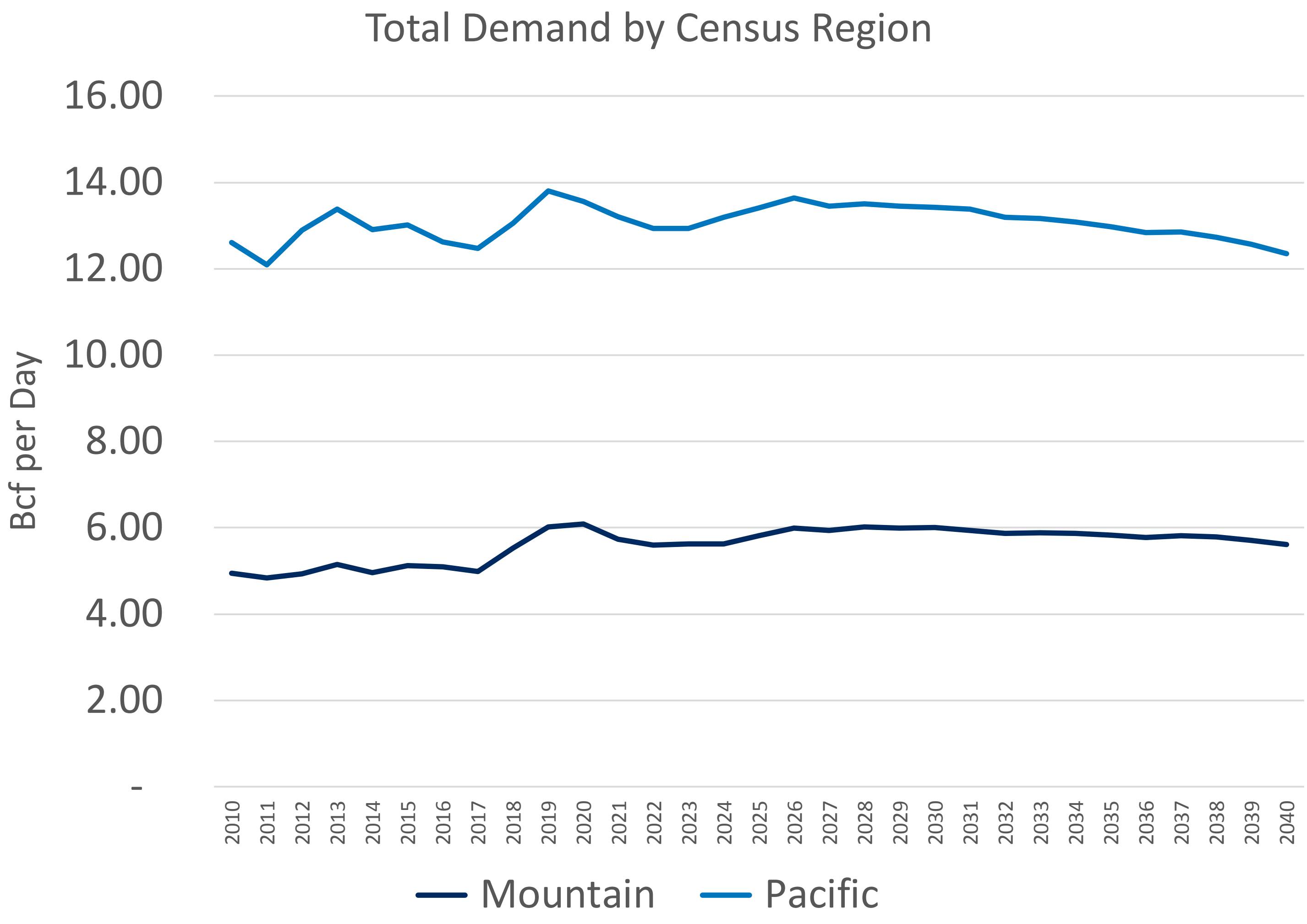
As of May 29, 2020



*WM does not assume Jordan Cove will enter service within forecasted period

Source: Wood Mackenzie

West

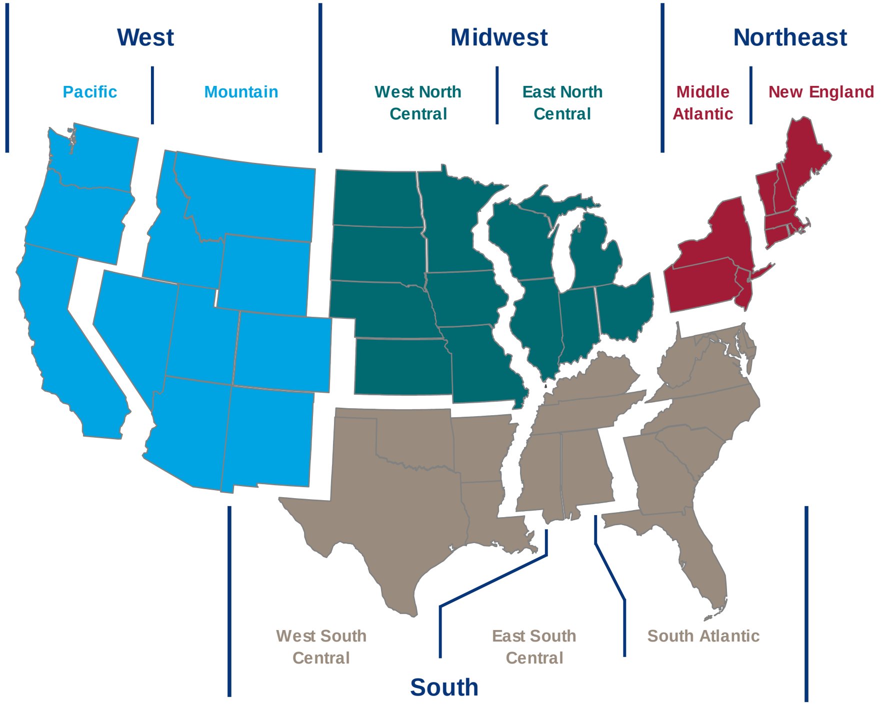


Wood Mackenzie

North America Natural Gas Long-Term View

2020 H1

Census Region Map

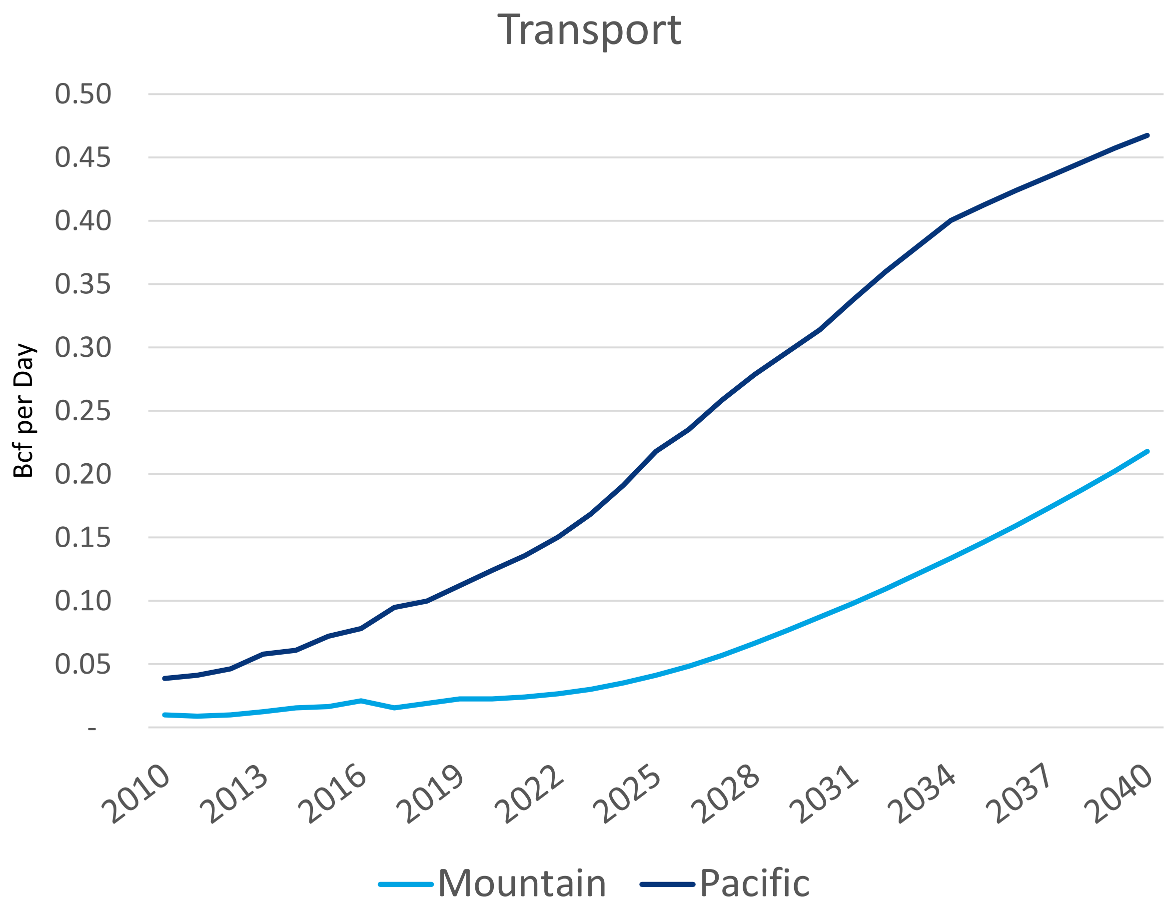


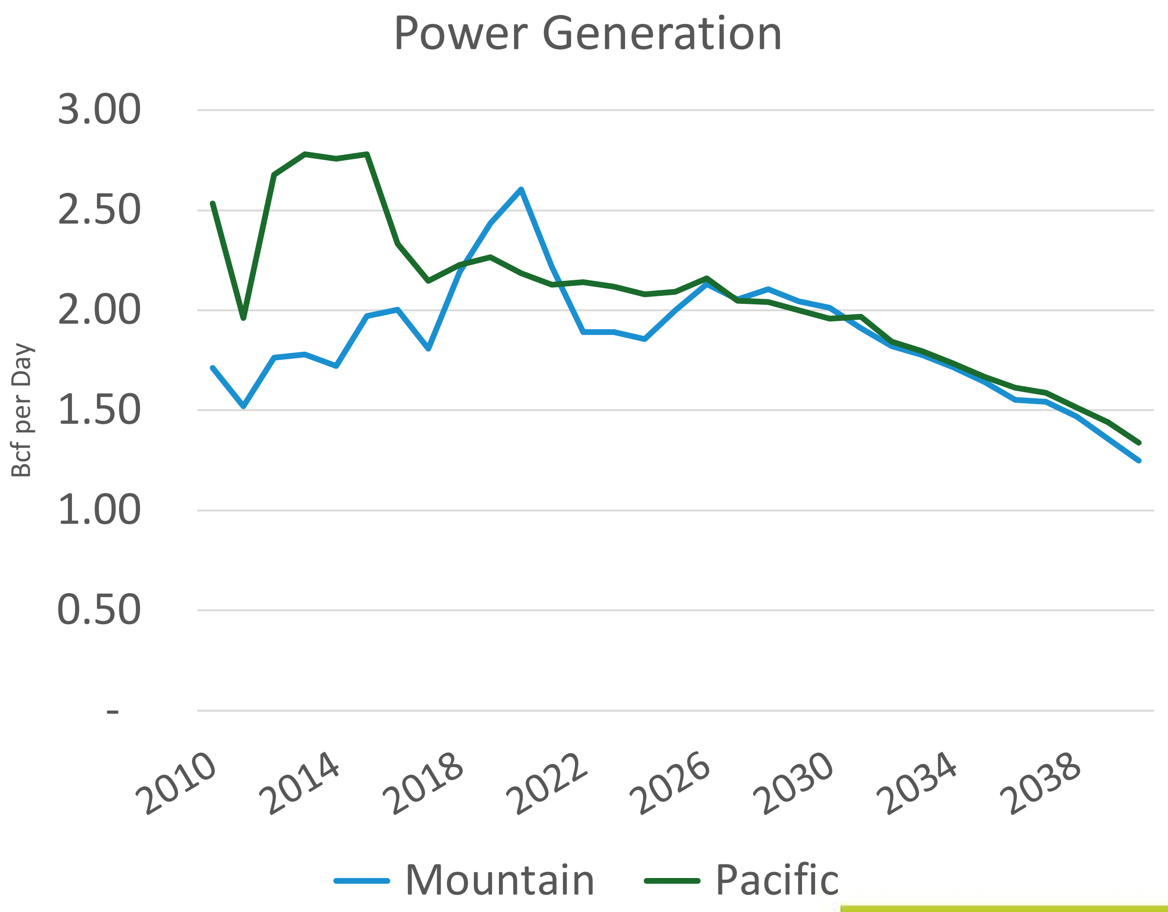
Note: Pacific does not include Alaska or Hawaii

Source: Wood Mackenzie

AVISTA

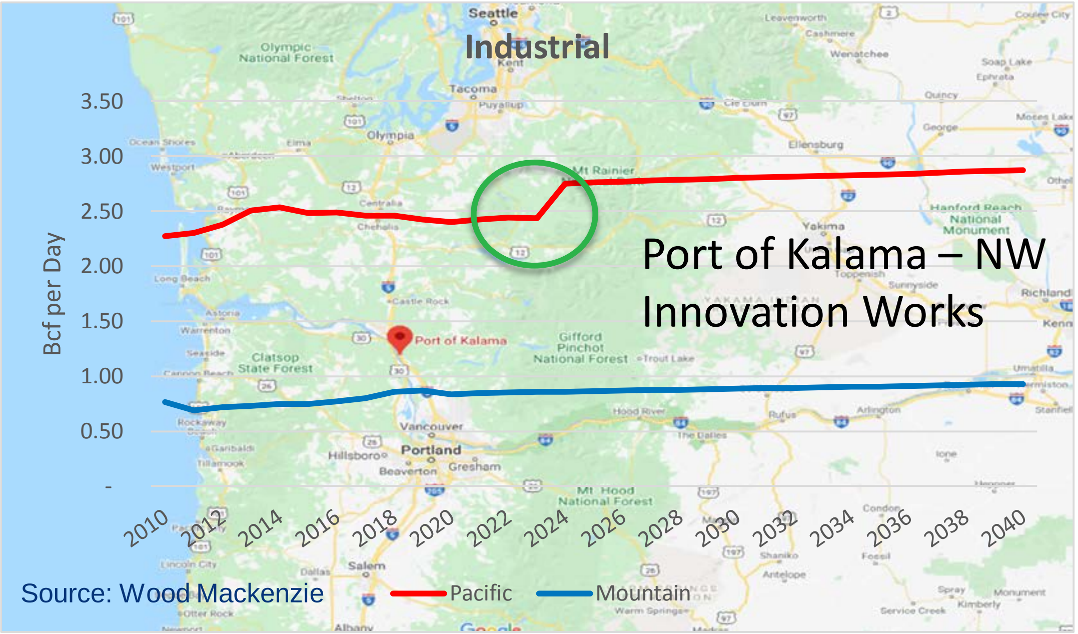
Power Generation and Transport demand

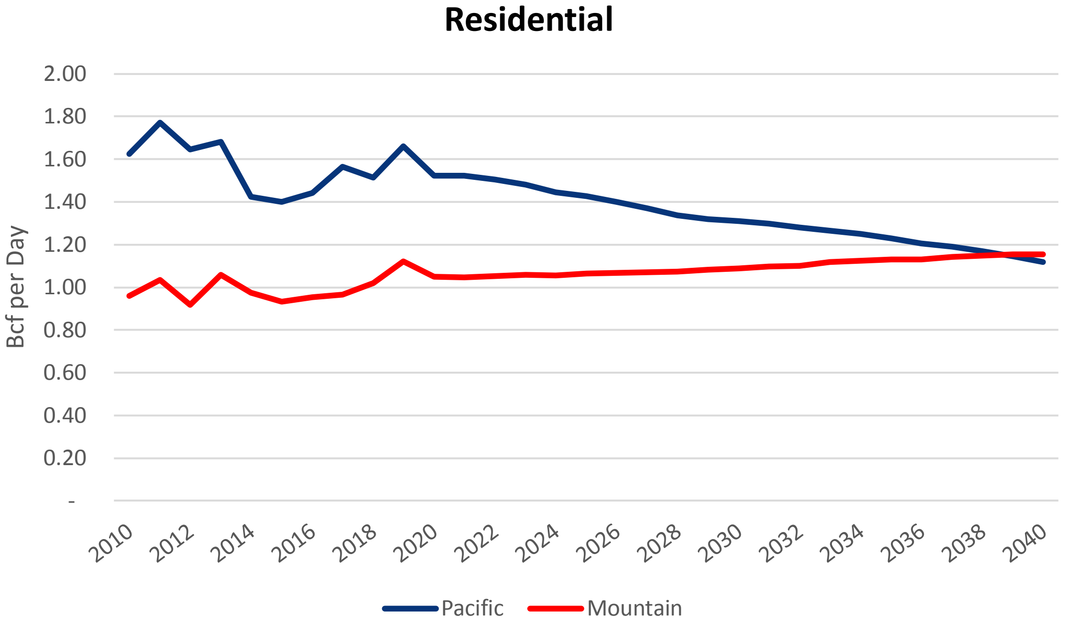


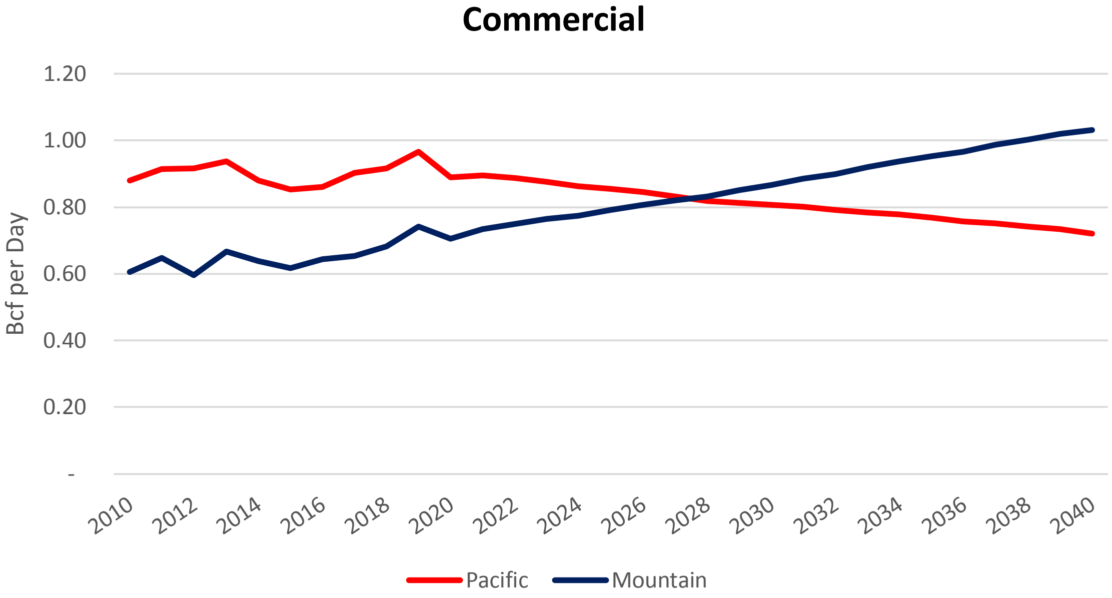


Source: Wood Mackenzie

West demand of Res-Com-Ind







Source: Wood Mackenzie

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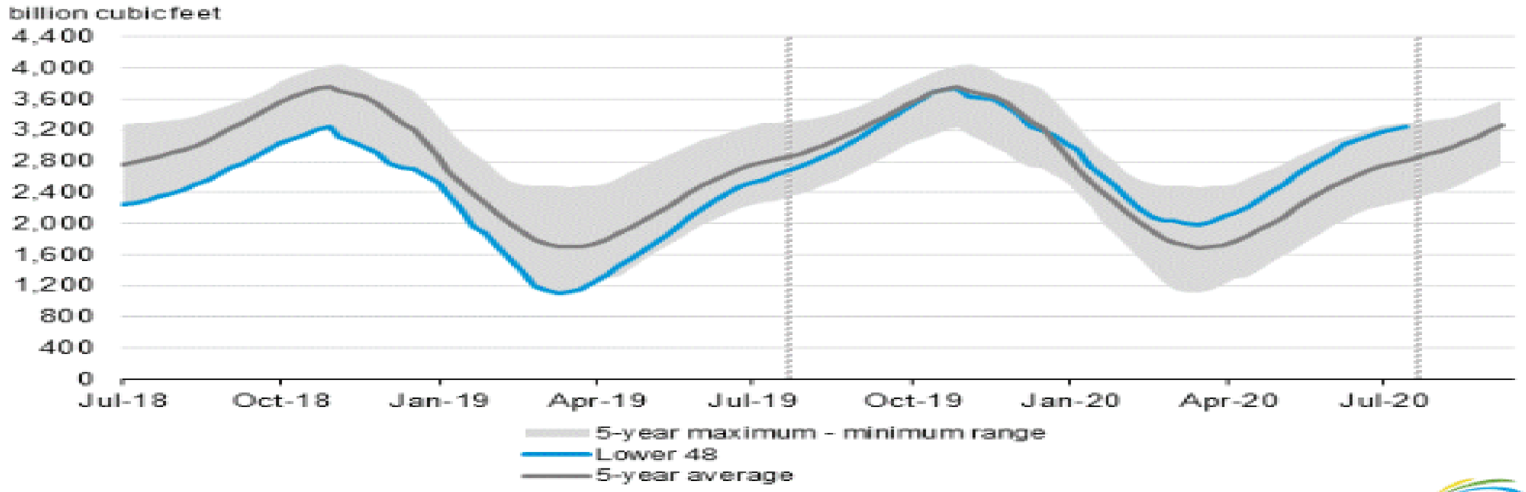
Us Natural Gas Storage

	Stocks billion cubic feet (Bcf)				Historical Comparisons			
					Year ago (07/24/19)		5-year average (2015-19)	
Region	07/24/20	07/17/20	net change	implied flow	Bcf	% change	Bcf	% change
East	706	693	13	13	591	19.5	626	12.8
Midwest	815	799	16	16	669	21.8	687	18.6
Mountain	196	190	6	6	155	26.5	176	11.4
Pacific	313	311	2	2	270	15.9	295	6.1
South Central	1,211	1,221	-10	-10	930	30.2	1,028	17.8
Salt	339	349	-10	-10	227	49.3	274	23.7
Nonsalt	872	872	0	0	703	24.0	754	15.6
Total	**3,241**	**3,215**	**26**	**26**	**2,615**	**23.9**	**2,812**	**15.3**

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

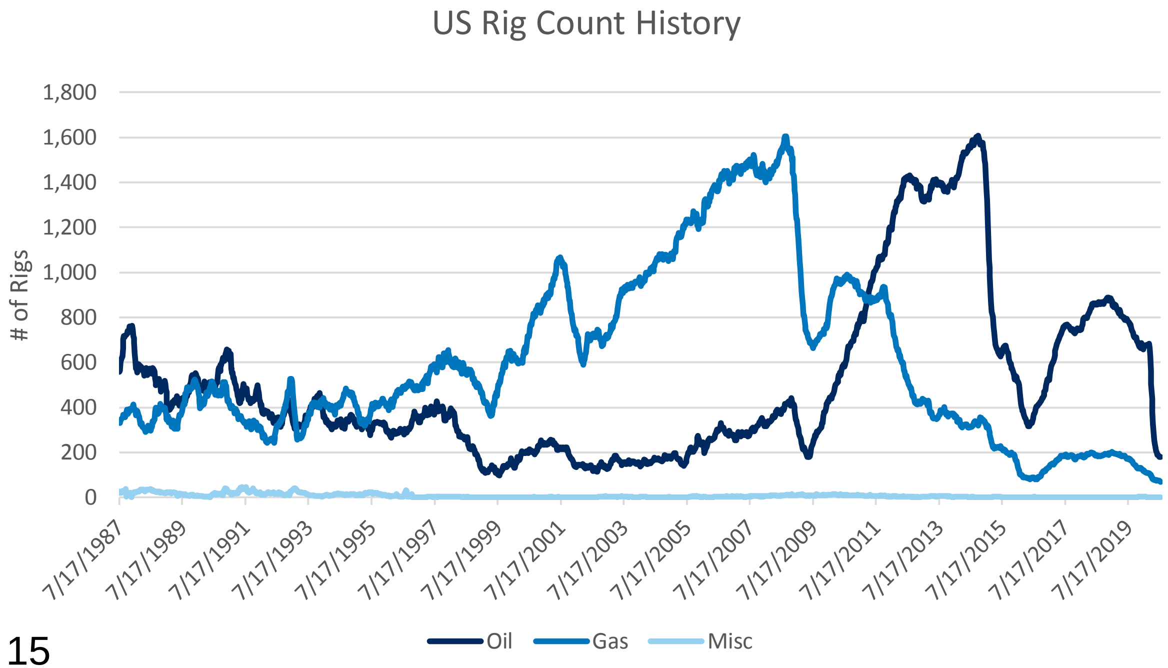
Working gas in underground storage compared with the 5-year maximum and minimum

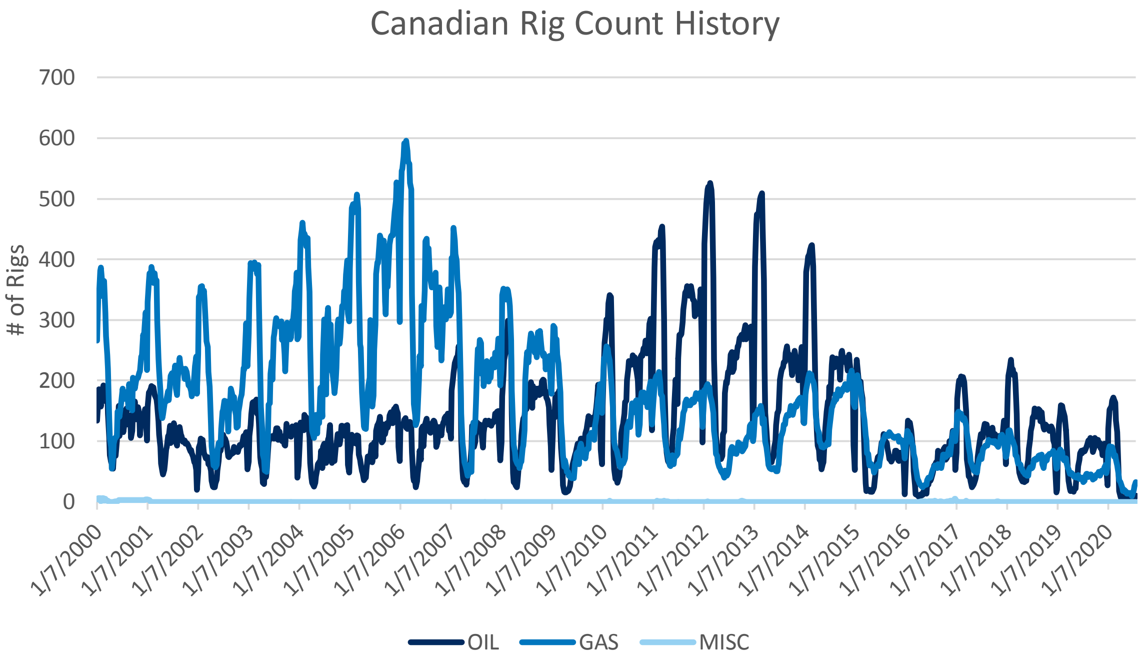


Source: U.S. Energy Information Administration

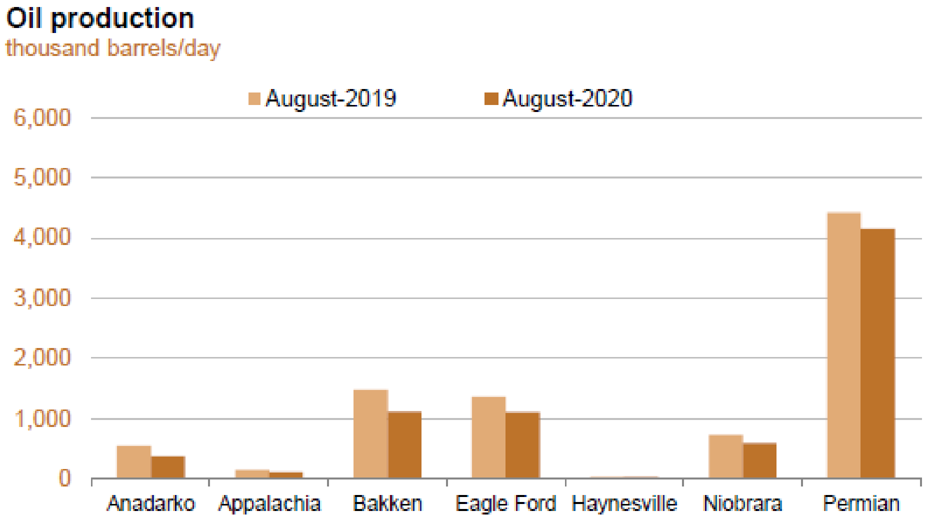
Rig Counts

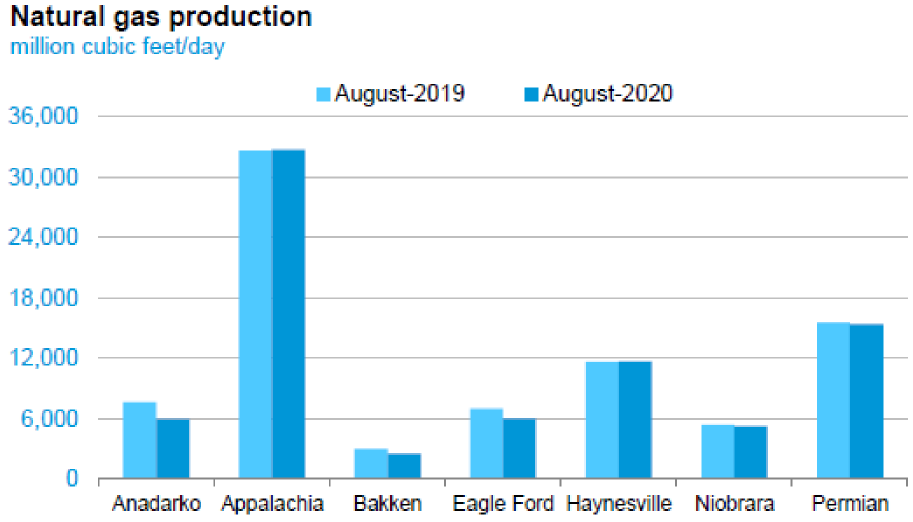
Area	Last Count	Count	Change from Prior Count	Date of Prior Count	Change from Last Year	Date of Last Year's Count
U.S.	24 July 2020	251	-2	17 July 2020	-695	26 July 2019
Canada	24 July 2020	42	+10	17 July 2020	-85	26 July 2019
International	June 2020	781	-24	May 2020	-357	June 2019

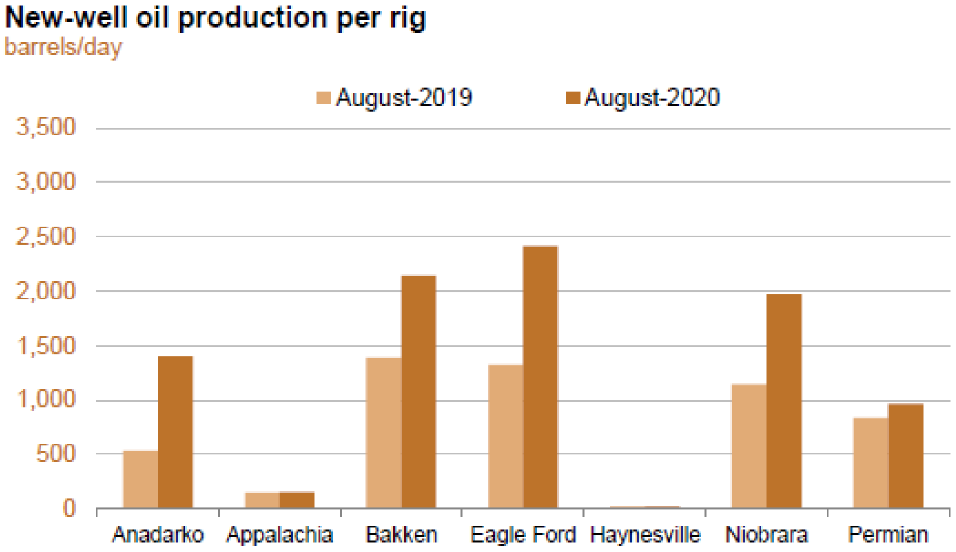


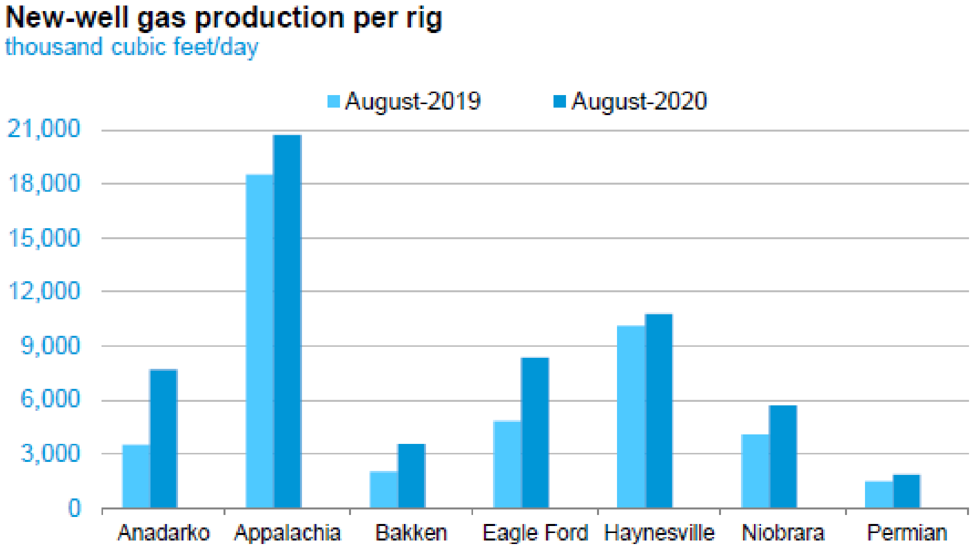


Production and Drilling efficiency

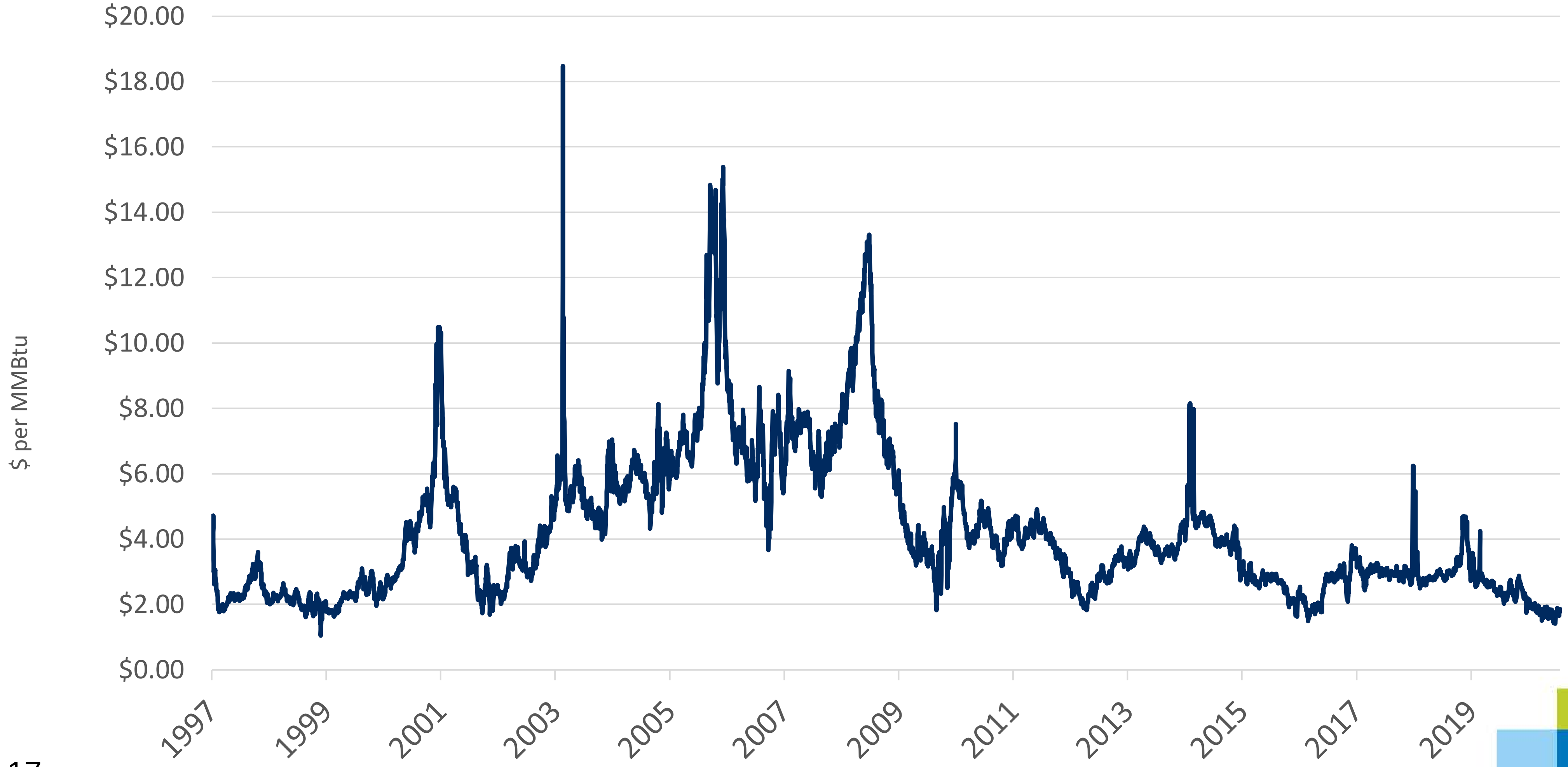








Historic Cash prices (Jan. 1997 – July 2020)



Upstream Emissions

Tom Pardee

Upstream Emissions

- Use based greenhouse gas emissions at the point of combustion and include upstream methane emissions
- Link for Natural Gas Advisory Committee information on upstream methane: https://www.nwcouncil.org/energy/energy-advisory-committees/natural-gas-advisory-committee

Global Warming Potential

5th Assessment of the Intergovernmental Panel on Climate Change		
Greenhouse Gas	**GWP – 100 Year**	**GWP – 20 Year**
CO_2	1	1
CH_4	34	86
N_2O	298	268

Global warming potential (GWP) factors for conversion to CO_2 equivalents (CO_2e)

https://www.c2es.org/content/ipcc-fifth-assessment-report/

Upstream Emissions Sources and Estimates

- Rockies emissions – The EPA estimates all leakage through a bottoms up analysis. It will estimate leaks based on equipment operated as designed and combines these values to determine an overall rate of 1%. The emissions and sinks study is published yearly and will capture emissions as they change.

- Canadian emissions (British Columbia and Alberta) – A value of 0.77% was developed from data pertaining to the recent environmental impact studies for the PSE Tacoma LNG plant, Kalama Manufacturing and Export Facility and the 2019 Puget Sound Energy IRP.

WSU Natural Gas Methane Study

- Sponsored by EDF and utilities to estimate the leakage of distribution systems
- National project and estimated a loss of **0.1 – 0.2** percent of the methane delivered nationwide
- Western region contributes much less as compared to the East
- “Out of **230 measurements, three large leaks accounted for 50%** of the total measured emissions from pipeline leaks. In these types of emission studies, a few leaks accounting for a large fraction of total emissions are not unusual.”

LDC Upstream Emissions

	Avista Specific Natural Gas	
Combustion	Lbs. GHG/MMBtu	Lbs. CO2e/Mmbtu
CO2	116.88	116.88
CH4	0.0022	0.0748
N2O	0.0022	0.6556
Total Combustion		117.61
Upstream		
CH4	0.313406851	10.66
Total		128.27

Upstream Emissions	Avista's Purchases	Emissions Location
0.77	89.72%	Canada
1.00	10.28%	Rockies
0.79		

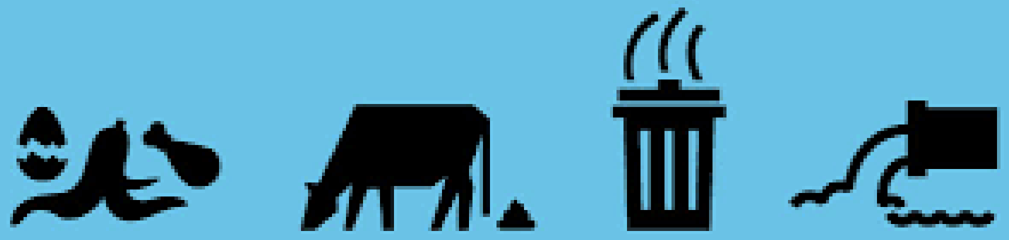
*Avista gas purchases
An average of the total volume purchased over the past 5 years by emissions location

Electric Upstream Emissions

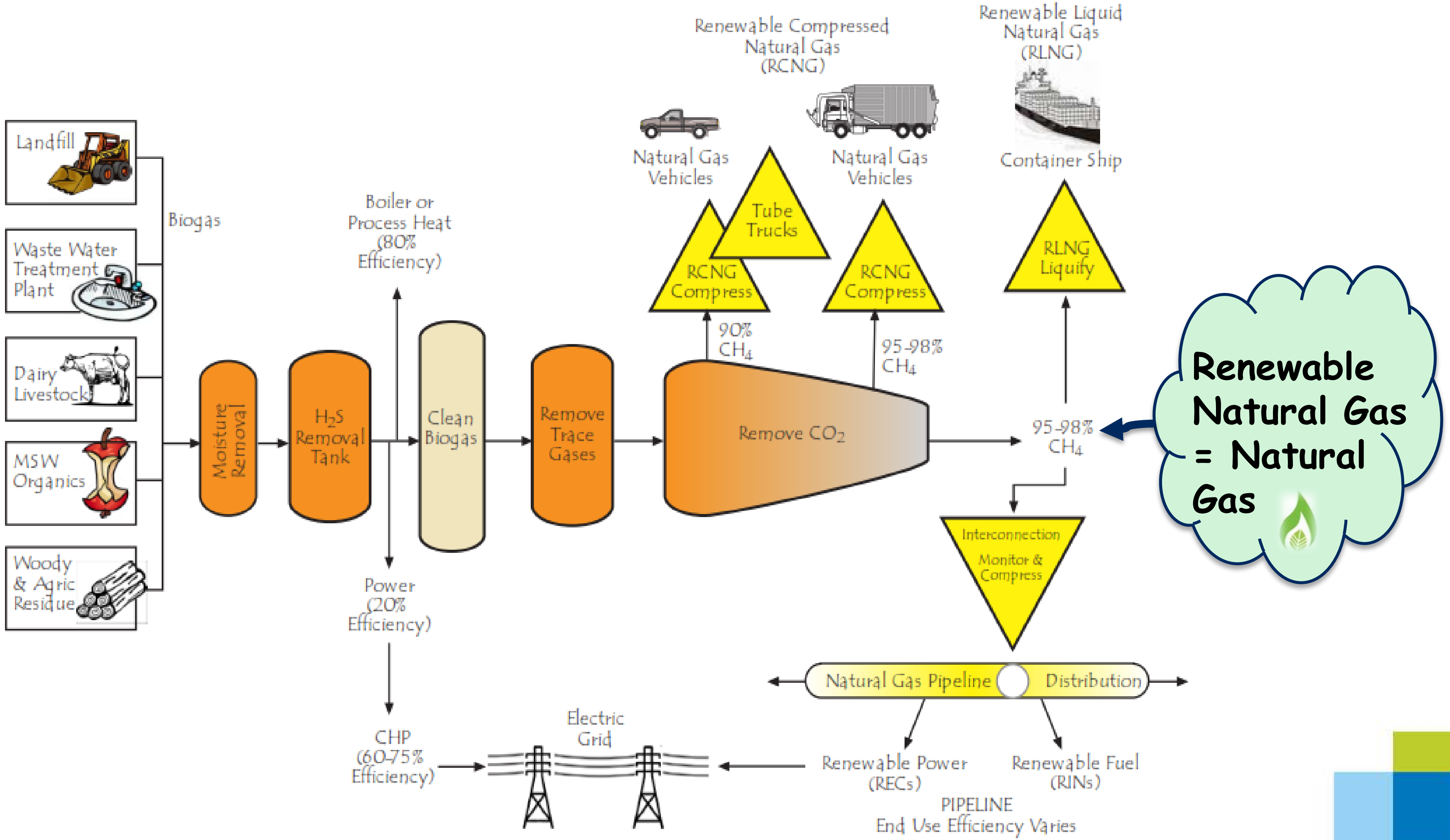
	Avista Specific Natural Gas	
Combustion	Lbs. GHG/MMBtu	Lbs. CO2e/Mmbtu
CO2	116.88	116.88
CH4	0.0022	0.0748
N2O	0.0022	0.6556
Total Combustion		117.61
Upstream		
CH4	0.304065693	10.34
Total		127.95
Upstream Emissions	Avista's Purchases	Emissions Location
0.77	100.00%	Canada
1.00	0.00%	Rockies
0.77		

*Avista Purchases
All firm transportation to supply gas is located in Canada

Renewable Natural Gas (RNG)



What is Renewable Natural Gas (RNG)?



Why does RNG matter?

Climate Change Solution

- Natural gas plays critical role for meeting aggressive green house gas (GHG) reductions goals, RNG even more so!
- Utilizes existing infrastructure
- Advantages of RNG
  - “De-carbonizes” gas stream
  - Gives customers another renewable choice

Carbon Intensity

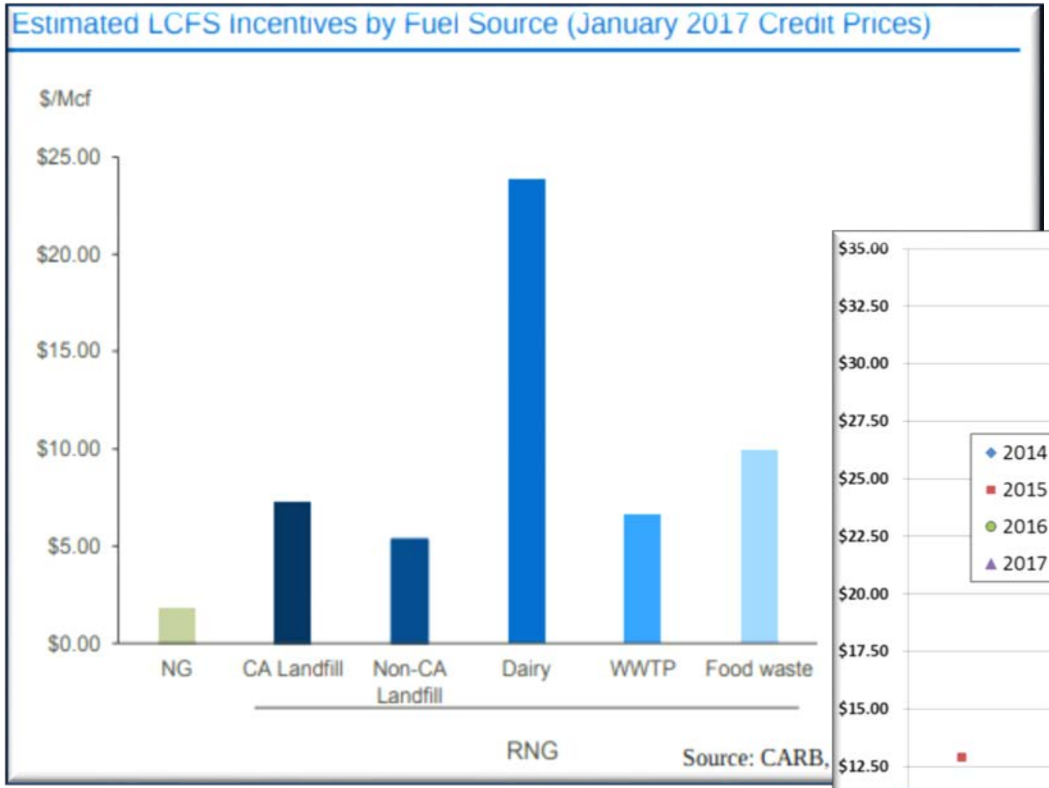
Fuel Pathway	Carbon Intensity $\frac{gCO_{2}e}{MJ}$
Diesel*	102.01
Gasoline*	99.78
Fossil CNG†	78.37
Landfill CNG†	46.42
WWTP CNG*	19.34
MSW CNG*	-22.93
Dairy CNG‡	-276.24

*California Code of Regulation Title 17, §95488, Table 6. Carbon intensity for WWTP is the average of two WWTP pathways.
†California Code of Regulation Title 17, §95488, Table 7.

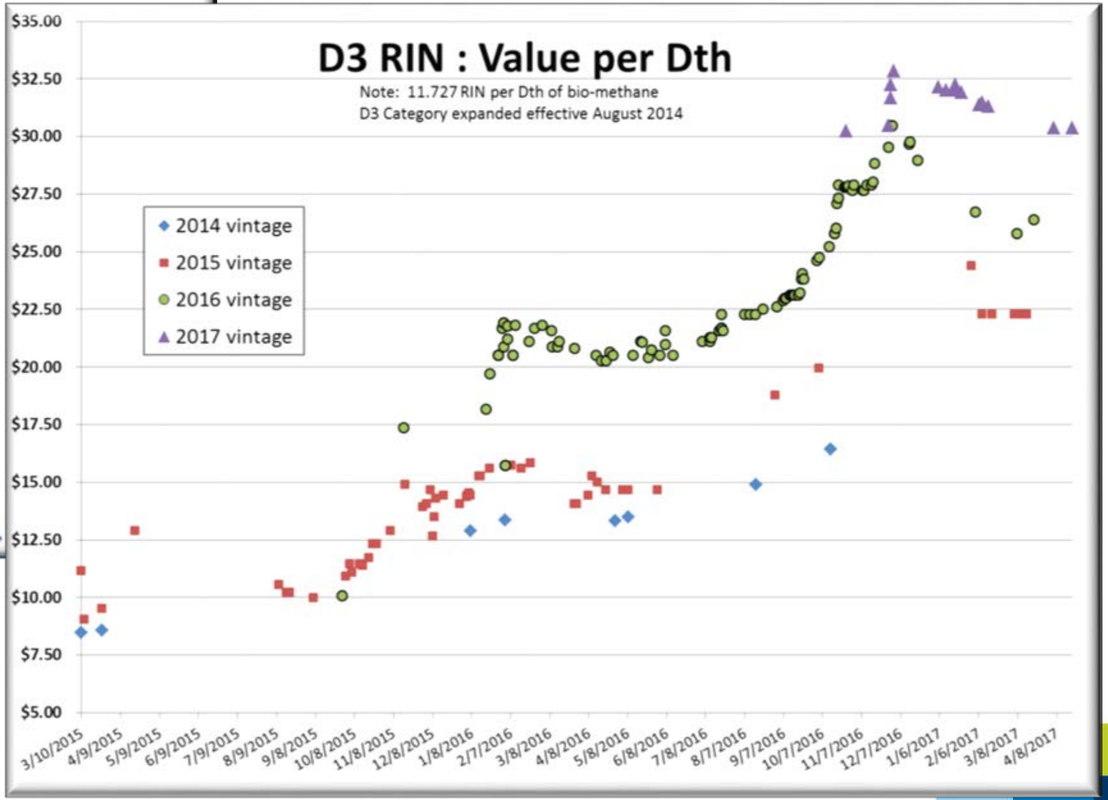
†Method 2B Application CalBio LLC, Dallas Texas, Dairy Digester Biogas to CNG.

RFS and LCFS Effect on RNG Value

RIN = renewable identification number



Source: CARB



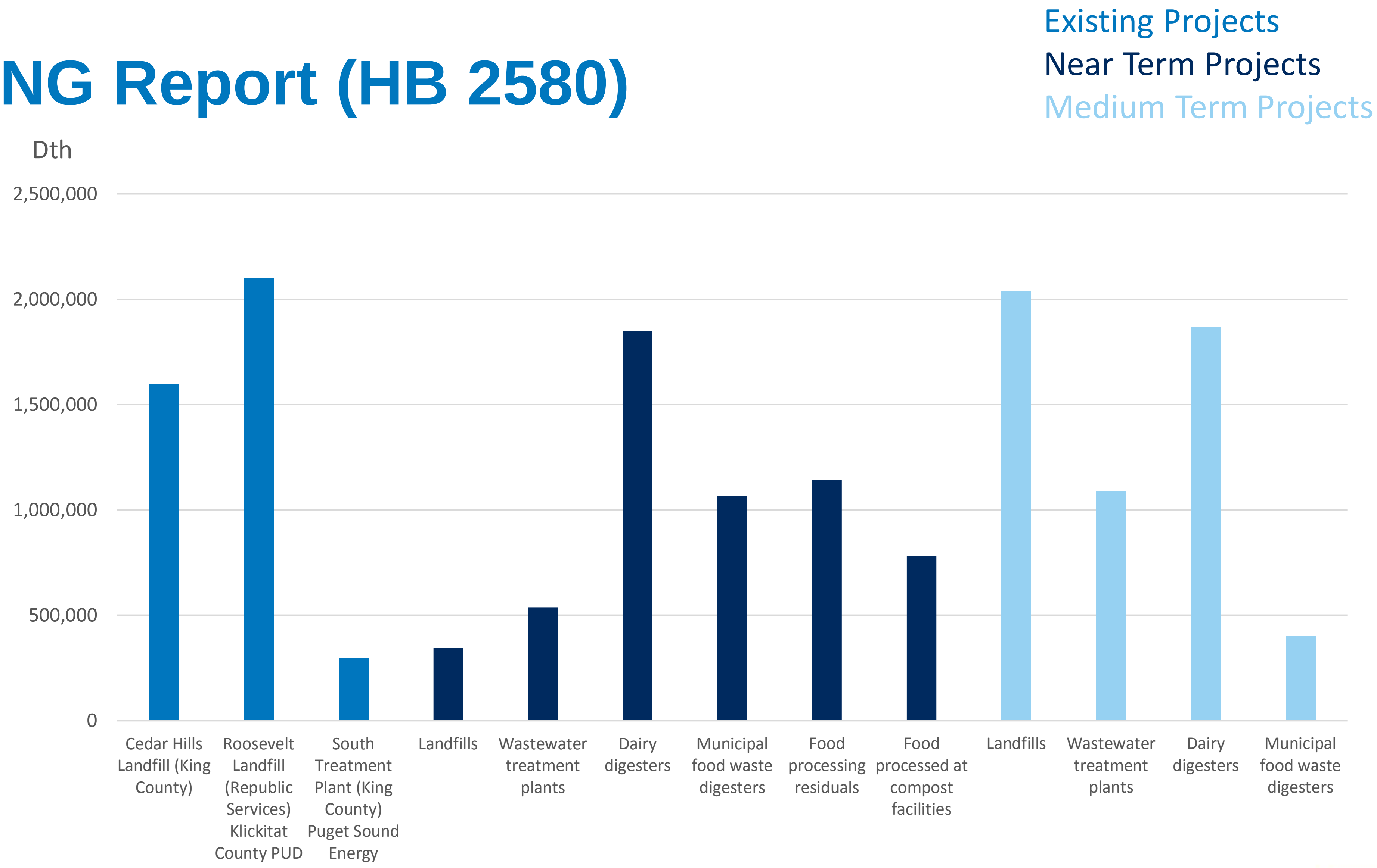
Source: EPA

What are the challenges & barriers?

- California RNG market ($30+/Dth v. $2/Dth)
  - Vehicle emission incentives shut-out other potential end users
  - Producers see the pot of gold in California

- Financing for producers
  - RIN market is volatile
  - No forward pricing for RNG RINs in carbon market
  - Vehicle market may be approaching saturation in CA
  - Producer/LDC partnerships may make sense

WA RNG Report (HB 2580)



WSU Energy Program, Harnessing Renewable Natural Gas for Low-Carbon Fuel: A Roadmap for Washington State

*Released December 1, 2018

ID RNG NREL Estimates

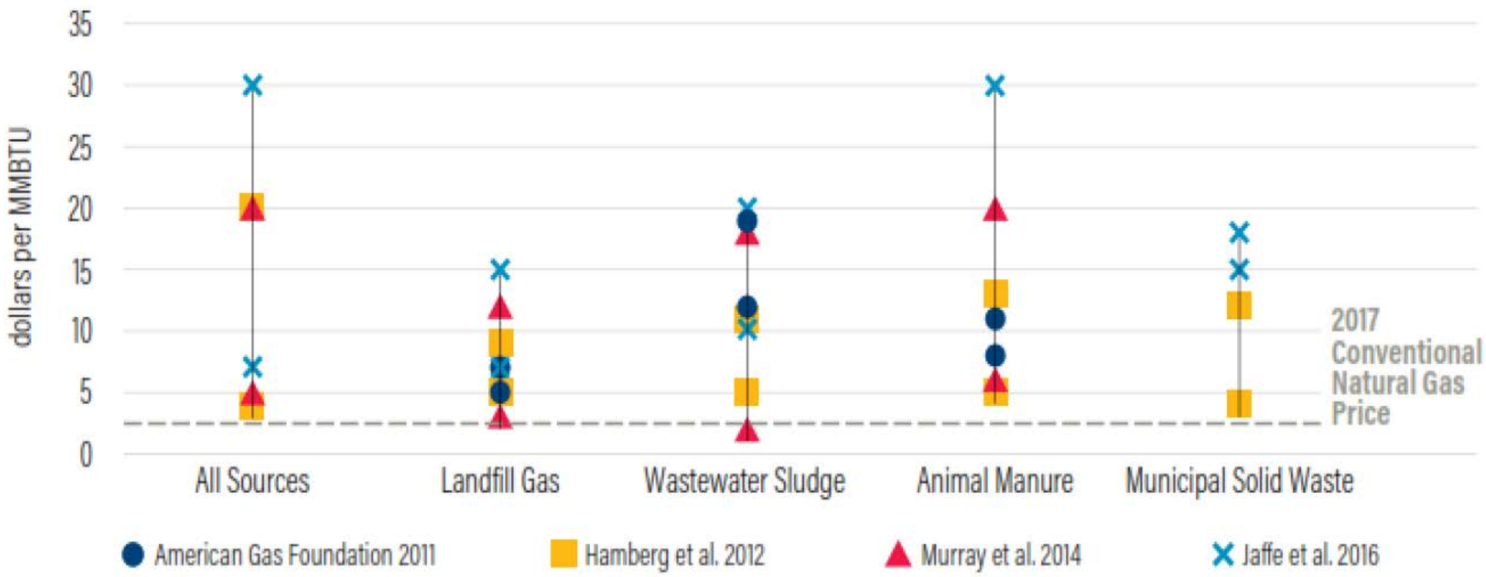
Total Potential Annual Production = 32 Bcf

Source - Anaerobic	MMBtu per Year
Landfills	3,712,221
Wastewater Treatment	6,196,531
Agriculture Manure	20,220,571
Source-Separated Organics (Solid Waste)	2,311,354
Total	**32,440,676**

National Renewable Energy Laboratory, NREL Biofuels Atlas

RNG $ per Dth/MMBtu

Avista Owned and Operated	ID - WA 2035 Premium Estimate ($ / Dth)
RNG - Landfills	$7 - $10
RNG - Waste Water Treatment Plants (WWTP)	$12 - $22
RNG - Agriculture Manure	$28 - $53
RNG - Food Waste	$29 - $53



Source: Promoting RNG in WA State

Natural Gas IRP

A detailed level of RNG understanding and evaluation process will be included in the Natural Gas IRP TAC #3 meeting on September 30, 2020

Natural Gas Price Forecast

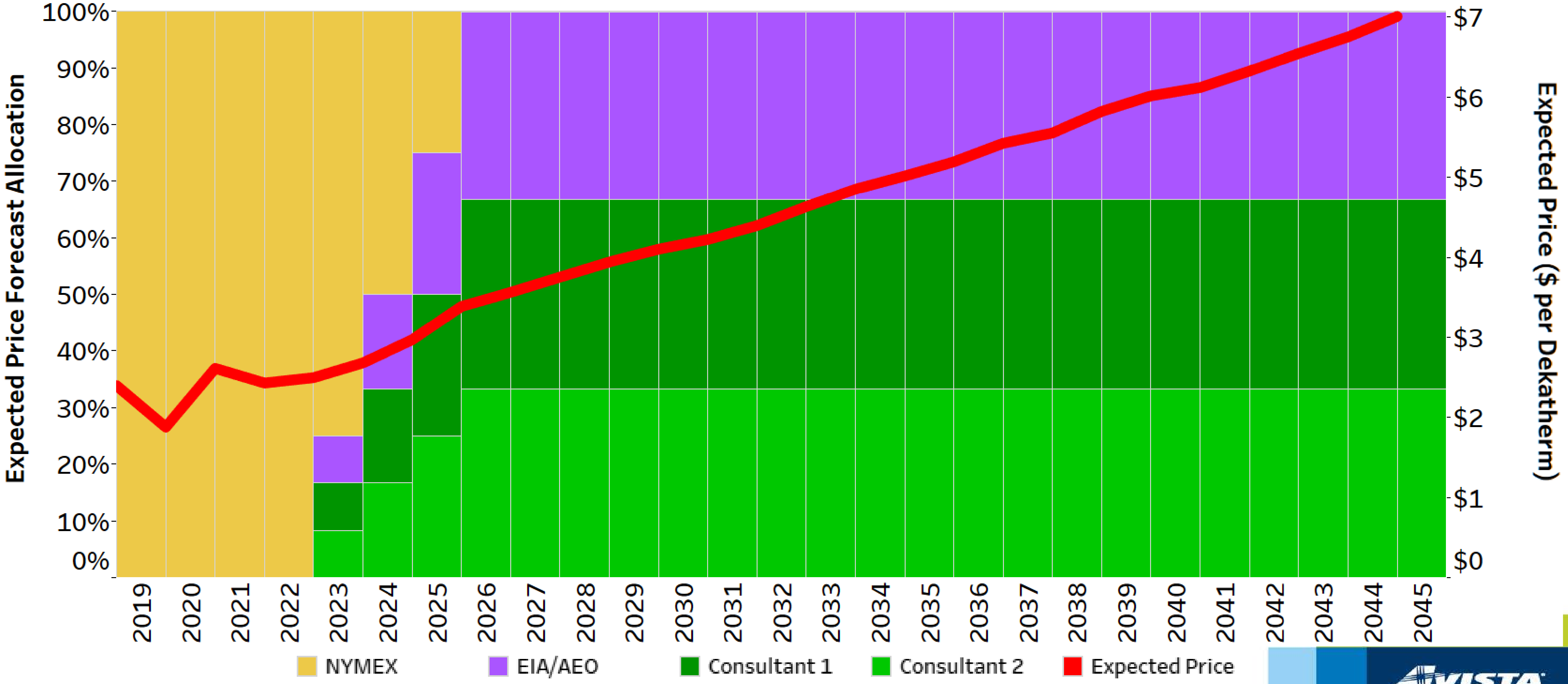
Michael Brutocao, Natural Gas Analyst
Second Technical Advisory Committee Meeting
August 6, 2020

Henry Hub Expected Price Methodology

- Expected Henry Hub prices derived from a blend of forward market prices on the NYMEX (as of 6/30/2020) and forecasted prices from the 2020 Annual Energy Outlook (EIA) and two consultants

	2020 – 2022	2023	2024	2025	2026 – 2045
NYMEX	100%	75%	50%	25%	-
EIA/AEO	-	8.33%	16.66%	25%	33.33%
Consultant 1	-	8.33%	16.66%	25%	33.33%
Consultant 2	-	8.33%	16.66%	25%	33.33%

Henry Hub Expected Price and Forecast Blending



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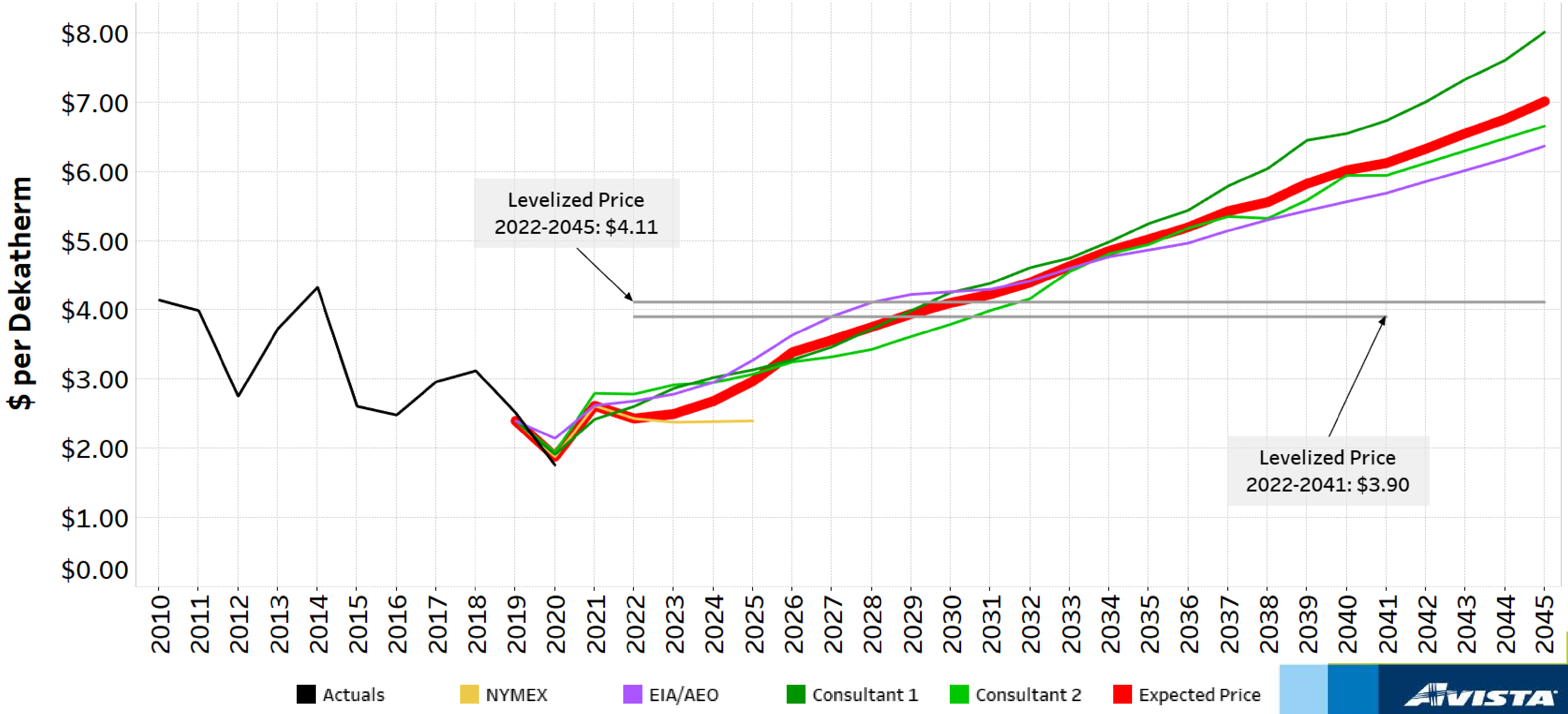
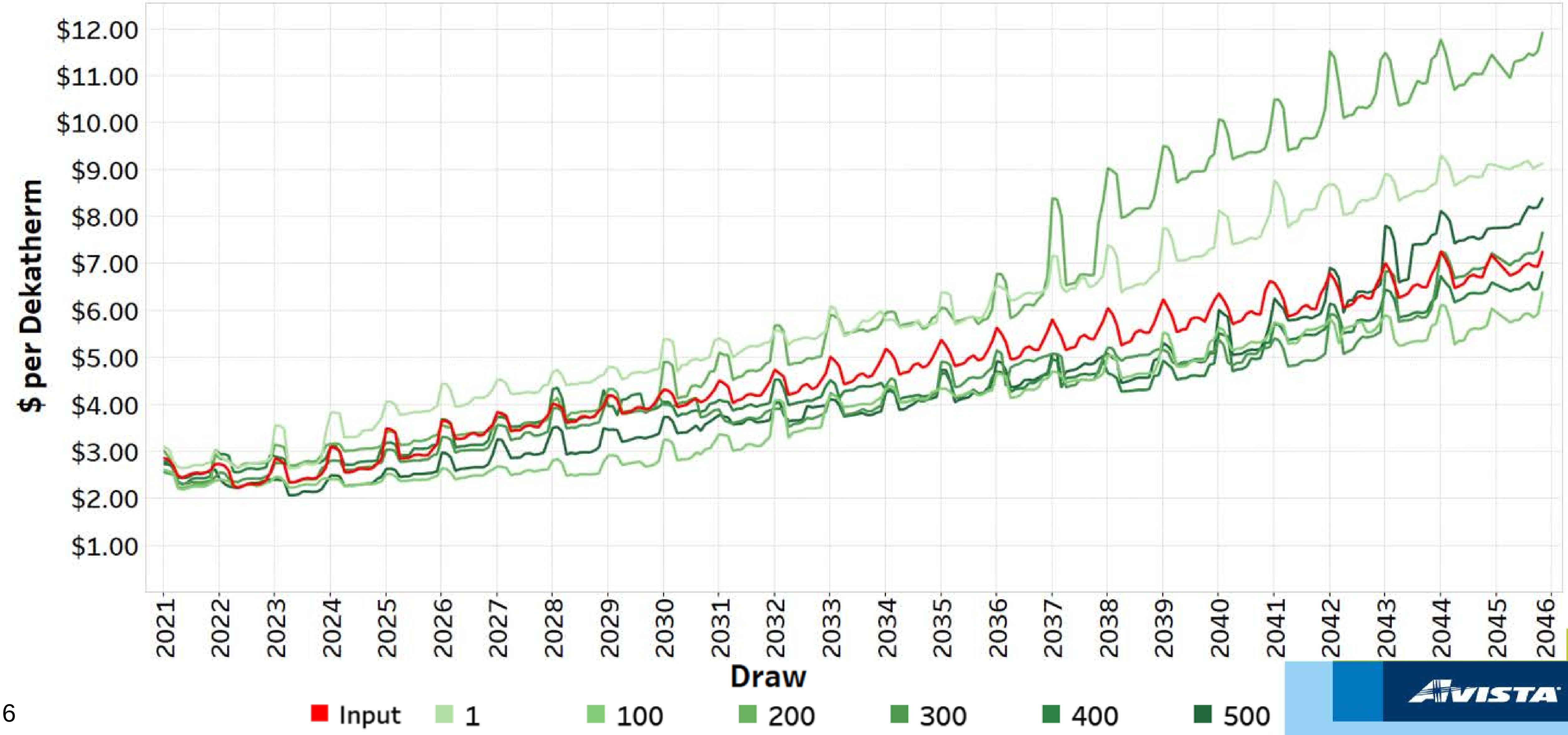
Henry Hub Expected Price and Average Annual Forecasts



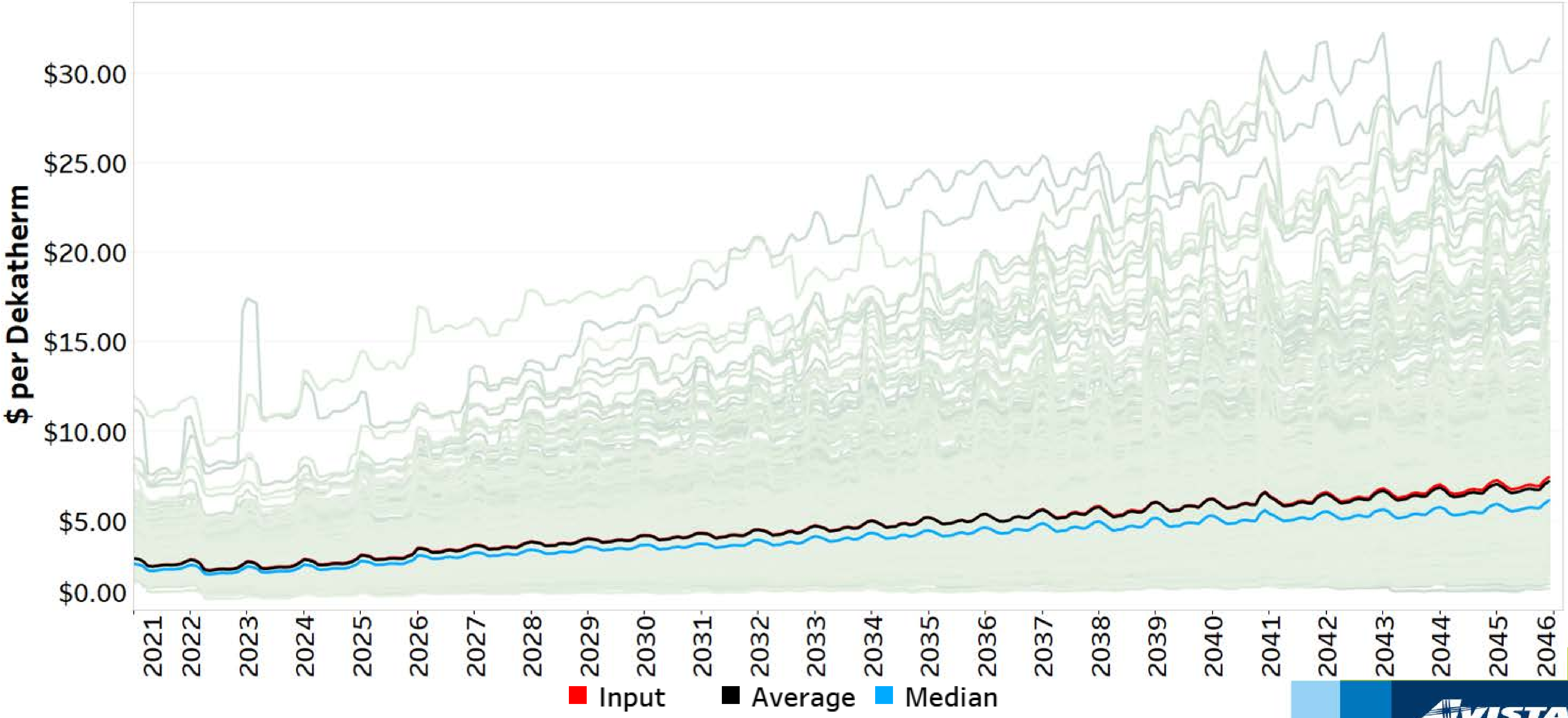
Stochastic Price Forecasting Methodology

- Evaluate a set of potential future outcomes based on the probability of occurrence
  - Expected Price used as the input
  - At each period, random price adjustments follow a lognormal distribution based on the Expected Price
    - It is common practice to use lognormal distributions in forecasting prices as they have no upward bound and should not fall below zero
- A single "draw" contains a set of unique price movements
- 500 (electric) and 1000 (gas) draws were evaluated

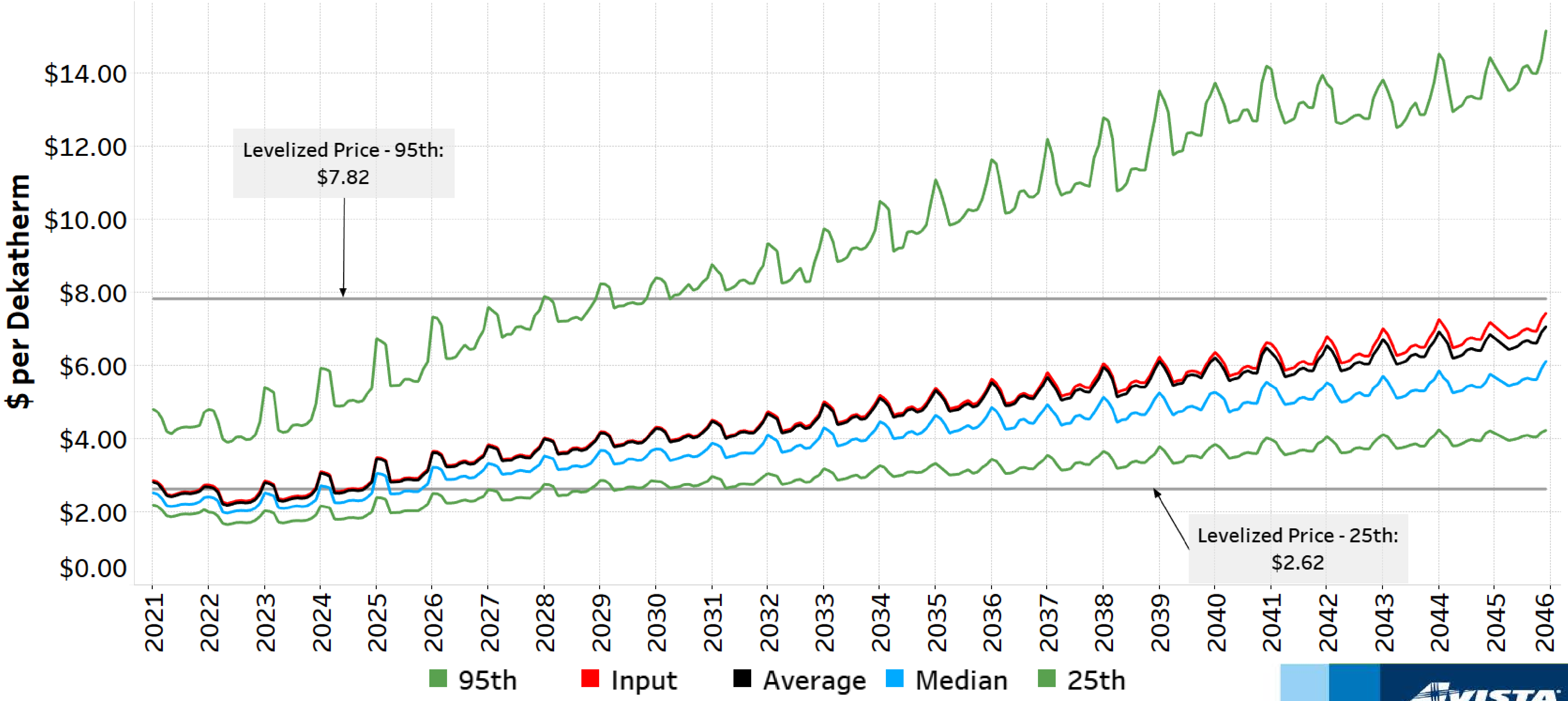
Sample Stochastic Price Draws



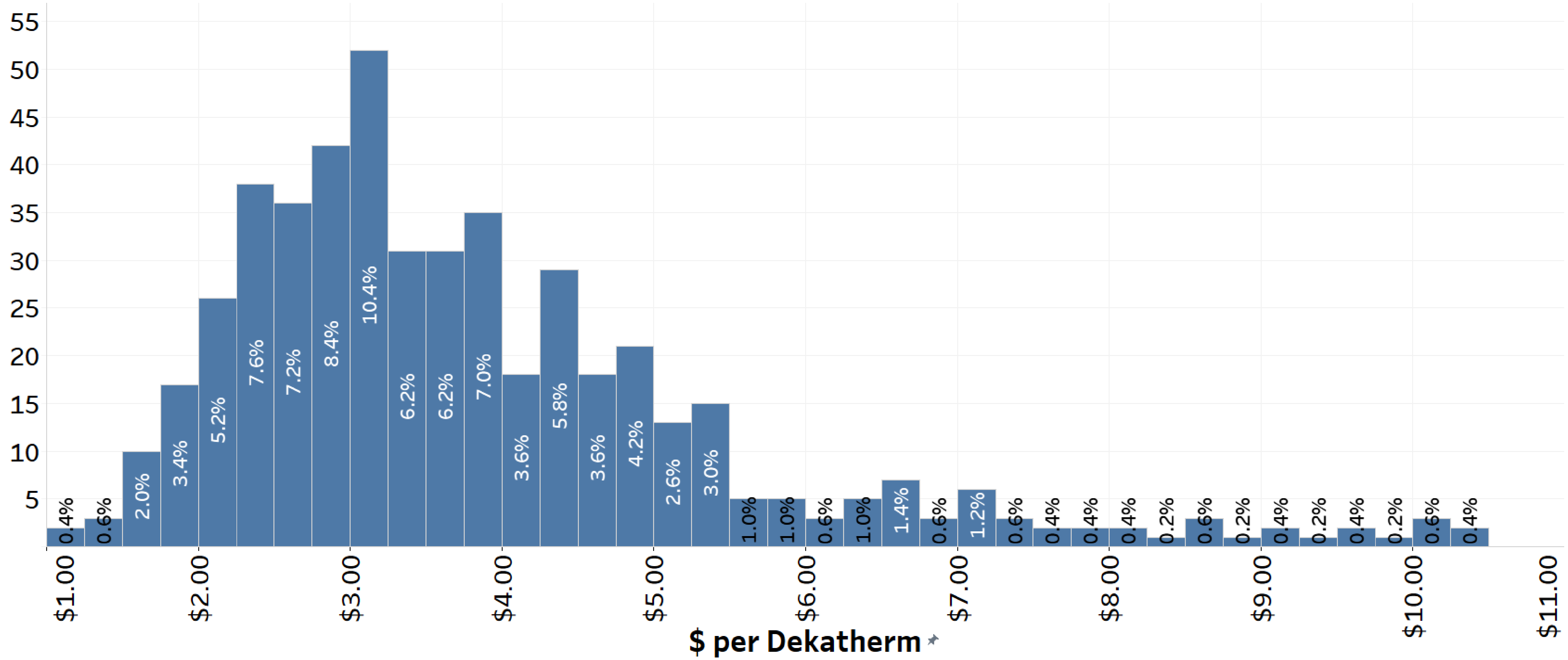
Stochastic Price Draws



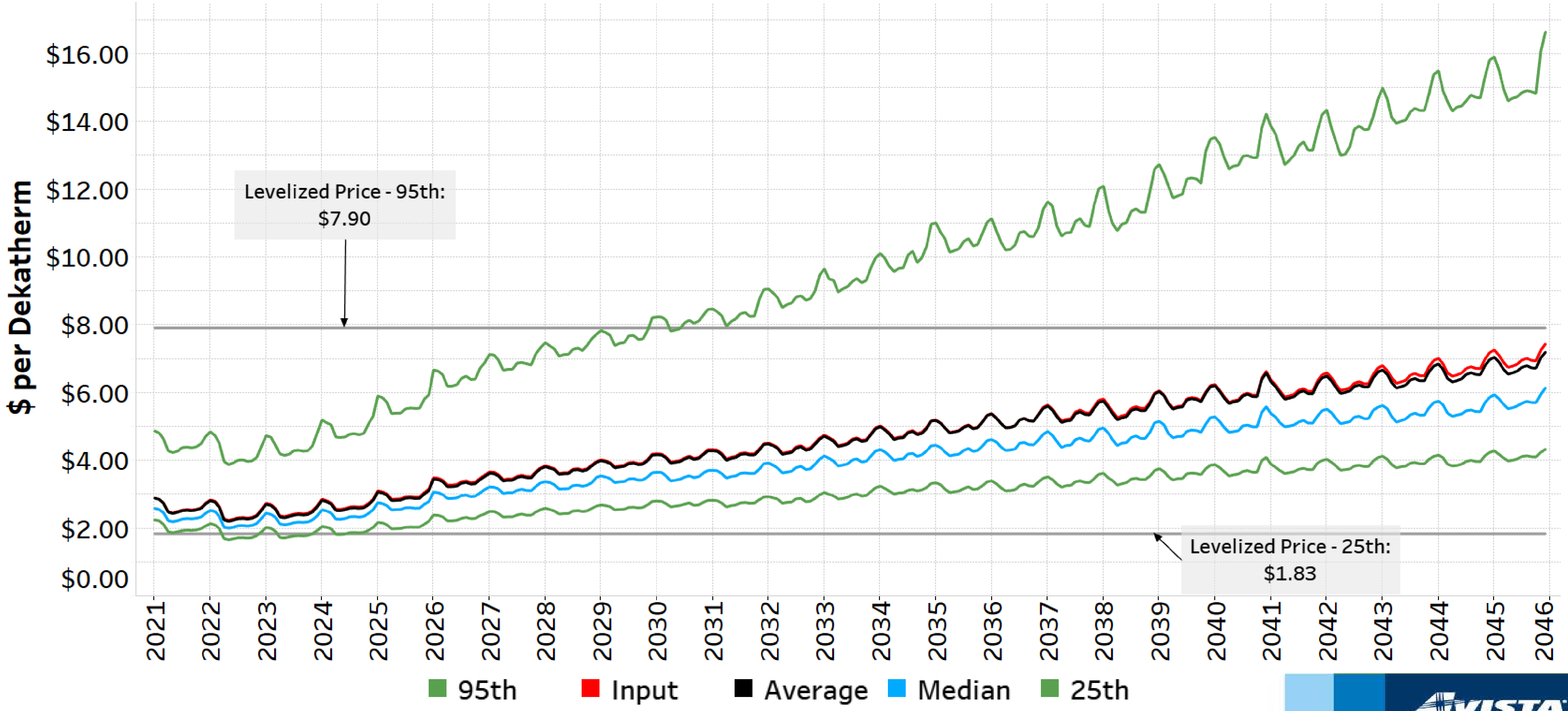
Stochastic Prices (Results from 500 Draws)



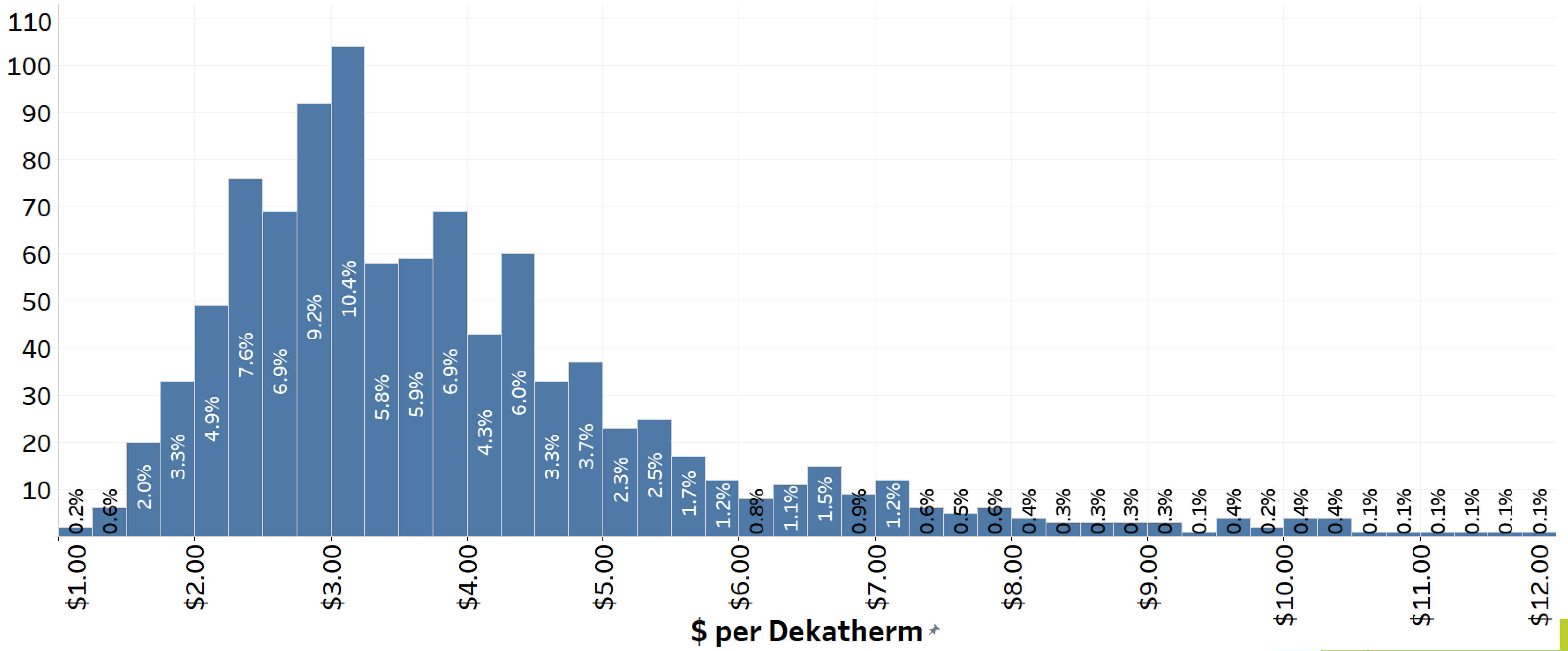
Levelized Stochastic Prices (Results from 500 Draws)



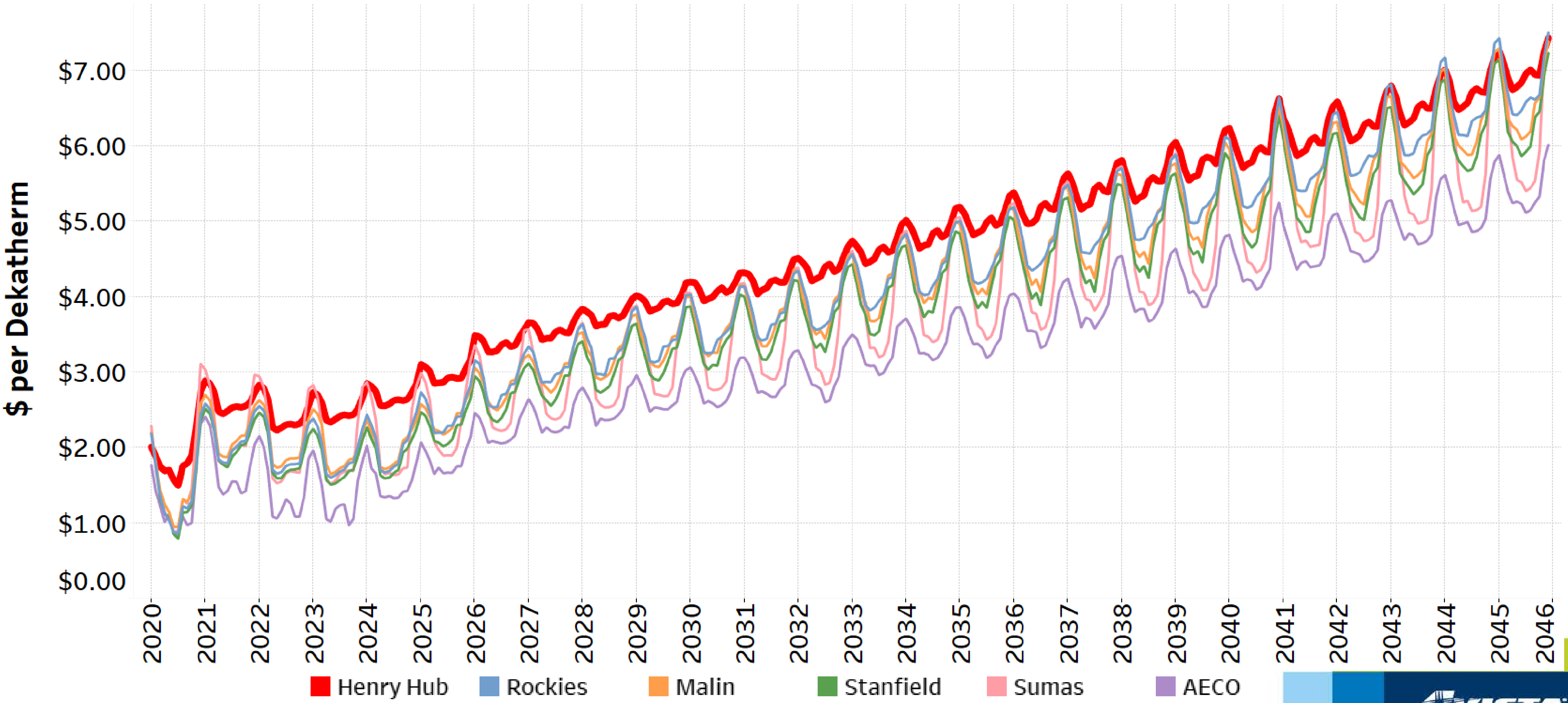
Stochastic Prices (Results from 1000 Draws)



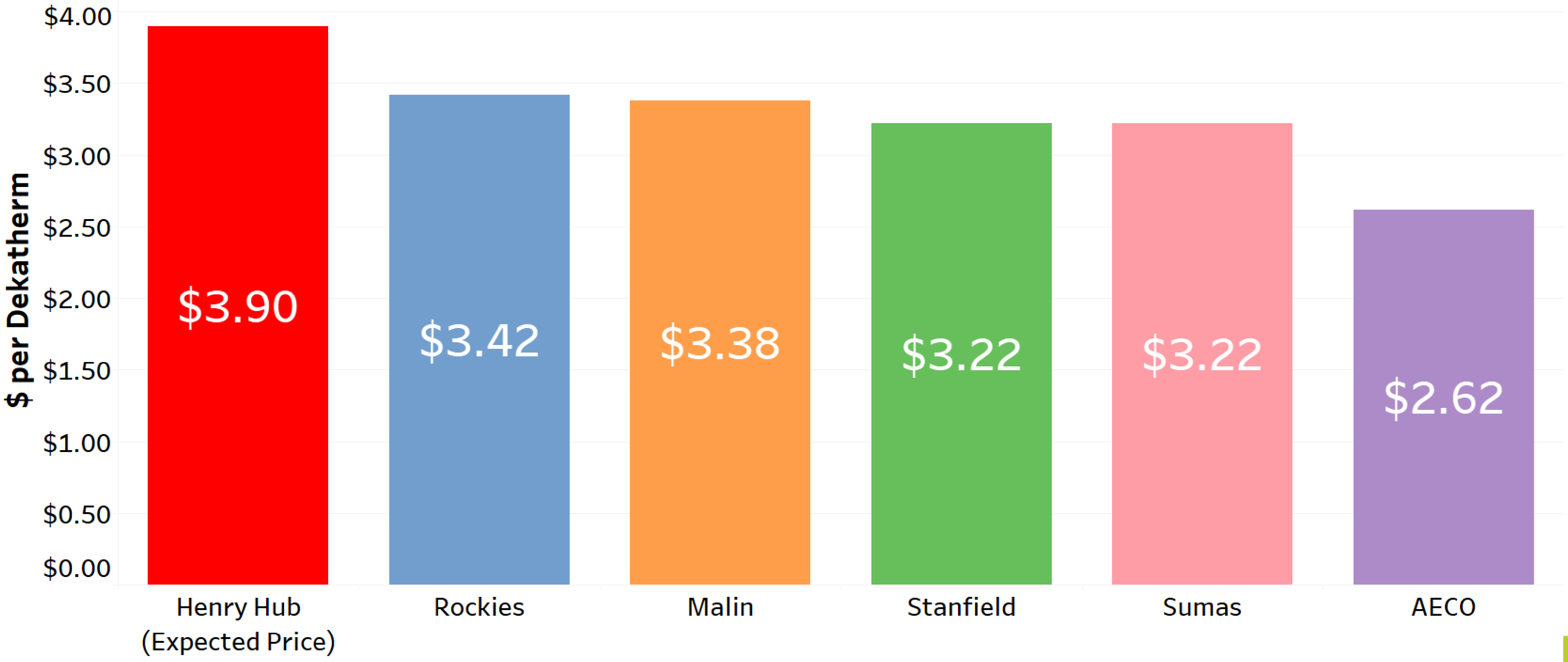
Levelized Stochastic Prices (Results from 1000 Draws)



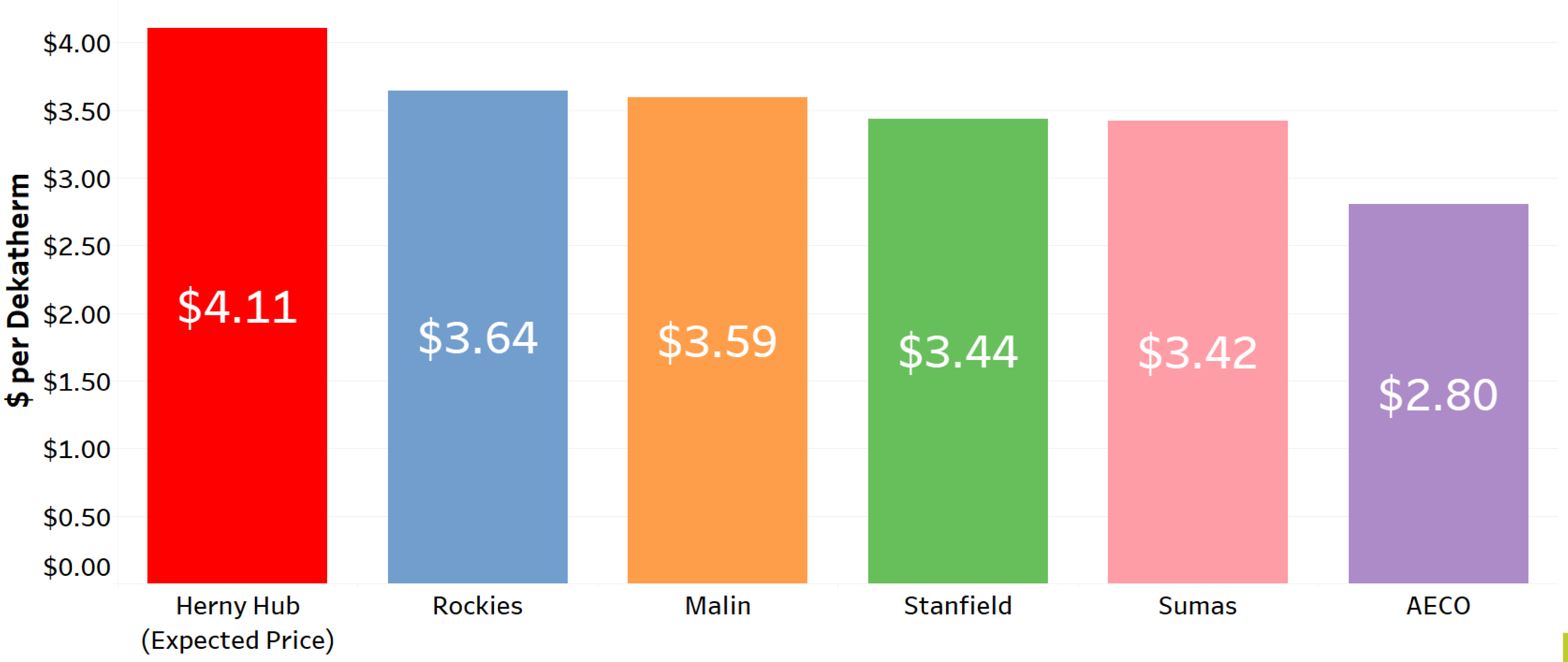
Prices by Gas Hub (Henry Hub Expected Price + Basis)



Levelized Prices 2022-2041



Levelized Prices 2022-2045



2021 Electric IRP
Regional Energy Policy Update

John Lyons, Ph.D.
Second Technical Advisory Committee Meeting
August 6, 2020

Production and Investment Tax Credits

- Production tax credit $15/MWh adjusted for inflation ($25/MWh for 2019) for 10 years for wind construction started by 12/31/20
- Investment tax credit for new solar construction drops from 30% in 2019
  - 26% in 2020
  - 22% in 2021
  - 10% from 2022 onward
- Will be watching for any possible extensions with all of the COVID-19 proposals

State and Provincial Policies

State/Province	No Coal	RPS	Clean Energy/Carbon Goal
Alberta	Yes	Yes	Yes
Arizona	No	Yes	No
British Columbia	Yes	Yes	Yes
California	Yes	Yes	Yes
Colorado	No	Yes	Yes
Idaho	No	No	No
Montana	No	Yes	No
Nevada	No	Yes	Goal
New Mexico	No	Yes	No
Oregon	Yes	Yes	Yes
Utah	No	Goal	No
Washington	Yes	Yes	Yes
Wyoming	No	No	No

Washington

- Clean Energy Transformation Act (CETA) SB 5116:
  - No coal serving Washington customers by end of 2025
  - Greenhouse gas neutral by 2030, up to 20% alternative compliance
  - 2% cost cap over four-year compliance period
  - 100% non-emitting by January 1, 2045
  - Social cost of carbon for new resources
  - Additional reporting and planning requirements
  - Highly impacted and vulnerable community identification and resource planning implications
  - Ongoing rulemaking in various stages for planning and reporting

Washington

- HB 1257: Clean Buildings for Washington Act
  - Develop energy performance standards for commercial buildings over 50,000 square feet (2020 – 2028) "… to maximize reductions of greenhouse gas emissions from the building sector"
  - By 2022, natural gas utilities must identify and acquire all available cost-effective conservation including a social cost of carbon at the 2.5% discount rate.(Section 11 and 15)
  - Natural gas utilities may propose renewable natural gas (RNG) programs for their customers and offer a voluntary RNG tariff
  - Building code updates to improve efficiency and develop electric vehicle charging infrastructure

Oregon

Executive Order 20-04

- New GHG reduction goal
  – 45% below 1990 levels by 2035
  – 80% below 1990 levels by 2050
- Directs 16 Oregon agencies to “exercise any and all authority and discretion” to reach GHG reduction goals and “prioritize and expedite” action on GHG reductions “to the full extent allowed by law.”
- Agencies are working on rulemaking and implementation

SB 98

- Development of utility renewable natural gas programs

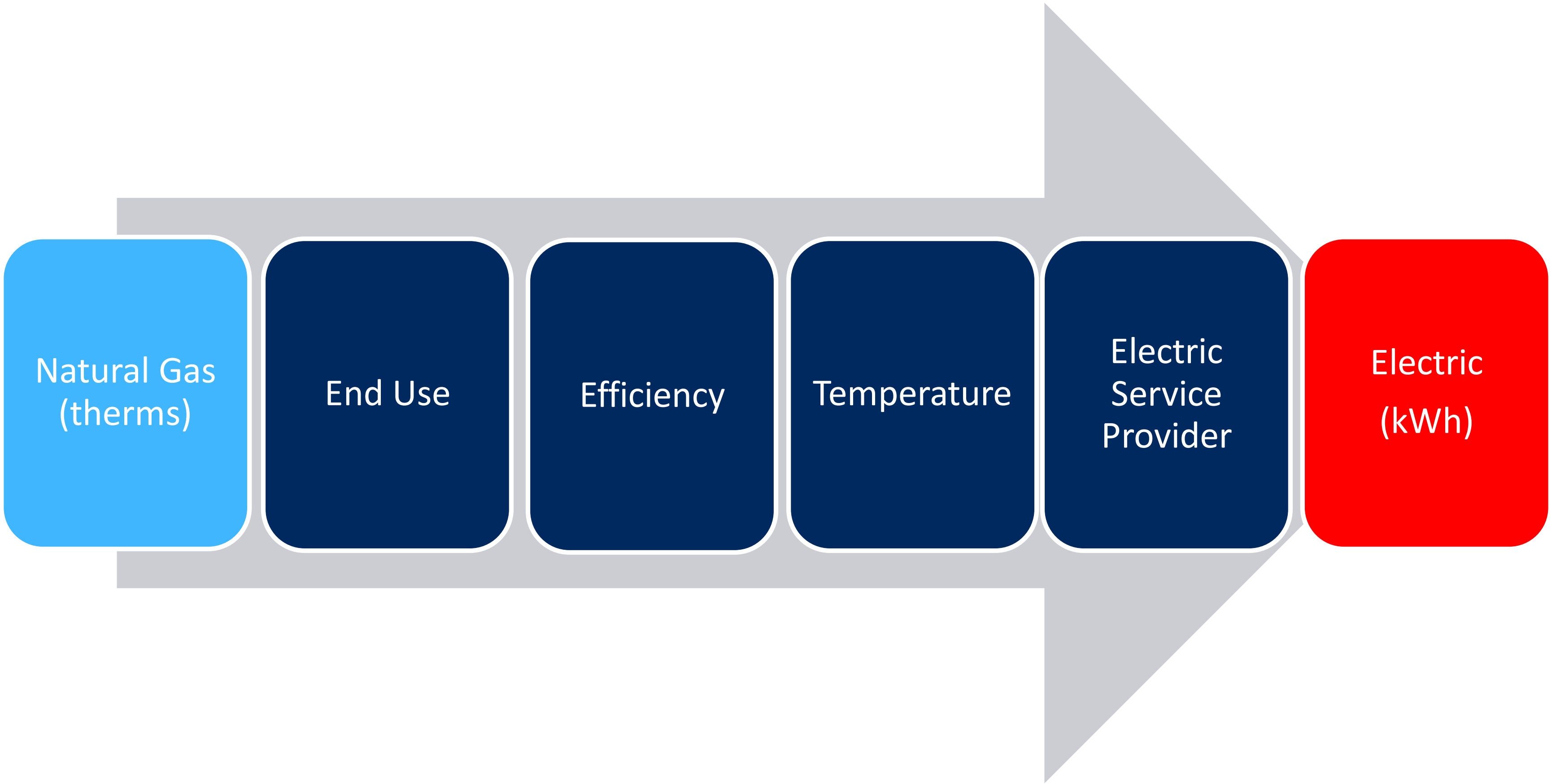
2021 Electric and Natural Gas IRPs
Natural Gas & Electric Coordinated Scenario

James Gall/Tom Pardee
Second Technical Advisory Committee Meeting
August 6, 2020

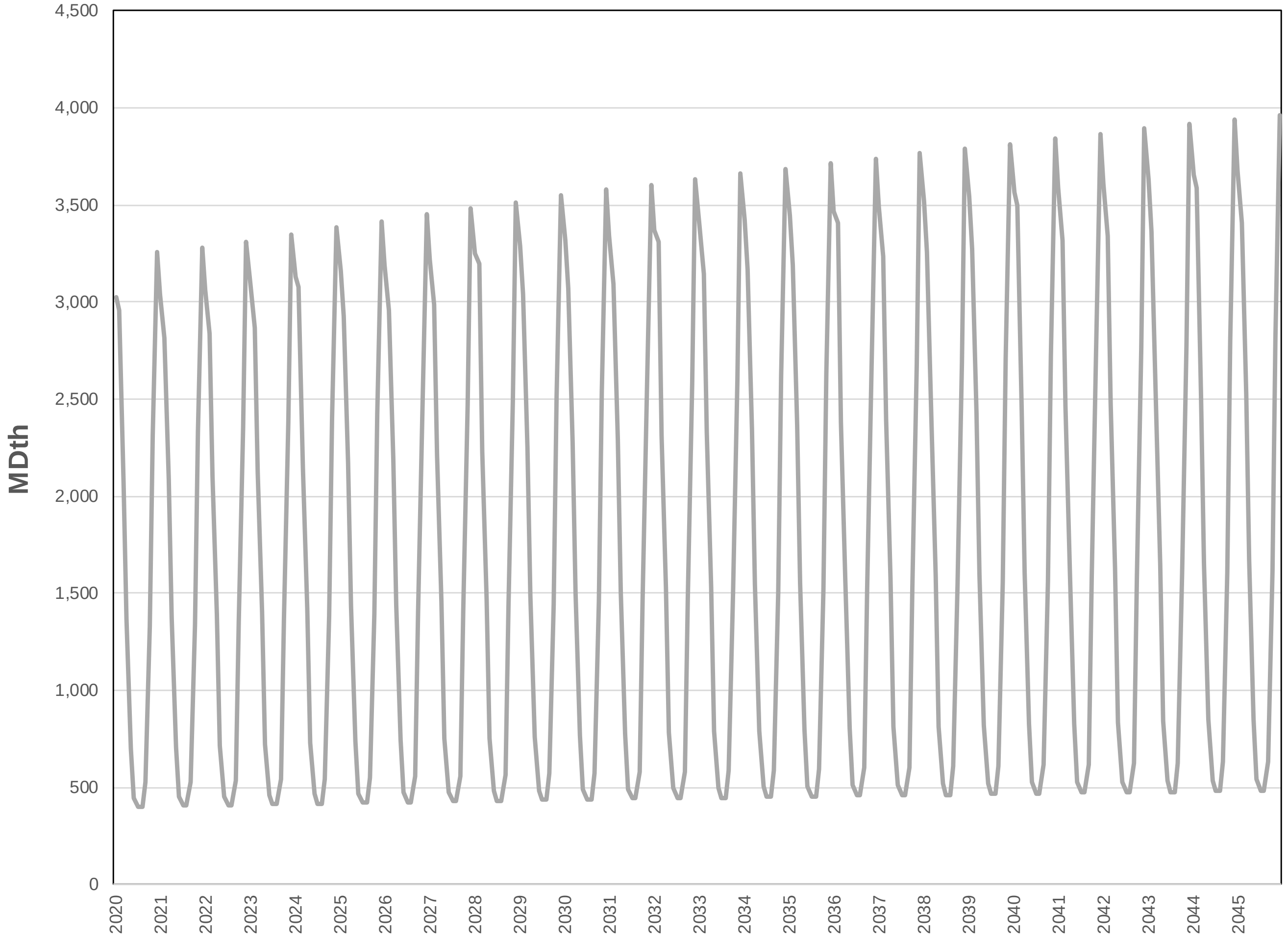
Scenario Goal

- Understand impact to electric resource planning if customers switch from natural gas to electric service
- Scenario Proposal:
  - By 2030: 50% of Washington Residential & Commercial customers
  - By 2045: 80% of Washington Residential & Commercial customers
- Potential Scenarios:
  - Hybrid natural gas/electric heat pumps
  - Highly efficient technology allows for cold temperature space heating

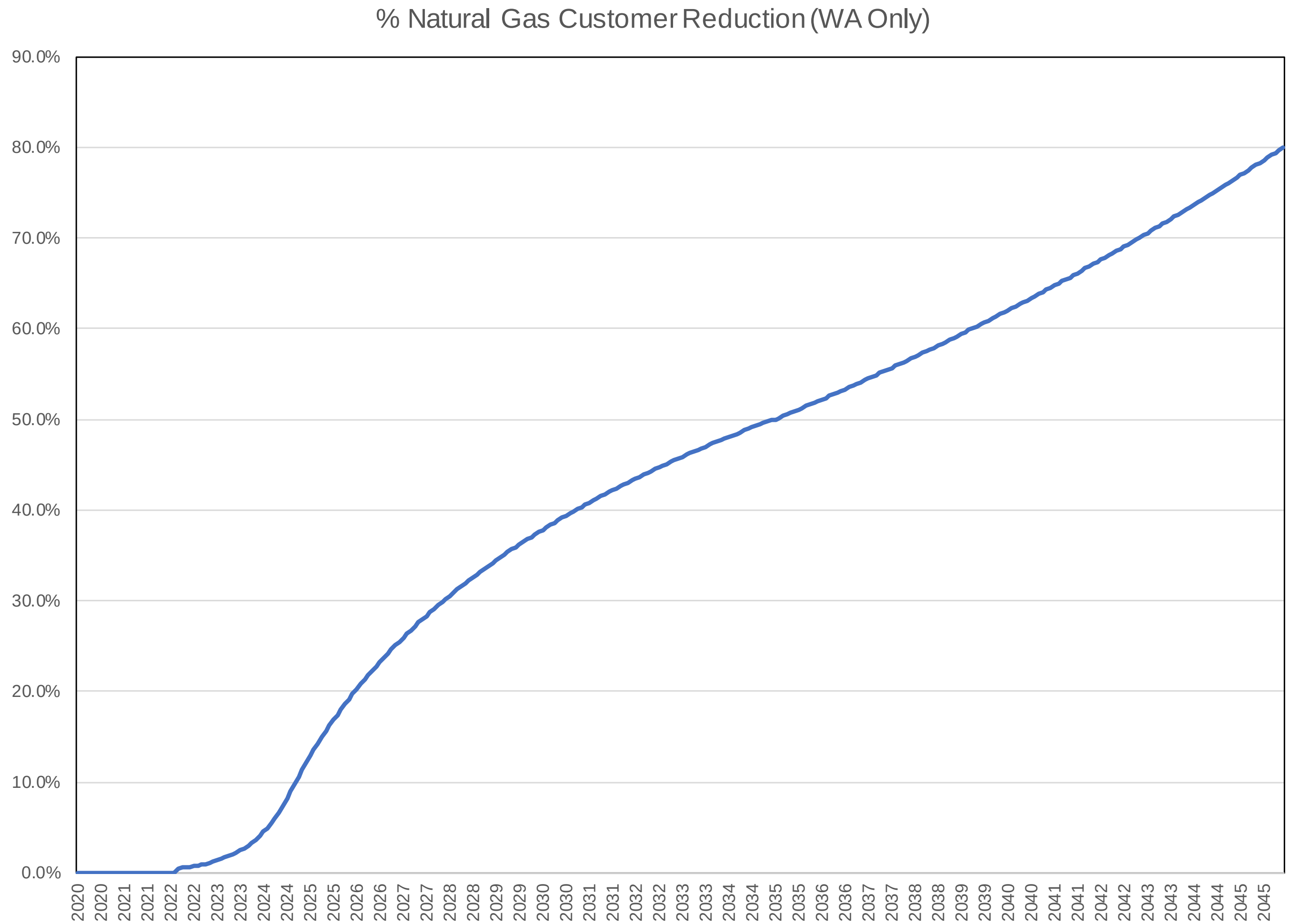
Converting Natural Gas Load to Electric Load



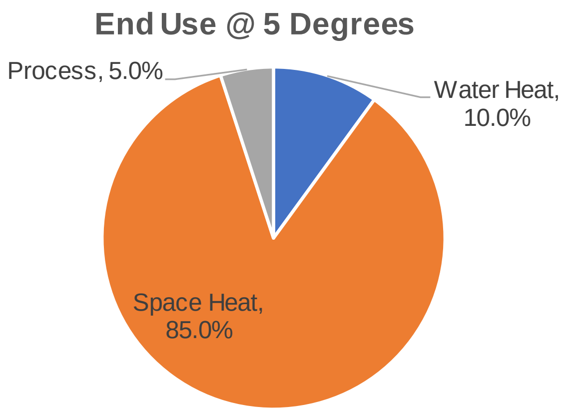
WA Res/Com Natural Gas Load Forecast

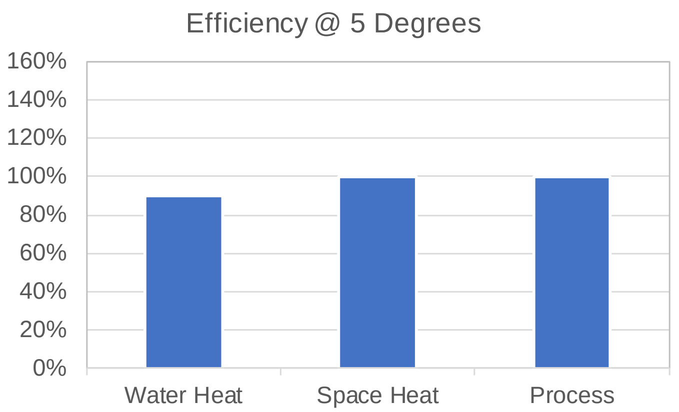


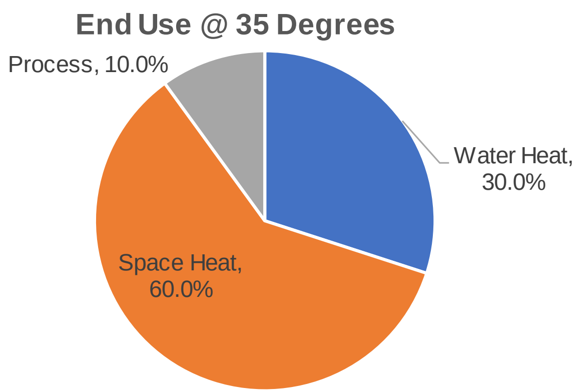
Customer Penetration Forecast

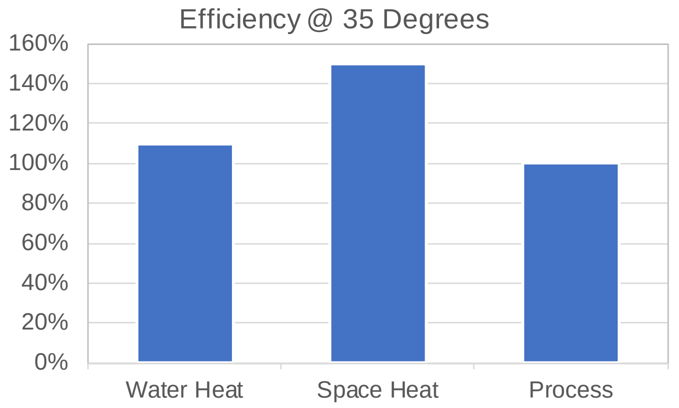


End Use Efficiency



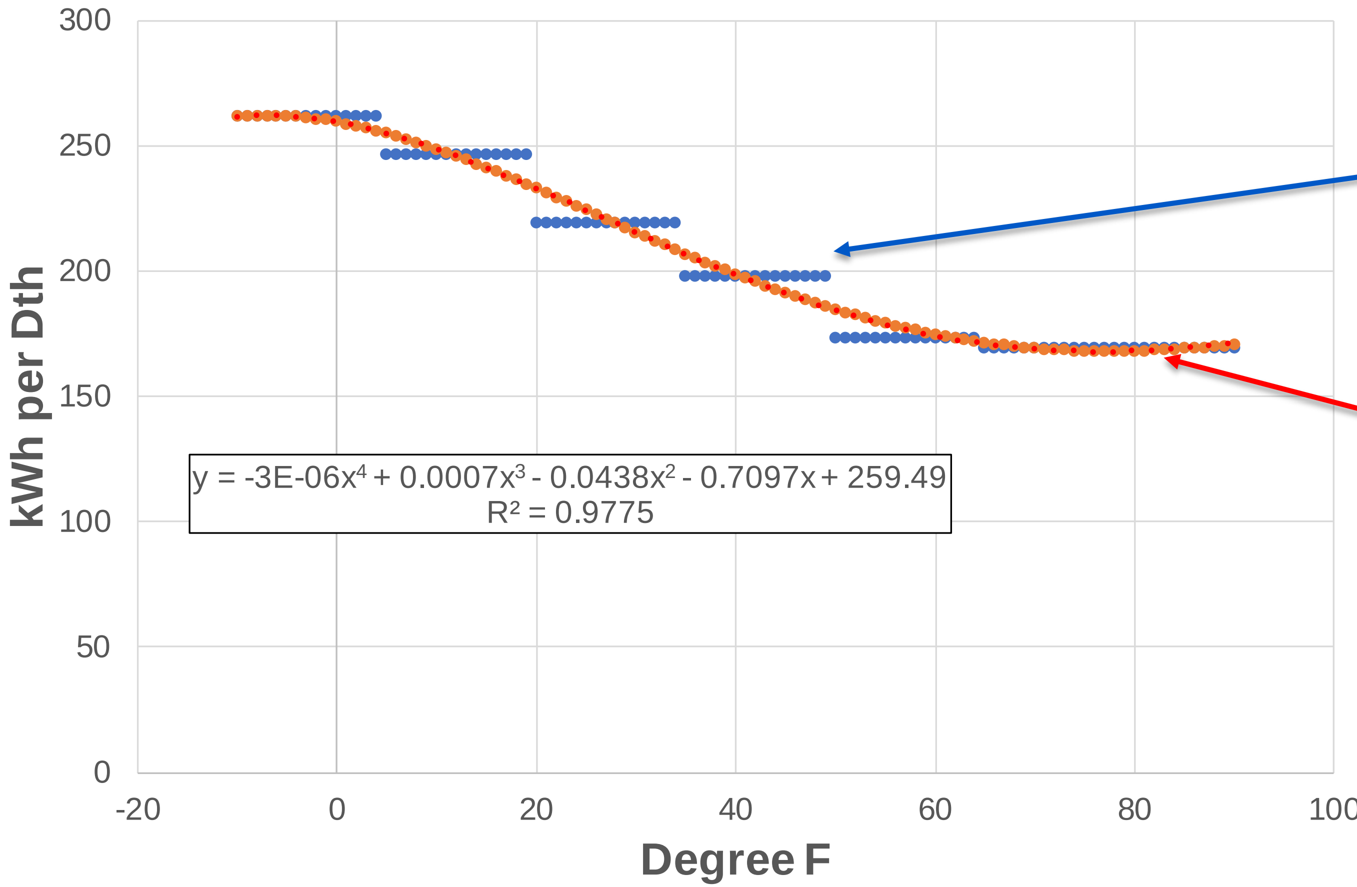






Note: All efficiency conversion use a 10% efficiency benefit to electric

Energy Conversion Factor



Use temperature point estimates for conversion efficiency

Curve fit to smooth out steps

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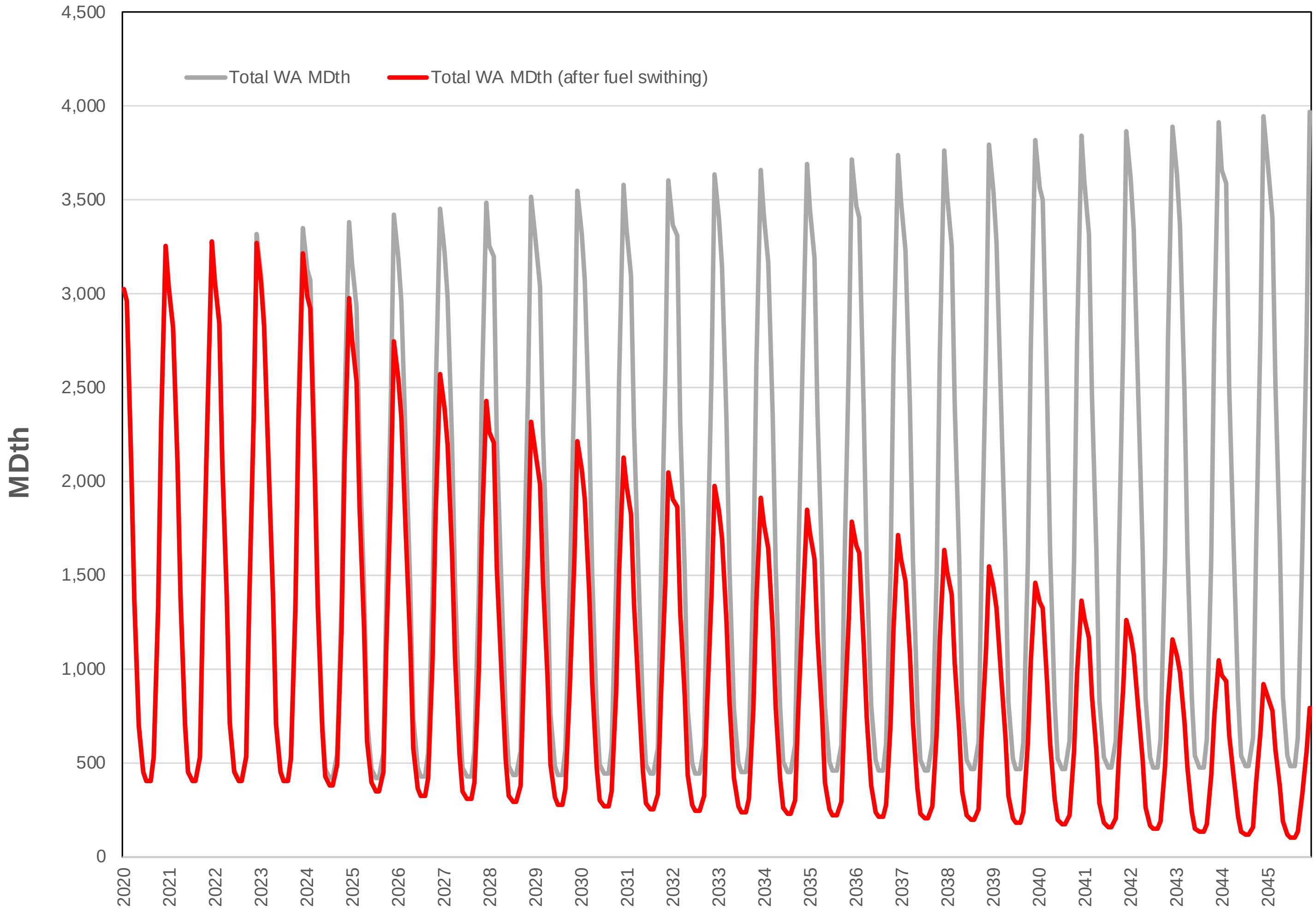
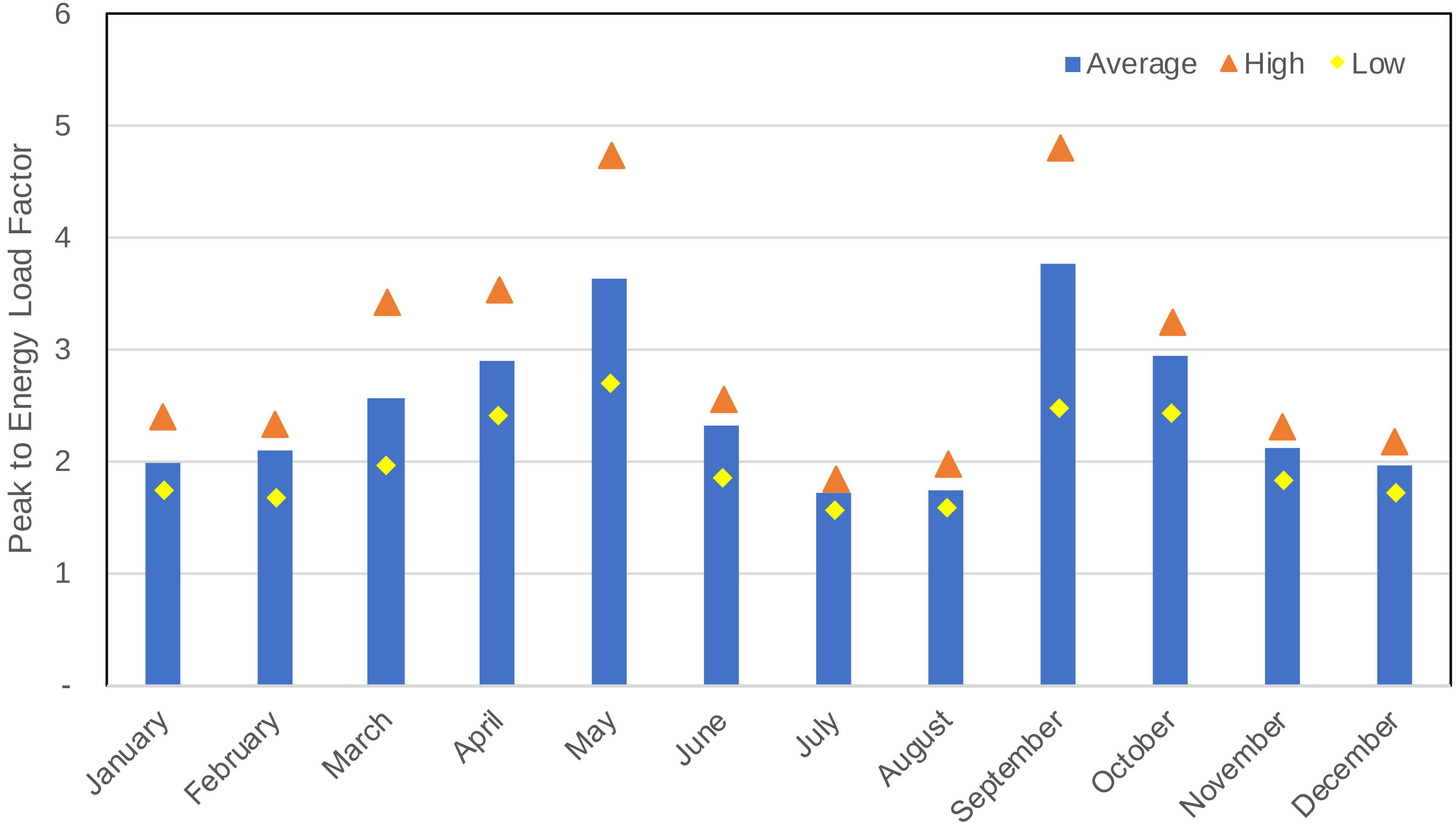
WA Res/Com Natural Gas Load Forecast



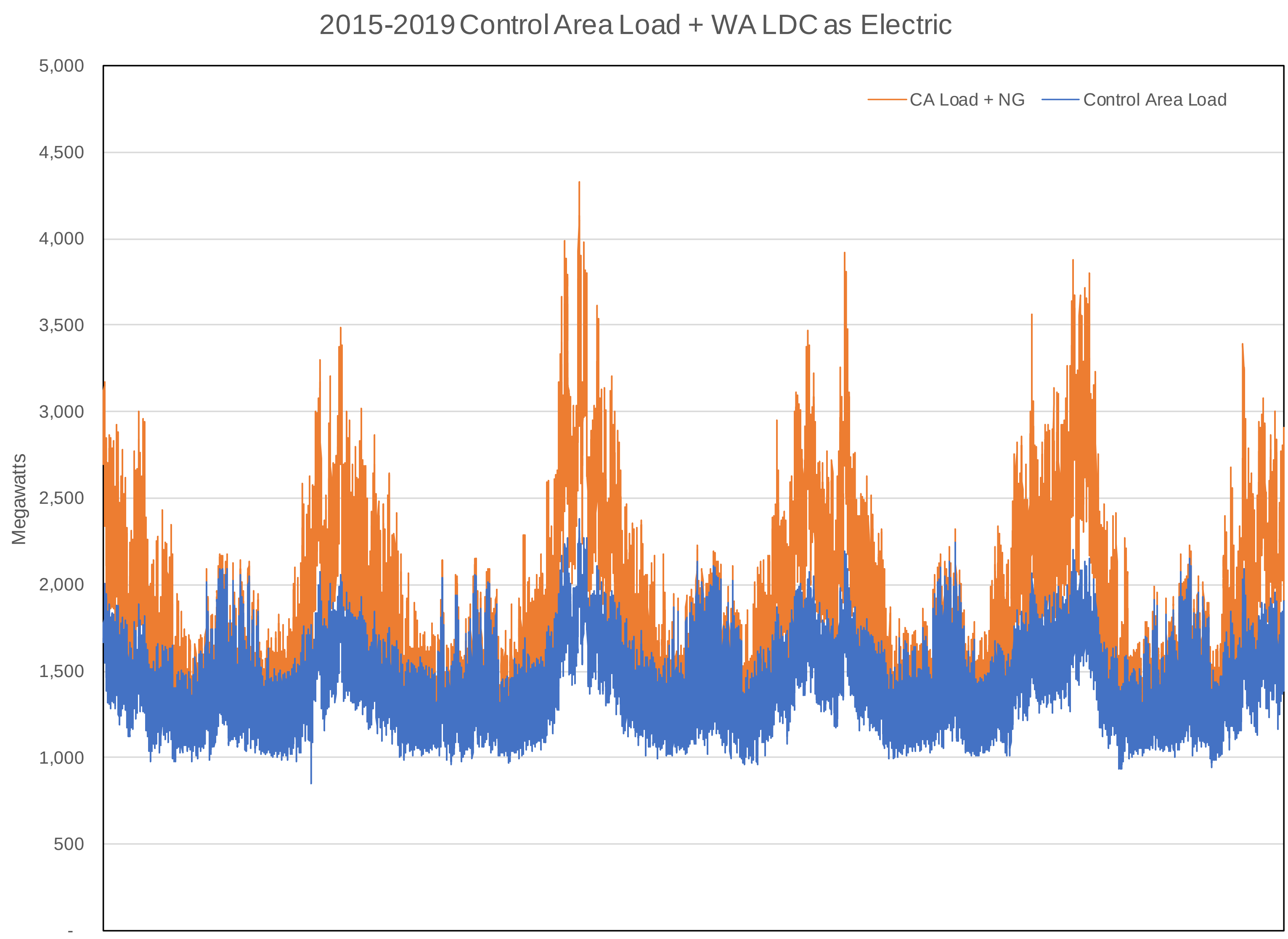
Electric Peak Estimation Methodology

- Natural gas is typically daily nominations, while electric is instantaneous.
  - Hourly flow metering is available for some areas
- Sampled large gate-station hourly instantaneous natural gas flow data
- Use sample data to estimate hourly natural gas load from 2015-2019
- Estimate Peak-to-Energy load factor for each historical month
- Use average monthly load factor for the peak adjustment

Estimated Load Factors (2015-19)

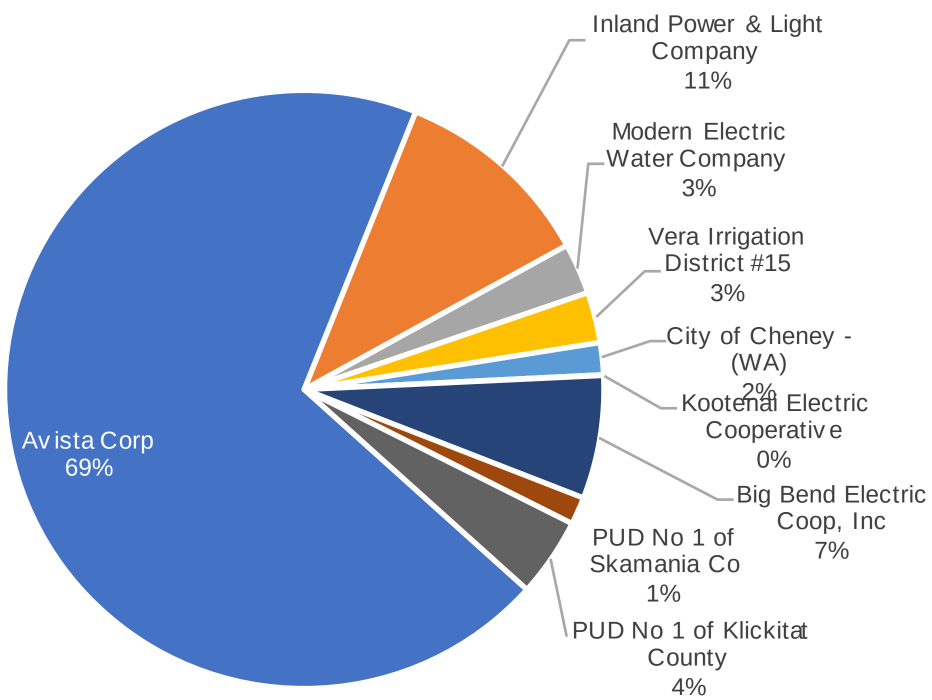


Hourly Electric Load History

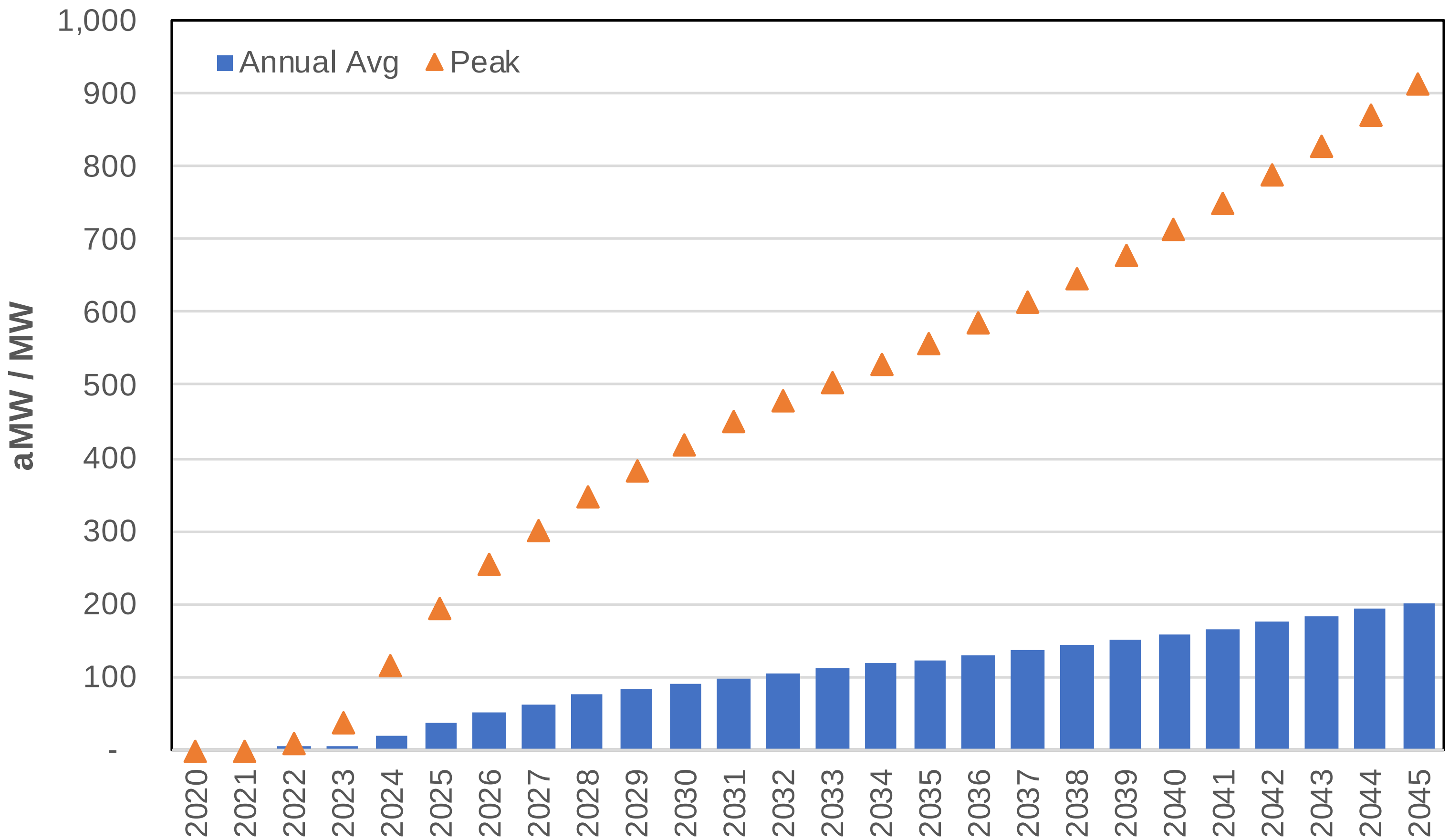


Eastern Washington Electric Service Providers

EIA reported retail sales for 2018
Scenario assumes Avista will receive 75 percent of electric conversions

