Energy Forecast

UPDATE TO THE WHOLESALE ELECTRICITY PRICE FORECAST

February 2013

Executive Summary

This Wholesale Electricity Price Forecast updates the forecast developed in 2010 for the Council's Sixth Power Plan, and it reflects the regional changes that have occurred in generating resources, natural gas prices, electricity demand, and state and federal environmental and emission policy. Future electricity prices were evaluated under a variety of CO_2 emission regulatory scenarios and high and low fuel price and demand sensitivities. The new power market outlook has resulted in a significantly lower wholesale price forecast than the Sixth Power Plan's medium forecast.

- Low spot market prices for wholesale power at the Mid Columbia pricing point are expected to continue but gradually grow over time with the price of natural gas and cost of CO_2 emissions.

Large supplies of hydro power in the region, low load growth, significant development of renewable power with low operating costs, and low natural gas prices have combined to keep market prices for electricity

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low. Continued low spot prices may act to mute price signals, which could discourage future power generation development in the region. Low prices may also affect avoided-cost calculations used for energy efficiency assessments.

- Natural gas prices exert a strong influence on the price of electricity, though gas consumption in the region may not significantly increase. Gas generation in the region is expected to surpass coal for good around the 2021 time frame.

Since natural gas-fired plants are often the marginal generating unit, gas prices play an important role in determining the wholesale electricity price. Variations in the future price of gas could have significant impact on electricity prices for the region.

- Federal and state level greenhouse gas regulatory policies will influence future electricity prices, CO_2 emission levels, and resource development. Even without a uniform federal cap and trade system or carbon tax, existing federal and state policies, coupled with low natural gas prices, are affecting CO_2 emissions and electricity prices.

The study of CO_2 emission trends, along with the impact of various emission policy decisions, has been identified as an important topic for the Seventh Power Plan. During the forecast update, new work was undertaken to model emissions using the same electricity market model that was developed to forecast prices. Modeled CO_2 emissions were found to compare well to actual historic emissions for the region, giving confidence to the integrity of future projections using this method. The results from the midterm forecast indicate that the region can expect future CO_2 emissions to decline, even without a federal CO_2 regulatory cost policy. This is due to coal plant retirements, state and proposed federal CO_2 performance standards, along with an increased reliance on energy efficiency, natural gas-fired generation, and wind energy. Modeling results indicate even lower emissions may result from a cost-based federal regulatory policy on CO_2 emissions.

- CO_2 emissions in the region are expected to drop as wind generation expands and coal plant closures such as Boardman and Centralia occur.

The forecast results indicate that the region can expect future CO_2 emissions to decline, even without a federal greenhouse gas regulatory cost policy. This is due to coal plant retirements, state and proposed federal GHG performance standards, along with continued emphasis on energy efficiency, natural gas-fired generation, and continued development of wind and other renewable resources. Modeling results indicate even lower emissions may result from a cost-based federal regulatory policy on GHG emissions.

Background

The Council forecasts spot market prices for wholesale power as part of its planning responsibilities. The forecasts are used in several of the Council's modeling and planning tools, including the GENESYS power adequacy model, the conservation supply curve model, and the regional portfolio model. Utilities and other organizations refer to the forecasts to aid in their resource planning. The Council collects and integrates the data that drives market prices, models the interrelationships, and produces scenario forecasts across a 20-year planning horizon. A few of the key price drivers include:

- Demand and energy efficiency forecasts
- Fuel price forecasts
- Existing generating resource capabilities and costs
- New generating resource capabilities and costs
- Generating unit retirements
- Greenhouse gas emissions policies

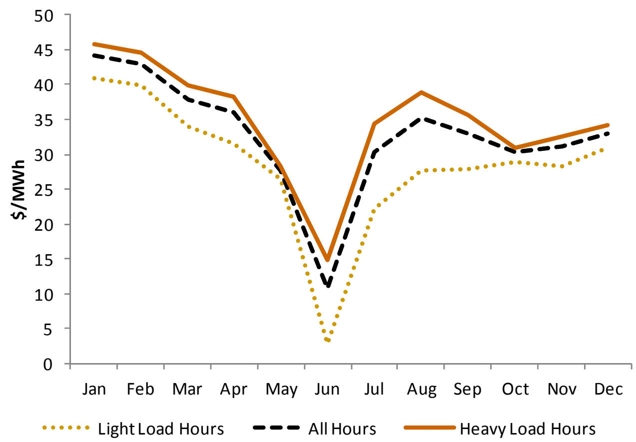
Power Generation in the Region

The five primary sources of power generation in the region are hydro, coal, natural gas, wind, and nuclear. On an average annual basis, hydro accounted for 59 percent of the system power for 2007 through 2011. The percentage that hydro contributes can vary from year to year based on water conditions. For instance, in 2011, hydro constituted 68 percent of the total system power. Coal and natural gas generation tend to fluctuate around hydro conditions. From 2007 to 2011, coal contributed 20 percent on average; while natural gas-fired generation was third at 12 percent. The contribution from wind power has been steadily increasing and provided 6 percent in 2011. These figures include generation within the Western Electric Coordinating Council portions of Idaho, Montana, Oregon, and Washington. The Idaho Power share of North Valmy and the Jim Bridger coal units were also included.

Mid Columbia Electricity Prices

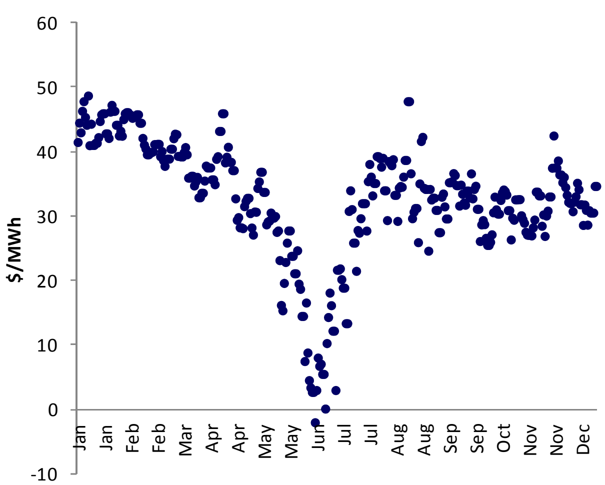
The Mid Columbia hub is one of eight electricity trading hubs in the Western United States. The Mid C represents an aggregation of the electricity market for the Northwest; the forecast prices in this report correspond to this hub. The forecast wholesale electricity prices in this report represent prices at the Mid C. Prices at the hub exhibit a strong seasonal pattern dictated by demand, as well as hydro and wind power generation. Surplus power from the region is often exported to California in the spring and summer.

