Technical Appendix L: Wholesale Market Availability Results

Contents

Introduction

The wholesale market availability of electricity is a key driver in resource decision making and captures the dynamics of supply of and demand for electricity throughout the Western power grid (the Western Electricity Coordinating Council (WECC) footprint).[1] To forecast market availability from 2027-2046 the Council has used a model, AURORA,[2] that can both estimate the buildout of future

[1] The Western Electric Coordinating Council is the not for profit corporation that exists to ensure a reliable bulk power system throughout the Western Interconnection, which includes the following: British Columbia, Alberta, Washington, Oregon, Idaho, Wyoming, California, Nevada, Utah, Arizona; most of New Mexico, Montana, Colorado; and some of the Dakotas, Nebraska and North Baja California.
[2] AURORA is a commercial production cost model licensed from Energy Exemplar.

resources throughout the Western grid and generate wholesale power prices via production cost modeling.

For the Ninth Power Plan, the Council's wholesale market availability forecasts are primarily focused on capturing the effects on wholesale market supply due to uncertainty about resource and transmission costs and availability. Multiple forecasts were used to align assumptions between the WECC-wide wholesale market availability analysis and the regional resource strategy analysis.

The first section discusses the scope and methodological setup of the WECC-wide capital expansion modeling studies, and the second section discusses the associated analytical results. The method for how the market availability study results are used to support the analysis using the Council's other models, OptGen/SDDP and GENESYS[3] is described in more detail in Technical Appendix K – Modeling Framework.

Modeling Methodology

Modeling Topology and Parameters

The general purpose of the wholesale market availability is to use the fundamentals of supply and demand to determine how much market resource is available during the plan horizon (2027 through 2046). The AURORA software is used to perform the capital expansion required to meet the obligations of the west-wide power system (demand, reserves, and policy obligations). The existing system and policies throughout the west are established as described in Technical Appendix B – Existing System and Policies. The capital expansion in AURORA is an investment module that adds to the existing system by building new generating or storage resources, as discussed in Technical Appendix G – New Generating Resources, to minimize total costs throughout the WECC over 20 years. The expansion can include builds for economics and to meet the following obligations: planning and operating reserve margins by operating pool, and annual zero emissions and renewable energy policy targets.

In addition to evaluating investment costs to meet obligations, AURORA also has a production cost modeling module. This is an economic dispatch model which means that electricity prices are based on the variable cost of the most expensive generating plant (marginal plant) or increment of load curtailment required for meeting load for each hour of the forecast period. The model co-optimizes the assignment of energy and reserves to minimize production cost. Capability is held back for both operating (contingency and balancing) reserves by pool or reserve sharing group, respectively.

Plant dispatch is simulated for 45 load-resource areas or zones specified in Table L - 1, which comprise the AURORA representation of the WECC.

[3] OptGen is a commercial capital expansion model and SDDP is a commercial production cost model that are licensed from PSR. GENESYS is a multi-stage production cost model co-developed by PSR and Council staff.

Table L - 1: Pools and Zones

Pools	Zones
Western Power Pool	27 zones - Pacificorp (West and East – Idaho, Wyoming and Utah), Western Area Power Administration (Upper Missouri, Colorado, Wyoming), Portland General Electric, Bonneville Power Administration (Oregon, Washington, Idaho/Montana), Northwestern, Avista, Tacoma Power, Seattle City Light, Puget Sound Energy (North, Central and Olympia), Public Service Colorado, Nevada Power (North and South), Idaho Power (Treasure Valley, Magic Valley and Far East), Chelan County PUD, Douglas County PUD and Grant County PUD
California Independent System Operator	10 zones - Pacific Gas and Electric (North, Bay Area and Path 26), Southern Cal Edison, Imperial Irrigation District, San Diego Gas and Electric, LADWP, Balancing Area of Northern California, VEA and Baja California
Southwest Power Pool	6 zones - Arizona Public Service, Salt River Project, Tucson Electric, Public Service New Mexico, El Paso Electric and Western Area Power Administration (WAPA) Lower Colorado Area
British Columbia	1 zone - BC Hydro
Alberta Electric System Operator	1 zone - Alberta Electric System Operator

The assignment of zones to reserve sharing groups is similar to the assignment of zones to planning reserve pools, but the Western Power Pool is split into two reserve sharing groups: the Northwest region and the Mountain West region for consistency with interpretation in other models. During the plan development many entities in the western grid are shifting from most entities being part of the Western Energy Imbalance Market (CAISO) and a few part of the Western Energy Imbalance Service (SPP) to a more even split of entities that have chosen to participate in the imbalance services associated with the upcoming day-ahead market structures, Enhanced Day Ahead Market (CAISO) and Markets Plus (SPP). Given that recent context, the current market modeling is more conservative with more balkanized reserve requirements and less reserve sharing than may happen in upcoming years' operations.

Similarly, while the regional capital expansion modeling can optimize while considering multiple pathways of demand, gas prices, forecast hydro runoff and renewable generation, the capital expansion in AURORA can only optimize over one deterministic set of forecasts given a set of existing system policies, parameters and retirements. Thus, not all estimates of demand, gas prices, forecast hydro and renewable generation were tested explicitly. A representative set of forecasts using the aforementioned pool reserve margins accounting for uncertainty in these forecasts were developed in consultation with the Council's System Analysis Advisory Committee (SAAC).

In Region Load Forecast

In general, the representative demand forecast in the Northwest region was modeled using the P5: Mixed Bag demand forecast trajectory informed by the CanESM climate data (a mid-level forecast among the five tested throughout the rest of the plan) which was constructed as described in Technical Appendix F – Electricity Demand Forecast.

Out-Of-Region Load Forecast

The power system simulation models used in the Ninth Plan focus on the Northwest, but also simulate the broader Western Interconnection. Simulating this larger footprint is important since the Northwest is not a power island and interacts with the full interconnection. To run the models in a full Western setup, an out-of-region load forecast is required.

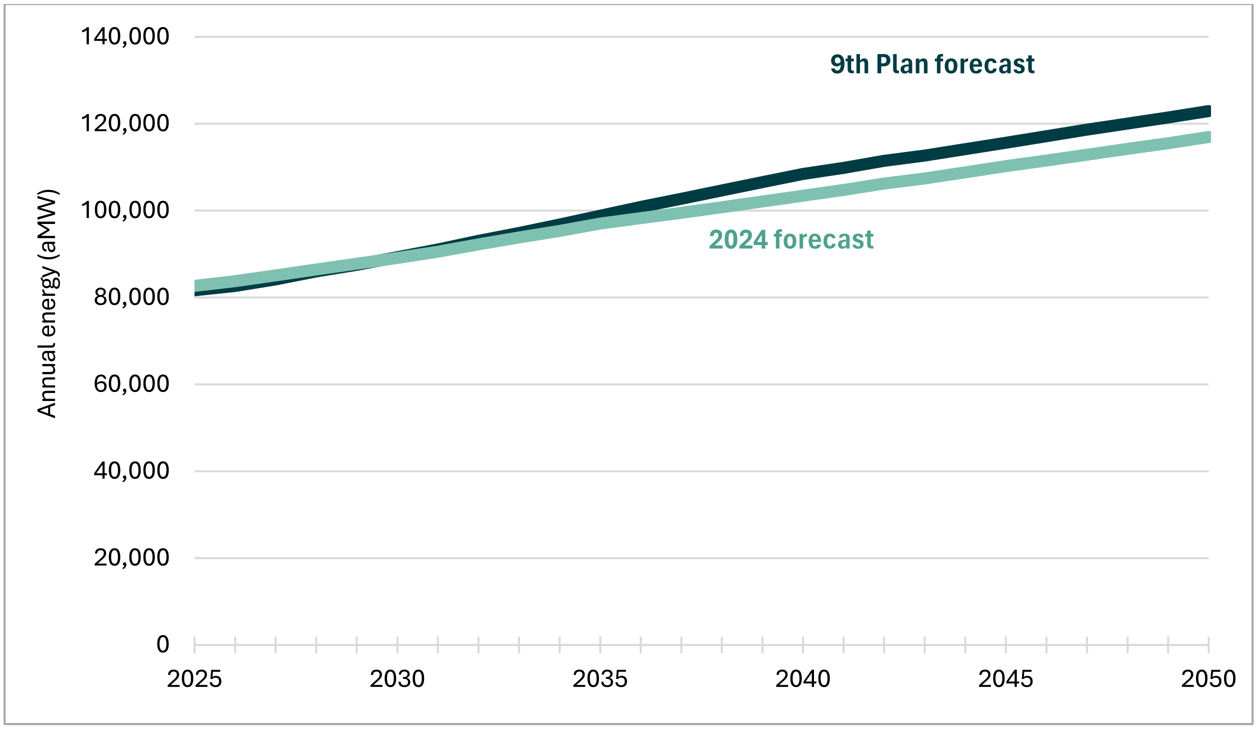
Unlike the Northwest load forecast, the out-of-region forecast is heavily reliant on other organizations' forecasts. It is a compilation of others' forecasts into a single forecast, as opposed to the Northwest forecast in regional strategy analysis in OptGen which includes different weather patterns and different load pathways, described in more detail in Technical Appendix K – Modeling Framework for each out-of-region zone. The main data sources used to create the out-of-region forecasts are:

- Utility integrated resource plans (and other utility level planning documents)
- The California Energy Commission Integrated Energy Policy Report
- FERC Form 714 data
- EIA Form 930 data

Much like the Northwest load forecast, the out-of-region load forecast has shifted upward in recent years (the forecast is refreshed every year or two for the adequacy study). The load drivers in the greater West are like those in the Northwest: data centers, electric vehicles, and general electrification. One interesting observation from the most recent California load forecast is that winter peak loads are growing significantly throughout the forecast period due to electrification.

