2025 Electric Integrated Resource Plan

Appendix A – 2025 Technical Advisory Committee and Public Presentations and Meeting Minutes

2025 Electric Integrated Resource Plan

Technical Advisory Committee Meeting No. 1 Agenda

Tuesday, September 26, 2023
Virtual Meeting

Topic	Time	Staff
Introductions	8:30	John Lyons
CEIP Update	8:45	Kelly Dengel
TAC Process and Methods Proposals	9:15	James Gall
PLEXOS Overview and Back Cast Analysis	9:45	Mike Hermanson
Break	10:45	
Available Resource Options Discussion	11:00	Lori Hermanson
Work Plan	11:30	John Lyons
Adjourn	12:00	

Microsoft Teams meeting

Join on your computer, mobile app or room device

Click here to join the meeting

Meeting ID: 294 629 977 632

Passcode: ULtVWS

Download Teams | Join on the web

Or call in (audio only)

+1 509-931-1514,,307115655# United States, Spokane

Phone Conference ID: 307 115 655#

Find a local number | Reset PIN

2023 IRP TAC 1 Introductions

John Lyons, Ph.D.
Technical Advisory Committee Meeting No. 1
September 26, 2023

Meeting Guidelines

- IRP team is in office Monday - Wednesday and also available by email, phone and Teams for questions and comments
- Stakeholder feedback responses shared with TAC at meetings, in Teams and in Appendix
- Working IRP data posted to Teams
- Virtual IRP meetings on Teams, in person available for full day meetings
- Final TAC presentations, meeting notes and recordings posted on IRP page

Virtual TAC Meeting Reminders

- Please mute mics unless speaking or asking a question
- Raise hand or use the chat box for questions or comments
- Respect the pause
- Please try not to speak over the presenter or a speaker
- Please state your name before commenting for the note taker
- This is a public advisory meeting – presentations and comments will be documented and recorded

Integrated Resource Planning

The Integrated Resource Plan (IRP):

- Required by Idaho and Washington* every other year
  - Washington now requires IRP every four years and update at two years
- Guides resource strategy over the next twenty years
- Current and projected load & resource position
- Develop alternative load/customer forecasts
- Resource strategies under different future policies
  - Generation resource choices
  - Energy efficiency / 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
  - Always looking for help with soliciting new TAC members
- Open forum while balancing need to get through topics
- Welcome requests for studies or different assumptions.
- Available by email or phone for questions or comments between meetings

Today's Agenda

8:30	Introductions, John Lyons
8:45	CEIP Update, Kelly Dengel
9:15	TAC Process and Methods Proposals, James Gall
9:45	PLEXOS Overview and Back Cast Analysis, Mike Hermanson
10:45	Break
11:00	Available Resource Options Discussion, Lori Hermanson
11:30	Work Plan, John Lyons
12:00	Adjourn

Clean Energy Implementation Plan

Biennial Report Update

September 26, 2023 – IRP TAC Meeting

Agenda

- CETA/ CEIP Background
- CEIP Biennial Update:
  - Energy Supply Specific Actions
  - Customer Benefit Indicators
  - Energy Efficiency & Demand Response Specific Actions
  - Named Communities Investment Fund
  - Public Participation
  - Conditions

CETA / CEIP Background

Clean Energy Transformation Act (CETA) Law – May 2019

Clean Energy Implementation Plan (CEIP) – Every 4 Years

Filed October 1, 2021, for 2022-2025 compliance period

Clean Energy Progress Report – Annually

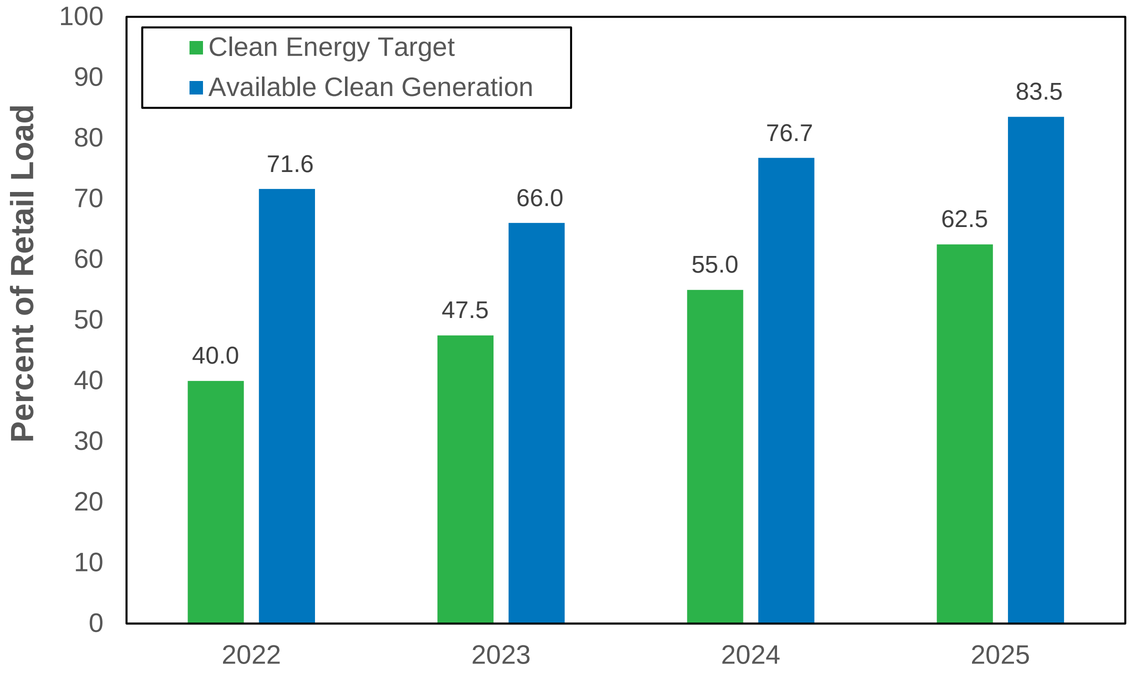
Filed June 29, 2023, for 2022 compliance period

Biennial CEIP – Every Two Years, Except where a CEIP is required

To be filed November 1, 2023

Energy Supply Specific Actions

Washington Clean Energy Targets



Notes:
1) Available generation through July 1, 2023, is actual generation;
2) Beyond July 1, 2023, assumes normal weather conditions;
3) Excess generation/ environmental attributes may be sold to reduce customer cost burden. All excess 2022 environmental attributes were sold.

Energy Efficiency & Demand Response Specific Actions

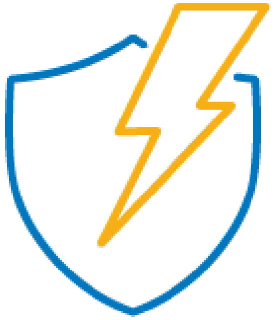
- Demand Response Pilots for 2024-2025
- Small Business Lighting Direct-Install Program
- Avista-Spokane Tribe Energy Partnership
- Low Income Weatherization & Deferred Maintenance Pilot
- Named Communities Investment Fund

https://www.myavista.com/energy-savings/rebate-overview

Customer Benefit Indicators

Affordability

- Participation in Company Programs
- Households with High Energy Burden
- Residential Arrears & Disconnects



Energy Security & Resilience

- Energy Availability
- Energy Generation Location

Access to Clean Energy

- Methods/Modes of Outreach & Communication
- Transportation Electrification

Environmental

- Outdoor Air Quality
- Greenhouse Gas Emissions

Community Development

- Named Community Clean Energy
- Investments in Named Communities

Public Health

- Employee Diversity
- Supplier Diversity
- Indoor Air Quality

Named Communities Investment Fund

- Specific action dedicated to the ***equitable distribution*** of ***energy and non-energy benefits and reduction in burdens*** to Named Communities

- Funding is limited to 1% of retail revenue or ~ $5.0 million annually

$2M
Supplement Energy Efficiency

$1M
Investments in Distribution Resiliency

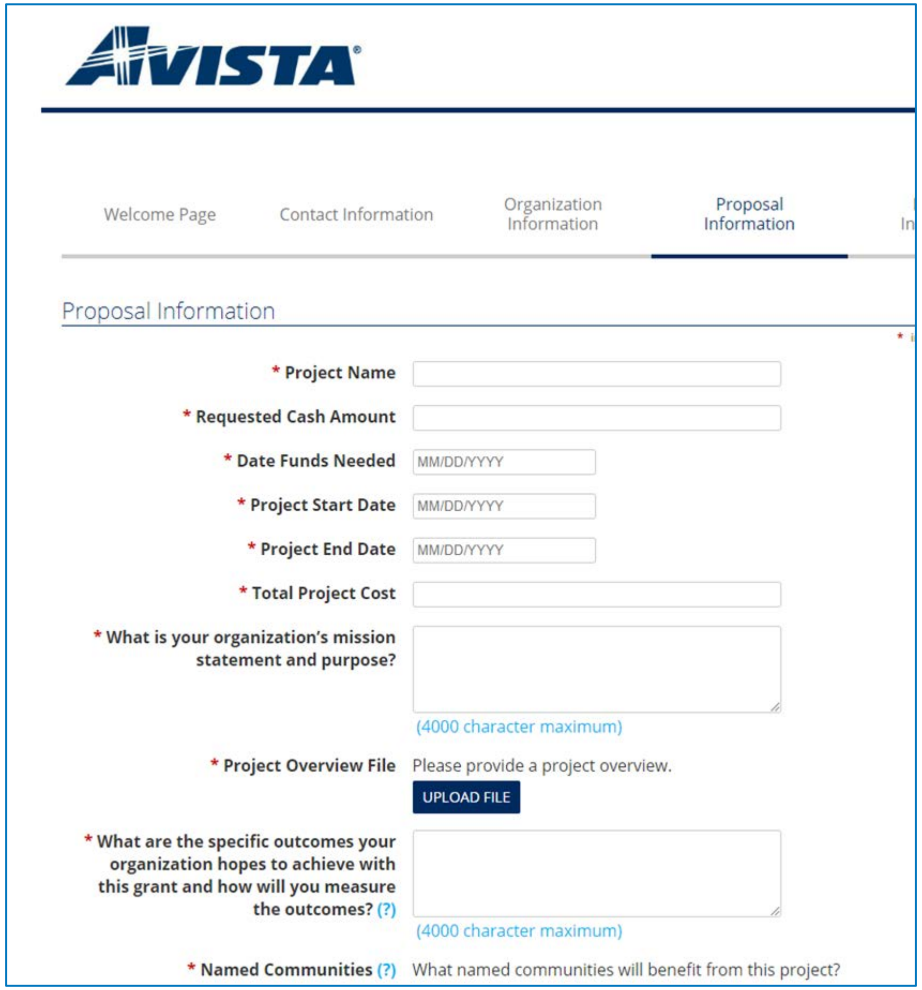
$1M
Incentives & Grants Customers/Third Parties

$500,000
Outreach & Engagement

$500,000
Other Projects, Programs or Initiatives

NCIF Application

- Open to government/community/non-profit agencies and organizations
- Establish a user ID and password
- Information about the applicant and proposal
- Application is open continuously
- Award decisions communicated within 45 days of submission



https://www.cybergrants.com/pls/cybergrants/quiz.display_question?x_gm_id=5440&x_quiz_id=11888

Equity Advisory Group's NCIF Prioritization

Rank	EAG NCIF Prioritized Initiatives
1	Focus efforts on improving energy efficiency (and EE awareness/education) for schools, community centers, and other places where Named Communities spend time
1	Focus efforts on improving energy efficiency for Spokane Tribe partners
2	Improve energy efficiency in multi-family and mobile home communities
3	Increase tree canopy and shade in Named Communities (consider tradeoffs with solar)
3	Increase access to energy efficient products and appliances for Named Communities
4	Increase awareness of and engagement in energy efficiency programs while also meeting whole-house needs through community-based partnerships and referrals to services
5	Set aside funds to match for energy efficiency grant applications for community organizations and tribal partners (could have higher feasibility)
6	Focus efforts on improving energy efficiency for community members without stable housing (consider including with other initiatives)

NCIF Requirements

Proposal assessments include:

- Serving Named Communities
- Equity Areas
- Customer Benefit Indicators

Customer Benefit Indicators

Participation in Company Programs
Number of households with a high energy burden
Availability of Methods/Modes of Outreach & Communication
Transportation Electrification
Named Community Clean Energy
Investments in Named Communities
Energy Availability
Energy Generation Location
Outdoor Air Quality
Greenhouse Gas Emissions
Employee Diversity
Supplier Diversity
Indoor Air Quality

Named Communities Investment Fund Projects

Energy Efficiency

- Health & Safety for Mobile Homes
- EE for Affordable Housing
- EE for Homes in Malden, WA
- Lincoln County Fairgrounds Lighting
- Spokane Tribe Building Energy Audits
- EE for Spokane Tribe Buildings

Distribution Resiliency

- MLK Center – Solar & Battery Storage
- Town of Malden – Solar & Ground Source Heat Pump

Incentives & Grants

- Kids Making Sense – Air Monitors

Outreach & Engagement

- Public Participation Plan
- NCIF Online Application

Projects & Initiatives

- Medical Battery Back Up Pilot
- Christ Kitchen

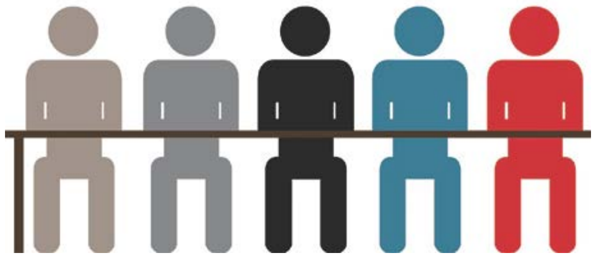
Public Participation Updates

Avista's Public Participation Plan was filed May 1, 2023

- Mitigate public participation barriers
- Implement meaningful strategies to engage all customers including vulnerable populations and highly impact communities,
- Ensure the equitable distribution of energy and non-energy benefits

Public Participation Updates

- Multi-Language Strategy
- CEIP Newsletter
- Public Comment Form
- Frequently Asked Questions & Answers
- Public Participation Meeting
- Equity Advisory Group (EAG)



Conditions

38 Conditions across 11 categories

- Interim & Specific Targets
- Baseline Conditions
- Specific Actions
- Demand Response
- Distributed Energy Resources & Distribution Planning
- Energy Efficiency
- Customer Benefit Indicators
- Public Participation & Equity Advisory Group
- Incremental Cost of Compliance
- Integrated Resource Plan
- Cost Recovery

TAC Biennial CEIP Review

- Post on IRP Teams site October 1
- Deadline for comments/questions October 13, 2023
  - Contact Kelly Dengel, Kelly.dengel@avistacorp.com
- Include comments/questions in filing Biennial CEIP November 1, 2023

Thank You

www.myavista.com/ceta

ceta@avistacorp.com

Appendix

CEIP Conditions

Condition 1

Once the Commission has adopted final "use" rules in Docket UE-210183, in its Clean Energy Implementation Plan (CEIP) docket, if different than Table 2.1 on page 2-3 in the CEIP, Avista shall update its CEIP to reflect the percentage of retail sales of electricity supplied by non-emitting resources and renewable resources in 2020 within 30 days.

Condition 2

Avista will apply Non-Energy Impacts (NEIs) and Customer Benefit Indicators (CBIs) to all resource and program selections in determining its Washington resource strategy, in its 2023 Integrated Resource Plan (IRP) Progress Report and will incorporate any guidance given by the Commission on how to best utilize CBIs in CEIP planning and evaluation. Avista agrees to engage and consult with its applicable advisory groups (IRP Technical Advisory Committee (TAC) and Energy Efficiency Advisory Group (EEAG)) regarding an appropriate methodology for including NEIs and CBIs in its resource selection.

Condition 3

Regarding transparency of resource acquisitions, Avista will provide an update at its next IRP TAC meeting following the acquisition, of any material demand-side resource acquisition or utility scale resource acquisition with a term longer than 2 years.

Condition 4

While inclusion in the CEIP could factor into a prudence determination, Avista agrees not to rely solely on the 2021 CEIP to justify prudence of utility scale renewable resource acquisitions made on or after January 1, 2022. While the CEIP may include specific actions Avista may take to comply with CETA's clean energy targets, prudence determinations of utility scale renewable resource acquisitions will be made through the general rate case process.

CEIP Conditions

Condition 5

In its 2023 Biennial CEIP Update and in future CEIPs, Avista will include descriptions of quantitative (i.e., cost based) and qualitative (e.g., equity considerations) analyses that support interim targets to comply with the Clean Energy Transformation Act's (CETA) 2030 and 2045 clean energy standards.

Condition 6

In its 2023 Biennial CEIP Update and in future CEIPs, Avista will include quantitative and qualitative risk analysis, if risk is used to justify deviating from the lowest reasonable cost solution that complies with CETA.

Condition 7

Avista commits to the following minimum Interim Renewable Energy Targets for the 2022-2025 CEIP implementation period:

Year	Interim Target
2022	40%
2023	47.5%
2024	55%
2025	62.5%

Condition 8

Avista in its IRP resource selection model for the 2023 IRP Progress Report will give the model the option to meet CETA goals with a choice between an Idaho allocated existing renewable resource at market price (limited to Kettle Falls, Palouse Wind, Rattle Snake Flats Chelan PUD purchase contracts 2 & 3) or acquiring a new 100% allocated Washington renewable resource for primary compliance. Further, the model will have the option to acquire new 100% allocated resource, market REC, or Idaho allocated REC (at market prices) to meet alternative compliance.

CEIP Conditions

Condition 9

Avista agrees to update and expand its Vulnerable Populations areas within its 2023 Biennial CEIP Update taking into account the additional criteria developed by the EAG and Energy Assistance Advisory Group (EAAG) and to ensure updates are in line with the definition of Vulnerable Populations outlined in RCW 19.405.020(40). Additional work is needed to develop a consistent methodology and data source identification. This additional work is primarily related to identifying a consistent data source(s) to evaluate each characteristic and then overlaying it onto a map.

Condition 10

By December 1, 2022, in collaboration with its EAG and EAAG and per WAC 480-100-640(5)(a) and (c), Avista agrees to identify at least one specific action that will serve a designated subset of Named Communities, to be funded by the Named Communities Investment Fund, and to identify and track all CBIs relevant to this specific action. The location identified for the specific action will be at the granularity of the designated Named Communities subset.

Condition 11

Avista will share and present the results, analysis, and conclusions of its pricing pilots with its EEAG, EAAG, and IRP TAC following the completion of the third-party evaluator's review of the pilots. If Avista develops pricing programs based on the results of its pricing pilots, it will work with its advisory groups to develop program targets.

Condition 12

When the Department of Commerce adopts a permanent standard for grid-enabled water heaters in WAC 194-24-180, Avista will develop a pilot demand response program. Avista will work with its EEAG on the pilot program implementation timing and how to incorporate results into its planning efforts.

CEIP Conditions

Condition 13	Avista will initiate its Distribution Planning Advisory Group (DPAG) no later than the end of 2022, and it must invite all existing advisory groups to participate in the new group. Avista acknowledges that stakeholders have limited resources and will consult between existing advisory groups and stakeholders regarding streamlining.
Condition 14	Avista will include a Distributed Energy Resources (DERs) potential assessment for each distribution feeder no later than its 2025 electric IRP. Avista will develop a scope of work for this project no later than the end of 2022, including input from the IRP TAC, EEAG, and DPAG. The assessment will include a low-income DER potential assessment. Avista will document its DER potential assessment work in the Company's 2023 IRP Progress Report in the form of a project plan, including project schedule, interim milestones, and explanations of how these efforts address WAC 480-100-620(3)(b)(iii) and (iv).
Condition 15	Avista agrees to evaluate the need for a targeted DER Request for Proposals (RFP) if a need is demonstrated as part of its DPAG process.
Condition 16	Avista will update its energy efficiency (EE) target no later than the 2023 Biennial CEIP Update, when the next Biennial Conservation Plan is due on November 1, 2023, based on continued discussion of its residential EE savings target and programs with its EEAG. Discussion will include program design elements which could promote more participation and additional uses of the Named Communities Investment Fund, if approved.

CEIP Conditions

Condition 17

As part of its CBI Participation in Company Programs, Avista agrees to track the number of residential appliance and equipment rebates provided to customers residing in Named Communities and the number of residential rebates provided to customers residing in rental units and commits to work to expand data availability during this CEIP period. Avista agrees to discuss programs to increase the number of participating households in Named Communities with its EEAG and move forward with feasible programs, if identified.

Condition 18

Avista agrees that the CBI – Number of Households with a High Energy Burden (>6%), will be separately tracked for all Avista electric customers, Known Low Income (KLI) customers and Named Communities. KLI customers are defined as those who have received energy assistance during the prior two years.

Condition 19

Avista agrees that for its CBI – Availability of Methods/Modes of Outreach and Communications, an additional metric will be identified to track increased availability of translation services by October 1, 2022. Once identified, a baseline for the metric will be established and the metric will be reported in the 2023 Biennial CEIP Update.

Condition 20

Avista agrees that for the CBI – Outdoor Air Quality, it will adopt a metric related to decreased wood use for home heating in its 2023 Biennial CEIP Update. The data included in this metric may include the data from the Company's wood stove replacement program offered in partnership with the Spokane Clean Air Agency, as well as data from other sources. Avista will work with its EEAG and other appropriate advisory groups to identify and evaluate additional wood stove usage metrics to be proposed in the 2023 Biennial CEIP Update, if applicable.

CEIP Conditions

Condition 21	Avista agrees that the CBI – Energy Availability will include a metric related to the frequency of customer outages for all customers, Vulnerable Populations, and Highly Impacted Communities.
Condition 22	Avista agrees to add the following CBI and metrics related to Energy Security: CBI: Residential Arrearages and Disconnections for Nonpayment Measurement 1. Arrearages and 2. Disconnections
Condition 23	Avista must formally present and discuss any Joint Advocate or other stakeholder proposed CBI that was not included in the Company's filed CEIP and the final Commission approved CEIP with conditions, to its advisory groups, customers, and other interested stakeholders at a CEIP Public Participation Meeting(s) and at a separate joint advisory group meeting(s), to include the EEAG, EAAG, and EAG. Following these discussions and careful consideration of the feedback received, Avista will propose an updated set of CBIs and associated metrics in its 2023 Biennial CEIP Update.
Condition 24	Avista must engage collaboratively with its advisory groups (EAG, EEAG, EAAG) to create a metric for Indoor Air Quality and submit formal metric for evaluation no later than in its 2023 Biennial CEIP Update.
Condition 25	Avista agrees that in its 2023 Biennial CEIP Update and future CEIPs and CEIP updates, CBIs will be categorized by statutory benefit area.

CEIP Conditions

Condition 26	For the CBI – Named Community Clean Energy Avista agrees to eliminate the current metric on "percent non-emitting renewable energy located in Named Communities," and instead measure the following in Named Communities: (1) total MWh of distributed energy resources 5 MW and under; (2) total MWs of energy storage resources 5 MW and under; and (3) number (i.e., sites, projects, and/or households) of distributed renewable generation resources and energy storage resources.
Condition 27	Avista's EAG shall not be responsible for the designation of Highly Impacted Communities and the Company's advisory groups should be facilitated such that this designation is not under consideration.
Condition 28	Avista will include a publicly available and regularly updated list of its EAG members and their organization or community affiliations on its website and in future Biennial CEIP Updates and CEIPs.
Condition 29	Avista agrees that all future EAG meetings will be fully open to the public.

CEIP Conditions

Condition 30

On or before October 1, 2022, Avista must file with the Commission:

a. A progress report on what actions have been taken since October 2021 to reduce barriers to public participation (e.g., steps taken to reduce barriers including but not limited to non-English speaking customers).

b. An update to the Company's customer engagement plan it will implement during the 2022-2025 timeframe and provide a progress report of this plan in the 2023 Biennial CEIP Update.

Condition 31

On or before October 1, 2022, Avista agrees to provide in its CEIP docket a report on the changes regarding the EAG Equity Lens Sessions discussed and made with the EAG in March 2022, the facilitator, and the Company.

Condition 32

Avista will participate in any further discussions and/or workshops regarding incremental cost calculations and incorporate any changes necessary to their methodology.

Condition 33

Avista agrees to model a scenario in the 2025 Electric IRP meeting the minimum level of primary compliance requirements beginning in 2030 that will create the glide path to 2045. If the results of this modeling differ from the Company's PRS and Clean Energy Action Plan, it must explain why.

CEIP Conditions

Condition 34	For its 2023 IRP Progress Report, Avista commits to reevaluate its resource need given acquisitions the Company has made since its 2021 IRP (e.g., Chelan PUD hydro slice contracts) and include those proposed changes in its 2023 Biennial CEIP Update.
Condition 35	Avista recognizes that not all CBIs will be relevant to resource selection (for example, some CBIs pertain to program implementation). For its 2023 IRP Progress Report, and future IRPs and progress reports, Avista should discuss each CBI and where the CBI is not relevant to resource selection, explain why.
Condition 36	For its 2023 IRP Progress Report, Avista will: a. At the September 28, 2022, Electric IRP TAC meeting, present draft supply side resource cost assumptions, including DERs. The Company commits to revising said cost assumptions if TAC stakeholder feedback warrants changes. Avista will update its 2023 Electric IRP Work Plan (UE-200301) to reflect the date of this TAC meeting. b. Use the Qualifying Capacity Credit (QCC) for renewable and storage resources from the Western Power Pool's Western Regional Adequacy Program (WRAP), if available, or explain why the WRAP's QCCs are inappropriate for use. c. Update its load forecast to include the baseline zero emission vehicle (ZEV) scenario from its Transportation Electrification Plan.

CEIP Conditions

Condition 37	In order to provide a means of recovery of prudently incurred costs associated with implementing this CEIP and associated conditions, the Company will file a separate accounting petition to address deferred accounting for such costs until they are reviewed and deemed prudent for recovery or not by the Commission.
Condition 38	Avista must choose at least two of its current CBIs which it will track for at least five subsets of Named Communities, at a granularity to be determined by agreement with Staff, stakeholders, and the Company's Equity Advisory Group. Avista will incorporate relevant updates in its 2023 Biennial CEIP update.

IRP TAC Process Change Ideas and Modeling Change Ideas

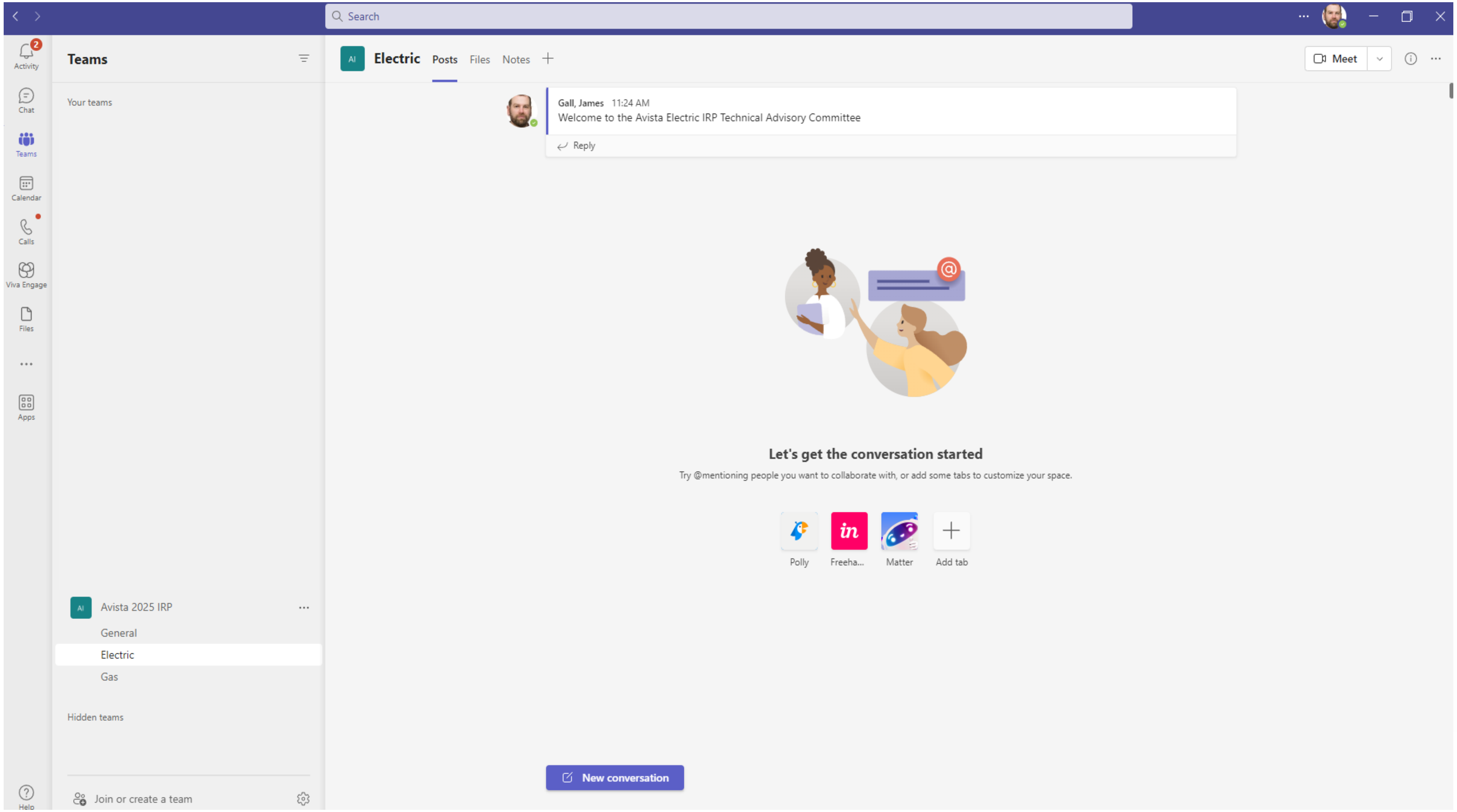
James Gall
Technical Advisory Committee Meeting No. 1
September 26, 2023

TAC Communication

Propose to use Microsoft Teams for primary TAC communication

- Advantages
  - File sharing ease
  - Open communication via chat function on files or questions to Avista or other TAC members
  - Eliminates email traffic for passive TAC members
  - TAC meeting recordings and chat messages are retained
- Avista will still post TAC meetings and slides on website
  - Documents/files shared with the TAC will be on Teams
  - Only “final” documents will be posted on website
- Avista will direct new interested TAC members to sign up to join the “Teams site”
- TAC meeting invites will come through Teams and email
- Electric and Natural Gas TAC members will have access to both “channels” on Teams

New IRP TAC Teams Site



WUTC Notice on Electric IRP’s

UTC
Washington Utilities and Transportation Commission

- Commission is discontinuing its practice of issuing acknowledgment letters for electric utility IRPs in all cases.

- Under CETA, the CEIP must be “consistent with the utility’s long-range integrated resource plan” and “informed by the investor-owned utility’s clean energy action plan,” which is developed as part of an electric IOU’s IRP. Therefore, any issues that interested parties may have related to an IRP can be litigated and decided by the Commission as part of a CEIP proceeding.

- As part of the Commission’s effort to reduce unnecessary administrative burden and duplicative processes, we are discontinuing our practice of issuing acknowledgment letters for electric IRPs in all cases.

AVISTA

Action Item Update

- Incorporate the results of the DER potential study where appropriate for resource planning and load forecasting.
- Finalize the Variable Energy Resource (VER) study. This study outlines the required reserves and cost of this energy type. Results of this study will be available for use in the 2025 IRP.
- Study alternative load forecasting methods, including end use load forecast considering future customer decisions on electrification. Avista expects this Action Item will require the help of a third-party. Further, studies shall continue the range in potential outcomes.
- Investigate the potential use of PLEXOS for portfolio optimization, transmission, and resource valuation in future IRPs.
- Continue to work with the Western Power Pool's WRAP process to develop both Qualifying Capacity Credits (QCC) and Planning Reserve Margins (PRM) for use in resource planning.
- Evaluate long-duration storage opportunities and technologies, including pumped hydro, iron-oxide, hydrogen, ammonia storage, and any other promising technology.
- Determine if the Company can estimate energy efficiency for Named Communities versus low-income.
- Study transmission access required to access energy markets as surplus clean energy resources are developed.
- Further discuss planning requirements for Washington's 2045 100% clean energy goals.

Plexos Introduction

- PLEXOS is a production cost model developed by Energy Exemplar
- The model benefits from a mixed integer-based design
- Avista plans to use the technology for portfolio modeling in the 2025 for resource valuation and market risk analysis

- Why did Avista bring in Plexos?
  - More sophisticated hydroelectric modeling capability than Aurora
  - Allows for proper valuation of energy storage benefits and needs, along with reserve costs associated with VERs due to mixed-integer logic
  - Capable of modeling transmission system detail
  - Potential PRiSM replacement- includes capacity expansion function
  - Potential use for combining power and natural gas IRPs

Load Forecast Update

- Avista has brought on Applied Energy Group (AEG) to conduct a long-term forecast of customer loads (Natural Gas & Electric)
- End use load forecast technique to better understand how loads will change due to electrification potentials
- Forecast will be consistent with DER potential study focusing on on-site solar and vehicle electrification
- AEG will provide three scenarios (expected case, low, and high)
- Process should enhance demand response and energy efficiency potential assessments

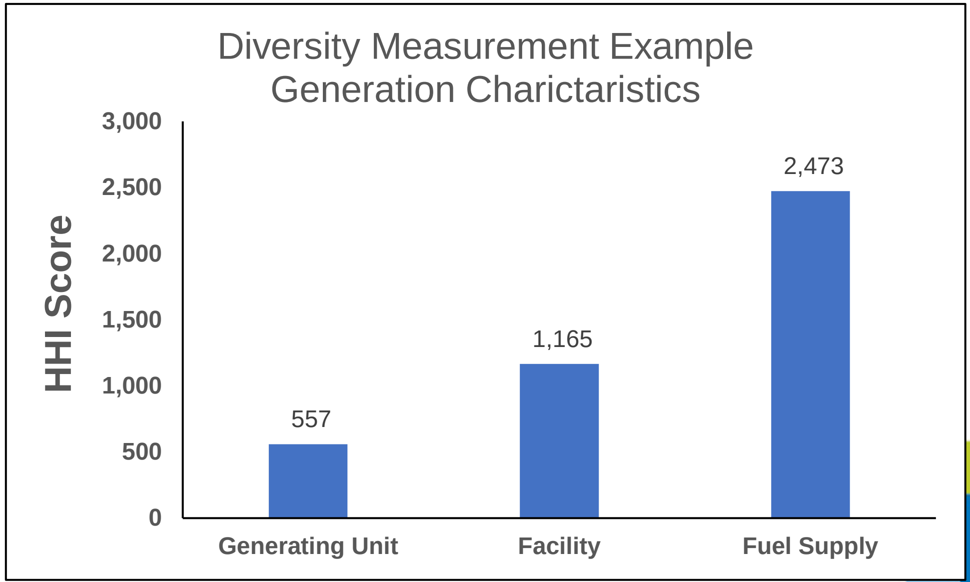
PRiSM Update

- Avista plans to continue to use PRiSM in the 2025 IRP
- Avista will test PLEXOS and compare results for potential replacement in the 2027 IRP
  – Why not now?
    - Time to build/test models
    - Energy efficiency modeling
    - Speed
- Testing Natural Gas IRP in PRiSM
  – Co-optimize natural gas system and electric capacity expansion to electrification choices are dynamic

Resiliency

- How should we include resiliency?
  - Feeder or customer level seems out of scope for an IRP
  - Generation sources and delivery seems plausible
- Can resource diversification measure resiliency?
- Quantification can indicate risks and could lead to different resource choices during acquisition.
  - Herfindahl – Hirschman Index
  - Measures whether or not a population is too heavily dependent on one component
- Any other resiliency ideas?

- Potential Metrics
  - Seasonal plant & unit (shaft risk)
  - Location fuel source
  - Transmission path
  - Wildfire risk level areas
  - Load diversity?



PLEXOS Overview and Back Cast Analysis

Mike Hermanson, Senior Power Supply Analyst
Technical Advisory Committee Meeting No. 1
September 26, 2023

Power Supply Modeling in the IRP Process

- Analytical framework to determine the long-run economic and operational performance of alternative resource portfolios
- Modeling is used to simulate the integration of new resource alternatives within our existing resource mix, thereby informing the selection of a preferred portfolio judged to be the most cost-effective resource mix after considering:
  - Risk
  - Supply reliability
  - Uncertainty
  - Government energy resource policies
- Avista utilizes multiple models in the IRP Process:
  - Aurora: Electric Price Forecast
  - Plexos: Dispatch of resources to meet projected load demands
  - PRiSM: Selection of new resources

Plexos

- Plexos is a widely used energy modeling software suite designed for electricity market analysis and power system optimization. It is used to make informed decisions about energy production, transmission, and distribution. Key aspects of the model include:
  - **Market Simulation**: allows users to simulate and analyze electricity markets, considering various factors such as supply, demand, pricing, and market rules. This provides insight into market dynamics and energy trading optimization.
  - **Power System Optimization**: optimizes power system operations including generation scheduling, unit commitment and dispatch. Multiple objectives such as minimizing cost, maximizing reliability, or reducing emissions can be set as targets.

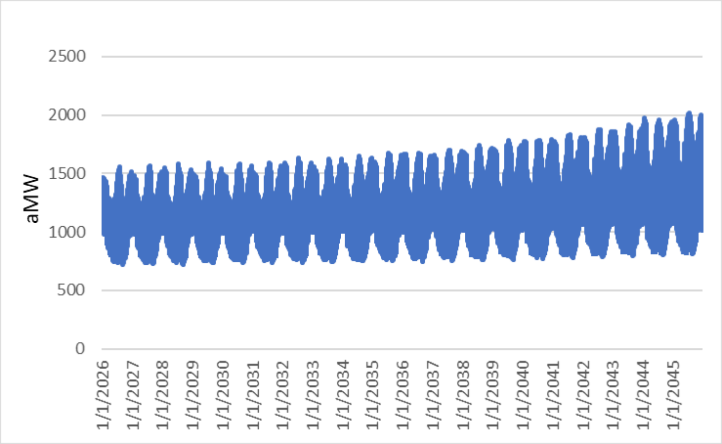
Plexos

- **Integration of Renewable Energy**: Plexos can incorporate renewable energy sources like wind and solar, assisting planners to assess the impact of variable generation on the power grid.
- **Transmission Planning**: It supports transmission system planning and expansion studies allowing the inclusion of transmission upgrade costs associated with potential resource additions.
- **Hydro Modeling:** Storage Hydro is modeled utilizing water inflow and reservoir sizes. Operational aspects such as scheduled maintenance, forced outages, minimum flows, maximum reservoir movement are all modeled. This is in comparison to the monthly energy values utilized in Aurora.

Plexos Implementation of Avista System

– The Plexos IRP model is a 20-year simulation to meet native load and contractual obligations with Avista owned generation, contracted generation, and market purchases.

Hourly Native Load



We are currently working with a consultant on a load forecast.
Some considerations include:

- Climate change impacts on load,
- Variability and uncertainty in EV load forecasts
- Penetration of electrification efforts

Avista owned & contracted generation

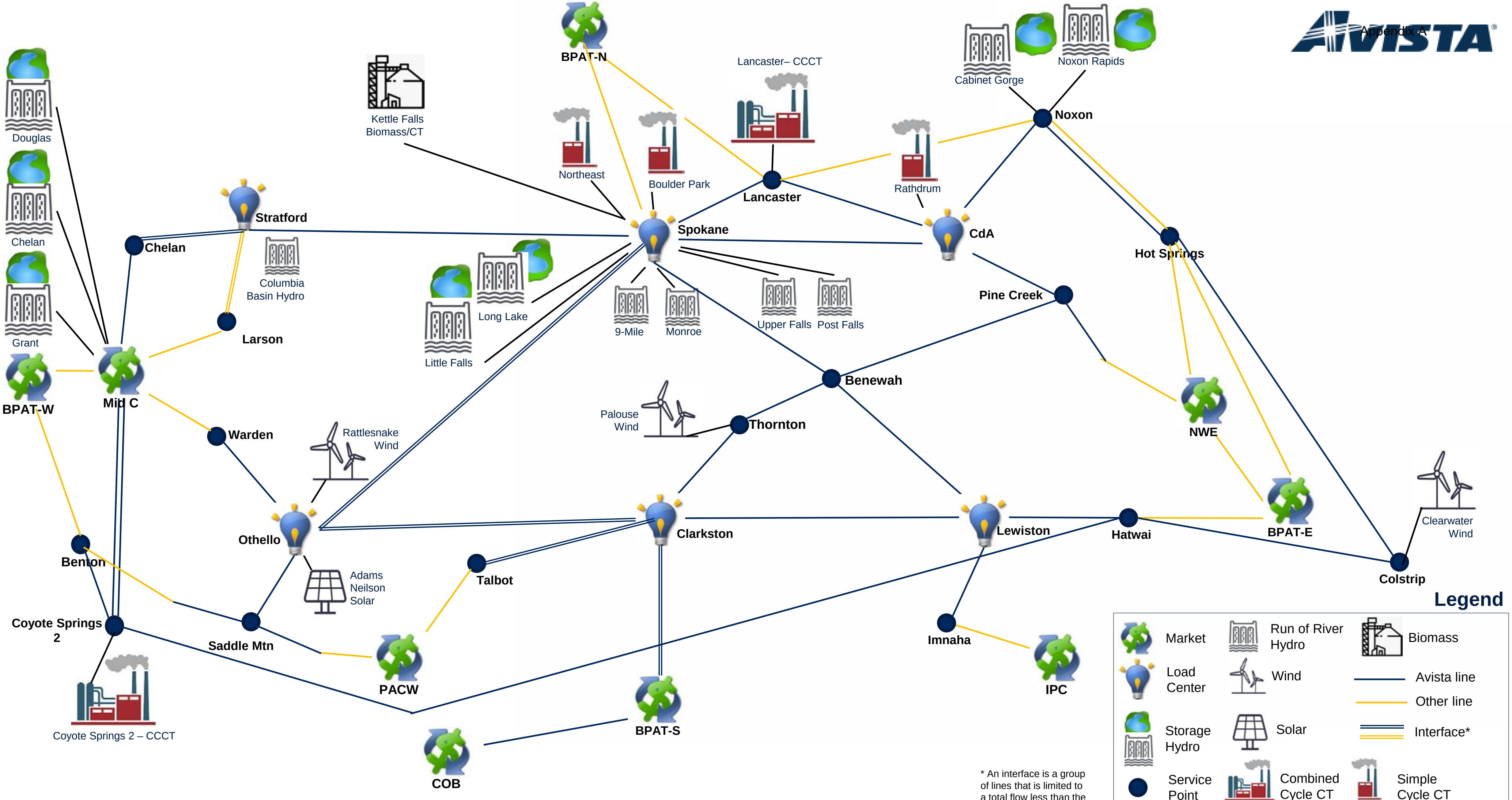
Generation considerations include:

- Regular scheduled maintenance and forced outages
- Timing and quantity of hydro and impact of climate change throughout the planning horizon
- Provision of ancillary services/reserves
- VER production
- Fuel cost

Market Purchases/Sales

Market Purchases are driven by Mid-C hourly price and any transmission constraints

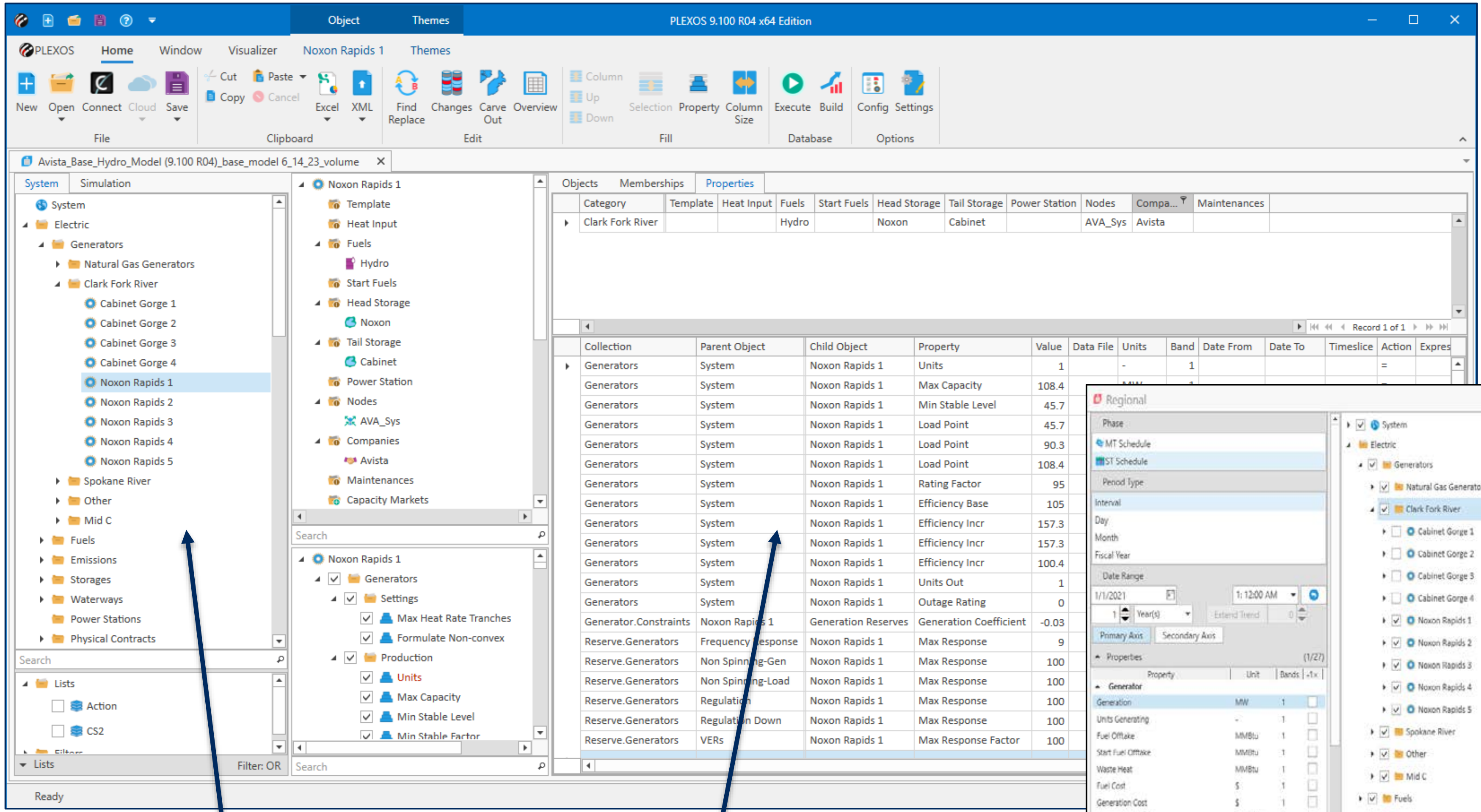
Native load + contractual obligations = generation + market purchases and sales every hour



Plexos Representation of Transmission System & Generation

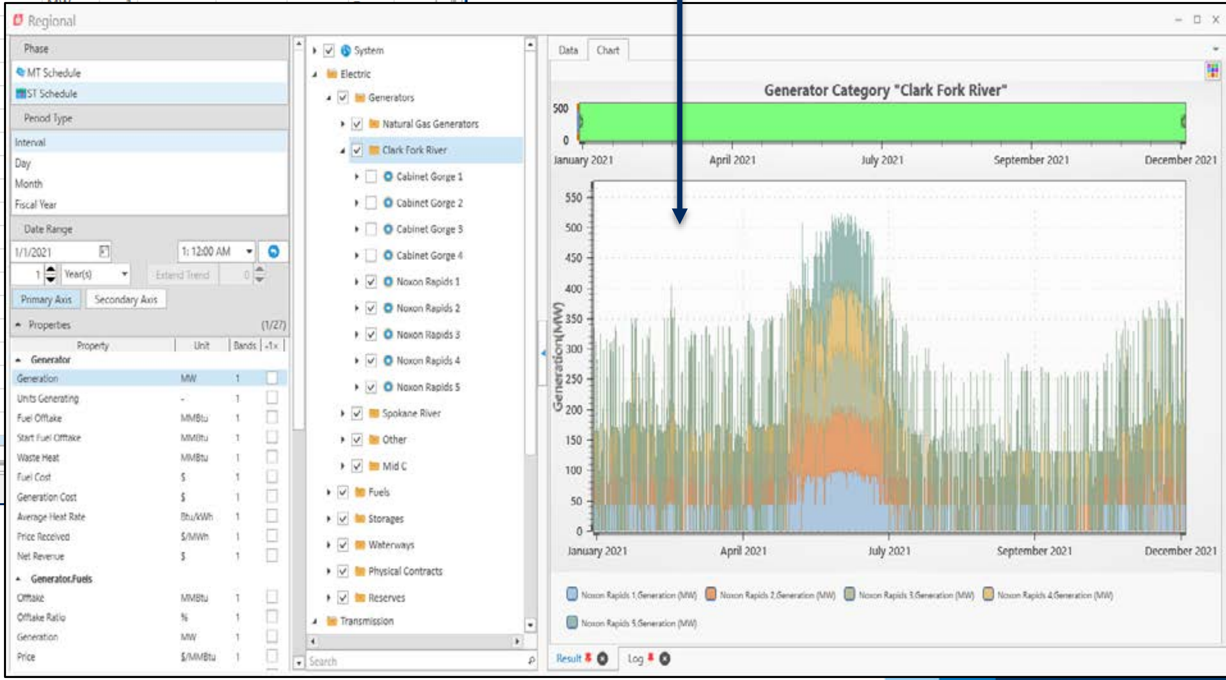
Plexos Implementation of Avista System

Appendix A



Collection	Parent Object	Child Object	Property	Value
Generators	System	Noxon Rapids 1	Units	1
Generators	System	Noxon Rapids 1	Max Capacity	108.4
Generators	System	Noxon Rapids 1	Min Stable Level	45.7
Generators	System	Noxon Rapids 1	Load Point	45.7
Generators	System	Noxon Rapids 1	Load Point	90.3
Generators	System	Noxon Rapids 1	Load Point	108.4
Generators	System	Noxon Rapids 1	Rating Factor	95
Generators	System	Noxon Rapids 1	Efficiency Base	105
Generators	System	Noxon Rapids 1	Efficiency Incr	157.3
Generators	System	Noxon Rapids 1	Efficiency Incr	157.3
Generators	System	Noxon Rapids 1	Efficiency Incr	100.4
Generators	System	Noxon Rapids 1	Units Out	1
Generators	System	Noxon Rapids 1	Outage Rating	0
Generator.Constraints	Noxon Rapids 1	Generation Reserves	Generation Coefficient	-0.03
Reserve.Generators	Frequency Response	Noxon Rapids 1	Max Response	9
Reserve.Generators	Non Spinning-Gen	Noxon Rapids 1	Max Response	100
Reserve.Generators	Non Spinning-Load	Noxon Rapids 1	Max Response	100
Reserve.Generators	Regulation	Noxon Rapids 1	Max Response	100
Reserve.Generators	Regulation Down	Noxon Rapids 1	Max Response	100
Reserve.Generators	VERs	Noxon Rapids 1	Max Response Factor	100

Results



System Components

Properties of each component

Plexos Implementation of Avista System

- Modeling challenges
  - Model has perfect foresight
  - Difficult to capture the myriad of constraints on a hydro storage system.
    - For example, management of a reservoir that is used for recreation and has residences on much of the shoreline
  - Balance between model complexity and runtimes
  - Difficult to capture the dynamics of trades that happen at different time steps, for example, day ahead, hour a head, EIM.
  - How to integrate forecast error in modeling
- Model will almost always have lower production cost than actual.

2021 Backcast – Plexos vs Actual Dispatch

- To verify that our model represented our system operation and dispatch we utilized 2021 inputs and compared the output of Plexos to actual 2021 data. In the model we utilized:
  - 2021 Hourly Load
  - Hourly hydro inflows
  - Hourly run-of-river generation
  - Hourly Mid-C Electric Price
  - Daily Gas Prices
  - Hourly renewable generation
  - Actual scheduled and forced outages
  - Reserves, including FRR, Non-Spin, Reg up and down, and VERs

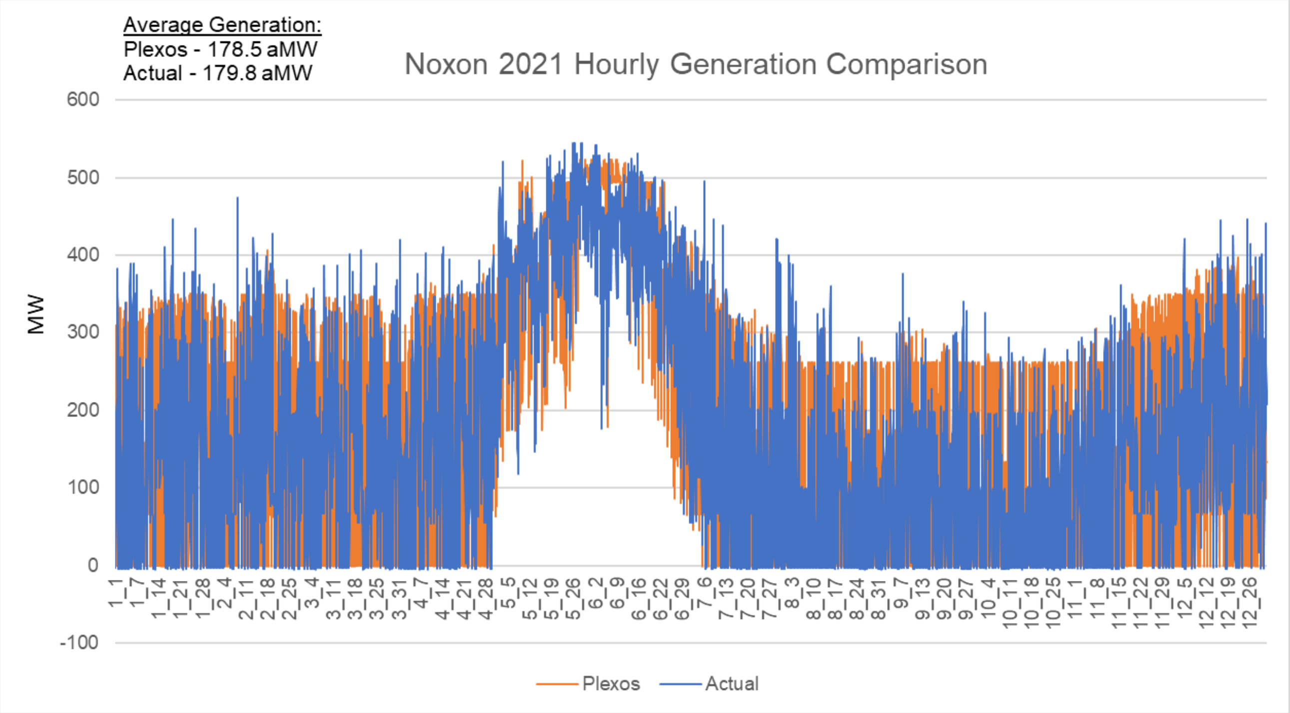
2021 Backcast Dispatch Comparison (aMW)

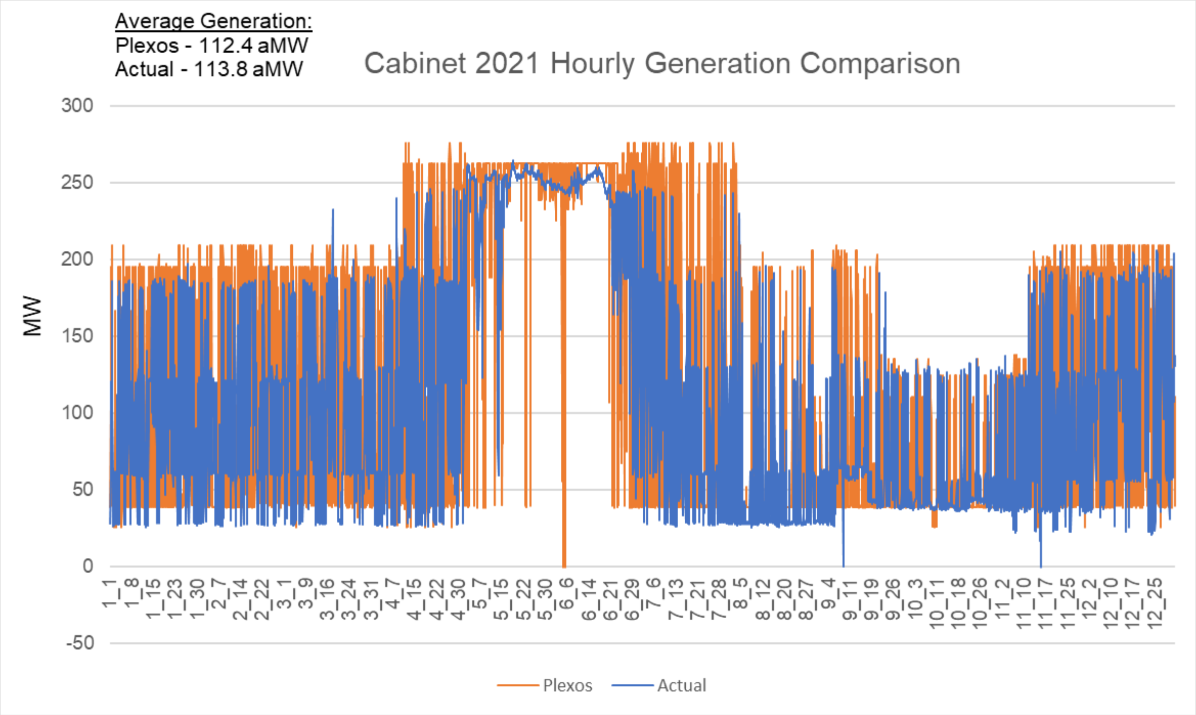
Facility	Actual Gen	Plexos Gen	Difference
Noxon Rapids	179.8	178.5	-1.3
Cabinet Gorge	113.8	112.4	-1.4
Long Lake	54.6	54.4	-0.2
Little Falls	23.7	23.2	-0.5
Mid Columbia	135.7	138.9	3.1
Coyote Springs 2	175.2	172.2	-2.9
Lancaster	207.8	205.2	-2.6
Rathdrum	20	18.1	-1.9
Boulder Park	7.9	7.7	-0.2
Kettle Falls GS	37	37.1	0.1
Kettle Falls CT	0.4	0.5	0.1
Colstrip	173.7	174.1	0.4
TOTAL	**1,130**	**1,122**	**-7**

Production Cost Comparison

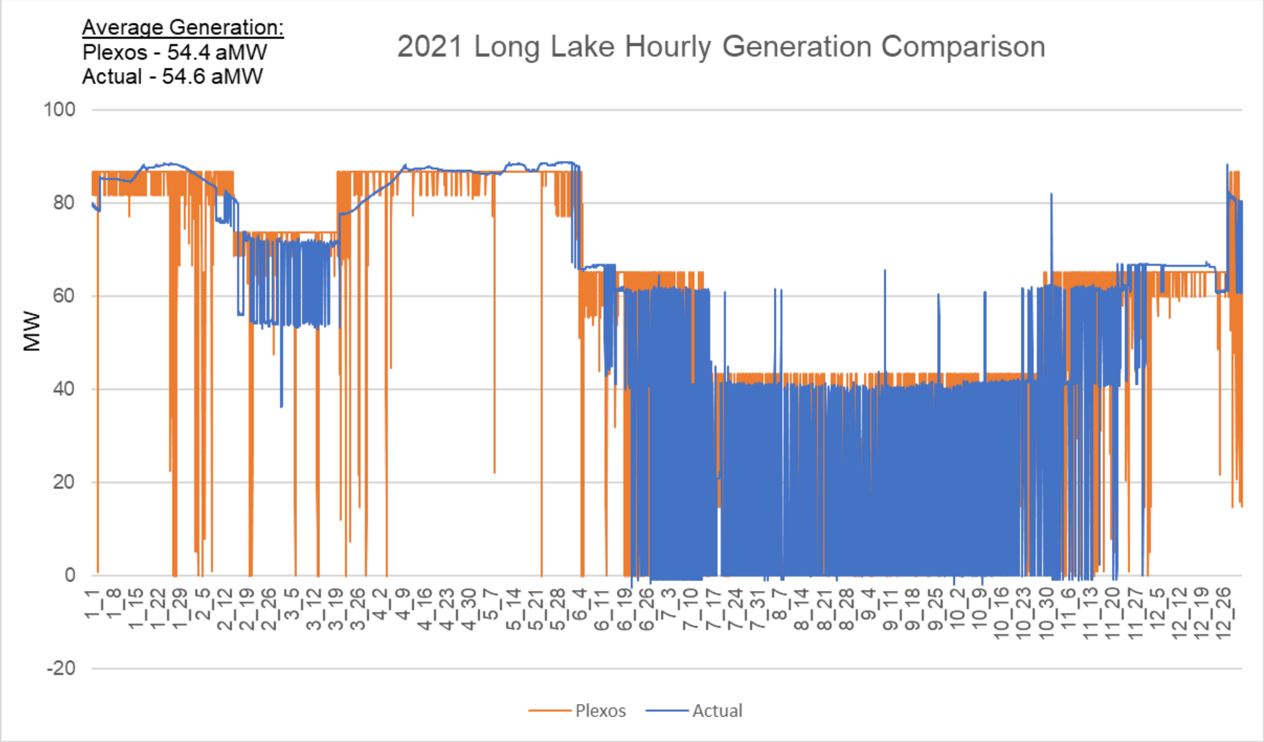
0.96% difference between mark to market of generation subtracting fuel costs

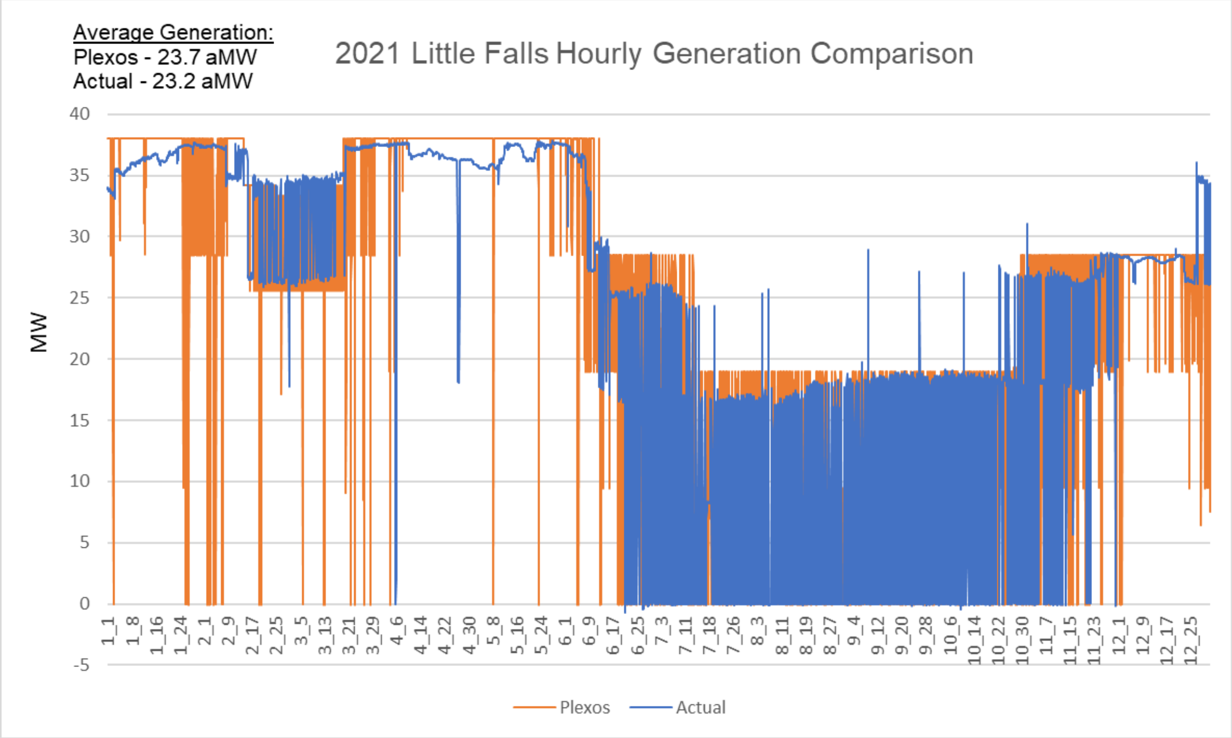
2021 Backcast Dispatch Comparison



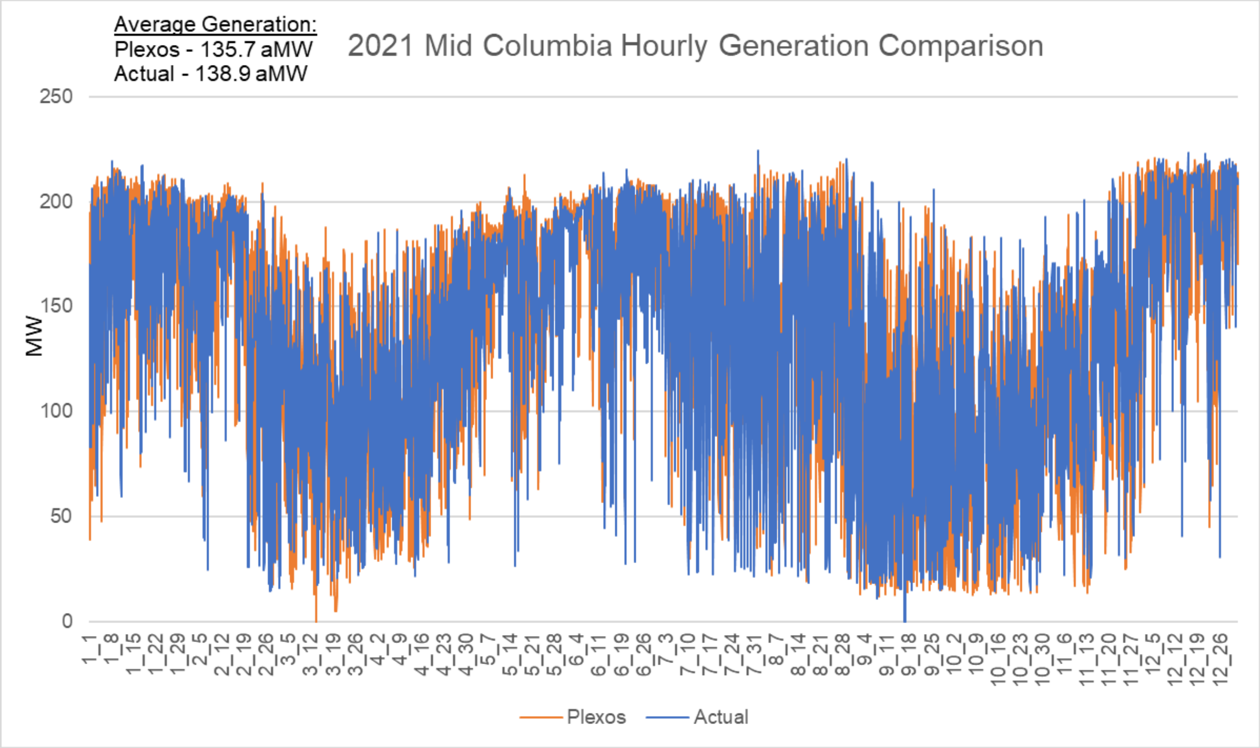


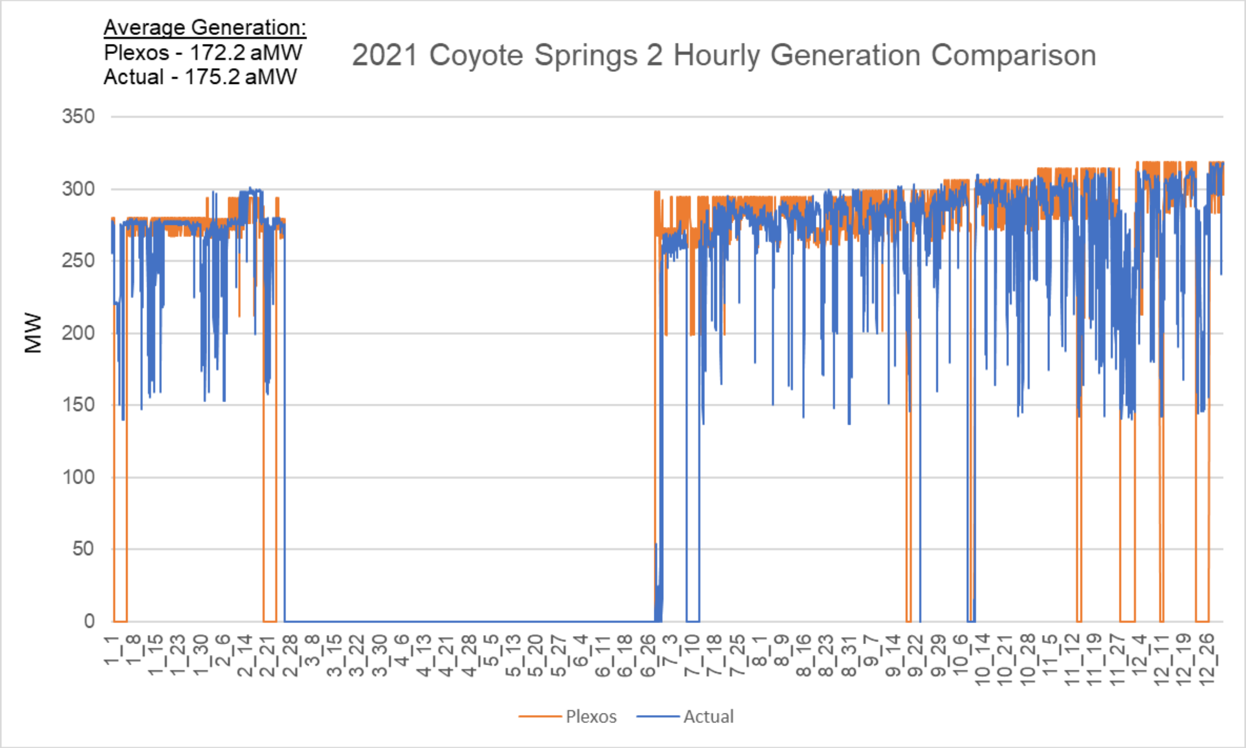
2021 Backcast Dispatch Comparison



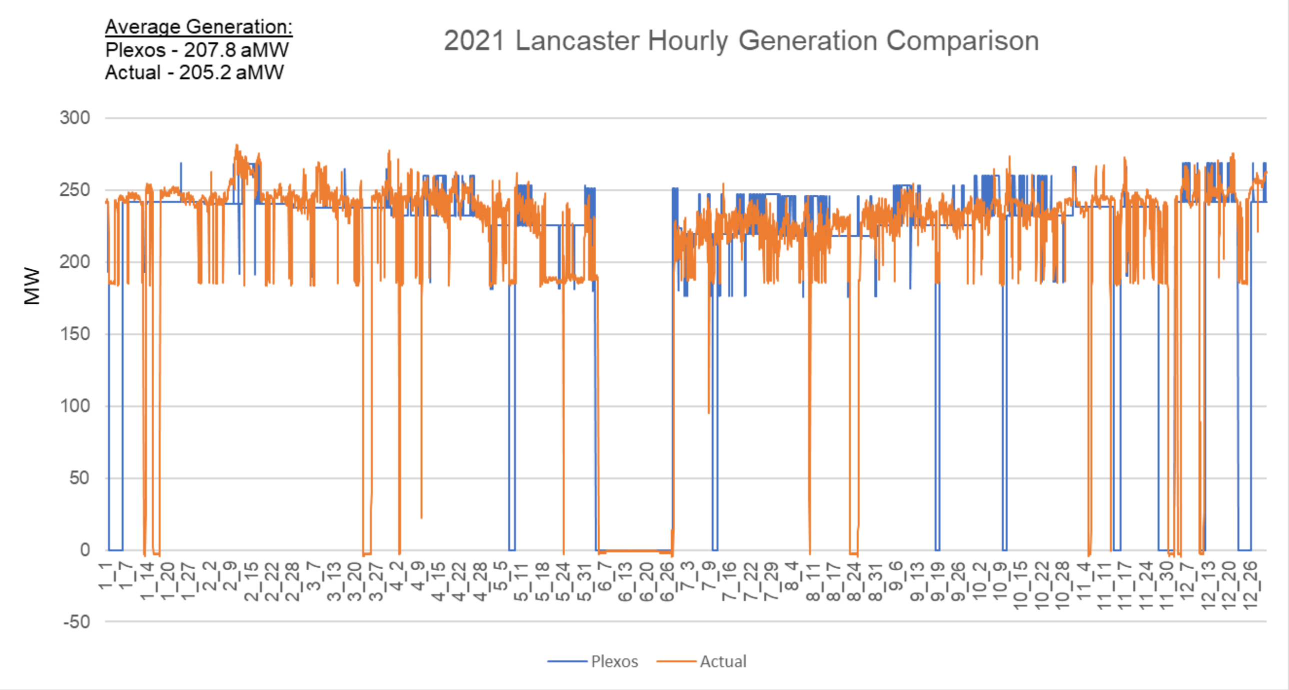


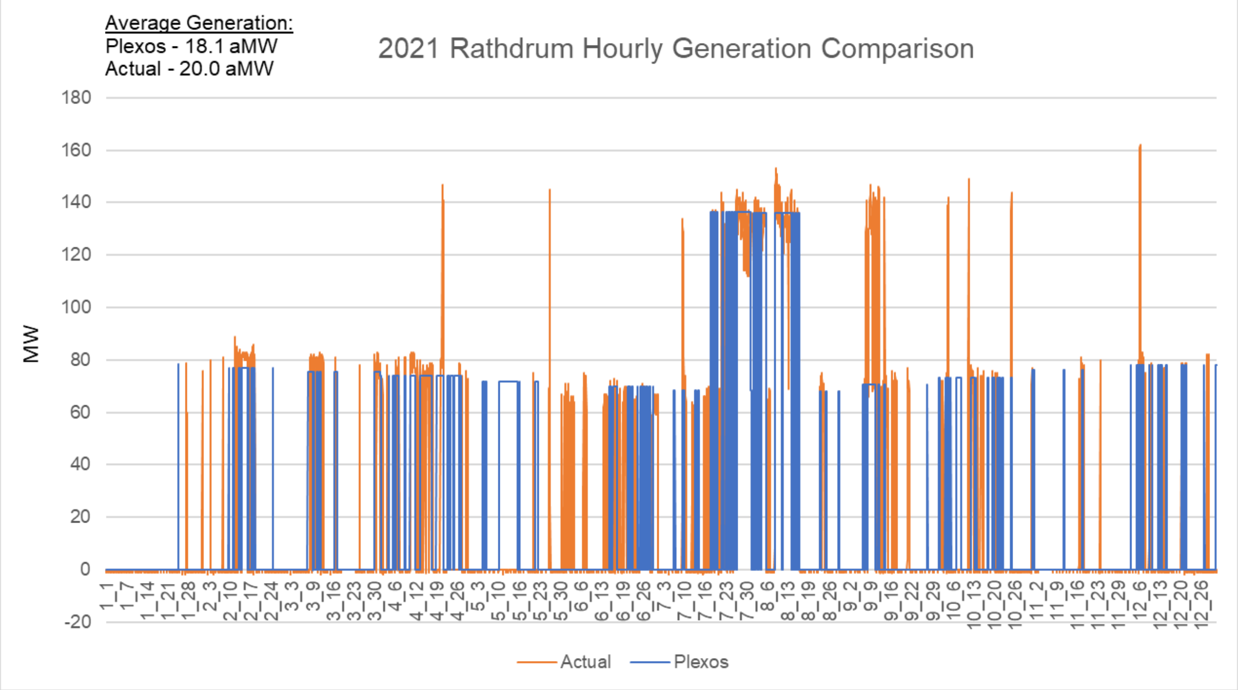
2021 Backcast Dispatch Comparison





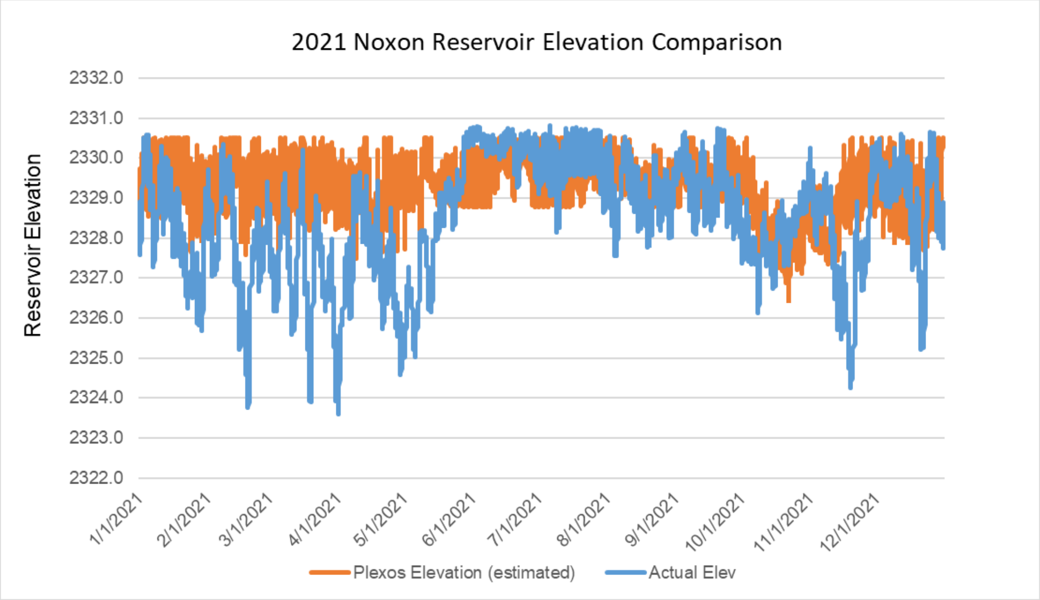
2021 Backcast Dispatch Comparison

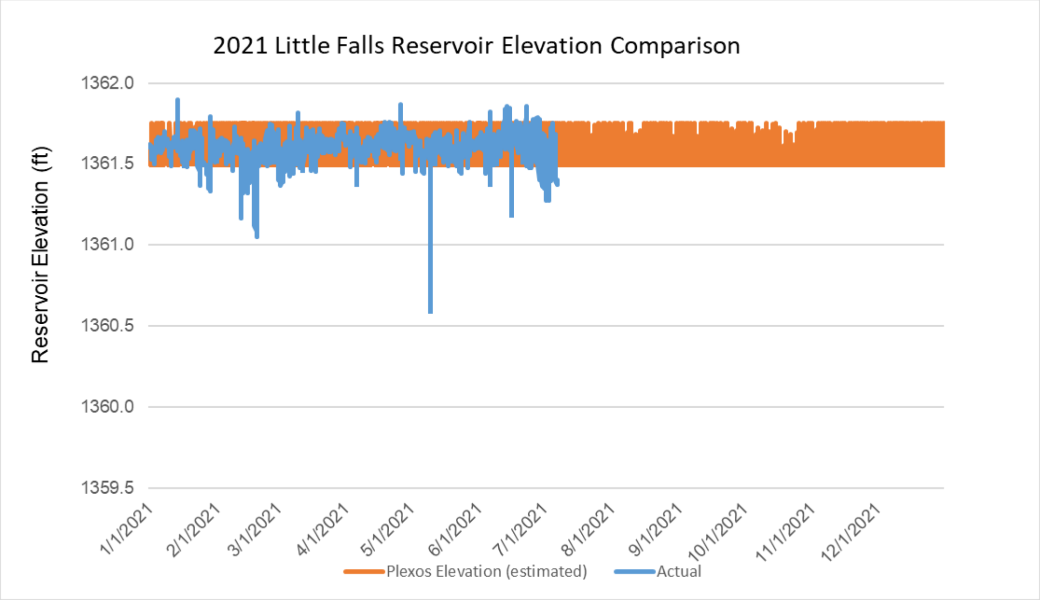


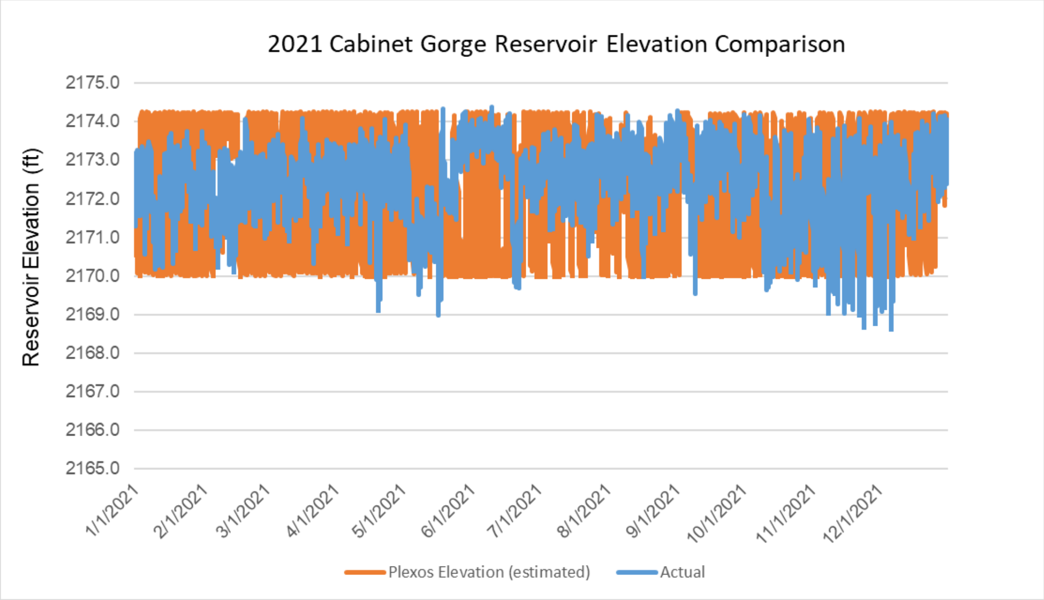


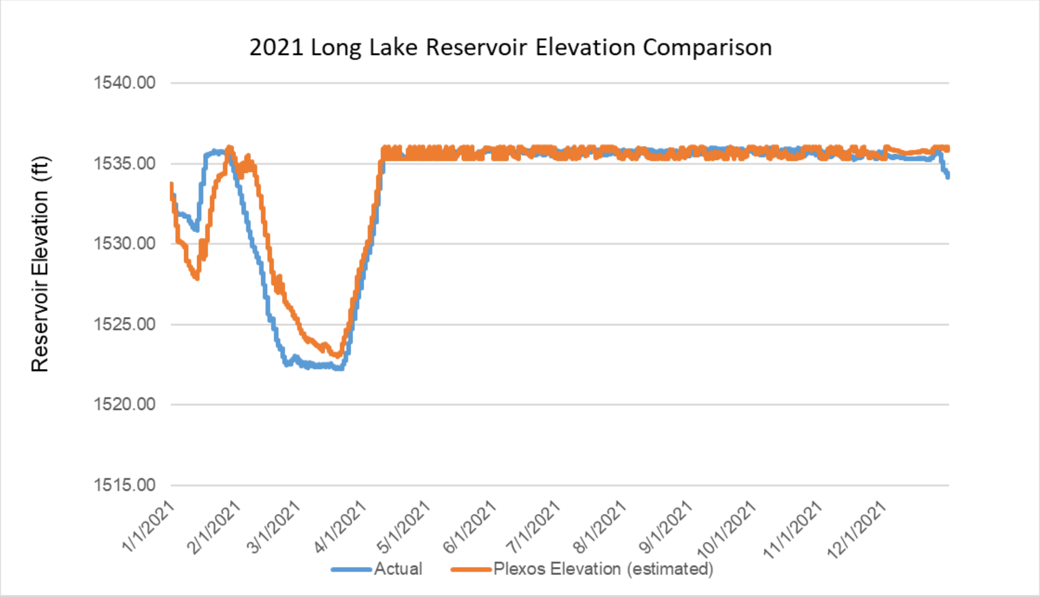
2021 Backcast Reservoir Elevation Comparison

Appendix A



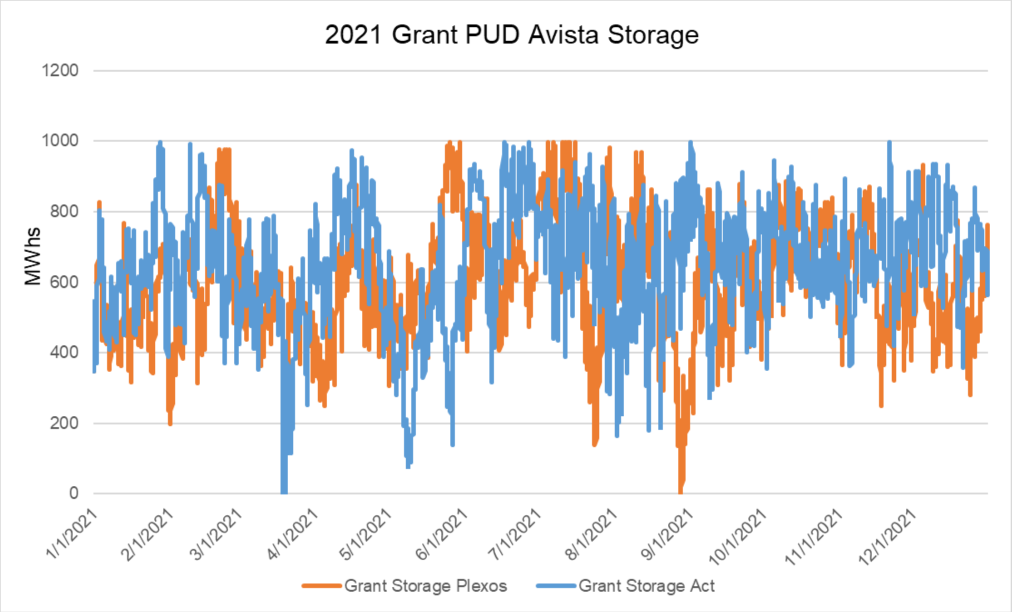


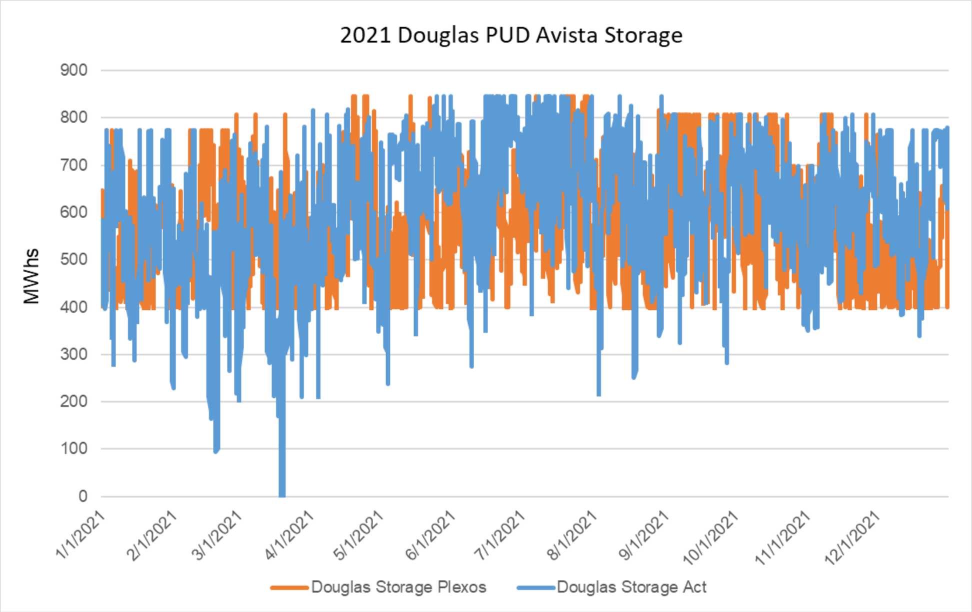


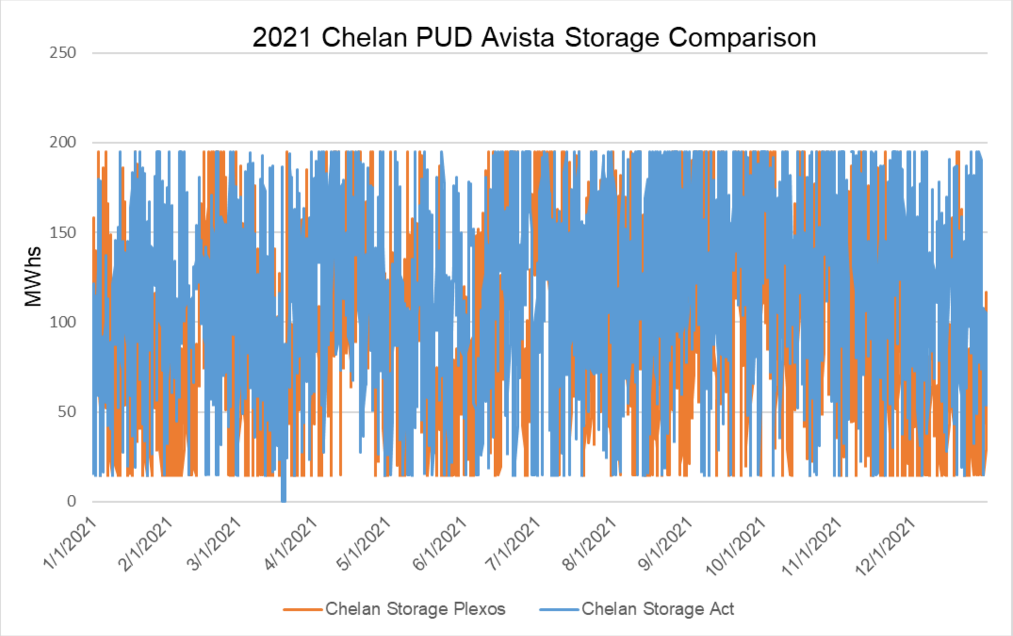


2021 Backcast Reservoir Elevation Comparison

Appendix A







Available Resource Options

Lori Hermanson
Technical Advisory Committee Meeting No. 1
September 26, 2023

Turbine Resource Options

Peakers

- Simple Cycle Combustion Turbine (CT)
  - CT Frame
  - 180 MW (2 units)

- Reciprocating Engines
  - 185 MW (10 units)

Baseload

- Combined Cycle CT (CCCT)
  - 312 MW (1x1 w/DF)

Fuels

- Natural gas
- Renewable natural gas
- Hydrogen
  - Ammonia
  - Synthetic natural gas

-Natural gas turbines are modeled using a 30-year life with Avista ownership
-Will continue to evaluate non-natural gas fueled resources in Washington and all fuel types in Idaho
-Will continue to evaluate potential upgrade opportunities on existing facilities

Renewable Resource Options – Solar and Wind

All Purchase Power Agreement (PPA) Options

Solar

- Residential (6 kW AC) – w/ and w/o battery
- Commercial (1 MW AC) – w/ and w/o battery
- Fixed PV Array (5 MW AC) – w/ and w/o battery
- Single Axis Tracking Array
  - With and w/o 100 MW 4-hour lithium-ion battery
  - With 100 MW 2-hour lithium-ion battery
  - With 50 MW 4-hour lithium-ion battery

Wind

- Wind (100 MW)
- Montana wind (100 MW)
- Offshore wind (100 MW)
  - Share of a larger project

Other “Clean” Resource Options

- Geothermal PPA (20 MW)
  - Off-system
- Biomass (58 MW)
  - i.e. Kettle Falls 3 or other
- Nuclear PPA (100 MW)
  - Off-system share of a mid-size facility
- Fuel Cell (25 MW)

Storage Technologies

Lithium-Ion

- Assumes: 86% round trip efficiency (RTE), 15-year operating life
- Assumes Avista ownership
- 5 MW Distribution Level
  - 4 hours (20 MWh)
  - 8 hours (40 MWh)
- 25 MW Transmission Level
  - 4 hours (100 MWh)
  - 8 hours (200 MWh)
  - 16 hours (400 MWh)

Other Storage Options

- Assumes 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 (65% RTE)
  - 8 hours (400 MWh)
- 100 MW Iron Oxide (65% RTE)
  - 100 hours
- 100 MW Pumped Hydro
  - 24 hours (2,400 MWh)
- 100 MW Pumped Hydro
  - 10 hours (1,000 MWh)

Resource Option Currently Being Researched

- Carbon capture and storage
- Fusion reaction (no real costs yet)
- Organic Solid Flow energy storage – proprietary nonflammable mixture of solid and water-based electrolytes
- Molten salt heat storage (using existing steam turbines)
- New hydro
- Regional hydro PPAs
- Others?

2023 IRP Work Plan

John Lyons, Ph.D.
Technical Advisory Committee Meeting No. 1
September 26, 2023

2025 IRP Work Plan

- IRP regulations require an IRP to be filed in Idaho by June 1, 2025, and an IRP in Washington on January 1, 2025.
- Work Plan shows process and timing of key IRP events
- Overview discussion
- TAC meetings and topics
- Document outline by chapter
- Timeline of major assumptions – market price assumptions and forecasts, third party studies, study requests from TAC, etc.

2025 IRP Work Plan – Modeling

- PLEXOS will be used to model resource dispatch, resource option valuation, and market risk analysis.
- PRiSM will be used for resource selection.
- Continue to use Aurora for electric market price forecasting, will evaluate other options for the 2027 Progress Report/IRP.
- Applied Energy Group (AEG) will develop energy efficiency and demand response potential studies, a long-term energy and peak load forecast using end use techniques, and a distribution energy resource (DER) potential study
- Intend to use generic resource assumptions from a variety of sources based on likely generation sites

Tentative 2025 Electric IRP TAC Schedule

- **TAC 1 (Tuesday, September 26, 2023):** Washington CEIP Biannual Update; available resource options discussion; PLEXOS overview and backcast analysis; TAC feedback on changes to process methods and assumptions; and 2025 IRP Work Plan IRP Process Review.

- **TAC 2 (March 26, 2024):** Natural gas market overview and price forecast; wholesale electric price forecast, Variable Energy Resource Integration Study results; future climate analysis update; and TAC scenarios feedback.

- **TAC 3 (April 2024):** Economic forecast and five-year load forecast; long run forecast (AEG), Conservation Potential Assessment (AEG); Demand Response Potential Assessment (AEG); and reviewed planned scenario analysis.

Tentative 2025 Electric IRP TAC Schedule

- **TAC 4 (May 2024):** IRP Generation Option Transmission Planning Studies; Distribution System Planning within the IRP & DPAG update; transmission and distribution modeling in the IRP; Load & Resource Balance and methodology; and new resource options costs and assumptions.

- **TAC 5 – Technical Modeling Workshop (June 2024):** PLEXOS tour, PRiSM tour, and New Resource Cost Model.

- **TAC 6 (July 2024):** Preferred Resource Strategy results, Washington Customer Benefit Indicator Impacts, resiliency metrics, portfolio scenario analysis, market risk assessment, and QF avoided cost.

- **Virtual Public Meeting – Natural Gas & Electric IRPs (September 2024):** recorded presentation, daytime and evening comment and question sessions.

2025 Electric IRP Draft Outline

Executive Summary

1. **Introduction, Stakeholder Involvement, and Process Changes**

2. **Economic and Load Forecast**
   - Economic Conditions
   - Avista Energy & Peak Load Forecasts
   - Load Forecast Scenarios

3. **Existing Supply Resources**
   - Avista Resources
   - Contractual Resources and Obligations
   - Customer Generation Overview

4. **Long-Term Position**
   - Regional Capacity Requirements
   - Energy Planning Requirements
   - Reserves and Flexibility Assessment

2025 Electric IRP Draft Outline

5. **Distributed Energy Resource Options**
   - Energy efficiency potential
   - Demand response potential
   - Generating and energy storage resources options and potential
   - Named Community Actions
   - Distributed Energy Resources Study Conclusions

6. **Supply-Side Resource Options**
   - New Resource Options
   - Avista Plant Upgrade Opportunities
   - Non-Energy Impacts

7. **Transmission Planning & Distribution**
   - Overview of Avista's Transmission System
   - Transmission Construction Costs and Integration
   - Merchant Transmission Plan
   - Overview of Avista's Distribution System

2025 Electric IRP Draft Outline

8. **Market Analysis**
   - Wholesale Natural Gas Market Price Forecast
   - Wholesale Electric Market Price Forecast
   - Scenario Analysis

9. **Preferred Resource Strategy**
   - Preferred Resource Strategy
   - Market Exposure Analysis
   - Avoided Costs

10. **Portfolio Scenarios**
    - Portfolio Scenarios
    - Market Scenario Impacts

2025 Electric IRP Draft Outline

11. **Washington Clean Energy Action Plan (CEAP)**
    - Decision Making Process
    - Resource Need
    - Resource Selection
    - Customer Benefit Indicators

12. **Action Plan**

Major 2025 Timeline

Exhibit 1: Major 2025 Electric IRP Assumption Timeline

Task	**Target Date**
Market Price Assumptions	December 2023
CCA/Other GHG Pricing Assumptions	
Natural gas price forecast	
Regional resources and roads forecast	
Electric price forecast	March 2024
New Resource Options Cost & Availability	March 2024
AEG Deliverables	April 1, 2024
Final Energy & Peak Load Forecast	
Energy Efficiency and Demand Response Potential Assessment	
Locational Energy Efficiency and Demand Response Potential	
Transmission & distribution studies complete	April 2024
Due date for study requests from TAC members	**March 20, 2024**
Determine portfolio & market future studies	May 2024
Finalize resource selection model assumptions	June 1, 2024

2025 Electric IRP Draft and Submission Dates

- Draft IRP will be available to the public on August 30, 2024, for comment
- Comments from TAC members due by November 15, 2024, or through Washington's public comment timeline
- IRP team will be available for conference calls or email to address comments with individual TAC members or with the entire group if needed
- IRP filed with Idaho and Washington Commissions on January 2, 2025

TAC 1 Meeting Notes, September 26, 2023

Attendees:

Diana Aguilar, Fortis BC; Ernesto Avelar, LIUNA; Shay Bauman, Washington Attorney General's Office; Shawn Bonfield, Avista; Tamara Bradley, Avista; Annette Brandon, Avista; Molly Brewer, UTC; Terrence Browne, Avista; Michael Brutocao, Avista; Logan Callen, City of Spokane; Terri Carlock, IPUC; Katie Chamberlain, Renewable NW; Thomas Dempsey, Myno Carbon; Joshua Dennis, UTC; Mike Dillon, Avista; Chris Drake, Avista; Michael Eldred, IPUC; Ryan Finesilver, Avista; Grant Forsyth, Avista; Gall, Avista; Annie Gannon, Avista; Amanda Ghering, Avista; John Gross, Avista; Leona Haley, Avista; Tom Handy, Whitman County Commission; Lori Hermanson, Avista; Mike Hermanson, Avista; Kevin Holland, Avista; Fred Heutte, NW Energy Coalition; Scott Holstrom, LiUNA 238; Tina Jayaweera, NWPCC; Clint Kalich, Avista; Mike Louis, IPUC; John Lyons, Avista; Jaime Majure, Avista; Ian McGetrick, Idaho Power; Kytson McNeil, DNV; Heather Moline, UTC; Lindsey Moon, Avista; Tom Pardee, Avista; Nathan Sandvig; Avangrid; Jesse Scharf, Fortis BC; Ryan Sherlock, Avangrid; Jaclynn Simmons, UTC; Dean Spratt, Avista; Lisa Stites, Grant County PUD; Jason Talford, IPUC; Charlee Thompson, NW Energy Coalition; Jack Tortorici, LIUNA; Jared Webley, Avista; Kirsten Wilson, Washington Department of Energy Services; Rachel Wilson, Form Energy; Yao Yin, IPUC.

Introductions, John Lyons

John Lyons: We do this for the recording and the plan is we post this after the meeting. So, in case there's something you want to check in on again. We also use it for the transcription, so, we're able to have some pretty good notes. James, you want to pull up the first presentation.

James Gall: I will try. That's it.

John Lyons: The first one in the new rooms. Plus, you will notice, we did give a second meeting invite here within the last week. That's because we've done a major shuffle on our conference room numbers with the technology. It changed all the room numbers and then resent things out. Hopefully we should be done with that. But if you've had any Avista meetings previously scheduled from more than a week ago, you may see that happen with the new rooms. I'll start away with the introductions, the first slide.

John Lyons: Meeting guidelines for the Technical Advisory Committee. IRP team, we are back in the office and Avista is back to at least three days a week in the office. Some people are four or five. We're in office Monday through Wednesday and also available by email, phone and Teams. We'll talk about that later today. There's a lot more involved with Teams, where you'll be able to interact with us, hopefully more. We'll be able to post new data as it comes out. This is where we get our stakeholder feedback and we share those responses. We'll share them at the TAC meeting, so if we had a question come up that we have to go in and figure out what did we do last time, we'll be able to pull that to share the next time. Some of them, though, we will be sharing through Teams and then we also post all, and print all of those in the IRP appendix so they'll be there for posterity's sake. It also does help all of us to make sure as we go through all these meetings that we're picking up on everything that we've been that we talked said that we were going to do the working data is going to be posted in Teams.

John Lyons: Last time it was we posted on the website. James will be talking about that a little later today. It'll be posted on Teams so we can update it a little more quickly when the data becomes finalized. It will still be posted out on the website as well, and then we will send it out to the TAC. So, like the Work Plan that got sent out with this TAC meeting. We are going to always offer the virtual IRP meetings on Teams, and we will offer in person for the full day meetings. Internally, we'll be here in person, but the external ones, the six plus hour meetings. Final TAC presentations, meeting notes and the recordings will be posted to the IRP page just like we've done previously.

John Lyons: And some reminders on the virtual tech meeting asked that you mute your mics unless you're speaking or asking a question. We do also try to watch for people as we see it pops up that they've taken their mic off, will try to call on you and we've got folks here from Avista watching that. If we don't get to you right away, it usually just means we're trying to find a good breaking point. There is a raise hand function you can use, or you can type questions in the chat box if it's one that is helpful for everyone, we'll just answer those to everyone. Otherwise, we may just answer them right in the chat. We asked you the respect, the pause. We've all gotten fairly good at working on these virtual meetings, but it's still does help to give people time to get through the technology, unmute things like that. Try not to speak over the presenter or a speaker, we know that's difficult, but we all strive to do that. And if you can state your name before commenting for the note taking software. Usually, it's pretty good about picking up who it is that's speaking if they're up to a direct computer. When you're in a room or you're using another type of microphone, sometimes that's a little helpful there. Just as a reminder, this is a public advisory meeting and we do record all the presentations and comments for posterity's sake. So, if you have something you really want in the IRP, that's a good way to be able to do it. If you don't want it in the IRP, probably best not to.

John Lyons: On the IRP itself, this is required by both states we operate in. Idaho and Washington. Every two years in Idaho and in Washington it's essentially every four years we do a full IRP and then the intervening 2-year period we do a Progress Report which looks very much like a full IRP. But since we're already doing it for Idaho, we do a full IRP. There are just a few nuances we do for Washington. And in that case, a lot of that has to do with the Clean Energy Transformation Act. As we've moved that direction, the IRP informs the Clean Energy Action Plan and the CEIP looks at the resource strategy over the next 20 years. If you've been with us for a while, you notice it was 20 plus years because we were going at least through 2045 to coincide with CETA. Now we're into that period where we're within 20 years, so, we're back to our normal timeline on that. We look at current projected load and resource position. What resources we have in place. What is going to be leaving us, like ending power contracts, things like that.

John Lyons: Looking at load growth and where load growth is occurring and what we're going to need to meet that. We look at alternative load and customer forecasts because we don't know the future exactly because if we did, we would not be talking to you on this meeting, we'd be on a beach somewhere if we were perfect. We do have to make different alternatives. We always start with an expected forecast and then we have high and low. If there are other ones that are important, like for example, do we have a quicker uptake of electrification for vehicles, housing, things like that. We develop resource strategies under different future policies. Again, since we don't know what the future is going to bring, we come up with different ideas of what it could be. We look at different generation resource choices, do we have an all wind, all solar, mix of the two, different types of storage technologies. We are looking for new resources that will be clean but that we can turn on and off, it's hard to do that with the sun and the wind. But are there some other resources like hydrogen of green ammonia, things like that we could look at. We include energy efficiency and demand response, transmission and distribution integration. We do now have a distribution planning group that you can participate in that we'll be talking about throughout this TAC series. This all results in a set of avoided costs that will help developers know what they be able to get if they submit us resources and just also knowing what that's going to be for our general planning needs. We also run market portfolio scenarios for when we have those uncertain future events. Those are the big picture events that will fundamentally change the market that we're looking at.

John Lyons: As far as the TAC itself, this is the public process of the IRP. This is where we get input on how we're going to study things, what we're going to study. If you have things that are questions that you're really concerned about, and you would like to know answers to. If you have a particular study in mind, let us know, or we can help you fashion a study that we could do to come up with that data. We go through all of our assumptions and results. And if you look in our past IRPs, we publish a tremendous amount of data so that you can look through it and decide are we, you know using reasonable assumptions or not, can we make them better? Better we do have a very wide range of participants, so not everyone is going to be very, you know, totally adept at certain parts of it.

Annie Gannon: Yeah, we lost the sound, I think.

Kevin Holland: John muted himself.

Gannon, Annie: Oh, there it is.

John Lyons: Alright, it just automatically muted for some reason. You can hear me again?

Chris Drake: Thank you.

Annie Gannon: Yes.

Charlee Thompson: We can hear you.

Chris Drake: Yep, we lost just the last 20 seconds.

John Lyons: OK, it just didn't like me, and I just had this life changing sentence that I said. But no, this is about TAC members, and we have a wide variety of people in the group and some of them are experts in one area versus another. Please ask away if you have questions because, like we've all learned in in school over the years, if you have a question, generally someone else has it too. So, please speak up and ask on that. It is an open forum. We're always trying to balance the needs of getting through the slide decks. If you just say have something where you agree with someone, do the thumbs up on the chat box. That does help. We also are always looking for help with soliciting new TAC members, and we have an arduous process to get on the TAC. You just send me an email and ask or call. That's it. If you want to be on the TAC, you can be. We have some people that participate for the whole series, and we have others that just come for the topics that are very important to them.

John Lyons: We do welcome request for studies or different assumptions. We may have a set of assumptions that we feel are appropriate for planning because we have to plan to what we actually see out in the market. But if you've got other assumptions you'd want us to take a look at as a scenario, you're welcome to do that and we'd happy to do that. And again, we're available by phone or email for questions or comments in between meetings. And I think James will talk about it later, but on the Teams, we may be able to start doing some more discussions on that.

John Lyons: Our agenda today, after the introduction, Kelly will go through the CEIP update and what's going on there. Then James will talk about the TAC process and some of the proposals for different methods we're going to be using this TAC series. Mike will give a PLEXOS overview. That's one of the major software that we use for the IRP that is new for this IRP. He's going to show a back cast on that towards Aurora. Take a break. Then Lori will discuss available resource options for different types of generation, demand response. You will have to wait for and be excited about the different types of generation like solar, wind, thermal plants, biomass, geothermal, things like that. And then I will finish out the day with the Work Plan. We plan to end by noon. You'll see we have a mix of long and short meetings going over this schedule.

CEIP Update, Kelly Dengel

Kelly Dengel: Good morning. Thanks. OK. But while James is putting that together, I'd like to thank you for inviting me. This is my first opportunity to speak at a TAC meeting. My name is Kelly Dengel. I'm a Project Manager in the Clean Energy Strategy Department and it it's a relatively new group that has been formed to try to keep up with the good work that this team does, also in energy efficiency and energy assistance and community engagement, all of those groups are involved or environmental too. I see you over there involved in how we pull off this Clean Energy Implementation Plan and today's information. It's an opportunity to give you an update on our implementation plan and the biennial. Can you go to the next slide?

James Gall: Yes.

Kelly Dengel: Today I'll share just the highlights of what's in the biennial. And you'll also have an opportunity to review it and provide commentary before we make our final filing with the Commission. You are likely all familiar with the Clean Energy Transformation Act, which informed us creating a Clean Energy Implementation Plan. We made a Progress Report earlier this year based on the 2022 compliance period and then the last item on this slide is actually the biennial, which is required every two years. We'll file it November 1st and it's giving an update to all the specific items we mentioned in the CEIP or the Clean Energy Implementation Plan.

James Gall: Alright, I guess this one is my slide. One of the crown jewels of the CEIP is the transition to 100% clean energy by 2045 and we're trying to show progress over the next four years. The first four years of the CEIP plan. For the first biennial, we are going to be reporting on the targets that we set through negotiation in the CEIP process, which is 40% clean energy compared to retail load in 2022, ramping up to 62½% by 2025. That's shown in the green bars and in blue is the amount of clean energy that's allocated to Washington customers prior to any sales to the wholesale market. In 2022, for example, we generated 71.6% of clean energy or qualifying clean energy compared to retail load. It might be worth noting that we did sell off the difference between the 71.6% and the 40% to third parties, at least the clean energy RECs component of that. We will continue to try to optimize those REC sales to benefit our customers until we are at a point where we need to retire all of the clean energy RECs for our customers. As we ramp up towards 2025, we are bringing on new resources which we talked about in the last TAC series where we acquired contracts. Chelan PUD, the Columbia Basin Hydro contracts, the Clearwater Wind, and the upgrade to Post Falls. We'll talk a little bit more about our resource portfolio in a future TAC meeting, but we are in good shape to comply with the ramp up requirements towards the 100% carbon neutral level by 2030. So that'll turn it over to Kelly.

Kelly Dengel: I mentioned energy efficiency as a large contributor to our CEIP and they have some specific items they've been working on. The first one there related to pilots for demand response and those should be available for people to enroll and learn about in Q2 of next year and it will be a two-year pilot for time of use and a peak time rebate. They also made some really good strides with the Spokane Tribe in conducting energy audits and their administration building, partnering with them to apply for grants, working on a solar opportunity, and also weatherization, common energy efficiency activities. And then the last bullet there, the Named Community Investment Fund is a specific action that I'll talk about later.

Kelly Dengel: But how can that speak to how we can make some of these opportunities that look less economic? Economic by funding them through this fund that we established in the CEIP and put more specific interest and specific focus on folks in Named Communities. Next, next we'll talk about the Customer Benefit Indicators. This is a large portion of the CEIP and how it's measured for us, ensuring an equitable distribution of the clean energy plan, and the benefits and potential burdens and call those non, what do we call those James on energy impacts.

James Gall: Non-energy impacts.

Kelly Dengel: Thank you. We worked with the advisory group, specifically that Equity Advisory Group to establish these CBIs, Customer Benefit Indicators. We have six benefit equity areas. The graphics across the top and 14 CBIs which have resulted in 74 individual metrics underneath each of those CBIs. The CEIP will give a 2021 baseline compared to a 2022 actual for each of these metrics and how we've performed in relation to the CBI and when we go into our next CEIP / IRP plan. We'll be talking about the CBIs and if there's changes, we'd like to make, or additions, we want to hear from folks. So that's something into the future. The next one is about the main Community Investment Fund, so this specifically made space for benefiting folks in Named Communities through the establishment of this fund. And we have $5,000,000 set aside. You can see the five different areas in which we intend to spend this money and that $2,000,000 for energy efficiency that supplements to get over the economic hurdle for some of the energy efficiency projects. And the remainder $3,000,000 is managed by our Community Outreach and Development Engagement group here in Avista.

Kelly Dengel: Next, we recently put an application online. Open to government agencies, nonprofits, and other community organizations to have access to the funds. This online application has had exposure and communication with our Community Action Partners and has been pretty popular. We launched this back in August and we've already had more than 10 applications come through for funding and the intent is to review them and get approval to award monies within 45 days of submission. When we go through this review process, we had talked with the Equity Advisory Group about how they thought these funds should be spent and what was a priority to them about projects. And so, this ranking and you'll see that obviously they have some really important things that catch two number ones or three, two number threes. How they think the money should be spent. We look at all the projects through this ranking lens and try to award in line with what they've prioritized. And you'll see the Spokane Tribe is the number one right there, and many of the energy efficiency and audit improvements and the grant partnering is a prioritized effort. So, we're filling that. And as other projects come through, we'll look at this prioritization list as another way to determine funding and approval.

Kelly Dengel: And the next slide talks about what the requirements of the project at a minimum should have. How does it serve a Named Community. I'm assuming that everyone on this call understands what a Named Community is, or at least the concept. And second, how does it fall into one of the equity areas? And then third, what is a

Customer Benefit Indicator that it can impact? And so those things are part of the application process and there are folks that have been made available to help in this application process. If you're unsure on how to fill it out or you unsure about how to find out what your CBI is. Next slide. We have funded, or planned to fund, projects in these areas and under energy efficiency. Of course, you'll see a lot of the Spokane tribe and two big projects under distribution resiliency and improvements to the Martin Luther King Junior Center here in Spokane. Through grant awarding with the Department of Commerce we're able to secure funds to work on a solar and battery storage project in the town of Malden. I don't believe there's a grant opportunity there, but trying to work on a solar and ground source heat pump project. Malden is the town that had all fires not too long ago. They're trying to reinforce and rebuild their town hall and this this will help them. That's what we have to date. The biennial will provide updates for each one of these projects and how much money was actually spent within 2022, through August of 2023, what we planned for the rest of the year, and in the 2024.

Kelly Dengel: The next subject of the biennial is public participation. We were required to file a public participation plan of this, partnered with a company called P3 or Public Participation Partners. They worked with us last year and a little bit in the previous year to come up with a plan of how to engage more customers and overcome the barriers that may limit them from wanting to participate. You could think language is a barrier, or where they're at might be a barrier, physically located. And so, we have updates.

Kelly Dengel: Next slide, James, we have updates based on what we said we would do on our plan and that includes a multi-language strategy for our website and our mobile app. We also want to make a way for customers to more easily engage with us. A lot of times our conversations are one directional. We give you a message, but through the CEIP process, in this public participation, we wanted to be more two-way. So, we're talking about a newsletter and a public forum comment section that we can implement some FAQs and obviously continue to get feedback from our advisory groups. These updates to our websites and particularly the CETA page should be coming in the next year and that is listed in the biannual as well.

Kelly Dengel: Finally, we had a bunch of conditions, 38 to be exact, that we were required to accept during our CEIP approval process. Over the last year and a half, we've been working to complete or start a plan for. The biennial will list each condition and then an update as to what Avista is doing to comply and meet that condition and, spoiler alert, for meeting them all. This is a great job and I think we'll have a nice story to tell. The last slide talks about how you can respond and review this biennial document. The document is available for posting. We're sending it out to all of our advisory groups, and I think James has a plan to put it on their new IRP Teams site. You can direct your comments or questions to me specifically and my email address is there. Please send them by October 13th, and we'll include the comments, questions in some type of matrix with the filing when it goes to the Commission on November 1st. At the end of this slide deck is a listing of all 38 conditions. If you're really interested in knowing what we had to do, you can go read through those. That's my presentation for today and hopefully you're really interested in reading this in the biennial and you have lots of comments for me. Are any questions on the chat? No typed questions? OK. If there's any questions of anybody in person, so hands up or pause this for a second, just in case something comes up. OK.

TAC Process and Methods Proposals, James Gall

James Gall: Well, thank you, Kelly. And I guess I am next, bear with me while I try to find my presentation. And looks like you can see it now alright. Well, as we started a new TAC process, we like to go over some of the changes we have in mind. Specifically, there's some major changes in the modeling software we'll be using, others mean a couple of process changes we'll cover. Also, we'll provide an update on the Action Items from the last IRP.

James Gall: First off, I want to talk about the TAC communication process that we're changing that John alluded to earlier with Microsoft Teams, which we've been using for our meetings over the last couple of years. But we're going to create an actual team that the TAC will be able to participate in. You'll be getting an invite, likely tomorrow, to access the Teams site, so I think you can use it through the same software you're using today to access this meeting, but there will be an actual Teams site that will allow you to see files that we share with you. There'll be a chat function for you to communicate with us or other TAC members that are all available in this. I'd say this really comes back to some comments we had from TAC members that either didn't want to engage or wanted to engage with other TAC members. This allows for each of you to engage at the level that you would like. So, if you don't want to see what other TAC members are saying, you don't need to go on the Team site. But if you want to communicate ideas that you have, maybe articles you've seen, files that you want to share with us, it's an Ave to do that. This will eliminate a lot of the email traffic for the passive TAC members. Like I mentioned, you'll also be able to access all of our recordings and all the messages that are on the Teams site are retained.

James Gall: We, like John mentioned earlier, will continue to post our TAC slides and our meeting information on the website, including the agendas and the slides. We will not be sharing on the website any draft documents like we've done in the past. We'll leave those on the TAC Teams site and then once we file the IRP and final documents are ready, we'll post those on the website as we do today. You should be getting an email and next day to sign up for this new Teams site. You'll continue to get TAC invites through email, but you'll also get one on the Teams site as well. And if you are also a natural gas TAC member, we'll have a Teams site for the natural gas IRP as well that will be actually in the same location on Teams. They are called channels that you'll be able to get to when you open this up, you'll see on the bottom there's an Avista 2025 IRP. There's a general section which you will see any generic comments or chat function, but then you'll have electric and gas options, and you can see there's posts for people. This is where the files, where you'll be getting files, and we'll see how this works. If it doesn't work, we'll try something new, but one thing that's important is to try things, and if you fail, fail fast and we can try something else. So, let's try this and see if it works, and if not, we'll try something else.

James Gall: Another interesting thing that's happened, at least for Washington, we got a notice from the UTC on the electric IRPs that the Commission will discontinue its practice of acknowledging electric IRPs in all cases. The second bullet is a quote from that. Notice we're under CETA, the CEIP must be consistent with the long-range utility’s integrated resource plan and informed by the investor utility’s Clean Energy Action Plan, which is developed in part of the IRP. Therefore, any issues that interested parties may have related to the IRP can be litigated and decided by the Commission as part of the CEIP process. How we see this, the CEIP, which is really a four year look at the Company's future will be the area to comment publicly about IRPs. I think this 2023 IRP did have a public process where there were comments to be filed. I'm not sure that will continue or not, but we are, definitely interested in comments as we go through the process as we have always been. I would say don't let this be a deterrent to comment in the IRP process and it is better that we get any comments or concerns through this process before we get to the CEIP, as the CEIP is definitely more focused on four years and sometimes they have a shorter timeline to get that completed. So, continue to use the IRP process as a as an avenue for advocating as you've done in the past. Idaho will continue to acknowledge IRPs, as far as I know, and that process will remain unchanged. But in Washington, there's a slight change.

James Gall: That's a quick update to different Action Items in our 2023 RP. I want to go through each of these items just to give an update where we're at. The first one is related to a distribution energy resource potential study and that is underway. We hired a consultant, AEG, and they're responsible for determining how much available solar and electric vehicles are on the system and where they are at on the system. And in addition, they'll be looking, as they've always done in the past with energy efficiency and demand response, at a spatial analysis of those potential options. For those of you that are following the DPAG process of it, which is the Distribution Planning Advisory Group, that will be the avenue for much of the work that's being done in this DER study. The plan is that any learnings we get from that study, whether that's changes to our load forecasts such as future EV or rooftop solar adoption that will be impacting our load forecast, and then we can use potential resource locations for future generation sighting as well. More to come on that, there will be a TAC meeting in the future to cover this topic. Once that report is complete, the next item is a variable energy resource study. That process was kicked off in the last IRP process and we are continuing to determine the required reserves and the cost of variable energy resources. We hope that the study will be complete for the 2025 IRP.

James Gall: The third bullet, which is alternative load forecasting methods. Again, we were looking at end use forecasting as an alternative to our historic load forecasting methodologies. We did also work with AEG. AEG who does our energy efficiency analysis for us for the potential study does do an end use load forecast, it determines those energy efficiency targets. We're going to be leveraging that work to help us do our long-term load forecast. It's going to be five years out towards the future, so we'll continue to use our existing methodologies for load forecasting for the first five years of the plan and then transition to the end use model for the long-term forecast. And the reason for this is if there are changes in customer use from potentially electrification, this is a better way to forecast that energy use because you're taking into account the types of equipment consuming that load. So more to come on that as well.

James Gall: The last bullet on the left is investigate PLEXOS, which we'll have a presentation about that later today. So, I'll skip that one, and the next one is with the Western Power Pool's WRAP program. I'd say this was very unique in its last IRP process to use the WRAP's QCC methodology and we did not use their proposed planning reserve margins for long term planning but I think that the idea here in this Action Item is to ensure that we want to keep using their methodology and then how do we transition to using, or should we be transitioning using the WRAP's planning reserve margins. There are two concerns with using their planning reserve margins. One is they only go out in the future for two or three years, and second, they have not done any long term QCC analysis. Our PRM analysis determined resource adequacy beyond those first two years. There's been an effort by the members to do a long-term study and that study would be determining QCC values likely out in the 2040 time period or 2045 time period and what the required PRMs would be out in that future and that would be used for planning in the IRP. If that that process is successful, so likely there will be a topic at a future TAC meeting to cover this as we learn more in that process.

James Gall: The next bullet is on long-term or long duration storage opportunities we mentioned in the last TAC process: pumped hydro, iron oxide, hydrogen, ammonia storage. We'll have a presentation by Lori this afternoon to seek input from you, the TAC members, for the technologies we should be looking at. Are there technologies that we shouldn't be looking at? Also, if there's anybody that has information on these technologies, whether it's cost information, where we're at in the development process that would be great for you to share with the group.

James Gall: Another topic related to Named Communities, like Kelly mentioned, communities that are defined by the State of Washington as Highly Impacted or Vulnerable Populations. The ask was to determine the amount of energy efficiency that is in those areas. In our last IRP process, we did break out energy efficiency by low income. We wanted to further look at that spatially and the Named Communities. That process will be beginning shortly in determining whether or not that's something that we can do with any accuracy.

James Gall: Next bullet was on transmission access. As some of you might recall, Washington State legislature did pass a bill that requires IRPs to look at transmission. We are going to be making some changes in our modeling process to account for that.

Actually, Mike will be going over that in the PLEXOS tool this afternoon. But we are also concerned about surplus energy and that tool will help us determine what is that future utilization of transmission to export excess renewable energies that we're going to be acquiring to ensure that we can meet 100% by 2045. That tool will help us manage that Action Item and then the last bullet will probably play out through the regulatory process. But that is looking at, how do we define what 100% is when we're in 2045. Does that mean that we should be planning our system as an electrical island? Does that mean that we will be allowed to buy power from others? How do we ensure that it's clean in a connected market? I don't think those will be answers we will have in the IRP, but it is an issue that needs to be addressed regionally, or at least in the State of Washington, because the implications of how you design rules for CETA will impact what our plan is. I'm going to pause there. If there's any questions. I guess not, OK.

James Gall: Just a real brief introduction of PLEXOS. I don't want to steal. We have a question [from unknown user in chat], I found when I set up an external facing Team site for the project that DES Energy is doing that non-state individuals invited to the Teams site could not access more of the site if they logged into the site via web browser rather than the Teams app on the computer. So probably the same is true for yours. So, we'll be looking into that. We hope it works. We're told it's going to work for us, so if we do run into roadblocks, we won't have to revert back to the old method, which I said, fail fast is OK, so hopefully we don't fail fast.

James Gall: Alright, so PLEXOS. Mike is going to cover a lot of PLEXOS later, but there's a few things I wanted to throw out there as you think about this, before we get to Mike's presentation. So, what is PLEXOS? It's a production cost model developed by Energy Exemplar, and its benefit, or its technology that it uses, is a mixed integer-based design which is very similar to what we use in our PRISM model, and we plan to use it for resource evaluation and market risk analysis. And what this is, when we look at each of the generating resource options, that Lori will be talking about later, is we need to determine how they're going to be dispatched and how much market value they create. Aurora does do a good job at this, looking at it from a market perspective, but as we acquire more renewables and then look at energy storage, we need to look at this from a portfolio basis and that's where PLEXOS really the strength in that tool. So, we think it's going to do a little bit better job at valuing energy storage from that portfolio. Especially with our reserve modeling. Of course, the future could create an RTO which would maybe allow for other options to model this in the future. But for now, in a control area environment, or balancing area environment. I think this technology is probably best suited for studying these resources.

James Gall: The other major change that PLEXOS brings to us, compared to using Aurora, is a more sophisticated hydro modeling technique. Aurora does a phenomenal job of dispatching hydro from a regional perspective, but when you look at it from a portfolio design, there's just constraints of the system that we can't model, and we think

PLEXOS is doing a much better job with that. We'll have some presentation by Michael. We'll show that in a little bit.

James Gall: As I mentioned with transmission earlier, it's capable of modeling detailed transmission. The last couple things on here is the future that we see with the tool. One is can it replace PRISM? Or should we replace PRISM, I guess is maybe another question, but it does have a capability of doing capacity expansion for both transmission and generation. We'll be testing that in this IRP process, but will continue to use PRISM for this IRP process. And then the last point is, it theoretically can do combined natural gas and power modeling and that's something that we would definitely be curious at looking into as well. There's definitely a future for expansion between IRPs, between fuels, so there is potentially, but we are going to take this a little bit slow just to ensure that we're comfortable with the results we're getting. And also, we are a small team of folks and so it does take time to build these tools out and ensure that we're getting correct results.

James Gall: Like I mentioned earlier on the load forecast update, we have an agreement with Applied Energy Group, AEG, to do a long-term load forecast. We're actually doing this for both natural gas and electric. The idea is to ensure that we understand the implications of electrification and what we're looking at here is, if we have customers switching between natural gas and electric, we wanted to ensure that we account for the correct amount of BTU transfer between the two fuel types and then the efficiencies of those options. So, AEG is in the process of conducting a load forecast for us. It's going to be consistent with that. Our potential state, like I mentioned earlier, they will be producing three scenarios for us, a high, a low and an expected case. And we'll be seeing, I think the first iteration of that load forecast in the next two months. We'll update it again and present it to the TAC in the spring. And then with that load forecast, they can use it to determine our demand response potential and our energy efficiency potential assessments.

James Gall: I think one of the challenges we had with, say for example demand response, is what is the amount of your water heaters there will be in the future from a electrification conversion for example. And this should say, streamline our process on the customer opportunity side for what does load growth look like? What do resource options look like from demand response and energy efficiency? We're excited about this change and it should hopefully provide a better result.

James Gall: Another update on PRiSM, like I mentioned earlier, we are looking at testing PLEXOS to replace PRiSM for the next IRP in 2027. But we're going to wait on that. We were a little bit concerned about, can PLEXOS do the level of detail for energy efficiency that we do in PRISM. Can it run fast enough to run the scenarios that we need in this IRP process? What is it going to take the build these portfolios out? We like PRiSM because it's nimble, it's very transparent, but is it the best technology to help us on this path? That is yet to be determined and one of the concerns I have with using PLEXOS to do portfolio modeling is that transparency, where PRiSM is, we can post that on our website. You can look at all the assumptions and PLEXOS requires you to buy a tool to look at those results. That's something we'll be considering, and we would like input from the TAC as well through this IRP process as we test it, and before we make a decision in the 2027 IRP. I think it would be helpful to hear your comments on what technology might be best suited for that next IRP.

James Gall: Another thing we are testing in PRISM is co-optimizing the natural gas system and electric expansion. What I mean by this is instead of having a separate IRP that looks at figuring out which resources are needed for the electric demand and the gas demand, we bring that all in one tool and the model can choose what's the best way to serve that demand. For example, if there is a heating demand, is it best suited to be served by electric or natural gas from a least cost basis.

Lori Hermanson: Got a question James.

James Gall: All right, I'll pause there. Fred, go ahead.

Fred Heutte: Hey there everybody. Fred Heutte, Northwest Energy Coalition. Good morning. Just a very quick comment on PLEXOS. I think you may very well know that PacifiCorp has been using that for a couple years now. And I hope you've been chatting with them about their experience. They had a lot of trouble. They did, in my personal opinion, not do a long enough transition approach. They did some. It wasn't like they just dived in. Throughout the early they were using system optimizer before that, not like they just completely jumped. But I don't think that they did enough of the transition like you're doing. It's very powerful. It's a beast. From what I understand, I've not seen a detailed run through. You know how it operates, but where they did do that was system optimizer.

James Gall: All right.

Fred Heutte: Using PLEXOS as your primary model is the right way to do it, and specifically on energy efficiency. I would concur about the potential there, where PLEXOS may have some advantages. You could talk to the PAC IRP team, Randy Baker and everybody there. They've done some very interesting things with PLEXOS too, and in some ways kind of overkill how complicated they've gotten with their EE analysis, but it's really robust. Hopefully you'll be able to figure this thing out and looking forward to how it all looks as you go through that.

James Gall: Hey Fred, I asked about this transparency issue. Are you comfortable with PLEXOS as a tool, is that transparent enough or would you like our transparency of PRISM?

Fred Heutte: You know honestly, and I follow modeling pretty closely, but I can't say that I'm a modeler or I know a lot about software, I'm not a practicing modeler. So, I think there may be a participants, stakeholders, whatever in the IRP process who might be interested in taking a look. Yes. You know, I think one of the really positive things about Avista’s approach to the IRP is you do make everything as available as possible. You know the models, the data, et cetera. I think we have a tradeoff here. PLEXOS is a really big beast.

I don't know what the licensing fees are, but you know they're pretty high. I think the key thing will be to you know that as long as you provide the kind of transparency into your methods and the outputs, the UTC staff and maybe some stakeholders that have really serious modeling capabilities of their own might be interested in taking a look at some of the results. But practically speaking, I think as long as we're sure that you're running things as you say, and we have a good interest in looking at specific details, outputs you're able to provide that. I don't really see a big problem.

James Gall: OK. Thanks, Fred. Any other comments before I continue on? Alright, I have my last slide and I'm hoping this last slide will get some feedback. I'm going out on a limb here and you might remember if you've been part of our TAC process, I think the last meeting in our 2023 RFP process, we talked a lot about resiliency and how do we include resiliency in IRPs is a challenge across the entire industry because most resiliency aspects are at the feeder level. And I think that's appropriate. But IRPs are typically at the generation level, somewhat transmission level and but there are things that are resiliency based that we should be looking at. I think about this as a resource diversification and John and I were spit balling a month ago about how do we deal with resiliency. And we came up with a methodology, the quantify of diversification, some of those that are finance nerds may have heard of the Herfindahl Hirschman Index. But we thought, is this a way to measure resiliency? And you know, maybe this ends up as a Customer Benefit Indicator, I don't know. But what I think we can do with this concept is look at diversification, not just the fuel types, but fuel locations. It's just the generator locations.

James Gall: What I've done on the right is come up with three different methods I had time for looking at diversification. One is the amount of generator units we have. The second one is facilities. Noxon has five units, but it is 1 plant, so from a risk point of view we've spread that risk of generation failure out across 5 units, which is great. But you're still at one site, so if there was an event, whether it was some type of catastrophe or a substation outage, you still have one facility, and you can lose the whole system. One thing on the substation is what we've done there to prevent that risk is put two substations there, that helps, but look at how spread out is our number of facilities, not just the number of units and then another item we looked at is fuel supply. So where does our fuel come from? What I mean by that is, like a natural gas plant, the fuel is coming from the GTN pipeline for example, and then you compare that to hydro. We have the Clark Fork River system; we have a Spokane River system and we have a Mid-Columbia River system and then we have different watersheds. We looked at where is the fuel supply from for our system. Where do those come from?

James Gall: The Herfindahl Hirschman Index looks at market share, or percentage of the population, and it comes up with a measurement of competitiveness and the higher the number that you come up with indicates less diversification of your resources. So, the academics came up with, if you have a score that's less than 1,500, you're very competitive and very diversified. For the two metrics we looked at, generating units and facilities, we are very diversified. We're well under that 1,500 and if you're between 1,500 and 2,500, you're in a moderate diversification level. And then if you're over 2,500, you're too concentrated in a particular area. On fuel supply, you see we're really close to that 2,500 and the question is from an IRP perspective and a generating perspective, should we be looking at resources that have other fuel supplies. That might be something we look at as an indicator of a resource choice for the next IRP. Should we keep the portfolio under 2,500 for example, for the different metrics?

James Gall: These are three metrics I threw out there. There's other metrics we could look at, such as transmission system, which path the resource is on. We could look at wildfire risk areas, do we have plants that are in wildfire areas and trying to ensure they are minimized or in different areas. Another one that we looked at is low diversity, and that's not necessarily the generation side, but we could do this analysis on our loads and maybe look at are their risks in different load types that are especially available now that we're looking at end use load forecasting. But I'm just curious if what others have seen on how do we deal with resiliency in IRPs, does this this seem appropriate? No, don't like it, or something else? I'm just curious of any feedback you have and if you want to think about it, it's OK you can email us later, but I'll pause. I see a hand go up. Heather, go ahead.

Heather Moline (UTC): Hi. Heather Moline, UTC staff. This is interesting. I've never heard of Herfindahl Hirschman. Thank you for that overview. Food for thought. Again, this is not Staff's opinion or the Commission's opinion, but you just asked for feedback. So, I wanted to put it out in the space. Maybe it does make more sense for resiliency to be quantified and incorporated into something like the CEIP as opposed to IRP, because CEIP tends to be a little more about local customer benefit and a little less about long range, large resources. That's just one thought. I would like feedback on the second thought, slash question, is to what degree have you all looked into the resources from the national labs and Energy Trust of Oregon on resilience quantification? And incorporation into resource considerations.

James Gall: Can you tell me a little bit more about that last statement about the national labs?

Heather Moline (UTC): Yeah. The Lawrence Berkeley National Lab and Pacific Northwest National Laboratory. This is one of the main questions that they've been doing research on for the last three years is, you can't include zero as a benefit or cost of resiliency because there is a benefit to resiliency. So, how do you put that into models? And I haven't seen any studies in the last year, but there may be some. I just wondered if that was research you all were doing.

James Gall: I guess we have not looked at those. We will. One thing that I see this related to is, because you've talked about values and we tried to quantify non-energy impacts in the last IRP and where I'm going with this is if the studies, if they're showing values for different resources, you could put that value in our optimization tool. But we'll look into that. I appreciate that. That's why we're doing so.

Anette Brandon: James, can I comment on this? This is Annette.

James Gall: Go ahead.

Anette Brandon: Hi, this is Annette Brandon, I'm in wholesale marketing and Heather, I have actually been following that PNNL resiliency modeling how to value as part of our equitable business planning initiative. James and I did look at it very briefly, although I'm not sure I pointed out to him what exactly that meant, but I have been following that pretty closely as we start to implement this overall project and so will be coordinating with that as we go forward.

James Gall: Alright. Well, it's one at least we have one idea to look into. Are there any other thoughts, comments.

Heather Moline (UTC): This is Heather again. That's great to know. And just so you folks know, you are not the only people asking this question. So, as we become aware of more things with the other companies, we'll be in touch.

James Gall: OK, appreciate it. The CEIP is definitely an avenue for, there'll be solutions or ideas to solve resiliency there. There could be an avenue of how we define a Customer Benefit Indicator for resiliency that will be in that process and maybe one of these HHIs is one of those. I do see it as a place for generator level resiliency and the relation there is I see what's going on and say, Texas, what was that four years ago? I can't remember, but having facilities that are capable of running and in cold weather for example, but if this is an area that's I'd say it's come up, but I'd say no one cracked that nut yet.

James Gall: I don't think we have either, but we're going to at least try to explore this, and we'll look at the national labs work, and we'll continue maybe to look at this as an option and maybe circle back with the TAC. But, if you have any ideas, let us know afterward or throw them in the chat.

James Gall: Alright, so what's next on the agenda is it a break. Can't remember, I don't know. Let's check here. PLEXOS is next. Then we'll go to break. Unless we need a break now. But we're supposed to take a break at 10:45, so we do have time. I'll bring up the PLEXOS slide deck and if you can, we can do that. Bear with us one second as we transition. Alright, I think it's there and Mike's ready to go, OK.

PLEXOS Overview and Back Cast Analysis, Mike Hermanson

Mike Hermanson: My name is Mike Hermanson. I'm a Senior Power Supply Analyst here at Avista and I'm going to be talking about how we are integrating PLEXOS into that IRP, analytical modeling for the 2025 IRP and also the testing that we've done to determine how well we are able to represent our system within PLEXOS. Just a little background here. Power supply modeling is integral to the IRP process. It's the analytical framework to determine the long run economic and operational performance of alternative resource portfolios. So, as you go into the future, what different resources solve your different various constraints in the most economic fashion. Our existing system, and potential additions to the systems, are subject to many constraints and uncertainties. For example, the timing of hydro generation, gas, power price movements, government regulations, and analytical models provide the framework to put all of those very complex pieces together that don't always move in the same way and then it allows us to assess the impacts these variables have on our system.

Mike Hermanson: And then, as we go into the future potential additions to meet the load obligations that we see coming in 2045 for the 2023 IRP. We used Aurora forecast electric prices, and over the planning horizon. We also used Aurora to dispatch the resources to meet load. That dispatch was then used in the Avista developed PRiSM model to select new resources to meet the projected load. For the 2025 IRP, we are taking a different approach. We're developing an electric price forecast in Aurora and then we will be using PLEXOS for dispatch and that dispatch will be used in PRISM to determine the resource selection, but concurrently with using PRISM. We plan to be testing the resource selection functionality with PLEXOS.

Mike Hermanson: Just a little bit of background on PLEXOS. It's from Energy Exemplar, who also makes Aurora. It's a widely used model for electric market analysis, power system optimization. It provides market simulation. It can analyze and simulate electricity markets considering various factors such as supply and demand, pricing market rules. This provides insight into the market dynamics and in adding energy trading optimization, which is a very important component of this considering different resource options going into the future. PLEXOS also provides for power system optimization. There's a multitude of constraints that you can put in there such as outages, maintenance, market prices, hydro variability, emissions targets. Hydro variability is an important one for our system. Being able to test different variability, and actually the variability more at a more granular time step than we were able to do in Aurora, allows for integration of renewable energy and looking at the impacts of these variable generation on the power grid and how that drives our need for extra reserves.

Mike Hermanson: PLEXOS also has robust transmission planning. It's forced transmission planning, expansion studies, allowing the inclusion of transmission upgrade costs associated with potential resource additions. Certain additions of resources such as solar are only going to make sense in certain areas, but do you actually have the transmission there to deliver that to the grid and to actually be utilized in the near term.

Mike Hermanson: Hydro modeling is where we see the biggest change over dispatch in Aurora. PLEXOS models hydro as water coming into a reservoir and then running through generators. It really represents how it is physically used, the physical movement of water and the maintenance of reservoirs. This is in contrast to how it was utilized in Aurora, where it's a bucket of megawatts and you can put some constraints on it. But it really does not mimic how we operate our hydro system, the flexibility that's inherent in it and also the operational constraints that are inherent.

Mike Hermanson: This slide just shows the general schematic how the model operates. On the left you can see we provided an hourly native load to be met by Avista, owned and contracted generation, market purchases and sales. The hourly load is generated outside of PLEXOS and as James mentioned, for the 2025 IRP we have contracted with AEG to assist us in developing an end use load forecast. That end use load forecast is also outside of PLEXOS will be able to do a lot more scenario analysis, especially as it relates to electrification and EV penetration as you go out into the future. All of the estimates of a government program in place or contemplated, are those going to be coming fruition and if they do, what kind of impact are they going to have on our load? That'll happen outside of PLEXOS.

Mike Hermanson: The next section is the Avista owned and contracted generation. The generation is optimized economically against the electric price forecast. You're trying to get the least cost energy, but there's many constraints that are inherent in these generating resources. PLEXOS allows for regularly scheduled maintenance and forced outages can be done in a statistical manner. The timing and quantity of hydro, including changes over the planning horizon we can bring to play, we do have for example, our hydro forecast bringing in climate change and the shift of water to earlier in the year as opposed to the current or what we've seen in the more recent past where we would get water in June and July. Now we're predicting seeing more in February, March, earlier melts. Let us know snowpack, so we have to bring that into the PLEXOS modeling. We also have in this this middle bucket here we're looking at and have the provision of ancillary services. The variable nature of wind and solar resources, and then we could also look at the impact of fuel costs on running our natural gas resources and in the future, looking at all alternate fuels such as ammonia and hydrogen.

Mike Hermanson: The next section that I look at when we're breaking apart PLEXOS is the market purchases and sales. All of the costs and constraints of our system are balanced against the markets that are available to us, such as the Mid C, which is the primary market that we are integrated with. But we also have some others in the northeast part of our system and COB, the model optimizes and solves at an hourly time step on the native load and then any contractual obligations, sales that were done, and these are met by generation and market purchases and sales every hour. It's a very robust system that you can bring in any multitude of constraints that are affecting your system. The granularity doesn't solve it. Actually, you can get much more granularity solving that at the five-minute time step. We have done some testing at the five-minute time step to look at EIM. Those all of course take quite a bit longer, but it is possible.

Mike Hermanson: This slide shows how our transmission system is represented in PLEXOS and it's a little busy, so just bear with me. Each of the light bulbs on this graphic represents a load center, and each of the green dollar sign icons represents a market where we can either sell or purchase power at, and then each of our generation sources is connected at the appropriate service point. Each of these lines is assigned a maximum flow that can occur on that line, and also power that goes over Avista owned lines which are shown in blue. I don't know if you can see the difference between the blue, kind of looks black, but the ones shown in blue do not incur a wheeling charge, while the power that moves over the yellow lines do incur a wheeling charge, which is dependent on the owner of the line. All of that is input into the PLEXOS system and then it makes decisions on which ways to move power to load centers based on the most economic pathway. This is an upgrade I would say from our previous IRP where we had a much more simplified representation of our transmission system and it's in reaction to the addition by the legislature into the IRP rules. I guess it's not by the legislature, but by the UTC to add into evaluating transmission constraints into your IRP considerations.

Lori Hermanson: We have a question from Yao. Do the cost of market purchases and revenue of market sales include wheeling costs and revenues?

Mike Hermanson: Yes. Essentially that'll be a hurdle rate to buy from the market if you're having to use transmission, so it'll be netted out.

Question from Room: How does the model build losses?

Mike Hermanson: If you got that, you're asking how does the model deal with losses, you can actually put losses, line losses into each one of the lines. We haven't done that just yet. We have right now the sophistication of the line representation has a three-stage maximum flow of megawatts can go across the line depending on the season, because it's temperature dependent. But we could also introduce line losses if we choose.

James Gall: But one thing to note, online losses is when we look at load or native load, you'll see that in any of the data files we provide and how our accounting system works is that load includes the distribution and transmission losses on our system. It does not include third party system losses, so I think where we might end up, like Mike said, is we could put in the transmission losses on the lines that are not Avista’s, but on the ones that are shown in blue or black, we’d likely not include those because they're embedded in our load forecast.

Mike Hermanson: This slide shows the PLEXOS interface. Just to see that real life software, the system that we use is built from components that are shown on the left pane. If you look at the main screen, we have the left pane, and it has all the system components. You have all the different generators, lines, markets and then you move into the middle pane, and you can see that all of these components are then connected and connected in different ways. Fuel is connected to a generator, is connected to a line, and then we can design properties to all of those, and then the bolt section of that first window is all of the properties that you add into each of these components, and it varies by the different generator you have. For example, natural gas generators have a lot of information about heat rate, whereas the reservoir components have a lot of information about hydro flow, how large the reservoir is, what min and max levels can occur in that reservoir, what are the ramp rates for example. And then PLEXOS has a pretty robust system to display results.

Mike Hermanson: This is just an example of the generation over a year at Noxon Rapids, one of our hydro facilities. You can look at all sorts of different resolutions. It's very integrated with Excel. If you're an Excel user, like most people are, you can export these results very easily to Excel and then do analysis on that also.

Mike Hermanson: I don't think I need to tell anybody on this call that representing these energy systems is very complex and representing energy production, market exchanges and transmission in a model has many challenges. With these complex models, it's always a balance between how much complexity is introduced versus runtime for the model. Currently, our 20-year run takes between six and seven hours to do one iteration of it. We plan to run the model with stochastic inputs to capture the uncertainty in our model inputs we would be using. Selection of water years is different than just the one prediction to see what the sensitivity our system has for different water years. In 2021, I believe we ran 500 model runs to capture this stochastic nature and capture the uncertainty in all of these. Then 2023, we’re at 300 model runs at six to seven hours a model run, and 300 runs gets quite lengthy, but there's different approaches to reduce the model runtime to kind of reel that in. We also use multiple machines and so we believe it's a doable challenge, but it will be a challenge. Looks like we had a question there. Heather, if you still had one.

Heather Moline (UTC): No, I was doing that math in my head, 6 to 7 hours times 500. You answered the question. Thanks.

James Gall: We do have 25 machines to spread that around, so it won't be that long of a math problem, but it'll be a long math problem.

Mike Hermanson: Another challenge with a model. We have perfect foresight. For example, electric prices are projected for the entire planning horizon. That is different than what we obviously have in the real world. Another challenge is this system has significant hydro resources with storage components. It's difficult to capture the myriad of constraints. We have licensed constraints, but sometimes the system is constrained by uncertainty or by other considerations on reservoirs, especially reservoirs that have recreation, they have homes that are built on the reservoir. That is capturing how perfect foresight is going to dispatch a hydro reservoir versus how it is dispatched in real life is a challenge and that's one of the things we've been working on quite a bit this last six months. It's difficult to capture the dynamics of trades that happen at different time steps. For the most part, we have power ahead trading that's happening at the market. So, they're looking at what generation we have available, the price of that generation, and then checking that against the market. Now we have day ahead, hour ahead and even EIM trading that is difficult to capture.

Mike Hermanson: Integrating forecast error into modeling, that's another challenge. We're operating our system with a forecast of what's going to occur. What's the forecast of the load? What's the forecast of the water? How much reservoir? You need to have for that, the runoff, when’s the runoff going to happen. When we just input the flows for the whole year, you can go in and solve, and it knows what's coming. That makes it a challenge to integrate and try and mimic how we would dispatch our system with imperfect information versus how PLEXOS dispatches our system with perfect foresight. As a result of all those challenges, the model will always have a lower production cost than actual. It'll be able to be more efficient than we would be able to just run our system. Our production cost is obviously always higher and so trying to get a sense of what that magnitude is really, the effort is to look and see what we can quantify what that forecast, and uncertainty, adds to the production cost to deliver energy.

Mike Hermanson: We started with PLEXOS back in January and our first approach was to see how close we could get PLEXOS to dispatch against an actual year where we had actual data. This is going to verify how we built our model. We built the model with the inputs to all of our hydro units, all of our generation, natural gas generation, and everything. And we used 2021 data including the hourly load, hydro inflows, run of river generation, the Mid C price, daily gas prices, the renewable generation actually scheduled, forced outages, and the reserves that we hold including the frequency response reserve, non-spin regulation up and down, and the reserves we hold for very little energy resources for when solar.

James Gall: We’ve got a question.

Lori Hermanson: Yao’s question was, isn't all the input data actual data in 2021.

Mike Hermanson: Yes, all of this data was actual data from 2021 and then we used that data with the system that we constructed. We constructed the generators, the transmission, and built the model, and then put 2021 data into it. And then the question is, how close can you get? Now we have the actual dispatch, and we're going to have the model dispatch, and how close can you actually get? Hopefully, if you're getting close, that means you constructed those components of your system correctly and are accurately representing them.

Mike Hermanson: This shows the actual 2021 generation, then the generation from the PLEXOS run, and then the difference. The units shown are the ones that can be dispatched and they're not close, not include the must run facilities. So, when we get solar generation, we just take that generation and you run that generation. It's not dispatched. That might be dispatched if you had a battery, and similarly our run of river projects, we just took the actual generation and put that into the model. So, what you're looking at are ones where choices could be made about when generation could occur, and also choices to be made or not. But outside influences could happen, such as hydro coming in differently or payments to be happening, forced outages.

Mike Hermanson: What we found out was the total actual generation was 1,130 average megawatts, while the model generation was 1,122 with relative percent difference 0.18%. It dispatched on an annual basis very closely and we also conducted an evaluation of the mark to market production costs, subtracting fuel costs and found that there was a 0.96% difference between what PLEXOS system cost would have been versus the dispatch generation. If we have the actual dispatch, did a mark to market, and then we looked at our actual total expenditures and we've found the difference between 2.96%. As mentioned in the previous slide, the model production cost was less than the actual production cost.

Mike Hermanson: The next series of slides show the hourly dispatch for selected generators. Blue shows the actual generation and orange shows the model generation. Noxon Rapids is shown on the left and Cabinet Gorge is shown on the right. There are differences between the model and the actual, but generally follow the same pattern. Since the model has perfect foresight for water supply and market prices, it's more likely to move to the maximum generation and then back off to minimum generation then the projects are actually operated. They just don't necessarily operate that way where you have a lot of power to measure reactions to it. Prices and the model production cost was less and the actual revenue from the actual generation was slightly greater than the model generation, I should say had more revenue than the actual generation, but it was fairly close. As you can see, the difference between the two just on average generation of PLEXOS being 178.5 average megawatts versus an actual generation of 179.8 and the things we were checking on was how we have our generators set up in PLEXOS. How is that water actually taken and turned into energy? Do we have all those parameters set up correctly? This is a check on that.

Mike Hermanson: As you can see, over on the right-hand side is the Cabinet hourly generation. You can see over on the September, October months, there were units out. We're able to take those units out in both instances and be able to capture that again. You still see a little bit more opportunistic movement in backing on and off generation in the model. But we did some adjustments to our ramping rates to try and address that. Now, we'll see that when we look at the reservoir.

Mike Hermanson: The next two graphs show Long Lake and Little Falls. An interesting piece here is that the PLEXOS generation in the spring is again using knowledge of water, prices, and is moving from maximum to minimum on occasion when the actual operation, is not doing that and that's to some degree you don't know when the water is going to come off and have them fill a reservoir. PLEXOS did because it had the whole year in front of it. Operators are making decisions about when to keep the reservoir full and not full. And you'll also see that dip there in February and March, and that's the annual drawdown in Long Lake and that really lowers the head. Once you lowered the head, you lowered the amount of generating capacity from each of the units. We're able to build that into the system. Again, these look very similar, Little Falls has a very small reservoir and in essence is run as a run of river at Long Lake. But again, the annual amounts are very close, and we are able to get the shapes we feel to be very representative of the actual.

Mike Hermanson: The next series of graphs show the total generation facilities from Chelan, Douglas, and Grant PUD. That's the Mid-Columbia hourly generation comparison. Again, it's able to follow the general patterns that occurred at those facilities. We have a contracted portion of generation at each one of these facilities and we have the ability to dispatch the plants within constraints that are provided by the PUD. The graph on the right is for Coyote Springs 2, which is a natural gas combined cycle facility. The actual values move, in the blue. They move more than the model values and that is because generation is dependent on temperature and so you have daily temperature movements in an effort to get more model efficiency and be able to keep the model running as quickly as possible, we ended up using monthly values and it's a very good approximation.

Mike Hermanson: This next one shows Lancaster. It's a contracted combined cycle facility, similar to Coyote Springs 2, and the actual value shows more variance than the model. Rathdrum is on the right-hand side and it's a simple cycle peaking facility. It has the largest percent difference between the model and actual values, and that is just due to the different ways that the model was able to address some of the peaking mode that came in, and so it didn't have to rely as much on this peaking facility to meet below.

Mike Hermanson: These four charts show the reservoir storage level throughout 2021 for each of the storage projects. On the left is that reservoir elevation, the forebay elevation, and across the horizontal axis is the months. You can see in the Noxon graph. You can see one of the changes that we made to. To kind of back off, PLEXOS' inclination to jerk the reservoir around, so to speak, which just operationally does not happen. We limited the hourly ramp rate and so that tightened up the reservoir movement as you can see in the springtime months. We were moving that around quite a bit more in actual operations, but to match the dispatch. We constrain the hourly ramping and that tightened that up a little bit.

Mike Hermanson: Looking at Cabinet Gorge, the orange is the model value. You can see how it likes to move hitting those hours where the market values are high. It's still within the range of what we actually see, but the reservoir does not move around quite as much as PLEXOS would like to do it. Or does do it in Cabinet over many iterations of trying different ways of time, tying the dispatch of these hydro units, this combination of using this hourly ramp rate at the reservoir at Noxon ended up providing the best match.

Mike Hermanson: If you look at the graph on the right-hand side. Those are for Long Lake and Little Falls. The bottom shows Long Lake and there's a drawdown that happens in springtime months, and then a significant increase, and then it runs within a fairly narrow band of reservoir heights. It's not doing big reservoir moves to meet price and that's a constraint that was put in to match the actuals. I guess this whole effort was really to get hydro to be close to the way we operate it, so that the rest of our system can balance against that and get a much more accurate picture of what the dispatch looks like and the production cost.

Mike Hermanson: You're probably wondering on Little Falls. Little Falls operates within a really tight band. You can see that PLEXOS is operating it within quarter of the foot. Those are in half foot increments and that graph in actuality operates slightly different with a little more volatility, but not much more. And also, halfway through the year before my elevation data, something happened with it in 2021. So, it only had a half year's worth of data.

Mike Hermanson: These last slide shows the model value for model versus actual values for the Mid-C reservoirs. And as I said, this isn't the sum total of how the Mid-C reservoirs are acting. This is how the portion that Avista controls is moving, it's not moving in total unison, but the magnitude and the variance. This is fairly similar. We're able to match the timing and the actual output for this Mid-C system fairly well. When we came to that end of all of these exercises, we came to the conclusion because PLEXOS we were just trying to test it out and figure out how well is this going to work for our system? We've been using Aurora for a long time, and I think we came to the conclusion that we can flex. Those can be used for the dispatch and match with and incorporate all of the constraints that we want. There's still more that we want to build it into it, and so our next steps are that. Building this into our IRP modeling.

Mike Hermanson: This is just looking at one year, whereas we'll be building out the full 20-year IRP and doing adding additional resources and doing that iterative process of looking at what we can generate out of PLEXOS versus what we can generate out of PRiSM and going through that process. But I'm not sure if there's any other questions as a lot of information all at once.

Lori Hermanson: There's no unanswered questions in the chat. There were several people that gave us additional information on resiliency, which we will follow up on.

James Gall: Alright, well, there's no questions for Mike. I appreciate the presentation. A lot of work has gone into PLEXOS and like I said, we see a bright future for it and the IRPs to come. We are little under 1/2 hour ahead of schedule, which is great, which means we can take a break. I think we could probably get back and finish early, so let's take a break until 10:30. Does that work for everybody? And then we'll get started on the available resource options with Lori at 10:30 and then finish up with the Work Plan and then adjourn, hopefully by 11:30, we can get done early, so we'll go on mute and see you back here at 10:30.

Available Resource Options Discussion, Lori Hermanson

John Lyons: Well, welcome back everyone. Hopefully you got a chance to get up and stretch a little bit as we get towards the end of our first TAC meeting. Lori is going to be up first and talk about generation resource options and then after that, I'll finish up with the Work Plan.

James Gall: We're thinking we'll probably be out about 1/2 an hour early today and before Lori gets started, this is an area where we like to get TAC feedback, so don't be shy. Use the chat. Lori will be monitoring the chat as she's to presenting and they go away. Lori.

Lori Hermanson: Good morning. I'm Lori Hermanson and I'm going to cover the resource options that we included in the last IRP for review. We would like your input as to whether or not you think that we should maybe not include ones that we did include, or maybe we've missed some. We'll talk about that as we go through, but that's basically where we're looking for feedback. If you want to go to the next slide, I'll start with the natural gas turbine options. We tried to model one of every different category, peakers and base load, and then the types of peakers. For peakers, we modeled a simple cycle combustion turbine frame type engine. The model is 2 units totaling 180 megawatts for the reciprocating engines. We modeled 10 units totaling 185 megawatts for baseload engines. We modeled a combined cycle combustion turbine 1x1 with duct fire, and that totals about 312 megawatts for these combinations. For these types of turbines, we also looked at different fuel types and not just natural gas – renewable natural gas, hydrogen in the form of ammonia, and synthetic natural gas. For these natural gas turbines, we considered them as Avista owned resources that would have a 30-year average measure life based on the policies that we're seeing in Washington and Idaho. We're going to continue to look at non-natural gas fueled options for Washington. But in Idaho will continue to look at all fuel types, and then we'll also continue to model and evaluate, or evaluate and model, potential upgrades of our existing facilities. Next slide please.

Lori Hermanson: We looked at renewable resources such as wind and solar. On the solar resources, we looked at varying sizes, applications, and storage options. We looked at a residential 6 kW unit as our resource option as well as a commercial one MW option. We looked at a 5 MW resource that was a fixed array. All of those, we modeled them with and without battery options. We also looked at single array or single access tracking arrays of varying sizes from 50 to 100 megawatts and varying sizes of storage duration. The ones that have lesser storage, those are used for integration purposes. If it's a longer duration storage, the model would pick them because they're needed for load shaping. For wind options, we looked at 100 MW options for all of them starting with on-system and off-system wind with the difference between those being the cost of transmission. Off-system, we looked at Montana wind because that was of interest for our stakeholders. We also looked at offshore wind, which was 100 megawatts of a larger share project of about 1,000 megawatts. For all of these, they are proxy sizes and Pacific Northwest locations. What the model does is it would look at these minimum sizes of say for wind at 100 megawatts, but it might end up selecting up to 400 or something at whatever makes sense based on the needs of our system. Again, we put them in as a minimum size and then it picks accordingly based on those minimum increments. So next slide please.

Lori Hermanson: We looked at other clean resource options such as geothermal. This would be a PPA of about 20 megawatts and it's an off-system resource because there's none right here in our service territory, so it would incur or include transmission costs. We looked at biomass, a generic biomass resource option, an example of that would be an upgrade or an additional unit at Kettle Falls or something else in the area. Something around that size of 58 megawatts. We also modeled a nuclear PPA as an option, it was

100 MW option, which is just a share of a larger off system resource and that's a mid-sized nuclear facility. And we also looked at a 25 MW fuel cell. Next slide.

Lori Hermanson: For storage technologies, we looked at more sizing and storage duration combinations and types of storage technologies than we had in the past IRP. Lithium ion, being one of the larger categories. We assumed a round trip efficiency of 86% of 15-year average operating life for those resources. We assume that we're the owner of these resources. We modeled various sizes of distribution and transmission level ranging from 5 megawatts to 25 megawatts. And again, the storage duration varied anywhere from 4 hours to 16 hours. We looked at other storage options such as vanadium flow, zinc bromide, liquid air, and iron oxide. I believe of all of those, the only one that was selected was iron oxide. Something that we're considering, and we'd like feedback on this, is maybe not modeling all of those, maybe just modeling iron oxide and lithium ion. Those were the ones that were selected this last time, but again, based on feedback from the groups. Also, based on reading and research in the industry, the lithium ion and iron oxide seem to be moving ahead, whereas those others don't see as much progress. We also modeled a few different pump hydro options, and these are again varying durations from 10 hours to 24 hours and increments in between. It would be basically a share of a larger project anywhere from 1,000 to 2,400 MW hours.

Lori Hermanson: Next slide, some additional things that were continuing to research that you're all probably hearing about these in the industry as well. Carbon capture and storage. This is where you capture the CO2 from generating facilities and then store them into underground geological formations. The only thing with this is there aren't really any of these geological formations in our service territory. We continue to follow the literature on those. There's been a lot of information out there on fusion reaction. That's where they have a nuclear reaction that creates a lot of heat or energy problem with this one. There aren't really any real costs out there. We haven't come across cost associated with that type of project. There are other battery options like organic, solid, flow, energy storage that's a proprietary non-flammable mixture of solid and water-based electrolytes. That's using renewable energy to heat carbon or graphite blocks too really high levels about 2,200 degrees Fahrenheit stored within insulated containers and then using that heat on demand as it's needed. I believe we've modeled some. We've included this in some of our demand response modeling done by AEG. As far as the molten salt heat storage, that's another one where you can use concentrated solar to direct it to a centralized receiver and raise the temperature really high to heat the salt medium and again, dispatch that as the heat is needed through a heat exchanger to produce steam. But there aren't really any steam turbines in our in our service territory where that could be applied.

Lori Hermanson: Those are some of the things that we've continued to follow and are researching. We'd love to hear information or feedback on other options that you might be aware of. As far as new hydro, we're always looking at possible expansions within our service territory such as our own units like Long Lake or Cabinet Gorge adding an additional unit at Post Falls. We recently obtained a contract with Columbia Basin Hydro and there might be some discussion about extending their irrigation canals. But then there's some consideration as to whether or not that would apply for CETA as new hydro or not. And then we also continue to evaluate new hydro like in the last RFP. We acquired additional slices of Chelan, and we continue to look at those. We have a Douglas [PUD] contract that expires in 2028, so the potential of expanding or extending something like or other things that might become available through BPA. That's everything in a nutshell. What was modeled and some potential considerations of things that we may model less of, for example on the storage or potential new technologies that are out there. We'd basically like to open this up for discussion with the group and see if there's any additional information you'd like to see more of, or less of, or new technologies that you're interested in that you think we should be modeling.

James Gall: If you need more time, don't be shy to email us afterward or enter something into the chat. What we're trying to do is, we have a limited amount of time to research technologies. What we're seeing in RFPs, we followed the Power Council, but we want to make sure we're not missing something that's in development now. I'd say that the one technology on here that we mentioned in passing is nuclear. There's been a lot of talk about small modular nuclear. I think we've taken the approach on that is to just keep it as a nuclear PPA option. That could be small modular. It could be something else. I'd say it's the one technology not talked about here but is definitely worth evaluating. These are going to be challenges that we have to face because the CETA goal of 2045 to be 100% renewable or clean energy requires technology sources that are not common today. We have to figure out long duration storage. Hydrogen-based fuels is what we found in the last IRP, along with iron oxide storage, was a potential pathway. But, as you do IRPs every two years and we need to evaluate if there are other pathways, because the IRPs before the 2023 did not even contemplate either of those technologies. Hoping that you know something comes around, but if you see something that's on the horizon, you see a journal article, just feel free to send it to us. We do want to ensure that whatever technologies we put in the IRP are commercially feasible. They don't necessarily have to be in development today and viable off the shelf, but they have to be something that's feasible and likely to be available in the time horizon. Fusion, for example, is maybe one of those resources, maybe it will, but it's not quite there yet as a proven technology. So that would be the one, for example, that we might not want to include. That's why we do IRPs every two years, and it might be available.

John Lyons: We also can add discussions on the new technology even if they're basically so far out of the realm of costs that they don't get modeled. We can still include them in the IRP as a discussion. We can start seeing where those would fit in and maybe even do some tipping point analysis to decide where that technology would have to be. We've done that in the past with nuclear where the thought was, we would not model it because it was too expensive, but we modeled how much lower the cost would need to get before we could implement it. That might be a good way to look at some of the new technologies. Also, we have opted not to as some other utilities model, we want to use a resource that looks like this, but they haven't identified it, and we've opted to stick with resources that are known and identifiable.

James Gall: Alright, I still don't see any comments, so I think we'll leave that one there for future discussion and we'll plan with these set of resources. We'll develop costs and other assumptions and there was a spreadsheet that you may recall from the last TAC process that went through our assumptions for each resource and a forecast of those costs. We'll work to update that spreadsheet with these resources and share that with the TAC when it's available. As Lori mentioned, there were a couple of resources that we were thinking about removing on energy storage. I'll go back to those real quick. They were not selected in the plans, and I wouldn't say development is stopped on these, but we're not seeing a lot of uptake in those resources in the energy space. But I just wanted to know if there's any objections to removing those. We're not going to yet, but just wanted to make an opportunity to voice any concerns about removing anything from the list, before we do that.

John Lyons: We've seen a real decrease in the number of the flow batteries that are showing up around the country, being bid in, and actually being done. Yao has a question, why did the model not select the storage?

James Gall: So, the ones that are in red, it's really a cost in round trip efficiency. There are you know, two trade-offs of storage. Either you are going to have a low round trip efficiency, you got to be very low cost. And if you're going to have a high range efficiency, there's likely a higher cost. And in these cases, there was better technologies for the cost or the efficiency for these not to be picked, I definitely think we need to keep following them. With moving to PLEXOS, there is a limited amount of studies we can do and I don't want to burden that model on the first time around with technologies that are probably not going to show up.

John Lyons: The big issue we've seen with the flow batteries and the liquid air is the constantly heavy pumps running. So, you have this this parasitic load that's going on all the time, whereas a lithium-ion battery, you don't think about. If you've got a power tool that you charge the battery up last summer and then you pop it in this next year, and it works just fine. On a flow battery, you would be out of power in not that long of a period of time because they are always running.

James Gall: OK, so let's switch to the Work Plan and then we'll wrap things up. Thank you, Lori. Bear with me one second while I find it. There it is.

John Lyons: You're building suspense. You know the excitement of the Work Plan. They just excited that we're getting close to finishing right now. We're being efficient alright. TAC meeting efficiency, that could be an Action Item.

James Gall: All right, John. Alright.

Work Plan, John Lyons

John Lyons: So, on the Work Plan, you would have seen that sent out with the draft slides. Go to the next one here. The Work Plan, as we talked about earlier, we do an IRP every two years – full IRP in Washington every four and a Progress Report in between. The Work Plan shows what the process is going to be and the major milestones, those key events that are going to be done. It starts with an overview discussion. This is going to look very similar to past Work Plans. There's the TAC meetings and the major topics on the meetings. We try to stick to those, but if we have new topics that people would like to discuss or new information that comes to light, we will put those in there. We have a document outline by chapter and then the timeline of major assumption. Big assumptions would be market price assumptions, gas and electric price forecast. Third party studies missing a “y” there. And a study request from the TAC, anything that comes up there and next slide.

John Lyons: PLEXOS, as we already talked about, it's going to be used to model resource dispatch, resource option valuation and market risk evaluation or analysis. PRiSM is still going to be used for resource selection. That's something we talked about earlier, considering a change in the future. But for this IRP, Aurora will still be used in this IRP for electric market price forecasting, and we will be evaluating other options for the 2027 Progress Report. Idaho IRP, as we discussed earlier, AEG is going to develop the energy efficiency and demand response potential studies. They're going to develop a long-term energy and peak load forecast using end use techniques, and then they'll also be doing a distribution energy resource potential study. That would show types, locations, give us some more data on that. And then we intend to use generic resources functions from several different sources. As we just talked about, is based on likely generation sources, so size even though when it actually goes out to an RFP, the sizes maybe slightly different based on the technologies each company has a, they're all reasonably close to each other, but they'll be some slight differences.

John Lyons: We just had our first TAC meeting and the next one's going to be March 26th in 2024. We'll get the gas and electric price overviews, wholesale electric price forecast, the variable energy resource integration study results. We started talking about those more last IRP cycle and we've done more work on that future climate analysis update and TAC scenarios feedback. We'll have some studies set, that we think you would like to see done, or that we're planning on doing, and then we'll get some input from all of you that you would like to include. These later dates, we haven't nailed down a date yet. We're just checking to see that month wise that works for people and then we'll see which of the timing works. We had a question from Yao.

Lori Hermanson: Yeah, she says, Aurora's market price forecasting depends on dispatch resources. If the dispatch is done in PLEXOS, how can the market price forecast correspond to the resource dispatches?

James Gall: great question. Aurora will continue to do a resource dispatch of the Western region. So, we'll do an expansion capacity study for the region. It just will not be an Avista focus. We'll end up with a regional price forecast for different locations and then feed that price forecast into PLEXOS. I guess the assumption we're making here is the resources that we choose, if they differ, then what the original forecast is by Aurora, that they're not going to impact the regional marketplace and basically what that means is we are a price taker. Because Avista is relatively small, the things that we do are not going to have a major shift in the western market. So, you could definitely argue a small disconnect there. But we think it's pretty minimal to Avista's process just because of our size. And because I brought up a price forecast, or you brought that up Yao, we are looking at using PLEXOS for market price forecasting in the future in a similar way that Aurora does. That is a functionality that it can do. If that proves out plausible in the future, we could do a price forecast and a resource forecast at the same time. I'm fearful that the length of time that it would take to solve maybe a challenge, but long term we are looking at options to use external forecasts for prices for the wholesale market, but we've not made any decisions there. I think there was another question.

Lori Hermanson: Yeah. She asked about if PLEXOS doesn't look at regions, only Avista, and they do have a similar regional database like Avista. Like Aurora does, we currently don't have it purchased, the database, and we're doing kind of a closed system model of just our own system. But that's something that we would consider in the future.

James Gall: Alright, thanks. Go ahead, jump in John.

John Lyons: OK. TAC 3 in April 2024, again we will be coming up with the actual dates on those. Also, if there is any input from the TAC of days of the week you would like us to focus on or to avoid. We generally want to not have TAC meetings on Mondays or Fridays, so we try to focus on Tuesday, Wednesday, Thursday. Then we look at the Idaho and Washington Commission calendars to see when they have major dockets on or open meetings. In April, we will be captivated with Grant's economic forecast and five-year load forecast. That is always a fun one. OK. Maybe just for me as an economist, but we do get good feedback on that long run forecast. The rest of this meeting will be AEG focused and all the studies they've done. That'll be that fundamentals-based forecast that we talked about earlier that they're doing. We'll have the Conservation Potential Assessment that will be split for Idaho and Washington that they've been running for us for several years. There will be a demand response potential assessment and then we'll review the plan's scenario analyses.

John Lyons: The Fourth TAC meeting will be in May of 2024. We will look at the IRP generation options, transmission planning studies and what those costs and what those are going to entail. Distribution system planning within the IRP and the DPAG update that we talked about earlier, trying to integrate our two processes, transmission distribution modeling in the IRP, the L&R balance and methodology to show what loads were serving, what resources we have going out over the next 20 years and then new resource option cost and assumptions. That's where we'll be seeing the big nasty spreadsheet that is the backup for what Lori just talked about showing all the different cost and the nuances of that data, sizes, how much we can get in a year, how long it takes to get it online, environmental considerations, all of that.

John Lyons: The fifth TAC meeting in June of 2024, that is going to be one that is very heavily modeling focused. Maybe if modeling's not your thing, that would probably be a good one to skip. If you want to get into it though, that is always a fun one. We'll have tours of PLEXOS, PRiSM and the new resource cost model. Anything else you wanted to add on that one, James, that'll be nerd fest. It's a lot of fun.

John Lyons: July of 2024, we've got our Preferred Resource Strategy results. That's all that work being done finally results in the mix of resources, types, sizes, timing over the next two decades. We'll do the Washington Customer Benefit Indicator impacts resiliency metrics. Finalizing what we kind of teed up a bit earlier today, portfolio scenario analysis, market risk assessments and the qualifying facility avoided cost for PURPA projects, and then we'll wrap up this 2025 IRP with the virtual public meeting. It'll be joint natural gas and electric. There will be recorded presentations about each IRP side, and a daytime and an evening period for comments and questions where it will be broken out, very similar to what we've seen in the past.

John Lyons: As far as the draft outlined, this is what the chapters will look like. A couple little changes, we've moved some things around, but similar overview. There'll be a short executive summary, introduction, stakeholder involvement, process changes, that's an important one, especially following along to see what's changed one IRP to the next. Then we get into the economic and load forecast, the regional economic conditions, the energy and peak load forecast and the different load forecasts and scenarios. Third chapter is what resources we already have in line, our own resources, contractual resources and obligations, and customer generation, so behind the meter type of things. The fourth chapter is the long-term position, regional capacity requirements, energy planning requirements, reserves and flexibility assessment.

John Lyons: Fifth chapter, we get into distributed energy resource options. We'll have energy efficiency potential, demand response potential, energy storage resource options and the potential for those options for named communities and DER Study conclusions.

John Lyons: Sixth chapter is going to be Supply Side Resource Options, discussion of the different options that Lori had brought up and the characteristics of those plant upgrade opportunities both for our thermal and our hydroelectric facilities. We will also have a discussion of those non-energy impacts that we talked about briefly earlier today.

John Lyons: Seventh chapter, Transmission Planning and Distribution. It's an overview of our transmission system, what the construction cost and integration is going to be for those, merchant transmission plan, and an overview of our distribution system. That's one area we've been expanding over time, is bringing more of the distribution system into the IRP and the DPAG information.

John Lyons: Eighth chapter, Market Analysis. Wholesale gas and electric price forecast and the scenario analysis. Ninth chapter, critical chapter in the IRP, the results, the Preferred Resource Strategy, the market exposure analysis, and the avoided cost.

John Lyons: Tenth chapter, this chapter will be portfolio scenarios and market scenario impacts and then we'll do the Washington Clean Energy Action Plan. That's the decision-making process involved with that resource needs, resource selection, and those Customer Benefit Indicators. This is one that will just be everything for CETA, basically, and then we wrap up with the Action Plan where we look at, as James talked about earlier today, what we've been doing on some of those Action Items. We'll do a thorough overview of where we ended up with the ones from last time and what either is ongoing or came up and we ran out of time, or it's an up-and-coming event or issue that we want to address.

John Lyons: And then the major timeline. December is the goal to have the market price assumptions. Natural gas price forecast and electric price forecast will be in March of 2024. New resource option cost and availability, also in March the deliverables from AEG, all of those studies that they're doing for us, final energy and peak load forecast, efficiency and demand response assessments for potential, the locational energy efficiency and demand response potential.

John Lyons: Sometime a little later in April, transmission and distribution study completion. March 20th, the due date for study requests from TAC members. The earlier you can get those requests to us, the more we're able to accommodate them, that's the date we know we can get to them if we get them by then. If there's things that come up a little later, we might have some room to stretch some of that. But that might be an issue where if we can't, it ends up being as an Action Item. The earlier you can get those to us, the better. May of 2024 will be determining the portfolio and market future studies. June 1st would be finalizing resource selection and model assumptions and you'll notice in this Work Plan. We didn't go into all the details of when things would be written, we will be again sharing those. The plan is to do that through Teams if that works, if not, we'll either do something else, or revert back to how we've been sharing them through the website.

James Gall: John, one thing I didn't see on here is when we will be filing the document and when the draft will out.

John Lyons: I wanted to leave a surprise for everyone. No, I didn't. I forgot to put that on there. We will be filing January 1st. You'll notice, this is a little condensed from the last one. For those of you that weren't with us last time, we had an extension for Idaho because we were waiting for the results of a renewable RFP and we had some significant amounts of resources that came online and we didn't want to put out a plan and then immediately have to change that plan because all these new resources. We had an extension of Lancaster, Columbia Basin Hydro, Clearwater Wind and we had the Myno project at Kettle Falls. There were some major changes that were going on there. I'm trying to remember, January 1st, 2025 will be the date. That also coincides with a CETA rule in Washington that changed our dates. We used to have them due in August, but it's always going to be January 1st now and is it October or is it earlier for our draft?

James Gall: I think it is October 1st.

John Lyons: I will update that final slide.

James Gall: Alright, any thoughts on the Work Plan? John and I have been doing these since 2005 like he mentioned earlier, we've kind of followed the same procedures as we've done in the past. Are there any topics on the TAC meetings that maybe you'd like to see, that you didn't see? That's something you can always email us about later if you don't have anything on top of your mind right now. We are going to be finalizing the Work Plan and filling it with the Washington Commission, I believe on the 1st of October. So, if you have any comments on the Work Plan, please try to send those to us as soon as you can and we'll try to include those in the final filing. We can always revise the Work Plan as we go through time, but it will be filed on the 1st, or if that's not, that's on the weekend.

John Lyons: Yeah. It will actually be in by the end of this week. We'll be getting this wrapped up.

James Gall: Any last comments or thoughts before we wrap up the day?

John Lyons: Alright. Well, thank you for participating in the Technical Advisory Committee meeting. We look forward to working with you for the 2025 IRP. And again, we're always available for questions, comments, all things you just want to chat about for resource planning, we really look forward to doing that.

James Gall: And be on the lookout for your Teams invite very soon, so hopefully it'll work alright.

John Lyons: Thank you. Have a good rest of your day and enjoy getting 50 minutes back.

<u>Meeting Chat:</u>

[9/26/23 8:59 AM] Charlee Thompson: Looking forward to reading the update!

[9/26/23 9:12 AM] Wilson, Kirsten G. (DES): Gall, James I found when I set up an external facing Teams site for a project that DES Energy is doing, that non state individuals invited to the Teams site could access more of the site if they logged into the site via a web browser rather than the Teams App on the computer. Probably the same is true for yours.

[9/26/23 9:32 AM] Brandon, Annette: James, can I comment on this?

[9/26/23 9:33 AM] Moline, Heather (UTC): thanks, annette!
like 1

[9/26/23 9:40 AM] Tina Jayaweera (NWPCC) (Guest)

FYI, The RTF sponsored a study last year on how to quan5ify resiliency value of EE. Details can be found here: https://rtf.nwcouncil.org/other/energy-efficiency-resilience-valuation-methodology-study

[9/26/23 9:42 AM] Moline, Heather (UTC): even more on resilience: pretty simply, OPUC is using presence of solar/storage in low/moderate-income areas with minimal infrastructure and/or high energy burden as a 'proxy' metric for resilience

[9/26/23 9:43 AM] Moline, Heather (UTC): 2023 OPUC Equity Metrics - Energy Trust of Oregon
2023 OPUC Equity Metrics - Energy Trust of Oregon

[9/26/23 9:45 AM] Hermanson, Lori: Thanks everyone for the additional info on resiliency. We'll continue to research these and more and incorporate as it makes sense.

[9/26/23 9:48 AM] Yao Yin: do costs of market purchases and revenues of market sales include wheeling costs and revenues?

[9/26/23 9:49 AM] Hermanson, Lori: Yes

[9/26/23 10:00 AM] Yao Yin: Are all the input data actual data in 2021?

[9/26/23 10:19 AM] Gall, James: we are on break and be back at 10:30

[9/26/23 10:47 AM] Yao Yin: Why did the model NOT select those storage?
[9/26/23 10:53 AM] Yao Yin: AURORA's market price forecasting depends on dispatch of resources. If the dispatch is done in PLEXOs, how can the market price forecast correspond the resource dispatches?

[9/26/23 10:55 AM] Yao Yin: PLEXOS doesn't look at regions, only avista?

[9/26/23 10:55 AM] Yao Yin: thanks!

[9/26/23 11:08 AM] Charlee Thompson: Thank you!

[9/26/23 11:08 AM] Dennis, Joshua (UTC): Thank you

2025 Electric Integrated Resource Plan

Technical Advisory Committee Meeting No. 2 Agenda

Tuesday, January 30, 2024
Virtual Meeting

Topic	Time	Staff
Introductions	8:30	John Lyons
How Avista Includes Equity Principles	8:40	Annette Brandon
Customer Benefit Indicators	9:30	Annette Brandon
Break	10:30	
How Avista Practices Equity Outcomes	10:45	Tamara Bradley
Equity Planning in the IRP	11:30	James Gall
Adjourn	12:00	

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2025 IRP TAC 2 Introductions

John Lyons, Ph.D.
Technical Advisory Committee Meeting No. 2
January 30, 2024

Meeting Guidelines

- IRP team is in office Monday - Wednesday and also available by email, phone and Teams for questions and comments
- Stakeholder feedback responses shared with TAC at meetings, in Teams and in Appendix
- Working IRP data posted to Teams
- Virtual IRP meetings on Teams, in person available for full day meetings
- Final TAC presentations, meeting notes and recordings posted on IRP page

Virtual TAC Meeting Reminders

- Please mute mics unless speaking or asking a question
- Raise hand or use the chat box for questions or comments
- Respect the pause
- Please try not to speak over the presenter or a speaker
- Please state your name before commenting for the note taker
- This is a public advisory meeting – presentations and comments will be documented and recorded

Integrated Resource Planning

The Integrated Resource Plan (IRP):

- Required by Idaho and Washington* every other year
  - Washington now requires IRP every four years and update at two years
- Guides resource strategy over the next twenty years
- Current and projected load & resource position
- Develop alternative load/customer forecasts
- Resource strategies under different future policies
  - Generation resource choices
  - Energy efficiency / 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
  - Always looking for help with soliciting new TAC members
- Open forum while balancing need to get through topics
- Welcome requests for studies or different assumptions.
- Available by email or phone for questions or comments between meetings

Today's Agenda – Equity Focus

8:30	Introductions, John Lyons
8:40	How Avista Includes Equity Principles, Annette Brandon
9:30	Customer Benefit Indicators, Annette Brandon
10:30	Break
10:45	How Avista Practices Equity Outcomes, Tamara Bradley
11:30	Equity Planning in the IRP, James Gall
12:00	Adjourn

Equity in Utility Operations

Annette Brandon

Technical Advisory Committee Meeting No. 2

January 30, 2024

Overview of Equity

Annette Brandon

Dictionary Definition

equity [**ek**-wi-tee] SHOW IPA

See synonyms for *equity* on Thesaurus.com

noun,plural **eq·ui·ties.**

1. the quality of being fair or impartial; fairness; impartiality: *the equity of Solomon.*
2. something that is fair and just: *The concepts and principles of health equities and inequities are important to society as a whole.*
3. the policy or practice of accounting for the differences in each individual's starting point when pursuing a goal or achievement, and working to remove barriers to equal opportunity, as by providing support based on the unique needs of individual students or employees.: Compare equality (def. 1).

Equity at Avista

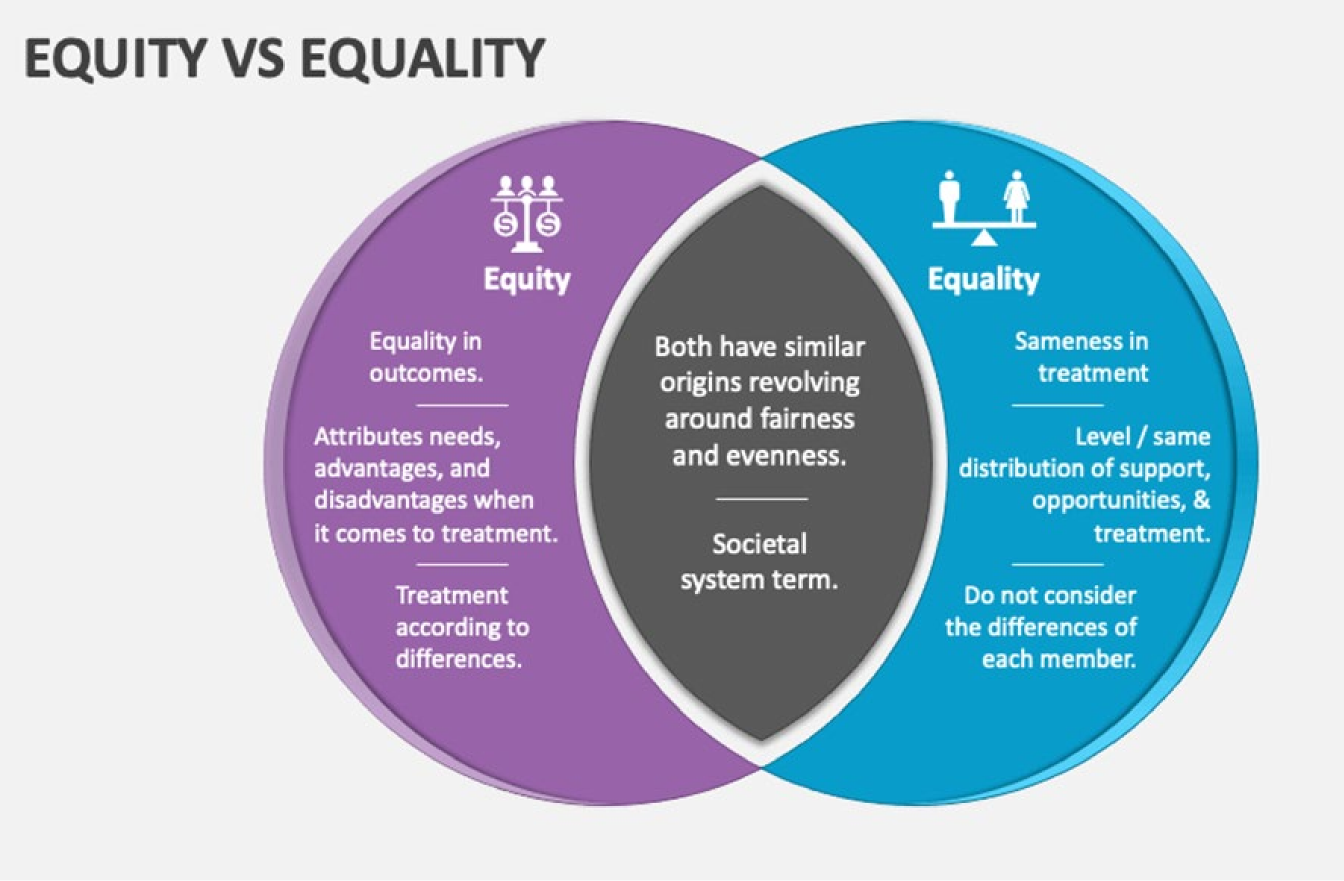
Focused on fair opportunities and access to resources which contribute to fair, equitable outcome

Fairness

- A “fair process” is defined as focus on ensuring no group of people share disproportional burden associated with policies, decisions or actions

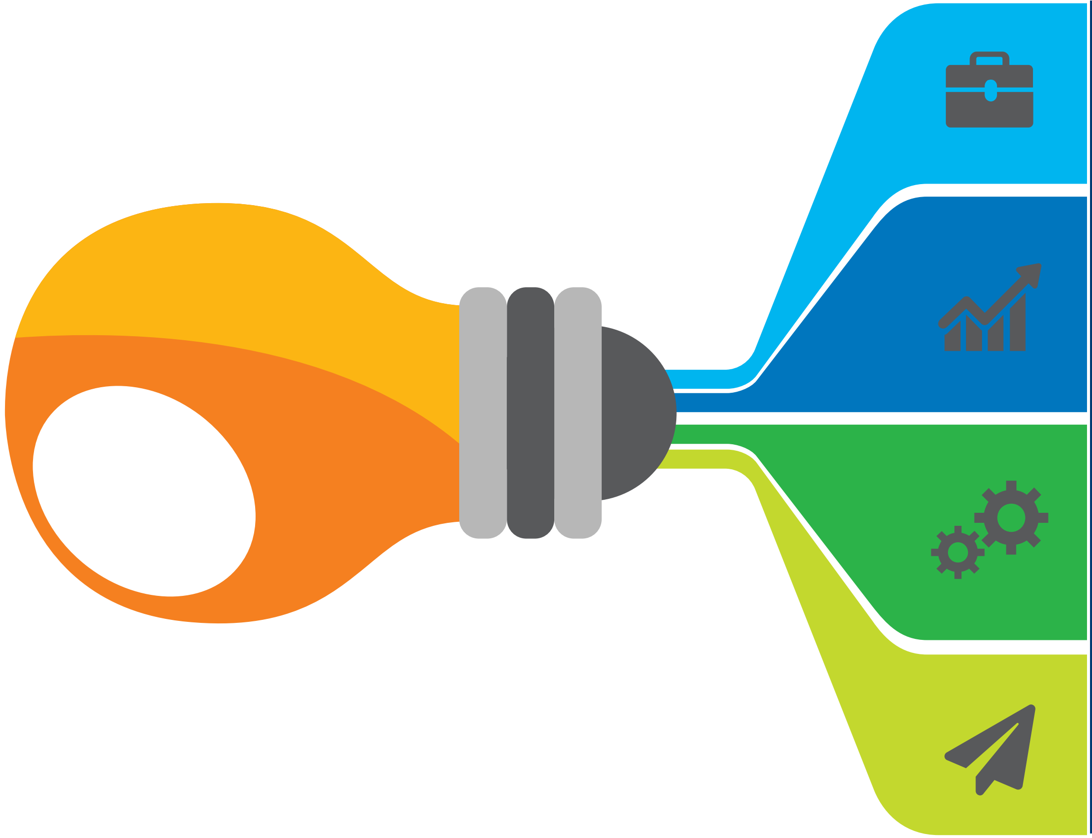
Foundation: Meaningful participation

- awareness and opportunity to participate
- has the ability to influence decisions
- Is considered in the decision-making process
- outreach efforts seek out and facilitate involvement of those potentially affected.



Evolution of Energy Justice

Equitably sharing the benefits and burdens involved in the production and consumption of energy services **and** **Fairness in how people and communities are treated in energy decision-making**



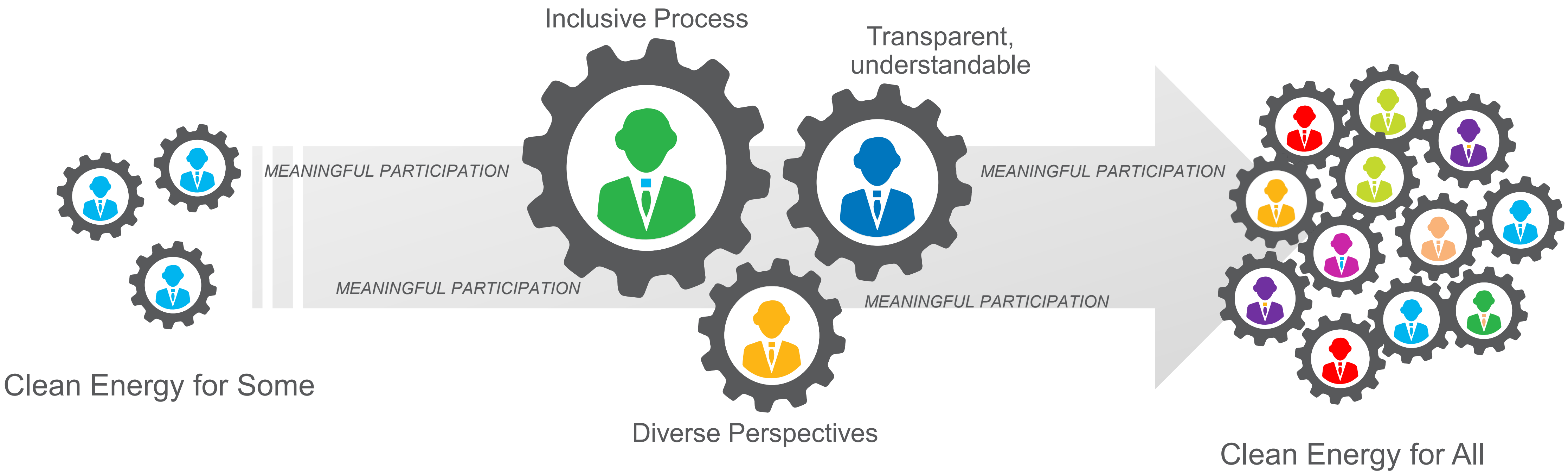
Environmental Justice 1970-1980
Participation in environmental Decision Making
Recognizes disporportional impacts
Advocates for right to clean environment

Climate Justice 1990-2000s
Climate change (i.e., fossil fuel) impacts
Emphasizes solutions do not perpetuate or worsen social or economic inequities

Energy Justice 2010
Reinforces need for voices in decisions
Emphasizes need for affordable and clean energy
Focus on inclusive in decision making

Today – Focus on Just Transition to Clean Energy

Transition to Clean Energy



Avista is Committed to a Clean Energy Future for all of our Customers

Balancing Multiple Objectives

Federal Justice40

Clean Energy Transformation Act

Climate Commitment Act

Federal Energy Regulatory Commission

Avista Serves Approximately 480,000 WA Customers

Electric

Natural Gas

Electric and Natural Gas

Regulatory Requirements

Washington State Equity Requirements

Clean Energy Implementation Plan 2019

- Focus on “just transition”
- Strong Public Participation
- Customer Benefit Indicators

Avista General Rate Case Conditions 2021

- “Capital Planning must consider and implement energy justice and its core tenets.”
  - Recognition, Procedural, Distributive, Restorative

Climate Commitment Act 2022

- Environmental Justice Council
  - Invest in those communities most impacted by climate change

Washington State
OFFICE OF EQUITY

Clean Energy Implementation Plan Requirements

- Avista will apply **Non-Energy Impacts (NEIs) and Customer Benefit Indicators (CBIs) to all resource and program selections** in determining its Washington resource strategy

- Avista agrees to engage and consult with its applicable advisory groups (IRP Technical Advisory Committee (TAC) and Energy Efficiency Advisory Group (EEAG)) regarding an appropriate methodology for including NEIs and CBIs in its resource selection.

- **Avista will consult with its EAG after the development of this methodology to ensure the methodology does not result in inequitable results**

AVISTA

Non-Energy Impact

- Contribution of investments that goes beyond the energy and demand costs
- Impacts (either positive or negative) can come in the form of **economic, social, environmental, and/or personal ways.**

Participant Benefits	
O & M Savings	Employee Productivity Increase
Health Benefits	Property Value Increase
Comfort Increase	Benefits to Low Income Customers

Societal Benefits	
Public Health	Economic Development
Improved Air Quality	Increased Employment
Water quality and quantity	Energy Security
Benefits to Low Income families	

Utility Benefits	
Peak Load Reduction	Less Debt Write Off
Transmission and Distribution Savings	Lower Collection Costs
Reduced arrearages	Fewer customer calls

General Rate Case Requirements: Energy Justice Core Tenets

"The processes or procedures Avista considers for all capital planning should consider and implement energy justice and its core tenets. The core tenets of energy justice are: recognition, procedural, distribution, restorative.

People
Recognition Justice

Customers, communities, employees
- Identify: Who and where do inequities exist?
- Awareness, understanding, recognition
- Barrier considerations

Process
Procedural Justice

Meaningful Participation
- Due Process / Collaborative
- Fair, equitable and inclusive involvement
- Targeted, intentional education and outreach

Performance
Distribution, Restorative

Distribution of benefits, burdens
- Evaluation of alternatives
- Program design and resource selection
- Accountability

Balancing Requirements – While Keeping Customer at the Center

AVISTA

Federal Justice40

NERC NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Clean Energy Transformation Act

UTC Washington Utilities and Transportation Commission

WECC

Climate Commitment Act

DEPARTMENT OF ECOLOGY State of Washington

Federal Energy Regulatory Commission

Avista Serves Approximately 480,000 WA Customers

Electric

Natural Gas

Electric and Natural Gas

Providence

Spokane Regional Clean Air Agency

SNAP NEIGHBORS BY YOUR SIDE

SPOKANE PUBLIC LIBRARY

Spokane Indian Housing Authority

DEPARTMENT OF ECOLOGY State of Washington

AVISTA

Resource and Program lifecycle Evaluation

“No action is equity neutral….each action either corrects or perpetuates inequities”

Meaningful Participation

Identify and Evaluate + **Prioritize** + **Selection** + **Execute**

Identify and Evaluate

Integrated Resource Planning

Transmission, System & Distribution Planning

Energy Efficiency

Customer Requested

Prioritize

Financial & Risk

Operational Needs

Equity

Cost Effectiveness

Impact to Process or Performance Metrics

Selection

Total Company

Capacity, Energy

Cost Effectiveness

System vs. State

Execute

Power Purchase Agreement

Self-Build

Program Deployment

Project Delivery

Integrated Resource Plans

Process and Performance Metrics

Process and Performance Metrics

People	Process	Performance
• Who has provided impact? • Have we intentionally solicited input? • Can I use feedback? • Have I made modifications to meet barriers?	• How will my project produce results? • Are there alternatives? • Am I making data-driven decisions? • Predict change or trend?	• How did we do? • How can we measure? • Are there patterns?

Focus Areas

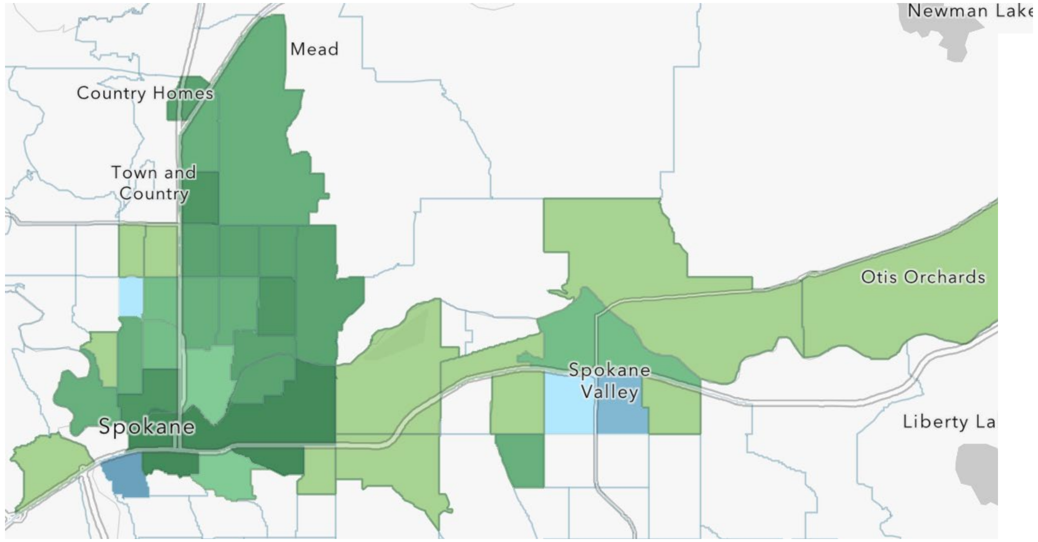
Who and Where we are focusing our equity efforts:

Highly Impacted Communities

Vulnerable Populations

- Sensitivities: physiological impacts
- Socioeconomic: housing, transportation, food and health care access, language barriers

Disadvantaged Populations



Justice40: Spokane County, Washington tract 53063000400
Population: 3,844

Zoom to

This tract is identified as disadvantaged. It has 4 categories that meet the criteria.

Energy

Health

Housing

Legacy pollution

There are 33 disadvantaged tracts in Spokane County and 306 disadvantaged tracts in Washington.

JUSTICE 40 POLICY PRIORITIES

- Decrease energy burden in disadvantaged communities (DACs)
- Decrease environmental exposure and burdens for DACs
- Increase parity in clean energy technology access and adoption in DACs
- Increase access to low-cost capital in DACs
- Increase clean energy enterprise creation and contracting in DACs
- Increase clean energy jobs, job pipeline, and job training for individuals from DACs
- Increase energy resiliency in DACs
- Increase energy democracy in DACs

Data Driven Consideration

Directly related to policy goals and the public interest
readily available
Focused on equitable outcomes
Clearly defined, articulated, and understandable
Based on dependable, pertinent, available data
Allows for comparison or trending
Transparent
Correlated with utility's actions; able to forecast
Updated regularly
Accurately reported regular reporting

CEIP Customer Benefit Indicators

Affordability	Energy Security & Resilience	Access to Clean Energy	Environmental	Community Development	Public Health
Participation in Company Programs Households with High Energy Burden Residential Arrears & Disconnects	Energy Availability Energy Generation Location	Methods/Modes of Outreach & Communication Transportation Electrification	Outdoor Air Quality Greenhouse Gas Emissions	Named Community Clean Energy Investments in Named Communities	Employee Diversity Supplier Diversity Indoor Air Quality

Customer Benefit Indicators in IRP

- Energy Burden (Affordability/Access to Clean Energy)
- Distributed Energy Resources (Community Development/Energy Resilience)
- Planning Margin (Energy Resilience and Security)
- Generation Location (Energy Resilience and Security)
- Air Emissions (Environmental/Public Health)
- Greenhouse Gas Emissions (Environmental)

Existing Customer Benefit Indicators:

- 11 of the 31 CBIs are modeled with forecasted values for each metric over the 20-year planning horizon
- PRS does not consider CBIs in objective function

Criteria:

- Categorized in accordance with benefit areas: affordability, development/resilience, security & resilience, environmental & public health, environmental
- Baselines are established and readily available
- Data is quantifiable
- Metrics are granular enough to be meaningful

How Metrics are Developed

Benefits

- Evaluation of benefits from energy or energy system:

- Social
- Economic
- Environment

Barriers

- Factors which limit participation or access:

- Physical Sensitives
- Socioeconomic
- Geographic proximity

Metrics

- How do these benefits correlate with energy

- Accountability: Process & Performance Metrics

Utilization

- Where will we utilize metrics?

- Clean Energy Plans
- Capital Investments
- Resource Planning
- Federal and State Grants

Understand Goal:

All customers, regardless of circumstance, have access to the energy they need for basic needs as well as social, economic and environmental needs.

Energy

Physical delivery of power

Basic Needs

Social

Inclusive and accessible processes

Economic

Job creation, economic growth, reliable supply, and affordability

Environmental

Public health, indoor and outdoor air quality, and sustainability

Burdens and Barriers

Affordability
- Unemployment or Underemployment
- Awareness of Programs
- Housing Conditions
- Income Disparities
- Economic impacts on fossil fuel workers

Access
- Not easily accessible for all customers due to financing or other accountability structures
- Geographic Accessibility
- Renters do not have easy access
- Mobile homes not able to use technology etc.

Reliability
- Aging infrastructure
- Limited investment in grid updates
- Lack of redundancy of supply

Performance and Process Metrics

Affordable	Security & Resiliency	Accessible
Economic & Community Development	Social, Health, & Environmental Benefits	Clean, Sustainable
Meaningful Participation	Safe, Sustainable	

Performance (Lagging)

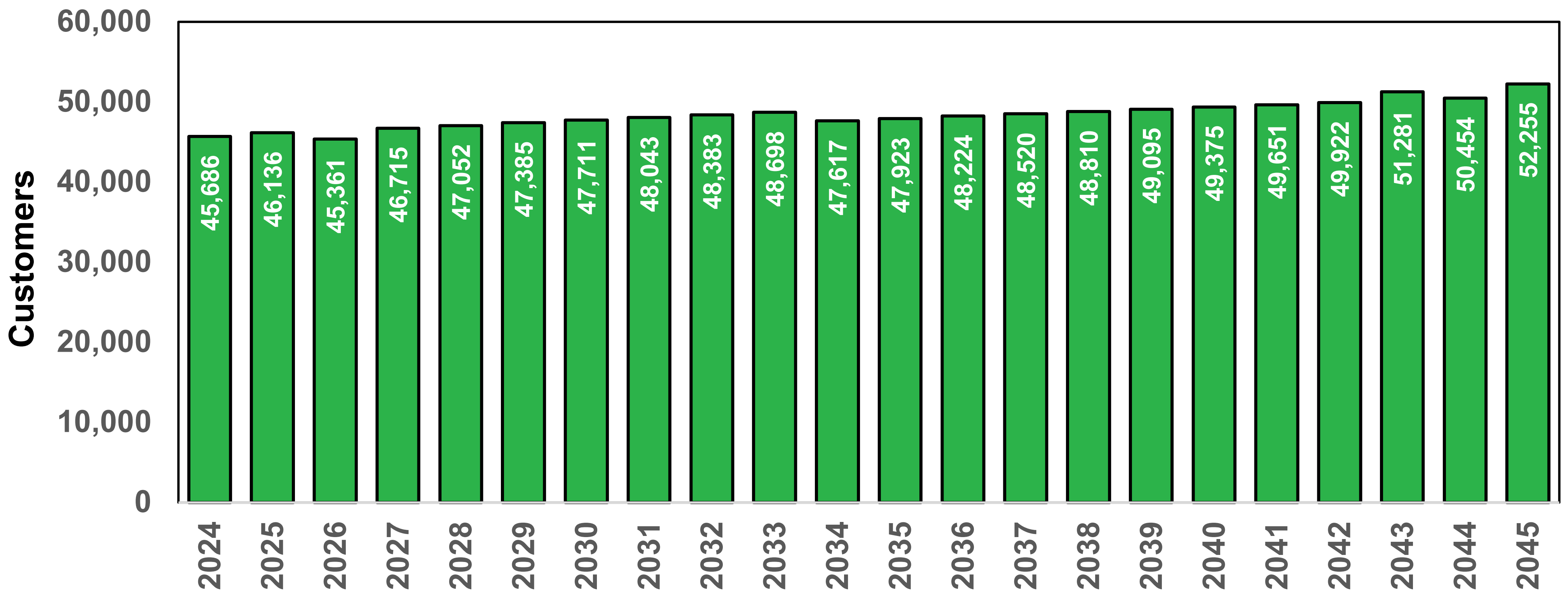
- How will we measure?
- Are customers impacted as intended?
- Accountability measurements or patterns

Process Metrics (Leading)

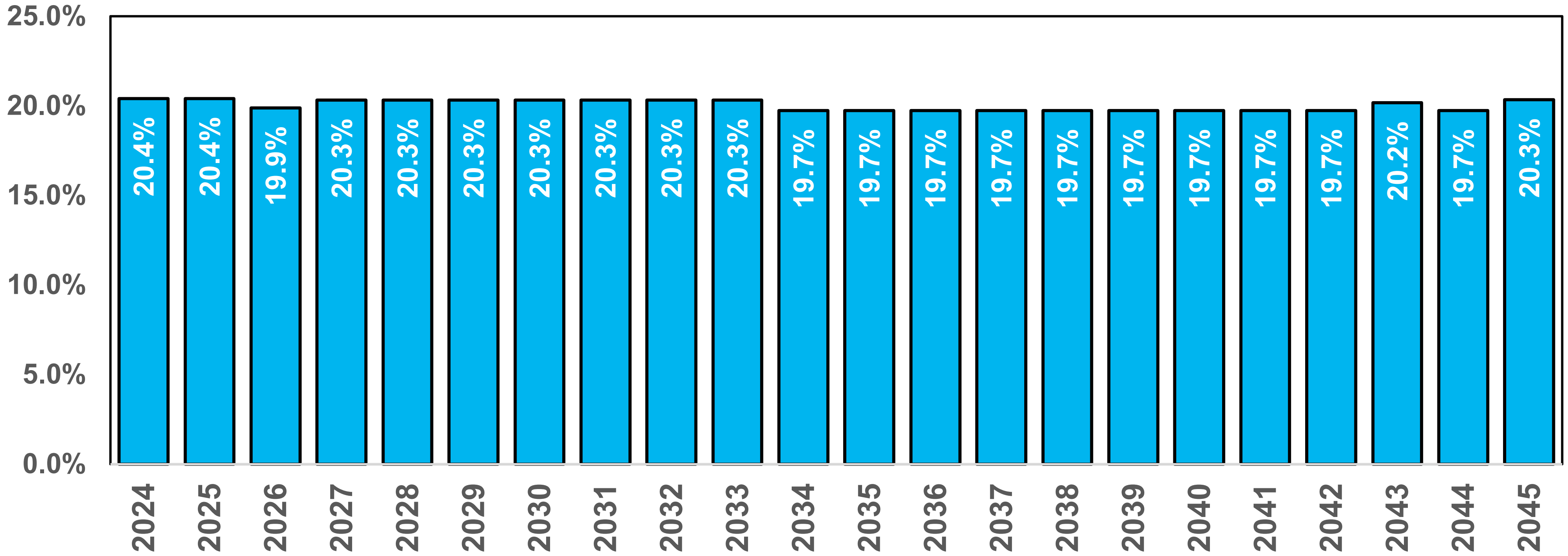
- How will we produce desired results?
- Useful to predict trends
- Mid-Cycle Adjustments

Supplemental

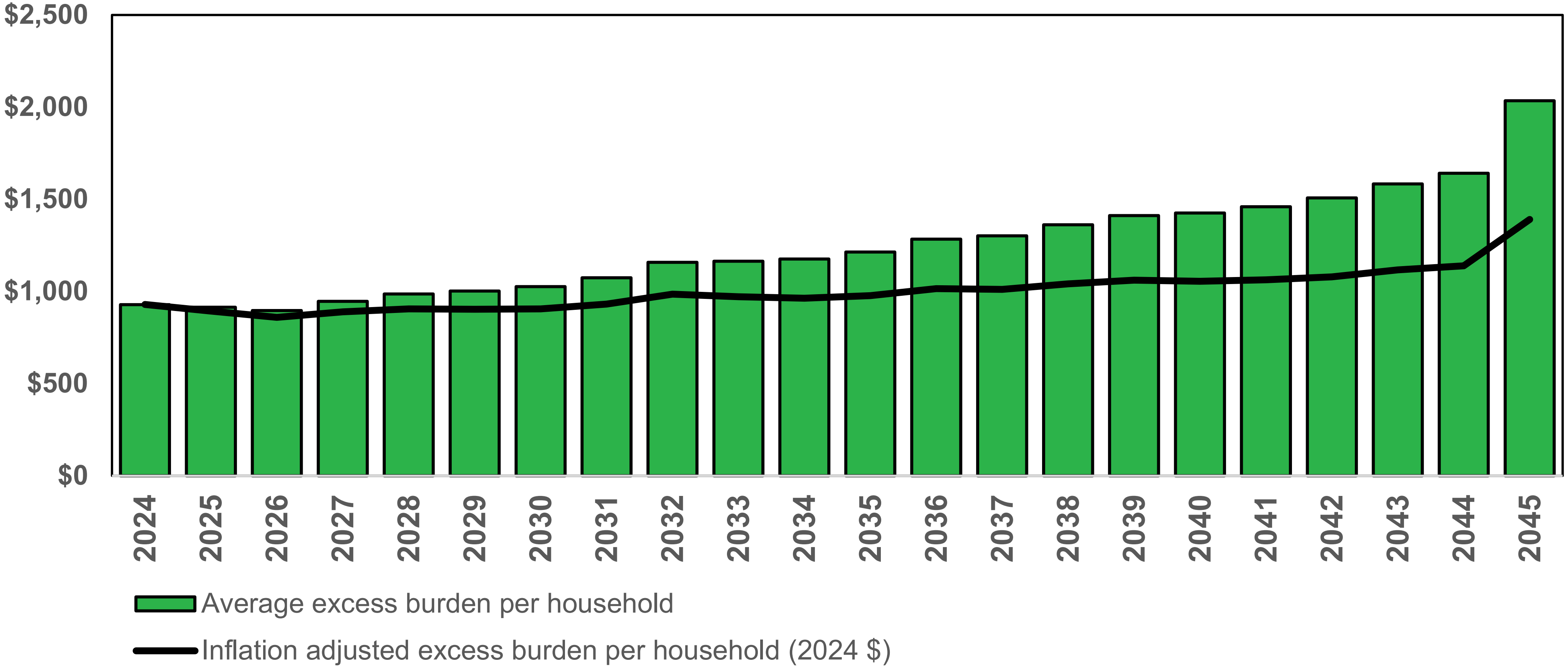
Customers with an Energy Burden



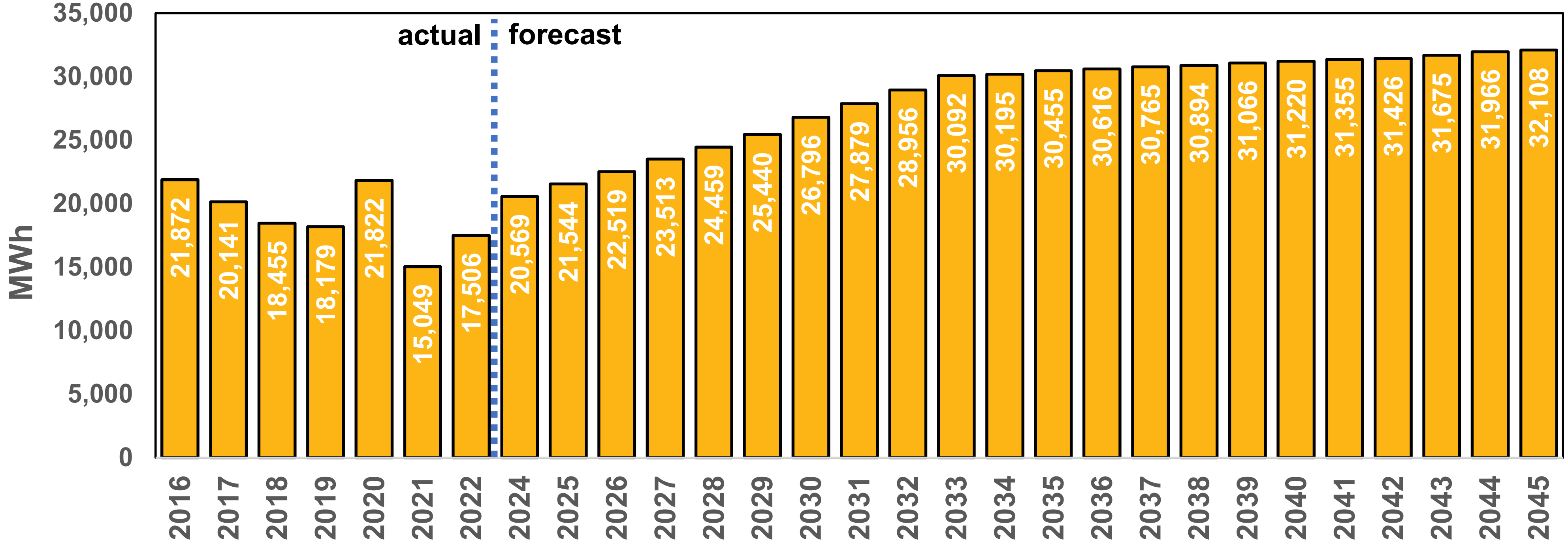
Percent of Customers with an Energy Burden



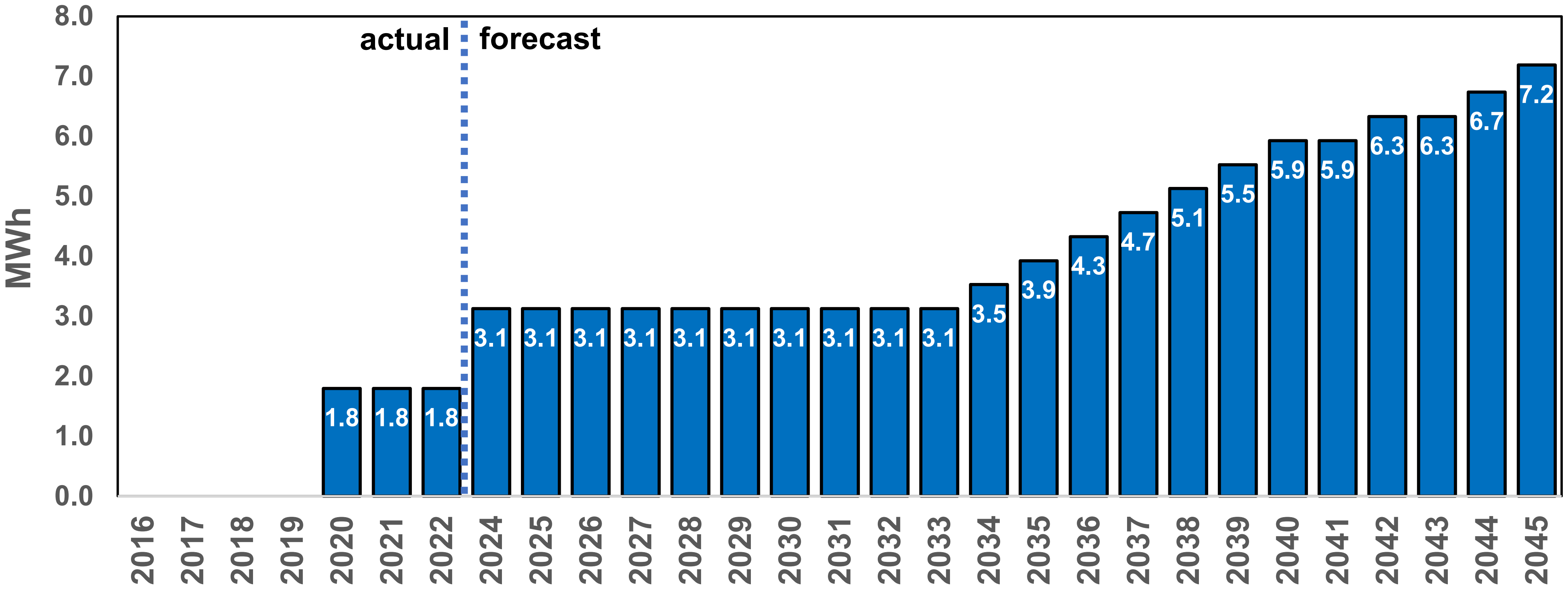
Average Excess Energy Burden



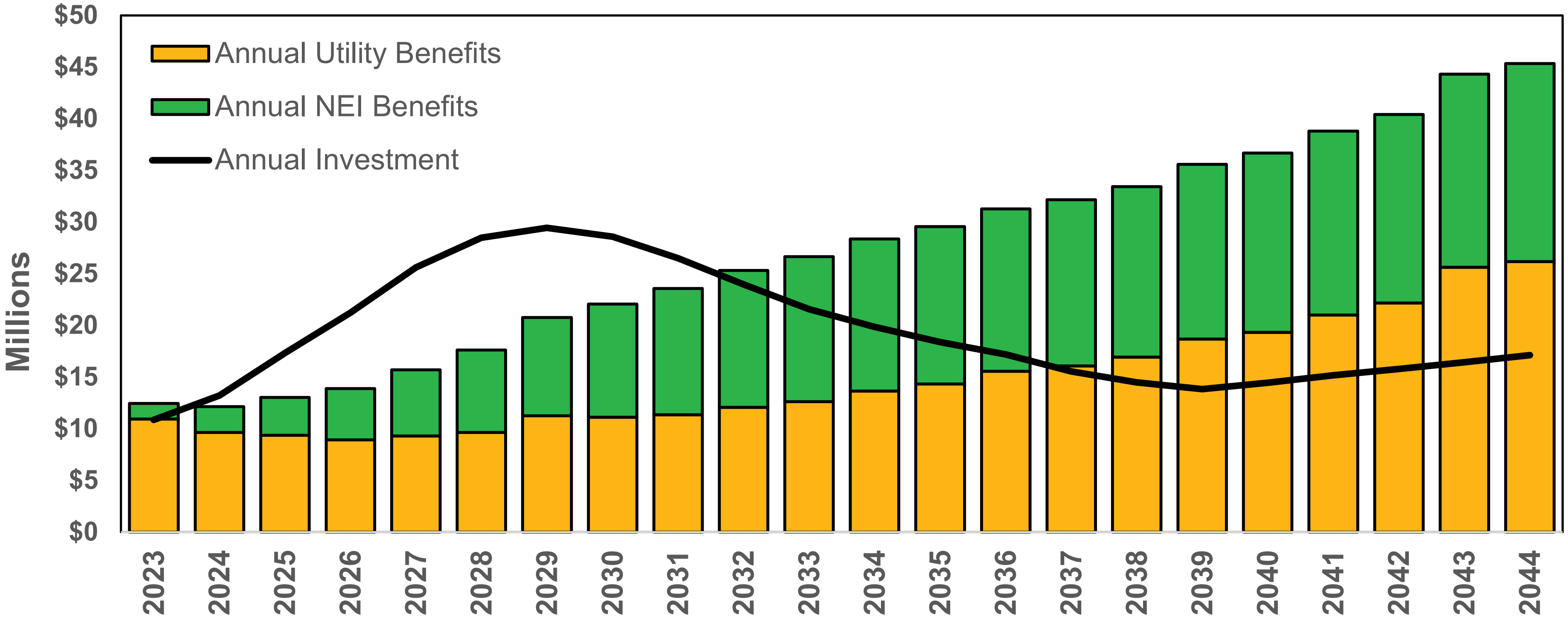
Total MWh of DERs in Named Communities



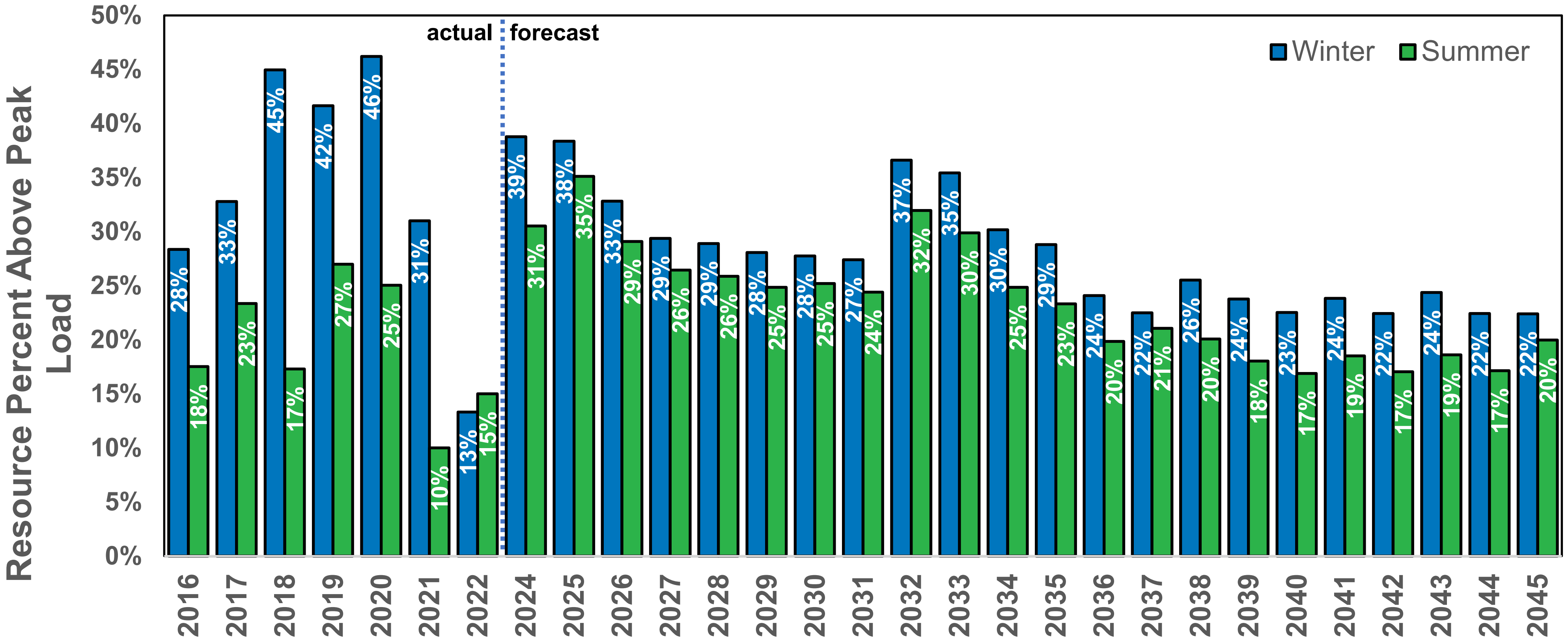
Total MWh Capability of Storage DER in Named Communities



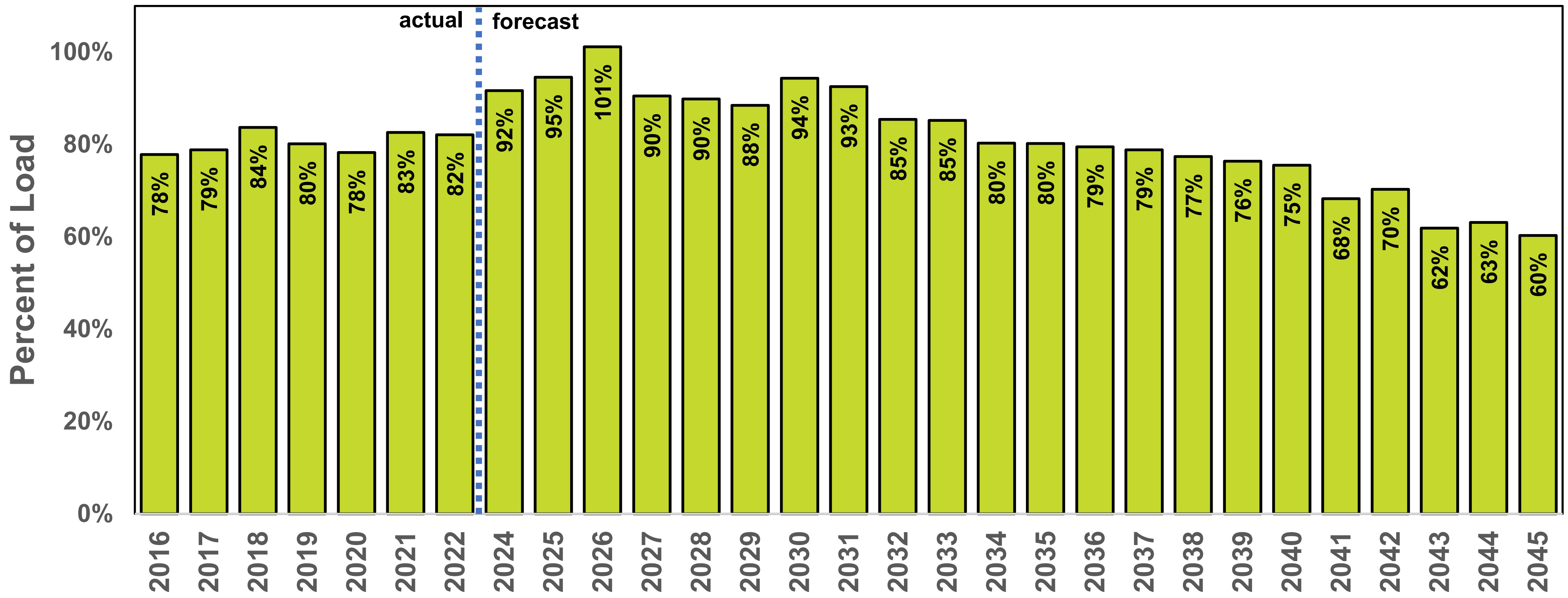
Annual Named Community Investment vs. Benefits



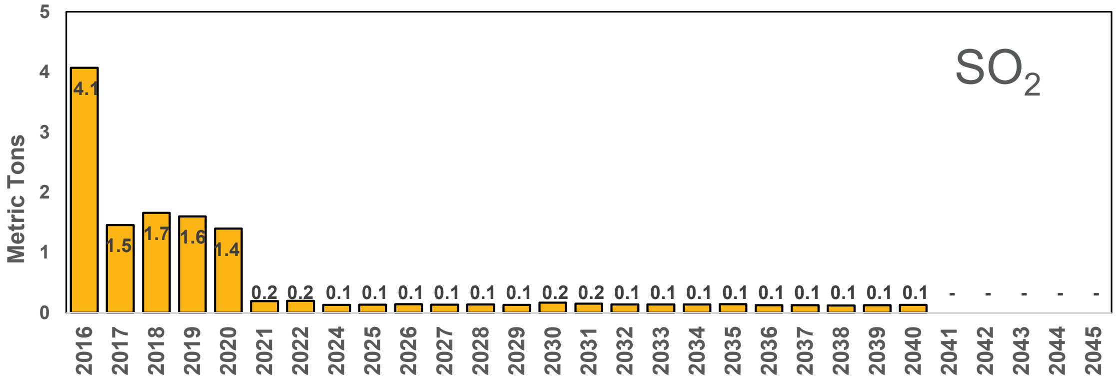
Planning Margin

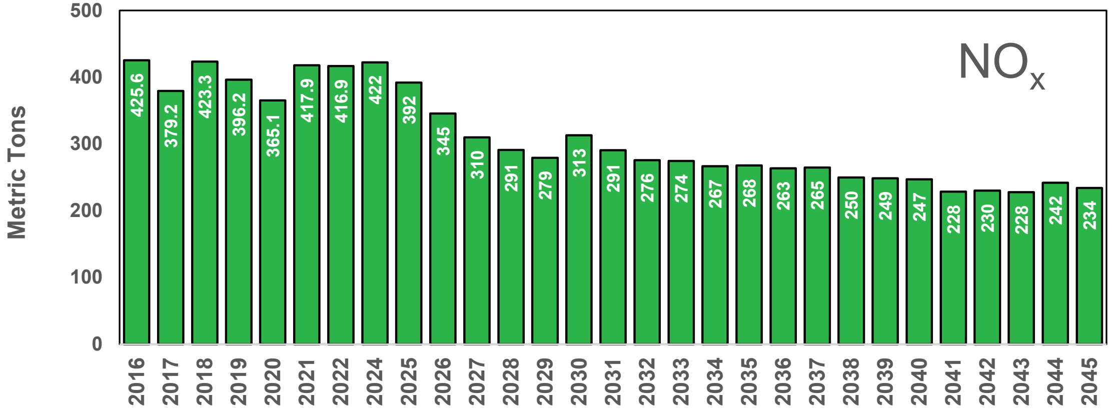


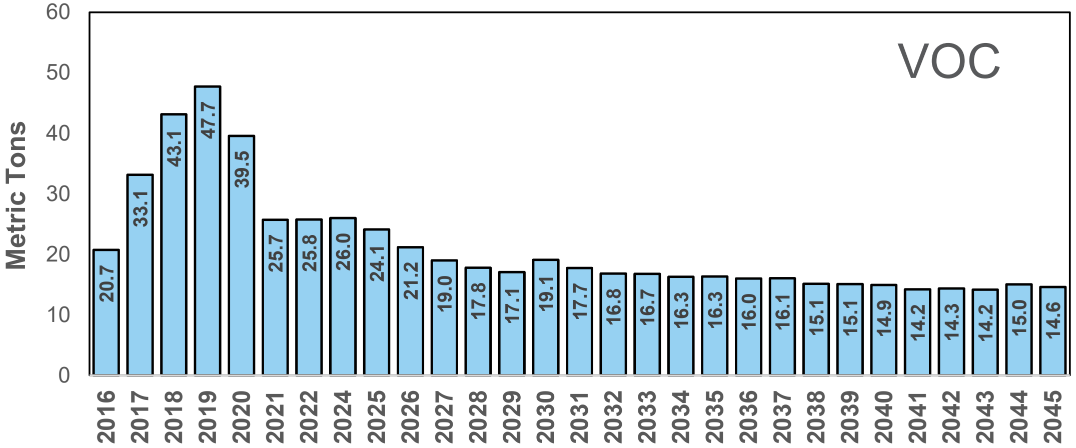
Generation in Washington State or Directly Connected to Avista Transmission



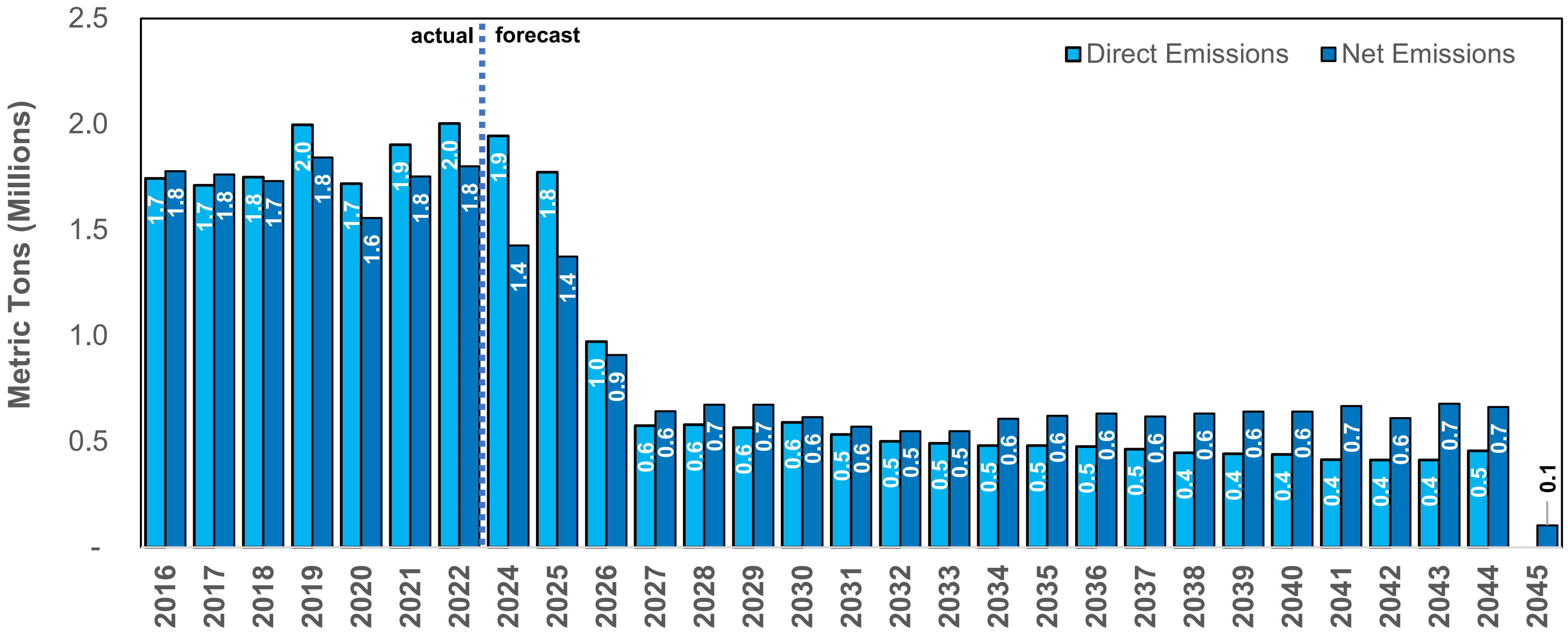
Washington Air Emissions



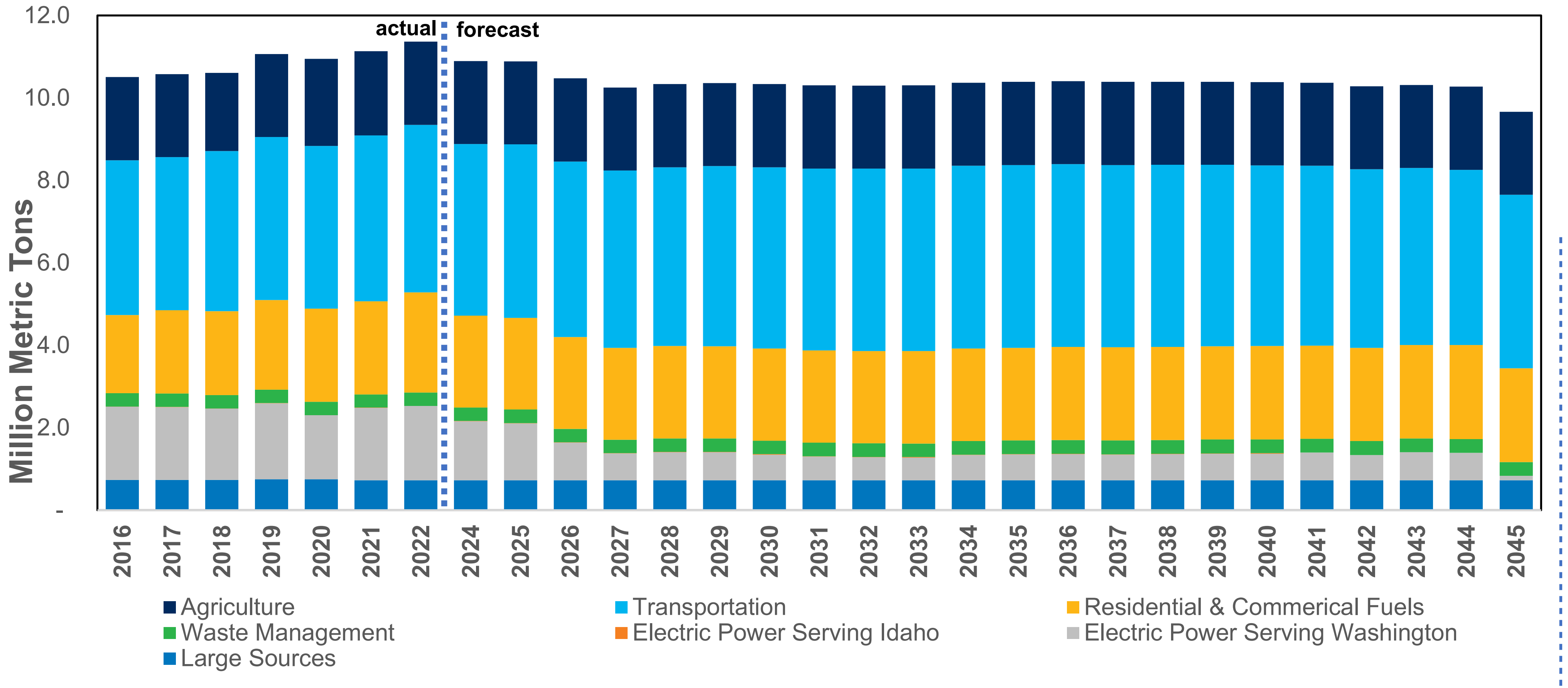




Greenhouse Gas Emissions (Washington Share)



Eastern Washington Greenhouse Gas Emissions

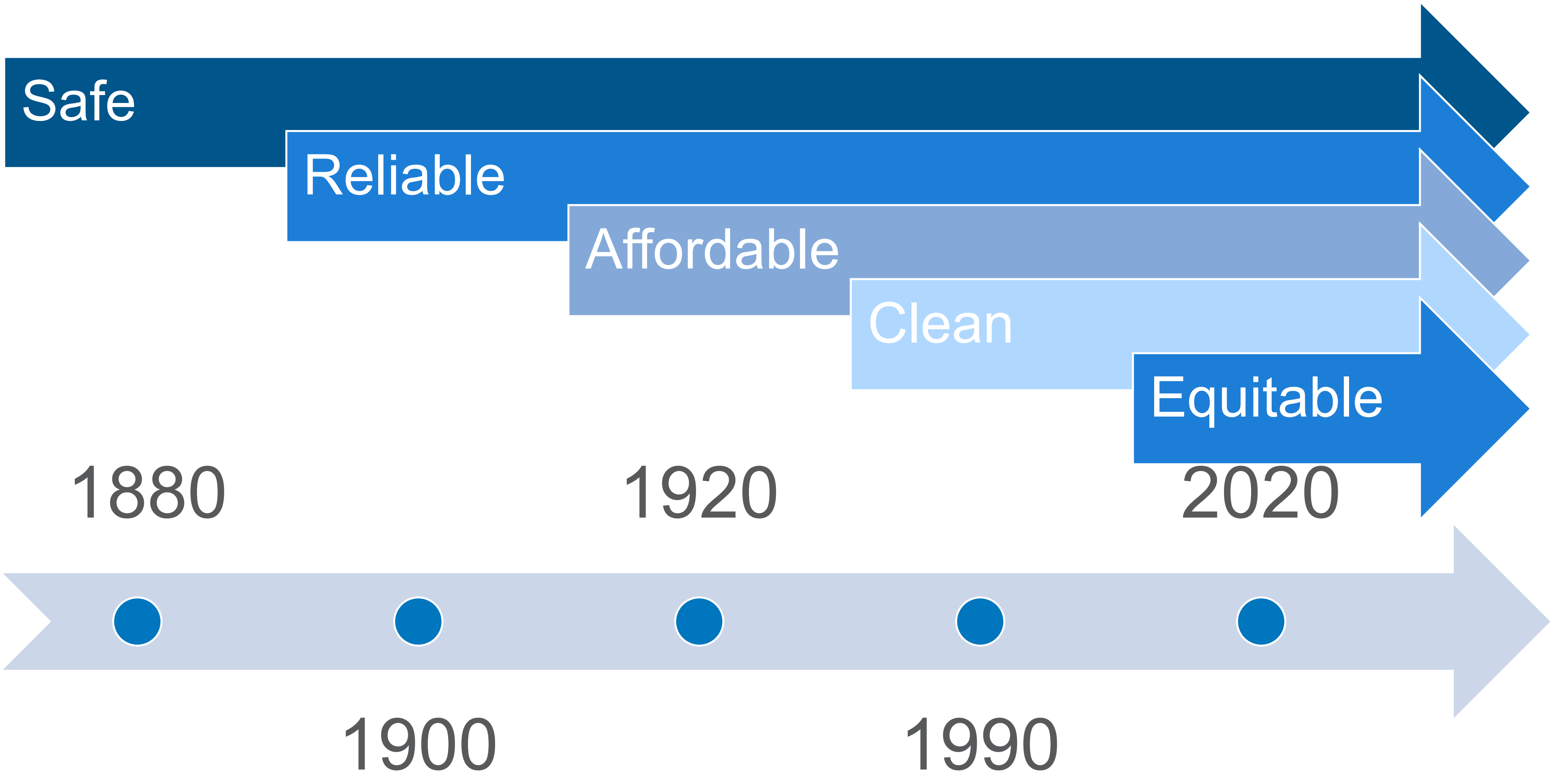


How Avista Practices Equitable Outcomes

Technical Advisory Committee Meeting No. 2

January 30, 2024

Evolution of Utility Industry



AVISTA

Equity Advisory Group

- Est. in Spring of 2021
- Significant input on our CEIP
- Ongoing monthly sessions
- 11/38 CEIP Conditions
- Oversee 500k of the Named Communities Investment Fund






Additional Advisory Groups

- Energy Assistance Advisory Group (EAAG)
- Energy Efficiency Advisory Group (EEAG)
- Distribution Planning Advisory Group (D-PAG)

CEIP Public Participation Strategy

- The Plan outlines barriers to participation in programs and services, strategies for reducing those barriers, and tools for increasing participation.
- Filed May 1, 2023
- Utility Language Strategy

Phase I
Project Planning
(August 4 - September 16, 2022)

Phase II
Assessment of Current Practices
(August 8 - September 30, 2022)

Phase III
Survey of Preferences
(September 5 - November 11, 2022)

Phase IV
Public Participation Plan Development

You'll be asked about your experiences with Avista in the past and how you'd like to be communicated with in the future. All questions are voluntary, and the entire survey should take about 3 minutes to complete.