Historic Monthly Wholesale Electricity Prices at Mid C for Year 2010

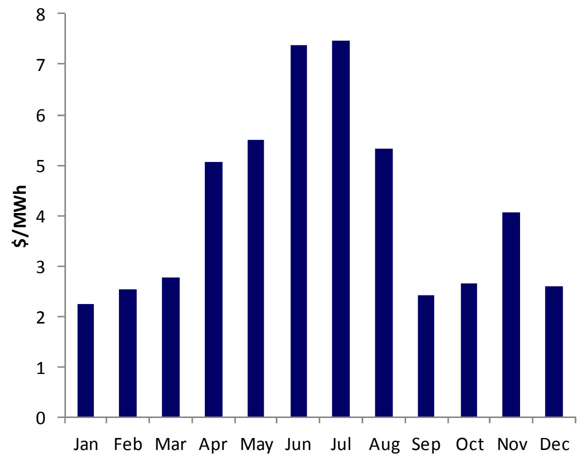


Daily prices can vary in the winter and summer based on extreme weather. The combination of strong winds generating power along with high spring/summer hydro runoff can also drive variation in prices. Negative pricing can occur at the Mid C, often in the spring and early summer when conditions produce abundant hydro power and wind power at the same time.

Historic Wholesale Electricity Prices at Mid C for Year 2010 Daily



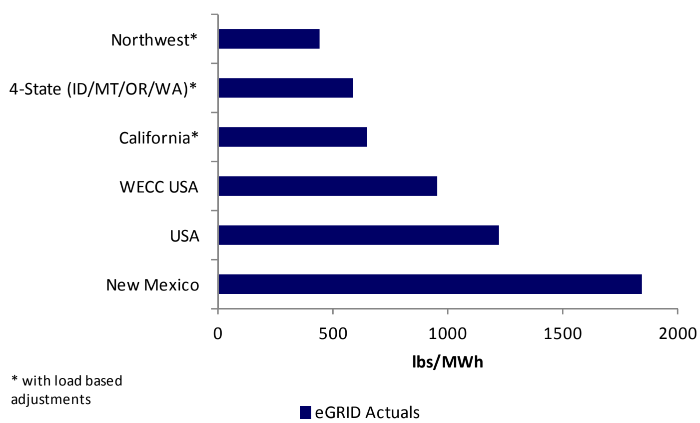
Historic Daily Standard Deviation at Mid C for Year 2010



CO_2 Emission Levels

The Environmental Protection Agency maintains a database of power production emission inventories for the United States called eGRID. For 2009, eGRID reported a CO_2 production rate of 587 lbs/MWh from the power system operating in the four-state region of Idaho, Montana, Oregon, and Washington. This rate is significantly lower than the national rate—52 percent lower--due to the region's abundance of hydro and wind power. Furthermore, forecasting results indicate that regional CO_2 emission levels will drop even lower over the next 20 years.

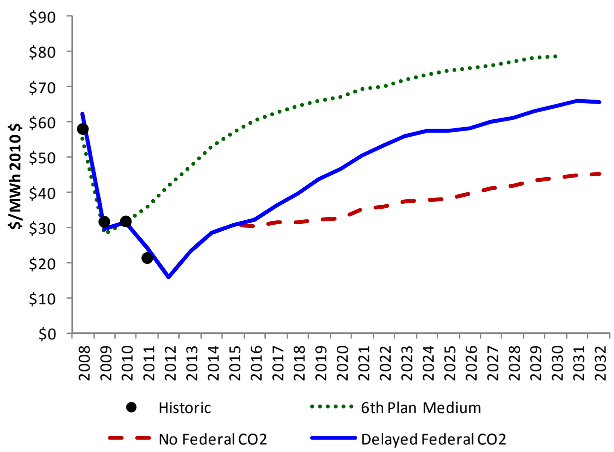
CO_2 Emission Rates for 2009 (lb/MWh)



Results

Due to changes to the power landscape, the forecast for wholesale electricity prices at the Mid C have dropped significantly from the Sixth Power Plan's medium case. Low spot market prices at the Mid C pricing point are expected to continue, but gradually rise over time as the price of natural gas and CO_2 emission costs increase.

Wholesale Electricity Price Forecast at Mid C



Plentiful hydro supplies, coupled with low natural gas prices, low load growth, and growth in wind power development are all important factors in lowering wholesale electricity prices. Though gas-fired generation in the region may not increase significantly, gas prices exert a strong influence on the price of electricity. As coal plants in the region retire, gas and renewable resources are expected to fill the gap and as a result, CO_2 emissions in the region are expected to decline.

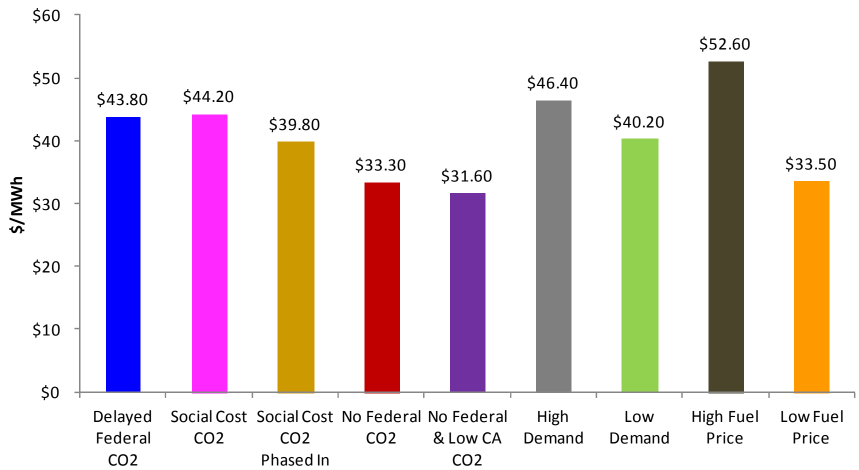
Electricity Prices

The price results for all the forecast cases are summarized in the following charts. Prices range from \$52/MWh for the case with high fuel costs and the delayed federal CO_2 policy down to \$32/MWh for the case with the least CO_2 regulation. The five CO_2 cases incorporated the same medium demand and fuel price forecasts in order to isolate the effect of different emission cost policies. The four demand/fuel sensitivity cases were run with the Delayed Federal CO_2 emissions policy, to gauge the impact of demand and fuel price alone.