Figure L - 1, below, shows the Ninth Plan's out-of-region load forecast compared to the forecast used in 2024 for the 2029 Adequacy Assessment. Note that this does not include Northwest loads (which as of 2026 account for roughly 20% of the West, on an annual energy basis). For annual energy the Ninth Plan's out-of-region load forecast averages 1.6 percent growth per year. These loads are assumed to include the impact of new demand-side resources (which is different than the frozen-efficiency load forecast developed for Northwest loads).

Figure L - 1: Ninth Plan Out-of-Region Load Forecast (does not include NW)



The out-of-region load forecast has an impact on model market fundamentals on many levels. First, it is the demand the models see and dispatch resources to meet. Second, it influences the resource buildout since it is used in the Western Interconnection capital expansion modeling. Thus, this forecast impacts the buildout, power prices, power flows, and the level of imports available for resource adequacy.

More discussion and detail on the out-of-region load forecast was shared at the April 2025 Council meeting, available here: https://www.nwcouncil.org/calendar/council-meeting-2025-04-08.

Gas Price Forecast

The gas price forecast utilized for the market availability study was the mid-level gas price forecast per the Technical Appendix E – Fuels Forecast.

Renewable and Hydro Generation Availability Forecasts

The renewable availability forecasts were developed per expected shapes from historical climate data outside the region and climate change informed data, using the CanESM model, inside the region as described in Technical Appendix D – Climate Model Data and Assumptions and Technical Appendix G – New Generating Resources. Similarly, the hydro runoff forecasts were developed per expected shapes and constraints from PNNL GODEEP climate data outside the region and climate change informed data, using the CanESM model, inside the region, as described in Technical Appendix D – Climate Model Data and Assumptions. In addition, the Council's GENESYS model is used to develop maximum and minimum hourly operation constraints and monthly inventory for hydropower on a zonal basis for consistency with Columbia River operations, since AURORA does not contain detailed water travel time and operations logic that reflect the limitations on generation and reserves for the hydro operations in the Pacific Northwest.

Modeling Setup

The capital expansion was run from 2026 – 2046 in two steps to better converge to a result within a reasonable planning timeline. After running the study chronologically through 24 hours a day and 365 days in a year, the model was taking too long to solve within plan timelines. Thus, a simplifying approximation of the hourly production costs was utilized to represent the variable costs in the overall cost minimization of both investment and production costs in the objective function.

This methodology of using a sample set of days to represent typical production cost behavior for the broader WECC was developed in consultation from the SAAC is as follows:

1. The capital expansion was performed twice with the minimized solution from the first study used to seed the second study.
2. In the first study, the capital expansion starts without an initial strategy seed, and the model calculates the investment to minimize total costs. In this study, production costs were simulated by performing the zonal dispatch of the WECC for 24 hours per month per year. The second Tuesday of every month was used as representative of all days in the month.
3. In the second study, the buildout from the initial long-term WECC buildout described in step 2 above is used as an initial seed for the a new study where the model seeks to modify the investment to minimize total costs, but the production costs were simulated by performing the zonal dispatch of the WECC for 48 hours per month per year. The first and third Tuesday of every month were used as representative of all the days in the month.
4. The buildout from the second study is considered to be the “optimized” buildout for a given sensitivity.

Each simulation supporting the wholesale market availability for a particular scenario/sensitivity was performed in this way.

Modeling Results

Summary

The investments in new generating resources stabilize wholesale prices throughout the WECC over time with a couple exceptions associated with emerging technology cost risk. By 2032, $58 to 59 billion[4] in capital investment per year is required to meet obligations. By 2046, $81 to 89 billion in

[4] All costs and prices in this section are listed in 2024 dollars.

capital investment per year is required to stabilize wholesale prices. Annual average prices over all zones range from $33 to 37 per megawatt-hour in the beginning of the study, and by the end of the study range between $18 to 60 per megawatt-hour on average across the sensitivities. Nameplate investment for the whole WECC ranged from 265 to 287 gigawatts by 2046 over all sensitivities to meet just over 50 average gigawatts of expected demand growth throughout the WECC.

Simulation Descriptions

The plan scenarios and underlying assumptions are described in more detail in Technical Appendix N – Scenario Modeling and Results. The perspectives of certain wholesale market availability sometimes support one or multiple sensitivities for the overall resource strategy analysis as described at a high-level in Table L - 2.

Table L - 2: Simulation Descriptions

Simulation	Scenario/Sensitivity Supported	Description
Constrained Resources and Transmission	Resource and Transmission Risk: Constrained Resources and Transmission	Constrains supply-side resources in the near-term (first 6 years), limits transmission to the existing system, and delays emerging technologies by 10 years.
Existing Transmission	Resource and Transmission Risk: Changing Transmission Availability	Existing transmission and projects that have already started construction
Transmission Plus	Resource and Transmission Risk: Changing Transmission Availability, Slower Demand-Side Availability	Transmission including what was included in the WestTEC 10-year study
Transmission Max	Resource and Transmission Risk: Changing Transmission Availability	Transmission including and additional to the WestTEC 10-year study
Emerging Technology Costs 25% Lower	Resource and Transmission Risk: Changing Emerging Technology Costs	Cost assumptions for emerging technologies are 25 percent lower. Transmission including what was included in the WestTEC 10-year study
Emerging Technology Costs 50% Higher	Resource and Transmission Risk: Changing Emerging Technology Costs	Cost assumptions for emerging technologies are 50 percent higher. Transmission including what was included in the WestTEC 10-year study.
Limited Short-Duration Storage Availability	Resource and Transmission Risk: Limited Short-Duration Storage Availability	Constrains the availability of short-duration (lithium ion) battery storage in the near-term (first 6 years). Transmission including what was included in the WestTEC 10-year study.
Evolving Federal Policy Landscape	Resource and Transmission Risk: Evolving Federal Policy Landscape	Assumes a change in Federal policy 2030, shifting to policies similar to Biden-era policies. Transmission including what was included in the WestTEC 10-year study.