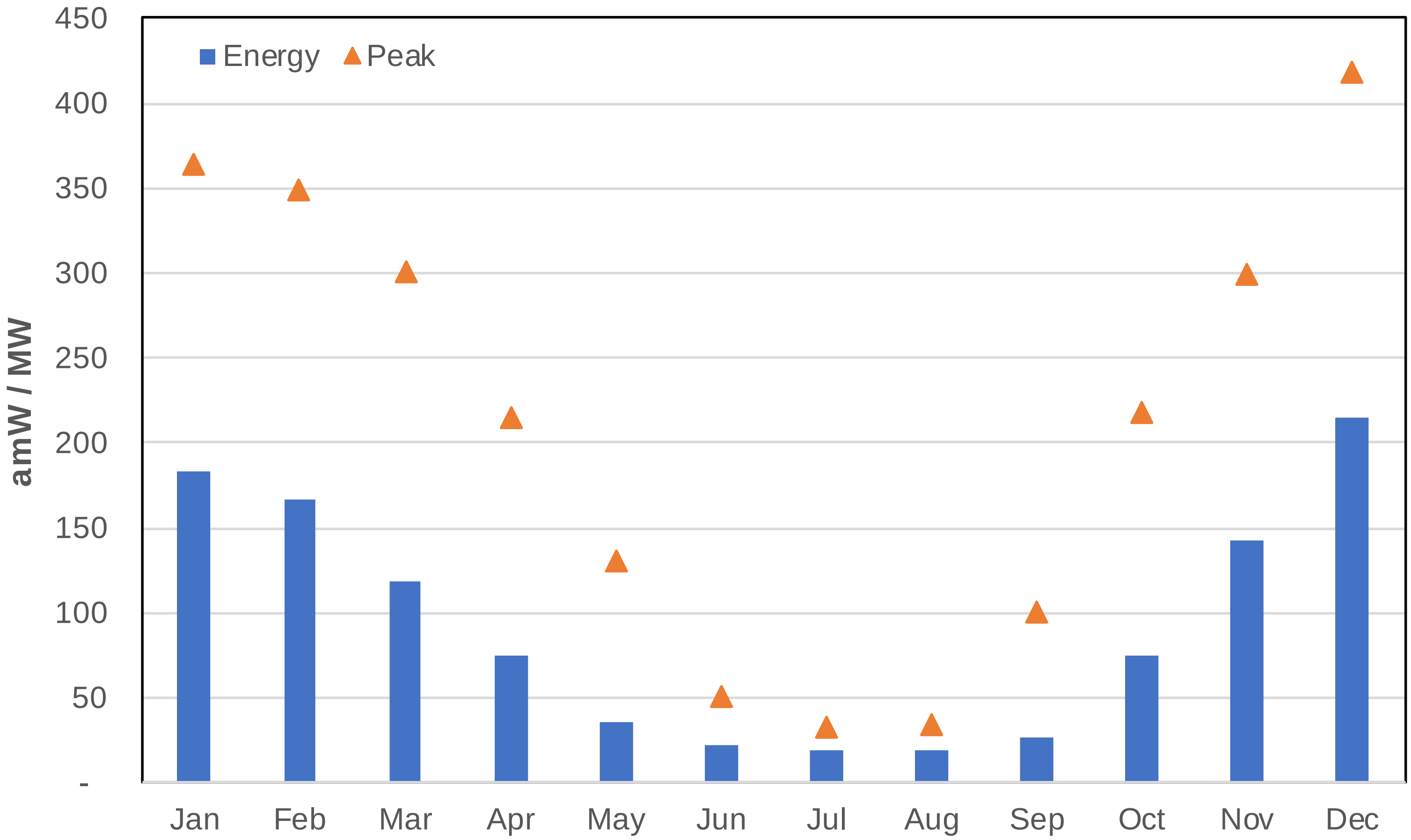


Annual Conversion Load Forecast

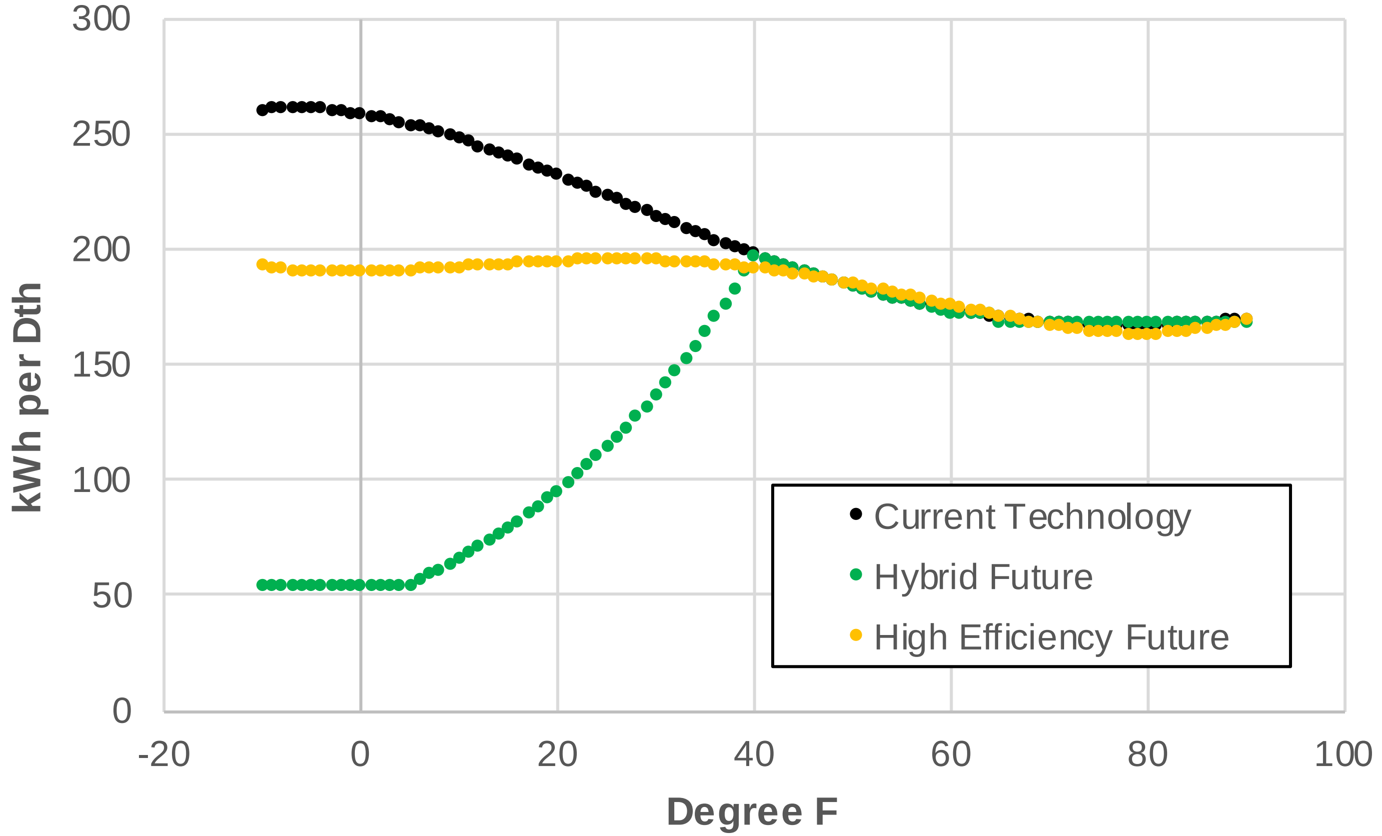


2020 IRP Forecast for 2030 absent fuel conversion:
Peak: 1,762 MW
Energy: 1,209 aMW

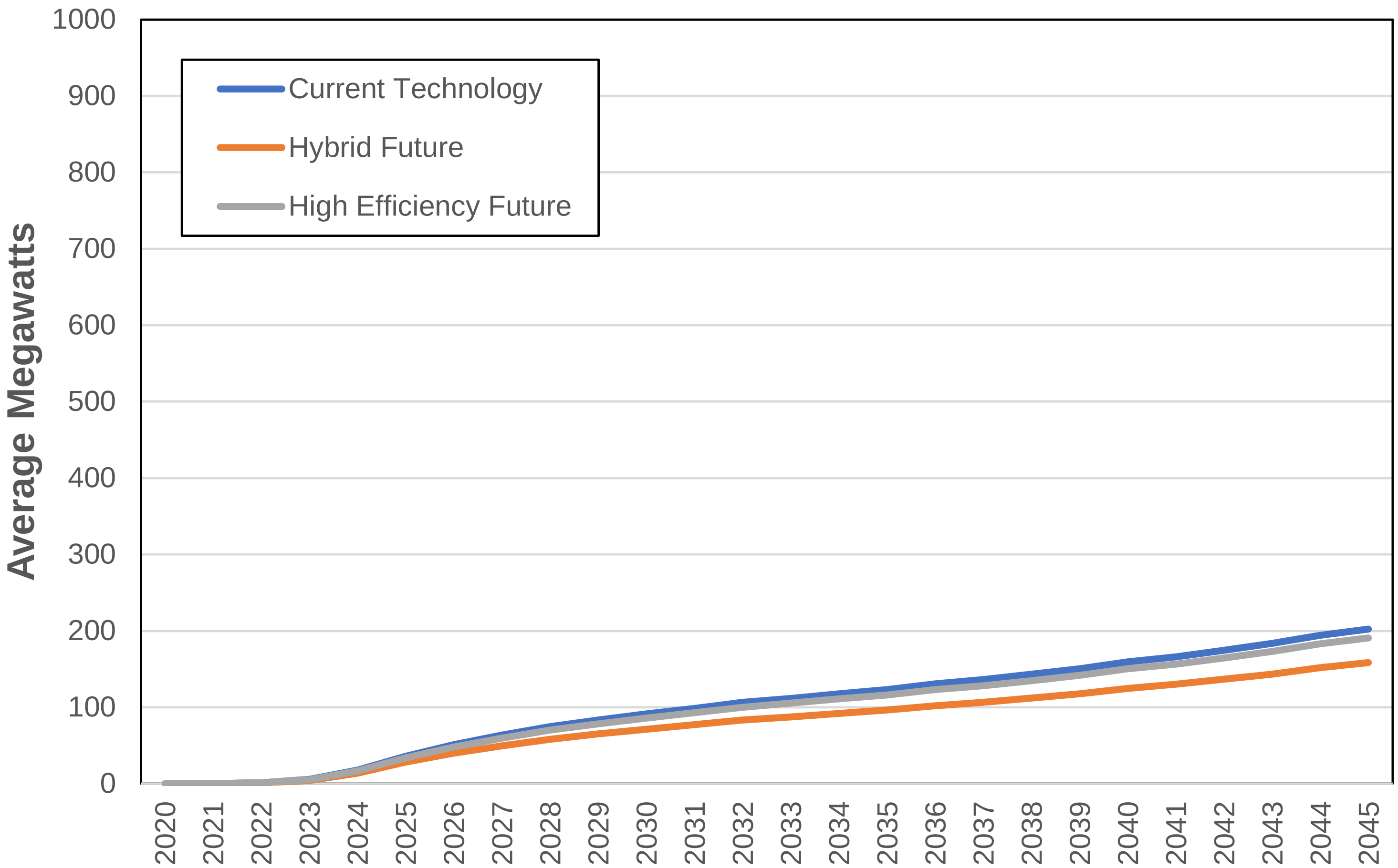
2030 Monthly Load Forecast



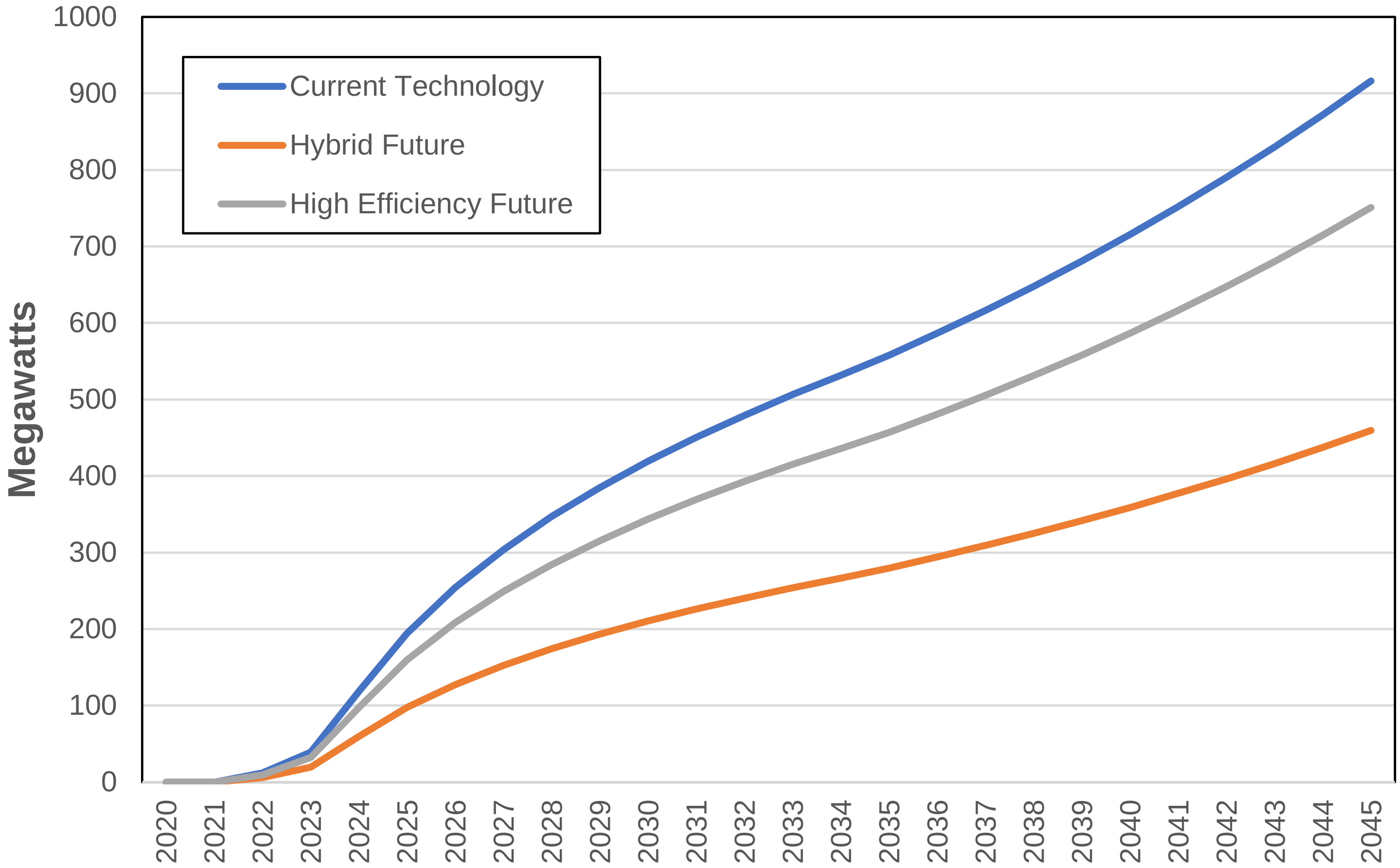
Scenario Analysis- Conversion Rates



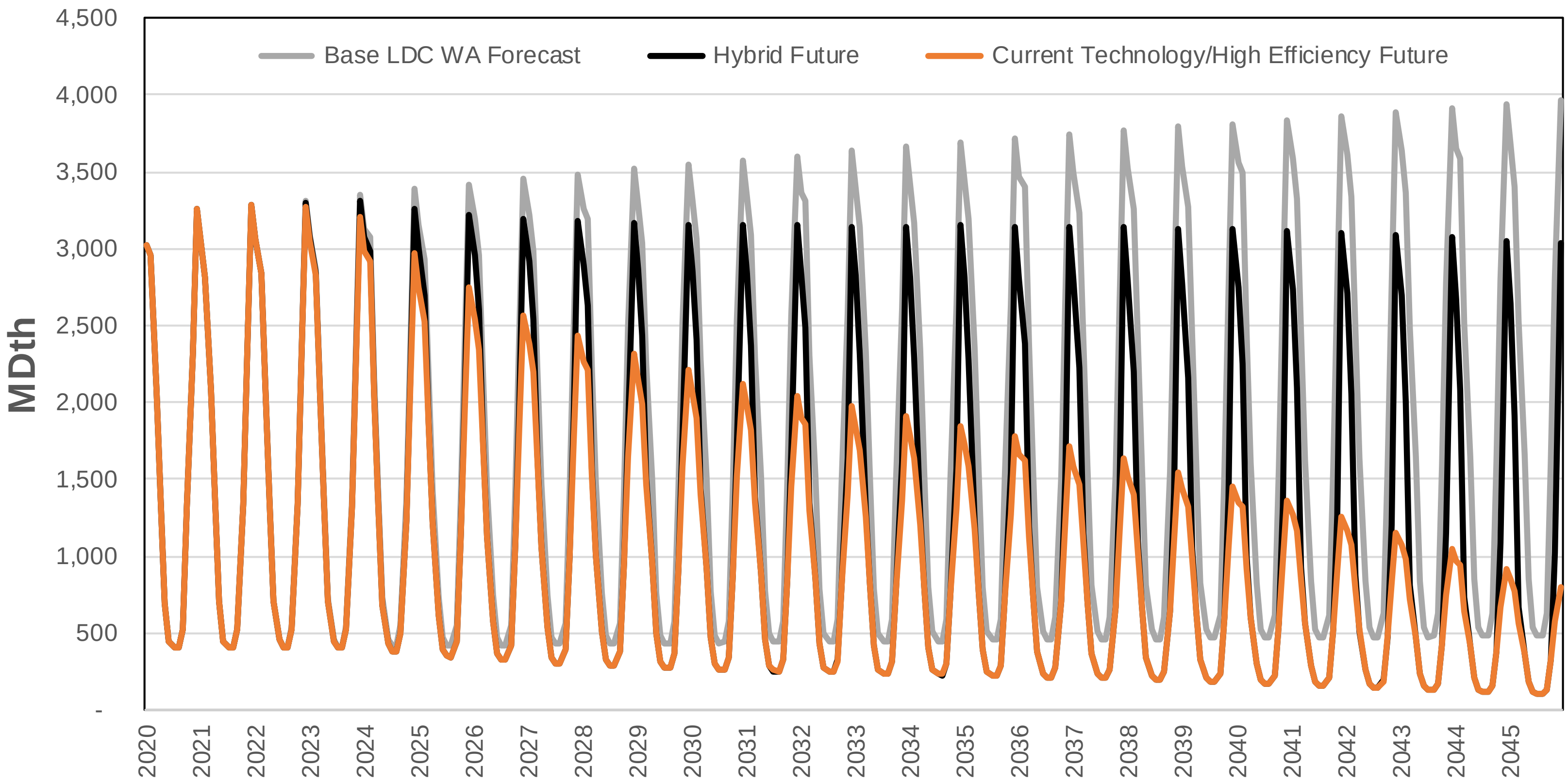
Scenario Analysis- Electric Energy



Scenario Analysis: Electric December Peak Load



Scenario Analysis: Natural Gas Demand



Next Steps

- Input into PRiSM model to determine resource selection and cost
  - Estimate cost meeting CETA requirements
  - Estimate cost using least cost methodology
  - Estimate emissions savings
  - Estimate $/tonne
- Conduct electric resource adequacy study if time permits

2021 Electric IRP
Washington Vulnerable Populations & Highly Impacted Communities

James Gall, IRP Manager

Second Technical Advisory Committee Meeting

August 6, 2020

Identifying Communities or "Customers"

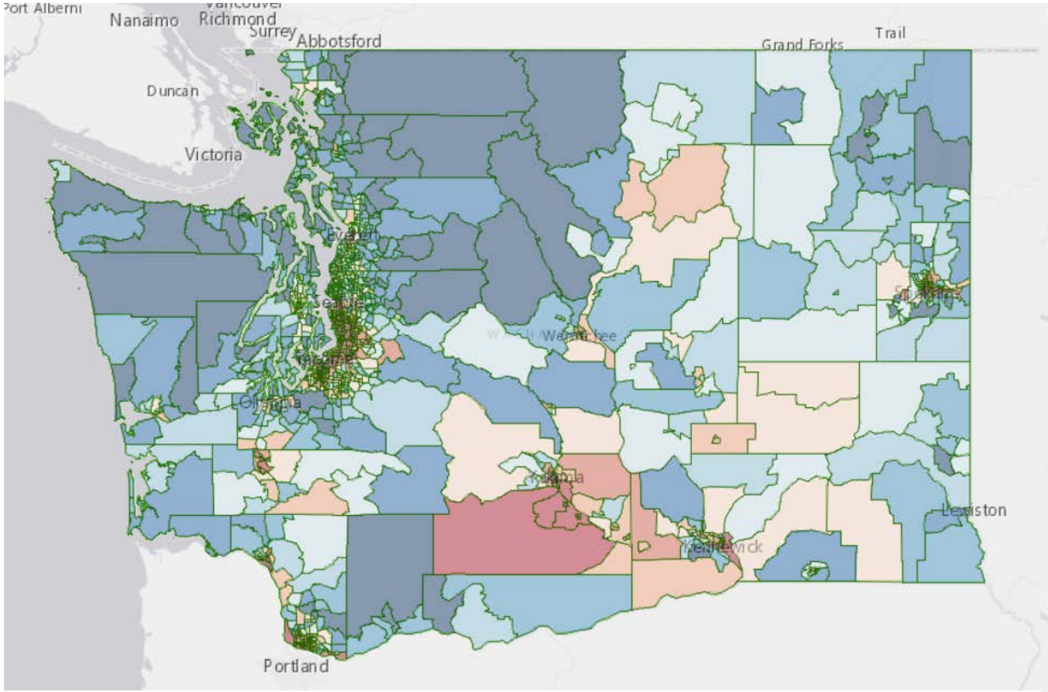
Highly Impacted Communities

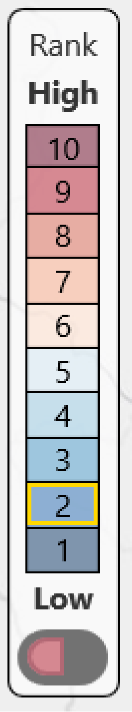
- Cumulative Impact Analysis
- Tribal lands
  - Spokane
  - Colville
- Locations should be available by end of 2020
  - State held workshops in August & September 2019

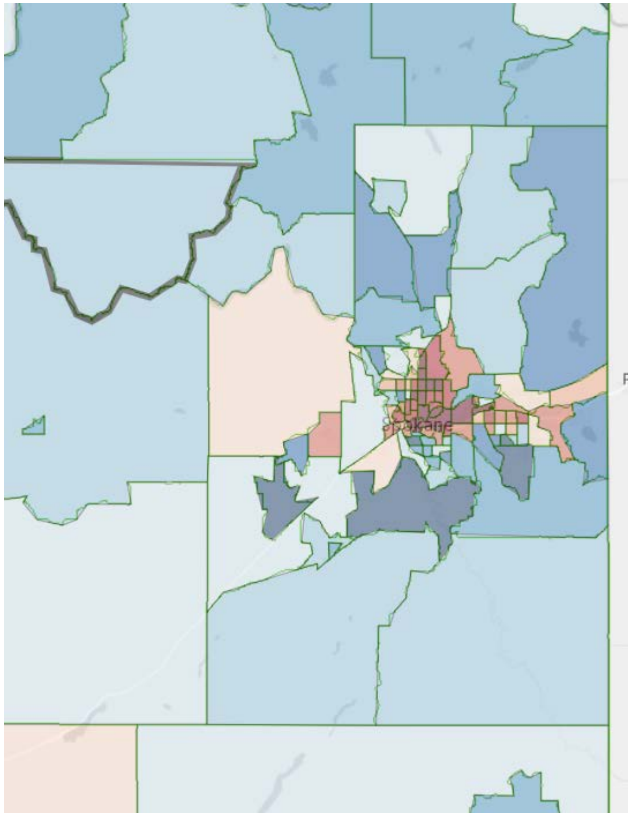
Vulnerable Populations

- Use Washington State Health Disparities map
  - What is disproportionate on a scale of 1 to 10?
  - Avista proposes areas with a score 8 or higher in either Socioeconomic factors or Sensitive population metrics
- Should we include other metrics to identify these communities?

Environmental Health Disparities Map





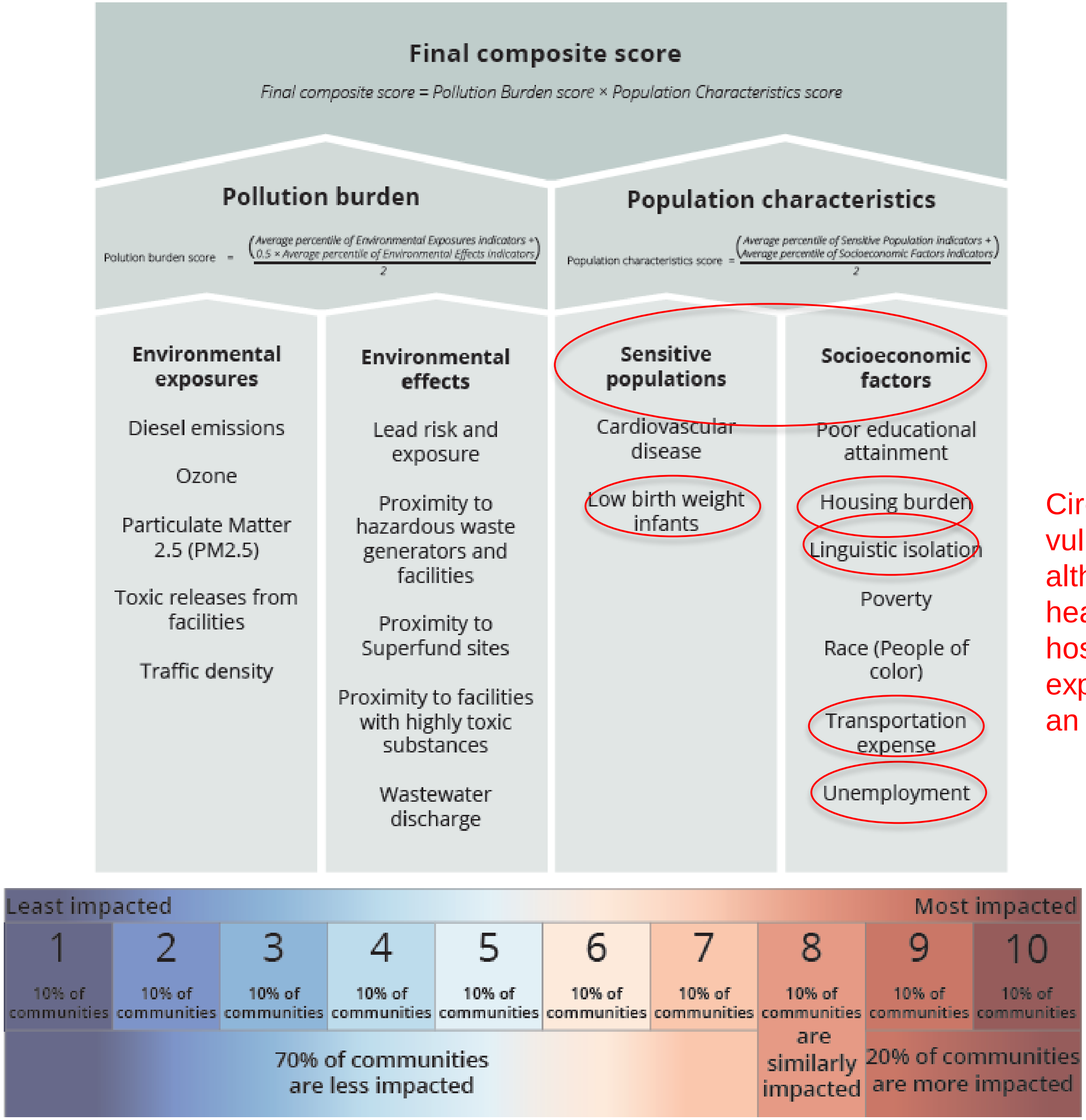


https://fortress.wa.gov/doh/wtn/wtnibl/

Department of Health data is divided up by Federal Information Processing Standards (FIPS) Code

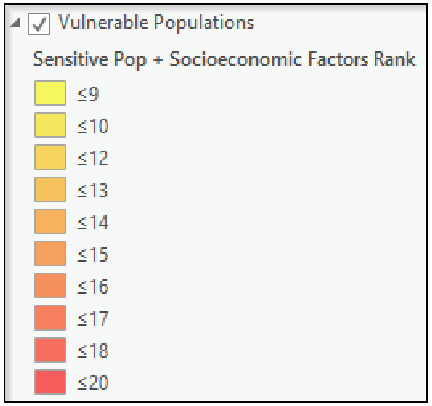
Environmental Health Scoring

From WA Department of Health



Circle areas match definition of vulnerable population, although access to food & health care, higher rates of hospitalization are not expressively included but are an indication of poverty

Selected Vulnerable Populations



Data is shown by combined score

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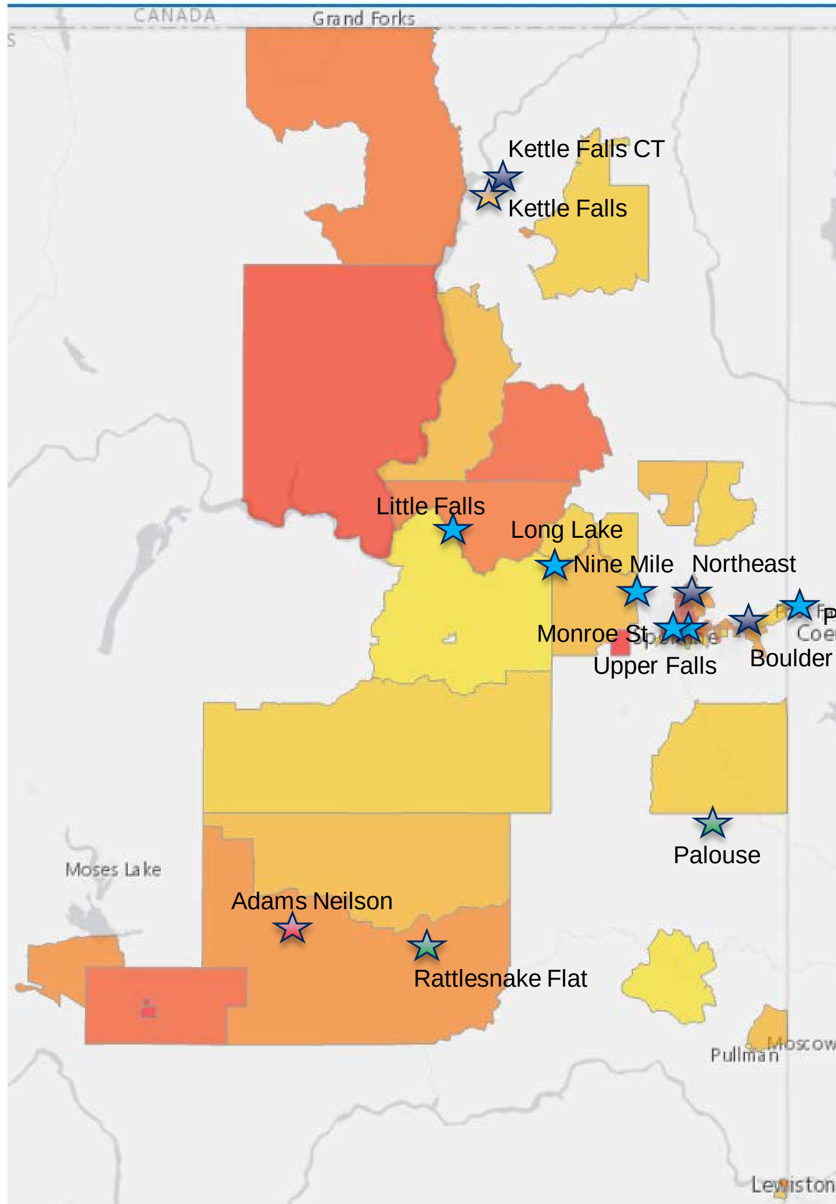


“Large” Resource Legend

- Natural Gas
- Biomass
- Hydro
- Wind
- Solar

Spokane Area “Avista” Vulnerable Populations

Resource Legend

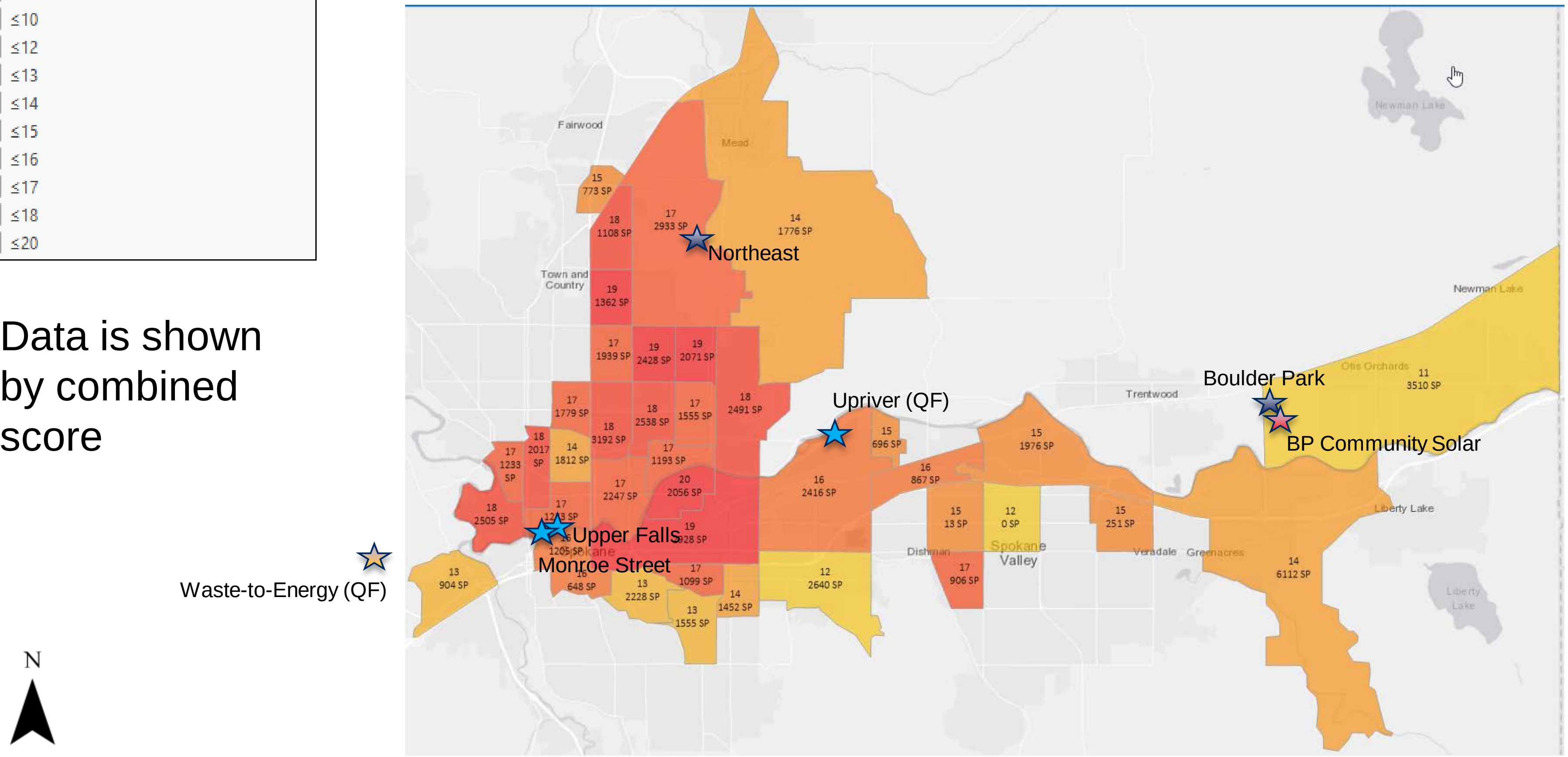
- Natural Gas
- Biomass/Other
- Hydro
- Wind
- Solar

Vulnerable Populations

Sensitive Pop + Socioeconomic Factors Rank

- ≤9
- ≤10
- ≤12
- ≤13
- ≤14
- ≤15
- ≤16
- ≤17
- ≤18
- ≤20

Data is shown by combined score



IRP Metrics *(From Last TAC Meeting)*

Metric	IRP Relationship
Energy Usage per Customer	• Expected change taking into account selected energy efficiency then compare to remaining population. • EE includes low income programs and TRC based analysis which includes non-economic benefits.
Cost per Customer	• Estimate cost per customer then compare to remaining population. • How do IRP results compare to above 6% of income?

Preference	• Should the IRP have a monetary preference?
	    • For example- should all customers pay more to locate assets (or programs) in areas with vulnerable populations or highly impacted communities?
	    • If so, how much more?

IRP Metrics *(From Last TAC Meeting)*

<table>
<tr><th>Metric</th><th>IRP Relationship</th></tr>
<tr><td>Reliability
• SAIFI: System Average Interruption Frequency Index
• MAIFI: Momentary Average Interruption Frequency Index</td><td rowspan="2">• Calculate baseline for each distribution feeder and match with communities

• Estimate benefits for area with potential IRP distribution projects

• Compare to other communities as baseline

• May be more appropriate in Distribution plan rather than IRP</td></tr>
<tr><td>Resiliency:
• SAIDI: System Average Interruption Duration Index
• CAIDI: Customer Average Interruption Duration Index
• CELID: Customer’s Experiencing Long Duration Outages</td></tr>
<tr><td>Resource Analysis</td><td>• Estimate emissions (NO_X, SO_2, PM2.5, Hg) from power projects located in/near identified communities

• Identify new resource or infrastructure project candidates with benefit to communities; i.e. economic benefit, reliability benefit

• Identify how resource can benefit energy security</td></tr>
</table>

Energy Use Analysis Results

- Uses five years of customer billing data
- Median income over the same period is used to estimate affordability
- Separated electric only vs electric/gas customers
  - Future enhancement include single/multi family homes, and manufactured homes

Energy/Cost Analysis

Electric Only Customers

Area	Fuel Type	Energy Use	Avg Bill	Income	% Income
Vulnerable Population Areas	Electric	998 KWh	$98	$42,730	2.8%
Other Areas	Electric	1,010 KWh	$100	$58,834	2.0%

Note: Mean energy use is statistically significantly different when removing energy use data below 100 kWh per month (1,049 kWh vs 1,082 kWh)

Natural Gas/Electric Customers

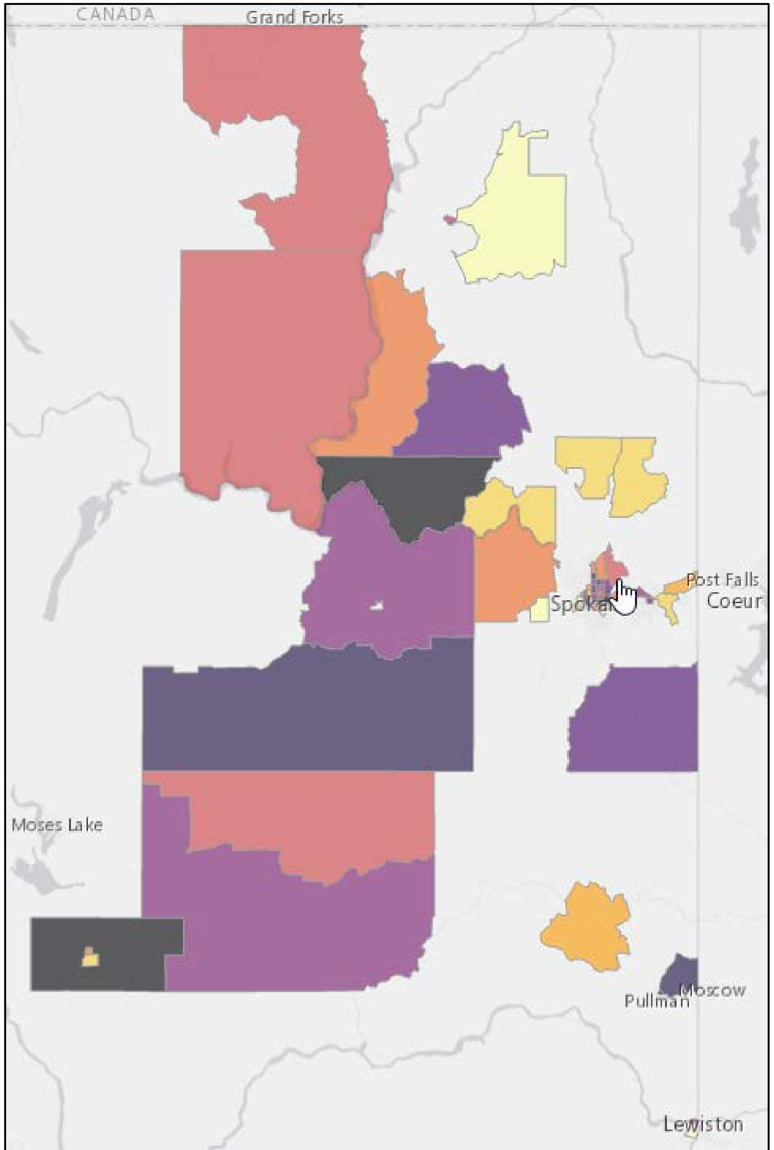
Area	Fuel Type	Energy Use	Avg Bill	Income	% Income
Vulnerable Population Areas	Electric	820 KWh	$80		
Other Areas	Electric	875 KWh	$84		
Vulnerable Population Areas	Gas	52 Therms	$47	$44,889	3.4%
Other Areas	Gas	62 Therms	$56	$68,250	2.5%

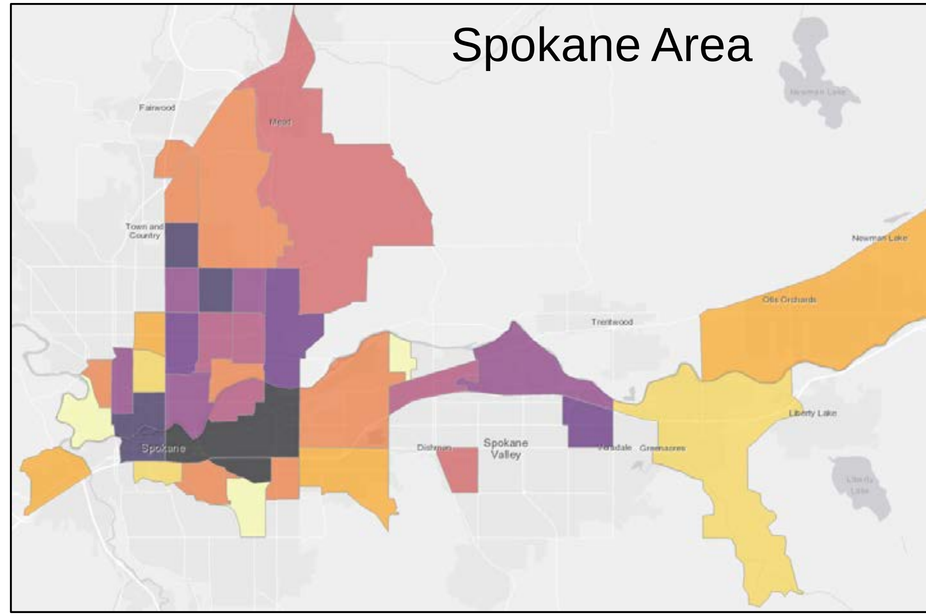
Note: Combined natural gas/electric homes have higher energy burden due to fewer multifamily homes included in the population or all electric home including homes with alternative heat such as wood, propane, oil, pellets. Future analysis needed to validate this hypothesis.

AVISTA

Vulnerable Populations

Electric Only Customers- Energy % of Income





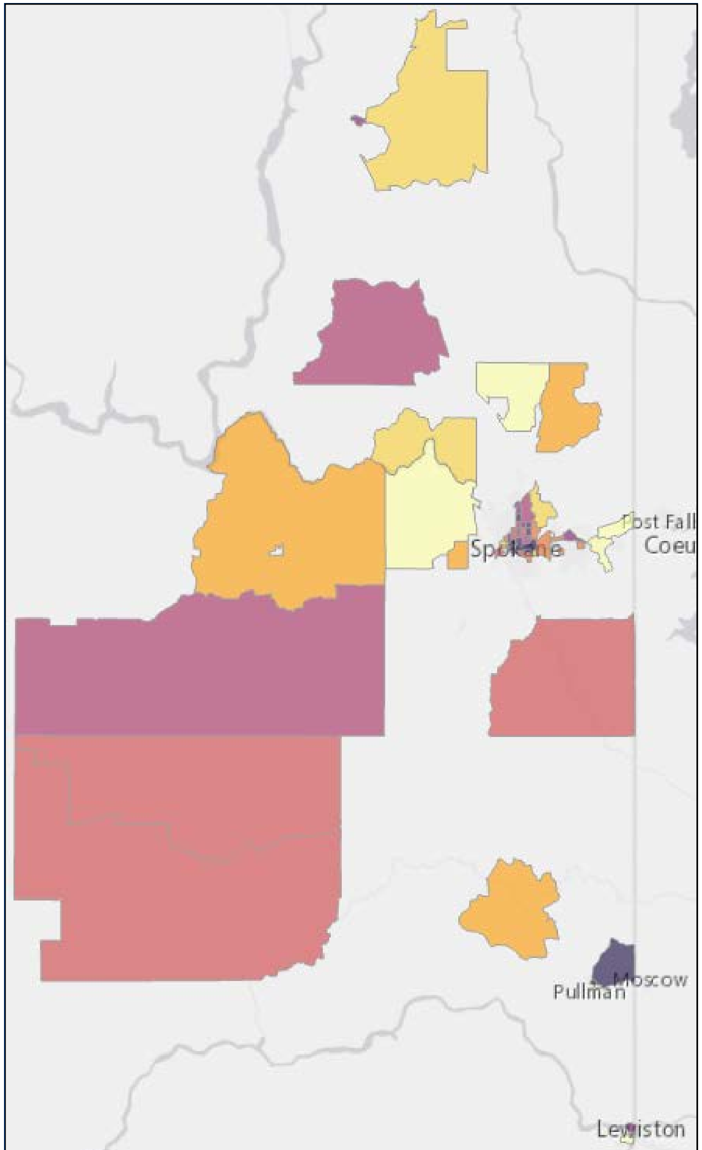
☑ Energy Cost as % of Income - Electric Only

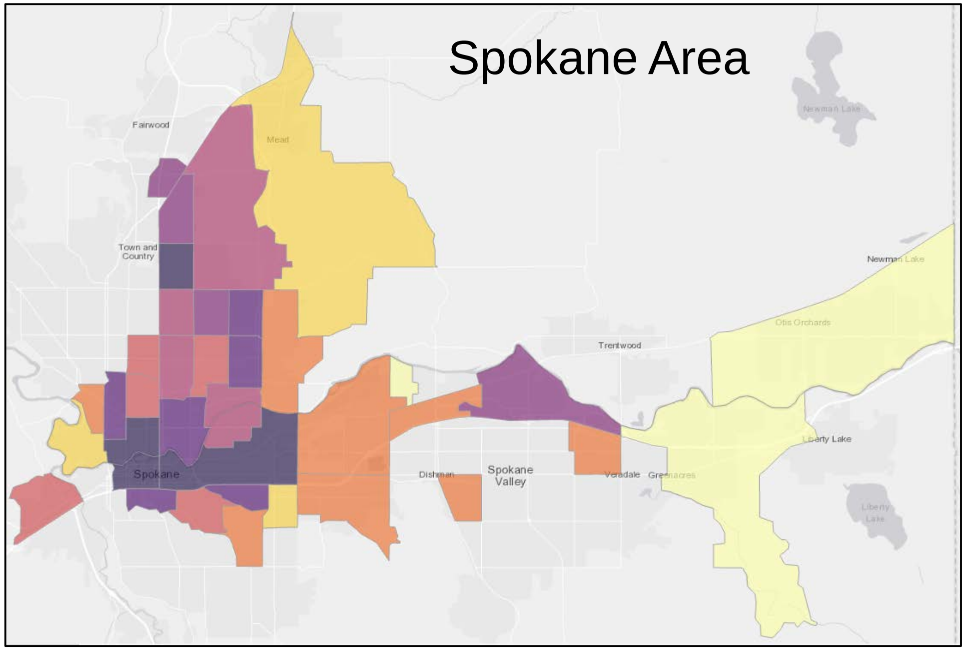
5 Year Avg for Electric Only Customers

- ≤ 2.08 %
- ≤ 2.24 %
- ≤ 2.41 %
- ≤ 2.56 %
- ≤ 2.69 %
- ≤ 2.95 %
- ≤ 3.12 %
- ≤ 3.34 %
- ≤ 3.84 %
- ≤ 4.27 %

Vulnerable Populations

Gas/Electric Only Customers- Energy % of Income





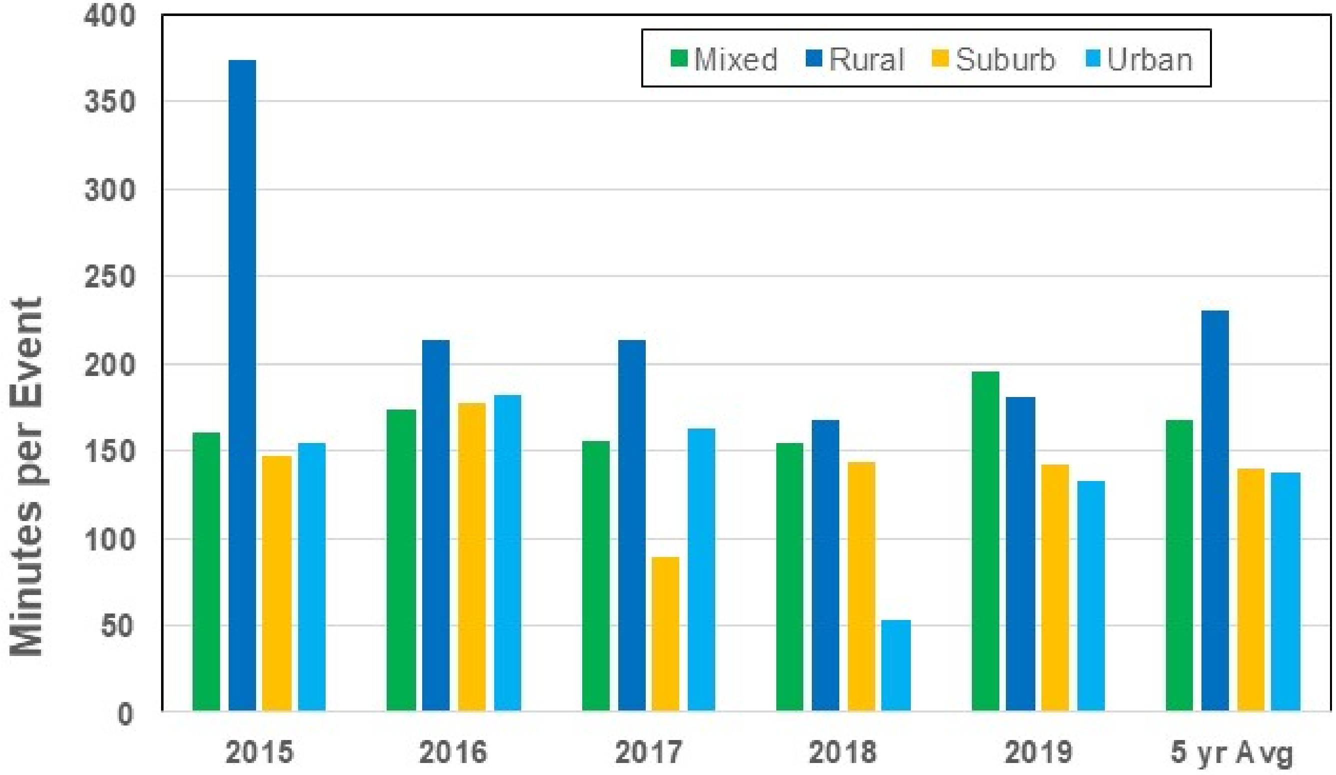
Energy Cost as % of Income - Electric & Gas

5 Year Avg for Customers with Both

- ≤ 2.64 %
- ≤ 2.81 %
- ≤ 3.04 %
- ≤ 3.32 %
- ≤ 3.66 %
- ≤ 4.01 %
- ≤ 4.49 %
- ≤ 5.10 %
- ≤ 7.92 %
- ≤ 11.07 %

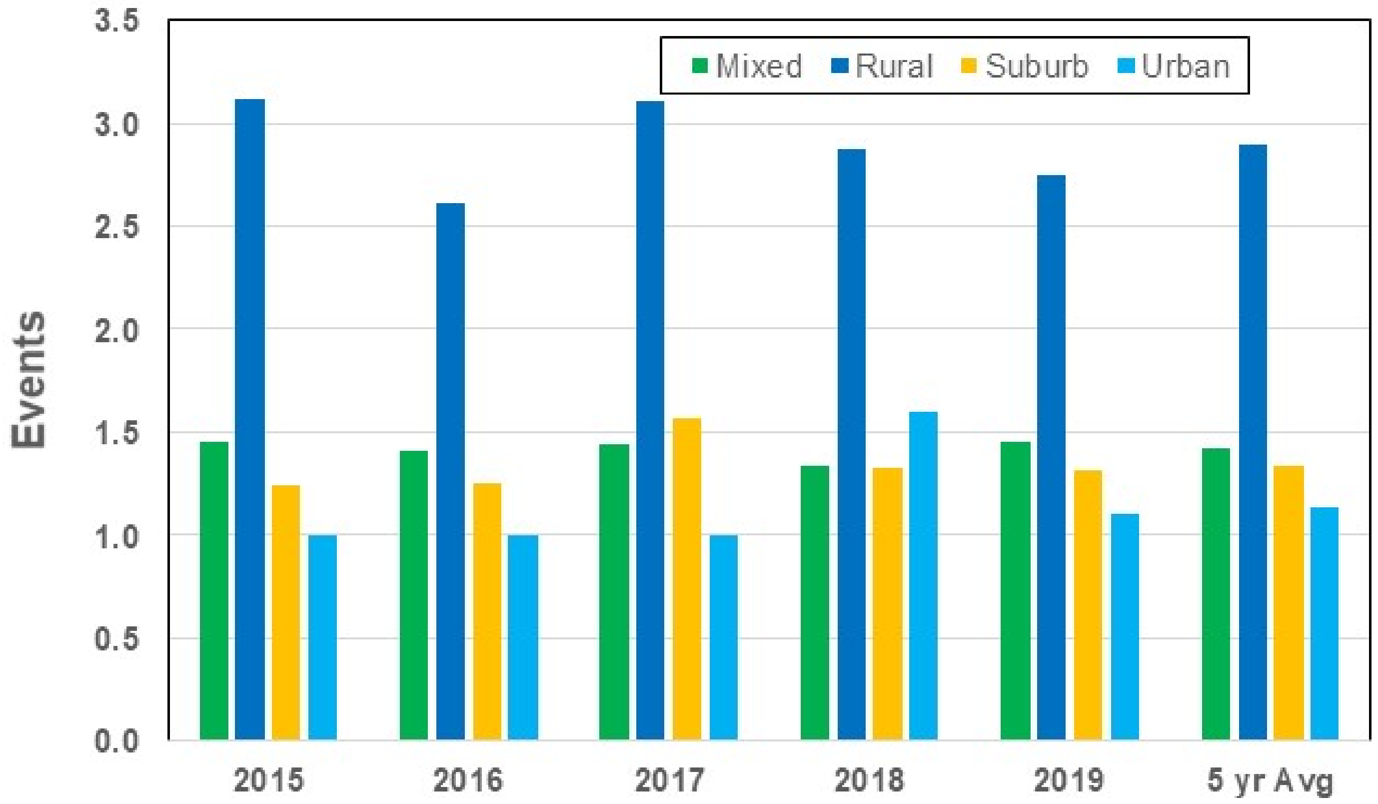
Reliability Data- CAIDI

Measure of resilience- minutes of outages per event
Excludes Major Event Days (MED)



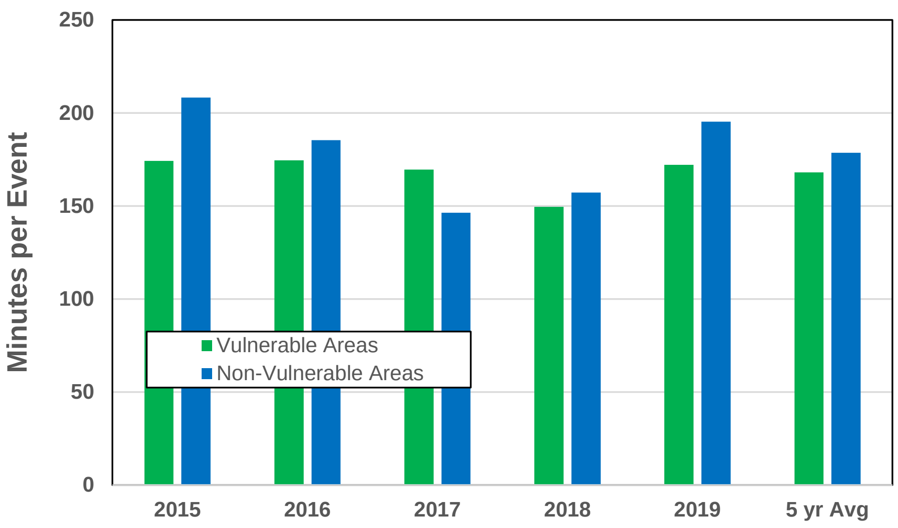
Reliability Data- CEMI

Measure of reliability- Events per Customer

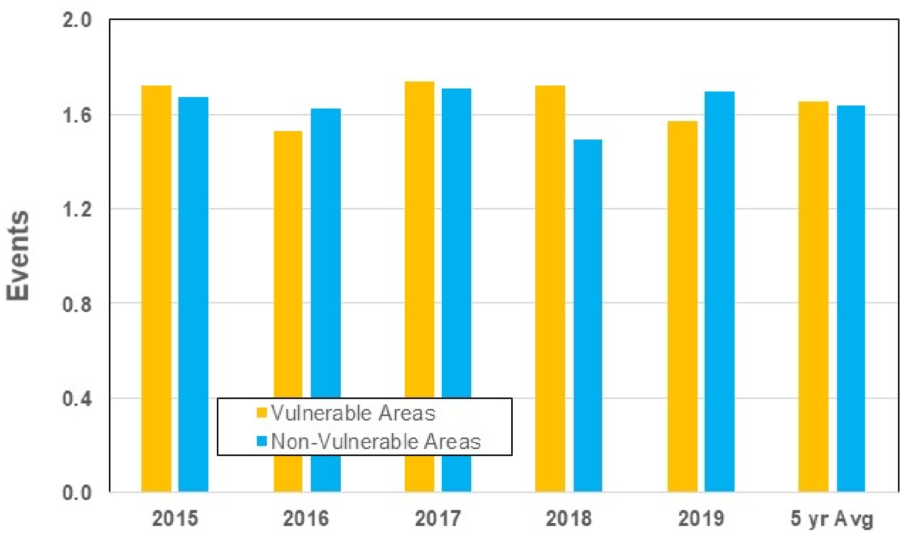


Vulnerable Area vs Non Vulnerable Areas

CAIDI

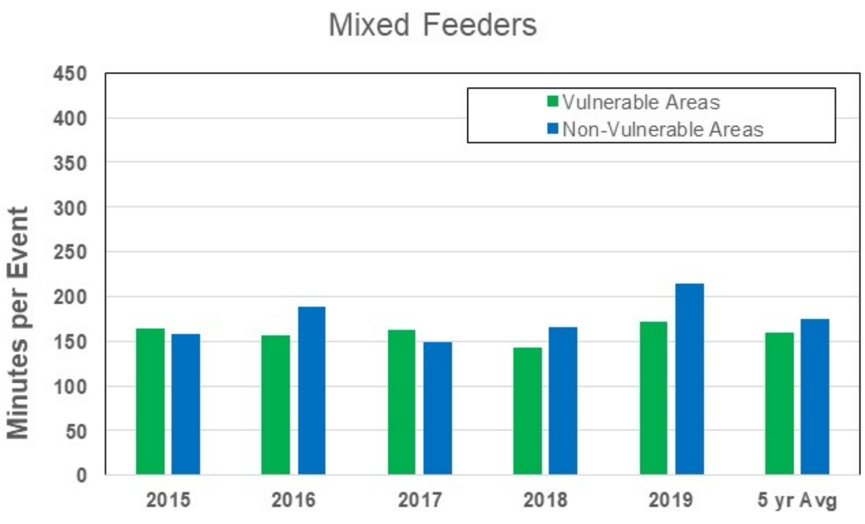


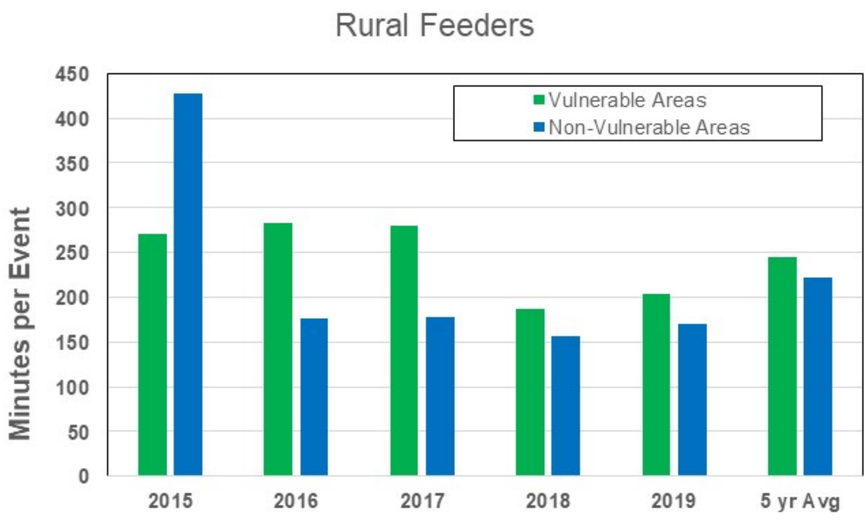
CEMI

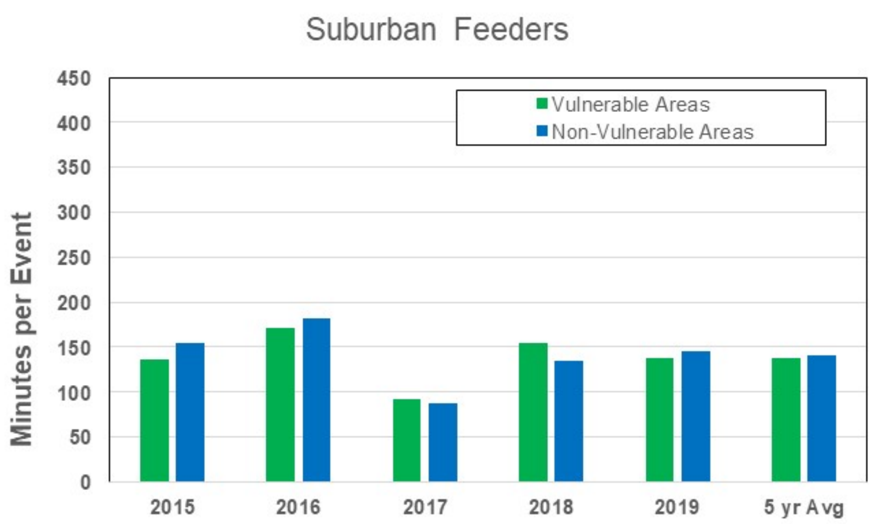


Note: 5 yr Average differences are statistically significantly different

CAIDI- By Feeder Type

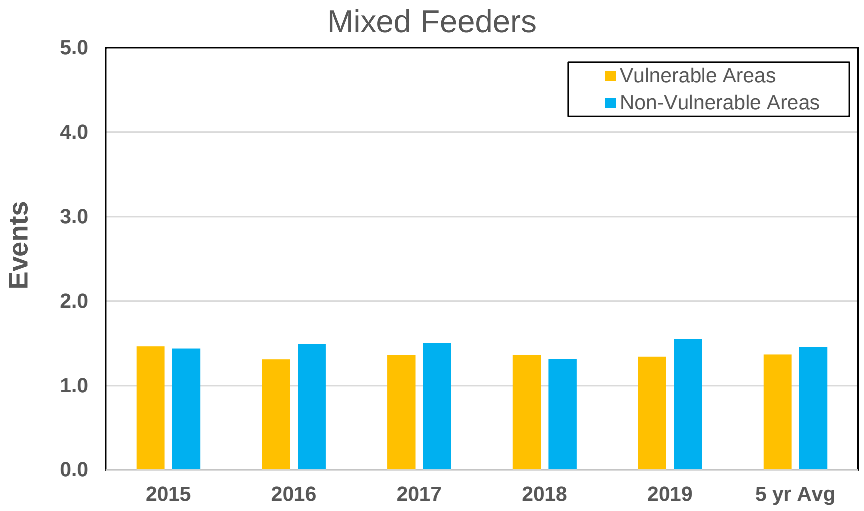


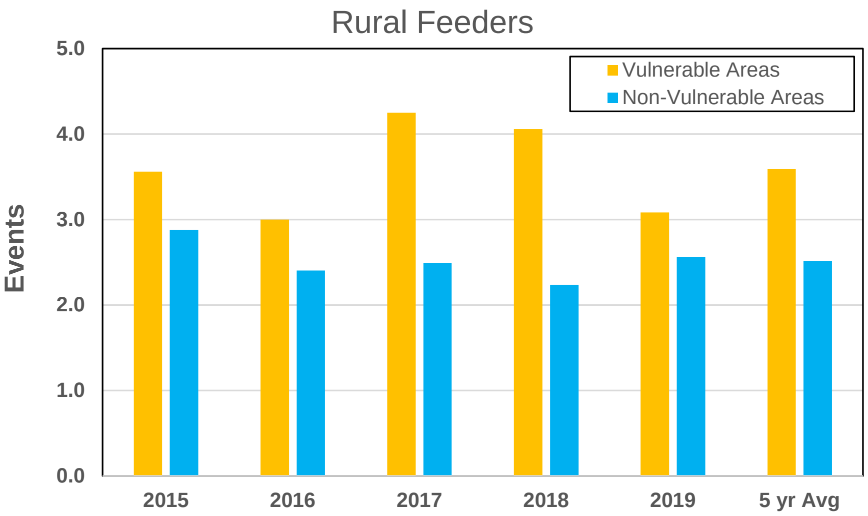


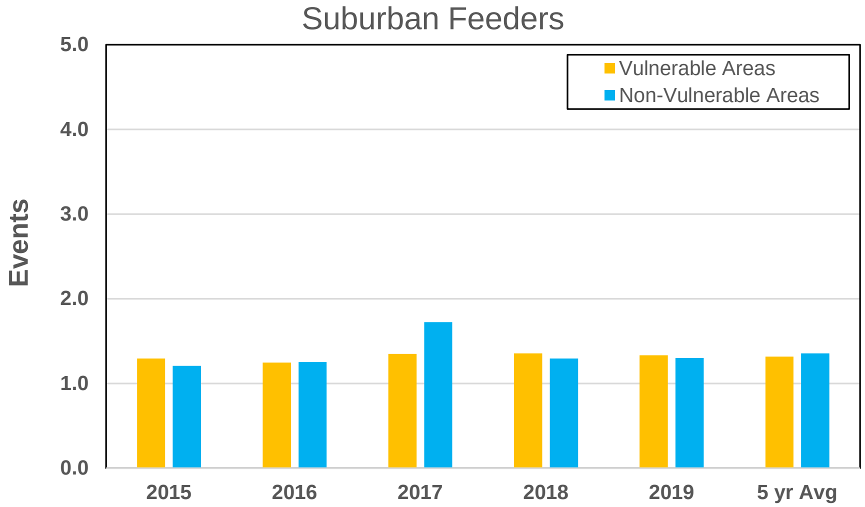


Note: Avista has no vulnerable areas with urban feeders

CEMI- By Feeder Type

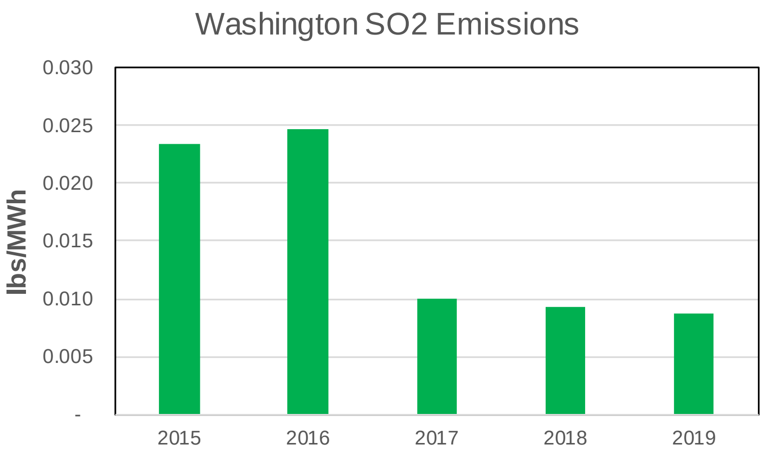


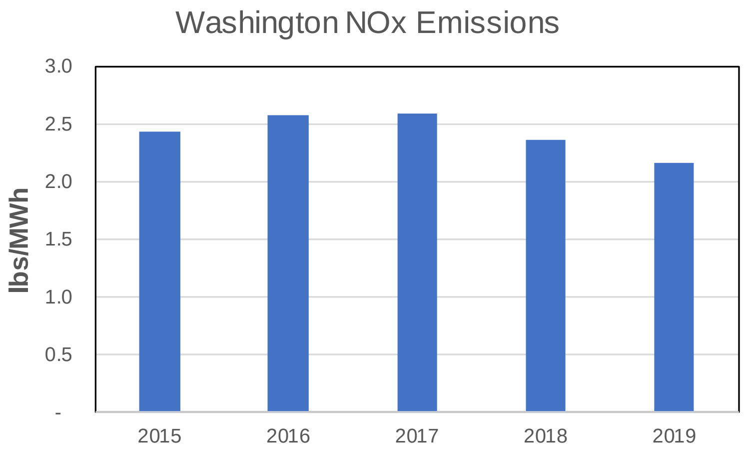


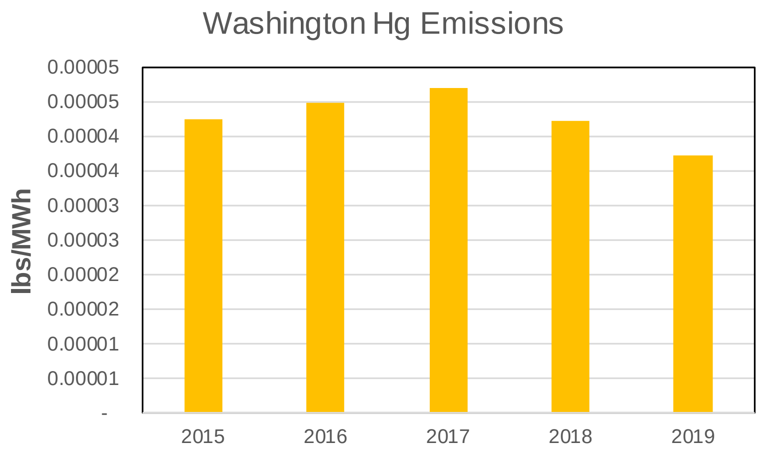


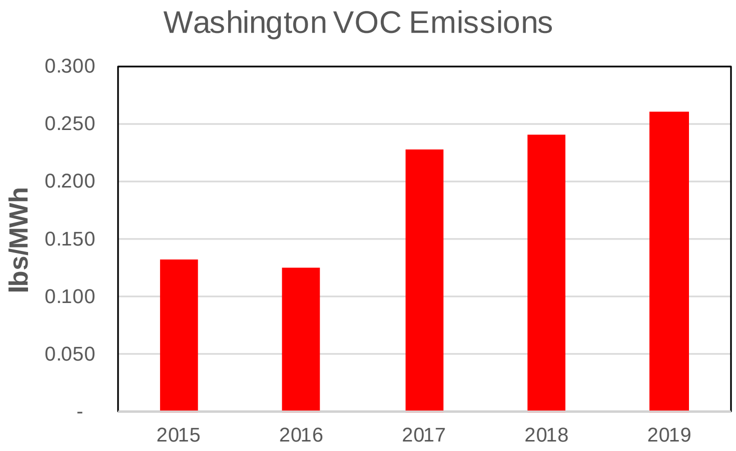
Note: Avista has no vulnerable areas with urban feeders

Avista's Washington Power Plant Air Emissions









TAC Input

- What other metrics can we provide in an IRP to show vulnerable populations and highly impacted communities are not harmed by the transition to clean energy

Second Technical Advisory Committee Meeting, Thursday, August 6, 2020

Virtual Attendees: James Gall, Lori Hermanson, John Lyons, Tom Pardee, Rachelle Farnsworth, Greg Nothstein, Dainee Gibson, John Chatburn, Mike Morrison, Terri Carlock, James McDougall, Michael Brutocao, Paul Kimball, State of Idaho (x2), Steve Vincent, Nikita Bankoti, Chip Estes, Joana Huang (UTC), Terrence Browne, Leona Haley, Jody Morehouse, Scott Kinney, Corey Dahl, Katie Pegan, Sellers-Vaughn (Casc); Joni Bosh, Devin McGreal, Vlad Gutman-Britten; Steven Simmons, Jennifer Snyder, Morgan Brummund, Max St. Brown (OPUC), Jorgen Rasmussen, Jorgen; Heutte, Fred Heutte (NWEC); Sudeshna Pal (CUB), Brian Robertson, A. Argetsinger, Guest (18), Kaylene Schultz, Grant Forsyth, Anna Kim (OPUC), Dan Kirschner, Katie Ware, Matt Nykiel, Ken Ross, Ashton Davis, and Steve Johnson (UTC).

Notes in *italics* are short responses from the presenters and notes with brackets [ ] and times after them were pulled from the chat function on Skype.

<u>**Introductions and IRP Process Updates, John Lyons**</u>

Matt Nykiel: What is the study request deadline for gas?

Tom Pardee: No formal deadline. Feel free to forward to me. We will be running gas models after this meeting and they will presented at TAC 3. Gas will show CPA results at the November meeting, but will share some things earlier such as measure list.

<u>**Natural Gas & Renewable Natural Gas Market Overview, Tom Pardee**</u>

Matt Nykiel: Since Avista gets a lot of gas from Canada, how is legislation impacting pricing and imports? Do you have general thoughts on this?

Tom Pardee: Haven’t heard of that. Wood-Mac does include legislation in their fundamentals based forecast. What does the legislation entail?

Matt Nykiel: Carbon tax on gas essentially. How is this impacting the market in Canada and what we get from them, the reverberating impacts to price? It is important to keep on our radar as we’re evaluating for Avista.

Tom Pardee: Yes, British Columbia has a carbon tax. We will look into this specifically and get back to the TAC.

Fred Heutte: Thanks for a very thorough survey. What are you seeing in near-term gas prices in 1, 2, 3 years due to COVID? Rig counts are dependent on early production in particular for Canadian short-term. There are a lot of ways it could go.

Tom Pardee: Canada has the lowest marginal costs for natural gas. There are a lot of liquids, not specifically drilling for natural gas but for oil so they need volumes to offset the high capital. They have a low break-even cost and so much capital is already invested, so they’ll be slower to react to pricing changes than the northeast and the US.

For oil or bitumen, they are based on the breakeven cost for liquids and oil. Dry gas is mostly about getting that out as cheap as possible.

Fred Heutte: That is helpful. Is Avista broadly speaking, sourced more from Alberta or BC? What is going on in the Canadian Basin?

Tom Pardee: Alberta is mostly liquids and BC, Motney, etc. is dryer. Broadly, Avista is AECO mostly.

Fred Heutte: So, not as much as Sumas. Thanks.

Nikita Bankoti (Slide 16, US demand): That is a lot of information to process. Seems to be increases in LNG exports, will Avista be procuring more LNG?

Tom Pardee: Across all areas across all sectors, if you take away LNG exports, it's mostly staying the same. If gas started coming in large increments from Canada, that'd have a huge impact on us since we get 90% of our supply from Canada. In the US everything is hedged financially at Henry Hub. Simple supply – Canada is king around here, gas is cheap. Alberta is main economic driver, at least 50%. If there were an issue, it'd come from Alberta. Does that help?

Nikita Bankoti: Yes, thank you so much.

Steve Johnson: To reduce to a more simple understanding, most of the growth in demand will be from LNG exports.

Tom Pardee: Yes, that's a fair statement.

Steve Johnson: There's a lot of LNG exporters in the world. The US will become the number one exporter if all of these planned projects come to fruition. The cost for gas here rises and negatively impacts LNG going forward. Most investors think gas prices will stay low, therefore LNG goes forward which relieves upward price pressure on gas. Focus on other side of the equation if LNG gas projects here go forward. Tells me a lot of dollars think prices stay very low since if they go up projects won't happen.

Tom Pardee: The cheaper oil is, the less likely LNG exports are wanted around the world. Can they burn bunker oil? If oil goes high, then more demand for LNG. These are often compared. If oil price is high, there is more demand for LNG exports. That is where LNG comes in. History of LNG is tied to oil so oil price dictates the LNG price. Now the linkage is broken and LNG is not as tied to oil as it was formerly. Now a LNG rate is Henry Hub plus. If oil is expected to go up, then my guess is there'd be more LNG. If oil goes up to $120 a barrel, a lot more LNG is cheaper.

Steve Johnson: One can expect gas to remain flat?

Tom Pardee: Yes. Regardless of LNG exports.

Nikita Bankoti: What is MSW? *Municipal solid waste.*

Fred Heutte: Wonder if you have been following Oregon AR632 docket for Northwest Natural RNG policies?

Tom Pardee: Yes, we have had members go to every AR632 rulemaking. We were a part of that. Trying to understand what the policy means. The gas side will have a more detailed overview. I'm not an RNG expert. If you have better information into RNG price on the east side you are always welcome to come over to our TAC.

Fred Heutte: Interesting info.

Jody Morehouse: Open rulemaking for SB passed 2 weeks ago in Oregon and were adopted 7/31/20. Will cover more in September TAC.

Nikita Bankoti: The Commission has an ongoing docket under UG-190818 for the Washington RNG Staff investigation.

Kathleen Kinney: Market pricing in the $10 - $12 range for RNG is doable. Utility is able to offer a consistent long-term price.

Kathleen Kinney: Comments via RNG; for market pricing $10-12 price is doable. If Utilities can offer a long-term prices that's something that producers are looking for. Another option, I haven't seen done in person is to buy LNG at a relatively low fixed costs until the LNG purchase requirement kick in and be able to sell long term when policies kick in. Avista can take advantage of that margin in the near-term. Again, I'm certainly willing to connect after this.

Matt Nykiel: I could use a refresher in terms of how gas impacts customer rates and how that is impacted through the price cost adjustment. How is the price set and passed on if higher or lower?

Tom Pardee: Within an LDC. You probably get cheap gas. Projected rate, say it's a dollar comes in higher, then in future rates, we'd charge more. Lower is passed through against rate projection for the future. Pass through at the cost of gas, but procurement charge with no markup. What we buy gas for is what we sell gas to customers for with no mark up. Optimization for Jackson Prairie or transport is for customers and goes against rates. If we sell gas for $50,000 premium in the market, it goes against rates to offset the commodity rate for overhead. PGA, or purchased gas adjustment is set on November 1st. How accurate you were on every November 1st is adjusted. If too high now, it reduces rates later. It is an accounting deferral balance.

Matt Nykiel: Thanks so much, appreciate the refresher.

Natural Gas Price Forecast, Michael Brutocao

Ben Otto: Can you tell us who the consultants are?

Tom Pardee: One is Wood-Mackenzie and the other is CERA. They are both well-known and respected within the gas industry. We put out this way so we don't have to get their approval which is difficult.

Ben Otto: This highlights our concerns. It is a public process, but having stuff we can't comment on specifically is concerning.

Dan Kirschner: Nominal dollars? *Yes.*

Nikita Bankoti: Why is there a difference in percentages used? What is the reason for blending and the mix across the years?

Michael Brutocao: Wouldn't want to assume one is more accurate than the other. Significant deviations in NYMEX more than accounts for risk and overtakes what you'd expect the nominal prices to be.

Nikita Bankoti: For 2023 weighting, why is NYMEX weighted more than the consultants? Due to standard deviation?

Tom Pardee: So for historic measures, NYMEX in the near term is the best indicator of everything that all traders know on that date. Fundamental forecasts take months. NYMEX changes daily and is the most up to date pricing with fundamentals. NYMEX actively trades about three-ish years out – it becomes a lot less liquid the further out you go. Further out is less liquid so you really don't know what the price is the further out you look.

Steve Johnson: Can I ask a follow up question? I recall these charts in the past IRPs. Three year forecast based on forwards or combination, then we take consultants with the forwards, update every IRP with the same upward trend further out with the same consultants. I'm not on board as we never seem to see these upward trends. It's the trends I'm not believing in. Will have to drop off in 10 minutes, but will circle back with the team on this topic.

Sudeshna Pal: Is there any visibility into the forecast models and discussion into the drivers and what is causing the trends? What are the drivers of this forecast?

Tom Pardee: Time. Known elements when putting the forecast together. For example, one forecast may have COVID included, but an older one might not. Individual assumptions and guessing about what may happen and when and how those impact prices. The further out you go, no one is going to be right, but they have people that look at these issues. No one is going to be right.

Ben Otto: Past two questions highlights the need to see these assumptions. Customers end up paying for this. Important so we can see and understand. The best practice is to disclose these forecasting techniques to understand them.

Fred Heutte: Gas future prices, NYMEX forward strip and the longer term by various consultants. NYMEX market for today is over $2 at Henry Hub. Really liquid and a good indicator. It is the largest in the world at about $1 trillion a year, but it doesn't go out far. Starts with 126,000 September contracts, but down to 7,000 by February, and at 18 months almost none. Further out less and less trades yet they report prices all the way out to 2032. Out to 18 months is very good. Longer term forecast basically take the same view – we'll have as much shale gas as we need forever. We don't know the underlying production cost. Prices have been on average over the prices over the last many years. What happens if the industry consolidates? The Wood-Mac and IHS consultants are really smart, doing the best they can. We don't have anything better than long term forecasts. What is the upside price risk – that is the question. Make sure to run a high price gas forecast if that comes to pass which is what the IRP is supposed to address.

James Gall: Appreciate the comments on the scenarios we do, which often don't get the focus they deserve. It is important to consider the scenarios from IRP to IRP. There are differences in resource choices. This topic has a lot of interest.

Nikita Bankoti (slide 9): Is there a reason there's more gas draws than electric? I believe it is less, but am not 100% sure. What's the reason behind that?

Tom Pardee: We do more gas draws because we can. We model on a daily basis. We have a smaller daily model than electric, which is modeled hourly. Ours doesn't take as long to model. One or two days per run, and week on the electric side for one scenario with 500 distribution draws.

Nikita Bankoti: OK, that makes sense.

Kathleen Kinney: Curious about the higher scenario above the $10-12 (tying into RNG), is there some way to use extended RNG contracts to take out the risk?

Tom Pardee: It is something we can consider because you're definitely taking some of the risk out with RNG. There is a major risk of not being able to get supply. Take risk out of a transportation pipeline. There was the explosion a few years ago on the west side. Cost risk, loss risk and how much RNG can take off the board.

Kathleen Kinney: It would have to be a long-term contract.

Fred Heutte: Two comments. Run another version of this gas price and market price looking at a peak of $3 shown. What about a peak of $4 with consolidation and a lower rig count? With lower supply, prices go up. Delivery risk and questions raised by that.

explosion and compressors. Has Avista looked at the risk involved with your main supply coming down from Alberta, which is very reliable? Have you looked at this risk?

Tom Pardee: Yes, we'll talk more about supply risk from major locations at TAC 3. We do look at it and there will be specific sensitivities around this.

Ben Otto: 100% or 90% of gas from Canada. Risk should focus on this and not necessarily on the hubs since all supply comes from Canada. Previously you've shown you only use Canadian supply.

Tom Pardee: We do use the other supply areas, although not as much. Where we have supply from is number 1 at AECO, number 2 at Sumas for peak and Jackson Prairie, and number 3 from Rockies for peak and Oregon. Each of these we look at to restrict or take out of the model to understand. In the overall portfolio, Rockies in about 1-in-10 situations.

<u>Upstream Natural Gas Emissions, Tom Pardee</u>

Tom Pardee: Upstream emissions are natural gas emissions that occur prior to the point of combustion.

Mike Morrison: When computing Global Warming Potentials, what were the residence times assumed for each gas? How long are they assumed to remain in the atmosphere?

Tom Pardee: 1 element of carbon, 1 factor of CH_4 equal to 34. Continues to grow (NO_x) in the 100 year potential.

Kathleen Kinney: CH_4 degrades to CO_2 near-term emission and decreases as it degrades over time.

Fred Heutte: I'm certainly not an atmospheric chemist. CO_2 not very interactive whereas methane is very interactive. For CO_2, half is taken up in a year into trees, ocean, and vegetation and the rest is over 1,000 years – impact is long. Methane – because it's interactive – it's in the atmosphere for 10-12 years and gone in 20.

Nikita Bankoti: Is this a recent EP estimate?

Tom Pardee: 2020.

Dan Kirschner: April 2020 – considers through 2018.

[8/6/2020 12:44 PM] Steven Simmons: https://www.nwcouncil.org/energy/energy-advisory-committees/natural-gas-advisory-committee (https%3a//www.nwcouncil.org/energy/energy-advisory-committees/natural-gas-advisory-committee) link to Northwest Power & Conservation Council work on methane & NGAC

Fred Heutte: We will be submitting comments in writing to Avista on this topic and won't belabor the point here. We are concerned with the emissions factor in the US and Canada. The EDF project has been working on this issue for better than a decade. Scientists and analysts in the US, the council adopting their low emissions rate in the US. The problem with the Canadian sources is they are based on old data. Recent publications in peer reviewed journals will show this. Reasonable data for US-sourced gas, but not Canadian-sourced gas which hasn't been updated.

Dan Kirshner: We have a bit of a different perspective than Fred and will provide our comments to the council. We support the regional approach Avista is taking as opposed to national averages. Puget Sound Clean Air Agency and the Port of Kalama data are government sponsored and is sufficient and a good approach for Canada. We disagree with NWEC for the Rockies. EPA has an annual update for Rockies. Each year is appropriate in that regard. Will send a letter regarding this. There are different perspectives on this.

Tom Pardee: Thanks Fred and Dan. The problem is Avista is not an expert on this upstream emissions issue, but we have some expertise.

Fred Heutte: We're not experts. Canadian FIMSA (0.78). It's like pricing. You do as best as you can. Appreciate there's different perspectives. Power Council – we feel this is the appropriate factors.

[8/6/2020 12:49 PM] Vlad Gutman-Britten: It would be useful to include at minimum a sensitivity with a higher leakage rate to understand the impact of that choice on resource selection.

Tom Pardee: We could do this as Dan mentioned to show sensitivity. If we were to use 2.3% for Rockies, it doesn't impact much because of how little gas we have from there. Scenarios will likely address some of this. One scenario will be to change this fraction.

[8/6/2020 12:50 PM] Vlad Gutman-Britten: For example using EDF's number. Yes. That would allow stakeholders to evaluate how important/not important this factor is. Thanks very much for your consideration.

[8/6/2020 12:52 PM] Ben Otto, ICL: Agree with Vlad. For any uncertain forecast it is good practice to assess a range of scenarios.

Fred Heutte: Some Canadian numbers are really dated and minor updates in the last 20 years.

Regional Energy Policy Update, John Lyons

Investment and production tax incentives:

PTC $15/MWh (base) for 20 years for wind started by 12/31/20

ITC for solar drops 30% in 2019, 26% in 2020, 22% in 2021, 10% from 2022 on

ITC for battery storage if filled with solar

[8/6/2020 12:57 PM] Vlad Gutman-Britten: On the incentive side, are you considering Washington state sales/use tax incentives for RE sited in the state?

James Gall: Yes we include those incentives in our Generating Resource Assumptions sheet.

[8/6/2020 12:58 PM] Snyder, Jennifer (UTC): I thought New Mexico passed a clean energy law. Am I mistaken?

Vlad Gutman-Britten: Yes.

Fred Heutte: Will put a link in the chat re: modeling this in Aurora from yesterday's NPPCC meeting. Here's the NW Council presentation and the spreadsheet. These are downloads from the Box file sharing service:

- https://nwcouncil.app.box.com/s/s2whne2t77a1qxpm17qtz5aorwuksjil
- https%3a//nwcouncil.app.box.com/s/s2whne2t77a1qxpm17qtz5aorwuksjil)
- https://nwcouncil.app.box.com/s/po27u2275z0cuanuix6oucnw7luz62bk
- https%3a//nwcouncil.app.box.com/s/po27u2275z0cuanuix6oucnw7luz62bk)

[8/6/2020 1:03 PM] Fred Heutte (NWEC): And the System Analysis Advisory Committee web page is here: https://www.nwcouncil.org/meeting/system-analysis-advisory-committee-webinar-august-5-2020 https%3a//www.nwcouncil.org/meeting/system-analysis-advisory-committee-webinar-august-5-2020)

Ben Otto: Back to tax credits slide. PTC could be charged to storage if charged with renewable. For this IRP will there be basic market power storage and renewable.

James Gall: We modeled both and treated the PTC correctly. Both technologies were selected. One bundled with storage and selected. Storage as a standalone resource with the credit. Both were selected.

[8/6/2020 1:05 PM] Rachelle Farnsworth: What happens to costs above 2%, and costs for Colstrip that could occur after 2025?

James Gall: Colstrip costs from a CETA perspective. The 2% cost gap not applicable to Colstrip since it'll be fully depreciated by 2025

Vlad Gutman-Britten: I don't believe the statute says for "new" resources. Can you explain your interpretation?

James Gall: Two instances 1) you're correct, 2) for new resource decision-making.

Matt Nykiel: Can you talk more about how the social cost of carbon was analyzed – fixed or variable cost?

James Gall: Planning on modeling social cost of carbon similarly to the expected case in the last IRP. Model plant's dispatch of real-time operations – new resources would include construction and operations costs of emissions (shared at last TAC meeting). Will be included in the optimization used to determine the least cost options. DR will be assigned an emission benefit. Scenarios will be run for the Idaho portion to understand the social cost of carbon implications for Idaho customers.

Nikita Bankoti: The Commission needs to update the social cost of carbon costs, it should be updated and on the website [WUTC] soon.

Matt Nykiel: Is Avista treating SCC as a fixed or variable cost.

James Gall: Variable. There's a price that's fixed (construction) but also variable cost assigned to operations.

Matt Nykiel: Can you clarify "analyzing social cost of carbon for Idaho", clarify the difference. I'm not totally taking up what you are putting down for Idaho.

James Gall: The social cost of carbon is included for Washington as required by law. Scenarios for that cost for Idaho. Will discuss at next electric TAC. For the variable cost, the price [per metric ton] of the social cost of carbon is fixed for each year, but the total cost is variable each year with the amount of emissions plus the emissions from construction. For Washington, it is in the expected or base case and as a scenario for Idaho.

[8/6/2020 1:12 PM] Fred Heutte (NWEC): Clarification from Joni: Hi all, Joni asked me to pass this along (she can add more via the phone): the 2045 standard is for non-emitting and RE.

Sec. 5. (1) It is the policy of the state that nonemitting electric generation and electricity from renewable resources supply one hundred percent of all sales of electricity to Washington retail electric customers by January 1, 2045. By January 1, 2045, and each year thereafter, each electric utility must demonstrate its compliance with this standard using a combination of nonemitting electric generation and electricity from renewable resources.

<u>Natural Gas and Electric Coordinated Study, James Gall and Tom Pardee</u>

James Gall: Potential scenarios – it would be helpful to have input on these; are these the right scenarios to look at?

Fred Heutte: Heating and cooling, are you also looking at water heating?

James Gall: Yes, we will get to that in a minute.

Kathleen Kinney: On the 10% efficiency, can you explain that more, is that a benefit to electricity?

James Gall: We're making assumptions of how folks will convert. We're reducing conversions by 10% in case we missed some efficiency benefits. More biased to electric.

Fred Heutte: Have you been following Power Council and their load forecast? Are you looking at a climate adjustment to the forecast for the substantial increase in late summer demand?

James Gall: Yes. That is a great question for the next meeting, it will probably be a topic at the next TAC.

Fred Heutte: Detecting a theme – lots of interesting stuff at the next meeting.

Kathleen Kinney: What portion are you assuming are heat pumps (of converted)?

James Gall: Most gas to electric is to heat pumps.

Kathleen Kinney: Is there a lower efficiency scenario too? Not everyone is going to convert to heat pumps.

James Gall: A lot of that can be derived from showing the efficiencies at various temps.

Dan Kirschner: Baseboards are 100% efficient at site. Are you assuming at site?

James Gall: This is at the site. When building generation, we'll have to adjust for losses.

Jennifer Snyder: Baseboard versus heat pump idea, if someone were thinking of going from gas to electric, most people wouldn't go from gas to baseboard.

James Gall: Conversions currently using furnaces are often ducted or point source heat. Homes with ducts will likely convert to heat pump. Those using point sources will use a mix and it's tough to determine the mix of baseboard to heat pumps.

Nikita Bankoti: Very drastic change in period, more energy use at peak, you'll be using a lot of different resources, will customers be charged a higher rate?

James Gall: Because of added load in the winter, what is the impact to customers? The IRP process will illustrate the cost impact as compared with the expected changes and also look at what the customer is avoiding on the gas side. Please look at the last IRP where we did a similar analysis. Cost is higher, emissions are lower. Will the customer be paying more? Will depend on price of power, environmental policies, and conversion costs (customer-borne). Lastly, we also need to address impacts on T&D – large conversion to electric will likely require T&D incremental infrastructure costs. We may not be able to address that in this IRP.

Vlad Gutman-Britten: Sorry, missed the first chunk of that. The idea of extra load needs to be served with long-duration storages. CCS and RNG that can fill in that role

Studies show that you can fill in the role without long-term storage. Are you looking at space and water heating?

James Gall: Looking at all end uses – water, space, process.

Vlad Gutman-Britten: In calculating peak are you incorporating latest codes?

James Gall: Yes we're trying to estimate what the peak is, then when we pick resources, the type of program that would reduce peak if cost effective.

Vlad Gutman-Britten: Incorporating that type of resource? *Yes.*

Jennifer Snyder: Are you modifying this within the CPA's technology potential?

James Gall: Yes, since increasing the amount of water heaters on the system.

Kathleen Kinney: Could it be looked at with a cost comparison using RNG to achieve the same emissions goal?

James Gall: Yes. Tom will have scenarios. My side will show electric and comparing both we can come to a conclusion. Advantage of gas/electric IRP at the same time – we can look at both.

Fred Heutte: Glad water heater load management is already addressed. With new cross sector load on the section including electrification, if that load can be managed, it should be. To what degree have you looked at managing space heat?

James Gall: Through the CPA. Look at manageable savings we can get from our existing load and how does that apply to this situation.

Ben Otto: Along with DR, applies to space heating load, applying a package of building shell improvements is another way to address this issue.

James Gall: We will look to AEG for this and work with the CPA to incorporate.

Jennifer Snyder: Depending on how much you can do this in your CPA, electric house has ability to be made tighter than gas heated house. Don't know if that will make a difference or if it can be captured in a CPA. Will have to get back to the group on this.

Kathleen Kinney (slide 15): I'm confused, I'm looking at the graph and it looks like higher is more efficient.

James Gall: Less efficient the higher you go on the Y axis. More kWh used per Dth replaced.

Sudeshna Pal: What is the current technology?

James Gall: Slides 6-7, the Base Case we already shared using current technology to estimate future loads using more efficient technology in the future. Hybrid uses gas and electricity more efficiently with existing technology.

[8/6/2020 2:24 PM] Vlad Gutman-Britten: I think we'll have comments on some of the end use efficiency assumptions, but will provide those in writing.

Mike Morrison (Slide 15): Dth to kWh is about 293, so what you are saying is the hybrid future is 6 times as efficient?

James Gall: That is not what this is showing at the amount of gas in the base scenario. We're using electric not gas. Trying to illustrate how much gas demand will go to electric. This may not be the best way to show that. We start with this track, but converting with simplifying, we remove space heat from the calculation. Efficiency components are multiplied to those end uses.

Mike Morrison: Ok, so this is only in the context of the conversion you are doing. It seems very complicated, you might have done it a simpler way.

[8/6/2020 2:28 PM] Steven Simmons: Have you thought about what might be the implications on the gas system in these scenarios - especially the hybrid system where you are relying on gas solely for peak days. More gas storage?

Tom Pardee: Will come out in the scenarios; maybe RNG can take some of this risk off the system. Will circle back to the electric TAC to show the results of modeling this on both sides.

<u>Highly Impacted & Vulnerable Populations Baseline Analysis, James Gall:</u>
Nikita Bankoti: Interesting to understand if company will use a map or delve into individual household data. Interesting that resources are in these neighborhoods. What does the company plan to do in this area regarding equity and community engagement? Are you considering any factors and pollution burden for these indicators?

James Gall: At this time, we haven't looked at those two items yet because it's outside of the law. The expectation is areas may be added, but we didn't want to go down that path until we get an indication from the state regarding these areas. May have low income in areas that aren't necessarily impacted. We have low income programs broader than these areas. Look at how the law is written – what these areas look like today versus the future. That's where we're focusing right now. Looking to include these populations in future IRPs as well as maybe programs to address these areas. There are limited things an IRP can do. Where does the IRP apply and where do other processes apply?

[8/6/2020 2:47 PM] Vlad Gutman-Bittmen: Given that the statute emphasizes health, I assume you mean locating non-emitting assets in identified communities? Just a note that not all resources that are "clean" under CETA are clean from a health perspective, like biomass for example, but understand your point. Thank you.

James Gall: Correct.

Max St. Brown: Lot of overlap with what we're doing for COVID and what customers are being impacted. Is this process of linking marketing data to customer data being documented?

James Gall: No we ended up using census data for the most past and not the marketing data.

Lori Hermanson: Trove purchases data from 27 different parties and compiled income data. We ended up using census data because the data was substantially different.

Nikita Bankoti: If you have data on average household size, can that be used?

Grant Forsyth: Yes there's average household size from the American Community Survey. It doesn't go very far back, seems to be volatile and has been smoothed so much it has little variation over time. It is somewhat difficult data to work with unless you use a 5-year moving average. You can get it down to the tract or block level, but can you do any time analysis? 3 – 5 year average smooths things out a bit and causes problems.

[8/6/2020 3:00 PM] Griffith, Kate (UTC): Are you able to see how this changes in summer or winter months?

James Gall: No, only annual data is available. Will probably be a future analysis to see from a heating versus air conditioning point of view.

Nikita Bankoti: Not a question. Just thinking if it will be easier to access and analyze population density data (in vulnerable areas) instead of household level data.

Vlad Gutman-Britten: Is the reason for the shorter outage in vulnerable areas because they're urban?

James Gall: Yes, more vulnerable populations are in suburban areas. Being in the mixed vulnerable and not vulnerable areas takes more time driving to them to fix the outage.

Vlad Gutman-Britten: Not being accusatory, but it is not accurate to say vulnerable areas are receiving a more resilient service because it is just in an urban area that is easier to service?

James Gall: Wouldn't go that far yet. The only ones that are less are rural areas. These are very rural areas and if the analysis is by customers per mile this may be the case. It would require more analysis and this may be the next step. Vulnerable areas seems to have more reliability in urban areas.

[8/6/2020 3:14 PM] Vlad Gutman-Britten: Controlling resilience for customer density does seems like a useful metric to develop to identify discrepancies. If they exist.

[8/6/2020 3:15 PM] Vlad Gutman-Britten: Will you resend the deck with new slides please?

[8/6/2020 3:15 PM] Yes, we will. Either later this week or early next at the latest.

[8/6/2020 3:18 PM] Ben Otto, ICL: Rathdrum gas power plant in Idaho is very close to the Washington border. Is this included?

James Gall: No, it is not included in this study being it's in Idaho.

[8/6/2020 3:19 PM] Vlad Gutman-Britten: I'm assuming this is assuming that pollution harms accrue near a facility? This isn't based on a pollution transport model? What about identified community down-wind even if they're not close to a facility.

James Gall: Haven't gotten down to that level. CS2 in Oregon and several CCCTs, Rathdrum, Colstrip, etc. and limited thermal generation in eastern Washington. This is really only what there is in Washington.

Fred Heutte: Not that I'm an expert, but there is a good study on this from Portland State. When you look forward to where the EV infrastructure can be placed, this is something we should consider forward-looking.

[8/6/2020 3:24 PM] Vlad Gutman-Britten: These strike me as good metrics, but I'm not sure the folks on the phone are necessarily well positioned to answer. That may require proactive outreach to groups active in some of the communities you identified, as well as Front & Centered.

Fred Heutte: CIMS or other data. Make sure to note where the data is coming from for these studies.

Ben Otto: Super fascinating. Really good work. We'd encourage Avista to apply the same thinking to Idaho. Just the right thing to do. Aligns with your corporate commitments.

Vlad Gutman-Britten: Agree, its great work.

Ben Otto: This presentation has helped me understand the right questions to ask.

Nicholas: The OPUC breakout is by area (block group) of the vulnerable population. One point of verification. Understand it as break out by area as being broadly, rather than by meter.

James Gall: Characterized by geography. Meters in an area, but not identified if a particular customer or not. Not necessarily every customer in that area is vulnerable. Remind ourselves not to focus on geography when developing programs.

Nicholas: Right. Thank you. Wanted to make sure. It is a challenge.

Economic, Load, and Customer Forecasts

Grant D. Forsyth, Ph.D.
Chief Economist
Technical Advisory Committee Meeting
August 18, 2020

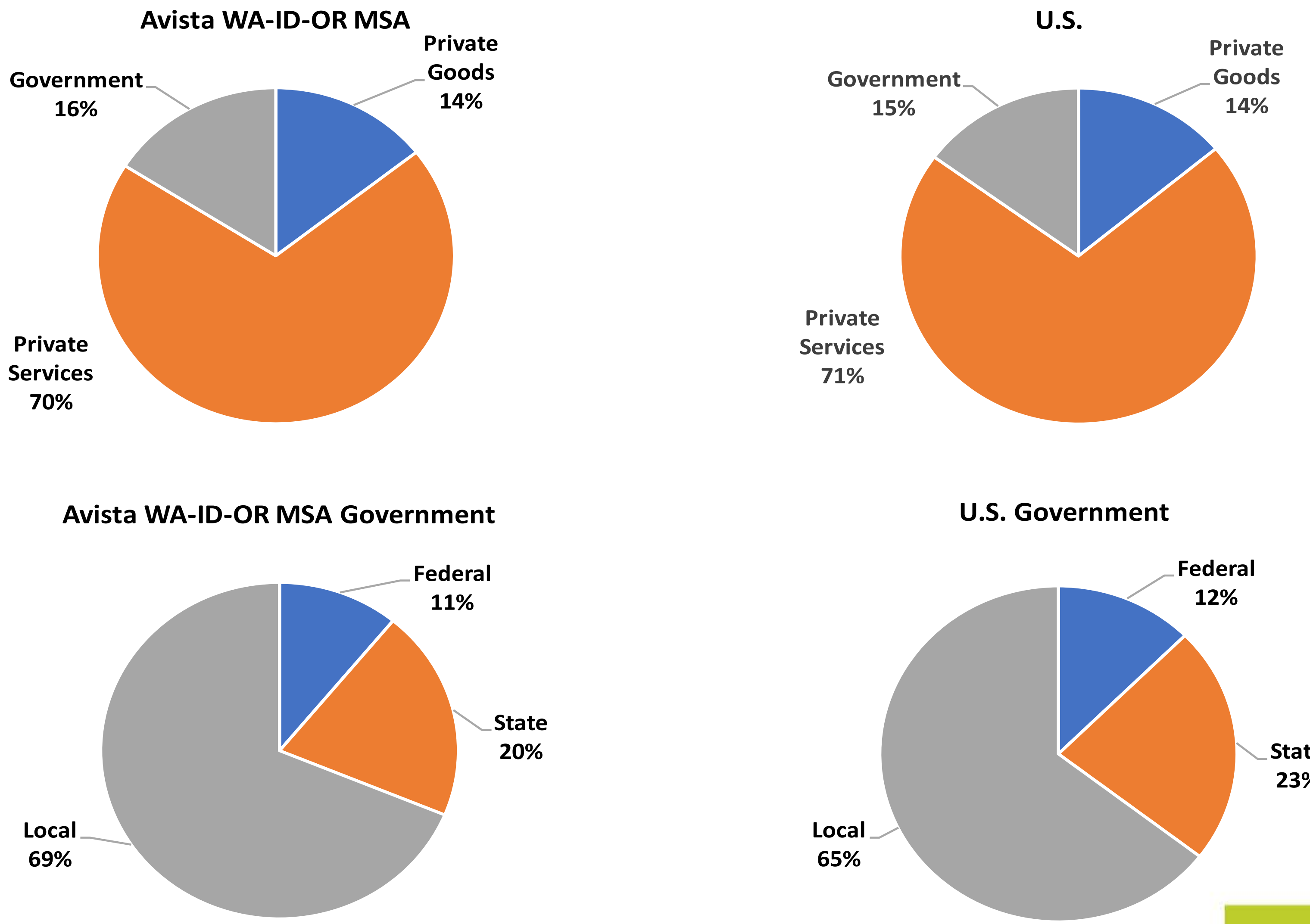
Main Topic Areas

- **Service Area Economy**
- **Long-run Energy Forecast**
- **Peak Load Forecast**
- **Long-run Gas Customer Forecast**

Service Area Economy

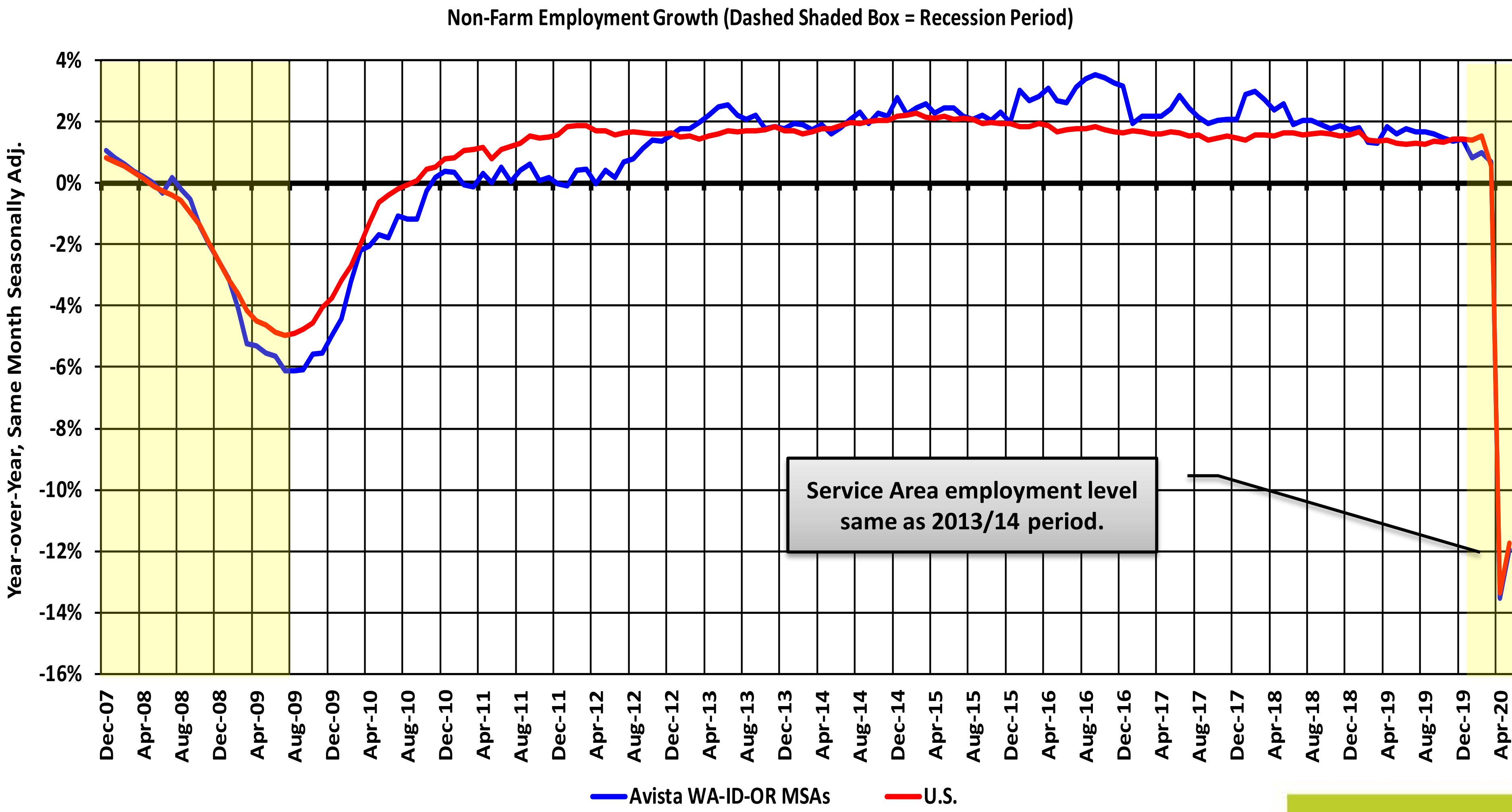
Grant D. Forsyth, Ph.D.
Chief Economist
Grant.Forsyth@avistacorp.com

Distribution of Employment, 2019



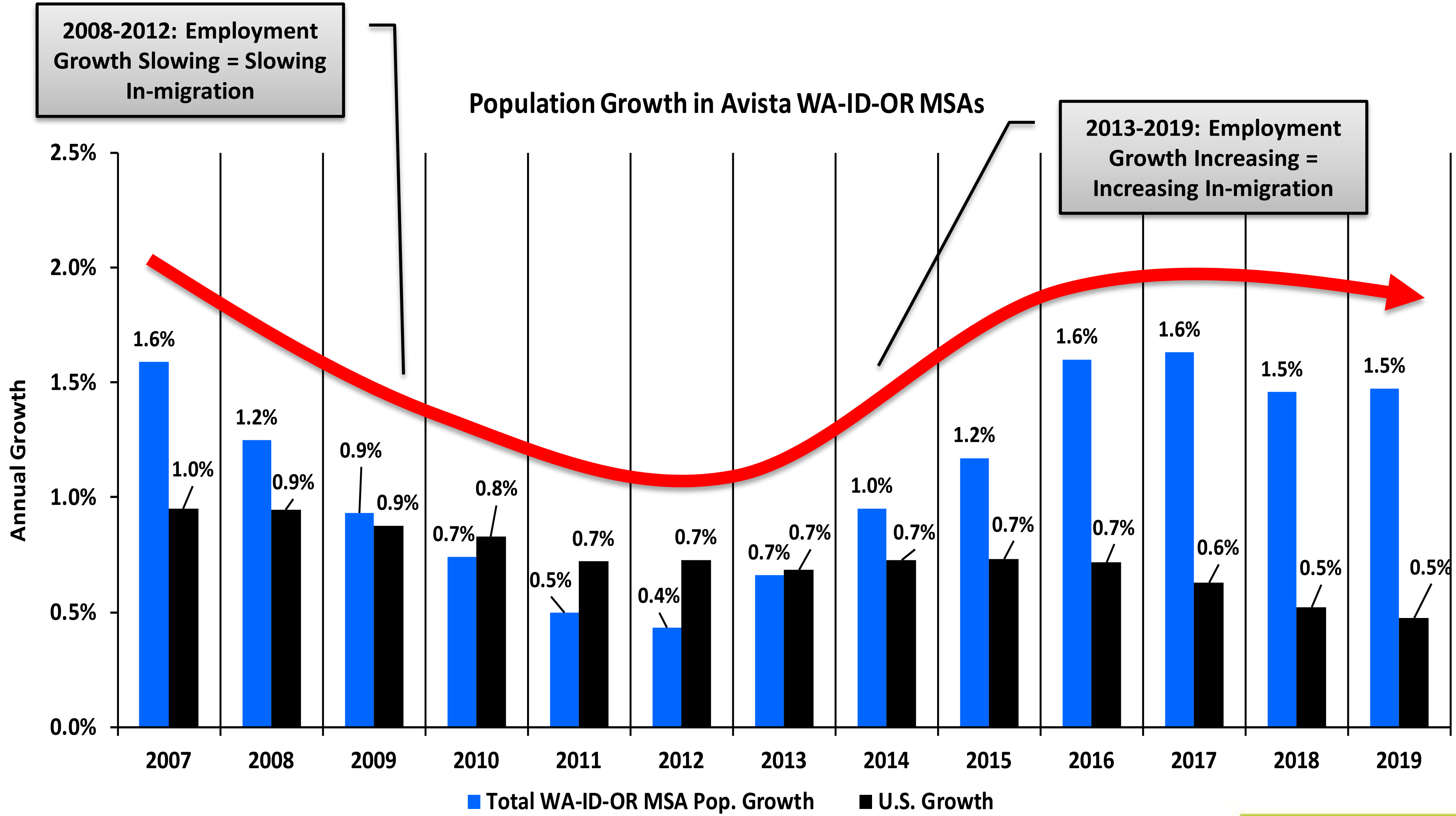
Source: BLS and author's calculations.

Non-Farm Employment Growth, 2009-2020



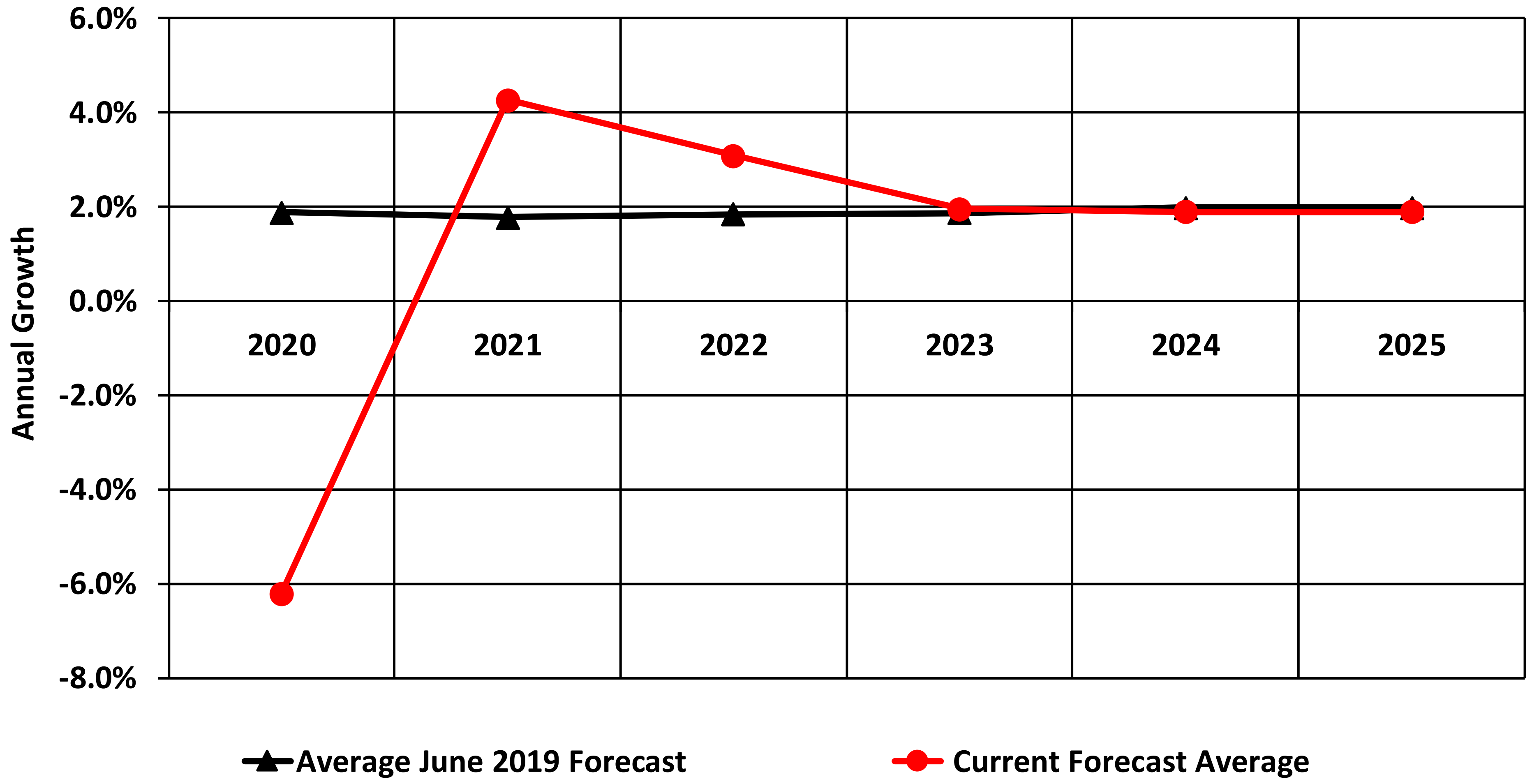
Source: BLS, WA ESD, OR ED and author's calculations.

MSA Population Growth, 2007-2019



Source: BEA, U.S. Census, and author's calculations.

GDP Growth Assumptions: 2021 IRP vs. 2020 IRP

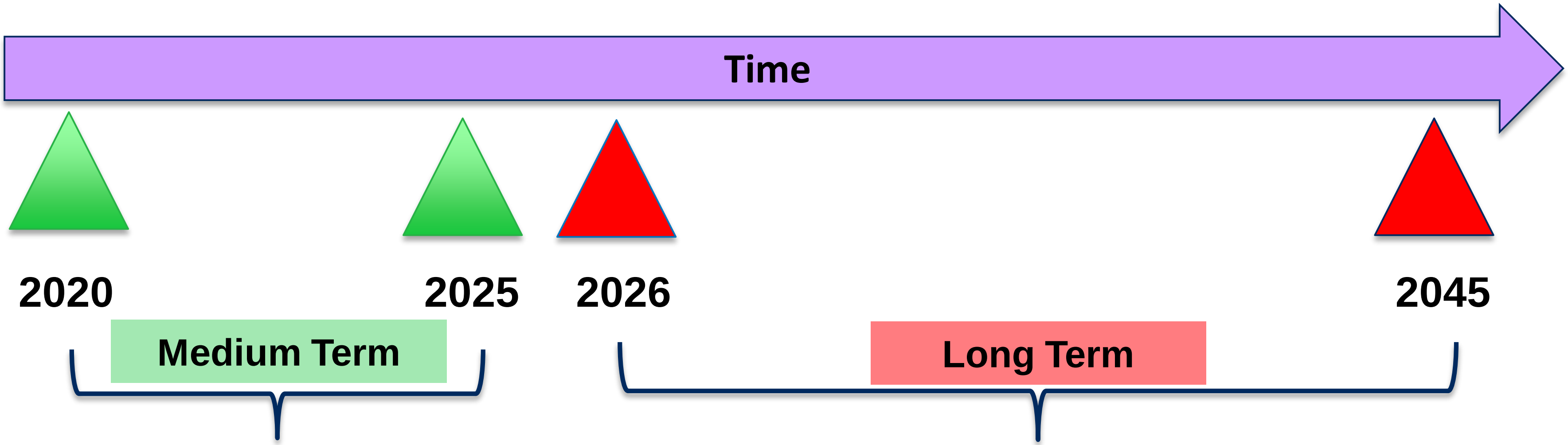


Source: Various and author's calculations.

Long-Term Energy Load Forecast

Grant D. Forsyth, Ph.D.
Chief Economist
Grant.Forsyth@avistacorp.com

Basic Forecast Approach



1) Monthly econometric model by schedule for each class.
2) Customer and UPC forecasts.
3) 20-year moving average for "normal weather."
4) Economic drivers: GDP, industrial production, employment growth, population, price, natural gas penetration, and ARIMA error correction.
5) Native load (energy) forecast derived from retail load forecast.
6) Current forecast is the "Summer/Fall Forecast" done in June.

1) Boot strap off medium term forecast.
2) Apply long-run load growth relationships to develop simulation model for high/low scenarios.
3) Include different scenarios for renewable penetration with controls for price elasticity, EV/PHEVs, and natural gas penetration.

The Long-Term Relationship, 2021-2045

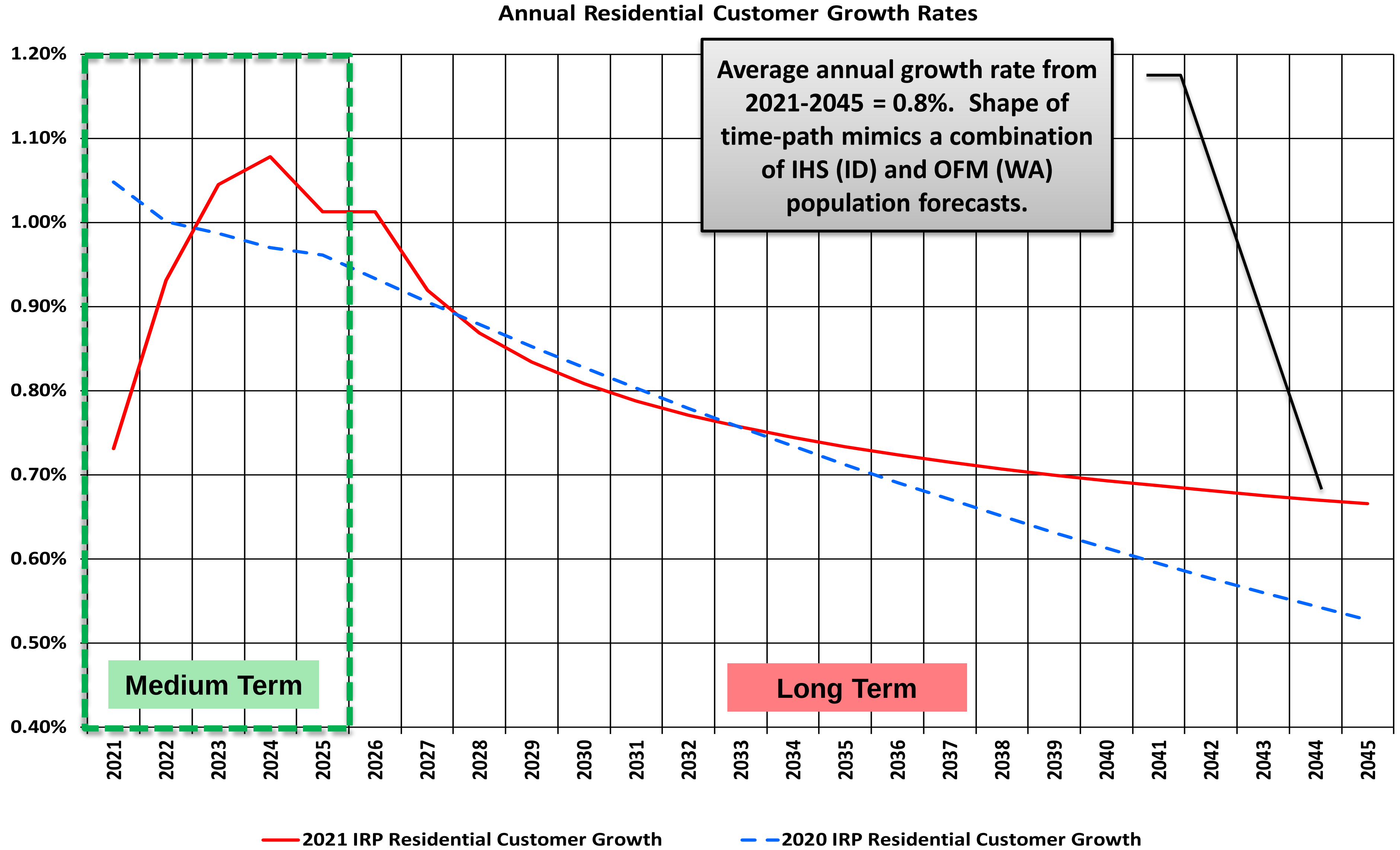
Load = Customers X Use Per Customer (UPC)

Load Growth ≈ Customer Growth + UPC Growth

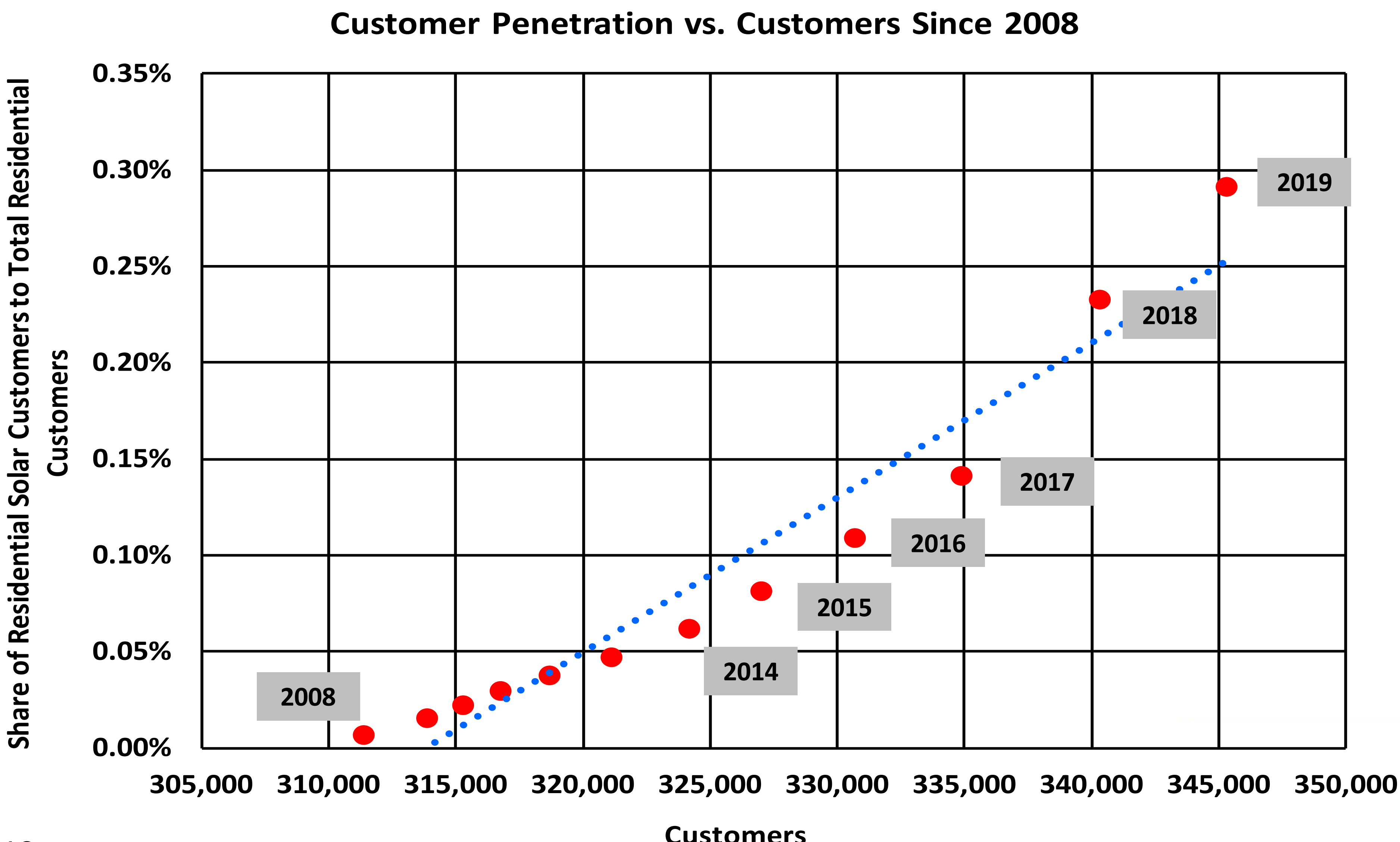
Assumed to be same as population growth for residential after 2025, commercial growth will follow residential, and slow decline in industrial.

Assumed to be a function of multiple factors including renewable penetration, gas penetration, and EVs/PHEVs.