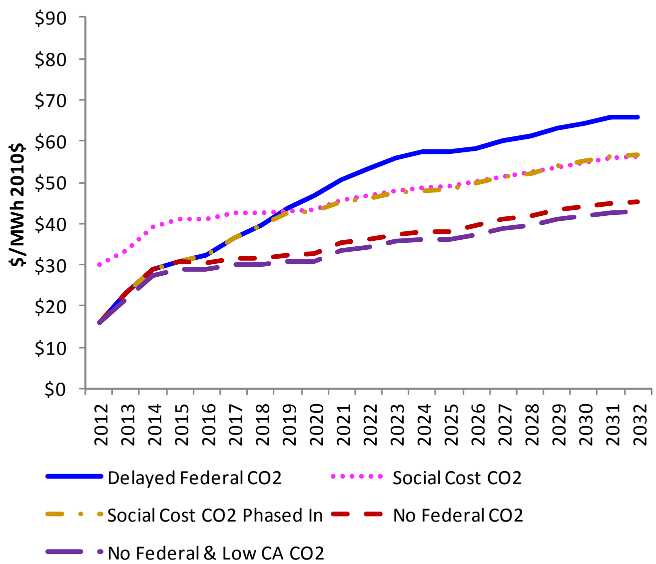
Average Annual Wholesale Electric Price Forecast ($/MWh 2010$)

Year	Delayed Federal CO2	Social Cost CO2	Social Cost CO2 Phased In	No Federal CO2	No Federal & Low CA CO2	High Demand	Low Demand	High Fuel Price	Low Fuel Price
2012	15.84	30.22	15.82	15.86	15.86	15.79	15.81	13.12	10.56
2013	23.26	33.65	23.26	23.23	21.64	23.97	21.73	23.90	16.42
2014	28.73	39.20	28.76	28.73	27.31	29.87	26.43	31.21	21.01
2015	30.80	41.12	30.85	30.63	29.08	32.12	28.30	33.69	22.84
2016	32.19	41.16	32.20	30.37	28.80	33.49	29.57	35.61	23.21
2017	36.35	42.43	36.35	31.42	29.90	37.42	33.92	41.04	26.15
2018	39.66	42.63	39.61	31.61	30.00	41.21	37.53	47.50	32.12
2019	43.82	43.15	42.60	32.42	30.73	45.52	41.39	52.03	35.02
2020	46.66	43.53	42.99	32.73	30.93	48.62	44.17	55.63	38.15
2021	50.59	45.79	45.39	35.42	33.61	53.08	47.37	61.29	40.78
2022	53.30	46.72	46.20	35.99	34.36	55.99	49.35	64.50	42.52
2023	55.93	47.88	47.56	37.41	35.56	58.92	51.66	67.78	44.00
2024	57.33	48.52	48.08	37.88	36.02	60.67	52.49	69.90	44.62
2025	57.50	48.90	48.40	38.07	36.00	61.56	52.55	70.59	44.40
2026	58.34	50.25	49.67	39.55	37.27	63.47	52.94	73.35	44.32
2027	60.04	51.26	51.29	41.13	38.71	65.27	53.91	76.25	45.03
2028	61.26	52.30	52.29	41.74	39.37	66.90	54.53	77.02	45.37
2029	63.15	53.77	53.88	43.23	40.91	68.74	55.70	79.78	45.79
2030	64.39	54.88	54.99	44.19	41.65	70.12	56.27	81.60	46.04
2031	65.85	56.08	56.12	45.04	42.49	71.16	57.59	82.98	46.58
2032	65.78	56.21	56.84	45.41	42.81	71.63	57.97	83.52	46.92

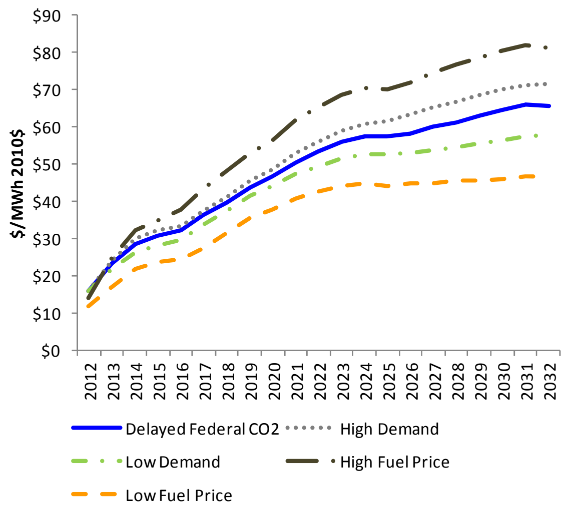
Levelized Wholesale Electricity Price Forecast at Mid C (2012 - 2032)



Wholesale Electricity Price Forecast at Mid C – CO_2 Cases

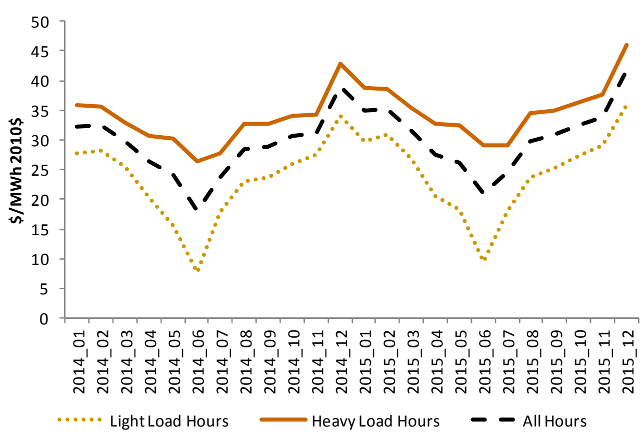


Wholesale Electricity Price Forecast at Mid C – Sensitivity Cases



The resulting levelized electricity prices over the planning horizon for the delayed federal CO_2 case and the social cost CO_2 case were close in value. The delayed federal CO_2 case assumes that a tax or regulatory cost is assigned to CO_2 emissions. The CO_2 cost curve is phased in beginning in 2015, ramps up sharply, and then begins to level off around 2022. In the social cost CO_2 case a cost to society from CO_2 emission is assumed. For modeling purposes in this forecasting cycle, the cost from emissions was attached to the electricity price as if it were a tax or regulatory cost in order to compare it to the other CO_2 regulatory cases. The forecast model also captures the typical seasonal and hourly pricing patterns at the hub. Prices are damped most during the load low hours of the day, and during periods of surplus hydro power.

