Chapter 6 Forecasts and Resource Inputs

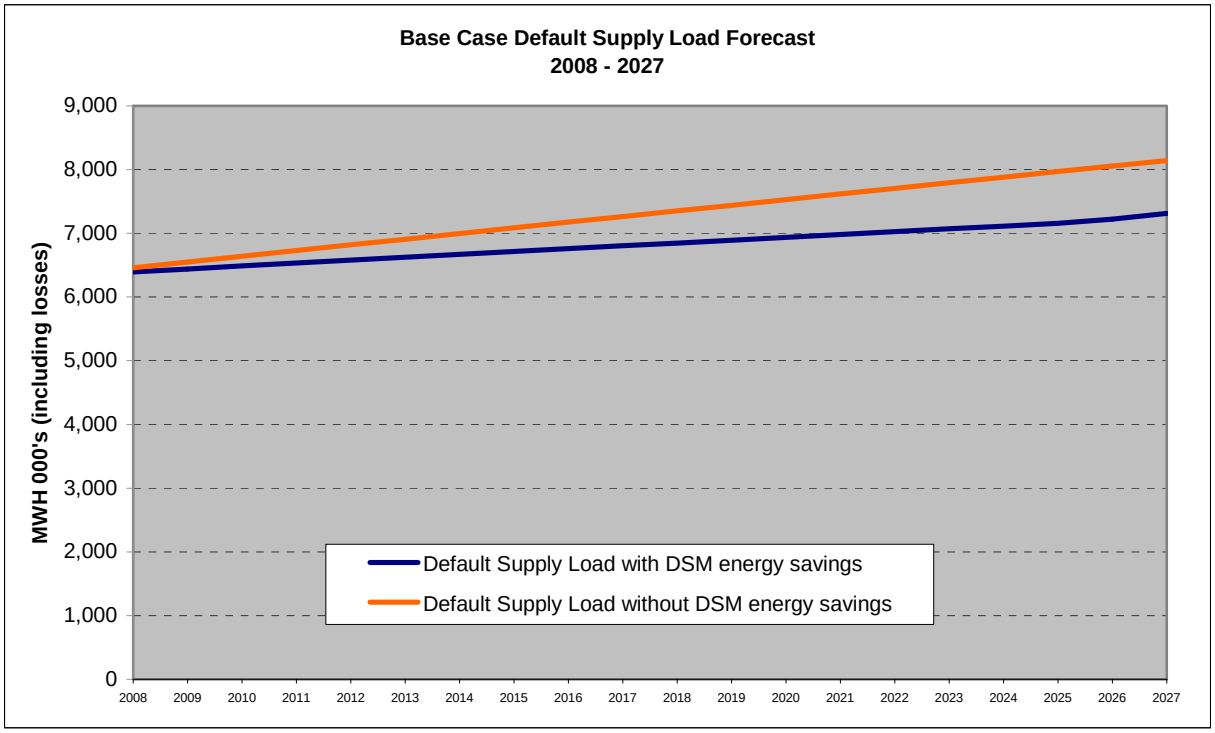
This chapter provides the reader with the key inputs that are used in the cost and risk analyses presented in chapters seven and eight. Section one of this chapter sets forth the long-term load forecast and the assumptions that drive the forecast. Section two provides the estimated load resource balance for the following twenty years. Section three provides detailed characteristics of each of the resources modeled including operational and financial parameters. Section four presents the CO_2 environmental cost adders on a per megawatt hour basis for each of the resources modeled.

Load Forecast

The long-term load forecast for NorthWestern customers has been updated and includes estimates of the energy required to meet NorthWestern Energy's load serving obligation for the period 2008 – 2027. The base case load forecast is the basis for generation resource and portfolio composition to achieve future load – resource balance.

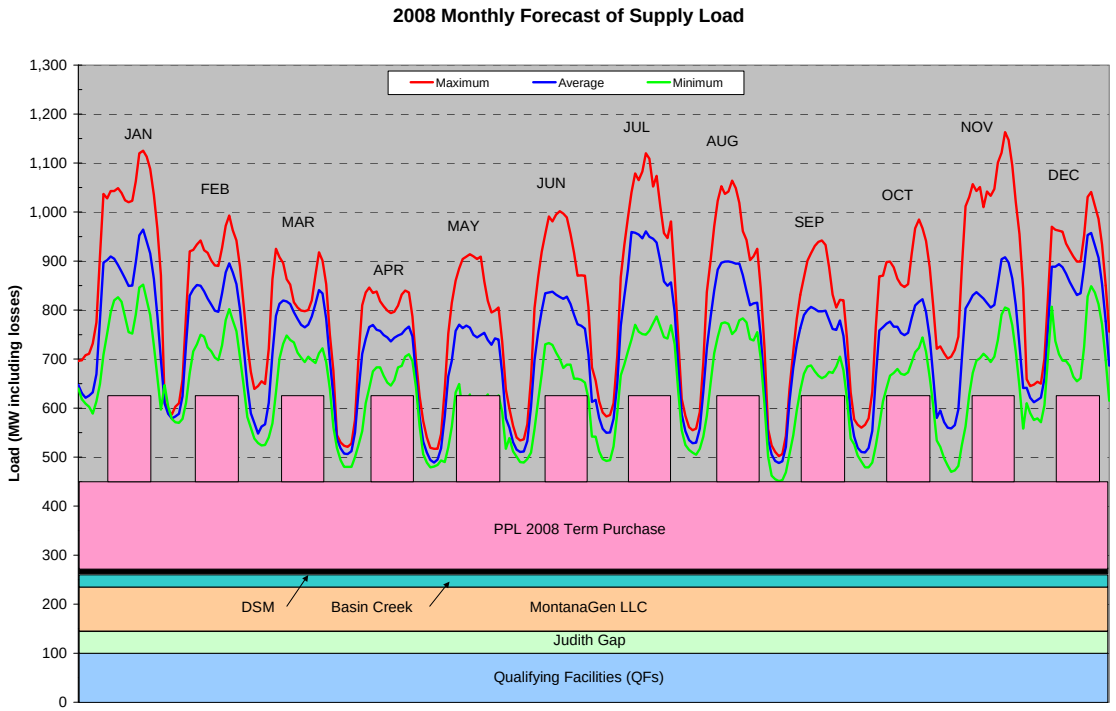
Results of the base case load forecast are presented for the period January 1, 2008 through December 31, 2027. The annual Supply load-serving obligation is estimated to grow from 6.4 million MWh to 7.3 million MWh or .7% annually. The estimated load-serving obligation is estimated to grow 1.3% annually, absent NorthWestern's DSM programs. Two growth curves are presented in Figure 6-1 to illustrate Supply load with and without the impacts from future DSM energy savings. A detailed discussion on the load forecast is in Volume 2, Chapter 6.