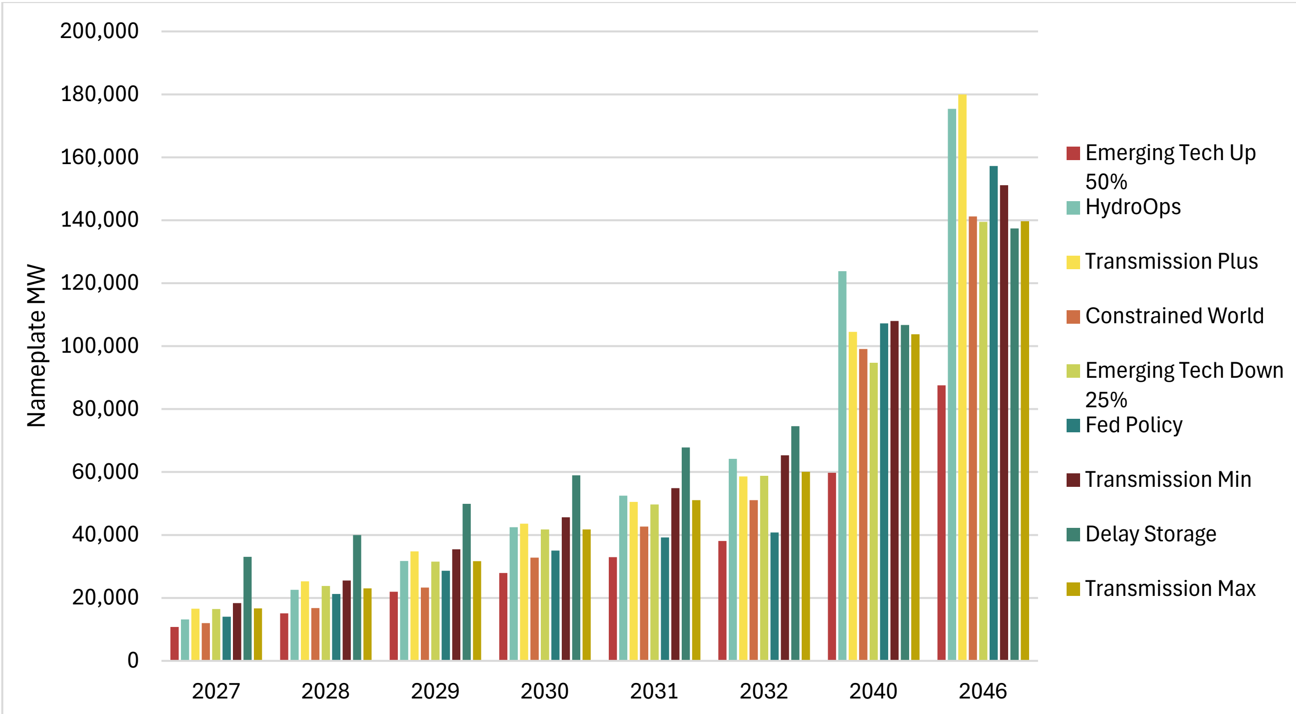
Simulation	Scenario/Sensitivity Supported	Description
Hydro Operations	Changing Hydro Operations: 2020 BiOp Flex Spill Operation, 2023 RCBA Operations, Recommended Spill and MOP Targets, Limited Flex Operations	Assumes Federal policies similar to Biden-era policies. Transmission including what was included in the WestTEC 10-year study.

Buildout Summary by Fuel Type

A portfolio of resource types, including emerging tech resources, were added in all cases for economics and to meet both policies and reserve margins. For policies associated with meeting zero emissions and renewable energy targets, there is a global modeling assumption that resources do not require specific siting to comply, thus the model often selects resources that are the most efficient at meeting these policies agnostic of location other than the convenience of higher resource availability, connectivity, or lower price. However, certain sensitivities incentivized location specific builds, by definition, due to emissions pricing policies and diversity of availability. Below the buildouts are broken apart by different new resource types: variable energy resources (uncertain fuel availability), natural gas resources (on-call fuel), short duration storage and mid/long duration storage (can shift capability but require more energy input than output).

Variable energy resources (VER) builds are driven primarily by the confluence of economics and policy. Emissions pricing in Canada, California, and Washington, which combined account for around 60% of the WECC demand, drives most early VER build. Existing state and local clean energy policies drive VER builds in the mid 2040’s. Additionally, existing renewable portfolio standards policies drive some VER builds starting in 2030.

Figure L - 2: Variable Energy Resources Build Outside the Region



As can be seen in Figure L - 2, many of the sensitivities have similar VER builds. However, delays in short duration storage seem to cause more VER builds earlier in the study. Higher priced emerging technology resources drive down the overall VER build due to worse economics for longer duration storage assets which are more useful in a portfolio with wind generation which tends to be the majority of VER build in the early and middle years of the study due to the current saturation of solar generation in the existing system. This effect can be seen in Figure L - 3 and Figure L - 4.

Figure L - 3: Onshore Wind Build Outside the Region

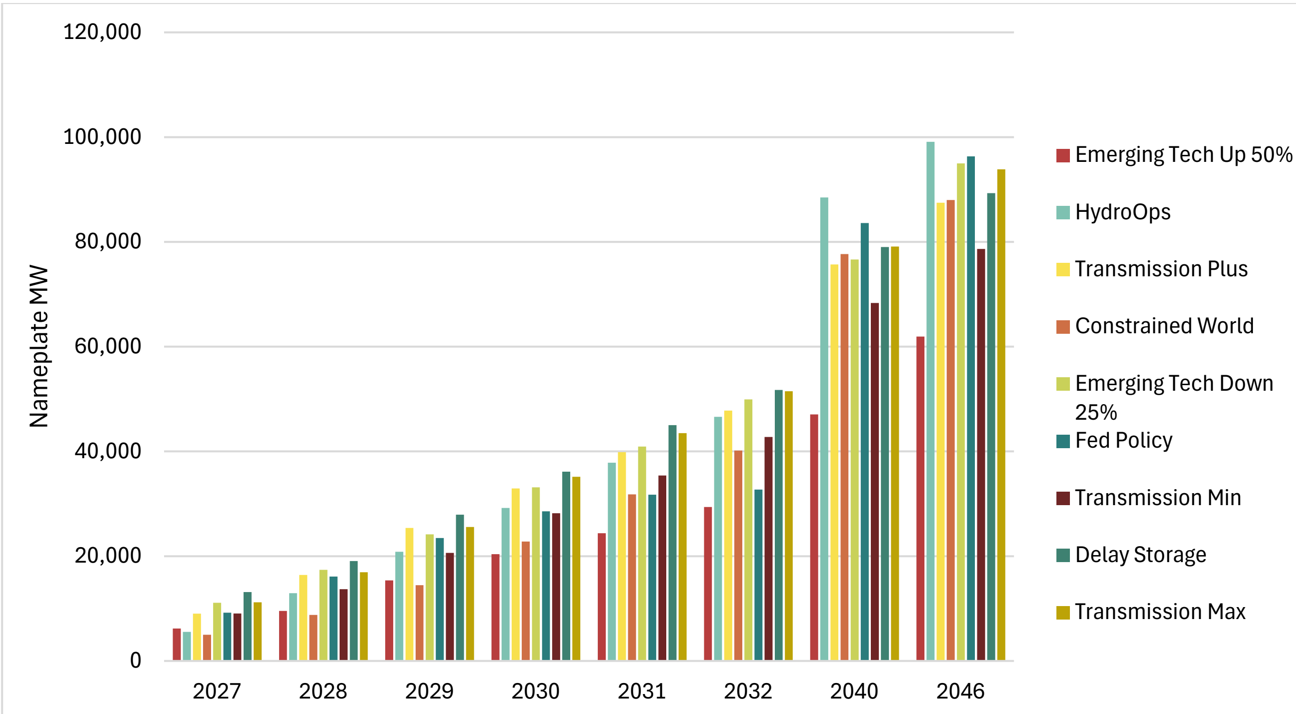
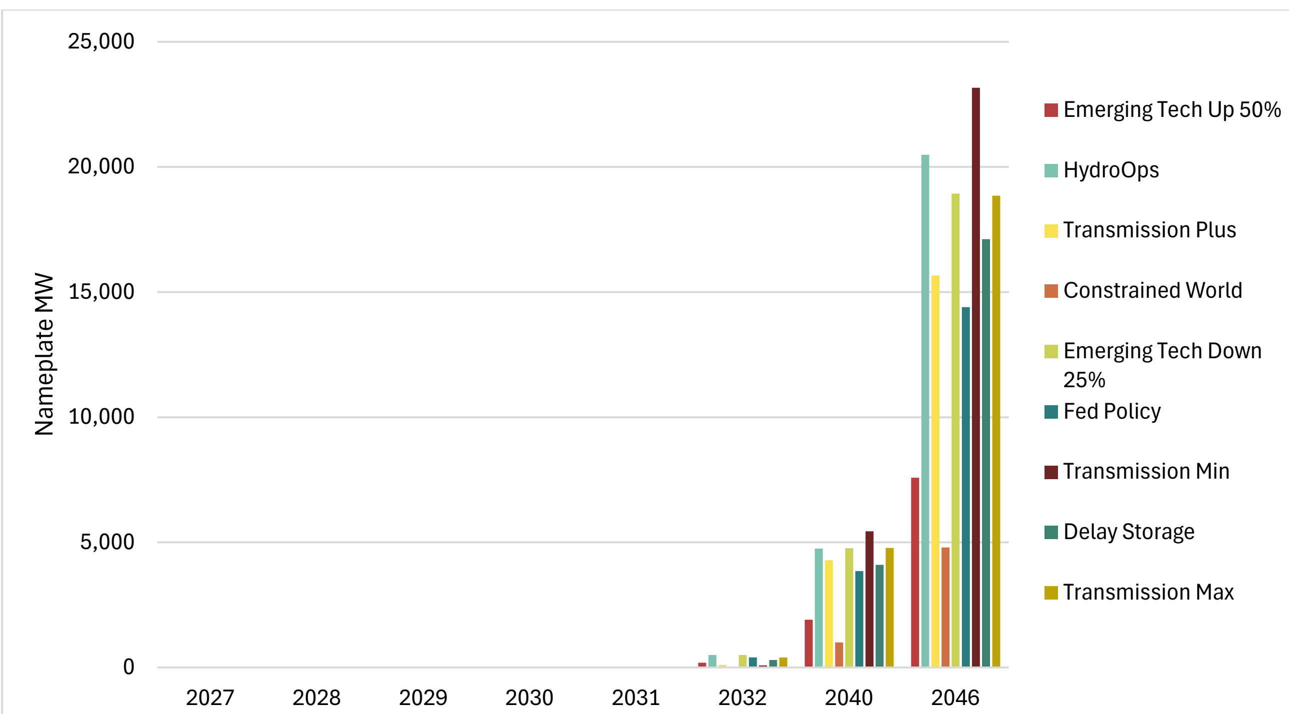