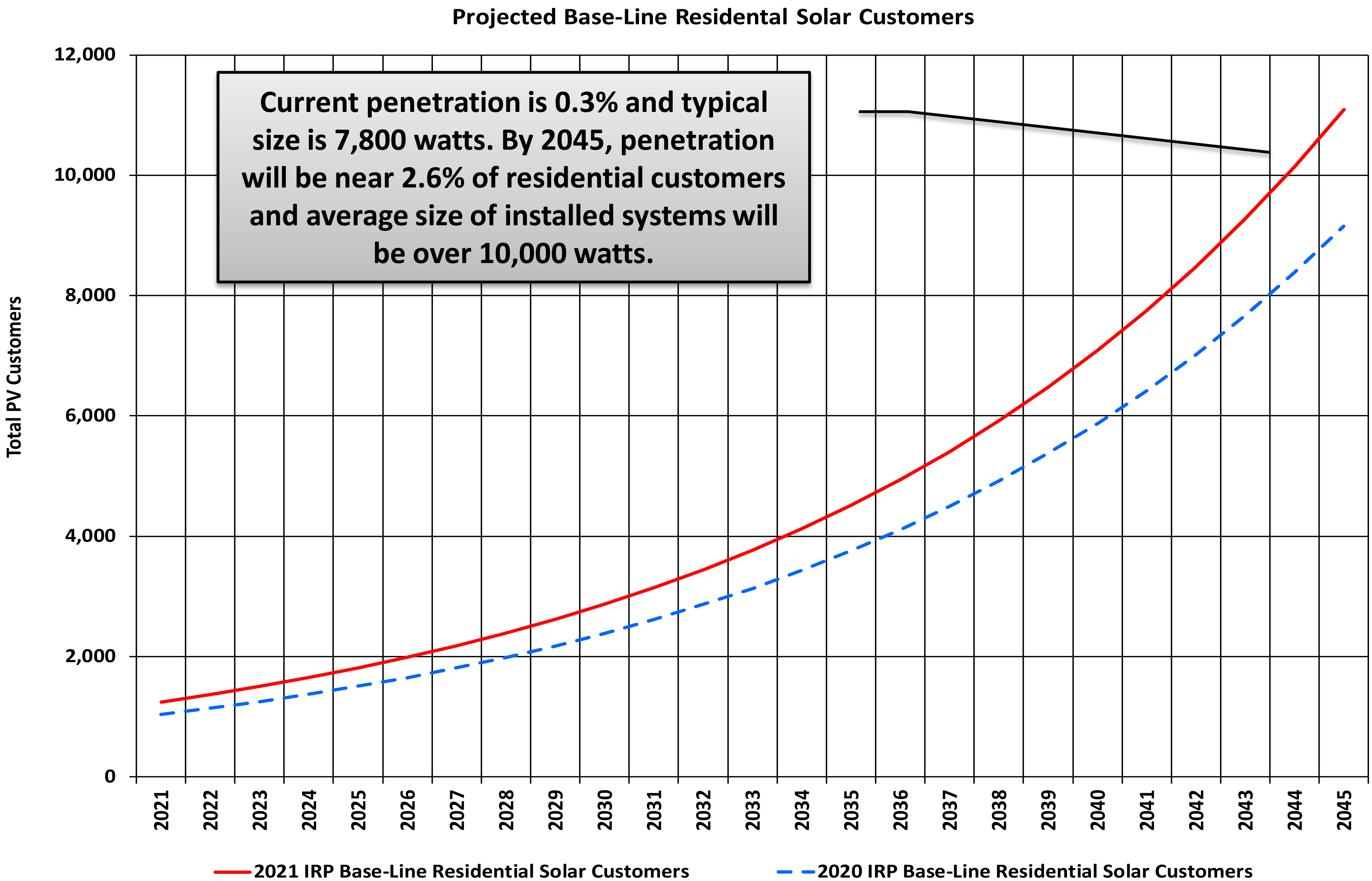
Residential Customer Growth, 2020-2045



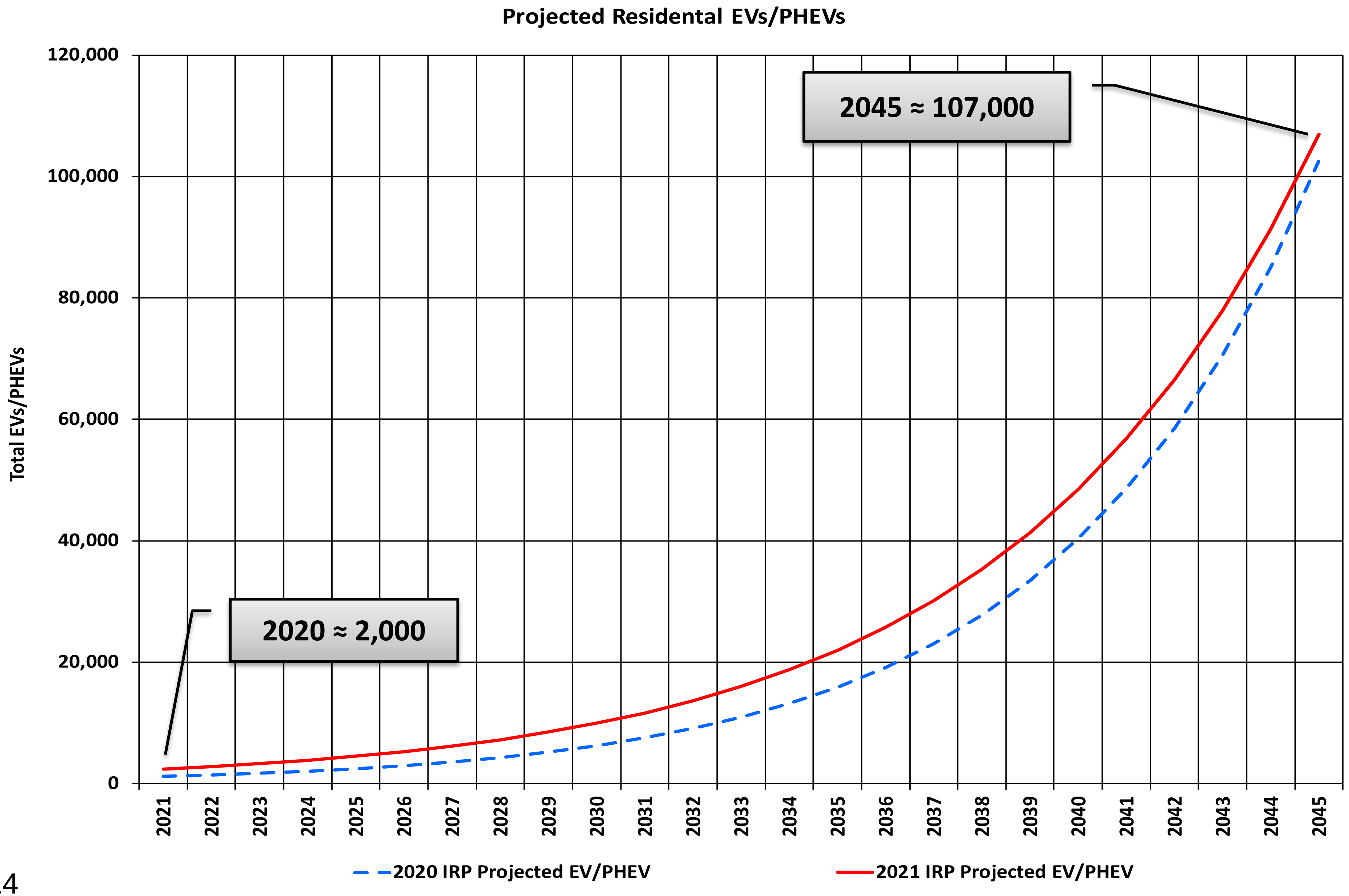
Residential Solar Penetration, 2008-2019



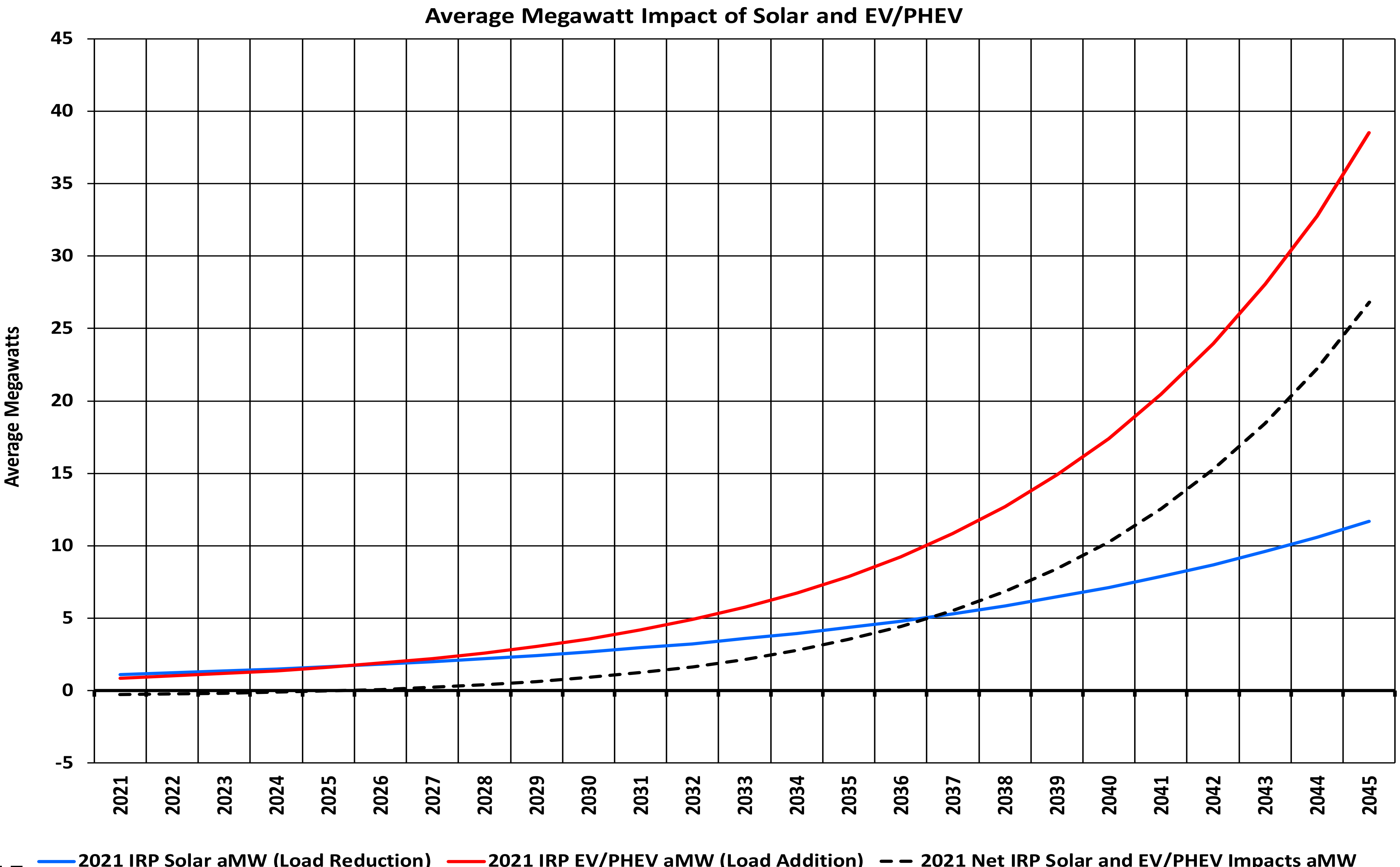
Residential Solar Penetration, 2021-2045



Residential EVs/PHEVs, 2021-2045

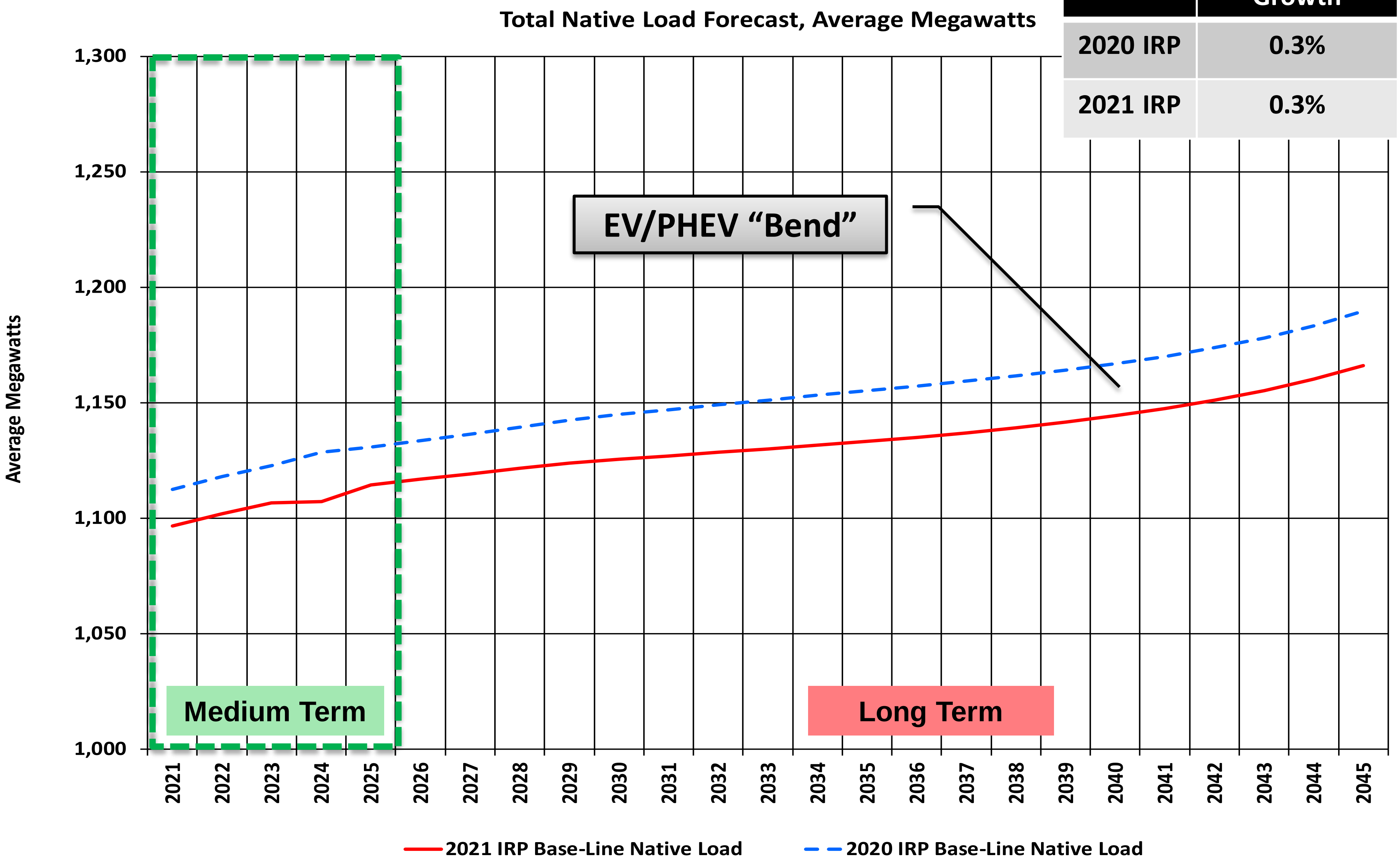


Net Solar and EV/PHEV Impact, 2021-2045

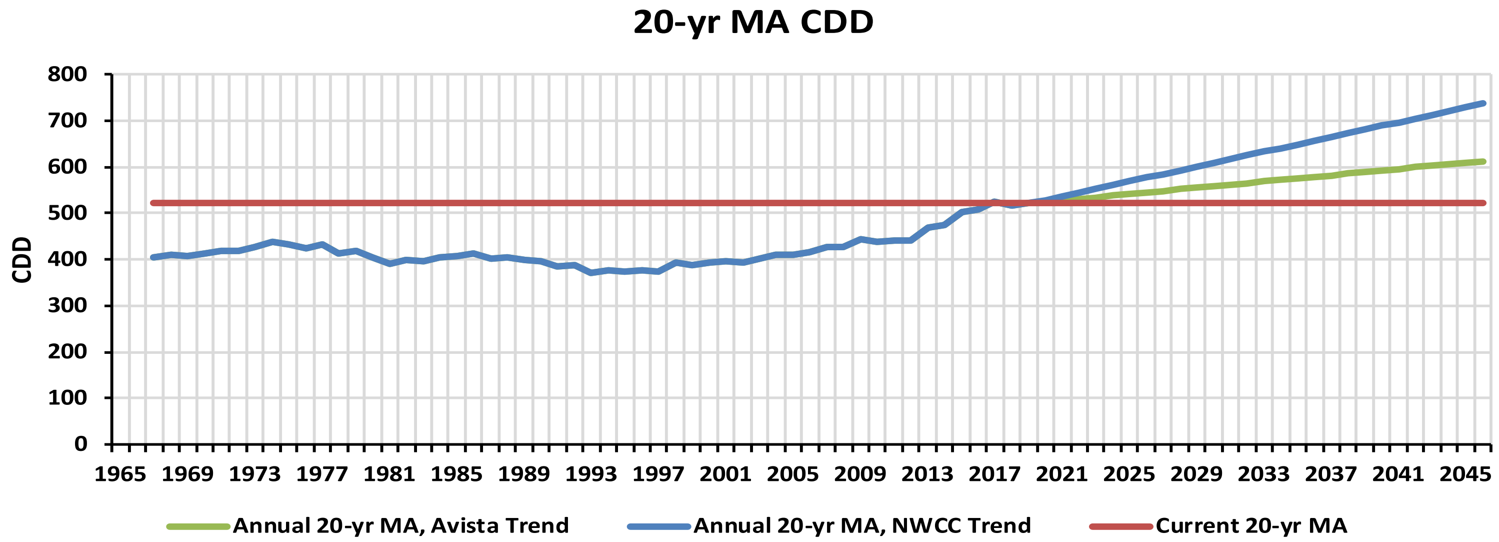


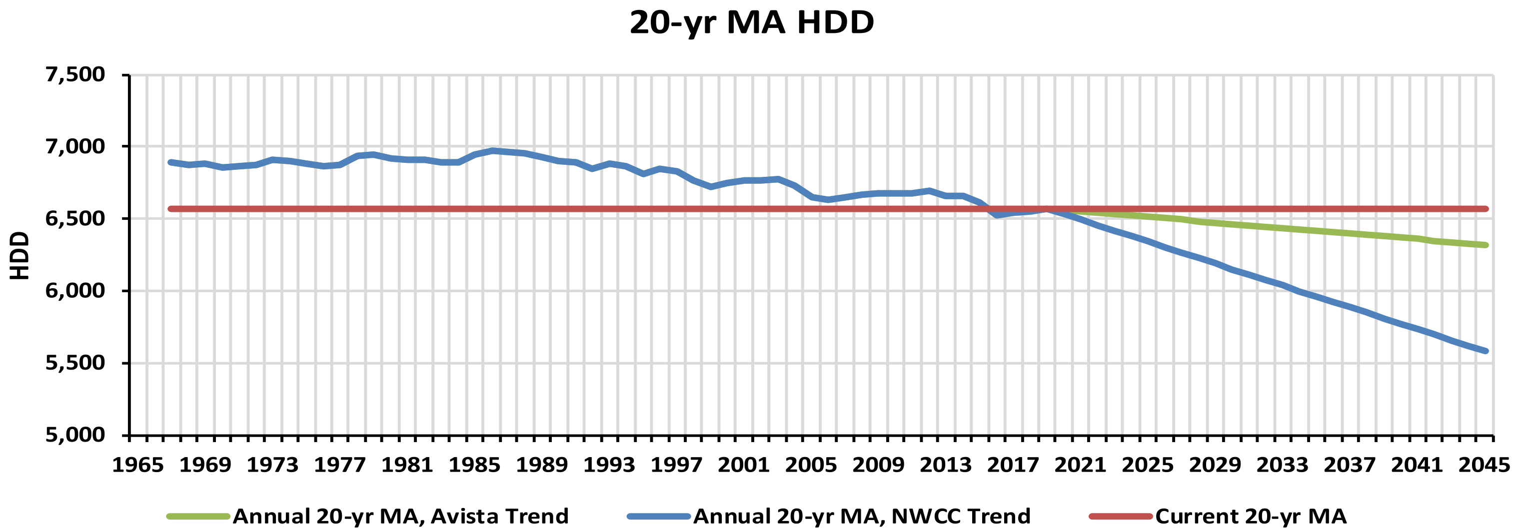
Native Load Forecast, 2021-2045

IRP	Avg. Annual Growth
2020 IRP	0.3%
2021 IRP	0.3%



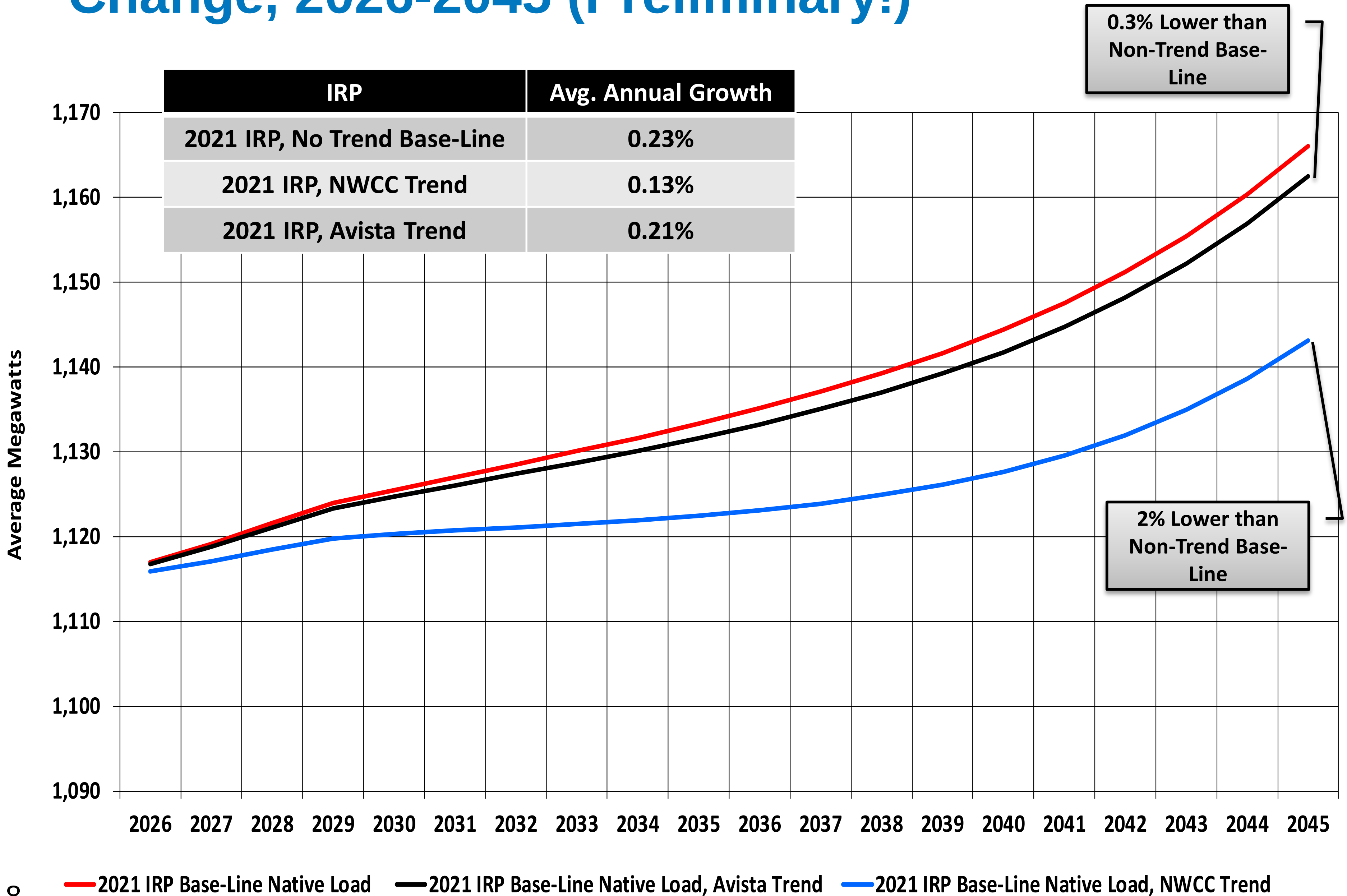
Climate Change: A Trended 20-year Moving Average (Preliminary!)



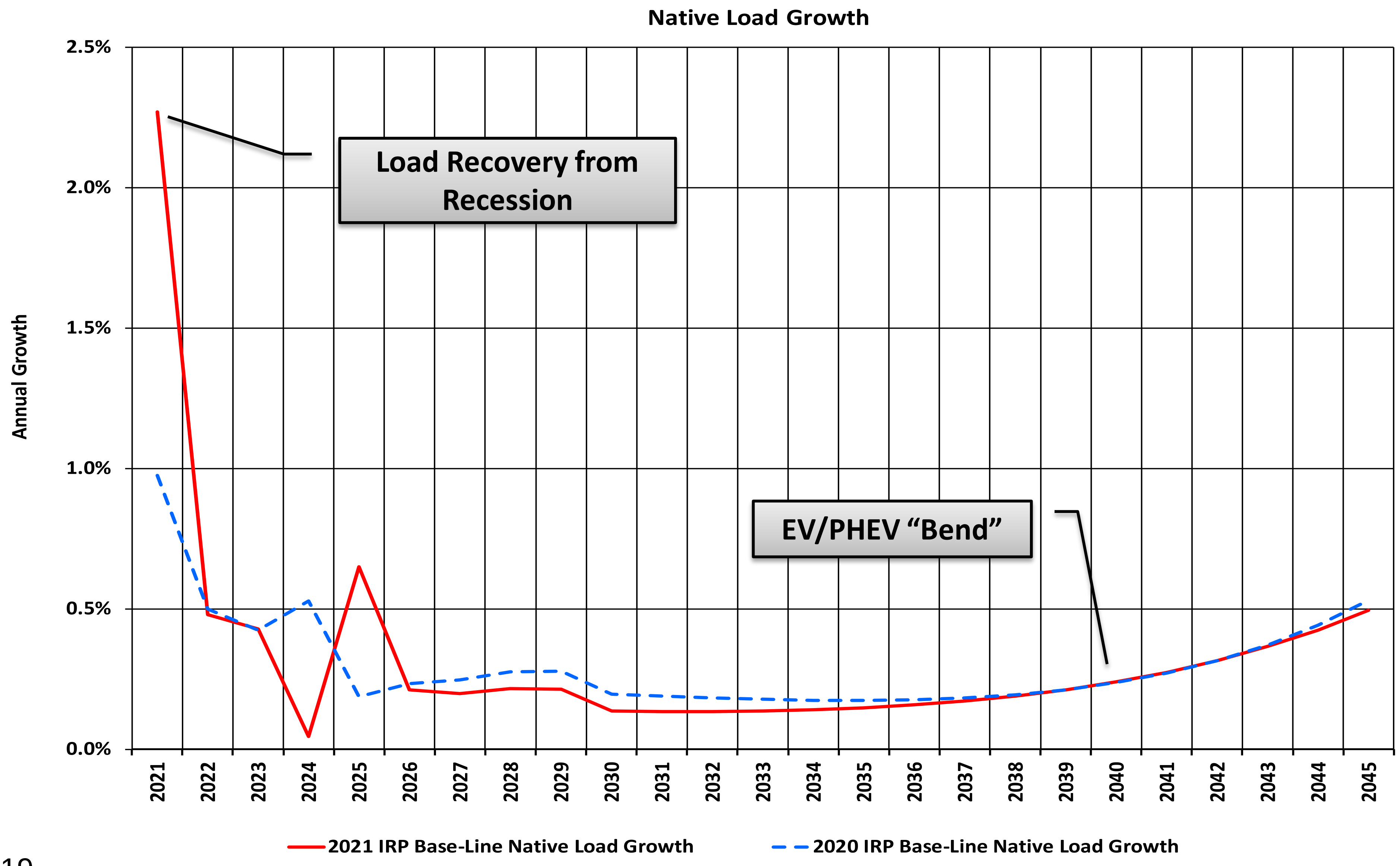


Annual Native Load Forecast with Climate Change, 2026-2045 (Preliminary!)

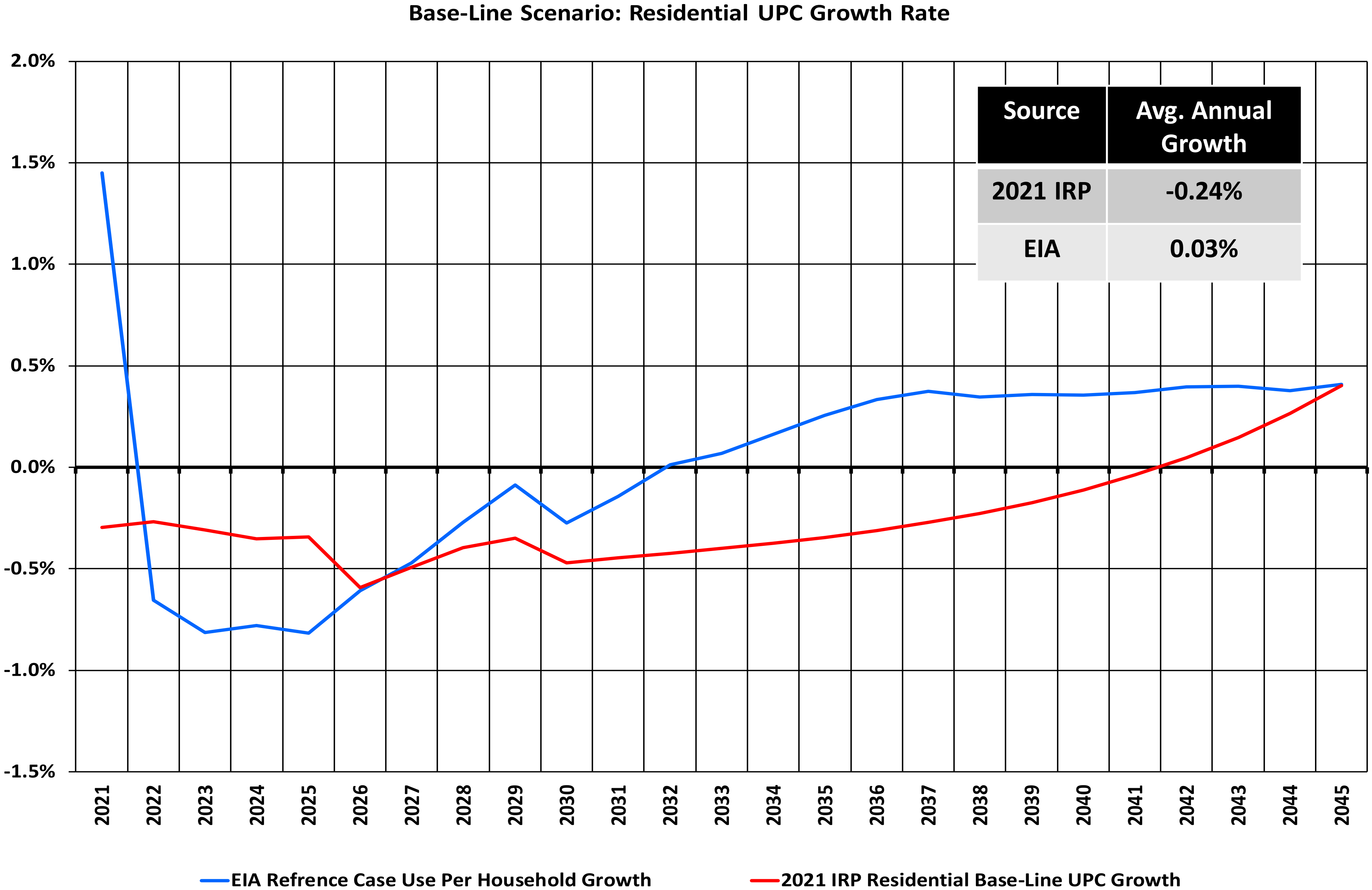
IRP	Avg. Annual Growth
2021 IRP, No Trend Base-Line	0.23%
2021 IRP, NWCC Trend	0.13%
2021 IRP, Avista Trend	0.21%



Native Load Growth Forecast, 2021-2045



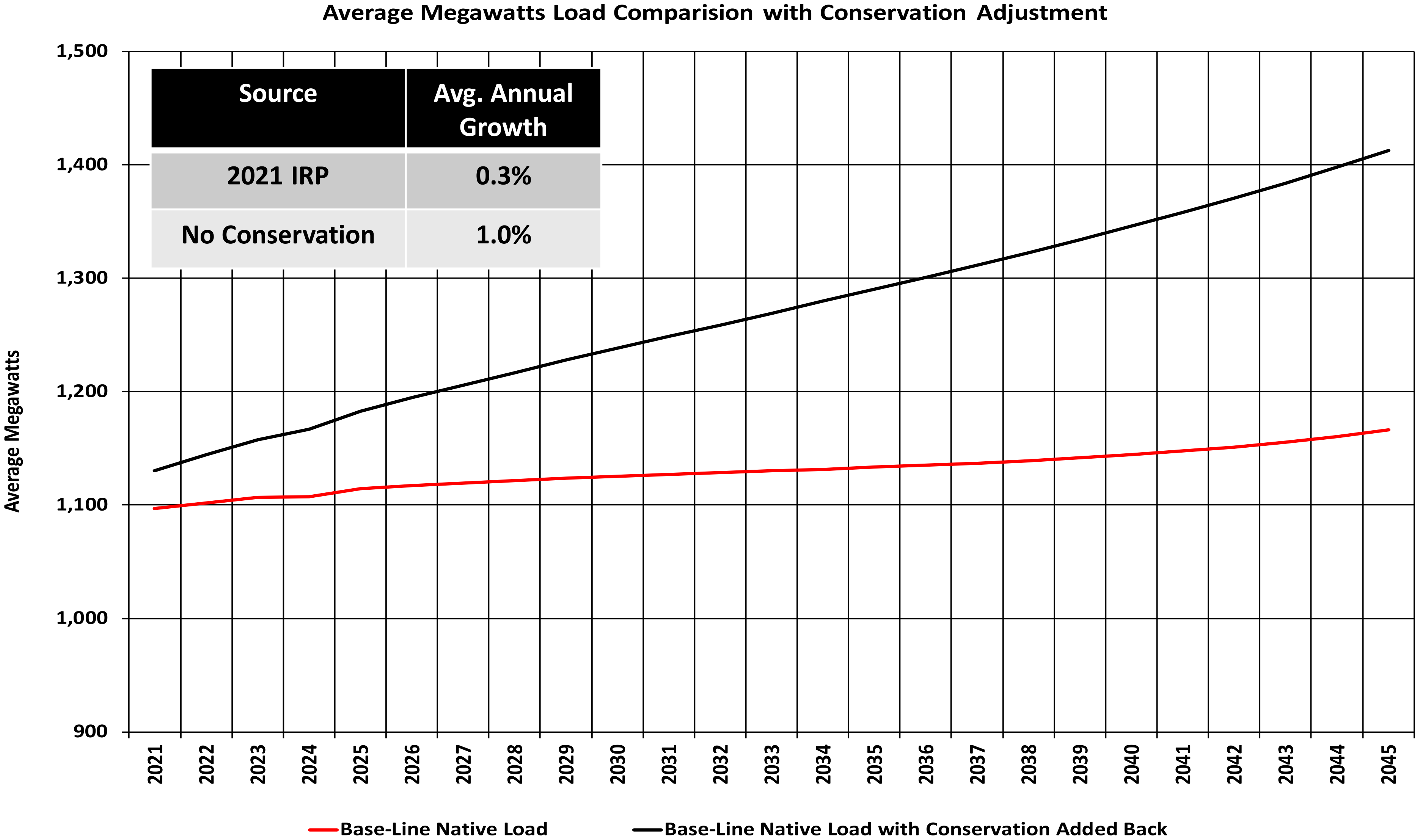
Residential UPC Growth: 2021-2045



Long-Run Load Forecast: Conservation Adjustment

Grant D. Forsyth, Ph.D.
Chief Economist
Grant.Forsyth@avistacorp.com

Comparison of Native Load Forecasts, 2021-2045



Peak Load Forecast

Grant D. Forsyth, Ph.D.
Chief Economist
Grant.Forsyth@avistacorp.com

The Basic Model

- **Monthly time-series regression model that initially excludes certain industrial loads and EVs (but those are added back in for the final forecast).**

- **Based on monthly peak MW loads since 2004. The peak is pulled from hourly load data for each day for each month.**

- **Explanatory variables include HDD-CDD and monthly and day-of-week dummy variables. The level of real U.S. GDP is the primary economic driver in the model—the higher GDP, the higher peak loads.** ***Model allows GDP impact to differ between winter and summer.***

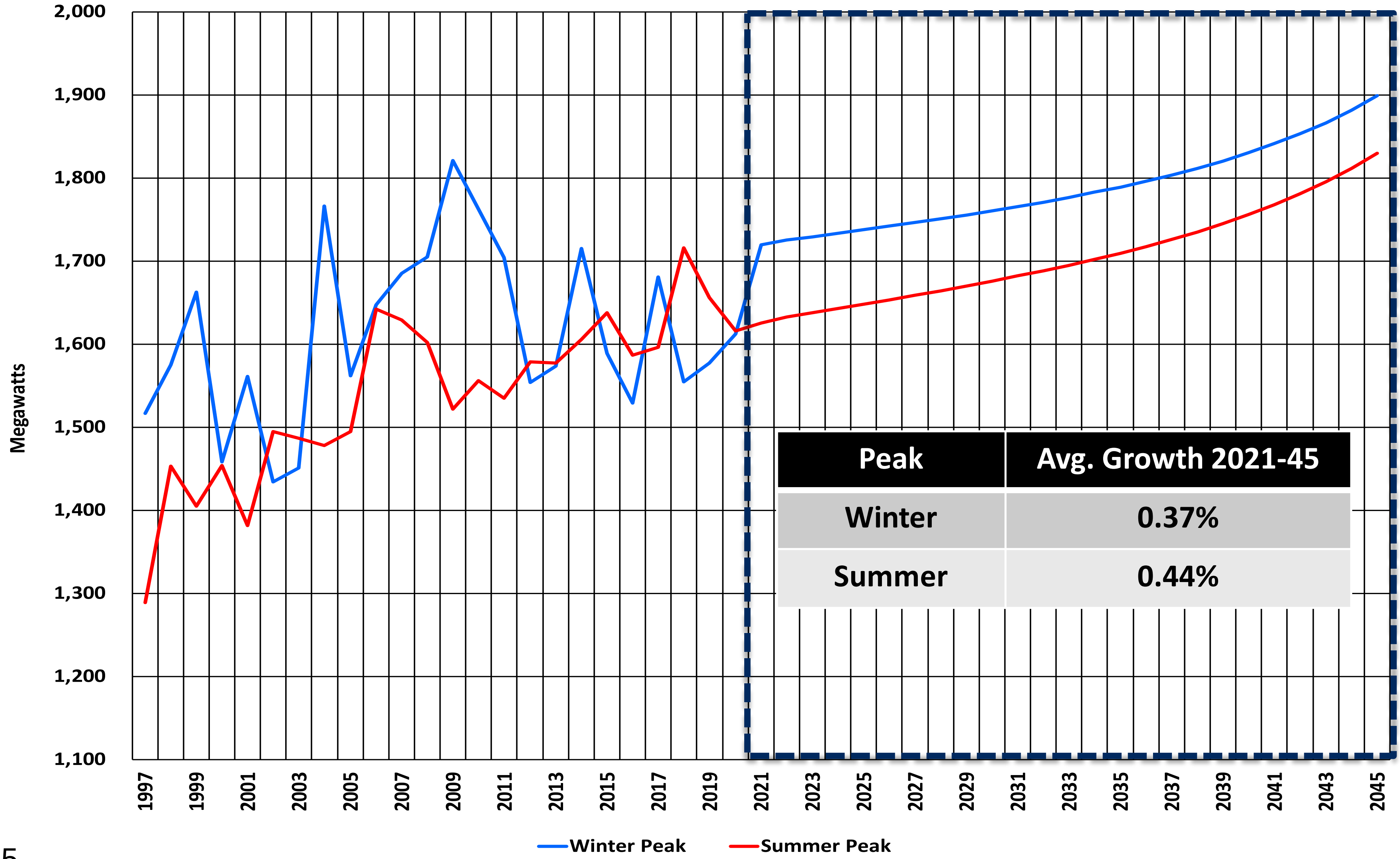
- **The coefficients of the model are used to generate a distribution of peak loads by month based on historical max/min temperatures since 1890, holding GDP constant. A starting expected peak load is then calculated using the average peak load simulated for that month going back to 1890. Model shows Avista is a winter peaking utility for the forecast period; however, the summer peak is growing at a faster than the winter peak.**

- **For comparison in the 2021 IRP, peak load is also calculated by averaging simulated peak loads over the last 30 years and 20 years.**

- **The model is also used to calculate the long-run growth rate of peak loads for summer and winter using a forecast of GDP growth under the "*ceteris paribus*" assumption for weather and other factors.**

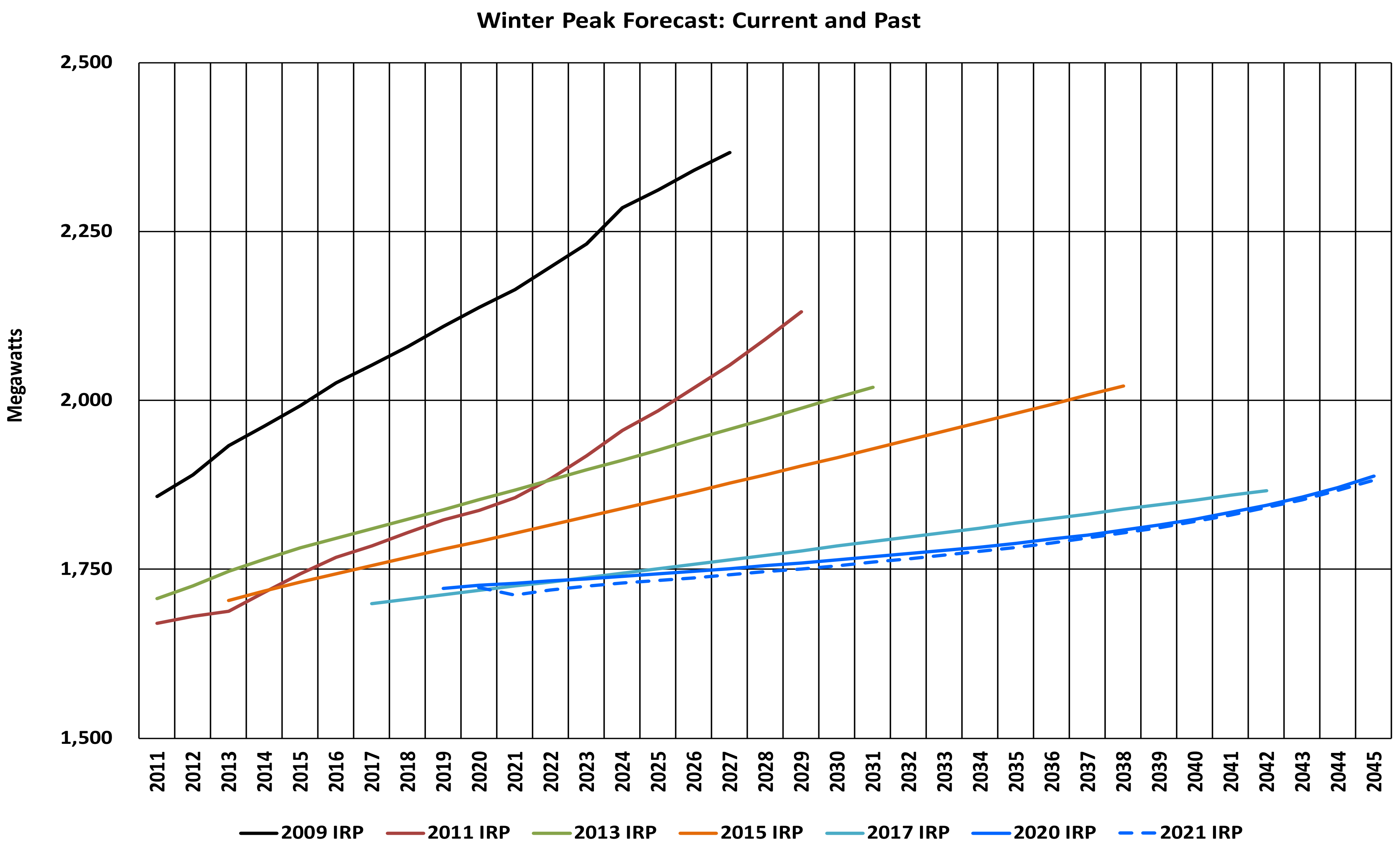
AVISTA

Peak Forecasts for Winter and Summer, 2021-2045

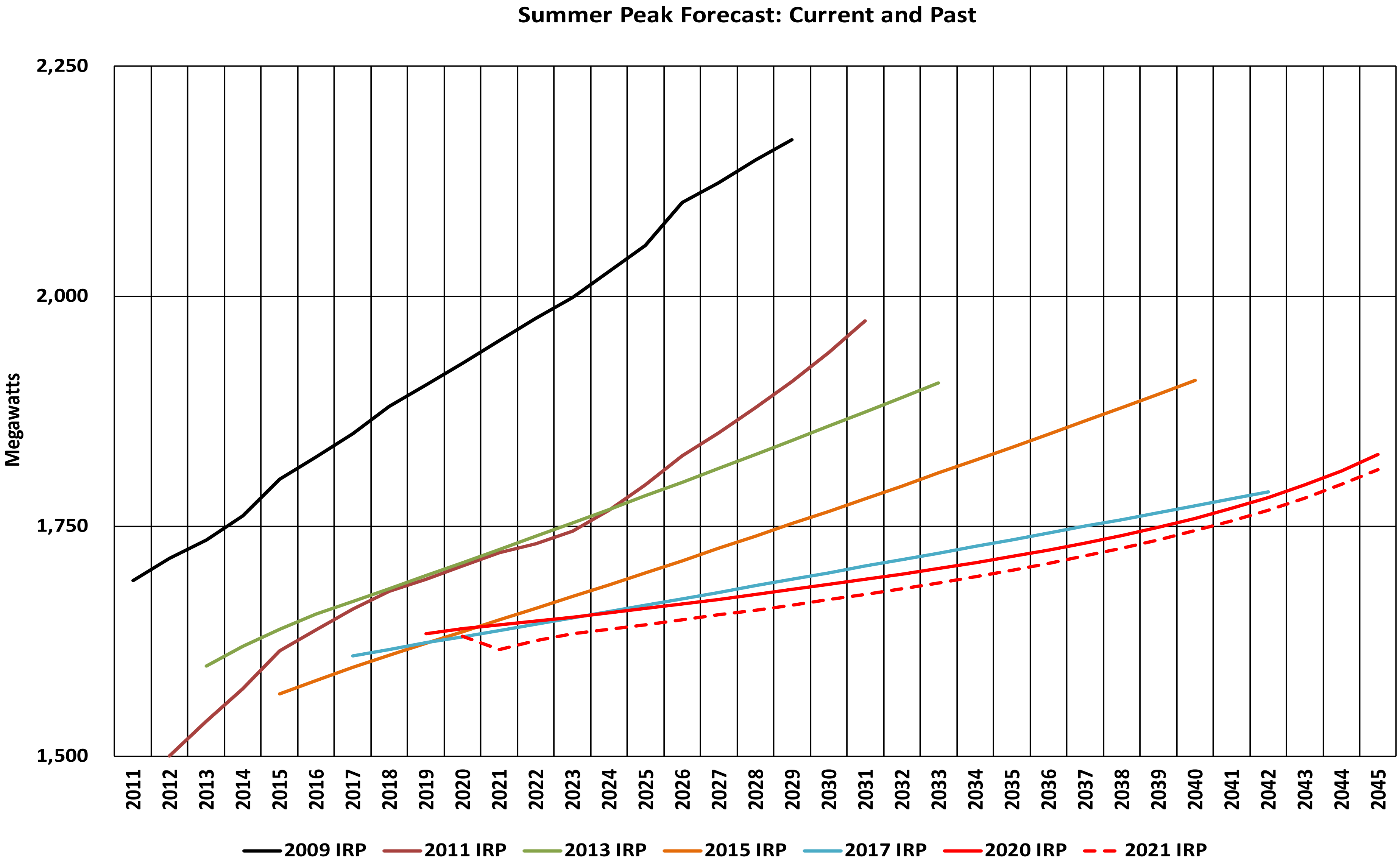


Peak	Avg. Growth 2021-45
Winter	0.37%
Summer	0.44%

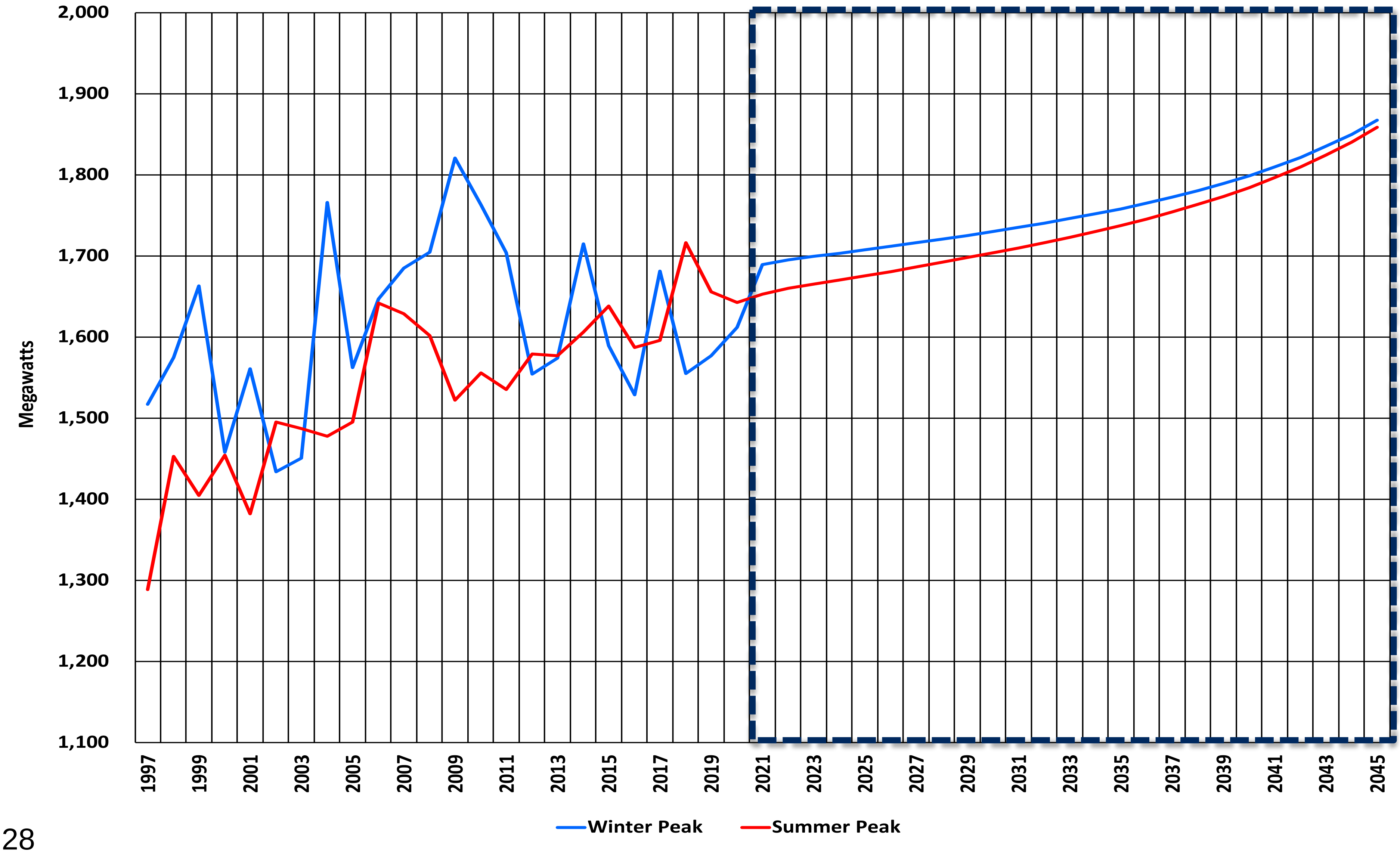
Load Forecasts for Winter Peak, 2011-2043



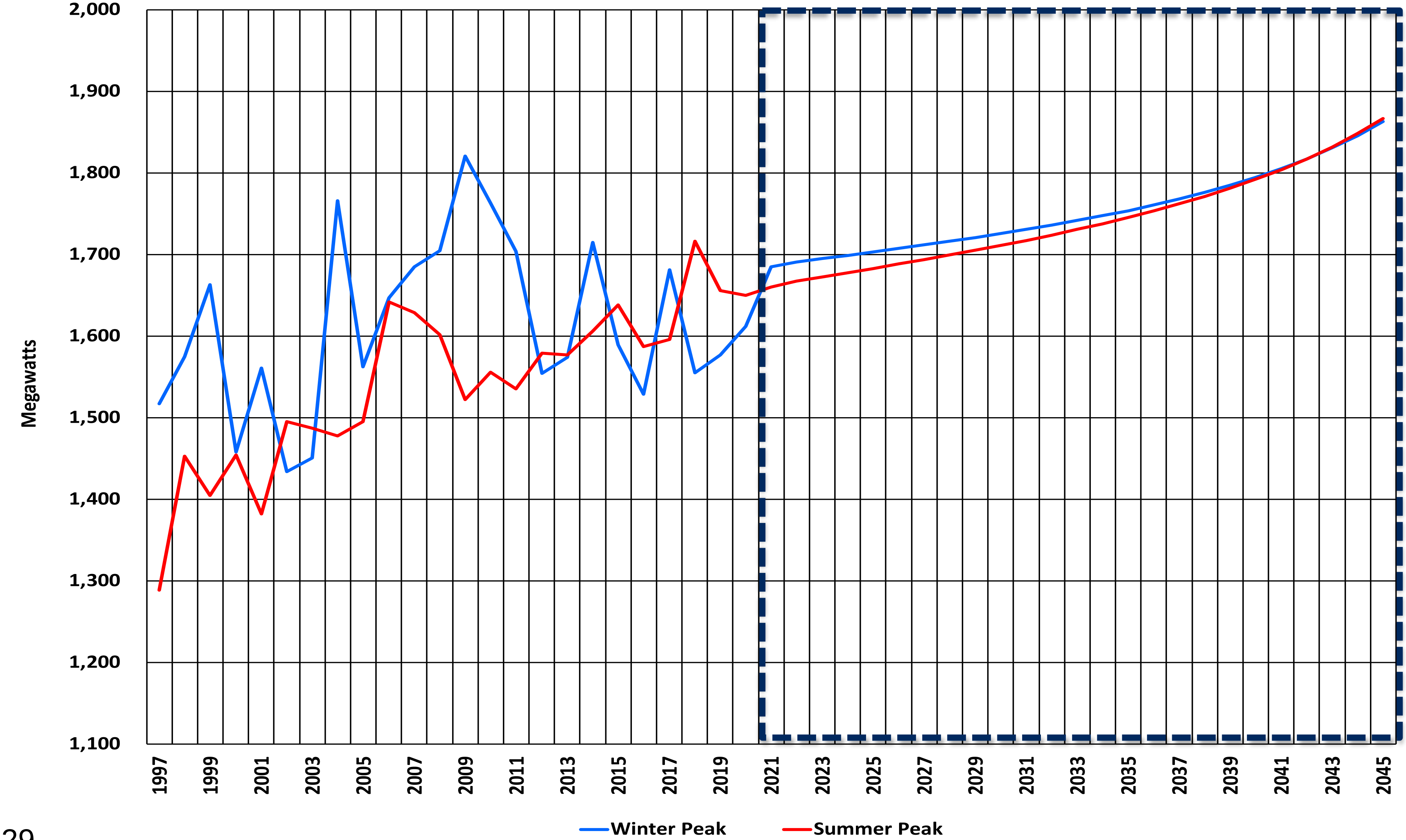
Load Forecasts for Summer Peak, 2011-2045



Peak Forecasts for Winter and Summer 30-Year Average Weather, 2021-2045



Peak Forecasts for Winter and Summer 20-Year Average Weather, 2021-2045

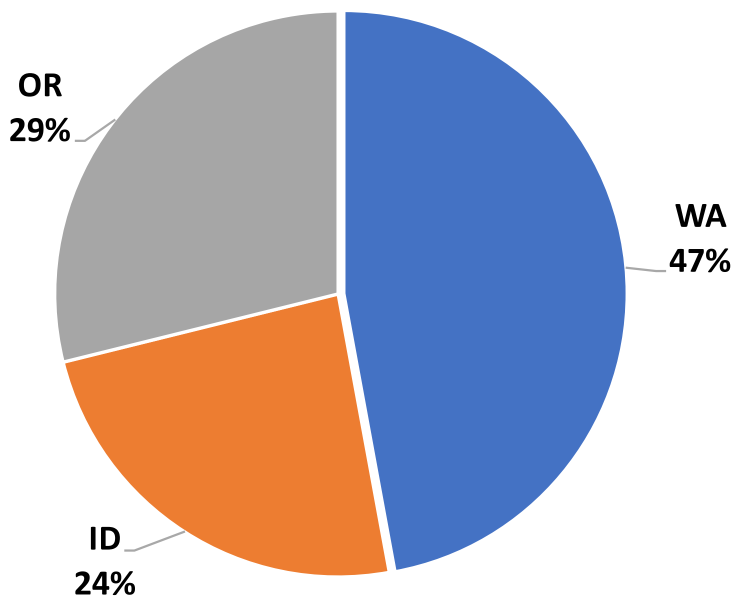


Long-Run Customer Forecast: Natural Gas

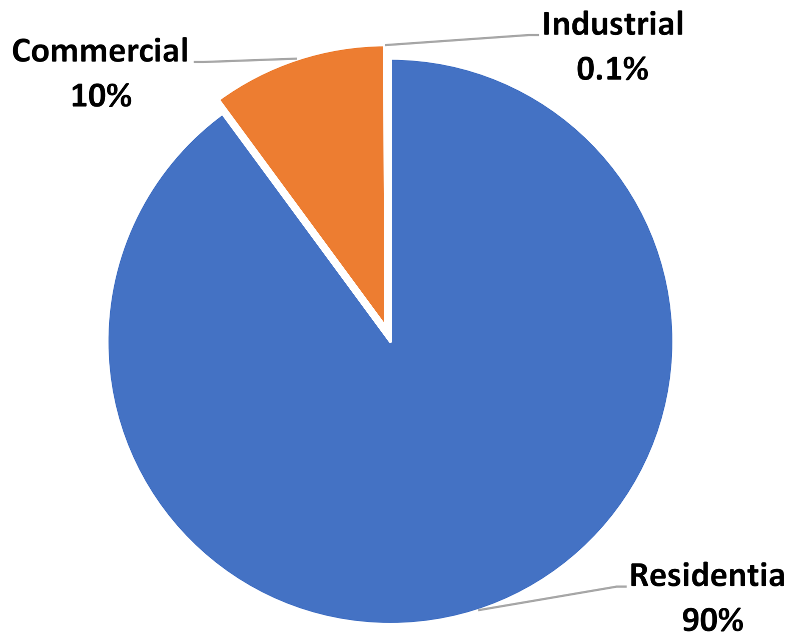
Grant D. Forsyth, Ph.D.
Chief Economist
Grant.Forsyth@avistacorp.com

Firm Customers (Meters) by State and Class, 2019

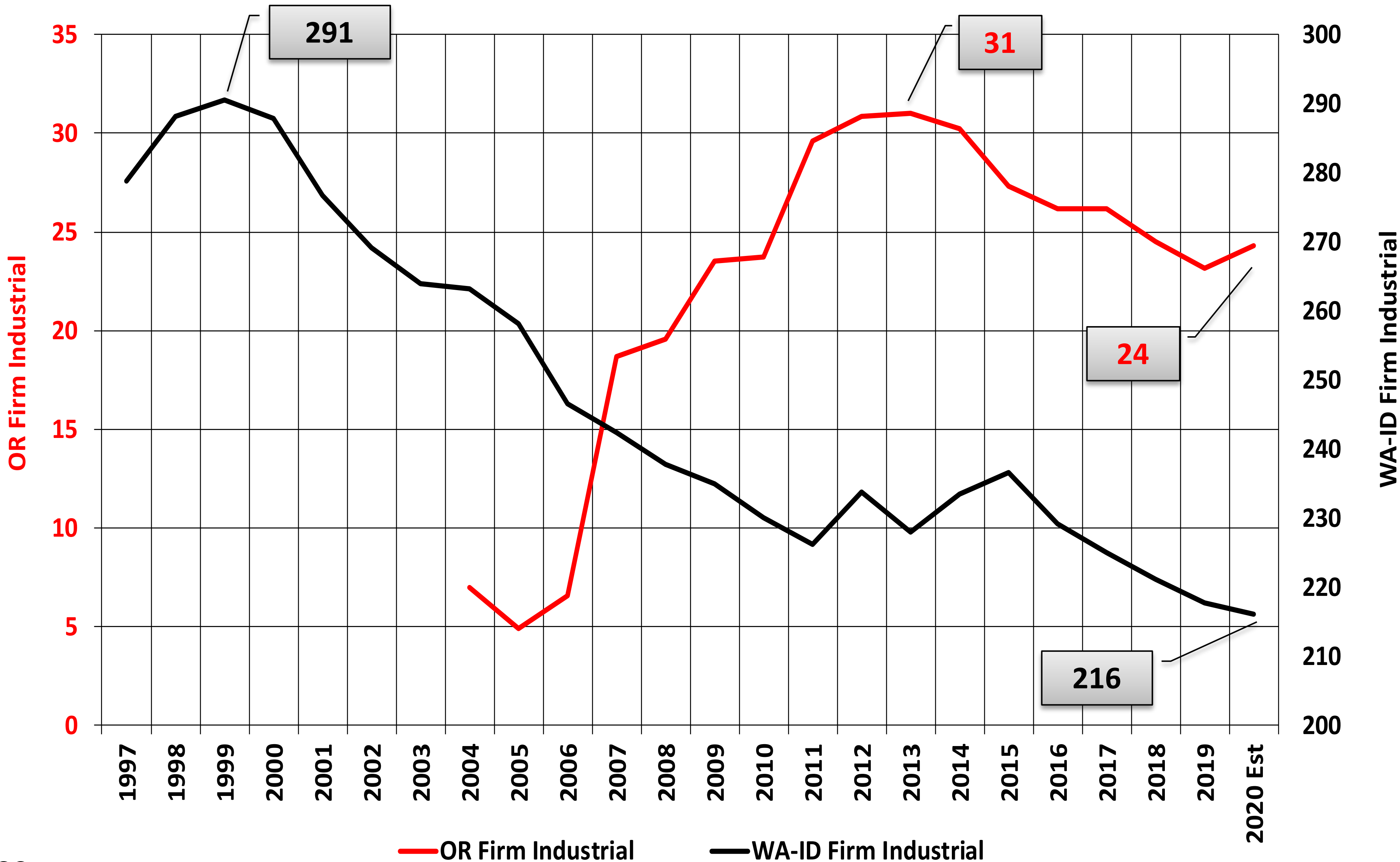
Firm Customers by State



Firm Customers by Class



System All Types of Industrial Customers, 1997-2020



Customer Forecast Models

- Forecast models are structured around each schedule, in each class, by jurisdiction. In the case of OR, this is done individually for each of Avista's service islands.
- Time series transfer function models (models with regressions drivers and ARIMA error terms).
- Simple time series smoothing models (for schedules with little customer variation).
- Same models used for the bi-annual revenue model forecast pushed out to 2045. The forecasts for this IRP were generated from the "Summer/Fall 2020" forecast completed in June.
- Customer forecasts are sent to Gas Supply for inclusion in the SENDOUT model.
- Example of transfer function model: WA sch. 101 residential customers…

Transfer Function Model Example

Monthly Customer (Meter Count)

Monthly Interpolated Population for Spokane MSA

Seasonal Dummies

$$C_{t,y,WA101.r} = \alpha_0 + \tau POP_{t,y,SPK} + \boldsymbol{\omega_{SD}}\ \boldsymbol{D_{t,y}} + \omega_{OL} D_{Oct\ 2015=1} + \omega_{OL} D_{Feb\ 2016=1} + \omega_{OL} D_{Mar\ 2018=1} + \omega_{OL} D_{Nov\ 2018=1} + ARIMA\epsilon_{t,y}\ (12,1,0)(0,0,0)_{12}$$

Outlier Dummies (Interventions)

Error Correction Component

Getting to Population as a Driver, 2020-2025 & 2026-2045

2020-2025 For Spokane, WA; Kootenai, ID, and Jackson+Josephine, OR

Average GDP Growth Forecasts:
- **WSJ, FOMC, Bloomberg, etc.**
- **Average forecasts out 5 full calendar years.**

GDP

Non-farm Employment Growth Model:
- **Model links year y, y-1, and y-2 GDP growth to year y regional employment growth.**
- **Forecast out 5 full calendar years.**
- **Averaged with IHS employment growth forecasts.**

Deviation in the most recent forecast!

EMP

Regional Population Growth Models:
- **Model links regional, U.S., and CA year y-1 employment growth to year y county population growth.**
- **Forecast out 5 full calendar years for Spokane, WA; Kootenai, ID; and Jackson+Josephine, OR.**
- **Averaged with IHS growth forecasts.**
- **Growth rates used to generate population forecasts for use in regression models—important driver for main residential and commercial schedules.**

Kootenai and Jackson: IHS population growth forecasts for 2026-2045

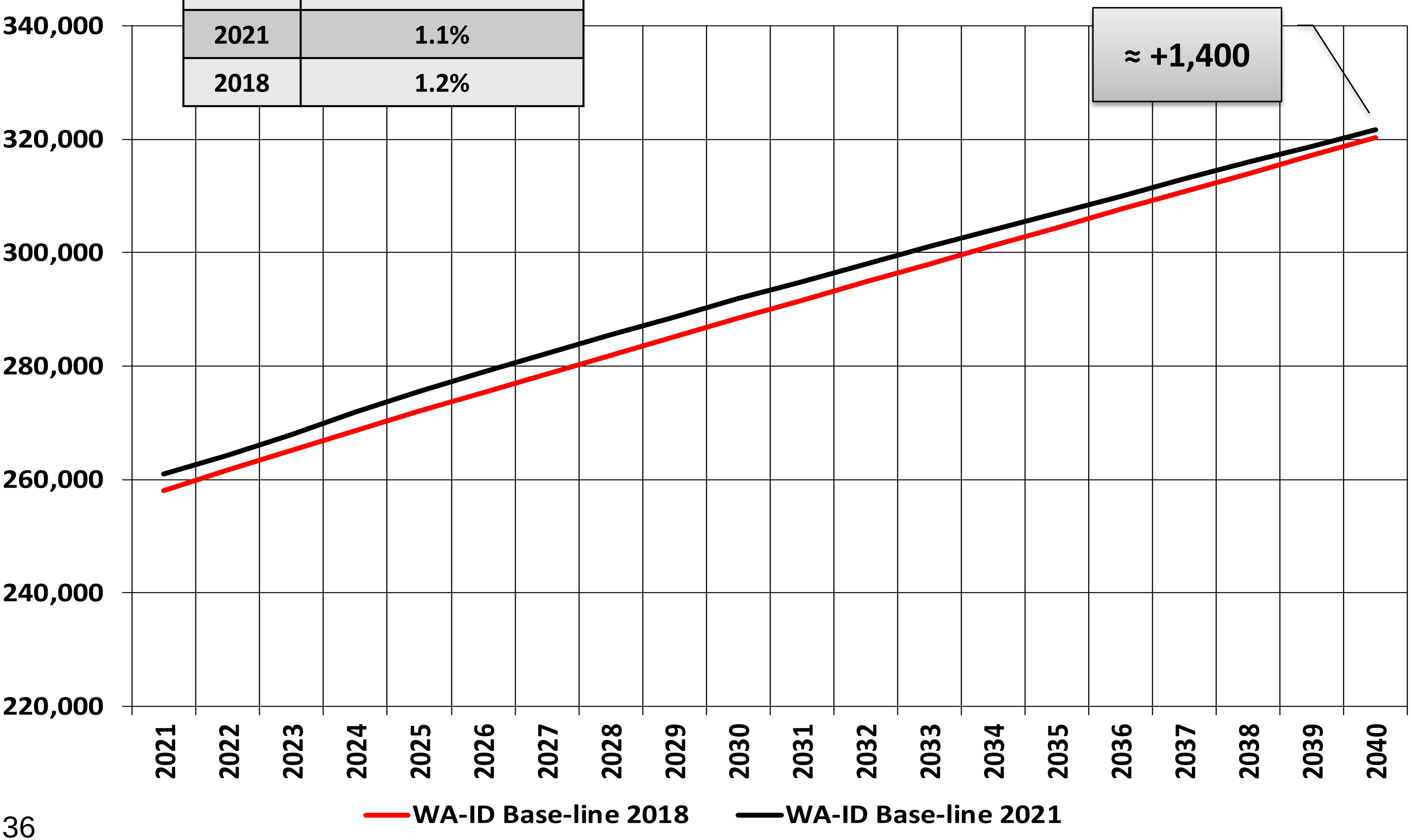
Spokane: OFM population growth forecasts for 2026-2045

OR Douglas, Klamath, and Union counties: IHS population growth forecasts for 2020-2045

Monlthly Interpolation assumes: $P_N = P_0 e^{rN}$

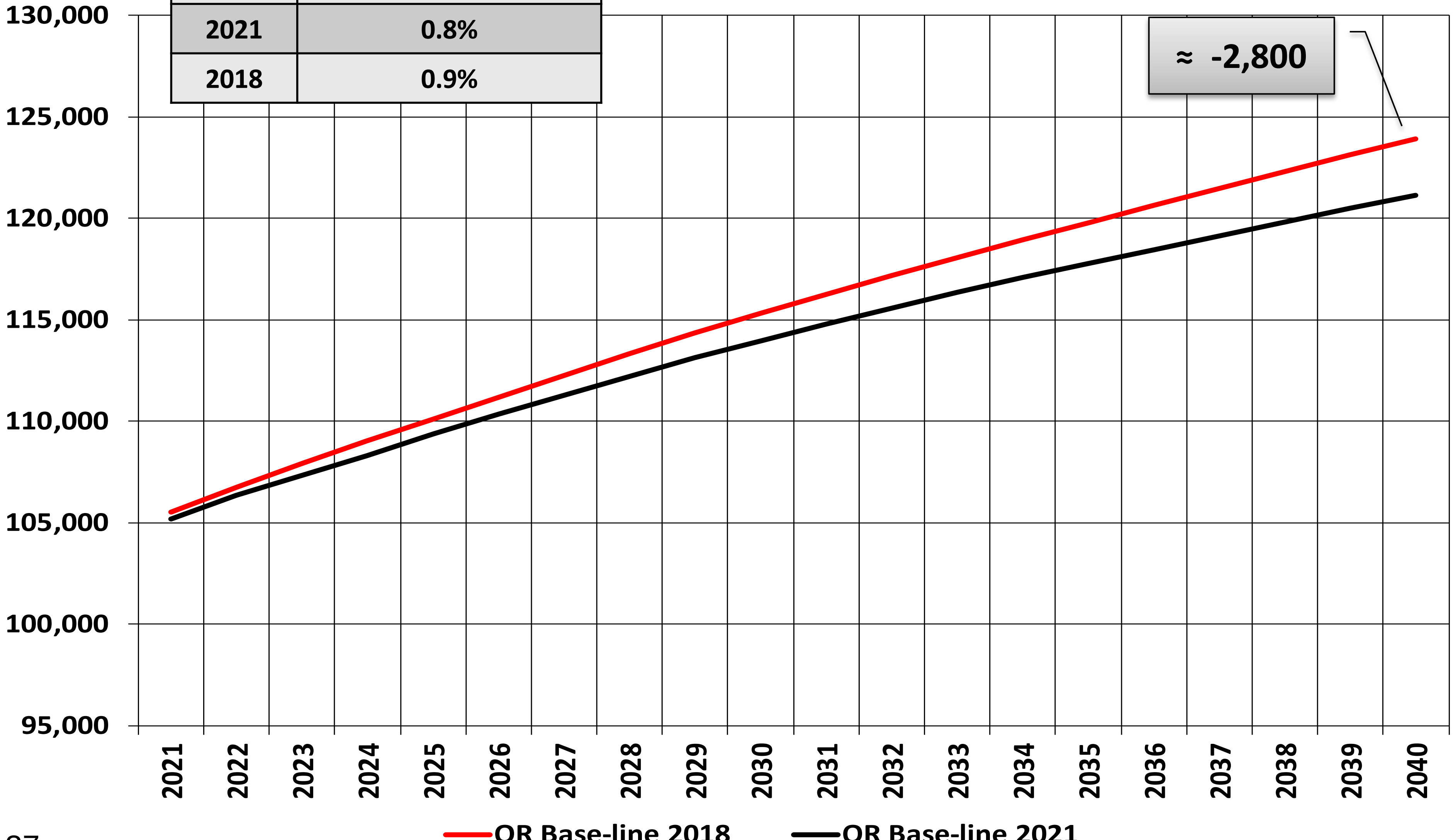
WA-ID Region Firm Customers, 2021-2040 (2018 IRP)

IRP	Avg. Annual Growth 2021-2040
2021	1.1%
2018	1.2%



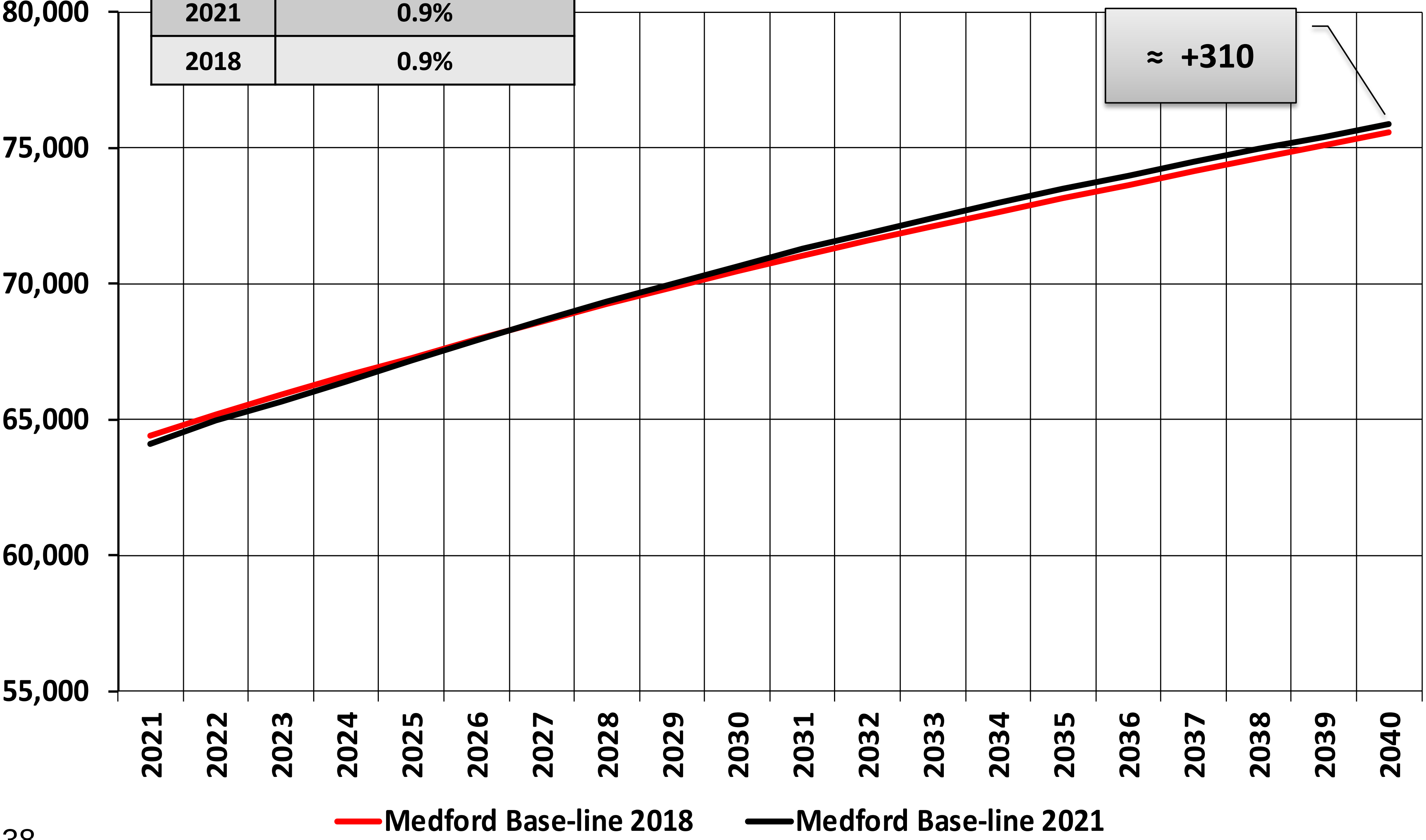
OR Region Firm Customers, 2021-2040 (2018 IRP)

IRP	Avg. Annual Growth 2021-2040
2021	0.8%
2018	0.9%

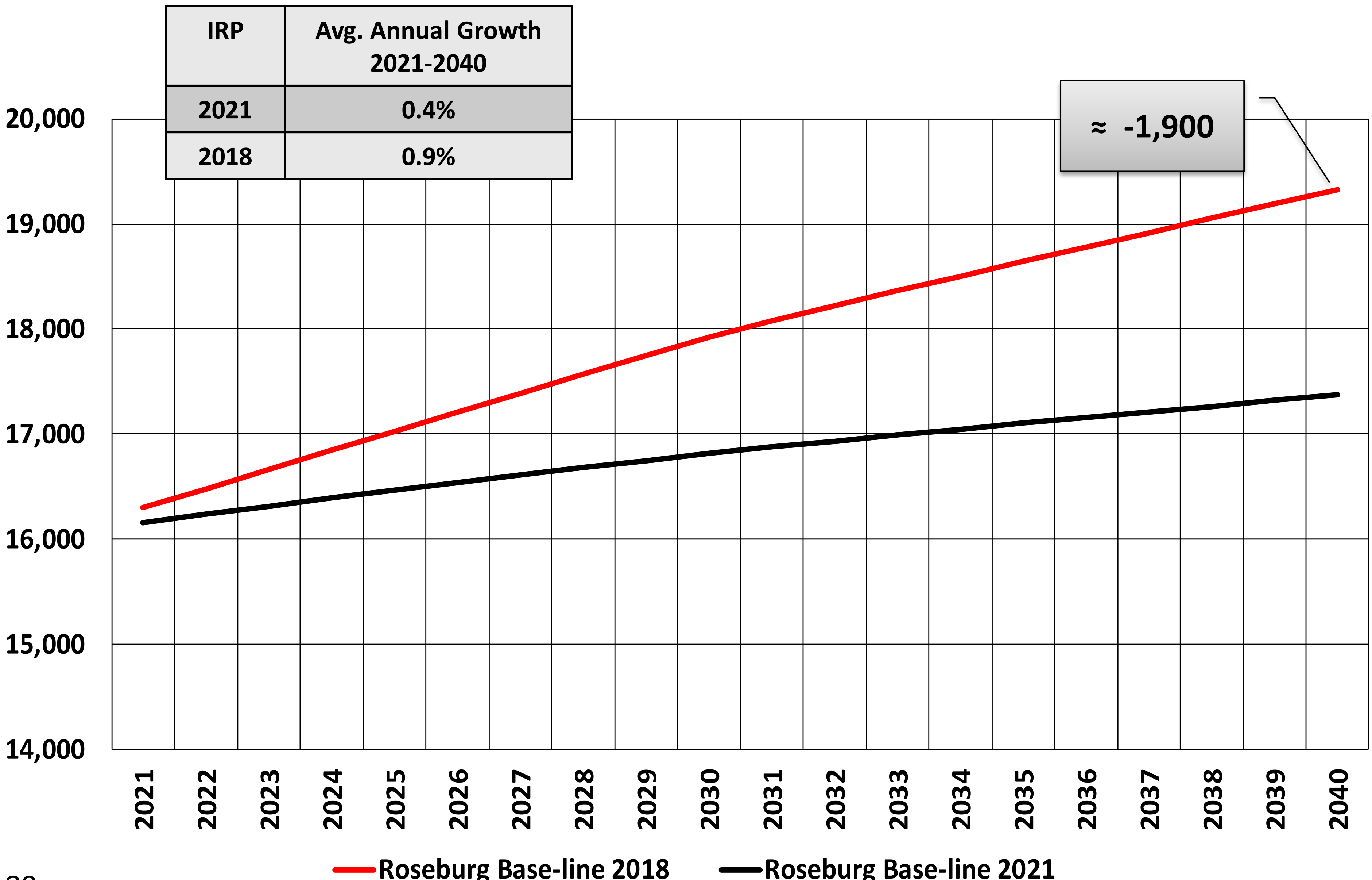


Medford, OR Region Firm Customers, 2021-2040 (2018 IRP)

IRP	Avg. Annual Growth 2021-2037
2021	0.9%
2018	0.9%

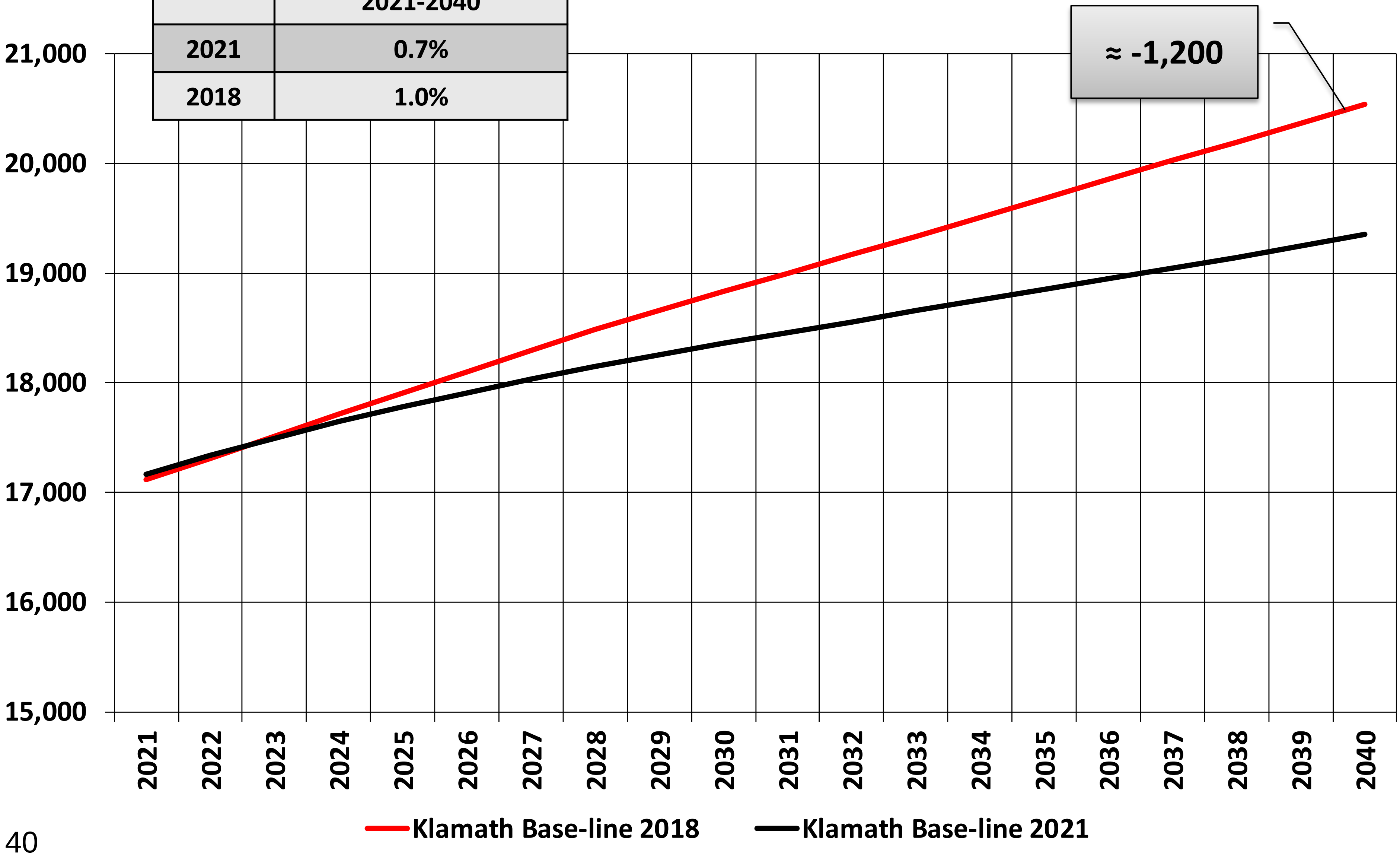


Roseburg, OR Region Firm Customers, 2021-2040 (2018 IRP)



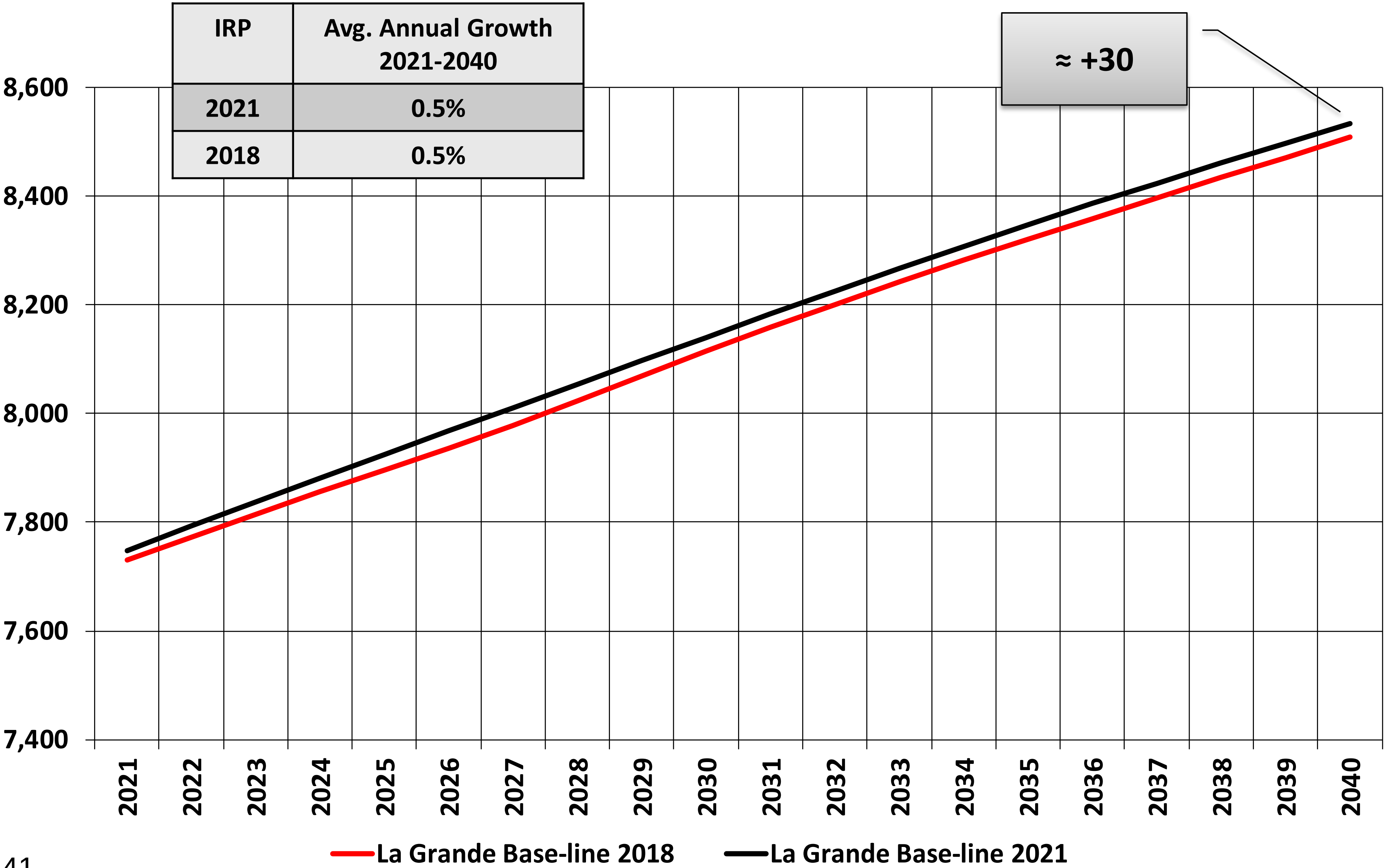
Klamath, OR Region Firm Customers, 2021-2040 (2018 IRP)

IRP	Avg. Annual Growth 2021-2040
2021	0.7%
2018	1.0%



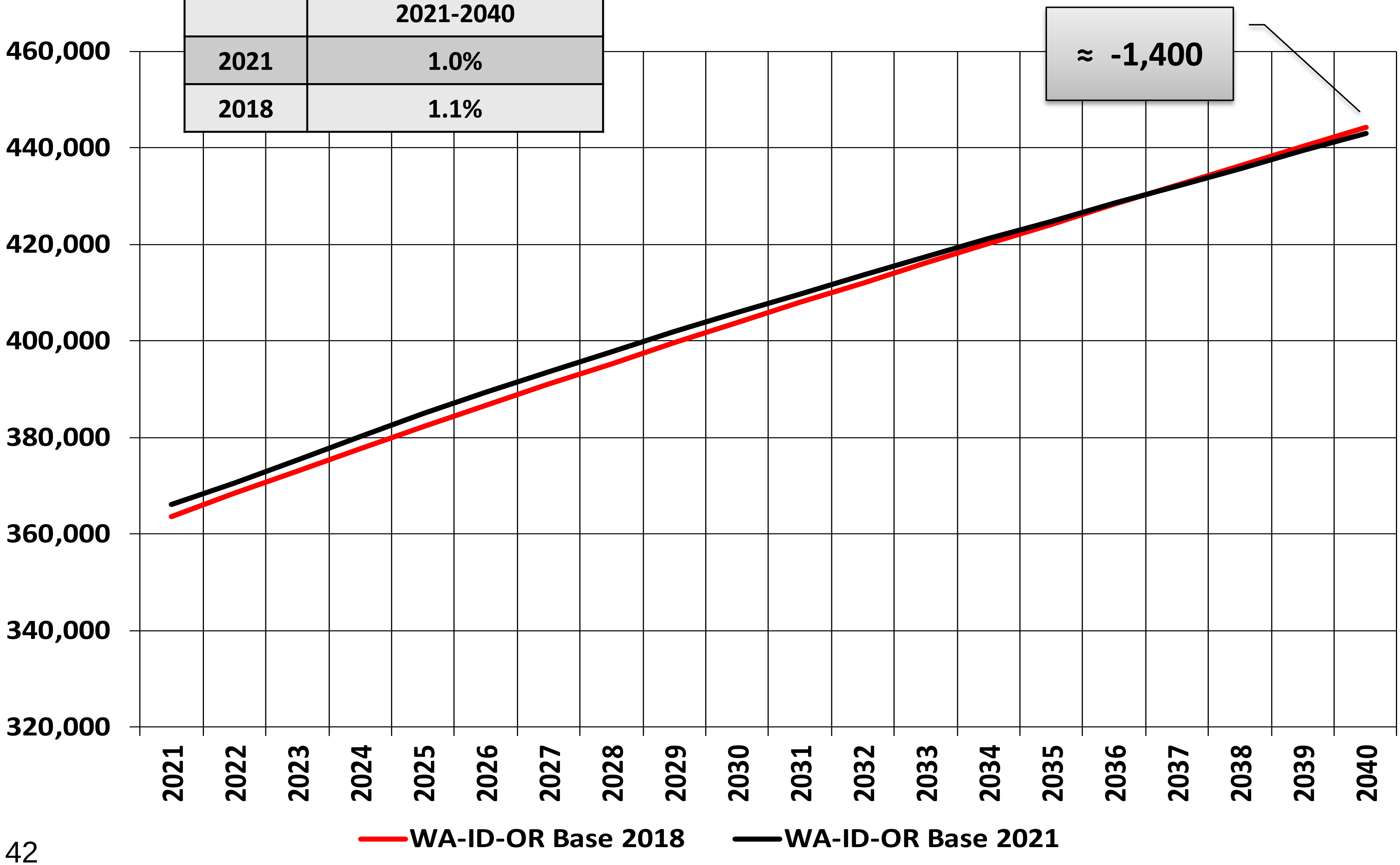
La Grande, OR Region Firm Customers, 2021-2040 (2018 IRP)

IRP	Avg. Annual Growth 2021-2040
2021	0.5%
2018	0.5%



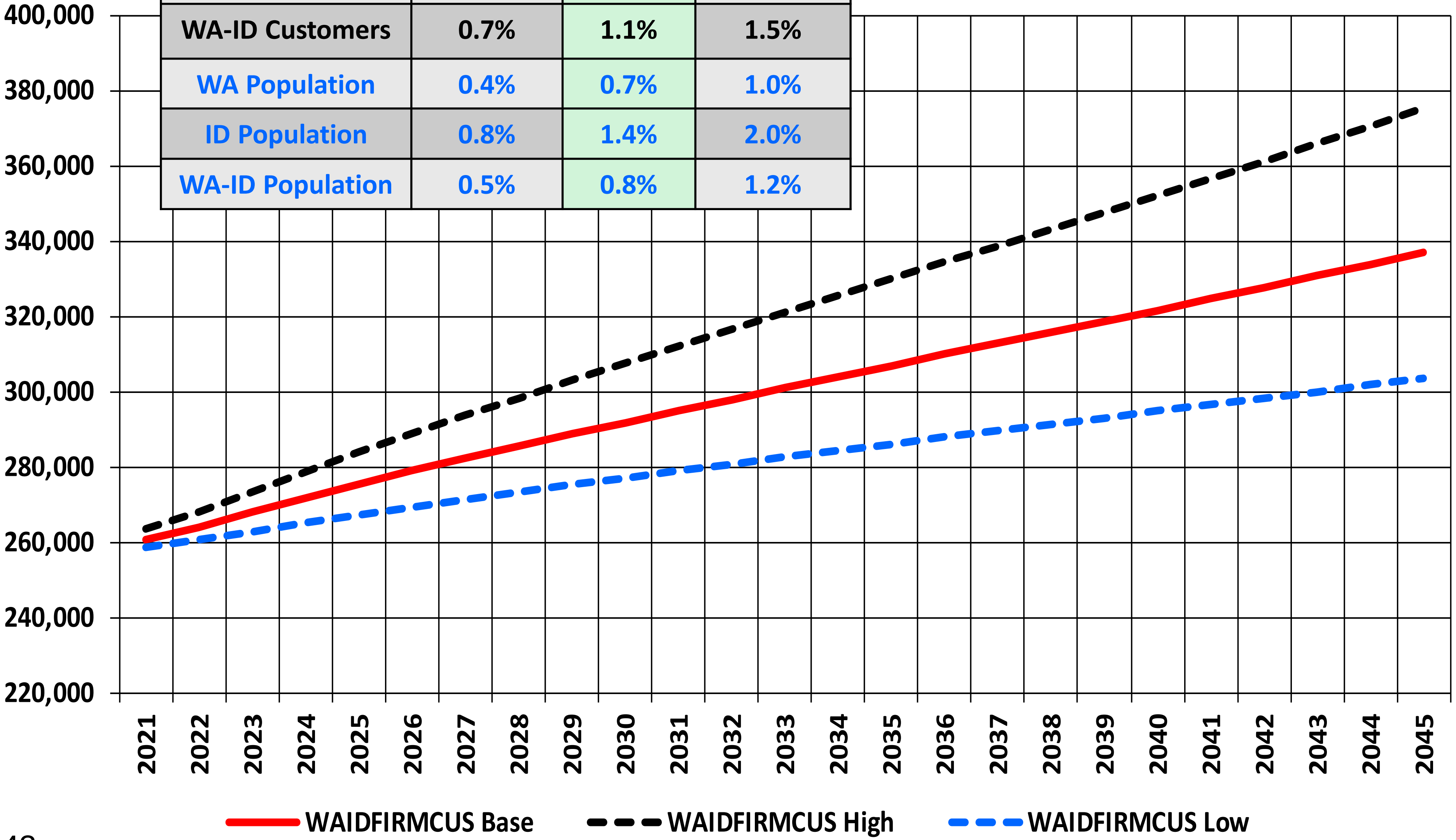
System Firm Customers, 2021-2040 (2018 IRP)

IRP	Avg. Annual Growth 2021-2040
2021	1.0%
2018	1.1%



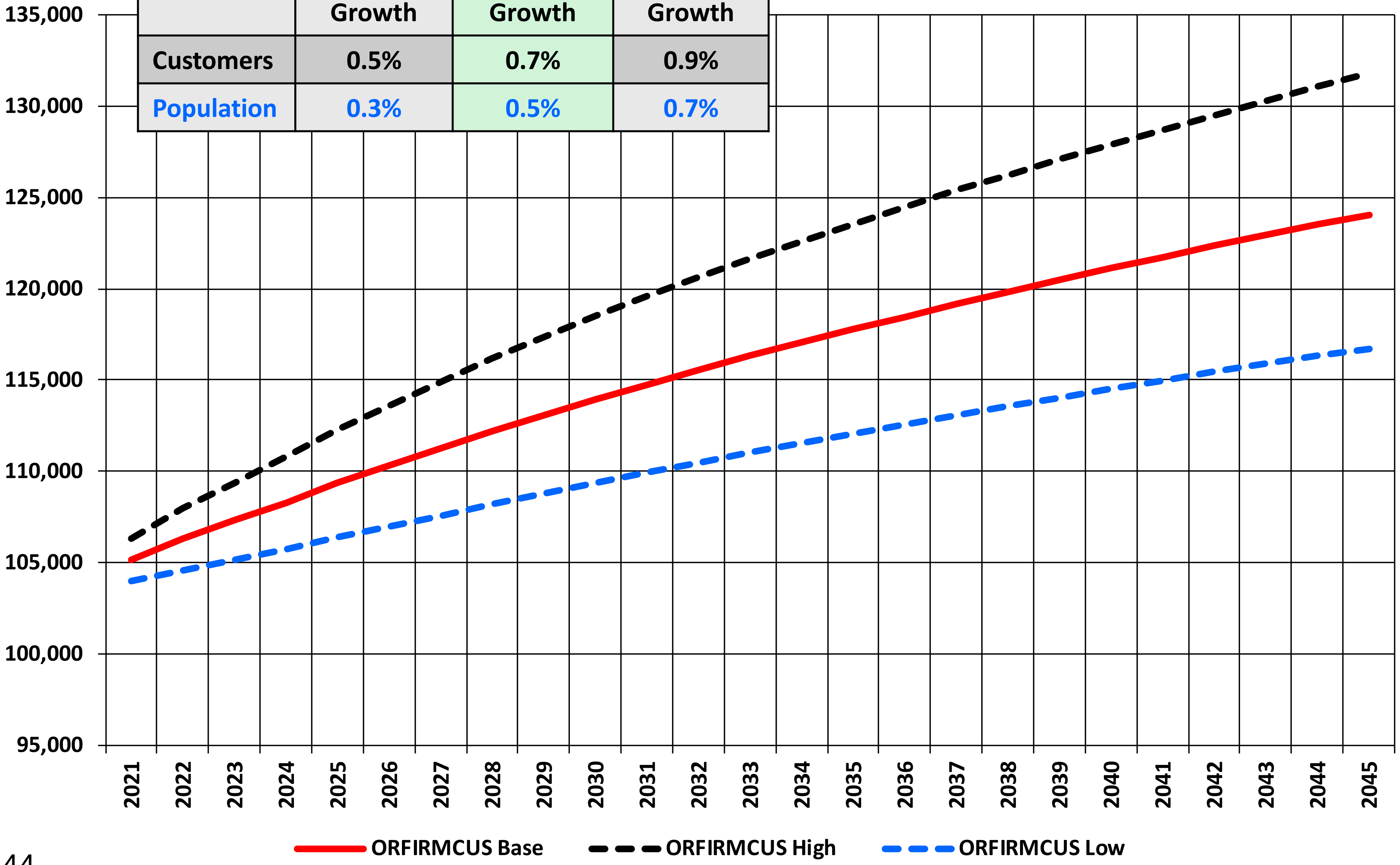
WA-ID Region Firm Customer Range, 2021-2045

Variable	Low Growth	Base Growth	High Growth
WA-ID Customers	0.7%	1.1%	1.5%
WA Population	0.4%	0.7%	1.0%
ID Population	0.8%	1.4%	2.0%
WA-ID Population	0.5%	0.8%	1.2%



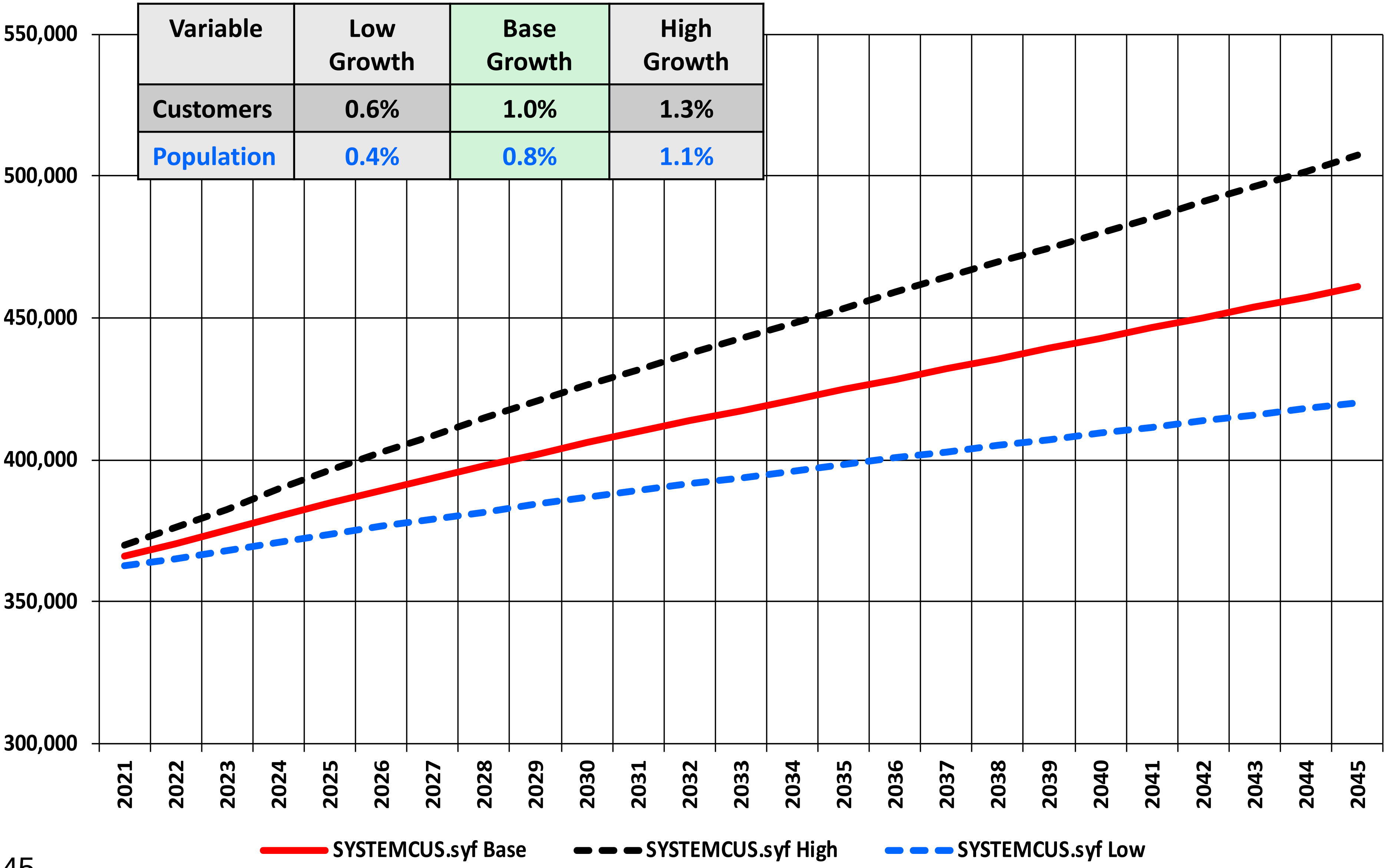
OR Region Firm Customer Range, 2021-2045

Variable	Low Growth	Base Growth	High Growth
Customers	0.5%	0.7%	0.9%
Population	0.3%	0.5%	0.7%



System Firm Customer Range, 2021-2045

Variable	Low Growth	Base Growth	High Growth
Customers	0.6%	1.0%	1.3%
Population	0.4%	0.8%	1.1%



Summary of Growth Rates

System	Base-Case	High	Low
Residential	1.0%	1.4%	0.7%
Commercial	0.5%	0.8%	0.1%
Industrial	-0.8%	2.2%	-3.8%
Total	1.0%	1.3%	0.6%
WA	Base-Case	High	Low
Residential	1.0%	1.3%	0.7%
Commercial	0.4%	0.7%	0.1%
Industrial	-0.8%	1.9%	-3.6%
Total	1.0%	1.3%	0.7%
ID	Base-Case	High	Low
Residential	1.4%	2.0%	0.8%
Commercial	0.4%	1.0%	-0.2%
Industrial	-1.0%	1.8%	-3.4%
Total	1.3%	1.9%	0.7%
OR	Base-Case	High	Low
Residential	0.7%	0.9%	0.5%
Commercial	0.6%	0.8%	0.4%
Industrial	0.0%	4.5%	-10.6%
Total	0.7%	0.9%	0.5%

AVISTA

TAC 2.5 Meeting, September 18, 2020

Virtual Meeting Attendees: Nikita Bankoti, Washington UTC; Ben Cartwright; John Chatburn, Idaho Energy Office; Corey Dahl, Washington Public Counsel; Ashton Davis; Daniel Hua, NPPC; Kevin Keyt, IPUC; State of Idaho; Katie Pegan, OEMR; Steve Johnson, Washington UTC; Charles Pegan; Dan Kirschner, NW Gas Association; Fred Huette, NWEC; Gina Saraswati; Kate Griffith, Washington UTC; Joni Bosh, NWEC; L Molander; Devin McGreal, Cascade Natural Gas; Michael Eldred, IPUC; Mike Morrison, IPUC; Morgan Brummund, Idaho Energy Office; Greg Nothstein, Washington Department of Commerce; Andrew Rector, Washington UTC; Richard Keller, IPUC; Ken Ross, Fortis; Sudeshna Pal, Oregon CUB; Ted Light; Terrence Browne, Avista; Vlad Gutman-Britten, Climate Solutions; Yao Yin, IPUC; Tom Pardee, Avista; Jody Morehouse, Avista; Jaime Majure, Avista; Paul Kimmell, Avista; Theophania Labay, Avista; John Lyons, Avista; Lori Hermanson, Avista; James Gall, Avista; Grant Forsyth, Avista; Ryan Finesilver, Avista; Michael Brutocao, Avista; Mike Tatko, Avista; Amanda Ghering, Avista; Clint Kalich, Avista; Shawn Bonfield, Avista; Marissa Warren, IPUC; two Unavailable; and four Guests

Replies in *italics* after questions are made by the presenter in the following notes.

<u>Economic Load and Customer Forecast (TAC 2.5)</u>

Grant Forsyth: MSA stands for metropolitan service areas. Includes Spokane, Coeur d'Alene, Lewiston/Clarkston, and Grants Pass in our service territory.

Grant Forsyth: [Slide 4]: Most or 2/3 is local government, and half or more of government employment is for education.

Grant Forsyth: 2008 slowing job opportunities. Population growth means more job opportunities. About 0.5% growth, 80-100% in-migration influencing load growth.

Steve Johnson: Now, generally speaking is there about a year lag between employment growth and population about a year later? *Yes, about that.*

Steve Johnson: Population drives service territory growth. Do we know why 2014 surged above the nation? *A little late in the process. Retirement demographic, jobs.* What does it correlate to GDP, higher or lower? *Multiple reasons. Employment is a primary driver. It has been an OK predictor in the past, but talk to people in real estate and a robust economy comes with job growth. Low housing costs bring equity refugees to the area after selling a house.* OK, thanks.

Steve Johnson: Is there a separate forecast for layoffs that local governments might do in the next 1.5 years and the rate of government job growth after that 1.5 year period? *No, it looks at total employment growth and the lagged by a year population growth.*

Grant Forsyth: Employment is also part of the GDP growth forecast based on an average of forecasts, at least over the medium term out to 2025. Big difference from

June 2019 to June 2020 with a 6 percent decline in GDP, expect 4 percent growth next year and then back down to 2 percent growth after 2022.

Andrew Rector: Do you run sensitivities on the growth rates? *Yes, did run sensitivities on this lately because of the COVID crisis with different types of recessions. The most sensitive is the industrial side. Slowed employment growth slows customer growth for two years after the recession, but clearly the most sensitive is industrial. Does that answer your question?* Yes, it does.

Grant Forsyth: Last year, I was asked to look at load if there was a recession every six years. Found that we get to the same place, but more volatility builds more noise into the model.

James Gall: There will be a high and a low load growth scenario. Not sure if we have it later, but we can add it to the slide deck later.

Steve Johnson: There are various GDP underlying assumptions of how COVID plays out. In regards to GDP estimates you used, do you know what the underlying assumption was related to COVID and how that plays out?

Grant Forsyth: In some forecasts you can observe the underlying assumptions and some you cannot. Some were predicting various things about COVID. Some were V shaped, some square root, and others W shaped. But averaged together you get the red line on Slide 7.

Steve Johnson: Does the company have an idea of how they think it'll play out from the scientists and economists?

Grant Forsyth: I'm allowed some discretion with that, but I tend to stick with a forecast procedure that the Commissions are aware of and familiar with. I did not use a lot of discretion using epidemiological sources. That is something I thought I'd never be asked looking back on forecasts.

Steve Johnson: Is it the company's forecast looking at the scientific community's look at a second wave? Do you think that is realistic? Does the Company agree a second wave is sound scientific reasoning?

Grant Forsyth: When this was first going on people like me stopped forecasting early in COVID. Even the Fed [U.S. Federal Reserve] stopped providing guidance. Started to look at economists forecasting with epidemiologist input for one, two or three waves, but it didn't provide that much guidance that largely impact the forecast. The NEBR [National Bureau of Economic Research] looked at how the Spanish Flu [in 1918].

Slide #9: Medium term of 2020 – 2025 is what we used in the revenue and earnings model in June 2020. 20-year moving average of weather (2000-2019) that gets updated every year.

Andrew Rector: When you say price do you mean price of electricity? *Yes, own price of electricity. Typically all-in annual prices – all revenues divided by usage for that schedule)*

Nikita Bankoti (Slide #9): Is GDP based on growth assumptions weighted a lot from 2020-2025?

Grant Forsyth: Good question. Typically what I'll do is to not increase uncertainty in the short run GDP for that period. I don't necessarily increase the uncertainty from that period.

Nikita Bankoti: I'm trying to understand if you assign an equal weight to GDP?

Grant Forsyth: Essentially a consensus as GDP filters through but no weighting. Washington State weights their revenue model. I use a single GDP treated as a consensus and drive that through the model. I don't have any weightings like the state does.

Nikita Bankoti: OK, that makes sense.

Mike Morrison: Multiplying customers by UPC isn't difficult, mathematically. Why did you use an approximation at all?

Grant Forsyth: I'm making sure everyone understands since not everyone does this kind of work, so I start from the beginning and build up from there. There two component parts you need to worry about to determine what's driving load. Customer growth and use per customer growth are the main things.

Andrew Rector: Can you say again? Overall the 0.8% is the same as the 2020 forecast, but shaped differently, is that what you're saying?

Grant Forsyth: Yes. Taking it a step further, long term population growth is about 0.8% on average. The U.S. is about 0.5% growth, so there is embedded in the forecast a certain amount of in-migration for our service area.

Mike Morrison: Red line, increases and then precipitous drop in 2026 – what's the drop coming from?

Grant Forsyth: Long-term forecasts. That drop reflects what the third-party forecaster are thinking will happen. Really the IHS forecast that can change from IRP to IRP based on their own modeling processes. The OFM forecast is more stable because they don't update as often as IHS.

Steve Johnson (slide #12): Is this acceleration in Washington state and related to incentives and programs?

Grant Forsyth: Washington probably dominates; if you look at customers who have solar, it's weighted to Washington. It is an assumption that we update as we get more information. The cost has come down a lot on solar and that encourages more solar adoption. Also technological changes – roofs that look like shingles, but it's actually solar.

Steve Johnson: Are you modeling commercially available?

Grant Forsyth: Some are available and some are in testing, but when looking out over time, assuming solar will accumulate at a rapid pace. It is an assumption. There is another slide coming up that talks about this in more detail.

Yao Yin: Why isn't residential solar considered from demand side versus supply side?

James Gall: Currently the customer controls that solar device and when it's producing. It belongs as a load component. In the event the utility offers incentives to change how they operate, that'd be a demand-side resource, but it could translate into a supply side resource.

Yao Yin: For other types of solar such as QF, do they belong to supply side? *Yes.*

Andrew Rector (Slide #12): What are your data sources for solar?

Grant Forsyth: Our own internal data from engineers that they collect. There is very little non-solar net metering on our system anymore. The data includes customer location and system size.

Nikita Bankoti (Slide #11): Again there is a lot of residential customer growth variation in 2021-2023, variation in GDP forecast, is it a good idea for this variability to be factored into the long-term forecast?

Grant Forsyth: I would need to think about this. Typically what happens with the medium term forecast, it is currently set up to mesh with the medium term forecast for the revenue model. The Company typically needs a medium term forecast to put into the revenue model. One of the frustrations with forecasters is how to handle this current COVID situation since it is atypical.

Steve Johnson: 10,000 watts in 2044. So that is a capacity factor of 15% on peak or on average? *On average, energy side rather than peak, approximately 10 aMW. It is on a spreadsheet.* I don't need precision just a general sense. Are you modeling solar to drop off before you get to your peak at 6 pm?

Grant Forsyth: It varies back and forth between 7 and 8 am to 5 to 6 pm where you see the most peaks occur.

Steve Johnson: Is solar making a small impact on peak? *Yes.*

James Gall: On winter, solar is making virtually no impact on peak, but maybe some peak shifting. In the summer, solar will reduce peak by about 60%. Subject to check, I think it is about 14% capacity factor on rooftop solar (DC rating not AC rating)

Fred Heutte: What method are you using? Are you using a simple logistic regression curve?

Grant Forsyth: It assumes an exponential growth function out to 2045. At some time we expect it to become logarithmic or some other type of term. It won't go on forever at this growth rate since we're just getting started.

Fred Heutte: Are you taking into consideration technology and cost reductions?

Grant Forsyth: That's why I'm assuming the size of growth due to technology developments and cost reductions. Allowing the size to grow and as they develop more solar, more ways to apply it.

Fred Heutte: I'm thinking about the experience curve. Can't project current trends to the longer term. Panel costs are not the majority of the costs now. Moved to telesales to drop costs. May drive the market more going forward.

Grant Forsyth: Two big uncertainties to model the longer term – solar and EVs.

Fred Heutte: We are encouraging utilities to look at higher EV penetration scenarios.

Grant Forsyth: We do have EV charging shape built into our future forecast.

Fred Heutte: How do you do rate design so we don't get a big hit?

Grant Forsyth: Where is policy going because that will shape a bunch of factors? Currently difficult to get a sense of where that's going.

James Gall: Commercial EVs?

Grant Forsyth: Residential EVs are highly correlated to growth in the commercial side. They follow each other. Implicit assumption that as EV are accumulated on the residential side, they'll accumulate on the commercial side.

Andrew Rector: Does it take into account EVs yet like buses? *No, it does not.*

Yao Yin: Is there a similar assumption between residential and commercial solar?

Grant Forsyth: Yes, but solar is still weighted heavily to the residential side, but I'm trying to maintain the correlation over time.

James Gall: Actually forecasting monthly, not hourly. We layer that into our models and will talk at a future TAC about how we are doing that.

Slide #15: At what point EV load starts to negate of solar? *The black dotted line. It bends up about 2040. When it does occur, it has a significant effect on load behavior.*

Mike Morrison: I don't think aMW is a useful metric in planning what we care about. I'm not sure of the relevance of aMW since capacity will occur over a couple of hours as opposed to over 24 hours. It shows magnitude.

James Gall: This is only the first slide. Coincident peak slide is coming up. Energy does matter – we look at peak and energy to meet both needs.

Yao Yin: For solar, we assume about 14% capacity factor, for EVs do we assume a certain percentage for solar?

James Gall: Yes, it's built into Grant's model, but I can't recall the exact factor. We look at the capability of a charge and the kilowatt per hour. We don't typically look at it that way so I don't have a factor right off.

Yao Yin: Do we assume certain hours EVs will get charged?

Grant Forsyth: Yes the profile tries to take that into effect.

Yao Yin: For the load forecast does this start monthly and peak hourly?

Grant Forsyth: Monthly and peak comes from Rendall's load profiles. Starts with hourly, converted to monthly. I may be misunderstanding your question.

Yao Yin: If we start with annual why do we convert to monthly?

Grant Forsyth: We are using monthly data to do peak load forecast so we have to convert it to monthly.

James Gall: For the IRP, we do use the monthly peak and energy in order to get to hourly. We look at winter/summer peak, annual energy.

Yao Yin: Another question regarding EVs, solar assumes about 14%, so do we have to assume a capacity factor for charging?

James Gall: There is a battery draw built into the model. 3,000 to 5,000 kWh per year depending on mileage. Great question.

Grant Forsyth: Assuming about 3,500 kWh per year from Rendall Farley's EV analysis submitted to the WUTC.

Yao Yin: Do you assume specific charging hours? *Yes, it's built into the load forecast and taken into account.*

Andrew Rector: Just for context, I have your EV plan in front of me with 3,153 kWh per year. *Sounds approximately right with what I entered.*

Vlad Gutman-Britten: What period of time is the trend your green line is using? *The whole time period.*

Mike Morrison: Is that a trend on individual years or 20-year moving average? Is that legal with a time series?

Grant Forsyth: I don't know if that's legal. I could try that. If I recall correctly, time series on a time series. It is heavily smoothed, but it's not being done nefariously. Can try it the other way certainly do it on the raw data.

Mike Morrison (Slide #17): So you got an increase of about 20% in cooling degree days, so people are going to buy more ACs with up to over 700 cooling degree days?

Grant Forsyth: This is my initial look, probably big implications for peak load; haven't done analysis for how I'd apply this to peak load. Additional adjustments will be needed. Multiple effects – income increasing, AC costs declining – leads to more purchase of ACs.

Fred Heutte: I had a little trouble on audio or dial in. On slide #18, double check of additive of slightly higher cooling degree days and quite a bit lower heating degree days. *Yes, that is the net effect through the regression model.* Agree with the approach of a 20-year moving average. Need at least 10 years and more is better. We can't go back too far or we lose the signal. Inter-year variability is very large. This seems to be in the right direction.

Grant Forsyth: Finally have analytically figured out how to shape that monthly. I appreciate the comments from everybody.

Mike Morrison: As far as conservation, I believe you go those numbers from your energy efficiency folks. We actually disagree with a lot of the numbers you got out of your energy efficiency group. The IPUC has asked Avista's conservation group to revisit their energy savings because IPUC disagrees with their estimates – very much over reporting.

Grant Forsyth: Fair enough. The information provided to me is what I have to work with.

Mike Morrison: Not criticizing you, but the information is dubious. There is very much over reporting in what energy efficiency has been doing.

James Gall: When we do capacity expansion modeling, we need an estimate of what our load looks like with our conservation. DSM programs compete against other resources. Based on what's picked (conservation) we adjust the black line up or down (slide 22).

Mike Morrison: Forecast based on average is that what we should be looking at.

Grant Forsyth: We do provide a band.

Mike Morrison: Are you really going to continue to be a winter peaking utility? I'm concerned with how you're doing your conservation programs (fuel switching).

Grant Forsyth: Yes, the conflict we face is the climate is changing, but the empirical data shows that winter is still the peak period. Summer is moving up and we need to be looking at an upper band.

James Gall: Grant is showing the average cold or hot day. In LOLP analysis, we simulate those bands. We typically see a winder band in the winter and typically a tighter band in the summer. This is used for loss of load based on probability of those ranges; what is the probability of one of these peaks aligning with an outage as such.

Substantial amount of fuel-switching from electric to natural gas. That peak is now removed. Both winter and summer are accounted for and optimized for.

Fred Heutte (slide 29): I have a comment about slide 25, but stay here. By eyeball it looks summer, but still winter mathematically. LOLP makes most sense, most important especially late summer – mid-July to mid-September.

Deborah Reynolds: As we're thinking about how energy efficiency will be incorporated into the load forecast, I've been thinking about taking the whole house efficiency and how that will affect summer load. Weatherization affects both summer and winter. Be thinking about how programs change over time. *Ok, will do that.*

Yao Yin: Winter and summer peak, have considered residential solar and EV conservation?

Grant Forsyth: Solar is not as direct and is embedded only to the extent it's in the historical data. EV effects are more direct. Solar does not have the same impacts on peak as EVs.

James Gall: We look at a peak credit to see how much it shaves peak. It was 2% in the last plan.

Nikita Bankoti: Do you include gas transportation customers?

Grant Forsyth: Yes, I do a forecast for transportation but not for the IRP because we're looking at core load.

Tom Pardee (slide 32): Transportation customers are tasked with getting their own transportation whereas we're responsible for the firm gas customers.

Andrew Rector: Is it economic things driving IHS's economic forecast in Roseburg?

Grant Forsyth: Yes, demographics. The only thing causing population growth is in-migration or else it would be negative. I think they're suggesting that in-migration is restrained. Natural birth rate is zero or negative there and only growth is from in-migration which they think will be lower than usual. It was revised down before the shutdown.

Andrew Rector: Interesting context. Thanks.

Nikita Bankoti (slide 46): Negative industrial growth, is that from COVID?

Grant Forsyth: No that's from a longer-term secular trend. This was in last IRP too. It seems to be more of an acute problem in Washington than Idaho. Industrial companies are exiting or relocating more heavily weighted towards Washington. Sneaking suspicion that customers are going out of business or moving locations. Goes through Actual May 2020 numbers but there could be some longer-term impacts from COVID that may not appear for up to 24 months.

James Gall: What has the gas side seen from COVID?

Grant Forsyth: I'd say gas data weathered better than east side out of heating. Transportation customers being mostly industrial are a pretty good indicator of the economy. Wood products firms, lumber, have done better with housing. Gas line explosion caused some problem with switching from transport to firm schedules. The Air Force Base and Idaho continue to be a surprise in terms of robust growth.

Deborah Reynolds: One last question. Have you looked at how robust transportation conservation programs might impact gas transportation load and how much flexibility there is in terms of the rate they pay?

Grant Forsyth: That's a whopper. Many years ago, we had this conversation in Oregon, at the time with the low gas costs, it didn't make economic sense.

Tom Pardee: We can have Terrance speak about this on distribution if they are firm. If on transportation, we can cut them. We'll have an answer at the next TAC.

Deborah Reynolds: Legislation passed that you have to get ALL and that might include transportation customers.

Shawn Bonfield: They don't pay into the tariff.

Deborah Reynolds: I agree which is why I need you guys to do some work.

2021 Electric Integrated Resource Plan
Technical Advisory Committee Meeting No. 3 Agenda
Tuesday, September 29, 2020
Virtual Meeting

Topic	Time	Staff
Introductions	9:00	Lyons
IRP Transmission Planning Studies	9:15	Spratt
Break	10:15	
Distribution Planning within the IRP	10:30	Fisher
Lunch	11:30	
Demand Response Potential Assessment	12:30	AEG
Break	1:30	
Conservation Potential Assessment	1:45	AEG
Electric Market Forecasts	2:45	Gall
Portfolio Scenarios	3:30	Lyons
Adjourn	4:00	

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2021 Electric IRP
TAC Introductions and IRP Process Updates

John Lyons, Ph.D.
Third Technical Advisory Committee Meeting
September 29, 2020

Updated Meeting Guidelines

- Electric IRP team still working remotely, available by email and phone for questions and comments
- Some processes are taking longer remotely
- Virtual IRP meetings until back in the office and able to hold large group meetings
- Joint Avista IRP page for gas and electric: https://www.myavista.com/about-us/integrated-resource-planning

Virtual TAC Meeting Reminders

- Please mute mics unless speaking or asking a question
- Use the Skype chat box to write questions or comments or let us know you would like to say something
- Respect the pause
- Please try not to speak over the presenter or a speaker who is voicing a question or thought
- Remember to state your name before speaking for the note taker
- This is a public advisory meeting – presentations and comments will be recorded and documented

Integrated Resource Planning

- Required by Idaho and Washington* every other year
- Guides resource strategy over the next twenty + years
- Current and projected load & resource position
- Resource strategies under different future policies
  - Resource choices
  - Conservation measures and programs
  - Transmission and distribution integration for electric
  - Gas distribution planning
  - Gas and electric market price forecasts
- Scenarios for uncertain future events and issues
- Key dates for modeling and IRP development are available in the Work Plans

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 involved in all or parts of the process
  - Ask questions
  - Help with soliciting new members
- 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 number or type of studies
  - Earlier study requests allow us to be more accommodating
  - **August 1, 2020** was the electric study request deadline
- Planning teams are available by email or phone for questions or comments between the TAC meetings

2021 Electric IRP TAC Schedule

- TAC 1: Thursday, June 18, 2020
- TAC 2: Thursday, August 6, 2020 (Joint with Natural Gas TAC)
- TAC 2.5: Tuesday, August 18, 2020 Economic and Load Forecast
- **TAC 3: Tuesday, September 29, 2020**
- TAC 4: Tuesday, November 17, 2020
- TAC 5: Thursday, January 21, 2021
- Public Outreach Meeting: February 2021
- TAC agendas, presentations, meeting minutes and IRP files available at:

  https://myavista.com/about-us/integrated-resource-planning

Process Updates

IRP data available on the web site:

- Avista Resource Emissions Summary
- Load Forecast
- CPA Measures
- Avista 2020 Electric CPA – Summary and IRP Inputs
- Home Electrification Conversions
- Named Populations
- Natural Gas Prices
- Social Cost of Carbon

Today’s TAC Agenda

9:00	Introductions, Lyons
9:15	IRP Transmission Planning Studies, Spratt
10:15	Break
10:30	Distribution Planning within the IRP, Fisher
11:30	Lunch
12:30	Demand Response Potential Assessment, AEG
1:30	Break
1:45	Conservation Potential Assessment, AEG
2:45	Electric Market Forecasts, Gall
3:30	Portfolio Scenarios, Lyons
4:00	Adjourn

Integrated Resource Plan (IRP) Transmission Planning Studies

Dean Spratt, Transmission Planning

Third Technical Advisory Committee Meeting

September 29, 2020

FERC Standards of Conduct

Non-public transmission information can not be shared with Avista Merchant Function employees

There are Avista Merchant Function employees attending today

We will not be sharing any non-public transmission information. Avista's OASIS is where this information is made public

Agenda

- Introduction to Avista System Planning
  - Useful information about Transmission Planning
  - Recent Avista projects

- Generation Interconnection Study Process
  - Integrated Resource Plan (IRP) Requests
  - Large Generation Interconnection Queue

Introduction to Avista System Planning

Avista's System Planning Group includes:

- Asset Performance and Management
- Distribution Planning
- Transmission Planning
  - Focus on reliable electric service
    - Federal, regional, and state compliance
    - Regional system coordination
  - Provide transmission service and system analysis
    - Planned load growth and changing generation dispatch
    - Interconnection of any type of generation or load
      - We are ambivalent about type (must perform though)

Information About Transmission Planning

- We care about the Bulk Electric System (BES)
  - Our 115 kV and 230 kV facilities (>100 kV)
- We identify issues where the Avista BES won't reliably deliver power to our customers
- Then put together plans to fix it
  - "Corrective Action Plans"
  - Mandated and described in NERC TPL-001-4
- We live in the world of NERC Mandatory Standards
  - Energy Policy Act of 2005

TPL-001-4

- Describes outage conditions we must study
  - P0: everything online and working
  - P1: single facility outages, like a transformer
  - P2, P4, P5 & P7: multiple facility outages
  - P3 & P6: overlapping combination of two facilities

Standard TPL-001-4 — Transmission System Planning Performance Requirements

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.
b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
d. Simulate Normal Clearing unless otherwise specified.
e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.
g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.
h. Planning event P0 is applicable to steady state only.
i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

Standard TPL-001-4 — Transmission System Planning Performance Requirements

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]
		5. Single pole of a DC line	SLG		
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]
				HV	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]
				HV	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes

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TPL-001-4, cont.

- A couple of NERC directives for the above faults
  - “The System shall remain stable”
    - Cascading and uncontrolled islanding shall not occur
  - “Applicable Facility Ratings shall not be exceeded”
    - Equipment ratings, voltage, fault duty, etc
  - “An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events”

Two Approaches to Reliability Issues

- Transmission Operations (TO) are guided by *significantly* different standards than Transmission Planning (TP).
- TO standards provide *flexibility* that TP standards do not allow
  - Operators can push system limits to ***SAVE*** the interconnected system
    - Shed load, overload equipment, etc – all short term
    - The planned system should give them the tools to do this
    - Standards continue to define this balance

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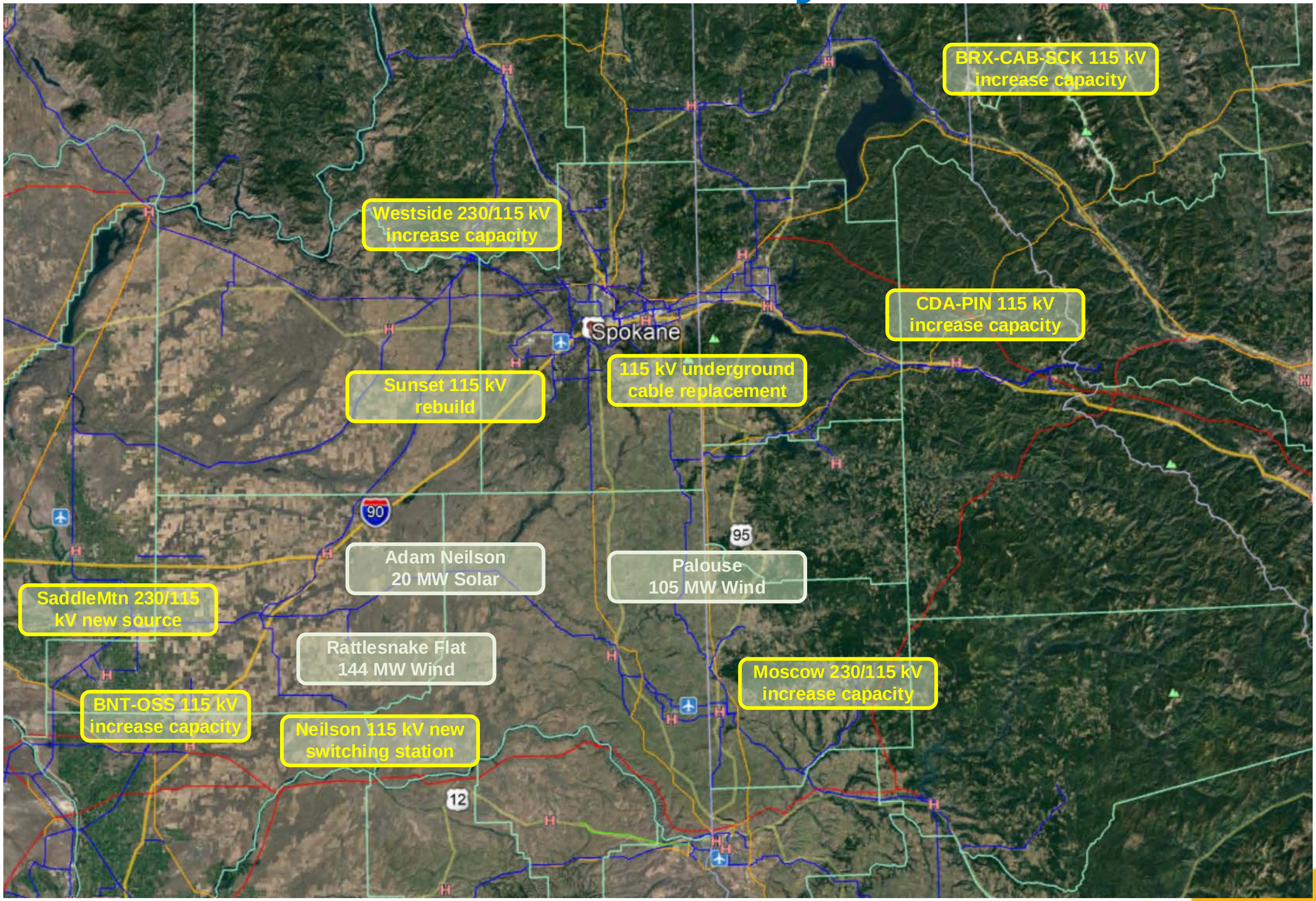
Standards are a Roadmap

Changes in equipment, analysis tools, experience, and expectations impact Avista's study process and results

WSCC DISTURBANCE-PERFORMANCE TABLE OF ALLOWABLE EFFECT ON OTHER SYSTEMS[1]

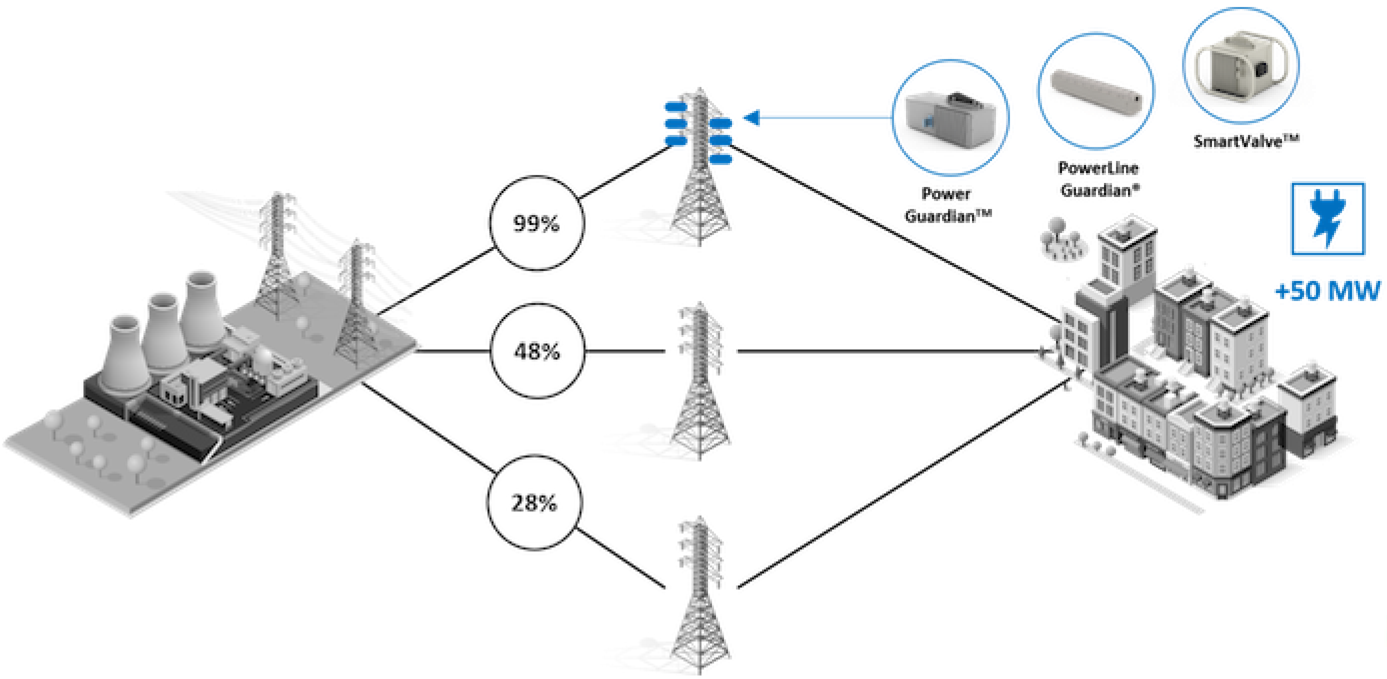
Performance Level	Disturbance(2) Initiated By: No Fault 3 Ø Fault With Normal Clearing SLG Fault With Delayed Clearing DC Disturbance (3)	Transient Voltage Dip Criteria (4)(5)(6)	Minimum Transient Frequency (4)(5)	Post Transient Voltage Deviation (4)(5)(6)(7)	Loading Within Emergency Ratings	Damping
A	Generator One Circuit One Transformer DC Monopole (8)	Max V Dip - 25% Max Duration of V Dip Exceeding 20% - 20 cycles	59.6 hz Duration of f Below 59.6 hz - 6 cycles	5%	Yes	>0
B	Bus Section	Max V Dip - 30% Max Duration of V Dip Exceeding 20% - 20 cycles	59.4 hz Duration of f Below 59.4 hz - 6 cycles	5%	Yes	>0
C	Two Generators Two Circuits DC Bipole (8)	Max V Dip - 30% Max Duration of V Dip Exceeding 20% - 40 cycles	59.0 hz Duration of f Below 59.0 hz - 6 cycles	10%	Yes	>0
D	Three or More circuits on ROW Entire Substation Entire Plant Including Switchyard	Max V Dip - 30% Max Duration of V Dip Exceeding 20% - 60 cycles	58.1 hz Duration of f Below 58.1 hz - 6 cycles	10%	No	≥0

Recent Transmission Projects



Non Wire Solutions are Evaluated

- We are documenting this with more clarity
- Non-wire options require robust wires to perform
  - Avista is working on the transmission fundamentals



Evaluated Batteries for T-1-1

- TPL-001-4 ~ T-1-1 for long lead equipment
  - Double transformer outages
    - Shawnee 230/115 kV outage followed by a:
      - Concurrent outage of Moscow 230/115 kV
  - Could we mitigate performance issues with storage?
    - Yes…but…
      - We would need a 125 MW battery
        - » Charge is 8 hours, discharge for 12 to 16 hours (outage is weeks to months)
      - A third transformer is a better solution
        - » Robust performance and much less $$$$

Requisitions: Requisitions >

Requisition 162964

Description: M08 - Westide 250/280MVA, 230-115-13.8kV, three phase auto transformer.
Created By: Wilson, Barnes Scott (Scott)
Creation Date: 12/06/2017 12:49:35
Deliver-To: One Time Ship To
Justification: This is the second transformer associated with the Westside Substation rebuild.

Status: Approved
Change History: No
Urgent Requisition: No
Attachment: View
Note to Buyer: Quote attached. Bid evaluation sheet pre
Shelly Campbell.