Figure 6-1, Default Supply Load Forecast



Residential and small commercial (GS-1 Secondary) customers comprise the majority of the Supply load. This load is seasonal and weather sensitive. Figure 6-2 presents a range of monthly Supply load shapes for 2008 and the supply resources in place to serve the load. The 2008 load is forecast to vary from a low of approximately 500 MW during off-peak hours to high values in excess of 1,100 MW during summer and winter weather extremes. Figure 6-2 demonstrates how serving the Supply load requires baseload, intermediate, and peaking resources due to the variability of the load in addition to market purchases by NorthWestern to meet fluctuating daily needs.

Figure 6-2, Monthly Forecast of Supply Load



Energy usage at the customer level is a key component in the estimation of future energy consumption. NorthWestern has evaluated residential and small commercial energy consumption at the customer level to better understand consumer behavior and plan for future load serving obligations. Figures 6-3 and 6-4 demonstrate the history and downward trend of energy usage for both residential and GS-1 secondary customers. Both rate classes display a trend to lower energy usage per customer on a weather-normalized basis. Although this trend cannot continue indefinitely, it is predicted to continue through the forecast period.

Figure 6-3, Residential Usage Per Customer

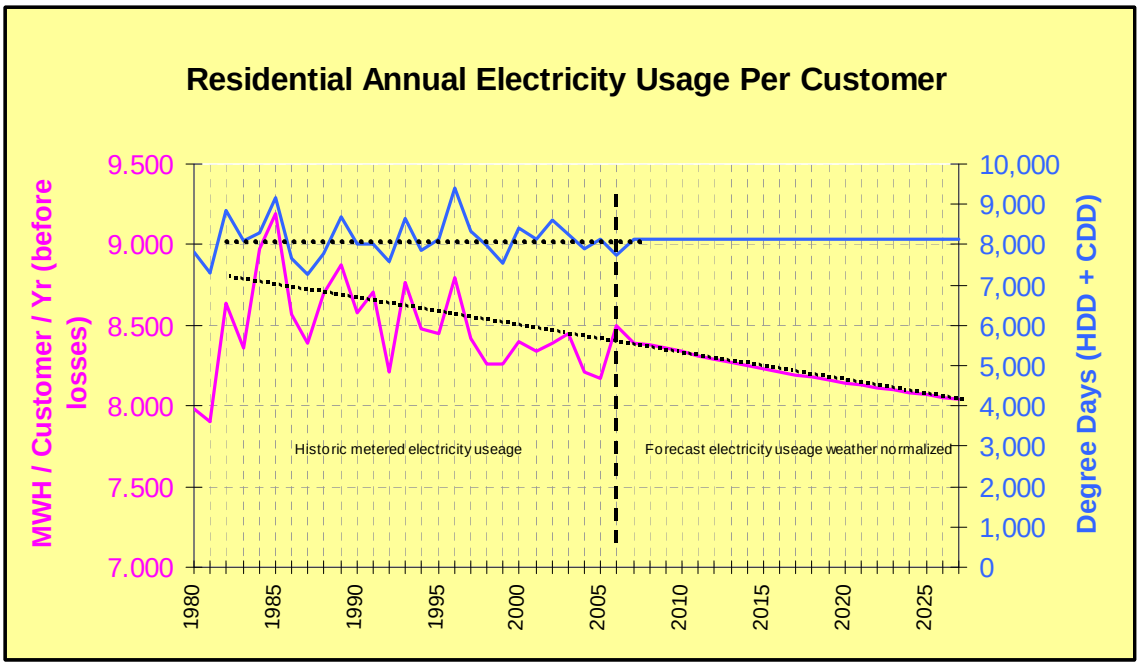
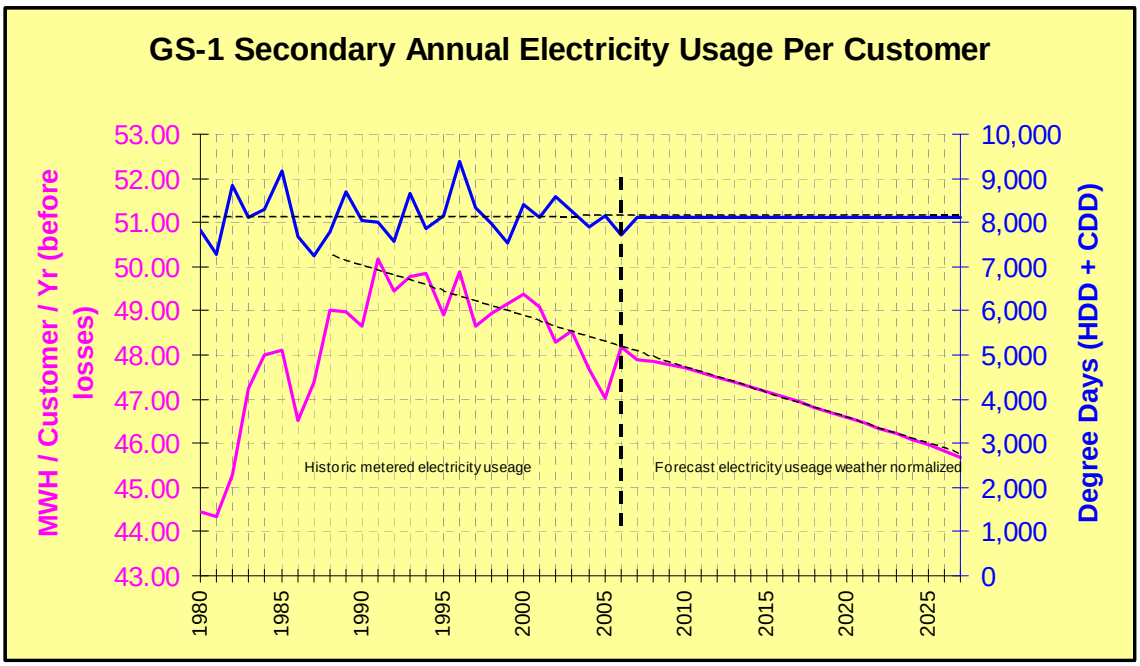