Request translations or paper copies of the survey by emailing info@pppconsulting.net or calling (919) 706-5449.

+ Queremos saber cómo involucrarle a usted y a otros clientes de Avista de manera más equitativa en futuros programas e iniciativas.

+ Мы стремимся найти оптимальные способы взаимодействия с вами и другими клиентами Avista в будущих программах и инициативах.

+ نرغب في معرفة كيف يمكننا إشراكك وعملاء Avista الآخرين بشكل أكثر إنصافًا في البرامج والمبادرات القادمة.

+ 我们希望知道如何让您和其他 Avista 客户能够更公平地参与到未来的计划和倡议之

Other Initiatives

Capital Planning

Federal/State Grants

Supplier/Employee Diversity

CEIP Customer Benefit Indicators

Affordability	Energy Security & Resilience	Access to Clean Energy	Environmental	Community Development	Public Health
Participation in Company Programs Households with High Energy Burden Residential Arrears & Disconnects	Energy Availability Energy Generation Location	Methods/Modes of Outreach & Communication Transportation Electrification	Outdoor Air Quality Greenhouse Gas Emissions	Named Community Clean Energy Investments in Named Communities	Employee Diversity Supplier Diversity Indoor Air Quality

Affordability Initiative

How Bill Assistance is Increasing Customer Affordability & Promoting Equity

Kelsey Solberg, Energy Program Manager

Alignment to CEIP

Customer Benefit Indicators

Affordability	Energy Security & Resilience	Access to Clean Energy	Environmental	Community Development	Public Health
Participation in Company Programs **Households with High Energy Burden** **Residential Arrears & Disconnects**	Energy Availability Energy Generation Location	Methods/Modes of Outreach & Communication Transportation Electrification	Outdoor Air Quality Greenhouse Gas Emissions	Named Community Clean Energy Investments in Named Communities	Employee Diversity Supplier Diversity Indoor Air Quality

Bill Assistance & Affordability

What is bill assistance?

Bill assistance aims to reduce the **energy burden** of limited-income households

Energy Burden is the percentage of household income that goes towards energy costs

High energy burden= >6%

Severe energy burden= >10%

Most forms of **bill assistance** are aimed at reducing energy burden to <6%

Result: Increased Affordability!

Bill Assistance at Avista: Goals & Purpose

- Increase Affordability
- Address Past-Due Balances
- Provide Support During Hardships
- Educate on Energy Conservation

Washington Low-Income Rate Assistance Program (LIRAP)

At-a-glance

Eligibility Zero to greater of 200% FPL or 80% AMI

Affordability

Bill Discount

Discount Tier 1:	Discount Tier 2:	Discount Tier 3:	Discount Tier 4:	Discount Tier 5:
Zero to 5% FPL	6 to 50% FPL	51 to 100% FPL	101 to 150% FPL	151%, Greater of

Past-Due

Arrearage Forgiveness
Zero to 50% FPL

Arrearage Management Program
51% FPL to the Greater of

Hardship

Emergency Share
Customers experiencing hardship or energy emergency

Energy Conservation

Conservation Education (ConEd)
Distribution of energy-saving items for homeowners and renters, paired with customer education, to reduce energy use

Increasing Affordability

Introducing My Energy Discount

Discounts are based on self-declared monthly or annual income

Jointly administered between Avista and agencies means more avenues for access

Nearly 18,000 customers who received income-qualifying assistance were auto-enrolled in October 2023

No paperwork or income verification required

Participants remain eligible for other helpful programs through their local agencies, as well as other energy assistance

6% of enrolled customers will be randomly selected to verify their income through their CAA

Discount percentages are designed to reduce customers' energy burden to <6%

Addressing Past-Due Balances

Washington Customer Arrears

29,170 customers with past due balances totaling **$6.3M**

Average Past-Due Balance: **$216**

Washington customers as of December 31, 2023

Addressing Past-Due Balances

Avista's LIRAP arrearage assistance is comprised of two unique programs

Each program has distinct eligibility criteria and benefit amounts, and are intended to provide relief for income-qualified, residential customers who have unmanageable past-due balances (arrears) on their bills.

Avista works closely with community action agencies to ensure the customer has access to the benefit when they need it most.

Arrearage Forgiveness Program (AFP)

Arrearage Management Program (AMP)

Program Enrollment Snapshot

My Energy Discount:
28,044 Active Participants

Arrearage Forgiveness Program:
351 Recipients (Oct-Dec 2023)

Arrearage Management Program:
662 Active Participants

 Data provided as of 12/31/23

2023 Saturation Rate

Washington		
	Number of Eligible Customers	129,266
	Percentage Receiving Assistance	24%
	Pre-Covid (2017-19) 3-year Average	15%

Saturation Rate equals the percentage of estimated eligible customers who are receiving any form of bill assistance. Data is reviewed and updated quarterly. Beginning in 2023 the Washington estimated eligible of 129,266 was calculated using Avista's 2022 Performance-Based Ratemaking data.

Equity in Program Design

Program features designed with equity in mind

Removing barriers with self-attestation of household income and size

Discount percentages designed to specifically address differential income tiers

Multi-lingual resources on the web, through customer service, and in outreach materials

Increased readability of Avista website, customer letters, promotional materials, etc.

Named Communities Investment Fund

Kristine Meyer, Avista Foundation Executive Director
Ana Matthews, Sr. Energy Efficiency Program Manager

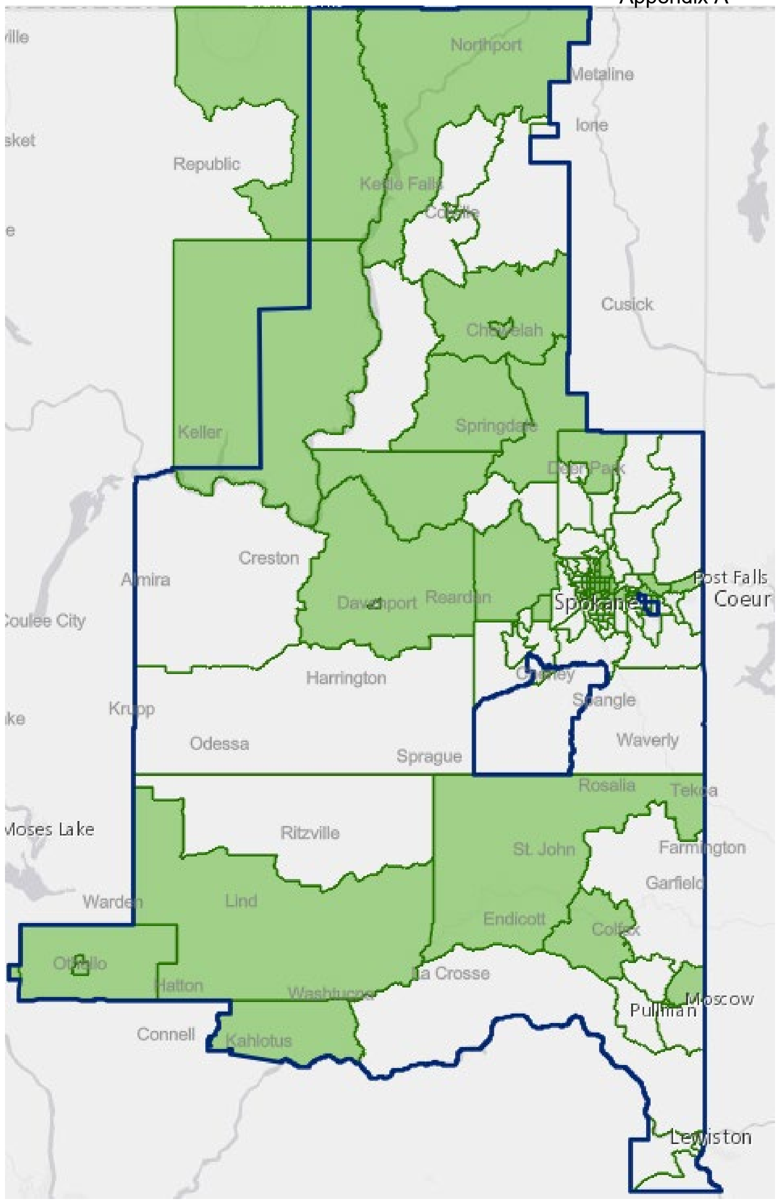
Avista's Named Communities

Specific Target and Actions for ensuring that all customers are benefiting from the transition to clean energy the equitable distribution of energy and nonenergy benefits and reduction of burdens to Vulnerable Populations and Highly Impacted Communities (Named Communities)

Vulnerable Populations

Highly Impacted Communities

142 census tracts in Avista's service territory
- 36 Health Disparities
- 12 Socioeconomic or sensitive populations indicators



Named Communities Investment Fund

- Specific Action dedicated to the equitable distribution of energy and non-energy benefits and reduction in burdens to Named Communities

- Funding is limited to 1% or approximately $5.0 million of electric revenues, annually

$2M
Supplement Energy Efficiency

$1M
Investments in Distribution Resiliency

$1M
Incentives & Grants for customers or third parties

$500,000
Outreach & Engagement

$500,000
Other Projects, Programs or Initiatives

Energy Efficiency NCIF

The cleanest energy is the energy that is never used.

40% or up to $2M

Supplement and support **energy efficiency** efforts targeted to Named Communities

- Community Identified Projects
- Multifamily Building Split Incentive
- Health & Safety for Manufactured & Mobile Homes
- Named Community Single Family Weatherization
- Community & Small Business Energy Efficiency

Equity in Practice: Outreach & Engagement

Multiple avenues to learn about and apply for NCIF

Online Applications

Existing Community Relationships

Informational Sessions virtual and in-person

Enhancement to company programs and projects

NCIF Process

Advisory

Confer with assembled advisory groups for equity, energy efficiency and assistance, etc. for guidance in program design and implementation. Engage customers through public participation.

Community & Business

Application process open to interested parties to submit proposals for funding

Existing Relationships/Channels

Internal and external interested individuals and/or parties make proposals through established channels or connections

Support/Guidance

For entities that have a clean energy idea and need support for developing their concept to fruition.

Resource "Braiding"

Consider and leverage all funding and other resources available (at the time of application).

Outputs + Results

Programs and projects that are designed to ensure equitable transformation for all customers, with committed focus for those residing in Named Communities

Factors for NCIF Consideration: Equity Assured

Equity

- Affordability
- Access to Clean Energy
- Community Development
- Energy Security
- Environmental
- Public Health

Equity lens requires unique consideration for each proposed project

Customer Benefit Indicators

(1) Participation in Company Programs
(2) Number of households with a High Energy Burden (>6%)
(3) Availability of Methods/Modes of Outreach and Communication
(4) Transportation Electrification
(5) Named Community Clean Energy
(6) Investments in Named Communities
(7) Energy Availability
(8) Energy Generation Location
(9) Outdoor Air Quality
(10) Greenhouse Gas Emissions
(11) Employee Diversity
(12) Supplier Diversity
(13) Indoor Air Quality

Implementation Plan Specific Actions

- Community Identified Project
- Multifamily Building Split Incentive
- Health & Safety for manufactured and mobile home
- Single Family Weatherization
- Community Energy Assistance
- Small Business Energy Assistance

Equity Advisory Group Initiatives

Energy Efficiency in Named Communities
(1) Improved awareness and energy efficiency for Spokane Tribe, multi-family and manufactured homes
(2) Increased Tree Canopy
(3)Increased access to products and appliances
(4) Increased awareness and engagement in EE programs
(5) Matching funds for EE grant applications
(6) Improved EE for those without stable housing

2023 Commitments & Funding: Equity Outcomes

Energy Efficiency

- Spokane Tribe reservation energy audits
- Lincoln County Fairgrounds lighting
- Malden homes weatherization
- KW Energy Duct Sealing for manufactured and mobile home in Stevens, Ferry and Pend Oreille counties
- Walnut Corners affordable housing PTAC (AC & Heating units) replacement
- SNAP Pine Villa affordable housing Phase 1 renovation (windows, insulation and doors)
- the.Supper Club new refrigerator and freezer
- Health & Safety for Manufactured Homes for two neighborhoods in Spokane County

Affordability	Energy Security & Resilience	Access to Clean Energy	Environmental	Community Development	Public Health
Participation in Company Programs Households with High Energy Burden Residential Arrears & Disconnects	Energy Availability Energy Generation Location	Methods/Modes of Outreach & Communication Transportation Electrification	Outdoor Air Quality Greenhouse Gas Emissions	Named Community Clean Energy Investments in Named Communities	Employee Diversity Supplier Diversity Indoor Air Quality

Community & Resilience

- Martin Luther King Community Center solar assessment
- Medical equipment and air conditioning for customers with power dependency pilot
- City of Spokane Parks & Recreation Tree Plotter software subscription

Combined

- Online application
- Martin Luther King Community Center HVAC retro-commissioning report, lighting, and windows
- Kettle Falls Community Chest facility renovation

Thank you!

Equity Planning in the 2023 IRP

James Gall
Technical Advisory Committee Meeting No. 2
January 30, 2024

Equity Related Items included in 2023 IRP Modeling

- Energy Efficiency
- Named Community Investment Fund (NCIF)
- Customer Benefit Indicators (CBIs)
- Resource Non-Energy Impacts (NEIs)
- Social Cost of Greenhouse Gas
- Maximum Customer Benefit Scenario

Energy Efficiency

- Split energy efficiency measures between “low-income” and non-low income
- Low-income includes higher NEI values where applicable
- Low-income measures can use a different cost value
- 2025 IRP will explore using named community potential rather then low-income

How impacts the plan:
Selects greater amounts of energy efficiency to serve future energy demand

Named Community Investment Fund (NCIF)

- Model must select $2 million (+) of the least cost, non-cost-effective energy efficiency per year
  - Increases energy efficiency targets
  - Shows possible future programs
- Model must "spend" $400,000 per year on incremental Distributed Energy Resources (DERs), including community solar
  - Demonstrates ways to increase DER in named communities
  - Impacts CBI metrics

How impacts the plan:
1) Quantifies the lowest cost, non-cost-effective low-income energy efficiency projects given the budget.
2) Selects generation/energy storage given the budget

Non-Energy Impacts

- Quantification of indirect and social impacts of resource decisions not included in resource costs
- DNV conducted the study for the 2023 IRP for resource selection if quantitative values are known or estimated
- DNV qualitatively identified costs for other impacts

How impacts the plan:

1) Energy Efficiency and Resource are on an even playing field for selection
2) Sets priority for CBIs using quantifiable measures

Non-Energy Impacts in IRP

Supply-Side Resources	Demand-Side Resources*
Public Health PM2.5, SO2, NOx	**Income & Health** Economic Develop. (income) less missed days of work
Safety Direct and indirect fatalities per GWh	**Health** Related to avoided costs such as medical
Environment Land use, water use, wildfire risk	**Property Value** Noise, visual air/temperature
Economic Jobs, earnings, output, value add added	**Energy Burden** Reduction in costs related to utility bill

IRP Resource Selection

- Not all NEIs are able to be quantified due to lack of data or difficultly in obtaining data.
- Phase II Energy Efficiency NEI Study in 2022.
- Avista is not planning a Phase II Supply Resource Study at this time.

*for illustrative purposes – residential used on this slide

Resource Acquisition Equity Considerations

- Resources are required to go through rigorous public process to be permitted
- RFP Resource selection includes
  - NEIs in economic analysis
  - Resources are selected based on scoring matrix including
    - Customer Energy Impact (cost): 40%
    - Risk Management (construction/solvency): 20%
    - Price Risk (change in price): 5%
    - Electric Factors (deliverability and technology risks): 20%
    - Environmental (permitting risk & air quality): 10%
    - Qualitative Non-Energy Impacts: 5%
      - Community involvement, Named Community impacts, location, local labor force, supplier and owner diversity

Maximum Customer Benefit Scenario

- Required in Washington IRP rules
- 2023 IRP included the following assumptions
  - In-state/connected renewables requirement (i.e. no Montana wind)
  - No ammonia/power to gas CTs (fuel cell allowed)
  - Lowering of excess energy burden required via community solar
  - No nuclear energy
- What do you like about the assumptions?
- What would you change?

2025 Electric IRP, TAC 2 Meeting Notes, January 30, 2024

In-Person Participants:

Dan Blazquez, Avista; Annette Brandon, Avista; Michael Brutocao, Avista; James Gall, Avista; Lori Hermanson, Avista; Mike Hermanson, Avista; Clint Kalich, Avista; John Lyons, Avista; Tom Pardee, Avista; and Darrell Soyars, Avista

Online Participants:

Diana Aguilar, Fortis BC; Sofya Atitsogbe, WUTC; Ernesto Avelar; Tamara Bradley, Avista; Kate Brouns, Renewable Northwest; Terrence Browne, Avista; Logan Callen, City of Spokane; Katie Chamberlain, Renewable Northwest; Nathan Critchfield, Puget Sound Energy; Kelly Dengel, Avista; Joshua Dennis, WUTC; Mike Dillon, Avista; Chris Drake, Avista; Ryan Finesilver, Avista; Grant Forsyth, Avista; Annie Gannon, Avista; Konstantine Geranios, WUTC; Amanda Ghering, Avista; David Hawkins; Scott Holstrom, LIUNA; Alexandra Karpoff, Puget Sound Energy; Mike Louis, IPUC; Ana Matthews, Avista; James McDougall, Avista; Ian McGetrick, Idaho Power; Kristine Meyer, Avista; Heather Moline, WUTC; Richard Newton, Northwest LECET; Kaitry Olson, Puget Sound Energy; Meghan Pinch, Avista; Melanie Rose, Avista; Amanda Silvestri, BPA; Kelsey Solberg, Avista; Dean Spratt, Avista; Marissa Steketee, Sapere Consulting; Lisa Stites, Grant County PUD; Jason Talford, IPUC; Andrea Talty, Puget Sound Energy; Charlee Thompson, NW Energy Coalition; Tyler Tobin, Puget Sound Energy; Brian Tyson, Puget Sound Energy; Kirsten, Wilson, Washington State Department of Enterprise Services; Rachel Wilson.

Introductions, John Lyons

John Lyons: We are still doing the virtual meetings on Teams always. In-person is available, especially for the longer meetings. Shorter ones we realize that's tough to come in for, but for the all-day meetings, it's still an option for in-person. We post the final TAC presentations, meeting notes and recordings on the IRP page.

John Lyons: Couple of reminders. Please remember to mute your mics unless you're speaking or asking questions. You can use the raise hand function in Teams or type something in the chat box for questions or comments. We ask that you respect the pause because sometimes it does take a little bit for people to unmute their phones, things like that. Trying not speak over the presenter and speaker. We're all really good at this now, the longer we've been doing these online meetings. We do ask that you state your name before commenting, and that's for the meeting notes software. If you're hooked up directly, your name is set up on it, it'll automatically put it on. But like in this room, it just says it's in this room, so that makes it a little more difficult.

John Lyons: This is a public advisory meeting. Just a reminder that presentations and comments are going to be documented and recorded. The IRP plan, remember IRPs are required by Idaho and Washington every other year. Washington now requires an IRP every four years, and then there's a Progress Report at two years, most of the same things. Plus, we're already doing a full IRP for Idaho. The IRP guides our resource strategy over the next two decades. It starts with the current projected load and resource position. Also looks at some alternative forecasts. We have an expected forecast and set of alternatives. If we had some major changes like electrification happened sooner or you had some new policy that changed the market. We also look at resource strategies under those different future policies. They look at different generation resource choices, different aspects for energy efficiency, demand response. You're seeing a lot more transmission and distribution planning integration. If you're interested in that, there is a Distribution Planning Advisory Group that's similar to the TAC that is now meeting. And then it all ends up in a set of avoided costs that are used. So, if someone wants to bid into, say they had a PURPA project they would like to bid in to sell something to Avista, that's where that number comes from. And then we also do a series of market and portfolio scenarios where those uncertain future issues that we’re either not sure which direction they're going or it's important enough that if we had a big change, we would want to see if that changes our strategy going forward.

John Lyons: This is the public side of thing. It is a real wide range of participants. If you've got a question, please ask. Because not everyone's going to be an expert in every area, and chances are if you've got a question someone else does too. So please go ahead and raise those. We are also always looking for help with getting new TAC members, so if there's someone that's interested in joining, you don't have to participate for the whole time, you can just participate for a part of it. It is an open forum, we're always trying to balance how much discussion we can get versus getting through the program that we have. If you've got different study assumptions, we do ask for those. The earlier you get them to us, the better chance we have to get those completed on time. If we can't complete them during this cycle, those can become Action Items for the next cycle. As we said before, we're always available by email or phone for questions or comments. If you want to set up a meeting with us between the TAC meetings, we're happy to do that as well.

John Lyons: For today's agenda, this is an equity focused meeting. If you remember our last meeting, I think it was the first TAC in September, I think it was 26th somewhere about there. We didn't have this meeting in here. Our next one was going to be, I believe in March, but we were asked by the Washington Commission as we've been talking about equity throughout the IRP, to have one specifically focused on equity issues. As a reminder, this is something that's in Washington law to have an equity focus on things. That's what we're going to be talking about today after the introduction and that's going to be about how Avista includes equity principles and then getting into those Customer Benefit Indicators, the way we measure some of these equity areas, we’ll take a short break, then Tamara will get into how Avista practices equity outcomes. That's a wider view, not just the IRP of what's going on at Avista for that. James will wrap up with how we're rolling equity planning into the IRP because we started doing this the last IRP and it's still a fairly new topic for us to work on. Do we have any questions before we move on to the next presentation? You're all quiet in the room here. Do we have anything there on the chat, James?

James Gall: It didn't sound like it yet.

How Avista Includes Equity Principles, Annette Brandon

James Gall: OK, alright, when I get that presentation loaded up and I don't know if it's showing there. I need to introduce Annette Brandon.

Annette Brandon: Well, I'll introduce myself anyway. Hi, my name's Annette Brandon and I am in the Energy Supply Department with several of the folks in the room here today – James and Lori and John and others. I primarily am in the Wholesale Marketing area. However, I'm on a special project to help to incorporate equity into our overall utility operations, beginning with the focus in capital planning. However, it's a nice offshoot of what we have done previously in our Clean Energy Implementation Plan [CEIP] that we started to in the last in the last IRP. Thanks for having me back here today. It's a good start for the process that we're working on right now. You'll notice that some of these slides have been updated. As we went through the final updating there was unfortunately, and embarrassingly for me, there were several typos in there. We cleared those all up before we showed these to you today. I just want to make sure that you know that's not typically how I do things like that. So, here's the final. We can move on.

Annette Brandon: A good place to start is an overview of what equity is. I thought instead of having any subjective what we think it is, or other definitions that are being used in different contexts, I thought we would just level set by saying this is what the actual dictionary definition is. Equity is the quality of being fair or impartial. What does that mean? Even so, if we take that one step further rather than just taking it as a standalone basis. If we put it into actual operations, if I can draw your attention down to #3, it's the pull, your practice of accounting for the differences in individual starting points when pursuing a goal or achievement and working to remove the barriers to equal opportunity by providing support based on unique needs of individual students or employees. For Avista, that would mean considering what circumstances may be limiting customer’s access or opportunity to receive the benefits of the energy system, which would be safe, reliable, affordable, etcetera. A good example of this is this new graphic that that I found. It's been redeveloped and I put the copyright on there. It's small, but this was redesigned by another company and what it is representing is in years past everything was focused on equality, so everything was the same meaning. If you were little and you had to jump off a tall curb, or you had or you were in a wheelchair, or you could not see you still had that curb you had to deal with when crossing the street. But as time passed, and as equity became more and more important, you can see that now those sidewalks have been modified. Now we can hear when we want to cross, we can hear how long we have to cross. It's been modified so you can easily roll down it and little people don't have to jump. Now they can walk down. I really like that. I think that has to speak to it a little bit better than some of the other illustrations that have been used in commonplace. The shoe example I'll get to a little bit later, but it really surrounds itself around the distribution of assets. In our case, the distribution of energy across our system, but I'll get to that in the next slide.

Annette Brandon: So, what is? What does that mean? What does that mean to us here at Avista? Because fair can also be a subjective term. I looked that one up. Also, if we're stuck with the dictionary.com, it's free from bias, dishonesty, or injustice, which would mean, taking off of our previous example, that an individual’s circumstance no longer predicts their outcome, which means a fair process. The process itself must be fair and must be based on meaningful participation. And I took the time to focus on meaningful participation here because meaningful participation is not check the box participation. I will keep saying that over and over because I think there's an effort out there to have public participation, public participation, public participation, but public participation just for the sake of it does not help us and does not help you. Meaningful participation means, and this is a truncated definition, just so it would go on the slide. But this is the Department of Energy. How they are defining it in their Justice 40 initiative when they are taking those investments and ensuring that disadvantaged communities are receiving the benefits of investments for their climate change efforts. It starts with awareness and opportunity for 2% to participate. Then, with that participation, the input we received has the ability to influence our decisions. And then, that is actually considered in our decision making and purposeful outreach efforts, which seek out and facilitate involvement of those potentially affected that goes very well back with the awareness and opportunity to participate. But I think this is really foundational to equity and back to my check the box example it it's difficult because the utility industry is so very complex. It is still very complex that we could be perfect in every single thing that we do. Perfect in checking every box in what this means and likely still not have full representation as desired, I guess by our regulators.

Annette Brandon: What I would like to see is a way for us to work together to first and foremost try to identify what does matter to our customers. We know affordability matters to our customers and we know holding Avista accountable to what we say is important to our customers. But do customers really want to be involved in, like a technical meeting such as this? Do they want to be right down in the weeds? Maybe. And if so, that's great. And if they have the ability to, that's great. But what about those who want to but don't have the ability? Or time, not just ability. That's where we have to work together outside of just Avista. We have to work with our Community agencies. We have to work with our Public Counsel unit. It really takes a village because it might be that somebody else can understand what we're doing and understand what the customer is seeking and act as that conduit. And so, that is really important as we're trying to navigate this, what does equity mean and how can we ensure that everything that we're doing is built on this meaningful participation? All right, next slide here.

Annette Brandon: This slide I took the time to show the evolution from environmental justice to where we are today for the just transition. That's because I think it's important to understand that this is not really new. It's just the terminology is new and the requirements are new. The evolution of energy justice started with the environmental justice movement in the in the 1970s and it was around the time of the civil rights movement as well. It had a focus on discrimination and environmental pollution that those were very much related or tied together, where everyone has the right to a clean environment regardless of their social, economic status or characteristics. It was one of the first times where there was recognition and acknowledgement that certain characteristics did result in disproportional environmental impacts back then, and it was the first time where there was strong advocacy for a right. The right to a clean environment. From there, it expanded into climate justice, kept all those still foundational thoughts but pulled into the climate justice age where that expanded the look into climate change impacts. That's the first time where we started hearing about fossil fuel impacts. And it also emphasized a need to identify solutions that did not perpetuate or worsen already existing inequities. In environmental equities, we already started to acknowledge and understand what those are and then climate justice is taking one step further and saying, OK, now that you know what they are, now try to make it so that that doesn't keep happening, then spend it on the energy justice. The terminology energy justice started in the 2010s, which is quite a while ago from now.

Annette Brandon: And we just recently started hearing about it. But the reason for that is that energy justice really started more in economic circles or legal circles. And it reinforces the need for voices and decisions and emphasize the need for affordable and clean energy. And again, reemphasize the focus on inclusivity and decision making. All of them build on each other. They're not distinct from each other, and energy justice has been in a lot of our regulation, but today, with the focus on the transition to clean energy, this is where now we're to the point where now we're being required.

Annette Brandon: The technical definition of energy justice is equitably sharing the benefits and burdens involved in the production and consumption of energy. So that's our generation. I think that as our generation, transmission and distribution of our energy, how can we ensure that our processes, not just our delivery, but our process is considering what customers need and what their unique characteristics are. And that is what tips on that second piece of that paragraph and fairness in how people's and community’s, people's fairness, and how people and communities are treated in energy decision making. OK, next slide.

Annette Brandon: That brings us, as I said in that last line to what the transition to clean energy means. Alright, so the transition to clean energy, it's in the spotlight everywhere. It's in the spotlight, not just for Washington staff, but nationally and lots of companies are talking about how they're committed to be green by 2030, 2040, 2050. You hear a lot of companies, so it's very much a focus on transition to clean energy and it's a just transition. Just transition means it takes equity just a little bit further and says not only do I want to make sure that I'm allocating resources in a manner that all have access to clean energy, but I want to seek to address the cause of those inequities. Why aren't they? Is there something that we can do as the utility to get there? We do believe that all individuals have the right to fair and clean up clean energy, but we have to balance a lot of things when we say right, it's kind of a squishy word, if you will, because yes, we believe that, but we have lots of constraints. We have to work with them, and lots of things to balance, but the ultimate goal is we want all customers to have the energy they need, not only for their basic needs, but beyond that, to economic development, to health outcomes, to a healthier environment, to all of those things that having safe, reliable, clean energy, energy and can deal.

Annette Brandon: OK, so I think I covered everything I had in my notes. This is what I just touched on a minute ago about balancing multiple in multiple objectives. I really wanted to spend just a little bit of time focusing on this, because I think that it goes without saying, but we need to say it out loud. There are several objectives that we're balancing in this IRP process as well as in our planning process, distribution planning, system planning, transmission planning.

Annette Brandon: We are not a standalone island utility. We interconnect with lots of different utilities and providers and distribution centers, and we're regulated by all kinds of four-letter acronyms, NERC, FERC, WECC. And then we have federal justice 40 initiative requirements, not so much requirements, but considerations rather the Clean Energy Transformation Act requirements and considerations. The Department of Ecology has departments or has considerations and requirements, so all of that we're trying to balance with the needs that we've identified from all the different people and areas that are on the right-hand side of the screen. That is all individual needs, but also clean air, Public Library, Department of Ecology. Also, a lot of these pictures represent people that are on our Equity Advisory Group, and we'll talk about that later in the presentation. But it is very much a balancing act, and our goal is that we want all customers to have access to this clean energy. Clean, reliable, safe, not even just limited to clean energy but limited to our energy portfolio.

Annette Brandon: All of the resources that go into the IRP analysis, we want to have processes that consider, and evaluate the appropriateness of those selections. It cannot go without saying, however, that we are an electric provider or an electric utility in this context, because this is electric IRP, we're also natural gas, but we're not a social agency. While it's very important that we understand those root causes, and we genuinely care about our customers, and want to ensure that we consider unique circumstances when we're planning. Sometimes the answer's going to be well, NERC says we're going to do this, and so we're going to do it.

Annette Brandon: It's important for me to point that out, because that does not mean that we're not being equitable or that we're not including equity. That just means that one piece of the whole process, the life cycle of an investment, that just means in that one decision point we're going to say we're not an island, we need to make sure that our neighbors are also reliable. And so, we are not going to put a transmission line, make a decision to put a transmission line in this neighborhood versus that neighborhood because we want to make sure that we're not having unintended consequences 15 years down the road. When I say 50 years down the road, my husband says no, more like 50 years down the road. Where now we've got the inverse going on and now the other one is not as reliable. So, we want to make sure that we're long-term planning. We're thinking about sustainability. We're thinking about everyone having reliability to the best of our ability. That's really important that we're balancing those objectives and the place for that comes into play, then that equity lens comes into play multiple places down the line and even up the line. I've got a slide that will walk through where that is.

Annette Brandon: Maybe before we move on, this was foundation setting as to what equity is, how we're viewing it, how we're balancing multiple priorities? Are there any questions or comments? Heather has a hand up. Hi, Heather.

Heather Moline (UTC): Hi. Thank you for that. This is Heather Moline with Utilities and Transportation Commission Staff. I'm just going to share in the chat some of what's in law that's connected to what Annette was saying and what's in orders issued by the Commission regarding what Annette was saying. I just want folks to know that what Annette was saying, she didn't just go and Google it. This stuff is required by Washington statute, and it's required by what the Commissioners have ordered regarding their utilities. The first thing that I'm sharing is this link to the final order from the Cascade general rate case. (UTC Case Docket Document Sets | UTC (wa.gov) see 08/23/2022 filing, Final Order 09 (four types of energy justice), as well as RCW 43.06D.020: Office established—Purpose. (wa.gov) and RCW 19.405.010: Findings—Intent—2019 c 288. (wa.gov)) Cascade is a gas utility. It's not an electric utility, but the Commission said, here are four types of energy justice that we expect all utilities that we regulate to be considering. And it was based on RCW 43.06D, which I also linked to in the chat, which is the definition of equity from the Washington State Office of Equity, a new state office. That was created three years ago, I think. The order that I shared comes from this definition and statute of equity that I shared. The last thing that I shared is this link to statute that probably all of us have heard of by now. The Clean Energy Transformation Act, CETA, 194-05-010, which is the very first place in law that the term equitable distribution is used. As we all try to figure out what this means and share resources that interpret what's there, I just wanted to make sure folks had access to this. What's in law and what's in Commission order about equity? Thanks.

Annette Brandon: Heather, your timing could not be more perfect because that is exactly what my next slide is on. Thank you for that. That couldn't be timed more perfectly, because here's the Washington State equity requirements, and Heather has been so kind to add the links into the chat now. If you would like to click those links, it will take you to the actual RCW and the WAC. As Heather just noted, the Clean Energy Implementation Plan, my words were it was focused on a just transition, that is the first time that the words equitable distribution is used and in my thought I just transmit transition is equitable distribution. It was equitable distribution of benefits and burdens. And then particular areas that the Commission wanted us to focus our time on and when we get to the Customer Benefit Indicator, we'll make sure that we talk about those.

Annette Brandon: That was the place where the term equitable was used. There was a strong public participation focus and there was also a strong Customer Benefit Indicator focus, and what those Customer Benefit Indicators are that we're going to talk about are, what I'm going to call process and performance metrics now. In that language back then, they did not use the word equity, but that's exactly what it was. That's exactly what we were doing.

Annette Brandon: Public participation is very similar to procedural equity and Customer Benefit Indicators can be the accountability portion of distributed or restorative, but this was this was the first place. While this does say Clean Energy Implementation Plan, that begins with the Clean Energy Action Plan, so really it should be Clean Energy Action Plan starts and then results in the Clean Energy Implementation Plan. Where we are today is talking about the IRP which will help to inform the Clean Energy Action Plan. In addition, in our general rate case conditions, we had I think in 2022, actually I think I have the wrong date there. Capital planning must consider and implement energy justice and its core tenants, and these are the core tenants. Thankfully, Heather just put the link in the chat and although that references the Cascade order, it is the same terminology that is in our order.

Annette Brandon: The Commission is being very intentional to ensure that we are all using the same definitions. I think early on, in the company we were saying internally we need to figure out how Avista is going to define equity. Now the Commission has defined it for us. This is exactly how they are defining it for us and by stepping through each of these four components, we will have justified or attempted to justify if that's the right terminology. We've shown that we've made good faith efforts to ensure that we have a fair, inclusive process that is proactively planning for equitable outcomes. I included the Climate Commitment Act on here. I put it in blue because it is related, but it's not directly related on the electric side. The primary avenue for reaching those disadvantaged, Named Community, frontline. They're using different terminology, and I don't recall which one they are using. The Environmental Justice Council from Washington State, they are helping to say this is where and in what communities we should invest in that are having disproportional environmental burdens. This is so the investments are for them primarily.

Annette Brandon: However, Avista does have a portion of that we need to make sure that we are considering low-income customers, which often are located in Named Communities. If we are going to distribute our portion, but our portion of the Climate Commitment Act, we need to ensure that we're doing that in a manner that's also dictated by law. Next slide.

Annette Brandon: This slide is actually recycled from last year's Integrated Resource Plan meeting where we were discussing with the TAC how we might include certain components in our resource selection in our IRP, this is a condition that we agreed to, and this is the basis for what we are setting the stage for today to do again. The requirements are that Avista will apply non-energy impacts and Customer Benefit Indicators to resource and program selections. Further, we agreed to consult and engage with all our equity or applicable advisory groups to include both NEI and CBI. And throughout this whole process, once we've developed a methodology, we want to ensure that our equity advisory group is comfortable with that. While this was part of the Clean Energy Implementation Plan, it's also part of our capital planning requirement that we talked about from the general rate case requirements. Also, we need to make sure that the Equity Advisory Group is comfortable with whatever we decide in that process as well. OK, so next slide.

Annette Brandon: What exactly is a non-energy impact? I took this off of a slide that's from one of the primary industry experts that address non-energy impacts. They can be broken out into participant benefits, utility benefits, and societal benefits. And to summarize them all in bullet points, it's the contribution of the investment that goes beyond the energy and the demand costs. Some of those impacts, and they can be positive or negative, can come in the form of economic, social, environmental and or personal ways. What does that mean? Some of the good examples that I've uncovered have been. First off, energy is foundational to economic growth. There is a correlation, I've not personally studied it, but this is what I've read, there is a correlation between high energy use and high economic growth. Again, I can't prove that, but that's what I read, and it seems it seems intuitive. Also, when you think of public health, I struggled with that one for a long time because I wasn't entirely sure how that fit in, except for environment. If you have healthy environment then you have healthy people but think about the fact that because we have safe, reliable power, think of all the technological advancements we have now. All of the life-saving equipment we have and all of our hospitals, we were able to develop and use daily to keep people alive for a lot longer and to have more successful surgeries and a healthier community. That was a direct relation too.

Annette Brandon: Also, some of the ideas to think about is, personal ways could be maybe education, let's say tech, access to online classes during the pandemic. If we hadn't had energy that allowed us to use our devices, to charge our devices, there could have been a lot of lost class time and maybe people would have had to put their whole entire year of college, or year or two or whatever, on hold. So, the primary challenge with these non-energy impacts is how do we measure them? How do we compare them? How do we use them as a basis for a proactive decision? Since we're here today for integrated resource planning, how do we consider this for something that's 20 years down the road? That's the challenge. That's what we need to think about. Next slide.

Annette Brandon: This is a very busy slide, and I have to say in these next couple of slides this is my first attempt at these and these most likely will change as it goes through all the leadership and all of the advisory groups here at Avista. But this is this is how it seems most intuitive to me, and I've been looking at this for a long time so I'm learning. I'm starting to almost speak slang already, since I've been saying this so much as it goes through the company will make sure that we clarify this a little bit better. The terminology recognition, procedural distribution, restorative I am not going to ask employees to use that terminology. We do need to use that terminology when we're writing and when we're justifying to the Commission and we do need to make sure that we don't lose sight of what it means, that we don't lose sight of how they relate together, because otherwise we're trying to put the genie back in the bottle. Now, what did we mean by that? We need to make sure we don't wind up in that place, so I would like to categorize this as people process and performance.

Annette Brandon: We are going to ensure that we have an equitable process, an equitable business planning process and integrated resource planning process, or just basically equitable business planning at the company that's focused on people. That's our recognition justice. I am saying this is not just customer communities, but it's all of us customers, communities, employees. It's identifying who and where the inequities exist, and honestly. First, it's recognizing, identifying and acknowledging that perhaps policies and procedures that we have, that we have chosen, or that are because of regulation, have resulted in unintended consequences, which may have resulted in unaffordable energy for some versus others or a host of other of other factors, and it really also is focused on barrier considerations. And when I say barrier, I mean what are those individual circumstances?

Annette Brandon: The second piece is process, which is meaningful participation. I think I fully covered that earlier. I won't go over that again. Foundational performance then, that's the distribution of the benefits and burdens and the reason I'm calling it performance is because this is where the metrics will fit in that we're about to talk about. This is where we're going to hold ourselves accountable, because if we can't measure how we're doing, how do we really know how we're doing? We need to make sure that we can say this is how we're doing now. There's a difference between a performance metric and a tracking metric, and there might be times where we need to track something. We just need to track it because we don't know, so we need to look for a trend rather than actual end result and that that's something that we need to consider as we go through it. At what point might it be a trend? At what point might it be a performance and at what point might a trend become a performance that could that could happen? Also, you might track it for several years and then have it be a performance. OK, next slide.

Anette Brandon: The reason why I bring this slide up again is I wanted to make sure that I did not leave out that we are very cognizant of the fact that we are also a multi jurisdiction utility and we have customers in both Idaho and Washington. There are different legislative and regulatory mandates and requirements going on in different states. I think this is where I just wanted to really reinforce that we are aware of that, and James can speak to this better than I can. But in in our modeling and in our resource selection, we are very much considering that and understand the impacts to Idaho. Considering things that potentially their regulators do not want to have considered in resource selection, and I say that cautiously because if everything just about least cost versus societal cost. It could be that cost isn't the determining factor. If it's equity and everything we do, and if we're considering equity, it might be that one point, that decision point, is not where it's layered on, it could be down the road in implementation. The next slide will go into that, but that's why I showed this again just to acknowledge that we understand that and we're planning for that.

Annette Brandon: Next slide and I even changed it yesterday. For a different reason, and I think I like the way it was yesterday better than today, but nevertheless, since this was in the slide deck, this is today's visual. This is the resource and program lifecycle that I've been talking about throughout this presentation. It really starts with identifying, evaluate and where we're at today. We're trying to identify and evaluate, so that's not only integrated resource planning, but also transmission planning, energy efficiency planning or customer requested. I added that on there because sometimes we have to allocate resources because we have the obligation to serve.

Annette Brandon: From there as a company, we prioritize by transmission and distribution. By several functional business groups that we have across the company and what our goal is, is to have some of those prioritization metrics include an equity metric right alongside cost effectiveness. Equity is very related obviously down there to the impact of process or performance metrics. But the point is that on a functional business unit team, equity will begin even as early as integrated resource planning. We have to talk about how to include it in functional business unit, it will have to happen there. On the selection, that's where we have a Capital Planning Group. The Capital Planning Group will even pull it up one step farther to ensure that as a company we truly are working towards a just transition of clean energy for all. I keep saying clean energy, but it's not limited to clean energy, really equitable access and opportunity to receive the benefits of the energy system.

Annette Brandon: Finally, once that's all done and we go to execute it, that doesn't mean that our consideration on equity is over. This is where I think there's going to be a lot of equity metrics we can put in, those equity metrics that might not have anything to do with cost. It might have to do with do we know if the customer is on this block where we're going to be doing work. Do we know what language they speak and have we informed them? Have we informed them in their language and have we informed them prior than the day before? And when we're translating, we're doing it with cultural competency or literal translation, because there is a difference. It might be those projects, making sure that we are focusing in on when we choose our suppliers. Are we making sure that we have supplier diversity efforts going on? Are we working collaboratively across internal departments? This is a work in process. We're not going to get it right. I'm not trying to say that any of us have it figured out, we don't have it figured out to be quite honest. Nobody really has it figured out.

Annette Brandon: There's several industry experts out there that are actively working on it. There is a group, Synapse Energy, which is Tim Wolfe. He has contracted with the US Department of Energy to come up with some recommendations for benefit cost analysis, but that's more for distribution planning. There are some ideas that he has there. Pacific Northwest National Laboratories has some ideas that they're working on also. Lots of things that are being considered out there, but it's just very complicated and again it's going to take a village not just in getting participation, but in insuring that we have the right mix and at what point. Heather, on the line, that's helpful. Because at what point does it need to be comparable between the utilities? Or does it? That's some of the challenges that we're that we're facing in this arena.

Annette Brandon: I think that's my last slide. I think I'm running on time right.

James Gall: That's OK because you're next.

Annette Brandon: OK, well, so they go to break here?

Jams Gall: No break here. We'll break after this presentation, but if you need a drink of water, that's OK.

Customer Benefit Indicators, Annette Brandon

Annette Brandon: OK, next slide. That leads me into how we are going to measure how we're doing. On this process and performance metrics, I am going to call them process and performance metrics because I think it makes more sense than Customer Benefit Indicator. But you know that hasn't been better yet either. Maybe we'll still use the terminology, but for me process and performance metrics helps me to distinguish between leading and lagging indicators. A leading indicator might be – have we intentionally solicited input by a number of times that we've gone out and asked, number of ways that we've gone out and asked, number of translations, do I know what the barriers are? Have I taken that step? Have I measured where those areas are?

Annette Brandon: Some of these leading indicators are going to be very difficult in the IRP process because when you're planning 20 years out into the future, I don't know how you're going to know how many times you go out and solicit input. Now, that's not to say that there's not a way. There's just not a way that I could think of or not a way that I could find in any research that I've done in the process portion. Proactively anticipating how your project's going to produce the results. The results anticipated was the word there. Anticipated results and then are alternatives that you need to know if there's inequities. Do I know that there's inequities? Does one area of town have more reliable energy than another? We have defined that on a map and I've got a slide on that, a few down, but we have defined all that and we have some individuals who've done outstanding work in helping us identify why those areas exist.

Annette Brandon: But one of the main things in these metrics is, am I making data driven decisions? What we want to do is attempt to take out subjectivity. We want to make sure that one person that's operating this in one area of the company versus another area of the company, we want to ensure that we all are working from the same playbook and that we're all reaching customers in the manner that means the most to them and in the areas that mean the most to them. And honestly, that's whether it's Washington or Idaho. We really want to reach those customers who previously we have not met their needs and that's a benefit regardless of what state you're in. And is it something that we can predict the change or can we trend it? And then once we've done that, how do we know how we did and how can we measure that? And are there patterns, that goes back to is it not a tracking metric or is it performance tracking?

Annette Brandon: This next area is who and where we're focusing our efforts. When I just talked about those maps, really a key factor will be the development of this portion of the map. This is not something that Avista can do on its own. We need help from a very broad, diverse group of people. We of course have the help of our Equity Advisory Group and that is very instrumental in us ensuring that we understand what our vulnerable populations are.

Annette Brandon: But let's see if I can be more organized on this slide. The focus is really the terminology: Highly Impacted Community, Vulnerable Population, Disadvantaged Population, Highly Impacted Communities. I pulled this out of the actual designation definition in the WAC, community designated by the Department of Health, based on the cumulative impact analysis required by RCW 19.405.140, or community located in census tracts that are fully or partially in Indian land. That's highly impacted. Scripted for us here out of this stuff. Now, what we have done is taken that definition, applied it to the map and let's say done, I should say in the process of doing, is we should be able to click into one of those census tracts and know why it's considered highly impacted. Is it considered highly impacted because of environmental exposure or proximity to Superfund sites, for instance? Or, those kinds of issues, it should tell us why, and so that will be very instrumental in when you're trying to make a decision. If I know why they're considered highly impacted, then I might consider an alternative differently.

Annette Brandon: Vulnerable populations is a little more subjective. It is based on sensitivities, those are physiological impacts, that would be something physically that impacts your ability or makes your climate or environmental impact worse. So, if I have asthma and then pollution is going to make me feel even worse than it's going to make James feel, who doesn't have asthma, for instance. And then, those socioeconomic conditions also: housing, transportation, food, healthcare, access, language barriers. Those are also on the map. You should be able to go in there and see what are on those maps. Then, disadvantaged populations, that's a term from Justice 40. It is very small over there in the Justice 40 policy priorities. It was too much for me to put down all of what they used as the basis, so I just put down what their priorities are, but they're very similar. They cross over into the same characteristics as vulnerable, but I did put an example of a census tract, when you open it up it will say OK, this is disadvantaged. These are the reasons why energy, health, housing, legacy pollution, and then if you scroll down, which the box right now is on our mapping, we're working on making it bigger so that you can easily scroll down. It has each of those, not mapped, but in a column chart. So you can see legacy pollution is the reason. So then as you're evaluating your process or your capital plan or whatever your project is. You can say OK, so if pollution is the primary driver, is my project going to impact that? Yes or no.

Annette Brandon: Again, we don't have this figured out, but we know that this is how we're going to at least define it and we're working towards other things not just defined by Department of Energy or defined by the Department of Health. Are there other things that are unique to Avista’s service territory? Likely there are some. There are some areas of town that that we know about that don't make sense to other people. So, when we say Peaceful Valley, we know what that means, but a lot of other, I don't want to use the term stakeholder anymore, interested parties won't intuitively understand what that means. So, we need to make sure that we're being very clear and understandable when we're describing things both internally and externally. And again, this process is giving us the opportunity to challenge our assumptions and challenge our shorthand, if you will, to make sure that anyone can pick up our planning guide and know what Peaceful Valley means, where it is and what the circumstances are in that area of town.

Annette Brandon: All right, let's try everything else. Back to data. This is where you really want to remove the subjectivity. This list that I pulled was actually from a list that was provided by Washington Staff in Puget Sound’s Clean Energy Implementation Plan. I liked it because I thought that it gave us some considerations of things that we should look at when we're considering Customer Benefit Indicators or process performance metrics. It is directly related to policy goals in the public interest policy goals in this context, was the Clean Energy Implementation Plan. Here in this context, what we would use for the integrated resource plan. Is it related to clean energy? Yes, but also all of the other operational parameters that are required in the WAC for integrated resource planning which is resource adequacy. Resiliency, if those are the same, I don't know. I'm not going to try to pretend like I'm an IRP expert, but there's pages of requirements on the IRP. Is the data readily available? Is it focused on an equitable outcome? Is it clearly defined, articulated, understandable? That's the same thing I was saying on the previous slide on does everyone know what it means? We can't just say Peaceful Valley. Does it allow for comparison or trending?

Annette Brandon: The other reason why we're here today is because correlating all of these factors with the utilities actions and are we able to forecast that is the challenge. That is the challenge because we can say we understand that energy burden, both sides of an energy burden, is your income and your expenses well. As a utility, we can sort of impact the cost. And when I say sort of, I mean we are regulated, and we do have requirements that we have to follow in the way that we do our rates. Now we're working collaboratively with the Commission, and the Commission is working towards their recognition of justice to make our restorative justice. To make sure that all of the utilities in Washington State, that we're considering how we might address policies like performance-based rate making. That's just one example of ways that the Commission is considering equity and how they may make changes to regulation, but that is so it is in our control but not really in our control. But then you might say, well, OK, the other side is income and related to income is education. You might say education is outside of our sphere of control. But is it? Because this is where we have to be very open as a company, and as all of you on the phone, open to considering, even if we're not directly involved in that, we're not educators. Is there an index or indirect link and could we measure it? What I mean by this is there's several professions in our, many is a better word, I think in the utility industry. There's accountants and there's engineers and there's professionals, but there's lots of traits, lots and lots of trades, and trades are excellent jobs. As a matter of fact, in high demand and we need all those trades. Could we impact income by looking at that math and identifying the areas of town where there's low high school graduation rates, could we have education sessions in those areas that promoted trades? Maybe? Would it make a difference? At least we could track it. I don't know the answer, but the purpose here is that it's asking us to think outside the box to help, not solve. Equity is not something to be solved. Equity is something to be considered. Could we do that for instance?

Annette Brandon: And then also it's as we learned through the last CEIP, it also has to be something that can be accurately reported regularly. Is it updated? We found that we found some information on asthma that we thought would have been a great source and I know that this went on later and Tamara can speak to this probably later. But when I was involved in the CEIP, we thought about asthma, but the data that we could find was dated. That's an example of the data out there. But does it help?

Annette Brandon: These are the Customer Benefit Indicators that we landed on in the CEIP. Now I do have to check my notes on this one. OK, so these are what we landed on in the CEIP and honestly, we did a pretty good job because when you think about those energy tenets. Those four energy tenets, which now I'm going to call people, process performance, there's also some corresponding principles. The principles aren't as widely distributed as the tenets are, but a lot of those principles are in these areas: affordability, access, security, resiliency, environmental. They're calling it something slightly different in those, and I think there's eight of them. They're calling it slightly different, but in the end, you could probably roll them all up under these same areas, but in the CEIP this is where we focused. Under each of these individual equity areas, there are individual indicators, and underneath the indicators are multiple ways that we're measuring, and I don't know how many we’re up to. Do you know Dan? How many indicators?

Dan Blazquez: 38 indicators.

Annette Brandon: And then I can't remember, I think it's 38 indicators. I don't know. Anyway, our data people have been very, very busy making sure. It's not quite as simple as it seems on this slide. So, last year what we did was we went through every single one of these and all of the metrics to determine which ones could be used in resource planning and what we came up with is on the next slide.

Annette Brandon: OK, the ones that we came up with on this slide, so we thought we could consider energy burden. That's affordability and access to clean energy, distributed energy resources. That's community development and energy resilience, planning margin, energy resilience and security, generation location. That's resilience and security, air emissions, environment, public health, and greenhouse gas emissions. That's environmental. In total we came up with 11 of the 31 that we could model and use as predictive over the 20-year, but the Preferred Resource Strategy does not consider CBIs in the objective function. I'll let James explain that as soon as I get to the criteria. The criteria was categorized in accordance with those benefit areas that we just talked about and baselines were established, readily available, we could quantify and the metrics are granular enough to be meaningful.

James Gall: Yeah, I just wanted to touch quickly on what do we you know. What do we do with the CBIs in the IRP, and we do track them and there's going to be some slides later that are in the complementary slides that are the different CBIs that we're tracking, both history and forecast to the plan. But what we mean by not an objective function is when the model is running and deciding which resources to meet. These specific metrics are not, there's no goal to change them. We're just tracking them to see where they're at. We have other metrics such as non-energy impacts that will move the model to choose different resources that will actually impact the CBIs, but these are not actually goals of the model to meet, but some of these have constraints. For example, our modeling has to have a minimum planning margin, which is one of the energy security metrics. So, different criteria for each of these metrics. But one thing we do want to get out of today, is if there's metrics that you want to see in the IRP, whether or not they're one of the 31 CBIs that we've been publishing in our last the CEIP. Or if there's something new that you may have, please bring that up today or email us later as well. So that it will keep going unless there's questions. OK.

Annette Brandon: What's the next line? OK, so this is how we envision developing these metrics. Not only do we like to develop these metrics here with the IRP, but we're walking through this process right now with our Equity Advisory Group because what happened in our Clean Energy Implementation Plan on the first go round is that, as many of you are aware, it was a very quick turnaround. Because it was such a quick turnaround, we utilized a lot of existing data, existing data that was readily available and met all those criteria. But we wanted to make sure that we fully vetted all the other great ideas that the Equity Advisory Group had. So, we spent time after that, going through every condition, characteristic that they outlined, and walking through what does that mean. I use that Peaceful Valley example because that was one of the metrics that we left on our list for consideration. But then later we came back and said, well, what does that mean? Let's walk it through and say can it be mapped. Do we know what the root causes are in that area? Is it something that we can have a metric on? Does it apply to a resource? We asked all those questions as we walked through, but still it felt like it needed a reset. It needed a reset because we have new people on the EAG, we have potentially new resources that could be evaluated. We just wanted to make sure that we level set and talk a little bit more about some of the basics. We started with what exactly are the benefits from the energy system? Because that's what they just keep saying. That benefits the energy system. What does that even mean? What's a social benefit of the energy system and what's an economic benefit and what's in environmental impact or environmental benefit? Some of those seem fairly straightforward, but some of them are not so straightforward. And if we want to make sure that we truly are giving the customer what they need in the manner in which they need it, we need to understand what that is and equity is a comparative construct. You need to be able to compare one group versus another group to determine if there is in an inequity.

Annette Brandon: So first we have to decide what is the benefit before you even get to measuring any kind of inequity. What is the benefit? Well, the benefit is that I can go home, and I can turn on my lights, and I can do all my basic needs. I can meet all my basic needs. OK. That's a benefit. Now, does one area of town versus another, are they limited to be able to go home and turn on the lights, so the liability. Well, maybe let's measure that. Let's see if there are, the terms that get used a lot are disproportional impact or disparities. Those inequities, those words are used a lot. And on its face, it's a comparison of an impact of something. In our case, energy, generation, transmission distribution. Do the benefits of that, these benefits compare between groups? Is there a difference? That's really what it means. That's we're trying to measure and then do we understand first what the benefits are? Do we understand why there are disparities? Is it geographic proximity? Is it physical attributes or sensitivities or they're socioeconomic? It could be things like redlining. Redlining is a process, or a practice, in the 1970s where mortgages were given to a certain race versus others. And although the intent of that was not to discriminate the unintended consequences was that's exactly what was happening is discrimination and that still stays today, and you still see that in areas of town. And unfortunately, we have that on our map too, that are mapped so we'll be able to identify that and measure where they are. But in terms of why some of the historical context is just the evolution of the industry itself when it used to be that energy was luxury. You could get safe, reliable power if you lived in town, but if you lived out of town, well, that was a risk you took. But not anymore. Not now that it's so imperative that we all have energy for so many different reasons.

Annette Brandon: Once we understand all of that, we can start to make some decisions. The first thing that we have to do is we need to correlate it. What does that have to do with us? Does that have to do with us and Avista? That would be direct and indirect if that example earlier of education, but another example could be housing. We don't build houses but we could help houses get more efficient and could we measure that? We likely could even do something through change out of, well I'm just making that up, there's lots of other things that we could do to help the condition of that house through our weatherization efforts and those metrics we have, it folds into accountability. Finally, once we know what these metrics are, what the goal is, then how are we going to use those to make our decisions? Those would be used in all these different ways in our clean energy plans, in our capital investments, in this scenario, and in in our federal and state grants.

We want it to be consistent across our company so that customers and employees don't think, oh well that stops at the border, or oh well that's only electric customers not natural gas customers. We want to understand the benefits of the overall energy system today. We're talking about just electric, but there's benefits of the natural gas system as well, so that shouldn't be forgotten either.

Annette Brandon: Next. These are just some of the examples of what these are. For me, energy is the actual physical delivery of the power. But social metrics might be is my process inclusive and accessible? Economic might be job creation, economic growth. Reliable supply and affordability and environmental might be public health. Indoor/outdoor air quality and sustainable. Sustainability might come in when you think about the fact that we're upgrading our resource or we're changing out a resource because we want to ensure that resource lasts a long time. Our dams are so important to us, and we need to make sure that they continue to be there for us. They're not only a clean resource, but they're great for reliability and for reserves and for a lot of other operational reasons. So, a focus on sustainability in that aspect is really important. Again, a lot of these things, the issue is what do we do about those factors that we cannot measure, but we know are important.

Annette Brandon: Next slide. Some of these barriers that we could consider, that again maybe correlate or maybe do not correlate, but unemployment or underemployment. Well, maybe we can correlate that with the number of job fairs. But long-term planning that doesn't apply. And once we get to resource deployment a lot of this is going to fit into resource deployment. As I said earlier, it's going to be part of an overall company strategy of working towards equity. So, awareness of programs we talked about that with barriers, housing conditions, income disparities. What else goes into income? There's lots of things besides just education, economic impacts. This was an example specific to the transition of clean energy. Are we considering the economic impacts on fossil fuel workers, for instance, we need to make sure we consider that if that is the consideration, access is kind of tricky word because it can mean physical access, or it can mean access to the process. So, we need to we need to make sure that the process is easily accessible for all customers. The flip side of that is it is not easily accessible for all customers due to financing or other accountability structures. A good example of that is transport electrification and that got brought up in a meeting last week. We can put fast chargers in certain neighborhoods, but what do we do about helping or should we help those individuals to have access to that clean technology? Is it geographically accessible? What about people that are renters that see the need, that understand it, but unfortunately, they don't see either the financial benefit or they're just flat out not allowed. And then some mobile homes just are not able to use technologies, that's your physical access.

Annette Brandon: And then reliability, you've got aging infrastructure, limited investment, grid updates, lack of redundancy and supply, reliability. I think after the events of the cold snap a few weeks ago, that lack of redundancy of supply. That could be something that we want to consider, that we need reliable supply, reliable diversity and supply. I think that's my last slide.

Annette Brandon: Oh no, not at all actually. So alright, so this is now. Diving a little deeper into the metrics themselves. The ones that are in green are the ones that we've been talking about. Clean energy was inferred because it was a Clean Energy Implementation Plan. If we're going to look at something that is consistent across the company, then we need to have a focus on clean and sustainable, and we should have some metric on meaningful participation. Currently, I really like the word sustainable because I just used it again, so we should also make sure that we have a metric on safety. Let's see what I'm missing. And, transparent like due process, really meaningful participation. We have it. There are areas that we have considered and areas that we should consider. The challenge is how? If we have performance measures, how are we going to measure? Are the metrics working as intended? Some of these questions stem from results-based accountability and our equity advisory consultant is certified in results-based accountability. I've seen a few places where that's being used in correlation with equity. I think that might be another method that we could use to develop some metrics, but I'm not sure that's applicable in this session.

Annette Brandon: The reason why we're doing this right now also, so the timing of this is good, is earlier when I was saying that we rushed the CEIP. Also, the limiting factor with that is that our Clean Energy Action Plan had already been developed. You can't go back and remake the, can't go back and recreate. This time we want to make sure that these metrics, whatever we decide, help to inform on a proactive basis. And then as it helps to inform our Clean Energy Action Plan, then as we get into the development of the Clean Energy Implementation Plan, that's where they'll have metrics that extend that across the clean energy as well as capital planning and integrated and grant work. That process will continue, it won't just stop, it's an ongoing process, but that's where the timing of this is right now, because James and his team are working on that right now. That's why these questions are coming up right now. There have been ideas that is there a way that you can take these metrics and do a point system. Some kind of a point system where you make everything a point whether it's quantified or qualified, make it a point. Because then you can pull it all into the same apples and apples, and then you can score it accordingly. That's an idea. How do you do that? How do you how do you prioritize that? That would be a lengthy conversation. Not saying that we couldn't have it at some point, but that would be a lengthy conversation. Also, as I referenced Tim Wolfe earlier, he has a least cost, best fit analysis, and so he has ideas. If it's mandatory and compliance, you would evaluate it one way versus if it had a little bit more optionality to it, you would evaluate it a different way. But again, I don't know if that is related to IRP planning. I think that is related to after if the model chooses a new wind farm, then it seems like you would use that in that area. That's where you would evaluate it. And again, if the goal is equity and everything you do and to ensure that we have an equitable overall process, it doesn't have to be only in this one piece as long as overall the goal at the end of the day or that we reach, we work towards meeting the goal at the end of the day that customers have equal opportunity to receive equitable outcome from our decisions and from our practices and policies.

Annette Brandon: What else did I print out here? There's lots of ideas in distribution planning, but a lot of it is about non-wire alternatives or grid mod. The US Department of Energy Modern Distribution Grid Strategy and Implementation Guidebook that was published in 2020. That gives some ideas as to how you might do that on a distribution level. They use things like target population identification, investment decision making, which includes program accessibility, energy cost index, energy burden, late payment index, appliance performance. Some of those they use also have some equity in investment decision making program funding, energy use, energy quality, energy quality which would mean like those are your measurements: SAIFI, SAIDI and CAIDI) those measurements, program impact assessment would be not necessarily affordability but it's program acceptance rate or energy savings or energy cost. Energy cost savings relates to energy burden which then relates to affordability but it's the catalyst side of the fact that a lot of the time we are impacting rates because we're building new resources or identifying new resources potentially in this process. So, the key is to do so, being good stewards of our resources and recognizing that this is going to have an impact and doing our best on that impact.

Annette Brandon: Let me see what else I have on this. I wish that there was some kind of energy standard that we could all follow, but there's not really. There's just a lot of focus on availability, affordability, due process, energy burden. We’re all really familiar with. That's the percent of household income. But I think do you have that? Second we can do some little bit of brainstorming sessions.

James Gall: Sure, we have some time.

Annette Brandon: Sure. That sounds good. I think I'll stop my brainstorming then. And then the rest of these slides are just supplemental. They are the metrics we're tracking.

James Gall: Since we have a little bit of time before a break, I'm going to go through quickly some of the metrics that we included in the last IRP. Maybe it'll give you some ideas on is this something that we should continue to use in the IRP? Is there something we're missing or should add? I'll quickly go through those and please raise your hand if you have any ideas or questions even on the metrics that we're tracking. I’ll try to give you a brief overview of how it's used and calculated.

James Gall: Annette mentioned energy burden in the IRP. We are trying to identify the number of customers that have energy burden with this. This is percentage of income versus the cost of their energy. This is, I would argue, a very high-level estimate. But the idea behind this metric is to ensure that we're not creating adverse cost to our customers that have the lowest ability to pay. Like we mentioned earlier, we're not targeting our modeling to ensure this this specific CBI goes down, but we're monitoring it now. Could you create a plan that requires us to reduce? Yes. And we'll get into that a little bit later today. This is just something we are tracking. So, this one, number of customers, it's around 45,000, it's very flat or around our low growth expectation. Another way to look at it is percentage of customers, around 20% of our customers have a high energy burden. They're above 6% of their income and that's expected to remain flat in this last IRP. What does that cost of excess burden measure? This is measuring the actual dollars that is above that 6% of their income. That's around $1,000 initially, and this is actually an area where we're seeing customers with lower incomes have a higher energy burden. CETA law, the Clean Energy Transformation Act is not likely to lower costs of electricity. It's going to increase cost to electricity. This kind of shows that impact to customers at lower incomes were they'll have a lesser ability to pay now with energy burden resource selections. Not the only way to address energy burden, which is one of the reasons why this is something we don't necessarily target in an IRP because there are other mechanisms to help these customers through energy assistance, rather than just resource selection.

James Gall: Another one that we're tracking is megawatt hours of distributed energy resources in in communities. Part of the CBIs was to increase distributed generation resources or storage resources in the Named Communities. We did have some new distributed energy resources selected through our Named Community Fund which contributed towards an increase. You can see the history and the forecast in this slide, history shows the real weather impacts of distributed energy resources. Production does change over time and the forecast is more of an average energy or expectation of normal weather going forward.

Kelly Dengel: A hand is raised.

James Gall: OK, go ahead Heather.

Heather Moline, (UTC): Thanks, Heather from Utilities and Transportation Commission staff, this includes energy efficiency savings.

James Gall: I don't believe so in this this case. We have a different metric for that one, but this one is just generation. I think energy efficiency would be higher if I remember right, generation and storage.

Heather Moline (UTC): This would be generation and storage. OK. That makes more sense. Is demand response included here or just generation and storage?

James Gall: I think this is just generation because demand response will be very few megawatt hours, you wouldn't notice it, and it would be available to all customers.

Heather Moline (UTC): OK.

James Gall: I think those are different metrics that we're tracking. And then, energy efficiency, I believe that's separate as well, but we could check that.

Heather Moline (UTC): And so DER's, this generation that's connected to the distribution system, so like rooftop for community solar and what else I guess is in this category is my question.

James Gall: Yeah, so this is mostly actually PURPA generation. This would not include customer owned generation. This is utility owned or utility purchased. We have a number of small hydro facilities in our service territory. That's what most of this generation actually probably is, PURPAs. PURPA would count anything that's under 5 megawatts.

Heather Moline (UTC): OK.

James Gall: Storage, for example, doesn't generate energy, it just moves energy. Actually, storage would probably reduce these amounts, so maybe it's not a good resource to put in here because it's a load. It's not a generator.

Heather Moline (UTC): OK, I'm chewing on how a PURPA hydro facility would necessarily bring a benefit to a community where it's located. I'm not saying it wouldn't. I'm just chewing on that.

James Gall: Yeah, that's OK. I could give you ideas if you want, but this was, again, in our CEIP process. This is one of the items that came up that we were asked to track. And if this isn't relevant anymore or should be changed, I think this is a good time to talk about that.

Heather Moline (UTC): Yeah, I would love to get your ideas, I think when people bring up DERs in Named Communities they mean because of the definition of CETA and because of the clean energy transformation standards which say equitable distribution of energy and nonenergy benefits to Named Communities. The intent here from that law is how are we distributing benefits and non-energy benefits equitably and so if you all are clear, that a hydro PURPA facility is bringing some benefit to the communities where it's located, even if it's owned by Avista or even if it isn't right? Then great. Let's talk about it. But I do wonder if this is what folks had in mind when they asked you to track this condition.

James Gall: Yeah, you're right. Definitions matter.

John Lyons: I thought this was also more for having a clean, local, reliable resource. We had an area that was a disadvantaged community, and they traditionally had some problems with outages by having a resource located in that community that should help with that.

Heather Moline (UTC): That makes more sense, which is different from. Well, it's not the same thing as equitably distributing benefits, non-energy benefits. This is just a hypothetical question. Oh, and I guess Sofya and Josh went away, but just before I jump in a hydro facility that's five megawatts or less located in a Named Community. The way the grid works, if there was an outage there, would it necessarily mean that outage would be restored quickly just because there's a PURPA hydro facility nearby?

James Gall: Well, I would argue an outage is going to take the, it's not going to prove it's more of a preventive of an outage if there is a load that can serve it. I wouldn't argue that this will prevent an outage. It may be more prevention in certain circumstances, but if you had a line go out from the generator to the customer, that's not going to prevent an outage. It's very situational, but I think this really was driven by economic benefits to the community. You have increased tax base, you have potential for jobs. So, their reliability helps, but you may have lower cost to the area because you have generation near a load that you don't have to upgrade distribution equipment as soon as you would otherwise. But reliability I think is very situational. Whereas if your system was overloading, but you have a generator there, that prevents an overload that would prevent an outage. I don't think these resources would sustain a customer through an outage unless the generator is at the customer's premise or directly connected, it's not going to prevent an outage. It's not going to serve a customer during an outage unless it's directly connected. OK, so we have two more hands up. Sofya, go ahead.

Sofya Atitsogbe (UTC): Hi, James, this is Sofya Atitsogbe with the Utilities, Transportation Commission as well. My first question was the same question Heather just asked about the resilience and the reliability enhancement that the DRs would bring to the Named Communities. I'm kind of surprised by your answer, because everything we see about the benefits of the DER and the economic reasons or the economic benefits older although exist are not as great as the reliability and resilience reasons for the DERs, so it's interesting that you are mentioning that they are actually secondary to the economic reasons.

James Gall: OK.

Sofya Atitsogbe (UTC): That's just a note that I would need to research further. And the second question, if that's the economic reasons that drive the DER, that's probably not that important. But if we go from the, I would say federal understanding that cause I'm hearing it from all the commissions including ours. Storage of energy is pivotal for the Named Communities that get a power disruption and although it's consumption, when the battery gets loaded, it is well, I considered generation when the battery gets discharged. My question is, doesn't it make sense to include the battery that would be able to serve as an energy source for the community that gets an outage into this DERs and Named Communities graph?

James Gall: Yeah, as far as a Named Community grant side, yes. But I actually was just saying a literal MW hour accounting of a storage resource, the amount of charging is going to exceed the generation. If you netted the two, it would be a reduction in generation, not an increase unless you ignored the charging cost. The way we dealt with storage, we had a separate category and that's on this next slide which shows the amount of MW hours that is available for charging. This is a better way to characterize energy storage and separate it out from this calculation here, which is why we did that because we didn't want to basically put a resource in there that's really a load and show that benefit. So, it is separated here. Again, this one is just intended to be how much energy we are acquiring. Storage we separate out, that makes it, I think, a little clearer.

Sofya Atitsogbe (UTC): Got it. Yeah. Thank you, James. Can I ask you to, when you go to the next slide, to also touch on if this battery storage will help Named Communities in resilience and reliability, but I'll wait until you get to that slide.

James Gall: We'll do that.

Sofya Atitsogbe (UTC): Thank you.

James Gall: OK, no problem. Go ahead, Josh.

Joshua Dennis (UTC): Joshua Dennis from Utilities and Transportation Commission. Also, I was going to talk about the battery situation, but I think Sofya touched on it. But I guess more so I would like to expand on that a little bit. I know that Avista has their virtual power plant at 3rd and Hatch with two named communities in that pilot and I was wondering if that in particular is going to be considered a load or generation because of some of the things that I was reading in the DOE application on what Avista was considering load and generation.

James Gall: Yeah. Just from a practical point on a battery is both a load when you're charging it and its generation when you're discharging it. Its generation is going to be less than you're charging as far as a battery that's owned by Avista and controlled by Avista. The load side is not charged to the customer. If a customer puts a battery in their house, they're going to have an increased bill because of charging that battery. Unless they have say time of use rates that they arbitrage but just need to be aware of what you're getting with a battery is you're being able to move power from one period to another at a cost of energy to do that. I don't know if anybody on the call from Avista that may have some information on how that program works at 3rd and Hatch to help with Josh's question. Otherwise, I'll be speculative on how that program works. I'm not hearing anybody from Avista jump in. We may have to get back to you, Josh, on that.

Joshua Dennis (UTC): Oh, for sure. Just one more considering grid modernization. And I know that a large focus has been on reliability, but could you touch on any metrics that intersect with the resiliency that's going on with the focus on energy justice for these Named and Highly Impacted communities?

Annette Brandon: There's a lot of information out there on resiliency, but of course no solutions. What tends to happen, and this would be evaluated in the DPAG, they start with a consideration for all of your operational parameters and then resiliency is added on top of that. That's where your difference between your least cost and what they are calling least cost best fit and I want to dig in my paperwork right now, but it's where two different scenarios are then added together to come up with the scoring. That's really what I've been following and trying to keep track of what's going on there with the national laboratories. It was put out from Berkeley. Wait, I have it exactly, here is the benefits and costs of grid modernization benefits that was put out in 2021 Benefit Cost Analysis for Utilities Facing Grid Modernization Investments, Trends, Challenges and Considerations. I've been looking at that, but so far, they haven't come up with any kind of solutions. I guess the answer to your question is I'm not sure yet. But I would imagine that would be looked at in our DPAG.

Joshua Dennis (UTC): Thank you so much.

James Gall: Alright, I'm going to touch on Sofya's question here on reliability when it comes to storage. Now there's what can happen and what is more of reality to some extent. If you think about a distribution system of a neighborhood and there's a storm that goes through, unless that battery is connected to that home directly and is isolated. When an outage goes through, it's not going to protect from reliability. Now, in a separate event, like if you had another heat dome event where there was a battery on a distribution system that could relieve loading on the line and prevent an outage from an overload, a battery can help with reliability in that situation. Just because we have additional energy storage in a Named Community doesn't necessarily mean it's going to prevent outages. It's going to prevent maybe extra cost to our system, or it could prevent an outage in a specific situation. Unless that customer has the battery and the ability to disconnect from the grid and use that storage, it is not going to prevent an outage for that customer. I think we just got to make it very clear on what you're getting with storage. Now if we created islanded off communities, then that would be a different situation. But hopefully that helps as we go through this.

John Lyons: A good example you'd see on that, success stories, where it'd be either a hospital or a university where they totally disconnect from the system, and they have their own battery storage system. That way they disconnect, they supply their own load, and then they usually have some other supplemental generation to refill the battery, a solar panel, something like that.

James Gall: Josh, go ahead.

Joshua Dennis (UTC): So, when you said disconnect, it reminded me, and I wanted to check on the progress so far with the microgrid project that the Spokane Tribe of Indians and Avista are working on because it sounds like it is something that directly is what you're talking about.

James Gall: Yeah, that is an example. I don't know if anybody from Avista on the call that can let everybody know what that project is. I know enough to be dangerous, but I'm not an expert. No one.

Tamara Bradley: I don't think we have Megan on the call, James, and she would be our SME [subject matter expert].

James Gall: I'll give a brief concept of that for those of you on the call. The Tribe was looking at trying to create a microgrid project and Avista was contributing dollars for designing the microgrid. What it would do is there are a number of buildings in the town there that would move to a backup generation source if there was a long-term outage. I don't know exactly what their planned technology is at this time, but that is the concept where it's a number of buildings would be able to sustain the outage, but it would be limited load. It's not as normal, but it's critical loads that are able to continue on and then I believe they had a desire to be able to stay online for those critical loads for up to a week. Again, it's in the design phase last I heard.

Annette Brandon: Can I comment more on the, can you go back one with the one slide? I want to comment on this slide a little bit. It took me a minute. I had to go back and reference what we had done in the CEIP. I think the reason why we're talking about this being the PURPAs and under 5 megawatts is because the condition and the associated CBI was under our Named Community Investment. Our Named Community Investment metric, that CBI. So that's why it was focused not on the economic benefit, but particularly on the megawatt hours. Actual investments were the total megawatt hours of DERs, five megawatts and under, and total megawatt hours of storage resources which he has on the next one. But I think that's probably why, because the purpose for this one wasn't to measure economic development. It was to measure just under 5 megawatts, which is consistent with the PURPA definition, and I'm reaching back, but I believe that's why we're tracking it this way.

James Gall: And I am starting to remember that I think customer owned solar may be included in here because I remember Kim was trying to identify those. So, there's a good chance that is in this in this calculation as well.

James Gall: All right. We got about 10 minutes before break. I want to kind of run through the rest of these. This is a good discussion and it's important to have, so let's continue as it comes up. Another metric we were asked to track through the CEIP process is to account for benefits that are either non-energy impacts or utility benefits compared to initial investment. This is a little bit of a loaded chart, but the concept is when we do our modeling, we have a benefit, which I would call a revenue or a benefit, whether it's an NEI or utility benefit. We are graphing the annual benefits of those resources. If for example, our model picked a community solar facility, there would be an energy benefit that would be shown in the orange and then there would be a non-energy impact benefit or cost that is shown in green. I believe the costs aren't shown in this case. We were asked to only show the benefits and those are the annual benefits of the resources that are selected for Named Communities. That's compared to an annual investment that is shown over time. To me this was, when you have people coming up with ideas, does this idea come across with the intent of the idea? I'm not sure, but this was what was asked of us. I don't know if this is something that we'll want to continue to do or we need to reshape or reimagine how this looks, but this is what was asked for us in the last CEIP. Definitely want feedback if you have it. If this works as is, that's good feedback. If we need to reimagine this, I'm up to that as well.

James Gall: Continuing on, since we have a limited amount of time, planning margin is the percentage of load, sorry the percentage of amount of generation that we have that's available during a peak hour compared to load. We have a history and a forecast. This is an area where our modeling actually has a minimum requirement of planning margins. And what you see in the past is what actually occurred. You're looking at how much generation was actually available against peak load and then the forecast is trying to forecast out based on normal weather conditions, how much generation is available compared to that expected peak load. Now as we go through time, you're going to see it move up and down like you saw in the last couple years. We also have new generation coming on over the next few years, which is why you see an increase from recent history. But again, this is an area where we actually do have a minimum requirement in our planning. We're going to be evaluating changing our minimum requirements in this IRP and they'll be some discussion of that in a future TAC meeting.

James Gall: Another thing that was asked of us in the last CEIP process is to look at generation that's connected to our system, or in the State of Washington. The reasons for this one is partly economic development. Partly you're increasing reliability and resilience because you're selecting resources that are on your system and not further away from your systems. There's the probability potential loss is greater when you look at projects further away from your system, that's at least the theory, but as you can see we’ve historically been around 80%. We expect that the increase as a percentage of our load when some new resources come online, but then after that our IRP expects a reduction of localized resources when we start looking at the same resources maybe that are in Montana or wind or systems that could be out of state. But in reality, an IRP versus when you actually go require the resources will likely come up with a different answer. It's interesting to track historically, but we can't necessarily predict if a resource that's 15 years from now is going to be in the State of Washington or connected to our system. We'll go through a request for proposal process where we'll evaluate alternatives, and we may select the one that's on our system in the state or we may not. So, this is very speculative in an IRP.

Clint Kalich: James, when you do your RFP valuation metrics, you have metrics to say bias for certain [too faint to hear] set this to occur, so it's not something that's lost in processing still and that can be affected by the metrics that's created when we do the …[trailed off].

James Gall: Correct.

Clint Kalich: If we have a need, we can increase the weighting of those types of things.

James Gall: Well, I don't know if everybody heard Clint, but he was mentioning. Quick mic check for everybody here because he is far away from the microphone.

Heather Moline (UTC): No.

Kelly Dengel: No.

James Gall: OK, I'll repeat what he said. Basically, in this instance, our request for proposal process when we evaluate resources will pick up this metric because we're going to include an incentive for the utility to want to acquire this resource, maybe over another resource. I'm going to actually touch on that in my last presentation of the day.

Lori Hermanson: The other question is about when the next IRP update is being released.

James Gall: OK, so the next IRP, we will have a draft out September 1st and we will file that with the Commissions in both states on January 2nd of 2025. So, it's coming up. Another one we track is Washington air emissions, and this is what our plants in the State of Washington are producing from an SO2, NOx and VOC perspective. We also have another one on greenhouse gas that's separate, but we've targeted just these three metrics from our last CEIP and this one I want to touch on. This is something we talked about. Are you planning for a specific outcome in this case? We include an economic penalty for these emissions so that our model can take the economic benefit or cost of these emissions and weigh that against other resources. Again, we have greenhouse gas forecast and the plan again, this is another thing just like the air emissions, we put an economic cost of these emissions and obviously CETA does require 100% clean energy by 2045. That's a goal or a target in the plan, regardless of what the metric is.

James Gall: We also tried to look at regional emissions in our plan. I would say this is a very difficult thing to do because we are not in control of transportation emissions. We also have customer level emissions we're not in control of. The only thing we can really account for is to look at history of where emissions are tracking in Eastern Washington. We could try to forecast how much our emissions are going to reduce. We can forecast maybe how much natural gas emissions are going to produce based on the plan. We can forecast how much EV load that we're including in our IRP, but that doesn't necessarily mean that emissions from the transportation sector are going to be falling. It depends on how much new cars are on the market. This is an area where it was a noble idea to model in an IRP. I don't know if this is something we want to continue doing in the next plan just because there's so many factors outside of our control, but I think it is important to at least track historically. But from an IRP perspective, can we forecast emissions? I think the answer is no. This might be one that maybe not be appropriate for an IRP in the future or maybe it is. But love to hear feedback on that since we are getting close to a break.

James Gall: That's the last slide I had. These are the metrics we're monitoring. We did have an idea to add a target on, I wouldn't say a target, at least a metric on how our resources are separated by fuel source. So, if we want a more diverse fuel supply, we've discussed creating a metric on that which would theoretically lead to increased resiliency. For example, I think it was in our last TAC meeting we talked about using a Herfindahl Index of our resource supply so that we could try to measure diversification of our resources. We also talked about potentially looking at a metric for wildfire resilience. We've done some more investigation on that, and I don't think that necessarily applies at least as a metric in our IRP, but that's something we can think about. But what I would like from the TAC here is if there are ideas that we’re not including, or there's items that we should probably think about changing or removing, let us know, We don't have to do that at this meeting here, but email would be appropriate afterward as well. But when we take a break, maybe that's the time to think about it if you want to. We'll just check in with the group when we return from break to see if there's any additional ideas. With that, let's take a break. We'll come back at 10:45, I think is what we had. OK. We're going to go on mute and then we'll be back at 10:45.

How Avista Includes Equity Principles, Tamara Bradley

James Gall: Welcome back. It's 10:45 before I turn it over to Tamara. I just wanted to check in if anybody had any additional thoughts on Customer Benefit Indicators during the break. I'll just let it pause for maybe a few seconds. Any ideas before I turn over to Tamara? OK, so if you do think of something, please put it in the chat or email me later. We're going to do a presentation on how Avista practices equity outcomes. Tamara Bradley is our, so we get your title right, but a Manager of Customer Impacts. Is that still what it is?

Tamara Bradley: Social impact. Close.

James Gall: I was close, alright.

Tamara Bradley: Close. Am I sharing slides, James or do you guys have my slides?

James Gall: It would be best if you did. You could do that.

Tamara Bradley: OK. One momento, please. Unfortunately, the slides that I have say draft across the top of them, but I think we'll be OK. Let me see if I can get there. Are you guys seeing them in the room?

James Gall: We do, but if you could make it bigger or full screen, that'd be better.

Tamara Bradley: I only have this version, I think. How about that? Is that a little better?

James Gall: That's better. Yeah.

Tamara Bradley: I can try once more. Oh, that's too big. OK, how about that?

James Gall: We can see it now.

Tamara Bradley: OK. Well, we will do our best. Thank you and welcome back from break. As James said, my name is Tamara Bradley. I'm the Manager of Social Impact here at Avista and I'm happy to give my friend, Annette Brandon a chance to catch her breath after all of that information. My colleagues are here today to actually share about some of the ways that at Avista, we are actually practicing equitable outcomes. I'll touch on a couple of our equity efforts and then we're going to dive into affordability and also the investments that Avista has already been placing into our Named Communities.

Tamara Bradley: So, with that, Annette had touched on the evolution of equity, but I have this light up here because I just want to point out that the energy industry is no different than any other industry and that we are really impacted by what's happening in the world around us. And so, for you historians out there, we are actually gearing up to celebrate our 135th birthday, and I won't make us sing happy birthday here. But we were founded in 1889 as Washington Water Power Company and back then, for many decades the emphasis was on safe and reliable energy. And then came the Great Depression, starting in 1929 that lasted till roughly 1939-1941 and then the focus was not only safe and reliable, but now we're going to add affordable energy into that. And then Fast forward to the 90s, one of the best decades, I'm just going to throw that out there. We start hearing about clean energy and the impacts to our environment, which really brings us to present time and the utilities building equity into our everyday practices, our deliverables and our outcomes.

Tamara Bradley: So, the first thing I wanted to highlight, and Annette mentioned the EAG and that is Avista's Equity Advisory Group. This group was actually established out of direction from CETA legislation, and it was formed all the way back in spring of 2021 and the members, I think Annette also pointed out they had actual significant impact on input on our 2021 Clean Energy Implementation Plan. That included definition of vulnerable customers in our service territory as well as the creation and prioritizing of our Customer Benefit Indicators. We continue to meet with the EAG monthly offering two different sessions. For three years we have met with this group on a monthly basis and when our plan was approved, our CEIP was approved June 16th, I think 2022. In that approval, Avista accepted 38 conditions that came along with the approval from the Commission. And of those 38 conditions, I think it's important to point out that 11 of those 38 had direct impact with the EAG, so that could have been where we needed their guidance, their support or their approval on those conditions.

Tamara Bradley: We filed the outcomes of those conditions in our biennial report, which was just recently filed in November 2023. The EAG is also significant because they have dollars to play with, so they provide direction on $500,000 of our named Communities Investment Fund and we're going to dive into that as well. And I like to explain that EAG either live, work, play or represent our Named Communities. These are not folks that speak utility talk. They are not a technical group. They really are our equity lens that we utilize to help Avista make decisions that affect our communities and the customers that we serve. We talk about a variety of topics. Could be anything from electric transportation to indoor/outdoor air quality.

Tamara Bradley: Our CBIs are the way that we are measuring. Over these next couple months, we're actually speaking to them about our current CBIs, but also looking at opportunities for new Customer Benefit Indicators for our 2025 CEIP. I have an audience, so I'm going to make a plug if you want to learn more about the EAG. If you're interested in attending, listening or becoming a member, I'm going to have my friend Annette throw my email into the chat and also Amanda, if you could put the CETA email address in there, that would be great. So, happy to talk with you offline if you would like to learn more about our Equity Advisory Group.

Tamara Bradley: I did want to point out, sorry, managing a couple different screens here that we do have additional advisory groups here at Avista besides the EAG. I'm just kind of biased towards that one, but we have the Energy Assistance Advisory Group, and this group is really an established forum that focuses on low-income energy assistance efforts. They monitor and explore ways to improve Avista's low-income rate assistance program, which is referred to as LIRAP.

Tamara Bradley: And in fact, the Washington low-income program just went through a major overhaul and Kelsey Solberg will speak to that after me and talk about the ways that equity is represented in that program. We have the Energy Efficiency Advisory Group, which is made up of stakeholders that advise Avista on conservation programs. And again, look for ways that we may modify or measure those programs differently or develop new programs. And then the DPAG, the Distribution Planning Advisory Group is our newest established in 2022. It is a technical group, and its purpose is to examine distribution efforts and non-wire alternatives for our major transmission and distribution investments. We also have the natural gas IRP, I think that was mentioned, and one that doesn't get talked about too often is an electric vehicle supply equipment stakeholder group. I just wanted to plug all of those and you can learn about all of our advisory groups at www.myavista.com/CETA and we will put that in the chat as well.

Tamara Bradley: Annette touched on public participation and equity as about really actively seeking out and empowering our customers and communities through meaningful, and I know she really stressed that word, meaningful participation. Equal opportunity and fair access to our energy services. So, removing barriers is key, especially for our customers that have faced many barriers to participation and not been able to participate in the past. We recognize that at Avista we are not experts at determining all of the barriers that our Washington customers face. So, in Q3 of 2022, we contracted with someone who is an expert and that is Public Participation Partners, referred to as P3, to examine which barriers our customers do face in our service territory, which was one purpose, but even more to help us build a mitigation plan on how to reduce those barriers to participation.

Tamara Bradley: In May of 2023, so many dates – so many reports, Avista filed our public participation report with the Commission. This public participation report is tied to CETA, but it is a separate report and this outlines our actions that we intend to implement to reduce the barriers that our customers face. I'm pleased to say that since May of 2023, we have actually implemented several of those action items and we will continue to carry out our plan throughout 2024 and 2025. We don't have time to go into the details of all the actions that are listed, but I wanted to point out our language strategy and our roadmap around language because that is a barrier that tends to rise to the top for Avista customers. We are in the process of developing our multi language road map and this is in order to provide really adequate assistance, information and accessibility to our non-English speaking customers. And we do this by evaluating our customer facing channels. This includes our website, our mobile app, our IVR which is our phone system and other areas of the company. That effort is underway. Again, it is a road map that will take some time to achieve all of it, but I think it's important to highlight.

Tamara Bradley: Other topics to touch on includes capital planning, federal and state grants, and supplier and employee diversity. Avista is developing and implementing equity as a requirement in our capital planning process. We're looking at how our large capital projects are being implemented and affecting the customers for that location and even more so giving the customers a voice to that project. I think Annette had also mentioned that. We know with this administration that there is a lot of federal money out there. There's a lot of state dollars out there and so Avista has established a key internal stakeholder group that is looking at securing funding that reduces the barriers and burdens that our customers face. This could be going after funding that increases access to clean energy, ensuring broadband to some of our most rural communities. As you know, Avista has a large service territory. Or even providing workforce training and energy related fields to those that may not have access otherwise.

Tamara Bradley: I'm going to the supplier and employee diversity aspect which, actually both of those are Customer Benefit Indicators in our CEIP. This is really important because Avista wants to represent through our suppliers and work force the communities in which we in which we serve. We know that diversity strengthens partnerships, it fosters innovation and competition. It enhances customer loyalty, and it contributes to the overall economic growth and development of our communities. Again, those are just highlights.

Tamara Bradley: The next slide is our CBI slide, which Annette also showed. It's important and you're going to see this from Kelsey as well in just a minute. But the reason why I have this slide up here is because regardless of what topics we're talking about with our Equity Advisory Group, we also hold quarterly public participation meetings. Our next one's going to be in March of 2024. Everything really ties back to our Customer Benefit Indicators. I touched a little bit on unemployed diversity and supplier diversity, but that first equitable area there, affordability, is so key to our customers. As we survey our customers, it's the one that always rises to the top and like I mentioned, our program just went through a major overall. I'm going to pass it to Kelsey Solberg. Who is our program manager of our low-income assistance programs to talk about that program in more depth. Kelsey, I'll give it to you, and you let me know as you want me to go through the slides.

Kelsey Solberg: OK, sounds good. Thanks, Tamara. Good morning everyone. As Tamara mentioned, I oversee our low-income energy assistance programs and we'll be talking today about how those programs help to increase customer affordability and also promote equity. We can Scroll down there. This will look familiar, I just wanted to highlight that the affordability CBI includes everything listed there. We have participation in our company programs addressing households with high energy burden. We did hear a little bit about energy burden from Annette earlier, but we'll touch on that, and then residential arrears and disconnects. Arrears are past due balances for our customers. These are all indicators that we really addressed through our bill assistance programs and then and that's what we'll be talking about here. We can scroll there.

Kelsey Solberg: Thank you. So what is Bill assistance? Bill assistance really focuses on increasing informed affordability and it uses energy burden as the metric for affordability. That's how we're measuring it. Energy burden, this was mentioned before, but it's pretty simple to calculate. This is just the percentage of monthly income that is going towards a household’s energy cost. What percent are they spending on energy of their overall income. Industry wide, we look at high energy burden as being 6% or greater than 6% and a severe energy burden being 10% and up. And so most forms of Bill assistance, including ours here at Avista are aimed at reducing that 2 below that 6% threshold. So that's increasing affordability is sort of the result of that.

Kelsey Solberg: If we Scroll down there for me. Thank you. These are the different ways that we aim to reduce energy burden. All of our programs fall into each of these categories. We have the affordability increase. We also seek to address past due balances for our customers, so helping them get back to a zero balance. We provide a lot of support during hardship, so we recognize that life happens. And we want to be able to meet customers where they're at and provide them with support. We also do education around energy conservation, using tools and resources, providing those to our customers so that they can actually reduce their usage of energy, therefore making it more affordable.

Kelsey Solberg: The next slide shows more of how we do it. This is a kind of at a glance overview of the programs that we offer at Avista that fall under that LIRAP umbrella or low-income rate assistance program. These all seek to reduce energy burden. You'll see the categories there on the left. We have affordability, past due, hardship, and energy conservation. Those are the ones that we just looked at and each of these has a program that's associated with it. But for the purposes of this, I'm really going to be focusing on those top two, so affordability and past due. This is really because one, these are most closely related to CETA, which we've been talking about today and they also have features that not only support affordability, but they also have a lot of equity design components that we will touch on as well. That's where we'll be focusing.

Kelsey Solberg: In terms of increasing affordability, this is one of the programs that really marks what Tamara mentioned as being kind of this overall overhaul or major change that happened just this last October in Washington. The new program that we launched is called My Energy Discount and in in many ways, like I mentioned, it really did change the landscape of the list for Avista. With this program, customers who are income qualified can receive a monthly discount on their Avista bill and not a discount based on their income. And these discount percentages are designed specifically to reduce that customer's energy burden to below 6%. Again, we're really aiming at reducing that energy burden for folks. And this is one of the ways that we're doing that. Another thing that's notable about this program is that there is no paperwork required, and so customers don't actually have to provide proof of income. They simply attest to their income and their household size, and we use that information to determine their discount percentage. It's a very low barrier in terms of accessing the program. Something else that makes this easier for customers is that we now are joint administrators of the program. Previously, customers could access energy assistance through their local community action agency, and that would involve making an appointment, getting to the appointment, perhaps they need childcare, or perhaps they need to translate. Or perhaps they need to pay for transportation. They would need to bring their paperwork and go through that process in order to get energy assistance. But now, as of October, Avista is a joint administrator so customers can actually come to Avista. They can call us, they can apply online, or they can file a paper application, and they can of course still go to their community action agency. But we're really just opening three additional doors to accessing these benefits that were not there before.

Kelsey Solberg: Customers who enroll in the program also remain eligible for other energy assistance programs. There are federal programs that are available. A lot of our action agencies have access to other grants or donation-based programs that they can support customers with, and so just because the customer receives this benefit does not mean that they become ineligible. It's just another item on their menu of supports. We auto enrolled 18,000 customers in October of 2023. These are customers who within the last two years had received income qualifying assistance. This was a way for us to increase accessibility to the program and recognizing that these are customers who have received energy assistance before, they're likely still eligible. And so, we're going to simply enroll them based on the income information that we have. And finally, we do have a verification process in place for this program and through this we will be selecting 6% of the customers who enroll in the program to be randomly selected for income verification. These folks would go through the process of going to their community action agency, verifying their income. And this is just a measure in place for us to really maintain the integrity of the program and sort of monitor how effective the income attestation or the self-attestation of income is going.

Kelsey Solberg: Thanks Tamara. Past due balances are the other piece of this puzzle that we're trying to address. I shared this to give you all a sense of the landscape of past due balances in Washington. These numbers are as of the end of December, but we have just over 29,000 customers who have past due balances. All of those together, totaling $6.3 million and the average past due balance is $216. So, this is clearly something that we are wanting to address and support our customers in getting on top of these past due balances. If we go to the next slide.

Kelsey Solberg: This really demonstrates the need, and this is how we are meeting that need or how we're addressing it. We have two different programs that fall under the umbrella of arrearage assistance. Again, arrearage being of a word for past due balance, and these programs are designed to meet customers in two different situations. We have our arrearage forgiveness program and this is for our customers with the greatest need. To give you an example, in Spokane County, if we had a household of four, they would be needing to make less than $15,000 a year to qualify for the average forgiveness program. So, like I said, really for our customers with a great need. Those customers can have their balance actually forgiven up to a certain dollar amount. For other customers whose income is slightly higher, we offer what's called an arrearage management program. This is essentially a payment plan that our customers can enter into with Avista, where over the course of 12 months they will pay 10% of their past due balance and Avista will credit 90% and that's under the assumption that the customer is making regular on time payments and that they're also paying off their new or their current charges as well. This is really a great opportunity for a customer who maybe had a situation happen where they built up a past due balance, but now they're in a better spot, more consistent income, and they're ready to address that in partnership with us. Those are the two programs that we have that are administered in partnership with our community action agencies.

Kelsey Solberg: This is a quick, very high-level view. We have a lot of data within each of these bullets around our active participants. The discount percentage they're receiving. The counties? They're in in the service territory that we serve and a lot more, but really just to give you a sense of how many folks are active in our program. In the bill discount program, we have a little over 28,000 participants active as of now. The next slide will show and we won't jump there quite yet, but the next slide will show a little bit more about what that number means for us putting it in context. We have 662 participants active in our arrearage management program, so they're currently enrolled, they're working to pay down that balance over the course of that year. From the launch of this program in October, just in three months, we've provided 351 customers with arrearage forgiveness. So just chipping away at those past due balances and then if we go to that next slide there, Tamara. Like I mentioned, giving those numbers a little bit more context, this shows you the percentage of customers who are receiving assistance out of those that are eligible.

Kelsey Solberg: This is our saturation rate for our LIRAP programs here. You'll see we have just under 130,000 customers in Washington that are estimated to be eligible. Their income is estimated to qualify them for these programs and right now within three months of the program we have 24% of those customers enrolled. And just to give you a sense of comparing that to past years pre COVID, so 2017 to 2019 over the course of three years, that average was about 15%. Just to show that this percentage or saturation rate has increased significantly and in line with CETA we're pursuing a 60% saturation rate by 2030 and then a 90% saturated by 2050. That number of eligible customers will also continue to rise based on what we're seeing already. We'll continue to be pursuing that increased saturation rate, but a lot of our outreach is really focused around increasing that 24% and reaching those customers.

Kelsey Solberg: Finally, just to highlight some of the pieces that we've put in place in terms of equity as we've been designing this program. I picked four major ones. The first one being the removal of barriers with self-attestation. This is something I touched on earlier, but before this was in place, customers did have to make that appointment. If English was not their first language, they might have had to bring a translator. Some of them have their children translating for them. Some people would have to get childcare, find transportation, but now they can simply just apply online. They can apply over the phone. We have customer service reps who are experts in this bill assistance program and have been really wonderful in enrolling our customers. They have access to translation services as well. They can help those customers who might not speak English, get enrolled, and customers can also still go to their community action agencies. But there are several other options for them. We feel like this is a been a huge measure and creating more access to this program, the discount percentages as I mentioned before, these are designed specifically to address energy burden and the percentages are higher for folks who have lower income.

Kelsey Solberg: Annette touched a lot on what's the difference between equity and equality. If we're going for equality, we'd give everyone the same percentage, but we're going after equity. So, we're saying based on your income and the discount tier that you fall in, will address your specific situation. We're really trying to create more equity in the discount percentage that folks are receiving so that their energy burden is being reduced proportionately to their situation.

Kelsey Solberg: Tamara touched a little bit on multilingual, this is a company-wide initiative that we're pursuing. We've done a lot within this program to have resources available on our website for non-English speakers and we have several more languages available in some of our print material. We've been intentional about having flyers and applications available in at least five different languages as a start for us in this way. Finally, increasing readability. This is something that we've been cognizant of pursuing a 6th grade reading level for all of our bill assistance content. We actually worked with some customers to get feedback on our website. We made things a little bit less jargony. We took out some acronyms and really just made it as accessible as possible so that people could easily apply and access the program.

Kelsey Solberg: So that is our affordability initiative. Glad to be passing it on here to Kristine Meyer and Ana Matthews, who are going to talk about the purpose and the early impacts of our Named Communities Investment Fund.

Kristine Meyer: Next, Kelsey, I was thinking about this looking at us being at the three-hour mark and driving across the state, would we be at Vantage yet? I think probably. Goodnight, 3 hours, you guys are troopers. My name is Kristine and I'm the Executive Director of our foundation and also managing alongside Ana Matthews, our Senior Energy Efficiency Program Manager, together we are managing the Named Community Investment Fund. We'll tell you a little bit about that today. Tamara, are you advancing our slides for us? If you'd go ahead and get us there.

Kristine Meyer: OK, so the Named Community Investment Fund, we talked a little bit earlier today about the Named Communities, but here they are represented geographically. These are communities that are defined by the [Washington] State's Department of Health and in the sense Eastern Washington, where we're situated. We're looking at about 142 census tracks that are targeted for investment of these dollars within our Eastern Washington Service Territory. Go ahead and advance the slide.

Kristine Meyer: The $5 million, where does that come from? This funding is equal to about 1% or approximately $5 million. 1% of our electric revenues annually. We divide this up into five different buckets. You'll see on the right there. Put on your glasses so you can see the font, but it's divided into $2 million for energy efficiency programs or investments, and then the other aggregates to $3 million that go into investments in distribution resiliency, things like solar investments, battery backups, things like that. And the other is about $2 million in other kinds of projects. Remember that Tamara mentioned $500,000 of that are in projects that were identified for focus from our Equity Advisory Group. Things like investment in tree canopy that reduces heat island impacts, third party investments, outreach and engagement so that we can share with folks in Named Communities. The opportunities to submit applications for these dollars and to explain the Named Community Investment Fund and CETA and those kinds of things to raise awareness, go ahead and advance the slide please, Ana.

Kristine Meyer: Wait, you're on mute.

Ana Matthews: Thank you. On this slide, I'm addressing one of the five buckets that Kristine covered on the previous page and that's the focus on energy efficiency, energy efficiency, energy efficiency, because it's comprised of programs that directly benefit customers. And as a cost-effective method for achieving clean energy goals, the cleanest energy is the energy that we never use. Helping our customers to use energy safely and efficiently is the strategy of this portion of the Named Communities Fund. The energy efficiency portion of the Named Communities has five separate categories. Similar to the energy efficiency for the Named Communities Investment Fund, overall energy efficiency has five distinct categories and the first and most importantly includes a commitment to public engagement through community identified projects. And Kristine talked a little bit about this, but this is the area where we've dedicated a portion of the funds to be utilized or identified by the Equity Advisory Group to identify the initiatives within Named Communities that are specific to energy efficiency.

Ana Matthews: What's really interesting is through a results-based activity process with the Equity Advisory Group, they identified energy efficiency initiatives that closely align with the specific energy efficiency actions that we've identified in our Clean Energy Implementation Plan. You can see the influence of our Equity Advisory Group, that is a huge component of that public participation process throughout our Clean Energy Implementation Plan as well as our commitment for what we're striving to do under the Named Communities Investment Fund for energy efficiency and the areas that group identified for concentrated attention. This includes the implementation of programs for multifamily complexes, and health and safety for manufactured and mobile homes. As we know, those folks have a lot to deal with in terms of maintaining the efficiency in their homes and we want to make a difference for them with specific emphasis on health and safety, weatherization for single family homes. What we can do to contain drafts in the wintertime so that investment that folks are making to heat their home isn't just going out the window. And focus on small businesses because we know that small businesses, they're mighty and they are doing a lot for the economy of our communities and can use all the help that they can and doing some energy efficiency initiatives or practices for them can really make a difference in their cost. This group also identified specific focus for tribes. We talked a little bit previously about the grid resiliency project that Spokane Tribe has undertaken. And there's an energy efficiency component to that project as well. And then, as Kristine mentioned, they have identified tree canopy which we know may have an energy efficiency benefit when the right tree is placed in the right place. Next slide please.

Ana Matthews: The biggest thing I want to impart to you about this slide is our commitment to leveraging all available methods for raising awareness amongst interested parties about the availability of these funds. We want to engage those parties so that they can bring forth proposals, recommendations, ideas for how we can make a difference for those that we're going to serve through the Named Communities Investment Fund with assurances that the transformation is equitable for all, to establish a variety of avenues for interested parties to share their ideas and proposals. We first started with an online application. It's simple to complete but assures that applicants consider all components of the project to assure alignment with the Clean Energy Transformation Act. This isn't usual projects that we're doing for general operations or any other initiative, it has to have a specific alignment with clean energy transformation. And what we're striving to achieve through a Customer Benefit Indicators additionally through our outreach program.

Ana Matthews: We have a robust outreach program at Avista. We've been in communities, gosh, for over 20 years now working with a variety of nonprofits to get the word out about all of our different programs. We have regional business managers that work with different government entities. And we have account executives that work with our business customer base. With all of those connections that we have in the community, we're leveraging those connections. We spread the word. We put the word out amongst all of those parties and then we're really dedicated to having an avenue open for those that are interested. They might have not engaged with Avista on any other initiative or activity before, but we want them to know that if they do have something that's going to help us achieve our clean energy initiatives that we'd like to hear their ideas or their proposal. We're looking to make sure that folks are aware of the funds. There's a variety of ways that they can make the proposal or share their interest, and then we're even reaching out to those organizations that may not have heard about it or may not even know that they could be interested in it.

Ana Matthews: So, as an example and what Kelsey was talking about, as we start to learn more about who's participating in the bill discount, we might see that there's a specific demographic group that's not represented in the participant pool. So, we'll probably approach an entity that's representative of that group and have discussions about how we could inspire participation amongst that target demographic and if needed, we could utilize the Named Communities Investment Fund to support them and engaging those individuals for that company benefit. Additionally, just to make sure that folks are aware of the benefit of the program, but then also how do they access it? We'll be hosting informational sessions either virtually or in person, and so virtually you know that just gives us an ability to cast a wide net to touch a lot of people from the comfort of their own office or home, but then in person too. We're willing to go out, have conversations with unique and specific organizations to make sure that they understand about the Named Communities Investment Fund and how to access that benefit. Next slide please.

Ana Matthews: With everything that's been shared, we wanted to provide you with the basics of the process. Not a comprehensive overview of the complex processes that we must undertake to ensure benefits for all customers while weighing equity considerations. This slide is simply to illustrate the whole named communities process and so with that it shows the avenues for access to an arrow in the middle that represents the complex vetting process that ensures accountability for funding selection to the equitable outcomes. And I just want to spend some time on that big arrow because it captures an abundance of actions from the receipt of the proposal to assure that submitting entity was supported through the process to the preliminary and subsequent screening activities that are across the board within our organization and externally. So that we're getting inputs on weighing on the different proposals that came forth to us and that the proposals are in alignment with our energy clean energy accountabilities as stated in our Clean Energy Implementation Plan with the assurance for equity and process. And to me, simply stated equity and process requires a unique consideration for the proposal and the identified impact for that targeted population.

Ana Matthews: Additionally, we look to leverage any existing programs, grants, or other funding our resource support opportunities. If there's a grant out solely funding a project, if there's another grant out there, or maybe we can leverage another activity that's going on in Avista, such as the tribe example that was shared previously, there was a Department of Commerce grant that we had assisted in writing for the grant. We're bringing in the Named Communities Investment Fund for any gaps and implementing that project. And then we just really want to ensure the prudent use of the funds with the positive benefit to the target population. Now I'm going to turn it over to Kristine. Who's going to cover the considerations that we have in that big arrow section.

Kristine Meyer: Thanks Anna. So, the big arrow that was in Anna's previous slide blows out to show you that there are so many different considerations that we're looking at, many different lenses in consideration to assure that equity is accomplished as one of the many different things that we're looking at when we're reviewing a proposal. There's the equity lens, and I won't read this, I'll let you guys spend some time on this and encourage you to come back to this slide later when you have a little bit of time, but we're looking at the features of equity in the first in the first box there, affordability and access to clean energy and those different features there. But then you'll remember that under equity in those earlier slides that you've seen several times that there are 13 different CBIs or Customer Benefit Indicators and a couple of those match up to each of the features of equity under affordability. Remember that CBIs one and two match up to affordability. Participation in programs and the number of households with a high energy burden going down, public health matches up to CBIs, number 13 matches up to indoor air quality and so on. And then in the third box, we're also looking at the implementation plan and specific actions there. We're looking at whether or not a proposal has a community identified project. Does it match up and have impact to single family weatherization? Maybe it might match up to a small business energy assistance benefit. Does it look at whether or not it impacts single family weatherization? And then finally, we're looking at Equity Advisory Group initiatives. Does the project have an increased tree canopy feature to it? Might it have some matching funds for energy efficiency grant applications? And I'll talk to this in a different way as well. Not every proposal hits on every single one of these features, but we're looking to maximize these things in each proposal. To the extent that they can, so the strongest proposals hit on as many of these as they can and do so in a way that maximizes and leverages the resources that we have to be able to do this. We have $5 million to use to accomplish as much as we can through these lenses.

Kristine Meyer: If you can imagine trying to maximize the benefits while minimizing the dollars utilized so that we can stretch them as far as we can to accomplish as much as we can. That's what we're trying to do. As we look at each of these proposals that comes through that process to ensure that equity is accomplished, as far as we can across those Named Communities. Next slide.

Ana Matthews: This slide captures all of the projects that were funded in 2023 for both the community and energy efficiency categories and in some cases, we had combined funding. As you can see, energy efficiency projects are in alignment with the categories I shared from the previous page, from audits for the Spokane Tribe to identify where energy efficiency improvements can be made at the facilities on the reservation to projects that help contain drafts for those residing in mobile and manufactured homes, to improvements for heating and cooling in affordable housing complex, to lighting for a facility at a rural community. And then a full renovation at a pantry up in Stevens County. These eight different projects to accomplish under energy efficiency we know will make specific impact and change for the customers in the organizations that were serve. At a minimum, these projects directly support our Customer Benefit Indicators of reducing the energy burden, increasing participation in Company programs, and investments of Named Communities, along with other benefit outputs that we haven't yet identified. Next, Kristine will take over the community and combined section of what we've given out in 2023.

Kristine Meyer: Now, take a look at the next groups of projects in the green boxes and the orange boxes. Last year, we also made some investments in these kinds of things. The tree canopy, as an example in the green section, we made an investment in the City of Spokane Parks and Recreation Department by helping them to purchase some tree plotter software. This is software that uses GIS technology to consider planting the right kinds of trees in the right kinds of places to minimize the impacts of heat islands so that they are stretching their dollars in plantings that will maximize the impacts to reduce heat effects in some of those neighborhoods and communities where those impacts are most detrimental. At the MLK Center, we helped by leveraging some dollars from Commerce and the federal government along with the Named Community investment monies to make an investment in some solar panels, some battery backup and improvements in their energy efficiency envelope to make that facility available when there are outages, to improve resiliency in that community. And that facility becomes a refuge when power outages might take place, as well as to improve the energy consumption in that facility to reduce the energy burden for that nonprofit organization. One of the things that you'll look at and see in the orange boxes and investment Ana mentioned earlier in the Kettle Falls Community Chest, that's a rural food pantry that we made some investments to improve their energy efficiency and reduce the burden there in their operations with their HVAC system. We also used some of the money from the Named Community Investment Fund to set up our online application to improve the accessibility to these dollars for folks to be able to submit their online applications and make them easier to access. We'll turn it over to James and the marathon continues.

Equity Planning in the IRP, James Gall

James Gall: The marathon is almost over. We're going to end at noon, and I believe we have one last presentation by me, and I'm going to try to bring that up. We're going to get into more of the nuts and bolts of how equity impacts our Integrated Resource Plan. Let me pause here so I can find my slides. I think it's this one. All right, hopefully everybody can see that.

Lori Hermanson: I can see it.

James Gall: It's a good sign. The goal here is to take everything we've learned this morning on what the company is doing from programs to Customer Benefit Indicators to how we want to incorporate equity. But how do we actually do it in the IRP? What are the steps that we are actually doing, and should we make any changes? Is this more of an informative exercise? Those are the two different goals here. An IRP is really looking at how do we serve customer’s power supply needs. That could be from energy efficiency, that could be from generation sources. But I want to touch on how that all works together. So, we're going to talk about energy efficiency and the Named Community Fund. There is an aspect of the Named Community Fund in the IRP. We'll talk about how Customer Benefit Indicators again are worked in non-energy impacts, social cost of greenhouse gas, and the last topic we'll get into is a maximum customer benefit scenario.

James Gall: Let's get going so we can get done by noon. For energy efficiency, when we look at modeling, energy efficiency or how we select it. We actually split energy efficiency into two categories. We have a low-income category and a non-low-income category. The low-income categories get what we call higher net energy impacts. So, when we look at energy efficiency programs we calculate a non-energy impact, but if it's a low-income customer, there's usually a different impact. That's non-energy compared to those that are higher incomes. What that tends to do is the model will choose based on that economic advantage, more low-income programs than say a non-low income program, even if the cost is the same from the utility perspective. The non-energy impact will move the selection to more of those programs.

James Gall: This next IRP, we are going to be trying, rather than just using low income, but we're going to look into a Named Community potential rather than a low-income potential. And what I mean by that is instead of looking at only income, we're going to try to parse out the energy efficiency potential by which customers are in those Named Communities from that map we had showed earlier. Again, how this impacts our plan is we're trying to select greater amounts of energy efficiency to serve customers in a more equitable way. At the end of the day, if we didn't make these specific changes, we would have lower energy efficiency targets in our plan. But with these changes it does increase the amount of energy efficiency that is selected. Feel free to raise your hand if you have any questions or comments throughout the slides.

James Gall: The next aspect is the Named Community Investment Fund. We are trying to model potential impacts of projects that will be selected by the team as projects are submitted. I don't know exactly what community organization will ask for dollars for solar or for energy efficiency. What we do to incorporate that in the plan is we select proxy resources. For example, we have a target in our model to spend an initial $2 million on energy efficiency. That may not be cost effective and what that does is that increases our energy efficiency target as well, but it shows that we're actually looking for programs that are beyond our required targets. We also put in our model around $400,000 that was an estimate of how much of that program money might be spent on solar or wind in our IRP, or sorry, not solar, wind, solar or storage. That number could change, but that caused the model to actually select the most cost effective solar or storage system to incorporate the likelihood of that types of programs will be in the future so that we're accounting for that energy benefit.

James Gall: For example, if we remind ourselves back on that storage slide, I showed earlier about how much additional storage was going to be added into the plan, though, that's storage selection due to this change in our modeling it without this Named Community Fund. Without these criteria selected, there wouldn't be any distributed solar selected in the plan. Because of that economic reason, it it'd be more cost effective to select if we needed storage. It's going to be more cost effective to do utility scale storage rather than distributed, so this helps take into account when the model is trying to choose which resources are most economic. It's a way to leverage or push the model towards specific outcomes.

James Gall: And then non-energy impacts. There's always this issue of, it goes back to Customer Benefit Indicators. But how do you prioritize one Customer Benefit Indicator over another? The approach we took is using non-energy impacts where we're trying to actually quantify the societal or indirect impacts of our choices. If a resource has an impact of air emissions, we want to quantify what that error, that impact, is and if the result ends up being that area, emissions are going to increase. We've included that outcome in our analysis. For example, we actually saw that event in the Northwest IRP where we saw, not a substantial reduction in NOx emissions because our model was selecting a power to gas ammonia turbine to serve load. Serving load is very important. Reducing air emissions is also important, but you set what is the cost to serve that load and weigh that against air emissions. Based on the economics of that non-energy impact of that air emissions, it was better to select a resource that had slightly higher air missions than one that did not. Because otherwise we would not be able to serve load in the future to come up with these cost impacts.

James Gall: We lean on a study that we got from DNV, a national consulting firm. They've attempted to look at non-energy impacts for different resource options and they try to quantify them when they're known, but there is let's say this is a study, or a field of study, that's continuously evolving. It's also not a skill set that's in a typical utility. And in order to do more or progress in the non-energy impact field, we have to hire consultants which cost money, which means that it leads to down the road higher rates. We need to balance how much do we want to spend on calculating non-energy impacts versus the cost to identify it and what the actual impact will be for the company. For this IRP, we're going to stick with the previous study. And then if we need to move to a separate study in the future or enhanced study, we're going to have to figure out the most efficient way to pay for that work. Again, what this will do from a planning perspective is it will actually change resource selection when you look at evaluating tradeoffs, including a benefit or a cost of a resource will change the outcome. If that cost or benefit is large enough to change the result. Yes, Sofya, go ahead.

Sofya Atitsogbe (UTC): James. Thank you. Maybe it would be a good time now to hear some thoughts from everyone present? Well, not everyone. Everyone who wants to speak on the quantification of non-energy impacts and their attitude towards it and the importance they see in Avista's IRP process for the non-energy impacts.

James Gall: Yep, happy to hear anything. I mean, if there's thoughts at the UTC, I just want to remind folks though, the last CEIP where we're required, where we agreed to include them, it would be good to know if we should continue this concept or pause or change like Sofya.

Sofya Atitsogbe (UTC): Not everyone. All at once. OK. Well, I suppose that is something that the UTC staff would like to hear other people's opinions on. I'll just keep it in the back of my mind. Thank you.

James Gall: Thanks Sofya, for bringing that up. Feel free to reach out afterward if you're not comfortable on this call, but you know we will be doing more collaboration in this IRP and that may lead to something in the CEIP that comes later. That's the Clean Energy Implementation Plan. A lot of the discussions on methodology of Customer Benefit Indicators, or how we use non-energy impacts, that comes up in that process too. There will be other opportunities to think about this situation. Also, I wanted to get into some of the non-energy impacts that we are including. We have two categories, both on supply side and demand side and in this area work really started on the demand side where we were asked to include impacts to income or public health, property values and energy burden. And then we got the thinking, you know, these impacts are not just to demand side or energy efficiency programs, they are actually impacts to the supply side. To be selecting resources on an equal footing, we conducted this study on the supply side for the last IRP and the focus was really on public health. What is the financial or economic impact of air emissions? We had PM 2.5 was quantified, SO2 and NOx. We looked at safety and what is the probability of an incident to workers or people around the facility, and an economic value of those fatalities or injuries. We looked at environmental impacts and this one was, I would argue, a little bit more qualitative because when you're impacting land, for example for a wind farm, you are paying for the land that's part of our energy cost. But you could argue there is a visual impact, but how do you quantify that? This is something that's kind of hard to do when, which is why I said maybe this is something we have to continue to study over time. Land use and water use are all things that we pay for when we build a resource, but may have an impact that isn't quantifiable.

James Gall: So those were qualified impacts economic what we looked at is when we invest in resources and capital costs there's construction costs, there's operating costs, and that leads to economic benefit to the Community, whether it's property tax benefits, it could be employment benefits. We try to include values to society around these facilities that we add to the system. If you have a resource, for example, that has more employees than another resource that will have a bigger economic impact to the community. Those are things that we were including and this plan.

James Gall: I wanted to talk briefly about how we can utilize equity when we acquire resources. I mentioned earlier that we talked a little bit about the RFP process. In an IRP we select resource needs, but that's not necessarily the specific resource we're going to acquire. We go to an open bidding process where developers have resources and can submit proposals. Avista could submit proposals and we evaluate them through a specific process and the Commission in Washington has a specific process that we follow to select resources and the resources that are going to be bid to us. They also have a process to get a permit, so it's a very rigorous public process. So, when a developer wants to build a wind farm, they have to get a conditional use permit, which requires them to do studies on how it impacts wildlife, how it impacts the community, and there is a time for the public to be part of that process. There are definitely many layers to engagement with customers or with citizens. When we select resources, part of it is on the developer of the resource and part of it also comes in when we evaluate those alternatives. For starters, those NEIs or non-energy impacts we talked about on the previous slide, we do include those when we select resources for serving load in Washington. And in addition to that, we have six different categories that we evaluate resources on the first one and the highest rating category.

James Gall: This slide is the topic, the percentage of how much we grade the proposals on, and then in the parentheses is some additional things we're looking at, customer energy impact. What we're talking about is 40% of our evaluation of a resource is the cost of that resource. Obviously, we're looking for the lowest cost resource, but given that's only 40% of the weighting factor that we selected when looking at resources. We also look at risk management. That is when we look at the ability of that company to construct a resource, how solvent are they. We're really looking at can they deliver on the project they say they can and at the cost. They say they can, so that's about 20% of the other grading. 5% is with price risk and that has to do with when they propose a project is the price fixed or is it variable. So, if you had a project that is fixed, that's going to be the same price for energy today, tomorrow, and the next day. That would get say 100% credit. But if you had a price that is based on the CPI or some other unknown metric, then we would assign a risk factor to that because we're not sure what price we're going to be paying for the energy. The 4th category is electric factors. This really has to do with deliverability and technology risks and what I mean by that is, let's say there's a project in central Washington. They have the ability to build it, they have the land, they have the permits, but they can connect it to the grid. The power cannot get from the location of the facility to Avista’s customers. The delivery risk or delivery impact, that's something we include. Also, technology. What if it's a new technology? Avista typically is not looking for high risk projects where we could be, we call it serial number one, where we're taking more of an R&D perspective. We're trying to actually serve customer load, so we are definitely looking at is a technology viable, their experience with the technology, and that's included in the evaluation.

James Gall: The last item has to do with non-energy impacts that are qualitative. This has to do with community involvement, Named Community impacts location. I think location was mentioned earlier where if a facility is in our service territory or connected to our system, we would give it extra credit. That's what we're talking about here. We're looking at local labor force use, and then supplier and owner diversity. That's 5% of the weighting. So, when our IRP comes out and we have a resource need identified, let's just pretend we have a resource need for a new wind project in 2029, for example. About two or three years ahead of that time, which would be a couple years from now, we would issue an RFP. And, we would be looking for solar or other alternatives. Just because the IRP selected a specific resource, we're not going to limit it to that resource. We're looking for something that can deliver those characteristics of, say, clean energy in that time frame. And then we would evaluate those options using this criteria. At least this is the criteria we used in our last evaluation process. The IRP is not the end of equity considerations in the selection process.

James Gall: The last thing, and I think this is my last slide, is we are required by the UTC to conduct what's called a maximum customer benefit scenario. In this scenario we're required to conduct, we're looking at what resource strategy changes would we make if we're trying to maximize customer benefits. Unfortunately, there's no definition or specific requirements of what the scenario must entail. So, it's really up to Avista and our TAC to come up with ideas on how we meet this requirement. Last IRP, what we did to meet this requirement is we called on our model to still find the lowest cost solution. But we're going to change the resource options available to the model, so some of the changes we made is the model could only pick in-state generation resources for renewables, which meant no Montana options. We told the model it could not select ammonia gas to power turbines because they have air emissions. So, if we were trying to maximize all of our Customer Benefit Indicators, we do see air missions would be one of those. Ammonia gas to power turbines, they have a small amount of NOx emissions and if you're trying to eliminate NOx emissions that would not be a resource you would select. So, we remove those fuel cells using hydrogen. We still allowed those lowering excess energy burden via community solar was a priority in this analysis. So, in their preferred strategy we would argue that to lower customer burden that we showed earlier would be met through energy assistance that Kelsey went through. But another way to do that is if we built community solar that was maybe paid for by some funding mechanism that would offset those customer bills. We would have more distributed energy resources potentially and then we would use that money towards low-income customers. So, the model was biased against selecting more of those resources.

James Gall: The last thing we included, which I think is maybe debatable, but no nuclear energy. It was an option that we talked about including. I think maybe we should talk about that one for this scenario. Is that really a benefit or not a benefit to maximizing customer benefits? I don't know if that is or is not, but that was something we assumed last time. With the few minutes we have left, I'm just curious if we think this is the right track. Should we want to make changes to this? Are we not thinking about something that was maybe intended? Should there be changes? We are open to ideas and nothing's wrong, nothing's right here, but any thoughts? It's OK if you don't. What we'll probably do. Got a hand up our Heather's got one. Thank you. Go ahead.

Heather Moline (UTC): Thank you. Staff will be following up on a few things that came up today. Some of this I think is moving a little too quickly for folks to be able to chew on and offer targeted feedback during this TAC meeting. I might think we want to discuss if you're, and this is not just Avista, if there's going to be as much content as there was today discussed in a room like this, we need two separate meetings. Just so there's at least a 10 second pause after every slide for folks to be able to chew on what they just heard. Luckily, Staff is a little more versed in this stuff than maybe other folks are, who don't do this for their day job. I think we do have some feedback, but we'll send it as a follow up in writing because I know that's helpful to you all. But I wanted to go back to slides 7, if that's OK., just that so resource acquisition, equity considerations, this is very creative to me. Thinking of these things as NEIs in the context of resource acquisition, because I'm used to thinking of NEIs only in the context of procuring, well, not procuring in planning, resource planning.

Heather Moline (UTC): So very cool. Going to chew on this. I'm not sure that I would say that all of these are equity related though. The first bullet, customer energy impact, that we would only say that's related to equity if it's considering whose bill is higher and whose bill is low or who has the ability to pay as opposed to keep costs low for everyone. Anyway, all that is just food for thought at this point.

James Gall: Some of that Heather, and we can talk about this when we talk offline, but some of that even though the non-energy impacts is 5%, some of those other equity conditions are embedded throughout. We just didn't call them out specifically. For instance, in your customer energy impact we asked the question is your project located in a Named Community and then it's score it receives a higher or lower score depending on if that's a yes or no because the thought there is that it would impact cost. I'm just picking this as an example, but it would impact cost and energy burden depending on whether it benefited those customers or not. I think we should probably have a follow up conversation on that also because during the RFP process itself that was a little bit of confusion, and it was hard for staff and others to compare us then to Puget because of that reason it's kind of embedded there. So, happy to happy to talk about that again. Heather, you mentioned something that's probably critical to how this TAC process works. We send slides out ahead of time to give people time to look at it. We talked about it here, but it sounds like maybe we need a third step in that. Do we maybe follow up emails, do we have another TAC meeting. Part B, a week later that's 1/2 hour for people to provide comment. That's a new concept to me I wanted to explore a little bit in the three minutes we have left. I would also because I feel a lot of times when I'm talking about equity that I'm talking at you all and I am aware of that and I don't know the answer, but I feel like you do, Heather. I don't know if this should be pre work or if this should be, I don't know exactly, but I do agree that this is a lot to digest and then to provide feedback. We're open to suggestions.

Heather Moline: I don't know the answer in that. I'm figuring this out with you all. I appreciate that, though. No, we'll confer internally. Staff has been thinking about guidelines on conducting TACs and the only thing that occurs to me in this moment is when the information is fresh. It’s good to provide different venues for input, so staff obviously will have the capacity to read through slides and provide written comment either before or after. But for folks who may not have time to do that, leaving a blank space after sharing dense information for folks to just chew on, it seems to me to be a best practice, which again, I recognize that you all have to get through all this information. You want feedback on it, but to me the way to solve that would be less information and more meetings. I don't know if that's right, but that just occurs to me as a solution about how to make sure there's space and that is accessible to people.

James Gall: OK, I'm going to throw out an idea. I'm not going to commit to it, but it's something we've tried, and maybe it helps, we've recorded the presentations before ahead of time and made them available. And then people could listen to them at their pleasure. And then we have the meeting to discuss high level topics. I think that works if people spend the time listening to the presentation, but if they don't then it may be a waste of time, but that's another approach. We look forward to that discussion. We do have more TAC meetings coming. We have our next electric one on March 21st. It's a half-day session like this. That meeting will definitely be a lot more technical than this meeting, and then we have a natural gas TAC meeting on February 14th as well. For those of you that are interested. I don't know if there's any last questions or thoughts before we go. OK. Well, I thank you for your time and input and we'll see you at our next meeting. Again, feel free to email us and or give us a call and we'll figure something out. Thanks. Have a good day.

2025 Electric Integrated Resource Plan

Technical Advisory Committee Meeting No. 3 Agenda

Tuesday, March 21, 2024

Virtual Meeting – 8:30 am to 10:00 am PTZ

Topic	**Staff**
Introductions	John Lyons
Review of January Cold Weather Event	James Gall
Wholesale Price Forecasts – Natural Gas and Electric	Planning Team
Portfolio and Market Scenarios Options	James Gall

2025 IRP TAC 3 Introductions

John Lyons, Ph.D.
Technical Advisory Committee Meeting No. 3
March 21, 2024

Today’s Agenda

Introductions, John Lyons

Review of January Cold Weather Event, James Gall

Wholesale Price Forecasts – Natural Gas and Electric, Planning Team

Portfolio and Market Scenarios Options, James Gall

Remaining 2025 Electric IRP TAC Schedule

- **TAC 4: April 9, 2024: 8:30 to 10:00 (PTZ)**
  - Future Climate Analysis
  - Economic Forecast & Five-Year Load Forecast
- **TAC 5: April 23, 2024: 8:30 to 10:00 (PTZ)**
  - Long Run Load Forecast (AEG)
  - Review Planned Scenario Analysis
- **TAC 6: May 7, 2024: 8:30 to 10:00 (PTZ)**
  - Conservation Potential Assessment (AEG)
  - Demand Response Potential Assessment (AEG)
- **TAC 7: May 21, 2024: 8:30 to 10:00 (PTZ)**
  - Variable Energy Resource Study
  - Portfolio/Market Scenarios
- **TAC 8: June 4, 2024: 8:30 to 10:00 (PTZ)**
  - Load & Resource Balance and Methodology
  - Loss of Load Probability Study
  - New Resources Options Costs and Assumptions

Remaining 2025 Electric IRP TAC Schedule

- **TAC 9: June 18, 2024: 8:30 to 10:00 (PTZ)**
  - IRP Generation Option Transmission Planning Studies
  - Distribution System Planning within the IRP & DPAG update

- **Technical Modeling Workshop: June 25, 2024: 9:00 am to 12:00pm (PTZ)**
  - PRiSM Model Tour
  - ARAM Model Tour
  - New Resource Cost Model

- **TAC 10: July 16, 2024: 8:30 to 10:00 (PTZ)**
  - Preferred Resource Strategy Results
  - Washington Customer Benefit Indicator Impacts
  - Resiliency Metrics

- **TAC 11: July 30, 2024: 8:30 to 10:00 (PTZ)**
  - Preferred Resource Strategy Results
  - Portfolio Scenario Analysis
  - LOLP Study Results

Remaining 2025 Electric IRP TAC Schedule

- **TAC 12: August 13, 2024: 8:30 to 10:00 (PTZ)**
  - Preferred Resource Strategy Results (continued)
  - Portfolio Scenario Analysis (continued)
  - LOLP Study Results (continued)
  - QF Avoided Cost

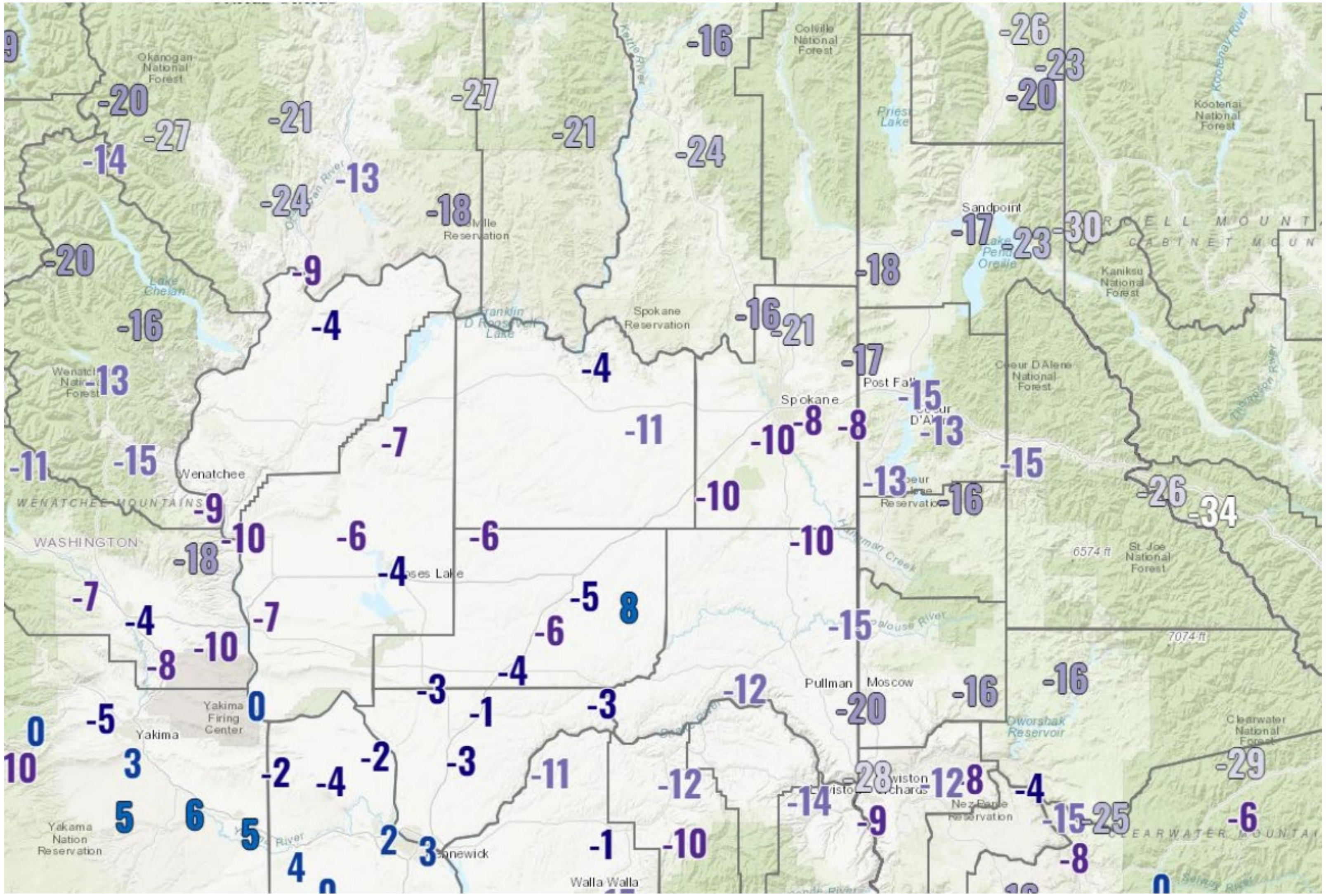
- **September 2, 2024- Draft IRP Released to TAC.**

- **Virtual Public Meeting- Natural Gas & Electric IRP (September 2024)**
  - Recorded presentation
  - Daytime comment and question session (12pm to 1pm- PST)
  - Evening comment and question session (6pm to 7pm- PST)

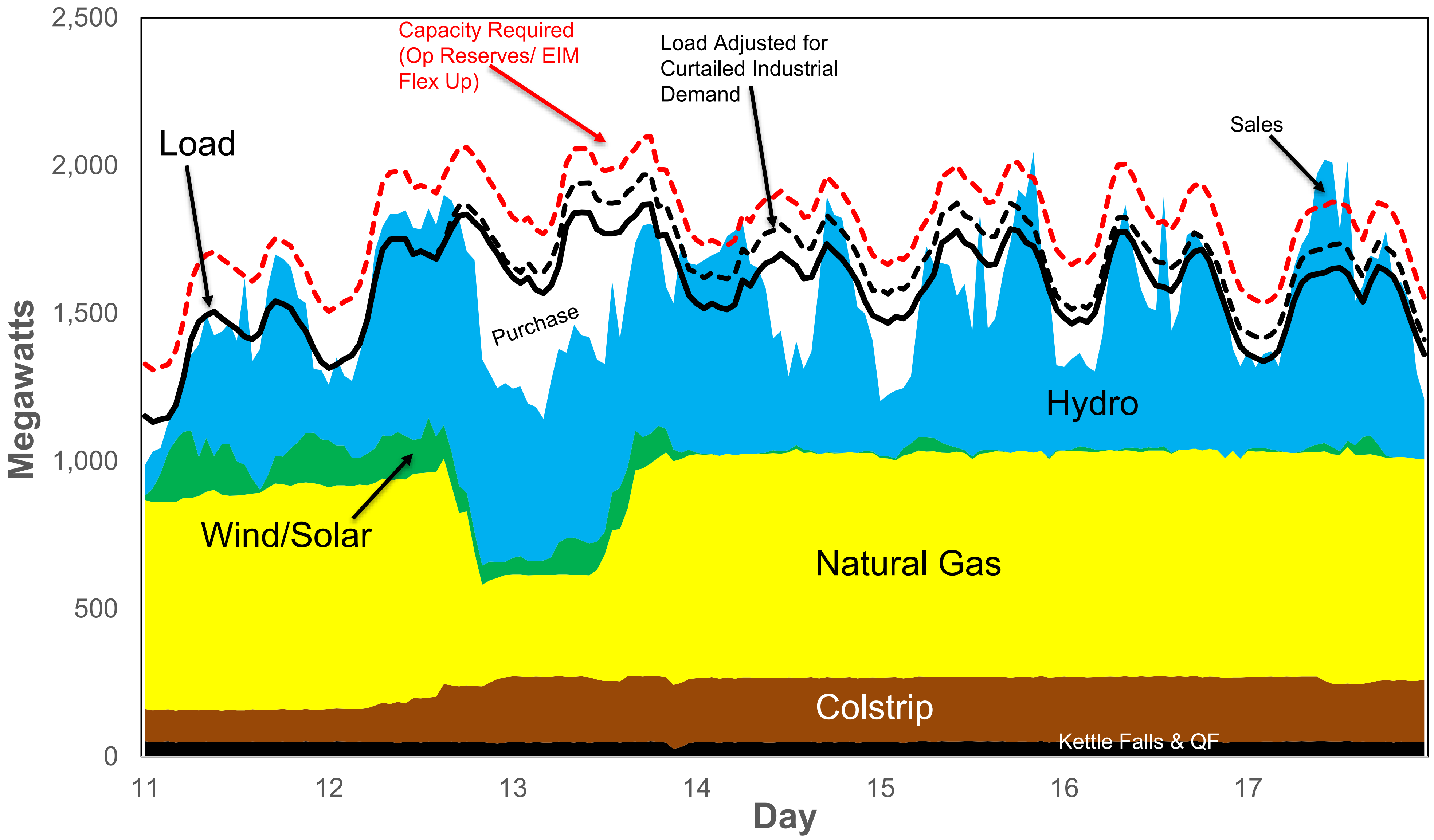
MLK Weekend 2024 Weather Event

James Gall, Manager of Integrated Resource Planning
Technical Advisory Committee Meeting No. 3
March 21, 2024

January 13, 2024 Low Temperatures

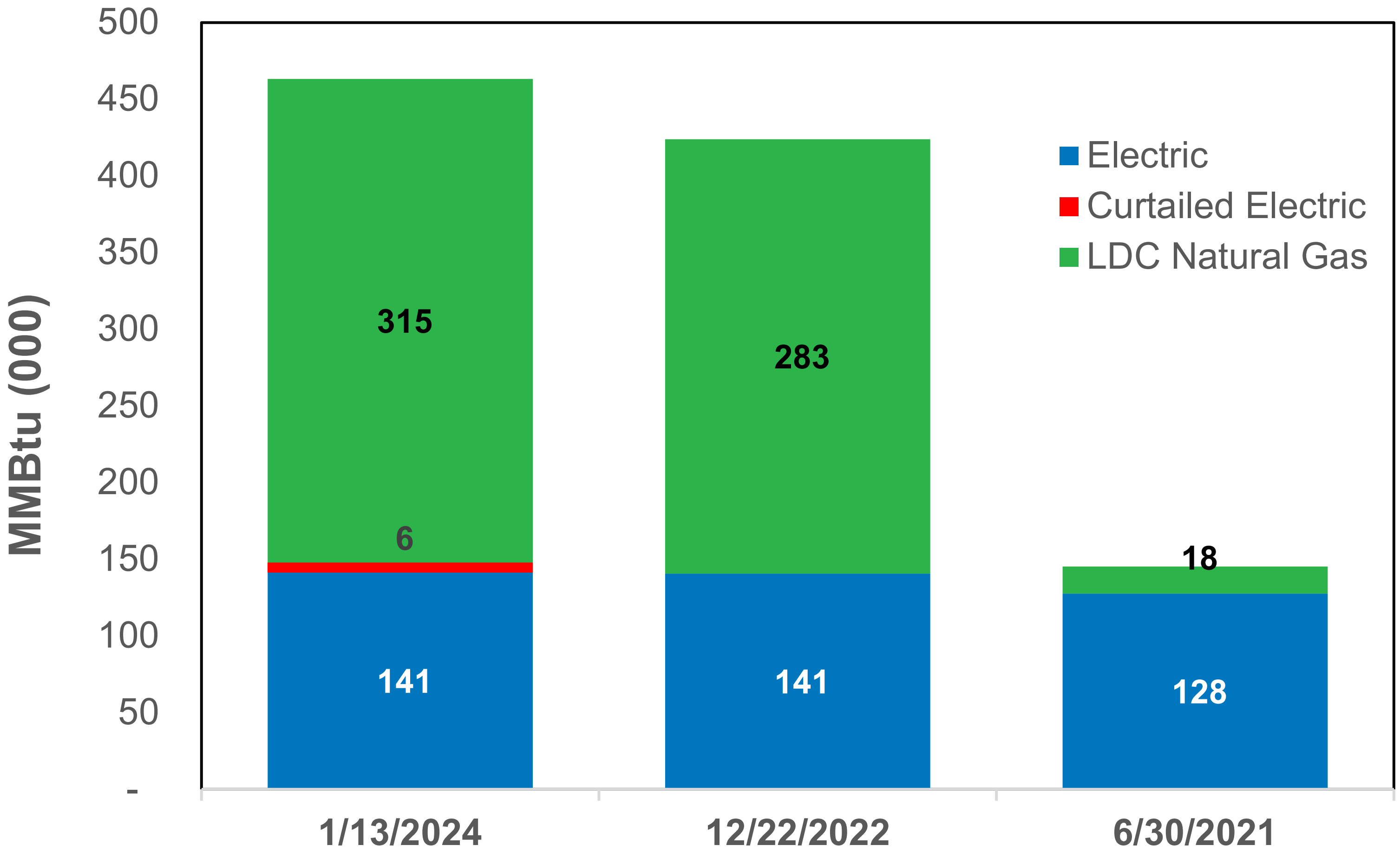


Loads and Resources



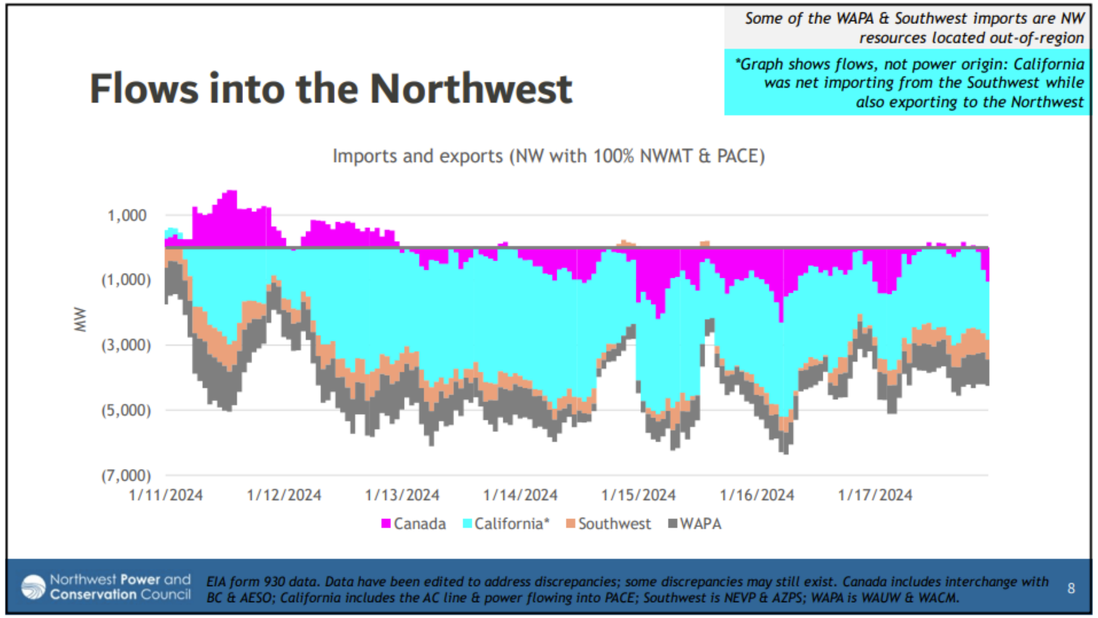
Gas vs. Electric Demand

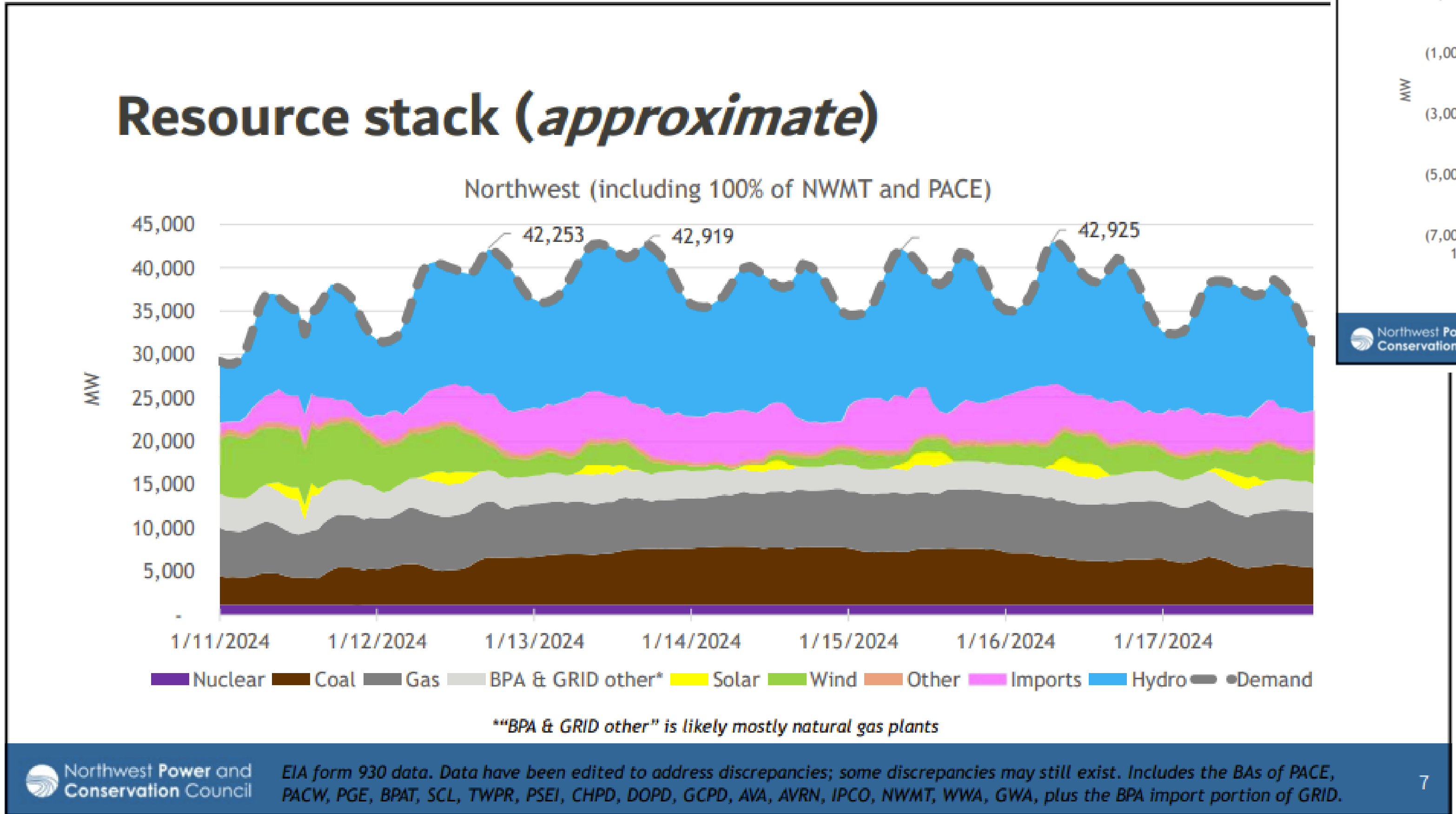
Total MMBTU of Daily Demand



Daily electric MWh multiplied by 3.412

Regional Power Challenges





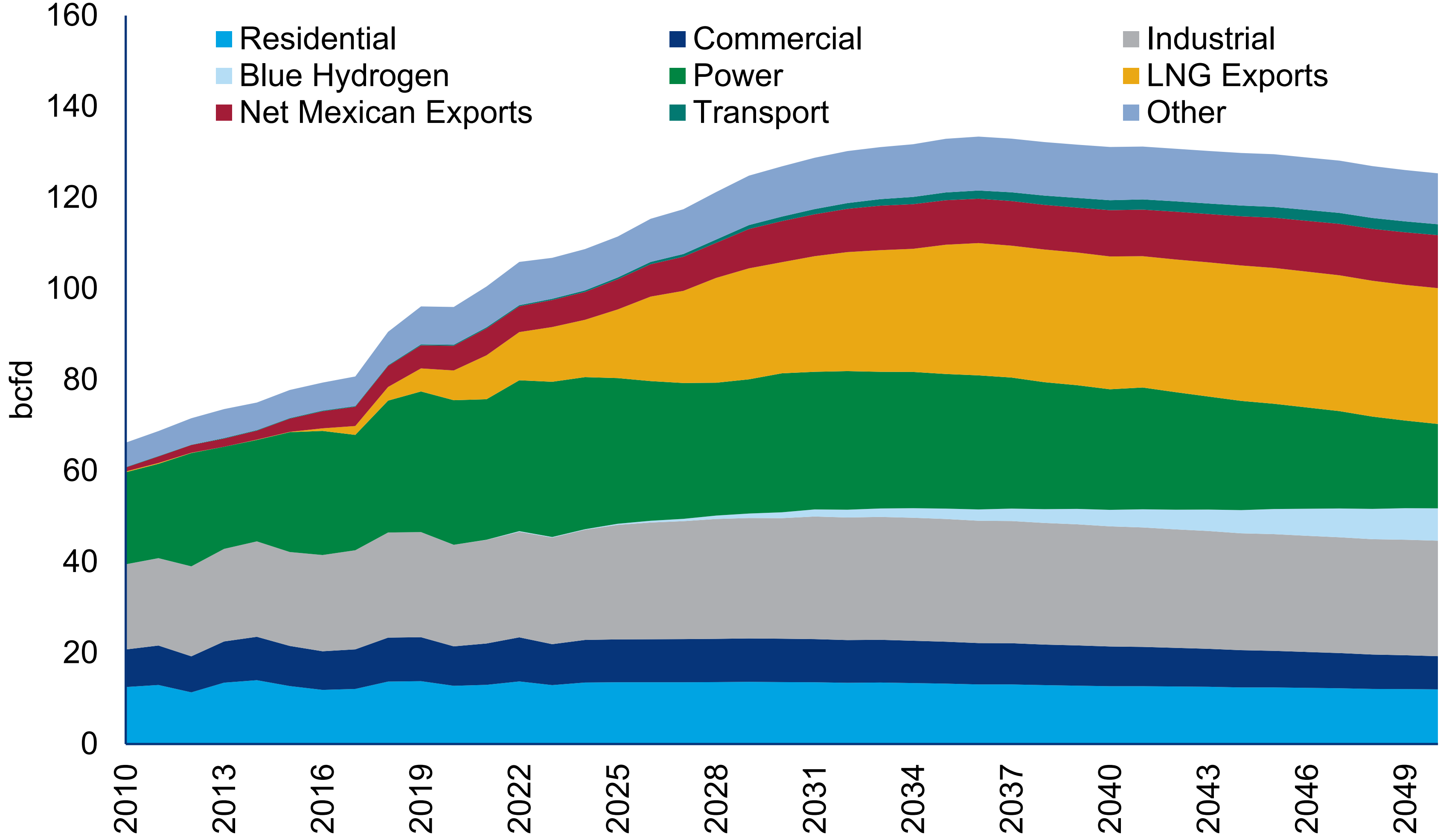
Potential Resource Adequacy Changes

- ✓ Update load forecast dataset to include new event.
- ✓ EIM Uncertainty Flex Ramp Up will be additional planning requirement.
- ✓ If planning margin is less than the single largest contingency resource, the planning margin will be adjusted to this level.
- Should we assume a low water for storage hydro resources QCC?
- Is a lower Loss of Load Probability (5%) target more prudent?
- Can Avista depend on the market in extreme events (330 MW)?
- Should we plan for meeting an extreme day such as this as a minimum resource adequacy standard vs LOLP method?

Natural Gas Fundamental Forecast
Wood Mackenzie

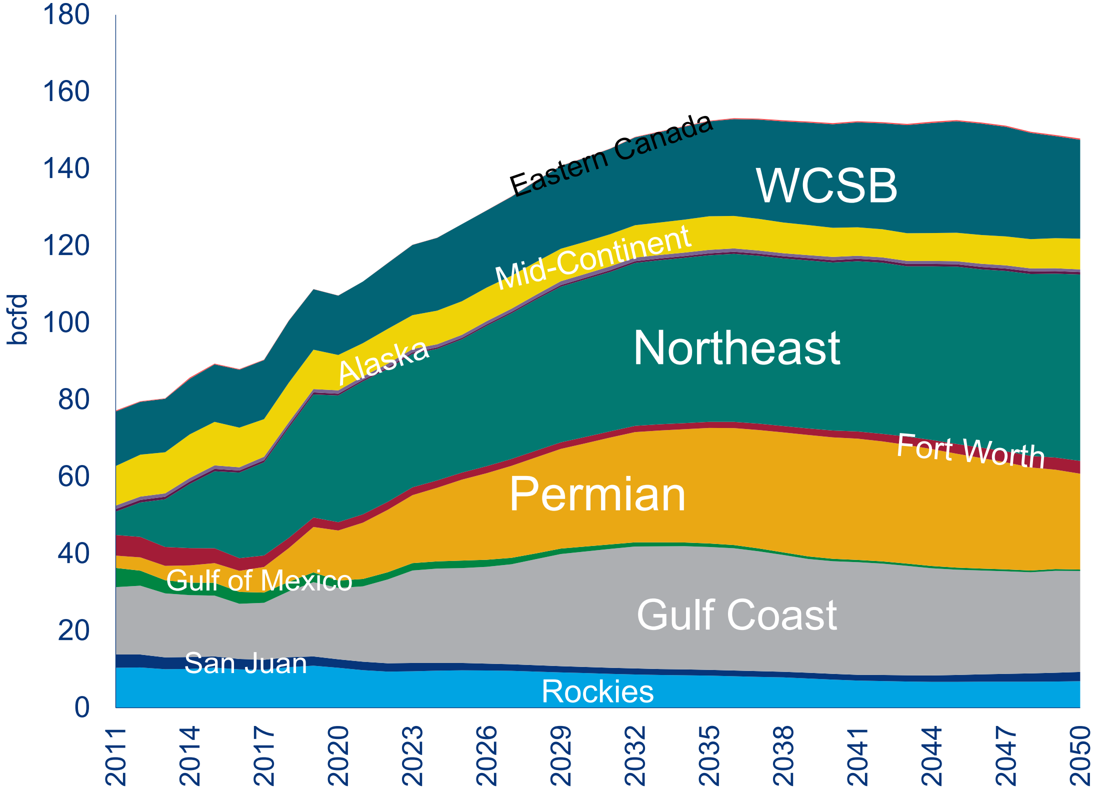
2025 – Electric IRP
Technical Advisory Committee Meeting No. 3
March 21, 2024

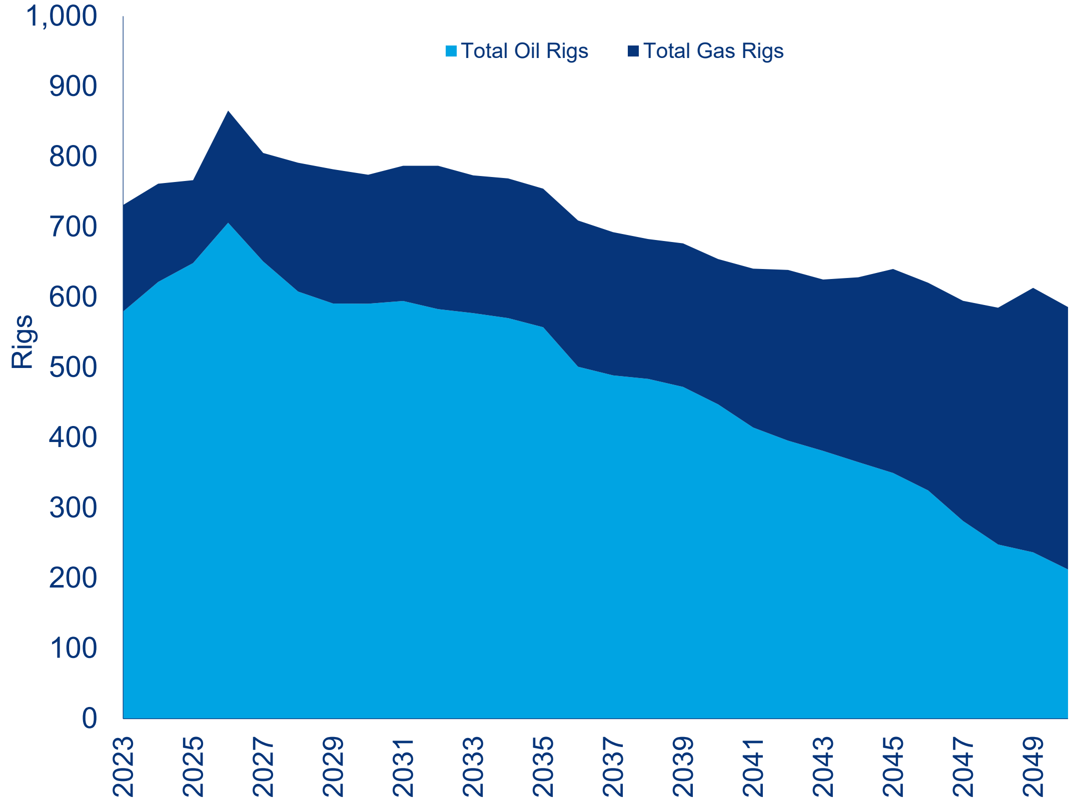
Lower 48 Demand



Source: Wood Mackenzie

North American Supply



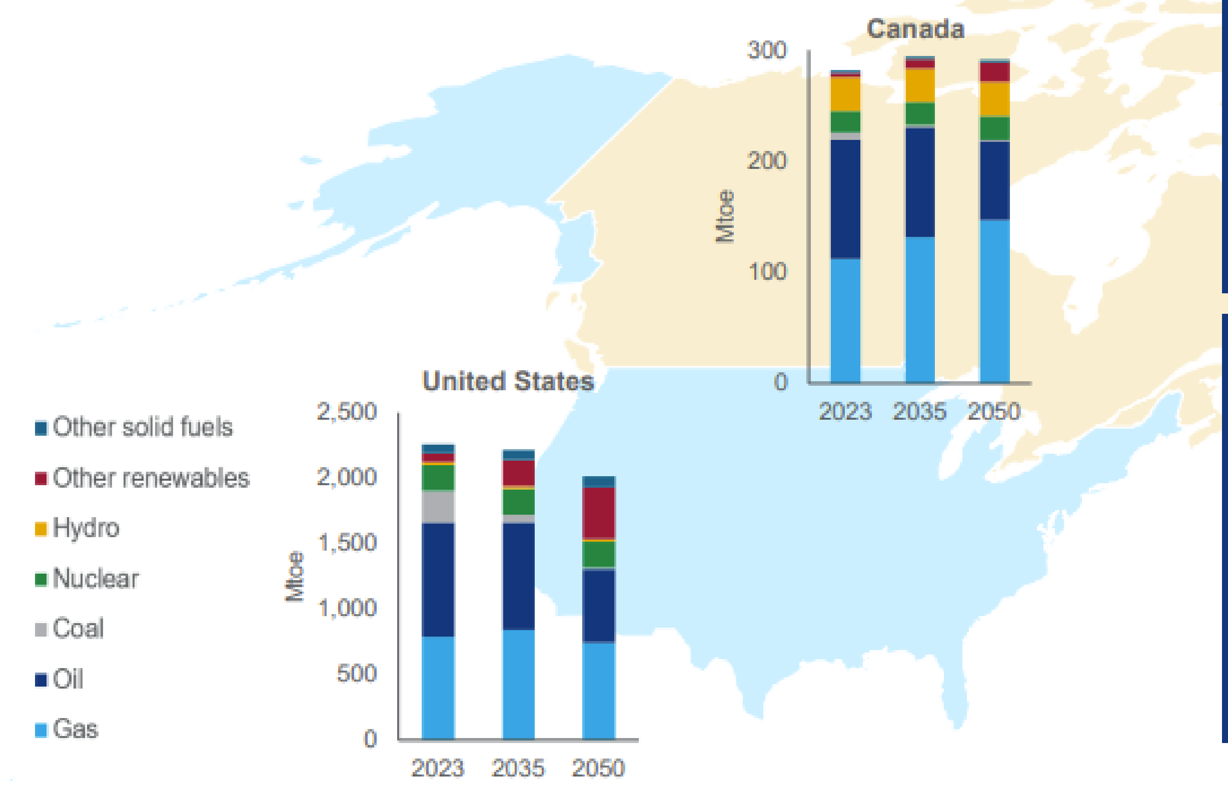


Source: Wood Mackenzie

Natural gas’ share of total energy demand increases over time

Gas plays a crucial role for energy security even through energy transition

Primary energy demand mix* in North America



Canada

- Industrial gas demand maintains steady growth to mid-century with rising oil sands production, especially with the recent approval of a new greenfield oil sands project.
- Gas intensive industrial projects are attracted to western Canada with low cost feedgas and potential decarbonization options such as carbon capture.
- Efforts to match the IRA in policy incentives spell good news for blue hydrogen and low-carbon industrial projects across both coasts with additional tax credits.

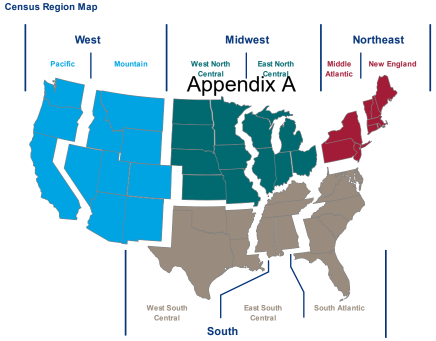
United States

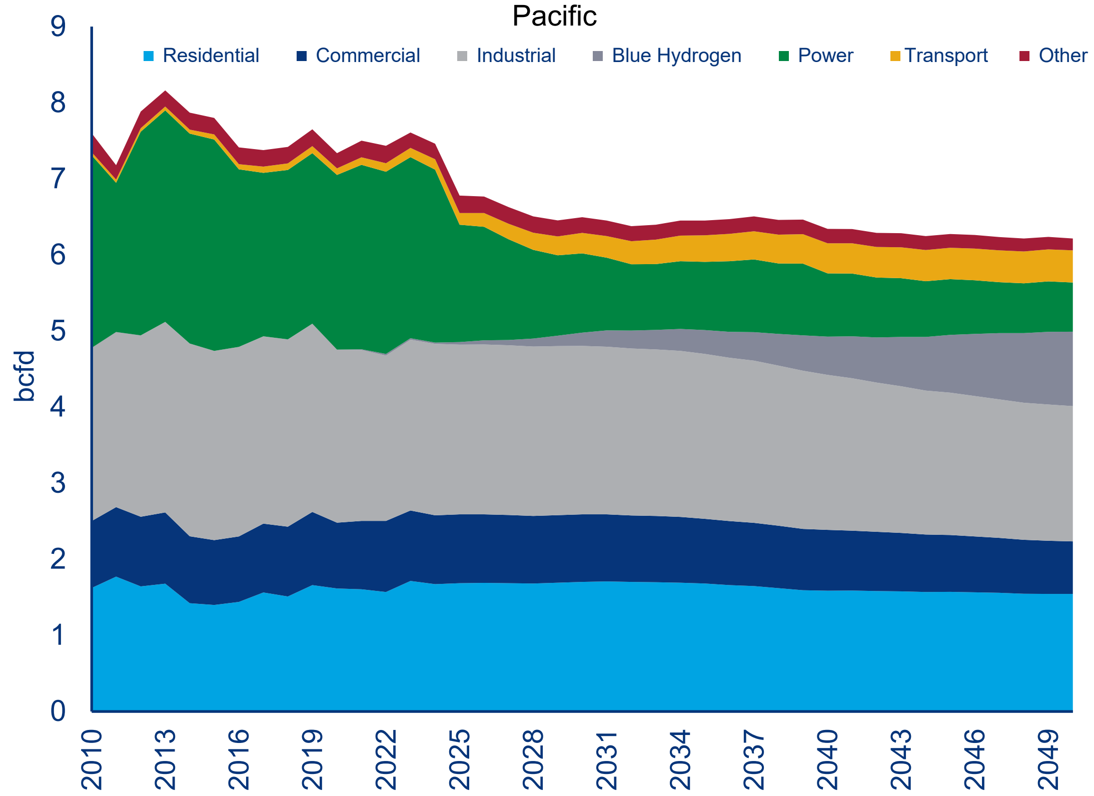
- Gas demand grows at a CAGR of 0.5% between 2023 and 2035, driven primarily by coal retirement in the power sector and new industrial projects. Post-2035, CAGR drops to -0.5% due to energy transition accelerating, such as gas displacement from low-carbon hydrogen in the industrial sector and building electrification in the LDC sector.
- While the IRA is expected to bring substantial build of renewables, large-scale deployment of renewables poses potential risk in the long term on transmission costs, interconnection costs and negative bidding. This helps natural gas demand in the power sector to stay relatively resilient even out in the long term.

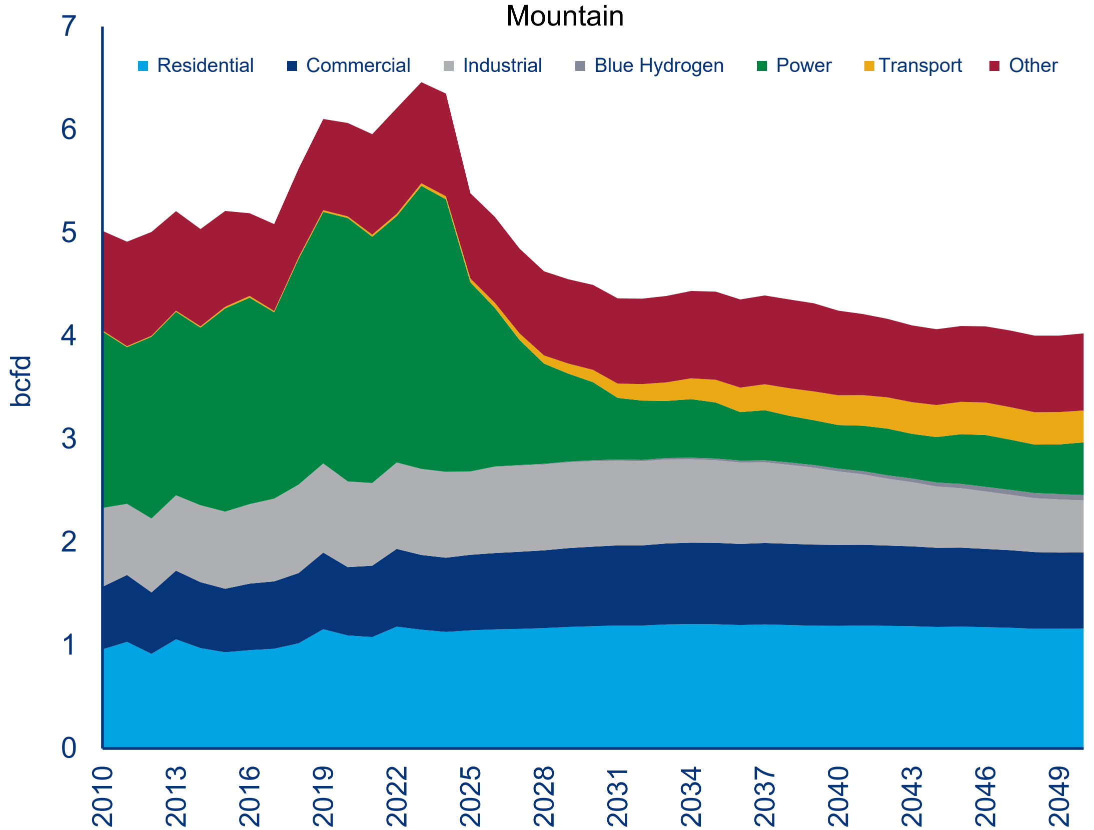
*Gas is based on Wood Mackenzie 2023 North America gas strategic planning outlook. Other commodities are based on Wood Mackenzie’s 2022 investment horizon.
Source: Wood Mackenzie Energy Transition Tool

Appendix A

Regional Demand





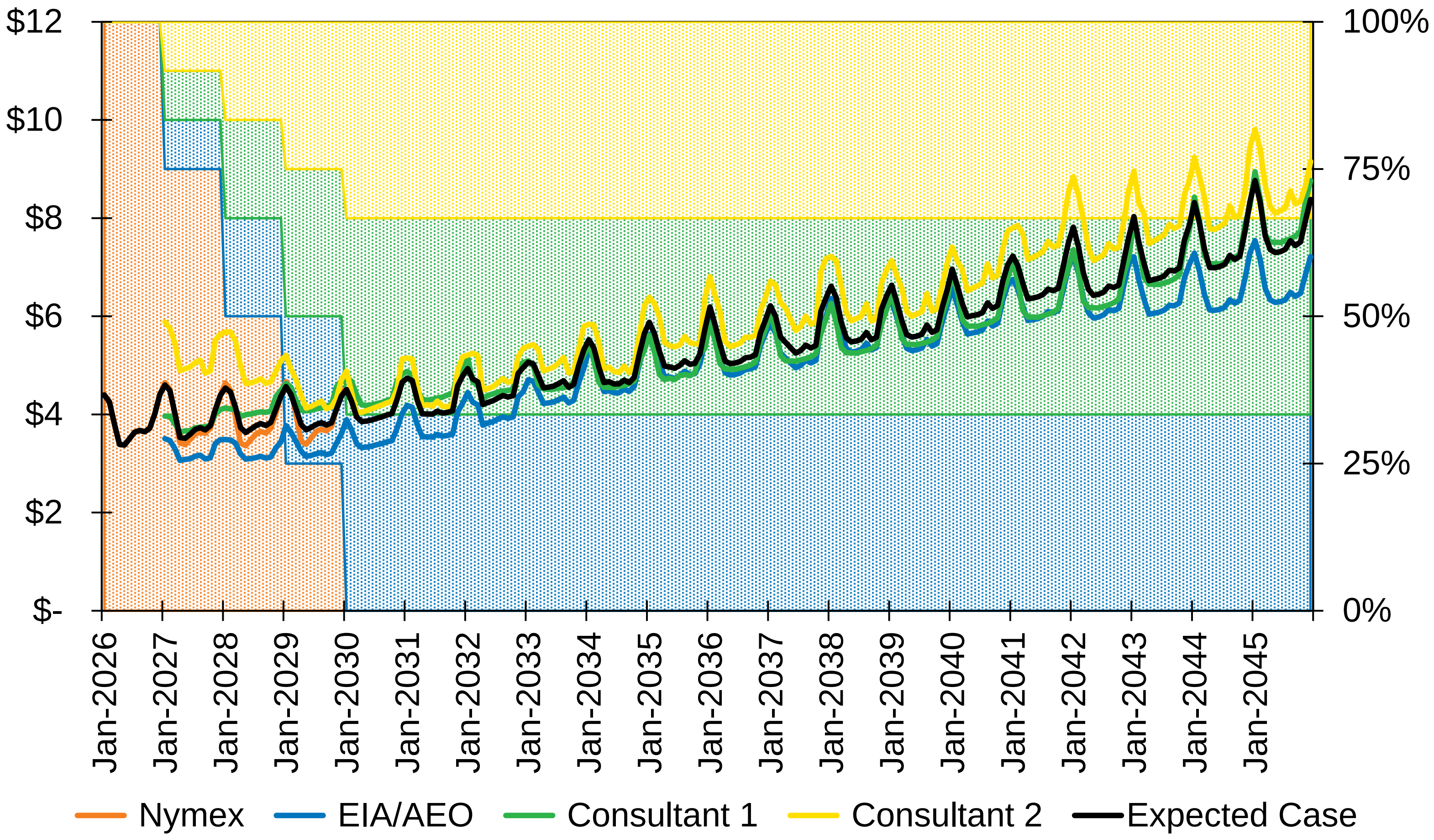


Source: Wood Mackenzie

Natural Gas Market Price Forecast

Michael Brutocao, Natural Gas Supply Analyst
Technical Advisory Committee Meeting No. 3
March 21, 2024

Henry Hub Expected Case Price Forecast

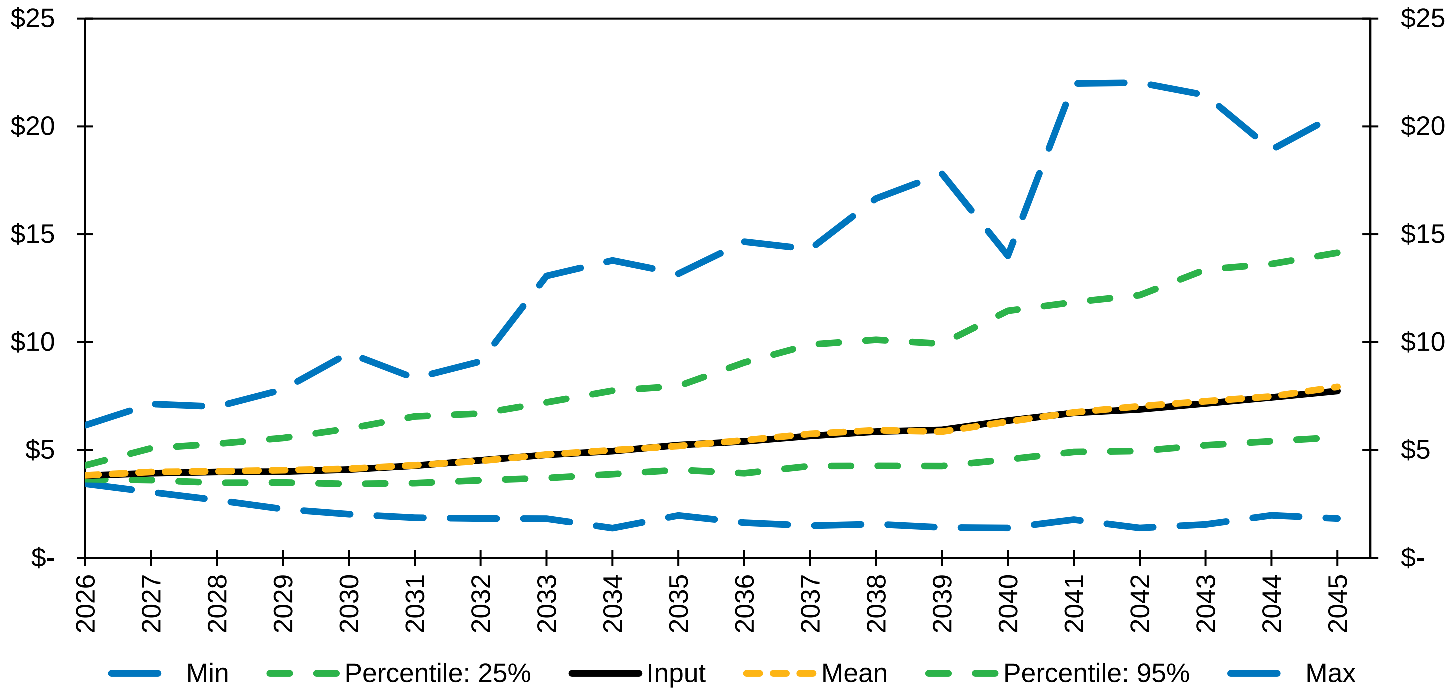


- Levelized Price: $4.99
- Data Sources
  - NYMEX forward market prices on December 15, 2023
  - Annual Energy Outlook 2023
  - Consultants 1 & 2 monthly price forecast
- Methodology
  - Average price of forecasts
  - Decreasing blend of NYMEX

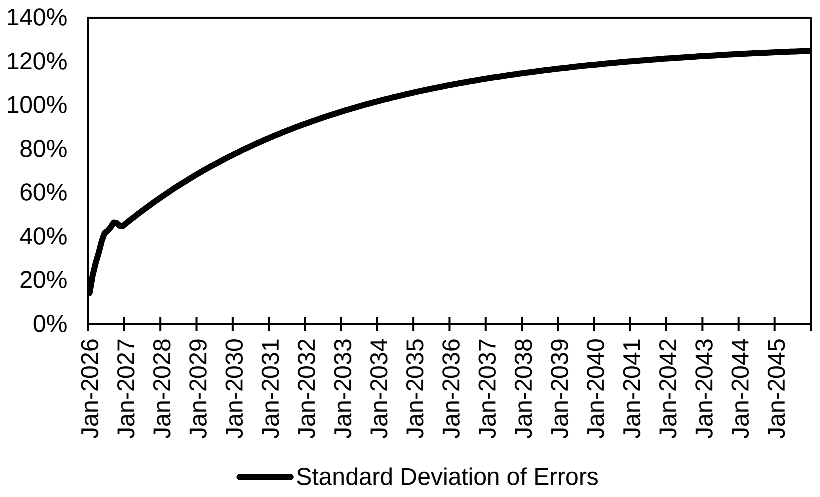
	NYMEX	Other
2026	100%	0%
2027	75%	25%
2028	50%	50%
2029	25%	75%
2030 - 2045	0%	100%

Annual Energy Outlook 2023 – Natural Gas Spot Price at Henry Hub

Henry Hub Stochastic Price Forecast



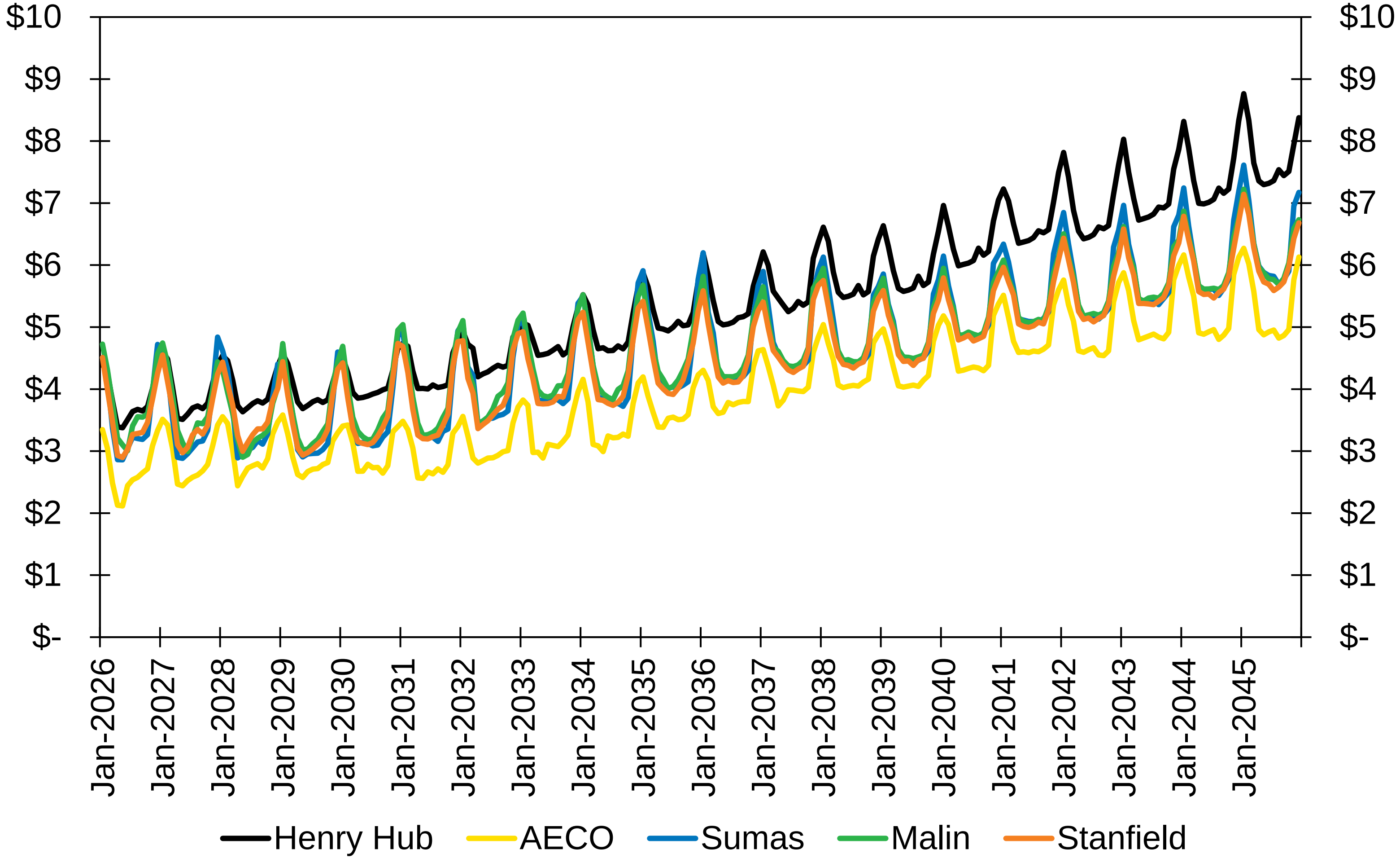
- Stochastic Inputs
  - Expected Case Forecast
    - Data Source: See previous slide
  - Autocorrelation (94.16%)
    - Data Source: Historical monthly prices at Henry Hub
  - Standard Deviation of Errors
    - Data Source: Historical daily NYMEX forward market prices
    - Data Source: Historical monthly prices at Henry Hub



- Methodology
  - Start from Expected Case Forecast
  - Perform adjustment for Autocorrelation to prior month
  - Randomly draw from prices with lognormally distributed standard deviation of errors

Historical Monthly prices at Henry Hub

All Basins Expected Case Price Forecast



Levelized Prices

Henry Hub	$4.99
AECO	$3.58
Sumas	$4.31
Malin	$4.37
Stanfield	$4.26

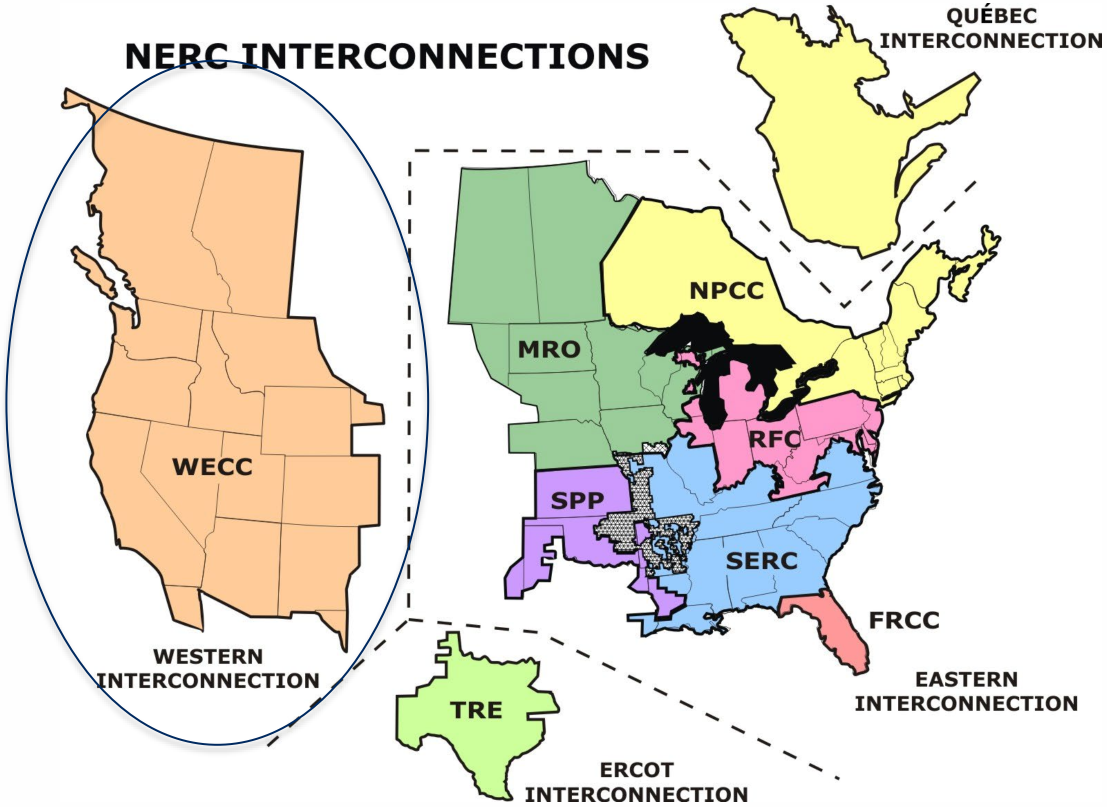
Data Source: Consultant 2 percent basis price differential to Henry Hub forecast

Wholesale Electric Market Price Forecast

Lori Hermanson, Senior Resource Analyst
Technical Advisory Committee Meeting No. 3
March 21, 2024

Market Price Forecast – Purpose

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

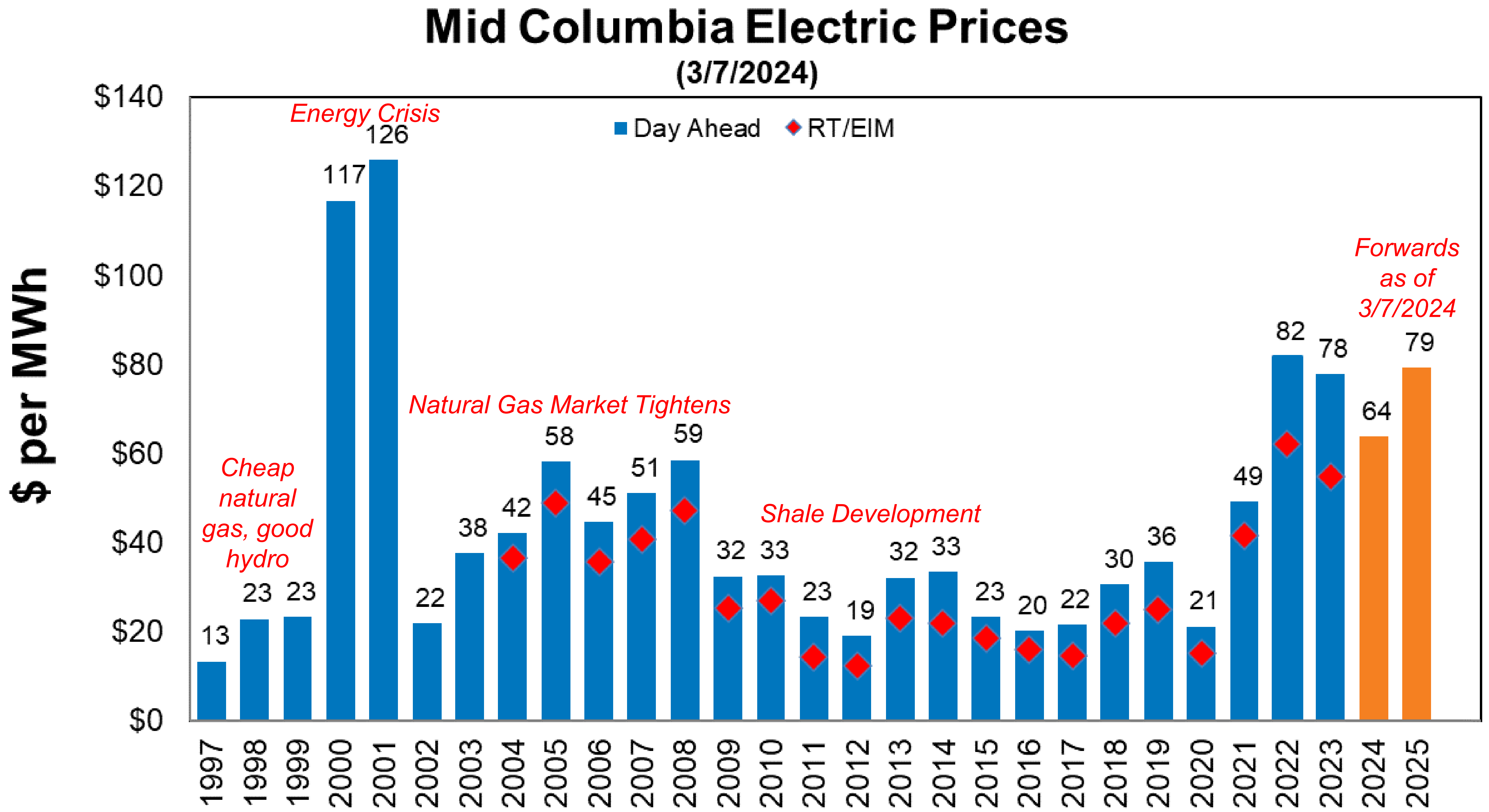


Source: NERC

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)
  - Regional energy stack
  - Transmission usage
  - Greenhouse gas emissions and cost
  - Power plant margins, generation levels, and fuel costs
  - Avista’s variable power supply costs

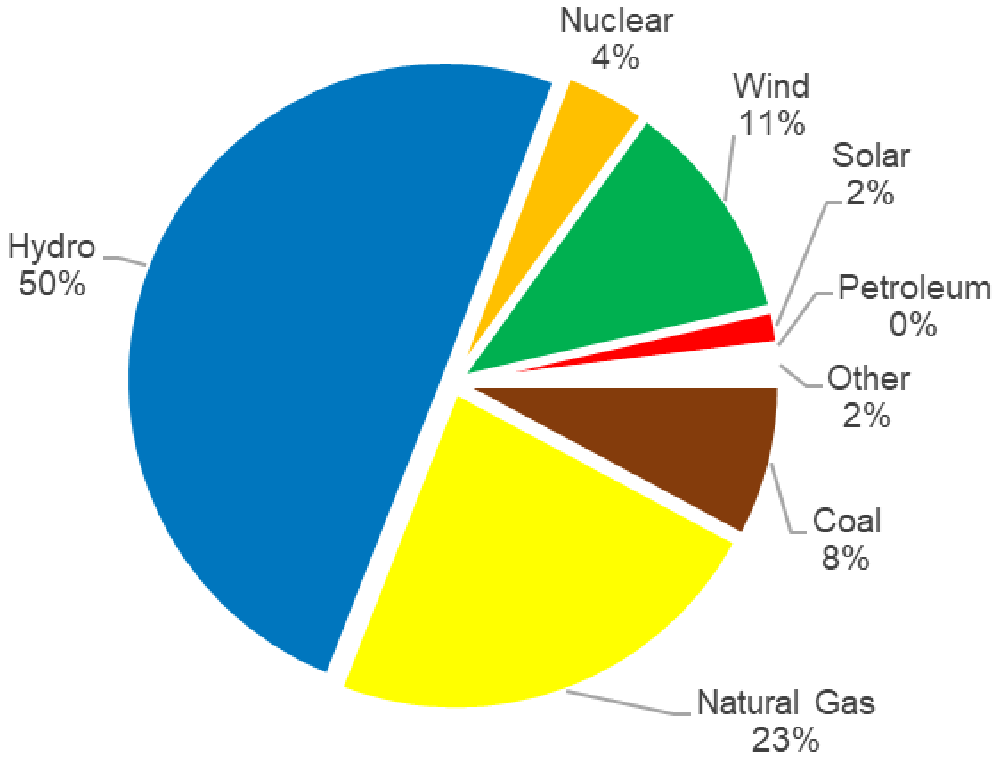
Wholesale Mid-C Electric Market Price History



2023 Fuel Mix

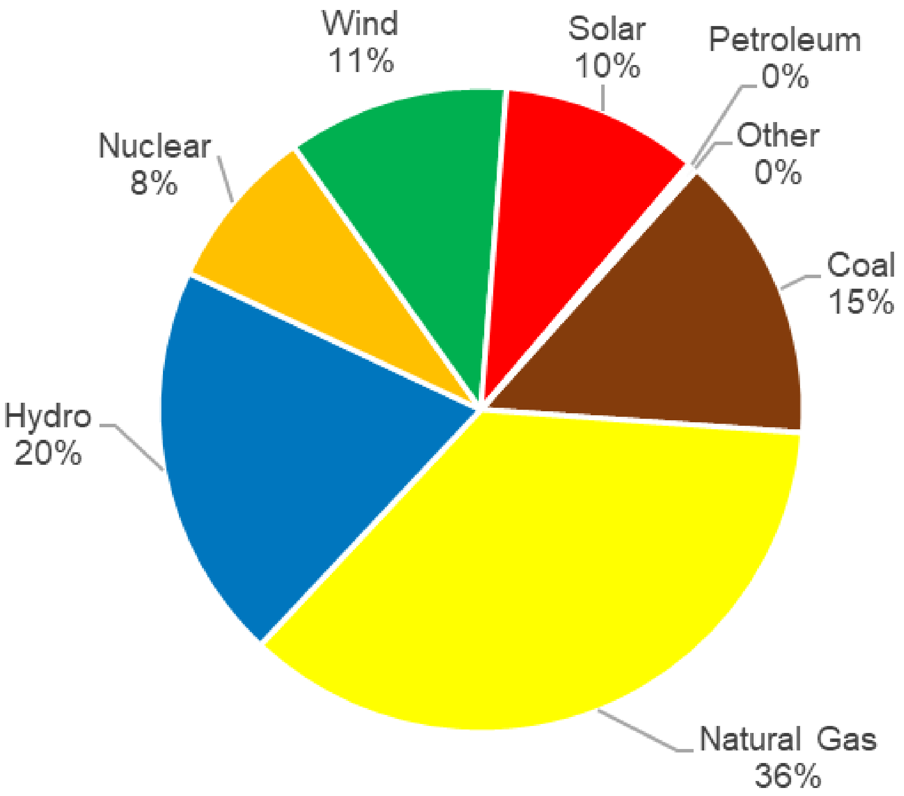
Northwest

69% GHG Emission Free



U.S. Western Interconnect

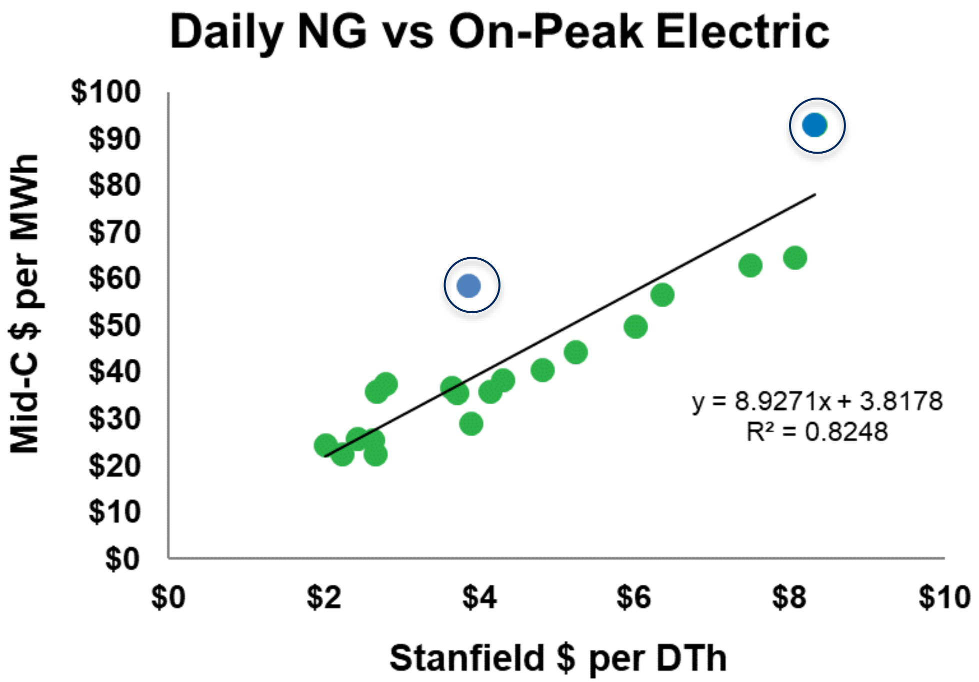
47% GHG Emission Free

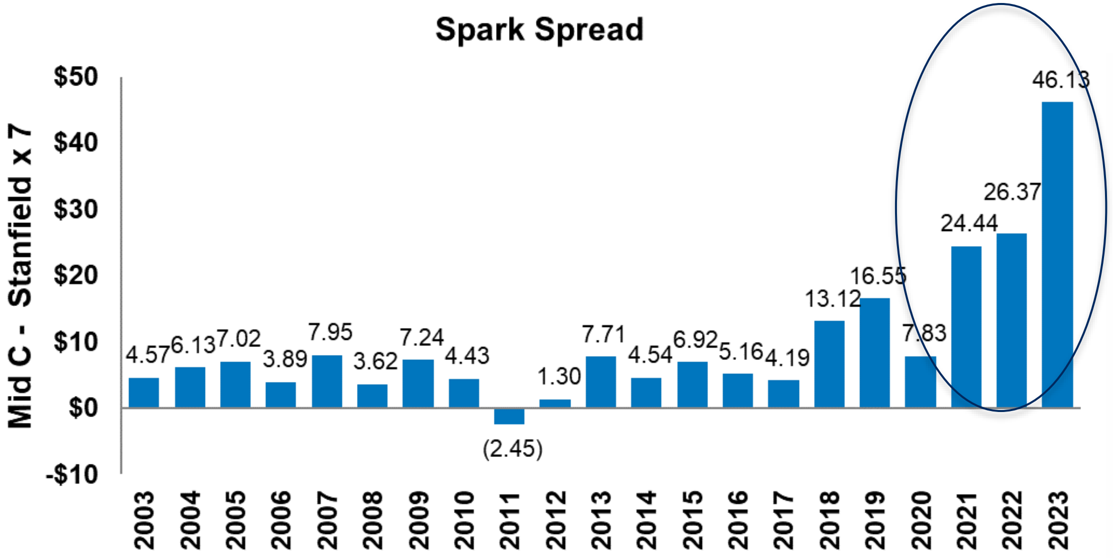


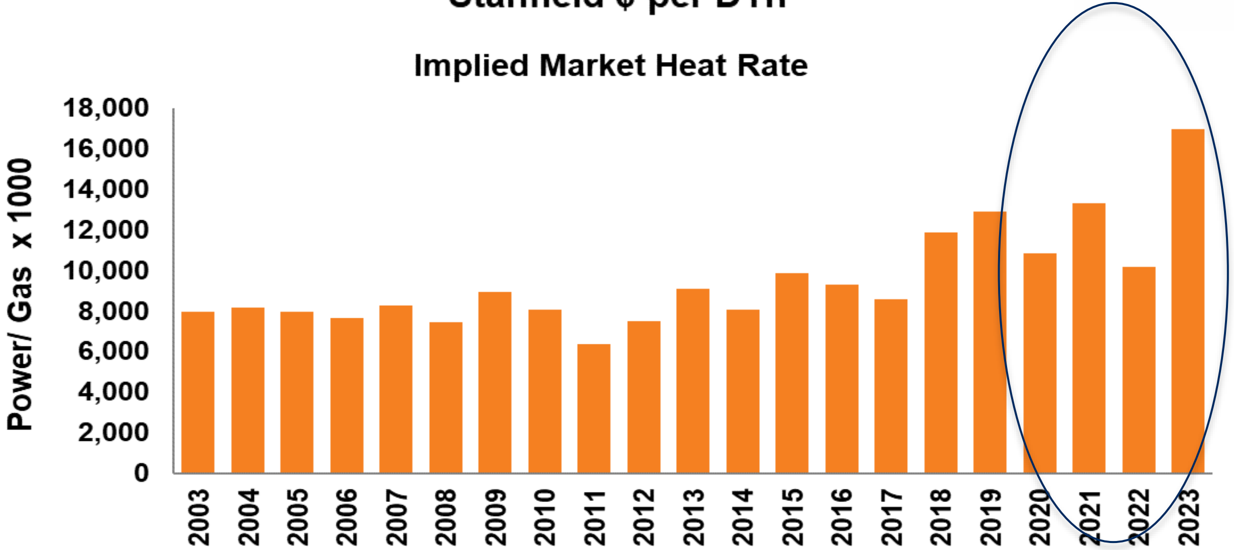
Source: EIA

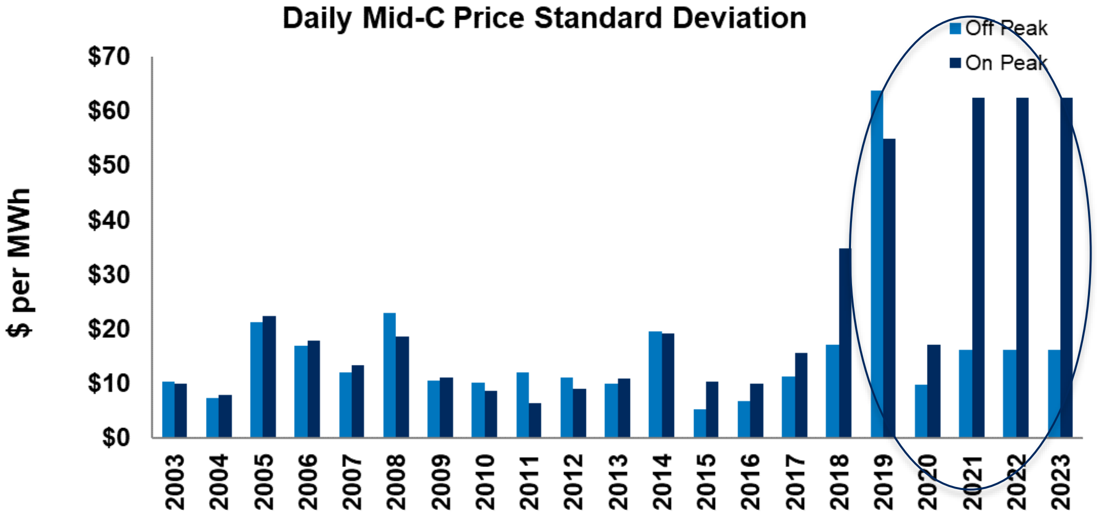
Appendix A

Market Indicators- Market is Tightening

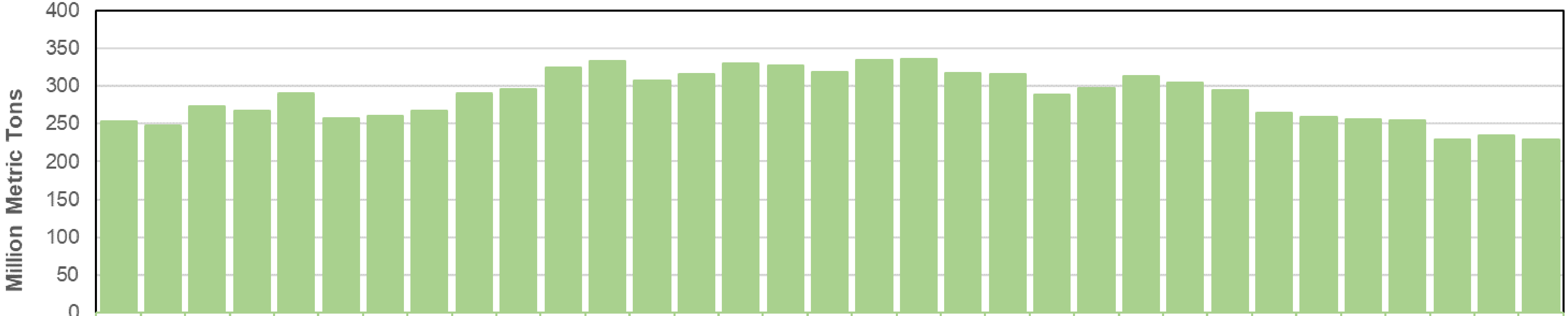








Electric Greenhouse Gas Emissions U.S. Western Interconnect



Change		1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
-3.7	WY	36	35	38	36	39	36	37	36	40	38	40	40	39	39	40	39	39	40	40	38	39	38	40	43	41	40	37	37	37	33	32	31	32
2.2	WA	9	9	11	11	13	10	12	10	13	12	16	16	13	15	15	15	10	13	14	14	14	8	7	13	12	12	10	11	11	15	12	11	11
-3.0	UT	29	28	30	31	32	30	30	31	32	33	33	33	34	35	36	36	37	39	39	37	36	34	32	36	35	34	28	28	29	28	26	30	26
5.8	OR	2	4	5	5	6	3	4	3	7	7	8	9	7	9	9	9	7	11	11	9	10	7	7	9	8	9	8	8	9	11	9	9	8
-16.0	NM	27	23	26	27	28	28	28	29	30	30	31	31	29	31	31	32	32	31	30	31	27	29	27	27	23	23	21	21	16	18	16	15	16
1.4	NV	17	18	19	18	20	18	19	19	21	21	25	24	21	23	25	26	17	17	18	18	17	15	15	16	16	15	15	13	14	14	13	14	14
-2.2	MT	16	17	18	15	18	17	14	16	18	18	17	18	16	19	19	19	19	20	20	17	20	17	16	17	17	18	16	16	15	16	10	13	14
1.8	ID	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	2	1	2	2	2	2	2	2	3	2
-1.8	CO	32	31	32	32	34	33	35	35	36	36	40	42	42	41	41	41	42	44	42	39	40	40	40	39	38	37	36	36	35	34	29	31	30
-8.2	CA	53	50	58	54	62	50	47	50	53	58	68	72	60	56	60	55	60	63	63	59	55	48	59	57	58	55	47	44	44	41	43	45	44
-0.2	AZ	33	33	36	38	39	33	33	36	39	41	46	47	46	47	53	52	54	56	59	54	56	54	52	55	54	50	45	44	47	44	36	34	33

Source: EIA

Emissions are adjusted for generation within the Western Interconnect

Modeling Process

1 Vendor Database
(2023 North American)

2 Input Changes
30 yr. hydro with climate change
NG prices
Regional Loads
Avista Resources/Loads
Operational Detail

3 Capacity Expansion
Add new resource forecast
(Capacity/RPS)
Include known retirements
Model adds resources to meet planning targets

4 Preliminary Deterministic Study

5 Test Year Stochastic Study
Test Resource Adequacy

6 Re-Run Capacity Expansion
Increase/Decrease Planning Margin Targets

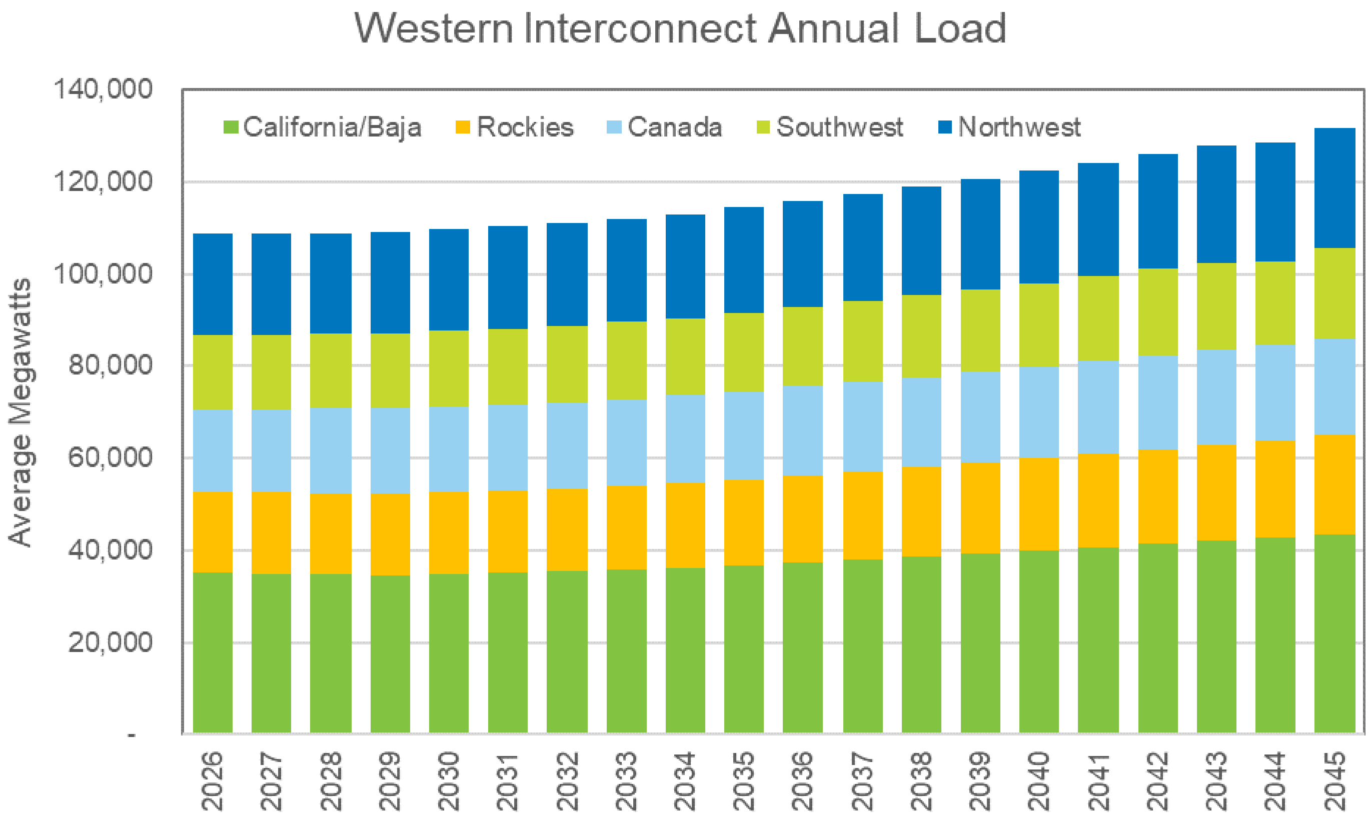
7 Run Full Forecast
Stochastic & Deterministic

8 Run Scenarios
Deterministic
Stochastic (if necessary)

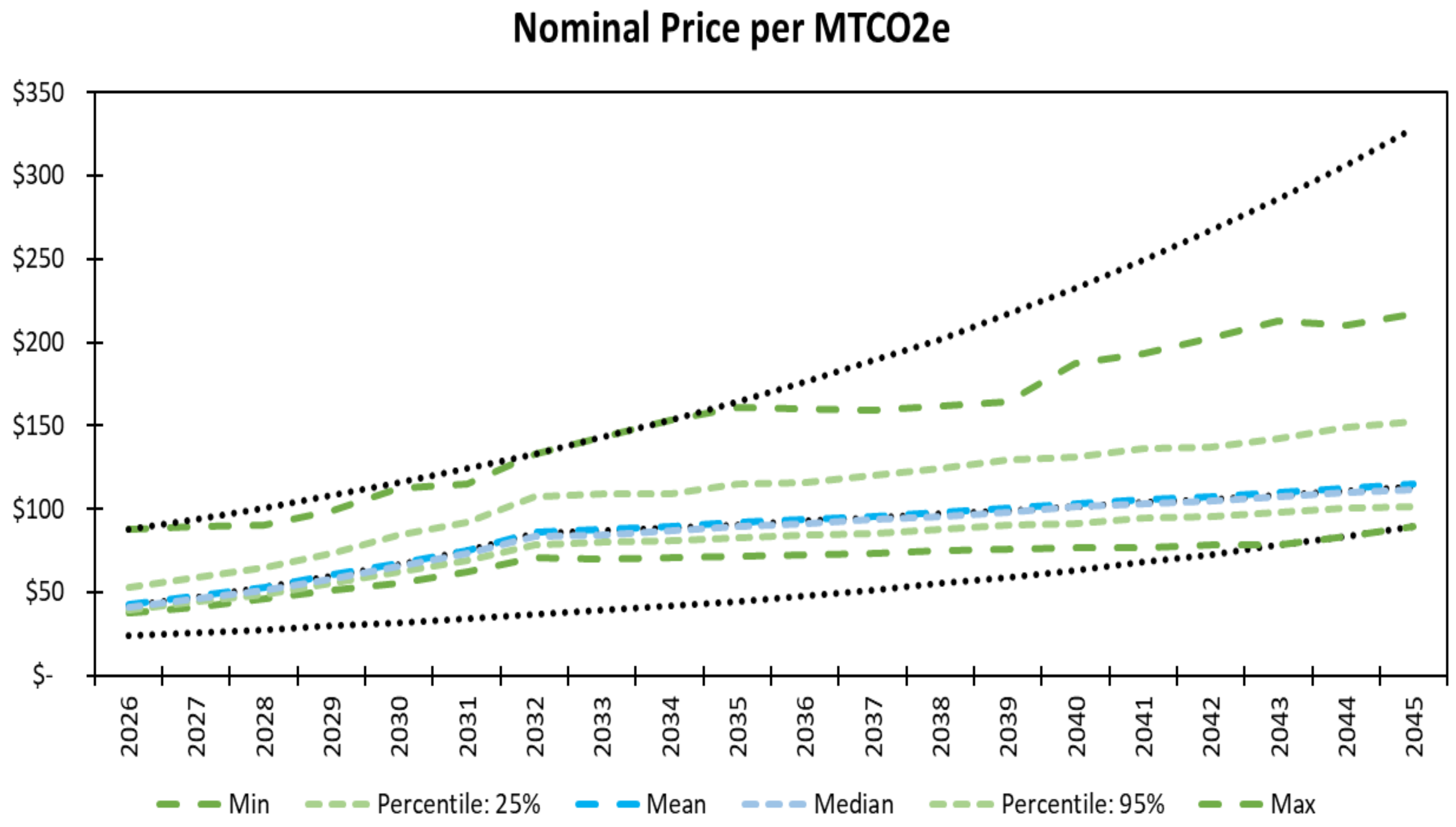
Draft forecast

Load Forecast

- Regional load forecast from IHS
  - Forecast includes energy efficiency
- Add net meter resource forecast
  - Annual input with hourly shape
- Add electric vehicle forecast
  - Annual input with hourly shape
- Future load shape differs from today's load shape



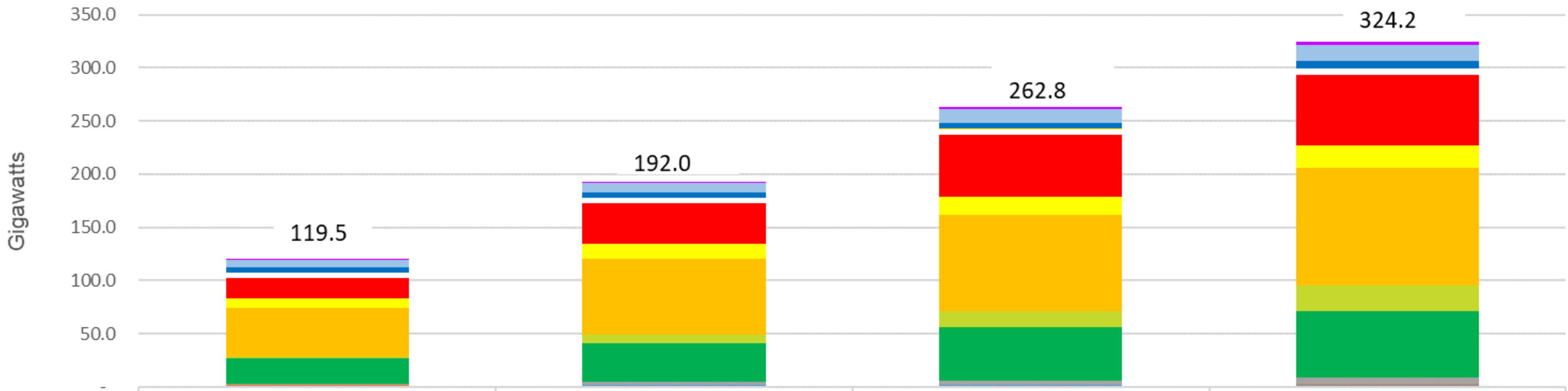
Carbon Pricing Assumptions



- Used consultant's carbon pricing
- $85.32 levelized carbon price
- Modeling CCA and CA/Quebec as a joint market; assume no national carbon price
- Regions importing into CA or WA incur a carbon price adder to transfer power
- Assumes carbon cost in dispatch for all resources beginning in 2031
- Stochastics – will use 300 random draws

Draft forecast

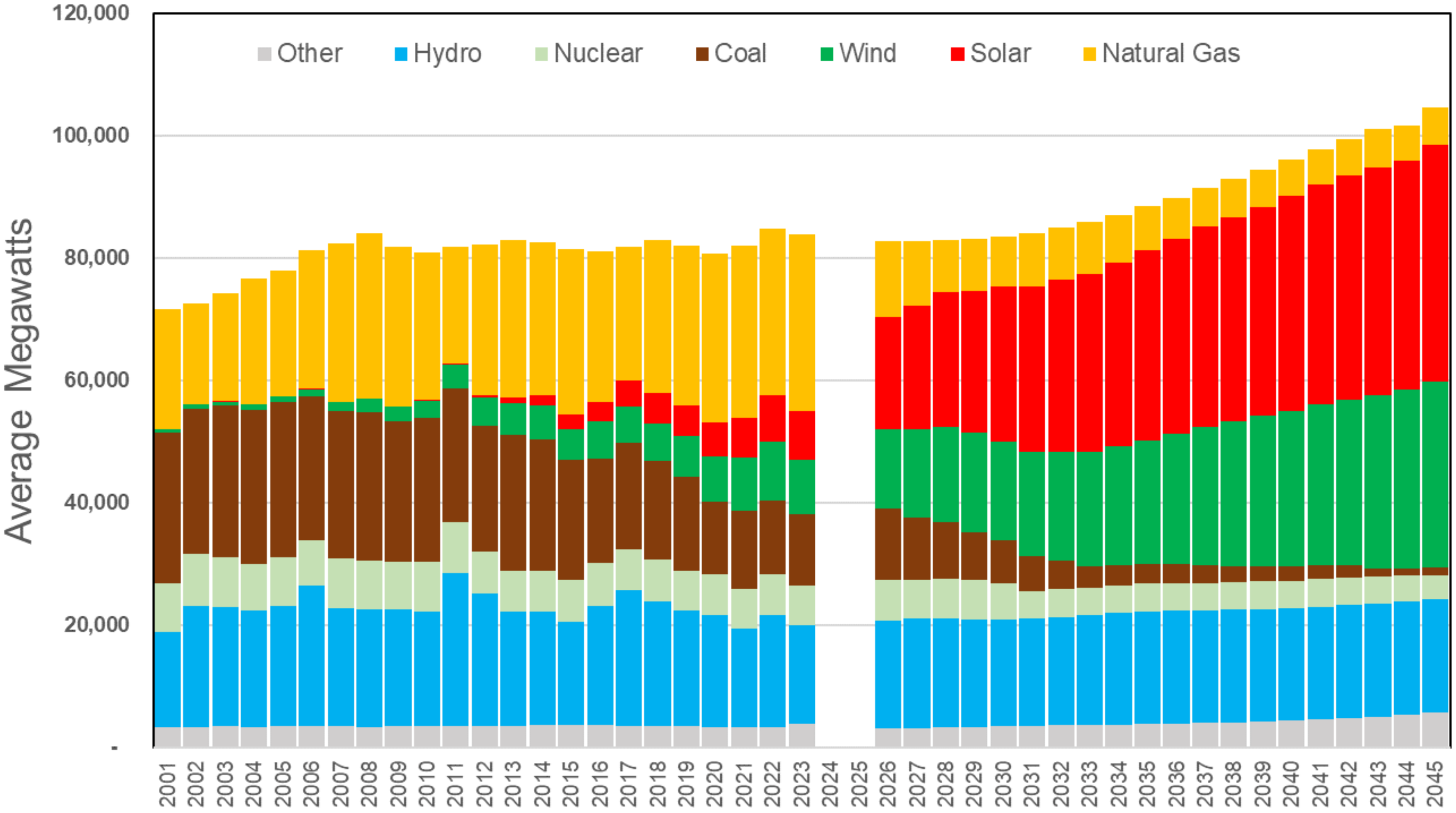
New Resource Forecast (Western Interconnect)



	2030	2035	2040	2045
H2CCCT	0.3	0.3	1.5	3.1
H2CT	-	-	-	-
SCCT	6.4	8.8	12.8	15.2
CCCT	4.9	4.9	5.9	6.4
Nuke	-	0.5	0.5	0.5
DR	5.1	5.3	5.5	5.8
Storage	19.1	38.1	58.0	66.8
Net-Meter	9.1	13.5	16.8	20.8
Solar	46.0	71.6	90.8	110.2
OSWind	1.5	8.3	15.2	23.9
Wind	23.8	35.9	49.4	62.8
Geothermal	1.8	2.8	4.1	6.0
Biomass	0.2	0.4	0.5	0.7
Hydro	1.3	1.5	1.8	2.1

Draft forecast

U.S. West Resource Type Forecast



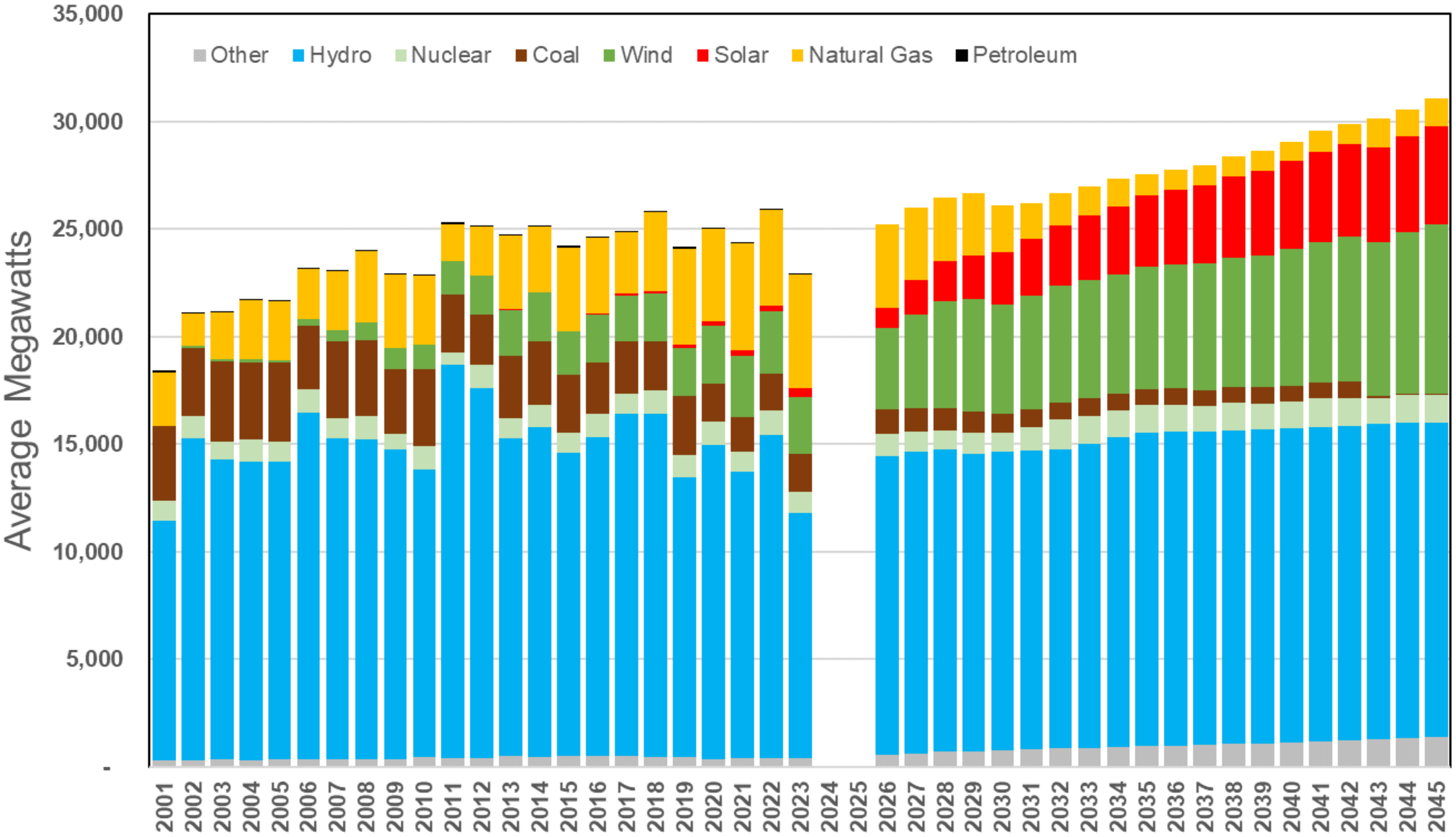
Significant changes 2045 to 2026 (aGW)

Solar:	+ 19.7
Wind:	+ 17.6
Nat Gas:	- 7.1
Coal:	- 8.1
Nuclear:	- 2.8
Other:	+ 0.6
Total:	+ 20.0

AVISTA

Draft forecast

Northwest Resource Type Forecast

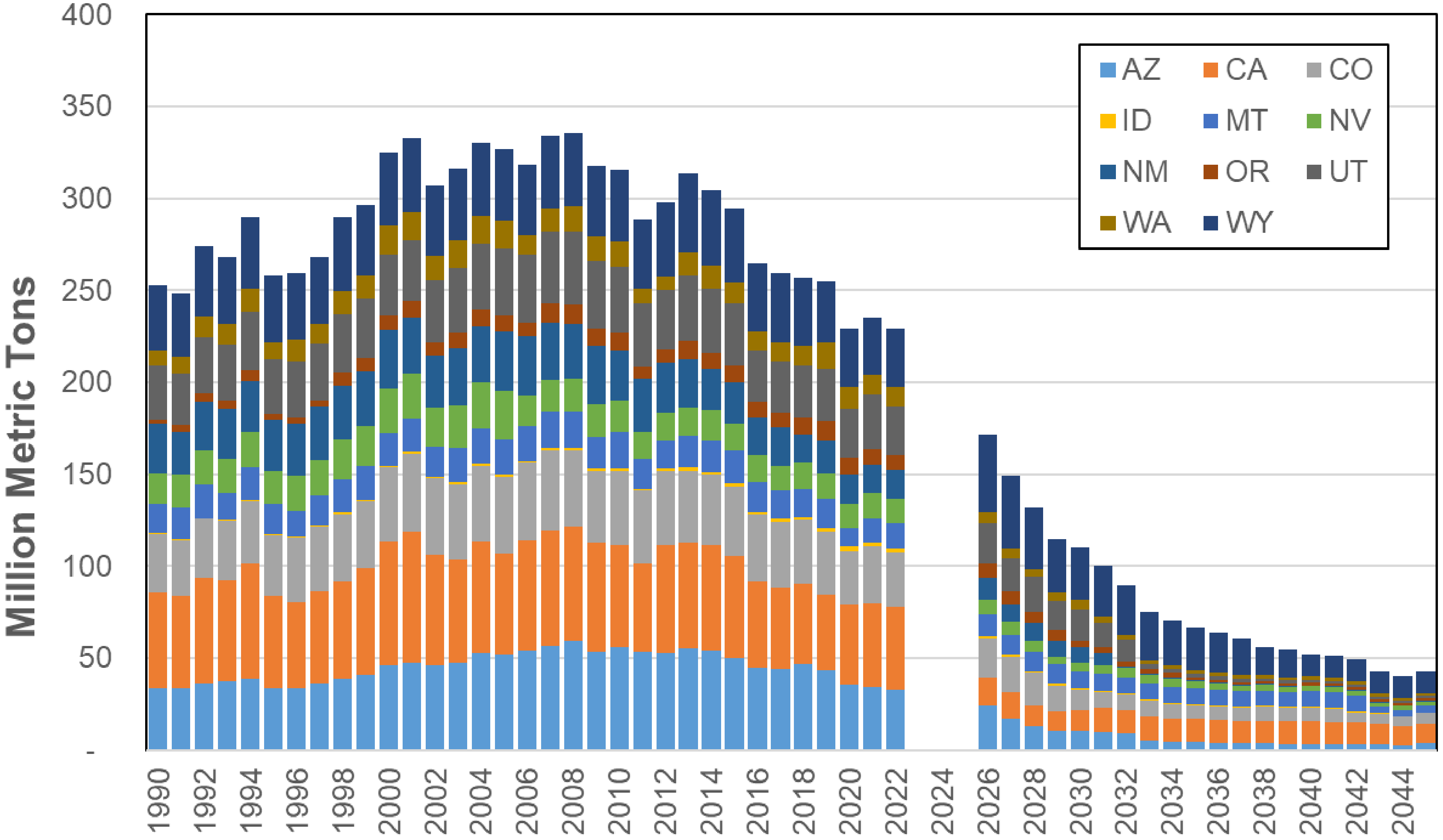


Significant changes (aGW) 2045 to 2023

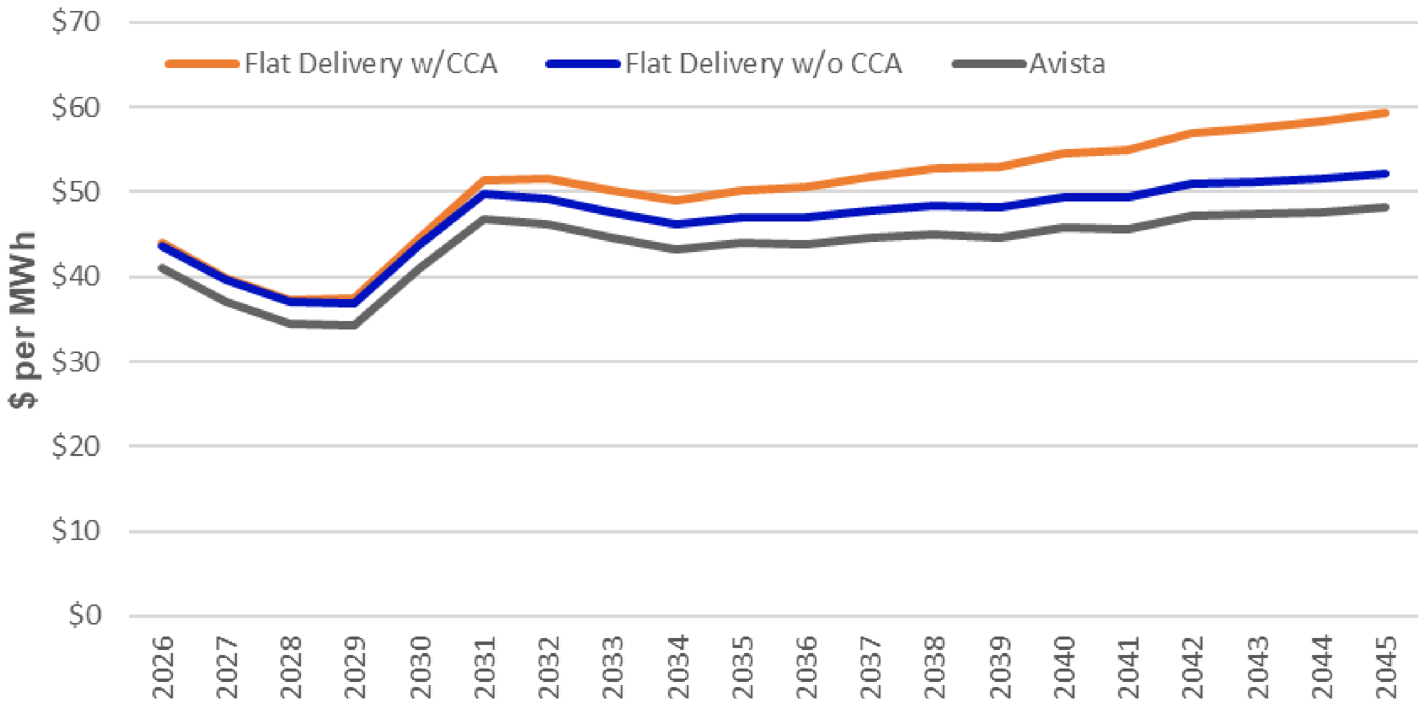
Solar: + 3.6
Wind: + 4.1
Nat Gas: - 2.6
Coal: - 1.1
Other: + 0.8
Nuclear: + 0.2
Total: + 5.1

Greenhouse Gas Forecast
U.S. Western Interconnect

Draft forecast

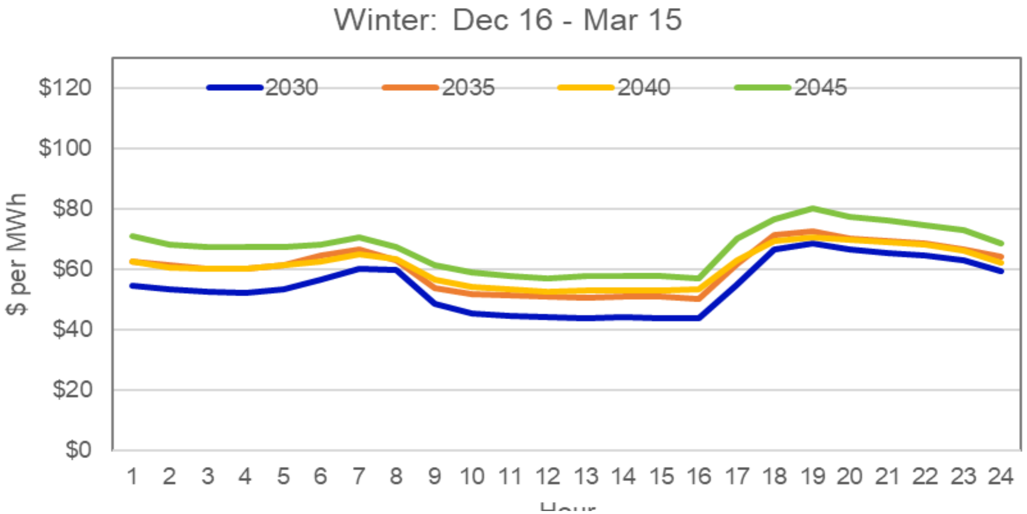


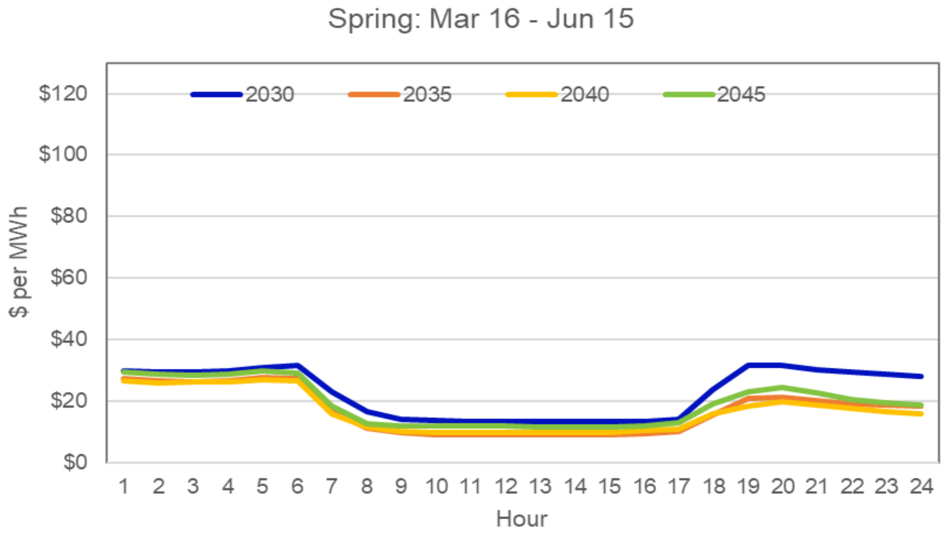
Mid-C Electric Price Forecast

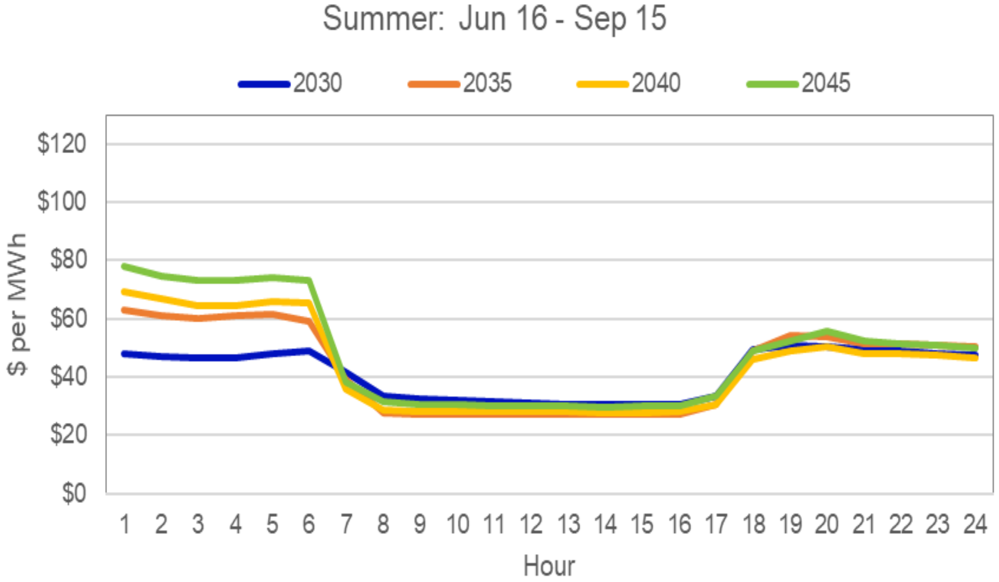


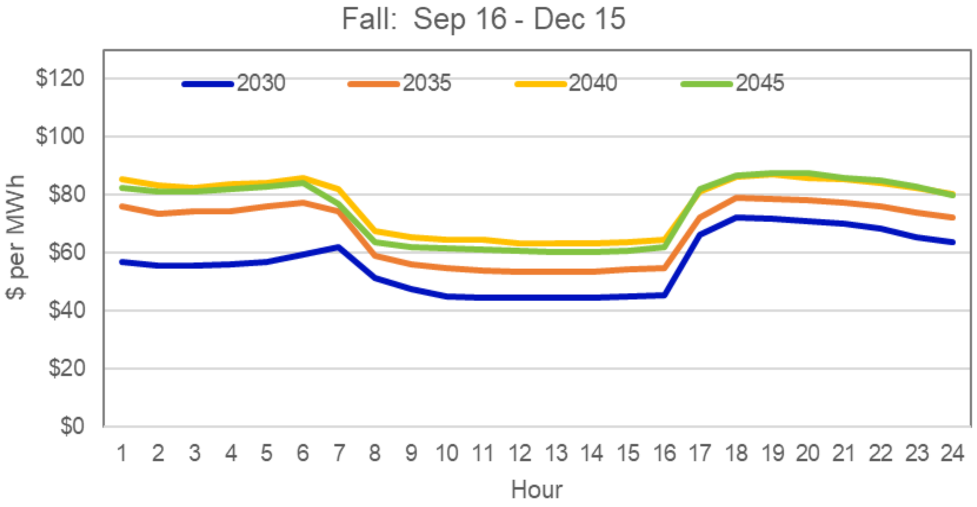
- Levelized Prices:
  - $48.12/MWh w/CCA
  - $45.52/MWh w/o CCA
  - $42.56/MWh Avista
- Forecast includes expected resource additions
- Potential for increased prices if new resources don’t come online

Hourly Wholesale Mid-C (w/o CCA) Electric Price Shapes



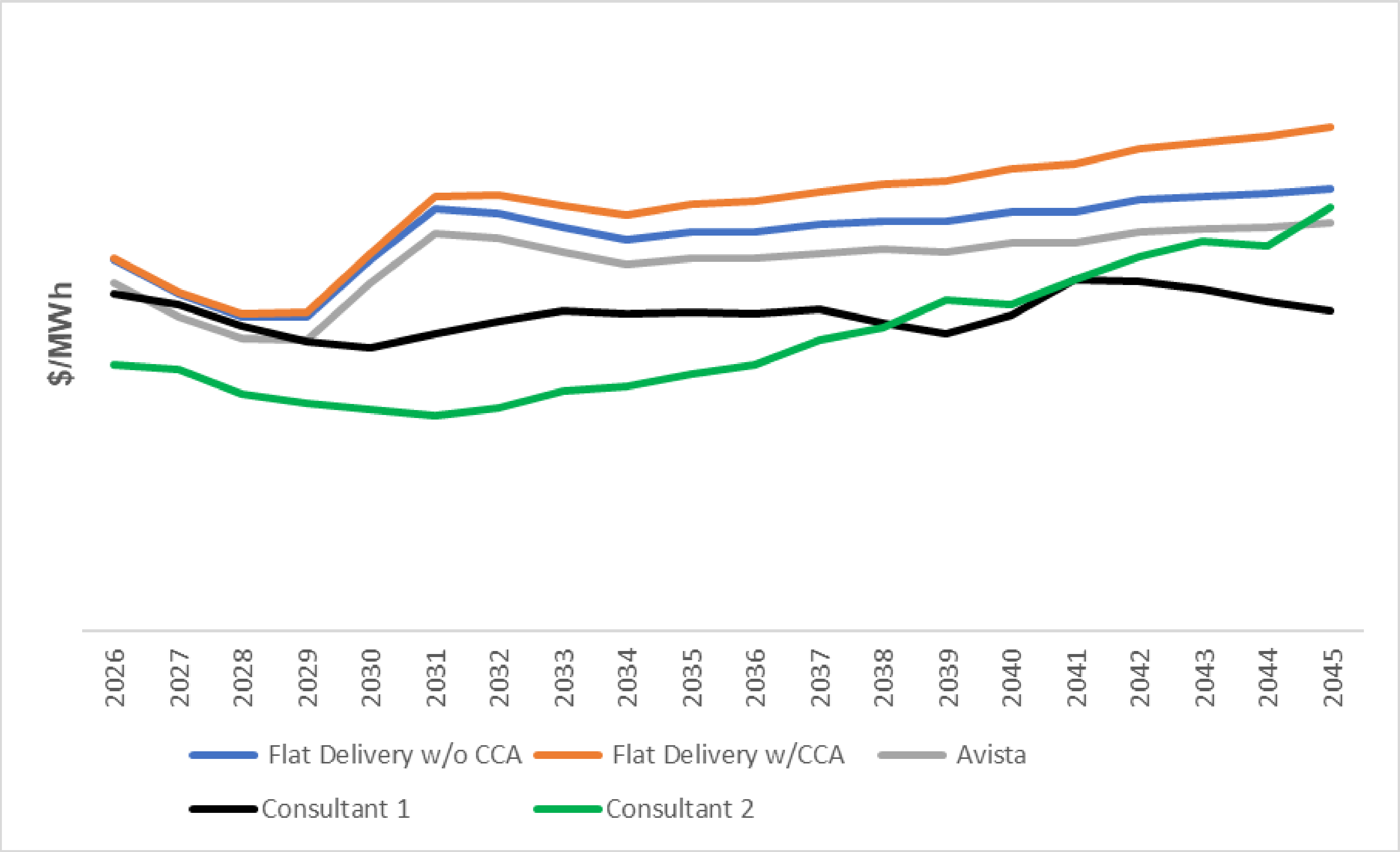






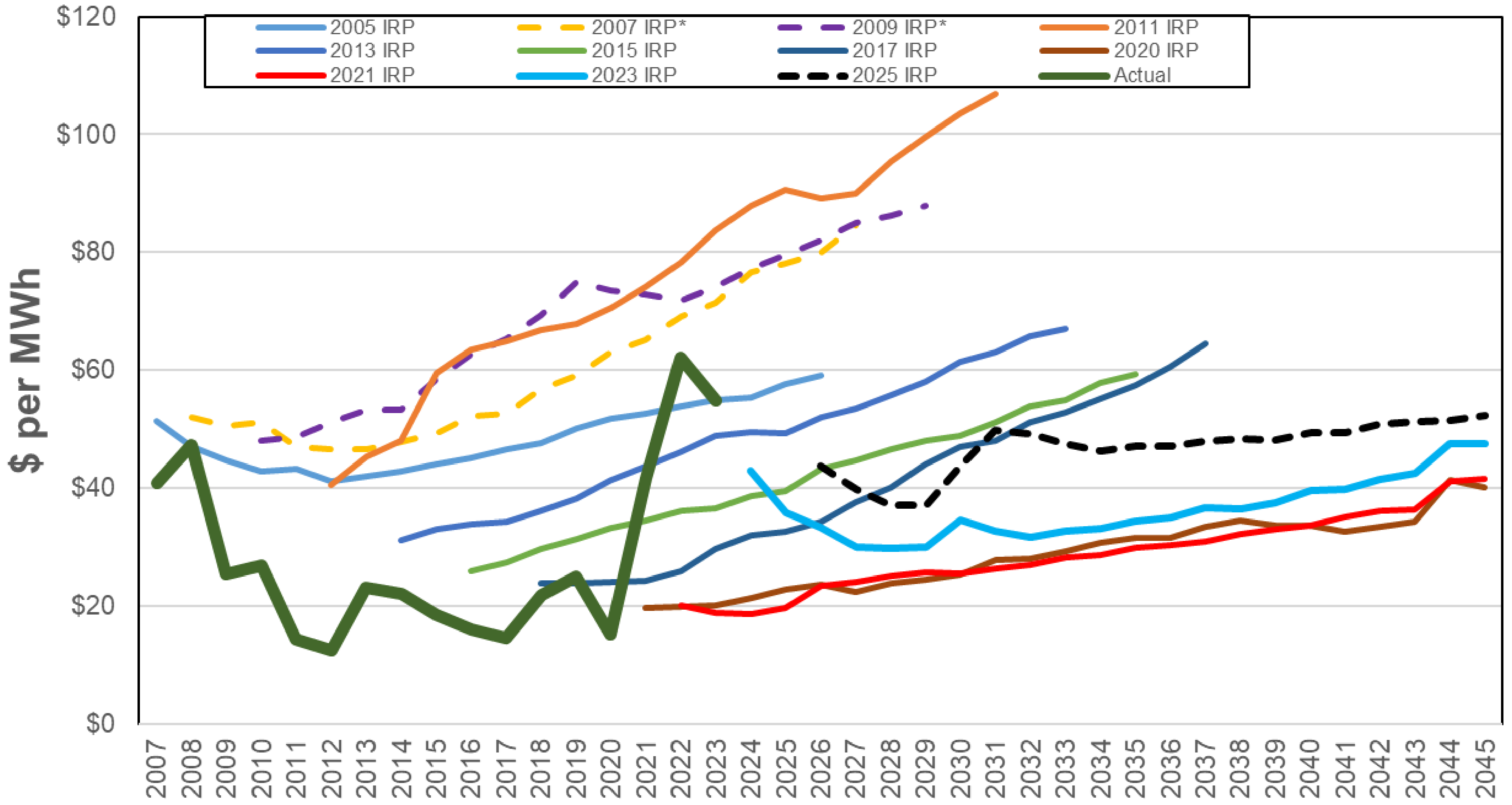
Draft forecast

Northwest Wholesale Electric Price Comparison



Draft forecast

Mid-C Price Forecast History and Actuals



Next Steps

- Finalize deterministic case
- Conduct stochastic studies and verify resource adequacy
- Run scenarios (deterministic/stochastic as appropriate)

2025 Electric IRP Portfolio Proposed Scenario List

	Scenario	Sensitivity	LOLP Study (2030)	LOLP Study (2045)
1	Preferred Resource Strategy	Deterministic Low NG Prices High NG Prices	X	X
2	Alternative Lowest Reasonable Cost			
3	Baseline: Least Cost Reliable Portfolio	Deterministic Low NG Prices High NG Prices	X	X
4	Clean Resource Portfolio by 2045	Deterministic Low NG Prices High NG Prices	X	X
5	Low Economic Growth (Low Load Growth)			
6	High Economic Growth (High Load Growth)			
7	80% Washington Building Electrification by 2045			
8	80% Washington Building Electrification by 2045 & High Transportation Electrification Scenario			
9	Extreme Building/Transportation Electrification for Washington & Idaho w/o new Natural Gas CTs			X
10	Maximum Washington Customer Benefits			
11	Least Cost + 500 MW Nuclear in 2040	Deterministic Low NG Prices High NG Prices		X
12	WRAP PRM		X	X
13	Least Cost + 0% LOLP		X	X
14	Power to Gas Unavailable			X
15	Minimal Viable CETA Target			
16	Maximum Viable CETA Target			
17	Preferred Resource Strategy w/ CCA repealed	No CCA Forecast		
18	Unconstrained Cost Preferred Resource Strategy			
19	High QCC on Demand Response (w/ minimum selection)		X	
	Avoided Cost Portfolios			
A	No Supply-Side Resource Additions			
B	Clean Capacity by 2045			

Other potential scenarios

- **RCP 8.5 Weather:** Given the expected case includes RCP 8.5 for summer, is it necessary to understand the impacts of lower winter capacity needs to warming temperatures?
- **20-year Weather:** Assumes the last 20-year average temperatures continue through the planning period to understand impacts of the warming temperatures.

