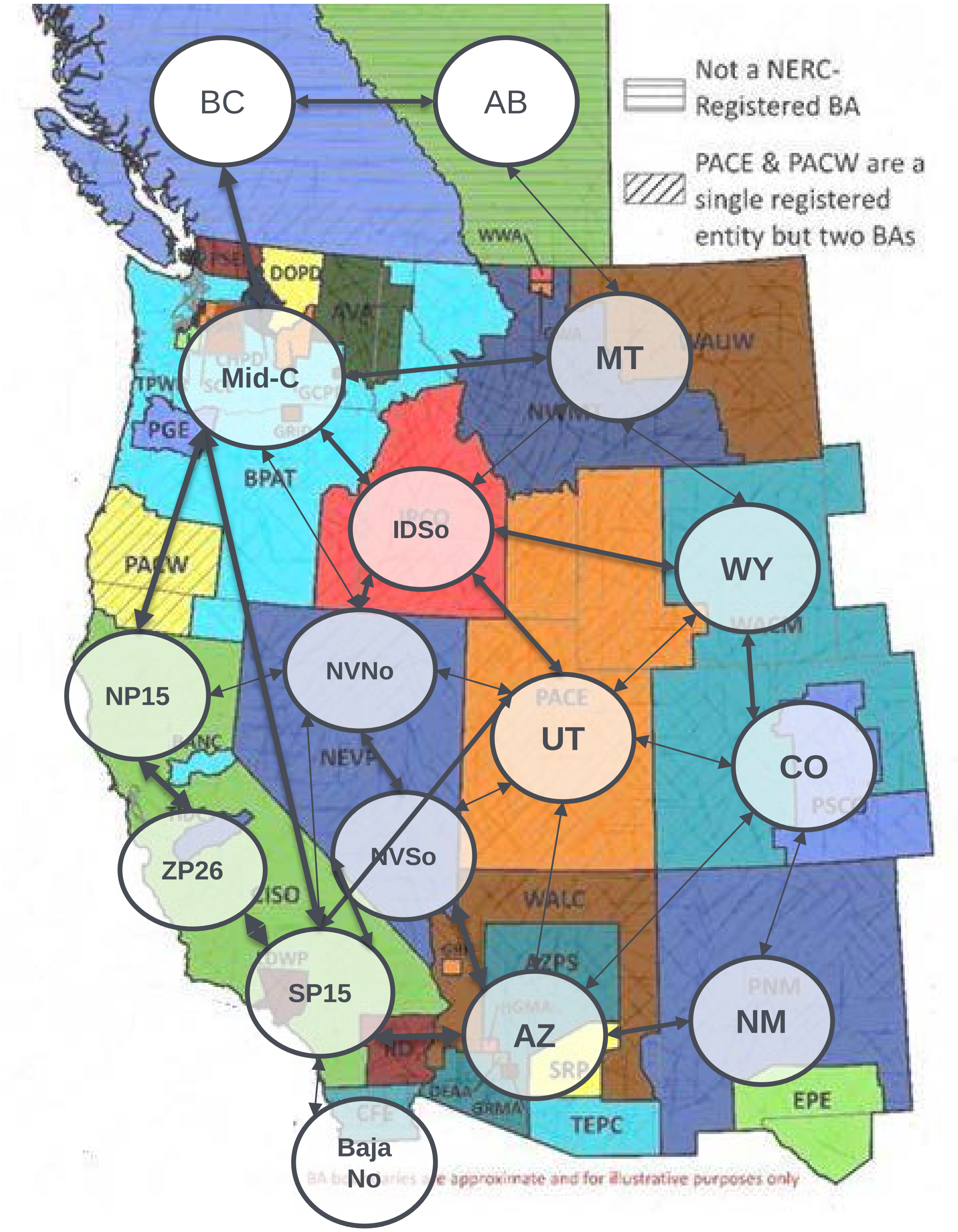
Wholesale Power Prices

A power price forecast is developed for each scenario modeled in the IRP. In this context, “power price” does not mean the rate charged to customers, it means the price to PSE of purchasing (or selling) 1 megawatt (MW) of power on the wholesale market given the economic conditions that prevail in that scenario. This is an important input to the analysis, since market purchases make up a substantial portion of PSE’s existing resource portfolio.

Creating wholesale power price assumptions requires performing two WECC-wide AURORA model runs for each of the four scenarios (AURORA is an hourly chronological price forecasting model based on market fundamentals.)

- The first AURORA run identifies the capacity expansion needed to meet regional loads. AURORA looks at loads and peak demand plus a planning margin, and then identifies the most economic resource(s) to add to make sure that all of the regions modeled are in balance.
- The second AURORA run produces hourly power prices. A full simulation across the entire WECC region produces power prices for all of the 16 zones shown in Figure 1 below. The lines and arrows in the diagram indicate transmission links between zones. The heavier lines represent greater capacity to flow power from one zone to another.