Figure 6-4, Secondary Usage Per Customer



NorthWestern has attempted to evaluate the price elasticity of demand for Supply customers as part of the load forecasting activity. Residential and small commercial customer electricity usage comes from a combination of factors. On a weather normal basis, both rate classes have demonstrated declining usage per customer and this decline is forecast to continue through 2027. Declining usage can be attributed to a host of factors including but not limited to:

Building codes/appliance codes
Disposable income
Real purchasing power
Family size
Number of appliances
Building equipment efficiencies
Thermal envelope efficiency levels
Energy price (and associated price elasticity)
And other factors

It is difficult to isolate and quantify the effects of price elasticity from the numerous other variables that contribute directly to customer electricity usage. In the preceding Figure 6-3 and 6-4 forecast, energy consumption for both Residential and GS-1 Secondary customer classes is shown to decline on a per-customer, weather normal basis.

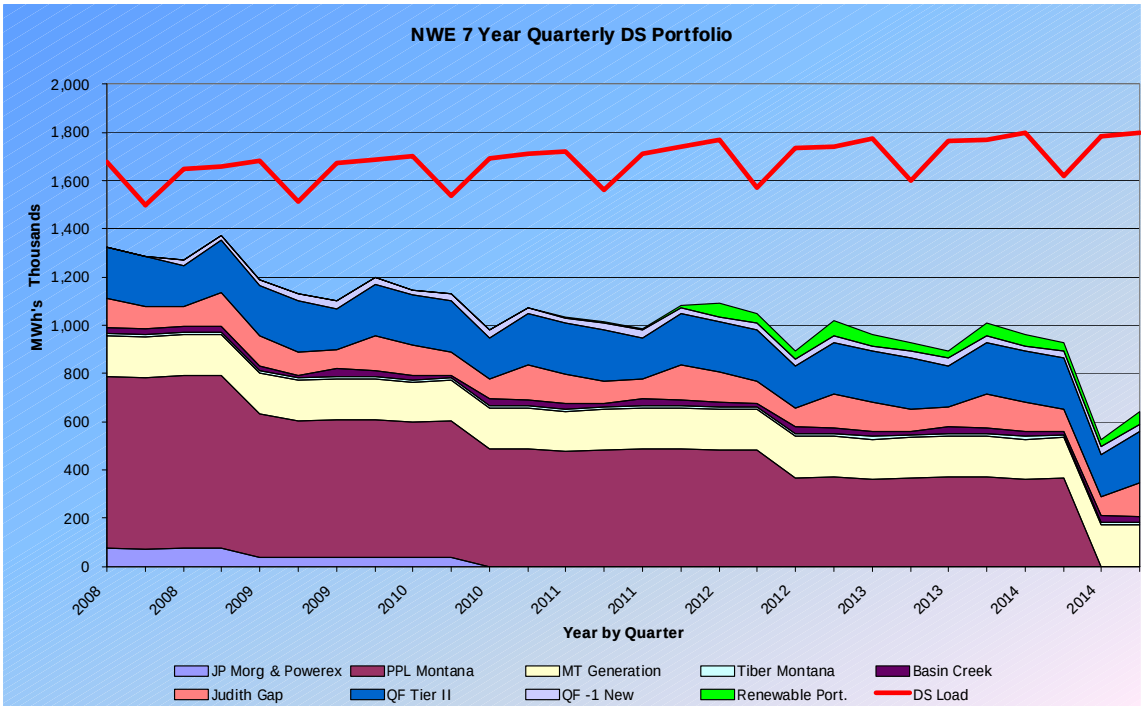
The projected usage decline is a continuation of the usage reduction trend that is observed in historical data. Price elasticity impacts are a subset of the other consumption reducing factors and are numerically less than the total observed and forecast energy usage decline. The per-customer usage decline value for both Residential and GS-1 Secondary rate classes will be on the order of 3-5 percent (should it actually occur as forecast) for the total 20-year period 2008-2027.

Load Resource Balance

Figure 6-5 below compares the expected customer energy requirements to the projected quarterly NorthWestern supply through 2014. The resource mix is shown as the projected energy amounts from all current resources and contracts. The projected deficit is the shortfall between the total resource output and the load. By the third quarter of 2014, the supply portfolio is facing a significant physical deficit. Unless the resource mix is augmented, the deficit will be met with purchases from the wholesale energy markets. This plan contemplates and analyzes various portfolios augmenting the current resource mix as is explained in Chapters 5 through 7.