Figure L - 4: Longer Duration Storage Resources Build Outside the Region



Other than pumped storage, most longer duration storage resources are considered emerging technology in the Ninth Power Plan. Due to delay in availability of long and mid-duration storage in the Constrained Resource and Transmission sensitivity and the higher cost in the Emerging Tech

1 Uncertainty sensitivity with 50 percent higher investment costs, those sensitivities had considerably
2 less longer duration storage. However, depending on its availability it was acquired in significant
3 amounts in all sensitivities, many times up to the available purchase limit. Additionally, longer
4 duration storage had a higher peak capacity contribution towards meeting reserve margins than
5 shorter duration storage and seemed to be key in the portfolio approach of meeting those criteria.

6 Shorter duration storage resources are broadly available and new stand-alone storage was built in all
7 the sensitivities but was specifically higher where longer duration storage was less available or more
8 expensive as seen in Figure L - 5 and Figure L - 6.

9 **Figure L - 5: Stand Alone 4 Hour Battery Build Outside the Region**

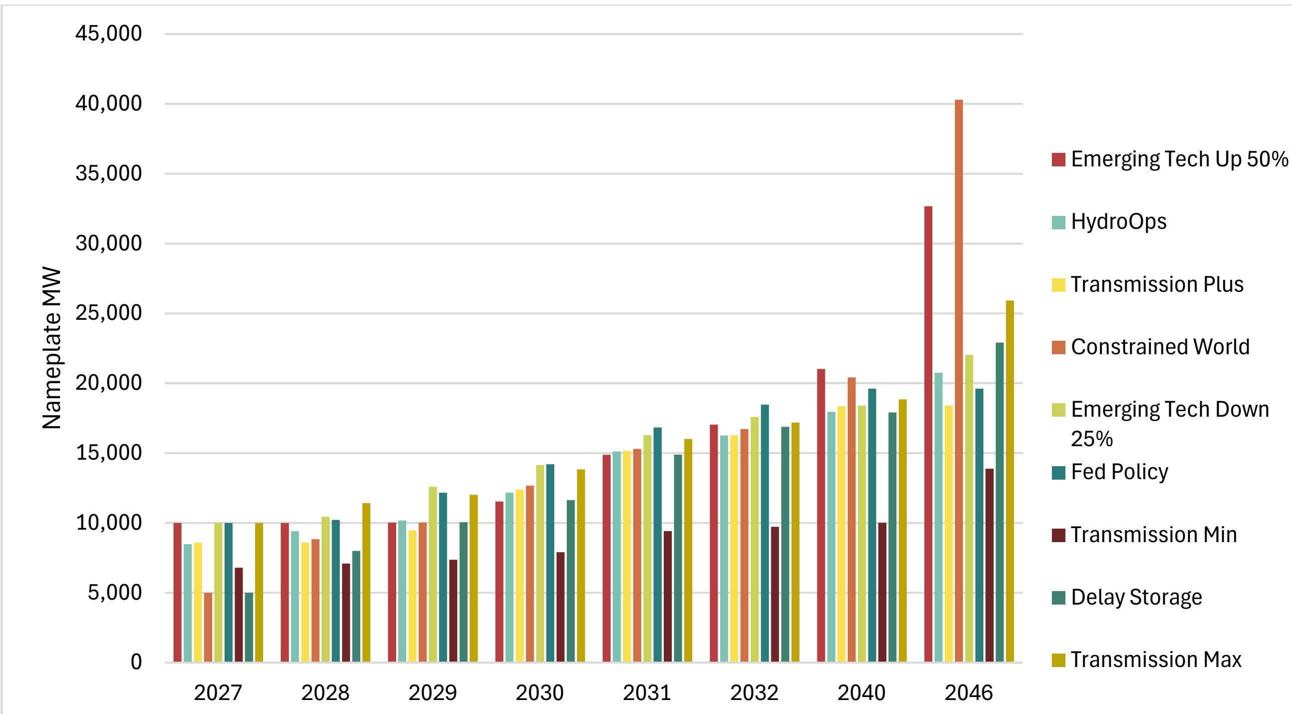


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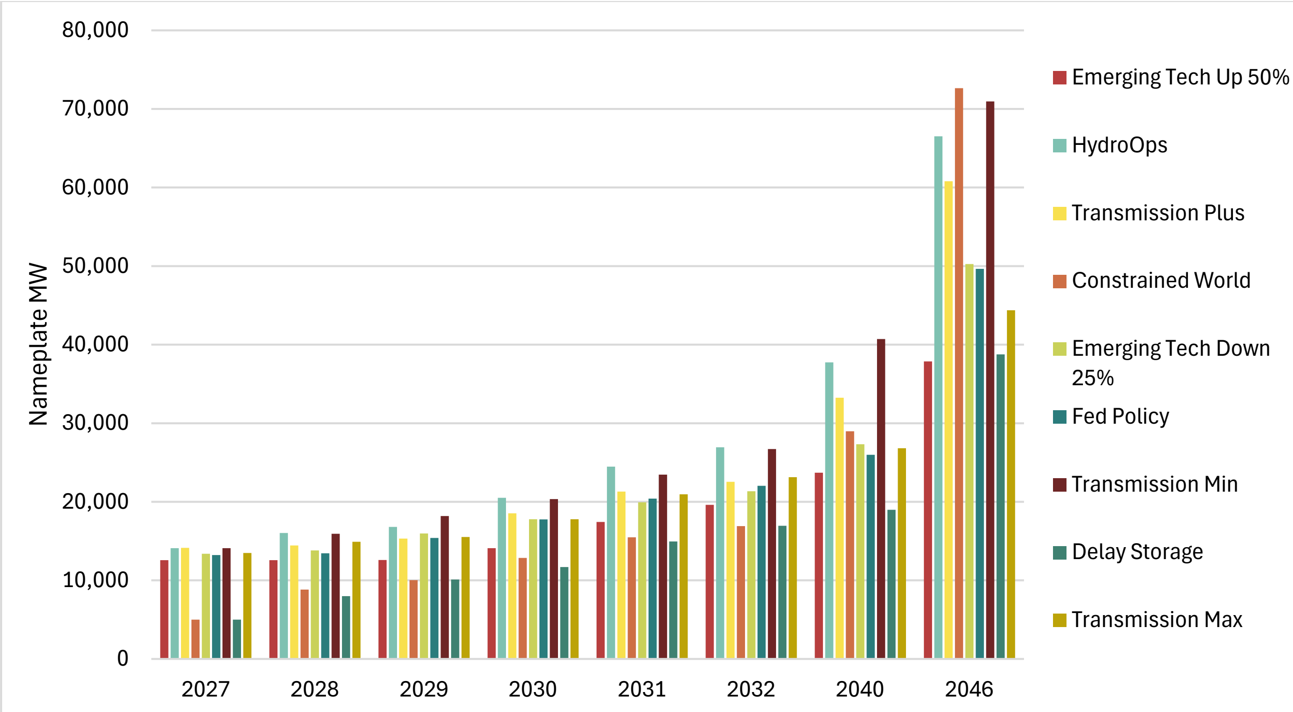
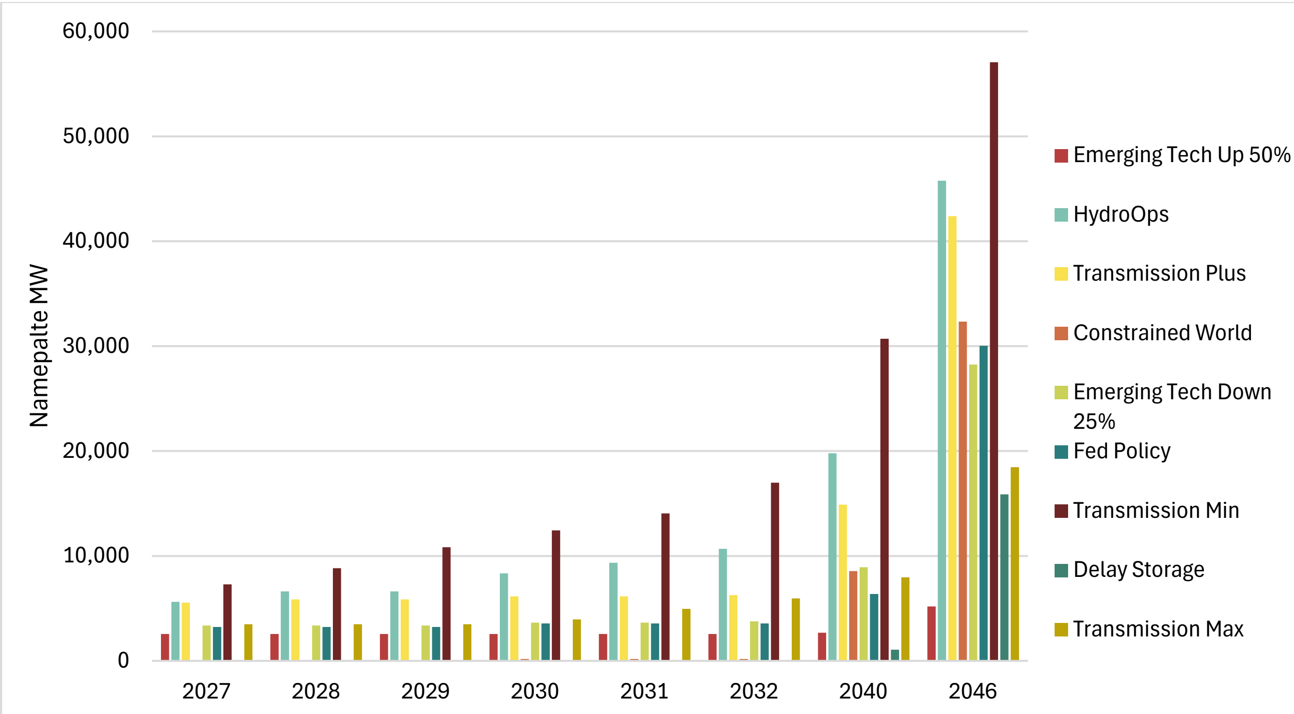
Figure L - 6: Short Duration Storage Build Outside the Region