Scenario Description:

1- **Preferred Resource Strategy:** Using the expected case load, resource, and stochastic price forecast, the model will determine the least cost resource strategy meeting each state's energy and capacity requirements. Portfolio will also track Customer Benefit Indicators in Washington and use Social Cost of Greenhouse Gas (SCGHG), Non-Energy Impacts, and Named Community Fund (NCIF) spending for Washington's portfolio optimization. Idaho's optimization will focus on least cost to meet energy and capacity requirements. Portfolio uses planning margin requirement to ensure 5% Loss of Load Probability (LOLP) in 2030. CETA targets are shown in Figure 1.

2- **Alternative Lowest Reasonable Cost**: Required study to determine CETA cost cap impacts. This scenario assumes no CETA clean energy requirements, no NCIF, but includes SCGHG for resource selection [in Washington] while meeting physical monthly energy/capacity requirements.

3- **Baseline: Least Cost Reliable Portfolio:** Determines the least cost portfolio to meet energy and capacity requirements based on economic decisions w/o SCGHG or CETA; same as the 'Alternative Lowest Cost Alternative' scenario w/o SCGHG prices for Washington. The portfolio will also be used to develop avoided costs as it separates portfolio costs by renewable and capacity premiums; quantifies the impacts of SCGHG.

4- **Clean Resource Portfolio by 2045**: Determines the portfolio to eliminate all greenhouse gas emitting generation resources in the portfolio by 2045. The resulting portfolio must meet all capacity and energy requirements.

5- **Low Economic Growth (Low Load Growth)**: Studies the portfolio effects of loads not materializing due to lower growth than forecasted.

6- **High Economic Growth (High Load Growth)**: Studies the portfolio effects of higher load levels materializing due to higher growth than forecasted.

7- **80% Washington Building Electrification by 2045:** Determines the least cost portfolio of converting 80% of Washington State natural gas residential and commercial demand to electric through heat/water conversions to heat pump and resistance technologies by 2045.

8- **80% Washington Building Electrification by 2045 & High Transportation Electrification Scenario**: Determines the least cost portfolio of converting 80% of Washington State natural gas demand to electric through heat/water conversions to heat pump and resistance technologies by 2045 along with a higher-than-expected electric transportation forecast.

9- **Extreme Building/Transportation Electrification w/o new Natural Gas CTs:** Determines the least cost portfolio of converting 80% of Washington & Idaho natural gas demand to electric through heat/water conversions to heat pump and resistance technologies by 2045 along with a higher-than-expected electric transportation forecast for both states. This scenario also assumes all natural gas resources are retired by 2045.

10- **Maximum Washington Customer Benefits:** Washington State required scenario to understand the portfolio and cost impacts of improving Customer Benefit Indicators. This portfolio will exclude non-Washington sited resources, air emitting resources and lower energy burden through additional energy efficiency and community solar for named communities. Higher named community penetration of roof-top solar and electric vehicles from the Distributed Energy Resource Study will also be considered.

11- **Least Cost + 500 MW Nuclear in 2040:** Uses the Preferred Resource Strategy assumptions with the addition of up to 500 MW of nuclear generation beginning in 2040.

12- **WRAP PRM**: Solves for the least cost portfolio meeting capacity, energy, and state policies using the Planning Reserve Margin currently required in the WRAP.

13- **Least Cost + 0% LOLP:** Solves for the least cost portfolio meeting capacity, energy, and state policies, but acquires generation to ensure the loss of load probability (LOLP) is zero rather than 5%.

14- **Power to Gas Unavailable:** Similar portfolio design as the "PRS" scenario without the option of using power to gas fuels such as Ammonia or Hydrogen.

15- **Minimal Viable CETA Target**: Uses the same portfolio design as the "PRS" scenario except the CETA targets for clean energy use the minimal viable targets from Figure 1.

16- **Maximum Viable CETA Target**: Uses the same portfolio design as the "PRS" scenario except the CETA targets for clean energy use the maximum viable targets from Figure 1.

17- **Preferred Resource Strategy w/ CCA repealed**: This portfolio uses the No CCA market price forecast and estimates the portfolio if the CCA is repealed by voters in November 2024.

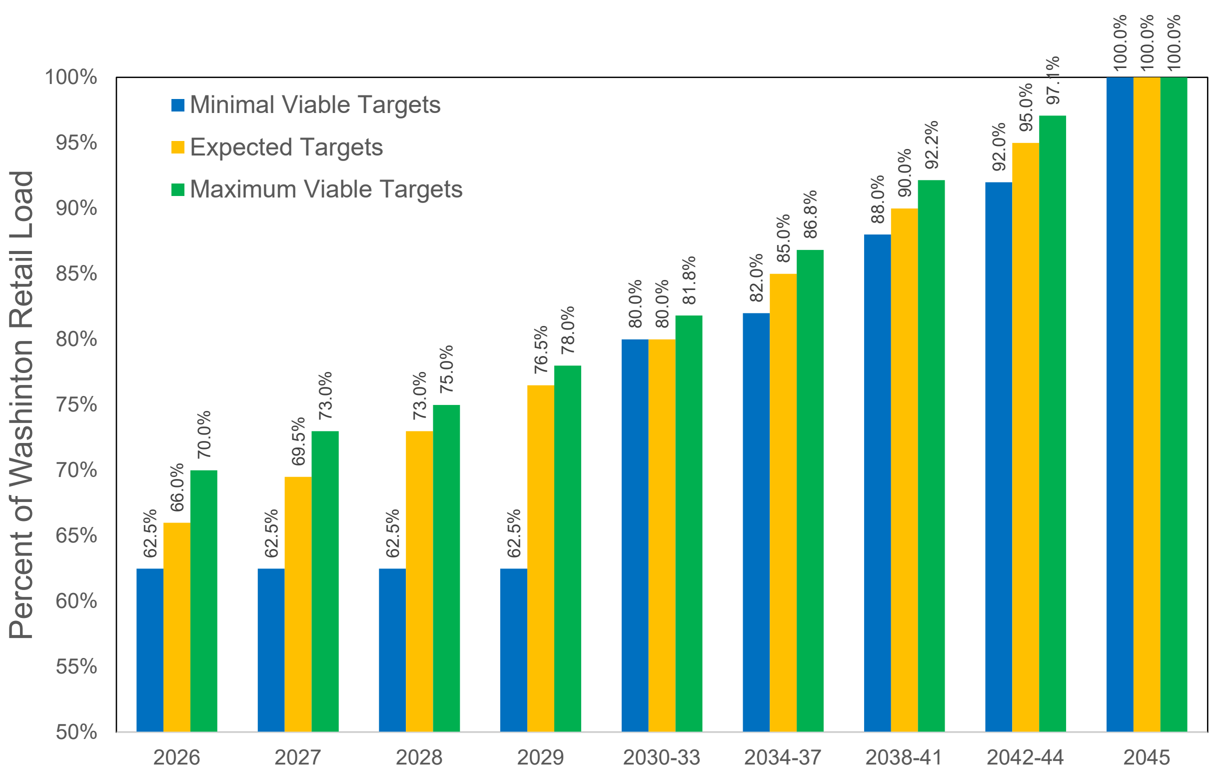
18- **Unconstrained Cost Preferred Resource Strategy:** In the event the PRS scenario is constrained by the 2% cost cap, this portfolio illustrates the cost to comply with 2045 CETA regardless of cost.

19- **High QCC on Demand Response (w/ minimum selection)**: This portfolio will be optimized using a higher QCC for demand response programs than used in the PRS scenario. If the portfolio does not result in higher demand response, the lower cost program options will be included in the portfolio.

Avoided Costs Portfolios:
No Supply-Side Resource Additions: This "portfolio" is only used to estimate the capacity premium of the avoided cost calculation; uses same EE selections as 'PRS' scenario; uses same assumptions as 'baseline' scenario except uses market purchases to meet demand instead of acquiring new resources.

Clean Capacity by 2045: This portfolio is similar to the 'baseline' scenario except it does not allow for new natural gas generation, does not require the model to satisfy monthly energy targets and assumes Coyote Springs 2 is not available in Washington in 2045. The portfolio is used to determine the clean capacity credit for avoided cost calculations only.

Figure 1: CETA Target Scenarios



2025 Electric IRP, TAC 3 Meeting Notes, March 21, 2024

Participants:

John Barber, Customer; Shawn Bonfield, Avista; Tamara Bradley, Avista; Molly Brewer, Washington UTC; Terrence Browne, Avista; Michael Brutocao, Avista; Logan Callen, City of Spokane; Katie Chamberlain, Renewable Northwest; Josie Cummings, Avista; Corey Dahl, Public Counsel; Kelly Dengel, Avista; Joshua Dennis, Washington UTC; Mike Dillon, Avista; Chris Drake, Avista; Michael Eldred, IPUC; Ryan Finesilver, Avista; Damon Fisher, Avista; Grant Forsyth, Avista; James Gall, Avista; Amanda Ghering, Avista; John Gross, Avista; Leona Haley, Avista; Lori Hermanson, Avista; Mike Hermanson, Avista; Jackson Parthasarathy, Grid United; Mary Kulas, White Gull Analytics?; Mike Louis, IPUC; John Lyons, Avista; Patrick Maher, Avista; Heather Moline, Washington UTC; Thomas Morrissey, NWPCC; Tom Pardee, Avista; Lloyd Reed; John Robbins, Wartsilla Energy Solutions; John Rothlin, Avista; Jennifer Snyder, Washington UTC; Dean Spratt, Avista; Lisa Stites, Grant County PUD; Brandon Taylor; Tyler Tobin, Puget Sound Energy; Yao Yin, IPUC

Introduction, John Lyons

John Lyons: I'm John Lyons with Avista's Resource Planning Group. Welcome to our third Technical Advisory Committee meeting today. We'll do a brief introduction, then we'll get into a review of the January cold weather event, then the wholesale natural gas and electric price forecast, and then we'll end with the discussion on portfolio and market scenario options that we're planning on looking at. We had some discussion here early on in this 2025 TAC process and a lot of the feedback that we got was that it's an awful lot of information that we're going through and members would like some time to process it and work that out in their mind. The thought was if we have more frequent TAC meetings that are shorter, that will keep people more involved with the process, but also, we will try to focus on just one or two key items.

John Lyons: We also, if you'll notice when I send out the email with the slide deck, we're trying to put on the key questions we're going to be asking you so you can start thinking ahead of time the ideas we would like to discuss. We will still take comments afterwards, if those come to you later. Also want to do a quick reminder, we have our DPAG [Distribution Planning Advisory Group] meeting next week that's on the 27th and that's going to be on EVs and solar in particular. If you're interested in those topics, be sure to call into that. If you're not on the DPAG, you can contact me, and I'll get you in touch with that.

John Lyons: Also, a lot of the data that we're starting to share is already out on the Teams site for the IRP. One thing we are asking if you go out to the Teams site, let us know if you're having problems pulling that data because we did receive a notice that there are some potential security issues and they might be locking some of that up, but so far it looks like people can still access it, but if they're not able to, please let us know. And then we would just go back to posting that on the website and after that part of the today's agenda, we do have the remaining TAC meeting.

John Lyons: Starting April 9th, will be every two weeks, with the exception of the Fourth of July weekend, and got those on there. They're also posted on the website, and you can see the topic. Next time we have future climate analysis and the economic forecast and the five-year load forecast. We also have the technical modeling workshop on June 25th. That is the only one that I haven't sent the meeting notice out yet, because I didn't want to hit everyone with too many meeting notices all at once. I'll be sending that out soon. August 13th will be the last TAC meeting for this series, this every other week schedule. We will release the draft IRP September 2nd and the final IRP January of 2025.

John Lyons: And then we also will have a couple of public sessions where we'll have a recorded presentation and then we'll have a daytime and an evening time period for comment. That's all I've got for the introduction, unless there's any questions. Hearing none James, do you want to take it over and start sharing the load event presentation?

Review of January Cold Weather Event, James Gall

James Gall: Do you see my slide?

John Lyons: I do.

James Gall: OK. We're in good shape then.

John Lyons: Hopefully someone outside of Avista can see that as well.

James Gall: Hopefully. Usually that's the case. Good morning everybody. The MLK weekend weather event. I'd say it's kind of the canary in the coal mine event for the region. The reason why I say that is I think that's the closest our system in between Avista and the region has been from not meeting loads. Actually, Avista did have to curtail some loads which I'll get to in a little bit. But it shows the dire need of resource adequacy in the Northwest. We'll go through some Avista's experiences.

James Gall: We had some very unique experiences during that event compared to the region Feel free to stop me as I go through this. If there's a question that comes up, there's your hand. I'll probably see that, or Lori or John might see it as well, and we can pause. Or go ahead and put it in the chat and that works as well. I'll getting started.

James Gall: This is just to give you an idea of the temperatures that we experienced on January 13th. These are the low temperatures. Spokane, which we typically plan for, we were minus 10 at the airport as a low. Our high was minus four, maybe minus two. Parts of our service territory got in the minus 20s, minus 28 down in Lewiston, or Sandpoint area minus 17. We saw extreme temperatures during this event, and this was, I would say, very similar to an event we had a year ago on December 22, 2022. We saw almost identical low temperatures and very close to the same high temperature. So, we saw two of these events in the winter in a row, but we actually saw different outcomes in load and also in performance.

James Gall: We'll get to the performance of the gas system in a minute. This chart represents our loads and resources, and this is what we're trying to balance. If you want to relate this to an IRP, this is the best illustration because the IRP is trying to plan our system to meet this type of an event and the black line on this chart represents what our actual load was. During this event, we had our highest load on the 13th, which is a Saturday, which is typically uncommon. But right here in our 18, in this black, dotted line represents what the load would have been if we did not have to curtail some of our industrial customers. One was voluntary, one was involuntary, and what I mean by involuntary, we had a natural gas issue on the GTN pipeline. Upstream of us there were some mechanical problems on a compressor station and that reduced the pressure for the Spokane area. In response to that, two of our natural gas facilities had to curtail, and a substantial amount of industrial customers also had to curtail. And when that happened, one of our industrial customers on the electric side has both gas and electric service had to reduce their loading. I see a hand up by Molly. You have a question?

Molly Brewer (UTC): Yeah, there's the question is, is curtailing like load shedding or what exactly is curtailing?

James Gall: Yeah. Think of his load shedding.

Molly Brewer (UTC): OK.

James Gall: Essentially asking that customer to reduce their demand. One of our industrial customers, we have an agreement to reduce demand and there's a compensation package for that and other customers. If there is a reliability event, there are some agreements to reduce demand in those circumstances. Those are very rare, and this is a very rare event.

Molly Brewer (UTC): OK. Thank you.

James Gall: From that point of view, the red line that's dotted on top represents how much capacity we actually have to hold on our system. Even though our load may have been at the level you see here, we actually have to reserve capacity on our system for that higher amount to meet two critical things. One is operating reserves. Those are reserves that we're required to hold by WECC, 3% of our load amount and 3% of our online generation. Those reserves are required to keep our system stable in the event a unit trips. For example, when we had to bring units down here in the early part of the day on Friday, something has to respond to that unit going down. That's why we hold these reserves and that's required by every generator and load serving entity in the Western Interconnect. The other component of capacity we have to hold is something that is newer to Avista and that is EIM flex ramp. When we participate in the EIM, we actually have to hold capacity on our system to participate in the market. Before EIM, we ran our system as we saw fit. We wanted to hold reserves for our needs, but now we actually have a mandated amount of reserves we have to carry. These two things add up to maybe a couple hundred megawatts between the two that we have to carry in reserve.

James Gall: I'm moving to the resource side. On the bottom we have our Kettle Falls in our qualifying facilities, and black - Colstrip and brown - our natural gas, and yellow – wind, solar is the green, and hydro is in the blue section. How this chart works is if you see colored area below the black line where purchasing power on the market and if we are the color is above the block line we're selling. You can see here, during our peak event when we lost our generation, we had a substantial purchase. When we plan our system and IRP we do expect to rely on the market to a certain amount. It's about 330 megawatts in our planning and we also intend to serve all of our loads. If from an IRP planning type of event, when we model those, we're trying to see what is the probability of a loss of load event? That is a circumstance where you can't serve all of your load with your generation or up to 330 megawatts from the market. This event actually qualifies. This would be a loss of load event in our planning process methodology.

James Gall: This is actually pretty concerning from a reliability point of view because it's starting to show maybe we do not have enough capacity. Going into this event, last IRP, we thought we had quite a bit more capacity than, or I should say we were capacity long I think to about 2035, but there's a few things that have changed since then. One is we are seeing substantially higher loads for this load level for the given temperature. Given that we had the same temperature last winter was around, I believe 70 or 80 megawatts higher at that peak hour, and that doesn't even include some of the load shedding we had to do. So, there has been some load growth, also this EIM flex ramp that we're required to hold that is something we've not really planned for. In the past, we've planned for a lower amount of flexibility. We're going to see in this next IRP, because of this event and we have real data to the look at, we need to start planning for these types of events and if a future occurs like we're we know in 2026, this brown, bar down here, Colstrip is not going to be available to us. How do we serve these events?

James Gall: We call them sustained peaking events and without a stable resource it's going to be difficult in the future to have a reliable system. One analysis I looked at after this event because again this is a low hydro event, high load event with some resource outages that if we even had 10 times as much wind which would be around 1,600 megawatts more of wind and 100 times more solar, say 2,000 megawatts of solar. That's the future we're tracking towards. How do we serve this event with those resources? And really, at the end of the day, it comes down to we need storage assets, but the amount of storage we need is so massive, the service of and I don't know how that's going to occur at least in the next decade. Just to give you an illustration, if the common battery of today is four hours, if we had four-hour battery and the renewable resources I mentioned earlier, we would need 14,000 megawatts of batteries. Now that's more than is on the Western system right now and that's just to serve our load. Long duration batteries is probably where we need to go. If we had 50-hour batteries, we would only need around 1,200 megawatts. But the challenge with that is at 1,200 megawatts at the 50-hour battery, even if we perfectly timed our dispatch, we would have nothing left at the end of this week to serve the next week.

James Gall: The key to have a future, a reliable future with no natural gas or no coal, we're going to need some extremely long duration energy storage facilities. I see a hand up. Actually, I see two hands up. I don't know who is first. Kelly, go ahead and go first.

Kelly Dengel: Yeah, James, thanks. This is Kelly, from Avista. This is just painting the picture of the electric customers and you're not really showing the picture of what the gas customers experienced, right? So just where?

James Gall: That's next line. Yep.

Kelly Dengel: OK, because then this pictures only compounded when you include the gas customers that were affected by outages or the shortage of resources as well. That's all I wanted to say.

James Gall: I'll get into that a little bit. I don't have the amount that had to be curtailed on the industrial side. Our firm customers were not curtailed, but I'll illustrate a little bit of how much equivalent electric load there is on the gas system. I can't see who had the other hand up but go ahead.

Jackson Parthasarathy: Jackson, with Grid United. Nice to meet you. Due to the kind of regional nature of this weather where you have this extreme event that's impacting the whole Pacific Northwest all at the same time creates large hurdles for resource adequacy as you're pointing out here. How do you think about, I guess to take a step back, you were talking about batteries as well and the resource build out of batteries that you might need in order to be able to serve load in such events where gas pressure drops, and gas plants leave the system. Do you think about interregional transmission, and I mean particularly one of our projects proposes to connect Colstrip with SPP and MISO and the ability to import resources from outside of the region. If you could talk a little bit about that.

James Gall: Sure. Actually, that's going to be one of my topics coming up on a couple slides.

Jackson Parthasarathy: OK.

James Gall: But you know transmission is, I'll put it this way, it's an option to help with resource adequacy if you can contract for a resource on the other side and there's been some historical examples of transmission is not a necessarily reliable resource and it can be, if you have differing weather patterns. But if you all have a similar event at the same time, it makes it a challenge to rely on the transmission. The one event that comes back to me was a summer event. I think it was in 2006 or 2007 and the whole West was hot and we could not send power to California or vice versa just because we both had severe events. But if we had contracted resources that we could depend on and we had pretty solid evidence that there is a diversity of resources over there, we might be able to argue there's a capacity value there. But again, do we have a secured asset over there and how much can we really rely on the market? Because even if you go into eastern Montana, which is not far from where you're talking about the wind facilities over there, they were frozen up. They could not produce energy. Is that going to be a similar circumstance in South Dakota, North Dakota? I don't know. It's a good question. I don't have the answer, but it definitely gives you options, I'll put it that way.

Jackson Parthasarathy: Thank you.

James Gall: All right. Just to wrap things up here. Assuming we did not have the loss of gas pressure, would this have been an IRP type of loss of load event. It probably would not have been, we would have been in our planning criteria although we did have higher loads, lower hydro production. Basically, what we're finding in resource planning when we do these analyses, we know it's going to be an event like this where you have high loads or slightly above high loads, low water, and then low renewable production and a unit trips. That's the remedy for having resource adequacy issues and those all compounded together. And this event from a price point of view, when we had to go out and buy replacement power almost this whole week was near $1,000 a megawatt hour at the first cap. This is an expensive event when you don't have resources available and that $1,000 represents the need of the region. And I got a slide a little bit later on that, but also the transmission system to California was on. There's two lines that connect the northwest to California. One of those was down on maintenance and that also made it difficult to move power around. So, there's another example. Can you rely on transmission and that case the PCDC intertie was not available at the time. OK.

James Gall: Into gas really quick. I just want to illustrate the amount of load that's on the gas system versus electric system on these days. As I mentioned earlier, this event compared to last winter was about the same load, but we did have to curtail some generation or some load on this event, that's that red bar there. What we did is convert the electric load to Btus, so we could compare those to the gas load, and this is our firm gas load in Washington and Idaho. You can see our gas load is almost three times as much as our electric load on these winter days. And we also set a winter peak load event for the gas system, but like Kelly had mentioned earlier, if you look at our gas system and you think of a future of we want to move people from the gas system to the electric system. Our loads would be substantially higher. How do we manage that?

James Gall: We've shown that in many scenarios in the last couple IRPs, but the 315 mmBtus use, or thousands of mmBtus, wouldn't quite be that much on the electric side. Electric system is a little bit more efficient, but still maybe 2/3 of that would be electric load and it's just a good illustration of the challenges of electrification of buildings, of the quantity of megawatts of just generation you need, but also how do you deliver that to load.

James Gall: It's a substantial challenge that the region would have if we electrify, and you compare that to our highest summer day. So, on our summer day, which was the Heat Dome event June 30th, 2021, highest peak hour we've ever seen and the amount of load that day though was still less than these events because most of that load was concentrated in the evening where the loads that you have in a winter event are all day long.

James Gall: And just to kind of give you an idea that event was like a 1-in-100 event. Some people may argue these winter event temperatures are not unheard of in Spokane. It was still not colder than our 2008 event, which isn't too long ago. Cold events are often. But when you don't get one, our winter loads don't look very high. But when you get a load event in the winter, it illustrates substantially higher loads. If we didn't have to curtail generation and two customers, our load would have been substantially higher than the most extreme event we've ever seen in Spokane.

James Gall: Just to wrap this up quick, from the regional perspective, this is a similar L&R chart on the bottom left and the pink area is my biggest concern. That's the amount of imports the region had to bring in, this here from the Power Council. The Power Council, I believe plans for around 1,500 megawatts of imports. The region was substantially short, did not have enough generation within its own system to meet pretty much most of the loads from late Friday into later in the week. This is really showing a resource adequacy problem in the Northwest during these events. You can see that in market prices, and also how much units are running, or peaking units are being dispatched more than they have been in decades because there's just not enough energy in the system to continue to meet demand. Demands are growing and we're not building dispatchable generation, so we're starting to see more and more reliance on our natural gas units. And as coal goes away because of lack of reliable generation and then moving to the right is the flow of those imports come from, a lot of those come through California. But my understanding is most of those flows really came from the southwest via California. We also did get some energy from Canada and especially Avista. We did rely on Powerex quite a bit. While our units did trip, so we appreciate their support, but I see Kelly, you have a hand up.

Kelly Dengel: Yeah. James, on the left with the resource stack, I see a tiny little bit of nuclear. Can you explain where that's coming from?

James Gall: Yeah, that's the Columbia Generating Station outside of the Tri Cities, it's around 1,100 MW.

Kelly Dengel: OK. Thank you.

James Gall: You're welcome. OK. Just to wrap things up. Since this is a canary in the coal mine event, what are things that we should be doing in resource planning to make sure we have an adequate system? I have three things in red that we are, I would say mostly going to do, or I should say highly considering. And then there's some other items that maybe we should consider. The first one is, obviously, we're going to update our load forecast with the data from this event. We're working on that this week. Grant has got that nearly wrapped up, but what that will do is show a higher load forecast for winter events in our next IRP, which means we'll have to acquire capacity resources sooner than later. Another thing we're doing is we're including the EIM uncertainty flex ramp in our resource planning. When we do our loss of load probability analysis, we'll include that capacity requirement at the levels we are seeing the EIM asking us to hold. We've always included a requirement for this, but the amounts we're being asked to hold are much higher than we anticipated when we did our last round of analysis.

James Gall: The third item is something that is, I think, a key for reliability. It's, I'd say less static. We call it the single largest contingency. What we mean by that is we should be carrying capacity above our or should say we should have a planning margin higher than our single largest contingency resource, which what that means essentially is if that largest contingency resource tripped, we would have at least enough capacity to cover the expected peak load from our other resources. Since Avista actually has probably the largest single contingency resource compared to its load of any of the control areas, that would essentially make us a little bit longer and likely the summer months is what we're expecting. That change would likely push us into a shorter position this summer as our Coyote Springs facilities is our largest single contingency unit.

James Gall: The fourth item has to do with low hydro years. The region used to always plan for low hydro, but when we started moving to loss of load probability type analysis, low hydro got moved to median hydro. When we got our QCC values for example, that's qualifying capacity credit in our regional resource adequacy program, they typically assume you know more of an average hydro or meeting hydro event, and should we be assuming a low hydro event which means lowering the expectation of our storage hydro units. And I think that has a lot to do with the regional response. We just did not get as much out of our hydro system as maybe we had hoped for from a regional perspective. At least that's my opinion.

James Gall: The next one, should we be looking at something different than 5% loss of load probability? Essentially, when you plan for resource adequacy, a 5% loss of load probably means that you're going to have a loss of load one out of every 20 years and that's kind of what we got here. Is that the right level of planning? Should we be planning for a more reliable system? And I think that might be a question for, even the tag here, is 5% too modest? Should we be more conservative and plan for something a little bit tighter? One percent, 2%? What's an acceptable outage when you're having an extreme cold event? I know there are consequences of losing load, especially when it starts affecting residential customers.

James Gall: Another thing is how much can we depend on the market which is the second to last bullet. We've always assumed around 330 megawatts. We were able to lean on the market for that amount for a short amount of time. That was definitely not something we could have done sustained. As you can see in that week, because the whole region was looking for the market. That goes back to even the transmission as well. We had more transmission. Can we rely somewhat on the market at a higher level and I say those are still questionable. The last one, is doing loss of load probability analysis or looking at statistics, a right way to do resource adequacy planning? Should we rather be looking at event planning where we have a low water year event, we have a low renewable output event with higher-than-average loads? Should we be planning for those events rather than a statistical probability of an event? It starts to make some sense to me to start looking at that. We'll be studying what that looks like in this IRP process, but that's all I have. Are there any questions, comments? Katie, go ahead.

Katie Chamberlain: Hi. I think you may have explained this at the beginning and I'm sorry if I missed it but could you just reiterate what happened with gas on your system? I think on the 13th.

James Gall: Yeah. The late the day before. GTN is a pipeline that we use to buy gas from for our local distribution customers and to supply our natural gas turbines. They had a compressor station issue in Alberta, and they were not able to deliver as much gas as we had requested. So, we had to bring down two of our facilities and then also some of the natural gas transport customers who buy gas on that system in our area also had to reduce their gas usage.

Katie Chamberlain: Got it. Thanks.

James Gall: Yeah. Any other questions? If not, I think I'm going to turn it over to Tom.

Wholesale Natural Gas Price Forecast, Tom Pardee and Michael Brutocao

James Gall: Tom, if you're got your slides ready to go.

Tom Pardee: I do.

James Gall: Yeah, it's all yours.

Tom Pardee: OK. I'll get my ducks in a row here. Share this screen. Pop this up. Hopefully it goes to the right screen. Hey, can everybody see that? OK.

James Gall: We see your North American supply slide, OK.

Tom Pardee: Tom Pardee, I'm the natural gas planning manager in James' Group, in the Integrated Resource Planning Group. One more real quick thing so I can see. OK, so I'm going to go over a fundamental forecast from Wood Mackenzie. These slides will give you an idea of what they're expecting as far as demand and supply within the region and nationally.

Tom Pardee: This slide here is a lower 48, just the continental lower 48 in the United States. What you can see here is the different breakouts for the demand between residential exports, Mexico LNG industrial and where I would point to, there's a couple interesting things in here. So, #1 this plot, the demand essentially is leveling out for natural gas within the mid-2030s time range and then it starts to decrease and I'll go into why that is. And then I'll also show the Pacific Northwest in our mountain regions.

Tom Pardee: Another interesting thing here is they expect blue hydrogen to come on more. Blue hydrogen would help serve this load demand or the fuel demand. Blue Hydrogen is using natural gas to create the hydrogen, you split it, and then you capture the carbon, and you store it. That's what blue hydrogen is. You can see that little blue sliver here, and if you can see my mouse there it is. By the 2050-time frame, there's I'd say, a more sizable market for blue hydrogen in these expectations. Net Mexican exports. This is exports from the United States and go to the generation plants in Mexico. There's some pipelines and interties that export it down there and they have quite a large load demand with air conditioning and otherwise, that feeds their generation plants. The sizable piece to this is the LNG exports, and for those that follow the market it's comes as no surprise, I believe there's 12 BCF a day of LNG exports is waiting to be built and that's on top of roughly the same amount as of today. And so, LNG exports is really what's driving this demand.

Tom Pardee: Finally, what I'll point out in here, because the other ones are mostly the same. I'll point out here the power demand. You can see power is green and over time it's shifting to a lower demand within the power sector and it's actually more substantial within our region. And like James, please interrupt me whenever there's questions. In order to fill this demand, there's a North American supply. On the chart on the left, this is telling you the region where supply is coming from. Rockies is one region that we get our gas from, and you can see over time that starts to decrease. The Gulf Coast is looking for an increase. Permian is in Texas. Fort Worth, of course, in Texas as well. But then you have northeast. Northeast is really Marcellus and Utica range. That's a lot of the high production, fracked gas and that looks like it's mostly going to stay the same, maybe grow a little bit. The other portion that we get our gas from is called WCSB, Western Canadian Sedimentary Basin. That's essentially any gas that we get from Western Canada and then they have a very small amount that comes from eastern Canada and feeds the East Coast of the state. One interesting thing here is if you look at the supply growth, and we're right in this region, if you look at that and then you compare that to the rig count, the rig counts are looking to increase by 2027 and then they slowly decrease. Actually, not really slowly in this depiction. A lot of gas gathering and production relies on efficiencies within the drilling process itself. This tells me that they're expecting higher production rates from lower rig counts. In other words, each well drilled is producing more and more gas, so you don't need as many rigs either oil in the large. Let me step back, an oil rig is essentially what you're doing. You're drilling for oil now in any process. That's why oil rigs are in here. There's going to be a byproduct of methane and some other a liquids, but they're primarily drilling and looking for oil within this lighter blue of the chart. But again, there is this side product or that extra product that they're not looking for specifically that adds to the economics. Because of that, the supply is going up because it's more efficient as the rigs are driving down. This is a look at the natural gas share of this. This is total energy.

Tom Pardee: The other was in just gas, so this is a look at total energy by fuel. Some things I'd point out here is that in the United States, you can see that gas is roughly staying the same, oil is decreasing overtime over this horizon from 2023 to 2050. And then you have a removal, mostly in coal, by 2050 there's not much energy coming from coal. Nuclear is staying roughly the same, but the other renewables are what you're driving that delta from, oil or gas, as far as an energy component to renewables. Canada in this case is looking at load growth in gas and they have a new LNG facility up there, LNG Canada. That's going to drive some of their demand. But overall, their trajectory for oil looks much the same and they have a lot of drilling and oil in Canada as well. You can see the overall energy demand of oil is expected to go down as well.

Tom Pardee: I believe this is my final slide. When we step back and look at from the US and then realize that policies are much different as compared to the US, we have the Pacific demand on the left and then mountain demand on the right. I pulled in mountain because of how they break it out. Idaho wasn't included in Pacific, as you can see. It's Washington, Oregon and California. Mountain includes Idaho, but there's a bunch of other states in there, the mountain regions. I'll start with the chart on the left, the Pacific region. Here again you can see blue hydrogen coming into their expectations here in the near term and then increasing to what is roughly a BCF a day by the long term by 2050. But the power demand in this chart is really what drives the reduction in demand in the Pacific region. By 2025, they're expecting power demand or power produced from gas to decrease by quite a bit. And then it slowly trickles down to maybe 750,000 MMBTU per day. I'll keep going. Residential demand in their expectations is staying roughly the same commercial, the same in industrial. It looks like it's going down and my expectation is this blue hydrogen is replacing this. This industrial load is now moving over to the mountain region, you see much the same depiction of the Pacific. In reality, what's driving the reduction here is the power, the lack of demand or decreasing demand in the power generation. The other is for byproducts and let me see. Pacific demand declines from 7 more moderate build out. In this piece, it's going towards other processes, chemical processes and things like that. In both cases, what you're seeing is an expectation from a fundamentals forecaster of reducing demand in both of these regions and I would say mostly because of the lack of power generation that's expected in the regions.

James Gall: Heather. Go ahead, you have your question?

Tom Pardee: Yeah.

Heather Moline (UTC): Yeah. Heather from (UTC), Tom. When were these demand forecasts from Wood Mackenzie created?

Tom Pardee: They only release theirs once a year, and unfortunately this was from March of 2023. We would just be on their new one. This is from their 2023 case, long term case.

Heather Moline (UTC): Thanks.

Tom Pardee: Yep. Any other questions?

James Gall: Kelly.

Kelly Dengel: Yes, any of these decreases in demand take into effect policy changes for the gas industry.

Tom Pardee: Yeah, I'd say both of them do. The decrease in power generation is definitely driving that from a policy change. And then also the increase in blue hydrogen expectation in the Pacific region, but also within the mountain regions as well. Any other questions? OK.

James Gall: Alright, I apologize. I probably didn't set up Tom's presentation too much, but I'll try to do that a little bit for the next two presentations and we're going to get into the natural gas and electric price forecast.

James Gall: These two price forecasts are extremely important for an IRP process. One, the gas forecast that Michael Brutocao is going to go through next is an input into our Aurora model that really helps drive what electric prices will be in the future or at least is one of the major components. We'll start with the gas forecast and then we'll get into the electric price forecast with Lori's presentation. Michael, if you're ready.

Michael Brutocao: I am trying to share my. Ah, there we go. Hopefully you can see this.

James Gall: We can see it.

Michael Brutocao: OK, I don't know if you see yourself on there also. Yeah. Thank you, James. Like James mentioned, I'll be covering our natural gas prices. Our forecast. When we generate our natural gas prices for the IRP, we first start by coming up with the expected price forecast. These are monthly prices and the first year you can see here, on the far left, 2026 is fully following what the forward market prices are on the NYMEX. The reason we do this is there's a high volume of trades at Henry Hub and these prices are very informed as we move out through time. The volume of trades decreases and eventually there aren't any trades going on and there's no information as to what prices may be out say 2040, mid 2030s. We bring in three different forecasts from various market consultants and the EIA's annual times three years and then eventually moves into purely forecasted prices.

Michael Brutocao: At the levelized price you can see is about $5 over this time and one reason we use three different price forecasts is that one may be biased upwards, one may be biased downwards for various reasons. Averaging these three or blending them in together decreases or offsets those potential biases. So, this is the expected price forecast, but not necessarily what we anticipate. Prices are going to be with 100% certainty. To address that uncertainty, we use a process called stochastics. How we run 300 stochastic price forecasts, you could think of each one of those as a different, back to this previous slide, as a different line. It may be higher, may be lower, in different months, but it varies from our expected price. These 300 draws all start from that expected price forecast. And then they move away back towards down. They differ over time, and that difference comes from two different inputs. The standard deviation of errors and the autocorrelation factor, so standard deviation of errors is essentially looking back at historic prices and what the market volatility has been.

Michael Brutocao: That allows us to draw around that expected price and you see overtime as these blue lines, the mean and max does start to widen. It's the jaws of our price forecast and the reason for doing that is that the further you get away from today, the less certainty there is around what prices may be. There's less information and it's more likely that prices are going to be further away from what you may expect, and the autocorrelation factor in this when it's drawing.

Michael Brutocao: Actually, let me let me back up here and just explain what one stochastic draw may do. You start with your expected price. Say it's $4 and based on historic markets, when you're in that first month that distribution around where that price might move in one month is much tighter than what a price might move from five months out or a year out. And so, we take a draw around $4 and we draw $5, we then start the next period recognizing that last month, even though we expected it to be $4, we drew up here at $5. That's where this autocorrelation piece comes in. It says we're going to, instead of now drawing from $4.05 like our expected price says, we're now going to draw from say, $5 or $4.98 and draw from there. That's what also allows this base to deviate from our expected case and the stochastics are a good way of measuring and addressing that kind of risk, of the risk around us not having the exact correct price forecast in our expected case.

James Gall: Michael, Molly has a hand up with a question.

Michael Brutocao: Oh yeah.

Molly Brewer (UTC): Yes, just wanted to know how is this taking in their houses measuring price effect of the Climate Commitment Act?

Michael Brutocao: So that that affect I.

James Gall: I can take that one, Michael. The Climate Commitment Act, it's a single state and that's affected on the retail side, not the wholesale side. The only way there'd be an effect is if there is a lessening demand of natural gas on our system that slightly affects national pricing or regional pricing. I'd say there's no direct or at least a very minor direct correlation between CCA and a long-term price forecast of the country.

Molly Brewer (UTC): OK. What about? Well, I guess you can't. I don't know how you would predict this. If there were something like CCA nationally or in many other regions over the next decade is that somehow, does that factor into this?

James Gall: Yeah, we do have a low price and a high price natural gas scenario price case. We'll run that through our Aurora model, so we can model those cases, or we would have a high carbon price case. I'd say it's outside of maybe this part of the price forecast, it would be more on the Aurora side.

Molly Brewer (UTC): OK. Thank you.

James Gall: Yep.

Michael Brutocao: All right. This is our last slide. To move those prices to our more local gas basins where we're purchasing gas from, we apply a basis differential that comes from our consultant too, basis differential forecast. That's the delta, the price difference between Henry Hub and say AECO, Maline, Sumas, Stanfield and this is just the expected case here. This would then be applied to every one of those 300 stochastic price draws we're running the model. This will also vary as you saw back here. It'll have that same general relationship. And I'll move it to Lori unless there are other questions.

James Gall: Josh has his hand up.

Michael Brutocao: OK.

Joshua Dennis (UTC): Howdy. So, my question is that those month to months are extrapolated to years in the forecast.

Michael Brutocao: Are they're all, they're all monthly.

Joshua Dennis (UTC): OK.

Michael Brutocao: Prices. I'm sorry, were you referencing this this past slide having kind of a inter linear?

Joshua Dennis (UTC): I think it was the slide before this one. Yeah. Wait.

Michael Brutocao: I'm sorry, OK?

Joshua Dennis (UTC): OK. Excuse me? I thought I heard that it was taken on a monthly and then extrapolated to a yearly. So that's my mistake. Thank you.

James Gall: Yeah. All when we.

Michael Brutocao: There is one yearly.

James Gall: Go ahead, Michael. Sorry.

Michael Brutocao: Well, I was just going to say this Annual Energy Outlook 2023 price forecast. But those are annual prices that they provide, and those are broken down to monthly prices. But everything else is purely monthly. Yes.

James Gall: Yeah, just going to add on our Teams site, the monthly price forecast is out there in a spreadsheet. So, if you're interested in looking at what our forecast is, it's that black line on this chart and you can go out and see that along with the pricing that Lori's going to present here.

James Gall: Next, on the electric side. Oh, there's any other gas questions.

Wholesale Electric Price Forecast, Lori Hermanson

James Gall: We'll move to electric. And we got about 30 minutes for the rest of the day. So, I think we should have plenty of time.

Lori Hermanson: OK, let me share my screen real quick. Can you see that in presentation mode? Yep.

James Gall: Now we see the other one. Sorry.

Lori Hermanson: Oh, sorry, on the screen.

James Gall: Yep. We lost your camera like we lost Michaels, but.

Lori Hermanson: How's that?

James Gall: That's much better.

Lori Hermanson: OK, so I'm Lori Hermanson. I'm the Senior Resource Analyst in the Resource Planning group, and I'll be covering the electric price forecast. The whole purpose of the price forecast is to estimate the market value of resources that end up in our IRP and estimate how those dispatchable resources dispatch the price, informs our avoided cost, which we use for our PURPAs and QF. And then finally, it could change the resource selection if resource production is counter to the needs of the wholesale market. For example, if there's a lot of renewables that have been built or forecast to be to be built in a different region than maybe less of those resources would be selected for our area.

Lori Hermanson: We use Aurora, which is a third-party software. It's owned and developed by Energy Exemplar. It's an electric market fundamentals production cost model. It simulates the dispatch of generation to meet load and we put in all the loads across all the WECC. We have all the resources we put in constraints, which could be things like transmission constraints, but it could also be policy constraints, state or federal. And then from all of that, we get the outputs which are our electric market prices. You have a general indication of what the regional energy stack is, what the transmission usage is, the greenhouse gas emissions, as well as the cost. What the margins are for the power plants, the generation levels, and the fuel costs. Finally, we're able to determine our variable power supply cost.

Lori Hermanson: Before we go deeper into the price forecast, let's look at the history of the Mid-C prices. Back in the late 1990s, there was good hydro and we had cheap natural gas prices. In 2000, 2001, we had the energy crisis that we all remember, and we saw prices above $100 a megawatt hour. After that, we resumed briefly our kind of normal conditions and then the natural gas market tightened as we had more demand and less supply, and we saw prices approximately double from what we were used to in 2009. And, for the next decade there were shale developments. And so, there was more supply available, and we saw prices dropping back down to what we'd formally had in the late

1990s and as we come into the recent years, we're starting to see more upward price pressure. This could be contributed to a few things, such as carbon policies in California impacting us, but largely this is indicating what James was touching on earlier in his presentation. It's a reliability issue and resource adequacy and because of these shortages of supply, you're starting to see the prices spike in 2022 and 2023, but then also predicted in our forwards for the next couple of years.

Lori Hermanson: Our 2020 fuel mix both for the Northwest and the WECC, this is based on EIA on their 2023 preliminary results. They usually update their 2023 results mid-year and so I only had access to preliminary results but our energy, or I should say our greenhouse gas emissions, compares better than against the WECC. We have 69% greenhouse gas emission free whereas the rest of the WECC is 47%. Largely this is no surprise. It's due to our high hydro base. We have a 50% hydro footprint while the rest of the WECC has about 20%. Our coal and natural gas footprints are lower compared to the WECC. Our wind and is on par and our solar is considerably less than other areas of the South. Compared to the rest of the WECC where they have 10% solar.

Lori Hermanson: Here are some other market indicators that are giving us some highlights that maybe the market is tightening. This chart on the top left-hand corner is daily natural gas compared to on peak electric prices. We show this because natural gas in the past has been the biggest contributor to power prices. Here we're seeing that even though we see spikes in gas prices here and there. Basically, the cost of, or the comparison is increasing. You're seeing some outliers here compared to most of the history and this could be driven by some of the carbon policies, like in California's carbon pricing. Washington implemented carbon pricing in 2023, but a larger contributor to this is our resource adequacy issues.

Lori Hermanson: The chart on the right is the spark spread. This is a comparison between the mid-C prices and the Stanfield prices. Historically from 2003 to late 2018/2019 and it's been fairly stable. Now we're starting to see some spikes especially in 2021 and 2022 and nearly doubling and 2023.

Lori Hermanson: This chart indicates the profitability of a combined cycle, which in the past, has been the marginal resource. But lately, especially in 2023, that marginal resource has been more of a peaker. Again, this is indicating resource adequacy issues and that there could be reliability issues. The chart on the bottom left-hand corner that shows the implied market heat rate, which is similar to the spark spread chart, but it compares the heat rate equivalent to price of power and gas. In the past you can see it's been stable around a heat rate of 8,000, whereas in more recent years we're seeing more spikes. And in 2023, it almost doubled what we've been seeing historically. Again, the impact from California and other carbon pricing could have some effect here, but again, reliability and resource adequacy issues are being indicated by what we're seeing in the market. And then oh, sorry.

James Gall: Hey Lori, we have a hand up. Heather has got her hand up.

Heather Moline (UTC): Thank you, Lori. Going back to spark spread, two questions. So first is I don't actually know what Stanfield times 7 means.

Lori Hermanson: Stanfield is one of the natural gas hubs. The Stanfield price times 7 subtracted from the mid-C price is what this this spark spread is.

James Gall: Yeah. Can I add a few things there, Lori?

Lori Hermanson: Sure.

James Gall: Other than a combined cycle which is, I'd say the main backstop of the gas resource is going to 7,000 heat rate. The cost to run a combined cycle would be the Stanfield price times 7 for the heat rate. This is showing the profitability of that facility and what happens is if the power price, your mid-C price minus think of it as your fuel cost gets too extreme. The value proposition of a combined cycle combustion turbine is increasing. This is showing is that these turbines, these combined cycle turbines, are vastly in the money, meaning that prices are so high, they're running nonstop, producing power. That is a good indicator of not enough generation in the Northwest to supply the demand, but also now that we have CCA in Washington, at least in 2023. Some of that is contributed to that, which would be a profit reduction, if you're selling into the Washington area. I think at the end of the day, all of these slides are showing the Northwest is capacity constrained and fuel constrained by high price spikes by being deeper in the resource stack and also seen in that last one that Lori's going to get to because volatility of market pricing.

Heather Moline (UTC): OK. Yeah, there's some details there I'm not tracking, but I'm not going to nitpick. Thank you.

James Gall: Yep. Yeah.

Heather Moline (UTC): Just the one thing I think the slides that were sent out, say, Stanfield times 7 minus, mid-C and so I just want to double check that it's actually mid-C minus Stanfield times 7.

Lori Hermanson: Yeah, we caught that after we'd sent those out. This is the corrected version, and we always send out the final slides after the presentation. Thanks for pointing that out.

Heather Moline (UTC): OK. Thanks.

Lori Hermanson: As James mentioned on that last chart on the bottom right-hand corner. That is just showing the standard deviation of the mid-C price. As you can see earlier on, there wasn't much, there was a lower standard deviation, and so there wasn't much volatility. But in the more recent years, you're seeing more volatility, again indicating that there's some reliability, maybe lack of resources available. This is a chart from 1999 to 2022. Again, my source was EIA and it's the greenhouse gas emissions. They only have data available through 2022, but you can see that compared to 1990 we are slightly lower than 1990. The states that have the largest decrease in greenhouse gas emissions are

New Mexico, California and Wyoming, the top three. Overall, our process for the price forecast, we start with the vendor database we purchase from Energy Exemplar. It's utilized within Aurora. We're using the 2023 North American database, which came available towards the end of 2023. In addition to that, we add additional inputs such as our 30-year Hydro, which includes climate futures. The natural gas prices that Michael had presented earlier, we put those into the price forecast. We add in regional loads from our consultants, regional loads including energy efficiency and hydrogen production. We add in our own forecast of EVs, net metering, our loads and resources, and any specific operational detail in regards to our generation resources. After that we do a capacity expansion.

Lori Hermanson: We run a capacity expansion model, which is where we put in generic resources and the model, based on the planning margins and the loads and everything, it indicates whether or not it's short or long and it will pull from the generic resources and select which ones need to be built. Then we'll run a deterministic study which we end up with some draft electric prices which I'm presenting today. After that we will run stochastics. The purpose of that is to test resource adequacy. We vary things like renewable load shapes, gas prices, carbon prices, other fuel prices. We vary all those along with hydro and climate futures, and end up with 300 different electric price forecasts.

Lori Hermanson: And then based on that, we look at the level of times that we're short on serving loads and if we need to, we will rerun another capacity expansion model that will build additional resources if necessary. Finally, based on all of that, we'll rerun a deterministic and stochastic run and those will be our final price forecasts. Based on those, we run various scenarios which James will present later today. That's our whole process. Currently we're at Step 5.

Lori Hermanson: I'm presenting today, the preliminary electric prices that came out of this preliminary deterministic study. Now we're testing our stochastic study and I'm doing some small sampling of runs. We'll be launching a full study soon. As I mentioned, one of the inputs is the load forecast. We get our regional load forecast from IHS, which is one of the consulting services. We subscribe to their forecast it includes energy efficiency and hydro production. We add to the load forecast net metering both annually and hourly as well as the electric vehicle forecast. From that we get a forecast of our loads from our planning horizon 2026 to 2045. You can see that the future looks different from today as it's definitely growing. The inputs are carbon pricing assumptions.

Lori Hermanson: We use consultant's carbon pricing, which rises to about $85.32. We are assuming that there's no national carbon tax. I think last IRP, we assumed that there was in some areas, or we did make that assumption. We're assuming no national carbon price. We're modeling both CCA and that we join California and Quebec as a joint market. That should bring the prices down somewhat. We also assumed that any regions importing into California or Washington incur a carbon adder, a carbon price adder for transferring power into those regions. We are also assuming that, for example, some of the larger generation in Washington. I'm going to forget the actual ones. I think it's Grays

Harbor and James, can you remember the other ones that we added carbon pricing to in 2025? Can you remember some?

James Gall: Yes, that's up in Chehalis have a direct price in 2025, Yep.

Lori Hermanson: And then for all the other carbon emitting resources, we added carbon cost to the dispatch starting in 2031. And then as I mentioned, when we do stochastics, this is one of the things that we will vary are the carbon prices options. Based on what you're seeing here, there's a flooring and a ceiling and the prices will vary between there and will take 300 random draws of that contributes to our price forecast. Did you have something to?

James Gall: Lori, Molly had her hand up.

Lori Hermanson: Oh, OK.

Molly Brewer (UTC): Yeah. And maybe this is James or Lori, I don't know. But is this where you're incorporating the social cost of greenhouse gases that we've been talking about, James, the one that the Commission puts out an order to update it cost?

James Gall: What will happen is this is the price that our model will see for dispatching units or selling into the market. And then when we do our capacity expansion study to select resources, that selection process for both energy efficiency and other resources, then that price will be included. So, if a Resource had a CCA price attached to it, it would take the difference, we'd add the social cost of carbon to this value. Yeah, this is what the model sees as a dispatch and then social costs will be in the resource selection side of it.

Molly Brewer (UTC): OK. Thank you for that clarification.

Lori Hermanson: OK. As I mentioned earlier, we put some generic resources into the model that it can select if certain regions are short in order to meet their demand and planning margins. Based on the new resources selected, this is our new resource forecast for the planning horizon, just some excerpts of certain years. But this is very similar to the level we had in the last IRP. The mix is changing slightly, but you're seeing more wind and more nuclear and things like that. This is the resource type history and forecast of the WECC as well as the significant changes by resource type. You can see how it's contrasting against history. You're seeing increases in solar and wind, decreases in natural gas, and those are the largest contributors to the changes for the forecast.

Lori Hermanson: Here's a similar look, but for the Northwest and you're seeing changes in the resource types, increases of solar and wind and decreases in gas and coal. And far as the WECC greenhouse gas forecast, compared to history, you're seeing a large decrease over time. Since 1990, we're seeing a decrease of 135 million metric tons. And then in the forecast from 2026 until 2045, you're seeing another decrease of 129 million metric tons. And at the end of the day, this is the result of the price forecast. It's basically mid-C prices.

Lori Hermanson: We created slightly different zones in Aurora this time compared to last time. Formerly, we had an Oregon, Washington, northern Idaho Zone, but with the CCA going into effect this time we broke it out a little bit differently. We have Washington with and without CCA. And then Avista, which is Eastern Washington, northern Idaho, trying to model based on different resources that could be selling into our market with or without CCA. At the end of the day, the levelized prices are around $48 [per MWh] with CCA around $45 without CCA, and about $42 for our Avista zone and contrasting that with our last IRP, I think our levelized prices were about $35. This price forecast includes quite a bit of expected additional resources in those early years between now and 2030. That's a lot of resources to get built and online and permitted. If those don't come to fruition, these prices would likely be much higher.

James Gall: Lori, I want to add one thing to that last slide and address the prices falling like you mentioned from all these new resources coming online at least projected to be coming online and then the price is bumped back up you can see in 2031. This has to do with our assumption on how allowances will be distributed by the CCA in the future. The law allows for a change in 2031 of how allowances are distributed to utilities and we're assuming at that point in time the projects in the State of Washington would have to include some type of price, the CCA price in its dispatch. The big change there is that assumption that any generator in the State of Washington would have a carbon price in its dispatch versus before that it's just plants that don't have free allowances or importing into the state. So that's the cost of the big change.

Lori Hermanson: Thanks James.

James Gall: Yep.

Heather Moline (UTC): Sorry. Can you repeat, Lori, the kinds of new resources you're talking about?

Lori Hermanson: The kinds of new resources let me hop back here. Whoops, sorry. These are the new resources that were selected from this deterministic run, and this is excerpts over time, 2030 through 2045. Most of the resources being selected are solar and wind, some storage. Those are the big contributors. See a little bit of offshore wind over time, but again are based on generic resources. What we actually acquire could be very different because if we go short, or if we're predicted to be short, we would issue an RFP and the people that submit for an RFP could be very different types of resources or mixes than what we're showing here. We put in generic resources and this is what's being selected.

James Gall: And this is selected for the West region, not Avista.

Lori Hermanson: Yes.

James Gall: Just to be clear, this is California, this is Arizona, Wyoming, Colorado, Washington, Oregon. This is not Avista’s preferred mix. This is what would likely serve the greater region. Just to be clear.

Heather Moline (UTC): Thanks.

James Gall: Yeah.

Lori Hermanson: Oops, sorry I went too far. OK, this is basically the same price we just showed, but by season, and this these shapes are very similar to what you saw in the last IRP. A lot of it makes sense. Spring you see it suppressed because of runoffs and all of them you see prices suppressed in the middle of the day. That's because solar comes up. Then you see these evening peaks as solar drops off and people are coming home from work and plugging in their EVs or that sort of thing. These are very similar to what we saw in the last IRP.

Lori Hermanson: Finally, well, I guess I have one more slide after this, but this is comparing the prices that we showed earlier in the flat delivery without CCA, the flat delivery with CCA, and the Avista prices for those zones compared to a couple of our consultant's prices. I think one of the consultant's price forecast was done in December and I think the other one was done in July. This is just to compare results. Finally, these are all of our IRPs since 2005, the black line is actual prices.

Lori Hermanson: This dotted black line is our draft electric price forecast for this IRP and all these other, I mean basically at the end of the day, shows that a price forecast is very difficult to predict what the mid-C prices are going to be. Of all these IRP that we've done, there's six points in time, not six forecasts, but six points in time where we actually got it right. It's just added context here, but it's difficult to forecast and it's based on all these inputs that are best informed to help determine what the prices are going to be. But at the end of the day, they're likely not right. That's why we do these price sensitivities and scenarios that James will be presenting next. That's everything I have. What's left in the process? We're going to connect our stochastic studies. We'll finalize our deterministic and stochastic case based on if we need another capital expansion run. Finally, we'll run scenarios and that's all I have for today. Are there any other questions?

James Gall: Looks like Heather has got a question.

Heather Moline (UTC): Yep, I'm back. Thank you, Lori. I don't know if this is for Lori actually. Do the slides on lower 48 demand for gas North American supply for gas, regional demand for gas Pacific versus mountain, those don't get used in the IRP. Right.

James Gall: Correct. They're context of what the national forecasters are assuming, which basically are used to help develop those natural gas price forecasts.

Heather Moline (UTC): Yeah. OK.

James Gall: They run a model. These consultants, they run a national model for demand of natural gas and that develops a price, and that price then is input into our Aurora model.

Heather Moline (UTC): Got it. That was going to be my next question. Is the thing that they're relevant for is that price forecast and you just answered that. Thanks.

James Gall: If the future was we're going to build a bunch more gas turbines, then maybe that would drop pricing. And for natural gas, if there was so much more demand than there was supply as an example, so.

Tom Pardee: Hey, Heather, if I can add more context to that. Think of that as just one of those forecasts that we use too. As Lori showed on the slides for price forecasting, those are all we have, different forecasts from different entities like the EIA or a few consultants in a forward price. We don't know what the price is going to be, but the law of averages basically states the more you have, the better it's going to be. But this is just one point out of the four points I believe that we used for the single price forecast. It's really just to give context. If I were to show you our other consultant, it's mostly the same and just came out more recently. It's just really contexts around, overall that they are expecting less gas use in our area. That's kind of the one to one of why prices are doing what they are.

Heather Moline (UTC): OK. Thanks.

James Gall: OK. Molly had a question. Go ahead Molly.

Molly Brewer (UTC): Yeah, this is going way back to that set of questions earlier for resource adequacy from that cold event. How are we meant to go about answering those questions. I just have follow up questions on them like how would we know if 1% or 5% probability is more reasonable things like that?

James Gall: I think the expectation of reliability needs to be somewhat directed by the Commission and that's my opinion. The utility is responsible for being able to provide a reliable service. I think there's a level of expectation of what that is now. I think there's also a level of expectation you're not going to overbuild your system. We've always looked at what's the industry standard for reliability, but it seems to me that consumer expectations are changing. Of what they expect. So, I think it's a broader question of what is appropriate for resource adequacy. I mean another example, WRAP set a standard, but is that standard the right standard of what our customers want? I don't know if there's an answer to that without having regulatory bodies or legislature saying this is what we expect. Otherwise, we're going to propose something and it's whether or not the Commission agrees with what we propose. I don't know.

Molly Brewer (UTC): Yeah.

James Gall: If that's helpful or not, but Yep.

Molly Brewer (UTC): No, I mean that is because I just don't know. What's the standard we're using to answer these questions?

James Gall: Yeah, there is no right answer, unfortunately.

Molly Brewer (UTC): That helps me understand the context of asking those questions.

James Gall: Yeah. Whether or not we use an example day as a resource adequacy standard. I think it's good practice to show that and it helps policymakers understand what they're getting into. If we build a bunch of four-hour batteries and rely on wind and solar and we have an event like this, you can see we can't serve it. That is a good indication why we need to look for longer duration storage or rely on natural gas. These are good examples to show to understand what the results are of decisions that get made in these planning processes. Unless there's any other questions, we were going to wrap up by 10.

Portfolio and Market Scenarios Options, James Gall

James Gall: I think we did reserve another 30 minutes on everybody's calendars for this meeting because we weren't quite sure on the time, but I'm not going to take that 30 minutes because the scenario section was really just to go over what we're thinking and let you all chew on that for a while, because we're going to actually cover scenarios in more detail at a future meeting. And let me look up when that is, John had shown that earlier, but I need to look it up again.

James Gall: We're going to cover the final scenarios at least the list and descriptions in TAC 7, but the document we sent out is a description of what we're thinking right now and how this works. We have 19 scenarios right now, or 18 if you don't include the expected case, and then under sensitivity this refers to what price forecast we would be using. That's that Aurora price forecast that we will be studying with each of these portfolio scenarios. Then we have an LOLP study. This represents which of these portfolios will undergo our reliability test to look at what's 5% loss of load probability or 1% if we ended up going there in the future. This is our list. We also have a description of each of the scenarios here.

James Gall: What we'd like the TAC members to do if you want to see something else besides these, you want to add, please let us know. Or if you don't think that one of these scenarios is useful, that's also feedback. But I'm trying to figure out when we wanted feedback. John, I don't know if you remember. I was looking at our Work Plan when we needed to get feedback from everybody on the scenario list. If you had that in your memory or not?

John Lyons: Not off the top of my head. I'm looking really quick.

James Gall: OK, I think I'm there. It is March now that would be today. We have got to push that out.

John Lyons: OK.

James Gall: Our Work Plan had it today, but if you have comments maybe next 30 days for the scenario list, provide those to us. If you want to see something different. Or in addition to these, we had some proposed ones that are on here as well, if that's something you're interested in. We cover what some of the information is on what the targets are on the bottom of what some of these scenarios are.

James Gall: So, with that, are there any questions, thoughts that people have? OK. Alright, so hopefully everybody likes the new TAC schedule of every two weeks. That's what we're going to be moving to going forward and the next couple TAC meetings are really going to concentrate on our load forecast, which I kind of given a clue earlier on. It will be a higher load forecast than we've seen in the past and we'll then go forth and figure out what our availability is for energy efficiency, what resource options we have, what our net position is over the next couple of months. By early summer, we should have some resource selection and show you what types of resources are going to be needed and when. It'll be for our team at least a very strenuous next probably three months, lots of work to get done. It's crunch times for us.

James Gall: If there's no other questions or comments, I guess we'll call it a day.

Heather Moline (UTC): Sorry, James.

James Gall: Yep.

Heather Moline (UTC): Heather here. That list of scenarios, where does that live? Or is it at the end of the presentation?

James Gall: Yeah, it is at the end of presentation we emailed out. We'll also post that to the website today or tomorrow. It's also out on the Teams site as well.

Heather Moline (UTC): Thank you.

James Gall: OK, have a great day everybody. We'll see you next week at the DPAG meeting, hopefully. Bye, bye.

2025 Electric Integrated Resource Plan
Technical Advisory Committee Meeting No. 4 Agenda
Tuesday, April 9, 2024
Virtual Meeting – 8:30 am to 10:00 am PTZ

Topic	**Staff**
Introductions	John Lyons
Future Climate Analysis	Mike Hermanson
Economic Forecast & Five-Year Load Forecast	Grant Forsyth

2025 IRP TAC 4 Introductions

John Lyons, Ph.D.
Technical Advisory Committee Meeting No. 4
April 9, 2024

Today’s Agenda

Introductions, John Lyons

Future Climate Analysis, Mike Hermanson

Economic Forecast & Five-Year Load Forecast, Grant Forsyth

Remaining 2025 Electric IRP TAC Schedule

- **TAC 5: April 23, 2024: 8:30 to 10:00 (PTZ)**
  - Long Run Load Forecast (AEG)
  - Review Planned Scenario Analysis

- **TAC 6: May 7, 2024: 8:30 to 10:00 (PTZ)**
  - Conservation Potential Assessment (AEG)
  - Demand Response Potential Assessment (AEG)

- **TAC 7: May 21, 2024: 8:30 to 10:00 (PTZ)**
  - Variable Energy Resource Study
  - Portfolio/Market Scenarios

- **TAC 8: June 4, 2024: 8:30 to 10:00 (PTZ)**
  - Load & Resource Balance and Methodology
  - Loss of Load Probability Study
  - New Resources Options Costs and Assumptions

- **TAC 9: June 18, 2024: 8:30 to 10:00 (PTZ)**
  - IRP Generation Option Transmission Planning Studies
  - Distribution System Planning within the IRP & DPAG update

Remaining 2025 Electric IRP TAC Schedule

- **Technical Modeling Workshop: June 25, 2024: 9:00 am to 12:00pm (PTZ)**
  - PRiSM Model Tour
  - ARAM Model Tour
  - New Resource Cost Model

- **TAC 10: July 16, 2024: 8:30 to 10:00 (PTZ)**
  - Preferred Resource Strategy Results
  - Washington Customer Benefit Indicator Impacts
  - Resiliency Metrics

- **TAC 11: July 30, 2024: 8:30 to 10:00 (PTZ)**
  - Preferred Resource Strategy Results
  - Portfolio Scenario Analysis
  - LOLP Study Results

- **TAC 12: August 13, 2024: 8:30 to 10:00 (PTZ)**
  - Preferred Resource Strategy Results (continued)
  - Portfolio Scenario Analysis (continued)
  - LOLP Study Results (continued)
  - QF Avoided Cost

Remaining 2025 Electric IRP TAC Schedule

- **September 2, 2024- Draft IRP Released to TAC.**

- **Virtual Public Meeting- Natural Gas & Electric IRP (September 2024)**
  - Recorded presentation
  - Daytime comment and question session (12pm to 1pm- PST)
  - Evening comment and question session (6pm to 7pm- PST)

IRP Climate Change Analysis

Forecasted streamflow and temperature changes for 2025 IRP Analysis

Mike Hermanson, Senior Power Supply Analyst

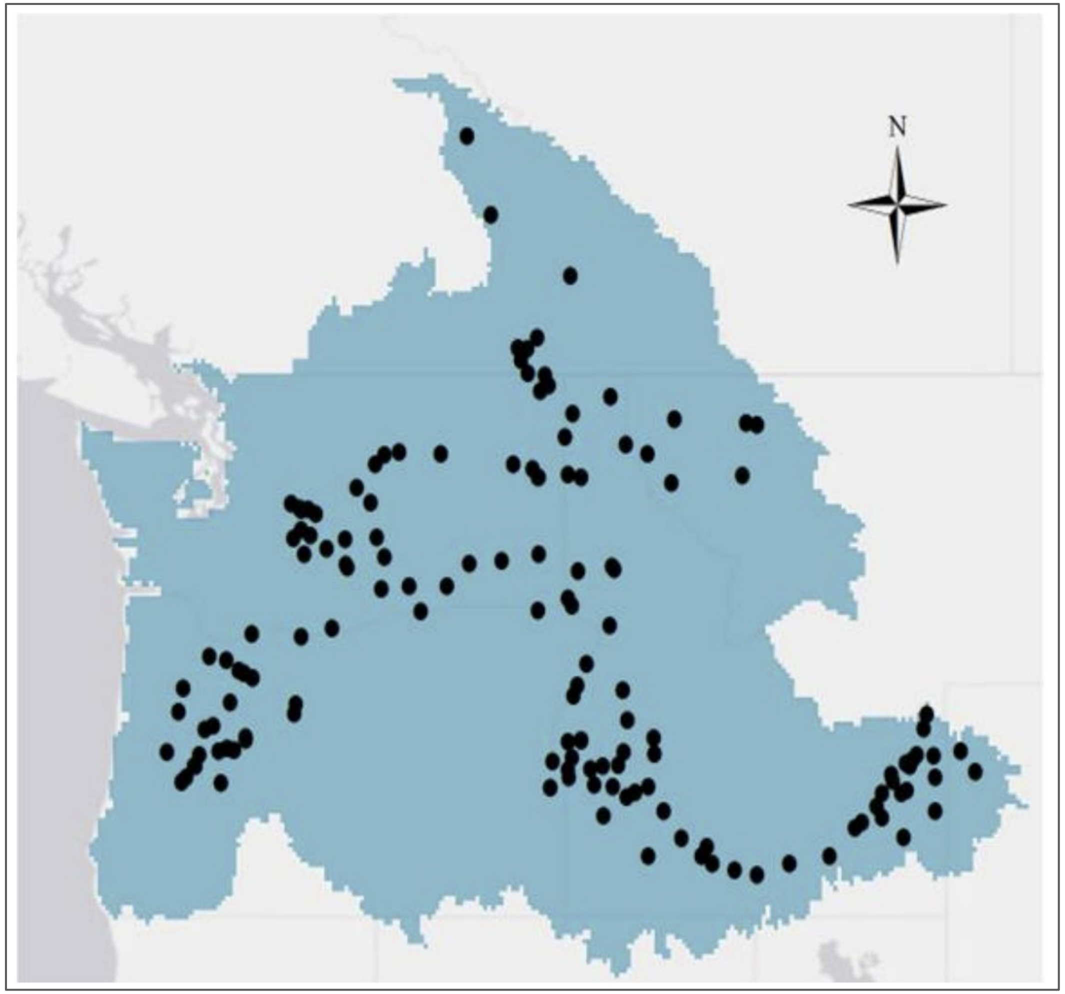
April 9, 2024

Overview

- Data sources and methodology
- Hydrogeneration
- Temperatures for load forecast
- Temperatures for peak load forecast

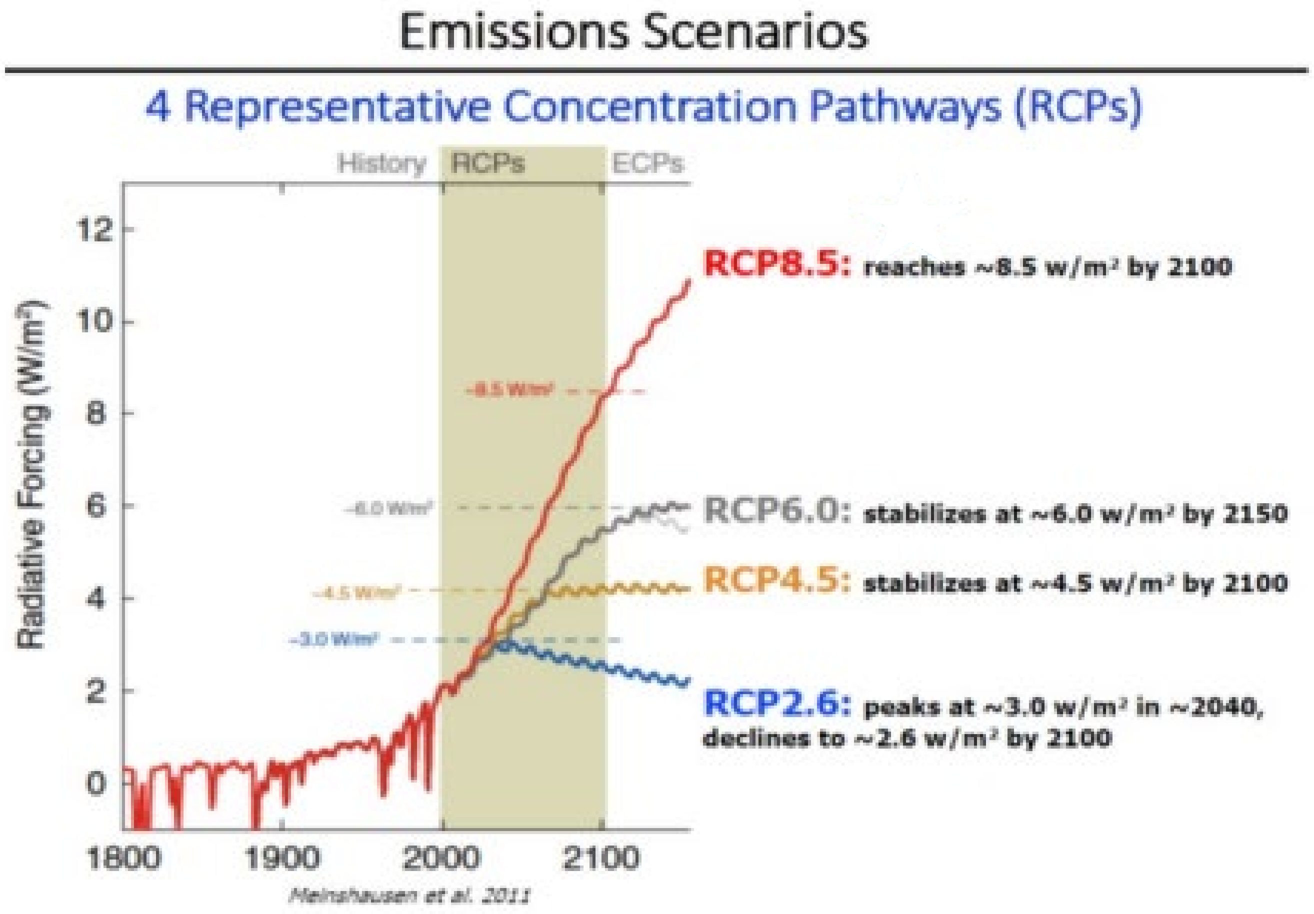
Data Sources

- Climate and Hydrology Datasets for RMJOC Long-Term Planning Studies: Second Edition
  - River Management Joint Operating Committee (RMJOC)
    - BPA, US Army Corps of Engineers, US Bureau of Reclamation
  - Research Team
    - University of Washington, Oregon State University
- Part I – Unregulated stream flows
- Part II – Reservoir Regulation and Operations
- Wind data – University of California-Merced
  - Data from 20 climate models downscaled using the MACA (Multivariate Adaptive Constructed Analogs).



Global Climate Models

- Global Climate Models (GCMs)
  - Coarse resolution ranging from 75 to 300 km grid size
  - Provides projections of temperature and precipitation, and other meteorological variables (wind)
  - Multiple Representative Concentration Pathways (RCP 4.5 & RCP 8.5)
  - 10 GCM models used in study
    - CanESM2 (Canada)
    - CCSM4 (US)
    - CNRM-CM5 (France)
    - CSIRO-Mk3-6-0 (Australia)
    - GFDL-ESM2M (US)
    - HadGEM2-CC (UK)
    - HadGEM2-ES (UK)
    - inmcm4 (Russia)
    - IPSL-CM5-MR (France)
    - MIROC5 (Japan)



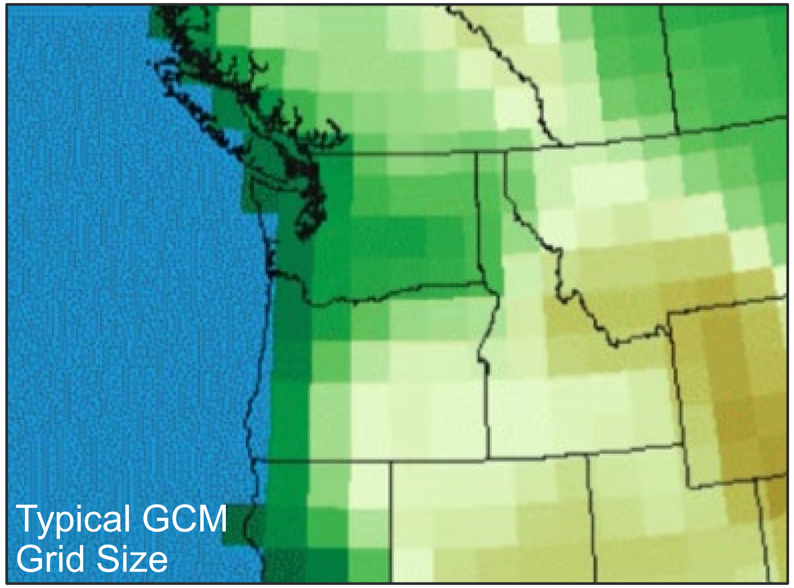
Representative Concentration Pathways

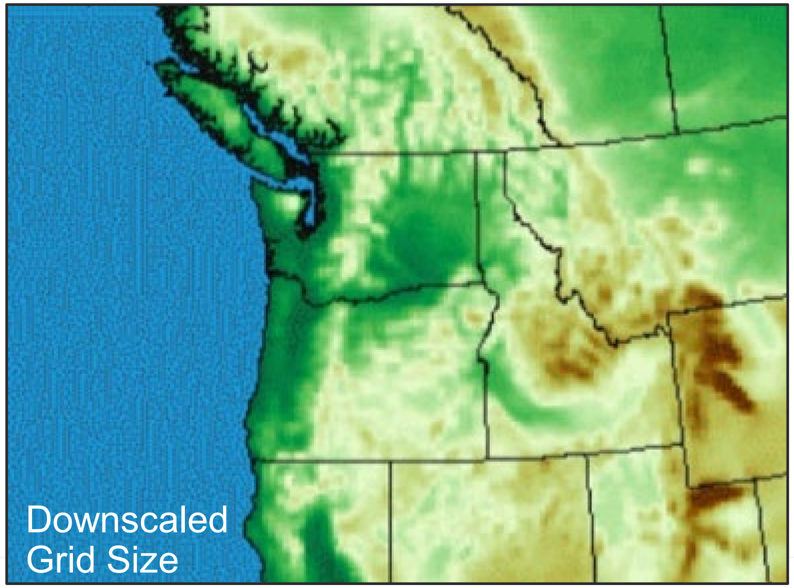
- Description by Intergovernmental Panel on Climate Change (IPCC)
  - RCP2.6 – stringent mitigation scenario
  - RCP4.5 & RCP6.0 – intermediate scenarios
  - RCP8.5 – very high GHG emissions
- RMJOCII Study evaluated RCP4.5 and RCP8.5
- RCP4.5 and RCP6.0 similar likely range by the end the IRP planning horizon

	Scenario	2046-2065		2081-2100	
		Mean	Likely range	Mean	Likely range
Global Mean Surface Temperature Change (C°)	RCP2.6	1.0	0.4 to 1.6	1.0	0.3 to 1.7
	RCP4.5	**1.4**	**0.9 to 2.0**	**1.8**	**1.1 to 2.6**
	RCP6.0	**1.3**	**0.8 to 1.8**	**2.2**	**1.4 to 3.1**
	RCP8.5	2.0	1.4 to 2.6	3.7	2.6 to 4.8

Downscaling Techniques

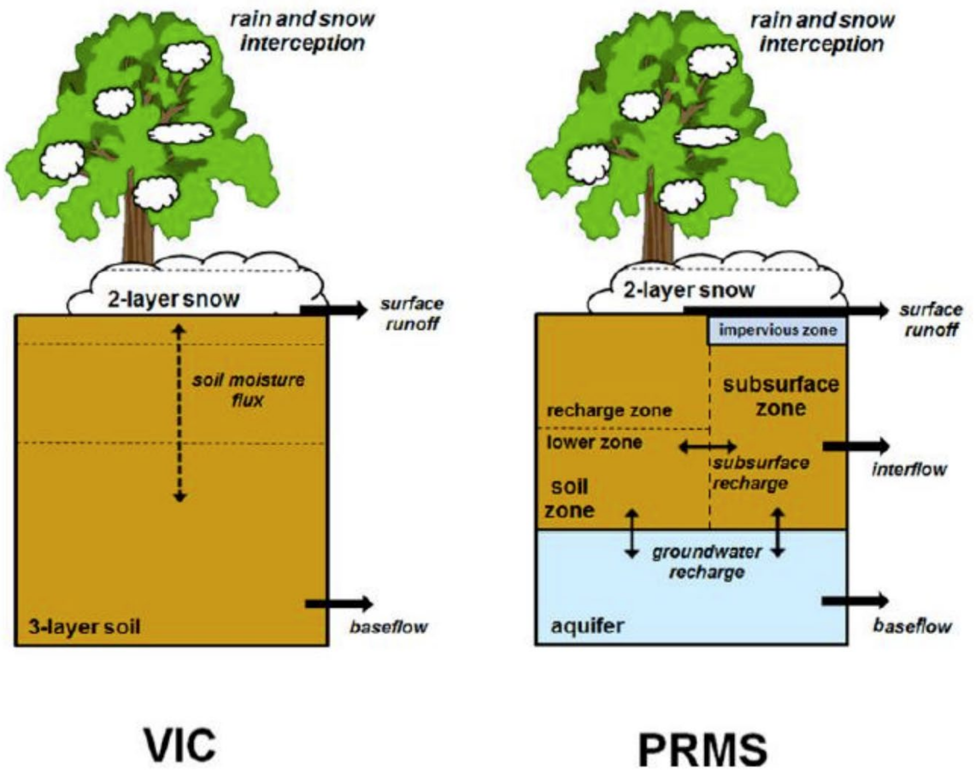
- Downscale GCM data to finer resolution necessary to model hydrology
  - Statistical methods to represent variation within large grid size
  - Two methods used (BCSD, MACA)
    - Bias Corrected Spatial Disaggregation
    - Multivariate Adaptive Constructed Analog



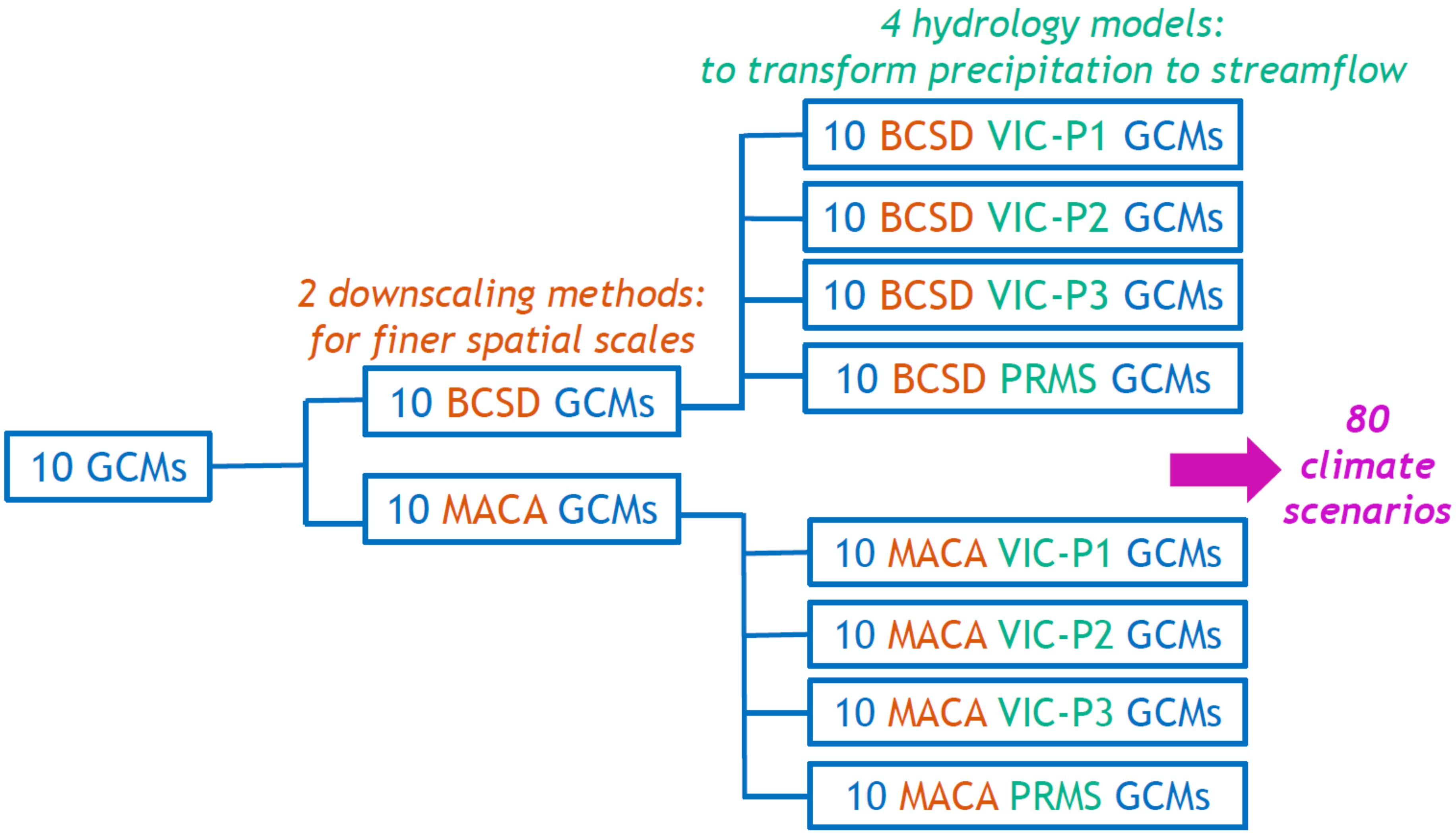


Modeling Climate Change Impacts on Hydrogeneration

- Hydrologic models
  - Downscaled temperature and precipitation is input to hydrologic models.
  - Hydrologic models use soil, geology, slope, vegetation, aspect, snow cover, etc. to model how precipitation translates into runoff and streamflow.
  - 2 different hydrology models used.
    - 1 version of PRMS model
    - 3 versions of VIC model
- Hydro regulation models
  - Unregulated streamflow is input to reservoir models of Columbia River system to generate regulated flows.



Modeling Climate Change Impacts on Hydrogeneration



2025 IRP Hydrogeneration

- BPA selected 19 of the 80 scenarios that encompass a sufficient range of uncertainty.
- Three regulated river flow data sets utilized:
  - BPA 1929-2018. Most recent data available from BPA for each Avista project.
  - 2019 utilized actual flow.
  - 2020-2045 used climate change data set.
- Median of 19 BPA selected scenarios was used in the flow data set.
- All flows were combined into one data set (1929-2045) and ran in Plexos to estimate generation for Noxon, Cabinet, Long Lake, & Little Falls
- Run-of-river projects were estimated utilizing regression analysis based on historical relationship of river flow and generation.

Results

Comparison of Annual (aMW) of Avista Hydro Projects

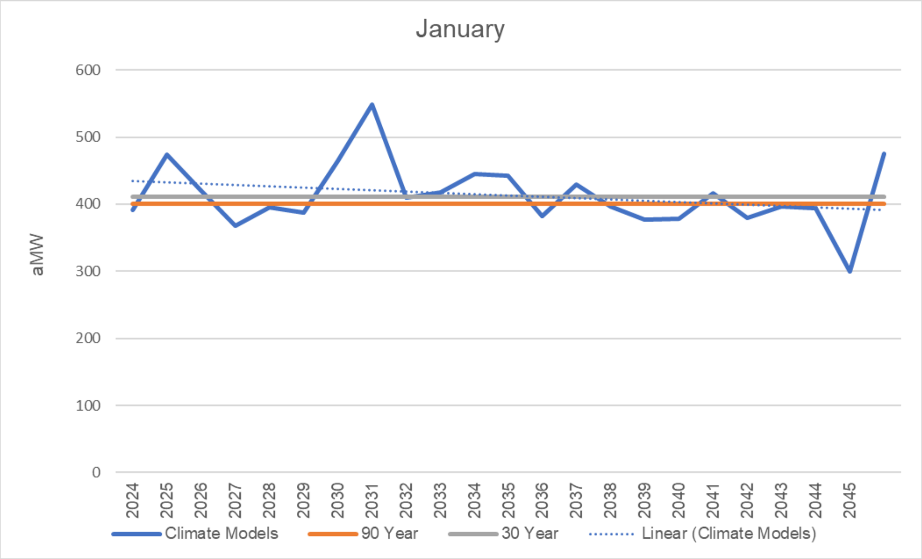
	90-Year Hydro (1929-2018)	Recent 30-Year (1994-2024)	Climate Change (2019-2049)
Mean	446	459	472
Median	363	390	408
Standard Deviation	224	204	211
10th Percentile	227	276	262

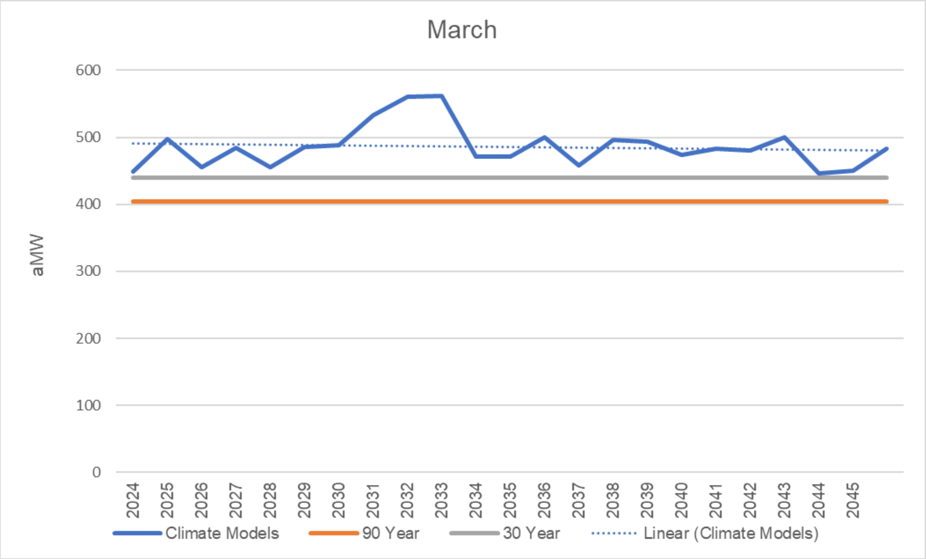
Note: Does not include Mid-C due to contractual changes during planning horizon that impact generation quantities

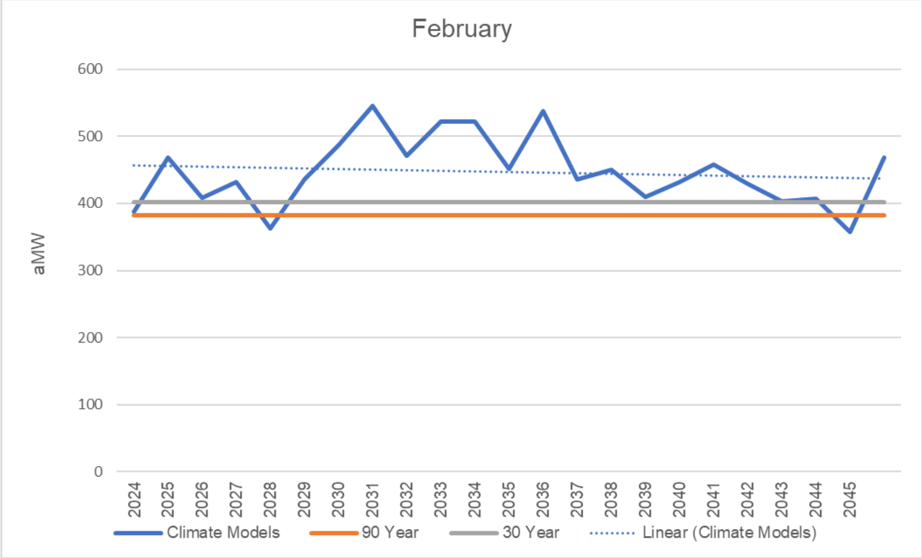
- Recent 30-year shows slight increase in annual energy
- Climate change scenarios show an increase in annual energy consistent with the projection of overall increase in precipitation in the Northwest

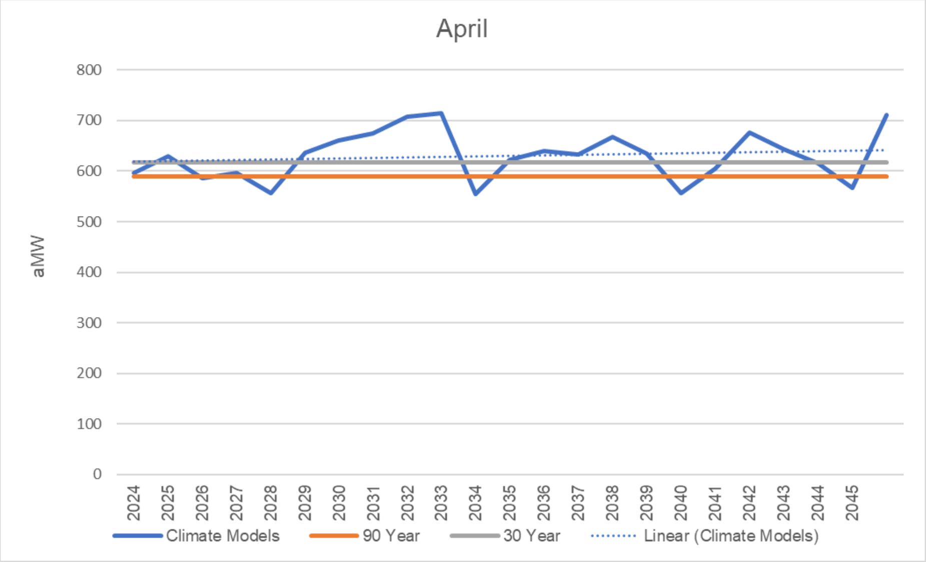
Results

2024-2045 Trend



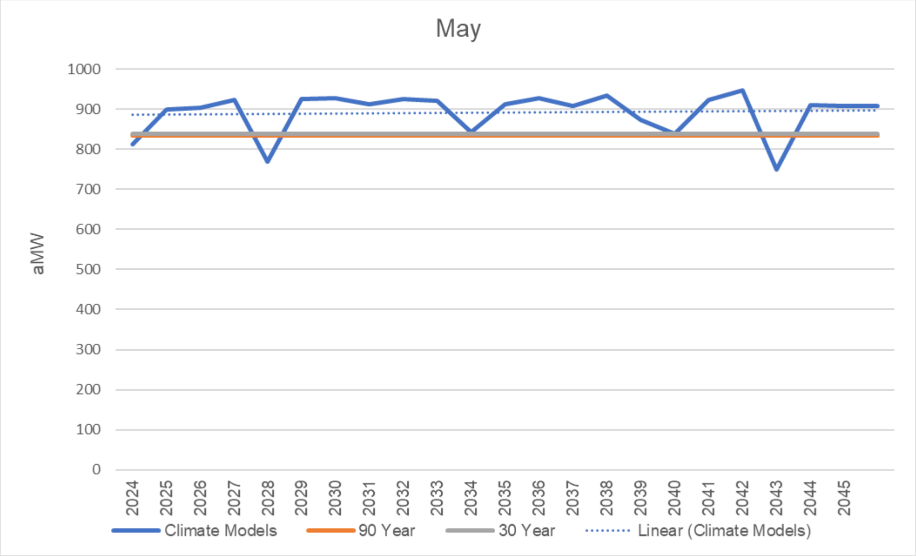


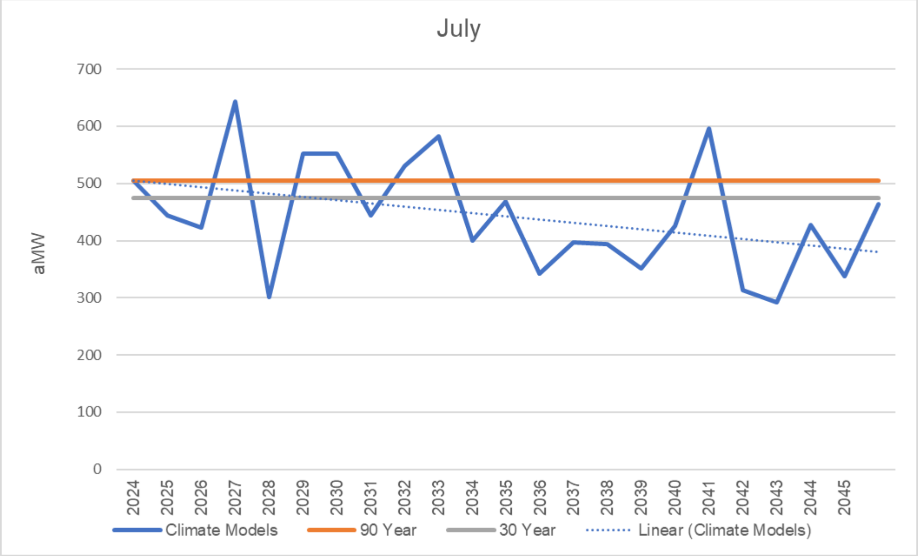


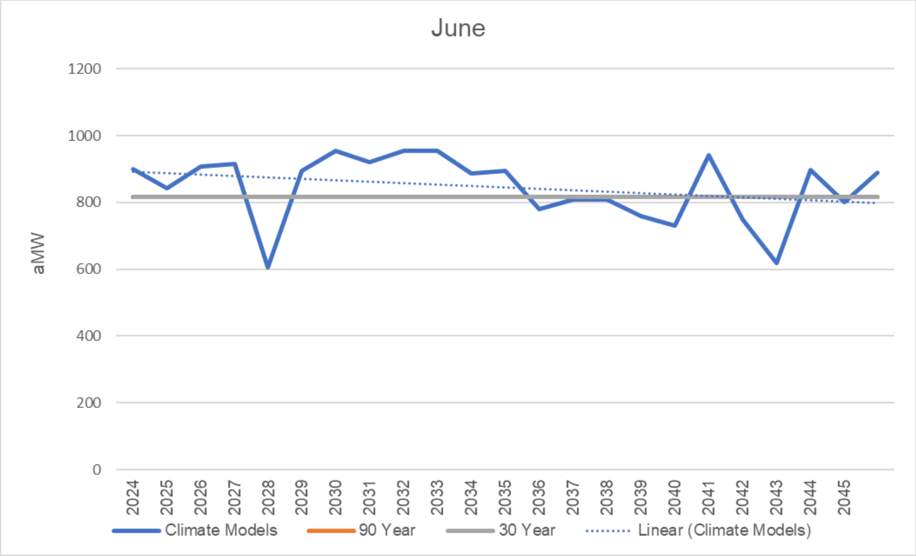


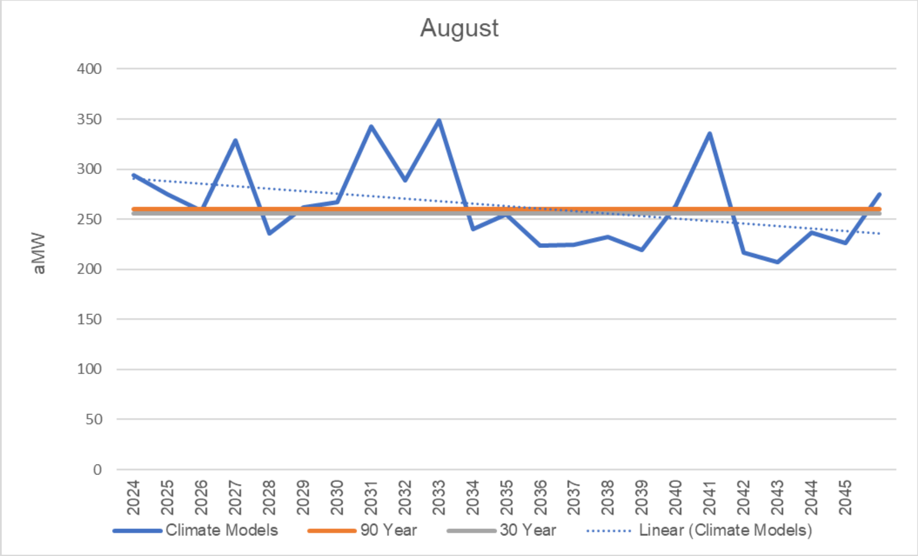
Results

2024-2045 Trend



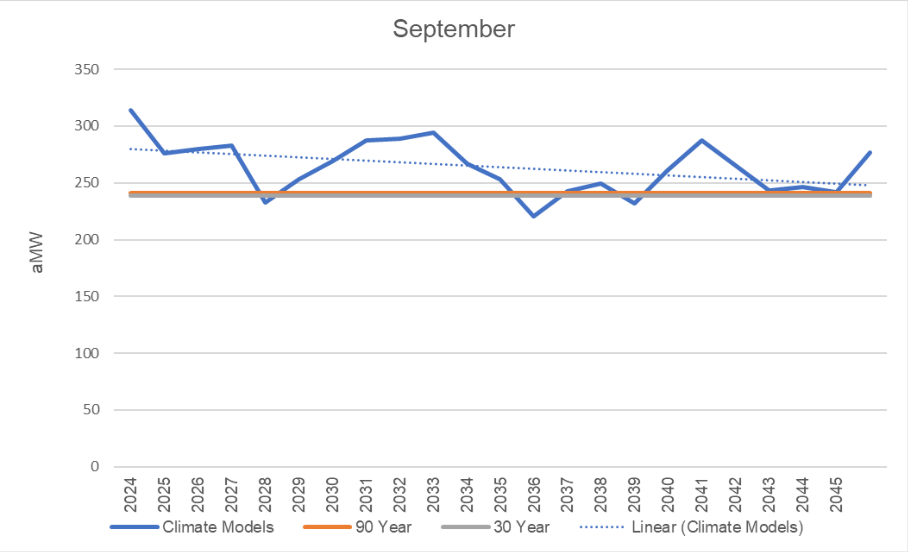


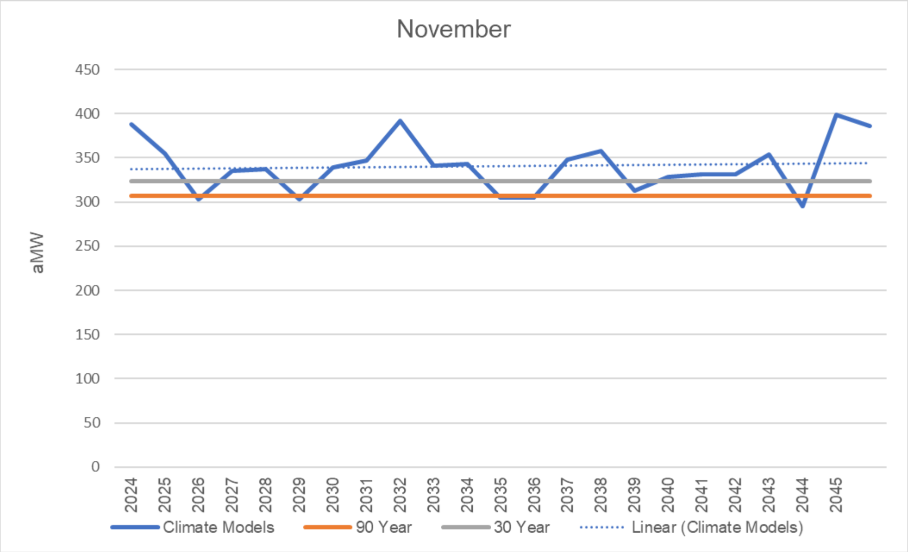


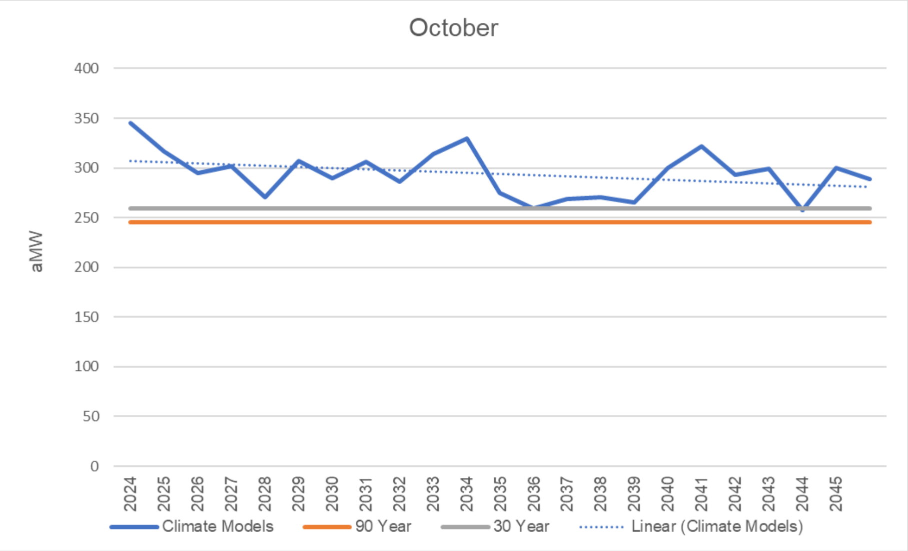


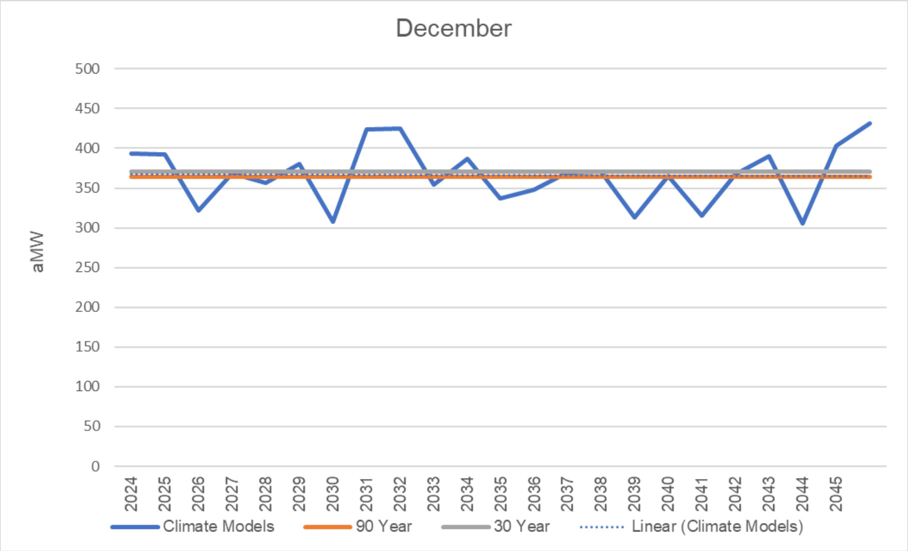
Results

2024-2045 Trend





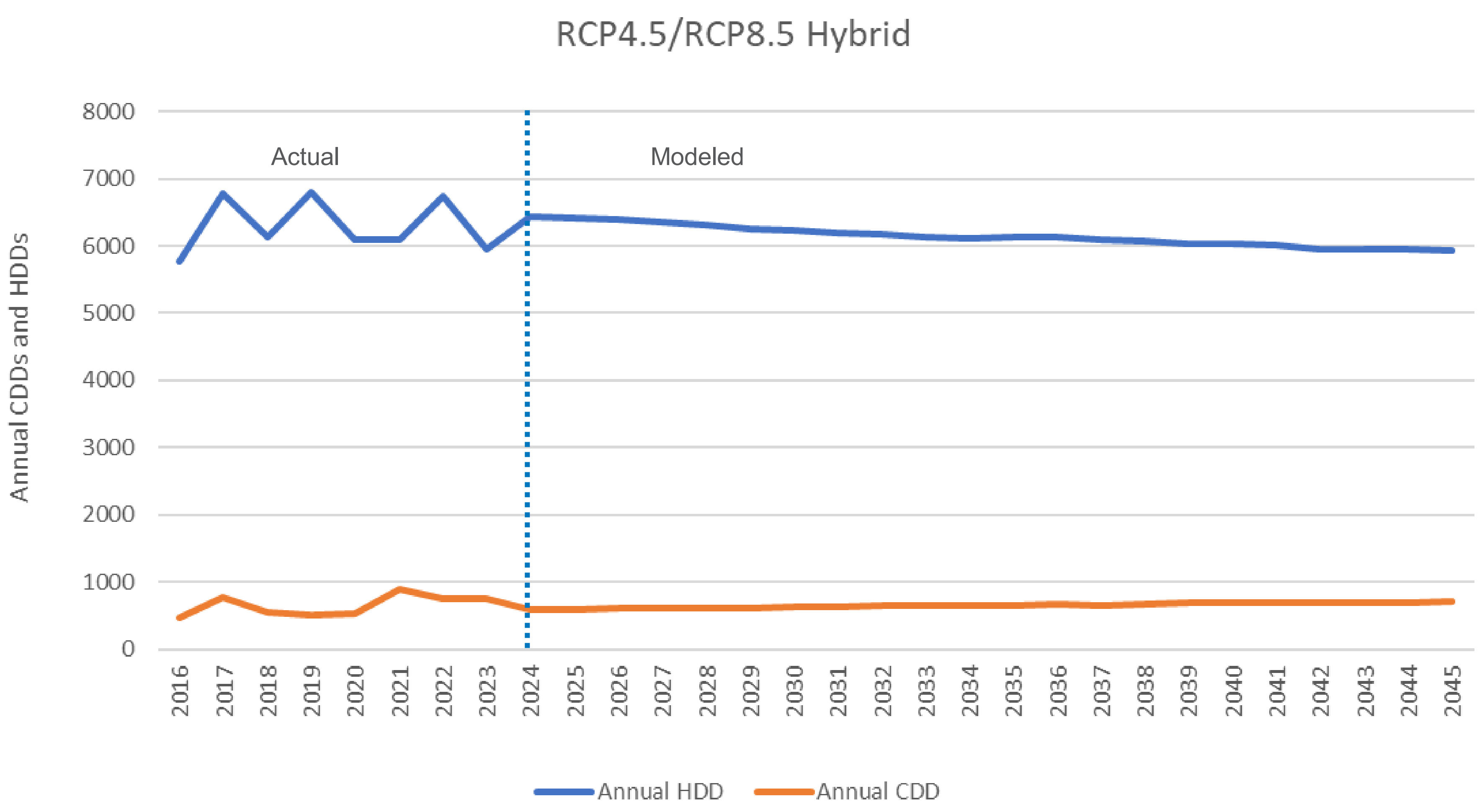




Climate Change Temperatures for Load Forecast

- Data:
  - Daily max and min temperature for Spokane airport through 2045 that correspond to the 19 BPA scenarios.
  - Data for both RCP4.5 and RCP8.5
- Temperatures for load forecast will use RCP4.5 for January – May and October – December, and RCP8.5 for June – September.
- Approach will allow representation of increasing temperatures over the IRP period without losing cold events that are important to plan for.

Climate Change Temperatures for Load Forecast

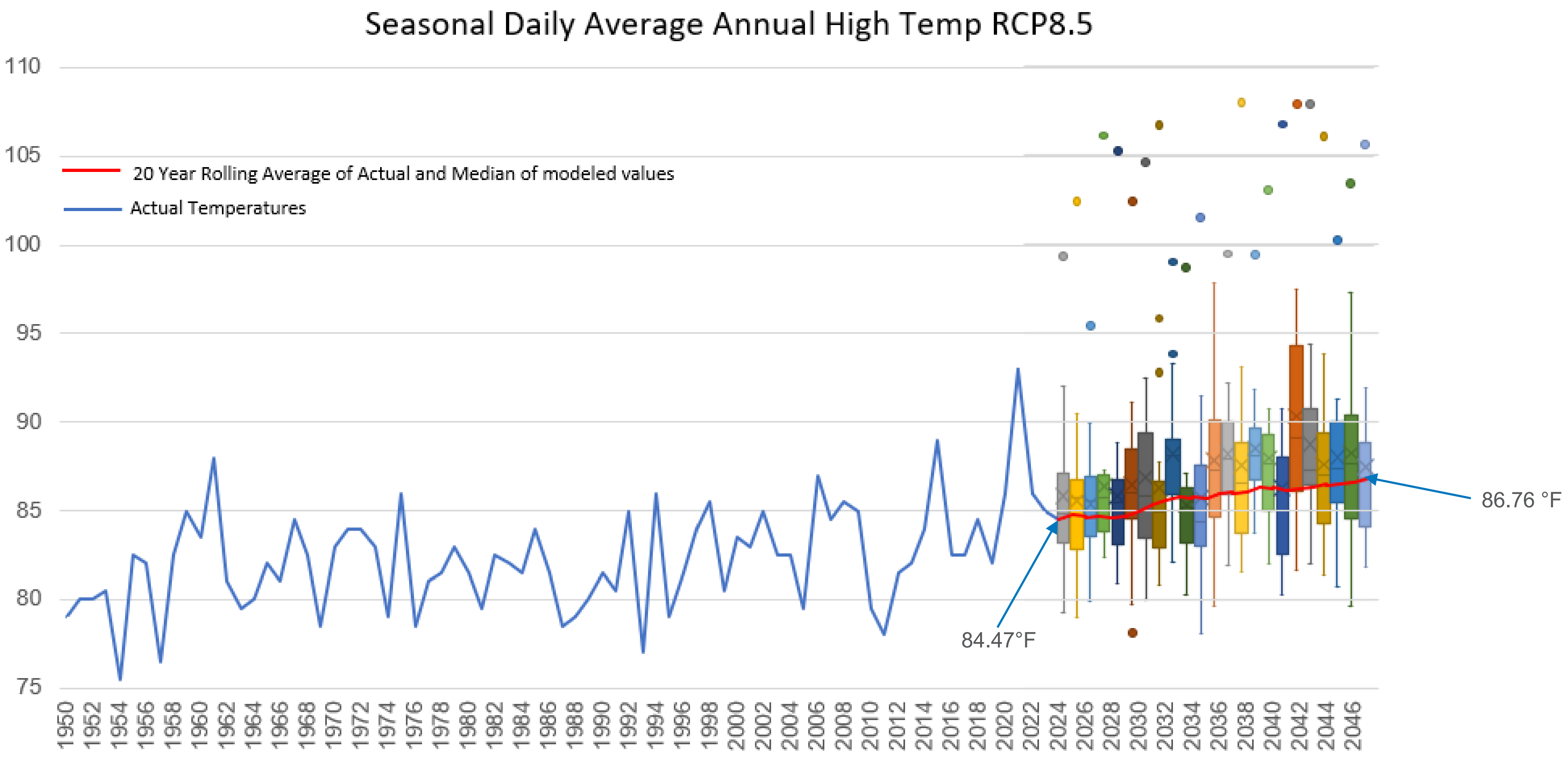


Climate Change Impacts to Peak Load

- Peak load model utilizes minimum/maximum daily average temperature for each season.
  - Winter – January through May, and October through December
  - Summer – June through September
- Winter uses RCP 4.5 and Summer uses RCP 8.5
- Median of minimum/maximum average daily temperature for each season of all models.
- Winter peak is based on a 76-year* moving average, summer peak is based on a 20-year moving average.

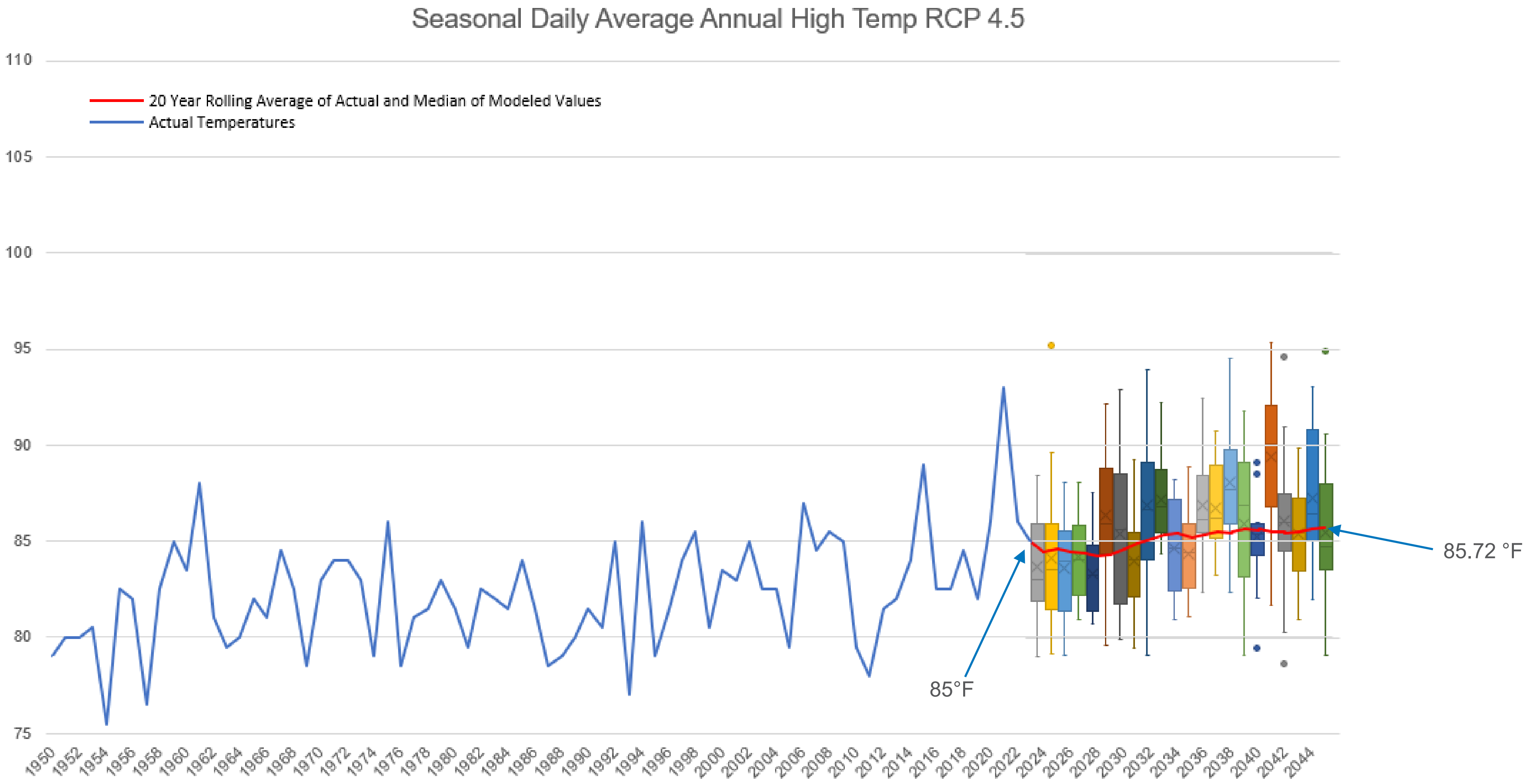
* Location for Spokane temperature data changed in 1947.

Climate Change Impacts to Peak Load



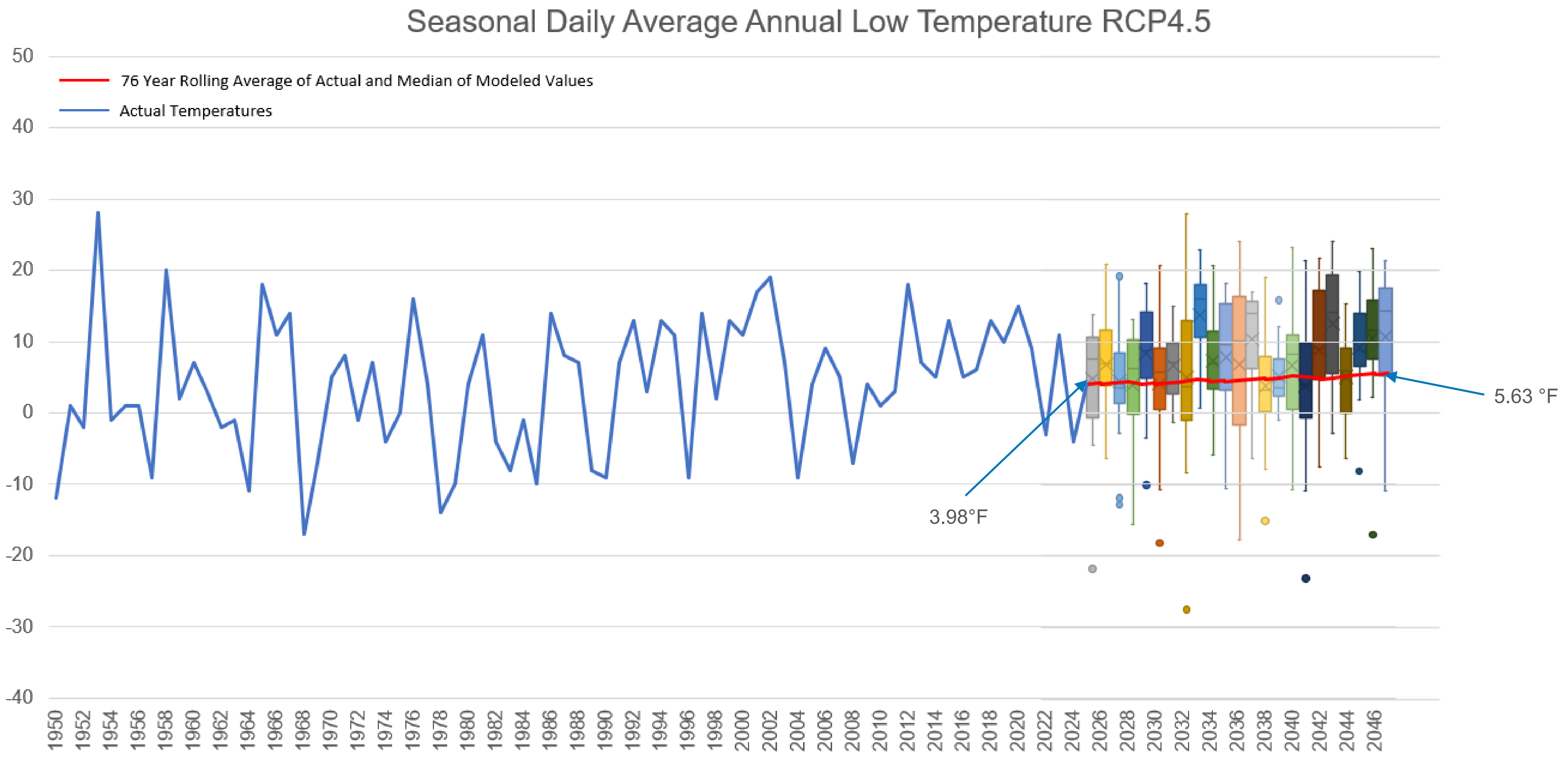
- Peak load estimate is a 1-2 event

Climate Change Impacts to Peak Load



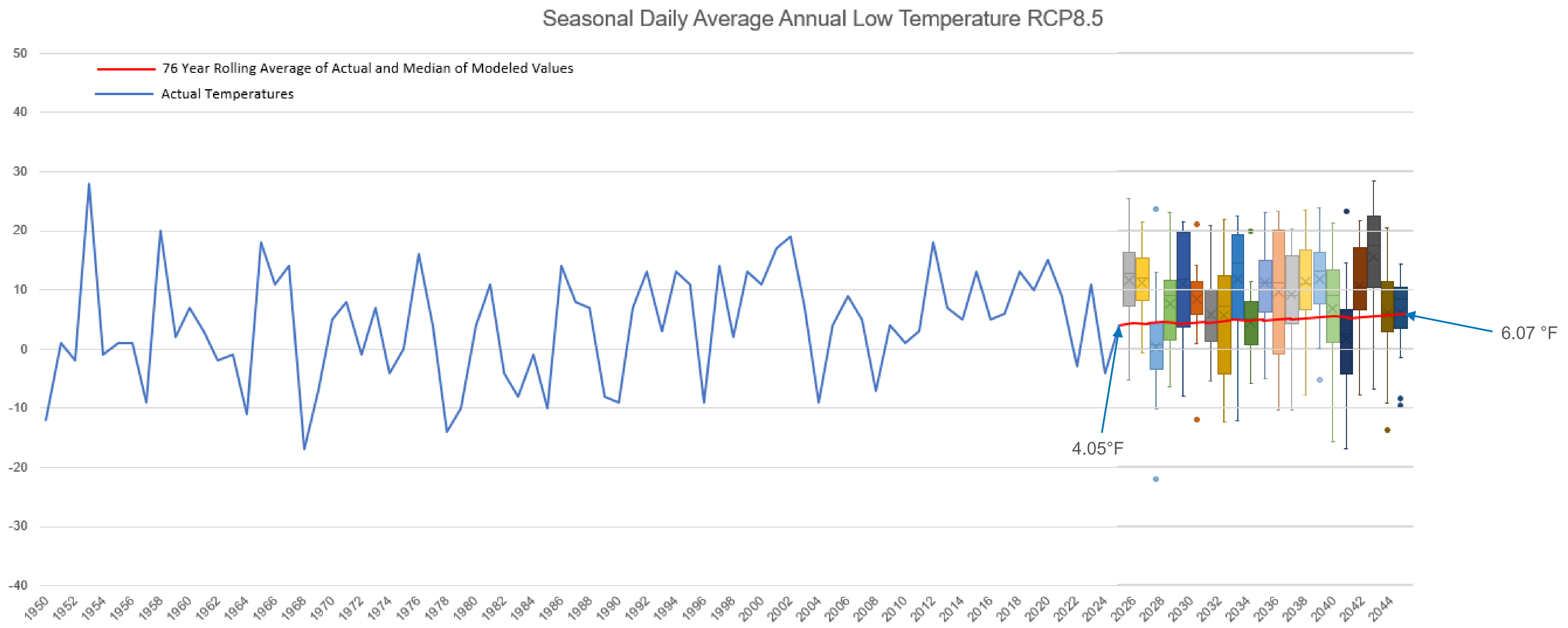
- Peak load estimate is a 1-2 event

Climate Change Impacts to Peak Load



- Peak load estimate is a 1-2 event

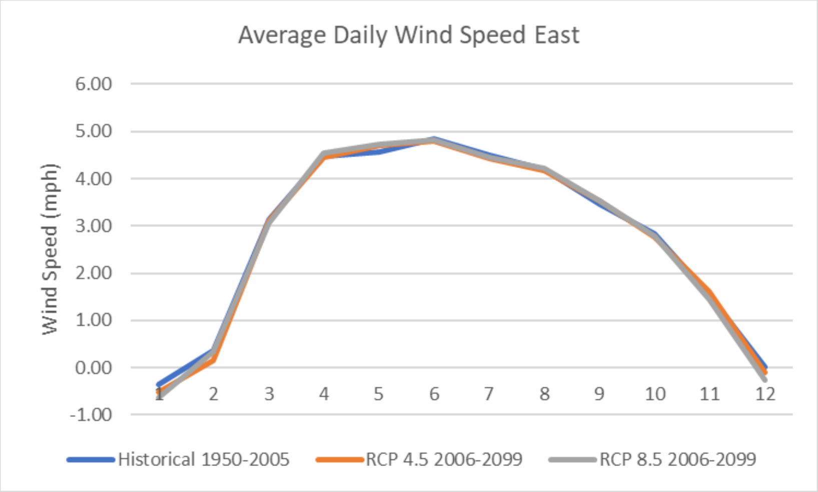
Climate Change Impacts to Peak Load

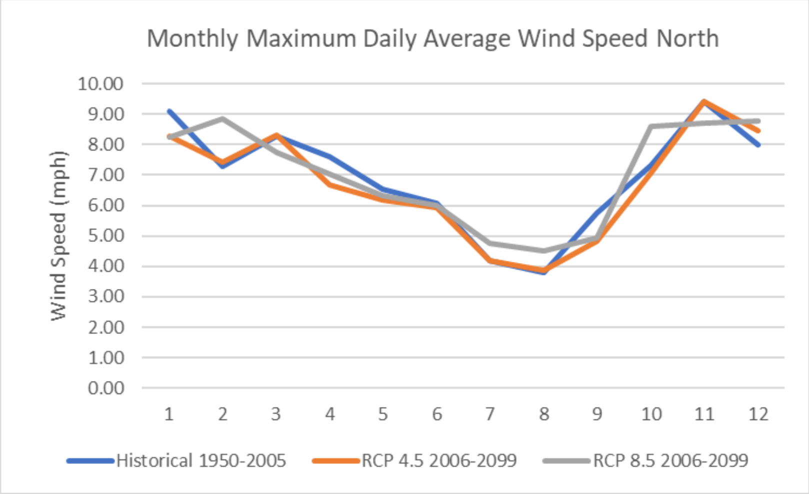


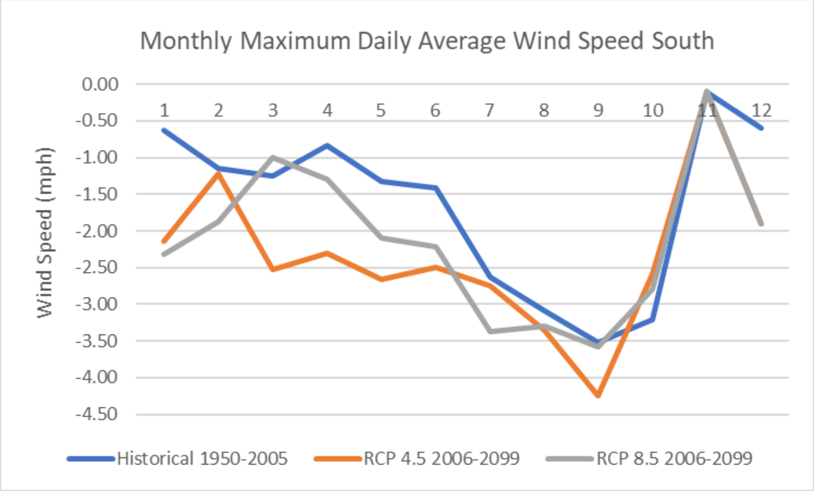
- Peak load estimate is a 1-2 event

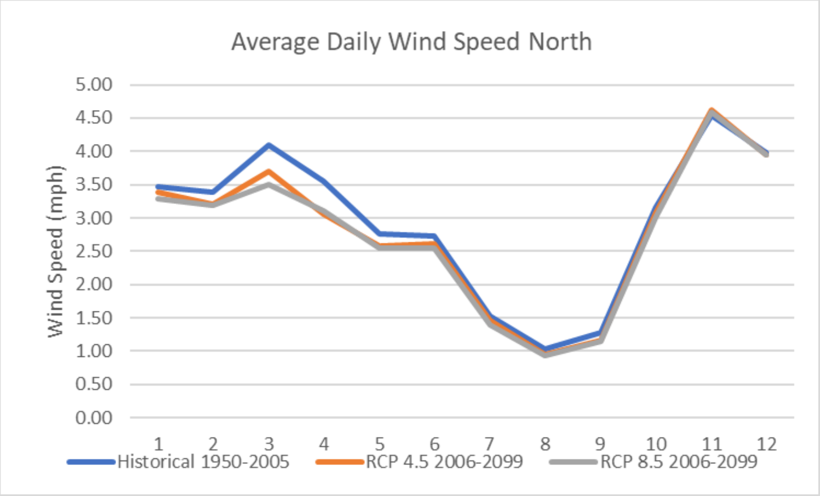
Climate Change Impacts to Wind Generation

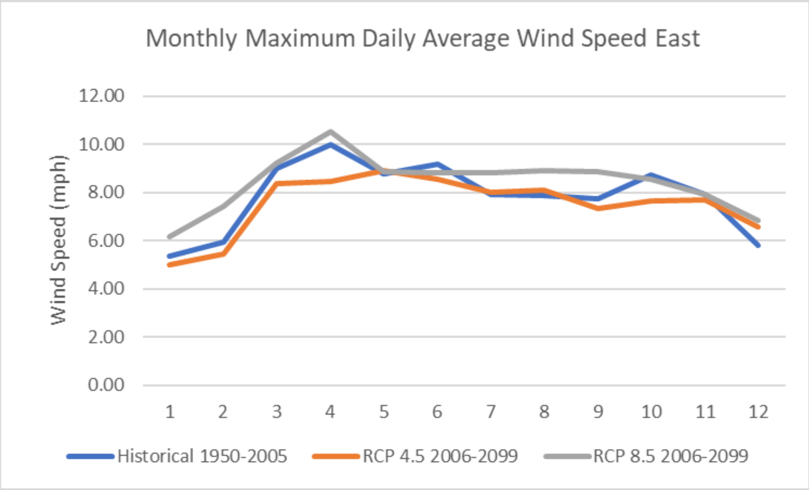
- Evaluated modeled wind speed in the north/south and east/west direction for a historical time period (1950-2005) and climate futures using the RCP4.5 and RCP8.5 (2006-2099) for the location of our Palouse Wind Project.

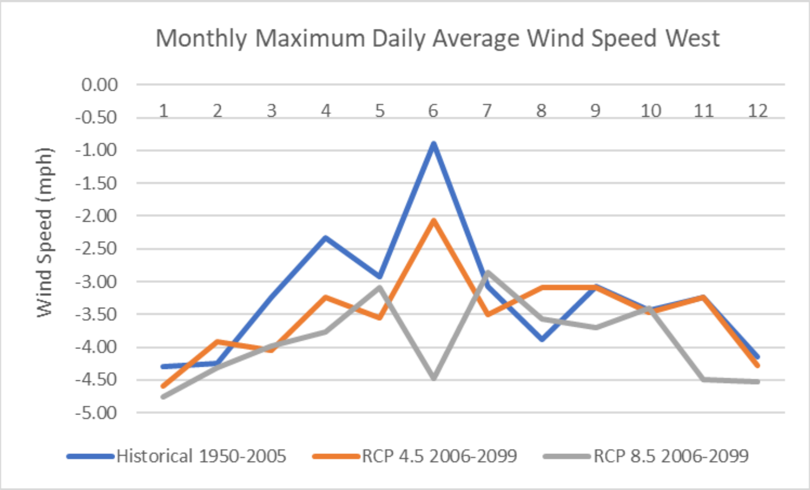












IRP Climate Change Approach Summary

- Proposed approach utilizes both RCP 4.5 (winter) and RCP 8.5 (summer)
  - Description by Intergovernmental Panel on Climate Change (IPCC)
    - RCP2.6 – stringent mitigation scenario
    - RCP4.5 & RCP6.0 – intermediate scenarios
    - RCP8.5 – very high GHG emissions
  - RCP4.5 & RCP6.0 are similar in IRP planning horizon
- Hydrogeneration – Proposing to utilize latest BPA regulated flows (1929-2018), one year of actuals and median of BPA selected climate models. Monthly flows were used in Plexos to develop generation.
- Peak Load Forecast – Proposing to use moving average of previous 20 years (summer peak) and 76 years (winter peak).
  - Used seasonal peak temperature (low and high)

TAC Meeting

April 9, 2024

2025 IRP: Economic Conditions and Preliminary Medium-Term Forecasts

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

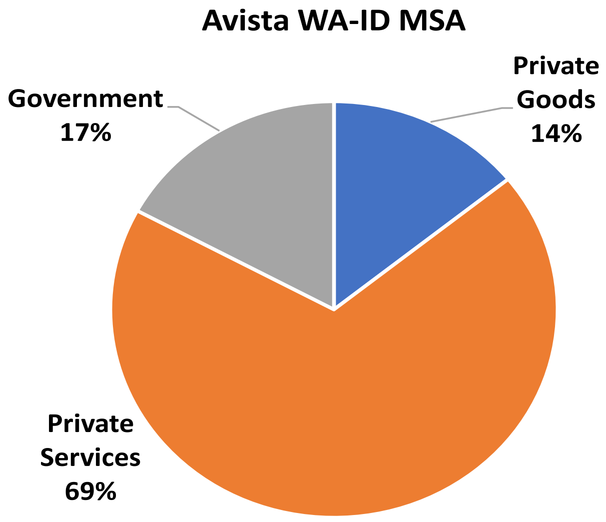
Outline

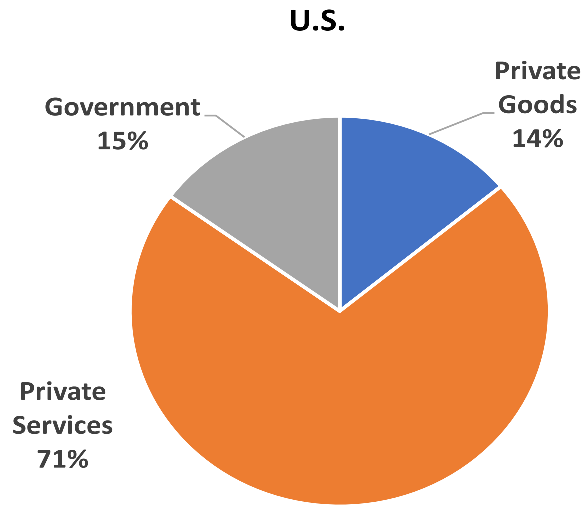
- Service Area Economy
- Medium-Term Energy Forecast (Spring 2024)

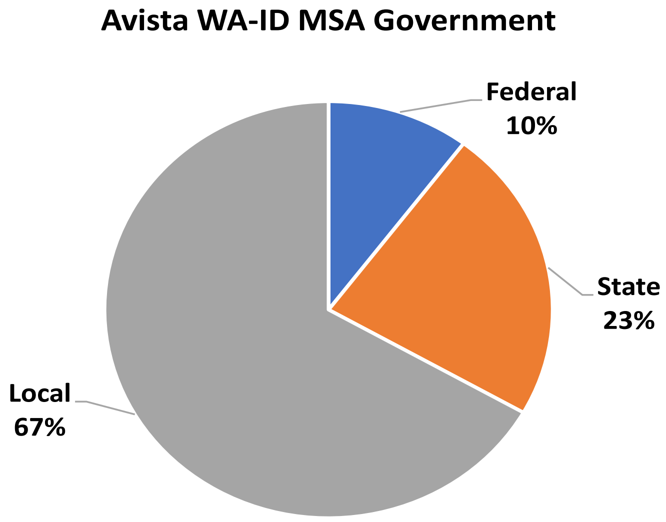
"This presentation is 40 minutes of a finite life you will never get back."

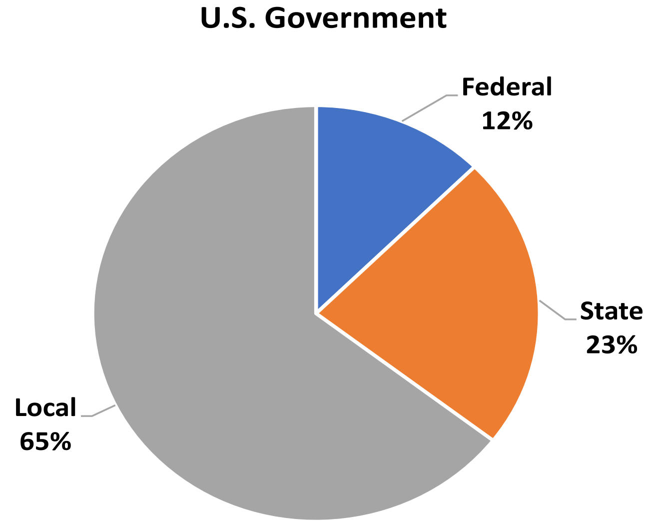
-Grant Forsyth, April 9, 2024.

Service Area Economy: Non-Farm Employment Structure







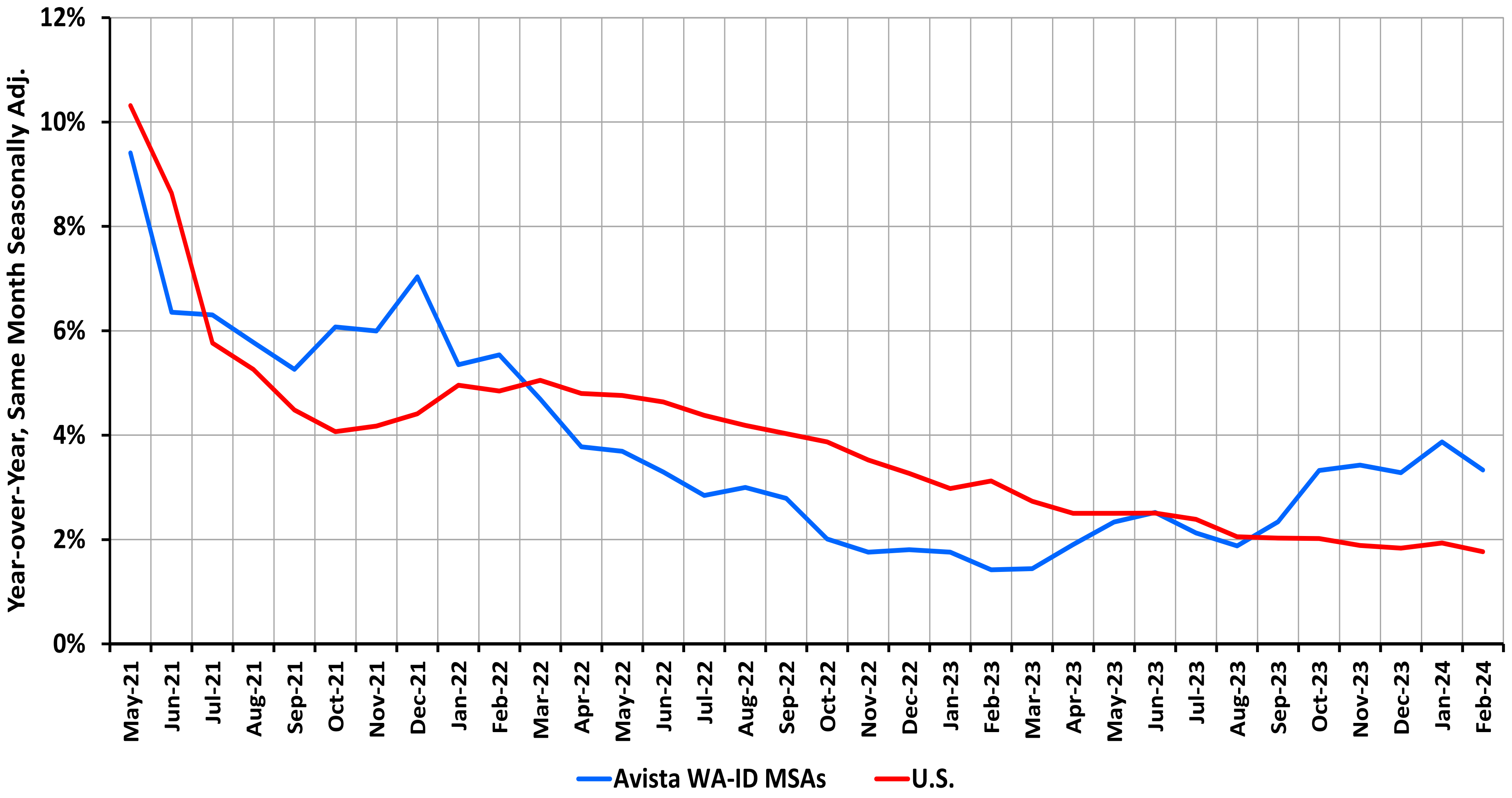


Comments

- Employment structure very similar to the U.S.
- Employment dominated by private services. Without service sector growth, very little employment growth will be generated.
- Majority of public sector employment is local and related to education.
- If agriculture is considered, it would account for about 1% to 1.5% of employment.

Source: BLS and author's calculations.

Service Area Economy: Non-Farm Employment

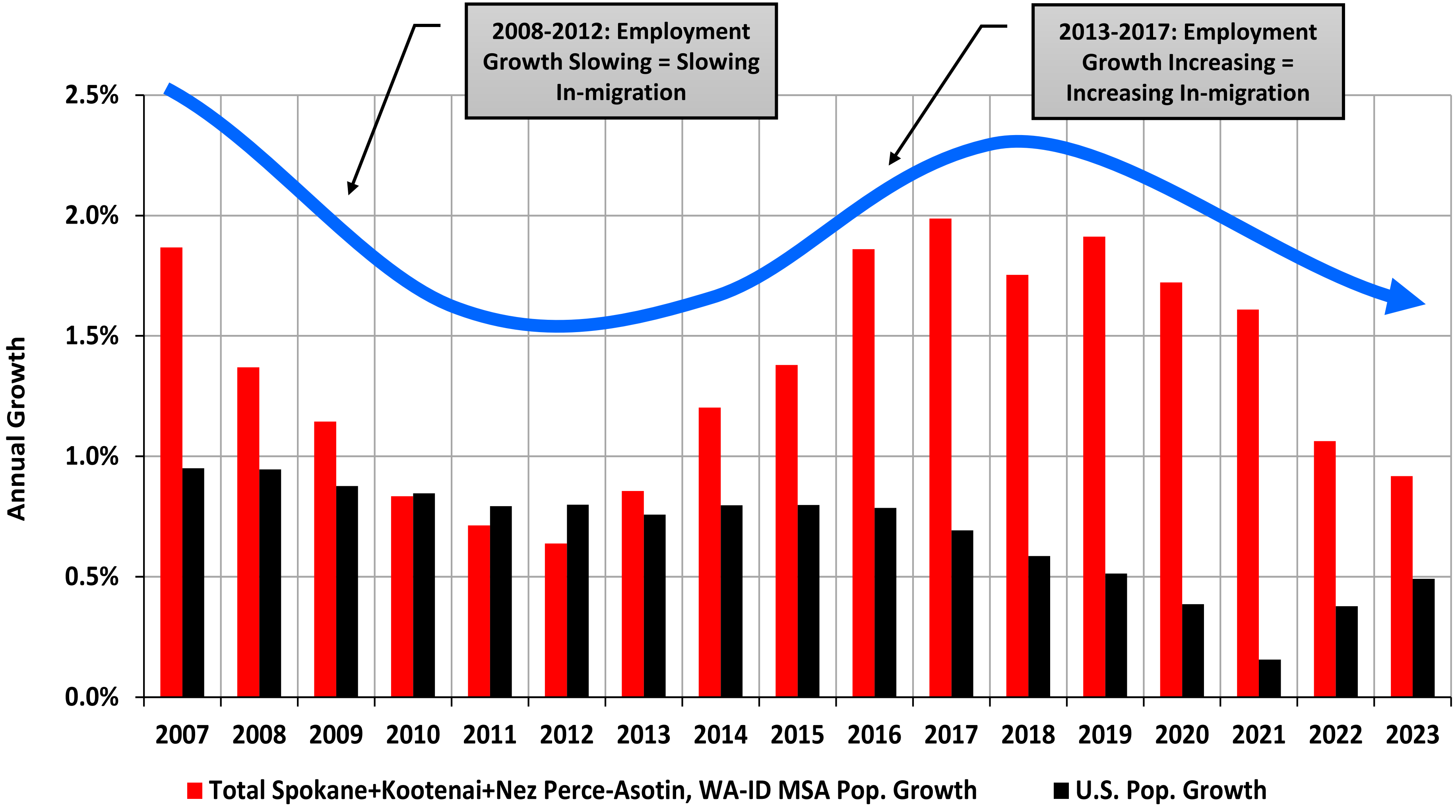


Comments

- **Region has recovered from the pandemic faster than the U.S.**
- **Growth has been strongest on the ID side.**
- **WA-ID employment growth has remained relatively strong, even with the rapid rise in interest rates.**

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

Service Area Economy: WA-ID Metro Population Growth

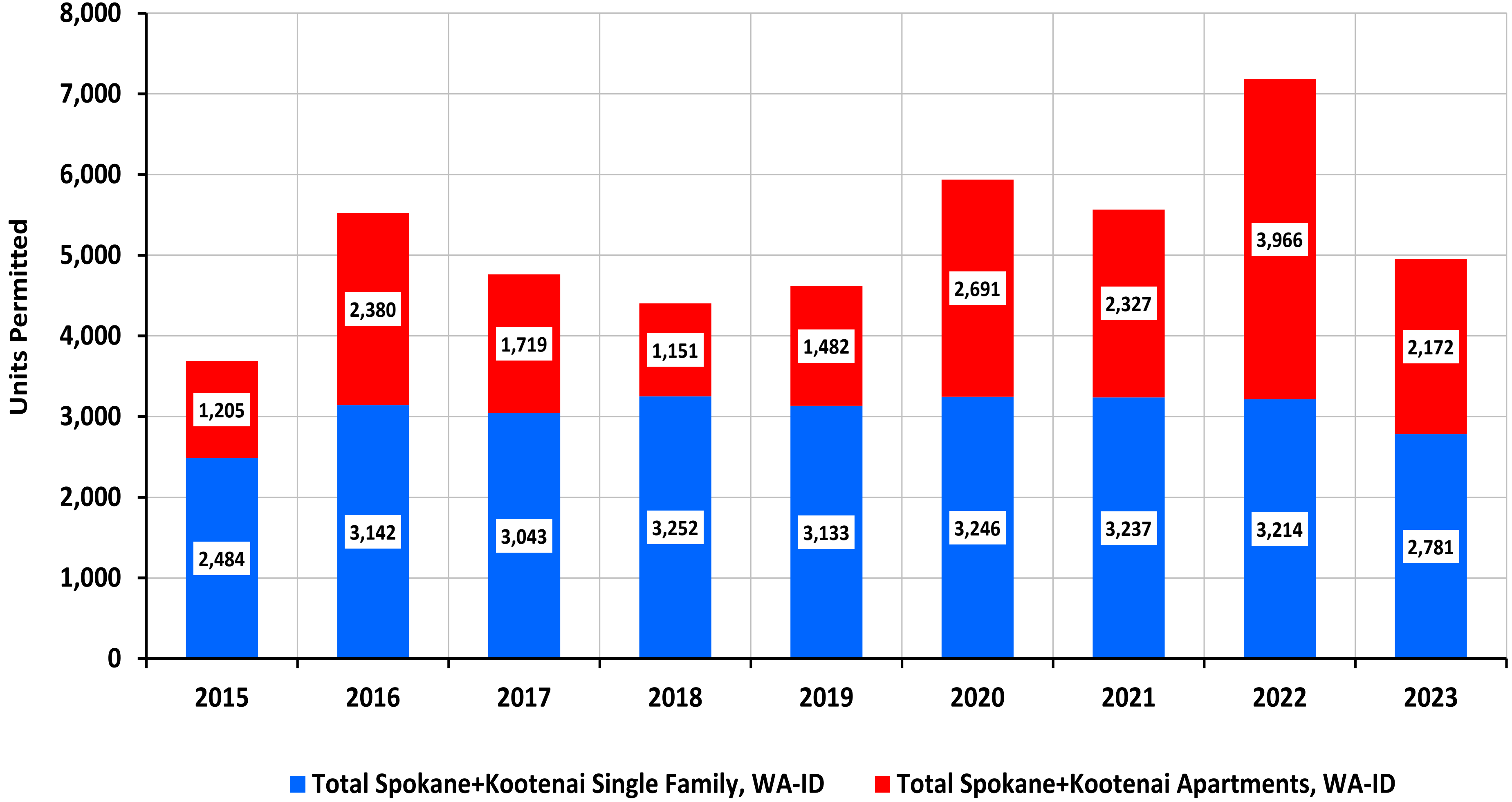


Comments

- Population growth drives most of our customer growth.
- Significantly higher than U.S. growth because of in-migration. Without in-migration, growth would look like U.S. or be lower.
- Growth is highest on the ID side.
- Strong employment growth is correlated with strong population growth…but
- Historical relationships may be changing due to high housing prices, but it's not clear at this point.

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

Service Area Economy: Spokane+Kootenai Residential Units Permitted

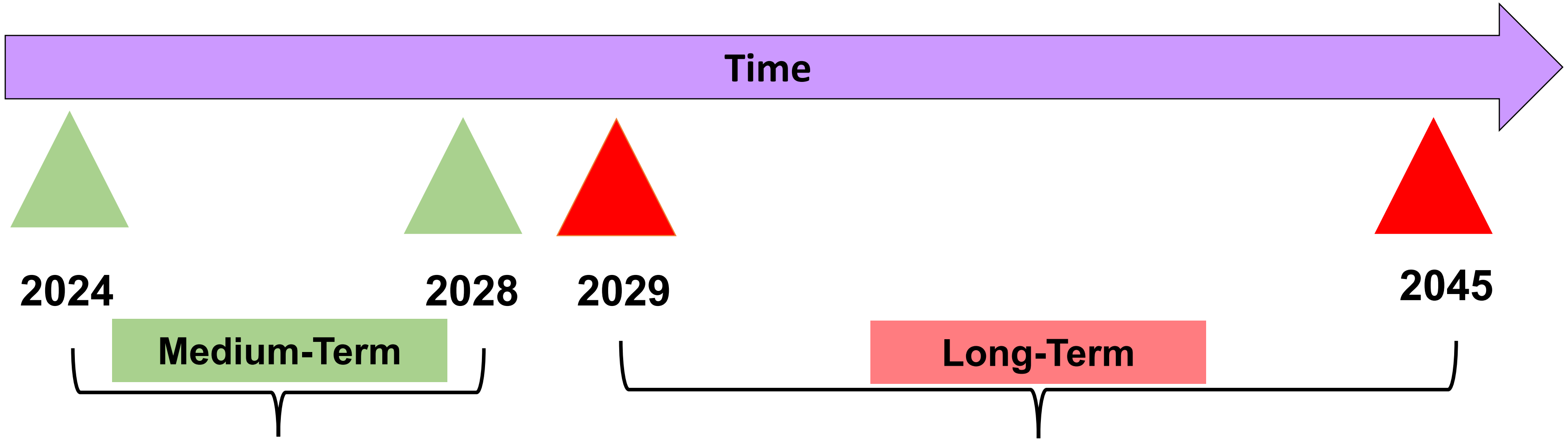


Comments

- Strongly connected to population growth.
- Held up surprisingly well given increase in interest rates.
- Prices of single-family housing have not declined significantly. The supply side remains constrained.
- Apartments and duplexes are still and important source of new housing in both WA and ID. Duplexes are counted as “single family” in the graph.
- Starting this year, ADUs are now covered by Construction Monitor.

Source: Construction Monitor and author’s calculations.

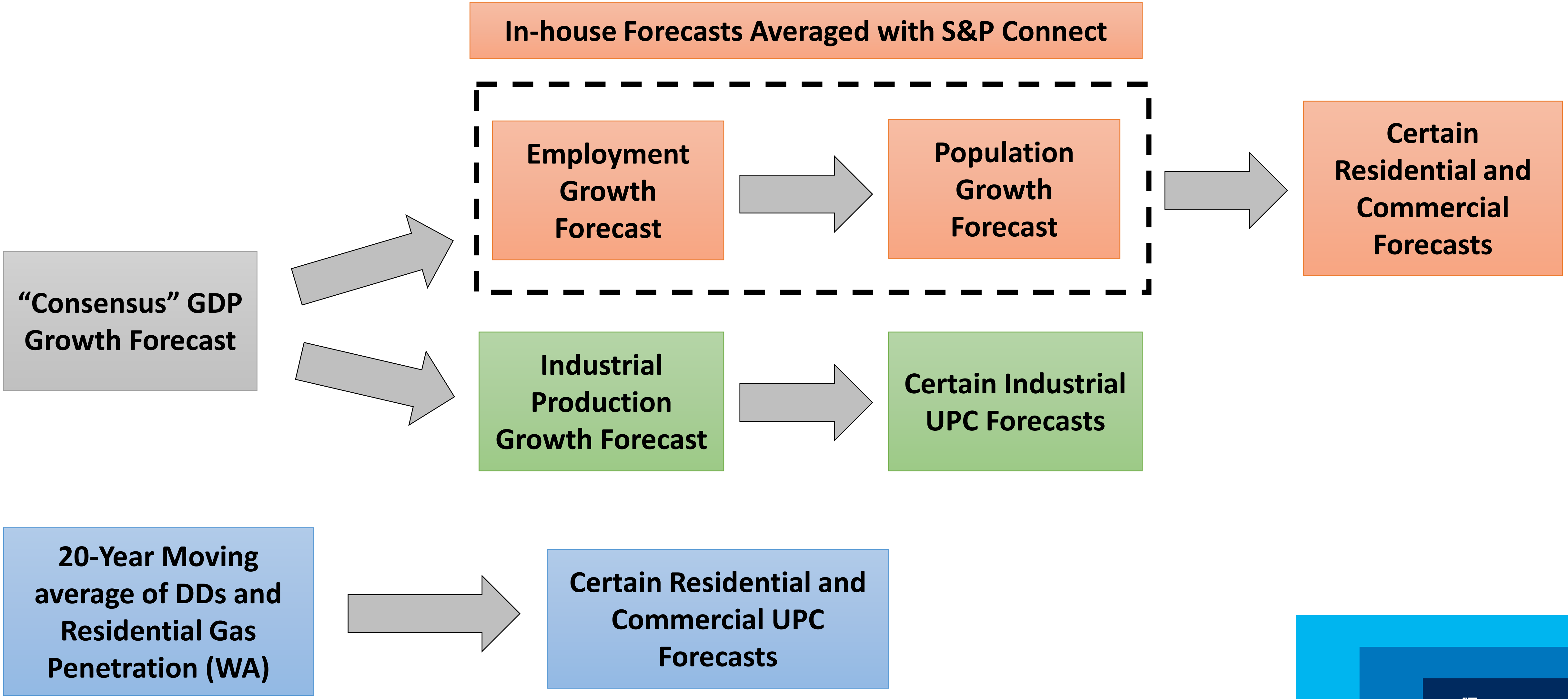
The Energy Forecast: Basic Approach



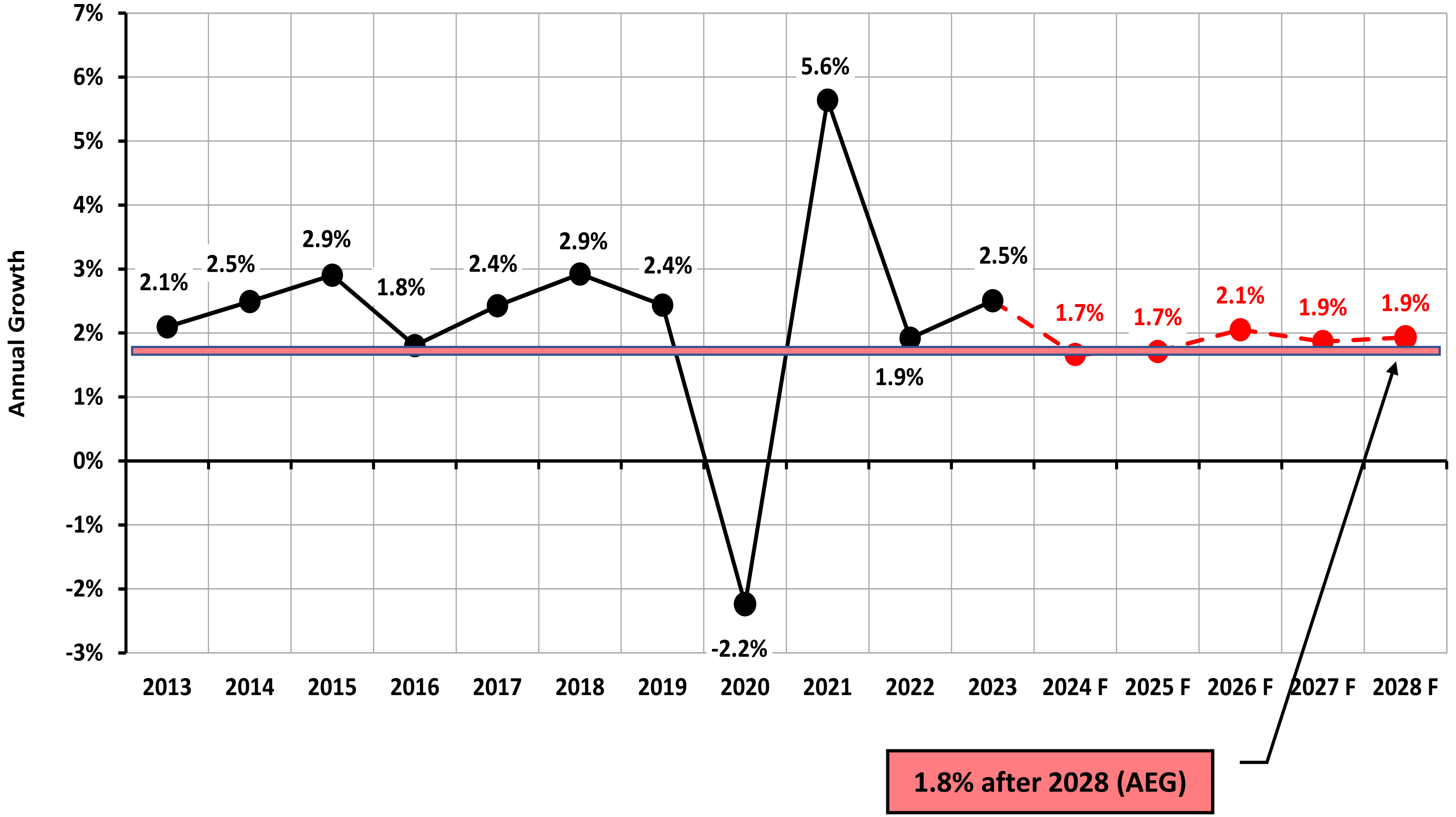
1) Monthly econometric model by schedule for each customer class.
2) Customer and UPC forecasts.
3) 20-year moving average for "normal weather."
4) Economic drivers: GDP, industrial production, employment growth, population, natural gas penetration.
5) Native load (energy) forecast derived from retail load forecast.
6) Current 2025 IRP forecast is the Spring 2024 Forecast (completed in March).

1) Shifting to end-use modeling.
2) Being handled by AEG with a few assumptions from Avista.

Medium-Term Forecast: Basic Approach



Economic Assumptions: U.S. GDP Growth Assumptions

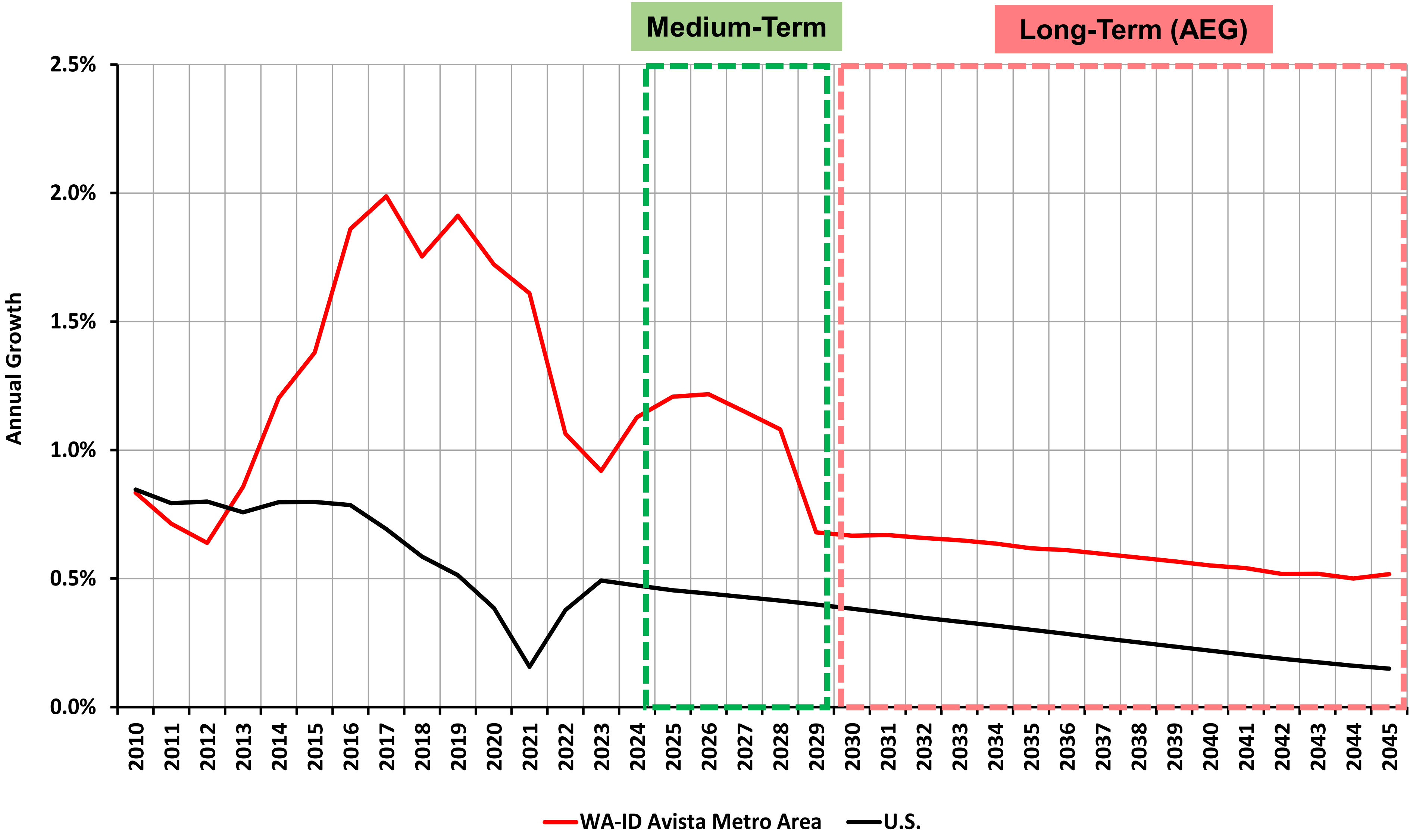


Comments

- **Long-run growth is the sum of population growth and labor productivity growth.**
- **U.S. continues to have weak productivity growth and weak population growth.**
- **The Fed's long-run expectation for GDP growth has fallen from 2% to 1.8% (red line). This is the growth rate assumed from 2029 to 2045.**
- **Long-run GDP growth must exceed 1.6% for industrial load to grow.**

Source: Various and author's calculations.

Economic Assumptions: Population Growth



IRP	Avg. Annual Growth, 2024-2028	Avg. Annual Growth, 2029-2045
2023 IRP*	1.1%	0.8%
2025 IRP	1.2%	0.6%
2025 WA	0.9%	0.3%
2025 ID	2.0%	1.4%

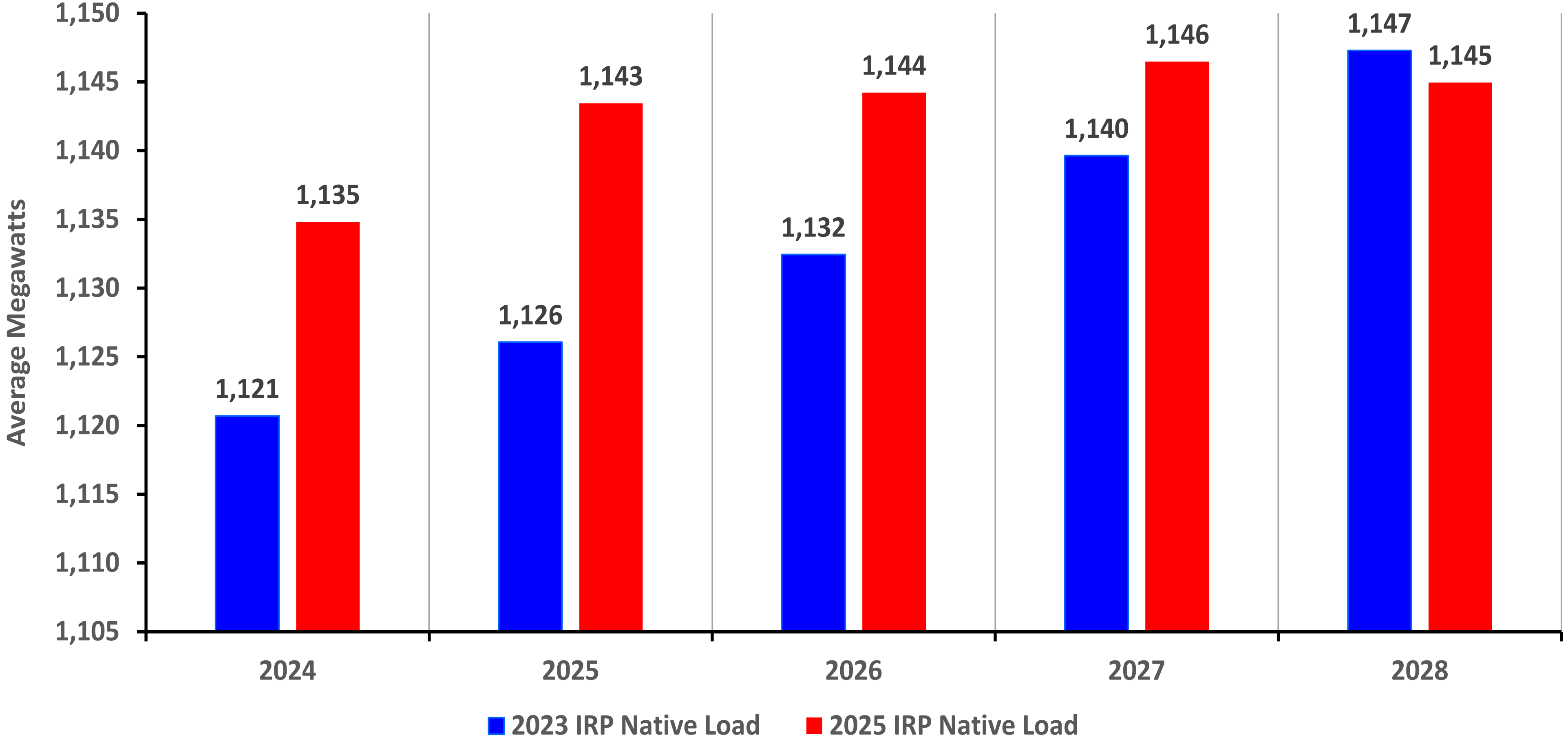
* Spring 2022 forecast in 2023 IRP

Comments

- **From 2029 on, the time-path reflects S&P 500 Connect population forecasts.**
- **Average population growth is a proxy for customer growth.**

Source: BEA, U.S. Census, S&P 500 Connect, and author's calculations.

Medium-Term Energy Forecast: Native Load



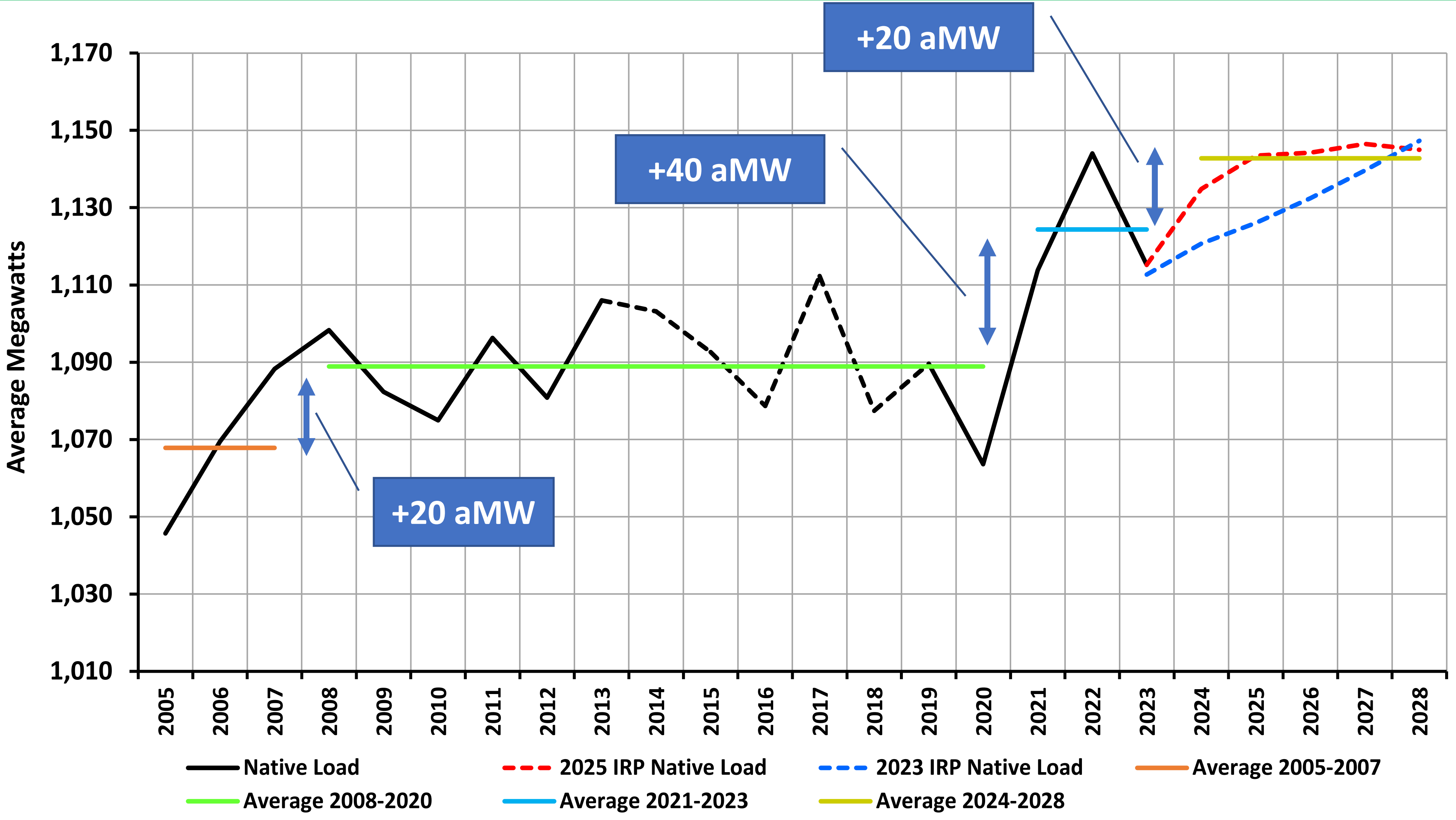
IRP	Avg. Annual Growth, 2024-2028*
2023 IRP	0.59%
2025 IRP	0.22%

* Spring 2022 forecast in 2023 IRP

Comments

- The difference reflects a step up in residential UPC starting in 2022, forecasted declining gas penetration in WA, and higher forecasted industrial loads.
- No significant difference by 2028.

Medium-Term Energy Forecast: Native Load since 2005



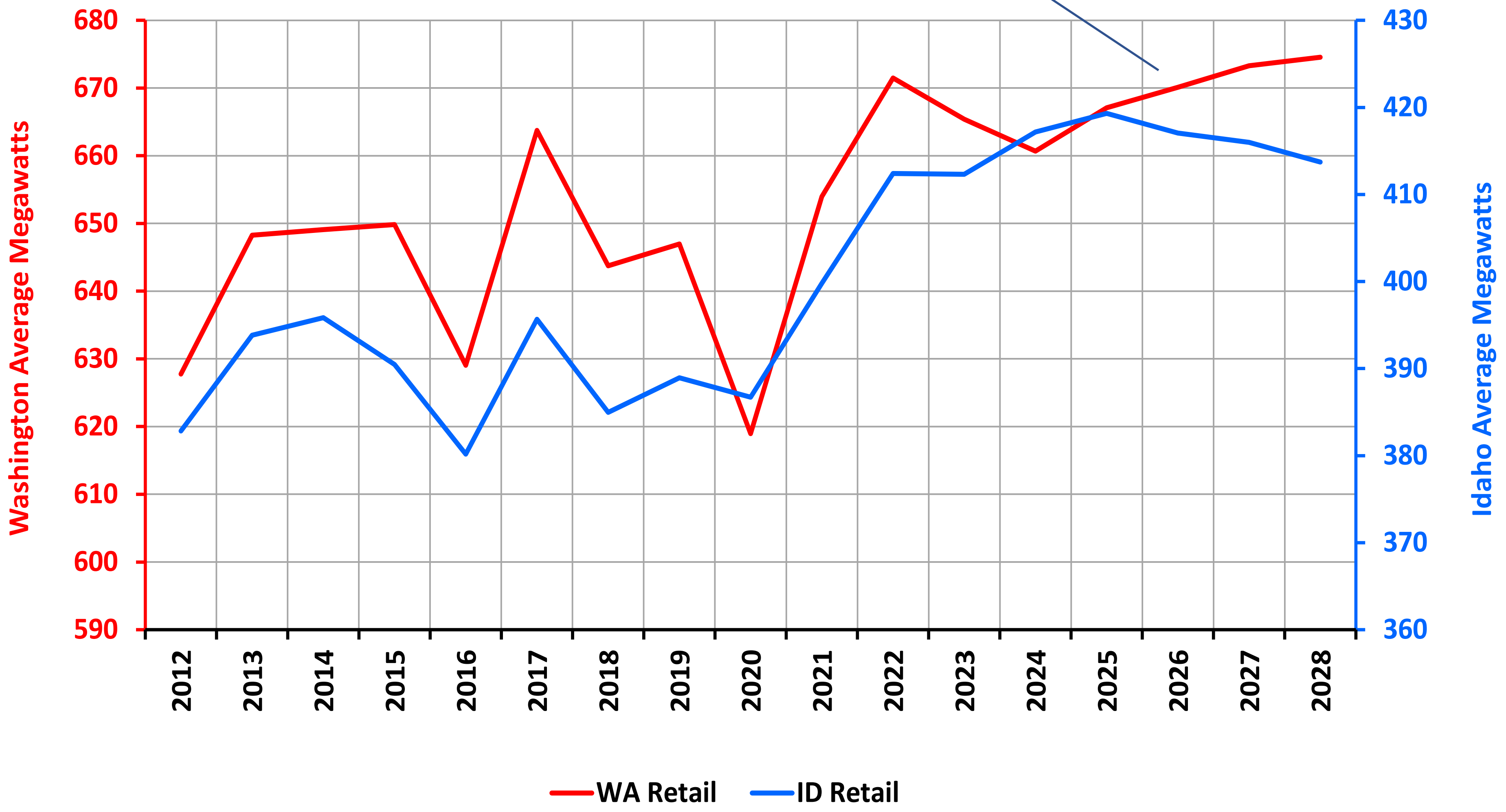
Comments

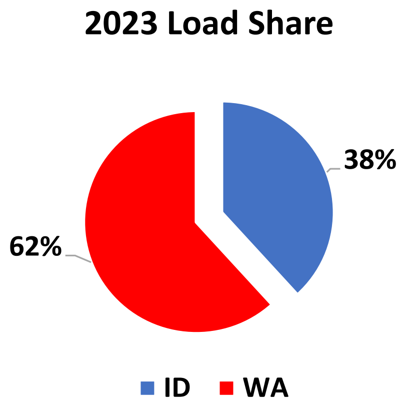
- **Prior to 2021/2022, the housing bubble period was the last significant step up in native load.**
- **The hybrid work environment will have some permanence, but commercial buildings still need to be heated and cooled.**
- **Dashed black line reflects an adjustment for a specialized contract with a large customer with self-generation.**

Medium-Term Retail Forecast: Washington vs. Idaho

Appendix A

WA forecast explicitly assumes residential gas penetration continues to fall. This generates a slightly different time-path in the forecast compared to ID





Questions?

TAC 4 Meeting Notes, April 9, 2024

Attendees:

Diana Aguilar, Fortis BC; Andres Alvarez, Creative Renewable Solutions; Soyfa Atitsogbe, UTC; John Barber, Customer; Shawn Bonfield, Avista; Kim Boynton, Avista; Tamara Bradley, Avista; Annette Brandon, Avista; Kate Brouns, Renewable Northwest; Michael Brutocao, Avista; Katie Chamberlain, Renewable Northwest; Josie Cummings, Avista; Kelly Dengel, Avista; Joshua Dennis, UTC; Paul Dietz; Grant County PUD; Mike Dillon, Avista; Nelli Doroshkin, Invenergy; Chris Drake, Avista; Michael Eldred, IPUC; Rendall Farley, Avista; Ryan Finesilver, Avista; Damon Fisher, Avista; Grant Forsyth, Avista; James Gall, Avista; Bill Garry, Customer; John Gross, Avista; Leona Haley, Avista; Tom Handy, Whitman County Commission; Shaun Harrington, Grant County PUD; Kyle Hausam, Avista; Mike Hermanson, Avista; Fred Heutte, NW Energy Coalition; Allison Jacobs, PSE; Erik Lee, Avista; Dan Lively, Clearwater Paper; Mike Louis, IPUC; John Lyons, Avista; Patrick Maher, Avista; Jaime Majure, Avista; James McDougall, Avista; Heather Moline, UTC; Molly Morgan, UTC; Paul Nichols, PSE; Michael Ott, IPUC; Tom Pardee, Avista; Michael Reimers, Grant County PUD; John Rothlin, Avista; Nathan Sandvig, Avangrid; Ryan Sherlock, Avangrid; Amanda Silvestri; BPA; Darrell Soyars, Avista; Dean Spratt, Avista; Victoria Stephens, IPUC; Lisa Stites, Grant County PUD; Jason Talford, IPUC; Brandon Taylor, PSE; Charlee Thompson, NW Energy Coalition; Jared Webley, Avista; Nathan Weller, City of Pullman; Bill Will, WASEIA; Yao Yin, IPUC;

Recording started with the first presentation after the Introduction.

Future Climate Analysis, Mike Hermanson

Mike Hermanson: OK, as John said, I'm going to be talking about the climate change analysis that we did. It's largely an extension of what we did for the 2023 IRP. But given the additional new staff and other people that were not part of that process, we're going to step through the whole methodology that we did. We're going to look at hydro generation. What's the impact of the predicted climate on hydrogenation? We're going to look at the temperatures that were used for the load forecast. We're still a few days away from getting the load forecast, so we're not able to do a before and after look at climate change versus no climate change on the load forecast, and then looking at temperatures for the peak load forecast where we've made some moderate changes to methodology.

Mike Hermanson: To start out. All of this data is based on work that was done by a joint committee of three of the major players on the Columbia River system. BPA, U.S. Army Corps of Engineers and the US Bureau of REC. They utilized research teams from the University of Washington and Oregon State. This has been a long study. They started out with unregulated stream flows. Looking at the system with no reservoirs or reservoir regulation. The second part was looking at what happened with new runs of these unregulated flows through their regulation modeling system. One piece of data that we did add to this year was looking at some wind data from the University of California, Merced. They have a data set where they've downscaled some of the data to a level at which is useful for looking at smaller regions. We looked at one of our wind projects on the Palouse.

Mike Hermanson: Getting to stream flow is a multi-step process. I'm going to start from the from the top where the basic model, the data that drives the models and then go through how you take these global climate models, which do not output stream flow. That is not output that they provide, so you need to do some additional modeling steps to get to stream flow. You start with a global climate model, and because it's a global climate model you need to have some sort of workable model size, and these are all spatially oriented. It uses model cells as the basic unit that you're looking at. And in global climate models, they range from 75 to 300 kilometers grid size. That's not, when you're looking at watersheds, the Columbia River watershed is obviously large, but we are looking at watersheds that contribute to smaller areas such as the Clark Fork or the Spokane River.

Mike Hermanson: The models provide projections of temperature and precipitation and other meteorological variables, but the temperature and precipitation is the most important part. Stream flow is the resultant output of the global climate model. An important concept in this process is to look at the future of greenhouse gas emissions, most notably carbon dioxide. The IPCC and other organizations that do this type of modeling developed a standard set of climate futures based on carbon dioxide. This chart to the right starts with real data and then you get 2000 to 2100 and that is predominantly the model data. It shows what the concentration pathway that is predicted. Depending on these different representative concentration pathways, and they are largely derived by implementation of greenhouse gas reducing policies, how successful they'll be, how widely they'll be taken. So, you have a range and they're denoted by a number. The higher number is the larger quantity of greenhouse gas emissions over a period of time, and so you have the RCP 8.5, 6.0, 4.5 and 2.6. The interesting thing to note about this chart is that the endpoint of a lot of these models is 2100, but the IRP timeline is actually ending in 2045, so you bisect that tan area, and you see the difference. When you get out to 2100, the difference between these scenarios is quite large, but in the middle and slightly to the left of the middle of that tan area, you'll see that greenhouse gas emissions and concentration within the atmosphere is a lot closer. Multiple models are used, academic institutions and different countries. There's a list here. I won't go through the list, but all of the different models that were used in the BPA, Corps and Bureau of Reclamation study.

Mike Hermanson: We have 10 global climate models and there is a lot of variance in the output. Some are biased high, some are biased low, so a lot of variation there. Now just a little additional information about the different concentration pathways. In a summary document from the Intergovernmental Panel on Climate Change, IPCC, the de facto governing body of climate change analysis. They described the scenarios in this fashion where RCP 2.6 is a very stringent mitigation scenario, the 4.5 and 6.0 are intermediate scenarios, and 8.5 was labeled as very high greenhouse gas emissions. The joint study evaluated RCP 4.5 and 8.5. They did not do 6.0, because it is largely similar to the 4.5 in the initial phases up to 2050 and then as you go up. It pretty much strikes the middle, there's just a lot of data. There's a lot of choices that needed to be made by this group doing this. This was also pulled from some summary information. Just looking at the RCP 4.5 and 6.0, and they had produced some information that were so in similar time frames, looking at the middle of the time frame versus the end of the time frame, and it looked at global mean surface temperature. Kind of an overall measure of what the impact of these different concentration scenarios are. And if you look in the 2046 to 2065, which is very close to the end of the 2045 IRP planning scenario, you can see that the 4.5 and 6.0 are very similar. I looked at what we wanted to use for the RCP scenarios. We kind of use this guidance. We didn't have the 6.0 to test, but we did have the 8.5 and the 4.5 and intermediate scenarios. Alright, seem to be consistent with the implementation to date of climate change. Policies and projection of hopefully where they go and so that's why we chose that. You can see that the mean is actually higher for the RCP 4.5 in the years going out from the end of the IRP planning scenario. That's kind of about our choices going forward because we're actually going to propose a hybrid method.

Mike Hermanson: Going through the mechanics of doing this global climate modeling down to the watershed scale, where you can actually get stream flow out of it. On the right-hand side, the top shows the typical global climate model grid size and as you can see there's, the resolution at the global scale is fine, but for what we're doing is not. They've been downscaled, which essentially means you use some sort of variable that is present within those large grid cells elevation, other climate data to correct for variations within that model size. Elevation would be a good example. You could have an amount, Spokane within one of these grids and we know that precipitation and snow accumulation and everything is different on the Palouse as opposed to in Spokane City. We have a 4,000, 5,000-foot elevation came from two methods were used and the bias corrected. Spatial disaggregation and the multivariate adaptive constructed analog. And then this is the point we turn the precipitation and temperature that we get from the climate models, and we turn that into stream flow, and it uses two different hydrology models, and then they use three versions of one model and another version of another model. So, we have four different models and what this does is predict, based on the temperature, amount of precipitation, and what kind of ground cover you have, what kind of soil you have. It predicts the hydrologic cycle and then you find out stream flow reacts to that and.

Mike Hermanson: Right now, we have 10 climate models. We have two ways of downscaling it and we have four different versions of hydrologic models that have all been used. And we put all of that together, you get 80 climate scenarios and that has a lot of data to work with. BPA, we follow their lead actually, selected 19 of the 80 scenarios and did work on finding 19 that represented a sufficient distribution of high, low, medium and felt that those 19 scenarios represented the 80 scenarios adequately. We used the ones that the BPA selected. That's what we use for the future climate scenarios. Now I'm going to talk a little bit about how we actually put together a whole flow data set because we have a flow data set that goes from 1929 to 2045. We use the BPA 90-year data set of stream flow and we use 2019. Is not within either of the climate change or the other BPA data set. And then we also used the climate data set to generate this data set went for 1929 to 2045. We used the median of the 19 BPA selected scenarios used in the flow data set. Once we have flow, we then need to turn that into generation within our system. And to do that, we used Plexos and use the functionality of that to generate what the generation would be for our four storage projects. We have four run of river projects in the series on the Spokane River and those were utilized, or the data we used, for that was a regression analysis based on historical relationship of river flow and generation.

Mike Hermanson: This is the output and looking at different time periods, the 90-year, and this is the total mean generation over this time-period noted. We also have contracts with the Mid-C. Projects, but we didn't include that in this because we have changing contractual slices into the future that complicate reporting back. And if we reported back, they're just total generation then that swamps what our generation would be, so this is looking at Avista hydro projects. It's largely consistent with what you hear about climate change in the Pacific Northwest, which is we're going to see more precipitation and as I move on to the next slides, you'll see what is really happening. We're getting a shift more in in the springtime, a little earlier than we've had. And then we are getting lower flows during the summer. So don't need to read off all of the values here. You guys can see that going from 90 years, the recent 30-year to the climate change time periods, the quantity, the total megawatts generated over those time periods increase.

Mike Hermanson: I'm going to go through each month just to give you a flavor for what is predicted in these charts. The orange line is the 30-year as a flatline.

Actually, the orange is the 90-year, gray is the 30-year and then the climate model is the average or monthly average for that time period. You can see the trend of where things are going. As you can see in these four spring, winter, spring months, we generally have a flat trend, but it's increasing generation over those other two time periods. Moving on to the late spring and summer, as you can see, May is still we're getting more generation and then as you move into June, July, August and then September and October, we're seeing a trend of decreasing generation as we move through the climate change time series and then December is pretty much similar for all of the different time periods.

Mike Hermanson: OK, so that covers the hydro generation portion of our climate change analysis and now we're going to look at temperatures for load forecast and two different ways of looking at it. When we're just looking at annual energy, we look at heating degree days and cooling degree days. And then for our peak, we look at the actual temperature. We use the daily max and min temperature for the Spokane Airport through 2045 that correspond to the 19 BPC scenarios. And then we are actually proposing to use data from both the RCP 4.5 and RCP 8.5 temperatures for the load forecast for the winter months, January through May and October. I guess that's not all winter, spring, and fall. Winter we're proposing to use the RCP 4.5. And then June through September using the RCP 8.5. This approach will allow us to look at worst case scenarios in both time periods. It'll allow us to evaluate what the impact of increasing temperatures from RCP 8.5 during the summer months whereas capturing the low temperatures that are still possible and appear to be continuing to be possible going into the future. The average temperature is increasing, but you still have those cold snaps as we had in early January. Those are still possible and represented in these climate datasets. So this chart shows the.

James Gall: You got a question from Molly. OK, Molly, go ahead.

Molly Morgan (UTC): Hi. I'm just on that last slide. I'm just curious, what would be any downsides or risks of using of this proposal of using the 4.5 and the 8.5 together? And then also, do you know of any other any other places that this has been done? Are there any other examples of that?

Mike Hermanson: We don't know of any examples, although I haven't done a cataloging of all approaches to climate change within different IRPs. Actually, this approach was really to address risk. What we were finding was that if you use the 8.5 during January and during the winter months that you're going to possibly miss out on that cold event. And you know from working with the Martin Luther King Junior Day event that we had. We know those risks are real and still important to plan for. They are still represented within the RCP 4.5, although as we get to the peak part, you'll actually see the differences we're talking about are. In some instances, a difference less than a degree, what we're finding is that you still have some of the outliers. Extreme values still are retained in the RCP 4.5 on the cold side, and we feel that's pretty important, especially in the Spokane area where those risks are real. It is important.

James Gall: Another thing to add Molly to that there's two sides. There's peak and then there's energy. And if we plan for, let's for example use the 8.5 case in the winter, we'll have less energy expected. And what will do is that will reduce the amount of generation we'll have to acquire in the long run, which could put us at risk of not being able to serve those loads, at least in a cost-effective way in the future. The choices that we make here are really going to impact what is selected in our models for new resource generation going forward. The approach we took is planning for, like Michael said that it's more of a risk adjusted value for both seasons that we are going to protect our customers from both forecasts of extreme cold, or sorry, extreme heat and then moderate cold.

Molly Morgan (UTC): OK. I'm just hearing that. So, 8.5 just at least for your service territory doesn't account enough for what you're seeing currently for winter events.

James Gall: Correct. And you'll see that in the chart coming up.

Molly Morgan (UTC): Right. Thank you.

Mike Hermanson: This chart presents the annual heating degree days and annual cooling degree days. You can see what's happened in actual terms and what was modeled. Modeled values are actually decreased. They don't quite represent the most recent period of time very well. But you know it's value. And so, we have the heating degree days, decreasing even under the RCP 4.5 scenario. You still have that climate change impact. You're going to have reduced heating degree days, so as we forecast load that will decrease the amount of energy that we are planning to meet. And then on the bottom, we have the cooling degree days and as you can see the heating degree days are significantly greater in number. And so, we're dealing with temperatures that our energy is heating even though we look like we're going to be a dual peaking facility, or utility annual cooling degree days due to increase. Those annual cooling degree days are based on the RCP 8.5. Using these model temperatures will be, the slight decrease in energy in the winter months and increased energy in the summer months.

James Gall: You have another question from Joshua.

Joshua Dennis (UTC): Hi, I wanted to ask on the Y-axis it says thousands and goes up by the thousands. Could you explain what that means?

Mike Hermanson: Those are the annual cooling degree days and heating degree days.

Joshua Dennis (UTC): Yes. No, not the annual cooling and heating degree days, but why does it go up by thousands?

Mike Hermanson: Because it’s the annual value.

James Gall: You're summing up all of the heating degree days and cooling degree days.

Joshua Dennis (UTC): OK.

Mike Hermanson: So, it's for the whole year.

Tom Pardee: Those are just the average increments between the annual heating degree days and the annual cooling degree days. In order to get it on the chart, to show the delta, it's choosing thousands.

James Gall: It's whole numbers.

Tom Pardee: It's just that's how many fewer cooling degree days we have compared to heating degree days. I'm just saying to show how can get heating degree days and cooling degree days on the same chart. It's choosing the increments of 1,000, but it's for illustration purposes.

Joshua Dennis (UTC): Oh. Thank you.

Mike Hermanson: If we just did a chart of annual heating or cooling degree days, it might choose 1,000 as the top value anyway.

John Lyons: Do we want to go over what the definition of a heating and cooling degree day is? Just for anyone as a reminder here.

Mike Hermanson: As a reminder, heating degree days is the degrees you take, you go from an average value of 65 being zero and a heating degree day is how many degrees do you need for the difference between what the temperature is outside. If it's 45 and you have your zero set at 65, you're going to have 20-degree days.

James Gall: and then you sum them up for the whole year, which is why winter is substantially larger than summer. There's just a lot more heating degree days in total over the course of the year than summer cooling degree days. So, if you were in Arizona, the chart would be flipped, essentially. John has a question.

John Barber: Yeah. How fine grained is that? Is that the maximum or the minimum temperature of a day? Or do you average it over the day, hour by hour?

Mike Hermanson: It's an average of the minimum and maximum of the temperature for the day.

John Barber: OK.

James Gall: So, might be about 10 minutes left in this section so you might have to speed it up.

Mike Hermanson: Yeah. OK, now we're going to move to peak load. Similarly, we are proposing to use the RCP 4.5 for winter and summer use the RCP 8.5. The other change that we have used is we're using the median of the minimum or maximum of the average daily temperature for each season of all the models. We have 19 models. We have a median and then we go and look for that whole season and we picked the lowest value and then and the winter peak is based on a 76-year moving average and the 76 years is based on that time where Spokane temperature data was moved to the Spokane airport. Summer Peak is based on a 20-year moving average and this is just the choices made on risk and also the movement of these different peak temperatures.

Mike Hermanson: I've got four different graphs that show the actual temperature up to 2024, and a red line which is the peak temperature that we are going to model. And then it's a box and whisker plot showing the median, average, and the extremes of each of the models. This is the distribution of the models, the dots are considered outliers by Excel for whatever approach they used to determining outliers. This is the annual high temperature for RCP 8.5. As you can see, it moves from 84 degrees to 86.76. After 20 years, you end up about the median of the last box and whisker plot.

James Gall: Fred has got a question. Go ahead.

Fred Heutte: Yeah. Hi everybody. It's Fred here at Northwest Energy Coalition. Just trying to find all the right buttons here. You may end up talking about this further along in the slides. But I just wanted to ask, this shows the outliers for the climate adjusted record going forward. I'm wondering if you've looked at the outliers for the historical record. You know, this is summer. But we just had the January freeze event which I've got temperature data for a lot of weather stations. And I would say we had some record setting temperatures for the day during that period, but not for the month. And I'm just wondering if you've looked at whether these outliers are happening more frequently, or they're higher, or they're about the same? If you've looked at that comparison.

Mike Hermanson: Well, what we are planning for with peak load is peak load and we're doing on a seasonal basis. So, we are looking at the entire period from November through February.

James Gall: Can I add something just to get to Fred's question. The historical period, Fred, those are the hottest days on record in the historical period versus the outliers in the forwards, you have those 19 different futures that is a value that is in those 19 futures that show up that are radically different than the rest of the data set.

Fred Heutte: OK, so if I'm following that, that means that you have the historical record with one data series, you're taking all 19 of the different GCM or whatever to look at the outliers in each one.

James Gall: Yeah.

Fred Heutte: So, this in effect kind of over represents what could happen.

James Gall: Exactly. That's where the top of that bar probably is, where it's statistically, that maximum is based on the data set.

Fred Heutte: OK.

Mike Hermanson: This is an attempt to show the real challenge of working with 19 different models and the fact that they are widely distributed.

Fred Heutte: Yeah. And just to say, I appreciate you doing that because I think it does highlight the internal models actually have some, I don't know that much about all this, but have some common starting points way back when and have kind of diverged. And of course, within the model each time when you run it, you're going to start with slightly different starting conditions. That's part of doing the modeling. So, you get this spread, but there is internal correlation with them a little bit. But I think what it really says is that the future is kind of hard to predict. And looking at a lot of models like you're doing is actually a better way to do this, even though it requires some additional interpretation. I think this is the right way to go.

James Gall: Thanks, Fred. We got about 4-5 minutes to get through I think four more slides, so we'll try to be quick.

Mike Hermanson: Just as a comparison, the RCP 4.5 looks like this. And it's also peak temperature on the hot side. You can see the ending value for 4.5 is a planning temperature of 85.72 planning, ending planning temperature for RCP 8.5 is 86.76, so that is the fundamental difference when you get to 2045 is about a degree. Now we're looking at the low temperature, and this is the RCP 4.5. A lot less volatility within these. The other ones mimic the climate ones models a little more, but for this we are using a 76-year because we want to capture a longer period of time. So, you end up with the temperature of 5.63 average daily temperature for the 4.5. Use the 8.5 you get to an average temperature of 6.07.