In this Plan, NorthWestern has proposed a financial hedging proposal that will serve two purposes in regard to load resource balance: first, it will provide greater price stability and second, physical reliability will be increased.

Figure 6-5, Seven-Year Load Resource Balance



Market Price Forecasts

NorthWestern initially sought to utilize energy price forecasts from the Cambridge Energy Research Associates (CERA) as was used in the 2005 EPP. CERA sells energy price forecasts under contract. For this plan cycle, CERA informed NorthWestern that they would have new non-disclosure language restricting NorthWestern from sharing the forecasts with its consultants and even the PSC staff. NorthWestern opted to find another forecast and reviewed the energy price forecasts from the Northwest Power and Conservation Council. However, it has been some time since the Council's price forecast for the Fifth Power Plan was updated, and the curves are not reflective of current market conditions. In particular, near term market pricing is much higher than even the Council's Medium High market projection.

As a result, NorthWestern used a price projection developed by Lands Energy Consulting. The Lands Energy price projection uses current forward market pricing as the starting point. It is important that the price forecasts reflect the near-term actual market alternatives that the utility currently faces. While the longer-term price projections will certainly change by 2009, the subsequent plan can be updated and inform utility resource decisions at that time.

The price forecast uses as inputs the NyMex monthly forward price strip for natural gas through September 2011 and the forward price strip for electricity through September 2008. Since the natural gas markets are more liquid out through 2011, the electricity prices are computed for the period October 2008 through September 2011 by applying the first year market heatrates to the gas prices. The market heatrate is the observed relationship between electricity and natural gas prices and is computed by dividing the electricity price by the natural gas price. The units for market heatrate are mmbtu/MWh, the same units that are used to quantify the operating efficiency of natural gas plants. In this way, the dispatch of a natural gas unit can be determined by comparing the unit's effective heatrate with the market heatrate. If the unit's heatrate is lower than the

market heatrate, the unit is economic at prevailing markets and should be run. Since the marginal natural gas unit operating at any given time drives the market relationship between natural gas and electricity, it is reasonable to expect that the market heatrate should be similar under either higher or lower market conditions.

In order to dampen short-term anomalies in the near-term market prices, the natural gas and electricity price inputs for the period October 2007 through September 2008 were based on forward price quotes over a year-long period. The forward prices for electricity and natural gas were collected for each of the monthly closing dates for NyMex natural gas from September 20, 2006 through August 21, 2007. The closing date is the last day on which the contract for the next month delivery of natural gas is traded. These 12 forward curves were then averaged for each period to produce a forward curve for this first 12-month period (October 2007 through September 2008). In this manner, the recent decline in forward prices was dampened by the somewhat higher market conditions of a year ago.

Beyond September 2008, the difference between the current forward prices and the averaged forward prices was relatively small (less than $0.50/mmbtu), so the current forward price curve was used from this point forward. Prices beyond September 2011 were determined by applying a simple annual escalation factor of 2.5%. The resulting annual values are shown below with the Council's curves shown as reference. In addition, Volume 2, Chapter 6 contains a detailed description of the factors underlying the price forecasts.

The NWPCC price curve is substantially lower than the resulting base case forecast, so these projections are used as a low market price projection in the intrinsic runs. Several observations can be made about the NWPCC price curve relative to the base case forecast: The NWPCC curve has less seasonal variations in the electricity curve and therefore has less seasonal variations in the

market heatrate; also, the relationship between natural gas and electricity prices is not static over time, and market heatrates gradually increase throughout the study period. There are a couple of reasons why the market heatrate might increase over time – namely, the natural gas based generation fleet will age and efficiencies will deteriorate, and there may be additional run hours that require less efficient units to meet the load requirements of the region. Countervailing to these drivers are the potential for new natural gas unit additions which will likely have lower heatrates than those in the existing fleet.

The same spreadsheet forecast tool that was used for the base case was also used to forecast the high case price. In order to develop the high case, the near term difference between the NWPCC forecast and the base case was added to the base case to create the same initial upward offset between the high and the base case. This adjustment amounted to about $21/mwh applied to the first year electricity price and about a $2.00/mmbtu adder to the natural gas price through 2011. The long-term projection is then computed using the same 2.5% escalation in prices. Figure 6-6 and 6-7 and Table 6-1 and 6-2 provided below show the three price forecasts used in this analysis.

