2024 Resource Program

Public Workshop

June 10th 2024

Current and Prior Workshops

- June 2024
  - Needs Assessment and Market Assessment study results
- April 2024
  - Needs Assessment data inputs and methods
- November 2023
  - Data, methods, and results of forecasting for BPA obligations and regional TRL;
  - Needs Assessment overview
- June 2023
  - Overview of planned scope and key expected innovations for 2024 Resource Program;
  - Relationship between 2024 Resource Program, Provider of Choice, 2026 Resource Program, and resource acquisition

Agenda

Start	End	Time	Topic	Presenter/Facilitator
9:00 AM	9:05 AM	5	Workshop Agenda and Format	Brian Dombeck
9:05 AM	9:10 AM	5	Introductory Remarks	Dave Moody
9:10 AM	10:25 AM	75	RP24 Needs Assessment Results	Esther Neuls
10:25 AM	10:40 AM	15	BREAK	
10:40 AM	11:55 AM	75	RP24 Market Assessment Results	Eric Graessley
11:55 AM	12:00 PM	5	Wrap up and Conclude	Brian Dombeck
12:00 PM			Conclusion	
Total		**180**		

Reminder: Power Planning at BPA

- Each year, BPA publishes the Pacific Northwest Loads and Resources Study – often referred to as the **White Book** - which analyzes BPA's projections of retail loads, contract obligations, contract purchases, and resource capabilities over a 10-year study horizon and <u>describes expected energy and capacity surplus/deficits</u> under varying water conditions.

- On a biennial basis, BPA conducts an IRP-like assessment collectively referred to as the **Resource Program** which examines uncertainty in loads, water supply, natural gas prices, and electricity market prices to <u>develop least-cost portfolios of resources</u> that meet BPA's obligations.

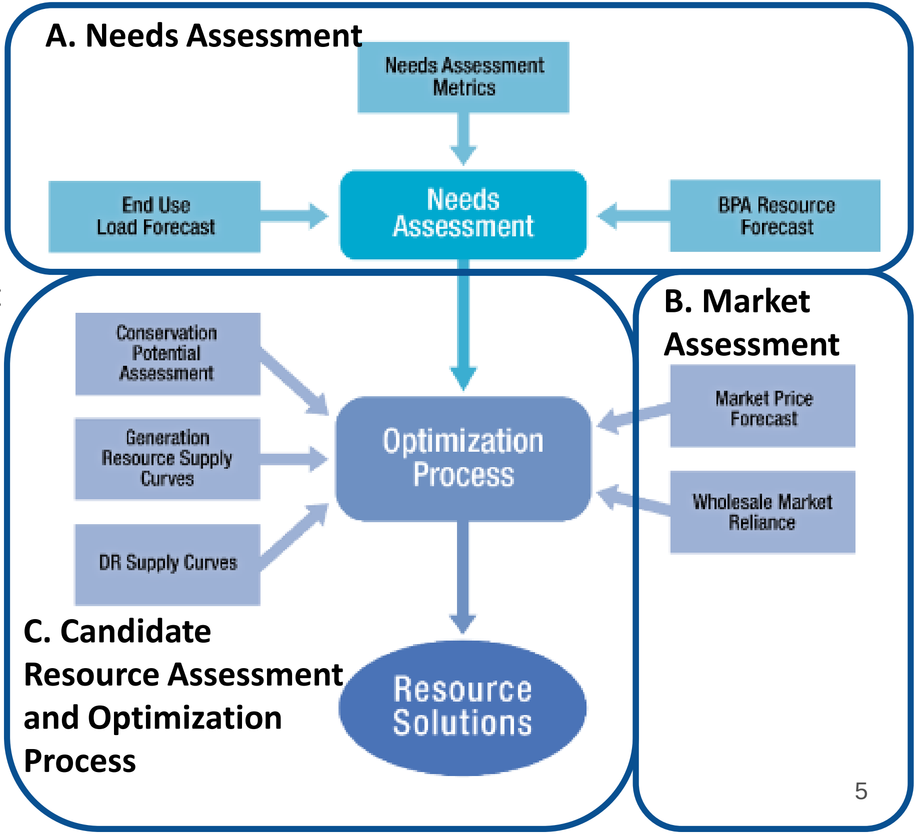
- These processes are voluntarily undertaken to inform acquisition strategies and provide valuable insight into how Bonneville can meet its obligations cost-effectively. They are neither decision documents nor a process required by any external entity.

Resource Program Process

A. The **Needs Assessment** measures the federal system's expected generating resource capabilities to meet projected load obligations

B. The **Market Assessment** simulates the evolution of power markets in the Western Interconnect to generate a long-term forecast of Mid-Columbia prices and market availability under a variety of generation, load, and economic conditions

C. The **Candidate Resource Assessment and Optimization Process** explores how the varying costs, performance, and availability of candidate demand-and-supply-side resources (including conservation, demand response, market purchases, and generating resources) as well as wholesale market reliance can be used to provide a least-cost resource strategy for meeting identified needs

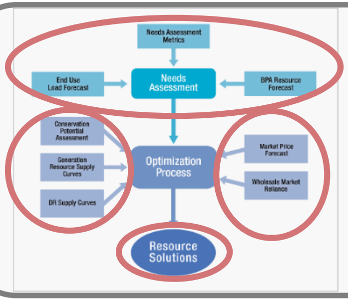


Planning Framework

Scenarios

Scenarios are comprised of a set of inputs that are consistently developed for a future outlook

Base – Business as usual scenario; load forecast beyond the current Regional Dialogue contracts (post 2028) assume no material contract election or rate structure differences from Regional Dialogue.



Fast Transition - high economic growth, accelerated decarbonization relative to Base scenario

Sensitivities

Changes to individual input assumptions (or smaller subsets of input assumptions) within a given scenario

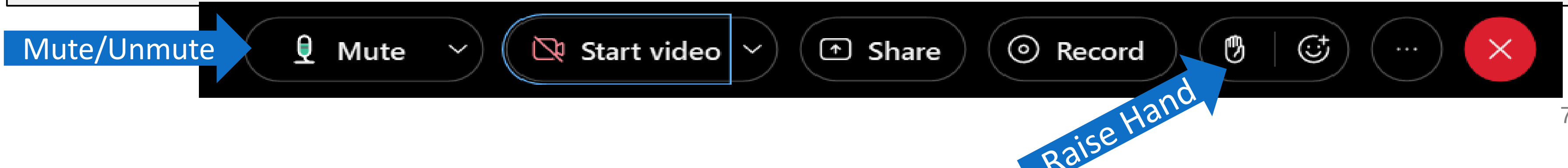
- Provide BPA decision-makers with additional options to address key strategic interests (PoC / Carbon Vision, etc)
- Evaluate solution sensitivity to specific assumptions
- Assess solution robustness

Format

- Presenters will communicate their preference for taking questions, which will be addressed in the order received
- Webex participants can adjust magnification of shared screen using (-/+) buttons
- If a question/opportunity for feedback arises during a presentation, please:
  - In-person: Raise your hand
  - Webex: Write it in the Webex Q&A *or* use the Webex "raise hand" feature; when called on, mute/unmute yourself.
  - Both: State your name and organization

Note: The "Chat" feature in Webex has been disabled for this meeting. Please raise your hand or type questions in the "Q&A" box and it will be reviewed by facilitators.

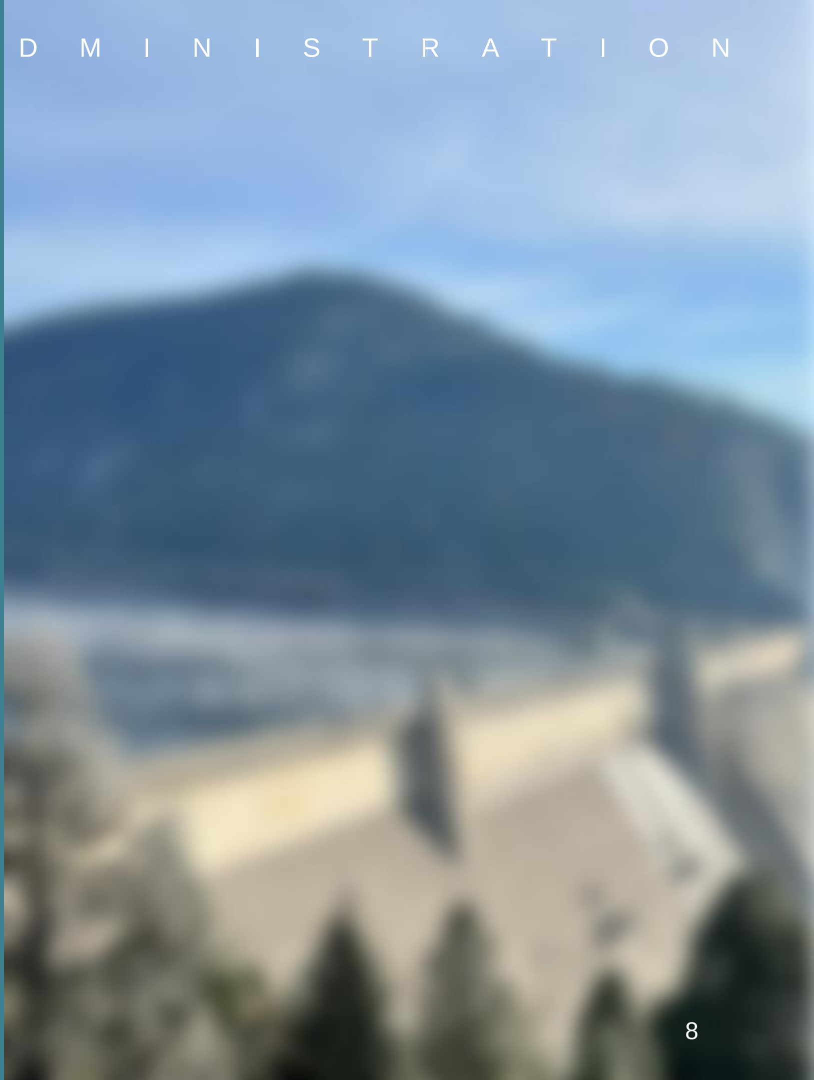
Webex:



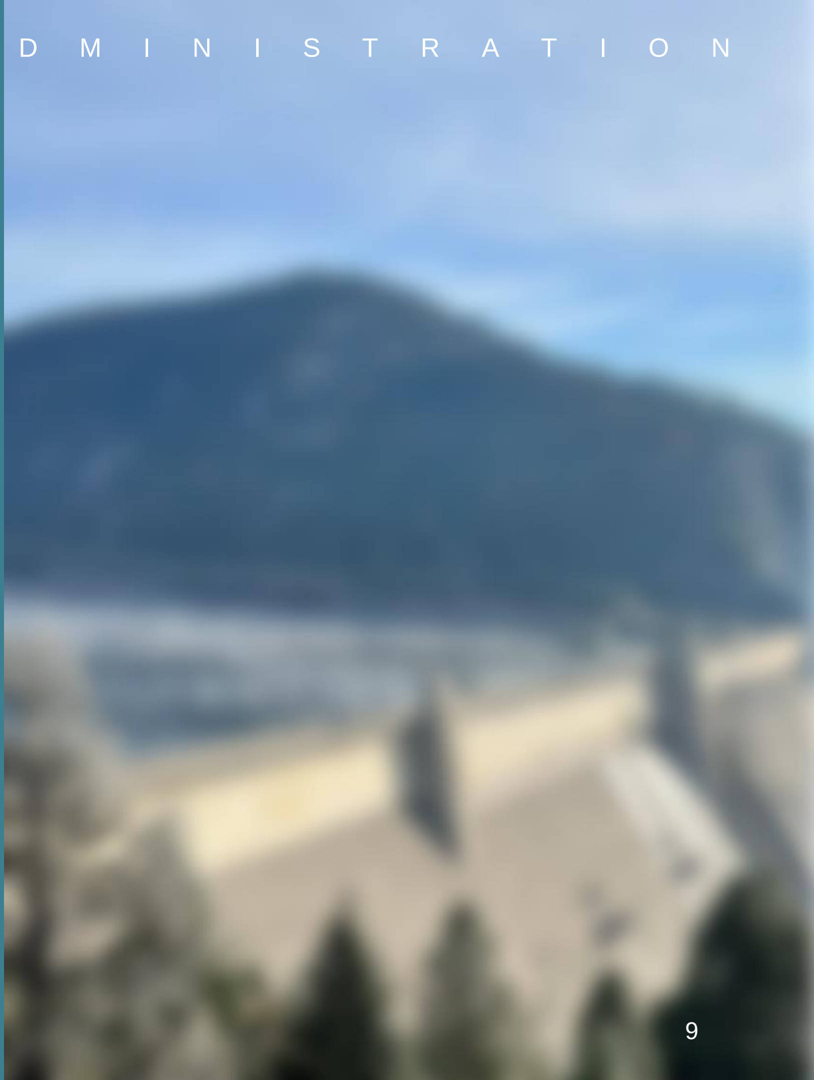
Introductory Remarks

Dave Moody

Deputy VP for Energy Efficiency



RP24 Needs Assessment Results



Esther Neuls

Needs Assessment Study Lead

Needs Assessment Overview

Objective

- To understand expected long-term inventory position of BPA Power services under varying load and resource conditions

Methods

- Compare hourly forecasts of BPA power service obligations and resource capabilities to develop set of metrics which describe expected future needs

Needs Assessment Metrics

- Annual Energy
  - Evaluates the annual average energy surplus/deficit under p10-by-month critical water conditions
- P10 Heavy Load Hour (HLH)
  - Evaluates the monthly average surplus/deficit over heavy load hours (hours ending 7-22, Mon – Sat, excluding holidays) under p10-by-month critical water conditions
- P10 Superpeak (SPK)
  - Evaluates the monthly average surplus/deficit over the six peak HLH per weekday (Mon – Fri) under p10-by-month critical water conditions
  - The ~120 superpeak hours per month are a subset of the ~384 heavy load hours month
- 18-Hour Capacity
  - Evaluates the monthly average surplus/deficit over six peak load hours per day across three-day extreme weather load events under median water (p50) conditions
    - Cold Snap – temperatures from January 2024 event for Dec/Jan/Feb
    - Heatwave – temperatures from June 2021 event for July/August

Major Updates for RP24

- Conduct separate analysis in MidC and SWEDE zones
- Incorporate impacts to generation from variation in fish operations by modeling return to CRSO preferred alternative after expiration of RCBA ("12/14 Agreement")
- Streamflows informed by climate change through both recent historical record (2020 Level Modified Flows) and RMJOC-II projections
- Updated modeling of hourly hydro generation (RiverWare)

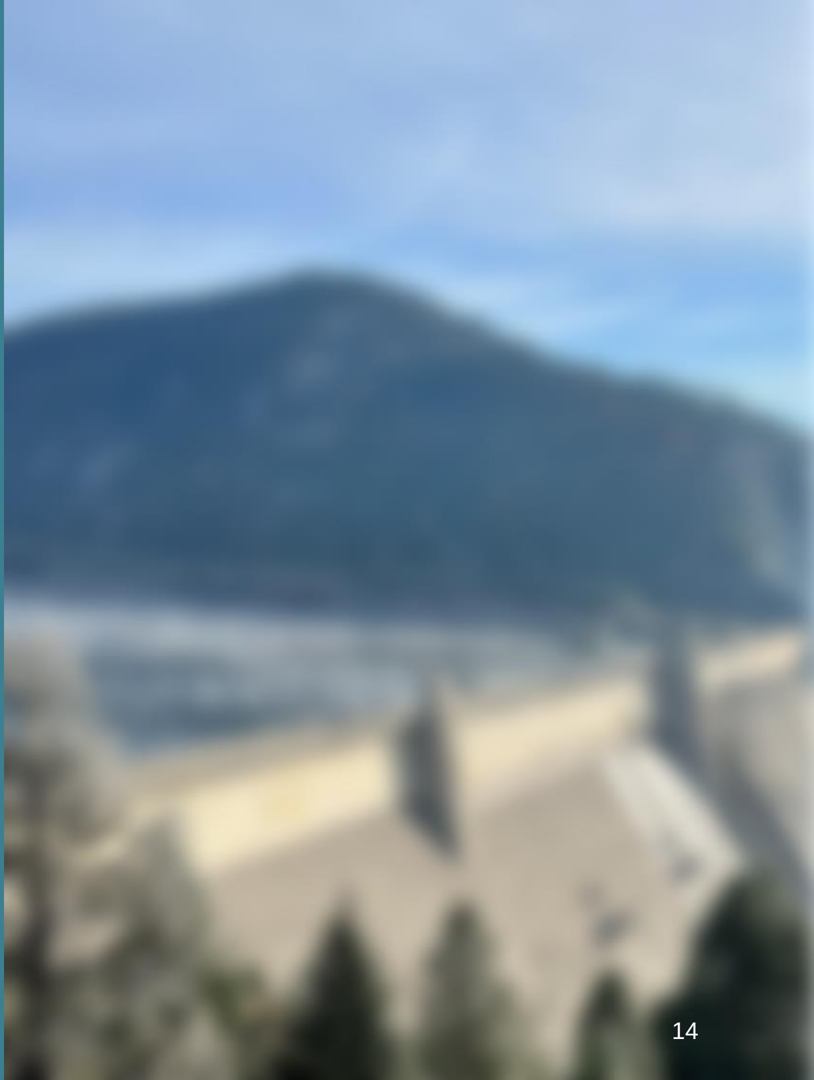
Key Takeaways

- Deficits generally increased relative to 2022 Resource Program (RP22) due to increased load obligations and decreased resource generation
- P10 SPK metric experiences the most significant increase in deficits due to updated hourly modeling
- 18hr capacity metric shows summer deficits for overall system and Mid-C, while SWEDE zone sees deficits in outyears winter months.
- P10 HLH metric remains most constraining governing metric in most periods

P10 Energy Metrics Results

Annual System surplus/deficit

RP24 Base and Fast Transition Scenarios



RP2024 Time Horizon and Sample Years

2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045

Fish Operations: RCBA (December 14th Agreement) | Columbia River System Operations (CRSO)

Hydro: 2020 Modified Flows (subset 1989-2018) | RMJOC-II Flows (2020-2049 & 2030-2059)

20XX Indicates simulated years.

- 2026-2028 all separately modeled
- 2031 & 2032 represent 6 years, 2029 to 2034
- 2037 & 2038 represent 6 years, 2035 to 2040 (pairs of years to incorporate odd/even operations)
- 2043 & 2044 represent 5 years, 2041 to 2045

HYDSIM Run

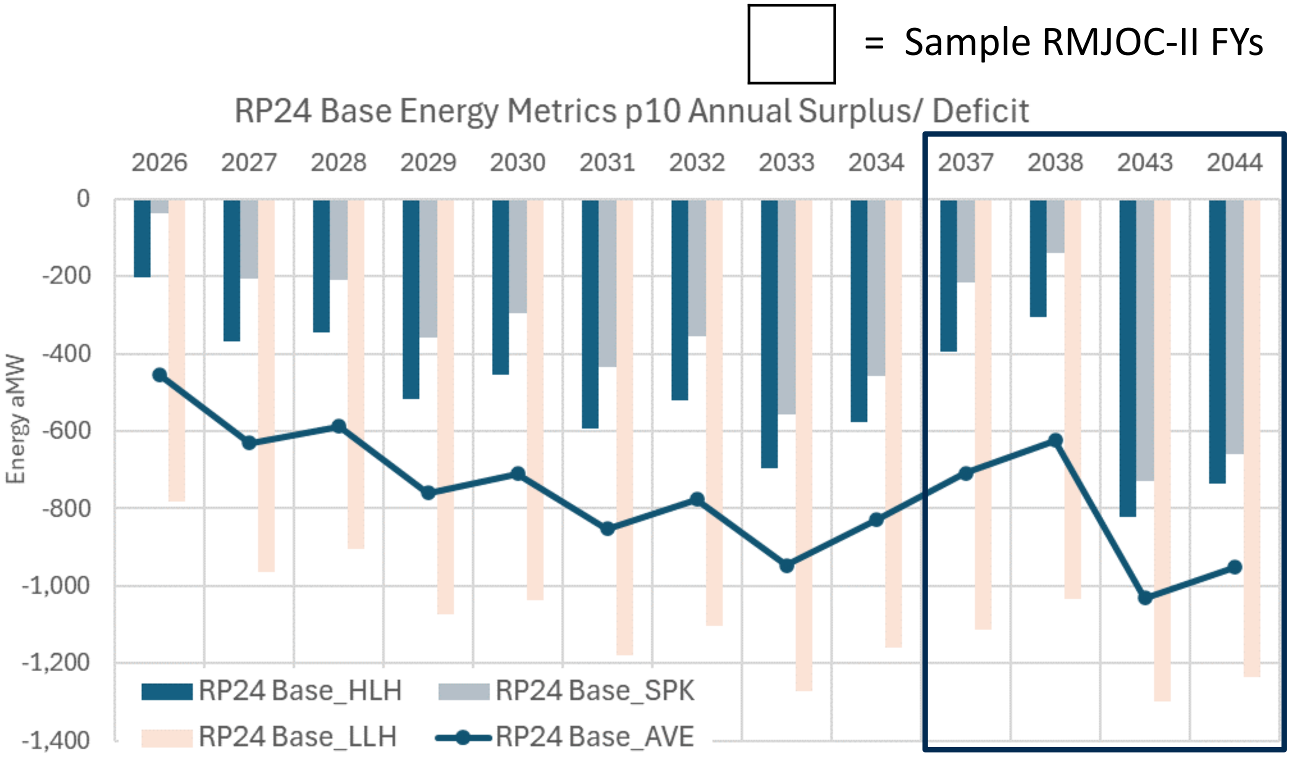
2020-2029	2030-2039	2040-2049	2050-2059

Subset of results used for 2035-2040

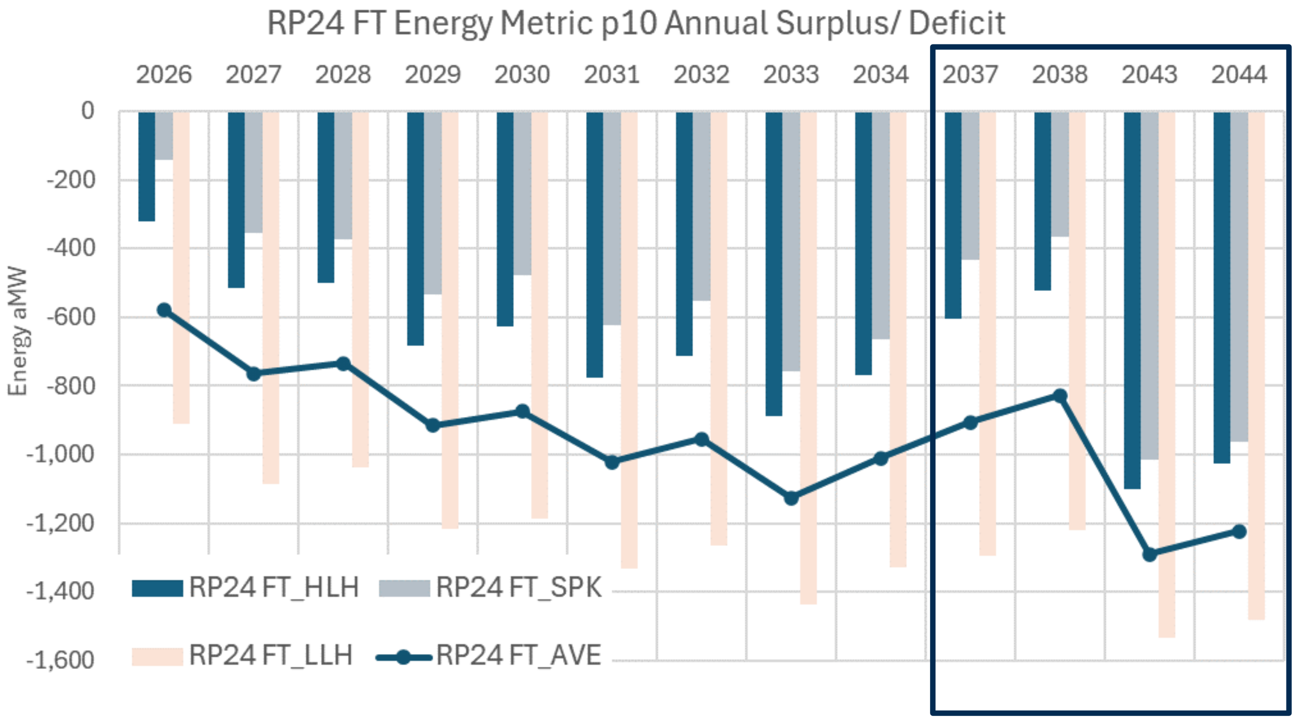
Subset of results used for 2041-2045

RP24 Base Case NA Energy metric results

- Columbia Generating Station refueling schedule contributed to the every-other-year effect
- LLH shows largest deficits due to load factoring behavior embedded in hourly modeling
- HLH the most constrained between HLH & SPK
- Variability in results for RMJOC-II years highlights uncertainties from incorporating climate change projections into hydro studies



RP24 Fast Transition (FT) Energy metric results

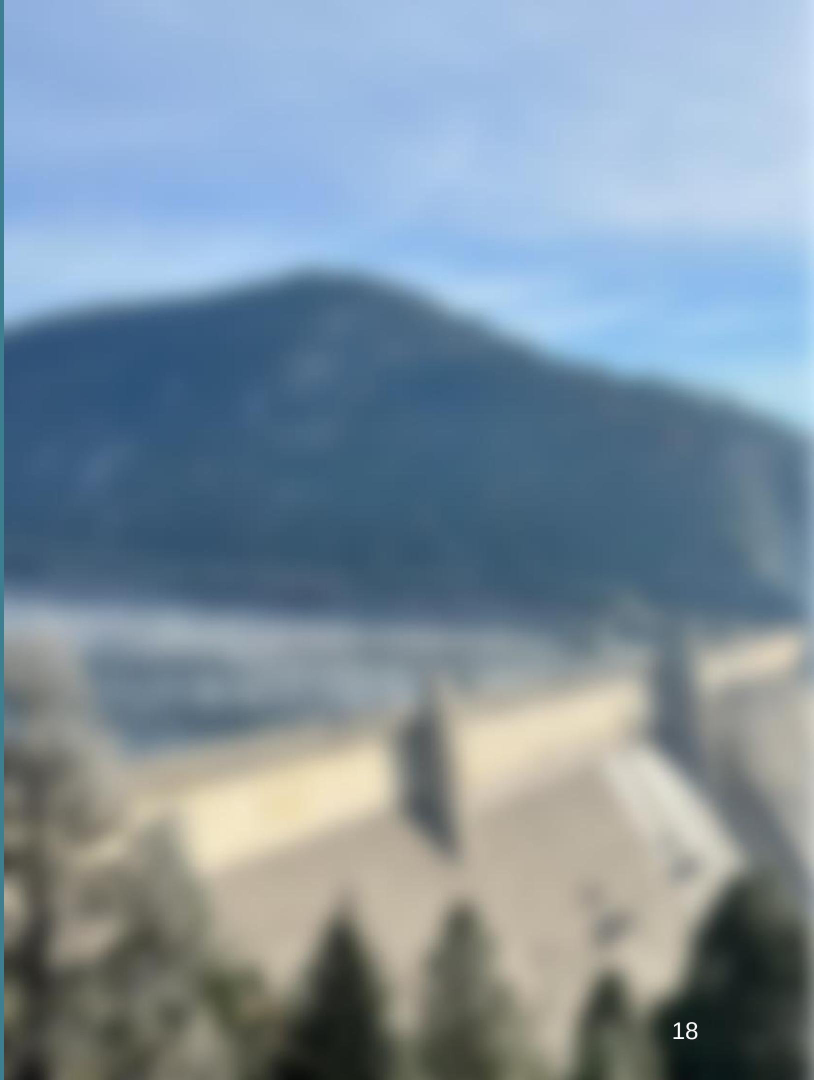


- Deficits are larger relative to RP24 Base case from increased obligation forecasts and unchanged system capabilities