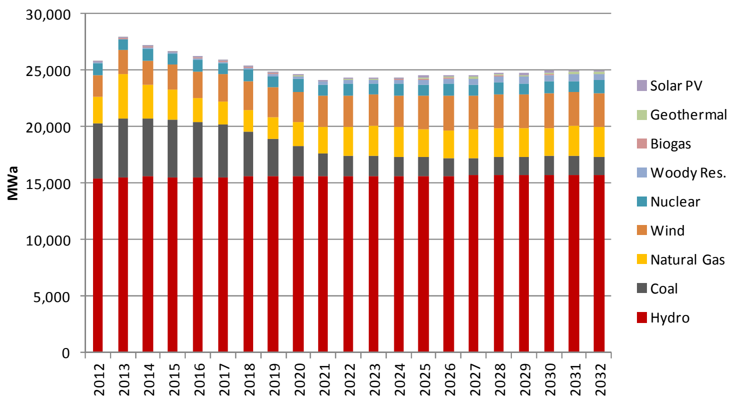
Wholesale Electric Price Forecast Mid C All Conditions - Delayed Federal CO_2 Case



Generation Mix

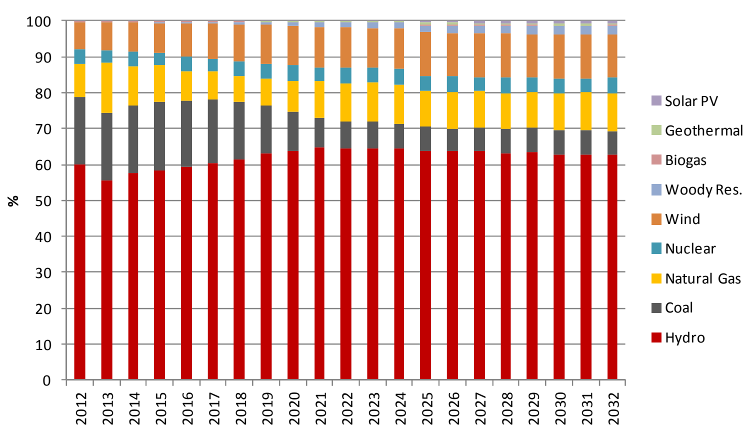
Hydro, Coal, Natural Gas, Wind, and Nuclear constitute the bulk of power production in the model.

Annual Power Generation Four-State Region (ID/MT/OR/WA) - Delayed Federal CO_2 Case



Over the planning horizon, hydro power remains constant, coal power declines, natural gas remains relatively constant, nuclear power is constant, and wind increases. The annual energy production in the region can fluctuate based on native demand, as well as export/import market conditions. Typically, the region is a net exporter of energy, primarily south to California. Wind power increases with renewable portfolio standard development, while coal power declines as the coal units Boardman and Centralia retire.

Annual % Power Generation Four-State Region (ID/MT/OR/WA) - Delayed Federal CO_2 Case

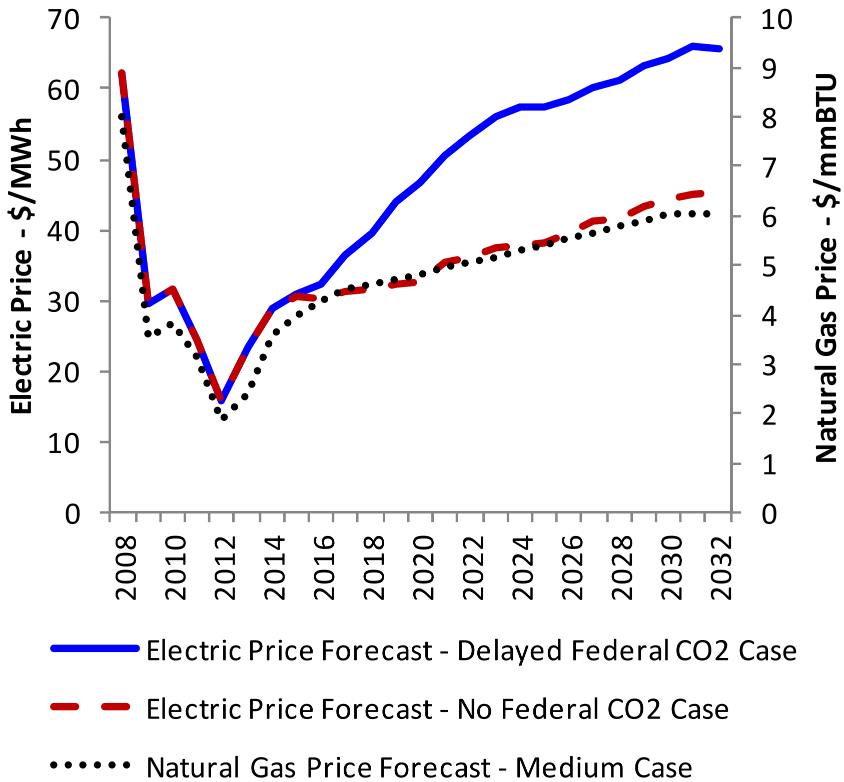


In the delayed federal CO_2 case, natural gas-fired generation surpasses coal-fired generation in 2021 for the four-state region. In the no federal CO_2 case, the gap in generation between coal and gas tightens, but gas never quite surpasses coal fired generation.

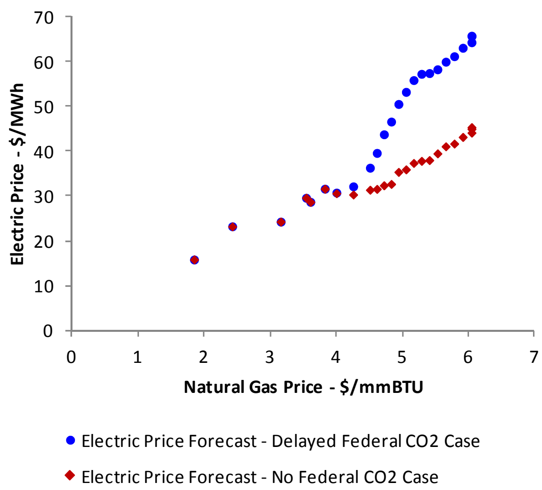
Role of Natural Gas Price

Since natural gas-fired plants are often the marginal generating unit, gas prices play an important role in determining the wholesale electricity prices. Variations in the future price of gas could have a significant impact on electricity prices for the region. A cost-based federal CO_2 policy could lead to higher electricity prices.