Figure 6-6

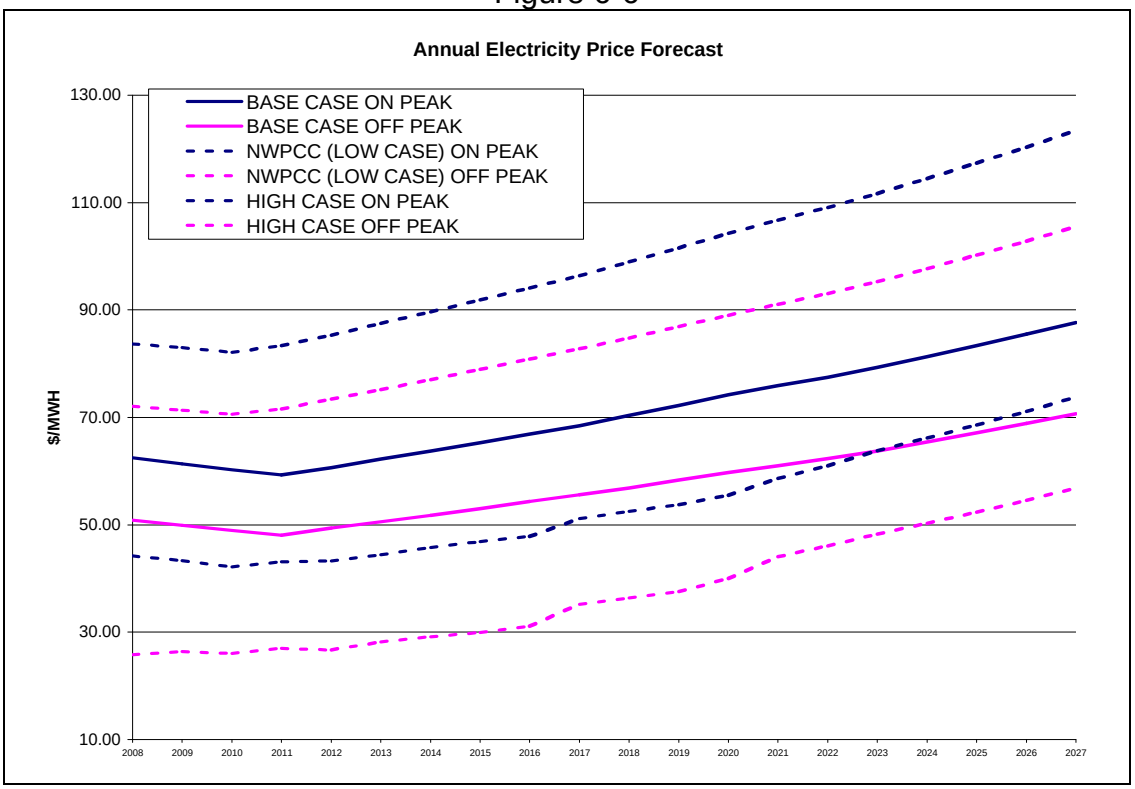


Figure 6-7

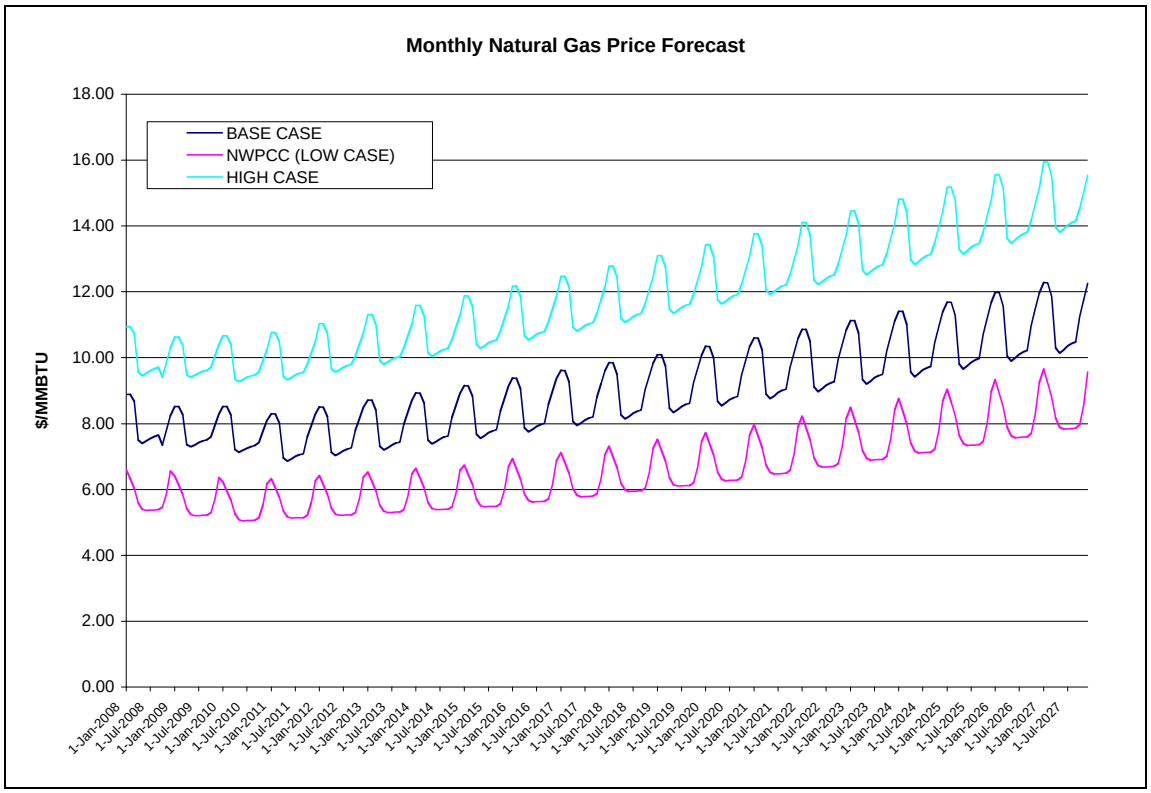


Table 6-1

Wholesale
Electricity Price Forecast
Average Annual Price
Nominal Dollars

	High Case $/MWH	Base Case $/MWH	Low Case $/MWH
2008	78.54	57.34	36.12
2009	77.87	56.32	35.86
2010	77.08	55.30	35.03
2011	78.15	54.35	36.01
2012	80.06	55.67	35.96
2013	82.09	57.08	37.26
2014	84.07	58.44	38.43
2015	86.17	59.90	39.45
2016	88.28	61.35	40.49
2017	90.39	62.79	44.14
2018	92.71	64.42	45.37
2019	95.10	66.10	46.62
2020	97.57	67.85	48.68
2021	99.82	69.36	52.21
2022	102.04	70.81	54.40
2023	104.46	72.46	56.99
2024	107.12	74.31	59.17
2025	109.85	76.22	61.45
2026	112.65	78.18	63.83
2027	115.52	80.19	66.33