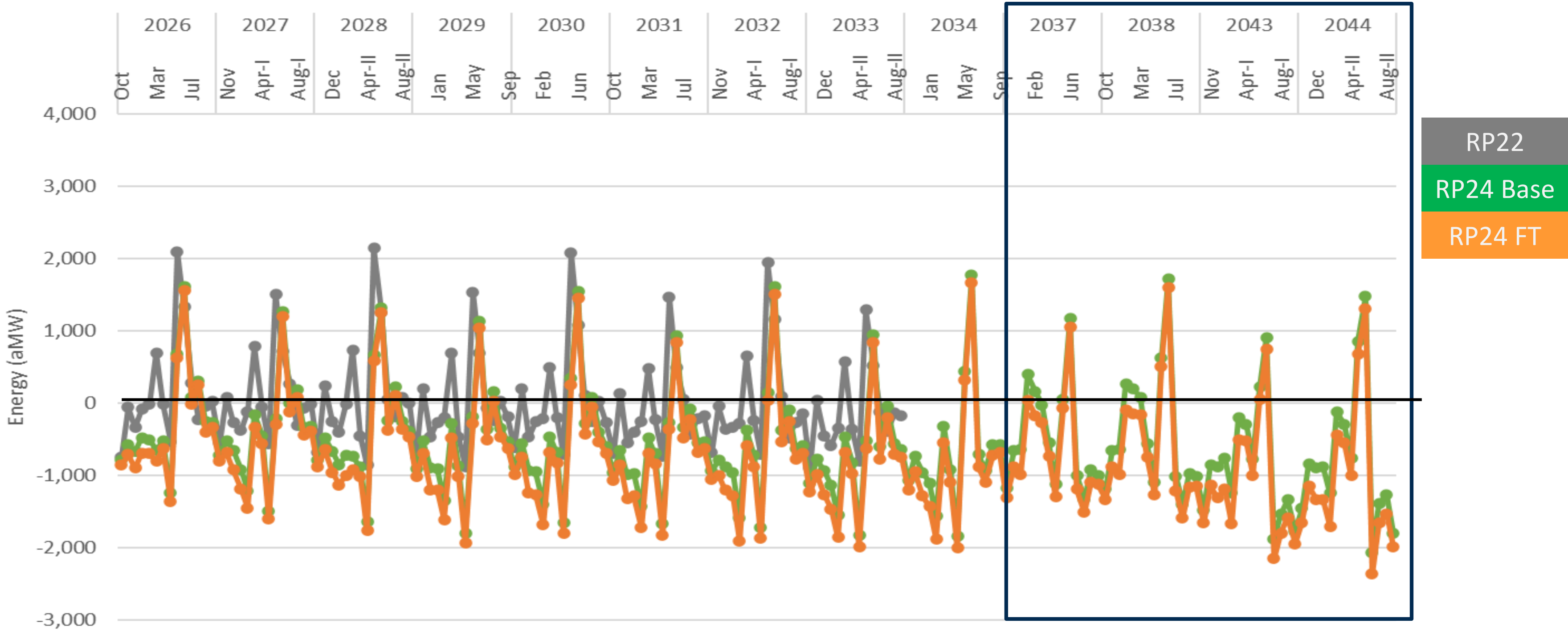
P10 HLH Metric Results

Monthly System surplus/deficit

RP24 vs RP22

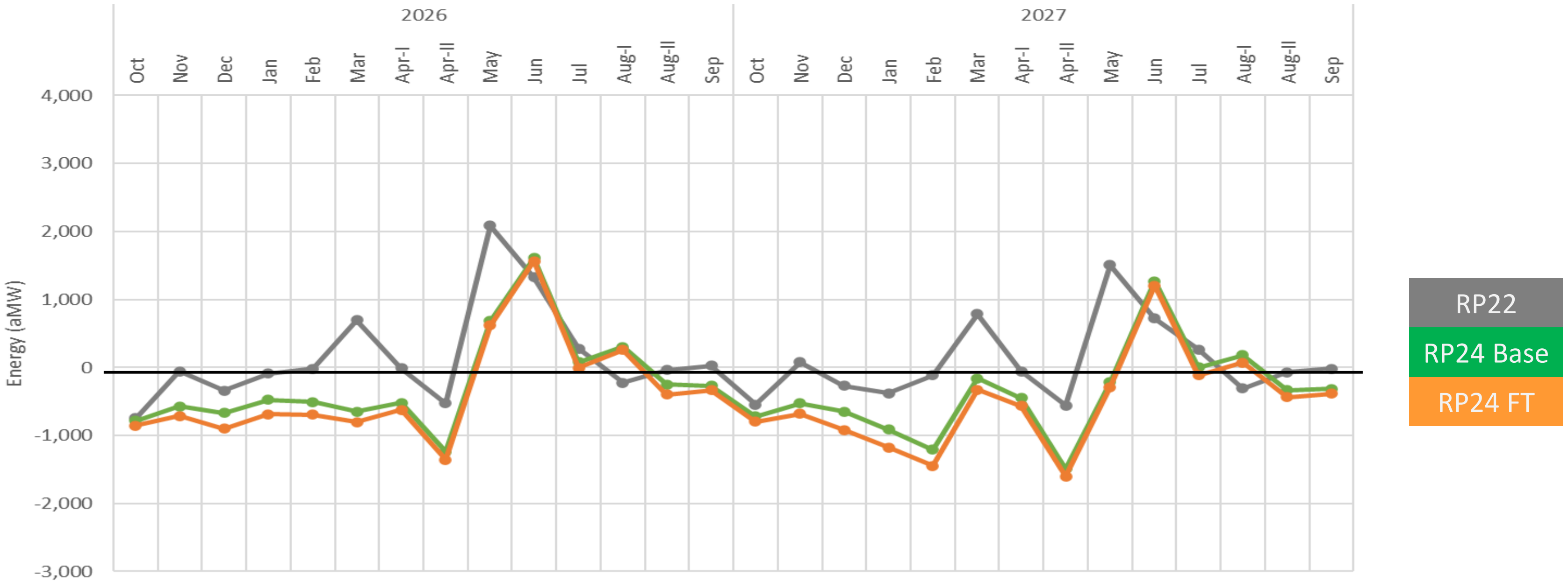


P10 HLH Surplus/Deficit (aMW) – Monthly



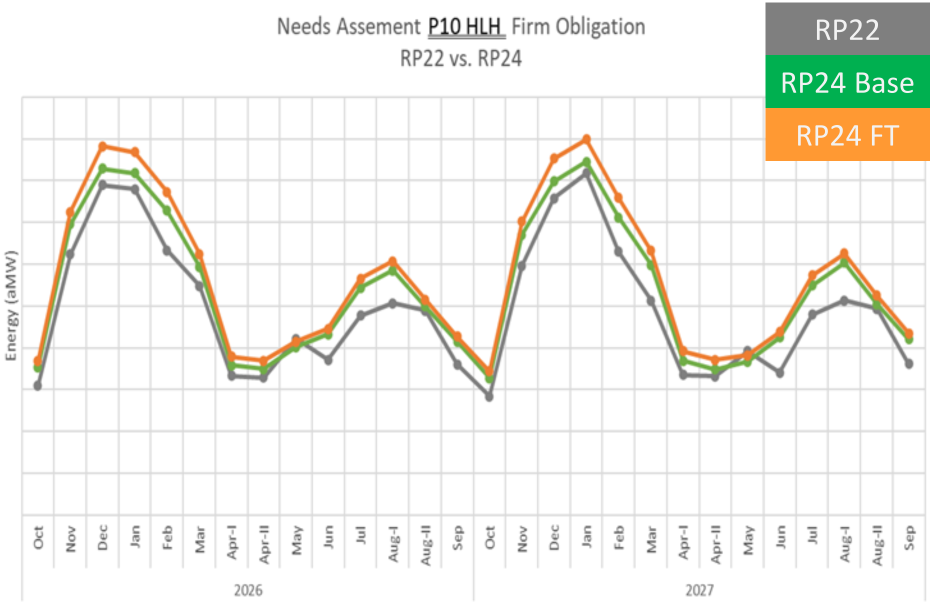
- Overall, RP24 more deficit than RP22

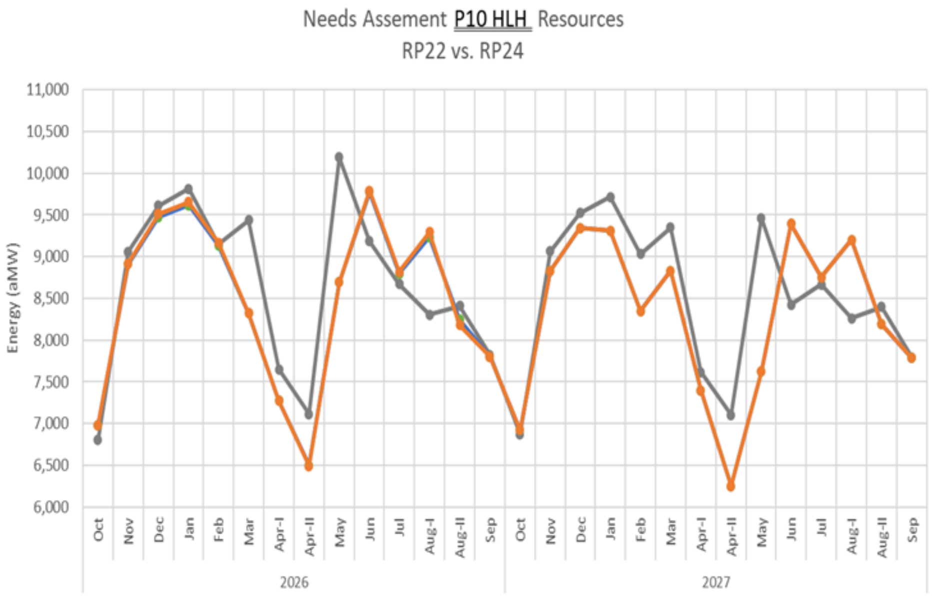
P10 HLH Surplus/Deficit (aMW) – FYs 26 & 27



- Largest deficit shifted from October to Apr-II; largest surplus shifted from May to Jun
- Aug-I inversion can be attributed to RCBA ("12/14 Agreement") operation change

P10 HLH Loads & Resources (aMW) – FYs 26 & 27

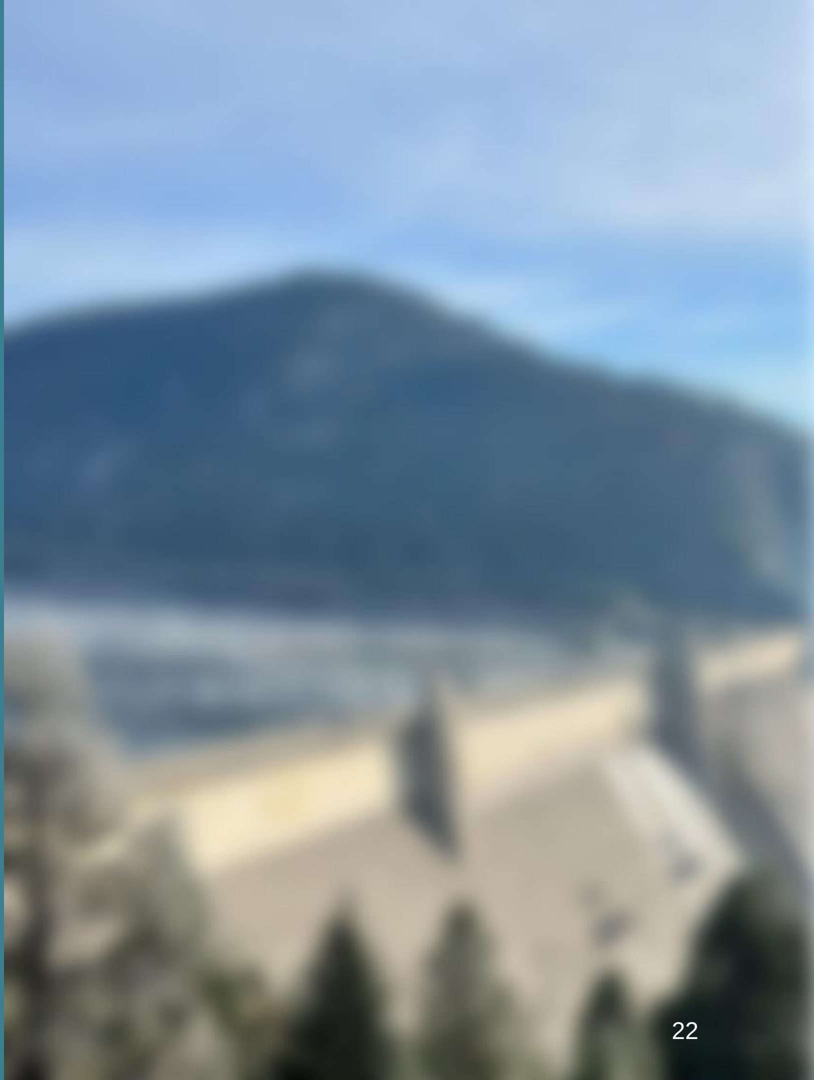




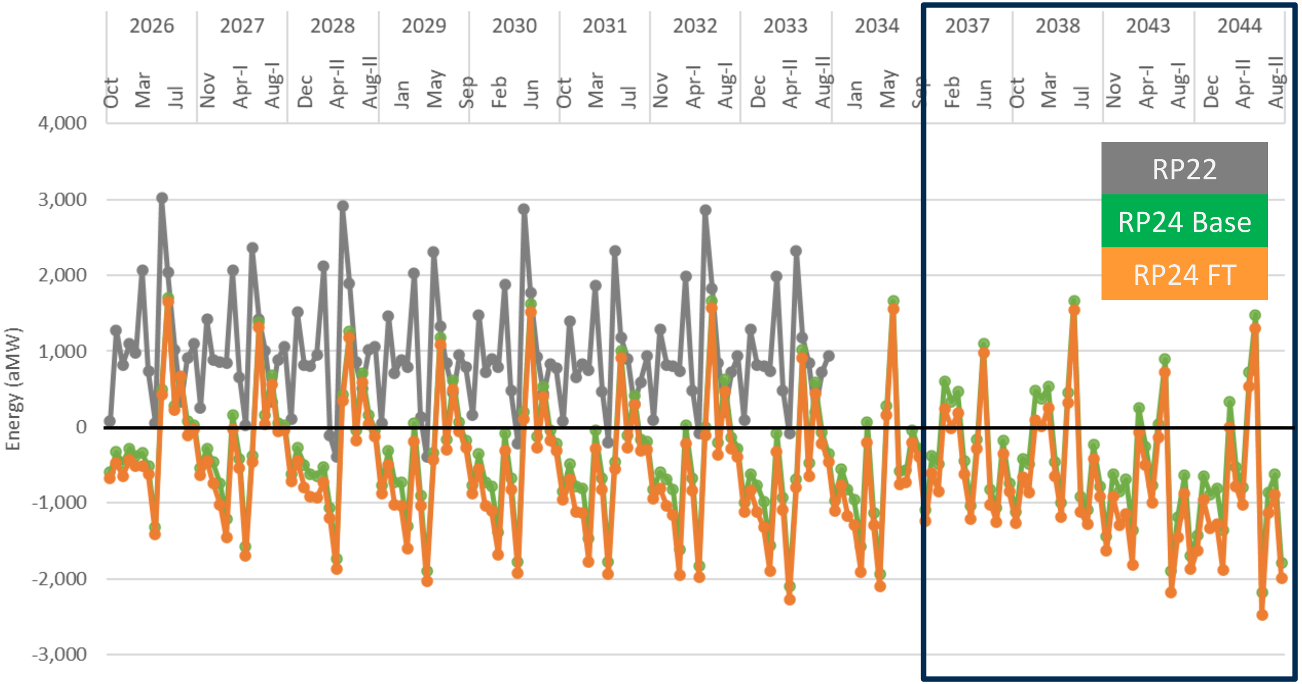
- Loads increased from RP22 to RP24 overall while resource capabilities decreased due to various operational changes

P10 SPK
Metric Results

Monthly System surplus/deficit
RP24 vs RP22

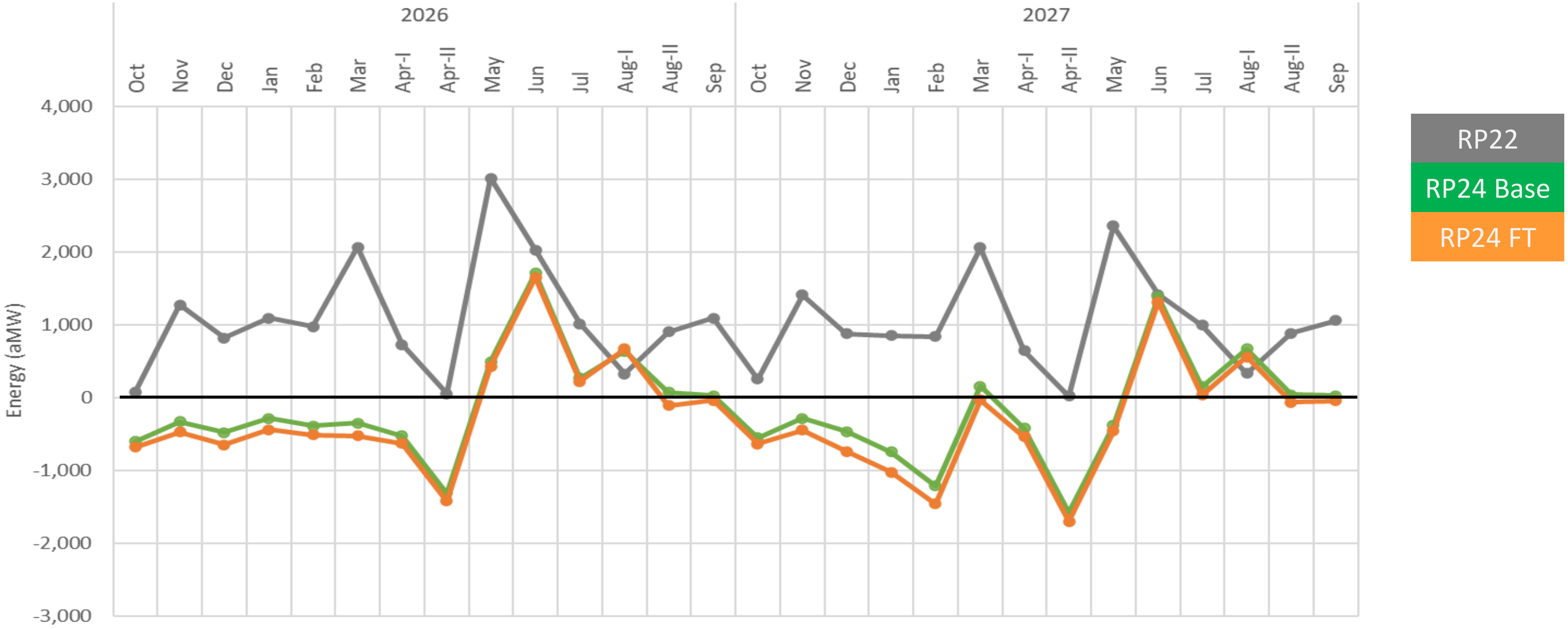


P10 SPK Surplus/Deficit (aMW)



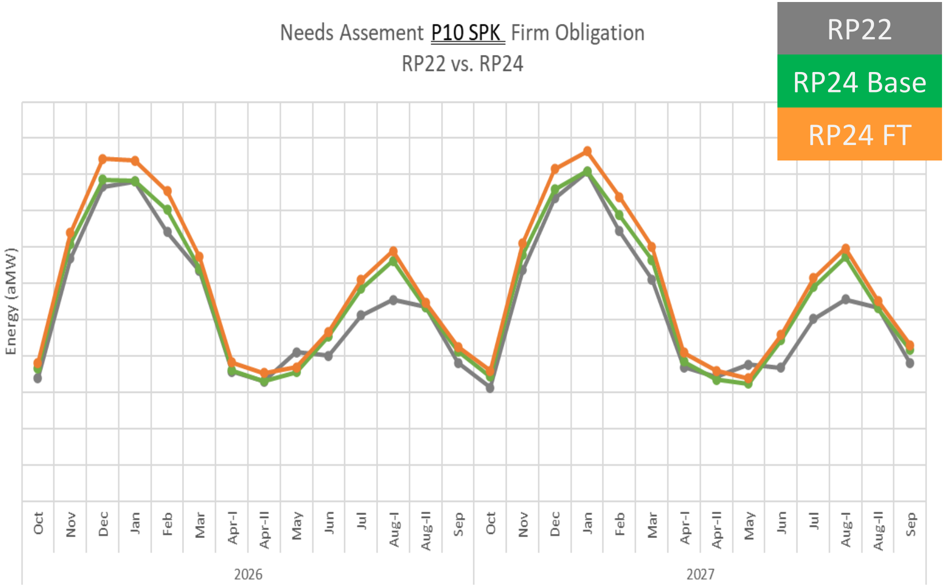
- RP20 used HOSS for hourly hydro modeling
- RP22 and RP24 used Riverware
- RP24 refined peaking behavior of projects which resulted in SPK deficits more aligned with pre-RP22 results

P10 SPK Surplus/Deficit – FYs 26 & 27



- Aug-I inversion attributed to RCBA ("12/14 Agreement") operation change

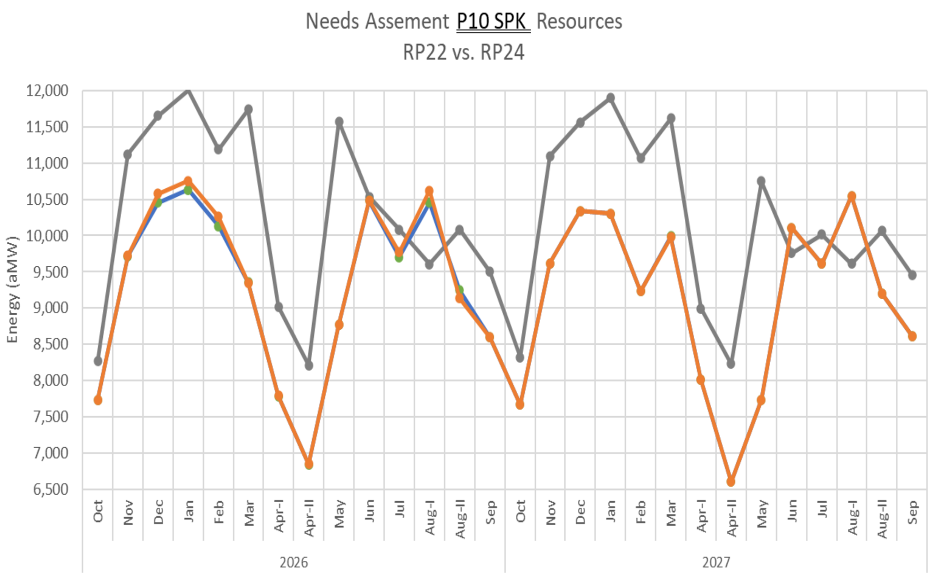
P10 SPK Loads & Resources – FYs 26 & 27



RP22

RP24 Base

RP24 FT

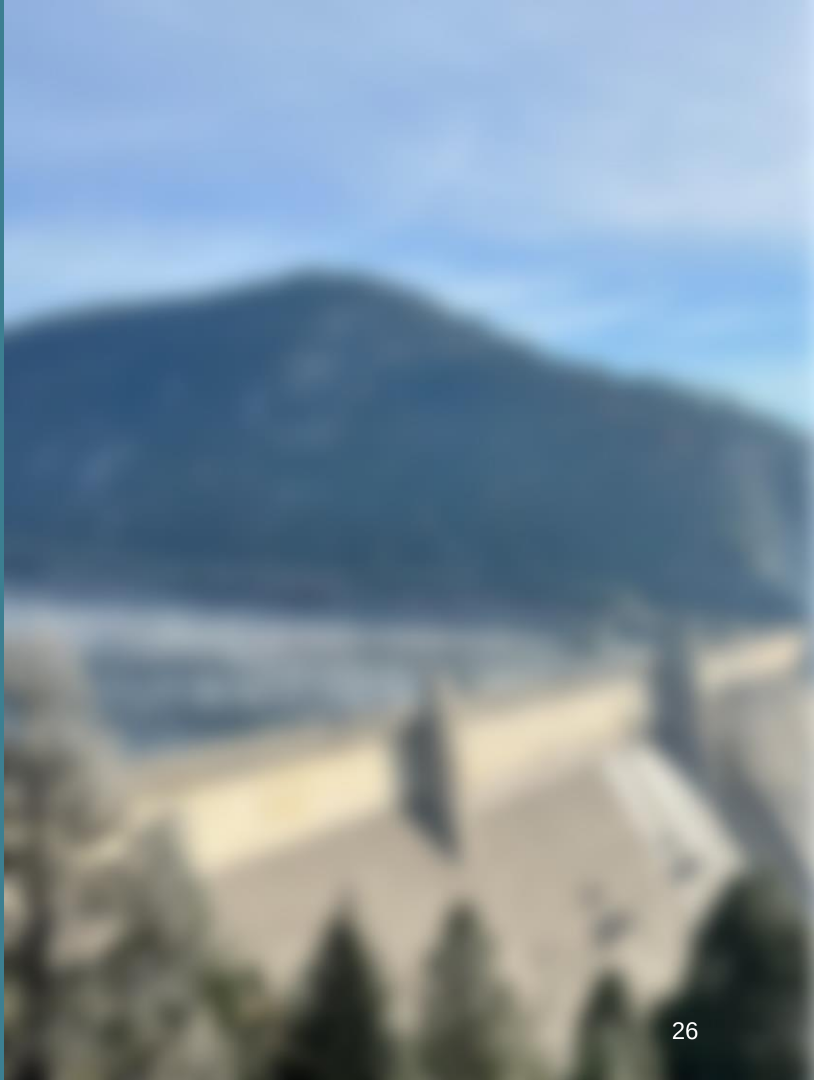


- Larger SPK loads in RP24 summer months than RP22
- Reduced hydro capabilities in many months due to refined hourly hydro modeling to better capture operational and fish constraints

P10 HLH &
P10 SPK

Monthly System surplus/deficit

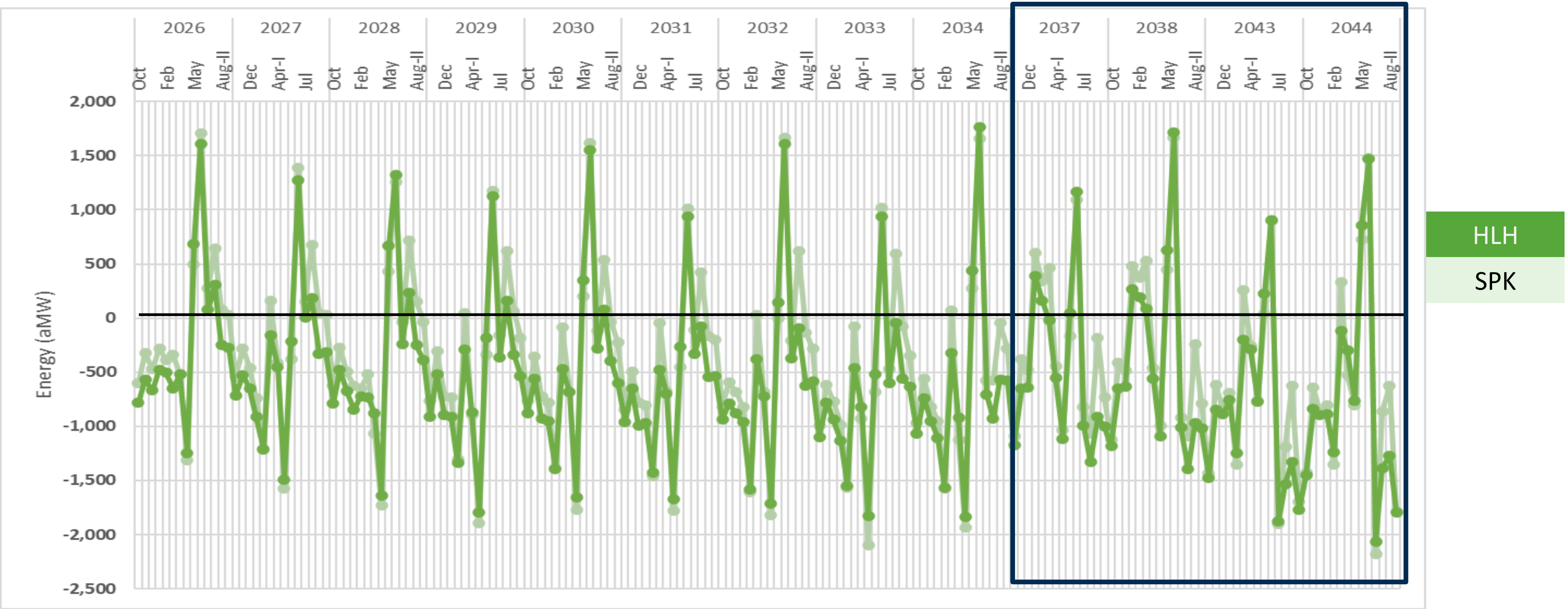
RP24 Base and Fast Transition Scenarios



Key Takeaways

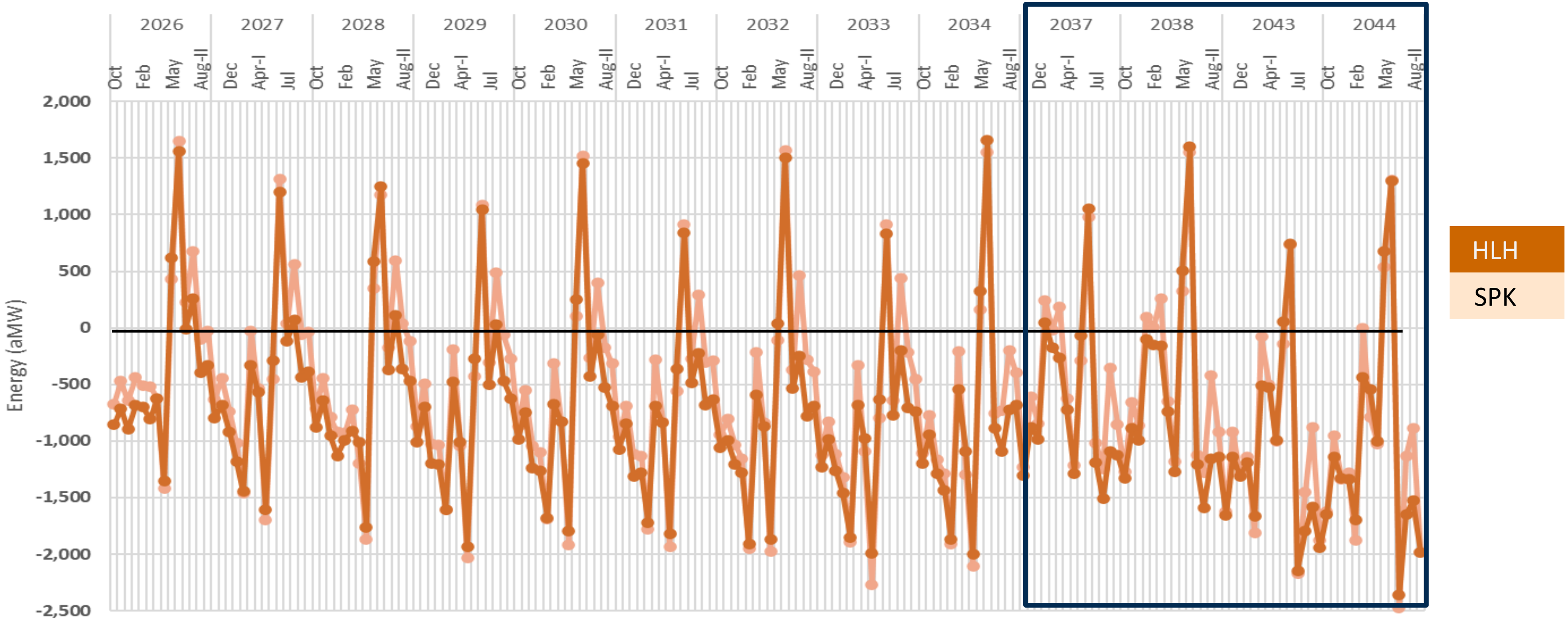
- Overall results are consistent with prior Resource Program Needs Assessment results showing P10 HLH metric deficits to be the most constrained periods and conditions for BPA to meet its obligations
- Notable exception: average SPK deficits consistently exceed average HLH deficits in Apr-II

p10 HLH vs. SPK Surplus/Deficit (aMW) – RP24 Base



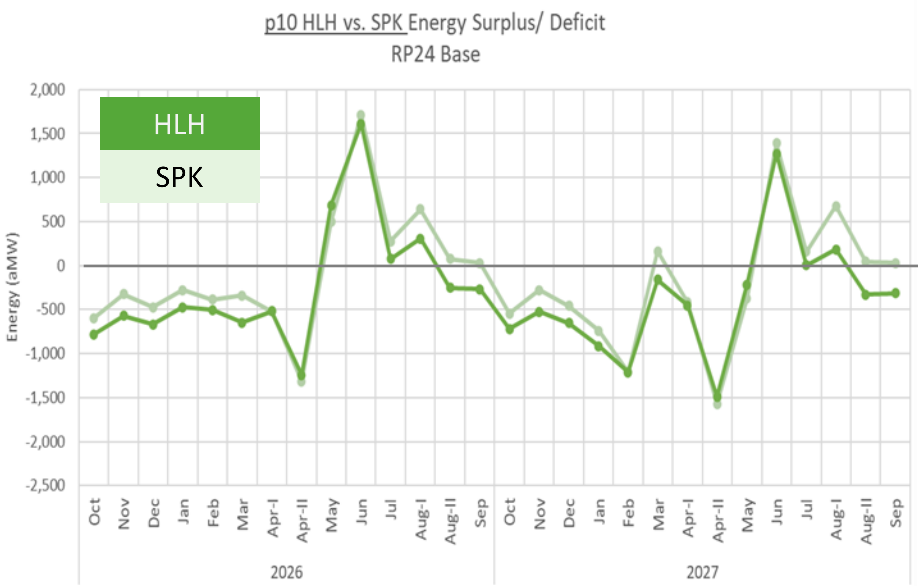
- Overall, HLH more deficit than SPK except for Apr-II in non-RMJOCII FYs