Details

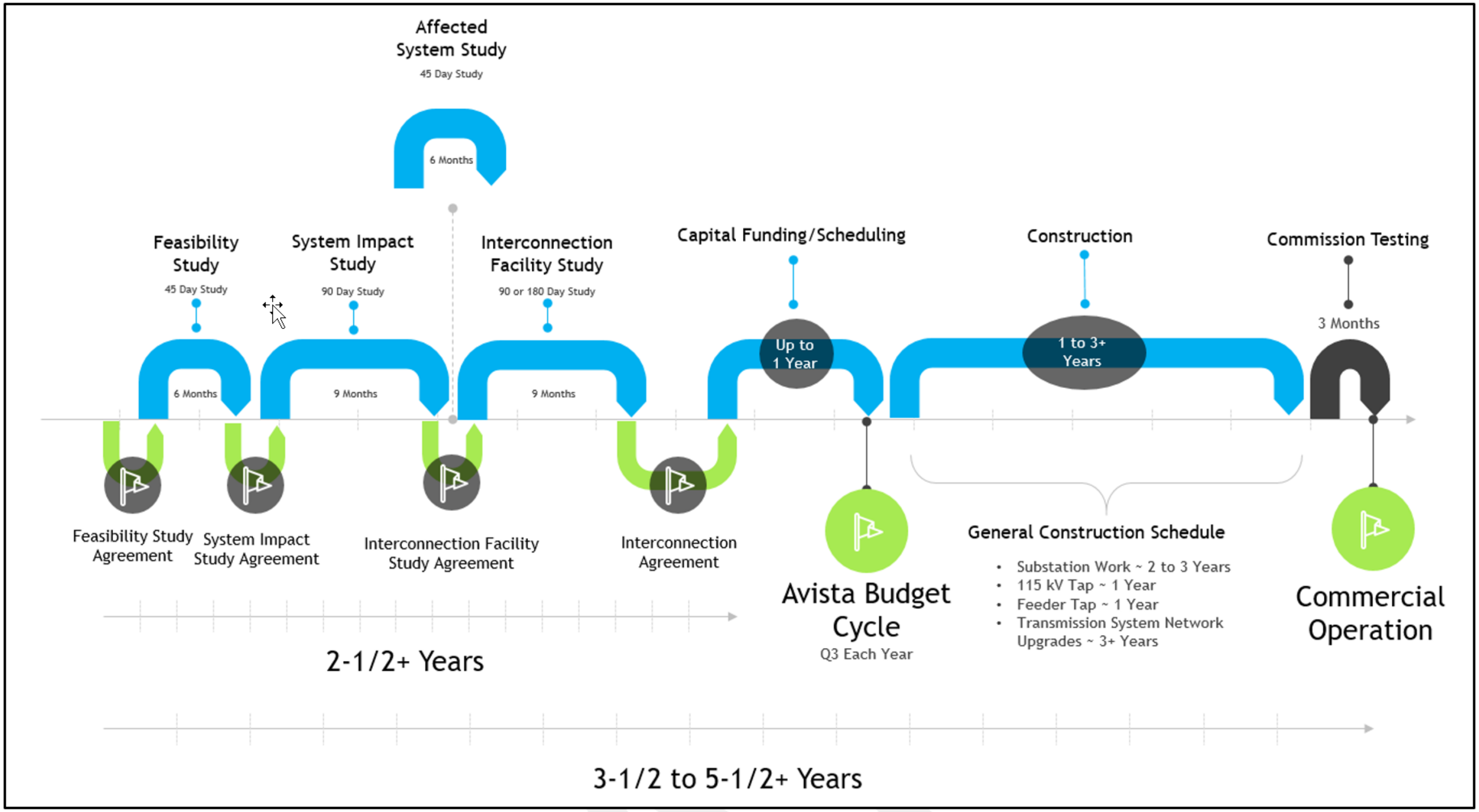
Line	Description	Need-By	Deliver-To	Unit	Quantity	Qty Delivered	Qty Cancelled	Open Quantity	Price	Amount (USD)
1	250/280MVA, 230-115-13.8kV, three phase auto transformer.	10/03/2018 12:51:34	One Time Ship To	Each	1	1	0	0	2397826 USD	2,397,826.00
2	SFRA Testing at factory and field	10/03/2018 12:51:34	One Time Ship To	Each	1	1	0	0	5400 USD	5,400.00
									Total	2,403,226.00

Generation Interconnection Study Process

Process for Generation Requests

- Two sources:
  - External developers
    - Enter via the OATT
  - Internal IRP requests
    - Feasibility Lite Study…then OATT
      - AVA Merchant MUST follow the OATT just like external parties
- Typical process:
  - Hold a scoping meeting to discuss particulars
  - Outline a study plan
  - Augment WECC approved cases for our studies
  - Analyze the system against the standards
  - Publish our findings and recommendations

Interconnection Study Timeline



Current Interconnection Queue

Generator Interconnection Applications								
Proj #	Date of Request	Status of Request	Service Type	Max Summer output	Max Winter output	Total (MW)	Projected In-Service Date	Type of facility
17	3/6/2009	Operational	ER	100	100	100.00	6/1/2011	Wind
46	10/6/2015	LGIA	NR	126	126	126.00		Wind
52	2/8/2017	LGIA	NR	100	100	100.00		Solar
53	4/11/2017	Operational	NR	19.2	19.2	19.2	12/15/2018	Solar
59	5/23/2018	SIS	NR/ER	116	116	116.00	6/1/2021	Solar & Storage
60	6/4/2018	IFS	ER	150	150	150.00	12/15/2022	Solar & Storage
61	6/4/2018	Withdrawn	NR	20	20	20.00	11/15/2019	Solar
62	6/8/2018	FS	NR/ER	123.2	123.2	123.20	11/30/2021	Wind
63	6/8/2018	FS	NR/ER	26	26	26.00	2/28/2023	Hydro
66	7/10/2018	FS	NR	71	71	71.00	7/1/2023	Wood Waste
67	8/27/2018	FS	NR/ER	80	80	80.00	6/30/2023	Solar
68	9/20/2018	FS	ER	750	750	750.00		Wind
69	9/20/2018	FS	ER	750	750	750.00		Wind
70	8/31/2018	SIS	NR	2.5	2.5	2.50	1/1/2019	Energy Storage - Battery
71	10/4/2018	FS	NR	7	7	7.00	8/15/2020	Solar
72	10/9/2018	FS	NR/ER	80	80	80.00	6/30/2021	Solar
73	10/12/2018	FS	NR/ER	100	100	100.00	6/30/2020	Solar
74	11/16/2018	SIS	NR/ER	0.1	0.1	0.10	1/15/2019	Energy Storage - Battery
76	11/27/2018	FS	NR/ER	200	200	200.00	12/31/2020	Solar
77	12/4/2018	FS	NR/ER	5	5	5.00	12/31/2020	Solar
79	12/4/2018	FS	NR/ER	5	5	5.00	6/30/2020	Solar

Current Queue, continued

Generator Interconnection Applications								
Proj #	Date of Request	Status of Request	Service Type	Max Summer output	Max Winter output	Total (MW)	Projected In-Service Date	Type of facility
80	12/17/2018	FS	NR/ER	19	19	19.00	6/30/2020	Solar
81	12/18/2018	FS	NR/ER	94	94	94.00	6/30/2020	Solar
82	2/20/2019	FS	ER	600	600	600.00	12/31/2021	Wind
83	3/27/2019	FS	ER	300	300	300.15	10/31/2022	Wind
84	4/17/2019	FS	NR/ER	5	5	5.00	8/31/2020	Solar
85	4/17/2019	FS	NR/ER	5	5	5.00	8/31/2020	Solar
86	5/29/2019	New	NR/ER	20	20	20.00	12/31/2022	Solar
87	6/17/2019	New	NR	5	5	5.00	8/31/2021	Solar
88	6/17/2019	New	NR	5	5	5.00	8/31/2021	Solar
89	6/17/2019	New	NR	5	5	5.00	8/31/2021	Solar
90	6/17/2019	New	NR	5	5	5.00	8/31/2021	Solar
91	6/17/2019	New	NR	5	5	5.00	8/31/2021	Solar
92	6/17/2019	New	NR	5	5	5.00	8/31/2021	Solar
93	6/17/2019	New	NR	5	5	5.00	8/31/2021	Solar
94	6/17/2019	New	NR	5	5	5.00	8/31/2021	Solar
95	6/20/2019	New	NR/ER	600	600	600.00	12/1/2022	Wind
96	6/20/2019	New	NR/ER	400	400	400.00	12/1/2022	Wind
97	6/24/2019	FS	NR/ER	150	150	150.00	12/31/2021	Solar & Storage
98	8/29/2019	New	NR/ER	80	80	80.00	12/1/2023	Solar & Storage
99	9/6/2019	New	NR	200	200	200.00	12/31/2021	Solar & Storage
100	9/27/2019	New	NR/ER	100	100	100.00	12/31/2021	Solar & Storage
101	10/22/2019	FS	NR/ER	500	500	500.00	9/1/2024	Wind & Storage
102	11/5/2019	New	NR/ER	200	200	200.00	11/30/2022	Solar & Storage
103	12/10/2019	New	NR	19.25	19.25	19.25	3/31/2021	Solar
104	3/2/2020	New	NR/ER	120	120	120.00	12/31/2023	Wind

2021 IRP *Transmission* Cost Estimates

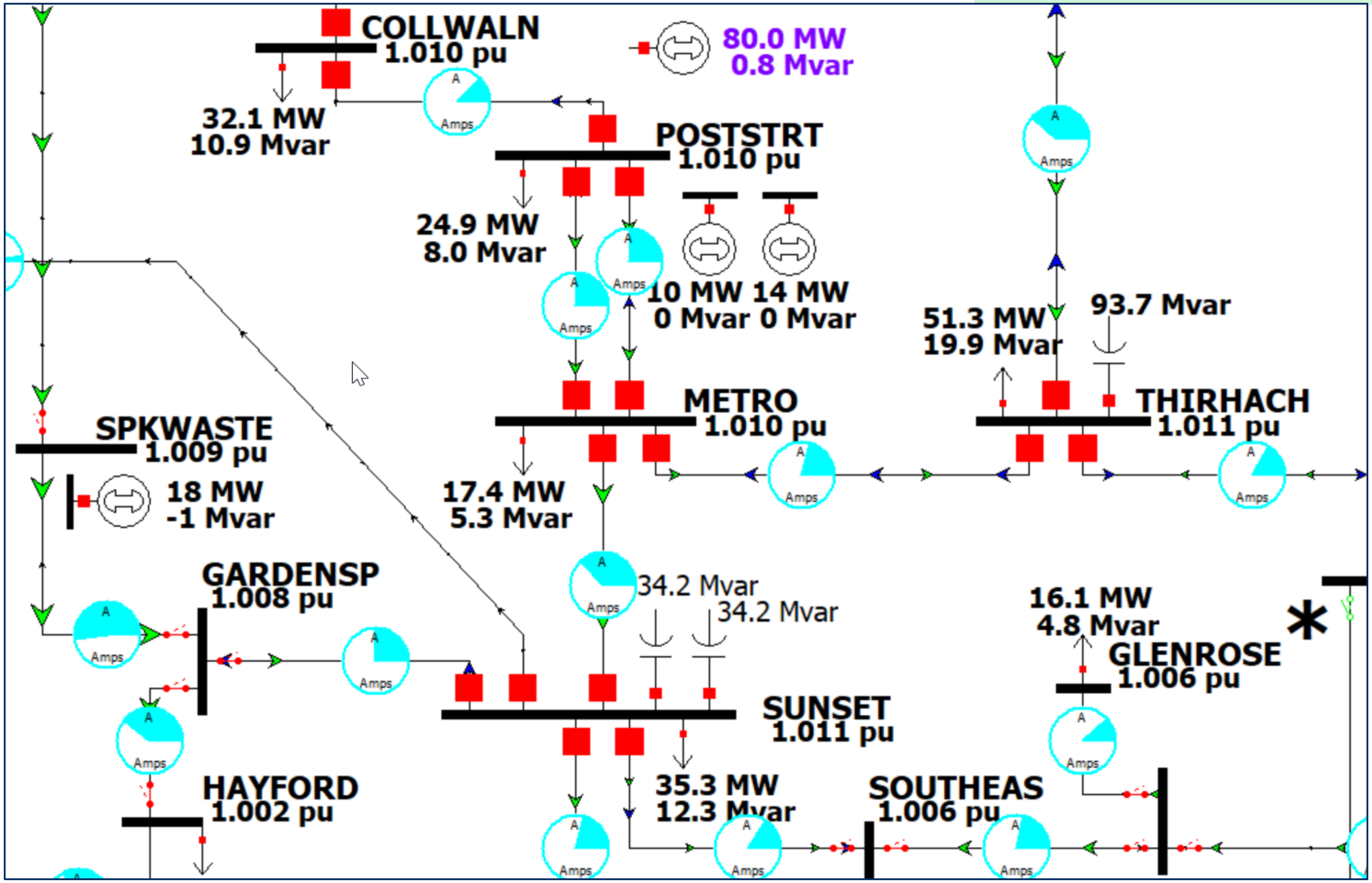
Assume anti-islanding scheme, but no RAS

Station	Request (MW)	POI Voltage	Cost Estimate ($ million)
Kootenai County (GF)	100	230 kV	4
Kootenai County (GF)	200/300	230 kV	80-100
Rathdrum	25/50/100	115 kV	<1
Rathdrum	200	115 kV	55
Rathdrum	50/100	230 kV	<1
Rathdrum	200	230 kV	60
Benewah	100/200	230 kV	<1
Tokio	50/100	115	<1, 20
Othello/Lind	50/100/200	115 kV	Queue Issues
Lewiston/Clarkston	100/200	230 kV	<1
Northeast	10	115 kV	<1
Kettle Falls	12	115 kV	<1
Kettle Falls	24/100/124	115 kV	<20
Long Lake	68	115 kV	33
Monroe Street	80	115 kV	2
Post Falls	10	115 kV	<1
Cabinet Gorge	110	230 kV	<14

[1] Preliminary estimates are given as -25% to +75%

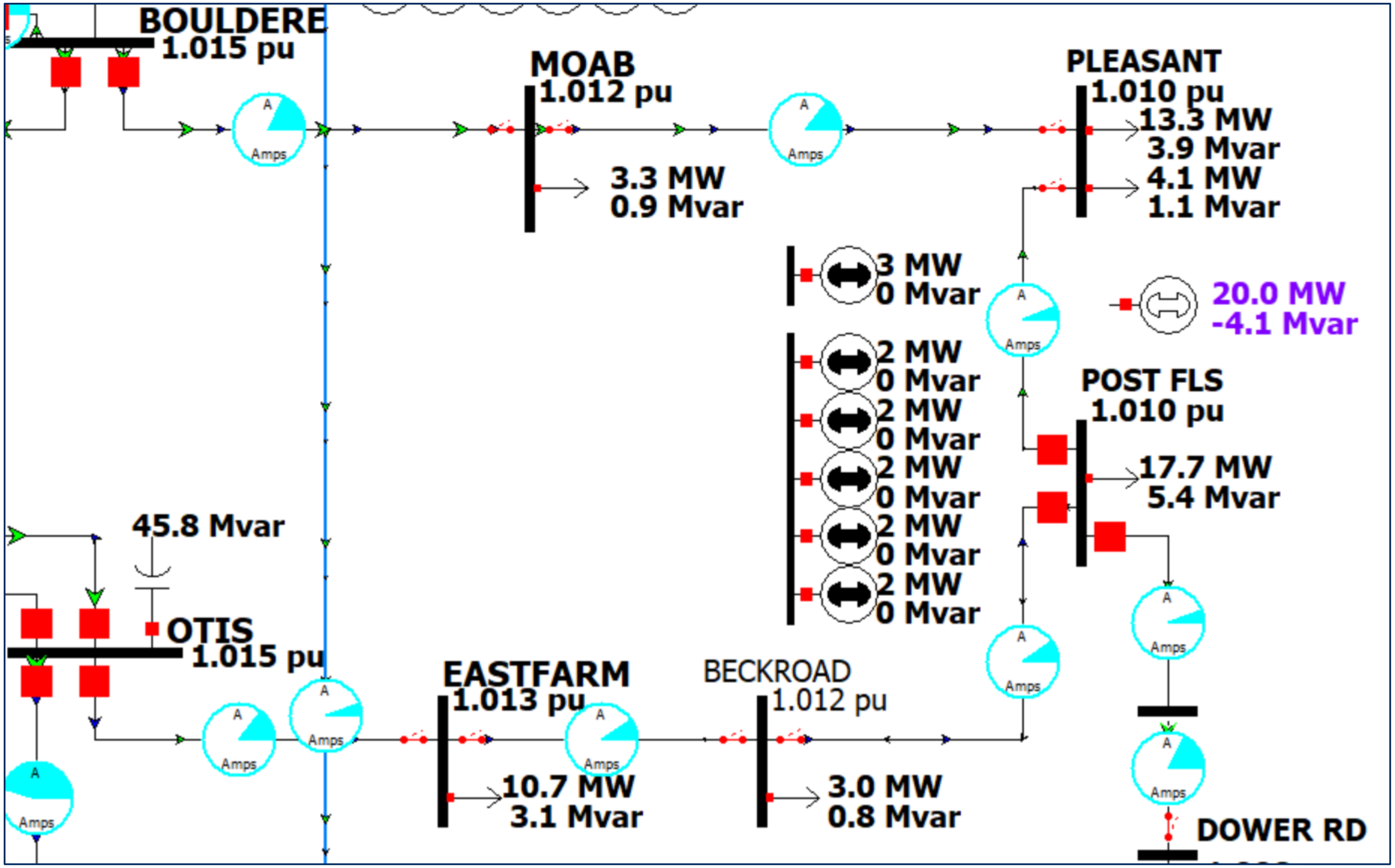
Monroe Street: 80 MW

Requires the Metro Rebuild Project be completed



Post Falls: 10 MW to 20 MW

Interconnection only



Questions?

Avista OASIS link:

http://www.oasis.oati.com/avat/index.html

Distribution Resource Planning

Damon Fisher, System Planning
Third Technical Advisory Committee Meeting
September 29, 2020

Goals of Electric Distribution Planning

- Ensure electric distribution infrastructure to serve customers now and in the future with a focus on:
  - Safety
  - Reliability
  - Capacity
  - Efficiency
  - Level of service
  - Operational flexibility
  - Corporate/Regulatory goals
  - Affordability

Distribution Resource Planning

- Washington House Bill 1126 (passed 2019)
  - https://app.leg.wa.gov/RCW/default.aspx?cite=19.280.100
  - 10-Year Plan
  - DER's and Non-Wire Alternatives
  - IRP Resource Needs
  - Temporal and spatial planning
  - Temporal and spatial value
  - Probabilistic analysis (Pessimistic, Optimistic)
  - Open Planning

Primary Goal of Distribution Resource Plan

- Where possible, solve distribution grid deficiencies using distributed energy resources (DER) that also contribute to system resource needs as identified in the Integrated Resource Plan.

Can IRP resource needs and distribution "fixes" be aligned? Certainly.

- Not without challenges.
  - Temporal need
  - Grid operation and flexibility
  - Resource adequacy- a new distribution definition?
  - System Protection

Typical Distribution System Deficiencies

- Low Voltage
- Capacity (Substation/Feeder)
- Asset Condition
- Contingency Switching Limits

What are DER's? – Distribution's Perspective

- Anything that can reduce demand or support voltage

  Real

  Targeted Energy Efficiency

  Targeted Demand Response

  Apparent

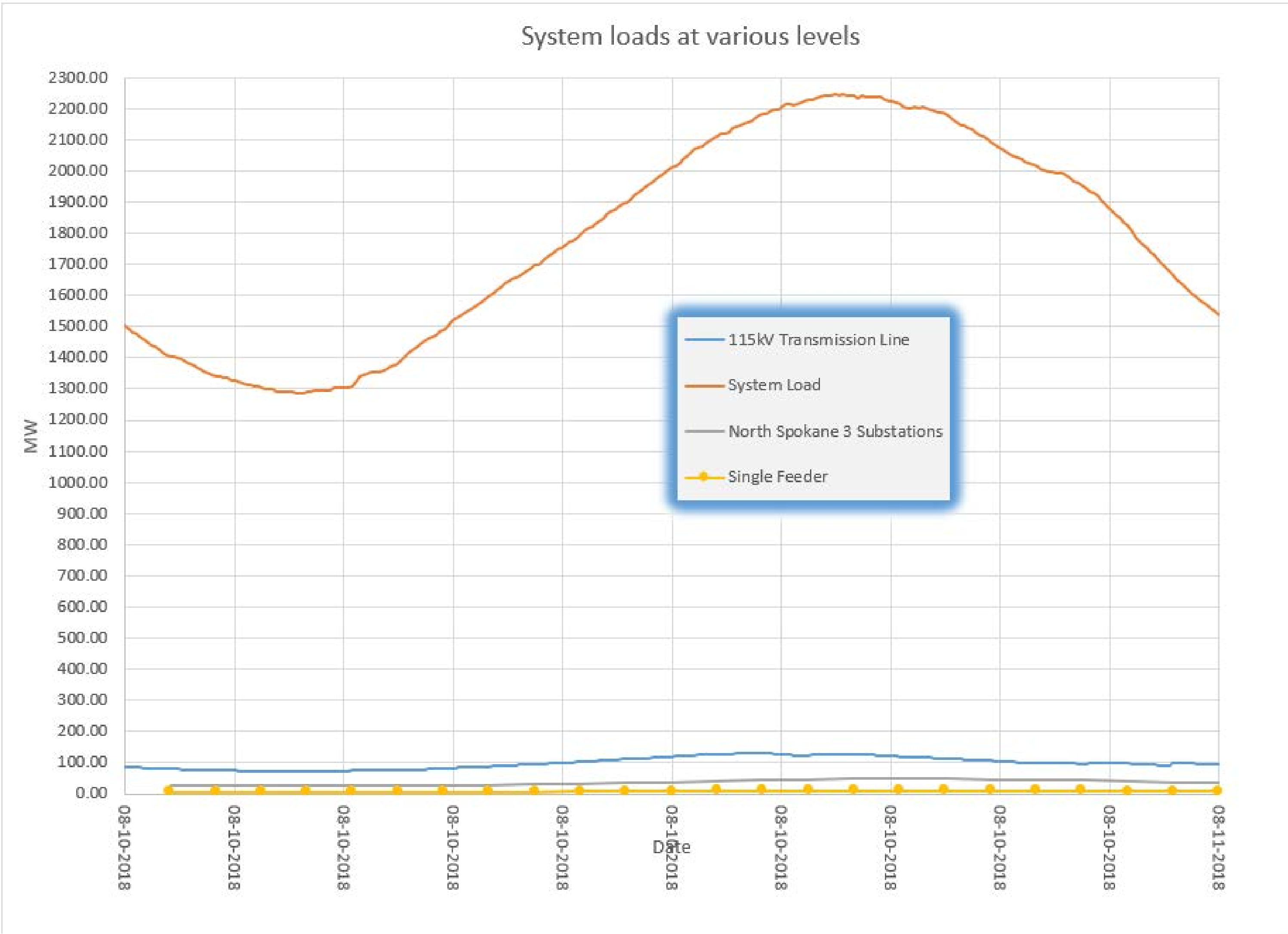
  Storage (Load shifting)

  Generation (Load service)

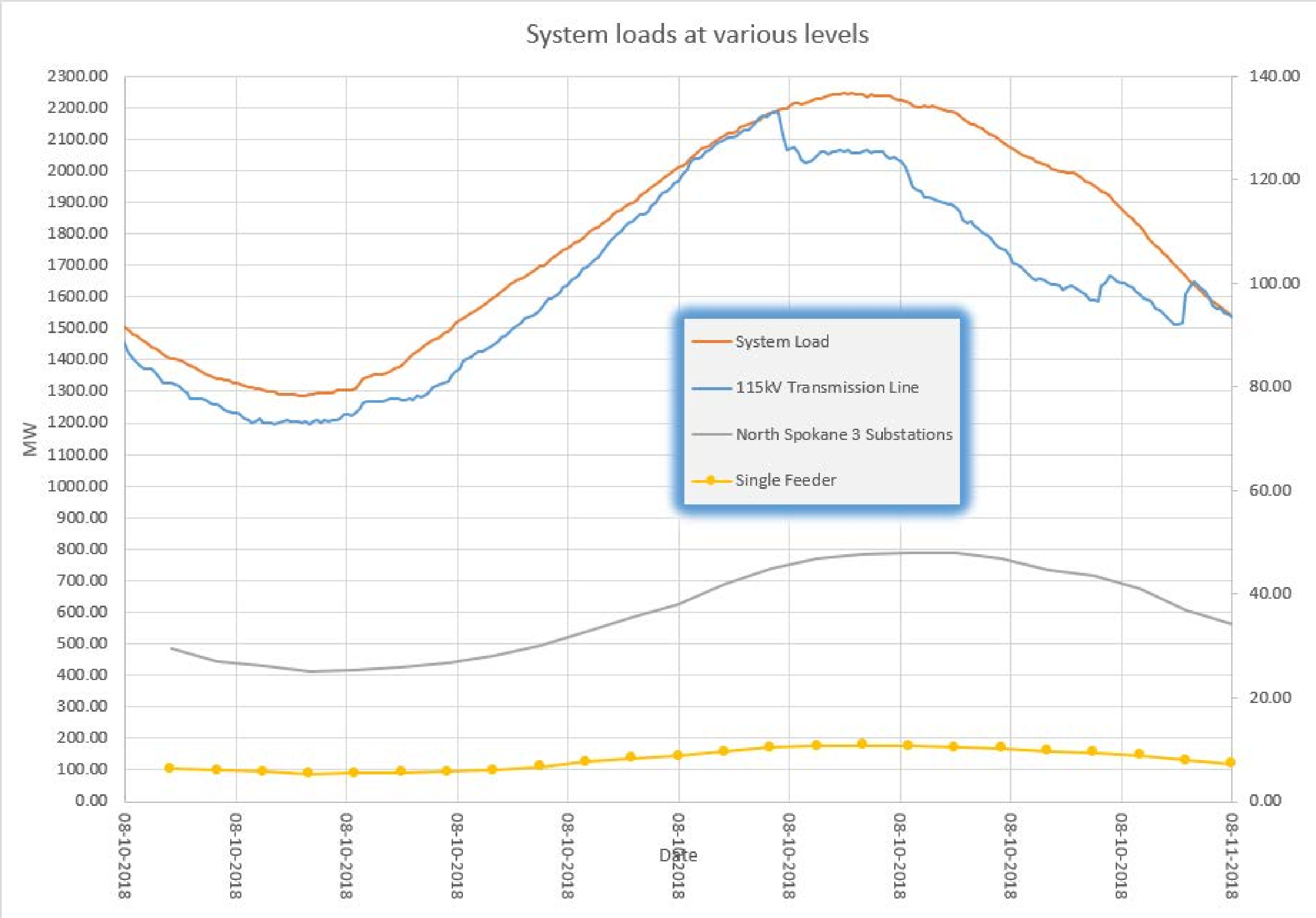
How Do DER's Get Implemented?

- Three Paths-
  1. Retail/Commercial Customer driven. Customers install DER's on their side of the meter for unknown reasons.
  2. The second way would be 3rd party grid connections (utility scale). We have a few requests in the queue and a 20MW installation in Lind Washington. These can cause grid challenges.
  3. The third way is utility-driven targeted DER's to solve grid issues on either side of the meter. Incentivized #1 and #2 above.

System Resources vs. Feeder Demand

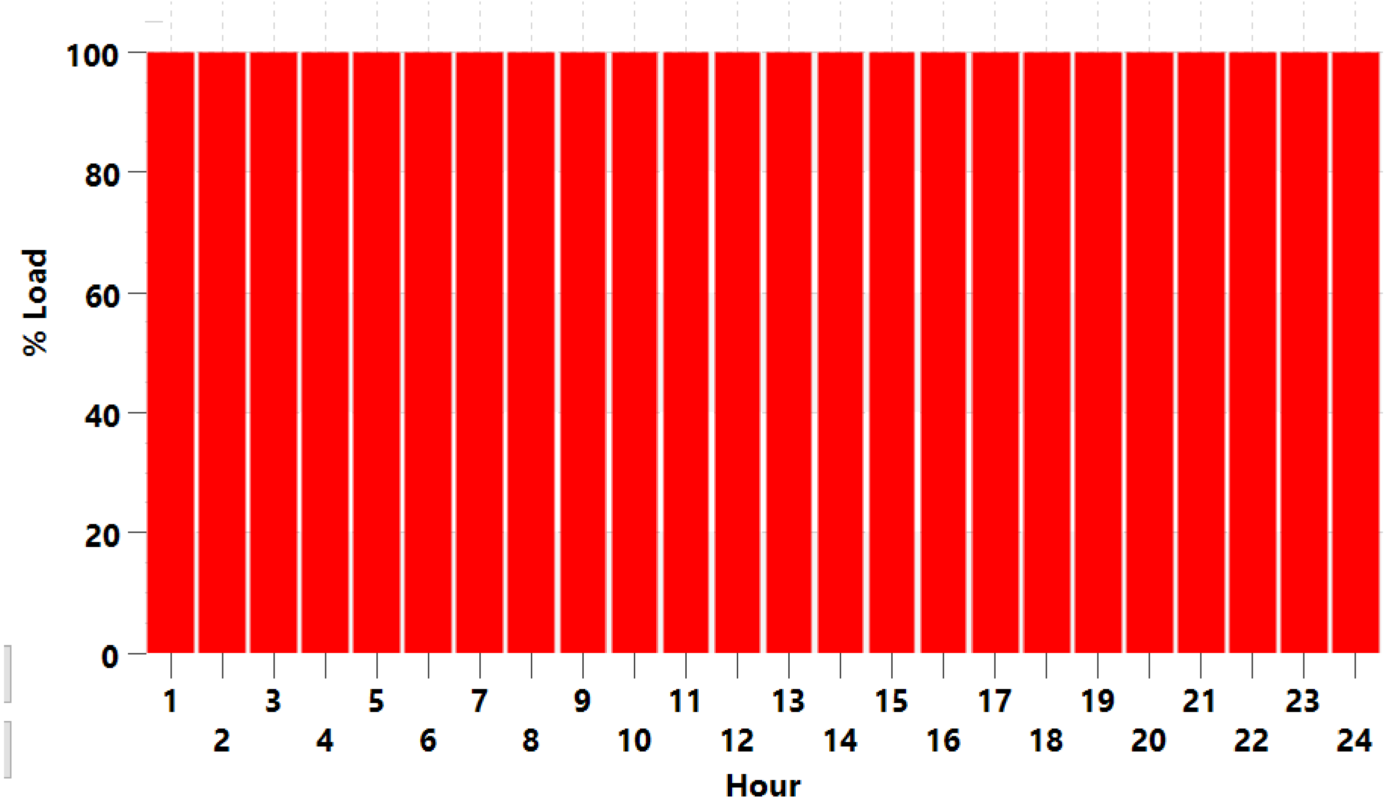


System Resources vs. Feeder Demand



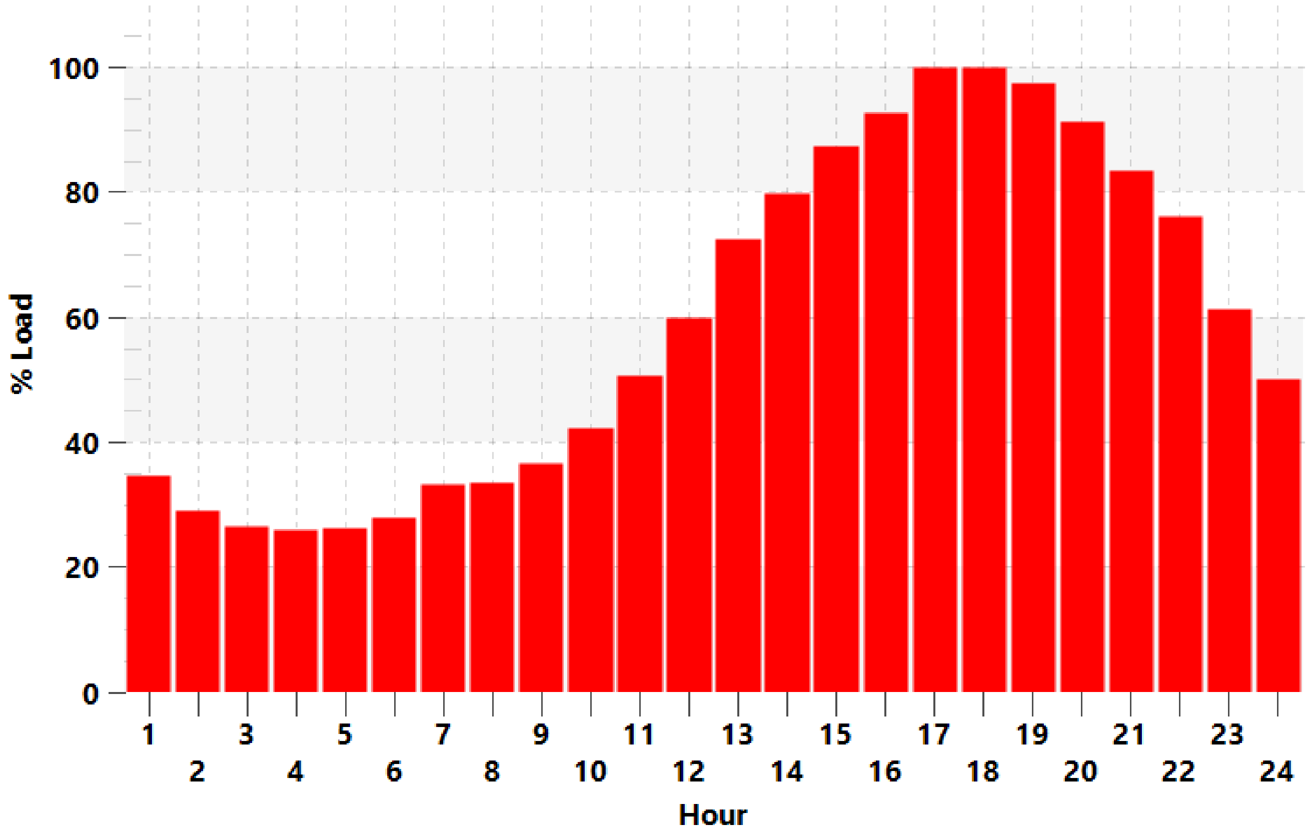
It Is All About Curves

- The ideal curve-

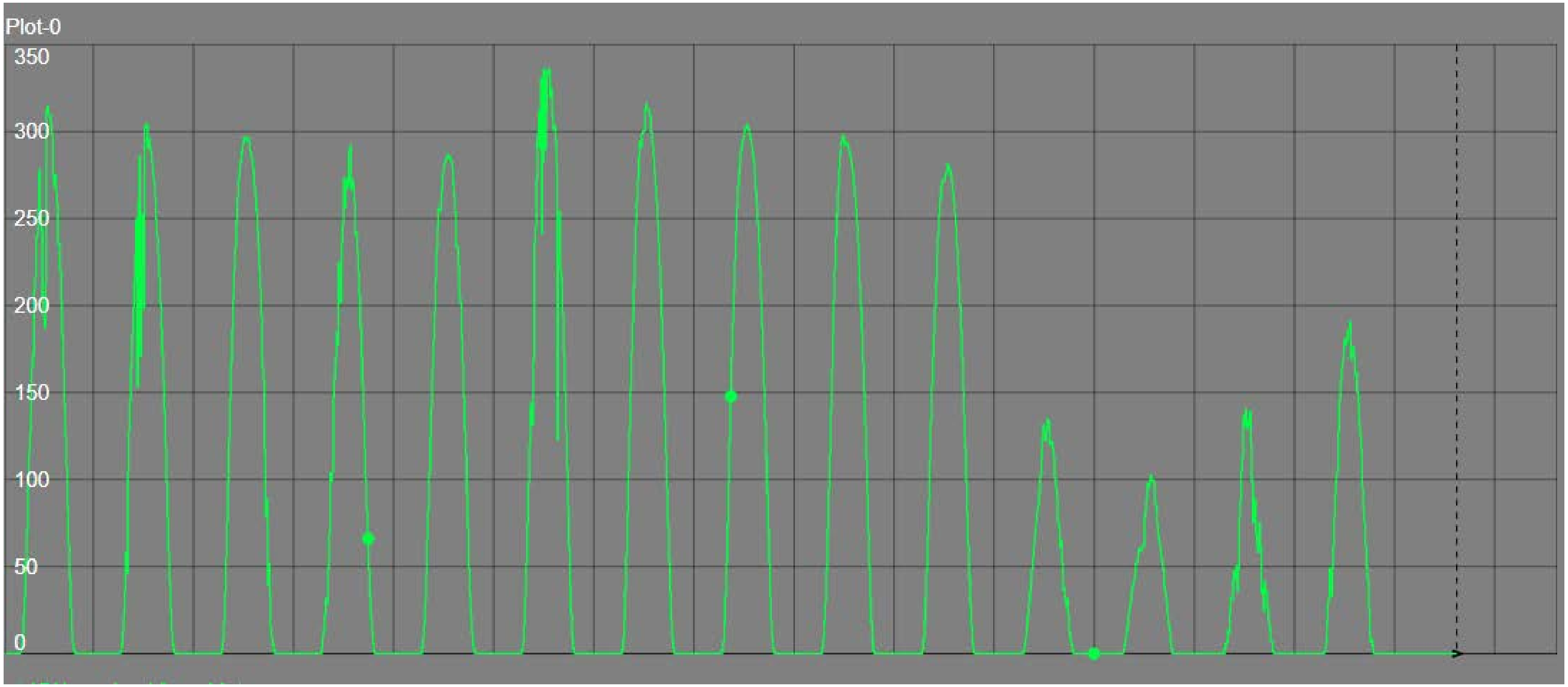


It is all about curves

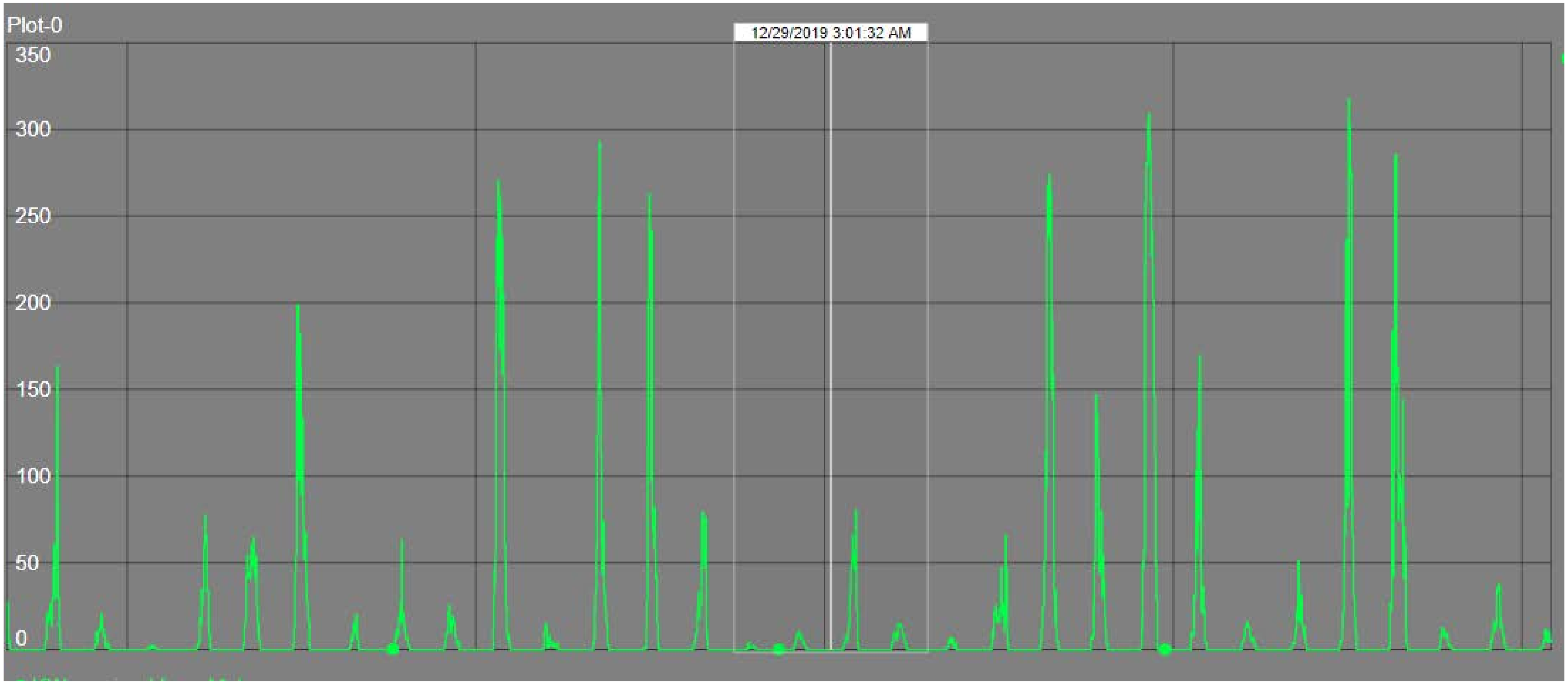
- A real curve (not ideal)-



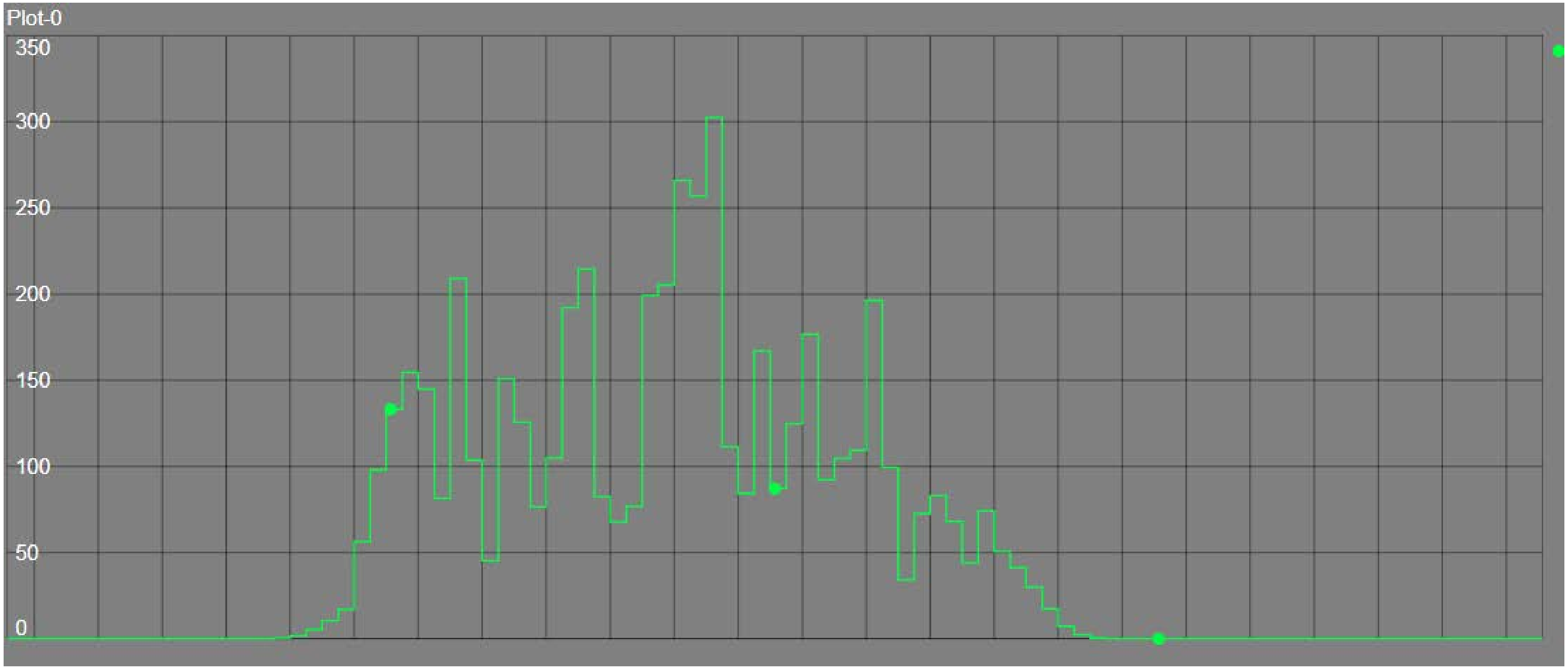
Can We Fix Curves with PV? Community Solar – Summer



Can We Fix Curves with PV?
Community Solar – Winter



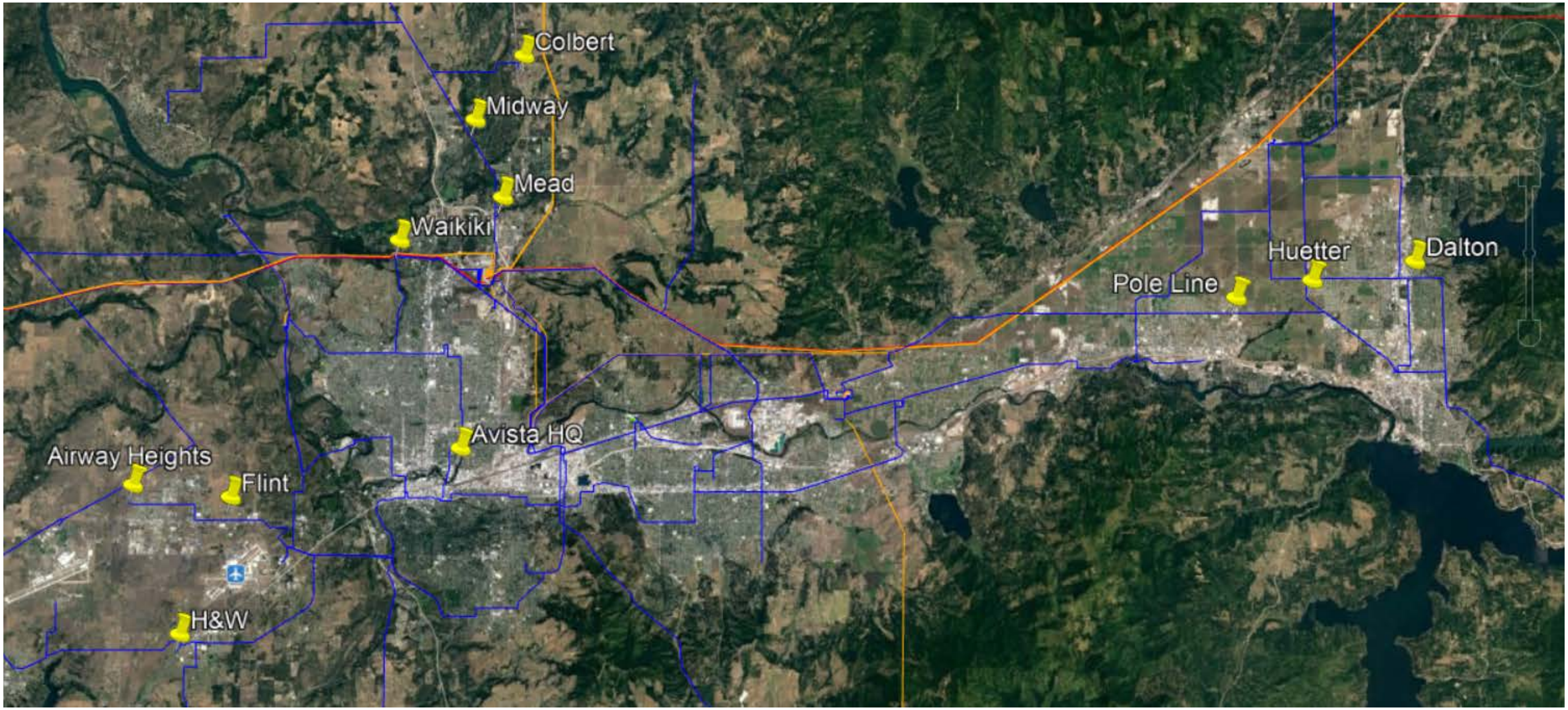
Can We Fix Curves with Just PV? Community Solar – Cloudy Day, Battery



Capacity Projects

53	Flint Road Station	Scope not complete. New distribution station located north of Spokane along the Airway Heights - Sunset 115 kV Transmission Line.	Q3 2022	Budgeted Not Scoped	
98	Midway Station	Scope not complete. New distribution station located north of Spokane along the Bell – Addy 115 kV Transmission Line.	Q1 2023	Budgeted Not Scoped	
80	Huetter Station Expansion	Scope not complete. Rebuild existing distribution station to two 30MVA transformers, 6 feeders, and looped through transmission with circuit breakers.	Q1 2025	Budgeted Not Scoped	

Locations


Colbert
Midway
Mead
Waikiki
Avista HQ
Airway Heights
Flint
H&W
Pole Line
Huetter
Dalton

DRP Implementation Gaps

- Spatial Load Forecasting
- Spatial DER Forecasting
- System Performance Criteria
- DER Acquisition and Implementation Processes
- Engineering/Operational Expertise

Interesting Distribution Efforts

- AMI data load disaggregation
- Hosting Capacity Maps
  - Example Hosting Capacity map: https://www.arcgis.com/apps/webappviewer/index.html?id=84de299296d649808f5a149e16f2d87c
- Northwest Utility DER Technical Discussion

Questions?

AEG
Applied Energy Group

AVISTA DR POTENTIAL STUDY

Preliminary Results Slide Deck – Sep 28, 2020

Energy solutions. Delivered.

AGENDA

- Methodology
- Program Characterization
- Preliminary Impacts
- Next Steps

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Methodology

APPROACH TO THE STUDY

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Data Collection

- Align with EE Potential study
  - Market Profiles
- Secondary Sources
  - Industry or regional reports & previous studies

Analysis Inputs

Characterize the Market

- Segmentation by Customer Class
  - Residential and C&I (General Service, Large General Service and Extra Large General Service)

Baseline Forecast

Develop list of DR Options

- DLC
- Third Party
- Storage
- Rates
- Ancillary Services

Program List

Characterize the Options

- Develop Program Assumptions
  - Impacts, Participation, Technology, Costs, Incentives

Potential Inputs

Estimate Potential

- Technical Achievable Potential
  - Potential for all programs regardless of cost and without consideration of dual participation
- Realistic Achievable Potential
  - Integrated case of cost-effective programs

Final Results

CALCULATION OF IMPACT (MW)

$$Program\ Impact_{year,program}$$
$$= Per\ Customer\ Peak\ Impact * Eligible\ Participants$$
$$* Participation\ Rate * Equipment\ Saturation\ Rate$$

where:

Year= Forecasted year between 2022 and 2045

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Program Characterization

DR PROGRAM OPTIONS

Program Type	Program Option	Mechanism
Curtailable / Controllable DR	DLC with two-way communicating or Smart T-stats	Internet-enabled control of thermostat set points, can be coupled with any dynamic pricing rate
	DLC Central AC	DLC switch installed on customer's Central AC
	CTA-2045 Water Heaters (WA)	Modular communications interface for water heaters that will become the new technology standard
	DLC Water Heating (ID)	DLC switch installed on customer's Water Heater
	DR providing ancillary services (Fast DR)	Automated, fast-responding curtailment strategies with advanced telemetry capabilities suitable for load balancing, frequency regulation, etc. Equipment considered for this option includes: **Battery Storage, Thermostats (heating/cooling), Electric Vehicles, Third Party Contracts, and Water Heaters**
	Smart Appliance DLC	Internet-enabled control of operational cycles of white goods appliances
	DLC Electric Vehicle Charging	DLC switch installed on customer's equipment
	Third Party Contracts-	Includes the following three measure options
	Capacity Bidding	Customers volunteer a specified amount of capacity during a predefined "economic event" called by the utility in return for a financial incentive.
	Emergency Curtailment Agreements	Customers enact their customized, mandatory curtailment plan. May use stand-by generation. Penalties apply for non-performance.
	Demand Buyback	Customers enact their customized, voluntary curtailment plan. May use stand-by generation. No penalties for non-performance. Requires AMI technology.
	Battery Energy Storage	Peak shifting of loads using stored electrochemical energy
	Behavioral DR	Voluntary DR reductions in response to behavioral messaging. Example programs exist in CA and other states. Requires AMI technology.
	Thermal Energy Storage	Peak shifting of primarily space cooling or heating loads using a thermal storage medium such as water or ice
Rates	Time-of-use Rates	Higher rate for a particular block of hours that occurs every day. Requires either on/off peak meters or AMI technology.
	Variable Peak Pricing	Much higher rate for a particular block of hours that occurs only on event days. Requires AMI technology.

AMI ASSUMPTIONS

Some of the options require AMI

- DLC Options- No AMI Metering Required
- Dynamic Rates- require AMI for billing
- Ancillary Options- require two way communicating controls

Washington currently has 93% AMI saturation

- Assume 100% saturation by 2022

Idaho will start AMI rollout in 2022 and will take 18 months to fully deploy

- Assume 33% saturation in 2022 and 100% by 2024

PARTICIPATION RATES
DLC PROGRAM OPTIONS

Program Option	Residential	General Service	Large General Service	Extra Large General Service
DLC Central AC	10%	10%		
DLC Smart Thermostats - Cooling	20%	20%		
DLC Smart Thermostats - Heating	5%	3%		
CTA-2045 WH	50%	50%		
DLC Water Heating	15%	5%		
DLC Electric Vehicle Charging	25%			
DLC Smart Appliances	5%	5%		

Sources:

- **DLC Central AC**– NWPCC DLC Switch cooling assumption- 5 yr ramp rate
- **DLC Smart Thermostats (Cooling)** – NWPCC Smart Thermostat cooling assumption- 5 yr ramp rate
- **DLC Smart Thermostats (Heating)** – Agreed upon estimate with Avista. NWPC participation estimate was too high.
- **CTA – 2045 WH** - NWPCC Grid interactive WH assumptions.
- **DLC Water Heating** – Best estimate based on industry experience – in line with other DLC programs
- **DLC Electric Vehicle Charging** – NWPC Electric Resistance Grid-Ready Summer/Winter Participation- 10 yr ramp rate
- **DLC Smart Appliances** - 2015 ISACA IT Risk Reward Barometer - US Consumer Results. October 2015. http://www.isaca.org/SiteCollectionDocuments/2015-risk-reward-survey/2015-isaca-risk-reward-consumer-summary-us_res_eng_1015.pdf

PARTICIPATION RATES
RATES AND STORAGE

Program Option	Residential	General Service	Large General Service	Extra Large General Service
Third Party Contracts		15%	20%	20%
Thermal Energy Storage		0.5%	1.5%	1.5%
Battery Energy Storage	0.5%	0.5%	0.5%	0.5%
Behavioral	20%			
Time-of-Use Opt-in	13%	13%	13%	13%
Time-of-Use Opt-out	74%	74%	74%	74%
Variable Peak Pricing Rates	25%	25%	25%	25%

Sources:

- Third Party Contracts – Best estimate based on industry experience
- Thermal Energy Storage – Best estimate based on industry experience
- Battery Energy Storage – Best estimate based on industry experience
- Behavioral - PG&E rollout with six waves http://www.calmac.org/publications/DNVGL_PGE_HERs_2015_final_to_calmac.pdf
- Time-of-Use Rates – Best estimate based on industry experience; Brattle Analysis and Estimate; Winter impacts ½ of summer impacts
- Variable Peak Pricing Rates - OG&E 2017 Smart Hours Study
- Real Time Pricing - Best estimate based on industry experience

PEAK IMPACTS

DLC PROGRAMS

Season	Program Option	Residential	General Service	Large General Service	Extra Large General Service
Summer only	DLC Central AC	0.5 kW	1.25 kW		
Summer only	DLC Smart Thermostats - Cooling	0.5 kW	1.25 kW		
Winter only	DLC Smart Thermostats - Heating	1.09 kW	1.35 kW		
Annual	CTA-2045 WH	0.5 kW	1.26 kW		
Annual	DLC Water Heating	0.5 kW	1.26 kW		
Annual	DLC Electric Vehicle Charging	0.5 kW			
Annual	DLC Smart Appliances	0.14 kW	0.14 kW		

Sources:

- **DLC Central AC and Smart Thermostats (Cooling)** –NWPC DLC Switch cooling assumption was close to 1.0 kW reduced to adjust for Avista proposed cycling strategy, Thermostats equal to switch
- **DLC Smart Thermostats (Heating)** – NWPC Smart thermostat heating assumption (east)
- **CTA-2045 Water Heating** - NWPC Electric Resistance Grid-Ready Summer/Winter Impact, Gen Service is 2.52x that of res based on DLC Central AC Res to C&I ratio
- **DLC Water Heating**- NWPC Electric Resistance Switch Summer Impact, Gen Service is 2.52x that of res based on DLC Central AC Res to C&I ratio
- **DLC Electric Vehicle Charging** – Based on Avista Research
- **DLC Smart Appliances** - Ghatikar, Rish. Demand Response Automation in Appliance and Equipment. Lawrence Berkley National Laboratory, 2015. Web. http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-05/TN205072_20150618T110004_Demand_Response_Automation_in_Appliances_and_Equipment.pptx

PEAK IMPACTS
RATES AND OTHER OPTIONS

Season	Program Option	Residential	General Service	Large General Service	Extra Large General Service
Annual	Third Party Contracts		10%	21%	21%
Annual	Thermal Energy Storage		1.7 kW	8.4 kW	8.4 kW
Annual	Battery Energy Storage	2 kW	2 kW	15 kW	15 kW
Annual	Behavioral	2%			
Annual	Time-of-Use Rate Opt-in	5.7%	0.2%	2.6%	3.1%
Annual	Time-of-Use Rate Opt-out	3.4%	0.2%	2.6%	3.1%
Annual	Variable Peak Pricing Rates	10%	4%	4%	4%

Sources:

- **Third Party Contracts** - Weighted average impacts from report: Impact Estimates from Aggregator Programs in California (Source: 2019 Statewide Load Impact Evaluation of California Aggregator Demand Response Programs)
- **Thermal Energy Storage** - Ice Bear Tech Specifications, https://www.ice-energy.com/wp-content/uploads/2016/03/ICE-BEAR-30-Product-Sheet.pdf
- **Battery Energy Storage** – Typical Battery size per segment
- **Behavioral** - Opower documentation for BDR with Consumers and DTE
- **Time-of-Use Rates** –Brattle Analysis and Estimate - PacifiCorp 2019 opt-in and opt-out scenarios. Summer Impacts Shown (Winter impacts ½ summer)
- **Variable Peak Pricing Rates** - OG&E 2018 Smart Hours Study, Summer Impacts Shown (Winter impacts ¾ summer)

AVERAGE EVENT DURATION FOR DLC OPTIONS

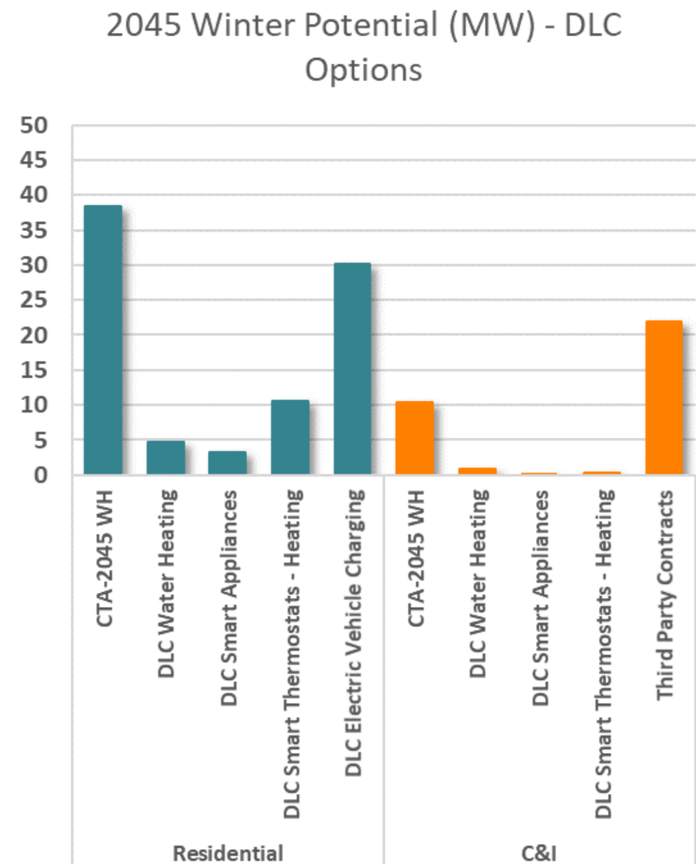
Option	Annual Event Hours	Average Duration per Event	Max Event Duration
Central AC	50	3 hrs	6 hrs
Smart Thermostats - Cooling	36	3 hrs	6 hrs
Smart Thermostats - Heating	36	3 hrs	6 hrs
Water Heating	100	3 hrs	6 hrs
Electric Vehicle Charging	528	6 hrs	8 hrs
Smart Appliances	528	6 hrs	8 hrs
Third Party Contracts	30	4 hrs	8 hrs

Technical Achievable Potential

DLC Options

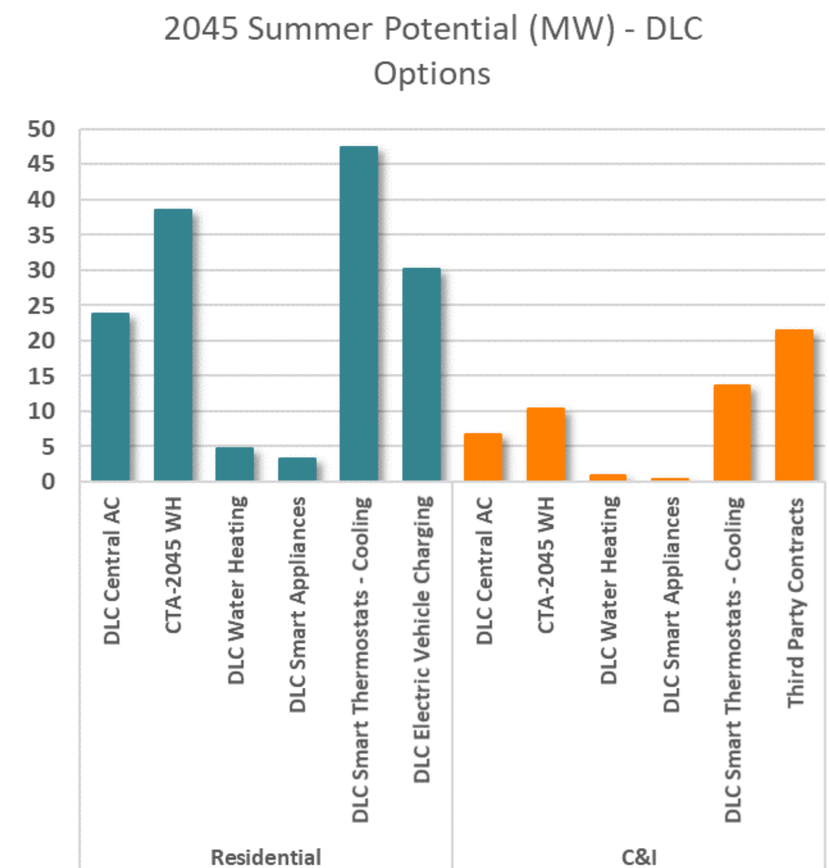
TECHNICAL ACHIEVABLE POTENTIAL
WINTER - DLC OPTIONS

Sector	Option	2022	2025	2035	2045
Residential	DLC Central AC	-	-	-	-
	CTA-2045 WH	0.0	1.3	21.1	38.5
	DLC Water Heating	0.5	4.3	4.7	4.6
	DLC Smart Appliances	0.3	2.4	3.0	3.3
	DLC Smart Thermostats - Cooling	-	-	-	-
	DLC Smart Thermostats - Heating	0.8	7.8	9.5	10.5
	DLC Electric Vehicle Charging	-	0.3	5.6	30.2
C&I	DLC Central AC	-	-	-	-
	CTA-2045 WH	0.0	0.3	5.2	10.4
	DLC Water Heating	0.1	0.6	0.8	0.9
	DLC Smart Appliances	0.0	0.3	0.3	0.4
	DLC Smart Thermostats - Cooling	-	-	-	-
	DLC Smart Thermostats - Heating	0.0	0.2	0.3	0.3
	Third Party Contracts	4.6	21.9	21.8	21.9



TECHNICAL ACHIEVABLE POTENTIAL
SUMMER - DLC OPTIONS

Sector	Option	2022	2025	2035	2045
Residential	DLC Central AC	0.6	6.8	14.5	23.7
	CTA-2045 WH	0.0	1.3	21.1	38.5
	DLC Water Heating	0.5	4.3	4.7	4.6
	DLC Smart Appliances	0.3	2.4	3.0	3.3
	DLC Smart Thermostats - Cooling	1.2	13.5	29.1	47.4
	DLC Smart Thermostats - Heating	-	-	-	-
	DLC Electric Vehicle Charging	-	0.3	5.6	30.2
C&I	DLC Central AC	0.2	1.9	4.1	6.8
	CTA-2045 WH	0.0	0.3	5.2	10.4
	DLC Water Heating	0.1	0.6	0.8	0.9
	DLC Smart Appliances	0.0	0.3	0.3	0.4
	DLC Smart Thermostats - Cooling	0.3	3.8	8.3	13.5
	DLC Smart Thermostats - Heating	-	-	-	-
	Third Party Contracts	4.5	21.4	21.3	21.4

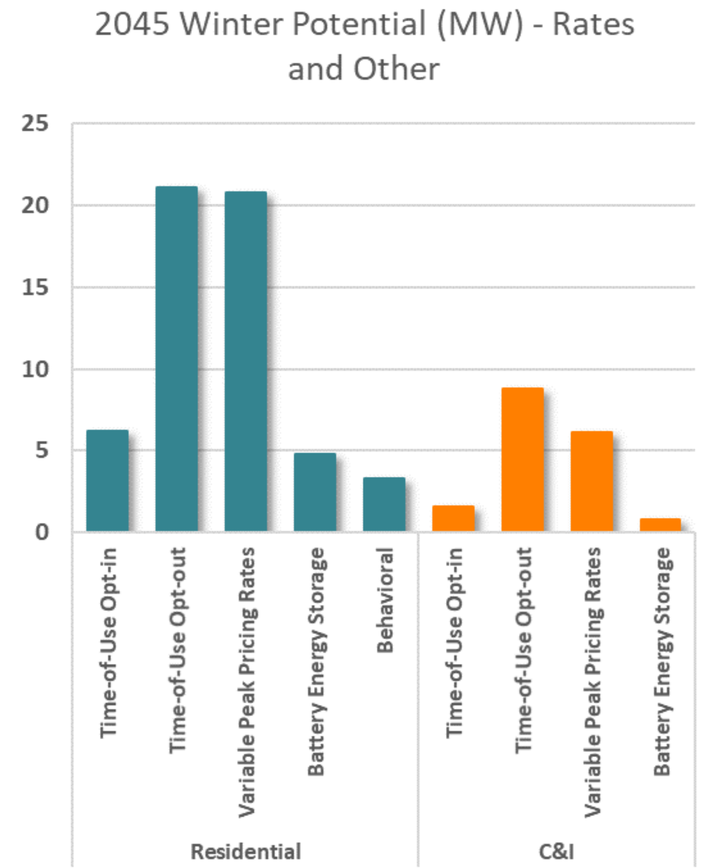


Technical Achievable Potential

Rates and Other Options

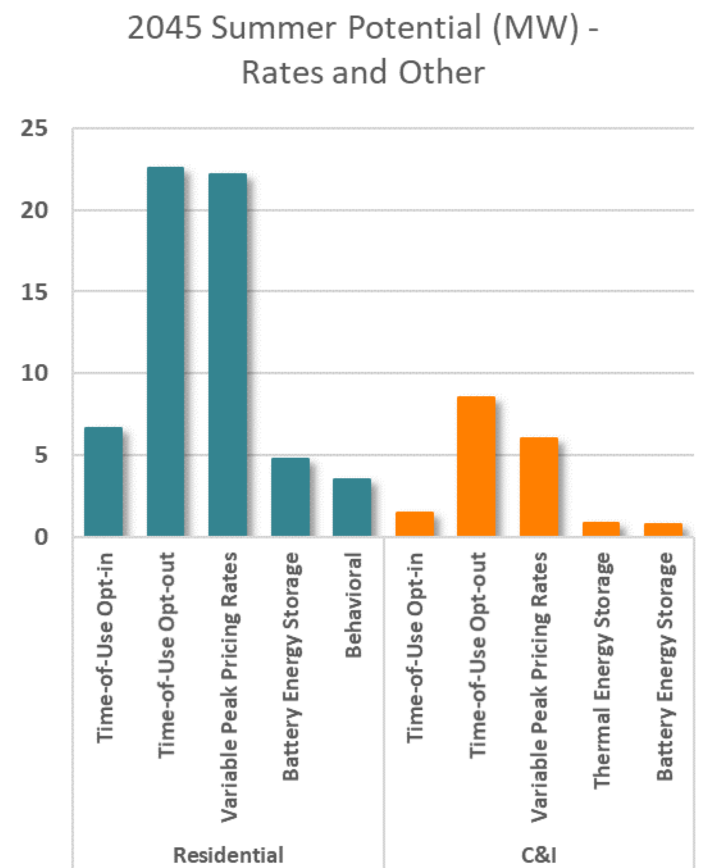
TECHNICAL ACHIEVABLE POTENTIAL
WINTER - RATES AND OTHER OPTIONS

Sector	Option	2022	2025	2035	2045
Residential	Time-of-Use Opt-in	0.4	5.0	5.9	6.2
	Time-of-Use Opt-out	19.6	19.4	20.0	21.1
	Variable Peak Pricing Rates	1.4	16.8	19.7	20.8
	Battery Energy Storage	0.1	0.6	4.3	4.8
	Behavioral	0.6	3.0	3.1	3.3
C&I	Time-of-Use Opt-in	0.1	1.4	1.6	1.5
	Time-of-Use Opt-out	10.4	9.2	8.9	8.8
	Variable Peak Pricing Rates	0.5	5.3	6.0	6.1
	Thermal Energy Storage	-	-	-	-
	Battery Energy Storage	0.0	0.1	0.7	0.8



TECHNICAL ACHIEVABLE POTENTIAL
SUMMER - RATES AND OTHER OPTIONS

Sector	Option	2022	2025	2035	2045
Residential	Time-of-Use Opt-in	0.5	5.4	6.3	6.6
	Time-of-Use Opt-out	21.1	20.7	21.4	22.5
	Variable Peak Pricing Rates	1.5	17.9	21.0	22.2
	Battery Energy Storage	0.1	0.6	4.3	4.8
	Behavioral	0.6	3.2	3.4	3.5
C&I	Time-of-Use Opt-in	0.1	1.4	1.5	1.5
	Time-of-Use Opt-out	10.1	8.9	8.6	8.5
	Variable Peak Pricing Rates	0.5	5.2	5.9	6.0
	Thermal Energy Storage	0.1	0.7	0.8	0.8
	Battery Energy Storage	0.0	0.1	0.7	0.8



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Ancillary Services

By Option

ANCILLARY SERVICE ASSUMPTIONS

Ancillary Option
Battery Energy Storage
Electric Vehicle Charging
DLC Smart Thermostats- Cooling
DLC Smart Thermostats- Heating
DLC Water Heaters
CTA-2045 Water Heaters
Third Party Contracts

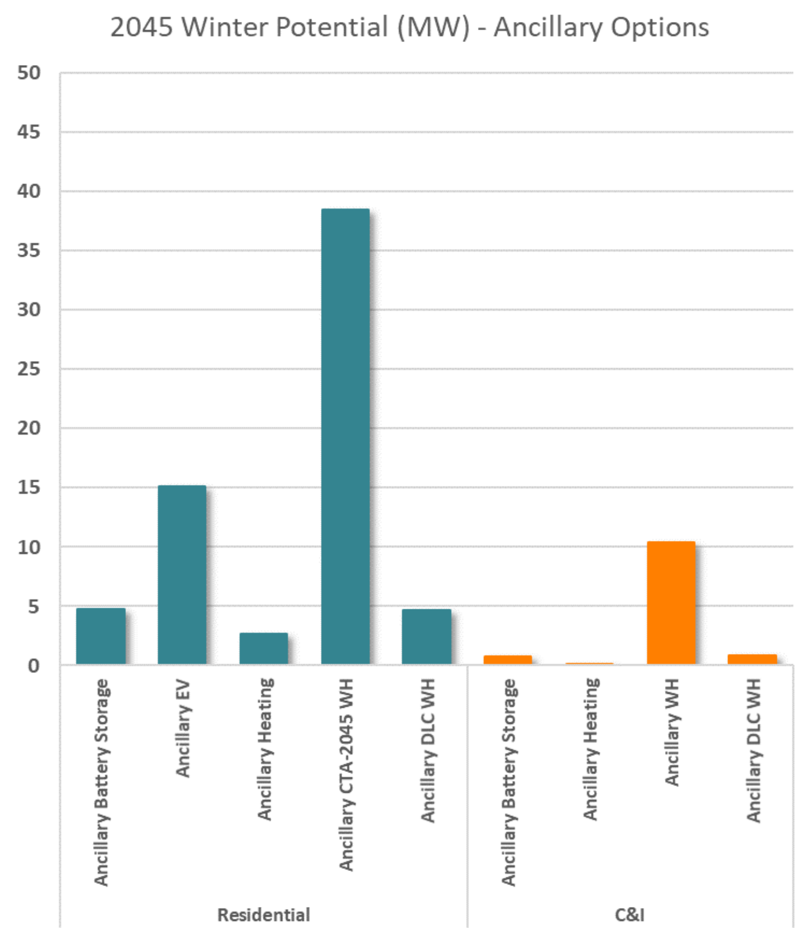
Participation Assumptions

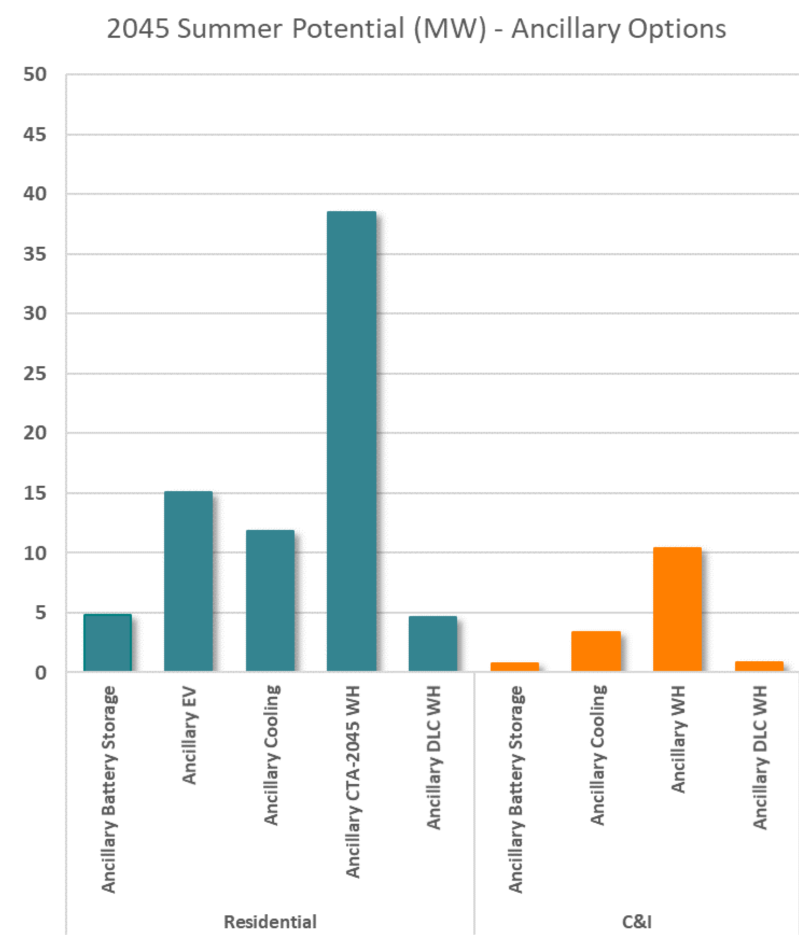
- Full for Battery/EV/WH
- Half for Heating/Cooling
- Third Party based on saturations of EMS systems for PAC C&I

Impact Assumptions

- Full for Battery/WH
- 75% for Third Party
- Half for Heating/Cooling/EV

ANCILLARY SERVICES
TECHNICAL ACHIEVABLE POTENTIAL





DR Event Shapes

Load Shifting Assumptions

SHIFT OR SAVE

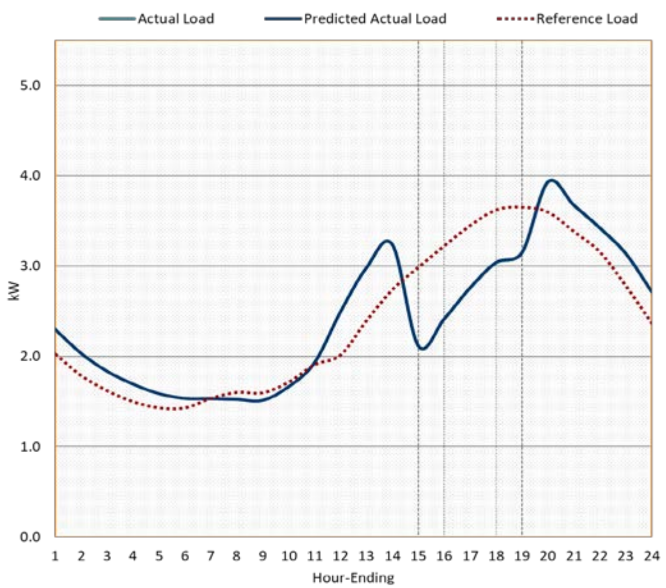
In order to incorporate the impacts into the IRP we need to understand how an even effects overall consumption

Depending on the program type, calling an event can have different effects

- Save energy (0% shift)
- Shift energy (100% shift)
- Partial shift

The next slide will show specific examples of each

Graph shows typical event shape for a Residential Variable Peak Pricing program



EVENT LOAD SHAPES

	Partial Shift				Full Shift				Full Save				Full Shift spread out before/after event			
Program	**DLC Central AC**				**CTA-2045 Water Heating**				**Time-Of-Use Opt-In**				**Variable Peak Pricing**			
State	**WA**		**ID**		**WA**		**ID**		**WA**		**ID**		**WA**		**ID**	
Season	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**
Pre-Event Shift Ratio	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	35%	35%	35%	35%
Post-Event Shift Ratio	65%	65%	65%	65%	100%	100%	100%	100%	0%	0%	0%	0%	65%	65%	65%	65%
Impact at Peak (kW)	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50								
Peak Impact Percentage	24.9%	23.1%	26.7%	25.5%	24.9%	23.1%	26.7%	25.5%	2.9%	5.7%	2.9%	5.7%	7.5%	10.0%	7.5%	10.0%
Hour Ending																
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-	-	-	-	(0.08)	(0.11)	(0.07)	(0.10)
16	-	-	-	-	-	-	-	-	-	-	-	-	(0.08)	(0.11)	(0.07)	(0.10)
17	0.43	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.05	0.11	0.05	0.10	0.14	0.20	0.13	0.18
18	0.46	0.49	0.50	0.49	0.50	0.49	0.50	0.49	0.06	0.12	0.05	0.11	0.15	0.21	0.14	0.19
19	0.46	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.06	0.12	0.05	0.11	0.15	0.22	0.14	0.20
20	(0.29)	(0.31)	(0.32)	(0.31)	(0.37)	(0.36)	(0.37)	(0.36)	-	-	-	-	(0.10)	(0.14)	(0.09)	(0.12)
21	(0.29)	(0.31)	(0.32)	(0.31)	(0.37)	(0.36)	(0.37)	(0.36)	-	-	-	-	(0.10)	(0.14)	(0.09)	(0.12)
22	(0.29)	(0.31)	(0.32)	(0.31)	(0.37)	(0.36)	(0.37)	(0.36)	-	-	-	-	(0.10)	(0.14)	(0.09)	(0.12)
23	-	-	-	-	(0.37)	(0.36)	(0.37)	(0.36)	-	-	-	-	-	-	-	-
24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

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Next Steps

NEXT STEPS

Finalize Technical Achievable Potential

Characterize Program Costs

Estimate Achievable Potential

- Integrated case
- Calculate levelized costs

Finalize Results

Kelly Marrin, Managing Director

kmarrin@appliedenergygroup.com

Tommy Williams, Lead Analyst

twilliams@appliedenergygroup.com

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2020 CONSERVATION POTENTIAL ASSESSMENT – UPDATE

Prepared for the Avista Technical Advisory Commitee

AGENDA

Topics

- AEG Introduction
- AEG's CPA Methodology
- Electric CPA Summary
- DR Analysis Summary
- Natural Gas CPA Summary

ABOUT AEG

AEG Applied Energy Group

Planning

- Baseline studies
- Market assessment studies
- Program design & action plans
- End-use forecasting

EM&V

- EE portfolio & targeted programs
- Demand response programs & dynamic pricing
- Pilot design & experimental design
- Behavioral programs

Implementation & Technical Services

- Engineering review, due-diligence, QA/QC
- M&V, modeling & simulation, onsite assessments
- Technology R&D and data tools (DEEM)
- Program admin, marketing, implementation, application processing

Market Research

- Program / service pricing optimization
- Process evaluations
- Market assessment / saturation surveys
- Market segmentation
- Customer satisfaction / customer engagement

VISION DSM™ Platform

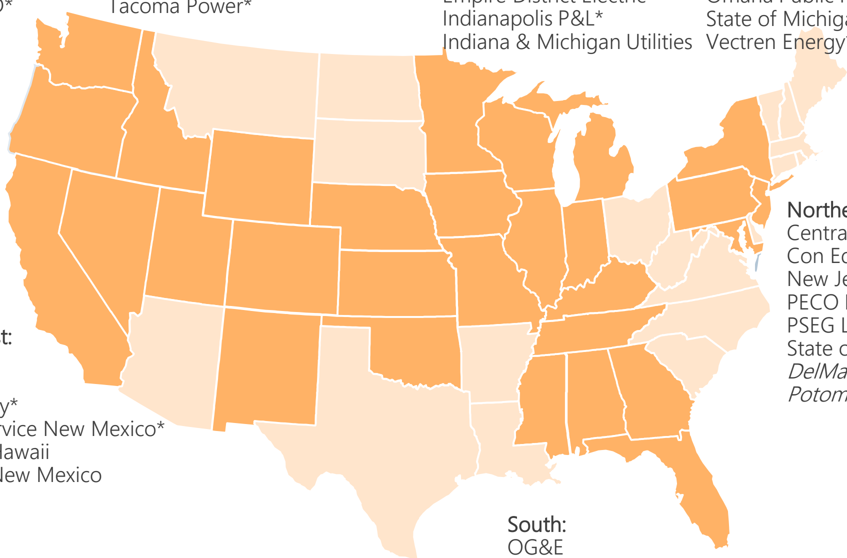
Full DSM lifecycle tracking & reporting

AEG EXPERIENCE IN PLANNING

Including Potential Studies and End-Use Forecasting

Northwest & Mountain:
Avista*
BPA*
Cascade Natural Gas
Chelan PUD
Cheyenne LFP
Colorado Electric*
Cowlitz PUD*
Inland P&L*
Oregon Trail EC
PacifiCorp*
PNGC
PGE*
Seattle City Light*
Tacoma Power*

Midwest:
Ameren Illinois*
Ameren Missouri*
Citizens Energy
Empire District Electric
Indianapolis P&L*
Indiana & Michigan Utilities
Kansas City Power & Light
MERC
NIPSCO*
Omaha Public Power District
State of Michigan
Vectren Energy*



Northeast & Mid Atlantic:
Central Hudson G&E*
Con Edison of NY*
New Jersey BPU
PECO Energy
PSEG Long Island
State of Maryland (*BG&E, DelMarva, PEPCO, Potomac Edison, SMECO*)

Southwest:
HECO
LADWP
NV Energy*
Public Service New Mexico*
State of Hawaii
State of New Mexico
Xcel/SPS

South:
OG&E
Kentucky Power
Southern Company (*APC, GPC, Gulf Power, MPC)*
TVA

Regional & National:
Midcontinent ISO*
EEI/IEE*
EPRI
FERC

* Two or more studies

AEG has conducted more than 60 planning studies for more than 40 utilities / organizations in the past five years.

AEG has a team of 11 experienced Planning staff plus support from AEG's Technical Services and Program Evaluation groups

AEG CPA Methodology

CPA OBJECTIVES

The Avista Conservation Potential Assessment (CPA) supports the Company's regulatory filing and other demand-side management (DSM) planning efforts and initiatives.

The two primary research objectives for the 2020 CPA are:

- **Program Planning:** insights into the market for electric and natural gas energy efficiency (EE) measures and electric demand response (DR) measures in Avista's Washington and Idaho service territories
  - For example, CPAs provide insight into changes to existing program measures as well as new measures to consider
- **IRP:** long-term forecast of future EE and DR potential for use in the IRP
  - Technical Achievable Potential (TAP) for electricity
  - Economic Achievable Potential (EAP) for natural gas

AEG utilizes its comprehensive LoadMAP analytical models that are customized to Avista's service territory.

OVERVIEW OF AEG'S APPROACH

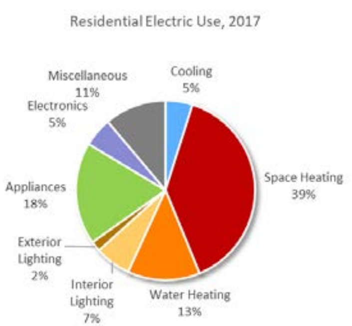
Overview – Electric and Gas

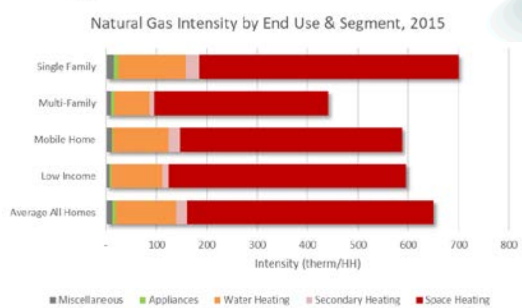
Market Characterization
- Avista control totals
- Customer account data
- Secondary data
- Avista market research

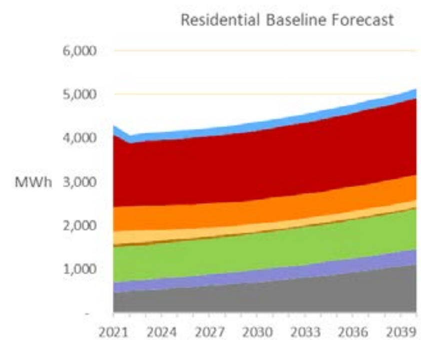
Identify Demand-Side Resources
- EE technologies
- EE measures
- Emerging measures and technologies

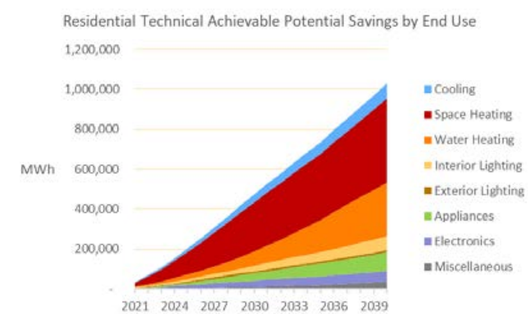
Baseline Projection
- Avista Load Forecast
- Customer growth
- Standards and building codes
- Efficiency options
- Purchase Shares

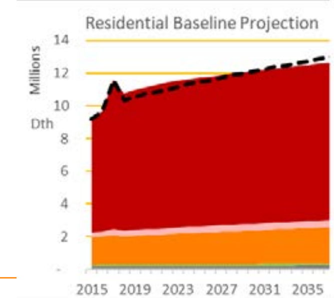
Potential Estimation
- Technical
- Technical Achievable
- Economic Screen *(TRC and UCT) are handled by Avista's IRP*

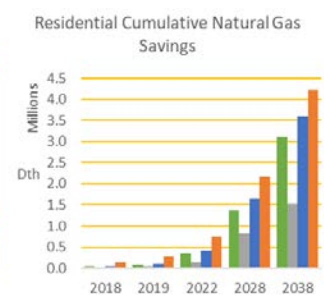












KEY SOURCES OF DATA

Prioritization of Avista Data

Data from Avista was prioritized when available, followed by regional data, and finally well-vetted national data.

Avista sources include:

- 2013 Residential GenPop Survey
- Forecast data and load research
- Recent-year accomplishments and plans

Regional sources include:

- NEEA studies (RBSA 2016, CBSA 2019, IFSA)
- RTF and Power Council methodologies, ramp rates, and measure assumptions

Additional sources include:

- U.S. DOE's Annual Energy Outlook
- U.S. DOE's projections on solid state lighting technology improvements
- Technical Reference Manuals and California DEER
- AEG Research

BASELINE PROJECTION
Overview

"How much energy would customers use in the future if Avista stopped running programs now and in the absence of naturally occurring efficiency?"

- The baseline projection answers this question

The baseline projection is an independent end-use forecast of electric or natural gas consumption at the same level of detail as the market profile

The baseline projection:

Includes	Excludes
• To the extent possible, the same forecast drivers used in the official load forecast, particularly customer growth, natural gas prices, normal weather, income growth, etc. • Trends in appliance saturations, including distinctions for new construction. • Efficiency options available for each technology , with share of purchases reflecting codes and standards (current and finalized future standards) • Expected impact of appliance standards that are "on the books" • Expected impact of building codes, as reflected in market profiles for new construction • Market baselines when present in regional planning assumptions	• Expected impact of naturally occurring efficiency (except market baselines) • **Exception:** RTF workbooks have a market baseline for lighting, which AEG's models also use. • Impacts of current and future demand-side management programs

Applied Energy Group

Electric CPA

AVISTA 2020 ELECTRIC CPA

CPA Methodology Overview

- Levels of Potential
- Economic Evaluation and IRP Integration
- Retained enhancements from 2018 Action Plan

Summary of EE Results

- Summary of Potential
  - High level results
  - Top measures
  - Potential by cost bundles
- Comparison to previous CPA

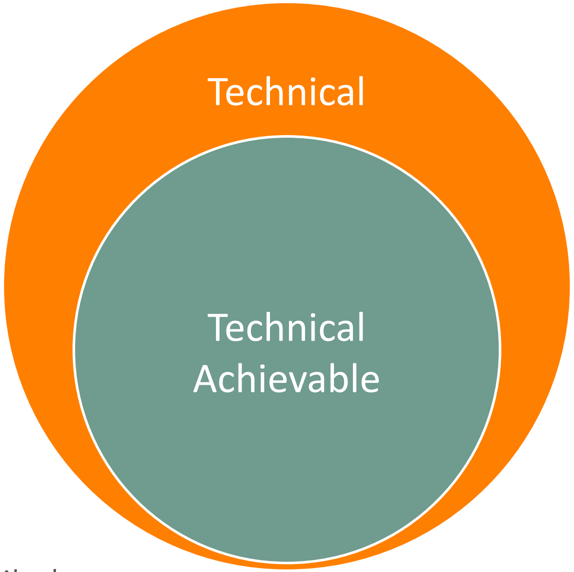
Summary of DR Results

AEG Applied Energy Group

TWO LEVELS OF SAVINGS ESTIMATES

Power Council Methodology

- Focus of the study is to explore a wide range of options for reducing annual energy use
- This study develops two sets of estimates:
  - Technical potential (TP): everyone chooses the most efficient option possible when equipment fails
    - This may include emerging or very expensive ultra-high efficiency technologies
  - Technical Achievable Potential (TAP) is a subset of TP that accounts for customer preference and likelihood to adopt through **both** utility-and non-utility driven mechanisms
    - To better emulate likely programs, Technical Achievable Potential calculates savings from efficient options more likely to be selected by the IRP



- In addition to these estimates, the study produces cost data for the TRC and UCT tests that can be used by Avista's IRP process to select energy efficiency measures in competition with other resources

ECONOMIC METRICS

Two Cost-Effectiveness Tests

AEG provided a levelized net cost of energy ($/kWh) for each measure within the achievable potential within Avista's Washington and Idaho territories from two perspectives.

- **Utility Cost Test (UCT):** Assesses cost-effectiveness from a utility or program administrator's perspective.
- **Total Resource Cost Test (TRC):** Assesses cost-effectiveness from the utility's <u>and</u> participant's perspectives. Includes non-energy impacts if they can be <u>quantified</u> and <u>monetized</u>.

Component	UCT	TRC
Avoided Energy	Benefit	Benefit
Non-Energy Benefits*		Benefit
Incremental Cost		Cost
Incentive	Cost	
Administrative Cost	Cost	Cost
Non-Energy Costs* (e.g. O&M)		Cost

*Council methodology includes monetized impacts on other fuels within these categories

Both values are provided to Avista for all measure level potential, so that the IRP can use the appropriate evaluation for each state: TRC for WA and UCT for ID.

ENHANCEMENTS RETAINED FROM 2018 CPA

AEG has preserved the enhancements to the CPA process that were included in the previous CPA:

- Any measures screened out in advance of technical potential are documented in the measure list along with the reason. As before, very few measures were excluded in this step
  - Measures that were excluded were generally either emerging measures with insufficient data to characterize properly, or highly custom measures that are instead modeled within broader retrocommissioning or strategic energy management programs.
- Full Technical Achievable potential is provided to the IRP along with TRC and UCT costs for each measure
- The Measure Assumptions appendix is again available, containing UES data and other key assumptions and their sources
- Demand Response potential includes analysis of both Summer and Winter possible programs

POTENTIAL ESTIMATES
Achievability

All potential "ramps up" over time – all ramp rates are based on those found within the NWPCC's 2021 Power Plan

- **Max Achievability**
  - NWPCC 2021 Plan allows some measures max achievability to reach up to 100% of technical potential
  - 7th Power Plan and prior CPA had a max achievability of 85%
  - AEG has aligned assumptions with the 2021 Plan and measures such as lighting reach greater than 85%
- **Please note** Power Council's ramp rates include potential realized from outside of utility DSM programs, including regional initiatives and market transformation

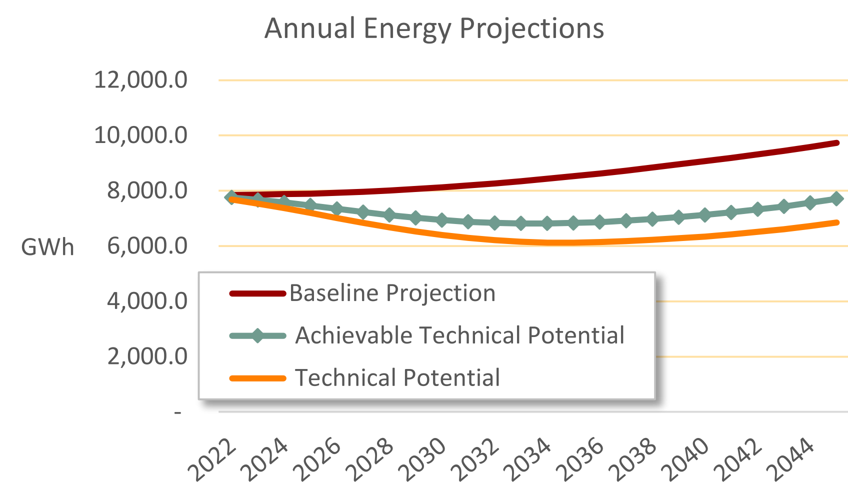
Measures examples over 85% Achievability:
- All Lighting
- Washers/Dryers
- Dishwashers
- Refrigerators/Freezers
- Circulation Pumps
- Thermostats
- C&I Fans

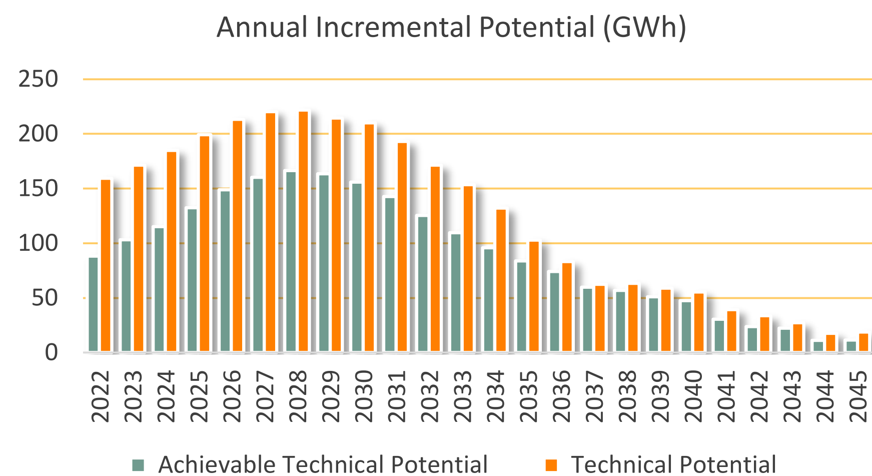
ENERGY EFFICIENCY POTENTIAL

Potential Summary –WA & ID All Sectors

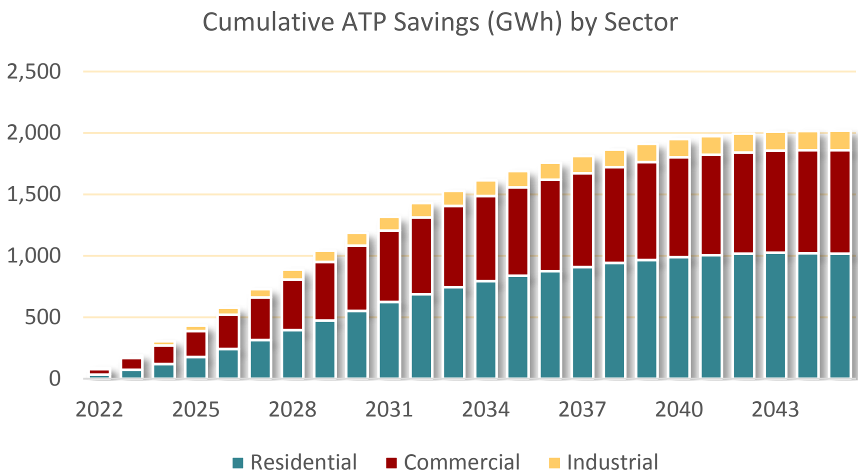
Projections indicate that energy savings of ~1.0% of baseline consumption per year are Technically Achievable.

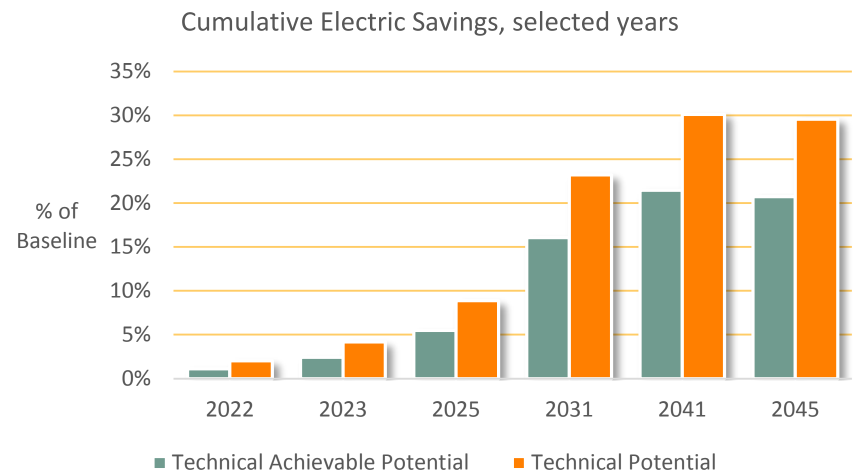
- 190 GWh (22 aMW) in biennium period (2022-2023)
- 1,317 GWh (150 aMW) by 2031
- This level of savings offsets future load growth





EE POTENTIAL, CONTINUED
Potential Summary – WA & ID, All Sectors

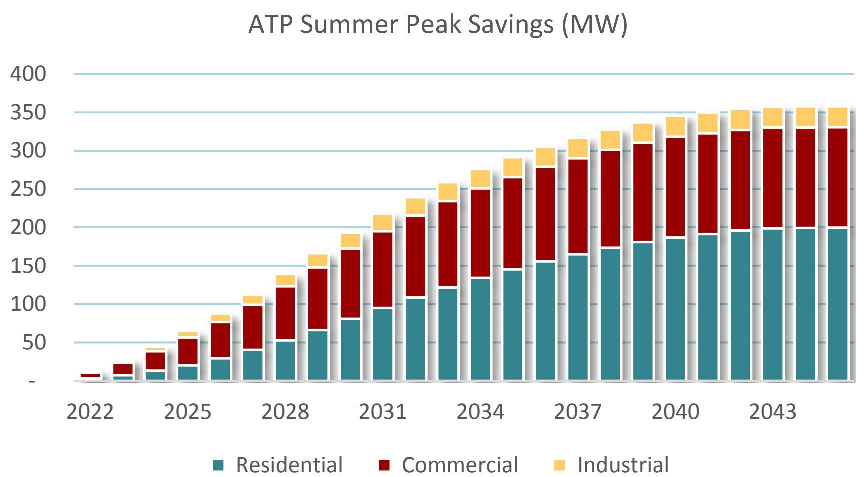


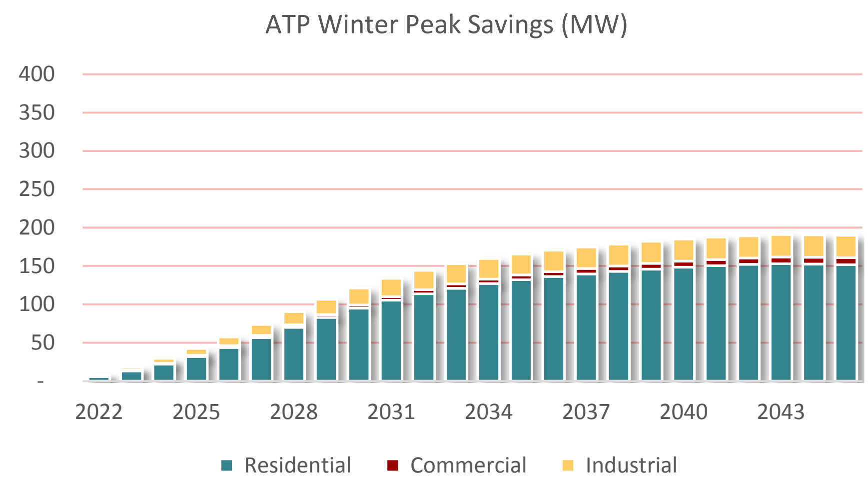


Summary of Energy Savings (GWh), Selected Years	2022	2023	2025	2031	2041	2045
Reference Baseline	7,842	7,863	7,898	8,192	9,193	9,727
Cumulative Savings (GWh)						
Technical Achievable Potential	88	190	432	1,317	1,974	2,019
Technical Potential	159	327	703	1,901	2,770	2,878
Energy Savings (% of Baseline)						
Technical Achievable Potential	1.1%	2.4%	5.5%	16.1%	21.5%	20.8%
Technical Potential	2.0%	4.2%	8.9%	23.2%	30.1%	29.6%
Incremental Savings (GWh)						
Technical Achievable Potential	88	103	133	143	31	11
Technical Potential	159	171	199	193	39	19

EE POTENTIAL - CONTINUED

ATP Peak Savings Summary – WA & ID, All Sectors



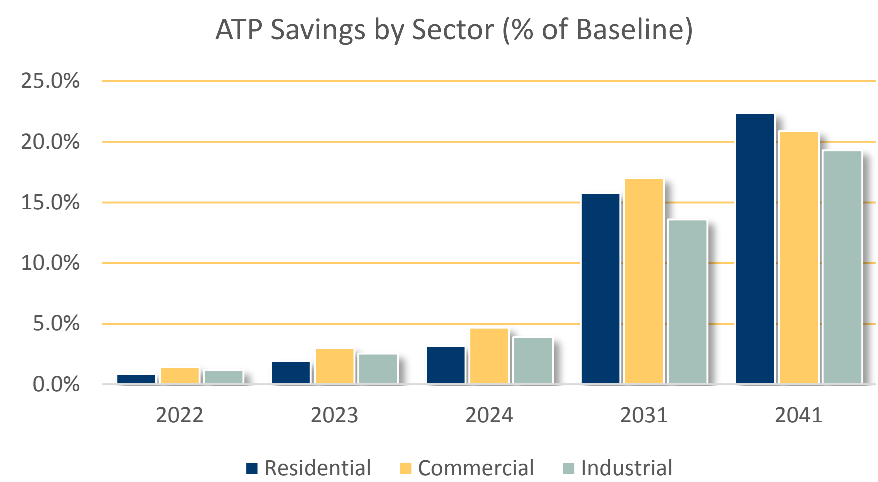


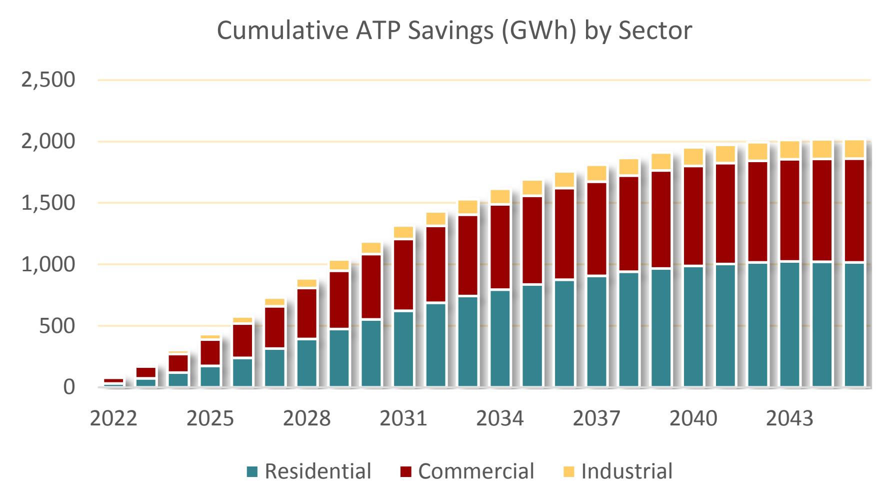
EE Peak Savings (MW), Selected Years	2022	2023	2025	2031	2041	2045
Reference Baseline						
Summer Peak MW	1,626	1,642	1,677	1,834	2,272	2,406
Winter Peak MW	1,518	1,522	1,529	1,574	1,716	1,791
Cumulative Savings (MW)						
Summer Peak	12.6	27.5	64.9	217.6	349.9	357.8
Winter Peak	8.2	18.2	42.6	134.1	187.5	190.1
Cumulative Savings (% of Baseline)						
Summer Peak	0.8%	1.7%	3.9%	11.9%	15.4%	14.9%
Winter Peak	0.5%	1.2%	2.8%	8.5%	10.9%	10.6%
Incremental Savings (MW)						
Summer Peak	12.8	15.2	20.4	25.9	4.9	0.9
Winter Peak	8.2	10.1	13.5	14.5	2.7	0.2

EE POTENTIAL BY SECTOR

Achievable Technical Potential – WA & ID

	2022	2023	2024	2031	2041
Baseline projection (GWh)					
Residential	3,774	3,785	3,796	3,953	4,489
Commercial	3,223	3,234	3,248	3,427	3,924
Industrial	845	843	839	812	780
Total Consumption (GWh)	**7,842**	**7,863**	**7,883**	**8,192**	**9,193**
ATP Cumulative Savings (GWh)					
Residential	32	72	120	623	1,004
Commercial	46	97	152	583	819
Industrial	10	21	33	110	151
Total Savings (GWh)	**88**	**190**	**304**	**1,317**	**1,974**
ATP Cumulative Savings (aMW)					
Residential	4	8	14	71	115
Commercial	5	11	17	67	94
Industrial	1	2	4	13	17
Total Savings (aMW)	**10**	**22**	**35**	**150**	**225**
ATP Cumulative Savings as a % of Baseline					
Residential	0.8%	1.9%	3.1%	15.8%	22.4%
Commercial	1.4%	3.0%	4.7%	17.0%	20.9%
Industrial	1.2%	2.5%	3.9%	13.6%	19.3%
Total Savings (% of Baseline)	**1.1%**	**2.4%**	**3.9%**	**16.1%**	**21.5%**





EE POTENTIAL - TOP MEASURES

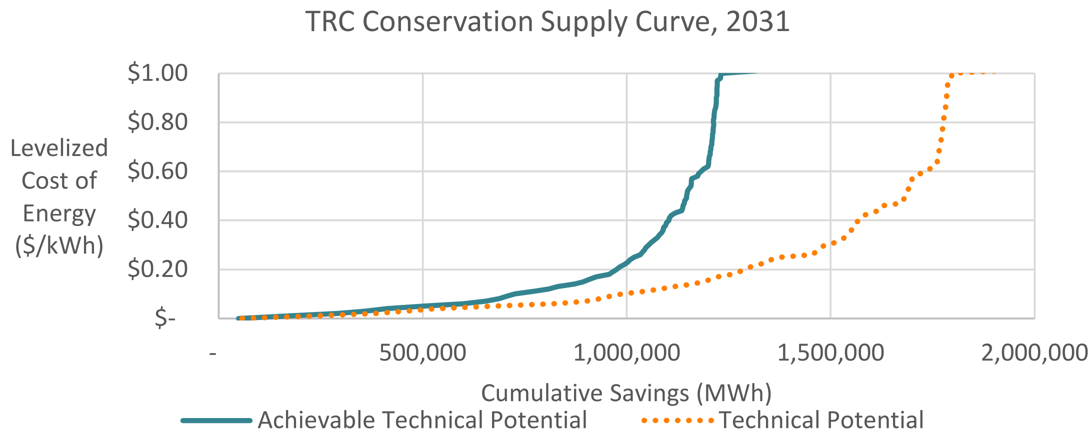
Cumulative Potential Summary – WA & ID All Sectors

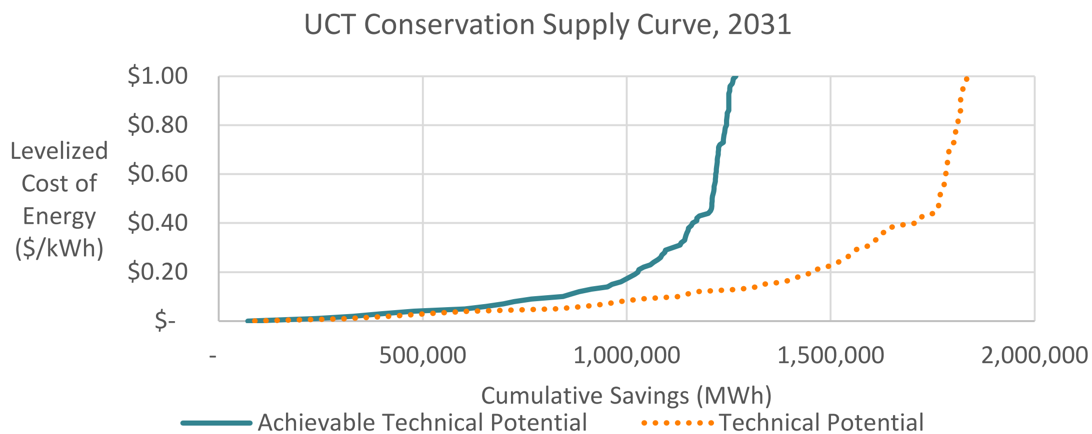
Technical Achievable Potential, Ranked by Savings in 2031 (MWh)

Rank	Measure / Technology	2023 Achievable Technical Potential (MWh)	% of Total	2031 Achievable Technical Potential (MWh)	% of Total	TRC Levelized $/kWh	UCT Levelized $/kWh
1	Commercial - Linear Lighting	9,139	4.8%	62,302	4.7%	$0.01	$0.00
2	Commercial - Retrocommissioning	9,318	4.9%	59,994	4.6%	$0.04	$0.04
3	Residential - Water Heater <= 55 Gal	2,647	1.4%	55,156	4.2%	$0.06	$0.05
4	Commercial - Strategic Energy Management	7,047	3.7%	44,581	3.4%	$0.09	$0.08
5	Residential - Ductless Mini Split Heat Pump (Zonal)	6,599	3.5%	42,085	3.2%	$0.60	$0.44
6	Residential - ENERGY STAR - Connected Thermostat	5,890	3.1%	40,216	3.1%	$0.18	$0.17
7	Residential - Windows - High Efficiency/ENERGY STAR	5,808	3.1%	35,780	2.7%	$1.14	$0.79
8	Residential - Ductless Mini Split Heat Pump with Optimized Controls (Ducted Forced Air)	1,485	0.8%	33,420	2.5%	$0.37	$0.26
9	Residential - Home Energy Management System (HEMS)	4,975	2.6%	30,271	2.3%	$0.27	$0.23
10	Residential - Windows - Cellular Shades	988	0.5%	28,248	2.1%	$0.18	$0.15
11	Commercial - HVAC - Dedicated Outdoor Air System (DOAS)	3,054	1.6%	21,141	1.6%	$0.68	$0.49
12	Residential - Insulation - Basement Sidewall Installation	2,933	1.5%	20,698	1.6%	$0.04	$0.03
13	Commercial - Space Heating - Heat Recovery Ventilator	5,128	2.7%	20,274	1.5%	$0.14	$0.10
14	Commercial - High-Bay Lighting	4,123	2.2%	19,394	1.5%	$0.00	$0.00
15	Residential - Windows - Low-e Storm Addition	2,832	1.5%	18,790	1.4%	$0.82	$0.33
16	Residential - Furnace - Conversion to Air-Source Heat Pump	639	0.3%	15,407	1.2%	$0.08	$0.06
17	Industrial - High-Bay Lighting	6,056	3.2%	14,687	1.1%	$0.00	$0.00
18	Commercial - General Service Lighting	3,181	1.7%	13,705	1.0%	$0.05	$0.03
19	Commercial - Interior Lighting - Embedded Fixture Controls	2,470	1.3%	13,523	1.0%	$0.08	$0.06
20	Residential - Connected Line-Voltage Thermostat	1,817	1.0%	13,433	1.0%	$0.12	$0.10
	Total of Top 20 Measures	**86,126**	**45.2%**	**603,105**	**45.8%**		
	Total Cumulative Savings	**190,351**	**100.0%**	**1,316,823**	**100.0%**		

SUPPLY CURVES

WA & ID Technical Achievable Potential by 2031





EE POTENTIAL
Top Measure Notes

- Some expensive or emerging measures have significant **technical achievable** potential, but may not be selected by the IRP due to costs
- Heat Pump measures, including DHPs and HPWHs, have significant annual energy benefits, however since heat pumps revert to electric resistance heating during extreme cold, they do not have a corresponding winter peak benefit
- In addition to being expensive, some emerging tech measures are included in Technical Achievable which may not prove feasible for programs at this time, but can be kept in mind for future programs, e.g.:
  - Advanced New Construction – Zero Net Energy
  - Connected Home Control Systems

EE POTENTIAL - CONTINUED

Peak Impacts – **Technical Achievable Potential**

	Top Measures - Winter Peak (MW) Reduction by 2031	2031 MW	% of Total
1	Residential - ENERGY STAR - Connected Thermostat	12	8.9%
2	Residential - Windows - High Efficiency/ENERGY STAR	10	7.8%
3	Residential - Windows - Cellular Shades	8	5.8%
4	Residential - Insulation - Basement Sidewall Installation	7	5.4%
5	Residential - Windows - Low-e Storm Addition	7	5.0%
6	Residential - Home Energy Management System (HEMS)	5	4.0%
7	Residential - Connected Line-Voltage Thermostat	5	3.4%
8	Commercial - Linear Lighting	4	3.2%
9	Residential - Building Shell - Air Sealing (Infiltration Control)	4	3.0%
10	Residential - Insulation - Floor Upgrade	4	2.9%
11	Residential - Ducting - Repair and Sealing	4	2.7%
12	Residential - Insulation - Floor Installation	3	2.5%
13	Residential - Water Heater <= 55 Gal	3	2.5%
14	Residential - Insulation - Ducting	3	2.4%
15	Residential - Ducting - Repair and Sealing - Aerosol	3	2.2%
16	Residential - Building Shell - Liquid-Applied Weather-Resistive Barrier	3	2.2%
17	Industrial - Fan System - Equipment Upgrade	3	1.9%
18	Industrial - Retrocommissioning	3	1.9%
19	Residential - Building Shell - Whole-Home Aerosol Sealing	2	1.8%
20	Industrial - Strategic Energy Management	2	1.6%
	Total of Top 20 Measures	**95**	**70.9%**
	Total Cumulative Savings	**134**	**100.0%**

	Top Measures - Summer Peak (MW) Reduction by 2031	2031 MW	% of Total
1	Commercial - Retrocommissioning	12	5.6%
2	Residential - ENERGY STAR - Connected Thermostat	11	5.0%
3	Residential - Windows - High Efficiency/ENERGY STAR	11	5.0%
4	Residential - Windows - Cellular Shades	10	4.8%
5	Residential - Ductless Mini Split Heat Pump (Zonal)	8	3.7%
6	Commercial - Strategic Energy Management	8	3.6%
7	Residential - Whole-House Fan - Installation	7	3.2%
8	Residential - Room AC - Removal of Second Unit	7	3.1%
9	Residential - Home Energy Management System (HEMS)	6	2.7%
10	Commercial - HVAC - Dedicated Outdoor Air System (DOAS)	6	2.6%
11	Residential - Insulation - Ceiling Installation	6	2.6%
12	Commercial - RTU - Evaporative Precooler	5	2.4%
13	Commercial - Linear Lighting	5	2.2%
14	Residential - Ductless Mini Split Heat Pump with Optimized Controls (Ducted Forced Air)	4	1.9%
15	Residential - Insulation - Wall Sheathing	4	1.9%
16	Commercial - Chiller - Variable Flow Chilled Water Pump	4	1.8%
17	Residential - Central AC	4	1.8%
18	Residential - Building Shell - Liquid-Applied Weather-Resistive Barrier	4	1.7%
19	Commercial - RTU - Advanced Controls	3	1.5%
20	Residential - Behavioral Programs (Incremental)	3	1.5%
	Total of Top 20 Measures	**128**	**58.7%**
	Total Cumulative Savings	**218**	**100.0%**

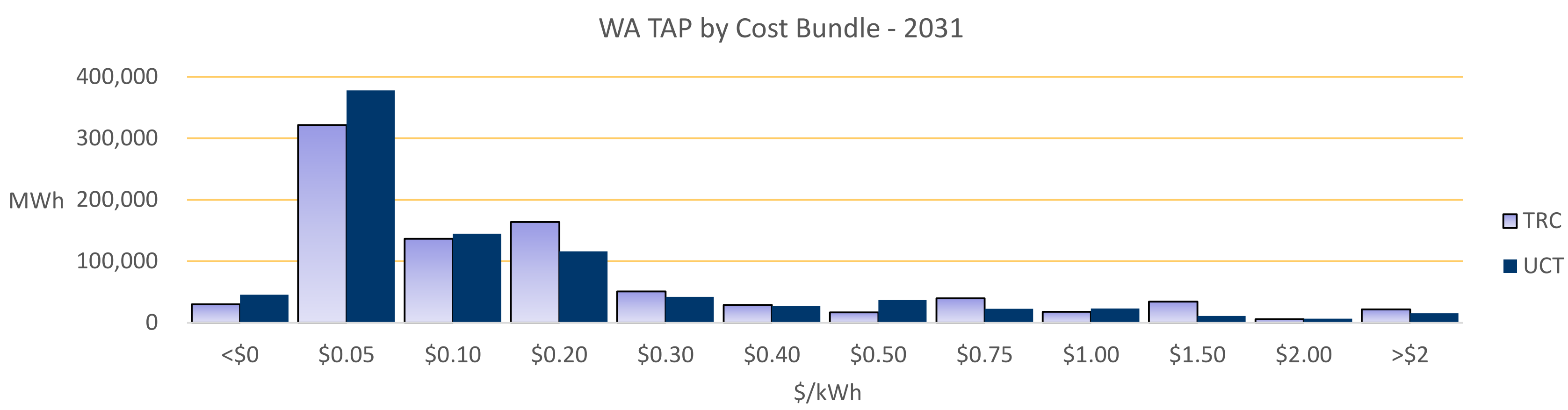
COST OF SAVINGS

WA – TAP by Bundled $/kWh

Washington

TRC $/kWh	2022	2023	2031
< $0.00	2,899	6,276	30,063
$0.00 - $0.05	21,071	45,441	321,449
$0.06 - $0.10	7,784	17,210	136,569
$0.11 - $0.20	8,689	19,108	163,687
$0.21 - $0.30	3,809	7,928	50,997
$0.31 - $0.40	1,680	3,665	29,050
$0.41 - $0.50	985	2,128	16,590
$0.51 - $0.75	2,750	5,952	39,772
$0.76 - $1.00	1,233	2,685	17,996
$1.01 - $1.50	2,754	5,954	34,569
$1.51 - $2.00	419	880	5,849
> $2.00	1,671	3,574	21,755

UCT $/kWh	2022	2023	2031
< $0.00	3,050	6,417	45,484
$0.00 - $0.05	25,187	54,710	377,861
$0.06 - $0.10	7,546	16,772	144,587
$0.11 - $0.20	6,766	14,588	115,890
$0.21 - $0.30	3,248	6,814	42,005
$0.31 - $0.40	1,603	3,418	27,599
$0.41 - $0.50	2,349	5,229	36,677
$0.51 - $0.75	1,639	3,542	22,466
$0.76 - $1.00	1,959	4,190	23,004
$1.01 - $1.50	712	1,522	10,768
$1.51 - $2.00	623	1,296	6,795
> $2.00	1,061	2,305	15,209



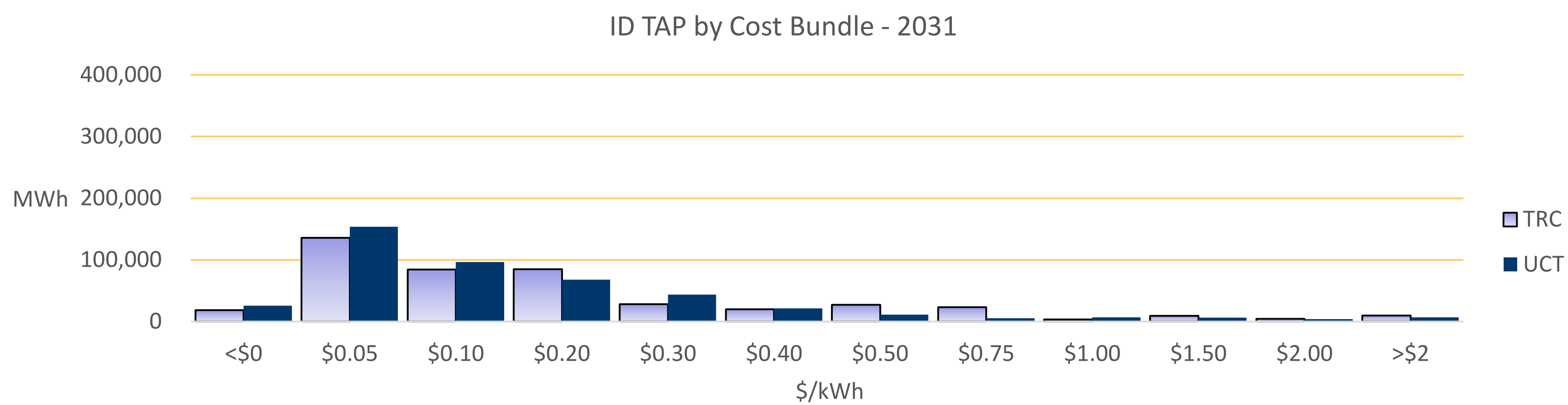
COST OF SAVINGS

ID – TAP by Bundled $/kWh

Idaho

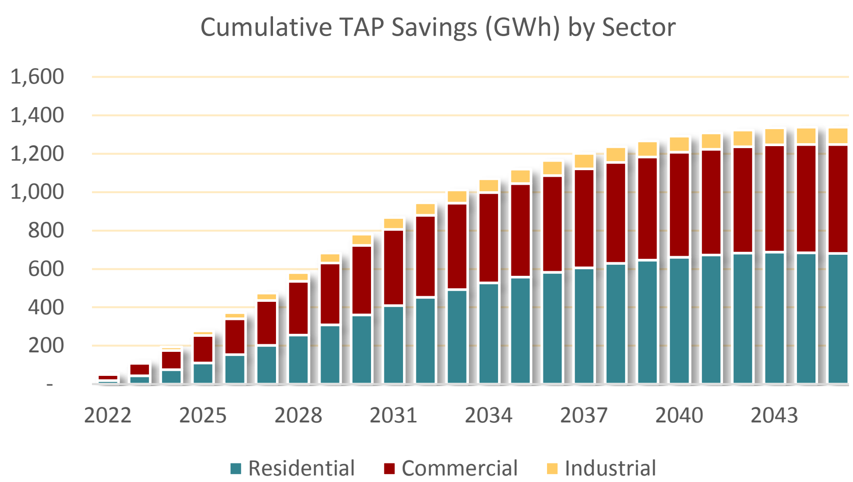
TRC $/kWh	2022	2023	2031
< $0.00	1,906	4,142	18,262
$0.00 - $0.05	11,189	23,472	135,613
$0.06 - $0.10	5,225	11,304	84,553
$0.11 - $0.20	5,335	11,461	84,826
$0.21 - $0.30	1,776	3,826	28,334
$0.31 - $0.40	1,037	2,306	19,831
$0.41 - $0.50	1,959	4,258	27,243
$0.51 - $0.75	1,638	3,594	23,138
$0.76 - $1.00	304	638	3,560
$1.01 - $1.50	806	1,705	9,065
$1.51 - $2.00	334	693	4,180
> $2.00	1,047	2,148	9,873

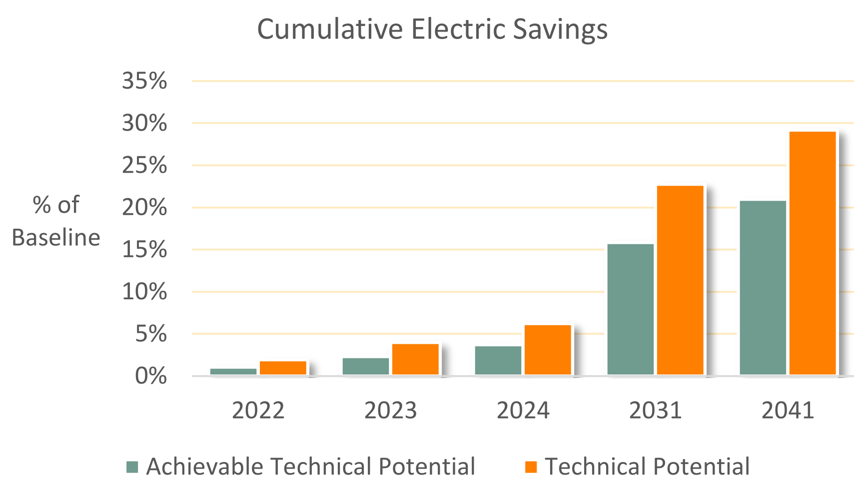
UCT $/kWh	2022	2023	2031
< $0.00	1,631	3,449	25,696
$0.00 - $0.05	12,929	27,284	153,798
$0.06 - $0.10	6,082	13,171	96,251
$0.11 - $0.20	4,224	9,124	67,796
$0.21 - $0.30	2,767	6,061	43,471
$0.31 - $0.40	1,455	3,140	21,259
$0.41 - $0.50	837	1,826	11,325
$0.51 - $0.75	406	884	5,279
$0.76 - $1.00	633	1,322	6,969
$1.01 - $1.50	540	1,124	6,089
$1.51 - $2.00	409	825	3,796
> $2.00	642	1,337	6,748



EE POTENTIAL, CONTINUED

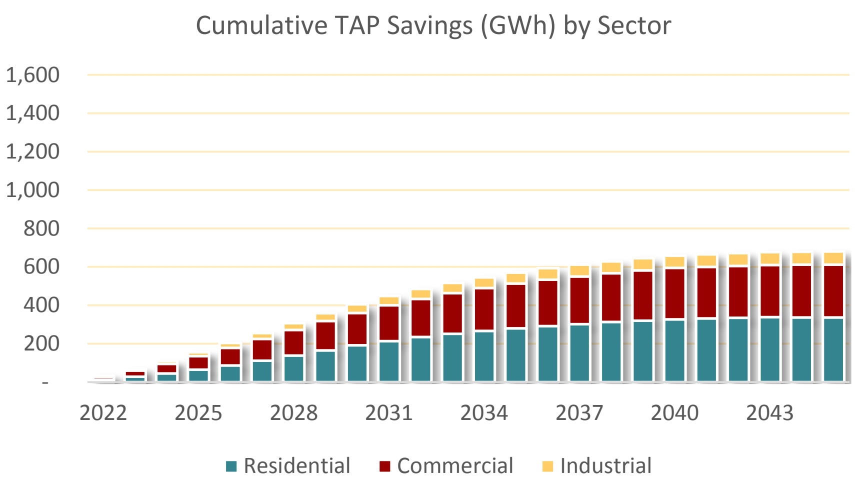
Potential Summary – Washington, All Sectors

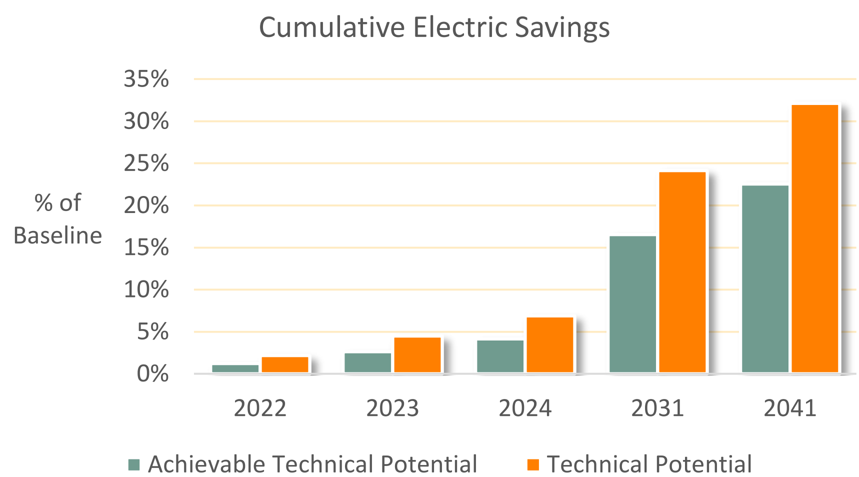




	2022	2023	2024	2031	2041
Baseline projection (GWh)	5,196	5,212	5,229	5,479	6,243
Cumulative Savings (GWh)					
Achievable Technical Potential	56	121	194	868	1,309
Technical Potential	101	209	325	1,247	1,822
Cumulative Savings (aMW)					
Achievable Technical Potential	6	14	22	99	149
Technical Potential	12	24	37	142	208
Cumulative Savings as a % of Baseline					
Achievable Technical Potential	1.1%	2.3%	3.7%	15.8%	21.0%
Technical Potential	2.0%	4.0%	6.2%	22.8%	29.2%

EE POTENTIAL, CONTINUED
Potential Summary – Idaho, All Sectors





	2022	2023	2024	2031	2041
Baseline projection (GWh)	2,646	2,650	2,653	2,713	2,951
Cumulative Savings (GWh)					
Achievable Technical Potential	33	70	110	448	665
Technical Potential	58	119	183	654	948
Cumulative Savings (aMW)					
Achievable Technical Potential	4	8	13	51	76
Technical Potential	7	14	21	75	108
Cumulative Savings as a % of Baseline					
Achievable Technical Potential	1.2%	2.6%	4.1%	16.5%	22.5%
Technical Potential	2.2%	4.5%	6.9%	24.1%	32.1%

Comparison with 2018 Electric CPA

NOTES ON COMPARISON

Comparison with Prior Potential Study

We are often asked to compare results between current and prior potential study estimates – it is important to define comparison parameters.