Wholesale Electric and Natural Gas Price Forecasts at Mid C and PNW E Zone



Natural Gas Price at PNW E Zone vs. Electricity Price at Mid C



CO_2 Emission results

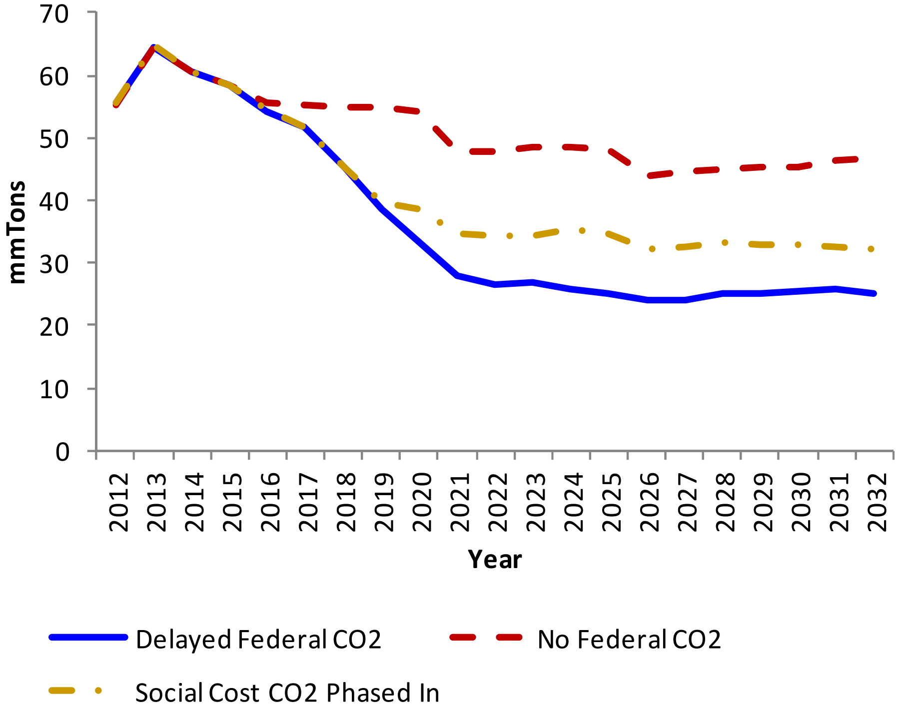
In addition to electricity prices, the AURORA$^{xmp®}$ dispatch model also calculates CO_2 production. Plant CO_2 production depends on power output, plant specific heat rates, and fuel specific emission rates. Forecast emissions from the dispatch model were compared to historic values as reported by eGRID. Some adjustments were made to the geographical source in order to accurately represent some load-based emissions. For example, the output of the Jim Bridger coal units was assigned to the Idaho South zone, and not Wyoming where the units are located. The Idaho Power share of the North Valmy coal units is also assigned to that zone. The model generated fairly accurate past results for the 2009 historic data point, coming within 2 percent of actual for the WECC U.S.A. and four-state regions.

CO_2 Emission (mmTons) for 2009

Region	eGRID Historic Emission mmTons	Modeled Emission mm Tons
WECC USA	349	356
4-State (ID/MT/OR/WA)	64	62
Northwest (ID/OR/WA/W. MT)	45	42

The forecast results indicate that the region can expect future CO_2 emissions to decline, even without a federal greenhouse gas regulatory cost. This is due to coal plant retirements, state and proposed federal GHG performance standards, along with continued emphasis on energy efficiency, natural gas-fired generation, and development of wind and other renewable resources. Modeling results indicate even lower emissions may result from a cost-based federal policy emissions.

Forecast CO_2 Emissions 4-State Region (ID/MT/OR/WA)



Methodology

The Council actively tracks the issues which may impact electricity prices. The development, costs, and output of generating resources in the region are updated on a consistent basis, as are loads and fuel prices. Other regional and WECC-wide energy issues are tracked as well, such as emission regulatory and cap and trade developments, the unfolding of California Once-Through Cooling (OTC) regulatory impacts, and the growth of state Renewable Portfolio Standards (RPS) development. Several of the Council's planning models utilize this information, as well as the dispatch model which is used to generate forecasts for electricity prices.

One of the key tools the Council uses to produce the forecast is the AURORA$^{xmp®}$ Electric Market Model from EPIS. This is an economic dispatch model; electricity prices are based on the variable cost of the most expensive generating plant or increment of load curtailment required to meet load for each hour of the forecast period. Plant dispatch is simulated for 16 load-resource areas which comprise the Western Electricity Coordinating Council (WECC). In this report, the region referenced as Northwest is composed of the zones Pacific Northwest Eastside (PNWE), Pacific Northwest Westside (PNWW), and Idaho South (ID S). The reference 4-State Region has the Northwest region plus Montana East. Each of the 16 zones are modeled to reflect their unique characteristics in terms of transmission constraints, load forecasts, existing generating units, scheduled project additions and retirements, fuel price forecasts, and new resource options. The dispatch model may add discretionary new resources within zones on an economic basis to maintain capacity reserve requirements or to provide energy. The demand within a zone may be served by native generation, curtailment or by imports from other zones based on economic decisions if the transmission capability exists. Transmission interconnections are characterized by transfer capacity, losses and wheeling costs. In addition to meeting demand, planning reserve margin targets are included in the model. These targets are based on the single highest hour of demand during the year. For the Northwest, both a summer (19%) and winter (25%) target are included.

The modeling process involves two main steps. First, a congruent set of assumptions and inputs (demand, fuel prices, resource availability and costs, etc.) are established and a long-term resource optimization run is performed. This run will set any economically driven capacity additions or retirements over the planning horizon. Then an hourly dispatch run is completed to determine electricity prices for each zone. In addition to electricity prices, the model can also be used to evaluate generation mix, fuel consumption, and CO_2 emission levels.

Inputs and Assumptions

The key inputs and assumptions are covered below. Expanded sections are provided on Once-Through-Cooling, CO_2 regulation, and forecast scenario set up.

Demand

The demand projections for each zone or load resource area were refreshed since the Sixth Plan, resulting in an overall lower forecast. The demand values as input to the dispatch model are net of conservation. The updates for the 4-State Northwest zones were based on the Council's 2012 demand forecast update; for the remaining zones, results from the WECC TEPPC group were used. High and low forecasts were built around the medium forecast and range from (-13%) under to +10% over the medium forecast. Historic loads were used for the years of 2008, 2009, and 2010.

Average Demand Forecast by Zone – Medium Case (average Megawatts)