Interestingly, while the total amount of stand-alone short duration storage is lower when there is less transmission, the model chooses to build a significant amount of short duration storage with solar via a solar hybrid resource in that sensitivity as can be seen in Figure L - 7.[5]

[5] Note that Figure L - 7 shows solar hybrid build by the nameplate megawatts of the inverter. In other words, since the hybrids are treated as a one-by-one hybrid, if the nameplate is listed as 100 megawatts, that indicates there is a hybrid with 100 megawatts of 4-hour battery and 100 megawatts of solar.

Figure L - 7: Solar Hybrid Build Outside the Region



Natural gas plants were acquired in most jurisdictions where they were allowed and/or did not have zero emissions policy targets. In the sensitivities, where emerging tech resources were higher cost or delayed and the sensitivity when less transmission was available, natural gas resources were acquired in larger quantities per Figure L - 8. New natural gas plants support reserve margins and displace less efficient thermal plants on the margin. No assumptions about conversion of newly acquired gas plants to another fuel in the future was explicitly made and in general the gas plants purchased outside the region were primarily new combined cycle units which tended to slightly lower Mid-Columbia[6] power prices on an annual basis as can be seen in Figure L - 9.

[6] Mid-Columbia (or Mid-C) is a standard, liquid trading hub for wholesale power in the Pacific Northwest region trading on the Intercontinental Exchange (ICE).

Figure L - 8: Natural Gas Build Outside the Region

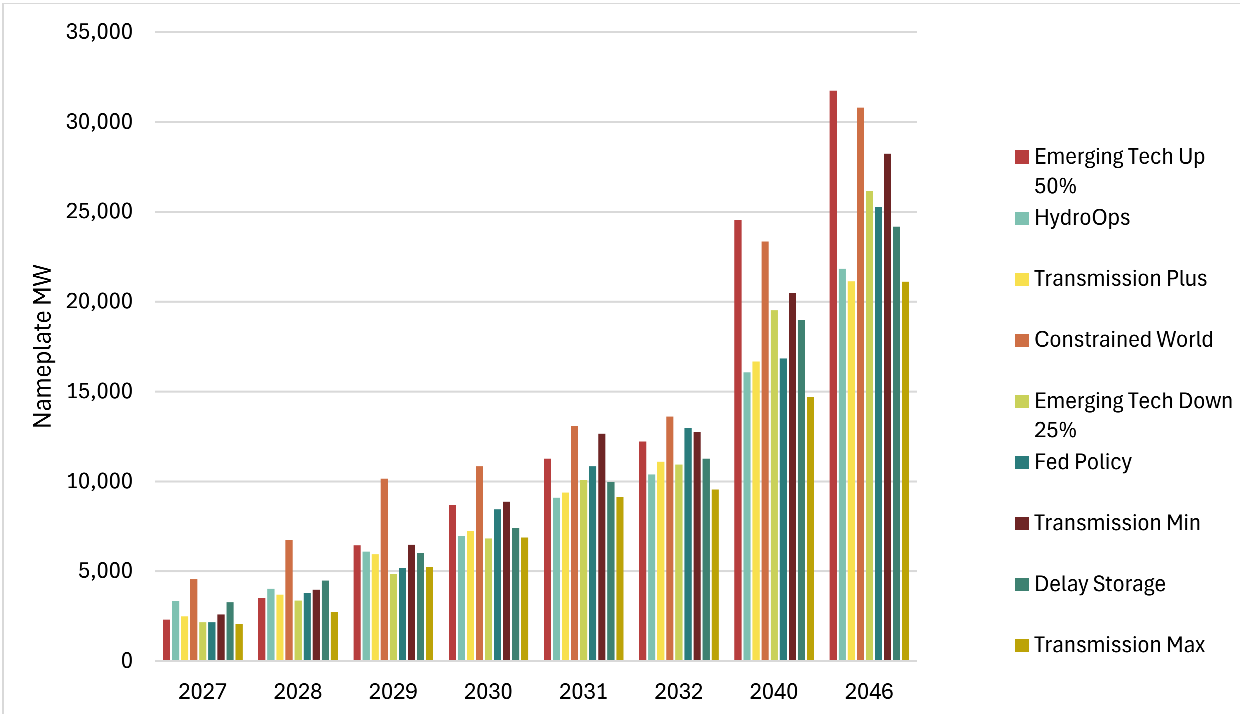
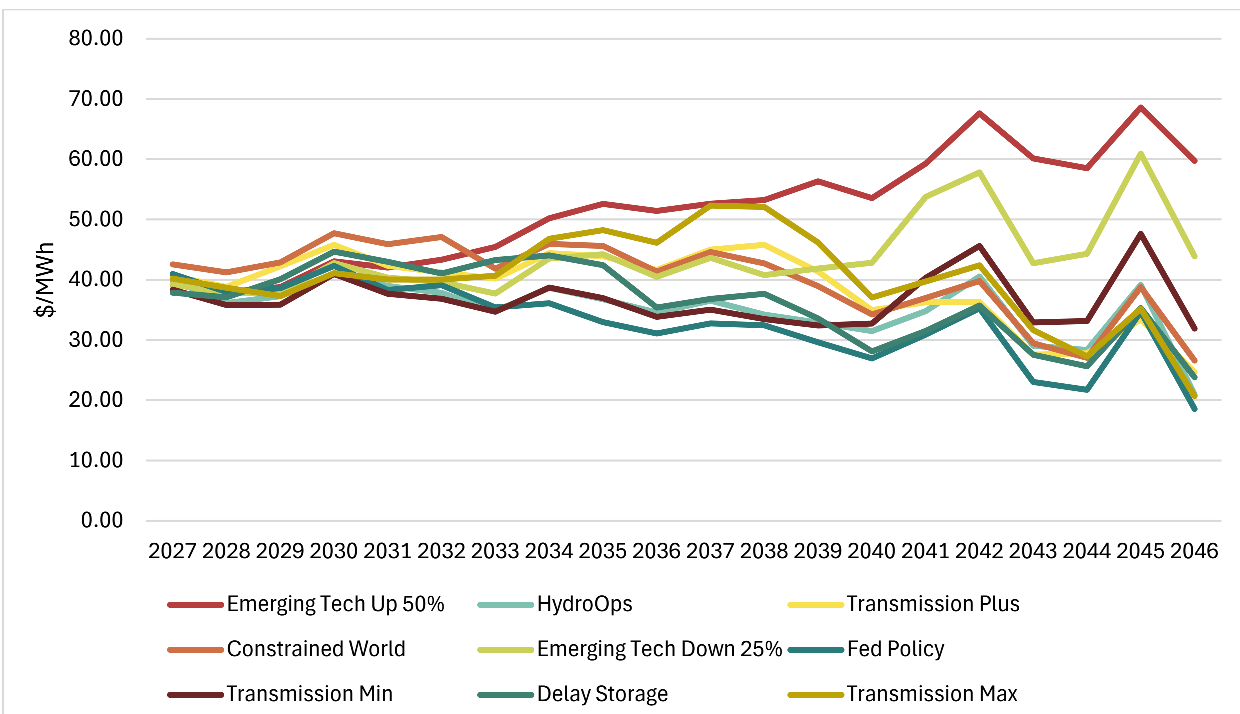