Aligning calendar years, rather than study years results in a more thorough comparison

- This is mainly due to things like equipment standards, which come on by calendar year, not relative to the start year of the study

Since we are not estimating potential in 2021, potential for that year must be removed from the comparison

- **First-Year Incremental Potential** - 2022
  - Prior Study: 2nd year of potential
  - Current Study: first year

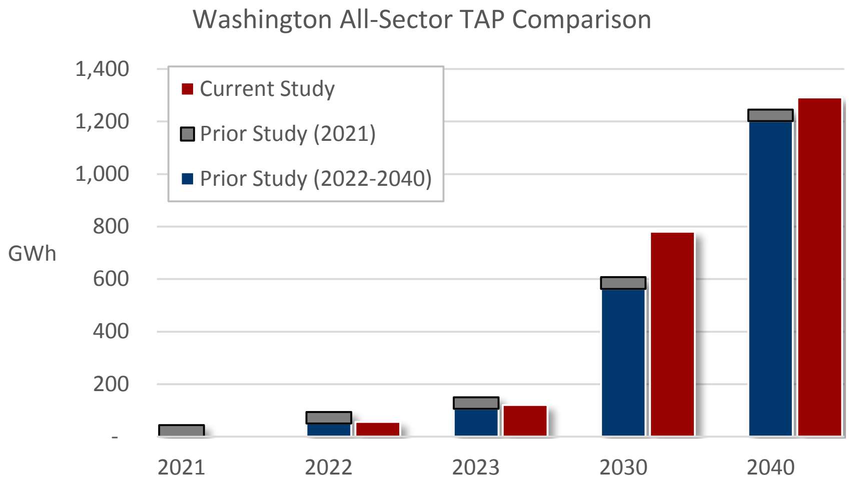
The previous study's 20-year look ended in 2040, therefore we must remove 2041-2045 from the comparison

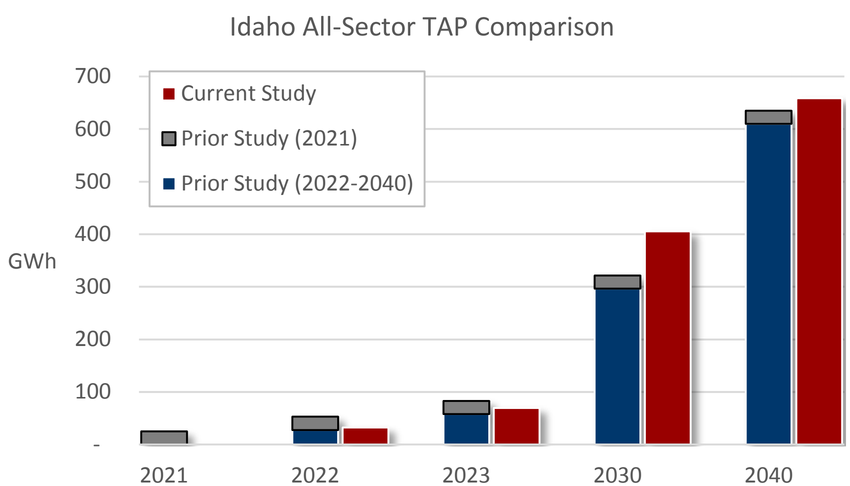
- **Cumulative Potential Comparisons** – 2022 through year 2040
  - This should have a minimal impact on potential since retrofits are mainly captured prior to this point

As a result, we can draw up to a 19 year comparison (2022-2040)

ACHIEVABLE POTENTIAL COMPARISON

Comparison with Prior Potential Study (2022-2037 **TAP**)

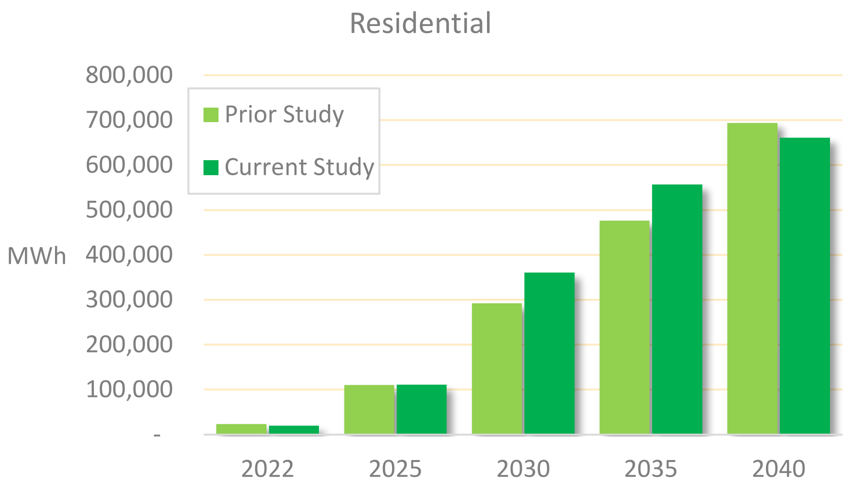


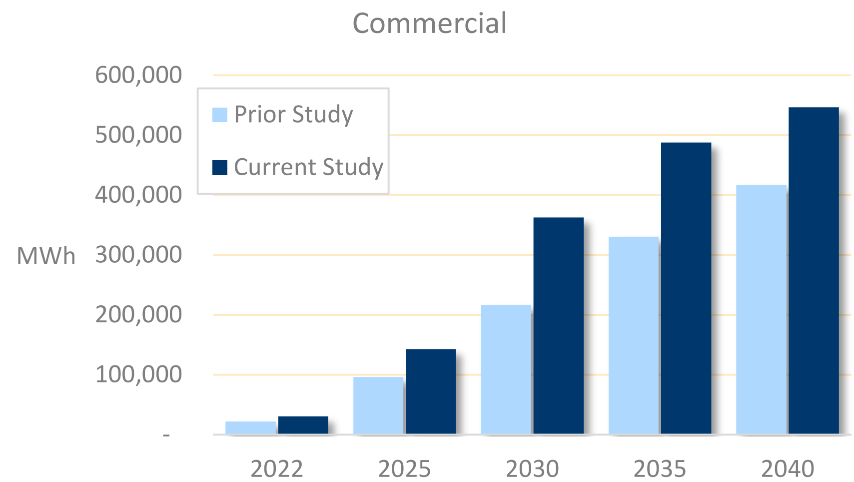


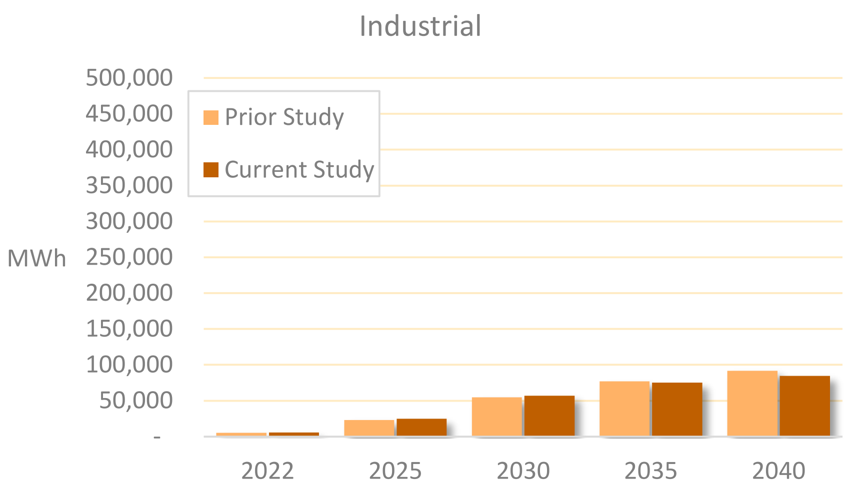
Sector (All States)	End Use	Prior CPA 2040 MWh	Current Study 2040 MWh	Diff.
Residential	Cooling	74,528	112,573	38,045
	Heating	444,182	442,897	-1,285
	Water Heating	267,144	217,843	-49,301
	Interior Lighting	63,331	24,122	-39,209
	Exterior Lighting	10,059	4,122	-5,937
	Appliances	91,966	82,297	-9,668
	Electronics	49,899	58,651	8,752
	Miscellaneous	35,248	45,661	10,413
Commercial	Cooling	99,708	145,262	45,554
	Heating	33,372	100,989	67,617
	Ventilation	73,363	116,241	42,878
	Water Heating	22,078	26,182	4,104
	Interior Lighting	261,940	210,469	-51,471
	Exterior Lighting	103,244	61,188	-42,057
	Refrigeration	42,103	119,602	77,499
	Food Preparation	0	8,517	8,517
	Office Equipment	3,805	14,945	11,139
	Miscellaneous	2,018	10,216	8,198
Industrial	Cooling	6,160	4,779	-1,381
	Heating	11,042	566	-10,476
	Ventilation	7,942	11,679	3,736
	Interior Lighting	52,125	49,781	-2,344
	Exterior Lighting	12,428	5,213	-7,215
	Motors	33,106	69,081	35,975
	Process	10,059	7,012	-3,047
	Miscellaneous	671	775	104
Grand Total		**1,811,520**	**1,950,662**	**139,142**

SECTOR-LEVEL ACHIEVABLE POTENTIAL

Washington - Comparison with Prior Study **– Technical Achievable**



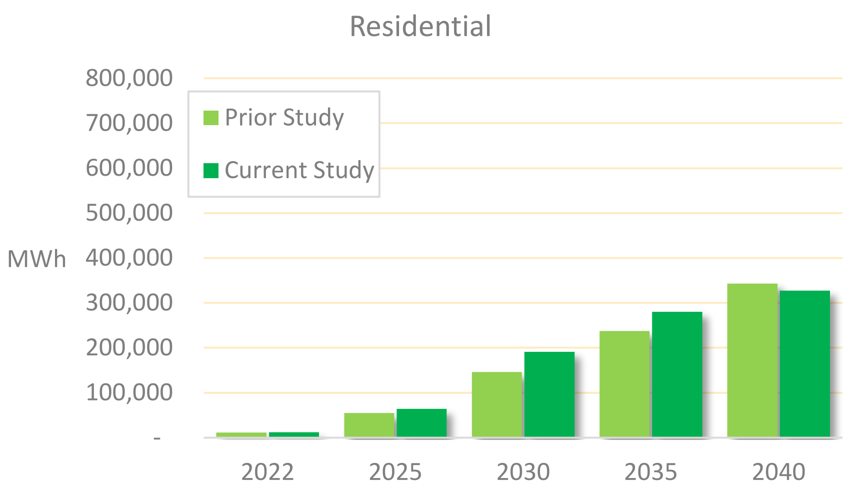


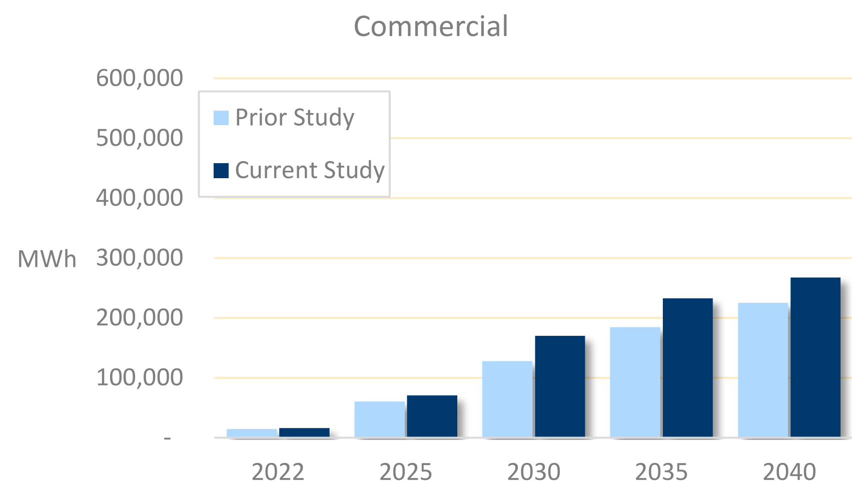


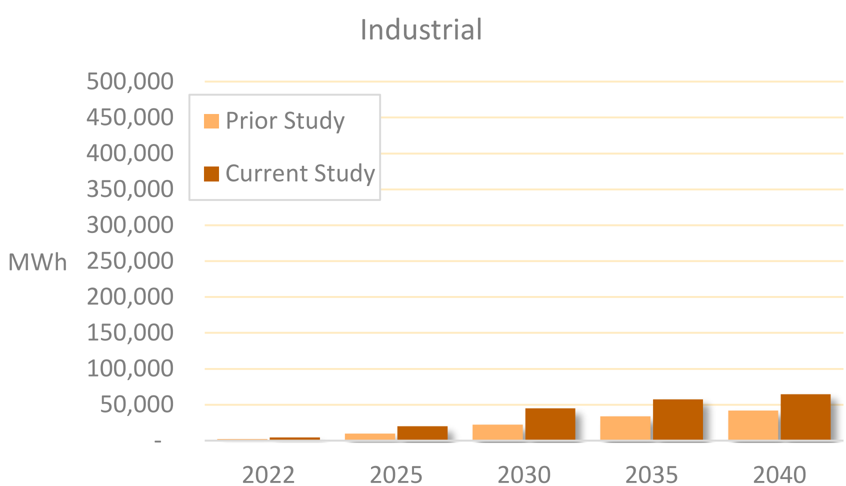
- 2020 savings already removed from prior study values

SECTOR-LEVEL ACHIEVABLE POTENTIAL

Idaho - Comparison with Prior Study – **Technical Achievable**







- 2020 savings already removed from prior study values

SECTOR-LEVEL NOTES

Comparison with Prior Potential Study – **Technical Achievable**

Residential:

- LED share of interior lighting market baseline continues to grow, reducing available potential from turnover of old units
  - This limits the extra potential Idaho gets from not having the EISA backstop in place
- HPWH savings have been revised slightly downward

Commercial:

- Decreases in interior lighting potential as base LED share grows in interior lighting; accelerated turnover and ramp rate compensates, but not completely
- Increased refrigeration potential from new and emerging measures, updated RTF workbooks
- HVAC retrocommissioning and controls (e.g. Strategic Energy Management systems) greatly expanded applicability in 2021 plan compared to prior study

Industrial:

- Increased potential in motors from updated retrofit applicability in 2021 plan

NEXT STEPS

- AEG has provided measure list and assumption appendices for EE to Avista for circulation
- Electric IRP will evaluate cost effective portfolio based on AEG provided savings and levelized costs
- Gas IRP will run with AEG-provided UCT cost effective potential

AEG

Applied Energy Group

Thank You!

Ingrid Rohmund, Sr. Vice President, Consulting
irohmund@appliedenergygroup.com

Ken Walter, Project Manager
kwalter@appliedenergygroup.com

Kelly Marrin, Managing Director

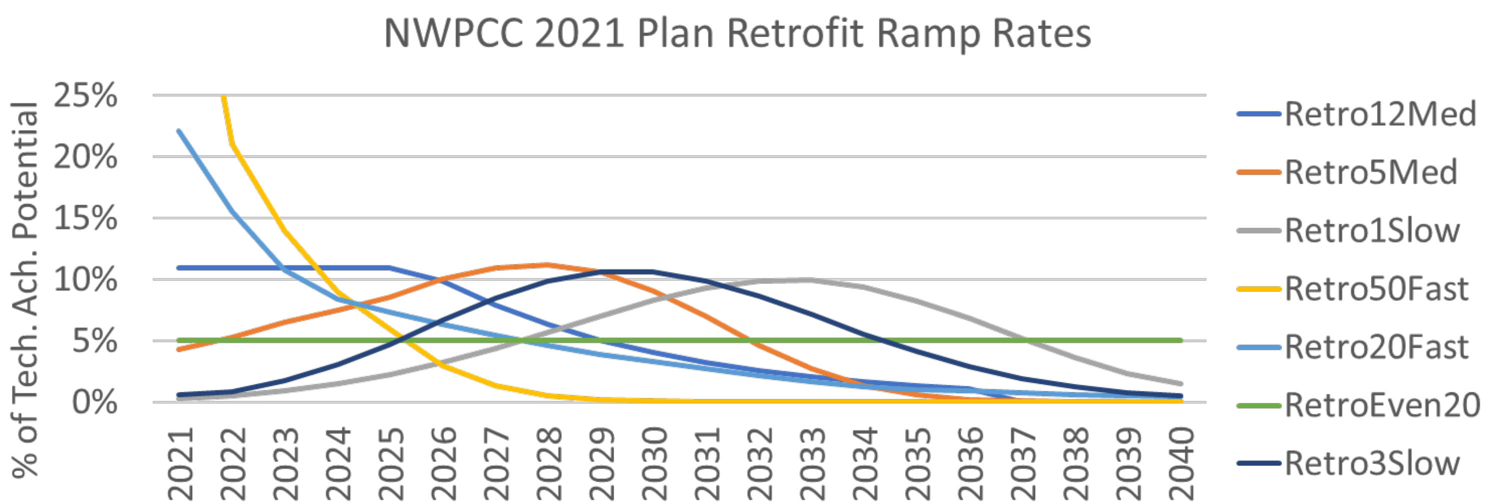
kmarrin@appliedenergygroup.com

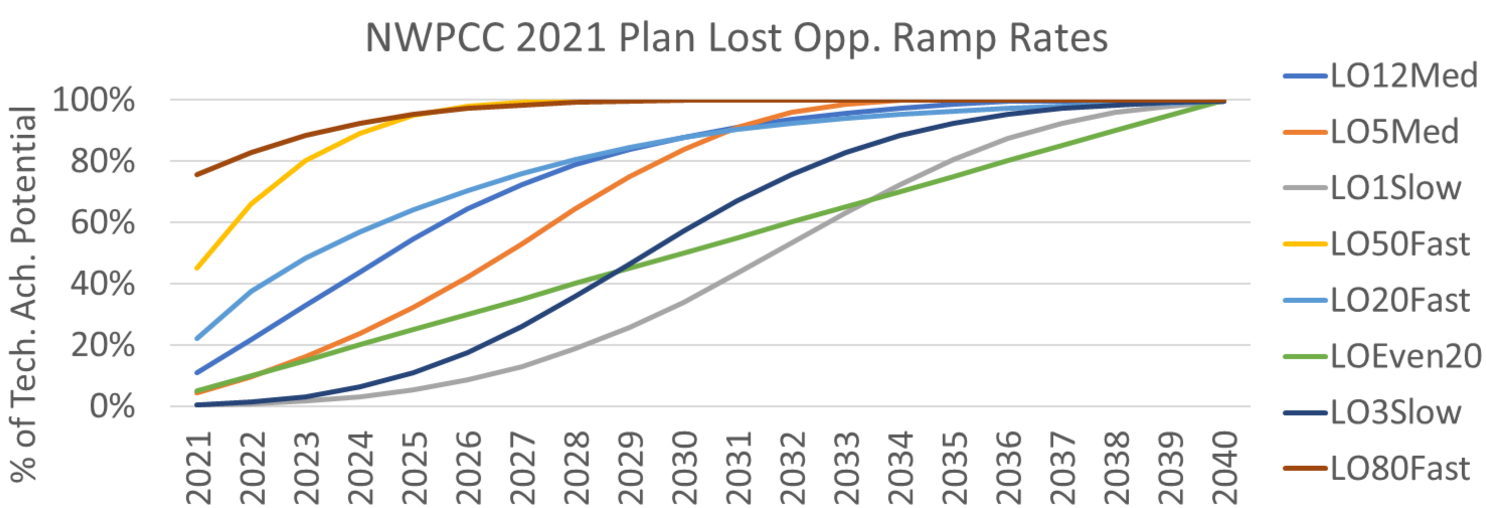
Tommy Williams, Lead Analyst

twilliams@appliedenergygroup.com

Supplemental Slides

NWPCC 2021 PLAN RAMP RATES





EE RAMP RATE CHANGES

Sector(s)	Measure Category	Equipment or Non-Equip	2019 CPA Ramp Rate	2021 Plan Ramp Rate
Res	Appliances	Equipment	LO1Slow	LO12Med
Res	Building Shell	Non-Equipment	Retro12Med	Retro5Med
Res	Energy Kits	Non-Equipment	Aerators: Retro3Slow, SH: Ret12Med	Retro3Slow
Res	HVAC	Equipment	LO5Med CAC, LO1Slow RAC	LO5Med CAC, LO12Med RAC
Res	HVAC	Non-Equipment	Thermostat&DHP Retro5Med, Retro3Slow	Thermostat&DHP Retro5Med, Retro5Med
Res	Lighting	Equipment	LO12Med & LO20 Fast	LO20Fast
Res	Water Heating	Equipment	LO3Slow	LO5Med
Res	Whole Home	Non-Equipment	LOEven20	NA
Res	Electronics	Non-Equipment	Retro3Slow	Retro3Slow

Sector(s)	Measure Category	Equipment or Non-Equip	2019 CPA Ramp Rate	2021 Plan Ramp Rate
C&I	Building Shell	Non-Equipment	RetroEven20	Retro1Slow
C&I	Compressed Air	Both	Retro5Med, Retro12Med	Retro5Med, Retro12Med
C&I	Energy Management	Non-Equipment	Retro12Med	Retro5Med
C&I	Food Service Equipment	Equipment	LO5Med, LO12Med	LO3Slow, LO1Slow
C&I	HVAC	Equipment	LO5Med, LO20Fast	LO5Med, LO12Med
C&I	HVAC	Non-Equipment	RetroEven20, Retro12Med, Retro3Slow, Retro1Slow	Retro12Med, Retro5Med
C&I	Irrigation	Non-Equipment	Retro12Med mostly	RetroEven20
C&I	Lighting	Equipment	LO20Fast/LO50Fast	LO80Fast
C&I	Motors	Non-Equipment	Retro12Med	Retro12Med
C&I	Refrigeration	Both	Retro12Med	Retro5Med

- Several residential categories were adjusted to faster ramp rates
- C&I changes mostly slowed adoption, except for lighting which is greatly accelerated and non-equipment HVAC (maintenance, tune ups, etc) which accelerated

Legend:
Faster Ramp
Slower Ramp
No Change
**compared to 2019 CPA Ramps*

DEFINITIONS OF POTENTIAL

Cumulative and Incremental

Over the following slides, we will display potential both as a **cumulative** impact on baseline as well as in annual **increments**

Cumulative potential includes the impacts of potential acquired from the first year of the study period (2022) through the year of interest, including effects of measures persistence

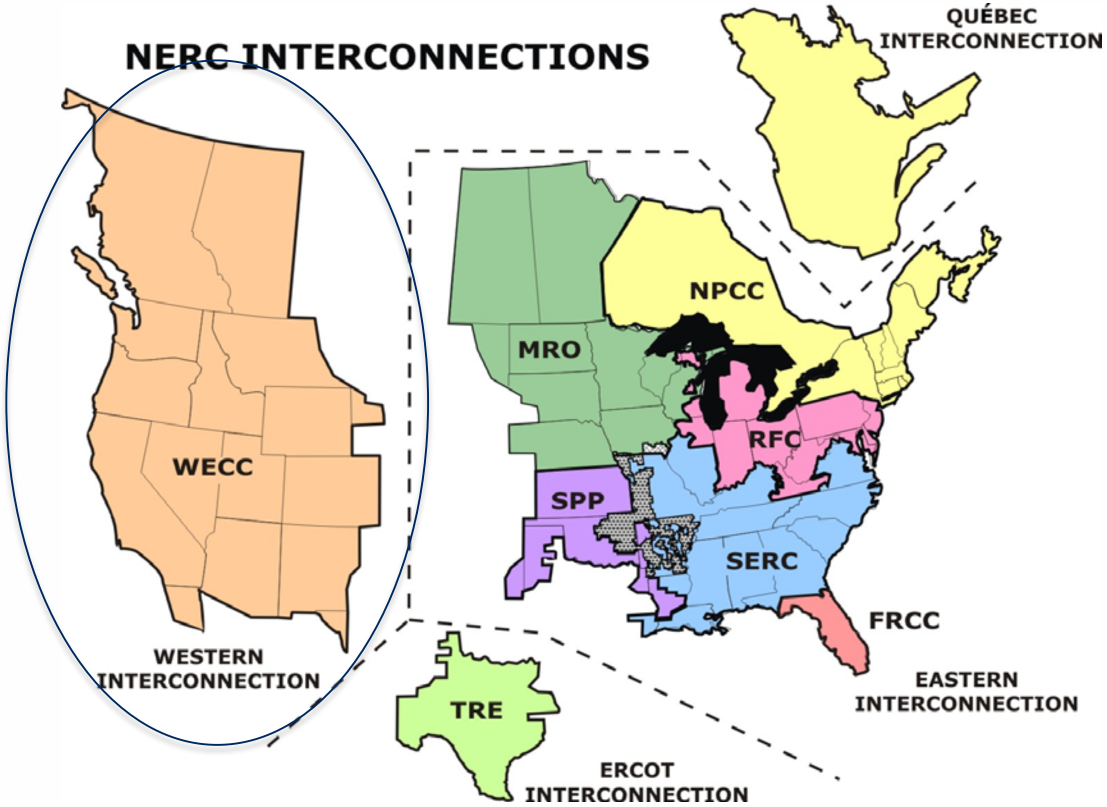
Incremental potential summarizes new impacts realized in any given year of interest, excluding the effects of measure repurchases

Electric Wholesale Market Price Forecast

James Gall, Electric IRP Manager
Third Technical Advisory Committee Meeting
September 29, 2020

Market Price Forecast – Purpose

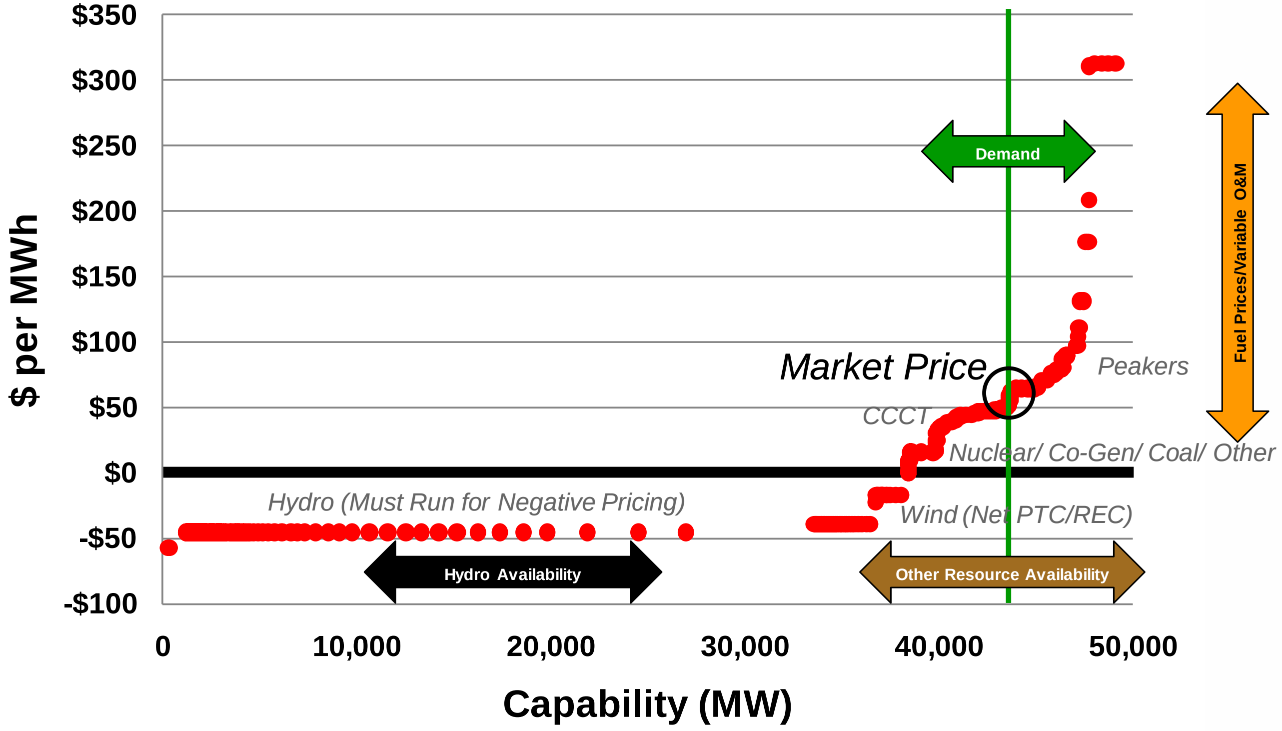
- Estimate "market value" of resources options for the IRP
- Estimate dispatch of "dispatchable" resources
- Helps estimate avoided costs
- May change resource selection if resource production is counter to needs of the wholesale market



Source: NERC

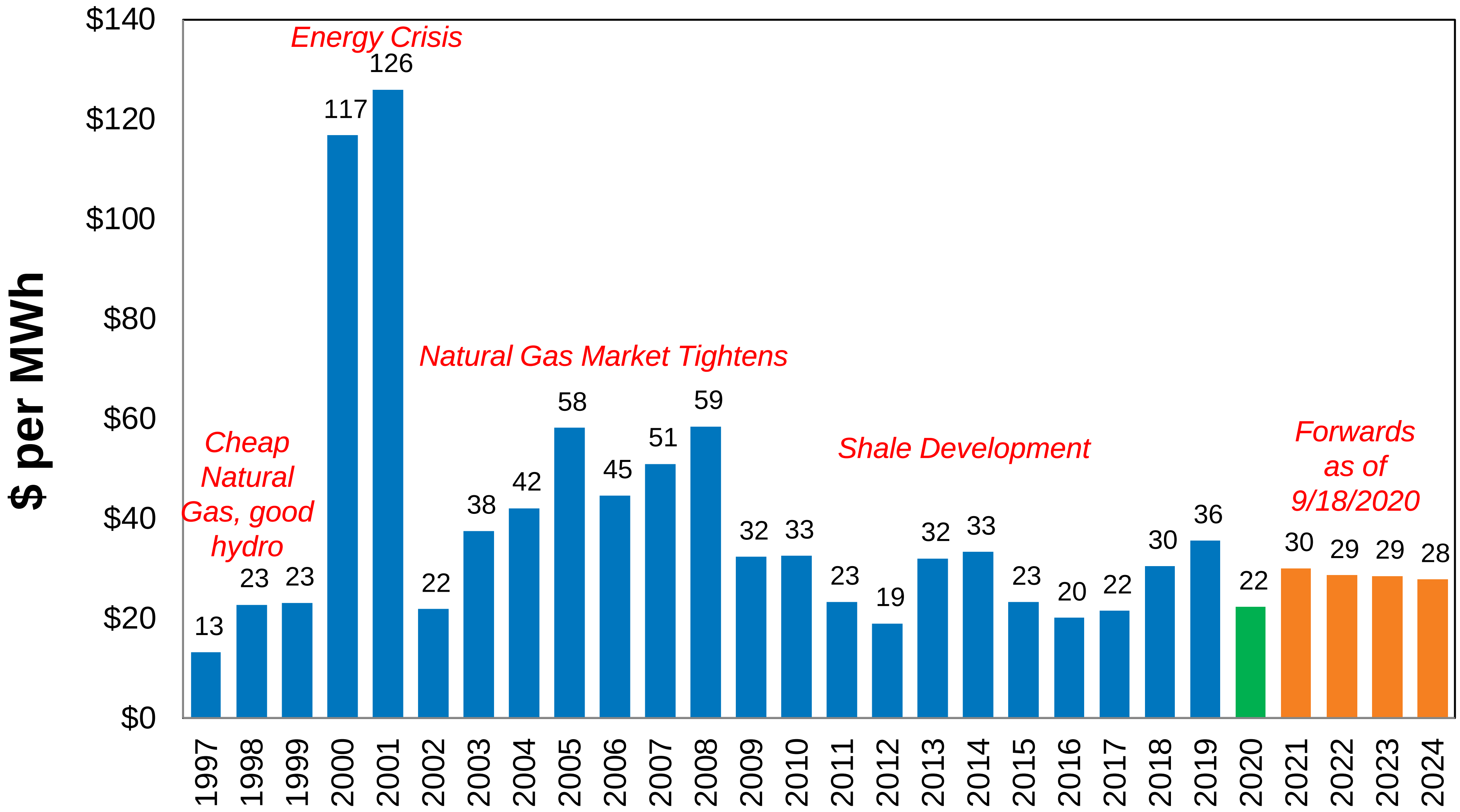
Methodology

- 3rd party software- Aurora by Energy Exemplar
- Electric market fundamentals- production cost model
- Simulates generation dispatch to meet regional load
- Outputs:
  - Market prices (electric & emission)
  - Regional energy mix
  - Transmission usage
  - Greenhouse gas emissions
  - Power plant margins, generation levels, fuel costs
  - Avista's variable power supply costs

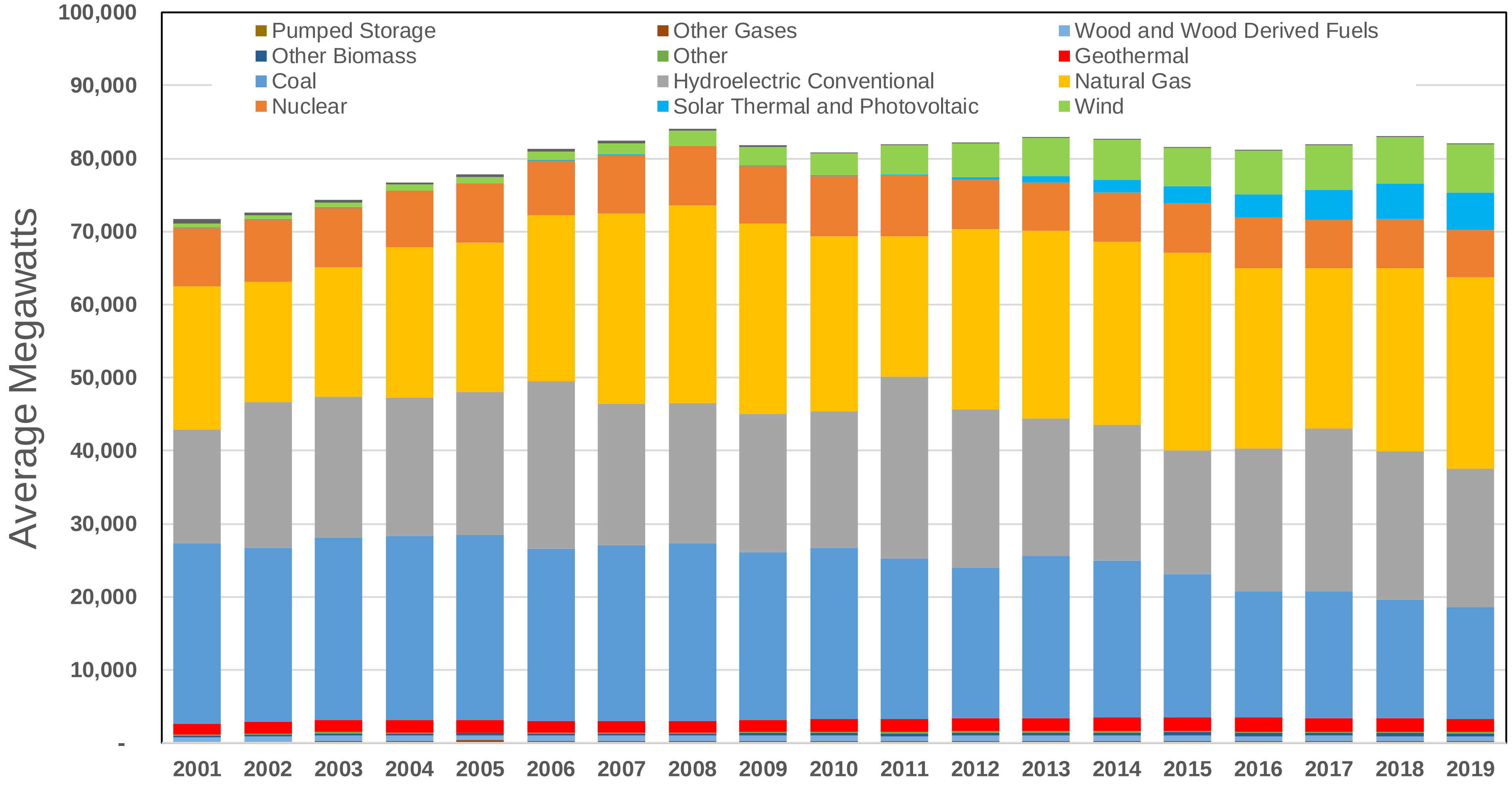


Note: minimum price is negative $25/ MWh (2018$)

Wholesale Mid-C Electric Market Price History



U.S. Western Interconnect Generation Mix



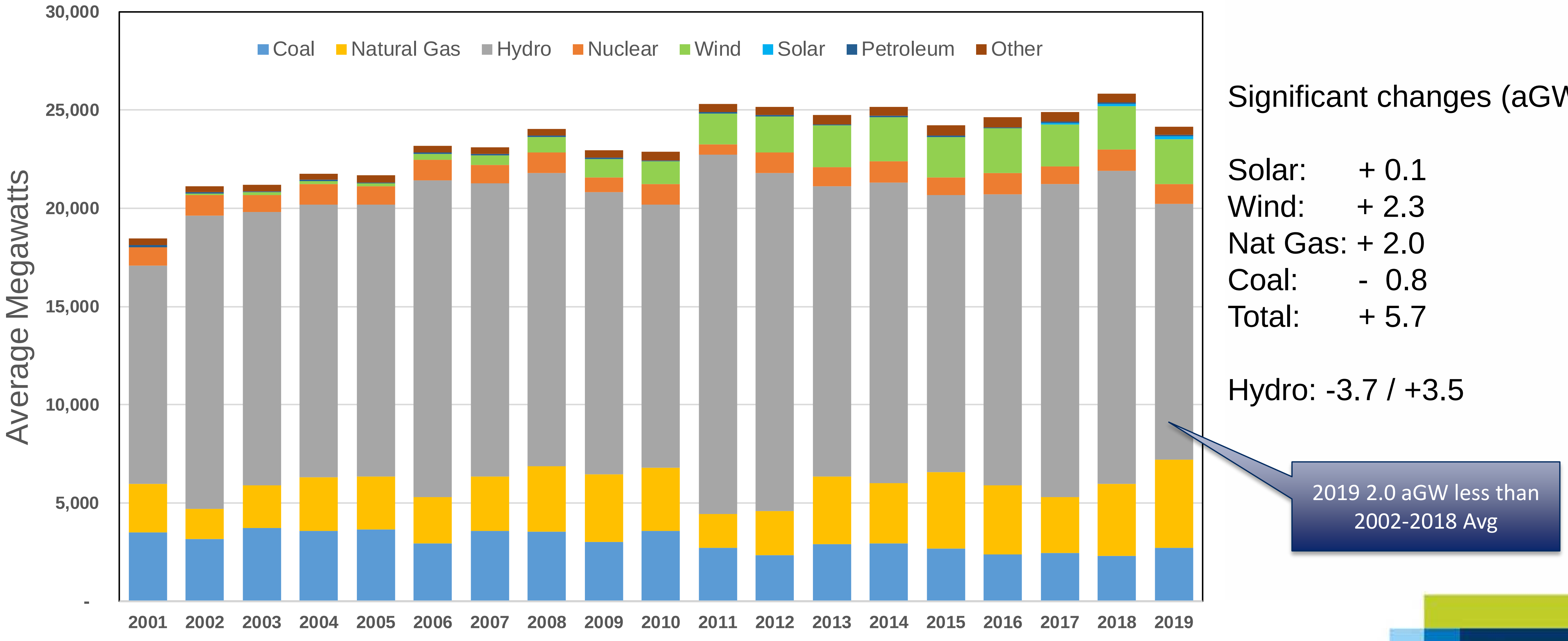
Significant changes (aGW)

Solar: + 5.0
Wind: + 6.2
Nat Gas: + 6.5
Coal: - 9.3
Nuclear: - 1.5
Total: + 11.0

Hydro: -4.2 / +5.2

Source: EIA

Northwest Generation Mix (ID, MT, OR and WA)



Significant changes (aGW)

Solar: + 0.1
Wind: + 2.3
Nat Gas: + 2.0
Coal: - 0.8
Total: + 5.7

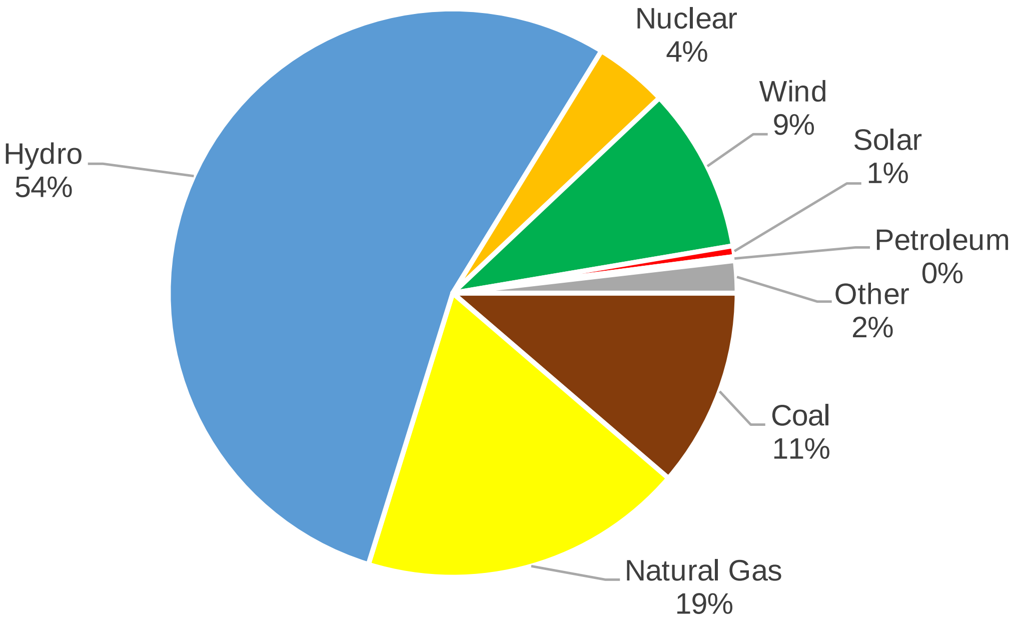
Hydro: -3.7 / +3.5

Source: EIA

2019 Fuel Mix

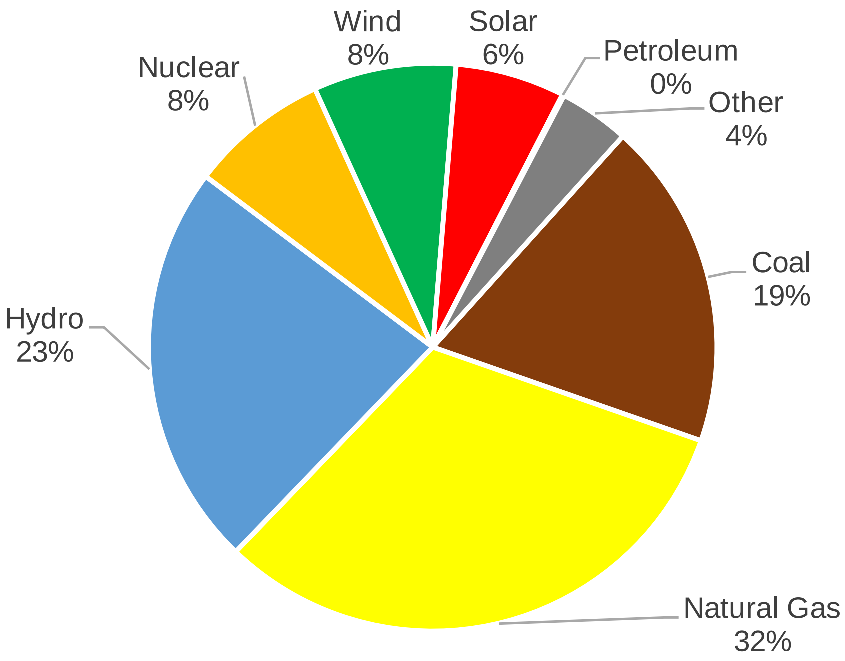
Northwest

70% GHG Emission Free*



U.S. Western Interconnect

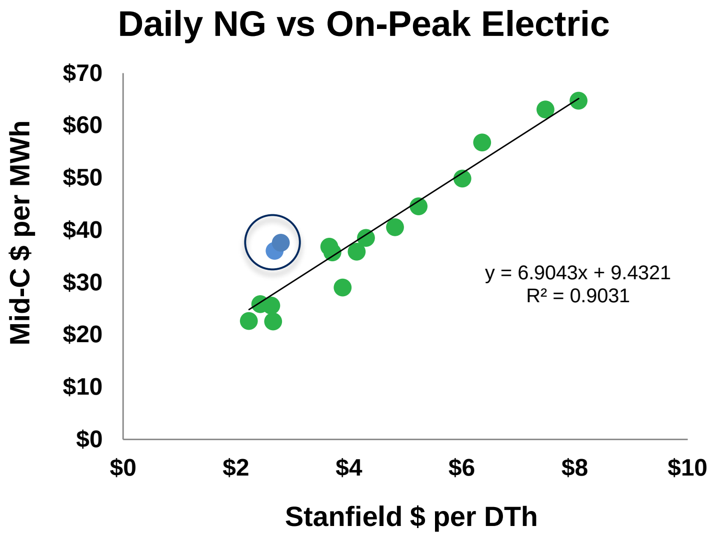
49% GHG Emission Free

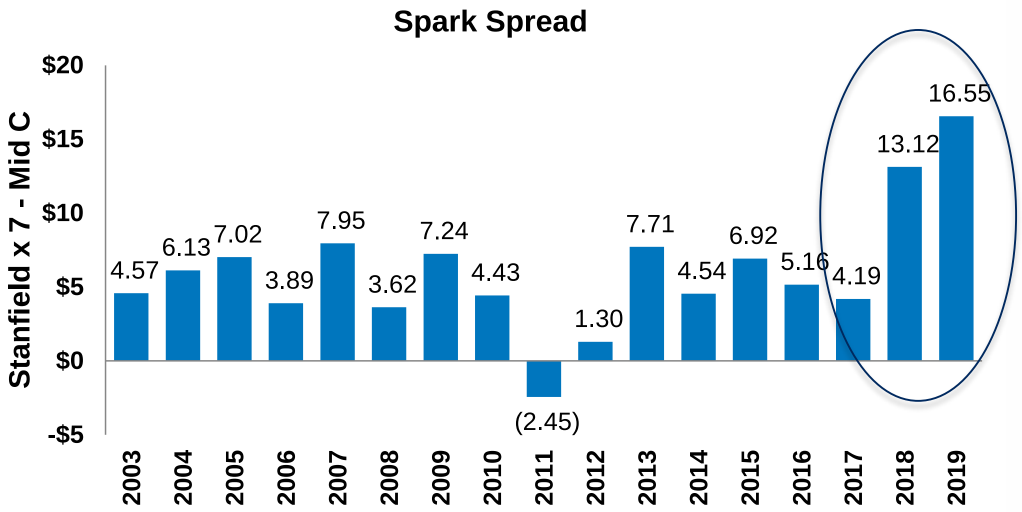


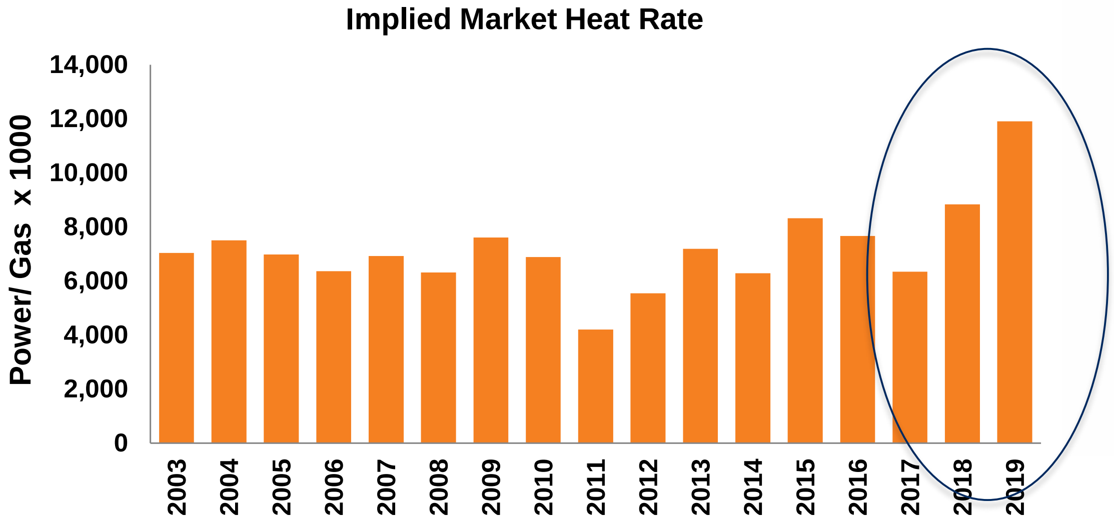
Source: EIA

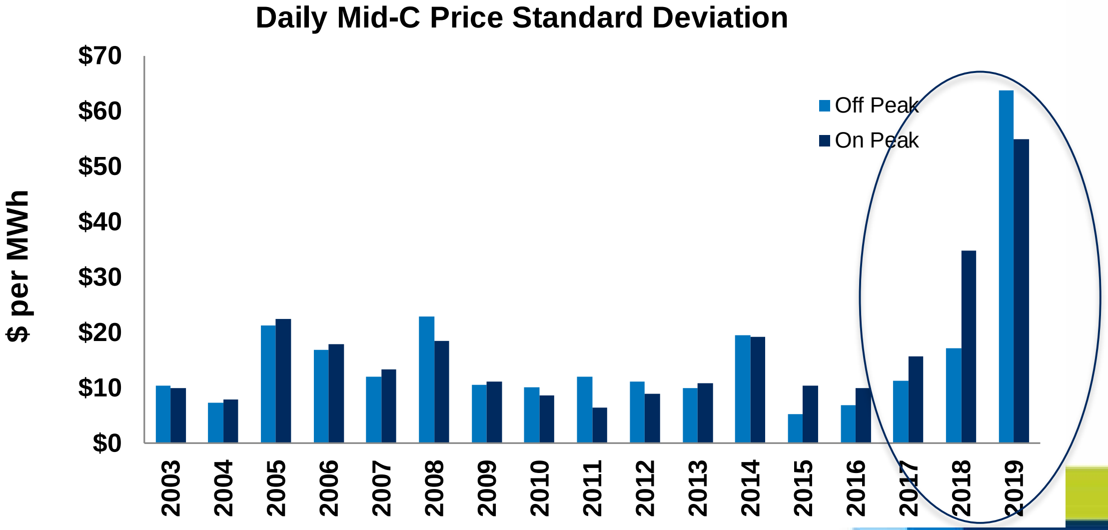
* Low hydro year dropped emission free statistic from 77% in 2018 to 70% in 2019

Market Indicators- Market is Tightening

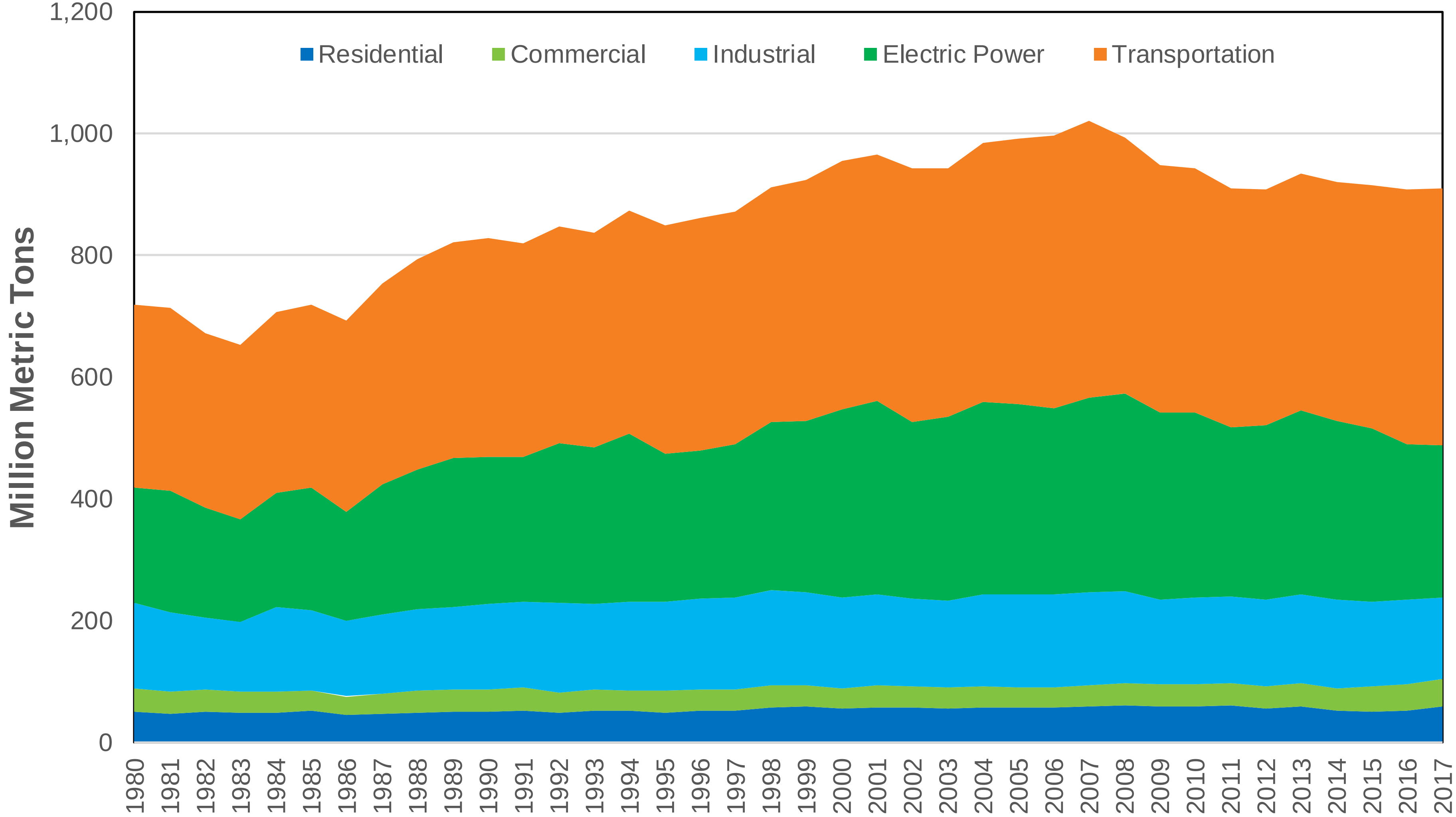








US Western GHG Emission End Use



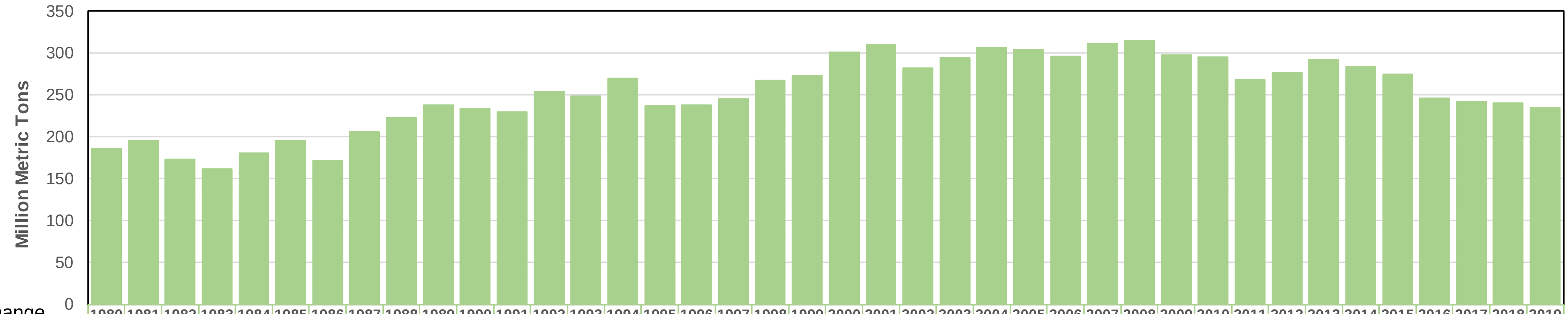
2017:
Transportation: 46%

Electric Power: 28%

Industrial: 15%
Commercial: 5%
Residential: 7%

Source: EIA

Electric Greenhouse Gas Emissions
U.S. Western Interconnect

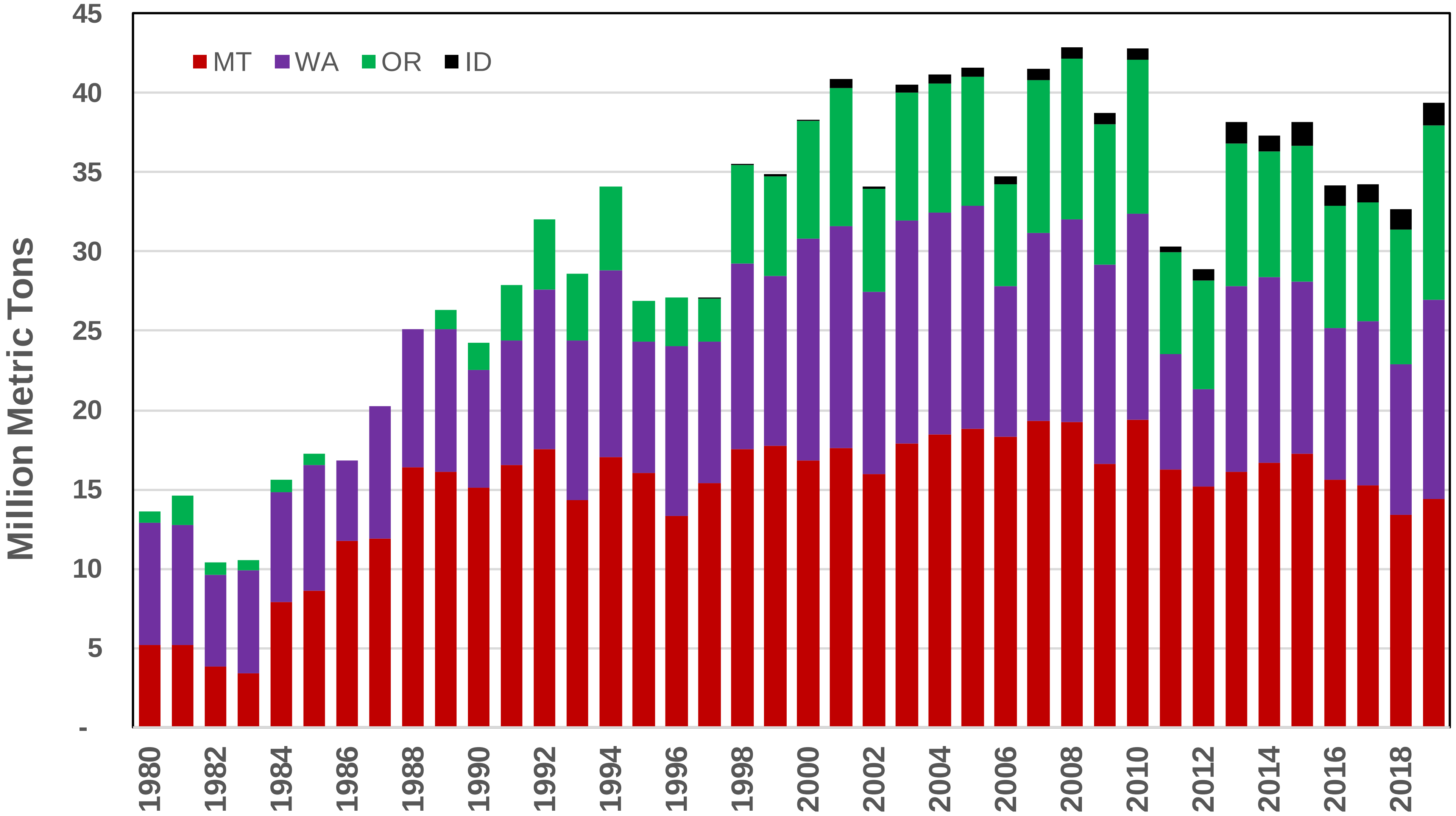


Change		1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
+5.9	WY	22	24	23	21	25	29	23	31	33	31	33	33	36	34	36	34	35	34	38	36
+4.9	WA	8	8	6	7	7	8	5	8	9	9	7	8	10	10	12	8	11	9	12	11
+18.1	UT	11	11	11	11	12	14	15	25	27	28	29	28	30	31	32	30	30	31	32	33
+10.3	OR	1	2	1	1	1	1	-	-	-	1	2	4	4	4	5	3	3	3	6	6
-4.4	NM	21	20	22	25	24	26	23	24	25	27	26	22	25	26	27	26	27	28	28	29
+1.9	NV	11	13	14	13	15	12	16	15	18	17	17	18	19	18	20	18	20	19	21	22
+9.2	MT	5	5	4	3	8	9	12	12	16	16	15	17	18	14	17	16	13	15	18	18
+1.4	ID	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
+11.4	CO	21	23	24	23	25	27	26	27	28	30	31	30	31	32	33	32	34	34	35	36
-26.6	CA	61	59	38	31	34	40	27	37	37	44	40	38	46	42	50	37	33	36	39	43
+16.4	AZ	25	31	31	26	29	31	25	27	29	35	33	33	35	37	38	32	32	35	38	40

Change		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
+5.9	WY	37	37	36	37	37	36	36	37	37	36	36	34	36	39	37	36	33	34	33	28
+4.9	WA	14	14	12	14	14	14	10	12	13	13	13	7	6	12	12	11	10	10	10	13
+18.1	UT	33	33	34	35	35	36	36	38	39	36	35	34	32	35	34	33	27	27	30	29
+10.3	OR	7	9	7	8	8	8	6	10	10	9	10	6	7	9	8	9	8	8	9	11
-4.4	NM	30	29	28	30	30	31	32	30	29	31	27	29	27	26	23	22	21	21	16	17
+1.9	NV	25	24	21	23	25	26	17	17	18	18	17	15	15	15	16	14	14	13	13	13
+9.2	MT	17	18	16	18	18	19	18	19	19	17	19	16	15	16	17	17	16	15	13	14
+1.4	ID	0	1	0	1	1	1	1	1	1	1	1	0	1	1	1	1	1	1	1	1
+11.4	CO	39	41	40	40	40	41	42	43	41	38	40	39	39	39	38	37	35	35	33	32
-26.6	CA	53	58	44	43	46	42	47	50	51	48	44	36	48	46	46	44	37	33	37	35
+16.4	AZ	45	46	45	46	52	51	53	55	58	52	54	52	51	55	53	50	44	44	46	42

Emissions are adjusted for generation within the Western Interconnect
2018 and 2019 estimates are subject to adjustment

Northwest Greenhouse Gas Emissions



The Forecast: 2022 to 2045

Deterministic Model

- Simulate based on average conditions
- 210,240 hours simulation
- Takes about 6 hours on one processor
- Good approximation to estimate impacts of assumptions- great for scenario analysis, but not risk
- Output Files: 26 GB

Stochastic Model

- Simulate 500 varying conditions
- Fuel Prices, Loads, Wind, Hydro, Outages, Inflation
- 105 million hours of simulation
- Takes about 5 days on 33 processors
- Allows for full evaluation of resource alternatives and accounts for risk
- Output Files: 360 GB

Modeling Process

Vendor Database

(2019 North American)

Input Changes

80 yr hydro

NG prices

Regional Loads

Avista Resources/Loads

Operational Detail

Capacity Expansion

Add new resource forecast

(Capacity/RPS)

Include known retirements

Model adds resources to meet planning targets

Test Year Stochastic Study

Test Resource Adequacy

Re-Run Capacity Expansion

Increase/Decrease Planning Margin Targets

Run Full Forecast

Stochastic & Deterministic

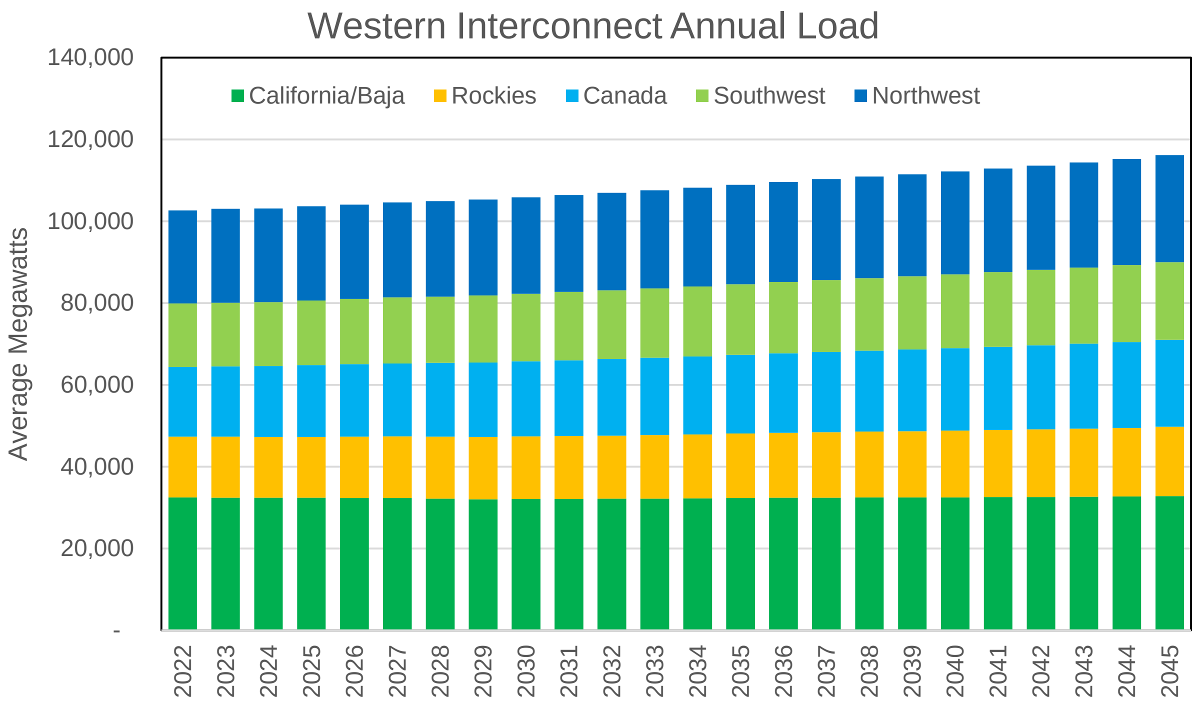
Run Scenarios

Deterministic

Stochastic (if necessary)

Load Forecast

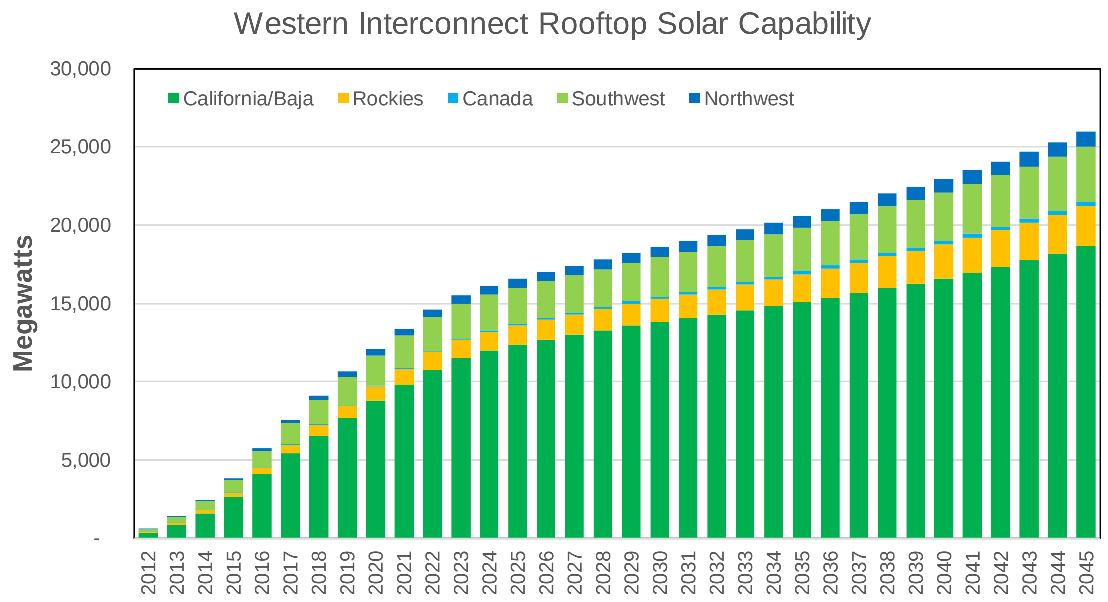
- Regional load forecast from ‘IHS
  - Forecast includes energy efficiency
- Add net meter resource forecast
  - Input annually with hourly shape
- Add electric vehicle forecast
  - Input annual with hourly shape
- Future load shape to be different then today’s load shape



Electric Vehicle and Solar Adjustments

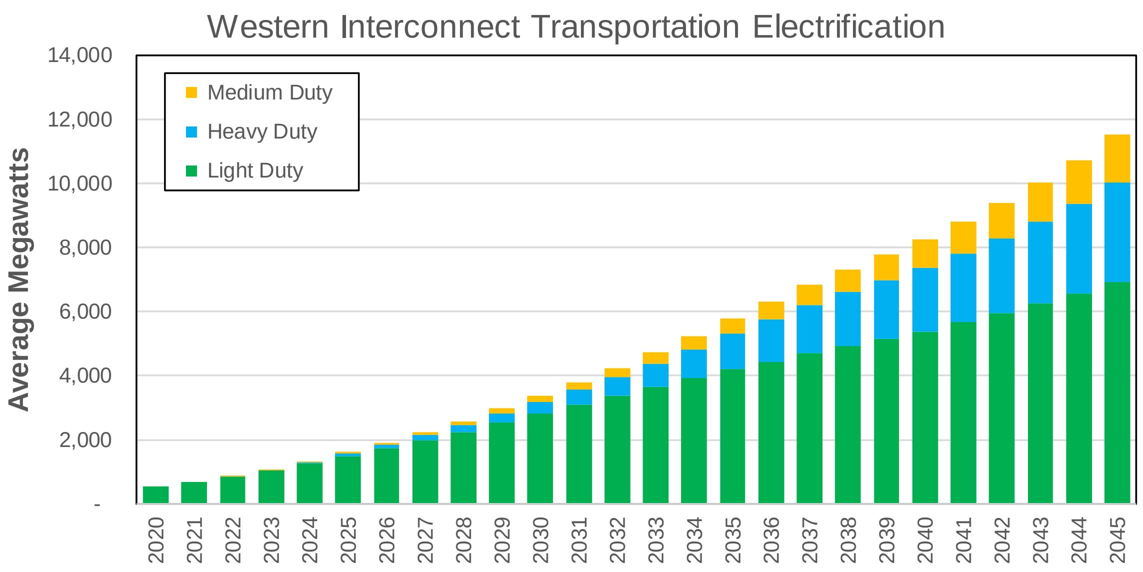
Roof Top Solar

- EIA existing estimates for history
- ‘IHS regional growth rates

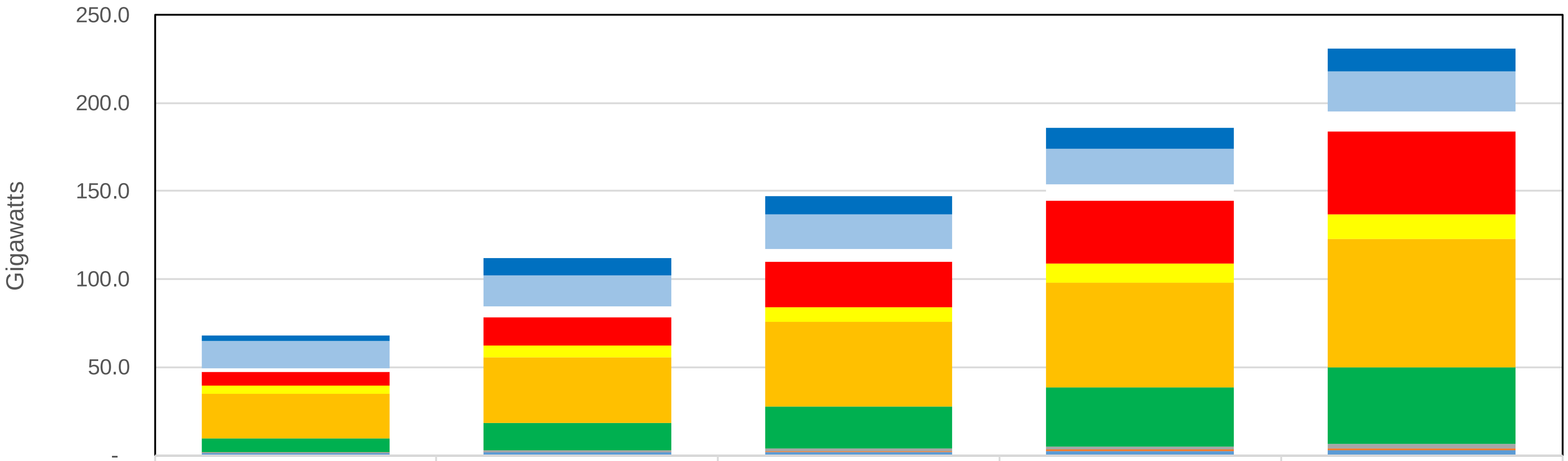


Electric Vehicles

- Penetration rates increase each year (2040 shown below)
- 15-30% light duty
- 12-15% medium duty
- 5% heavy duty

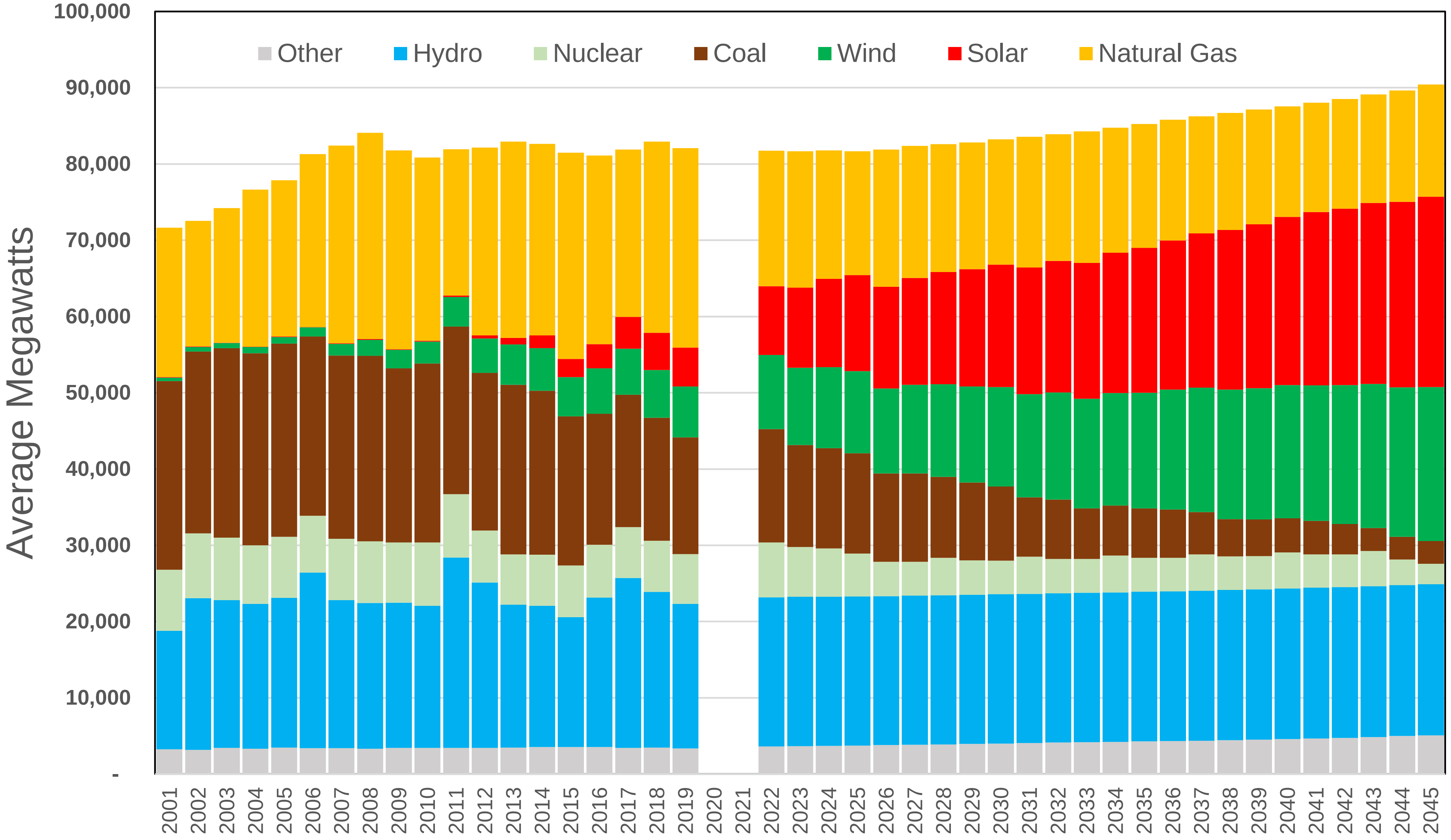


New Resource Forecast (Western Interconnect)



	2025	2030	2035	2040	2045
CCCT	3.3	9.9	10.7	11.6	12.8
SCCT	15.4	17.8	19.3	20.2	22.7
DR	2.1	6.0	7.6	9.5	11.5
Storage	7.9	16.2	25.7	35.5	47.1
Net-Meter	4.5	6.5	8.5	10.8	13.9
Solar	25.5	37.5	47.8	59.7	73.0
Wind	7.8	15.7	24.1	33.4	43.3
Geothermal	0.3	0.7	1.2	1.9	2.9
Biomass	0.2	0.4	0.6	0.7	0.9
Hydro	1.3	1.6	1.9	2.4	2.8

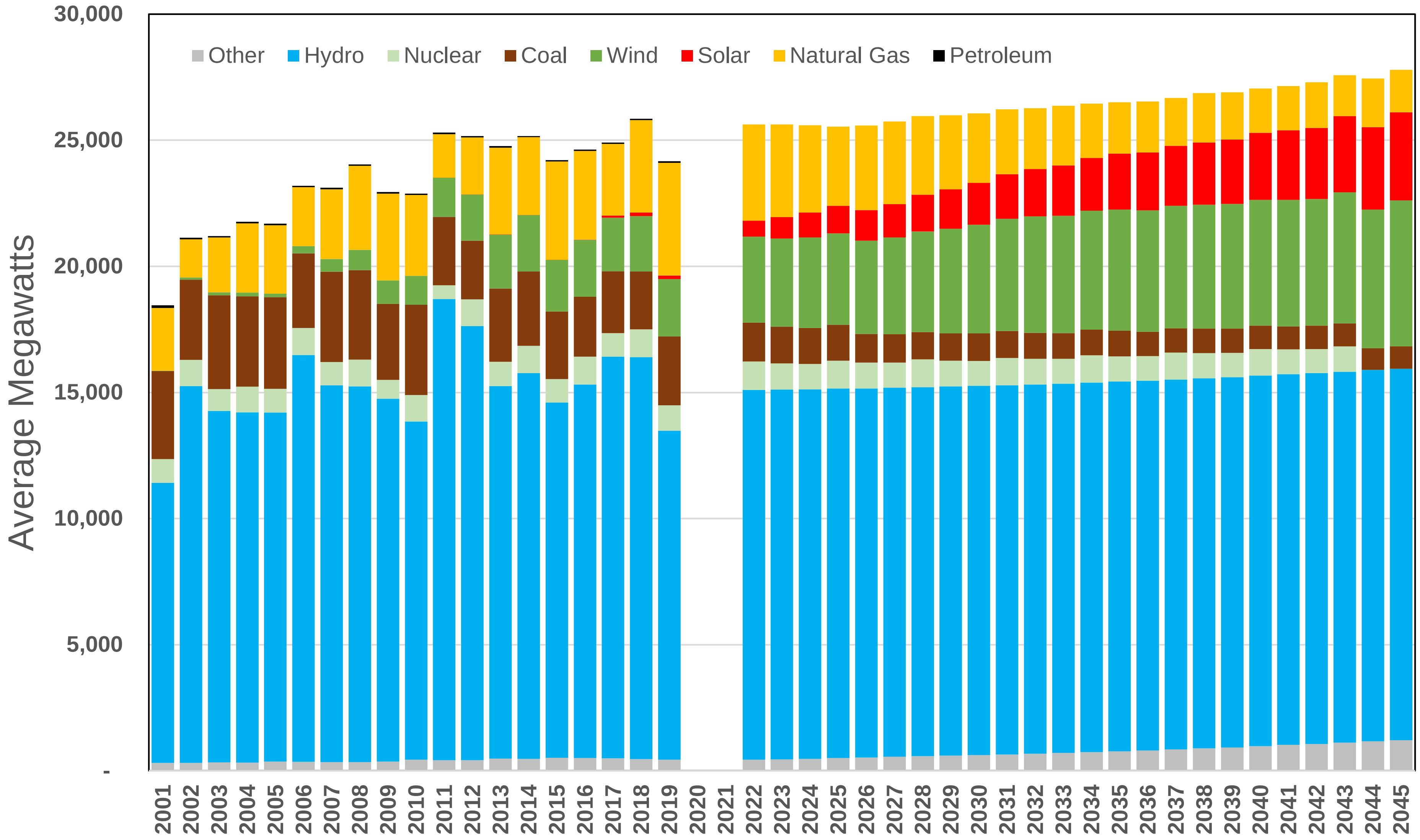
U.S. West Resource Type Forecast



Significant changes 2045 to 2022 (aGW)

Solar: + 15.9
Wind: + 10.5
Nat Gas: - 3.1
Coal: - 11.9
Nuclear: - 4.5
Other: + 1.5
Hydro: + 0.3
Total: + 11.9

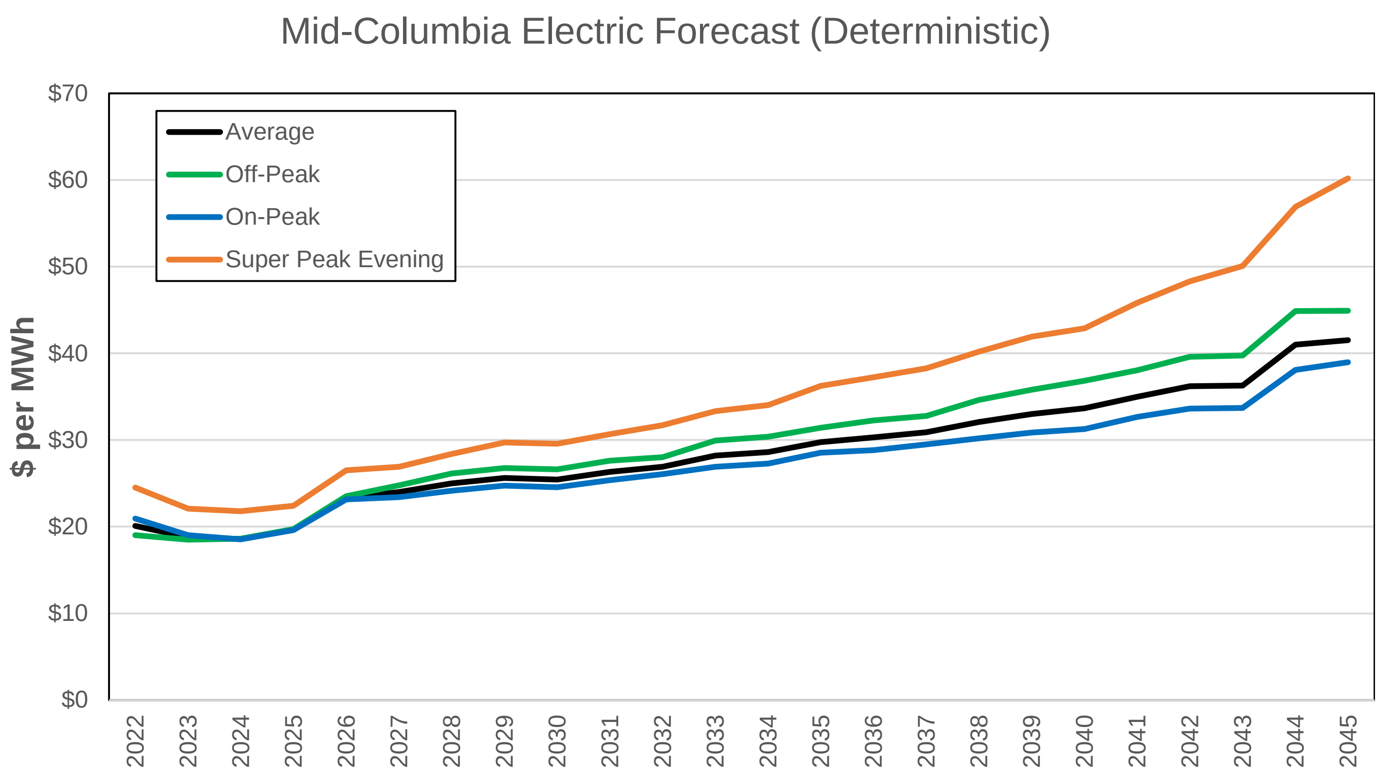
Northwest Resource Type Forecast



Significant changes (aGW) 2045 to 2022

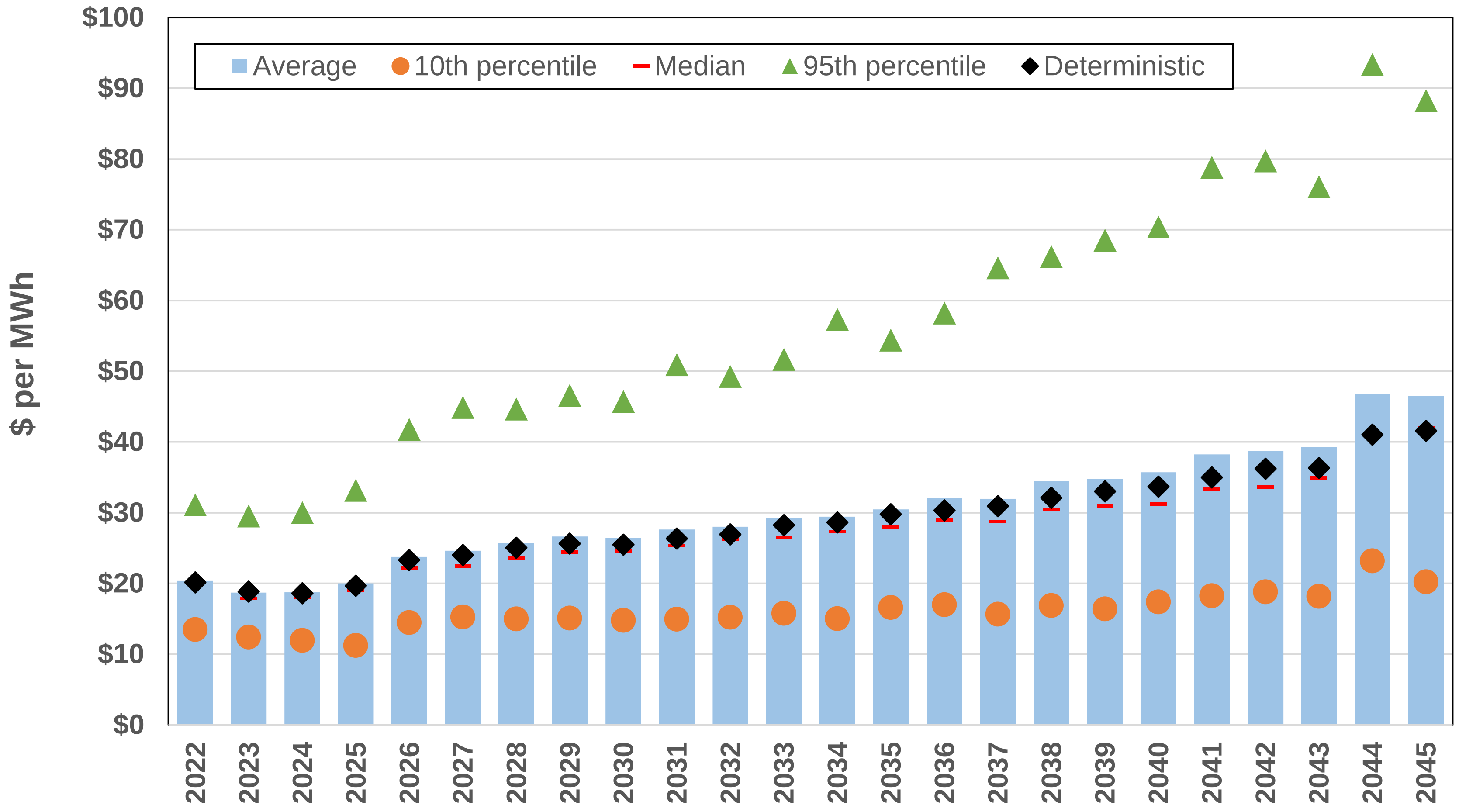
Solar:	+ 2.9
Wind:	+ 2.4
Nat Gas:	- 2.1
Coal:	- 0.6
Other:	+ 0.7
Nuclear:	- 1.1
Total:	+ 2.2

Mid-C Electric Price Forecast



- Levelized Prices:
  - 2022-45: $26.05/MWh
  - 2022-41: $23.03/MWh
- Off-peak prices over take on-peak in 2024 on an annual basis
- Evening peak prices remain high (4pm-10pm)

Mid-C Price Forecast (Stochastic- Draft)



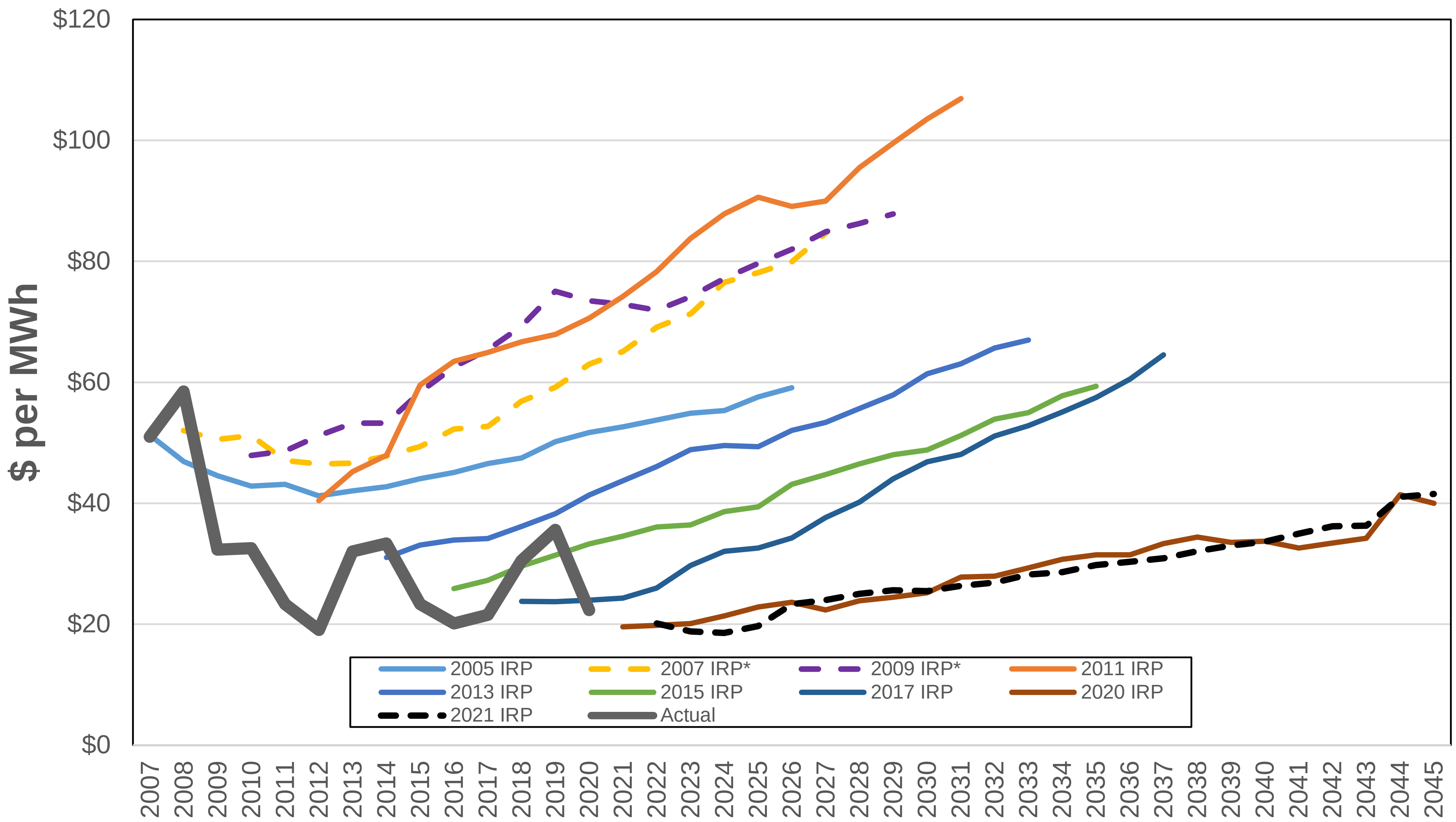
<u>24-yr Levelized Prices</u>

Mean: $27.11/MWh

Median: $24.84/MWh

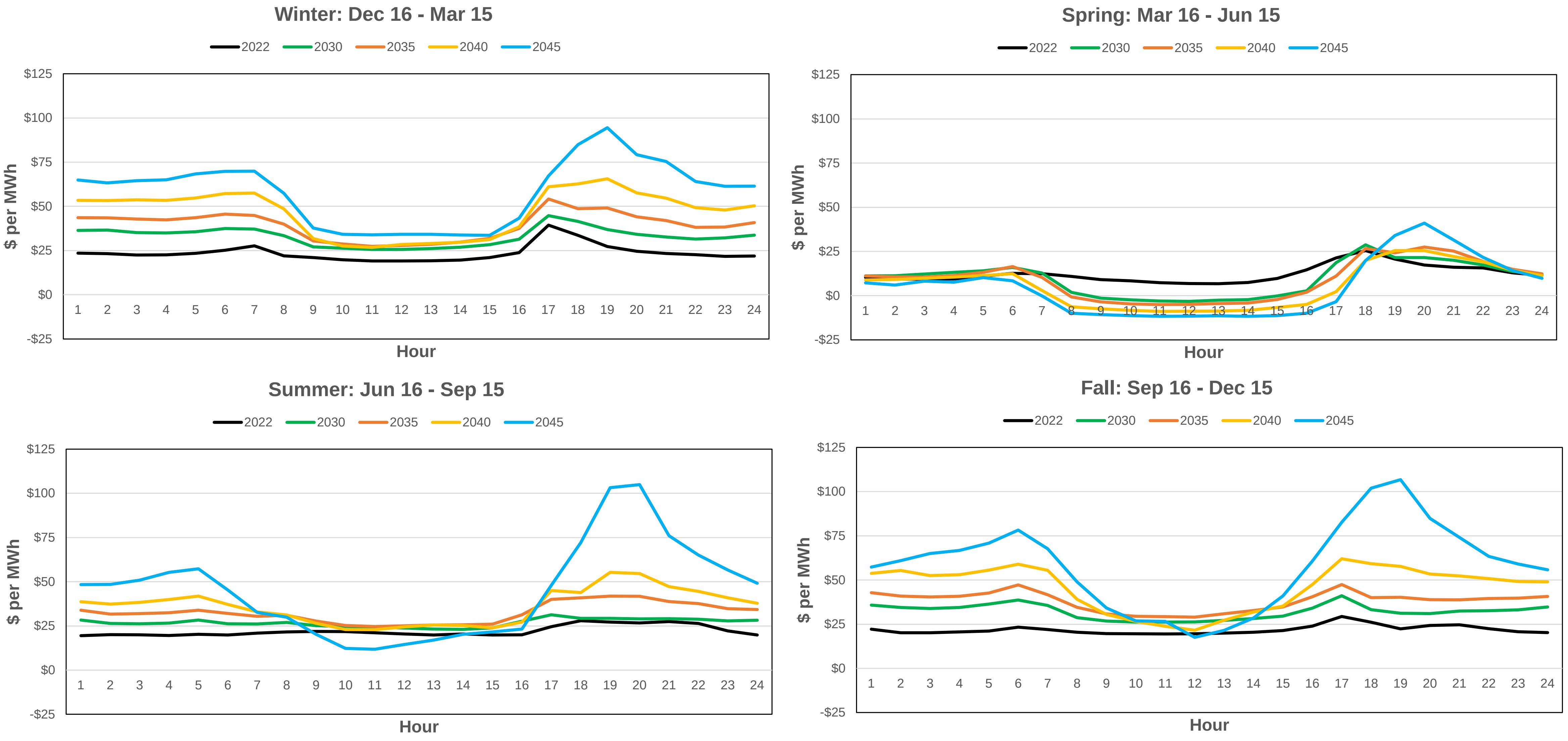
Deterministic: $26.05/MWh

Mid-C Electric Price Comparison vs. Previous IRPs

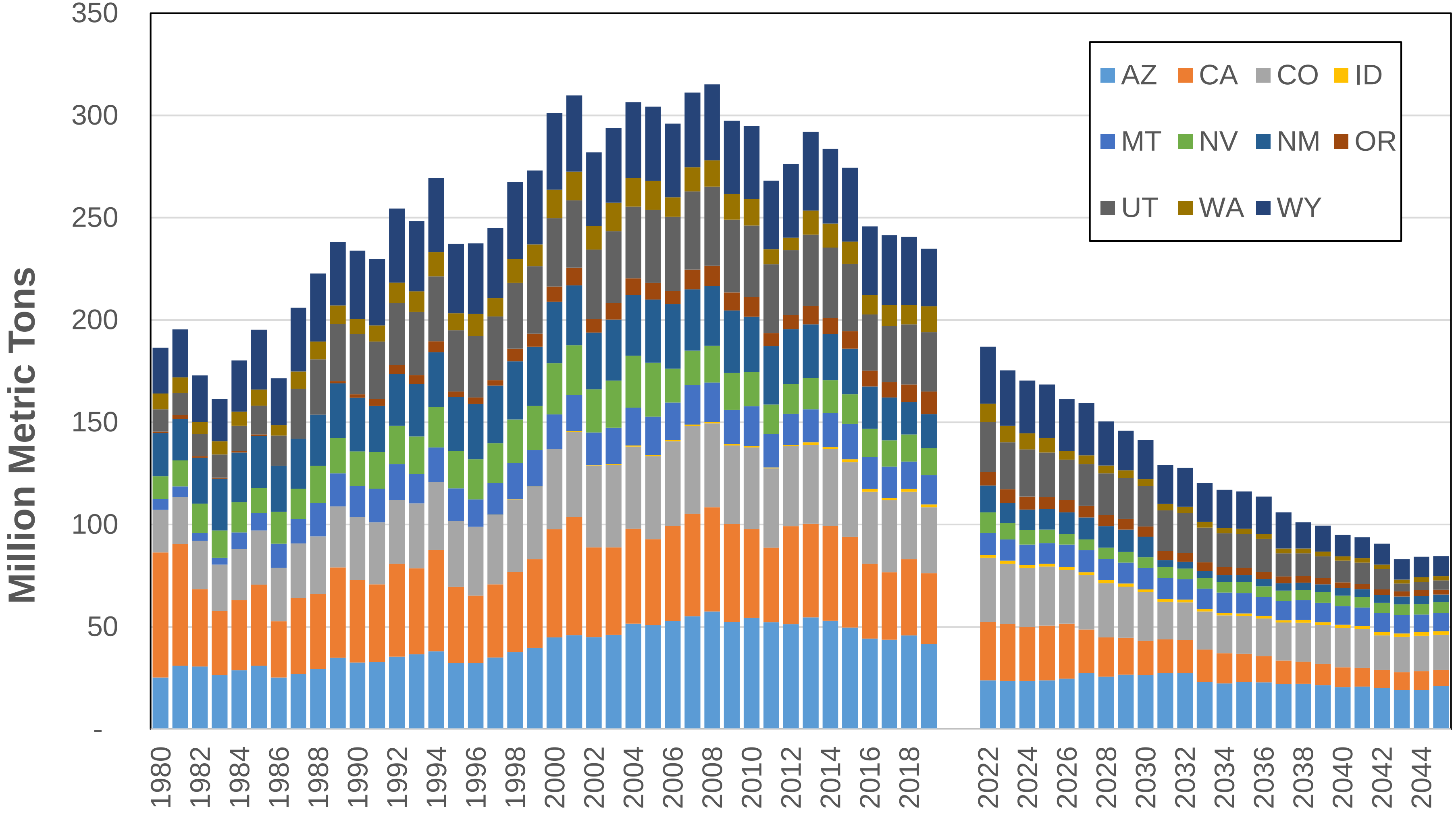


* These forecasts use price scenarios without GHG “taxes” to make all forecasts consistent

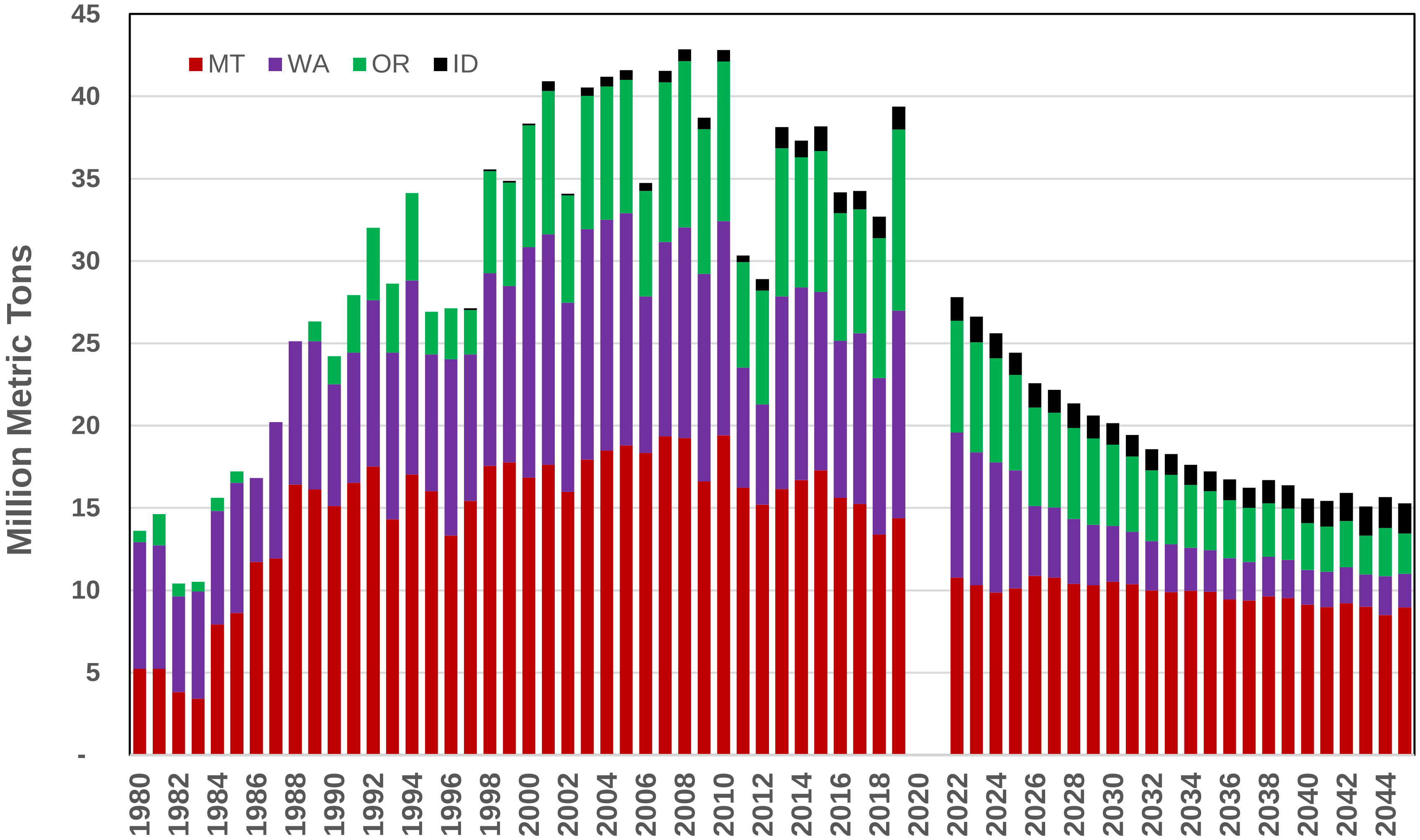
Hourly Wholesale Mid-C Electric Price Shapes



Greenhouse Gas Forecast
U.S. Western Interconnect

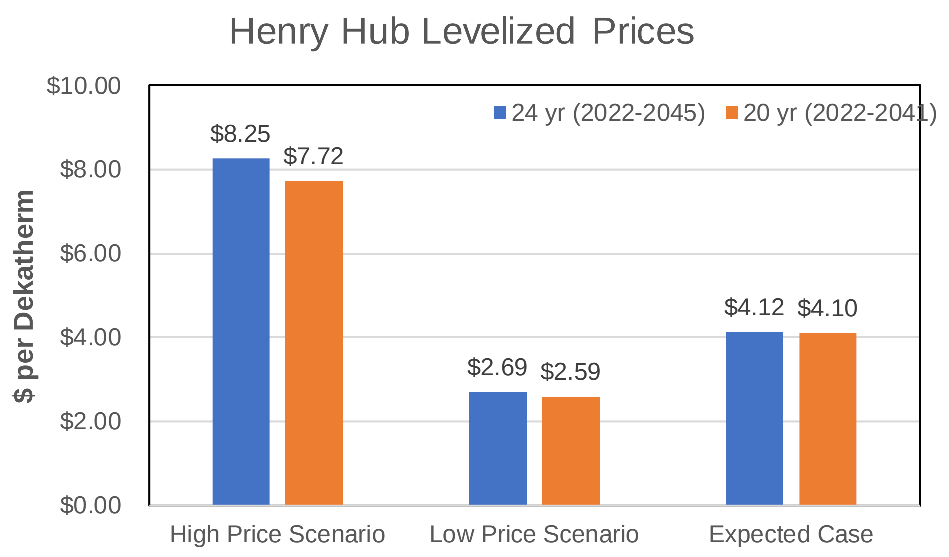


Greenhouse Gas Forecast
Northwest States



Market Scenario Assumptions

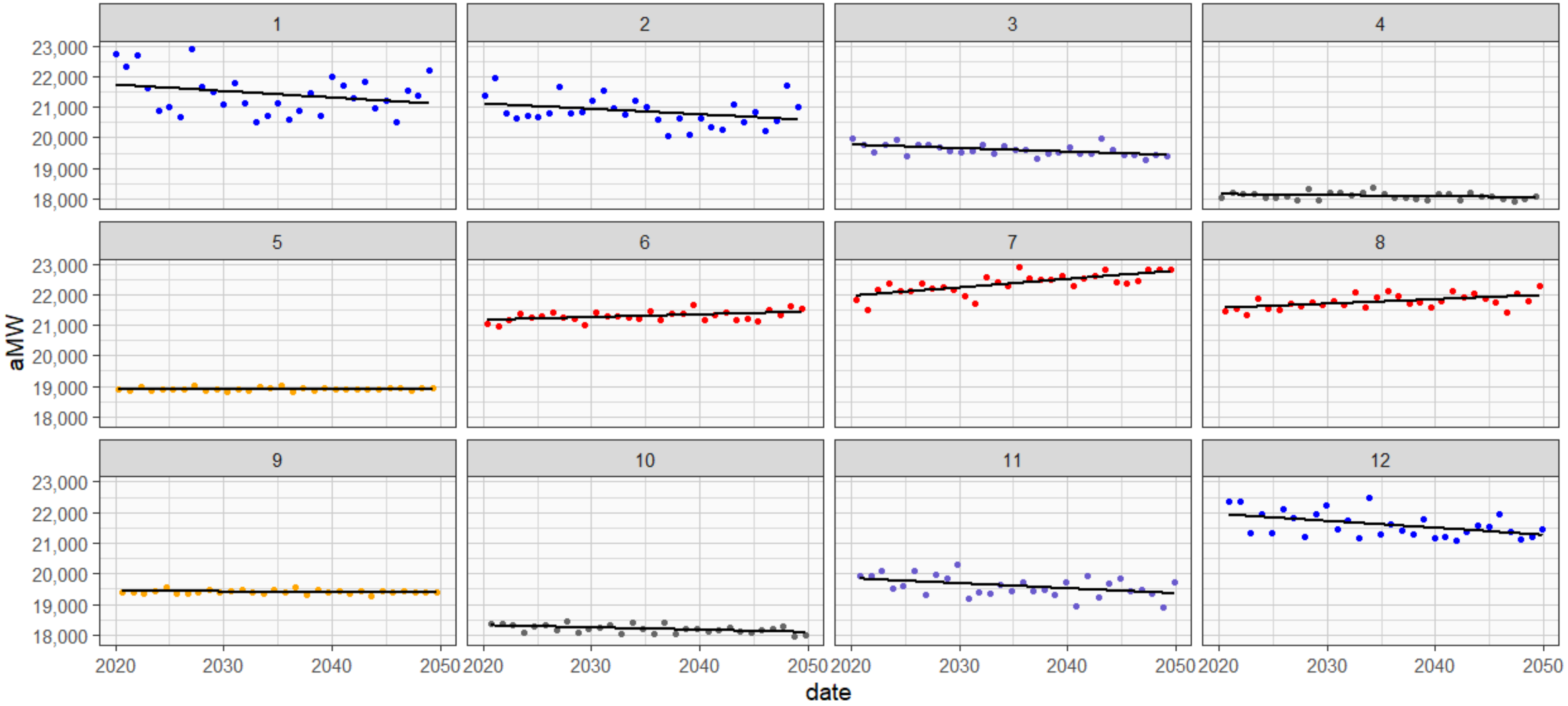
- **High Natural Gas Prices**
  - 90th percentile of stochastic prices using 1,000 draws
- **Low Natural Gas Prices**
  - 25th percentile of stochastic prices using 1,000 draws



- **Social Cost of Carbon "Tax"**
  - Western Interconnect Carbon "Tax" on Generation
  - SCC pricing beginning in 2025, trending up beginning in 2022.
- **Climate Shift**
  - Uses NWCC three climate futures
  - Trend Northwest hydro and loads for warming temperatures
  - Lower NG CT capability due to temperature change

Climate Shift Methodology (Loads)

- Uses 2024 operating year forecast.
- Overlays the 2020 to 2049 temperature forecast using an average of three climate models chosen by the NPCC.
- Create a linear trend of load based on changes in weather*- referred to as scalers.
- Apply scalers to expected case load forecast.

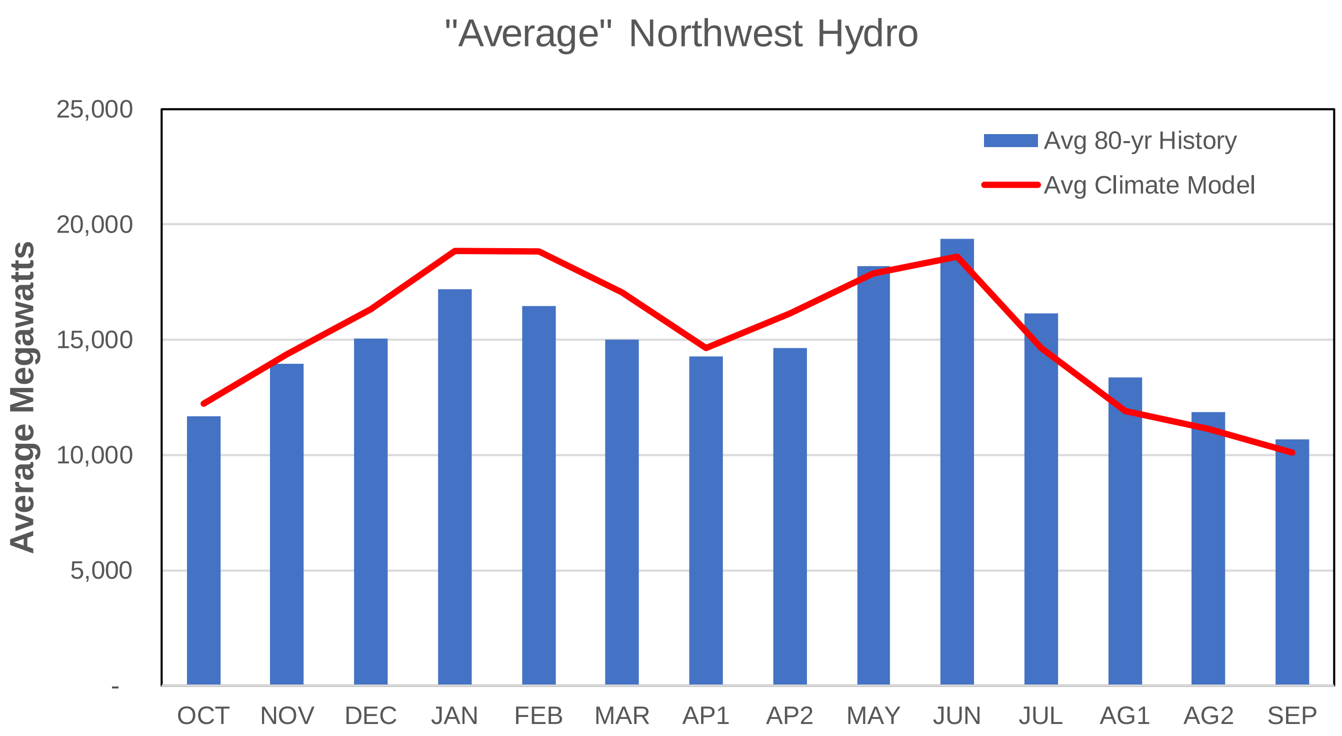


Data & scalars provided by PNUCC

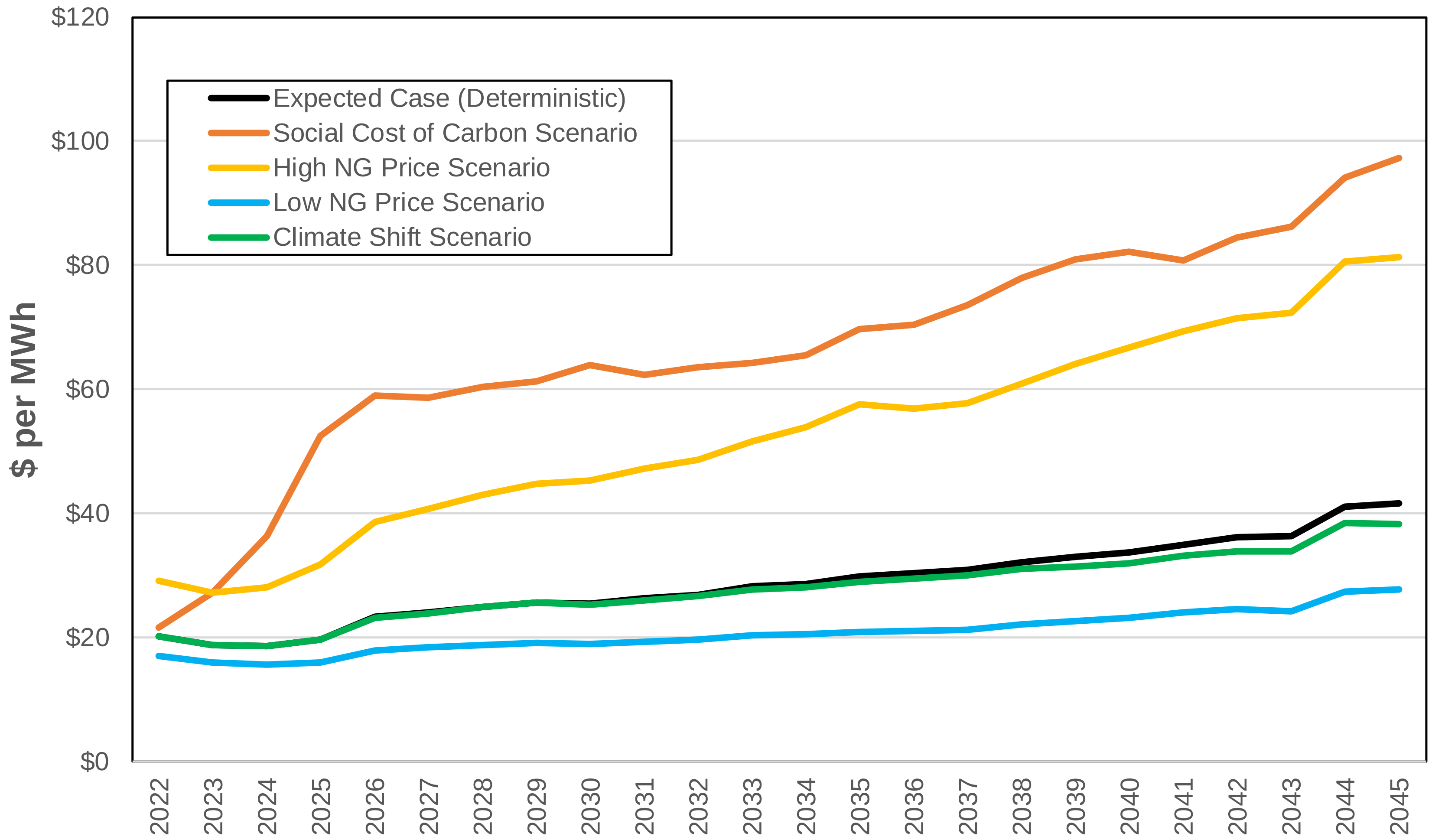
* does not include secondary changes in load due to climate shift

Climate Shift Methodology (Hydro)

- NPCC provides 80-year hydro history and three models with 30 years of potential hydro for the 2040's.
- Compare the average of three climate models to the 80-year hydro history.
- Linearly trend the change between the beginning and the end of the forecast.



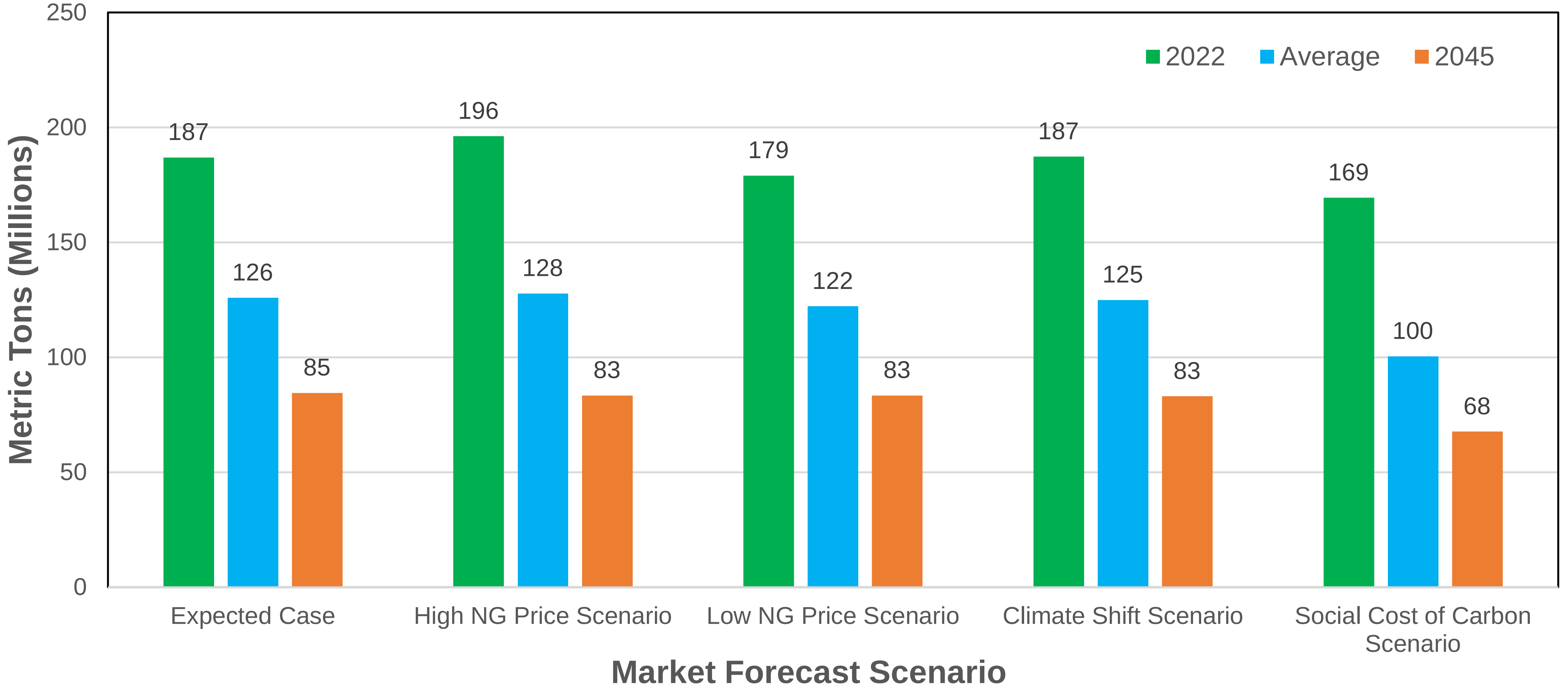
Scenario Results: Wholesale Electric Prices



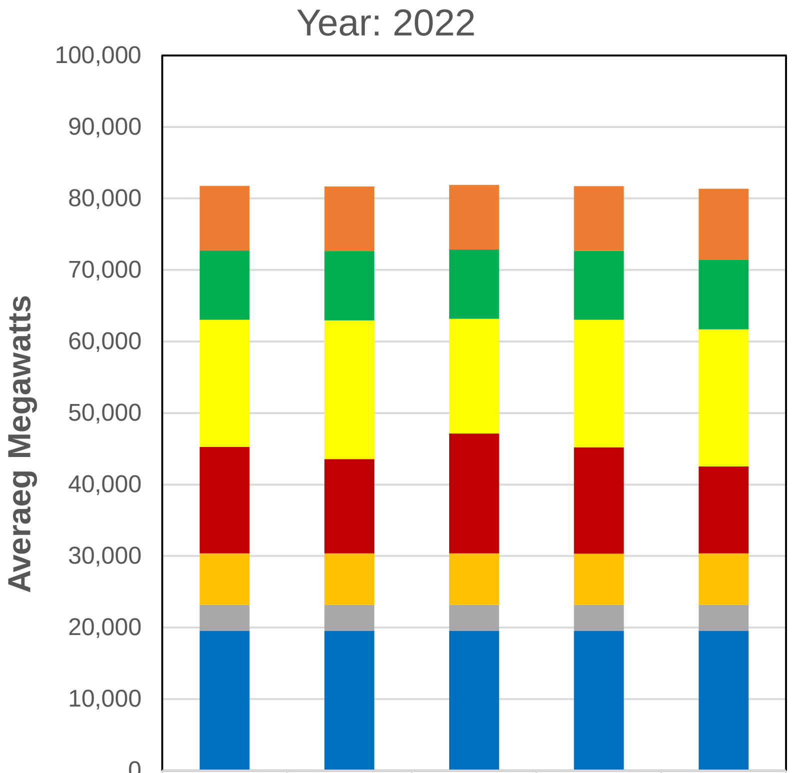
Levelized Prices (2022-2045)

- Expected Case: $26.05/MWh
- Social Cost of Carbon: $58.56/MWh
- High NG Prices: $46.07/MWh
- Low NG Prices: $19.35/MWh
- Climate Shift: $25.51/MWh

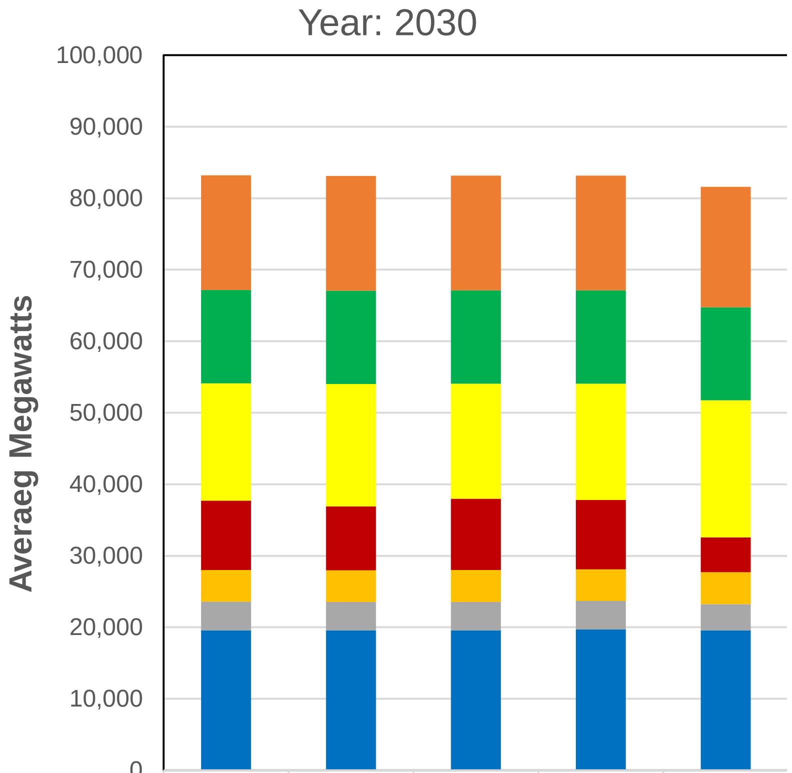
Scenario Results: US Western Interconnect GHG Emissions



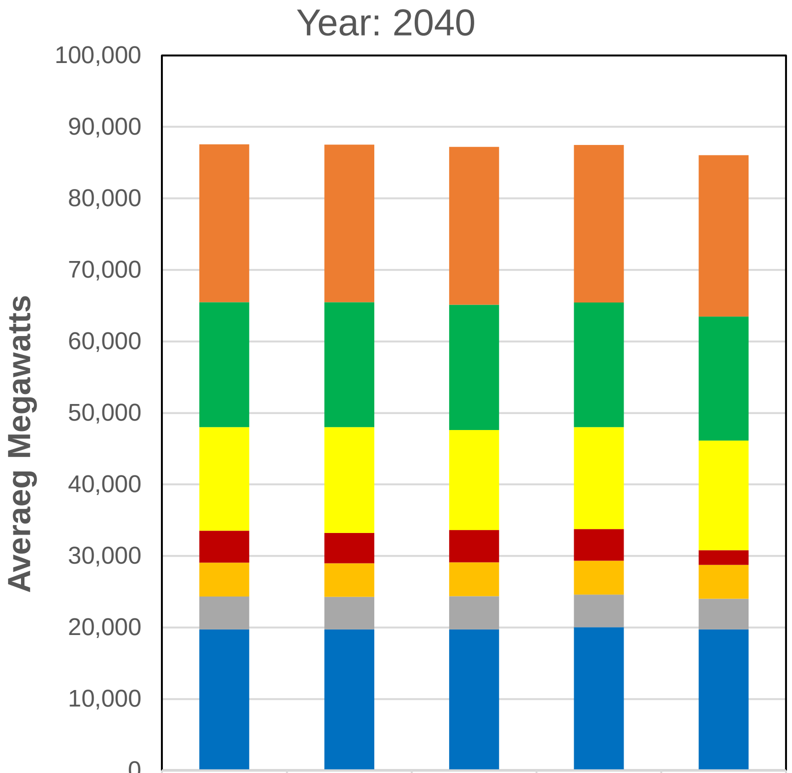
Scenario Results: U.S. Western Interconnect Resource Type



	Expected Case	Low NG Price Scenario	High NG Price Scenario	Climate Shift Scenario	Social Cost of Carbon Scenario
Solar	9,024	9,023	9,024	9,022	9,978
Wind	9,698	9,698	9,700	9,692	9,694
Natural Gas	17,785	19,394	16,002	17,788	19,158
Coal	14,870	13,160	16,783	14,886	12,164
Nuclear	7,188	7,187	7,195	7,178	7,185
Other	3,623	3,625	3,604	3,597	3,628
Hydro	19,570	19,570	19,570	19,570	19,571



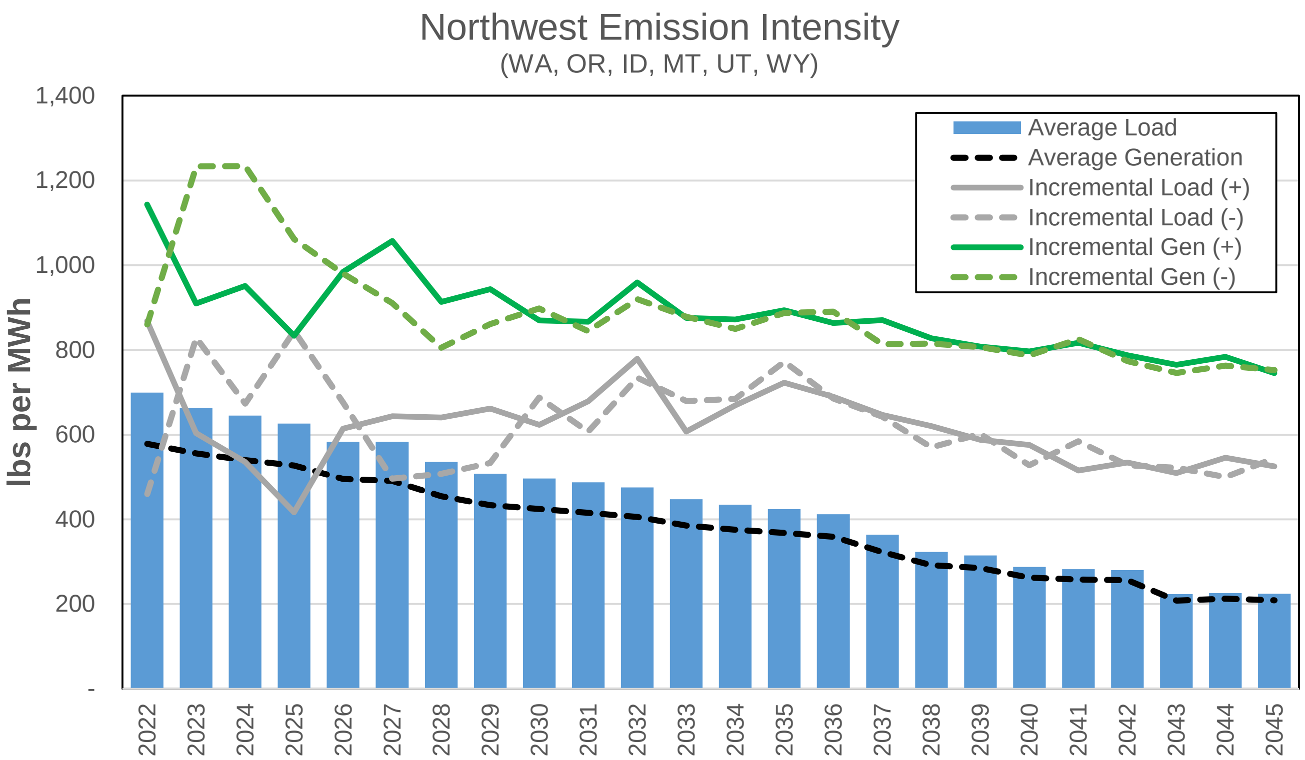
	Expected Case	Low NG Price Scenario	High NG Price Scenario	Climate Shift Scenario	Social Cost of Carbon Scenario
Solar	16,053	16,047	16,059	16,050	16,864
Wind	13,048	13,033	13,057	13,049	13,010
Natural Gas	16,411	17,126	16,094	16,267	19,170
Coal	9,699	8,935	9,973	9,670	4,874
Nuclear	4,426	4,416	4,432	4,424	4,440
Other	4,013	3,992	3,994	4,007	3,680
Hydro	19,568	19,568	19,568	19,694	19,568



	Expected Case	Low NG Price Scenario	High NG Price Scenario	Climate Shift Scenario	Social Cost of Carbon Scenario
Solar	22,059	22,040	22,071	22,033	22,550
Wind	17,477	17,461	17,498	17,455	17,367
Natural Gas	14,489	14,782	13,997	14,255	15,309
Coal	4,477	4,251	4,535	4,410	2,069
Nuclear	4,729	4,713	4,740	4,714	4,727
Other	4,605	4,550	4,632	4,585	4,295
Hydro	19,726	19,726	19,726	20,028	19,726

Incremental GHG Emissions for Energy Efficiency

- This IRP assumes GHG emissions from load reduction and associated emissions from market purchases/(sales)*
- 2020 IRP assumes average emissions each year based on average emissions compared to load each year. (See blue bars)
- Avista believes average emissions best represents the associated emissions for market purchases/sales:
  - Should this be based on load or generation?
- Avista is considering using incremental emissions for valuing energy efficiency for Washington's cost analysis:
  - Load or generation calculation method?
  - Increase load vs. decrease load method (or average)?
  - At what granularity to apply benefit?



* Purchases related to storage resources assumes a slightly different provide due to charging times

Data Availability

Outputs

- Expected Case: annual Mid-C prices by iteration (stochastic)
- Expected Case: hourly Mid-C prices (deterministic)
- Scenarios: monthly Mid-C electric prices
- Regional resource dispatch
- Regional GHG emissions
- Avista resource dispatch data will be included within PRiSM Model

Inputs (Not already Posted)

- Climate shift scaling factors for load/hydro
- High/low natural gas prices

2020 Electric Integrated Resource Plan
Draft Portfolio Scenario Analysis

John Lyons, Ph.D.
Third Technical Advisory Committee Meeting
September 29, 2020

Portfolio Scenarios – 2020 IRP

1. Preferred Resource Strategy
2. Least Cost Plan- w/o CETA
3. Clean Resource Plan: 100% net clean by 2027
4. Rely on energy markets only (no capacity or renewable additions) w/o CETA
5. 100% net clean by 2027, and no CTs by 2045
6. Least Cost Plan w/o pumped storage or Long Lake as options
7. Colstrip extended to 2035 w/o CETA
8. Colstrip extended to 2035 w/ CETA
9. Least Cost Plan w/ higher pumped storage cost
10. Least Cost w/ federal tax credits extended
11. Clean Resource Plan w/ federal tax credits extended
12. Least Cost Plan w/ low load growth (flat loads- low economic/population growth)
13. Least Cost Plan w/ high load growth (high economic/population growth)
14. Least Cost Plan w/ Lancaster PPA extended five years *(financials will not be public)*

Others: Efficient frontier portfolio (least risk, 75/25, 50/50, and 25/75)

Portfolio Scenarios- 2021 IRP

1. Preferred Resource Strategy
2. Baseline Portfolio 1 (No CETA renewable targets)
3. Baseline Portfolio 2 (No CETA renewable targets/SCC)
4. Clean Resource Plan (100% Portfolio net clean by 2027)
5. Clean Resource Plan (100% Portfolio clean by 2045)
6. Social Cost of Carbon applied to Idaho
7. Least Cost Plan- w/ low load growth
8. Least Cost Plan- w/ high load growth
9. Least Cost Plan- w/ Northwest Resource Adequacy Market Peak Credits
10. Heating Electrification Scenario 1
11. Heating Electrification Scenario 2
12. Heating Electrification Scenario 3
13. Least Cost Plan- w/ climate shift
14. Least Cost Plan- w/ 2x SCC prices
15. Colstrip serves Idaho customers through 2025
16. Colstrip serves Idaho customers through 2035
17. Colstrip serves Idaho customers through 2045
18. If necessary: CETA deliver to customers each hour
19. If necessary: other resource specific scenarios depending on outcome of PRS results

TAC Meeting 3 Notes – September 29, 2020

Virtual Attendees: Shay Bauman, Shawn Bonfield, Annette Brandon, Terrence Browne, Morgan Brummund, Michael Brutocao, Ethan Case, John Chatburn, Corey Dahl (Public Counsel), Michael Eldred (IPUC), Chip Estes, Ben Fadie, Rachelle Farnsworth (IPUC), Ryan Finesilver, Damon Fisher, James Gall, Amanda Ghering, GS, Guest (5), Leona Haley, Lori Hermanson, Jan Himebaugh (BIAW), Elizabeth Hossner, Tina Jayaweera, Clint Kalich, Kathlyn Kinney, Dean Kinzer, Melissa Kuo, Scott Kinney, John Lyons, Fred Heutte (NWEC), Jaime Majure, Kelly Marrin, Stuart M., Eli Morris, Katie Pegan, Tom Pardee, Jorgen Rasmussen, Jeff Schlect, Jennifer Snyder (WUTC), Darrell Soyars, Collins Sprague, Dean Spratt, State of Idaho, Jason Thackston, Unavailable (1), Ken Walter (AEG), Tom Williams, Katie Ware, and Yao Yin (IPUC).

Notes in *italics* after questions were made by the presenter.

IRP Transmission Planning Studies – Dean Spratt, Avista

Yao Yin (Slide 15): When Avista contracts with a QF [qualifying facility under PURPA], does the QF contract for transmission at the same time? *Probably a better merchant question. It was studied by us and neighboring utilities. They typically don't have tools to conduct full qualified studies. Does that help?* Yes, thank you.

Dean Spratt: Regarding QF versus non-QF impacts, these are studied by us [Avista transmission] and others. The scope is different for these.

Yao Yin (Slide 16): Does a QF get into the same queue regarding scope of the project?

Dean Spratt: Yes. Anyone, QF or not, that wants to get on the system has to go through the [same] interconnection process. A QF or large project has to go through the interconnection request. There is one queue that captures everything. Transmission planning only sees the larger projects. It could be a cut-off for smaller projects. There are different rules for different states.

Jeff Schlect: I'm going to chime in here. I'm the Senior Manager of Transmission Services here at Avista. Yes, all projects work through the same queue under FERC or by state agreement based on the size of the project. There is one queue for all sizes, but they could be subject to a FERC process or to some other process.

Yao Yin: Thanks Jeff. I was unsure of the small project cut off.

Distribution Planning within the IRP – Damon Fisher, Avista

Jennifer Snyder: HB 1126 has been codified in RCW 19.280.100.

Rachelle Farnsworth: Talk about how and if the company is looking at smart inverters and how you will use those?

Damon Fisher: Latest IEEE. Yes, but how planning is going to integrate remains to be seen. I don't think the hardware has caught up with the standard yet, maybe by 2021 or 2022. We are not quite there. We would implement that as stated in the new 1547 right through. There are concerns with transmission faults in Germany and California where a lot of load was dropped due to the large amount of inverters and them not recognizing it was a short trip and needed to stay online longer. A distribution fault drops all generation and transmission fault stays online longer.

Rachelle Farnsworth: Yes, I was just curious on smart inverter policy and settings. Where is the company on developing a policy on this?

Damon Fisher: Existing 1547 is what we are following. New 1547 is the ride through ability. Thank you. That is system protection and I'm not an expert on it.

Kathlyn Kinney: Is there something outward facing where you publicize where grid issues are and where DR is needed?

Jennifer Snyder: Do you have studies on where DR would be helpful?

Damon Fisher: No, there isn't yet. We've been working hard to get modeling for facilities hosting capacity for load and later generation. There are lots of benefits internally for guiding new load to where it doesn't create system constraints. Lots of work is being done on these maps with this intent. Can approach more sophisticated customers first with incentives to help with grid constraints. Some of these studies are out there, such as the work done in New York. I will send a link. If anyone is interested, New York has one that is pretty interesting. New York was able to work through it. There are a few studies out there.

Damon Fisher (Slide 14): 15 days in December, it's dark before 4 pm back in the old days when we went to work. Something that would give me pause would be to just use solar to fix a grid issue when there are situations like that.

Damon Fisher (Slide 15): Will drastic changes in the day cause a problem as a grid fix issue? Need data and studies. What if we fix the curve with a battery or use two DERs? Maybe we just go straight to a battery. All of these are considerations in fixing the gird and adding resources when available to the system.

Damon Fisher (Slide 17): Blue is transmission. Orange is the 230 kV lines. BPA is in there as well. Airway Heights is a big growth area. We don't serve the new Amazon facility directly, but local growth in the area is occurring through our substation feeders nearby and they are approaching their limits.

Yao Yin (slide 19): I'm not very familiar with the concept of hosting capacity. What does that mean?

Damon Fisher: Our system can host your generation. Like 5 MW of solar. We can do pre-analysis of the system with gobs and gobs of analysis to show constraints on a map. If it's in a development and you want to put in 1 MW of solar, where can I get it attached quicker? I can also do that for load. Pre-analysis of where you can add more resources without causing system problems. Load is also interesting. Generators who might be interested in hosting solar or whatever generation on our system. You run through scenarios of attached generation and look for constraints such as high voltage problems. Map can then be geo-referenced that tells generators of where you can locate projects. Possibly to do pre-analysis to shorten Dean's queuing process. Intend to do this with load and generation and where to locate generation without causing problems.

Yao Yin: Does that consider upgrades only for existing or does it assume upgrades happen?

Damon Fisher: Yes. Run analysis until you encounter the first constraint. If done correctly, you can do a hosting map that will guide these projects without requiring system investment. Hosting capacity map will go stale when resources are added. Easy to go stale if maps aren't maintained. How often do you do this? It could be a resource intense operation. Possibly automate it, but that remains to be seen.

Damon Fisher (Slide 19): AMI data is 5 minutes out of the meters. Can apply various techniques to the data to pick out what load is occurring. Where are we getting electric vehicles as more of them are out there? Will we have less visibility of where they are and what they are doing to the system as they are charging? Can look for the most offensive user of energy or demand (AC) and then target those as a DER candidate. This causes all sorts of weird questions on tariffs, targeting, etc. For northwest utility DERS, this is an enlightening conversation with everyone. What is right, appropriate, average and above average?

Demand Response Potential Assessment – Kelly Marrin, AEG

Kelly Marrin: This Demand Response (DR) Potential Assessment shows the preliminary results. It is not the first round, but is not finished yet.

Brian Fadie (Slide 11): The first note under sources mentions an Avista proposed cycling strategy for DLC Central AC and Smart Thermostats (cooling). Can you describe that further?

Kelly Marrin: The Power Plan has something closer to 1, when talking to Avista about what they might use, they said they'd implement something more moderate so AEG adjusted this down.

Kathlyn Kinney: On the percentage with EV charging, what is getting measured? Is it a percentage over the top and will this be changing over the year, what exactly is being measured here?