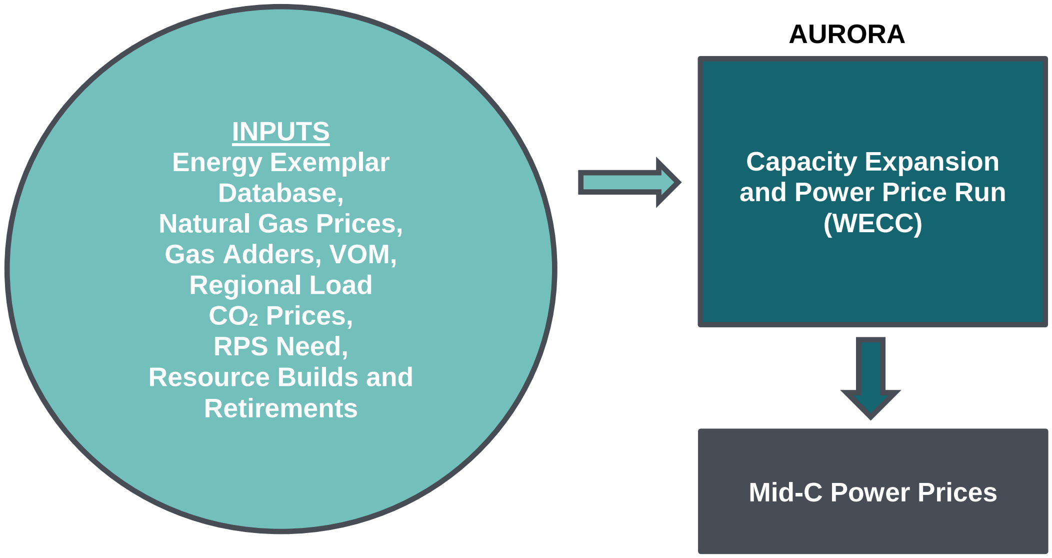
Figure 1: AURORA *System Diagram*



The Pacific Northwest Zone, labeled Mid-C in the preceding diagram, is modeled as the Mid-Columbia (Mid-C) wholesale market price. The Mid-C market includes Washington, Oregon, Northern Idaho and Western Montana.

Figure 5-2 illustrates PSE's process for creating wholesale market power prices.

Figure 2: PSE IRP Modeling Process for AURORA *Wholesale Power Prices*



The AURORA database starts with inputs and assumptions from the Energy Exemplar 2018 v1 database. PSE then includes updates such as regional demand, natural gas prices, gas pipeline adders, variable operations and maintenance (VOM), CO_2 prices, RPS need, and resource retirements and builds.

2021 IRP progress report scenario: Mid

The base scenario is a set of assumptions that is used as a reference point against which other sets of assumptions can be compared.

- Demand –
  - For electric power price modeling, the NPCC Seventh Power Plan regional mid demand forecast is applied to the WECC region
- Natural Gas prices –
  - Mid gas prices are applied, a combination of forward market prices and Wood Mackenzie's fundamental long-term base forecast.
- CO_2 price/Regulations –

  - The social cost of carbon, expressed as a cost adder for resources in Washington or delivered to Washington
  - For natural gas generation fuel, upstream CO_2 emissions are added to the emission rate of natural gas plants in PSE's portfolio model.
  - CO_2 prices for California and British Columbia (B.C.) are included.
- Clean Energy/RPS regulations
  - For Washington state, at least 80 percent of electric sales (delivered load) are met with non-emitting/renewable resources by 2030 (per CETA) and 100% by 2045; plus, all other renewable portfolio standards (RPS) and clean energy regulations in the WECC[1] are applied.

Regional Electric Demand

Regional demand must be taken into consideration because it significantly affects power prices. This IRP uses the regional demand developed in the Seventh Power Plan by the Northwest Power and Conservation Council (NPCC or "the Council").[2] Regional demand is used only in the WECC-wide portion of the AURORA analysis that develops wholesale power prices for the scenarios.

Gas Price Inputs

For gas price assumptions, PSE uses a combination of forward market prices and fundamental forecasts acquired in Fall 2018 from Wood Mackenzie.[3] Three gas price forecasts are used in the scenario analyses.

MID GAS PRICES. From 2020-2023, this IRP uses the three-month average of forward marks for the period ending December 31, 2018. Forward marks reflect the price of gas being purchased at a given point in time for future delivery. Beyond 2023, this IRP uses the Wood Mackenzie long-run, fundamentals-based gas price forecasts published in November 2018.