Figure L - 9: Mid-Columbia Annual Average Power Prices



In comparison, California prices go up over time as can be seen Figure L - 10. This price differential should incentivize regional exports to California in general and in particular on a seasonal basis in the summer where prices in California and throughout the west are higher than in the region as can be seen in Figure L - 11 and Figure L - 12. This differential in seasonal pricing is similar to historical patterns as demand in the broader WECC (other than Canada) has traditionally peaked in the summer whereas the Northwest has peaked in the winter.

Figure L - 10: California Annual Average Power Prices

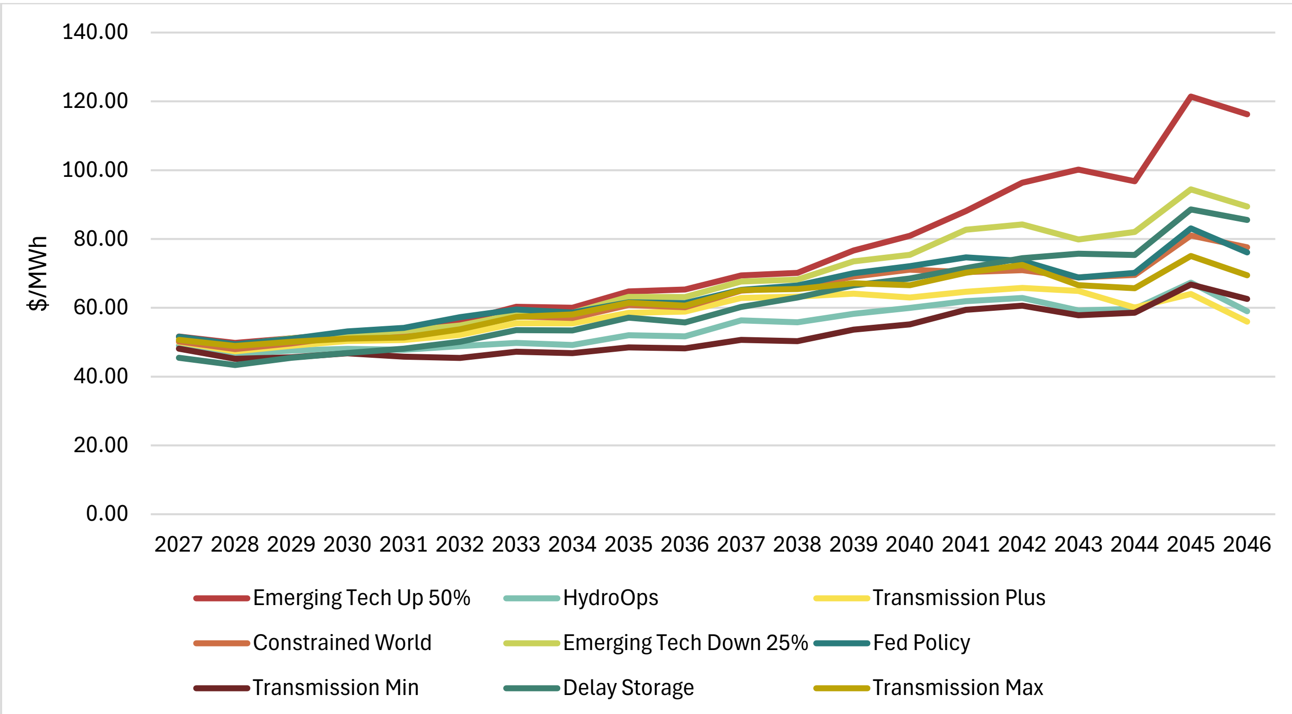


Figure L - 11: California Summer Average Power Prices

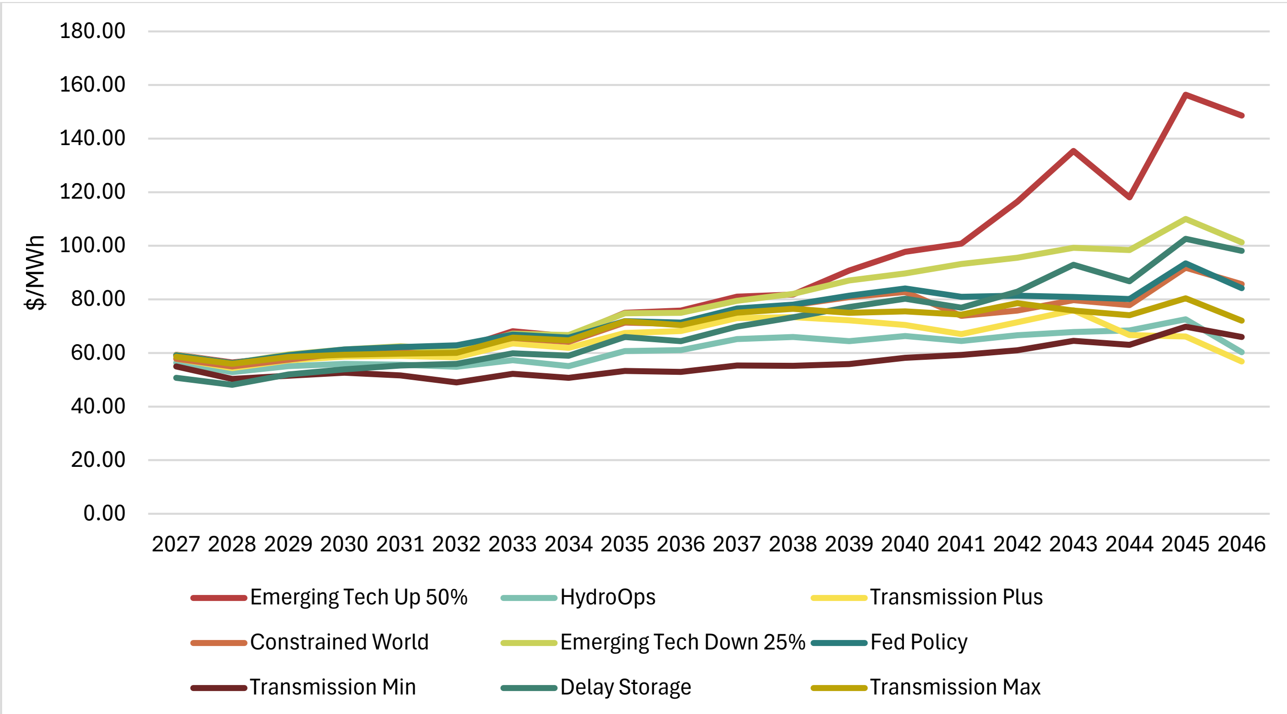
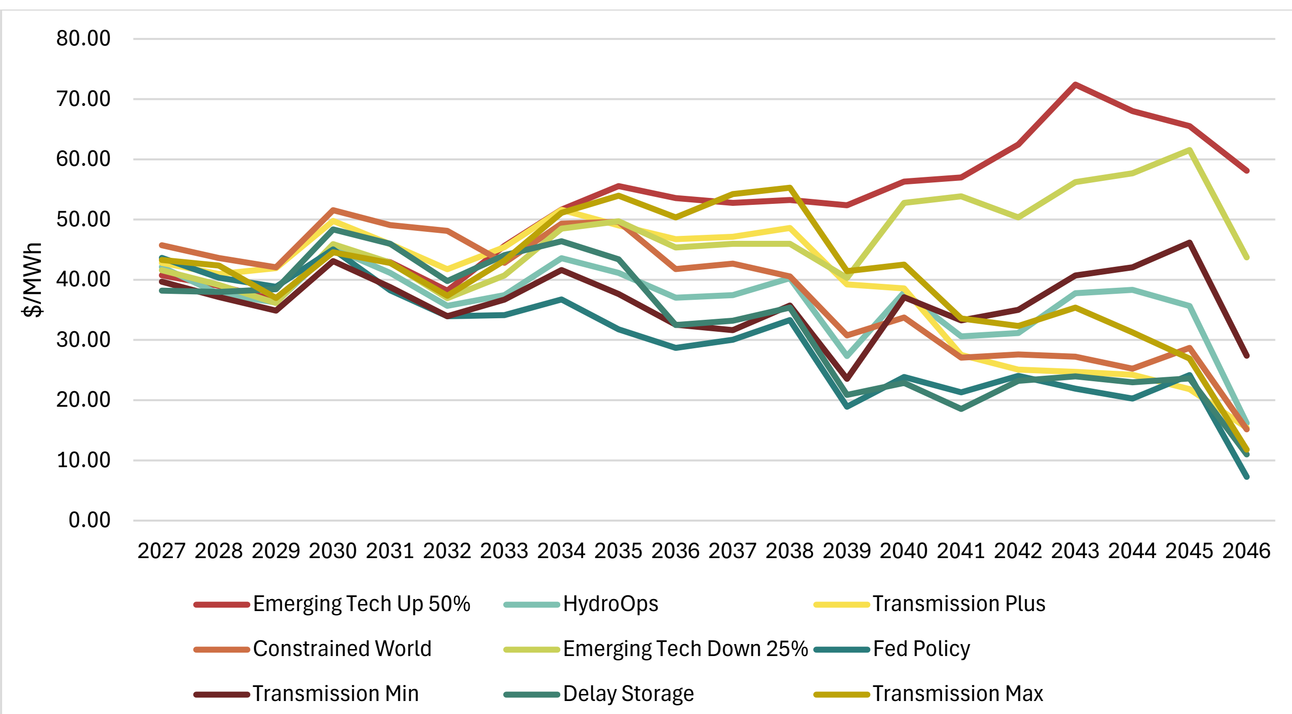