Table 6-2

Natural Gas Price Forecasts
Average Annual Price
Delivered Price
Nominal Dollars

	High Case $/MM BTU	Base Case $/MM BTU	Low Case $/MM BTU
2008	9.98	7.92	5.78
2009	9.91	7.79	5.60
2010	9.81	7.66	5.44
2011	9.93	7.53	5.53
2012	10.18	7.71	5.62
2013	10.43	7.90	5.71
2014	10.69	8.10	5.80
2015	10.96	8.30	5.89
2016	11.23	8.51	6.05
2017	11.51	8.72	6.22
2018	11.79	8.93	6.39
2019	12.08	9.15	6.57
2020	12.38	9.38	6.75
2021	12.69	9.61	6.97
2022	13.01	9.85	7.19
2023	13.33	10.10	7.42
2024	13.66	10.35	7.66
2025	14.00	10.60	7.90
2026	14.35	10.87	8.15
2027	14.71	11.14	8.43

The market price forecasts represent the cost of the highest cost unit needed to serve regional load – the marginal unit. Currently, there are no cost adders to these marginal units based on their CO_2 emissions. Since NorthWestern's modeling for the 2007 Plan will incorporate carbon emissions adders to the different unit options in all scenarios, it is important to make a similar adjustment to the market price forecast, reflecting the impact carbon cost adders will have on the marginal unit. A reasonable approach is to approximate the carbon output of the marginal unit using a natural gas fired combined cycle combustion turbine. At times, the marginal unit may be a peaker, or dip into coal or hydro. But typically, the marginal unit will be a baseload natural gas unit. The carbon cost adders, therefore, were added to the electricity market projections using the

CCCT CO_2 emissions rate as the assumed market emission rate. Table 6-3 below summarizes how the market forecast was adjusted with the carbon cost adder:

Table 6-3, Market Forecast Adjusted Carbon Cost Adder

Year	Combined Cycle CO2 Proxy	Carbon Tax/Adder			Market Carbon Adder		
		Low	Medium	High	Low	Medium	High
	(tons/MWh)	($/ton)	($/ton)	($/ton)	($/mwh)	($/mwh)	($/mwh)
2005	0.42900						
2006	0.42900						
2007	0.42900						
2008	0.42900						
2009	0.42900						
2010	0.42900		$9.57	$9.65		$4.11	$4.14
2011	0.42900		$9.81	$10.37		$4.21	$4.45
2012	0.42900		$10.05	$11.15		$4.31	$4.78
2013	0.42900		$10.31	$11.99		$4.42	$5.14
2014	0.42900		$10.56	$12.89		$4.53	$5.53
2015	0.42900		$10.83	$38.99		$4.65	$16.73
2016	0.42900	$9.57	$11.10	$41.53	$4.11	$4.76	$17.81
2017	0.42900	$9.81	$11.38	$44.23	$4.21	$4.88	$18.97
2018	0.42900	$10.05	$11.66	$47.10	$4.31	$5.00	$20.21
2019	0.42900	$10.31	$11.95	$50.16	$4.42	$5.13	$21.52
2020	0.42900	$10.56	$12.25	$53.42	$4.53	$5.26	$22.92
2021	0.42900	$10.83	$12.56	$56.89	$4.65	$5.39	$24.41
2022	0.42900	$11.10	$12.87	$60.59	$4.76	$5.52	$25.99
2023	0.42900	$11.38	$13.19	$64.53	$4.88	$5.66	$27.68
2024	0.42900	$11.66	$13.52	$68.73	$5.00	$5.80	$29.48
2025	0.42900	$11.95	$13.86	$73.19	$5.13	$5.95	$31.40
2026	0.42900	$12.25	$14.21	$77.95	$5.26	$6.09	$33.44
2027	0.42900	$12.56	$14.56	$83.02	$5.39	$6.25	$35.61

The market carbon adders shown in the right three columns are the amounts that are added to the market price forecasts by year in the low, medium, and high carbon adder cases.

Parameters of Resources Modeled

In order to effectively review different resource options in a comprehensive operational/financial model, the resource parameters for each resource discussed in Chapter 5 needs to be defined quantitatively. These parameters include the following:

- Operational Parameters
  - Installed Capacity
  - Location on the Grid
  - Efficiency/Heatrate
  - Availability Factor
  - Minimum run levels
  - Start times and ramp rates
  - Shaping or integration requirements
  - Lead time for construction
  - Emissions levels
- Financial Parameters
  - Initial construction costs
  - Fixed O&M (do not vary with the level of plant output)
  - Variable O&M (varies based on the level of plant output)
  - Transmission costs

In order to set a reasonable level for these parameters, NorthWestern benchmarked the resources using data from other regional IRPs, and other sources such as the NWPPC and the Future of Coal paper recently published by MIT. This information was collected and assembled into a single data set for review. In order to put all the data on a common financial basis, cost estimates were escalated to 2007 dollars using an annual adjustment of 4.1%. This value is representative of the escalation rate reported by the Bureau of Economic Analysis in their Price Index for Private Fixed Investment Structures/Power and Communication.

This resulting set of values for capital costs, fixed O&M, and variable O&M were then reviewed by NorthWestern's staff with support from consultants and the ETAC. In general, the available data was averaged by resource type to determine an initial set of proposed cost values for modeling purposes. In some cases, data was excluded from the averages. Such exclusions were due to the

fact that the data point represented an outlier relative to the other similar sources, the capacity did not match well, or the resource type has seen recent technological advances – in which case the older data was excluded.

A final adjustment was made to account for the recent boom in industrial construction costs. Generally, the boom in prices is attributed to the competition for materials and labor originating from China. A recent Megawatt Daily article cited that the cost of a supercritical coal plant had risen to $2,500/kW, and the cost of a combined cycle gas turbine had risen to $1,000/kW[3]. These were compared to the results from the benchmarking process in Table 6-4 below.