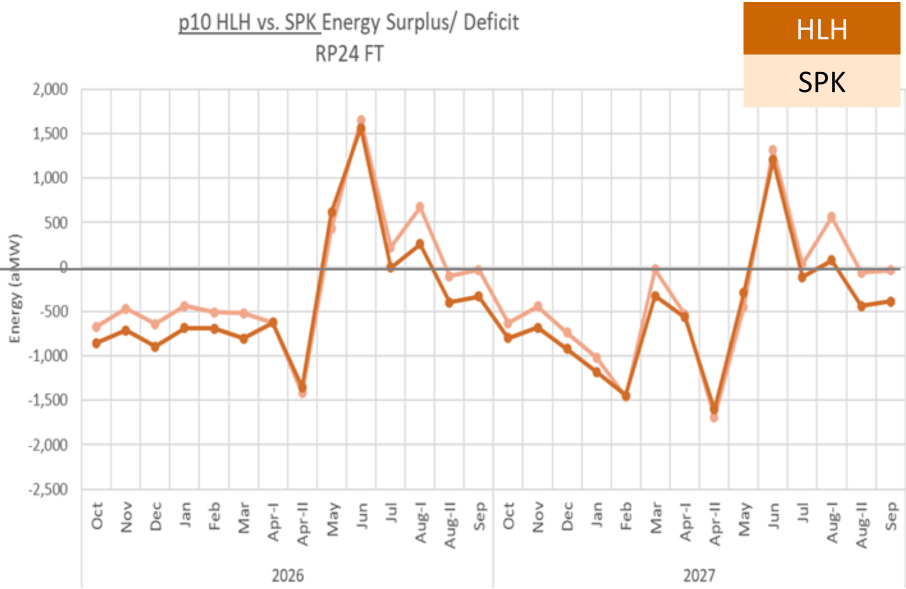
p10 HLH vs. SPK Surplus/Deficit (aMW) – RP24 FT



- Following RP24 Base trends, HLH more constrained than SPK with Apr-II the exception

p10 HLH vs. SPK Surplus/Deficit (aMW) – RP24 FYs 26 & 27

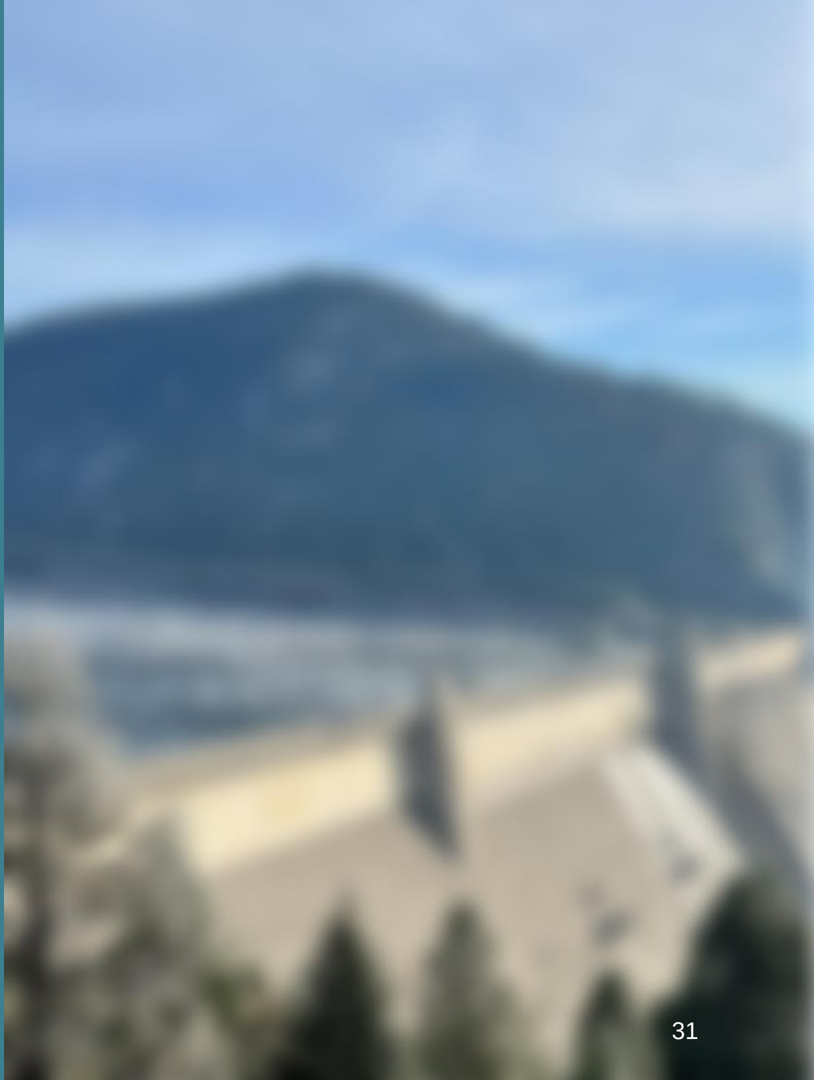




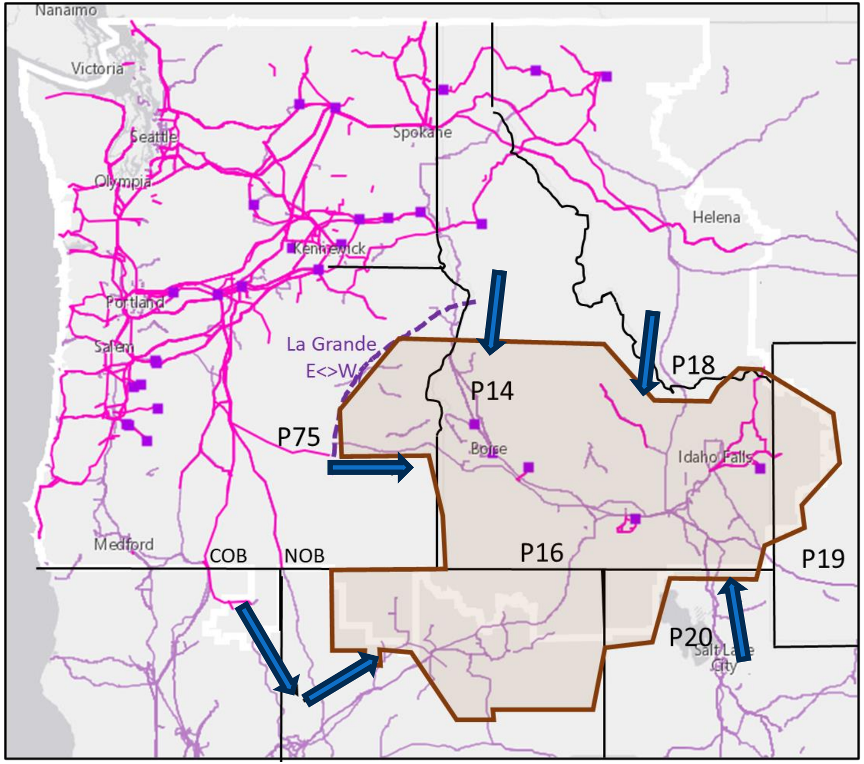
- FT has slightly deeper deficits/smaller surpluses than RP24 Base

P10 Energy Metrics – by Zone

RP24 Base and Fast Transition Scenarios



WRAP & RP24 Zones: Mid-C & SWEDE



Western Resource Adequacy Program (WRAP) likely requires BPA load in each zone to be served with a combination of physical resources (with qualifying capacity) and firm transmission (from resource to the load).

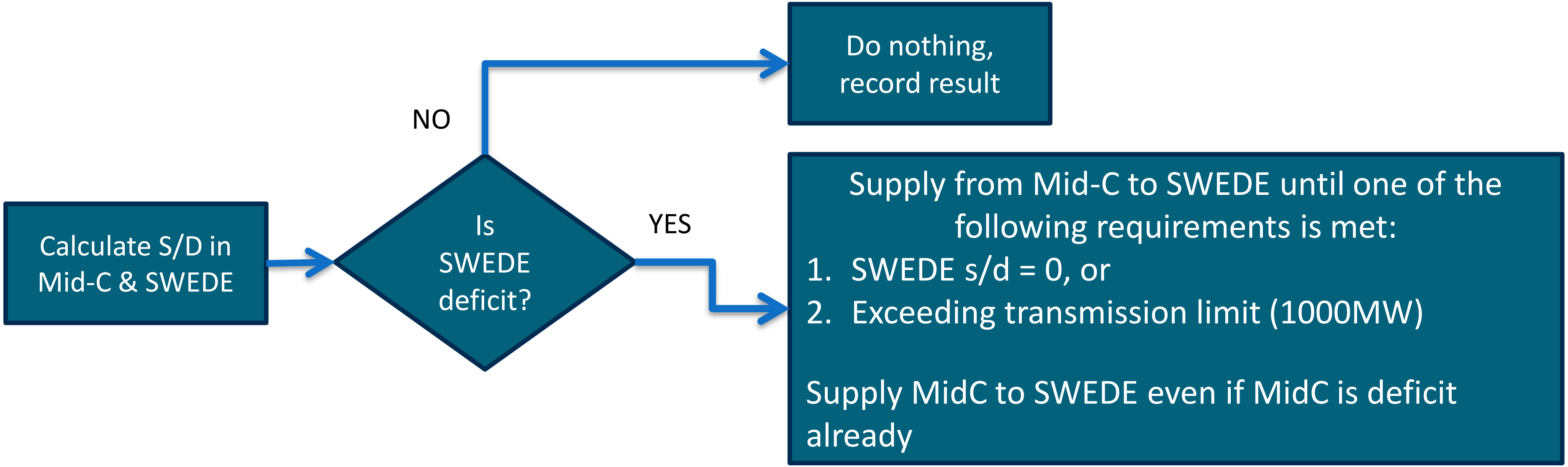
Currently, without B2H, the SWEDE region has heavily constrained transmission paths.

Mid-C (outside of the shaded enclosure)

BPA SWEDE (**S**outh-**W**est **E**ast **D**iversity **E**xchange)

Pink lines are BPAT, purple dots are Hydropower, purple lines are other transmission, P# is a WECC path

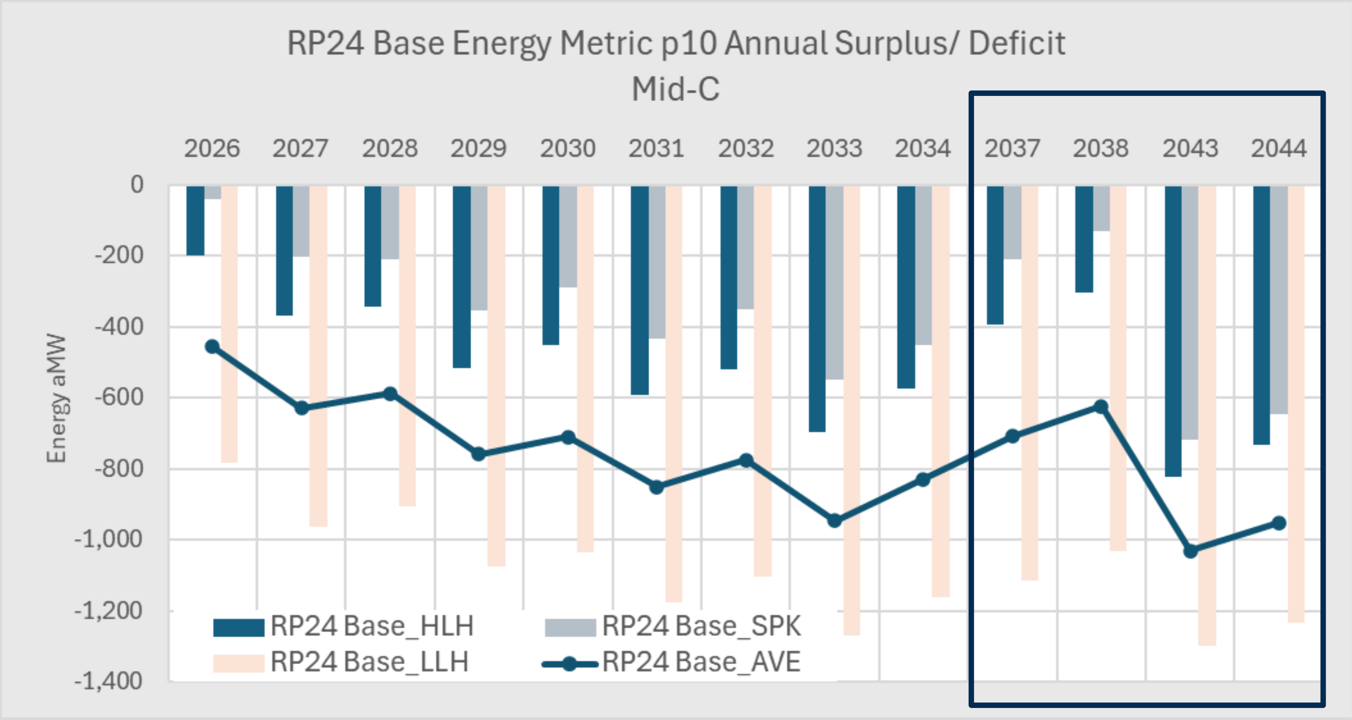
Transfer from Mid-C to SWEDE by Design



- This calculation takes place at the hourly level
- Without transfers from MidC, SWEDE is always deficit

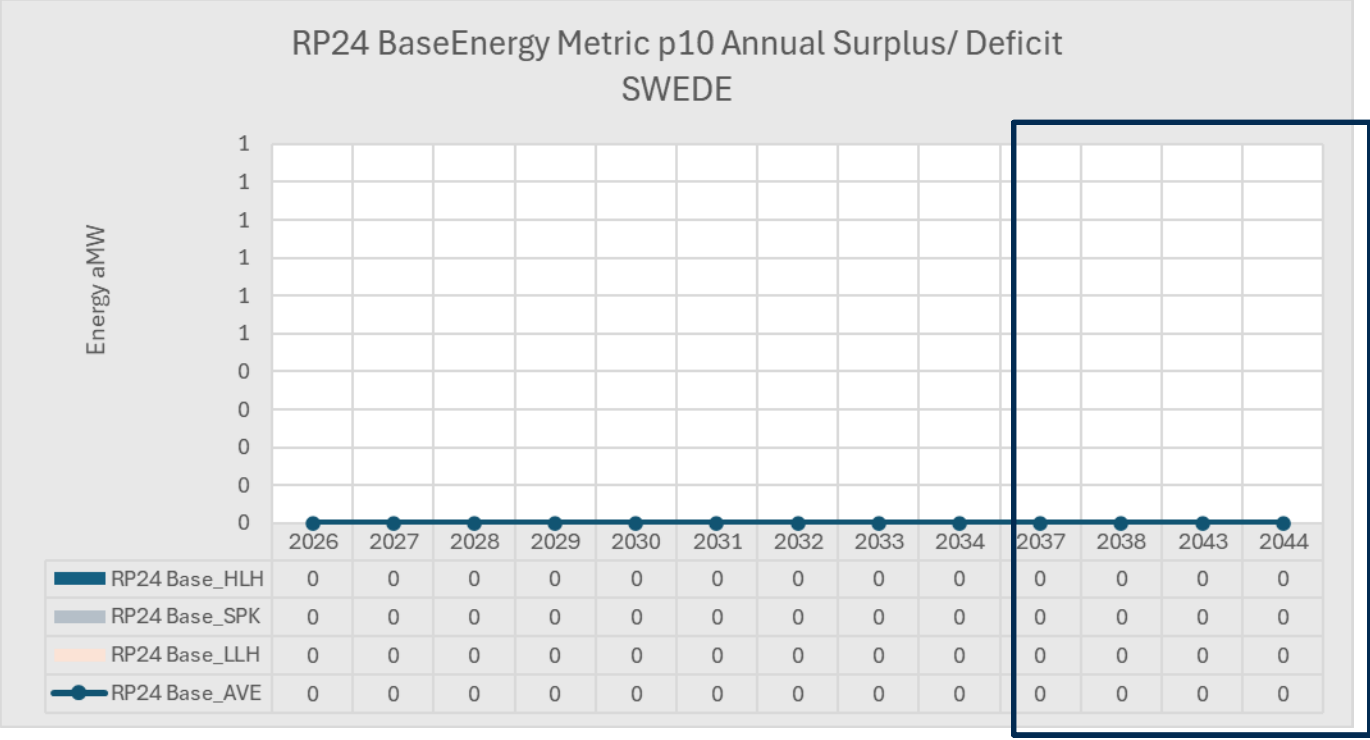
RP24 Base Mid-C Energy metric results

- MidC results reflects previously shown system-wide trends
- RP24 FT Mid-C results (not shown here) follows RP24 Base results, with increased deficits in all metrics, respectively.

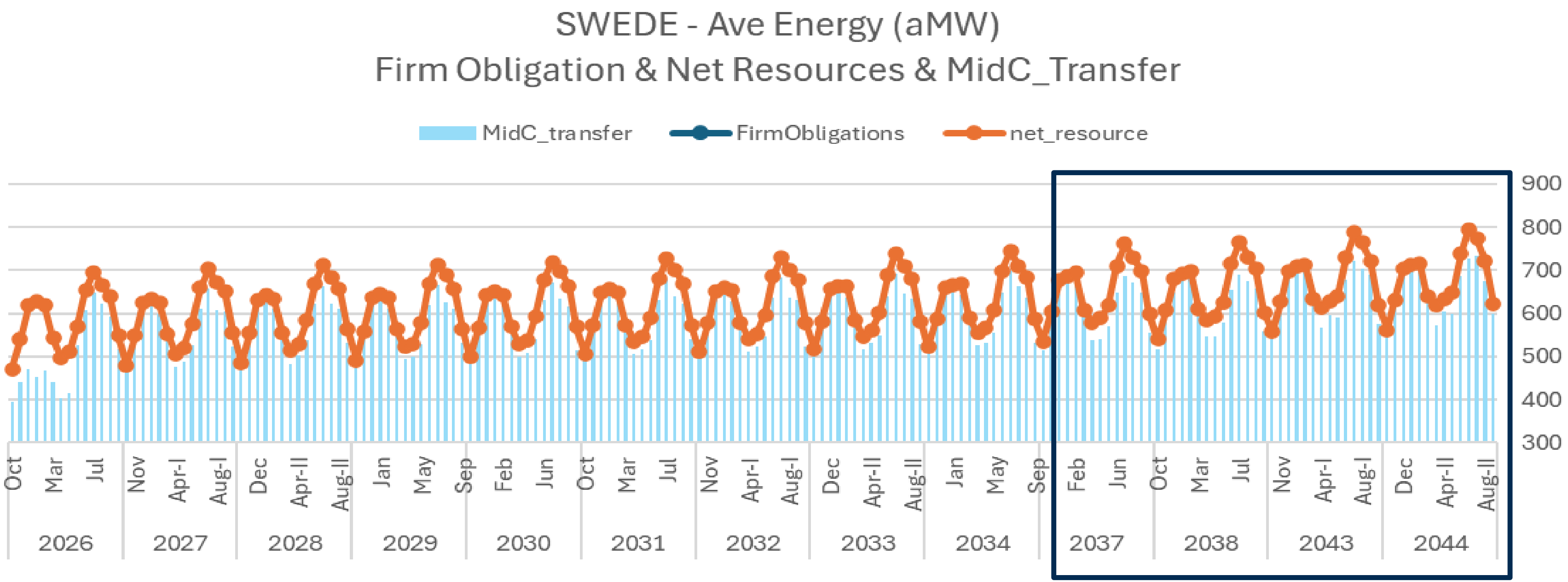


RP24 Base SWEDE Energy metric results

- By design, Swede is net zero for all metrics.
- RP24 FT SWEDE results (not shown here) are the same as Base, with all metrics achieving surplus/ deficit balance due to the build-in transfer design.



RP24 Base SWEDE Loads & Resources - Average Energy (aMW)

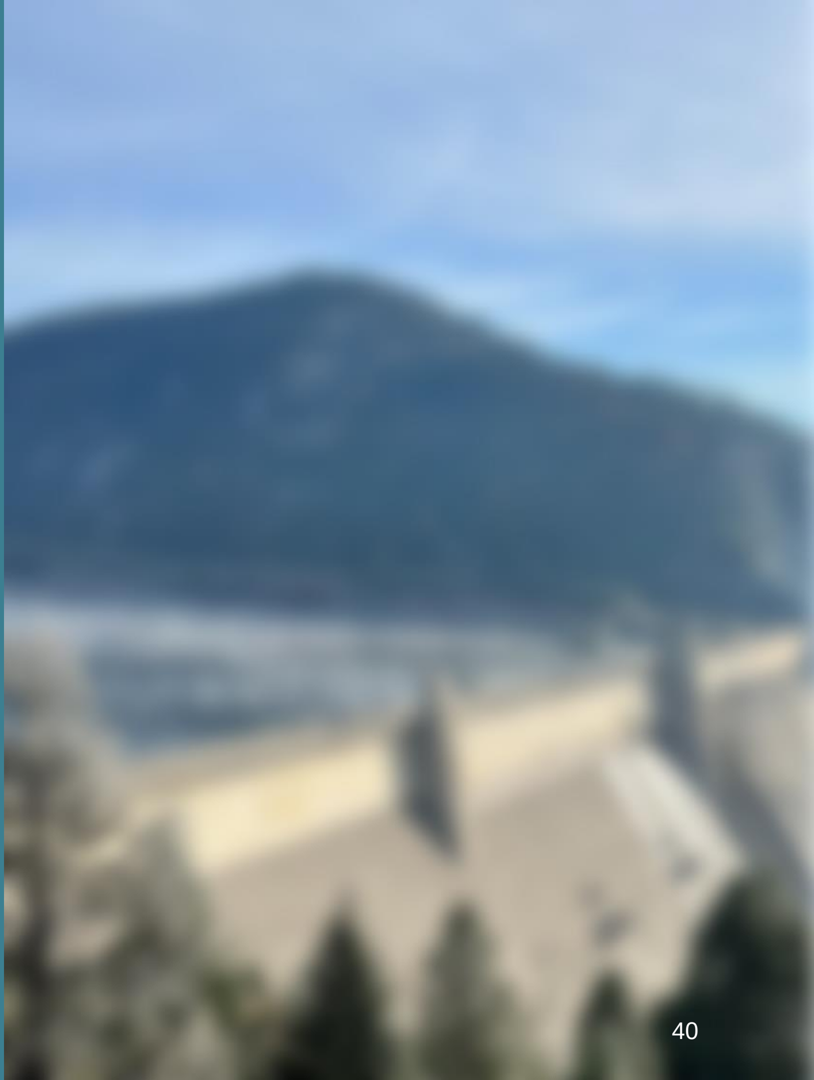


- Morgan Stanley contract (Intra_Regional transfer (IN)) expires after April 2026.

18hr Capacity Metric

Monthly System surplus/deficit

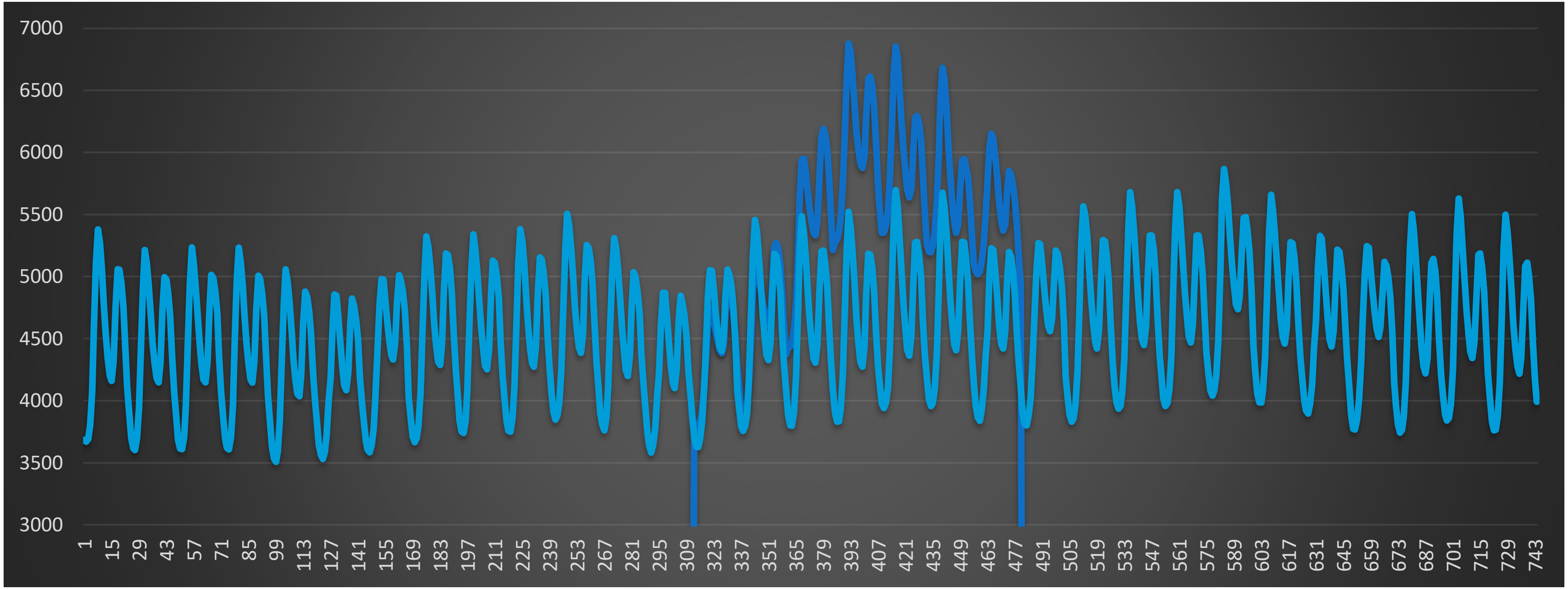
RP24 Base and Fast Transition Scenarios



Key Takeaways

- The 18hr “capacity” metric evaluates the monthly average surplus/deficit over six peak load hours per day across three-day extreme weather load events
- Load excursions under extreme weather events modeled using actual temperatures from Jun21 and Jan24 heat/cold events, respectively
- Resources modeled under p50 hydro to show sustained peaking capabilities of system with typical fuel supply
- Results show System-wide 18hr deficits during summer months for FY2035+

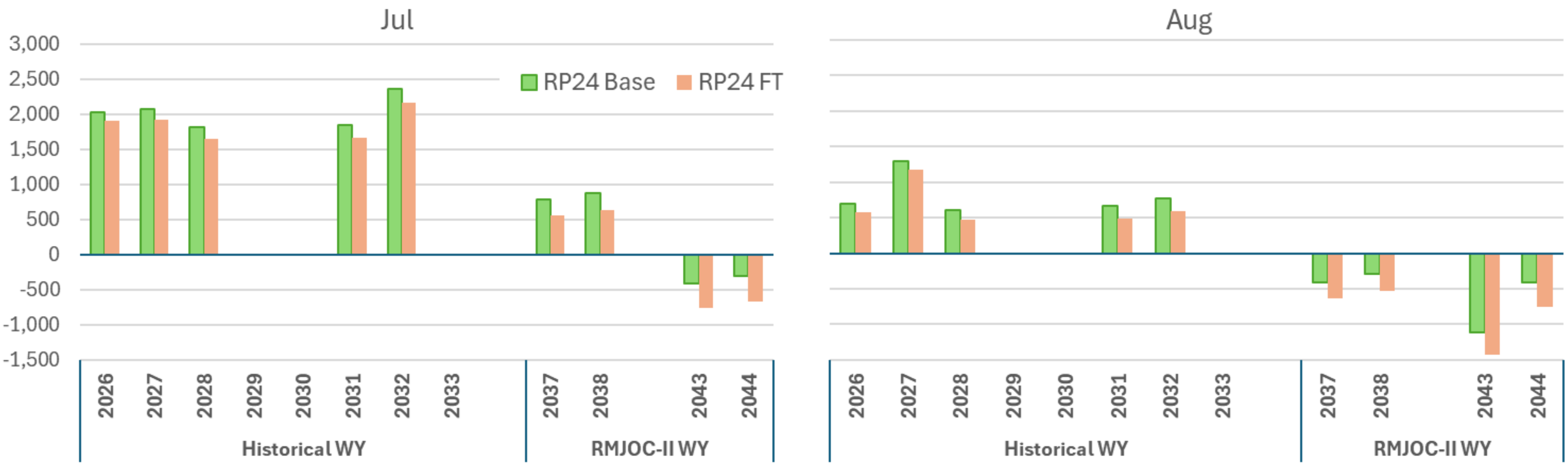
Example of Extreme Weather Load Excursion



Note: This shows a reference winter event.