Mike Hermanson: The last thing we looked at and it's another output. These global climate models, as you can see the historical values were 1955 or 1950 to 2005 and the RCP, the climate change looked at data from 2006 to 2099. On the left is average daily wind speed. Palouse location has a northeast wind direction that's predominant. As you can see, it's essentially the same. We don't predict much change. The climate models don't predict much change in generation. The wind speed from the north direction again is very similar. On the far right are the opposite directions of the predominant wind out there. You see a little more divergence and the negative values are because that's how they're represented the different direction. You can see that the monthly maximum temperatures are not temperatures, but wind speeds are lower. The lower frequency direction and there's a little bit more volatility between the actuals versus the climate models. But given the predominant directions and average wind speed in the predominant direction, we don't see much as far as planning and changes in wind speed, I'm not really sure how accurate predicting wind speed into the future is. It's kind of a tangential parameter from these climate models.

James Gall: We have a question. Did you look at hourly at all to see if there's a 12 by 24 change or is this, I recall the data is daily though, right?

Mike Hermanson: The data is daily.

James Gall: Yes. So, no, for Andres. We can't do hourly with the climate model. Just daily.

Andres Alvarez: OK. Thank you. Just curious to know if there was any hourly shape differences because that will affect the benefit, right. If the hourly shifts are changing, that could be of concern, but it seems probably unlikely.

Mike Hermanson: Just to sum up our proposed approach. Utilized the RCP 4.5 for the winter, 8.5 for the summer, just to remind here of why we chose the 4.5 and the 8.5 looking at the description of the IPCC. We're using a combination of the latest BPA regulated flows, one year of actuals and then the median of the selected climate models for generation estimates and then the peak load forecast. Proposing to moving to use moving averages of previous 20 years and 76 years. The real change would be using seasonal peak temperatures both low and high and that's the background in the proposed approach going forward with the IRP as it relates to climate change.

James Gall: Are there any questions before we move on to the economic forecast and load forecast? And while you're thinking about that, feel free to contact us through email or give us a call afterwards. We do have a question that showed up, Jason says: using a combination of low lows and high high scenarios, does that create unrealistic ramps between models?

James Gall: I'm thinking is that a question more of how the model transitions from one season to the other season? Is that what you're thinking, Jason? Yes. It's a daily model. So, I guess I don't know if there really is a ramp.

Mike Hermanson: It's monthly values and there's not really a ramp, especially as you can see the ultimate difference was 1 degree when it was all done. It did not appear in crunching the data that we ended up with some sort of situation, although that is in fact somewhat what we wanted to create was a better approach to the risk profile for summer different from winter.

James Gall: Molly had a question. Go ahead, Molly.

Molly Morgan (UTC): OK, this is not super well formed, but just thinking of various elements. This is one approach to do the 4.5 in the winter and 8.5 in the summer. Let's say, I think in one of the last meetings, you were asking about the loss of load probability and that's currently at 5% and should or could that be at like 1% or 2%? What would the effect be say if you use the RCP 8.5 year round and then also use the loss of the probability of 1%, would that solve a similar problem or not?

James Gall: Maybe, so how the loss of load probability works is it will randomize both historical and future temperatures. If you use the 8.5 scenario, you're going to have less draws of colder temperatures, and if you're planning for a loss alone at 1%, you're effectively you could get to the same solution. At the end of the day, what it comes down to is how much extra capacity over expectation are you you're trying to acquire. You could theoretically get to a similar answer there, but then it would have a different answer if you'd probably used 4.5 and 1% loss of load probability versus 8.5 and 1% loss of load probability.

Molly Morgan (UTC): Yeah, those would probably get you something different, right?

James Gall: Correct.

Molly Morgan (UTC): Yeah, because there's also thinking of risk in a different way, like the risk of overbuilding.

James Gall: Yeah, I guess overbuilding. It depends. There are two sides of what we're building. One is overbuilding of energy and then there's the overbuilding of capacity, and those are real risks. The problem is you don't know the future and so you're trying to come up with something reasonable and affordable and that's the greatest challenge with resource adequacy is this has been an issue for decades, what do you plan to? For the region, the WRAP came up with a method of 1-in-10 which means you have one event in a 10-year period. Or is it one event in a 100-year period. It's an expectation of what our customers expect from us. I don't know who makes that decision. The utility has an obligation to serve, and we propose something, but at the end of day it's up to the Commission to approve those additions. It would be nice in the perfect world that the Commission or the legislature says this is how much you should build, but we're not in that world. We're trying to propose something that we think is reasonable that we're going to plan to and build resources to. It is a judgment call at the end of the day. But I would also ask the question is loss of load probability modeling or LOLE modeling with the WRAP, is that the right method? I'm not so sure it is after the event we had in January because you're essentially planning not to meet extreme events and should we be modeling for extreme event planning.

James Gall: And I said those are valid questions, but I don't know who has the right answer. We can propose to build resources to meet a low water year and high loads, in a cold event or a hot event. It's up to the Commission to approve those plans or those resources that we acquire. I think we're going to have to work together on trying to figure out what is the right amount of capacity to build.

Molly Morgan (UTC): Hello. Right. Because if you don't accept any such events, then you're likely going to be overbuilt. Is the idea right?

James Gall: Yeah, I mean, can you restate that real quick just so I make sure I?

Molly Morgan (UTC): Like if you if you plan to not accept any such events, like you're saying it could be 1-in-10 years or 1-in-100.

James Gall: Correct.

Molly Morgan (UTC): So, you extend that, maybe I don't know if you can ever say zero, but in that situation, you are likely going to be overbuilt. So, that's the trade-off.

James Gall: Yeah, I know, building is not a bad thing. It's just what can you afford?

Molly Morgan (UTC): Yeah. That's the impact cost.

James Gall: Don't know. Yeah.

Molly Morgan (UTC): Yeah. OK. Thanks.

James Gall: Yep. Let's move to Grant’s presentation.

Economic Forecast and Five-Year Forecast, Grant Forsyth

Grant Forsyth: We got about 35 minutes for a 40-minute presentation. So OK, so I'm going to jump right in. I'm going to talk about something I've talked about many times in these IRP meetings. We are going to talk about economic conditions of our service territory just to make sure that everybody's on the same page about what we look like, and we'll also talk a little bit about what I'm building into the medium-term forecast, which incidentally is a forecast I do twice a year. It goes out approximately 5 to 6 years depending on what time of year I start the forecast and I say preliminary in this case because I just redid the forecast in March and I sent that to our consultants, which I'll talk about in a minute. We're working with some consultants who have an end use model to do the longer-term forecast. They're going to provide a presentation where the first five years of their long-term forecast is this March forecast that I just did that goes to 2028.

Grant Forsyth: Excuse me. We're going to talk about the structure of the service territory here, economy, and then we'll go into the medium-term energy forecast, which again I just did it this March. I usually begin these presentations with some sort of quote. This year in an act of hubris, I put myself in there, “this presentation is 40 minutes of a finite life you will never get back.” And if you give me the business, it might be even longer. Just consider that as I go through the presentation.

Grant Forsyth: Let's talk about the service area economy. The best and most succinct way to understand the structure of our service territory is to look at non-farm employment. I'm in particular focused on how our metro areas that we serve look in Washington and Idaho. That's what an MSA is. How that looks relative to the US as a whole, I focus on our MSA areas that we serve because that's really where the bulk of our customers are. And really, that's where the best data is collected is for metro areas, but it gives you a flavor for how we look relative to the US and the truth is we look a lot like the US from the metro point of view.

Grant Forsyth: We have a situation where just like the US employment is dominated by private services. What's really important to understand is that without service sector growth, because it's so dominant at almost 70% of employment, if services are not growing, we don't really have very much employment growth at all.
To give you an example of what constitutes services, one of the major employers in our service economy is healthcare. OK. Then we have private goods. These are going to be companies, predominantly manufacturing construction. Manufacturing construction will dominate private goods. And then, of course, the other major employer is going to be government. It's interesting to talk about government. I always like to talk in more detail because government gets everybody worked up and it's important to talk about how government is actually divided. It's actually pretty interesting in terms of people working for the government, where do they work in terms of state, local or federal. It turns out the bulk of government employment is state and local, and most of state and local employment is actually education because it turns out young people take enormous amounts of resources.

Grant Forsyth: Federal employment is actually pretty small. It's 10% in our region, it's about 12% in terms of the US as a whole. When we think about government, it's important to understand that it's mostly local government, followed by state and most of state and local is going to be education. People have asked in the past what about agriculture because we do serve a big Ag region. In particular the Palouse, so if you consider agriculture, it would account for 1% to 1½% of employment. If you included all types of employment, the reality is agriculture is a super important generator of income in our service territory. But because agriculture is so focused on automation and productivity, it has become a very small share of employment. But it is a significant share of income. Spending a little more time talking about non-farm employment growth more recently as we come out of the pandemic, it's useful to look at what's happened since May 2021 because that's where post pandemic growth really peaked as we began to recover from the worst parts of the shutdown.

Grant Forsyth: And what you can see is we've actually done pretty well. We've avoided a recession everybody expected in 2023 because of higher interest rates. And what you can see is more recently Washington, our service territories in Washington and Idaho have really picked up employment growth, really surpassing the United States, which actually continues to grow at a pretty good pace. One thing to remember is if you were to divide out the Washington and Idaho side, it's really the Idaho side that has been growing the fastest. And we're going to see that with different indicators as well. So, let's look at population growth. The reason I like to spend some time talking about population growth is that it drives most of our customer growth. We've had population growth on average significantly higher than the US because of in migration. This is a really important topic or point I want to make is that without in migration growth our service territory would look either close to the US depending on which county it is around half a percent, or it would actually be zero or negative. Again, depending on the county, because the reality is most growth now is being driven by people moving around the country and not because of babies being born. In a lot of counties that we serve, the death rate exceeds the birth rate, so any positive population growth has to come from people moving there. People move to the region. Historically, when our employment growth is better than the US as a whole and that has historically reflected the fact that housing here is relatively cheap.

Grant Forsyth: What we've seen historically is that as our employment growth slows relative to the US, in migration slows. So, population growth slows, and we saw that coming out of the housing bubble. OK, we get the recovery from the housing bubble bursting. And what we can see is that in migration starts to accelerate. Our population growth really starts to accelerate beyond the US and as we get into the pandemic period and post pandemic period, we can see population growth starting to slow. Again, that reflected in migration is slowing, but we're still probably going to grow faster than the US as a whole because we still look a little bit stronger in terms of economics. The modeling that I do tends to favor showing us having higher population growth than the rest of the US because we're going to have higher employment growth. Now there's one caveat, and this is something I'm going to be tracking as we move through time is that we have gone from a service territory with relatively affordable housing to our service territory without affordable housing. It'll be interesting to see whether or not the employment growth that we get when it's higher than the rest of the US do we get the same kind of push in, in migration that we used to given the fact that we no longer have the same level of affordability, but something I'm going to have to look at, it's something I'm paying attention to. But generally speaking, the outlook for customer growth is going to track on average close to population growth. And I'm assuming at this point in the model, based on economic assumptions that our population growth will exceed the US, but it's totally dependent on in migration.

Grant Forsyth: Now one thing about housing, let me talk about this briefly. No surprise, permitting for new housing is strongly connected to population growth, but we've also underbuilt for the last decade. One of the issues is that as people continue to move to the region and we've been under building single family homes in particular, where are people living as they in migrate in? It's just important to point out is that we're seeing a big emphasis on apartments. That blue bar that you see in the graph is the number of permitted single family units, and I count townhouses and condos as single-family units. And the red bar is really just apartment units. These are the larger apartments that are being built in the region and what you can see is really starting in 2020 we've been absorbing a lot of our population growth through apartments. On the single-family side, we're also seeing a larger share of single families being moved towards duplexes and now with the Construction Monitor Service that we buy to track these permits, they're breaking out accessory dwelling units, ADUs, and we're starting to see more ADUs being built too as people try to take advantage of new, more lenient policies towards higher density. OK. But going forward, we're going to see a lot more people probably living longer in apartments than we've seen historically. OK, let me stop. Are there any questions so far before I get on to the medium-term forecast?

James Gall: No questions.

Grant Forsyth: OK, so this has changed from previous IRP. Here we've got this timeline we're trying to forecast over. My current medium-term forecast is the green triangles, it covers 2024 to 2028. OK. To do that forecast, it's based on monthly econometric models that forecast by class by schedule. I'm forecasting customers and use per customer and to get load I multiply those forecasts together. Weather is handled as a 20-year moving average that I update each year. When I get a new calendar year of data. The main economic drivers are things like GDP, industrial production, employment growth, population, and natural gas penetration. In particular, the natural gas penetration is a variable in Washington because that's where it seems to matter the most. I can use that retail forecast then to convert it into a native load forecast based on historic norms. OK. And again, the current 2025 IRP forecast is the spring 2024 forecast completed in March, but we could at some point in the future update this when I redo the forecast in six months. So, if you look at the red triangles, when we go beyond 2028 to 2045, this is where we shift to the long-term forecast.

Grant Forsyth: Historically I handled this modeling approach, but because of the enormous policy changes that are occurring that are regulating potentially down to the appliance level, we really needed to shift our approach. We've hired a consulting Group called AEG who you've probably heard speak at our TAC meetings in the past, but they are now handling the long-term component. OK, using some inputs that I provide to them and so they're essentially shifting us in the long term to an end use modeling process. The idea is that we're going to get a better handle on how these restrictions on gas, other types of policies that are coming down there, how they affect load in the long run with more detail and more flexibility than I was able to provide in the past with my own method. Now, James, just to make sure we're correct about this, AEG is going to be giving us a presentation in the future, correct.

James Gall: Two weeks hopefully,

Grant Forsyth: OK. They will probably be there providing this discussion between the red triangles and what they're going to do is they're taking my medium-term forecast and an on an annual basis, that's their first five years, and then it's their model beyond that. Do I have that correct?

James Gall: You have that right.

Grant Forsyth: Let's talk a little bit about the analytics, how I do this, it's complicated. It's boring. It's miserable, but I'll give you a sense of what I go through to get this medium term forecast with the main economic drivers. OK, so let's start with the GDP forecast. I go out, I collect a whole bunch of different forecasts from different sources for GDP growth over the next five years. I've averaged them so I get a consensus GDP growth forecast across many different forecasters. This helps avoid systematic biases that you may get with a single source forecast. OK, so look at the green rectangles first so I can use that GDP forecast then to forecast industrial production growth based on historic norms between how GDP grows and how has how US industrial production is going to grow. OK. I get the US industrial production index, the historical numbers from the Federal Reserve. OK, that means I've now got a forecast for industrial production growth and that's going to inform the use per customer forecast for certain industrial customers who have sensitivity to industrial production. What's happening with the industrial production in the US. If we go to the bars, they're triangles above and the kind of reddish ones, I'm also using GDP to forecast employment growth for our region. So, what happens is that GDP growth at the national level informs what our employment growth should look like in our service territory. But I'm also going to go ahead and average those employment growth forecasts that I'm generating with forecasts from S&P Connect, which used to be IHS Connect. S&P bought them a few years ago. I'm essentially taking an average of my employment forecasts derived from GDP. And GDP forecast that they derived themselves. And then what I get is an average of employment growth. And historically, what we've seen is there's a close association between employment growth in one year and what population growth looks in the next year, and in particular, that's the connection between health of your economy and in migration. OK, so what I do is I take the employment growth forecast, generate my own population growth forecast. But then again, I averaged that with the population growth forecast of S&P Connect. Again, trying to mitigate that bias potential of a single source forecast and then what happens is those population growth forecasts are the really significant driver of certain residential and commercial forecasts and in particular of customer forecasts. In fact, on the electric side, in the long run are historical customer growth has been pretty close to what our historical population growth has been. They're almost the same. You can really use population growth. The average growth you're forecasting as the proxy of customer growth, OK, so there's that component down below and the blue boxes, you can see the other drivers, I have a 20-year moving average of degree days. That's what DD is, and in the case of Washington, I use my gas forecast to estimate how much gas penetration we have in our service territory and that's actually an important driver for residential use per customer in Washington. It seems to matter less than Idaho, so it's now in the Washington side, not necessarily the Idaho side. And again, those weather variables and that gas penetration inform certain residential and customer use per customer forecast in terms of weather and again, gas penetration on the industrial side. There's not a lot of weather sensitivity. So that's a lot of questions about that. Nothing else. OK, I'll wait.

James Gall: [Reading question from chat] OK, if time allows, can you go over any relationship between the employment growth, population growth and family unit size?

Grant Forsyth: Right. I've looked at this over time. We're getting population growth, but over time it looks like we have a downward trend in household size and that's a trend all over the US and the expectation reading all of the more recent demographic research and analysis, the growing expectation is the household size will continue to decline going forward. And so again, increasingly what that means is organic population growth is going to be small, zero, or potentially negative because of deaths exceeding births. Population growth becomes even more heavily weighted towards end migration. Keep in mind the longer people have to rent apartments in order to find housing, that may also curtail family size for a longer period of time, or at least cause less of an incentive to have kids. Does that answer the question? OK. I'll assume so unless you protest.

James Gall: OK, alright. No other questions so far.

Grant Forsyth: OK. Again, we could spend hours on this. I would be happy to do it, but I won't so, let's talk about one of the big economic assumptions, because again, this drives a lot of different things as we just discussed. This is GDP growth in the United States. The black line is showing you historically what has happened, and the red dotted line is the current consensus forecast that I have built into the March forecast over the forecast period. OK. Keep in mind, in the long run GDP growth is a sum of population growth and labor productivity growth. And if you look at the forecast for population growth in the United States increasingly for us to return back to roughly 2% GDP growth, which is the prepandemic norm, we're going to have to make sure that we have a pretty good productivity growth around 1½%. This population growth in the United States is about 0.5%, so productivity growth isn't at least 1½%. It's going to be hard to be at that roughly 2% GDP growth, but that's the consensus view, so that's what I built in the forecast.

Grant Forsyth: The Fed’s long run expectation for GDP growth has actually fallen from 2%. It's now down to 1.8% and so I'm assuming this is what I've given to AEG. I've asked AEG to assume in their models the Fed’s long term growth rate of 1.8% and that's what they're going to assume from 2029 to 2045. And keep in mind that 1.8% assumes that most of that growth has to be coming from productivity growth, labor force productivity growth, because population growth out to 2045 in the US is going to continue to decline. OK. It's also important to recognize that increasingly, I'm not showing a lot of industrial production growth and that's because in the long run, based on historic norms, GDP growth in the US has to be about 1.6%, at least for the industrial load to show any growth in the forecast that I do for our service territory. And actually, even if you were at, say 1.7% or 1.8%, industrial load does not grow very much at all. You really need to see it over 2% before you begin to see industrial load pick up on our service territory. One of the outcomes of these assumptions is we're not really showing a lot of industrial load growth. And in fact, as we're going to talk about a little bit later, we're starting to see some customers leave larger schedules for smaller schedules in our service territory because their load growth appears to be falling over time and that shifts them into a different schedule for smaller firms. Some of that might be just efficiency gains that are occurring. OK.

Grant Forsyth: Again, another big indicator is population growth. Because population growth is really going to be a proxy for customer growth in the long run in our service territory. What we can see here in this slide, the red is for our service territory. The black is the US Census forecast for the US. I just thought it was interesting to compare it and so that's what I'm assuming in the medium term and the current medium-term forecast. This is what I've asked AEG to assume in the longer term so you can see that our population growth is declining over time, but we're typically going to be ahead of the US. Again, the assumption is that in migration is going to continue over the forecast period. Right. The little box up above shows you a little bit of a comparison between the last IRP, which was based on the spring 2022 forecast in the medium term, and then where we are now with the March 2024 forecast. A little bit lower in the longer term compared to what we had in the 2023 IRP. But again, most of that growth is going to be happening in Idaho. OK, so that gets us to really just a picture over the next five years of what is native load look like. Again, this is derived from my retail load forecast and it’s really kind of interesting. What we've really seen following the pandemic has been this step up in use per customer that's occurred. It's a step up that really occurred starting in 2022 and what that's done is pushed up our native load a bit so that we're really reaching that 2028 level early, meaning the 2028 level that was forecasted in the 2023 IRP we’re essentially there within a couple of years and that reflects this step up that I've built into the forecast that we're observing in the historical data. OK, the other thing that's going to be different too is that I'm assuming a much more aggressive declining penetration in Washington, OK. And at least in the near term, compared to the previous 2023 IRP, industrial load is a little bit higher because the economic assumptions are a little bit more favorable even though the long-term outlook for industrial load is not much growth. But on a level basis, we're a little bit higher than the 2023 IRP. Questions.

Grant Forsyth: OK, so let's get a little bit longer picture. This is something James asked me to put in, and I think it's actually highly instructive. The black line that you see there is our actual native load since 2005. Right now, that dotted line there is an adjustment I'm making for a complex contract we have with a very large customer with its own generation. I'm just making sure that we reflect the load we would have had to provide if its generation went down and so we get a much clearer picture of what our true obligation on native load would have been. It makes the chart much more correct and in that sense it's just interesting to see that if you look at the last time we had a significant step up in load was the housing building boom that burst in 2008. And you can see there what I'm showing is the average gain and load that occurred between that housing boom period and when it stopped. We gained about 20 average megawatts in terms of energy. And then we really didn't change much for more than a decade. But we get to the pandemic. We have this step up because what we think is going on is that you have this hybrid work environment where you have people at home longer, more frequently and working. That means they're heating and cooling more frequently, but all of these buildings that they're not working at or only partially working at, still have to be cooled and heated. I think what it's doing is providing a step up in overall usage, and it shows up pretty clearly in the data. And we're also seeing this, by the way, in the peak load. I've also adjusted the peak load for this step up, which is about 40 megawatts following the worst of the pandemic.

Grant Forsyth: What you see after that is the current forecast. That's the red dotted line. OK. The current medium-term forecast shows us stepping up again about another 20 average megawatts. Again, that reflects to some degree these restrictions on building and in Washington, more electric load because of declining gas penetration. You compare that against the blue line, which is really the red and blue line. There is just what we saw in the previous graph. It's just this idea that we're going to reach that 2028 number and we show in the 2023 IRP faster than we expected. We're talking about maybe 60 average megawatts that have been built over a relatively short period of time. Questions.

James Gall: I just want to add one thing. This does not include any large industrial loads coming to our service territory, whether it's a data center or an existing, we'll call it a DSI customer. We do have a number of entities contemplating either moving their DSI load to Avista's load and data centers have been talking to us on occasion. There is, let's say, more risk of a step up in and this IRP then we've seen in past IRPs. We'll probably look at a scenario where there is a step up in load and then we also may be looking at, depending on what happens with one of the industrial customers, we may add that load to this load forecast. Once we know whether or not they're coming.

Grant Forsyth: Right. I think James is making it very good point for us. If we're going to see industrial load grow, it's not going to necessarily come from our existing customers. It's because somebody steps into our service territory, which will provide a step up in load. The other thing I would point out about that, and I think this is an interesting policy dilemma, I serve on a tax preference Commission in Olympia and one of the things we reviewed in 2016 is a tax preference that supports data centers, that encourages data centers. It is a policy dilemma, I think, that I don't know if the state has thought about encouraging the location of data centers, increasingly large and power dependent data centers. At the same time, they're trying to electrify transportation and electrify heating. It could pose some real challenges for us, and I would just point that out.

Grant Forsyth: Your misery is almost over. OK. James asked me. I think again this was a good idea to put in a slide that reminds people that we're a Washington and Idaho electric service territory and it's important to think about the two different jurisdictions. Washington is about 62% or 2/3, whereas Idaho is just over 1/3. It's significant, even though they're going in different policy directions, it's interesting to look individually. This is their retail forecast. If you wanted to convert this into native load, you could adjust it for line losses. To keep things simple, it's just the retail converted to average megawatts without any adjustments for line losses to make it native load. You see a little bit different time path in the forecast period 2024 to 2028. The time path for the two jurisdictions looks different, and that reflects the assumption I'm explicitly building into the residential load forecast for electric of declining gas penetration. And what that does is it gives you a different load growth path then what you see in Idaho, which has no restrictions on gas. If we're going to continue to restrict gas and gas penetration falls, my econometric model assumes that drives up use per customer and along with customer growth that's going to continue to push up load at a faster rate in the Washington side of our service territory compared to the Idaho side. If you didn't have that occurring in Washington, those gas restrictions, I think the time path between the two jurisdictions would look similar because you'd have gas offsetting some of the pressure on use per customer on the electric side. Questions? I think I pushed through that pretty well. Yeah, you got 4 minutes left. OK. Good. Questions?

James Gall: [reading from chat] Yeah. We do have a question. What are the Washington gas restrictions?

Grant Forsyth: Yes. Well, I'm quite conservative about that because it's more than I have to point this out. I'm essentially assuming in the gas forecast for Washington that there is no more gas growth in Washington after 2024. From 2025 on our gas customers are constant. You think gosh, that's pretty restrictive. You might judge me on that, but I'd also point out there's some other things coming down the pike other than those restrictions in terms of the building code, our line loss allowance. I mean, I should say our extension allowances, our extension allowances essentially go away in 2025 in Washington and that means it's going to be a lot more expensive to hook up with gas. I think that's the case of the building code as well. It's not that it's restricting gas as it's more of making it more expensive to put gas in right to how the credits work for getting a building permit. I think at the end of day, what you're saying is, is the net between the two stays constant. I don't see a lot of growth now. It may turn out that gas is still valuable to people, and they're going to, growth might not be constant in the future, but until I start to see how consumers are going to respond to what's a pretty dramatic change in the ability and cost of getting gas, I'm going to treat it pretty conservatively. And that means that if you hold gas customers constant over the forecast horizon, gas penetration starts to fall and that pushes up use for customer in the forecast on the residential side.

James Gall: Well, we got two minutes left. To prepare people for the next meeting. We're going to be talking about the next part of the load forecast. AEG will be doing an end use modeling and what you're going to find there is it is a combination model of gas and electric where they're forecasting out the number of customers that are viable in the service territory and looking at how they're going to be choosing gas versus electric going forward. And I wanted to bring up climate change because when we did a study on this over the winter to prepare for this. We found that, as you know, warming temperatures occur, that's going to make it less and less cost effective to electrify, meaning that if you have a lot of load out there or cold temperatures, you're going to have to look at the economics of switching. If you're not heating a lot in the future, switching may not be as cost effective because of the upfront costs we're finding in that future. That will be something to look for in the next presentation by AEG on the load forecast. Just how that tradeoff between gas and electric is going to be in the future? Also, the economics of energy efficiency does that that changes out in the future. It'll be interesting presentation. This is a new idea for Avista that look at end use modeling, and it'll also tie into the EV forecast and the solar forecast that we saw at the DPAG meeting last week as well. We're at 10 o'clock, and I know many of you have to go, but appreciate the time coming today, asking great questions. If you do have other questions or comments, please email me or John or the IRP email address. There's also the Teams site. Don't forget about that. There is data out there. There's a chat feature if you want to send messages to us. Again, thank you for your time today and we'll see you in two weeks and have a great day.

2025 Electric Integrated Resource Plan

Technical Advisory Committee Meeting No. 5 Agenda

Tuesday, April 23, 2024

Virtual Meeting – 8:30 am to 10:00 am PTZ

Topic	**Staff**
Introductions	John Lyons
Long Run Load Forecast	AEG
Load Forecast Comparison	Avista Staff
Review Planned Scenario Analysis	James Gall

2025 IRP TAC 5 Introductions

John Lyons, Ph.D.
Technical Advisory Committee Meeting No. 5
April 23, 2024

Today's Agenda

Introductions, John Lyons

Long Run Load Forecast, AEG

Load Forecast Comparison, Avista Staff

Review Planned Scenario Analysis, James Gall

Remaining 2025 Electric IRP TAC Schedule

- **TAC 6: May 7, 2024: 8:30 to 10:00 (PTZ)**
  - Conservation Potential Assessment (AEG)
  - Demand Response Potential Assessment (AEG)

- **TAC 7: May 21, 2024: 8:30 to 10:00 (PTZ)**
  - Variable Energy Resource Study
  - Portfolio/Market Scenarios

- **TAC 8: June 4, 2024: 8:30 to 10:00 (PTZ)**
  - Load & Resource Balance and Methodology
  - Loss of Load Probability Study
  - New Resources Options Costs and Assumptions

- **TAC 9: June 18, 2024: 8:30 to 10:00 (PTZ)**
  - IRP Generation Option Transmission Planning Studies
  - Distribution System Planning within the IRP & DPAG update

- **Technical Modeling Workshop: June 25, 2024: 9:00 am to 12:00pm (PTZ)**
  - PRiSM Model Tour
  - ARAM Model Tour
  - New Resource Cost Model

Remaining 2025 Electric IRP TAC Schedule

- **TAC 10: July 16, 2024: 8:30 to 10:00 (PTZ)**
  - Preferred Resource Strategy Results
  - Washington Customer Benefit Indicator Impacts
  - Resiliency Metrics

- **TAC 11: July 30, 2024: 8:30 to 10:00 (PTZ)**
  - Preferred Resource Strategy Results
  - Portfolio Scenario Analysis
  - LOLP Study Results

- **TAC 12: August 13, 2024: 8:30 to 10:00 (PTZ)**
  - Preferred Resource Strategy Results (continued)
  - Portfolio Scenario Analysis (continued)
  - LOLP Study Results (continued)
  - QF Avoided Cost

- **September 2, 2024- Draft IRP Released to TAC.**

- **Virtual Public Meeting- Natural Gas & Electric IRP (September 2024)**
  - Recorded presentation
  - Daytime comment and question session (12pm to 1pm- PST)
  - Evening comment and question session (6pm to 7pm- PST)

APPLIED ENERGY GROUP

Avista Energy Electric Forecasting

Prepared for Avista Energy TAC Meeting 4/23/2024

Background

AEG has worked with Avista for multiple Conservation Potential Assessments going back to 2010

As part of the CPA, AEG creates a baseline projection at the segments and end use level, which provides granular insight on peak impacts and changes in individual technology classes

Now Avista is using AEG's LoadMAP™ end use model directly to inform its official load forecast, including effects of state energy codes, potential electrification and market trends in a clear and direct manner.

Major Modeling Inputs and Sources

Avista foundational data

Avista power sales by schedule

Current and forecasted customer counts

Retail price forecasts by class

Survey data showing presence of equipment

Avista: Residential customer survey conducted in 2013

NEEA: Residential and Commercial Building Stock Assessments (RBSA 2016 and CBSA 2019)

US Energy Information Administration: Residential, Commercial, and Manufacturing Energy Consumption Surveys (RECS 2020, CBECS 2018, and MECS 2015)

Technical data on end-use equipment costs and energy consumption

Regional Technical Forum workbooks

Northwest Power and Conservation Council's 2021 Power Plan workbooks

US Department of Energy and ENERGY STAR technical data sheets

Energy Information Administration's Annual Energy Outlook/National Energy Modeling System data files

State and Federal energy codes and standards

Washington State Energy Code

Idaho Energy Code

Federal energy standards by equipment class

Market trends and effects

RTF market baseline data

Annual Energy Outlook purchase trends (in base year)

Forecast Process

Market Characterization

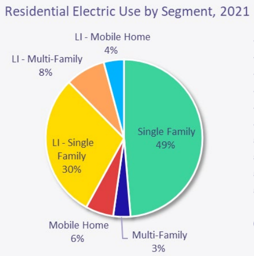
- Segmentation
- End Use and Technology List
- Allocate electric loads & calibrate

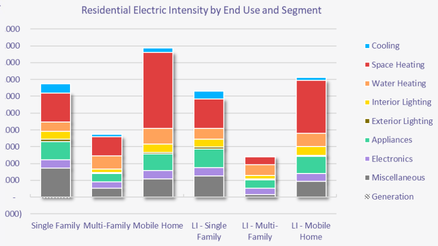
Run Baseline Projection (Annual)

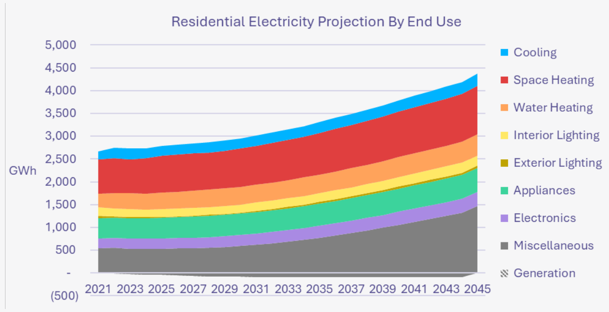
- Customer Forecast
- Stock Turnover
- Purchase Decisions

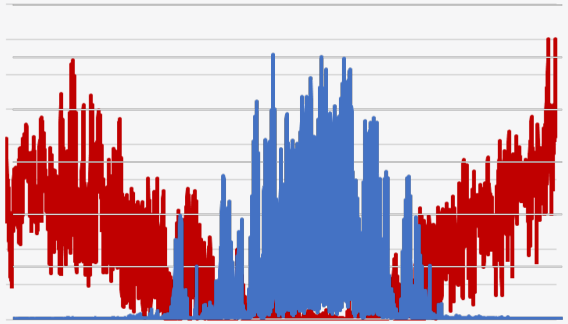
Create Hourly Forecast

- Assign end use load shapes
- Aggregate energy by shape
- Apply hourly shape throughout forecast period



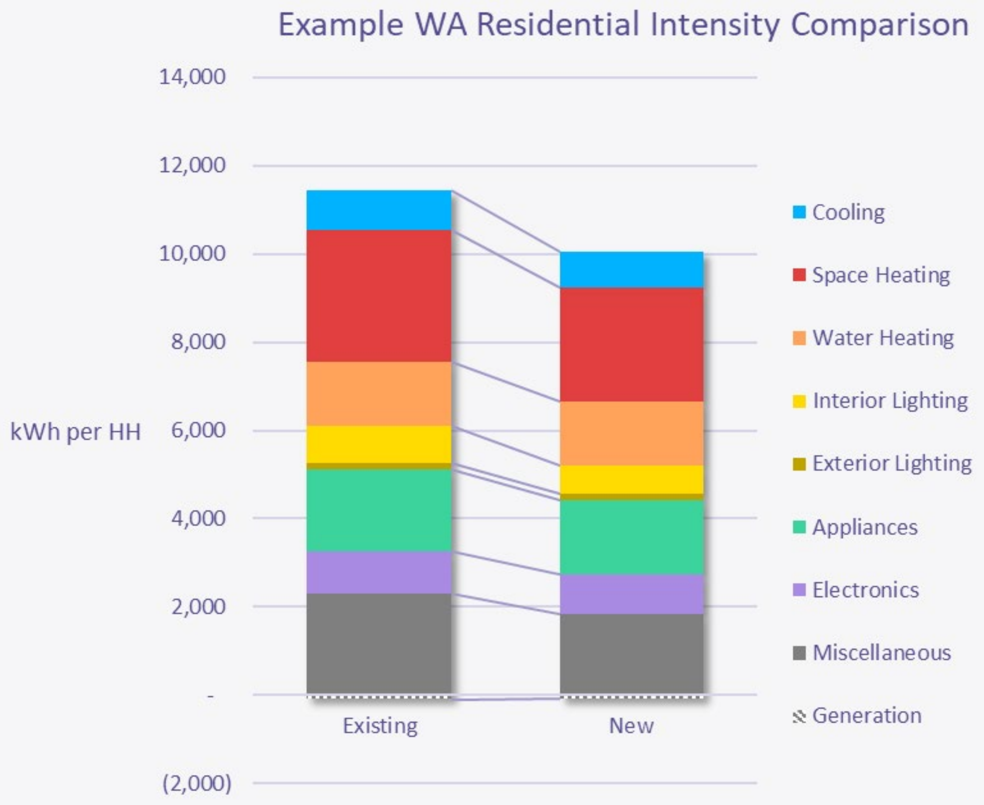






Existing vs New Buildings

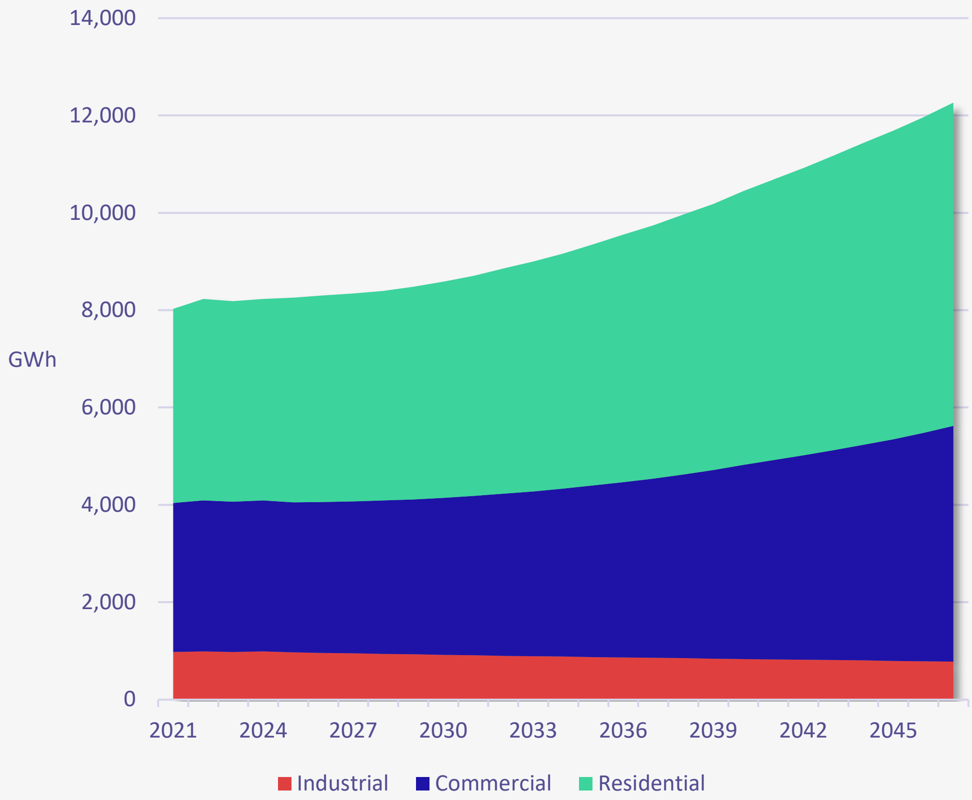
- Modeling tracks existing building stock separately from new code-compliant buildings
  - Buildings also undergo renovation at a rate consistent with the DOE's National Energy Modeling System, converting them into code-compliant structures
- Presence of equipment in new buildings is adjusted to comply with energy codes where applicable
  - For example, all new residential structures are assumed to use electric heat pumps for space heating



System Total Load Forecast

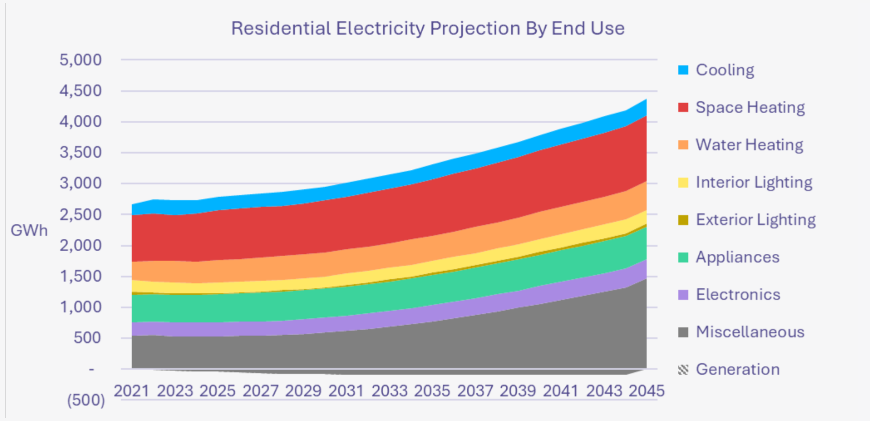
Washington + Idaho Combined

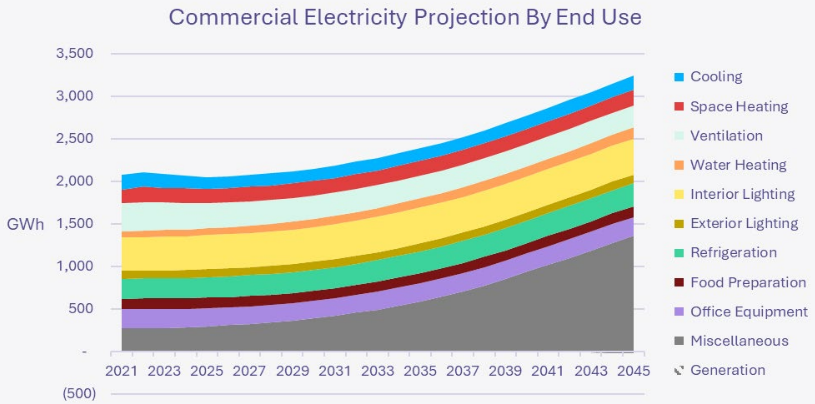
- Customer growth and electrification from natural gas systems combine for a projected 53% increase in electric loads over the forecast period, or 1.6% annually
- Growth from electrification is roughly equal to growth from customer increases (~2,400 GWh each)
- Includes:
  - Projected cooling and heating degree days according to climate trends in Avista's territory
  - Market efficiency impacts (such as trends toward LED lighting as baseline), which are saving over 1,000 GWh in the forecast period compared to minimum codes & standards
  - Solar and EV projections from the DER study in Washington (Avista projections for Idaho)

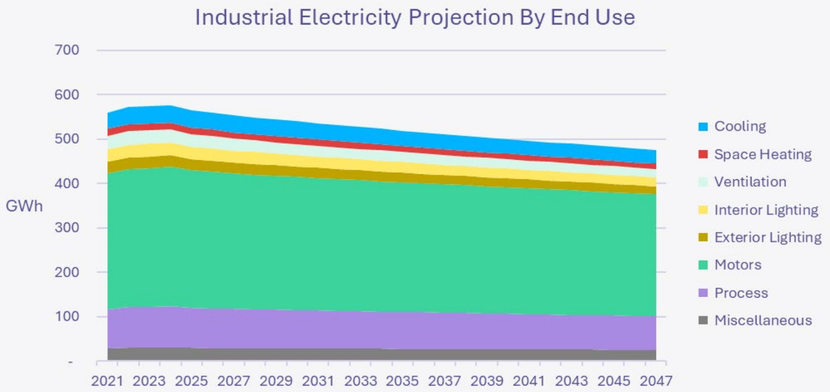


Washington Sector-Level Forecasts

- WA Residential is the fastest growing sector, at 1.97% per year, driven by space heating and EV growth
- Commercial EV charging also adds over 1,000 GWh per year by 2045
- Industrial loads have continued to trend downward and no new load increases are anticipated

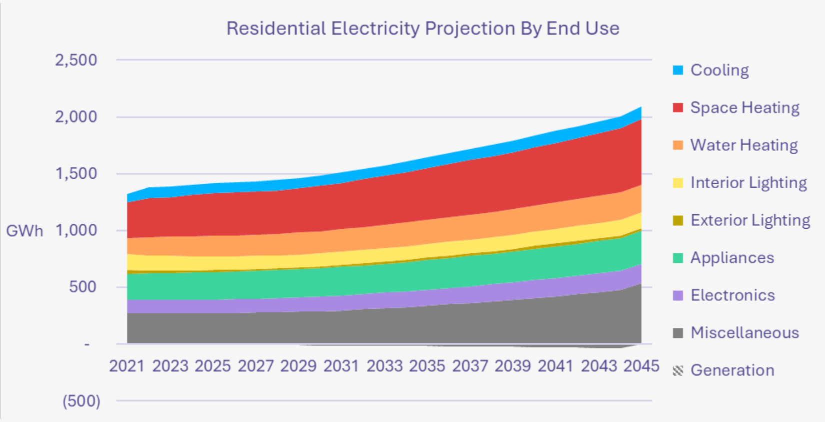


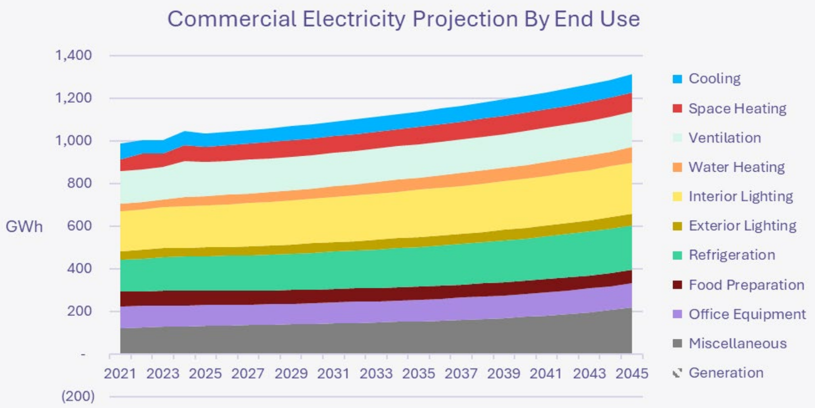


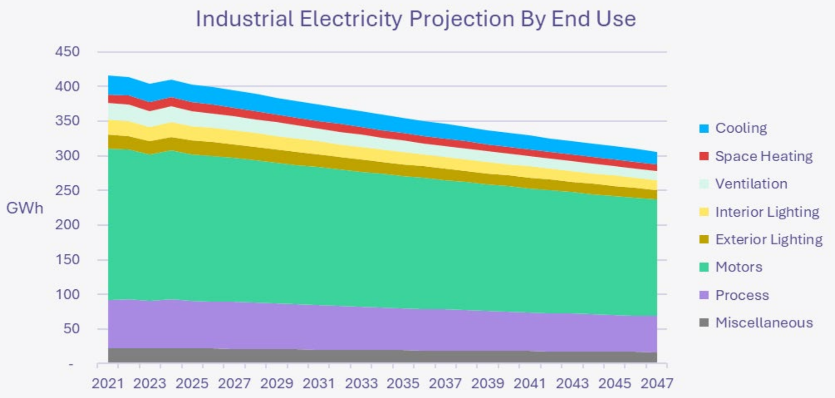


Idaho Sector-Level Forecasts

- ID load growth is not as fast as WA, mainly due to lower electrification and much less EV.
- ID is projected to see greater increase in customers than WA however, so there is still significant growth in both the Residential and Commercial sectors

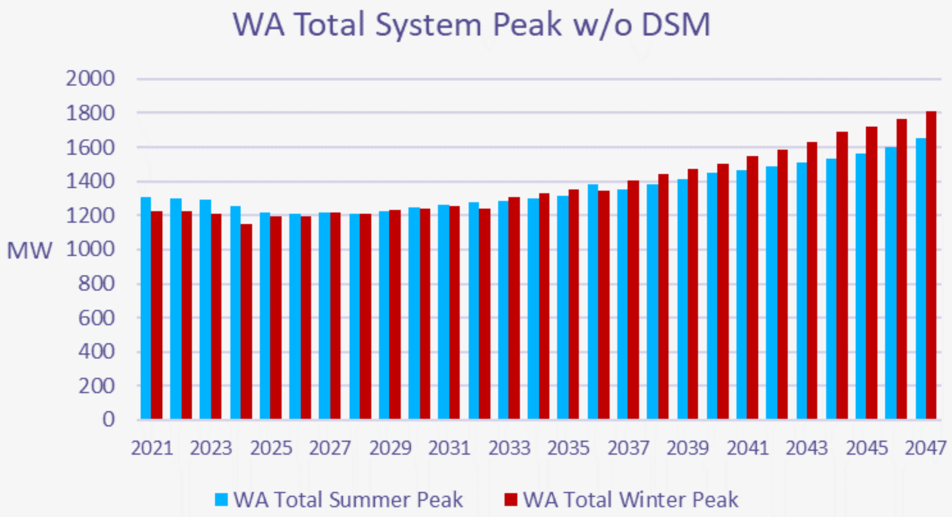


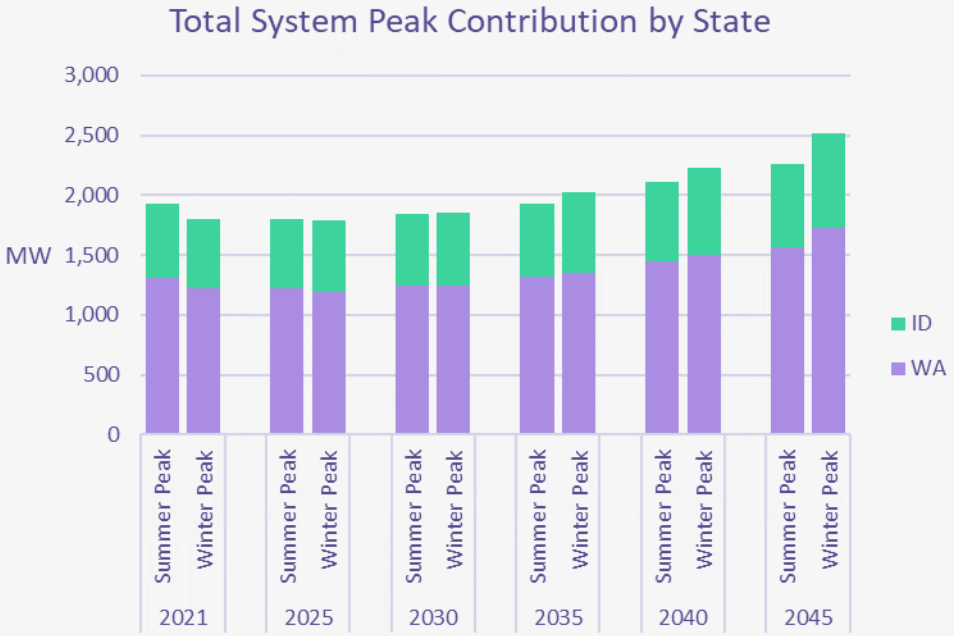


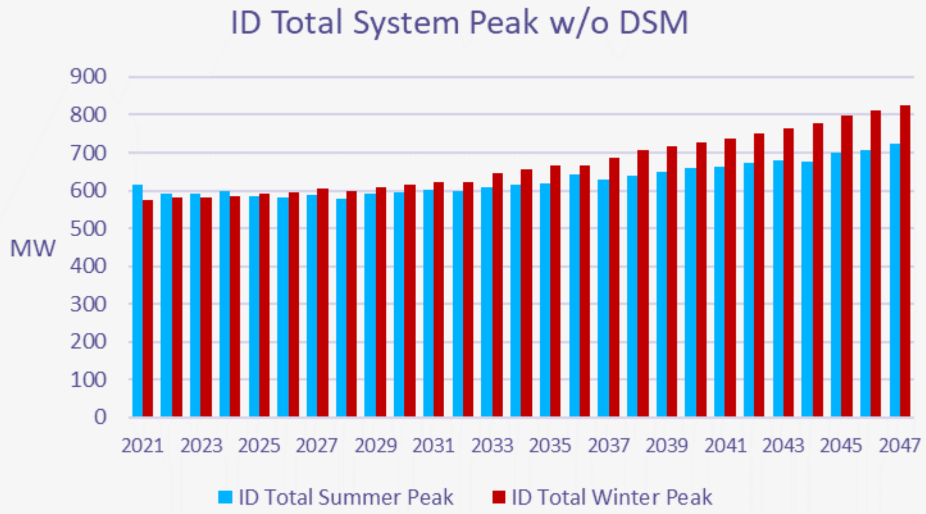


Peak Forecasts

- Winter system peaks are projected to be higher than summer by around 2030+, however this projection is very sensitive to assumptions on when EVs will be charging.
- AEG used an annual charging shape provided by Cadeo and developed in the DER study.





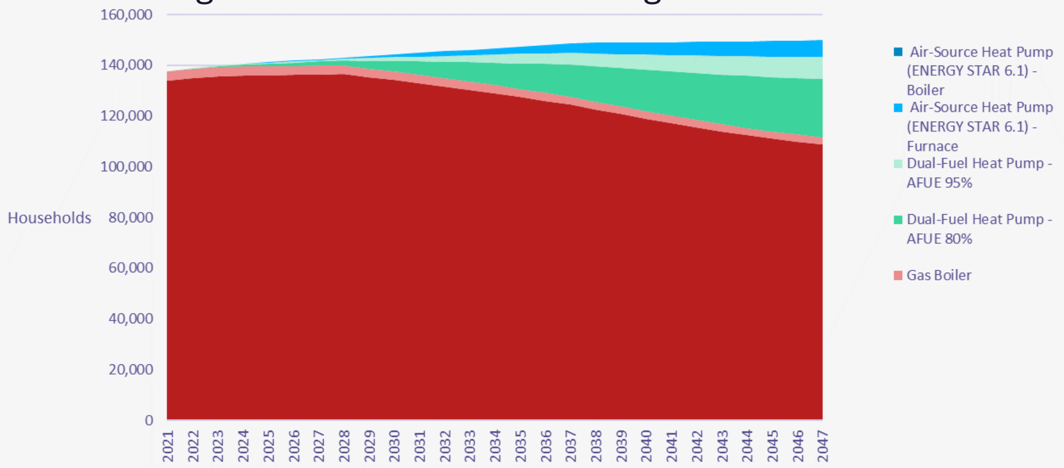


Appendix A

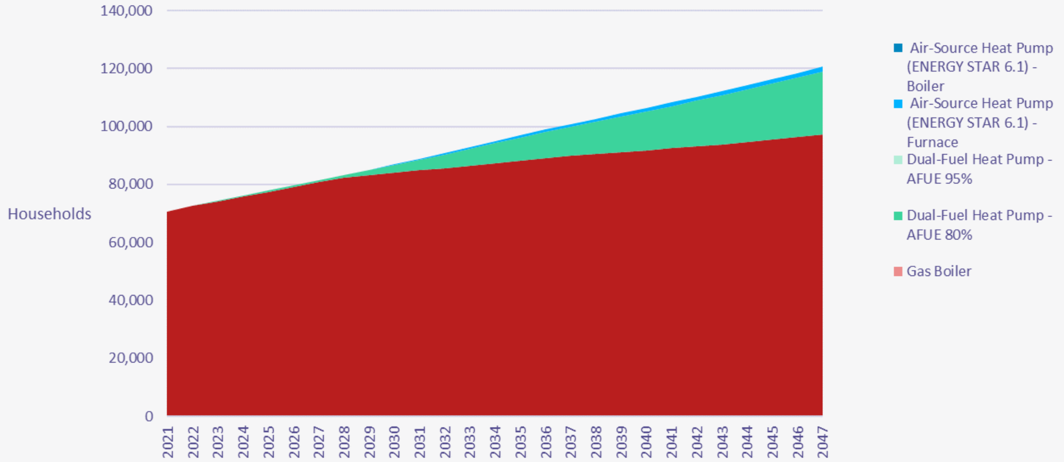
Electrification Decision Modeling

- Gas customers were modeled the same way as the electric market, with the option to replace existing gas space or water heating equipment with electric alternatives, using purchase decision logic copied from the US DOE's National Energy Modeling System.
- Conversion costs include the possibility of a panel upgrade and associated labor. The model compares the lifetime cost of ownership including up front costs and associated lifetime fuel costs.
- As data on customer electrification is not readily available*, electrification purchases were seeded with a value ¼ that of dual-fuel heat pump installations, which do have documented market shares for WA and ID.

Washington Residential Gas Heating Market Transformation



Idaho Residential Gas Heating Market Transformation



Electrification Projection

Stock share converted by 2045

Residential	Washington	Idaho
Space Heating - Dual-Fuel Heat Pump	29,422 (20.0%)	19,424 (16.7%)
Space Heating – Full Electric ASHP	6,242 (4.3%)	1,578 (1.4%)
Water Heater – HPWH	1,611 (1.7%)	256 (0.4%)

Commercial & Industrial	Washington	Idaho
Space Heating - Dual-Fuel Heat Pump	515 (6.7%)	760 (8.9%)
Space Heating – Full Electric ASHP	134 (1.8%)	46 (0.5%)
Water Heater – HPWH	712 (8.3%)	678 (6.7%)

Thank You.

Phone: 631-434-1414

2025 IRP Load Forecast

James Gall & Mike Hermanson
Technical Advisory Committee Meeting No. 5
April 23, 2024

Transition End Use Model to Load Forecast

Energy

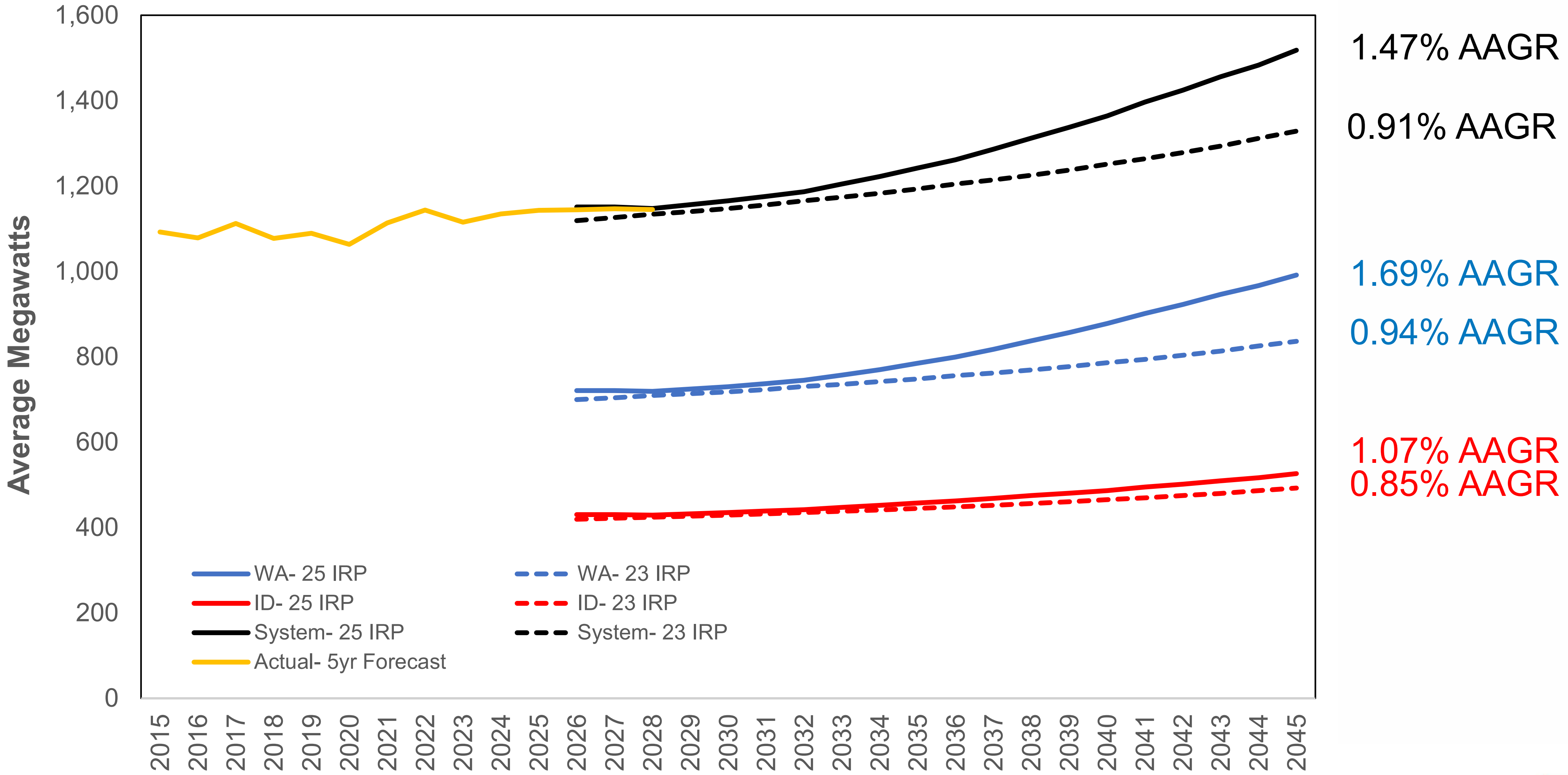
- Starts with AEG's forecast w/ & w/o DSM
- Add energy losses (T&D)
- Add large industrial loads

Peak

- Estimate 2024 weather adjusted peak load using historical and future weather data for each month
- Escalate loads using AEG's end use model's peak growth factors
- Add large industrial loads
- Demand response and/or managed loads not included

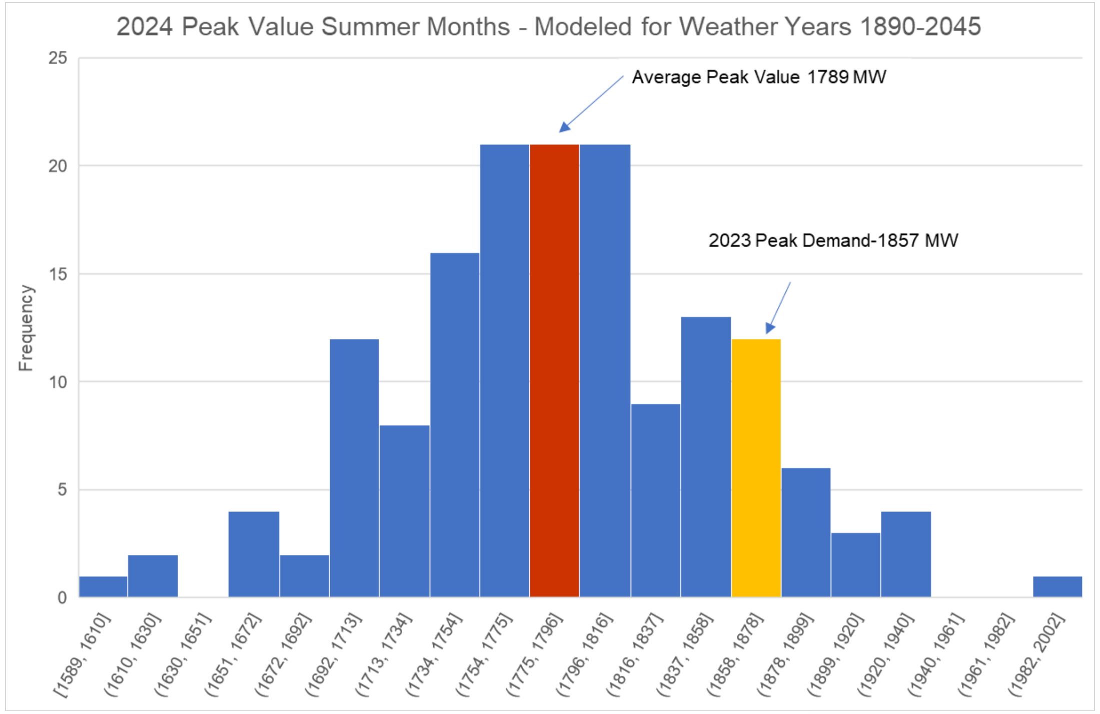
The PRiSM model will include a load forecast without DSM and the model will select cost effective programs and may adjust this estimate to ensure the amount of selected energy efficiency arrives at a similar net load forecast as presented today.

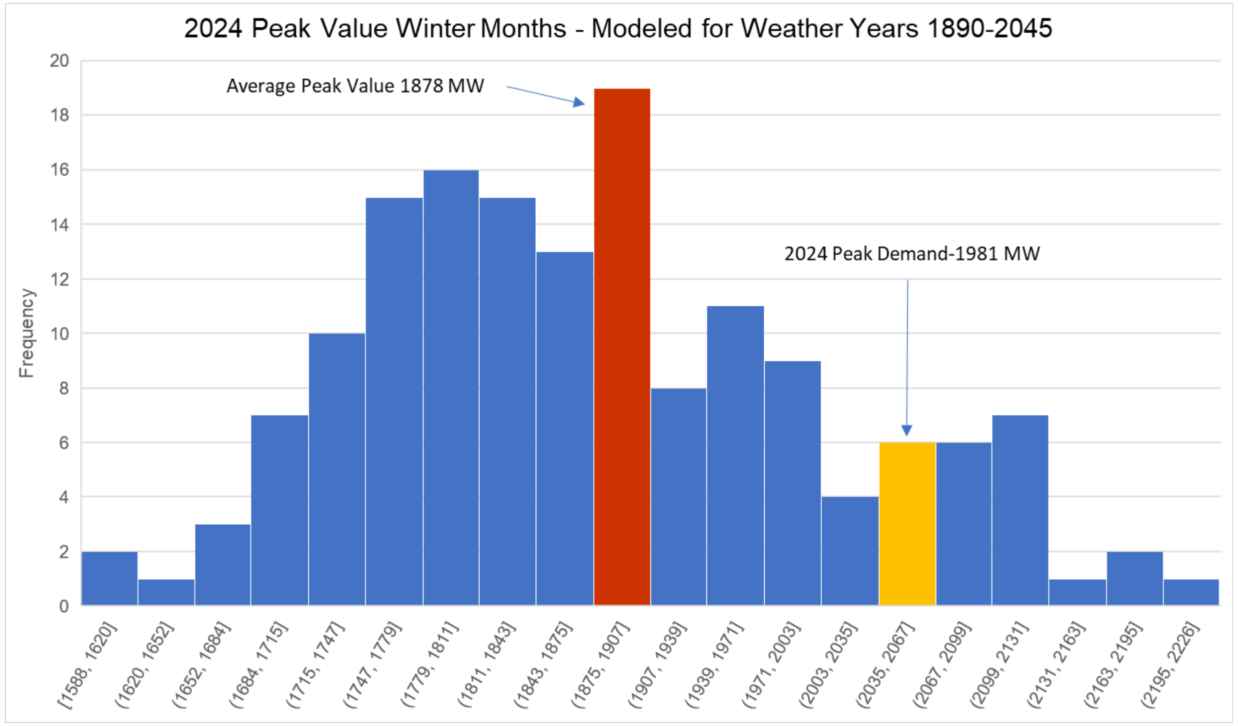
Energy Forecast



Note: Includes 67 aMW of energy efficiency w/ losses: ~60 aMW (WA) & ~7 aMW (ID)

Peak Distribution





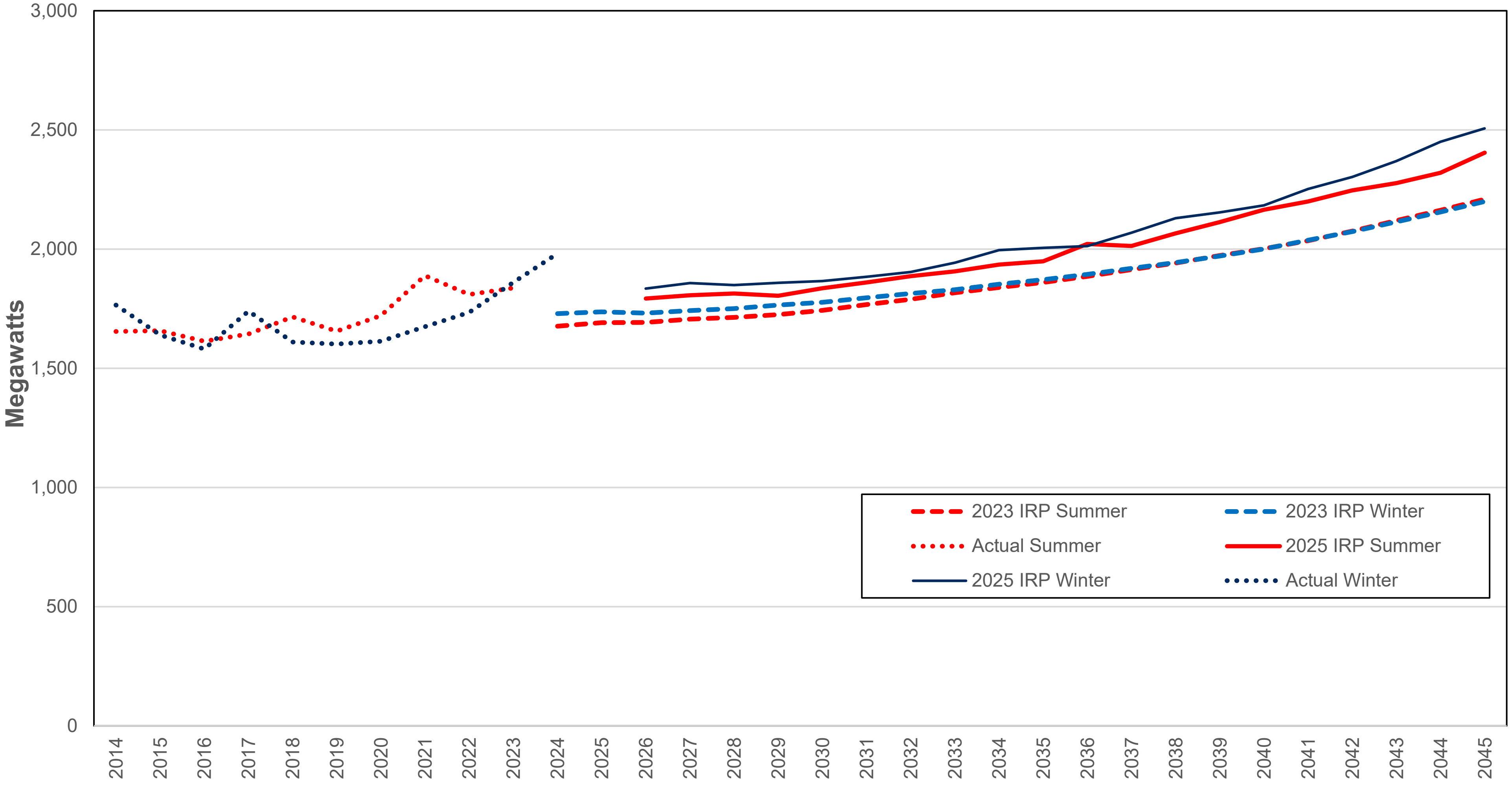
Load and Temperature

2002 MW 93 ºF
1589 MW 77 ºF
1791 MW 82 ºF

Load and Temperature

2226 MW -17 ºF
1588 MW 28 ºF
1892 MW 3 ºF

Peak Forecast (1-in-2 weather event)



Note: Historical peak values include curtailed loads

2025 Electric IRP Portfolio Proposed Scenario List

	Scenario	Market Price Sensitivity	LOLP Study (2030)	LOLP Study (2045)
1	Preferred Resource Strategy	Deterministic Low NG Prices High NG Prices	X	X
2	Alternative Lowest Reasonable Cost			
3	Baseline: Least Cost Reliable Portfolio	Deterministic Low NG Prices High NG Prices	X	X
4	Clean Resource Portfolio by 2045	Deterministic Low NG Prices High NG Prices	X	X
5	Low Growth (Low Load Growth)			
6	High Growth (High Load Growth)			
7	80% Washington Building Electrification by 2045			
8	80% Washington Building Electrification by 2045 & High Transportation Electrification Scenario			
9	Extreme Building/Transportation Electrification for Washington & Idaho w/o new Natural Gas CTs			X
10	Maximum Washington Customer Benefits			
11	Least Cost + 500 MW Nuclear in 2040	Deterministic Low NG Prices High NG Prices		X
12	WRAP PRM		X	X
13	Least Cost + 0% LOLP		X	X
14	Power to Gas Unavailable			X
15	Minimal Viable CETA Target			
16	Maximum Viable CETA Target			
17	Preferred Resource Strategy w/ CCA repealed	No CCA Forecast		
18	Unconstrained Cost Preferred Resource Strategy			
19	High QCC on Demand Response (w/ minimum selection)		X	
20	Data Center in 2030		X	
21	Nuclear Cost Sensitivity			
22	RCP 8.5 Weather		X	X
23	80% Washington Building Electrification by 2045 & High Transportation Electrification Scenario with RCP 8.5 Weather			X
	Avoided Cost Portfolios			
A	No Supply-Side Resource Additions			
B	Clean Capacity by 2045			

Scenario Description:

1- **Preferred Resource Strategy:** Using the expected case load, resource, and stochastic price forecast, the model will determine the least cost resource strategy meeting each state's energy and capacity requirements. Portfolio will also track Customer Benefit Indicators in Washington and use Social Cost of Greenhouse Gas (SCGHG), Non-Energy Impacts, and Named Community Fund (NCIF) spending for Washington's portfolio optimization. Idaho's optimization will focus on least cost to meet energy and capacity requirements. Portfolio uses planning margin requirement to ensure 5% Loss of Load Probability (LOLP) in 2030. CETA targets are shown in Figure 1.

2- **Alternative Lowest Reasonable Cost**: Required study to determine CETA cost cap impacts. This scenario assumes no CETA clean energy requirements, no NCIF, but includes SCGHG for resource selection [in Washington] while meeting physical monthly energy/capacity requirements.

3- **Baseline: Least Cost Reliable Portfolio:** Determines the least cost portfolio to meet energy and capacity requirements based on economic decisions w/o SCGHG or CETA; same as the 'Alternative Lowest Cost Alternative' scenario w/o SCGHG prices for Washington. The portfolio will also be used to develop avoided costs as it separates portfolio costs by renewable and capacity premiums; quantifies the impacts of SCGHG.

4- **Clean Resource Portfolio by 2045**: Determines the portfolio to eliminate all greenhouse gas emitting generation resources in the portfolio by 2045. The resulting portfolio must meet all capacity and energy requirements.

5- **Low Growth (Low Load Growth)**: Studies the portfolio effects of loads not materializing due to lower growth than forecasted.

6- **High Growth (High Load Growth)**: Studies the portfolio effects of higher load levels materializing due to higher growth than forecasted.

7- **80% Washington Building Electrification by 2045:** Determines the least cost portfolio of converting 80% of Washington State natural gas residential and commercial demand to electric through heat/water conversions to heat pump and resistance technologies by 2045.

8- **80% Washington Building Electrification by 2045 & High Transportation Electrification Scenario**: Determines the least cost portfolio of converting 80% of Washington State natural gas demand to electric through heat/water conversions to heat pump and resistance technologies by 2045 along with a higher-than-expected electric transportation forecast.

9- **Extreme Building/Transportation Electrification w/o new Natural Gas CTs:** Determines the least cost portfolio of converting 80% of Washington & Idaho natural gas demand to electric through heat/water conversions to heat pump and resistance technologies by 2045 along with a higher-than-expected electric transportation forecast for both states. This scenario also assumes all natural gas resources are retired by 2045.

10- **Maximum Washington Customer Benefits:** Washington State required scenario to understand the portfolio and cost impacts of improving Customer Benefit Indicators. This portfolio will exclude non-Washington sited resources and resources with air emissions. The objective will select resources to lower energy burden through additional energy efficiency and community solar for named communities. Higher named community penetration of roof-top solar and electric vehicles from the Distributed Energy Resource Study will also be considered.

11- **Least Cost + 500 MW Nuclear in 2040:** Uses the Preferred Resource Strategy assumptions with the addition of up to 500 MW of nuclear generation beginning in 2040.

12- **WRAP PRM**: Solves for the least cost portfolio meeting capacity, energy, and state policies using the Planning Reserve Margin currently required in the WRAP.

13- **Least Cost + 0% LOLP:** Solves for the least cost portfolio meeting capacity, energy, and state policies, but acquires generation to ensure the loss of load probability (LOLP) is zero rather than 5%.

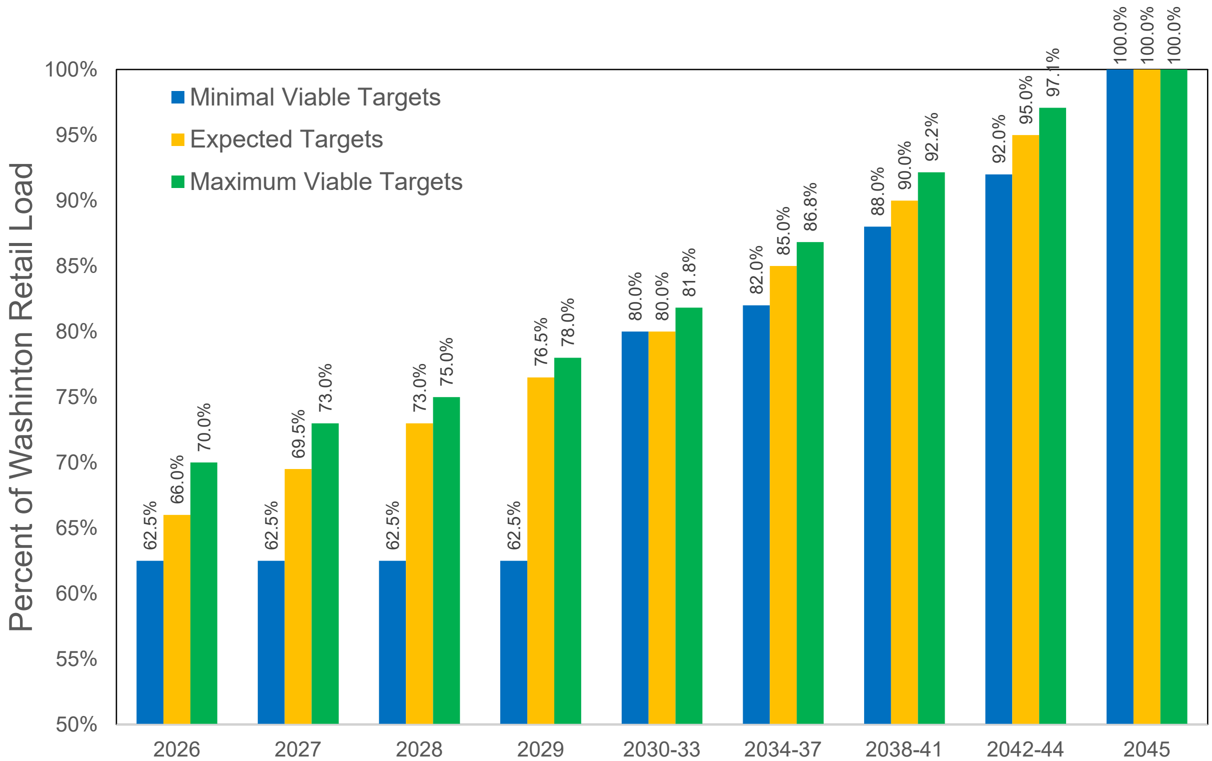
14- **Power to Gas Unavailable:** Similar portfolio design as the "PRS" scenario without the option of using power to gas fuels such as Ammonia or Hydrogen.

15- **Minimal Viable CETA Target**: Uses the same portfolio design as the "PRS" scenario except the CETA targets for clean energy use the minimal viable targets from Figure 1.
16- **Maximum Viable CETA Target**: Uses the same portfolio design as the "PRS" scenario except the CETA targets for clean energy use the maximum viable targets from Figure 1.
17- **Preferred Resource Strategy w/ CCA repealed**: This portfolio uses the No CCA market price forecast and estimates the portfolio if the CCA is repealed by voters in November 2024.
18- **Unconstrained Cost Preferred Resource Strategy:** In the event the PRS scenario is constrained by the 2% cost cap, this portfolio illustrates the cost to comply with 2045 CETA regardless of cost.
19- **High QCC on Demand Response (w/ minimum selection)**: This portfolio will be optimized using a higher QCC for demand response programs than used in the PRS scenario. If the portfolio does not result in higher demand response, the lower cost program options will be included in the portfolio.
20- **Data Center:** Add 100 MW of load in 2030 due to a new data center load.
21- **Nuclear Cost Sensitivity:** Determine cost of nuclear to be selected in PRS (if not already selected)
22- **RCP 8.5 Weather:** Use RCP 8.5 climate future for the load forecast
23- **80% Washington Building Electrification by 2045 with RCP 8.5 Weather:** Determines the least cost portfolio of converting 80% of Washington State natural gas residential and commercial demand to electric through heat/water conversions to heat pump and resistance technologies by 2045 includes RCP 8.5 weather for the load forecast.

Avoided Costs Portfolios:
No Supply-Side Resource Additions: This "portfolio" is only used to estimate the capacity premium of the avoided cost calculation; uses same EE selections as 'PRS' scenario; uses same assumptions as 'baseline' scenario except uses market purchases to meet demand instead of acquiring new resources.

Clean Capacity by 2045: This portfolio is similar to the 'baseline' scenario except it does not allow for new natural gas generation, does not require the model to satisfy monthly energy targets and assumes Coyote Springs 2 is not available in Washington in 2045. The portfolio is used to determine the clean capacity credit for avoided cost calculations only.

Figure 1: CETA Target Scenarios



Fifth TAC Meeting for the 2025 Electric IRP, April 23, 2024, Meeting Notes

Attendees:
Sofya Atitsogbe, WUTC; John Barber, Avista; Amber Blackstock, Avista; Shawn Bonfield, Avista; Annette Brandon, Avista; Molly Brewer, WUTC; Kate Brouns, Renewable NW; Michael Brutocao, Avista; Katie Chamberlain, Renewable NW; Josie Cummings, Avista; Stefan de Villiers, PCU; Mike Dillon, Avista; Chris Drake, Avista; Jean Marie Dreyer, WA Public Counsel; Michael Eldred, IPUC; Ryan Finesilver, Avista; Damon Fisher, Avista; Grant Forsyth, Avista; James Gall, Avista; Bill Garry, Customer; Konstantine Geranios, WUTC; Amanda Ghering; Avista; John Gross, Avista; Leona Haley, Avista; Kyle Hausam, Avista; Lori Hermanson, Avista; Mike Hermanson, Avista; Andy Hudson, Applied Energy Group; Fred Heutte, NW Energy Coalition; Allison Jacobs, PSE; Clint Kalich, Avista; Mary Kulas; Erik Lee, Avista; Kimberly Loskot, IPUC; John Lyons, Avista; Patrick Mahr, Avista; Jaime Majure, Avista; James McDougall, Avista; Ian McGetrick, Idaho Power; Tomas Morrissey, NWPCC; Fong Nguyen, AEG; Kevin Nordt; Michael Ott, IPUC; Tom Pardee, Avista; John Rothlin, Avista; Ryan Sherlock, Avangrid; Amanda Silvestri, BPA; Nathan South; Darrell Soyars, Avista; April Spacek, Avista; Dean Spratt, Avista; Victoria Stephens, IPUC; Lisa Stites, Grant County PUD; Charlee Thompson, NW Energy Coalition; David Thompson, Avista; Kenneth Walter, AEG; Jared Webley, Avista; Bill Will, WASEIA; Kelly Xu, PSE; Yao Yin, IPUC; Cole Youngers, Avista

<u>Introduction, John Lyons</u>

John Lyons: Welcome to the fifth TAC meeting for Avista’s Electric IRP for 2025. Glad you're able to join us and we're getting good feedback on having these more often shorter TAC meetings. So, we aren't showing off as much as the same time. Today is going to be a big change for us because we're going from our traditional forecast. Grant would have presented last time where he did our economic and the short-term forecast, but now for the long run forecast, AEG has been doing that. We're having them do for us, so they will go through that. Then we'll talk about our load forecast comparison and the changes between the two. And we are going to finish up with the scenario analyses that we started talking about last time. We have at least one addition in there and if you've got any other changes, we'll talk about those. We have the upcoming meetings every two weeks. We do have the Fourth of July week off. It is out there, but that will get cancelled. We won't have that meeting, but next time we'll also be a very AEG focused meeting with the conservation potential assessment and the demand response potential assessment. I also still need to send out the Technical Modeling Workshop meeting because that is a little bit off the schedule, and you can see the rest of those coming through into August. Alright, James, is there anything you'd like to say before we get started?

Long Run Load Forecast, AEG

James Gall: I just wanted to introduce AEG and Ken Walter, and I wanted to thank him for presenting to us today the work that he and his team have done on our load forecast. It's definitely a new methodology that we're approaching, and I see Ken has his camera on and. Are you ready to go?

Ken Walter: Yeah, I think I am. I was actually seeing if anybody else from my team had managed to jump on here. You guys like a nice early start, but it looks like I'll be Speaking for AEG today, which is fine.

James Gall: Yeah. Alright. Well, we'll turn it over to you.

Ken Walter: Alright. And then our second technical check of course is can folks see the screen that I'm presenting?

James Gall: We can.

Ken Walter: Ken Walter: OK, great, right.

James Gall: We're good and can all be watching the chat, and Lori will be as well for any questions on the chat. Anybody feel free to raise your hand and then I'll call on you. That way, Ken doesn't have to monitor that.

Ken Walter: Thanks, James. Appreciate it. Alright, with that intro for anybody who doesn't know me on the call already, my name is Ken Walter, I'm senior manager with Applied Energy Group. I lead our market assessment division, which is pretty much all things potential study, market research, and in this case specifically baseline forecasting. Just a little bit of background, we have been working with Avista for multiple CPAs going back all the way to 2010, and always as part of those CPAs, we do develop a baseline projection. Now normally the process would be, we would develop a projection, compare it to the forecast that Grant would give us and then look for any differences in assumptions there might be driving those gaps. And that's really only used for the CPA calculations, and it's not used by Avista for full load forecasting. But there are advantages in using a full end use model for forecasting, which is why we've undertaken this joint effort with Avista where you can really explicitly put in things like building code changes, changes in standards to equipment and rather than having to do some kind of trending from the past, you actually have that in as an explicit built in effect that's going into the forecast. It affects future energy loads and of course, as we get further down the line in the CPA, it affects potential as well.

Ken Walter: Major modeling inputs and sources are the same as what we would normally use in the normal CPA process. It starts with Avista's foundational data that is actual power sales by individual schedules that we can allocate into our modeling sectors. It is current and forecasted customers. Those still come straight from Avista and from Grant’s forecast. New to this part is actually including the retail price forecast because customer behavior is sensitive to that. And adding that enhancement to the way that we're modeling was an important step this time around. The second piece is as we are allocating all of that energy down into the different technologies and end uses, we need data to break that up and that starts with survey data. Avista has a residential customer survey from 2013. We combine that with survey information from the NEA residential and Commercial building stock assessments. You see, I've noted we are still using [Residential Building Stock Assessments] RBSA 2016. The RBSA 2022 data was just released a couple of weeks ago. It was not in time to be part of this particular buildup, so that'll be part of the next CPA. Also, a lot of information from the US Energy Administration. They have their own survey information, the RECS data, which as of 2020 is down to the state level. On very detailed, there's also CBECS 2018 data that was just released last year. And again, we start as tight as we can to Avista data and then expand from there to gap fill as needed or to break things into more specific pieces.

Ken Walter: Then we need options for how things are going to change over time, and we need the technical details on how pieces of equipment use energy so that technical data on end use equipment costs and energy consumption comes. Again, we start as local as possible. RTF workbooks, Northwest Power and Conservation Council's Power Plan workbooks. We expand out from there to US DOE sources, Energy Star technical data sheets and other information from the EIA, including their Annual Energy Outlook, which is a national energy model that they update every year, and we take a lot of their input information and in some cases even their same calculation methodology, which I'll talk about in a little bit. Another huge input and a big part of why we do it this way is state and federal energy codes and standards. Keeping track of the separate realities of Washington State Energy Code, Idaho Building Codes and Energy Codes. And of course, federal energy standards, which are constantly under update. We have an engineering team that spends a long time keeping up with all of their changing rules and what's going to happen in the future. The final thing that we want to incorporate is the actual market trends and effects. There are cases where you have something like LED lighting, which technically is above the federal minimum standard of lighting but is one of the most common purchases that people are making in the current years. We include things like RTF market, baseline assumptions on different equipment classes and as mentioned, the Annual Energy Outlook, which does include purchase decision trends that we can seed our model and then let things like what's going on with retail prices or local weather influence decisions from there. It takes a lot of data to build these up.

Ken Walter: The process, and I'll be focusing just on this baseline forecast for this. I won't be talking about the CPA portions specifically, but it still looks a lot like it does for our standard CPA process. We start with market characterization. This is for a singular base year, something that we have a complete calendar year of data. We could look at actual customer consumption and use per household or per commercial building, breaking that up into different segments that have different classes of energy use. Single family homes and multifamily homes don't use energy the same way.

Ken Walter: We have a low-income segment for each housing type. On the residential side and on the commercial side, we break things down into different businesses because again, your restaurant, your hospital and your office building don't have the same kind of end use loads. They don't have the same kind of schedules, and that's critical. Once we get to the third block on here. Once we have all of those energy loads calibrated down and actually shared out, made sure that it's matching the billing data by the kWh, then we can run a baseline projection first on an annual basis. That's the way our models are originally set up and this can track customer forecasts, stock turning over, you have vintage units that maybe a little out of date. They turn over into at least minimum efficiency, and if we have one of those market trends, they may go above that keeping track of all the stock that's actually present in each of those options and running everything through a purchase decision model to try and predict what customers are going to be doing just on their own. Those annual values, and this is a big enhancement for this effort, now with Avista is to turn those annual values into an hourly forecast, which is what Avista needs for its planning purposes. To do this, every end use, every piece of technology, is assigned to an end use load shape and in some cases those are even specific to different building types, and different technologies. Even heat pumps versus electric resistance heat for example, aggregating all of these disassociated energy loads to their individual shapes and then calibrating that again, back to an actual year, we have 2021 and 2022 actual hourly loads from Avista. We can calibrate the model output for those two years and then apply those factors to all future years so that we actually get hourly shaped loads all the way into 2045-2047 that are shaped correctly to what Avista has seen on its system in the past. Since we're tracking individual loads as space heating load or cooling load or whatever it is growing differently because of the different end use as being calculated. You can see how that might change the hourly shape on the year for Avista’s system into the future, and we'll take a look at some of those results in a minute. Any questions that we've gotten to so far that are burning in people's minds?

James Gall: You have no questions in the chat yet.

Ken Walter: OK, great. A couple of the finer details before we see results. One of the things we do have to keep track of is existing versus new building stock or at least code compliant which we call new. New construction does include a certain amount of renovation of existing, but new construction is just easier to say. The important things here is that we're adjusting all of the new buildings or good compliance to conform with the energy codes in the respective states. That includes upgrading our values and changing those in our simulations. It also includes presence of equipment where we're expecting less gas in Washington and more electric heat. But of course, it's going to be heat pumps. There are a lot of factors influencing up and down use per household or use per commercial structure. All new residential structures are assumed to be using electric heat pumps in Washington. Still a good presence of them in Idaho, but of course it's not mandatory. All of those things are being kept track of as the model runs through and we have a difference in the stock between the two.

Ken Walter: Then we get to results which have a very interesting uptick. We'll talk about what's actually driving all of that. This look is total consumption year over year, total GW hours for Washington and Idaho combined. There are a lot of things contributing to this growth. First, there is customer growth and that is provided by Avista. There is also electrification going on and that is something that we are modeling explicitly. We have modeled the gas system and the electric system, and the gas customers are given the opportunity, not required, but allowed through economic purchase decisions to electrify if it looks attractive from the customer perspective or at least relative to other options. We're growing by 53% out to 2047 or about 1.6% annual. The total electrification growth and the total growth just because of customer increases are about a 50/50 split. It's about 2,400 GW hours for each by the end. This is inclusive of projected cooling and heating degree days. This is a climate trend inclusive forecast. It also does include, as I mentioned, market efficiency impacts. So, this is naturally occurring purchases of efficient equipment LED being the most obvious one, but including some other things as well, some higher efficiency heat pumps or things that are seen in past purchase data and expected to continue. Those are saving about 1,000 GW hours in this forecast period, so if you can imagine that green line being another inch taller on the right, that's what it would be without those market baseline assumptions.

Ken Walter: We're also including solar and EV projections in Idaho. Those are again from Grant’s projection, based on trends that they've seen in their customers on the Washington side. There is the concurrent DER study that has been going on for Avista. We took the same solar and EV projections for Washington that were part of that study, and a lot of that Bell Curve is also inclusive of EVs. They have some interesting implications. Looking at the sector level for Washington overall, across both states and all sectors, Washington residential is the fastest growing place. It's almost 2% a year and that is space heating growth as people are bringing on heat pumps from electrification and EV growth. If you look down at the bottom left chart, you can see that gray wedge a little more than doubling in size, EVs are a significant piece of that gray miscellaneous category. Commercial EV charging is also coming on and that's adding over 1,000 GW hours by 2045, so it is a not insignificant load.

Ken Walter: Industrial loads are continuing to trend downward. This is just in keeping with past industrial, there's no anticipated large new loads coming online there. Same perspective for Idaho. Although customer growth is actually going to be, or is projected to be, a little bit larger in Idaho. The actual load is not growing as fast because there's much less electrification and much less EV that are expected to come on in Idaho at this time. You do still see some pretty good growth, but that is mostly from customer increases.

Ken Walter: Let's look at peaks. This is a very interesting one. What you'll see in the trend is if you look right around 2030, that is the parity point where winter system peaks outpace summer and that is as more of these electric heat pumps are coming online. They are more peak efficient than electric resistance, but they are still contributing to greater winter electric loads, especially around the coldest parts of the year. There is also a significant contribution to peak in both seasons from these EVs. When people charge has a lot of sensitivity around where the peak actually hits. There's a lot of vehicles out there. If they're all plugged in at the same time, that's a lot of load. We are currently using an annual charging shape across the year that was provided by CADEO with part of the DER Study. Obviously, there are a lot of assumptions that are based into that, probably one of the main things to mention is that it does not assume that people are trying to avoid a peak hour. It's not a time of use shape, and that's something that can definitely be explored in scenarios like James was mentioning earlier. That's one thing I will say about this is the exact shape or magnitude of these peaks is very sensitive to where that EV load lands could be a lot higher. This is actually not assuming they're all coincident, but it could also be lower than this if they were all shifted completely away from the peak hour.

Ken Walter: I mentioned electrification and I'm sure some people were curious about a little more detail on how we're modeling that. This is completely focused on the electric forecast, but I want it to mention the gas modeling that we're doing so that we could contribute these inputs to the electric forecast and have an understanding of where the gas customers may be coming over. We have gas models set up the same way as we do the electric. And as I mentioned, they're given the option basically alongside various efficiencies of gas equipment. There is an electrification option that uses no gas but has an annual cost of the electricity for whatever model. That would be whether that's a heat pump, water heater or an electric heat pump heating system. We offered both dual fuel heat pump replacements, so gas backup system and a full electrification option which was much less economically attractive. We're using the purchase decision logic that is copied from that Annual Energy Outlook. The National Energy Modeling system, which basically just evaluates relative to one another the recognized attractiveness. It then can be calibrated to existing purchases that have been seen in the market. It does its own shuffling from there to look as things change into the future. How does that change? It uses those calibration factors again to say, people are already doing some of this or very little of this compared to how attractive it is and it uses those terms into the future. If you look over on the right, you can see up in Washington, we have a lot more expansion, but if you notice it's the two green lines, actually the dual fuels are significantly more present than full electrification. The gas backup systems are just less expensive and there's a lot more attractiveness there and more purchase data just in the background information that we have, they are pretty well present.

Ken Walter: There is some weakness in seeding these just because it is very difficult to get information on what people replaced gas with. Electric, there's a lot of surveys that you can identify who has heat pumps now, but things like RSA and Rex don't ask what you replaced. So, for right now we are seeding full electrification away from gas with a value that's about 1/4 of the existing dual fuel purchases, which those are well documented. It seems to provide a pretty good picture that matches assumptions for Washington and Idaho. That is another assumption that could be updated, but it's working pretty well and giving a fairly sensible result at the moment, but just wanted to mention where that information is coming from. And if anybody likes numbers, because we're all people who like numbers around here, this is the total share of gas customer stock that gets electrified by 2045. In our current modeling, in residential, it's a hair shy of 30,000 dual fuel heat pumps go in. In Washington, a little shy of 20,000 in Idaho, full electric is obviously significantly less, but much stronger in Washington. A little over 6,000 units, around 1,500 in Idaho and then heat pump, water heaters replacing gas systems about 1,600 in Washington, they gain a big boost from being focused on in the code. That's not including anything from new construction code, but it's just there's a lot of trend towards them in Washington, whereas in Idaho, there's only 256 units. It's not a very attractive option in the C&I space, it's much lower, it's just it's not as strongly competitive in C&I. There's not a lot of economic drivers and really not a lot of past purchase data that suggests directive, so dual fuel heat pumps is a few hundred, 515 in Washington, actually a few more in Idaho. Again, that's just related to the seed data. I was a little bit surprised, but there are a few more dual fuel heat pumps that already exist in Idaho than in the Washington data. Could be a source bias, but that's what we're running with. And then for full electrification, very small 134 in Washington, just 46 systems in Idaho. And then for water heaters, 712 in Washington and 678 in Idaho. So, pretty similar, but also just small numbers all around in C&I. And that's everything I've got prepared slide wise, but I'm happy to field questions if there are any at the time.

James Gall: You have nothing in the chat yet or hands raised, but I did want to mention one thing because you mentioned on the EV shape and then you know we're using what we call a non-mitigated load shape for EVs. When we look at our demand response options in the next TAC meeting that you'll provide, that will help us put an option out there to see what it costs to try to manage those EV shapes. That will be coming in the next TAC meeting. But I'm just going to pause a little bit for any questions that people have before we go to the comparison to the last IRP. You got off easy, Ken. I don't know if I'll get that treatment, but a question, we got one. I'll go ahead. It's in the chat. I'll read it out. Why do we use Grant’s forecast for short term instead of this forecast? That's a good question. I don't know. Grant, do you want to take that one if you're online?

Grant Forsyth: Yeah, this is Grant. Because Grant doesn't want two different forecasts in the short term.

James Gall: That's a good answer, Grant, but yeah.

Ken Walter: It's a very good answer, actually, and neither do we.

James Gall: Grant's forecast is used for the company's financial planning. And having two forecasts does create issues. We have another question. Chat from Michael Ott. I'll read it. Is the dual fuel heat pump more common in more extreme winter climates compared to milder climates?

Ken Walter: We were really only looking at the data specific to Washington and Idaho, so I didn't actually compare it to some of the milder states or more southern states. That's a pretty interesting question we could take a look at. They're not huge. They're less than around 5, plus or minus percent of purchases kind of anywhere we saw, but I could take a look and see what some of the other states look like.

James Gall: And then we have another question. How do we handle the transition between the two forecasts? So, between Grant's five year and the long term.

Ken Walter: Is that a question for me or for you well?

James Gall: I think it might be for you.

Ken Walter: We are calibrating our model to grants forecast. Once we've run out of Grant's stuff to calibrate to, our model is just off on its own from there, but because we've spent those first few years calibrating, it's really starting in lockstep and just carrying those trends forward.

James Gall: Thank you. Let's pause a little bit again for any more thoughts that come up. We have a hand up, Kate, go ahead.

Kate Brouns: Hey, thank you. I just said I'd speak this in case it was a little more complicated, but you mentioned using a customer survey from 2013 and I can't recall what that survey was exactly used for but was hoping you could speak to. Does that feel like it's still relevant or does it need to be redone or is that informed by other surveys to feel more updated?

Ken Walter: Yeah. I'd say at this point we've shifted to mostly using our BSA data and Rex data with an eye on the old GENPOP survey just because it is a little bit more out of date and not to put too many people on the spot. But we did just send a proposal over to Kim Boynton on the CPA side and recommended a new market research survey. Although many of the utilities here are in RBSA territory, we have sometimes suggested that every once in a while it's good to do your own. Take the temperature of your own customers, especially because you can ask questions that RSA doesn't. It could be very useful for you. It's still nice to get a look at how Avista customers, at least at that time, were different from the basic RSA population and we still apply some of those trends and shifts just because two groups are not the same. But yeah, we've mostly moved to more recent sources. And then if Avista was to do another survey, that would immediately become our top priority source again.

Ken Walter: Alright. I see another one in the chat. I can actually look at the chat right now. Benefits of a couple of screens. Can we explain why Idaho expects a total system winter peak before Washington? If you just look at the first couple of years, you can actually see that in Idaho the winter and summer peaks are just closer together to begin with. So, it doesn't take very much growth in space heating for it to outpace the summer peak. One thing I should mention as we're electrifying systems, we are accounting for people who already have cooling. That's another thing that's going on is we may be bringing over a heat pump, but it's not just adding cooling load to the summer side where deducting people who already had essential AC or a room AC depending on what kind of heat pump came over. That difference can be there as well.

James Gall: OK. I think we're close. I don't see any more hands or questions. Ken, thank you very much and I will now.

Ken Walter: No. Yeah, absolutely. And if questions do pop up, feel free to pass them through James. He'll hand them off to me.

James Gall: OK, alright. There's one more from Yao. We got a new one. Yes, the short-term forecast doesn't take into account of any use, correct?

Grant Forsyth: Yeah.

James Gall: So that would be yes and no.

Ken Walter: That's correct.

James Gall: I would argue.

Ken Walter: Well, yeah, it takes into account historical trends and Grant can tell me if I'm putting too many words in his mouth and on the very short term, that's usually enough or you're not going to see enough disparity between the end use forecast and the short term. It's really the long term that the end use really starts to see things that the short term can't see.

Grant Forsyth: Yeah, this is Grant. Yao, my model is a time series forecast and so end-use trends are going to be embedded in the data. Historically, and hopefully I don't have this wrong, Ken, it hasn't been that hard to match the short term forecast with what you guys are doing in terms of your modeling approach.

Ken Walter: Correct. Yeah, we're talking like 10th of a percent adjustments at most.

Forsyth, Grant: Right. So, it's really just making sure from a policy point of view that the forecast we're using to make financial decisions isn't different than that first five years in the IRP. We want consistency there and it's pretty acceptable I think because again it's not that far off from what AG's models would produce on its own and which means that transitioning to the longer term is, is again not a problem. OK.

James Gall: Alright. Anything else? OK.

Grant Forsyth: Thanks Yao.

Load Forecast Comparison, Avista Staff

James Gall: All right, so the goal, the next slide deck is to really go through, how does this forecast compared to our previous IRP? And then also we have to make some adjustments to this forecast to be useful in the IRP and we have to take an account losses and some other weather adjustments. I'm going to go through these slides to kind of walk you through how we take AEG's forecast to, to how we would include these loads into our resource planning model, like in and in Grant. Please add in as a necessary. I'll need your help as much as possible if there's certain questions.

James Gall: We're going to cover two tracks on how we transition this end use model to our actual load forecast. And the first part, is two different energy forecasts. We have an energy forecast and we have a peak load forecast. On the energy forecast side, we start with AEG's forecast, and we do a forecast with and without expected DSM or energy efficiency. We then have to add losses to that load forecast because that forecast that Ken had just gone through does not include line losses from the transmission and distribution system. We add that to the forecast and then we also have to add large industrial loads that AEG is not modeling. Historically, we've had two large industrial loads and now we have a third one now that we're accounting for. We agreed to take on a former customer, that was, we'll call it a market customer. They're going to become an Avista load starting in July or August and it's approximately 30 average megawatts, and a little bit higher than that for peak. We have a higher load forecast from an energy perspective from that need for the peak side. The forecast that AEG has done is using a load shape we can describe, but that load shape doesn't necessarily represent the temperatures that we've seen historically, or we expect to see in the future. What we need to do is adjust those temperatures to account for what our temperature forecast will be to create what we call a one-in-two forecast. We're going to demonstrate how that looks here in a little bit. Then we take that new load forecast that we're going to calculate, we call it a baseline and apply the AEG forecast for load growth at the time of peak. So that peak forecast you show, before Ken, we will take the percent change of those loads and apply that to what we call it our adjusted peak load from 2024. Then we add our losses, actually we started with losses already then included in our baseline amount, and then we add large industrial loads.

James Gall: And then just as a note, we're not including demand response or any managed loads at that time just to make sure that's clear. We calculate a base year based on what we think a 1-in-2 temperature is for a peak and that's for 2024. We apply AEG Peak load forecast growth rates to those historical weather and future weather periods and then we take these forecasts and put them into our PRiSM model to help us choose resources. Now we do have to have two forecasts. We have one forecast that's with DSM or energy efficiency and one that's without. And the reason why we do that is we want to look at how much energy efficiency is cost effective in our model. We'll actually start with a load forecast that excludes future energy efficiency and we see what is selected by our model and we are then trying to match up the amount of energy efficiency selected versus how much we think was in the original forecast. It's possible that they will align, but it's also possible they won't. What we're trying to end up with in our load forecast is the forecast you're going to see today that is net of energy efficiency and then what we select is energy efficiency that's cost effective and would be effectively added to the forecast without energy efficiency. That probably doesn't make a lot of sense, but I'll try to walk through that on the next slide.

James Gall: Looking at our energy forecast, I have it broken out between our two states and our system. This yellow line shows our actual forecast for five years and then the historical periods before that you can see we have a little bit of weather variation, then it starts to slow growth, and then we get a much stronger growth and that solid black line. We're at about 1.47% annual average growth rate (AAGR) when you include the losses in industrial customers. That's compared to our previous forecasts of around 0.91%. But you can see we are on a higher level than our previous forecast at the last IRP. We don't have loads broken out by state historically, but going into the future you can see that Washington is substantially higher than our previous forecast, mostly due to the amount of EVs and electrification that we're assuming. Idaho is a little bit closer in the amount forecast compared to last IRP. The big difference between the Idaho and the Washington side is the amount of EVs added and electrification is substantially higher than the previous IRP. The Idaho assumptions on electrification is higher, but the EV assumption is the same. Back on energy efficiency, these forecasts that you have in the solid lines, they do include energy efficiency estimates, that's around 60 average megawatts in Washington and around 7 average megawatts and Idaho. Again, this is the forecast our model will try to align to after we readjust it when we enter in our loads into our PRISM model. Effectively it would add the 60 average megawatts in Washington and 7 average megawatts of Idaho to these forecasts and then try to figure out if those are the right energy efficiency measures. Are they cost effective? If they are perfectly aligned, we'll end up back at these forecasts. If they're not aligned, we'll adjust our forecast without energy efficiency so that they align. At the end of the day, these lines that you see will be what we're trying to add resources to, OK. Are there any questions or no questions? Alright, I confused you all enough that you were afraid to ask questions. That's good right now. Just joking. OK.

James Gall: We'll move on to how we deal with this base here. And Mike, please jump in if you I’m saying anything incorrect. All right, we have to start with a base year to adjust for weather and we want to do a forecast that is a 1-in-2 peak. What we mean by that is we look at our historical years of data and our forecasted years of temperatures and we're looking for what is the average coldest day, what is the average hottest day. And we're trying to find that temperature and then what would our peak be at that temperature? These distributions you see here are the historical, back on the winter side is on the right, summer is on the left, and these temperatures actually go back to 1890 and then they have forecasts of temperatures through 2045. You can see in the red it's kind of that 1-in-2 area that is our, call it our 1-in-2 peak value we're trying to start with and then as a comparison we're showing the last two peak events in each season. So, 2023, we had a much warmer summer peak event than the average. You can see that in yellow and then this last January you can see where that lines up when we had a higher or much colder day than we did on average. So again, we're trying to take this data and apply historical temperatures, future temperatures and come up with what we see as a 1-in-2 event or 1-in-2 temperature for summer when we do our forecast. We're using what periods of time, Mike, to the summer. Yeah. The summer period is June to September. Yeah. I mean, what years we're going back 20 years, rolling 20-years data and then winter is 76 rolling years. So, what that means is when we have a rolling temperature going forward, as we include a change in the temperature forecast, we’re changing that baseline temperature over time and what that does is it creates a trend in the summer of higher loads and then the winter would trend to lower loads given the same economic conditions, the same number of customers. How does that look when you transition this to the full data set? We have and solid black or blue, I can't quite tell, that is the winter peak and then in red is the summer peak. When we adjust for the temperatures, winter is still slightly higher than summer. They do crossover briefly there in 2036 and then the winter stays higher continually. You can see these peaks are much higher than our previous forecast from the last IRP. Two reasons for that. One is the new industrial load that's included and then the second reason is these events we saw in 2023 and 2024 were much higher than what we had seen in the past. This higher winter and summer loads are now embedded into this forecast to make it more accurate. This 1-in-2 event that is causing our peak forecast to be higher and what to allude to what we'll probably see in a future TAC is our resource need is going to come sooner because of these higher loads.

James Gall: In our last IRP, we had a resource deficit year of around 2035. We expect that to be much earlier, but we haven't completed that work yet to see when our resource deficit will be. But at the end of the day, our peak loads are going to be higher. This says, look at history really quick, you can see in the winter we've had actually pretty mild winter peak loads and we were getting a lot of questions. Are you really summer peaking? Because your summers are consistently higher than winter over the last few years and the reason for that was we just never got a real winter cold event. But the last two winners have changed that, and it's definitely demonstrated that winter is still a concern. It's just a matter of temperature, but the summer temperatures have been over the last say, 5 to 7 years been more consistently on the hotter side then winters have been consistently on the colder side, at least on a peak event. Fred, you had your hand up. Do you have a question?

Fred Heutte: Well, yeah, actually, I was going to wait and see your next slides because the slide deck that John sent around said that would, what does it say here? It says winter and summer charts, so peak load by temperature will be added in the final slide deck actually. I'm actually hoping you'll show that because I think it's pretty important stuff to look at.

James Gall: Yeah, that's the slide right here that we added.

Fred Heutte: Ah, OK.

James Gall: Yao has a question too. I'll read it off. So, Yao is asking, do we know how much of the difference between the 2023 IRP load and 2025 IRP load is due to methodological change, Grant's versus AEG? Yeah. The base year values that we start with is the same methodology. In both Grant's method and this method, we use the historical data, and we used a future data set to come up with a 1-in-2 peak value. The difference between the two methods has to do with how we grow the loads over time. In the past we grew loads based on GDP forecasting. Grant, please jump in if there's more than GDP. There's also an EV forecast. There's a solar component and electrification component that we're done independently, but is there anything besides GDP Grant that we included?

Grant Forsyth: Other than the things you listed, GDP was the economic driver over time in addition to EV accumulation and electrification were going to be the other two big ones and solar accumulation. So, it was kind of unaffected, but the economic driver is GDP growth.

James Gall: OK. The AEG forecast uses an end use decision-based forecast, but they all do both resolve the number of customers that are expected to come online. Back to you Fred.

Fred Heutte: Yeah. Now I actually have a question. What we saw in the January freeze period, mid-January, was Avista and I think many other utilities experienced what I would call a demand surge which was above projected levels. I'm not pointing fingers here at all. I think this is a really important thing to understand. I'll note that, among other things I've seen, the CAISO said that they had to adjust their demand forecast in the market because the conditions in the Northwest were basically outside of the historical data that they had been using. Likewise, SPP on the Monday which was the 15th, I guess they saw a demand surge that was not anticipated in their models for their region. Which is through the upper Midwest down toward Texas. I think we've seen this in the last couple of big extreme weather events, cold and heat. And I'm just, not to answer right now, but just to think, I'm sort of putting on my thinking cap on this is. Is there something going on that is new that we, when you get these extreme conditions, the people are using the equipment, heating or cooling equipment a lot more? Is there something kind of a nonlinearity happening at the end of the distribution that we ought to be paying more attention to in terms of peak? Because then the implication is, is there a way to do some load management? Figure out what to do in markets. How the WRAP is going to affect this? Those are all pretty important issues now, so really any thoughts you have. I guess my question is, have you looked in more detail at these kinds of events to see if there's something structurally new going on?

James Gall: I think Grant has a theory and I’ll let him respond to that.

Grant Forsyth: Yeah. Fred, this is Grant. One of the things we're seeing in our service territory is this odd outcome from hybrid work. What's happening is that you have a lot of businesses now in our service territory with hybrid workers. You have some people working at home, some people working in the offices, but what that means in effect is you have more people working from home on average than pre-pandemic. So, they're going to use more energy during the day than they would have in the past, but you're also still partially using those commercial buildings. They still have to be heated and cooled and so when I look at our peak load data and I put in a control variable for really the 2021-2022 period going forward, what we're seeing is a step up that's occurred in peak load of about 40 megawatts. My theory is that this hybrid work environment has stepped up heating and cooling because now we're using homes more frequently. But those businesses still have to be heated and cooled.

Fred Heutte: Yeah. That actually is a good point. I hadn't thought of that, and at the same time I also have to observe, though, that the January event was both during a holiday weekend when those businesses would be either closed or curtailed and then it can take you to the following week, at least here in Oregon, especially with our ice storm, another whole series of issues. I think that makes a lot of sense that there's one element to look at and then, we lived through here in Portland, probably not something that you all have never experienced. But we had 15-degree weather with 50 mile an hour wind here. Now that is not a very West side kind of weather pattern and I think everybody cranked up all the heating stuff that they had that may be less of an issue for where you are because I think people are more used to these cold waves. Anyway, thanks. That's a very good point about load, the spread on load because of working at home.

James Gall: I'm going to add a couple things to that and maybe explain the variance. That variance that you might be talking about was the cold weather event we had in December of 2023. And it was nearly the same temperature as we saw in Spokane between the two events, but the load in 2024 was much higher. But there were a couple things that were different going on. One was a Saturday and 2024, it was our peak day. So, you were seeing what Grant was talking about, heating and buildings that are not being occupied likely and at certain businesses and also homes. But in 2023, that peak event happened when schools were out. Typically, when schools are out, there's less load overall on the system, at least in theory. It's possible that if you would adjust for schools, whether it's universities or primary, you could come up with the difference in that load from that point of view. We haven't quantified that. But that was also a big difference between the two events.

Fred Heutte: Yeah. Appreciate it. Thanks. This is a really useful stuff.

James Gall: Yep. OK. That's all we have on peak and energy forecasts. We will be sharing this data shortly. It'll be out on the Teams site. We'll post our monthly forecast for both peak and energy, hopefully by the end of the week or next week. Any other questions or on chat? No questions yet, OK? It might give them a minute.

<u>Review Planned Scenario Analysis, James Gall</u>

James Gall: OK. While we're waiting for that, I'm going to bring up our load or scenario Word document and we'll go through that. We are running at time, aren't we? We had until, yeah, we're doing good. Yeah. OK, so I'm going to zoom in. Hopefully you can read this. We did not get through this in the last TAC meeting as much as we would have liked, but we do want to cover what the scenarios are.

James Gall: This is really not meant to be something I read through, but we've been sharing this list over the last I think, month or so. We did get a few comments on additional scenarios to be looking at, but I want to walk you through how this is oriented in case there was some confusion. So how this works is we have a list of scenarios that we plan on running and what I call these are scenarios or portfolio scenarios, which means that we will be either adjusting the resources selected in our portfolio or it will change assumptions such as load that we'll be planning to. So right now, we have 23 portfolio scenarios and then in the market price sensitivity category, this is where we would adjust the market prices that we use to evaluate the resource options. For example, we do 300 simulations of future market prices that is used for all of these scenarios and then scenarios that will be testing a higher or lower gas price which then correlates to a higher or lower electric price forecast will also be using, we call it interior deterministic forecast for electric prices. For the Preferred Resource Strategy, we'll take that portfolio and test it. How well it performs and our stochastic price forecast, already deterministic price forecasts, which will be similar and then we'll test it against low and high prices. And the other scenarios you see here that also are being tested with low and high prices, you can see how well those scenarios, those portfolios, compare against the PRS with different low and high price sensitivity. This column really represents the sensitivity of that portfolio to external forces in the market.

James Gall: The LP 2030 and 2045 columns. These represent the cases where we'll run a resource adequacy, we'll call it a test, against the portfolio. Our model that we use to select resources, it's a monthly time step model. There's no model out there that can optimize our portfolio on an hourly basis over thousands of potential futures. So, we have to set a time step and a planning margin to calculate what we think would solve our portfolio in extreme cases. And then we have to test that in a model that does move around loads at a more extreme basis, or temperatures, or hydro conditions. These are the portfolios we'll be testing these cases against and what years will be testing them against these resource adequacy studies. They take about three days to run one portfolio, so we can't necessarily run all of them, but we'll try to run as many as we can. We may not be able to get through all of this list, but our intention is to get through this list of portfolios with the resource adequacy test. We are going to be running a resource adequacy test for this where we call it the 2030 baseline and what we'll be doing is looking at the load forecast. We just shared our existing portfolio and use that resource adequacy test to come up with our planning margin that we'll be using in this IRP and that planning margin will be different than what was being discussed in the WRAP right now. But that is the intention and we'll be sharing that at the TAC meeting, I think in about a month.

James Gall: Moving down, we have a list of the scenarios and the assumptions in the scenarios and what makes them different. Lastly, down below for CETA, there are some scenarios regarding CETA compliance targets. I call these out in the chart because in our CEIP conditions, we were asked to test different CETA target goals. I wanted to share these to see if these make sense for the scenarios, we test CETA against because there was a condition that we had to look at a minimal viable target and the columns in blue is what we're calling the minimal viable target that may comply with law and then the ones in orange are the ones we've planned to and our expected case. And then since we have a minimal viable target for also going to be showing in green a maximum viable target and we can then look at what is the cost of compliance of these three different measures, because that was requested of us in our CEIP process.

James Gall: Yeah. Yao has a question? Yao, go ahead? She asked if do LOLP studies, generate LOLP values for 2030 and 2045? So, what they will do is tell us how well the portfolio performed. If we use the historical 5% loss of load probability metric, that metric will tell us, did our portfolio exceed or comply with that 5%? I'm not saying we're going to be using 5% at this time, but it will test whether or not that portfolio will do that. The second thing it can help us identify, at least in the 2030 study that we start off with, is it will help us identify our planning margin. We can identify how many additional resources we need to acquire or what our resource compared to load metric is to hit that 5% loss of load probability. It's really has two pieces. One is to help us identify planning margin and two, whether or not our portfolio is reliable or not. Hopefully that answered the question.

James Gall: OK, the last time we sent out this list, we had 19 scenarios. We did add #20 which was a data center scenario where we would test adding a data center to our service territory. We also added a nuclear cost sensitivity scenario, and this is to represent at what cost would nuclear be cost effective if it's not already selected in our PRS? And the reason why we added this one is we were asked by a lot in public, all of the CEIP public meeting process, we got a lot of questions on nuclear. Why we're not looking at nuclear and the answer is we are looking at it, but it has really come down to cost. So, we thought it'd be good to identify the cost nuclear would be cost effective because at this point in time there's really only one large project that's been completed in the last 10 years. And there's been a lot of small modular reactors talked about, but none of them actually have been built yet to see what they costs are or if you had multiple sets of units what the cost looked like.

James Gall: Another one that we will be adding is an RCP 8.5 weather scenario and what this represents, as we talked about in the last TAC meeting, we're going to be using the RCP 4.5 weather future for winter and RCP 8.5 for summer and that is a warmer, RCP 8.5 refers to a warmer forecast versus the 8.5. I'm sorry, the 4.5, which is a slightly warmer forecast compared to history. We'll be testing our portfolio against the 8.5 weather scenario.

James Gall: Another one that we've added as requested by Commission staff in Washington is to do some combinations of forecasts and we're going to call this 80% building electrification by 2045. What that means is that when Ken shared how many existing customers would be transitioning to electrification, this would increase that electrification transition from I think he had 20% by 2045 to 80% and then we'd be adding to that a high transportation electrification forecast, so higher EV option and then also add warmer temperatures. Add those three together for that forecast. We have a total of 23 forecasts. Fred, go ahead.

Fred Heutte: I just have to reach for the right buttons here. So just to say very briefly on the nuclear, recent analysis for the IRPs for Avista, excuse me, Avista, Puget and PacifiCorp, both are in Washington State, of course have shown very, very high cost for nuclear. The analyst this has been done by, you know, very respected engineering firms, Burns & McDonnell and Black & Veatch, showing capital costs in the $8 to $10,000 per kilowatt range, but also, and this is pretty important, O&M costs that are really high, somewhere between $100 and $200 a kilowatt year. I tend to think it's going to be toward the higher end of that, but even if it's the lower end, if you add it up over the lifetime of the plant, that adds a lot of cost. So just to point that out. A question I actually have is about the next item, the climate load growth issue, which one is it there they have 2022 I guess. So if you could say a little bit more about data sources for that and how you're going to profile what the weather will be from these climate models, which is a lot of work to be able to use that because the models have really, the global models have really big areas that they're covering. Downscaling is a complicated thing to do. So, if you could talk a little bit more about what data you're planning to use, that would be helpful.

James Gall: Yeah. Those forecasts come from, I don't know if you were, I think you were at the last TAC meeting we had two weeks ago. We covered that. But Mike, you want to just give him the source again?

Fred Heutte: Yeah, just to refresh on that, because I don't recall all the details. I mean to do it not in detail, just a general sense of it.

Mike Hermanson: The baseline is from the study done by the RMJOC 2, which is Army Corps of Engineers, Bureau of Reclamation, and BPA. They use 10 global climate models to go down and model, and train to end up with stream flows. We're using the temperatures from the 10 global climate models. You get a max and a minimum every day, and so we are using the median value of the 10 climate models and doing the seasonal high and the seasonal low for the peak calculation.

Fred Heutte: Yeah. OK, that's great. I'm just to observe and I presume you're in contact with the people at the Power Council, who now have quite a bit of experience dealing with the downscale data. I'm pleased to see this, that I guess is my response.

James Gall: Yeah, we're using the same data set. The difference, I guess between the Power Council and Avista is the Power Council is using three of those ten models and we're using all of them and doing a median approach.

Fred Heutte: Yeah, I guess the issue for me is really about the downscaling. We don't need to cover it right now, but something I'm interested in knowing a little bit more about.

James Gall: Yeah. We've seen in the gas IRP process for some other locations in Oregon, the downscaling of that data was a little bit counterintuitive, and we have a new approach for that on the gas side. And I think when we plan on talking about that, is at least three weeks out, that is TAC 5. Probably, I think it's early June, so about a month and 1/2. We've seen the downscaling of the Spokane area has not been, I would say, counterintuitive to maybe some other areas. So, we're fairly certain it's reasonable and actually, yeah.

Fred Heutte: So, like Ashland, yeah.

James Gall: Roseburg. Lagrande. Yeah. An issue there was that those locations were on the edge of the RMJOC study area. We were provided another data source that covered the whole United States, and could down get down scaled values for wherever. I think that added to a little bit of data source for those locations.

Fred Heutte: Alright, thanks a lot.

James Gall: Yes, I just want to check with anybody. Do we want to have me go through a description of some of these other scenarios that we didn't cover? Are there questions on certain ones? I want to be the greatest use of our time. We have 20 minutes left, because what I'm really seeking is do we need to add any additional scenarios that you have in mind? Are there scenarios on here you think we shouldn't be looking at? I just want to gauge the group here where you want to take this next 20 minutes because I don't think me talking about every scenario might be productive. OK. We could end early because I think the goal here is to nail down a list of portfolio options. We're going to be evaluating as soon as possible, so we talked about, I think the last TAC meeting by, I can't remember. I keep changing the dates on when we need to finalize portfolios, but John, what do you want to have not from two meetings ago. That would be about there now. Yeah, we're getting close. Yeah, that's your hand up. Go ahead Molly.

Molly Morgan (UTC): Hey, could you just remind me what the maximum Washington customer benefit scenario is all about?

James Gall: I would love to do that one because that is probably the biggest challenging portfolio that we have to model. I'm going to go down here to the listing of it. In the Washington IRP rules, we’re required to do what's called a maximum Washington customer benefit scenario. We covered a little bit of this, maybe three TAC meetings ago, but the idea is to look at our Customer Benefit Indicators that we're improving in our CEIP and try to optimize or to maximize their score. If the lack of a better term is, how do we make those Customer Benefit Indicators look the best? For example, if you have an indicator of energy burden, what portfolio could we do that lowers energy burden the most? We're thinking of this properly as kind of at the extremes. There are not a lot of CEIP Customer Benefit Indicators that the IRP really looks at is, most of them are say on the customer delivery side. But we're trying to look at how to maximize those. So, one of them is that energy burden, selecting resources that lower the energy burden as much as possible. Another one is looking at air emitting resources, trying to minimize air emissions from our resources. Another one is to locate resources in Washington State or in our service territory because we have a CBI that is focusing on trying to add resources in the local service territory for job growth. We also look at additional energy efficiency that helps with the energy burden as well as rooftop solar. It's rooftop community solar. Solar energy and efficiency help the energy burden and then EVs are kind of a debatable one, but you could argue that we'll be looking at a higher EV potential. So, our distributed, sorry distribution energy resource study that we are going through the DPAG process has two forecasts for EVs and solar. One is the amount of solar and EVs expected, but we also have a case that if there are areas in Named Communities that are lagging in potential EV or solar adoption, what would it look like if they were higher? So, we're adopting those forecasts in this scenario as well. At the end of the day, this scenario is pushing the envelope on things that we could do to maximize Customer Benefit Indicators, but without taking into account cost. So, this model or this portfolio won't be looking at costs, they'll be just focused on the extremes of those Customer Benefit Indicators.

Molly Morgan (UTC): OK. And in the second sentence, this says this portfolio will exclude should that be included or what? Why does that say exclude?

James Gall: Exclude non-Washington sited resources, I guess. Maybe it should be a period after that, but yeah.

Molly Morgan (UTC): Period. Yeah, because the other ones, he said, are included. So yeah, maybe just clarity there.

James Gall: Yes.

Molly Morgan (UTC): Right.

James Gall: So, we’re excluding non-Washington air emitting resources as well. For example, here's the example of that. Obviously, we're trying to minimize carbon emitting resources in Washington from CETA, but there are non-carbon emitting generation sources that have for example NOx emissions. So, if you're trying and we have NOx emissions for example, as CBI, so this scenario would exclude a NOx emitting resource from selection. That way it would show because if you have, for example we had ammonia turbines in our last IRP, that still has NOx. Our CBI for NOx emissions declined but it didn't go to zero. So, in this scenario that NOx emission CBI would go to zero, but at a higher cost.

Molly Morgan (UTC): Got it. And just to follow up on, OK, thank you. This scenario would show kind of a combination of maximizing all of these CBIs at once. OK.

James Gall: Correct. All CBIs to the greatest extent possible, ignoring cost.

Molly Morgan (UTC): Got it.

James Gall: Yeah, that's a couple of questions. One of them? What are the Washington CCA assumptions used in these portfolios? And I'll let you answer that, and I'll give you the other. OK. Lori, you have to make sure I can get these right. For Washington, we get free allowances for the CCA compliance. So, for our plants, at least through 2031, we don't include any CCA costs after 2031. The law basically does not say how emissions will be allocated. We will get some free allowances. We may have to auction them back. We don't know essentially what happens after 2031, so any generator in the State of Washington, or imports into the State of Washington, in our modeling will have a portion of the CCA cost if it's out of state that's attributed to Washington, it will have a CCA cost adder. Any resource in the State of Washington after 2031 will have a CCA price adder on its dispatch.

James Gall: We also have resources that in our model, from a price forecasting point of view, have carbon emissions that are in state and don't get free allowances. There's a couple of those plants. So, the price forecast essentially does not include a CCA adder for inside of the state generators until 2031. But before 2031, there is a price adder for importing into the state. So, what we've done in our price forecasting is we've created two prices. We have an import into Washington price, and we have an Avista located price that does not include that carbon emission until you actually import it into the state. So, effectively before 2031, there's no carbon pricing impacting our plant dispatch unless it's being imported into the State of Washington. Hopefully that answers it.

Avista: In her second question, what is the WRAP assumption used in these portfolios given the fact that this will not enter into binding phase until summer of 2027?

James Gall: Yeah, good question. We are not going to be using WRAP planning margins in any of these portfolios except for the number 12. So, #12, we'll use the WRAP planning margin beginning in 2027, but all the rest of the portfolios, unless they're a resource adequacy portfolio, will use a planning margin that we will be identifying through our resource adequacy modeling that we will share in about a month. What about QCCs? QCCs we will be using WRAP QCCs. For those of you don't know what QCC is, it's a qualifying capacity credit. For each resource in the WRAP, that's included in the WRAP footprint, is given a percentage of its capacity that qualifies towards meeting the monthly peak value. We'll be using those QCC values for all our resources and will be using the same accounting methodology that WRAP uses as well, but we will not be using the WRAP planning margin except for scenario #12. We will be calculating our own planning margin based on the WRAP accounting.

James Gall: Are there any portfolios you don't see on this list that you feel that we should be looking at? If something does come to mind, please let us know. Let's create a deadline by the end of the week to get us the new portfolios that you're considering, the reason why we need to start to cut this off is one for load forecasting. We're working with AEG on doing any adjustments to the load forecast for these scenarios, so we'll have to make sure we can make this a manageable request for them to do some work on the load forecasting side. And we also have to be able to build the assumptions into our models for selecting resources. So, if something comes to mind before the end of week, let us know and then we'll let you know if that's something we can do or if it'll have to be for the next IRP depending on how challenging the request is correct. That's a hand up, go ahead Fred.

Fred Heutte: Yeah. The one that I'm thinking about that might be worth doing is something about a high gas price sensitivity. I'm thinking about why this would matter. It might change the relative mix of resources. It would perhaps have a little bit of an incremental effect on demand. Depressed demand from pricing effects and also might change market dispatch across the western market. I can't recall exactly what your gas projection is, but the prospect of quite a bit higher gas prices for a variety of reasons; eventual decline in shale gas, LNG exports, it's at least worth a look, I think.

James Gall: Yep, we will. We do have that on the list that's in our market price sensitivity now. It's I guess a question of if it's high enough for you, but we will be modeling a higher forecast, I think it's the 75th percentile of our forecast. We have an expected forecast, and we have 300 different prices that create that distribution and it's I believe this 75th percentile. I think it's about $2.00 higher on average than our expected case.

Fred Heutte: OK, so now I guess I've been looking right at it and didn't quite figure it out. But you know, in these scenarios, all have sensitivities that represent that. OK, now I got it.

James Gall: Any other questions? Alright. We have a deadline by the end of the week for any new ideas. And again, if you have any ideas on anything IRP related, feel free to send John or myself an email or give us a call. Our next TAC meeting will be in two weeks, and we'll cover energy efficiency, demand response potential and anything else for the order. I’m getting a lot of head nods. We thank you for participating today. We appreciate the questions again, like to thank AEG for the good work on the load forecast. We've been working on that project for at least nine months now and we'll see how this works going in the future. Thank you again. Have a great day and for those of you that will be on the gas TAC meeting tomorrow, we'll see you tomorrow. OK.

Dean Spratt: Thanks everyone.

2025 Electric Integrated Resource Plan
Technical Advisory Committee Meeting No. 6 Agenda
Tuesday, May 7, 2024
Virtual Meeting – 8:30 am to 10:00 am PTZ

Topic	**Staff**
Introductions	John Lyons
Conservation Potential Assessment	AEG
Demand Response Potential Assessment	AEG

Microsoft Teams meeting

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2025 IRP TAC 6 Introductions

John Lyons, Ph.D.
Technical Advisory Committee Meeting No. 6
May 7, 2024

Today's Agenda

Introductions, John Lyons

Conservation Potential Assessment, AEG

Demand Response Potential Assessment, AEG

Remaining 2025 Electric IRP TAC Schedule

- **TAC 7: May 21, 2024: 8:30 to 10:00 (PTZ)**
  - Variable Energy Resource Study
  - Portfolio/Market Scenarios

- **TAC 8: June 4, 2024: 8:30 to 10:00 (PTZ)**
  - Load & Resource Balance and Methodology
  - Loss of Load Probability Study
  - New Resources Options Costs and Assumptions

- **TAC 9: June 18, 2024: 8:30 to 10:00 (PTZ)**
  - IRP Generation Option Transmission Planning Studies
  - Distribution System Planning within the IRP & DPAG update

- **Technical Modeling Workshop: June 25, 2024: 9:00 am to 12:00pm (PTZ)**
  - PRiSM Model Tour
  - ARAM Model Tour
  - New Resource Cost Model

Remaining 2025 Electric IRP TAC Schedule

- **TAC 10: July 16, 2024: 8:30 to 10:00 (PTZ)**
  - Preferred Resource Strategy Results
  - Washington Customer Benefit Indicator Impacts
  - Resiliency Metrics

- **TAC 11: July 30, 2024: 8:30 to 10:00 (PTZ)**
  - Preferred Resource Strategy Results
  - Portfolio Scenario Analysis
  - LOLP Study Results

- **TAC 12: August 13, 2024: 8:30 to 10:00 (PTZ)**
  - Preferred Resource Strategy Results (continued)
  - Portfolio Scenario Analysis (continued)
  - LOLP Study Results (continued)
  - QF Avoided Cost

- **September 2, 2024- Draft IRP Released to TAC.**

- **Virtual Public Meeting- Natural Gas & Electric IRP (September 2024)**
  - Recorded presentation
  - Daytime comment and question session (12pm to 1pm- PST)
  - Evening comment and question session (6pm to 7pm- PST)

AEG
APPLIED ENERGY GROUP

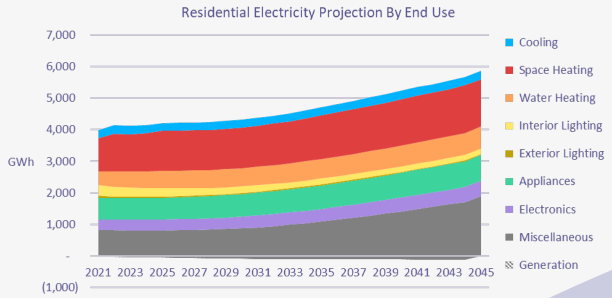
Avista Energy Electric CPA Draft Results

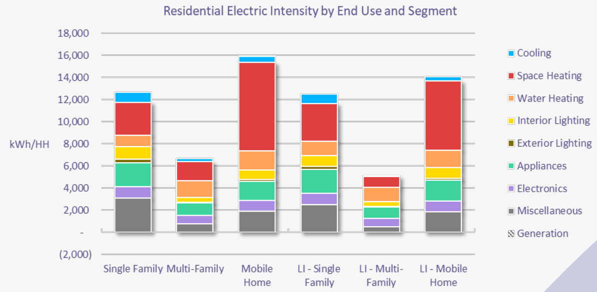
Prepared for Avista Energy TAC Meeting 5/7/2024

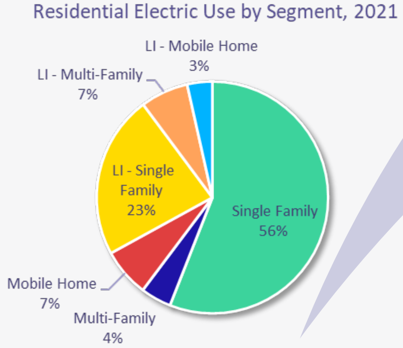
CPA Objectives

- Assess a broad set of technologies to identify long-term energy efficiency and demand response potential in Avista's Washington and Idaho service territories to support:
  - Integrated Resource Planning
  - Portfolio target-setting
  - Program development
- Provide information on costs and seasonal impacts of conservation to compare to supply-side alternatives
- Understand differences in energy consumption and energy efficiency opportunities by income level
- Ensure transparency into methods, assumptions, and results

EE Modeling Approach







Market Characterization

- Baseline studies
- Utility data
- Secondary data

Baseline Projection

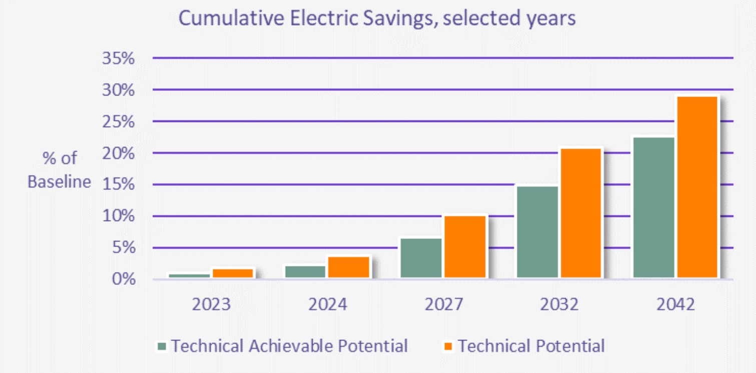
- Utility forecasts
- Standards and building codes

Identify Demand-Side Resources

- EE equipment
- EE measures
- Emerging tech.

Potential Estimation

- Technical
- Achievable Tech.
- Economic screen in IRP



Major Modeling Inputs and Sources

Avista foundational data

- Avista power sales by schedule
- Current and forecasted customer counts
- Retail price forecasts by class

Survey data showing presence of equipment

- Avista: Residential customer survey conducted in 2013
- NEEA: Residential and Commercial Building Stock Assessments (RBSA 2016 and CBSA 2019)
- US Energy Information Administration: Residential, Commercial, and Manufacturing Energy Consumption Surveys (RECS 2020, CBECS 2018, and MECS 2015)

Technical data on end-use equipment costs and energy consumption

- Regional Technical Forum workbooks
- Northwest Power and Conservation Council's 2021 Power Plan workbooks
- US Department of Energy and ENERGY STAR technical data sheets
- Energy Information Administration's Annual Energy Outlook/National Energy Modeling System data files

State and Federal energy codes and standards

- Washington State Energy Code
- Idaho Energy Code
- Federal energy standards by equipment class

Market trends and effects

- RTF market baseline data
- Annual Energy Outlook purchase trends (in base year)

Appendix A

Forecast Update – DOE HPWH Standard

New efficiency requirements take effect in 2029

- Forecast shown at the time of the previous TAC meeting (April 23rd) did not include the new water heater standard published on April 30th

- Ordinarily, forecast assumptions would already be frozen for this cycle, however this standard has a huge impact on both baseline and a major savings measure within the CPA

Impacts

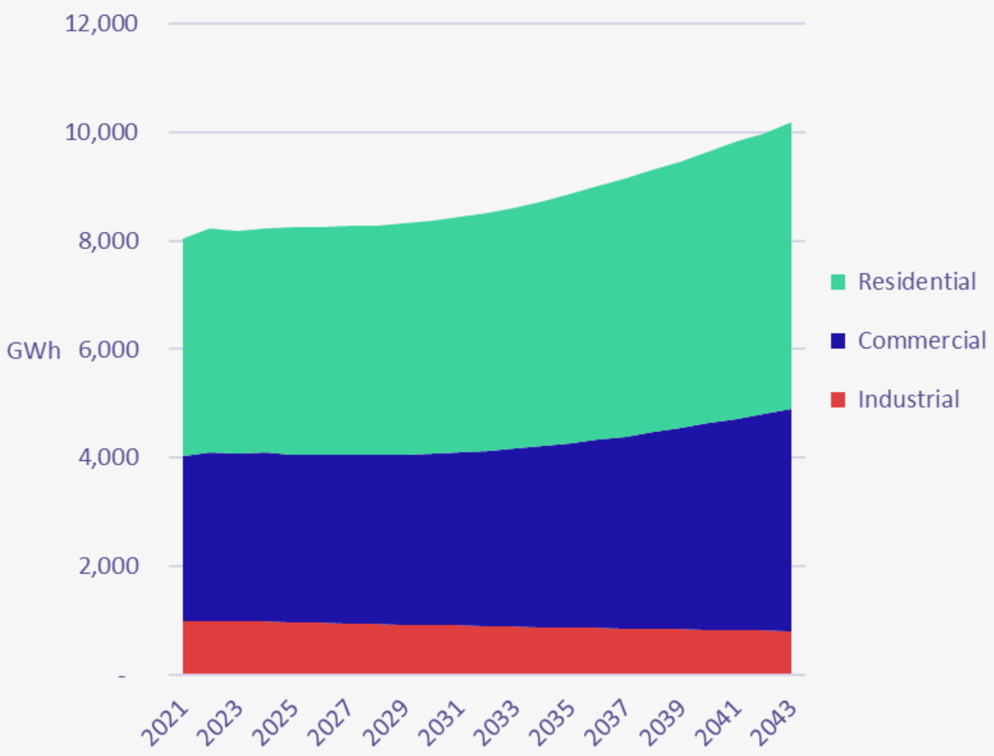
- Reduces consumption growth by ~297 GWh (33.9 aMW) by 2045
- Reduces Peak growth by ~29 MW in Summer and ~52 MW in Winter (est.)
- Delays Winter Peak overtake of Summer by about 10 years
- Moves majority of DHW savings into baseline instead of CPA

Water Heater Size	Efficiency Requirement
20 to <55 Gallons	UEF 2.3 (CCE Tier 1)
> 55 gallons	UEF 2.5 (CCE Tier 2)

Baseline Forecast - Updated

Washington + Idaho Combined

- Customer growth and electrification from natural gas systems combine for a projected 30% increase in electric loads over the forecast period, or 1.12% annually
- Growth from electrification is ~2,400 GWh
- Includes:
  - Projected cooling and heating degree days according to climate trends in Avista's territory
  - Market efficiency impacts (such as trends toward LED lighting as baseline), which are saving over 1,400 GWh in the forecast period compared to minimum codes & standards
  - Solar and EV projections from the DER study in Washington (Avista projections for Idaho)
  - DOE HPWH standard starting in 2029



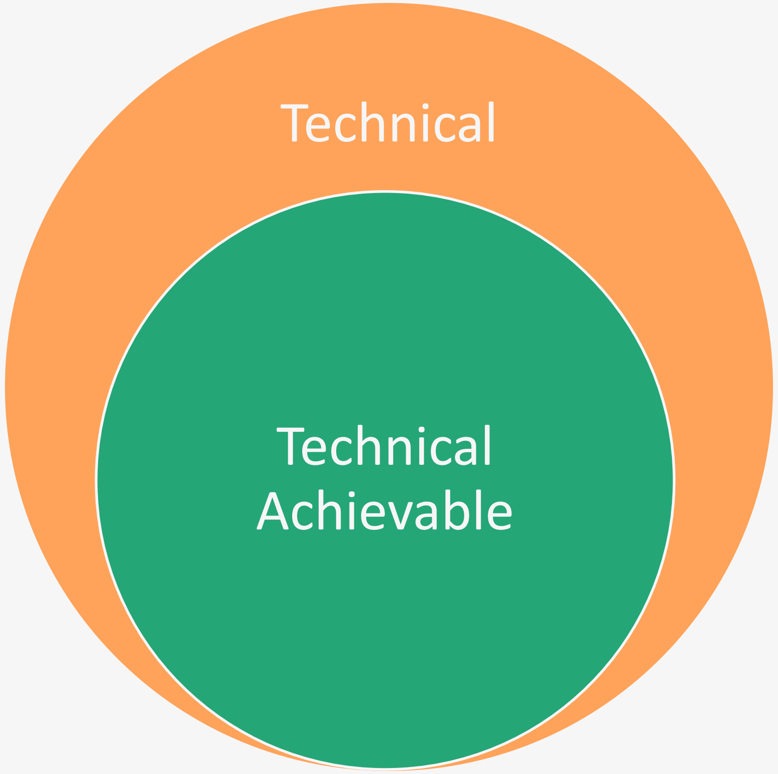
Levels of Savings Estimates

NW Power Council Methodology

This study develops two sets of estimates:

- Technical potential (TP): upper bound on potential, assuming all of the most energy efficiency opportunities are adopted without consideration of cost or customer willingness to participate.
- 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, but does not consider cost-effectiveness

In addition to these estimates, the study produces cost data for the Total Resource Cost (TRC) and Utility Cost Test (UCT) perspectives that can be used by Avista's IRP process to select energy efficiency measures in competition with other resources (see next slide)



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**
  - **Previous Power Plans assumed a maximum achievability of 85%**
  - **AEG has aligned assumptions with the 2021 Plan and measures such as lighting reach greater than 85%**
- Note that Council ramp rates are agnostic to delivery to acquisition mechanism and include potential that may be realized through utility DSM programs, regional initiatives and market transformation, or enhanced codes and standards

Measures examples over 85% Achievability:

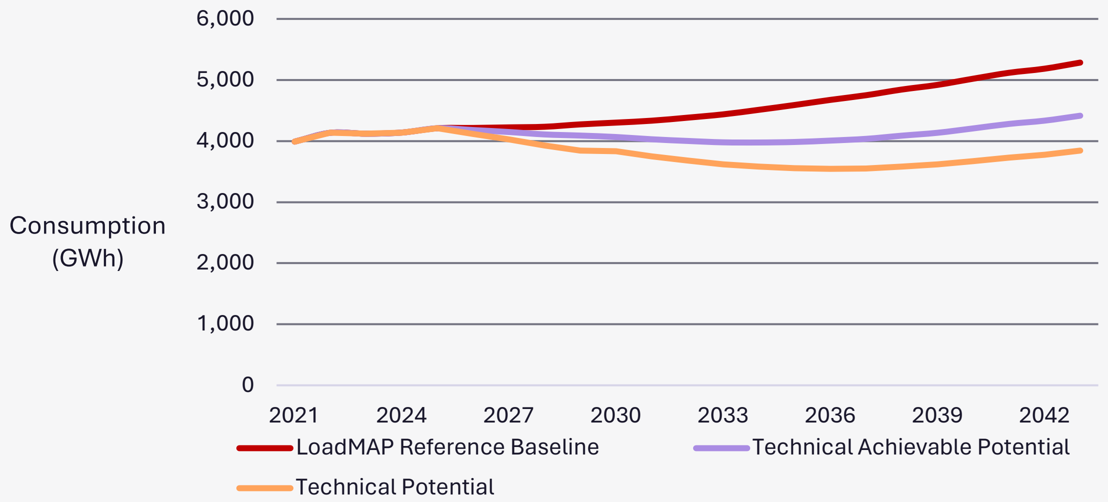
- All Lighting
- Washers/Dryers
- Dishwashers
- Refrigerators/Freezers
- Circulation Pumps
- Thermostats
- C&I Fans

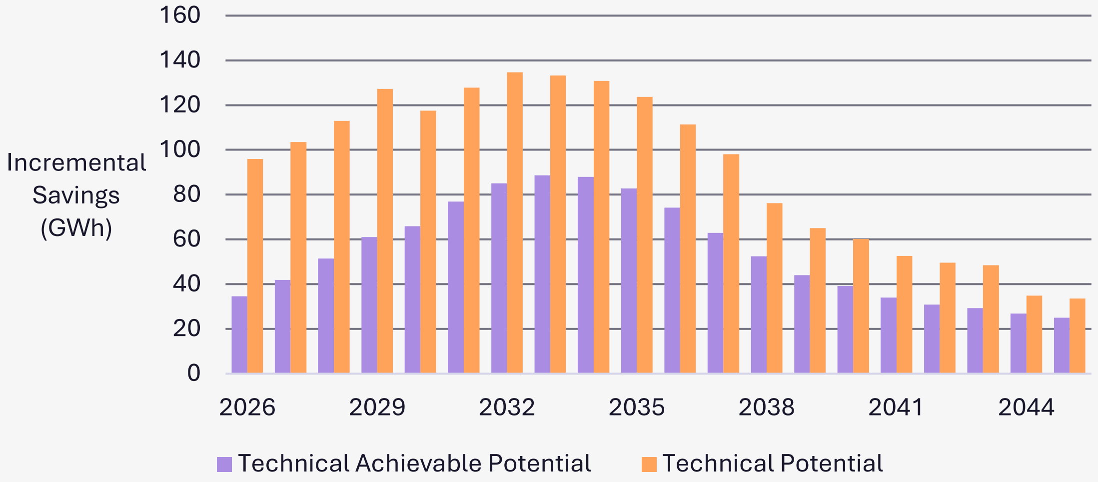
Residential Electric Draft Results

Appendix A

Residential EE Potential

- Draft results indicate energy savings of 1.0% of baseline consumption per year are Technically Achievable.
  - 76 GWh (8.6 aMW) in next biennial period (2026-2027)
  - 604 GWh (69.0 aMW) by 2035
  - 890 GWh (101.6 aMW) by 2045
- Top measures in 2045 include:
  - Heat Pump Water Heaters
  - ENERGY STAR 7.0 Windows
  - Level 2 Electric Vehicle Chargers

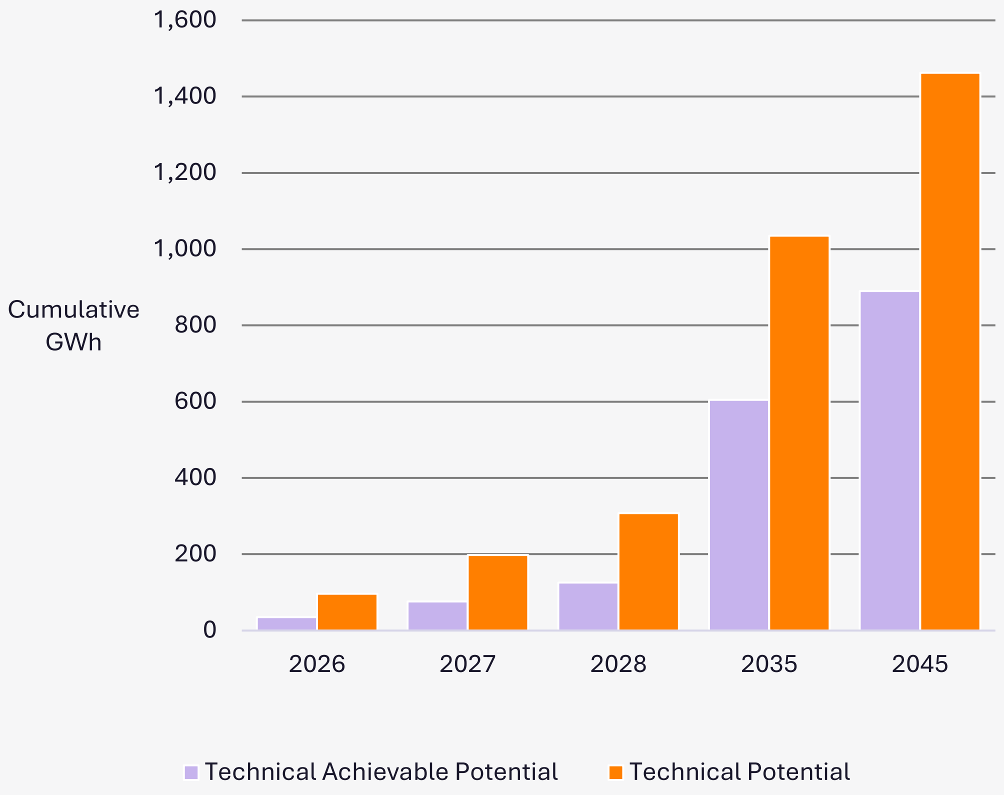




Residential EE Potential

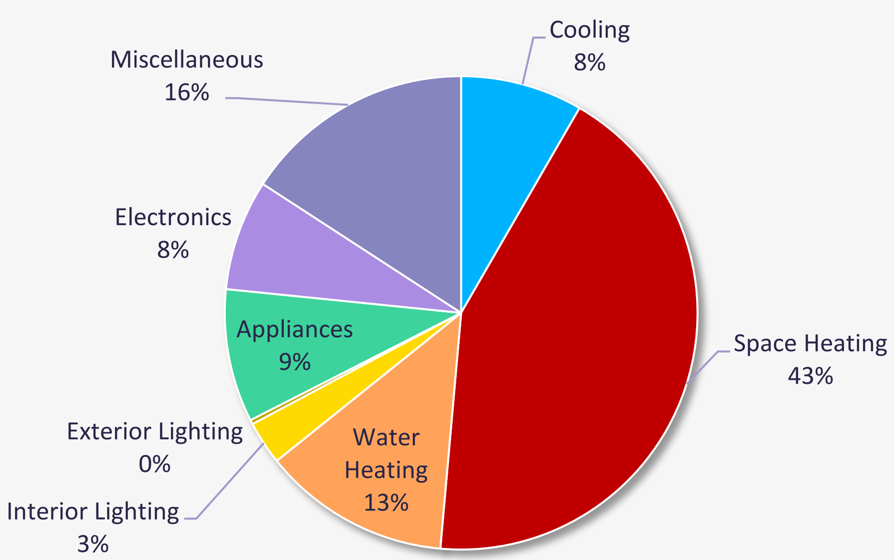
WA and ID

Summary of Energy Savings (GWh), Selected Years	2026	2027	2028	2035	2045
Reference Baseline	**4,215**	**4,224**	**4,234**	**4,590**	**5,432**
Washington	*2,798*	*2,804*	*2,810*	*3,063*	*3,670*
Idaho	*1,417*	*1,421*	*1,424*	*1,527*	*1,763*
Cumulative Savings (GWh)					
Technical Achievable Potential	35	76	125	604	890
Washington	*23*	*50*	*83*	*413*	*617*
Idaho	*12*	*26*	*42*	*191*	*274*
Technical Potential	96	198	307	1,035	1,462
Energy Savings (% of Baseline)					
Technical Achievable Potential	0.8%	1.8%	3.0%	13.2%	16.4%
Washington	*0.8%*	*1.8%*	*3.0%*	*13.5%*	*16.8%*
Idaho	*0.8%*	*1.8%*	*3.0%*	*12.5%*	*15.5%*
Technical Potential	2.3%	4.7%	7.3%	22.6%	26.9%
Incremental Savings (GWh)					
Technical Achievable Potential	35	42	51	83	25
Washington	*23*	*28*	*34*	*58*	*17*
Idaho	*12*	*14*	*17*	*25*	*8*
Technical Potential	96	103	113	124	34



Residential EE Technical Achievable Potential

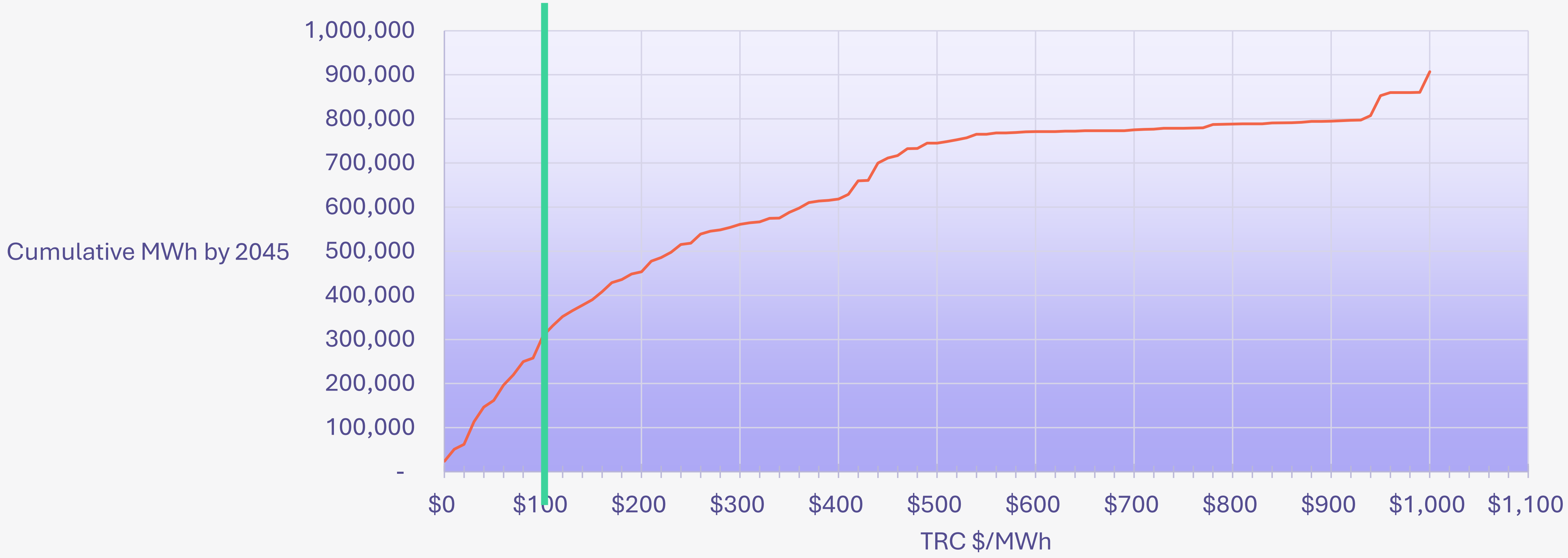
Top Measures Summary (ID & WA Combined)



Rank	Measure / Technology	2045	% of Total	TRC LCOE ($/kWh)
1	Windows - High Efficiency (ENERGY STAR 7.0)	88,239	9.9%	$0.43
2	Water Heater (<= 55 Gal) - NEEA Tier 5 Heat Pump (CCE 3.5)	62,528	7.0%	$0.07
3	Electric Vehicles - Level 2	51,493	5.8%	$0.16
4	Windows - High Efficiency (Triple Pane) - U-0.17	35,246	4.0%	$0.56
5	Ducting - Repair and Sealing	33,947	3.8%	$0.14
6	Insulation - Wall Sheathing - R-19	29,879	3.4%	$0.22
7	Advanced New Construction Designs	28,923	3.2%	$0.15
8	Engine Block Heater Controls	27,356	3.1%	$0.08
9	Home Energy Reports	25,919	2.9%	$0.05
10	Insulation - Ducting - R-8 Ducts (Retrofit up to code)	25,355	2.8%	$0.19
11	Building Shell - Air Sealing (Infiltration Control)	25,229	2.8%	$0.59
12	TVs - ENERGY STAR (9.0)	24,637	2.8%	$0.00
13	Clothes Dryer - UCEF 2.62/CEF 3.93 - ENERGY STAR 1.1/2028 Standard	23,742	2.7%	$0.24
14	Air-Source Heat Pump - SEER 16.0 / HSPF 9.2 | SEER2 15.2 / HSPF2 7.8 (ENERGY STAR 6.1)	21,888	2.5%	$0.48
15	HVAC - Maintenance and Tune-Up	21,227	2.4%	$0.50
16	Clothes Washer - CEE Tier 2	21,070	2.4%	$0.03
17	Ducting - Repair and Sealing - Aerosol	19,136	2.1%	$0.75
18	Home Energy Management System (HEMS)	16,881	1.9%	$0.30
19	Linear Lighting - LED 2035 (152 lm/W system)	16,063	1.8%	-$0.15
20	Insulation - Floor Upgrade - R-30	14,834	1.7%	$0.49
	Total of Top 20 Measures	**613,591**	**68.9%**	
	Total Cumulative Savings	**890,281**	**100.0%**	

Residential Supply Curve

A large portion of Technical Achievable Potential is very costly



Residential EE Technical Achievable Potential

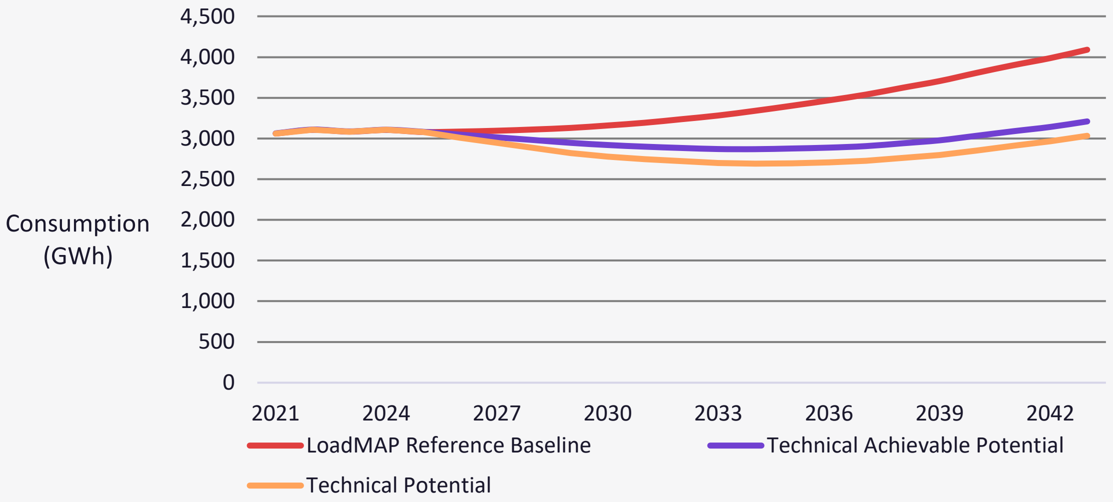
Major drivers and Changes from prior study

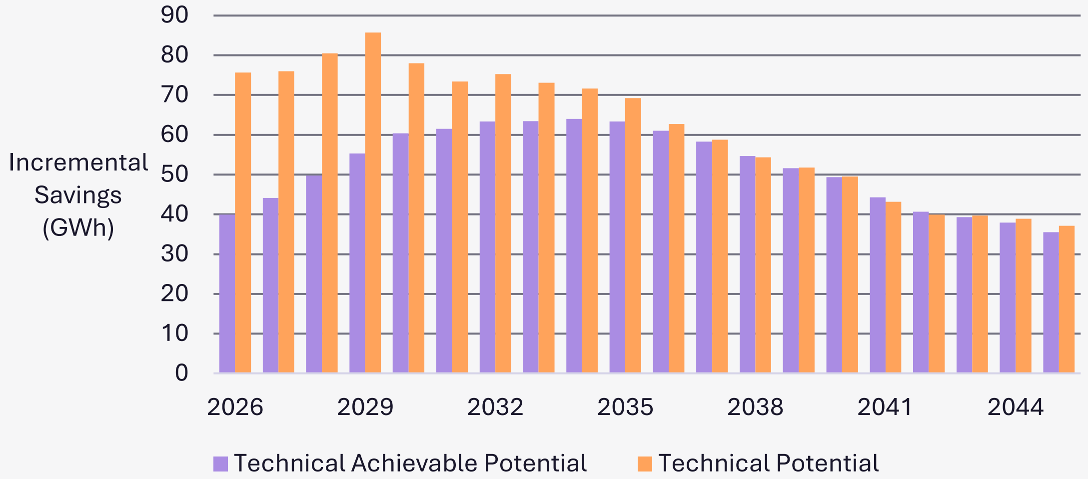
- Higher tiers of Heat Pump Water Heaters have been added since the prior study, which provides some opportunity even above the new federal standard
- Large growth of Electric Vehicles, particularly in Washington give more opportunity for EV Charger savings.
- Efficient Windows have higher ENERGY STAR requirement. AEG also updated base assumptions using latest Residential Energy Consumption Survey data.
- Connected Thermostats have lower savings than prior study due to lowered savings and lifetime assumptions in RTF workbooks.
- Updated the applicability of several measures to reflect new market data available (ie, RECS 2020), reduce overlapping applications, and better reflect market balance between competing non-equipment measures

Commercial Electric Draft Results

Commercial EE Potential

- Commercial Technical Achievable potential is slightly higher than Residential, roughly 1.1% of baseline per year
  - 84 GWh (9.5 aMW) in next biennial period (2026-2027)
  - 527 GWh (60.1 aMW) by 2035
  - 943 GWh (107.6 aMW) by 2045
- Top measures in 2045 include:
  - LED fixture replacements bundled with controls
  - Level 2 EV Chargers in WA
  - HVAC System upgrades

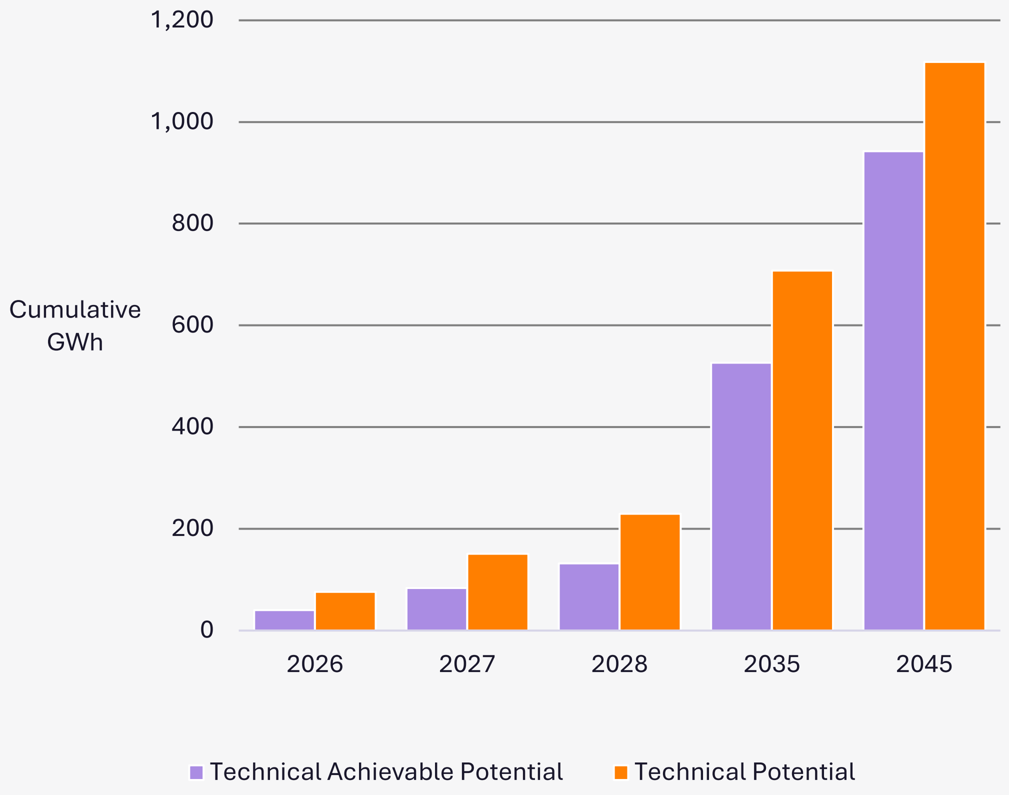




Commercial EE Potential

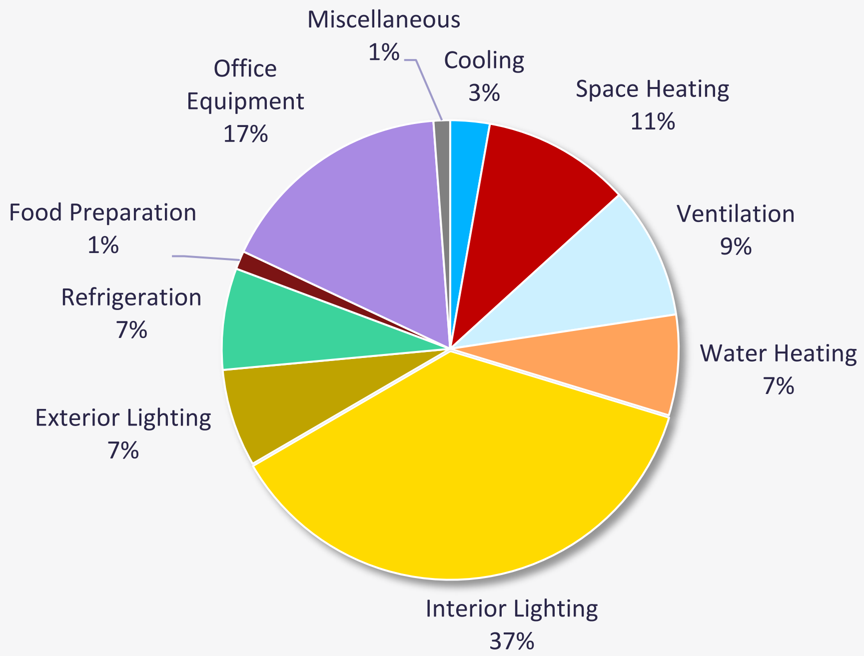
WA and ID

Summary of Energy Savings (GWh), Selected Years	2026	2027	2028	2035	2045
Reference Baseline	**3,086**	**3,097**	**3,112**	**3,403**	**4,274**
Washington	*2,049*	*2,056*	*2,066*	*2,305*	*3,034*
Idaho	*1,037*	*1,041*	*1,046*	*1,099*	*1,240*
Cumulative Savings (GWh)					
Technical Achievable Potential	40	84	132	527	943
Washington	*28*	*59*	*94*	*374*	*687*
Idaho	*12*	*24*	*38*	*153*	*256*
Technical Potential	76	151	229	708	1,118
Energy Savings (% of Baseline)					
Technical Achievable Potential	1.3%	2.7%	4.2%	15.5%	22.1%
Washington	*1.4%*	*2.9%*	*4.5%*	*16.2%*	*22.6%*
Idaho	*1.1%*	*2.3%*	*3.7%*	*13.9%*	*20.6%*
Technical Potential	2.5%	4.9%	7.4%	20.8%	26.2%
Incremental Savings (GWh)					
Technical Achievable Potential	40	44	50	63	36
Washington	*28*	*31*	*35*	*45*	*27*
Idaho	*12*	*13*	*14*	*18*	*9*
Technical Potential	76	76	80	69	37



Commercial Technical Achievable EE Potential

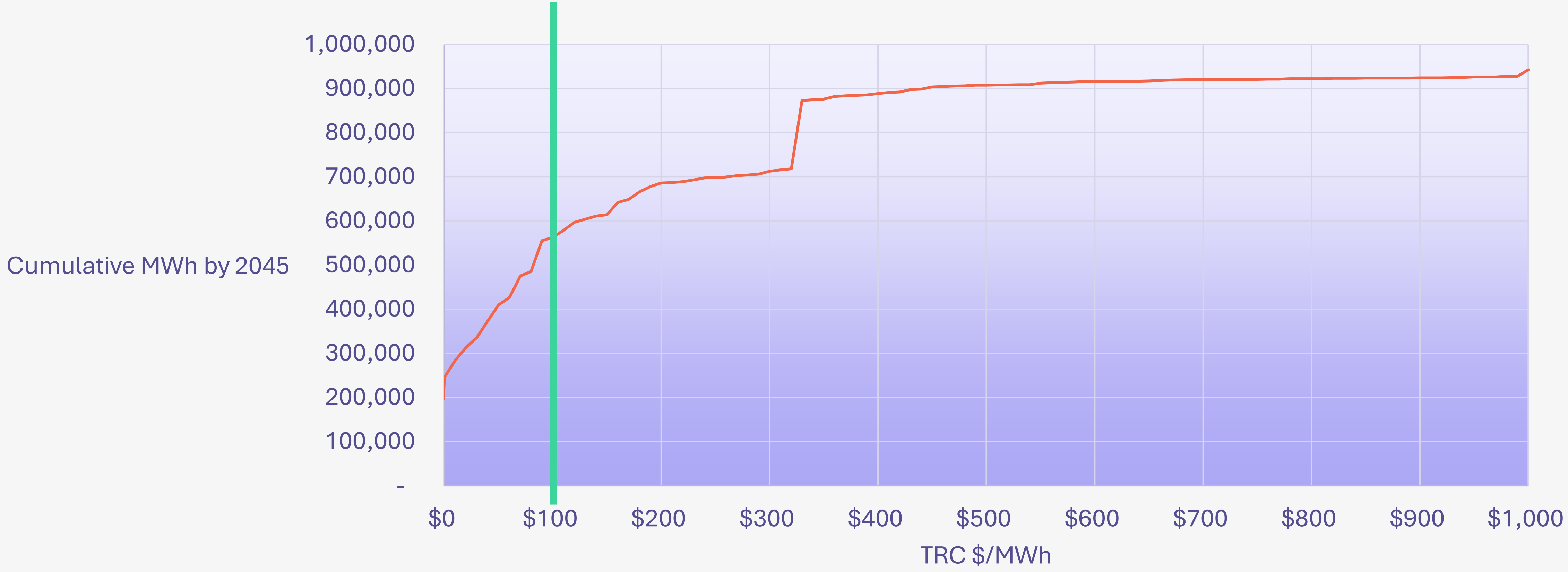
Top Measures Summary (ID & WA Combined)



Rank	Measure / Technology	2045	% of Total	TRC LCOE ($/kWh)
1	Linear Lighting – LED Fixture w/ Embedded Controls	176,027	18.7%	$0.00
2	Electric Vehicle Chargers - Level 2	157,586	16.7%	$0.31
3	Air-Source Heat Pump - IEER 20.3 / COP 3.7	42,489	4.5%	$0.42
4	Server - ENERGY STAR (4.0)	32,087	3.4%	$0.06
5	High-Bay Lighting - LED Fixtures w/ Embedded Controls	32,048	3.4%	$0.00
6	HVAC - Energy Recovery Ventilator	31,766	3.4%	$0.65
7	Ventilation - Variable Speed Control	31,620	3.4%	$4.32
8	Office Equipment - Advanced Power Strips	31,544	3.3%	$0.97
9	Water Heater - Pipe Insulation	31,097	3.3%	$0.08
10	Strategic Energy Management	30,256	3.2%	$0.18
11	HVAC - Dedicated Outdoor Air System (DOAS)	29,384	3.1%	$7.26
12	Desktop Computer - ENERGY STAR (8.0)	27,107	2.9%	$0.09
13	Refrigeration - Economizer Addition	26,547	2.8%	$0.10
14	Water Heater - Solar System	19,713	2.1%	$0.23
15	Ductless Mini Split Heat Pump	17,208	1.8%	$0.41
16	Retrocommissioning	11,752	1.2%	$0.19
17	Refrigeration - High Efficiency Compressor	8,700	0.9%	$4.03
18	Lodging - Guest Room Controls	8,615	0.9%	$0.17
19	Grocery - Display Case - LED Lighting	7,416	0.8%	$3.98
20	Area Lighting – LED Fixtures w/ Embedded Controls	7,297	0.8%	$0.00
	Total of Top 20 Measures	**760,259**	**80.6%**	
	Total Cumulative Savings	**942,676**	**100.0%**	

Commercial Supply Curve

A large portion of Technical Achievable Potential is very costly

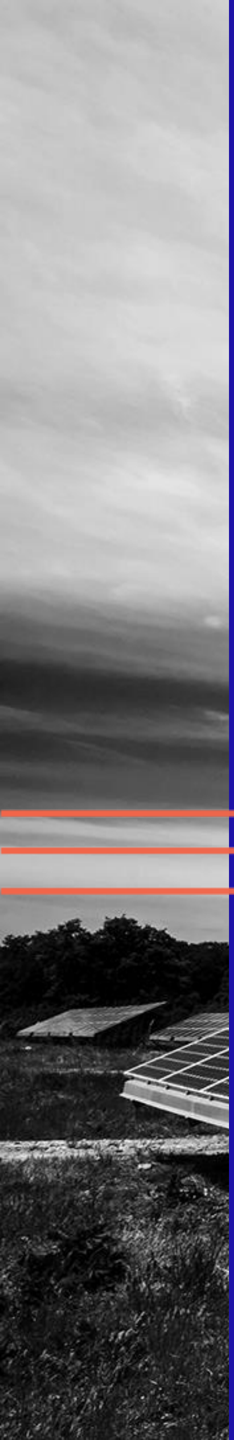


Commercial Technical Achievable EE Potential

Major drivers and Changes from prior study

- Updated lighting baseline to latest RTF market assumptions, actually increased available LED market
- Commercial EV fleets are a new modeling aspect, assumptions from DER study have a large population and RTF workbooks give valuable savings
- Updated applicability of shell and controls measures to latest market data and to avoid overlapping applications

Demand Response



DR Study Approach

Data Collection → Characterize the Market → Develop list of DR Options → Characterize the Options → Estimate Potential

Data Collection

Align with EE Potential Study
- Market Profiles

Secondary Sources
- Industry or regional reports
- Previous studies

Characterize the Market

Segmentation by Customer Class
- Residential
- General Service
- Large General Service
- Extra-Large General Service

Develop list of DR Options

Program Categories
- Conventional DLC
- Smart/Interactive DLC
- Curtailment
- Energy Storage
- Time-Varying Rates/Behavioral
- Ancillary Services

Characterize the Options

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

Estimate Potential

Technical Achievable Potential
- Potential for all programs regardless of cost and without consideration of dual participation

Achievable Potential
- Integrated program options without participant overlap

All Program Options

Conventional DLC	Central AC Water Heating
Smart/Interactive DLC	Grid-Interactive Water Heating Smart Thermostats (Cooling/Heating) Smart Appliances
Third Party Curtailment	Emergency Curtailment
Energy Storage	Battery Storage Thermal Storage
Time-Varying Rates/Behavioral	Behavioral Time-of-Use Electric Vehicle Time-of-Use Electric Vehicle V1G Telematics Variable Peak Pricing Peak Time Rebate

Current and Future DR Programs

Current DR Programs include:

- Electric Vehicle TOU
- Electric Vehicle V1G Telematics
- Third Party Contracts (one large industrial customer for 30 MW)

DR Pilot Programs beginning in June 2024:

- Time-of-Use Opt-in
- Peak Time Rebate

Pilot Programs will run for two years starting in 2024

- For DR potential, AEG ramps up pilot programs to steady state participation once pilot period has commenced

Advanced Metering Infrastructure (AMI) Assumptions

Some of the options require AMI

- DLC Options- No AMI Metering Required
- Dynamic Rates- require AMI for billing

Washington

- Assume 100% throughout study for all sectors

Idaho starting AMI rollout March 2027

- 36-month deployment schedule

Assumptions and Updates

Smart Thermostat - Heating Program will piggyback off Cooling Program

Shared Admin, Development, and O&M Costs

Grid-Interactive Water Heaters

Split results across water heater type- ER and HP

- Per-customer impacts reflect AEG-estimated grid-interactive water heater peak kW

Dynamic Rates

PTR - Residential and General Service

VPP - Large and Extra-Large General Services

EV TOU - General Service and Large General Service

TOU - Residential and General Service

Program Impact and Cost assumptions based on NWPCC 2021 Power Plan assumptions and DR program results from surrounding utilities

Diverged from these where appropriate

- Customization for Avista’s service territory
- Where NWPCC program information wasn’t available

Calculating DR Potential

DR Program Impact

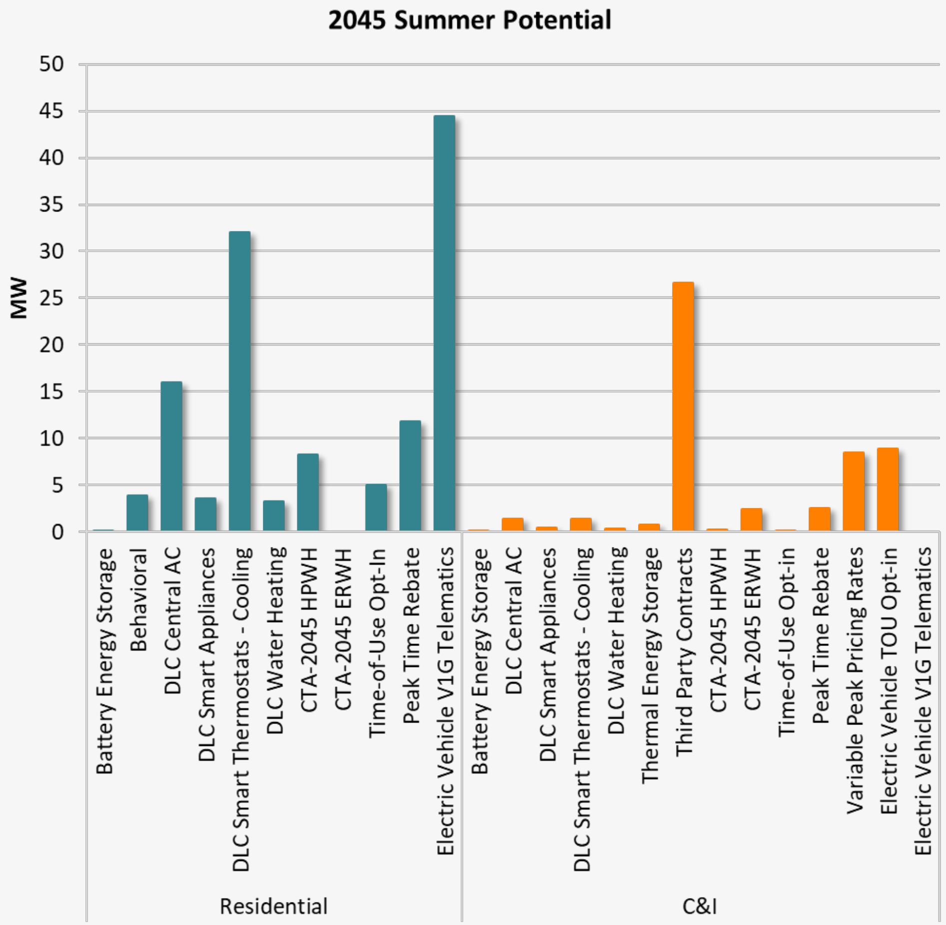
Per-Customer Peak Impact	Eligible Participants	Participation Rate	Equipment Saturation

Draft DR Results

Appendix A

Summer DR Potential - Technical Achievable

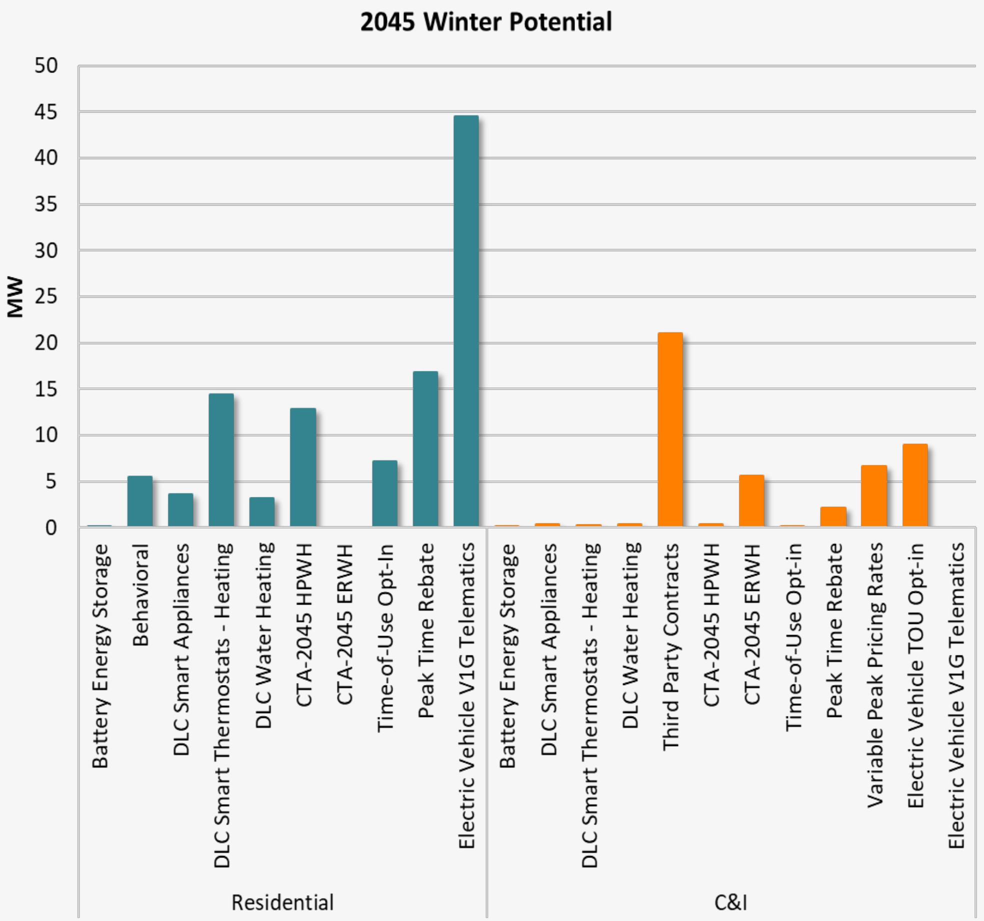
Summer TAP	2026	2027	2028	2035	2045	2045 from 2022 CPA
Baseline Forecast (Summer MW)	**1,802**	**1,792**	**1,769**	**1,958**	**2,215**	**1,986**
Battery Energy Storage	0.0	0.0	0.0	0.1	0.1	5.5
Behavioral	1.1	1.8	2.2	3.4	3.8	4.4
CTA-2045 HPWH	0.0	0.0	0.1	3.5	8.5	1.0
CTA-2045 ERWH	0.1	0.2	0.5	4.9	2.4	5.3
DLC Central AC	1.2	3.7	8.7	14.3	17.4	15.4
V1G Telematics	0.9	2.8	4.7	16.4	44.5	29.3
DLC Smart Appliances	0.3	0.9	2.2	3.5	4.0	3.7
DLC Smart Thermostats - Cooling	2.3	7.0	16.6	27.4	33.4	30.7
DLC Smart Thermostats - Heating	-	-	-	-	-	-
DLC Water Heating	0.3	0.8	1.9	3.0	3.5	2.4
Electric Vehicle TOU Opt-in	0.1	0.2	0.4	2.7	8.9	4.7
Thermal Energy Storage	0.0	0.1	0.3	0.7	0.7	0.8
Third Party Contracts	7.9	12.5	17.0	24.1	26.6	29.1
Time-of-Use Opt-in	0.2	0.5	0.9	4.5	5.1	10.3
Time-of-Use Opt-out	7.4	6.9	6.6	2.7	3.1	39.6
Variable Peak Pricing Rates	0.6	1.8	4.1	7.6	8.4	5.4
Peak Time Rebate	0.3	0.8	2.3	12.5	14.3	15.5



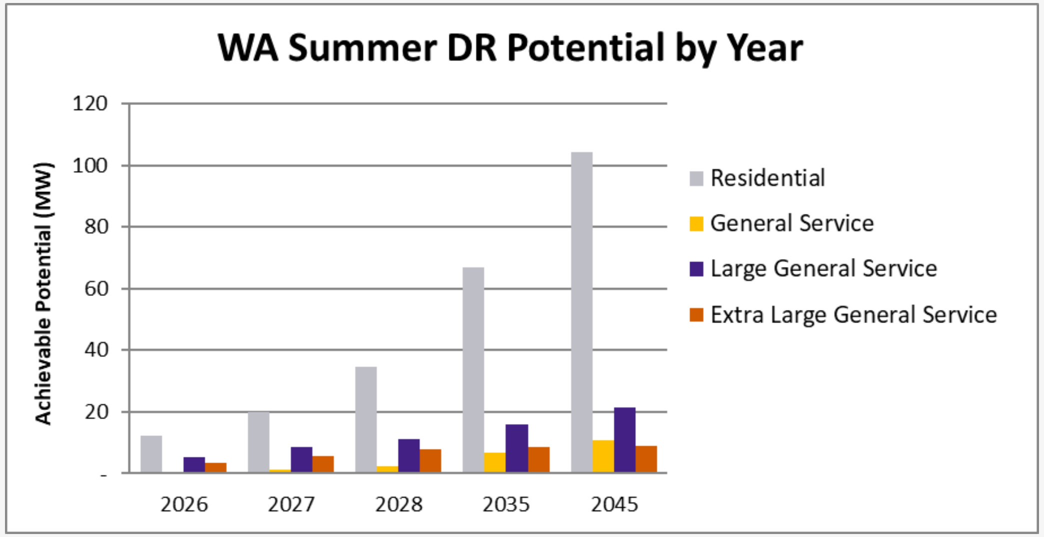
Winter DR Potential – Technical Achievable

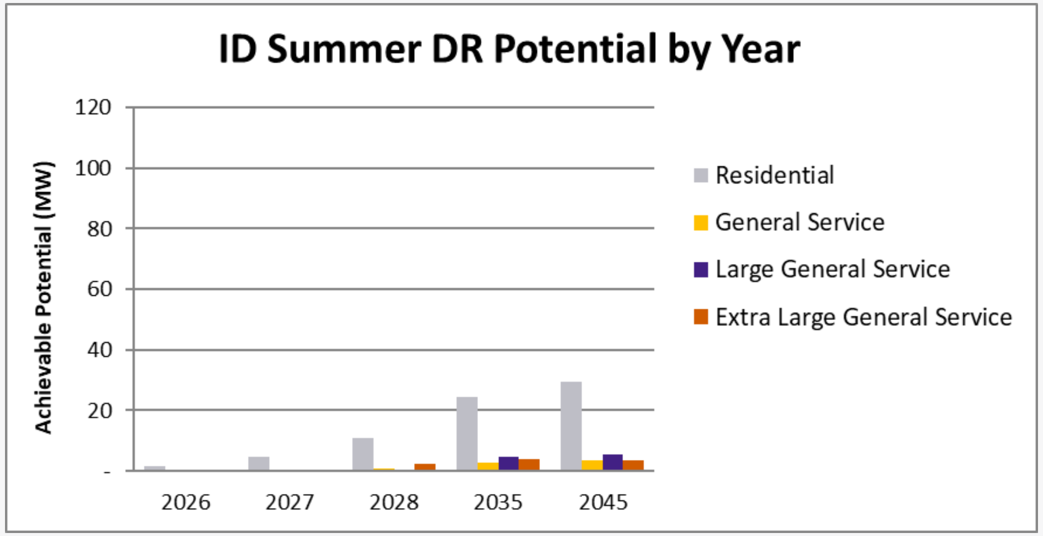
Appendix A

Winter TAP	2026	2027	2028	2035	2045	2045 from 2022 CPA
Baseline Forecast (Winter MW)	**1,819**	**1,835**	**1,817**	**1,963**	**2,375**	**1,936**
Battery Energy Storage	0.0	0.0	0.0	0.1	0.1	5.5
Behavioral	1.4	2.3	2.9	4.7	5.5	4.2
CTA-2045 HPWH	0.0	0.0	0.1	5.5	13.2	2.6
CTA-2045 ERWH	0.1	0.5	1.1	11.4	5.6	5.7
DLC Central AC	-	-	-	-	-	-
V1G Telematics	0.9	2.8	4.7	16.4	44.5	29.3
DLC Smart Appliances	0.3	0.9	2.2	3.5	4.0	3.7
DLC Smart Thermostats - Cooling	-	-	-	-	-	-
DLC Smart Thermostats - Heating	0.8	2.5	6.0	10.9	14.6	5.8
DLC Water Heating	0.3	0.8	1.9	3.0	3.5	2.4
Electric Vehicle TOU Opt-in	0.1	0.2	0.4	2.7	8.9	4.7
Thermal Energy Storage	-	-	-	-	-	-
Third Party Contracts	5.8	9.3	12.6	16.8	21.0	29.6
Time-of-Use Opt-in	0.2	0.6	1.2	6.2	7.2	9.9
Time-of-Use Opt-out	9.6	9.0	8.5	3.6	4.3	38.3
Variable Peak Pricing Rates	0.4	1.3	3.0	5.3	6.6	5.5
Peak Time Rebate	0.3	1.0	2.9	16.0	18.9	14.8

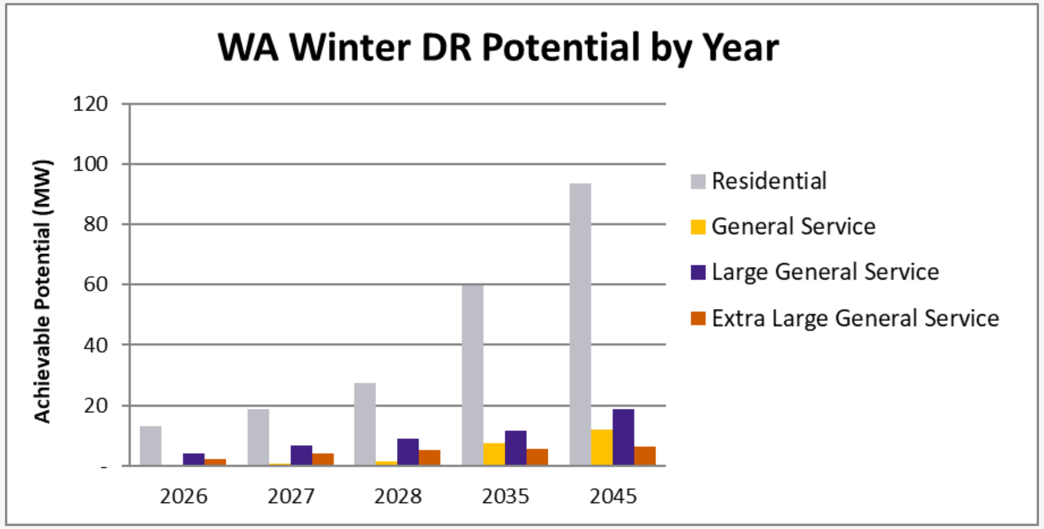


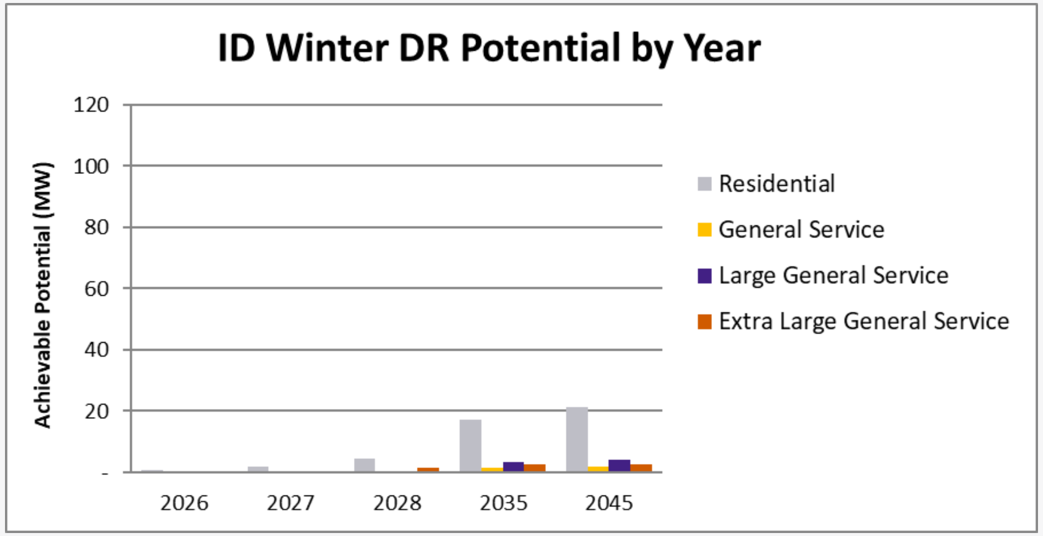
Summer DR Potential





Winter DR Potential





Developing Demand Response Resource Costs

- DR Programs have both upfront and ongoing costs according to the table below
- DR costs are amortized over 10 years to allow programs time to fully ramp up
- Levelized costs are presented in $/kW-year

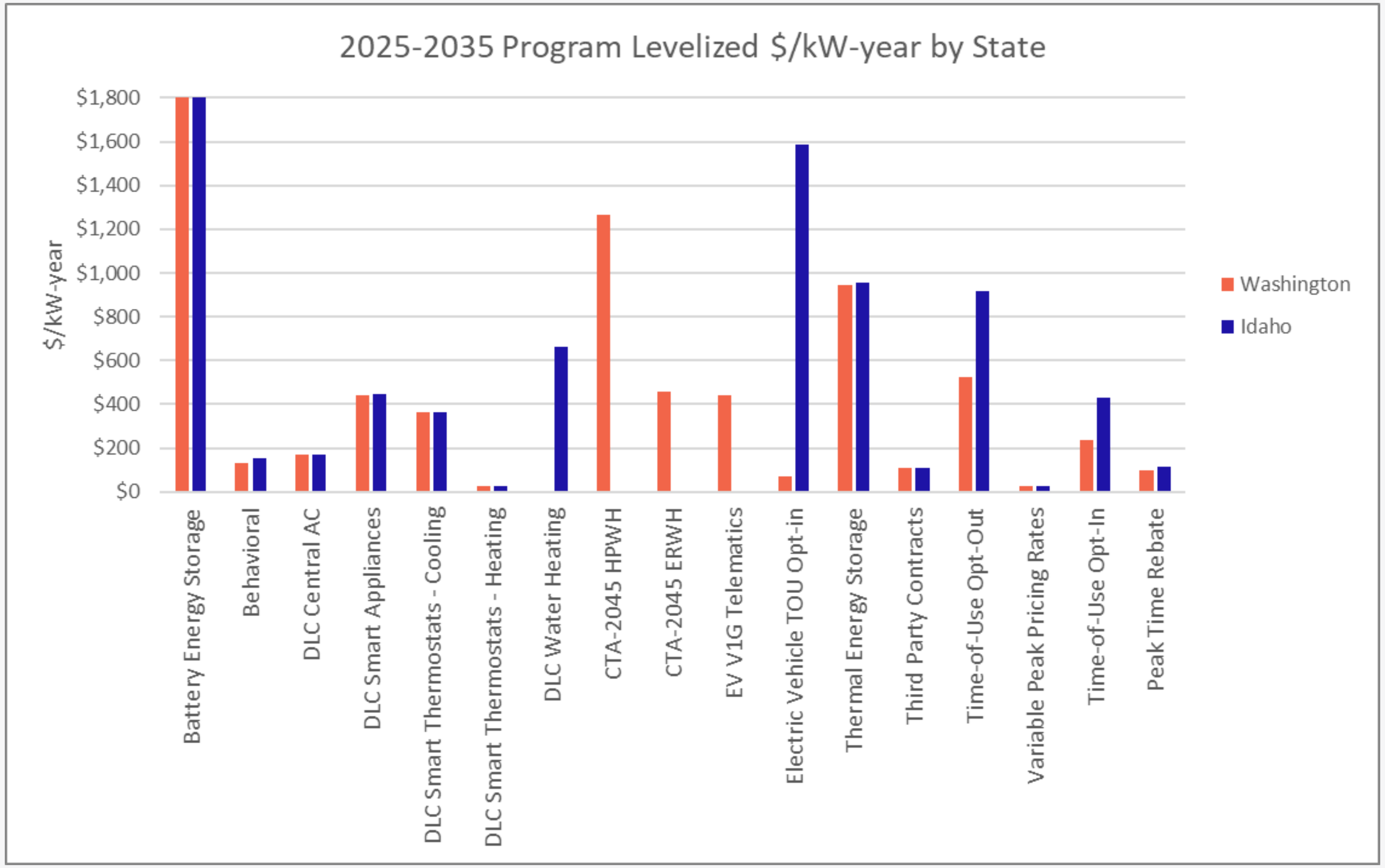
One-Time Fixed Costs	One-Time Variable Costs	Ongoing Costs
Program Development Costs ($/program)	Equipment Costs ($/participant)	Administrative Costs (shared costs)
	Marketing Costs ($/participant)	O&M Costs ($/participant)
		Incentives ($/participant or $/kW)

Example: Residential Grid-Interactive Electric Resistance Water Heaters

Cost Type	Unit	Cost
Development	$/program	$34,000
Administrative	$/program/yr	$40,800
O&M	$/participant/yr	$0
Marketing	$/new participant	$60
Equipment	$/new participant	$170
Incentive	$/program/yr	$24

Program Levelized Costs by State

Max Levelized $ / kW-year @ Gen 2025-2035	Washington	Idaho
Battery Energy Storage	$2,446.83	$6,046.75
Behavioral	$128.84	$150.75
DLC Central AC	$169.62	$169.82
DLC Smart Appliances	$442.50	$446.16
DLC Smart Thermostats - Cooling	$364.56	$363.45
DLC Smart Thermostats - Heating	$26.47	$26.57
DLC Water Heating		$660.70
CTA-2045 HPWH	$1,263.36	
CTA-2045 ERWH	$455.26	
EV V1G Telematics	$442.49	
Electric Vehicle TOU Opt-in	$70.05	$1,585.73
Thermal Energy Storage	$944.90	$954.97
Third Party Contracts	$108.54	$108.67
Time-of-Use Opt-Out	$524.41	$918.04
Variable Peak Pricing Rates	$24.98	$26.09
Time-of-Use Opt-In	$235.01	$431.20
Peak Time Rebate	$100.15	$114.20



Next Steps

- AEG still working on Industrial modeling, planned to wrap up by May 10th
- Working IRP Inputs for EE and DR due to Avista by May 17th

Thank You.

Phone: 631-434-1414

AEG

APPLIED ENERGY GROUP

Avista 2025 Electric IRP TAC 6 Meeting Notes May 7, 2024

Attendees:
Sofya Atitsogbe, UTC; Shawn Bonfield, Avista; Kim Boynton, Avista; Annette Brandon, Avista; Terrence Browne, Avista; Kate Brouns, Renewable NW; Michael Brutocao, Avista; Logan Calen, City of Spokane; Katie Chamberlain, Renewable NW; Kelly Dengel, Avista; Joshua Dennis, UTC; Mike Dillon, Avista; Michele Drake, Avista; Jean Marie Dreyer, Public Counsel; Michael Eldred, IPUC; Ryan Finesilver, Avista; Grant Forsyth, Avista; James Gall; Avista; Bill Garry; Konstantine Geranios, UTC; Amanda Ghering, Avista; Michael Gump, Avista; Leona Haley, Avista; Tom Handy, Whitman County Commission; Lori Hermanson, Avista; Mike Hermanson, Avista; Andy Hudson, Applied Energy Group; Rachelle Humphrey, Avista; Erin Heuvel, Avista; Dave Lockhart, CHC Hydro; Kimberly Loskot, IPUC; John Lyons, Avista; Patrick Maher, Avista; Joel Nightingale, UTC; Tomas Morrissey, NWPCC; Fuong Nguyen, Applied Energy Group; Austin Oglesby, Avista; Tom Pardee, Avista; Meghan Pinch, Avista; Nathan South; Dean Spratt, Avista; Victoria Stephens, IPUC; Lisa Stites, Grant County PUD; Darrell Soyars, Avista; Briana Stockdale, Avista; Kenneth Walter, Applied Energy Group; Bill Will, WASEIA; Tommy Williams, Applied Energy Group; Yao Yin, IPUC; Renee Zimmerman, Avista.

Introductions, John Lyons

John Lyons: [Recording not started immediately] Conservation Potential Assessment and the Demand Response Potential Assessment, we will be going over those today. If you have any questions on those or if there were any follow-ups from last week, probably could get those answered too. For upcoming meetings, next one, again it'll be in two weeks on May 21st we'll get into the variable energy resource study and portfolio market scenarios, and then we go on from there. The June meetings, I still need to schedule the June 25th and send that meeting request out. So, you'll be seeing that coming out soon. And then the last ones there, we will skip the Fourth of July. That one is off. And then we'll wrap up with this side of it on August 13th and then in September, we'll release the draft IRP and have the public meetings. We'll have prerecorded videos on that and then we'll have discussion times. There will be a daytime and an evening time to give people an opportunity to discuss. James, did you have anything else you wanted to add?

James Gall: Yeah. Just going to follow up on last meeting. You might recall, we discussed the load forecast. We do we owe the TAC our final load forecast. We'll try to get that out next week. We've been revising it a few times with AEG as they're wrapping up their analysis, so we'll have our final load forecast out, could be Friday or could be Monday next week. Look for that on that Teams site. We have been updating the Teams site with other information, all of the current TAC presentations are out there on the Teams site as well as we have been posting the final and the draft TAC presentations out there too. And then if we're ready for AEG to get started and Ken, are you out there? You're not hearing.

Andy Hudson: Hey, James, this is Andy. Unfortunately, Ken is stuck in traffic right now. There's an accident on the highway where he is.

James Gall: OK.

Andy Hudson: I was thinking that maybe we could do demand response first as an alternative because I think we have.

James Gall: Yeah. That works for me.

Andy Hudson: Tommy, on the line here.

James Gall: OK, let's do that.

Andy Hudson: Let me confirm that.

Tommy Williams: Yeah. Andy, would you like to present the slides, or would you like me to pull it up?

James Gall: I would rather have you pull it up and that way I can follow the chat and interrupt you if any questions come up.

Tommy Williams: Sure, that sounds good.

James Gall: Alright. In all seriousness though, if you do have a question in the chat, go ahead and put it on there. I'll watch the chat and try to interrupt Tommy at a pause. If you want to ask your question, or have a comment or reply, you can definitely raise your hand as well. Go ahead, Tommy, whenever you're ready. I see your screen.

Demand Response, AEG

Tommy Williams: OK. Let me just get down to the demand response section. All this Ken will cover when he gets in, but we're just going to go ahead and start with the demand response section, which we pull a lot from the EE [energy efficiency] study. When we start discussing this, it's usually better fit. Once you know they go first, but in lieu of that, I will start and give you a sense of how we calculate the demand response potential for the Avista territory. The process we go through and then which programs we're going to be analyzing potential for, and what they look like in the Avista territory from 2025 through 2045, a 20-year span there. OK.

Tommy Williams: An initial approach to the study. First, we have a data collection stage where we align with the EE side and that's through either market profiles, a survey, day-to-day to come up with saturations, baselines, things of that nature, and just make sure we're in tandem with that study so there's no surprises and everything's in alignment. The next stage is we characterize the market. This is when, for the EE side, they break it out by residential, commercial and industrial. That's slightly different than what we do for the demand response potential study. We break it out by residential, general service, large general service and extra-large general service. These are broken out by schedules and obviously the largest schedule fits into the extra-large general service and so forth. There are some industrial customers in the large general service and some in the extra-large general service sections. But I just wanted to break that down for you.

Tommy Williams: For the list of demand response options, we have six or so different categories. First is traditional DLC options. These involve switches for the utility to be able to control the end use on the customer side just through an on and off switch. It's more of the conventional method that we've seen over the past 10-20 years, but we also have smart interactive DLC. These are thermostats, things of that nature, curtailment structures. This is for some of the larger customers, so large and extra-large service customers would fit into this category where they elect to provide a certain amount of megawatts or kilowatts that typically a larger customers will fit into this category and they will elect to provide those services when called upon. Energy storage technologies is both thermal and battery. We'll get into that a little bit later.

Tommy Williams: There was a new battery storage forecast that came out and we’re relying on that to inform what the potential might look like and it dropped quite a bit on the battery side. We can discuss that in a bit. Also, time varying rates and behavioral, this is time of use, peak time rebates available, peak pricing and behavioral programs. And then ancillary services, we won't go over these in this discussion, but some of the programs that weren't an ancillary service through their end use technology can elect to be on these programs. And it's really a subset of the parent program that can go on these ancillary type programs. We model them, we just won't discuss them in this presentation. Then we develop program assumptions. These are typically impacts from around the country of similar programs. We also used the Northwest Power Council assumptions to supplement anything that we can't figure out using other programs from around the country. But mostly we take impacts, participation rates, the technology that each program uses, costs and incentives of those programs. And then there's two different types of potential that we run. It's technical and achievable potential. This what we'll be discussing here. It's where every program is standalone and they're not interactive, so each program is run by itself in a vacuum, whereas the achievable potential, we haven't run this for Avista yet, but it will come this week once we get everything settled with the TCP potential. But this is where the programs are allowed to overlap. If two different programs, such as DLC – central AC and a smart thermostat program. They don't pull from the same customer pool. They can't overlap. Same customers can't be on both programs, so that's the difference.

Tommy Williams: OK, moving on. Again, I discussed most of these already, so I won't spend too much time on them, but this is the full gamut of programs that we’re looking at. Big hitters, I would say, are smart thermostats. Would interactive water heating? Emergency curtailment capacity building shouldn't be here anymore for this third-party curtailment program. We're only running on the largest customers now. We removed general service, which was a capacity bidding type program from this. It's only just emergency curtailment and in this case the largest customers. And then the whole bunch of time varying rates and behavioral.

Tommy Williams: OK, so current and future demand response programs. There are three programs that are currently being run in the Avista territory. One is electric vehicle time of use. Second is electric vehicle V1G telematics. This is where the utility can control the time, which vehicles are being charged, but the vehicle cannot give back to the grid in this case. And then one large industrial customer for 30 megawatts is on a third-party contract program at the moment. Allowing all three of these to grow throughout the time frame. For DR pilot programs, this is starting two in June of this year. One is a time of use opt in and the other is a peak time rebate program we discussed with Avista and they're going to run these for two years starting this year in June. Once that period is over, we have our traditional ramp rates, these ramp up to fully fledged programs at the end of this cycle. But they keep them low up until that point. It's small, intermittent potential for these time-of-use opt in and peak time rebate, but then they ramp up to fully fledged programs. A lot of these costs are, for instance the time used opt in, you'll notice that some of the costs associated with this are low in Washington, because those are sunk costs that have already been incurred by Avista. That is one assumption that we made in this, that those costs have already been incurred. We won't see those when we look at levelized costs for each of these programs. However, for Idaho, those costs have not been incurred yet, so there's a there's a larger upfront cost to get that program up and running. However, we do assume that they have any cost that went into one program that can be transferred over to the next. We assume that those are already sunk as well, so it's just a couple of development costs that are with Idaho on that one. Hopefully that made sense.

James Gall: Hey, Tommy.

Tommy Williams: Yes, please.

James Gall: This is James. I just wanted to bring up on these current programs and the pilots. These are all in Washington State and we don't offer any of these programs in Idaho yet.

Tommy Williams: Thank you.

James Gall: Thanks for summarizing these. I'll let you.

Tommy Williams: Yes, that's correct. The pilot programs are Washington only. However, the potential, we do assume that Idaho will pick them up once AMI gets rolled out. I believe that's next slide beginning in March of 2027. These programs do require AMI, so dynamic rates we need them for billing and is required. Idaho AMI is not expected to be rolled out until March of 2027. These programs begin in, I think the assumption is they begin in 2028. Once this process has begun for AMI. And that'll be on a 36-month deployment schedule. OK, a couple of assumptions and then we get into the meat of that. For smart thermostats, heating program will pick it back off the cooling program, they share costs for creating interactive water heaters of the potential split out between electric resistance and heat pumps. Heat pumps have a lower potential per customer. However, electric resistance are also expected to with a new. Water heater forecast heat pumps are expected to take over the market by 2045. I'm sure the team will get into that a little bit more. But that's just the expectation going forward. So electric resistance, the potential overall for this program is lower than expected because of the heat pump saturations by 2045.

Tommy Williams: OK, so dynamic rates, we kind of went through these a bit, but there's four of them and these are the classes that each are expected to use these types of programs. Peak time rebate is residential general service. Variable peak pricing, we model this as large and extra-large service so they're not overlapping. Electric vehicle time of use – general Service, large general service. Time of use is residential and general service, so customers have the choice between PTR and TOU. For residential and general service, as I mentioned before, we mostly base impacts and cost assumptions on the Northwest Power Council with supplemental information from programs around the country trying to get as close to Washington and Idaho as possible for those program assumptions and that we diverge from them where appropriate.

Tommy Williams: And then just to give you a sense of how we calculate potential for demand response programs, there's really four elements. We have our per customer peak impact. As I mentioned, for water heaters that's lower end electric resistor, higher electric resistance, lower and heat pumps. We feed those into a model where the impact is multiplied by the eligible participants, which is a function of the participation rate of the total number of participants that can be on a certain program and the saturation of the equipment in the territory. So, imagine all of these four components multiply together to get the number of participants that are on this rate per year multiplied by the expected impact per customer.

James Gall: We have a question in the chat.

Tommy Williams: Yes.

James Gall: Alright, so this is for time of use. Do residential and general service use the same on-peak and off-peak hours?

Tommy Williams: Yes, I believe it would be. It depends how we how we want to set that up and maybe that's a question for Leona on how that program might be set up. If you have an answer.

Leona Haley: Yeah, I certainly do. Thanks, Tommy and James. This is Leona. I'm a program manager on the Energy Solutions side of the house and our pilot programs are using the same hours for residential and general service.

Tommy Williams: Yeah. Thanks Leona. OK, so this is the.

Leona Haley: Thanks.

Tommy Williams: As long as there are no more questions, we'll get into the results. The initial results of the technical, achievable potential, and so some of the biggest as you can see on the right, this is from the previous CPA cycle. All the grayed-out numbers are reflections of what we expected in 2045 in the last cycle versus what we're expecting in 2045 on this new cycle. And we can see a lot of the differences right off the bat. Battery energy storage is essentially next to nothing. These are all in megawatts, so by 2045 we're expecting just over 0.1 megawatts for better energy storage and that's solely due to a new forecast that came out for better energy storage.

We assume that forecast is accurate, but they still will not pay for those batteries to be installed for those customers. This is going to be a, you own it, you can be on the program type of a thing. If we wanted to drive this up with incentives for paid batteries for solar customers, that's the original assumption, that it would be a percentage of solar customers that can be incentivized to purchase batteries. But right now, we're just using the battery storage forecast. Some options in the future that we could toggle.

Tommy Williams: Behavioral is pretty similar. Heat pump water heater and to the left resistance water heater. We can see that left resistance goes up to nearly five megawatts by 2035 and then it decreases to 2.4. This is because of the residential saturation assumptions that are made because of the new heat pump water heater saturation forecast, and these are expected by 2045 to completely take over the market and residential. That's why this increases so much. Unfortunately heat pumps don't offer the same potential per unit as an electric resistance water heater, it's still nearly nine megawatts by 2045, so it's no slouch, but if it were electric resistance, it would be a bigger number here. Just wanted to summarize that for you.

Tommy Williams: For AC, this is pretty similar to previous years. I think it is just a larger customer forecast in residential, so more customers equal more potential there. V1G telematics, this is a huge increase, and it's really due to further assumptions we made about this program. For this program, we're assuming 90% of a customer's EV load is available for this type of program, and by 2045 we also have a new EV forecast from the same folks that brought us the battery storage forecast. With that, there's more electric vehicles in the system by 2045, so that's an additional increase. There are the ones I wanted to point out here for the summer. Potential or a doubling of EVs, or you opt in. This was due to let me get my notes here. That's just electric vehicles because the new EV forecast. That's why they're so high. And then let's see any other ones that I wanted to point out. TOU opt in, this is because there's lowered impacts and lower participation rate in general service. Then we saw in the previous assumption and then this was a huge drop because we, whoops, we made some changes to the assumptions for TOU opt out. The way this program works is you have an initial starting steady state participation and then it goes down over time because customers are expected to opt out of this and go back to the standard rate. We lowered the potential participation rate at the beginning, from I think 74 to 20, so that it took a big drop from the previous year, previous cycle, and I just wanted to present why that is. I think that's all I have on that.

James Gall: They tell me we have another question.

Tommy Williams: Yes, please.

James Gall: That's related to storage and batteries, but it says does battery energy storage include using residential EV batteries for demand smoothing?

Tommy Williams: No, it does not.

Tommy Williams: Yeah, this is specifically for solar batteries. We can develop this further as things come out. I don't think we have a good idea of what the potential for EV batteries is at the moment. So, it remains to be seen. I would love to include that and that's something that is exciting for the future, to have a vehicle to grid option and to pull that resource from a vehicle. I think that's the way of the future, but no, this does not include that at the moment.

James Gall: OK. I just wanted to remind the TAC one thing on the energy storage forecast. The DPAG, or distribution planning group, did a presentation. Actually, AEG and CADEO did a presentation on our future forecast for electric vehicles, solar and energy storage and that study was conducted and completed about a month ago. It was used to estimate the amount of energy storage you see here in the electric vehicles. That's how it's all connected together.

Tommy Williams: Correct.

James Gall: OK. No more questions so far. Good, keep going.

Tommy Williams: Good, very good. OK, winter looks fairly similar to summer. The main difference here is that there's heating options and a thermal energy storage. Summer, it's really just smart thermostats. Heating is the big difference, and with that there was an increased heating saturation due to air source heat pumps coming online. There are expected to be a lot more of those than what we saw from the previous cycle. That's why we're seeing that big jump. Other than that, it's pretty similar to what we saw in the summer impacts. Just want to run down here. OK. Yeah, pretty similar to what we saw for summer. That's the main thing, is that there's heating and in winter. Just wanted to give you a quick look at what we're seeing by sector here for summer and winter and by state. We can't really stack this potential because these are standalone results, and when we do the integrated case, which we will in the future, then we'll be able to stack these up and see what it would look like if all these programs were run at once. But we can't really show that, so, we break these out by sector and the different programs essentially at this point. But residential is the big driver of most of this potential. Large and extra-large annual service, these are mostly third-party contracts that are making up this. And electric vehicles, those are the two main programs that make up these two bars here. Residential, we have time varying rates, everything goes into this and there's a lot more customers. So that's why we're seeing so much potential. Similar story with Idaho.

Tommy Williams: And very similar to summer is winter. Not much to say there and then I wanted to get into costs. Do your programs have both upfront and ongoing costs? Up front, costs are to filament costs. And then there's also one time cost that go with equipment. Customers need equipment to run these types of programs, otherwise there won't be eligible. That makes up our eligibility list for each of these programs, and there's also marketing costs, costs it takes to get a customer onto the program, ongoing costs, there's administrative, operating costs and incentives to keep a customer on a program. You keep them doing what they're supposed to be doing. OK. An example, resistance water heaters pulled this out. This is for residential, this would be for Washington only. Just another thing, Washington is the only state right now that has a rollout of interactive water heaters, DLC, water heaters is what we use that in Idaho because they don't, there's not an expectation for grid and interactive water heaters to be rolled out in that state yet, so we're running a DLC water heating program for that for now. This is a Washington only. We expect development costs of about $34,000 for the residential sector administrative, this $150,000 is assumed for a full-time employee for a whole program. The whole program includes residential general service, any other classes that we're running these, and also the heat pump water heaters. We break that $150,000 out depending upon the allocation of what each full-time employee will do for each section of that program. Just this $40,000, is a piece of that for marketing $60.00 to bring a new customer onto this program equipment, $150 to hook up that grid Interactive system onto a typical water heater. It's a module and a $24.00 incentive per year for a customer beyond the program. All that being said, these costs go into the model, and we output them all to that 20-year time frame. So, what we do to oops, levelized it back to a single year value. We take a levelized cost per kW you per year and bring that back using a discount rate to a single year value. Per kilowatt saved for each of these programs so we can see that battery energy storage, there's the amount of kilowatts, potential kilowatts, saved for that program is so low that each of the kilowatts that the cost per kilowatt blows it out of proportion. It's way up here as you can see on the top here. Some of the lowest costs contributors are Washington for EV TOU opt in. There's a lot more vehicles expected to be in Washington rather than Idaho, so when we see a large number over here and a low number over here, that essentially tells us that the amount of customers are much more prevalent that can be on that program in a certain state rather than the other. But that's why we break it out by state year two. Let's see, anything else to bring up?

James Gall: Yeah. Question Tommy on the DLC smart thermostats, there's a cooling that has a very high cost and a heating that has a very low cost.

Tommy Williams: Yeah, some good. Yeah.

James Gall: Are you assuming that the reason why the heating is such a low cost is because you're activating the cooling program? Can you kind of talk about that interaction?

Tommy Williams: Yes. I mentioned before that the heating program piggybacks off the cooling program. The heating customers are a subset of the cooling customers and so we assume a lot of the costs that go into the cooling are here rather than in the heating program. That's really the difference there.

James Gall: Thank you.

Tommy Williams: Yeah. OK. I think that's all I really wanted to say. Is Ken on by chance? Still in traffic?

Andy Hudson: I'm not sure, I guess if he's not chiming in, he's probably not on yet. Looks like Fuong has joined us, though. I think he could get started on the presentation.

Tommy Williams: Sure.

Andy Hudson: Do you want to keep sharing this slide deck, Tommy?

Tommy Williams: Now I will. I would love to.

Andy Hudson: Yeah. Great. Thanks.

Fuong Nguyen: Right. I just got on.

Tommy Williams: You're a little light on the you can speak up.

Fuong Nguyen: Oh, really? Better.

Tommy Williams: Still a little light.

Fuong Nguyen: OK.

Tommy Williams: Is either sharing the same thing.

Any Hudson: Yeah, I can't hear very well.

Fuong Nguyen: OK. I'll try to call back in.

Tommy Williams: OK.

Sofya Atitsogbe (UTC): Hi, this is Sofya at the chalkboard with Washington Utilities Transportation Commission. Maybe on the DR slides, you could talk more about the equipment cost.

Tommy Williams: Sure.

Sofya Atitsogbe (UTC): Yeah, it shows.

Tommy Williams: Anything in particular on that?

Sofya Atitsogbe (UTC): It showed $170 on one of your slides.

Tommy Williams: Oh, sure. Yeah.

Sofya Atitsogbe (UTC): For new participant, yes.

Tommy Williams: You want me to talk about that?

Sofya Atitsogbe (UTC): Could you please tell me what kind of costs are included in that?

Tommy Williams: Sure. I'm just pulling up the input generator here, which goes into the cost a little bit. More specifically, give me one sec.

Leona Haley: Tommy, this is Leona. I think I might be able to help with that too.

Tommy Williams: Yeah, go ahead.

Leona Haley: The customer has their water heater, and they want to participate, so Avista would send the customer a communication module to plug into their water heater. There's that cost. And then there's other cost, too, to the communication pieces and then when we did get some of those costs, I believe from the Bonneville study and then I'll.

Tommy Williams: That's right, yeah.

Sofya Atitsogbe (UTC): I haven't seen the Excel sheets, but my colleagues are telling me that in Washington, the water heaters that are sold in Washington are all CTA-2045 ready. So, my assumption is that they don't require any more equipment.

Leona Haley: Yeah. Sofya, a good point. They are ready, but they do require a communication module to communicate with the utility.

Sofya Atitsogbe (UTC): Got it. So, this requirement for the equipment doesn't satisfy the requirement to communicate with the utility.

Leona Haley: Correct.

Sofya Atitsogbe (UTC): OK. Thank you.

James Gall: Alright. Are there any other DR questions? This is a good way to fill time if you have any questions on DR or any other topic while we're waiting unless he's back.

Fuong Nguyen: Yeah, I'm back. Does this sound any better?

James Gall: We can hear you much better.

Tommy Williams: Much better.

Fuong Nguyen: OK, great. I don't know if Tommy had already covered this slide on the CPA objectives. The CPA is set to, or what we want to achieve, is to assess the technologies and identify the long-term energy efficiency and demand response, which Tommy already addressed. The potential for Washington and Idaho to support the IRP, planning and setting targets for the portfolio as well as developing their energy efficiency programs. We also need to provide the information on cost and impacts of the conservation to compare to the supply side alternatives in the model, as well as understand the differences in the energy consumption and the energy efficiency opportunities. By modeling the different income levels in residential and as always, we the transparency of our modeling methodology and the assumptions that go into the model, as well as the results coming out of it.

Fuong Nguyen: We talked to this slide in the previous TAC meeting of our modeling approach. It's a four-step approach where we begin by characterizing the market and setting the base control totals and segmenting the market. And characterizing the energy use in the base year, we segment the market and disaggregate the usage for each sector and segment in the business territory. Previously, we presented the baseline projection which includes utility failure. We compared to the utility forecast which includes no standards and building codes in that forecast. And then for the potential, we identified the measure resources. We identify energy efficiency equipment that can replace the baseline equipment and measures that can also save energy as well as a new energy technologies that may come down the line. Then what we're going to show here today is the potential estimation where we apply the ramp rates and come up with the technical and achievable technical potential which goes into the IRP for the economic screen.

Fuong Nguyen: Any questions so far? OK. And I think this is also a slide from the previous presentation which describes the inputs into the model and the sources that we use. I won't spend too much time here, but we prioritized the Avista data, sales and customer accounts, and retail price forecast. We also use survey data to show what the equipment is in the territory. And we also thought back on secondary sources, such as the US EIA data from Recs and Cpex and Max, and then to characterize the measures and the equipment and end uses. We rely on the RTF workbooks, the Council workbooks, US DOE data, and Energy Star data sheets, things like that. We also take into account the energy codes and standards that are present in each of the different states for Avista, and we look at market trends from RTF such as the lighting, RTF light workbooks, and things like that. So. a couple weeks ago, we showed the load forecast for Avista, but in the interim, there was a new water heater standard published on April 30th for water heaters. Usually, we freeze any standards at a point in time, so that we're not constantly updating the model and the forecast as we're doing this study. But since this standard has such a huge impact on both the baseline and the savings for the CPA, we decided to update the models with this. The new standard, the efficiency requirement here showing the table on the right is for water heaters less than 55 gallons will have to be a Tier 1 heat pump water heater, and for water heaters greater than 55 gallons, it's a Tier 2 requirement. The impacts that we're showing in the call out there, it reduces the energy consumption in 2045 by 297 GW hours and the peak growth by 29 megawatts in the summer and 52 MW megawatts in the winter. It's a pretty significant impact. It also delays the winter peak taking over the summer by about 10 years. It delays that and it moves the big part of this, it moves to the water heating savings from the baseline or into the baseline instead of the CPA. I'll pause here, if anybody had any questions.

Sofya Atitsogbe (UTC): Hi, this is Sofia at the UTC again. Can you please explain again, so this update delays the winter peak, overtaken by the summer peak by about 10 years, is that right?

Fuong Nguyen: Yes. In previous forecasts, the peak it becomes, winter earlier in the previous forecast because the water heating mostly hits the winter peak. It moves it, the water heating usage is lower because of the standard. So, the peak isn't hit in the winter as much as it was before.

Sofya Atitsogbe (UTC): Got it. Thank you.

James Gall: And finally, we have a question in chat. Is the 10-year delay just for Washington or does that also apply for Idaho?

Fuong Nguyen: I do not know off the top of my head. I think we were looking at both combined. I have to go back and check on the separate states when that happens in nature or state.

James Gall: Thank you. OK. Before you move on, I just wanted to remind the TAC on peak forecasting. AEG does a peak forecast for us that is based on a specific weather methodology, and we do a second round of their peak forecast, adjusting for our weather forecast. The final load forecast which we will be sending out soon may have slightly different results than what you see here, but I think it is pretty consistent where we are going to be seeing a very similar peak in the winter and summer forecast amount going forward. So, there's definitely been some changes since the last TAC meeting and look for that soon. But go ahead Fuong.

Fuong Nguyen: Thanks James. Yeah, and here is the updated baseline forecast for Washington, Idaho, combined. The customer growth, electrification of natural gas systems combined for a 30% increase in electric loads over the period from 2021 to 2045. It's about 1.1% each year. Which is 2,400 GWh from the electrification. The forecast provides the assumptions in the forecast includes the projected pulling, hitting degree days and climate trends, market efficiency impacts from LEDs and other things like that. We also include solar and EV projections from the recently completed DRDR study for Washington, which is what you see, that tail end of the growth is mostly electric vehicles and as we mentioned before, it's the heat pump water heater standard in 2029.

Kenneth Walter: Alright. And I think this is my turn to step in. Sorry folks, this is Ken.

Walter with AEG I was a bit late to the game this morning courtesy of a couple of accidents on the freeway on the way in. It is surprisingly difficult to speak to a PowerPoint deck from inside a car and bumper to bumper traffic, so I apologize that I didn't get a chance to introduce myself at the top of the call, but I'll do my best to help out on things now. The next piece will actually cover the draft working efficiency potential that we've been able to put together for Avista starting first with just a quick review of the level of savings estimates that we do. This is in accordance with Northwest Power Council’s methodology, similar to what's used in the 2021 Power Plan. For Avista, specifically on the electric side, we develop only two levels of potential. First being technical, which is a hypothetical upper bound on all savings potential, assuming the most efficient energy efficiency opportunities are put in throughout all of Avista’s territory with no consideration of how expensive they are or even really worrying about customer willingness to participate. Every piece of equipment at turnover is put in, so this is bypassing the Council's ramp rates entirely. That is pretty pie in the sky. It includes extremely expensive and emerging technologies. Much more useful data point is the achievable potential which does a little bit of a sanity check to remove things that are like $1,000,000 a MW hour or something of that level. But also most importantly, this is where we apply the Power Council ramp rates so that what we are able to pass along to this process is something that has a sensible schedule of potential adoption still consistent with Council methodology, but importantly the technical achievable potential is there for every measure and is still not doing a cost filter. We're not outright rejecting technologies, but we may not be choosing like the V REF Seer 24 central air conditioners because something like a Seer 16 is just a more appropriate dollars per MW hour. That's more in the realm of something the IRP would find potentially attractive. The idea is not to have measures drop out entirely unnecessarily. In addition to the technical achievable potential, what we provide to Avista for their planning process are the levelized costs from both the total resource cost and utility costs test perspectives. And that way the IRP can look at on an hourly basis and throughout the forecast period what resources are available at what cost and make a sensible selection at a very granular level using the data that we were able to give them. Any questions on these levels before we start looking at results? OK, cool. Yes.

Atitsogbe, Sofya (UTC): Hi. Sorry, are you going to be going into the total resource cost methodology? I'm particularly interested in nonenergy impacts because I heard that staff comments were noted and then this time around you were doing something differently.

Kenneth Walter: I think that comment may be in the gas conversation, but at any rate, yeah, in either one of these, we are careful to include all NEI that RTF quantifies first.

Sofya Atitsogbe (UTC): So that would be on the gas?

Kenneth Walter: That would be anything that's dollar quantifiable, whether that's water savings, detergent savings in the case of DHCP. There's some avoided wood smoke. All of these are documented through our study, so anything the RTF has already quantified and then obviously in Washington, we also have the 10% adder for conservation.

Sofya Atitsogbe (UTC): OK. Thank you.

James Gall: Sofya, it's James. We do have a second round of NEI that get put on these levelized costs that comes after what AEG does and that is the same study that we're relying on from the last IRP. I don't know if Kim has anything to add to that, but because I'm kind of speaking out of turn there. But there is another round in this. If I recall correctly, it's mostly focused on the low income. Kim, if you had anything to add or not.

Kim Boynton: Yeah. Nope, you're getting it.

James Gall: OK. And we will provide when we send out our PRiSM document. It will have every single program, what the savings potential is, what the levelized cost is, what the additional NEI value is for every single program. So, you'll be able to look at those.

Sofya Atitsogbe (UTC): Great. Sounds good. Thank you.

James Gall: You're welcome.