Figure L - 12: Mid-Columbia Summer Average Power Prices



However, note that both the region's and California's prices tend to increase a bit in the winter, as can be seen in Figure L - 13 and Figure L - 14, due to increased electrification in both load forecasts. This would indicate that perhaps the traditional seasonal hedge where the Northwest would count on imports from California during poor hydro conditions may be less economic than in the past due to those increased California winter loads in the long term. However, it should be noted that, on average, the prices within the region stay flatter whereas California has lower prices midday and higher prices around the morning and evening ramp within the first five to ten years. Therefore, winter regional imports from California may continue to be economic in the middle of the day.

Figure L - 13: Mid-Columbia Winter Average Power Prices

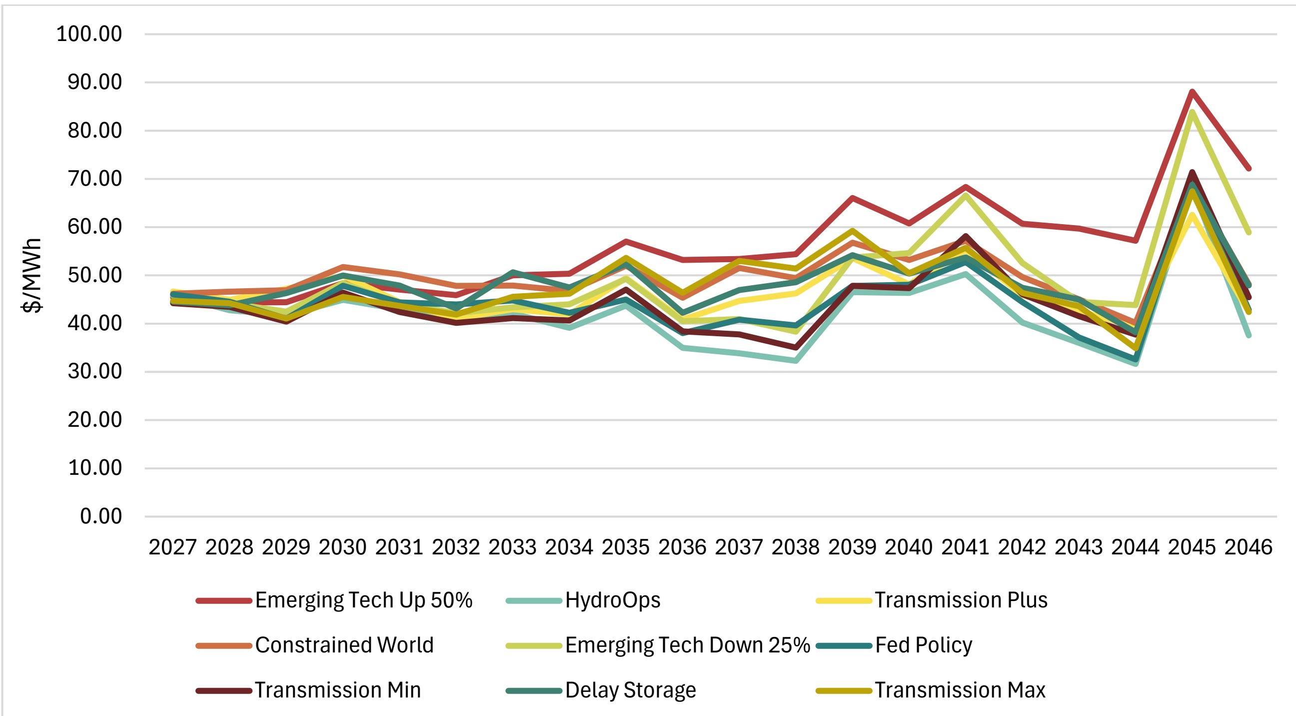
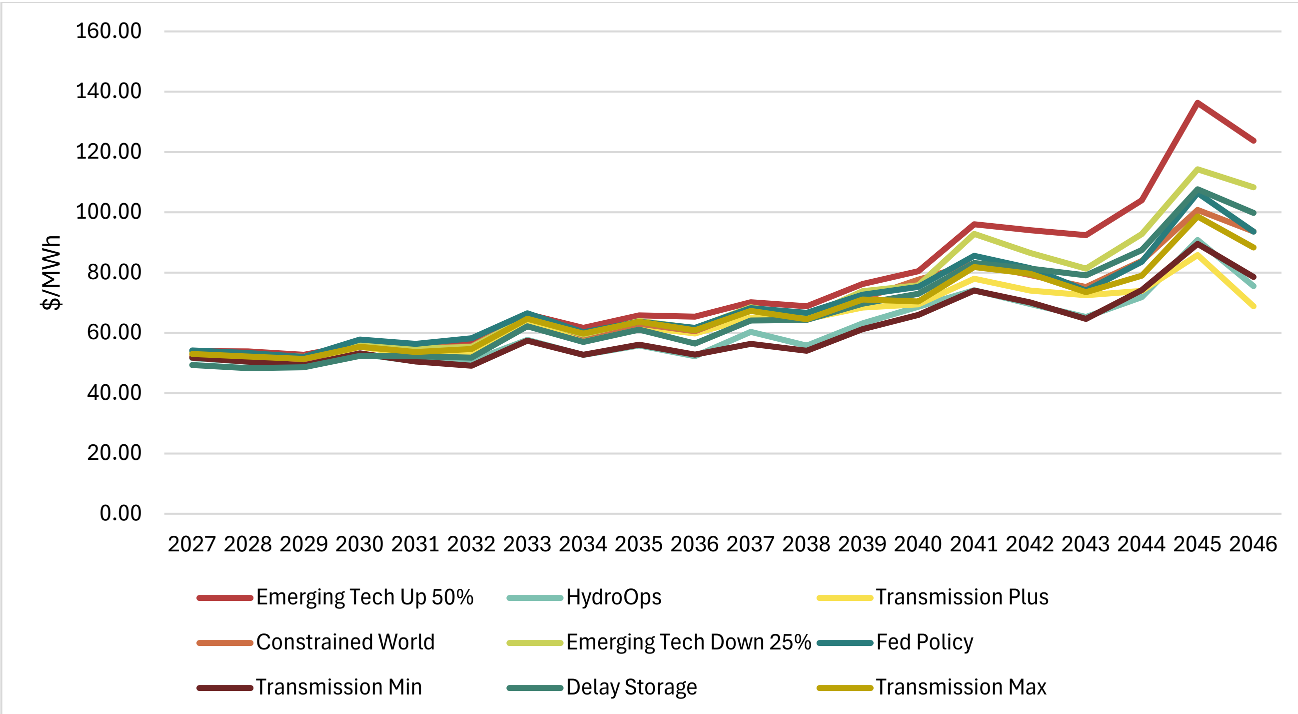


Figure L - 14: California Winter Average Power Prices



With an increase in transmission projects from the east side of the WECC to the west increasing connectivity per the transmission expansion described in Technical Appendices B and N, and the Mountain West sporting higher capacity factor wind resources that provide diversity to the existing solar buildout in the Southwest in conjunction with the increasing clean policy requirements over time, the Mountain West power prices are dropping over time as seen in Figure L - 15. Traditionally, due to limited connectivity with the Mountain West, less power was transmitted east to west, but that may change with the increased connectivity.