Table 6-4, Resource Construction Cost

Resource	Benchmark Cost	MWD Cited Cost	Percent Increase
Coal – Supercritical	$2,083 /kW	$2,500 /kW	20.0 %
Nat Gas – CCCT	$777 /kW	$1,000 /kW	28.7 %

Based on this documented significant cost increase summary, a final adjustment was made to the construction costs reflecting the current realities of this business sector. Based on the evidence of the cost increases, and in consultation with ETAC, an adjustment of 15% was applied to the final results for Capital Cost of the benchmarking process. The results of the benchmarking process and the various adjustments are summarized in the Resource Summary tables listed below. A more detailed explanation of the resource costs and operating parameters is included in Volume 2, Chapter 6.

For the coal plants and the Alberta oil sands projects, there was an additional transmission cost adder applied to the construction and variable O&M costs based on the cost to acquire needed transmission and the variable costs/losses incurred during operation.

[3] Platts "Megawatt Daily", June 13, 2007.

The coal plant adjustment was based on an assumed new 230 kV line needed from the Gillette, Wyoming area to the Broadview substation – a distance of 208 miles. Using cost data from the Northwest Power Pool's NW Transmission Assessment Committee, this transmission adds $338/kW to the construction costs and 11.4% in losses. The transmission required from the Oil Sands region of Alberta is much greater. In this case, it was assumed that new transmission would be required from Fort McMurray, Alberta which is in the heart of the Athabasca Oil Sands region (see map in Volume 2), to Townsend, Montana – a distance of 891 miles. Due to the large distance, a 230 kV line would not make economic sense, so the costs for construction and operation of a 500 kV line were assumed. The modeling cost for this transmission line was set at $728/kW for construction costs and includes 8.4% in line losses. Necessarily, the 500 kV line would be sized to transmit more power than the 230 kV line. If the Oil Sands are developed for export of electricity to the United States, NorthWestern would likely be a participant in projects sized much larger than NorthWestern's needs. These transmission costs are additive to the costs summarized in the table below. (See Table 6-5 Resource Cost Summaries.)

The fixed costs of all of the resources carried into the dynamic modeling phase of the resource plan are input into the model, on a nominal levelized basis, for the year in which the resource is first in service. This fixed revenue requirement then remains constant for the life of the resource. The fixed resource costs include all capital cost recovery, depreciation, all taxes, and insurance.

A static revenue requirements model is used to make this calculation. The model provides a Total Present Value of Revenue Requirements (TPVRR) factor. The TPVRR factor is calibrated for each $1,000 of capital expenditure, and is multiplied by the cost per kW installed for each resource type, to arrive at a TPVRR/kW for the particular resource option. This value is then levelized using a Levelized Capital Recovery Factor (LCRF) to arrive at the nominal levelized

cost of the resource option for the base year. This value is then escalated to each potential year of the resource being put into service.

Table 6-5, Resource Cost Summaries

Fuel Source	Technology	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Var O&M ($/MWh)	Notes
Coal	PV Subcritical	$2,028	$38.78	$2.36	Exclude ALT, AVA, SCL data
Coal	PV Sub w/ CCS	$3,076	$38.80	$2.00	Also include a loss of output based on parasitic load
Coal	PV Supercritical	$2,395	$43.70	$1.92	Excludes Portland General - too low
Coal	PV Super w/ CCS	$3,854	$57.60	$2.53	Also include a loss of output based on parasitic load
Coal	IGCC	$2,600	$63.52	$1.93	Exclude 05 Data and PAC Dual Gasifier, also exclude Fixed O&M from IPC, PGE based on extremely low values
Coal	IGCC w/CCS	$3,380	$79.40	$3.94	Added 30% to the Capital cost, 25% to FOM, and 104% to VOM vs. non-sequestered based on the MIT study
Natural Gas	CCCT	$894	$11.52	$3.04	Straight Average
Natural Gas	CCCT w/ CCS	$1,182	$14.18	$3.74	Also include a loss of output based on parasitic load
Natural Gas	CHP	$1,202	$24.19	$1.27	Average of AVA and PAC 25 mw units
Natural Gas	Internal Combustion	$1,011	$13.32	$5.41	Costs based on PAC-07 info, heatrate adjusted
Natural Gas	SCCT Aero	$897	$30.21	$2.69	Intercooled, used PAC Utah as a reference unit
Natural Gas	SCCT Frame	$634	$7.50	$4.83	Used IPC as example. PAC-07 had very high heatrates, etc.
Natural Gas	SCCT LMS	$756	$2.29	$7.50	Straight Average (PGE and NPC)
Natural Gas	Generic Regulating Resource	$884	$7.81	$6.46	Included for expected addition of new regulating resource
Oil Sands	Oil Sands	$594	$4.85	$3.07	AVA and NWE Averaged
Wind	Wind	$1,960	$28.20	$1.27	Use recent data - exclude PGE (FOM and VOM were out of alignment with others)
Biomass	Wood Waste	$2,834	$75.77	$9.84	Used 25mw capacity, exclude PSE cap cost (too low), SCL Fixed O&M (too high), PSE Var O&M (too low).
Geothermal	Geothermal	$1,736	$25.23	$4.66	
Solar	Photovoltaic	$6,000	$0.00	$0.00	
Compressed Air		$856	$4.70	$4.08	Costs highly speculative estimate
Pump Storage		$ 1,269	$8.52	$2.53	Costs highly speculative estimate

Table 6-6 shows the “Annualized Levelized Resource Fixed Costs $/kW Installed” for each resource type and each year of the Plan.