Kenneth Walter: All right. And this is just a note on the ramp rates that I was referring to earlier. We do still take those from the Northwest Power Council's 2021 Power Plan. Those ramps themselves are still consistent with what was used in the 7th Power plan, aside from some assignments. There are only a few curves that are assigned to each measure based on what's deemed inappropriate rollout and we are remaining with the assignments that the Council has used the maximum achievability for these measures ramps up over time. But all of them are designed to reach usually about 85% of technical potential. However, some have gone up to 90% or even 100%, is a partial list on the right for measures that are actually above that 85% threshold that the Council has reevaluated, and we have aligned our assumptions with that. It's really important to note that the Council's ramp rates, and really the design of the conservation potential assessments, are agnostic to the delivery of programs and explicitly are intended per the Council to include potential that might be realized not just through utility programs, but also through regional initiatives, market transformation, especially in the long term or some future codes and standards that are not available on the books yet. As we mentioned, we've explicitly modeled things that are actual law now, but the Council ramp rates may include savings in those four years that are possibly going to be achieved through codes and standards as well. Especially when we start looking at top measures and you may hear some commentary from Avista, there may be things that make more sense for a different initiative than for Avista’s own programs. But that is intentional and that is consistent with Council's methodology.

Kenneth Walter: OK. Let's look at a couple of sectors of draft results, starting with the residential sector. The graph on the top right, just to orient, that is consumption. Total residential consumption across both states in these different scenarios, the dark red line on top represents that baseline. That counterfactual, if program stopped running, and then the other two lines are our technical achievable. That's the purple and then under technical potential scenario that is the lowest we estimate residential consumption could go under a technical potential scenario. And then the bottom chart, you can see year over year savings from both of those scenarios and that curved shape that you see is a pretty consistent result of the Councils ramp rates which tend to be a bit front loaded and then peter off as the markets get exhausted towards the end of the market. Draft results as we have them now are showing about 1% per year savings as technically achievable, that's 76 GWh in the biennium period or 8.6 aMW. And then you can see we've also got the totals across the 10- and 20-year marks getting all the way up to 890 GW hours by 2045.

Kenneth Walter: And a little preview of top measures. Heat pump water heaters are still in the conversation for technical achievable, which is a pretty interesting result. Also, big right now are Energy Star windows, which have received an enhanced definition yet again, so level setting the remaining market for that, moving that goalpost forward and keeping consistent with RTF workbooks. Also, EV chargers, as we mentioned earlier in the baseline slides, we have incorporated the CADEO research into EV growth and projections, especially in Washington and also the RTF has updated their information on those chargers which has increased the savings opportunity from those upgrades. We can talk about that a little bit more on the top measure slide.

Kenneth Walter: The next slide, we're sticking with still this high-level view. Here you can get a little breakdown between the two states, but we are showing cumulative total savings again for technical achievable and technical potential on the right side and then also on the left where you get the state split. You can just see that Washington versus Idaho; these are pretty proportionate to their base loads. You can see Washington has a much higher base load and significantly higher technical achievable potential. I meant to correct that chart. I apologize, the percentages there have a row lock issue. They are actually very similar percentage across the states. I will update that slide deck so that it can be send it out to folks who'd like to see it. Focus on technical achievable by itself is about 16% of savings and technical potential about 26.9%.

Kenneth Walter: And if we can go to the top measures slide. Alright, this is where we start getting into the details of what's actually driving these savings levels that we're seeing on the left. You can see a quick breakdown by the different end uses of where technical, achievable potential is coming from and on the right is the list of more detailed measures. As mentioned, windows, water heaters and electric vehicles are the top three here, but also included on this chart, for putting these measures in context, we've included the levelized cost of energy. This is the 20-year average value there and the reason to do that is really to make the point that not all of these measures are going to be cost effective or pass the IRP necessarily. You can see some of them are actually very expensive and we'll put them in a little bit more context graphically on the next slide, but there's still some good stuff here that is likely to pass the IRP. You can see the number 2 measure there. This represents heat pump water heaters that are above this new federal standard and that you can see over 62,000 MWh there that are showing only about 7 cents a kWh in TRC costs. That is likely to be pretty attractive in the IRP. We'll see how it lands. It may even become more attractive depending on how it impacts peak values. That'll be something James will tell us later when he gets it into his model.

Kenneth Walter: In contrast, looking at the two windows measures at 43 cents a kWh and 56 cents a kWh, those are much higher costs than Avista’s avoided costs and pretty unlikely to pass through the IRP. Just pointing out that this is still an interim step and has yet to go through cost effectiveness testing, but it is still an interesting representation of where there's a lot of kilowatt hours in Avista's territory. And this is really the illustration to drive that home. What we're showing here is a supply curve, as you go out towards the right savings get more expensive and as you go up the left side that is in order to get the next bar. If you want to move higher on the total savings you've acquired, then you have to move further right into more expensive territory. The green line that we've placed there is an approximation of where the IRP has stopped finding things cost effective past this point. You can see out of the almost 900,000 MWh that we've identified of technical achievable potential only about 300,000 MWh of that comes in under that $0.10 a kWh or $100 a MWh mark. This is pretty well expected. We draw a big net with these CPAs and there tend to be some very expensive things out there, but this is a good context for what we're actually looking at here.

Kenneth Walter: Some notable changes from prior CPAs: #1 the big heat pump water heater change has been pretty impressive. A lot of moving parts, as we've already been talking about, there are higher tiers that NEEA and RTF have added to their analysis. So, there is additional savings in those, but we are still competing with that new federal standard. Without it, the heat pump water heater potential would be three to four times bigger than it is. But those savings have really been rolled into baseline impacts now. The EV chargers were barely a blip on the radar in the previous study, and as mentioned, this is part of the big growth that's been forecast by CADEO and also increased forecast just even from Avista's internal estimates. And RTF revised its workbooks and where there was previously very little savings opportunity between two different levels of chargers. They have increased those savings estimates substantially from their analysis and we've incorporated into this.

Kenneth Walter: I already mentioned that energy efficient windows have a higher Energy Star requirement and we have updated our market-based assumption in keeping with RTF workbooks and the 2020 residential Energy Consumption Survey data for the State of Washington which provides a little bit more accurate estimate of the remaining market for this new, way higher efficiency window.

Kenneth Walter: Connected thermostats took a big hit. I didn't dwell on them too much on the previous slide, but they were previously a number one or two measure technical achievable for Avista. RTF has cut the savings by a third and cut the lifetime in half which really brought them down in this analysis. And then there's just been some bookkeeping and house cleaning applicability of several measures reflecting new remaining market data available. I already mentioned the Rex 2020 data making sure that we didn't have overlapping applications. For example, connected thermostats are in competition with home energy management systems. A single customer can't install both and we want to make sure that's reflected in our applicability and just making sure that we have a good balance in our market. Were there any questions on residential potential before I move on to commercial?

Kenneth Walter: OK, great. On commercial, we've got the same views here. This is consumption under the different scenarios in the top right annual savings year over year in the bottom right, slightly higher technical achievable potential as a percent of baseline. It's 1.1% a year or 84 GWh in the biennial period. Gets all the way up to 943

GWh by 2045. And in commercial, although you do see those level 2 EV chargers coming in, in the Washington side where we see, predicting a lot of fleet growth. The bigger story, and maybe surprising to some folks depending on how long you've been keeping track of these, we still are showing a lot of available LED fixture replacement potential. Specifically, in our modeling, we're including this as a bundled measure that replaces conventional lighting with an LED fixture and bundled controls at the same time. I can talk a little bit more about what that looks like when we get to our top measures slide. And then there are some various HVAC system upgrades that I just kind of lumped into one bullet here individually, not all of them are huge, but collectively there's a pretty good source there.

Kenneth Walter: We can look at the data slide. And again, same slide here to get some split, although I'm not going to dwell on it because again, I need to correct that table and I apologize that that version didn't go out before this call. But again, a good look at how total savings is growing over time. On the right there, you can see that same 943 technical achievable GWh and 2045 compared to over 1,000 of technical potential, that's about 22% of the baseline and 26% for technical. Right and top measures, which is the more interesting conversation than totals. There you see in that pie chart on the left side there is plenty of lighting which I know a lot of us have been talking about in the industry over the last few years. There's a big story that lighting is transforming. LED is becoming the way of the land we have updated to the newest workbooks from RTF, as far as their market baseline assumptions for lighting and LED lighting. This is incorporating all of that and in a couple of lighting categories, particularly high bay, but also insert some early years for linear. Did relax actually what they thought was going to be happening in terms of LED market penetration in both of those cases, it's still getting up into the 90 plus percent by the end of the 20-year period. But it opens the door for a little bit more opportunity in the early years and in high bay actually just doesn't get as high as it did period. It's actually expanded the opportunity there a little bit as well as having higher efficiencies predicted by DOE starting in 2035. For the set last 10 years of the study, we have even higher LED efficiency than we had previously. Again, this is with embedded controls at time of replacement, which gives a really nice boost to savings for very little extra cost. And that's inclusive of this as well. So, they are saving more than a standard LED fixture replacement would. You can see a little more detail on some of the HVAC measures I mentioned, #3 there with air source heat pump upgrades and #6 energy recovery ventilators in the HVAC system. Again, you can see both of those though are pretty expensive $0.42 and $0.65 per kWh respectively, so they may be a strong savings available source, but they're also fairly expensive and we don't expect them to pass the IRP. I think I saw a question pop up in the chat.

James Gall: Yeah. I'll read it for you. Has to do with LED fixtures. The question is does LED fixture replacement only exist for commercial customers and not residential?

Kenneth Walter: We have some LED bulb replacement, and the residential side is very little. If you were to flip back to that slide, it's a pretty small slice in terms of what we're talking about here. These are the big 4 and 8-foot linear lighting fixtures that have embedded controls in the unit. We have not seen that in the residential space and it's also worth pointing out that there's very little linear lighting in residential. It is a low single digit percentage of lighting that's available there. So, not a lot of resource if they were to be found or tried to implement there. People's garage shop lights are not a huge source of energy savings there. All right. Here's the same supply curve. Looking at the commercial potential again, that green line representing where the IRP has previously stopped selecting, and again you can see only about half the savings here on the commercial side are below that level. Again, this isn't final. This is an approximation. We'll see what James's model picks when it gets that detailed hourly impacts and costs, but it's a good level set for what we might expect to come through the IRP filter.

Kenneth Walter: Couple of notes on some commercial changes since the last one. I've already discussed the lighting baseline, making sure that we are using RTF latest assumptions. Commercial EV fleets are having a very big impact. We did not include commercial EV at all in the previous study, so that is an enhancement just overall. And then having those big fleet growth assumptions from Cadeo. And then again, just like in residential, we always make sure that we're taking the time to make sure that applicability of building shell and controls measures are updated to the best data that we have available. We want to avoid overlapping implications, or even just overstating as buildings have been renovated over the last couple of years, making sure that we're applying things appropriately to older building shells and not overstating the opportunities there overall. Actually, the commercial technical achievable potential is a little bit higher than it was in the previous study, however. Right.

Tommy Williams: That's it.

Kenneth Walter: No.

Tommy Williams: Oh, let's go down to the slide here.

Kenneth Walter: There we go. Next steps I just presented residential and commercial. To those of you who are wondering where industrial is, we are still working on that and plan to wrap up the end of the week and working IRP inputs will be headed to Avista the following week. That's where we're at on the AEG side. James, I don't know if you have more things that you'd like to add to next steps as far as this group is concerned.

James Gall: After I get myself off mute. I think the next steps after you guys wrap up will be taking your data and putting it in our PRiSM model for resource selection. And, like you mentioned earlier, we'll see where the economics move programs in or out and we'll try to make all data available as soon as we can. Once we're ready, the idea will be to give the TAC an opportunity to look at the measures, the savings and the costs of all the savings.

James Gall: I think that's all we have planned for today. I don't know if there's any questions or comments any of the TAC members have. OK. Well, I'll ramble on just for a little bit in case something comes up, but our next TAC meeting will be in two weeks. On Thursday, we will be covering our wind and solar integration study that determines how much integrating those resources cost from a, we'll call it intermittency point of view, and that study has been about a two-year process working with some different consultants and internally with our models. That will be the first study I think we've done since 2007 for integrating those resources. That's a big deal for us. We'll also get into some of the scenario analysis that we've been working on over the last couple of weeks. Stay tuned for that. Any last call for any questions or comments before we call it a morning? Alright. We'll see you in two weeks. Have a great day.

Leona Haley: Thank you.

James Gall: Thanks Ken, Fuong, and Tommy as well.

Kenneth Walter: Thank you, buddy.

Sofya Atitsogbe (UTC): Thank you.

Tommy Williams: Yep. Thanks everyone.

Andy Hudson: Thanks everybody.

Tommy Williams: Take care.

2025 Electric Integrated Resource Plan

Technical Advisory Committee Meeting No. 7 Agenda

Tuesday, May 21, 2024
Virtual Meeting – 8:30 am to 10:00 am PTZ

Topic	Staff
Introductions	John Lyons
Variable Energy Resource Study	Clint Kalich
Portfolio/Market Scenarios	James Gall

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2025 IRP TAC 7 Introductions

John Lyons, Ph.D.
Technical Advisory Committee Meeting No. 7
May 21, 2024

Today’s Agenda

Introductions, John Lyons

Variable Energy Resource Study, Clint Kalich

Portfolio/Market Scenarios, James Gall

Remaining 2025 Electric IRP TAC Schedule

- **TAC 8: June 4, 2024: 8:30 to 10:00 (PTZ)**
  - Load & Resource Balance and Methodology
  - Loss of Load Probability Study
  - New Resources Options Costs and Assumptions

- **TAC 9: June 18, 2024: 8:30 to 10:00 (PTZ)**
  - IRP Generation Option Transmission Planning Studies
  - Distribution System Planning within the IRP & DPAG update

- **Technical Modeling Workshop: June 25, 2024: 9:00 am to 12:00pm (PTZ)**
  - PRiSM Model Tour
  - ARAM Model Tour
  - New Resource Cost Model

- **TAC 10: July 16, 2024: 8:30 to 10:00 (PTZ)**
  - Preferred Resource Strategy Results
  - Washington Customer Benefit Indicator Impacts
  - Resiliency Metrics

Remaining 2025 Electric IRP TAC Schedule

- **TAC 11: July 30, 2024: 8:30 to 10:00 (PTZ)**
  - Preferred Resource Strategy Results
  - Portfolio Scenario Analysis
  - LOLP Study Results

- **TAC 12: August 13, 2024: 8:30 to 10:00 (PTZ)**
  - Preferred Resource Strategy Results (continued)
  - Portfolio Scenario Analysis (continued)
  - LOLP Study Results (continued)
  - QF Avoided Cost

- **September 2, 2024- Draft IRP Released to TAC.**

- **Virtual Public Meeting- Natural Gas & Electric IRP (September 2024)**
  - Recorded presentation
  - Daytime comment and question session (12pm to 1pm- PST)
  - Evening comment and question session (6pm to 7pm- PST)

Avista Variable Energy Resource Integration Study Update

Clint Kalich

Technical Advisory Committee Meeting No. 7

May 21, 2024

Table 18: Integration Costs for Base Scenarios

Appendix A

Wind Location	Wind Capacity	System Penetration	Forecast Error	Cost ($/MWh)	Cost (% Mkt)
Columbia Basin	100 MW	5%	15%	$2.75	5.0%
50/50 Mix of CB & MT	200 MW	10%	10%	$6.99	12.7%
Diversified Mix	400 MW	20%	8%	$6.65	12.1%
Diversified Mix	600 MW	30%	8%	$8.84	16.1%

Table 24: Effect on Integration Cost of Short-Term Liquid Markets

Wind Capacity	System Penetration	Wind Location	Base Cost ($/MWh)	10-Min Mkt Savings (percent)	10-Min Mkt Savings ($/MWh)	10-Min Mkt Cost ($/MWh)	Annual Savings ($000/yr)
100 MW	5%	C. Basin	$2.75	61.7%	$1.70	$1.05	$490
200 MW	10%	50/50 Mix	$6.99	60.8%	$4.25	$2.74	$2,456
400 MW	20%	Diversified	$6.65	38.9%	$2.59	$4.06	$2,994
600 MW	30%	Diversified	$8.84	40.6%	$3.59	$5.25	$6,224

Table 27: Market Price Impacts on Integration Cost

Market Case	Wind Capacity	System Penetration	Wind Location	Forecast Error	Integration Cost ($000)	Integration Cost ($/MWh)	Base Case Savings (percent)
Low Market Prices	100 MW	5%	C. Basin	15.0%	$ 181.90	$ 1.32	-52%
	200 MW	10%	50/50 Mix	10.0%	$ 589.87	$ 2.67	-62%
	400 MW	20%	Diversified	7.5%	$ 1,872.51	$ 3.88	-42%
	600 MW	30%	Diversified	7.5%	$ 2,404.10	$ 3.98	-55%
High Market Prices	100 MW	5%	C. Basin	15.0%	$ 920.56	$ 2.99	9%
	200 MW	10%	50/50 Mix	10.0%	$ 5,792.80	$ 8.53	22%
	400 MW	20%	Diversified	7.5%	$ 9,489.50	$ 7.54	13%
	600 MW	30%	Diversified	7.5%	$ 20,280.32	$ 10.45	18%

Differences Between Traditional Resources and VERs

Traditional Resources

- Gas, coal, hydro, and biomass
- Reliable and known fuel supply
- Responsive to operator direction
- “Net contributors” to system ancillary service requirements *
- Generation variation is predictable,** as is generally “caused” by operator instructions

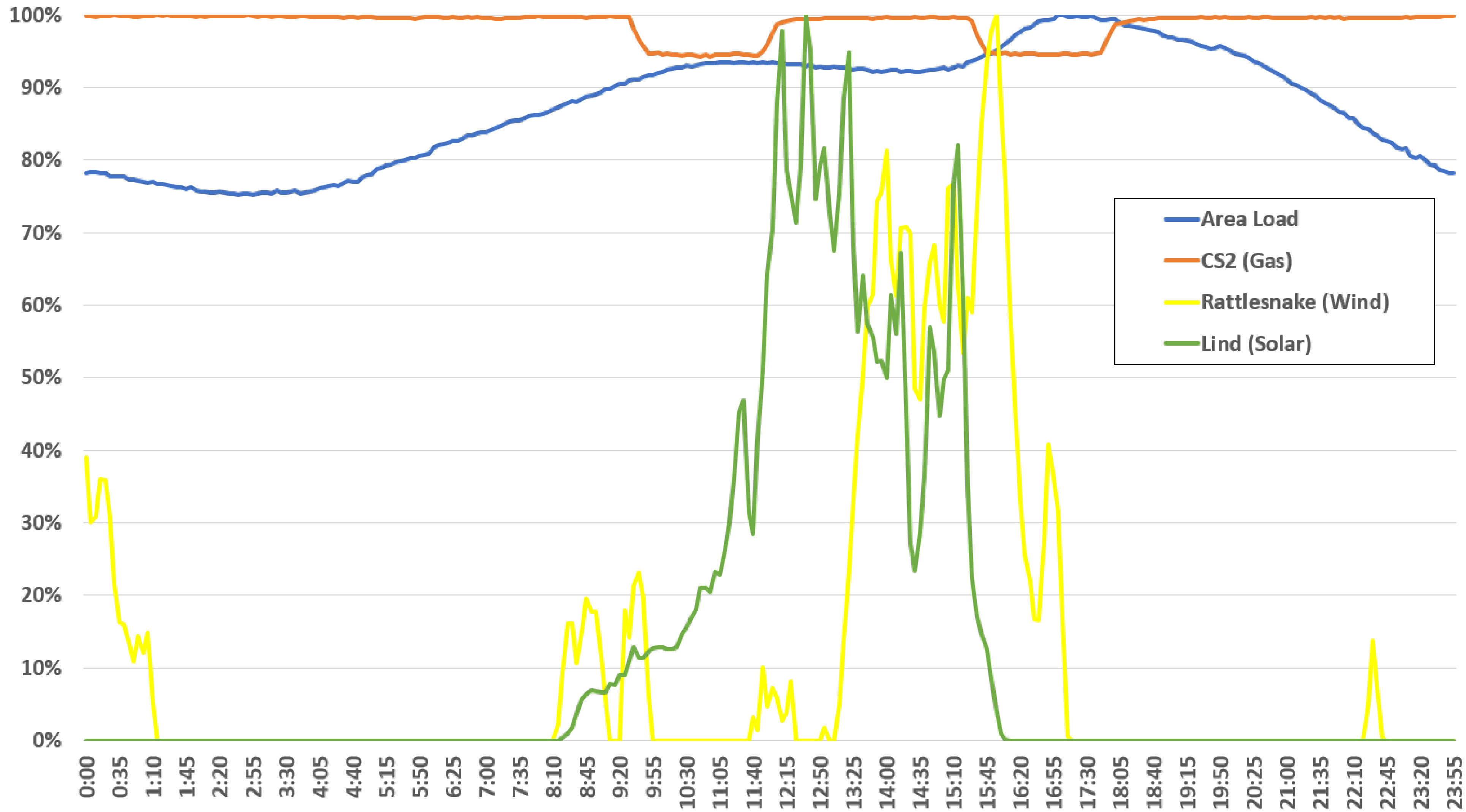
Variable Energy Resources

- Fuel supply subject to the weather
- Geographical dispersion may help ***
- Wind fuel supply issues
  - 36x as hard to forecast as load
  - geographical diversity helps
  - varies moment to moment
  - wind needs 10-50 mph to generate
- Solar fuel supply issues
  - 22x as hard to forecast as load
  - driven mostly by cloud cover
  - less benefit from geographical diversity

* ancillary services covered in later slide
** excludes variation from forced outages that affect all resources
*** but estimating this savings is difficult given varying methods employed

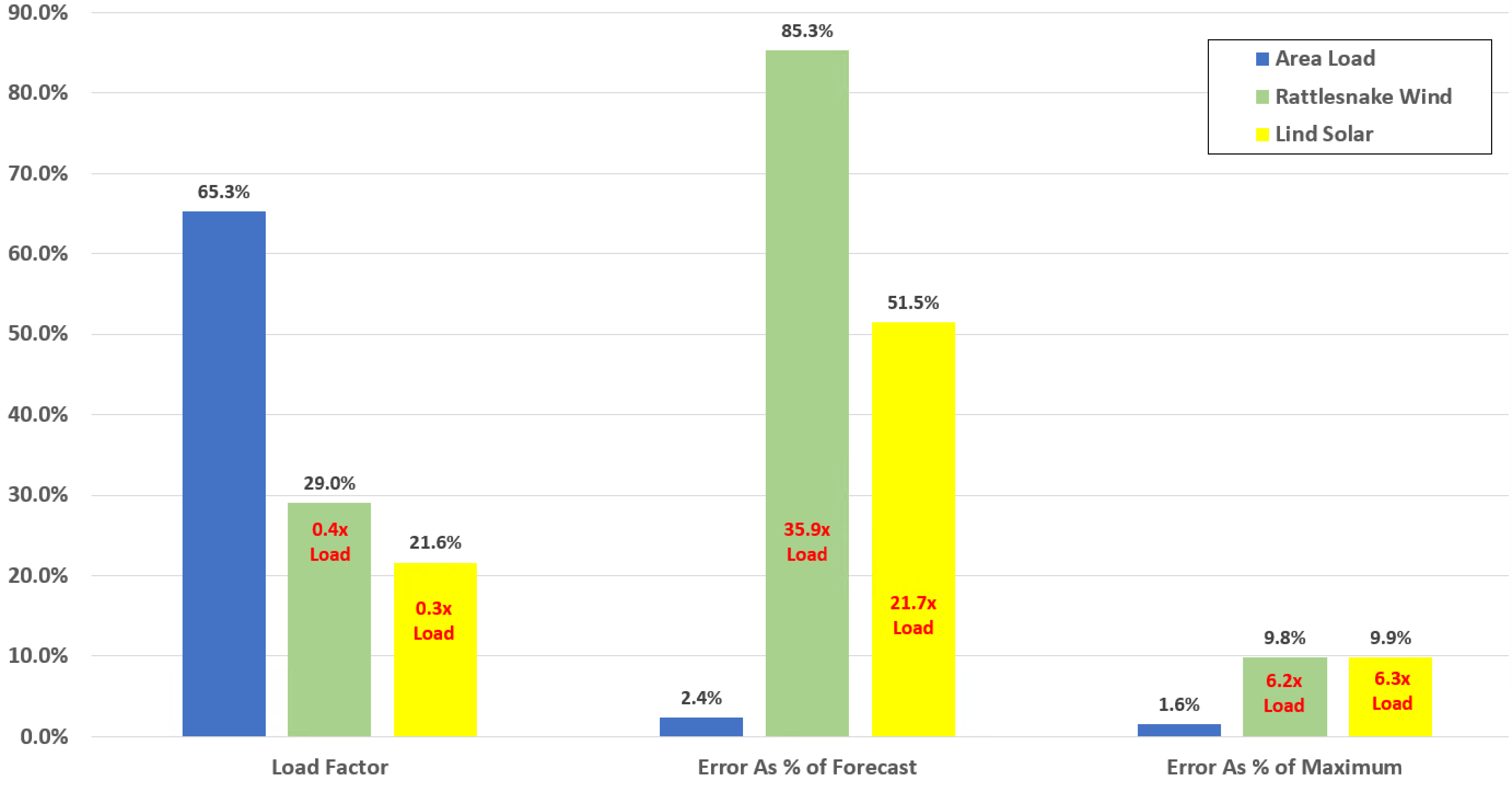
Loading Profiles (as % of Daily Maximum Loading)

January 1, 2024 (5-Minute Data)

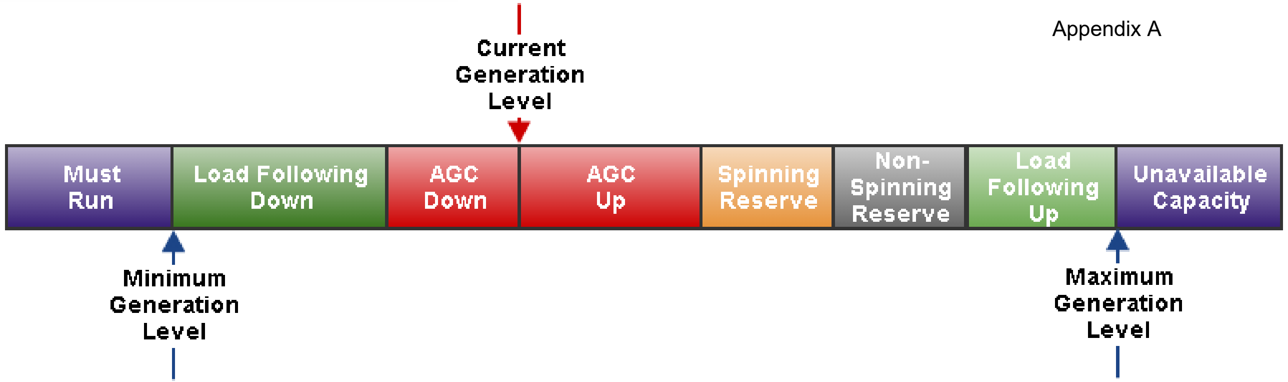


Comparing Predictability of Load, Wind, and Solar

January 1, 2023, through April 30, 2024 (Hourly T-1 vs. Actual Data)



Ancillary Services

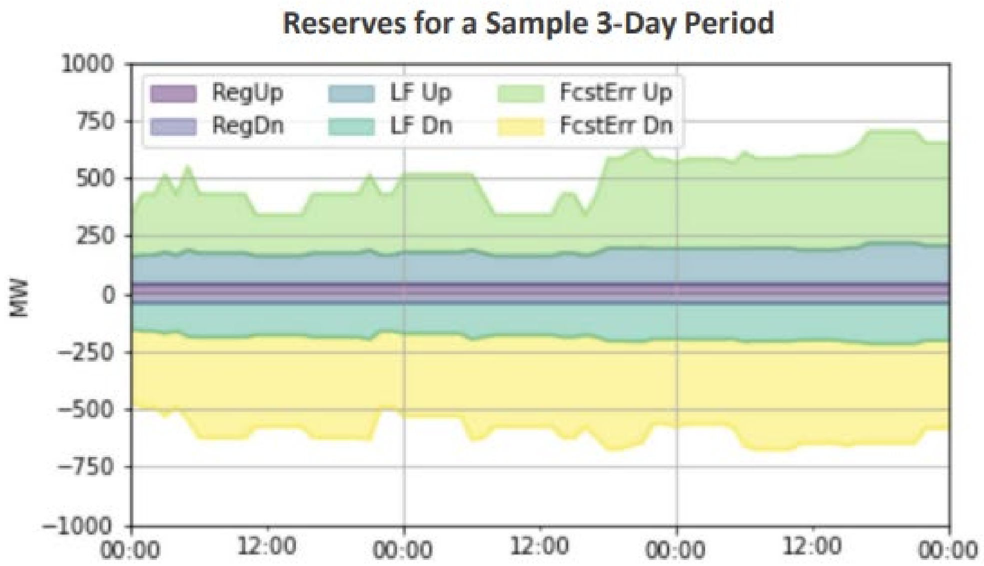


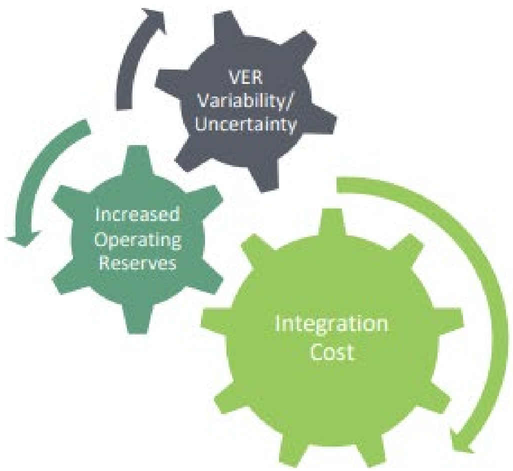
- What are ancillary services?
  - capacity services matching real-time variance between load & generation
- Why do we need ancillary services?
  - customer load variation
  - VER forecast error
  - forced outages
- How do we supply ancillary services?
  - (generally) "hold back" generator capacity

Ancillaries as They Pertain to VERs (Solar, Wind)

Operating Reserves

- **Operating reserves are latent dispatchable capacity that can be called upon to maintain reliability during sudden, unexpected changes of system load or generation**
- **Avista currently holds operating reserves types**
  - **Regulation Reserves** are procured to handle rapid, unexpected variations in net load
  - **Load-Following Reserves** are procured to handle hour-to-hour variations in net load
  - **Forecast Error Reserves** are procured to handle net load uncertainty in the hour-ahead timeframe
  - **Spinning Reserves** are procured to cover NW reserve-sharing agreement for load and forced outages
- **Reserves are required in both the up and down direction**
  - An "up reserve" is defined as a reserve held to deploy a sudden increase in generation
  - All reserve types are mutually exclusive and held independently





Ancillaries as They Pertain to VERs (Solar, Wind)

Key Concepts

- Integration costs are driven primarily by the need to hold higher levels of reserves
- Higher reserve levels are needed because of large variability and uncertainty of VER production
- Higher reserve levels means de-optimizing system operations relative to what they would have been absent additional VERs

VER Integration Study Scope

Purpose and Overview

- What's included in the study?
  - consumptive capacity and its costs
  - impacts of EIM ("fast") markets
  - potential future portfolio VER buildouts
  - sensitivity scenarios
- What's not included in the study?
  - alternative capacity resources (e.g., batteries)
  - new utility-controlled storage *
  - VER-driven investments in existing infrastructure
  - distributed generation or response beyond what's in IRP

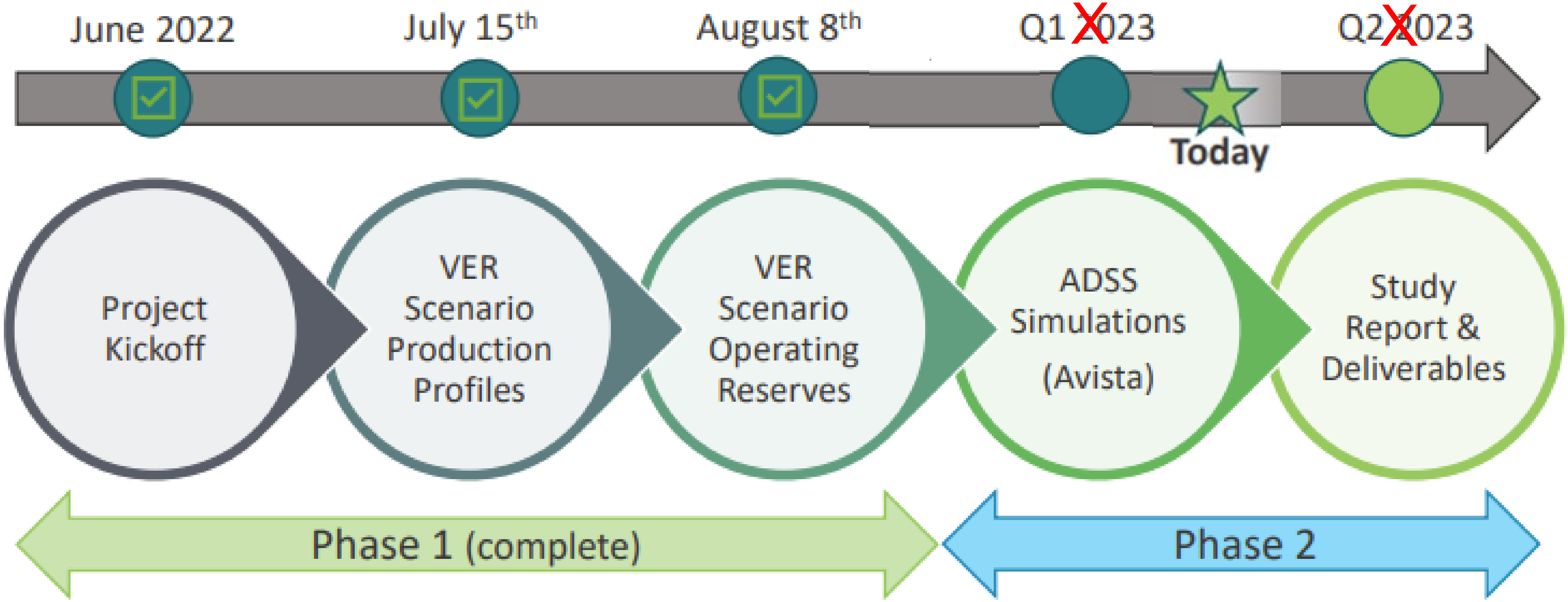
• we assume size of wholesale market grows commensurate with added VER resources to address need to transact greater volumes of power (e.g., 2,500 MW scenario has 2,500 MW of additional market)

VER Integration Study
Purpose and Overview

- Consistent application supporting varying analyses
  - Integrated Resource Planning
  - resource acquisition processes (e.g., RFP)
  - transmission rates
  - PURPA avoided cost calculations
- Define “Consumptive Capacity” associated with incremental variable energy resources
- Determine costs of carrying consumptive capacity

VER Integration Study Timeline

Timelines have slipped a bit



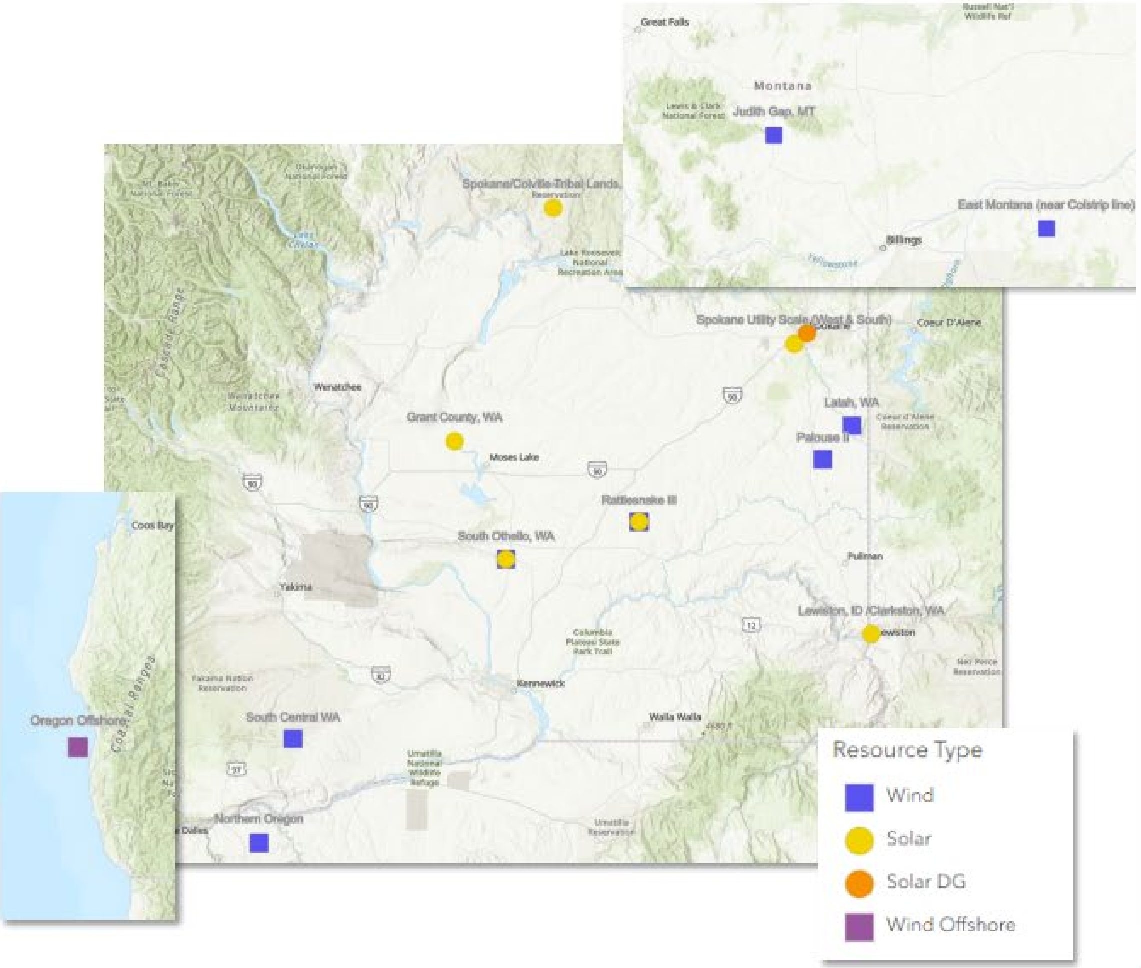
* ancillary services covered in later slide
** excludes variation from forced outages that affect all resources
*** but estimating this savings is difficult given varying methods employed

VER Buildout Scenarios

Locations Based on Past Proposals

- Three VER portfolios
    - Solar, Wind, 50/50*
- Four VER penetrations
    - 400, 800, 1500, 2500 MW

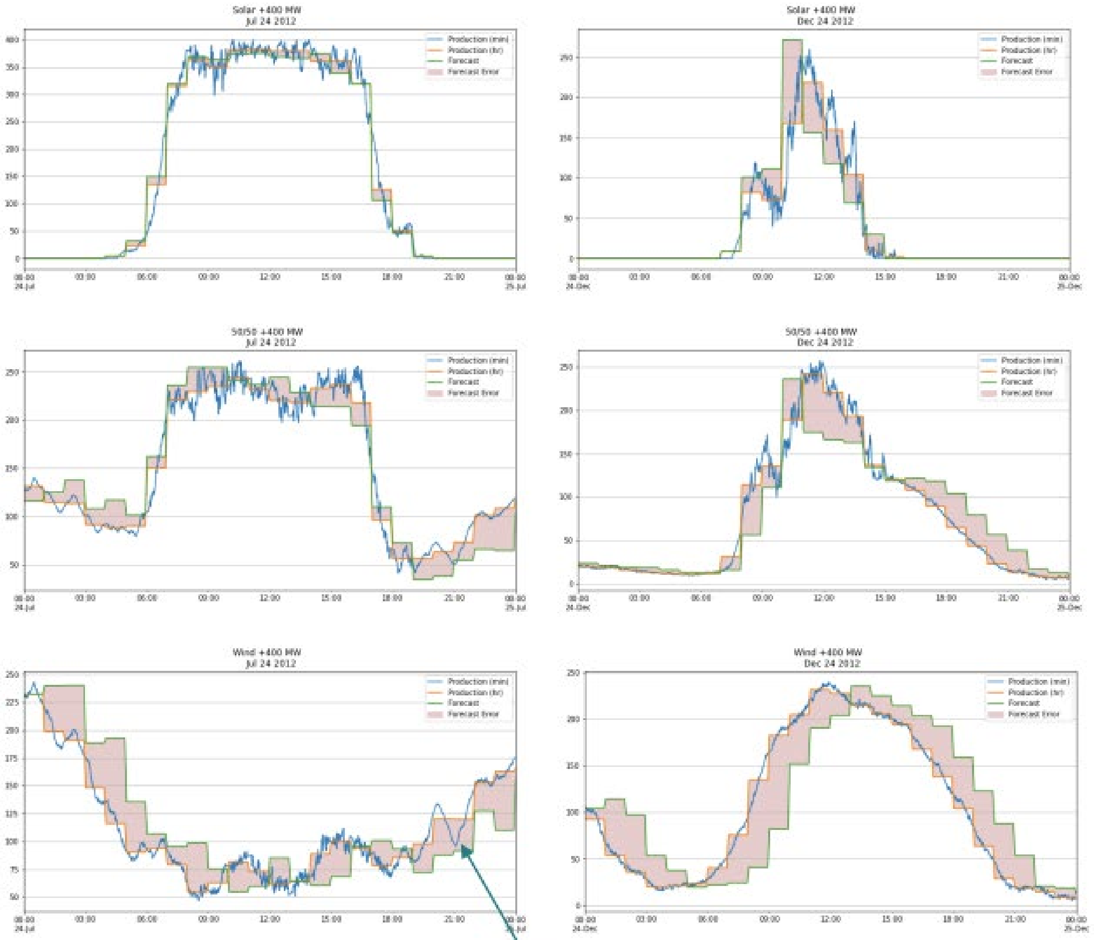
	Type	Wind	50/50	Solar	Wind	50/50	Solar	Wind	50/50	Solar	Wind	50/50	Solar
North Colstrip, MT	Wind	100	100		200	200		200	200		400	200	
Judith Gap, MT	Wind	200	100		200	200		300	200		400	300	
South Othello, WA	Wind	100			100			100	100		150	100	
Rattlesnake II	Wind				200			200	200		200	200	
Palouse II	Wind				50			75	50		75	75	
Northern Oregon	Wind				50			200			200		
Latah, WA	Wind							125			125	125	
Oregon Offshore	Wind							200			550	250	
South Central WA	Wind							100			200		
Rattlesnake III	Wind										200		
Lewiston, ID /Clarkston, WA	Solar		200	300		200	300		300	300		300	300
Othello/Lind, WA	Solar			100		200	400		200	400			400
Spokane/CDA DG	Solar						100		150	300		350	500
Grant County, WA	Solar									200		200	200
Spokane/Colville Tribal Lands, WA	Solar								100	100		100	200
Rattlesnake Wind	Solar									200		300	200
Spokane Utility Scale (West & South)	Solar												300
East Montana (near Colstrip line)	Solar												400



* 50/50 mix created based on nameplate capacity (e.g., 200 MW solar, 200 MW wind)

VER Profiles and Forecasts

- **Forecasts for wind resources utilized the NREL WIND dataset**
  - ❖ Wind forecasts were validated to ensure that hour-ahead forecast errors were consistent with available industry forecast methods available to Avista
- **Forecast for PV resources utilized the NREL SIND dataset**
  - ❖ PV forecasts represented a 2006 weather year, and were adjusted to represent forecast errors consistent with available industry forecast methods available to Avista
- **Site-specific production/forecasts were summed together to represent total VER production/forecast for each VER scenario**



Wind Forecast Error: 27% - 31%
PV Forecast Error: 6% - 8%

Reserve Calculations

- **Reserve levels are determined by taking a statistical confidence interval of "errors" that represent unanticipated variability or uncertainty contributed to the system by VERs**
  - Reserve calculations identify the MW level of reserves required to 95-99% of variability and uncertainty of VER integration for each scenario.
  - Each reserve calculation results in an MW value that represents the latent spinning reserve capacity, which should be held by other dispatchable generators in the Avista system, as defined by constraints in the ADSS production cost model.
- **Energy Strategies' calculated reserve confidence intervals via statistical analysis based on 7 historical weather years**

Regulation Reserves

- Procured to handle rapid, unexpected variations in load or generation
- **Regulation Error = 1-min Net Load – 10-minute Net Load Rolling Average**
- Calculated as a 3σ confidence interval of Regulation Errors
- On-Peak and Off-Peak values calculated by month

Load-Following Reserves

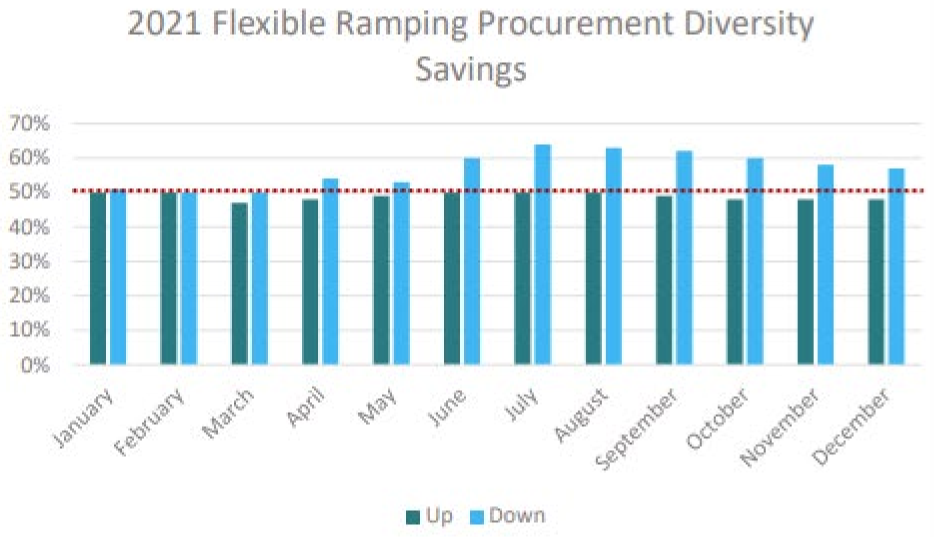
- Procured to handle hour-to-hour variations in net load
- **Load-Following Error = 1-min Net Load – Hourly Average Net Load**
- Calculated as 2σ confidence interval of Load-Following Error
- Calculation bins load-following reserves held in operating hour by VER forecast
- Discounted by 25% to represent EIM Diversity Benefit

Forecast Error Reserves

- Used to handle net load uncertainty in the hour-ahead timeframe
- **Forecast Error = Net Load – Net Load Hour-Ahead Forecast**
- Calculated as 2σ confidence interval of forecast errors
- Calculation bins forecast reserves held in operating hour based on VER forecast
- Discounted by 25% to represent EIM Diversity Benefit

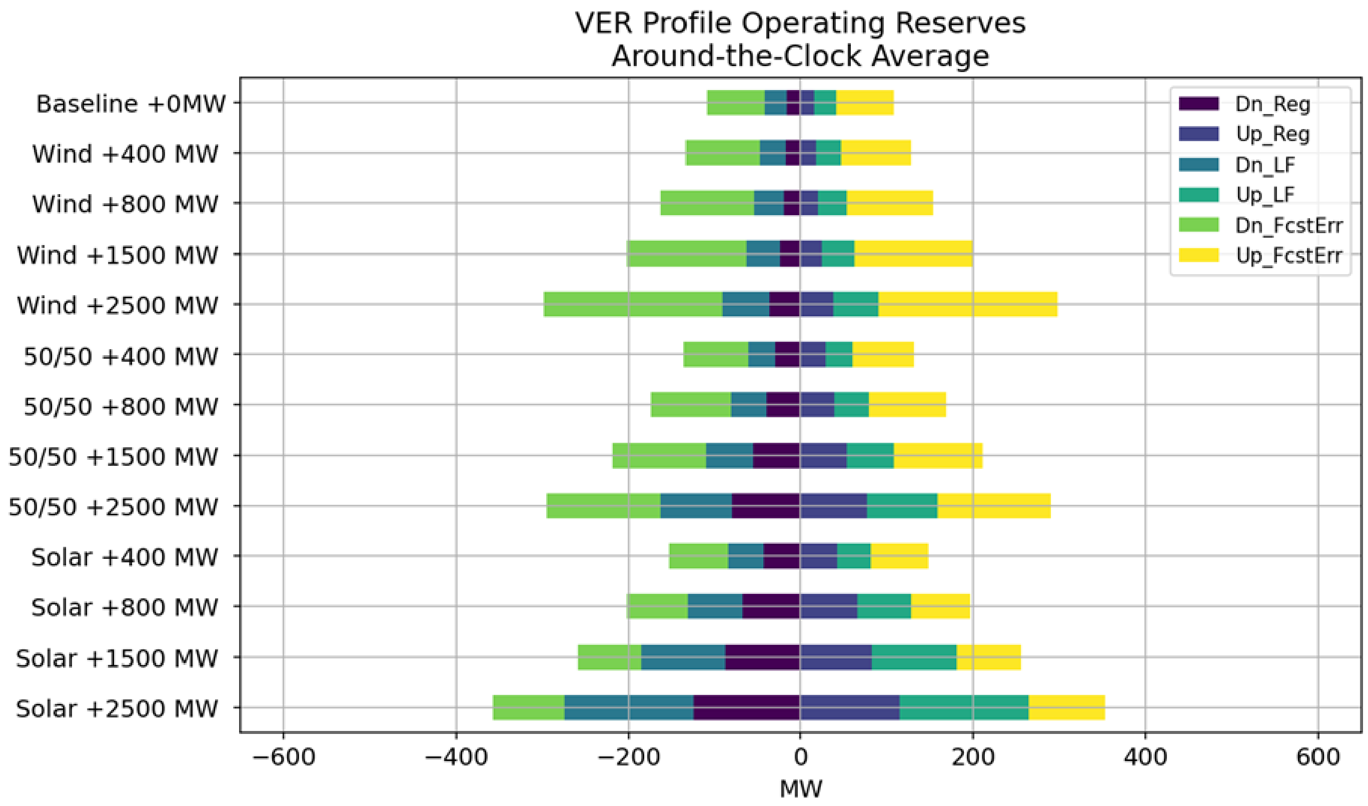
EIM and Reserves

- **The Western EIM facilitates procurement of flexible ramping capacity to address variability that may occur in real-time dispatch**
  - The application of flexible ramping capacity serves to reduce the level of Load Following and Forecast Error reserves held within the Avista BAA footprint
  - **In 2021, Western EIM flexible ramping procurement diversity savings averaged to approximately 50%**
- **However flexible ramping capacity likely would not represent a 1:1 reduction in load-following and forecast error reserves due to:**
  - Flexible capacity may be constrained by EIM import/export limitations and, thus, may not be as dependable as physical capacity, resulting in Avista still carrying some additional level of reserves
  - Flexible ramping capacity changes hour-to-hour, depending on system conditions, so more reserves may be required in some hours, indicating it may be appropriate to assume some reduction in the average flexible ramping diversity benefit
  - An EIM participant can be excluded from the flexible ramping diversity benefit if they fail the flexible ramping test, which would also serve to reduce the flexible ramping procurement savings



EIM and Reserves

- **The graph shows how reserve levels relative to the Avista Reference, and how reserve levels change between VER scenarios**
  - ❖ Up- and down reserve levels are similar, in aggregate
  - ❖ Solar seems to be driving more reserve increases per MW of installed capacity, primarily due to load following
  - ❖ Wind Forecast error is larger than PV forecast error, and drives more of the reserves in the wind-only scenarios



- For the VER integration study, we reduced consultant-calculated load following and forecast error reserves by 50% to reflect benefits of EIM diversity

Study Methodology

- 2021 actual system conditions with ADSS software
  - Hydro conditions, outages, fuel prices
- Run Avista system portfolio with and without VER
  - 2 VER condition scenarios: without new VER, with new VER
  - 5 VER addition scenarios: 400, 800,1500, 2500 MW
  - 3 VER mix scenarios: all solar, all wind, 50/50 solar/wind (by nameplate)
  - 3 market conditions scenarios: low, base, high prices
  - **In total, requires 90 scenarios of 2021 under varying conditions**
- Calculate deltas between scenarios to determine integration costs

Removing Commodity Energy Value from Study

Two cases include the same energy amounts to avoid biasing results

- “Without VER” scenarios
  - input monthly 12x24 energy shape
  - no incremental reserves
  - emulates a firm contract delivery of same energy quantity as With VER
- “With VER” scenarios
  - input hourly-varying energy shape from consultant study
  - input incremental reserve levels from consultant study
- Subtracting “Without VER” value singles out integration

Preliminary Study Results – Average Costs

Changeset	Integration Cost ($/kW-mo)			Integration Cost ($/MWh)		
	Base	High	Low	Base	High	Low
Existing	0.16	0.23	0.11	0.78	1.11	0.53
5050 400	0.05	0.15	0.03	0.20	0.66	0.11
5050 800	0.12	0.24	0.08	0.50	1.00	0.34
5050 1500	0.33	0.64	0.21	1.53	3.00	1.00
5050 2500	0.57	0.84	0.49	2.90	4.23	2.50
Wind 400	(0.00)	0.09	(0.00)	(0.01)	0.37	(0.01)
Wind 800	0.33	0.71	0.19	1.31	2.85	0.78
Wind 1500	0.90	1.50	0.62	3.78	6.31	2.62
Wind 2500	1.92	2.48	1.74	8.96	11.62	8.14
Solar 400	0.22	0.41	0.14	1.10	2.09	0.72
Solar 800	0.36	0.70	0.22	1.89	3.71	1.17
Solar 1500	0.42	0.80	0.28	2.46	4.64	1.62
Solar 2500	0.84	1.13	0.77	6.00	8.14	5.50

Preliminary Study Results – Marginal Costs

Changeset	Integration Cost ($/kW-mo)			Integration Cost ($/MWh)		
	Base	High	Low	Base	High	Low
Existing	-	-	-	-	-	-
5050 400	(0.03)	0.10	(0.03)	(0.13)	0.39	(0.13)
5050 800	0.11	0.24	0.07	0.42	0.97	0.28
5050 1500	0.36	0.72	0.23	1.66	3.33	1.08
5050 2500	0.62	0.91	0.54	3.15	4.60	2.74
Wind 400	(0.12)	(0.00)	(0.08)	(0.40)	(0.00)	(0.28)
Wind 800	0.39	0.88	0.23	1.45	3.32	0.85
Wind 1500	1.04	1.74	0.72	4.26	7.13	2.95
Wind 2500	2.12	2.74	1.92	9.84	12.75	8.97
Solar 400	0.26	0.54	0.17	1.34	2.81	0.87
Solar 800	0.43	0.87	0.26	2.33	4.73	1.42
Solar 1500	0.47	0.90	0.31	2.85	5.46	1.87
Solar 2500	0.91	1.24	0.84	6.91	9.38	6.37

Next Steps

- Finalize study results
- Generate final study report
- Use in future IRPs/RFPs/transmission tariff

VER Study Uses in the 2025 IRP

- Integration Cost ($/kW-month) included as a resource cost (slide 18)
- Reliability modeling will include a “Flex Ramp” adjusted for EIM benefits reserve determined by this study (slide 15)
- Capacity expansion modeling will include a small incremental flexible capacity requirement for each state using this study

Questions?

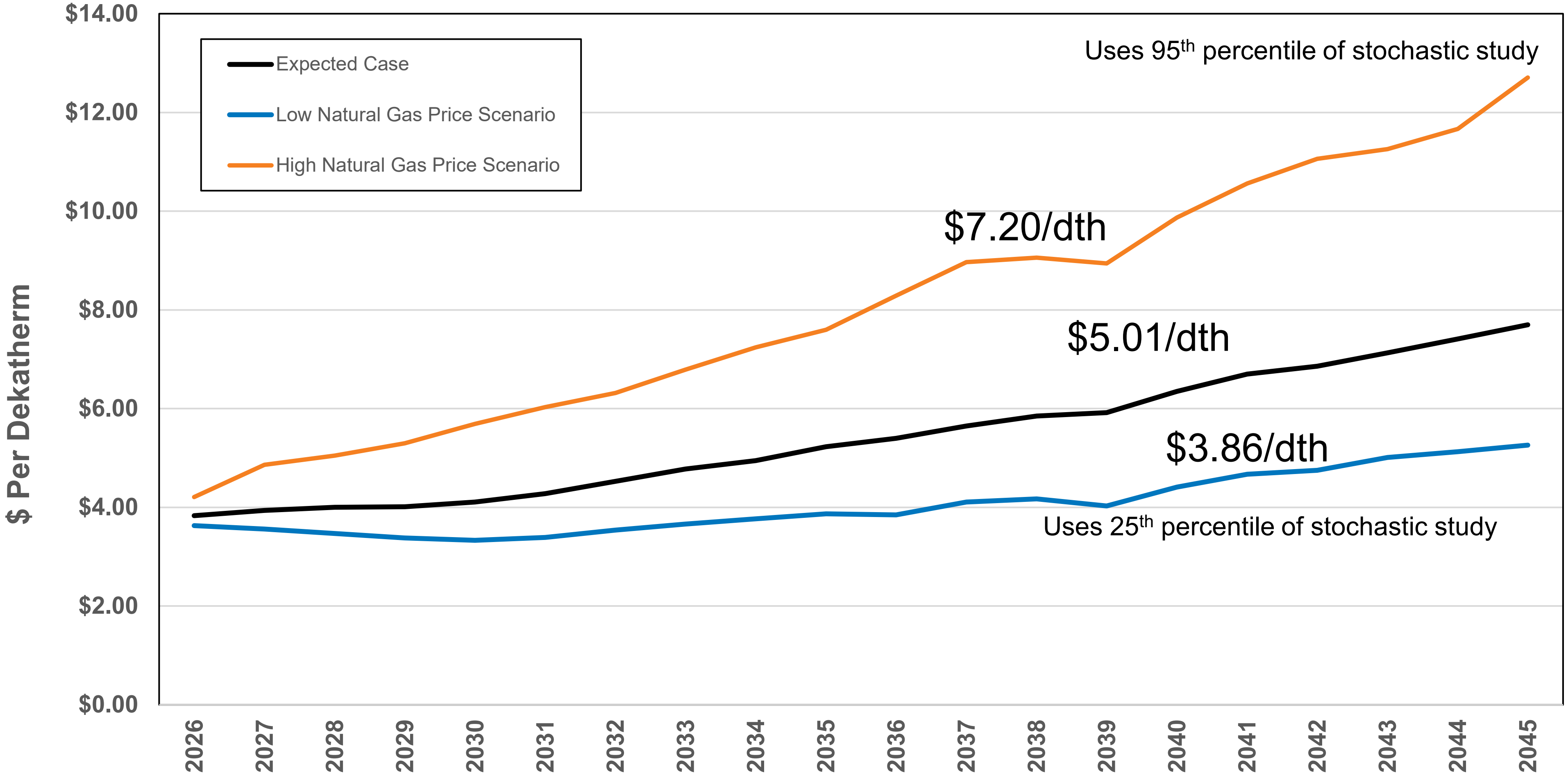
2025 IRP Market Scenario Update (DRAFT)

James Gall
Technical Advisory Committee Meeting No. 7
May 21, 2024

Market Scenario Update

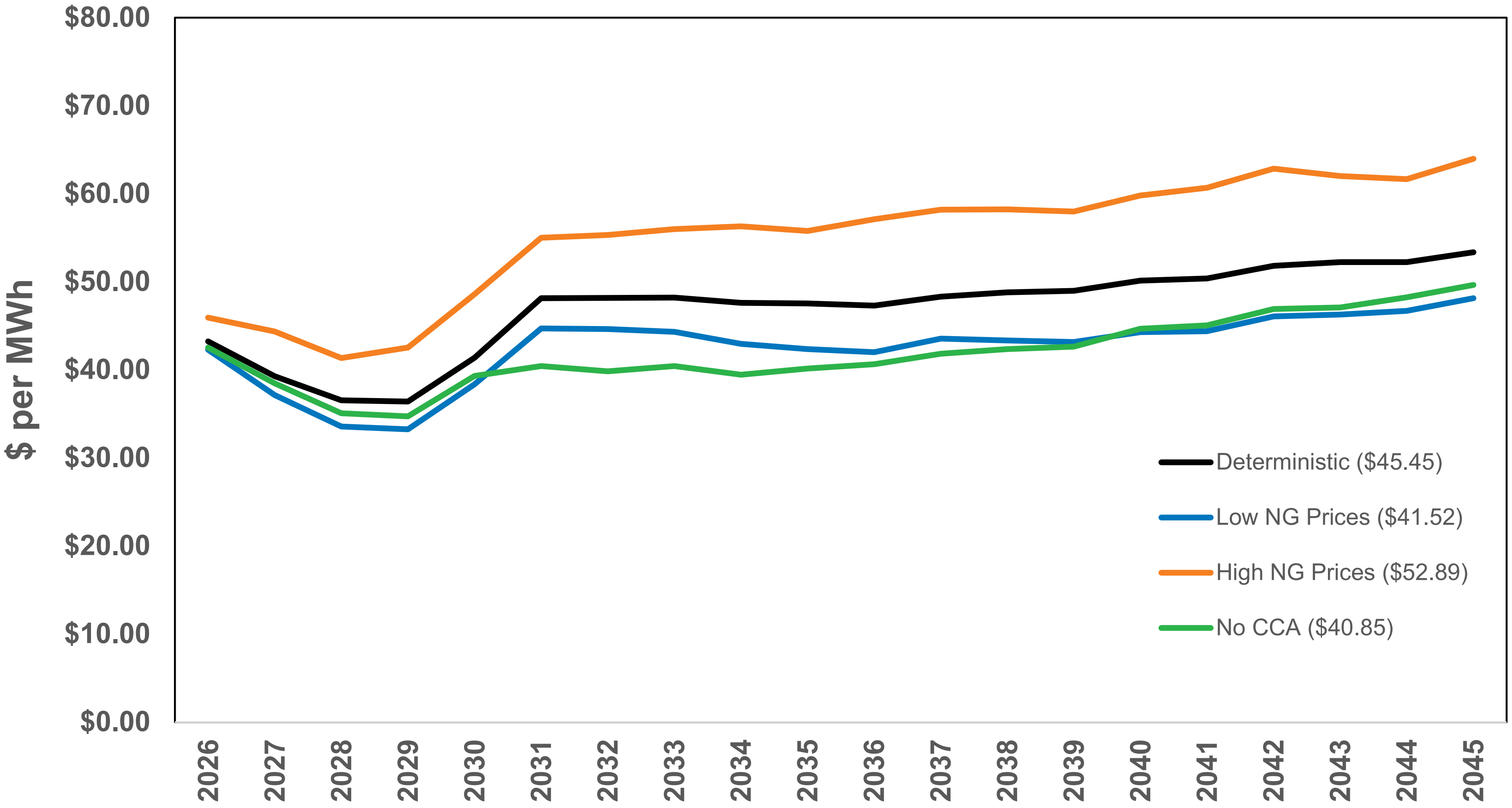
- Expected Case (Deterministic/Stochastic)
- Low Natural Gas Prices
- High Natural Gas Prices
- No Washington Climate Commitment Act

Henry Hub Natural Gas Prices



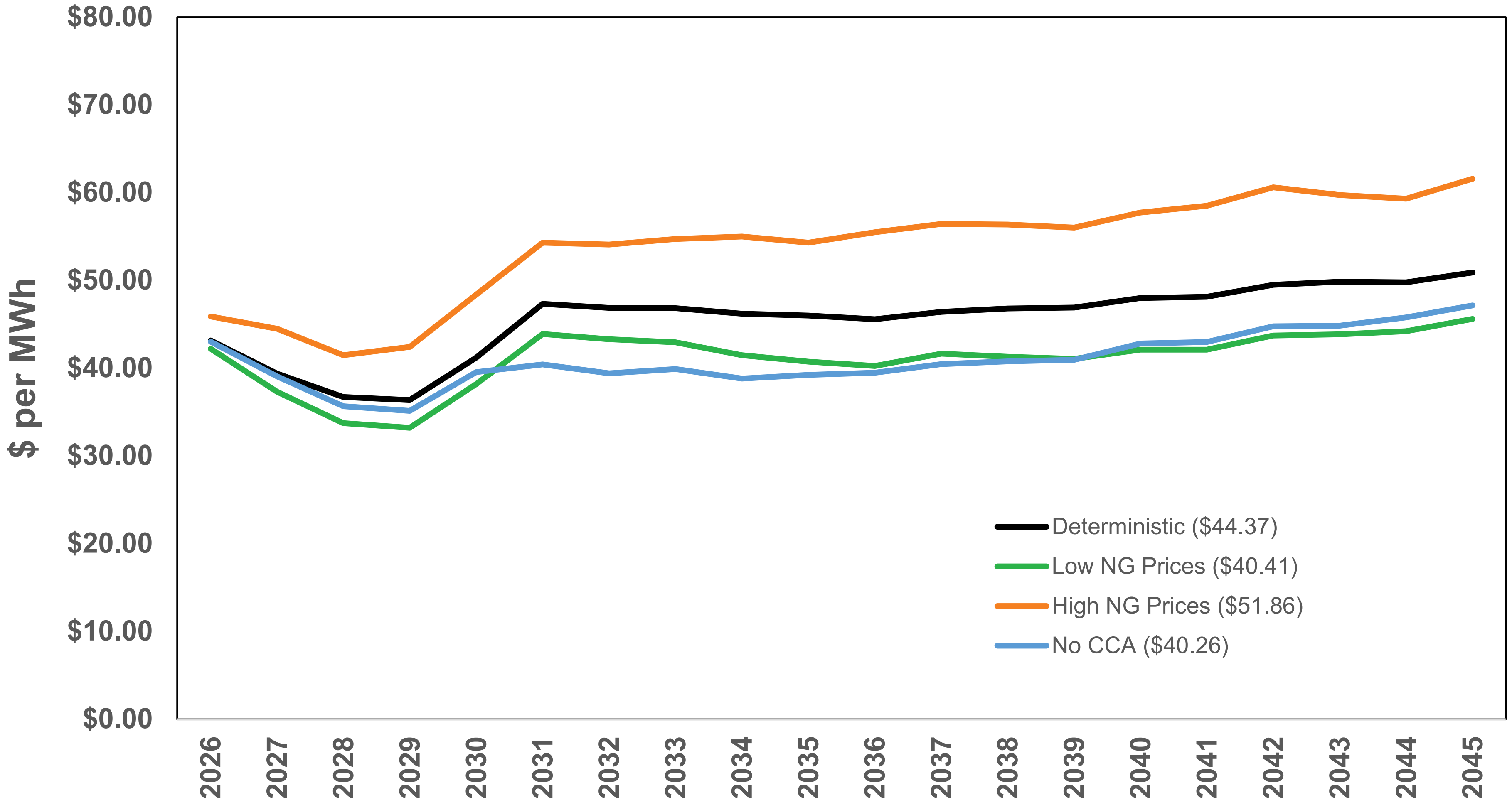
Prices inserted are 20-year nominal levelized

Electric Price Forecast
Mid-Columbia (Washington Delivery)



Prices inserted are 20-year nominal levelized

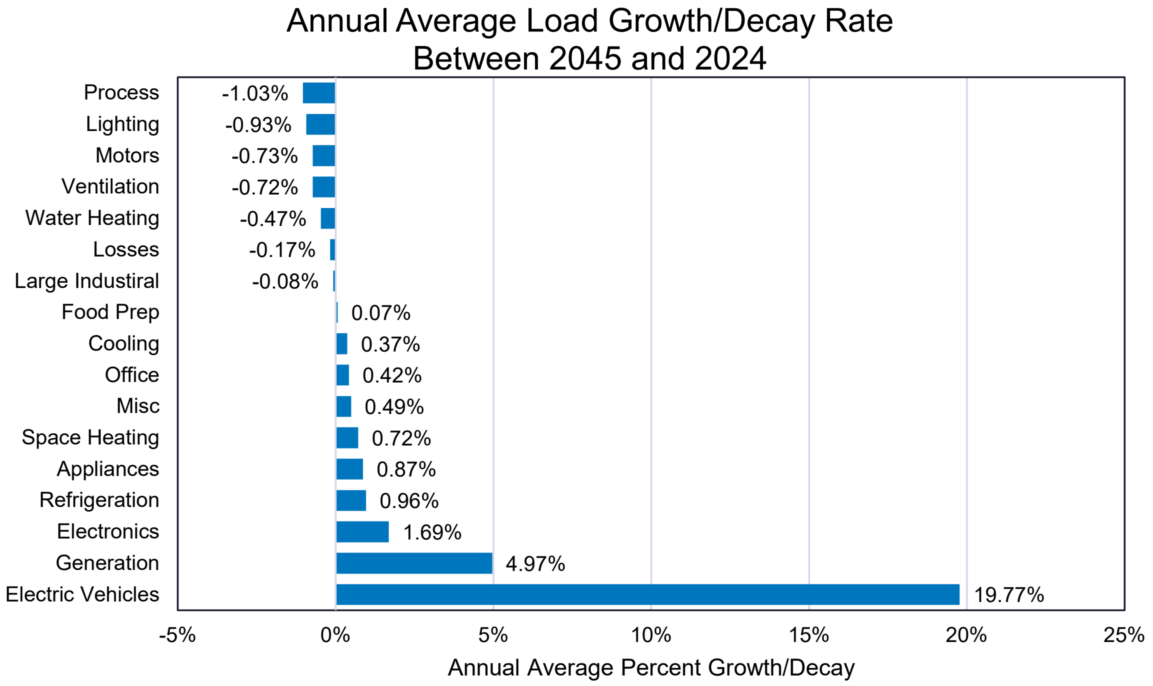
Electric Price Forecast
Mid-Columbia (Non-Washington Delivery)

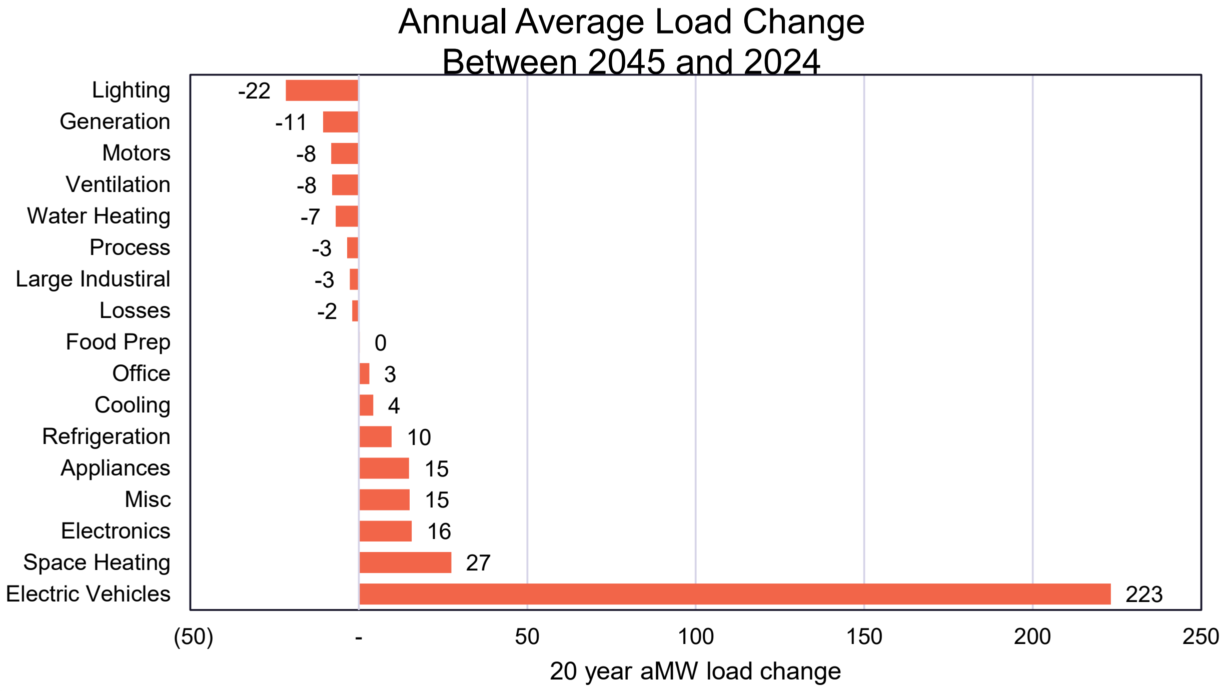


Prices inserted are 20-year nominal levelized

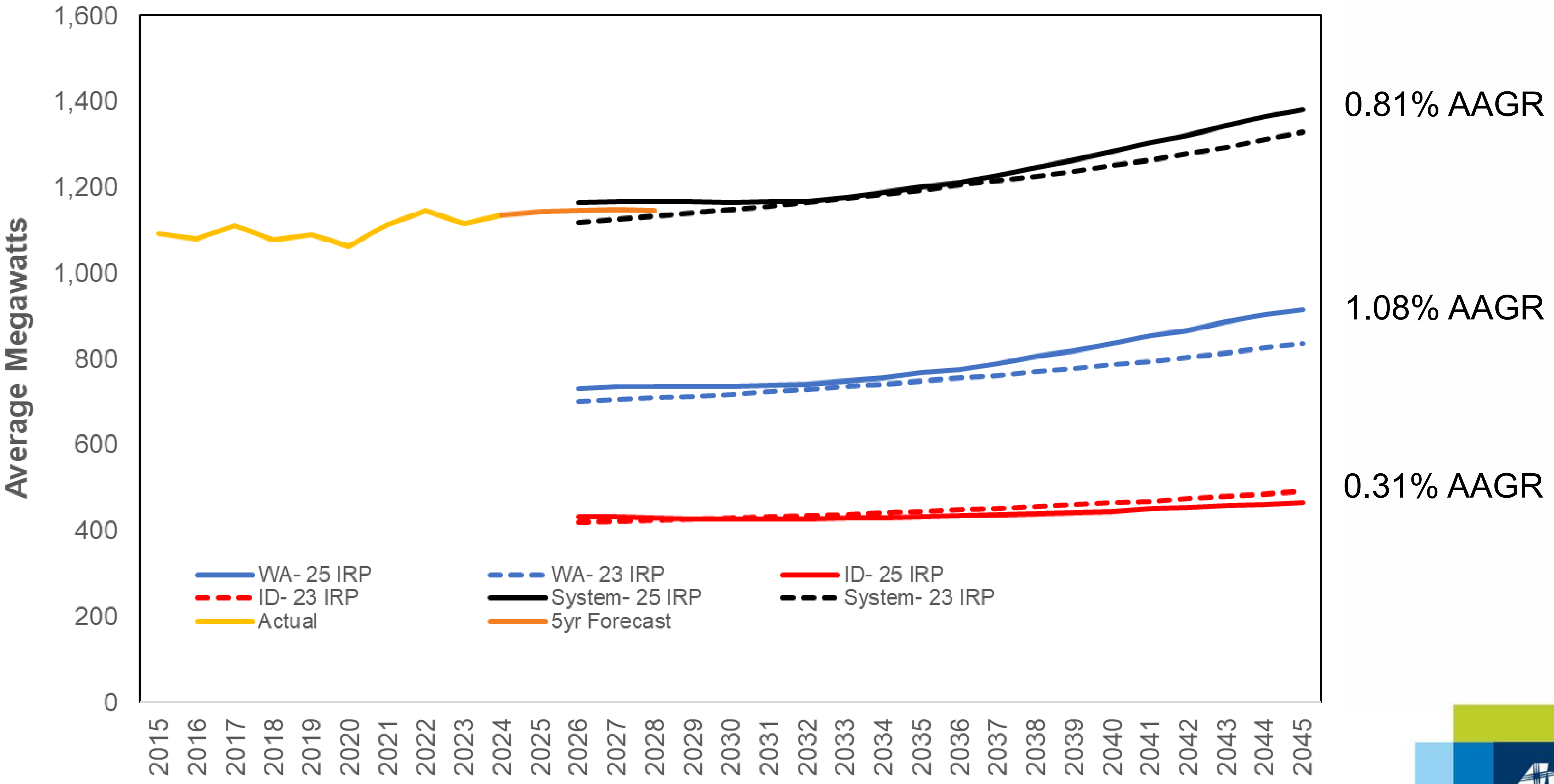
2025 IRP Load Forecast

System End Use Changes in Load Forecast

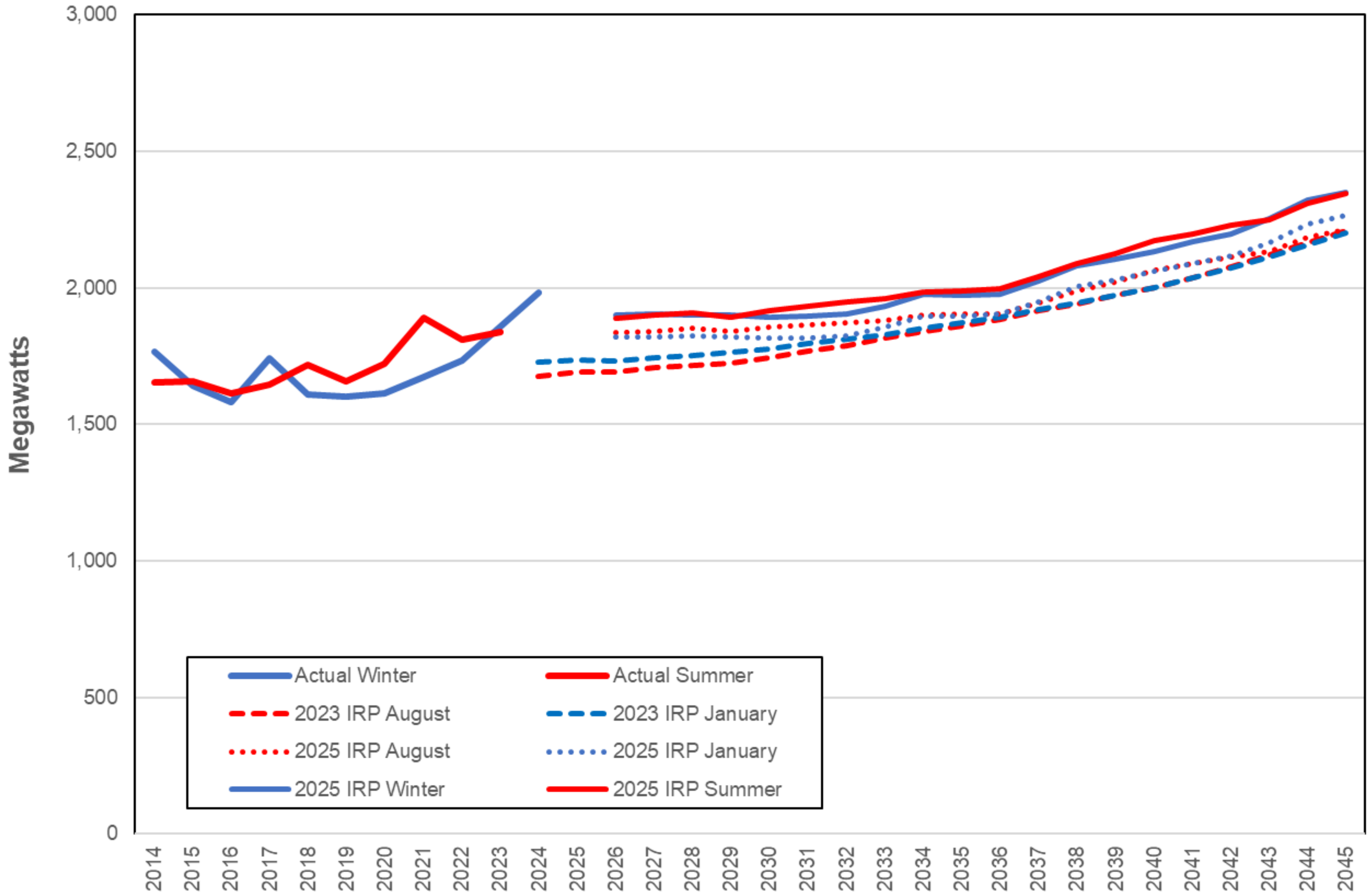




Energy Forecast



Peak Forecast (Forecast is 1-in-2 Weather Event)



1.02% Winter AAGR

1.10% Summer AAGR

TAC 7 Meeting Notes, May 21, 2024

Attendees:

Sofya Atitsogbe, UTC; Kim Boynton, Avista; John Barber; Molly Brewer, UTC; Kate Brouns, Renewable NW; Michael Brutocao, Avista; Logan Callen, City of Spokane; Katie Chamberlain, Renewable NW; Josie Cummings, Avista; Kelly Dengel, Avista; Mike Dillon, Avista; Jean Marie Dreyer, Public Counsel; Michael Eldred, IPUC; Rendall Farley, Avista; Ryan Finesilver, Avista; Grant Forsyth, Avista; James Gall, Avista; Bill Garry; Konstantine Geranios, UTC; Amanda Ghering, Avista; Michael Gump, Avista; Leona Haley, Avista; Tom Handy, Whitman County Commission; Fred Heutte, NW Energy Coalition; Kevin Holland, Avista; Joanna Huang, UTC; Clint Kalich, Avista; Scott Kinney, Avista; Seungjae Lee, IPUC; Dan Lively, Clearwater Paper; Kimberly Loskot, IPUC; Mike Louis, IPUC; John Lyons, Avista; Patrick Maher, Avista; Jaime Majure, Avista; Ian McGetrick, Idaho Power; Tomas Morrissey, NWPCC; Austin Oglesby, Avista; Michael Ott, IPUC; Tom Pardee, Avista; Meghan Pinch, Avista; John Rothlin, Avista; John Calvin Slagboom, WSU; Dean Spratt, Avista; Victoria Stephens, IPUC; Lisa Stites, Grant County PUD; Jason Talford, IPUC; Charlee Thompson, NW Energy Coalition; Yao Yin, IPUC.

Variable Energy Resource Study, Clint Kalich

[Recording and transcription started after the introduction.]

Clint Kalich: But we still didn't have real data to compare to, whereas today we do. We have a lot more information in the industry to study, so let's step into that. Let's just step back at the beginning here. I will mention though, that there is a work group, if you're interested, I think the folks, some of the folks I see on the invite list today are attending today were included in our workshops on the variable energy resource study. I will say that we've been paused on that study primarily because of an effort we went into the EIM, and we had to do a lot of new coding to support EIM within the ADSS software. And when we finally stopped that effort and finished and went into EIM in 2022, we found a lot of what industry insiders called technical debt. For me, what that means is a software doesn't work. While we got the software to work great for our trading floor and for the EIM integration, all of the tools we used in ADSS for planning, which was actually what it was originally designed to do, had broken. The development team over the last year and a half has been putting all of the pieces back together so that we can do these studies.

Clint Kalich: So, we had to pause this variable energy resource study. There were three phases. The first phase was the data collection, and then going over to Energy Strategies, a consulting firm, to calculate the incremental ancillary services, which I'll talk about that are necessary to run the study. Then there was the ADSS model runs that actually occur. The third phase is back to Energy Strategies whereby they take a look and audit the results of our ADSS software model runs. We're currently in Step 2, which is the modeling. We're very close, but we're not finished. But the work group has paused while we're waiting for the ADSS software to be brought back to life for the planning modules of that software.

Clint Kalich: Now let me step back the differences between traditional resources and VERs. So, what are traditional resources? There are quite a few different ones. I don't have them all here, but traditionally in the northwest – coal, gas, hydro, and biomass have traditionally been used. They have a reliable and known fuel supply. In other words, if you have a coal plant, you have a pile of coal out there. You know the fuel is there and you can turn it on and off when you need it. It's responsive to operator direction either on a scheduling basis for the next hour, or even instantaneously hour-to-hour, or automated on AGC where the computers control it. If they ask for 10 more megawatts, they get 10 more megawatts. If they ask the resource to back off 10 megawatts, the resource backs off. That's generally not how variable energy resources work. I'll talk about those in a minute. We talk about them, or I talk about them, as being net contributors to system ancillary service requirements. In other words, because you can control them and move them around, they actually support system operations and system reliability. The generation, the variation is predictable, as it's generally caused by operator instruction. So, if you look at a resource performance, say at our Coyote gas plant, you're going to see a lot of up and down, not anything like a variable energy resource, but almost all of those ups and downs are driven by the operators. The operators wanted those plants to move up and down. They're not reacting to the movement of those plants, so if a variable energy resource comes offline because the wind stops, you can bring this resource up and it's predictable and controllable. That's what a traditional resource is. It generally helps your system respond to load changes, but variable energy resources are quite a bit different. They act, in some ways a lot more like a load, although they're tremendously more variable than load.

Clint Kalich: What are some of the characteristics of variable energy resources now? The obvious one, I didn't even list it here, is it's carbon free. That's one of the huge benefits some of the traditional resources are carbon free biomass, nuclear, but variable energy resources certainly are carbon free, and that's why we're chasing those resources to, as part of our decarbonization strategy. But the downsides are the fuel supply is subject to weather, and these are some of the things that cause this integration costs that we're studying. The good news is that geographical dispersion can help, and in fact you're going to see in some of the statistics today we expect as we get geographical dispersion from our existing resources, which all are within our fairly small footprint. In other words, they're located close to our loads, but the downside is they all operate within the same weather patterns. But as you get geographical dispersion, it should help. Let's talk about wind fuel supply issues specifically. It depends on how you look at it. I have some pictures on this, but wind is about 36 times as hard to forecast as load. In other words, it's 36 times less predictable, and I'll show some statistics on that later. So, it's a huge challenge. One MW of wind is like 36 megawatts of load, so we've always dealt with load and loads have been difficult to deal with. But wind is much more variable, so it has really challenged our industry.

Clint Kalich: I've already talked about geography, but when it varies moment to moment. Literally, you can lose an entire wind farm over a period of a few minutes, especially when a large blast of high-speed wind comes into play. There's cut outs, you lose them instantly. Other instances where it gets very cold, you may lose those turbines more slowly. Or when the wind is coming online, you may have turbines come online, still very quick, but it won't be instantaneous. There's a lot of variability there. And another thing is you need wind to generate between roughly 10 and 50 mph to be able to make any power out of these plants. A lot of times wind is lower than 10 miles an hour or above 50 mph, and in those cases, you don't have any wind generation.

Clint Kalich: On the solar side. Depend again on how you look at the statistics. Solar isn't as tough to forecast as wind, but it's still about 22 times as hard to forecast as load. And substantially this is driven by cloud cover. I mean, certainly solar is variable, but a lot of the variability is the fact that the sun goes down, the sun going down is fairly predictable. So, what's driving the variability on solar otherwise is cloud cover. As the clouds go overhead there appears to be less benefit from geographical diversity, at least as far as the variability goes. But there are some geographical benefits due to diversity. Again, things we learned with energy strategies and studies were done on the data we had.

Clint Kalich: Let's just look at a few pictures I talked about when being 36 and solar being 22 times as variable. Here's some data, I picked the first day of January 2024 and it's not a bad day or a good day. It just was wonderful because it shows some of the variability. You can see the load shape there in blue. I'm starting at 80% of what I did to make them apples to apples is I graphed their average load relative to their peak for the day. So, you can see here for in the load we start out the beginning of the day at just under 80% of the peak for the day. In that moment in time, and you can see it goes from 80% down a little bit and then comes up and by the end of the day, we're back down about where we started. So, you can see variability from fairly smooth and predictable because, again, load is reasonably predictable, and you can see where the load went.

Clint Kalich: Similarly, on Coyote, that's the orange line at the top. You can see Coyote came in running at capacity all day. We backed it off a little bit. Midday it came back up. Back it off a little bit again, and then brought it back up and you can see here that changed. These changes, though, were driven by operator choices, so we would call it this day, Coyote was wonderfully predictable and controllable, so Coyote causes no real issues around reliability or variability.

Clint Kalich: But then let's look at wind and solar. Rattlesnake Wind. I grabbed in yellow. Here's what Rattlesnake Wind did, it started out at 40% of its 150 MW nameplate at the beginning of the day, fairly rapidly, over an hour dropped to zero, was offline for seven hours, and came back on a little bit, dropped offline, came up a little bit, and then back up midday. Interestingly enough, this wasn't our peak load. You can see our peak loads here and then, but it performed as soon as our peak load happened this day. Rattlesnake dropped offline and down again. You can just see all the variability and here's wind, of course. Wind in green. It's dark, so you don't have any solar in January until you get into the 8:00 o'clock hour. You can see it came up fairly predictable, but obviously we had some cloud cover and it dropped, it recovered, and now we were in the middle of the day. We had much more solar and then you can see the variability though with the cloud cover and then evening happens and it shuts off. And of course, our peak loads, here it's dark, so we have no generation contribution from solar at all. This graph says lots of things, but this is a pretty standard day for our resources and our loads. There's nothing unique or unusual about this. This is not an example that is that is biased against wind or solar. It's just an average day and what we deal with, and this is what the rest of our portfolio deals with, the movement around load, which is reasonably predictable but does move up and down. And this variability around wind and solar, it's a tough thing, but our operators obviously deal with it.

Clint Kalich: This is statistics. Taking a look at our forecast, if you look at one hour before the actual delivery of the resource and what we actually got, so how much error was there in the forecast one hour before you actually incurred, in this example the load. So, here's the average load factor of these resources over a year. Our load factor on our retail load is about 65%. So, for each MW on average, we deliver .65 megawatts to serve load relative to our peaks on wind. It averaged in this period of time, January through April of 2024. So, a year, actually it's a year and four months, it was a 29% capacity factor and it's about 40% of the load factor of our load. And then solar was 22%, about 30% of the load factor of our load. But let's look at the forecast error as a percent of the forecast itself, you can see here this is pretty standard. The mean average error on loads about 2.4%. And the way we buy these services from third party forecasting services, they're state of the art forecasts, whereas you look at when you're off by 85.3%, the average error relative to your forecast is 85.5%, which is that 36 times I talked about. And then if you look at solar, it's about 51-52%. So, some pretty amazing statistical difference between 2.4% versus 85%.

Clint Kalich: If you want to look at nameplate capacity. Some people like to look at the error and forecast relative to nameplate. I don't think that's the right way to look at it, because that's not how we do our system operations, but you might see these statistics in some publications. I wanted to provide it as a percent of maximum capacity. Load is 1.6% whereas wind is 10 and solar is 10. They're about the same into their nameplate capacity, so I wanted to share that information. Any questions at this point? I'll go ahead and stop. I just dumped a bunch of statistics out there, so if anybody had any questions, I'll pause for a minute.

James Gall: We've got a hand raised. Want to go ahead?

Fred Heutte: And there. Yeah. It's Freddie Heutte, Northwest Energy Coalition. As usual, I have a question or two, so this is for I just missed something. This is just for all of your wind and all of your solar combined, right? It's not just a single facility.

Clint Kalich: Well, all we really have, Fred, is we have two wind farms and we have one solar facility.

Fred Heutte: Right. OK.

Clint Kalich: This is Rattlesnake by itself, and this is our Lind solar plant by itself. There's not a lot of diversity in our portfolio, so the statistics wouldn't be greatly different, but you'll see our study looked at the diversity because we expect to see diversity.

Fred Heutte: Right, exactly.

Clint Kalich: In fact, you're going to see the next tranche of wind actually reduce our wind integration costs relative to what we have today, because it should add diversity to our portfolio. We expect it to.

Fred Heutte: Right, and this was.

Clint Kalich: You're going to see our incremental VERs are actually going to lower our average integration costs. They will probably in our RFPs get a reduction in cost because of the benefits we expect them to bring. So yes, this is just one project by itself.

Fred Heutte: Right.

Clint Kalich: This is not a portfolio. That said, I really don't have a portfolio today that has much diversity relative to this. I have one solar farm, so that's all I have.

Fred Heutte: Right. Got it.

Clint Kalich: Yeah. Well, it's a good clarification.

Fred Heutte: I think where this goes is it's an interesting tradeoff. Actually, it really argues for and even within some of the large wind and solar facilities, there is going to be variability within them. [Where they] have a couple of thousand acres, there's going to be some variability, maybe not very much. One thing we've learned, my friend Justin Sharp, a meteorologist here in Portland, just finished a big report for the energy system integration group on weather data and grid operations. His doctorate is in Columbia Gorge wind. You can't get more complicated than that. We've learned a lot from his work that a lot of micro variability, but really, looking at it, even a fairly large [project] like Rattlesnake or Lind. The interesting tradeoff here is you get more diversity, maybe with smaller new solar and wind facilities spread out over a wider area, but then that maybe might raise the cost a little bit because you get economies of scale with a 200 MW wind farm or solar versus a 20 MW one. But the diversity has real value and is really something I hadn't really thought about it like that. These really big developments have a lot of local impact, so there can be local opposition and so on. It really says something about the strategy we have to look at going forward. Finally, just want to commend you now personally and Avista for sticking with us for the last two decades and really being out on the leading edge of this because we all learn from what you're finding and that's really pretty important right now.

Clint Kalich: Well, thank you for that. Absolutely I think all of what you just said is true. This study will help us value that diversity to an extent the one piece that this does not do, we didn't when we had our contract with Energy Strategies, and part of the challenge is probably technically possible, but we didn't look at trying to say well what if we for example instead of buying 20 or 50 MW solar farms, what if we targeted 2 to 5 MW solar farms trying to get greater diversity. I think there's a lot of challenges to doing that as far as transmission and contracting and economies of scale as you mentioned, but there may be some diversity benefit. We could do some scenario analysis based on some back of the envelope diversity assumptions. In other words, if we could increase diversity and reduce reserves by 50%, what are we willing to pay for it? But here's the flip side of that, though, is our integration into the EIM has already substantially managed a lot of that. I'll talk about it later today. We've taken the reserve obligation of these, even these diversified portfolios that Energy Strategies worked on, and we cut the incremental reserves by half, which is about what we're seeing as a diversity benefit in the EIM. That's the reduction we're seeing because you're getting the full footprint of their larger forecast. So, in some ways, we've already accounted for that, and we've accounted for it in this study.

Fred Heutte: Yeah, the real, the big breakthrough for me was about a decade ago, the Western wind and solar integration study, which Michael Milligan worked on, among others, showed one they had multiple pieces. I could put the link in the chat here in a moment, just in case anybody's interested. Really showed that resource diversity across a big footprint like a regional footprint that the decorrelation of the output of these different resources and also the types of resources.

Clint Kalich: Good.

Fred Heutte: So, it's a geographic diversity and resource type diversity that you get some benefits from, and the market is a way to capture all that. And of course, that then depends on having enough transmission.

Clint Kalich: Yeah. We're involved, I think, in all those facets. We've joined the EIM. We're looking at EDAM and Markets Plus and of course looking at ways to support that transmission build out. All of those things were aware of, we certainly want to see those costs come down. Frankly, we need those costs to come down or they translate to cost. What are we doing physically that creates those costs and what it is, what I call consumptive capacity, and every MW I need to set aside, say, to follow a VER, I can't follow a MW of load. Essentially, I end up having to build all this additional capacity, which is low utilization, very expensive. All of these things benefit the system and at the end of the day, benefit and make the VER resources and the decarbonization more efficient, and hopefully at the end of the day, customers having a lower cost or even if they have a higher cost of decarbonization, we want to minimize what that incremental cost is. All of these aspects are how we get there.

Clint Kalich: Let's move on. I've got a lot of slides, a lot of data, so let's talk first about ancillary services, because I talk about consumptive capacity and that's really what this all is about. It's a deoptimized use of the non-variable resources. In other words, our other resources that are under control of the operators, they have to operate differently and they're deoptimized from what they otherwise would do. Let's look at this picture at the top, there's this current generation level we have what's called automatic generation control and we have to carry a certain percentage of our capacity online that responds to the frequency of the larger grid. We call that automatic generation control and load can move up and down. So, our generation level needs to bounce up and down in this red zone based on our load requirements. If a wind farm stops generating, our generation backs off a few megawatts, you have to move up the rest of your resources to cover that variance or down if the generation is more than you expected it to be. So, you have this instantaneous ability where the system we have to manage loads and resources in instantaneous time. We need to make sure we have resources that can respond instantaneously.

Clint Kalich: Beyond that, we have some of what people call regulation service too. There's some overlap there, but those are resources that are online and responsive. In addition to that, there's some spinning and non-spinning reserves. Those are called contingency reserves if you have a forced outage, so let's use a few examples. If we had a gas plant and the transformer signals that there was some problem with the transformer, the plant operators would require us to shut that plant off immediately and that was unexpected. We have to have reserves of other resources that we can rely on to back up that, in Coyote’s case, 300 megawatts of capacity. That's a lot of capacity on a wind farm. It could be cold weather cutouts or overspeed cutouts for our Kettle Falls biomass plant. It could be a problem with our fuel supply, we feed a bunch of waste fuel products in there and we can have problems with various things going on there. Whether we have tube leaks in the boiler or trouble feeding the fuel into the boiler, there's lots of things that could cause issues. You could also have a transmission outage that separates your generator from your load, and you have to have other resources to step up. Those are there and they're called contingency reserves because you don't exercise them very often, but you still have to have them available.

Clint Kalich: Then there's what I call load following, which is the load following up and down. If you're carrying a schedule for an hour, you promised to serve all of your load variability, all of your other variability in your system, and you're selling 100 megawatts to the to various external parties. You're holding 100 MW net schedule outside your system to third parties, but you're load and everything's changing, you still have to hold your system steady by bringing those other resources up and down. They don't necessarily have to be responsive to AGC, but eventually you're going to have to replace it as load moves up in the morning. For example, you might have a 200 MW swing from 6:00 o'clock AM to 7:00 o'clock AM. Where do you make up that 200 megawatts? It's really expensive to have AGC resources provide that because there aren't that many resources that are able to move that fast. So ,what you do is you have other resources that I call slower, they're slower responsiveness, but the AGC can capture the movement of the load for a while. Then you bring one of these load filling resources on and direct it to operate up more as the AGC will back down and then you can reset. It's almost like a stair step for your AGC units, so that's load following and then in addition to that you have certain resources that you have to run. If you have a nuclear plant or a coal plant, Colstrip, we have minimum operating levels we have to run. So, the minimum you can generate in your portfolios and then there are units that maybe are offline or derated and that would be your maximum generation level. So, you're at your current level and you move up and down in the hour, depending on what you're doing there and those are what helps you do that or answer your services to be able to move and respond to load changes.

Clint Kalich: So, what are their capacity services matching real time variance between load and generation? I pretty much have explained that at nauseam here. Why do we need them? And I already said this as well, customer load variation, VER forecast error, and the other major categories, forced outage, and we've already talked about those. So, what we're talking about for variable integration VERs study is we're looking at additional incremental load following up and down and additional AGC. And also, when you have a new resource, you always have spinning and non-spinning requirements that come along with any asset, but that's the same on a per MW basis, whether you have wind or you have gas or biomass or nuclear. Those pretty much are apples to apples. There's no difference, but what really is different in the case of variable energy resources is this load following and regulation, the blue and the red or excuse me the green and the red. That's what we're quantifying today.

Clint Kalich: And I'm going to show some slides on that piece, and I'll start showing actually some how do we provide it. And I already talked about, it's essentially a hold back on the existing generators we have. Noxon, instead of maximizing its generation on the peak hours of the day, might have to reduce the amount of peak hour generation it provides so that it can cover these incremental ancillary services. That means Noxon generates less value for customers in the energy market because it's providing ancillary services for the variable energy resources. I'm going to show a few slides throughout.

James Gall: Hey, Clint. Before you go to the next slide out, there was a question in chat that I missed from I think a statement you made earlier. This is from Yao. It says I think you mentioned that there was a pause in the study, but what is your timeline for completing the study? And we're going to show results here. Is there a pause?

Clint Kalich: Yeah. We had that pause and it's been almost two years now, our software is back up and running. We still have a few little issues where we get a few hiccups in the network, but substantially now we can complete the studies. You'll see preliminary work today. We're just about to the point of finalizing the study and then we'll have Energy Strategies review the data to make sure that that they think it meets their understanding of a good wind integration study, that third party review, and then we'll have some results. I would say late summer, end of the year worst case.

Clint Kalich: And I think, James, you're planning even if we haven't completely finalized it, you plan in the IRP is to use the preliminary results, right?

James Gall: That is correct, yes.

Clint Kalich: Because we are very close. We've actually run numbers. We have a good feel for the numbers. They're looking very reasonable. I have a few slides here, if they look like this with that aqua blue or blue green color, these actually are Energy Strategy’s slides that I've cut out to share. Again, the workshop, and if you're interested and you haven't seen the workshop presentation materials, reach out to I guess John maybe is the best resource there and we can get you those. We can also get you on that workshop group so that you'd be updated when we do have our next public meeting on variable energy resources. But here are the operating reserves and they show an example of. The one piece I didn't mention was the forecast here. There are actually 3 components, regulation, load following, and then there's forecast error. Remember, I showed that slide before where you have a forecast hour ahead and so maybe you think your wind resource is going to generate 100 megawatts next hour, but it actually generates 80 or maybe it generates 120 megawatts. The energy you need to make up that delta between the forecast and the actual has to come from another resource on your system, that's the pieces here. You can see in this picture the regulation Energy Strategy’s showed, just an illustration here, over a one-day period actually looks like it's 1-2-3-day period and then you've got the load following up and down and then the forecast error. You have to carry reserves up and down to cover that forecast error to make sure you can meet loads. Those are the four categories and I already mentioned the spinning and non-spinning reserves, but they're both in the upward and downward direction because you don't know exactly where that wind resource is going to be back to that example you thought you had 100 coming in, but did you end up at 80 or 120, or at 0, or 150 the maximum capacity of the wind facility. Really don't know where it is, but what's important is statistically to understand what those incremental obligations are.

Clint Kalich: We'll go to the next slide here. Let's talk about some key reasons for this. Some of this will get a little bit repetitive, but I want to make sure everybody remembers the key concepts. First of all, integration costs are driven by the need to hold higher reserve levels, the regulation, the load following and the forecast error. They're needed substantially and the reason we separate VER resources out is because of their large variability and uncertainty relative to traditional resources and even load. And again, the key concept here. Why is there an opportunity cost? Why is there a cost of incremental reserves? Because we're deoptimizing our system operations relative to what they would have been if we didn't have VERs in our system. That's ultimately where it comes out as costs. Now the benefit of the fuel being free on when we account for that and the portfolio costs too. There's also a lot of benefits around wind and solar because they don't have any fuel costs. We do account for that in our planning as well. Again, you can have a lot of value for the VER, but a little bit of it comes back in the form of these additional ancillary services that we have to do the integration costs. It's not like we're ignoring the other benefits of the resource at all.

Clint Kalich: So, what's included in the study scope? First of all, we're talking about what I've called consumptive capacity. Those ancillary services we need and the cost, we're considering the impacts of EIM and already kind of gave away the answer there. We've reduced the amount of incremental ancillary services by 50% to reflect the savings that the EIM is seeing with the diversity of the larger West Coast footprint. We're considering how the build outs look different levels and I'll show the levels of build out we're looking at going forward, but it's basically between adding 400 to 500 megawatts of incremental wind and we're looking at sensitivities based on diversity. In other words, do we have a lot of Columbia Basin wind, or do we include wind that's diversified around the entire northwest, including east of the Rockies in Montana? And then we're looking at market prices; low, medium and high wholesale market prices because we learned in our 2007 study, and it's been confirmed in this study that with higher or lower prices you see a different integration cost. It's important to at least be aware of that information. So, what's not in this study. We're not looking at batteries here. Certainly, to the extent you put batteries on a wind farm or a solar farm, you reduce the variability. Potentially you also offer, if it's configured correctly, you offer the utility an opportunity to arbitrage the energy market and provide ancillary services out of these batteries. So, they can stand alone on their own and generate value into the portfolio beyond just helping mitigate some of these impacts of variable energy resources. Now the fact that they aren't included in this study doesn't mean we're not considering it. James is doing a lot of work around this for the IRP. So don't think that we aren't studying it. It's just in this specific variable energy resource study, we're not evaluating batteries today.

Clint Kalich: OK, I already talked about batteries on the wind farm. We're not looking at other storage assets on the portfolio in this study either, so we're not matching. If we put 400 megawatts of wind into our portfolio, theoretically we aren't putting another 400 or 800 or 200 megawatts of batteries in to provide general capacity into our portfolio. We're assuming our non-VER portfolio stays the same size. We're not making any other investments in existing infrastructure. We're dealing with what our portfolio is today and we're not looking at further distributed generation or demand response beyond what's already in the IRP. Those are all being considered in the IRP, but they're not part of this study. One thing that is important to note though, which kind of gets back to and somewhat contradicts what's being said here on batteries. We are assuming as we add for resources, and remember I said up to 2,500 megawatts, we're essentially talking about adding as much new VER resource capacity here as we already have on our entire system. This is a huge, I can't emphasize enough, 2,500 megawatts is a huge amount of variable energy resources for Avista. It's a doubling of our system capacity. We are assuming on that case that we are able to go out and interact in the hourly markets up to another 2,500 megawatts. We are assuming a lot of additional liquidity that doesn't exist in the wholesale marketplace today, which in some ways acts a lot like a battery would act if we put a battery on our system. If we didn't assume that the system couldn't solve, we literally would have blackouts and we would have oversupply situations, extreme oversupply and blackouts situations. You just can't consume. Actually, the blackouts probably are less likely, but you have huge oversupply conditions, or you be dumping wind all the time and the economics, it would just be tremendously cost prohibitive. You'd have no place to put that surplus energy to reduce or to buy down the cost of that asset. You buy 2,500 megawatts of wind if on average you can only use 20% of that because you can't balance in the market. The cost of customers would just be huge, so we really do need to get that power out into the broader marketplace. And when it's surplus to our needs, we can reduce the cost customers pay and also then use those dollars to buy energy in times when our wind is not operating. We can go out to the market and buy that power and replace it. Those are important concepts here, yes.

James Gall: Hey, Clint, we have a question in the comment. The chats? Yeah, I was asking, what are the justifications for not including batteries in the study?

Clint Kalich: Well, I think it's just a scope creep. There's an infinite number of scenarios you could run, so like I said, we're looking at that in the IRP. It just isn't done at this level of specificity. That being said, James and I yesterday were actually talking specifically about bringing battery technology into ADSS so that we can model it within the larger portfolio. We'd be able to do exactly that. It's just a matter of time and effort to do that work, so we're well on the way. ADSS can model batteries. The operational intricacies of batteries. It has some of the most powerful battery modeling capabilities of anything out there that I've seen out there in industry in the marketplace today. We'll be able to do some really good work around that, but in this study, we weren't able to do that given the time and constraints we have, but it's coming.

James Gall: We got another question now from Fred. Fred, do you want to go ahead?

Fred Heutte: Yeah, just a note, and I realize this study scope is way down the track and you probably can't really change it. And I also recognize the many complexities involved in doing battery or hybrid analysis. That's a very complicated thing, but I'll put a link in the chat here to an article that just came out. S&P Global has done a big study of hybrids around the country, noting among other things, 98% of what's in the CAISO or California queue is hybrids now on the solar side. Anyway, this is kind of a multi layered complex thing. I guess my sense is what you've laid out would provide at least an understanding of what the balancing needs are and the opportunity for time shifting. You can use the solar during the day or wind whenever it happens, and if you don't need it right then, or you have other resources, or you have the market that also is available, then you have an opportunity to shift. I think that there is a premium for having your own control of that or the facilities in your footprint. So just wanted to note that because we're all wrestling with this issue of how to combine different types of resources into portfolios that perform the way you really need to meet load.

Clint Kalich: Yeah. And Fred, we've been looking at this and my belief is the utility is much better served by a battery that isn't tied to a renewable resource because there's going to be a lot of opportunity for periods when the battery isn't needed to balance that resource. Solar, I mean at night for example, you could use it more broadly and get extra value, but those are the questions that we're looking at. If you have a raw wind energy resource versus something where you match it up with a small or a large battery relative to the size of the very resource, what is that incremental cost? Absolutely looking at that, that's important, back to that idea of finding the lowest cost way of meeting customer needs. Those are exactly what James and friends are doing on the IRP work.

Fred Heutte: Right. And the issue, as you mentioned, the issue of standalone batteries versus hybrid combination, whatever you want to call that. Resources that co-optimize at the point of interconnection, that's a whole other set of issues, because batteries have a lot of capability and a lot of different places in the system. And you know, I just foresee a future where we have kind of a shifting mixed bag of all of it, which makes it hard to analyze. There's no question, but I think there's real value in having that kind of diversity and figuring out from the modeling what that value is. And you know, you might not ever be able to say here's the optimal mix of these different kinds for variable energy resources and storage. And really, I would add demand response to that, but at least you'd have a sense of where the good approximate balance might be and that will help with resource acquisition.

Clint Kalich: That's exactly what we're trying to do. And of course you have to balance that now with your diversity. There's less value to match these up uniquely with a wind or a solar farm because you already have a lot of diversity. Again, back to the ADSS model, we have the ability to model it tied to the specific asset and then we can look at that scenario. We can also model it as something that is a portfolio wide asset that can be used to optimize so that you get the full energy, I call it energy arbitrage on the battery, but beyond that we should though be able to with another phase of this study and that that's the one thing we've talked about. This was phase one. We should be able to ask Energy Strategies to modify their models within the capability of these storage assets to reduce the variability. If they can't do it, I know how to do it, it's just a matter of staff time to be able to reduce the variability that these assets would see and then we can see a commensurate reduction in the ancillary services that passes through to much less integration cost. You could somewhat approximate it. You'll see some examples from 400 to 2,500 megawatts. So, if you can go from 1,500 megawatts down to a 400 MW equivalency of variability, you can see the integration costs come down. I think you can interpolate, extrapolate, whatever you want, to use the data here to get a feel for what the potential benefit might be and that I think is what's important here today out of this study. We can do that and we have the models to do the specific work we need to get some more data to run through the models. But I think we're making some pretty good headway. We want consistent application to support various analysis.

Clint Kalich: I talked about the IRP James is working on and he needs to account for some of these costs when we go out and acquire resources, how the goal in an RFP is to meet your various requirements, to serve load. And these days, to serve load carbon free. But you also need to account for the different performances and so you need to be able to find a way to get an apples-to-apples comparison. That's really what the VERs study does. If you choose a solar resource, you might have $2.00 integration cost; whereas, if you pick wind, it might be $1.00. You need to be able to get these to be closer to apples-to-apples.

Clint Kalich: Transmission. We actually have an interest in modifying our transmission rate that we charge customers that that move wind and solar across our facilities. Right now, there is no incremental charge associated with these costs in order to support a change to your FERC tariff, you have to have a study like this in place. So, one of the outcomes of this study will also be an opportunity to bring that forward and be able to recover the costs that our customers right now are paying incrementally for third party VER resources coming across our system. Finally, the last piece is for PURPA in our avoided cost calculations. We need a way to differentiate between say a seasonal hydro versus a biomass versus a waste coal plant versus wind or solar. These numbers can be used to help set PURPA avoided cost and they have been in the past and we hope to be able to use them in the future. In fact, in Washington today we don't have any VER costs associated with PURPA because our study wasn't fresh enough. The Commission was concerned that the study hadn't been done more recently than 2007, so we didn't have a discount on wind or solar. This study will help us to bring that into our PURPA published rates. We can for non-published rates, negotiated rates we can include them, but for published rates the Washington Commission wanted a new study. We're going to define the consumptive capacity, so in the study we're identifying the capacity we need. Where is it coming from? How much of its regulation? How much of it is load following? How much of it is a forecast error? And then, what that cost is. That's really the purpose of this study, to provide a consistent analysis, define what we need, and then define what the cost is, and do that over these scenarios with increasing quantities of ancillary service mixes.

James Gall: Hey, Clint, before you move on, there's another question from Yao it's will integration costs be applied to other resources such as hydro in addition to wind and solar?

Clint Kalich: Yao, the thought there is those resources, they contribute to the system value. So, we don't see those as having a system cost, they actually add system value by providing ancillary services. For example, if I took Noxon out of our portfolio, you would see the portfolio cost go up because that resource provides ancillary services to the system. There wouldn't be in my view any need to do that work. You could, I guess, argue that you might look at all of your resources incrementally like that and determine how much value they provide to this system. But know that the existing assets, we're not going to add big wind resources, but in the existing asset portfolio, the value of those assets is already embedded in the system today. So there is no thought of non-VER resource integration costs. If you bring a hydro project to us today under PURPA, we don't anticipate we would discount or credit you for ancillary services. In fact, most of the ancillary service value of our hydro wouldn't extend to a PURPA anyway because they're not dispatchable. Flip side is they're fairly predictable, so you don't have as much uncertainty around those. And this is the timeline for, and James how are we doing and I'm cutting, I think we're done at 10. I don't know how much time you want it on your part. This has taken quite a bit longer than I thought to go through it. What are your thoughts there? Should I just burn through these or are you going to postpone what you're doing?

James Gall: I'll probably postpone what I'm doing if we don't have time. I think this is important and we have a lot of engagement. So, keep going.

Clint Kalich: OK. All right, so here was our original time frame to do this study. This was a slide from the Energy Strategies update that we did last year. Actually, in 2022, I'm sorry, late in 2022. Clearly, we're doing the simulations now. We're basically here today and then the study report, hopefully like I said, will be coming out in the summer, certainly by the end of the year. Let's talk about, I apologize – it's a little bit small here, but we looked at these different and the data is available in that slide presentation that we have. We can get that to you, or these slides were made available I think last week. But we looked at three VER portfolios. We looked at a full solar portfolio, really these are for bookends. We looked at a full 100% wind and then we looked at a 50/50 mix of wind and solar on a nameplate capacity basis. In the 400 MW case, we would have 200 megawatts of wind and 200 megawatts of solar. And then we looked at 4 VER penetration levels. We already have that 260ish megawatts today comprised of Rattlesnake Flat Wind, Palouse Wind and Lind Solar, sometimes called Solar Select. But we have three VERs today of significance. These are incremental additions to that, and you can see here down below in this, it's very small numerically, but it shows you basically in each case the locations that the resources were assumed to land. Obviously, I've left diversity. If you have smaller integration but you can see here over the various scenarios how much was being added and then you can see the geography here of the Northwest that was assumed where these plants ran, and this is out in Montana. This is farther out to the east the graph shows, but you can see here some of the resources that we're looked at. Again, in the interest of time, I'll leave it at that.

Clint Kalich: This is the data that was looked at here. The data for when we use the NREL wind data set, which I think was available from 2007 through 2014. I might be corrected here as we go forward. I might have the specific statistics and then we use the NREL. It's the NREL solar data set here for the solar forecast and then Energy Strategies using some of their capabilities, statistics and otherwise generated profiles for these various portfolios that I showed on the previous slide. Then they showed some pictures of the data, this is their slide on reserve services where it talks about regulation reserves, load following, and forecast error. In the interest of time, I'm not going to dive into the details here unless there's questions, but the idea is in each one of the mixes of resources and incremental quantities of resources, Energy Strategies looked at how that would impact these three categories and ancillary services and gave us the incremental ancillary services necessary to serve those very resources.

Clint Kalich: We wanted to spend a little time on the EIM. I mentioned earlier, all of our resources are in a fairly small geographical footprint, but when you enter the EIM, you get a lot of diversity savings. Actually in the work that Energy Strategies did, we were assuming a 25% reduction in ancillary service requirements, but upon further study and thought, we moved to the full 50%. Which if you look at what the EIM forecast for wind and variability relative to what our system statistics are, it's about a 50% reduction. I'm a little concerned that might be an overstatement because once we went to a larger, more diversified portfolio, I'm not sure we get a full 50% reduction. Just the statistician in me thinks that, but in this study, we're going to assume the full 50% reduction in ancillary service requirements. Which is a big deal that makes a big difference in this reserve studies. This is the statistics, sorry.

James Gall: Clint, Fred has question here.

Fred Heutte: Yeah, very quick one on your system now, what provides or pre-EIM what provides the ancillary services, hydro and gas, or both.

Clint Kalich: Yeah, Fred. It depends on the ancillary services. I would argue most all of our resources have something to contribute that we own and control. Even our Kettle Falls biomass plant has some ability to do some load following, but substantially, I did a study probably 10 years ago, because there was a lot of debate internally about where we would follow this additional incremental load.

Fred Heutte: Right.

Clint Kalich: And my argument was that we would run out of Mid-C capacity. and we'd be supplying it out of our Clark Fork. And internally there was a lot of debate, and actually I had a lot of folks argue with me about that. But to me, the models didn't lie. Actually, the study showed about 95% of the year after we brought Palouse in 2012, a year after that, about I estimated 95% of the incremental ancillary services were covered by Noxon. Now, in more recent years, we've seen the market get more volatile and we've seen the gas plants start to play a larger load in providing ancillary services. You will see Coyote now run a lot more variability within the hour to provide some of the load following, and even some of the regulation will put it on AGC. I would say the heavy hitters are Noxon and Coyote. Those are the two heavy hitters, but our entire portfolio helps us with all the different needs we have.

Fred Heutte: Right. Thanks.

Clint Kalich: Yeah, because if we bring all these incremental obligations they come into our larger system, we manage them together, not incrementally. It really is an incremental, but this gives you a feel for and Energy Strategies did update this chart. If you went to the workshop, you'd see larger bars. But based on the baseline up to 2,500 megawatts, these are the incremental, on average, the incremental ancillary services we have to carry in megawatts up and down from the zero point. With 800 megawatts of diversified wind and solar, we need roughly call it 175 MW down and well about 175 MW up in total capacity broken out between regulation slash AGC load following and forecast error. And then you can see what the components are incrementally.

Clint Kalich: On the study methodology, how do we do this? 2021 was a reasonably average system, so we used 2021. We used the actual system conditions, including forced outages, or hydro conditions and what fuel prices were in 2021. I'll try to jump ahead of what your question might be, which is maybe why didn't you study more years? This is a tremendously computationally expensive exercise, and even though I use 2021, we did move market prices around, so we were able to look at different market prices. Unlike the 2007 study, we didn't look at varying hydro conditions, so we still assume average hydro even within a high market price condition here. And actually, we've seen some of that. It seems like prices are driven more by natural gas prices than they are driven necessarily by hydro. In some, there's a lot of mix in there. We're running the system with and without the variable energy resources to look at that incremental and I want to be careful here when I say with and without. In the with case, we bring the VER resource in and all of its variability. In the without case, we still are bringing the energy in because we aren't interested in trying to figure out the arbitrage value, the actual energy commodity value that's already accounted for in the RFP process. So, we bring that in as a 12 by 24. We bring in an average monthly energy shape and we stick that into the without case, so it doesn't have any variability associated with it, but the energy does come into the system. So, we're able to calculate. We're not mixing into, and I call polluting, we're not polluting the variable energy integration costs with the arbitrage value or the timing of when we get the energy.

Clint Kalich: We're really bringing out and quantifying just the incremental integration costs here. We're doing two conditions: with and without the VER we talked earlier. There's actually five VER scenarios besides the existing condition. We have 400, 800, 1,500, and 2,500 megawatts of incremental VER. And then we look at those 3 mixes and then we also look at three market conditions. You can see how this adds up to lots of market runs. It's around 80 studies of 2021 with our system. Well, I guess it came out to 90, so 90 different scenarios that we had to run. We ran the year 2021. Every time we run this, or update it, we have to run 90 different studies of 2021 and then we go calculate the delta between all these scenarios to determine the cost of integration and the average cost in the incremental cost.

Clint Kalich: I'm going to show some data in a few slides here. We're moving the commodity value, I guess I did carry a slide on this, so this is our without VER scenarios. I already talked about the fact that we put the energy shape in the 12 by 24 energy shapes with no reserves and then the with VERs scenario. We put the whole thing in just as it is expected to come from Energy Strategies in its raw case. By subtracting the VER out, the without VER case from the VER case, we get to single out the integration. I'm sorry, I should have covered this in the slide, not earlier when I didn't have the benefit of the slide, but we just want to get to the integration. Is that clear? That's a pretty complicated concept. I remember when I first was introduced to it back in the early 2000s by EnerNex, I had a little trouble consuming what all that meant, but all again we're trying to do is we're not trying to value the timing of when the energy comes or the fact that we've added a whole bunch of additional energy into our system. What we want to model is just the variability and the capacity costs of providing those incremental ancillary services. The energy in a non-VER case is the same amount of average energy as the VER resource would provide in the VER case. Probably made it worse by explaining that.

Clint Kalich: Let's talk about results. These are preliminary, so please, I assume Fred, you're taking a screenshot, but please be aware that these will change modestly, but you can see here and actually they have changed a little bit from the version that was sent out in the draft. We hadn't completed the study yet and we've identified a few data issues. There were substantial that I'm happy to talk with offline about that made an impact on the incremental cost, but here's what we're expecting the cost today to be with our existing portfolio. Base prices, $0.16 per kW month comes out to about $0.78 per MWh. That's quite a bit lower than the study that we came up with. I think I've got a slide a little bit later on that to show what they were, but in fact let me jump ahead if I've got it. I thought I had a slide. I want to go back to this. Well, I showed it earlier with 600 megawatts, almost $9 a MWh. We're talking here about just tremendously lower costs. In fact, with 200 plus megawatts, we were about $7.00 a MWh and we're talking here about being about $0.78. So, a huge reduction here associated with this study. Associated with the existing portfolio. But then when you bring in a wind resource of 400 megawatts, you actually see that our integration costs drop to actually a penny of savings per MWh. What that means is there's a tremendous amount of diversity in that window resource relative to our existing portfolio and that's because we're assuming a diversified resource of when in fact our next incremental quantity of wind that we procured through an RFP driven substantially by the need for diversity will be Clearwater Wind out of Montana. And you can see here, we actually expect this to be a benefit to our portfolio and we go from an average $0.78 per MWh down to this is again draft to roughly the integration cost dropping to zero. It's a huge benefit of having that diversity. But then if you increase up to go from 400 to 800 megawatts of wind, your average integration cost now as a $1.31 per MW hour and you can see it $2,500, excuse me, 2,500 megawatts of wind, you're about $9 per MW hour of cost with high market prices, it goes up, maybe 50%. Low market price is fairly similar. Cost depends on the quantity. If you look at the solar case. Well, I thought it was interesting about solar is in the low penetration quantities, solar actually has higher integration costs, but when you get into these large diversities and Fred, I think this has exactly to do with what you discussed, if you get a lot of because the solar facilities are smaller in size and you get a tremendous diversity of solar, you actually see the integration costs not go up nearly as aggressively as wind. I still think there's more work to be done here. This still may be a little bit high, I don't know because that wasn't the absolute focus of this study to look at small versus large wind farms. But this shows wind farms are, excuse me, solar farms are smaller in size than wind farms, so that may be why we're seeing some of this lower cost as we get to larger penetration relative to wind. Some interesting results there. And then if you look at the diversified case. Let's look at 800 megawatts, you're talking about $0.50 per MWh versus if you did all the wind, it's $1.30. If you did all solar is $1.90, so these numbers, it's pretty interesting.

Clint Kalich: The diversity, what it does, it definitely shows the strategy we've been pursuing for a number of years on acquisitions of trying to pick up more diversity, is it pays off. If you can get a price that's competitive for the energy itself now, if we get a bid from Montana, it's $10 more per MWh. The diversity benefit can't overcome that $10 likely, but at least it does bias us towards getting more diversity. The other thing to keep in note though is and the reason I started out with the dollar per MWh, that's how we traditionally talked about it. But we actually model, we build these resources on a per kW month basis because it really is based on their nameplate capacity. It's not based on, this is 1,500 megawatts at nameplate, not of energy. So, these are the right ways to look at it. If we're doing 800 megawatts of wind, we would actually want to include in our RFP analysis $0.33 a kW month for integration cost associated with that wind portfolio.

James Gall: Clint, I think Fred's got, somebody wants to add here.

Fred Heutte: Yeah. One more quick question. Just for comparison here, looking at the dollars per MWh, the production cost for solar and wind is, I'm guessing somewhere between $20 and $30. So when you start getting up to $6 to $8 bucks, that does start to look like a pretty significant amount. If I’m getting that right.

Clint Kalich: Well, I'd love to be able to buy solar for $20, but irrespective it's $20 or $40, it's definitely getting up to be a pretty substantial piece. I mean, you're really starting to do some pretty perverse things to the rest of your portfolio to be able to integrate that much variability and that really I think is the challenge before us, is if, and keep in mind for this is doubling our system capacity, this isn't a, James and I were talking about this, we were questioning the value of even doing the analysis and presenting 1,500 and 2,500 because we don't think this is something that's going to happen in the next 10 years.

Fred Heutte: Right, it's not small.

Clint Kalich: Should we really even be studying this? And there is a possibility in the final results of the study, we don't even provide this information. It may just be considered too nosebleed to be doing, but yeah.

Fred Heutte: Well, I think it's interesting just as kind of a corner case or whatever. You really Max things out and look, this is what happens. But I think what you're saying is that the likely landing zone will not be at the high end.

Clint Kalich: Or we'll have batteries. We'll have a different market system, will have batteries to go with it.

Fred Heutte: And then you have the right exactly.

Clint Kalich: We're not going to be able to just dump 2,500 megawatts of wind. We're going to have to make other portfolio choices and bring those in to match up with that window resource, so.

Fred Heutte: Right. And of course, there are other issues in terms of getting large amounts of various transmission capacity and all that onto the grid.

Clint Kalich: Yes.

Fred Heutte: Alright. Thanks.

Clint Kalich: Yeah. And those types of things would be considered in the other aspects of the RFP outside of the integration cost. I wouldn't define those as integration costs. I mean, they are in a certain sense, but as far as the consumptive capacity pieces that we’re modeling here, they would be considered otherwise. And then if you go to the next slide, here's the marginal cost associated with these different resources. It probably makes sense for our next tranche of resources that we don't charge the average. You probably should account for the fact the next 400 megawatts of wind actually would probably discount. We probably should give that a credit because they actually benefit our portfolio based on the results of this study. James and I have been talking about whether we should use average or incremental and maybe that's something folks want to talk about here today. We certainly will in the wind, the VER workshop. But there's the marginal cost. We just wanted to look at those incrementally here. Let's go to the next slide.

Clint Kalich: Next steps, obviously we need to finalize these results. We need to get the report out and then we need to use it in our future IRPs or RFPs and get our transmission tariff with FERC updated as well. Those are the next steps going on and then, James put this slide together for the 2025 IRP, I mentioned that kW month charge. I don't know if that's slide 18 anymore. It's actually slide 19 or 20. I'm not sure which one we'll use. James can speak to these. More specifically, we're going to increase the flex ramp requirement in our reliability modeling because in those cases where we're adding a lot of new VERs to serve increased load over time, we will need to account for the incremental reserves necessary to integrate the wind. It will have a diversity, excuse me. Not a diversity, it will have a reliability impact because absent the VER, that Noxon example, we'd have maybe an extra 10, 20 or 50 megawatts of capacity to serve an extreme load. But if it's being consumed for a variable energy resource, that may not be possible. And then we talked here about including a small flexibility requirement as well in capacity expansion modeling. That's my slides, James. I have given you a whole 8 or 18 minutes. If there aren't any other questions anyway, so that's all I had, I think.

<u>**2025 IRP Market/Scenario Update (Draft), James Gall**</u>

James Gall: Any questions for Clint before we move on to the next presentation? Bear with me one moment, I'm going to try to transition to the next slide deck. OK, hopefully you guys see this. I'm probably going to go a little faster than I would like just because we have about 18 minutes left. The purpose of this portion of the presentation is to give you an update on where we're at on both market scenarios and our assumptions on portfolio scenarios. We've also made some changes, and to finalize our price forecast for the wholesale energy market. We've also finalized our load forecast and we're providing some updates to those as well. They get started on the market side.

Just to remind everybody, we're looking at four different market price forecasts for this IRP. There's obviously the expected case. We run a deterministic case, which Lori Hermanson, presented a couple months ago, and we have just finished our stochastic case. I think it finished up yesterday. That's 300 simulations of varying assumptions on load and hydro, carbon prices and wind production, inflation, and several other variables. We're also running the low hydro, or sorry low natural gas price case, high natural gas price case, and another scenario where we do not have the Climate Commitment Act in Washington. As many of you know, there is an initiative on the November ballot to repeal that law, so we're running that case and in the event that happens.

James Gall: On to the assumption side of things. For Henry Hub, here are the prices that we're assuming in these different scenarios. The expected case is around $5 a dekatherm levelized and then the low case we're at $3.86 and the high case $7.20. The high case we're using the 95th percentile of the prices that we assumed in the stochastic modeling and then the low case is the 25th percentile. We're trying to get a broad understanding of where [market electric] prices would be in the event that our gas assumptions are wrong so we can judge whether or not a resource that may be a higher cost that's related to gas would have an impact in a different price scenario. For example, when we look at potentially adding natural gas peakers in our portfolio, would that still be the choice in the high gas price scenario. That's the value of these sensitivities.

James Gall: Moving to electric prices, we do have preliminary results where deterministic cases around $45.00 a MW hour, which is actually a couple dollars less than the previous forecast that we shared a couple months ago. We've been going through the model and making sure we got the model working properly with all the correct assumptions. We did revise our forecast down, so it looks like, at least on the deterministic case, we're on $45.00 and then the low-price case, that's shown in blue comes in around $41 and then the high price case is $53. These are for prices that are delivering at the Mid-C with Washington to delivery. As we discussed a couple months ago with the CCA in place, it kind of complicates things. Whether or not there is a delivery into the State of Washington, which could have a CCA allowance cost versus prices that are traded at the Mid-C but not delivered in the state, which would have a lower price without the allowances. We have two prices shown here. One is a Mid-C delivery and then another price and the next slide. That's without a Washington delivery. And then lastly, we did run a case without the CCA that does have a forward $5 lower price approximately without CCA. I would say the reason why you don't see a lot of variation here, maybe compared to some previous IRPs of years past, is that the portfolio is extremely renewable. We're using basically the same portfolio of resources across the region because regardless of if the CCA exists, or what prices are of natural gas, the portfolios are getting more renewable and more energy storage over the next 20 years. You're seeing here is that prices where natural gas really don't have as much impact on the electric prices. The same thing goes for the CCA. If you looked at our portfolio for the northwest, with and without CCA, and you kept that portfolio design out in the future, you would see much greater variation in the results. But because of the additional solar wind and storage, you don't see that variation.

Tom Pardee: James, just a question.

James Gall: All right, go ahead.

Tom Pardee: It is from Kevin. Does the price forecast include hourly pricing?

James Gall: Yes. This is a based on an 8,760 hourly price out 20 years and we run 300 of those. Actually, for the stochastic, but for these deterministic cases, it's the expected hydro, expected load, and expected conditions on an hourly basis. If we looked at on peak versus off peak prices, you would see definitely a difference in the prices or even extreme peaks. On the non-delivery in Washington, prices are a little bit less. It's a couple dollars spread, but again its kind of the same shape as we saw before. OK. So that's that on prices. Again, we'll be using these to run sensitivities on the portfolios that we have gone over. Actually, the last several TAC meetings that just to test them, whether or not the portfolio would be better off with a different resource in the event of some of these scenarios. Fred has got a question. Go ahead, Fred.

Fred Heutte: Yeah. Quick one. I realize we're running out of time here. On the gas price forecast, I wonder if you're looking at or including any assessment of what will happen to regional prices when the new LNG Canada export facility goes online, which is probably the end of this year. Now I realize that this mostly does not come from British Columbia, but still, that's a 2 billion cubic feet a day resource facility that's going into operation. Total gas production in the Western Canada Sedimentary based, BC and Alberta together, is about 17 BCF right now. I'm just wondering if you're looking at that and if you have any observations on what that might mean for prices?

Tom Pardee: Yeah, Fred, good question. This is Tom. What I understand of the project is that our own production up in the Montney and they have their own dedicated pipeline to the facility. But to directly address your question, the price is considering that this is a blend based on the presentation a couple two or three TACs ago, but they would have, I mean, it's a global look as how they do the modeling and knowing that Canada LNG camp was coming on, that would be included in the price forecasts.

Fred Heutte: OK. Thanks.

Tom Pardee: Good. And just a quick recap on how these prices are developed, we do a blend between forward prices, the EIA long term price forecast and then two consultant long term price forecasts that are blended together to create that black line in the middle. And then we've looked at historical volatility and forward prices to come up with how those prices may vary over time. And then the high and low case is the statistical result of those forecasts.

James Gall: OK, we got about 10 minutes and I have about 3 hours of material left that I'm going to try to reduce down to 10 minutes. But, if there are questions, we don't get too today, we can always push some of this out to the next TAC and we are doing this every two weeks. So, that's possible if we get stuck in the next 10 minutes. First, on the load forecast, we had AEG conduct an end use load forecast for us and they did a presentation on that about a month ago. Two weeks ago, they did a presentation on our energy efficiency forecast. Since that time, we've been working with them to finalize the load forecast and there's been actually quite a bit of revision since then. One of the big changes has to do with the water heater requirement for basically a heat pump water heater I believe by 2030 in the federal standard. That was a major reduction in our load forecast and then also another change was they were implementing some price elasticity into the load forecast as well. At the end of the day, what you're going to see here is a much lower forecast than we presented about a month ago as we've been going through the data that AEG has provided us. One of the benefits of using an end use forecast is we can see the load changes that we expect between now and 2045.

James Gall: And this is an interesting couple charts of where the load is reducing and where the load is increasing by end use. On the left we have several different categories of end uses and obviously the negative ones are ones that we expect loads to reduce over the next 20 years. Areas where loads are expected to increase. Obviously electric vehicles is the largest increasing amount of load generation, which interesting on this one. It shows up as positive, but it's actually a reduction, which is it reducing load. But that's the second largest growing area. Then you have electronics, refrigeration, appliances, space heating are rolling off the top increasers. Decreasing a lot of it is lighting, ventilation processing, mostly on the industrial side. Water heating, which I mentioned before, is also on that list of reduction from a low point of view. Percentages may not matter when they're a small amount, but when you look at total load changes, lighting is the biggest reducer. Same with generation. That's mostly solar generation, motors and ventilation, but you can see that load growth is really coming from electric vehicles, space heating, because we do expect quite a bit of electrification in the next 20 years, but also electronics, appliances, refrigeration and a little bit from cooling as well. But it's definitely an interesting way to look at how loads are going to change over the future.

James Gall: Now that we actually have an end use look at the system. OK, so what is that? Where do we come out from a load forecast point of view? I believe we were at 1.5% energy growth and the previous TAC meetings and then we're now down to about 0.81%. How this slide works is in yellow or orange is our actual energy we've witnessed in the last 9 plus years. And then in Orange is the load forecast that Grant had presented to us at that TAC meeting. And then the black solid line represents what our final load forecast is. We are moving our load forecast a little bit higher in the short run compared to Grant's forecast due to a large industrial load that's going to be on our system starting in August and then we expect loads to continue to flatline and then slowly increase in the 2030s, and then goes up quite a bit higher as the electric vehicle forecast kind of kicks in. As far as the state level look in blue is Washington, and in red is Idaho, where Washington is expecting higher load growth from the electric vehicle sector and a little bit on the electrification sector. Idaho is staying more flat because we expect less EVs in Idaho and less electrification as well. The codes and standard changes that are expected from the federal level to have more of an offset in Idaho compared to Washington because there's just not as many loads taking over and the dotted lines represent the last IRP's forecast from 2023. A little bit higher loads on a system basis than the last IRP, mostly driven from Washington. I'd say the two biggest drivers of that is the higher electric vehicle forecast and a little bit more electrification than the previous forecast.

James Gall: OK, I'm moving to peak. We also have some revisions there as well. We've also tried to make it a little bit easier to understand on how we look at peaks, because peak is kind of a difficult thing to look at because when you look at history, you could have a peak that shows up in January, November, even March from a winter point of view. In the summer, peaks are most likely going to be in either late June, July or August. On the historical side of this, we have a seasonal peak, blue is winter, red is summer. Showing on the right is in the solid lines. Our forecasted peak, we call them a seasonal peak, which could be the highest event in the winter and in the summer. You can see that our peak forecast is a little bit less for winter compared to our event we had in January and that's because we're forecasting we would call it one in two event versus in last January was a, we'll call it an extreme event. I'm where we actually had a planning margin to our loads to cover that variability.

James Gall: In the dotted lines that are shown in there are the monthly peaks. When we look at planning in the IRP, we look at a monthly peak level of January, February, etcetera and that's what our model plans to. But we add a planning margin to cover that and that planning margin that we add is intended to cover that seasonal peak as well as other outages or extreme events. So, we want to include the dotted line in there to give you a reference of what the January and the August peaks are. But we do acknowledge there is, from a seasonal perspective, a much higher peak so that when we compare history to forecasts, it's more relative. The biggest takeaway, though, is compared to our last IRP, we have significantly higher peaks expected and that's really driven by one, we have a new industrial load, but two, we actually had two significant events both winter and the last year. That's really helped us reset our data because when you don't have, especially in the winter, a significant peak event without that data. What you're looking at is going to it's going to be reflective of the past historical data. So, if you don't have a peak event in your data set, that's recent, you're going to underestimate what you expect peaks will be in the future.

James Gall: We have got about 2 minutes left. I think I'm going to stop there, and we'll get into portfolio scenarios at the next TAC meeting because I think this is going to be a little bit more detail than I can cover in 2 minutes. I can't talk specifically on electrification, so we wanted to cover what we're looking at from our electrification scenarios. I think that deserves definitely more time than two minutes. I'm going to stop there. Grant has a comment. Go ahead, Grant.

Grant Forsyth: Yep. Thank you. So just real quick though about the peak load forecast too. I would just throw out that there was an adjustment. Now there I put in an adjustment. Now in the peak load forecast, uh for a post pandemic change too, because of the hybrid work environment that seems to have pushed up people out a bit as well.

James Gall: Thank you. Anything else? We have one minute left. If there are no other questions, we'll see you in two weeks, but I'll leave the mic open for any questions. Try to answer comment could be come back to the issue of new industrial load and for future work job. Do you have something in mind, what you want to know?

Fred Heutte: Yeah, my thought there is that everybody is all a big uproar about this and there's a lot going on with new data centers, and actually a lot of other types of industrial load. You've got a pretty good area for that kind of development, and I think, Spokane is a big high-tech center and you've got a good system. I'm just wondering if you're seeing any potential for significant new industrial load. And like I said, maybe this is something to bring up later.

James Gall: Yeah. We are going to run a scenario. I believe it's 100 megawatts in 2030. We're going to run that scenario, the industrial load we just picked up was an existing customer that was, I wouldn't call it there an existing load that was not our customer. They moved their load to us, but we are consistent on a data center coming, which is why we're going to be running that 100-megawatt scenario. Another scenario I want to talk about briefly today, but we didn't get to, is the decarbonization efforts for central systems that are owned by the state and that could create a significant large load as well, especially universities. That's another scenario we could probably cover as well.

Fred Heutte: Thanks.

James Gall: Alright, we'll see you in two weeks. Have a great week and we'll see you later.

Charlee Thompson: Thank you.

James Gall stopped transcription.

2025 Electric Integrated Resource Plan

Technical Advisory Committee Meeting No. 8 Agenda

Tuesday, June 4, 2024

Virtual Meeting – 8:30 am to 10:00 am PTZ

Topic	**Staff**
Introductions	John Lyons
Electrification Scenarios	James Gall
New Resources Options Costs and Assumptions	Michael Brutocao
2030 Loss of Load Probability Study	Mike Hermanson
Load & Resource Balance and Methodology (Moved to TAC 9)	Lori Hermanson

2025 IRP TAC 8 Introductions

John Lyons, Ph.D.
Technical Advisory Committee Meeting No. 8
June 4, 2024

Today’s Agenda

Introductions, John Lyons

Electrification Scenarios, James Gall

New Resources Options Costs and Assumptions, Michael Brutocao

2030 Loss of Load Probability Study, Mike Hermanson

Load & Resource Balance and Methodology, Lori Hermanson
(Will be covered in TAC 9 meeting)

Remaining 2025 Electric IRP TAC Schedule

- **TAC 9: June 18, 2024: 8:30 to 10:00 (PTZ)**
  - Load & Resource Balance and Methodology
  - IRP Generation Option Transmission Planning Studies
  - Distribution System Planning within the IRP & DPAG update

- **Technical Modeling Workshop: June 25, 2024: 9:00 am to 12:00pm (PTZ)**
  - PRiSM Model Tour
  - ARAM Model Tour
  - New Resource Cost Model

- **TAC 10: July 16, 2024: 8:30 to 10:00 (PTZ)**
  - Preferred Resource Strategy Results
  - Washington Customer Benefit Indicator Impacts
  - Resiliency Metrics

- **TAC 11: July 30, 2024: 8:30 to 10:00 (PTZ)**
  - Preferred Resource Strategy Results
  - Portfolio Scenario Analysis
  - LOLP Study Results

Remaining 2025 Electric IRP TAC Schedule

- **TAC 12: August 13, 2024: 8:30 to 10:00 (PTZ)**
  - Preferred Resource Strategy Results (continued)
  - Portfolio Scenario Analysis (continued)
  - LOLP Study Results (continued)
  - QF Avoided Cost

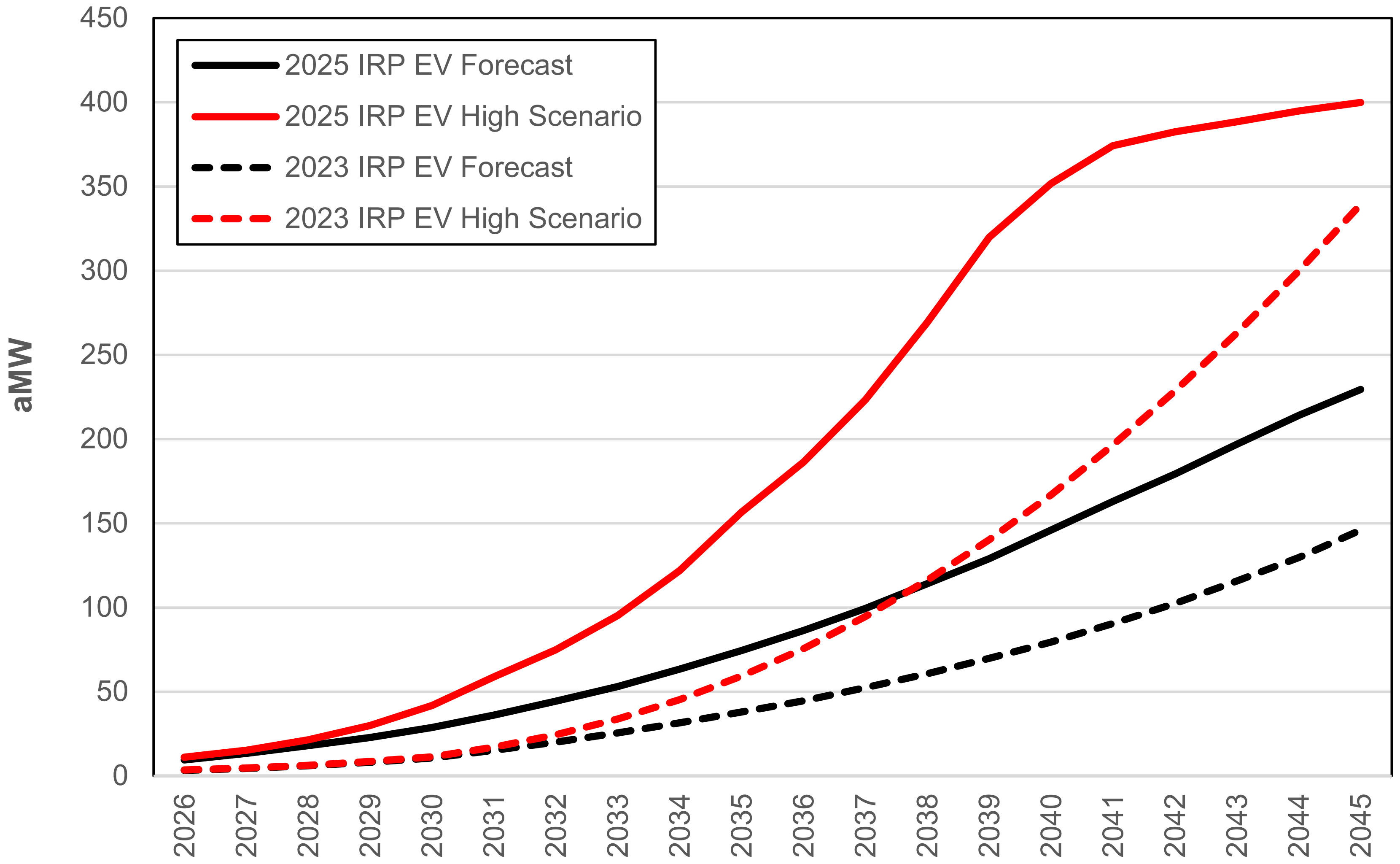
- **September 2, 2024- Draft IRP Released to TAC.**

- **Virtual Public Meeting- Natural Gas & Electric IRP (September 2024)**
  - Recorded presentation
  - Daytime comment and question session (12pm to 1pm- PST)
  - Evening comment and question session (6pm to 7pm- PST)

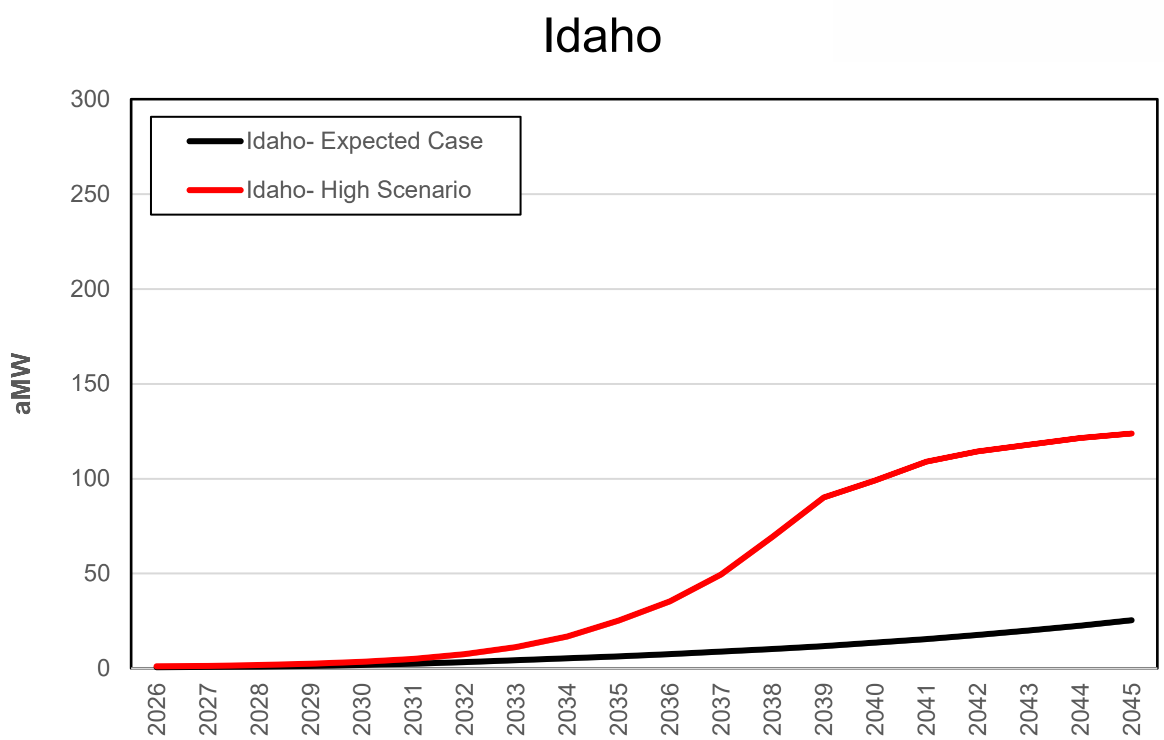
2025 IRP Portfolio Scenario Update (DRAFT)

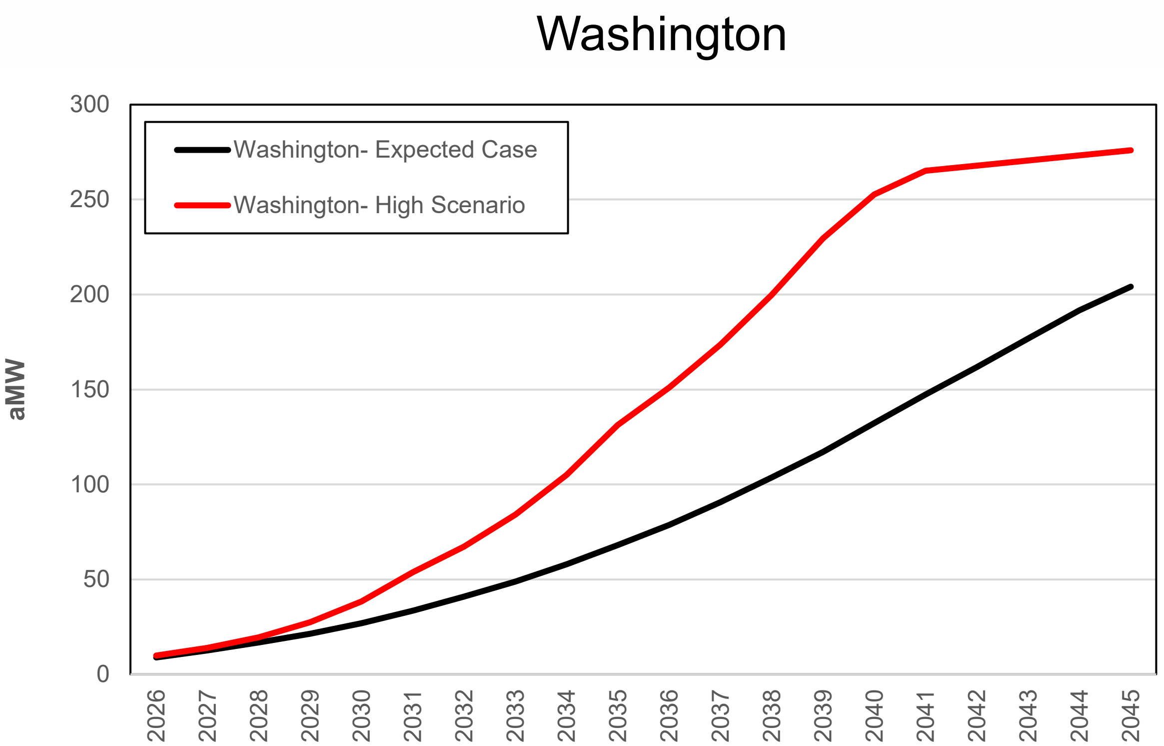
James Gall
Technical Advisory Committee Meeting No. 8
June 4, 2024

High Electric Transportation Scenario

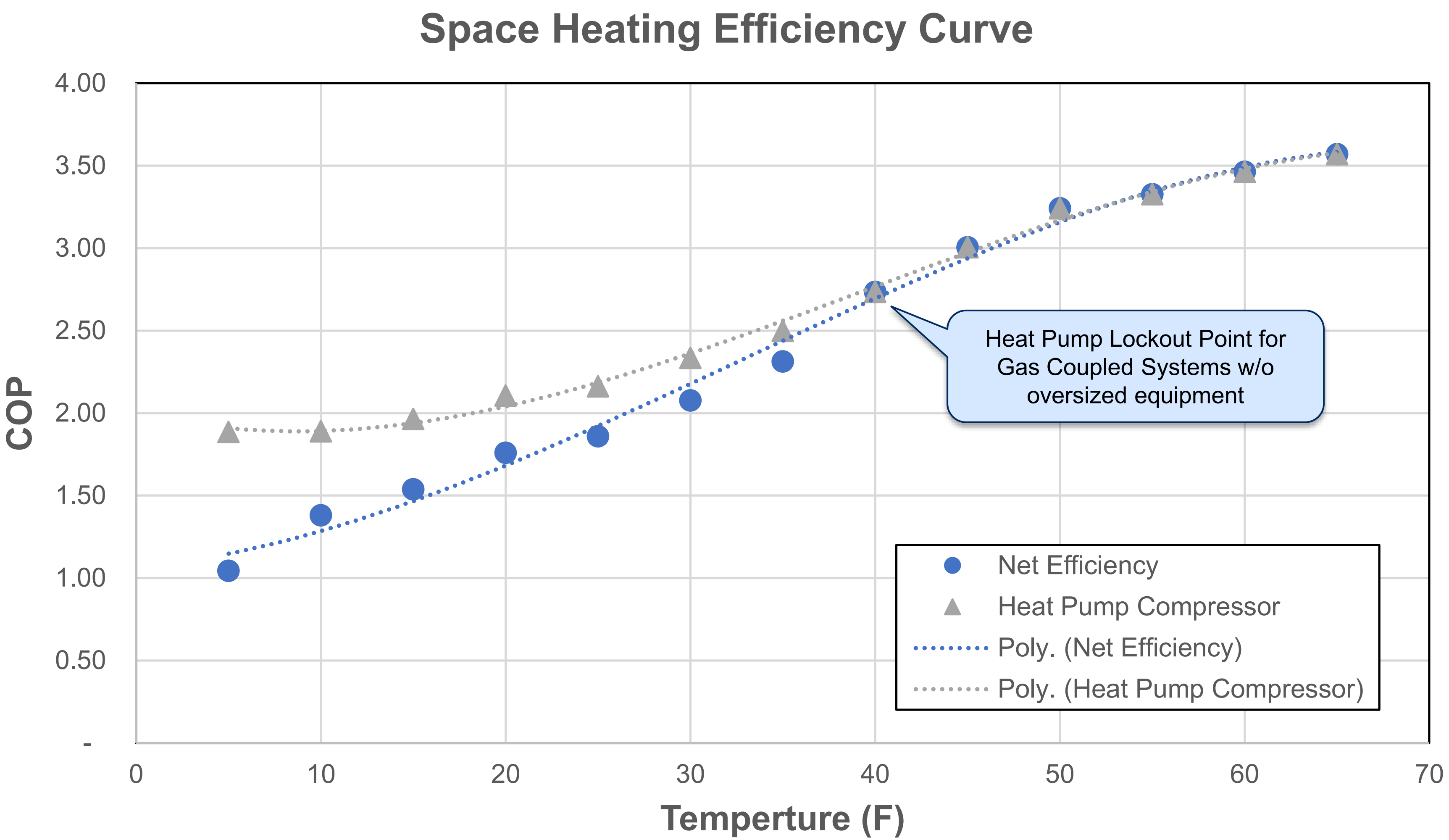


State Electric Vehicle Load Projections





Space Heat Assumptions for Building Electrification



For homes with central heating, the homeowner may find efficiency, cost, equipment longevity challenges when retrofitting to fully electric due to increased duct sizing requirements and installation cost.

Retrofit HP on NG furnace may have similar outcomes

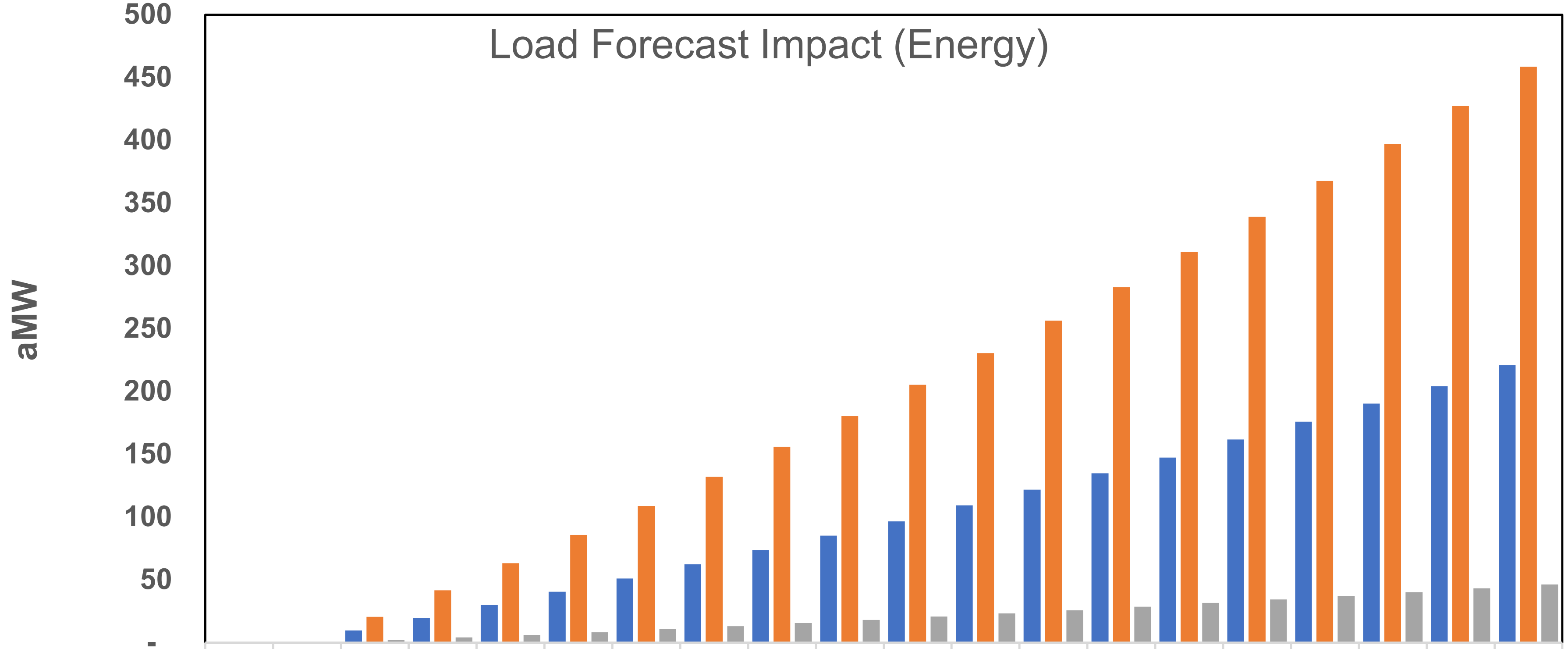
NREL Study of Actual Systems in the Northwest

Field Validation of Air-Source Heat Pumps for Cold Climates

https://www.nrel.gov/docs/fy23osti/84745.pdf

Building Electrification Electric Impacts

80% Reduction in WA/ID System Natural Gas Usage by 2045

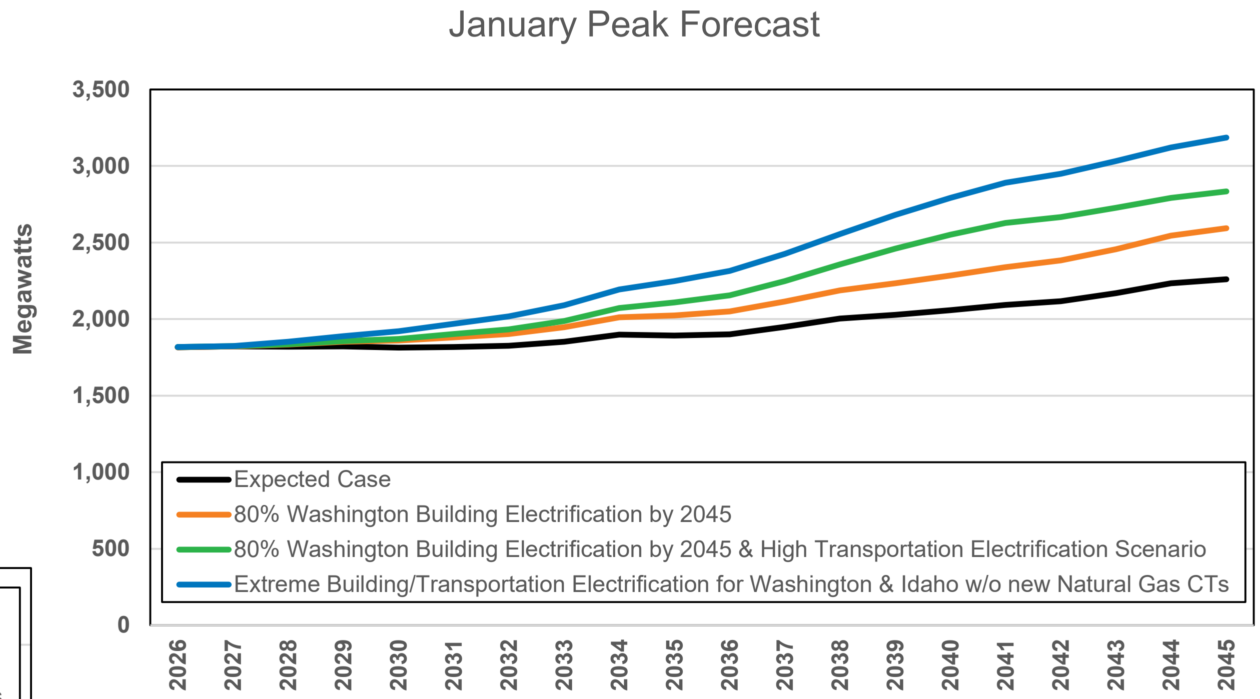


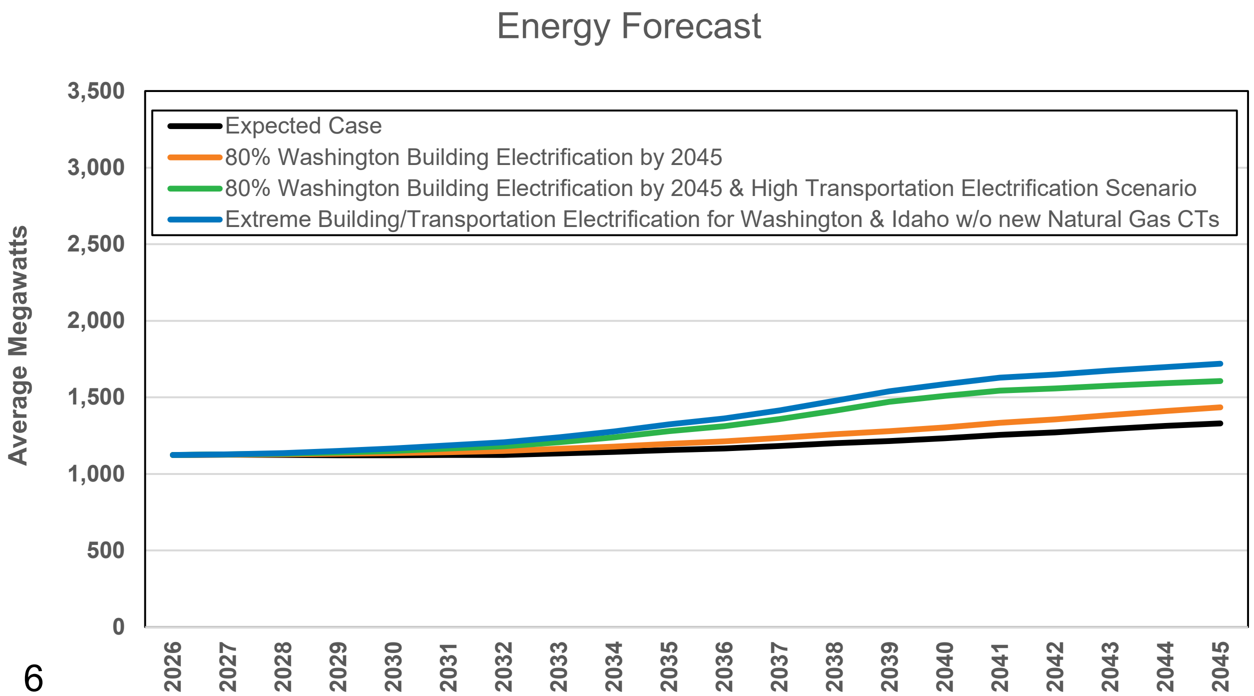
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Annual Energy	-	-	10	20	30	41	51	62	74	85	97	109	122	135	147	162	176	190	204	221
January Energy	-	-	20	42	63	86	109	132	156	180	205	230	256	283	311	339	368	397	427	458
August Energy	-	-	2	4	6	8	11	13	16	18	21	23	26	29	32	35	37	40	43	46

Assumes 75% of WA and 90% of ID natural gas customers use Avista electric

Load impact is close to even between states

Load Forecast Comparison





Load Forecast Scenarios Still Under Development

- Load forecast data will be posted on Teams site once finalized
- Remaining scenario update:
  - Maximum Washington Customer Benefits: EV/Solar penetration to be increased in Named Communities
  - Data Center in 2030: Assume 200 MW in Idaho service area
  - RCP 8.5 Weather: in process
  - Low Growth: see assumptions below
  - High Growth: see assumptions below
  - Campus Building Electrifications: Should this be a scenario or added to existing scenario?
    - 30 MW to 60 MW winter load

Load Forecast Economic Conditions

	Expected Case	Low Growth Scenario	High Growth Scenario
2045 Area Population	941,587	857,869	1,001,564
Avg. GDP	1.80%	1.26%	2.26%

Supply Side Resource Options

2025 Electric IRP, 8th Technical Advisory Committee Meeting
June 4, 2024

Michael Brutocao, Natural Gas Analyst

DRAFT

Overview and Considerations

- IRP supply-side resources are near commercially available technologies with potential for development within or near Avista's 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.
  - Interconnect included for off-system resources.
- An Excel file will be distributed with all resources, assumptions and cost calculations for TAC members to review and provide feedback.

IRA Details

- Production Tax Credits ($2022 USD)
  - Geothermal, Solar, Wind and Biomass
    - $0.026 per kWh tax credit
  - Nuclear
    - $0.015 per kWh tax credit plus $0.003 base credit ($0.018 total per kWh credit)

- Investment Tax Credit (Battery Storage, Pumped Hydro, Solar)
  - Costs incurred thru 2032 qualify for a 30% tax credit
  - Credit falls to 26% in 2033, 22% in 2034, 10% in 2035/2036, and 0% in 2037
  - Additional 10% low-income tax credit
  - Domestic production adder of 10%

Resources Not Modeled

- Carbon Sequestration
- Coal
- RNG except as fuel for Frame CT
- Sodium, Vanadium, and Zinc Bromide Batteries
- Wave

Resources Modeled

Resource	Fuel Source	MW	Capacity Factor	Capital $/kW (2026)
Frame CT	Natural Gas	180		$831
Frame CT	Ammonia	90		$1,079
Frame CT	RNG	90		$831
Reciprocating Engine	Natural Gas	185		$1,272
Combined Cycle	Natural Gas	312		$1,271
Small Nuclear Modular Reactor	Uranium	100	93%	$8,224
Wind (On System)	Wind	100	35%	$1,500
Wind (Off System)	Wind	100	35%	$1,642
Wind (Montana)	Wind	100	42%	$1,582
Wind (Off Shore/System)	Wind	100	49%	$5,220
Geothermal (Off System)	Earth	20	90%	$5,139
Hydrogen Fuel Cell	Hydrogen	25		$6,703
Kettle Falls 2nd Biomass Unit	Wood Waste	58	50%	$5,308
Kettle Falls Upgrade	Wood Waste	11	60%	$2,864
Rathdrum CT 2055 Uprates two unit operation	Natural Gas	5		$925
Rathdrum CT: Inlet Evaporation 2 unit operation	Natural Gas	10		$167
Palouse Repower	Wind	120	36%	$1,200
Rattlesnake Repower	Wind	180	27%	$1,200
Lind Repower	Solar	25	24%	$1,114

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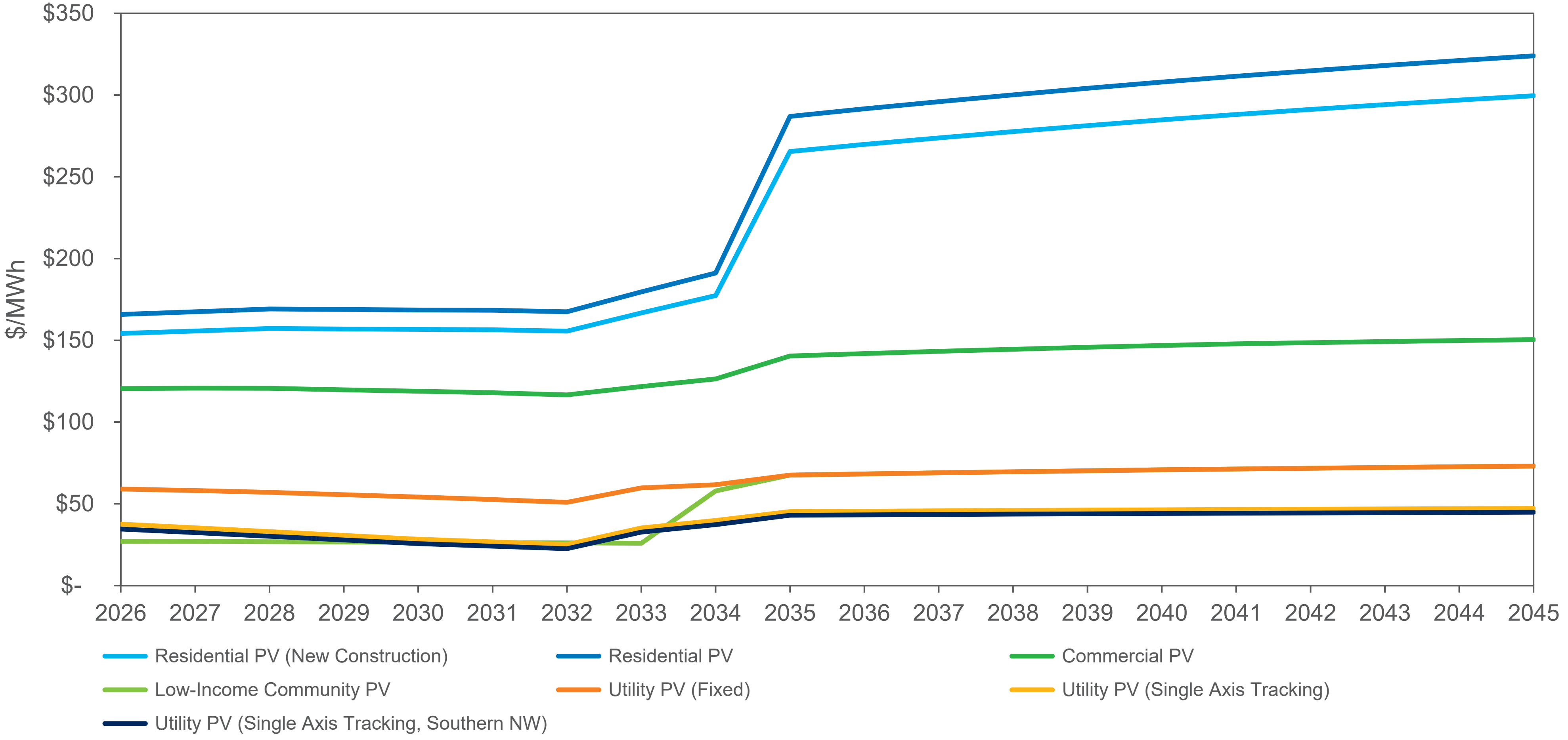
Resources Modeled (continued)

Resource	Fuel Source	MW	MWh	Capacity Factor	Capital $/kW (2026)
Residential PV (New Construction)	Solar	0.006		16%	$3,810
Residential PV	Solar	0.006		16%	$4,141
Commercial PV	Solar	1		17%	$2,297
Low-Income Community PV	Solar	<1		30%	$369
Utility PV (Fixed)	Solar	5		30%	$1,845
Utility PV (Single Axis Tracking)	Solar	100		30%	$1,392
Utility PV (Single Axis Tracking, Southern NW)	Solar	100		32%	$1,392
Distribution Scale Lithium-ion		5	20		$2,195
Distribution Scale Lithium-ion		5	40		$3,934
Lithium-ion		25	100		$1,663
Lithium-ion		25	200		$2,979
Lithium-ion		25	400		$5,613
Flow		25	100		$1,317
Flow		25	200		$1,383
Iron Oxide		100	10,000		$2,574
Pumped Hydro	Water	400	3,200		$4,070
Pumped Hydro	Water	100	1,600		$3,655
Pumped Hydro	Water	100	2,400		$3,384

Solar PPA Price/Implied Energy Payment



*Community PV does not include administrative costs (~$25/kW-year)

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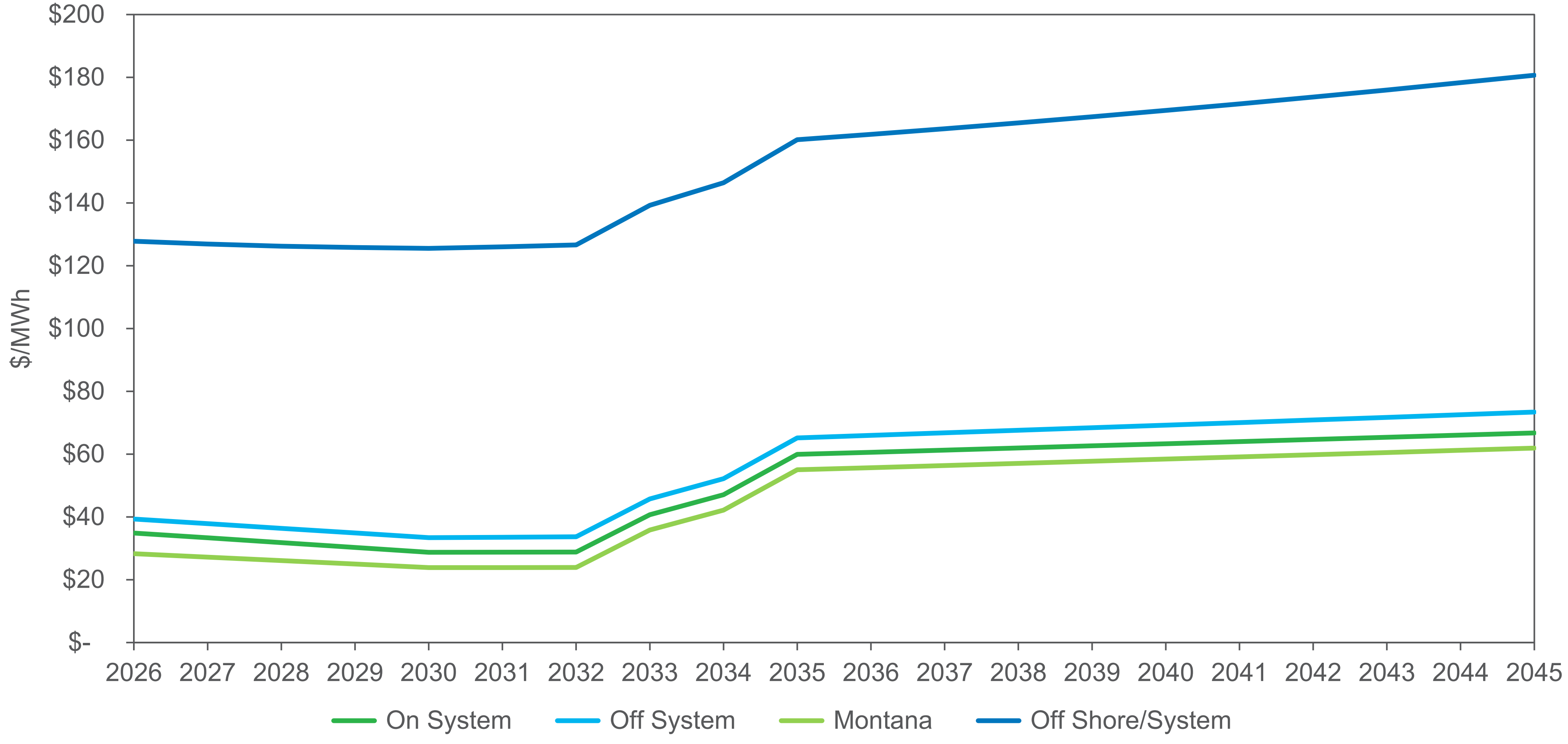
Wind PPA Price/Implied Energy Payment



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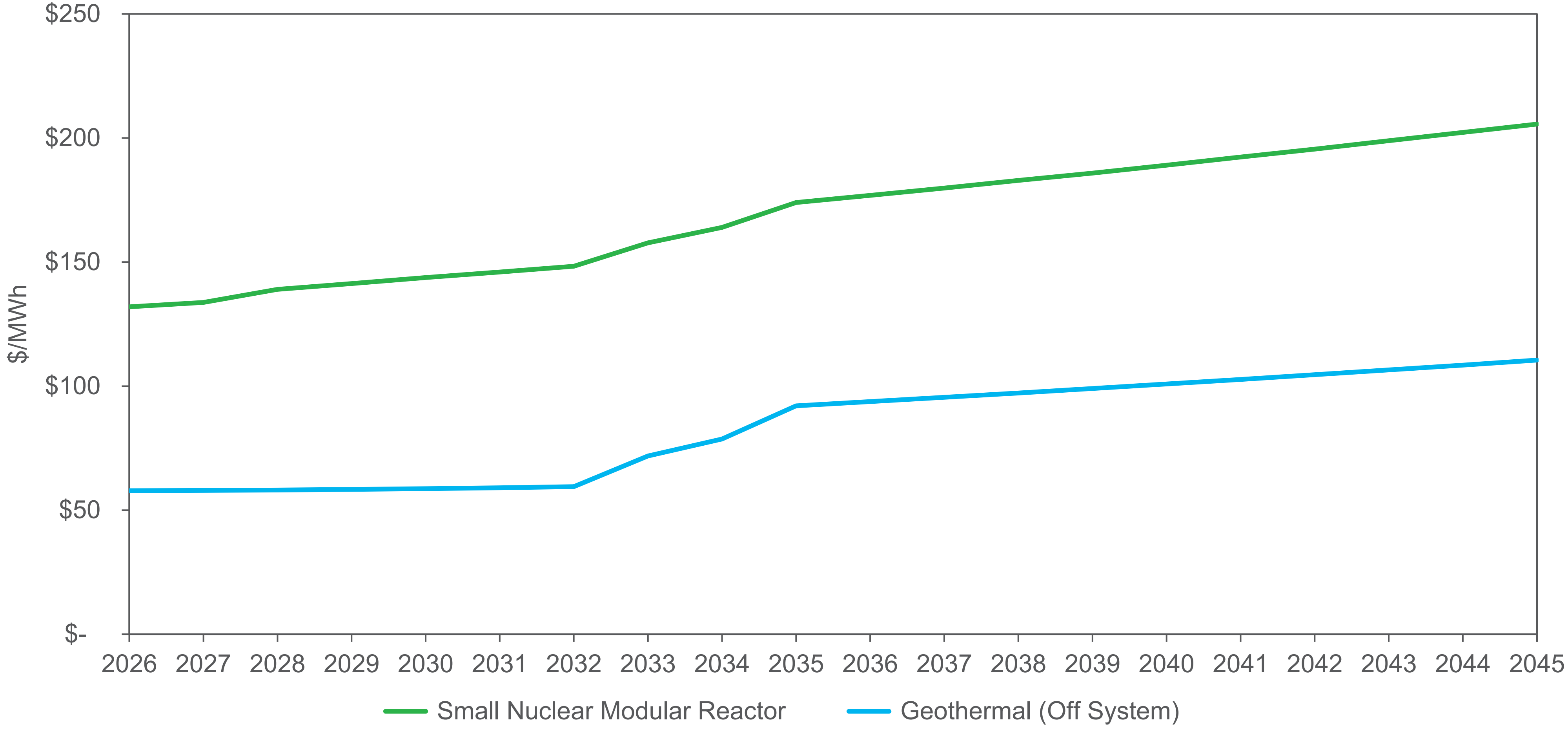
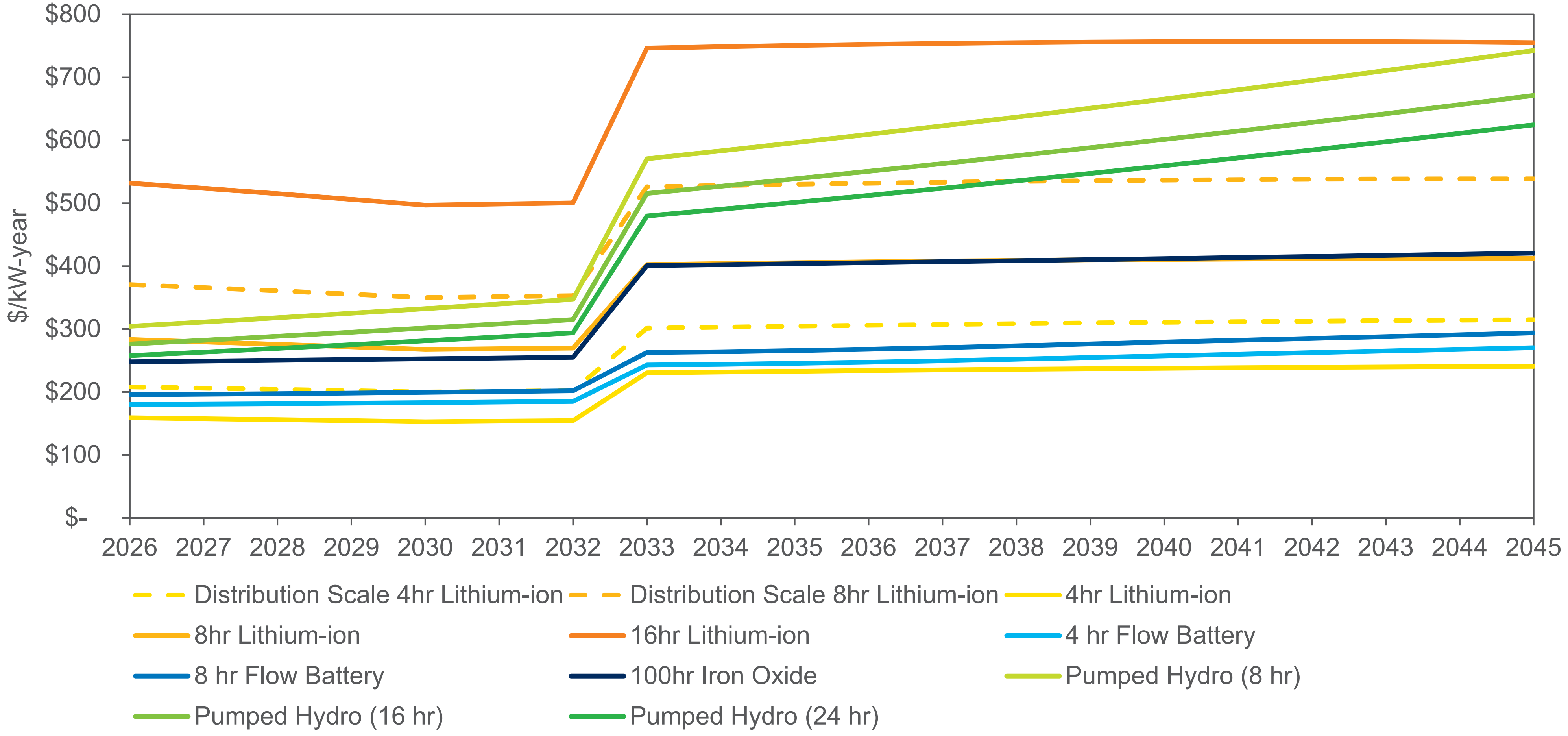
Baseload Clean Energy



Appendix A

Energy Storage PPA Price/Implied Capacity Payment



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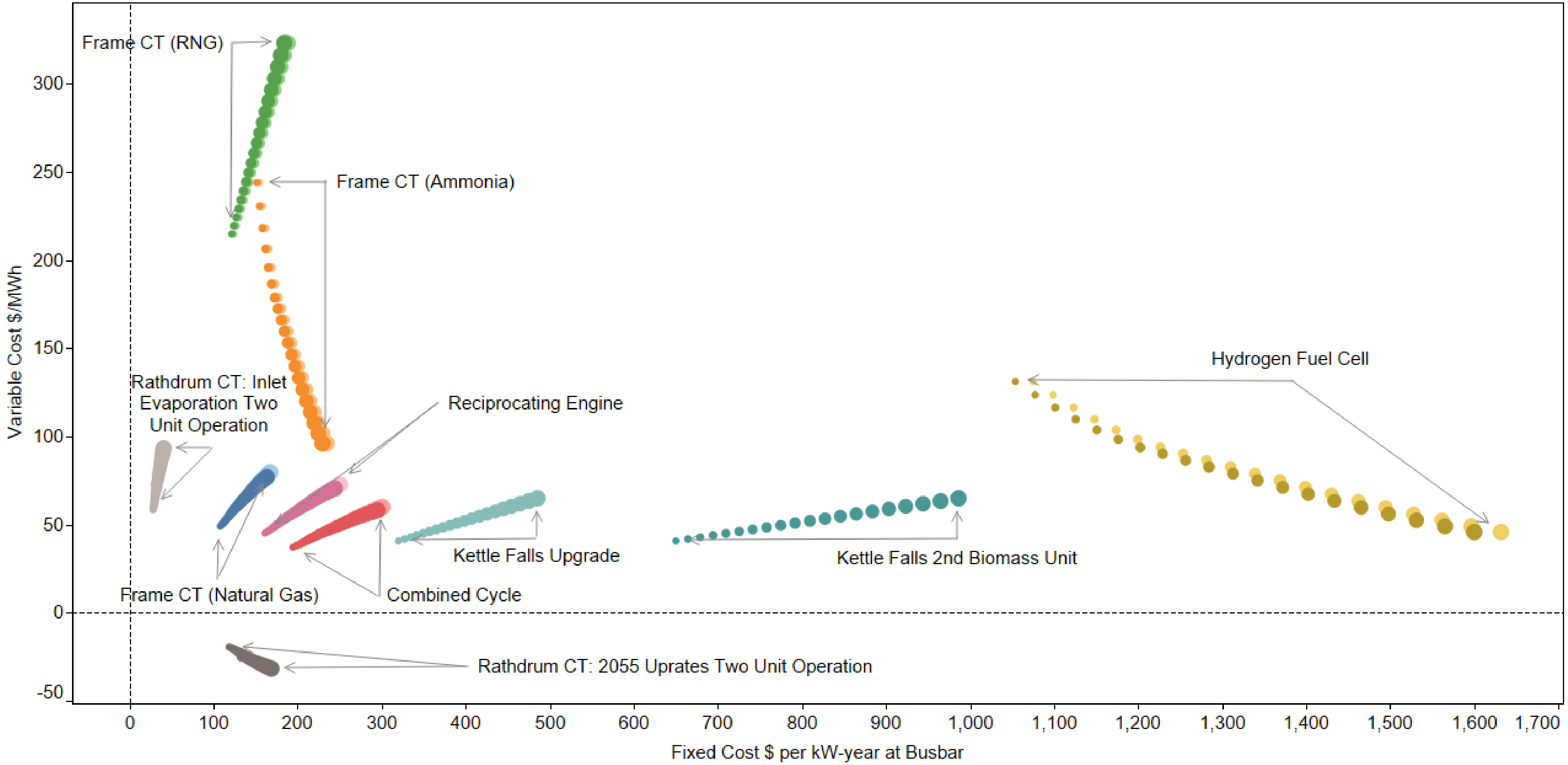
Dispatchable Resource Variable vs Fixed Cost



Resources with lighter and darker shades indicate costs in Washington and Idaho, respectively

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NEI Cost Studies to be Added

- Avista obtained licenses to run the IMPLAN model for Washington and Oregon to be able to run our own economic impact studies for each of the new resource types
- Still learning and configuring the model as this time and will report back to the TAC as the studies are completed
  - Upstream emissions estimates
  - Estimated direct, indirect and induced jobs for construction and operations
  - Reviewing additional outputs of the IMPLAN model for possible inclusion in the IRP

2030 Loss of Load Probability Study (DRAFT)

Mike Hermanson
Technical Advisory Committee Meeting No. 8
June 4, 2024

Topics

- LOLP Purpose
- Study Methodology
- Reliability Metrics
- Results
- Planning Margin

Purpose of Loss of Load Study

- Determine the ability of our system to meet load and reserves each hour when subjected to 1,000 iterations with different combinations of:
  - Water years
  - Load
  - Temperature
  - Maintenance
  - Forced outages
  - VER production
- Utilized currently expected portfolio of resources in 2030 and availability to purchase up to 330 MW from the market.
- Climate data utilized for water, load, and temperature in future years.

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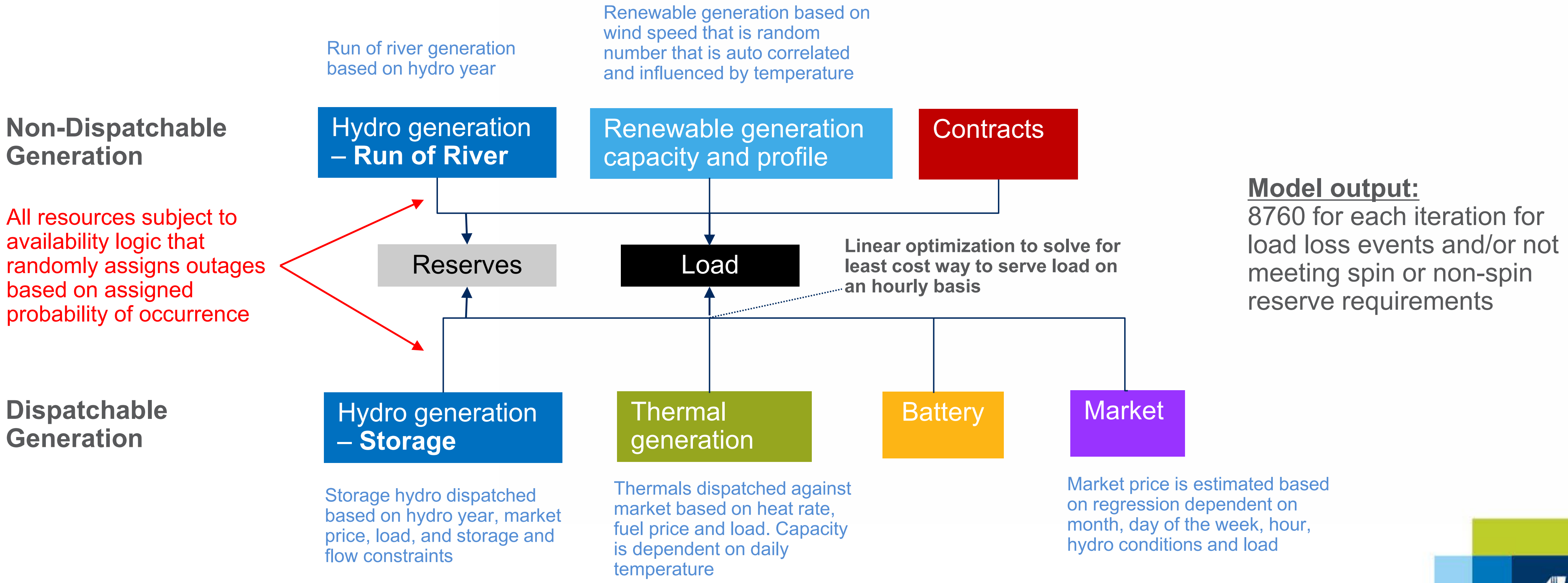
Modeling Framework

- Avista Reliability Assessment Model (ARAM) - Excel based model with VBA code and linear optimization Excel Add-in What's Best!



Reliability Metrics

- Studies are conducted with 1,000 iterations of the ARAM Model
- Model metrics provide insights and targets to achieve a reliable system
- Metrics
  - **LOLP** – *Loss of Load Probability*: Calculated by counting the number of iterations where there is unserved load or unmet reserves and dividing by the total number of iterations.
  - **LOLE** – *Loss of Load Expectation:* Calculated by counting the days where there is unserved load or unmet reserves and dividing by the total number of iterations.
  - **LOLEV** – *Loss of Load Expected Events*: Calculated by counting the number of consecutive blocks of unserved load or unmet reserves and dividing by the number of iterations.
  - **LOLH** – *Loss of Load Hours:* Calculated by summing the number of hours with unserved load or unmet reserves and dividing by the total number of iterations.
  - **EUE** – *Expected Unserved Energy:* Calculated by summing all of the unserved MWhs over the study period and dividing by the number of iterations. Two versions are presented one with unmet reserves and one without.

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Reliability Metrics

Metric	Use
LOLP	Can be used to determine the probability or likelihood of events due to insufficient capacity.
LOLE	The majority of entities conducting LOLE studies primarily use it to establish resource adequacy criteria. Industry standard is 0.1 days per year LOLE.
LOLH	The LOLH metric is computed by a large number of entities in North America. However, only one entity uses this metric as a reliability criterion, with their criterion set a 2.4 hours per year.
LOLEV	The LOLEV metric is useful in systems that are concerned with the frequency of events, regardless of duration or magnitude.
EUE	EUE is useful in estimating the size of the loss of load events so planners can estimate the cost and impact of the loss of load events.

Note: information taken from NERC, Probabilistic Adequacy and Measures Report, July 2018

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2030 Existing Portfolio
12x24 Resource Deficiency

- The following chart presents the sum of the hourly average of loss of load over 1,000 iterations by month and hour in MWhs:

2030 No Additional Resources

Month \ Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	10.2	11.5	13.2	14.6	15.4	20.2	31.7	39.4	32.0	28.9	25.9	22.1	20.1	14.3	16.5	14.8	17.3	17.8	18.8	19.2	19.5	17.6	14.2	12.8
2	2.4	3.2	4.3	5.8	6.9	10.0	12.2	15.8	11.0	8.8	6.3	5.5	3.9	2.3	2.4	3.2	3.6	4.0	5.6	5.5	6.7	6.5	6.1	6.1
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.9	1.3	0.8	0.1	0.0	0.0	0.0	0.0
8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.6	1.2	0.6	0.1	0.0	0.0	0.0	0.0
9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	0.1	0.1	0.1	0.1	0.1	0.1	0.4	0.1	0.2	0.4	0.3	0.1	0.0	0.1	0.1	0.2	0.3	0.0	0.3	0.0	0.3	0.2	0.3	0.1
12	9.1	8.1	9.0	12.7	14.1	19.8	27.1	29.5	28.3	29.0	23.4	21.2	19.1	14.8	15.9	16.0	18.0	20.3	20.6	22.8	21.2	22.7	19.1	15.6

Summary of metrics

- Planning margin determined by running model with increasing values of additional dispatchable resource

Metric	Additional Dispatchable Resources					Target
	Base	50 MW	100 MW	150 MW	200 MW	
LOLP	13%	10.4%	7.6%	5.2%	4.2%	5.0%
LOLE	0.44	0.32	0.24	0.16	0.11	
LOLH	4.98	3.66	2.48	1.71	1.12	
LOLEV	0.98	0.83	0.62	0.48	0.32	
EUE (with reserves)	1084	783	520	340	203	
EUE (without reserves)	1066	768	511	334	199	
Implied Planning Margin	21.0%	23.8%	26.6%	29.3%	32.1%	

LOLP – Loss of Load Probability
LOLE – Loss of Load Expectation
LOLH – Loss of Load Hours
LOLEV – Loss of Load Expected Events
EUE – Expected Unserved Energy

- Interpolated model runs to calculate 167 MW to achieve a 5.0% LOLP
- Consider (evaluate) moving winter planning margin from 22% to 30%

Avista 2025 Electric IRP

TAC 8 Meeting Notes

June 4, 2024 8:30 to 10:30 am PTZ

Attendees:

Sofya Atitsogbe, UTC; John Barber, Customer; Kim Boynton, Avista; Molly Brewer, UTC; Kate Brouns, Renewable Northwest; Michael Brutocao, Avista; Logan Callen, City of Spokane; Katie Chamberlain, Renewable Northwest; Josie Cummings, Avista; Kelly Dengel, Avista; Mike Dillon, Avista; Jean Marie Dreyer, Public Counsel; Michael Eldred, IPUC; Rendall Farley, Avista; Ryan Finesilver, Avista; Grant Forsyth, Avista; James Gall, Avista; Bill Garry, Customer; Konstantine Geranios, UTC; Amanda Ghering, Avista; Michael Gump, Avista; Leona Haley, Avista; Tom Handy, Whitman County Commission; Lori Hermanson, Avista; Mike Hermanson, Avista; Fred Heutte, NW Energy Coalition; Kevin Holland, Avista; Joanna Huang, UTC; Clint Kalich, Avista; Scott Kinney, Avista; Seungjae Lee, IPUC; Dan Lively, Clearwater Paper; Kimberly Loskot, IPUC; Mike Louis, IPUC; John Lyons, Avista; Patrick Maher, Avista; Jaime Majure, Avista; Ian McGetrick, Idaho Power; Tomas Morrissey, NW Power & Conservation Council; Austin Oglesby, Avista; Michael Ott, IPUC; Tom Pardee, Avista; Meghan Pinch, Avista; John Rothlin, Avista; John Slagboom, WSU; Dean Spratt, Avista; Victoria Stephens, IPUC; Lisa Stites, Grant County PUD; Jason Talford, IPUC; Charlee Thompson, NW Energy Coalition; Yao Yin, IPUC.

<u>Introduction, John Lyons</u>

James Gall: We're going to do that right now.

John Lyons: And as a reminder, if you have a question, either use the raise hand function or bring it up in the chat and we've got a couple people here in the room watching for those. If we don't get to you right away, we're just waiting for a good pause on that. But we will get to those. Anything else you'd like to add, James.

James Gall: I just want to cover what's coming up next. Like they see, the next meeting is June 18th and at that meeting we're going to cover transmission and distribution planning. And then on the 25th of June, we'll cover our technical models. That's I guess an optional meeting for those that want to dive into the models a little bit more deeply, we're going to cover the PRiSM model, the ARAM model, and then the resource cost model that's actually being discussed today. It's the model that was used to come up with the costs that Michael is going to cover later and then July 16th will be the pinnacle of the IRP process where we're going to share our Preferred Resource Strategy results and then we'll continue that process over the summer before we file our draft IRP on September 1st. So, with that, I guess we'll get started. Unless there's anything else.

John Lyons: Yeah, I think we're good, James.

Electrification Scenarios, James Gall

James Gall: You might get any questions before we get started. I'll find my presentation and we'll get going, right? Give me a second. I'm on one screen today and it makes it hard to find everything.

James Gall: OK, I think our last TAC meeting, we left off on trying to go through the different scenarios we're going to be covering and electrification was where we left off last time we covered, I believe it was the updated load forecast, and this time we wanted to share the scenarios that we were planning on conducting with that load forecast with electrification to get started. Let's go to the next slide.

James Gall: The first one I wanted to cover is our high electric transportation scenario. In this scenario, we wanted to take a look at the high case of what customers may do to electrify vehicles. Our base case, that's shown in the dotted red line put together for our IRP study is our base assumption that has a significant amount of commercial vehicles and a significant amount of residential vehicles. Light duty vehicles, compared to our last IRP, which is shown in the dotted black line. And in that case that we're assuming for our current base case is actually higher than our high case in the 2023 IRP showing in the dark black line. But we want to make sure this IRP covered, I wouldn't call it a worst case scenario, or maybe call it the best case scenario for electrification where we tried to look at trying to get what happens if almost all vehicles as compared to today electrified by 2045 in both states. What does that mean? It means about 1.1 million vehicles would be electrified by 2045. In this high case assumption, in that dark red line, we also wanted to make that look like more of an S curve growth pattern to show what happens if customers adopt electrification much faster than we assumed in the base case. You can see that curve grows much quicker and then flattens out about the 2040 period. It's about 400 aMW in total for this case.

James Gall: And if we move to the next slide, this shows you what it looks like between the two states. And on Idaho, it's a significant increase for this scenario because our base case doesn't assume a lot of electrification in the Idaho Service territory. Most of the growth, at least compared to the base case, is much higher than the Idaho case on the Washington side, while it is higher than our expected case, it's really moving that load growth faster in the earlier years and then flattening off. That's what our high case it's going to be for the for electrification of transportation. Definitely welcome comments or thoughts on this if you have any. I'm going to pause there if there's any thoughts or comments? OK.

James Gall: And what we're going to kind of cover, back to this when we wrap this up with the other scenarios, and then I'm going to move to building electrification and building electrification. It comes down to how heat pump technology works, and really there's two types of appliances we're talking about. For the majority of building electrification, one is water heating, and the other one is space heating. Space heating is really what I want to talk about today. Water heating is a little bit more simplified because you're converting natural gas water heaters to likely a heat pump water heater. That changeover is a little bit less controversial compared to space heating. On the space heating side, we're utilizing a study done by NREL as referenced in the bottom left corner. This study looked at cold weather heat pumps in mostly the Spokane area and a few other areas that have colder winters. And the study looked at, I believe, around 12 different buildings or homes and they were trying to identify how well they performed in cold weather. Each of these buildings had different designs of their system, which is kind of what's reflective of what we would expect today because a lot of data you may see for heat pumps on how well they perform in cold weather really depends on the building they're in. And I'm going to get to that in a little bit. But the gray line on this chart is trying to represent how efficient a heat pump is supposed to be in the cold weather from the study. On the bottom X-axis you have temperature, outdoor temperature, and then on the left side you have COPD and this is efficiency. The best way to think about this is an efficiency of 1 would represent a forced air electric furnace that is resistance heat. And if you have a COP of two, you're twice as efficient as that electric resistance furnace. When you're at around 65 degrees in this study by NREL, they found that you're a little bit over 3.5 times more efficient than an electric furnace. But what happens is as temperatures decline, the heat pump loses its efficiency. At the coldest temperature they recorded in this study was about 5 degrees. They found that a heat pump was a little bit less than 2.0 efficiency, so a little bit less than two times more efficient than the electric resistance.

James Gall: But there's some issues with that. One is the heat pump on its own couldn't provide all of the heat for the building, so auxiliary heat had to turn on, and then too many of these heat pumps have to go into a defrost cycle when it's around 35 degrees. So, you have efficiency losses between the auxiliary cycle and the defrost cycle. The blue line represents what the net efficiency is. Of these, these heat pumps and cold weather, still, even at 5 degrees or slightly above 11 COP, you get below that. You basically trend down to a COP of 1, and it's also possible you could go below one if your unit gets stuck in a defrost and it's on full resistance. And of course, if your heat pump is oversized for your home, you may be able to get a higher COP then these are showing, but that means you're going to be installing more expensive equipment for your home and have quite a bit more cycling. You have a question. All right? Well, from Fred, OK.

Fred Heutte (NWEC): Hey there. It's Fred Heutte, Northwest Energy Coalition. Good morning, everybody. I'm not familiar with this report, but thanks for providing the link or the reference, but I have a couple of quick questions. Could you say what the net efficiency line represents?

James Gall: Yeah. That's taking into account the auxiliary heat and the defrost cycle.

Fred Heutte (NWEC): OK.

James Gall: What their actual efficiency is, of delivered heat in the home, so if it's five degrees out between the heat pump and the auxiliary heater, you're a net efficiency. At five years it would be just over one on average.

Fred Heutte (NWEC): Right. And then the other question is that little bubble there says heat pump lockout point. What do they mean by lockout point?

James Gall: Yep. That's what I was about ready to get to.

Fred Heutte (NWEC): OK, before you go on, I just want to say about the defrost cycle, new heat pumps where I'm staying here in Portland on January 13th, it got down to 15 degrees here, wind chill was below zero with 50 mile an hour wind. Spokane is not unfamiliar with that kind of condition. We certainly are not. What I noticed was, and these brand new Daikon heat pumps are good, they were defrosting about every 20 minutes in those conditions and definitely you know the temperature dropped inside. I mean, that's pretty extreme, especially over here in the West side. But I just want to say I have personally experienced this divergence on the curve that you see.

James Gall: Yeah. And if you do check the study out, there's a good chart they show for each home. How much defrost is happening and it's quite enlightening. I think, like you just said, you experienced that event and it is, I guess, the downside of a heat pump technology and maybe that's when I get to this heat pump with the gas lockout, that's a solution for it. All right.

Fred Heutte (NWEC): Yeah. Oh, it also noticed that Northwest natural came yesterday and took away our gas meter. A few months after we shut off. So, we're really committed now to the heat pump side.

James Gall: Alright, OK, what do I mean by heat pump lockout for gas? This is something we're remodeling from our last IRP, we haven't modeled this scenario in this electric IRP, but will be modeling the gas IRP. But if you have a hybrid heating system, this explains why we've mentioned there's a point where you want to transfer your heat pump from natural gas or from electric to natural gas. In the event you had a combo set up and you have instead of an electric axillary unit you have a natural gas unit. You get to a point, and this example it's around 40 degrees, when the heat pump can't on its own provide enough heat for the building. That's when the auxiliary unit, in this case natural gas, have to start turning on. You can see everything left of that curve. There's a divergent where you start losing efficiency. But basically, also at that point, if your house is designed in a way that your heat pump cannot satisfy the heating load, then you're going to have to use an axillary system. If your home and your HVAC system is sized properly at around 40 degrees, your heat pump would have to switch over to an axillary system. If it had a natural gas auxiliary, if it had an electric auxiliary, you can continue to maintain both. But if you oversized your system, you could possibly have your lockout, the lower temperature maybe down to 30 degrees, but that depends on the system. Where I'm going with this is every home is really unique and it's set up for what the heating capacity of its heat pump is versus the home’s design. On average, we assume it's around 40 degrees where if you do have a natural gas backup, that's where it would switch over. Alright, what does this all mean for load? In this case, if you moved 80% of our gas system to electric, this is what you end up with new load. The orange line represents the January energy amount. It's about 450 megawatts of average energy. If we wanted to convert 80% of gas load to electric and this includes the space heating we just covered at the efficiency curves, water heating, and then we call it other natural gases.

James Gall: Now, not all of the load that's on the gas system and either state wouldn't become Avista electric customers. We estimate around 75% of Washington customers would be Avista customers on the electric side, the rest would be potentially Inland Empire. Sorry, Inland Paper are Inland Power or Vera Modern. Some of the other coops and municipalities in our area, also on the Idaho side, it'll be about 90% of the natural gas customers would become electric. So, there are actually higher loads than this. It's just they would not be in our service area, the electric service area.

James Gall: Going back to this on the blue bar represents how much annual energy there would be. And in gray represents the August energy. August really represents maybe the water heating amount of this electrification and then the space heating as you can see in the orange, significantly higher than when you average all that out, it looks around 200 megawatts. I believe our January load today is around 1,300 average megawatts, so you'll be adding about 450 megawatts to 1,300 just to give you a comparison of how much extra load this is to the electric system. Quite significant. So, what does this mean when you add all these up?

James Gall: We had three scenarios we promised to run in the IRP. The first one obviously is the expected case, which we will show everybody in the next TAC in July. We guess the one after the next one and then we had three other load scenarios. We're going to cover that with electrification.

James Gall: The first one is the 80% building, Washington building electrification. That is basically this chart here, but just for the Washington service territory, we're going to while just Washington on its own for building electrification, that's the orange line in these charts. And then we will then do a second scenario where we combine the building electrification and the high transportation electrification just for Washington. That's in the green line. And then in the blue line will be a combination of both states.

James Gall: High electrification scenarios, that would be what I called the ultra-high load case in blue where we're looking at 2045. Our peak January forecast would go from about 2,150 megawatts up to 3,250 megawatts. So, about 1,000 MW load increase.

James Gall: That's the four scenarios for electrification. We are looking to give everybody an update on other load forecast scenarios. It seems like most of the scenarios that we've been asked to do this time around are related to load. Here's just a quick rundown. The maximum Washington customer benefit scenario, there is a different load forecast for that. We're going to have a different EV and solar penetration load that's in the Named Communities. We're still working on getting that data from the DER study for that case, so that will have a slightly higher EV forecast than our Expected Case. And then a higher solar forecast, those might offset a little bit, but that will be used in our maximum Customer Benefit Indicator scenario.

James Gall: We'll be doing a data center scenario where we would get a 200 MW new data center load and we are assuming that would be in the Idaho Service territory by 2030. We could move that to Washington as well. I guess it depends on what it might be beneficial to run it in both states, but I guess that's something we can discuss if there's interest in one state versus together, but about 200 megawatts I think is probably the upper end of what we're seeing for data center sizes.

James Gall: The third scenario we're going to be conducting is the RCP 8.5 case. That's still in progress. We have two other ones that we're looking at as well, low growth and high load growth. And these are two scenarios that are based on economic conditions. I've got some examples of those economic conditions down in the bottom. We're still working on getting those load forecasts complete. The last one is a scenario that we haven't talked about yet, but it's something I was going to mentioned that might be interesting. I think the Washington State legislature passed a campus building electrification or decarbonization bill. I can't remember if it was this year, I think it was last year. We have a number of campuses in the service territory that could, depending on the how they meet that requirement, electrify a significant amount of heating load. We're debating whether we should do this scenario or not. It could be as much as maybe 60 megawatts of winter peak load, could be even as low as 30 MW. That's something we're thinking about and happy to listen to any thoughts on that bill. If you have any information on that, or if this sounds like a good scenario, but I also don't want to overwhelm the process with a million different scenarios because we are getting, I think over 20 scenarios. That's all I have for slides. If there's any comments or feedback on what was just presented.

Fred Heutte (NWEC): Yeah, it's.

James Gall: Right answer question. Yeah, go ahead.

Fred Heutte (NWEC): Yeah, it's Fred. Just a very quick question. Is there any particular reason to specify Washington or Idaho on the data centers? There's some reason why it would make a difference.

James Gall: There is. If it's in Washington, we have to supply with 100% clean energy by 2045. Idaho there is not that requirement now.

Fred Heutte (NWEC): Alright.

James Gall: The data center itself may ask for that, so I guess we could make the assumption no matter what service territory it is, they want 100% clean supply. That might solve that issue.

Fred Heutte (NWEC): Yeah, I think most of the operators want that now anyway. Certainly, you're in Oregon.

James Gall: Yeah. Maybe that's what we'll do is we'll just assume it's 100% clean, no matter what state it's in. And then that solves that problem. Alright, good comment. Thank you. Alright. Anything else? If not, we'll skip to the resource presentation by Michael and there should be lots of things to talk about there. So, whenever you're ready.

New Resources Options Costs and Assumptions, Michael Brutocao

Michael Brutocao: Trying to get this to share. Alright, looks like it's working. I'll be covering our supply side resource options that we're modeling this IRP. It's basic graphs throughout this, so feel free to interrupt. There might be some awkward pauses, a lot of time for questions, but jump in. Some of the overviews and considerations these resources we're considering, the current and near commercially available technologies that are both within or near this service territory.

Michael Brutocao: Are these costs? There are variables such as location, equipment, fuel prices and ownership that are going to affect resource costs and have those little vary. We are also modeling resources as PPAs as well as Avista owned. These assumptions do not mean that these are the only means of resource acquisition. Those resources that are modeled as PPAs are the solar, wind, nuclear and geothermal. Owned would be all others. That might be battery storage, pumped hydro, fueled gen. These costs do not include any transmission or interconnection costs except for off system resources. An Excel file will be distributed that basically shows how all this was calculated and broken out and that I think will be covered at the June 25th meeting. The technical modeling workshop.

Michael Brutocao: OK, how the IRA was included in these costs. There are production tax credits for geothermal, solar, wind and biomass, as well as nuclear. And then there are investment tax credits for battery storage, pumped hydro and solar again. Solar is modeled as both a PTC and ITC separately, and then the lower of the two costs are taken. The lower the two approaches for the ITC, it's a 30% tax credit for those resources through 2032 and then that falls to 26% in 2033 to 22% and 2034, and 10% in 2035 and 2036. For residential customers, residential solar goes down to 0% in 2037.

James Gall: Molly has got a question. Molly.

Molly Brewer (UTC): Yeah. I was just curious, the Commission came out with the policy statement on incorporating the IRA in the IRP. I don't have specific examples right now, but I'm just curious if you know, is that captured and what we're seeing here?

James Gall: Exactly what we're capturing. Yes.

Molly Brewer (UTC): OK, good. Just wanted to make sure. Thanks.

James Gall: Yeah. We're trying to include everything we know about potential for ITCs. But the real challenge one is, the, we have a blank on the name the IJ, JIJ.

Molly Brewer (UTC): Yeah.

James Gall: You know, those are a little bit more challenging for long term. They're more focused on, it seems like shovel ready projects, so that is not going to be included, but anything IRA related will be included in this, our assumptions for those.

Molly Brewer (UTC): Cool. Thanks.

James Gall: Yep. And then we do have a question in chat. Since pumped hydro likely qualifies for the 10% domestic content bonus ITC, should it be 40% for pumped hydro? Batteries, presumably not qualified due to foreign sourcing.

Michael Brutocao: That's a good question. I will have to check that. I didn't know that the country would be qualifying there. We'll verify that and we'll add that to the tax credit if we do agree with that. On the battery side, that is something we are assuming that and the iron oxide batteries would get the extra 10%. But the lithium ion we're assuming would not. That should maybe address Matthew’s comment. I wanted to say I think we have something happening to that 10% domestic production adder. But I can't check, verify that right now.

Michael Brutocao: Here's just a list of some resources that are not being modeled. I'll point out on line three. RNG is not being modeled except as a fuel for a frame CT. And some of the resources that were something, but it's the first of two sizes on resources that are being modeled. See at the top, those first three frames, CTs differ by fuel source, so there's natural gas, ammonia and RNG. That being the differentiating factor of those and then the bottom 7, starting with Kettle Falls and below, those are all upgrades to existing resources. And this is mostly for reference. It's a lot of information to take in at once and cover, but if there are any questions, please feel free to, we can come back and answer.

James Gall: Michael, do you mind covering where we put the sources for our cost assumptions?

Michael Brutocao: Yeah, there are obviously some internal, but maybe those upgrades, but the majority of not all of these costs are from NREL, from the most recent annual study. The, blanking on the name of that, I can certainly share that with anybody who's interested. So, these are the rest of the top half or the top portion. You can see the solar resources and then down below, some of those storage batteries and pumped hydro.

Michael Brutocao: And then we'll get into a couple graphs. I think there's five of them that are going to show you the levelized cost of these resources. Here's our solar resources. The Y axis, these are in dollars per MWh. On this, I want to point out the note in the bottom, community PV does not include administrative costs. Which about $25 per kilowatt year. And it also points out the low-income community PV, I believe looks like through 2033 that model is assuming Washington covers 80% of the capex and then it takes ITC or PTC depending on which is cheaper and the following one or two years, I think for the rest time period. Fred has a question.

Fred Heutte (NWEC): Yeah, very, very quick on the community solar. Did I hear you right? Not including admin costs, but the admin costs are $25 a kilowatt year?

Michael Brutocao: Yeah.

Fred Heutte (NWEC): OK, doesn't seem like all that much, but not unimportant. OK, thanks.

James Gall: We're still validating that number for admin, a lot of it depends upon how big the program gets. If we had just one program with say less than a megawatt facility, it's probably going to be significantly higher than that. But if you start, let's say you get 10 megawatts or more than you're probably in that range.

Fred Heutte (NWEC): Yeah, I can see that. Just a note, we have a pretty extensive community solar program in Oregon. It’s been a long haul to get where we are. It's actually quite good, but it's also had a lot of struggles with costs, interconnection and admin costs. Like you said, it's not a cheap thing to do the way we are doing it. Anyway, it will, especially for us, given our transmission constraints over here on the West side, I think it's going to be increasingly seen as being very valuable. Our projects typically are in the 1 to 3 MW range. So, you're not really getting scale economies from that, but you're also getting a better distribution in places where they can fit in well. It can add up to quite a bit, but yes, it's more expensive obviously than doing bigger grid connected.

James Gall: Yeah. And I believe the Washington credit is for projects less than 1 MW. I don't know how I let it string those together and we're just starting to investigate this, but it's going to struggle from similar challenges you've seen in Oregon.

Fred Heutte (NWEC): Yeah. And just so everybody knows, rough rule of thumb on these solar projects is, I don't know if this may be an over underestimate, but I would say approximately 10 acres per MW for space.

James Gall: Yep. That sounds correct for a non-tracking system. Alright, Molly has a question. Yeah, Molly.

Molly Brewer (UTC): Yeah. What is commercial PV?

Michael Brutocao: Yeah. Commercial is, I think it's just a one MW, so basically a commercial customer.

Molly Brewer (UTC): Commercial customer. OK. Thank you.

Michael Brutocao: Yeah. See the residential customer, commercial customer, and then we broke out residential between new construction and existing construction because the costs of a new construction home is quite a bit less than an existing home, but commercial, it was about the same.

Molly Brewer (UTC): OK.

Michael Brutocao: Alright, one thing that you'll see on the remainder of the slides here is this jump in the middle, just make that connection, this is being phased out, ITC and PTC credits.

Michael Brutocao: OK, there's wind, offshore wind at the top, and then the rest keeps on system, off system here locally and then Montana wind. These are MW hours on the Y-axis. Baseload energy. These would be nuclear, small nuclear, modular reactor on top and geothermal system on the bottom. These are in MW hours on the left-hand side. And a bit more going on here. These are all the energy storage options, batteries as well as pumped hydro. Hydro is in the kind of green hues and here they move into the top of the chart. Everything else is going to be batteries. And where you see these dotted lines, that is the cost for distribution scale of this type. For example, this would be the 4-hour lithium-ion battery. The utility scale is down below and the solid line. And if you can't see it, the 8-hour lithium-ion for that orange dotted line, it's kind of hiding behind this 100-hour iron oxide battery. Another question from Matthew. Matthew, do you want to cover your question?

Matthew Shapiro: OK. I guess this is a little bit in the spreadsheet that is in the future, but did these factor in the different life spans of the technologies like the 15-year lithium ion versus the 60 to 100 year for the pump storage? That was my first question. Then because the levelized cost of storage should be immediately even if you only used 45 years or something like that. When you compare it with the cost from the earlier slides, it shouldn't be that much higher I would imagine. Then the other is related to why it jumps in 2032 when the effect of the ITC is essentially to lower the cost of building the project. So, the 2032, as long as the project enters construction by that time it captures 100% and then at 2033. If it has, it enters construction by 2033, it's a bit lower, et cetera, et cetera. And then it drops away completely if it doesn't enter a construction, but once it's in place, the ITC is for the construction of the project. The effect is permanent. So, just wondering why that jumps up so much at 2032 and then why the pump storage number keeps going up whereas the lithium ion is flat into the future. Those are, I guess, three questions really.

Michael Brutocao: Yeah, we may need a refresher on those, but now I'm forgetting the very first one. The lifespan is accounted for in two ways. In one, there's the reinvestment, I think for batteries it's replacing dead cells. And then, there's also a different. I'm working on the word, just different depreciation period for the assets with different life spans. We're using 50 for pumped hydro. Or 45. It might be 50.

Michael Brutocao: I think I answered your first question. The second that I think there is a challenge though on your second question on the construction start date. If you do start in 2032, you're going to get the tax credit, even though it's not complete until 2035. I think that's a valid argument. We'll have to think about how to address that because we don't know what projects are going to be there. But you're probably right. We could probably extend that out, at least three or four years to take that into account. That's a fair argument where the other battery technologies, they're going to have a much shorter construction cycle, so I don't think that's as big of an issue.

Matthew Shapiro: Well, the pump storage is going to be able to take advantage of the ITC for its entire lifespan because essentially, you're lowering the cost of the capex of the project for its entire lifespan versus the batteries.

Michael Brutocao: Correct.

Matthew Shapiro: If they're coming online, they're first replacement and say, 15 or 20 years of the system doesn't get the ITC and all of a subsequent replacements over the course of the equivalent lifespan of the pump storage presumably don't get the ITC.

Michael Brutocao: Yeah, I think.

Matthew Shapiro: And so, it benefits the pump storage much more really.

Michael Brutocao: Correct. Yeah, I think there's a misunderstanding of the chart. The price you see here assumes when it was put into service, a project built in 2032 gets that price forever versus the price that was in service in 2033 gets that price forever.

Matthew Shapiro: Right.

Michael Brutocao: We're doing exactly what you're referring to. I could have made that a little more clear. But yeah, and the same thing with the other projects on the other slides, that's the price when it's in service. Still here it's effective price is going to be straight.

Fred Heutte (NWEC): Yeah, just a quick comment, I think.

James Gall: Fred, then Sofya.

Fred Heutte (NWEC): I think I agree with your approach here that basically these tax credits, you can net them out against the capital cost up front like a lump sum. The question of how they apply over time is a different, that's a project finance question I think, but I think for planning purposes this is fine. So, something, let's lithium ion, which has a say or 10- or 15-year replacement cycle over 50 years you'll have a couple of those, but you'll already have a incorporated the full value of the tax credits up front. And you know you can levelize that out, but I don't really see a big obstacle here. The way project finance deals with these tax credits is all over the map, and that's a whole other subject.

James Gall: Sofya.

Sofya Atitsogbe (UTC): Thank you. Hi. This is Sofya Atitsogbe with Washington UTC. I have a question about 2035. The U.S. signed an agreement to go coal free after 2035 and understand that Avista will not have any coal on the system by that time. But maybe that would influence the prices of the energy resources for which Avista will compete with the competitors. Do you know what impact it will have if any at all?

James Gall: I don't think we know the impact. We're assuming how each of the costs of all the resources change over time is the annual assumptions and they're looking at competing for a different, you don't think about concrete, steel lithium, the different other materials that are used to build these assets. They're taking that into account. I would to some extent, but you know obviously this is a new question that probably get reflected in the next draft that NREL puts out. But our cost assumptions for future cost declines or increases come from the NREL study. I guess the answer is it's not considered to our knowledge. I don't know how it would affect costs.

Sofya Atitsogbe (UTC): Gotcha. Thank you.

John Lyons: Yep, let me pick up the question on the difference between the flat for lithium ion and the increasing cost for pumped hydro on the later years and that goes back to the question – how did NREL assume costs were going to decline? They're probably assuming that it's more of an increase in inflation over time on the pumped hydro and the lithium ion there, assuming there's still probably some technological solutions getting in there that would flatten it out, correct, OK.

James Gall: Thank you.

Michael Brutocao: Dispatchable resources, so on the left-hand side we'll see variable costs in dollars per MW hour and on the X-axis you see fixed costs per kilowatt year. Yeah. For some of these, there are two different shades of color. The lighter shade is going to indicate a cost of Washington, with darker shade being Idaho costs, and then to help you kind of read it, the bubbles as they increase in size, that's indicating that we are moving forward in time. The smallest dot on any of these lines is going to indicate 202026 costs and the largest bubble is going to indicate 2045 costs. And again, these are level is so when it unit is. Built, I guess and put in the service that would be. That cost is. Lovely eyes still can't answer question, yeah. So if you go ahead.

Sofya Atitsogbe (UTC): Oh sorry. I'm seeing my hand up, it's not.

James Gall: I just want to bring one thing up on the variable cost. This is both fuel costs and variable operating costs. And then for projects like the ammonia turbines, that assumes that the cost of the hydrogen to produce the ammonia that is included as a variable cost rather than a fixed cost. So that's, I guess, yet to be determined if that resource is picked, if it's a fixed cost or variable, we just assume it's a variable cost, same with hydrogen. And then lastly on the Rathdrum CT, is a negative cost and that is because that upgrade lowers the heat rate of the overall facility. So, the variable cost is actually less, but there is a capital cost to do that upgrade.

Michael Brutocao: Thank you, James. And I will pass it off to you Dr. Lyons.

John Lyons: OK, so a little bit of a change that we've seen. Last IRP, we had some NEI studies we had an outside consultant run. It was DNV, if I remember right. There were a lot of things that we looked at and thought it would be nice if we could actually run some of these studies ourselves. So, we went and looked at different modeling applications that we could do these studies and we ended up getting IMPLAN. IMPLAN is one of the major, the two major, modeling software for this. It's a more inexpensive one, started in the 1970s for the US Forest Service to be able to look at these non-energy impacts. We now have a license to run it for Oregon and Washington. We've just been getting into it. We've done some preliminary studies and we're getting into the nuances of what we actually get out. There's a lot of data that comes out of these studies, but which ones that we feel comfortable with using because some of the data is thinner than in other areas. Say you wanted to run a study for a modular nuclear reactor. No one has built one of those yet, so there's no data for that. But we can say run a study that shows what is the net impact of building a wind project in Washington. We would have the direct impact of jobs, the indirect impact of the jobs for all the businesses that supported that, and then you would also have the induced jobs from all those people making money and getting to spend it in the community. We can also calculate upstream emissions estimates, there's some we have again better data than others, but at least this gives us the opportunity to run these studies. Other things that you can have in there would be a local state and local tax receipts and what would be there We're still getting our feet wet in this, but we'll be sharing more with that model outputs on this as we go along.

2030 Loss of Load Probability Study, Mike Hermanson

Mike Hermanson: Hi, my name is Mike Hermanson. I'm a Senior Power Supply Analyst here in the resource planning team, and I'm going to be covering the 2030 loss of load probability study that we just recently completed. I'll talk about the purpose of a loss of load probabilities study, the methodology that we used, some of the metrics that you can pull from the results, and then look at the results from our study. And then the ultimate result is the planning margin, which is the amount of resources we would carry in excess of our load projection.

Mike Hermanson: The purpose of the loss of load study is to determine when your system cannot meet load and there's a number of reasons why you would not have enough resources to meet load. You have different water years, and you have different load projections, and different load years. The temperature is different each year. You can have maintenance outages that are planned. You can also have forced outages that are unplanned and of unknown duration, and then we also have additional variable energy resources that are being added to our system and you cannot accurately predict like you can with a gas CT how much production you're going to get out of that. We run this study in a Monte Carlo fashion. We run 1,000 iterations and it does different combinations of these water years. The load, the temperature, maintenance, and forced outage the software combines those in in all sorts of different iterations and then determines at what point can we not actually meet the load. That is as expected of the system. We're looking at our system in 2030, but with no increased resources. We're looking at what we have planned right now, and we have a market-purchases that are allowed, up to 330 megawatts from the market and the period of record that we used was 1947 to 2045. All future data is the climate data that we used for our water and load and temperature in the future years only. Got a question.

James Gall: Go ahead, Molly.

Molly Brewer (UTC): Yeah, with the availability of the 330 MW hours from the market, I think I recall some time ago you guys saying that might be in question. So curious, where does that come from? And is that availability in question?

James Gall: Sure. It's been a number that we've used for quite a long time. We looked at what has been available from the market, looked at data, and we are actually possibly reevaluating that expectation from the market, but it's kind of been a rule of thumb almost. I would say professional judgment. Has all come into that and just experience with what we've been able to get from the market. Also, a conservative value. You don't want to just have your whole system rely on the market and so that value has been used in previous loss of load studies. And so, we continued this study, but we have had discussions of increasing it. I'll add a couple things there. The MLK event was an example of this where we were able to get more than this amount before our units tripped, but then there was a question of could we have gotten that amount as it got colder that weekend. I think this is going to be a debate internally. Do we stick with this number? Do we increase it? Do we lower it? And I think when Mike gets to the results, you'll see what the impact of this is. Because for every MW you change from this number basically changes how much we would need in our system future. It's a major assumption and we're going to have to keep looking at this, but the results are going to see here today is based on the 330 MW, but that's subject to change. Fred, go ahead.

Fred Heutte (NWEC): Yeah. My question is, I would assume by 2030, all of us will be in a day ahead market, you haven't made the decision yet. Actually, I don't know. I'm just wondering, does that change the nature of how you address the market issue? Do you assume that you're going to get roughly the same quantity from an organized market as opposed to bilateral? Or is there much difference? And then I guess the other question with the other issue for me, and we certainly learned this in January, was the value of the organized market or the day ahead market in optimizing the dispatch, which makes it a whole lot easier to count on that. Whatever quantity you want, you have a higher likelihood of actually getting it because you don't have the obstacles of bilateral training to get what you need. I'm hopeful that it will increase it but also you have the WRAP's coordination on top of that. Alright.

Mike Hermanson: That's kind of blending to maybe we should plan for a higher amount, but then you look at the resource adequacy of the system that is, I would say in an even position or short position. I think in a perfect world where there are resources being added to be reliable system, I think we could increase this number. But then on the other hand, if resources aren't built, then maybe we should be lowering this number. I guess it just depends on your, go ahead.

Fred Heutte (NWEC): Yeah. I have to say that I also am taking some concern from the count of Northwest Power Council. Just had their Resource Adequacy Advisory Committee last week. They're showing we're pretty OK through the end of the decade with the kinds of resources that are currently in plans, staying on track. But we get into trouble if we have a bigger data center load growth outcome than is kind of a moderate one, more of an aggressive one. I agree that the real underlying issue here is what is the overall resource adequacy of the northwest? of the West? That's really the issue driving this.

Mike Hermanson: Yep, thanks. This is just a look at what the methodology is to arrive at the total load numbers. Essentially, we use an Excel based model with VBA code and then it uses a linear optimization Excel add in that's called What’s Best and it's an hourly model and it basically runs our system virtually for every hour and it's targeted to meet specific loads and resources or reserves that we have put in hourly loads and then the hydro generation and storage, and that is a dispatch storage, and that's the linear optimization portion of this. We have thermal generation and then we have historical hydro generation from run of river projects. We have renewable generation that is dependent and autocorrelated and it's influenced by temperature, and we have the ability to add batteries and then we have all of our contracts in there. And so essentially it runs every hour of a year and tries to solve for meeting the load and the reserves and then we output the results, and we can look at how many iterations it has not met load.