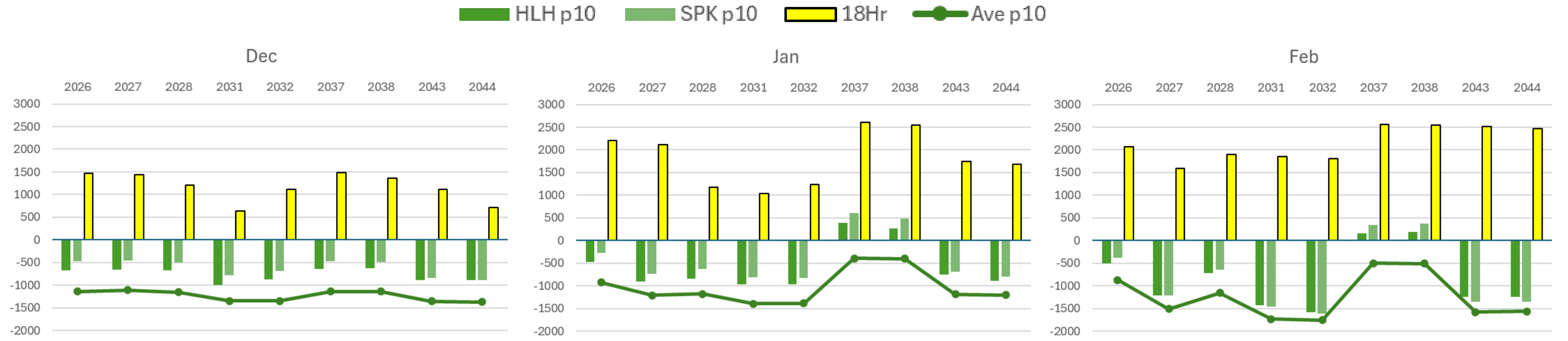
BONNEVILLE POWER ADMINISTRATION

Capacity 18Hr: System Surplus/ Deficit aMW

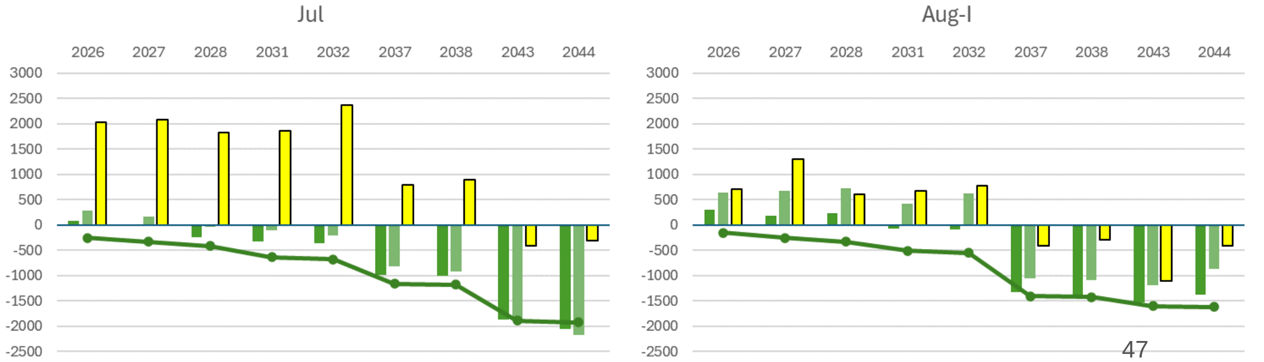


- Jul & Aug started to see deficits of 500 MW to 1500 MWin RMJOC-II outyears
- Winter months (Dec/ Jan/ Feb) did not show any deficits

RP24 Base NA Metrics Comparison (aMW) - System

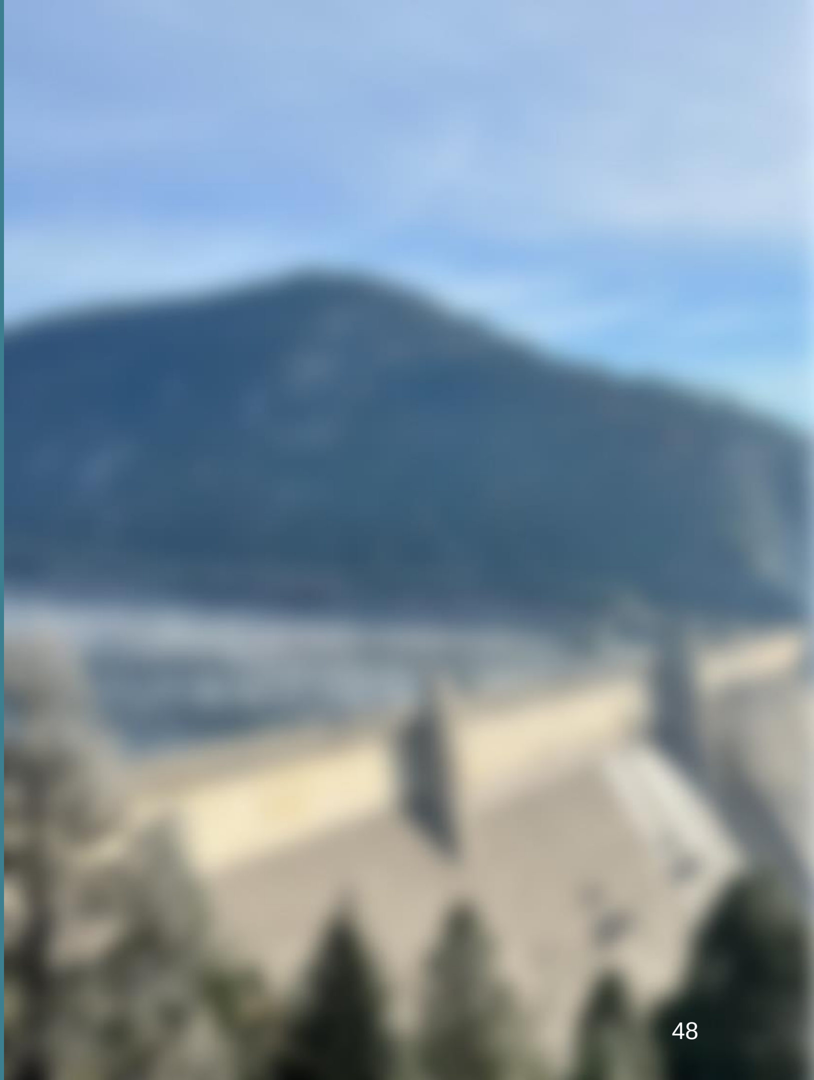


- P10 HLH still most constraining metric across months studied for 18Hr metric
- FT (not pictured) shows same relationship amongst metrics with deeper deficits/smaller surpluses from increased loads



18hr Capacity Metric – by Zone

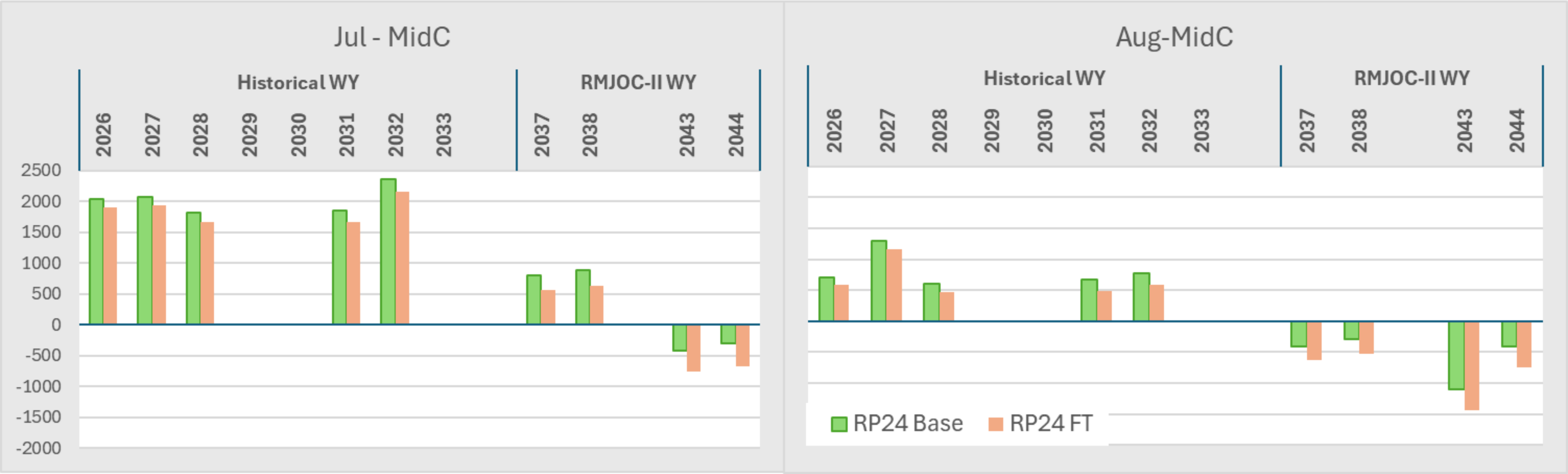
RP24 Base and Fast Transition Scenarios



Key Takeaways

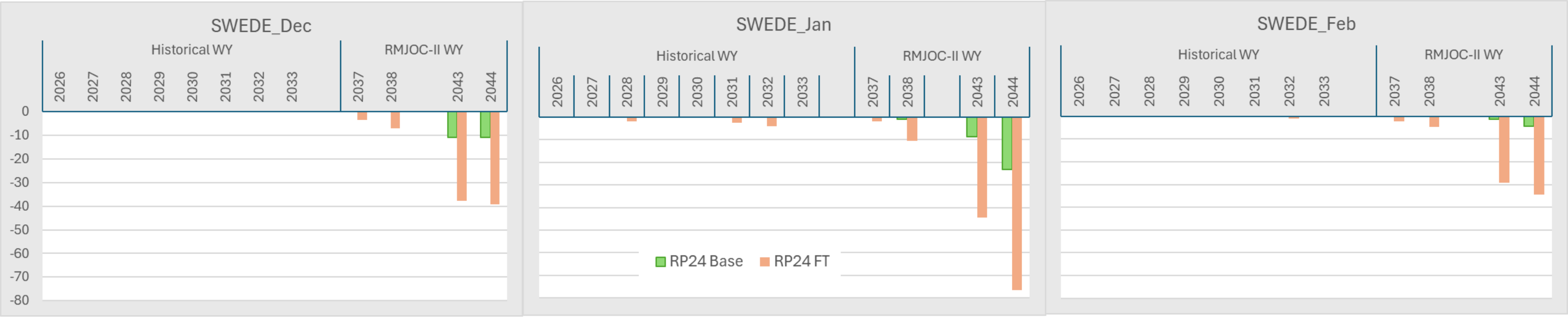
- MidC experiences 18hr deficits during summer months for FY2035+ in RP24 Base and FT
- SWEDE experiences small but meaningful 18hr deficits during winter months as early as FY28 in RP24 FT
- Zonal approach assumes no expansion in transmission capabilities from MidC to SWEDE over the entire 20-yr study horizon

Capacity 18Hr: Surplus/ Deficit aMW – Mid-C



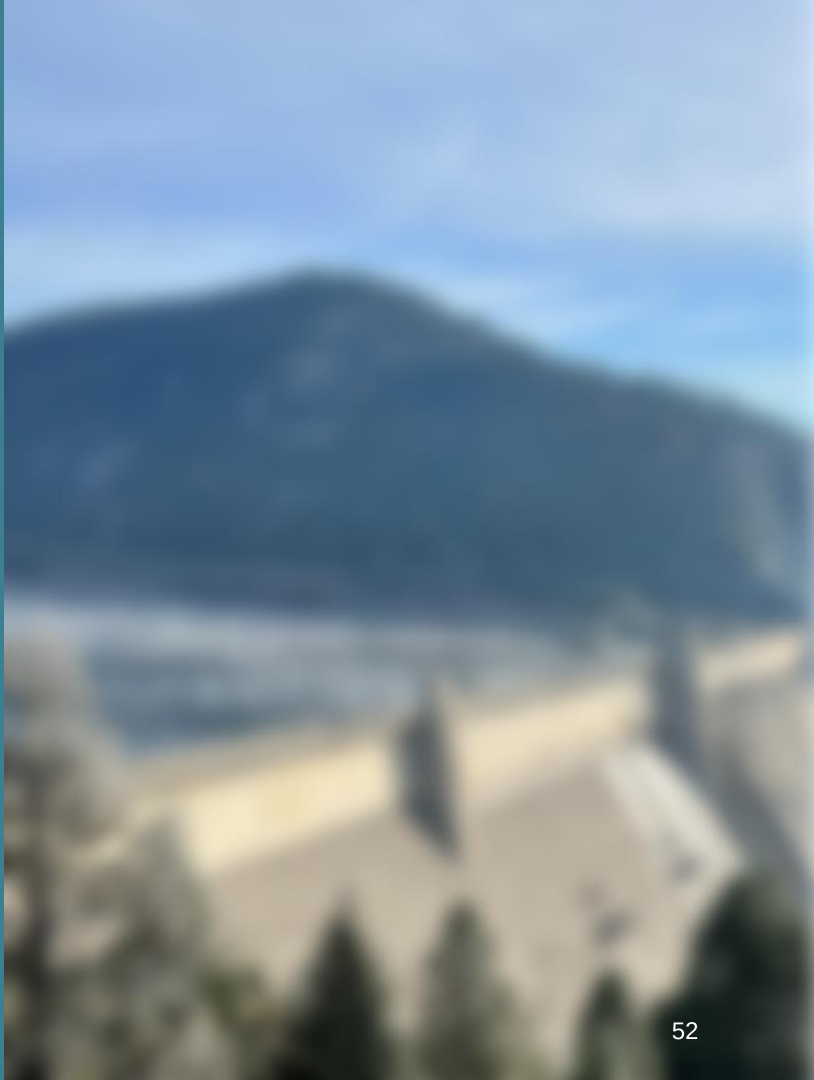
- 18hr capacity Mid-C results matches System results
- No deficits in winter months
- Summer months deficits only observed in RMJOC-II outyears

Capacity 18Hr: Surplus/ Deficit aMW - SWEDE



- 18Hr Metric in SWEDE only have deficits in the Winter Months
  - Deficits in Base case begins to show in RMJOCII out years.
  - FT case, non-RMJOCII out years begins to show small deficits.
- No deficits observed in summer months.

RP24 Sensitivity Study Results



Sensitivities for Needs Assessment

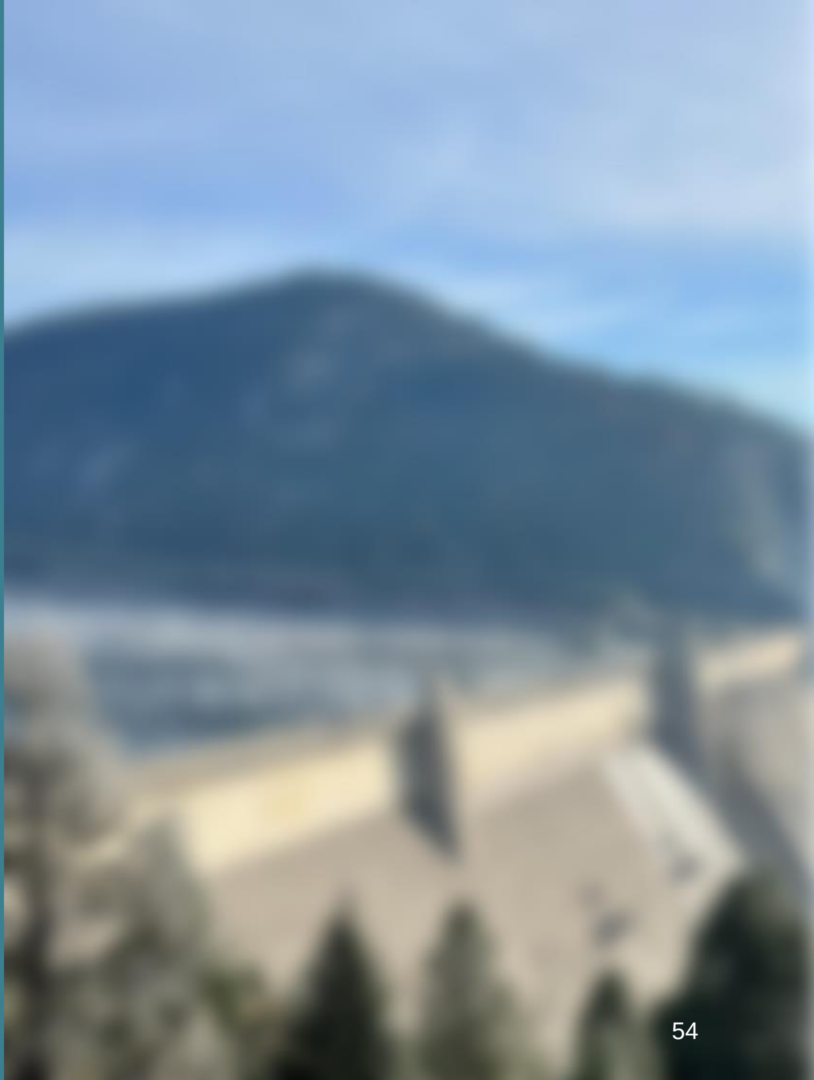
Original Sensitivity Plan

- Flat block/NR Load Service
- Above-RHWM Load Service
- B2H Delay
- T1 System Size

Updated Sensitivity Plan

- Block High Load Adder
- Shaped Medium Load Adder
- B2H Delay (no change)
- T1 System Size (no change)

Load Adders



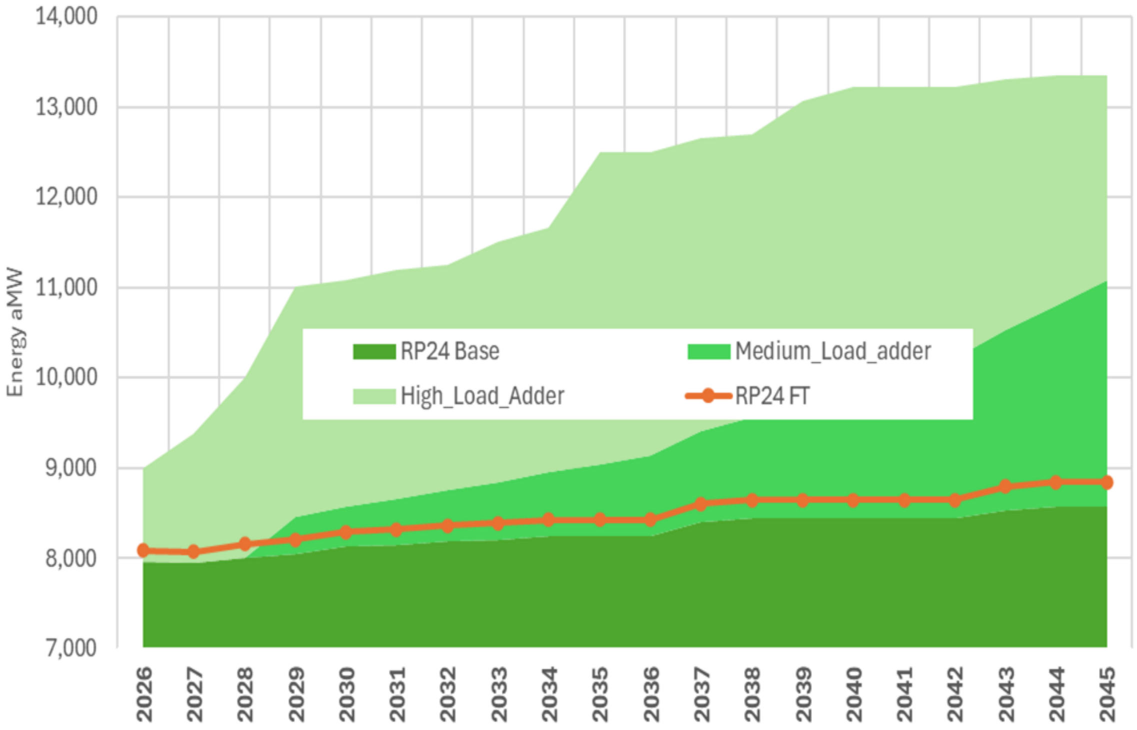
Load Adders - Overview

- **Methods:**
  - High load adder is a flat block load added to every hour uniformly across the year.
  - Medium load adder is shaped load added to each hour. Shaping is based on current Slice Block load shape.

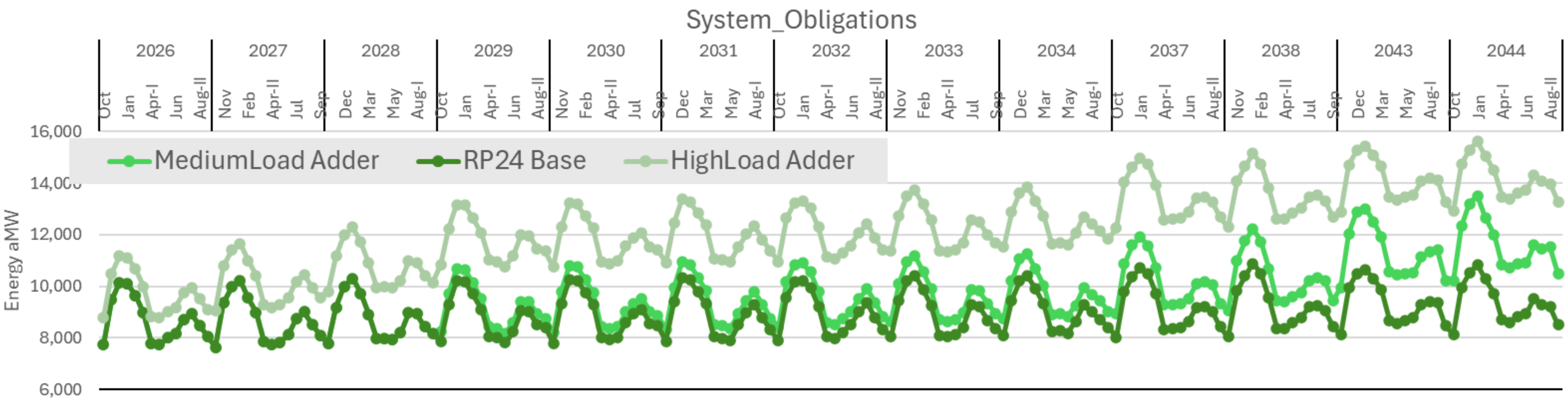
- **Main findings:**
  - Under High block load adder sensitivity, p10 HLH metric will see deficits in all periods of the year as early as FY2027
  - Under Medium shaped load adder sensitivity, p10 HLH metric deficits increase by ~30% by FY2031 from RP24 Base case, and deficits swell to more than double by FY 2044

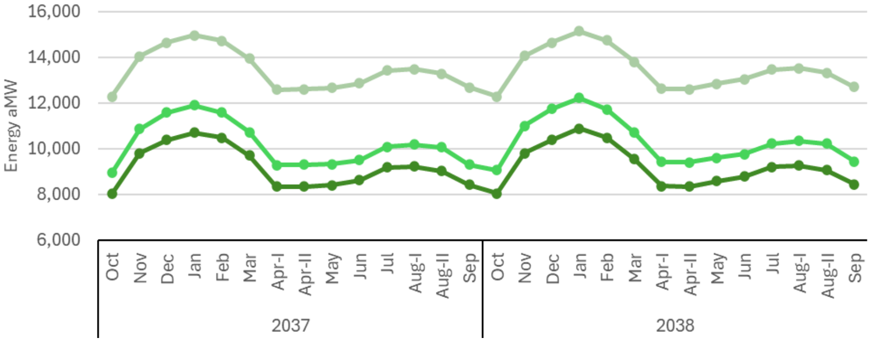
RP24 Base, FT, and Load Adder Sensitivities

- Medium load adders (shaped) presents a gradual load increase:
  - Starts in FY2029 with additional 400 aMW and ends in FY2045 with additional 2,500 aMW
- High load adders (block) are more aggressive
  - Starts in FY2026 with additional 975 aMW reaching almost 4,800 additional aMW by FY2040.
- RP24 FT load is slightly higher than RP24 Base



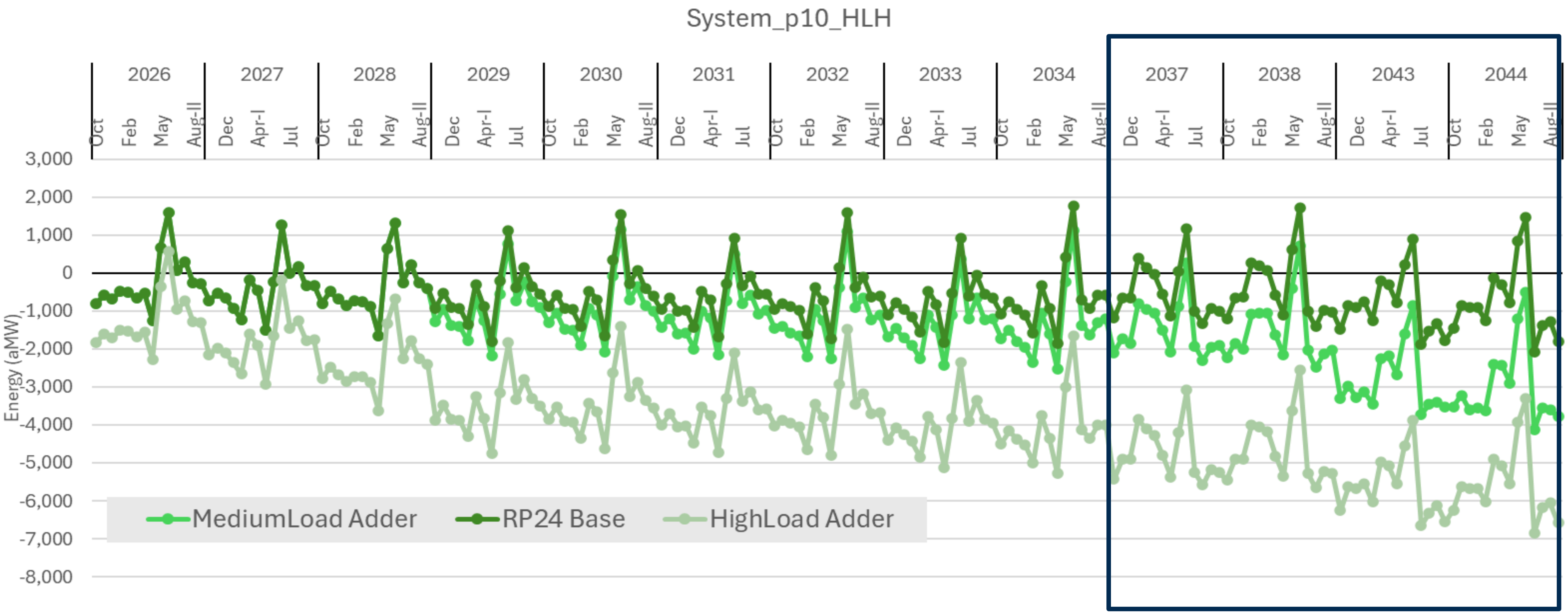
Load Adders Monthly Obligations



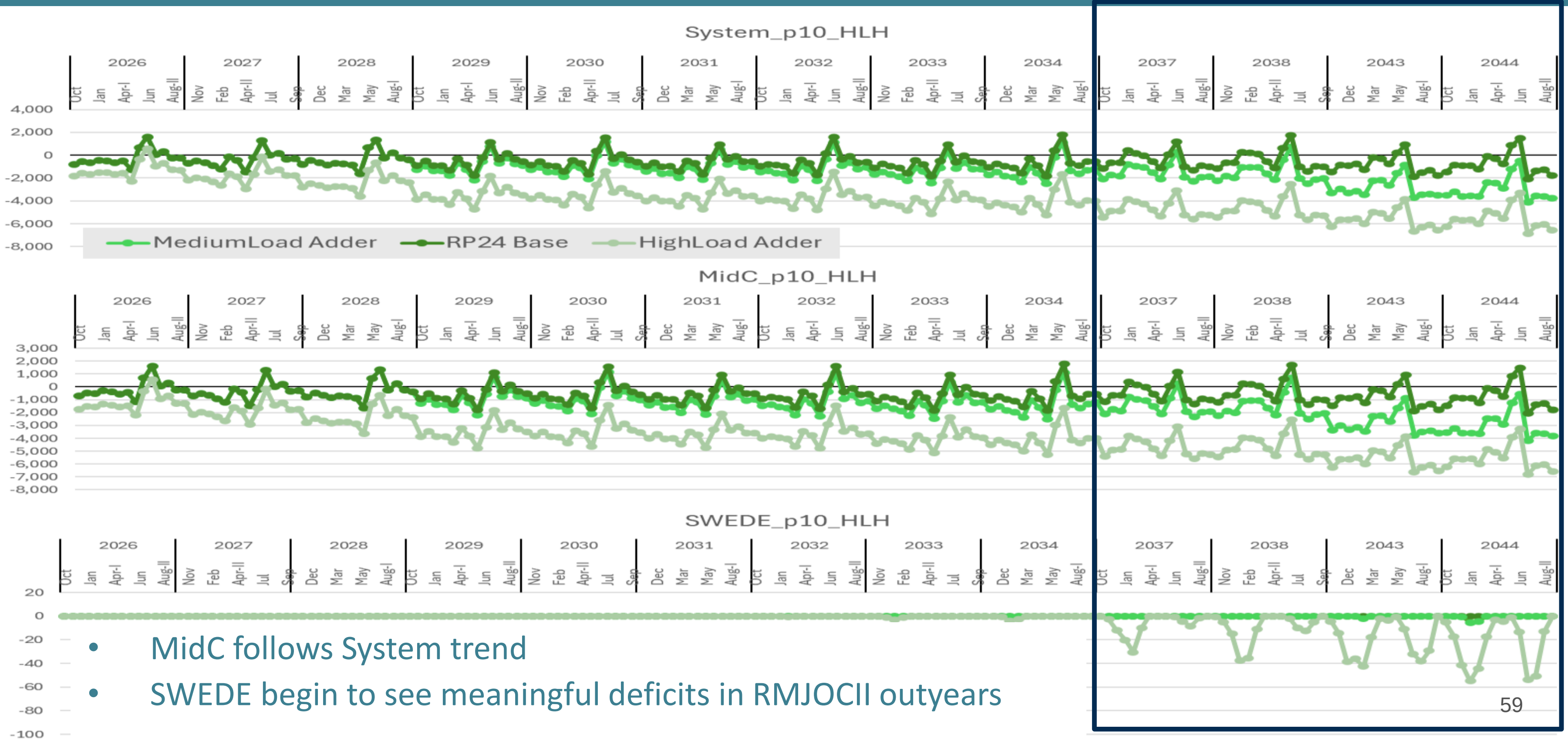


- High load growth implemented by shifting all hours by adder
- Medium load growth implemented by scaling all hours by implied annual growth rate
- Shaping preserves load factor while shifting increases it