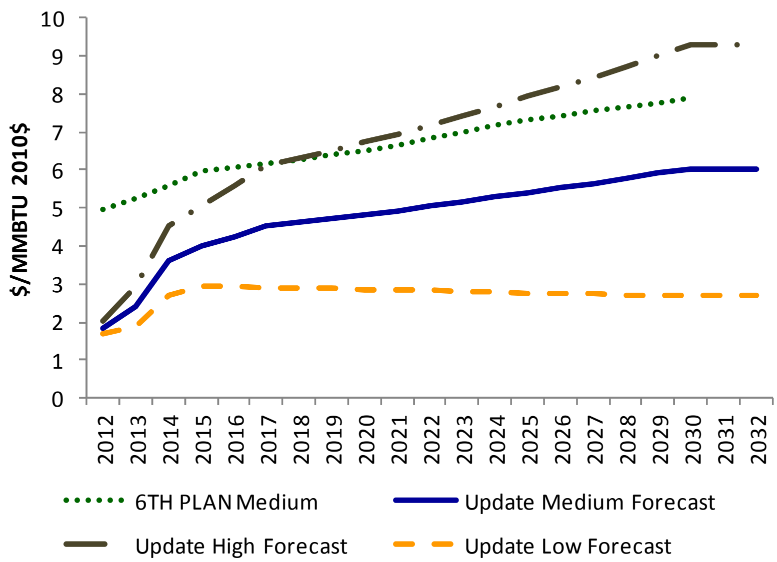
Year	PNW East	PNW West	Idaho South	Northwest Region	WECC
2012	5,096	13,355	2,326	20,777	101,372
2013	5,111	13,395	2,333	20,839	103,003
2014	5,145	13,485	2,348	20,978	104,516
2015	5,183	13,582	2,365	21,130	106,245
2016	5,230	13,707	2,387	21,324	107,670
2017	5,243	13,740	2,393	21,376	109,316
2018	5,297	13,882	2,418	21,597	110,907
2019	5,305	13,904	2,421	21,630	112,286
2020	5,291	13,866	2,415	21,572	113,225
2021	5,288	13,858	2,413	21,559	114,703
2022	5,328	13,964	2,432	21,724	116,006
2023	5,369	14,072	2,451	21,892	117,303
2024	5,422	14,209	2,475	22,106	118,370
2025	5,439	14,255	2,483	22,177	119,854
2026	5,472	14,342	2,498	22,312	121,142
2027	5,513	14,449	2,516	22,478	122,454
2028	5,580	14,624	2,547	22,751	123,621

2029	5,616	14,719	2,563	22,898	125,332
2030	5,670	14,859	2,588	23,117	126,793
2031	5,724	15,001	2,612	23,337	128,398
2032	5,778	15,144	2,637	23,559	129,595

Fuel Prices

The fuel price inputs for each zone were based on updated natural gas and coal forecasts from the Council's fuel model. The high and low forecasts were designed to range as much as 50 percent higher and lower than the medium forecast. Historical coal, fuel oil, and natural gas prices are used for years 2008 through 2010.

Natural Gas Price Forecast Input –variable cost at PNW East zone



Annual Natural Gas Price by Zone - Medium Forecast ($/MMBTU 2010$)

Year	PNW East	PNW West	Idaho South
2012	1.85	2.37	2.10
2013	2.42	2.90	2.57
2014	3.61	3.97	3.52
2015	4.00	4.33	3.84
2016	4.25	4.56	4.04
2017	4.51	4.80	4.24

2018	4.61	4.89	4.33
2019	4.72	4.99	4.41
2020	4.83	5.09	4.50
2021	4.94	5.19	4.59
2022	5.05	5.29	4.68
2023	5.17	5.40	4.78
2024	5.29	5.50	4.87
2025	5.40	5.61	4.97
2026	5.53	5.72	5.07
2027	5.65	5.84	5.17
2028	5.78	5.96	5.27
2029	5.91	6.07	5.37
2030	6.04	6.19	5.48
2031	6.04	6.19	5.48
2032	6.04	6.19	5.48

Existing and Committed Resources

A comprehensive update of the resource base for the dispatch model was completed. The data sources included the 2011 Early Release of the EIA-860 Annual Electric Generation Data Report, the Council's Northwest Generating Resource database, and the Council's resource tracking worksheets. As in previous Council forecasts, projects under construction and resources in advanced development are considered to be committed and completed as scheduled.

New Resource Alternatives

Discretionary new resource options (resources available to be added on an economic basis to maintain capacity reserve requirements or to provide energy) include combined-cycle plants, simple-cycle gas turbines, wind projects, utility-scale solar photovoltaic plants, solar thermal plants, supercritical coal-steam units and integrated coal gasification combined-cycle plants with CO_2 sequestration. The earliest available service dates were adjusted for consistency with the current year (2012) and the project development and construction lead time assumptions of the Sixth Plan. New coal-steam units were prohibited in states and provinces with CO_2 emissions rate performance standards, and in all US areas for the "No Federal CO_2 Case" (see case descriptions). Wind output shapes were updated as described below, otherwise new resource cost and performance characteristics were unchanged from Sixth Plan assumptions.

Renewable Portfolio Standards (RPS)

State RPS mandate the development of renewable resources for the states of Arizona, California, Colorado, Montana, New Mexico, Nevada, Oregon, and Washington. For this forecast, the existing and projected RPS resources were updated for the states of California, Montana, Oregon and Washington. New RPS resources are forced into the model assuming that the new RPS resource requirements are met over time.

Forced Retirements

Announced retirements are assumed to occur when scheduled. Several coal plants, including Boardman, Carbon, and Centralia are assumed to close. Not included is the proposed end-of-year 2017 retirement of San Juan 1 and 2 recently announced by Public Service New Mexico. Table 2 contains a list of assumed coal unit retirements with dates and capacity.

Retiring Coal Units

Unit	Zone	Fuel	Retirement Year	Capacity (MWh)
Carbon 1	Utah	Coal	2014	67
Carbon 2	Utah	Coal	2014	105
Corette 1	MT E	Coal	2015	154
Boardman 1	PNW E	Coal	2020	585
Centralia 1	PNW W	Coal	2020	670
Centralia 2	PNW W	Coal	2025	670

Hydropower

The capacity and energy parameters for this forecast were unchanged from the Sixth Power Plan forecast. Historic Pacific Northwest monthly hydro energy data was used for years 2008 through 2010; average hydro conditions were used for 2011 and later years.

Wind Curves

Representative 8760 hourly wind shapes from the years 2008-2010 were developed from historic wind data. The 2010 shapes were repeated for the remaining years.

Zones

Sixteen zones, or load-resource areas, were used to model the WECC electric reliability area. The local region was divided into three zones named PNW E, PNW W, and ID S.