Mike Hermanson: Reliability metrics are an interesting thing. They are hard to find as an industry standard. You cannot go out there and find that NERC has put together a target for each of these types of metrics and the metrics are all similar, but they do have their differences. The main metrics that we looked at were lots of load probability and that's calculated by counting the number of iterations where there is unserved load. That could be any 8,760, anytime that we were not able to meet load that counts as one and then you divide that by the total number of iterations, and you get a percentage.

Mike Hermanson: Lots of load expectation is similar, but you're just counting the days where there is unserved load or unmet reserves. So, instead of 8,760 chances you have 365 days that could have a loss of load. Loss of load, expected events, like I said, similar calculated by counting the number of consecutive blocks of unserved load and then divided by the number of iterations. Loss of load hours actually starts to look a little more deeply, I think at the duration of any time you have an event where you've lost the load and then the expected unserved energy actually looks at how many megawatts you were short. It starts to get into magnitude. Being able to look at all five of those is fine and it is similar to what the Power Council is now doing, looking at three different metrics. We're moving in that direction, but currently we look at that one metric to inform our planning reserve margin.

Mike Hermanson: This is taken from a NERC document. The probabilistic adequacy and measurement report. This is as close as I could come to finding some sort of description about an industry standard, but they are very quick to point out that all utilities are different. What their loads are derived from or different, their resource mix is different. This is a description of how it was described in this report and what these are used for. The LOLP is really used to look at the probability or likelihood of events due to insufficient capacity. LOLE is primarily used to establish resource adequacy criteria. This is the closest one to a kind of an industry standard. It has a 0.1 days per year or one event one day in 10 years. The LOLH metric is computed by a large number of entities in North America, but only one entity uses this metric has arrived reliability criterion and they look at a goal of 2.4 hours per year. The LOLEV metric is useful in systems that are concerned with frequency of events, regardless of duration, magnitude, and the UAE is an estimate of the size of the loss of load events. You can look at that cost and impact of those events.

Mike Hermanson: Now I'm going to get into the results of our study This is looking at how many the sum of the hourly average loss of load across 1,000 iterations. It's looking at months on the vertical across hours and so you can start to see what times of years we're having loss of load issues and it's not surprising the winter months during the peak hours are our most problematic at this point. We have a smaller issue during the months of September and August and a little bit in May and one in June, but primarily the loss of load with our current system is occurring in the winter months. The way we use this, the loss of load, is to establish our planning reserve margin and you can do that by taking what your base case is, what you currently have planned for 2030 and then you incrementally add additional resources, and these are additional dispatchable resources. These results show the metric on the left for each of these additional resources and so to get at. I should back up a second and say that Avista’s target is really to meet an LOLP of 5%, and that's a target that we've been using for a number of years.

Mike Hermanson: And then the other metrics we're starting to look at, but have not incorporated into our decision-making, and we're just looking at the LOLP and the use of it is to look at our load versus our resources. We have a target load, and we look at what happened with what we have. For example, if we had a target load of 1,000 MW and we have resources at 1,000 MW, then we would have a balanced system. But when you put it into the tool to look at the LOLP with all of the additional uncertainty, you start to get a different answer. What we do is add in the amount of dispatchable resources that we've added in, and then divide the load, or the resources by the load. And we're looking to hit that target at 5%. Our base case, we have an LOLP of 13%. That would end up with an implied planning margin, to achieve that we need 21% additional resources than we currently have to have that kind of margin that will account for all of the uncertainty within the system.

Mike Hermanson: And as you can see, as you add additional resources, your planning margin goes up because you're adding in additional resources. So, your resources needed to achieve these lower LOLPs, so you need to add 200 megawatts, for example, to get the 4.2% LOLP. So, you've added a lot of ability to absorb unexpected events. We're looking at a target of 5% and so did an interpolation of these results and we would need to add 167 megawatts to achieve an LOLP of 5%. Right now, we're in the process of digesting these results and right now we have a planning margin of 22%. So, 22% above our forecasted load and looking to see what planning reserve margin we. Worse, with Teams, here it is covering up the one number I need to see. To achieve a loss of load probability of 5%, the planning margin would need to be 30%.

Mike Hermanson: Another option we we're looking at it, it goes back to the discussion we had earlier on market, should we assume more market and keep the same planning margin is the other alternative. It's either add resources or be more reliant on the market. That's the debate we're having and would like to hear your opinion about one thing I wanted to also add what's changed from our last IRP that shows us and that is the reserve discussion we went through with the last TAC being that Clint Kalich went through from the work Energy Strategies in the solar integration study and basically discovered we need to carry more reserves than we had in the past. If you look at the amount of reserves that that study resulted in, it is basically the difference in added capacity between our 22% planning margin and the 30% and accounts for I believe 7% of that 8% change.

Mike Hermanson: By holding the additional capacity back for variable energy resources is what's driving, the change from 22% to 30% and the results here. But then you ask the question, should we stay with that assumption of the market at 330 MW meeting the reserve? Should we be more market dependent or less market dependent? I think this is a great study that basically shows you where we're at and then we got to identify what tradeoffs are best for our customers. Is this to be more market reliant or to build more generation to supply the variability because we are definitely subject differently to changes in load because of our resource design. We have a lot of energy that is, we have capacity, but we don't have a lot of energy that goes with it. I would like to maybe go back to the previous slide real quick and you notice in this one in the winter months. We just lost it that one. We're especially in January in December, we're having issues in all hours, which is showing that we have an issue with energy and capacity storage is a great solution for the summer months that you see here where you have a 5 hour issue, but we're needing something that's definitely long duration and that creates challenges because we have a significant hydro system that can't generate continuously days on end. And so, we're going to kind of be in a new situation that's driving these high planning margin requirements just because of a lack of sustainable energy in these peak periods.

James Gall: I just saw we got a post in the chat, which we'll take a look at. That's a good reminder. That's regarding the NERC forecast, but I just want to open it up if there's any last comments or questions on this. It's highly technical, but I think this is extremely important to discuss because we're going to debate if should we be planning for more market or more resources. Go ahead, Molly.

Molly Brewer (UTC): Just to confirm, if you're planning for more market, then you'd be OK with going below 5% LOLP.

James Gall: I think what it means is, well, I guess depends on the way you look at it.

Molly Brewer (UTC): But that's the trade off, right?

James Gall: We would assume, let's say we went with 500 MW market, we would let the model buy 500 MW for the market. We would recalculate the LOLP based on 5%. For example, here we are using that 330 MW you're already assuming.

Molly Brewer (UTC): Oh, got it.

James Gall: Let's say you added zero. You had zero market. Our planning margin would be, I'm just going to throw out a number, 15%. We're already assuming a certain level of market, which is prudent. It's just a matter of what is the appropriate level.

Molly Brewer (UTC): You keep 5%, but it would end up being a lower MW hours number and then that's a lower planning margin.

James Gall: Correct.

Molly Brewer (UTC): OK. Thank you. I don't have an answer for that, but I'll want to chew on that.

James Gall: Yeah, definitely. Another option is we move to go with the higher market but use the 0.1 LOLE is another option we could change to a different metric. I know LOLP is, from a Power Council point of view, is falling out of favor for the three other metrics, but so there there's definitely options out there. I saw two hands pop up. Let's go to John first and then Fred.

John Calvin Slagboom: Hi, good morning. Thank you for this presentation. I just wanted to ask a question regarding what assumptions is the model making when it comes to purchasing from the market in these scenarios? What is the market area that that's purchasing from and any other information that you can provide?

James Gall: It's essentially a number that the model has available to it. When the model is solving to meet load, it has 330 MW available to it. We do have the ability to do different types of markets so we can run different amounts for peak times versus off peak times. We also have what I called a constrained market, which we base off of temperature so that we can set a different market amount for a certain temperature level. In this particular study, it was 330 MW for everything, but we could do different things. It's really just an inputted number that can be applied based on different time periods, peak, non-peak and then again that constrained market condition when you could have the market shrink when it's a really cold event.

John Calvin Slagboom: OK, so when you're saying the temperature variability, is that essentially baking in reliability issues that come with heating or cooling events?

James Gall: Yeah. I mean it's essentially use. We're assuming that if we were having a really cold event, then that the market is going to shrink because everybody needs it.

John Calvin Slagboom: Yeah. OK, got it.

James Gall: And that's the 330 MW that we're referring to.

John Calvin Slagboom: OK, good to know. Just wondering, because there's this pretty significant heating event a couple years ago that if I'm understanding the documents I read correctly, put a lot of strain on the WECC, the Western interconnect, and it caused some reliability issues. And as we see increased temperature events happening and interconnectedness, if we were relying on these market-based solutions without backing up with enough generating options, there might be a bigger issue at hand I'm wondering about.

James Gall: Yeah, that's our primary concern as well.

John Calvin Slagboom: OK.

James Gall: If there's a balance, it's just trying to figure out what's that appropriate balance.

John Calvin Slagboom: Yeah. Thank you.

James Gall: Great.

Fred Heutte (NWEC): Yeah, I have a more general question. I see you've got one more slide maybe so I'll I can just hold off.

James Gall: Yeah, we got rid of that one, Fred. So go ahead.

Fred Heutte (NWEC): OK. Well, really broad questions actually. Just you mentioned the Power Council got these new kind of multipart multi-metric approach. They're really giving it finally, giving it a full drive around the track. I'm still wrestling with what I like and maybe I'm not so sure about in all of that. My first question is what do you think about what they're doing and is it providing any of the insights that are useful for your approach?

James Gall: You know, I think there was the biggest insight is trying to help with that market assumption. Their analysis showed that the system, if resources are added to the system, the system would be efficient in the same time period that we're talking about here. But that's a big if. I also then look back on what was the issues that they had lost a load, it was a cold day, and it was a low water year. Basically, the conditions we just saw this last January and it makes me wonder, what if you may have a low probability or meet your criteria because you assume that a low water, you're in a high load, only occurs less than 5% of the time or whatever the number is. I think that is on our minds. We're really planning for that event and if we're not planning to meet a low water year and a high load event or cold day, we're planning to fail, and that's what concerns me the most. I mean, we can meet load on all other events except for when those two conditions occur as a region. It makes me wonder what is the right planning methodology? Should we just be planning for that event, that scenario, because we can meet all the other scenarios? Probably still want to run these studies. Validate that, but that was my takeaway from the Council's presentation.

Fred Heutte (NWEC): Yeah.

James Gall: I know we have Tomas on here as well and you could probably speak to that more than I can, but.

Fred Heutte (NWEC): Yeah, I was thinking more about the methodology here. They've got this. They're really committing now to this multipart metric. And I think conceptually that makes some sense to me. But then the question is, LOLP or LOLE or any of them is as a single metric is pretty straightforward. It's not exactly pass fail, but when you're in danger and when you're not pretty straightforward. On the other hand, those single metrics cannot represent the three legs of the stool, which is frequency, duration and magnitude. I get that in I generally feel like any of these, like you were just saying, any of these methods will tell us what we already know, which is that we're especially with low water, high demand we got problems in the Northwest and also in the summer, not just the winter, because a little bit more hydro in the summer actually helps us quite a bit in the late summer. But the real issue is going to be demand. And really, this is for me, this is the really underlying thing we think we've learned, especially in January, the demand surge that accompanies these kind of extreme weather events is not fully represented in our load modeling or at least in our modeling. The way I think, we really need to now and everybody is kind of grappling with that. So, no matter what metric you've got, that's a really important underlying thing. And I know you also saw that in the heat dome in 2021, with equipment stress and everything else that happened. So just a thought on that.

James Gall: Yep.

Fred Heutte (NWEC): My second question is referring to the WRAP. The WRAP has a very elaborate approach to resource adequacy. I have some concerns about it. I'm on the Program Review Committee, which is just the thing that reviews the rules, but I've been thinking a lot about this also. Puget seems to be pretty enamored with the WRAP approach. I am wondering though because I don't think it's really built for this kind of long-term planning. And it's an important thing. And you know, if this is going to be in the WRAP, the binding program will start whenever it starts. But I think the issue for me is that, that looks to me more like an input into the IRP process because now you have in the short run, the next few year’s commitments, that you know you have to meet that to become part of the area assessment. But I have some concerns about some of the approaches in the WRAP, especially on the assumption of average load and the way they do the storage, hydro modeling, and the seasonal approach rather than the month-by-month approach for each of the seasons. Where in a season, now that early June does not look like late August. Early December, early November does not look like January. I just wonder what Avista’s views are on the WRAP and how you are approaching that given that you're committed to it.

James Gall: Yeah, great question. On the WRAP, what we've done is our L&R, which is the presentation we're going to cover next. We're going to shift to that the next meeting. We're using, I'd say the WRAP methodology for how we account for loading resources. The planning margins that Mike went through that would assume you know QCC methodology for resources, so how much qualifying capacity does each of our resources get compared to what we call is our 1-in-2 load event. The WRAP has, like you mentioned, a different load methodology. That's a lower load forecast. It's more of a coincident regional load look, that's a ten year look versus a little longer period. That's an area where we would differ, but as far as your idea of incorporating the WRAP in the short run, we've looked at what our position is with the WRAP in the short run, and it basically shows we have sufficient resources. There are some challenges in some of the maintenance months, but we're sufficient in that short run. But our initial thinking is to use WRAP QCC values to try to make an assumption of how QCCs will change over time. But at the end of the day use our planning metrics because we don't know what the WRAP is going to be long-term as far as the planning margins required.

Fred Heutte (NWEC): Yeah.

James Gall: Hopefully that helps.

Fred Heutte (NWEC): I just say that's a pretty reasonable way to look at it.

James Gall: Yeah. I do like your idea of maybe putting in a constraint short term but given our length compared to the WRAP, that's probably more work than we need to do. But it's probably something the utilities should probably look at. But it is a challenge because we don't know what, for example, the biggest issue we're seeing is storage. The WRAP gives storage a very high qualifying capacity credit, but if everybody has storage only resources and the amount of gas and coal decline as expected, energy short resources like storage are going to have a lower QCC value and we're trying to incorporate that. But that's where the study that Mike just did. We're going to be doing another study with our Preferred Resource Strategy both in 2030 and 2045. Love to make sure we can still comply with whatever metric we end up choosing. That still meets that regardless of what we think WRAP will do.

James Gall: And then there is our other concern on the WRAP is, will the WRAP survive and if all the utilities are not participating then the WRAP is not meeting its intended goal there's not a market out there to go get resources. If one or two major utilities don't show up and participate, that's a concern for us as well. Lastly, the other concern, and something that you brought up, that monthly versus seasonal. I believe there's three months that the WRAP doesn't look at and that means, and they've traditionally not done that because there's enough generation in those months. But what if every utility puts their resources on maintenance in those months and we could create a problem in months that are normally not an issue but become an issue because everybody's dispatchable resources are on maintenance. That's something to watch out for as well.

Fred Heutte (NWEC): Yeah, I think people forget. It's not just peak load, it's also the amount of resources. It's the balance between them. It really matters. We've seen situations in so-called shoulder months where we got in trouble. Fortunately, early October of 2019, when the compressor, the big pipeline explosion happened in BC and Jackson Prairie is on an outage for maintenance that it was a close call. It was a low demand period, but it was still a close call. So those things can happen.

James Gall: Yep.

Fred Heutte (NWEC): I agree with your view that the WRAP is still on spec to some degree, I think we are finally really seeing that. The other thing that really bothers me about the WRAP is for those of us who are not, you're in the program. For those of us who are on the outside, there is no information. We have zero information about this showing period. Even though it's a voluntary season showing period, we don't know what the total amount of load resources UCC by resource category, PRM, any of it and that bothers me a lot.

James Gall: OK. We have about one minute left. Any last questions or comments before we call it a day? OK. We're going to cover Lori's presentation on loads and resources at the next TAC meeting. Hopefully we can get to it. We all saw the transmission and distribution hopefully be able to cover all three of those. We're also going to be meeting internally over the next couple of weeks and hopefully we'll have some of these assumptions of nonmarket, decided upon then. If not, we'll discuss it at our TAC meeting again next time. Thank you for coming today and we'll see you in two weeks and have a great day. And if you can come to the natural gas TAC meeting tomorrow.

Charlee Thompson: Thank you.

Dean Spratt: Thanks. Good job guys.

Teams Meeting Chat Content:

[8:48 AM] Fred Heutte (NWEC): Thanks this is a really interesting NREL study with assistance from Ecotope. 4 of the 13 sites are in the Spokane Valley, most of the rest in SE WA, and lots of very detailed per-site results. like 1

[8:49 AM] Fred Heutte (NWEC): correction 7 of the 13 in Spokane area

[8:56 AM] Unknown User: Since pumped hydro likely qualifies for the 10% domestic content bonus ITC, total should probably be 40% for pumped hydro. Batteries would presumably not qualify due to foreign sourcing remaining dominant.

[9:06 AM] Unknown User: Do these factor in the different lifespans? With Li-Ion at 15 years and pumped storage at 60-100 years, the comparative levelized cost of storage should be lower for pumped storage even if up-front cost is slightly-to-somewhat higher (using 8 hours as the basis of duration), even if you only used, say, 50 years (the usual initial term of a FERC license). ALSO, why does it jump at 2032? IF it's related to the ITC cliff, the ITC essentially lowers capex so permanently lowers annual cost.

[9:13 AM] Unknown User: Thank you.

[9:26 AM] Unknown User: I coordinated a study of the economic and employment impacts of small modular nuclear reactors back in 2010 using IMPLAN, which might be helpful. Here is a link to the tudy: https://www.nrc.gov/docs/ML1802/ML18023A166.pdf

[9:43 AM] Slagboom, John Calvin (Guest): NERC is forecasting insufficient operating reserves in multiple markets, in above-normal conditions. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf

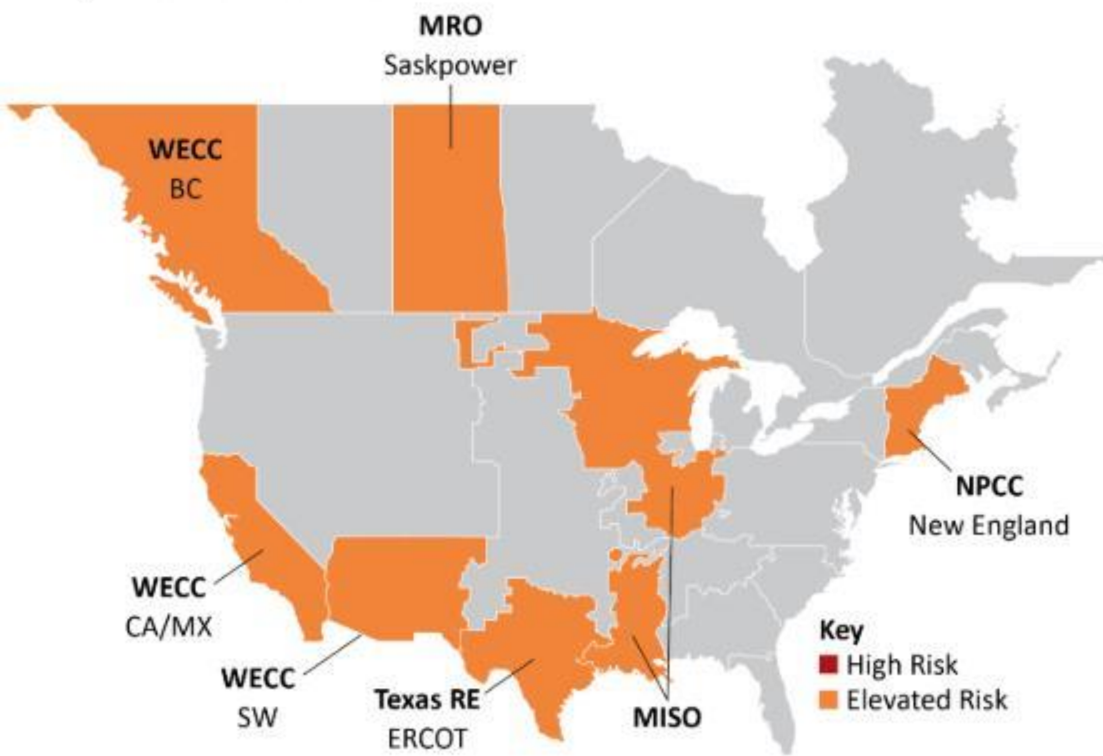


Figure 1: Summer Reliability Risk Area Summary

Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Normal	Sufficient operating reserves expected

AVISTA

2025 Electric Integrated Resource Plan

Technical Advisory Committee Meeting No. 9 Agenda

Tuesday, June 18, 2024

Virtual Meeting – 8:30 am to 10:00 am PTZ

Topic	**Staff**
Introductions	John Lyons
Loads & Resources Discussion	Lori Hermanson
IRP Generation Option Transmission Planning Studies	Dean Spratt
Distribution Planning and Microgrids	Damon Fisher

2025 IRP TAC 9 Introductions

John Lyons, Ph.D.
Technical Advisory Committee Meeting No. 9
June 18, 2024

Today's Agenda

Introductions, John Lyons

Loads & Resources Discussion, Lori Hermanson

IRP Generation Option Transmission Planning Studies, Dean Spratt

Distribution Planning and Microgrids, Damon Fisher

Remaining 2025 Electric IRP TAC Schedule

- **Technical Modeling Workshop: June 25, 2024: 9:00 am to 12:00pm (PTZ)**
  - PRiSM Model Tour
  - ARAM Model Tour
  - New Resource Cost Model

- **TAC 10: July 16, 2024: 8:30 to 10:00 (PTZ)**
  - Preferred Resource Strategy Results
  - Washington Customer Benefit Indicator Impacts
  - Resiliency Metrics

- **TAC 11: July 30, 2024: 8:30 to 10:00 (PTZ)**
  - Preferred Resource Strategy Results
  - Portfolio Scenario Analysis
  - LOLP Study Results

- **TAC 12: August 13, 2024: 8:30 to 10:00 (PTZ)**
  - Preferred Resource Strategy Results (continued)
  - Portfolio Scenario Analysis (continued)
  - LOLP Study Results (continued)
  - QF Avoided Cost

Remaining 2025 Electric IRP TAC Schedule

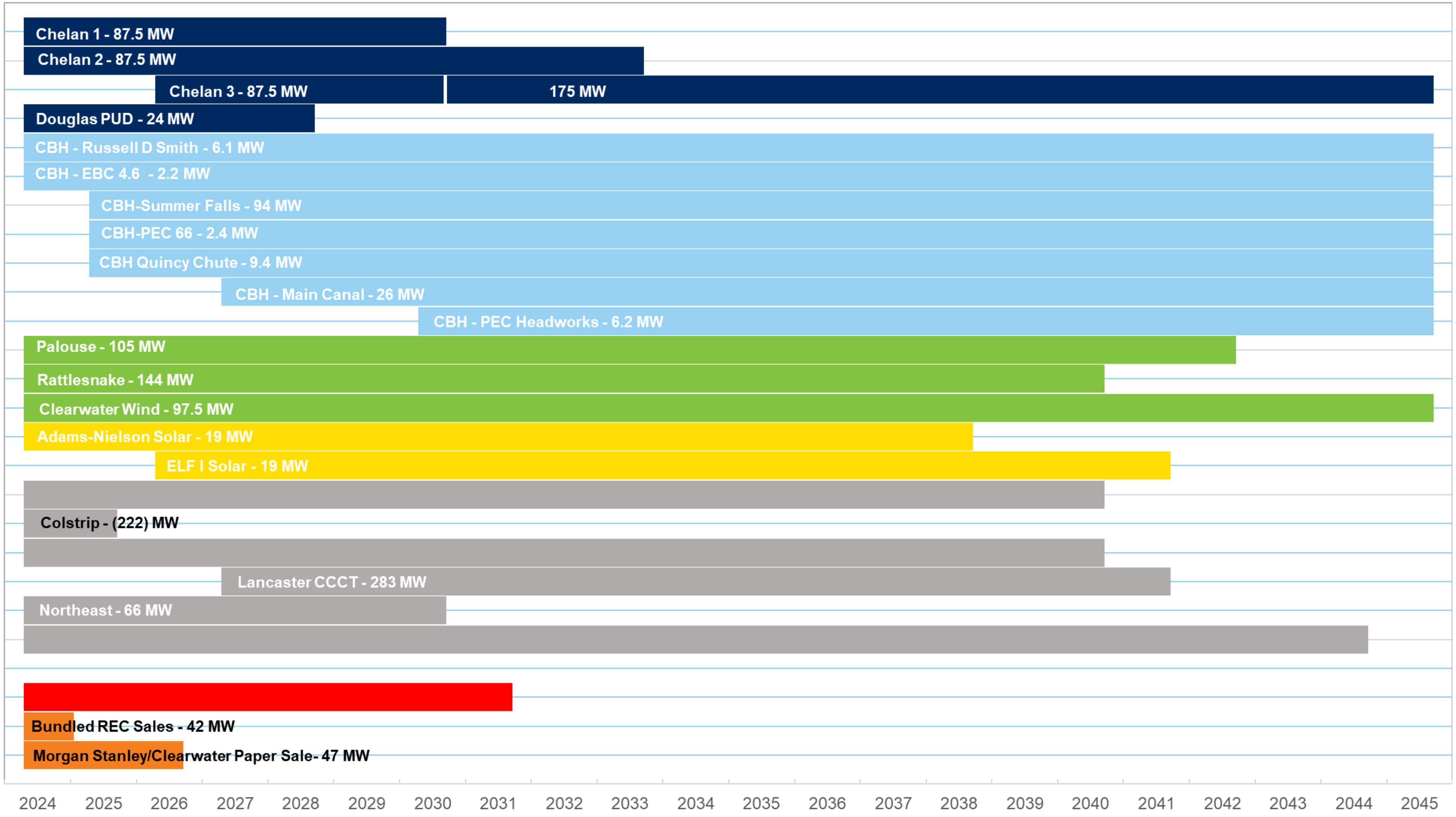
- **September 2, 2024- Draft IRP Released to TAC.**

- **Virtual Public Meeting- Natural Gas & Electric IRP (September 2024)**
  - Recorded presentation
  - Daytime comment and question session (12pm to 1pm- PST)
  - Evening comment and question session (6pm to 7pm- PST)

2025 IRP Loads & Resources Discussion

Lori Hermanson, Senior Power Supply Analyst
Technical Advisory Committee Meeting No. 9
June 18, 2024

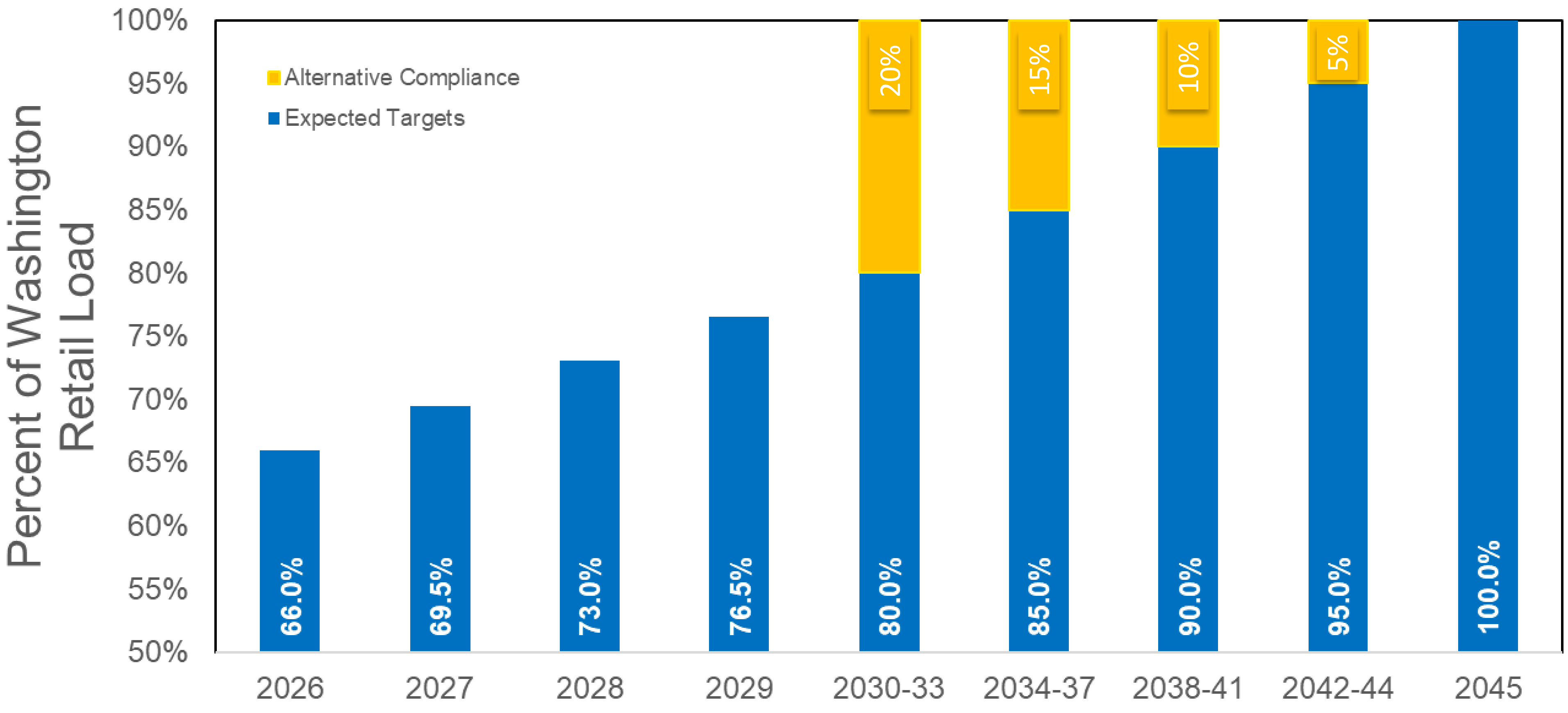
Portfolio Realignment



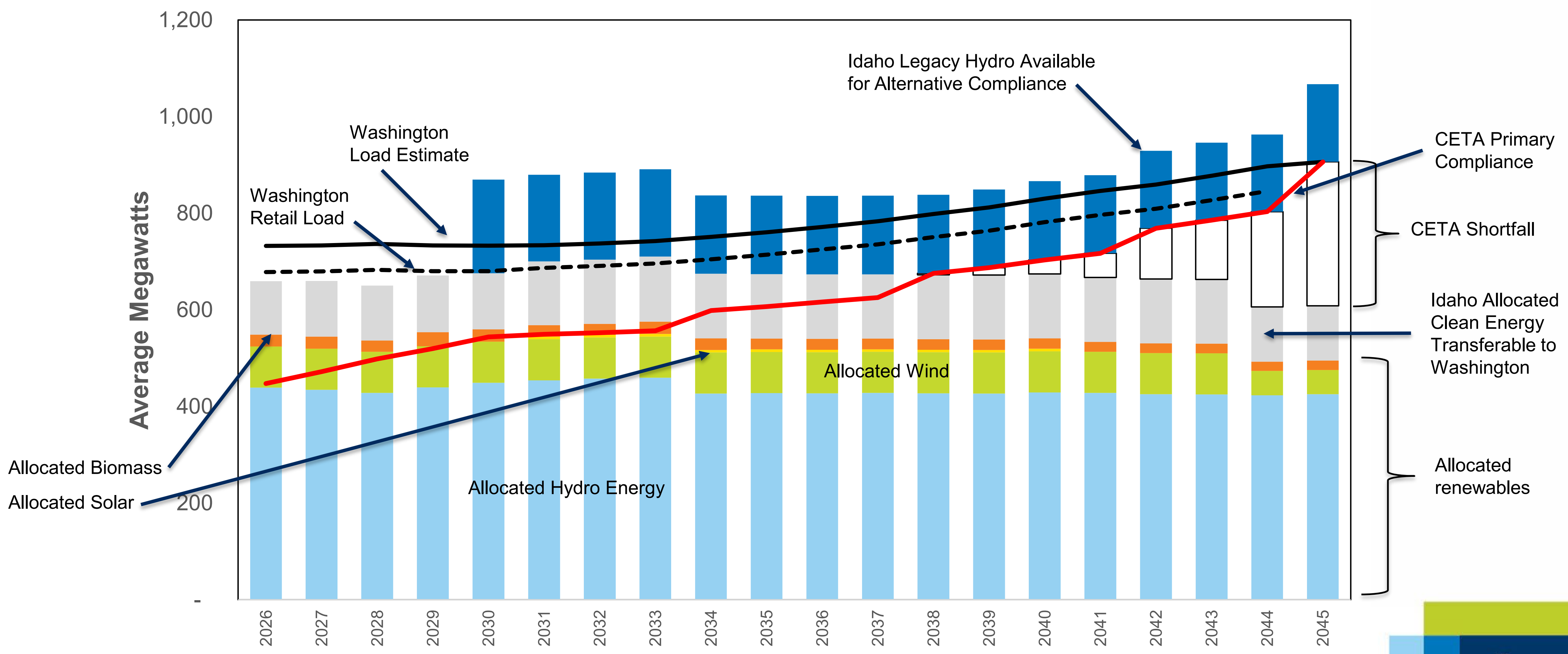
Monthly Net Energy Position

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
2026	(25)	26	175	348	696	508	177	78	200	171	63	22	204
2027	(1)	54	209	381	750	553	226	133	254	215	94	57	244
2028	(7)	96	209	374	743	551	219	126	255	219	98	51	245
2029	9	87	234	401	760	563	221	122	258	227	106	67	255
2030	13	86	234	394	754	561	217	121	254	227	105	69	253
2031	16	97	245	398	768	579	231	125	264	229	108	72	261
2032	21	142	251	405	769	580	223	122	257	227	102	72	264
2033	14	103	252	399	765	571	214	112	253	226	105	71	258
2034	(44)	64	205	344	696	509	161	60	210	184	44	12	204
2035	(65)	54	195	337	690	500	148	45	195	167	32	5	192
2036	(76)	88	186	326	677	484	133	33	182	154	11	(17)	182
2037	(91)	37	170	307	665	473	119	16	170	146	(5)	(32)	165
2038	(110)	18	148	290	639	439	73	(16)	148	124	(23)	(57)	140
2039	(129)	6	138	272	622	419	52	(35)	138	110	(37)	(71)	124
2040	(131)	29	126	260	612	387	29	(57)	120	93	(46)	(105)	110
2041	(246)	(134)	20	148	510	272	(108)	(179)	9	(16)	(160)	(214)	(8)
2042	(525)	(402)	(244)	(34)	323	82	(372)	(433)	(248)	(271)	(415)	(489)	(252)
2043	(585)	(462)	(313)	(103)	272	29	(426)	(485)	(298)	(328)	(485)	(562)	(312)
2044	(617)	(445)	(339)	(132)	249	2	(464)	(516)	(321)	(347)	(510)	(594)	(336)
2045	(798)	(664)	(510)	(246)	151	(93)	(612)	(666)	(473)	(505)	(677)	(764)	(488)

Proposed CETA's Clean Energy Goals



Washington Clean Energy Position



Capacity L&R Discussion Issues

- **Avista is not settled on capacity planning assumptions**
- **LOLP studies indicate a need for increased planning margin or higher market reliance.**
  - Current market reliance limit is 330 MW in "constrained" hours
  - Avista's main challenge is energy limited capacity resources
- **Other capacity planning issues under consideration**
  - Maintenance planning
    - Historically maintenance is not included in L&R planning due to uncertainty on timing and number of units out year to year
    - Should we plan for a minimum maintenance assumption?
  - 3rd Parties in our control area
    - Should we plan for 3rd party load and transmission schedules who under schedule during peak events?
  - Should we use an alternative capacity planning methodology
    - For example, low water, low VER, and high load event

Integrated Resource Plan (IRP) Transmission Planning Studies

Dean Spratt, Transmission Planning

Technical Advisory Committee Meeting No. 9

June 18, 2024

FERC Standards of Conduct

Summary of requirements

- 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
  - Overview of recent Avista projects
- Generation Interconnection Study Process
  - Integrated Resource Plan (IRP) Requests
  - Large Generation Interconnection Queue
  - Third year into the Cluster Study Process

Introduction to Avista System Planning

Avista's System Planning Group includes:

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

Information About Transmission Planning

- Our focus is the Bulk Electric System (BES)
  - Avista's 115 kV and 230 kV facilities (>100 kV)
- We identify issues where Avista's BES won't reliably deliver power to our customers
- Then we develop 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

NERC Standard TPL-001-5

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

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. Simula
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Steady State (

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Stability Only

j. Transi

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 S					
P2 Single Contingency	Normal S					

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Inte… Tr… Serv…	
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		
		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		
				HV	Yes	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	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P5 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System[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]	No
				HV	Yes	Yes
P6 Multiple Continge *(Two overlapp singles)*	Loss of one of the	Loss of one of the following:				

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

TPL-001-5, 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

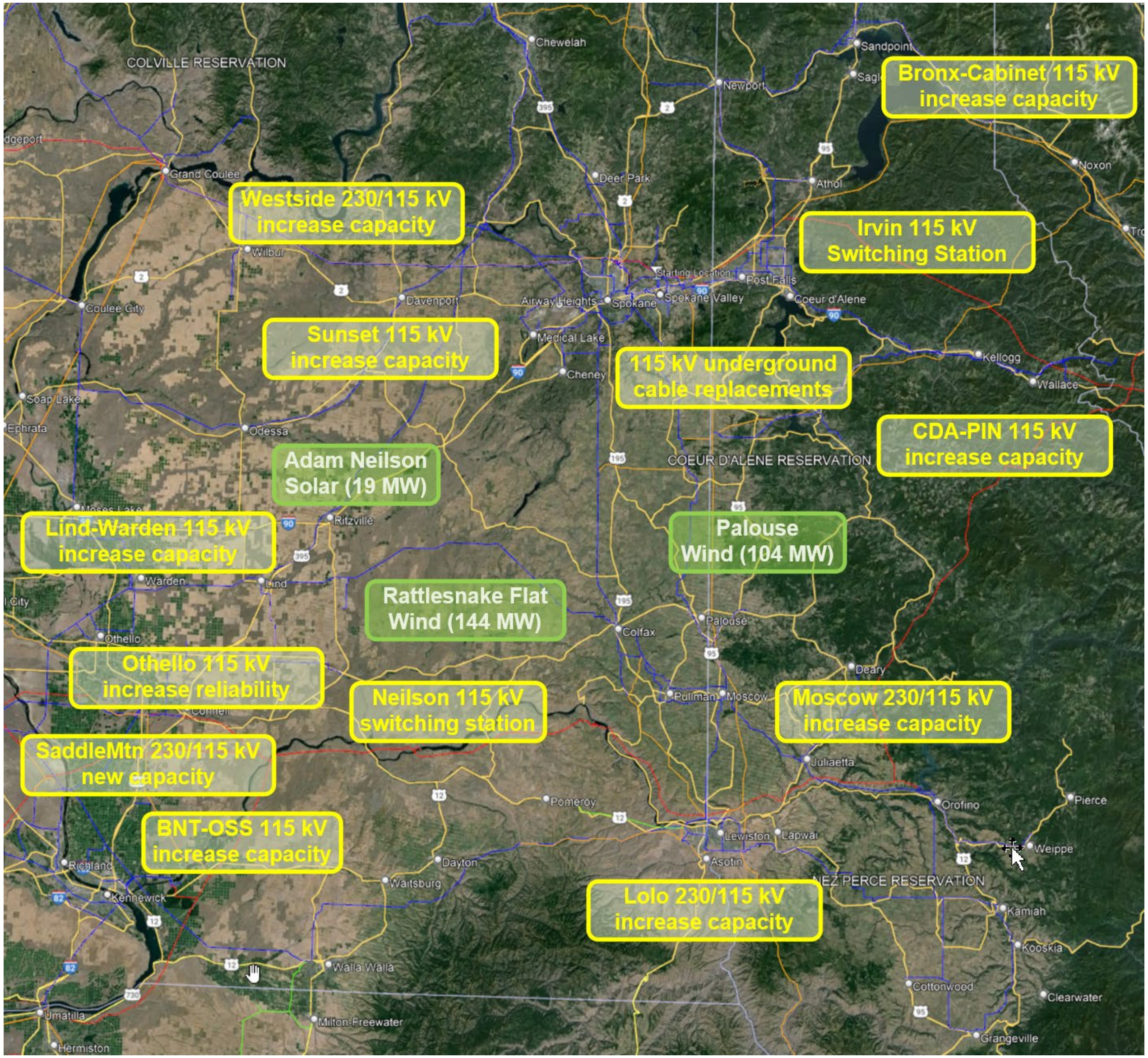
- Transmission Operations (TO) are guided by *significantly* different standards than Transmission Planning (TP)
- TO standards provide *flexibility* that TP standards do not allow
  - Operators can push system limits to ***SAVE*** the interconnected system
    - Shed load, overload equipment, etc. –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

Standards are a Roadmap

- Western Systems Coordinating Council (WSCC)
  - Ensure that disturbances in one system do not spread to other systems.
    - Operating agreement with 40 electric power systems established in 1967
- Western Electricity Coordinating Council (WECC)
  - Responsible for coordinating and promoting electric system reliability established in 2002
- North American Electric Reliability Council (NERC)
  - Ensure the reliability of the North American bulk power system reformed in 2006; Corporation in 2007
    - Established as a voluntary organization in 1968

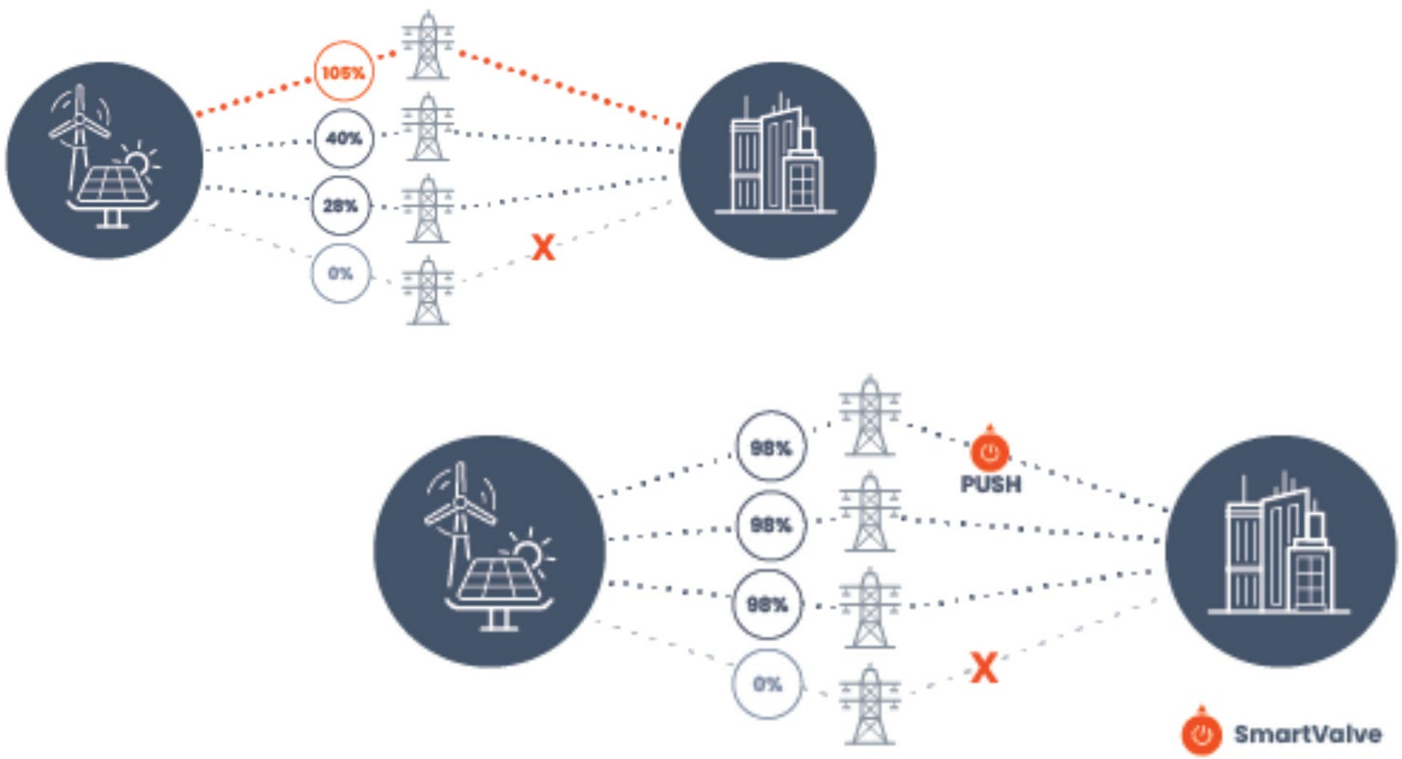
AVISTA

Recent Transmission Projects



Non-Wire Alternatives are Considered

- 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-001-5 ~ 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 transformer.
  - Could we mitigate performance issues with storage?
    - Yes…but…   We would need a 125 MW battery
      - Typical charge is 8 hours, discharge for 12 to 16 hours
      - Transformer 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 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 findings and recommendations

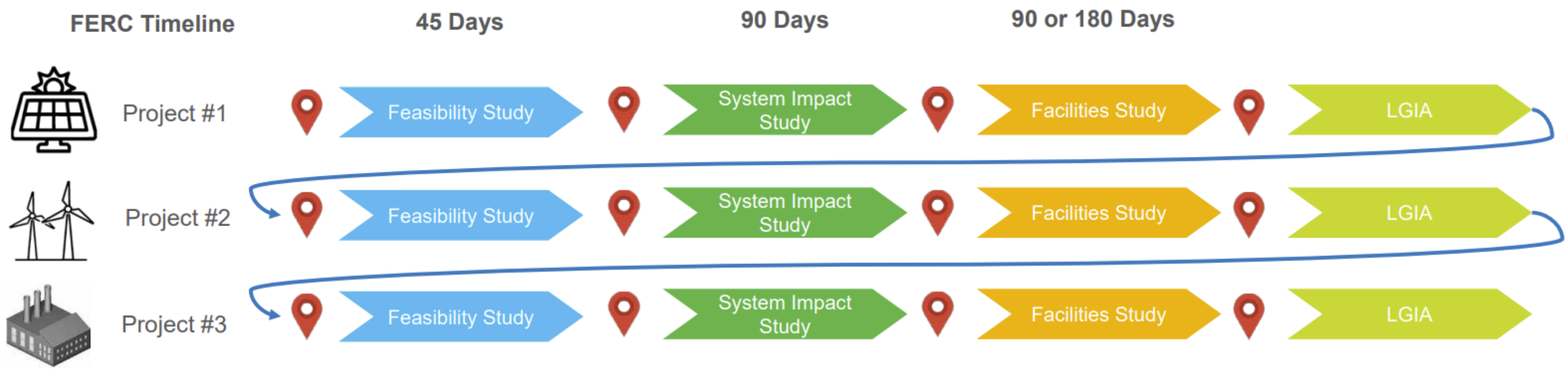
Transition to Cluster Study Process

Challenges with Serial Interconnections

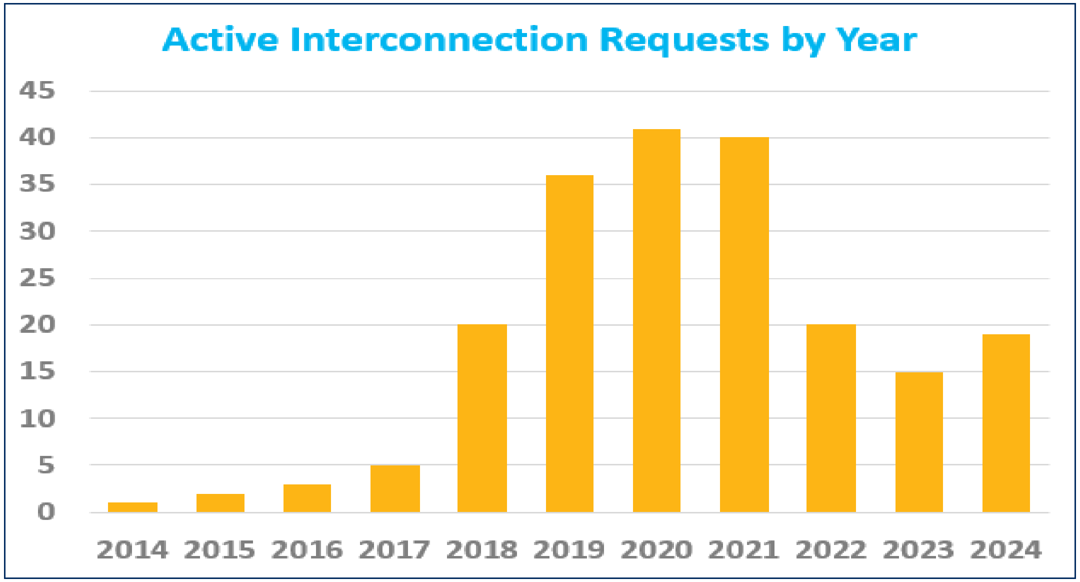
- Large serial queues become difficult to process efficiently
- Interdependency of projects becomes complicated
  - Studying single projects is inefficient compared to studying projects in a group
  - Projects that do not reach commercial operation may cause re-studies
  - System Upgrade allocation
- The serial process is difficult for the developers and the utility

Transition to Cluster Study process in 2022

Serial Process was Complex and Slow



Interconnection Requests necessitated a better Process



Two-Phase Cluster Study Process

Benefits and Objectives

- Create a more efficient process
- Design a process with definitive timelines that can be consistently met
- Allocate System Upgrades proportionally
- Ensure commercially viable projects have a clear path for development
- Alleviate the backlog in the queue

Current Interconnection Queue

Serial or Cluster Number	Point of Interconnection	Max MW Output	Type	County	State
Q59	Roxboro 115kV	60.0	Solar/Storage	Adams	WA
Q60	Dry Creek 230kV	150.0	Solar/Storage	Asotin	WA
Q63	Post Falls 115kV	26.0	Hydro	Kootenai	ID
Q66	Kettle Falls 115kV	71.0	Wood Waste	Stevens	WA
Q97	Lolo 230kV	100.0	Solar/Storage	Nez Perce	ID
TCS-03	Warden 115kV	80.0	Solar/Storage	Adams	WA
TCS-14	Dry Creek 230kV	375.0	Wind/Storage	Garfield	WA
CS23-06	Shawnee - Thornton 230kV	255.9	Wind	Whitman	WA
CS23-12	AVAHub-04 230kV	199.0	Storage	Franklin	WA
CS23-13	Davenport 115kV	40.0	Solar	Lincoln	WA
CS23-14	North Fairchild Tap 115kV	40.0	Solar	Spokane	WA
CS24-01	South Othello 13kV	1.1	Solar	Adams	WA
CS24-02	Third & Hatch 13kV	0.5	Storage	Spokane	WA
CS24-03	Saddle Mountain 115kV	150.0	Storage	Adams	WA
CS24-04	Benewah 230kV	100.0	Storage	Spokane	WA
CS24-05	Rathdrum 230/115kV	203.0	Natural Gas CT	Kootenai	ID
CS24-06	Bronx 115kV	120.0	Natural Gas CT	Bonner	ID
CS24-07	Othello 13kV	2.0	Solar	Adams	WA
CS24-08	AVAHub-04 230kV	199.0	Solar/Storage	Franklin	WA
CS24-09	Othello 13kV	9.5	Solar	Adams	WA
CS24-10	Spangle 115kV	80.0	Solar/Storage	Spokane	WA
CS24-11	Thornton 230kV	70.0	Solar	Whitman	WA
CS24-12	Shawnee - Sunset 115kV	40.0	Solar	Whitman	WA
CS24-13	Benewah - Thornton 230kV	95.0	Solar	Whitman	WA
CS24-14	South Fairchild Tap 115kV	40.0	Solar	Spokane	WA
CS24-15	Bluebird 230kV	300.0	Wind/Storage	Lincoln	WA

Generation Integration Cost Estimates

Generation Integration at New sites

POI Station or Area	Requested (MW)	POI Voltage	Cost Estimate ($ million)
Big Bend area near Lind (Tokio)	100/200	230kV	127.8
Big Bend area near Odessa	100/200/300	230kV	170.5
Big Bend area near Othello	100/200	230kV	216.8
Big Bend area near Othello	300	230kV	258.7
Big Bend area near Reardan	50	115kV	9.7
Big Bend area near Reardan	100	115kV	12.8
Lewiston/Clarkston area	100/200/300	230kV	1.9
Lower Granite area	100/200/300	230kV	2.9
Palouse area, near Benewah (Tekoa)	100/200	230kV	2.4
Rathdrum Prairie, north Greensferry Rd	100	230kV	34.0
Rathdrum Prairie, north Greensferry Rd	200/300/400	230kV	51.9
Sandpoint Area	50/100/150	115kV	1.6
West Plains area north of Airway Heights	100/200/300	230kV	2.4

Preliminary estimates are given as -25% to +75%

Cost Estimates, continued

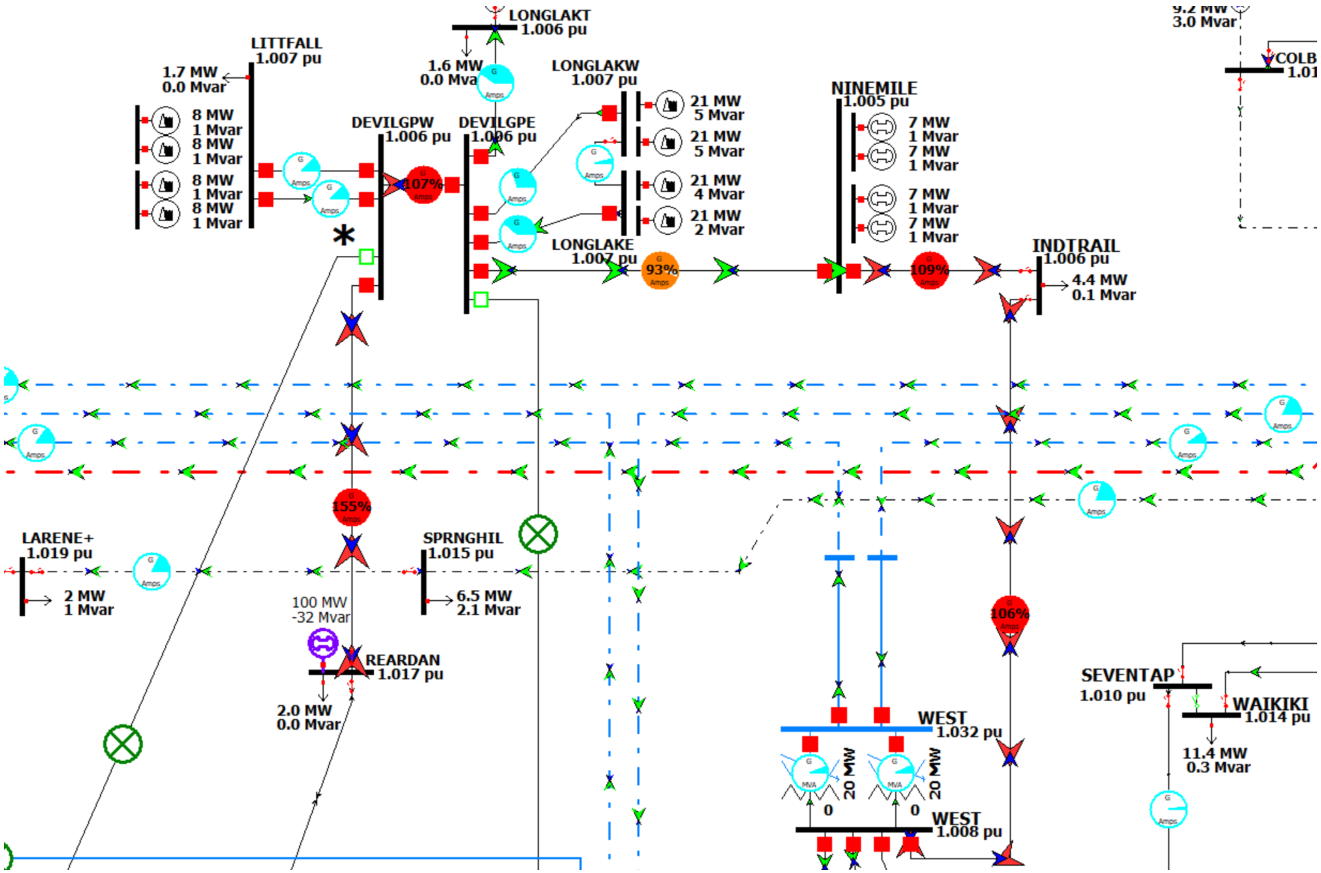
Increase in Capacity or Additional Generating Facilities at existing generation sites

POI Station or Area	Requested (MW)	POI Voltage	Cost Estimate ($ million)
Kettle Falls Station	50	115kV	1.6
Kettle Falls Station	100	115kV	19.0
Northeast Station	50	115kV	1.6
Northeast Station	100	115kV	7.7
Palouse Wind, at Thornton Station	100/200	230kV	1.4
Rathdrum Station	25/50	115kV	11.1
Rathdrum Station	100	230kV	15.9
Rathdrum Station	200	230kV	40.5

Preliminary estimates are given as -25% to +75%

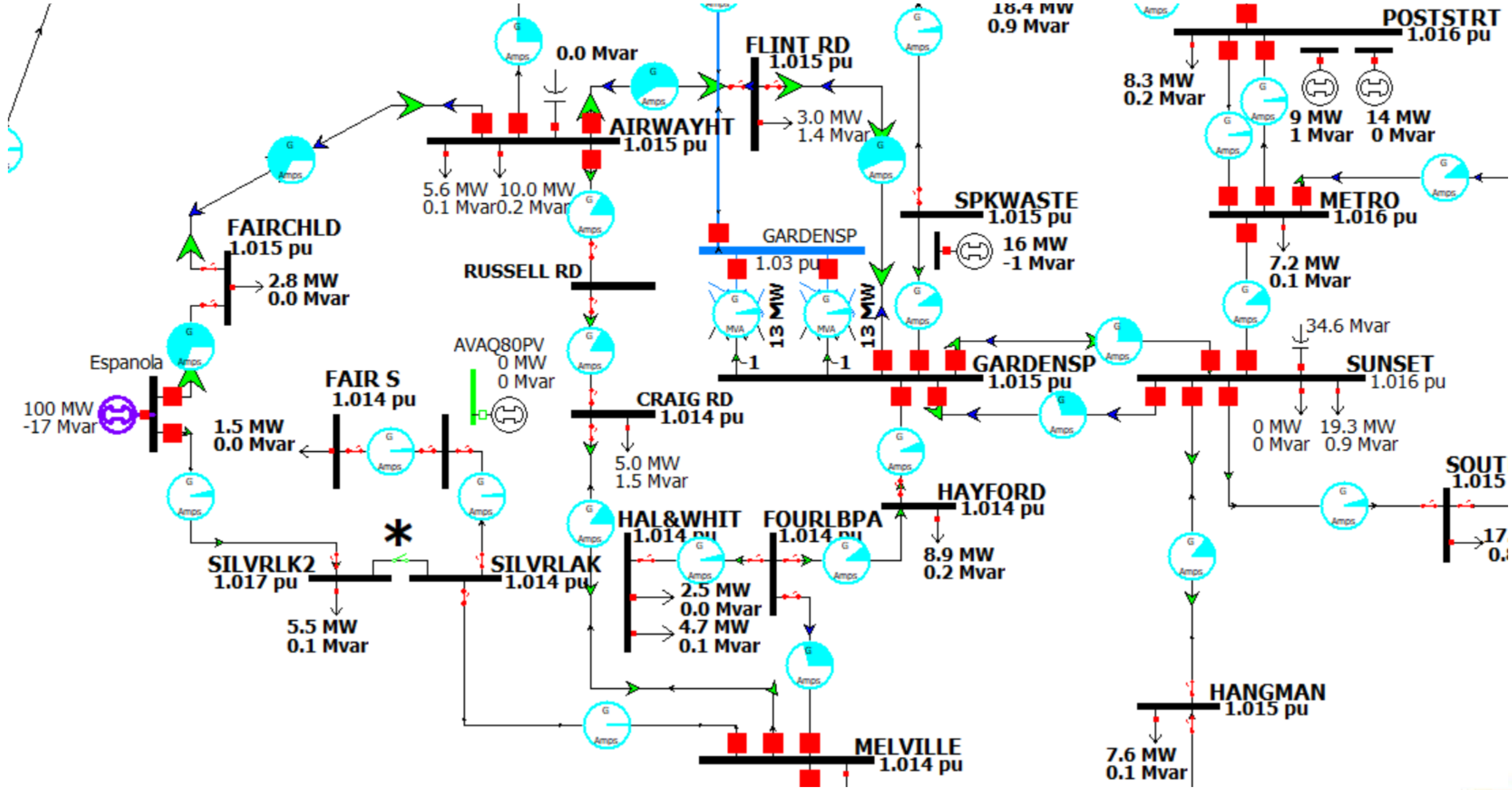
Reardan: 100 MW

Choice of interconnection point may result in extensive system reinforcements



Espanola: 100 MW

Optimizing the interconnection point is a key benefit of the Cluster Study process



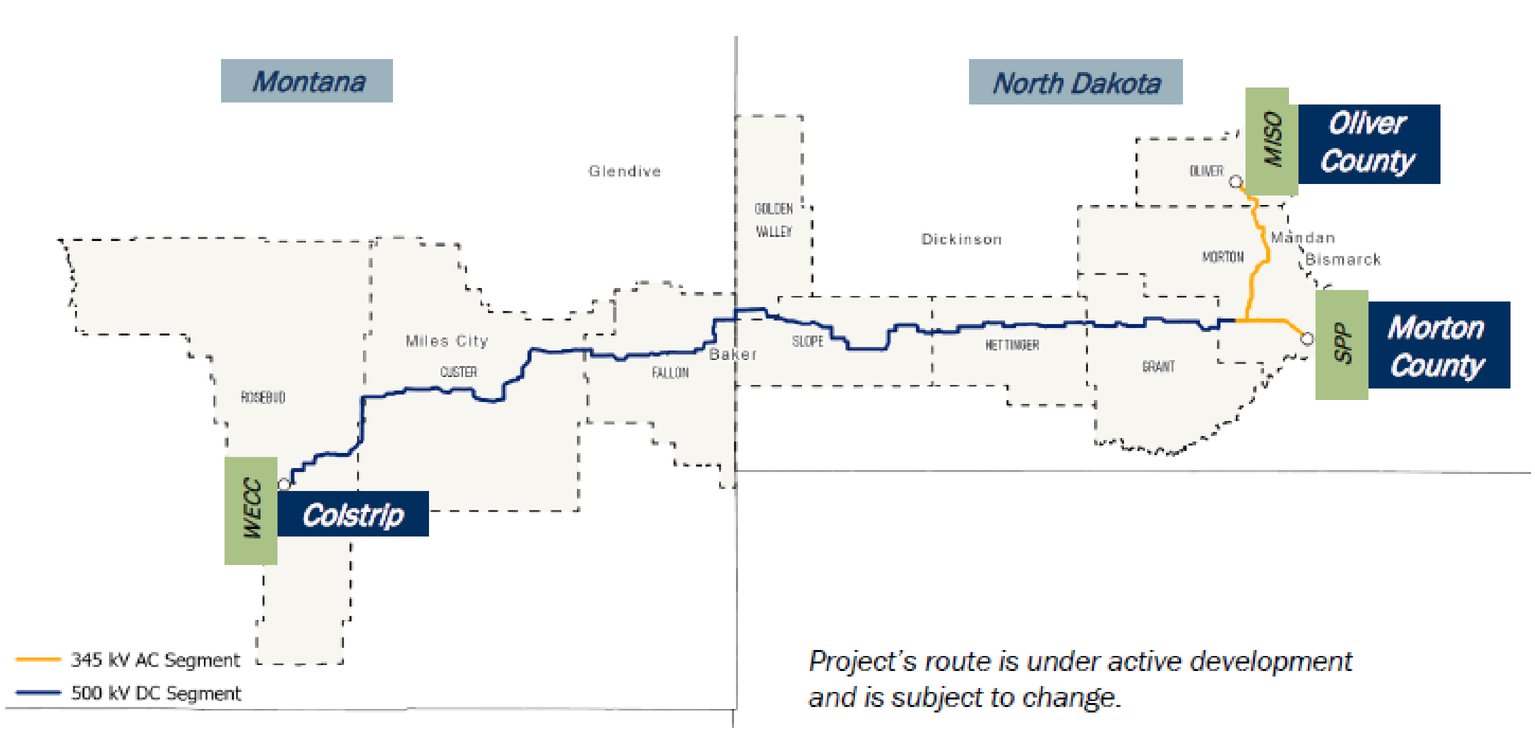
Questions?

Refer to Avista's Open Access Same-time Information System (OASIS) link for information regarding System Planning and the Interconnection Process at:

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

- Generation Interconnection (Serial)
- Generation Interconnection Cluster Studies
  - 2022 Cluster Study
  - 2023 Cluster Study
  - 2024 Cluster Study
  - Application Documents

North Plains Connector



- 2025 IRP will model this transmission expansion as a capacity market resource up to 300 MW.
- QCC will be limited to the difference between line rating and Montana Wind QCC.
- Project can be selected beginning in 2033 or any year thereafter.

Distribution Planning and Microgrids

Damon Fisher, System Planning

Technical Advisory Committee Meeting No. 9

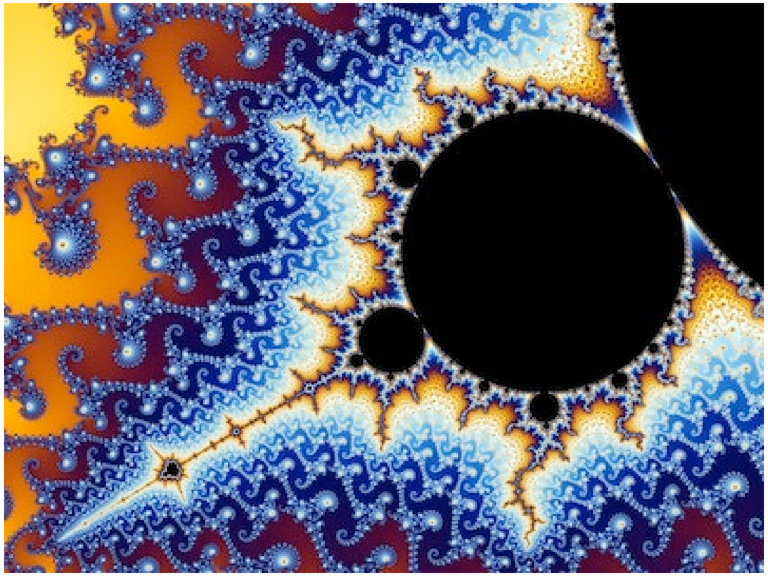
June 18, 2024

Goals of Electric Distribution Planning

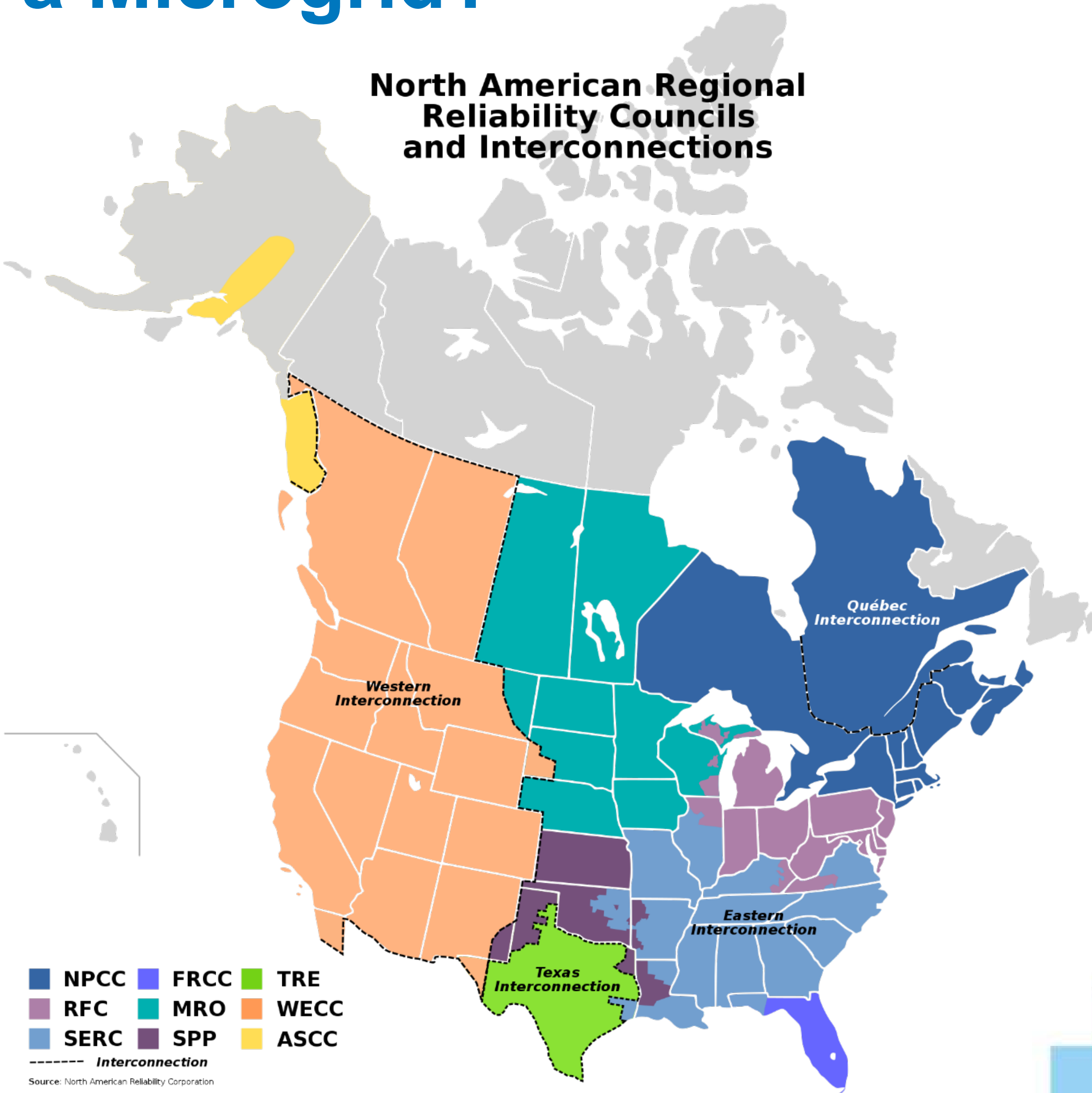
- Ensure electric distribution infrastructure to serve customers now and in the future with a focus on:
  - Safety
  - Reliability
  - Capacity
  - Efficiency
  - Level of service
  - Operational flexibility
  - Corporate/Regulatory goals
  - Affordability

What is a Microgrid?

- What is a microgrid?
  - Same as a “macro” grid but smaller (self similar)
  - Maintain Voltage and Frequency within limits
  - Respect Thermal Limits
  - Load = Generation
  - Protected equipment



What is a Microgrid?



What is a Microgrid?

- Major equipment-
  - Microgrid Controller and Communications
  - Generation (PV, Wind, Thermal, Fuel Cells… etc.)
  - Storage and/or dispatchable source
  - Grid disconnect switch
- Major functionality-
  - Black start capable
  - Island mode
  - Grid Synchronization
  - Managed Demand

Why a Microgrid?

Typically, one of four reasons or combination of them-

1. Resilience
   - Critical Load
   - Essential Service
2. Economic
   - Demand charges
   - Energy arbitrage
   - Other utility services
3. Climate goals
4. Difficulty serving load or getting service
   - Remote/isolated

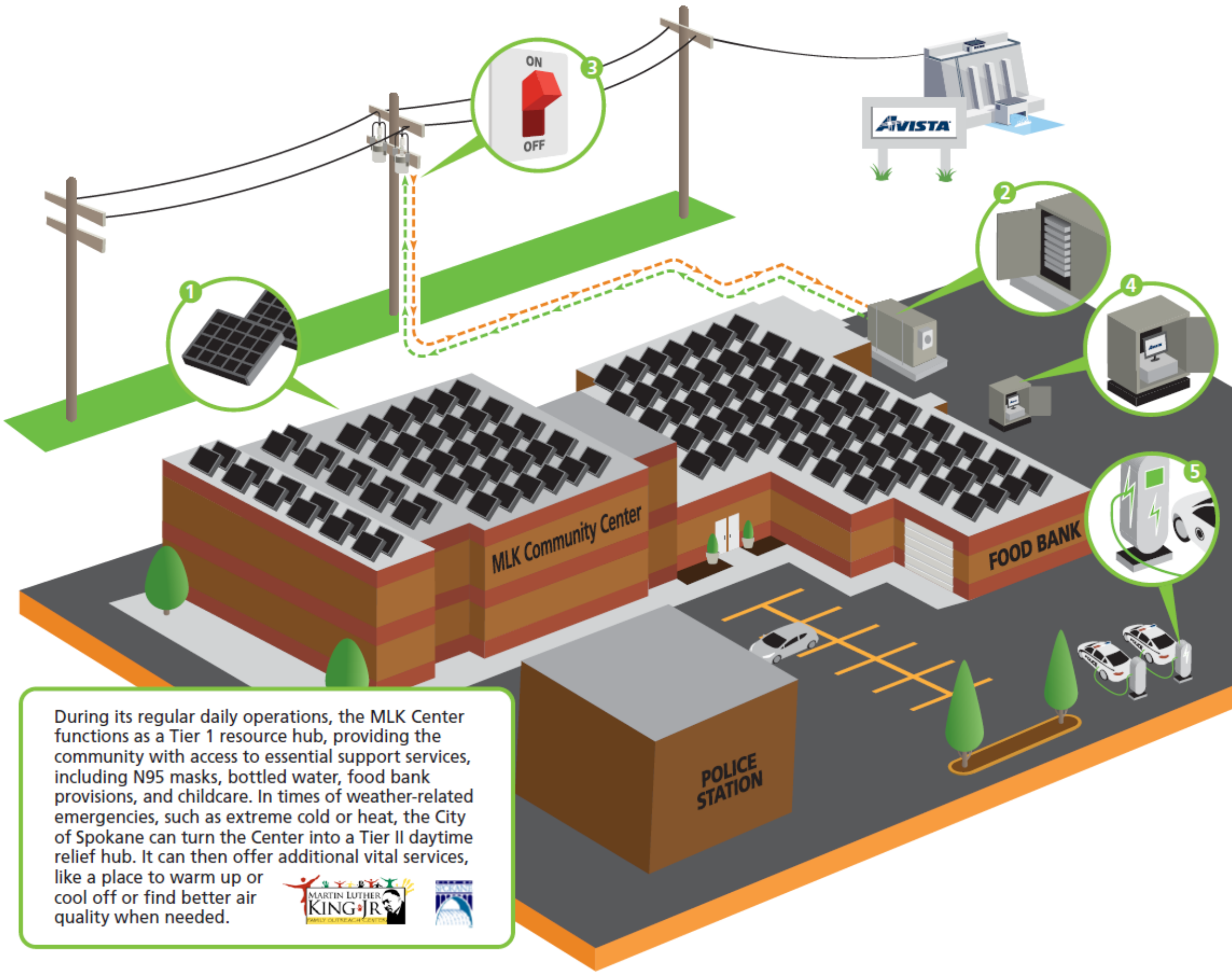
Microgrid as a resource

- A microgrid is a black box that the utility can ask for help. That help will usually be in the form of reduced demand or increased generation.
  - Depending on the goals of the microgrid and the current state of the system the microgrid controller may say-
    - I can't help
    - Sure, here you go
    - Sure, I am going into island mode
- The incentives/agreements between the microgrid owner and the utility will greatly influence the answer.

Avista and Microgrids

- Avista has a couple of microgrid projects.
  - WSU Spokane campus (demonstration/pilot)
    - Solar + Battery
  - MLK Center (Out for bid)
    - Solar (115-kW dc array) + Battery (500KW/1MWh) + Natural Gas Generator (150kW)
    - Approximate cost $2.5 million (grants and matching funds)

Avista and Microgrids



During its regular daily operations, the MLK Center functions as a Tier 1 resource hub, providing the community with access to essential support services, including N95 masks, bottled water, food bank provisions, and childcare. In times of weather-related emergencies, such as extreme cold or heat, the City of Spokane can turn the Center into a Tier II daytime relief hub. It can then offer additional vital services, like a place to warm up or cool off or find better air quality when needed.

MLK Resiliency Center

Operated by the MLK Community Center

1. **SOLAR PANELS:** Produce clean, renewable electricity to run the Center and charge the batteries when grid power is out.
2. **BATTERY STORAGE:** Powers essential operations during unexpected outages, enabling the Center to function as an emergency community hub. During a power or natural gas outage you can receive the following services and resources in your neighborhood:
   - Food bank refrigeration
   - Kitchen operations
   - Lighting
   - Showers
   - Heating & cooling
   - Outlets (for charging phones)

   Battery storage also lessens the strain on Avista's grid, boosting resilience.
3. **GRID INTERFACE SWITCH:** Disconnects the Center from Avista's grid when there is a power outage, allowing the microgrid batteries to sustain the center independently.
4. **MICROGRID CONTROLLER:** Manages the different modes and provides control/monitoring of the microgrid.
5. **EV CHARGERS:** Excess electricity can be utilized during an outage to power two electric police cars stationed at MLK.

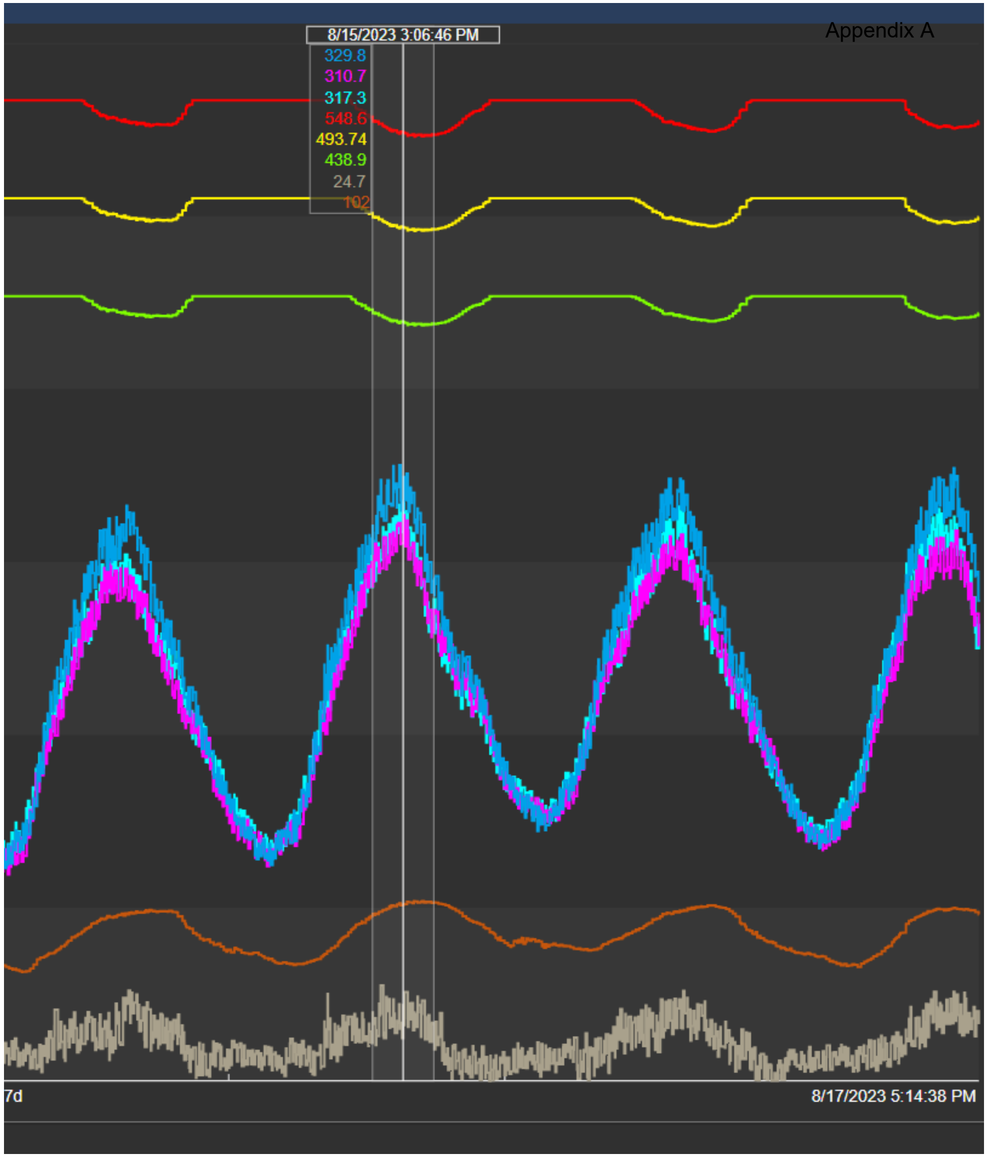
Avista and Microgrids

How could it be a resource?

Feeder 3HT12F5

- Mitigate a grid constraint
  - Transformer
  - Feeder

- Mitigate a resource constraint



Advantages of Microgrids

1. Ride through grid outages for those served by the microgrid.
2. Control system optimizes resources on the microgrid for the desired goals.
3. Billing flexibility and autonomy.
4. Grid resource options.

Disadvantages of Microgrids

1. Initial costs can be high. Equipment is expensive and the systems are custom-made designs which are complex.
2. Extra costs for the ongoing maintenance and the local expertise to maintain it.
3. Regulatory, policy, and contractual complications.

Distribution Planning Advisory Group

- Avista's overarching Distribution Planning goals are:
  - Develop a transparent, robust, holistic planning process for electric system operations and investment
  - Create a long-term plan to ensure we are maximizing operational efficiency and customer value
- Distribution Planning Advisory Group (myavista.com)
- Next meeting Wednesday, July 24, 2024, 9:00 AM-10:50 AM

Questions?

Avista's 2025 Electric IRP
TAC 9 Meeting Notes
June 18, 2024

Attendees:
John Annu, Fortis BC; Sofya Atitsogbe, UTC; Kim Boynton, Avista; Annette Brandon, Avista; Moly Brewer, UTC; Kate Brouns, Renewable NW; Terrence Browne, Avista; Logan Callen, City of Spokane; Katie Chamberlain, Renewable NW; Kelly Dengel, Avista; Joshua Dennis, UTC; Mike Dillon, Avista; Chris Drake, Avista; Jean Marie Dreyer, Public Counsel; Michael Eldred, IPUC; Ryan Ericksen, Avista; Rendall Farley, Avista; Ryan Finesilver, Avista; Damon Fisher, Avista; James Gall, Avista; Bill Garry; Amanda Ghering, Avista; John Gross, Avista; Leona Haley, Avista; Tom Handy, Whitman County Commission; Kyle Hausman, Avista; Lori Hermanson, Avista; Mike Hermanson, Avista; Fred Heutte, NW Energy Coalition; Kevin Holland, Avista; Clint Kalich, Avista; Paul Kimmell, Avista; John Lyons, Avista; Austin Oglesby, Avista; Sarah Pambianchi, Invenergy; Jared Schmautz, Avista; John Calvin Slagboom, WSU; Dean Spratt, Avista; Victoria Stephens, IPUC; Lisa Stities, Grant County PUD; Art Swannack, Whitman County Commission; Jason Talford, IPUC; Charlee Thompson, NW Energy Coalition; Taylor Vallas, Invenergy; Bill Will, WASEIA; Yao Yin, IPUC; Cole Youngers, Avista.

<u>Introductions, John Lyons</u>
John Lyons: Alright, so again, welcome to our TAC meeting. Today we're focusing on load and resource discussion. That was the one Lori is going to pick up. We ran out of time, last time we had such a good discussion. Dean Spratt's going to be talking about transmission projects and all of the work that goes in from that side of the company and what we're putting in for that. Damon Fisher is going to talk about distribution planning and specifically about microgrids. James, did you want to go through some of what we've got for upcoming meetings?

James Gall: Yeah. So, slide deck, our next TAC meeting is going to be a modeling seminar. I believe that's on the 26th or 27th John, so it's one of those.

John Lyons: Yeah.

James Gall: Fortunately, we're confused. There's a gas TAC meeting, I think on one of those days and the electric on the next one. But anyway, the plan is to go through the PRiSM model. We plan to have a version of that posted either Friday or Monday on Teams to look at prior to the TAC or the modeling session, and then we'll go through that model and how it works. We'll also go through the new resources spreadsheet so you can see how our assumptions are derived for our new resource cost as Michael Brutocao went through last week, and then we'll also get into our ARAM modeling, which we're still working on. Look forward to that and then the next TAC meeting will be after the Fourth of July. We're going to skip the next two weeks and then I will be showing our Preferred Resource Strategy and our capacity need at that meeting Lori kicked off here in just a second. We're going to talk about our L&R position. We're going to be mostly focusing on energy and renewable needs, but we're going to have some discussion time on capacity needs as well. So, let's skip going. Go ahead, Lori. If you want to pull it up, slide mode. There we go.

Load & Resource Position, Lori Hermanson and James Gall

Lori Hermanson: I'm Lori Hermanson, Senior Power Supply Analyst in James' group. As he mentioned, we're going to talk about our loads and resources positions. Since our last IRP, we've had a couple of RFPs, that renewable RFP and an all-source RFP. We've acquired quite a few resources since then, and this is an overview of our resources and what's coming online, what's either expiring or retirements. To start at the top, we've had an ongoing slice of Chelan, 87.5 megawatts and that's been on our books for a while, but that will expire in 2030. A second slice started at the same percent or the same amount 87.5 megawatts, and that will expire in 2033. We have a third slice that we acquired about the same time and that starts in 2026 and then in 2030 when the first slice expiring, that third slice will jump up to 10%, so 175 megawatts. We have a small Douglas, 24 MW, a contract that expires in 2028. To help us with our summer capacity, we acquired a contract with Columbia Basin Hydro and there's 7 projects that come on at varying times and you can see those there and those will extend through the end of the planning horizon to 2045.

Lori Hermanson: We have some ongoing wind, Palouse and Rattlesnake, and we've added recently, and it was a need in our last IRP that we added Clearwater Wind for just under 100 megawatts and that will go through 2045. We have Adam Nielson Solar, a 19 MW project and that expires in 2040. I'm sorry, in 2038, that expires 2038. And then also solar is a new 119 megawatts that's coming online or projected to come online mid-2026 and will continue through about 2040. Boulder Park Solar will be expiring, projected to expire in 2040.

Lori Hermanson: As you know, Colstrip is going offline for Avista at the end of 2025. So that's 222 megawatts. Kettle Falls CT will expire in 2040. Lancaster is really a contract extension. It's on ongoing now through late 2026, but with this recent contract will continue through 2041. And finally, Northeast, that retirement we're projecting that it will be through the end of 2029, but any of this could be updated, so that could go offline sooner, but that's what we're projecting right now. Rathdrum units one and two of 176 megawatts we anticipate won't be retired until 2045, right before we have to be 100% clean. And Stimpson is a smaller industrial customer that 5 MW load and generation, that will go offline. Actually, they made an announcement earlier this year that they're going out of business and will no longer be generating. We have a recent contract with Inland Empire Paper for 30 megawatts of demand response and that's on our books until 2031. And then there's a couple of sales, one of bundled RECs and then the Morgan Stanley Clearwater Paper sales. That's an overall look at our resources and when they're being added and taken off for retirements or expirations of contracts.

Fred Heutte: Yeah, just a couple clarifying question or one clarifying question. Could you just say what kind of resource Northeast is?

Lori Hermanson: It's a peaker, isn't it?

James Gall: Yeah, it's an aero derivative natural gas turbine.

Fred Heutte: OK, for some reason I didn't know about that. That's fine. By the way, this Fred Heutte, Northwest Energy Coalition.

James Gall: Yeah.

Fred Heutte: Good morning, everybody. Also, congratulations on the 30 MW DR contract. That's looks like a good one. Thanks.

Lori Hermanson: Thank you. This has helped out a couple of times in the last couple of years. OK, so here's our energy position. It's as you can see on an annual basis, we're in good shape, especially with those most recent acquisitions. But there are a few months where we're short. An example of that is January 2026 and that's related to one of those sales that I mentioned at the bottom of our last slide. As you know, we're participating in the non-binding WRAP program. The forward showing winter periods for November through March and the summer periods are June through September. Basically, the region is shifting or intending to shift most of the maintenance to those shoulder months. If we were to include maintenance of this, you might see some more shortages in generally those shoulder months, but sometimes they'll be something that occurs in those winter or summer periods. But that's all I have to say there. James, do you have anything else you want to add on this one?

James Gall: Yeah. This is our monthly net energy position and what is kind of surprising for the last IRP, we were expected to show a lot of length after the last RFPs where we had when we acquired Clearwater Wind and Lancaster. Now we're showing a slight deficit for a few years and nearly 2026 through 2029 in January. This is a little surprising to us. It's really driven by a large amount of load increase and our load forecast in the January time period. So, we're trying to think about how do we solve this small issue from an IRP perspective? We don't necessarily think it's a good idea to acquire resources for such a small position, but it does demonstrate that we are in a kind of a deficit period. I know in Washington State if there is a deficit period, we are required to do an RFP but so this got us asking some questions internally about how do we want to handle this small deficit. We haven't shown yet the capacity deficits. We're going to probably share that again. Like I mentioned earlier in July, we're still working through that analysis. We may show deficits early on in the plan. We may not. That's yet to be determined, but with these deficits, it does have a consequence from issuing an RFP. It's something we're looking at if we want to go to next slide. But before I go there, are there any questions on what's been presented so far on where we're at on energy position? OK, alright.

James Gall: Should we also on this last one, I think we touched that last TAC meeting, but maybe just remind everybody we're projecting relying on the market for 330 megawatts, but that's another thing that you know could be up for discussion is whether or not they should be relying more or less with everybody being in the WRAP and shifting maintenance to the similar times and that kind of thing.

James Gall: We are going to talk a little bit about clean energy and then we're going to shift back to capacity really quick. We proposed CETA targets for this IRP. These are the same targets we used in the 2023 IRP as well. I guess the next four years, the official targets will be part of the CEIP process, but this is what our proposal is into that CEIP process. 66% in 2026 moving up to 76.5% by 2029. And then obviously meeting the 80% target by 2030. And 2030, that's when the 4-year period starts and we're proposing to go from 80% to 85% in the next 4-year period, then 90%, 95%, and 100% by 2045. Again, these targets will be discussed again in the 2029 IRP, at least after 2030 for that CEIP process, but this is what we're assuming to date. We will be modeling a couple different scenarios with different targets we agreed to in the last CEIP process. How our model works? It will be trying to target this amount of clean energy over either the year before 2030 or over the 4-year period after 2030, but it does have monthly energy targets. There's also an annual, or sorry, hourly targets. Washington State is contemplating, in an IRP process for planning purposes in the new rulemaking for use rules, and we're watching that to decide what we need to issue in this IRP, if they have our rules that require hourly accounting.

James Gall: By the time we issued the IRP, we go to the next slide using those targets. This slide is a complicated way of showing what our energy position is for Washington State clean energy targets. How this works? Because Washington is quite complicated. Unfortunately, we get kind of a complicated chart, but I'm going to start with the black line that you see going across the table. That is our Washington State load estimate. It starts around 800 average megawatts, but growing over time you can see loads are very flat like we've mentioned in the previous TAC meetings, then start to escalate as we expect electric vehicles and more electrification of buildings to happen. But that's not what the Washington State CETA targets, at least not until 2045, would actually use this calculation, called retail load. And what retail load is, actually, it's just sales plus you can remove out any qualifying facilities or PURPA contracts, but it also lets you remove out any resources that are clean energy that's sold as clean energy. For example, the Solar Select program is one of those. So, we reduce our load obligation by those amounts and we our goal is actually that dotted black line. So, where we're at today, the bars make up the different resources we have that qualify. The light blue represents our hydro. That's allocated to State at Washington. We have wind energy in the green allocated to Washington, and the very small slice of yellow you have are solar and you can see that doesn't start until after our customer agreement with the Solar Select program ends and then we'll have that resource available for meeting CETA targets. We also have some biomass at Kettle Falls, shown in in orange, and then that's where things start to get more complicated. We have two states in our system and we have resources that are required to meet energy loads. But they also qualify for CETA and in our last CEIP process, there was an agreement that we could use energy that was allocated to Idaho or meeting Washington law cited targets assuming that Washington compensated Idaho for those RECs. That amount of energy is shown in gray, and the energy that we're allowing to be transferred between states, if necessary, is newly acquired resources and Kettle Falls. Mostly it is our wind contracts, the Columbia Basin contract, the New Chelan contract. Those are allowable to move between states, at least in our last CEIP. The last block is the blue block. That's our legacy hydro that's allocated to Idaho. We are assuming that is available to meet alternative compliance in 2030, but not before using all the resources we have available to us.

James Gall: Using an annual compliance target mechanism, we actually have enough clean energy. Assuming this load forecast till about 2038, we have a small deficit in 2038 from a clean energy perspective. Although, if you look at monthly compliance mechanisms or hourly compliance mechanisms, that would likely be pushed up sooner on a monthly basis, it would likely be pushed up to about 2035. We haven't yet looked at the hourly basis yet. We're still working on that, but that could be pushing up our needs sooner. This doesn't mean that we expect we don't expect renewables to be selected in our process sooner. There are ITC and PTC considerations. There are actually energy considerations as well, but this is just an indication of where we're at from a clean energy perspective.

James Gall: OK, before we go the next slide, are there any questions? OK, alright. We're doing well on energy, but the last thing I want to talk about capacity, which is actually something pretty difficult for us to quantify it right now. Our last TAC meeting, we did go through some loss of load probability analysis and we're continuing to look at that to see if we have it right because that is actually what I call the most important assumption in IRPs – what is your resource need? We settled on our energy need. We're now focusing on capacity and would like some advice from the TAC if you have any to give us. Again, we've not settled on a planning capacity planning assumption yet. Like Lori mentioned earlier, we have the 330 megawatts of market we relied on the past. We're looking at should we keep that the same? Should we increase it? Should we increase our planning margin as another consideration as well? We're still running additional LP analysis and we hope to have a recommendation to the TAC for the next TAC meeting is in July.

James Gall: We do have some questions to see if there's any response or thoughts on. One is maintenance planning and IRPs. We've traditionally not used maintenance in our plans. We don't want to go out and build resources for maintenance, but we do see this come in as a bigger issue because, one, the WRAP does not let you include resources in your L&R position when they're out on maintenance. We generally don't want to have resources on maintenance, but it does occur. One question is, should we plan on the IRP a minimum maintenance amount. For example, we could come up with a schedule of maintenance in the future and plan for that. But the problem with that methodology is maintenance changes year-to-year. You may have one particular unit on or out, but then the next year it's another one. One option is we could consider a fixed amount of maintenance based on the probability of what types of plants are likely to be out during a peak event and use that as a planning criteria. For example, we would add 100 megawatts for likely maintenance. That's one option we've been thinking about or we could try to plan out what that means it could look like in the future.

James Gall: Another consideration we have for capacity planning is that we do have other utilities in our control area that we're responsible for during peak events. For example, we have third party loads, and we have third party generation in our control area. For example, on the third-party loads, they're supposed to provide the generation or the energy for that load on a scheduled basis. But sometimes those schedules turn out to be wrong. That did happen in the January event, the winter event we had during the MLK weekend, where one of our extra say two of the loads in our BA under scheduled and we had to make up for that energy that was not delivered. The flip side could be said for generation resources in our control area where they schedule a certain amount of generation, and that generation doesn't materialize. That hasn't been a big issue for us right now, but it could if additional resources are built in our control area that are not dynamically scheduled out of our system. We don't necessarily have a recommendation on what we should plan for on this one, but it's something we're definitely wrestling with and curious if anybody has any thoughts on that one.

James Gall: And then the last one, should we be looking at different capacity planning methodologies? The region and the industry has been using loss of load probability analysis for the last 20 years. Before that, I believe we used some different technology, different methodologies on planning margin. And I remember there was a lot of work done on risk and I'm starting to feel like that might be a better methodology than looking at loss of load probabilities where we would instead plan for a low water, low VER and a high load event. That could be an alternative to looking at 5% loss of load probability because when we run our loss of load probability analysis, we're set up pretty well to deal with any event besides those events. And when I see that, that tells me we're planning to fail in those events. And is that something we should be considering? Should we be planning for something different than something more on the tail risk area? I'm going to pause there. Are there are any thoughts on the issues that we brought up? If I don't hear any, we're going to come up with some recommendations at the next staff meeting. But I'd love to get your feedback if there are any before we make any decisions. Go ahead, Art.

Commissioner Art Swannack: Yeah, my thought is you should be planning for maintenance outage because you're running against such a tight supply system and having that double peak now. It seems like it should be able to calculate what normal maintenance is and maybe throw in a small risk factor for something extraordinary on that. And then what was the last one you were talking about just a second ago?

James Gall: Yeah. Should we be planning on a risk? I'd say it had targeted reliability where we actually plan to meet a low water, low wind, high load event instead of doing a statistical analysis. The idea is, we estimate what that event looks like, and we plan resources around the event.

Commissioner Art Swannack: Yeah, my thought that popped in my head is in my experience over 50 years is when we get dry, we also don't necessarily have wind and we don't have water. So yeah, you should be doing something that increases the planning for that kind of risk. Thanks.

James Gall: Appreciate that. I saw Fred's hand up next and we'll go to Sofya.

Fred Heutte: I just want to preface this by saying that I'm a member of the WRAP Program Review Committee and have been involved in it all along, but I also have to say it's been difficult to have to provide input into the program development. I just want to say I've tried but have not always succeeded. The issue of maintenance or outages, just broadly speaking, either planned or unplanned, whatever terminology you want, is where I never really was able to get full engagement because it's actually a pretty important issue and there are lots of layers to it. I won't go into it here because you all know that stuff pretty well, but I will observe one thing that I'm not sure about is because the WRAP has a seasonal program, which is fine and does seasonal kind of aggregate, had qualifying capacity contributions and all the rest of it, which is where the plan maintenance goes, comes into effect. One, I'm not entirely sure. For example, if you have a unit that's on maintenance for the first two weeks of the summer season, you probably don't really care because you're going to have plenty of hydro around to cover that in this part of June, but later in the summer, if you have to take it offline for a week, ahead and not have it just be a forced outage. How does that work? My sense is that if you looked at this basically on a monthly basis and you have to juggle assets the risk here because of what the program requirements are. And I tell you, having read the entire program document, I'm still wrestling with some of the details like this. Trying to figure out, what I'm really saying is, I would not recommend taking a maintenance headroom adjustment or whatever you want to call it for an entire season, but rather have it basically be something like monthly. So, you're not overburdening what you got to deal with. That was my basic input.

James Gall: Thanks. It has been a challenge. If we take a unit out for a week, for example, like you said, in a seasonal period, we don't get accounted for that month and it could create some challenges, especially in those shoulder months when we're typically out on maintenance at our unit. But we also have our hydro. For example, we could take a unit out during the low event. We don't get accounted. Most of our hydro are 100 megawatts or less and that's where we're thinking about it. From this perspective, the hydro units we’re taking out in the summer months and the winter events, that we're considering the larger combined cycles are typically off in the spring. That's a little bit less of an issue, but it's mostly on the hydro unit side where we're also looking at. Some of our units, we'll take them out for a year at a time to do major repairs because they are over 100 years old. Something we're looking at appreciate the comments there. I'm going to go to Sofya.

Fred Heutte: I just might add one thing, which is, as a member of your program review committee, I will be very open to hearing suggestions for refining these kinds of elements, not just the maintenance, but other things in the program design. We got some more time now since the participants have all said let's wait till 2027 for the binding program. But like I say, I will be very supportive of fine tuning. You know that makes sense.

James Gall: OK. Sofya. Your hand disappeared.

Sofya Atitsogbe (UTC): Hi, this is Sofya Atitsogbe with Washington UTC. I'm personally in support of modeling for maintenance, especially considering that at least as resources are kind of old and require a lot of maintenance. So, if that happens, we need to model for it. That's my personal opinion and I wanted to comment on the alternative capacity planning methodology that Staff is in general in support of modeling the plausible worst-case scenario, which goes well with low water, high load event for example. That makes sense for Staff.

James Gall: Yeah. Is your support of looking at it or moving to that type of planning criteria?

Sofya Atitsogbe (UTC): Definitely looking at it.

James Gall: OK. I'm just checking now on.

Sofya Atitsogbe (UTC): Staff doesn't have a position if we should move to it. Yeah.

James Gall: OK. That's where I check it. OK, alright. I think that is probably something we need to present at the TAC. What that looks like if we go to that methodology just to see what the magnitude is and I want to be careful here because we don't want to gold plate the system. There is a market we can rely on as well. It's just we're wrestling with is, we did have some close calls recently that we're really paying attention to. And it's definitely in certain circumstances and it's just a matter of how we want our system to apply. This is a regional question. The region's trying to figure this out as well, and we know that the system is tight, but we also don't want to overbuild. Also, there's some of the resources that we're limited to creates other challenges. We're not allowed to build gas turbines that could create some challenges as well. Looking at just energy storage or just renewables, so we're trying to be careful here and thoughtful, but do the right thing as well to keep our system reliable. Art. I still see your hand up. I don't know if you had a second comment, or if you forgot to take it down. Right. I guess maybe Art left for a moment.

James Gall: Are there any last comments before we go over to Dean's presentation? OK. I guess we will have a proposal at our July meeting for our resource capacity need. We'll also will try to show a scenario that worst case low water, high load. What does that look like? I appreciate the comments, especially on maintenance. We'll come up with a proposal as well for that at the July meeting. OK, we'll move on to Dean.

James Gall: There is a question for me now. Should we test the 330 MW assumption based on the recent market experience? We are testing what our position, or our planning margin, would be if we move to 500 MW, we were able to get 330 MW in the January event. Actually, we're able to get more than that from the market, but you know I'm not sure we could have gotten it if we had prolonged outages like we saw. What happened in January was we lost three generation units due to the gas pipeline compressor station outage. We were able to get replacement energy for that. But as the weekend continued, we got higher loads, but our generation returned. So, we were not in deep with the market during the high peak event when other utilities struggled. We're comfortable with the 330 MW. We're maybe comfortable with going a little higher, but that's something we're testing. Alright, Dean, go ahead.

Transmission Planning, Dean Spratt

Dean Spratt: Right. Good morning, everybody. Dean Spratt. I'm in our transmission planning department and I'm discussing today transmission planning studies. A little bit about our group and then a little bit about generation or connection and supporting the IRP group. Moving on, and I'll show you really quick. You can stop me anytime during the presentation, but there'll be time for questions at the end, and we'll be covering distribution and transmission later in the presentation. Our group, we'll start with that one. We have lots of rules on the transmission system. That seems like a layer on the layer, then another layer, but one of them, the first standards of conduct. This one generally is just stating that we can't share nonpublic transmission information specifically with our merchant group, but with anybody in real time. There are merchant employees here today, so I will not be sharing any nonpublic transmission information. And then our Avista Oasis site, which is Open Access, Same Time Information System is where that information is posted. If there is any nonpublic information, it would be posted there and these slides were posted ahead of time and they are posted on our business integration, integrated resource planning groups website as well.

Dean Spratt: Today I'm going to talk about our System Planning Group, what we do and how we do things. Useful information about us and then an overview of some recent larger projects, and then move on to a second portion which is the generation interconnection study process we do for the IRP group as far as integrating generation under transmission grid, talk about our large generation or connection queue, and then a quick update on our cluster study process we transition to.

Dean Spratt: So, intro to our group. Within our System Planning Group, we tackle our distribution planning and transmission planning and break that into two halves. They're usually on a little different time frame and a little different scope of the projects, but they do overlap quite a bit as well. We try to work together as a team to bring projects forwards in a timely manner that makes the best sense for the company within transmission planning. We work on reliable electric service. We're kind of unique in the sense we have to question earlier about deterministic or probabilistic determination of what we're going to do and how we do it. We're more on the deterministic side. What happens if these bad things all happen? We try to put that on a piece of paper and say from there as a corporation we want to build to that extent or not and make that judgment call. And it's usually more of a what's best for the system and a balance of the different areas. What can we get done and what makes the best sense for the next step, as far as the system reinforcement, so we're held to federal, regional, state, and local compliance standards.

Dean Spratt: And then there's quite a bit of regional system coordination. Obviously, our transmission connects really strong with Bonneville Power Administration’s, but also the same story with our neighbors, the internal transfer customers, Kootenai Electric is a part of. Also as an example on that, a lot of our edges either we serve that area, or BPA serves that area, or Grant serves that area. We have a handshake with our neighbors to help them when they have an outage by carrying their load, and vice versa. If we have an outage, they carry our load, so that's kind of a system coordination. That's unique to the transmission system. And then our group plans either transmission or system loads, studies, analysis of those.

Dean Spratt: We're always paying attention to load growth. That's kind of the simple one. It tends to grow for the most part, then the one that's a little more challenging for our group is generation mix that's changing over time. And then also changing as different market influences change the way to dispatch existing generation and then the other one is just generation dispatch. Also in the last part, as far as our group doing interconnection studies or ambivalent about the type, we try to think about is it 100 megawatts of whatever it is, be it renewables, we try to not worry about what it is. We have more focus on how systems perform which is convenient in the IRP studies because then I don't have to look to James to say what exactly do you want. To put where you just kind of nicely says I'd like 100 megawatts in this neighborhood. And you say no, that's going to cost you much. You need to put it in a different neighborhood. Trying to keep it simplified that way, our bottom line is just performance or transmission planning as a whole.

Dean Spratt: We focus on the bulk electric system for Avista that's 115 kV and 230 kV. BPA has a 500 kV network that supports us over the top of us that does long distance transmission, transport. FERC and NERC look at the local electric system, anything above 100 kV. That discounts the sub transmission system. Avista really doesn't run sub transmission we’re either transmission or distribution, as opposed to other companies with a larger 69 or 46 kV system. We identify issues where this spoke electric systems can't reliably deliver power to come to our customers and then alert to that as we figure out how we're going to fix it. Officially, that's called the corrective action plan. We have a system assessment performed every other year. Within that is the projects that we believe would be the best alternative fixes to problems as soon as we get through the system assessment. We jump into a more focused project study where we look at a handful of really distinct alternatives and figure out which is the best to bring forward within the company. Those are mandated and described in NERC’s TPL standards. And then I was going to always like to fall back to this. We live in a world of NERC mandatory standards. It really became apparent after the Energy Policy Act of 2005.

Dean Spratt: Just a quick overview of the NERC TPL standard. I'm not to go into the detail below, but I think it's one of the longest standards within the NERC suite of standards as far as specifying how and what we're going to look at for seasonal studies. The years we're going to look at, 1-year, 5-year, and 10-year, I think that's going to move out to 20 is a new change to be happening TPL standards. Then, once we figure out what the world looks like, then we start to beat it up as the way to think about it, the thing that really hammers the system for our point of view. We usually start out with the P0, and this is the classification with the TPO, which is everything online and the world's great and we turn it with a single facility outage, lock out a transformer. We check everything across our system, then we hit it a little harder with the multiple facility outage, like a bus or breaker failure for detection system failure, double circuit outage, and we'll move on to overlapping combinations. We take a look at what happens if I lose an autotransformer, and then a second large autotransformer area, or one whole generating facility followed by another generating facility. We tend to push the system pretty hard to see where it squeaks and then go out of the TPL standard. This is what we're supposed to do, so that system shall remain stable. This is kind of joking.

Dean Spratt: The big three, there's only two listed here, but if something happens, NERC expects that our system won't cascade into all the other systems, and we knock out the Western Interconnect. That's kind of an obvious one. Realistically, we're not even supposed to know our neighbors without knowing that we're going to knock down our neighbors. That's part of what we're checking where the edges are. Facility rating shot, I cheated. This is kind of a straightforward one. You shouldn't overlook your equipment, stay adequate, equipment shouldn't fail or fault. And then it's kind of a nice summary here and object to the planning process and minimize the likelihood and magnitude and non-consequential load loss following planning events. We look at what could happen. The idea is we really shouldn't be knocking out customers because we didn't plan for it and that's what naturally occurring that if you have a line trip to lockout and you drop 3 substations, that's going to happen because they're on that line. But if we have a line trip, we shouldn't have to shed load at yet another substation for that loss. That's the drive. That's what we're up to.

Dean Spratt: I put this in because it helps to clarify something that does get lost in the mix right now. 24/7 we have transmission operators and distribution operators in real time watching systems and ready to act. If we do have an event via windstorm or just a simple line outage, they have a little bit more flexibility in their scope and the transmission standards tied to that. If they need to, they can shed load. If they need to, they can overload equipment so they can operate to do the best on the system in the real time based on what could be happening. Taking a step back from a planning point of view, looking 5 and 10 years in the future, we're trying to build a system that they can operate and maintain that also doesn't have something that's predictable that knocks out load that they shouldn't have to deal with. We're trying to get ahead of where they're operating to.

Dean Spratt: We pay attention to their operations on a pretty regular basis to find where the weak spots in our current system make and sure that we're putting patches on that over time, and then also solving for load growth and large load additions or generation removals. The standards are our road map early on in the Western Interconnect, there was Western Systems Working Council in 1967, 40 different electrical power systems. They didn't have control areas or balancing authorities at that time. The Portland Generals and the Avistas all sat around and said, hey, we should establish a set of general standards to operate to make sure I don't bump into your system. We don't bump into my system and we kind of have a good handle on how our systems are going to operate. OK, through the 2000s, when Western Electric Coordinating Council became its own entity. And there's a couple reasons for that. But again, as opposed to just a subset of electric utilities, now every electric utility within the Western Interconnect adhere to some common guidelines and rules.

Dean Spratt: Then just after that, North American Electric Reliability Council, NERC, came up with standards from 1968, but they were enforced starting in 2006, but officially in 2007. This became a new set of rules and standards that spread out across the nation. Something that might be happening in New York and something that's happening in the State of Washington have to perform the same general requirements. That's the road map of our standards. Over time, we'll move into what's the result of that. We go through the study process, we check out the alternatives, we look at the non-wires, looked at generation, batteries, whatever we can do out of that mix in yellow.

Dean Spratt: This is a pretty busy slide. I'm just going to talk about a couple of the high points. In yellow, these are system reinforcements over the last decade. Roughly speaking, going to start in the top right-hand corner just to talk to one that brought Noxon-Cabinet 115 kV. This is an area that we share with BPA. It has 115 kV line serving about 220 megawatts. Starting in about the year 2000, we had realized, us and BPA that our aligned conductor wasn't strong enough to carry that load under N minus 1 or minus 1 minus 1. We slowly reinforced that system to carry the load through the 2010s and the 2015s, finished up those projects, and have operated reliably. Since we're starting to the spot where the load is starting to push the system now, it's not a thermal issue. It's turning into a voltage lapse, this issue, so we'll be going back to that area to add some reactive support. We've talked about some generation reinforcements, some alternate solutions as far as batteries or so we're starting to kick around what we can do up in that area. We have portions of it, 115 kV line that could be completed that would add a fourth line of the system, which adds some reliability. That's probably going to be the wires solution we'll bring forward, but it will be verified against a handful of the other alternatives.

Dean Spratt: And I moved to, in this picture, the middle of the map, the green colored boxes. These are just through the kind of official means. All three of these projects knocked on the door, said we'd like to integrate generation onto your system and then not even knowing where the generation was going to go at that time. We started studies and then either it could have been sold off system or it could have been purchased for a long-term agreement on our system. And the three that we are referencing this morning; Adam Neilson Solar which is 20 megawatts out in the Big Bend area; Rattlesnake Flat 144 MW wind facility in the Big Bend area, then the first large renewable put on the system was Palouse Wind which is kind of on the Palouse, when you said Moscow-Pullman area and our system little over 100 megawatts.

Dean Spratt: That's a general kind of snapshot of reinforcements. This is transmission specific. If you looked in any one of these areas, there's quite a few distribution reinforcements and then also kind of the handshake between distribution and transmission, some new substation reinforcements to carry load in this area of these areas, I should say. Whenever we look at any transmission project, we look at anything we can do. So, when I say can do, we try to think of all the tools and the toolbox to fix a problem. We always check the feasibility of alternate transmission solutions. That's the low hanging or the obvious answer for a planning point of view. But we also bring in non-wires solutions, batteries generation. We try to think of all the things we can put in the mix, then grab which is the most prudent at the moment based on a handful of factors and move forward with the project and then work through that with the corporation to finalize the project and move on to building whatever infrastructure is required to meet load needs.

Dean Spratt: A quick example of a non-wires alternative is batteries. That's always on the list. That's a simple, straightforward one. He'd say it that way. They're not. They're super simple, but at a certain scale they become pretty obvious. In the Moscow Pullman area, this example, we have two auto transformers which are the large 230 kV to 115 kV sources for our system. Our 230 kV is a main grid system that moves generation around the area and feeds load centers. We step it down to 115 kV for load service, so again there's two of those in the Moscow-Pullman area. Part of our studies and transmission planning is a T minus 1 minus 1, which is just a multiple community or overlapping cadency. So, loss of the transformer. So, we might have a transformer out for maintenance and then as it's out, the second transformer that feeds that area could have the bushing fail. So, both transformers are out and specifically in the Moscow-Pullman area, that would be lights out for both cities to two colleges down there. It's a pretty big hit as far as exposure. The total load for that area is 125 megawatts. We could put a battery that could last some amount of time, but we're talking now cost benefit analysis, the battery would have to be. Our backup stuff, typically when we have batteries on the system, usually they charge overnight and discharge 12 to 16 hours during the next day. That's a standard sized battery.

Dean Spratt: We talked about transformer outages, they can be weeks to months. So, whatever that extra resource that we'd call on has to not just make it through the next day or the next peak cycle, it would have to make it through the next week and on to potentially a month’s worth of time. If it was a large failure of the second transformer and the maintenance was no long duration maintenance outage. We look at what it costs you, but batteries against that project is a solution and compared to what it costs. But that third transformed area, so this project's not in place yet. This will be worked on over the next couple of years, but a transformer just off the shelf is about a $2.5 million dollar investment and then probably another $2.5 to $3 million to integrate it. So about $5 million would be into a third transformer to feed the area and we bow to the N minus one or two minus one 1, minus 1 outage issue. For this specific use and quick overview of that and I'm going to stop there for quick questions because we're in the middle point of what I was presenting. And then I'm going to try to be respectful with Damon's time. So, if there are no questions on my zip through the second half to the end, we will have more time for questions.

Dean Spratt: Not seeing any hands, I'm going to keep on going through the generation interconnection process. Obviously, we do the load studies. We do that on a regular basis. The other thing that comes in that's kind of out of our control specifically is how many people want to knock on Avista's transmission door, saying we'd like to drop off some new generation for Avista specifically or for external parties. So, two sources, it's going to developers and then internal IRP requests, regardless of our kind of feasibility study for the IRP group to figure out roughly how much it cost to integrate power onto the system. Everybody that wants to truly integrate around the system has to go through it. Open Access Transmission Tariff process that's pulled out and we're always refining that and making that for firms as time goes by. In fact, it's becoming more challenging, which is good from a planning point of view because a lot of the answers are questions going in, but we still have to go through the process. Typical process: hold the spoken meeting, outline a study plan, update the WECC approved cases for our interconnection studies, analyze the system against the standards, and then publish findings. Recommendations are pretty straightforward. Some surprise us.

Dean Spratt: Recently, I'm going to bring this up, we transitioned to a cluster study process. It's a FERC now mandated process, but it's an optional process in the past. The precursor to the cluster study process with serial interconnection process, there's a little bit of detail here, but the next slides got a picture that makes it a little bit more clear. The serial process, the first project to come in at the top, project number one, we had 45 days to do a feasibility study followed by a system impacts study followed by facility study. We'd write a large generation interconnection agreement and then we'd repeat the cycle. We had twenty of these on the books. We would have to go through that full cycle and the full cycle was roughly about three months. As you can see in the chart below, from the old days on call it in 2014-ish time, the number of interconnections. They came in and we could manage within our shop. As time went forward, roughly 2017 into 2018, we started to see spillover. We couldn't get all the 2017 projects done. So, a couple went into 2018, then we had a larger handful of projects in 2018, plus the spillovers turned into 2019, right around 2018-19. We were looking at the reality and said we have an optional cluster study process. We really should go to bat and convert our company to the cluster system, cluster study process, which can be a lengthy process. We transitioned over and obviously it knocked our numbers down to about 20 and that's been manageable. We hired some extra staff to do that as well.

Dean Spratt: This just talks about the cluster study style that we've settled on. This is the queue that's active right now. The queue is on the left hand side or the stuff that was from the older serial process: our Post Falls reinforcement, Kettle Falls reinforcements are rebuilds are in that and those are probably moving forwards. The other ones may or may not move forwards, the TCS or the transition cluster. When we transition to the cluster study process, second one on that list, the TCS-14 is moving forward, which is a really large wind farm, 375 megawatts with a couple hundred megawatts of batteries. If I remember correctly, like 190 then the CS was the first true cluster study cycle. In 2023 we have 4 projects that are still working through the process.

Dean Spratt: Then the 2024 cluster study cycles that list. Right now we're working through that as we as we speak and then these are the estimates for the IRP group. This is if you drop off generation of new sites, so I'll just say really quick out in the Big Bend area, we only have a 115 kV system there, so it takes 230 kV reinforcement to be able to put any generation. That's why the larger numbers are on that column, and then this point, existing generation sites that are on Avista’s transmission system. So, these happen to be a little bit stiffer. Areas that already have built for some generation, so again the possible bit more straightforward, and then I'm going to skip this example and top to questions and I'm going to say James has a quick slide at the end of this questions to kind of talk. I'm going to hand it over to James if I don't see questions and then take the last slide and he can give me the nod when he wants to see the last slide.

Dean Spratt: Just while people are thinking of questions, the costs that are shown on the previous couple of slides, those are what we're using in our IRP analysis for each of our resource options. If we get a large amount of resource selection, for example in the Big Bend area, it would trigger a major resource build or I should say a transmission build. And what we're finding is, these transmission constraints actually influence what resources get picked in the IRP process. They're important assumptions. But what we're finding, at least in the preliminary analysis, is that we need more transmission and the latter half of the plan and this study work is instrumental into trying to help us figure out what the options are we have that are realistic. Given the situation, because this, you know we're rebuilding the Big Bend area, the $200 million, you know that's if all things go well. It could take a decade or longer to build these and cost more. Any questions on transmission? Kelly has a question. Go ahead, Kelly.

Kelly Dengel: Just a short one on one of those interconnection slides there was Post Falls Hydro listed at 115 megawatts. Can you explain that one?

Dean Spratt: I do. I think it's on the queue. I'm sorry James probably tackled this as well, but Post Falls hydro is just that and an older plant. We've had a plan to rebuild the whole plant kind of back and forth and I think we're back to the drawing board for a new kind of reinforcement there, but it's still in the queue. I think it's going to get pulled shortly, if not already. Yeah, I think it might be pulled as well. And I think the same thing for the Kettle Falls queue position there. That was for the upgrade that we were looking at doing out of the last RFP. That is, since it got cancelled, so I think those two Avista projects will be pulled. OK, alright.

Kelly Dengel: Thank you.

James Gall: Let's go to the last slide. I want to talk just briefly on the North Plains Connector, you may have seen this in the news. I think Clearing Up had an article on it, but there is a large transmission project that's being developed that connects the Western Interconnect with the Eastern Interconnect via Colstrip. The idea behind this line would be to utilize the Colstrip transmission system to bring power West or even East to help us with the market liquidity, we would connect with both MISO and SPP. I think Portland General Electric is committed to this project. We're evaluating this project whether we'd like to commit to the idea, at least for this IRP, is to include this as a resource option in our modeling. The big challenge we have is there's not necessarily a resource behind this. So, you're treating this as a market resource and it's also a market resource that is connected to a transmission leg that is limited by how much generation we would likely have at that market. We will be studying this in the IRP as a capacity only resource that's got limitations based upon what generation gets cited in our IRP at Colstrip. It is a 2033 or later project, so we're going to be modeling it as an option after that period and look at it just as a capacity resource. There will be opportunities to arbitrage markets between the two areas when we're long. Or when we're short between the two areas, we're not going to have time to model that in the IRP, but we would likely will look at that later. But it's something I want to bring to the TAC as something we're looking at. I do see Fred with his hand up. Good, Fred.

Fred Heutte: Yeah. Really glad to hear that you're going to be taking a look at this. I mean, there's a long way from here to there. It's a big build. It's a lot of money. It's a whole lot of siting, et cetera. We've talked to the Grid United team, Michael Skelly and his team. They're very capable, he used to run clean line, which is now building a couple of big DC projects. The time frame on this I presume is like early to mid-2030s. See, like you said, 2033. That fits in really well with the bigger picture. I just really encourage Avista to keep looking at this. One of the big advantages of this is it gives access to both of the big midcontinental markets. You have both SPP and MISO. That means that this would then have access, assuming that Avista, we would like Avista to join the EDAM of course because that's going to be a very big market then you would have access to 60% plus of 2/3 of the country. And I think that's really important, especially in these peak winter events, or summer events even, but certainly in the winter events, one of the things that I've done a little bit of an analysis of from the January freeze was looking at what happened with wind. Did the Columbia Gorge is kind of a separate issue. There are specific issues there, but from Eastern Washington on east all the way, you get a big surge of wind when the big cold air mass comes in from the Arctic and then it dies off for a couple days. And then that whole front moves on the front edge of it and the wind keeps moving to the east, and I've documented this now in the Northwest, in SPP and MISO. It's something that we can draw on if you have this kind of connector to where the wind is going to be at any given moment in those kinds of events. So just wanted to point that out because there is an issue with wind kind of pausing or ceasing during the very coldest period. But the bigger market footprint you can access the better off you are. And of course, the Southwest and the winter also will have a lot of surplus. Just want to say again, I'm really glad to hear you're looking at this one.

James Gall: Thank you. Sofya, go ahead.

Sofya Atitsogbe (UTC): Yeah, echoing lots of what Fred has just said. To me it looks like a lot of diversification opportunity. That would be at least two or three time zones. The solar would be at a different time. There would be an opportunity to draw from there and you have more options for wind. It sounds, especially since it's North Dakota. So that sounds like a good hedge strategy, absolutely.

James Gall: Yeah. Thank you. Again, we're going to be modeling this as an option, to see if the model picks it, and then we'll go from there. I guess we'll be talking about this in July when we show the selection. We'll see if it makes the mix or not, but we do see a lot of positives with it. Unfortunately, we can't model it I think as well as we like in the time frame we have without delaying the IRP because we see really two different value streams. One is this diversity benefit that, I think Sofya has brought up, and then there's a capacity benefit during a peak event, which we can model fairly easily and quickly in this IRP. That diversity benefit is going to take a little bit more time. So, if it makes it in the cut from a capacity only benefit, I think that's a good sign that this is a worthwhile project. I don't want to leave Damon with a no time. Let's shift to Damon's presentation on microgrids. While Damon is putting this up on the screen, we've had a lot of interest in microgrids. We're not quite in a position to model them in an IRP, at least we're not going to distribution planning IRP system yet, but we want to just talk about what they are and what benefits they can provide. There is a transmission planning process that we have called a DPAG and this is kind of an intro to that side of the public process. So, with that, I'll give it to Damon.

Distribution Planning, Damon Fisher

Damon Fisher: Thanks again, my name is Damon Fisher, with System Planning and today I'm going to speak about microgrids. I'm not an expert in microgrids by any shape or form, but they are there are something of interest in the business of distribution system planning.

Damon Fisher: Let's get to it. This is a boilerplate slide that you've seen several times already. I don't know that I need to speak to it too much, but distribution planning, we're looking out ten years in the future. We're doing a plan. The runway length for distribution facilities is getting longer and longer. The power transformers and things like that are becoming quite long lead time items. So, I think over five years we're getting way out there for our transformers and things like that. So, any capacity issues that are coming up on the on the grid need to be identified as soon as possible.

Damon Fisher: We've got a 10-year plan that we're working on a 2-year cycle. We do a system assessment. From our assessment, we develop projects, capital projects to do in the future and during that process we consider these things. So, what is a microgrid seems obvious, but it's the same as a macro grid, but smaller, it's self-similar. I'm thinking about this. If you're familiar with the fractal, a little picture of 1 there, it's a mathematical curiosity. No matter how close you zoom into that picture, it looks the same. You keep zooming in, keep zooming in, keep zooming in. It keeps repeating itself somewhere. That's what a microgrid is. It needs to perform just like a macro grid and the same issues it needs to maintain voltage and frequency respect. Thermal limits load equals generation, right? That's a rule in the Systems. You can't violate that, and the equipment's protected, particularly generators and stuff like that. Otherwise, they can be damaged, just like on the macro grid. So, you're either shedding, shedding load, or turning generation off in some way, shape or form whenever to protect the system from damage. You still have to do that at a microgrid.

Damon Fisher: We were just talking about this, I think about a line going from the orange to the green there, a DC line. The Western interconnection has a heartbeat.

The Eastern Interconnection has a heartbeat, and so does the Texas interconnection, and those heartbeats shall not mix. These things function on their own. If you look at the continental United States as a grid, there's, maybe 3 microgrids in it. You'd like to think of it that way. There are DC interconnections that exist between the Western interconnection and the Eastern interconnection. I'm not exactly sure what their function is, but they are there so they can talk to each other, but you can only talk to each other in DC form, right? Because DC has no heartbeat. DC is bivalent. It's my understanding that Alberta up there, and maybe even BC, can island themselves from the Western Interconnection system if they wanted to. Alberta could be a microgrid. That's how big it could be. That's not what we're talking about here. We're talking about distribution.

Damon Fisher: What's in a microgrid? The major equipment is all very similar to a macro grid. This is very similar to the way the system is today, the transmission system, the microgrid controller. There's a lot of controls that have to happen and these are local, sophisticated controls and communications among other pieces and parts that are in that microgrid. Microgrids could be an Air Force Base. It could be a building, but this all needs to happen. OK, generation of some sort, it could be renewable it could be thermal fuel cells, which generation it could be on the system and then storage or some dispatchable source. This is kind of important, but something that can follow the load and be asked to do something. That can't be your only thing. You went with the battery. That will work with a dispatchable source like a diesel generator, that will work, but that’s important, that might be more of a functionality thing. I don't know. But storage and dispatchable sources are important, and then a grid disconnect switch. A point of common coupling with the grid.

Damon Fisher: There's a point, on one side is the grid proper and on the other side is the microgrid proper. And that's a very important thing to do. No one definition of a microgrid is that it can operate grid connected. All the little components of the microgrid function. Well, perform and do what they need to do. However, the controller wants to do it. Does it still function with that grid disconnection? Close that point of common coupling. There are definitions of a microgrid that say that it still needs to work right with that switch closed. If that switch, if it doesn't, and that switch is open, then you're maybe thinking now you're moving over into a backup situation. Hospitals, even Avista, here we have backup generators. They turn on after that switch is, we're disconnected from the from the grid. That's probably the most common way if you want to fit that into your definition of microgrid, is a backup power source. It's how it has been done in the past and typically that is driven by the customer. The customer decides that they have facilities that they need to power. If power goes out and they take care of it, spend the money and make that happen.

Damon Fisher: Major functionality of a microgrid would be its black start capable. So, it can it turn itself on, if disconnected from the grid for whatever reason. Power goes out on the grid that switch is open. Everything's black. There's no power. Can it turn on and create a microgrid and serve load? That's an important piece of the puzzle. It's not always possible. We have generation facilities that can't turn on without power, surprising, but that's true.

Damon Fisher: OK, it needs to be able to island. It needs to be able to respectfully disconnect and connect to the grid without causing problems. The way that works typically is that that grid disconnect switch, the point of common coupling, the microgrid controller will manipulate low generation or whatever, such that the power flow across that switch is 0, and once that happens, it can open everybody on the microgrid. Doesn't know this happened. They just continue doing what they're doing, but the microgrid is no longer connected to the grid, no longer operating with the grid, and great synchronization is really important. After doing that and running as a microgrid for a while, how do you connect back up? Well, you need to be synchronized, so the heartbeats need to become the same again. Like I mentioned, heartbeat says frequency and phase. The frequency needs to be the same and the angle. We need to be synchronized before that switch closes. At that point of common coupling and then another piece function at least managed demand. The demand on the microgrid needs to be controllable in the sense that, well, this is not an important building. I need to shut that off or turn it on or the microgrid controller needs to have control over that in some way, shape or form and depending on what the goals of the microgrid are, which are varied and very significant.

Damon Fisher: Why does somebody do a microgrid? Resilience is probably, and I mentioned backup power. Backup power is a resilience play. OK, so you got a critical load or essential service that you cannot tolerate an outage. Maybe it's an assembly line or something, some process that needs to go, hospital, critical load. Things like that. So that’s a resilience plan. Then there's an economic plane. That would be, a demand charge shifting, taking control over your bills if the billing structure, the rate structure for this kind of thing and not all of them do. Maybe you can defer or avoid demand charges and energy arbitrage, other utility services that you may provide the local utility and climate goals.

Damon Fisher: Typically, at least, conceptually these microgrids in the future are going to have renewable generation of some sort. Put on a solar roof and that kind of stuff. These will help folks with microgrids, it can help folks sneak climate goals either prescribed or self-determined climate goals. And then, if you have difficulty serving load or getting service because you're isolated, you're on it literally, on an island. If you just sit on the middle of nowhere, you can set up a microgrid to power yourself. Whatever yourself is, some resorts in the middle of the mountains or whatever it happens to be. It becomes prohibitively expensive to drag wires to your facility. So how does it take to get it? Is it a resource?

Damon Fisher: This is the place we talk about resources. A microgrid could be resource in a sense that it's kind of a black box. It operates that way and the utility can ask it for things and then you can ask it for capacity. And then the black box will talk to itself. Have a conversation with itself and say yes I can help you with that or I can't help you with that. It all depends on how that microgrid is set up, and those can be driven by incentives and agreements between the microgrid owner and the utility.

Damon Fisher: Maybe the microgrid owner has to demand response agreement with utility. And so, you've been called upon. They have promised to do something, so they could set up their controller to do it right, or if they have internal things that they want to do, they got to maintain a state of charge on their battery for some reason or whatever. The grid won't violate the rules that it's been given the microgrid, so it can't be a resource. I don't think that the DER that are involved in these things that's need to be in a microgrid in order to still be a resource. You can still call upon these things. I think the microgrid piece is it's an opinion thing. Microgrid piece, really it feels to me like a big resilience point thing. Do you really need resilience then? This is what you do if you just want to have DERs and that kind of thing. They can still function as a resource to the grid, but you don't have all the complications or expense. This one has a couple of micro, well we have one microgrid and one in the works. we have the WSU Spokane Campus demonstration pilot. I don't know a lot about this. I know that they've islanded it successfully and so it's more of a playground for the R&D group that they do stuff with it. It's not used for any particular reason other than learning. That's what is functioning, however, we have a project out for bid for the MLK Center, which is a Community Center. For a microgrid, that's 115 kW DC solar array battery and natural gas generator. Approximate cost for this is $2.5 million and there were grants applied for, but it was a grant applied for by the MLK Center, and then we are providing matching funds. Alright, some funding source. I don't know exactly where that's coming from. A Named Community Fund, thank you.

James Gall: You have a question? She says what's Avista's ultimate goal with microgrids?

Damon Fisher: At this point? It's the same as everything else. We're learning about these things and there is no official goal that I'm aware of. But right now, I think the more we learn, the more we will be able to look at these things as solutions to particular problems. I know we have some problems on the distribution grid that these might actually pencil out on. They haven't been applied to that, but so it's going to be. I'll describe it as this, microgrids will just be another tool in the toolbox to fix, to mitigate, distribution issues. There's a lot of money out there on the federal side for microgrids. The problem is Avista can't actually apply for that money. The money has to go to somewhere like the MLK Center, a tribe, some other group. They initially apply for it, and then we can do matching funds and funding. We can do some things to help on it, but it's not something that we can actually drive. There's a hand up, go ahead.

Brewer, Molly (UTC): Thank you.

Joshua Dennis (UTC): Hi, Joshua Dennis with the Washington UTC. I don't see any mention of the Spokane Microgrid. Here it was mentioned in the BCP, and I was wondering what the progress would is on that.

Damon Fisher: The Spokane microgrid with a tribe? I'm not aware of what this is. I'm not sure what the status of that is.

Joshua Dennis (UTC): Uh, yes.

James Gall: I know there's work going on to keep a few buildings energized as a microgrid that's moving forward. I don't know exactly where it's at in the process. I’m s going to check if there are any folks online that could give a brief update on that one. I don't. No one’s responding, so unfortunately Joshua we will have to get back to you on that one.

Kevin Holland: Hey, James.

Joshua Dennis (UTC): I guess that raises a second question and I guess with this being a toolbox that Avista has to mitigate distribution issues, what would Avista's ownership model preference be?

Damon Fisher: Very good question. There are some I think, and somebody correct me if I'm incorrect, but if a third party were to own this, they would need to be the customer. They would not be able to have a microgrid and sell. If they had a campus, some sort of business campus or something, where there were other renters on the site, they wouldn't be able to sell to those other folks. A microgrid for them may be problematic. I think because they're not a utility. From an ownership point of view, from a planning point of view, these things would be something that we would mitigate and feed or should probably. A very long feeder out in the middle of nowhere. This is the distance, the separation thing, to get to get past voltage issues or loading issues and things like that. This is something that would be probably owned by the utility. It could be and I think it's case by case basis, but Kevin you came on, I think he was saying.

Kevin Holland: Yeah, actually, can you hear me?

James Gall: Yep.

Kevin Holland: Yeah, I think I think that's exactly right. I think a lot of these in terms of what the ownership are and devising the divisional lines between customer owned facility components and Avista owned facility components will be potentially variable by project. But obviously I think along with what was said, the applications will be different depending. It's another tool in the toolbox that we can use and therefore I think as it applies in different situations, and depending on what the goal of the customer and the coordination with Avista leads to, I think the structures could be different, but obviously having this MLK resiliency project and some of the other ones that were conceptually in different phases will provide us with a lot of insight. I think John Gibson probably is a good reference to point us in a direction. I know he's not on the call today, but we could certainly ask some additional questions of John because his group has been intimately involved in putting this together and crafting some of the intricacies of these types of projects, but they'll be different for different applications. I think that's exactly right that it provides us with a tool in the toolbox that we can apply in different usage and situations in terms of whether it's a grid resiliency program, whether it's a resiliency program for that customer in and of themselves from a tribal perspective. Whether it's energy, independence and sovereignty, so different applications for different uses.

Joshua Dennis (UTC): Thank you.

James Gall: Going to Sofya.

Sofya Atitsogbe (UTC): Data sets. Thank you. Avista recently filed the affiliated interest filing for the Connected Communities of Spokane. As I understand, this is also a microgrid project. Is that correct? My understanding is it's downtown Spokane that the one of the new Avista buildings are part of it. It's part of it. Could you give an update on that project?

James Gall: I'm trying to see if there's anybody in the room that can, I know enough to be dangerous, but I'm not going to say anything because, Kevin, I don't know if you know anything more than I do.

Sofya Atitsogbe (UTC): A lot of thoughts.

Kevin Holland: Yeah, James, I think you and I are kind of in the same boat. It's a very unique project in terms of the component tree and how it's self-sustaining and yet potentially also helping the grid. But the project in and of itself has very little connectivity. This sounds odd, but a small amount of connectivity to the Energy Supply group and so we would probably need to defer to someone like Latisha Hill or potentially John Gibson, again to give an update on the Connected Communities project as a whole. Nicole Hydzik is moving forward, but I know with that particular facility that were involved in downtown and the three buildings I think are two or three buildings and that's sort of an incubator type situation that continues to mature.

Sofya Atitsogbe (UTC): That wouldn't be a question that I will just comment on that. As part of CETA, resiliency is very important for the State of Washington.

James Gall: Sofya, catch up. Go ahead.

Sofya Atitsogbe (UTC): I think lots of people will be keeping a close eye on Avista's learnings, among other things, from the microgrid pilots. We would like to see information about what challenges Avista has presently in resiliency planning, and that's rates, what lessons are learned and what is to do in that regard. Thank you.

James Gall: Thanks. We'll try to do this at the next TAC meeting. We'll see if we can get an update on both the Spokane Tribe project and the Connected Communities. But we do have two minutes left. But we can go a little bit longer if you guys can stick around. We definitely can. We might lose our room momentarily, so we'll see how that goes. But game to go ahead and see what we can get done.

Damon Fisher: If you look at this diagram, this is an actual diagram that was sent out with the resiliency center. You could see all the components and pieces, what you don't see on here is the gas generator, which I believe came after some study was done in terms of a requirement of it lasting longer. So, the microgrids can last that amount of time or forever. The difference of cost could be significant. If not, it's more stuff. So now that the requirement change, I don't know the change or whatever there is some discovery but now there's a natural gas generator in the mix here. This is the actual Center, the top of the roof, to the white part is the roof. That's where the solar would go. And then they get red roof there. I believe this is an outline police station or some sort of secure what they do there. So, how does how does this help Avista? Well, what it could do, it's not really from a service point of view, from a capacity or it's not quite that useful from the distribution grid point of view. This is the actual feeder it's on, this is last summer's peak load. I think the temperature there is 102 degrees on that feeder. It's got to go all the way up to the green line there to get to 80% utilized. That's quite a bit of room on it still, but let's assume it didn't, and so what you could do is this. It could call them and say, hey, you can you help us out here with some capacity issue, a great constraint on the transformer feeder. And then all the way up to the system wide you maybe you can ask for a resource.

Sofya Atitsogbe (UTC): I don't think we would want to spend a lot of time investigating which schools are open but take a little bit out of there and give up a little bit.

Damon Fisher: That's how it could happen. Well, this is the resiliency advantage. The user utilizes all their resources in a more optimized way because nobody has the same goals with their microgrid and then they have flexibility and autonomy with their billing and then then it opens it up for grid resource options. This vintage, they are costly. I don't know if you saw $2.5 million for half a MW of battery storage for the MLK resiliency play. It's kind of expensive. I don't know if there's a particular thing about the MLK thing that makes it so expensive, but just for reference, a brand new 60 MW six feeder substation is going for about $11 or $12 million on our system. So that's $2.5 million. The owner of the microgrid, utility or otherwise, has extra cost for ongoing maintenance and local expertise to maintain it. Some of this was actually brought up regulatory policy, contractual complications. It does complicate things, but that's for the business to do is get complicated, I guess. So those things at all, typically here down.

Damon Fisher: The last thing I have to say is, the DPAG, Distribution Planning Advisory Group, is meeting July 24th. I'm not sure if everybody on here gets an invite. No, but that does not say what we will be talking about. I don't know, hosting capacity maps and improving and we currently have. The TAC has been told about the DPAG and we've tried to do it but if you want to be on the DPAG you can contact me, and I can get the information to it.

James Gall: Just do it through the regular IRP channels and we'll make sure that gets to Damon’s group. Alright, that's all I have for over time. We thank you for sticking with us. We will see you at our modeling workshop, if you care to join us. Otherwise, we'll see you after the Fourth of July holiday in our next TAC meeting. Thank you. Have a great day.

Sofya Atitsogbe: Thank you for the presentation.

Joshua Dennis (UTC): Thank you.

2025 Electric Integrated Resource Plan

Technical Advisory Committee Meeting No. 10 Agenda

Tuesday, June 18, 2024

Virtual Meeting – 8:30 am to 10:00 am PTZ

Topic	Staff
Introductions	John Lyons
Preferred Resource Strategy Results	Planning Team
Resource Adequacy	
Washington Customer Benefit Indicator Impacts	
Resiliency Metrics	

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2025 IRP TAC 10 Introductions

John Lyons, Ph.D.
Technical Advisory Committee Meeting No. 10
July 16, 2024

Today's Agenda

Introductions, John Lyons

Preferred Resource Strategy Results, Planning Team

- Resource Adequacy
- Washington Customer Benefit Indicator Impacts
- Resiliency Metrics

Remaining 2025 Electric IRP TAC Schedule

- **TAC 11: July 30, 2024: 8:30 to 10:00 (PTZ)**
  - Preferred Resource Strategy Results
  - Portfolio Scenario Analysis
  - LOLP Study Results

- **TAC 12: August 13, 2024: 8:30 to 10:00 (PTZ)**
  - Preferred Resource Strategy Results (continued)
  - Portfolio Scenario Analysis (continued)
  - LOLP Study Results (continued)
  - QF Avoided Cost

- **September 2, 2024- Draft IRP Released to TAC.**

- **Virtual Public Meeting- Natural Gas & Electric IRP (September 2024)**
  - Recorded presentation
  - Daytime comment and question session (12pm to 1pm- PST)
  - Evening comment and question session (6pm to 7pm- PST)

2025 Electric IRP Document

Chapter/Sub Chapter	TAC Date
Executive Summary	October 1, 2024
1. Introduction, Stakeholder Involvement, and Process Changes	October 1, 2024
2. Economic and Load Forecast	September 3, 2024
a. Economic Conditions	
b. Avista Energy & Peak Load Forecasts	
c. Load Forecast Scenarios	
3. Existing Supply Resources	October 1, 2024
a. Avista Resources	
b. Contractual Resources and Obligations	
c. Customer Generation Overview	
4. Long-Term Position	September 3, 2024
a. Regional Capacity Requirements	
b. Energy Planning Requirements	
c. Reserves and Flexibility Assessment	
d. Variable Energy Resource Integration Study	
5. Distributed Energy Resources Options	September 3, 2024
a. Energy Efficiency Potential	
b. Demand Response Potential	
c. Generating and Energy Storage Resource Options and Potential	
d. Named Community Actions	
e. Distributed Energy Resources Study Conclusions	
6. Supply-Side Resource Options	September 3, 2024
a. New Resource Options	
b. Avista Plant Upgrade Opportunities	
c. Non-Energy Impacts	
7. Transmission Planning & Distribution	September 3, 2024
a. Overview of Avista's Transmission System	
b. Transmission Construction Costs and Integration	
c. Merchant Transmission	
d. Overview of Avista's Distribution System	
8. Market Analysis	October 1, 2024
a. Wholesale Natural Gas Market Price Forecast	
b. Wholesale Electric Market Price Forecast	
c. Scenario Analysis	
9. Preferred Resource Strategy	September 3, 2024
a. Preferred Resource Strategy	
b. Market Exposure Analysis	
c. Avoided Cost	
10. Portfolio Scenarios	October 1, 2024
a. Portfolio Scenarios	
b. Market Scenario Impacts	
11. Washington Clean Energy Action Plan (CEAP)	September 3, 2024
a. Decision Making Process	
b. Resource Need	
c. Resource Selection	
d. Customer Benefit Indicators	
12. Action Plan	October 1, 2024

Appendix

Chapter/Sub Chapter	Proposed Completion Draft
TAC Presentations *(Already Available)*	January 2, 2025
Work Plan *(Already Available)*	January 2, 2025
AEG EE/DR Potential Assessment	September 3, 2024
10-year Transmission/Distribution Plan	?
Transmission Generation Integration Study	September 3, 2024
DER Study	September 3, 2024
Public Input and Results Data *(Already Available)*	October 1, 2024
Confidential Inputs and Models	January 2, 2025
Historical Generation Operation Data (Confidential)	January 2, 2025
New Resource Transmission Table	January 2, 2025
Resource Portfolio Summary	October 1, 2024
Washington State Avoided Costs	January 2, 2025
Public Comments	January 2, 2025

2025 Electric Integrated Resource Plan

Draft Preferred Resource Strategy

James Gall & Mike Hermanson

Technical Advisory Committee Meeting No. 10

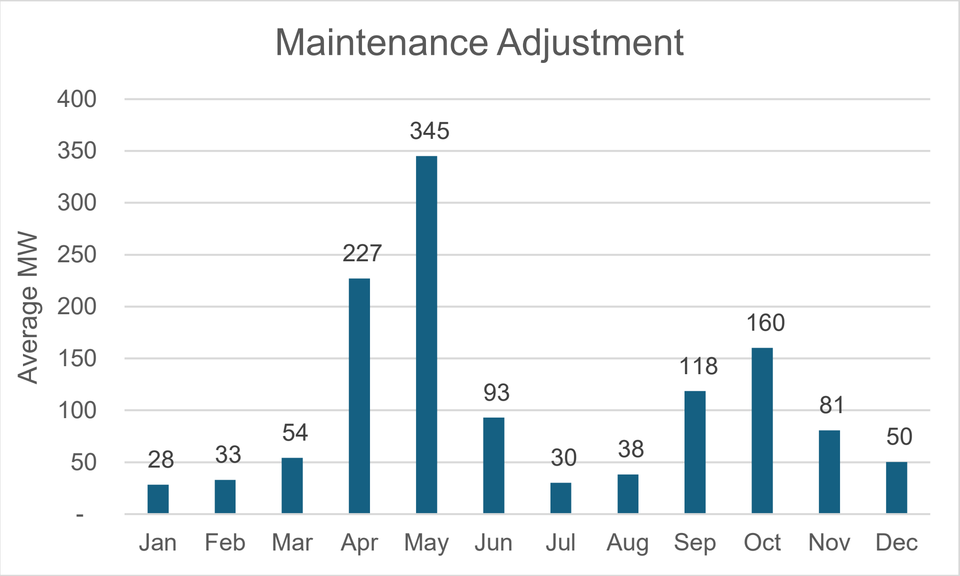
July 16, 2024

LOLP Study Update

- During subsequent analysis after the June 4, 2024 TAC Meeting it was determined some industrial loads were double counted – both in the hourly load model that is an input to the reliability model and the reliability model itself
- The net result of this correction reduces the quantity of dispatchable generation to reach our LOLP Standard of 0.05

Metric	50 MW Additional Dispatchable Gen – Draft Presented June 4, 2024	Updated LOLP with corrected industrial loads
LOLP	10.4%	5.0%
LOLE	0.32	0.1
LOLH	3.66	1.56
LOLEV	0.83	0.333
EUE (with reserves)	783	268.4
EUE (without reserves)	768	256
Implied Planning Margin	23.8%	23.8%

Resource Adequacy Assumptions



- Winter PRM: 24% (was 22%)
  - Uses 5% LOLP and 330 MW of market
- Summer PRM: 16%
  - Based on single largest contingency
- Maintenance adder
  - Idea is to include adjustment to L&R position for units likely to be taken on maintenance
  - Averages actual maintenance 2014-2024 & forecast 2025-2045 schedules
    - History shows significant outages in winter months, forecast does not- this splits history and the forecast.
  - Weighted average of outages (% of month x QCC)

Resource Position

Monthly Peak Hour Position

Capacity	1	2	3	4	5	6	7	8	9	10	11	12
2026	(40)	108	288	369	243	136	9	(22)	271	247	153	4
2027	(3)	146	333	429	306	198	65	33	327	296	194	44
2028	(2)	140	324	424	305	192	47	27	315	292	189	37
2029	2	157	333	428	309	191	63	44	337	301	197	53
2030	(55)	90	267	358	266	130	(3)	(33)	264	246	131	(15)
2031	(62)	86	268	360	265	122	(11)	(39)	276	245	132	(14)
2032	(71)	77	254	350	264	99	(17)	(50)	256	234	118	(28)
2033	(107)	41	219	318	232	111	(25)	(58)	257	204	80	(69)
2034	(230)	(76)	105	210	136	14	(117)	(150)	159	99	(25)	(183)
2035	(225)	(76)	102	209	130	33	(128)	(155)	152	98	(24)	(183)
2036	(236)	(83)	99	201	126	10	(132)	(162)	138	90	(35)	(191)
2037	(297)	(139)	46	154	84	(24)	(175)	(207)	120	45	(85)	(246)
2038	(365)	(201)	(13)	102	36	(87)	(234)	(258)	68	(10)	(151)	(316)
2039	(398)	(231)	(43)	78	7	(116)	(277)	(303)	45	(39)	(178)	(348)
2040	(473)	(303)	(107)	19	(41)	(189)	(343)	(375)	(17)	(96)	(245)	(417)
2041	(525)	(351)	(157)	(27)	(72)	(197)	(381)	(415)	(64)	(138)	(290)	(474)
2042	(838)	(666)	(471)	(263)	(276)	(471)	(657)	(695)	(326)	(426)	(604)	(789)
2043	(910)	(736)	(538)	(324)	(326)	(494)	(684)	(721)	(367)	(481)	(665)	(858)
2044	(992)	(814)	(612)	(388)	(383)	(553)	(741)	(787)	(408)	(548)	(741)	(935)
2045	(1,291)	(1,115)	(904)	(674)	(574)	(792)	(996)	(1,032)	(652)	(813)	(1,033)	(1,246)

Monthly Energy Position

Energy	1	2	3	4	5	6	7	8	9	10	11	12
2026	(26)	22	170	345	706	518	173	74	198	170	59	16
2027	(4)	48	199	372	753	556	220	129	251	213	90	50
2028	(10)	89	199	365	747	553	213	123	252	217	93	45
2029	7	81	224	392	763	566	215	118	256	225	102	61
2030	10	79	225	385	757	564	212	117	251	225	100	62
2031	13	89	234	388	771	581	225	120	261	226	103	66
2032	17	134	240	396	771	582	217	118	254	225	97	65
2033	11	95	242	390	768	573	208	108	250	223	100	64
2034	(48)	56	194	334	698	511	155	56	207	181	40	5
2035	(69)	46	184	328	692	501	142	41	191	164	27	(2)
2036	(80)	80	175	316	680	486	127	29	179	151	6	(25)
2037	(95)	30	160	297	668	474	113	11	167	144	(10)	(39)
2038	(114)	10	138	280	641	441	67	(20)	145	122	(28)	(63)
2039	(133)	(1)	127	262	625	421	46	(39)	134	108	(41)	(78)
2040	(168)	(13)	81	216	581	355	(11)	(96)	83	55	(85)	(147)
2041	(250)	(141)	9	139	513	274	(106)	(176)	12	(15)	(163)	(220)
2042	(527)	(407)	(250)	(39)	332	91	(370)	(431)	(246)	(271)	(419)	(494)
2043	(587)	(468)	(319)	(108)	281	38	(424)	(482)	(296)	(326)	(488)	(568)
2044	(619)	(450)	(346)	(136)	259	11	(462)	(513)	(318)	(346)	(513)	(600)
2045	(866)	(733)	(578)	(310)	101	(143)	(672)	(725)	(533)	(565)	(744)	(836)

Northeast “retire”

Market is allowed to meet this target

Propose waiver for RFP requirement

Preferred Resource Strategy (Sent out on July 10th)

Nameplate MW	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Shared System Resource																				
Mrkt/Trans	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas	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	0
Wind	0	0	0	0	0	100	100	200	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	25	0
PtoG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	10	0
RNG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Washington																				
Mrkt/Trans	40	4	10	0	0	0	0	0	0	0	0	50	0	0	50	50	50	50	0	50
Natural Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	0	1	1	1	1	1	101	1	1	1	1	0	1	1	1	1	1	1	183	1
Wind	0	0	0	200	200	100	0	0	0	0	0	0	0	0	0	140	0	120	0	200
Storage	0	0	0	0	0	0	50	0	0	0	0	0	0	0	0	0	0	0	91	62
PtoG	0	0	0	0	0	0	0	0	0	0	0	0	90	0	0	0	195	0	94	0
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	153
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	20
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RNG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Idaho																				
Mrkt/Trans	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas	0	0	0	0	99	0	0	0	0	0	0	91	0	0	0	0	124	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	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	25	0
PtoG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RNG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Preferred Resource Strategy (Updated)

Nameplate MW	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Shared System Resource																				
Mrkt/Trans	40	4	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas	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	0
Wind	0	0	0	0	0	100	100	200	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
PtoG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	10	0
RNG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Washington																				
Mrkt/Trans	0	0	0	0	0	0	0	0	0	0	0	50	0	0	50	50	50	50	0	50
Natural Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	0	1	1	1	1	1	101	1	1	1	1	1	1	1	1	1	1	1	200	5
Wind	0	0	0	200	200	100	0	0	0	0	0	0	0	0	0	140	0	120	0	200
Storage	0	0	0	0	0	0	50	0	0	0	0	0	0	0	0	0	0	0	104	62
PtoG	0	0	0	0	0	0	0	0	0	0	0	0	90	0	0	0	196	0	94	0
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	150
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	20
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RNG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Idaho																				
Mrkt/Trans	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas	0	0	0	0	99	0	0	0	0	0	0	90	0	0	0	0	124	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	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	35	0
PtoG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RNG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Named Community Investment Fund Considerations

- NCIF project spending on future resources size and type is unknown.
- IRP accounts for these potential projects by forcing the model to select excess energy efficiency and DERs
- The table below is the estimated selection assuming
  - $2 million spending on energy efficiency
  - $400k annual credit toward DERs
  - Spending limits increase each year due to inflation

Time Period	Distribution Level Solar	Distribution Level Energy Storage	Energy Efficiency
2026-2035	600 kW/year	Not selected	1,444 MWh/year
2036-2045	900 kW/year	4 MW (2044)	1,150 MWh/year

Long Term Resource Changes

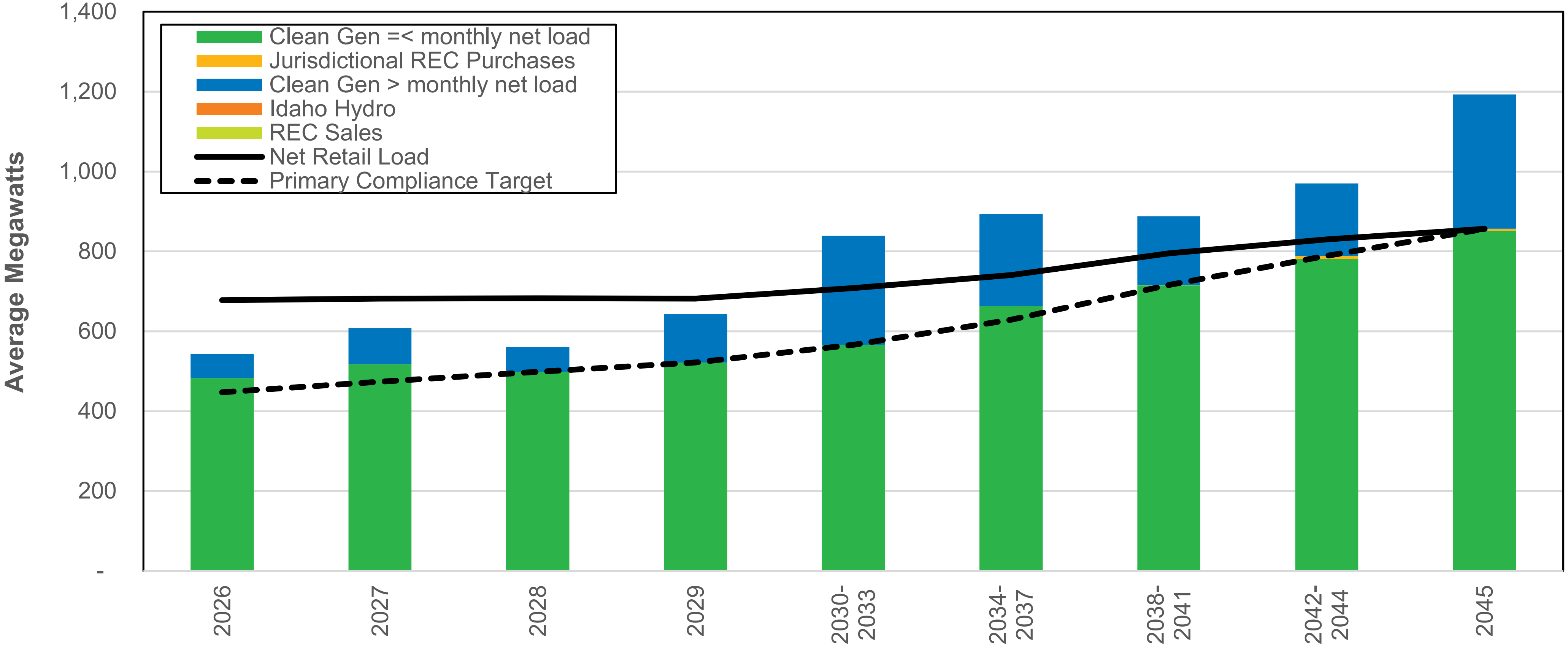
Resource	2026-30	2031-35	2036-40	2041-45	Total
Natural Gas	99	0	90	124	313
Natural Gas Retirements	(64)	0	(36)	(456)	(556)
Thermal Total	**35**	**0**	**55**	**(333)**	**(242)**
Power to Gas CT	0	0	90	196	287
Hydrogen	0	0	0	94	94
Power to Gas Total	**0**	**0**	**90**	**291**	**381**
Northwest Wind	400	300	0	460	1,160
Montana Wind	0	200	0	0	200
Wind PPA Expirations	0	0	(145)	(105)	(250)
Wind Total	**400**	**500**	**(145)**	**355**	**1,110**
Distributed Solar	2	4	3	7	15
Utility Scale Solar	0	100	0	200	300
Solar PPA Expirations	0	0	(20)	0	(20)
Solar Total	**2**	**104**	**(18)**	**206**	**295**
Rate Program	20	7	4	0	31
Direct Load Control	13	20	10	18	61
Demand Response Total	**33**	**27**	**14**	**18**	**92**
Short-Duration Storage (4hr)	0	50	0	104	154
Mid-Duration Storage (8-24 hr)	0	0	0	35	35
Long-Duration Storage (>24hr)	0	0	0	62	62
Energy Storage Total	**0**	**50**	**0**	**201**	**251**
Hydropower	0	0	0	0	0
Hydropower Contract Expirations	(12)	(88)	0	0	(100)
Hydropower Total	**(12)**	**(88)**	**0**	**0**	**(100)**
Regional Transmission	0	0	100	200	300
Nuclear	0	0	0	150	150
Biomass	0	0	0	10	10
Geothermal	0	0	0	20	20
Market	53	0	0	0	53
Other Total	**0**	**0**	**100**	**380**	**480**
All Resource Total	**459**	**593**	**97**	**1,119**	**2,267**
Additions	588	681	297	1,680	3,246
Subtractions	(76)	(88)	(201)	(561)	(926)

PRS Resource Adequacy

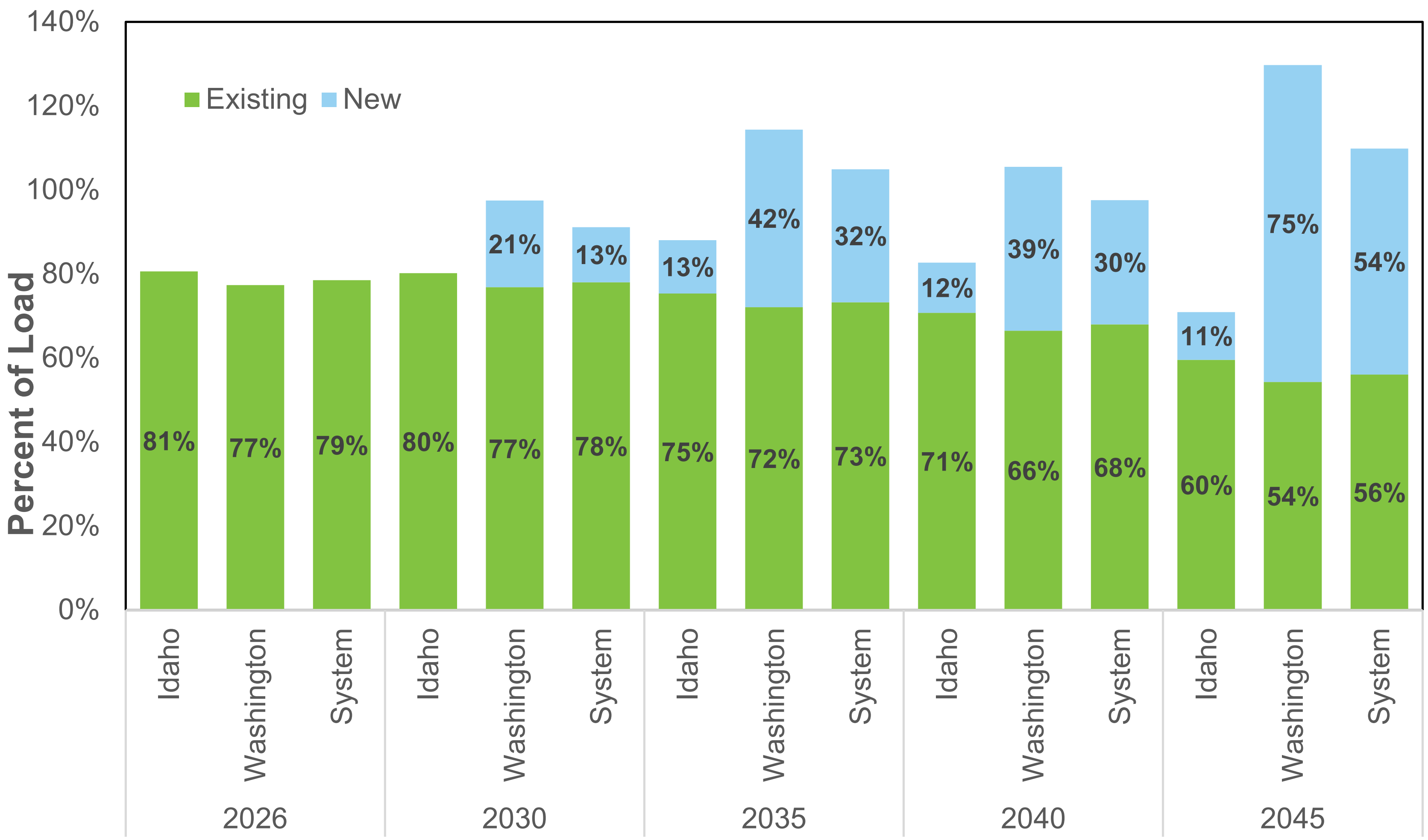
- The PRS for the listed year is used as the resources available along with market purchases and sales, and reliability metrics are calculated.

Metric	2030 PRS	2045 PRS
LOLP	0.5%	2.3%
LOLE	0.01	0.05
LOLH	0.075	0.528
LOLEV	0.019	0.128
EUE (with reserves)	6.7	103.4
EUE (without reserves)	6	103

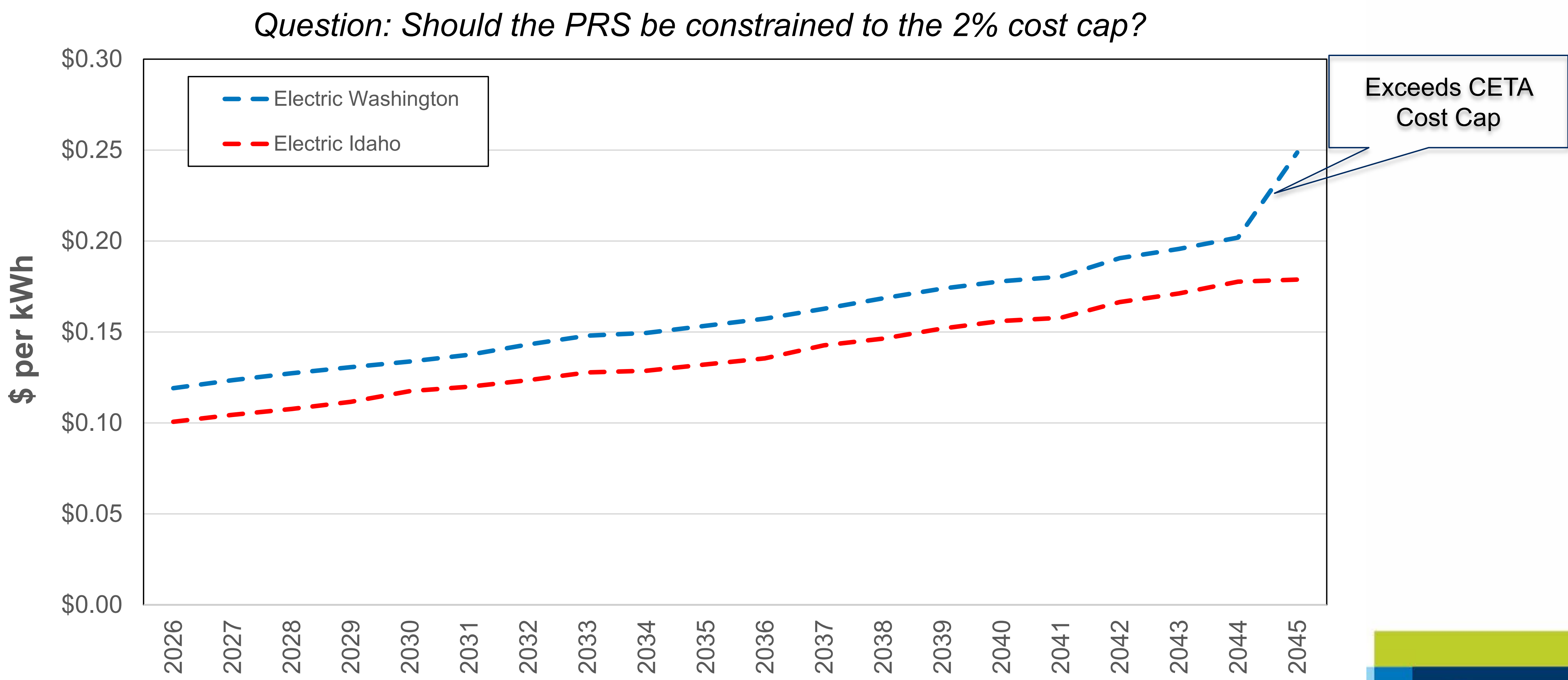
Clean Energy Transformation Act Compliance



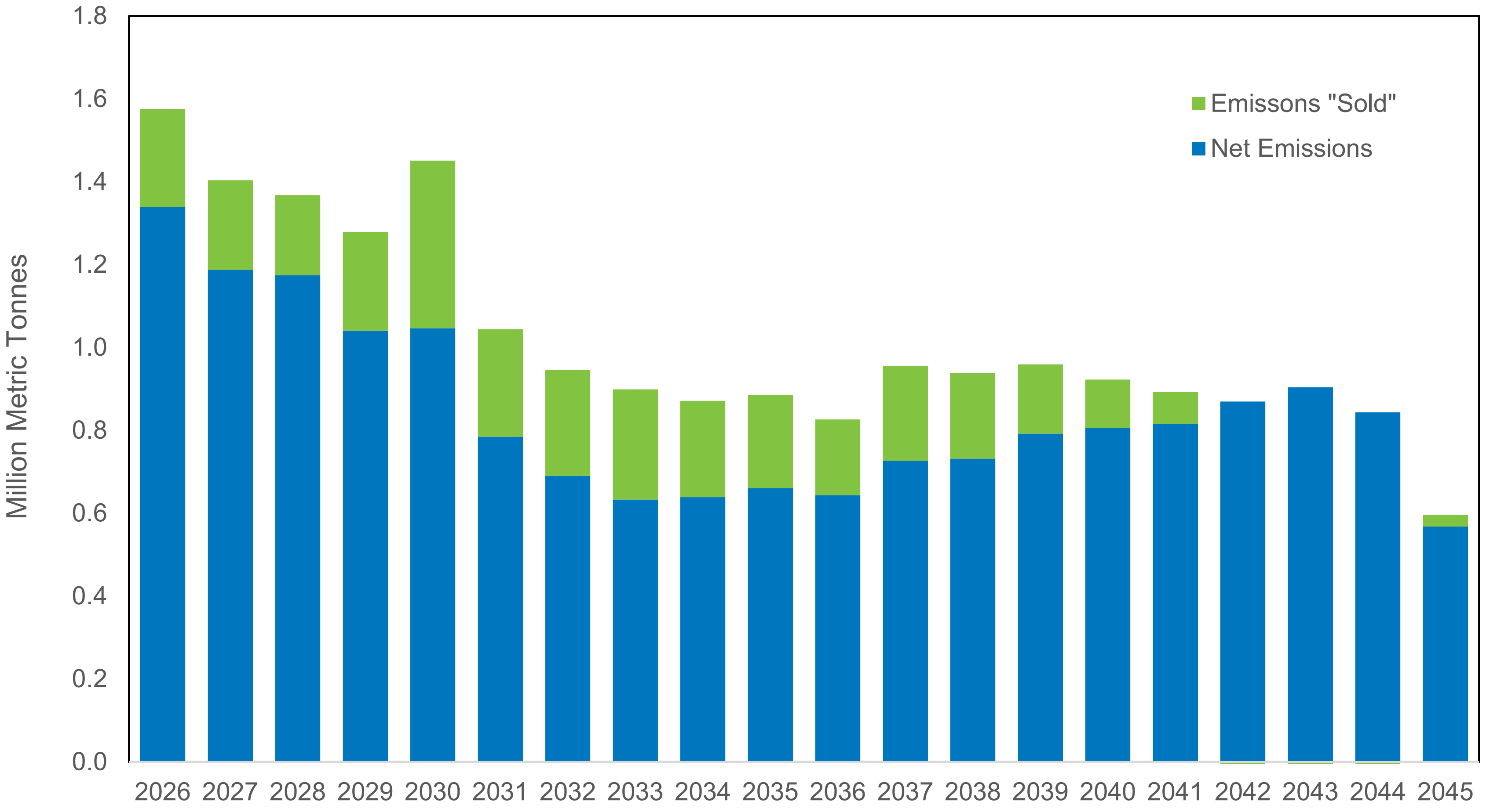
Clean Energy Forecast as Percent of Load



Average Energy Rate Forecast (Nominal)



Net System Greenhouse Gas Emissions



Transmission Considerations

- **Rathdrum Area**: New natural gas CTs begin in 2030, these are likely located in North Idaho, new transmission will be required, if projects continue to be sited in the area additional reinforcement is needed.
- **Off-System Imports:** Need to increase connections to markets/areas to reach additional wind to import by 2045
- **North Plains Corridor**: 300 MW of transmission to MISO/SPP is selected late in the study, this considers capacity value only. If the project has significant energy value, the project could be selected earlier.

Demand Response

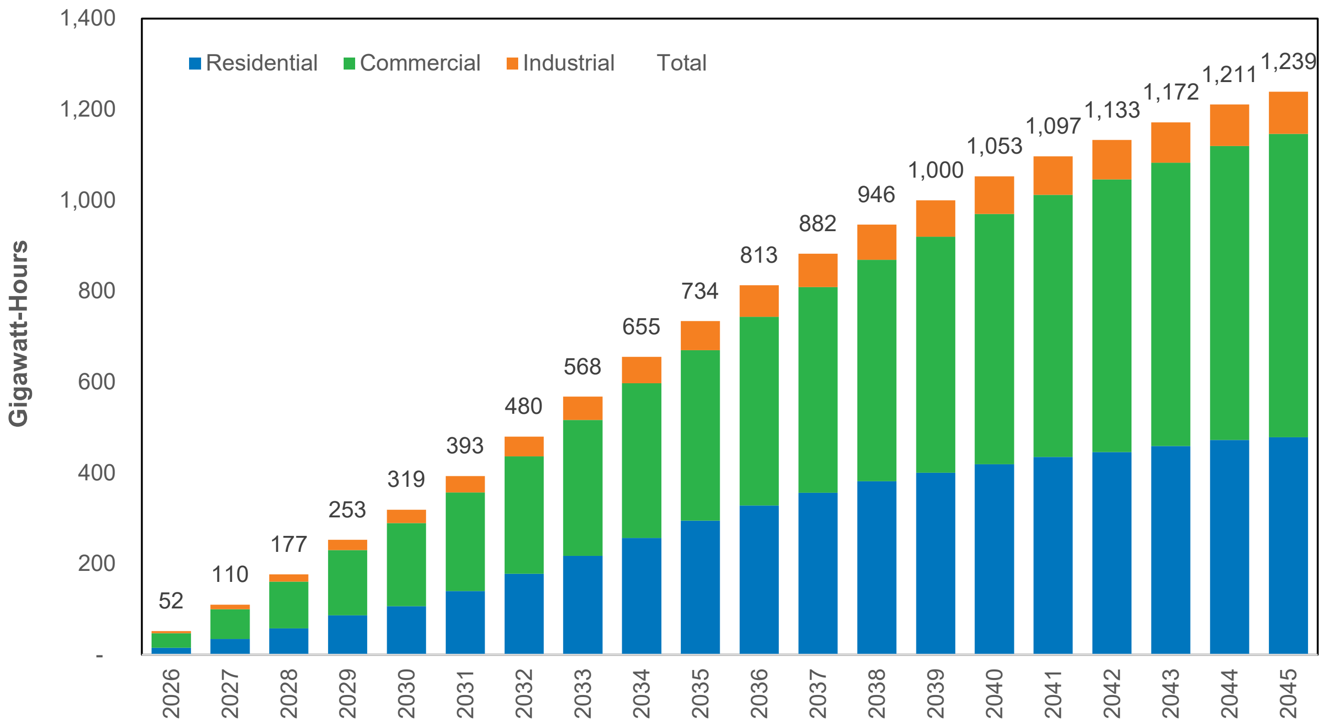
Program	Customer Segment	Washington Start Year	WA: Total Potential	Idaho Start Year	ID: Total Potential
Electric Vehicle TOU	Commercial	2026	8.8	2029	0.9
Battery Energy Storage	All	2026	10.4	2029	2.8
Peak Time Rebate	Residential/Sm. Com.	2026	6.0	2029	4.2
Variable Peak Pricing	Large Commercial	2033	5.4	2031	1.8
Third Party Contracts	Large Commercial	2035	20.0	2040	6.6
Behavioral	Residential/Sm. Com.	2037	1.9	2040	1.3
Time of Use Rates	Residential/Sm. Com.	2039	2.5	2038	1.7
Smart Appliances	Residential/Sm. Com.	2042	2.5		n/a
CTA WH	Residential/Sm. Com.	2042	5.6		n/a
Central A/C	Residential/Sm. Com.	2043	9.8		n/a
		Total MW by 2045	**72.9**		**19.3**

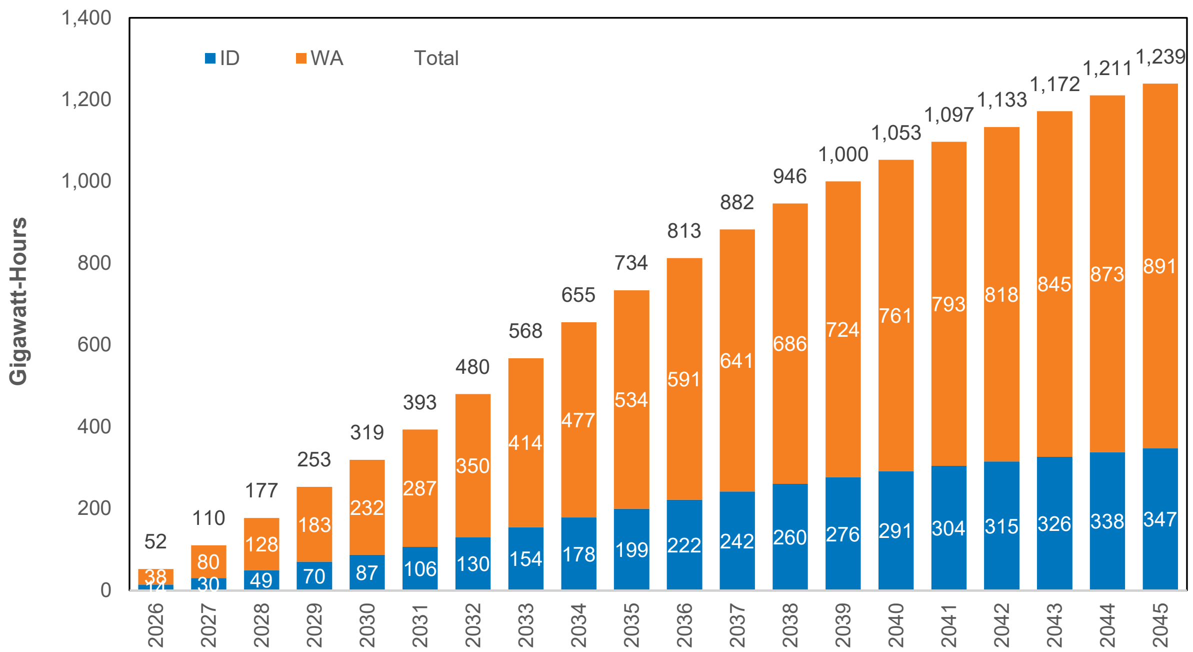
Assumptions:

- Current industrial contract remains
- Idaho AMI by 2029
- Total savings assumes projects do not overlap into other programs

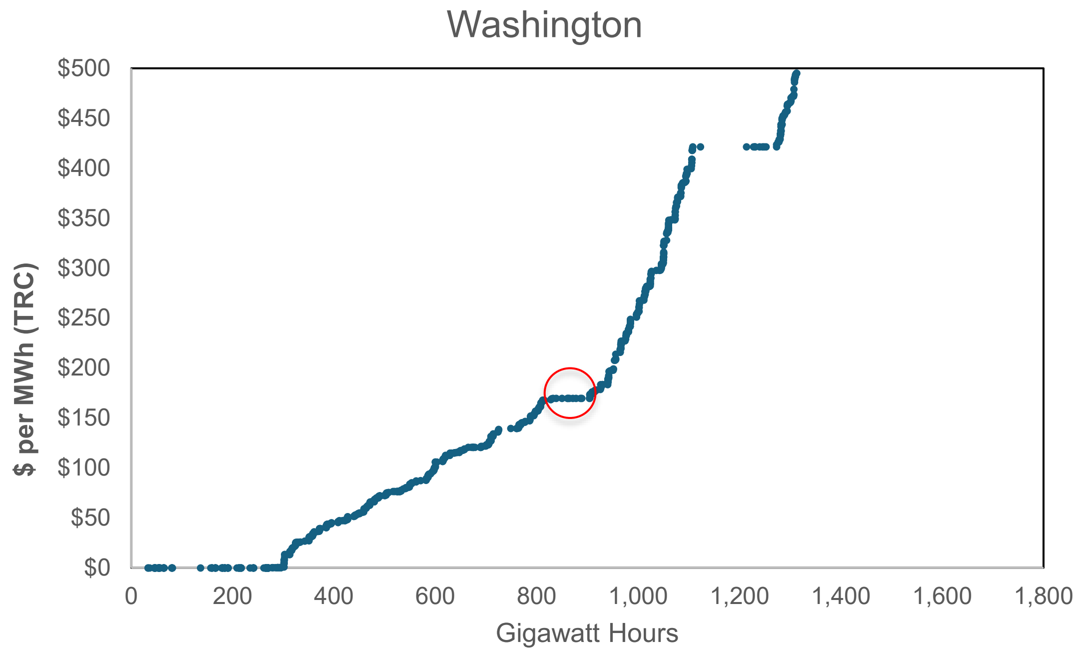
Energy Efficiency By Sector & State

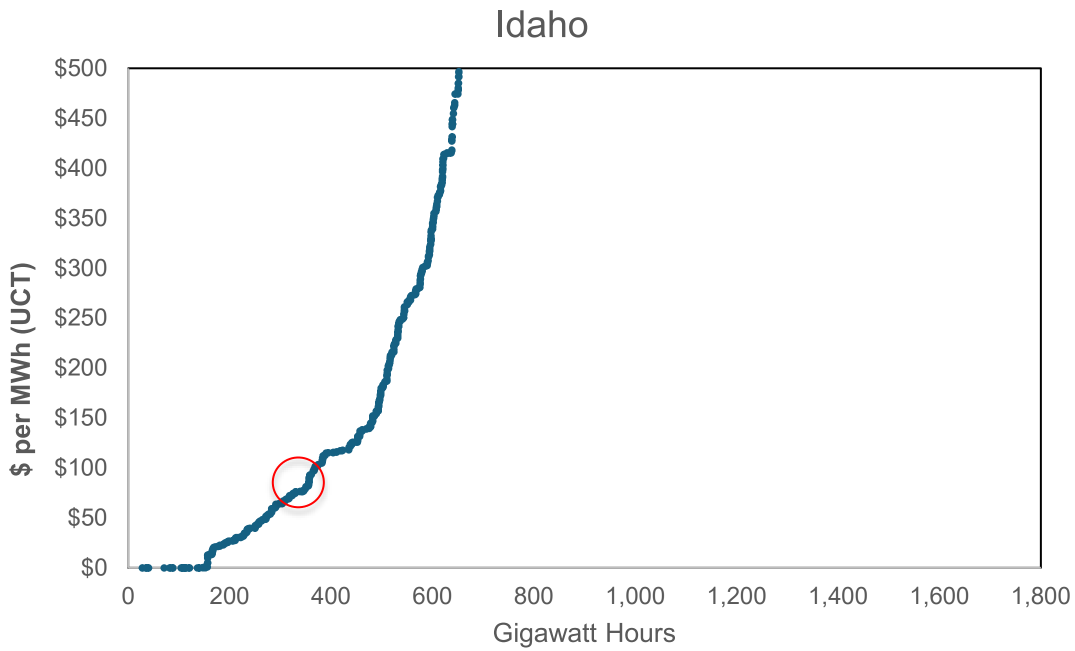
- New energy efficiency meets 9.8% of 2045 system load
- Washington Biannual target to be calculated later





Energy Efficiency Supply Curves (2045)



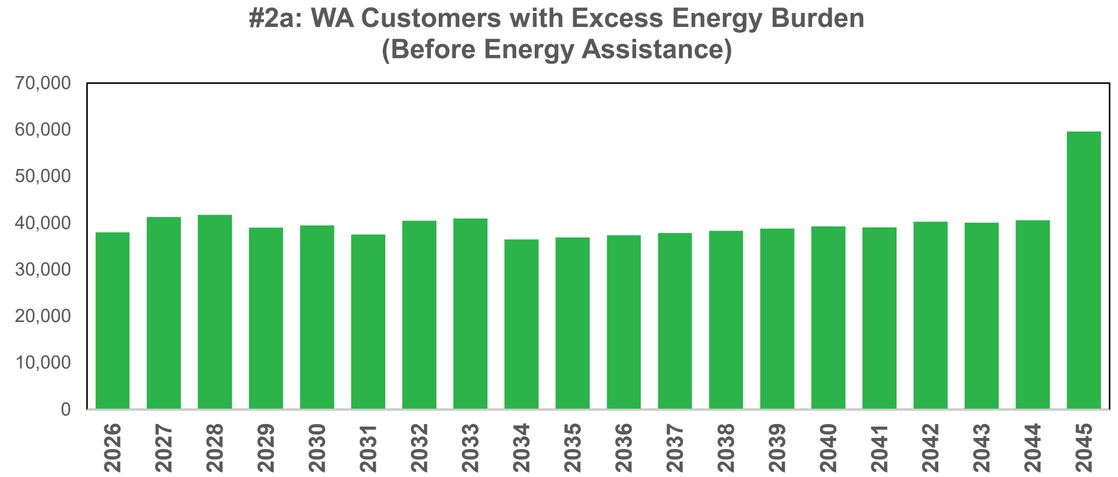


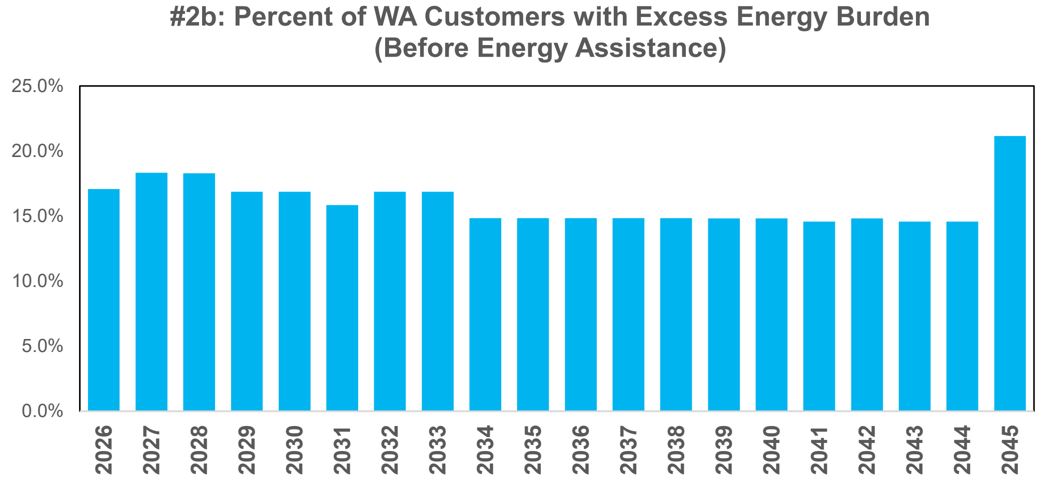
2035 Top Measure Savings (GWh)

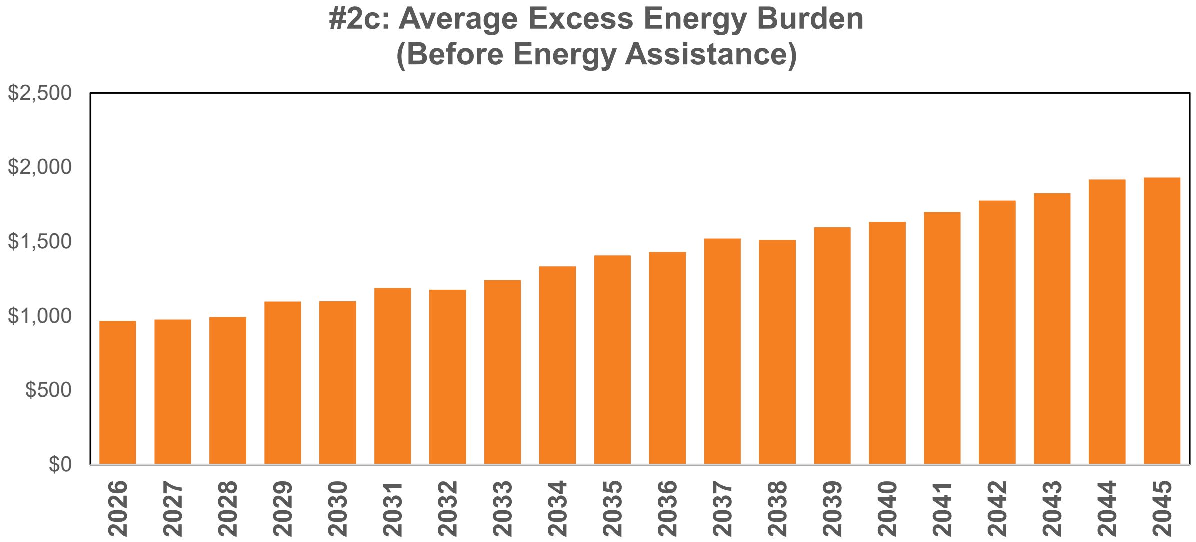
Row	Measure	State	2035
1	Linear Lighting	WA	81.34
2	Windows - High Efficiency (ENERGY STAR 7.0)	WA	27.98
3	High-Bay Lighting	WA	25.00
4	Building Shell - Air Sealing (Infiltration Control)	WA	20.12
5	Water Heater - Pipe Insulation	WA	19.88
6	Insulation - Ducting	WA	19.61
7	Ducting - Repair and Sealing	WA	17.70
8	Engine Block Heater Controls	WA	17.69
9	Ductless Mini Split Heat Pump	WA	17.56
10	Air-Source Heat Pump	WA	16.04
11	Server	WA	14.71
12	Water Heater (<= 55 Gal)	WA	13.69
13	Office Equipment - Advanced Power Strips	WA	10.97
14	Home Energy Reports	WA	10.43
15	Insulation - Ceiling Installation	WA	9.26
16	Ducting - Repair and Sealing - Aerosol	WA	8.66
17	Lodging - Guest Room Controls	WA	8.62
18	Ventilation - Variable Speed Control	WA	8.60
19	Advanced Industrial Motors	WA	7.81
20	Insulation - Wall Sheathing	WA	7.46
21	TVs	WA	6.93
22	Windows - Low-e Storm Addition	WA	6.63
23	Insulation - Ceiling Upgrade	WA	6.26
24	Kitchen Ventilation - Advanced Controls	WA	5.89
25	Personal Computers	WA	5.81

Row	Measure	State	2035
1	Linear Lighting	ID	43.34
2	High-Bay Lighting	ID	12.70
3	Engine Block Heater Controls	ID	11.05
4	Insulation - Ducting	ID	8.04
5	Water Heater - Low-Flow Showerheads	ID	7.58
6	Ducting - Repair and Sealing	ID	6.75
7	Water Heater - Pipe Insulation	ID	5.97
8	Insulation - Ceiling Installation	ID	5.96
9	Ducting - Repair and Sealing - Aerosol	ID	5.00
10	Air-Source Heat Pump	ID	4.91
11	Lodging - Guest Room Controls	ID	4.69
12	Personal Computers	ID	4.40
13	Windows - Low-e Storm Addition	ID	4.34
14	Ventilation - Variable Speed Control	ID	4.27
15	Home Energy Reports	ID	4.24
16	Grocery - Display Case - LED Lighting	ID	3.89
17	TVs	ID	3.81
18	Retrocommissioning	ID	3.67
19	Clothes Washer - CEE Tier 2	ID	3.60
20	Fan System - Equipment Upgrade	ID	3.40
21	Refrigeration - High Efficiency Compressor	ID	3.28
22	Advanced New Construction Designs	ID	2.98
23	Kitchen Ventilation - Advanced Controls	ID	2.80
24	HVAC - Energy Recovery Ventilator	ID	2.66
25	Water Heater (<= 55 Gal)	ID	2.59

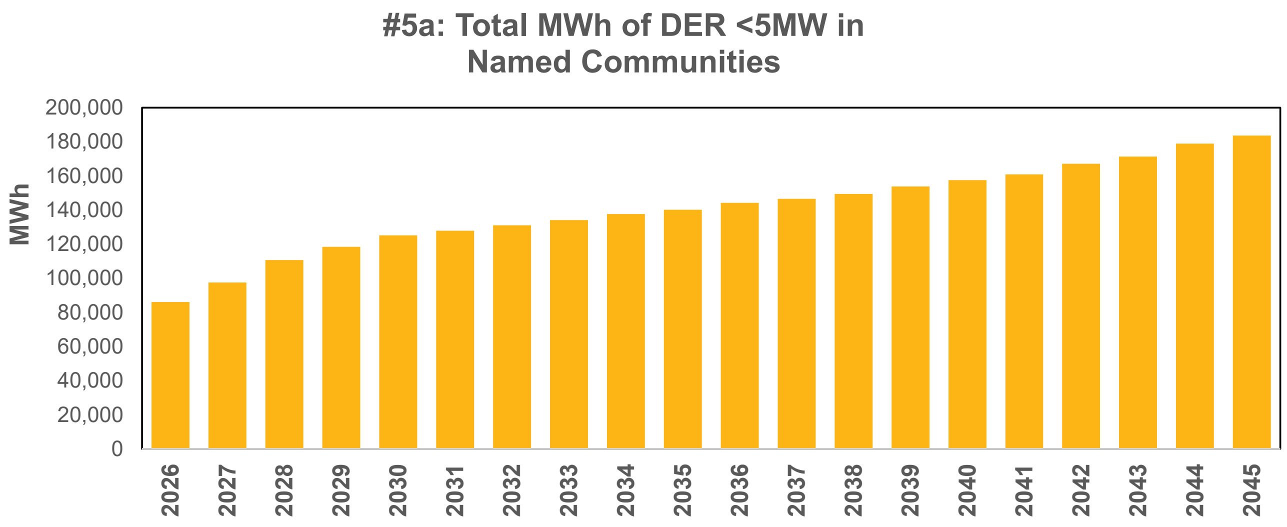
Washington Energy Burden CBI

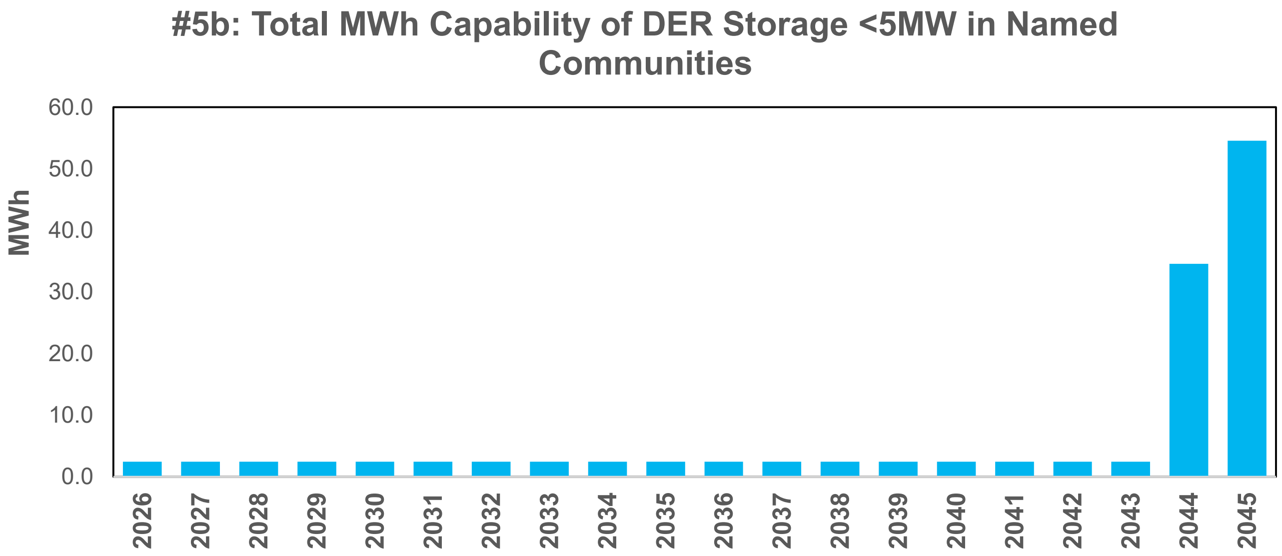




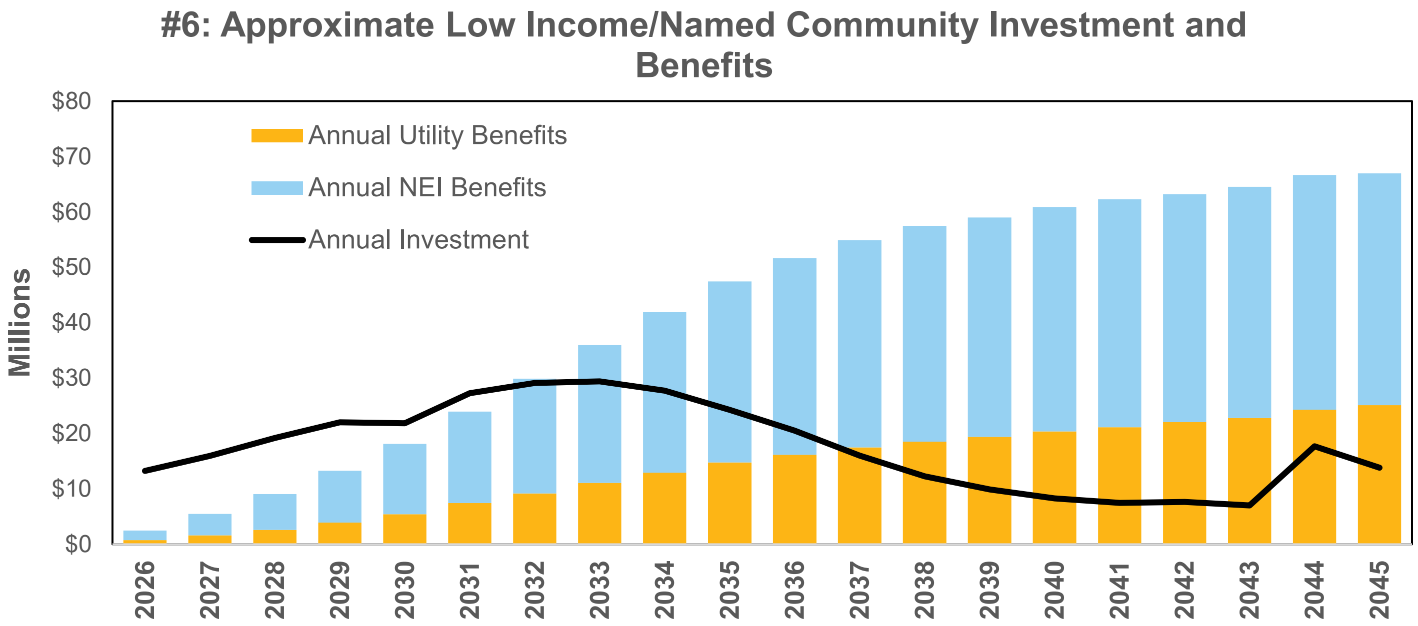


DER Additions CBI

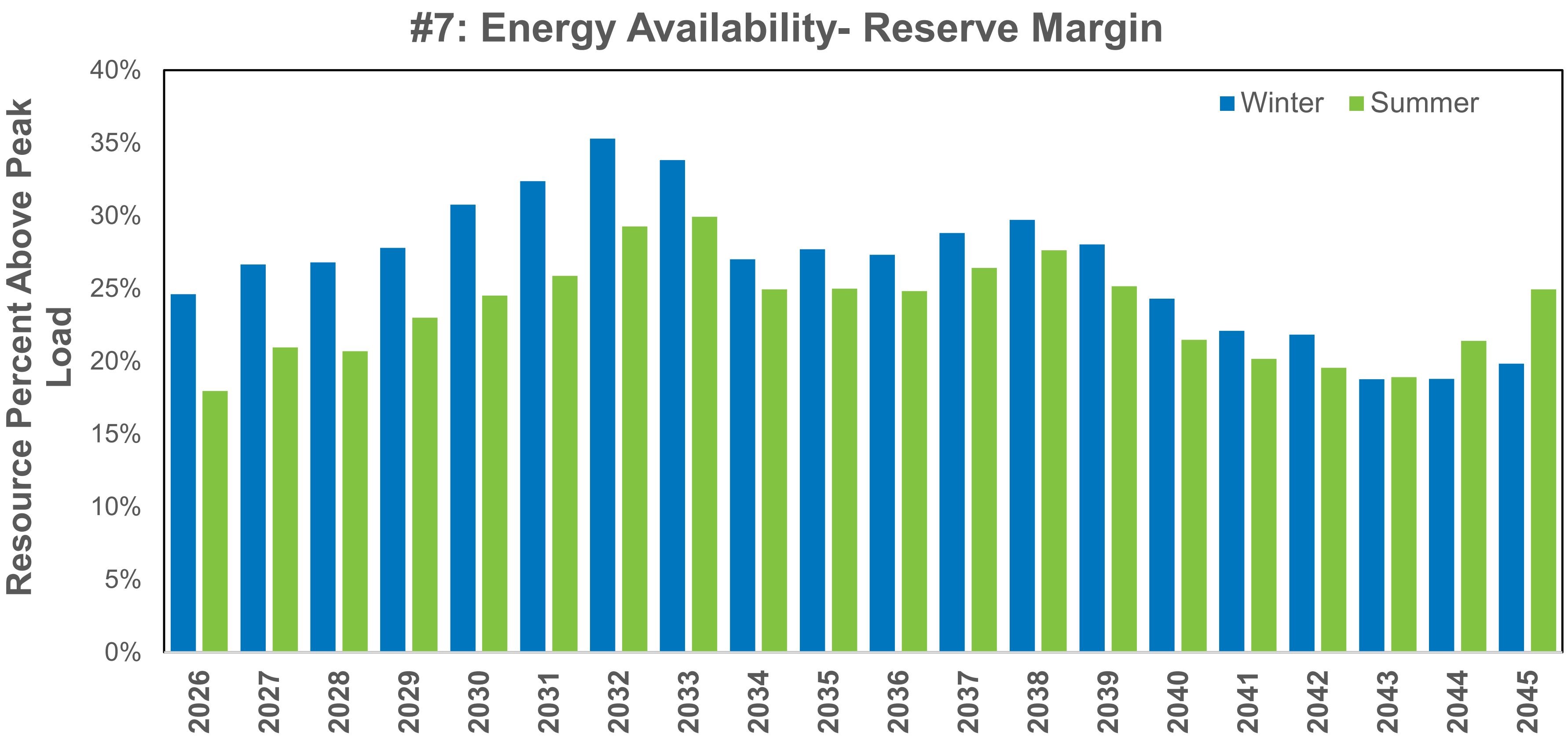




WA Low Income/Named Community Investments CBI

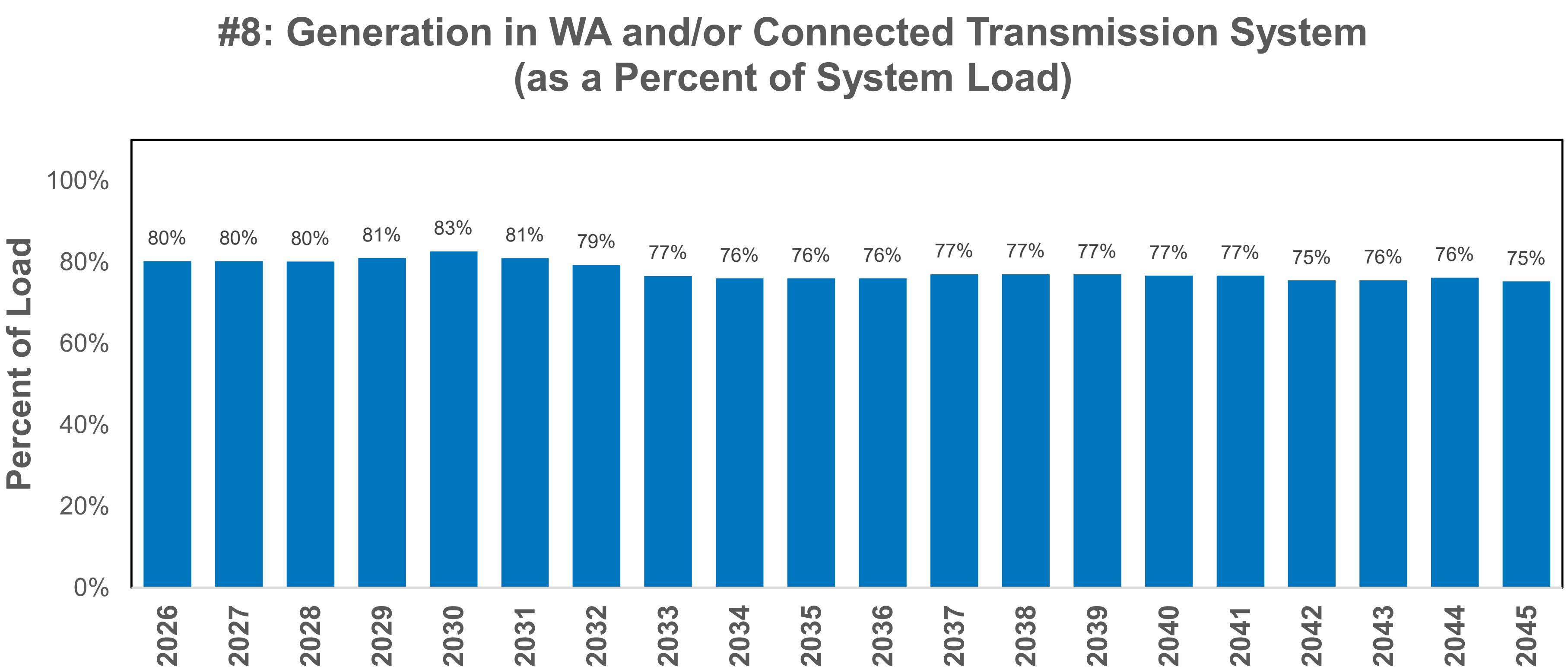


Reserve Margin CBI

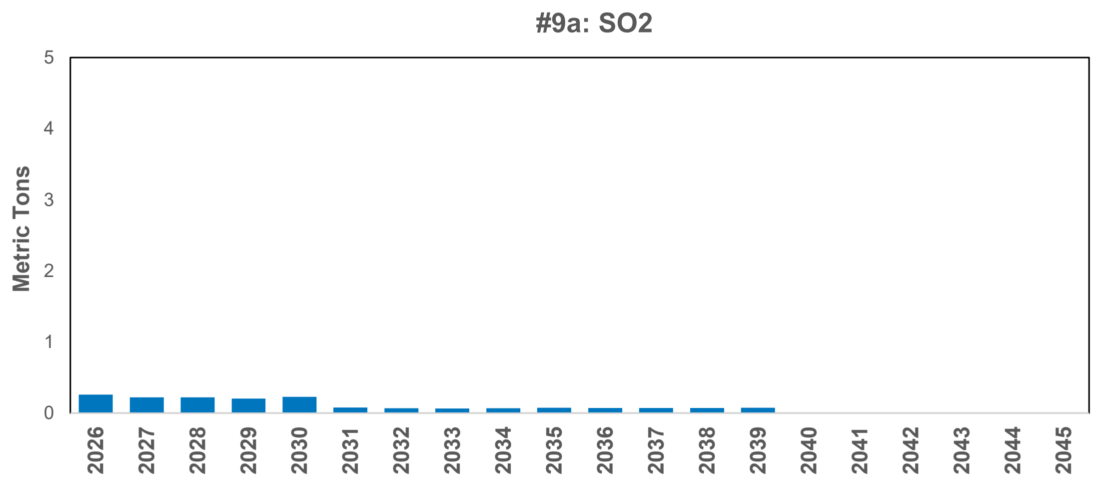


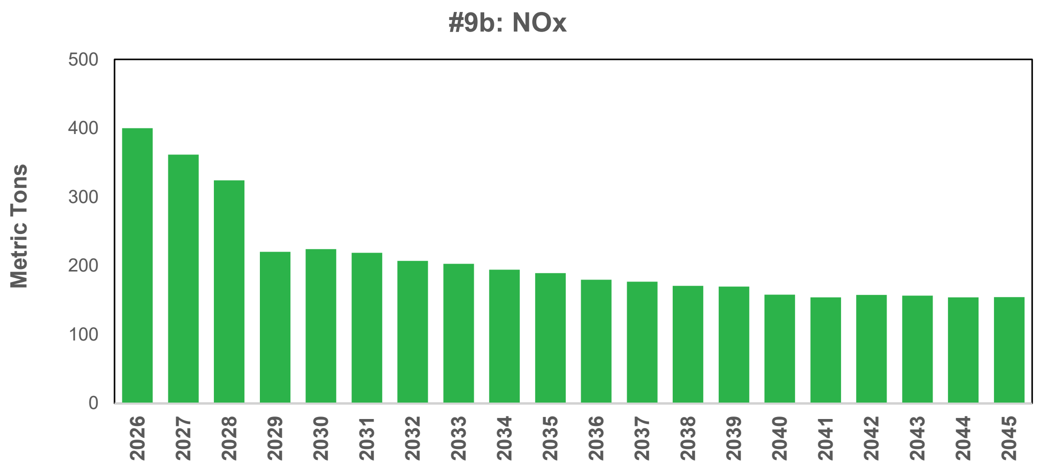
Notes:
- Regional Transmission not included in Reserve Margin
- Demand Response reduced from peak load

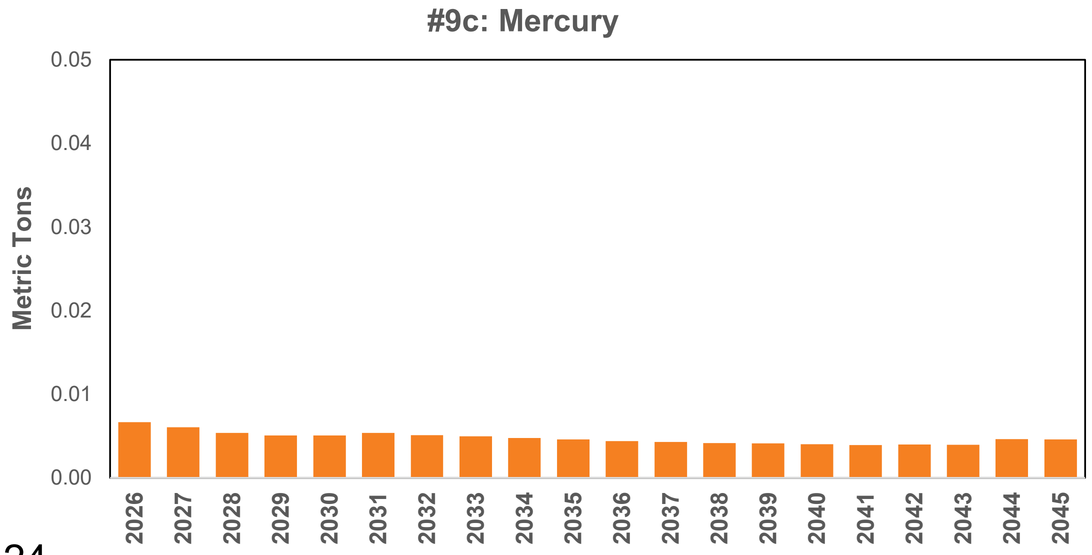
Generation Location CBI

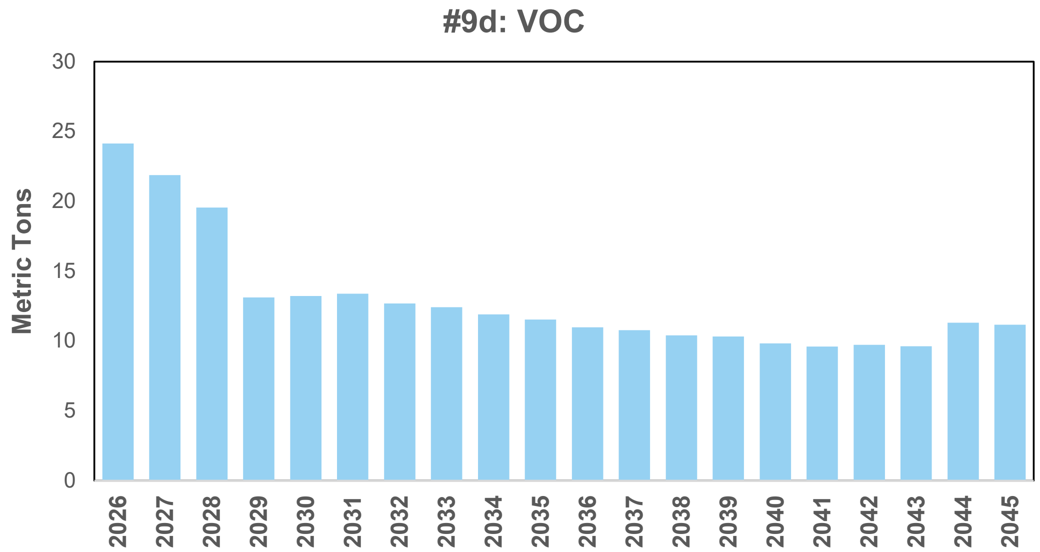


Washington Air Emissions CBI

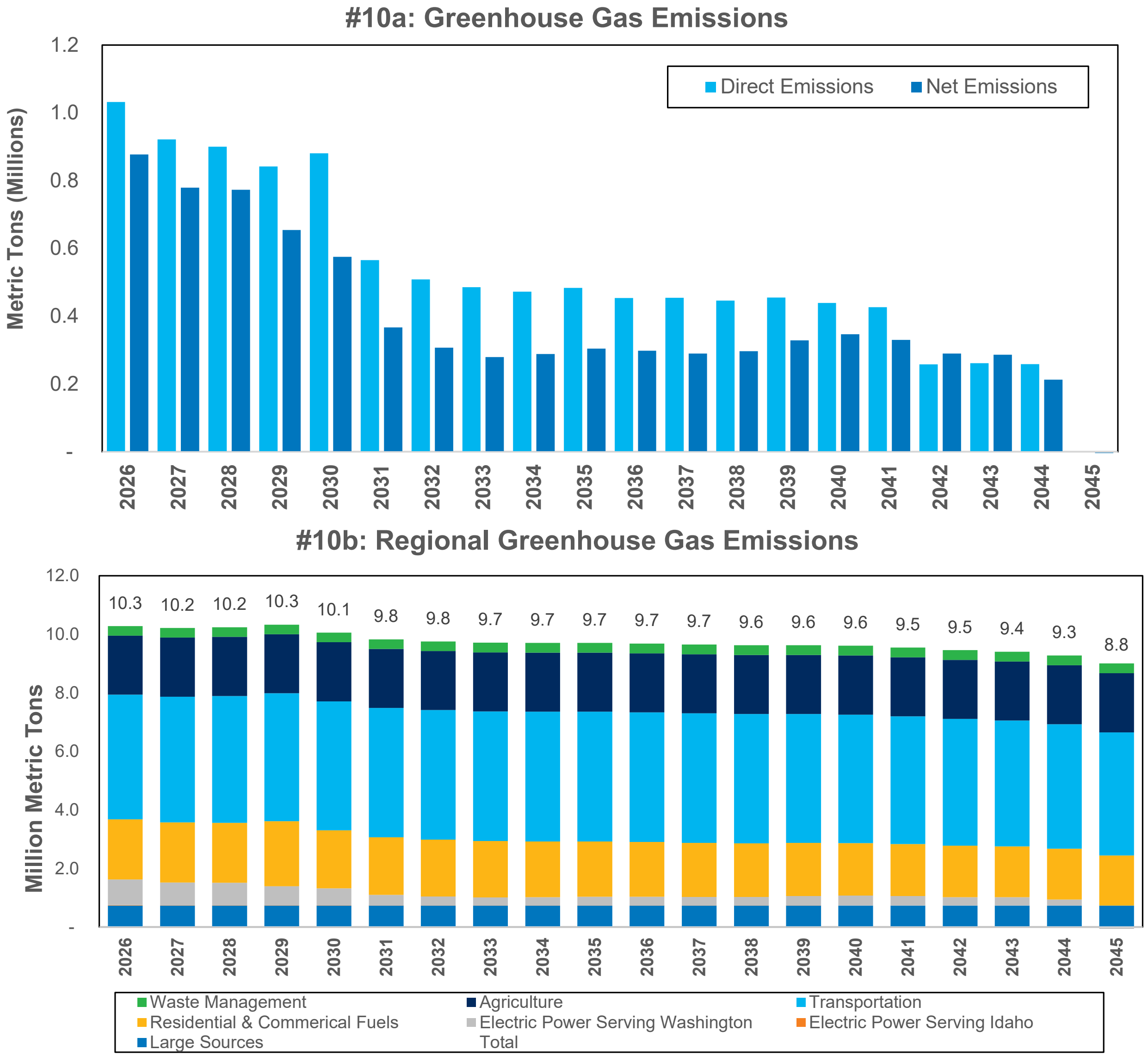




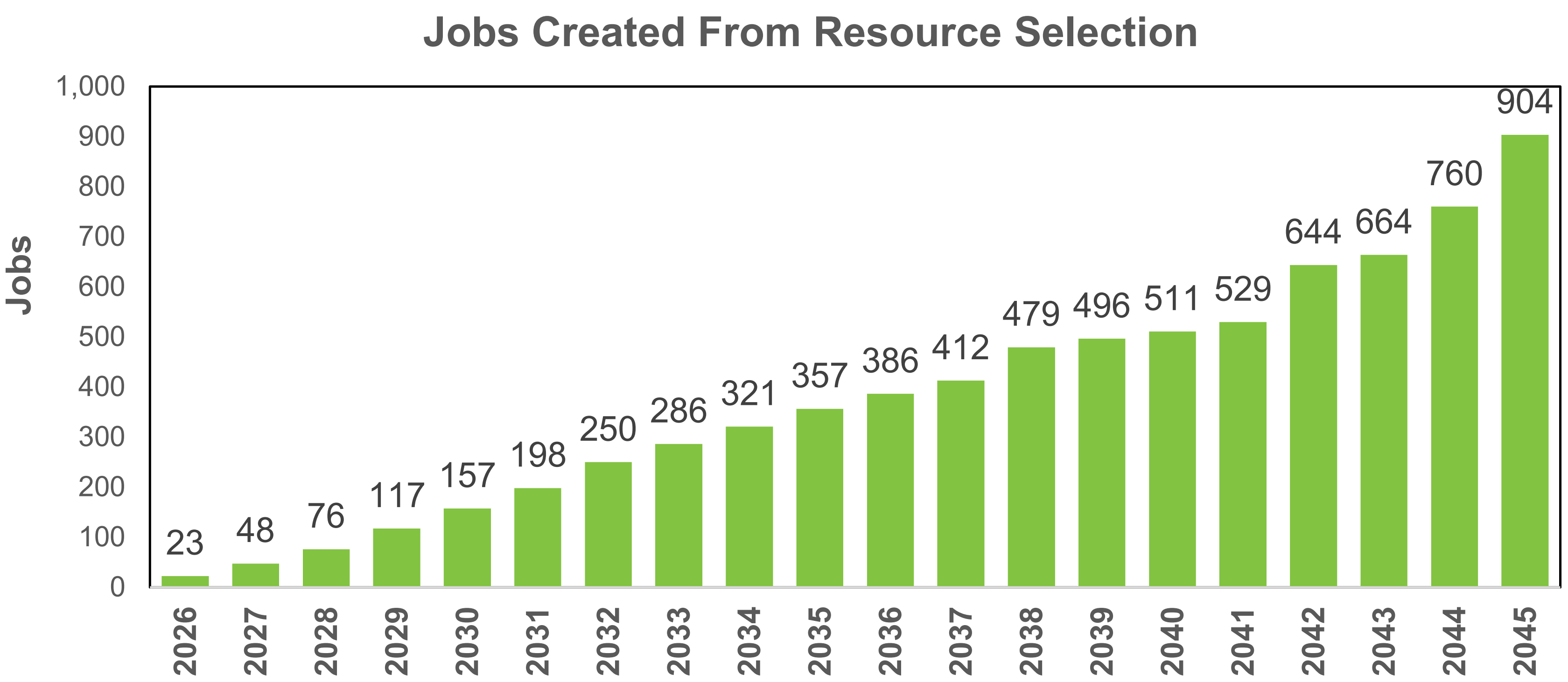




WA Greenhouse Gas Emissions CBI

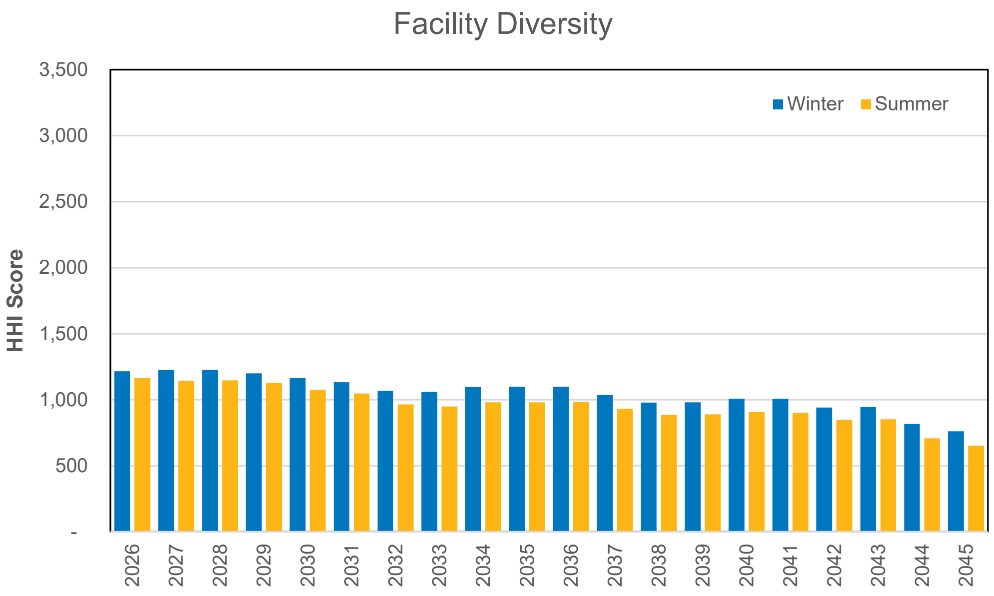


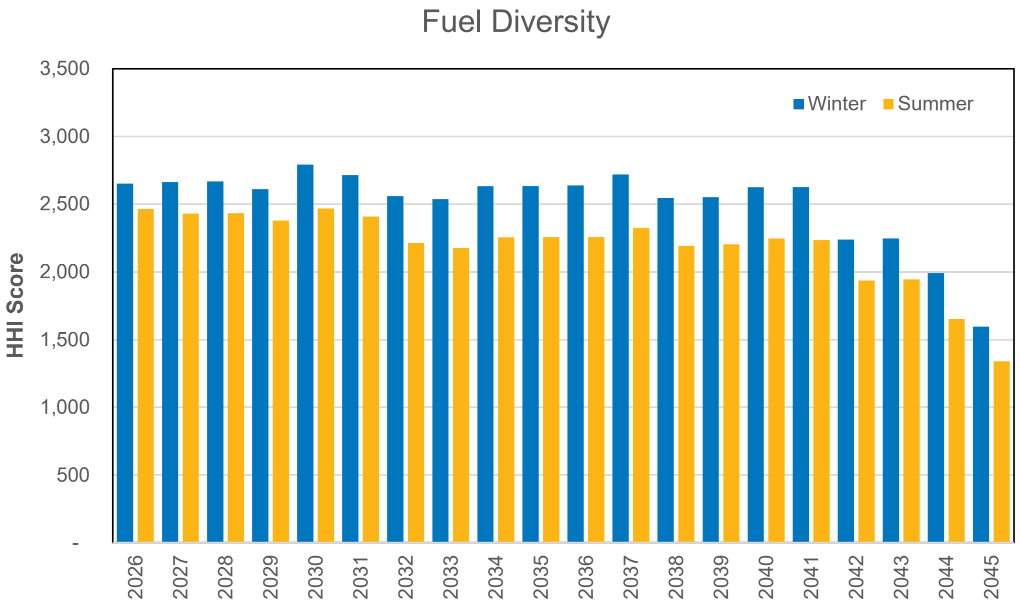
Job Creation (Direct and Induced)



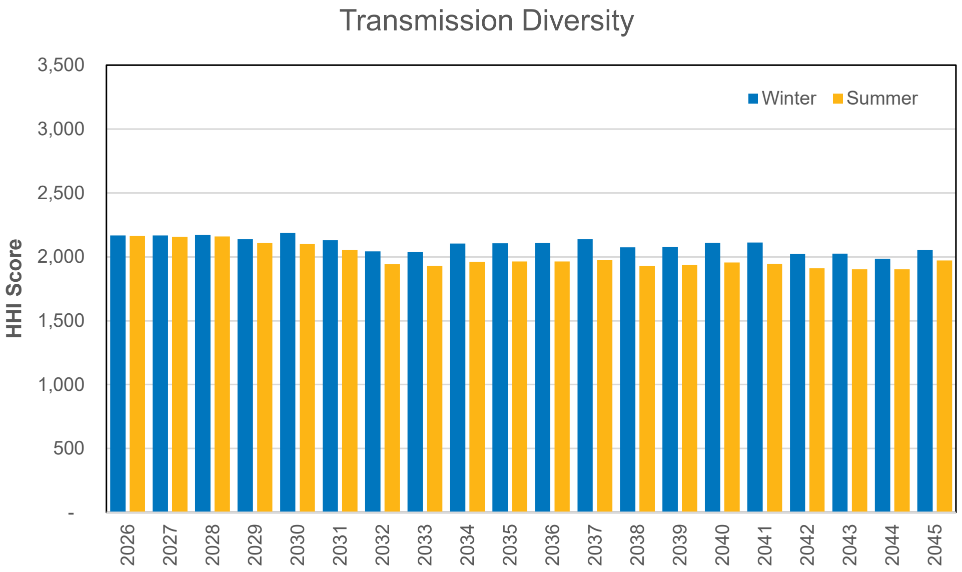
Job estimates based on spending to job relationship today using INPLAN

Resource Diversity (Resource Resiliencv Metrics)





Score	Metric Meaning
<1,500	Competitive Marketplace
1,500-2,500	Moderately Concentrated
>2,500	Highly Concentrated



Avista 2025 Electric IRP
TAC 10 Meeting Notes
July 16, 2024

Attendees:
Sofya, Atitsogbe, UTC; John Barber, Customer; Shawn Bonfield, Avista; Kim Boynton, Avista; Michael Brutocao, Avista; Logan Callen, City of Spokane; Katie Chamberlain, Renewable NW; Kelly Dengel, Avista; Joshua Dennis, UTC; Mike Dillon, Avista; Michele Drake, Avista; Jean Marie Dreyer, Public Counsel; Michael Eldred, IPUC; Rendall Farley, Avista; Ryan Finesilver, Avista; Damon Fisher, Avista; Grant Forsyth, Avista; James Gall, Avista; Bill Garry; Konstantine Geranios, UTC; Leona Haley, Avista; Jared Hansen, Idaho Power; Lori Hermanson, Avista; Mike Hermanson, Avista; Fred Heutte, NW Energy Coalition; Erin Heuvel, Avista; Annu John, Fortis; Erik Lee, Avista; Seungjae Lee, IPUC; Kimberly Loskot, IPUC; Mike Louis, IPUC; John Lyons, Avista; Ana Matthews, Avista; Ian McGetrick, Idaho Power; Heather Moline, UTC; Molly Morgan, UTC; Tomas Morrissey, NWPCC; Austin Oglesby, Avista; Kaitlyn Olson, PSE; Tom Pardee, Avista; Meghan Pinch, Avista; Jared Schmautz, Avista; Xin Shane, Avista; John Calvin Slagboom, WSU; Nathan South; Darrell Soyars, Avista; Collins Sprague, Avista; Dean Spratt, Avista; Victoria Stephens, IPUC; Briana Stockdale, Avista; Jason Talford, IPUC; Andrea Talty, PSE; Brandon Taylor, PSE; Charlee Thompson, NW Energy Coalition; Tyler Tobin, PSE; Taylor Vallas, Invenergy; Bill Will, WASEIA; Greta Zink, Avista.

Introductions, John Lyons

John Lyons: Alright, welcome to the 10th TAC meeting. Hopefully everyone had a good time off for the Fourth of July and getting that week off for the meeting here. We have a pretty full schedule today. We're going to be talking all things Preferred Resource Strategy results and then some subtopics on resource adequacy, the Customer Benefit Indicator impact study for Washington and resiliency metrics. Right now we're going to talk a little bit about schedule because we are coming up on when the draft is going to be due fairly soon.

James Gall: Alright, I guess that's my cue to talk about the schedule. We're in the middle of July and we do have a draft due to the TAC and the Commissions on September 1st or the Monday after. We don't think we can get a complete draft done by that time, but we're committing to a schedule that has certain chapters done by the September 3rd timeline and then we'll continue with the rest of the chapters on October 1st. And what's on the screen right now is a list of all the chapters that we provided. Some of the subheadings, and we're going to provide this document to the TAC after the meeting, it'll be included in the slide deck, but the idea is that chapters. The economic load forecast would be on time. The L&R chapter, distributed energy resource option chapter, which includes energy efficiency and demand response. Supply side options, transmission planning, Preferred Resource Strategy would all be available along with the CEAP. The draft of those on September 3rd and then the remaining chapters would be available by the end of the next month, and also including the Action Plan by the end of the month. Also, we have a number of appendices that we will have different deadlines proposed for when they would be released. Some of those would be available in September, some in October, and then some in January at the normal filing time. I do know we have a draft, or a comments on the draft IRP. There's any comments due back to us on the around the middle of November, I don't anticipate changing that schedule. And then I do know that there's at least Washington has a process for commenting on the draft that will probably occur sometime in December. I'm going to pause there. If there's any thoughts brought up, I know this is maybe a surprise that was not in the slide deck that we sent out last week. OK, not hearing any comments. I think it's maybe a good time to make like, do we have Molly? Yep. Molly, go ahead.

Molly Morgan (UTC): If I was just going to, I'm sorry, appreciate you showing, getting specific about what's coming. We spoke about this already. I think this looks fine. I just wanted to check in about the Work Plan. You note, I think November 15th, as the date that you would want comments back from TAC members. Is that still what you're thinking? I'm just wondering with things coming a bit later, is there going to be flexibility on that. We'll have to fit in an open meeting after that as well.