Load Adders in p10 HLH surplus/ deficit – RP24 Base

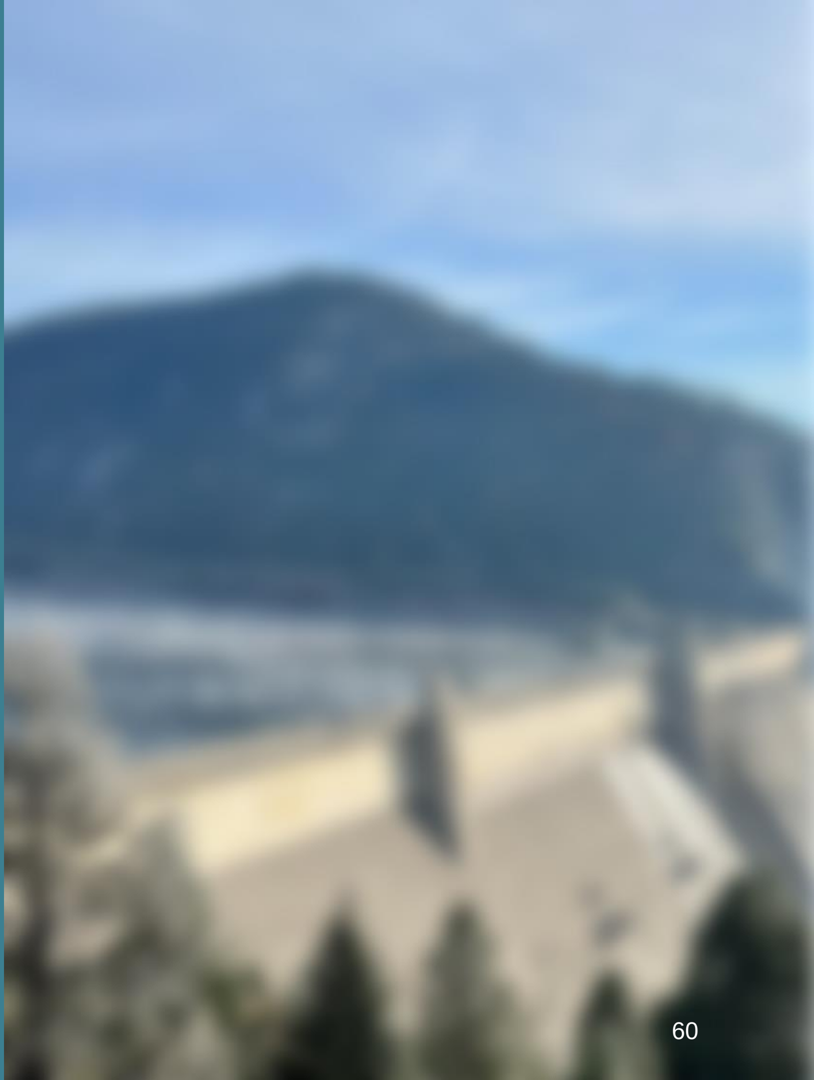


Load Adders in p10 HLH surplus/ deficit – RP24 Base



- MidC follows System trend
- SWEDE begin to see meaningful deficits in RMJOCII outyears

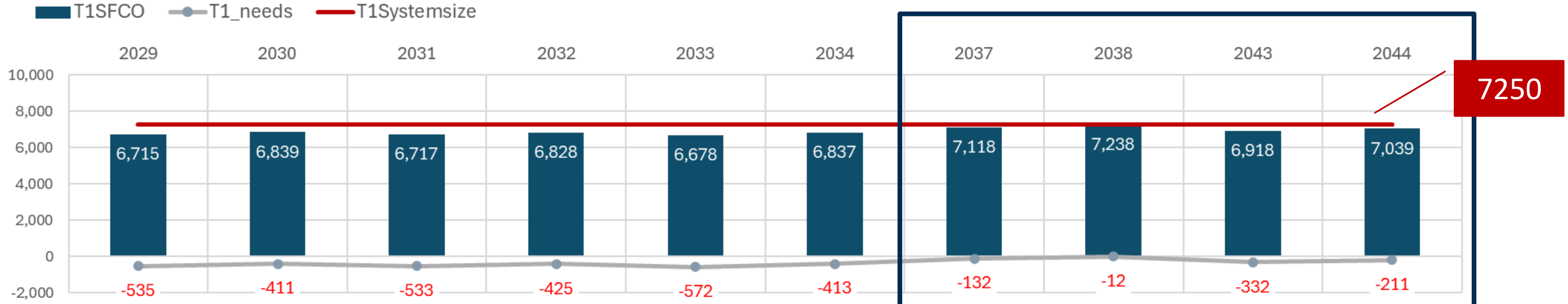
T1 System Augmentation Metric Results

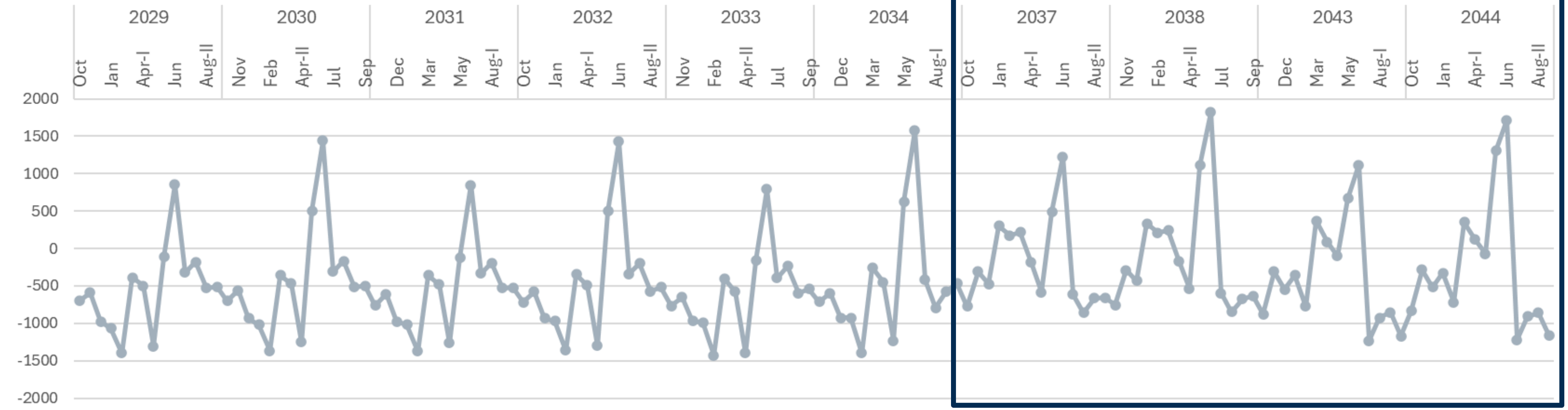


T1 System Size sensitivity - Overview

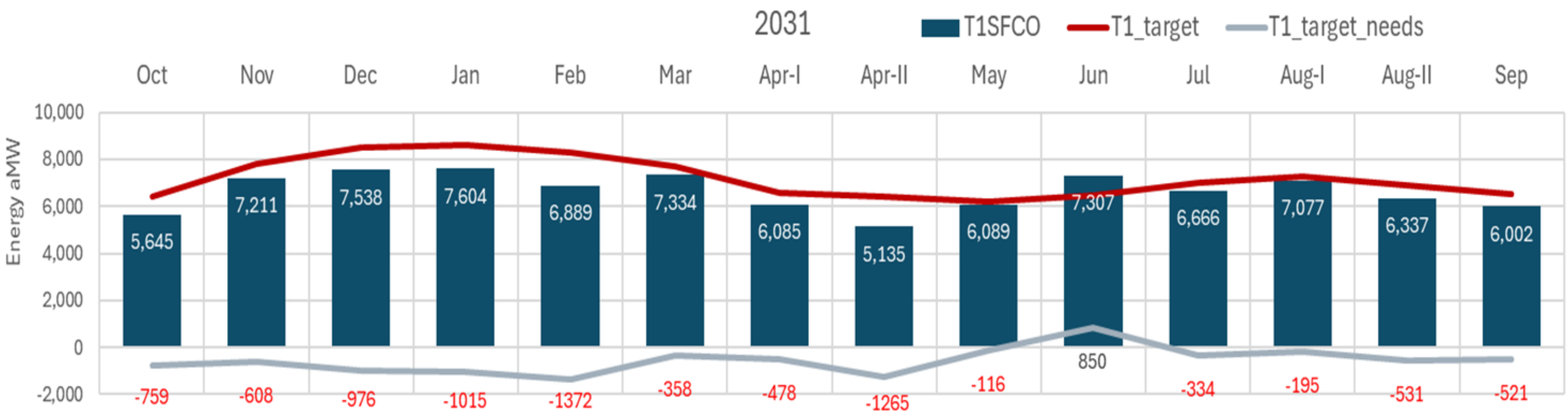
- **Methods:**
  - Forecasted T1 System Firm Critical Output (T1SFCO) is calculated at the hourly level as the sum of existing hydro and non-hydro resource capabilities net of transmission losses, USBR sales, CER exports, and Slice product returns
  - Target T1SFCO is 7250 annual aMW shaped to reflect forecasted hourly shape of T1 obligations
  - Metric is the month-average delta between the hourly forecasted and target T1SFCO under P10 hydro conditions
- **Main findings:**
  - Annualized needs of close to 500 aMW in Historical WY FYs, which imply much larger monthly needs during fall and winter
  - Magnitude of needs significantly impacted by streamflow assumptions under RMJOC-II, ranging from 72 to 272 aMW

T1System Size sensitivity Results



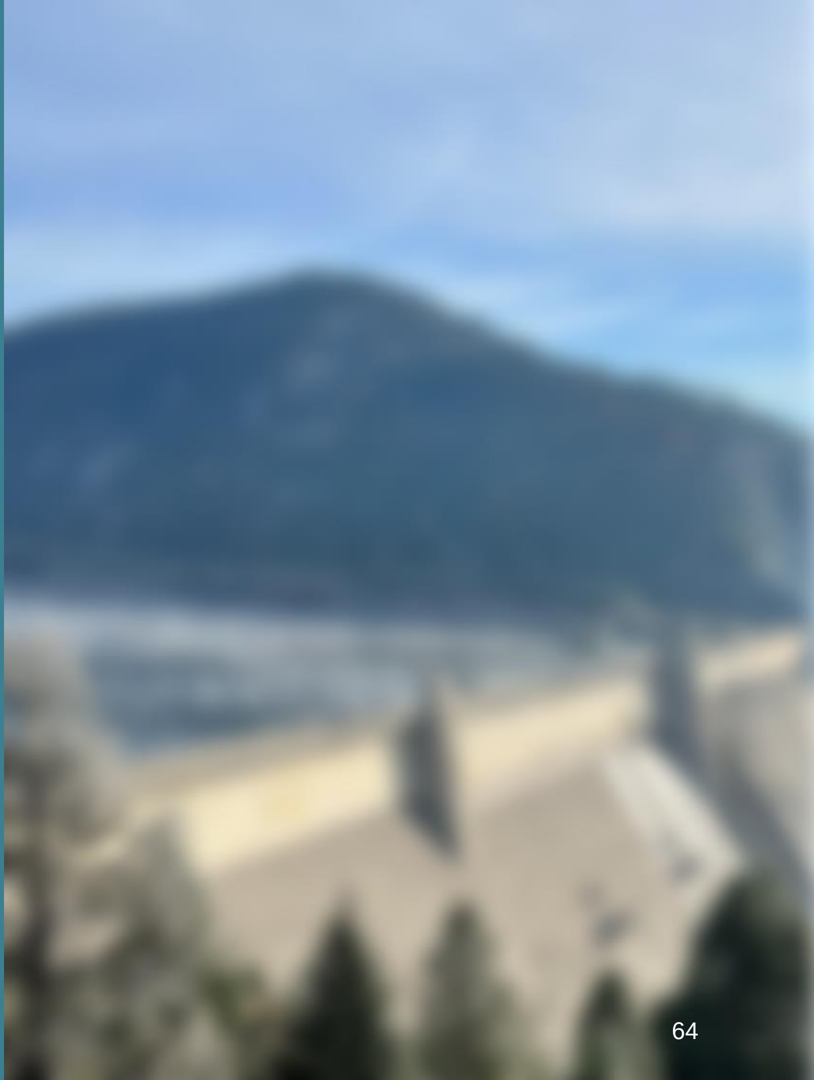


T1System Size – Close up FY2031 needs



- Shaped monthly T1_target annualized to 7250 aMW.
- Gap between T1_target line and T1SFCO bar indicates T1_target_needs.

B2H Delay



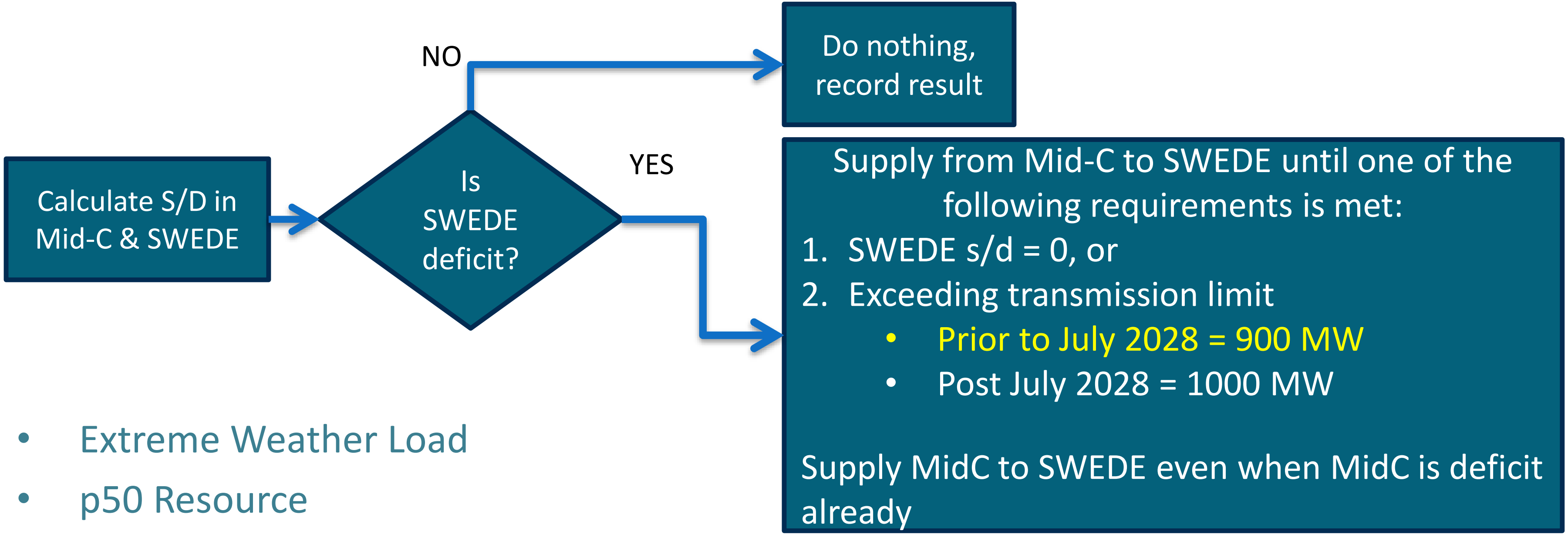
Boardman to Hemingway (B2H) Delay - Overview

- **Methods:**
  - Analyze impact to 18hr capacity metric from 2-yr delay in B2H energization leading to temporary periods of curtailed transmission capability from MidC to SWEDE zones

- **Main findings:**
  - Delay coupled with expiration of Morgan Stanley contracts causes small but meaningful deficits during extreme weather events during Jan/Feb in SWEDE zone
  - Deficits appear under RP24 Base and FT load forecasts as early as FY27

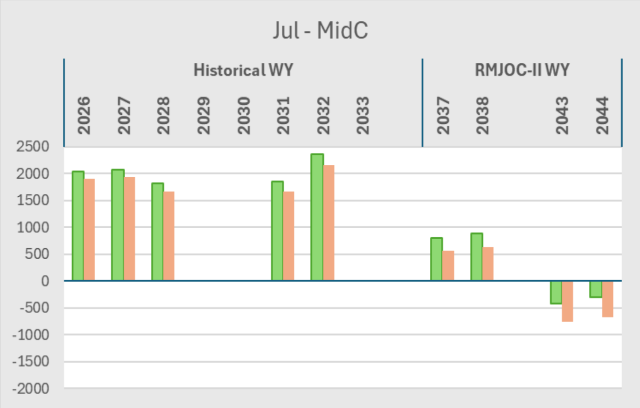
B2H Delay Planning

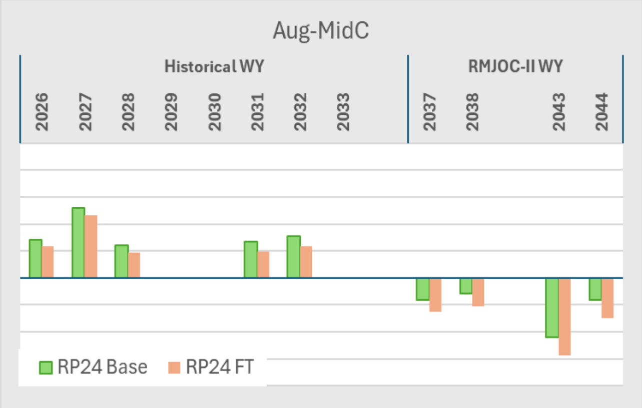
- Assume B2H delayed until July 2028.
  - Reduce transmission capacity from 1000 MW firm to 900 MW.



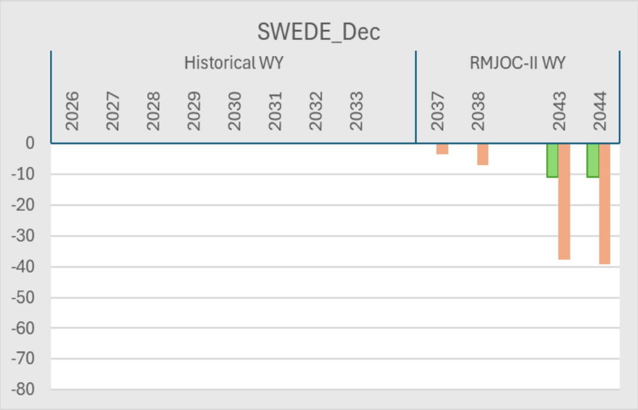
- Extreme Weather Load
- p50 Resource

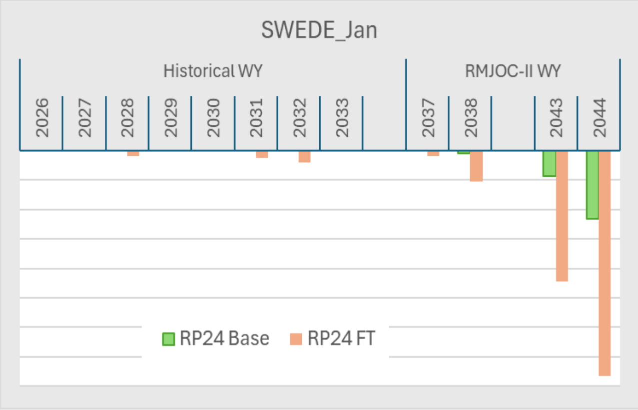
Capacity 18Hr: Surplus/ Deficit aMW – MidC & SWEDE (Recap)

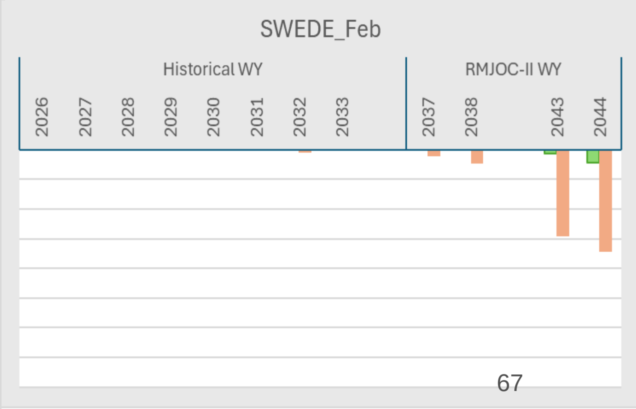




- Mid-C saw deficits only in summer months of RMJOC-II outyears.
- SWEDE only saw deficits in winter months towards the outyears.







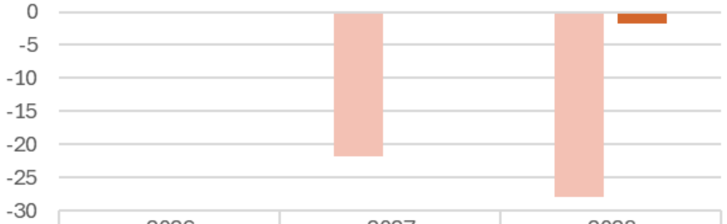
B2H Delay Results – 18Hr Capacity

RP24 Base JAN- SWEDE

	2026	2027	2028
Jan_B2H	0	-7	-11
Jan	0	0	0

- With reduced transmission capacity to 900MW:
  - RP24Base: Jan in 2027 & 2028 showed additional deficits
  - RP24FT: Jan and Feb in 2027 & 2028 show additional deficits
  - Morgan Stanley contract expires in April 2026.

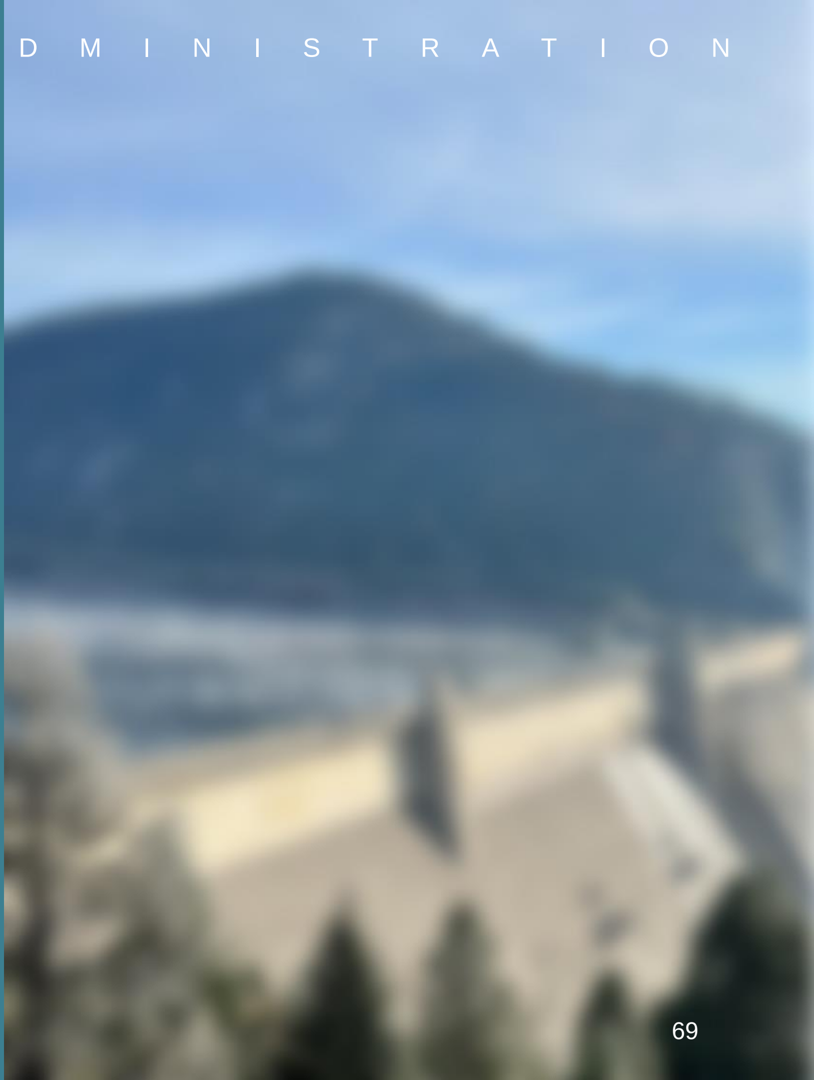
RP24FT JAN-SWEDE



	2026	2027	2028
Jan_FT_B2H	0	-22	-28
Jan_FT	0	0	-2

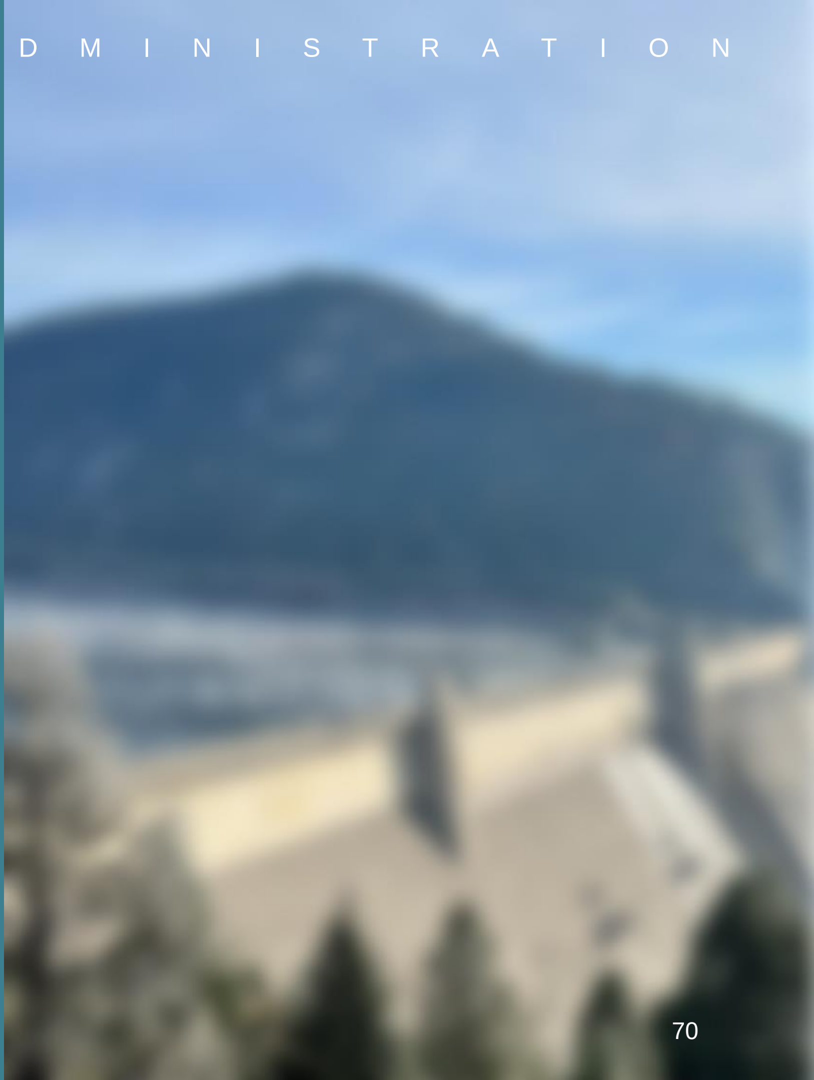
RP24FT FEB-SWEDE

	2026	2027	2028
Feb_FT_B2H	0	-1	-2
Feb_FT	0	0	0



Questions?

RP24 Market Assessment Results



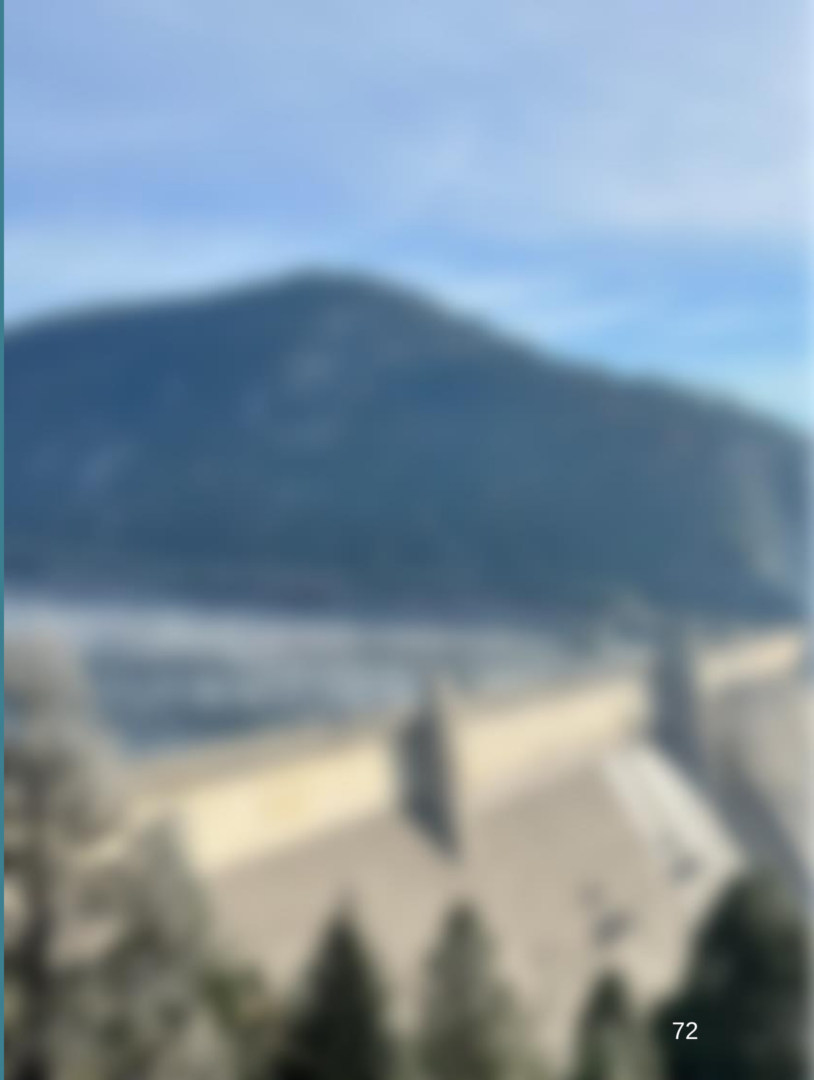
Eric Graessley

Market Assessment Study Lead

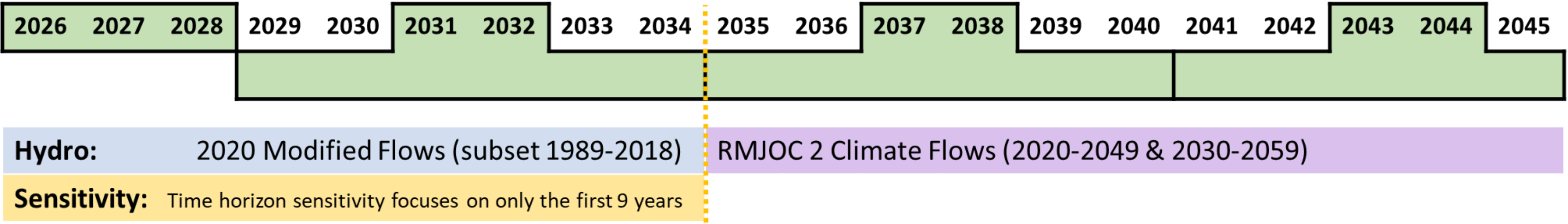
Key Takeaways

- Northwest average price forecast levels have increased moderately, and the distribution of prices across ranges of potential future conditions has increased substantially.
- Inflation Reduction Act (IRA) impacts (including electrification load increases) significantly increase expected buildouts throughout the WECC.
- The combination of additional new resource buildout and improved modeling of short duration storage resource operation resulted in an increase to projected market depth available to meet BPA energy needs.