Kelly Marrin: This is an average per customer reduction per event and accounts for all participants whether they're plugged in or charging. As EV penetration increases, megawatts will go up and that'll show up in EV saturation. Impacts start low, but by 2045 they will be substantial as we have more EVs.

Yao Yin: Any assumptions regarding battery duration and efficiency?

Kelly Marrin: We will provide more detail on technical research done on batteries. We have six hours storage assumed per day and 8 hours for larger batteries.

Tina Jayaweera: There a number of electrification scenarios in the IRP, have you incorporated that in your work?

Kelly Marin: We are not doing any scenarios. We are using the same forecast.

James Gall: From energy efficiency, those electrification scenarios already include them. We have not discussed DR yet, but will discuss this when our studies are complete. Tina thanks for reminding us to circle back and do that analysis.

Yao Yin: Big picture, if a technology is used for ancillary services does it hurt the chance for it to serve other purposes? For example, a battery. Are these two mutually exclusive?

Kelly Marrin: That's right. Ancillary service doesn't always have a specific time, so we don't add these and don't stack the value of ancillary services on top of the capacity. If there's an overlapping event. Ancillary services are not at a specific time, they can be at any time of the year or day. We never add these to the other programs. This loads first. Capacity is looked at separately and in a particular order. They account for not calling the same load at the same time but for ancillary service. It's a completely different load and we assume this doesn't happen during system peak event times.

Yao Yin: So there is an order?

Kelly Marrin: Yes, could do either one, but not both.

Damon Fisher: Have any of the grid limitations been taken into consideration? All batteries operating on a feeder at the same time that cause voltage whip-sawing if they are on all at once?

Kelly Marrin: We haven't gone into that level of detail. This is a broad brush study, less broad than before, but take it with the idea of trying to get a sense of what the potential could be. But we haven't looked at it at the technical level of response.

Damon Fisher: The feeder itself could be at the limit itself, not the technical potential.

Kathlyn Kinney: At a high level, how does this compare to increasing electricity demand over time? How close are we to breaking even?

Kelly Marrin: Haven't gotten to that step yet. If we add up all of the DR reductions versus the forecast. We haven't gotten to that step yet, but when we add up at a very high level of the percentage – I think close to 10%, but 5 – 10% of total peak demand by 2045.

Kathlyn Kinney: Do we know what the increase from electrification will be?

James Gall: It's available on the website, but is about 800 MW over the next 24 years. If we did all these programs, we can offset more than our load growth. DR is only for those couple of hours. We still have the rest of the year to deal with.

Fred Heutte: I just came in from another call I had to run to. DR is a key interest these days. Specifically, we think the new standard grid-integrated water heaters will provide a lot of savings. We are very interested in utilities trying to show this. How many electric water heaters are now in the Avista service territory? We've seen increasing periods of very high pricing at Mid-C and elsewhere. Will that be folded into the value of DR?

Ken Walter: The water heater number is not in front of me, but we could map it.

Fred Heutte: 45-55% in the region. It is helpful to know. I've looked at the saturation assessments, but don't know for sure. My guess over time is a high number above 50%.

James Gall: That is the plan. We'll assign a price to call on DR. From a modeling perspective, it's difficult, it will need to be done outside of the model. Not sure of the price yet, so there is a market opportunity to take advantage of. It is not impossible to model, but very difficult.

Fred Heutte: Lots of different factors with coal retirements and limited DR now.

Tina Jayaweera: For the transmission and distribution side, how can DR help with this and what we heard earlier? Haven't finished with costs for both T&D particulars.

Kelly Marrin: A question we need to address together when we get there. Sounds like there could be additional value from geographic-specific DR. Definitely on the location specific side. Will make a note of that for when we get there and will revisit with Avista when we get there.

<u>Conservation Potential Assessment – Ken Walter, AEG</u>

Tina Jayaweera: Is the T&D deferral being incorporated here?

Ken Walter: It's being incorporated in the avoided cost. I'll ask Ryan if he remembers. It's not an exact value. We are looking into how to have a more prospective approach to historic value of the net plant value for T&D deferral.

Tina Jayaweera: The Council has a proposed methodology, I can't remember if Avista used that?

Ryan Finesilver: No, it wasn't used but we'd be happy to talk about it.

Tina Jayaweera: Ok, we can talk about it offline.

Brian Fadie: Is the social cost of carbon being considered in these cost effectiveness tests?

James Gall: Yes, we include it for incremental energy efficiency. There will be more emissions avoided somewhere else in the region. There is a slide on that later today. More energy efficiency and more incremental emissions are avoided and we would include that benefit.

Yao Yin (Slide 14): In the load and resource balance, which line is used to determine the amount of energy efficiency?

Ken Walter: The middle green line, but we provide savings at the measure level. About 7,000 line items.

James Gall: The load forecast which we show there is reduced somewhere between the red and the hashed lines. Energy efficiency programs that are cost-effective will reduce that load.

Grant Forsyth: Forecast without energy efficiency included, run PRiSM, and then I gross up the forecast for energy efficiency that could be existing in the future.

James Gall: Yes, it's a circular chicken and egg issue as we don't know what programs will be used in the future. The idea is to get a forecast of programs that are cost effective to increase or decrease loads, then iterate between the two. Start with a high load forecast, select energy efficiency programs with PRiSM, and then redo the forecast with and without energy efficiency for energy and for peak load.

Yao Yin: In Grant's forecast without energy efficiency, PRiSM is then used to select and adjust that load. How does this slide fit into that process (slide 14)?

James Gall: There are a number of programs that are available to be selected as to whether they should move forward or not.

Ken Walter: Pool of all measures is what the model selects from.

Richard Keller: Is slide 14 in GWh, not aMW? *Yes, GWh.* Thanks.

Tina Jayaweera: Catching up with industrial customers in your assessment, are those two large industrial customers eligible for energy efficiency programs?

Ryan Finesilver: I believe all customers are eligible. All customers pay into the efficiency program. So I guess the question is how we are accounting for industrial customers in the IRP? They are not in the baseline. The problem is we can't apply a curve to a single individual customer. The large industrial company makes its own energy efficiency decisions, which is not something we can do on a model level.

James Gall: We need to take this issue back as a group internally and discuss it.

Tina Jayaweera (slide 15): How are you accounting for the missed energy efficiency for these two customers?

Ryan Finesilver: Assume that their efficiency will be included as well.

Ken Walter: Not in baseline so not included. Can't apply a curve designed for a whole population to a single individuals. Other clients have approached this by having AEG speak to these customers and see what they intend to do.

James Gall: Sounds like we need to discuss this internally.

Ken Walter: Tina, thanks for the idea.

Tina Jayaweera: How are you determining the peak impact for energy efficiency? What is the methodology?

Ken Walter: The ratio of peak kW to annual kWh based on end use shapes on an hourly level. We use that to segment.

Tina Jayaweera: For load shapes, what are your main sources?

Ken Walter: Open EI and I think the Yakima weather station.

Yao Yin: When are the peak hours for Avista for both winter and summer?

James Gall: 7-8 am in morning or 5-6 pm in the evening for the winter. Summer peaks around 4 pm or 6 to 7pm. summer peak usually occurs in July or August and winter is in the end of November through mid-February. The days of the week also matter, Monday through Wednesday are usually the highest load. Some peak weather events occur on holidays or weekends when loads are lower.

Yao Yin: What is the method used to determine peak hours?

James Gall: Looking at actual load history.

Tina Jayaweera: For energy efficiency do you take the average or the peak?

Ken Walter: We do it based on the actual single peak hour.

Yao Yin: I'm a little confused, is it the single peak hour, not a period but one hour?

James Gall: Yes, we assume it as a single hour as opposed to an average over 2 to 3 hours.

Yao Yin: How did you determine which hour?

James Gall: For each month, Grant looks at the hottest and coldest day of the month and averages the historic weather years to come up with a peak hour.

Yao Yin: That results in one single peak hour instead of the timeframes you mentioned earlier?

James Gall: Our modeling is at the annual peak perspective. We are not looking at when that specific hour is. We are given a high water mark and then looking at measures to reduce it from there. Value we are looking at is an average. The future is an expectation of what that will change to.

Tina Jayaweera: The IRP is an hourly model. Are you taking 8760 hours from energy efficiency? The peak from here doesn't actually get used. Is that correct?

James Gall: The 8760 is used for the economic analysis of energy valuation for how much energy is worth. We get a summer and a winter peak value. Evaluate on energy and then how much it lowers winter or summer peak value for the L&R.

Tina Jayaweera: Confused about peak of a couple of hours versus what we have here.

James Gall: We don't know a specific hour when it will occur.

Tina Jayaweera: That makes sense and it can shift around. My concern is on the energy efficiency side, it's over or under estimating because it's not just one hour.

Ken Walter: How a peak event breaks down across end use typically won't be materially different so there is not much risk of over or under estimating.

Tina Jayaweera: My concern is with winter, if it occurs in the morning versus the evening, equipment operates differently. I don't know how impactful this would be, just exploring.

Ken Walter: I'm making a note on that.

James Gall: No model can evaluate every hour so that the model can solve. We don't know the specific hour when a peak will occur. It is not a consistent hour for every day. All inputs are available on our website in the same format I used in the IRP.

<u>Electric Market Price Forecast, James Gall</u>

Richard Keller (slide 4): Is this the average annual price?

James Gall: Yes, for on peak and off peak.

Richard Keller: How does the model look at hourly reliability attributed to operating reserves?

James Gall (slide 12): The model is solving for operating reserves on a system basis for an area or zone and not on a utility basis. Six percent operating/spinning and non-spinning reserves and 2% for regulation. Hopefully, that helps.

Fred Heutte: A lot of data there. I'm not terribly surprised with trying to take into account all of the things in the stochastic model. There is a jump logic approach to shock parameters, I'm wondering if you do something like that to pick up a COVID or such an event. PAC does something similar.

James Gall: Not specifically, but there are specific tail shock events that do occur. A black swan event is great to test as a scenario. They show up, but not at the same time. Stochastic modeling tries to take into account an event like those tail events.

Yao Yin (slide 12): Is there an algorithm that calculates whether the wind/solar can be integrated?

James Gall: There is not a specific requirement looking at the instantaneous number. There is not a dynamic reserve held for winter. It holds back capacity for integration based on the inputs. We can model this in the future, but it probably wouldn't solve in time to be useful as it would slow the model to a crawl. The model wouldn't solve in enough time to be usable. Maybe the technology will get better so it could solve.

Yao Yin: Is the amount of reserve percentage manually entered?

James Gall: Yes, for price, but for reliability it's dynamic at the local system level. We include it for our need at a local system level. In the resource adequacy portion and in PRiSM it is rolled up in the model runs and set aside for capacity from the reliability model.

Yao Yin: Is the local dynamic done within PRiSM?

James Gall: No, in the reliability model which estimates what the planning margin should be and then that number gets put into PRiSM. We will talk about that in the next meeting.

Fred Heutte: The SAAC talked about this in the morning. What is the west going to do for new resources for the late 2020s and early 2030s with the shape of prices? They are seeing a similar issue for the regional modeling.

James Gall: Yes, that's the rest of the presentation.

Charlie Inman (Slide 13): How many zones are in Avista's [Aurora] model?

James Gall: 12 to 14. We are using the same database as the 2020 IRP. There is a newer one, but that one came out too late for this IRP.

Yao Yin (slide 16): Is DR considered on the supply side and not as a load adjustment?

James Gall: It is a load adjustment, but the model dispatches it so it acts like generation. Included it here because it acts like a generator – same with net metering.

Yao Yin: Net metering is a reduction to load and DR is dispatched?

James Gall: Correct. Model first goes to DR to select the amount of DR. DR is dispatched by the model, but it may or may not be chosen.

Yao Yin: So the amount of DR is from a model result whereas net metering is based on an entered number?

James Gall: Correct. Along with combined cycle and simple cycle generation. There is a process to shut off generation – typically renewables have a tax credit and can operate with a negative price. Hydro has a negative $25 price but it often can't be turned off due to a fish constraint. Negative prices are based on dispatch order.

Kathlyn Kinney (slide 22): Is there somewhere where pricing here transfers to price reductions and scenarios where higher priced renewables still fit in and make sense?

James Gall: When the model looks at a resource choice it's looking at the margin. It is willing to pay more for the resource that meets those super peak hours. Now you have to pay for solar plus storage and the extra cost may not equal the extra benefit you get from that solar plus storage resource. Start to see what hours to dispatch a DR program and whether they are for economic or for reliability reasons. As far as demand goes, we are starting to see where some of those resources might be dispatched.

James Gall: Back to slide 21, the history of electric price forecasts since I've been doing them here since 2005. A few times we got it right and others we were too high. In the teens we were getting lower and now we are pretty close to the market. Prices over the last 15 years have been falling, similar to loads.

James Gall (slide 24): In the analysis, we will make a decision about if a plant is uneconomic, such as Colstrip. In Washington, there is a cost cap for new renewables and it is load versus generation based in other states.

James Gall (slide 25): The rest of the slides are on scenarios that we agreed to perform previously for this IRP.

Yao Yin: Which natural gas forecast will be used for the October 15th filing [Idaho avoided cost filing]?

James Gall: Will need to check. We used expected price (middle), which is based on the forecast from the consultants we hire rather than a higher or lower gas price

Yao Yin: Why don't we include the expected case in here?

James Gall: It is, these are higher and lower scenarios for high and low gas prices.

Jennifer Snyder: Can you give a high level overview of your social cost of carbon modeling and what's changed?

James Gall: The model was used to acquire the resources based on the resource plus cost of the social cost of carbon plus upstream emissions plus construction costs. Energy efficiency used an average rate, we have been talking about using an incremental cost (talked about more this afternoon). Market purchases/sales use an average emission rate as well – this is not a change. Two changes – energy efficiency average to incremental and including a social cost of carbon cost for resource acquisition.

Corey Dahl: What is the problem with the social cost of carbon?

James Gall: To capture the cost of carbon associated with the manufacturing and construction processes associated with the resources – both sides. We used construction and operations life cycle carbon analysis study from NREL. It is a small amount of dollars, but it tries to estimate the total carbon costs associated with different resource choices.

Kathlyn Kinney (slide 31): Incremental means?

James Gall: To run existing infrastructure, how would the system operate in that world.

Jennifer Snyder: I was kicked off the call and just rejoined. I missed what you said and will have to talk with you later.

James Gall: That's fine, we can have an offline conversation.

2021 Electric Integrated Resource Plan

Technical Advisory Committee Meeting No. 4 Agenda

Tuesday, November 17, 2020
Virtual Meeting

Topic	**Time**	**Staff**
Introductions	9:00	Lyons
Final Resource Needs Assessment	9:15	Lyons
2020 Renewable RFP Update	9:45	Drake
Break	10:20	
Portfolio Modeling Overview	10:30	Gall
Lunch	11:30	
Draft PRS and Scenarios	12:30	Gall
Adjourn	2:00	

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2021 Electric IRP
TAC Introductions and IRP Process Updates

John Lyons, Ph.D.
Fourth Technical Advisory Committee Meeting
November 17, 2020

Updated TAC Meeting Guidelines

- IRP team working remotely through the rest of this IRP, but still available by email and phone for questions and comments
- Some processes are taking longer remotely
- Virtual IRP meetings until able to hold large group meetings again
- Joint Avista IRP page for gas and electric: https://www.myavista.com/about-us/integrated-resource-planning
  - TAC presentations
  - Documentation for IRP work
  - Past IRPs

Virtual TAC Meeting Reminders

- Please mute mics unless speaking or asking a question
- Use the Skype chat box to write questions or comments or let us know you would like to say something
- Respect the pause
- Please try not to speak over the presenter or a speaker who is voicing a question or thought
- Remember to state your name before speaking for the note taker
- This is a public advisory meeting – presentations and comments will be recorded and documented

Integrated Resource Planning

- Required by Idaho and Washington* every other year
- Guides resource strategy over the next twenty + years
- Current and projected load & resource position
- Resource strategies under different future policies
  - Resource choices
  - Conservation measures and programs
  - Transmission and distribution integration for electric
  - Gas distribution planning
  - Gas and electric market price forecasts
- Scenarios for uncertain future events and issues
- Key dates for modeling and IRP development are available in the Work Plans

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 involved in all or parts of the process
  - Ask questions
  - Help with soliciting new members
- 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 number or type of studies
  - Earlier study requests allow us to be more accommodating
  - **August 1, 2020** was the electric study request deadline
- Planning teams are available by email or phone for questions or comments between the TAC meetings

2021 Electric IRP TAC Schedule

- TAC 1: Thursday, June 18, 2020
- TAC 2: Thursday, August 6, 2020 (Joint with Natural Gas TAC)
- TAC 2.5: Tuesday, August 18, 2020 Economic and Load Forecast
- TAC 3: Tuesday, September 29, 2020
- **TAC 4: Tuesday, November 17, 2020**
- TAC 4.5: December 2020 – 2 Hours on Scenarios
- TAC 5: Thursday, January 21, 2021
- Public Outreach Meeting: February 2021
- TAC agendas, presentations, meeting minutes and IRP files available at:

  https://myavista.com/about-us/integrated-resource-planning

Process Updates

Available IRP Data:

- Avista Resource Emissions Summary
- Load Forecast
- CPA Measures
- Avista 2020 Electric CPA – Summary and IRP Inputs
- Home Electrification Conversions
- Named Populations
- Natural Gas Prices
- Social Cost of Carbon

Files Added Since TAC 3:

- High and Low Natural Gas Prices
- Market Modeling Results
- Climate Shift Scenario Inputs
- 2021 IRP New Resource Options

Today's TAC Agenda

9:00	Introductions, Lyons
9:15	Final Resource Need Assessment, Lyons
9:45	2020 Renewable RFP Update, Drake
10:20	Break
10:30	Portfolio Modeling Overview, Gall
11:30	Lunch
12:30	Draft PRS and Scenarios, Gall
2:00	Adjourn

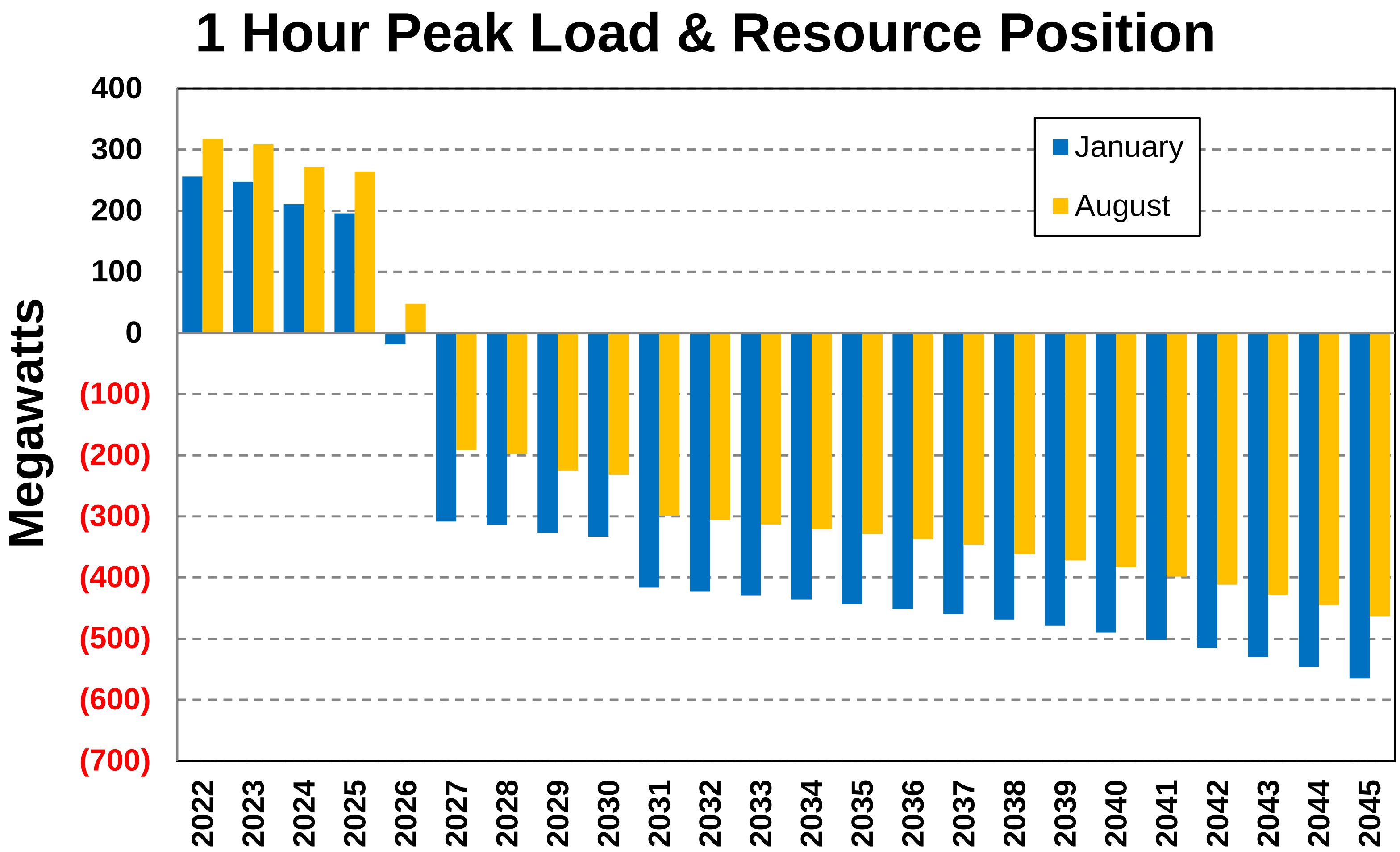
2020 Electric IRP
Resource Need Assessment

John Lyons, Ph.D.
Fourth Technical Advisory Committee Meeting
November 17, 2020

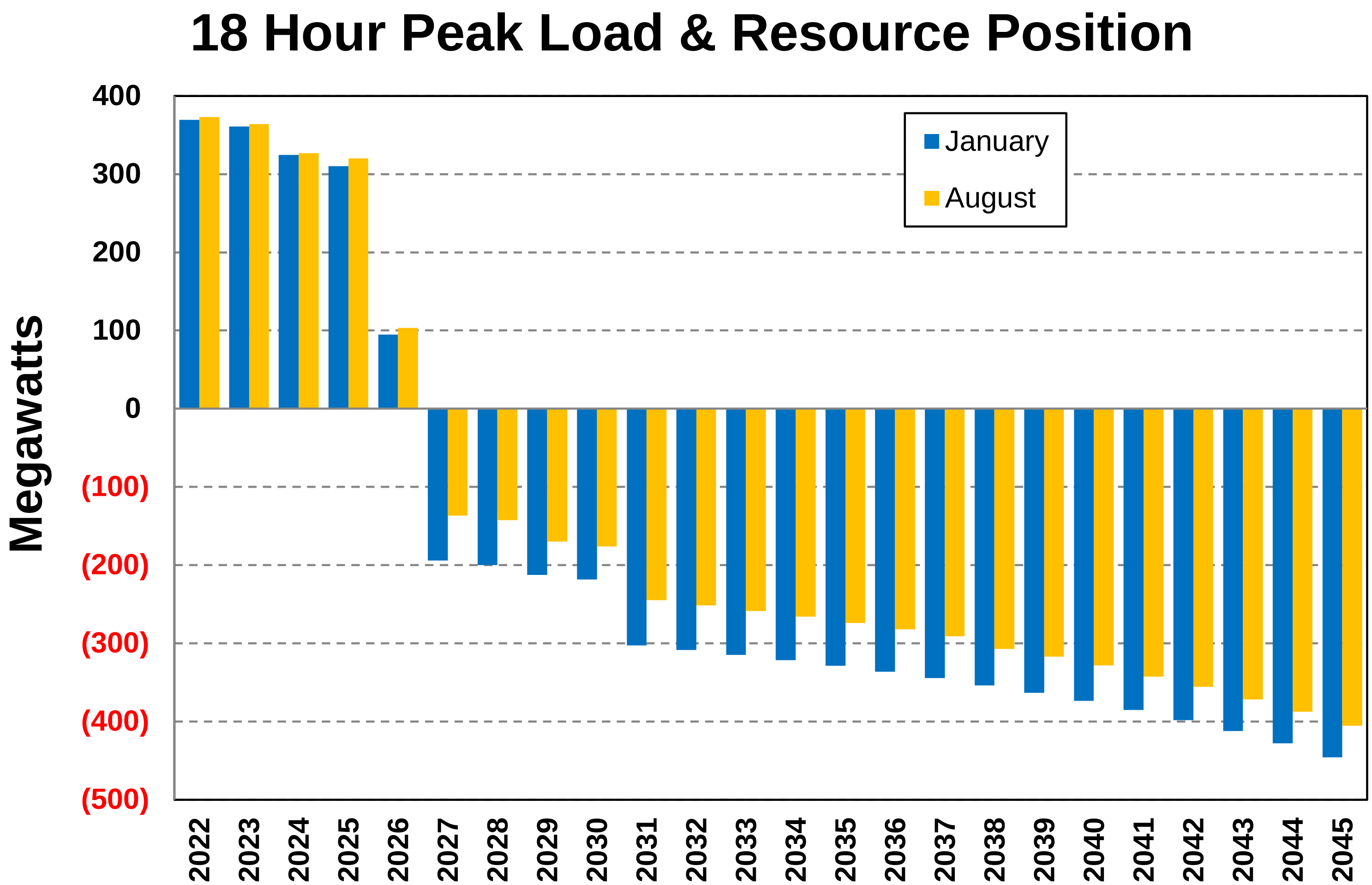
Load & Resource Methodology Review

- Sum resource capabilities against loads
- Resource plans are subject to 5% LOLP analysis – determines planning margins
- Colstrip is included through 2025 per 2020 IRP
- Capacity
  - Planning Margin (16% Winter, 7% Summer)
    - Using 2020 IRP result; pending future analysis
  - Operating Reserves and Regulation (~8%)
  - Reduced by planned outages for maintenance
  - Plan to largest deficit months between 1- and 18-hour analyses
- Energy
  - Reduced by planned and forced outages
  - Maximum *potential* thermal generation over the year
  - 80-year hydro average, adjusted down to 10th percentile

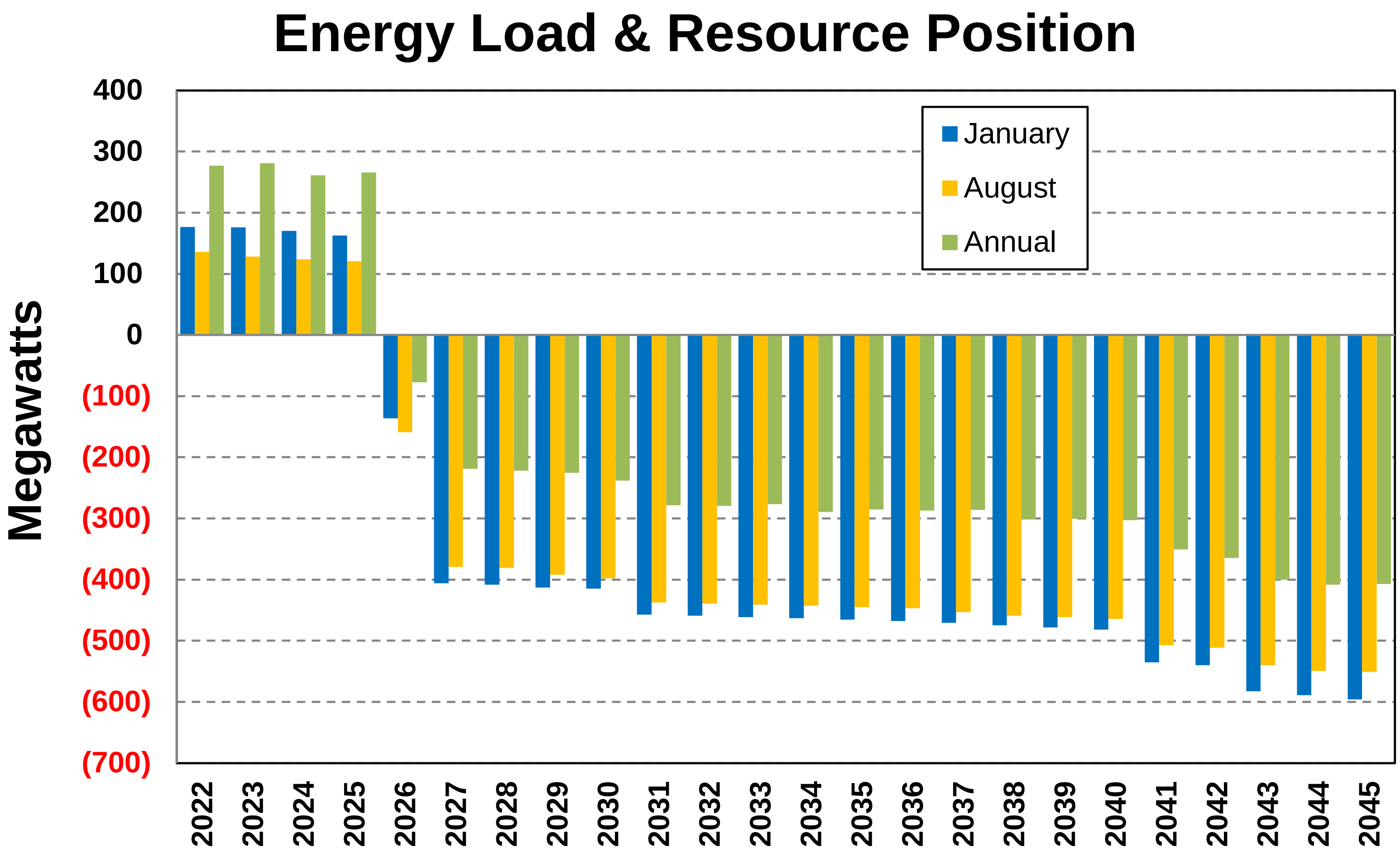
One Hour Peak Load & Resource Position



18-Hour Peak Load & Resource Position



Energy Load & Resource Position



Avista's Clean Energy Goal

Goals

- 2027 – 100% carbon-neutral
- 2045 – 100% clean electricity

How we will get there

- It's not just about generation – various solutions are necessary
- Maintain focus on reliability and affordability
- Natural gas plays an important part of a clean energy future
- Cost effective technologies need to emerge and mature

AVISTA

Washington State Clean Energy Goals

- Energy Independence Act or Initiative 937
  - 15% of Washington retail load after 2020
  - Not modeling for this IRP since CETA takes us beyond 15%
  - Last IRP anticipated the inclusion of qualifying BPA and Wanapum generation, neither of which materialized
    - Avista decision to offset costs in lieu of BPA RECs
    - Inability to use Wanapum because of difference in hydro methodology
- Clean Energy Transformation Act
  - By 2025 – eliminate coal-fired resources from serving WA customers
  - By 2030 – electric supply must be greenhouse gas neutral,
  - By 2045 – electric supply must be 100% renewable or be generated from zero-carbon resources

2020 Renewable RFP Update

Chris Drake, Wholesale Marketing Manager
Fourth Technical Advisory Committee Meeting
November 17, 2020

Justification

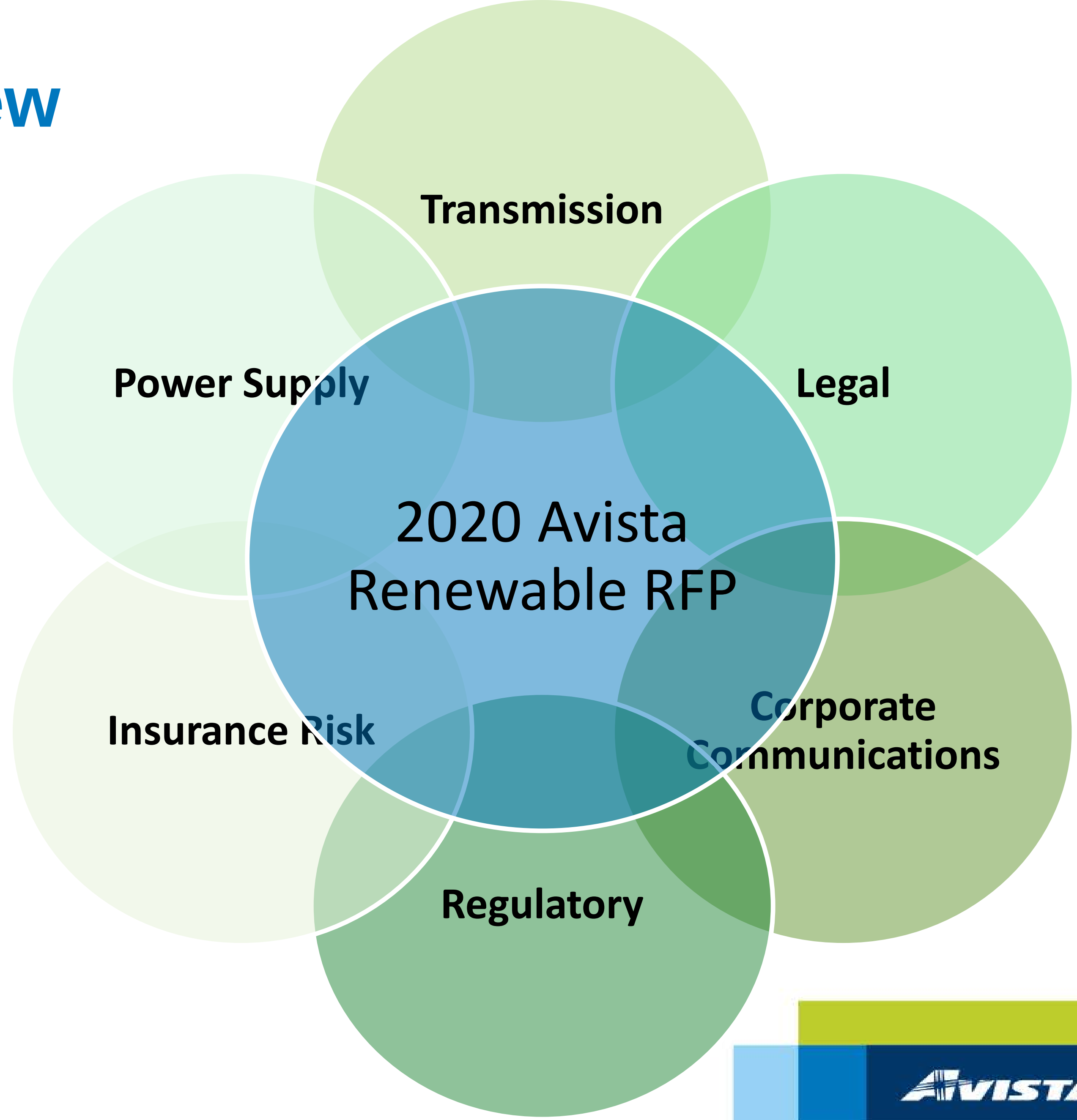
- Integrated Resource Plan (IRP) - Preferred Resource Strategy (PRS)
- Market indicators suggested competitive pricing for renewables
- Competition for preferred sites
- Corporate renewable goals – systemwide
  - Carbon neutral by 2027
  - 100% clean electricity by 2045
- If bids are not compelling, no obligation to contract
- Capacity Request For Information (or similar investigation) may be considered at a later date

2020 IRP Preferred Resource Strategy

Resource Type	Year	Capability (MW)
Montana wind	2022	100
NW wind	2022-2023	200
Kettle Falls upgrade	2026	12
Colstrip 3 & 4 exits portfolio	2026	-222
Rathdrum CT 1 & 2 upgrades	2026	24
Long-duration pumped hydro	2026	175
Lancaster PPA expires	2026	-257
Post Falls upgrade	2027	8
Montana wind	2027	200
Mid-Columbia hydro	2031	75
Northeast CTs retires	2035	-55
Long Lake 2nd powerhouse	2035	68
Liquid-air storage (16 hours)	2036-2041	100
Wind (including PPA renewals)	2041-2043	300
Lithium-ion storage (4 hour)	2042-2045	300
Solar w/ storage (4 hours)	2044	55
4-hr Storage for Solar	2044	50
Supply-side resource net total (MW)		1,133
Supply-side additions through 2045 (MW)		1,667
Demand Response through 2045 (MW)		112
Energy Efficiency through 2045 (aMW)		187

Cross-Departmental Review

- Power Supply
  - Wholesale marketing, resource planning, real-time, traders, credit and resource optimization
- Transmission
- Regulatory
- Insurance/Risk
- Corporate Communications
- Legal



New Elements of 2020 RFP

- New and existing projects were eligible to bid
  - New renewable resources
  - Nonemitting electric generation (existing)
- Updated evaluation methodology criteria
  - Risk Management, Net Price, Price Risk, Electric Factors, Environmental
  - Added Community Impact
    - Avista service territory economic impact
    - Equity provisions
    - Vulnerable and highly impacted communities
    - Energy security
- Published evaluation methodology

RFP Communications

AVISTA

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Renewables RFP

Avista released a request for proposals on June 26, 2020 seeking pricing from renewable energy project developers capable of constructing, owning and operating up to 120 average MW's for delivery to Avista's electric utility service territory. Please respond to the RFP by completing the following forms and submitting them to 2020renewablerfp@avistacorp.com by July 22, 2020.

- Request for proposals
- Exhibit A
- Exhibit B
- Exhibit C
- Exhibit D

2020 RFP Target Schedule (subject to change)

- June 26, 2020 – Release RFP
- July 22, 2020 – Preliminary Information due
- July 31, 2020 – Short list identified
- August 21, 2020 – Detailed Proposals due from short-listed bidders
- August 21, 2020 through September 9, 2020 - Negotiations with short-listed bidders
- October 16, 2020 – Final bidder(s) selected
- December 15, 2020 – Final contracting complete with successful bidder(s)

Please note: The RFP does not constitute a legal offer or otherwise create a binding agreement or obligation to consummate any contemplated transaction. Any such obligation or agreement will be created only by the execution of definitive agreements, the provisions of which, if so executed, will supersede the RFP. Avista reserves the right to cancel the RFP at any time in its sole discretion.

Savings Tools

Energy Saving Advice

Tools For Your Business

Energy and Savings Profile

Green Options

- My Clean Energy
- Onsite Generation
- Community Renewable Options
- Electric Transportation
- Compressed Natural Gas

Avista Marketplace

Rebate Overview

Rebates: Washington

Rebates: Idaho

- Published on www.myavista.com
- Press Release
  - Local media contacts
  - GlobeNewswire distribution to over 600 national outlets

AVISTA

Renewable Generation Need

- RFP for up to 300 MW renewables
- 2020 IRP's PRS model
  - 2022 Montana wind – 100 MW
  - 2022-2023 NW wind – 200 MW
- Anticipated proposals – mix of wind/solar/storage

2020 Avista Renewable RFP

Wind

Solar

Storage

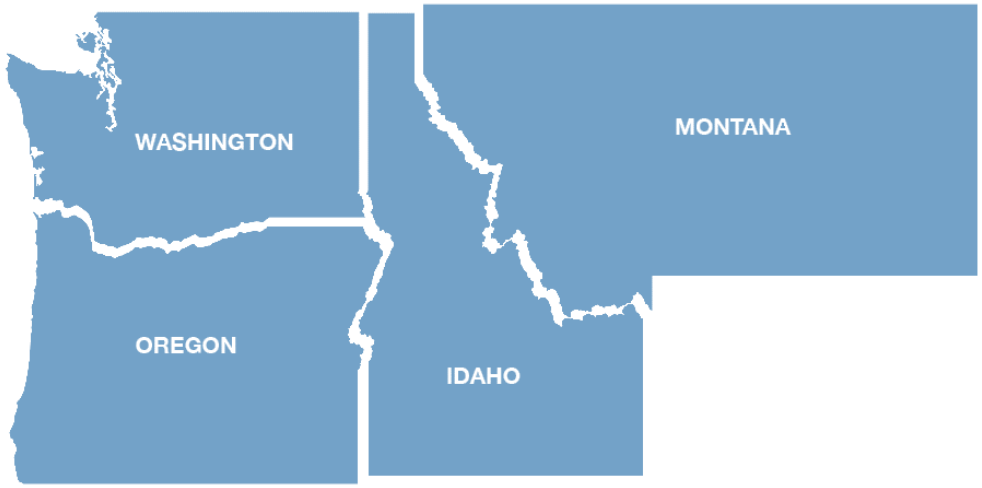
Repowering

Bids Received July 22, 2020

- 42 projects
- 25 developers
- 27 solar (many with battery options)
- 13 wind (some with battery option)
- 1 hydro
- 1 biomass

RFP Initial Reactions

- Good selection of shovel ready and existing projects
- Good geographic distribution
  - Projects throughout Northwest with majority in Washington, then Montana, Idaho and Oregon
- Prices were higher than 2018 RFP
  - Sunsetting PTC
  - Increased construction costs
- Multiple capacity projects submitted
  - Hydro
  - Biomass



2020 Avista Renewable RFP Evaluation Methodology

General Qualifications

- Compatibility with resource need
- Site control
- Financial plan to bring project to completion
- Credit requirements
- Procurement plan
- Project completion no later than December 31, 2023

Evaluation Criteria

- Risk Management - Credit and Developer Experience
- Net Price - Nominal levelized cost / MWh
- Price Risk - Fixed price, construction, fuel supply
- Electric Factors - Interconnection, transmission, technology
- Environmental - Permitting
- Community Impact - Community involvement, Avista service territory, vulnerable populations

2020 Target Schedule (and Milestones Completed)

- ✓ June 26, 2020 – RFP Released
- ✓ July 22, 2020 – Preliminary Information Due
- ✓ July 31, 2020 – Short-list identified and notified (along with other bidders)
- ✓ August 21, 2020 – Detailed proposals received from short-list
- ✓ October 16, 2020 – Final bidder(s) selected for continued review
- December 31, 2020 – Contract negotiation(s)

2020 RFP Next Steps

- Continue to address specific attributes within proposal(s)
- Contract negotiations with successful project(s)
- Continue internal review to make a final determination

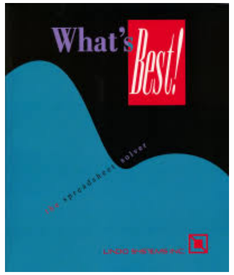
PRiSM Model Overview

James Gall, Electric IRP Manager
Fourth Technical Advisory Committee Meeting
November 17, 2020

What is PRiSM?

- Preferred Resource Strategy Model
- Mixed Integer Program (MIP) used to select new resources to meet resource needs of our customers

The user interface



The solver interface

The solver

New PRiSM Features for 2021 IRP

- Significant changes were made to this IRP's model due to individual state policies.
  - Model purpose: Same as before with additional constraints and options.
  - New Constraints: Must meet individual state L&R balance requirements and clean energy goals.
  - New Options: Resources can be added for a specific state or the system.
  - New Outputs: State level cost and rate estimates along with resource strategies.
  - Model will be fully available and published on IRP website.
  - Model is continually being vetted.

Objective Function

Intro to linear programing: https://www.youtube.com/watch?v=Uo6aRV-mbeg

Minimize: (WA “Societal” $NPV_{2022\text{-}45}$) + (ID $NPV_{2022\text{-}45}$)

Where:

WA $NPV_{2022\text{-}45}$ = Market Value of Load + Existing & Future Resource Cost/Operating Margin + Social Cost of Carbon + EE TRC

ID $NPV_{2022\text{-}45}$ = Market Value of Load + Existing & Future Resource Cost/Operating Margin + EE UTC

Subject to:

- Generation Availability & Timing
- Energy Efficiency Potential
- Demand Response Potential
- Winter Peak Requirements
- Summer Peak Requirements
- Annual Energy Requirements
- Clean Energy Goals
- T&D Constraints

Optimization Tolerance: 0.0001 or 1,500 seconds (Note: certain studies longer solution times allowed)

Optimized Cost vs. Actual Costs

- Objective function includes social costs that are not part of utility revenue requirement.
- This is used for resource optimization only.
- Social costs may include:
  - Energy Efficiency
    - TRC
    - Non-energy benefits
    - Power Act 10% adder
    - T&D Savings
  - Social Cost of Carbon

- Actual costs illustrate expected cost ratepayers will pay.
- Estimate annual revenue requirements.
- Estimate average rates.

Aurora Integration

- Aurora's price forecast and resource dispatch are inputs into PRiSM.
- Each **supply resource's** operations is included by iteration.
  - Includes MWh, GHG, Revenue, Fuel Cost, VOM costs.
- **Avista load and existing contracts** are also entered in totals.
- **Energy efficiency** load shapes are marked to market and used for the energy value of these programs.
- **Demand response** options are not modeled in Aurora, but use hourly price results for a market value.

Thermal Resources

- Model may retain or exclude specific resources in any year.
  - Retirements are for both states (except Colstrip).
  - No re-allocation of existing resources between states.
- Includes major future capital spend for continued operation along with O&M costs.
- Resource costs and benefits are allocated using PT ratio (65% WA, 35% ID).
- Lancaster PPA expires in October 2026.
- Northeast assumes retirement in 2035 & Boulder Park in 2040.
- Kettle Falls CT is excluded from retirement option, but is excluded from winter peak due to pending pipeline review.
- Colstrip must be removed in Washington by 2025.
  - Model can remove earlier or retain for Idaho.
  - Washington’s share of cost after 2025 are not included in model.

Hydro Resources

- Available for full length of study.
- Post Falls assumes rebuild in 2025 (found cost effective in 2021 IRP).
- Energy, capacity, and clean energy attributes split between states using PT ratio (65% WA/35% ID).

Other Existing “Resources”

- PURPA
  - CETA has provision for in-state PURPA generation reducing clean energy obligation.
  - For modelling purposes, generation is allocated to each state it qualifies under PURPA.
- Other Wholesale Contracts
  - Current PPAs are allocated to each state using PT ratio.
  - Except for Adam’s Neilson Solar- fully allocated to Washington.
  - PURPA related resales are fully allocated to state it qualifies for under PURPA
- Renewable Energy Credits (RECs)
  - Each state receives “RECs” from its “PT ratio” share of resources.
  - Model allows for sale of RECs between states subject to limits.

Energy Efficiency

Washington

- AEG provides EE potential by year and program
  - Winter peak savings
  - Summer peak savings
  - Annual average savings
- Electrical savings are grossed up for T&D losses
- Benefit of T&D Capital Avoidance ($25.35 per kW-yr)
- Total Resource Cost (TRC) test
- Add value for non-energy benefits ($23 per MWh)
- Power Act 10% adder for energy and capacity value
- Social Cost of Carbon using regional incremental emission rates per MWh
- Included in L&R constraints to avoid new supply resource options

Idaho

- AEG provides EE potential by year and program
  - Winter peak savings
  - Summer peak savings
  - Annual average savings
- Electrical savings are grossed up for T&D losses
- Benefit of T&D Capital Avoidance ($25.35 per kW-yr)
- Utility Cost Test (UCT) for cost effectiveness
- Included in L&R constraints to avoid new supply resource options

Demand Response

- Programs available in each state determined by AEG.
- AEG estimated capital amortized over 5 years and a levelized cost is created by combining the O&M costs.
- Projects must ramp in over time (except large industrial).
  - 25 MW of industrial DR for Washington
- Water heating is different between states:
  - WA includes CTA-2045
  - DLC water heating in ID
- Energy arbitrage and savings is included based on 50% of potential use.
  - 10% preference adder included for Washington.
- Peak Credit is using 2020 IRP estimate of 60%.
  - Additional studies may be available to validate.
  - Based on prior IRP- this estimate could be too high.

Supply-Side Options

- Uses levelized fixed and variable costs for potentially owned resources (i.e. natural gas, storage).
- Uses PPA $/MWh or $/kW-yr costs for resources.
- All generation costs are available on the IRP website.
- Washington PPA options includes rate of return for clean resources.
- Resources must be added in increments of probable size of actual acquisition- not any value- this assumption can increase cost or change resource strategy.

Clean Energy Goals

- **Washington**
  - 100% clean energy (carbon neutral) by 2030
  - 100% clean energy by 2045
- **MAJOR ASSUMPTIONS:**
  - By 2030, Washington's clean energy must equal 100% of net retail sales; 20% of this total may come from RECs.
    - Only REC purchases assumed are from Idaho customers at $7.50/MWh escalating
  - 2045, 100% goal of all 100% of electrons clean is not modeled at this time (likely 2024 IRP).
  - Between 2030 and 2045 REC transfers decline to zero.
  - Prior to 2030 REC transfers are limited to non-hydro resources to encourage early acquisition.

- **Idaho**
  - No clean energy requirement.
  - Idaho is allowed to sell REC's to Washington LSE.
  - Other REC sales to other parties are not modeled.
  - Scenarios will show cost of additional renewable energy acquisition.

Greenhouse Gas Emissions

- The model estimates the GHG emissions for thermal resource dispatch.
  - Market purchase/sale effects are estimated using the regional average emission rate.
  - Storage resources include a market based GHG adder.
- Societal emissions saved from Energy Efficiency using an incremental emissions approach are estimated.
- Includes upstream emissions for natural gas resources.
- Construction and operation emissions are included.

Social Cost of Carbon or Social Cost of Greenhouse Gas

Washington

- Costs are included for resource dispatch of new thermal & storage options.
- Cost are also included for existing natural gas-fired resources.
- Energy Efficiency receives a social credit for emission savings.
- No cost are included for market transactions, except for storage resources.
  - This would give extra incentive to renewables by valuing the social cost of carbon on non-Avista resources. [Potential scenario]
  - Model time step doesn't allow for SCC on purchases only.

Idaho

- No direct cost of GHG is included.
- Objective function is 65% Washington Cost-therefore existing resources are influenced by this cost and could have effects on Idaho.
- A scenario using the Washington methodology will be studied.

Transmission

- Resources have either a capital investment or a wheeling charge.
  - Capital investments are based on the transmission cost estimates from the September 2020 TAC 3 meeting.
- Resource options in the Rathdrum, Idaho area are a challenge.
  - Approximately 100 MW can be added without significant investment.
  - Over 100 MW may either require additional infrastructure or Remedial Action Scheme (RAS).
    - RAS has not been studied
  - Avista has resource options in the area without new transmission (i.e. Lancaster), but if Lancaster operates and Avista builds new resources would require an investment or RAS.
  - For this analysis no additional Rathdrum transmission is assumed until either Lancaster is ruled out from an RFP or RAS is determined to not be an option.
    - By including the additional transmission cost could either create a portfolio where Idaho must pursue a more costly option- an RFP needs to decide this rather then an IRP without cost of a Lancaster extension.

Resource Adequacy Check

- To the furthest extent possible, portfolios will be studied for resource adequacy for 2025, 2030, and 2040.
  - Each study takes 3 days to complete; Avista has only 2 machines capable of this work.
- If a portfolio fails the adequacy test- additional capacity will be required or noted.
- Avista does not expect to complete all studies for the draft IRP release.
  - Although studies will be conducted through February for the final draft portfolios requiring this work.
  - All other studies will need to rely on the planning margin for its resource adequacy test.
- Reliability data input files are still in process and results are not available at this time.

Equity Provisions

- Avista previously identified potential areas within its system qualifying for VP/HIC status, although final determination is still ongoing.
- A baseline analysis for cost and reliability/resilience has been completed.
- Avista is developing an Equity Advisory Group (EAG).
  - EAG will determine final VP/HIC determinants.
  - Develop outreach plan for each community to understand energy needs and preferences.
  - Study solutions and develop programs to meet needs of the communities.
- Process to develop a solid plan for these VP/HIC communities will not be available for this IRP.

DRAFT

Least “Reasonable” Cost Strategy & Baseline Analysis

“Not Preferred Resource Strategy Yet”

James Gall, Electric IRP Manager
Fourth Technical Advisory Committee Meeting
November 17, 2020

Safe Harbor Statement

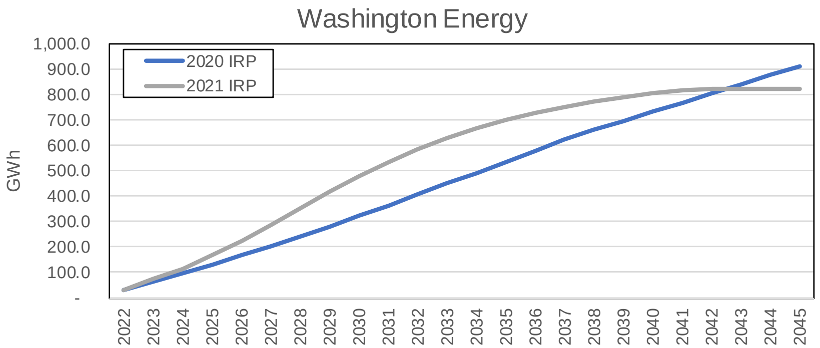
This document contains forward-looking statements. Such statements are subject to a variety of risks, uncertainties and other factors, most of which are beyond the Company's control, and many of which could have a significant impact on the Company's operations, results of operations and financial condition, and could cause actual results to differ materially from those anticipated.

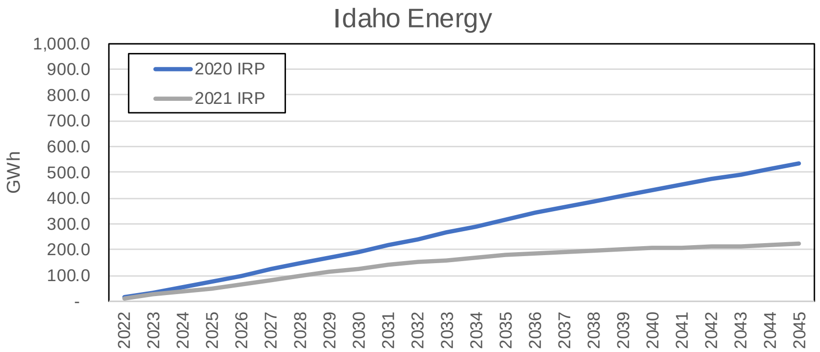
For a further discussion of these factors and other important factors, please refer to the Company's reports filed with the Securities and Exchange Commission. The forward-looking statements contained in this document speak only as of the date hereof. The Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events. New risks, uncertainties and other factors emerge from time to time, and it is not possible for management to predict all of such factors, nor can it assess the impact of each such factor on the Company's business or the extent to which any such factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement.

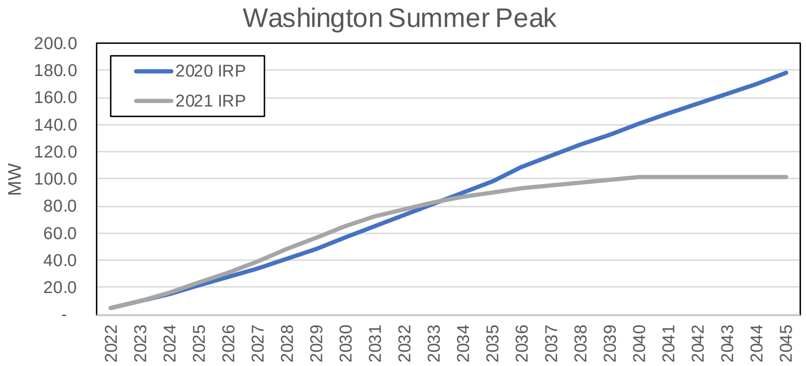
Other Caveats

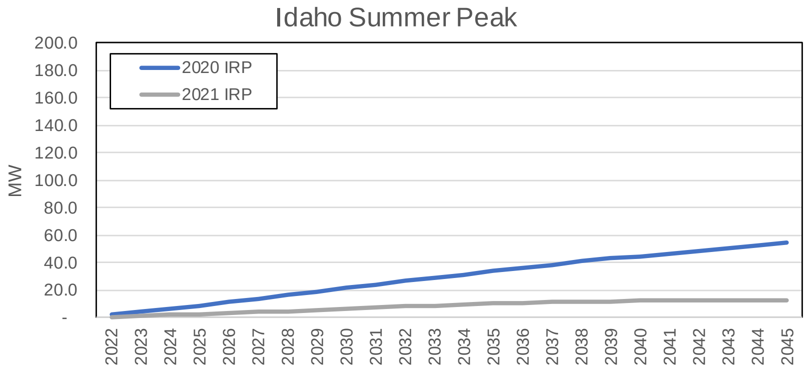
- Clean Energy Transformation Act (CETA) rules and requirements are not complete.
  - This is Avista's best estimate of known requirements.
- Avista is negotiating with the renewable Request for Proposals (RFP) shortlist bidders
  - This may change the results of the resource plan due to a potential contract.
- IRP resource options are primarily "new" resource options- RFP will determine whether or not existing resources can be acquired at similar or lower cost than "new" options.
- Avista may not be able to physically retire or exit certain resources as the IRP PRiSM model determines.
- No future state specific resource cost allocation agreement has been made.
- Forward looking rates include non-modeled power supply cost escalating at 2% per year-
  - **DO NOT TAKE THIS AS A RATE FORECAST**
  - This is for informational purposes only

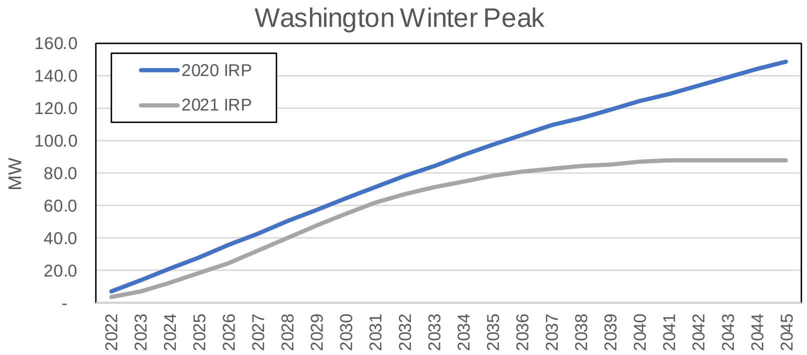
Energy Efficiency Results

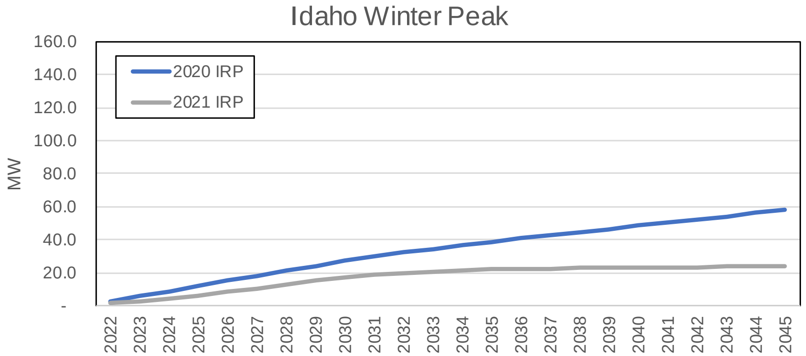












NOTE:
Energy Efficiency results do not materially impact supply resource strategy.

Supply resource strategy is based on the load forecast for both energy and peak.

EE is first estimated, then added to the load forecast; the model then picks economic EE to have net load equal to the load forecast

Cumulative Energy Efficiency End Use Results (GWh)

	2023		2031		2045	
	WA	**ID**	**WA**	**ID**	**WA**	**ID**
Appliances	0.7	0.1	6.6	0.8	15.6	2.7
Cooling	6.4	0.5	41.7	2.8	61.2	7.0
Electronics	1.1	0.2	15.2	4.8	27.1	9.3
Exterior Lighting	4.3	1.4	24.8	7.8	37.2	14.3
Food Preparation	0.1	0.0	2.2	0.4	5.9	0.9
Interior Lighting	21.1	13.0	103.6	49.3	176.3	89.6
Miscellaneous	1.5	0.3	16.0	2.8	36.0	5.5
Motors	4.9	3.4	35.3	24.0	41.3	27.0
Office Equipment	0.6	0.0	3.6	0.0	6.2	0.0
Process	0.7	0.1	4.1	1.1	4.5	1.4
Refrigeration	8.3	0.3	60.9	2.3	70.0	2.6
Space Heating	13.1	3.5	122.9	30.3	175.4	39.9
Ventilation	5.3	0.7	31.0	5.2	46.1	12.5
Water Heating	4.6	1.4	65.9	8.3	120.6	9.7
Total	**72.7**	**25.1**	**533.7**	**140.0**	**823.4**	**222.3**

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Cumulative Energy Efficiency Segment Results (GWh)

	2023		2031		2045	
	WA	ID	WA	ID	WA	ID
College	2.7	0.7	13.8	4.2	19.5	7.5
Grocery	6.8	0.2	47.6	1.4	56.6	1.7
Health	2.7	0.9	14.5	4.7	23.0	8.1
Industrial	12.0	7.9	62.5	41.1	91.4	61.1
Large Office	6.6	1.3	43.6	8.8	67.5	16.5
Lodging	1.4	0.6	8.9	2.9	13.2	4.9
Low Income	3.4	1.7	40.4	10.7	60.8	13.2
Miscellaneous	6.1	1.9	41.5	10.7	61.3	19.1
Mobile Home	0.7	0.2	7.2	1.4	14.2	2.1
Multi-Family	0.5	0.2	7.6	1.2	16.6	1.9
Restaurant	2.1	0.2	15.1	1.6	20.2	2.3
Retail	5.6	2.0	35.8	10.3	52.8	17.9
School	3.1	0.1	18.5	0.4	28.7	0.8
Single Family	14.4	5.1	147.6	28.6	250.3	42.8
Small Office	2.4	1.1	16.9	7.4	26.5	13.5
Warehouse	2.4	0.9	12.4	4.7	20.8	8.9
Total	**72.7**	**25.1**	**533.7**	**140.0**	**823.4**	**222.3**

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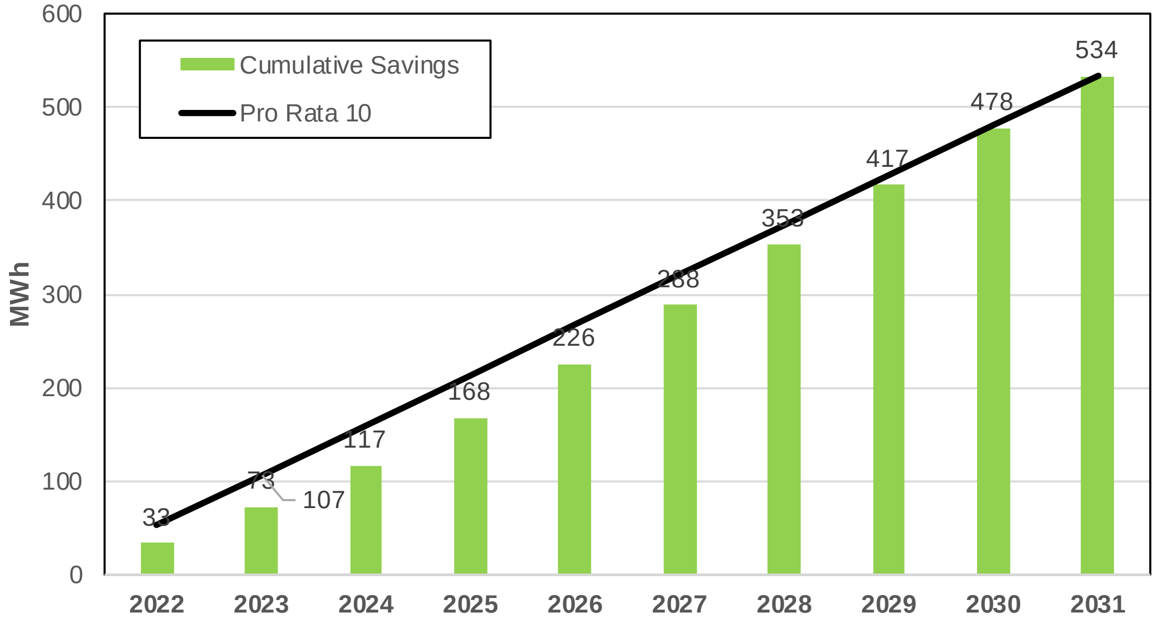
Higher Washington Energy Efficiency Goals

More Aggressive Ramp Rates & Higher Avoided Costs

Biennial Conservation Target (MWh)	Based on 2021 IRP	Based on 2020 IRP
CPA Pro-Rata Share	106,740	72,338
Distribution and Street Light Efficiency	219	504
EIA Target	106,959	72,842
Decoupling Threshold	5,348	3,642
Total Utility Conservation Goal	112,307	76,484
Excluded Programs (NEEA)	-14,016	-14,016
Utility Specific Conservation Goal	98,291	62,468
Decoupling Threshold	-5,348	-3,642
EIA Penalty Threshold	92,943	58,826



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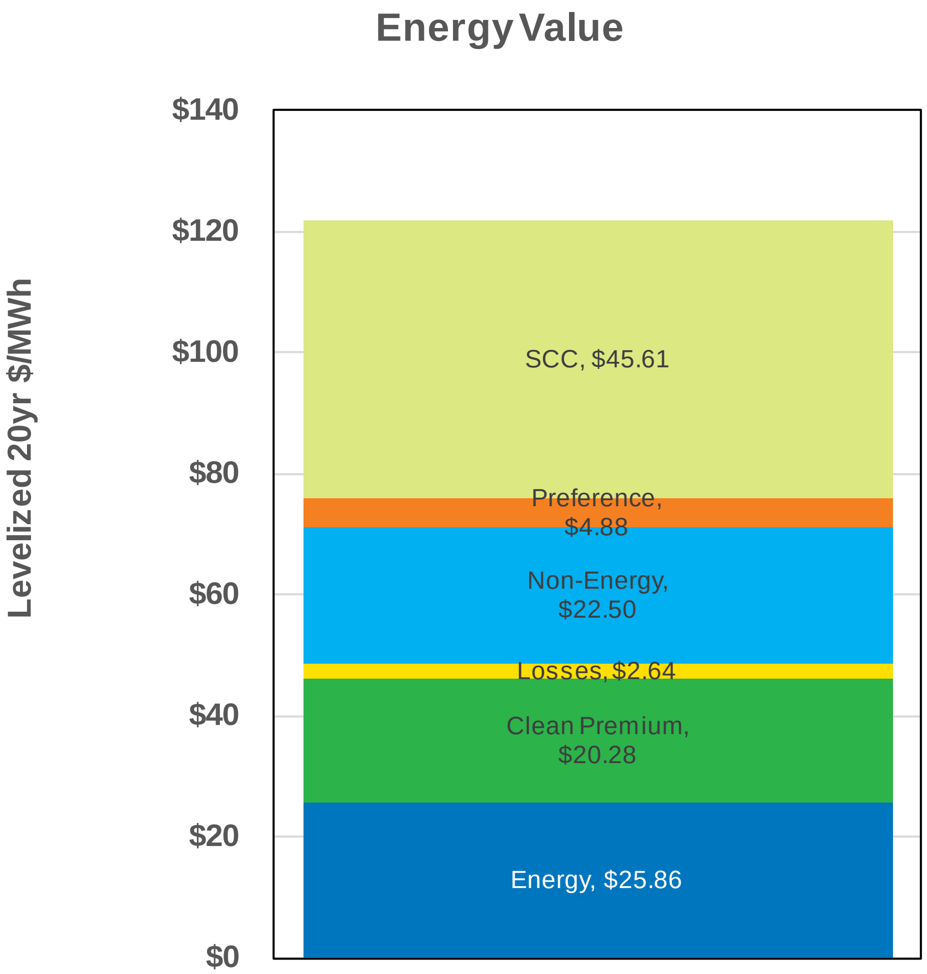
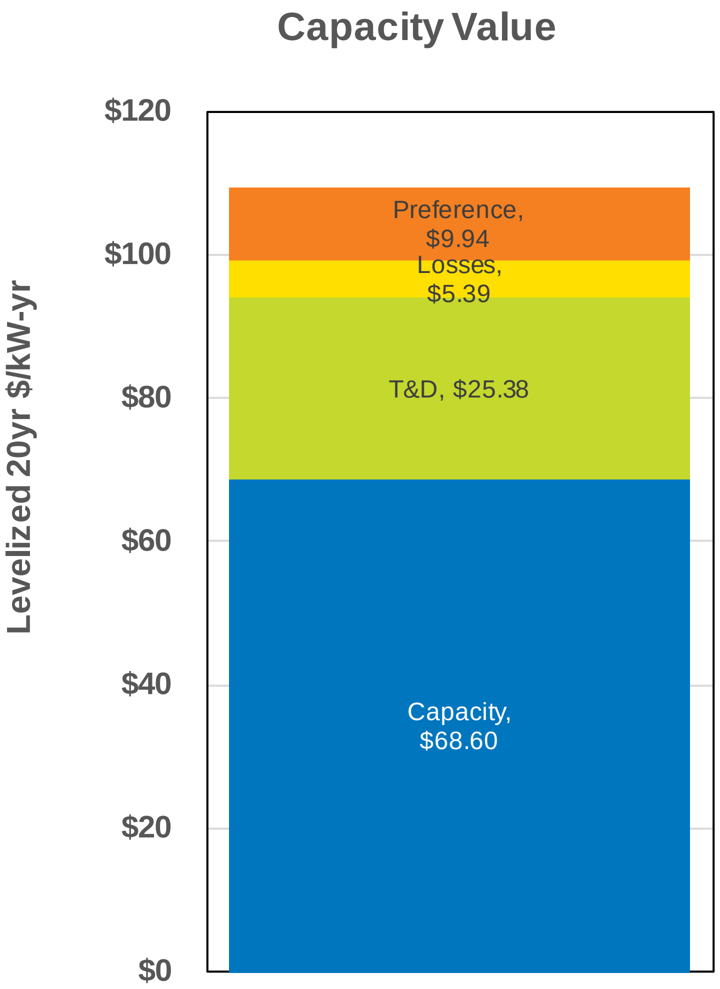
Stacked 20-Year Levelized Energy Efficiency Avoided Cost (WA)





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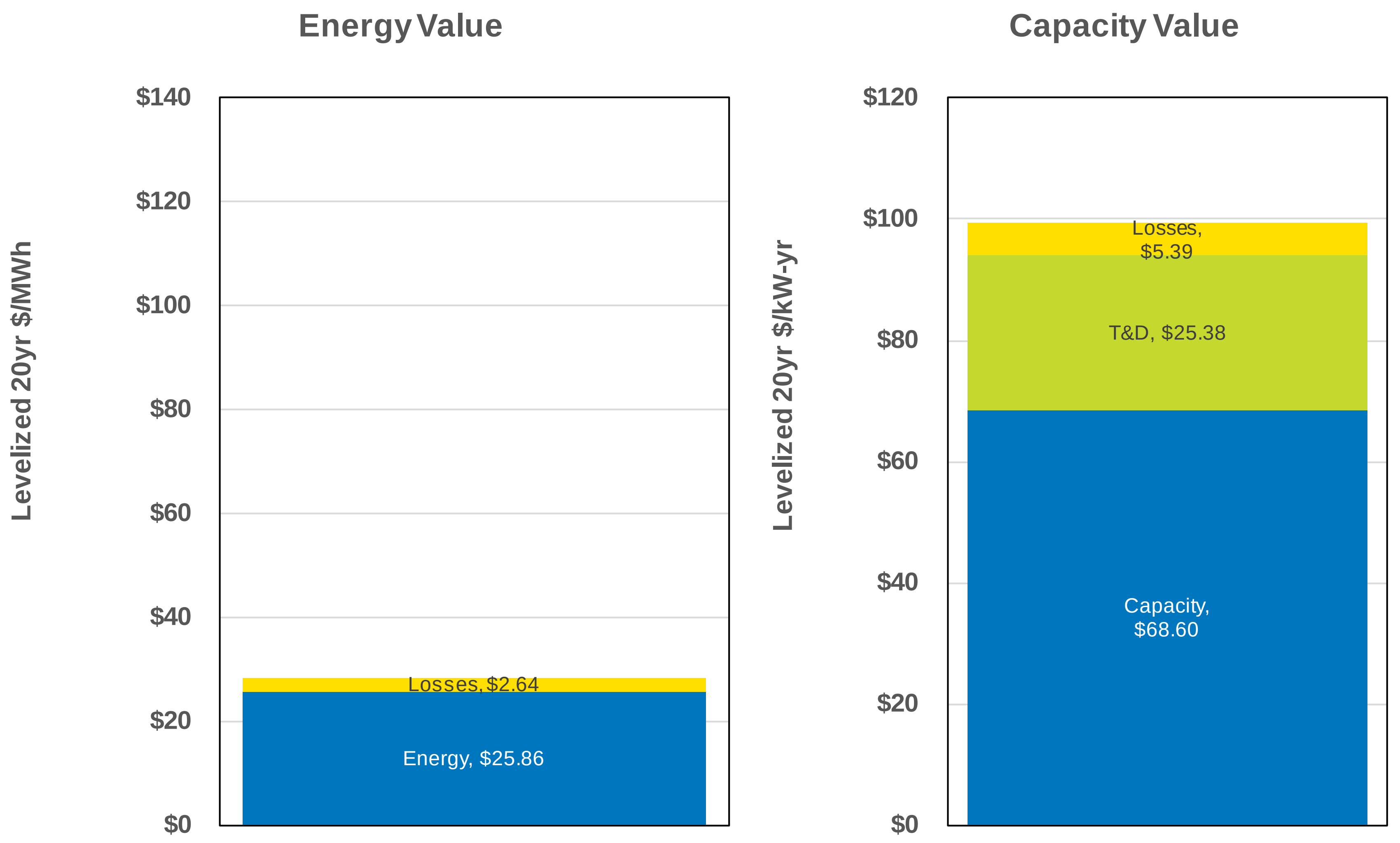
Stacked 20-Year Levelized Energy Efficiency Avoided Cost (ID)



Demand Response

Program	Washington	Idaho
Time of Use Rates	2 MW (2024)	2 MW (2030)
Variable Peak Pricing	7 MW (2024)	6 MW (2030)
Large C&I Program	25 MW (2027)	n/a
DLC Smart Thermostats	7 MW (2030)	n/a
Third Party Contracts	15 MW (2031)	n/a
Behavioral Programs	1 MW (2039)	n/a
Total	56 MW	8 MW

Note: DR programs in another state for the benefit of the other state is not modeled

2022-2025 Supply Side Resource Changes

2022: Economic to exit out of Colstrip 3 & 4 (Both)

2023: 100 MW of Montana Wind (WA)

2024: 50 MW of Montana Wind (WA)

2025: No Action

NOTE: Renewable RFP may change this strategy

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2026-2029 Supply Side Resource Changes

2026: 50 MW Montana Wind (WA)

48 MW NG SCCT (Both)

Lancaster CCCT contract ends (Both)

2026/27: 84 MW NG SCCT (ID)

84 MW NG SCCT (Both)

12 MW Upgrade Kettle Falls (Both)

2028: 50 MW Montana Wind (WA)

2029: 50 MW Solar + 50 MW 4-Hour Storage (Both)

NOTE: Renewable RFP may change this strategy

2030-2033 Supply Side Resource Changes

2030: No Action

2031: 75 MW Hydro Contract Renewal (WA)

2032: No Action

2033: No Action

NOTE: Renewable RFP may change this strategy

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2034-2037 Supply Side Resource Changes

2034: 5 MW Rathdrum CT Upgrade (Both)

2035: 50 MW Solar + 50 MW 4-Hour Storage (Both)

Northeast Retires (Both)

2036: 50 MW Hydrogen SCCT (WA)

55 MW NG SCCT (ID)

2037: No Action

2038-2045 Supply Side Resource Changes

2038: 50 MW Montana Wind (WA)

2039: No Action

2040: 50 MW Solar + 50 MW 4-Hour Storage (Both)

2041: 50 MW Solar + 50 MW 4-Hour Storage (WA)
50 MW Montana Wind (WA)
Boulder Park Retires (Both)

2042: 50 MW Montana Wind (WA)
50 MW Solar + 50 MW 4-Hour Storage (Both)

2043: 50 MW Solar (WA)
100 MW Solar + 100 MW 4-Hour Storage (Both)

2044: 50 MW Solar + 50 MW 4-Hour Storage (ID)

2045: 150 MW Solar (WA)
30 MW Storage (ID)

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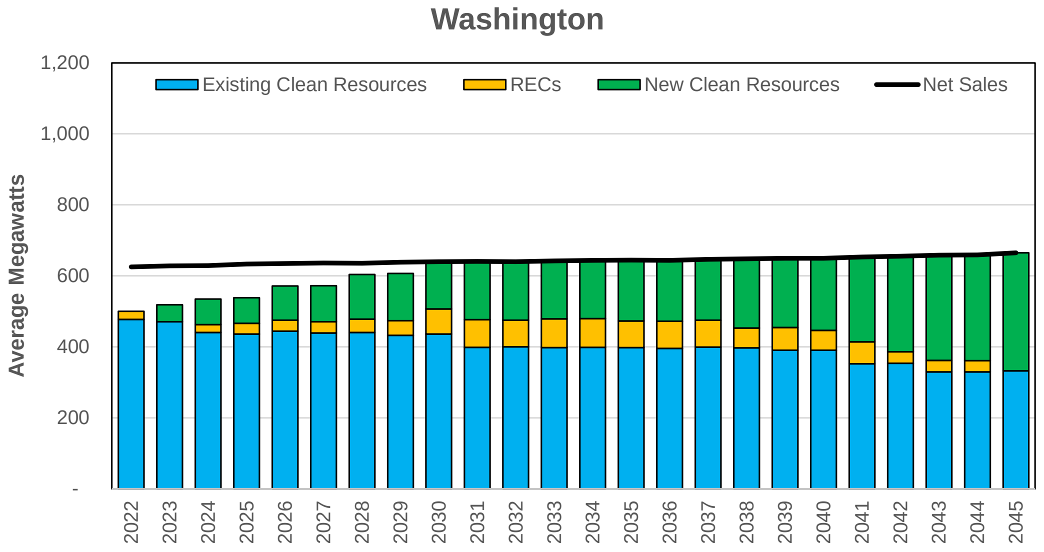
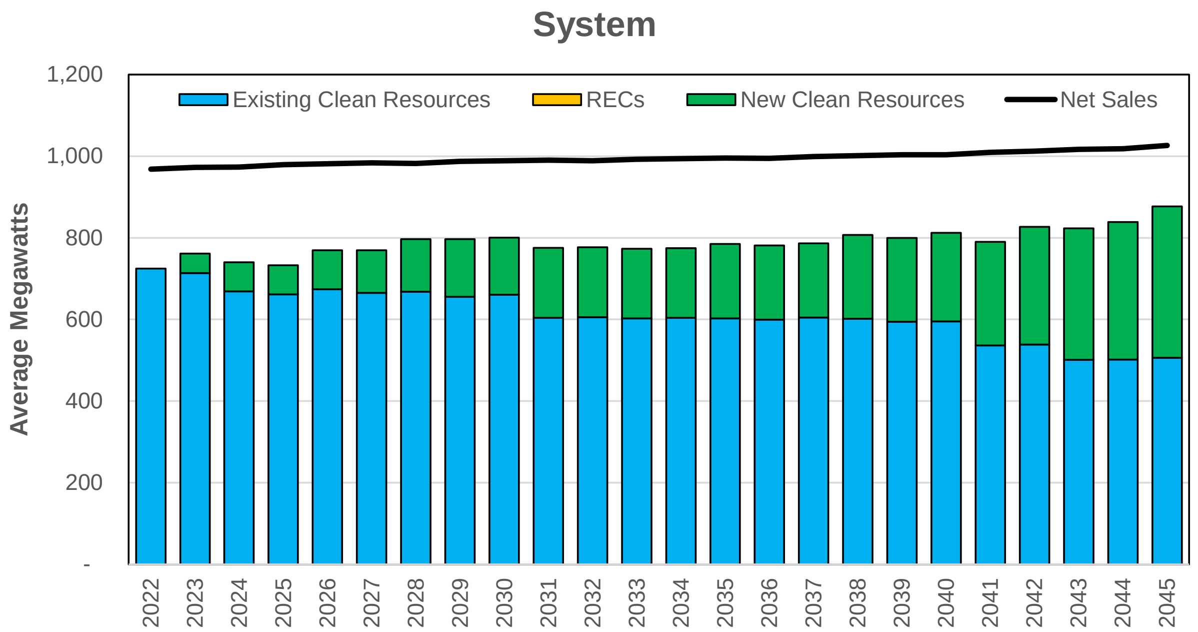
Least Reasonable Cost Resource Selection (MW)

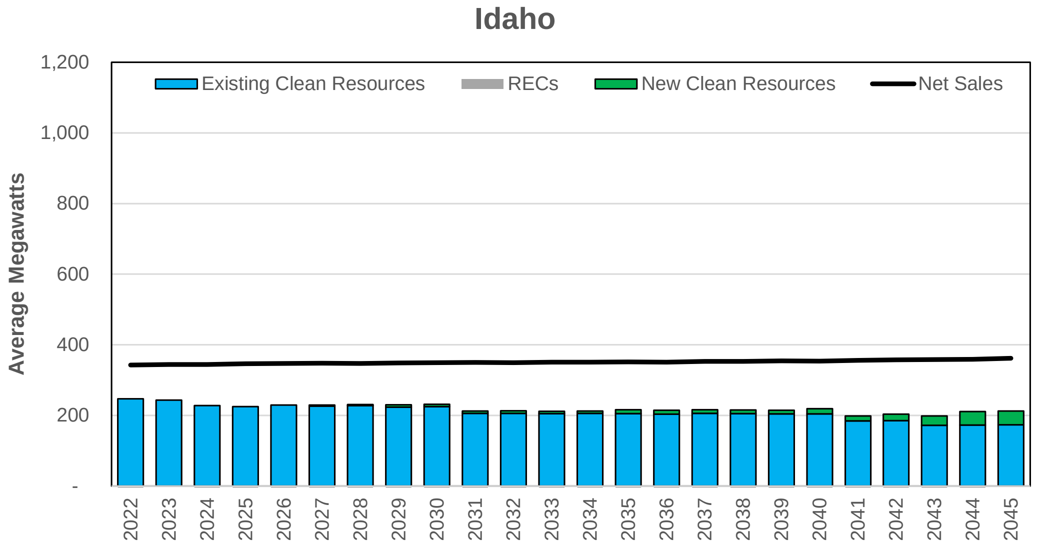
Nameplate MW	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Shared System Resource																								
NG CT	0	0	0	0	48	84	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	50	0	0	0	0	0	50	0	0	0	0	50	0	50	100	0	0
Storage Added to Solar	0	0	0	0	0	0	0	50	0	0	0	0	0	50	0	0	0	0	50	0	50	100	0	0
Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydrogen	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other- (Clean Capacity)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Thermal Upgrade	0	0	0	0	0	12	0	0	0	0	0	0	5	0	0	0	0	0	0	0	0	0	0	0
Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Washington																								
NG CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50	0	50	0	150
Storage Added to Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50	0	0	0	0
Wind	0	100	50	0	50	0	50	0	0	0	0	0	0	0	0	0	50	0	0	50	50	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydrogen	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50	0	0	0	0	0	0	0	0	0
Other- (Clean Capacity)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Thermal Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	0	0	0	0	0	0	0	0	0	75	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DR Capability	0	0	1	4	9	37	37	37	38	42	47	54	56	56	56	56	56	56	56	57	57	56	56	56
EE- Winter Capacity	3	4	5	6	7	7	8	8	7	6	5	4	4	3	2	2	2	1	1	1	1	0	0	0
EE- Summer Capacity	5	5	6	7	8	8	9	8	8	7	6	5	4	3	3	2	2	2	2	0	0	0	0	0
Idaho																								
NG CT	0	0	0	0	0	84	0	0	0	0	0	0	0	0	55	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50	0
Storage Added to Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50	0
Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30
Hydrogen	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other- (Clean Capacity)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Thermal Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DR Capability	0	0	0	0	0	0	0	0	1	3	7	9	10	10	10	10	9	9	9	9	9	9	9	8
EE- Winter Capacity	1	1	2	2	2	2	2	2	2	2	1	1	1	0	0	0	0	0	0	0	0	0	0	0
EE- Summer Capacity	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0

Note: DR is cumulative due to the small changes year to year

Clean Energy Share (aMW)







System Clean Resource Percentage

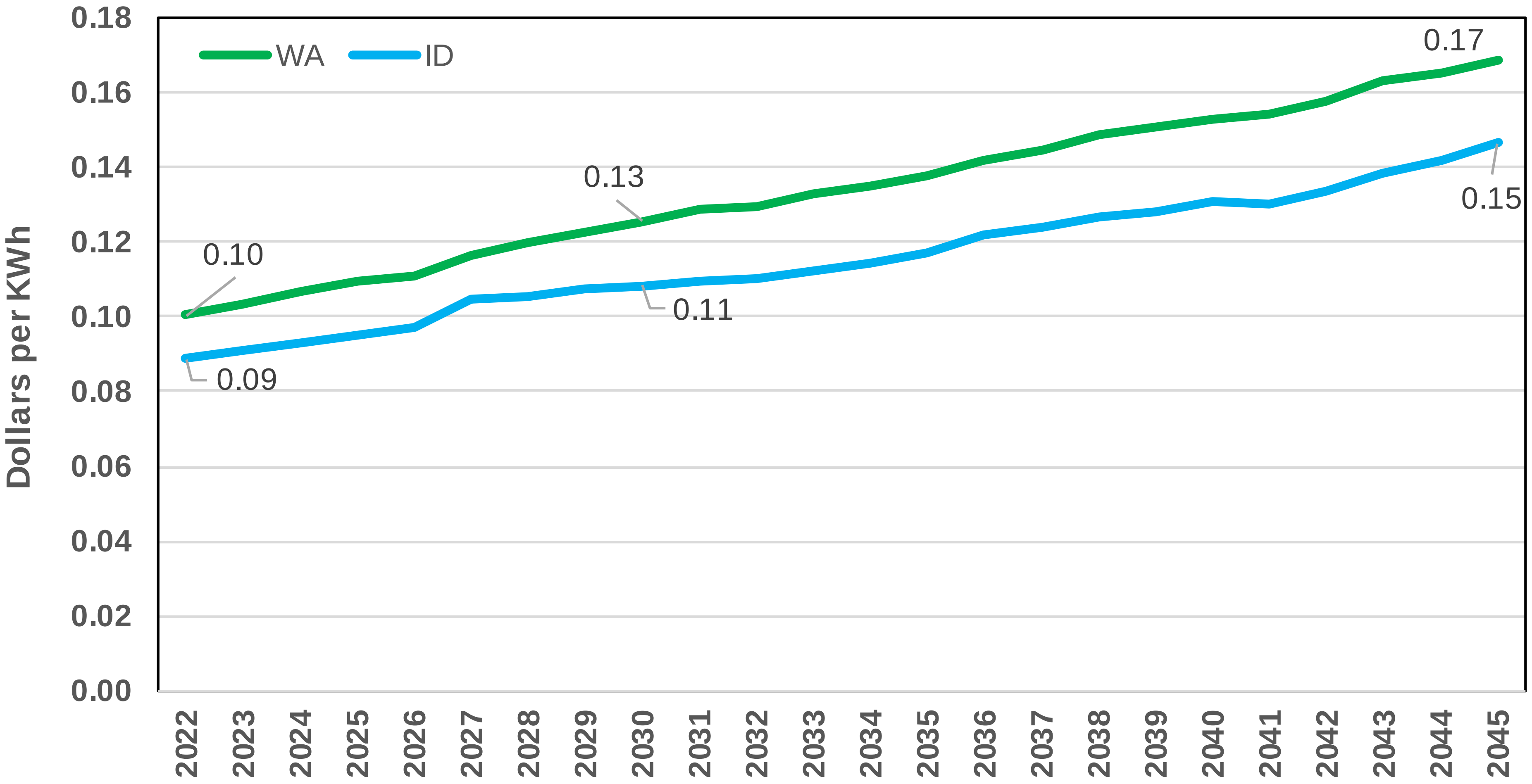
2022: 74.8%

2027: 78.3%

2045: 85.5%

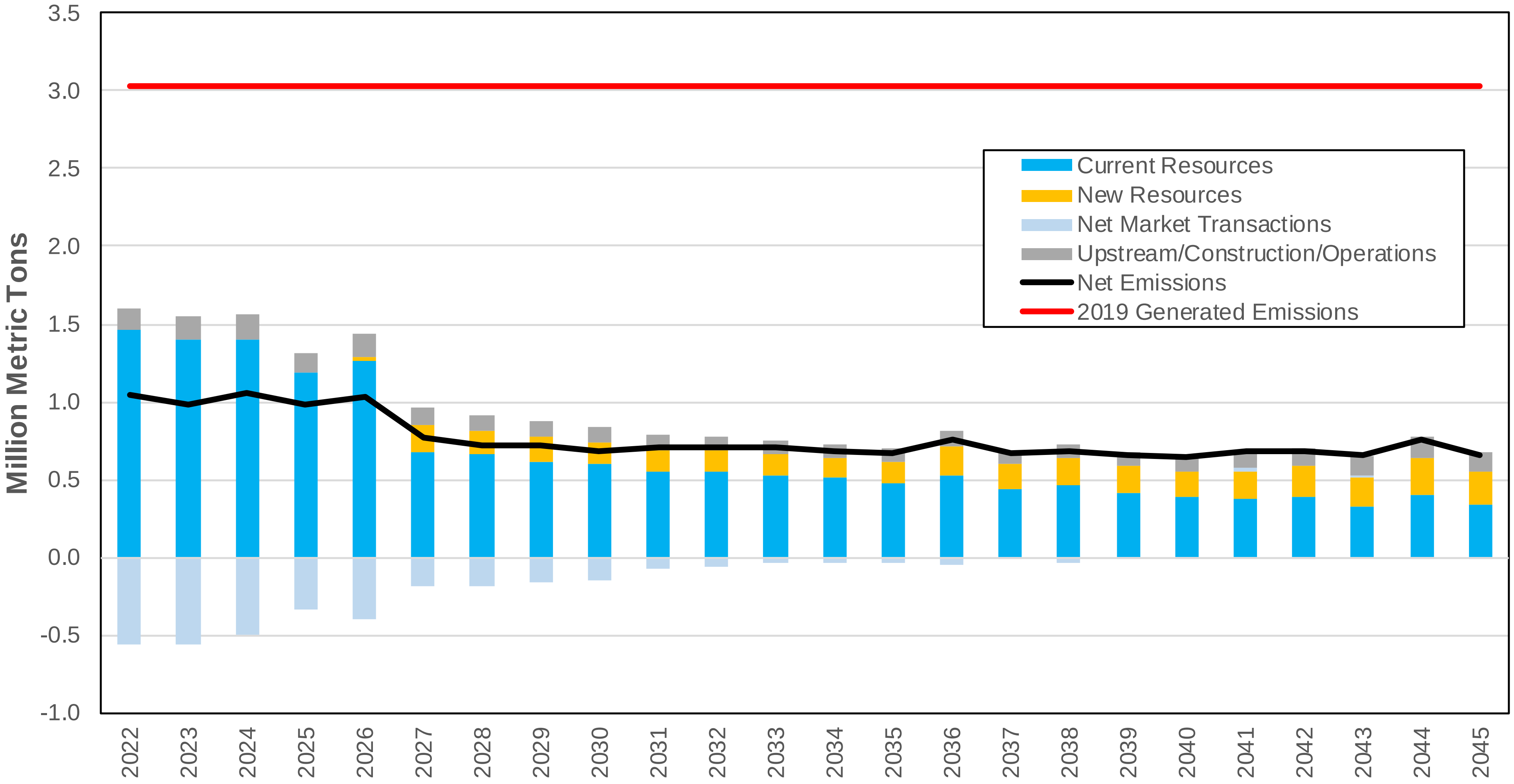
Excludes Clean Market Purchases

Annual Average Least Reasonable Cost Rate Forecast



NOTE: Estimated rates only using 2% annual rate increase for non-modeled costs

Greenhouse Gas Forecast



Note: Assumes Colstrip exits the portfolio

Baseline Analysis

1. **Least Reasonable Cost Strategy:** Includes all requirements
2. **Baseline Portfolio 1:** Excludes CETA's 2030 and 2045 goals
   – Used for incremental cost calculation
3. **Baseline Portfolio 2:** Baseline Portfolio 1 + removal of SCC
   – Energy Efficiency held constant from LCS
   – Used to estimate cost of capacity by comparing to Baseline 3
4. **Baseline Portfolio 3:** Baseline Portfolio 2 + removal of capacity constraints
   – Estimates cost to serve load without new resources

Resource Mix Summary

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	1. LRCS	2. Baseline 1	3. Baseline 2	4. Baseline 3
Shared System Resource				
NG CT	132	132	479	0
Solar	300	150	150	0
Storage Added to Solar	300	150	150	0
Wind	0	0	0	0
Storage	0	33	0	0
Hydrogen	0	0	0	0
Other- (Clean Capacity)	0	0	0	0
Thermal Upgrade	17	17	17	0
Hydro	0	0	75	0
Washington				
NG CT	0	84	0	0
Solar	250	0	0	0
Storage Added to Solar	50	0	0	0
Wind	400	0	0	0
Storage	0	30	0	0
Hydrogen	50	100	0	0
Other- (Clean Capacity)	0	0	0	0
Thermal Upgrade	0	0	0	0
Hydro	75	75	0	0
DR Capability	56	55	35	3
EE- Winter Capacity	88	86	88	88
EE- Summer Capacity	101	94	101	101
Idaho				
NG CT	139	139	0	0
Solar	50	0	50	0
Storage Added to Solar	50	0	50	0
Wind	0	0	0	0
Storage	30	90	80	0
Hydrogen	0	0	0	0
Other- (Clean Capacity)	0	0	0	0
Thermal Upgrade	0	0	0	0
Hydro	0	0	0	0
DR Capability	8	19	19	2
EE- Winter Capacity	24	23	24	24
EE- Summer Capacity	13	13	13	13

Cost Comparison of Baseline Scenarios

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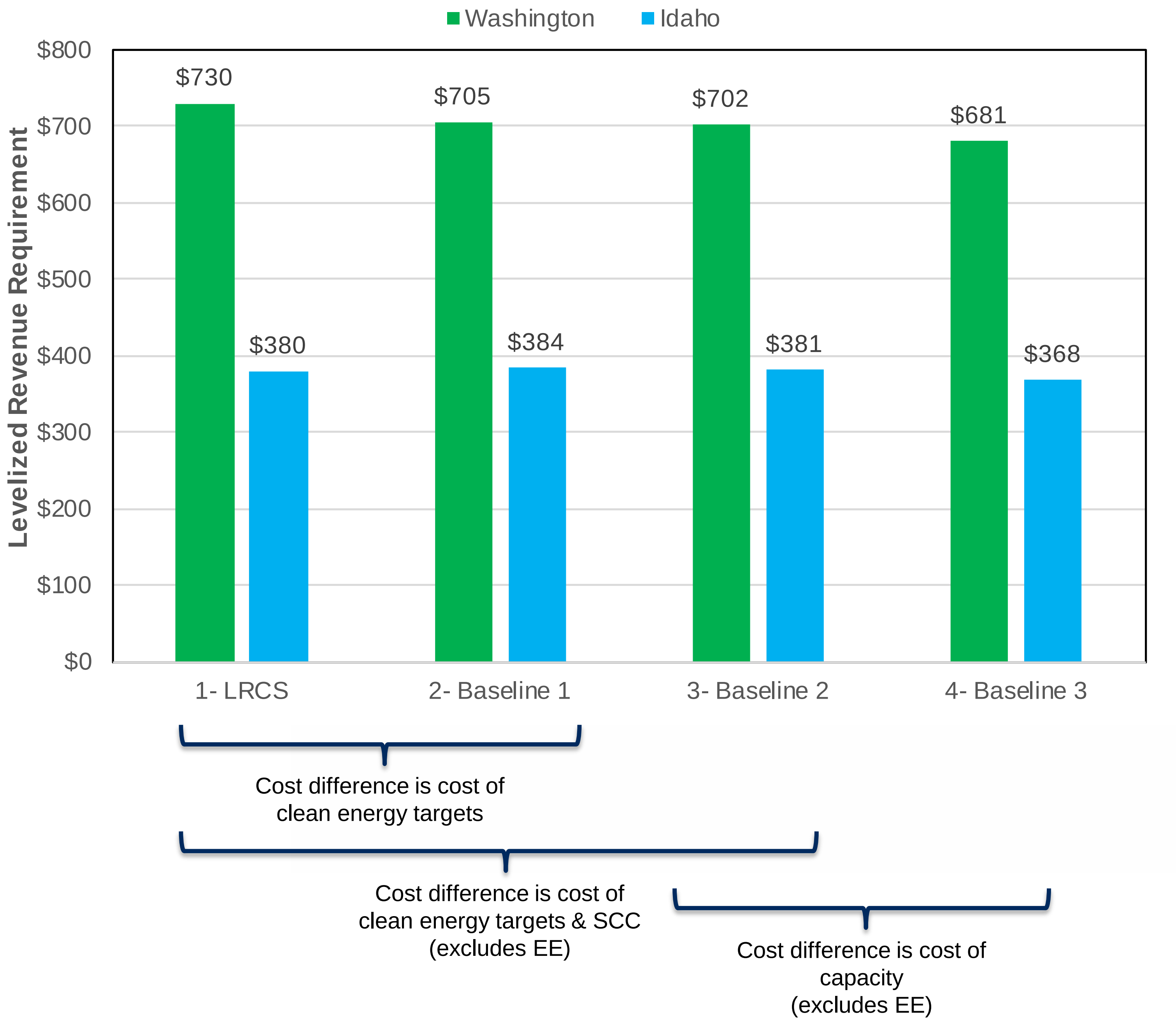

Washington CETA Cost Cap Analysis (assumes current methodology)

Washington Incremental Cost Calculation	2022	2023	2024	2025
Revenue Requirement w/ SCC	651	669	693	698
Baseline (Total Revenue Requirement Plus SCC)	649	657	670	675
Annual Delta	2	12	23	23
Percent Change	0%	2%	3%	3%
Four Year Max Spending				118.4
Annual Max Spending	29.6	29.6	29.6	29.6
Forecasted Spend				59
Forecasted to be under cap				(59)

Incremental cost

Annual spending to use cap

Washington Incremental Cost Calculation	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Revenue Requirement w/ SCC	718	715	735	749	763	775	782	797	810	825
Baseline (Total Revenue Requirement Plus SCC)	685	702	713	725	735	754	759	775	786	798
Annual Delta	33	13	22	23	28	22	23	22	24	28
Percent Change	5%	2%	3%	3%	4%	3%	3%	3%	3%	3%
Four Year Max Spending				127.9				136.8		
Annual Max Spending	32.0	32.0	32.0	32.0	34.2	34.2	34.2	34.2	36.5	36.5
Forecasted Spend				91				94		
				(37)				(43)		

Washington Incremental Cost Calculation	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Revenue Requirement w/ SCC	855	861	889	900	914	925	951	984	1,013	1,030
Baseline (Total Revenue Requirement Plus SCC)	829	834	868	877	887	888	912	936	986	996
Annual Delta	25	27	21	23	27	37	39	48	27	34
Percent Change	3%	3%	2%	3%	3%	4%	4%	5%	3%	3%
Four Year Max Spending		146.0				158.5			113.2	
Annual Max Spending	36.5	36.5	39.6	39.6	39.6	39.6	37.7	37.7	37.7	
Forecasted Spend		104				108			113	
		(42)				(50)			0	

Increases exceed 2% each year over baseline, but rate cap is exponential.

Avista should hit 2042-44 rate cap.

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New Supply-Side Resource Avoided Costs

Year	Flat ($/MWh)	On-Peak ($/MWh)	Off-Peak ($/MWh)	Clean Energy Premium ($/MWh)	Capacity Premium ($/kW-Yr)
2022	$20.37	$21.67	$18.63	$0.00	$0.00
2023	$18.70	$19.22	$18.01	$17.32	$0.00
2024	$18.73	$19.04	$18.32	$17.66	$0.00
2025	$20.00	$20.05	$19.92	$18.02	$0.00
2026	$23.74	$23.68	$23.83	$18.38	$0.00
2027	$24.65	$24.27	$25.16	$18.75	$82.67
2028	$25.69	$24.87	$26.79	$19.12	$84.32
2029	$26.66	$25.77	$27.85	$19.50	$86.01
2030	$26.46	$25.48	$27.80	$19.89	$87.73
2031	$27.63	$26.48	$29.19	$20.29	$89.49
2032	$28.02	$26.86	$29.58	$20.70	$91.28
2033	$29.30	$27.94	$31.16	$21.11	$93.10
2034	$29.46	$27.85	$31.65	$21.53	$94.96
2035	$30.48	$28.82	$32.71	$21.96	$96.86
2036	$32.10	$30.38	$34.43	$22.40	$98.80
2037	$31.95	$30.08	$34.48	$22.85	$100.78
2038	$34.46	$32.26	$37.45	$23.31	$102.79
2039	$34.77	$32.28	$38.13	$23.77	$104.85
2040	$35.70	$32.94	$39.40	$24.25	$106.94
2041	$38.23	$35.77	$41.56	$24.74	$109.08
2042	$38.72	$36.41	$41.84	$25.23	$111.26
2043	$39.27	$36.92	$42.44	$25.73	$113.49
2044	$46.82	$44.10	$50.49	$26.25	$115.76
2045	$46.48	$44.00	$49.80	$26.77	$118.07
20 yr Levelized	**$25.86**	**$25.18**	**$26.78**	**$25.27**	**$57.64**
24 yr Levelized	**$27.18**	**$26.36**	**$28.30**	**$25.33**	**$62.15**

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Least “Reasonable” Cost Strategy & Baseline Analysis

“Not Preferred Resource Strategy Yet”

James Gall, Electric IRP Manager
Fourth Technical Advisory Committee Meeting
November 17, 2020

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Safe Harbor Statement

This document contains forward-looking statements. Such statements are subject to a variety of risks, uncertainties and other factors, most of which are beyond the Company's control, and many of which could have a significant impact on the Company's operations, results of operations and financial condition, and could cause actual results to differ materially from those anticipated.

For a further discussion of these factors and other important factors, please refer to the Company's reports filed with the Securities and Exchange Commission. The forward-looking statements contained in this document speak only as of the date hereof. The Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events. New risks, uncertainties and other factors emerge from time to time, and it is not possible for management to predict all of such factors, nor can it assess the impact of each such factor on the Company's business or the extent to which any such factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement.

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Portfolio Scenarios- 2021 IRP

1. Preferred Resource Strategy
2. Baseline Portfolio 1 (No CETA renewable targets)
3. Baseline Portfolio 2 (No CETA renewable targets/SCC)
4. Baseline Portfolio 3 (No additions)
5. Clean Resource Plan (100% Portfolio net clean by 2027)
6. Clean Resource Plan (100% Portfolio clean by 2045)
7. Social Cost of Carbon applied to Idaho
8. Least Cost Plan- w/ low load growth
9. Least Cost Plan- w/ high load growth
10. Least Cost Plan- w/ Northwest Resource Adequacy Market Peak Credits
11. Heating Electrification Scenario 1
12. Heating Electrification Scenario 2
13. Heating Electrification Scenario 3
14. Least Cost Plan- w/ climate shift
15. Least Cost Plan- w/ 2x SCC prices
16. Colstrip serves Idaho customers through 2025
17. Colstrip serves Idaho customers through 2035
18. Colstrip serves Idaho customers through 2045
19. If necessary: CETA deliver to customers each hour
20. Social Cost of Carbon “Tax” Least Cost Strategy
21. If necessary: other resource specific scenarios depending on outcome of PRS results

Only black font scenarios are shown in this presentation

Scenario Descriptions

1. **Least Reasonable Cost Strategy:** Includes all requirements
2. **Baseline Portfolio 1:** Excludes CETA's 2030 and 2045 goals
   – Used for incremental cost calculation
3. **Baseline Portfolio 2:** Baseline Portfolio 1 + removal of SCC
   – Energy Efficiency held constant from LCS
4. **Baseline Portfolio 3:** Baseline Portfolio 2 + removal of capacity constraints
   – Energy Efficiency held constant from LCS
5. **Clean Resource Plan (2027)**
   – Add constraint to meet or exceed 100% of all retail sales with clean energy
6. **Clean Resource Plan (2045)**
   – Add constraint to meet or exceed 100% of all retail sales with clean energy
   – All thermal resources must exit by 2044
   – No new thermal resources
7. **Social Cost of Carbon applied to Idaho**
   – Includes SCC as cost adder to generation and savings for EE using same method as Washington State

Scenario Descriptions Continued

15. **Least Cost Plan- with 2 time SCC prices**
    – Double of Social Cost of Carbon charge for Washington Only
16. **Colstrip serves Idaho customers through 2025**
    – Colstrip obligated to run through 2025 in both states
17. **Colstrip serves Idaho customers through 2035**
    – Colstrip obligated to run though 2035 for Idaho
18. **Colstrip serves Idaho customers through 2045**
    – Colstrip obligated to run through 2045 for Idaho

Portfolio Sensitivities

- Portfolio scenarios will be tested with alternative price forecasts
  - High Natural Gas Prices
  - Low Natural Gas Prices
  - Social Cost of Carbon “Tax”
  - Climate Shift
- Likely available for draft document, but not TAC presentations

Scenario Cumulative Resource Selection

	1. LRCS	2. Baseline 1	3. Baseline 2	4. Baseline 3	5. CRS (2027)	6. CRS (2045)	7. SCC ID	15- LRCS 2x SCC	16- Colstrip 2025	17- Colstrip 2035	18- Colstrip 2045
Shared System Resource											
NG CT	132	132	479	0	0	0	48	0	132	132	132
Solar	300	150	150	0	650	670	200	100	300	300	300
Storage Added to Solar	300	150	150	0	650	625	200	100	300	300	300
Wind	0	0	0	0	250	550	0	0	0	0	0
Storage	0	33	0	0	0	0	0	0	0	0	0
Hydrogen	0	0	0	0	0	0	0	0	0	0	0
Other- (Clean Capacity)	0	0	0	0	0	20	0	0	0	0	0
Thermal Upgrade	17	17	17	0	17	12	17	17	17	17	17
Hydro	0	0	75	0	0	0	75	0	0	0	0
Washington											
NG CT	0	84	0	0	48	0	84	144	0	0	0
Solar	250	0	0	0	100	0	350	0	250	250	250
Storage Added to Solar	50	0	0	0	0	0	50	0	75	0	0
Wind	400	0	0	0	200	450	400	600	400	400	400
Storage	0	30	0	0	0	250	0	140	0	10	10
Hydrogen	50	100	0	0	50	100	50	100	50	50	50
Other- (Clean Capacity)	0	0	0	0	0	50	0	0	0	0	0
Thermal Upgrade	0	0	0	0	0	0	0	0	0	0	0
Hydro	75	75	0	0	75	75	0	75	75	75	75
DR Capability	56	55	35	3	56	104	56	55	55	57	57
EE- Winter Capacity	88	86	88	88	89	91	90	98	88	91	92
EE- Summer Capacity	101	94	101	101	99	115	116	142	113	100	100
Idaho											
NG CT	139	139	0	0	120	0	84	223	139	139	55
Solar	50	0	50	0	300	585	0	0	0	0	50
Storage Added to Solar	50	0	50	0	125	200	0	0	0	0	50
Wind	0	0	0	0	150	50	0	0	0	0	0
Storage	30	90	80	0	0	0	40	50	90	70	130
Hydrogen	0	0	0	0	0	250	50	50	0	0	0
Other- (Clean Capacity)	0	0	0	0	0	0	0	0	0	0	0
Thermal Upgrade	0	0	0	0	0	0	0	0	0	0	0
Hydro	0	0	0	0	0	0	0	0	0	0	0
DR Capability	8	19	19	2	19	19	21	7	8	17	20
EE- Winter Capacity	24	23	24	24	25	33	39	23	22	21	23
EE- Summer Capacity	13	13	13	13	18	22	36	12	15	11	15

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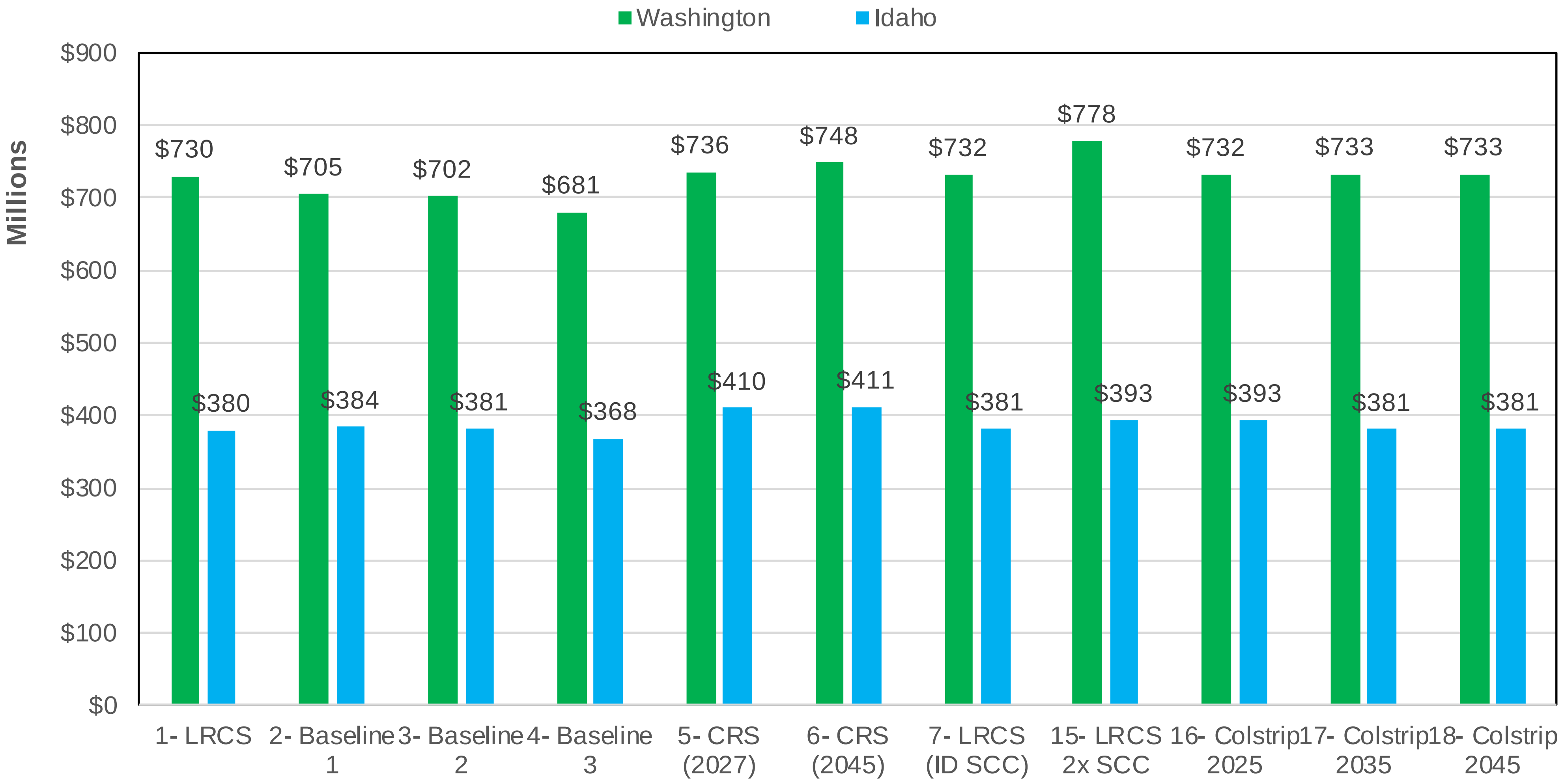
Existing Resource "Exits"

	1- LRCS	2- Baseline 1	3- Baseline 2	4- Baseline 3 w/ EE	5- Clean Resource Plan (2027)	6- Clean Resource Strategy (2045)	7- SCC Idaho	15- 2x SCC	16- Colstrip 2025	17- Colstrip 2035	18- Colstrip 2045
Coyote Springs 2	-	-	-	-	-	2044	-	2022	-	-	-
Lancaster	2026	2026	2026	2026	2026	2026	2026	2026	2026	2026	2026
Colstrip (3)	2021	2021	2021	2021	2021	2035	2021	-	2025	2035	2045
Colstrip (4)	2021	2021	2021	2021	2021	2021	2021	2025	2025	2035	2045
Kettle Falls	-	-	-	-	-	-	-	-	-	-	-
Kettle Falls CT	-	-	-	-	-	2044	-	-	-	-	-
Boulder Park 1-6	2040	2037	2026	2040	2040	2040	2040	2030	2040	2040	2040
Rathdrum 1	-	-	-	-	-	2044	-	-	-	-	-
Rathdrum 2	-	-	-	-	-	2044	-	-	-	-	-
Northeast A&B	2035	2035	2026	2035	2035	2035	2035	2035	2035	2035	2035

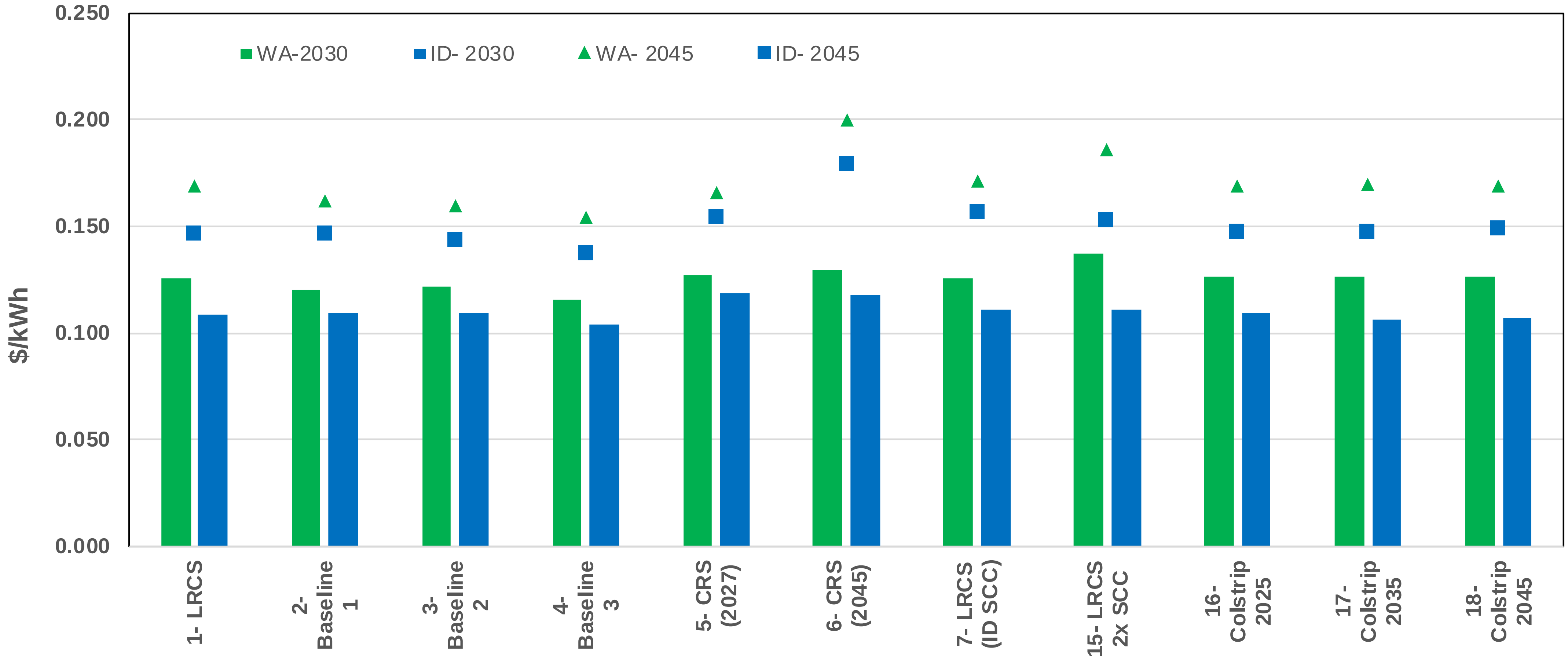
Note:
Assumes each plant is available through December 31st of the final year;
Exception: Lancaster PPA expires Oct 2026.
Dash indicates no plant exit in the study

AVISTA

2022-45 Levelized Revenue Requirement

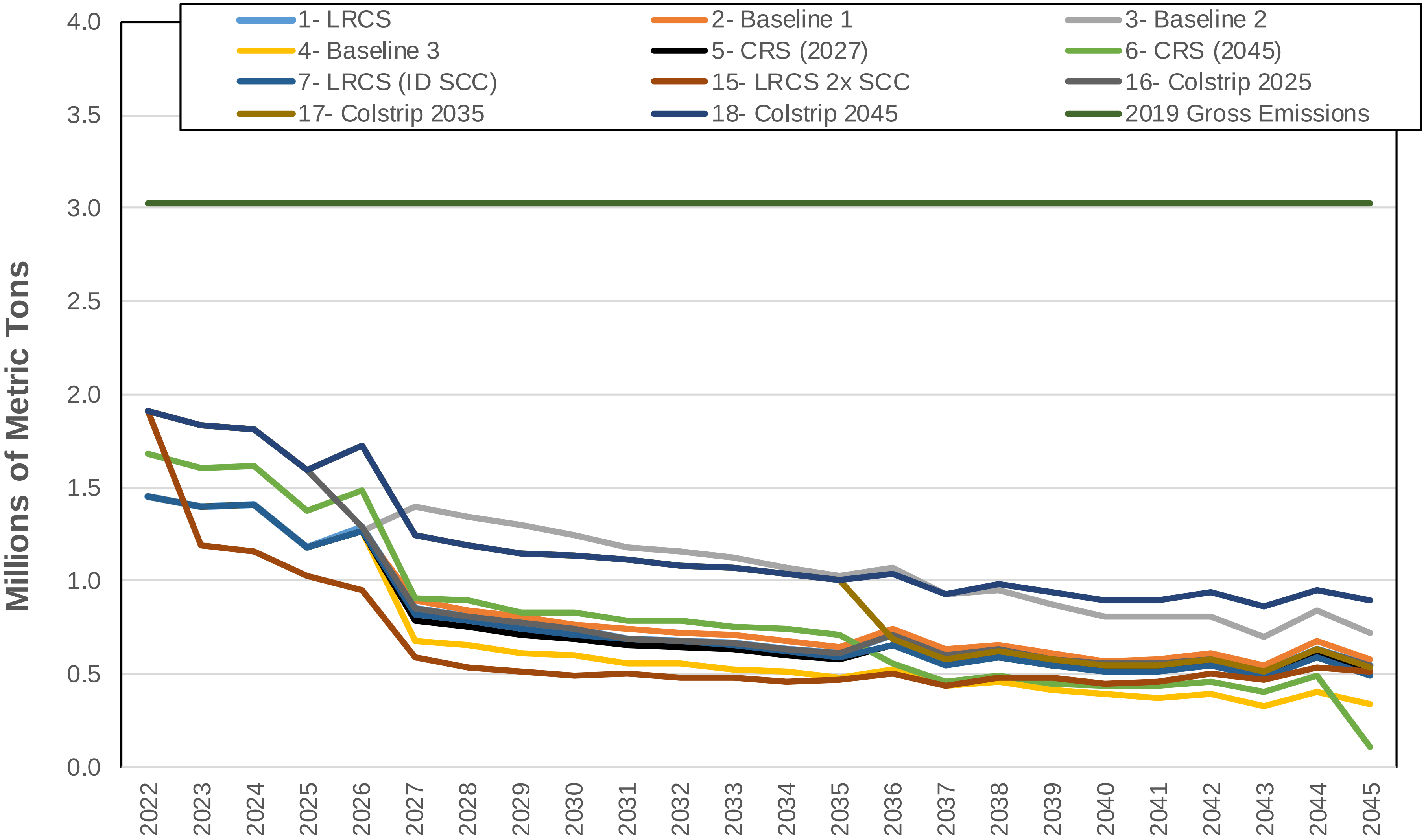


Rate Estimates (Average Annual)



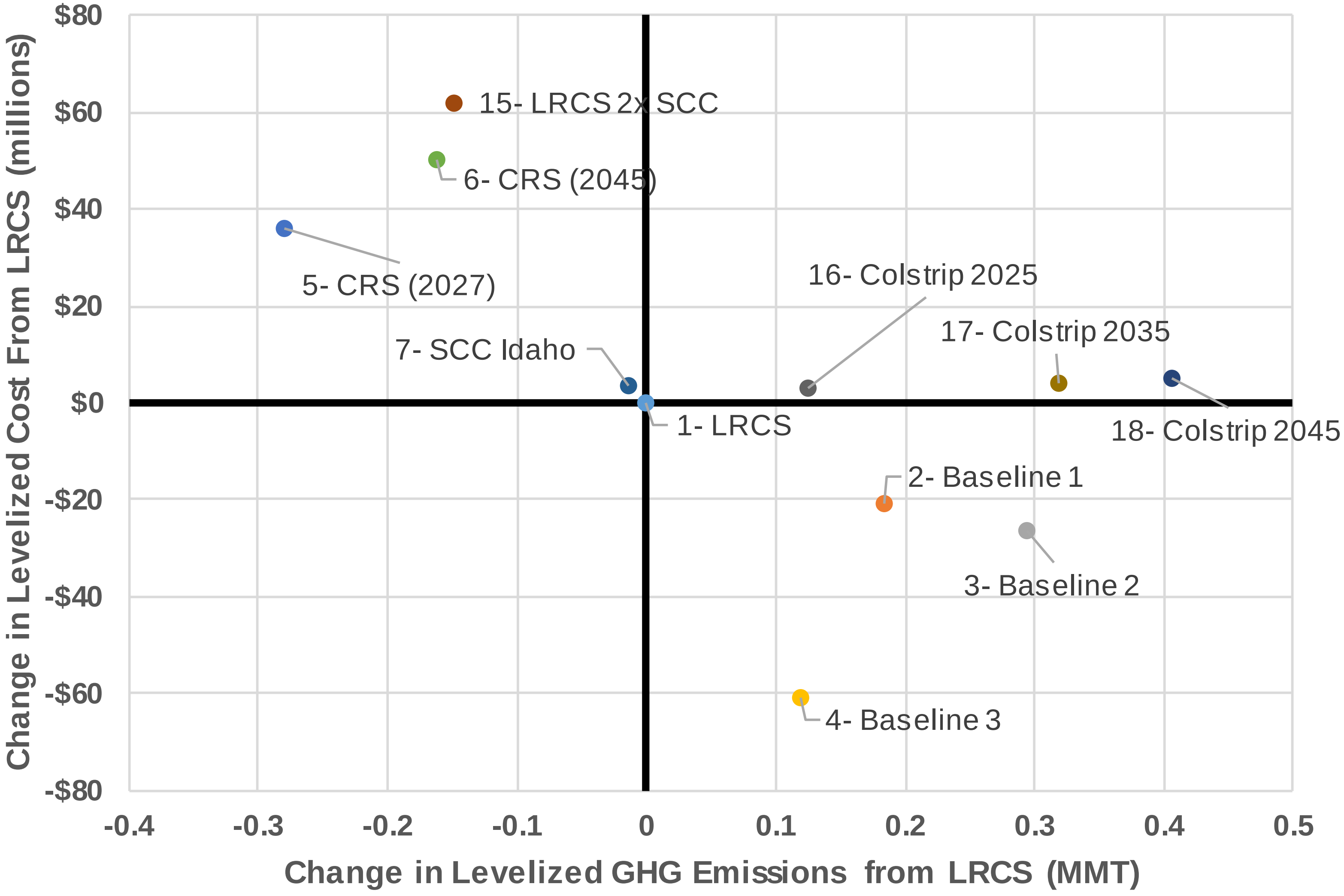
Annual Greenhouse Gas Emission

Avista Dispatch & Storage Purchases



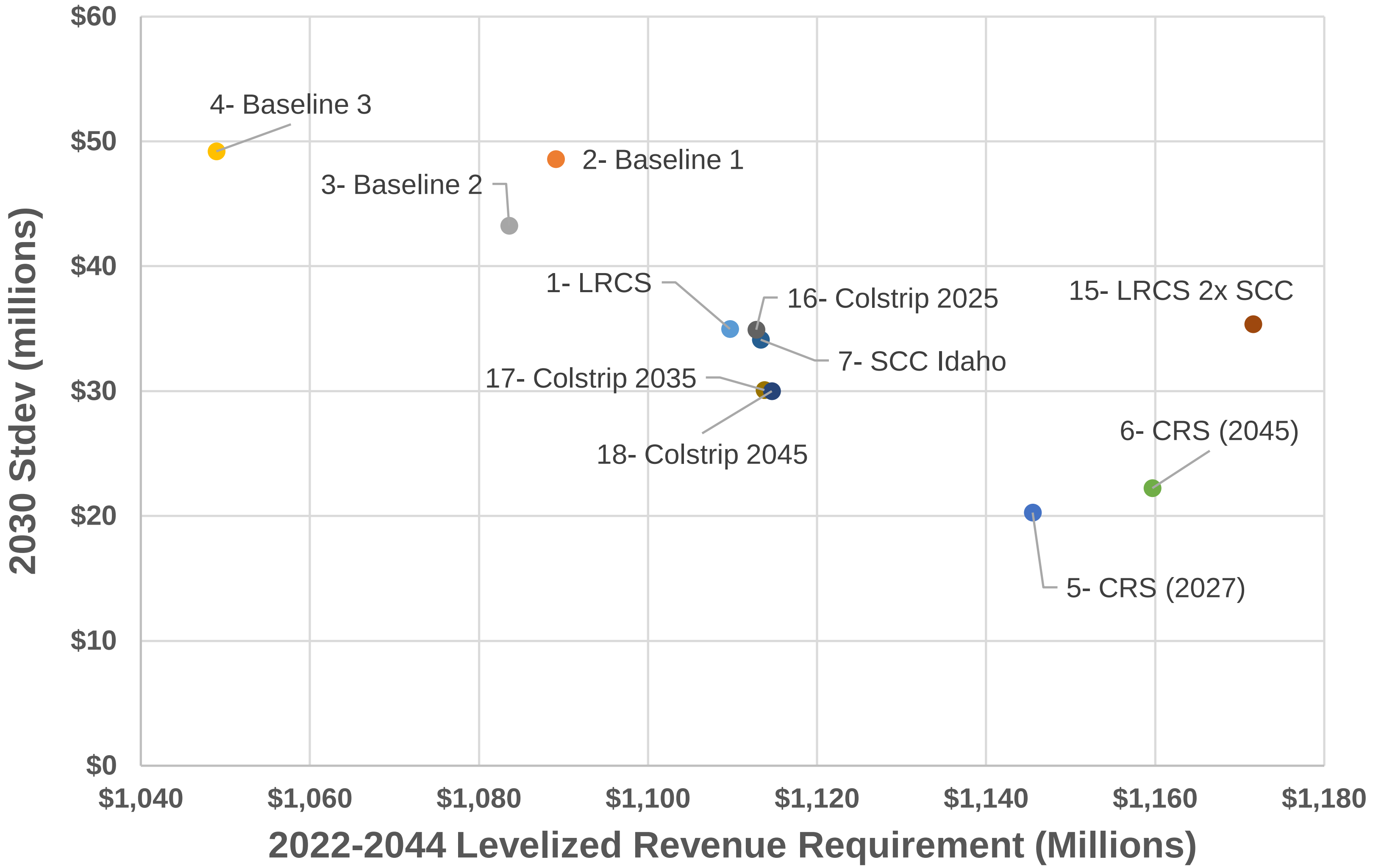
Cost vs. GHG Tradeoffs

Change in Levelized Cost vs. Change in Levelized Net Emissions



2030 Risk Analysis

Measures 2030 standard deviation of "modeled" power cost compared to levelized cost



Note: PPA cost are considered "fixed" for this analysis- meaning the cost do not change with changes in delivered energy

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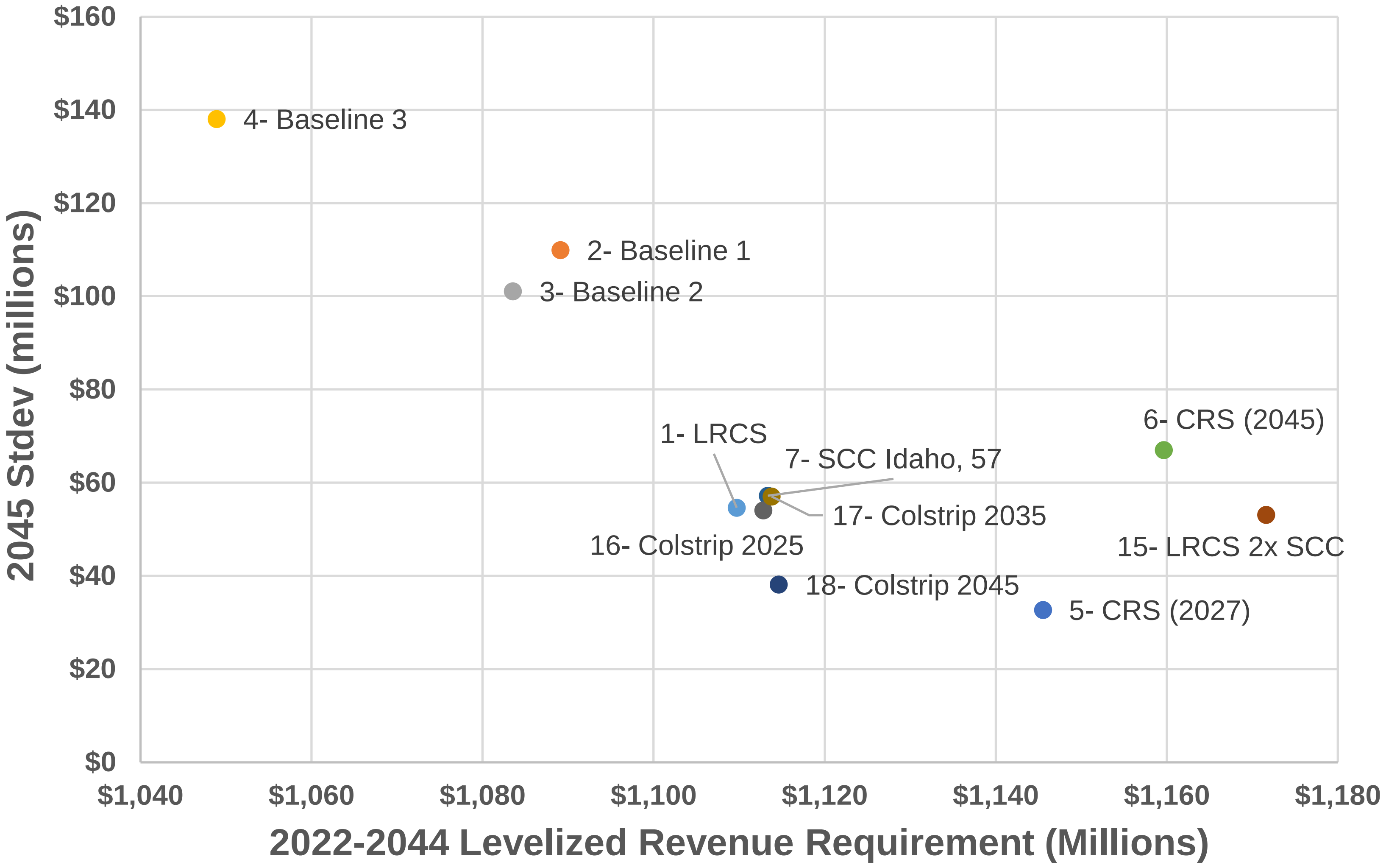
2045 Risk Analysis

Measures 2045 standard deviation of “modeled” power cost compared to levelized cost



Note: PPA cost are considered “fixed” for this analysis- meaning the cost do not change with changes in delivered energy

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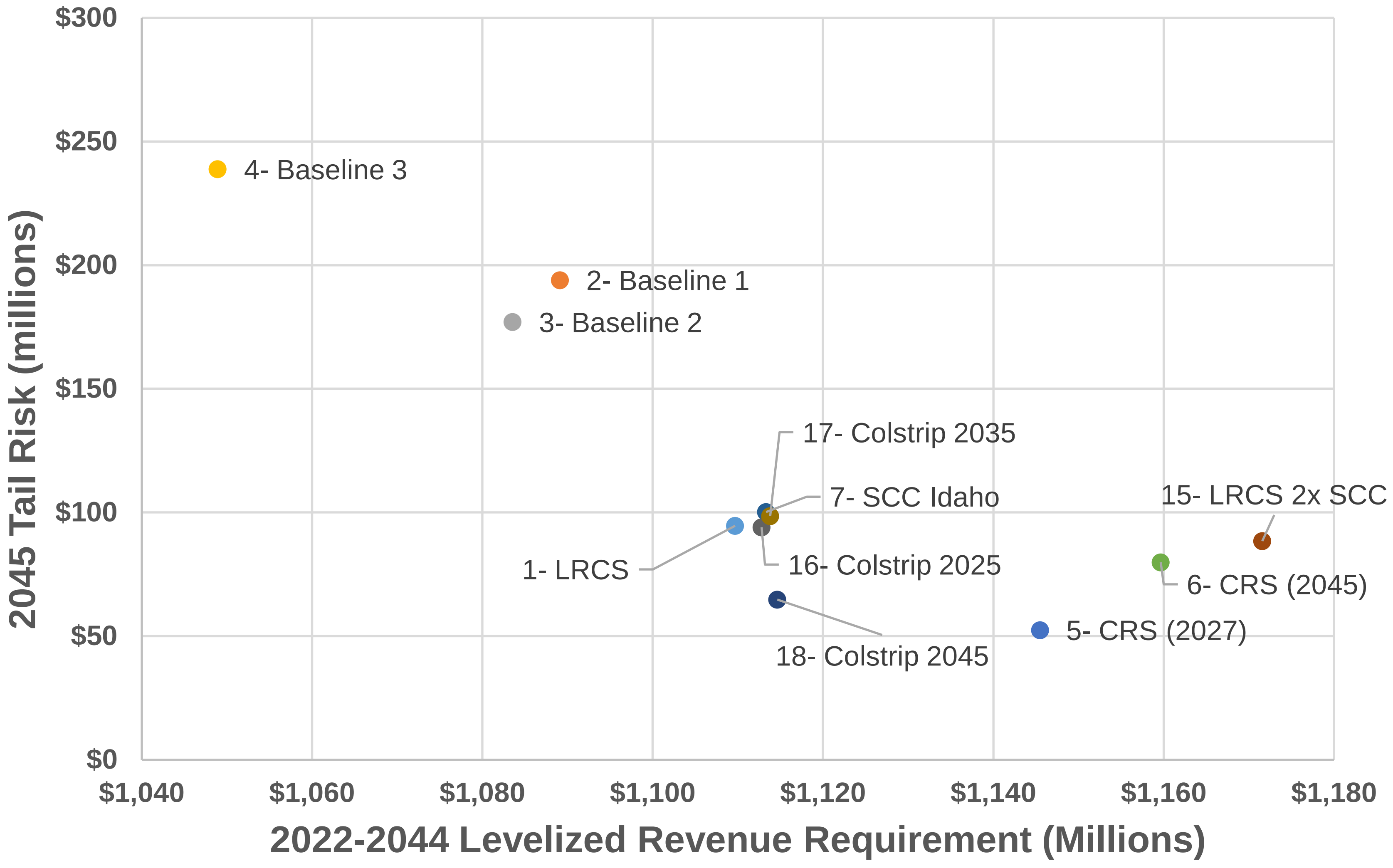
2045 Upper Tail Risk Analysis

95th percentile power cost minus mean power cost compared to levelized cost



Note: PPA cost are considered “fixed” for this analysis- meaning the cost do not change with changes in delivered energy

Next Steps

- Post PRiSM model to website
- Complete other scenarios and sensitivities
- Begin reliability studies
- Update PRiSM model for any modifications
- Select Preferred Resource Strategy
- Re-run scenarios and sensitivities
- Continue reliability studies if necessary

2021 Electric IRP TAC 4 Meeting – November 17, 2020

Annette Brandon, James Gall, Lori Hermanson, John Lyons, Tom Pardee, Chip Estes, Dainee Gibson-Webb (ICL), Dean Kinzer, Jody Morehouse, Kevin Keyt, Annie Gannon, Leona Haley, Clint Kalich, Melissa Kuo (Clearwater), Michael Eldred (IPUC), Mike Louis (IPUC), Rachel Farnsworth (IPUC), Peter Sawicki (Mitsubishi Power), Jennifer Snyder (UTC), Terri Carlock (IPUC), Jan Himebaugh (BIAW), Shay Bauman (PC), Joanna Huang (UTC), Ryan Finesilver, Marissa Warren, Jaime Majure, James McDougal, Joni Bosh (NWEC) , Amanda Ghering, George Lynch, Katie Ware, Ian McGetrick, John Chatburn, Amy Wheeless (NWEC), Corey Dahl (Public Counsel), Jorgen Rasmussen, Jared Hansen, Garrett Brown, Pat Ehrbar, Charlie Inman (PSE), Steve Johnson (UTC), Terrance Brown, Jared Hansen (IPUC), Chris Drake, Scott Kinney, Jason Thackston, Darrell Soyars, Sean Bonfield, Thomas Dempsey, Jeff Schlect, Ben Otto (ICL), Meghan Pinch, Grant Forsyth, Tina Jayaweera, and Tomas Morrissey (PNUCC).