James Gall: Yeah, that's a good question. I don't think we should change that date just because of the majority of the IRP that is typically, I'd say people question or more controversial is all going to be available. And the expected timeline, I'd say lesser important chapters that are coming later. So, I wouldn't propose the change that.

Molly Morgan (UTC): OK. We would for the open meeting. We'll just have to all coordinate about that early because that'll probably happen sometime early December and that can be a busy time for everybody. Yeah, just flagging that we should.

James Gall: OK.

Molly Morgan (UTC): Yeah. Just start thinking about when we can make that happen.

James Gall: Yeah. We do have, I think two additional TAC meetings on schedule and maybe it would be good on the last TAC meeting if we could have a date locked in. I don't know. Is that too soon? That'd be mid-August. Is that too soon to try to scope that out or should that be later?

Molly Morgan (UTC): That's a good question. I was thinking maybe a little later than that, maybe by sometime in September we could do that, and it'll just let you know depending on if the Commissioners want it as a recessed open meeting, I'm guessing. So, since those December meetings are rather busy already, I think I'd probably shoot for some time in September – ironing that out.

Draft Preferred Resource Strategy, James Gall

James Gall: OK, alright. Any other comments? OK, I don't want to apologize for wanting to not pause too much. We do have a lot of content and I think we're going to have some interesting discussion with the Preferred Resource Strategy. So, let's move to that. We'll pull that up one second here. Hopefully everybody sees this slide. OK. The plan today is to go through what we call our draft Preferred Resource Strategy. It is slightly updated from what we sent out last week. And we're going to show a slide that shows what it was last week, what it is this week, and then we are planning on having another TAC meeting in two weeks. We'll probably show this again, if there's any changes, we'll go through that. But I'm trying to lock this down at the next TAC meeting, so if you have thoughts and comments on this draft, we'd like to hear those today or very shortly thereafter. Let's get started with this. Mikes going to start us off on a recap on resource adequacy and then we'll get to the resource strategy. OK.

James Gall: On June 4th at the TAC meeting, we presented the results of our loss of load probability study and subsequent to that we are doing some rechecking and the process to do this study is kind of a two-step process. We have two different models. We have a model that develops an hourly mode, and we also have the model that does the reliability testing, and in that process we had industrial loads both in the hourly model and then also in the reliability model. And so, it doubled that, so we ended up with basically too much load in our first version. And as you can see, the first column shows what was presented on June 4th. The LOLP was 10.4%, we're aiming at 5% and so we need to add 176 and 167 megawatts of extra dispatchable resources to get that down to 5%. We have now corrected that and got the loads the way they should be. And with that, we only need 50 megawatts of dispatchable generation, and the implied planning margin that we calculate from that is the same. The real difference is that we needed less dispatchable generation to meet that 5% loss of load target and so that was going forward with that and adding. We're now testing the Preferred Resource Strategy and different scenarios through the same process and being attuned to the intricacies of adding our industrial loads in different locations when you're using a multiple model train to get your answer. OK, so let's go to the next slide. And Fred has a question. Fred, go ahead.

Fred Heutte: Fred here at Northwest Energy Coalition. Could you just say what implied planning margin is?

James Gall: I was going to get to that on the next slide.

Fred Heutte: OK, that's fine.

James Gall: Yep. OK. When we run our existing portfolio through our reliability model, the idea is to create a planning margin that we need to include into our PRiSM model. Think of it as we have our existing system, you're comparing that existing system to your future loads, if you're resource deficit, you're adding perfect capacity resources to develop a planning reserve margin. And based on the study that Mike was working on, that planning margin in the winter is 24% last IRP, we're at 22%. And what that means is if you look at our expected load, our 1-in-2 load future, we would add 24% to that and that would cover forced outages, it would cover poor hydro to some extent and would cover extreme loads to some extent. And that assumes we would still rely on 330 megawatts of market. It does not assume that we would never have an outage or be more than 330 megawatts deficit. It just means that in 95% of the cases we could meet 100% of the load. At that level, there's still 5% probability that we would not meet, load or have to buy more than 330 megawatts from the market. In our in our model which we do have out there on our website, we're using 24% for winter planning margin, 16% for the summer. The 16% metric is based on our single largest contingency, which is the Coyote Springs 2 plant, and then we have another adder to that and that is maintenance. That's something we covered in our last TAC meeting, we wanted to include an adder for maintenance. But the one problem we were talking about last time was we don't necessarily know long term when our maintenance is going to occur. We have some idea. We know we're going to try to move schedules during non-peak months, but sometimes we do have to take units out at the peak months.

James Gall: We looked at history and we looked at a forecast as well of the things we know about and we've done some analysis on those outages. That's the chart on the upper right corner on how many megawatts we would be adding to our resource need for those maintenance periods. It's mostly in April, may a little bit in October. We're trying to avoid peak months in the winter and peak months in the summer, but a little bit will likely occur. For our final IRP, our assumptions are going to be again, we're reading this as winter or planning reserve margin 24%, some were 16% and that includes on top of that, a small amount of maintenance in the peak periods.

James Gall: OK, what does that mean for resource needs? These are the table of our resource deficits. But on the left is our peak hour deficit by month and year, and on the right is our energy deficit. Both of these do include adjustments for reserves. On the one on the left, planning reserve margin is included. Now on energy, on the right, we include a contingency reserve for the event of bad water or higher loads or bad production out of our VERs system. What this shows is in 2026, we are deficit 40 megawatts in January and we're deficit 22 megawatts in August. And that shrinks, actually, the next two years because there's a sale contract that we have in 2026 that goes away and that's why we go back to a smaller deficit and then because of these small deficits and the one large deficit, we're proposing to use the market to meet these requirements. In our Preferred Resource Strategy, you'll see there is a market purchase to cover these deficits. And then in 2030 is when we start to see our official long term deficit beginning. And in this case, in the capacity side where in the peak hour position winter is the driving period followed by summer, which is just slightly less deficit in the longer period of times. Energy is a little different story. We do have, or actually barely, even in the winter months, in the summer months in the spring, months where we’re obviously very long on energy position. So, when our model tries to solve for these deficits, it's looking at each month on an energy point of view and a capacity point of view to solve these deficits.

James Gall: And then I just wanted to point out also in 2030, we do expect our first natural gas plant to retire. That's our Northeast Combustion Turbine and we're expecting that to retire in 2030, which is a change from the last time IRP from 2035 to 2030. There is a small probability that it could retire earlier than that depending on its emissions testing that it's undergoing for meeting the air quality requirements in the state of or in the county of Spokane, alright. I'm not going to cover this too much.

James Gall: This is the resource strategy we sent out last week. We did make some changes to the strategy. The big change was moving the market purchase that showed up under the Washington category to the system category and I'll cover that in a second. But I'll just moved up to the new Preferred Resource Strategy. We do have those market purchases, I moved those over to the shared system. The big change in the model from last IRP, or last week to this week, is having the market purchases at least in the short term as a system resource and the previous version of the model that was done by state. I didn't think that was appropriate given that we don't have resource allocation by state right now.

James Gall: The second major change is we put in a credit for DER resources for T&D benefits to the system. That's something we've included in energy efficiency in the past. We thought it was appropriate to include that credit for DER Solar and DER batteries and demand response, so those changes do have an effect on the Preferred Resource Strategies around $28.00 per kilowatt-year. And the resulting change was that is a little bit more demand response and a little bit more distributed solar. Some of those occur later in the study. It’s not a big impact early on, so how this Preferred Resource Strategy works is on the top there's a table that we call shared system resources. These are resources that are picked for both states and we would allocate that capacity or that energy between each state using our existing PT ratio, which is around 65% Washington and 35% Idaho. The bottom two tables show resources that are specifically picked for Washington or for Idaho. But just a caveat, this is somewhat of a pretend land of what is driving the resource. When we actually get to cost recovery and how resources are allocated and real life. Right now, we are still under a PT ratio resource allocation. We do not split our resources up by state at this time. Now, that doesn't mean we won't in the future, but as of now, that is not the case. But we're just trying to illustrate which states are the drivers for the resources and which states and which resources really make sense for both systems.

James Gall: Starting with Washington, actually I'm going to back up, starting with the shared system where we have the market resources which we covered. There are around 400 megawatts of wind generation that occurs in that 2031 - 2033 period. And that follows the Washington wind that you see a little bit earlier on the wind resources and somewhat solar. What we're finding in this version of the IRP is the ITC and the PTC are driving selections early before need. So, when the PTC and ITC go away in 2033 is what our model assumes. I don't know if it will or not, but the model sees an opportunity to get lower cost for renewables. The model is picking as much wind and solar as it can prior to building major transmission systems. That is why we see so much wind early in the study. We did limit the amount of wind per year to 200 megawatts, otherwise it would try to build all the wind at one time, which didn't seem practical to us. We're assuming a layering on of wind in this resource strategy beginning in 2029 ending in 2033, but that will be solely dependent on what can be acquired in the future with a minimal transmission cost. If we reran this model with less when available at cheaper interconnection cost, it would probably pick less. There is from a future operational point of view, this strategy could change depending upon what resources are really available when we go out to bid.

James Gall: The last resource to cover on the shared resources is a 10 MW biomass later on in the time period that is really related to Kettle Falls. You might recall in prior IRP's we had a 10 MW upgrade. Earlier on we worked with a third party to get that done, that's ended, and we really don't see that as an upgrade opportunity in the short run. But in the longer run, when we're looking at repowering that plant at some point in the future, we likely to see an upgrade there so that's what the 10 megawatts at the end of the period is. Moving to Washington, the near-term selections are solar and distributed energy resource solar, and what this really is related to is one part of the Named Community Fund and one part community solar where tax credits are available for community solar. We also have a Named Community Fund. We know that there will be solar to some extent done in the future in our system using those different funds. This is taking that future solar that we honestly don't know what that future looks like into account. It's a little bit less than 1 MW a year, but we do want to reflect there will be some type of community based solar in our system, so that is what's represented there. We do see a solar facility picked in 2032 that does have a battery attached to it. That's why you see a 50 MW storage facility at the same time, as though 100 MW solar facility in 2032.

James Gall: And we did cover a little bit on wind. The strategy there is for Washington as well as there are different locations selected in the model. I didn't provide the full detail on this version. It isn't our model, but we have 200 megawatts of Montana wind selected and then the remaining of it is either off system, wheeling that wind in on maybe the Bonneville system, and then some located on the business system. I think that limit is around 500 megawatts and then later on in the portfolio for Washington, we do start to see those 50 MW market transmission purchase. What that is, is that transmission line we talked about last week associated to move power in from MISO or from SPP that connects in Colstrip. We allow the model to pick it in any increments of 50 MW and because we didn't have all the value streams for that that soon to be the best case to test whether or not it made sense, but it did get picked at its full 300 MW need is just choosing it over a longer period of time. We may refine that assumption in the next week or two as we get some more information on that transmission line, but that is what those 50-megawatt selections are referring to is that transmission line connection at Colstrip.

James Gall: We do have, just like in the last IRP, power-to-gas or ammonia selections. Those are basically CTs that run on ammonia. It is selected in 2038. That's the 90 megawatts selected again later in 2042 and the 94 megawatts associated with that line item in 2044 is actually Coyote Springs cofiring with hydrogen and that was selected. There are some challenges with that selection where we have to actually be able to get hydrogen delivered to Coyote. But if Coyote is going to continue to be operating for serving Washington customers, we'd likely need to have a green fuel source. If it's possible to get hydrogen delivered there, it would make sense to co-fire at that facility. We can do around 30% hydrogen at that facility.

James Gall: Wrapping up on the Washington side and 2045, we do see a lot of acquisitions to replace lost capacity of Rathdrum and the rest of Coyote Springs. Along with trying to serve 100% clean energy in Washington, which has some challenges, when you're looking at it from serving 100% all the time and we're going to get to some of the financial challenges with that in a little bit. But we do see nuclear energy selected, we do see iron oxide battery selected. It takes a lot of different resources to get to 100% by 2045 and there will be costs associated with that when we get to that slide. But this is the first time we have actually seen nuclear get picked in Avista's IRP, at least in the Preferred Resource Strategy.

James Gall: Moving to Idaho, Idaho is a little bit simpler. We've seen mainly natural gas CTs picked for Idaho. They really follow when resource deficits began. When we see 2030, we see a selection there and then that selection serves the needs for the next several years. We have some lumpiness and then you see another one in 2037 and then another in 2042 when Lancaster goes away and then a small solar facility, storage facility late in the period.

James Gall: I think I've heard some. So go ahead, there's a question in the chat. It's from Nathan. So, the model is saying the power-to-gas is less expensive than solar plus battery from 2038 on. That is correct. What is going on in that situation is we do have significant winter needs and 4-hour batteries, even with solar do not provide us the expected QCC which is qualifying capacity credit in the winter months. We have a system. Let's say you have a sustained cold weather event that we're trying to serve a battery plus solar could not do that where an ammonia backed, or a hydrogen backed with storage long term storage could serve that customer for that load.

Nathan South: Thank you. So, the model is limited itself to a 4-hour battery duration.

James Gall: No, we gave it a 4-hour, an 8-hour, and a 16-hour.

Nathan South: OK.

James Gall: What we do is we assign a QCC value for each duration. The longer the duration, the higher qualifying capacity credit it gets.

Nathan South: Got it. OK. Thank you.

James Gall: Yep. Fred has a question. Go ahead Fred.

Fred Heutte: Yeah, actually I have a few questions. I don't want to break from this page, and we can come back to it, but I have a question back on slides three and four. On slide three, I'm just trying to get a better bearing on what you mean by market here, 330 megawatts of market and is that day ahead real time? Is that advanced purchases? What kind of market is that?

James Gall: They'll be day ahead real time.

Fred Heutte: OK. And in that regard, and I'm not trying to pin down any real direct numbers here, especially from the experience in January, is that within a reasonable range?

James Gall: Yes. And maybe the reason why I say yes is when we lost our turbines on Friday and Saturday morning, we actually were able to buy I think 500 megawatts. Wen we got our turbines back, we were not in a resource deficit position anymore. We were actually fairly even. Could we have gotten 330 MW? I don't know that answer.

Fred Heutte: Yeah. It's not a complete. Yeah, completely for sure thing. OK, got it. And of course, the situation is changing across the region pretty constantly, so all kinds of issues on that, but I think that seems pretty reasonable. On the next slide, slide 4, just a quick question, the top row there where it says 1 to 12, I wasn't clear about what those are.

James Gall: Yep. All those are months, January through December.

Fred Heutte: OK.

James Gall: Yep, I can fix that.

Fred Heutte: OK, good. That makes sense.

James Gall: I'll fix that.

Fred Heutte: It seems obvious now that you say it. I just don't know why I didn't pick that up, and you may have actually said it, so sorry about that.

James Gall: Yep.

Fred Heutte: And now to the Preferred Resource Strategy. I did have a question and now I'm missing it a little bit. Oh yes, the market in transmission. So that's the Northern Plains Connector transmission. It's a very interesting project. Of course, where I live here in Portland, PGE has signed a kind of development agreement, and I think Puget is looking at that pretty closely. Have you been in contact with the developer on that?

James Gall: Yes, we have.

Fred Heutte: OK, like any big project like that, there are lots of ifs, but it is a very interesting project and I thought what was most interesting was you said it gives you some access to wind and MISO, actually it also connects, that project configuration as I understand it, also connects into SPP it's one of the interesting things about it. So, you really do get a much bigger access to a very wide market and one of the things we notice, that I noticed, in January was that as these big cold events come through that caused the high demand, first you get in any locale, you get a little bit of a wind surge when the big front comes through. And then as the front moves toward the east, the wind dies off where you are, but further east there's more wind. I did look at MISO and SPP for the January period and found that actually does happen. So, I think that's a realistic approach in terms of expanding access to wind resources, in the winter especially, and it makes a lot of sense. The Northern Plains Connector is a big expensive line, but it would have benefits all year-round in terms of access, not huge. I mean, it's a couple thousand megawatts. I guess you've got huge market size on the West side and in the Eastern Interconnection, but it could be very valuable.

James Gall: Yeah. I'm going to briefly cover how we modeled that one and that might change. For this first draft, we model it as a capacity only resource and we let it pick it in 50 MW increments at any time after I think 2036. We do not at that time we've done the study, we don't have the arbitrage value or opportunities to market power between the different hubs. We looked at it only from a capacity resource. And what I mean by only capacity resource, think about it as connecting at Colstrip and we have capacity associated with the wind that's in Colstrip. So, we're only giving it a capacity credit based on the remaining capacity above what the Montana wind provides us. It has a small capacity value we're accounting for that it's still picked, but we're not accounting yet for any of the market opportunity that's there. And with that, I would imagine if we had that value, we would see that consolidate more into an earlier selection. Where would it actually show up in reality? We can't take 50 megawatts a year. We're going to have to take it likely all at once when it's completed, so we may have a revision on that selection in the next version of this, but we still don't have that arbitrage value yet.

Fred Heutte: OK. Yeah, that makes a lot of sense actually. I would say I'm pleased to see you're thinking about this in a kind of big picture sense and trying to look at this step by step, that makes a lot of sense.

James Gall: Yep. I have a little bit of caution on modeling specific projects because we've done that in the past and we've been burned where the costs were much higher, or the project couldn't get done. That's another consideration. Should we even include it in the final plan? Because there is no other resource in this strategy that's related to it as a specific resource. That's another concern that I have, because we don't know if it'll actually materialize and should that belong in an IRP or not.

Fred Heutte: Yeah. I see that point, given the track record of this particular developer, though I think you know a lot of the good United people including the CEO came from Clean Line and they've shown some capability here. That gives me a little bit more reassurances I guess. What year is the model allowed to start picking that?

James Gall: I can't remember if it's 2036 or 2037, but it's in that period.

Fred Heutte: Yeah, that seems reasonable. I think you could probably get a little earlier, but it's a really big project, it'll take a long time.

James Gall: Thanks for the comments. Any other comments coming through? OK. And I’ll just pause there. If there's anything else that comes to mind before we get to the results. OK. And just wanted to remind everybody in two weeks that our next TAC meeting will probably cover this again. If there are any changes, we'll cover those. If not, we'll probably cover how this compares to some of the scenarios we're going to show next time and actually I believe at the next TAC meeting. After that, we're going to continue this theme of results for the next two TAC meetings and then, as we start writing this up in the draft document.

James Gall: OK. I did cover a little bit on the community solar Named Community Investments. I just wanted to cover this slide; this one might be new as well. It's really regarding how we handle the unknown of the Named Community Investment Fund. We have $5 million a year that goes into this fund and lots of different projects could come out of it. There is a portion of it that has community-based proposals. There are energy efficiency proposals. There's potentially a reliability proposal. We don't know what's going to happen with this these dollars, so we try to include what we can by incenting the model to pick resources that could be picked, and we do that by putting constraints on them all to spend a certain amount of money. We do have it spend $2 million a year on energy efficiency and how it's credits towards DERs, that's around $400,000. And what the result of those adjustments are, is we do see 600 kilowatts of solar added a year until 2036, and it goes up to 900. We do see a little bit of distribution levels, energy storage in the last half of the IRP, and then we do see increases in energy efficiency that are pretty significant actually compared to the last plan. So that's 1,400 MW hours a year in the first 10 years and it drops down a little bit in the last 10 years. But we are trying to account for unknowns that fund will create.

James Gall: This is another interesting way to look at how our resource strategy is going to change. We have new resources in the top of each section and then retirements as well. You can see our natural gas retirement, net retirement, is around 242 megawatts. Although we have some additions, we have quite a bit of retirements. We have additions and power-to-gas or hydrogen as well. It's nearly 400 megawatts over the period. You can see how our wind changes we have between the Northwest wind, Montana wind, and our PPAs. And then we have 300 MW net additional solar. Then they have demand response. There are 92 megawatts, which we haven't covered demand response yet, but that's a precursor to what I'm going to get to in the next couple of slides, the demand response. An additional 250 megawatts of storage, we will be losing 100 megawatts of hydro, and then down the last section is the other resources that are being acquired between the regional transmission we just talked about, nuclear, biomass and geothermal and a little bit of market in the early periods.

James Gall: That is our draft strategy at this time and let's get into some of the other results. Wanted to just check in on what we've done on resource adequacy for these two strategies. Mike, do you want to cover this?

Mike Hermanson: Yeah, this is looking at the 2030 Preferred Resource Strategy and then also the 2045 strategy. So, what we do is take our current fleet of resources and contracts and obligations and put them into our reliability model. Use 2030 load and the results are 0.5% LOLP and as a reminder 5% is our target, so we're well below that and also well below the LOLE that's used regionally, is 0.1. So, we are actually one quarter of magnitude below that. And we also use the 2045 resource strategy that James has just been going over and come up with an LOLP of 2.3% and LOLEV .05%. Some of the other metrics we went over in the June 4th TAC that you can refer back to, those are some of the metrics that are associated with duration and magnitude that the Northwest Power Council is integrating into their reliability modeling and that's the reason they don't really have any targets for utility specific applications because each utility has different needs and systems that they're operating and loads reacting to. The bottom line is that the Preferred Resource Strategy is adequate to meet the reliability standards that we've set for ourselves, and we will be doing scenario analysis with the different scenarios that are tested, the different aspects of the resource strategy: different loads, different weather futures, etcetera. We have the whole list of them that's out there. I can recite them, but yes, basic message is we are resource adequate for this Preferred Resource Strategy.

James Gall: And before we go to Fred, I'd say one of the reasons why the metrics are so low is this, the lumpiness of resources in 2030. We have some wind coming online, but a larger natural gas facility than I guess what would be required to get exactly the 5%. That's going to drive that 2030. If you looked at this at 2035, it might be closer to 5% because you have the loads that are growing to offset that lumpiness of resources and actually the same thing actually occurs in 2045. There's some lumpiness as well that is occurring. Fred, still got his hand up? Go ahead.

Fred Heutte: Yeah, a quick one, just if I'm looking at the numbers for EUE with reserves without reserves, they're very close together. What does that tell you about? And I'm not quite clear about reserves, what reserves means here in this situation. Or maybe a better way to ask this is at what point do you become concerned about what the E value is? I presume this is well within what you're looking for.

James Gall: Yeah. I'll answer, maybe your first question first with and without reserve. Our model can trigger an outage if it's a reserves miss or a delivery risk or an out miss. So, you have so to be 100% compliant for every hour you have to meet all of your reserve requirements and all of your energy requirements. We do have cases where it doesn't occur very often that we could miss the reserve requirement. That's what the difference is there. As far as what's acceptable, I don't think we have a metric of what's acceptable. You can see, obviously in 2045 it's significantly high. I guess we'd have to compare that to what our case was with adding though that 50 megawatts of perfect capacity, if we go back to slide, I'll go back to in one second, it'd be 103 MW hours and then in that perfect case we had 268. So, we're still lower there. I guess you may argue maybe 268 is that the right value. It looks like we do have a typo there on the one above it. What the fix is for that? Yes. There's a target where you have been only really targeting that 5% LOLP, and also looking at LOLE at the same time, so we don't really have a target.

Fred Heutte: OK. Yeah, that makes sense. I'm just thinking an operational sense. So this basically, if I'm understanding this, if you have well, no, I think you explained it pretty well, that's fine. I was trying to relate it to what happens if you get into a 1-in-2 situation, but that's probably you can't go directly to that kind of thing with this kind of model.

James Gall: Yeah. And what we're really looking at here is, are we near 5% or not? And if we were away, let's say we were 10% LOLP, we would know we probably had overstated our QCC values. Given that we're below, you can almost argue we've understated them a little bit. But in 2045, I said there's some lumpiness and resource acquisition, but this is telling us we're kind of in the right ballpark of judging our reliability metrics for each resource is what happens is we're running separate models. So, you're running a capacity expansion model separately from your resource adequacy model, so you have to make assumptions on how well each resource is going to perform. This is basically showing it's performing where a little bit, maybe conservative, slightly conservative, on our assumptions for how well each of those resources will perform.

Fred Heutte: Yeah. Well, you don't want to overbuild, but on the other hand, you want to be a little bit long. I think that makes sense.

James Gall: Yeah. OK. Alright. Let's move on. Unless there's any other questions. OK, I know we have about 45 minutes left. That should be plenty of time. The first item I wanted to cover is how we compare it to CETA, and this is looking at CETA from an annual and four-year metric point of view. How this works is the dotted line is the CETA target that the model is trying to meet from a primary compliance point of view and the black line is the compliance point of view from the 100% for Washington. That 100% would really start in 2030. Before 2030, that Black Line is just a reference line and you can see the green bar is how much generation would count towards primary compliance and then in blue is how much would count is, over that we call it net monthly load. So, there's been proposals that if your generation exceeds your load, you would not be able to count that towards primary compliance. So, that blue represents how much energy is above our load. It is still generation, we'd own, but it would not count towards primary compliance. Those rules are not final yet, but it's just illustrative of how our model is looking at this. We have the primary compliance that is equal to our load or less. And if it's over our load, it counts towards alternative compliance. So, what this does is it creates a very long position for renewables, partly because the model is trying to acquire renewables early for the PTC in the IRA before expirations. But we do expect because of this goal of 100% every hour of the day in 2045, you can see we're going to have a tremendous amount of excess generation to meet that 2045 target which makes you wonder why, but all can explain a little bit. Think of it as you have your highest load period in January for example, and in order to serve that load in January, you really have two options. You either build a lot of renewables to hope you have generation show up available in those hours, or you build a lot of long duration batteries to meet that load. Or maybe the third case is you build a bunch of nuclear plants. And what this strategy really unfolded is it's a diversification of those three things. One is you build a lot of renewables, and you'll have a probability of some of them helping you out in your peak months. Two, you build quite a bit of long duration storage, which is your ammonia turbines, and then three is you have a little bit of nuclear. This approach is a little bit of everything rather than relying on one of those three things to help you meet that 2045 target, at least for Washington, OK.

James Gall: If you look at energy as a function of our load today, we're around 80% clean energy. And then by 2030, as a system, we're going to be closer to 90% and then you can see as you march forward, we're well in excess of 100%, right, 110% by 2045 because of those instances I'm talking about where you can see Washington has a significant over production of renewable energy compared to its load. And then Idaho is around 70%. In this strategy, over produce renewables to ensure that you have enough generation in the critical months when you need it, but also having some diversification on that with nuclear and long duration storage using power-to-gas.

James Gall: OK, so what does this do for rates and how should we include rates in the model? I have some questions for the TAC on this. This is our rate forecast. Again, this is not what it will be. This is how the strategy affects rates when you leave everything constant. So, how we look at this is we have a power cost forecast in our model and what we do is we take that power cost forecast and add that to a representation of all remaining costs that we don't model. And we know that all remaining costs we don't model will increase over time, so we escalate that. We're trying to understand is how are our costs affecting the average rate of a customer. We calculate that amount for Washington and Idaho. You can see Washington rates are a little bit higher than Idaho today. We don't need to get into reasons why that is, but on the Idaho side it's a fairly constant growth. On the Washington side, it actually follows the same pattern. This last IRP, there was a little bit of a separation going on. We're not seeing that this time, but by 2045, we do expect to see a radical price increase due to meeting that 100% 2045 requirement. We did see this in the last IRP as well, a little bit less dramatic, but it did occur. We have not been modeling the 2% cost cap in the IRPs and I guess maybe a question to the TAC is if we should be and how should we be modeling or creating a portfolio for CETA from a clean energy perspective, or should we be modeling it from a perspective of considering the cost cap, or not. We could be showing a scenario that has that cost cap constraint in there but it's really what do we want to have as our resource strategy, something that meets the law, but not the cost cap and the law. Or do we reflect that and say, yeah, there's a cost cap, we're not going to be able to stay under that and our resource strategy should be something that's more in line with where we think it will be because of that cost cap. I want to pause there if there's any thoughts. There's someone in chat. OK, go ahead.

Molly Morgan (UTC): I don't know. Maybe you said this and I missed it, but why is it just in the last year that you're exceeding the cost cap? Is outlook an intentional decision or how does that work out?

James Gall: The reason why has to do with the magnitude of resource changes by 2045. You have gas facilities still available to Washington until 2045. In 2045, even though you're adding renewable energy, you're losing a significant amount of capacity. You have to replace that capacity in that year. Now if we had resources retiring earlier on and you were doing that over time you would see maybe the same endpoint, but more gradually to that end point, but yeah.

Molly Morgan (UTC): Yeah. OK, that's kind of what I was thinking it was. And so, you're asking if you modeled the preferred resource strategy with the 2% cost cap the whole time, that would be the scenario where you would not have that spike at the last year.

James Gall: You would not, and you would not meet CETA's 100% requirement.

Molly Morgan (UTC): OK, got it.

James Gall: Yep. I mean based on what we did last IRP, we would probably leave this how it is. It is 20 years from now and a lot can change. It's something to keep an eye on. From my perspective, which is to not put the cost cap in maybe look at it as a scenario, but it's something to keep an eye out on.

Molly Morgan (UTC): So, you're basically saying your model is showing for the entire range, you cannot meet the CETA cost cap.

James Gall: Correct. And we haven't modeled, we haven't put the constraint on there. It says OK, you got to stay below the cost cap, so will it do things differently to achieve staying under 2% a year? I haven't tested that yet, but my expectation is it would not be able to meet the 2045 target and stay under there.

Molly Morgan (UTC): I feel like we'd at least want to see that as a scenario, just because that would be a problem if that's really what it's showing. So, we want to know that.

James Gall: OK, of these costs, nominal or real. These are nominal dollar or nominal rates, average rates, so not a residential rate, not a commercial rate. Think about it as total utility cost divided by retail sales, but not adjusted for inflation. It is taking into account inflation, so inflation is taken out of this, no inflation is included. We include nominal pricing of resources, non-power costs or increasing at I think a little over 3% a year. So, this includes inflation. If we took this and then took inflation out, it would be fairly flat. Until you get to the last year.

Nathan South: That's maybe an important thing to call out on the slide.

James Gall: Yep. OK, we can add that comment OK, right. I'm going to go next to greenhouse gas emissions. This is starting in 2026. What our system emissions would look like. Today, we have Colstrip, which these emissions are anywhere from 2.5 to 4 million tons. We don't see that reduction here, but there is a significant reduction before the 2026 time period and then we do see emissions declining. The decline in emissions is really related to our expectation of our natural gas resources running less. It's not necessarily resources going away, even though we have a small gas plant that will be going away in 2030. But that one really doesn't run. It's there for reserves, but the reductions are really due to changes in dispatch because the market, or the overall region, has more renewable energy. If that doesn't occur, you'll likely see flatter emissions. We do see reductions until the 2030s and then it stays fairly flat, and then and it drops off a little bit in 2045, and that's because of going away from utilizing hydrogen at Coyote. And then in 2045, if you're wondering, that's really the Idaho portion of the portfolio that is remaining. But this is the emissions associated with the Preferred Resource Strategy from a system point of view. The ones that are, what we mean by sold versus net, is we're trying to calculate how much emissions in total from our plants. That's the combination of the two. And then in green represents a number of system sales that we make, and we just assigned those sales to the portfolio average emissions. That's what's accounted for in the green. Now, it's possible we may sell clean energy for those sales and that would have no emissions associated with it or we may not. We just don't know what that that future looks like. We don't make assumptions on are we selling clean or are we selling non-clean. But we're just saying, for our sales, these are the amounts associated with them based on our system emissions. We can see in 2042, we stopped selling on a net basis, and then 2045, there's a little bit more, but some of these sales are really a result of our resource position where we were very long in some months. And as you add more and more clean energy, you're going to be long on an energy basis quite often. On top of that, we are planning for contingency of energy, which means on, on an average year, you should be selling excess generation in non-peak events.

James Gall: Alright, so getting back to some of the other resource selections and related selections. Transmission is a component of our modeling when typically focused on the generation side, but there are transmission actions that come out of our resource selection. We'll start with the Rathdrum area. In order for these natural gas facilities to be built, there will be transmission associated with those. We do model that transmission. We also model the cost of the gas delivery as well, but on the transmission point of view, there would have to be transmission additions. If we do cite additional projects in that area, we'll need additional re-enforcement. So, what those transmission items are, some of the things that Dean covered in a previous TAC, meaning those costs associated with those. But in order for this all to happen, we do interconnect requests and then the transmission group will study those requests based on the official amount of capacity we're asking for and they'll determine what re-enforcements are needed.

James Gall: Another long-term thing we need to start thinking about is off system imports and this is not related to the North Plains Connector, but we do need additional access to import renewable energy and really just to access markets by 2045. This will likely mean we will need to build new transmission to other areas off our system to bring in more renewable energy. There's just not enough either renewable energy on our system that we have imported or the cost to build additional transmission in our service area to get to those renewables could be more. We're looking at the model saying it might be cheaper to build to other markets than to build major transmission systems in our system. Whatever flavor that turns out, and we will need additional transmission to meet the amount of wind that is selected in the model. And that 2045 period, the last one we've already covered quite a bit, but the North Plains Connector that has been selected as well. Ask your question Fred.

Fred Heutte: Yeah, real quick on the new CTs, if those actually go forward, how much cost or how many line miles roughly do you think would be needed for the transmission?

James Gall: I think the cost is $14 million. I don't know if it's. I think it's 9 miles built. It's more of a reconductoring.

Fred Heutte: OK. Yeah, it's not like a 50 mile or 100-mile kind of build.

James Gall: No. Now if you site significantly more transmission in that area or generation in that area, that would be a case where there would be a major rebuild and I don't know if Dean is on the call or if somebody from the transmission group could bail me out on what that looks like. I'm not hearing any. Go ahead.

Dean Spratt: I am but I was in the middle of typing an email. If you'd repeat the question, sorry.

James Gall: Dean, the question is, what has to be built for adding one unit? And then wrap them area versus adding several units over there.

Dean Spratt: No, that's perfect. Sorry, I just want to make sure I'm clear on the question. Right now, that's a specific spot. We have a little bit of overgeneration currently. When I say overgeneration, when we first had modeled the generation, the CTs there now typically didn't run in the springtime when the hydro was running. With the EIM and the market changes we've seen as of late, they're running quite often and we're at the existing transmission capacity when the CTs are running, the combustion turbines and the combined cycle at Lancaster is running, and we're having high transfers East to West because of hydro and high Montana-Northwest flows. So, what we're running into, and the results are pointing to, is we're going to have to add some more transmission. Some more transmission capacity to add more generation, specifically in the Rathdrum area.

Fred Heutte: OK. It sounds like you're getting high utilization. If not, overuse on the transmission and a little bit more headroom would be needed.

Dean Spratt: That's correct. Right now, proposed a project out of the last system assessment to put a remedial action scheme to bring generation down under certain circumstances.

Fred Heutte: OK.

Dean Spratt: I worked with their operations group and right now we just wrote an operating procedure to manually bring generation down once what we're calling the West of Lancaster cut plane hits a certain level and we're going to try to operate that because it's not very often it happens, but it it's been more recent over the last few years. And then from there, we could entertain a remedial action scheme. Our operations team is a little concerned because it's a pretty good amount of generation that could be tripped for an outage in that area, which might drive a transmission project. We're working through that actually, again, revisiting that with the latest cluster study entries this cycle. And then we're looking at it again, revisiting it from a load service point of view as well.

Fred Heutte: OK. Yeah, I didn't realize you were, that Avista had. Maybe I'm not too surprised that remedial action schemes, so RAS, whatever makes some sense. Thanks, that was useful detail.

Dean Spratt: Yeah, sorry for missing the extent of the question right off the bat. Trying to do three things at once. This is never the best technique.

Fred Heutte: No, it's great because I got more than I expected from the answer. So, appreciate it.

Dean Spratt: Probably should be quieter next time.

James Gall: Thanks, Dean.

Dean Spratt: Thanks guys. Bye.

James Gall: OK. Let's move on to demand response. We got about 20 minutes left or so. A lot of slides left. Demand response in this IRP is definitely a radical change on the demand response side. Comparing the last plan, and there are some reasons for that which we'll get into in a little bit, but we have around 73 megawatts over the 20 years selected in Washington around 20 MW, little less than 20 MW for Idaho. Some of the reasons for the big changes are a couple of things. One is the programs for capacity or qualifying capacity credit in the last IRP. We think that as more of a resource responding to meeting load. In this case, we're thinking of them as a load reduction, so the net effect of that is they get an additional capacity credit of the planning reserve margin. They're getting more value than what they were last IRP as far as capacity credit. Think of it as you needed 100 megawatts, and this could respond to that 100 megawatts. Now it's taking that off of the 100 MW need. Your planning margin is calculated net of DR, so that actually moved the needle a little bit on selection of DR.

James Gall: The other big change was we did assign some distribution and transmission credits to these projects. Like I mentioned earlier, at the beginning of the meeting around $28.00, that did add a few more programs selected. The program selected are electric vehicle time of use rates. That's actually a program we have piloting right now on the commercial sector, maybe it's not a pilot anymore, but we do expect around 9 megawatts of savings there with the time period. A battery energy storage with that is referring to customers that have batteries in the future. We don't have a lot of batteries in our system right now, but batteries in the future we would do some aggregation of those batteries and potentially save around 10 megawatts. There is also a peak time rebate that is a pilot we're taking on right now. It's around 6 megawatts variable peak pricing, which is kind of how it sounds, that we have a different price during certain periods for certain customers. That's around 5 megawatts savings. And the 2033 period, you can see there's a gap. We have three programs that should be initiated early in the IRP period and then we have another section in the early 2030s, and then more in the 2040s. But in the 2030s, you're starting to get into variable peak pricing. Your party contracts, which is a third-party aggregator. Some kind of a behavioral program. Surprisingly, time of use rates actually doesn't show up until 2039. That was actually a program that showed up earlier in the last IRP. I think the reason for that change is the expected savings compared to the cost have changed in this new version of the DER potential study. But it does continue to show up, just later in the study. Then smart appliances, CTA water heaters in the late 2040s, and then central air conditioning response as well in the late 2040s. Some of these, it might be appropriate to look at earlier when we go out to bid. I kind of mentioned a little bit on an RFP in the future. We're not saying that we would start these programs later, but some of these programs could be looked at and comparative to those RFP responses if may be there's costs that could be cheaper than what we're assuming. We would likely expect some of these options to be studied earlier if there are third parties that want to propose projects to us. On the audio side, three programs didn't show up as cost effective, not the last three at the end of the period. But there's also a delay in some of the earlier projects that is due to AMI not being available in Idaho until our assumption date of 2029. Fred, go ahead.

Fred Heutte: Yeah, just poking around for the right buttons here to push. I guess my reaction to this is it seems way under what I would expect both in total amount and in kind of the onset of the programs. For example, on the CTA water heaters, the CTA on the shelves now, they were going out now. Every water heater here in Washington, electric water heater, has to have that device in it and I get that there are complexities to rolling that kind of program out. But 2042, and then 5.5 megawatts. What I'd like to ask is maybe have a separate side discussion with whoever on your staff would be good, you or your staff or whoever at the company to talk a little bit more about the DR here and just get a better handle on what the inputs are because the model just does what the model does.

James Gall: Yep.

Fred Heutte: I'm thinking more about the inputs when my general thought is the DR here is competing with the market that we talked about earlier and how does that look? That's where my thought is going.

James Gall: Yeah. On the CTAs that water is the resistance side non-heat pump, so the heat pump water heaters, just not a lot of energy there to save at time of peak. They just don't use anything, so that's the reason why. We could probably arrange a call to AEG, our consultant on that, who came up with these assumptions. We can schedule a call with them if you'd like. The other thing to think about is on the individual program. Some of the reactions that customers take can fall in different categories. So, when you look at them in total versus individual. Let's just say you're looking at peak time rebate. If we just did a peak time rebate and nothing else, you could get more than 6 megawatts. But the problem is that when you have these other programs, they may show up somewhere else, and that's what we're trying to reflect here in the total number is, I guess really more important versus where it's allocated out, because you're going to see higher amounts if you only had one program versus you had multiple programs. So, like first, you may have some customers with water heaters.

Fred Heutte: Yeah.

James Gall: There's different categories where it could show up on how it's responsive. You got another comment?

Fred Heutte: Yeah. Appreciate that. I would be happy to meet with you and AEG, which means that I have to really dig more and really go through all the detail on all the relevant materials here, which I will do. One thing I would say also is that the kind of cross program issues you just mentioned. If rate design is one part of it and then specific programs as the other part, I think what PGE, Portland General Electric, has done. Now my utility, their flexible load plan has at least given them a framework for addressing those kinds of issues. And they've done a lot in their smart grid test bed to see how you can roll out different things and try to encourage customer support for that and not a lot of confusion because I realize that's a big a big issue here. I would be very interested in following up with you about this. My general sense is just, for example on the heat pump or the either electric resistance or heat pump water heaters.

James Gall: Yeah.

Fred Heutte: Yeah, they're not very much one by one, but there's a whole lot of them out there. And if that kind of program, the other thing about that is it doesn't, I think for the most part, I wouldn't say 100%. What are yours? Can be operated in such a way that customer doesn't even know when the program is happening when a call is being done.

James Gall: Yep.

Fred Heutte: From the experience we had from 2018 with the BPA and other utilities doing the pilot field test on that, I think it's pretty clear that this is the one demand response resource that is pretty safe to do in terms of customer impact. It's not like air conditioning or time of use type thing where you're going to have a little, maybe a little bit of discomfort if you raise your thermostat. That sort of thing. I just hope that we can find at least, I would like to get a better understanding of what your inputs are here, and we can have that discussion.

James Gall: OK.

Fred Heutte: Thanks.

James Gall: Yeah. Just make sure you follow up with me. I wanted to bring up one comment though on the total, this is a pretty significant total for us, 73 megawatts. If you add the other 30 MW that we have from industrial, you're at 100 megawatts and our peak load for just Washington. I'm just doing some numbers off the top of my head here. It's around 1,400 megawatts. You're at 100 megawatts, divided by 1,400, you're at 7% of peak load.

Fred Heutte: Yeah, that's actually pretty good. I would agree with you about that. But the other thing here is about the timing. Waiting until early 2040s for a lot of this or late mid-2030s to early 2040s.

James Gall: Yeah.

Fred Heutte: That just makes me wonder. It just makes me wonder. Thanks.

James Gall: I'll explain some of that because it's important to get into and it has a lot to do with our load growth pattern. The forecast I should say, who knows what it will be? But the load growth is very mild until the mid-2030s, and that's where you're seeing the wind. The small amount of QCC value you get from the wind and a little bit on the energy storage with the solar, but you have very mild load growth for peak figure meeting a lot of your peak growth between the early DR and the renewables. Plus, on the Idaho side, you have the peaker but the load growth really starts to take off in the mid-2030s and that's why you're seeing it delayed. If we had load taking off in the early 2020s, 2030s or late 2020s, then you would see it earlier. It's really a function of when that load takes off.

Fred Heutte: Yeah, I can see that. But I also wonder given where we are right now across the West and market prices during peak periods right now, it's not a problem because gas prices are historically low, natural gas prices, and that may not I predict that that will not in fact persist. The history of gas is very volatile. I expect those prices to start climbing sometime, but when is always a good guess. One more thing, by the way, I think I mentioned this before, there is a big demand pull coming real soon on Canadian gas from the new LNG exports. The big LNG Canada terminal is already receiving gas. They haven't shipped anything yet. That's 2 billion cubic feet a day. Your supply is partly coming from BC I guess and maybe some from the Rockies, and then some from Alberta. It's complicated, but I think that the price pressure on gas is pretty obvious going forward. The market prices are going to start elevating again in the near future. I would now not predict, but so I just think that this is worth another look. Thanks.

James Gall: Appreciate it. Alright, let's go. We have 10 minutes left. A comment from Leona on that too.

Tom Pardee: She just mentioned Avista's participating in NEEA End Use Load Flex Project that includes work with the CTA 2045 water heaters.

James Gall: More to come on that. Alright, so we're running out of time, and I have like 10 slides left. I'm guessing we're not going to get through them all, OK, because we're going to bring this up again in two weeks. I'll continue this conversation and give you time to think about what we talked about today. Moving on to energy efficiency, we are definitely seeing higher energy efficiency amounts compared to the last IRP. There's just more potential than the previous plan, which was actually a little bit of a surprise to us. Some of these numbers are really kind of hard to the materialize in our head, but it's energy efficiency. What was selected compared to what load would be without energy efficiency, it's around 10% of load. Typically, we also like to show the biennial target. We're not quite ready to show that yet because we're trying to separate what's NEEA programs versus what's Avista programs. But we're definitely seeing Washington is going to higher percentage of energy efficiency compared to Idaho. Typically, if all things were equal, you'd see about 65% of programs in Washington and 35% in Idaho. Washington's a little bit higher share of that. I think it's closer to 73-ish percent, and that's really related to higher avoided costs for the Washington side of the service territory versus the Idaho side of the service territory. So, we're seeing more savings in Washington. The breakdown on the left shows you where residential versus commercial versus industrial, but the real fun part is on the next slide that's coming up.

James Gall: But from a supply curve point of view, this is actually from more of an economist’s point of view, the more interesting slide, but it shows you that potential ignoring costs. You have GW hours on the bottom. How much you could actually get over the next 20 years versus the cost of those measures. And as we call them, the supply curve, the circled areas represent where we're selecting our quantity of energy efficiency over that period. In Washington, you're at around $150 per MW hour and what is driving that is partly the energy savings, the capacity value savings, but a lot of it is non-energy impacts as well. The avoided cost in Washington, say around $150 from a selection point of view versus an actual of what it cost, we’re still calculating that, but that's the equivalent selection point in Washington. Idaho, we use a UCT method, but that's around $70 where that crossover point. It's a much lower value because it does not include non-energy impacts, does not include social cost of carbon impacts and the 10% Power Council adder. So, you have a much lower avoided cost point for Idaho.

James Gall: What are the top measures that were selected? This is something we've never shown before, but I thought it would be interesting to look at. Lighting is still one of the top measures picked. Windows actually showed up in Washington, and that's really driven by non-energy impacts. That's why that shows up, same with some of the other measures that have not appeared in the past. But we do see insulation, water heating related measures, shell measures, and then, well, you're stuck with heat pumps in there. More water heating, but you can go through this list if you're interested in it. Also, in our PRiSM model for those you who want to really dig into the details, we do have every measure that is available, and you can see whether or not they're picked or not by state. And if you're interested in that and you need help, give us a call or an email. We'll help you find those, but this just gets you an idea in the first 10 years the measures that are being picked. OK.

James Gall: We have two options we can try to go through as much of the CBI results now, or we can, if there's any comments on energy efficiency, we can cover those now. But I just want to pause really quick to gauge the audience on where we should proceed because we only have about 5 minutes left. OK. I'm not hearing any ideas, so maybe what I'll do is just cover an overall structure of the CBIs and maybe not go through the slides yet, but we'll pick these up next time. But for CBIs, we have in the last CEIP a number of metrics that we've committed to modeling in the IRP. And those are energy burden related items, DER items, low income, community investments and another one is the reserve margin, generation location, air emissions and greenhouse gas emissions. Those metrics were all ones we could add to modeling. Those are shown here when we run scenarios, there's been some requests that we show these metrics with scenarios we're going to need to try to figure out how to do that in a useful manner, but we are still committing to these CBIs. We did create two new CBIs as well. I don't want to call them CBIs because they're not necessarily official CBIs because that will be figured out later. But we did create a job metric calculation using the IMPLAN model that we recently acquired. We could see how many jobs are created based upon the resource selection, that's included in here. And then we also have resource diversity calculations for those of you have been part of the TAC for the whole TAC cycle, we were talking about doing some resource diversity or resiliency metrics. We did create a few of those for this IRP. Regarding facility diversification, fuel diversification, transmission diversification. We'll get into those next time.

James Gall: We're probably, I guess we do have 5 minutes. We could probably cover this one, but what we're trying to measure here is using the Herfindahl [Hirschman] Index. Do we have a diverse set of resources or not? The metrics are if you're over 2,500, you're very concentrated, not very diverse. If you're between 1,500 and 2,500, you're moderately diverse, and if you're less than 1,500, you're very diverse. And what we found is that from our generation point of view, we're very diverse. We have lots of units that not one unit is the main concern or a group of units, but when you get into transmission, we are getting more consolidated. We only have few areas where generation is created. We don't have a lot of areas where generation is created. It's usually north Idaho, it's West, and the Mid-C. We do see some diversification. We're in that mid-area, but then on fuel diversification, we are towards the higher end earlier on where we have very few fuel sources. But as you add resources towards 2045, our fuel mix is getting more diverse. There's less, I guess you can say with resiliency concerns potentially from that matter, but I'm hearing some it was just confirming that it's IMPLAN. OK. But this is kind of a new metric. We thought it'd be interesting to study, and I would say the results of this show, there's not a lot of concern, but there appears to be some benefits and some of the fuel diversity of our resource selection compared to where we're at today. Any other comments? I don't want to get into all these slides. We do have them available. Like I said, we'll cover some of these next TAC meeting. Anything before we call it a day?

Fred Heutte: Yeah, this is Fred. Just to say, not now, but maybe we can come back and talk a bit more about this diversity metrics.

James Gall: Get like I said, I don't know if it's useful or not. It's something we thought we'd try.

Fred Heutte: Well, the idea of it is really good, but it's interesting to see what it is now and what it might become.

James Gall: Alright. Any other comments? Alright, so next TAC meeting, if there's any changes to the resource strategy will cover it. We will cover as many scenarios as we can in the next week as we got to get slides out by Wednesday or Thursday morning. We'll have a few scenarios. Definitely, we won't have them all by next TAC meeting and then the next staff meeting. Hopefully we'll have all the scenarios completed. I see a hand up. Go ahead.

John Calvin Slagboom: Good morning. I have a question about way back at slide six. It looks like there was 150 megawatts of nuclear projection for 2045. Did I miss something with regards to that or was that not spoken to?

James Gall: Yep. We did talk about it briefly.

John Calvin Slagboom: OK. Because I was at the Future of Electric Generation conference with Avista at the SL Conference Center in Pullman and there was some questions about that. But something like that wasn't on Avista's radar in terms of something that you were planning for, but it's on the slide. So, I'm just confused. Want to get some clarification?

James Gall: I could probably explain why. Our last resource strategy, nuclear wasn't selected. A lot of people, they've not seen our new strategy yet, so they might be thinking of what we had in our last plan. Now we're continuing that process of every two years. This is starting point. We've had this strategy out internally for a week, so it may not be fully communicated to everybody and it's in a draft status right now.

John Calvin Slagboom: OK.

James Gall: Let's say you went to that conference next year and this was our final strategy and then you might get a different answer.

John Calvin Slagboom: Awesome. Thank you very much. Appreciate that.

James Gall: This is just off the cutting room floor, I guess you could say. OK. We're at 10 o'clock. I appreciate everybody's time today. Appreciate the interaction and we'll see you all again in two weeks. And for those of you that are on our gas TAC process, we'll see you tomorrow.

Chat Notes:
[8:19 AM] Meeting started

[8:57 AM] Nathan South: So the model is saying the PtoG is less expensive than solar+battery from 2038 on?

[9:25 AM] Nathan South: Are these costs normalized to current dollars?

[9:46 AM] Haley, Leona: Avista is participating in the NEEA End Use Load Flex project that includes work with the CTA-2045 water heaters.
like 1

[9:56 AM] Fred Heutte (Unverified): presume that "INPLAN" is IMPLAN . . .

[9:56 AM] Pardee, Tom: correct, IMPLAN

[9:57 AM] Fred Heutte (Unverified): no prob :)

[9:58 AM] Molly Morgan (UTC):(Unverified): yes I think its useful to look at

[10:05 AM]: Meeting ended: 1h 46m 4s Avista's 2025 Electric IRP TAC Meetings Tuesday, July 16, 2024 8:30 AM - 10:00 AM. 1h 31m 23s

2025 Electric Integrated Resource Plan
Technical Advisory Committee Meeting No. 11 Agenda
Tuesday, July 30, 2024
Virtual Meeting – 8:30 am to 10:00 am PTZ

Topic	**Staff**
Introductions	John Lyons
Connected Communities Program Update	Kit Parker
Avista – Spokane Tribe Energy Resiliency Partnership Update	Meghan Pinch
Preferred Resource Strategy Results	Planning Team
Avoided Costs	James Gall
Remaining TAC Schedule & Scenario Planning	James Gall

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2025 IRP TAC 11 Introductions

John Lyons, Ph.D.
Technical Advisory Committee Meeting No. 11
July 30, 2024

Today's Agenda

Introductions, John Lyons

Connected Communities Program Update, Kit Parker

Avista – Spokane Tribe Energy Resiliency Partnership Update, Meghan Pinch

Preferred Resource Strategy Results, Planning Team

Avoided Costs, James Gall

Remaining TAC Schedule and Scenario Planning, James Gall

Remaining 2025 Electric IRP TAC Schedule

- **TAC 12: August 13, 2024: 8:30 to 10:00 (PTZ) – Scheduled**
  - Preferred Resource Strategy Results (continued)
  - Portfolio Scenario Analysis (continued)
  - LOLP Study Results (continued)
  - QF Avoided Cost

- **Propose to extend TAC 12 meeting to 2.5 hours and move to:**
  - September 10, 2024, 9:00 am to 11:30 am (PTZ)
  - September 17, 2024, 9:00 am to 11:30 am (PTZ)
  - September 17, 2024, 1:00 pm to 3:30 pm (PTZ)

- **September 2, 2024- Draft IRP Released to TAC with the following chapters:**
  - Economic and Load Forecast
  - Long Term Position
  - Distributed Energy Resource Options
  - Supply Side Resource Options
  - Transmission Planning and Distribution
  - Preferred Resource Strategy
  - Washington Clean Energy Action Plan

Remaining 2025 Electric IRP TAC Schedule

- **Virtual Public Meeting- Natural Gas & Electric IRP (Moving to November 2024)**
  - Recorded presentation
  - Daytime comment and question session (12pm to 1pm- PST)
  - Evening comment and question session (6pm to 7pm- PST)

- **October 1, 2024- Remainder of Draft IRP Released to TAC with the following chapters:**
  - Executive Summary
  - Introduction, Interested Party Involvement, and Process Changes
  - Existing Supply Resources
  - Market Analysis
  - Portfolio Scenarios
  - Action Plan

Connected Communities

Kit Parker, Renewables Products and Services Manager

Technical Advisory Committee Meeting No. 11

July 30, 2024

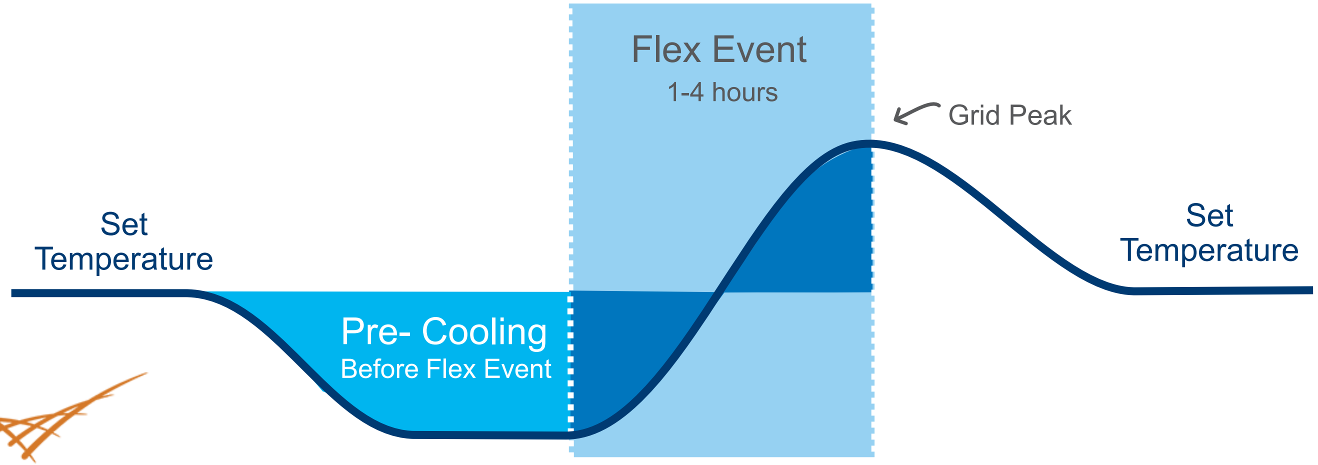
Program Objectives

- Create flexible load
- Reduce energy costs
- Maintain occupant comfort
- Foster community-based solutions
- Develop scalable model

75-125
Buildings and Homes
50-75 Residential and 25-50 Commercial

1 - 2.25MW
Flexible Load Created

During Program Flex Events



Shifting load to avoid grid peaks

Customer Thermostat

Remains within a comfortable 1°– 4° F adjustment

Load Shifting

Moving energy use to another time in the day

Pacific Northwest
NATIONAL LABORATORY

AVISTA edo

AVISTA

Project Timeline

PROJECT PLANNING

Strategic planning and design for delivering demand flexibility and energy measures.

2023

July

PILOT ASSESSMENT

Enrollment of first participants and testing of planned energy measures

2025

January

TESTING PHASE

Completion of enrollment and analysis of preliminary testing from flex events

2025

July

ANALYZE & EVALUATE

Aggregation and examination of energy efficiency measures and grid service testing

2026

July

REVIEW & PUBLISH

Finalization of a business model playbook allowing for program replication and management

2027

July

AVISTA®

Spokane Tribe of Indians

Avista - Spokane Tribe Energy Resiliency Partnership Update

Meghan Pinch, Manager, Energy Efficiency Programs

Technical Advisory Committee Meeting No. 11

July 30, 2024

Clean Energy Fund Grid Modernization Grant Award Overview

Awarded project: Financial support to design and engineer a clean and resilient energy storage project in partnership with the Spokane Tribe. The project will support increased energy resilience and energy sovereignty. Funding does not include construction of project.

Project Funding: $480,000 in total (Avista to provide $240,000 in-kind match to $240,000 in funding from Department of Commerce).

Grid Modernization grants will support utilities across the state in building and integrating new technologies that support their clean energy transition plans.

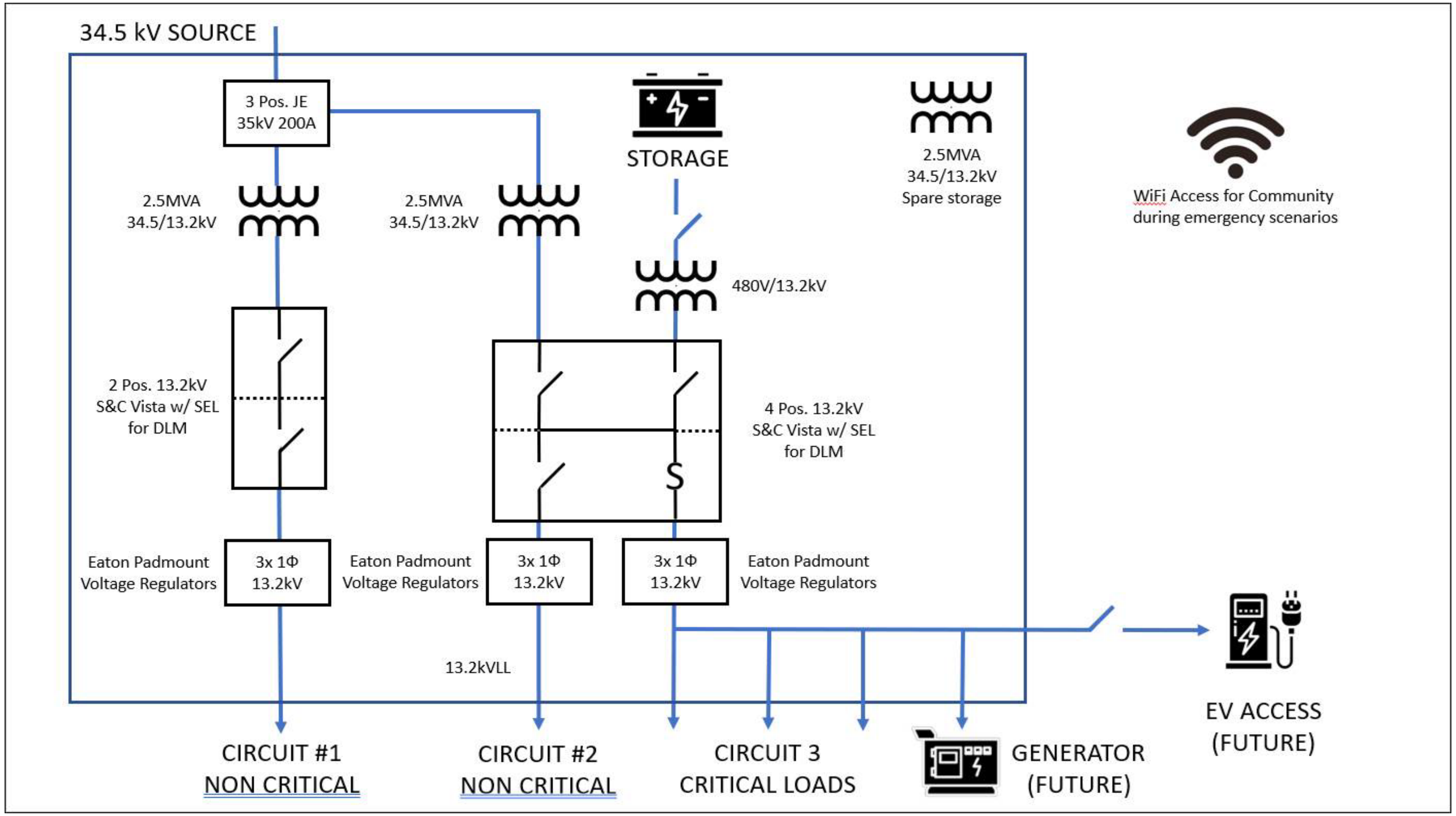
Spokane Tribe Grid Resiliency Station

"Switchable" platform that could enable power to be switched between three or more stepdown circuits in an emergency

Would replace elevated building transformers currently behind post office / trading post

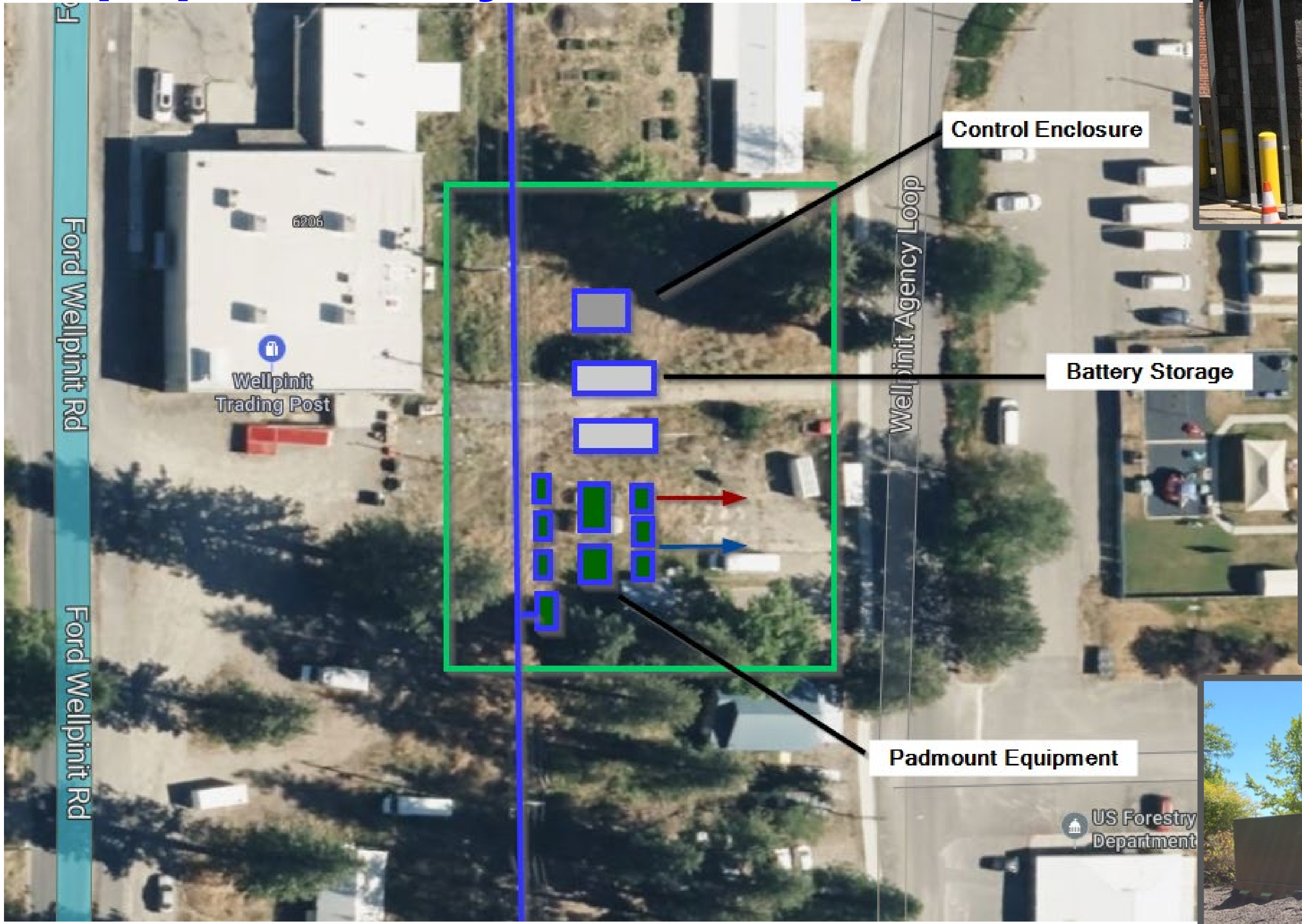
Would create a "critical loads" circuit to provide power to Tribal Admin building, Wynecoop Memorial Health Clinic, and Public Safety buildings during emergencies

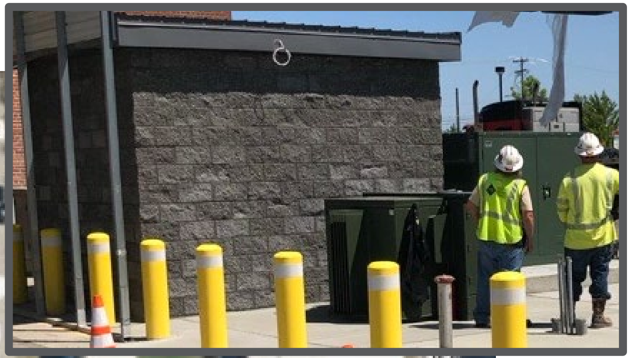
Could leverage existing generation resources to sustain summer loads for up to 7 days



Equipment Layout Concept

Appendix A





AVISTA

Recent Activities and Next Steps

- Avista provided technical assistance to the Tribe in applying for $2.75 million from Department of Commerce Tribal Clean Energy Grant
- Additional funding been committed from a mix of federal formula Tribal DOE grants and Avista-provided funding
- Total project costs are expected to be around $6.65 million
- Avista and the Spokane Tribe are considering applying for additional grant funding for additional scope items

2025 Electric Integrated Resource Plan
Draft Preferred Resource Strategy

James Gall
Technical Advisory Committee Meeting No. 11
July 30, 2024

Preferred Resource Strategy (7/16/2024)

Nameplate MW	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Shared System Resource																				
Mrkt/Trans	40	4	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas	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	0
Wind	0	0	0	0	0	100	100	200	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
PtoG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	10	0
RNG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Washington																				
Mrkt/Trans	0	0	0	0	0	0	0	0	0	0	0	50	0	0	50	50	50	50	0	50
Natural Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	0	1	1	1	1	1	101	1	1	1	1	1	1	1	1	1	1	1	200	5
Wind	0	0	0	200	200	100	0	0	0	0	0	0	0	0	0	140	0	120	0	200
Storage	0	0	0	0	0	0	50	0	0	0	0	0	0	0	0	0	0	0	104	62
PtoG	0	0	0	0	0	0	0	0	0	0	0	0	90	0	0	0	196	0	94	0
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	150
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	20
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RNG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Idaho																				
Mrkt/Trans	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas	0	0	0	0	99	0	0	0	0	0	0	90	0	0	0	0	124	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	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	35	0
PtoG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RNG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Revised Preferred Resource Strategy (2026-35)

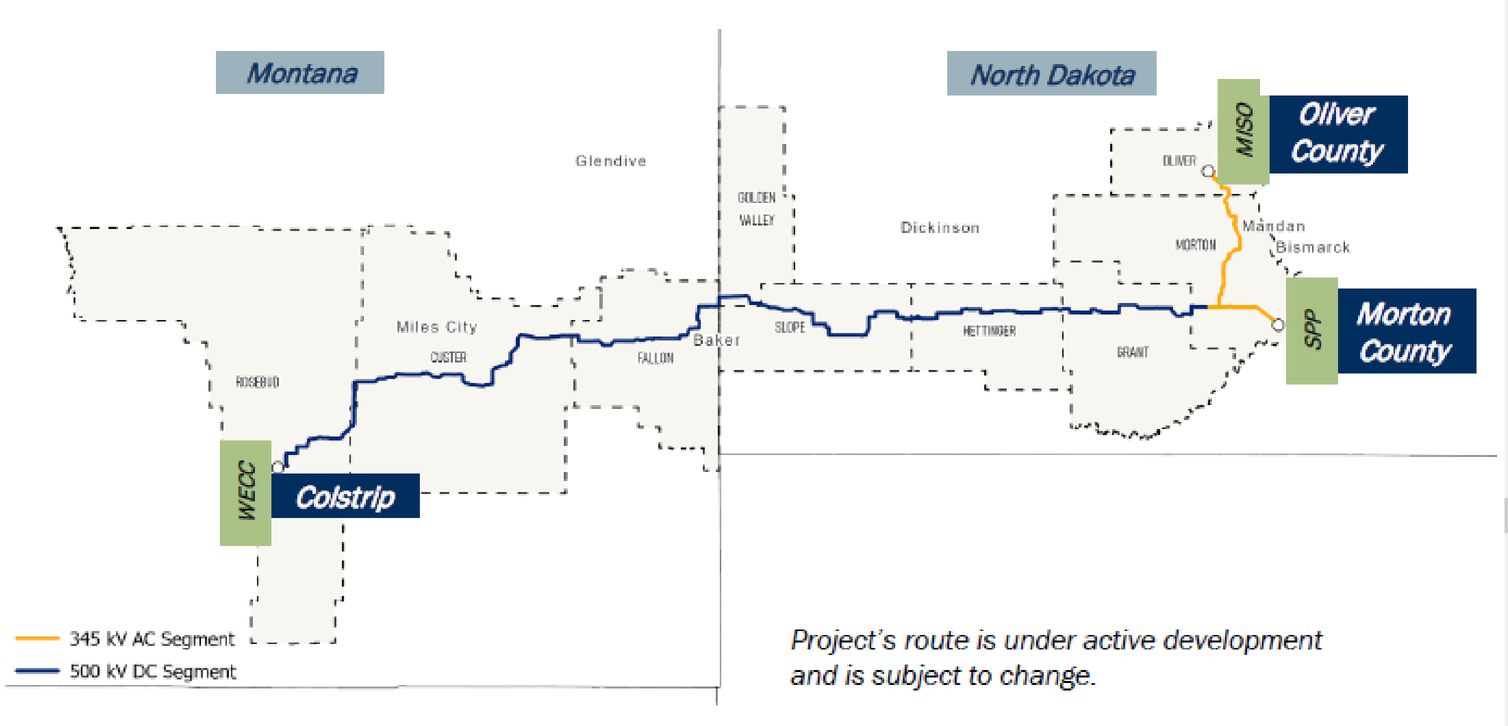
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Washington (MW- Nameplate)											
Market	25.8	2.5	6.4	-	-	-	-	-	-	-	**34.6**
Regional Transmission	-	-	-	-	-	-	-	198.4	-	-	**198.4**
Natural Gas	-	-	-	-	-	-	-	-	-	-	**-**
Solar	-	0.5	0.6	0.6	0.7	0.8	0.8	1.0	0.5	0.5	**5.9**
Wind	-	-	-	200.0	200.0	165.9	66.0	104.0	-	-	**736.0**
Storage	-	-	-	-	-	-	-	-	-	-	**-**
Power to Gas	-	-	-	-	-	-	-	-	-	-	**-**
Nuclear	-	-	-	-	-	-	-	-	-	-	**-**
Geothermal	-	-	-	-	-	-	-	-	-	-	**-**
Biomass	-	-	-	-	-	-	-	-	-	-	**-**
Total	**25.8**	**3.0**	**6.9**	**200.6**	**200.7**	**166.7**	**66.8**	**303.4**	**0.5**	**0.5**	**974.9**
Cumulative Demand-Side Management											
Demand Response (MW)	0.5	1.4	3.0	4.9	7.2	8.7	9.4	10.2	11.1	12.4	
Energy Efficiency (aMW)	3.4	7.1	11.2	15.8	19.7	24.0	29.2	34.5	39.8	44.5	
Idaho (MW- Nameplate)											
Market	13.6	1.3	3.3	-	-	-	-	-	-	-	**18.2**
Regional Transmission	-	-	-	-	-	-	-	101.6	-	-	**101.6**
Natural Gas	-	-	-	-	90.2	-	-	-	-	-	**90.2**
Solar	-	-	-	-	-	-	-	-	-	-	**-**
Wind	-	-	-	-	-	34.1	34.0	53.3	-	-	**121.4**
Storage	-	-	-	-	-	-	-	-	-	-	**-**
Power to Gas	-	-	-	-	-	-	-	-	-	-	**-**
Nuclear	-	-	-	-	-	-	-	-	-	-	**-**
Geothermal	-	-	-	-	-	-	-	-	-	-	**-**
Biomass	-	-	-	-	-	-	-	-	-	-	**-**
Total	**13.6**	**1.3**	**3.3**	**-**	**90.2**	**34.1**	**34.0**	**155.0**	**-**	**-**	**331.5**
Cumulative Demand-Side Management											
Demand Response (MW)	-	-	-	0.1	0.3	0.7	1.0	1.2	1.3	1.3	
Energy Efficiency (aMW)	1.2	2.6	4.1	5.9	7.2	8.6	10.5	12.6	14.5	16.3	
Resource Reductions (MW)	**0**	**0**	**0**	**12**	**64**	**0**	**0**	**0**	**88**	**0**	**164.0**

~78,000 MWh
Biannual EE Target

Revised Preferred Resource Strategy (2036-45)

	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Washington (MW- Nameplate)											
Market	-	-	-	-	-	-	-	-	-	-	**-**
Regional Transmission	-	-	-	-	-	-	-	-	-	-	**-**
Natural Gas	-	-	-	-	-	-	-	-	-	-	**-**
Solar	0.5	0.5	0.5	0.5	0.5	0.5	0.5	180.5	120.5	0.6	**305.1**
Wind	-	-	-	-	-	140.0	-	120.0	108.4	200.0	**568.4**
Storage	-	-	-	-	-	-	-	90.0	86.1	85.3	**261.4**
Power to Gas	-	-	-	-	90.2	-	209.8	-	-	94.3	**394.3**
Nuclear	-	-	-	-	-	-	-	-	-	100.0	**100.0**
Geothermal	-	-	-	-	-	-	-	-	-	20.0	**20.0**
Biomass	-	-	-	-	-	-	-	-	-	64.4	**64.4**
Total	**0.5**	**0.5**	**0.5**	**0.5**	**90.7**	**140.5**	**210.3**	**390.5**	**314.9**	**564.6**	**1,713.6**
Cumulative Demand-Side Management											
Demand Response (MW)	13.6	15.1	18.8	26.5	31.9	36.6	40.6	44.6	48.4	51.6	
Energy Efficiency (aMW)	49.1	53.5	57.6	61.1	64.4	67.6	70.0	72.7	75.2	77.3	
Idaho (MW- Nameplate)											
Market	-	-	-	-	-	-	-	-	-	-	**-**
Regional Transmission	-	-	-	-	-	-	-	-	-	-	**-**
Natural Gas	-	-	-	-	90.2	-	94.9	-	-	-	**185.1**
Solar	-	-	-	-	-	-	-	-	-	-	**-**
Wind	-	-	-	-	-	-	-	-	-	-	**-**
Storage	-	-	-	-	-	-	-	-	-	-	**-**
Power to Gas	-	-	-	-	-	-	-	-	-	-	**-**
Nuclear	-	-	-	-	-	-	-	-	-	-	**-**
Geothermal	-	-	-	-	-	-	-	-	-	-	**-**
Biomass	-	-	-	-	-	-	-	-	-	3.2	**3.2**
Total	**-**	**-**	**-**	**-**	**90.2**	**-**	**94.9**	**-**	**-**	**3.2**	
Cumulative Demand-Side Management											
Demand Response (MW)	1.4	1.4	1.7	2.1	2.5	2.9	3.7	5.8	8.7	10.6	
Energy Efficiency (aMW)	18.2	20.0	21.7	23.2	24.6	25.9	27.0	28.2	29.3	30.4	
Resource Reductions (MW)	**0**	**0**	**0**	**20**	**36**	**140**	**282**	**105**	**0**	**390**	**973**

North Plains Connector



At the 7/16/2024 TAC Meeting: 300 MW of this resource was selected between 2037-45. It was discussed this resource cannot be acquired in increments and not all benefits were modeled at this time

Wind Selection Observations

- 850 MW of wind is selected between 2029-2033, this is a financially beneficial early action taking advantage of IRA benefits and low PPA prices.
  - If tax credits change or low priced PPA terms do not materialize, this selection will change.
  - Avista has limited transmission to integrate new wind in the service territory, if wind projects are exported off system, the PRS selection will reduce.
- Concerned with Montana Wind winter QCC could underestimate need for winter capability.
- Additional wind could be economic for Idaho customers, but the model allocates to Washington due to limited options to meet long-term CETA goals.

Demand Response

Program	Customer Segment	Washington Start Year	WA	Idaho Start Year	ID
Electric Vehicle TOU	Commercial	2026	8.8	2029	0.7
Battery Energy Storage	All	2026	10.4	2035	1.5
Variable Peak Pricing	Large Commercial	2026	5.4	2029	1.7
Peak Time Rebate	Residential/Sm. Com.	2035	5.5	2040	4.0
Behavioral	Residential/Sm. Com.	2038	1.9	2043	1.0
Time of Use Rates	Residential/Sm. Com.	2038	2.5		n/a
Third Party Contracts	Large Commercial	2039	18.0	2044	3.1
CTA ERWH	Residential/Sm. Com.	2041	3.4		n/a
Central A/C	Residential/Sm. Com.	2043	5.2		n/a
Total MW by 2045 (Highest of Summer/Winter)			**61.2**		**12.0**

Assumptions:

- Current industrial contract remains
- Idaho AMI by 2029
- Total savings assumes projects do not overlap into other programs
- Totals include ramped savings to 2045, based on the time period the program was selected

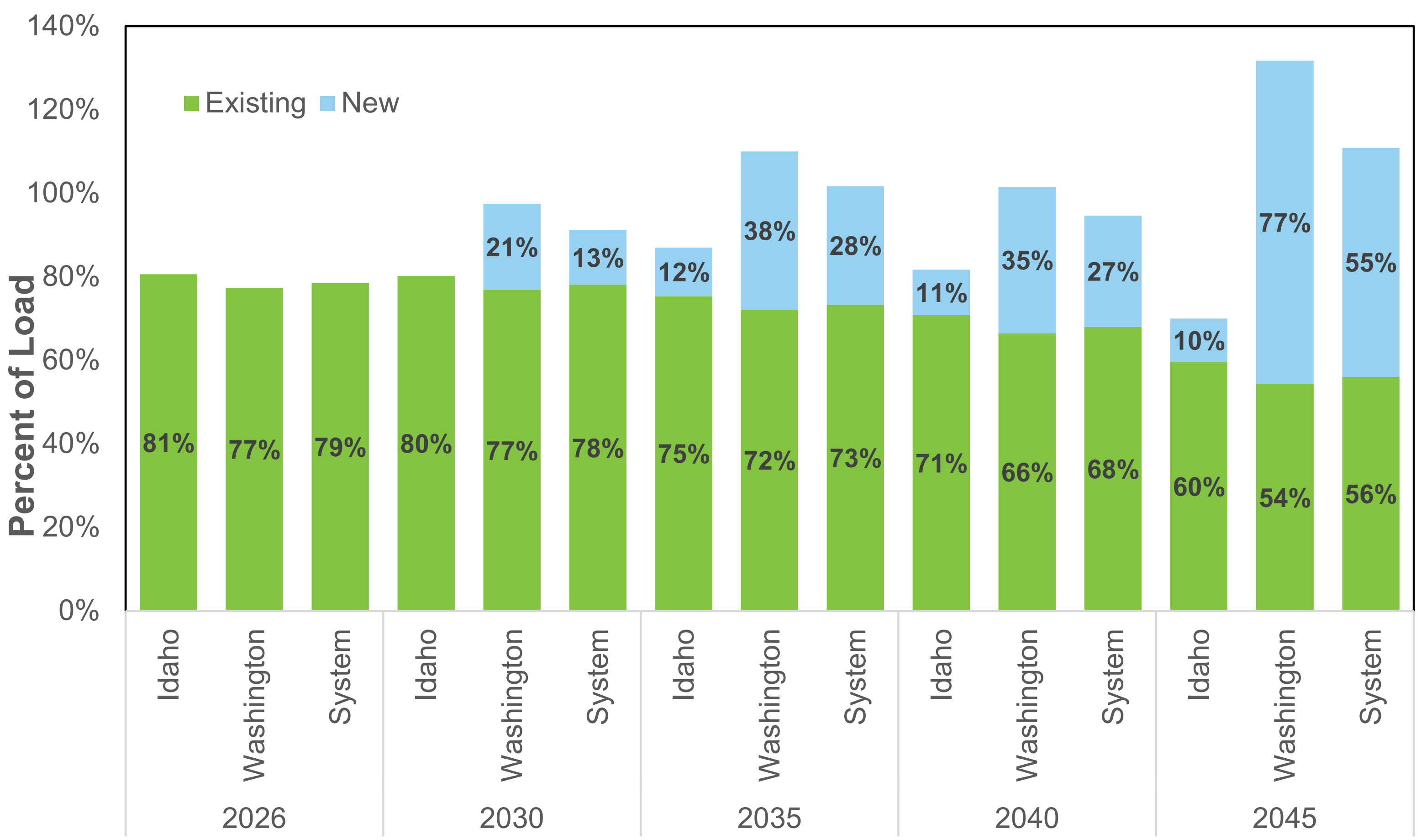
Energy Efficiency Top Measure Types

Row	Measure	State	2035	Row	Measure	State	2035
1	Linear Lighting	WA	81.34	1	Linear Lighting	ID	43.34
2	Windows - High Efficiency (ENERGY STAR 7.0)	WA	27.98	2	High-Bay Lighting	ID	12.70
3	High-Bay Lighting	WA	25.00	3	Water Heater - Pipe Insulation	ID	7.90
4	Water Heater - Pipe Insulation	WA	18.13	4	Ducting - Repair and Sealing	ID	6.75
5	Ducting - Repair and Sealing	WA	17.70	5	Insulation - Ceiling Installation	ID	5.96
6	Ductless Mini Split Heat Pump	WA	17.11	6	Air-Source Heat Pump	ID	4.91
7	Air-Source Heat Pump	WA	16.05	7	Lodging - Guest Room Controls	ID	4.69
8	Water Heater (<= 55 Gal)	WA	13.69	8	Windows - Low-e Storm Addition	ID	4.34
9	Home Energy Reports	WA	10.43	9	Ventilation - Variable Speed Control	ID	4.27
10	Insulation - Ceiling Installation	WA	9.26	10	Home Energy Reports	ID	4.24
11	Ventilation - Variable Speed Control	WA	8.60	11	Grocery - Display Case - LED Lighting	ID	3.89
12	Advanced Industrial Motors	WA	7.81	12	Clothes Washer - CEE Tier 2	ID	3.60
13	Insulation - Wall Sheathing	WA	7.46	13	Fan System - Equipment Upgrade	ID	3.40
14	Windows - Low-e Storm Addition	WA	6.63	14	Refrigeration - High Efficiency Compressor	ID	3.24
15	Building Shell - Air Sealing (Infiltration Control)	WA	6.03	15	Kitchen Ventilation - Advanced Controls	ID	2.75
16	Kitchen Ventilation - Advanced Controls	WA	5.89	16	HVAC - Energy Recovery Ventilator	ID	2.66
17	Clothes Washer - CEE Tier 2	WA	5.70	17	Water Heater (<= 55 Gal)	ID	2.59
18	Strategic Energy Management	WA	5.38	18	General Service Lighting	ID	2.17
19	Insulation - Ceiling Upgrade	WA	5.16	19	Ventilation - Demand Controlled	ID	2.07
20	General Service Lighting	WA	4.90	20	Insulation - Ceiling Upgrade	ID	1.69
21	Pumping System - System Optimization	WA	4.89	21	Area Lighting	ID	1.68
22	HVAC - Energy Recovery Ventilator	WA	4.77	22	Water Heater - Faucet Aerators	ID	1.48
23	Fan System - Equipment Upgrade	WA	4.54	23	Furnace - Conversion to Air-Source Heat Pump	ID	1.32
24	Connected Thermostat - ENERGY STAR (1.0)	WA	4.49	24	Pumping System - System Optimization	ID	1.27
25	Refrigeration - High Efficiency Compressor	WA	3.98	25	Refrigeration - High Efficiency Evaporator Fan Motors	ID	1.26

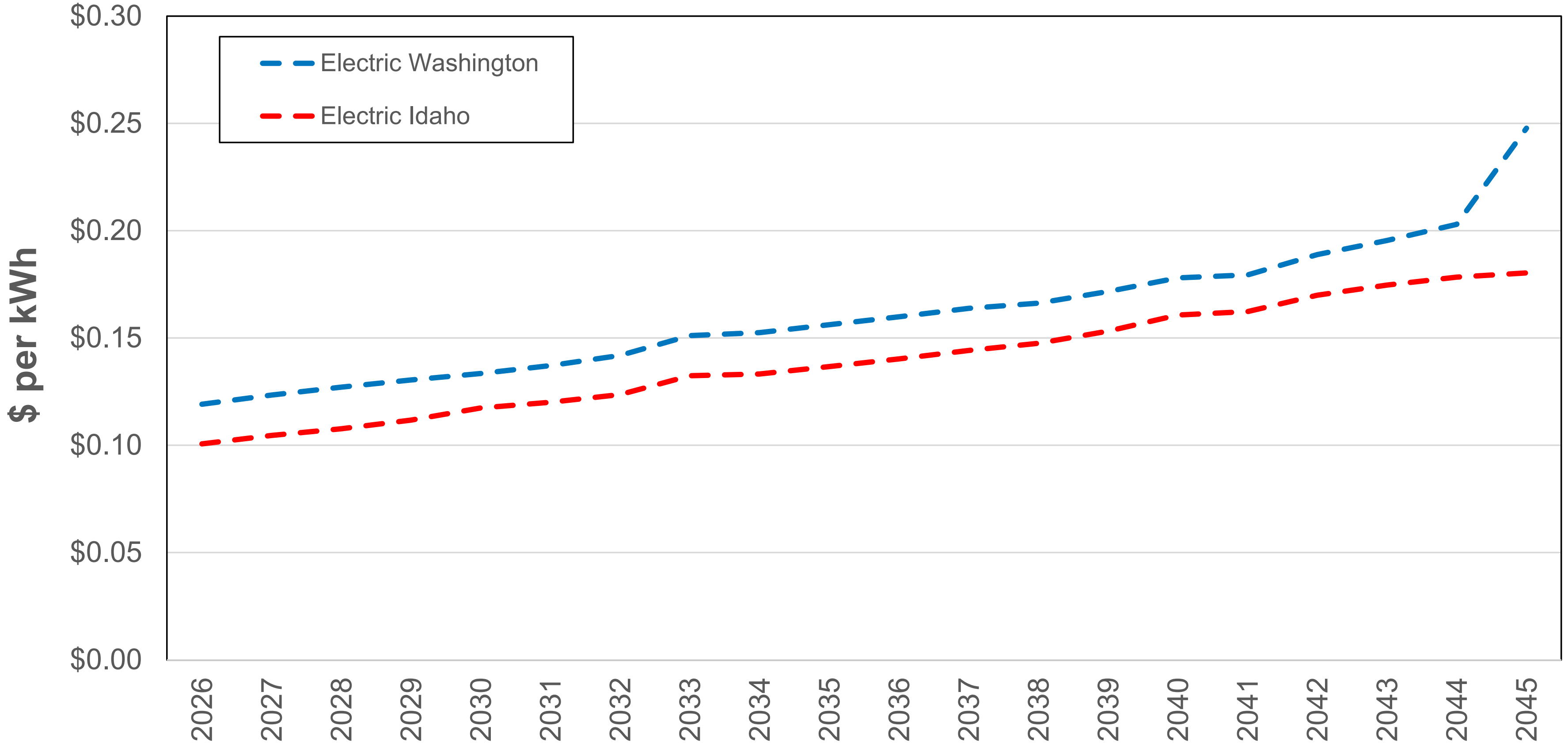
Avista Transmission Considerations

- **Rathdrum Area**: New natural gas CTs begin in 2030, these are likely located in North Idaho, new transmission will be required, if projects continue to be sited in the area additional reinforcement is needed.
- **Off-System Imports:** Need to increase connections to markets/areas to reach additional wind to import by 2045.
- If within system renewables are exported off system, additional transmission within Avista BA will be needed.

Clean Energy Forecast

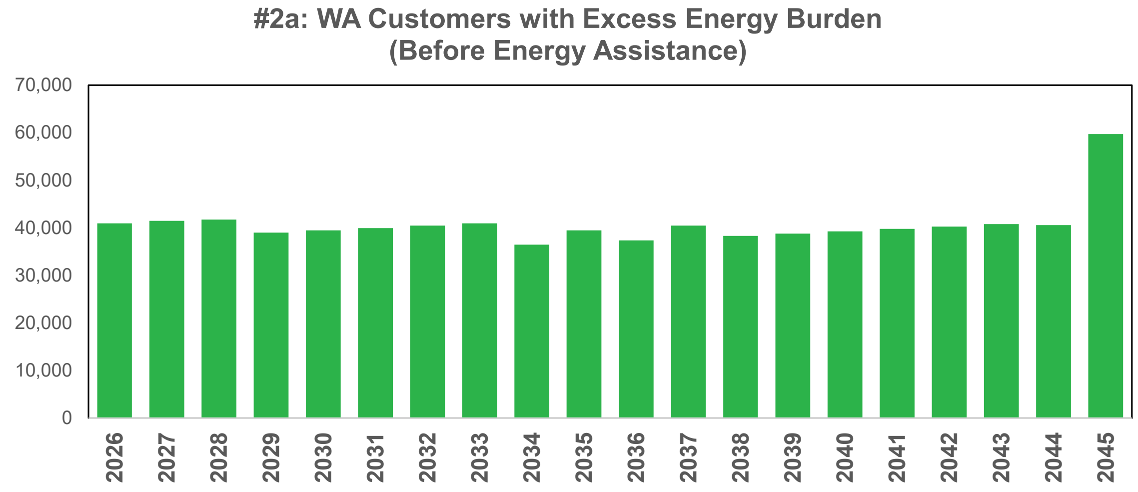


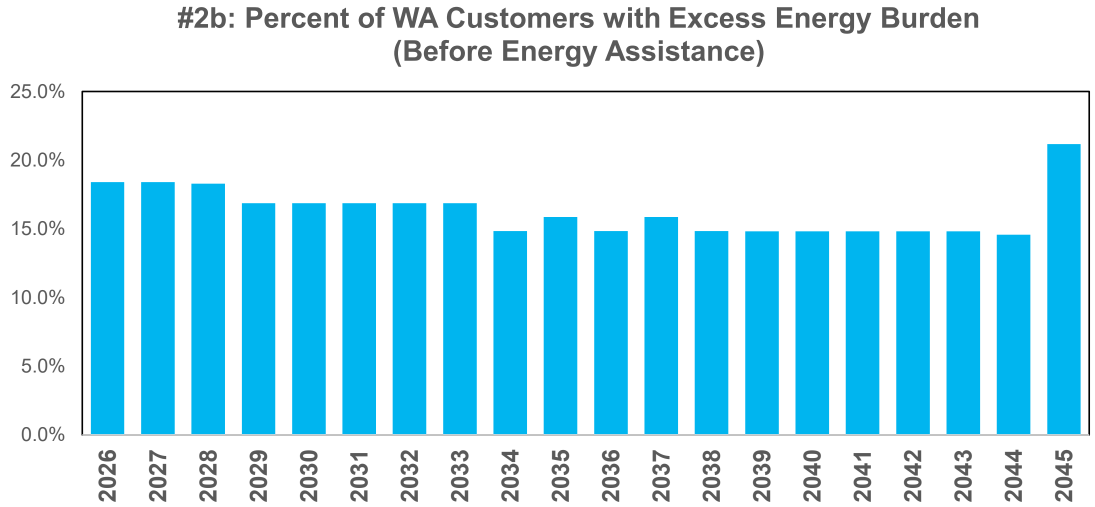
Average Energy Rate Forecast

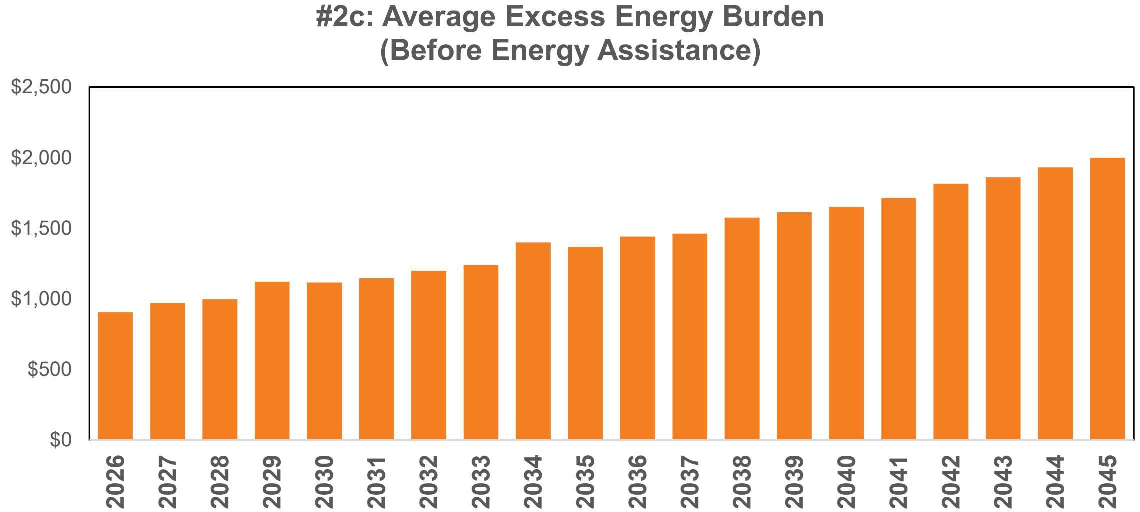


Assumes non-modelled cost increase by 3.8% per year

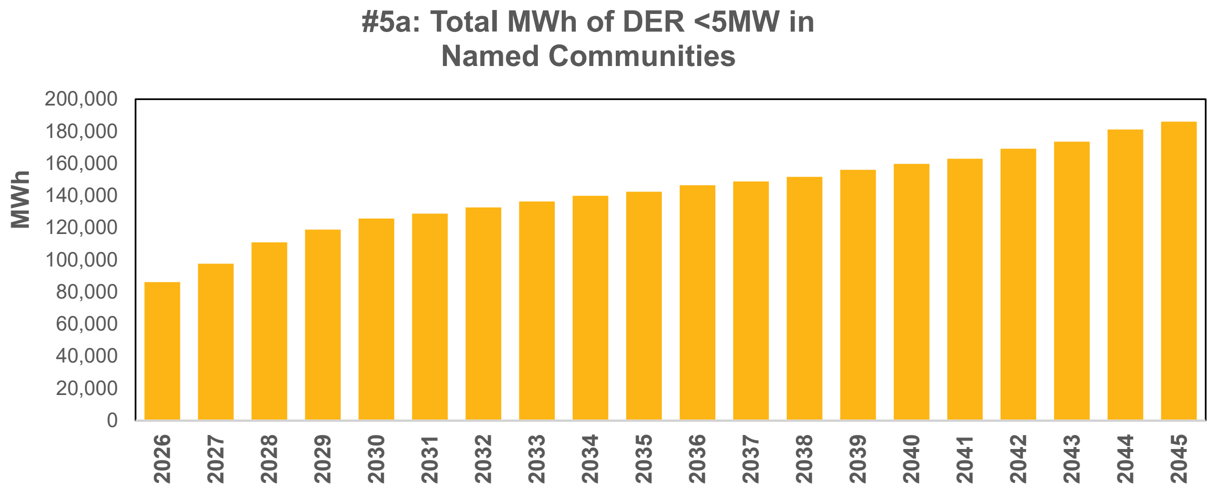
Washington Energy Burden CBI

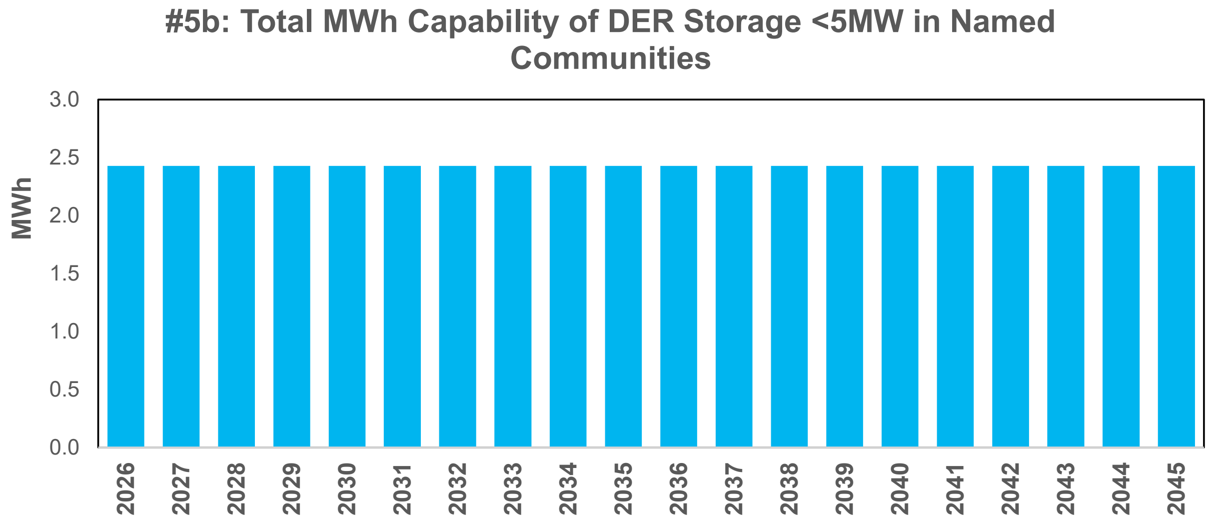




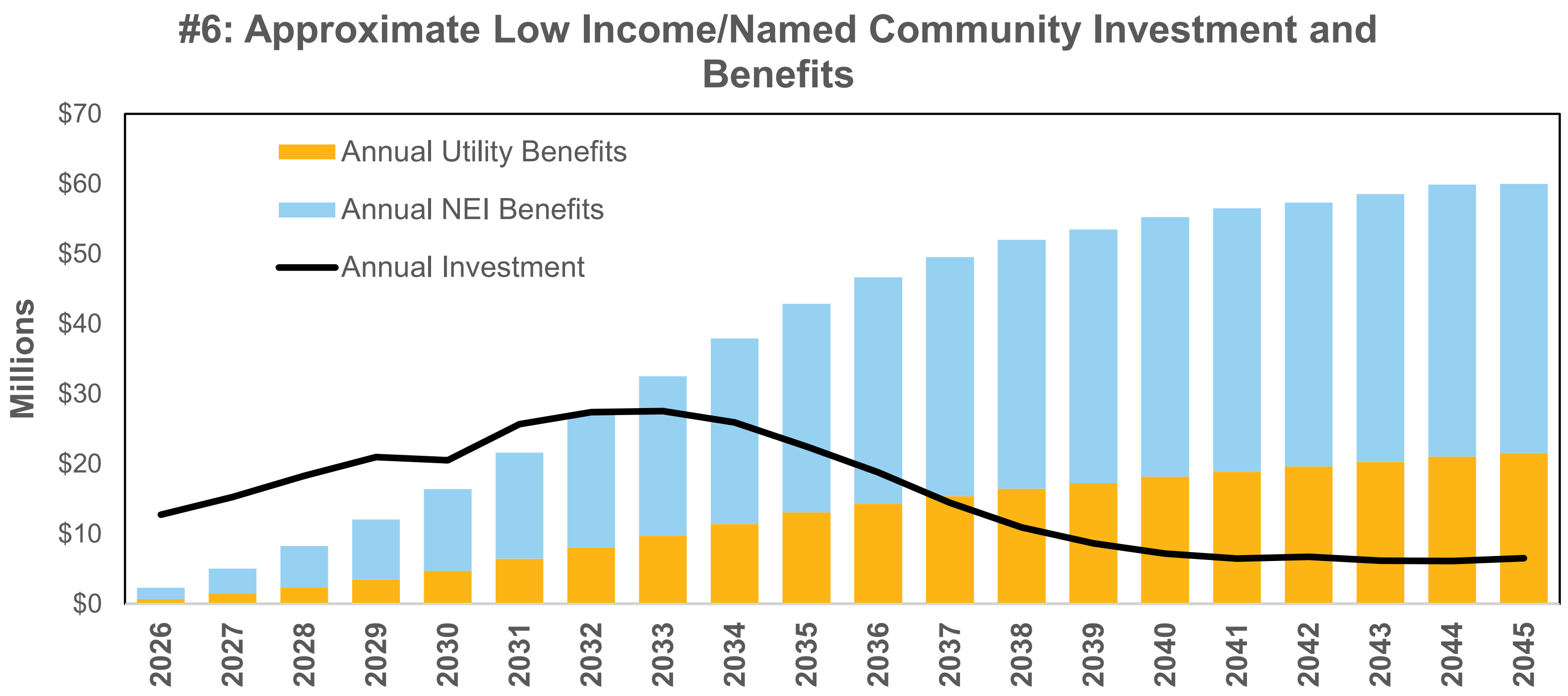


DER Additions CBI

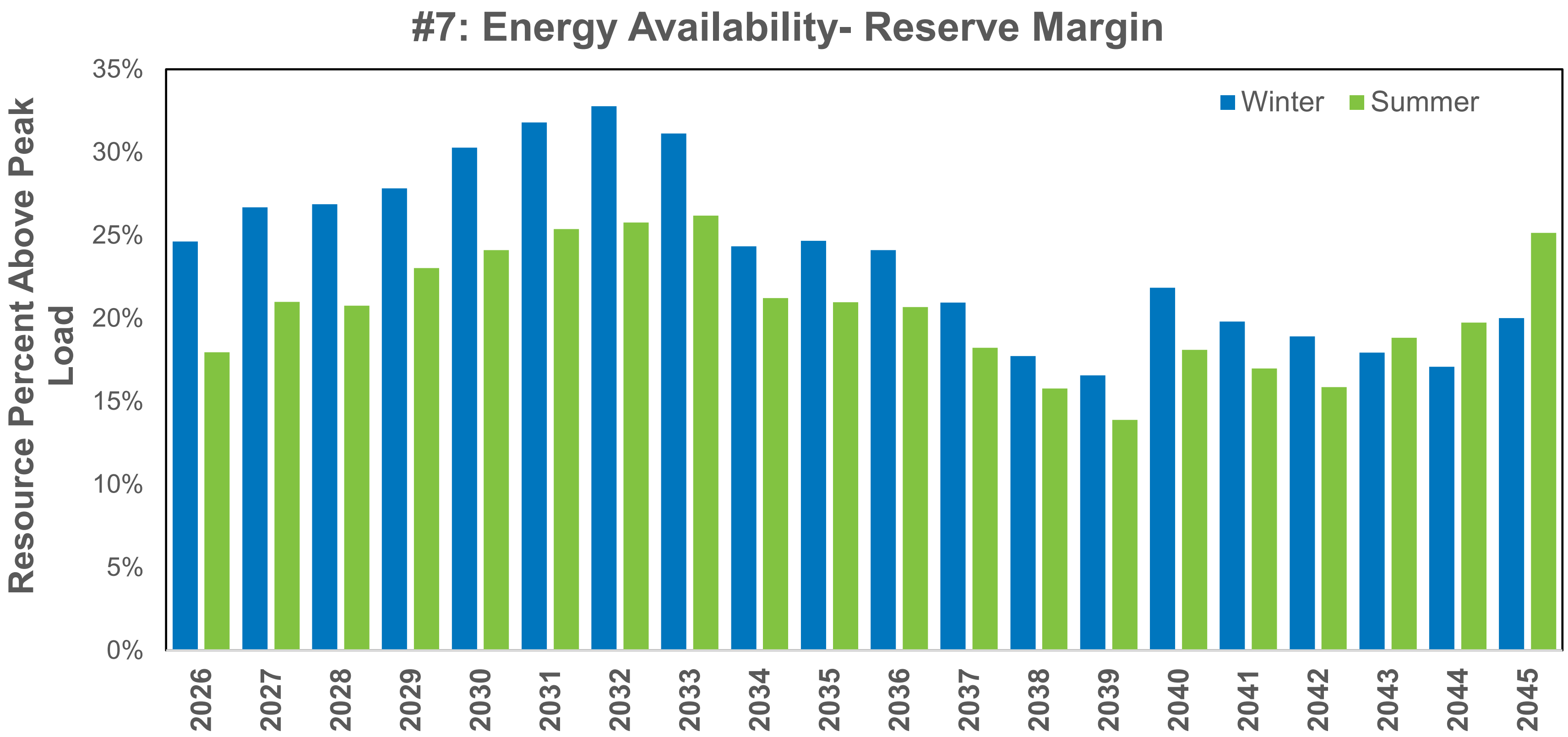




WA Low Income/Named Community Investments CBI



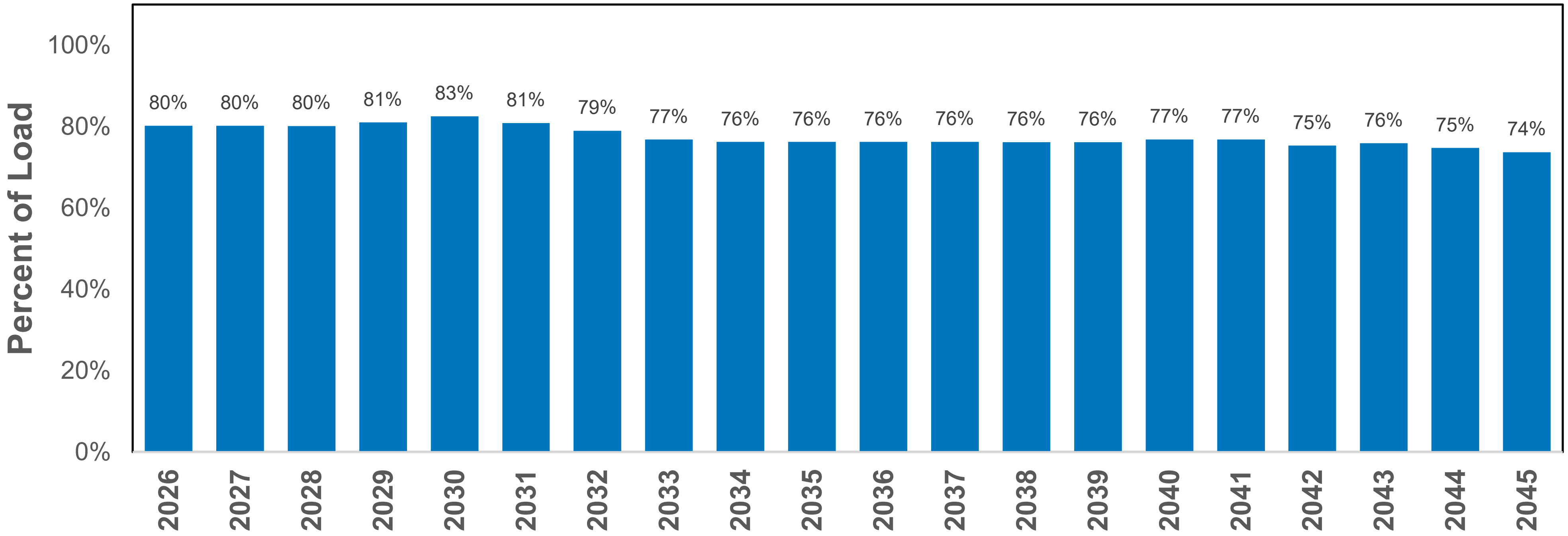
Reserve Margin CBI



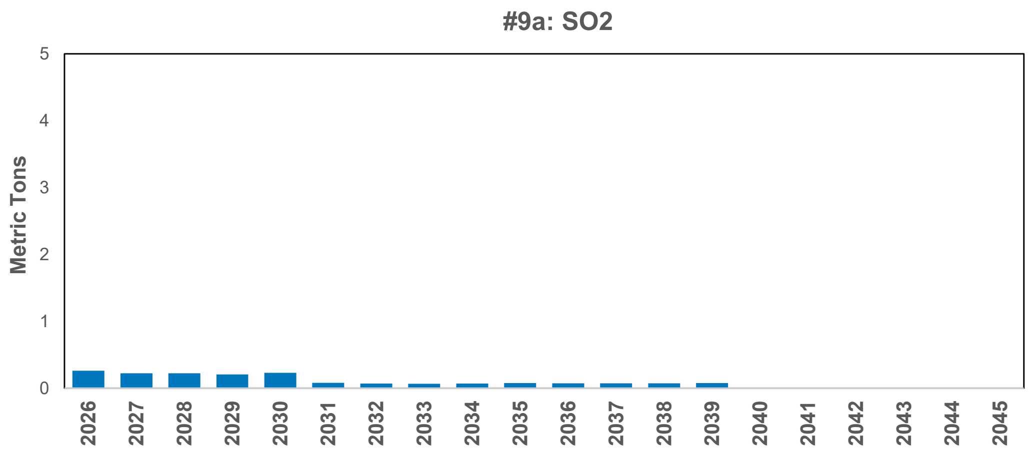
Notes:
- Regional Transmission not included in Reserve Margin
- Demand Response reduced from peak load

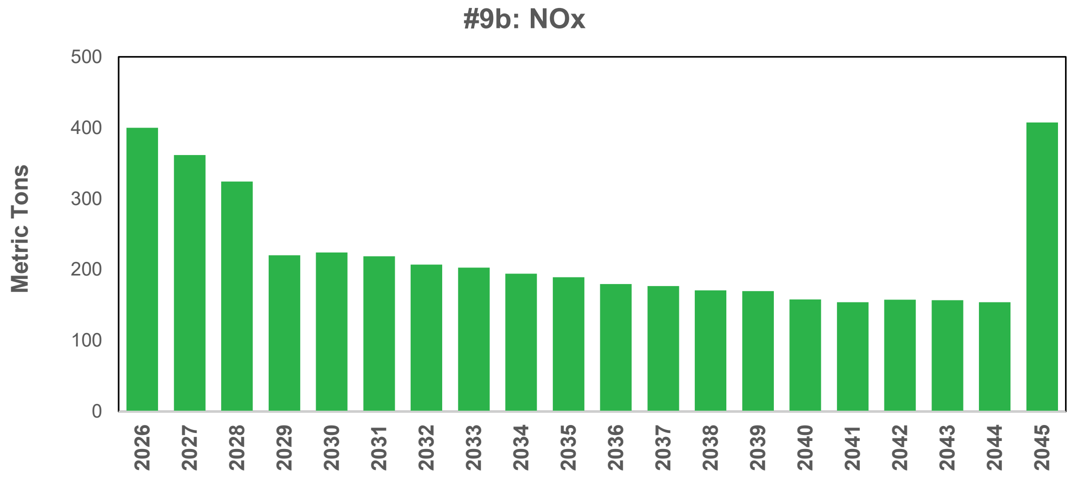
Generation Location CBI

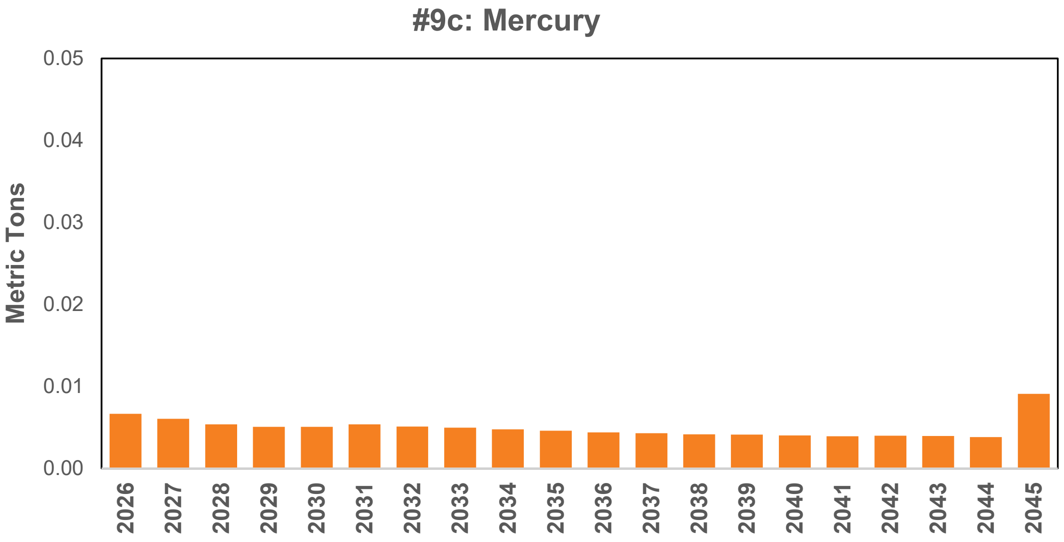
#8: Generation in WA and/or Connected Transmission System
(as a Percent of Generation)

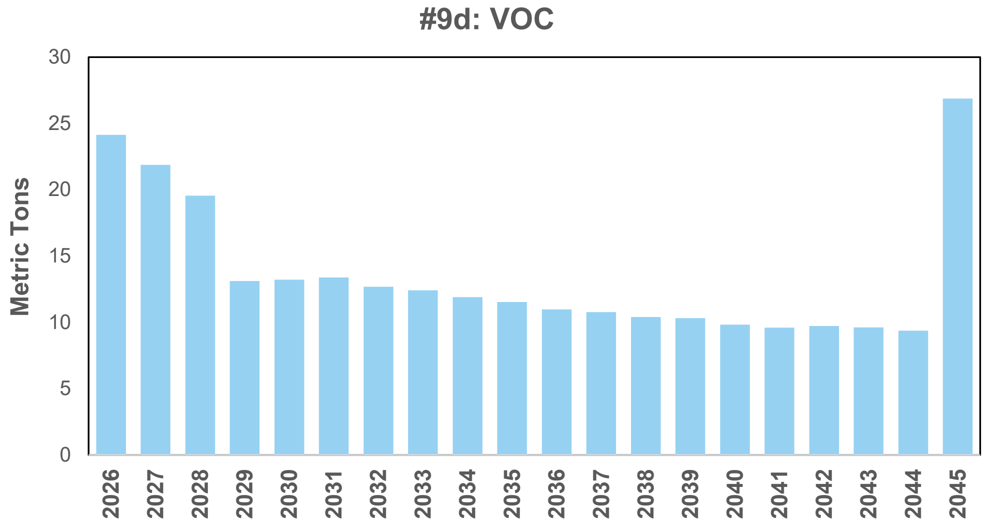


Washington Air Emissions CBI

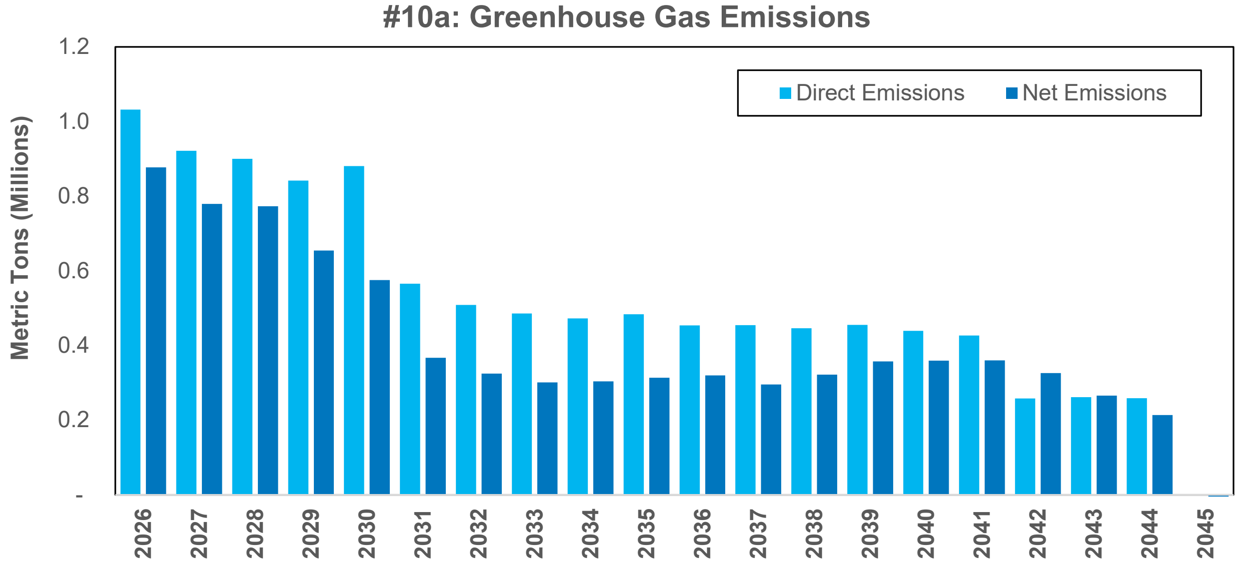


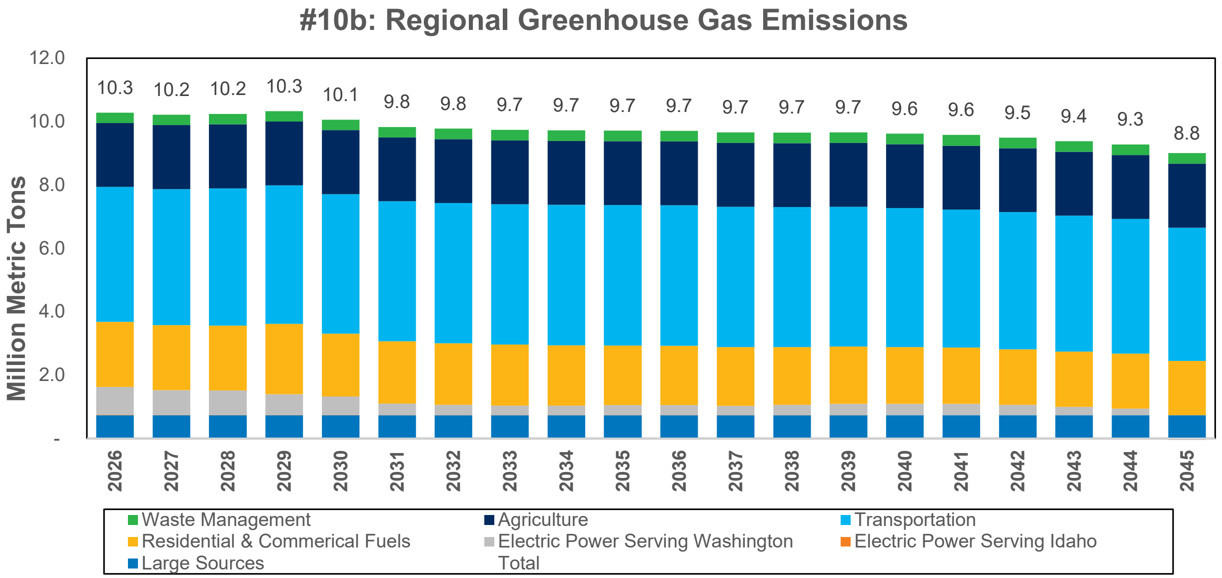




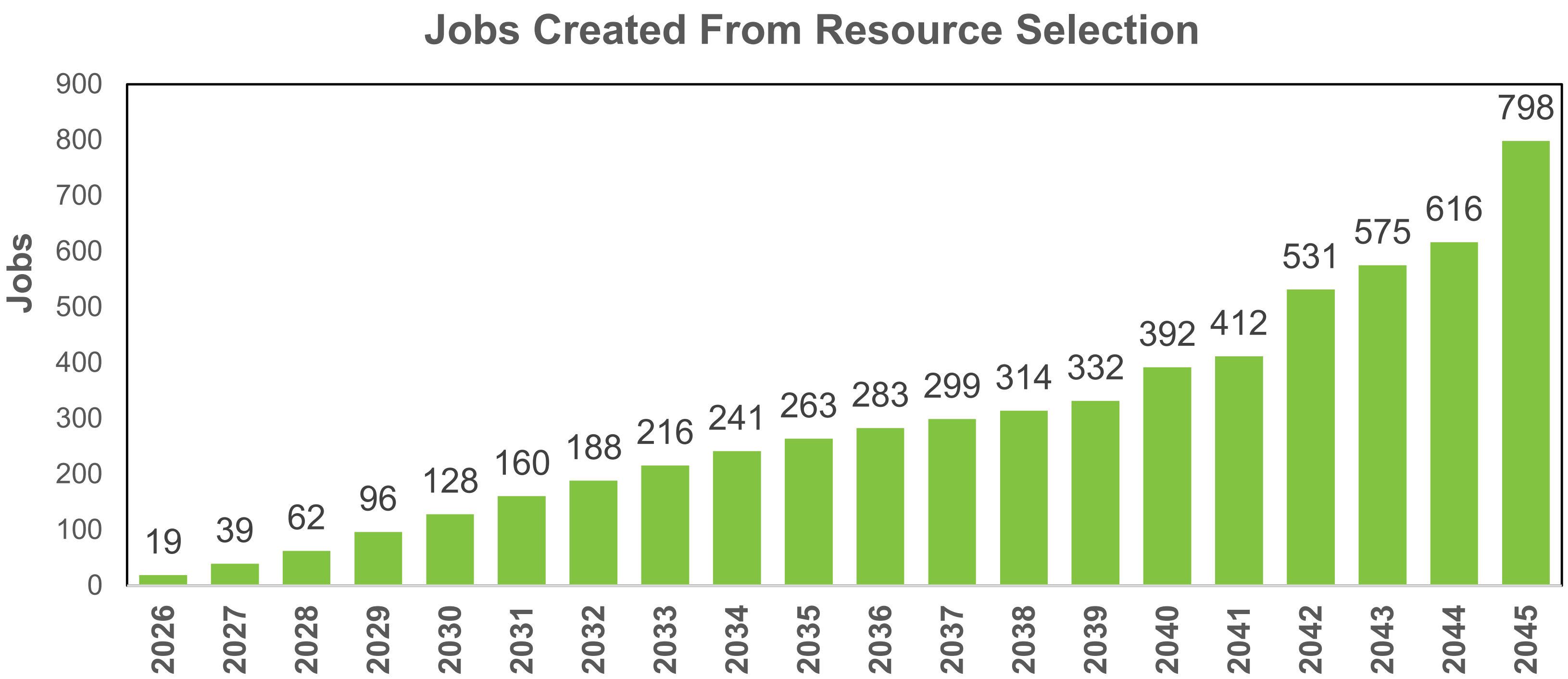


WA Greenhouse Gas Emissions CBI



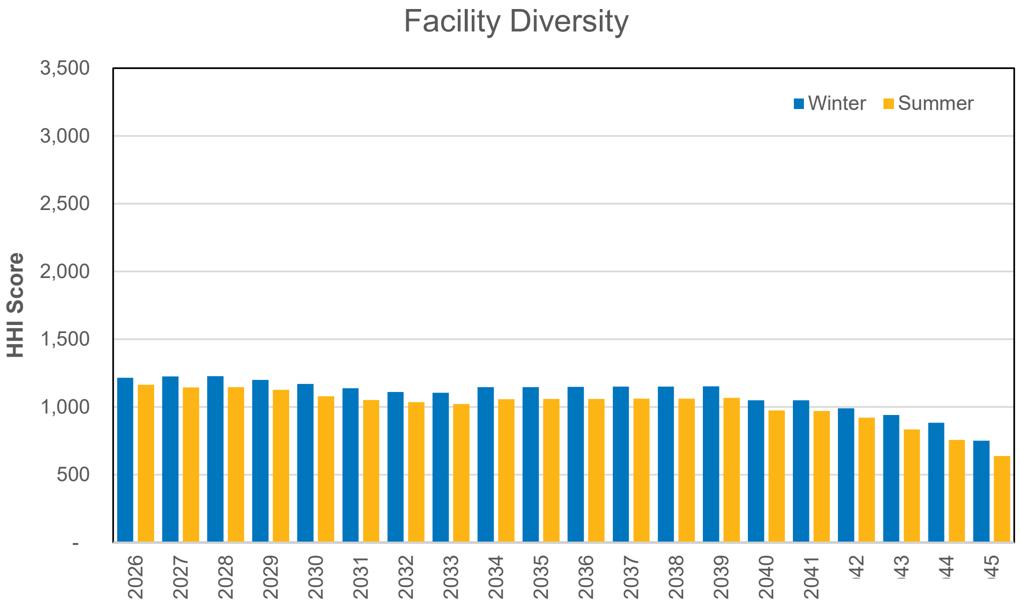


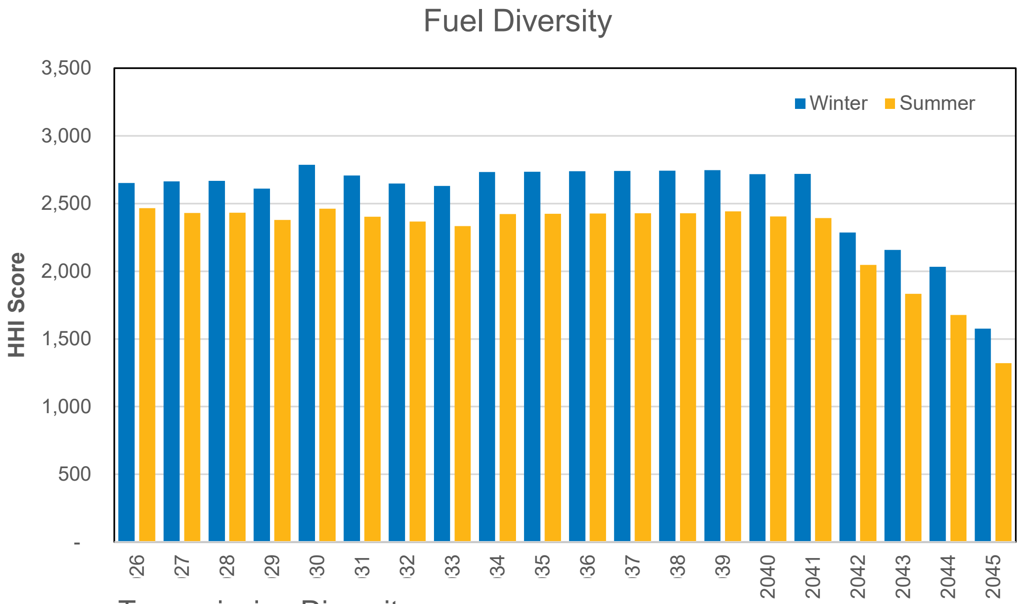
Job Creation (Direct and Induced)



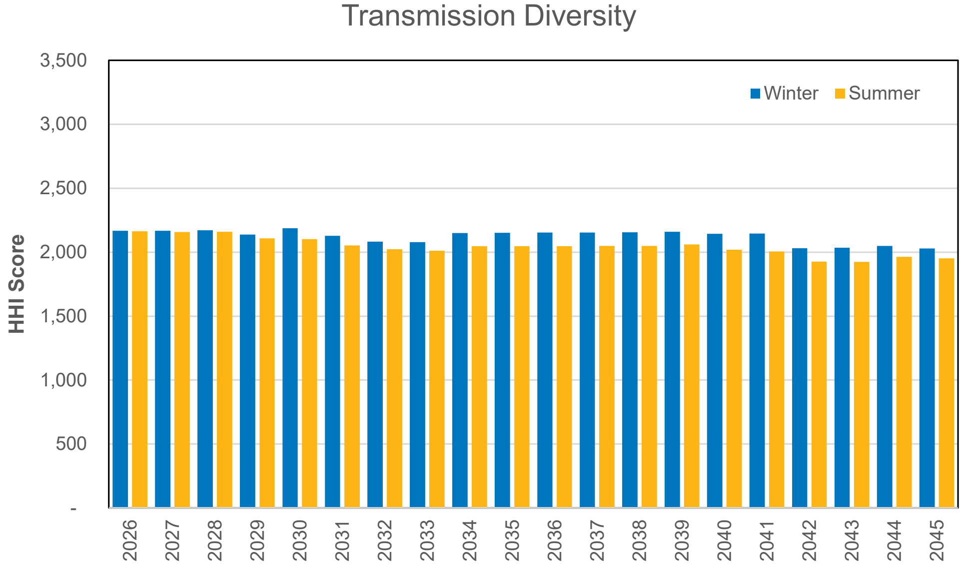
Job estimates based on spending to job relationship today using INPLAN

Resource Diversity (Resource Resiliency Metrics)





Score	Metric Meaning
<1,500	Competitive Marketplace
1,500-2,500	Moderately Concentrated
>2,500	Highly Concentrated



Avoided Costs

	Washington				
Year	Flat Energy ($/MWh)	On-Peak Energy ($/MWh)	Off-Peak Energy ($/MWh)	Capacity Premium ($/kW-Yr)	Clean Capacity Premium ($/kW-Yr)
2026	$41.98	$40.46	$43.12	$0.0	$0.0
2027	$38.14	$38.58	$37.82	$0.0	$0.0
2028	$35.40	$37.03	$34.18	$0.0	$0.0
2029	$35.04	$36.64	$33.84	$0.0	$0.0
2030	$39.18	$40.90	$37.89	$27.2	$82.4
2031	$44.10	$46.40	$42.38	$27.8	$84.1
2032	$44.33	$47.09	$42.27	$28.3	$85.8
2033	$45.40	$48.29	$43.23	$28.9	$87.5
2034	$45.55	$48.72	$43.17	$29.5	$59.8
2035	$46.71	$49.96	$44.27	$30.0	$61.0
2036	$46.40	$49.74	$43.90	$30.6	$62.2
2037	$47.66	$51.45	$44.82	$31.3	$63.4
2038	$47.77	$51.51	$44.98	$31.9	$64.7
2039	$48.48	$52.35	$45.58	$32.5	$66.0
2040	$49.59	$53.79	$46.43	$33.2	$67.3
2041	$50.01	$54.44	$46.68	$33.8	$68.6
2042	$52.31	$56.90	$48.88	$34.5	$70.0
2043	$52.97	$57.66	$49.45	$35.2	$71.4
2044	$53.84	$58.61	$50.27	$35.9	$72.8
2045	$55.07	$59.83	$51.48	$36.6	$74.3
20 yr Levelized	**$44.13**	**$46.60**	**$42.27**	**$21.28**	**$49.93**

	Idaho				
Year	Flat Energy ($/MWh)	On-Peak Energy ($/MWh)	Off-Peak Energy ($/MWh)	Capacity Premium ($/kW-Yr)	Clean Capacity Premium ($/kW-Yr)
2026	$41.61	$40.42	$42.50	$0.0	$0.0
2027	$37.88	$38.70	$37.26	$0.0	$0.0
2028	$35.13	$37.19	$33.57	$0.0	$0.0
2029	$34.57	$36.64	$33.01	$0.0	$0.0
2030	$38.56	$40.85	$36.84	$27.2	$0.0
2031	$43.00	$45.74	$40.96	$27.8	$0.0
2032	$42.74	$45.92	$40.36	$28.3	$0.0
2033	$43.82	$47.20	$41.29	$28.9	$0.0
2034	$43.92	$47.54	$41.19	$29.5	$0.0
2035	$44.93	$48.59	$42.18	$30.0	$0.0
2036	$44.50	$48.21	$41.72	$30.6	$0.0
2037	$45.69	$49.82	$42.61	$31.3	$0.0
2038	$45.66	$49.68	$42.64	$31.9	$0.0
2039	$46.29	$50.42	$43.19	$32.5	$0.0
2040	$47.28	$51.69	$43.96	$33.2	$0.0
2041	$47.66	$52.29	$44.19	$33.8	$0.0
2042	$49.92	$54.68	$46.35	$34.5	$0.0
2043	$50.52	$55.38	$46.88	$35.2	$0.0
2044	$51.24	$56.12	$47.58	$35.9	$0.0
2045	$52.39	$57.26	$48.71	$36.6	$0.0
20 yr Levelized	**$42.78**	**$45.62**	**$40.65**	**$21.28**	**$0.00**

Capacity Credit is lower due to margin from wind projects, CT capacity payment is ~$90/kW-yr

Portfolio Scenarios (includes changes)

Methodology	Load Scenarios	Resource Availability	Other
Alternative Lowest Reasonable Cost [only used for 2026-2029]	Low Growth	Clean Resource Portfolio by 2045	17% PRM (replaces lower WRAP PRM scenario)
Baseline Least Cost Portfolio [excludes CETA]	High Growth	500 MW Nuclear in 2030	30% PRM (replaces 0% LOLP scenario)
Minimal Viable CETA Target	RCP 8.5 Weather	Power to Gas Unavailable	Maximum Washington Customer Benefit
Maximum Viable CETA Target	80% Washington Building Electrification by 2045	~~Nuclear Cost Sensitivity~~	PRS w/ CCA repealed
PRS Constrained to the 2% Cost Cap (replaces unconstrained cost cap)	80% Washington Building Electrification by 2045 & High Transportation Electrification Scenario	~~High QCC on Demand Response~~	
	80% Washington Building Electrification by 2045 & High Transportation Electrification Scenario with RCP 8.5 Weather	Regional Transmission not Available	
	Extreme Building/Transportation Electrification for Washington & Idaho w/o new Natural Gas CTs	Northeast Early Retirement	
	Data Center in 2030	On-System Wind Limited to 200 MW	
		No IRA Tax Incentives	

***Proposed Portfolio Changes in Red*

Avista 2025 Electric IRP
TAC Meeting No. 11
July 30, 2024, 8:30 am to 10:00 am (PTZ)

Participants:

Andres Alvarez, Creative Renewables Solutions; Soya Atitsogbe, UTC; John Barber, Magneglide; Shawn Bonfield, Avista; Kim Boynton, Avista; Michael Brutocao, Avista; Katie Chamberlain, Renewable NW; Josie Cummings, Avista; Kelly Dengel, Avista; Joshua Dennis, UTC; Diedesch, Avista; Mike Dillon, Avista; Jean Marie Dreyer, Public Counsel; Michael Eldred, IPUC; Rendall Farley, Avista; Grant Forsyth, Avista; Leona Haley, Avista; Lori Hermanson, Avista; Mike Hermanson, Avista; Fred Heutte, NW Energy Coalition; Annu John, Fortis BC; Bill Garry; Konstantine Geranios, UTC; Clint Kalich, Avista; Alexandra Karpoff, PSE; Mary Kulas; Seungjae Lee, IPUC; Kimberly Loskot, IPUC; John Lyons, Avista, Ian McGetrick, Idaho Power; Molly Morgan UTC; Tomas Morrissey, NWPCC; Austin Oglesby, Avista; Kaitryn Olson, PSE; Michael Ott, IPUC; Tom Pardee, Avista; Kit Parker, Avista; Meghan Pinch, Avista; John Rothlin, Avista; Jared Schmautz, Avista; John Calvin Slagboom, WSU; Darrell Soyars, Avista; Dean Spratt, Avista; Dillon Stambler, Creative Renewable Solutions; Lisa Stites, Grant County PUD; Jason Talford, IPUC; Charlee Thompson, NW Energy Coalition; Bill Will, WASEIA; Rachel Wilson, Form Energy; Yao Yin, IPUC.

<u>Introductions, John Lyons</u>

John Lyons: We will give it another minute here and then we'll get started. OK, welcome again to the 11th TAC meeting. We're up to 30 people now, so I think we're ready to get moving to the first slide James. Today we've got a couple of different things to go through on the Connected Communities program update and the partnership with the Spokane Tribe that centers on resiliency that came up two TAC meetings ago and we kind of bumbled our way through it without knowing what it is. So, we brought the experts in so they can give you a short presentation about what's going on with those projects. Then we are back on the Preferred Resource Strategy results, and I think are we locked down now. James, maybe we're locked down on the Preferred Resource Strategy. And then James is going to talk about the avoided cost. We'll follow up in the end with the remaining TAC schedule and scenario planning.

John Lyons: Next slide. We are scheduled right now to have an August 13th meeting on our two-week schedule to go over the PRS portfolio analysis, LOLP study results, some additional work on that, and the QF avoided cost. What we're proposing is we cancel that August 13th meeting and have another meeting on either September 10th or the 17th. Oh yeah, they're both 9:00 to 11:30, so it'll be another hour on those meetings, so we can have a little more time to finish up modeling and time for people to digest things. We'll give you some time to think about if you the 10th or the 17th works for you on that. September 2nd, we will have the first release of the IRP draft and it'll have those chapters in there. And then the next page in October we will have the remaining chapters sent out. And then also in September, we have our virtual public meeting that's more for the general public, so they can provide input, ask questions about the TAC.

James Gall: John. That one is going to get moved out to November. OK.

John Lyons: We are going to move that to November. OK, cool. We'll update that on the final slide was just asking if we had a date pinned down for that. So, virtual public meeting which should be getting moved to November, October 1st, will be the rest of those chapters that we weren't quite able to get to by September 1st. Any other things you want to chat about, James?

James Gall: Yeah. Just one quick thing given that we only have an hour and a half today and a lot of material. John did mention we'd like to cancel the August 13th meeting, but if we don't get through all the material, we can have that meeting opened up for finishing up anything we didn't get through today, or if there's any more dialogue we want to have, we can leave that space open for that if we need to. Our goal really is just to not create any new work. Right now, we're trying to draft up a majority of the IRP over the next 4 ½ weeks before we release the draft and then give us a little bit of time to get all the scenarios completed and documented as well. We just needed a little work with the schedule. This is I'd say an abbreviated IRP timeline. Normally we have about two years to complete and we're doing it in less than a year and a half and we're starting to feel that crunch now, so I appreciate patience and understanding. Any questions before we move on? OK.

<u>Connected Communities, Kit Parker</u>

James Gall: Kit, are you a ready and able to share your slides?

Kit Parker: I am. I guess so. Let me see. Would you like me to share my slides then?

James Gall: I would love that, if you could share your slides.

Kit Parker: Kit Parker: OK, give me a second. I'll pull them up.

James Gall: I don't know if you've lost your feed or what happened. Might have lost Kit. OK, so looks like we lost Kit. Oh, there she's back.

Kit Parker: I came back. I'm so sorry. Can you hear me now?

James Gall: OK, we can hear you. Yeah.

Kit Parker: OK, apologies for that. OK. And now I will share this screen that should come through OK.

James Gall: We can see it.

Kit Parker: OK.

James Gall: Yeah, it's all yours.

Kit Parker: Thanks for your patience. My name is Kit Parker. I am the Renewables and Storage Product Manager and I'm also the Program Manager for this program called Connected Communities. I'm joined by Mike Diedesch. He's the Manager of the Energy Innovation Lab, and he's also on this call. I'm going to talk through what our Connected Communities program entails and our current state. What's our current status? If you look at this slide, you'll see there are four logos on the bottom, and these are all of the partners who are working together for this iteration of Connected Communities.

Kit Parker: Connected Communities is a DOE grant and they awarded 10. There were 10 programs that were awarded through this first round of Connected Communities funding, and Edo is the purple and green here. Edo is the prime recipient, so they receive the funds from the DOE and then we are the subrecipients along with Urbanova and then Pacific Northwest is also partnered in there as well. This is the team that is putting together Connected Communities.

Kit Parker: The gist of our Connected Communities program is basically demand flexibility. We're looking at if we give products, basically grid connected products that are on the customer side of the meter, if we give these products to the customer. You could think of the smart thermostat as the primary product that we're working with, although there's an element of residential batteries that customers can be eligible for. If we give these to the customer, or in the case of the battery, we provide a rebate that helps them get these products, can we then have connected access to that asset with the ability to adjust the set points specifically for the thermostat? Can we adjust those set points during a grid event which we call a flex event and move those assets in a way that does not affect customer comfort but also provides benefit to the grid. Our range here for the smart thermostats is between one and four degrees. It's actually mostly going to be around a 2-degree temperature setpoint change. An example that you could think of would be if there's a heat dome and we have maybe 100 smart thermostats out across a particular substation. What is the grid impact? If Avista is able to then adjust the set point of those thermostats by 1 to 3 degrees during a heat dome event, or some other grid event, what is the material impact to the grid and how significant are those benefits?

Kit Parker: Taking a quick look, what you see here is this precooling concept and this is the program Connected Communities is looking at both residential, small, medium business and commercial C&I, and we've picked the Third and Hatch substation for a couple of reasons. One is that it's approaching its capacity, so it's a fairly constrained substation, but it also has a very diverse set of customers that are served by this Third and Hatch substation. This particular substation and that diversity means there are residential, and we've got lots of different types of customers who are residential customers. We've got part of Rockwood which would be higher income, single family. We've got the Logan and East Central neighborhoods, which are going to be lower income and maybe more multifamily. So, a lot of residential diversity, but there's also a lot of commercial diversity served by this particular substation as well. And if you think of Sprague, the little strip of Sprague, down by the U District, there are lots of small businesses served by the substation there. But there are also a lot of academic buildings. The hospitals are on this feeder on this substation and commercial and industrial, so bigger commercial plants or commercial customers as well. By doing this demand flexibility program on the Third and Hatch substation, we're able to test how lots of different customers respond.

Kit Parker: One of the things we're learning is what type of incentives, or how do you need to compensate customers in order for them to be comfortable with relinquishing some control over their thermostats or their batteries? And we always emphasize that during an event, a customer always has the ability to go back to their thermostat and set it back to whatever they would prefer. The goal is that they can't actually tell is that it's their comfort is not affected, but if they don't want to participate in that event, they always maintain the ability to opt out of the flex event. OK. I'll pause, are there any questions? I don't know if Mike wants to add anything. OK. This is a five-year program, and we are kind of in this early.

James Gall: You have a hand up, Sofya.

Kit Parker: Yeah. Oh, great.

Sofya Atitsogbe (UTC): Yeah, sure. Hackett, this is Sofya with Washington UTC. Could you go back one slide?

Kit Parker: Yes.

Sofya Atitsogbe (UTC): OK. You mentioned that this is a joint project with a bunch of companies. What is the plan for this substation? Does that mean it will defer the upgrade of the substation? Or what is the goal of that project?

Kit Parker: I'll pause to see if Mike, if you want to take that, but I'm happy to jump in.

Michael Diedesch: Yeah, I would say that for this substation, this is a demonstration of how we could achieve that deferral using these different methods. So rather than just looking at grid side assets, this is our way of demonstrating how customer side assets could participate in that sort of thing. It's unique among the Connected Communities projects where Avista is, I believe, the only one who's got a locational based demand flexibility program and that is the main reason why we are doing it. Location based is for that concept of customer participation in reducing our distribution constraints, which can defer capital projects.

Sofya Atitsogbe (UTC): Thank you. Do you have an approximation of either the cost you're planning to defer or the constraint you're planning to relieve with that project.

Michael Diedesch: And not off the top of my head though, but I could. research that and get back to you.

Sofya Atitsogbe (UTC): Sure. Thank you.

Michael Diedesch: Yep.

Kit Parker: Anything else before I move on? Awesome. Thanks for the question. OK, so this is a five-year program and we're kind of between the pilot assessment and the testing phase. The first year of the program was basically studying this particular feeder, looking at the customer data in terms of usage and capacity, looking at the different products that were available and based on the particular constraints of this feeder and the customer behaviors, which product packages do we think would have the most material impact. And then, testing. The first year was a lot of modeling to figure out how we wanted to structure the program. Now we're into this pilot assessment phase, which has a big enrollment component. This is where we're going out and we are beginning to engage to recruit customers. We're going to have residential, small and medium business, and C&I – commercial and industrial customers. We have just launched recruitment trying to get folks enrolled into this program. Behind the scenes, they're also working on getting all of the technology in place so that we will actually be able to dispatch assets during particular events.

Kit Parker: The next phase will be the testing phase, where we'll pilot basically with a handful of customers, do the end-to-end testing, making sure that the system works, making sure that everything is responding the way that we would expect. And then this 4th year is full program deployment where we are analyzing and evaluating how the program works. What is working well? What is not working? Making any modifications that we need for this particular program to be as successful as possible. This final year is where we will summarize, basically do a report and summarize all of our learnings and make a recommendation for how the program might be scaled in the future. Any questions on this? OK. John, James, this is my last slide. I'll turn it back over to you.

James Gall: Thank you, Kit. And if there are any questions that come up later, hopefully you can hang out for a little bit. But, in the meantime, we'll move over to Megan.

Kit Parker: Thank you. Sure.

Spokane Tribe Energy Resiliency Partnership Update, Meghan Pinch

James Gall: Megan's can share her screen as well. She's shaking her head. She's next to me in the room, so it makes it a lot easier to communicate. Alright, go ahead Meghan, whenever you're ready.

Meghan Pinch: Hi everybody I'm here to give an update on the partnership between Avista and the Spokane Tribe on an energy resiliency project we've been working on. Back in the Fall of 2022, Avista entered into a contract with the Washington State Department of Commerce to receive some funding to design a grid resiliency solution for the Spokane Tribe. At that time, we also entered into an MOU with the Spokane Tribe to jointly create this project. The reason that Avista got engaged with because the tribe had a big fire in 2016. A wildfire that caused a lot of damage beyond maybe what it would have because they had a lot of their pump equipment, and their firefighting equipment was disabled. They didn't have power to adequately fight the fire, so they lost a lot more structures and a lot more timber than they would have, and that was the beginning of their Children of the Sun Solar Initiative and also their desire to have more resiliency during wildfire events. So, that wildfire outage scenario has really been the governing principle. The idea has been that the request from the Tribe was to design a resiliency solution that could power their critical loads. There have been some buildings identified that count as critical loads for up to seven days during a wildfire outage.

Meghan Pinch: A caveat is that seven days includes existing generation resources. There is a diesel generator that is a part of the administrative buildings, backup infrastructure, a propane generator and some solar generation assets already on site. The concept that we've come up with over the last two years of working closely with the Tribe through reviewing some of their planning documents and a series of design workshops with tribal leaders and public safety leaders is this concept here, I'm not an engineer, but I'm learning how to read these diagrams based on this project and I also want to say the Innovation Lab, Mike's team who you just heard from, has been really involved in designing this concept and modeling the scenarios we've been talking about. Anyhow, the concept is the switchable platform that could enable power during emergencies to be shifted to critical loads and we see it in the diagram. It's demarcated as circuit 3.

Meghan Pinch: The concept is that three buildings that have been designated as critical loads: the Tribal Administrative Building, the Wynecoop Memorial Health Clinic, and the Public Safety Building would be the three buildings that would be prioritized on this circuit during emergencies. The other important piece of the design concept is that this concept which we're calling the resiliency station, would replace a set of existing stepdown circuits that are currently routed through elevated building transformers. They're in a place right now that the Tribe would like to redevelop, so we think it's an elegant solution and that solves that problem and also gives a lot more reliable infrastructure. So, what you see here also is that the critical load cycle will have a battery that will back up and then it will also have some expandability so that if the Tribe wanted to, at some point, bring in bigger scale of generation or even add EV charging or any other sort of grid infrastructure. This would be a platform, an expandable platform, that would allow them to do that. The innovation lab has done quite a bit of modeling, and the idea is that we would prioritize the battery ahead of the diesel generator so that the carbon footprint would be lower. We're confident that this design for summertime loads of those three buildings will enable us to hit that seven-day outage duration goal in most scenarios.

Meghan Pinch: It's pretty exciting. We're really excited about the concept. Also, if you prefer pictures of what this could look like, this is a very rudimentary concept of what the equipment layout could be. This is the site also and it's in Wellpinit right behind the Wellpinit Trading Post. There would be a fence enclosure, probably a concrete masonry wall. And there would be a controls enclosure. The idea is that at some point we could also make that an interpretive or teaching center, because we anticipate this concept will have a lot of buzz and a lot of people will want to come visit and learn about it. There's also going to be some training needs in terms of training workforce to operate the microgrid. There would be battery storage and then the pad mount equipment would also be behind the enclosure and that would be how we would replace the current distribution infrastructure.

Meghan Pinch: I'm going to pause for any questions about the concept. OK. Well, still open to questions if they should come up in terms of recent activities and next steps. We matured the design enough over the last six months that we thought confident to go ahead and apply for construction funding. Avista works closely to provide technical assistance to the Tribe, who recently submitted an application a couple weeks ago to the Department of Commerce's Tribal Clean Energy Grant Fund and the maximum award amount, there is $2.7 million. We went ahead and supported an application for that total amount, and it is a really critical piece of the overall estimated cost. At this point, we anticipate the project costs are going to be around $6.5 million. The addition to the $2.75 million from the Department of Commerce, if that is awarded, which we should hear about in the next couple months, the gap between those two numbers will be provided by a mix of Avista provided funding through the Named Community Investment Fund and the Spokane Tribe has been awarded a Department of Energy Grid Resiliency Grant. We're still working through the details of which pieces would come from which funding source, but we feel confident that we can hit that $6.65 million in funds. The caveat here is that number doesn't include some additional scope items that would really make the project above and beyond. For example, maybe public EV charging or that interpretive center idea that I discussed. At this point, those two components are not in the total project costs. We are currently looking for additional funding to support those additional scope items and that is the update.

James Gall: Any questions for Meghan? Appreciate Meghan and Kit joining us today. We do get questions that we're not experts on and we appreciate the ability to bring folks in to help with those questions as they come in. Thank you again, and we're going to transition to our normal scheduled program of talking about the IRP and just bear with me one second while I switch screens.

Kit Parker: Thanks for having us.

<u>Draft Preferred Resource Strategy, James Gall</u>
James Gall: Hopefully everybody sees the Preferred Resource Strategy, which I do, and we have about an hour, and I think that will be enough time to get through this slide deck where we won't need next week, but feel free to ask questions as we go along either in chat or raise your hand. Lori is going to be watching out for any messages. And like John mentioned, we are trying to lock down a Preferred Resource Strategy. We are planning on sending out a draft document at the end of next month and we think we've nailed it down there. There are plausible changes that could

happen in the next several months that would require us to change this, but based on the information we have now, we think we're going to stick with what we have shared today, unless there's some excellent comments that would have us revise our strategy.

James Gall: To start off I just have this slide as a reference. This is our strategy that we showed at the last TAC meeting and there's been one major change since then and that has to do with the transmission line that you see halfway down that 50 megawatts that show up between 2037 and 2045 that had to do with the agreed United Transmission line from Colstrip to the North Dakota area and the big change where we're proposing that you're going to see in the next slide has to do with how that project would come to fruition. We can't necessarily just grab any size of that project that we want at any time. It's kind of a one and done type of deal and so our proposed strategy is to move that resource as a selected resource in 2033 and you're going to see that, this new layout of the resource strategy.

James Gall: This is just showing 2026 through 2035, and you see regional transmission; 198 megawatts for Washington and 101.6 megawatts for Idaho. That assumes that resource is in place by 2033. The reason for that change has to do with a couple things. Like I mentioned earlier, it's you can't acquire it at any time and the second reason is when we're looking at that resource from a modeling perspective, we're really first testing whether or not it's makes sense from a conceptual point of view of helping out with capacity needs. And then we did not look at resiliency but arbitrage of our markets between MISO, SPP and the Pacific Northwest. And so that value stream was not in the analysis and when we started looking at placing arbitrage values in the analysis, that resource became more and more economic. I think it provides pretty good justification of putting that resource in all of the scenarios that we studied. There is an effort underway internally to look at that arbitrage value that will be probably provided at a later time, maybe even outside the IRP process. But at this time, we're not committing to the project. We're just looking at it from an IRP perspective. This looks to be attractive, and we want to ensure that if we do pursue that project, we know what the impacts are to the rest of the portfolio.

James Gall: That change then had a cascading effect on other resources that were picked in the strategy. This strategy we're showing today has those cascading changes. Before I continue, are there any questions? No questions in the chat? And then I'm going to have a I think a slide detailing what that transmission line looks like, a little more. OK, this resource strategy includes around 78,000 MW hours of energy efficiency in the first two years for the biennial target. That's an increase from the last IRP. I think we're getting close to finalizing that number now. That's going to probably go to the Energy Efficiency Advisory Group. There'll be more discussion on that assumption and result in that process, but this is a preliminary look at that target for generation resources. The first need is really to begin some type of community solar projects beginning in 2027. You see those flow out through the whole time period for Washington State and that is a placeholder resource for what could come out of the Named Community Investment Fund, similar to the projects that Meghan and Kit already talked about. There could be projects that fit in that category we don't know about. We want to make sure we account for generation that could be in the portfolio in the future, so that we don't necessarily overbuild something else or at least in the academic modeling of the IRP.

James Gall: The first major resource in the IRP is a 200 MW wind facility in 2029. That's similar to what we saw in the last version of this a couple weeks ago. I even went back and looked at the 2023 IRP and it seems to be there's a common theme that we'll need wind, even in that IRP wind was setting within 2030, we had 200 megawatts, but there is definitely a string of wind beginning in 2029 all the way through 2033 when the tax credits expire. We are seeing wind selected in both states, both Washington and Idaho, largely due to the expected low cost of wind energy which I think we have a slide on that, on the risk of this assumption in the IRP. But I'll get into other resource selections in the first 10 years. I'd like to go over the Idaho category, a natural gas turbine, which would be something that's like Rathdrum Unit 3, shows up in 2030. Again, we are splitting up our resource strategy between states. They have different planning requirements. They also have different energy and capacity needs, but the one challenge we have, at least for right now, is all of our resources are not assigned to each state.

James Gall: The IRP is a little bit of an academic exercise where it shows needs of each state. But when resources are acquired and accounted for, they are split between the two states on a, we call it a PT ratio basis, which is based upon load. Right now, Washington is a little bit under 65% of our load and Idaho is the remaining. Those costs are typically split out between those two amounts as time goes on, though what we've seen at least in this IRP is the loads are growing faster in Washington due to electrification of transportation and buildings. And that PT ratio, or amount of ratio that gets allocated between cost change, and so that would mean that Washington would have a higher percentage of the existing resources in the future. Also in this IRP we assume locational demand like demand response is allocated by state. PURPA resources as well and Idaho actually has a little bit greater deficit in the early years than Washington due to that assumption. Moving on to other items, I've noticed in this first ten years is we do have a significant amount of DR programs beginning over the next 10 years, it's around 12 megawatts by the end of the decade of selection in Washington, a little over 1 MW and Idaho and those are through beginning of programs that are expected to increase over time. I have a slide a little bit later on those programs and when they would likely begin. Before I move on, are there any questions? Rachel's got her hand up. Go ahead, Rachel.

Rachel Wilson: Thanks James. This is Rachel Wilson from Form Energy. I'm a little surprised about the lack of storage in this first 10-year planning period. It seems a little counter to some of the trends in resource planning and a little bit of a surprising result. I'm wondering if you might speak to that a little bit.

James Gall: I'm happy to. I've been looking at quite a bit on this strategy. Why is there no storage and there are a couple of reasons why. The first reason I would say is slow load growth, it is the big one where the wind and the demand response is able to capture most of the capacity increases along with the natural gas resource for Idaho. I ran a scenario where we had needs earlier. Let's say if there was a need of 50 megawatts continually beginning in 2026, we would see energy storage selected. So, it's a really a matter of timing of when you're in resource need versus how much time you have to develop something else. And in our case, developing a third unit at Rathdrum appears to be a much lower cost than building a battery. Now, at the end of the day, the academic exercise of the IRP is kind of a moot point because what will happen in reality is, the IRP identifies resource needs, we will issue an RFP to meet those capacity needs and all resources will have an opportunity to bid in. And if solar plus a battery, or just a standalone battery, or a natural gas turbine is the lowest cost given the resource needs, then we'll be able to figure out what is truly the lowest cost. Unfortunately, IRPs don't factor in real resources. That's why I keep bringing up how it's kind of an academic exercise, but we'll see what the market brings. I would anticipate we'll have an RFP out in probably Q1 of 2025 in order to be able to act on these resource needs by the end of the decade. Hopefully that answers Rachel’s question.

Rachel Wilson: Awesome. Thank you.

James Gall: Alright. Any other questions before we go the next decade, which is the little bit more interesting? OK, nothing yet. Alright, let's get to the last decade, where I would say a lot of things happen at least on the Washington side of the service territory. We'll start with Idaho because it's a little simpler, but what we're seeing is natural gas turbines remain to be the lowest cost option to serve peak loads for the Idaho side of the service territory. Small load growth and offsetting generation that is retired. Basically you're retiring a natural gas resource and replacing it with another natural gas resource is really what the model is showing and in reality that may happen, I guess we'll wait and see, but at least the gas prices and the cost of technology that seems to be the lowest cost strategy, there is a little bit of demand response selected for Idaho up to about 10 megawatts in that period of time along with a little bit of energy efficiency around 30 average megawatts.

James Gall: And then in the last year, 2045, that portion of a biomass plan is actually upgrading our Kettle Falls unit. At some point, that plant will need to have a major overhaul and that might be a good opportunity to upgrade that facility at that time. On the Washington side, which is definitely more interesting, as far as the quantity and needs of resources, you have a few things going on in Washington on that. You start to see rapid load growth from electrification. You have replacing of natural gas resources that are going to have to be retired or removed from the portfolio by 2045. So, you have a massive amount of resource need and then it's just a question of what technologies can meet that need. We do forecast solar, small solar for the Community Fund like we talked about earlier, but in 2043 through 2045, we would likely see larger amounts of projects being online. We do see wind replacements of our current PPAs that it will be expiring at the end of the decade. That's what the wind resources in 2041 and 2043 represent. And then additional wind beyond that period.

James Gall: We start seeing storage show up at the end of the decade. Those include likely long duration energy storage, which is what will be needed in that period of time. Also, related to storage, we have power-to-gas section starting in 2040. Power-to-gas is really two categories of resources. One is cofiring hydrogen at our Coyote Springs 2 facility, and that is there in 2045, and then a new facility that would use a clean hydrogen that's converted to ammonia as a storage mechanism and burn in a CT that is around 300 megawatts between 2040 and 2042. We do see nuclear continue to stay in the plan in 2045 as a base load renewable resource or I should say clean resource. Also, geothermal and a second unit of Kettle Falls was selected in 2045. Those totals at the end of the planning horizon should be enough to keep our system reliable and meet the 2045 targets. Cost will be a concern and we're going to have a discussion on that in a little bit of what we've figured out on cost. But it's kind of an interesting resource strategy just because of how our loads are growing and the CETA needs. I would say the model is basically back ending a lot of resources because of how our portfolio is designed, where resources are not likely to retire that are using natural gas until late in the study. So, when you're replacing capacity, we're able to chip away at it with other resources besides large new technology projects like power-to-gas or nuclear. Time will tell on load growth whether or not that changes. You have a question, Molly? Molly, go ahead.

Molly Morgan (UTC): Yeah. What resource or combination of resources ends up replacing peaker plants?

James Gall: I'd say that power-to-gas is really a peaker plant. Those are modeled after a natural gas CT, but instead of using natural gas, they're using ammonia.

Molly Morgan (UTC): OK.

James Gall: So that's around 400 megawatts of those resources or 300 megawatts of that peak of resource.

Molly Morgan (UTC): OK.

James Gall: Another 94 MW is the cofiring of hydrogen in Coyote, which will probably in that period of time look more like a peaker than a base load facility.

Molly Morgan (UTC): OK. Thank you. Thank goodness. Yeah.

James Gall: Yep. Alright. Any other questions? Not yet. I'd miss demand response and energy efficiency in the outer years. We do see around 52 megawatts of demand response by the end of that decade. And like I said, we'll go through some of those programs a little bit, but also energy efficiency continues to increase over this period of time. OK.

James Gall: Really quick on the North Plains Connector Project, this is a reference of the discussion I had earlier where we're assuming the 300 MW portion of this line. I believe it's around 3,000 megawatts total, so Avista would have about a 10% share of it. It's a line that goes from Colstrip to North Dakota, connecting into MISO and SPP. When we get into scenario analysis, unless we're doing a scenario that's without this line, we are assuming this line is in all scenarios as a fixed resource. We're not letting the model pick this resource. It's going to be either in or out depending upon the scenario. The reason for that is it's we just don't have all of the information yet as far as the arbitrage value to include in the analysis along with the avoided capacity cost. But when we started looking at arbitrage of values, it didn't take a lot of arbitrage value to be added to the capacity value that it could bring to our system to be cost effective for both states. So, it seemed like a resource that would be a good fit to lock in. As we study what the impacts are for the other resources. Going back to when and actually when is probably I'd say the biggest risk item in the next 10 years besides load growth. And this is because the model is selecting a tremendous amount between 2029 and 2033.

James Gall: I've talked to some other utilities that are seeing some similar results where we do a price forecast of the wholesale market. That has definitely risen in the last couple of years, and we see at least theoretical low PPA pricing due to the IRA tax credits. And when you look at a high market price and a low PPA, it models this is a big winner. We should go out and build as much of this stuff as possible and then reality will have to hit at some point where one the biggest risks I'm seeing in that 850 megawatts of wind is, can it all be built on the transmission system that we have in this IRP? Assume we could build around 500 megawatts of wind in our service territory without new transmission, and then another 200 MW, I believe in Montana. And then I believe it was 200 MW off our system. But as all utilities in the Northwest needing renewables to meet requirements in Washington and Oregon, some of those projects will likely not be available to Avista. If any projects within our service territory get exported off of our system, that will likely reduce the amount of wind that would be selected in the 2029 to 2033 period.

James Gall: We're going to look at a scenario where we do limit the amount of wind to see what that does in the portfolio. My expectation is that it will likely defer that resource to later in the study when it's needed. So, we have this interesting phenomenon where you have a low-cost resource you can acquire early versus when you need it from a physical point of view. And for those of you who have been following our IRPs for some time, we are definitely in a renewable resource length position compared to CCA targets versus some of our peers. Wind is not necessarily a resource need for meeting those targets. It is helpful but the result of the modeling shows if you don't need something and it's not cost effective, you'll want to delay that purchase as long as possible. But given the model is seeing it as cost effective, it wants to acquire as much as possible, but if you run out of that supply, it's going to defer that as long as possible because we would need to likely build new transmission to import, to be able to bring that wind to the service territory. And that will have an increased cost to our system and our customers. The third area that is a concern for wind and this modeling exercise and it's really not necessarily I don't think could impact the amount of wind, but it could impact the other resources we would need and possibly lead to some different resource decision making.

James Gall: That is the way Montana wind QCC, especially in the winter. The modeling that we are doing this time around utilizes some of the wrap QCC values for Montana wind which are I would say relatively high compared to the northwest and what that does in the modeling grand scheme of things is that adds capacity to our system that we would be relying on and what we saw in the January cold weather event is that Montana wind was not available due to 2022 extremely cold weather and I guess it's a question of whether or not the QCC values we're assuming from Montana when is it appropriate or not and if it's deemed to be too high over the next couple of years you would likely see additional need for capacity. In that case, you might see energy storage start to pop up as an economic alternative. That's something we're going to need to continue to monitor whether or not we can actually rely on Montana wind for capacity, especially in the winter time. We definitely would still see it likely economic from an energy perspective, similar to the northwest wind, but the capacity benefits are at a little bit of a risk.

James Gall: The last bullet is something we touched on a little bit in the last TAC meeting and that has to do with why not more wind. For Idaho, when it's economic and the cost in the marketplace and that has to really do with constraints of the system and trying to prioritize meeting the constraint of CETA. Let's say you have one state that has a CETA target. The other state doesn't. The benefit is equal to both, but one state has a requirement, the other state doesn't. What the model wants to do is allocate the few resources that it can to one state to make sure it meets that goal. Again, who knows, or at least right now all costs are shared between the two states on a PT ratio. But if you have a limited supply of a resource, the model is trying to optimize every dollar it can. It's saying that we should allocate to Washington because it has a CETA requirement versus Idaho does not. That's a reason why we're not seeing more wind in Idaho. OK. Any questions or thoughts that I may have brought up that you want to chat about. Questions and chat right now. OK.

James Gall: Now there are some other losses, accounted for losses, so I'm assuming you're speaking of losses from the Montana side of things. We do a reduction in energy delivery for losses the model optimizes for meeting the energy targets and capacity targets, so we account for those as basically a deduction in generation, but you still have to pay for the energy. If you pay for the energy, but it's not all delivered when you're trying to match up generation against load. OK. Nothing else. Anything else?

James Gall: OK, let's keep going. I was talking about demand response. Like I mentioned, we have a quite a bit of a demand response program selected in the Preferred Resource Strategy and some of them begin immediately, but they don't necessarily result in a large amount of megawatts immediately. And some programs show up a little bit later than I think a lot of people were hoping to see last TAC meeting, but there are reasons for that. It has to do with what our load forecast looks like. The first one that was selected was really three programs in the first year, electric vehicle time of use rates, which is a commercial pilot really that's kind of already underway, but the. Our total load expectation or savings from around 9 megawatts is what our study showed from our consultant that looked at our the total available. Cool.

James Gall: Demand response savings at peak hours. They did a potential study that looks at a variety of different programs and tries to allocate how much could we depend on over the 20 years of the IRP for that load savings where you have some programs, or I should say end uses, that could be really placed into multiple different categories. And so, they're trying their best efforts to trying to figure out what that savings would look like depending on which program you select. The values you see here are showing the highest value of either summer or winter over the 20-year period where these programs really start at a lower amount then grow over time.

James Gall: The second one is battery energy storage. This program is really an aggregation of customer batteries, similar to the Connected Community idea that Kit talked about earlier, but we would be starting now. Our program here, where we would as customers add batteries to their homes, we would try to initiate an agreement with them to dispatch them during grid events. There are definitely not 10 megawatts of batteries on our system right now, but there could be over the life of the IRP based upon our distribution, energy resource locational study that we had done earlier this year.

James Gall: The third program is variable peak pricing. It seemed to be a very cost-effective program, easy to implement, that saved around 5 megawatts. So those first three programs are cost effective, at least in the first three years. Those programs were also cost effective in Idaho. There's a little bit of a delay on two of them really having to do with needing AMI metering in Idaho to do some of these programs and AMI was not expected, at least assumed in the model until 2029. You start to see those programs show up as cost effective, peak time rebate shows up in 2035. That is a pilot project we're working on this year. That program pilot will, I think, continue for a couple years and maybe based upon the learnings of that pilot, we may see that. And if we have more load growth, we could see that program being selected earlier to continue on, we'll have to wait and see how that pilot proceeds.

James Gall: We have behavioral programs and time of use rates in 2038. Time of use rates is another one of those programs that we are piloting, and this one was a little bit interesting because in our last IRP, this one showed up with a much larger savings and showed up earlier. What we're finding is the cost to develop that program is definitely higher in this last potential study and the savings potential was much lower and that's why it's being pushed out, but still cost effective in that later period of time when you have significant loads to meet. Third party contracts, that's an aggregator concept and that shows up in 2039. I'm hopeful that when we go out for bid for capacity resources, we would have some aggregators bid in for this potential and maybe have, hopefully show higher potential, maybe even lower cost. This one is probably something that's going to need to be bid into an RFP process. If not, we'll have to look at building a program when it appears to be cost effective. We do see CTA water heaters start to show up in the end of the cycle and along with controllable air conditioning units. And what's interesting with the CTA water heaters, there's been a lot of talk with those because it's maybe an easier to implement program. Because of the similar technologies already on the water heater, but there's still a significant cost to the utility to be able to connect those water heaters. Also depending upon if it's a heat pump water heater or a non-heat pump water heater, the savings definitely is much lower on the heat pump water heater. It's potentially a lot of cost for very little savings at least on the heat pump water heater, much why it wasn't selected. But the traditional water heater style was selected, but the amount of those available on the system, I guess the wait and see based on energy codes if that quantity can really be available. So that total, up to around 61 megawatts for Washington, 12 MW in Idaho between the two were a little over 70 megawatts. Our peak load is around, let's say 1,850 today, around 4% of our peak load that was cost effective from a demand response program point of view. But for Washington, 61 MW out of maybe 1,200 MW, it's a definitely a much bigger share maybe around over 5% of peak load. That's on top of the 25 to 30 megawatts we already have on our system today. Any questions on demand response? OK, let's keep going.

James Gall: Moving on to energy efficiency, this is a similar slide we show last time on how much was selected. Actually, I just saw a chat. Yeah, they said this thread DR programs looks good, but the start dates are perplexing, especially the CTA water heater. Thank you, Fred, and again it it's really just driven by low needs. If we had a high load scenario where we had a capacity need immediately, you would start to see these move up. I doubt you would see CTA move up just because of the cost to implement it for very little savings. You got to have the water heaters, and the customer base to justify the expense of that one. But you will see, like I said, in high load cases a lot of these programs move up faster. We can just say that I have the load to justify it, that could happen. I mean we do an IRP every two years. Last IRP we had one program selected. This IRP, we have how many of them here? Eight of them. We continue to revise as we go along, and we see whether or not loads prove out to be there or not.

Fred Heutte: Yeah, I do have a question because I just had a comment before and the question is on the CTA, the plug connected water heater program. Is that cost basically driven by material cost or by customer incentives.

James Gall: I don't know. Yeah, check to see if Leona is on the call.

Leona Haley: Yeah, James.

James Gall: Go ahead.

Leona Haley: Yeah. Thanks James and Fred. Leona Haley. I work in the energy efficiency demand response group under Meghan Pinch, and we are looking at CTA 2045 grid enabled water heaters. Right now, we are part of NEEA's end use load flexibility project and currently the cost that have been modeled in the IRP are a result from that Bonneville - Portland General study and others from 2018. As we move into this pilot project with NEEA, those costs can be revised with NEEA's market transformation prowess I guess is the right word, expertise. Those costs may be driven down and we may see some efficiencies there, which will in turn influence the value here in this IRP modeling process.

Fred Heutte: 59:09 Yeah. Thanks for that. I'm very familiar with that. No, 2018, I guess you know field test whatever going to call it actually worked pretty closely with NEEA, Bonneville, PGE, you know that were the kind of the main drivers of that that test really showed the very wide-ranging capabilities of this. Approach with the water heaters and you know now both Oregon and Washington have requirements for all the new electric water heaters to have the CTA plug. So you know it's out there and we felt for quite a long time because basically, you know the program can be run in such a way that customers really don't feel any impact. You know they can always override as you've mentioned for other programs. So just. Yeah, I'm. I'm going to be following up with NEEA about that. We see a lot of potential for this and also for it to be a more of a regional approach, not just utility by utility. Appreciate that it's at least in the list, but I'm hopeful that it will move up in the activation dates.

James Gall: Yeah. Fred. I'm going to kind of reach a little bit on September, suggestions here on the ones that are picked. But you know, I think the region definitely has capacity needs and I guess it's maybe a societal question is should our customers do DR early at our expense for the benefit of the region? It really is where I'd say the argument is going is because the region needs capacity benefits. We have customers that may or may not be able to fluctuate their load for that, but should we be doing programs early for the benefit of the region versus our customer need? That's another answerable question by me, but I guess if we did programs earlier, that would be the situation we'd be in.

Fred Heutte: Yeah. I would agree with that and also point out that there are lots of opportunities in the new organized markets to monetize that because if we're really hot over here in Portland and you've got some flexibility in your area, can we find a way to make that happen? And just to mention a couple things, the PG&E has been talking, I don't know the details in this, has been talking to the California ISO about some fine tuning to the EIM so that their demand response program in effect can bid into the EIM. And then, of course, the day ahead markets. Whichever one, or both, emerge in the Northwest will offer another opportunity for that. The issue here is the markets give us an ability to tap into the load and resource diversity. Well, that includes load flexibility across the region across the big footprint. Our hope is that the economics of demand response kind of peak oriented activity could benefit a lot from that and don't have an exact analysis of that yet, but hope that everybody keeps that in mind is that the market availability of an organized market whether it's real time or day ahead gives a lot more opportunity than to you to get more value out of the demand response.

James Gall: Yeah, I think we're going to need, in addition to that, some type of capacity payment to really drive early acquisition for the grid. It's regional support that would be I think the key thing missing from that, but you have a comment from Jason.

Fred Heutte: Alright, thanks.

James Gall: So alright, what Jason? He said he's interested in what the value streams are being used to inform the benefits of DR programs. Yeah, sure. Actually, this is something we've actually, I'd say improved on last IRP. There are several benefits. The first benefit is obviously just the capacity reduction to avoid building another resource. So that's the capacity benefit I was mentioning to Fred where we did this as a region. We're not saving anything for our customers or saving it for other utilities and we're not getting compensated. So, in the effort of what's selected here, there's a benefit to our customers of avoiding generation. The second value stream is also related to what Fred mentioned, which is the energy value that you save from the energy market. When prices are typically high during a demand response event, you are saving spending that money for either buying a resource or able to sell something else, so you're getting an economic energy value. Another benefit we included here is savings on the T&D system. That is, if we implement these programs overall, the concept is that we would have less T&D construction on our system and similar to a T&D benefit, peanut butter across the system for energy efficiency. The other new benefit we included on the suggestion of Idaho Commission staff was that we include this as a load reduction rather than just a resource option. So, what that does is you get a benefit of reducing your planning reserve margin. Instead of just saying, OK, 60 megawatts of savings from a societal point of view, we're actually saving planning margin on top of that. That's another benefit we included here. The values do get multiplied by what's called a QCC value, which is what it's capable of producing over a long period of time. And that is still I'd say, an open-ended question of how much you can rely on demand response in a prolonged winter event when these programs are typically shedding load for three to four hours. And similar to a battery, in fact at least a lithium-ion battery, this something that should have a reduction in QCC value over time or is it fairly stable? We made a very conservative assumption, I guess, depending on your point of view of keeping the QCC value relatively high over the period of the 20 years. So, I'd say DR has a little bit of an edge over other resources in this IRP versus other options. Time will tell whether or not that proves out to be a good assumption or not, but we're trying to definitely encourage the model to pick DR in an economic going to be where we have information.

Tom Pardee: Joshua from the UTC says has Avista done studies to see the benefits of implementation of DER earlier in terms of customers getting used to DER participation? Like in my mind if the customers get used to participation earlier that opens up to many emerging opportunities that may seem more invasive, Avista controlled EV charging for load shifting, for example, in the future.

James Gall: Yeah, maybe two thoughts on that. One, I'm going to lean on Leona, maybe to answer, but we do have an electric vehicle time use rate for commercial vehicles. And if Rendall is on he could probably speak to that, it's been very successful on encouraging those commercial customers to charge at different times. But I was hoping Leona, maybe could talk about the pilot project we did in Pullman on whether or not customers like or do not like these programs. But I see Joshua has the hand up, but if you want to add Joshua before we go to Leona.

Joshua Dennis (UTC): I wanted to say that the example, just like off the top of my head, but more importantly I think my question is more of a behavioral one. I think that if and like I said, in my mind, if we could, if Avista could get people to participate in DRs sooner and have more experience with it, there might be opportunities in the future for Avista to expand. They're DR program selection with like emerging technologies that might be more invasive, and people might be hesitant to participate in those.

James Gall: Yep. So, what I guess I'm hearing is the more you make it available now, the less resistance you'll see in the future. Is that where you were going there?

Joshua Dennis (UTC): Yeah.

Leona Haley: Yeah. The only thing I'd like to add to Joshua's point and the smart grid demonstration project, it was one of several pilots we've had over the years. But in that particular one, we did have more of an automated demand response, if you will, where the customer was not notified of events, they were more automatic, they could override them at any time simply by getting onto their thermostat app or right out the thermostat itself inside the home or business. And we noticed that there weren't many event opt outs and the attrition was normal attrition that you'd see in these types of programs. To your point, that's all I had. Thanks.

James Gall: Yep. Alright, Rendall any thoughts on EVs and Joshua's comments?

Rendall Farley: Have a few. To your comment on the commercial electric vehicle time of use rate, we implemented that in 2021 and it has been very successful, but it's been limited just because the market for medium and heavy-duty electric transportation has been light so far. But we expect that to increase in the future as well as light duty fleets and larger workplace charging hubs and so forth. We think that time of use rate will be very effective from early results we've seen so far. One other thing I did want to mention too was something we've been working on or looking to launch once we have funding secured for it, is a smart charging program for residential customers. Our early pilot results show that we've shifted only about 5% of total load with the customers that are participating is on peak. That's a substantial shift from uninfluenced charging loads. Most people uninfluenced without a time use rate will tend to come home from their errands or work and just plug in the car in the late afternoon or early evening. And that tends to be on peak year-round. So that looks like it's got good potential to scale. It's not listed here in this table because it's a little too early to hang our hat on it, but it's pretty promising. So I did want to mention that too.

James Gall: Thanks, Rendall.

Rendall Farley: Yeah.

James Gall: Alright, back to energy efficiency. These are a list of the top programs selected. I actually have a new chart that's probably going to be coming out in the next draft of the IRP that summarizes a little bit better, but this will get you an idea of what savings are picked by state. As you see in the top couple items, lighting is still the top energy savings measure. In Washington, we do see a higher percentage of total savings compared to Idaho. I believe around 71ish percent of our total savings is Washington, when it's around 65% of the load. So, we do see a little bit higher energy efficiency there. That's due to higher avoided cost, due to requirements of how we evaluate energy efficiency by including that social cost of carbon, the Power Act adder of 10%, and some cost related to the CCA. So, we do see a little bit higher uptake in Washington. Also, I should mention the non-energy impacts as well push up saving. For example, windows that show up in Washington that are a little bit different than maybe Idaho is likely due to non-energy impacts. But there for your reference like I mentioned earlier, there is the Energy Efficiency Advisory Group where they're going to be probably covering this type of information a little bit more detail beyond what the Power Planner I can any questions on energy efficiency. But again, we'll have some more summarized information to document that goes out in a month.

James Gall: I wanted to talk about transmission again briefly because we did mention the 300 MW DC line to North Dakota, but we are evaluating transmission projects within our system as well in the IRP process because as you add generation, it may or may not trigger additional transmission builds. A lot of the resources the model is picking are resources that can easily interconnect with our system, but when you have certain resources, depending on the location could have significantly higher cost to connect and the model did select two different transmission projects that we should be evaluating and one of them is the Rathdrum area. We are going to need new transmission between Rathdrum and the Spokane area if we're going to put any type of generation out in that area, whether it's a natural gas CT or a storage project, enforcement is likely needed out there to meet new generation needs. And the second one also is off system imports. What we're finding is if we're going to need the amount of renewables expected, that may not come from something that's within our system. If we basically run out of opportunities for when in our area, we're going to have to go off system, and that means we're going to need transmission to reach out to other areas. So, this one is depending upon where resources end up in the future. Can we get enough locally, or do we have to go elsewhere? And so, we would need to increase capacity to those other locations. The challenge is where you increase and I don't think that's a known quantity yet, but it's something we need to evaluate because this is a 10 plus year exercise to build larger scale transmission like we talked about with the case to North Dakota. Now this would be on top of that. Our project and then the last one is something I mentioned earlier. If we start to see renewables exported off of our system and we don't have enough renewables, that's easily connectable in our service territory, we could or we would need to build additional transmission. So, depending on what happens with our loads and resources within our system, where they go, we need to build additional transmission and those again are our 10-year project. In the best-case world, you don't need it, but in the worst case, you would. Likely I don't have to make that decision on do we start these projects or not? But it's something that is showing up as an opportunity, or at least a concern if we start to see projects exported off our system, we're going to need additional transmission.

James Gall: Alright. We're going to shift to some of the results of this strategy. What that does to our portfolio, whether it's cost or share of clean energy and this example, this shows right now we're around 80% clean energy as compared to how much we generate over the course of the year versus what our load is. This is not saying at all that every hour is served 80% clean energy. This is just basically over the course of how much we produce versus what our load is allocated by state. And what you see is in, at least for Washington, you can see that first wind addition in 2029 and 2030, you can see Washington start to move up to almost 100% clean energy that's 77% that 98% allocated to Washington. There is obviously a target to be 100% by 2030 and we do have resources that are allocated when in reality to both states, so there would be a shift in generation to comply with Washington CETA there to hit the 100% target. But as we go over time, you can see we're adding both renewable to Washington and Idaho. But as you get to 2045, we are going to have more renewable energy than load in this scenario, largely driven by the requirement, really two requirements in the modeling effort. One, at least for Washington, all load all the time has to be by renewable or non-emitting resource. What happens is you have months that are higher load months that you're going to need to build renewable generation to help support that, which means you're going to be long on renewable energy. And other months, what we're seeing is that phenomenon and the solution to that phenomenon is more storage, but then the question of how do you optimize between overbuilding or renewables and storage. If renewables are very expensive, then you must start to look at or storage. But if renewables are cheap, you look at less storage and more renewables. Last IRP showed more storage, less renewables. This IRP is showing more renewables, less storage, which is an interesting phenomenon, but that is what is driving the 2045 excess over 100%. But I see a hand up. Go ahead, Sofya.

Sofya Atitsogbe (UTC): Hi James. I have two questions about the development from 2030 to 2044 in Washington is that the decline in the existing resources? Is that mainly retirement or is that all some kind of low water years incorporated here as well?

James Gall: It's actually PPA expirations might be a better term than retirements, but we have contracts that are renewable energy that will go away. So, you got to replace those and some of those replacements that you see in blue are basically the same resource. For example, our Rattlesnake Wind Project, a 20-year PPA, it's likely, at least hopefully likely, we can renew that PPA and continue that resource. That's what you're seeing there in those reductions.

Sofya Atitsogbe (UTC): Got it.

James Gall: And then the far out years, you do start to see a little bit of reduction in

Kettle Falls generation, which probably is not really seeable on here, but you start getting oversupply events that could reduce the amount of renewables depending on what season you're generating in.

Sofya Atitsogbe (UTC): Thank you. And I do understand that for Idaho, the percentage of clean energy is declining with time.

James Gall: Correct. That again, goes back to that PT split so anything that's existing today in the model is allocated based on that PT ratio. So, Idaho is getting the same reductions.

Sofya Atitsogbe (UTC): Yeah.

James Gall: Over time, really it's washing. It's just a matter of how we allocate resources as well. It gets a little bit odd because the states have different levels of PURPA resources as well.

Sofya Atitsogbe (UTC): And my last question would be, you mentioned the new opportunity to connect to the transmission line. Does that forecast take into account that opportunity or is this one without it?

James Gall: Yeah. It's with it, but we don't assume any renewable energy is delivered on it. Think of it as there's going to be market purchases. We're not counting market purchases in this. It's just the renewables that we would be controlling so that energy, whether it's sold or purchased, is not included in here. That's a good question.

Sofya Atitsogbe (UTC): OK. Thank you.

James Gall: Yep. Actually, that issue shows up in another short later as well. Hopefully, I will remember to talk about that. OK. This is our rate forecast and this is not a, don't take this home this is what our rates are going to be. That's the first caveat, but it's a very interactional rate forecast, it's the concept. We're trying to calculate what is the average cost per kWh of our load by state and IRPs don't model the world we could. It would take a lot longer, which I mean by that is we're not modeling every transmission line upgrade, every distribution line upgrade, all of our A&G costs, we make some assumptions that those costs are going to grow over time and we're just seeing what is the impact of power supply costs on that total revenue requirement and then dividing by how much sales there are. Both states look very similar actually in growth patterns between Idaho and Washington until you get to the end of the strategy, you start to see a little bit of a separation in 2042, but it gets to be a large separation in 2045. I think the last IRP we started to see a little bit more separation earlier but not this time. But the reason why this is an important chart, it's really just a, come back to what is likely to happen in the 2045 period. Maybe it's just it's so far out there we probably should be really concentrating on it too much, but there's a cost cap in Washington of 2% per year and there's a lot of math behind the scenes asked to happen to the calculate that. But, the resource strategy that we presented here today, if it came to fruition, how it's modeled, which it obviously won't, but there would be definitely some cost cap constraints in that 2045 period and we've looked at should we be modeling the cost cap or not. In our Preferred Resource Strategy, we've decided not to. We're going to try to run a scenario on what that cost cap would do to our Preferred Resource Strategy that's going to come in the next TAC meeting, but definitely 2045 has got some substantial cost considerations because you are losing, think about it, as all of our gas generation has to be replaced. It's just a quantity, you're taking low-cost generation and replacing it with higher cost generation that we just saw on the previous slides. You start to see real cost impacts at that point in time. I guess over all the next six IRP's, this will start to kind of shape its way out on what this will look like. But it is definitely on our minds, at least 20 years out, there could be some cost impact questions for Avista. Know how the utilities may have cost cap considerations earlier, but at least for events it looks like it's going to be in that end of the 20-year cycle.

James Gall: Alright, so this is something we didn't get to last IRP TAC meeting, but we have some Customer Benefit Indicators [CBIs] we can go through. In our CEIP process, the Clean Energy Implementation Planning process, there is something called a Customer Benefit Indicator. And there is, I can't tell you how many, let's say there's thirty of them and what we're trying to do is with those indicators is measure how well we are assisting customers in the energy transition process. We've picked out different CBIs that can be relatable to the Integrated Resource Plan and so I'm going to go over some of those today. I would definitely say these are not the official numbers we file necessarily as the amount because the IRP is a little bit of an academic exercise, but these are very good indicators of where, directionally measurements are going. First one has to do with energy burden, or really impact the customers rates, and you can see 2045 customers that have excess energy burden. Excess energy burden is that their utility bill, total between gas and electric, exceeds 6% of their income. And right now, it's around 40,000 customers, but we model and in Washington State we have that situation and that appears to remain relatively flat until 2045. And if we actually saw that rate increase, you would see in on that conditional 20,000 customers have an excess energy burden now. One way is we can deal with energy burden today is through transfer payments or energy assistance and that helps bring that energy burden down. But, in 2045, when you start having to replace significant capacity resources, we're going to see that number go up, which could be more assistance or what other options do we have to reduce that energy burden? That's where we're trying to account for energy efficiency improvements made.

James Gall: Community Solar is one option that's been discussed as a way to reduce energy burden, and that's something we're going to show in the maximum customer benefit scenario. The chart on the right gets into the percentage of customers. While the number of customers is staying relatively flat, the percentage of customers is slightly declining until you get to that last year 2045, but a little under 20%. And then by the time you get out to 2044, you're at 15% before a large rate increase and then, how much is that energy burden, that average energy burden, it's around $1,000 today or in a couple of years. That would increase to $2,000. Obviously, these are nominal dollars. They have inflation in them, so that's why that's definitely increasing.

James Gall: We're at 2 minutes left. That's telling me that we're probably going to have another TAC meeting to finish up. I think that is probably where we need to end, but I'm going to go back to, before we call it a day, if there's any preferences for the September meeting. If I can find that slide from the introduction. Because I could talk all day. We don't want to do that and we don't see that yet on our screen. Oops, wrong one, sorry. Working off a very small screen. There we go. OK.

James Gall: We are going to have the finish these slides at the next meeting on I believe August 13th and we'll continue the discussion. As far as the September meeting to finish up scenarios, we have three options: September 10th, 9:00 to 11:30 or the 17th from 9:00 to 11:30 or 1:00 to 3:30. I just want to know if there's any, maybe the best question to ask is are there any that are a nope for anybody? Otherwise, we'll probably pick. If somebody has a no, let us know. Let John know or put it in the text, and we'll pick out a date. Just email us. We'll wait for the next couple days to see what response we get. If it's up to me, I would prefer the 17th to give us a little bit more time to wrap all the work up, but so we'll see if that doesn't work for somebody, we'll definitely go with the 10th. Appreciate the time today. Great discussion. Hopefully we don't change the strategy again, but we got to lock it down at some point. Thank you and have a great day.

Charlee Thompson: Thank you.

James Gall stopped transcription.

2025 Electric Integrated Resource Plan

Technical Advisory Committee Meeting No. 12 Agenda
Tuesday, August 13, 2024
Virtual Meeting – 8:30 am to 10:00 am PTZ

Topic	**Staff**
Introductions	John Lyons
Preferred Resource Strategy Results (continued)	Planning Team
Avoided Costs	James Gall

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2025 IRP TAC 12 Introductions

John Lyons, Ph.D.
Technical Advisory Committee Meeting No. 12
August 13, 2024

Today’s Agenda

Introductions, John Lyons

Preferred Resource Strategy Results, Planning Team

Avoided Costs, James Gall

Remaining 2025 Electric IRP TAC Schedule

- **TAC 12: August 13, 2024: 8:30 to 10:00 (PTZ) – Scheduled**
  - Preferred Resource Strategy Results (continued)
  - Avoided Costs

- **NEW TAC 13: September 17, 2024: 9:00 am to 11:30 am (PTZ)**
  - Scenario Analysis
  - IRP Next Steps

- **September 2, 2024- Draft IRP Released to TAC with the following chapters:**
  - Economic and Load Forecast
  - Long Term Position
  - Distributed Energy Resource Options
  - Supply Side Resource Options
  - Transmission Planning and Distribution
  - Preferred Resource Strategy
  - Washington Clean Energy Action Plan

Remaining 2025 Electric IRP TAC Schedule

- **Virtual Public Meeting- Natural Gas & Electric IRP (November 2024)**
  - Recorded presentation
  - Daytime comment and question session (7:30 am to 8:30 am, PTZ)
  - Evening comment and question session (6:00 pm to 7:00 pm, PTZ)

- **October 1, 2024- Remainder of Draft IRP Released to TAC with the following chapters:**
  - Executive Summary
  - Introduction, Interested Party Involvement, and Process Changes
  - Existing Supply Resources
  - Market Analysis
  - Portfolio Scenarios
  - Action Plan

2025 Electric Integrated Resource Plan
Draft Preferred Resource Strategy

James Gall
Technical Advisory Committee Meeting No. 12
August 13, 2024

Preferred Resource Strategy (7/16/2024)

Nameplate MW	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Shared System Resource																				
Mrkt/Trans	40	4	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas	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	0
Wind	0	0	0	0	0	100	100	200	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
PtoG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	10	0
RNG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Washington																				
Mrkt/Trans	0	0	0	0	0	0	0	0	0	0	0	50	0	0	50	50	50	50	0	50
Natural Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	0	1	1	1	1	1	101	1	1	1	1	1	1	1	1	1	1	1	200	5
Wind	0	0	0	200	200	100	0	0	0	0	0	0	0	0	0	140	0	120	0	200
Storage	0	0	0	0	0	0	50	0	0	0	0	0	0	0	0	0	0	0	104	62
PtoG	0	0	0	0	0	0	0	0	0	0	0	0	90	0	0	0	196	0	94	0
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	150
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	20
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RNG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Idaho																				
Mrkt/Trans	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas	0	0	0	0	99	0	0	0	0	0	0	90	0	0	0	0	124	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	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	35	0
PtoG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RNG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Revised Preferred Resource Strategy (2026-35)

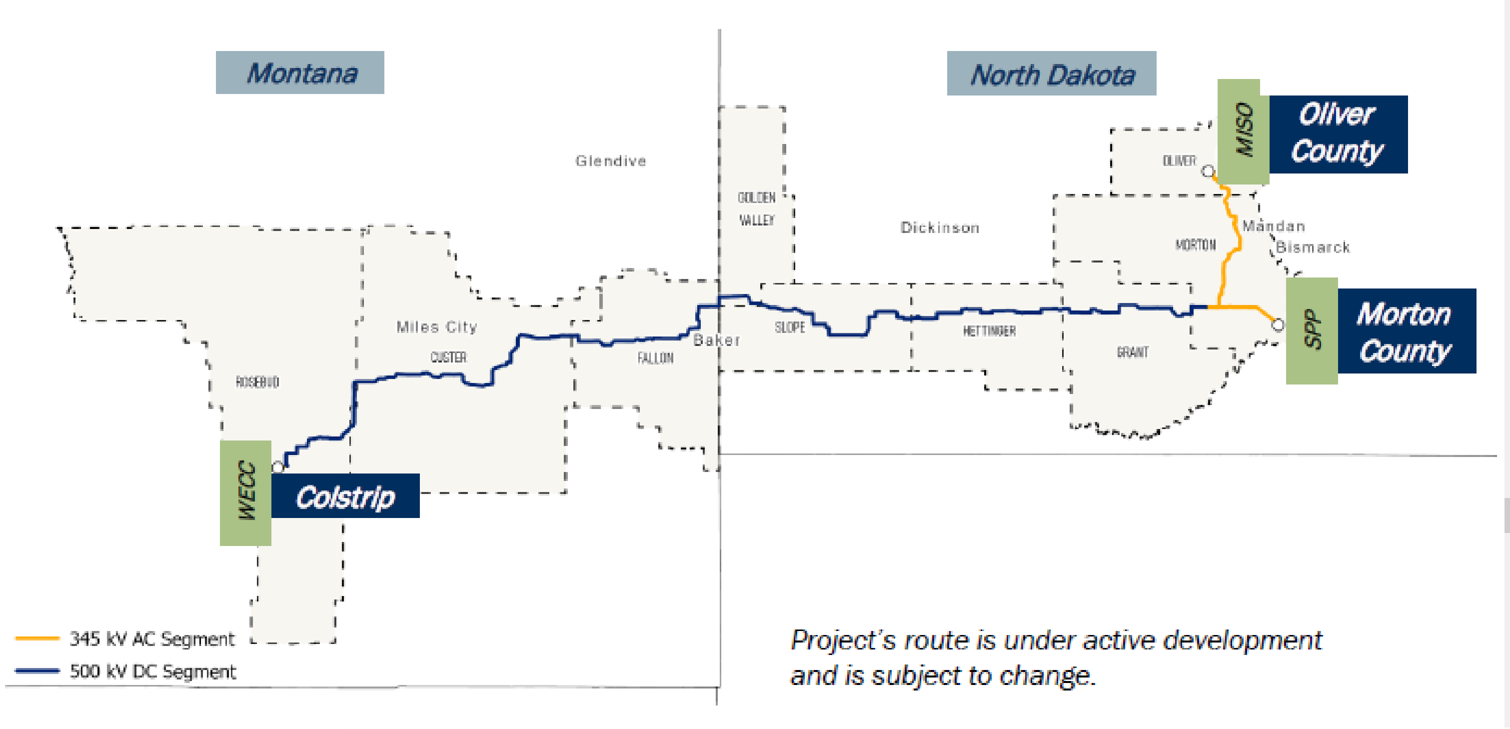
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Washington (MW- Nameplate)											
Market	25.8	2.5	6.4	-	-	-	-	-	-	-	**34.6**
Regional Transmission	-	-	-	-	-	-	-	198.4	-	-	**198.4**
Natural Gas	-	-	-	-	-	-	-	-	-	-	**-**
Solar	-	0.5	0.6	0.6	0.7	0.8	0.8	1.0	0.5	0.5	**5.9**
Wind	-	-	-	200.0	200.0	165.9	66.0	104.0	-	-	**736.0**
Storage	-	-	-	-	-	-	-	-	-	-	**-**
Power to Gas	-	-	-	-	-	-	-	-	-	-	**-**
Nuclear	-	-	-	-	-	-	-	-	-	-	**-**
Geothermal	-	-	-	-	-	-	-	-	-	-	**-**
Biomass	-	-	-	-	-	-	-	-	-	-	**-**
Total	**25.8**	**3.0**	**6.9**	**200.6**	**200.7**	**166.7**	**66.8**	**303.4**	**0.5**	**0.5**	**974.9**
Cumulative Demand-Side Management											
Demand Response (MW)	0.5	1.4	3.0	4.9	7.2	8.7	9.4	10.2	11.1	12.4	
Energy Efficiency (aMW)	3.4	7.1	11.2	15.8	19.7	24.0	29.2	34.5	39.8	44.5	
Idaho (MW- Nameplate)											
Market	13.6	1.3	3.3	-	-	-	-	-	-	-	**18.2**
Regional Transmission	-	-	-	-	-	-	-	101.6	-	-	**101.6**
Natural Gas	-	-	-	-	90.2	-	-	-	-	-	**90.2**
Solar	-	-	-	-	-	-	-	-	-	-	**-**
Wind	-	-	-	-	-	34.1	34.0	53.3	-	-	**121.4**
Storage	-	-	-	-	-	-	-	-	-	-	**-**
Power to Gas	-	-	-	-	-	-	-	-	-	-	**-**
Nuclear	-	-	-	-	-	-	-	-	-	-	**-**
Geothermal	-	-	-	-	-	-	-	-	-	-	**-**
Biomass	-	-	-	-	-	-	-	-	-	-	**-**
Total	**13.6**	**1.3**	**3.3**	**-**	**90.2**	**34.1**	**34.0**	**155.0**	**-**	**-**	**331.5**
Cumulative Demand-Side Management											
Demand Response (MW)	-	-	-	0.1	0.3	0.7	1.0	1.2	1.3	1.3	
Energy Efficiency (aMW)	1.2	2.6	4.1	5.9	7.2	8.6	10.5	12.6	14.5	16.3	
Resource Reductions (MW)	**0**	**0**	**0**	**12**	**64**	**0**	**0**	**0**	**88**	**0**	**164.0**

~78,000 MWh
Biannual EE Target

Revised Preferred Resource Strategy (2036-45)

	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Washington (MW- Nameplate)											
Market	-	-	-	-	-	-	-	-	-	-	**-**
Regional Transmission	-	-	-	-	-	-	-	-	-	-	**-**
Natural Gas	-	-	-	-	-	-	-	-	-	-	**-**
Solar	0.5	0.5	0.5	0.5	0.5	0.5	0.5	180.5	120.5	0.6	**305.1**
Wind	-	-	-	-	-	140.0	-	120.0	108.4	200.0	**568.4**
Storage	-	-	-	-	-	-	-	90.0	86.1	85.3	**261.4**
Power to Gas	-	-	-	-	90.2	-	209.8	-	-	94.3	**394.3**
Nuclear	-	-	-	-	-	-	-	-	-	100.0	**100.0**
Geothermal	-	-	-	-	-	-	-	-	-	20.0	**20.0**
Biomass	-	-	-	-	-	-	-	-	-	64.4	**64.4**
Total	**0.5**	**0.5**	**0.5**	**0.5**	**90.7**	**140.5**	**210.3**	**390.5**	**314.9**	**564.6**	**1,713.6**
Cumulative Demand-Side Management											
Demand Response (MW)	13.6	15.1	18.8	26.5	31.9	36.6	40.6	44.6	48.4	51.6	
Energy Efficiency (aMW)	49.1	53.5	57.6	61.1	64.4	67.6	70.0	72.7	75.2	77.3	
Idaho (MW- Nameplate)											
Market	-	-	-	-	-	-	-	-	-	-	**-**
Regional Transmission	-	-	-	-	-	-	-	-	-	-	**-**
Natural Gas	-	-	-	-	90.2	-	94.9	-	-	-	**185.1**
Solar	-	-	-	-	-	-	-	-	-	-	**-**
Wind	-	-	-	-	-	-	-	-	-	-	**-**
Storage	-	-	-	-	-	-	-	-	-	-	**-**
Power to Gas	-	-	-	-	-	-	-	-	-	-	**-**
Nuclear	-	-	-	-	-	-	-	-	-	-	**-**
Geothermal	-	-	-	-	-	-	-	-	-	-	**-**
Biomass	-	-	-	-	-	-	-	-	-	3.2	**3.2**
Total	**-**	**-**	**-**	**-**	**90.2**	**-**	**94.9**	**-**	**-**	**3.2**	
Cumulative Demand-Side Management											
Demand Response (MW)	1.4	1.4	1.7	2.1	2.5	2.9	3.7	5.8	8.7	10.6	
Energy Efficiency (aMW)	18.2	20.0	21.7	23.2	24.6	25.9	27.0	28.2	29.3	30.4	
Resource Reductions (MW)	**0**	**0**	**0**	**20**	**36**	**140**	**282**	**105**	**0**	**390**	**973**

North Plains Connector



At the 7/16/2024 TAC Meeting: 300 MW of this resource was selected between 2037-45. It was discussed this resource cannot be acquired in increments and not all benefits were modeled at this time

Wind Selection Observations

- 850 MW of wind is selected between 2029-2033, this is a financially beneficial early action taking advantage of IRA benefits and low PPA prices.
  - If tax credits change or low priced PPA terms do not materialize, this selection will change.
  - Avista has limited transmission to integrate new wind in the service territory, if wind projects are exported off system, the PRS selection will reduce.
- Concerned with Montana Wind winter QCC could underestimate need for winter capability.
- Additional wind could be economic for Idaho customers, but the model allocates to Washington due to limited options to meet long-term CETA goals.

Demand Response

Program	Customer Segment	Washington Start Year	WA	Idaho Start Year	ID
Electric Vehicle TOU	Commercial	2026	8.8	2029	0.7
Battery Energy Storage	All	2026	10.4	2035	1.5
Variable Peak Pricing	Large Commercial	2026	5.4	2029	1.7
Peak Time Rebate	Residential/Sm. Com.	2035	5.5	2040	4.0
Behavioral	Residential/Sm. Com.	2038	1.9	2043	1.0
Time of Use Rates	Residential/Sm. Com.	2038	2.5		n/a
Third Party Contracts	Large Commercial	2039	18.0	2044	3.1
CTA ERWH	Residential/Sm. Com.	2041	3.4		n/a
Central A/C	Residential/Sm. Com.	2043	5.2		n/a
Total MW by 2045 (Highest of Summer/Winter)			**61.2**		**12.0**

Assumptions:

- Current industrial contract remains
- Idaho AMI by 2029
- Total savings assumes projects do not overlap into other programs
- Totals include ramped savings to 2045, based on the time period the program was selected

Energy Efficiency Top Measure Types

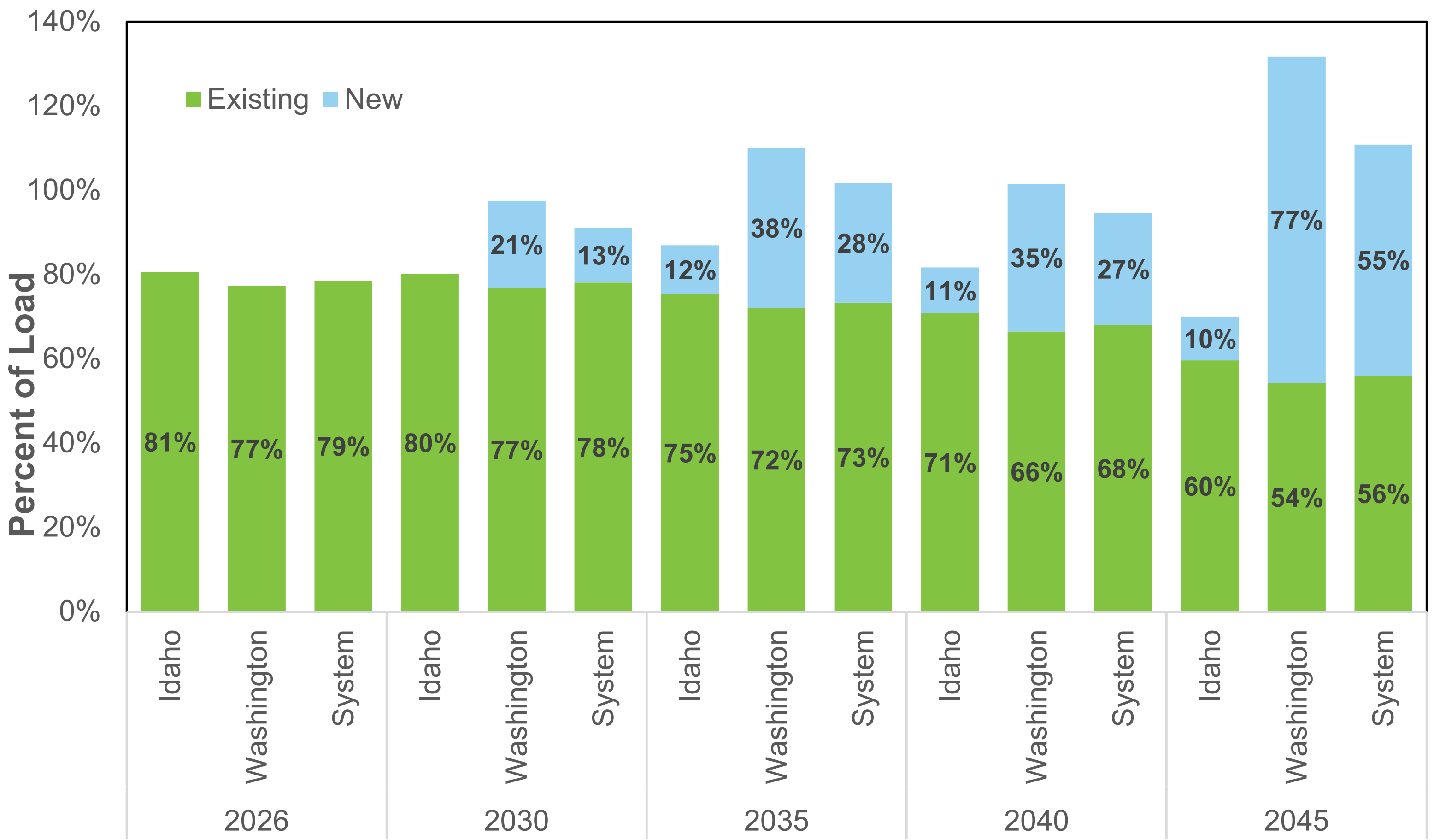
Row	Measure	State	2035
1	Linear Lighting	WA	81.34
2	Windows - High Efficiency (ENERGY STAR 7.0)	WA	27.98
3	High-Bay Lighting	WA	25.00
4	Water Heater - Pipe Insulation	WA	18.13
5	Ducting - Repair and Sealing	WA	17.70
6	Ductless Mini Split Heat Pump	WA	17.11
7	Air-Source Heat Pump	WA	16.05
8	Water Heater (<= 55 Gal)	WA	13.69
9	Home Energy Reports	WA	10.43
10	Insulation - Ceiling Installation	WA	9.26
11	Ventilation - Variable Speed Control	WA	8.60
12	Advanced Industrial Motors	WA	7.81
13	Insulation - Wall Sheathing	WA	7.46
14	Windows - Low-e Storm Addition	WA	6.63
15	Building Shell - Air Sealing (Infiltration Control)	WA	6.03
16	Kitchen Ventilation - Advanced Controls	WA	5.89
17	Clothes Washer - CEE Tier 2	WA	5.70
18	Strategic Energy Management	WA	5.38
19	Insulation - Ceiling Upgrade	WA	5.16
20	General Service Lighting	WA	4.90
21	Pumping System - System Optimization	WA	4.89
22	HVAC - Energy Recovery Ventilator	WA	4.77
23	Fan System - Equipment Upgrade	WA	4.54
24	Connected Thermostat - ENERGY STAR (1.0)	WA	4.49
25	Refrigeration - High Efficiency Compressor	WA	3.98

Row	Measure	State	2035
1	Linear Lighting	ID	43.34
2	High-Bay Lighting	ID	12.70
3	Water Heater - Pipe Insulation	ID	7.90
4	Ducting - Repair and Sealing	ID	6.75
5	Insulation - Ceiling Installation	ID	5.96
6	Air-Source Heat Pump	ID	4.91
7	Lodging - Guest Room Controls	ID	4.69
8	Windows - Low-e Storm Addition	ID	4.34
9	Ventilation - Variable Speed Control	ID	4.27
10	Home Energy Reports	ID	4.24
11	Grocery - Display Case - LED Lighting	ID	3.89
12	Clothes Washer - CEE Tier 2	ID	3.60
13	Fan System - Equipment Upgrade	ID	3.40
14	Refrigeration - High Efficiency Compressor	ID	3.24
15	Kitchen Ventilation - Advanced Controls	ID	2.75
16	HVAC - Energy Recovery Ventilator	ID	2.66
17	Water Heater (<= 55 Gal)	ID	2.59
18	General Service Lighting	ID	2.17
19	Ventilation - Demand Controlled	ID	2.07
20	Insulation - Ceiling Upgrade	ID	1.69
21	Area Lighting	ID	1.68
22	Water Heater - Faucet Aerators	ID	1.48
23	Furnace - Conversion to Air-Source Heat Pump	ID	1.32
24	Pumping System - System Optimization	ID	1.27
25	Refrigeration - High Efficiency Evaporator Fan Motors	ID	1.26

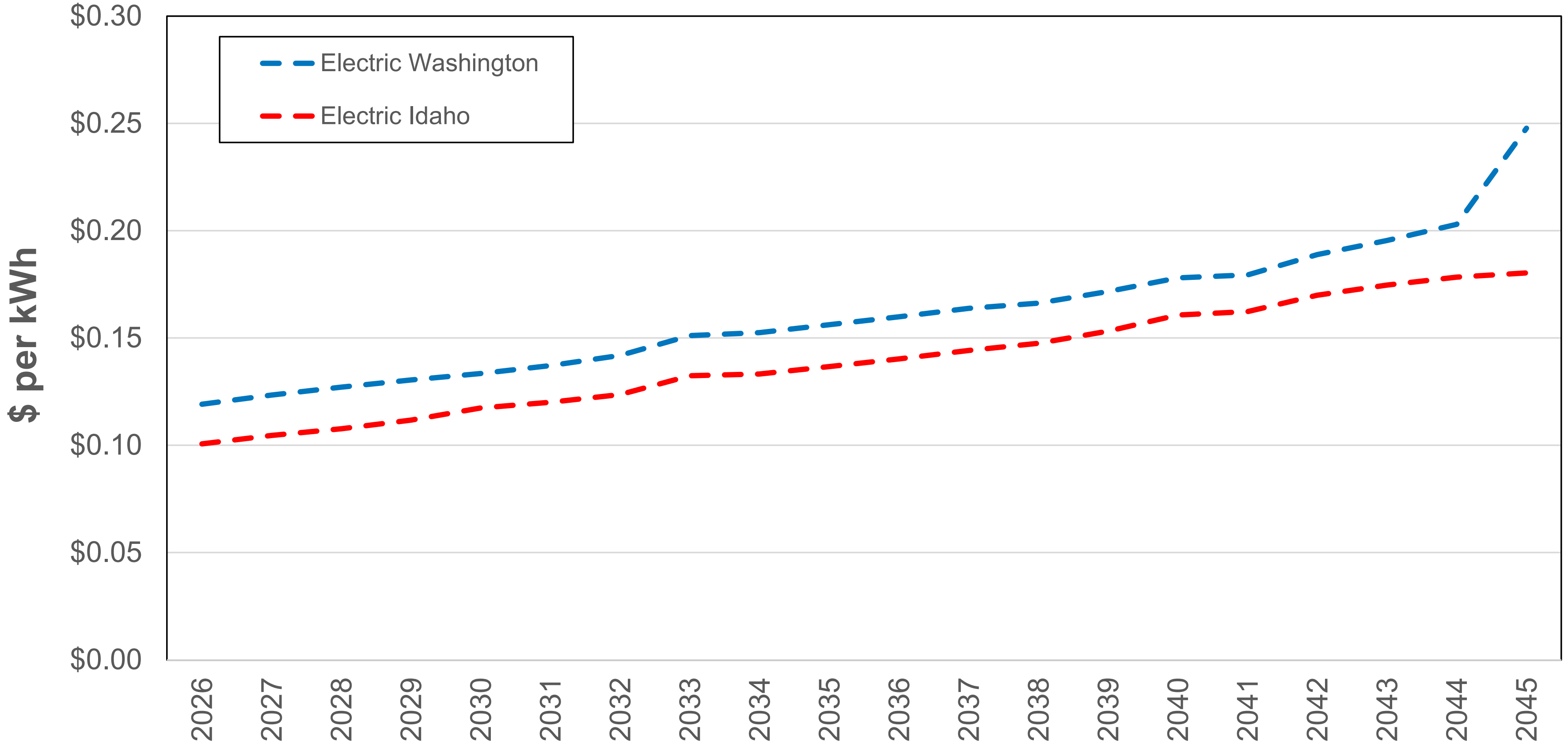
Avista Transmission Considerations

- **Rathdrum Area**: New natural gas CTs begin in 2030, these are likely located in North Idaho, new transmission will be required, if projects continue to be sited in the area additional reinforcement is needed.
- **Off-System Imports:** Need to increase connections to markets/areas to reach additional wind to import by 2045.
- If within system renewables are exported off system, additional transmission within Avista BA will be needed.