Market Prices, Key Inputs, and LTCE



RP2024 Time Horizon and Sample Years

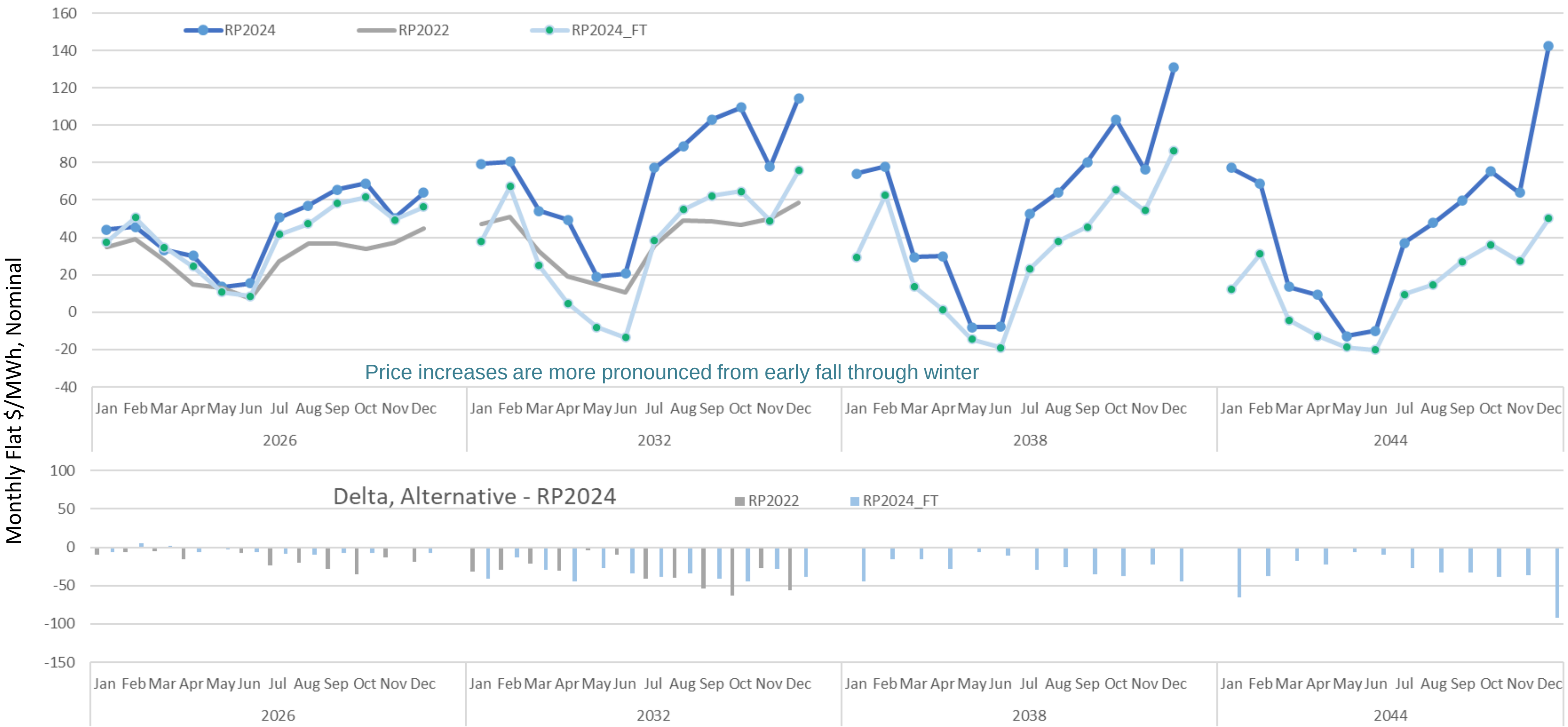


20XX Indicates simulated years.

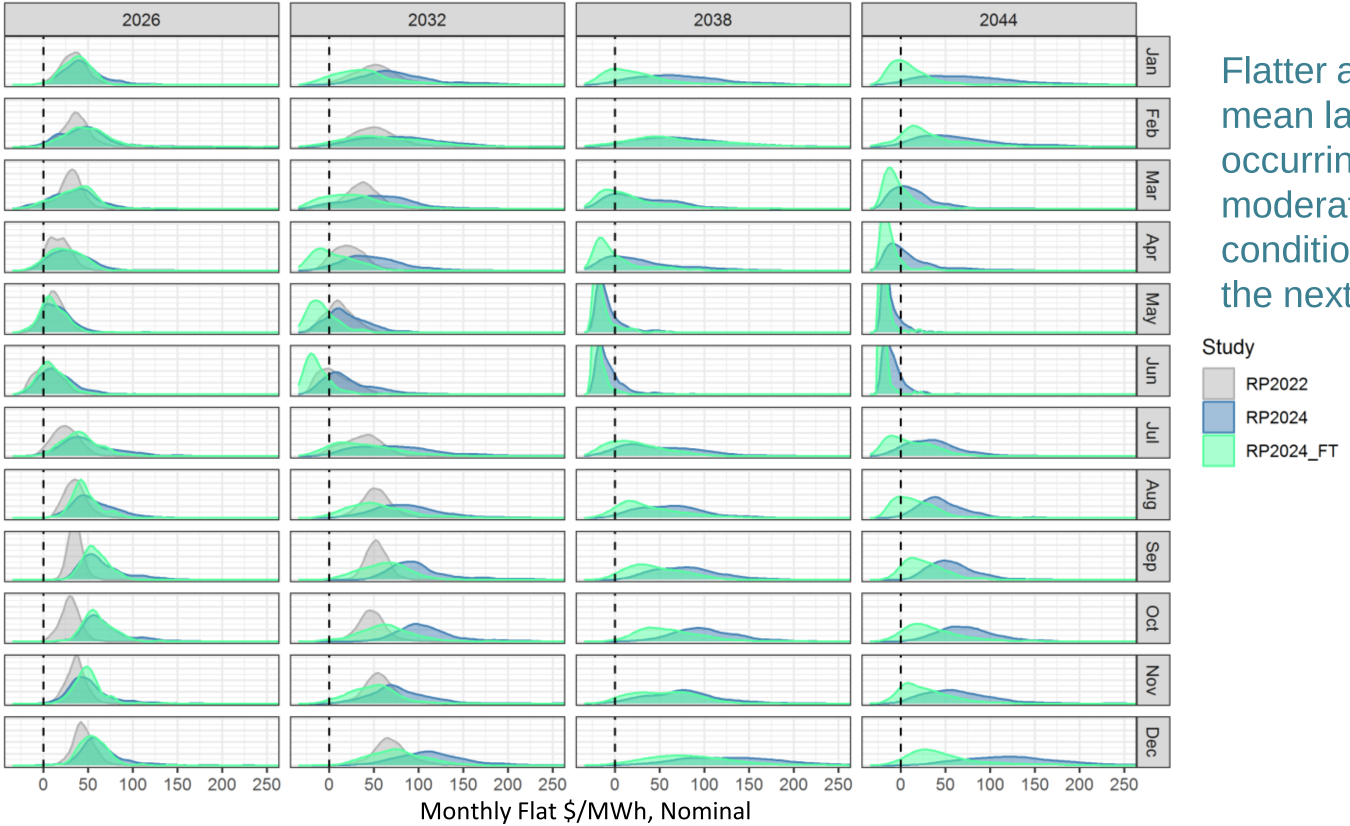
- 2031 & 2032 represent 6 years, 2029 to 2034
- 2037 & 2038 represent 6 years, 2035 to 2040
- 2043 & 2044 represent 5 years, 2041 to 2045

The sensitivity will be part of our automated checks and will help understand which resources are being selected because of out-year (2035 and beyond) assumptions.

Mid-C / NW Average Prices

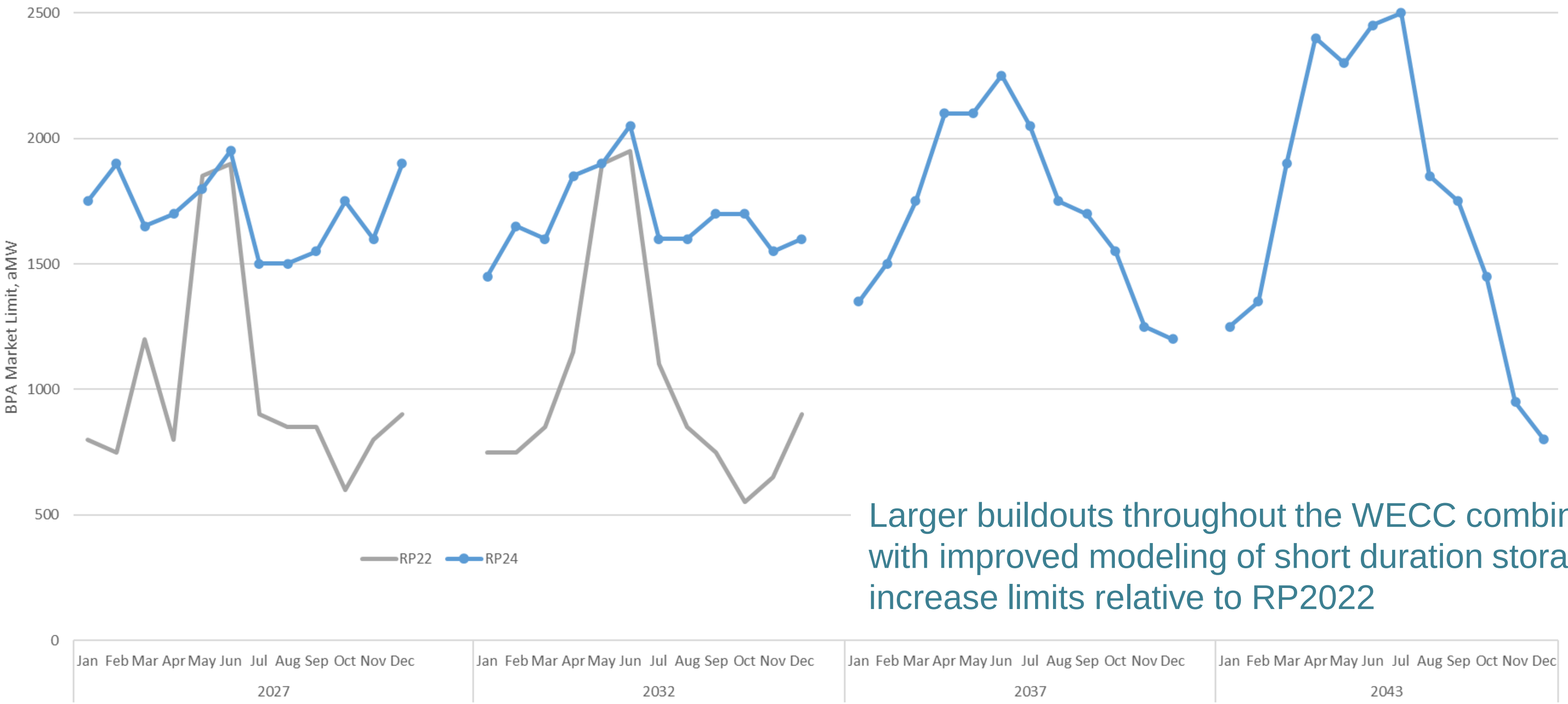


Mid-C / NW Price Distributions



Flatter and wider distributions mean larger price swings are occurring with more moderate changes to conditions from one period to the next.

BPA Market Depth



Larger buildouts throughout the WECC combined with improved modeling of short duration storage increase limits relative to RP2022

BPA Uses of Aurora Long Term (LT) Price Forecasts

- **Resource Program**
- **Competitiveness / LT rates**
- **Associated Lack of Market (LOM) spill impacts projected inventories**
- Treaty negotiations
- Alternative fish operations
- Independent hydro efficiency upgrade evaluation
- CGS economic analysis
- Evaluate impacts of various carbon policies
- LT build assumptions also influence rate case price forecasts
- Inform other, one-off LT valuations

Aurora Refresher

- Aurora is a versatile **production cost model** widely used to evaluate the economics, evolution, and operation of wholesale electricity grids (utilities, regulators, system operators, planning entities, consultants, and investment firms across the globe).

- Production cost models solve for the least cost method of meeting load, given resource and transmission constraints (resource limits and variable costs, line capability, wheeling costs, and losses), and assume the marginal cost (cost of the next incremental MW) of producing and delivering energy is a good proxy for energy prices.

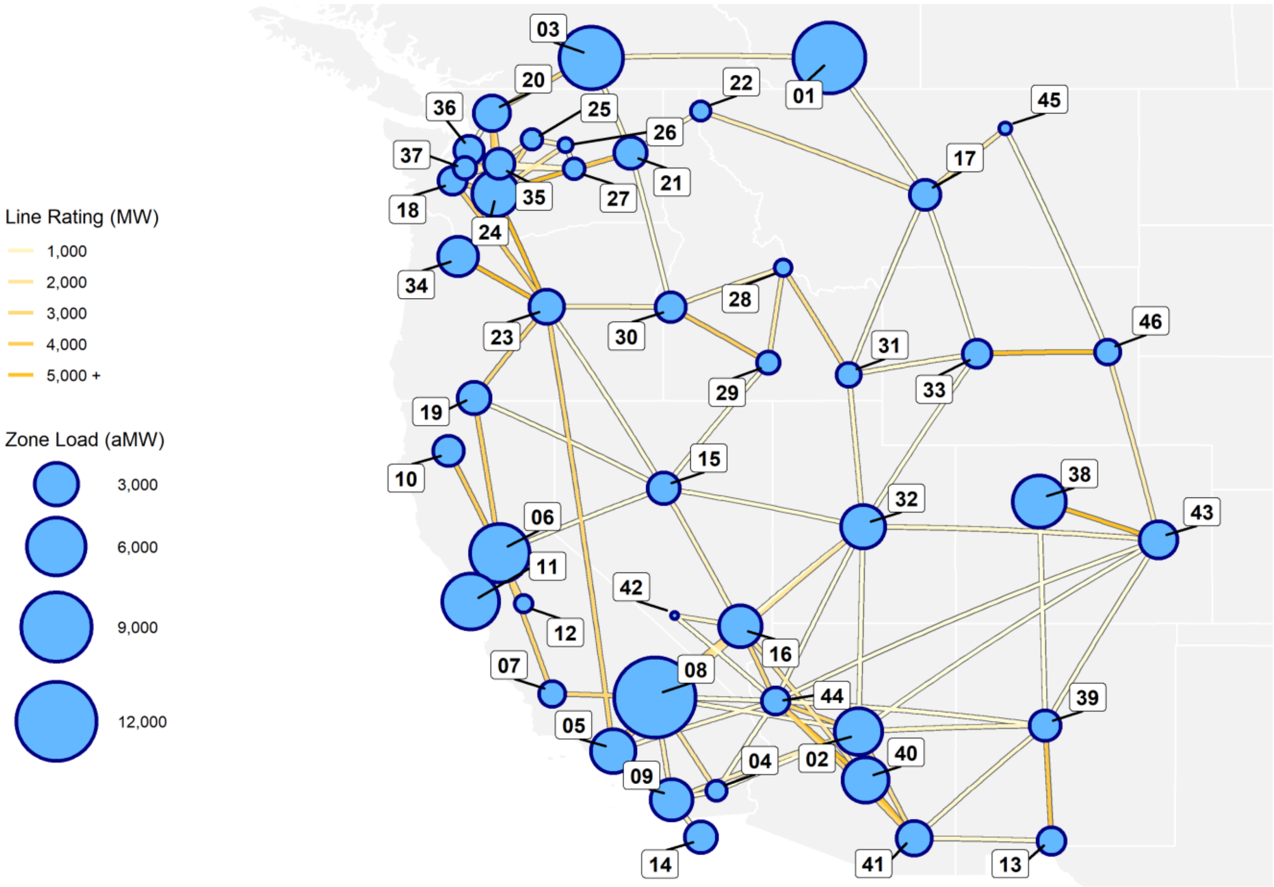
- **We calibrate the model based on recent Day Ahead (DA) prices (2018-2022), but we do not explicitly account for the following:**
  - Market design differentiation (**NO**: forward curves / firm contracts / DA - RT markets & forecast error, source & sink, local commitment considerations), **all of the WECC is effectively modeled as a single ISO** (centrally optimized and dispatched)
  - Behavioral components of power markets (in reality, bids may differ from actual marginal cost)
  - AC flows / nodal prices, and transmission system is fixed over time (Aurora has the capability, not yet implemented)
  - Ancillary services (again, Aurora has the capability, not yet implemented)
  - No thermal resource duct firing / peak heat rates / unit dependency

- Aurora is a deterministic model**, we produce a distribution of price forecasts** by **using a Monte Carlo technique that draws from historical variation of: loads, hydro generation, gas prices, transmission capability, wind generation, and CGS availability.**

- We use a 46-zone topography of the Western Interconnection that is mostly aligned with BAs (see next slide), and solve for *hourly* prices

Aurora Topology

Zone Short Names	
01	Alberta
02	APS
03	BC
04	IID
05	LADWP
06	PG&E North
07	PG&E ZP26
08	SCE
09	SDG&E
10	BANC
11	PG&E Bay Area
12	TIDC
13	EPE
14	Baja
15	NV North
16	NV South
17	NW MT
18	Olympia
19	PAC W
20	Puget North
21	Avista
22	BPA IDMT
23	BPA OR
24	BPA WA
25	Chelan
26	Douglas
27	Grant
28	ID Power FE
29	ID Power MV
30	ID Power TV
31	PAC E ID
32	PAC E UT
33	PAC E WY
34	Portland GE
35	Puget East
36	Seattle CL
37	Tacoma
38	PS CO
39	PS NM
40	Salt River
41	Tuscon
42	VEA
43	WAPA CO
44	WAPA LwCO
45	WAPA UprMO
46	WAPA WY



Aurora and Market Design (WEIM / Resource Adequacy)

- Aurora does not explicitly account for differences in market structure (bilateral vs ISO or different time horizons). It simulates the interconnect as if the WECC were centrally dispatched in a single ISO, and we assume that prices will tend to converge on the marginal cost of generating & delivering electricity.

- Aurora has capabilities to model components of the Western Energy Imbalance Market (WEIM), but these tend to be computationally prohibitive and incompatible with existing models and methodologies.
  For example:
  - Sub-hourly (incompatible with risk and rate case models, requires significant investment)
  - Nodal topography (Locational Marginal Prices—LMP, including congestion, this change requires significant investment)
  - Can use commitment logic to lock in DA commitment, and add deviations load and renewable resources + reliability commitments to better approximate Real Time (RT) – DA dynamics

- Alternatively, attempting to modify Aurora to depict price differences resulting from the current bilateral structure of NW markets would be highly speculative (we could adjust wheeling adders… but by how much?)

- Aurora assumes regions will meet reliability targets in a coordinated, efficient manner. Effectively, the base assumption is that Resource Adequacy (RA) efforts are successful and well-designed throughout the interconnection

Ultimately, we are not making any adjustments to account for possible differences resulting from participation in Western Energy Imbalance Market (WEIM) or Western Resource Adequacy Program (WRAP)

Aurora Inputs

- Calibration
- Negative Prices
- Gas Prices
- Clean Policy
- Loads & Electrification
- Transmission Builds
- Long Term Capacity Expansion (LTCE)

Aurora Calibration 2018-2022

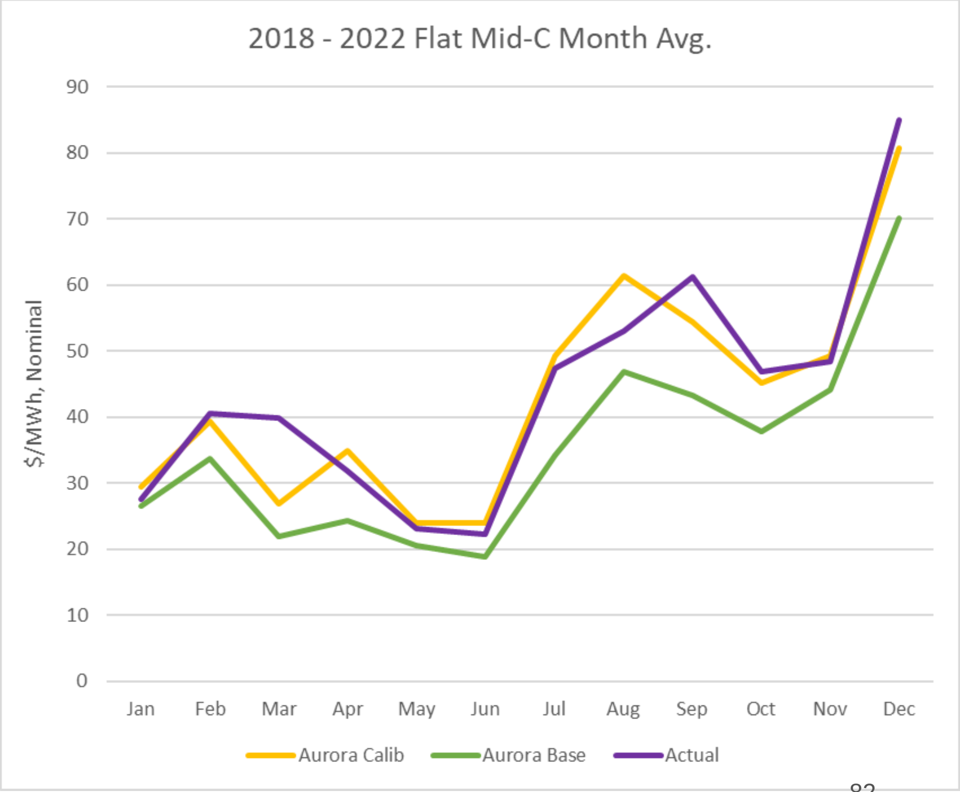
There are two main reasons Aurora price forecasts are wrong:

1) Get the fundamentals* wrong

2) Get the relationship between fundamentals and prices wrong (not capturing important details of how markets and the grid work / behavioral effects)

Benchmarking (running Aurora with actual fundamentals and comparing results to actual prices) allows us to isolate and address the 2nd problem through calibrating thermal resource bid behavior

* ‘Fundamentals’= loads, hydro generation, gas prices, transmission capability, renewable generation, etc.



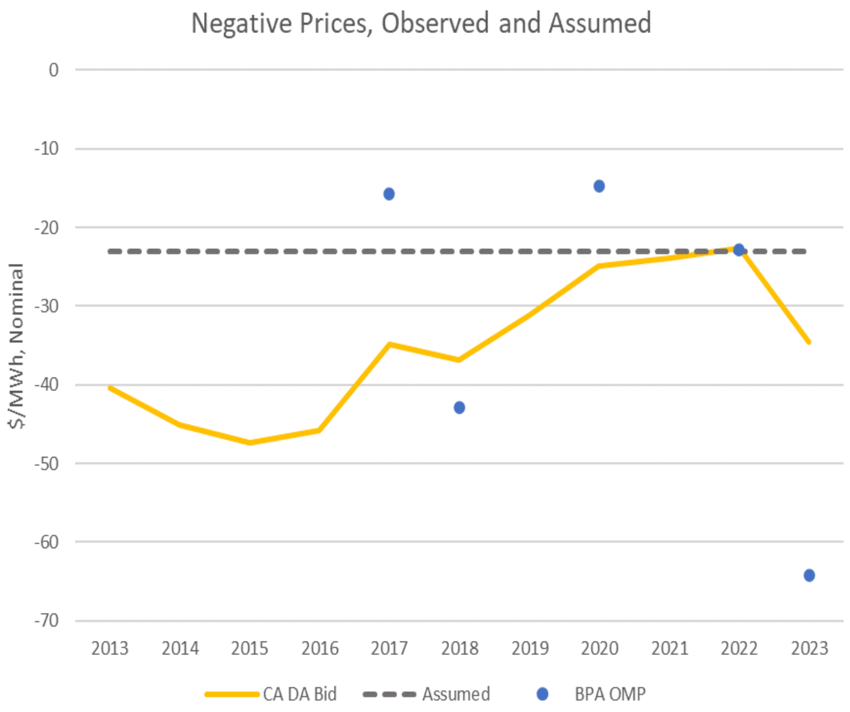
Negative Prices

- **Main drivers: policy**. Incentives and requirements introduce costs to curtailing renewable resources
  - Forgone RECs / PTCs (IRA) / PPA revenue / Potentially having to build additional resources
  - 'replacement cost' of renewable energy

- Generally, consultants and other production cost modelers *do not* include negative prices

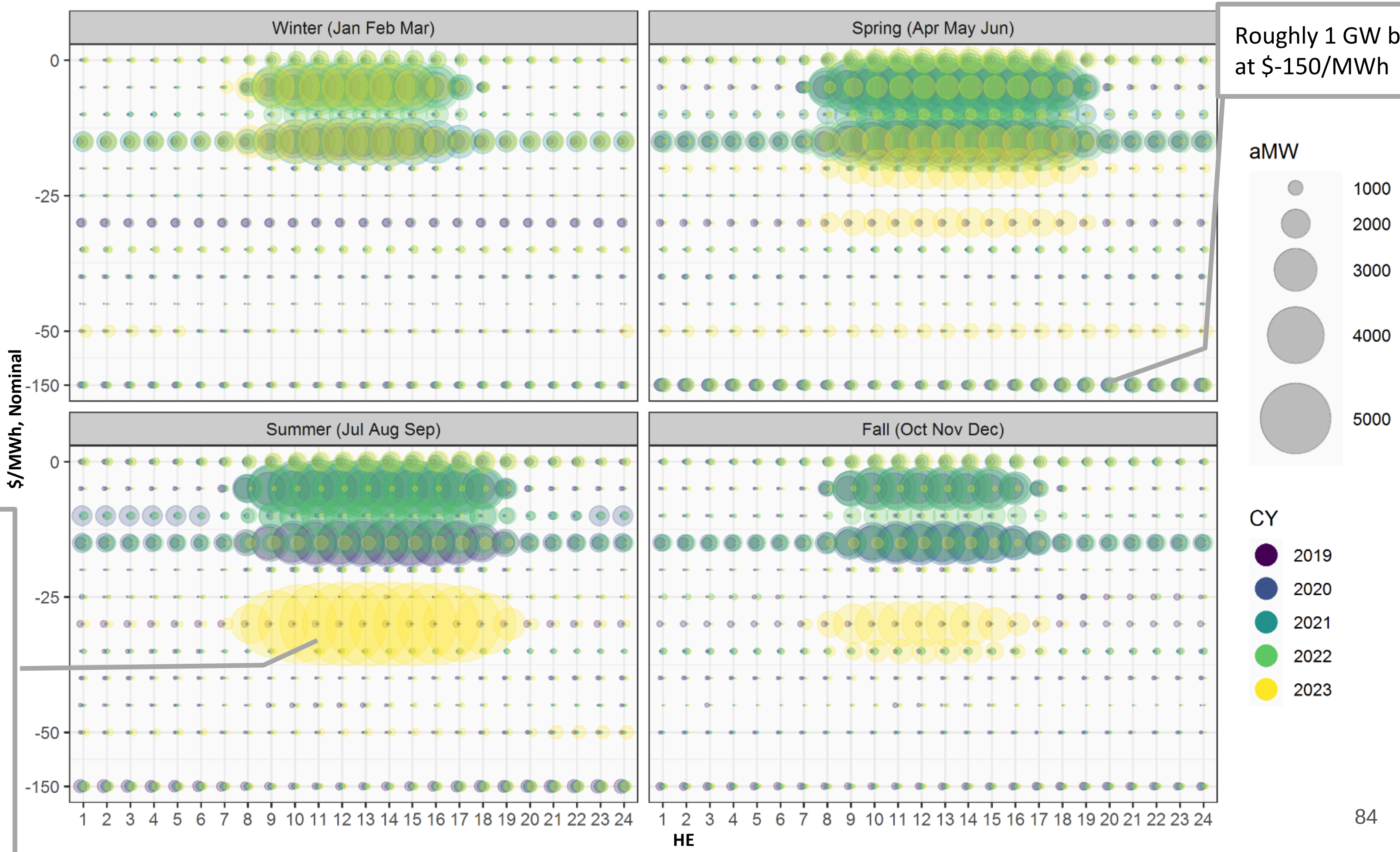
- **BPA models all renewable resources bidding at ~negative $23/MWh**

- We include mechanisms to reflect maximum hydro spill up to latest TDG limits and set BPA BA wind to curtail at $0/MWh, approximating Oversupply Management Protocol (OMP) effects. All other hydro is set to -$25/MWh, to curtail after renewables.