Any notes in italics are short response from the presenter for each topic.

<u>Introductions, John Lyons</u>

No questions

<u>Final Resource Needs Assessment (formerly L&R), John Lyons</u>

Steve Johnson: Are Colstrip and Lancaster the deficits in 2026/27?

James Gall: The loss of Colstrip for 220 MW and Lancaster for 222 MW are the two major changes from the 2025-2027 period.

<u>2020 Renewable RFP Update, Chris Drake</u>

Steve Johnson: Under proposed CR103 for IRP planning with CETA requirements, if the deficit is within 4 years you will need an RFP. I notice your capacity need is just over 4 years out. Do you anticipate issuing another RFP after this one?

James Gall: The resource strategy may call for resources ahead of need or it may call for a renewable or non-capacity need. If this RFP can satisfy those needs that could push this earlier resource shortage further out. If there's still a need after this RFP is complete, we'll need to do an RFP in the next year or so since it will be close to that 4-year window if something new needs to be built.

Steve Johnson (Slide 5): I'm concerned with that being late given the general region is also needing resources around this date and we will be in a capacity crunch. We're waiting, but that could pose a problem with coal retirements and everyone else being in the same boat at the same time. Rather, could you smooth purchases out ahead of time as opposed to buying just before the need?

James Gall: You have the same concerns we do.

Jason Thackston: Can't time these perfectly. We need to ensure reliability which guides the timing to early rather than to later acquisition while trying to balance affordability, etc.

Portfolio Modeling Overview, James Gall

Ben Otto via chat: Avista – can you send out a copy of this portion of the presentation materials? Thank you. *An email was just sent with the updated slide decks.* Thanks John and Lori. The PRiSM slides are the ones I was looking for.

James Gall: It will be sent out shortly to the entire TAC.

Peter Sawicki: How do you look at new technology such as renewable hydrogen?

James Gall: The list of resources included in our model, forecast of costs, and forecast of how costs change are all on our website and are out there for input from the TAC. Two renewable hydrogen options were included.

Mike Louis: Quite a bit of additional functionality that you're building into PRiSM, what steps are you taking for validation of that model?

James Gall: How would you define validation?

Mike Louis: How well does the model represent operations and how well is the model producing something that represents reality.

James Gall: That is the benefit of building the model in Excel. It is easy to audit and how it works is transparent. You can see the L&R balances, if the costs are reasonable, and it is reviewed by internal and external folks to make sure the model is producing a result based on the math we intended. There may be some disagreement with assumptions for inputs, but you can review the math. For operations, we are not proposing any changes to our operations based on PRiSM modeling. This is a financial exercise to determine who pays for resources in the future as opposed to how we currently allocate resources.

Mike Louis: That helps a lot James. At the end of the day with my experience in modeling, I'd like to see a validation plan to ensure validity for all the tests and the results to see if they are reasonable. I'd like to see a comprehensive plan of how you thought of this ahead of time and how you tested it.

James Gall: We'll talk about a lot of these tests this afternoon. The scenarios test the validity of the model a lot.

Steve Johnson: Is this the model you'd use if you were examining DR in a single source context? Would you still use this model?

James Gall: No, this is a planning tool. If you were choosing what to acquire, we'd use something else – a more granular model. You could use this model for capacity value, etc. You could put in resource options from an RFP to see what it'd pick, but it might be better to use a more granular tool.

Steve Jonson: This model is enough to give you some value such as capacity value?

James Gall: Yes, it gives you the financial value, but not the reliability value. Operational value and reliability value, you could put all of that into this tool and let it pick your options. If you have a large amount of choices that are vastly different, this tool would work; if the choices are more similar, you'd probably want a different tool.

Michael Eldred: Does that apply to new resources also?

James Gall: New resources are different and can be acquired just for one state or allocated between both states. Operationally, they are the same, but the payments for them could be different.

Mike Louis: For Colstrip, are you modeling those units separately?

James Gall: Yes, we are modeling Colstrip units with separate capital and O&M costs.

Ben Otto: Are you saying there is already a certain amount of efficiency in the load forecast and some can be selected? And what happens if it can choose more than is out there?

James Gall: We don't know what energy efficiency is out there so we iterate. We keep rerunning it until the amount selected and the amounts in the CPA are essentially the same. Limits of econometric as opposed to end use forecast.

Jennifer Snyder: To make sure I have this correct about end effects for Grant's load forecast, no matter how much cost-effective energy efficiency is selected, it's never going to reduce it?

James Gall: It's not going to change significantly. Grant does make assumptions on how customers change their use through the use per customer numbers.

Grant Forsyth: I'm on the call. There are specific factors that reduce use per customer and some that can't be explained, but it could be "efficiency". There is some amount of energy efficiency I'm projecting going forward.

Jennifer Snyder: Ok, thank you. A follow up on that. How does that dynamic work with DR?

James Gall: Good segue to the next slide. We have no historical DR programs [non-pilot size], so DR doesn't affect load for the forecast. DR is treated differently from that point of view. EVs could be a concern.

Grant Forsyth: There is nothing explicit for EVs. The load forecast assumed the amount used per year per customer.

Steve Johnson: I'm trying to understand what kind of assumptions of cost and value streams you put into your model.

James Gall: We assume Mid-C prices and not necessarily the value of selling any beyond what goes into California.

Steve Johnson: CPUC regulatory action, that hasn't been taking into account, but maybe taking that into account has an impact on price. Would you put that into your model?

James Gall: We value based on our market at the Mid-C, we're only trying to value for intra-hour energy. Other values are outputs based on your choices as compared to energy-only resources.

Amy Wheeless via chat: Do you make any assumptions about consumers buying CTA 2045 enabled water heaters due to markets (e.g., someone in the CdA area buying a water heat at a Spokane Lowes)?

James Gall: We're not considering that.

Ben Otto: How are some results showing a shared system and then some are assigned for each state?

James Gall: Let's table that math to this afternoon's discussion.

Ben Otto: If you sell RECs and return the revenue to Idaho customers, what about increments of more than 20% being sold to Washington?

James Gall: We could show that. I will add it to the list. It would be available renewable energy times the REC price.

Charlie Inman via chat (slide 15): For market transactions, the Washington CETA defines the emission rate of "unspecified market purchases" as 0.437 metric tons per MWh. Will this be included at all in the modeling process?

James Gall: Not at this time. It is in CETA, but is related to a different use and we're looking at this for the future. That default emissions number is based on a gas turbine. We're including the average market emissions rate for all purchases and storage. We're unable to model general purchases now, but will look at this for the future. There is an opportunity for adjustment.

Jennifer Snyder: I don't recall what that is in CETA. *It's in section 7.* I will read it over lunch.

Steve Johnson: There is not a lot of time for debating when it comes to the evaluation for transmission. For resources, you aren't including any end-of-life resources past the end of useful life, have you thought that there is an advantage to someone else operating a resource, if it isn't your least cost resource?

James Gall: Transmission costs are levelized; even if a resource does go offline, we benefit from the available transmission. There is quite a bit of advantage if someone else operates with all of that transmission interconnection. You've identified a head scratcher of what could happen, but how can you model everything.

After lunch

Ben Otto: James, I thought of a question at lunch. What $/MWh is Avista using for the social cost of carbon? Is it the Washington UTC adopted numbers?

James Gall: Ben, the social cost of carbon is the Washington adopted value for CETA. It is available on the website in Excel form by year.

<u>Draft PRS and Scenarios, James Gall</u>

Steve Johnson: We are really on a roll now. This raises questions about whatever happened to the idea for super freezing air.

James Gall: Liquid air shows up in some scenarios for some options in the future. Hydrogen showed up rather than liquid air due to the resource assumption differences for peak credits. Both are about storage, but fuel replacement as well. Hydrogen assumes no constraints and gets a peak credit; whereas, liquid air has some constraints – while there is an air storage tank, we might not be able to refill it quickly.

Stave Johnson: Thanks. That's informative.

Peter Sawicki: What does "both" mean?

James Gall: Both means the resource serves both states. It serves 65% Washington and 35% Idaho.

Peter Sawicki: For the 2029 resource picks, is that additive? *Yes, but we could amend that later.*

James Gall (slide 16): DR is cumulative, but the rest of the resources are shown when they show up in the portfolio. DR programs need to start earlier than they are needed to give time to sign customers up for the program.

Darrell Soyars: How are transmission costs built in for each resource like in Montana where they would be further away?

James Gall: It's complicated, we talked about it briefly earlier today. One avenue is the Colstrip transmission line where we own rights for a little less than 200 MW. Another is NorthWestern Energy transmission which could be a wheel. Other resources could be a wheel request or a capacity build out.

Ben Otto: You said some amount of the gas [generation] is driven by capacity needs. What is the amount of hours? Is this a capacity shortfall for a few hours or for several months? What can we see?

James Gall: We looked at 1-hour, multiple hours, etc. When we calculate peak credits, we run that through an 8760 to get the 5% LOLP. We need resources with long duration winter generation capability to make sure we have resource adequacy. There are several hours and they are definitely in the November to February period and during hours 14 - 18, but I can't tell you the exact hours. It's difficult to have a resource adequate system.

Jennifer Snyder: I'm wondering at the avoided cost in 2022 if on-peak is cheaper than off-peak, or does it switch partway down.

James Gall: If I'm remembering correctly from the last TAC meeting, the amount of solar added to the entire system in California, Oregon, Nevada, Arizona and other spots in the west; the new solar is likely to drive prices in the middle of the day to zero or negative prices.

Steve Johnson: I have a question or recommendation. Is it possible to add the rate of return adders to PPAs after the modeling analysis?

James Gall: Yes, it's possible. I think I've heard of 3 to 4 more scenarios today and I already have 20 more. It can be done, but not sure if they will be done in time to file this IRP. It depends on whether we'll have time to fit these all in

Steve Johnson: It might be better to have a portfolio as bid by bidders less the rate of return adders so we can compare the two.

James Gall: It won't change the result much, but it will change the avoided cost

Amy Wheeless: Can you remind me of the timeline for next steps?

James Gall: The next meeting is in two to three weeks. We are using the PRS resources in the current model. There will be a draft IRP out on January 4th. We are hoping to include new resources if the 2020 Renewable RFP contracts are signed in time for the draft release in January, but we may need to modify a lot by then.

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Draft 2021 Preferred Resource Strategy

James Gall, Electric IRP Manager
Technical Advisory Committee Update Meeting
December 16, 2020

Safe Harbor Statement

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Other Caveats

- Clean Energy Transformation Act (CETA) rules and requirements are not complete.
  - This draft PRS uses Avista's best estimate of known requirements.
- Avista is negotiating with the 2020 renewable Request for Proposals (RFP) shortlist bidders
  - This may change the results of the resource if a contract is signed.
- IRP resource options are primarily "new" resource options- RFP will determine whether or not existing resources can be acquired at similar or lower cost than "new" options.
- Avista may not be able to physically retire or exit certain resources as the IRP PRiSM model determines because of contract limitations.
- No future state specific resource cost allocation agreement has been made.
- Forward looking rates include non-modeled power supply cost escalating at 2% per year-
  - **DO NOT TAKE THIS AS A RATE FORECAST**
  - This is for informational purposes only

Cumulative Energy Efficiency End Use Results (GWh)

	2023		2031		2045	
	WA	**ID**	**WA**	**ID**	**WA**	**ID**
Appliances	0.3	0.1	3.5	0.8	11.6	2.7
Cooling	5.6	0.5	36.8	3.2	53.1	9.1
Electronics	1.1	0.2	14.1	4.8	25.2	9.3
Exterior Lighting	4.1	1.4	24.1	7.8	36.3	14.3
Food Preparation	0.1	0.0	2.2	0.4	5.9	0.9
Interior Lighting	20.3	13.0	100.1	49.3	171.1	89.6
Miscellaneous	1.3	0.3	11.2	2.8	22.9	5.5
Motors	4.9	3.9	35.3	25.6	41.3	28.8
Office Equipment	0.6	0.0	3.3	0.0	5.8	0.0
Process	0.7	0.1	4.1	1.1	4.5	1.4
Refrigeration	8.2	0.3	60.2	2.3	69.4	2.6
Space Heating	12.6	3.6	120.3	30.8	171.1	40.6
Ventilation	5.1	0.7	29.8	5.2	44.8	12.5
Water Heating	4.3	1.5	62.8	8.6	114.2	10.6
Total	**69.2**	**25.6**	**507.8**	**142.9**	**777.1**	**227.8**

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Cumulative Energy Efficiency Segment Results (GWh)

	2023		2031		2045	
	WA	**ID**	**WA**	**ID**	**WA**	**ID**
College	2.1	0.7	11.0	4.2	15.5	7.5
Grocery	6.8	0.2	47.4	1.4	56.3	1.7
Health	2.7	0.9	14.3	5.1	22.8	10.3
Industrial	12.0	8.4	62.5	42.8	91.4	62.9
Large Office	6.5	1.3	43.1	8.8	66.8	16.4
Lodging	1.3	0.6	8.6	2.9	12.5	4.9
Low Income	3.0	1.8	37.3	10.8	53.7	13.5
Miscellaneous	5.1	1.9	35.6	10.7	54.5	19.1
Mobile Home	0.6	0.2	5.5	1.5	8.7	2.3
Multi-Family	0.4	0.2	7.5	1.3	16.3	2.2
Restaurant	2.1	0.2	14.9	1.6	19.8	2.3
Retail	5.6	2.0	35.7	10.3	52.7	17.9
School	2.6	0.1	16.6	0.4	26.5	0.8
Single Family	13.8	5.1	139.6	29.1	234.2	43.7
Small Office	2.2	1.1	16.1	7.4	25.1	13.5
Warehouse	2.3	0.9	12.1	4.7	20.2	8.9
Total	**69.2**	**25.6**	**507.8**	**142.9**	**777.1**	**227.8**

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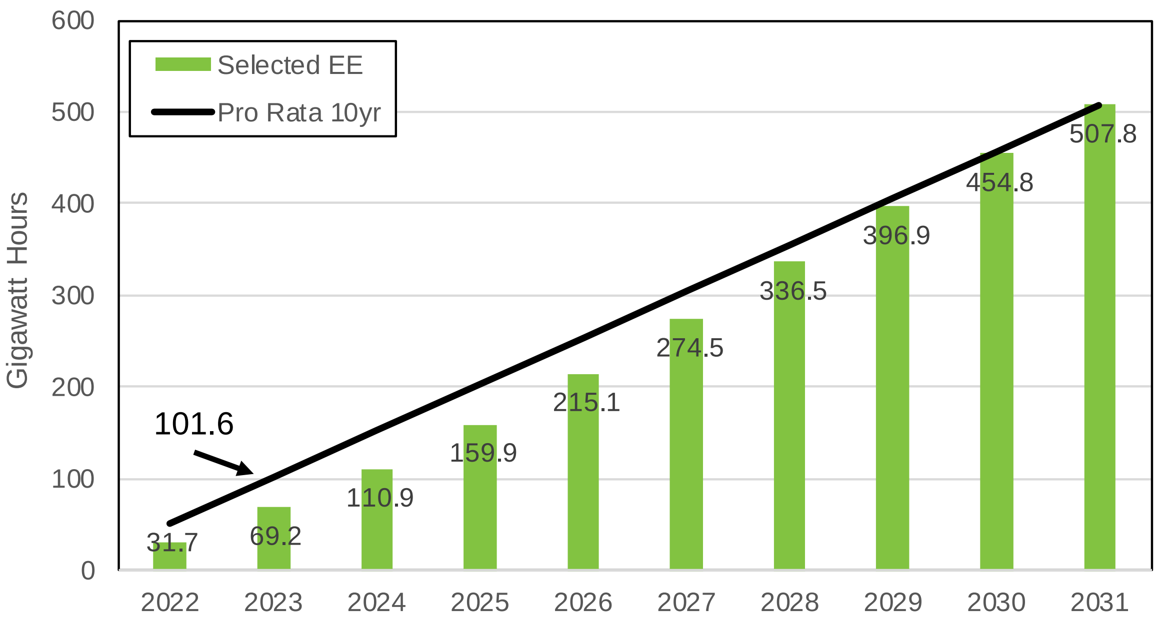
Higher Washington Energy Efficiency Goals

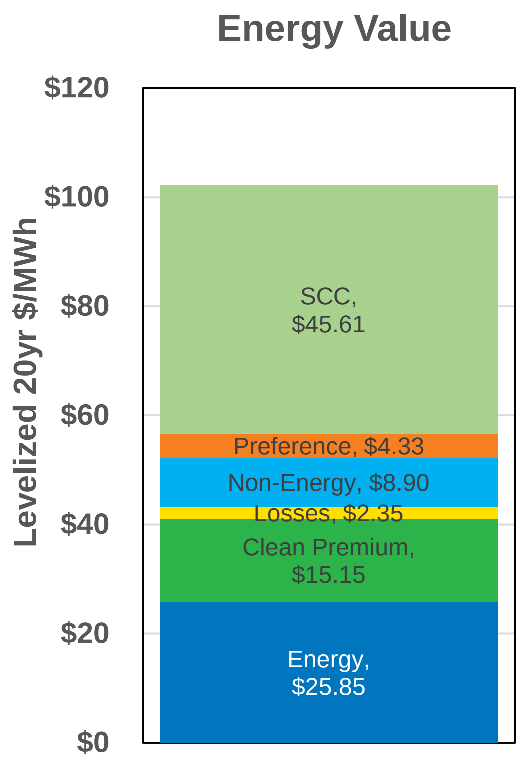
More Aggressive Ramp Rates & Higher Avoided Costs

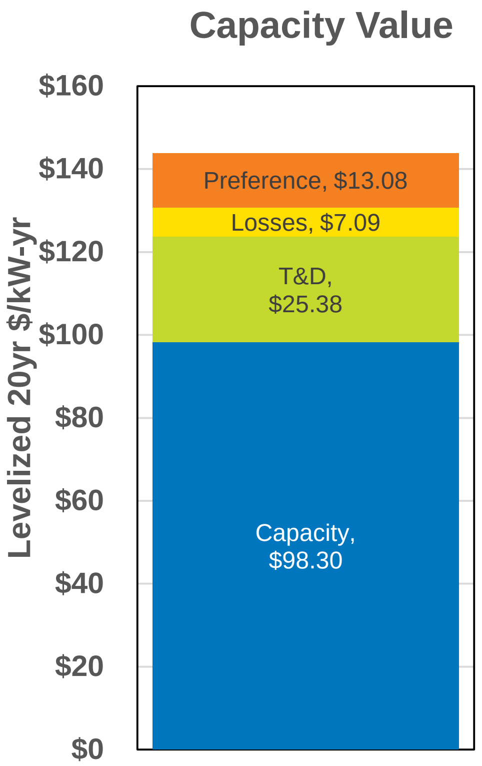
Biennial Conservation Target (MWh)	Based on 2021 IRP	Based on 2020 IRP
CPA Pro-Rata Share	101,566	72,338
Distribution & Street Light Efficiency	219	504
EIA Target	101,785	72,842
Decoupling Threshold	5,119	3,642
Total Utility Conservation Goal	106,904	76,484
Excluded Programs (NEEA)	-12,896	-14,016
Utility Specific Conservation Goal	94,008	62,468
Decoupling Threshold	-5,119	-3,642
EIA Penalty Threshold	88,889	58,826



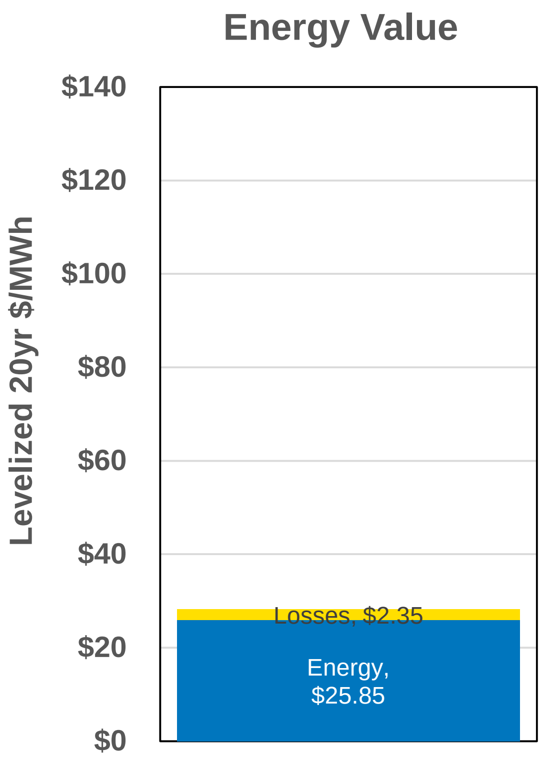
24-yr Levelized Avoided Cost for Energy Efficiency

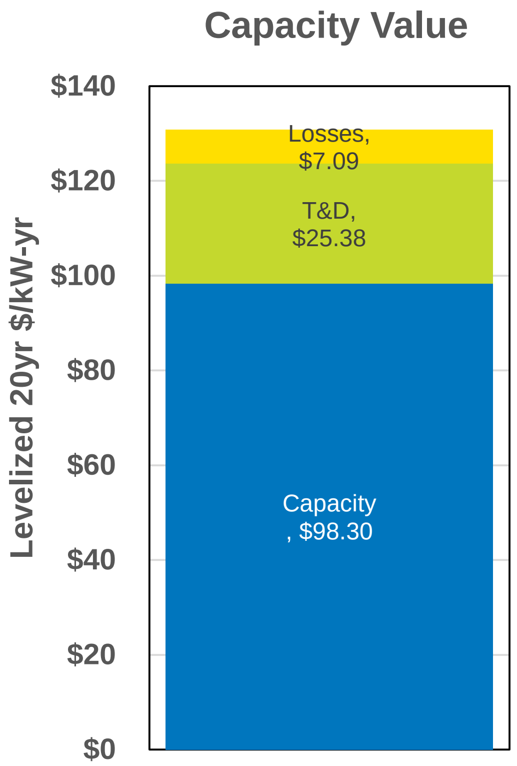
Washington





Idaho





Winter (January) Capacity Position (MW)

Item	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Baseline Load Forecast	1,719	1,725	1,729	1,733	1,738	1,742	1,746	1,751	1,756	1,761	1,766	1,771	1,777	1,783	1,789	1,796	1,804	1,812	1,821	1,830
Embedded EE (added back)	5	11	18	26	35	45	56	66	76	84	91	96	100	104	107	109	111	112	114	115
Load Forecast w/o EE	1,724	1,736	1,747	1,759	1,773	1,787	1,802	1,817	1,832	1,845	1,857	1,867	1,877	1,887	1,896	1,905	1,915	1,924	1,935	1,945
Selected EE	5	11	18	26	35	46	56	67	76	84	91	97	101	105	108	110	112	114	115	116
Colstrip Losses Adjustment	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
Other Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Load Estimate	**1,706**	**1,712**	**1,716**	**1,720**	**1,725**	**1,729**	**1,733**	**1,738**	**1,743**	**1,748**	**1,753**	**1,758**	**1,764**	**1,770**	**1,775**	**1,782**	**1,790**	**1,798**	**1,807**	**1,816**
Planning Margin	273	274	275	275	276	277	277	278	279	280	280	281	282	283	284	285	286	288	289	291
Reserves + Regulation	137	137	136	136	136	137	137	137	137	138	138	138	139	139	139	140	140	141	141	138
Oper. Reserves Hydro Credit	-17	-17	-13	-13	-13	-13	-12	-12	-12	-8	-8	-8	-8	-7	-7	-7	-7	-7	-7	-7
Net Requirement	**2,099**	**2,106**	**2,114**	**2,119**	**2,125**	**2,130**	**2,135**	**2,141**	**2,147**	**2,158**	**2,164**	**2,170**	**2,177**	**2,184**	**2,192**	**2,200**	**2,210**	**2,220**	**2,231**	**2,238**
Long Term Sales	-101	-101	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Long Term Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Clark Fork River	798	798	798	798	798	798	798	798	798	798	798	798	798	798	798	798	798	798	798	798
Spokane River	163	163	163	153	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165
Mid-Columbia Contracts	228	227	147	146	145	144	142	135	135	63	63	64	64	64	64	64	64	64	64	64
PURPA Contracts	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78
Palouse	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Rattlesnake Flats	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	0
Adams Nielson Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Placeholder	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Placeholder	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coyote Springs 2	318	318	318	318	318	318	318	318	318	318	318	318	318	318	318	318	318	318	318	318
Lancaster	283	283	283	283	283	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Colstrip (3)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Colstrip (4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kettle Falls	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47
Kettle Falls CT	11	11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Boulder Park 1-6	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	0
Rathdrum 1	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88
Rathdrum 2	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88
Northeast A&B	66	66	66	66	66	66	66	66	66	66	66	66	66	66	0	0	0	0	0	0
Net Position	**5**	**-4**	**-2**	**-17**	**-12**	**-301**	**-307**	**-320**	**-326**	**-409**	**-415**	**-421**	**-428**	**-435**	**-509**	**-517**	**-527**	**-536**	**-547**	**-587**

Assumes Colstrip 3 & 4 are removed from the portfolio from 2022 to 2041 due to economic results of this study

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Demand Response

Program	Washington	Idaho
Time of Use Rates	2 MW (2024)	2 MW (2024)
Variable Peak Pricing	7 MW (2024)	6 MW (2024)
Large C&I Program	25 MW (2027)	n/a
DLC Smart Thermostats	7 MW (2031)	n/a
Third Party Contracts	14 MW (2032)	8 MW (2024)
Behavioral	1 MW (2041)	n/a
Total	56 MW	15 MW

Notes:
1) Programs in another state for the benefit of the other state are not modeled
2) Operationally programs are likely for both states regardless of timing
3) 2027 start date is effectively 11/1/2027

2022-2025 Supply-Side Resource Changes

2022: Economic to exit out of Colstrip 3 & 4 (Both States)

2023: 100 MW of Montana Wind (WA)

2024: 100 MW of Montana Wind (WA)

2025: No Action

NOTE: Renewable RFP may change this strategy

2026-2029 Supply-Side Resource Changes

2026/27: 12 MW Upgrade Kettle Falls (Both States)

283 MW Lancaster CCCT contract ends Nov 2026 (Both States)

126 MW NG SCCT (Both States)

85 MW NG SCCT (ID)

2028: 100 MW Montana Wind (WA)

2029: No Action

NOTE: Renewable RFP may change this strategy

2030-2033 Supply-Side Resource Changes

2030: No Action

2031: 75 MW Hydro Contract Renewal (WA)

2032: No Action

2033: No Action

2034-2037 Supply-Side Resource Changes

2034: No Action

2035: 5 MW Rathdrum CT Upgrade (Both States)

66 MW Northeast Retires (Both States)

2036: 87 MW NG SCCT (Both States)

2037: No Action

2038-2041 Supply-Side Resource Changes

2038: 100 MW Solar + 50 MW 4-hour Lithium-ion Battery (Both States)

2039: No Action

2040: No Action

2041: 25 MW Boulder Park Retires (Both States)

100 MW Montana Wind (WA)

36 MW Natural Gas Reciprocating Engine (ID)

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Draft Preferred Resource Strategy Selection (MW)

Nameplate MW	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045		Total
Shared System Resource																										
NG CT	-	-	-	-	-	126	-	-	-	-	-	-	-	-	87	-	-	-	-	-	-	-	-	-		213
Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-		100
Storage Added to Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	-	-	-	-	-	-	-		50
Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
Other- (Clean Capacity)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
Thermal Upgrade	-	-	-	-	12	-	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-		17
Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
Washington																										
NG CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	117	122	-	149		388
Storage Added to Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	58	61	-	75		194
Wind	-	100	100	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-		400
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	-		12
Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
Other- (Clean Capacity)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
Thermal Upgrade	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
Hydro	-	-	-	-	-	-	-	-	-	75	-	-	-	-	-	-	-	-	-	-	-	-	-	-		75
Idaho																										
NG CT	-	-	-	-	-	85	-	-	-	-	-	-	-	-	-	-	-	-	-	36	-	-	-	-		122
Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
Storage Added to Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10		10
Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
Other- (Clean Capacity)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
Thermal Upgrade	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-
Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-

Note: Storage resources include 16-Hour Liquid Air Energy Storage and 4-Hour Lithium-ion.
Does not include results of 2020 Renewable RFP.

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Draft State Total Resource Selection (MW)

Nameplate MW	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Washington																									
NG CT	-	-	-	-	-	83	-	-	-	-	-	-	-	-	57	-	-	-	-	-	-	-	-	-	140
Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	66	-	-	-	117	122	-	149	454
Storage Added to Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	33	-	-	-	58	61	-	75	227
Wind	-	100	100	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	400
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	-	12
Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other- (Clean Capacity)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Thermal Upgrade	-	-	-	-	8	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	11
Hydro	-	-	-	-	-	-	-	-	-	75	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75
Idaho																									
NG CT	-	-	-	-	-	128	-	-	-	-	-	-	-	-	30	-	-	-	-	36	-	-	-	-	195
Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	34	-	-	-	-	-	-	-	34
Storage Added to Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	-	-	-	-	-	-	-	17
Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other- (Clean Capacity)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Thermal Upgrade	-	-	-	-	4	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	6
Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

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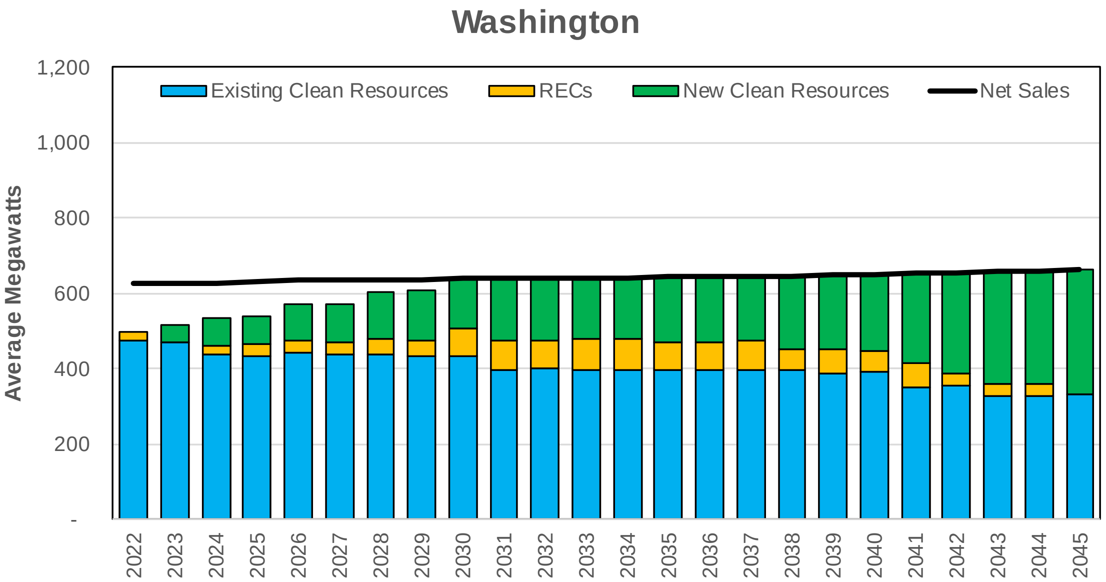
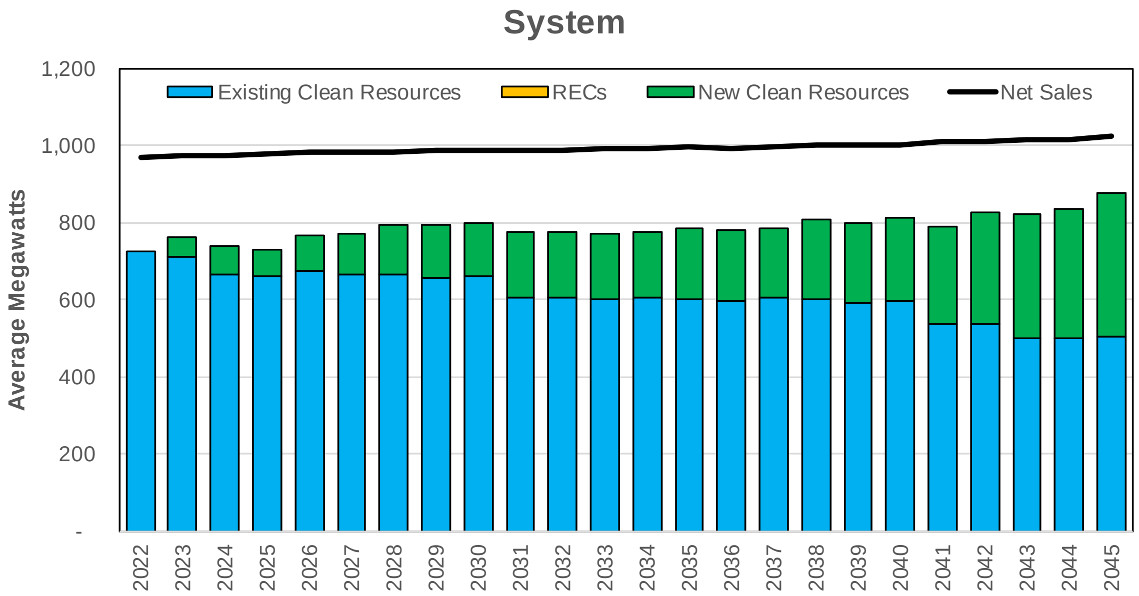
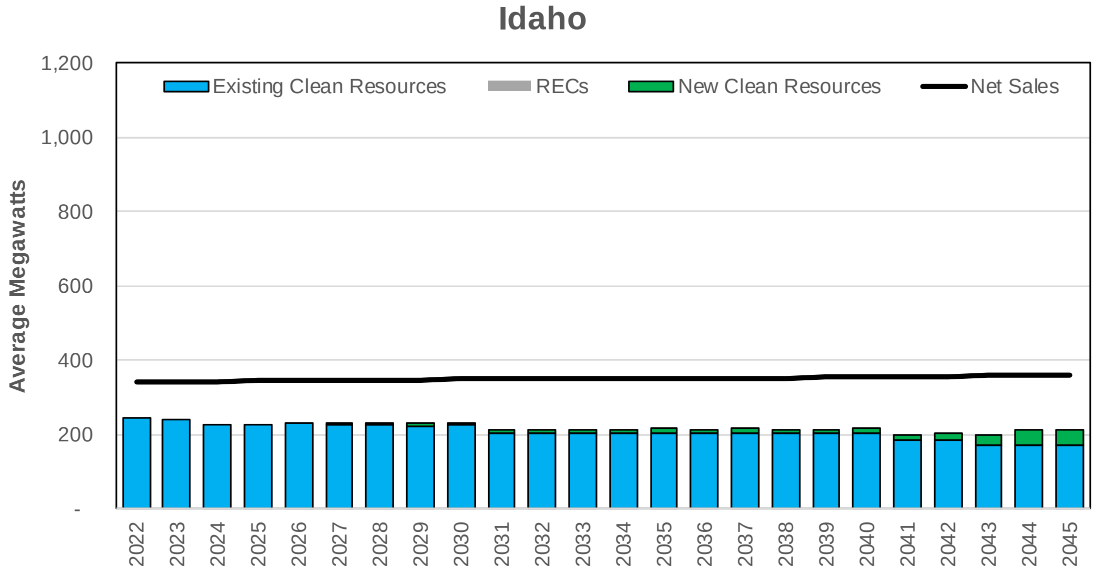
Clean Energy Shares (aMW)







System Clean Resource Percentage

2022: 74.8%

2027: 78.3%

2045: 85.5%

Excludes Clean Market Purchases

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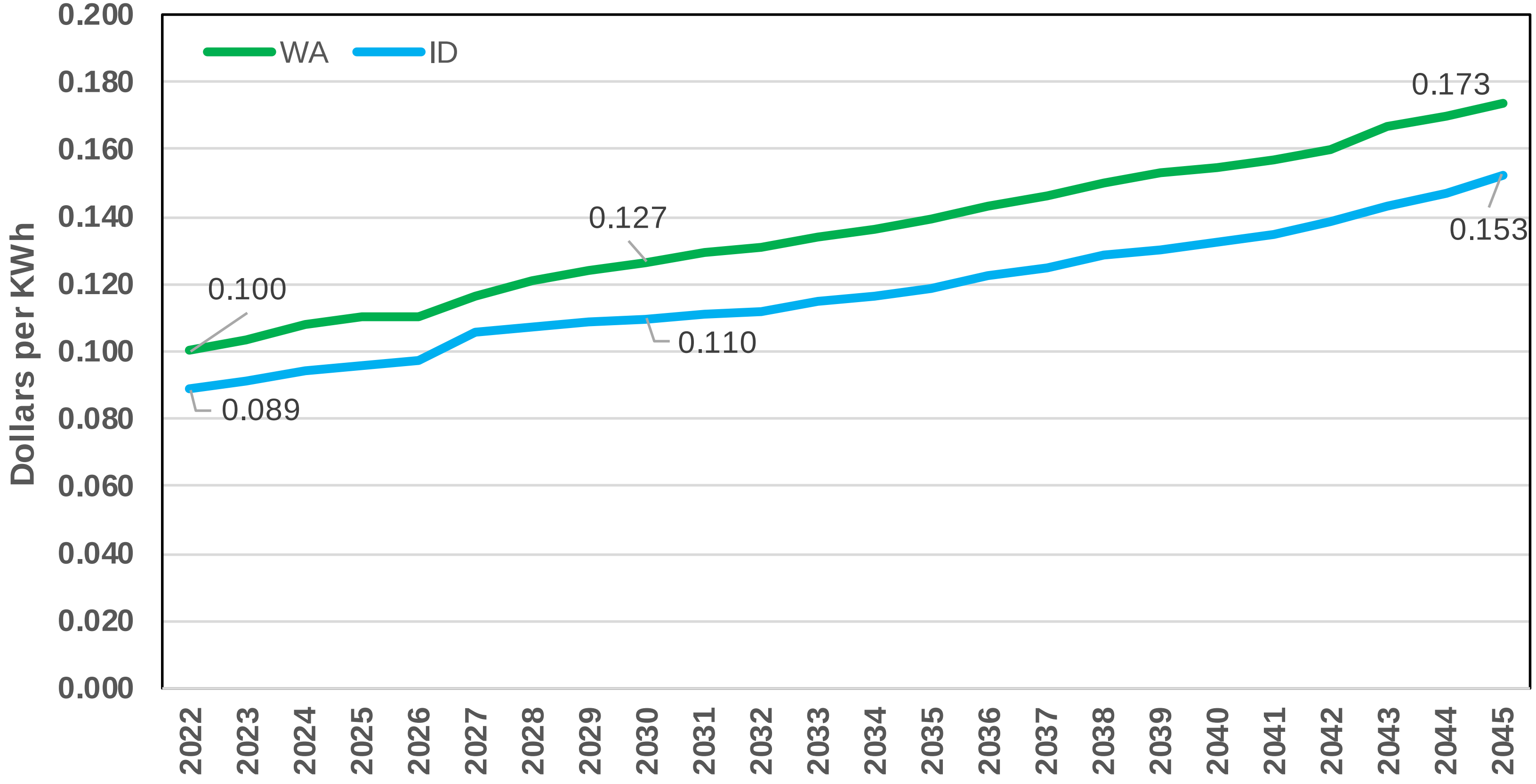
Annual Average Least Reasonable Cost Rate Forecast



NOTE: Estimated rates only using 2% annual rate increase for non-modeled costs

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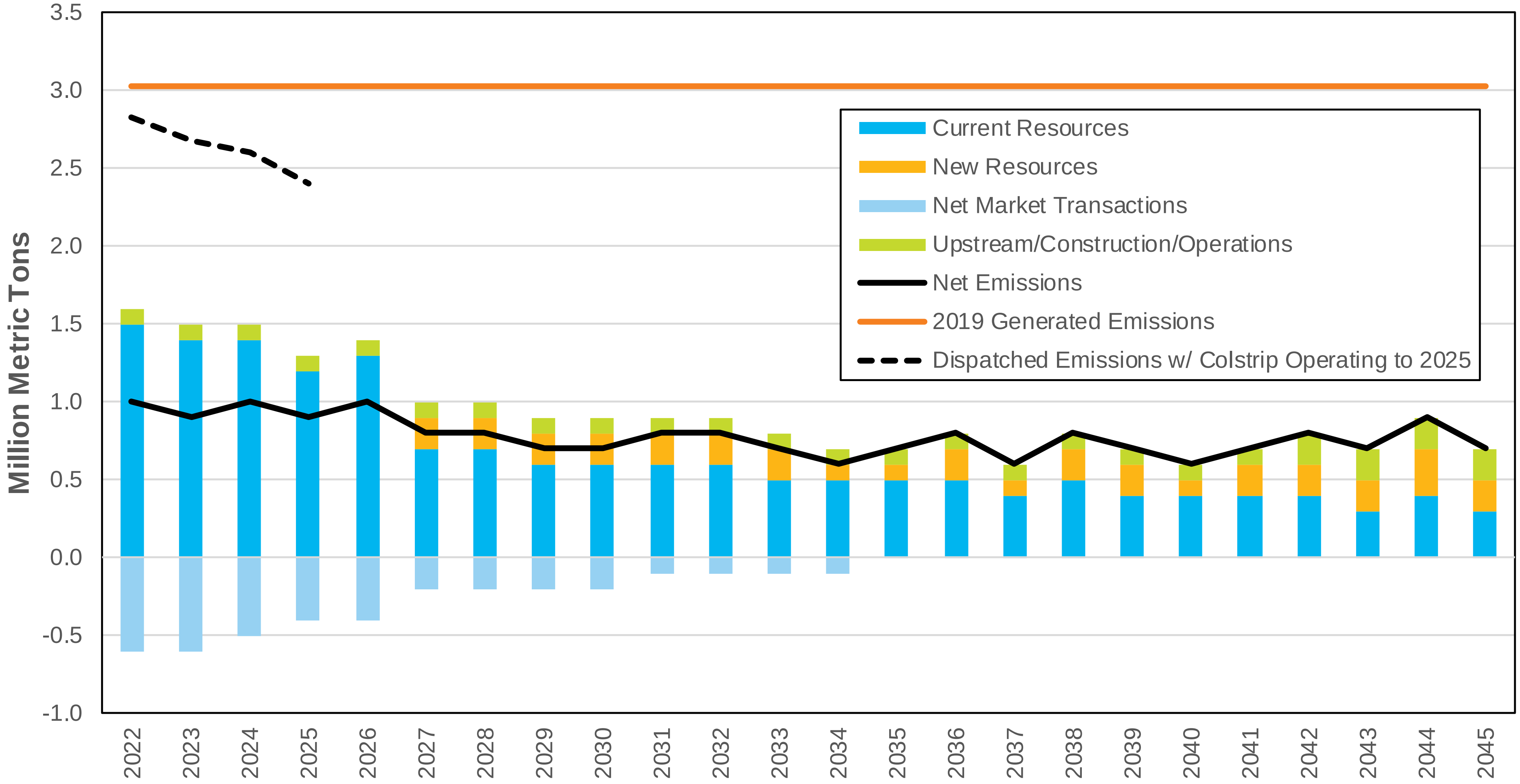
Greenhouse Gas Forecast with Draft PRS



Note: Assumes Colstrip exits the portfolio in 2022

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New Supply-Side Resource Avoided Costs

Year	Flat ($/MWh)	On-Peak ($/MWh)	Off-Peak ($/MWh)	Clean Energy Premium ($/MWh)	Capacity Premium ($/kW-Yr)
2022	$20.37	$21.66	$18.65	$0.00	$0.00
2023	$18.71	$19.34	$17.89	$13.27	$0.00
2024	$18.73	$19.04	$18.32	$13.54	$0.00
2025	$19.99	$20.05	$19.92	$13.81	$0.00
2026	$23.74	$23.68	$23.82	$14.09	$0.00
2027	$24.63	$24.27	$25.12	$14.37	$115.1
2028	$25.67	$24.99	$26.58	$14.65	$117.4
2029	$26.65	$25.77	$27.83	$14.95	$119.8
2030	$26.46	$25.48	$27.78	$15.25	$122.2
2031	$27.63	$26.48	$29.15	$15.55	$124.6
2032	$28.02	$26.86	$29.57	$15.86	$127.1
2033	$29.30	$27.96	$31.08	$16.18	$129.7
2034	$29.42	$27.98	$31.33	$16.50	$132.2
2035	$30.47	$28.81	$32.68	$16.83	$134.9
2036	$32.10	$30.38	$34.41	$17.17	$137.6
2037	$31.95	$30.08	$34.45	$17.51	$140.3
2038	$34.46	$32.26	$37.39	$17.86	$143.1
2039	$34.77	$32.31	$38.04	$18.22	$146.0
2040	$35.67	$33.15	$39.01	$18.58	$148.9
2041	$38.23	$35.77	$41.52	$18.96	$151.9
2042	$38.71	$36.40	$41.79	$19.34	$154.9
2043	$39.27	$36.92	$42.40	$19.72	$158.0
2044	$46.82	$44.18	$50.34	$20.12	$161.2
2045	$46.45	$44.31	$49.28	$20.52	$164.4
20 yr Levelized	**$25.85**	**$25.20**	**$26.72**	**$14.04**	**$80.3**
24 yr Levelized	**$27.18**	**$26.39**	**$28.22**	**$14.50**	**$86.6**

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Portfolio Scenario and Market Sensitivity Analysis

James Gall, Electric IRP Manager
Technical Advisory Committee Update Meeting
December 16, 2020

Safe Harbor Statement

This document contains forward-looking statements. Such statements are subject to a variety of risks, uncertainties and other factors, most of which are beyond the Company's control, and many of which could have a significant impact on the Company's operations, results of operations and financial condition, and could cause actual results to differ materially from those anticipated.

For a further discussion of these factors and other important factors, please refer to the Company's reports filed with the Securities and Exchange Commission. The forward-looking statements contained in this document speak only as of the date hereof. The Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events. New risks, uncertainties and other factors emerge from time to time, and it is not possible for management to predict all of such factors, nor can it assess the impact of each such factor on the Company's business or the extent to which any such factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement.

Scenario Descriptions

1. **Least Reasonable Cost Strategy:** Includes all requirements
2. **Baseline Portfolio 1:** Excludes CETA’s 2030 and 2045 goals
   – Used for incremental cost calculation
3. **Baseline Portfolio 2:** Baseline Portfolio 1 + removal of SCC
   – Energy Efficiency held constant from LCS
4. **Baseline Portfolio 3:** Baseline Portfolio 2 + removal of capacity constraints
   – Energy Efficiency held constant from LCS
5. **Clean Resource Plan (2027)**
   – Add constraint to meet or exceed 100% of all retail sales with clean energy
6. **Clean Resource Plan (2045)**
   – Add constraint to meet or exceed 100% of all retail sales with clean energy
   – All thermal resources must exit by 2044
   – No new thermal resources
7. **Social Cost of Carbon applied to Idaho**
   – Includes SCC as cost adder to generation and savings for EE using same method as Washington State

Scenario Descriptions (Continued)

8. **Least Cost Plan- with low load growth**
   – Loads decline by 0.11% per year vs. +0.31% per year
9. **Least Cost plan- with high load growth**
   – Loads increase by 0.73% per year vs. +0.31% per year
10. **Least Cost Plan- w/ Northwest Resource Adequacy Market Peak Credits**
    – Use Regional Planning Margin of 12% & Regional Peak Credits
11. **Heating Electrification Scenario 1**
    – WA customers electrify with exiting heating technology
12. **Heating Electrification Scenario 2**
    – WA customers electrify using hybrid systems (i.e. NG furnace & electric HP & HPWH)
13. **Heating Electrification Scenario 3**
    – WA customer electrify using technology without COP rates not falling below freezing temperatures
14. **Least Cost Plan- with 2 time SCC prices**
    – Double of Social Cost of Carbon charge for Washington Only

Scenario Descriptions (Continued)

15. **Colstrip serves Idaho customers through 2025**
    - Colstrip obligated to run through 2025 in both states
16. **Colstrip serves Idaho customers through 2035**
    - Colstrip obligated to run though 2035 for Idaho
17. **Colstrip serves Idaho customers through 2045**
    - Colstrip obligated to run through 2045 for Idaho
18. **CETA delivers by the hour**
    - Approximates resource selection requiring clean energy delivery by hour
19. **Social Cost of Carbon applied to net purchases/sales**
    - Includes SCC planning penalty on the net of market purchases/sales (2020 IRP assumption)
20. **Average Market Emissions Rate applied to Energy Efficiency SCC**
    - Replaces incremental market emissions for average market emissions for SCC on EE (2020 IRP assumption)

Scenario Descriptions (Continued)

1a. Least Cost Plan with Climate Shift

- Re-optimized PRS with alternate load and generation forecast assuming warming temperatures

1b. Least Cost Plan with Social Cost of Carbon "Tax"

- Re-optimized PRS with market carbon tax on fossil fuel generation

Scenario & Sensitivity List

Number	Scenario	Expected Case	High N. Gas Price	Low N. Gas Price	Social Cost Carbon Tax	Climate Shift
1	Preferred Resource Strategy	X	X	X	X	
2	Baseline Portfolio 1 (No CETA renewable targets)	X				
3	Baseline Portfolio 2 (No CETA renewable targets/SCC)	X	X	X	X	
4	Baseline Portfolio 3 (No Capacity Constraints)	X				
5	Clean Resource Plan (100% Portfolio net clean by 2027)	X	X	X	X	
6	Clean Resource Plan (100% Portfolio clean by 2045)	X	X	X	X	
7	Social Cost of Carbon applied to Idaho	X				
8	Least Cost Plan- w/ low load growth	X				
9	Least Cost Plan- w/ low load growth	X				
10	Least Cost Plan- w/ Northwest Resource Adequacy Market Peak Credits	X				
11	Heating Electrification Scenario 1	X				
12	Heating Electrification Scenario 2	X				
13	Heating Electrification Scenario 3	X				
14	Least Cost Plan- w/ 2x SCC prices	X				
15	Colstrip serves Idaho customers through 2025	X	X	X	X	
16	Colstrip serves Idaho customers through 2035	X	X	X	X	
17	Colstrip serves Idaho customers through 2045	X	X	X	X	
18	CETA deliver each hour	X				
19	Social Cost of Carbon applied to net Purchases/Sales	X				
20	Avg market emissions rate applied to SCC for EE	X				
1a	Least Cost Plan- w/ climate shift					X
1b	Least Cost Plan- w/ SCC “Tax”				X	

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Scenario Cumulative Resource Selection

	1- Preferred Resource Strategy	2- Baseline 1	3- Baseline 2	4- Baseline 3	5- Clean Resource Plan (2027)	6- Clean Resource Plan (2045)	7- SCC Idaho	8- Low Load Forecast	9- High Load Forecast	10- RA Market	11- Electrification 1	12- Electrification 2	13- Electrification 3	14- 2x SCC	15- Colstrip Exit 2025	16- Colstrip Exit 2035	17- Colstrip Exit 2045	18- Clean Energy Delivered Each Hour	19- SCC on Net P/S	20- Use Avg Mrkt for EE SCC	1a- LCP w/ Climate Shift	1b- LCP w/ SCC
Shared System Resource																						
NG CT	213	132	132	0	84	0	223	65	84	88	84	84	84	196	213	125	211	126	250	86	172	247
Solar	100	0	0	0	549	899	0	104	0	100	0	0	0	100	100	100	100	100	0	101	-	411
Storage Added to Solar	50	0	0	0	275	450	0	52	0	50	0	0	0	50	50	50	50	50	0	50	-	206
Wind	0	0	0	0	0	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	323
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	9
Hydrogen	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-
Other- (Clean Capacity)	0	0	0	0	20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-
Thermal Upgrade	17	17	17	0	17	12	17	17	21	17	17	17	17	17	17	17	17	17	17	17	21	17
Hydro	0	75	75	0	0	75	75	0	0	0	0	0	0	0	0	0	0	0	0	0	-	75
Washington																						
NG CT	0	144	147	0	48	0	0	48	92	49	200	159	200	0	0	51	0	0	0	84	-	-
Solar	388	0	0	0	26	0	496	131	493	552	277	536	425	379	388	388	387	788	120	389	372	-
Storage Added to Solar	194	0	0	0	0	0	248	0	246	94	138	268	212	189	194	194	194	369	60	194	111	-
Wind	400	0	0	0	400	400	400	400	514	300	894	628	796	400	400	400	400	700	616	400	400	350
Storage	12	68	68	0	24	312	22	0	113	0	486	279	474	23	12	22	13	512	22	12	21	865
Hydrogen	0	0	0	0	0	75	0	0	0	0	397	84	199	0	0	0	0	0	0	0	-	-
Other- (Clean Capacity)	0	0	0	0	0	96	0	0	20	0	20	20	20	0	0	0	0	100	0	0	-	-
Thermal Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-
Hydro	75	0	0	0	75	0	0	75	75	75	75	75	75	75	75	75	75	75	75	75	75	-
DR Capability	56	104	97	3	56	104	57	49	49	34	49	49	49	57	56	56	56	56	49	56	49	35
EE- Winter Capacity	86	85	86	86	89	92	86	86	86	85	118	114	114	88	86	86	86	86	85	81	86	87
EE- Summer Capacity	92	92	92	92	100	101	93	92	92	96	121	97	99	94	92	92	92	92	92	79	97	115
Idaho																						
NG CT	122	97	97	0	148	0	57	135	194	148	91	132	91	127	122	165	73	158	92	169	120	-
Solar	0	0	0	0	200	250	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	-
Storage Added to Solar	0	0	0	0	0	50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-
Wind	0	0	0	0	194	200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	327
Storage	10	20	33	0	0	20	10	0	28	49	26	16	26	29	10	24	24	10	34	10	-	176
Hydrogen	0	50	50	0	0	232	50	0	50	0	100	50	100	0	0	0	0	0	0	0	-	-
Other- (Clean Capacity)	0	0	0	0	0	20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-
Thermal Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-
Hydro	0	0	0	0	0	68	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-
DR Capability	15	18	20	2	16	20	19	8	16	19	19	18	19	18	15	9	9	15	15	19	16	8
EE- Winter Capacity	24	29	24	24	31	37	38	24	24	24	32	29	32	25	24	22	21	24	29	25	24	39
EE- Summer Capacity	13	13	13	13	26	30	35	13	13	20	15	13	15	13	13	11	11	13	13	13	35	53

Existing Resource "Exits"

	1- Preferred Resource Strategy	2- Baseline 1	3- Baseline 2	4- Baseline 3	5- Clean Resource Plan (2027)	6- Clean Resource Plan (2045)	7- SCC Idaho	8- Low Load Forecast	9- High Load Forecast	10- RA Market	11- Electrification 1	12- Electrification 2	13- Electrification 3	14- 2x SCC	15- Colstrip Exit 2025	16- Colstrip Exit 2035	17- Colstrip Exit 2045	18- Clean Energy Delivered Each Hour	19- SCC on Net P/S	20- Use Avg Mrkt for EE SCC	1a- LCP w/ Climate Shift	1b- LCP w/ SCC
Coyote Springs 2	-	-	-	-	-	2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lancaster	2026	2026	2026	2026	2026	2026	2026	2026	2026	2026	2026	2026	2026	2026	2026	2026	2026	2026	2026	2026	2026	2026
Colstrip (3)	2021	2021	2021	2021	2021	2044	2021	2021	2021	2021	2021	2021	2021	2021	2025	2035	-	2021	2021	2021	2021	2021
Colstrip (4)	2021	2021	2021	2021	2021	2021	2021	2021	2022	2021	2021	2021	2021	2021	2025	2035	-	2021	2021	2021	2021	2021
Kettle Falls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Kettle Falls CT	-	-	-	-	-	2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Boulder Park 1-6	2040	2040	2040	2040	2040	2040	2040	2040	2040	2037	2040	2040	2040	2040	2040	2040	2040	2040	2039	2040	2040	2040
Rathdrum 1	-	-	-	-	-	2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rathdrum 2	-	-	-	-	-	2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Northeast A&B	2035	2035	2035	2035	2035	2035	2035	2035	2035	2035	2035	2035	2035	2035	2035	2035	2035	2035	2035	2035	2035	2035

Note:
Assumes each plant is available through December 31st of the final year;
Exception: Lancaster PPA expires Oct 2026.
Dash indicates no plant exit in the study

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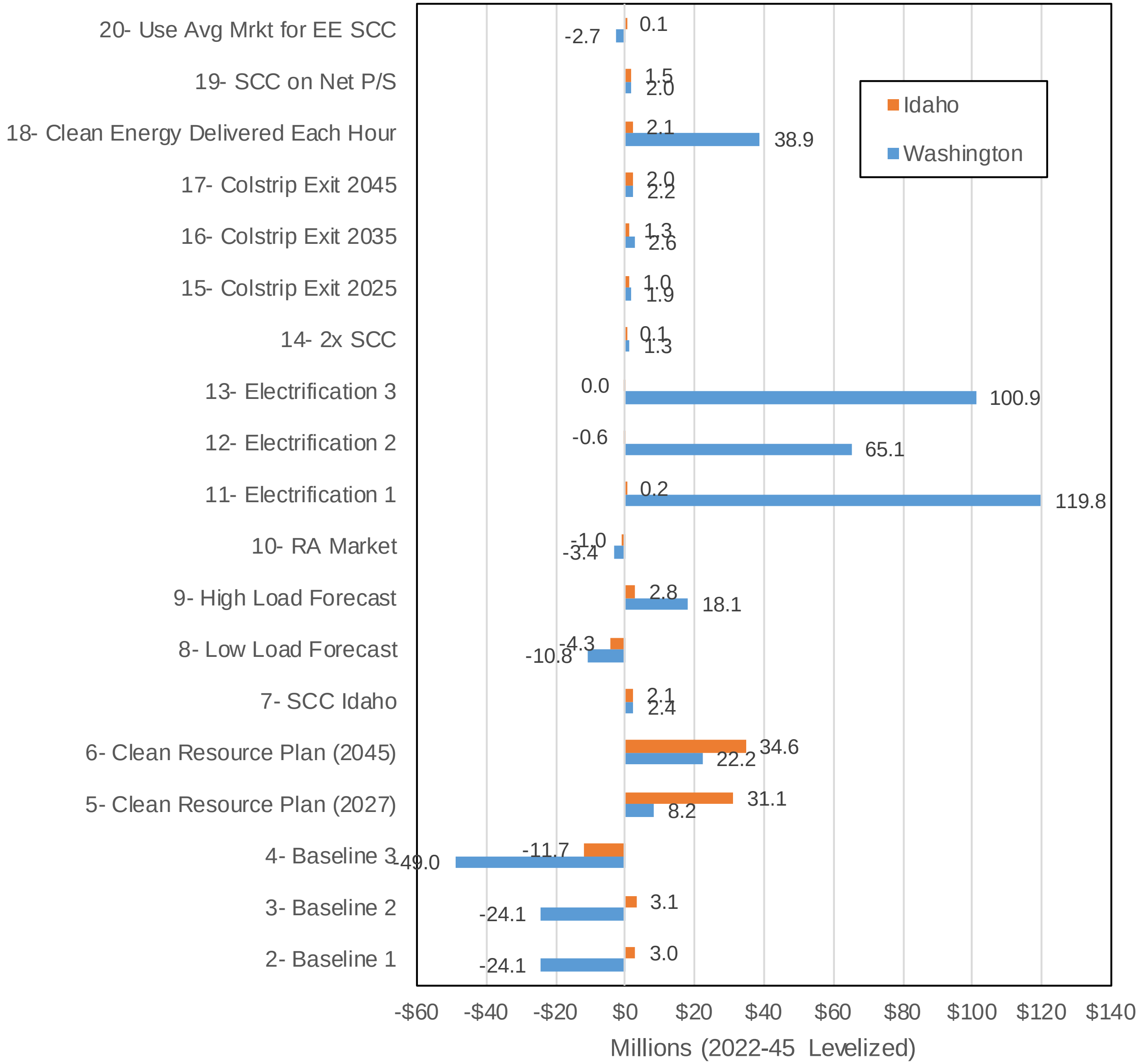
2022-45 Levelized Revenue Requirement Delta from PRS



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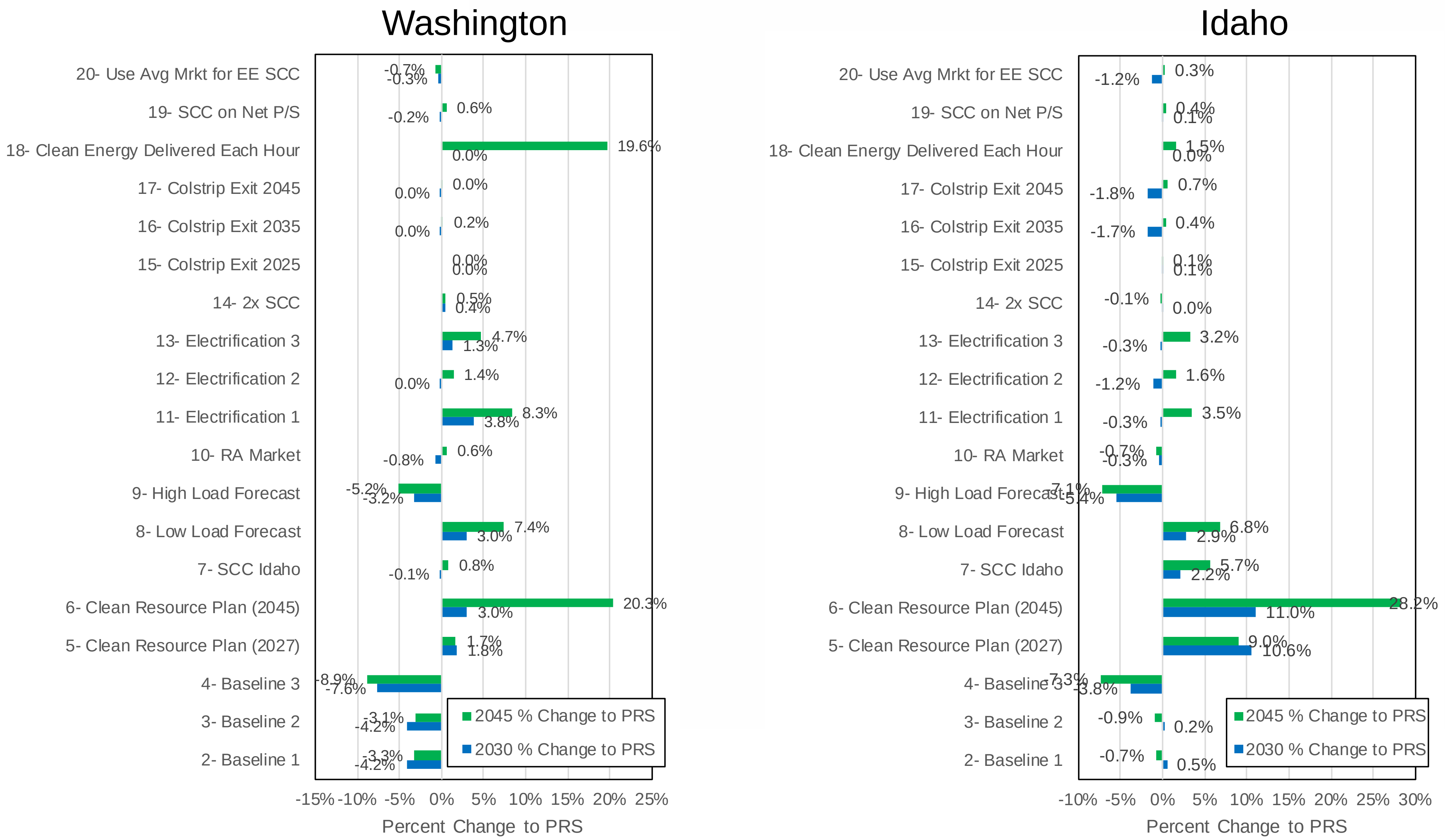
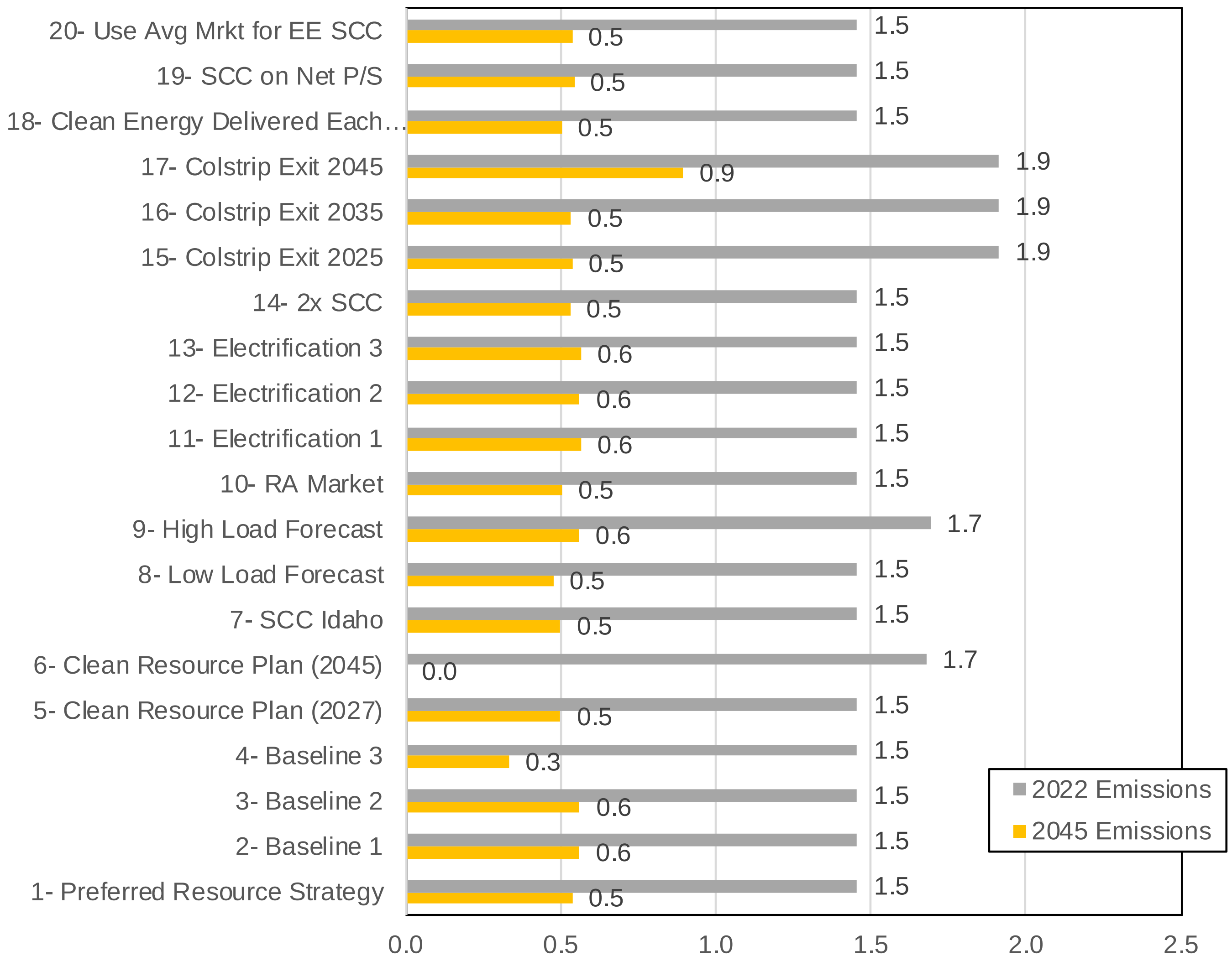
Avg Energy Rate Delta from PRS (2030 & 2045)



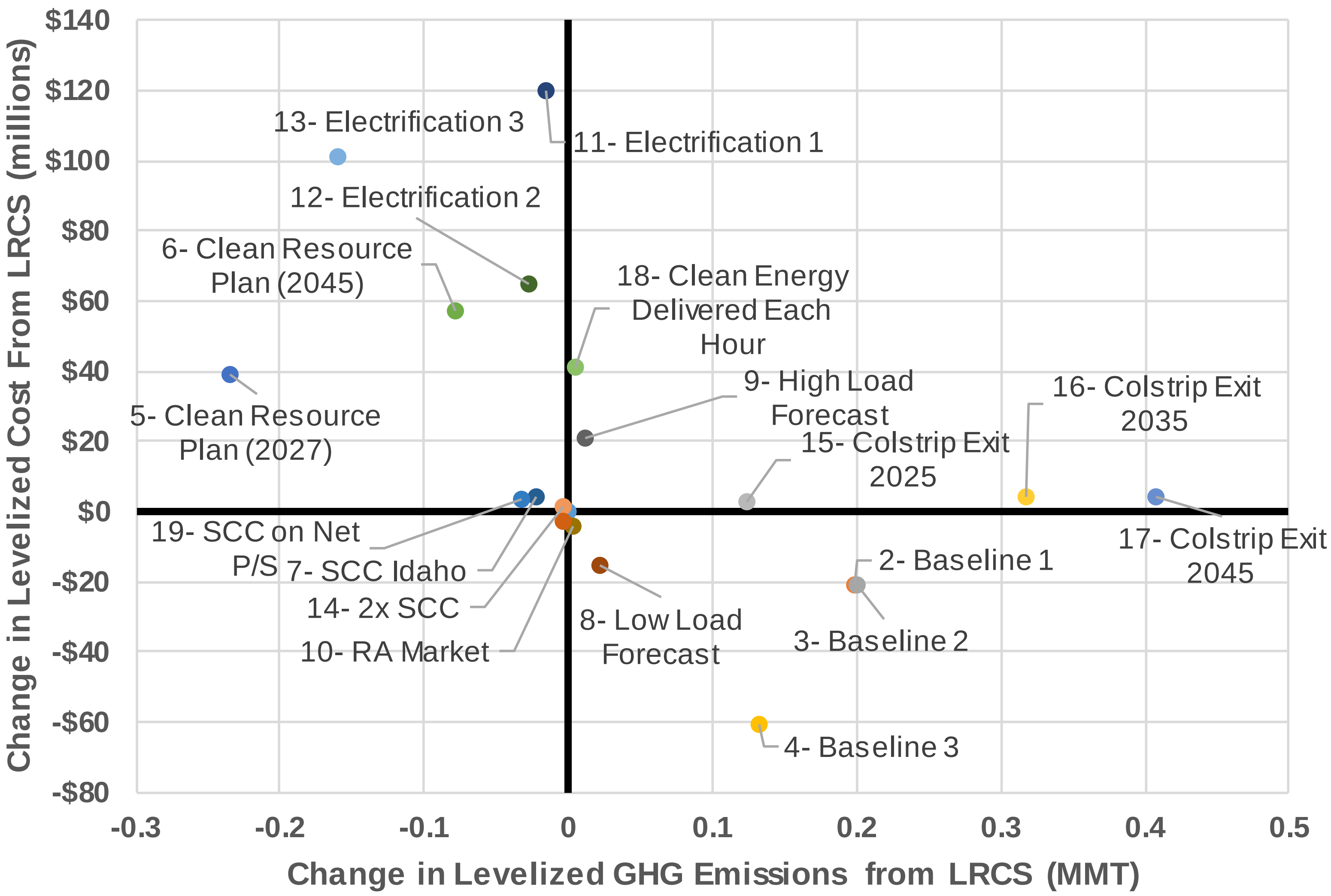
Annual Greenhouse Gas Emission

Avista Dispatched GHG Emissions



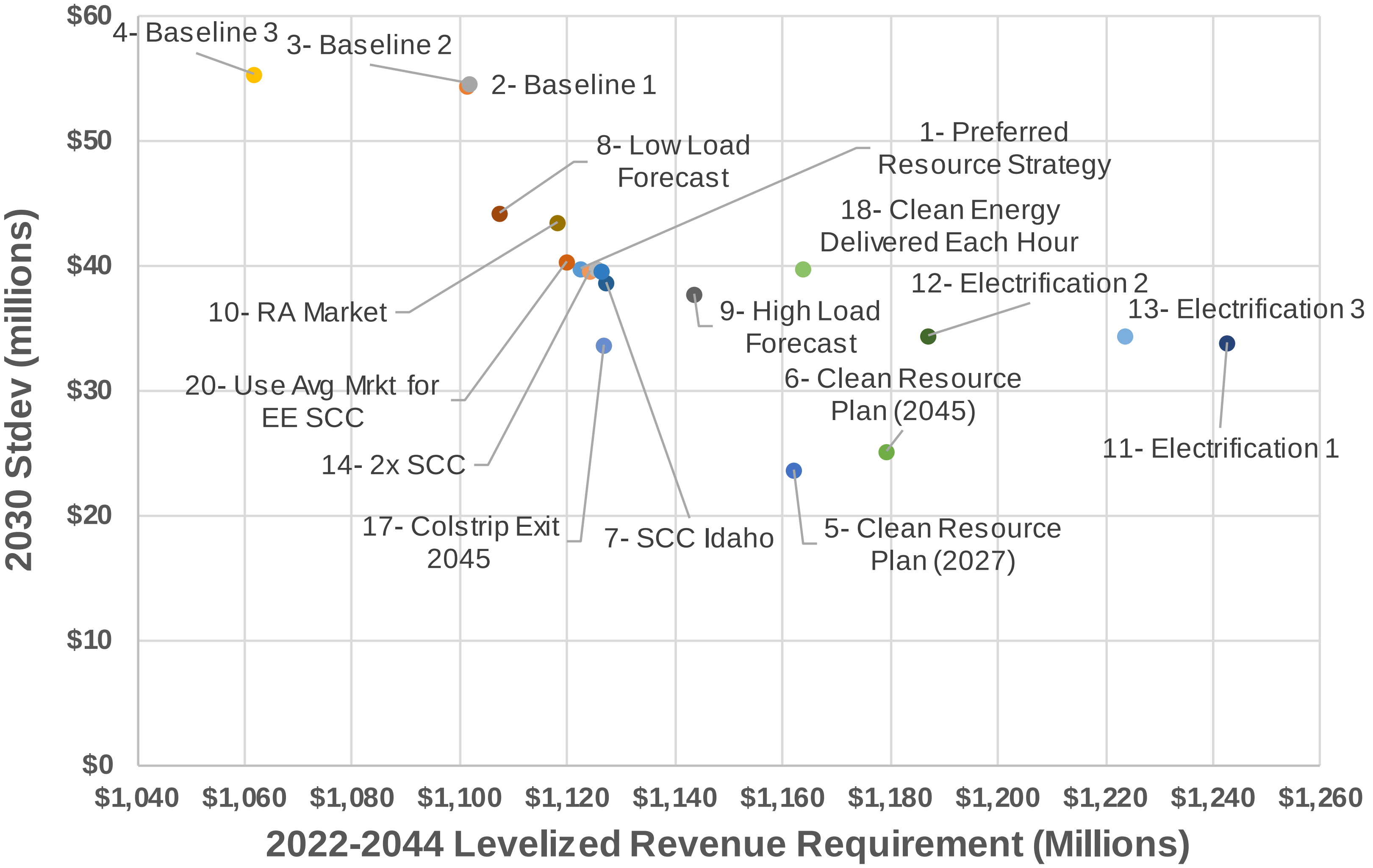
Cost vs. GHG Tradeoffs

Change in Levelized Cost vs. Change in Levelized Net Emissions



2030 Risk Analysis

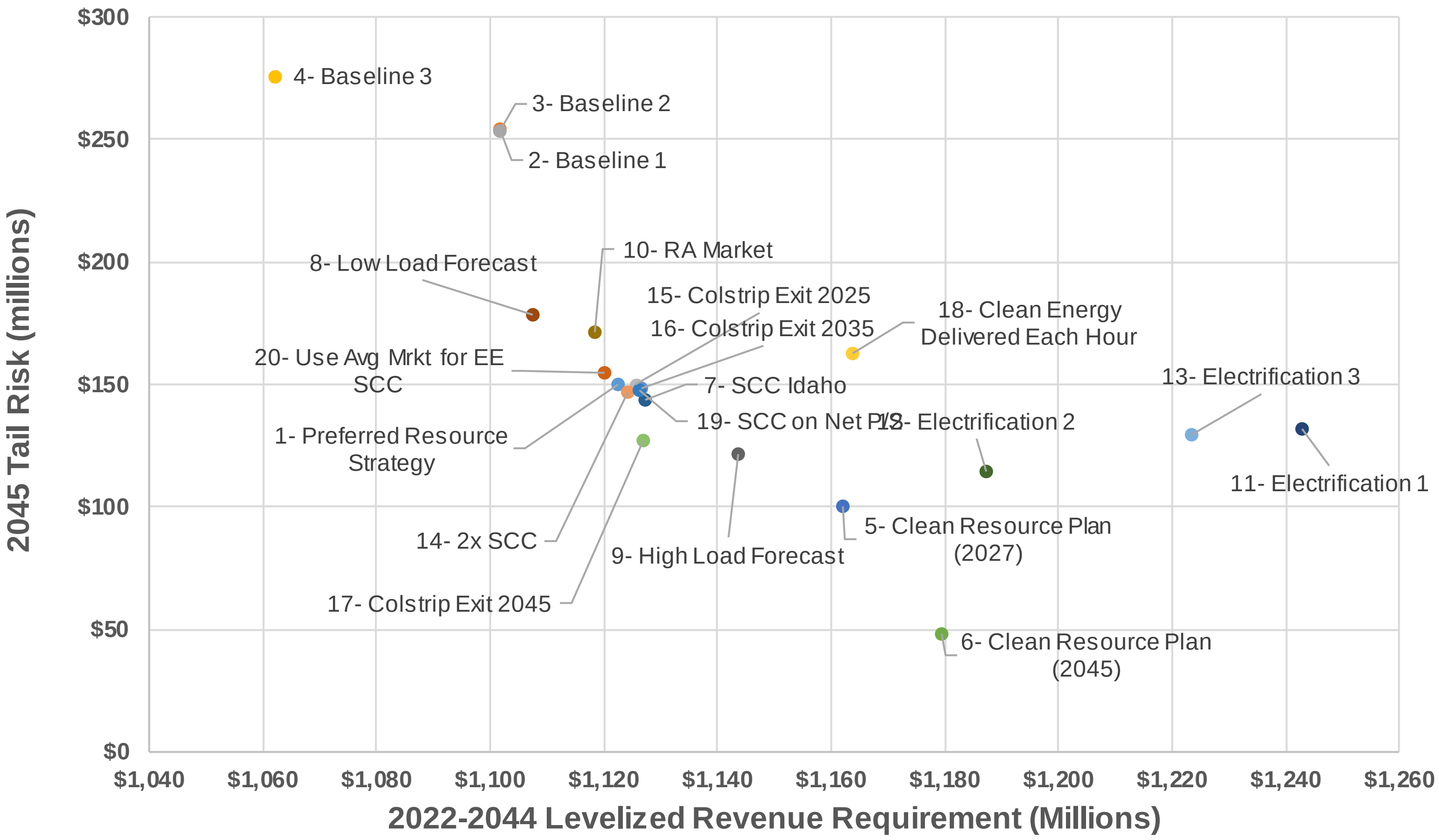
Measures 2030 standard deviation of “modeled” power cost compared to levelized cost



Note: PPA cost “fixed” for this analysis- meaning the PPA cost does not change with changes in delivered energy

2045 Upper Tail Risk Analysis

95th percentile power cost minus mean power cost compared to levelized cost



Note: PPA cost “fixed” for this analysis- meaning the PPA cost does not change with changes in delivered energy

Portfolio Results Summary

Scenario	WA- PVRR ($ Mill)	ID-PVRR ($ Mill)	WA 2030 Rate ($/kWh)	WA 2045 Rate ($/kWh)	ID 2030 Rate ($/kWh)	ID 2045 Rate ($/kWh)	2030 Stdev ($ Mill)	2045 Stdev ($ Mill)	2045 Tail Risk ($ Mill)	2045 GHG Emissions (MT)
1- Preferred Resource Strategy	8,703	4,543	0.127	0.173	0.110	0.153	40	87	150	0.54
2- Baseline 1	8,418	4,578	0.121	0.168	0.110	0.152	54	148	254	0.56
3- Baseline 2	8,418	4,580	0.121	0.168	0.110	0.151	55	148	253	0.56
4- Baseline 3	8,125	4,405	0.117	0.158	0.106	0.141	55	162	276	0.33
5- Clean Resource Plan (2027)	8,800	4,910	0.129	0.176	0.121	0.166	24	56	100	0.50
6- Clean Resource Plan (2045)	8,965	4,951	0.130	0.209	0.122	0.196	25	35	48	0.00
7- SCC Idaho	8,732	4,568	0.126	0.175	0.112	0.161	39	82	143	0.50
8- Low Load Forecast	8,575	4,492	0.130	0.186	0.113	0.163	44	101	178	0.48
9- High Load Forecast	8,916	4,576	0.123	0.164	0.104	0.142	38	70	122	0.56
10- RA Market	8,663	4,531	0.126	0.174	0.109	0.152	43	94	171	0.50
11- Electrification 1	10,117	4,545	0.131	0.188	0.109	0.158	34	88	132	0.57
12- Electrification 2	9,471	4,536	0.127	0.176	0.109	0.155	34	71	115	0.56
13- Electrification 3	9,894	4,543	0.128	0.181	0.109	0.158	34	85	129	0.57
14- 2x SCC	8,718	4,544	0.127	0.174	0.110	0.152	40	85	147	0.53
15- Colstrip Exit 2025	8,725	4,555	0.127	0.173	0.110	0.153	40	87	150	0.54
16- Colstrip Exit 2035	8,734	4,558	0.127	0.174	0.108	0.153	34	85	148	0.53
17- Colstrip Exit 2045	8,729	4,567	0.127	0.173	0.108	0.154	34	72	127	0.89
18- Clean Energy Delivered Each Hour	9,162	4,567	0.127	0.207	0.110	0.155	40	115	162	0.50
19- SCC on Net P/S	8,726	4,561	0.126	0.174	0.110	0.153	40	84	148	0.54
20- Use Avg Mrkt for EE SCC	8,671	4,543	0.126	0.172	0.108	0.153	40	88	154	0.54

Reoptimized Portfolios with Market Changes

- Studies how PRS would change given fundamental shift in energy planning future.
- Stochastics are not modeled
  - 1a: Climate Shift
  - 1b: SCC Tax

Deterministic Scenario	WA- PVRR ($ Mill)	ID-PVRR ($ Mill)	WA 2030 Rate ($/kWh)	WA 2045 Rate ($/kWh)	ID 2030 Rate ($/kWh)	ID 2045 Rate ($/kWh)	2045 GHG Emissions (MT)
1- Preferred Resource Strategy	8,690	4,545	0.126	0.173	0.110	0.153	0.40
1a- LCP w/ Climate Shift	8,597	4,498	0.125	0.171	0.109	0.149	0.35
1b- LCP w/ SCC	8,854	4,766	0.128	0.168	0.119	0.159	0.23

Sensitivity Comparative Analysis

	Change in PVRR vs Expected Case			Change in Levelized GHG MT vs Expected Case		
Portfolio	High NG Prices	Low NG Prices	SCC	High NG Prices	Low NG Prices	SCC
1- Preferred Resource Strategy	6.1%	-2.1%	5.5%	-18%	16%	-18%
3- Baseline 2	8.8%	-3.0%	11.5%	-18%	17%	-18%
5- Clean Resource Plan (2027)	3.6%	-1.3%	-0.1%	-18%	16%	-18%
6- Clean Resource Plan (2045)	2.6%	-0.9%	0.0%	-12%	6%	-25%
15- Colstrip Exit 2025	5.7%	-2.0%	5.7%	-14%	11%	-23%
16- Colstrip Exit 2035	5.2%	-1.8%	6.6%	-11%	5%	-30%
17- Colstrip Exit 2045	4.8%	-1.7%	7.3%	-10%	3%	-31%

	Change in PVRR vs PRS			Change in Levelized GHG MT vs PRS		
Portfolio	High NG Prices	Low NG Prices	SCC	High NG Prices	Low NG Prices	SCC
3- Baseline 2	1%	-3%	4%	1%	1%	1%
5- Clean Resource Plan (2027)	1%	5%	-2%	-1%	-2%	-1%
6- Clean Resource Plan (2045)	2%	7%	0%	33%	13%	13%
15- Colstrip Exit 2025	0%	0%	0%	23%	13%	11%
16- Colstrip Exit 2035	0%	1%	1%	59%	32%	25%
17- Colstrip Exit 2045	-1%	1%	2%	75%	41%	34%

2021 Electric IRP TAC 4.5 Meeting Notes, December 16, 2020

Shawn Bonfield, Lori Hermanson, Kein Keyt, Mike Morrison, Morgan Brummund, Dean Sprattt, Amanda Ghering, Grant Forsyth, Clint Kalich, James McDougall, Jason Thackston, Scott Kinney, Logan Callen, Corey Dahl, Dainee Gibson-Webb, Fred Heutte, Jared Hansen, Ian McGetrick, John Chatburn, Jorgen Rasmussen, Katie Ware, Michael Eldred, Mike Morrison, Rachelle Farnsworth, Shay Bauman, Jennifer SnyderShelly McNeilly, Ricky Davis, Marrisa Warren, Joni Bosh, and Katie Pagan.

Notes in *italics* are the short resonses from the presenter.

Mike Morrison via chat: Please explain how Cumulative Energy Efficiency is determined. (The Cumulative Part.)

James Gall: It is the total amount acquired to date of the prorata period.

Mike Morrison: What about retirements?

James Gall: The AEG forecast includes those retirements, so it's included this in. Energy efficiency trails off at the end of 2045 due to this.

Mike Morrison: What would be relevant are the cumulative amounts of what's still in place [for energy efficiency].

James Gall: I think that's what is included here, but we should confirm with AEG.

Mike Morrison: What about capacity savings?

James Gall: Coming up.

Mike Morrison: Were the planning margin forecasts computed assuming increased renewable use?

James Gall: Two ways to address that issue. Can either increase your planning margin or decrease the peak credit on renewables. We chose to decrease the renewable peak credit.

Fred Huette: On DR, can you speak to water heaters, heat pumps, etc., and what it looks like in terms of cost effectiveness?

James Gall: I was surprised that one wasn't picked up. I would imagine that when we do our plan in 4 years, it'll probably get selected. I think it was on the margin for this IRP.

Fred Heutte: We will be recommending to move on this anyway.

Jennifer Snyder: A pilot CTA – 2045 program would likely make sense in the CEIP.
Yes.

Fred Heutte: You may already know this, but today in the Spokesman was a great headline regarding Rattlesnake Flat Wind going online – congratulations.

James Gall: Thank you!

Mike Morrison: A couple of slides ago, planning margin reserves and regulation for new renewable resources. Can you walk through the Montana wind and what it was before and after you derate it?

James Gall: For 35% capacity credit at 200 MW, there is 70 MW of reliable energy. We exchange a gas CT for wind and then determine at what level we reach the LOLP of 5%. We then compare that amount of wind with the gas CT to get to the 5% LOLP. We had to discount wind by 35% to get to the same capacity. It declines as you get more wind.

Mike Morrison: What about diversity of wind farms located all over?

James Gall: In Montana there is a large probablity of wind when it's cold in Spokane, unlike northwest wind. Adding more wind decreases the capacity peak credit. Wind diversity helps with regulation, but there is still a capacity issue.

Mike Morrison: Your critical need seems to be in the winter. Why are you focusing on winter?

James Gall: Sometimes those events aren't Avista-driven. There was one summer event in 2004. Winter is really our concern.

Mike Morrison: I think your IRP mentions others. Summer curtailments – you've had three events in the summer.

Fred Heutte: Montana wind capacity factor is 35-40%, but you're using ELCC to arrive at 35% peak capacity credit under stress conditions, is that correct? *Yes.* It's a big state and that doesn't seem out of range. Have you considered matching wind with storage?

James Gall: We have not modeled matching wind with storage together, even though we have modeled them separately. We have modeled solar plus storage. In our last renewable RFP, we only had one combined solar plus storage proposal so we may look at this for the next IRP. It may be more reduction or integration cost, we will look at this in the next IRP.

Fred Heutte: You're mostly hydro so you have more flexibility versus a stand alone resource and some opportunities.

James Gall: Potentially

Fred Heutte: Clean energy premium would be added to the first three columns for Washington?

James Gall: Yes, for example a new flat PPA would get both the clean energy premium and a capacity premium based on the profile of the resource.

Fred Heutte: What will happen with the off-peak and on-peak price flips?

James Gall: With all of the new solar in California and across the west, this causes the prices to flip during the day with the result being no market to sell into during our daytime peak. We have a super-peak price too in the evening peak.

Fred Heutte: On slide 15, in 2027 you have a CT for Washington and Idaho. How is this one allocated to the states?

James Gall: It could be either. We tried to illustrate the driver for the resource need.

Jennifer Snyder: Baseline portfolio 2, you ran it four times.

James Gall: We used that scenario with different market variables to show how that portfolio would do in a high or low gas price market, etc. This helps us understand the limitations of that portfolio in different market futures.

Fred Heutte: What is the purpose of portfolio 18?

James Gall: If the commisssion decides by 2030 for clean energy needing to be delivered to load by hour. This case was done to determine our best guess of how to do that. It shows the cost impacts of that change from matching generation to load by the hour.

Fred Heutte: Our understanding is it is not hour by hour, but it is interesting to look at.

Jennifer Snyder: What is the cost difference in Washington based on differing exit dates for Colstrip from 2022 to 2025?

James Gall: Because we have a shared system, the resource choices Idaho makes may impact Washington. Idaho may be long and may decide not to participate in some of the resources. That is why the costs could be lower or higher in Washington. It depends on if they stand alone on a resource choice versus splitting the costs with Idaho customers.

Fred Heutte: What are the minimum machine requirements to run PRiSM?

James Gall: There are not any machine minimums, but software requirements. Must have a license and a modern machine with 4-8 gigs of RAM to probably solve in about 8 hours. Could get that down to minutes or to an hour with a better machine.

Fred Heutte: That gives a sense of the feasability so thanks for doing this.

Fred Heutte: I would like to try a scenario with a lot of batteries, DR, etc. and see what it takes to max out the system. Run one scenario with high performance, flexible and clean resources.

Mike Morrison: Could you explain ARAM?

James Gall: After the Janaury 4, 2021 filing we could schedule a one hour meeting to go through that.

2021 Electric Integrated Resource Plan

Technical Advisory Committee Meeting No. 5 Agenda

Thursday, January 21, 2021
Virtual Meeting

Topic	Time	Staff
Introductions	9:00	Lyons
Review Draft 2021 IRP	9:15	Lyons
Draft Resource Plans and Scenarios	9:45	Gall
2021 IRP Action Items	10:45	Lyons
Lunch	11:30	
ARAM Model Overview	12:30	Gall
Break	1:30	
Clean Energy Implementation Plan and Clean Energy Action Plan Discussion	1:45	Gall/Lyons
Draft IRP Comments from TAC	2:15	
Adjourn	3:30	

→ Join Skype Meeting

Trouble Joining? Try Skype Web App

Join by phone

509-495-7222 (Spokane) English (United States)

Find a local number

Conference ID: 67816

Forgot your dial-in PIN? | Help

2021 Electric IRP
TAC Introductions and IRP Process Updates

John Lyons, Ph.D.
Fifth Technical Advisory Committee Meeting
January 21, 2021

Updated TAC Meeting Guidelines

- IRP team working remotely through the rest of this IRP, but still available by email and phone for questions and comments
- Some processes are taking longer remotely
- Virtual IRP meetings until able to hold large group meetings again
- Joint Avista IRP page for gas and electric: https://www.myavista.com/about-us/integrated-resource-planning
  - TAC presentations
  - Documentation for IRP work
  - Past IRPs

Virtual TAC Meeting Reminders

- Please mute mics unless speaking or asking a question
- Use the Skype chat box to write questions or comments or let us know you would like to say something
- Respect the pause
- Please try not to speak over the presenter or a speaker who is voicing a question or thought
- Remember to state your name before speaking for the note taker
- This is a public advisory meeting – presentations and comments will be recorded and documented

Integrated Resource Planning

- Required by Idaho and Washington* every other year
- Guides resource strategy over the next twenty + years
- Current and projected load & resource position
- Resource strategies under different future policies
  - Resource choices
  - Conservation measures and programs
  - Transmission and distribution integration for electric
  - Gas and electric market price forecasts
- Scenarios for uncertain future events and issues
- Key dates for modeling and IRP development are available in the Work Plans

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 involved in all or parts of the process
  - Ask questions
  - Help with soliciting new members
- Open forum while balancing need to get through all of the topics
- Welcome requests for studies or different assumptions.
  - **August 1, 2020** was the electric study request deadline for the 2021 IRP, new requests will be taken up in the 2023 IRP
- Planning team is available by email or phone for questions or comments outside of TAC meetings

2021 Electric IRP TAC Schedule

- TAC 1: Thursday, June 18, 2020
- TAC 2: Thursday, August 6, 2020 (Joint with Natural Gas TAC)
- TAC 2.5: Tuesday, August 18, 2020 Economic and Load Forecast
- TAC 3: Tuesday, September 29, 2020
- TAC 4: Tuesday, November 17, 2020
- TAC 4.5: Wednesday, December 16, 2020 – PRS & Scenarios
- **TAC 5: Thursday, January 21, 2021**
- Public Outreach Meeting: February 2021 (Do we still need this?)
- WUTC Public IRP Open Meeting: February 23, 2021
- TAC agendas, presentations, meeting minutes and IRP files available at:

  https://myavista.com/about-us/integrated-resource-planning

IRP Documentation Available

- Draft 2021 IRP
- Avista Resource Emissions Summary
- Load Forecast
- CPA Measures
- Avista 2020 Electric CPA – Summary and IRP Inputs
- Home Electrification Conversions
- Named Populations
- Natural Gas Prices
- Social Cost of Carbon
- High and Low Natural Gas Prices
- Market Modeling Results
- Climate Shift Scenario Inputs
- 2021 IRP New Resource Options
- 1 – Preferred Resource Strategy
- 2 – Baseline 1 No CETA Renewable Targets
- 3 – Baseline 2 No CETA Renewable Targets/SCC
- 4 – Baseline Portfolio 3 No Additions
- 5 – Clean Resource Plan (2027)
- 6 – Clean Resource Plan (2045)
- 7 – Social Cost of Carbon Idaho
- 8 & 9 – High and Low Load Forecasts
- 10 – RA Program
- 11 – 13 – Electrification 1, 2 & 3
- 14 – 2x SCC
- 15 – Colstrip Serves Idaho through 2025
- 16 – Colstrip Serves Idaho through 2035
- 17 – Colstrip Serves Idaho through 2045
- 18 – Clean Energy Delivery by Hour
- 19 – SCC on Net Power Supply
- 20 – Use Average Market for EE & SCC
- PRiSM Draft Results (12/7/20)

Process Updates

- January 4, 2021 – draft IRP released to TAC
- February 23, 2021 – WUTC hearing about draft IRP
  - Discussion about need for another public outreach meeting
- March 1, 2021 – Comments from TAC on draft IRP due
- March 2021 – final IRP editing, printing and compilation of Appendices
  - Inclusion of 2020 Renewable RFP results?
- April 1, 2021 – publication and submission of the 2021 Electric IRP with the Idaho and Washington Commissions
  - IRP and appendices will also be available on the Avista web site
- Commissions will schedule hearings and accept comments about 2021 IRP

Today’s TAC Agenda

9:00	Introductions, Lyons
9:15	Review Draft 2021 IRP, Lyons
9:45	Draft Resource Plans and Scenarios, Gall
10:45	2021 IRP Action Items, Lyons
11:30	Lunch
12:30	ARAM Model Overview, Gall
1:30	Break
1:45	Clean Energy Implementation Plan and Clean Energy Action Plan Discussion, Gall and Lyons
2:15	Draft IRP Comments from TAC
3:30	Adjourn

2021 Electric IRP Document Overview

John Lyons, Ph.D.
Fifth Technical Advisory Committee Meeting
January 21, 2021

2021 Electric IRP Chapters

1. Executive Summary
2. Introduction, IRP Requirements, and Stakeholder Involvement
3. Economic and Load Forecast
4. Existing Supply Resources
5. Energy Efficiency
6. Demand Response
7. Long-Term Position
8. Transmission & Distribution Planning
9. Supply-Side Resource Options
10. Market Analysis
11. Preferred Resource Strategy
12. Portfolio Scenarios
13. Energy Equity
14. Action Plan
15. Clean Energy Action Plan

2021 Electric IRP Chapters 1 – 3

- Chapter 1: Executive Summary
  - High level summary of 2021 IRP and PRS
- Chapter 2: Introduction, IRP Requirements, Stakeholder Involvement
  - TAC overview and rules guiding IRP development
  - Major changes from the 2017 and 2020 IRPs
- Chapter 3: Economic and Load Forecast
  - Economic conditions in Avista’s service territory
  - Avista’s energy and peak forecasts
  - Load forecast scenarios

2021 Electric IRP Chapters Ch. 4 – 6

- Chapter 4: Existing Supply Resources
  - Avista's resources
  - Contractual resources and obligations
  - Avista's natural gas pipeline rights overview

- Chapter 5: Energy Efficiency
  - Conservation Potential Assessment
  - Energy efficiency modeling and selection

- Chapter 6: Demand Response
  - Demand response potential study
  - Overview of past demand response pilot programs

2021 Electric IRP Chapters Ch. 7 – 8

- Chapter 7: Long-Term Position
  - Reliability adequacy and reserve margins
  - Resource requirements
  - Reserves and flexibility requirements

- Chapter 8: Transmission and Distribution Planning
  - Overview of Avista's Transmission System
  - Future Upgrades and Interconnections
  - Transmission Construction Costs and Integration
  - Merchant Transmission Plan
  - Overview of Avista's Distribution System
  - Future Upgrades and Interconnections (includes project evaluated with DER alternative)

2021 Electric IRP Chapters Ch. 9 – 10

- Chapter 9: Generation and Storage Resource Options
  - New resource option costs and operating characteristics
  - Potential Avista plant upgrades

- Chapter 10: Market Analysis
  - Fuel price forecasts
  - Regional resource additions
  - Regional greenhouse gas emissions forecast
  - Market price forecast
  - Scenario analysis

2021 Electric IRP Chapters Ch. 11 – 13

- Chapter 11: Preferred Resource Strategy
  - Resource Selection Process
  - Preferred Resource Strategy
  - Avoided cost

- Chapter 12: Portfolio Scenarios
  - Portfolio Scenarios
  - Portfolio cost, risk and environmental comparisons

- Chapter 13: Energy Equity
  - Vulnerable populations
  - Highly impacted communities
  - Equity Advisory Group

2021 Electric IRP Chapters Ch. 14 – 15

- Chapter 14: Action Plan
  - Progress made on Action Items from the 2017 and 2020 IRPs
  - IRP projects identified for the 2023 IRP
- Chapter 15: Clean Energy Action Plan
  - Action items for CETA compliance between this and the 2023 IRPs

2021 Electric Integrated Resource Plan Overview

James Gall, Electric IRP Manager
Fifth Technical Advisory Meeting, 2021 IRP
January 21, 2021

Planning Environment

- 65% of load
- 2030/2045 clean energy mandate
- Eliminate coal generation by 2025
- Greenhouse gas emission penalties
- Electrification push
- Climate change considerations
- Energy Equity
- Distributed energy resource planning

Risk

Environment

Cost

Reliability

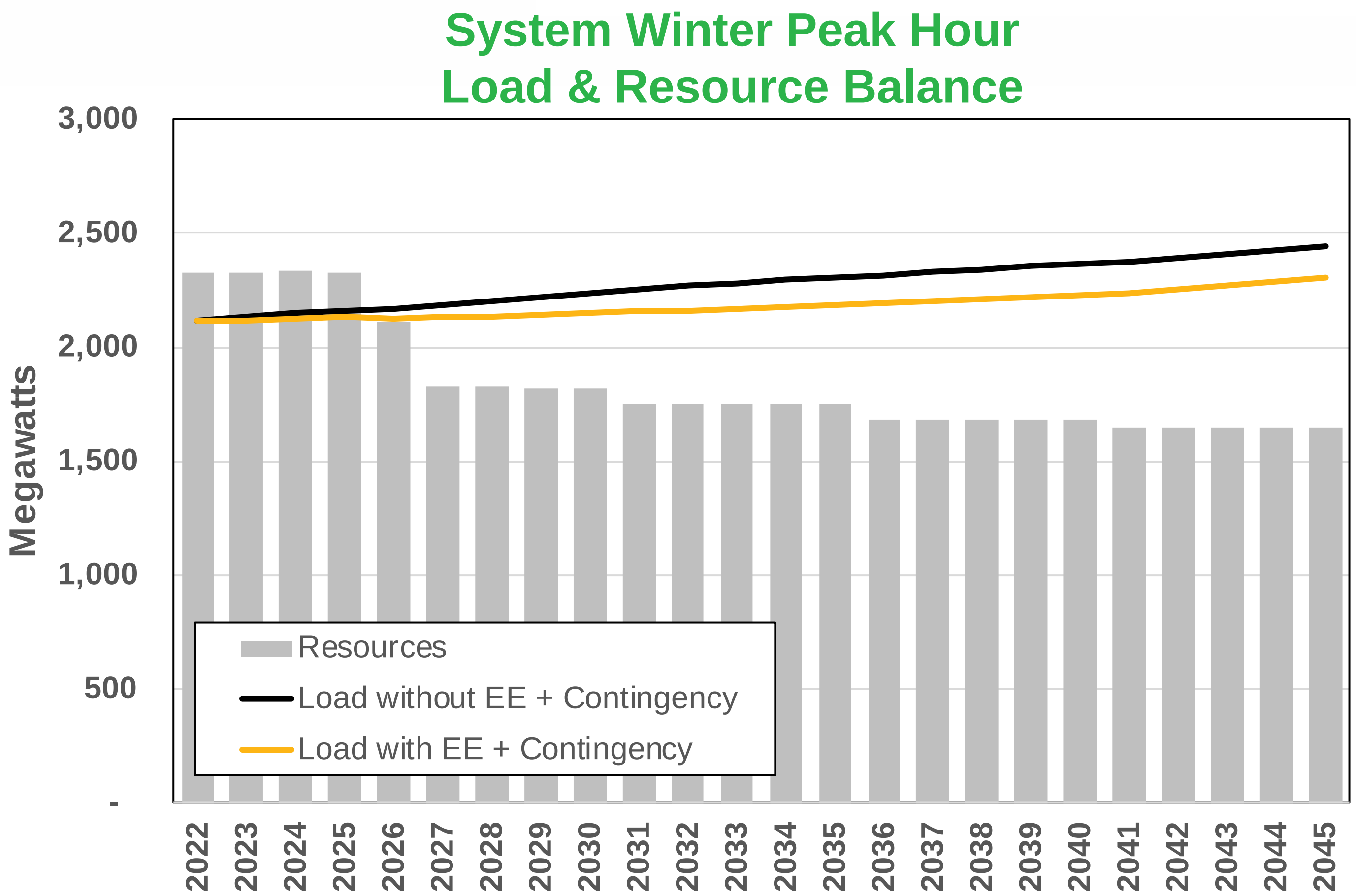
Rates

- Market effects
- State policy on Avista's resources

- 35% of load
- Least cost planning
- Cost allocation

Avista Reliability Needs

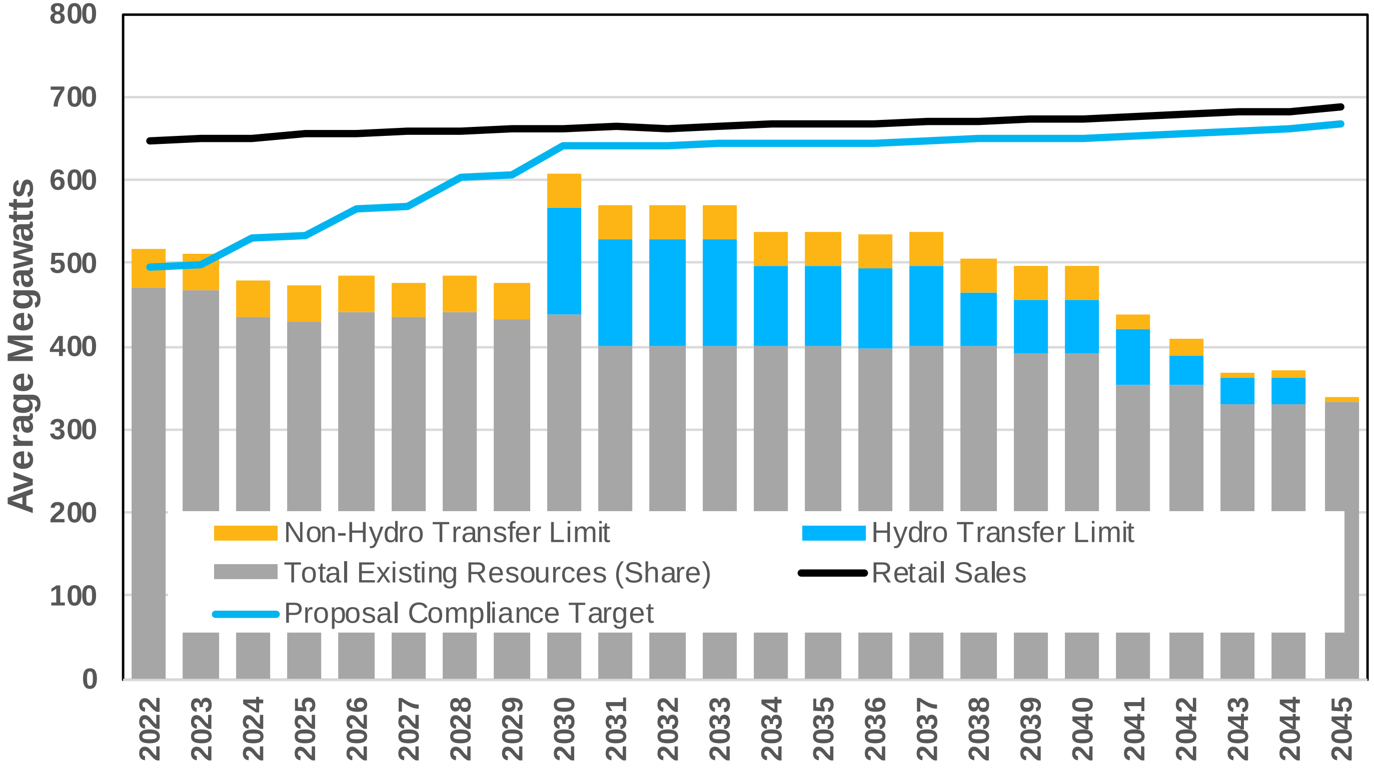
- Meet average coldest day’s peak hour load, required reserves, and a 16% planning margin.
  - Maintain 5 percent Loss of Load Probability.
  - Regional effort to “pool” resources by creating resource adequacy market may lower resource need.
- ~300 MW needed Nov-2026 (expiration of Lancaster PPA)
  - Additional 200 MW by 2036
- Aging Infrastructure & state policy pressuring existing resources to close:
  - Colstrip: 2025 (WA)
  - Northeast CT: 2035
  - Boulder Park: 2040
  - Coyote Springs 2 CCCT/Rathdrum CTs ???
- Load growth & changes
  - 0.3% annual average growth.
  - Large potential increases with electrification.
  - Climate change might lower winter and increase summer peak growth. (required study in next IRP)



Washington Clean Energy Requirements

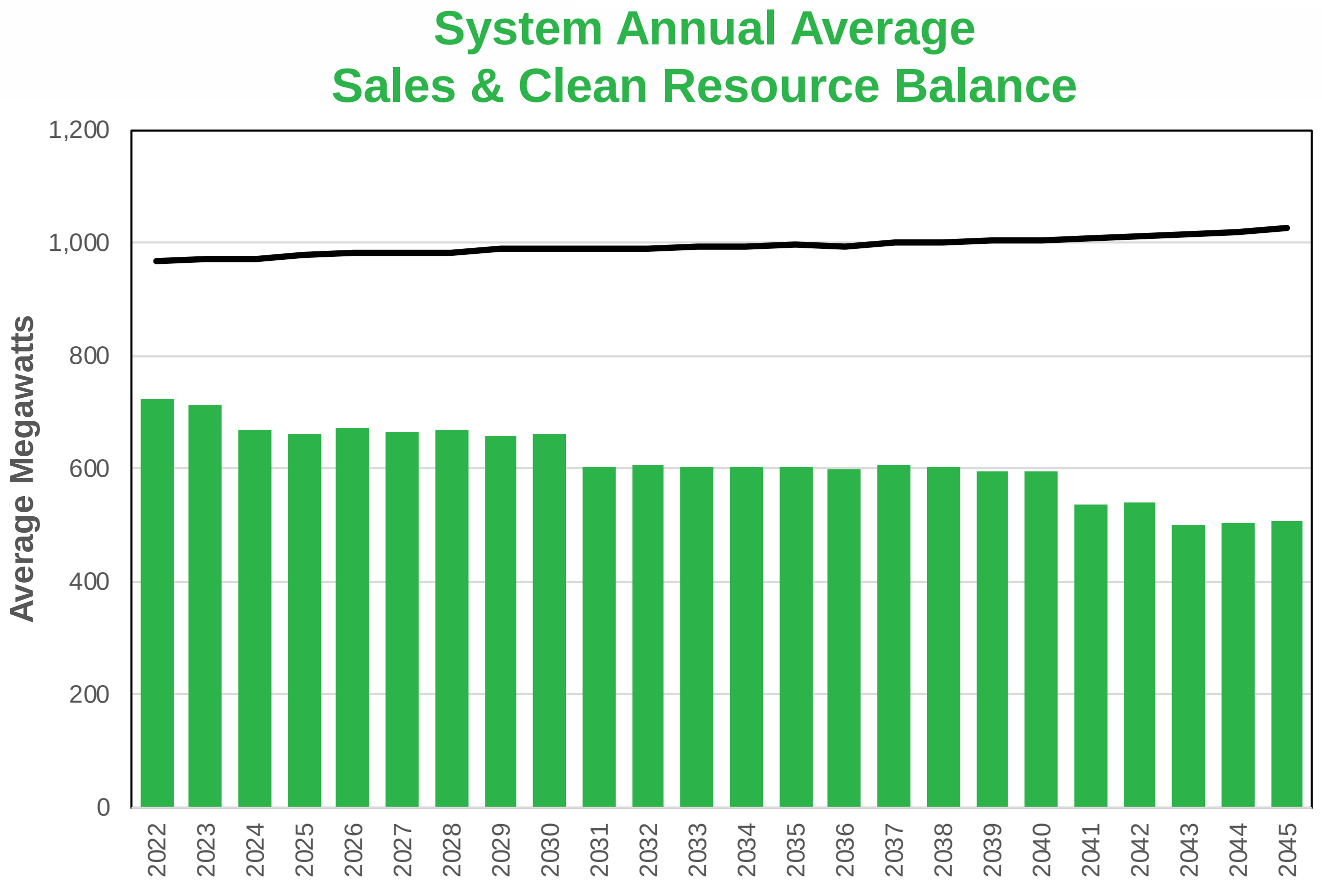
- Avista must create glidepath to 2030 clean energy requirements.
- By 2030, 100% of “net” Washington retail sales must “use” clean energy.
  - 20% can be met with unbundled RECs.
  - might require real-time clean energy delivery.
- Resource Allocation
  - Washington customers “buy” Idaho clean energy share.
    - Assumes Idaho’s wind/biomass may be sold to WA without limitation.
    - Assumes Idaho’s hydro purchases limited to 20% of sales beginning in 2030, then declining.
- By 2045, 100% of Washington sales must be served with clean energy.
  - May require real-time clean energy delivery.

Washington Retail Sales & Clean Resource Balance



Avista's Clean Energy Targets

- In 2022, Avista generates clean energy equal to 75% of retail sales.
- To meet 100% clean energy by 2027, Avista must acquire ~320 aMW.
  - 800-1,000 MW of wind or 1,800 MW solar (DC).
- Increases to over 510 aMW by 2045.
  - Driven by load growth and expiring contracts
- Avista goal is 100% real-time clean energy delivery by 2045.
  - Requires substantial investments in energy storage to meet winter loads.
  - Electrification of space & water heating compound these issues.



Resource Options

- Multiple factors drive resource selection
  - Cost or price
  - Clean vs. fossil fuel
  - Capacity value or “peak credit”
  - Storage vs. energy production
  - Location
  - Availability (new vs. existing)
- Resource retirements
  - Future capital investment
  - Operating & maintenance cost/availability
  - Fuel availability
  - Carbon pricing risk

Clean Resources

Wind
Solar
Biomass
Hydro
Geothermal
Nuclear

Fossil Fuel Resources

Natural gas peaker
Natural gas baseload
Coal (retention)
Customer generation

Demand Resources

Energy efficiency
Conservation
Load control
Rate programs
Fuel switching
Co-generation

Storage

Pumped hydro
Lithium-ion batteries
Liquid air energy storage
Flow batteries
Hydrogen

Resources in italics were not directly modeled for this IRP

IRP's Preferred Resource Strategy - Supply Resources

- IRP focuses on state goals and system reliability to find lowest reasonable cost to serve customer load.
- Develop resource needs assessment for each state.
  - State policies drive resource choices.
  - Cost allocation based on state policies.
  - Rate forecasts.
- Does not include resources in current RFP.
- Limits existing resources acquisition to 75 MW of additional regional hydro after 2031.
- Resources are selected either as system resource (65%/35%) or state resource.
- Resources economically or contractually expected to leave the Avista resource mix are in green, natural gas-fired are in orange, energy storage are in blue and clean resources are in black.

Supply-Side Resource Changes

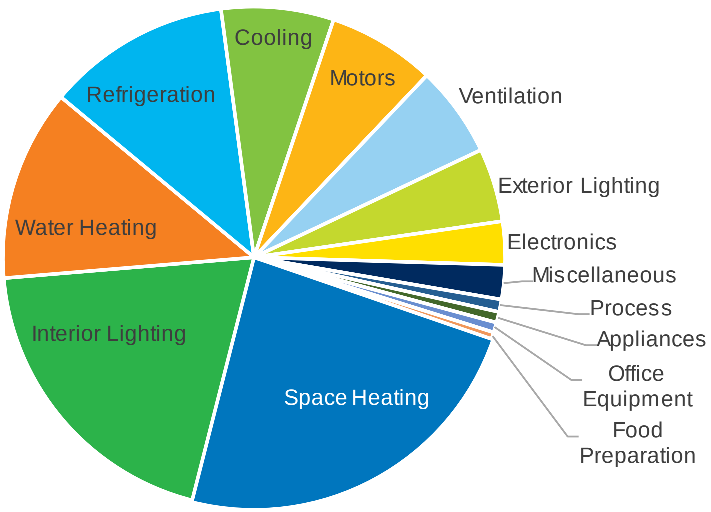
Resource Type	Year	State	Capability (MW)
Colstrip	2021	System	(222)
Montana wind	2023	WA	100
Montana wind	2024	WA	100
Lancaster	2026	System	(257)
Kettle Falls upgrade	2026	System	12
Natural gas peaker	2027	ID	85
Natural gas peaker	2027	System	126
Montana wind	2028	WA	100
NW Hydro Slice	2031	WA	75
Rathdrum CT upgrade	2035	System	5
Northeast	2035	System	(54)
Natural gas peaker	2036	System	87
Solar w/ storage	2038	System	100
4-hr storage for solar	2038	System	50
Boulder Park	2040	System	(25)
Natural gas peaker	2041	ID	36
Montana wind	2041	WA	100
Solar w/ storage	2042-2043	WA	239
4-hr storage for solar	2042-2043	WA	119
Liquid air energy storage	2044	WA	12
Liquid air energy storage	2045	ID	10
Solar w/ storage	2045	WA	149
4-hr storage for solar	2045	WA	75
Supply-side resource net total (MW)			1,024
Supply-side resource total additions (MW)			1,581

IRP's Preferred Resource Strategy - Demand Resources

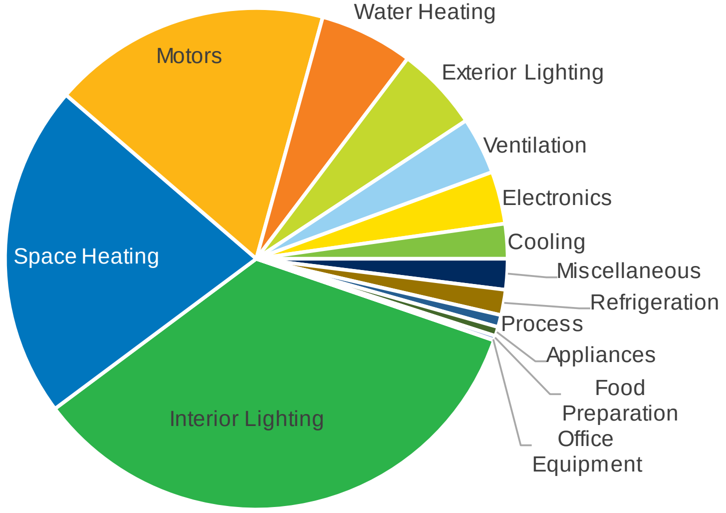
- 63% of EE programs are C&I.
- 77% of EE savings are from Washington.
- Washington avoided cost are $106/MWh plus $151/kW-year for capacity.
  - Driven by social cost of carbon and clean energy avoided costs.
- Idaho avoided cost are $30/MWh plus $137/kW-year for capacity.
- EE reduces winter peak by a 101% ratio to energy savings and 97% ratio for summer.
- Washington 2022-23 target is 89,000 MWh; 50% higher then previous biennium and higher than the IRP's two year cost effective acquisition amount.
- 10-year target is 651 GWh or 74 aMW.
- Time of use and variable peak pricing requires significant rate design effort leveraging metering infrastructure.
- Demand response has limited reliability benefits due to duration and call limitations.

Energy Efficiency End Use Targets

Washington



Idaho



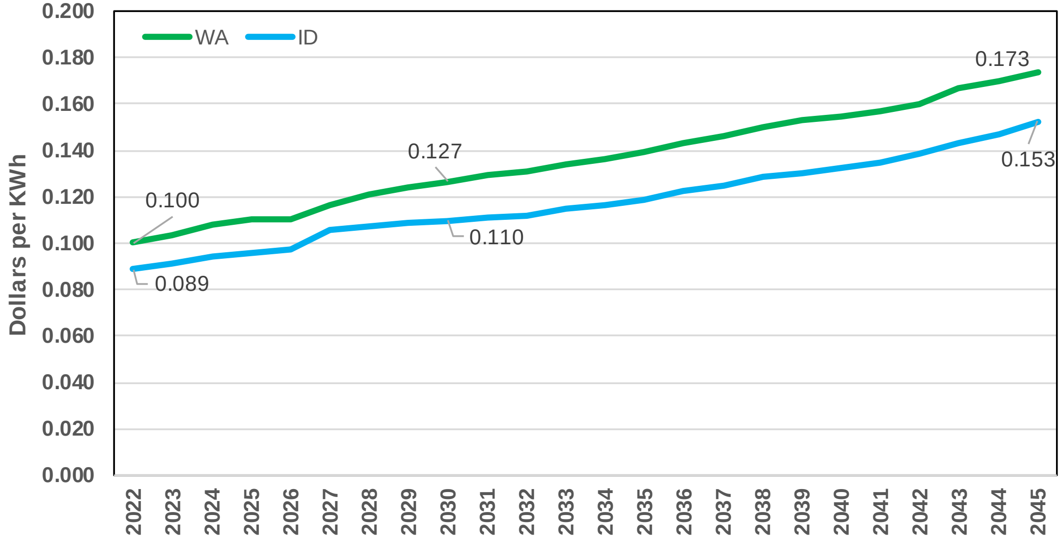
Demand Response

Program	Washington	Idaho
Time of Use Rates	2 MW (2024)	2 MW (2024)
Variable Peak Pricing	7 MW (2024)	6 MW (2024)
Large C&I Program	25 MW (2027)	n/a
DLC Smart Thermostats	7 MW (2031)	n/a
Third Party Contracts	14 MW (2032)	8 MW (2024)
Behavioral	1 MW (2041)	n/a
Total	**56 MW**	**15 MW**

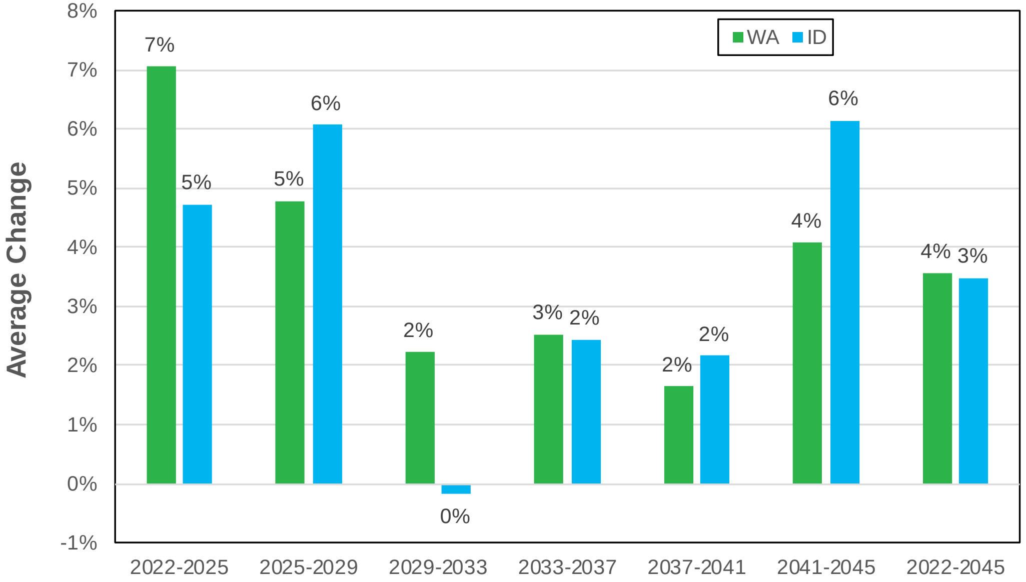
Preferred Resource Strategy Costs and Rates

- Existing and new costs are allocated between the states Avista serves.
- Washington rates are ~1 cent (12%) higher per kWh today.
  - Spread increases to 1.7 cents (15%) by 2030 and 2.0 cents by 2035.*
- Power costs rise well above inflation over first 8 years due to clean energy and capacity additions.

Overall Energy Rates



Power Cost Rate Change



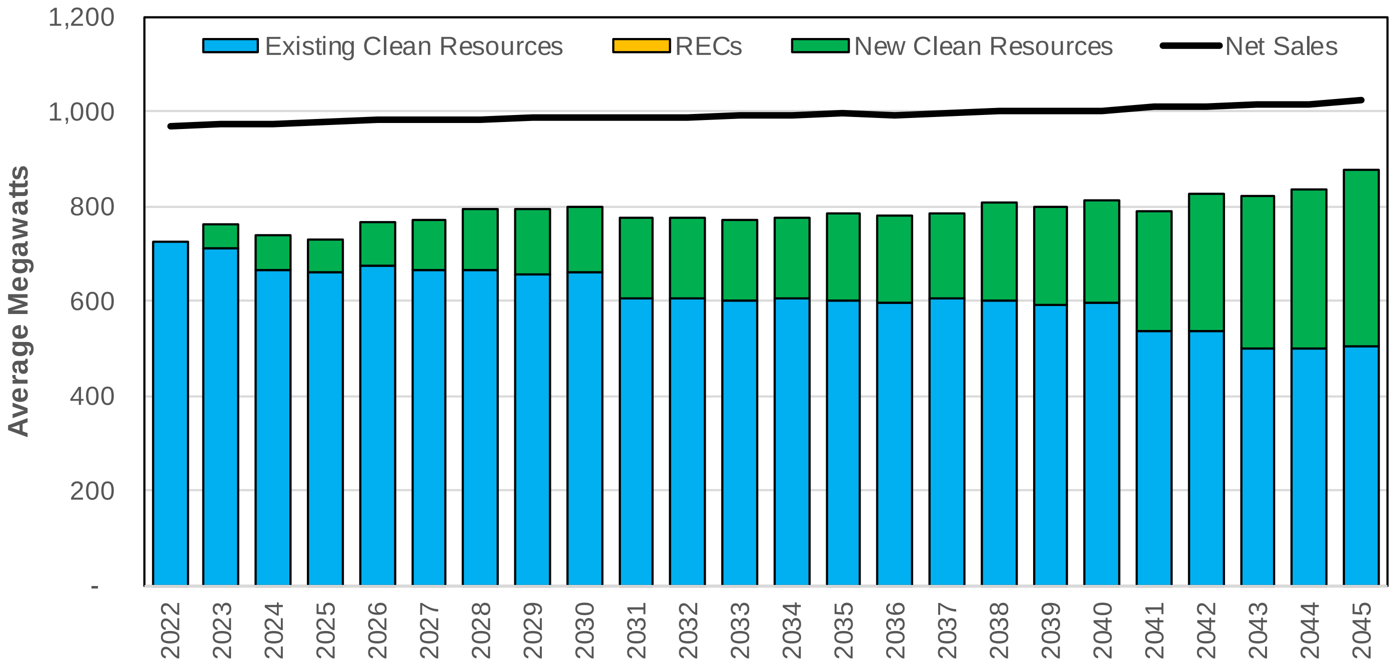
* Non-power related cost such as non-generation transmission, distribution, and administration, are not directly modeled in the IRP and assume a 2% annual growth rate.

DRAFT

Clean Energy Shares (aMW)

- By 2030, Washington customers will have clean energy equal to 100 percent of its retail sales.
- Idaho's clean energy share will lower both Idaho and Washington rates.
  - 46% clean by 2030 and 60% clean by 2045.
- Clean energy as percent of system sales increase to 78% by 2027 and 86% by 2045.
- Short-term clean energy purchase may increase these estimates.
- Avista could purchase RECs to meet 2027 goals.
- Idaho customers have opportunity to sell excess hydro RECs to reduce rates.

Clean Energy Forecast



Greenhouse Gas Emissions Forecast

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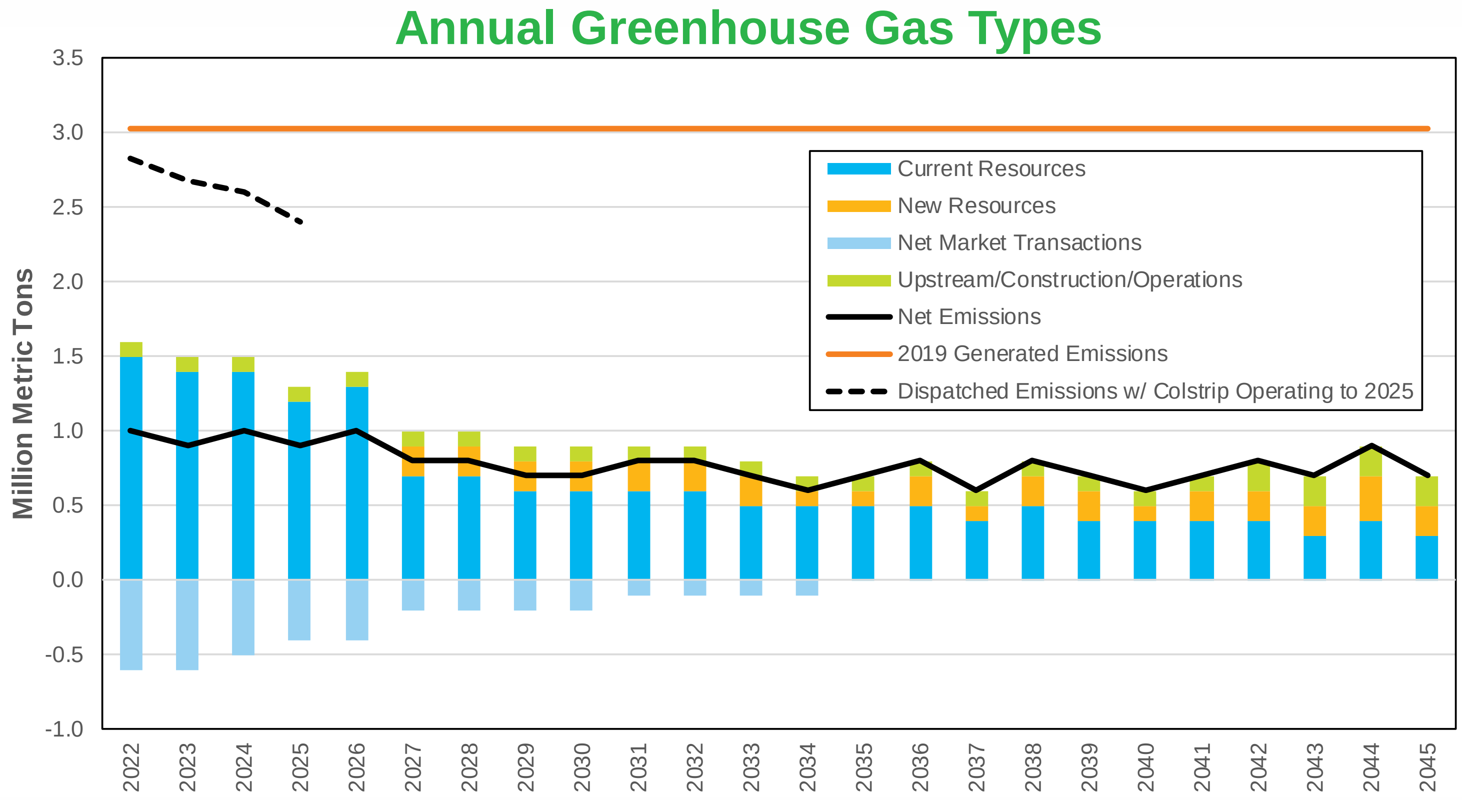
- 2020 emissions were ~2.7 million metric tons.
- Colstrip responsible for >1 million tons.
  - Colstrip emissions would fall regardless as the plant dispatch decreases over time.
- By 2030, emissions fall by 76 percent.
- Emissions from natural gas upstream operations and construction are included in this IRP.
  - Washington load portion includes these emissions priced at the social cost of carbon.
  - WUTC recently ruled these emissions accounting is encouraged but not required.
- Net emissions include market purchases and sales at the regional emission intensity rate.



IRP Insights given uncertainty

- WUTC's rulemaking regarding "use" of energy may require significant market transformation and require additional clean and storage resources.
- Electrification of Washington's space and water heat will significantly increase winter peak (up to ~700 MW) and annual energy (155 aMW) needs.
  - New winter load will require significant investment in winter capacity- such as natural gas turbines or long-duration storage.
  - Energy rates from power acquisition rise 8% excluding non-power costs such as T&D and home owner costs.
- Water heater load control may offer opportunities if program costs decline (55+ MW).
  - AC control is low cost option if summer peaks significantly increase.
  - Electric vehicle control is cost prohibitive now, but costs are falling.
- Hydrogen-fired turbines show potential to be lowest overall cost resource to serve winter loads in a 2045 100% clean energy future.
  - Liquid air energy storage (LAES) and pumped hydro are better nearer term options with intermediate energy duration options.
  - Lithium-ion is low cost when coupled with solar or need for short durations.
- A regional resource adequacy program is needed to address regional reliability risk and lower Avista's new resource needs and costs (<1%).
  - Resource mix could favor solar and hydro.
- Retaining Colstrip through 2025 increases cost by 1%.
  - Tradeoff is higher power cost risk with an early exit.
- Meeting the clean energy goals increases total cost by 5%.
  - Idaho rates are 10% higher in 2027/ 28% higher in 2045.
  - Washington rates are 4% higher in 2027/ 20% higher in 2045.
- Energy equity public engagement in Washington may lead to new programs, resources, or investments.
  - Equity budget requirements and limitations are unknown.
- Climate change (warmer temperatures) reduces power costs and resource needs
  - Hydro runoff better matches winter peaks and spill is less.
- Policy requirements with high carbon "taxes" support higher clean energy levels and conservation investments.

Highlights

From the Preferred Resource Strategy

- Avista needs new clean resources to comply with CETA.
- New capacity resources are required to maintain reliability.
- Avista will need to pursue demand response, rate design, and increase energy efficiency.
- Exiting Colstrip is economic, but higher risk.
- Long-duration storage is critical to meeting 100% clean energy objectives.

From Scenario Analysis

- Climate change lowers power costs.
- State/national policies will increase both rates and costs.
- Electrification will significantly increase power supply requirements. T&D and homeowner costs are not estimated at this time.
- Real-time clean energy delivery will be challenging for industry and current market structure.
- Meeting Avista's clean energy goals will be a challenging without new technology or increasing rates.