CO_2 Price Inputs

The electric analysis modeled the social cost of carbon as cited in the Washington Clean Energy Transformation Act (CETA) as a cost adder to thermal resources in Washington state and as a tax across the WECC and the cost of upstream natural gas emissions. In addition the SCC, the analyses modeled the costs imposed by existing CO_2 regulations in California and British Columbia.

[1] / *WECC, the Western Electricity Coordinating Council, is the regional forum for promoting electric service reliability in the western United States.*

[2] / *The NPCC has developed some of the most comprehensive views of the region's energy conditions and challenges. Authorized by the Northwest Power Act, the Council works with regional partners and the public to evaluate energy resources and their costs, electricity demand and new technologies to determine a resource strategy for the region.*

[3] / *Wood Mackenzie is a well-known macroeconomic and energy forecasting consultancy whose gas market analysis includes regional, North American and international factors, as well as Canadian markets and liquefied natural gas exports.*

SOCIAL COST OF CARBON. The social cost of carbon cited in CETA comes from the Interagency Working Group on Social Cost of Greenhouse Gasses, Technical Support Document, August 2016 update. It projects a 2.5 percent discount rate, starting with $62 per metric ton (in 2007 dollars) in 2020. The document lists the CO_2 prices in real dollars and metric tons. PSE has adjusted the prices for inflation (nominal dollars) and converted to U.S. tons (short tons). This cost ranges from **$86 PER TON IN 2020 TO $184 PER TON IN 2039.**

RENEWABLE PORTFOLIO STANDARDS (RPS) and CLEAN ENERGY STANDARDS

Renewable portfolio standards and clean energy standards currently exist in 29 states and the District of Columbia, including most of the states in the WECC and British Columbia. They affect PSE because they increase competition for development of renewable resources. Each state and territory defines renewable energy sources differently, sets different timetables for implementation, and establishes different requirements for the percentage of load that must be supplied by renewable resources.

To model these varying laws, PSE identifies the applicable load for each state in the model and the renewable benchmarks of each state's RPS (e.g., 3 percent in 2012, 9 percent in 2016, then 15 percent in 2020 for Washington State RCW 19.285). These requirements are applied to each state's load. No retirement of existing WECC renewable resources is assumed, which may underestimate the number of new resources that need to be constructed. After existing renewable resources are accounted for, they are subtracted from the total WECC RPS need, and the net RPS need is added to AURORA as a constraint. We then run the long-term capacity expansion with the RPS constraint, and AURORA adds renewable resources to meet RPS need. Technologies modeled included wind and solar.

WASHINGTON CLEAN ENERGY TRANSFORMATION ACT (CETA). CETA requires that at least 80 percent of electric sales (delivered load) in Washington state must be met by non-emitting/renewable resources by 2030 and 100 percent by 2045. For the 2019 IRP, PSE reviewed the Washington Dept. of Commerce fuel mix report. For utilities that are currently more than 80% hydro, it was assumed that they will get 100% by 2030 and for utilities that are less than 80% hydro, it was assumed they will get 80% by 2030. This broke down to 52% of sales in Washington met by utilities that will get 100% by 2030 and 48% of sales in Washington from utilities that will get 80% by 2030. This averaged to the assumption that 90% of sales in Washington will be met by renewable resources by 2030.

Figure 3 is a table of the assumptions modeled for each state in the 2019 IRIRP.

State	State Legislation	RPS/Clean Energy Standards modeled in 2019 IRP
Arizona	Arizona Corporation Commission (ACC) Decision 69127	15% by 2025
Colorado	SB 15-254	20% of its retail electricity sales in Colorado for the years 2015-2019; and 30% of its retail electricity sales in Colorado for the year 2020 and each following year
California	SB 100	2030: 60% of retail sales must be renewable or carbon-free electricity 2045: 100% of retail sales must be renewable or carbon-free electricity
Idaho	None	N/A
Nevada	SB 358	22% for calendar year 2020 24% for calendar year 2021 29% for calendar years 2022 and 2023 34% for calendar years 2024 – 2026 42% for calendar years 2027 – 2029 50% for calendar year 2030 and every year thereafter (must generate, acquire or save electricity from renewable energy systems)
New Mexico	SB 489	40% renewable resources by Jan 1, 2025 50% renewable resources by Jan 1, 2030 80% renewable resources by Jan 1, 2040 100% zero carbon resources by Jan 1 2045
Montana	SB 164	15% by 2015
Oregon	SB 1547	Large investor-owned utilities: 50% by 2040 Large consumer-owned utilities: 25% by 2025 Small utilities: 10% by 2025 Smallest utilities: 5% by 2025
Utah	SB 202	20% by 2025
Washington	SB 5116	100% of sales to be greenhouse neutral by 2030 – 80% must by be my non-emitting/renewable resources State Policy: 100% of sales met by non-emitting/renewable resources by 2045
Wyoming	None	N/A