BPA OMP weighted avg price: ~ -$29/MWh

CAISO Negative DA Bids



Roughly 1 GW bidding at $-150/MWh

Most negative bids seem to be solar, bids are getting more negative recently.

Nearly 5 GW bidding at ~ -$30/MWh

Gas Prices (Stanfield)

Increase in RP2024 avg forecast gas price driven mostly by increases in upper bound risk included in the distribution of forecast prices.

Clean Policy

- Including the IRA resulted in very significant increases in renewable buildout
  - Modeled as production tax credit at the base level for solar and wind (PTC tends to yield more value for these resources), and 30% ITC for all other eligible resources.
  - Assume benefits will begin to taper off in 2035.
- Modeling is focused on capturing supply-side policy requirements and includes the following:
  - WA’s RPS,CETA, and carbon prices
  - OR RPS and decarbonization requirements
  - CA Carbon prices and SB100
  - Alberta RPS and carbon prices
  - Best estimates of all WECC state, utility, and municipal RPS and clean standards (*see next slide)*
- Rely on other studies to estimate policy impacts on the load side, discussed in later slides

B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N

Clean Policy

Base		2030	2035	2040	2045	2050
RPS	AZ	15%	15%	15%	15%	15%
	CA	60%	60%	60%	60%	60%
	CO	21%	21%	21%	21%	21%
	ID	0%	0%	0%	0%	0%
	MT	15%	15%	15%	15%	15%
	NM	50%	65%	80%	80%	80%
	NV	50%	50%	50%	50%	50%
	OR	26%	32%	36%	36%	36%
	UT	0%	0%	0%	0%	0%
	WA	15%	15%	15%	15%	15%
	WY	0%	0%	0%	0%	0%
ZEM	AZ	30%	30%	30%	30%	30%
	CA	60%	68%	85%	98%	98%
	CO	30%	38%	48%	58%	67%
	ID	10%	25%	41%	53%	53%
	MT	0%	0%	0%	0%	0%
	NM	50%	65%	80%	88%	98%
	NV	50%	50%	50%	75%	98%
	OR	38%	54%	57%	57%	57%
	UT	37%	37%	37%	37%	42%
	WA	80%	80%	90%	98%	98%
	WY	0%	0%	0%	0%	0%

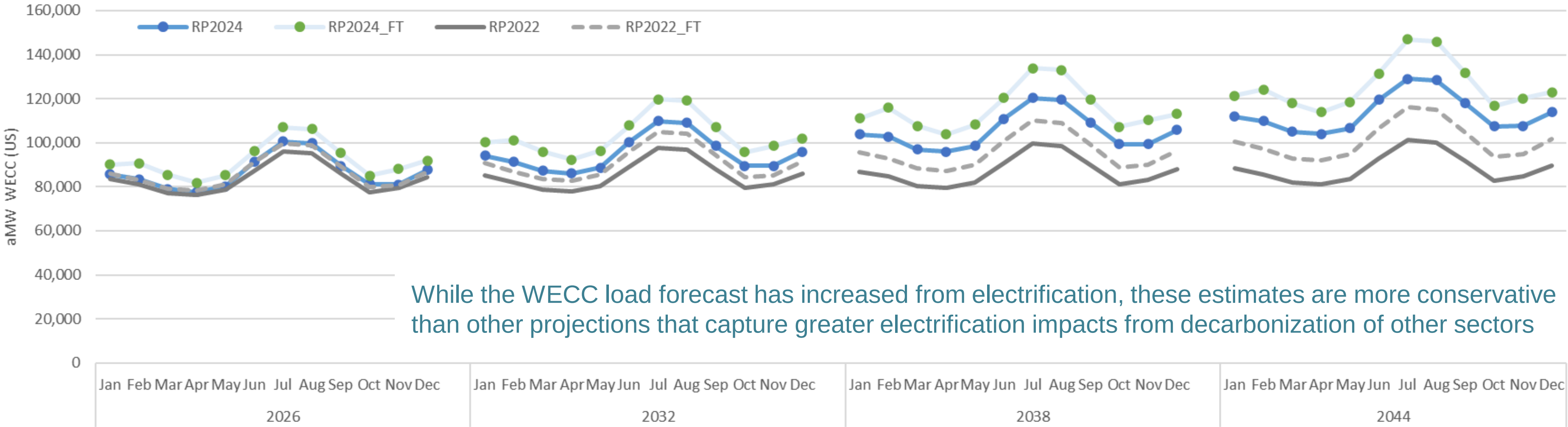
Fast Transition		2030	2035	2040	2045	2050
RPS	AZ	15%	15%	15%	15%	15%
	CA	60%	60%	60%	60%	60%
	CO	21%	21%	21%	21%	21%
	ID	0%	0%	0%	0%	0%
	MT	15%	15%	15%	15%	15%
	NM	50%	65%	80%	80%	80%
	NV	50%	50%	50%	50%	50%
	OR	26%	32%	36%	36%	36%
	UT	0%	0%	0%	0%	0%
	WA	15%	15%	15%	15%	15%
	WY	0%	0%	0%	0%	0%
ZEM	AZ	30%	30%	40%	65%	98%
	CA	60%	68%	85%	98%	98%
	CO	30%	38%	48%	65%	98%
	ID	10%	25%	41%	65%	98%
	MT	0%	25%	40%	65%	98%
	NM	50%	65%	80%	88%	98%
	NV	50%	50%	50%	75%	98%
	OR	38%	54%	57%	65%	98%
	UT	37%	37%	40%	65%	98%
	WA	80%	80%	90%	98%	98%
	WY	0%	25%	40%	65%	98%

The Fast Transition (FT) represents a scenario where all states in the WECC transition to mostly zero emission (ZEM) resources by 2050.

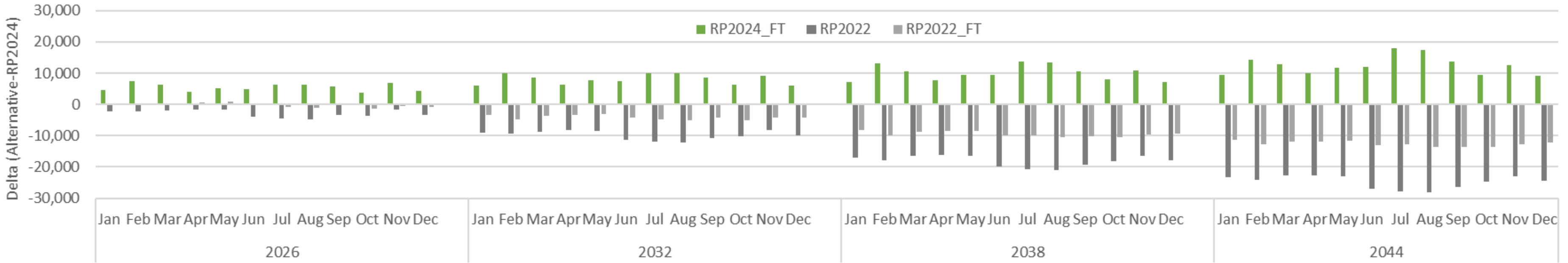
The FT is not a net zero study and modeling continues to struggle to achieve 100% zero emission scenarios.

B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N

Loads & Electrification (WECC US)



While the WECC load forecast has increased from electrification, these estimates are more conservative than other projections that capture greater electrification impacts from decarbonization of other sectors



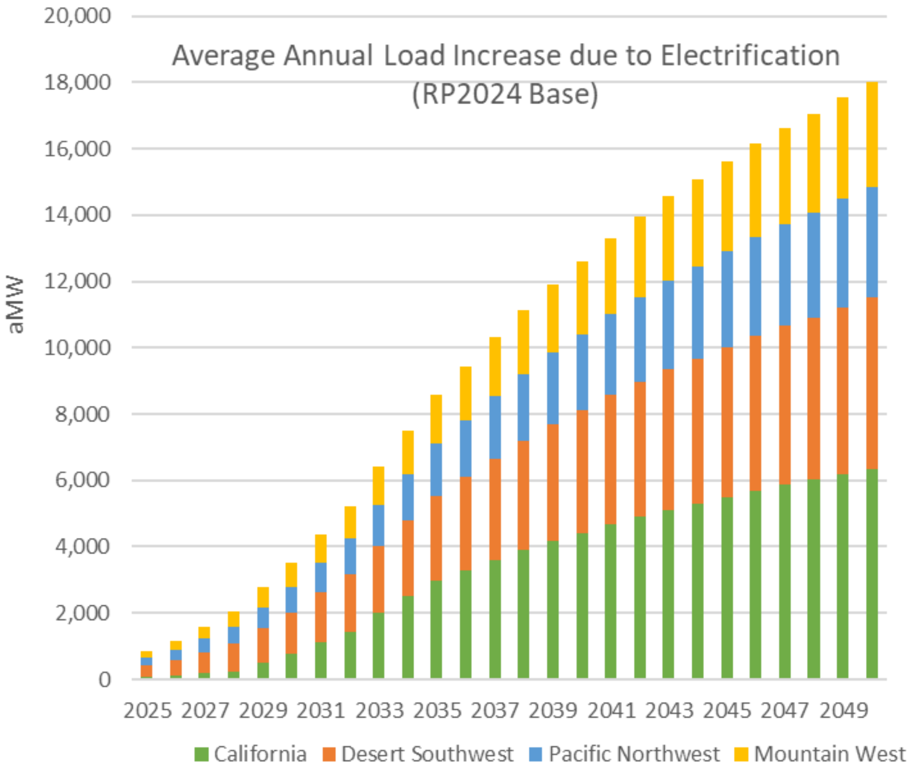
Loads and Electrification

- **RP2024 Includes Increased Electrification** Consistent with the BPA load forecast, WECC load forecasts were adjusted to account for increased electrification largely relying on the EIA 2023 AEO, which leveraged NREL electrification studies to help capture IRA impacts

- **NREL Electrification Futures Study** includes increased loads due to electrification from four sources:
  - Transportation
  - Commercial
  - Residential
  - Industrial

- **Electrification adders are flat increases to load and do not include modifications for hourly shaping**

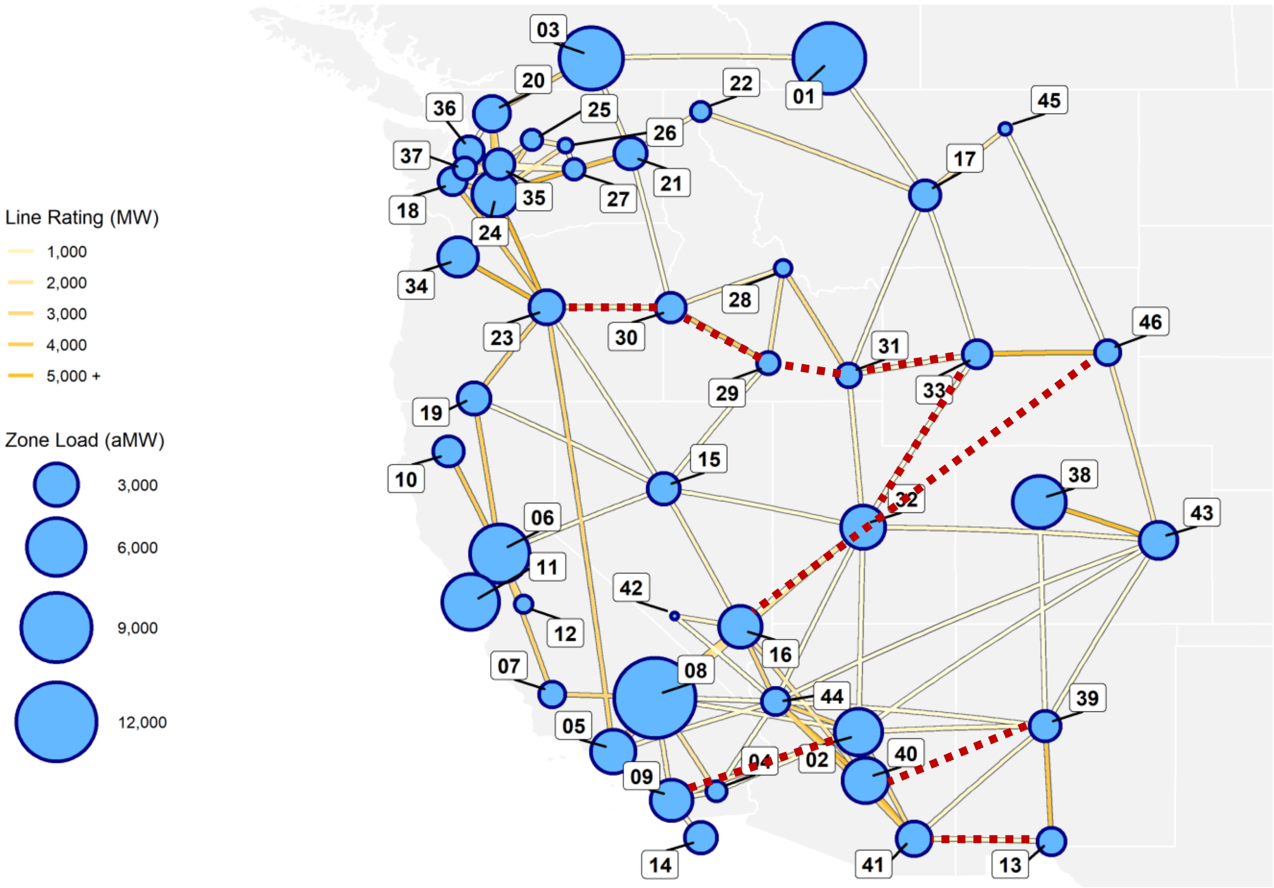
- **RP2024 Fast Transition** uses the increased load values from RP2024 plus an adjustment factor to capture higher load forecast values, consistent with BPA load forecasts in the needs assessment.



New Transmission Builds

- B2H (2027)
- Gateway West (2026 to 2030)
- Gateway South (2025)
- TransWest Express (2028)
- SunZia (2027)
- North Gila-Imperial Valley (2026)

Does *not* include potential increases in PNW transfer capabilities from BPA investments



Zone Short Names	
01	Alberta
02	APS
03	BC
04	IID
05	LADWP
06	PG&E North
07	PG&E ZP26
08	SCE
09	SDG&E
10	BANC
11	PG&E Bay Area
12	TIDC
13	EPE
14	Baja
15	NV North
16	NV South
17	NW MT
18	Olympia
19	PAC W
20	Puget North
21	Avista
22	BPA IDMT
23	BPA OR
24	BPA WA
25	Chelan
26	Douglas
27	Grant
28	ID Power FE
29	ID Power MV
30	ID Power TV
31	PAC E ID
32	PAC E UT
33	PAC E WY
34	Portland GE
35	Puget East
36	Seattle CL
37	Tacoma
38	PS CO
39	PS NM
40	Salt River
41	Tuscon
42	VEA
43	WAPA CO
44	WAPA LwCO
45	WAPA UprMO
46	WAPA WY

New Resources and Emerging Tech

- Continue to rely on two types of clean, firm flexible resources to achieve clean policy goals and maintain system reliability:
  - **Base**: Very high fixed cost, low variable cost resource. Modeled after Small Modular Reactor (SMR), also comparable to traditional fossil fuel base resource with Carbon Capture & Sequestration (CCS)
  - **Peaker**: Low fixed cost, high variable cost resource. Modeled after hydrogen (H2) combustion turbine with onsite electrolysis and storage, also ~comparable to combustion turbine running on other bio/renewable fuels / traditional peaking resource with CCS

- Other new resource options also included solar, wind, four and eight hour Battery Energy Storage Systems (BESS), limited offshore wind, small amounts of geothermal, and limited natural gas (NG) where not policy restricted.

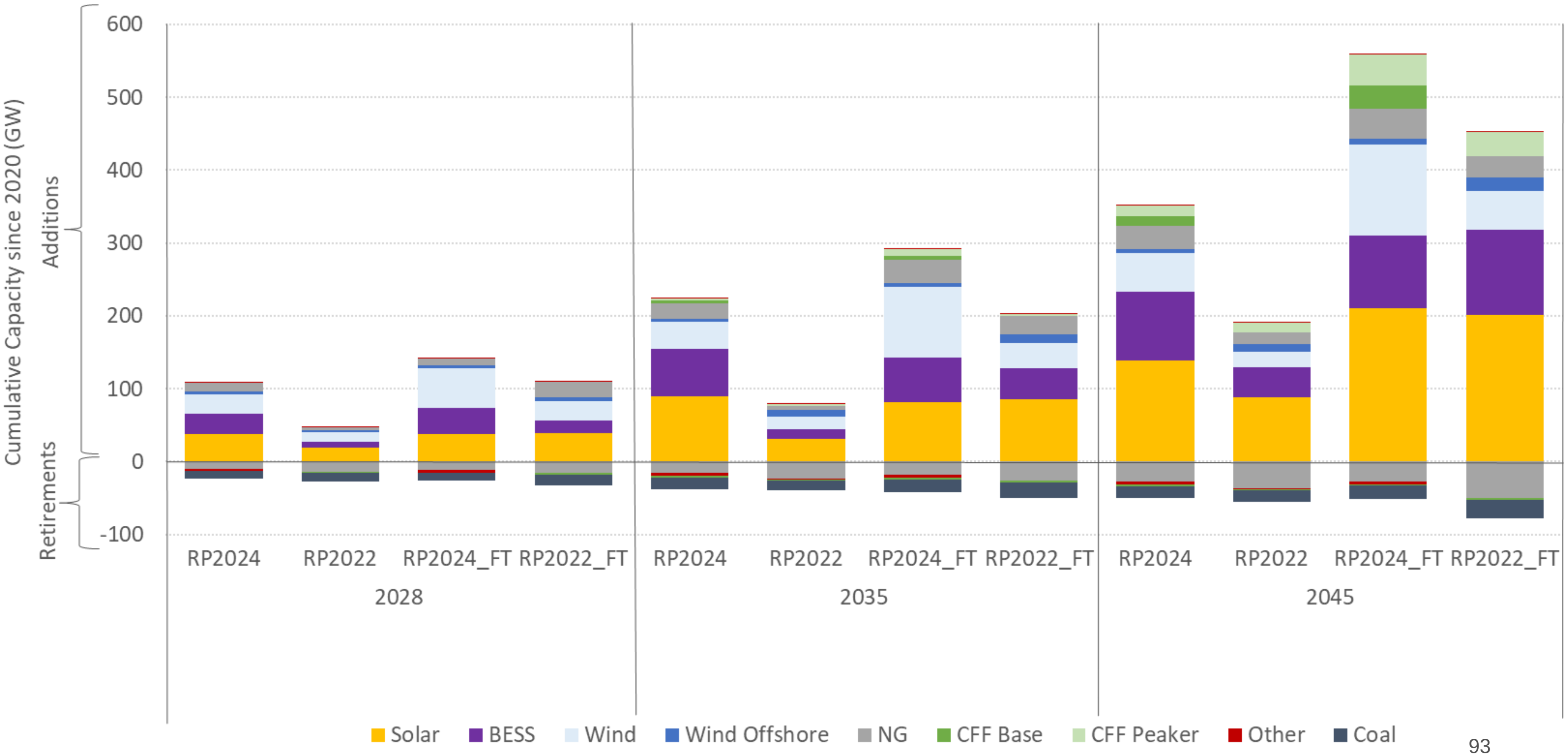
Aurora Resource Build: LT Capacity Expansion

1. Start with existing resources

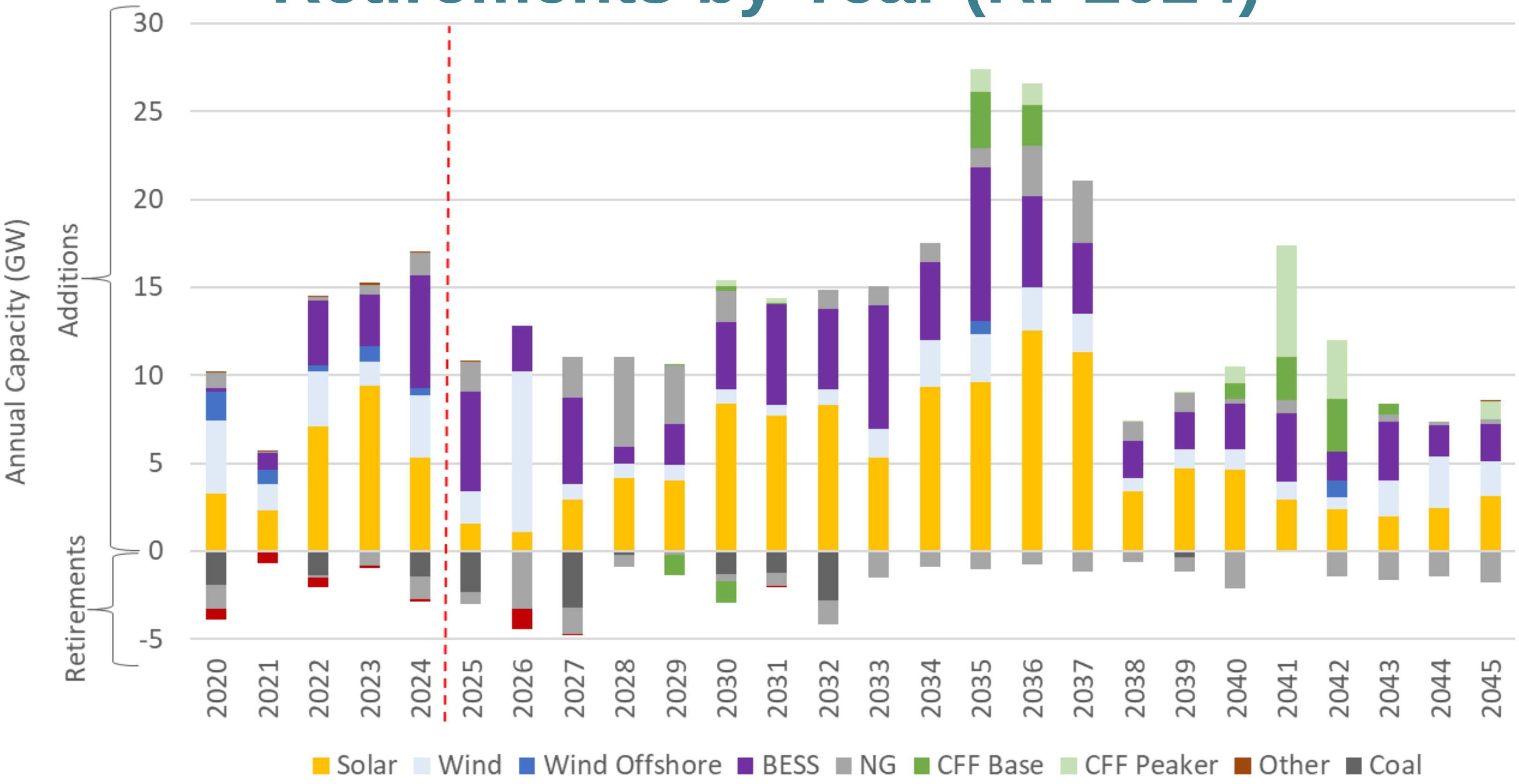
2. Lock in high likelihood builds and retirements over the duration of the next rate period (through 2028) – sources include IRPs, data from consultants, EIA, and the BPA generation interconnection queue (exceptions being Diablo Canyon retirement, some once through cooling (OTC) generation in CA, and Site C in BC)

3. Allow Aurora to build and retire additional resources based on economics, ensuring pool planning reserve margins are satisfied and all relevant state policies (Renewable Portfolio Standards (RPS) / zero emission targets) are met
   - Use dynamic peak credits for variable resources (wind and solar), updated iteratively
   - Get policy constraint shadow prices which should help inform expectations of costs of policy compliance and negative price behavior

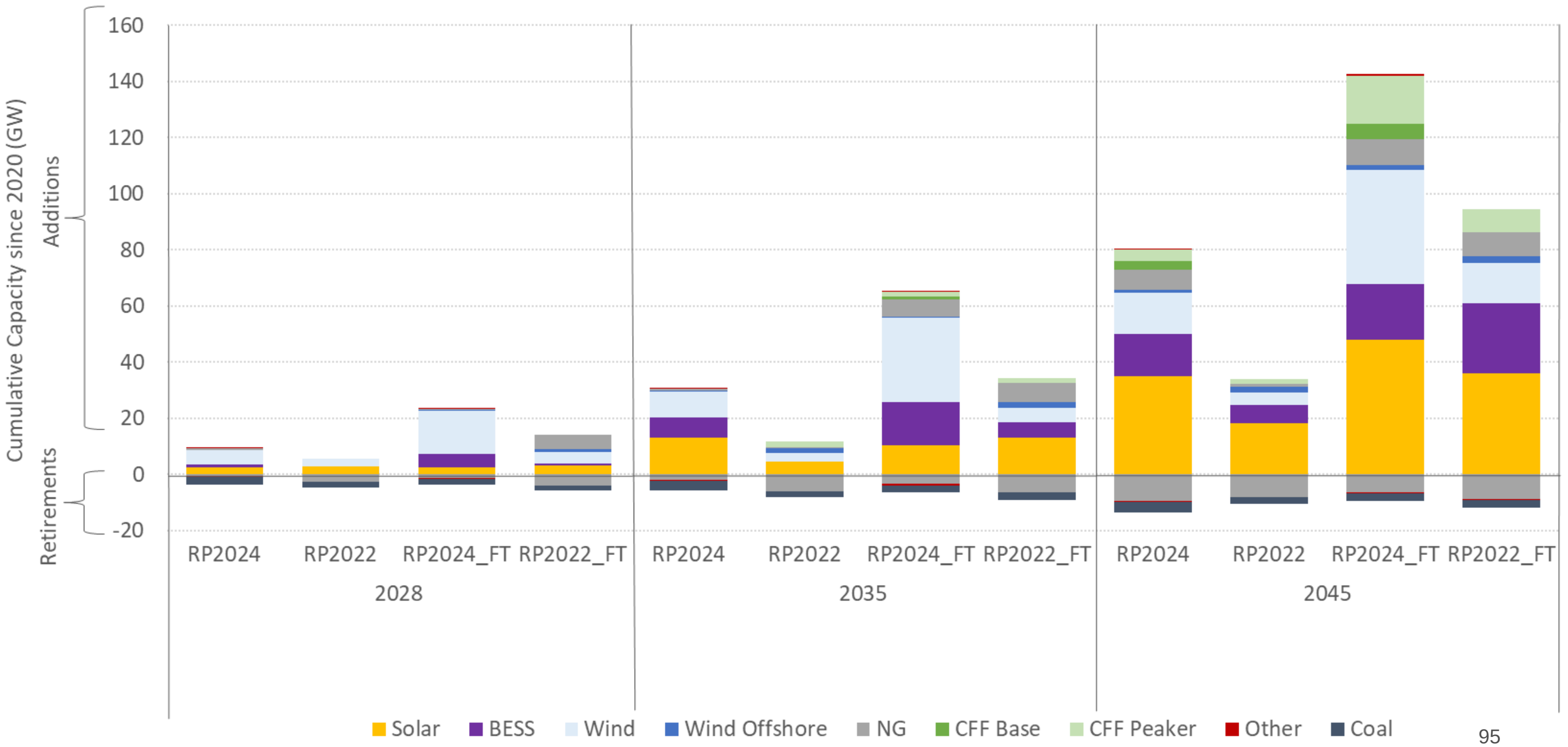
Cumulative WECC (US) Builds and Retirements (2020 Start)



Incremental WECC (US) Builds and Retirements by Year (RP2024)

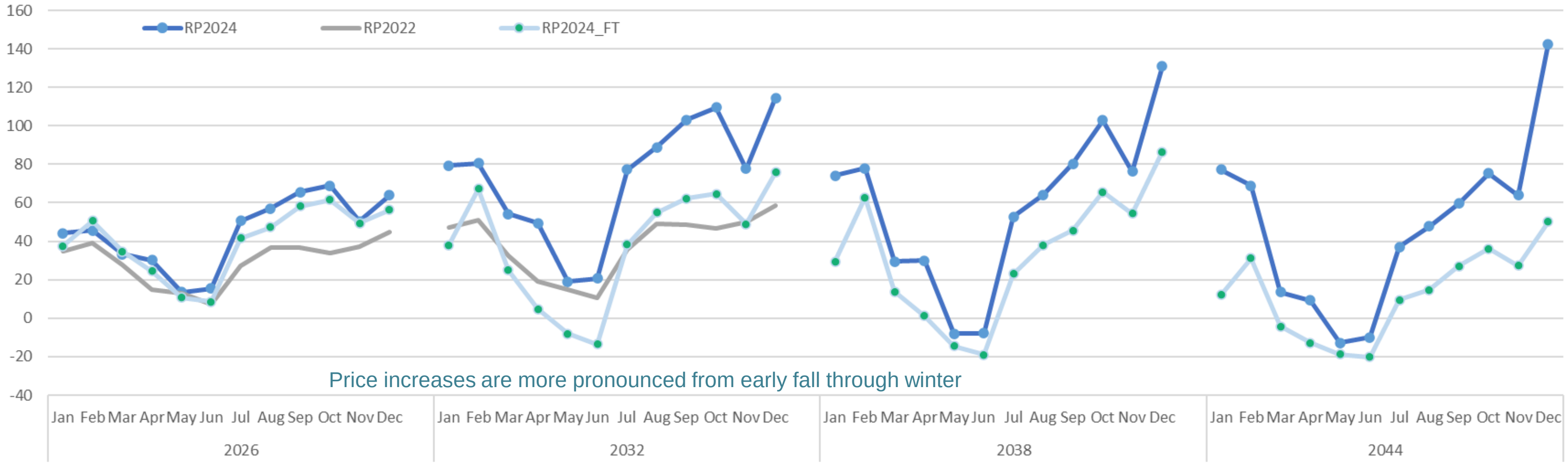


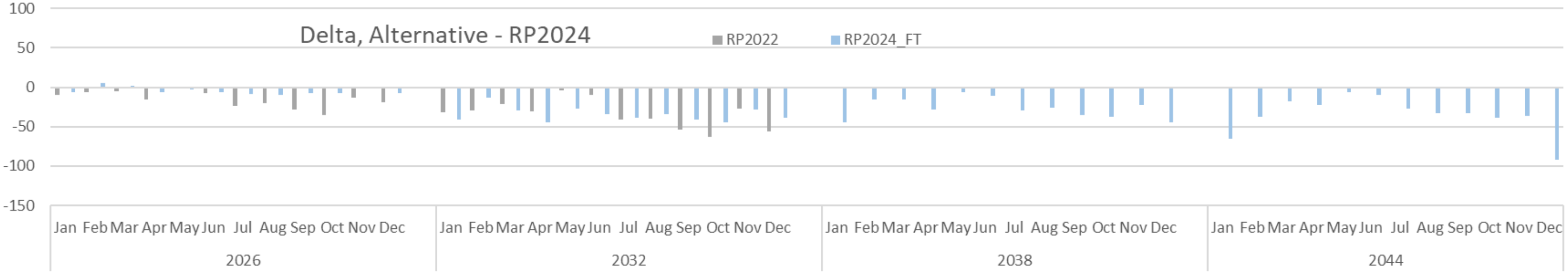
Cumulative PNW (US) Builds and Retirements