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Extra Slides

Tables & figures from Draft IRP of potential interest

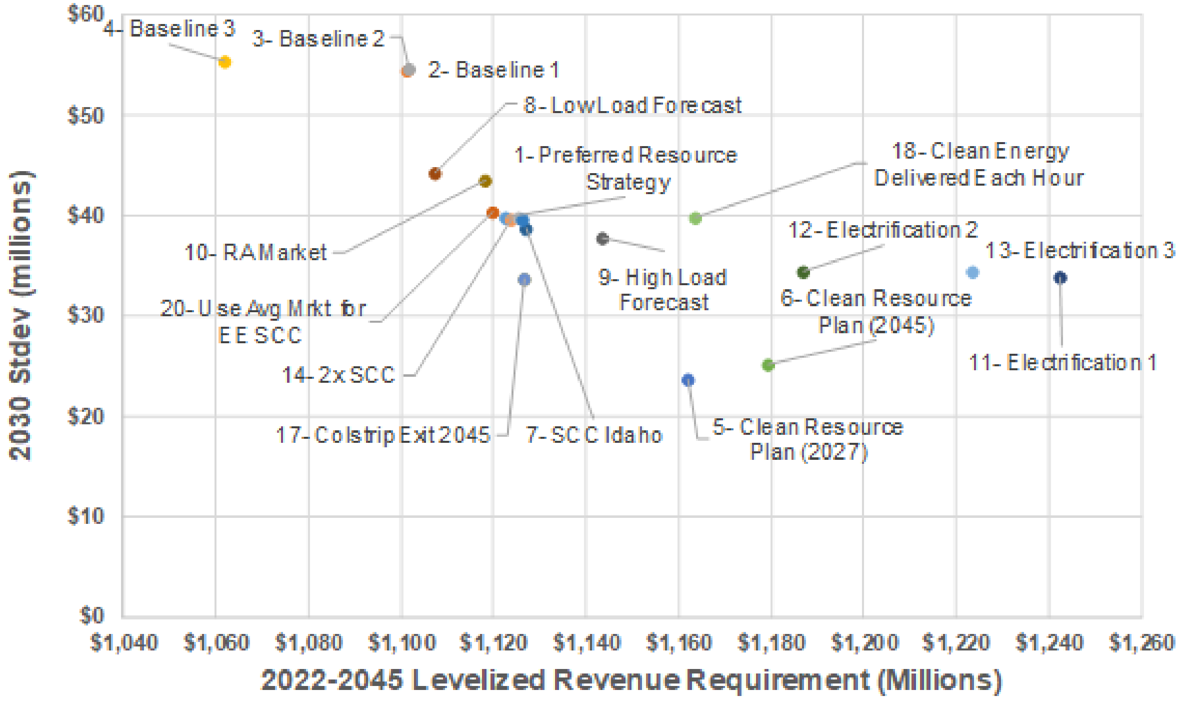
Scenario Analysis

Sorted by System PVRR (highest to lowest)

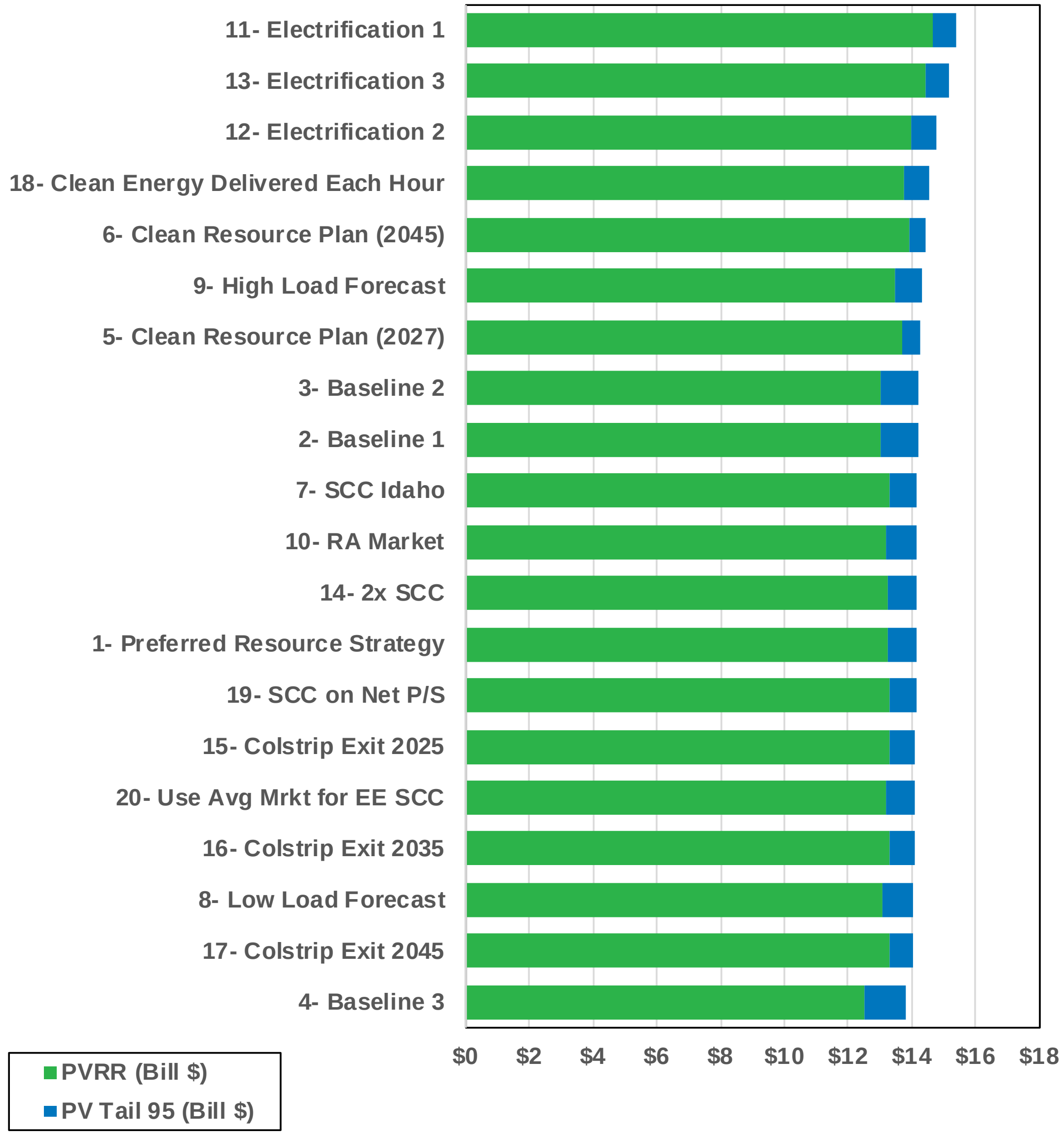
Scenario	System-PVRR ($ Bill)	WA-PVRR ($ Bill)	ID-PVRR ($ Bill)	WA 2030 Rate ($/kWh)	WA 2045 Rate ($/kWh)	ID 2030 Rate ($/kWh)	ID 2045 Rate ($/kWh)	2030 Stdev ($ Mill)	2045 Stdev ($ Mill)	2045 Tail Risk ($ Mill)	2045 GHG Emissions (MT)
11- Electrification 1	14.7	10.1	4.5	0.131	0.188	0.109	0.158	34	88	132	0.57
13- Electrification 3	14.4	9.9	4.5	0.128	0.181	0.109	0.158	34	85	129	0.57
12- Electrification 2	14.0	9.5	4.5	0.127	0.176	0.109	0.155	34	71	115	0.56
6- Clean Resource Plan (2045)	13.9	9.0	5.0	0.130	0.209	0.122	0.196	25	35	48	0.00
18- Clean Energy Delivered Each Hr	13.7	9.2	4.6	0.127	0.207	0.110	0.155	40	115	162	0.50
5- Clean Resource Plan (2027)	13.7	8.8	4.9	0.129	0.176	0.121	0.166	24	56	100	0.50
9- High Load Forecast	13.5	8.9	4.6	0.123	0.164	0.104	0.142	38	70	122	0.56
7- SCC Idaho	13.3	8.7	4.6	0.126	0.175	0.112	0.161	39	82	143	0.50
17- Colstrip Exit 2045	13.3	8.7	4.6	0.127	0.173	0.108	0.154	34	72	127	0.89
16- Colstrip Exit 2035	13.3	8.7	4.6	0.127	0.174	0.108	0.153	34	85	148	0.53
19- SCC on Net P/S	13.3	8.7	4.6	0.126	0.174	0.110	0.153	40	84	148	0.54
15- Colstrip Exit 2025	13.3	8.7	4.6	0.127	0.173	0.110	0.153	40	87	150	0.54
14- 2x SCC	13.3	8.7	4.5	0.127	0.174	0.110	0.152	40	85	147	0.53
1- Preferred Resource Strategy	13.2	8.7	4.5	0.127	0.173	0.110	0.153	40	87	150	0.54
20- Use Avg Mrkt for EE SCC	13.2	8.7	4.5	0.126	0.172	0.108	0.153	40	88	154	0.54
10- RA Market	13.2	8.7	4.5	0.126	0.174	0.109	0.152	43	94	171	0.50
8- Low Load Forecast	13.1	8.6	4.5	0.130	0.186	0.113	0.163	44	101	178	0.48
3- Baseline 2	13.0	8.4	4.6	0.121	0.168	0.110	0.151	55	148	253	0.56
2- Baseline 1	13.0	8.4	4.6	0.121	0.168	0.110	0.152	54	148	254	0.56
4- Baseline 3	12.5	8.1	4.4	0.117	0.158	0.106	0.141	55	162	276	0.33

Quantitative Risk

2030 Standard Deviation vs Levelized Revenue Requirement



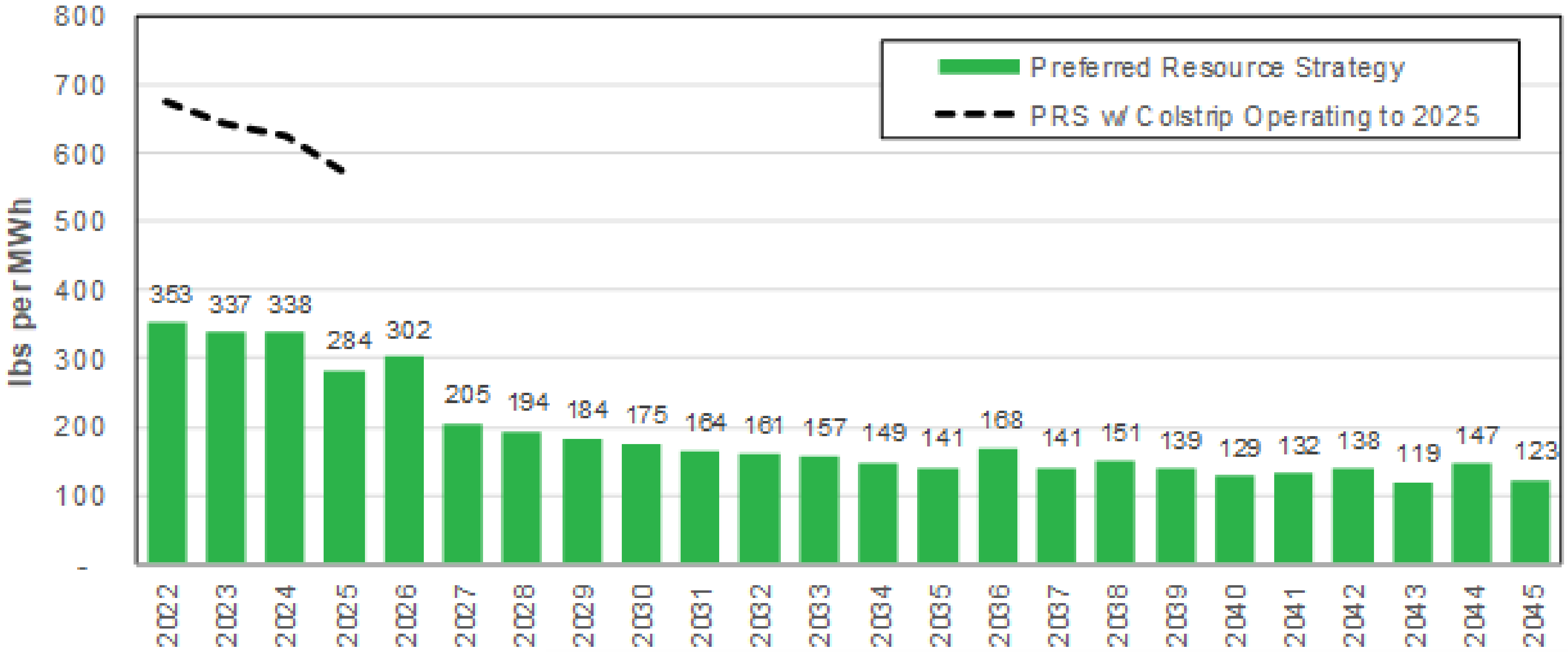
PVRR + PV TailVar95 Risk



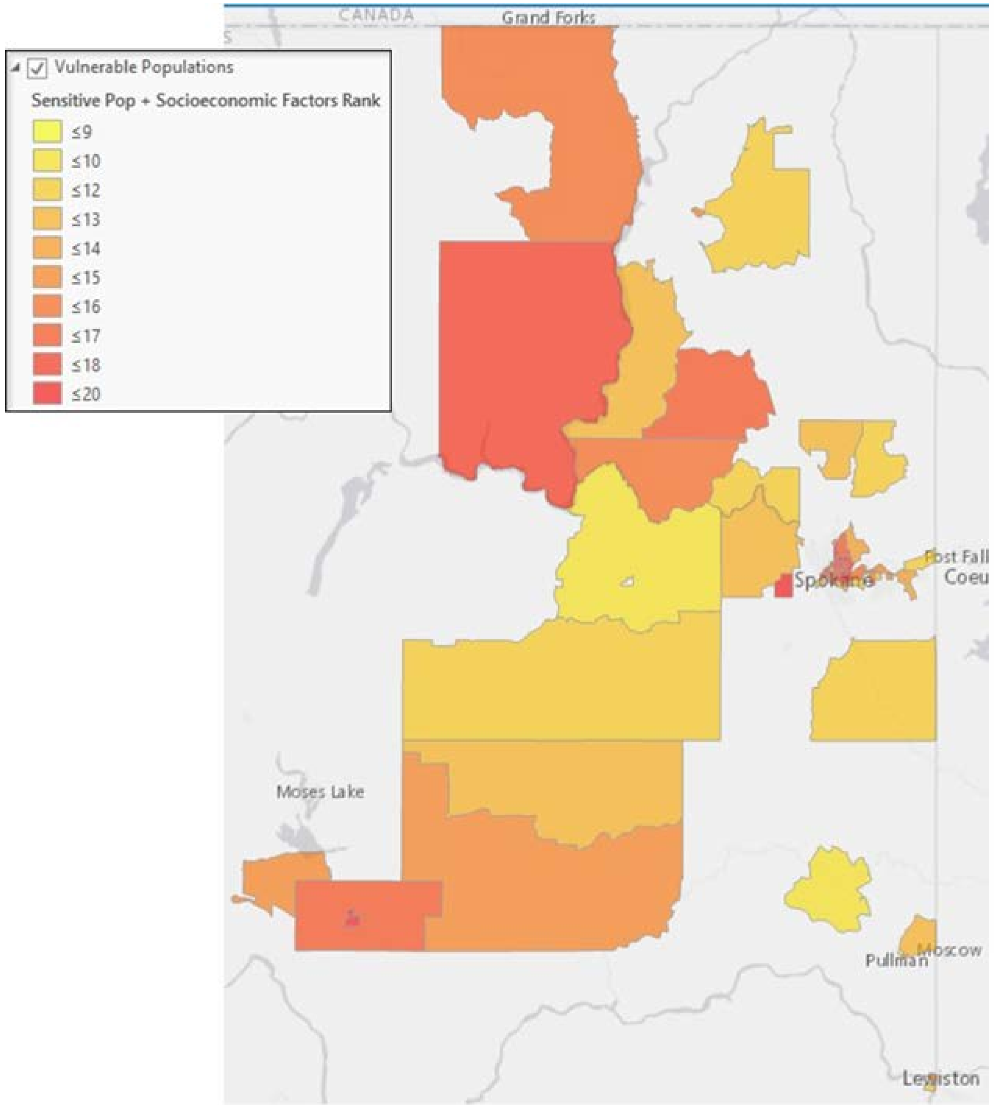
Avoided Costs

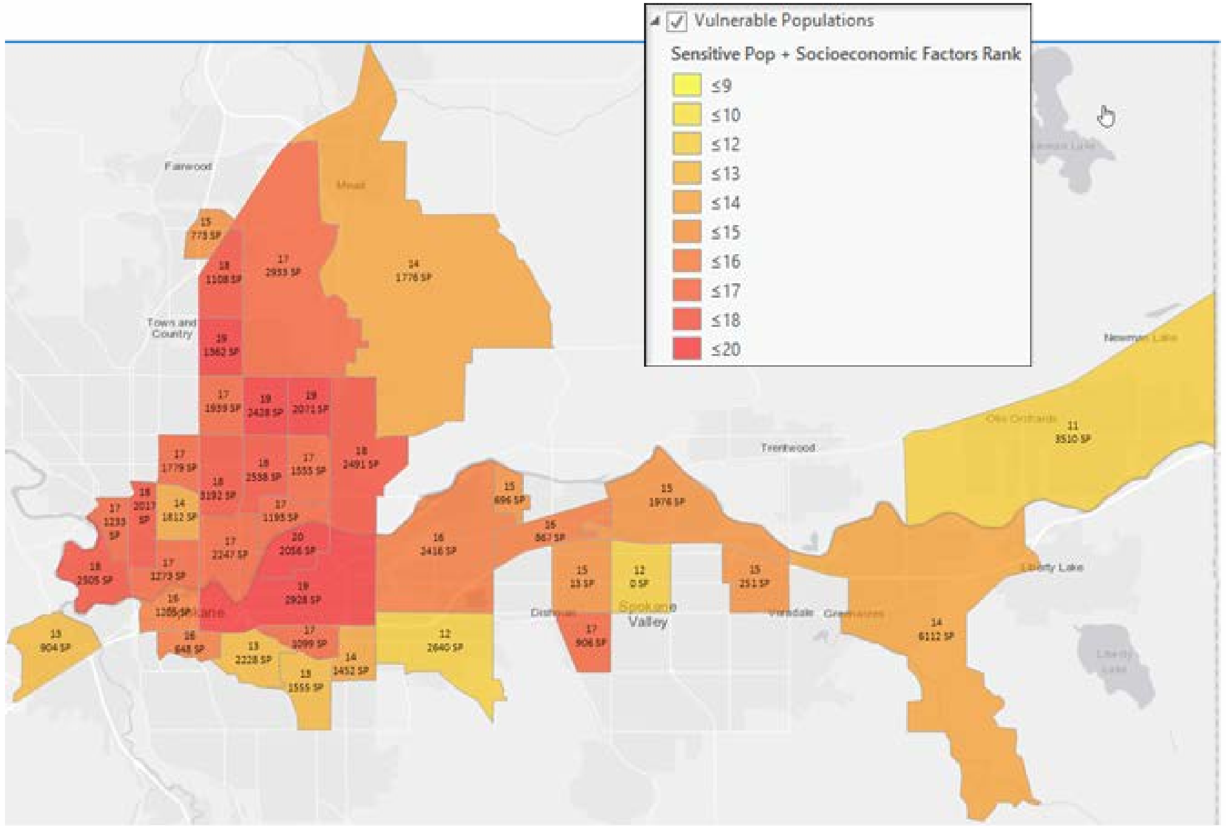
Year	Energy Flat (MWh)	Energy On-Peak (MWh)	Energy Off-Peak (MWh)	Clean Premium (MWh)	Capacity ($/kW-Yr)
2022	$20.37	$21.66	$18.65	$0.00	$0.00
2023	$18.71	$19.34	$17.89	$13.27	$0.00
2024	$18.73	$19.04	$18.32	$13.54	$0.00
2025	$19.99	$20.05	$19.92	$13.81	$0.00
2026	$23.74	$23.68	$23.82	$14.09	$0.00
2027	$24.63	$24.27	$25.12	$14.37	$115.10
2028	$25.67	$24.99	$26.58	$14.65	$117.40
2029	$26.65	$25.77	$27.83	$14.95	$119.80
2030	$26.46	$25.48	$27.78	$15.25	$122.20
2031	$27.63	$26.48	$29.15	$15.55	$124.60
2032	$28.02	$26.86	$29.57	$15.86	$127.10
2033	$29.30	$27.96	$31.08	$16.18	$129.70
2034	$29.42	$27.98	$31.33	$16.50	$132.20
2035	$30.47	$28.81	$32.68	$16.83	$134.90
2036	$32.10	$30.38	$34.41	$17.17	$137.60
2037	$31.95	$30.08	$34.45	$17.51	$140.30
2038	$34.46	$32.26	$37.39	$17.86	$143.10
2039	$34.77	$32.31	$38.04	$18.22	$146.00
2040	$35.67	$33.15	$39.01	$18.58	$148.90
2041	$38.23	$35.77	$41.52	$18.96	$151.90
2042	$38.71	$36.40	$41.79	$19.34	$154.90
2043	$39.27	$36.92	$42.40	$19.72	$158.00
2044	$46.82	$44.18	$50.34	$20.12	$161.20
2045	$46.45	$44.31	$49.28	$20.52	$164.40
20 yr Levelized	**$25.85**	**$25.20**	**$26.72**	**$14.04**	**$80.3**
24 yr Levelized	**$27.18**	**$26.39**	**$28.22**	**$14.50**	**$86.6**

PRS Greenhouse Gas Intensity



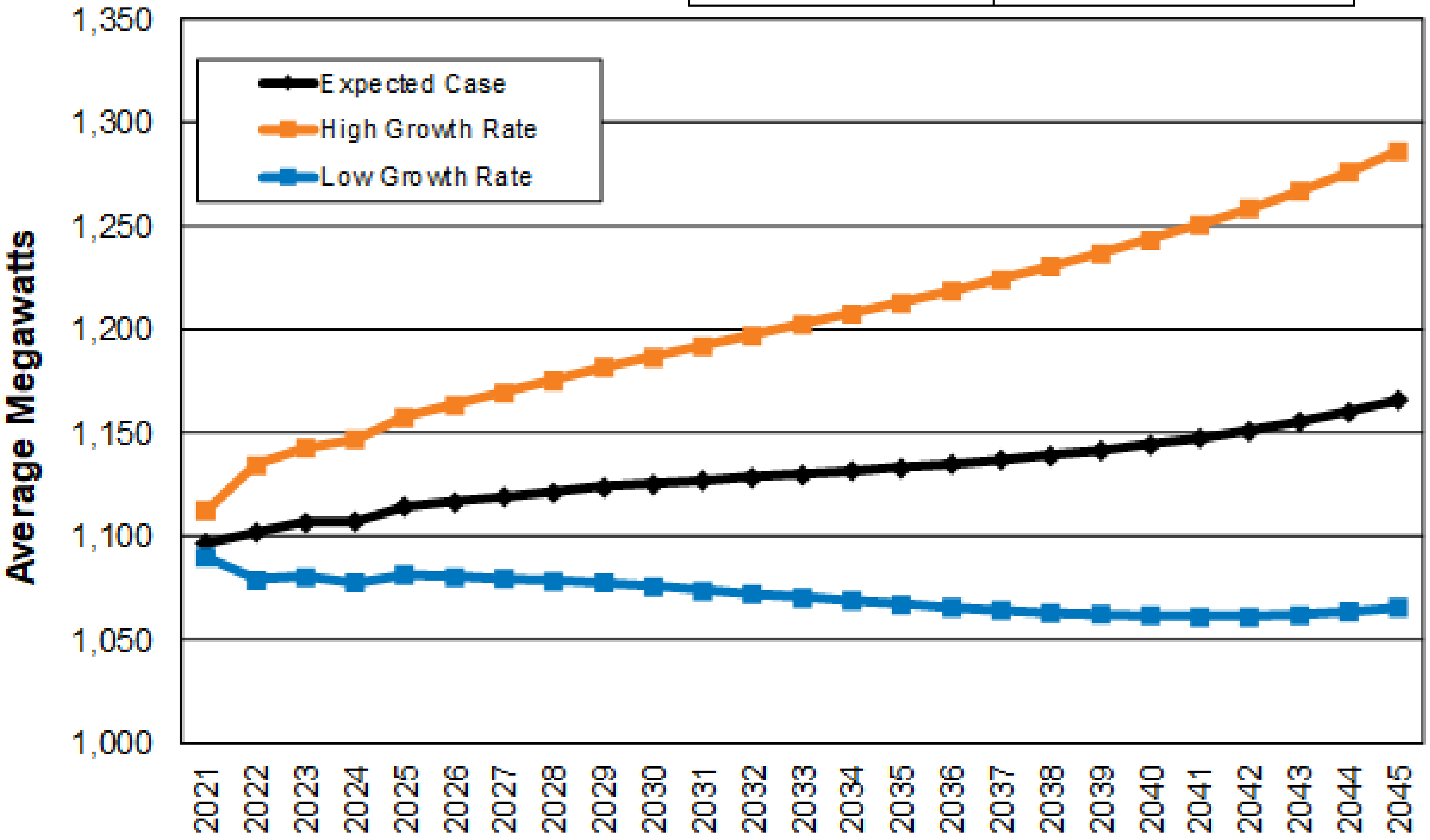
Initial Vulnerable Population Areas





Energy Forecast

Economic Growth	Average Annual Native Load Growth (percent)
Expected Case	0.30
High Growth	0.70
Low Growth	-0.10



2021 Electric IRP Action Items

John Lyons, Ph.D.
Fifth Technical Advisory Committee Meeting
January 21, 2021

Summary of 2017 IRP Action Plan

- Generation Resource Related Analysis
  - Continue to review existing facilities for opportunities to upgrade capacity and efficiency
  - Model specific commercially available storage technologies
  - Upgrade the TAC concerning the EIM study and Avista's plan of action
  - Monitor regional winter and summer resource adequacy, additional LOLP studies
  - Post Falls redevelopment update
  - Ancillary services valuation for storage and peaking technologies using intra hour modeling capabilities
  - Monitor state and federal environmental policies affecting Avista's generation fleet

- Energy Efficiency and Demand Response
  - Consider moving T&D benefits from historical to forward looking values
  - Decide on potential and cost study for winter and summer residential DR programs
  - Use the UCT methodology for Idaho energy efficiency programs
  - Share list of energy efficiency measures with TAC prior to CPA completion

Summary of 2017 IRP Action Plan

- Transmission and Distribution Planning
  - Maintain existing Avista transmission rights
  - Continued participation in BPA transmission rate proceedings
  - Participate in regional and sub-regional efforts to expand transmission system
  - Coordinate IRP and T&D planning to evaluate alternative technologies to solve T&D constraints

2020 Resource Acquisition Action Items

- Determine plan for Long Lake expansion and file with appropriate agencies concerning if the project meets CETA and licensing issues
- Continued pursuit of pumped storage opportunities
- Conduct transmission network and air permitting studies for contingency CTs if pumped hydro is not available
- 2020 RFP for renewable energy capacity (2022-2023 online)
- 2021 RFP for capacity resources (on-line by 2026)
- Additional studies for the eventual shutdown of Northeast CT in 2035

2020 Analytical & Process Action Items

- Continued study of costs of intermittent resources, and financial costs and capabilities of different resources to meet the variability
- Include greenhouse gas emissions from resource construction, manufacturing and operations
- Investigate third-party market price forecast for use with future IRPs
- Participate in CETA rulemaking
- Participate in development of regional resource adequacy program

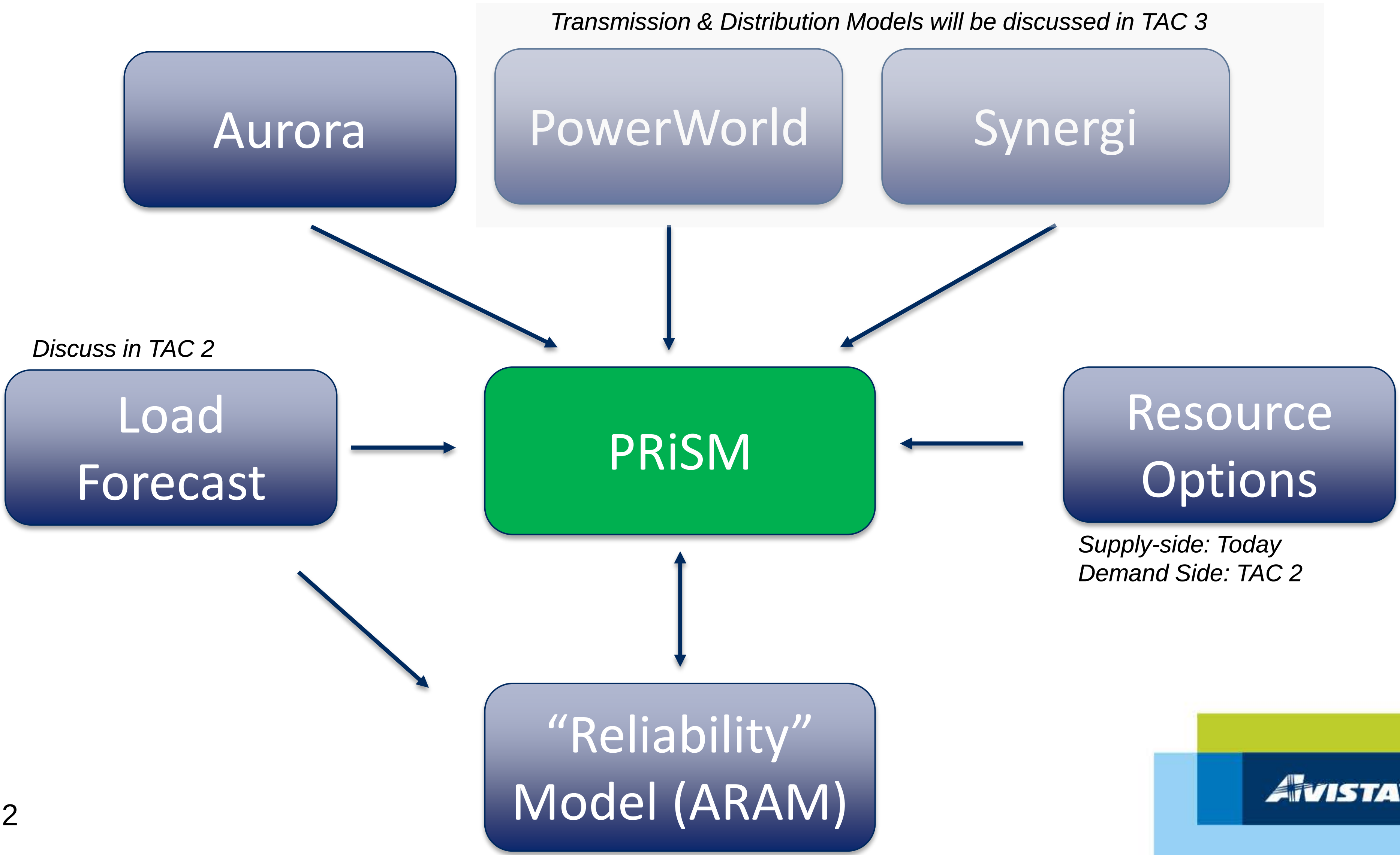
2021 IRP Action Items

- Continue 2020 Action Items with shortened 2021 IRP
- Investigate consultant for hydro and load shift from climate
- Investigate integration of resource dispatch, resource selection and reliability verification functions in IRP modeling
- Study natural gas supply issues and options for Kettle Falls CT
- Determine if distribution planning should be separate process
- Form an Equity Advisory Group
- Conduct existing resource market potential estimate of amount and timing of existing resources through 2045
- Additional DR peak credit analysis
- Partner with a third-party to identify NEI benefits

2021 Electric IRP
Modeling Process Overview

James Gall, IRP Manager
Fifth Technical Advisory Committee Meeting
January 21, 2021

IRP Planning Models



What is Reliability Planning

- Estimate the probability of failure to serve all load
  - Avista's reliability target is 95% of all simulations serve 100% of load and reserve requirements
- Model randomizes events
  - Hydro, weather (load, wind, resource capacity), forced outages
- Typically large sample size 1,000 simulations
- Can be used to validate if a portfolio is reliable
  - Estimate the required planning reserve margin (PRM)
  - May be used to estimate peak credits for new resources (ELCC)
- Gold standard: regional wide program with enforced requirements to each utility
  - Set required methodology, planning margin, and resource contribution based on regional model

2021 IRP Table 7.1: LOLP Reliability Study Results without New Resources

Month	2025 with Colstrip	2025 without Colstrip	2030	2040
Jan	0.6%	2.7%	10.5%	32.7%
Feb	0.1%	0.6%	4.2%	15.0%
Mar	0.0%	0.0%	0.5%	2.9%
Apr	0.0%	0.0%	0.0%	0.0%
May	0.0%	0.0%	0.0%	0.0%
Jun	0.0%	0.0%	0.0%	0.1%
Jul	0.0%	0.3%	1.7%	33.0%
Aug	0.0%	0.1%	0.6%	30.5%
Sep	0.0%	0.0%	0.0%	0.9%
Oct	0.0%	0.0%	0.0%	0.5%
Nov	0.0%	0.0%	0.7%	5.0%
Dec	0.8%	3.2%	7.1%	17.1%
Annual	1.4%	6.3%	21.2%	81.4%

Table 11.5: Reliability Metrics of PRS

Year	2025 (PRS)	2030 (PRS)	2040 (PRS)	2030 (333 MW NG)
LOLP	4.6%	5.4%	8.8%	5.2%
LOLH	1.45 hours	1.74 hours	2.89 hours	1.89 hours
LOLE	0.12	0.14	0.21	0.15
EUE	233 MWh	266 MWh	548 MWh	316 MWh
Total Events	126	148	228	160

Scenario Analysis

- Due to limited time, focus on scenarios with reliability implications
- Any other scenario we should look at?

#	Scenario	Year Studied	LOLP	LOLH	LOLE	EUE
1	PRS	2030	5.4%	1.74	0.14	266
5	Clean Resource Plan (2027)	2030	5.7%	1.66	0.13	250
6	Clean Resource Plan (2045)	2040	7.5%	2.98	0.22	643
10	Resource Adequacy Program	2030	6.4%	2.67	0.2	510
16	Colstrip Exit 2035	2030	5.7%	1.77	0.14	287
11	Electrification Scenario 1	2040	TBD	TBD	TBD	TBD

DRAFT

2021 Electric IRP
Clean Energy Action Plan

John Lyons, Ph.D.
Fifth Technical Advisory Committee Meeting
January 21, 2021

Clean Energy Action Plan

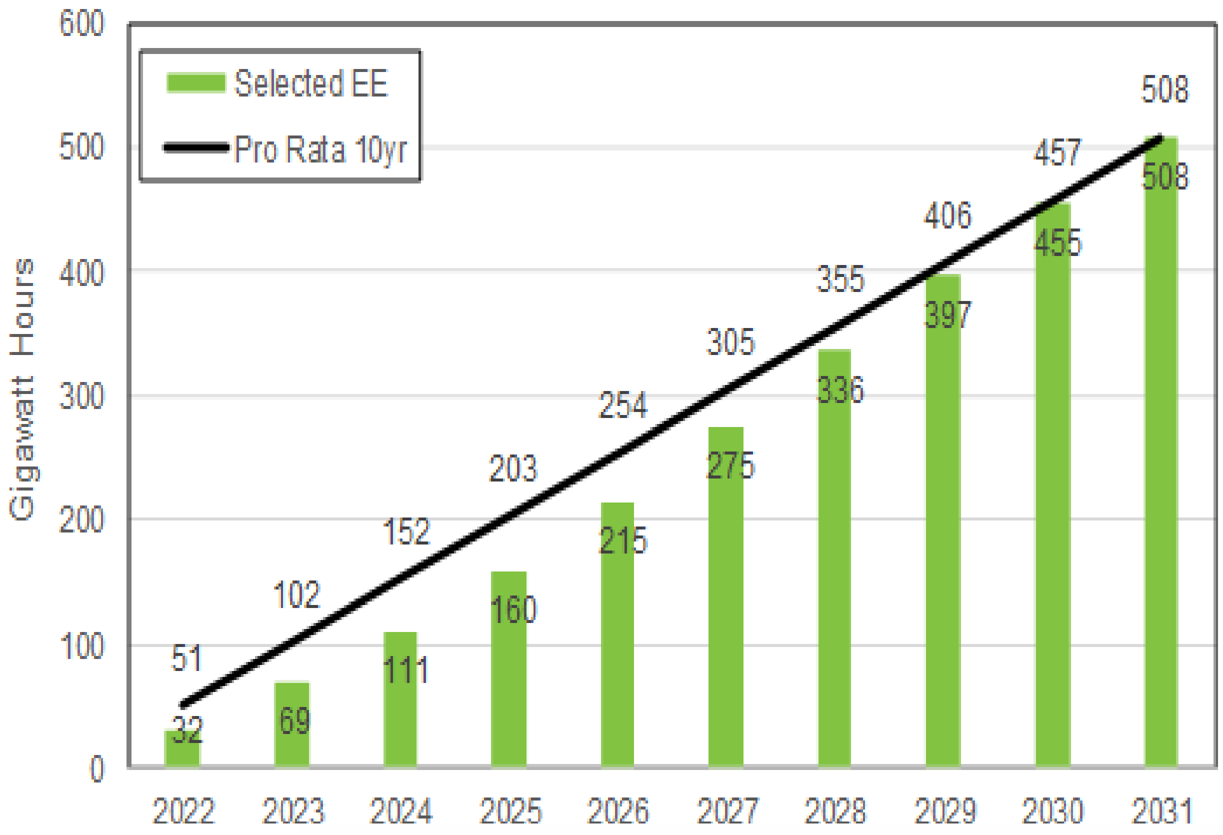
The CEAP must:

1. identify and be informed by the utility’s ten-year cost-effective conservation potential assessment;
2. if applicable, establish a resource adequacy requirement;
3. identify the potential cost-effective demand response and load management programs that may be acquired;
4. identify renewable resources, non-emitting electric generation and distributed energy resources that may be acquired and evaluate how each identified resource may be expected to contribute to meeting the utility’s resource adequacy requirement;
5. identify any need to develop new, or expand or upgrade existing bulk transmission and distribution facilities; and identify the nature and possible extent to which the utility may need to rely on alternative compliance options, if appropriate.

- CEAP is available in chapter 15 of the 2021 IRP

Energy Efficiency Savings

Figure 15.1: Washington 10-year Energy Efficiency Target



- 508 GWh of cumulative energy efficiency or 61.3 aMW with T&D line loses.
- Reduce winter peak 64.3 MW and summer peak 69.5 MW.

Resource Adequacy

- Participating in development of a regional resource adequacy program.
  - 16 percent winter peak and 7 percent summer peak planning margins, plus operating reserves and regulation requirements.
  - A resource adequacy program could reduce Avista's new capacity needs by up to 70 MW in 2031 based on the current draft program design.
  - Could reduce future resource acquisitions if successfully implemented.
- 2021 IRP identifies 83 MW of natural gas-fired capacity for Washington by November 1, 2026 to replace Lancaster PPA and maintain reliability.
- Future RFP may identify a lower cost clean resource.

Demand Response and Load Management Programs

Table 15.1: Demand Response and Load Management Programs

Program	Washington
Time of Use Rates	3.1 MW (2024)
Variable Peak Pricing	8.9 MW (2024)
Large C&I Program	25.0 MW (2027)
DLC Smart Thermostats	0.6 MW (2031)
Total	37.6 MW (2031 Total)

- CEAP identifies new programs with the potential to reduce load by 37.6 MW by 2031.
- Begin in 2024 with time of use and variable peak pricing opt-in programs, estimated to be 12 MW by 2031.
- 25 MW large commercial customer program offering is likely before the Lancaster PPA ends in 2026.
- Heating and cooling program starts in 2031 with 0.6 MW of savings and grows to over 6 MW by 2045.
- Future RFPs may identify other DR opportunities.

Planned Clean Energy Acquisitions

Table 15.2: 2022-2031 Washington Clean Energy Targets (aMW)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Retail Sales	647	650	651	655	657	658	658	661	662	663
PURPA	22	22	22	22	22	22	22	22	22	22
Solar Select	6	6	6	6	6	6	0	0	0	0
Net Requirement	**619**	**623**	**624**	**628**	**629**	**631**	**636**	**640**	**641**	**642**
Target Clean %	80	80	85	85	90	90	95	95	100	100
Clean Energy Goal	**496**	**498**	**530**	**534**	**567**	**568**	**604**	**608**	**641**	**642**
Owned Hydro	292	288	288	285	292	289	292	289	291	291
Contract Hydro	96	95	65	66	65	64	63	58	59	23
Kettle Falls	24	23	23	21	23	21	22	20	21	19
Palouse Wind	24	24	24	24	24	24	24	24	24	24
Rattlesnake Flat Wind	36	36	36	36	36	36	36	36	36	36
Adams Neilson Solar	0	0	0	0	0	0	6	6	6	6
Available Resources	**473**	**466**	**436**	**431**	**439**	**434**	**441**	**433**	**436**	**399**
Shortfall	**23**	**33**	**94**	**103**	**127**	**134**	**163**	**174**	**204**	**242**
Resource Forecast										
Montana Wind	0	48	96	96	96	96	144	144	144	144
Kettle Falls Upgrade	0	0	0	0	6	6	6	6	5	5
Regional Hydro	0	0	0	0	0	0	0	0	0	31
ID AVA Ren. Purchase	23	0	0	7	25	32	13	25	42	41
ID AVA Hydro Purchase	0	0	0	0	0	0	0	0	13	21
Total Energy/RECs	**23**	**48**	**96**	**103**	**127**	**134**	**163**	**175**	**204**	**242**
Net Position	**0**	**15**	**2**	**0**	**0**	**0**	**0**	**1**	**0**	**0**
Total Clean Resource Need	**23**	**48**	**96**	**103**	**127**	**134**	**163**	**175**	**191**	**180**

Transmission & Distribution Improvements

- 2021 IRP did not identify any significant transmission or distribution improvements.
- Future transmission investment follows the 10-year plan in Appendix G.
- Two interconnection requests to Avista transmission to evaluate up to 200 MW in Rathdrum and additional capacity at Kettle Falls.
  - Kettle Falls interconnection request does not require any significant improvements.
  - Rathdrum results will not be available until later in 2021.
- Reviewed potential resource acquisitions that could defer distribution investments, but none were selected in this IRP.
- Will begin designing a public process for distribution planning in 2021.

Energy Equity

- Developing plan for equitable distribution of benefits and reduced burdens on highly impacted communities and vulnerable populations.
- Washington is identifying highly impacted communities and guidance on cost premiums.
  - Avista developed methodology to identify vulnerable populations and will finalize after forming Equity Advisory Group (EAG) in 2021.
  - EAG will guide determination of communities and help design outreach and engagement to distinguish and prioritize indicators and solutions.
  - Committed to energy efficiency program pilot for vulnerable populations starting in 2021.
- Enhancements to energy efficiency cost effectiveness test include non-energy benefits.
- Avista prioritizes efficiency projects to improve resiliency and increase energy security in these communities and gives a preference to renewable projects in vulnerable areas.
- Future request for proposals may yield more beneficial renewable resources.

Cost Analysis

- IRP compares PRS cost to baseline portfolio without CETA requirements to show if alternative compliance (2% cost cap) will be required.
- Avista expects to be below cap by $64 and $61 million for first two of the four-year compliance periods.

Table 15.3: 2022-2024 Washington Cost Cap Analysis (millions $)

	2021	2022	2023	2024	2025	Total
Revenue Requirement w/ SCC	651	651	669	700	705	
Baseline		650	657	672	678	
Annual Delta		1	11	28	27	67
Percent Change		0.2%	1.7%	4.2%	4.0%	2.5%
Four Year Max Spending		33	33	33	33	132
Comparison vs Annualized Cost Cap		(32)	(22)	(5)	(6)	(64)

Table 15.4: 2025-2028 Washington Cost Cap Analysis (millions $)

	2024	2025	2026	2027	2028	Total
Revenue Requirement w/ SCC	705	714	718	744	755	
Baseline		688	709	721	731	
Annual Delta		26	9	23	23	81
Percent Change		3.8%	1.3%	3.2%	3.2%	2.9%
Four Year Max Spending		36	36	36	36	143
Comparison vs Annualized Cost Cap		(10)	(27)	(13)	(12)	(61)

2021 Electric IRP
Clean Energy Implementation Plan (CEIP)

James Gall, Electric IRP Manager
Fifth Technical Advisory Meeting
January 21, 2021

CEIP Overview

- File by October 1, 2021. (draft by Aug 15, 2021)
- Include current clean energy mix (2020).
- Set targets for energy efficiency, demand response and clean energy acquisition using median hydro conditions.
- Include an assessment of indicators of Highly Impacted Communities and Vulnerable Populations through work with the Equity Advisory Group.
- Include specific actions the utility will make to meet clean energy goals; including resource adequacy and equity considerations.
- Calculate incremental costs.
- Create public participation plan (due on May 1, 2021).
- Interested parties have 60 days to provide written comments to the Commission.
- Commission will set an open public meeting; after adjudication, Commission will approve, reject or approve with condition the utility's CEIP or CEIP update.

Public Participation

- A public participation plan must be filed with the WUTC on May 1, 2021.
- Avista will begin public participation on the CEIP toward the end of May 2021.
- All TAC members are welcome to join; please contact John Lyons at john.lyons@avistacorp.com or 509-495-8515 to be on the CEIP email list.
- Equity Advisory Group is currently forming.
  - Ana Matthews leads this effort
  - Contact her at 509-495-7979 or ana.matthews@avistacorp.com for more information

Clean Energy Implementation Plan (CEIP) Details of Requirements

WAC 480-100-640
CEIP Content – Filing Requirements, Interim Targets

1. Utility must file with the commission a CEIP by **October 1, 2021**, and every four years thereafter; must describe the utility's plan for making progress toward meeting the clean energy transformation standards
2. Interim targets.
   a) Utility must propose a series of interim targets that
      i. Demonstrate utility's reasonable progress toward meeting the standards.
      ii. Consistent with WAC 480-100-610 (4).
         – EE, DR, Safety, Reliability, Balancing system, Equity
      iii. Interim targets must be proposed in the form of the percent of forecasted retail sales of electricity supplied by nonemitting and renewable resources prior to 2030 and from 2030-2045
   b) Must include utility's percentage of retail sales of electricity supplies by nonemitting and renewable resources in 2020 in the first CEIP it files.
   c) Each interim target must be informed by the utility's historic performance under median water conditions

3) CEIP Content – Specific Targets

a) Utility must specific targets for energy efficiency, demand response and renewable energy.
   i. EE target much encompass all other EE and conservation targets and goals required by the Commission; must be described in the BCP; utility must provide forecasted distribution of energy and nonenergy costs and benefits
   ii. Must provide proposed program details, budget, measurement and verification protocols, target calculations, forecasted distribution of energy and nonenergy costs and benefits for the utility's demand response target.
   iii. Must propose the renewable energy target as a percent of retail sales of electricity supplied by renewable resources, details of renewable energy projects or programs, budgets, forecasted distribution of energy and nonenergy costs and benefits

b) Must provide description of technologies, data collection, processes, procedures and assumptions used to develop targets

4) CEIP Content – Customer Benefit Data

a) Identify highly impacted communities using the cumulative impact analysis pursuant to RCW 19.405.140 combined with census tracts (Indian country).

b) Identify vulnerable populations based on adverse socioeconomic and sensitivity factors developed through the Equity Advisory Group (EAG) process and public participation plan; describe changes from the utility's most recently approved CEIP.

c) Include proposed or updated customer benefit indicators and associated weighting factors related to WAC 480-100-610(4)(c) such as energy benefits, nonenergy benefits, reduction of burdens, public health, environment, reduction in cost, energy security and resiliency. Customer benefit indicators and weighting factors must be developed consistent with the EAG process and public participation; describe any changes from the most recently approved CEIP.

5) CEIP Content – Specific Actions

Include specific actions the utility will take over the implementation period; actions must meet and be consistent with the clean energy transformation standards and be based on the utility's CEAP and interim/specific targets; specific action items must be presented in a tabular format providing

a) General location, if applicable, proposed timing, estimated cost, whether resource will be located in a highly impacted community, will be governed by, serve or benefit highly impacted communities or vulnerable populations in part or in whole.

b) Metrics related to the RA including contributions to capacity or energy needs.

c) Customer benefit indicator values, or a designation as nonapplicable, for every customer benefit indicator described in section (4) (c)

6) CEIP Content – Narrative Description of Specific Actions

CEIP must describe how the specific actions:

a) Demonstrate progress toward meeting the standards.
b) Demonstrate consistency with the standards in 480-100-610(4)
   i. An assessment of current benefits and burdens on customers, by location and population, and the projected impact of specific actions on the distribution of customer benefits and burdens during the implementation period.
   ii. Description of how the specific actions in the CEIP mitigate risks to highly impacted communities and vulnerable populations and are consistent with the longer-term strategies and actions described in the utility's most recent IRP and CEAP
c) Consistent with proposed interim and specific targets;
d) Consistent with the IRP;
e) Consistent with the resource adequacy requirements and a narrative describing how the resources identified in the most recent RA assessment conducted or adopted by the utility demonstrates that the utility will meet its RA standard;

6) CEIP Content – Narrative Description of Specific Actions (continued)

f) Demonstrate how the utility is planning to meet the clean energy transformation standards at the lowest reasonable cost such as
   i. Utility's approach to identifying lowest cost portfolio of specific actions that meet the requirements as well as its methodology for weighting considerations
   ii. Utility's methodology for selecting the investments and expenses it plans to make over the next 4 years that are directly related to the utility's compliance with clean energy transformation standards and demonstrate investments represent a portfolio approach to investment plan optimization
   iii. Supporting documentation justifying each specific action identified in the CEIP

CEIP Content

7. Include a projected incremental cost as outline in WAC 480-100-660 (4).
8. Detail the extent of TAC/EAG or other public participation in the development of the CEIP.
9. Describe any utility plans to rely on alternative compliance mechanisms as described in RCW 19.405.040 (1) (b)
10. If the utility proposes to take the early action coal credit, it must satisfy the requirements in that statutory provision by
    – Demonstrate the proposed action constitutes early action by presenting the analysis by detailing with and without the proposed early action
    – Compare both the proposed early action and the alternative against the same proposed interim and specific targets

11) CEIP Content – Biennial CEIP Update

- Utility must make a biennial CEIP update filing on or before November 1 of each odd-numbered year that the utility does not file a CEIP.
- CEIP update may be limited to the BCP requirements.
- Must file its biennial CEIP update in the same docket as its most recently filed CEIP and include an explanation of ow the update will modify targets in its CEIP.
- Utility may file in the update other proposed changes to the CEIP as a result of the IRP progress report.

480-100-645
CEIP Review Process

1. Interested parties may file written comments with the Commission within 60 days of the utility's filing.
2. Commission will set an open public meeting; after adjudication, Commission will approve, reject or approve with condition the utility's CEIP or CEIP update; Commission may order, recommend or require more stringent targets.
   a) Commission may adjust or expedite interim or specific target timelines.
   b) Parties requesting the commission make existing targets more stringent or adjust the existing timelines has the burden of demonstrating the utility can achieve the targets or timelines.

2021 Electric IRP TAC 5 Meeting Notes, January 21, 2021

Meeting Attendees: Andres Alvarez; Shawn Bonfield, Avista; Annette Brandon, Avista; Terrence Browne, Avista; Corey Dahl; Thomas Dempsey, Avista; Grant Forsyth, Avista; Annie Gannon, Avista; Amanda Ghering, Avista; Dainee Gibson-Webb, Idaho Conservation League; Michael Gump, Avista; James Gall, Avista; Lori Hermanson, Avista; Fred Heutte, NEWC; Clint Kalich, Avista; Kevin Keyt, IPUC; Scott Kinney, Avista; John Lyons, Avista; Jaime Majure, Avista; James McDougall, Avista; Ben Otto, Idaho Conservation League; Tom Pardee, Avista; Lance Kaufman (AWEC); Marissa Warren, Idaho Office of Energy Resources; Michael Eldred, IPUC; Mike Louis, IPUC; Mike Morrison, IPUC; Montoya Lina; Morgan Brummell; Rachel Farnsworth, IPUC; Shay Bauman; Jennifer Snyder, WUTC; Terri Carlock, IPUC; Tina Jayaweera, NW Power Council; Yao Yin, IPUC; Chip Estes; Joni Bosh, NWEC; Katie Pegan; Katie Ware.

Notes in *italics* are responses made by the presenter.

<u>Introductions and 2021 IRP Process Updates, John Lyons</u>

John Lyons (slide 6): Is the public open meeting that is scheduled for February 2021 still needed now that we have an open public meeting at the WUTC on February 23, 2021?

Rachel Farnsworth: What was going to be covered in the public outreach meeting? *Probably a high level overview of the draft IRP and an opportunity for the public to comment before publishing it.* I'm not sure I agree with not having that public meeting, but will discuss it with our Idaho team. There was a lot of interest in participation for the last IRP, so take that into consideration.

Ben Otto: I think providing a public opportunity to comment on the draft IRP before it is finalized is a good idea.

James Gall (slide 7): If you want to run scenarios, get a hold of me because you'll need Gurobi and What's Best licenses to make the models work. You can review the results from the model runs without the licenses.

John Lyons: We do not have signed contracts yet for the successful bidders of the 2020 Renewables RFP and those contracts will change the near term PRS if signed. For the results of the 2020 renewable RFP, what's the cut-off to include them and rewrite the IRP? Is it the end of January, sometime in February, or some other time?

Jennifer Snyder: If possible, at all, it'd be great to have it included, time allowing. If there is only time for a letter or appendices about the contracts, that'd be ok too.

Ben Otto: What is the likelihood and scale of changes to the PRS that could come from the RFP?

James Gall: It doesn't change the resource need, but it changes the resource mix in the early years.

John Lyons: We are hoping to be finished with contracts by end of the first quarter.

Review Draft 2021 IRP, John Lyons

Jennifer Snyder: Chapter 13, the EAAG is referred to as the EEAG.

Draft Resource Plans and Scenarios, James Gall

Mike Morrison: Could we further discuss the definition of a 5% LOLP?

James Gall: Let's defer that to the ARAM discussion.

Joni Bosh: What do the green and blue stand for?

Lori Hermanson: Green resources are being retired and blue storage resources are being added.

Thomas Dempsey: Why is there a 2021 retirement of Colstrip?

James Gall: Models show retirement when it's cost-effective, but it doesn't mean Colstrip will retire in 2021.

Katie Ware: Did you explore the sensitivity of a mix of lithium-ion and long-duration storage?

James Gall: Excellent question. Lithium-ion and long-duration storage are all resource options, so the model when looking at capacity need can choose from any of those resources. Longer duration resources have a higher peak credit which is why it is selected over lithium-ion, even though lithium-ion could be a cheaper resource. Lithium-ion is lowest cost when combined with solar, but liquid air is best for long term storage.

Katie Ware: Is there a scenario of storage mixes. *Yes, we'll discuss it in detail later.*

Yao Yin: Based on the table and modeling, there are different needs for different resources. How does the company reconcile this when acquiring resources?

James Gall: It's a real challenge for us. We identify the need, then need to determine who [which state or system] is driving the need and who is paying for it. We definitely need a company strategy on how to assign responsibility for recovery of new resources and we need to figure out how to do that with the commissions.

Yao Yin: How do you decide what resource to acquire in reality when it comes to operational decisions?

James Gall: If we acquire all of these, we'll operate them to meet load if needed. Actual acquisitions are decided through a competitive process like an RFP.

Tina Jayaweera: Are DR impacts for both summer and winter? *Yes, many impacts for both summer and winter.*

Yao Yin: For the DR and energy efficiency programs in the preferred program, are they based on the third-party or the study?

James Gall: The third party determines the price and the potential and our model selects the measures.

Yao Yin: Are they bundled? *No.* Is DR the same way?

James Gall: Yes, each individual measure, about 7,000 of them, can be selected. This is the same by DR and by state.

Fred Heutte: I'm wondering about DR, CT2045 for new water heaters and heat pumps, electric resistance, why didn't these show up?

James Gall: The costs were given by AEG, it was the next resource in [just missed being selected in this IRP]. The potential was quite large, but it was not competitive. If the pricing comes down about 20% in the next plan, it'll be selected.

Fred Heutte: I'm going to investigate AEG's numbers as it doesn't seem this would be that expensive. In my view, utilities in Washington should just acquire these.

Tina Jayaweera: Thermostats may not save the same amount in summer as in winter, is the 7 MW in the summer or winter?

James Gall: It's the winter savings. I have the summer savings available too, but didn't show them here. They are in the supporting documents. Feel free to dig into them.

Jennifer Snyder: Have you done any analysis on bill impacts? The Washington rate is higher but so is energy efficiency, does it make the comparison any different?

James Gall: Great question, I don't have the answer. Maybe that's something we can investigate.

Fred Heutte: About the below the zero sales, can you walk through the math? My sense is there will always be gas in the market, about half of a coal plant.

James Gall: There's several methodologies, you've described one. We sell system power, then incremental cost and emissions change. I try to keep things simple here. For every MW sold, we estimate the amount of emissions the NW emits. It's really an unknown and I try to show it both ways. It goes away in 2025.

Fred Heutte: It's a net sales, but if you didn't sell, what's the marginal analysis?

James Gall: I agree. I've done it and it's difficult. Average hourly emissions by our system and the regional emissions. However, we can't do that to that level with the models we have. Maybe we can in the future. We have annual models so I don't know how much we bought or sold each hour.

Fred Heutte: Agreed, this is a first cut and gives us a sense. It's not easy to do this hourly. Ultimately, we need to land there. Hydro complicates this too.

Joni Bosh: So system power is unspecified power?

James Gall: Two types of power – Avista's system power, sales and purchases. We don't know what we're buying each hour so we'd have to determine a mix of this.

Mike Morrison: Do the liquid air energy storage systems currently in your portfolio assume the existence of waste heat from thermal plants? Is this waste heat generated by hydrogen or biomass? If so, does your modeling include these costs?

Thomas Dempsey: 100% renewable is not available yet.

Mike Morrison: You assume the use of waste heat to power the high temp side of the engine, but the efficiency was above this.

Thomas Dempsey: I believe we provided an answer for that question, but I don't have that in front of me.

James Gall: Or we used a lower efficiency in this plan, but I'll need to get back to you on that.

2021 IRP Action Items, John Lyons

Fred Heutte: The Power Pool is having an update on resource adequacy next Friday. I'll add a link. [NWPP Resource Adequacy Program public webinar next Friday, Jan. 29, 1-2:30 pacific time https://www.nwpp.org/events/86]

John Lyons: Thanks for sharing that around.

Jennifer Snyder: I wanted to know if you are looking at other DER investments and how are you planning on doing those in the future?

James Gall: We currently evaluate those DER resource options in the plan. The challenge is they're not getting selected from an economic point of view. Are there additional economic or equity benefits that we need to study? Unless there's a specific reason to pick DERs due to a locational benefit to help with the economics, they're not going to be economic and will not be chosen. This takes quite a bit of time to study.

Jennifer Snyder: Other values will have to drive it to be accepted.

ARAM Model Overview, James Gall

Mike Morrison: What is your definition of LOLP?

James Gall: I'll explain it when I open the model.

Lance Kaufman: If you're unable to meet your load requirements, it counts as a loss of load event. Can you explain this further?

James Gall: We track both ways – if we can't meet our reserve obligations to WECC or we can't meet our load, both can occur at the same time.

Scott Kinney: It's a NERC requirement that you have to maintain your operating reserves to avoid blackouts across the whole system. For example, in California this summer during the heat wave, they had to start shedding load. You have to shed load to save the entire interconnection.

Thomas Dempsey: Can you clarify the question I thought I heard? Suppose we're carrying 100 MW of reserves, but we need 50 MW. If we have already used it, we no longer have the 100 MW of reserve. Is that situation an event?

Scott Kinney: We can call on other reserves in the region.

Yao Yin: For existing and/or new resources, how do we determine the capacity?

James Gall: For both existing and new resources, and we will get to the capacity later in the presentation.

Lance Kaufman: Can you explain the dispatch logic? Are things being co-optimized? How is thermal, hydro/storage being re-dispatched?

James Gall: The model is not concerned with cost but with availability. It will dispatch based on a priority of economics. Each resource is trying to serve that load equally but in a high load event everything will run.

Lance Kaufman: Will you cover storage logic later?

James Gall: Yes. This is a reliability model. The first version was with no economics. This model now has economics included.

Mike Louis: If the market is used to meet reserves, is the amount constrained?

James Gall: Essentially, from a market point of view, we're using our reserves to meet the load. We could buy from the market in the future to meet reserves.

Lance Kaufman: Is there a risk of having that flat so that it misrepresents reliability?

James Gall: I haven't tested that. There could be a couple of months where there could be a reliability problem. I'm leaning toward it not being a big impact, but I don't know for sure without testing.

Andreas Alvarez: What timeframe is the model optimizing these storage resources?

James Gall: All 8760 at the same time. The model has perfect foresight, which is more than reality.

Yao Yin: Where is the 16% planning margin located?

James Gall: It's not an actual input or output. We're going to talk about this more later.

Andreas Alvarez: When it's storing, is it seeing a price for charging?

James Gall: Yes, there's an economic charge for charging and dispatching storage. It is set up with a very high price to not serve load, so it is optimizing to serve load. Really only focusing on hours where there will be an hour needed.

Andreas Alvarez: It's charged for that hour to avoid the $5,000.

Mike Morrison: How are storage efficiencies determined?

James Gall: Determined by what storage resource was chosen.

Mike Morrison: How does it keep track of when storage devices are charging and dispatching?

James Gall: Showed the dispatching versus charging in the model. It can't draw more than what the limits are.

Mike Morrison: Is the model smart enough to say the battery isn't charged enough or what needs to be charged?

James Gall: The power of the What's Best program is that it creates a linear equation to solve for the parameters, subject to constraints, to minimize the cost to serve load.

Lance Kaufman: Could you clarify for the hourly load forecast, when you say you're looking at historical years, are you taking historic temperatures and putting them into the current forecast?

James Gall: Yes. Load forecast with weather using actual data for a particular year. In theory. We have to create a regression to create an hourly load shape and match that with weather.

Lance Kaufman: Where would we look to see the details of this by year?

James Gall: Historical hourly loads are used to create a regression equation which is used to multiply the historical daily temperatures to estimate the hourly loads included in the model. Since the ARAM model includes proprietary data it can't be shared.

Lance Kaufman: On the years tab, have you done analysis between the water year and the load year?

James Gall: Yes, on an annual basis. On an annual basis there is no correlation, but on a weekly basis, there could be correlation. We're varying these inputs on an annual basis. We chose not to put a correlation in there.

Andreas Alvarez: Is Montana wind assumed to be central or eastern?

James Gall: It is eastern Montana wind. I don't recall which wind turbine was used.

James Gall: Yao asked earlier how this relates to planning margin. We are trying to get as close to 5% LOLP as possible. So the question is how many resources or how much market availability do I have to add to achieve this? Here we will put a constraint on how much can come from the market. We're concerned with really hot or cold days – those are the days we're concerned about market availability. If the temperature is above 80 or below 2 degrees, it triggers a market availability constraint. The 16% planning margin is the amount of extra resources needed above our load assuming this constrained market availability.

Andreas Alvarez: Will you be going over peak capacity contributions?

James Gall: If I reduced gas and increased wind to come up with the same LOLP that would result in a 25% peak credit. The difficulty is when you add more wind the value of the peak credit degrades.

Clean Energy Implementation Plan and Clean Energy Action Plan, James Gall

Yao Yin: Is there a separate preferred portfolio for each state?

James Gall: Our PRS identifies what resources are driven by each state, but all resources are needed.

Yao Yin: In the ARAM model, do we look at the entire system? *Yes*.

Jennifer Snyder: Is John the main contact? Are you considering the CEIP being the same team makeup as the IRP?

James Gall: We have not decided yet. We'll be working on that.

Draft IRP Comments from TAC

Mike Morrison: I've perused the draft. You definitely listened to some of our last comments and incorporated them. I appreciate that. I'll be really looking at the capacity calculations and making sure the assumptions make sense. Anything you can do to enlighten me would be helpful. Keep up the good work. This has been a really helpful presentation.

James Gall: John is taking notes and we'll be putting these on our website. We'll respond where we can today if possible and for sure later in the final IRP.

Yao Yin: A clarifying question, for the preferred portfolio on the list of system need and by Idaho and Washington, did you mean that the final list includes all resources and this slide identifies the drivers?

James Gall: Correct. The slide includes all preferred resources needed to serve the system and the color of each resource identifies the driver as being system, Idaho or Washington.

Jennifer Snyder: The UTC doesn't necessarily expect you to meet everything in this IRP since the rules just came out. Can you add in some narrative on the maximum customer benefit scenario and what that might look like to help with the discussion going forward?

James Gall: I don't know if the drafters of the rule have an expectation of what they're expecting for that scenario. The definition of the maximum customer benefit scenario is what I am challenged by. I'm puzzled on what it means.

Jennifer Snyder: You and I are right there on that. PSE is doing 150% of cost-effectiveness for energy efficiency. I don't necessarily think this is the way to go. If you were going to increase the customer benefit, how would you maximize things?

James Gall: What is the meaning of customer benefit – reliability, financial, etc.? We're already solving for the maximum financial benefit. We'll mull it over. I think we already have the scenario like PSE.

Shawn Bonfield: The newly formed equity advisory group may inform this scenario from that perspective. I see this as a narrative of how we'll use that group.

Yao Yin: On the slide about all the chapter content, for chapter 13 on the use of the preferred portfolio in determining avoided costs, did you mean for PURPA or for energy efficiency?

James Gall: We meant for both. Avoided cost of our preferred strategy which could be used for PURPA, energy efficiency or a supply-side resource. We will be adding the estimated avoided costs showing how folks can calculate the avoided costs of their particular resource.

Yao Yin: What is your justification of using the preferred portfolio of new resources instead of existing resources?

James Gall: We have an existing resource stack, but if we had a new resource to consider the cost we are avoiding would be from acquiring a new resource.

2021 Integrated Resource Planning

February 24, 2021

Meeting Format

- 5:00 to 6:00
  - Welcome- Jason Thackston, SVP of Energy Resources
  - Overview of Avista's Electric Resource Plan- James Gall
  - Overview of Avista's Natural Gas Resource Plan- Tom Pardee
- 6:00 to 6:30
  - Attend first breakout session
- 6:30 to 7:00
  - Attend second breakout session
- This meeting will be recorded

Objectives of Today's Meeting

- Overview of Avista's electric and natural gas systems.
- Learn about considerations when planning to meet customer load.
- Explore Avista's proposed resource plan for natural gas and electric supply.
- Opportunity to ask questions and provide feedback in breakout sessions.
- Poll questions to provide instant feedback.

Avista Generation Capability of Company-Owned Resources and Service Territory

Washington	CUSTOMERS
Electric	243,031
Natural Gas	153,467

Idaho	CUSTOMERS
Electric	127,134
Natural Gas	78,061

Oregon	CUSTOMERS
Natural Gas	98,194

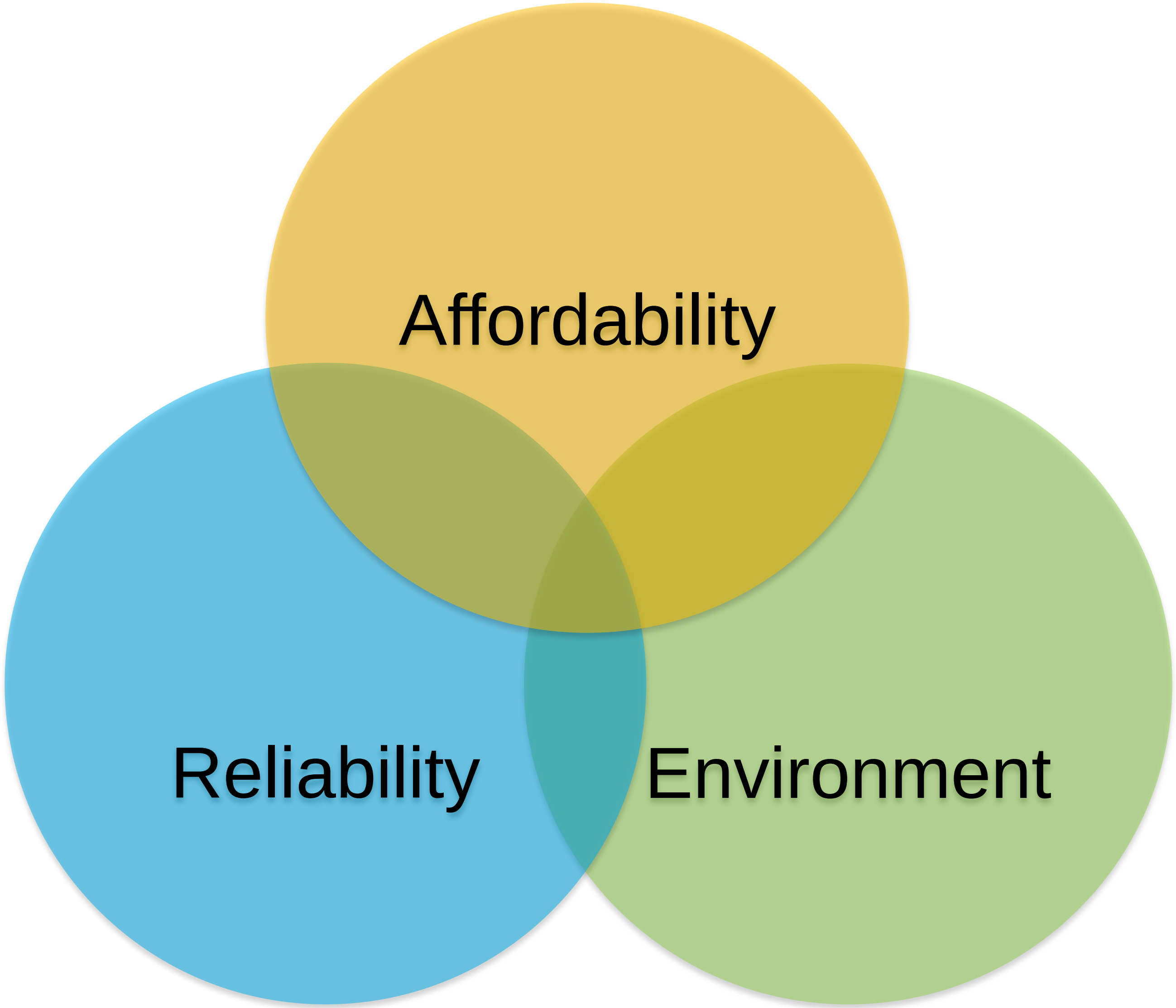
Non utility-owned or operated	GENERATION CAPABILITY (MW)
16 Lancaster N.G. (fired) (Rathdrum, ID)	270.0
17 Palouse Wind (Oakesdale,WA)	105.0

Hydroelectric	GENERATION CAPABILITY (MW)
1 Noxon Rapids (Noxon, MT)	562.4
2 Cabinet Gorge (Clark Fork, ID)	273.0
3 Long Lake (Spokane, WA)	88.0
4 Little Falls (Spokane, WA)	35.6
5 Nine Mile (Spokane, WA)	22.4
6 Post Falls (Post Falls, ID)	15.4
7 Monroe Street (Spokane, WA)	15.0
8 Upper Falls (Spokane, WA)	10.2
Total Hydroelectric Capability	**1,022.0**

Thermal	GENERATION CAPABILITY (MW)
9 Coyote Springs (Boardman, OR)	284.4
10 Colstrip (Units 3&4) (Colstrip, MT)	222.0
11 Rathdrum Combustion Turbines (Rathdrum, ID)	166.5
12 Northeast Combustion Turbines (Spokane, WA)	64.8
13 Kettle Falls Biomass Plant (Kettle Falls, WA)	53.5
14 Boulder Park (Spokane, WA)	24.0
15 Kettle Falls Combustion Turbine (Kettle Falls, WA)	6.9
Total Thermal Capability	**822.1**

Avista also owns Alaska Light & Power in Juneau, AK

Maintaining Balance is Important



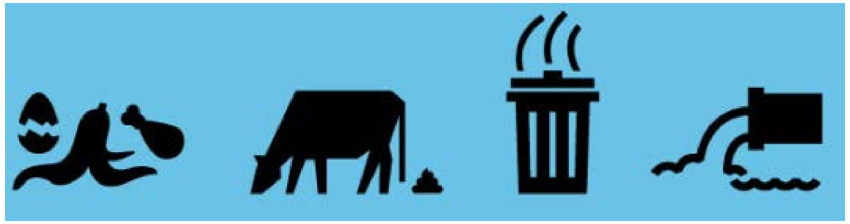
Avista's Clean Electricity Goal

Avista's goal is to serve our customers with **100 percent clean electricity by 2045** and to have a **carbon-neutral** supply of electricity by the end of **2027**

- We will maintain focus on **reliability** and **affordability**
- **Natural gas** is an important part of a clean energy future
- **Technologies and associated costs** need to emerge and mature in order for us to achieve our stated goals
- It's **not** just about generation

Providing Cleaner Natural Gas

- We are committed to reducing **greenhouse gas emissions** in our natural gas business too
- Achieving reductions requires an "**all-of-the-above**" approach:
  - **Gas supply and distribution opportunities** like renewable natural gas
  - **Upstream strategies** like targeted sourcing with suppliers
  - **Engagement with customers** to increase energy efficiency, demand response, and voluntary programs
- Just like our clean electricity goals, reducing greenhouse gas emissions in our natural gas system will require **advances in technology** and **reductions in the cost** of those technologies
- **Affordability** will guide our decisions



What is the Purpose of an IRP?

- Required to be filed with our state regulating commissions every two years.
- Allows for public feedback and participation.
- Commissions acknowledge plans but do not approve the plans.

- Understand supply needs to serve our customers over the next 20 years.
- Evaluate resource options to meet future needs.
- Determine which resources are best suited to meet customer need.
- Sets course for acquisition of resources.

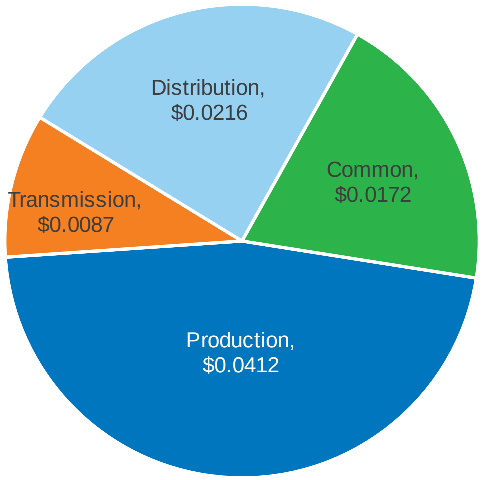
Electric Integrated Resource Plan

Poll

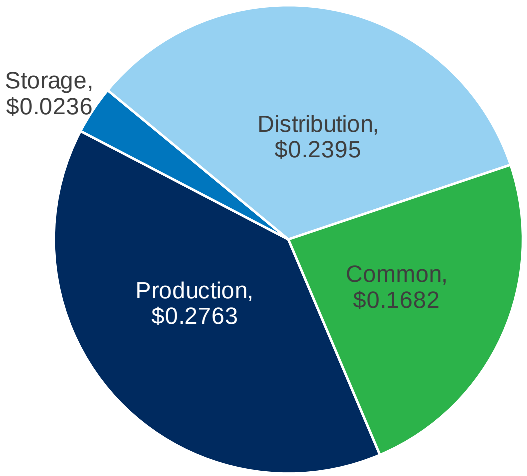
What makes up your energy rate?

Begins with Cost to Serve All Customers

Electric



Natural Gas



Customer Type

- Residential
- Commercial
- Large Commercial
- Industrial
- Water Pumping
- Street Lighting

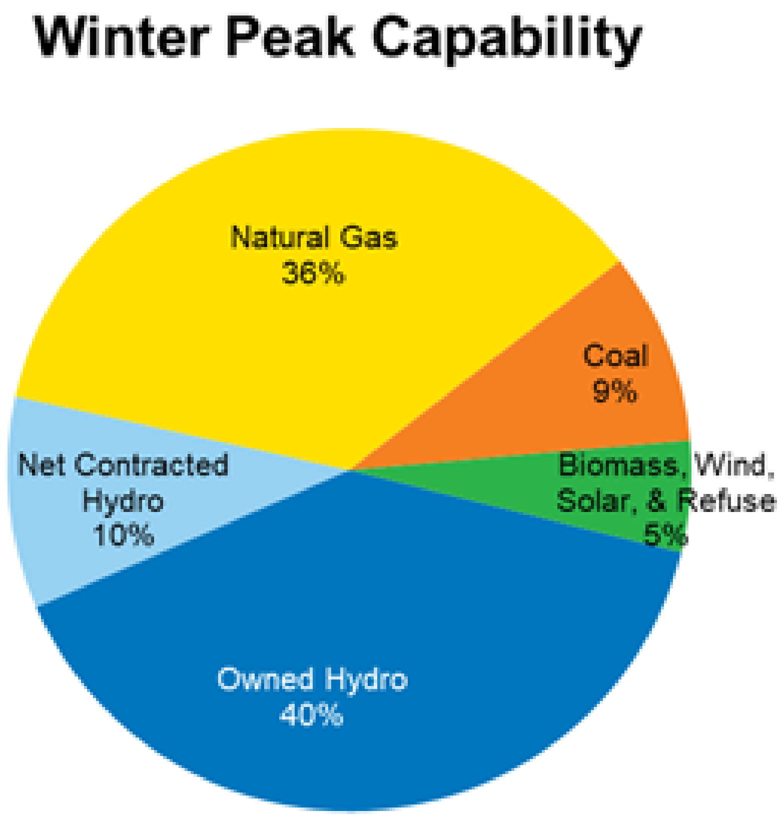
Pricing Type

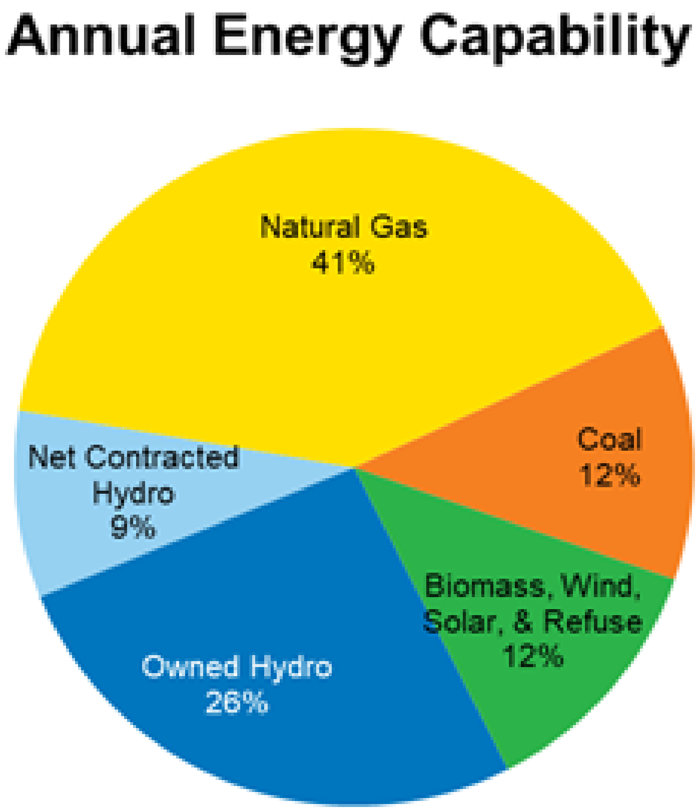
Fixed Charge
Monthly connection charge

Energy Charge
The amount of energy used over the month

Demand Charge
The highest use over an hour in the last 12 months

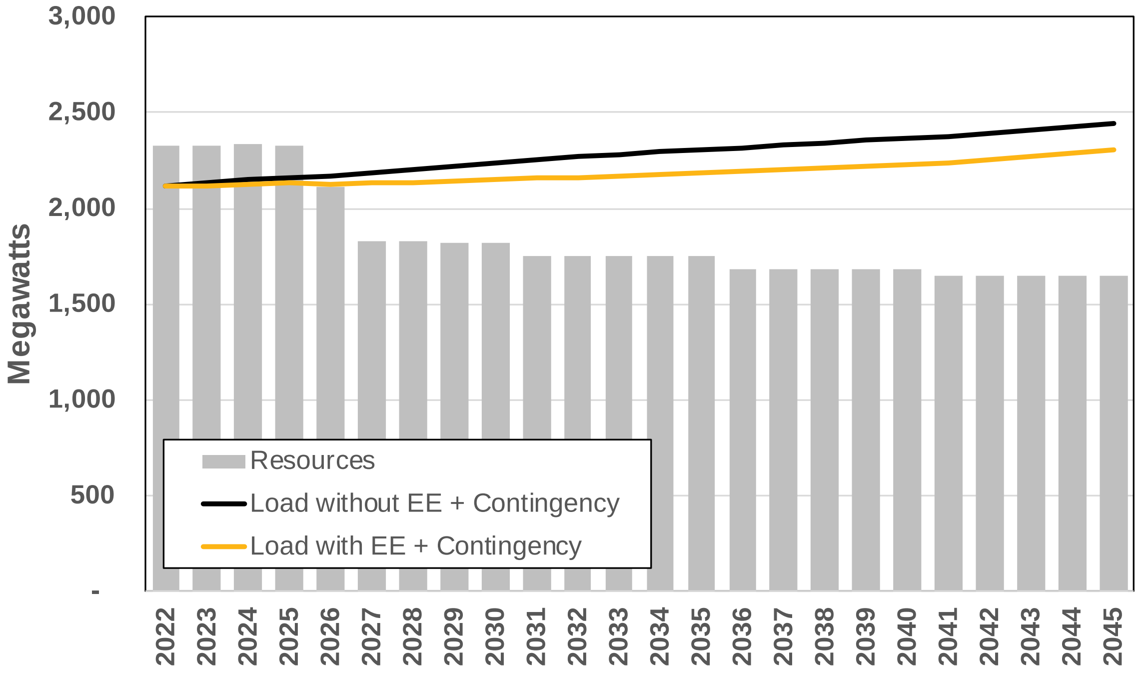
What fuels our generating resources?



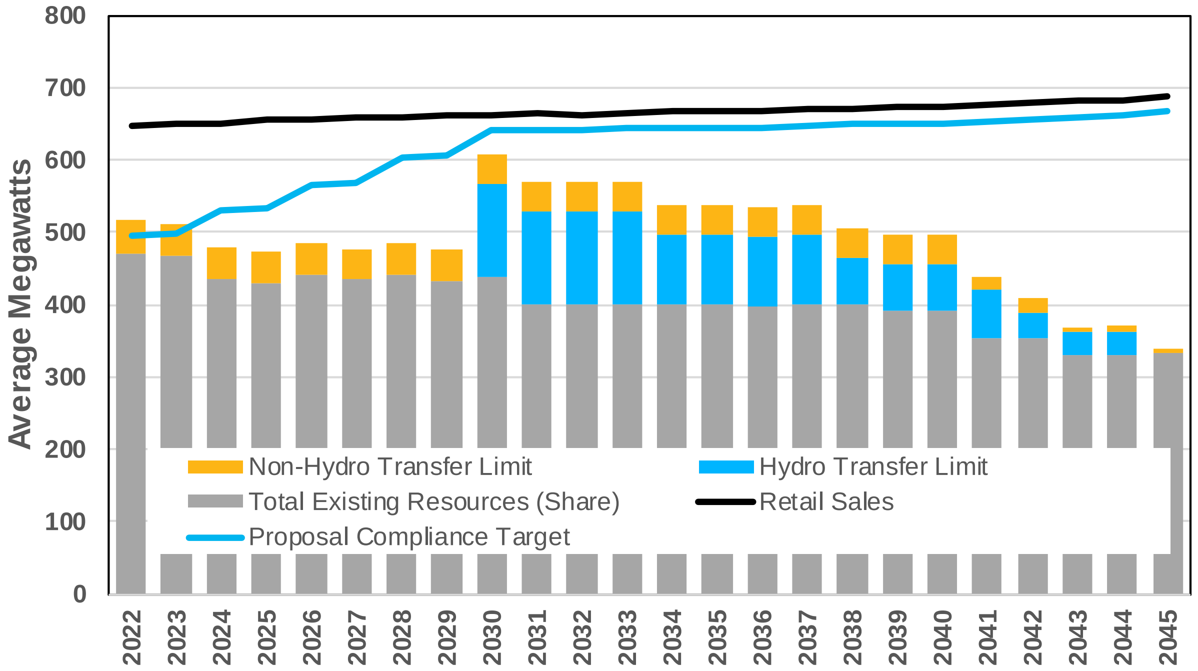


Why does Avista need new electric resources?

Meet System Winter Peak Load



Meet Washington Clean Energy Requirements



Avista also plan to meet summer peak conditions & to ensure it generates enough energy over the course of the year in poor hydro conditions.

What are the available options to meet our electric customer obligations?

Clean Resources

Wind
Solar
Biomass
Hydro
Geothermal
Nuclear

Fossil Fuel Resources

Natural gas peaker
Natural gas baseload
Coal (retention)
Customer generation

Demand Resources

Energy efficiency
Conservation
Load control
Rate programs
Fuel switching
Co-generation

Storage

Pumped hydro
Lithium-ion batteries
Liquid air energy storage
Flow batteries
Hydrogen

Resources in italics were not directly modeled for this IRP

Electric IRP's Preferred Resource Strategy over the next 10 years

Generation Portfolio

- By end of 2025: Exit Colstrip
- 2023-24: Add new renewables (i.e. wind, solar, hydro)
- 2026-2027: Replace Lancaster natural gas plant (natural gas generation is lowest cost option) & increase capacity at the Kettle Falls Generating Station & Post Falls
- 2028: Add new renewable resources (Montana wind)
- 2031: Acquire existing Northwest Hydro Capacity
- 2035: Replace Northeast natural gas plant with upgrades to Rathdrum CT and acquire new capacity

Energy Efficiency

- Energy Efficiency meets 68% of future load growth
- Industrial & commercial customers provide 2/3 of savings
- Residential Single family home is largest single segment
- Washington top targets: Lighting, space heating, water heating, refrigeration, and cooling
- Idaho to targets: Lighting, space heating, and motors

Demand Response

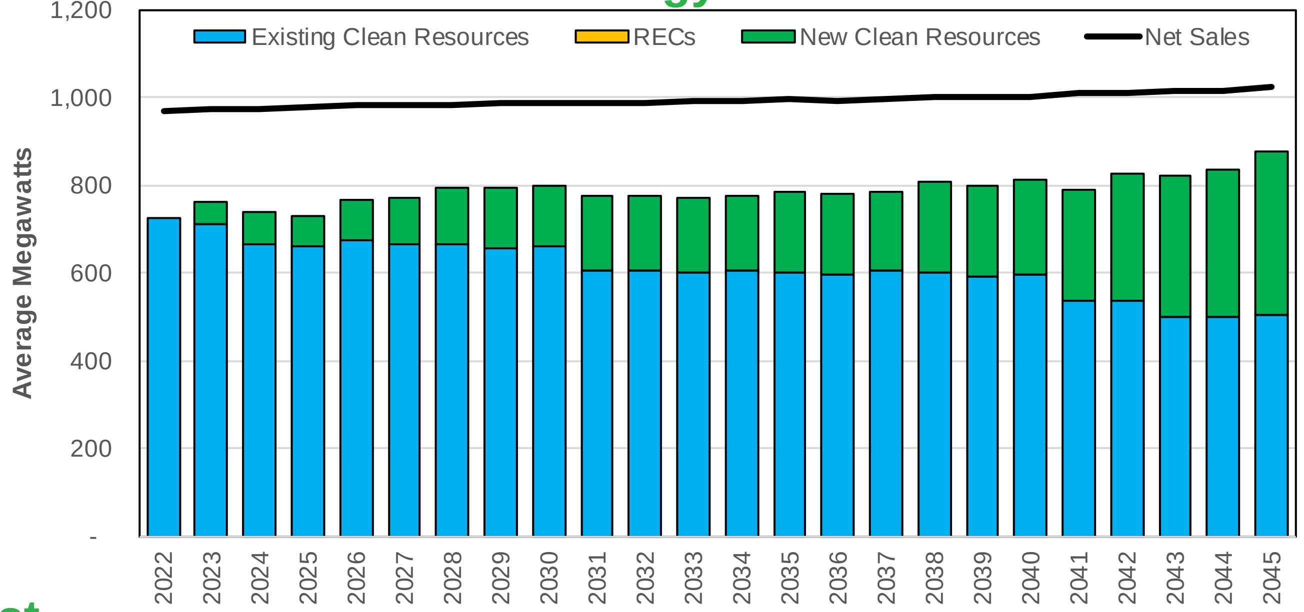
- 2024: Offer new rate programs (opt-in)

  (Time of use rates & variable peak pricing)
- 2026/27: Industrial load control
- 2031-32: Smart thermostat controls and commercial load control

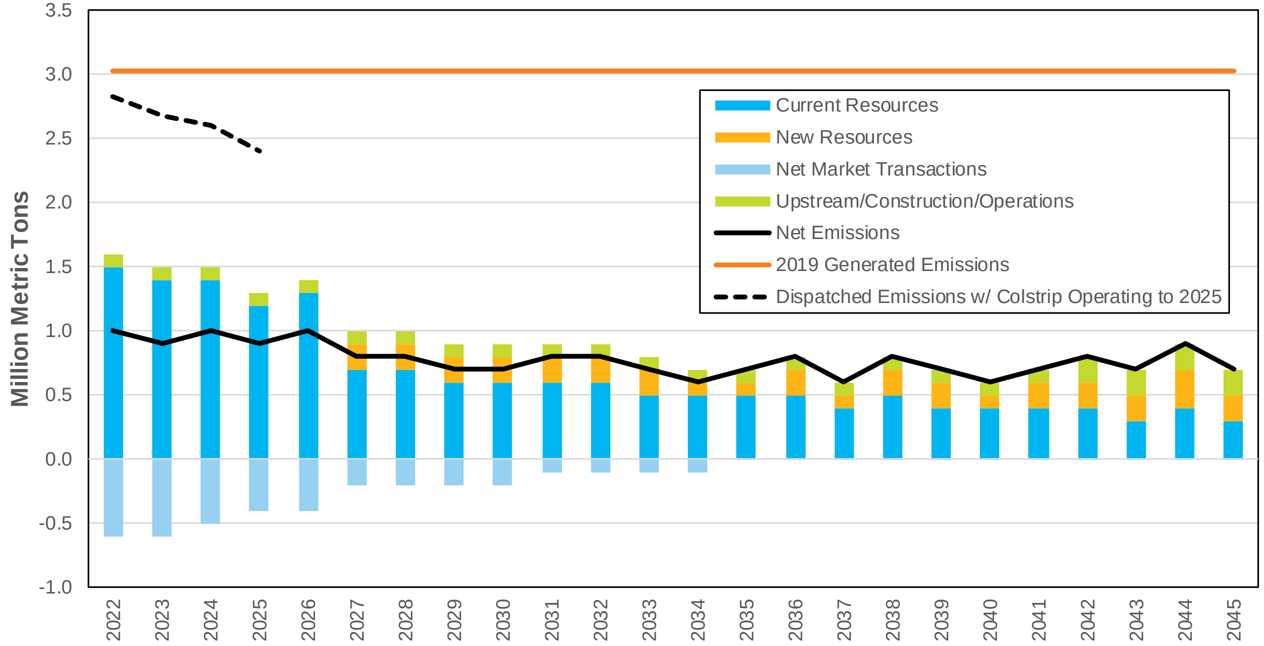
Avista's Cleaner Future

- Clean energy percent of system sales increase to 78% by 2027 and 86% by 2045.

Clean Energy Forecast



Greenhouse Gas Emission Forecast

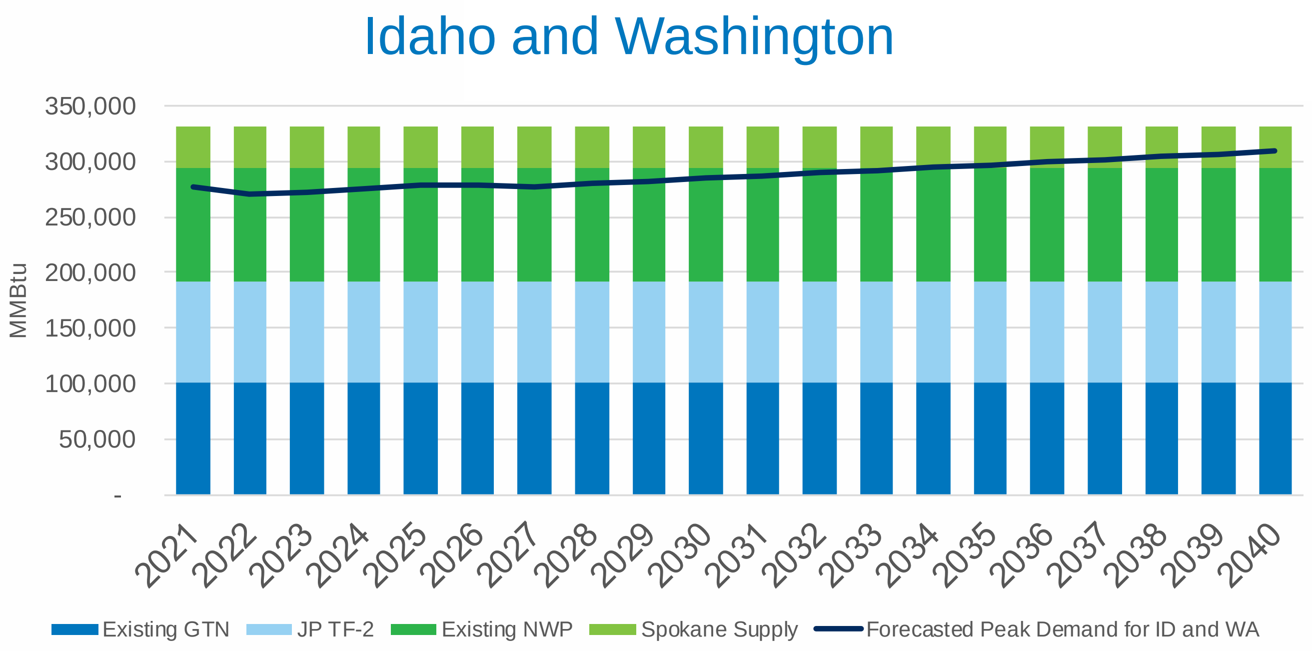


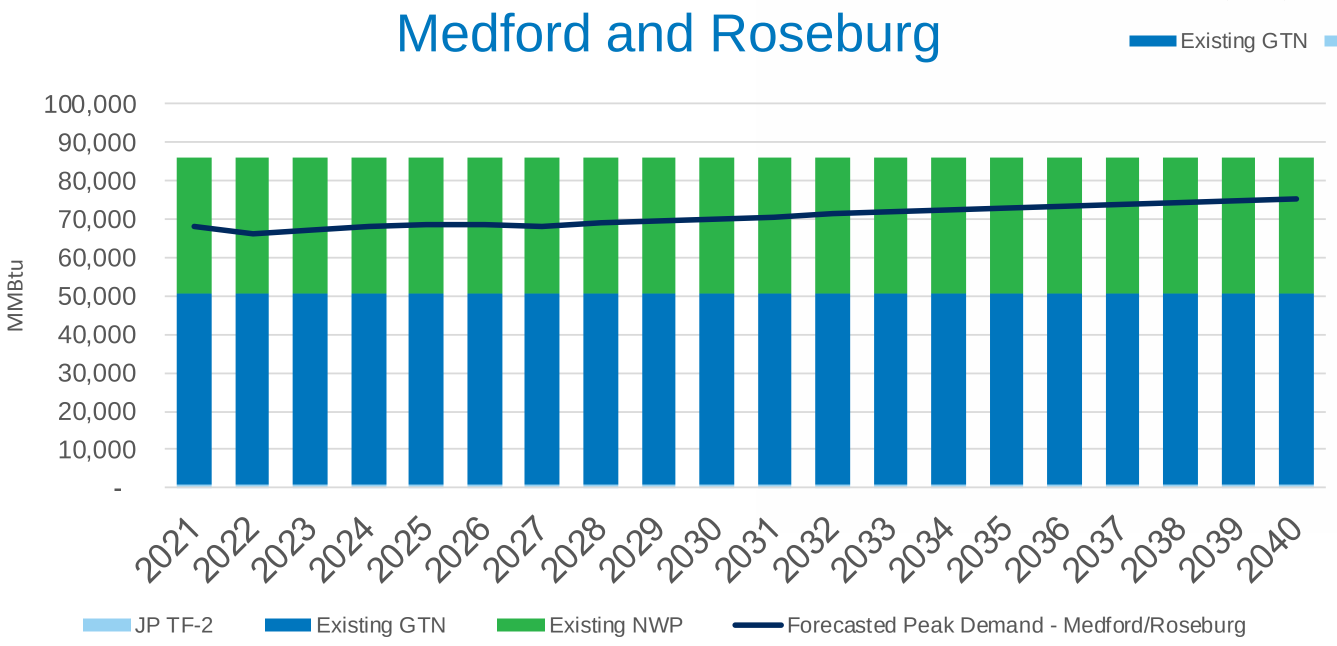
- By 2030, Avista's greenhouse gas emissions fall by 76 percent.
- 2019 Northwest power emissions were 57 million metric tons (Avista is 5.2% of those emissions).
- Power is 20% of all NW greenhouse gas emissions.

AVISTA

Natural Gas Integrated Resource Plan

Existing Resources vs. Peak Day Demand





What are the available options to meet our natural gas customer obligations?

<u>Clean Resources</u>

Renewable Natural Gas

Hydrogen

Power to Gas

<u>Fossil Fuel Resources</u>

Natural gas

Coal gasification

<u>Demand Resources</u>

Energy efficiency

Conservation

Load control

Rate programs

Fuel switching

<u>Storage</u>

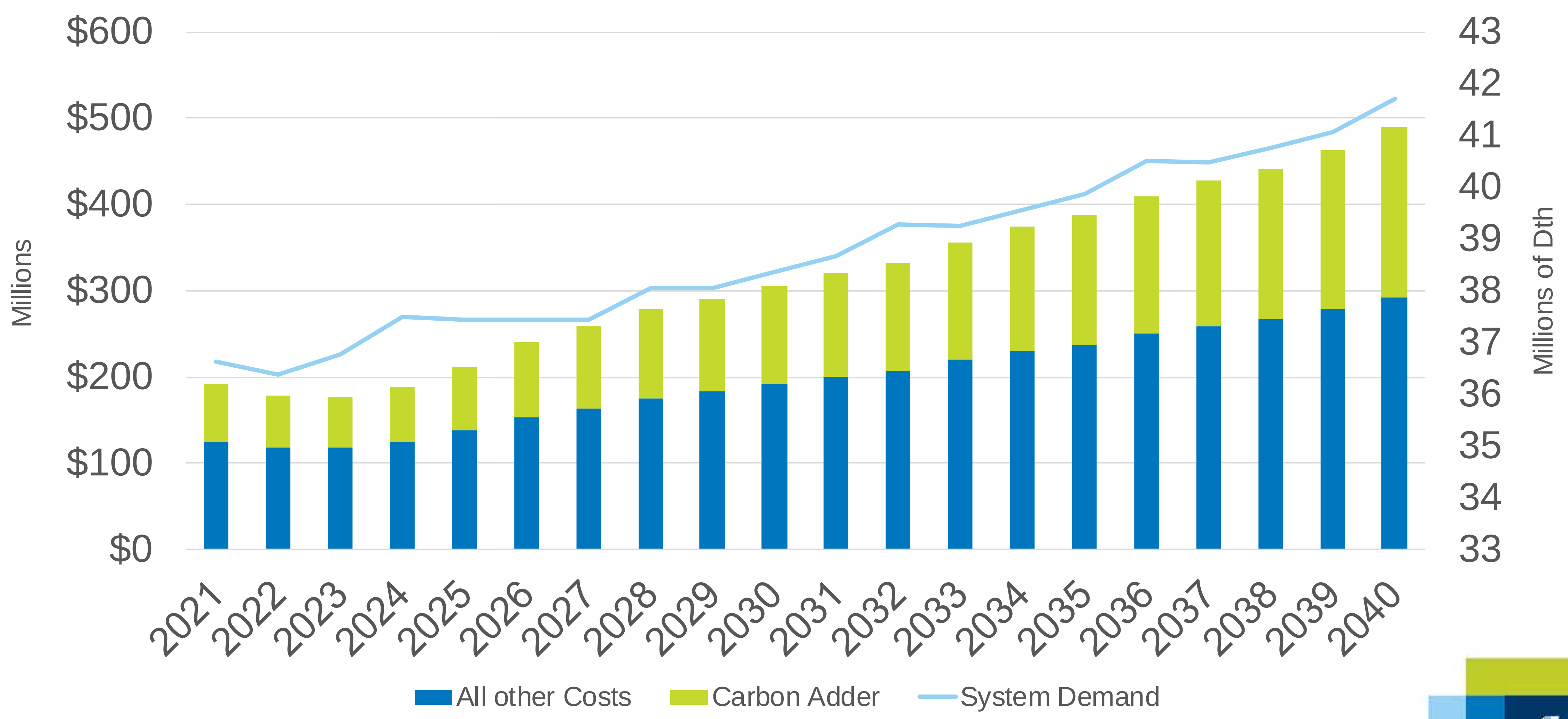
Jackson Prairie Storage Facility

Liquified Natural Gas

Compressed Natural Gas

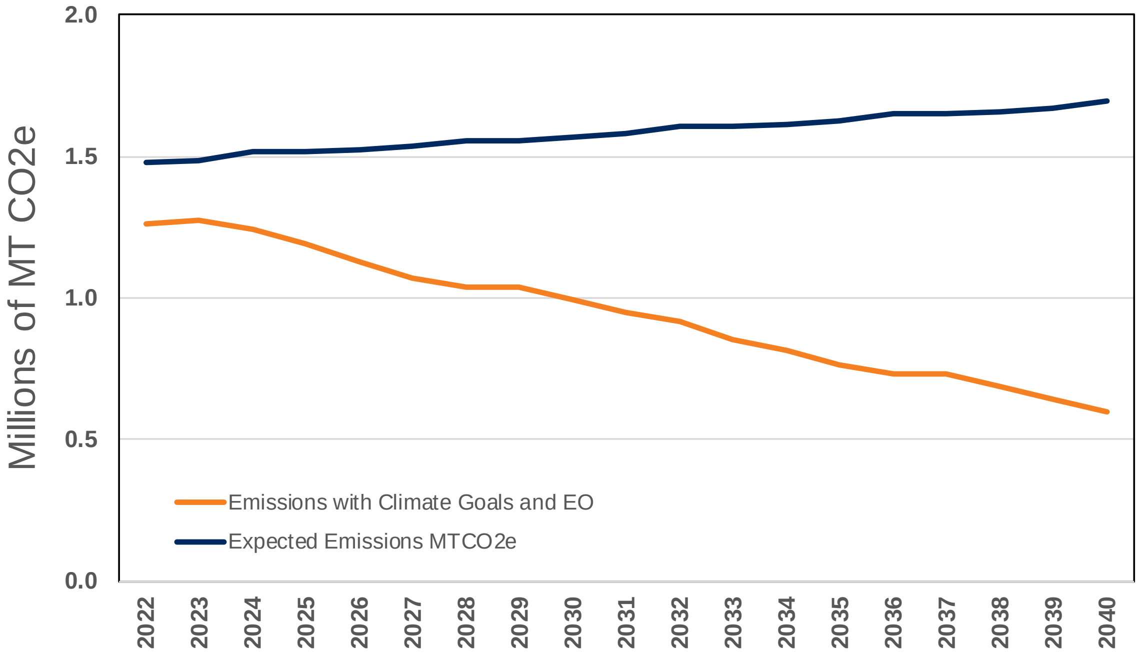
Resources in italics were not directly modeled for this IRP

Natural Gas System Cost vs Carbon Adder

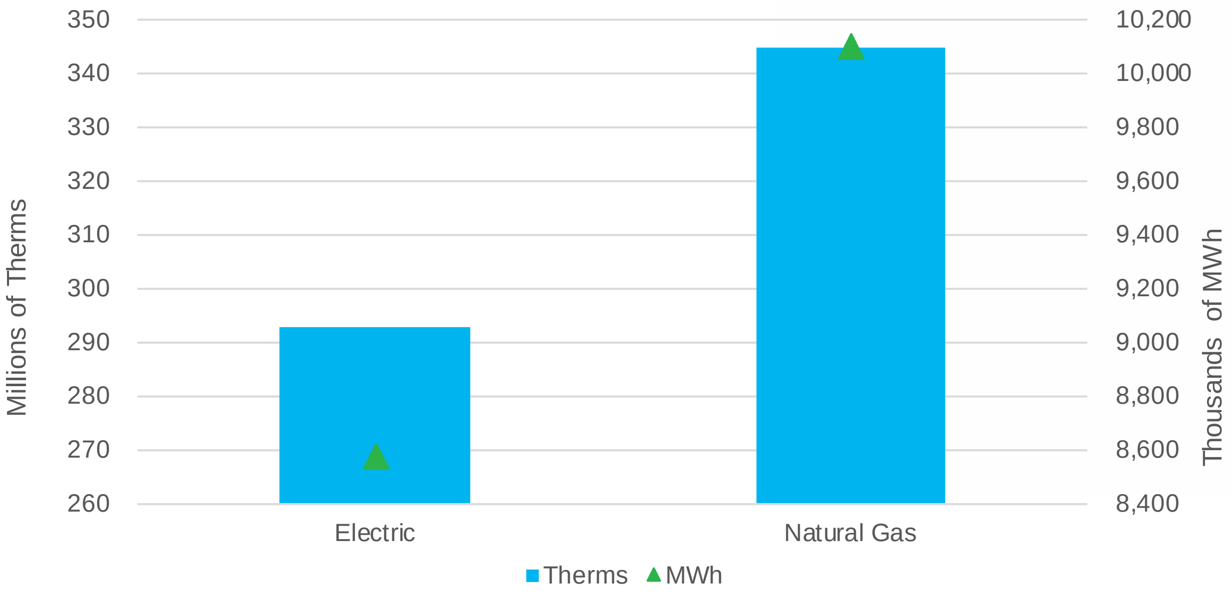


Avista Natural Gas – A Cleaner Future

Carbon Reduction Goals (Oregon & Washington)



2019 Retail Energy Delivered



Oregon - Executive Order 20-04

- 80% reduction by 2050

Washington - Goal

- 95% reduction by 2050

How do I get involved with the IRP?

How to learn more:

https://myavista.com/about-us/integrated-resource-planning

Email: irp@avistacorp.com

Washington UTC

www.utc.wa.gov

Electric Docket: UE-200301
Natural Gas Docket: UG-190724

Idaho PUC

https://puc.idaho.gov/

Oregon PUC

www.oregon.gov/puc

- Breakout rooms today
- Provide written comments to Avista's planning team by March 5th.
- Provide written comments to your state's commission
- Join Avista's Technical Advisory Committees
  - Electric IRP
  - Natural Gas IRP
  - Energy Efficiency
- Future participation opportunities
  - Equity
  - Energy Assistance
  - Distribution Planning

Breakout Sessions

- Two 30 minute break out room opportunities.
- You can access breakout rooms by using the links in the chat box or stay in this session
  - Passcode: Avista
- Short presentation by Avista staff (5 minutes)
- Opportunity to ask Avista staff questions or provide comments.
- Any questions not answered today will be available on the IRP Avista website by March 12.
- Limit of 300 participants in each room

- Generation Resource Selection & Reliability
  - Stay here or use registration link
  - Webinar ID: 82608251 3174
- Energy Efficiency & Demand Response
  - https://us02web.zoom.us/j/82664724856?pwd=QzdUMk9zUE1nRjViYTlXRkJ5S2p5UT09
  - Meeting ID: 826 6472 4856
- Affordability & Equity
  - https://us02web.zoom.us/j/88435288369?pwd=bGtNK3JYbTBCcktCV2JMRE1sT09CZz09
  - Meeting ID: 884 3528 8369
- Environmental Topics
  - https://us02web.zoom.us/j/89096065417?pwd=M0FzYWZHdjhTQlRRR2xwOSs4M1ByZz09
  - Meeting ID: 890 9606 5417
- Natural Gas Service
  - https://us02web.zoom.us/j/84369554229?pwd=YkZJc0ZrUm91NVFSanNJNmxPaVB4UT09
  - Meeting ID: 843 6955 4229

Breakout Session Ground Rules

- Due to the large response to this public meeting, please limit oral comments and questions to 30 seconds.
    - Avista will try to answer all questions.
    - Avista will also provide written responses if we cannot fully address the question.
    - Comments will be acknowledged and recorded.
- If you would like to make a comment or ask a question.
    - Use the “raise hand” feature in the meeting controls.
    - We will call upon each person to speak.
    - Please comment on areas within the breakroom topic
- Please do not repeat questions or comments.
    - If you have the same comments- please indicate in the chat box or send an email to irp@avistacorp.com with your comment
- In the event we do not get to your comment or question in the allotted time, please email irp@avistacorp.com
- Please limit comments or questions to resource planning- this means in relation to the energy we serve and not the delivery of energy. If you have these questions or any others please see.
    - http://myavista.com/smartmeters
    - askavista@myavista.com

Resource Selection & Reliability Breakout Room

James Gall
Thomas Dempsey
Damon Fisher

Resource Options

- Multiple factors drive resource selection
  - Cost or price
  - Clean vs. fossil fuel
  - Capacity value or “peak credit”
  - Storage vs. energy production
  - Location
  - Availability (new vs. existing)

- Resource retirements
  - Future capital investment
  - Operating & maintenance cost/availability
  - Fuel availability
  - Carbon pricing risk

- Non-energy costs & benefits
  - Social cost of carbon
  - Locational siting
  - Health, economic, and other benefits (still to come)

Clean Resources

Wind

Solar (utility and customer)

Biomass

Hydro

Geothermal

Nuclear

Fossil Fuel Resources

Natural gas peaker

Natural gas baseload

Coal (retention)

Customer generation

Demand Resources

Energy efficiency

Conservation

Load control

Rate programs

Fuel switching

Co-generation

Storage

Pumped hydro

Lithium-ion batteries (utility & customer)

Liquid air energy storage

Flow batteries

Hydrogen

Resources in italics were not directly modeled for this IRP

Supply-Side Resource Changes

- Long-term acquisition of new resources will be conducted with a public request for proposals (RFP).
  - Avista recently added the Rattlesnake Flat Wind project in 2020.
  - Avista is currently working with clean energy proposals from is most recent RFP- this RFP will determine a portion of the resource need in 2023-2024.
- New resource selection is determined by deliverability and lowest economic cost subject to resource policy requirements of each state

Resource Type	Year	State	Capability (MW)
Colstrip (Coal)	By end of 2025	System	(222)
Montana wind	2023	WA	100
Montana wind	2024	WA	100
Lancaster (Natural Gas)	2026	System	(257)
Post Falls Modernization (Hydro)	2026	System	8
Kettle Falls upgrade (Wood-Biomass)	2026	System	12
Natural gas peaker	2027	ID	85
Natural gas peaker	2027	System	126
Montana wind	2028	WA	100
NW Hydro Slice	2031	WA	75
Rathdrum CT upgrade (Natural Gas)	2035	System	5
Northeast (Natural Gas)	2035	System	(54)
Natural gas peaker	2036	System	87
Solar w/ storage	2038	System	100
4-hr storage for solar	2038	System	50
Boulder Park (Natural Gas)	2040	System	(25)
Natural gas peaker	2041	ID	36
Montana wind	2041	WA	100
Solar w/ storage	2042-2043	WA	239
4-hr storage for solar	2042-2043	WA	119
Liquid air energy storage	2044	WA	12
Liquid air energy storage	2045	ID	10
Solar w/ storage	2045	WA	149
4-hr storage for solar	2045	WA	75
Supply-side resource net total (MW)			1,032
Supply-side resource total additions (MW)			1,589

Energy Efficiency and Demand Response Breakout Room

Ryan Finesilver
Leona Haley

Energy Efficiency & Demand Response

Conservation Potential

Study to determine overall conservation potential

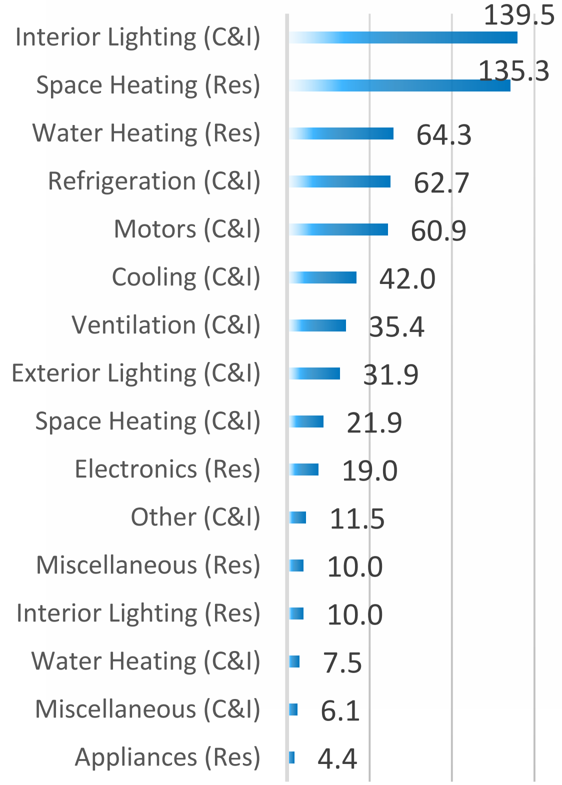
Integrated Resource Planning

Preferred Resource Strategy selects “measures” and sets target

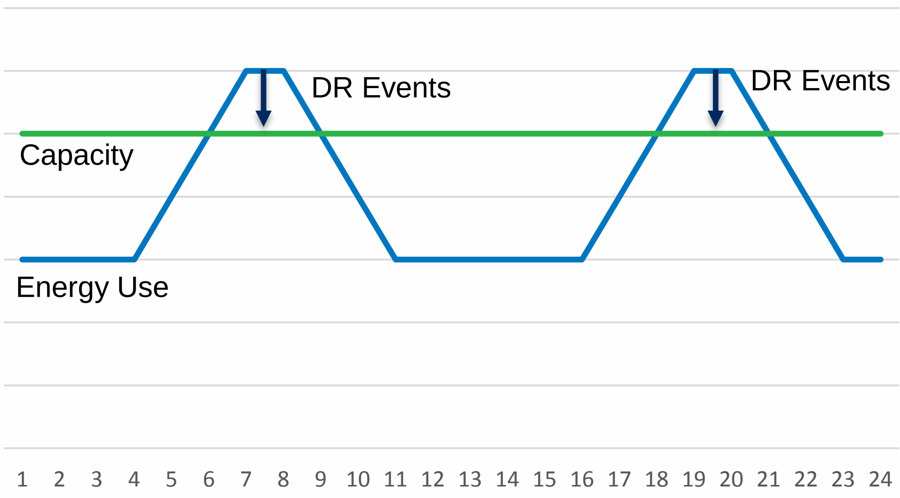
Energy Efficiency Program

Program designed to “incent” customers to make energy efficiency choices

10-YEAR GWH CONSERVATION POTENTIAL

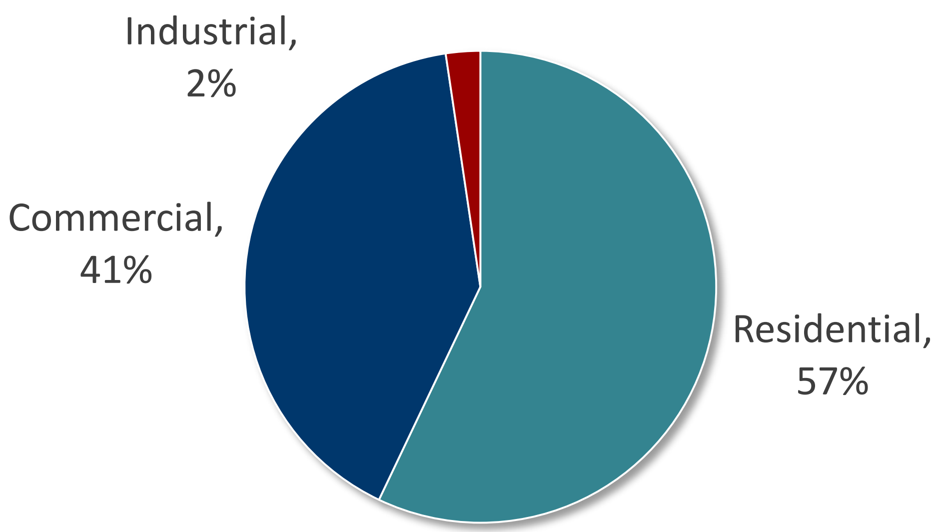


Demand Response

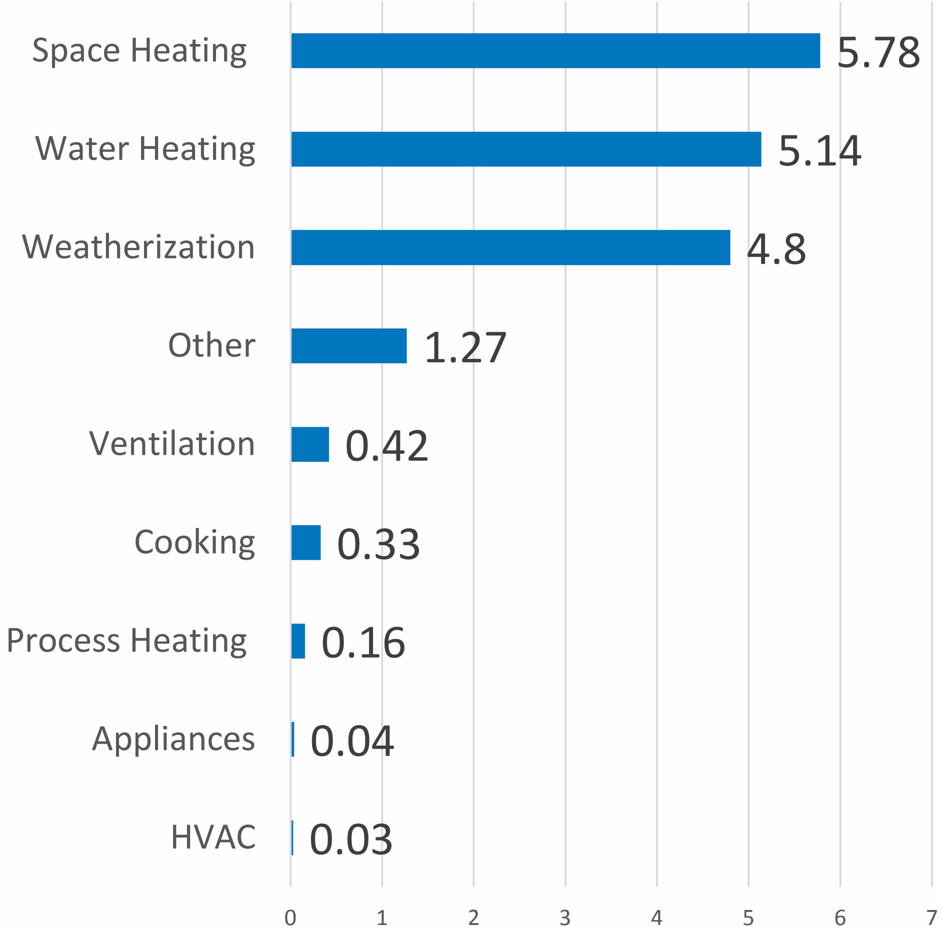


Program	Washington	Idaho
Time of Use Rates	2 MW (2024)	2 MW (2024)
Variable Peak Pricing	7 MW (2024)	6 MW (2024)
Large C&I Program	25 MW (2027)	n/a
DLC Smart Thermostats	7 MW (2031)	n/a
Third Party Contracts	14 MW (2032)	8 MW (2024)
Behavioral	1 MW (2041)	n/a
Total	**56 MW**	**15 MW**

Natural Gas Energy Efficiency

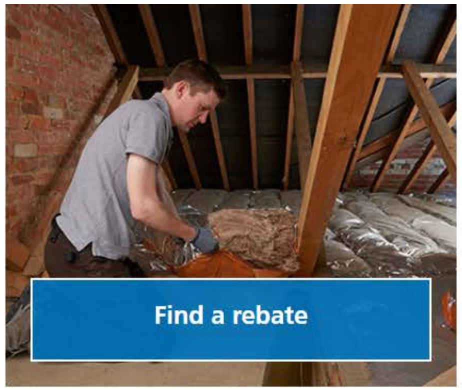


Millions of Therms



Way to Save

https://www.myavista.com/energy-savings/way-to-save



Affordability and Equity Breakout Room

Ana Matthews
Shawn Bonfield
Renee Coelho
Lisa McGarity

Energy Rate Forecasts

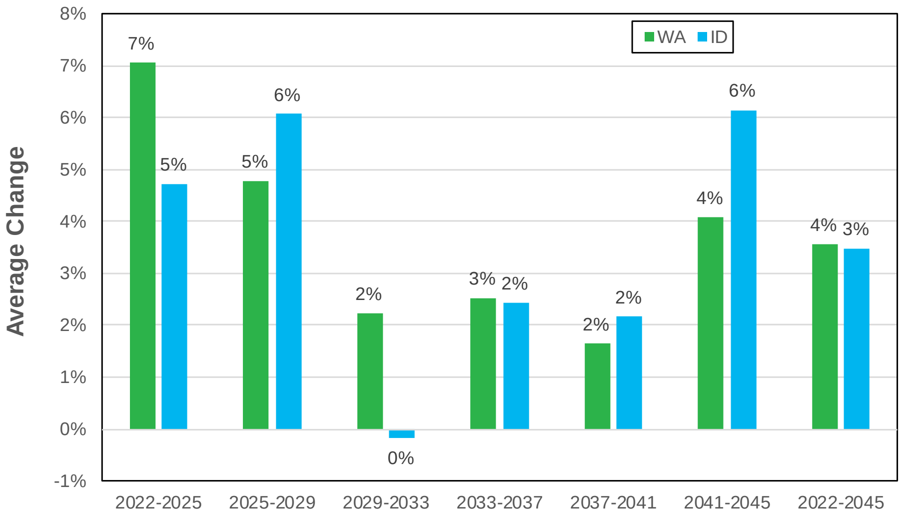
Electric Rates:

- To meet Avista's reliability requirements and Washington clean energy policies electric rates will increase.
- Today, Washington rates are ~1 cent (12%) higher per "average" kWh.
- Going forward the difference between Washington and Idaho rates will continue to separate.
    - Both Idaho and Washington customers financially benefit by lower rates unless Idaho's share of clean resources are kept in Idaho.

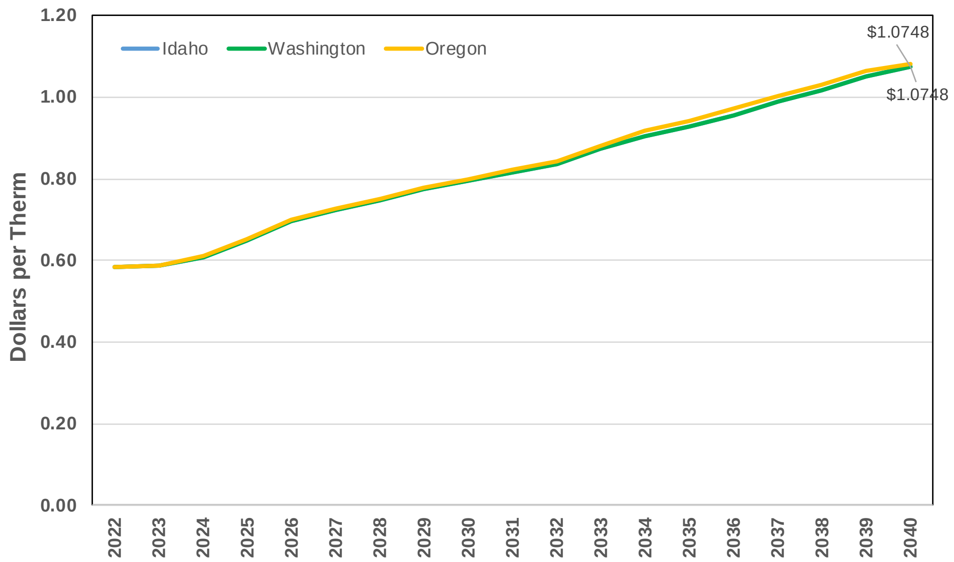
Natural Gas Rates:

- Natural gas rate increases are driven by increases in the price to acquire the natural gas commodity and general inflation to operate the system.

Electric Power Cost Rate Changes



Annual Average Natural Gas Rate Forecast



Note: Assumes 2% annual increase in non-energy resource costs

Energy Equity and Energy Assistance Overview

- Washington State's recently passed legislation CETA (Clean Energy Transformation Act) requires
  - equitable distribution of energy benefits and reduction of burdens to vulnerable populations and highly impacted communities;
  - long-term and short-term public health, economic, and environmental benefits and the reduction of costs and risks;
  - and energy security and resiliency.
- It is the intent of the legislature that in achieving this policy for Washington, there should not be an increase in environmental health impacts to highly impacted communities.

Bill Assistance

LIRAP Heat

LIRAP Senior/Disabled Outreach

Emergency Assistance

LIRAP Emergency Share

COVID-19 Hardship

Rate Discount

Senior/Disabled

To Be Implemented

Percent of Income Payment Plan

Arrearage Management Program

Conservation Education

Energy Fairs

Workshops

General and Mobile Outreach

Energy Efficiency

Low-Income Weatherization

Low-Income Rate Assistance Program (LIRAP)

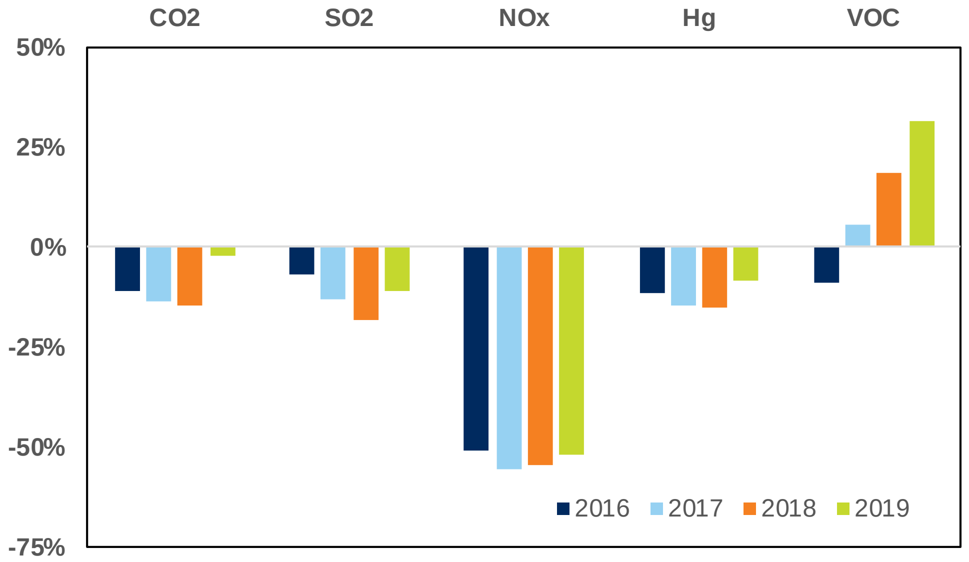
Environmental Topics Breakout Room

John Lyons
Bruce Howard

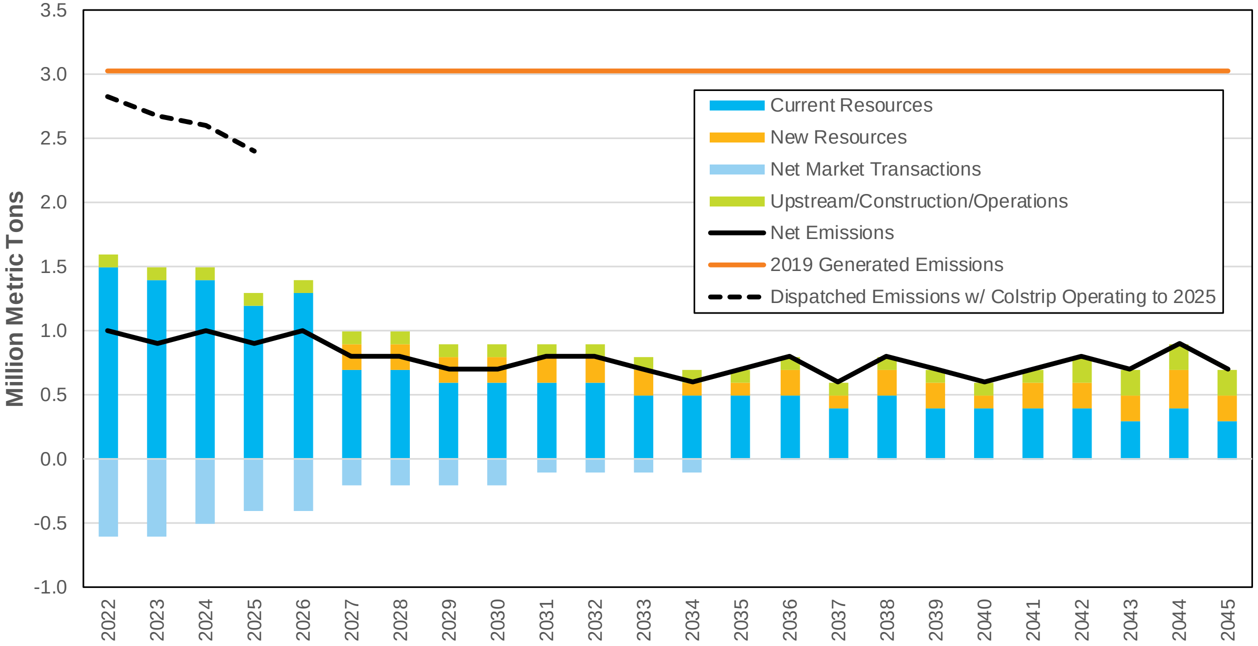
Avista's Environmental Footprint

- By 2030, Avista's greenhouse gas emissions fall by 76 percent.
- 2019 Northwest power emissions were 57 million metric tons (Avista is 5.2% of those emissions).
- Power is 20% of all NW greenhouse gas emissions.

Total Change in Air Emissions Since 2015



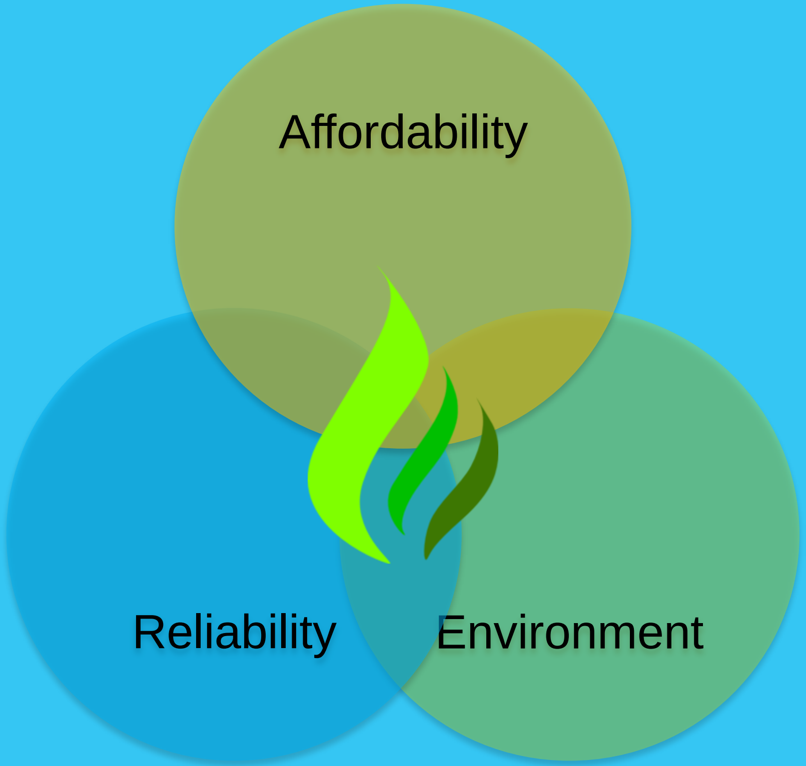
Greenhouse Gas Emissions Forecast



- Total emissions are determined by utilization of facilities and control technology.
- NOx emissions fall by over 50% due to smart burn technology at Colstrip coal fired facility,
- VOC emission rise is due to increased plant utilization and new testing at the Kettle Falls Biomass facility,

Natural Gas Breakout Room

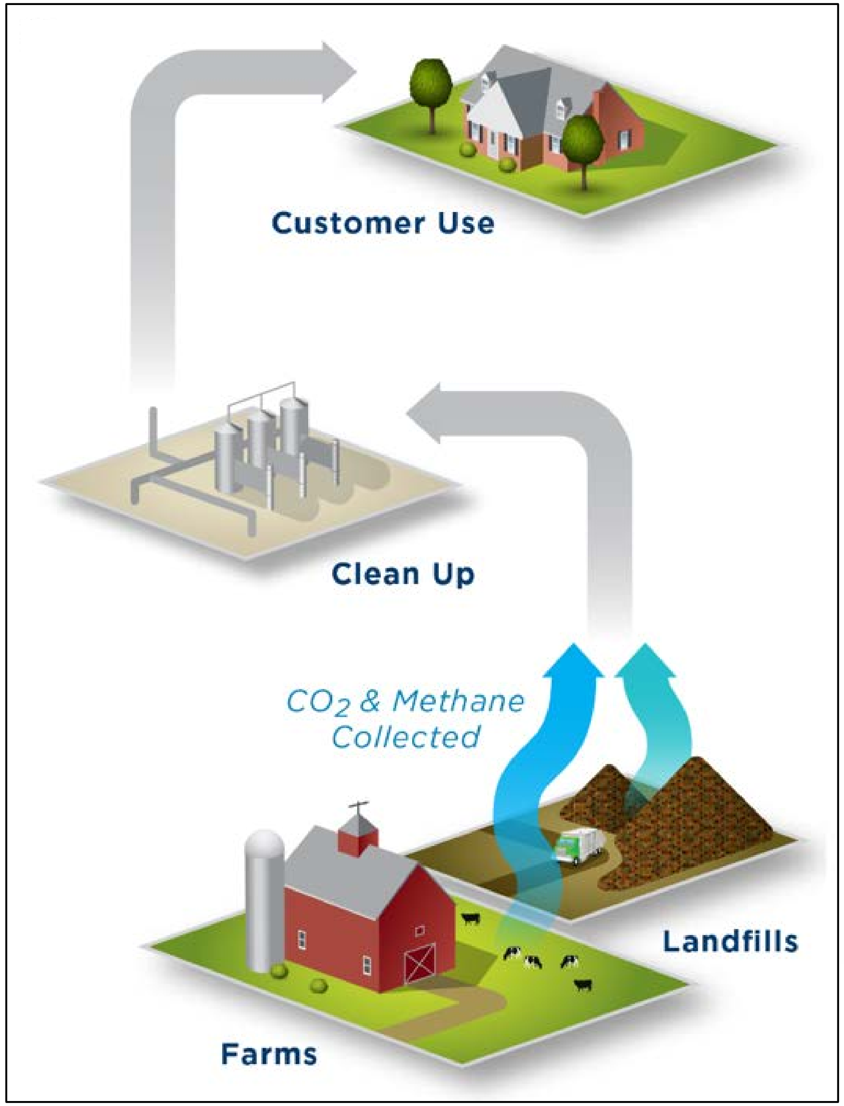
Tom Pardee
Michael Whitby
Jody Morehouse



Carbon Reduction Pathways

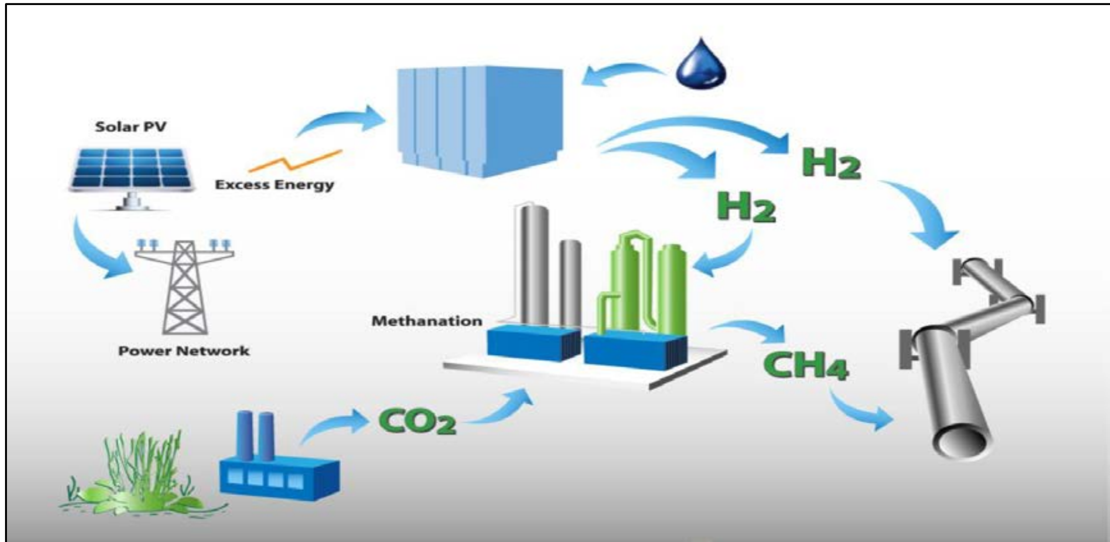
Renewable Natural Gas (RNG)

- Biogas from decomposing waste streams is captured
- The gas is scrubbed to pipeline quality RNG
- RNG flows through existing natural gas pipelines to end users



Power to Gas with Hydrogen

- Renewable electricity converts water to hydrogen
- Hydrogen is combined with waste CO_2 to make RNG
- RNG flows through existing natural gas pipelines to end users



Natural Gas is Critical to a Clean Energy Future

- In the right applications, **direct use of natural gas is best use**
- Natural gas generation provides **critical capacity** as renewables expand until utility-scale storage is cost effective and reliable
- Full electrification can lead to **unintended consequences**:
  - Creates new generation needs that can increase carbon emissions
  - Drives new investment in electric distribution infrastructure, causing bill pressure
  - Home and business conversion costs borne by customers
  - Puts at risk energy **reliability and resilience, energy choice, and affordability**
- Customers have paid for a vast pipeline infrastructure that can utilized for a cleaner future by **transitioning the fuel** and keeping the pipe
- A comprehensive view of the energy ecosystem leads to a **diversified approach to energy supply** that includes natural gas