AURORA$^{xmp®}$ Zones

Zone Name	Geographic Area
PNW E	Eastern Oregon, Eastern Washington, Avista Idaho, Northern Idaho, Western Montana
PNW W	Western Oregon, Western Washington, PacifiCorp CA area
ID S	Southern Idaho including Idaho Power and PacifiCorp Idaho areas
E Montana	Montana east of the Continental Divide
California North	California north of Path 15
California South	California south of Path 15
Wyoming	Wyoming
Colorado	Colorado
New Mexico	New Mexico
Arizona	Arizona
Utah	Utah
Nevada North	Sierra Pacific area
Nevada South	Nevada Power area
British Columbia	British Columbia Canada
Alberta	Alberta Canada
Baja	WECC interconnected grid in Baja CA

Once-Through Cooling

Regulatory activities in California are acting to phase out or mitigate the use of Once-Through Cooling (OTC) systems over time (years 2008 – 2034). This affects mostly older gas-fired steam units, but will also impact the nuclear plants in the state. Assumptions consistent with current California Water Resources Control Board planning were used for this forecast, which are:

- 18 of the affected plants will remain in operation through mitigation or retrofits, including the San Onofre nuclear units (10,797 MW capacity total)
- 41 plants will retire over the planning horizon (11,127 MW capacity total)
- 34 plant replacements will come on-line (5,877 MW capacity total)
- Expected activities results in a net reduction of around 5,250 MW capacity in the state

OTC Timeline for Assumed Capacity Retirements and Replacements

Changes to the power production capabilities in California have an impact on the Northwest power system. The Northwest region is often a net exporter of power south to California, especially in the summer when cooling related demand is high in California and hydro production in the Northwest is strong. In the winter, the Northwest may import available power from California to meet heating demand in the region when seasonal hydro production is low. Therefore limitations to future California production may increase exports from the Northwest in the summer, and reduce imports from California in the winter.

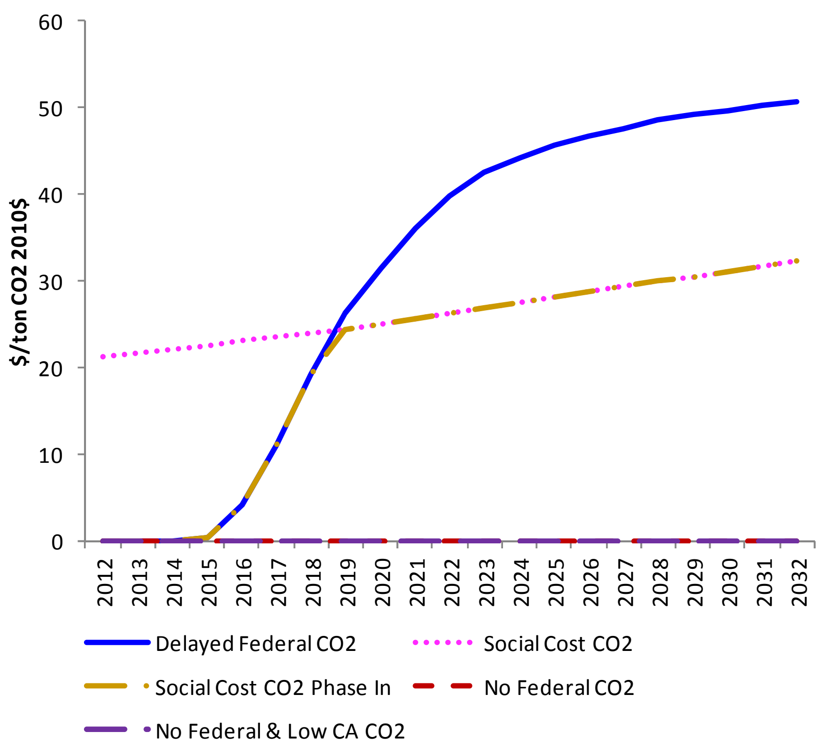
Once-Through Cooling Unit Assumptions

Unit	Capacity-MW	Modeled Status
Diablo Canyon 1,2	2,240	Continue to Operate
Encina 4,5	630	Continue to Operate
Mandelay 1,2	430	Continue to Operate
Morro Bay 3,4	673	Continue to Operate
Moss Landing CC 1,2	1,020	Continue to Operate
Moss Landing Power Plant 6,7	1,509	Continue to Operate
Ormond Beach 1,2	1,516	Continue to Operate
Pittsburg 5,6	629	Continue to Operate
San Onofre 2,3	2,150	Continue to Operate
Haynes CC	1,150	Retirement
El Segundo 3,4	650	Retirement
Alamitos 1-6	1,997	Retirement
Contra Costa 6,7	672	Retirement
Encina 1-3	320	Retirement
Harbor CC	462	Retirement
Haynes 1,2,5,6	979	Retirement
Humboldt Bay ST 1,2	105	Retirement
Huntington Beach 1-4	904	Retirement
Pittsburg 7	682	Retirement
Potrero 3-6	362	Retirement
Redondo Beach 5-8	1,334	Retirement
Scattergood 1-3	817	Retirement
South Bay 1-4	693	Retirement
Alamitos 1-6 R	1,470	Replacement
Carlsbad Energy Center 1,2	540	Replacement
El Segundo CC 1,2	537	Replacement
Haynes 11-16	600	Replacement
Humboldt Bay IC 1-10	167	Replacement
Huntington Beach Energy Proj 1,2	939	Replacement
Marsh Landing Gen Station 1-4	724	Replacement
Redondo Beach 7,8	900	Replacement

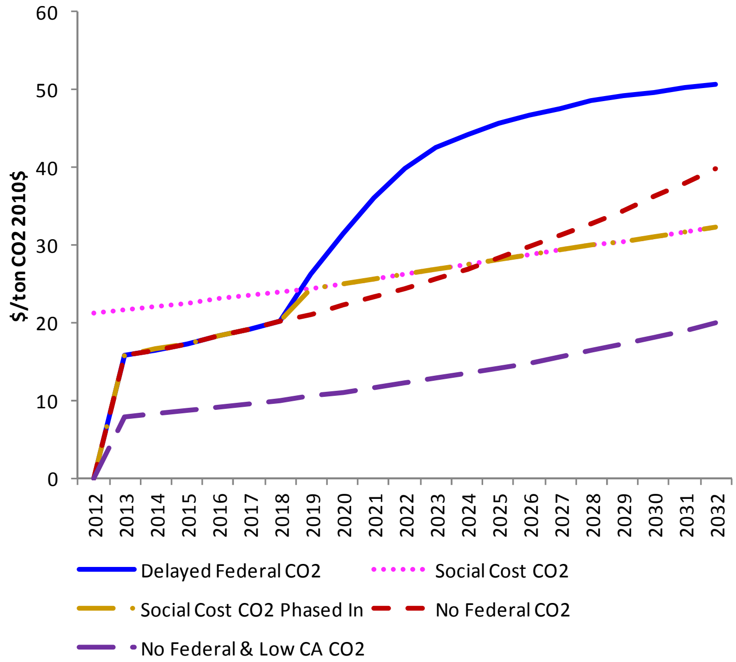
CO_2 Regulatory Policy

For this forecast cycle, five CO_2 emission cases were modeled to evaluate the effects of federal and state level regulatory policies on future electric prices. Though no US federal CO_2 regulatory cost policies have been enacted, California is implementing a cap and trade program (AB32), starting in 2013, and the British Columbia Parliament began imposing a carbon tax in July 2008. For each forecast case, CO_2 price curves (\$/ton CO_2) were set up in AURORA$^{xmp®}$ to represent a US federal price, a California price, and a British Columbia price for emitting CO_2. In this way, a cost is attached to any CO_2 emission produced by the modeled power generation within each region. The California price curve was assigned to the North and South California zones and to the California utility equity share of certain plants physically located outside the state to model the cost for emitting CO_2 from in-state power units. In addition, a hurdle rate was imposed on imports to the state based on emitting intensity. A federal price curve as assigned to the other zones, including those in the Northwest. All of the forecast cases include a price for CO_2 emissions for California and British Columbia.