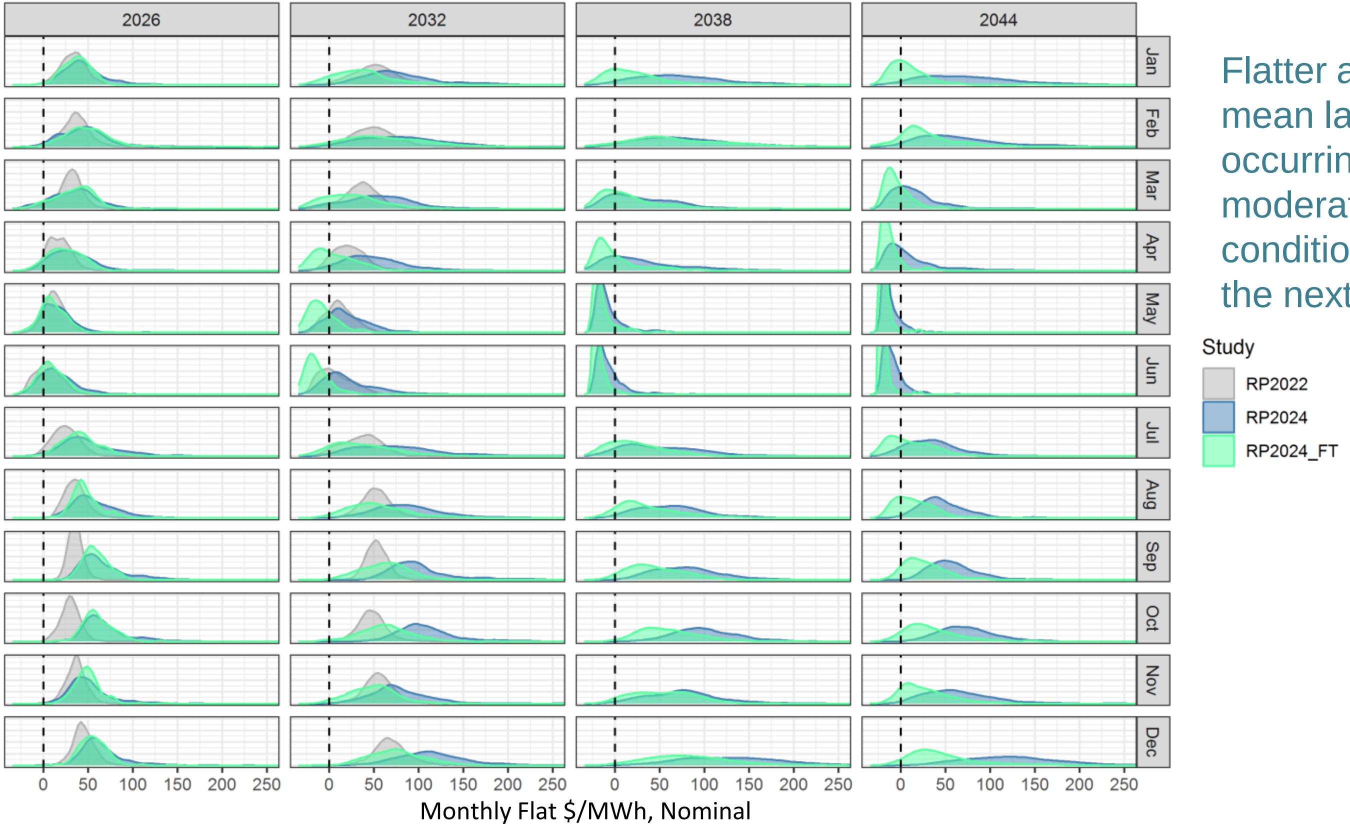
Mid-C / NW Average Prices

Monthly Flat $/MWh, Nominal



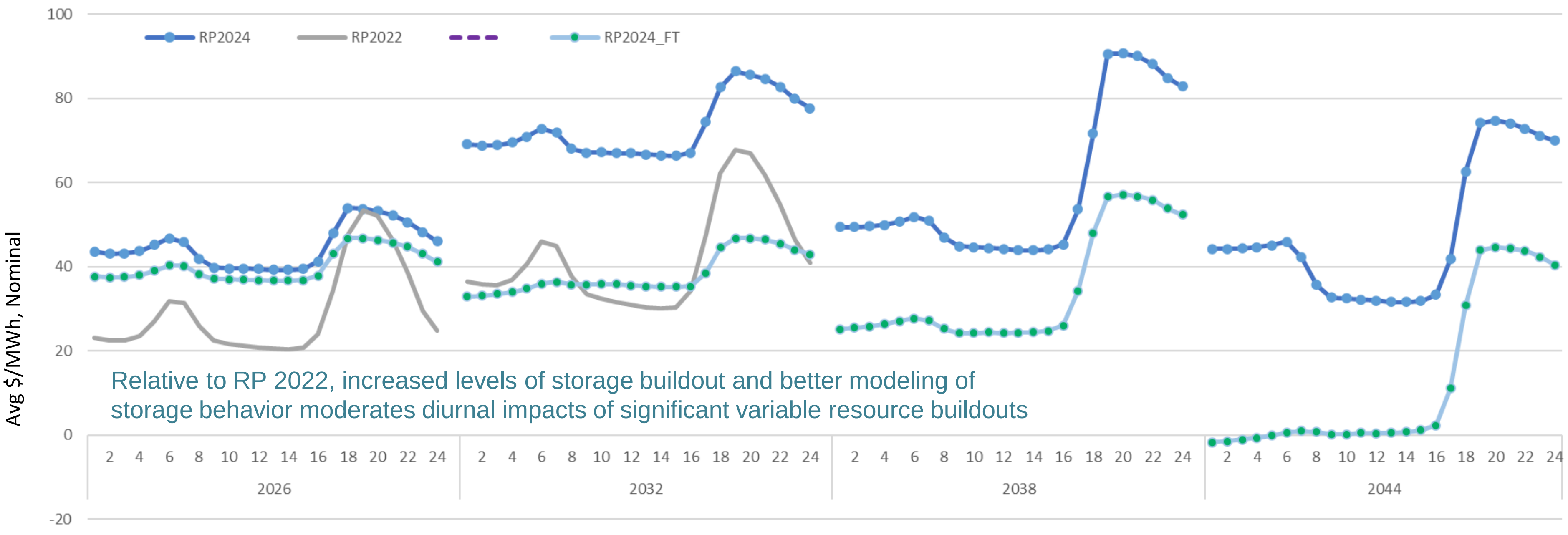


Mid-C / NW Price Distributions



Flatter and wider distributions mean larger price swings are occurring with more moderate changes to conditions from one period to the next.

Mid-C / NW Hourly Prices

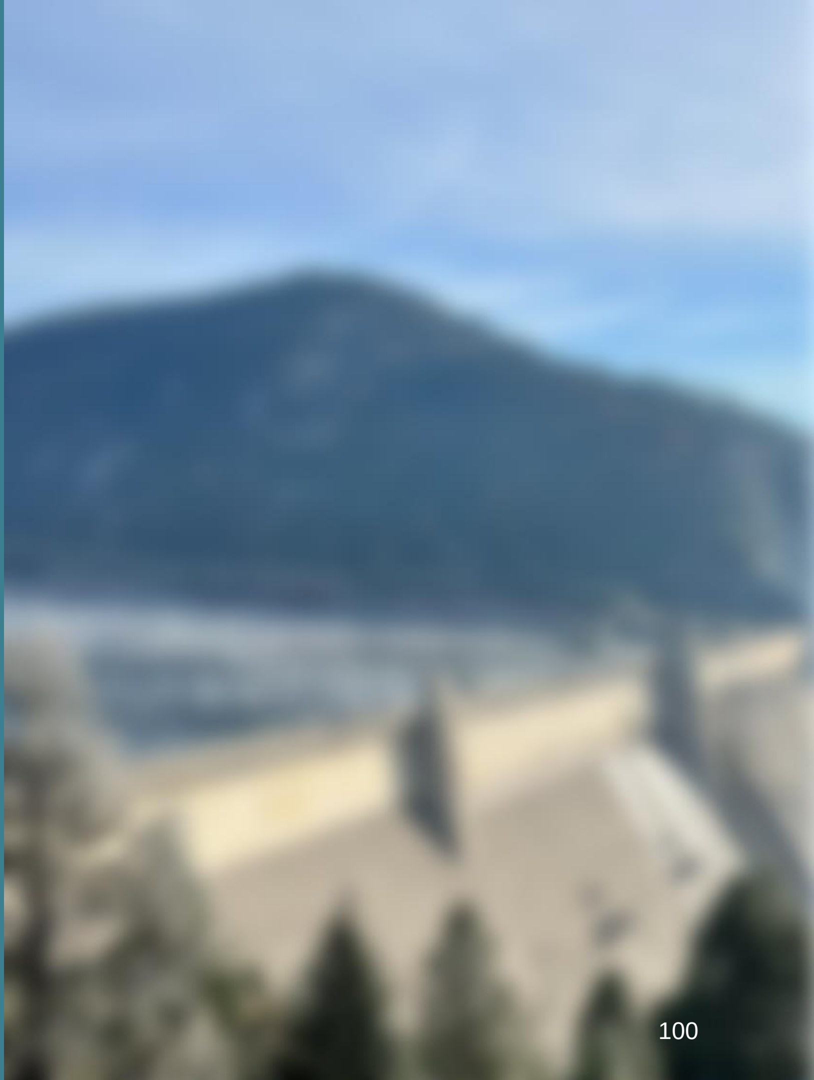


Relative to RP 2022, increased levels of storage buildout and better modeling of storage behavior moderates diurnal impacts of significant variable resource buildouts

Key Market Price Uncertainties

- Clean policy and system reliability are assumed to be maintained over the study horizon. A reduced clean policy scenario (slower transition) has not been modeled for RP 2024.
- Additional load risks:
  - Have not included rapid load increases from data centers or other sources.
  - Electrification levels and differing impacts on seasonal /diurnal loads.
- Other than NW hydro, potential climate change impacts to WECC loads and resources are largely not captured.
- New resource risks: other new technologies / cost reductions in new resources or cost increases / lack of new resource availability from supply chain or transmission restrictions.
- Impacts from longer duration / seasonal storage or changes in demand-side behavior that could mitigate occurrence of negative prices.
- Changes in ancillary service requirements associated with greater reliance on variable res

Market Depth



Market Limits in Aurora

- ‘Market’ definition: any combination of NW energy acquisitions from less than 5 years out, down to and including real-time, based on the projected marginal cost of producing and delivering energy.

- Prior to the 2018 Resource Program, market limits were set using historical liquidity assessments and SME judgment.

- 2018 changed to rely on a fundamentals-based method using Aurora, primarily to capture more forward-looking considerations.

Fundamental Method Review

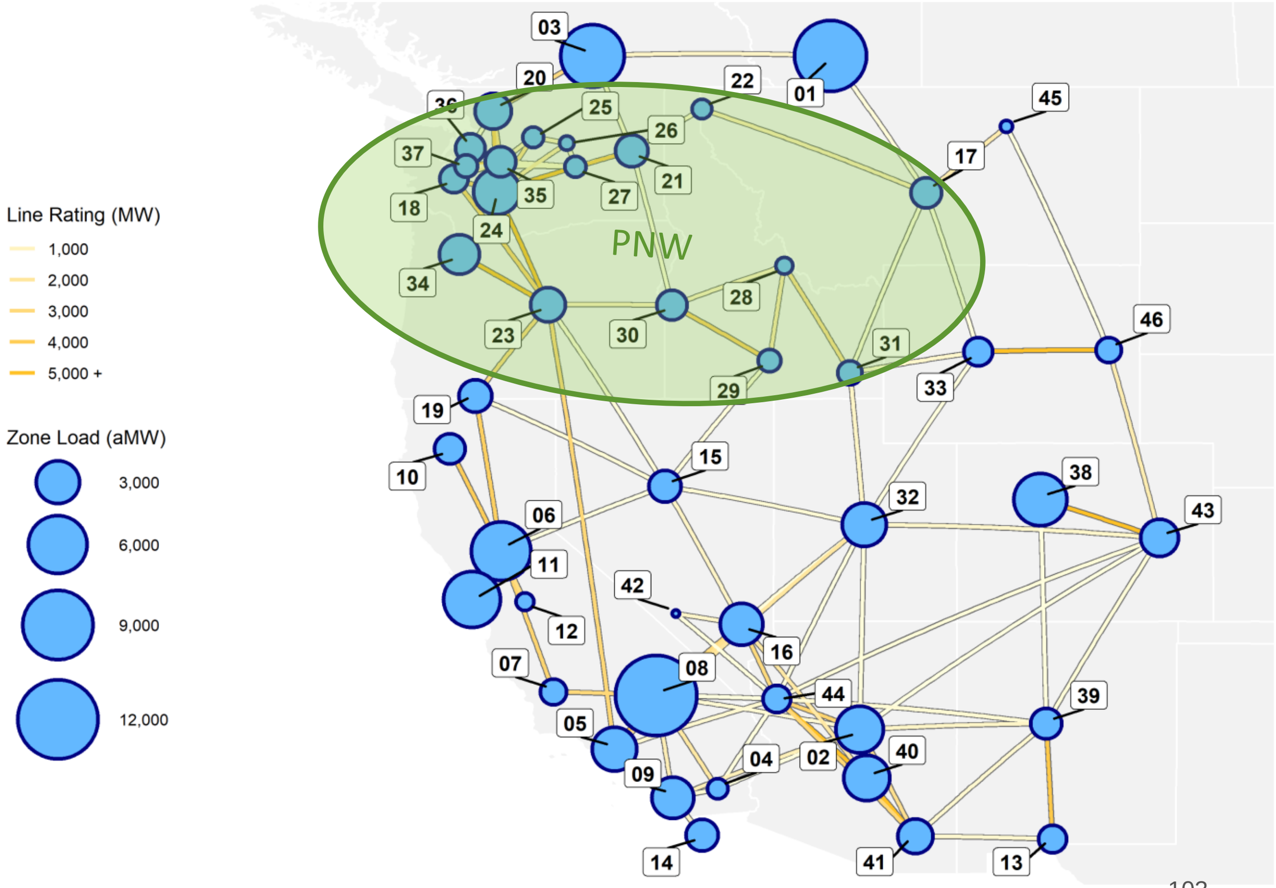
We're trying to find the difference between regional energy availability (considering **physical** load resource balance and ignoring contractual obligations) when all participants / BAs plan and build for zero market reliance*, and when all regional participants increase market reliance right up to the reliability threshold (building fewer new resources / retiring more resources than the 'no reliance' base). Keep in mind:

- **Relying on the market does not increase WECC loads.** Our expectations of loads is not changing, it's a question of which resources will serve loads and whether we can serve expected load with fewer resources than a zero market reliance base.
- **Relying on the market does not require regional surplus generation** (even when the region just meets reliability requirements, there's still significant room for market reliance by leveraging load and resource diversity within and among regions).

*Zero market reliance for the region means that each BA builds resources to meet 100% of their individual needs (energy, capacity, and clean policies). This produces an overbuilt system for the region.

PNW Region

Zone Short Names	
01	Alberta
02	APS
03	BC
04	IID
05	LADWP
06	PG&E North
07	PG&E ZP26
08	SCE
09	SDG&E
10	BANC
11	PG&E Bay Area
12	TIDC
13	EPE
14	Baja
15	NV North
16	NV South
17	NW MT
18	Olympia
19	PAC W
20	Puget North
21	Avista
22	BPA IDMT
23	BPA OR
24	BPA WA
25	Chelan
26	Douglas
27	Grant
28	ID Power FE
29	ID Power MV
30	ID Power TV
31	PAC E ID
32	PAC E UT
33	PAC E WY
34	Portland GE
35	Puget East
36	Seattle CL
37	Tacoma
38	PS CO
39	PS NM
40	Salt River
41	Tuscon
42	VEA
43	WAPA CO
44	WAPA LwCO
45	WAPA UprMO
46	WAPA WY



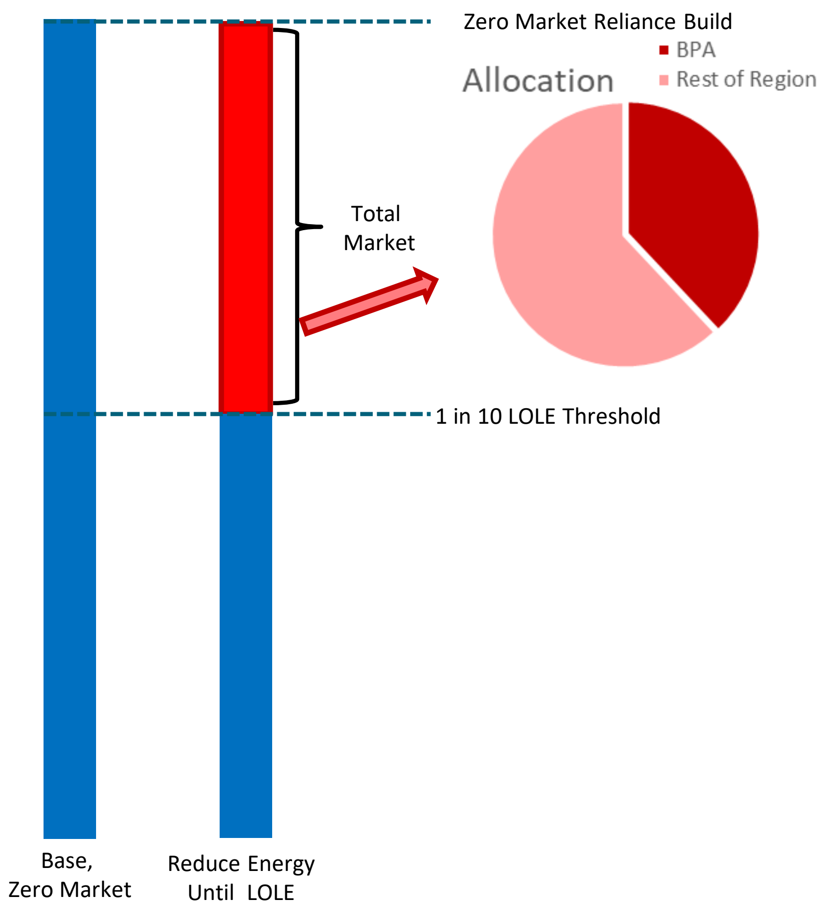
Fundamental Method Review, cont'd

1. **Start with our base resource build and assume this reflects zero market reliance in the region (this is the key shortcoming)**

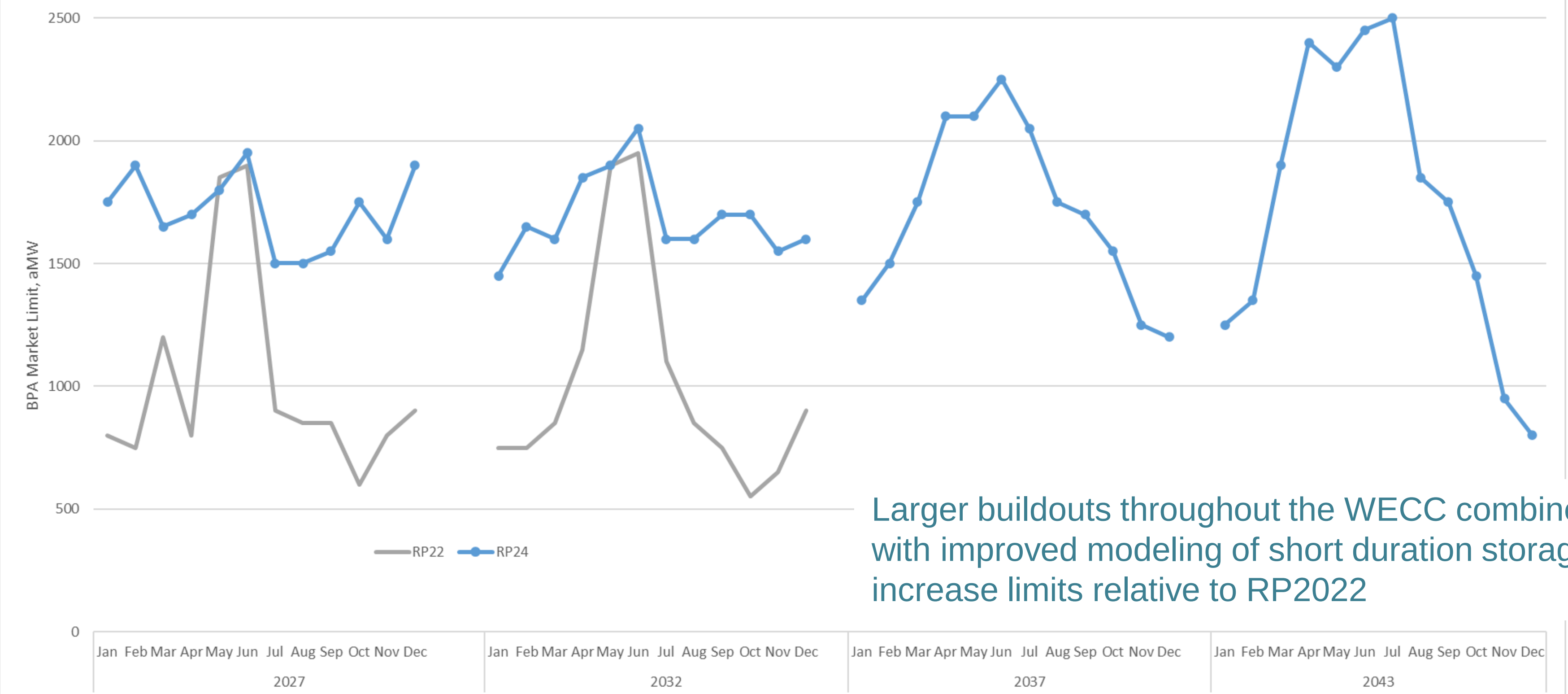
2. Add incremental load increases to approximate greater resource retirements / fewer resource additions associated with higher levels of regional market reliance

3. On a monthly basis, determine level at which greater market reliance causes region to exceed 1 day in 10 years (2.4 hours / year) Loss of Load Expectation (LOLE)

4. Allocate a share of the market reliance to BPA and accept this as our market reliance limit


Zero Market Reliance Build
Allocation
BPA
Rest of Region
Total Market
1 in 10 LOLE Threshold
Base, Zero Market
Reduce Energy Until LOLE

BPA Market Depth



Larger buildouts throughout the WECC combined with improved modeling of short duration storage increase limits relative to RP2022

Key Market Depth Uncertainties

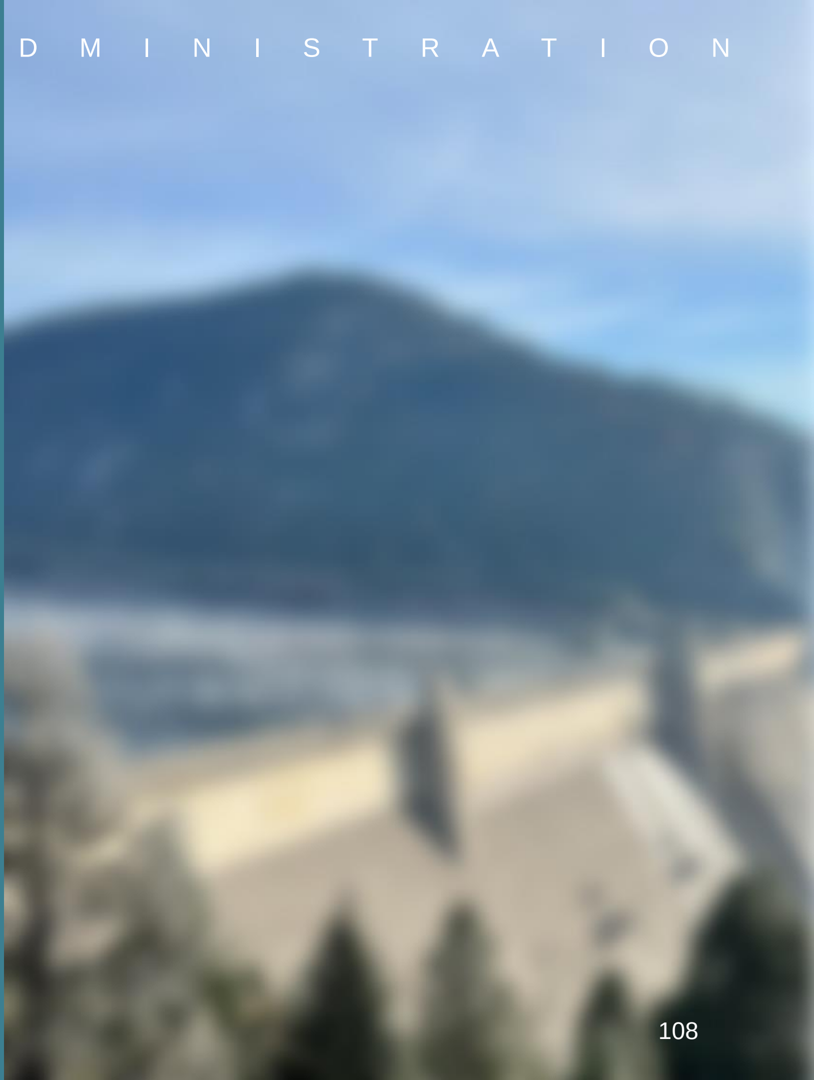
- RP2024 assessment is more dependent on assumed overbuild of the WECC.

- Assumes benefits of market reliance are allocated by share of regional load, ignoring contractual obligations and potential for free riding / planning misalignments (different metrics, forecast methodologies, etc).

- Aurora is simplistic depiction of the grid (no nodal topology/AC flows) and operations—might overestimate resource capabilities / underestimate ability to better utilize existing resources.
  - Single time step (~Aurora runs are most analogous to DA market) misses impacts of load / renewable forecast error.
  - No ancillary services (do we need more resources or can we just run the system with more reserves?).

- Risk modeling in Aurora has room for improvement.
  - Models operate independently and rely on historical, observed fundamental variation.
  - Resource outages are not stochastic (other than CGS).
  - No pipeline outages / derates (potentially overestimates reliability contributions of NG resources).

Questions?



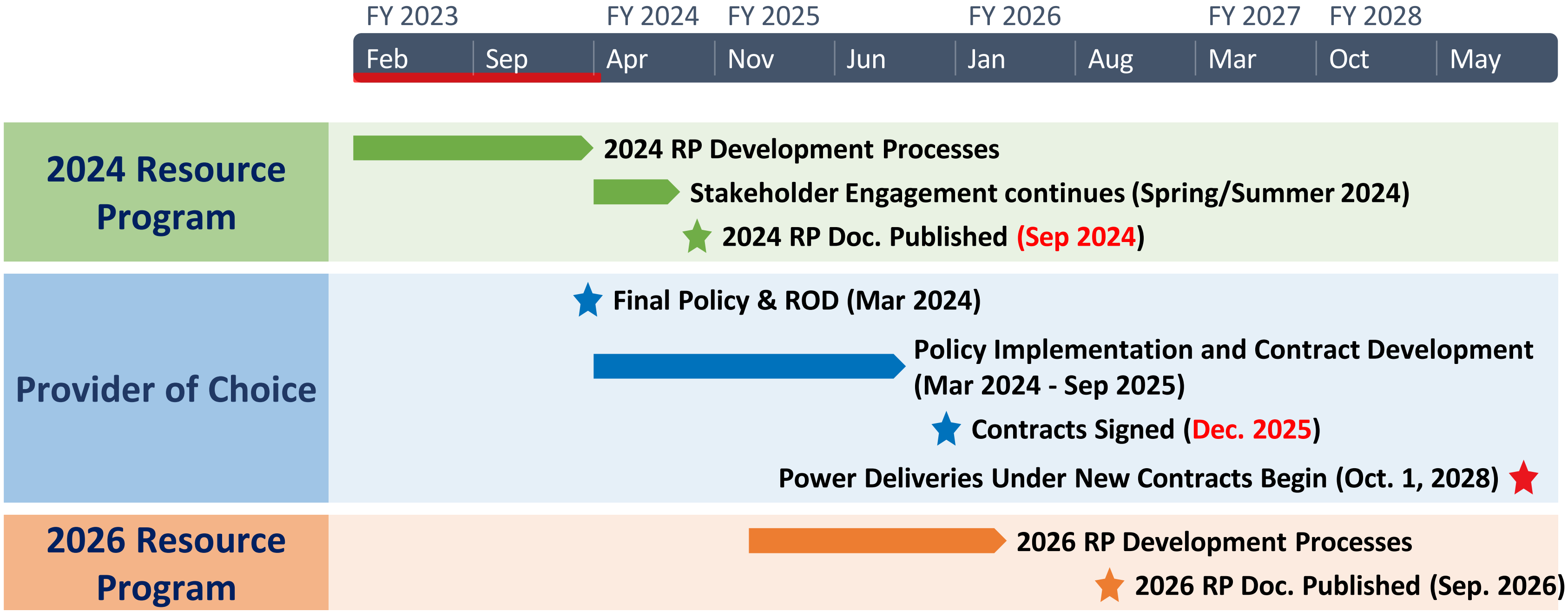
Next Steps

- Public Workshop Schedule
  - August 2024: Resource Solutions for all scenarios and sensitivities

- Final publication of 2024 Resource Program expected in September 2024

B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N

Resource Program and Provider of Choice



Get in Touch

Resource Program Contacts:

Ryan Egerdahl, Program Manager, rjegerdahl@bpa.gov
Brian Dombeck, Program Coordinator, bjdombeck@bpa.gov

Find Us:

Email: ResourceProgram@bpa.gov
Web: Resource Planning (bpa.gov)