Figure L - 15: Mountain West Annual Average Power Prices

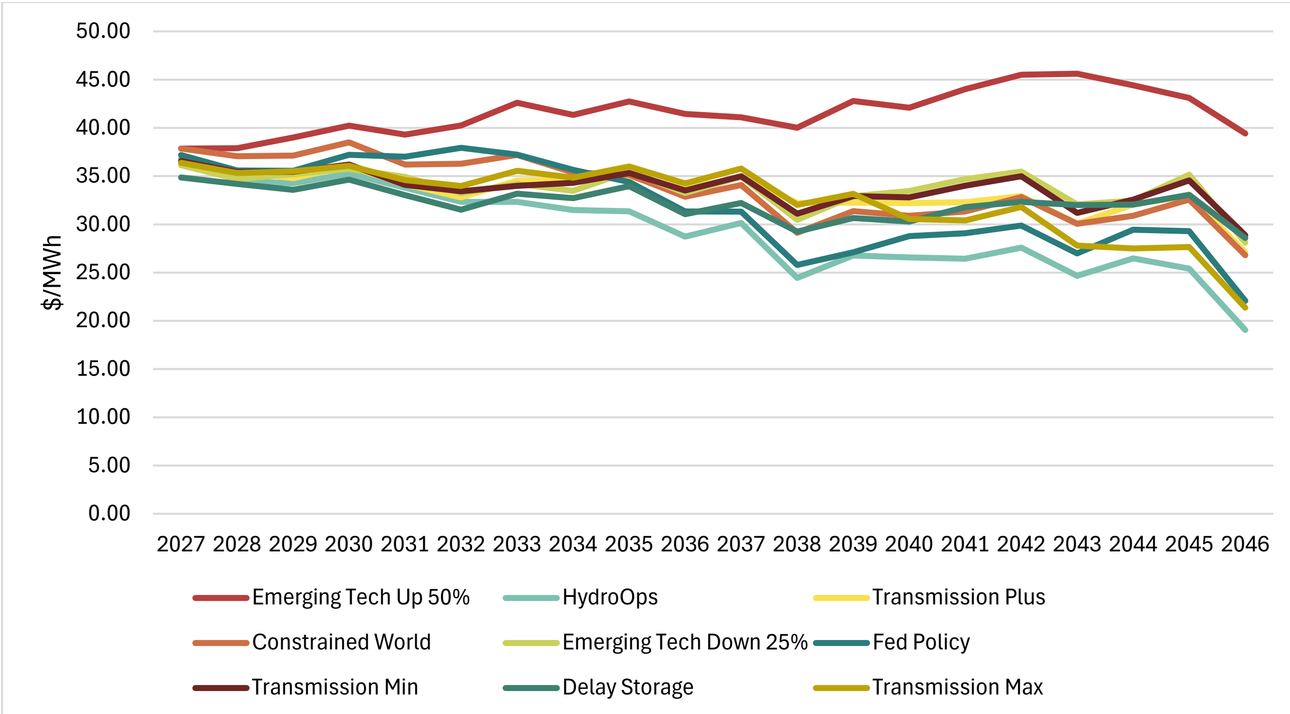
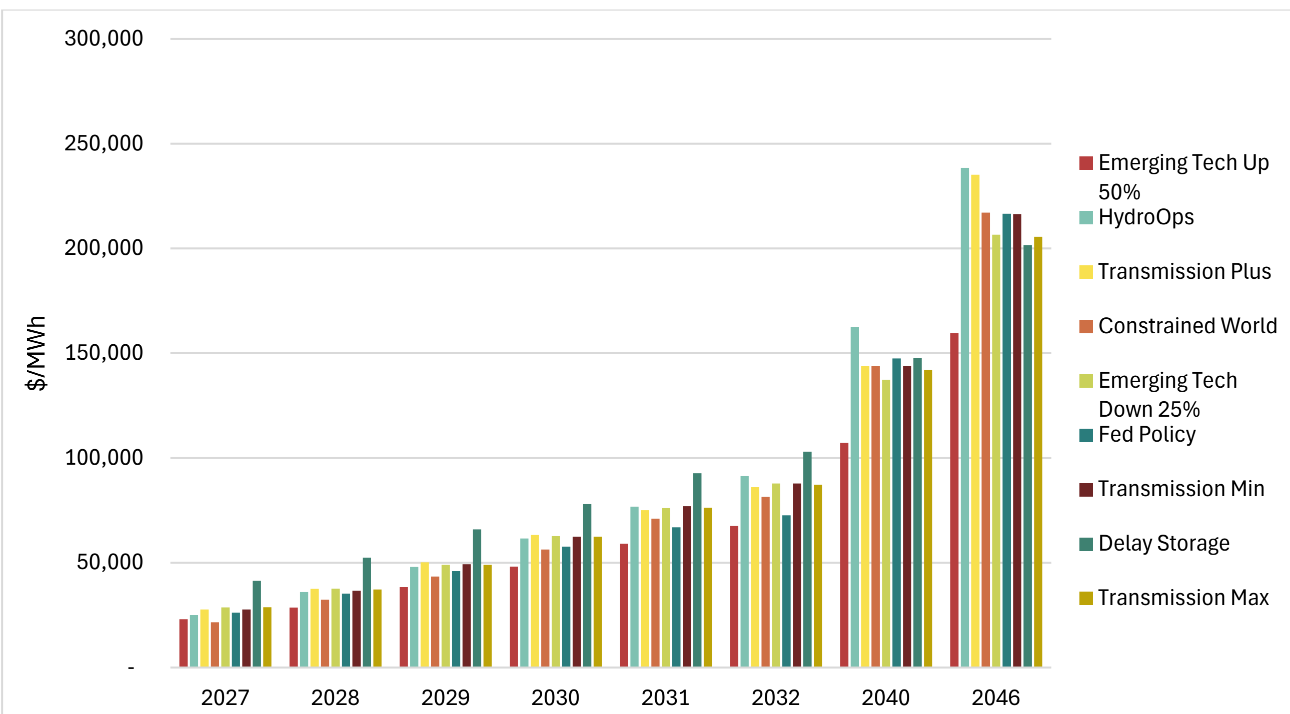


Figure L - 16: Total Out of Region Build in Nameplate Megawatts



In summary, the AURORA buildouts shown in Figure L - 16 seem to indicate that outside the Northwest resources will play a large role in WECC expansion, between 159 to 238 gigawatts by 2046. Most of the resources built are a balance of solar, wind, longer duration storage and gas. The high prices in the winter morning and evening ramp periods and the lack of persistent negative pricing implies that the economics of the market long-term are likely to be quite different than previous recent studies. This is likely due to the effect of the increased load growth outpacing the policies. Additionally, traditional regional fundamentals around seasonal arbitrage are likely to shift due to policies, shifts in magnitude of seasonal demand, increased transmission connectivity and the resulting access to diverse power sources with lower variable costs.

Further Reference

For more information pertaining to the public process of vetting the assumptions and methodologies in this technical appendix please reference the following meetings:

- **July 17, 2025 SAAC meeting:** https://www.nwcouncil.org/meeting/system-analysis-advisory-committee-2025-07-17
- **August 26, 2025 SAAC meeting:** https://www.nwcouncil.org/meeting/system-analysis-and-resource-adequacy-combined-advisory-committees-2025-08-26
- **November 5, 2025 SAAC meeting:** https://www.nwcouncil.org/meeting/system-analysis-advisory-committee-2025-11-05
- **January 6, 2026 Council meeting:** https://www.nwcouncil.org/fs/19713/2026_01_3.pdf#page=8