Clean Energy Forecast

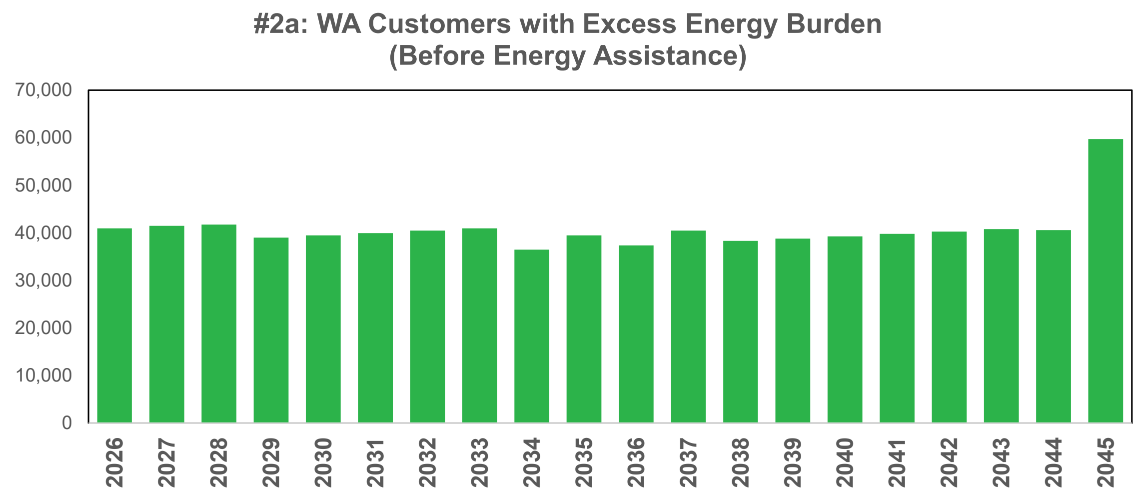


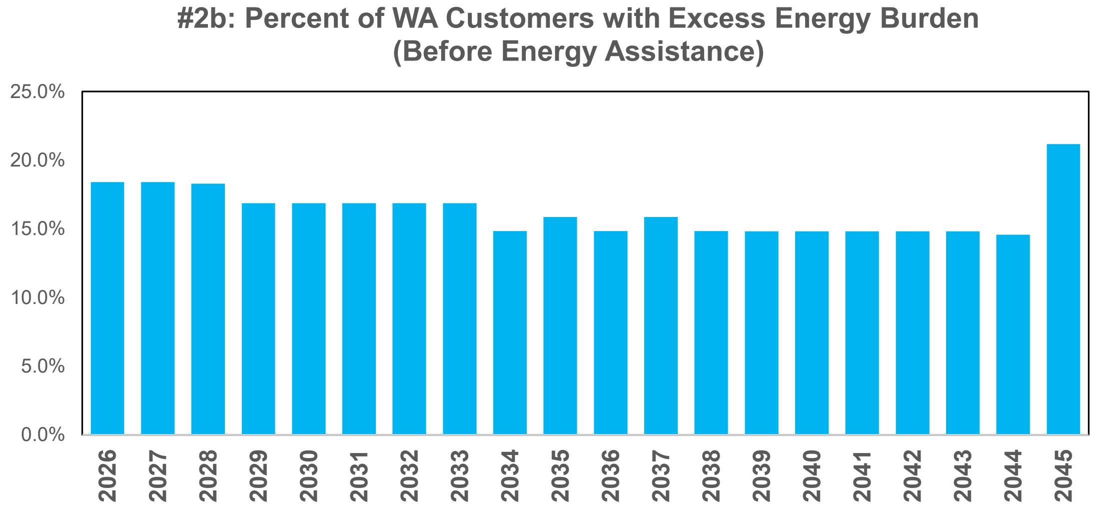
Average Energy Rate Forecast

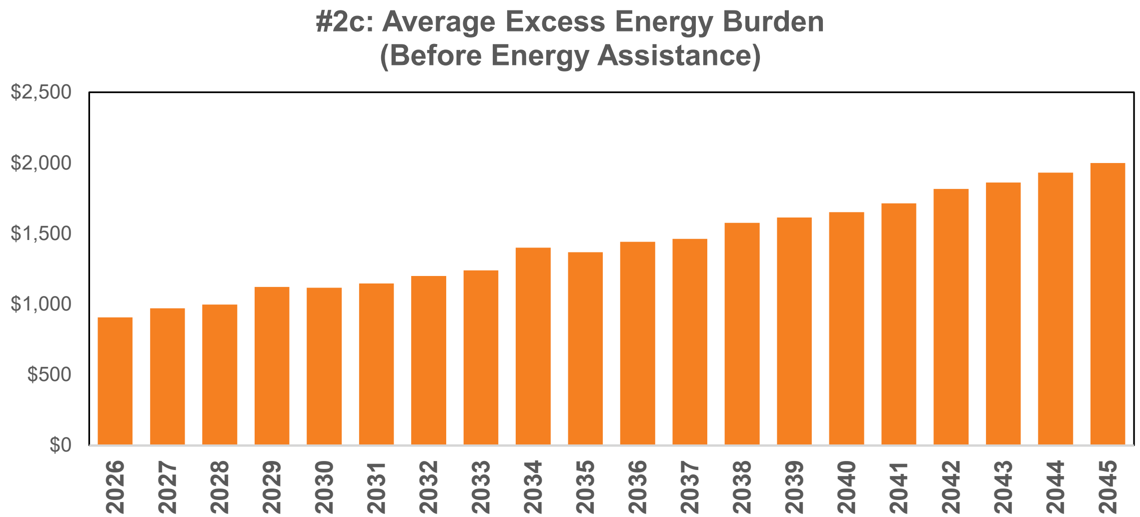


Assumes non-modelled cost increase by 3.8% per year

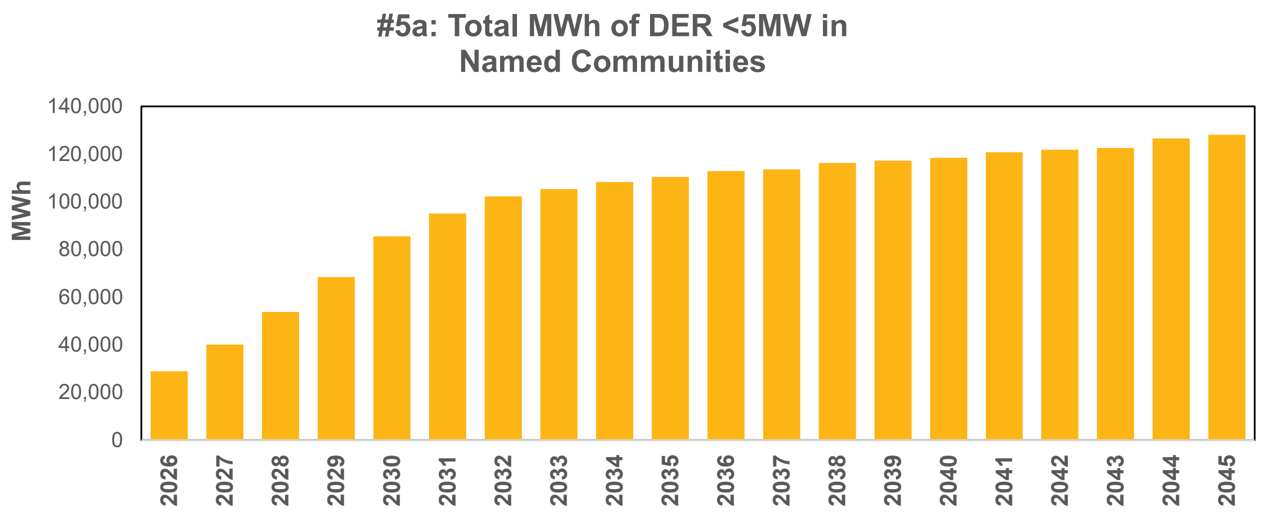
Washington Energy Burden CBI

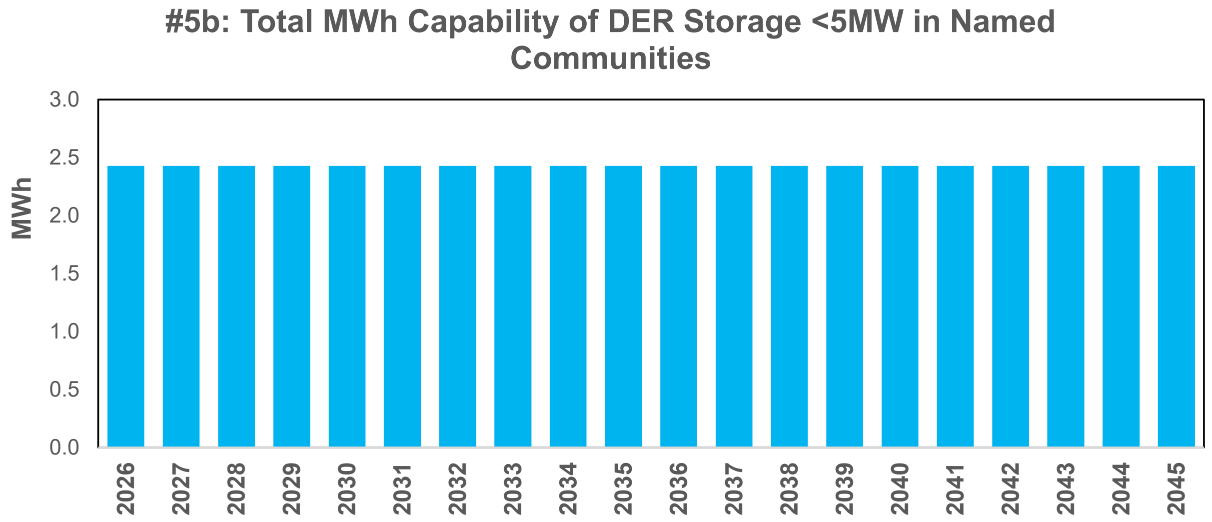




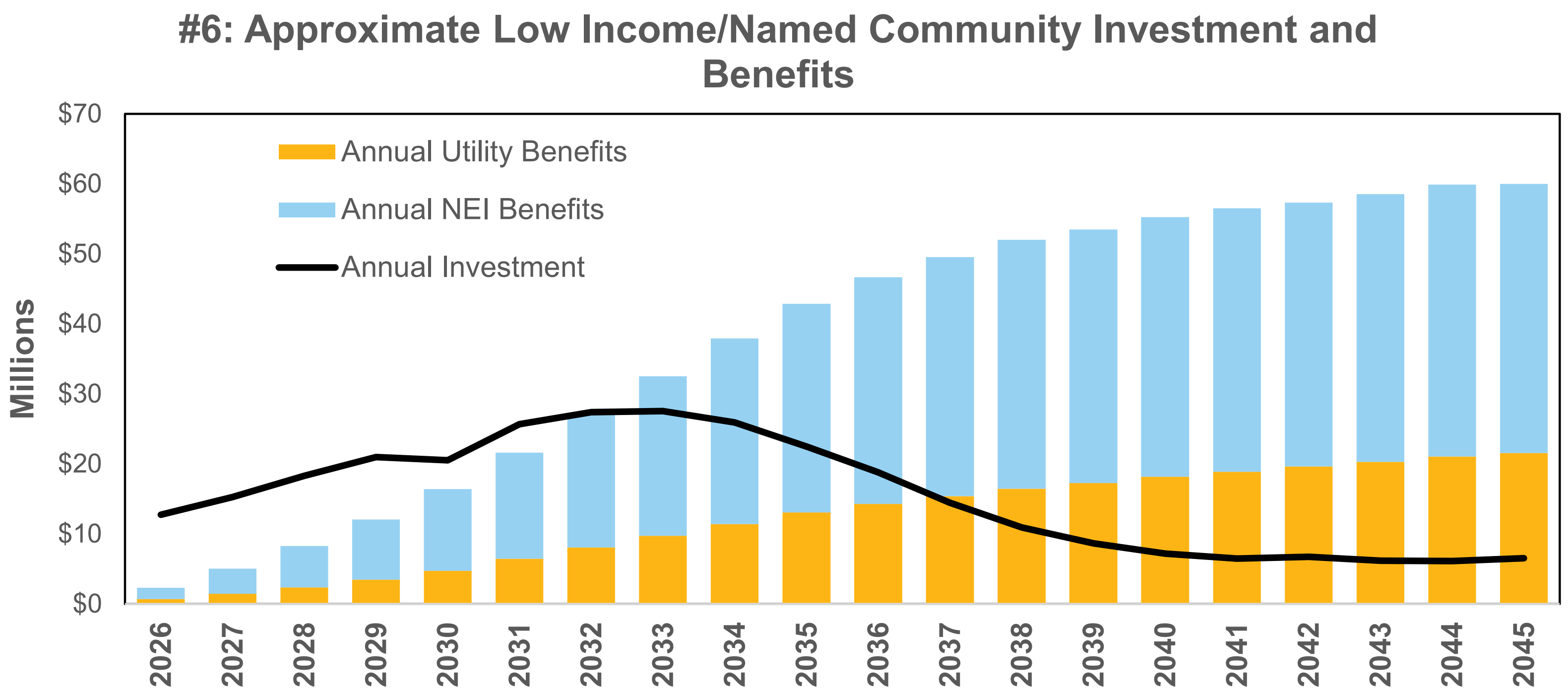


DER Additions CBI

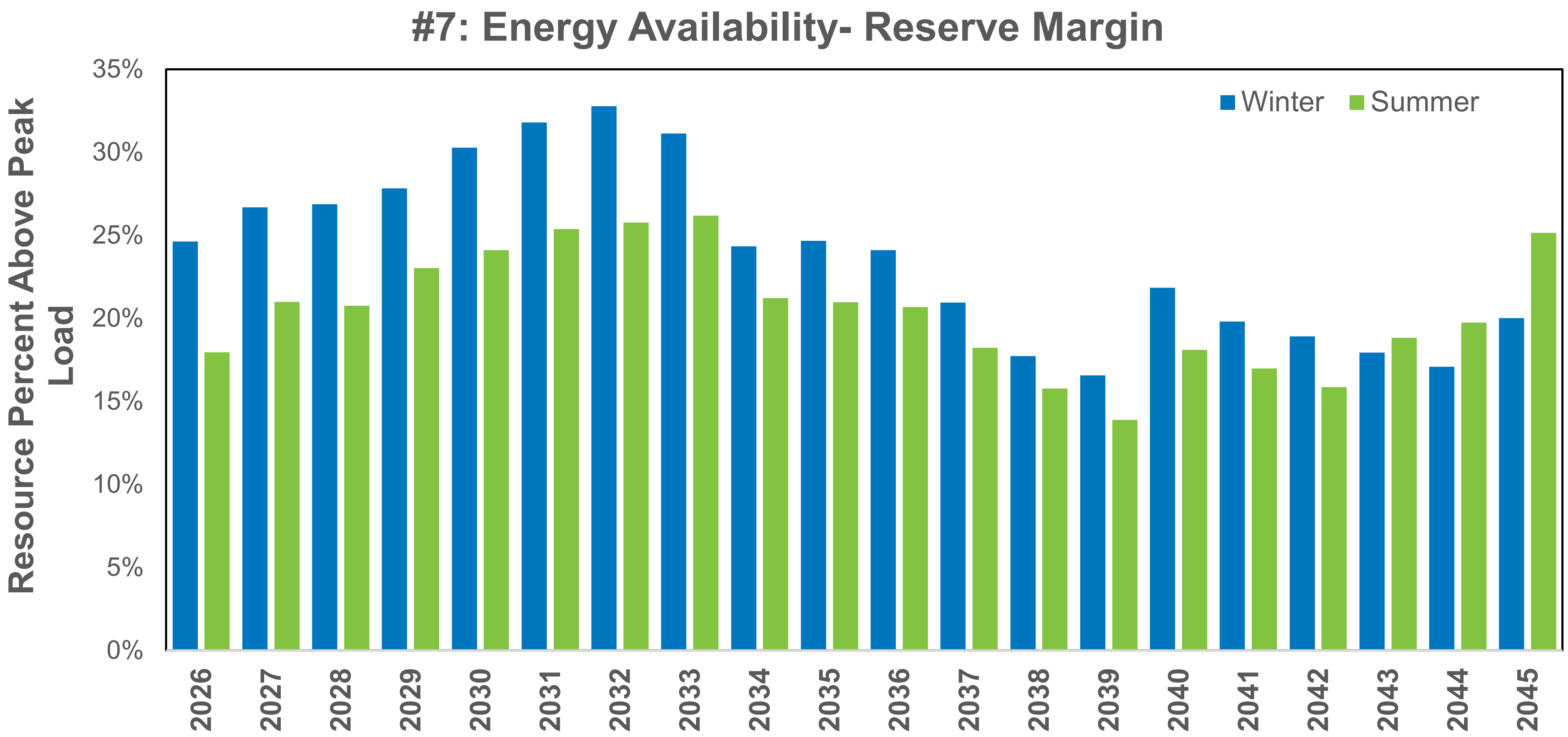




WA Low Income/Named Community Investments CBI

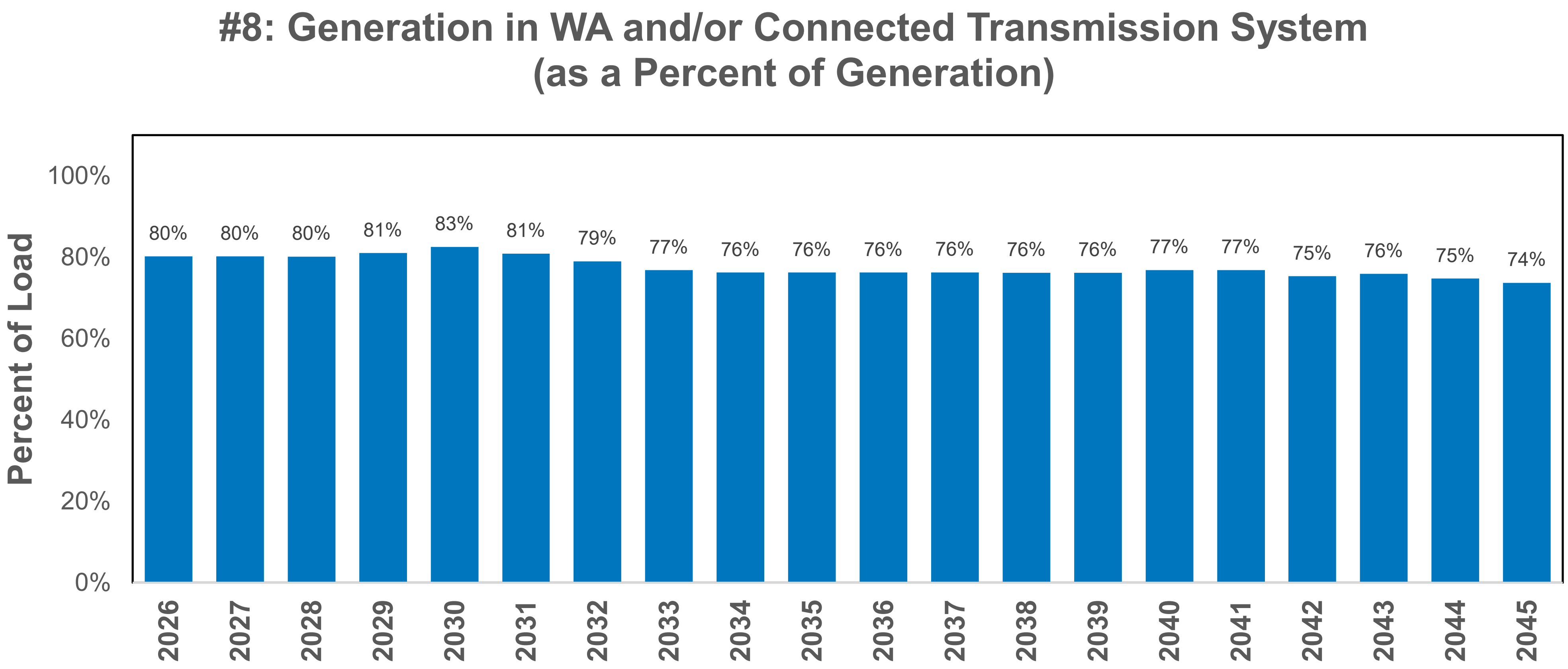


Reserve Margin CBI

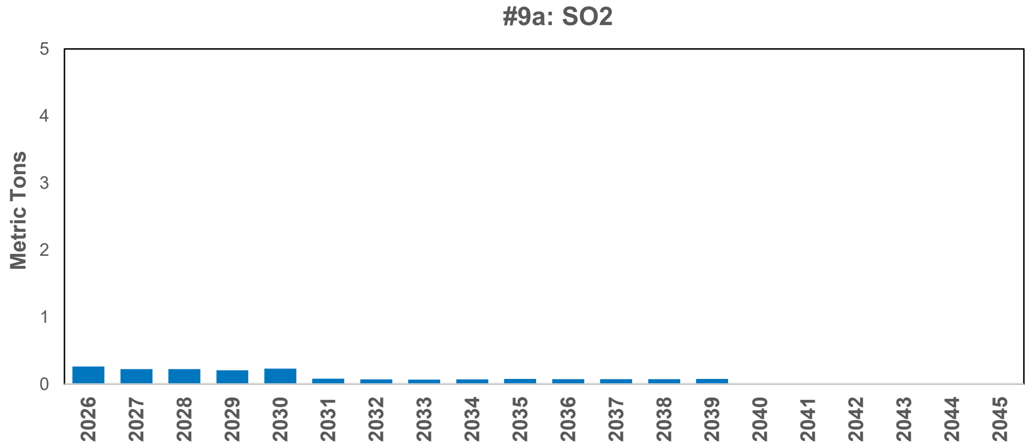


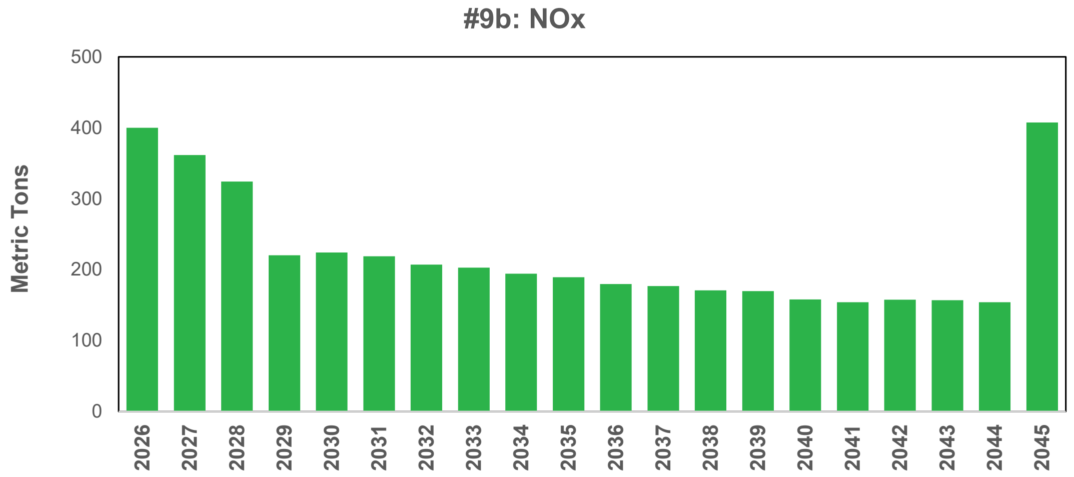
Notes:
- Regional Transmission not included in Reserve Margin
- Demand Response reduced from peak load

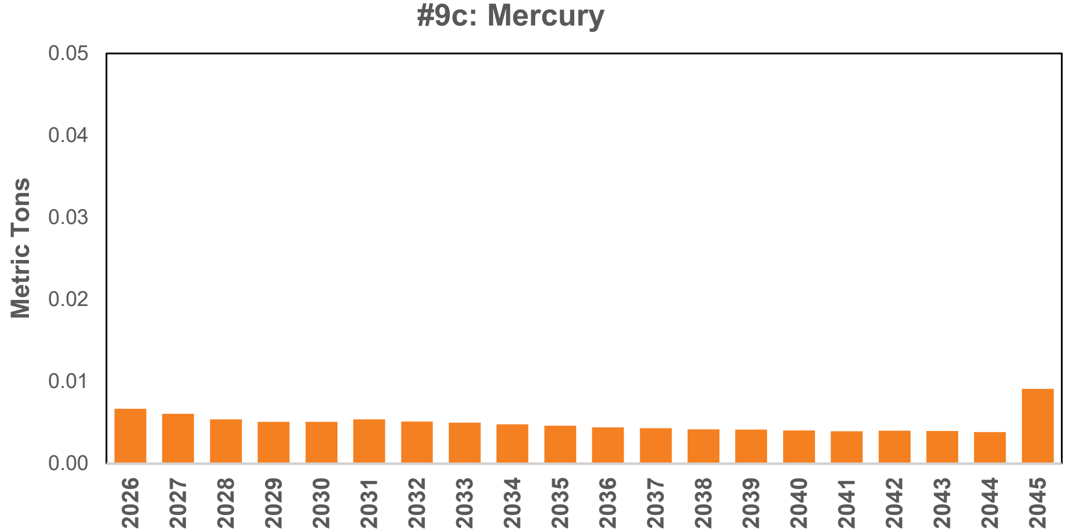
Generation Location CBI

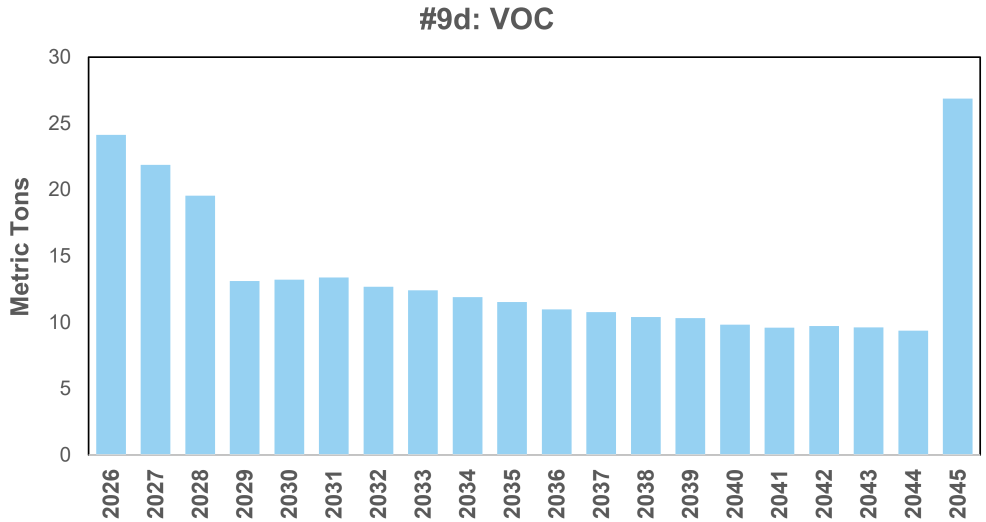


Washington Air Emissions CBI

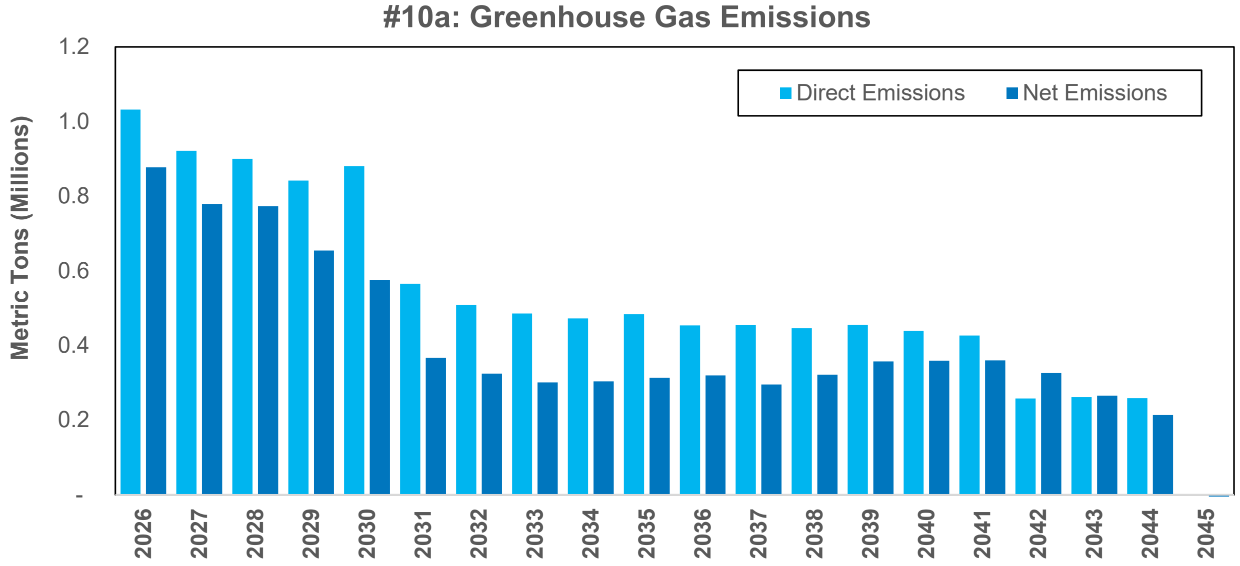


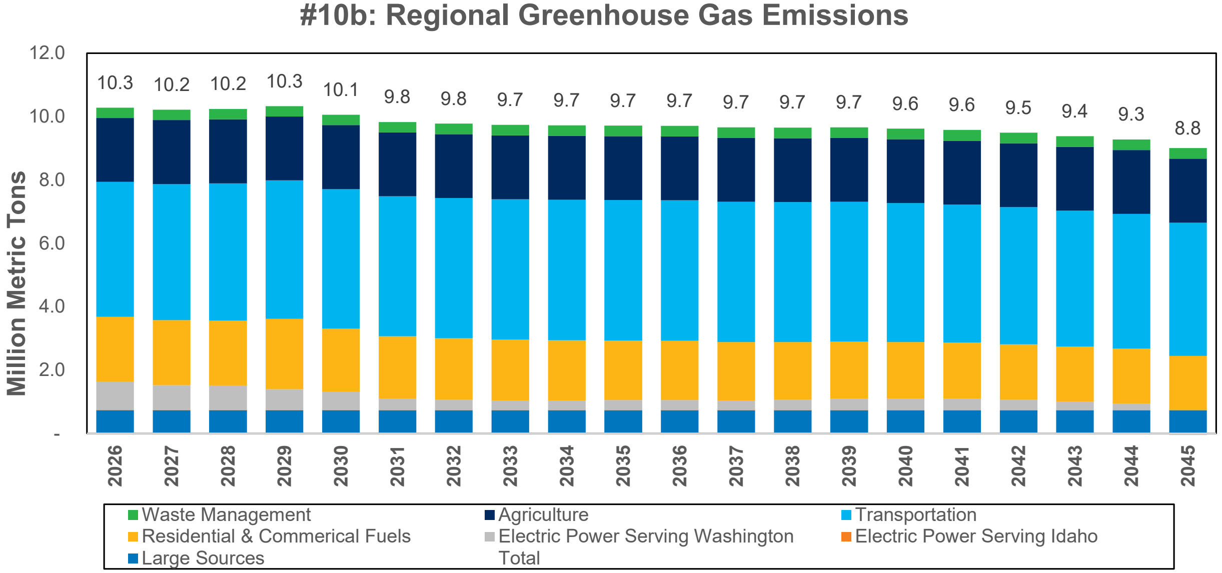




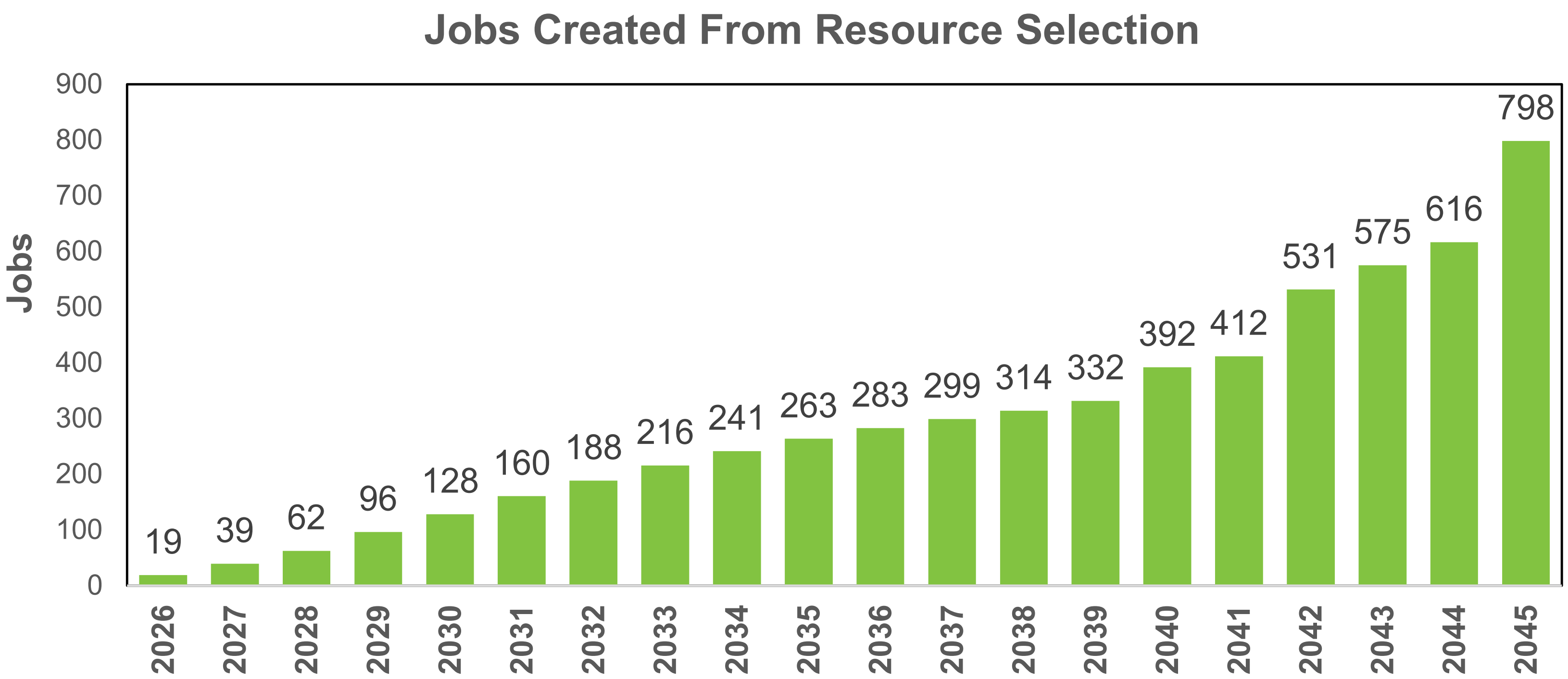


WA Greenhouse Gas Emissions CBI



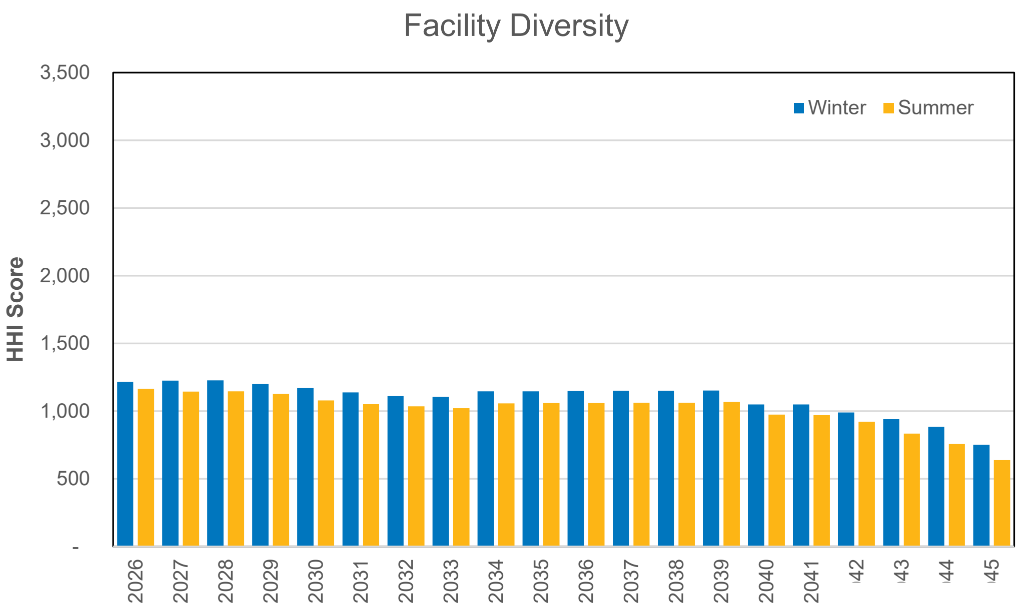


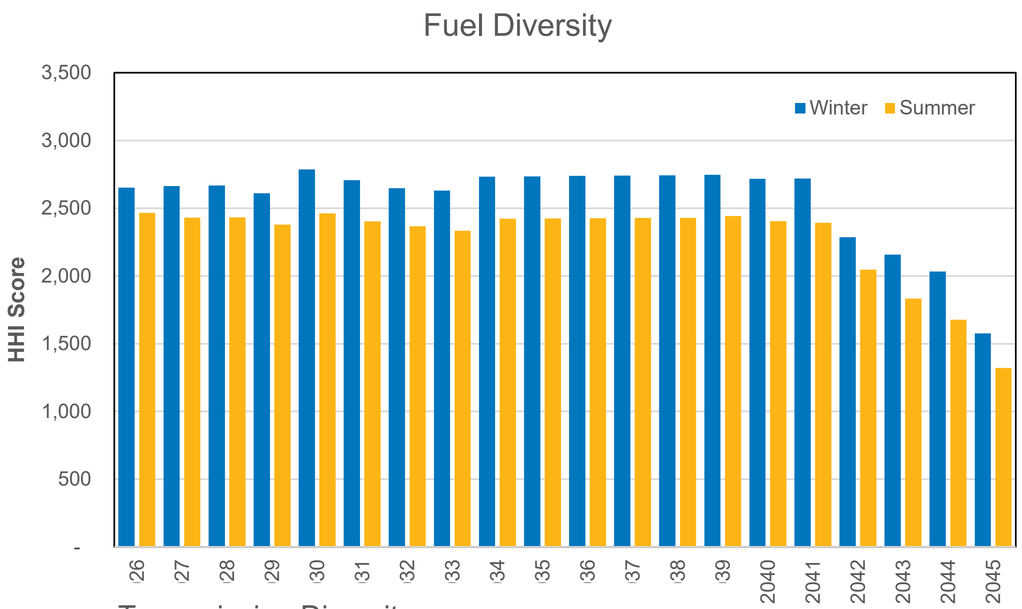
Job Creation (Direct and Induced)



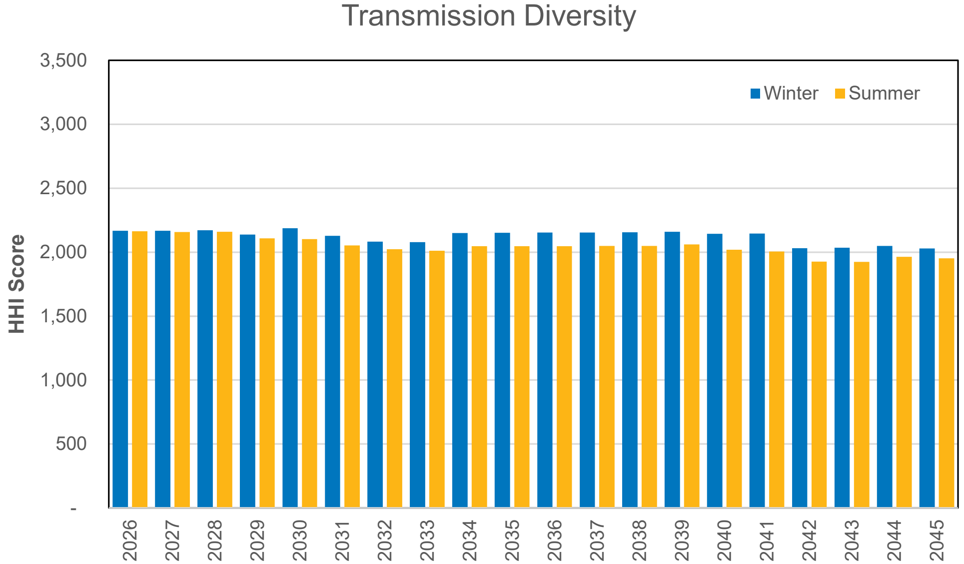
Job estimates based on spending to job relationship today using IMPLAN

Resource Diversity (Resource Resiliency Metrics)





Score	Metric Meaning
<1,500	Competitive Marketplace
1,500-2,500	Moderately Concentrated
>2,500	Highly Concentrated



Avoided Costs (Idaho)

Year	Flat Energy ($/MWh)	On-Peak Energy ($/MWh)	Off-Peak Energy ($/MWh)	Energy Premium ($/kW-Yr)	Capacity Premium ($/kW-Yr)
2026	$41.61	$42.50	$40.42	$0.00	$0.00
2027	$37.88	$37.26	$38.70	$0.00	$0.00
2028	$35.13	$33.57	$37.19	$0.00	$0.00
2029	$34.57	$33.01	$36.64	$0.00	$0.00
2030	$38.56	$36.84	$40.85	$4.46	$100.30
2031	$43.00	$40.96	$45.74	$4.55	$102.30
2032	$42.74	$40.36	$45.92	$4.64	$104.30
2033	$43.82	$41.29	$47.20	$4.73	$106.40
2034	$43.92	$41.19	$47.54	$4.82	$108.50
2035	$44.93	$42.18	$48.59	$4.92	$110.70
2036	$44.50	$41.72	$48.21	$5.02	$112.90
2037	$45.69	$42.61	$49.82	$5.12	$115.20
2038	$45.66	$42.64	$49.68	$5.22	$117.50
2039	$46.29	$43.19	$50.42	$5.33	$119.80
2040	$47.28	$43.96	$51.69	$5.43	$122.20
2041	$47.66	$44.19	$52.29	$5.54	$124.70
2042	$49.92	$46.35	$54.68	$5.65	$127.20
2043	$50.52	$46.88	$55.38	$5.77	$129.70
2044	$51.24	$47.58	$56.12	$5.88	$132.30
2045	$52.39	$48.71	$57.26	$6.00	$134.90
Levelized	**$42.77**	**$40.64**	**$45.60**	**$3.48**	**$78.20**

Avoided Costs (Washington)

Year	Flat Energy ($/MWh)	On-Peak Energy ($/MWh)	Off-Peak Energy ($/MWh)	Energy Premium ($/MWh)	Capacity Premium ($/kW-Yr)
2026	$41.98	$43.12	$40.46	$0.00	$0.00
2027	$38.14	$37.82	$38.58	$0.00	$0.00
2028	$35.40	$34.18	$37.03	$0.00	$0.00
2029	$35.04	$33.84	$36.64	$3.31	$0.00
2030	$39.18	$37.89	$40.90	$3.37	$132.30
2031	$44.10	$42.38	$46.40	$3.44	$135.00
2032	$44.33	$42.27	$47.09	$3.51	$137.70
2033	$45.40	$43.23	$48.29	$3.58	$140.40
2034	$45.55	$43.17	$48.72	$3.65	$143.20
2035	$46.71	$44.27	$49.96	$3.73	$146.10
2036	$46.40	$43.90	$49.74	$3.80	$149.00
2037	$47.66	$44.82	$51.45	$3.88	$152.00
2038	$47.77	$44.98	$51.51	$3.95	$155.00
2039	$48.48	$45.58	$52.35	$4.03	$158.10
2040	$49.59	$46.43	$53.79	$4.11	$161.30
2041	$50.01	$46.68	$54.44	$4.20	$164.50
2042	$52.31	$48.88	$56.90	$4.28	$167.80
2043	$52.97	$49.45	$57.66	$4.37	$171.20
2044	$53.84	$50.27	$58.61	$4.45	$174.60
2045	$55.07	$51.48	$59.83	$4.54	$178.10
Levelized	**$44.13**	**$42.27**	**$46.60**	**$2.87**	**$103.50**

Portfolio Scenarios (includes changes)

Methodology	Load Scenarios	Resource Availability	Other
Alternative Lowest Reasonable Cost [only used for 2026-2029]	Low Growth	Clean Resource Portfolio by 2045	17% PRM (replaces lower WRAP PRM scenario)
Baseline Least Cost Portfolio [excludes CETA]	High Growth	500 MW Nuclear in 2030	30% PRM (replaces 0% LOLP scenario)
Minimal Viable CETA Target	RCP 8.5 Weather	Power to Gas Unavailable	Maximum Washington Customer Benefit
Maximum Viable CETA Target	80% Washington Building Electrification by 2045	~~Nuclear Cost Sensitivity~~	PRS w/ CCA repealed
PRS Constrained to the 2% Cost Cap (replaces unconstrained cost cap)	80% Washington Building Electrification by 2045 & High Transportation Electrification Scenario	~~High QCC on Demand Response~~	
	80% Washington Building Electrification by 2045 & High Transportation Electrification Scenario with RCP 8.5 Weather	Regional Transmission not Available	
	Extreme Building/Transportation Electrification for Washington & Idaho w/o new Natural Gas CTs	Northeast Early Retirement/Late	
	Data Center in 2030	On-System Wind Limited to 200 MW	
		No IRA Tax Incentives	

***Proposed Portfolio Changes in Red*

2025 Electric IRP
TAC 12 Meeting Notes
August 13, 2024

Attendees:

Andres Alvarez, Creative Renewable Solutions; Shawn Bonfield, Avista; Michael Brutocao, Avista; Logan Callen, City of Spokane; Josie Cummings, Avista; Kelly Dengel, Avista; Joshua Dennis, UTC; Mike Dillon, Avista; Chris Drake, Avista; Michael Eldred, IPUC; Ryan Ericksen, Avista; Ryan Finesilver, Avista; Damon Fisher, Avista; Grant Forsyth, Avista; James Gall, Avista; Bill Garry; Amanda Ghering, Avista; John Gross, Avista; Leona Haley, Avista; Lori Hermanson, Avista; Mile Hermanson, Avista; Fred Heutte, NW Energy Coalition; Kevin Holland, Avista; Annu John, Fortis BC; Steve Johnson; Clint Kalich, Avista; Paul Kimmell, Avista; Corey Kupersmith, Sun2o Partners; Erik Lee, Avista; Seungjae Lee; IPUC; Kimberly Loskot, IPUC; Patrick Maher, Avista; Jaime Majure, Avista; Heather Moline, UTC; Austin Oglesby, Avista; Kaitlyn Olson, PSE; Michael Ott, IPUC; Tom Pardee, Avista; John Robbins, Mitsubishi; Jared Schmautz, Avista; John Calvin Slagboom, WSU; Darrell Soyars, Avista; Collins Sprague, Avista; Dean Spratt, Avista; Lisa Stites, Grant PUD; Jason Talford, IPUC; Charlee Thompson, NW Energy Coalition; Taylor Vallas, Invenergy; Bill Will, WASEIA; Rachel Wilson, Form Energy; Yao Yin, IPUC;

Introduction, John Lyons

John Lyons: We'll get started here in just a minute or two. Alright. Well, we crossed 30 people on the meeting, so I think we're good to get started. We've been pushing around 50 for the meeting. Today we'll finish up the slide deck from last time with the Preferred Resource Strategy results and then go into the avoided cost. Any other questions though that have come up, things you want to ask us about, now would be a good time to bring those up. We already went over the second page of this. James, if you just want to pop to the third page, remaining schedule of the TACs. After today we did add that lucky 13th TAC meeting on September 17th. It's going to be a slightly longer meeting from 9:00 to 11:30. We'll cover the scenario analysis and next steps of the IRP. By that time, we'll have the first part of the draft out, that'll be September 2nd. We'll have those first chapters out, so economic and load forecast chapter, long term position where we're at with the resources and our needs, the distributed energy resource options and everything that goes along with DERs, supply side resource options. All the new resources and what we modeled and what their characteristics are, the transmission planning and distribution sections chapter will be done. The big one, the Preferred Resource Strategy, what we plan on doing over the next 20 years and we'll have the Clean Energy Action Plan in there. Those will all be out by September 2nd, released to the TAC.

John Lyons: Then on the next slide, in October, October 1st when we release the rest of the IRP draft. It'll be the executive summary, the introduction chapter that has all the background if you want to look where something is in the IRP and why we did it for regulatory requirements that's in there. Existing supply resources, our current mix of what we have, and we'll have discussions on that. The market analysis for the regional studies, the portfolio scenarios and then the action plan of review of what we were asked to do in the last IRP, the 2023, and where we're at with all of those. And then it'll have what the projects are for the next IRP.

John Lyons: Then we are having the virtual public meeting that is being moved to November. There will be a morning session and an evening session on that. We're not doing a lunch time this time, and there will be a prerecorded presentation that people can watch whenever they want, and that way it'll have a little more time for a discussion and interaction. James, do you have anything else you want to add?

James Gall: No, it said it on the virtual public meeting. That's still being developed, so just there could be changes, but we will let the TAC know about those schedule changes when we have a date and times and how we're going to structure those. You'll all be invited plus we'll send out an invite to all of our customers as well. There's also, through the CEIP process, a quarterly public meeting, and I believe this IRP presentation will be part of that quarterly meeting as well. So more to come out about that. Alright. Any questions on the last TAC meeting before we try to finish up the last TAC meeting? I'll just give a pause there for people to think about that as I try to transition to the other slide deck, OK.

John Lyons: We did have one question hanging out from last time and I believe that was on the Connected Communities. You should have seen the answer for that when I sent out the slide deck, we got that from that area basically. And if I remember right, it was regarding if we had some of the class information on that and how is that being able to replicate that? Basically, it's a pilot program where we're getting that data and then seeing how we can apply that to other areas of the distribution system.

Preferred Resource Strategy Results, James Gall

James Gall: Alright, I think we left off on this slide last time. If somebody remembers differently, let us know. We did check the notes and then reporting, and we got here, jumped around a little bit, and then we had to call it a morning. I think I did cover this slide on what our energy forecast for average rate was and we were starting to get into this session of kind of what happens in 2045 when CETA goes to 100%, which causes the blip in 2045.

James Gall: I'm going to go to the next slide and then we're going to cover the energy burden CBI and the rest of the CBIs. Then we'll get into divided cost section and then I have another scenario, or a slide on scenarios, for what we're going to see next time. On the Washington Energy Burden CBI, there are really three calculations that we were required to do and all of these CBIs, we're only in the IRP. We're looking at ones that affect resource selection or resource selection I should say affects the CBI. There are a lot of CBIs that are not necessarily related to resource planning, and we're going to cover those in the document you're going to see go out in a couple of weeks about which ones are applicable to the IRP and which ones are not. But the ones that we're going to go through today are the ones we see as applicable and they're the same CBIs from the last IRP. But we've also added a couple measurements that could be CBIs if the CEIP process says this is something we should probably add, we'll get into that in a little bit.

James Gall: As far as customer energy burden, on the top left, this represents the number of customers with excess energy burden. What that means is that we're looking at trying to calculate how much energy burden each customer has. We look at their income, their usage of natural gas and electric, and try to estimate how many customers have an energy burden over 6% of their incomes. I'd say this is an estimate. We don't necessarily have incomes for every customer and we're basically using average incomes from census tracts and then looking at average usages for those census tracts and creating a distribution around those census tracts to come up with an estimate. It's around 40,000 customers we think would be in this criteria in 2026 and that number really stays fairly flat as we expect our rates to increase but also salaries to increase. We also have reducing energy use from energy efficiency that's included. But by the time you get the 2045, you start to see where a radical change happens. When you have that rate increase that we showed in the previous slide for going to 100% [clean], which brought up in the last TAC meeting some discussion of that probably being at a risk of hitting the cost cap in 2045 where that rate increase probably would not be as high if everything happened as the IRP forecasts, which I'm not going to say is going to happen, but who knows. But that's what it's starting to look like.

James Gall: The second chart to the right of that takes the same data on the left but divides that by total number of residential customers. Basically, what this shows is as a percentage of the total population the customers having energy burden are declining until you get to 2045. The last chart on here represents how much is that energy burden or excess energy burden. If you take 6% of their income, and the amount of dollars that's not being covered by the 6%, how much extra dollars is that? A little under $1,000 is what we calculated for 2026, but that increases over time with inflation. So from an inflationary adjusted value, it's probably fairly flat, but I see a hand up from Heather. Go ahead.

Heather Moline (UTC): Yeah, James, sorry. Can you just repeat that? Oh, this is Heather from the UTC. Can you repeat that point about the 2045 jump and something about how that would be different, or how that would be expected, given what the IRP shows, or given the 2% cost cap. I didn't really follow that.

James Gall: Yeah. Sure.

Heather Moline (UTC): Thank you.

James Gall: Got it. You have no problem. I kind of skipped over that to some extent because I'm not sure what I covered last time versus this time. But in 2045, we are by law, I guess the goal is to be 100% clean energy, but when you look at the resources that we have to remove and then add to the system to get to that, that jump is obviously more than 2% from 2044 to 2045. But that necessarily isn't how the cost cap calculation is going to occur in that time. Actually, we have very little direction from the statute or law on how that's going to work in 2045 because the 2% cost cap really is through 2044. So, if the 2045 period, if it's 2045 or a 4-year period, whatever you want to call that, if that has a similar cost CAP calculation methodology compared to what we're required to do between now and 2044, we would likely exceed that cost cap. The resources that are called for to get to 100% in that period, since we would exceed that cost CAP, we're not going to see those resources. So, you're going to have a lesser rate increase in reality, if we followed the cost cap methodology in that period. We're going to have a scenario to share at the next meeting of what that would likely look like, but again, you don't know what the cost cap is going to look like in 2045, but that's where I was going with the 2045 cost cap. I don't know if that helps or not, Heather.

Heather Moline (UTC): Yeah, I think I'm hearing it depends on what the cost cap methodology is. Yeah, I'm tracking. Thank you.

James Gall: Yeah. Because if you look at the first, the four years now, it's 2% of revenue requirement. The first of the 4-year period times four, 3 * 2% for the third period and so on. The cost cap from a period is actually extremely high. It's not 2% period to period, it's much higher. But in 2045, I don't know what it's going to be. The other challenge is when you get to 2045, your cost cap is going to be based on everything that you've done from the time the law passed the 2044 as well. You don't even know what our baseline would be in 2044 to calculate the cost cap. So, we're going to guess what it could look like, but I'm not sure. And I see Charlee has her hand up. Go ahead.

Charlee Thompson: Yeah. Good morning everyone. My question, still on the energy burden CBIs, just clarifying the projection through 2045. It's based on projected rate increases and census tract level income data. Is that right? But not base.

James Gall: Is that correct?

Charlee Thompson: Sorry, go ahead.

James Gall: No, you finish your thought here. I thought you were done. Go ahead.

Charlee Thompson: Wait a second there, your part to the question, it is not based on other factors like Avista’s internal goals for its energy assistance programs, right, like it's new bill assistance programs or EE programs?

James Gall: Yeah. It's before energy assistance, so any energy assistance program that's not included what it does include though is if we did community solar. We had some community solar forecasted in the IRP that's included. So, it is this census tract based of income, and it's based on how Mike's going to.

Mike Hermanson: There's actually three sources of income data. We have people that are participating in some sort of assistance program, and they provided their income data to Avista. We've used that. We had a third-party data source that we used and then the remaining ones are from the census tracts. There are three sources of data with different levels of accuracy. No, I've forgotten all the question points. Did we get them all?

Charlee Thompson: Yeah, I think so. Is that based off of rate increase and then the income data and good to know that there's three different sources and then the second was it doesn't include energy assistance projections.

Mike Hermanson: Yep.

Charlee Thompson: That was helpful. Thank you.

James Gall: And the rate increase it's based on this slide here. We take the existing rate structure that we have today and escalate it at the rate of growth of this forecast. Now this forecast is power supply only. But what we do for the non-power supply cost that we model, we increase those that 3.8% per year. Obviously, that fluctuates every year or every rate case, but we try to keep everything that we don't model constant or constant growth and then just show the effects of power supply costs. Alright.

Charlee Thompson: Thank you.

James Gall: You're welcome. Any other questions? Alright, so let's go to the DER CBIs. this slide is actually slightly updated from what we sent out. That's on the first chart on top. I was awaiting to get some results, for those of you that may have been following along, we had a consultant help us do a DER forecast, which is basically a solar, battery, small wind forecast for our company along with an EV forecast and they did a differential between where solar is going to be in a Named Community designated area or non-designated area. The previous slide had the forecast for all areas, and I was able to get a breakdown of the Named Communities only and that's what this reflects. So, we have solar owned by customers in this chart that are in Named Communities, it also includes any small PURPA projects that would be in any community, plus any solar that we've proposed in the IRP. Small, community solar based is in here. We do see a radical increase from 2026 to we'll say 2030, early 2030s and slower growth thereafter. The reason for that trajectory is in the solar forecast the consultant has done, it's based upon how tax credits are working. In 2033, that's when the IRA expires and that's why it slows its growth, then grows with more of a constant rate.

James Gall: That's our forecast for energy, mostly solar in Named Communities and the second chart below is the storage assumed in Named Communities. I've not updated this one yet for any of the storage that's included in that DER forecast, we do need to make that update, but it's very small. It probably won't look much different than this one, because those are mostly kWh amounts, but so I do owe an update on that one. We did not select any DER energy storage on the distribution system in the IRP. That does not mean there won't be any coming in our next distribution plan. And what I mean by that is, and if you are following the DPAG process as well, you might hear somebody in the future with some of the plans are there. But the advantage with an IRP is we can create what's called an avoided cost, which we're going to talk about later. That avoided cost could help the Distribution Planning team when they're looking at solving constraints or growth on the distribution system. They have options and they can use some of our information in the IRP to identify whether or not an energy storage project would be cost effective on the distribution system. If it is cost effective, we would then pick up that information in the next IRP. So that's going to be an iterative process for distribution energy storage, so nothing yet. Question, go ahead Joshua.

Dennis, Joshua (UTC): Joshua Dennis, UTC, I had a question about your 5A. With that, total megawatts of DR in Named Communities. You mentioned small PURPA projects included in there. And I was wondering, did any of them have liquid fuel generation in those included? Yeah.

James Gall: Liquid fuel. It'd be water that's liquid, but no, they're all mostly small water or hydroelectric facilities.

Dennis, Joshua (UTC): Thank you.

James Gall: Yeah, we the only other besides hydroelectric we have is that's not hydroelectric. Sorry, we have a waste to energy facility and that's large in Spokane and we have a large biomass generator in Lewiston, ID. We had another lumber mill that has since closed. We have another one that we just signed, but it's a net PURPA that's kind of a different thing, but it is biomass.

Dennis, Joshua (UTC): Thank you.

James Gall: You're welcome. And actually, now that you brought that up, I'm just going to give you, the IRP, when we release that, the existing supply chapter covers all the PURPA resources, what they are, where they're located, their sizes and what they're contract term is. So, look for that in the IRP. You can also check the last one, but we'll have some updates this time around. OK, let's move on. This chart is, I'd say, a very complex one, but I'll try to walk you through it. Let's say it's one of those, there were good intentions. I'm not sure if it paid off or not, and the good intentions for the CBI when we were developing these three years ago, but the goal was to look at investment and that's the black line of investment in Named Communities or low income in our case. One of the challenges with investment is in an IRP we don't we know, if it's a generator we know what the capital cost is, but when you're looking at an energy efficiency program, for example. From an IRP perspective, we just get a levelized cost. So, we have to translate that somehow into an upfront investment. This is a very calculated estimate of what the investment is, but the black line represents how much in a given year is invested in the Named Community or a low-income community.

James Gall: In the case of energy efficiency, that raises every year until about 2033. And then as energy efficiency starts to slow down and the forecast of the additional or incremental investment slowly declines. This is a not a cumulative investment or an investment. This is just an annual investment there in the black Line and actually in 2030 you can see it kind of stays constant for a year which is kind of an anomaly out of the energy efficiency forecast. The bars represent the benefit, and the orange represents the utility benefit. Or what do I call that is really the avoided cost of the energy or capacity? And then the blue bar portion represents the NEI value. For energy efficiency, we've worked with the consultant to help us identify any NEIs or non-energy impacts for energy efficiency and for some supply side resources as well. But we're taking those two benefits and adding them together and then this is a cumulative version of the benefit. It's showing you by the end of the study you have about 60 million in cumulative benefits. And then when we have the annual investment going forth, this is what was asked of us to create, and like I said, it's very informative. It's not like an NPV analysis, but it's kind of an interesting view of about how you could look at, I guess costs and benefits. Any questions?

Tom Pardee: Steve has a question. Are the numbers for solar and storage broken down between behind the meter versus on the distribution side of the meter?

James Gall: I guess maybe that relates back to this one. Here, this is the line that says solar. That's in total 5.9 megawatts that is in front of the meter and also the small solar that's in this and the, let's just say that's 10 megawatts in front of the meter for small distributed solar and then the majority of what you could say, what would be the remaining amount would be behind the meter solar. So, all of the customer solar. I don't have a breakdown of each, but I think between that 10 megawatts plus what we have today, which is another, let's say half a megawatt is from the meter, yeah. OK.

James Gall: Any other questions, Tom? OK, let's keep going. Reserve margin. This is actually an interesting result I got from the resource strategy, and it's really due to a transmission line, but we'll cover that in a moment. Our resource planning model, we had a constraint for planning reserve margin. We've covered this in multiple TAC meetings that we plan to have planning margin to ensure we have reliability, but this is also a CBI. The CBI is a little bit different, but its goal was to look at how well your reserve margin is. We're trying to calculate a reserve margin and if you look backward in time, the reserve margin jumps around because we're looking at actual load and we're looking at actual generation. But, looking forward, we should always expect the reserve margin to be what our modeling constraint is, 24% I believe winter and 17% or 18% in the summer, but we're not seeing that and there's a reason why. That is because our transmission line, the 300 MW line we've talked about in the previous couple meetings from Colstrip to Montana, is basically increasing market reliance. And we're not including that in our calculation. So, from a reserve margin of resources, we would control in the future, you can see our reserve margins slowly start declining after 2033 when that line is proposed, and the IRP stays around 15-20%. But it was just interesting when you take out that line because you're assuming that's a market purchase that you're relying on for reserve margins.

James Gall: Doesn't make us less reliable because now we have additional market access. But it was just kind of an interesting result of that change also on demand response, we deducted that from our load as well. That would still get your reserve margin above the required ratio, but that's another note as well that we're reducing peak demand by DR. But again, this is kind of interesting though. It's just showing our future though is more market reliant with that transmission addition. We are running and we have shown the TAC, the reliability results from the PRS that still show in 2030 and 2045 if resources are built as forecast, we do have a reliable system with that market reliance addition. Nothing to worry about here, it is just kind of an interesting result of data.

James Gall: Alright, so the next one is where our resources are located. This one we've calculated the total amount of generation that is in our forecast and divide that by the total amount of generation. I actually missed one thing in the first statement there, the amount of generation that's in Washington State or connected to our transmission system. The idea behind this CBI was to try to look at resiliency of our system and the theory, the background behind this, is that if resources are in the State of Washington or connected to our transmission system directly, we would be more resilient because resources are closer to the load of the State of Washington. We did the calculation over about 80% and that stays fairly constant, slightly declines a little bit over time. And the reason for that slight decline really has to do with some Montana wind that's forecasted, but in reality, we don't know where a lot of our future generation is going to be located. We're going to do RFPs in the future. They may or may not be located in Washington, so this may be better to look at retrospective over time. If it's still important when we go through the CEIP process, but it's hard to forecast necessarily where things are going to show up in the future, but that one does not look like it's going to significantly decline. Could slightly depending on where resources are eventually cited.

James Gall: OK, air conditions. This one, there's going to be actually two sets of these charts you're going to see in the IRP document. You'll see this set, which is related to the CBI, and we have we have another set that is for our total system. But in the case of the CBI for Washington, it's only plants in Washington State which is Kettle Falls, Boulder Park, Northeast and Kettle Falls CT. This is a forecast of those resources plus anything that's added that might be in Washington in the future. Top left is SO2 which is from a natural gas facility, our Kettle Falls facility is very low and basically goes to zero out in the future. NOx is another story, and you're going to see increases, especially in 2045 for the other ones as well. But NOx at Kettle Falls, there's some amount of NOx at our peakers. But you see a reduction over time. That increase at the end really has to do with the forecast assumes we're going to need more biomass generators out in the future. A Kettle Falls Unit 2 and a Kettle Falls upgrade is contemplated. Out of that future, to get to the 100% goal, there would be NOx related to those plants. Also, we have hydrogen-based ammonia plants forecast in the late 2030s. There would be NOx related to those facilities as well. I saw a question pop up.

Tom Pardee: Yeah, it's from Steve Johnson. I assume the IRP will discuss the reserve margin in the context of low hydro years and financial adequacy versus physical resource adequacy. Yes, I'll put that way.

James Gall: I'll come back to that, Steve, and after I get this slide. You make some good points there I want to cover. Alright, so back on NOx. We have new facilities that are contributing to NOx and whether it's biomass or ammonia. But we do see reductions from the natural gas side of things and that's the same case with mercury and VOCs as well. But as far as the ammonia facilities, it's really affecting only the NOx calculation. The biomass is what's driving the, just say NOx is a combination of the ammonia and the biomass. But the VOC and mercury is mostly driven by the biomass units. When the model is looking at resources, we do include a societal cost for each of these emissions. It's just one of the challenges when you're trying to get to 100%. You're trying to get to 100% all the time and you need some baseload generation. So, the model is looking at OK do I build basically in this period of time, I have biomass, I can probably build around, we'll say 60 megawatts or 70 megawatts of biomass which is plausible versus nuclear. And that's really your only two options for more of a base load style resource out in this period in time. We have some peaker options via the ammonia and hydrogen type resources for peaking. Those do get selected as well and the same with the energy storage which gets selected as well. But the model definitely it's wanting more baseload resources at this time because I think our loads are quite a bit higher. That's why we're starting to see nuclear and these generators we did not see in the previous IRPs. Comment from Charlee. Sorry, I missed this. VOC is primarily from which resources? Kettle Falls and future biomass facilities.

Charlee Thompson: Thank you.

James Gall: Yep, alright. I'm going to go back to Steve's question on resource adequacy. What we definitely see when we run our resource planning model is when you have a low water year and a high load period in the winter like we saw in this January, that's when you're going to see risk of not serving 100% load. Reliability models are trying to do, take 1,000 simulations of varying conditions, but the idea behind it is you can serve all of your load in 95% of those conditions. But the conditions you can't serve load in are usually those cases where you have high loads, lower water, or a resource outage. Those are still at risk in the future and the way to solve that risk is really two options. One, you create more diversity in the region and have a regional approach which is what's going on through the WRAP process. Now, whether or not that planning margin the WRAP comes up with is high enough to cover that condition remains to be seen. But the second solution is you just have to start planning for a low water year or a combination of events, which means effectively you're planning for a lower LOLP standard. Instead of planning for 5%, maybe you plan for 1% and that would be a solution to that. And actually, we have some scenarios on that in the next TAC meeting. Hopefully, that addresses Steve comment. There's I say definitely risk. The other option I guess is you have more market reliance that's kind of what we saw in January where the region exceeded what its local resources could provide. It had to go to the market and was able to get it from another region. But I think I saw a hand come up. Steve just said thank you. Alright, appreciate the questions and comments. Steve does have his hand up. Steve, you still have a question?

Steve Johnson (Guest): Well, I do and it really relates. I mean your explanation, James was perfect. And then what I wanted the audience to realize is that during that period of tough to meet load, whether or not you lose load or not, prices get really high both for energy and for capacity. And that's why I introduced that concept of financial resource adequacy. You might want to say yes or no to the question when these events happen and this is more of a financial question than a resource, physical reliability question. Will the Company keep the lights on, but show up more or less bankrupt, like 24 years ago? I mean, that's what's kind of these are, statistical averages for the physicality of resource adequacy.

James Gall: Yeah.

Steve Johnson (Guest): But we have to start really putting back on the plate that concern about how do we survive financially and what do we look like at that moment financially, I want to read about that now in the IRP, I don't want to take up time in this meeting. I just wanted to lay that question down. I'll be looking at the IRP to see what that looks like because this is pretty tough times out in the market. I mean I do not envy. I do not want to be a trader meeting load right now, so good luck.

James Gall: Alright. Well, appreciate that. You make a good point on the financial side of it because that is the risk you have when you're in the market. I remember, even 10 years back, trying to do analysis on a financial resource adequacy where you're weighing the cost to go to a greater financial, or sorry, you're way in the cost of higher market prices to be less reliable or should you build more resources to avoid that cost and whether it's a societal cost or true market cost. That was always kind of a goal to try to model that. And I don't think we were able to achieve that, we left it to planning margins, but it maybe it could be appropriate again.

Steve Johnson (Guest): Yeah.

James Gall: But I think what you're seeing though with $3,000 prices that we saw in January is maybe buying, capacity can be cost effective when you're comparing it to those substantial price spikes or even getting more market access. Having more transmission to other markets is another avenue as well, but very good comments. Appreciate it, Steve.

Steve Johnson (Guest): OK. Thanks.

James Gall: You're welcome. Alright, I think we're on this slide next, greenhouse gas emissions. I'll say one of these slides which is tables and charts is very useful. The other one is a little bit of a challenge and we're going to cover that in a second. But on the top one, again, this is Washington share of emissions. We take our total emissions and then take the Washington share of those and then that's what you're seeing in this top chart, and they are declining over time as resources are, or I should say our natural gas resources, there's two things happening. One is some of our peers are retiring over time, which drives the reduction slightly for the Washington share. And then the second one is we expect our natural gas generators to run less in the future, which that is due to if all of the renewables show up, that is expected in our price forecast, there's going to be less hours that our gas facilities will be dispatched. No, I'll say this is like what Steve mentioned earlier, right now prices are extremely high, the market is very tight, so we're seeing gas plants dispatch a lot and actually they've probably, I think it's some of the all-time highs for a capacity factor point of view. But if resources are built out in the future like we're expecting, they should slowly decline. Also, we have in the models and about 2031 we expect, if the CCA continues past the November election, at some point will the commit or will the ecology change the rules as allowed in 2031 for how resource or how allowances are given to utilities. We assume the worst-case scenario where we're including the price of the CCA in dispatch of all resources in 2031. That creates a reduction in dispatch for some of our facilities as well. That's the dark blue line, or I'm sorry, the light blue line. The dark blue line represents how much net emissions are, which means when we sell power, we're including some of the emissions of our total system in that sale. And that's why it's lower. In the outer years, you can see that dark blue line is actually a little bit higher, and that's because our system becomes a net buyer. About 2042, we go from a net seller to a net buyer in the marketplace.

James Gall: The second chart to the bottom was another one of those CBIs that has good intentions. Unfortunately, we can't get the data to do it for the most part, but the idea was to look at regional emissions from not just Avista, but from other industries and calculate an emissions forecast. The challenge with that is, we're just a small amount of emissions in the region and transportation is a large amount of it. And that big light blue line you can see it's not really declining. We tried to make our best shot at that, but with the CCA and CETA, you would expect emissions to decline further from that transportation sector. But I don't know if they will or not. I don't have a good way to forecast that. The only thing we can really forecast is emissions related to Avista’s natural gas system. We're going to propose to remove this CBI. I included it here and in the document that we're going to send out a couple weeks, I'm not going to include it there because we just can't get data for the rest of the region and forecast it. But again, it's good intention of a CBI, but it's just something we're probably going to have to let go of because of lack of data. Alright.

James Gall: OK, so that's all the CBIs. Now we're going to get a couple different metrics that were brought up through the TAC process that we want to share some results of from the Preferred Resource Strategy. The first one is jobs. We got a tool called IMPLAN and IMPLAN is an economic model that helps figure out the economic impact of investment. If you ever read in the newspaper, something that's built is going to create X amount of jobs and is going to add millions of dollars to the local economy. They're using a tool like IMPLAN to do that calculation. So IMPLAN, with an “m” it's an “m” so we'll fix that, what we did is we looked at all of the investment types that are in the Preferred Resource Strategy, energy efficiency or generating resources. When it's wind or solar, we got a value of the number of jobs per $1 million investment, if I recall right. Yes. OK, so we got a job per million-dollar investment. We went through our strategy and try to come up with how many jobs were created and this is what we came up with. It starts out with around 19 jobs in 2026 goes up to around 800 by 2045. This includes direct jobs. Tell me, John. Go ahead and allow to you to go through.

John Lyons: Basically, these are the jobs that would be done beyond the initial injection into the economy. There's the money that's spent by hired people to go in and to erect the wind facilities, put up solar panels, things like that, and then it's those indirect jobs that are developed because of that. As they're in town, they're buying lunch. They're going to movie theaters. They're buying houses. All that stuff that helps grow the local economy and the numbers that were coming up, they are small, but that is what we come up with. There's been a really good study that just has come out recently from the national labs where they were able to use the really hyper detailed Census data where they had to basically sign all these secrecy agreements to look at it. But they've looked at it, and you're right around nationally about 0.55 jobs per $1,000,000 of investment most now we're just looking at this as the whole statewide. A lot of those jobs are usually local, that study from the national labs actually looked at 6 miles out from the facility and that's where the bulk of them are. But those do tend to be longer term jobs, so they looked out six or seven years and the jobs were still there.

James Gall: All right. I thought I'd put on this one. This is new jobs. It doesn't include lost jobs, so we do have power plants that are retired. It doesn't net those out as well. It's a one-sided look at this. But anyway, it's interesting results. I there was some interest in job data from our public participation process I think. The Equity Advisory Group was very interested in that and seeing if we can do some local spending, if will that help develop some of these lower income areas. Going forward, the one challenge with this is IMPLAN is not free. It costs money and we're using it. We actually got it for the gas IRP to help with some values of the gas system. I'm not sure we're going to continue to have this model available, so I don't know if it's going to be a good one to include ongoing, but we have it today, so we want to utilize it and see what its capabilities are. This is what we got from it.

James Gall: Alright, I think this is my last metric slide and this is on resource diversity. Early on in the TAC process, about a year and a half ago, we had a short discussion on how do we measure resiliency in an IRP from a generator point of view where a lot of times resiliency was where it gets really categorized. OK, what's the resiliency of really the delivery system? How well are you going to be able to deliver the electrons on the distribution system when there's a storm or an outage of some kind when we're trying to look at generation diversity? We thought, OK, that might be a way to look at resiliency because if you had a major event, if all of your resources are located in that specific area, maybe that's more at risk. And therefore, if you have more diverse resources, you're going to be more resilient. It's a stretch. I'll put that way. So, we went along with this ride for a little bit to see if this made any sense. We looked at how can we measure diversity of the resources of our system? We came up with a methodology called the Herfindahl index and that's used for measuring whether or not there's monopolistic powers in certain markets. And I got an economist next to me. He probably wants to say something, if he wants to, he can.

John Lyons: It's Herfindahl-Hirschman. Can't forget Hirschman.

James Gall: I know. Sorry. OK. Thank you. They came up with the methodology of calculating a score of how diversified the marketplace is. The bottom left of this chart represents what they came up with, what is diversified versus not so diversified. If you had a score above 2,500, you're highly concentrated, and that means that there's not a lot of diversity. Think about it. It's more of a, I won't call it monopolistic, but closer to that realm. If you look at a monopoly to perfect competition, economic modeling, when you got a conversation should explain that. But well, and this is it, basically this is the same study that would be done say if you've got two businesses want to merge. So, when AT&T and T-Mobile wanted to merge, the Federal Trade Commission would have actually run those numbers and see what is the HHI go to and see how much further it goes up. It gets too concentrated. Then they have to decide and say is that too much of an issue with competition and we need to just totally block it? Or can we have them divest some asset? Same thing, grocery stores are going to merge, trucking companies, whatever it's going to be, because if you have too much concentration, you have too much market power and you can essentially control the market. Traditionally, you'd think like 80 plus percent would be generally considered a really strong monopoly. But think of things like OPEC, which controls about 40% of oil production in the world, and they can swing prices with that 40% quite a bit.

James Gall: This is just a mathematical way of us looking at that dispersion of resources, kind of like how we use Black Scholes model for some of the finance issues we were looking at that in the past, so trying to use some new tools to apply them. Alright, so we came up with three metrics. I'll go through each of these: facility, fuel and transmission. Facility was obviously the lowest, most diverse methodology we look at. That is looking at every unit that we have and counting it, counting every unit on its own. So how this really works is you take the unit capacity, and you square it, and then you add them all up and they came out. But when you look at it as a unit basis, we have a lot of diversity across our units because it's really a function of quantity in this calculation, which ended up being, I would say, not a good metric. While we have a lot of units which creates this score to go down, the problem is that one of our units is a very large, actually two of our units, Coyote Springs 2 and you have like we call a shaft risk. Even though we have a very low score here, one unit on its own is a high percentage of the total. But from a scoring of HHI, it didn't show up. So, we don't like this metric because of that. What I mean by shaft risk is, for example, Coyote

Springs 2, which is in the wintertime around 300 and we'll call it 20 megawatts. As a percentage of our peak load, that's a high percentage if you lost that resource, replacing it is a harder challenge. This resource diversity, you'd expect that that would show up, but it didn't. And so, while we have low or quite a bit of diversity and resources, but you still have a large shaft risk issue. And when you look at a shaft risk percentage of Avista versus any other utility in the West Coast, I think we're still the highest shaft risk utility in the West when you look at the largest unit as a percentage of your peak load. While this one looks good from this point of view, but when you dig into the shaft risk issue, we have some challenges, which is why in our planning margin requirements we have a minimum planning margin of our largest single contingency for summer. And that's for that reason. So that one didn't quite work out so good.

James Gall: Looks good on paper, but there's some challenges there, so the next one we looked at was fuel diversity and this one actually kind of interesting because it's fairly stable, then all of a sudden it just radically declines where we were at that edge of highly concentrated and then a reduction. And what we're doing here is looking at what is really the fuel source of our generation. Think about hydro. We have four hydro sources. We have the Mid-C, the Columbia River, it's a hydro source. We have the Clark Fork River. We have the Spokane River and now we have some irrigation hydro. Really, those are our four sources.

James Gall: And then we look at natural gas, we really have one source and that's the GTN pipeline. Then you look at wind, we have two sources now, we have a wind regime in the Eastern Washington area and now we have a wind regime in Montana, so we have very few sources of where our energy comes, so that's why it's fairly highly concentrated. But when you get past 2041, we start to see a decline there and that's because we start seeing new resources show up in the resource strategy from other locations. And that is when you start getting into ammonia turbines or getting other energy storage. You're getting nuclear in the out years, you started to see that fuel diversity. This one I thought was the most interesting of the three because it actually showed that benefit of having a more diverse set of resources and it didn't necessarily have an underlying challenge behind it like the facility diversity.

James Gall: Now the third one was transmission, and this one was really kind of thought of being based on a wildfire risk. Let's say you had a very large wildfire. It took out a geographic area. How diverse are your resources from a geographic point of view? Let's say we had six areas of our system and you lost one. Could you recover from that loss of one of the six. That was kind of the background thought of this one, but we split up our resources and areas of our system. I call either transmission, or geography might be a better term, but this one was in that mildly concentrated area. It stayed flat the whole time, but there was one problem with this one, it actually probably could decline drastically, we just don't know where resources are physically going to end up. While this one it is a good metric, but in going look in the future if you don't know where your resources are going to be, it's a hard one to forecast. So, that one I probably do not see as useful because of that purpose or that reason. But anyway, it was a good intellectual exercise. We'll probably continue to look at this to some level in the future, but it is definitely a hard thing to model from a generation perspective and considering an IRP. But we definitely learn a few things in this process.

James Gall: OK, this is the last slide before I go to avoided costs. Are there any questions? OK, we have 30 minutes left. I think we might get done early. We'll see. OK, so avoided costs. I've kept these slides fairly simple. What the results are and how avoided costs work is we're trying to estimate if we had to acquire new resources based upon the IRP, what is the cost of those resources on generic terms? So, we look at what resources were picked in the Preferred Resource Strategy for both Idaho and Washington and try to back into what those costs are. And you can use that information to help you or help us decide between IRPs if energy efficiency or a small resource is cost effective. Now it's a big resource, we'd likely go out to bid in an RFP, but for something small it's very helpful to help us come up with what a resource is really worth. It can be also useful in setting PURPA rates as well, because PURPA it's required to be paid based on avoided cost.

James Gall: For the most part, avoided costs are based on a market price forecast. You see on both of these charts there's an on peak and off peak and a flat price, and that is our Mid-C price forecast from our Aurora model. You'll see there is a difference in price, slight difference between the Washington and Idaho. Washington is slightly higher and that has to do with the CCA and what happens is, we're using a delivered into Washington price for Washington; and for Idaho, we're using a not delivered price into Washington. It's kind of a call like a borderline price. The prices are not much different, and actually that's something we were seeing in the marketplace as well today that there's a premium to delivery in Washington, but the premium is not substantially higher than one that's not delivered in Washington. We're seeing that in our world modeling as well. That is what on peak off-peak flat is. That's a Mid-C price forecast, on peak would be delivered in the middle of the day between, don’t want to get this wrong, 7:00 AM and 10:00 PM except for Sundays. That's off peak, so off peak is really nighttime pricing. You can see the nighttime pricing or off-peak pricing is actually, I want to make sure you got these. I think these are backwards actually these get switched on me. We're going to revise this chart, I apologize, but I think this one on the Washington side is correct. I think I might have switched to label on the Idaho side on the on off peak, but the off-peak prices in the long run are higher than the on peak and that has to do with solar. So over forecasting on the future is in the middle of the day, prices will decline drastically and that drives the on peak price lower, although during the on peak period it has the highest prices in the late evening. But overall, for the 16-hour period, the prices are lower compared to off peak. So, when we look at resources from an hourly point of view, we can look at it and say, OK, solar, you produce a lot of on peak power, but most of your power is in the middle of the day when the prices are the lowest. So, that would get less value than, say, a resource that produces power at night or in the evenings. Looks like you have a question come up and come up. Note from Heather. OK, no problem. If there's any questions you feel free to jump in, happy to kind of go through them. Go ahead. Yao.

Yao Yin: Thank you. I have a couple questions about prices. Did you say Washington’s prices are higher?

James Gall: I did say that. Washington prices, subject to check on the previous slide, should have higher energy prices from the Mid-C calculation, so the energy portion that is based on market prices will have a higher price.

Yao Yin: Do we assume the market for market purchases and market sales, we use the same Mid-C prices?

James Gall: From an IRP perspective, we typically do, but in reality there is a spread between buying and selling. That could be from a reality perspective, that's something to consider and then this is from other cases we've been involved with. When you're long, can you really get that price? These are just showing what the market price forecast is, not looking at a position of a utility, but just this is what the market price forecast is.

Yao Yin: And we don't distinguish purchase or sale for the IRP purpose?

James Gall: Correct. This is just the raw price of the market for the forecast.

Yao Yin: Last question, so the Washington prices are higher due to CCA.

James Gall: Yep.

Yao Yin: Did you say that?

James Gall: Correct.

Yao Yin: But my understanding of the CCA is for off system sales, it doesn't distinguish the two states. I mean only the dispatch cost. For example, for Boulder Park, I think the company proposes in multiple prior cases that Idaho would pay the Idaho portion, but for off system sales based on our last understanding. In the last case, it doesn't distinguish both Washington and Idaho.

James Gall: Depends on where your delivery point is, so if you're delivery point is in Washington, then you're assessed a carbon price. And if you're delivery point is not in Washington, you're not assessed a carbon price. The challenge though in the marketplace is there's not a major difference in the price that you get between a delivered in Washington product versus a delivered in non-Washington. The carbon price is really reflective of where the product is delivered to after the fact. How do we model that in an IRP? This goes back several TAC meetings, but we have a market that's just Washington and then we have a couple different zones in our model that are not in Washington and the price that we're showing for the Idaho is the price of a non-Washington product that's in the northwest. So, if we were going to try to if we had a market or. Make sure I get this right. We have an Avista zone, and we have BPA zone, and we have an Oregon zone, and we have a Washington zone. The Washington zone is going to have the highest price because of the carbon cost in that state. But the three other zones around it are going to have similar pricing because they're going to have to either one to serve Washington. They're going to have to dispatch and pay that price that drives those prices up higher and that price that's outside of that state is what we're using for the Idaho calculation. Does that make sense or not?

Yao Yin: I think I understand what you're saying. When you say delivery point, you mean for the transaction that happens and to me, you have to specify where the energy goes to and if it's outside of Washington, then the Mid-C transaction prices could be lower.

James Gall: Yeah, if it's outside of Washington, you may. Let's say you're selling. You may sell for the same price you're just not paying the cost of the carbon. Let's say you had a transaction that's just say Mid-C and you don't know who the counterparty is, and so you sell it for, let's say $100. And after the fact you found out it was delivered to Puget, you're going to have to pay a carbon penalty. If it was delivered to Portland General, you wouldn't have to pay the penalty. That's what the structure of the marketplace is now. My understanding is you and that's why there's not, and this one it's some of the challenges we were having in the Northwest is you don't know if you have a liability or not. So, you're going to start seeing more and more, you're going to have pricing outside of the State of Washington that is lower, but we're seeing today is that pricing outside the State of Washington is not much lower.

Yao Yin: OK. That is why we see the difference between Idaho avoided costs and Washington what it costs.

James Gall: Correct for that. For the market price portion, now when I get into the energy premium and the capacity premium, there will be different reasons for that.

Yao Yin: OK.

James Gall: And I'll cover those in a minute.

Yao Yin: OK. Thank you.

James Gall: Yep.

Tom Pardee: First question from Steve is shouldn't the IRP start modeling 4:00 to 8:00 PM Summer?

James Gall: We've done that in the past and I think where Steve is going, here is a chart showing a different instead of on off peak we show a 1/3 segment of time where different segments in time we could do that. It’s not a bad idea. The model doesn't kick that out right now. We'd have to do it manually, so maybe that's a good one for the next IRP, but good idea. OK. And then second question from Jason, what is the revolution in the Mid-C energy price forecast can go to? It is an hourly forecast and we run 300 simulations of future hydro, load, wind, forced outages. We have 300 hourly forecasts. And when we look at resources, we take that hourly forecast and look at how is that resource going to dispatch and then we can match up those dispatch hours with the hourly forecast.

James Gall: Alright, OK. I think we've covered the energy side of this, or at least the flat on peak, off peak. Again, the Idaho, apologize, the labels should be flat on off and it's showing on off flat, so I apologize for that. We'll fix that. I'm going to leave it. Leave this on the Washington one for this next discussion to avoid the mix up on the previous slide. But for the energy and capacity portion, this is actually a result of how the Preferred Resource Strategy compares to other scenarios. So, what we're trying to look at is the breakdown of how much additional cost our resources are and divide them in between is it really the energy we need or is it the capacity we need. And what you're seeing here, in both Idaho and the Washington, is a majority of the benefit you need is capacity related. We're trying to serve those highest load hours of the year. We do show a small energy premium as well because we do need energy in our forecast, but a majority of it is capacity and it's mostly driven by wintertime. We have a winter peak and a summer peak. You need both. Winter has higher need than summer, but not much higher. But if you had a resource that only provided you summer, you would not solve your winter problem and vice versa. When we look at capacity values for resources, we have to look at when is it providing energy, when it's needed and what is the driving force of it. That's the advantage in the PRiSM models. It's trying to find resources that solve both of our winter needs and summer needs, but this is a breakdown of what it's costing us to serve that capacity. And then we have broken that out. Think of it is as if you only served your load with market, you would be paying the pricing that's on the left of the charts. That flat energy price and on off peak. And if you're going to serve only your energy needs, like, for example, CETA is an energy need to some extent you pay the energy premium to solve your energy requirements you have by month. But if you're going to serve your peak needs, you got to pay that extra cost on the capacity premium.

James Gall: And I thought I saw a comment pop up, but just now observation from Steve. OK about the differentials in market being driven together. Yeah, I think where the Mid-C is going, that the price is on off peak is collapsing and solar storage is the reason for that, and that's been our forecast for a while obviously. It's been a hard pill to swallow as a forecaster as this future, when the present is much different. But what I mean by that is, we've been forecasting collapsing spreads for a couple IRPs, now because of storage and solar and until recently we haven't really seen that. We think there's about 6,000 megawatts of storage in California now. We're starting to see some pricing effects of that. And then also just amount of solar down there as well. We're starting to see this future show up. It's been a little slower than we thought, but it's starting to show up.

James Gall: OK. Any other questions on avoided costs? This is I'd say from last IRP versus this IRP mostly similar. The big issue is when on the capacity premium, when we're short, 2030 is what we're showing here for when that capacity period would start and we've talked about a couple IRPs ago, we have some small deficits, 2026 and 2027, they go away. but our long-term capacity need starts really in 2030 unless we get a new large load, or we lose a resource. So, that's subject to revision based on that. But we're doing all the other calculations based on the long-term resource need is 2030 and the energy premium is zero until 2029. That is, when the first large scale renewable resource, or I should say an energy resource was selected which is 2029 for Washington, we shifted that to 2030 for Idaho because the resource that was selected in the IRP in 2029 was a Washington driven resource, so that's shifted to

2030 for the Idaho version. We do similar calculations as this for energy efficiency. They are different. They're actually a little bit higher because we're looking at a future without energy efficiency to calculate what it cost for those. Those are going to be in the document itself. You can read about it in a couple weeks, but again those are a little, they're a similar methodology, little bit higher pricing, but these are the ones you see here are more for resource based what it cost. OK, we have about 15 minutes left. I think we're going to be done early, which is the first time in, I think, a very long time for an IRP TAC meeting for at least the electric side.

James Gall: This is my last slide. This is a kind of a preview of the next TAC meeting. We're going to go through the scenarios which you see. There are a lot of them, which is why we are suggesting more time. I think I added them all up yesterday, it was 25 scenarios we're now going to be running. Some of these will have reliability results and then some will just be resource only, no analysis and then we'll try to get into the costs and benefits of these. But I've broken the scenarios into 4 categories. The first one is a methodology category where we're testing different methodologies. An example of that is alternative lowest reasonable cost. That's a requirement for CETA’s cost cap calculation, which is used for the first four years of the plan. That's kind of a methodology scenario. We also have a baseline portfolio, which excludes CETA entirely, it is a methodology portfolio to show where we would otherwise be. We have different CETA targets and then we have the cost cap scenario. Those are methodology scenarios. One of the bigger categories we have is load scenarios where we're testing different load growth, whether it's lower growth or higher growth, different weather, electrification of buildings and transportation, also data centers. So those will be all the load growth scenarios. The next category has resource availability, and you see two of them that are crossed out here and those two were ones that we proposed in the earlier TAC meetings that we are going to remove because one is on the nuclear cost sensitivity, we were not expecting nuclear to be selected, so we wanted to see what price nuclear would be selected. Since it's picked in the strategy, I didn't see any value including that. The other one I crossed out was the high QCC on demand response and that was really a test of whether or not we'd see more demand response if we had higher QCC values. Given the Preferred Resource Strategy has fairly high QCC values for demand response and it's we'll call it base case, it didn't seem necessary to run that case.

James Gall: I could cross those two out, but we did add in red some other scenarios that I thought would be helpful when we go through the resource strategy. One is on regional transmission. What I mean by that one is the Colstrip to MISO, SPP line we talked about. We've included that in our Preferred Resource Strategy. I'd like to test what our PRS would look like without that line, so that's what that one's about.

Northeast, it's been a resource we forecasted to retire in 2030. We wanted to test if that plant has longer life or shorter life, how does that change the resource strategy because right now, in 2030 you have we have five years to come up with a solution. But what if you have less time to come up with a solution? Where you have more time to come up with a solution? What does that do to our portfolio? Actually, that one to me is probably of all of these portfolio scenarios on the list, that's to me is the most important too because that's the one that's a near term decision. A couple more of that that showed up when we're starting to go through our resource analysis, or the preferred strategy is limiting. If we had to limit to our amount of wind on system in our modeling. What I mean by that is we modeled 500 megawatts of wind in our system that could be interconnected at very low cost. But if another utility, a third-party, or one of these developers that are developing maybe 500 megawatts of wind. If they sell that project to another utility, that's less that we can interconnect at a low price. So, if we don't have access to cheap wind, how does that change our portfolio? That's what that one's about.

James Gall: Another one we wanted to test is, and this is really a result of the amount of wind picked in the Preferred Resource Strategy, that it was all picked very early. The model saying it's cost effective to go into wind early to take advantage of the tax credits. But I want the test whether or not that resource decision is driven by the tax credits. Is it driven by need? Is it driven by high market prices? What's causing that? That early selection of wind, or the amount of wind in this scenario I think will help show that. That's why we're going to run a case with no sensitives. So, that's the resource availability. Obviously, the top three that we had in black, there are ones we proposed before and then other changes we have other portfolios we were going to run a case that had a lower resource strategy or PRM for can't talk, sorry, planning reserve margin to represent more of a WRAP scenario. We decided just to make that a 17% scenario to replicate maybe what the WRAP will go to, because we don't know exactly where the WRAP's going to end up long term and then we want to run another scenario that has a 30% PRM to replicate, we're trying to achieve a 0% loss of load probability or something as close as possible to 0. So those are, that's really to simplify the modeling. And so those are two that we're working on and then we have the maximum customer benefit scenario and we're going to be doing a scenario with what happens if the CCA is repealed. If there are any changes to the strategy if that happens? We're working on these right now. The goal is to show those at the next TAC meeting in September, and then we'll also have these written up and described in the IRP that will come out, I believe October 1st.

James Gall: That is all I have today. Any questions, comments, concerns? OK. Well, let's wrap it up. OK, go ahead. Yes, I think we're done for the day. Go ahead, Steve.

Steve Johnson: I had just one annoying question. Not quite related to the slides exactly, but I assume that the IRP is not going to discuss the merits of selling off Avista’s distribution system. And I asked this question because there's a neighboring utility struggling with solvency with regard to their system. And so, is it Avista’s view that they're distribution system has a net positive financial value to them considering fire risk and short liability?

James Gall: Well, that is definitely a challenging question. I don't know, is Kevin around or if there's someone above our pay grade that would like to? Yeah.

Steve Johnson: Well, that's OK. I'll just look for it now, IRP or somewhere else. We don't have to go into that topic here today.

James Gall: Well, you're not going to find that discussion in the IRP probably.

Steve Johnson: Yeah. Well, maybe the ratepayer, the shareholders and the board will think about that. But there is a question here. I just wanted to bring it up on a recorded line. Just having fun, thank you very much.

James Gall: Yeah. You're welcome, Steve, maybe we can talk about that offline someday and opine on a different theoretical possibility.

Steve Johnson: Well, I don't laugh because there is serious risk to people's life and safety. It's not, you know, but also there's these broad financial results which may or may not cure the actual problem, which is the risk to the community.

James Gall: Yep.

Steve Johnson: So, we're going to, we're in a sort of dysfunctional relationship. And I have some concerns about it, but it's not exactly an IRP question, but that does need to be a question in the public realm somewhere for the utilities with public engagement. So, we'll find a place. Thanks.

James Gall: Appreciate it. It's definitely a concerning topic, that is, I know on our board's mind and our executive’s minds, but you know, there's a crossroads, customers obviously need power, but there's these risks. And if the utility has to bear all of those risks, we may not be able to afford to be a utility or the rates may not be affordable and we can't get insurance or limited insurance for fire risks. These are definitely major challenges.

Steve Johnson: Well, and the decision making, the metrics for decision making, shouldn't be shareholders managing the risks. It should be the public interest and so we may have a whole set of wrong metrics driving decision making at this point. It's a little tenuous, but it's a big subject. I didn't mean to rob the meeting, hijack the meeting, so we'll move on. Thanks.

James Gall: Yep. All right. Well, I don't know if there's any other questions or comments, so I don't know if you robbed it, but at least you extended it a couple minutes.

John Lyons: We are starting to see some of the commissions grapple with how do you take that issue up because we have specific work filed, some made some filings in the states that are basically raising that question. And usually it was, no, we can't do it that way. But then I think the commissions are saying, but this is something we need to take up, look at, and I haven't heard anything like it. I'm sure they're discussing it, but how do you handle it? State by state? Do you hand it nationally?

James Gall: It is definitely a regional issue for wildfires. But there's going to be implications across the country for that.

Steve Johnson: Well, I just don't know what it didn't apply some years down the road. If we have a lot of distributed energy resources on a vulnerable distribution system, I don't know, it just gets more and more complicated. We'll cross those bridges, unfortunately, when we get to them, I bet. Thank you so much for your time.

James Gall: You're welcome. Alright. Any other questions or comments? I think we'll call it a day. We'll see you in September. And I look forward to everybody's feedback on the draft IRP as it comes out over the next couple of weeks. Thanks again. Have a great day.

2025 IRP TAC 13 Introductions

John Lyons, Ph.D.
Technical Advisory Committee Meeting No. 13
September 17, 2024

Today’s Agenda

Introductions, John Lyons

PRS Update and Scenario Analysis, Planning Team

IRP Next Steps, James Gall

Remaining 2025 Electric IRP TAC Schedule

- **Virtual Public Meeting – Electric IRP (November 13, 2024)**
  - Recorded presentation
  - Daytime comment and question session (7:30 am to 8:30 am, PTZ)

    https://us02web.zoom.us/j/82646796064?pwd=PeQBOudUk4HQCOajIb516GwK9DawJX.1

    Meeting Topic: Avista Energy Resource Planning

    Meeting ID: 826 4679 6064

    Passcode: 530027

  - Evening comment and question session (12:00 pm to 1:00 pm, PTZ)

    https://us02web.zoom.us/j/89000361941?pwd=oxE9EjWvBOy3q0OOdynqbAb6WDy3nV.1

    Meeting Topic: Avista Energy Resource Planning

    Meeting ID: 890 0036 1941

    Passcode: 302233

Remaining 2025 Electric IRP TAC Document Schedule

Section	Chapter	Availability
	Executive Summary	October 1, 2024
1	Introduction, Involvement, and Process Changes	October 1, 2024
2	Preferred Resource Strategy	Available
3	Economic and Load Forecast	Available
4	Existing Supply Resources	Available
5	Resource Needs Assessment	Available
6	Distributed Energy Resources Options	Available
7	Supply-Side Resource Options	Available
8	Transmission Planning & Distribution	Available
9	Market Analysis	October 1, 2024
10	Portfolio Scenarios	October 1, 2024
11	Action Plan	Available

Remaining 2025 Electric IRP TAC Document Schedule

Section	Appendix	Availability
A	TAC Presentations	IRP website
B	Work Plan	IRP website
C	Draft AEG EE/DR Potential Assessment	Available
D	10-year Transmission/Distribution Plan	Available
E	Transmission Generation Integration Study	Available
F	DER Study	Available
G*	Public Input and Results Data	October 1, 2024
H	Confidential Inputs and Models	January 2, 2025
I	Historical Generation Operation Data (Confidential)	January 2, 2025
J	New Resource Transmission Table	January 2, 2025
K	Washington State Schedule 62	January 2, 2025
L	Public Comments	January 2, 2025

* Original Appendix K – Resource Portfolio Summary moved into Appendix G

2025 Electric Integrated Resource Plan

PRS Update and Scenario Analysis

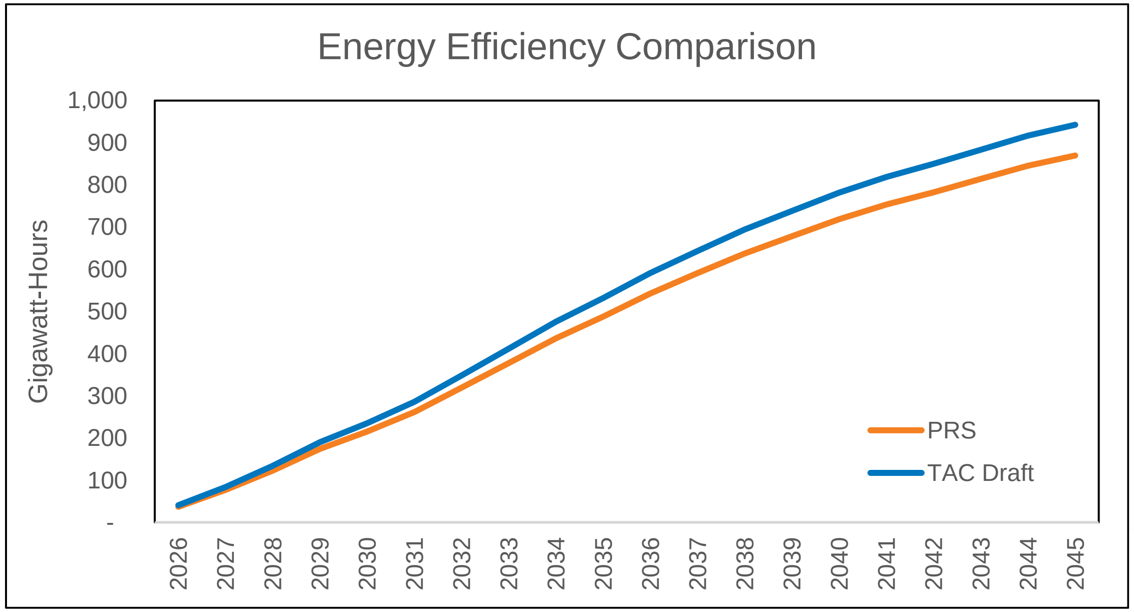
James Gall

Technical Advisory Committee Meeting No. 13

September 17, 2024

PRS Changes Since Last TAC Meeting

- Line losses were double counted in the energy efficiency analysis.
- Does not affect generation resource portfolio.
- Economic potential in 2045 is 7.7% lower.



Portfolio Risks

- Nuclear Availability
- Northeast CT Availability
- Economic Growth
- Data Center
- Clean Energy Preferences
- Power to Gas Availability
- Future Weather
- Regional Transmission
- Building Electrification
- CETA Rules
- Transportation Electrification
- Reliability Objectives
- Climate Commitment Act
- IRA Tax Incentives
- Distributed Energy Resources

Scenario Analysis Insights

- Demand response and energy storage are best resources to quickly add capacity.
- Due to limits on power-to-gas (P2G) resources, nuclear is go to resource for higher loads in Washington.
  - May create cost concerns as nuclear energy is estimated at $144/MWh in 2030 and $206/MWh in 2045.
- Wind is relied upon for winter capacity contribution.
- Additional wind beyond the PRS is difficult due to transmission limitations, pushing solar/nuclear to meet clean energy targets if loads increase.
- Natural gas CTs remain the lowest cost resource for Idaho customers; but will require long lead times and infrastructure development.

Portfolio Scenarios

Methodology	Load Scenarios	Resource Availability	Other
2- Alternative Lowest Reasonable Cost	5- Low Growth	4- Clean Resource Portfolio by 2045	10- Maximum Washington Customer Benefit
3- Baseline Least Cost Portfolio	6- High Growth	11- 500 MW Nuclear in 2040	12- 17% PRM
15- Minimal Viable CETA Target	7- 80% Washington Building Electrification by 2045	14- Power to Gas Unavailable	13- 30% PRM
16- Maximum Viable CETA Target	8- 80% Washington Building Electrification by 2045 & High Transportation Electrification	21- Regional Transmission not Available	26- PRS w/ CCA repealed
17- PRS Constrained to the 2% Cost Cap	9- 80% System Building Electrification by 2045 & High Transportation Electrification, No New NG CTs	22- 2026 Northeast CTs Retirement	
	18- 200 MW Data Center in 2030	23- On-System Wind Limited to 200 MW	
	19- RCP 8.5 Weather	24- No IRA Tax Incentives	
	20- 80% System Building Electrification by 2045 & High Transportation Electrification Scenario No New NG CTs with RCP 8.5 Weather	25- 2035 Northeast CTs Retirement	

Preferred Resource Strategy

Nameplate MW	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Shared System Resource																					
Mrkt/Trans	39	4	10	0	0	0	0	300	0	0	0	0	0	0	0	0	0	0	0	0	353
Natural Gas	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	0	-
Wind	0	0	0	0	0	100	100	157	0	0	0	0	0	0	0	0	0	0	0	0	357
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
PtoG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	10	10
RNG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
DR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
Washington																					
Mrkt/Trans	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
Natural Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
Solar	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	181	120	1	311
Wind	0	0	0	200	200	100	0	0	0	0	0	0	0	0	0	140	0	120	108	200	1,068
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	90	86	85	261
PtoG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	90	0	210	0	0	94	394
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	100
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	20	20
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	58	58
RNG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
DR	25	0	0	0	0	0	0	0	0	6	0	0	4	20	0	6	0	10	0	0	70
Idaho																					
Mrkt/Trans	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
Natural Gas	0	0	0	0	90	0	0	0	0	0	0	0	0	0	90	0	95	0	0	0	275
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
Wind	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	-
PtoG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
RNG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
DR	0	0	0	3	0	0	0	0	0	3	0	0	0	0	4	0	0	1	7	0	17

Reliability Metrics:

Year	LOLP	LOLE	LOLH	LOLEV	EUE	EUE without reserves
2030	0.032	0.072	0.73	0.176	114	107
2045	0.033	0.093	1.05	0.304	172	116

Methodology Scenarios

2- Alternative Lowest Reasonable Cost

- **Purpose:** Understand impact of CETA for the 2% cost cap calculation. Used for CEIP analysis for the first 4 years.
- **Assumption Changes:** Removes CETA clean energy targets and Named Community spending assumptions and allows natural gas CTs.
- **Results Summary:**
  - Resource portfolio shows fewer renewable resources acquired, 466 MW less wind, 211 MW less solar, and 136 MW less energy storage.
  - Energy efficiency is slightly lower. Some natural gas is added to Washington and more resources are selected as system resources.
- **Cost/Rate Impacts:** Long-term Washington energy rate is 16% lower, although Idaho's is 6% higher, in the CEIP period PVRR for Washington is $4 million less.
- **Resource Adequacy Assessment:** Both 2030 and 2045 show lower LOLP results then the PRS whereas 2045 is 1.4%; indicating the potential to reduce the PRM and have lower cost.

3- Baseline

- **Purpose:** Understand cost impact of CETA going forward, assists in determining avoided costs.
- **Assumption Changes:** Removes CETA targets, NCIF spending minimum, SCGHG, NEI, allows natural gas in Washington in 2045. Energy efficiency is not changed.
- **Results Summary:**
  - Renewable generation greatly reduced, but 700 MW of early wind acquisition for both states remains.
  - All capacity resource needs are moved to Natural Gas CTs (+700 MW), Energy Efficiency changes were not modeled. Only portfolio with higher emissions in 2045 than 2026.
- **Cost/Rate Impacts:** Long-term Washington energy rate is 17% lower, although Idaho's is 2% higher (PVRR is lower for Idaho than PRS).
- **Resource Adequacy Assessment:** Pending, but expectations are system will be less than 5% LOLP and may allow for lower PRM.

15- Minimal Viable CETA Targets

- **Purpose:** Supports CEIP Condition 33 “Avista agrees to model a scenario in the 2025 Electric IRP meeting the minimum level of primary compliance requirements beginning in 2030 that will create the glide path to 2045. If the results of this modeling differ from the Company’s PRS and Clean Energy Action Plan, it must explain why.”
- **Assumption Changes:** Uses CETA Targets:

		2026	2027	2028	2029	2030-2033	2034-2037	2038-2041	2042-2044	2045
#15	Primary	62.5%	62.5%	62.5%	62.5%	80.0%	82.0%	88.0%	92.0%	100.0%
#15	Alternative					20.0%	18.0%	12.0%	8.0%	0.0%
PRS	Primary	66.0%	69.5%	73.0%	76.5%	80.0%	85.0%	90.0%	95.0%	100.0%
PRS	Alternative					20.0%	15.0%	10.0%	5.0%	0.0%

- **Results Summary:**
  - No material change due to same goals in 2030 and 2045, results will be more impactful in the CEIP analysis for greater REC sales.
  - Further, without natural gas CTs as a long-term option, resource selection is limited to clean energy.
- **Cost/Rate Impacts:** No impact.
- **Resource Adequacy Assessment:** not studied due to same result as PRS.

16- Maximum Viable CETA Targets

- **Purpose:** Supports CEIP process to estimate resource portfolio changes to support CEIP.
- **Assumption Changes:** Uses CETA Targets:

		2026	2027	2028	2029	2030-2033	2034-2037	2038-2041	2042-2044	2045
#16	Primary	70.0%	73.0%	75.0%	78.0%	81.8%	86.8%	92.2%	97.1%	100.0%
#16	Alternative					18.2%	13.2%	7.8%	2.9%	0.0%
PRS	Primary	66.0%	69.5%	73.0%	76.5%	80.0%	85.0%	90.0%	95.0%	100.0%
PRS	Alternative					20.0%	15.0%	10.0%	5.0%	0.0%

- **Results Summary:**
  - No material change due to same goals in 2030 and 2045, results will be more impactful in the CEIP analysis for lower REC sales.
- **Cost/Rate Impacts:** No impact
- **Resource Adequacy Assessment:** Not studied due to same result as PRS.

17- PRS Constrained to the 2% Cost Cap

- **Purpose:** Due to uncertainty of cost cap calculation for 2045 and the 2045 PRS rate increase projection, this scenario offers up a lower 2045 rate impact replicating a potential cost cap.
- **Assumption Change:** PRS between 2026-2043 is unchanged, but the model solves for revenue requirement cap in 2045 (Alternative Lowest Reasonable Cost). The cap is limited to 8% (2045 Revenue Requirement of scenario without retiring Coyote Springs 2 x 2% x 4)
- **Results Summary:**
  - Coyote Springs 2 remains on the system as a shared resource (with 30% hydrogen). Requires Idaho to offset generation remaining for Washington.
  - Washington resources in 2044/45 shift to use less wind, nuclear, biomass, and energy storage, but more solar and P2G.
- **Cost/Rate Impacts:** Washington 2045 rates are 9% less, Idaho's rates increase 3.5%.
- **Resource Adequacy Assessment:** not studied, but resource selection does not indicate a risk.

Load Scenarios

5- Low Load Growth

- **Purpose:** Understand resource selection impact if loads take lower trajectory.
- **Assumption Change:** Uses lower load growth forecast (0.34% per year vs. 0.85%)
- **Results Summary:**
  - No resource changes as compared to PRS until 2033.
  - Long term less wind (93 MW), 162 MW less solar, 100 MW less nuclear, and 10 MW less demand response.
- **Cost/Rate Impacts:** 2030 rates are slightly higher due to less load to spread fixed costs, but long-term rates are slightly lower then the PRS.
- **Resource Adequacy Assessment:** Not studied.

6- High Load Growth

- **Purpose:** Understand resource selection impact if loads take higher trajectory
- **Assumption Change:** Uses higher load growth forecast (1.75% per year vs. 0.85%)
- **Results Summary:**
  - Short-term- increase demand response and acquire wind earlier.
  - Long-term for Washington, acquire additional demand response, solar, and nuclear to meet load growth.
  - Long-term for Idaho acquire more natural gas CTs.
- **Cost/Rate Impacts:** 2030 rates are slightly lower due to less load to spread fixed costs, but long-term rates are higher than the PRS (WA +6%) and (ID: -7%).
- **Resource Adequacy Assessment:** Not studied.

7- 80% Washington Building Electrification by 2045

- **Purpose:** Understand resource selection and cost impact if 80% of 2026 natural gas demand moves to electric service.
- **Assumption Change:** Natural gas LDC load converts to electric demand and assumes 75% former natural gas load becomes Avista electric load. Results in an additional 356 MW of peak load by 2045 and 107 aMW of energy.
- **Results Summary:**
  - Biggest impact is a reduction to system resources and these resources (357 MW wind) are allocated to Washington.
  - Idaho requires 20 MW more natural gas in the 2040s.
  - Washington needs 240 MW more solar, 276 MW of energy storage, and 141 MW more nuclear.
- **Cost/Rate Impacts:** Idaho's 2045 rate impact is 2% higher, but Washington's 2045 rate is 12% higher. When taking into account reduction in the natural gas costs of the LDC, customers overall pay 25% more between 2043-2045 when conversion cost are considered.
- **Resource Adequacy Assessment:** Not studied.

8- 80% Washington Building Electrification by 2045 & High Transportation Electrification

- **Purpose:** Understand resource selection and cost impact if 80% of 2026 natural gas demand is moved to electric service and higher electric transportation trajectory occurs.
- **Assumption Change:** Uses same electrification forecast as scenario 7, plus the high transportation load scenario (+127 MW winter peak, 76 aMW energy).
- **Results Summary:**
  - Biggest impact is a reduction to system resources and these resources (357 MW wind) are allocated to Washington.
  - Idaho then requires 14 MW more natural gas in the 2040s plus a share of a Kettle Falls upgrade. In addition to the wind/biomass allocation.
  - Washington will need 240 MW more solar and 375 MW of energy storage and 222 MW more nuclear.
- **Cost/Rate Impacts:** Idaho’s 2045 rate impact is 2.5% higher, but Washington’s 2045 rate is 11% higher. When taking into account reduction in the natural gas costs of the LDC, customers overall pay 33% more between 2043-2045 when conversion cost are considered.
- **Resource Adequacy Assessment:** Not studied.

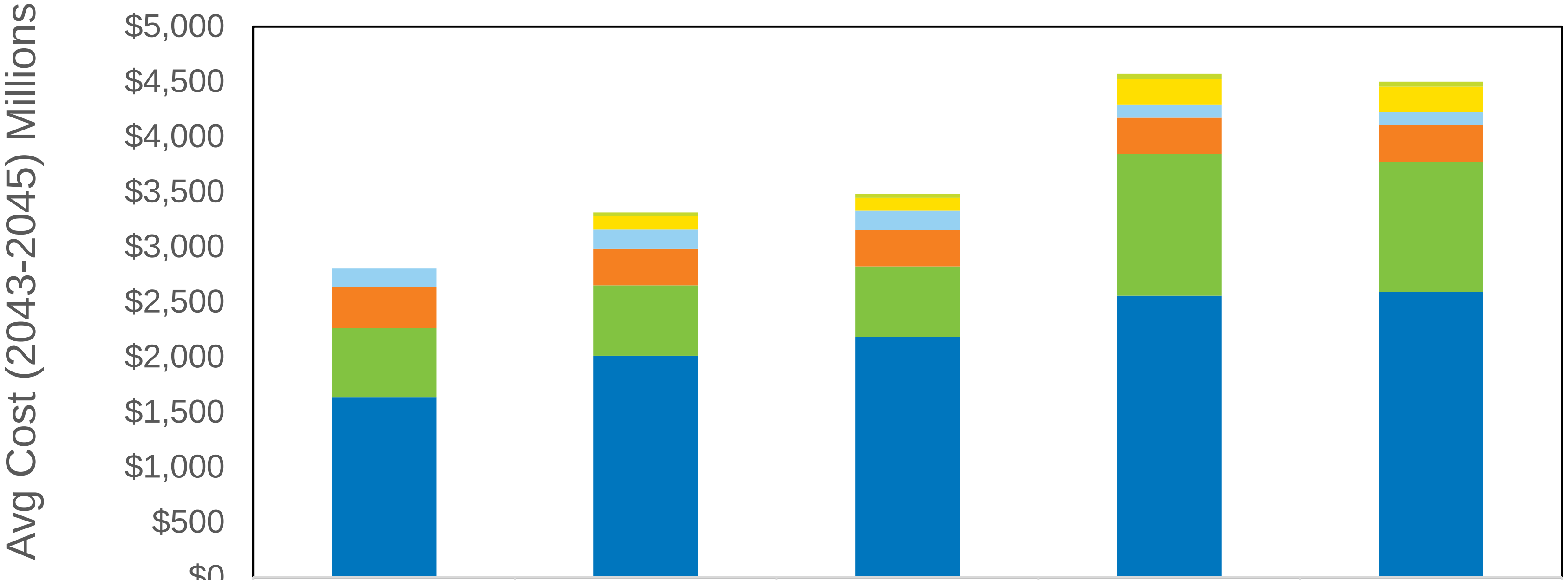
9- 80% System Building Electrification by 2045 & High Transportation Electrification, No New NG CTs

- **Purpose:** Simulates highest load possible. Similar to scenario #8, but Idaho building and transportation loads are electrified.
- **Assumption Changes:** Disables new natural gas generation, uses scenario #8 loads for Washington. For Idaho assumes 90% reduction in 2045 natural gas load. Idaho Building Electrification adds 394 MW winter peak load (115 aMW) by 2045. The high transportation scenario adds 126 MW winter peak (104 aMW) by 2045.
- **Results Summary:**
  - Resource allocation is better aligned between states as each state has similar objectives, including +96 MW of winter peak reducing energy efficiency.
  - New natural gas is removed (-275 MW) and 200 MW less wind.
  - Adds +800 MW of solar, +877 MW of energy storage, +726 MW nuclear to the PRS.
- **Cost/Rate Impacts:** Idaho's 2045 rate impact is 36% higher, but Washington's 2045 rate is 25% higher. When taking into account reduction in the natural gas costs of the LDC, customers overall pay 63% more between 2043-2045 when conversion cost are considered.
- **Resource Adequacy Assessment:** 2045 is well below 5% threshold, potential for lower PRM study

Reliability Metrics:

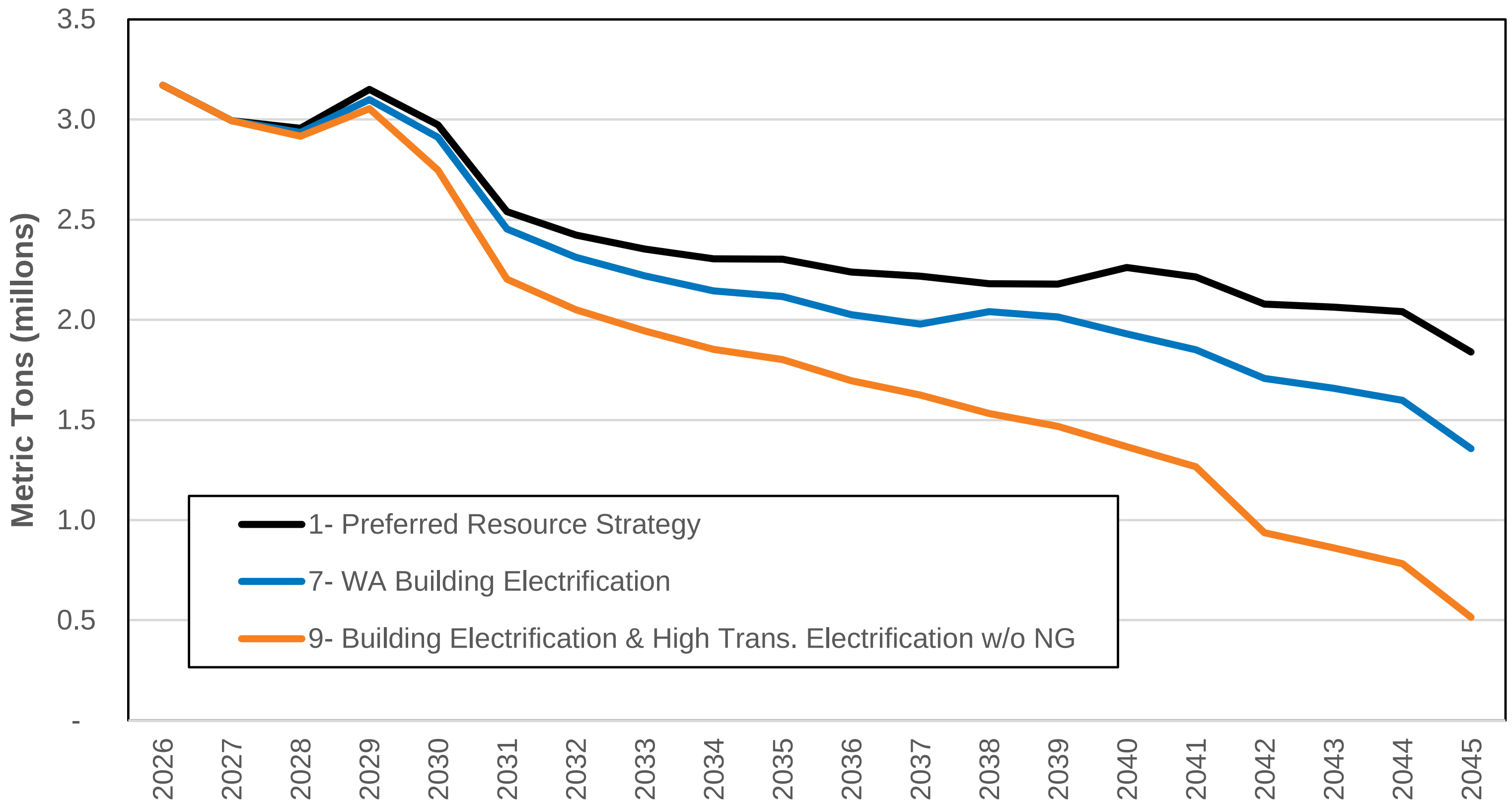
Year	LOLP	LOLE	LOLH	LOLEV	EUE	EUE without reserves
2045	0.011	0.035	0.348	0.122	56	1

Electrification Cost Summary



	1- Preferred Resource Strategy	7- WA Building Electrification	8- WA Building Electrification & High Trans. Electrification	9- Building Electrification & High Trans. Electrification w/o NG	20- Building Electrification & High Trans. Electrification w/o NG w/ RCP 8.5
Other Utility Cost Impacts	$0	$37	$34	$46	$46
NG Site Conversion Cost	$0	$118	$118	$233	$233
Natural Gas Idaho	$172	$175	$174	$118	$118
Natural Gas Washington	$369	$332	$331	$333	$333
Electric Idaho	$626	$639	$639	$1,283	$1,183
Electric Washington	$1,636	$2,012	$2,184	$2,558	$2,588
Total	$2,803	$3,313	$3,480	$4,570	$4,501
2041-45 Electric/Natural Gas GHG (WA/ID)	1.94 mmt	1.78 mmt	1.77 mmt	1.16 mmt	1.04 mmt
2026-30 Electric/Natural Gas GHG (WA/ID)	2.93 mmt				

Greenhouse Gas Emission Savings



- Includes both Electric and Natural Gas LDC
- Washington and Idaho Only
- Does not include transportation emissions
- Incremental Cost for #7 is $828/metric ton levelized

19- RCP 8.5 Weather

- **Purpose:** Understand impact of warmer winters to the resource strategy.
- **Assumption Change:** Uses RCP 8.5 future temperatures instead of RCP 4.5 for winter seasons for energy and peak weather normalization.
- **Results Summary:**
  - Reduces need for winter peaking generation.
  - Resources no longer needed by 2045 include: natural gas CT (-46 MW) and biomass (-58 MW), but more energy storage (+64 MW) is selected, there is also a shift in system allocated generation for P2G projects and wind and small nuclear increases.
- **Cost/Rate Impacts:** Minimal change to rates and slightly less PVRR (-0.2%).
- **Resource Adequacy Assessment:** A future with no cold winters indicate the PRM could be reduced

Reliability Metrics:

Year	LOLP	LOLE	LOLH	LOLEV	EUE	EUE without reserves
2045	0.006	0.007	0.030	0.009	2	0

20- 80% System Building Electrification by 2045 & High Transportation Electrification, No New NG CTs, w/ RCP 8.5 Weather

- **Purpose:** Evaluates highest load obligation with warmer winter weather forecast.
- **Assumption Change:** Combines scenarios 9 and 18.
- **Results Summary:**
  - Comparing to scenario #9: +3 MW solar, +46 MW wind, -49 MW energy storage, -46 MW nuclear, and +7 MW demand response.
- **Cost/Rate Impacts:** Idaho's 2045 rate impact is 26% higher, but Washington's 2045 rate is 28% higher then PRS. When taking into account reduction in the natural gas costs of the LDC, customers overall pay 60% more between 2043-2045 when conversion cost are considered.
- **Resource Adequacy Assessment:** Not studied.

18- 200 MW Data Center in 2030

- **Purpose:** Understand implications of large data center in Washington.
- **Assumption Change:** Adds 200 MW of load to Washington in 2030, assumes PT ratio allocates more existing resources to Washington.
- **Results Summary:**
  - With PT ratio impact, 90 MW of additional natural gas is required due to lost capacity for Idaho.
  - For Washington, short-term impacts include faster acquisition of wind, demand response, and P2G projects. In the long-run +321 MW Solar, +67 MW P2G, and +97 MW nuclear.
- **Cost/Rate Impacts:** Idaho 2045 rate: +3.7%, Washington 2045 rate: -4.2%.
- **Resource Adequacy Assessment:** 2030 study pending.

Resource Availability Scenarios

4- Clean Resource Portfolio by 2045

- **Purpose:** Determine resource selection and cost impacts of not adding natural gas resources and removing all gas generation by 2045.
- **Assumption Change:** No natural gas as an option and retires Coyote Springs 2 in 2044.
- **Results Summary:**
  - Significant portfolio changes. Resources are selected closer to a system basis.
  - Short-run: more wind, energy efficiency, demand response, and energy storage for Idaho and less natural gas.
  - Long-run: nuclear (+384 MW) replaces natural gas, but more wind (+130 MW), solar (+62 MW), demand response (+58 MW), energy efficiency (+14 MW), and energy storage (+93 MW) is needed. Only reduction in resources is P2G (-94 MW).
- **Cost/Rate Impacts:** Both states show higher cost, Washington 2045 rates are 17% higher and Idaho 55% higher.
- **Resource Adequacy Assessment:** 2030 study requires higher planning margin to be resource adequate with 24%, planning margin LOLP is 6%, but 2045 resources are adequate with the PRS's PRM at 1.7% LOLP.

Reliability Metrics:

Year	LOLP	LOLE	LOLH	LOLEV	EUE	EUE without reserves
2030	0.06	0.194	2.117	0.435	359	339
2045	0.017	0.025	0.144	0.051	18	16

11- 500 MW Nuclear by 2040

- **Purpose:** Understand resource impact of large nuclear facility in 2040.
- **Assumption Change:** 500 MW nuclear forced into model in 2040 as a system resource, does not retire any resources (such as Coyote Springs 2).
- **Results Summary:**
  - Removes 185 MW of new natural gas for Idaho and increases system wind and P2G resources.
  - Significant reductions in system resources (mostly Washington): wind (-606 MW), solar (-300 MW), energy storage (-200 MW), biomass (-58 MW), and demand response (-15 MW).
- **Cost/Rate Impacts:** Idaho 2045 rate: +30%, Washington 2045 rate: +9%.
- **Resource Adequacy Assessment:** Near 0% LOLP due to resource length.

Reliability Metrics:

Year	LOLP	LOLE	LOLH	LOLEV	EUE	EUE without reserves
2045	0.006	0.007	0.03	0.009	2.1	0

14- Power to Gas Unavailable

- **Purpose:** Understand impacts if hydrogen and ammonia are not available as a fuel.
- **Assumption Change:** Disable ammonia and hydrogen resource options.
- **Results Summary:**
  - Reduces shared wind resources and increases Idaho's need for natural gas by 72 MW.
  - Washington's resource needs change by losing 394 MW of P2G and replaces it with 288 MW of energy storage, 122 MW of nuclear and small changes to wind, solar, and demand response.
- **Cost/Rate Impacts:** Idaho 2045 rate: +4%, Washington 2045 rate: +11%.
- **Resource Adequacy Assessment:** LOLP near target level

Reliability Metrics:

Year	LOLP	LOLE	LOLH	LOLEV	EUE	EUE without reserves
2045	0.04	0.137	1.641	0.375	324	323

21- Regional Transmission not Available

- **Purpose:** Removes the 300 MW regional transmission. The scenario helps understand resource portfolio impacts rather than cost impacts due to arbitrage benefits not include in the PRS.
- **Assumption Change:** Removes the 300 MW transmission and associated market availability.
- **Results Summary:**
  – 113 MW of additional system wind- taken from Washington.
  – Idaho requires more natural gas (+25 MW) and energy storage (+25 MW).
  – Washington requires 141 MW of energy storage, nuclear (+10 MW), solar (+9 MW), demand response (-15 MW).
- **Cost/Rate Impacts:** N/A.
- **Resource Adequacy Assessment:** Not studied.

24- No IRA Tax Incentives

- **Purpose:** Useful in determining if IRA is responsible for the early wind acquisition in the PRS and determines portfolio/cost impacts if the IRA is repealed.
- **Assumption Change:** Changes resource costs to reflect IRA expiration in 2026.
- **Results Summary:**
  - No system wind resource (-357 MW), results in 13 MW more natural gas for Idaho in 2030.
  - Washington acquires 262 MW more wind and 36 MW more energy storage and Kettle Falls Unit 2 is removed, small increases to solar and demand response.
- **Cost/Rate Impacts:** Idaho rates are 0.5% higher and Washington rates are 2.7% higher.
- **Resource Adequacy Assessment:** Not studied.

23- On-System Wind Limited to 200 MW

- **Purpose:** Understand resource portfolio changes if wind connected to Avista's transmission system is wheeled off system rather than to serve Avista customer load.
- **Assumption Change:** Limits on-system wind to 200 MW without building large transmission infrastructure.
- **Results Summary:**
  - System wind is 357 MW lower, results in 13 MW more natural gas for Idaho in 2030.
  - Washington's wind is 261 MW lower, energy storage is 53 MW lower and nuclear is 54 MW higher
- **Cost/Rate Impacts:** Idaho rates are 0.5% higher and Washington rates are 3.3% higher.
- **Resource Adequacy Assessment:** Not studied.

22- Northeast CT’s Retire in 2026

- **Purpose:** Determine resource portfolio change without Northeast CTs available.
- **Assumption Change:** Disable Northeast CTs.
- **Results Summary:**
  - Immediate need for 79 MW energy storage as a system resource and 100 MW system wind earlier.
  - Idaho portfolio needs 32 MW less natural gas, +31 MW more energy storage as (2030 NG CT is gone), also more system allocated wind.
  - Washington’s allocated wind falls by 208 MW and needs 40 MW less energy storage, but 22 MW more nuclear.
- **Cost/Rate Impacts:** 1% rate impact for Idaho in 2030, no rate impact for Washington. 2045 rate impacts are 0.4% for Idaho and 0.8% for Washington. System PVRR is 0.6% higher
- **Resource Adequacy Assessment:** Not studied.

25- Northeast CT’s Retire in 2035

- **Purpose:** Determine resource portfolio change with Northeast CTs extended 5 years.
- **Assumption Change:** Disable Northeast CTs in 2035.
- **Results Summary:**
  - Defers need to build Idaho’s new natural gas CT, in its place is 36 MW of energy storage between 2030 and 2032 and total natural gas CT need is 21 MW less.
  - System wind is moved earlier in time.
- **Cost/Rate Impacts:** No early year rate impact, but Idaho’s 2045 rates are 0.7% higher, but system PVRR is slightly lower then PRS.
- **Resource Adequacy Assessment:** Not studied.

“Other” Scenarios

10- Maximum Washington Customer Benefits

- **Purpose:** Washington IRP rules require a scenario intended to maximize customer benefit indicators.
- **Assumption Change:**
  - DERs: Solar (164 MW) and 38 MW of energy storage.
  - No new air emitting resources are allowed in Washington (i.e., no P2G CT or biomass).
  - No out of system resource can serve Washington loads (except up to 200 MW of shared Montana wind).
  - Increase energy efficiency credit from 10% to 20%.
  - Includes more solar and EV load from DER potential study with higher penetrations in Named Communities
  - Regional transmission line remains.
- **Results Summary:**
  - Washington selection increases: solar (+284 MW), energy storage (+337 MW), nuclear (+189 MW), demand response (+50 MW), and energy efficiency (+5 MW)
  - Washington selection decreases: wind (-145 MW), biomass (-64 MW), geothermal (-20 MW), power to gas (-394 MW)
- **Cost/Rate Impacts:** 12.7% higher rates in 2045.
- **Resource Adequacy Assessment:** Not studied.

Customer Benefit Indicator Comparison (2045)

Customer Benefit Indicator	Measurement	PRS	Max Customer Benefits	Change
#2a: WA Customers with Excess Energy Burden	Customers	59,696	59,143	(553)
#2b: Percent of WA Customers with Excess Energy Burden	% Customers	21.2%	21.0%	-0.2%
#2c: Average Excess Energy Burden	$	1,998.3	1,801.6	(196.7)
#5a: Total MWh of DER <5MW in Named Communities	MWh	185,973	574,875	388,902
#5b: Total MWh Capability of DER Storage <5MW in Named Communities	MW	2.4	306.4	304.0
#6: Approximate Low Income/Named Community Investment and Benefits	Annual Investment ($mill)	6.5	68.8	62.2
#6: Approximate Low Income/Named Community Investment and Benefits	Annual Utility Benefits ($mill)	21.6	37.0	15.4
#6: Approximate Low Income/Named Community Investment and Benefits	Annual NEI Benefits ($mill)	38.4	35.5	(3.0)
#7: Energy Availability- Reserve Margin	Winter %	20.0%	19.9%	-0.1%
#7: Energy Availability- Reserve Margin	Summer %	25.1%	28.2%	3.1%
#8: Generation in WA and/or Connected Transmission System	% of Generation	82.0%	83.7%	1.7%
#9a: SO2	Metric Tonnes	-	-	-
#9b: NOx	Metric Tonnes	0.0	0.0	(0.0)
#9c: Mercury	Metric Tonnes	407.5	148.4	(259.1)
#9d: VOC	Metric Tonnes	26.9	9.2	(17.6)
#10a: Greenhouse Gas Emissions	Direct Emissions (metric tonnes)	-	-	-
#10a: Greenhouse Gas Emissions	Net Emissions (metric tonnes)	(0.2)	(0.2)	(0.0)
#10b: Regional Greenhouse Gas Emissions	Metric Tonnes	8.8	8.8	(0.0)

12- 17% PRM

- **Purpose:** Illustrates resource portfolio relying on increased market for resource adequacy. Resembles potential future where the WRAP enables utilities to plan for fewer resources.
- **Assumption Change:** Adjusts winter PRM from 24% to 17%, summer remains at 16%.
- **Results Summary:**
  - Near term changes: Exchanges Idaho's 90 MW 2030 CT for 105 MW solar and selects system wind resources earlier (2030).
  - Idaho: Natural gas (-62 MW) and solar (+105 MW).
  - Washington: Solar (-101 MW), energy storage (-131 MW), and other resources such as wind, nuclear, demand response have small changes.
- **Cost/Rate Impacts:** Washington has 1.7% lower rates in 2045, Idaho's rates 0.2% lower. Overall PVRR is $69 million less (0.4%).
- **Resource Adequacy Assessment:** Close to 0.05 LOLP Target, and over 0.1 LOLE Target

Reliability Metrics:

Year	LOLP	LOLE	LOLH	LOLEV)	EUE with reserves	EUE without reserves
2030	0.045	0.127	1.394	0.293	232	221
2045	0.047	0.103	0.855	0.26	149	145

13- 30% PRM

- **Purpose:** Illustrates resource portfolio relying less on market resources for resource adequacy. Resembles potential future where LOLP should be near zero.
- **Assumption Change:** Adjusts winter PRM from 30% to 17%, summer remains at 16%.
- **Results Summary:**
  - Near term changes: Adds 100 MW of system wind in 2027 and 87 MW of Washington energy storage in 2026.
  - Idaho: Natural gas (+25 MW) and energy storage (+25 MW).
  - Washington: Energy storage (+157 MW) and demand response (+3 MW).
- **Cost/Rate Impacts:** Washington has 1.4% higher rates in 2030 and 1.7% higher in 2045; Idaho's rates increase by 0.2% in 2030 and 1.5% in 2045. Overall PVRR is $183 million higher (+1.2%).
- **Resource Adequacy Assessment:**

Reliability Metrics:

Year	LOLP	LOLE	LOLH	LOLEV)	EUE with reserves	EUE without reserves
2030	0.016	0.034	0.46	0.115	81	80
2045	0.008	0.017	0.148	0.035	18	17

26- PRS w/CCA Repealed

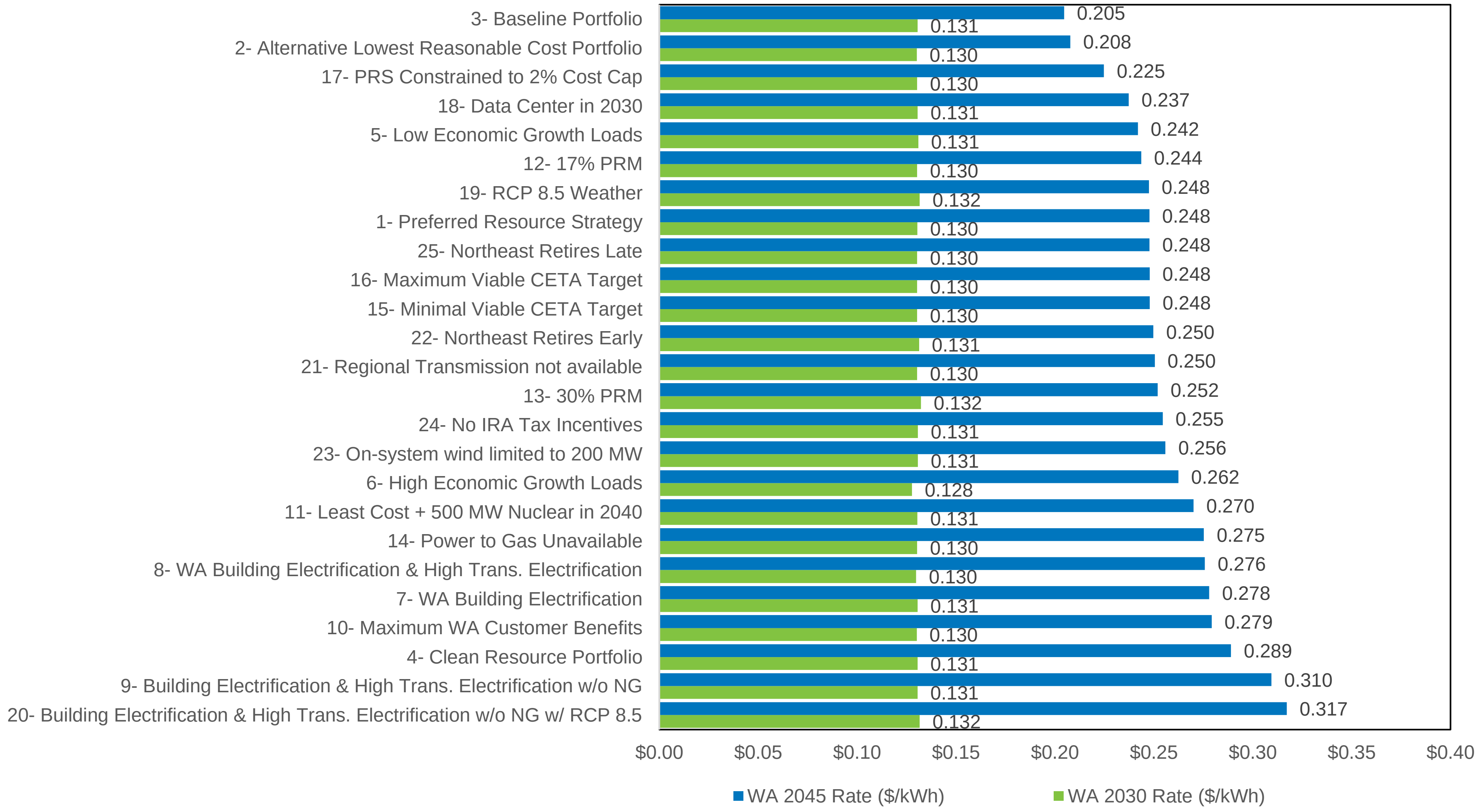
- **Purpose:** Understand impact to PRS if CCA is repealed in November 2024 election.
- **Assumption Change:** removes CCA from market price forecast, results in lower wholesale price forecast.
- **Results Summary:**
  - Near term changes: The first wind acquisition moves from 2029 to 2030, and Idaho's 2030 CT reduces to 46 MW.
  - Idaho: Total natural gas CTs unchanged as 2030 need is shifted to later load growth, and less system wind is selected.
  - Washington: Renewable need mostly unaffected due to CETA, but solar (+8 MW), energy storage (+27 MW), nuclear (+34 MW), biomass (-58 MW), and demand response (+3 MW).
- **Cost/Rate Impacts:** Undetermined. Lower wholesale prices reduce market sales and increase customer cost, but future allowance distribution methodology could impact the customer cost.
- **Resource Adequacy Assessment:** Not studied.

All Scenario Comparisons

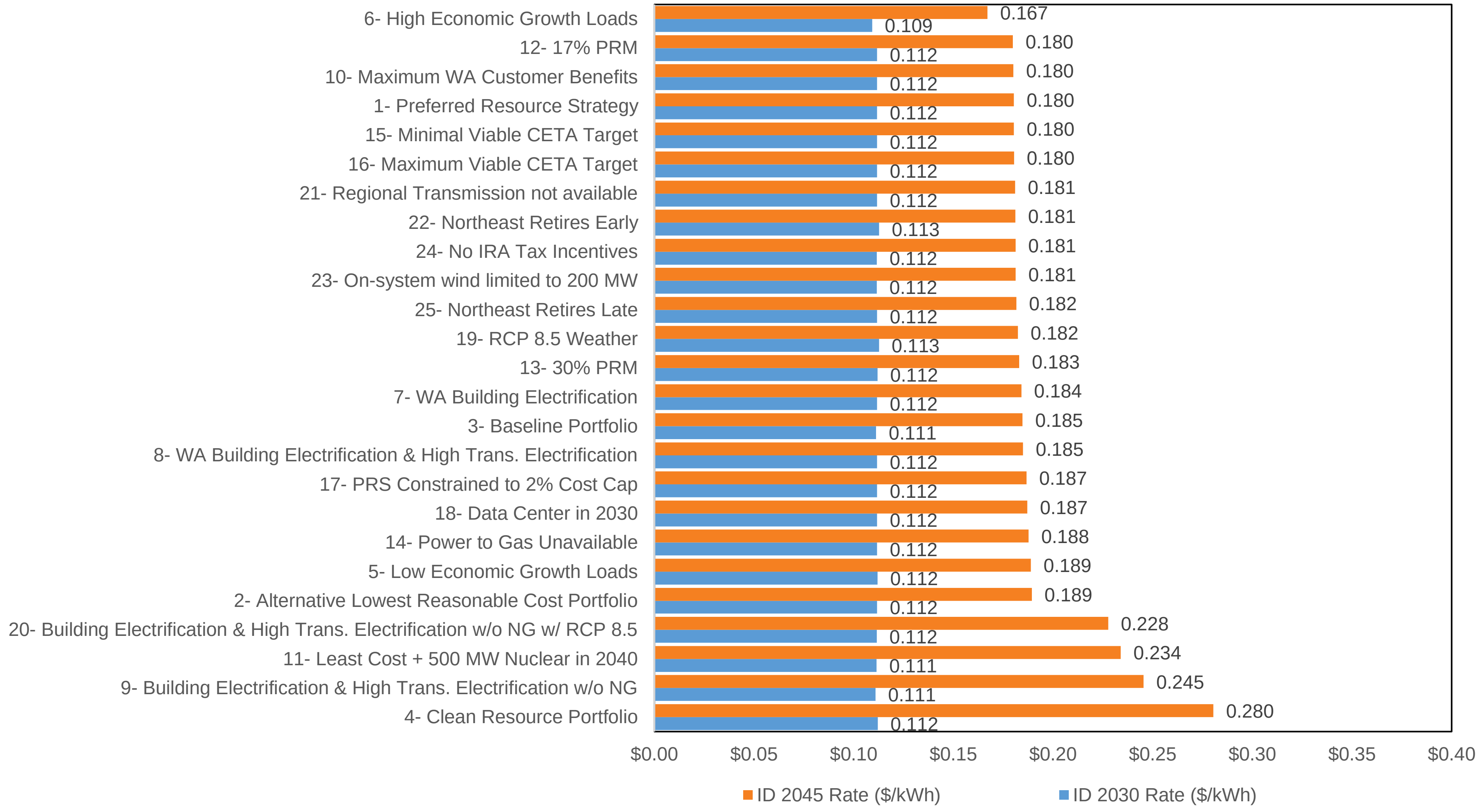
Portfolio Cost Comparison

Scenario	WA- PVRR ($ Mill)	ID-PVRR ($ Mill)	TOTAL PVRR ($ Mill)	WA 2030 Rate ($/kWh)	WA 2045 Rate ($/kWh)	ID 2030 Rate ($/kWh)	ID 2045 Rate ($/kWh)
1- Preferred Resource Strategy	10,924	4,758	15,682	0.130	0.248	0.112	0.180
2- Alternative Lowest Reasonable Cost Portfolio	10,796	4,766	15,562	0.130	0.208	0.112	0.189
3- Baseline Portfolio	10,851	4,655	15,506	0.131	0.205	0.111	0.185
4- Clean Resource Portfolio	11,135	4,873	16,007	0.131	0.289	0.112	0.280
5- Low Economic Growth Loads	10,641	4,711	15,352	0.131	0.242	0.112	0.189
6- High Economic Growth Loads	11,494	4,964	16,458	0.128	0.262	0.109	0.167
7- WA Building Electrification	11,825	4,793	16,617	0.131	0.278	0.112	0.184
8- WA Building Electrification & High Trans. Electrification	12,374	4,791	17,165	0.130	0.276	0.112	0.185
9- Building Electrification & High Trans. Electrification w/o NG	13,295	6,195	19,490	0.131	0.310	0.111	0.245
10- Maximum WA Customer Benefits	11,188	4,767	15,956	0.130	0.279	0.112	0.180
11- Least Cost + 500 MW Nuclear in 2040	11,697	5,124	16,822	0.131	0.270	0.111	0.234
12- 17% PRM	10,880	4,734	15,614	0.130	0.244	0.112	0.180
13- 30% PRM	11,083	4,781	15,864	0.132	0.252	0.112	0.183
14- Power to Gas Unavailable	11,020	4,772	15,792	0.130	0.275	0.112	0.188
15- Minimal Viable CETA Target	10,923	4,758	15,681	0.130	0.248	0.112	0.180
16- Maximum Viable CETA Target	10,923	4,758	15,681	0.130	0.248	0.112	0.180
17- PRS Constrained to 2% Cost Cap	10,867	4,767	15,634	0.130	0.225	0.112	0.187
18- Data Center in 2030	11,794	4,871	16,666	0.131	0.237	0.112	0.187
19- RCP 8.5 Weather	10,907	4,752	15,659	0.132	0.248	0.113	0.182
20- Building Electrification & High Trans. Electrification w/o NG w/ RC	13,342	5,941	19,283	0.132	0.317	0.112	0.228
21- Regional Transmission not available	10,902	4,717	15,620	0.130	0.250	0.112	0.181
22- Northeast Retires Early	10,993	4,775	15,768	0.131	0.250	0.113	0.181
23- On-system wind limited to 200 MW	11,030	4,781	15,811	0.131	0.256	0.112	0.181
24- No IRA Tax Incentives	11,266	4,754	16,019	0.131	0.255	0.112	0.181
25- Northeast Retires Late	10,922	4,758	15,680	0.130	0.248	0.112	0.182

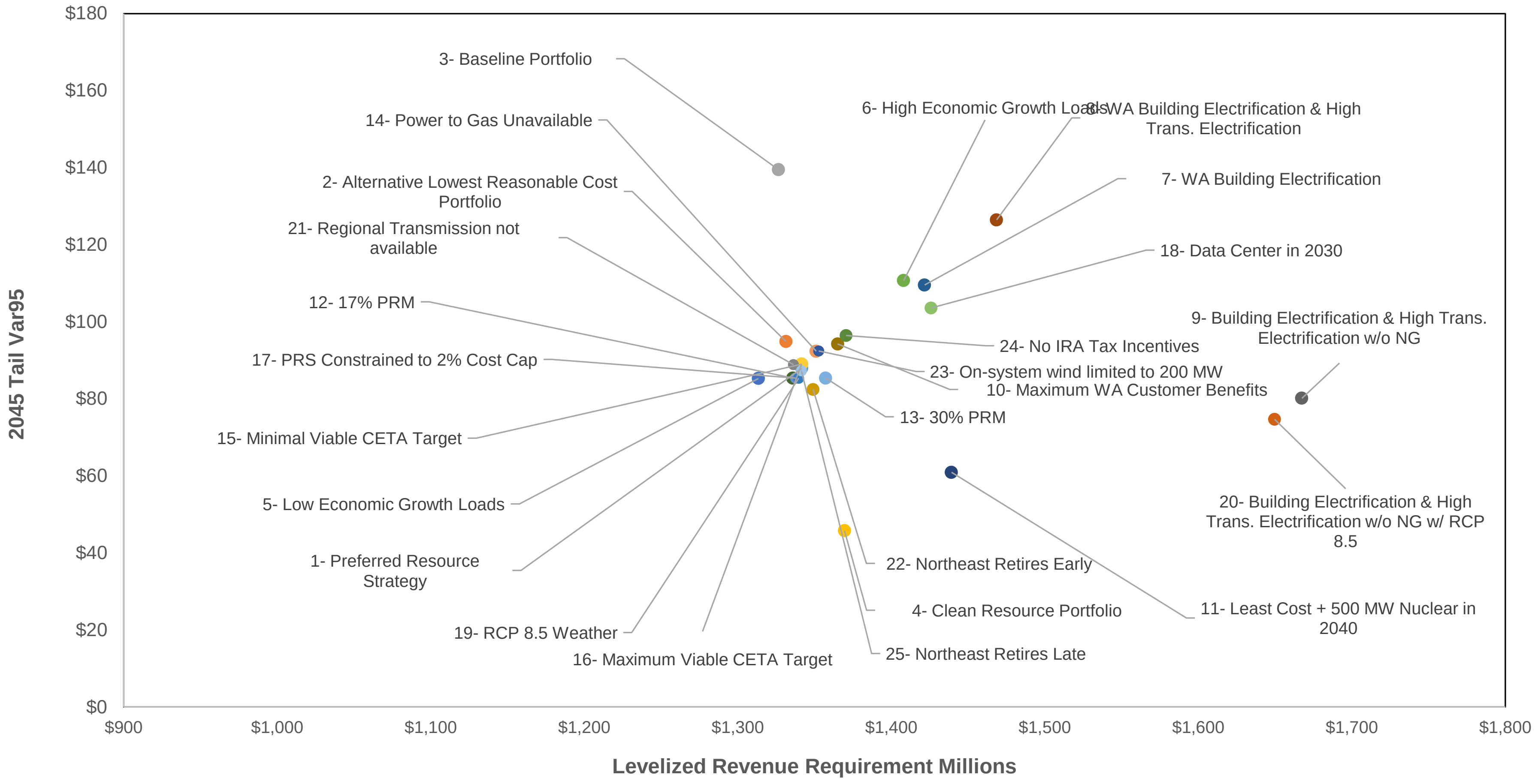
Washington 2030 and 2045 Average Energy Rates



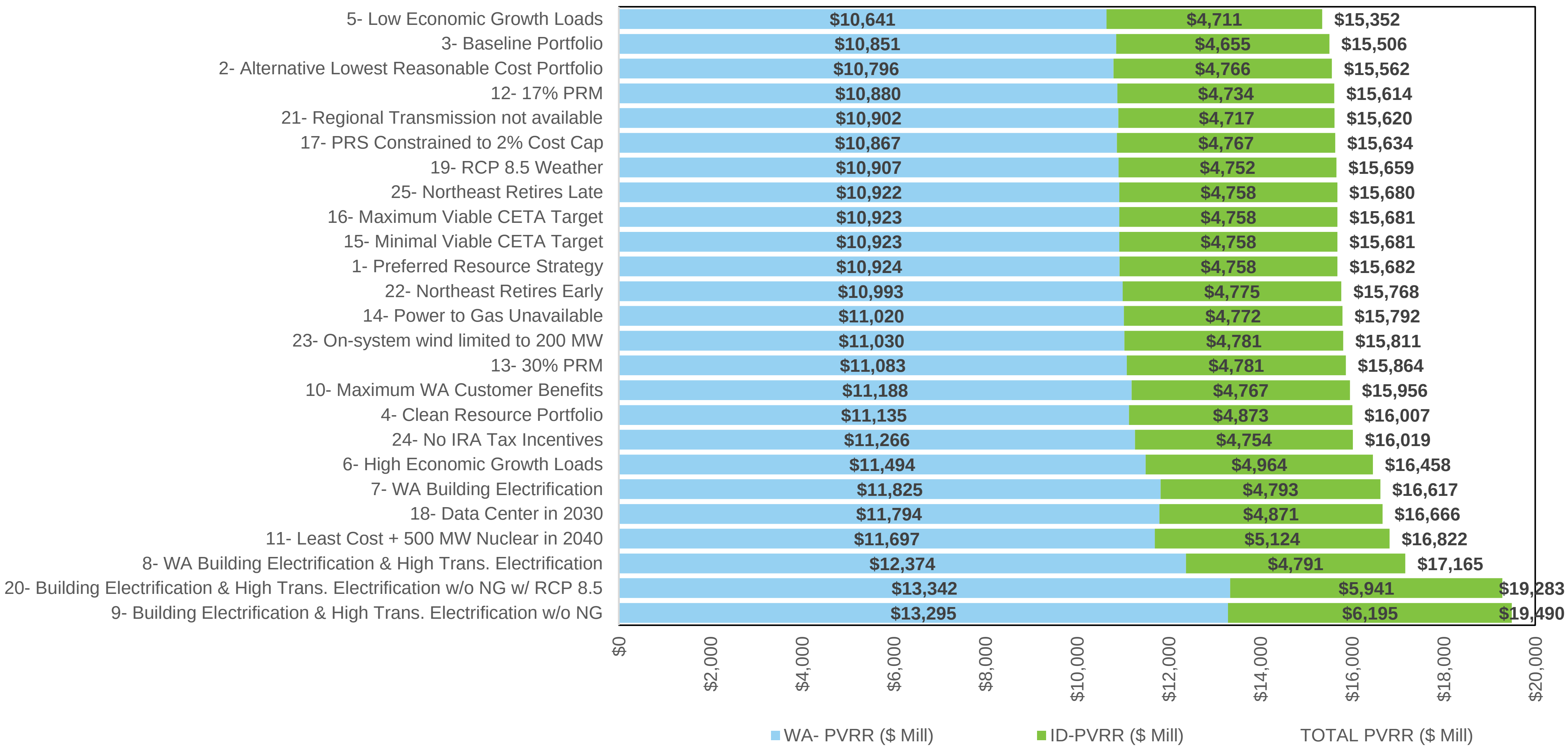
Idaho 2030 and 2045 Average Energy Rates



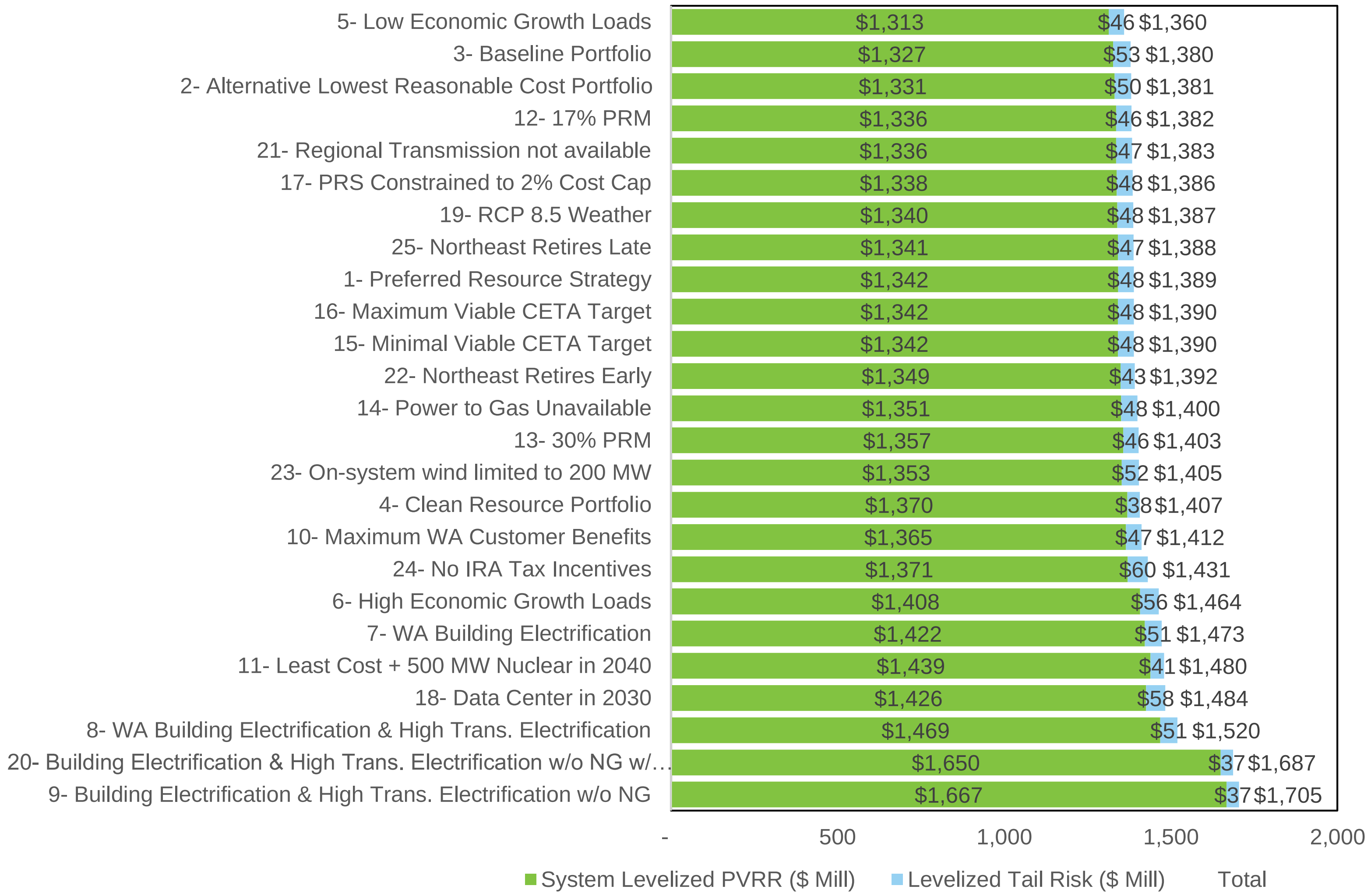
Cost (PVRR) vs. Risk (2045 Tail Var)



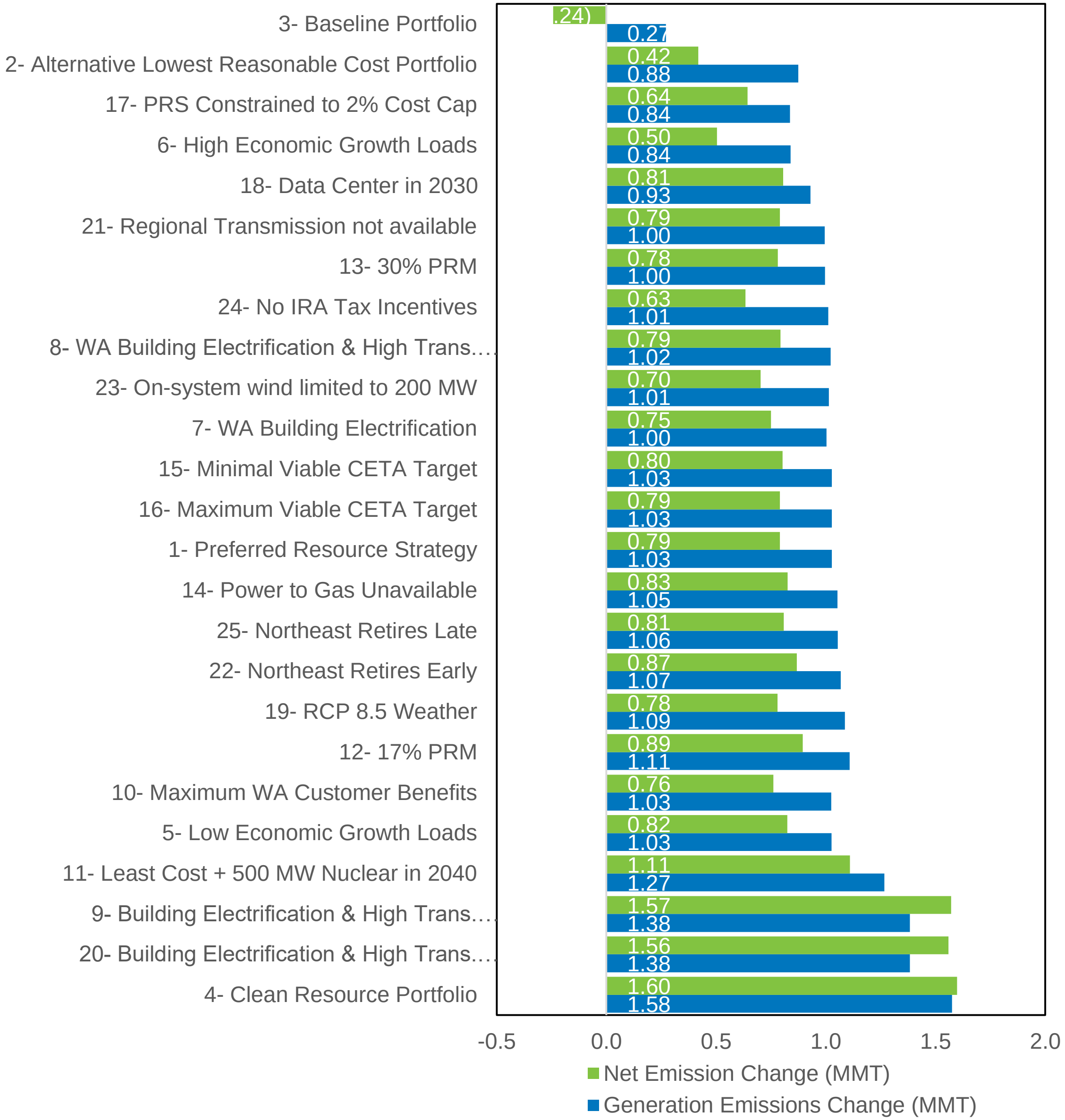
Present Value of Revenue Requirement (2026-2045)



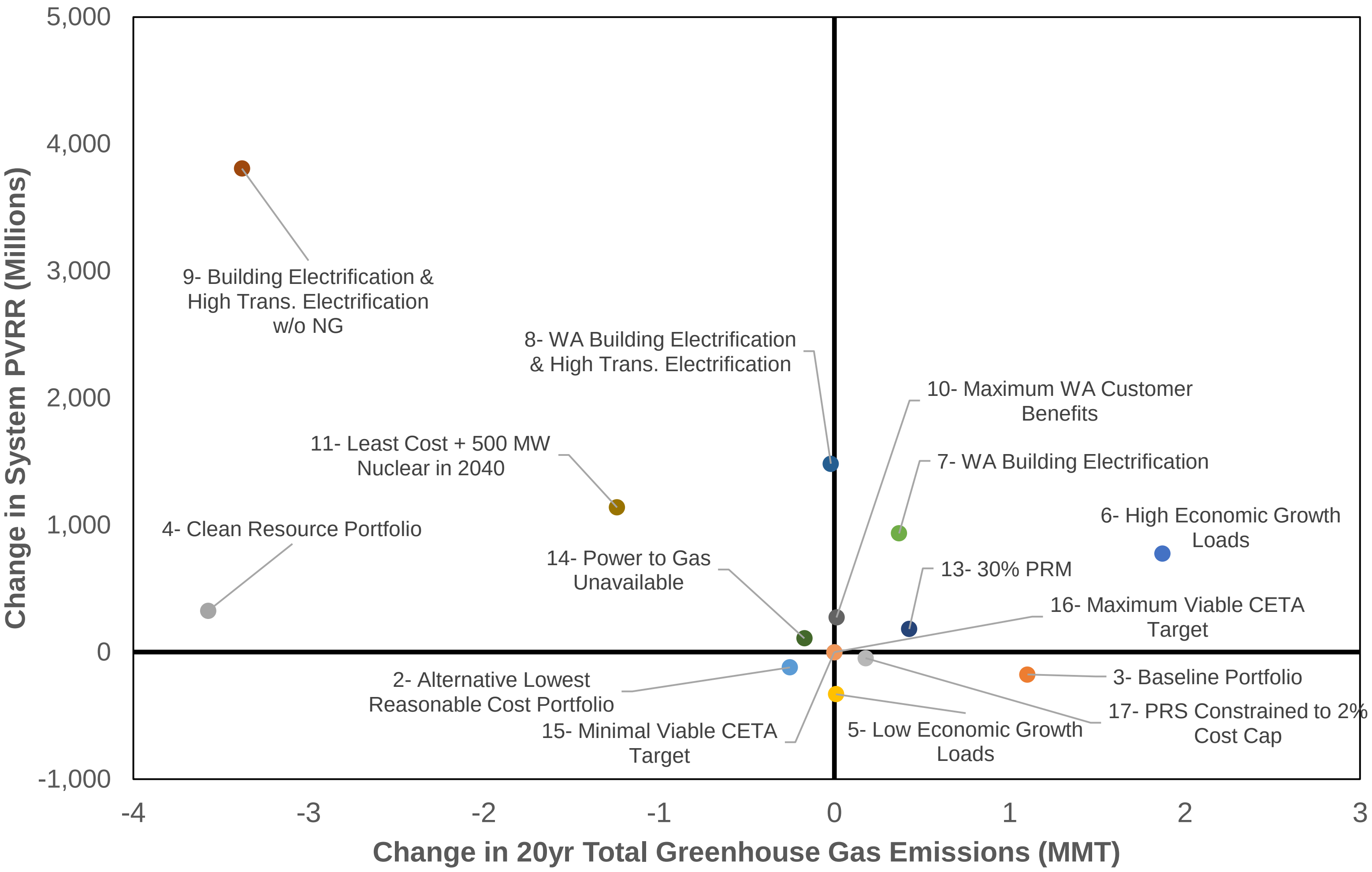
Risk Adjusted PVRR



Greenhouse Gas Emission 2045 vs. 2026 Change



Change in Emissions vs. PVRR Cost



Natural Gas Price Sensitivity Analysis

PVRR Impact of Change in Natural Gas Prices

Portfolio	Change in PVRR vs Expected Case Market Pricing					
	Washington		Idaho		System	
	High NG Prices	Low NG Prices	High NG Prices	Low NG Prices	High NG Prices	Low NG Prices
1- Preferred Resource Strategy	0.8%	-0.1%	3.1%	-1.7%	1.5%	-0.6%
3- Baseline Portfolio	2.1%	-0.9%	1.3%	-0.6%	1.8%	-0.8%
4- Clean Resource Portfolio	1.0%	-0.2%	0.3%	-0.1%	0.9%	-0.2%
11- Least Cost + 500 MW Nuclear in 2040	0.7%	-0.1%	0.9%	-0.4%	1.1%	-0.4%

GHG Emissions Sensitivity to Natural Gas Prices

Portfolio	Total GHG Emissions vs Expected Prices	
	High NG Prices	Low NG Prices
1- Preferred Resource Strategy	-13.0%	7.7%
3- Baseline Portfolio	-14.0%	8.8%
4- Clean Resource Portfolio	-9.4%	5.7%
11- Least Cost + 500 MW Nuclear in 2040	-11.8%	6.8%

Portfolio vs PRS	Total GHG Emissions vs PRS	
	High NG Prices	Low NG Prices
3- Baseline Portfolio	-2.3%	-0.1%
4- Clean Resource Portfolio	-9.4%	-14.6%
11- Least Cost + 500 MW Nuclear in 2040	-1.8%	-4.0%

2025 Electric IRP
TAC 13 Meeting Notes
September 17, 2024

Attendees:

John Barber, Magneglide; Shawn Bonfield, Avista; Kim Boynton, Avista; Annette Brandon, Avista; Michael Brutocao, Avista; Logan Callen, City of Spokane; Katie Chamberlain, Renewable NW; Kelly Dengel, Avista; Chris Drake, Avista; Michael Eldred, IPUC; Rendall Falrey, Avista; Ryan Finesilver, Avista; Damon Fisher, Avista; James Gall, Avista; William Garry; Konstantine Geranios, UTC; Amanda Ghering, Avista; Leona Haley, Avista; Lori Hermanson, Avista; Mike Hermanson, Avista; Kevin Holland, Avista; Fred Heutte, NW Energy Coalition; Annu John, Fortis BC; Alexandra Karpoff, PSE; Paul Kimmell, Avista; John Lyons, Avista; Heather Moline, UTC; Molly Morgan, UTC; Tomas Morrissey, NWPCC; Austin Oglesby, Avista; Kaitryn Olson, PSE; Michael Ott, IPUC; John Calvin Slagboom, WSU; Nathan South; Darrell Soyars, Avista; Dean Spratt, Avista; Lisa Stites, Grant County PUD; Charlee Thompson, NW Energy Coalition; Bill Will, WASEIA

<u>Introduction, John Lyons</u>

John Lyons: Oh, good, James. You started the recording. Glad you remembered on that. Going to flip to the next slide here.

James Gall: I will try. It's giving me issues here, so bear with me here. All right. I'm going to have to stop sharing really quick. Sorry, John. I apologize.

John Lyons: No, not a problem. Basically, everyone, what we are going to be doing today is mainly going over the results of the scenarios, so we have been busy running all of those and getting the data for them. James is going to be spending the bulk of today sharing the results of those. And then once we get the slide deck up here, you already should have seen the draft of the IRP for the bulk of the chapters that came up. And there we go. We've seen today's agenda. And if you want to just go right to the PRS update because, James, I believe you had one or two little things that you had to update on that. Is it for energy efficiency, I think.

James Gall: Yeah, it's correct. Yep.

John Lyons: And then scenario analysis, then the next steps, just going to wrap up for the day and what the plans going to be for getting everything done for the January 1st publication date. And next slide. We have set a date for the virtual public meeting. It'll be for joint natural gas and electric IRP. There'll be a recorded presentation and there's going to be a 7:30 to 8:30 in the morning meeting Pacific Time and then there will be, looks like we have an evening one from 6 to 7 pm.

James Gall: John, actually, there are a couple corrections on this one.

John Lyons: Or is it noon, OK? So, it is noon that we're doing.

James Gall: Noon and then no natural gas. Sorry, I apologize.

John Lyons: Oh, OK, good.

James Gall: We'll update that slide.

John Lyons: OK. We will do that, but it is going to be November 13th. So, we have that.

James Gall: I believe so.

John Lyons: OK. Those all be posted on the website too? And then the next slide. We already have quite a few of the chapters that were sent out, the remaining ones: the introduction, involvement process changes. Basically, where you can look to see where things are going to be located in the IRP in the organization of. It will be adding the market analysis chapters and portfolio scenarios and then we'll be able to write the executive summary when those are completed. That'll be October 1st. We'll send those out and then you'll have the complete draft of the IRP. I think James, is that all, we do have the appendices. And I believe we did have a slight change towards the end there where we're combining two of them for the data.

James Gall: Yeah, that's Appendix K going to go away and be part of Appendix G.

John Lyons: We're trying to organize those so they're all little bit easier to go through. Presentations are already on the website, Work Plan, those first batches of data for the studies, and then we'll finish. We already have quite a bit of the public input and results data. James, if you want to talk about what's out on the Teams site.

James Gall: Yeah, I really was going to keep that in the context of today. What the presentation, there's, I'd say, a limited, we have 26 scenarios and that's a lot of information to cover in 2 1/2 hours. But if somebody wants to dig into the results more, I do have a file out there that summarizes all of the scenarios. And then once we get past October 1st, I'll be posting all of the PRiSM models out on the Teams site as well, and eventually they'll be on the website. If you want to dig in, it's going to be available for you to do that. We're going to keep it mostly high level today just to get through all of the scenarios.

John Lyons: I think that takes care of it. If you want to start going on the results.

James Gall: OK, I'm going to see if I can get this to move over to the other presentations. See here. We see the right thing.

John Lyons: Yes.

Scenarios, James Gall

James Gall: Yep, we do. OK, good. So, like I mentioned earlier, we have about 26 scenarios to go through. We've also done a couple of different, we'll call them market sensitivities that I'll cover today, but before I get into the scenarios which actually are really the most interesting part of the IRP, because it tells you how our resource strategy could change as time goes on because we all know the Preferred Resource strategy will change. I don't know if any of them have been correctly right in my 20 years of history here at Avista. It gives definitely a glimpse into what could happen in the future. Before we go there, we do have one change dimension on the PRS. This was actually, we were able to get it corrected in the IRP document that went out as a draft, but it has to do with energy efficiency. We were meeting with AEG and right before we're ready to publish the draft IRP, we realized that losses, line losses for energy efficiency will be double counted. So, we had to rerun our model, come up with the correct economic potential for energy efficiency. The slide here shows the difference between what we presented in the TAC meeting, I believe in August, and then the final result once we removed losses. Losses are around 5½%. That covers most of the reduction. The other reduction, to get to 7.7%, has to do with some of the economic choices when the resource provides less benefit than it thought it would. The model actually selected slightly less energy efficiency, so this is like I said earlier, it's been updated in the draft IRP, it did not change our Preferred Resource Strategy on that generation or the supply side at all.

James Gall: We've been running our energy efficiency separate from the supply side selection to lock it down. That choice actually helped us quite a bit here to ensure it didn't have a ripple effect on the rest of the analysis, but just something to be aware of. OK. Over the course of the TAC meetings, we've talked about portfolio risks, and this is a scattered chart of all the different risks that we've covered over the year and a half of going through this IRP. A lot of it has been around load. We've talked about weather quite a bit. We talked about data centers. We talked about CETA and the impacts it has on the portfolio with different interpretations of rules.

James Gall: Another big topic we've covered is what resources are going to be available. Northeast is actually the biggest resource on our mind as that's the closest one to a retirement date. Is nuclear going to be around? Is power-to-gas going to be a real resource? We talked about the regional transmission line going into North Dakota. But what we're trying to do is take all of these risks that were discussed in the TAC meetings and come up with different scenarios on how it could impact the resource strategy. And then also look at the reliability of the portfolio with some of these changes and then the question is, do we do loop backs of whether or not our portfolio is reliable? Do we change the scenario or results? Or if it's more than reliable enough, do we go back and try to reduce the amount of resources that are needed. We ended up doing 26 scenarios. And as you might think about, we have 26 scenarios with the trial and error of a lot of these scenarios. We probably run our capacity expansion model probably 150 to 200 times to make sure these 26 scenarios are looking in the right light, as far as what the scenarios intent is. Some of the insights I found going through the scenarios is demand response and energy storage is really the fastest resource we can add, if we need capacity if the load forecast comes out to be too low next time we look at resource acquisitions. For example, in the upcoming RFP, we're going to be looking at those two options, they are probably the best to meet capacity needs. When to some extent they can help meet some capacity needs, but it takes maybe an extra year or so to get one of those facilities online.

James Gall: Looking out more out in the future. There are really two technologies being discussed, at least we found in the analysis to be help us meet winter peaks. That's power-to-gas, and that's ammonia or hydrogen. Depending on how much of that resource is able to contribute, when I mean by that is how much fuel we're able to get. So, how much hydrogen or ammonia we're able to get out of the marketplace. If that is a constrained resource. And CETA continues in its same form. Nuclear energy appears to be the only real resource that can meet the goals of CETA out in the 2040s. A lot of our scenarios show a significant nuclear acquisition in the out years and that creates a cost on the system because the prices I have here ranges between $144 to $206/MWh and that can create a cost cap concern from a CETA perspective. That's something to look for as we go through time. Obviously, it's not something that's an immediate issue today, but it's definitely something we've caught on in the analysis.

James Gall: Going back to wind in the PRS. There's a significant amount of wind around 1,000 megawatts and at 1,000 megawatts, even at 5% or even 10% capacity contribution that's 100 megawatts of capacity contribution. You're leaning on wind and that creates a risk for the utility because we saw during the January cold weather event, wind was not a significant capacity contribution. It creates a little bit of a risk to rely on wind to even meet a small amount of capacity, but that is something we've seen in the modeling. The other thing to think about is transmission limitations. The PRS that we presented last TAC meeting. It's really trying to maximize the amount of wind that's available given the transmission limitations we think the system has and then what happens is if once you hit those transmission limitations, that's when nuclear and solar also starts to show up. If we hit our transmission limitations earlier and still need clean energy, that's where we're nuclear and solar will likely increase its need. But if we have transmission expansion, it may lessen or defer that net need.

James Gall: And then lastly for Idaho analysis, we do see natural gas CTs repeatedly showing up as a low-cost option. There are some challenges with natural gas CTs and that's permitting. The time it takes to permit those resources and then the infrastructure transmission pipeline, potentially energy or natural gas storage, even with all those costs, natural gas for our Idaho customers seems to be the least cost. It just takes time to get those resources online. But again, at the end of the day, all of our resource selections will likely go through an RFP process with specific projects and we can then see what's the most cost effective once we have specific information rather than generic information in an IRP.

James Gall: OK, so like I mentioned earlier, we did run 26 scenarios. That includes the Preferred Resource Strategy. I've lumped them into the four different buckets to cover today. The first bucket will cover some different methodologies on different portfolios and we'll get into some low growth scenarios, resource availability scenarios, and others maybe get combined in the final report, but we're trying to group these into a rational order. The numbers you see on each of the scenarios correspond to the order we created these scenarios, and they were assigned a number. We just we left those numbers as we created the scenarios in our modeling. You might see those numbers attached to some charts in the future, either in the document or in the presentation. This slide is really for reference as we go through the scenarios on what was included in the Preferred Resource Strategy. I don't want to cover this too much in detail, but we'll just mention a few things. That's more near term. And that is, we do have a little bit of market in the early period and that's related to a contract that's going away that 39 megawatts kind of buys back a contract that we have. And then the model switches to DR and community solar and then eventually a wind acquisition by the 2030s. And I saw a hand up and I think it was Molly. Go ahead, Molly.

Molly Morgan (UTC): Yeah. Just a question, I don't see this in the draft IRP like this actual table. Is that coming in October, then?

James Gall: Let me see here. We have, like I said, I think it's a simplified table in draft we do have. This is in the appendix, so we'll have an appendix that has a table that's very similar to this for every portfolio.

Molly Morgan (UTC): OK.

James Gall: So that will be a spreadsheet and on our team site you have access to this. Right now there's a file. I think it's called. PRiSM scenario results out there and then also the prism file that created this is on the team site as well. So you have the full model for this specific scenario.

Molly Morgan (UTC): OK. You said this this isn't in an appendix. Currently, though in what you filed.

James Gall: No, it is not.

Molly Morgan (UTC): Yeah. OK.

James Gall: Yeah.

Molly Morgan (UTC): Yeah, I think this would be. I just like seeing it like this. I think it'd be good to have it in the filing itself, so maybe supplement that in October because I saw like in Chapter 2, the PRS chapter, it's broken up in different ways.

James Gall: Yeah, we can do that.

Molly Morgan (UTC): But yeah, it's nice to just see it all laid out. Thanks.

James Gall: OK, we'll do that. We'll put it in there and it'll be in the new chapter too. Alright. Any other questions or thoughts before we get to the scenarios?

Heather Moline (UTC): Yep. This is Heather from UTC staff. James, did you say solar or community solar by a certain year?

James Gall: Yeah. The solar you see in there under Washington, I don't know if my mouse is the point, but that the ones that you see going across. That is community solar that's picked in the model. And that represents some funding by the State of Washington that's funneled through Washington State University to pay for a majority of the cost, if not all the costs, for community solar projects. When we model that basically free solar, we'll call it that. It does pick basically as much of the free solar you can get. How that works, I believe it's a 200 or 199 kilowatt size project or less. You can group some together. But that's something the Company is looking at. As we look at how we can access that funding and my expectation is that's going to be probably a topic of interest in the CEIP process. That actually ends up looking like.

Heather Moline (UTC): So, not utility scale. It looks like utility scale is not found within the Preferred Resource Strategy at all. You're just talking about community solar.

James Gall: Yes and no. Community solar, early on. Utility scale solar shows up late if you look at 2043/2044, it does show up, which actually is an improvement from the last IRP. We had no solar show up besides community solar.

Heather Moline (UTC): So that it doesn't actually differentiate here, but you're saying that 2043 within the solar row that jumped from 1 to 181? So, 180 megawatts of utility scale.

James Gall: Correct.

Heather Moline (UTC): OK.

James Gall: And if you go to, and maybe that's something we'll break out, that next chart we have all of these technology categories. We are modeling around 50 or 60 different resource options. We could even break that down further. You can see what's DER solar, what's utility scale, and then on system wind in Montana on the AVA system. We have further breakdowns. This is more of a summary shot of it. OK. Any other questions? We have about two hours and it should be on time. Let me know if we need to take a 5 minute break potentially at maybe, I don't know, 10:15 am. That might be appropriate.

James Gall: OK. My plan is to cover each scenario, do a high-level summary of the results and what the assumptions are. And then I have some slides at the end that are really a combination of all the scenarios. I'm not going to spend a lot of time on those if we couldn't get that far through the presentation, but please interrupt me as we go. Lori's watching the chat. Just feel free to interrupt me at any time. OK. The first scenario, we call it the alternative lowest cost scenario, is part of CETA's requirements to calculate a counterfactual portfolio to calculate the 2% cost gap, I almost thought about not including this in the IRP. It's really a CEIP or Clean Energy implementation plan scenario. It covers the first four years as that counterfactual portfolio, but regardless, it is here. I don't want to spend a lot of time on it just because it's really focused on the four years for the CEIP. And in that four years, the model is basically coming up with a very similar result. Just because our resource position is a little bit less energy efficiency in this scenario for the first four years, but largely the same. But if you extended this out over time, it does acquire quite a bit less resources because this scenario does not include the CETA targets. But it does include the social cost of carbon adder, and that combination results in a little bit less wind, less solar and then less energy storage. And then at the end of the day, it results in less cost for Washington. Although it's going to be unique in this scenario and the next one, you're going to see, Idaho actually sees slightly higher cost in how you shuffle resources around between the states. Washington's always trying to in the model take low-cost energy resource or clean energy resources to meet CETA, and sometimes that can cause issues on the Idaho side of the portfolio depending on how future costs are allocated and then we did look at some resource adequacy views of this. They are both below the 5% threshold, actually significantly below that, because the model is designed in a way to have more renewables and when you have more gas turbines like in this example, it actually makes the system more reliable. You could actually in fact need less. But anyway, that's the scenario. Like I said, it's really going to be used for the CEIP process. It's going to come up again there.

James Gall: Let's move on to the next one. And that's we call the baseline scenario, and this is very similar to the alternative least cost scenario, but it removes the social cost of greenhouse gas, it removes NEI calculations. Basically, it's what our portfolio would look like if we planned our system like it was planned, say, 10-15 years ago where we were just solely looking at. least cost planning for the system. It's actually for the Idaho service territory. It's very similar as well, a least cost look. The results really are basically less renewable generation, 700 megawatts of wind still remains, but it's less than it was in the PRS and a lot of our capacity needs are no longer served by energy storage in this scenario where nuclear it's served with natural gas. And like the previous scenario, costs are lower for Washington, about 17% lower by 2045. And what I mean by cost, what I'm talking about there, is the average rate of energy. There's really two looks at costs that we publish, one of them is PVRR that's present value revenue requirement. The second one is the energy rate, that total cost to serve divided by how much sales or energy sales or our retail load. I like to show the average cost of energy more than PVRR. Oftentimes, because it takes into account the change in load, where if you just looked at PVRR it is kind of misleading because if you have a low load scenario, your PVRR is going to be lower but your rate, your energy rate could be higher. This scenario again, it's another one of those counterfactual results, because we need this scenario one, it helps demonstrate some of the costs of energy policy, but also helps us with calculating our avoided costs. This is one of the scenarios we use to help us calculate the capacity value or the energy value in the in the IRP. So that's baseline scenario. There's going to be a little bit more detail on each of these in the actual document as we're writing these up, so be on the lookout for those.

James Gall: The next one in this category is related to CEIP condition #33. This will likely also show up in the next CEIP as well. But what we were asked to do is look at a scenario with minimal primary compliance targets by 2030. The reason behind this scenario is in this last CEIP process customers have a lower cost if we have targets that are lower than a constant trend towards 80%. The table in here shows the PRS targets versus what the scenario assumed. The CETA target for primary compliance is around 62.5% for 2026. We keep that flat and then it jumps up at 2030 to 80% and then it's a slower trajectory all the way to 2045. And what we found in this scenario is compared to the Preferred Resource Strategy, there's really no material change in the in the results and there's a few reasons for that. A lot has changed since this condition was brought to us. Because one is, we have more renewable energy than is needed to comply with CETA to around 2034. The second reason why there's not a change is the renewable energy that's selected in the Preferred Resource Strategy for Washington is not driven by the percentages in the early years of the study, it's really driven by an economics where the price forecast of energy is less than the forecasted average energy cost of wind. In that shorter term period, because of the IRA, the amount of clean energy required to hold really is not changing the results for this acquisition. But what does change though, is the amount of revenue the company would get through REC sales. And that's something we're going to cover more in the CEIP process. Is that if we have higher targets that force us to retire renewable energy, that takes away our ability to resell the RECs or potentially into the CCA market at a higher price, because if we have two options with clean energy, when you have excess, you can either sell it as specified clean and get a higher price for it on the energy market. Or you can sell off the REC and either one of those benefits customers. If we have higher targets, that's less revenue available for our customers. That's like I said earlier, that's going to get covered in the CEIP process in a similar way as the last CEIP process when most of the cost impacts were due to the REC value of the renewable energy. OK.

James Gall: The next one is the opposite of that scenario where we maximized the amount of RECs that we would hold preceded as that changed the result. Again, this one surprisingly had no impact as well. And that's really because we are trying to hit targets out in the future. Now if we lower the targets in 2045, before 2045, you could see a different target or a different result, but because all of these see the scenarios are targeting 2045 at 100%. It's not changing the result because that generation's got to be built. It's just a matter of timing. So, this one really found no significant change at all. All right.

James Gall: This next one is actually pretty important. I thought that has to do with the cost cap calculation in 2045. And there was a chart I showed at the last TAC meeting that showed fairly constant average rate increases through 2044. And then in 2045, the price, the average price of energy in Washington, shot up significantly. And that's due to a couple things going on in 2045. Number one, we have to have all natural gas out of the system for Washington unless we have the 2% cost gap. That means we have a significant resource retiring in 2045. That would be Coyote Springs 2. Two, the other issue in 2045, is that's when a nuclear plant is selected at near $200 a MWh we described earlier. Three, that is a switchover and CETA from trying to be matching clean energy to retail sales to clean energy meeting full load. So, in 2045 versus say 2044, we're trying to not only step our increase towards 100%, but you're also trying to cover load, which is around an additional 5½% of our clean energy requirements. At that point in time, even if you try to acquire some resources earlier, you have a significant cost at the tail end of our portfolio. What we tried to do is estimate what would that 2% cost cap be when you get to 2045. The first line of thought I had is, well, we could just use our alternative lowest cost, lowest reasonable cost scenario, but that's really only valid for the first four years. We would need to come up with a theoretical alternative lowest reasonable cost portfolio that would be created in 2044. That's what we did. We calculated, basically took our Preferred Resource Strategy, assume all that happens and then in 2044, what would our portfolio look like if we did not meet CETA and come up with this future scenario and that creates a cost in 2045. We then take that cost, calculate the cost cap which is 2% of revenue requirement in 2044. And then we're assuming it's a four-year compliance period. That's a whole other story, but we're assuming that and that basically limits our 2045 increase to 8%. So, between 2044 and 2045 you can have an 8% increase in rates. It's not 2%, but that's how the rules work. And in that scenario, what happens is Coyote Springs 2 remains an allocated resource to Washington. It does assume we could burn around 30% of that generation with hydrogen, but what happens is because of that, Idaho would need more natural gas generation because it's no longer taking what was from Coyote Springs 2 and then it does shift to less wind, less nuclear, less biomass and energy storage for 2045. That cascades to lower rates for Washington, about 9% lower in that 2045 case. Idaho would see a slight increase because it no longer has a Coyote Springs 2 plant it's going to be able to utilize. Hopefully that makes sense, but what we're trying to illustrate here is that we see in 2045 that we're likely to exceed the cost cap, but we're not expecting to see a cost cap issue until that period of time to comply with CETA. OK. That was a lot. I just want to pause there before we go to the load scenarios. If there's any questions. OK, Molly, go ahead.

Molly Morgan (UTC): Yeah, I still just struggle to wrap my head around this. So, you're saying that you might not meet the 2% cost cap in 2045. And what would your resources look like given that?

James Gall: Yeah.

Molly Morgan (UTC): Yeah, I think I'm still not really understanding. Why you would exceed the cost CAP in 2045 specifically? Can you try to put that another way?

James Gall: Sure. In 2045, we have to replace Coyote Springs 2. And we have to move to 100% renewable or clean energy in every hour of the day. That's the big change from 2044 to 2045. And the resources necessary to do that, which is on the third line or fourth line from the bottom. Washington resource in 2045, use less wind, nuclear, biomass and energy storage. Those resources that are removed essentially have a cost that's so much that it's going to trigger that cost cap. And well, one thing in 2045, it's unclear in the legislation whether or not there is a cost cap. That's, I guess, an unknown but we're just illustrating here, is based on what we know today. The resources it's going to take to meet that 2045 goal are going to be significantly more than an 8% rate increase in 2045.

Molly Morgan (UTC): OK. I guess I just wonder why, given that this is all supposed to be incremental, and I think I see you're using incrementally less alternative compliance from 2030 to 2045, why is it all happening in one, why is there a problem in one year?

James Gall: Yeah. I've looked at what if we try to acquire resources earlier, but it really comes back down to trying to solve a portfolio that's every hour of the year. So, what that does is you have to create or build enough resources that your odds of serving that energy is available. It's just the quantity of resources that you're trying to comply with. In 2044, the law says we're meeting towards 100% of retail load. That doesn't include losses. In 2045, we now have to meet our losses with clean energy. There's a step function in 2045 of a higher compliance threshold. And it's not only a percentage of time, let's say it was monthly compliance or even annual compliance in 2044. That's a lot different than trying to comply with every single hour of the day. Renewable, no matter if it's a low hydro year, a low wind month, you're trying to now comply every second of the day has to be clean energy and that's a significant step function compared to 2044.

Molly Morgan (UTC): Conceptually, that makes sense.

James Gall: Yeah, and we could acquire those resources, say in 2044, and spread them out, but then you're going to bring your cost cap earlier.

Molly Morgan (UTC): Yes, I mean I guess that's a question if you're acquiring these resources even earlier than that and flattening that cost increase. Would it actually exceed that in any one year if it's spread out over five or six more years, for example?

James Gall: Yeah, I did test that and that was why the model was pushing everything out to the last year, because it was trying to lower its cost as much as possible by pushing out. But you could acquire it earlier, but I think you're going to hit the cost cap earlier in that scenario.

Molly Morgan (UTC): And so I think you said one question is, it's unclear in the law if there even will be a cost cap going from 2044 to 2045.

James Gall: That's correct.

Molly Morgan (UTC): Which is something we can't know right now.

James Gall: Correct. In the law, I guess I'd say it's written more as a goal in 2045 because the penalties are not described after 2044.

Molly Morgan (UTC): OK. Thank you. Heather has her hand up.

Heather Moline (UTC): James, what do you mean by meeting losses with 100% renewable?

James Gall: In pre-2045, the law is very specific on the targets for clean energy. It says retail load and that's defined as sales minus the PURPA generation. And then minus clean energy that's served to a customer, but in 2045. The language is different and it basically implies you're serving, you can't use a carbon emitting resource, so that implies that you're no longer trying to meet loss. Your retail load. You're trying to meet all of load with clean energy because you can't use a thermal resource. So that implies you're now going from retail sales to meaning load.

Heather Moline (UTC): OK. Line losses.

James Gall: Yep.

Heather Moline (UTC): I just wasn't clear on that, OK.

James Gall: Sorry. Were there any other hands up, OK. All right. I'm going to try to describe this a little better in the in the document. Some may argue this scenario would be more of our Preferred Resource Strategy because it takes into account the cost cap by given the unknowns of how that's all going to be treated, we thought it'd be best to leave a scenario and have this discussion. And at the end of the day, this is more than 20 years out from now and we probably should spend more time in the next five years than the last year of the plan. We'll move on to the load scenarios. OK.

James Gall: Scenario #5 is low load growth and the idea here is that we have lower loads than our current forecast. Our current forecast is about 0.85% load growth per year. This flattens it out to around 0.34%. The theory is that you have less population growth and that reduces our loads downward. And then in the results of that from lower loads, we have really no changes in our resource strategy until through 2033. But when you get out to the longer period of time, when you're actually have less obligation to meet: wind is lower, solar needs are lower, and the nuclear plant goes away. You don't need as much demand response. You actually have lower costs if you look at it from a PVRR point of view, but if you look at it from an average. Annette. A great point of view. Your rates are slightly higher because you have a fixed cost of our system that's now being spread out over less energy sales. So, you have slightly higher rates, but we've been running these types of scenarios for quite a while on how low trajectories work. This is pretty similar to those past scenarios where you just need less resources. But you know from our current point of view, when we don’t have a lot of needs, for resources in the short run, unless we have load growth. It's a better position to be in if you have lower loads than higher loads.

James Gall: Because the next scenario, when you get into higher loads earlier like some of these other scenarios we are getting into. Then the utility has to respond quickly. In this case we have a higher population growth leading to higher load needs, about 1.75% per year. This requires demand response earlier. It's a quick acting resource like we mentioned, earlier and then also wind shows up earlier as well because, it's kind of interesting here, this is where wind is actually contributing to capacity a little bit where if you have small capacity needs and you have clean energy requirements at the same time. The model will pick wind earlier to help meet those small low growth increases, but it also saves it from having to buy wind later on. Long run though, the model is picking more demand response and solar to meet the growth of higher loads and this has to go back to it reaching the limits of its wind acquisition. In the long run, where we don't have enough transmission to bring that wind on. So, it's looking at the next tier of resources. It's used up all of its wind. It's used up all of its power-to-gas in Washington, so it's using nuclear and solar to help meet that growth. And then in Idaho, it's simple to meet additional low growth without the CETA constraints. It just basically builds more natural gas turbines. From a rates perspective, it's actually higher because in both states you're serving your incremental load with incrementally more expensive resources. We've seen in other cases, if you have plentiful resource opportunities, you could actually lower rates sometimes. In some cases, you'll see that, but in this case it does say slightly less rates, but the PVRR is higher. It's about 6% higher.

James Gall: OK, so going on to electrification scenarios, this is an enhancement we did in this IRP to model a very simplified natural gas system so that we could understand the impacts to total emissions. To potentially natural gas rates, if we move customers from the natural gas system to the electric system. And what this scenario assumes is that based on today, if 80% of that demand for natural gas, if we move 80% of that demand to electric by 2045. If you think about what the gas demand is today versus 2045, the remaining gas demand is about 20% of what it is today. That's what the scenario is trying to assume, and then that gas load has two options when it electrifies. If they're in an Avista service territory, they become Avista electric customers. If they're in another service territory, they would go into, say, Inland Power and Light. Some analysis we've done a few years ago, we assume around 75% of our Washington natural gas customers become electric customers.

James Gall: In regard to your last two scenarios, I had a question. Are these high or low load growth differences driven by changes in the number of customers or by the changes in usage per customer or both? OK, going back. It's the number of customers that are the driver or population growth and economic growth. So, they are, I believe that when AEG did this and Mike, if you might remember, correct me if I'm wrong, but it's population. It's mostly population. There's a little bit of economic growth but driven largely by population.

James Gall: All right, so back to electrification. We have customers moving. This first scenario is just looking at Washington. You have 75% of the 80% loss in customer going to electric Avista? So, what that does to our electric load is it adds around 356 megawatts of peak load in the winter and around 107 average megawatts to energy. I think we covered some of the assumptions around this scenario in past IRPs, but the concept is that these customers who are converting, they'll be using a heat pump technology and for both water heating and space heating and while heat pumps are more efficient. It can be more efficient than resistance in cold weather, but at a certain point when you get to around 5° or less, that efficiency radically decreases. So that's why you're seeing significant peak load increases for serving that gas load also. Even if you were more efficient than resistance, you still have added load because it's more demand. So, what we see going on in this scenario with that added load, basically trying to serve 356 megawatts more peak load in winter is you're going to have to move first. The first thing we saw was the wind that we have allocated to Idaho gets, I guess, gobbled up by Washington. Washington has this higher load, and it wants as much clean energy as it can get to serve that higher load to meet CETA. That's the first thing we see. The secondary effect means Idaho gets left with a little bit less capacity from its wind, and it's got to build more natural gas. And then what Washington has to do now to meet that extra demand, that 356 megawatts of demand, it's saying I got to build solar 240 megawatts, I got to build more energy storage and I got to build more nuclear. Question, Fred, go ahead.

Fred Heutte: Hi, it's Fred here at Northwest Energy Coalition. A real quick question about the heat pumps in really cold weather, do you, is that I agree you know that's what the I've looked at some of the manufacturers spec sheets for that, but I'm wondering if you have any actual observational data, you know what's happening in your? You know, in your territory in those kinds of conditions like back in January.

James Gall: Yeah.

Fred Heutte: Just to hone in on what the actual effects are.

James Gall: Yeah, the best thing we have is the PNNL study. They did a study on heat pumps in the Spokane area and they had, I believe, 12 different sites. They monitored, I think, six or seven were in Spokane and few were located in other areas, and they calculated basically what the efficiencies of that technology was at different temperatures. And it's looking at the systems, not ductless systems. That's really the powerfulness of that study is if you're switching a gas customer, most 99% of the cases that have natural gas heating, they have a ducted system and they'd be replaced with a heat pump. That is what we used to calculate the efficiency rates at different temperatures. I have a link to that report, it's in the IRP document. There should be a footnote link to it, but it's also in one of the slides from a previous TAC meeting. But we can try to hunt that down and put it in the chat later.

Fred Heutte: Yeah. I appreciate. I do remember that now. Thanks for reminding us. The one only thing about that, and I don't want to get sidetracked on this, is there are a lot of ductless or mini splits. I've got one. And just to recognize that this is a real effect, but I think it needs a little bit more. It's going to be pretty important in the future with more of the gas to electric conversions happening. In that kind of demand surge, which we saw in January, is a very important factor for peak load management.

James Gall: Nathan Scott or I'm sorry, Nathan South, asked if the cost savings from deactivated or abandoned gas infrastructure is included in the electrification scenario. Yeah. I have a slide coming up on that, but the savings is mostly from the throughput of less natural gas, abandonment of natural gas systems is likely not to occur. And actually, what we're finding is due to the Adyl-a replacements, you're actually going to see further investments in the natural gas system for safety purposes. The only way you can abandon natural gas lines is if everybody on the system is gone off that line and on these high-level scenarios, we don't know exactly which part of our system you're going to turn off, but even if you're abandoning that line, you still have to recover the costs that the utility is stranding in that line. You just avoid future maintenance, so I would say the answer is no, but the impact of that is, is it say is minimal; potentially, but we'll cover what that is in about three or four slides from now. That's a good question. All right. Any other questions on this scenario? Just to finish it up from electric only point of view, about 12% higher rates. There's a secondary effect that can happen in these scenarios where you're basically adding more load to existing customers and that's you're going to have more feeders that are going to need to be upgraded or split up and that's an additional cost that comes to the system in addition to the generation that you need.

James Gall: OK. The next scenario, we took that higher building electrification then added onto it a higher electric transportation trajectory. We already have a pretty high electrification of transportation in our base case. But this takes it another level up where we have more and more customers adding EVs to the system. Effectively, this adds another 127 megawatts to winter peak and then 76 average megawatts of energy. Like the previous scenario, we have the shift of more wind to Washington, which puts Idaho into having to go get more gas. But you get the same results. Basically, building more solar, more energy storage and more nuclear to meet these higher loads. And then again, you have higher rates. In this case, the rates are actually a little bit less than the previous case because you're getting, I would say, your energy concentration is a little bit better, so you get a slightly higher rate. And what I mean by concentration is a load factor, so a little better in this case.

James Gall: The next scenario we looked at is taking the scenario we did with Washington, then adding that to Idaho. In this scenario, call it the highest load case possible, you take all of Washington and Idaho, and you make it the highest transportation electrification case possible. That adds around a million cars, I believe, equivalents by 2045. Then you have 80% of your Washington customers from today converting to electric on the gas system. In Idaho, it assumes 80% of future Idaho customers are now electric. And in Idaho, we have a little bit greater concentration of gas customers that are on our system. We assume about 90% of the lost gas customers stay on electric system, but what this results in is essentially, we assumed that you wouldn't be taking customers off the natural gas system and building gas turbines. We turned off the ability to burn new natural gas in this scenario and the result is we would have to build around 800 megawatts of additional solar to the PRS and almost 900 megawatts of energy storage. And then another 726 megawatts of nuclear. That'd be about 826 megawatts of nuclear. That's almost one of the largest plants that they just built down there in Georgia. So high loads essentially at the end of the day, implying that nuclear is the lowest cost option because it is the only clean option that can meet significant load growth out in the out years. I mean obviously energy storage, wind and solar are helpful, but nuclear is definitely the go to resource. Costs. This is where costs get a lot higher, mostly because of the nuclear energy. We're seeing Idaho's rates around 36% higher, Washington's about 25% higher, and in reality, the rates are about the same. It's slightly higher in Washington at the end of the day, because Washington's already is required to have higher rates when you get to the time from a reliability. This is a study we actually got it to do a reliability study with the level of nuclear and energy storage and solar. The system is still reliable. 0.1% LOLP, which is below our 5%, so theoretically we may need slightly less nuclear generators to meet this scenario's reliability target, but it definitely is possible with that amount of new generation.

James Gall: All right. To summarize, back to the question posed earlier, when you start putting together natural gas costs and the electric costs, that's what this slide is trying to accomplish. We have it broken up into different categories of costs. The first category is an estimated impact of converting gas customers to electric that are impacting other utilities, not just Avista. So, the 25%, customers that would be now on Inland would have their own cost to comply or to meet that new load growth. That's estimated in that first line. The second line is estimating the amount of conversion costs to convert that site to electric. This is on the low end of the costs. This is what we used in the previous natural gas IRP. We're finding a lot of examples where it's significantly higher cost to convert, but if you go back to our 2023 Gas IRP, those are the costs that we're using in this study. And then in the natural gas in Idaho and the natural gas in Washington, this is the revenue requirement for serving those customers that are remaining on the system and those do decline as you electrify more customers, but you still have the fixed costs that you're trying to recover. Now these costs are really only shown for 2043 to 2045 during the period of time where there's a higher saturation of natural gas customers. And then you have the cost for the electric system in Washington and Idaho. So, there's about a, I think it was around 25%

increase in costs for each specific state. Moving to this now, you do have some emission savings. Today we're around 3 million tons and then between the two systems, in this example, I should say today in 2026, because today we have Colstrip, but in 2026 it'd be around 3 million tons. And then we'd be down to between 1.2 million tons in the scenario #9. Actually, I think I have a typo in scenario #20, that should be closer to the 1.16, so we'll correct that. So, you're saving around 3 million tons from today, but only less than 1,000,000 tons. In sense compared to the PRS. I have a reported number of what this cost per ton of savings levelized and I'd like to say it's around $600 of cost per dollars per ton saved was around $600, if my memory serves correctly. And then here's some emission savings from greenhouse gas these three scenarios we have the base case, the PRS in black, and then blue, the Washington case, and then in nine, as Washington, Idaho in it. So, there's the total savings, I guess 828. Of the average cost for scenario #7. Think 600 for maybe scenario #9, but you know if you look at cost savings compared to say a social cost of carbon even in the outer years, you're around $200 a ton. So, this is not the greatest strategy for carbon reduction, at least from an economic point of view. The gas system heating homes is extremely efficient, especially in our area. All right. I'm going to move on to scenario 19.

James Gall: And unless there's any questions on those electrification scenarios. Yeah, we can always go back. And how we doing on time? Let's go another 10 minutes and we'll take a short break. Because catch my breath. All right, so scenario 19, we were asked to do a scenario where we used a warmer weather forecast in the winter. or those of you that have been following along, we chose to use these RCP scenarios for future weather. Basically, there are two sets of data that we have access to and are provided by Bonneville Power Administration that help us with our hydro data and our temperature data. RCP 8.5 assumes you have a greater amount of emissions in the future, which then lead to higher temperatures in the future, and there's RCP 4.5 which is less emissions in the future, leading to lower temperatures. In the future and the Preferred Resource Strategy or Expected Case scenario assumes the RCP 8.5 higher temperatures for the summer months and we use a lower temperature forecast, RCP 4.5 for winter. And just by judging the historical results over the last four years, compared to these forecasts, for temperatures that were all done pre-2020, we actually found, and I think we're going to have this in the document, but the RCP 8.5 is probably a closer projection to the summer months. Actually, I think actual temperatures in the summer are slightly higher. They're slightly warmer and then in the winter months, we're seeing temperatures have actually trended to be colder than these weather futures. We are starting to see definitely warmer summers and cooler winters. I think we're going to see that trend again this year based on some forecast I saw yesterday. At least for this next year, but in this scenario, we test if we have warmer winters, how much would that change our resource strategy? And at the end of the day, if you're planning for less winter need, you're going to have less resource need because the winter is really what's driving the capacity needs in this in this IRP. And what that ends up doing is it lowers the amount of natural gas for Idaho that's needed about 46 megawatts and also eliminates the biomass plant that we saw in 2045 at Kettle Falls. But it does increase the amount of energy storage needed and it does shift around some of the resources that were planned for each individual state. And then we did see a small increase in nuclear, a couple megawatts. But the change in the costs is pretty minimal. Point of view is I think you know it's minus 0.2% savings. But I think from a rates perspective, it's slightly higher if I remember correctly. But pretty minimal change for the RCP 8.5 while it's warmer. And temperature, we're not assuming those are what the temperatures are going to be in the future. It's a blend between history and the RCP 8.5 following our same methodology for calculating future weather in the future for peak planning, where instead of using the RCP 4.5 case. But at the end of the day, it does give us less resources in the wintertime. We're still working through the resource adequacy test on this one. We had a preliminary result, but we're not able to share that yet as we need to do some review of it. It'll be in the final report in a couple weeks, or I should say the draft report in a couple weeks.

James Gall: The last scenario on load, at least this type of load, is we combined that previous scenario where we did everything we could to increase load from electrification and then we assumed the warmer winter. In this case and the comparison for generation shown here is compared to that scenario #9 and basically we could get a little bit more wind on the system, less energy storage, less nuclear, a little more demand response. But again, I think it's the same story. It's just you need slightly less winter resources in that future, but again you have a similar rate impact as we saw before. It's just basically higher electric rates also because of its higher load and you're now using higher cost resources to meet that higher load, so not surprising. This scenario, #18 is probably the most useful scenario in this whole process. Honestly, because data centers are knocking on every utility’s door around the country trying to find a place they can build a data center. This is kind of, I'd say, a low case scenario for a future data center. We assume 200 megawatts in Washington by 2030. And what we're seeing from data centers is anywhere from this size up to 500 megawatts, the timeline that a lot of these data centers are looking for is what can you do in three years? What can you do in five years? But this is I'd say, a good illustration of the type of data centers we're hearing about coming to different utilities. Heather, go ahead.

Heather Moline (UTC): James, I'm multitasking. Did you say you know of data centers that are going to be added to Avista's load in their future, or just if that happens, this is what we're estimating.

James Gall: That's if this happens. There's no data center that's got an agreement to come to Avista at this time. So, if it happened. In the way we're going to describe the scenario, this is what it would look like. There's lots of alternatives that could happen as well. But this is one theoretical scenario put that way. Is that helpful?

Heather Moline (UTC): Yeah. Yeah, it is.

James Gall: OK. All right. The biggest issue we first saw when we were doing the scenario is what happens. So, I am going to back up, in our IRP world of planning, which is not always real, we allocate resources by a PT ratio and the model can pick resources for a specific state, OK. Reality is we don't do that. We just split resources up by state based on load. So, the big first issue that happens when you have a data center of this magnitude added to the system is the PT ratio would change if you had a large load, unless we had some agreement where it didn't. OK. The scenario assumes the PT ratio gets adjusted, so when you add 200 megawatts to Washington, more of the existing generation is allocated to Washington and less to Idaho.

James Gall: OK. So that's the first kind of lesson learned here. If you have a large data center coming on the system now, the same is true if it got built in Idaho. They'd get more generation, because the model assigns generation to states, when you have a large load in Washington, that creates a bigger hole for Idaho to fill. Even though in this scenario the data center is in Washington that's got to comply with CETA, the model says you got to go build more natural gas in Idaho because effectively, 35% of our portfolio is Idaho. It has to fill that gap, so that was the first lesson learned is if we get a data center in the future, should this be treated as a state load or should it be carved out? If it's carved out, what access does it have to existing resources and what new resources should be attributed to it? I think there's a gigantic ratemaking issue that's got to be addressed for the data center and that an IRP is not going to do it. It can be helpful to understand it, but it's definitely not the place to figure that out.

James Gall: OK, now we got over that. What does it do to our resource strategy? And I just lost my slides. So, there it goes. In the short run, because you get to meet this by 2030 it basically pushes a lot of our resource needs sooner, so the wind shows up sooner, demand response shows up sooner, power-to-gas projects show up sooner, but overall, we got to build more solar. We got to build more power-to-gas and then more nuclear. Basically, it just pushes everything up sooner and then adds more of the existing resource types. It's kind of interesting what it did in this scenario because it's a high load factor. The shift created a higher rate for Idaho and Washington's rates actually declined. A data center can be beneficial depending on the rate structure. Works with the cost allocation, but overall data centers because they have a high load factor. You're basically spreading more fixed costs of the system to them, so you could have a lower rate. I did another scenario just for fun because I like to do things for fun. What if you had 500 megawatts of data center? Well, that takes away some of the benefits you see here, because then the model has to get extremely creative. How would you serve 500 megawatts immediately with the constraints we have and essentially, it's basically maxing out every type of resource it can. Wind, max it out. Trying to build as much solar as it can and energy storage as it can. Right now, it's even saying we should build Kettle Falls Unit 2 now and then basically on the back end has to build a bunch of nuclear. And what the, I guess the concern, we're starting to see with these data centers, if we had one show up on our system is there's just a limited amount of low-cost resources that we see today. And if the data center gets those low-cost resources and they get cost allocated those resources. That's going to mean all of our non-data center customers in the future are going to get, they're going to now have to pay for more of a nuclear plant, or they're going to have to pay for transmission upgrades. So, I'd say rate structure is really, really important on if we bring in a data center. How do we handle rate structure? So I just wanted to get that across that if this happens, it is going to be quite the process to figure all this out, but it's definitely highlighting concerns when you're in a resource constrained environment. How to make sure that both customers with the data center or the non-data center customers are protected? We're going to be doing a resource accuracy assessment of the scenario. It's going to be done tomorrow, I believe. We'll see if it passes. I have some suspicion it's going to be a close one for 2030 with these sets of resources, but we may have to actually even acquire more capacity to meet this large load than what we have here. OK. Let's take a quick break and then we'll go through the remaining scenarios and then wrap things up at 11:00. We're going to be here till 11:30, so another hour. So, let's come back at what, 10:25? Does that sound good? Sure. OK, 10:25.

Break

James Gall: OK. We're going to get started back up again. Hopefully everybody got refreshed. I was able to get some more water so that was good. Lots of talking today, but now we're going to move on to resource availability scenarios sharing your screen I don't think. Unless it's me. OK, we have a screen. Problem is it moving, is it working now? No, not yet. Not yet, nothing. Oh, OK. All right. Sounds like we have a screen issue. I'll try to reshare. Hopefully you see resource availability now. Yes. OK. We're in good shape.

James Gall: OK. We're going to start with what's called a clean resource portfolio by 2045. This scenario assumes that we have no gas, or coal for that matter, resources in 2045. Basically, the portfolio lets our generators retire out or PPA contracts expire, then we would do likely an early retirement of Coyote Springs 2 in 2044. Essentially, the model is trying to serve both states, Washington and Idaho, with clean energy. This kind of aligns with the clean energy strategy the company has talked about over the last four or five years. And the strategies talked about, this is a goal of the company to be in this portfolio, but it's got to be cost effective to achieve and as we get to the costs, you'll see why. The strategy still contains natural gas and continuing to use Coyote as we do the cost. At the bottom. Now in this scenario, it's kind of similar because Idaho has a similar objective as Washington. You get a lot of resources that are, I'd say, more system resources, but it still assigns some resources to each state. But it does move things around quite a bit. So, when you go to look at say a table, you can see a lot of resources move around between states. Share the PRS, but at the end of the day, in order for this to happen in the short run, more wind is needed earlier. Basically, a movement up in wind and then higher energy efficiency targets because the energy efficiency avoided cost would be higher in this scenario, especially for Idaho. You would see more demand response and more energy storage for Idaho. And obviously less natural gas, so there'd be a significant change for the Idaho portion of the portfolio without natural gas in the future. And then in the long run in the outer years, again, nuclear is the main resource that meets this capacity need that's supported by the power-to-gas resources. We've been talking about the ammonia turbines. But because Coyote Springs 2, which we had assumed would be burning 30% hydrogen in 2045, it can't go to 100% hydrogen, so that unit would be retired. That's got to get replaced with something as well. We would have a limited amount of ammonia gas turbines, but in addition to that, the capacity is met by the nuclear which adds 384 megawatts to the 100 that we had. A little bit more wind at 130 megawatts more solar, or demand response. Like I said, more energy storage and energy efficiency, the power-to-gas losses, again, attributed to Coyote Springs 2. The costs are 55% higher for Idaho and then in Washington, they're about 17% higher because of lost resources that would have been allocated to Washington or not allocated to Idaho.

James Gall: Now we get to resource adequacy. We started to see some interesting things. One is in 2030, when we ran the loss of low probability model, it did not meet the 5% threshold, so we actually increased the planning margin and we haven't run that scenario yet to see if it complies with the 5%. But we saw early on without the gas CT and the other resource additions in 2030 we would have to have more capacity, but by 2045 the portfolio solving for the lower planning margin was reliable, likely due to the amount of nuclear energy on the system. Without some big base load capacity resource that we've seen later in the portfolio, that scenario is going to have reliability issues. Definitely an interesting result on this one.

James Gall: Let's move on to the next one. Unless there are any questions, no questions. OK, did my camera come back on? Yeah, you're showing. OK, good. All right, since we've been talking about nuclear quite a bit. We were going to run. Oh, go ahead, Nathan.

Nathan South: Hey, James, thanks for that. Was that the? No, natural gas slide. When I typed in the earlier question that you, you said we're going to get to that in a few slides. Was that the one or are you still coming up on a slide that shows the cost benefits of abandoning the gas resources?

James Gall: Oh. Yeah, that slide was this one right here.

Nathan South: OK. So, I guess my question with that latest slide is the LRP in my understanding stops at 2045, right?

James Gall: Yep.

Nathan South: So, you're not realizing, you're not accounting for any future infrastructure or operational savings of getting rid of gas beyond 2045, right?

James Gall: Correct. All of our resources are we call them levelized for the period in time to get around that issue.

Nathan South: OK. Got it. I guess it just appears to me. And again, I'm probably the most lay person in this group here, that it's kind of like the sum of all bad scenarios with that in that you're not realizing any of the future benefits of electrification of going to a single electricity model versus a combined electricity and gas model.

James Gall: I'd say no from the perspective that we model everything as a levelized cost. We're basically assigning the cost and the benefit at the same time. An example of that is the nuclear plant, where you know you're adding the cost of its share of that year that it occurs with the benefit of the emission savings of that year. If you continued it out further in time, you'll see that benefit. I guess that's why I try to show benefits of the specific year versus spread over time. Because if you look at that specific year, you're taking into account.

Nathan South: Got it.

James Gall: That cost of that resource of that year and then that emissions benefit. So if we you could take say 2045 to look at the cost difference and the emission difference and then that gives you your cost of carbon and that would imply for future periods as well.

Nathan South: OK. Thank you.

James Gall: But you know what you bring up is an issue, we modeled, say, 40 years, you can then get around this levelization and do things that's a little bit more accurate. But then where do you stop the same issue in 40 years?

Nathan South: Right, right.

James Gall: It just continues on forever.

Nathan South: Yep.

James Gall: So that's why we went to this levelization method. It's not perfect, but it's the best we can do unfortunately.

Nathan South: Understood. Thank you.

James Gall: Yep. OK, back to nuclear. We originally were going to do a test that looked at what cost is nuclear cost effective, and we did that. We were going to do that because there were always questions about why is nuclear not picked, it seems to be the best option out in the future and lo and behold, it got picked in our PRS. So, we thought, OK that scenario is not really relevant anymore, so we then went to let's just put in a large nuclear plant, and I should say that should be nuclear by 2040. Instead, 2045 and see how that impacts the model. And what we did is we added this nuclear plant early. The plant in the PRS showed up in 2045. This brings it in 2040, which I'd say, we could probably at the earliest build, 2035 is probably the earliest a nuclear plant could show up. Some may argue sooner, but the 10-year window is what we're seeing it as. But in this scenario, we did not retire any resources along with it. I guess in hindsight, maybe we could look at if you brought on 500 megawatts of nuclear, you could retire Coyote Springs 2. But we looked at it more as the resources you would avoid building in this scenario, rather than what you could retire from your existing fleet. The result was that avoids more natural gas resources for Idaho. And then for Washington, building a nuclear plant earlier has a big impact on meeting CETA because it reduces a significant amount of wind that would be added to the system. The solar that's in the back end, a lot of the energy storage in the back end, the Kettle Falls Unit 2 biomass facility is wiped out. It makes it a lot easier to meet CETA obligations with a gigantic clean energy base load plant for Washington. That rate increase is only around 9%, but for Idaho it's a significant increase. If we assume that nuclear was allocated to Washington or to Idaho, I guess if you ran a scenario where the nuclear plant was built and only assigned to Washington customers, and it is a pro rata share, say 300 megawatts to Washington. See, a nine percent increase in Idaho would be protected and continue on doing natural gas. But unless nuclear prices come down, we're going to see a significant rate shock for Idaho customers. From a reliability perspective, it basically solves a lot of our reliability challenges. I guess one thing to note here is our planning reserve margin. If you calculated it, it would be, I think by 2045 above our planning target cause Coyote Springs 2 is still on the system, but nuclear definitely, a large base load unit makes reliability a lot easier to manage in the out years. If cost comes down for nuclear or if the IRA tax incentives get extended out 20 years for this nuclear plant in the future, then maybe that rate increase is closer to zero for Washington and Idaho could be significantly reduced. But as you see the common theme I mentioned earlier, nuclear does solve a lot of issues out in the future when you're in a resource constrained environment. OK.

James Gall: Moving on. One thing that I'd say that the 2023 IRP spent a fair bit of time on because it was showing this resource, this power-to-gas or ammonia or hydrogen resource as cost effective, and we're one of the first ones that show that, and this continues to be cost effective. The one big difference that we did in this IRP versus the last IRP is we limited how much the model could pick of this resource because it wanted to build, I think, 800-900 megawatts of it in the last IRP and that definitely showed it's an attractive resource. That's one reason why we're seeing nuclear this time around, because we did limit this resource. And the reason why we limited it is it basically requires new supply chain of moving hydrogen around the Northwest. It requires storage of either hydrogen if you're going to use it for, say, Coyote Springs 2. Or requires a conversion to ammonia for burning in a CT. And so, we have to have a significant supply chain system built up. There are also significant energy losses of this technology. It's about a 20% round trip efficiency, so if you look at how much energy you got to build or have excess energy to create this fuel, you start to get massive amounts of capacity for renewables. That all may happen. Not saying it won't happen, but it seemed to be you don't want to put all of your future plans into one technology that's based upon this new infrastructure. I think a lot of it can be built. There are definitely groups out there trying to build hydrogen infrastructure, so it's probably going to happen. It's just a matter of how much of that infrastructure is going to be built. And how much of it can you rely on? So, we did a scenario here that basically let's say it didn't happen, and we didn't have power-to-gas as a future, we wanted to test that. What if you had a limited amount of power-to-gas? We kind of know what that looks like from the last IRP, but in this case, we would have a need for more for Idaho.

James Gall: We'll start with Idaho; it reduces the share of wind and increases the need for natural gas. So why is that? It's because Washington is going to need more of those wind resources that Idaho was allocated that are again, we have a limited amount of low-cost wind and if we need to, and if Washington is in a pressure point where it needs more of those resources to meet CETA then it's going to suck those up and take those away from Idaho. That's what's happening for the Idaho side of the service territory, for the Washington side of the service territory, it asked to replace almost 400 megawatts of power-to-gas. And it does that with energy storage, nuclear, and then a little bit of wind, solar and demand response. We're replacing 400 megawatts of capacity and it's about a similar capacity total between the energy storage and nuclear. It's a long duration storage, most likely being picked there, but from a rates perspective, going back to that 2045 future point in time. Washington rates around 11% higher. Idaho is around 4% higher and from a reliability perspective, we're still around that 4% threshold. So, it's a little bit higher than I believe our PRS was, it was around 3.6%, but still definitely a reliable future without this technology. But that's mostly due to relying more on nuclear.

James Gall: As I project out in the future, we're really going to go down to pass or both paths. In the future to meet future load needs with CETA is we got to be paying attention to nuclear technology. We got to be following power-to-gas technology and long duration storage. It's those three technologies are really going to be, one of those or all of those are going to be in the future. And if you look at past Northwest build outs, there's always a run to a certain technology in a period of time. In the 1980s, it was coal, and in the early 2000s it was a rush to natural gas. And then we had the rush to wind. It feels like we were in a rush right now, maybe to solar. And then definitely a rush to the lithium-ion batteries in California. What's that next rush going to be? Is it going to be one of those three technologies in the 2030s. So, we wanted to test what each of those do to our portfolio because we don't know exactly what will happen, but we'll wait and see.

James Gall: See that comment from Fred Hewitt in regards to your last scenario and he said the problem with the 500 MW nuclear even assuming optimistic cost projections is forced outage or single shaft risk. Good point. On the shaft risk if, yeah, if we had a Vogtle unit two or three on a system our size that is definitely a risk. Now if we have small modular reactors, those hundred MW sized units that actually would probably lower our shaft risk. Say, for example, Coyote 2 is at 300 megawatts. Now we have 100 MW shaft risk, so that is I guess a benefit. We'll see where that technology goes. If the SMRs can get built then that's good potential option for us. And if not, then if we have a Vogtle style unit, we're going to have to spread that shaft risk, hopefully with our neighboring utilities, that they're also willing to go nuclear and I'd say nothing in this IRP says we're going to go build a nuclear plant, but it's just illustrating that's the type of technology that's needed to meet some of these goals with the load projections we have. OK.

James Gall: Next one's on transmission and this goes back to the last TAC meeting where we talked about the Grid United transmission line that goes from Colstrip to North Dakota. And we talked about we assumed a 300 MW share of that transmission line in the PRS that starts in 2032. And what we're trying to do in this scenario is understand if that path was not built, what would that do to our resource choices. How would it change? Because 2032 is really from an IRP perspective, not that far away. We are not testing the cost or the change in cost because of a couple reasons. One is, at the time we're doing all this analysis, we didn't have the benefit side of the transmission lines arbitrage between markets. So, we're missing a big component of the cost benefit analysis. We'll do that separately if we decide to move forward with this line. We'll have a cost benefit analysis. And two, when we did the initial study, we found it to be cost effective on a capacity basis alone, but it was spread out over time and that didn't make rational sense. We put it all into the one year in 2032 when the line would be built. Again, we're testing here for what's the resource change, not for cost, as that will come later. What does the model do without this line is the question. First thing it does is basically replacing capacity so that for that line, the benefit of the line to the PRS, is it provides basically a clean resource capacity benefit. And now it's got to go build something on the generation side to replace that in this assumption of the portfolio. For Idaho, it's building more gas, more energy storage, and it's also reallocating some wind to Washington. Then on top of that, for Washington, we have to have more energy storage, a little bit more nuclear, little bit more solar, a little bit less demand response, surprisingly. But basically, it's use what we have today as options, but do a little bit more. From a cost benefit in the future, if we make a decision on this plan, it would also likely be a benefit to customers. That's a lost opportunity, but again from a total portfolio perspective, it's not a big impact, but it does require some changes. Especially in the 2030 time period, if we don't have that line. OK.

James Gall: The next one that we're looking at, and we're getting to the end of these, hopefully no one is asleep, but there are no IRA tax incentives. This study really came about because we were seeing a lot of wind built early in the portfolio before need.

Basically, the PRS is saying we don't have a need for wind from a CETA perspective, but it's being picked from a cost-effective point of view, because you have this tax incentive that's pushing it earlier. And you have high market prices compared to the price of wind. I want to test if we didn't have the high-rate tax credits or they got repealed in a future administration, would that change our portfolio, would we get a different answer? We assumed the IRA benefits of just the wind and solar and nuclear resources, not the energy efficiency side of the equation, but the generation side, the PTC and the other tax credits went away. What would happen and what we did see is actually less wind being picked, about 357 megawatts less wind overall and it's actually moving some of that wind that was allocated to Idaho over to Washington to replace that wind that it was reducing. The model is allocating wind to Idaho because it's cost effective compared to the market price because of the PTC and high prices. But without that IRA, it's saying, well, Washington's got to go get a bunch of wind anyway, so I'm going to basically go get what Idaho didn't get, but then in total, it also is saying we would need more energy storage. Kettle Falls Unit 2 would go away, which actually the PTC doesn't impact on that period, but it's an interesting result. And then a little bit more solar and demand response. One of the interesting things though is how it affects rates and the model at least for Washington, no matter if there's a PTC or not with the IRA, Washington still has to be 100% clean by 2045 because of CETA. But what it does is it shifts some of the costs from Washington ratepayers to the federal tax base. So, in the case without the IRA, Washington customers have to pay for those costs. Real costs rather than shifting it to the federal government. That's about 2.7% higher in 2045, the IRA being around is more of a benefit for Washington than Idaho. Because you're able to save money by basically having a different set of customers pay for the portion of your costs.

James Gall: Alright, so let's go to number 23. This is actually I'd say, in the top 5 portfolios as far as risks to our system. The other top five ones coming up next, but the on-system wind limitation. So, we had in our model around 500 megawatts of wind that could be added to our system without major transmission build outs. And what happens if, let's say a data center or another utility in the Northwest acquires a wind facility that's in our BA. We have a balancing area or balancing authority that manages the generation on the transmission system in our area and we have, if you look at our transmission queue, there's a lot of wind and lot of solar and batteries that are in that queue and they are applying to connect to our system. And if they are built and they connect to our system, that generation could serve Avista's load, or it could serve another utility’s load. Or it could be sold on the open market. Who knows what will happen to it? So, what we're assuming in this scenario is that some of that 500 megawatts that we think is easy to connect based on that cluster study gets taken off system and when that gets off system that leaves less generation available to Avista's customers at a low cost. The scenario basically limits that low cost when the 200 megawatts and what we want to see is what does that do to our portfolio and what it does is quite shockingly, or not shockingly or not surprising, is we're going to have less wind on our system and because it's just not economic anymore. Because a lot of that wind, especially built early in our system, is driven by an economic acquisition rather than need. Now it does end up stealing more from Idaho. Call it stealing, but it does have to shift more of that wind to Idaho because it's a limited amount. Actually, I am just now looking at it. I did not change this. Pull it on the 3rd, so I'm going to have to punt on this one for what other resource changes were made. But I believe it is mostly just the loss of wind. This bullet here is same as the previous one. I did not update it, so I'm going to have to update that one. But on the cost side. Oops, let me go back to here. I believe these cost ones are accurate, Idaho would have slightly higher rates and then Washington would have 3.3% higher rates without that low-cost wind. But I'm going to have to update that bullet there.

James Gall: OK, so going on to the next one, we have two scenarios we ran around the Northeast CT. The Northeast CT is a natural gas turbine built in 1978 that is located in the north side of Spokane. It's around 66 megawatts in the winter. I think in the 40s for summer capability, it's limited to 50 run hours a year and its general purpose is an emergency generator for our system to provide non-spinning reserves and it's obviously at the end of its life. It's just a matter of what retirement date do we want to assign to this resource in the IRP. This IRP assumed 2030, the previous IRP assumed 2035. And we want to test in this plan different years when this unit could basically retire. What if we retired it now? What if we left it in 2030? What if we retired in 2035? This project doesn't have any book value to it anymore. It's fully depreciated. It is definitely able to, as long as we can get parts if something breaks on it, it can continue to be a fully operational facility. But it does have limitations on how much it can run really due to emissions, and it does not have the NOx control of say a modern gas plant would have due to its age. That's why it's limited in its number of hours it can operate.

James Gall: If we lost this resource today, we decided we're going to retire today, what would happen? We would have to replace it with energy storage. Around 79 megawatts and we would be then looking at adding some wind earlier. One thing that's interesting it does from the Idaho side is that because you need the resource early, there's not enough time to build a gas unit elsewhere on the system to replace it. The model actually picks less natural gas, and it takes on some of that 79 megawatts of energy storage. It does build a little bit more gas later, but overall, it builds less gas if we retired Northeast today. It also gets allocated a little bit more wind. For Washington, we have less wind and less energy storage, but we do have to pick more nuclear in the long run, but I think the story here is that if we lost the unit today, we're going to have to go to energy storage to replace it now, even if we retire in 2030. When we go through the RFP process, there's a good chance that energy storage could be the lowest cost, or it could be a gas turbine in Idaho. I don't know what the ultimate decision will be because we haven't done the RFP yet, but it definitely is a viable option. For us, cost impact of retiring the plant early is about a 1% rate impact for Idaho in 2030. Washington really didn't see an impact, but long run they're slightly higher rates for both states retiring earlier compared to 2030.

James Gall: Shifting if it retired in 2035. We would see a little bit different scenario. You're basically extending the life of this resource and that would defer the need for the 90 MW gas plant for Idaho in 2030. Instead, you still need some capacity and that moves over to energy storage, but in total, once Northeast does retire, you'd have to replace it with something. And so, it does build a little bit of gas, but not as much as the PRS from a cost perspective. There's no rate impact until after the resource is retired, but at the end of the day, Idaho's rates would be about 0.7% higher. Going to retire later, it's kind of an interesting thing, no matter what. If you retired early or later, rates are higher in 2045 than the PRS, so looks like 2030 is kind of a sweet spot from a rate perspective. Although I think the PVRR is lower on your entire in 2035, but no decision has been made yet on the timing of the resource. More to come, I guess in time.

James Gall: OK, so I got a few more scenarios to go through. We got 30 minutes. OK, so I think we're going to make it at least through the remaining scenarios. I don't know if we're going to get to the summary information, but that's going to be high level anyway. I guess this is a good reason why next IRP we should do less scenarios. It's just a bug in your ear and we should probably maybe limit to maybe 10 but this is where we're at today. This scenario is the maximum Washington customer benefit scenario. This is required by Washington rule for IRPs. And although I'd say the rule is kind of kind of on specific requirements, but the I think the intent of this is we have these Customer Benefit Indicators that we track in the CEIP process. The idea is how can we improve those CBIs simultaneously, if possible, to a maximum capability. So, what is the theoretical maximum we could do? You can't maximize everything because for example, if you increased, we'll call it DER solar, that would have a rate increase and that would cause a CBI of energy burden to also increase. There's got to be some. I guess negotiation between each of the CBIs. We put together this list of assumptions on how this would work. I'm going to go through that and then going to go through some of the results. The first thing we assumed is there would be an increase in DER solar and energy storage. And what this would do essentially is this would be more like community solar. An increase in that benefit, will call of that solar, would go to low-income customers to help with energy burden. So, it helps that energy burden CBI. It also helps with the CBI regarding increasing DER solar and storage as well. I'd say this is an arbitrary value to some extent.

James Gall: The second one is no air emitting resources. In Washington, we have a CBI that tracks NOx emissions and NOx emissions are a result of burning ammonia. If we didn't have an ammonia plant, we would have less NOx also for biomass plants like our Kettle Falls facility, there are air emissions that are either NOx or SO2. So, you would be removing any new emissions of those facilities. We have CBIs regarding having more local resources and this next one basically prohibits anything outside of the state. We did allow the 200 megawatts of Montana wind because it ties together with that transmission line into the east, but the model was only allowed to build that 200 MW share of Montana wind, but nothing else that was really off of our system. We also increase the energy efficiency credit requirement that's 10% for the Power Act to increase that to 20% to have the model acquire more energy efficiency than it would otherwise. I believe the last time we looked at this, we just let it pick all energy efficiency that was available. We tried to cap that a little bit in this scenario to adding just another 10% adder and then for those of you that have been following our process, the DPAG (the distribution planning process similar to this TAC), they hired a consultant to help them estimate how much solar and EVs would be on our system in the future. And that study resulted in two forecasts. One is an expected case, and the second one is that Named Communities, low-income communities or disadvantaged communities. However, you want to count them. We ran a scenario to show what if they had similar solar adoption of adoption as other areas? We got a high case of solar and EV. So that's included in the study. And then lastly, like I mentioned, the transmission line to the East is included. What does this do to our results? Well, obviously you're doing more purposely energy storage and solar. That's going to show up. But because you're losing the power-to-gas and the biomass, you got to replace that with something. It's pushing more towards storage, nuclear, demand response and a little bit more energy efficiency. That's what you're getting compared to the PRS in this scenario, what you're losing is you are losing a little bit of wind. Obviously, the biomass, geothermal, those improve the CBI. If you remove them because you're using either less air emitting resources or more on system resources, geothermal is likely to be off of our system. And then obviously power-to-gas, that's another air emitting resource. So, there's a cost impact to this and that's about a 13% rate increase for Washington in 2045 to have this portfolio look this way versus that preferred case.

James Gall: And then I have this chart here that shows the how the maximum customer benefit scenario compares to the PRS for 2045 for each of the CBIs. I'm not going to go through all these, but the intent was to show an improvement, or a modest improvement, to everything that's on this list that was possible from the CBI. Could one of them be way better? Yes, but that would likely have an impact on another one. So, I thought it was a good way to thread the needle on trying to improve all of the CBIs to some extent to comply with this portfolio requirement. OK.

James Gall: I got a few more to go through. We're going to now shift to resource adequacy scenarios. The 17% planning margin scenario was trying to replicate what a future WRAP world may be. In this case, what I mean by WRAP is that we all, as a region, plan together to have lower planning margins so we can build less resources. Essentially what this portfolio does is it builds less wintertime resources. Very similar actually to the scenario where we had the RCP 8.5 scenario that had less winter capacity as well. Again, obviously it's going to pick less capacity resources, less natural gas, less energy storage. No surprise there. We also see lower rates. You're building less capacity. You're going to have lower rates. The thing that concentrated in really is the resource adequacy assessment. It is higher than it would have been at 24%, but it's still meeting the threshold. We're going to be looking into this a little bit more on why are we still at 5%. That's good news if we're able to have a 5% LOLP with 17%, that's good news. We can potentially lower our planning threshold. Although what's curious is this is because the model is building resources early to comply with 2030. And we actually have a higher than, or we have a closer PRM to 24%. That's probably what's happening in 2030. But by 2045, is our portfolio because we have so much nuclear. Maybe or power-to-gas. Is it still complying with a lower PRM? So, we look into this a little bit more because it could definitely mean that we have too much, or I say too little capacity credit, for certain resources is maybe one way of looking at this. But the one challenge we have is the capacity value of a particular resource is really impacted on what other resources are picked. So, if you have a lot of base load generation that allows, say, a storage project or maybe a wind project, an improved ELCC as if we didn't have that other resource there. This is going to have to be a little bit of an iterative process on what's the appropriate PRM. This is to show in 2045 if there's maybe an opportunity to lower it.

James Gall: But some may argue that 5% LOLP is too high. We've actually done this other scenario where we increase the PRM to try to get the model to have near zero LOLP as possible. We got pretty close in 2045. We're at 0.008, so that's just under 1% LOLP. Guess we need a higher PRM to get to zero, but the intent was what if we had a system that had basically zero risk of resource adequacy issues. So, we moved it up to 30%. We were going to have to acquire more wind in this scenario in the short run. More energy storage as well. We were about 1.6% in this case, and then Idaho would be a little bit more gas, a little more energy storage, but in the long run it's adding basically energy storage. Energy storage seems to be the best way to push this up to

30% if loads aren't growing and we're just trying to get more resource adequacy, more energy storage seems to be the solution. That leads to slightly higher rates about 1.4% in 2030. For Washington 1.7% in 2045, 2% higher rates for both states. And that gets you closer to a 0% loss of load probability. I guess there's an economic question, is the probability of less outages worth 2%? And I'm not going to decide that, but it makes you think about is that appropriate? I think if you looked at years past, maybe that extra resource adequacy might have been worth it. Cost more than 2%. We're looking at around 2% or less and maybe there is some argument that. Higher or lower LOLP target is what we should be looking at.

James Gall: My last scenario is related to the election in Washington State and in Washington State, the Climate Commitment Act is on the ballot to be repealed. I don't know what's going to happen there, but we wanted to run a scenario that looked at what would happen if the CCA was repealed. So, what the resource changes would be? The costs are another challenge, I'll get to that reason why in a little bit. But in order to do this, we had to create a new price forecast that has the CCA gone. The CCA basically inflated wholesale prices in the Northwest and without the CCA, we'd see prices fall. If you're a seller with clean energy, higher prices are good. And if you're not, if you're a buyer, higher prices are bad. That's why I say the cost is a little bit more of a challenge because there's a lot of complexities to that market that is created in Washington, but the focus here is on the resource strategy. Near term, what it did actually is quite interesting, it pushes back wind a little bit because there's not as much profit potential for the first wind acquisition and then it reduced the CT in Idaho, and we shifted generation resources around. In Washington, it actually increased solar slightly; energy storage, slightly; nuclear slightly. It removed the biomass facility. It no longer became cost effective. And then demand response increased. Basically, it had to fill the biomass, swap with nuclear and energy storage. It moved resources around; the CCA; from a Washington perspective, is not really the driver of resources. That was not a surprise, that little bit of a shift. The challenge will be in the future. Let's say the CCA is repealed versus looking at the PRS. Now, you basically have a lower price forecast. So, when we go out to RFP wind resources, we may have thought would be cost effective may not be cost effective. That would defer its decision. We'll wait until November to see what happens. Then the question is would we create a new PRS? If the CCA is repealed, I don't know if we've made that decision yet, and I don't think this scenario is, we're not using it. We call it stochastic case for it. So, we'd have to evaluate. Should we be doing additional work to recreate this Preferred Resource Strategy on the same rigor as our other studies? Do we leave it as is based on the portfolio really not changing materially? But it's something we're going to have to ask ourselves if that happens in November before we file the document in January. Love feedback on if that happens. Maybe we get back together at the TAC. I don't know yet, but we'll wait and see what happens.

James Gall: Last thing I have is, and we have about 15 minutes, we're going to explain what's in these slides and not going to go into depth on them. This is really for you to look at later, and if you have questions on them, we can definitely answer those. But this slide is intended to look at the rates and PVRR for each state and how this works is on the PVRR. The first three columns, that shows what the present value revenue requirement is for each of the state’s portfolios. The little graphic on the arrow up or down is trying to measure how it compares to the PRS. The rate side is on the right where we have the 2030 average rate and the 2045 for both states. For all 20, only 25 portfolios are shown here the CCA the no CCA portfolio runs off of a different market price forecast and it would not be comparable. That's why it's excluded on here.

James Gall: This next one is basically a graphical representation of this table here for those of you that like charts to see the lowest rate versus what's the highest rate in rank order. And they're ranked by 2045 rank. Rates for Washington and then we have Idaho here as well. And then this chart is focusing on comparing levelized cost to risk and what we define by risk here is tail var. We did a calculation of the tail var for each of the portfolios based on the 300 simulations we did, and we can measure, OK, what resources have less risk compared to cost. For those of you been following Avista’s RPS for a long time, we used to do what's called an efficient frontier. And this kind of gets you that idea of measuring cost versus risk because you can see there's some scenarios that have definitely more cost but a lot less risk. For example, on portfolio 4 on the bottom, the clean resource portfolio, there's significantly less risk than the PRS in 2045, but it has a slightly higher cost. So, it helps you measure your trade-offs between what you give up for lowering risk. That's what that one is. And then for those of you that like PVRR comparisons, this is a rank order PVRR. And this one is basically the same data as you saw on the first table and then we created this. This one it's PVRR, but it adds risk to it. So, you have a rank order, a PVRR with risk for those of you that are interested in that type of analysis. The next one is on emissions. If you want to know how the emissions are changing. This shows the reduction of emissions from 2045 versus 2026 where all portfolios have reductions in electric emissions with the exception of the baseline portfolio, which has slightly higher emissions. And then for those of you who want to compare emissions to cost, his graphic breaks down the change in emissions versus the change in carbon emissions cost for all the portfolios.

James Gall: And then to wrap things up, we did stress test a few portfolios with high and low natural gas prices to see their impacts to the portfolio. How this works, is on the first line Preferred Resource Strategy, we'd look at if you had higher gas prices or lower gas prices, how would cost change? Compared to our expected case, obviously if you have higher gas prices, this is showing that we're going to have higher costs to serve our load under the Preferred Resource Strategy and lower cost low gas prices. But this shows in relation to some of the other portfolios where the baseline portfolio that was heavy on building natural gas, you can see the PRS is less sensitive to natural gas pricing. That's not a surprise. And then if you had the clean resource portfolio, you become even less sensitive. The natural gas prices, especially for the Idaho side of the service territory because you have less gas. And then we threw in the nuclear scenario as well in here to illustrate the same thing. I think this is a requirement I believe in the State of Idaho that we look at this analysis. But we want to choose the portfolios that made the most sense, that had more or less natural gas in it. Then we did similar analysis with the greenhouse gas emissions, and this basically shows the change in total emissions. Over the 20 years, if you have differences in gas prices, so we have higher gas prices, our existing natural gas fleets are going to run less, and we'll have less emissions. And if you have low gas prices in the future, we will have more emissions from the gas plants. They will be more in the money, and they will be more cost effective to run. So, that's available there.

James Gall: That's my last slide. I'm actually shocked I was able to get through them all with keeping my voice, but what's coming next like John mentioned? At the end of the month, we're going to release the full version of the IRP draft with the missing chapters mostly from the scenarios. The market price forecast and the introductions. We're going to add the table Molly requested on the PRS. We'll have the data for each of the PRiSM studies. We'll have a summary of all the portfolios available as well, following John's slides that he mentioned earlier. I just want to pause there if there's any questions that we have before we call it a day. No questions yet, unless something pops up shortly. OK, absent any reason to get back together for maybe the CCA discussion, this will be our last TAC meeting. We do have the public meeting you're definitely invited to come to in November. I believe there will be meetings on the IRP by both commissions at some point in time. I don't think those have been scheduled yet to review the IRPs, but absent any questions, I'll keep rambling in case something comes up. But I just want to thank everybody for hanging in there with us through this last year and a half. We appreciate the questions that are asked. Definitely the interest in Avista and in its resource future. Because we did not come up with all this stuff on our own, we do rely on other people like yourselves to help us refine what the study helps us find good data sources because we're all kind of working through this together and appreciate involvement. Also, the changes in how we've done TACs, we hope that the shorter meetings that are more frequent have been helpful. They're definitely a lot more work on our side. We're going to be thinking about how we keep short meetings in the future, but also be able to keep up with the quantity of work at the pace we have for the next IRP. We may be reaching out to a few of you to help us navigate what the 2027 IRP looks like. That is fast approaching.

James Gall: Any questions or comments? Thank you. Alright, we still have people awake. That's a good sign. Again, thank you, if you have questions, please reach out to us through the Teams site or e-mail. The public process I know will be beginning in each state, so we look forward to reading people's opinions and comments on the IRP and again the IRP is really a stage that's set for an RFP for resource acquisition where it meets the road. I guess you could say when we go to actually meet, require resources, and then the CEIP process for Washington will be kicking off in January for the 2026 through 2029 time period. We'll see what remains of this IRP that makes it into that plan. I think I rambled enough. There's no questions yet. So again, thank you and hopefully we'll have a draft out for you guys to read soon.

James Gall: stopped transcription