Federal Emission Price



California Emission Price



CO2 Regulatory Price Cases ($/ton CO2) in 2010 dollars

Year	FED Delay. Fed CO2	FED No Fed CO2	FED Social Cost CO2	FED Social Cost CO2 Ph. In	FED No Fed & Low CA CO2	CA Delay. Fed CO2	CA No Fed CO2	CA Social Cost CO2	CA Social Cost CO2 Ph. In	CA No Fed & Low CA CO2	BC Social Cost CO2	BC All Other Cases
2008	0.00	0.00	19.53	0.00	0.00	0.00	0.00	19.53	0.00	0.00	19.10	4.61
2009	0.00	0.00	19.92	0.00	0.00	0.00	0.00	19.92	0.00	0.00	19.70	11.65
2010	0.00	0.00	20.32	0.00	0.00	0.00	0.00	20.32	0.00	0.00	20.32	16.49
2011	0.00	0.00	20.77	0.00	0.00	0.00	0.00	20.77	0.00	0.00	21.22	21.66
2012	0.00	0.00	21.22	0.00	0.00	0.00	0.00	21.22	0.00	0.00	21.96	26.29
2013	0.00	0.00	21.69	0.00	0.00	15.79	15.79	21.69	15.79	7.89	22.75	29.36
2014	0.00	0.00	22.14	0.00	0.00	16.58	16.58	22.14	16.58	8.29	23.61	31.20
2015	0.47	0.00	22.60	0.46	0.00	17.41	17.41	22.60	17.41	8.70	24.54	33.14

2016	4.12	0.00	23.07	4.12	0.00	18.28	18.28	23.07	18.28	9.14	25.49	35.19
2017	11.08	0.00	23.55	11.08	0.00	19.19	19.19	23.55	19.19	9.59	26.47	37.36
2018	19.21	0.00	24.02	19.20	0.00	20.15	20.15	24.02	20.15	10.07	27.50	39.63
2019	26.38	0.00	24.49	24.49	0.00	26.38	21.16	24.49	24.49	10.58	28.56	42.15
2020	31.48	0.00	24.97	24.97	0.00	31.48	22.21	24.97	24.97	11.11	29.64	44.74
2021	36.03	0.00	25.60	25.60	0.00	36.03	23.33	25.60	25.60	11.66	30.92	47.51
2022	39.88	0.00	26.22	26.22	0.00	39.88	24.49	26.22	26.22	12.25	32.27	50.47
2023	42.46	0.00	26.84	26.84	0.00	42.46	25.72	26.84	26.84	12.86	33.64	53.60
2024	44.23	0.00	27.48	27.48	0.00	44.23	27.00	27.48	27.48	13.50	35.06	56.75
2025	45.68	0.00	28.10	28.10	0.00	45.68	28.35	28.10	28.10	14.18	36.50	60.45
2026	46.65	0.00	28.71	28.71	0.00	46.65	29.77	28.71	28.71	14.88	37.96	63.82
2027	47.57	0.00	29.32	29.32	0.00	47.57	31.26	29.32	29.32	15.63	39.46	68.08
2028	48.58	0.00	29.93	29.93	0.00	48.58	32.82	29.93	29.93	16.41	41.03	72.37
2029	49.31	0.00	30.53	30.53	0.00	49.31	34.46	30.53	30.53	17.23	42.64	76.90
2030	49.73	0.00	31.14	31.14	0.00	49.73	36.19	31.14	31.14	18.09	44.30	81.70
2031	50.19	0.00	31.74	31.75	0.00	50.19	37.99	31.75	31.75	19.00	46.01	86.81
2032	50.62	0.00	32.36	32.36	0.00	50.62	39.89	32.36	32.36	19.95	47.77	92.14

Forecast Scenarios

Five forecast cases were developed around CO_2 scenarios. Price sensitivities to demand and fuel prices were also tested.

1 Delayed Federal CO_2

This case assumes a federal CO_2 emissions policy in the form of a regulatory cost mechanism is implemented, beginning in 2015. The price curve is the same one identified in the Sixth Power Plan, but simply deferred for five years. Once the federal price curve overtakes that of California, the federal prices are applied to the California emissions.

2 Social Cost CO_2

This case applies the estimated social cost of CO_2 from the Interagency Working Group on Social Cost of Carbon, under US Executive Order 12866. The 3% discount case was selected. These costs estimate damages associated with incremental carbon emissions each year and are applied to any CO_2 production, beginning in 2008. For modeling purposes, the cost was implemented as a regulatory cost.

3 Social Cost CO_2 Phased In

This case models a potential implementation of the social costs of CO_2 in the US in the form of a regulatory cost mechanism. A CO_2 tax or cost ($/ton) was phased in over time, beginning in 2015, eventually reaching the Social Cost CO_2 value in 2019 for all the zones within the US.

4 No Federal CO_2

This case asumes no federal regulatory cost policy is implemented. The case assumes continued implementation of the California Cap and Trade program, and also assumes implementation of proposed federal CO_2 performance standards limiting plant CO_2 production rates to a gas-fired combined-cycle plant equivalent.

5 No Federal & Low CA CO_2

This case models a future with no federal CO_2 policy, and with the California CO_2 price curve reduced by half.

Summary of Forecast Cases

Number	Name	CO_2 Policy	Demand	Fuel Price	Note
1	Delayed Federal CO_2	Delayed Federal CO_2	Medium	Medium	
2	Social Cost CO_2	Social Cost CO_2	Medium	Medium	
3	Social Cost CO_2 Phased In	Social Cost CO_2 Phased In	Medium	Medium	
4	No Federal CO_2	No Federal CO_2	Medium	Medium	Proposed US EPA CO_2 performance standards in effect
5	No Federal & Low CA CO_2	No Federal & Low CA CO_2	Medium	Medium	Proposed US EPA CO_2 performance standards in effect
6	High Demand	Delayed Federal CO_2	High	Medium	
7	Low Demand	Delayed Federal CO_2	Low	Medium	
8	High Fuel Price	Delayed Federal CO_2	Medium	High	
9	Low Fuel Price	Delayed Federal CO_2	Medium	Low	