Table 6-6, Annualized Levelized Resource Fixed Costs $/kW Installed

ANNUAL NOMINAL LEVELIZED RESOURCE FIXED COSTS $/KW INSTALLED																					
					Annual	Inflation	2.50%														
	RESOURCES	2008 Cost/KW Installed	Life	TPVRR Factor	LVLCR Factor	Nominal Levelized 2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
1	Coal-PV Subcritical	2028	30	1.247	0.09237	$234	$239	$245	$252	$258	$264	$271	$278	$285	$292	$299	$306	$314	$322	$330	$338	$347
2	Coal-PV Subcritical w/CCS	3076	30	1.247	0.09237	$354	$363	$372	$382	$391	$401	$411	$421	$432	$442	$454	$465	$477	$488	$501	$513	$526
3	Coal-PV Supercritical	2395	30	1.247	0.09237	$276	$283	$290	$297	$305	$312	$320	$328	$336	$345	$353	$362	$371	$380	$390	$400	$410
4	Coal-PV Super w/CCS	3854	30	1.247	0.09237	$444	$455	$466	$478	$490	$502	$515	$528	$541	$554	$568	$582	$597	$612	$627	$643	$659
5	Coal IGCC	2600	30	1.247	0.09237	$299	$307	$315	$323	$331	$339	$347	$356	$365	$374	$383	$393	$403	$413	$423	$434	$445
6	Coal IGCC w/CSS	3380	30	1.247	0.09237	$389	$399	$409	$419	$430	$440	$451	$463	$474	$486	$498	$511	$524	$537	$550	$564	$578
7	Gas CCCT	894	30	1.254	0.09237	$104	$106	$109	$112	$114	$117	$120	$123	$126	$129	$133	$136	$139	$143	$146	$150	$154
8	Gas CCCT w/CCS	1182	30	1.254	0.09237	$137	$140	$144	$147	$151	$155	$159	$163	$167	$171	$175	$180	$184	$189	$193	$198	$203
9	Gas CHP	1202	30	1.254	0.09237	$139	$143	$146	$150	$154	$158	$161	$166	$170	$174	$178	$183	$187	$192	$197	$202	$207
10	Gas Oil Sands	594	30	1.254	0.09237	$69	$71	$72	$74	$76	$78	$80	$82	$84	$86	$88	$90	$93	$95	$97	$100	$102
11	Gas SCCT Frame	634	30	1.254	0.09237	$73	$75	$77	$79	$81	$83	$85	$87	$89	$92	$94	$96	$99	$101	$104	$106	$109
12	Gas SCCT Aero	897	30	1.254	0.09237	$104	$106	$109	$112	$115	$118	$120	$124	$127	$130	$133	$136	$140	$143	$147	$150	$154
13	Gas Internal Combustion	1011	30	1.254	0.09237	$117	$120	$123	$126	$129	$132	$136	$139	$143	$146	$150	$154	$157	$161	$165	$170	$174
14	Gas LMs	756	30	1.254	0.09237	$88	$90	$92	$94	$97	$99	$102	$104	$107	$109	$112	$115	$118	$121	$124	$127	$130
15	Generic Regulating Resource	884	30	1.254	0.09237	$102	$105	$108	$110	$113	$116	$119	$122	$125	$128	$131	$134	$138	$141	$145	$148	$152
16	Biomass	2834	30	1.247	0.09237	$326	$335	$343	$352	$360	$369	$379	$388	$398	$408	$418	$428	$439	$450	$461	$473	$485
17	Geothermal	1736	30	1.247	0.09237	$200	$205	$210	$215	$221	$226	$232	$238	$244	$250	$256	$262	$269	$276	$283	$290	$297
18	Wind	1960	30	1.247	0.09237	$226	$231	$237	$243	$249	$255	$262	$268	$275	$282	$289	$296	$304	$311	$319	$327	$335
19	Solar PV	6000	30	1.254	0.09237	$695	$712	$730	$748	$767	$786	$806	$826	$847	$868	$890	$912	$935	$958	$982	$1,007	$1,032
20	CAES	856	30	1.247	0.09237	$99	$101	$104	$106	$109	$112	$114	$117	$120	$123	$126	$129	$133	$136	$139	$143	$146
21	Pumped Storage	1269	30	1.247	0.09237	$146	$150	$154	$157	$161	$165	$170	$174	$178	$183	$187	$192	$197	$201	$207	$212	$217
22	500KV Transmision	728	50	1.528	0.08608	$96	$98	$101	$103	$106	$108	$111	$114	$117	$120	$123	$126	$129	$132	$135	$139	$142
23	230KV Transmision	406	50	1.528	0.08608	$53	$55	$56	$58	$59	$60	$62	$63	$65	$67	$68	$70	$72	$74	$75	$77	$79

The carbon output from the various resources was discussed in Chapter 4. These carbon emission rates were converted to a dollars per megawatt hour value and added to the variable operating costs of the units by multiplying the emission rate times the carbon cost adders. The carbon cost adder is a curve, changing each year, which defines an escalation of the increases in unit variable costs over the twenty-year analysis timeframe. Table 4-2 in Chapter 4 lists the carbon output for various resources, measured on a tons per megawatt hour basis. Tables 6-7, 6-8 and 6-9 below contain the levelized values of these variable costs by unit type for each carbon adder case to give a sense of the relative size of the actual cost impact resulting from carbon emissions in the different carbon scenarios. These unit cost adders were adjusted in GenTrader® for each of the carbon scenarios.

Table 6-7

NorthWestern Energy

Dollar Impact of Carbon Adders on Resources

Low Carbon Adder

Year	Carbon Tax/Adder	Coal - PV Subcritical	Coal - PV Supercritical	Coal - IGCC	Gas - SCCT Aero	Gas - Internal Combustion	Gas - LMs	Generic Regulating Resource	Gas - CCCT	Gas - CHP	Gas - Oil Sands	Gas - SCCT Frame
	1.012	0.9149	0.791	0.582	0.582	0.582	0.582	0.429	0.429	0.429	0.365	
	($/ton)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)
2008	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2009	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2010	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2011	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2012	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2013	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2014	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2015	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2016	**$ 9.57**	$ 9.68	$ 8.86	$ 7.01	$ 4.08	$ 2.37	$ 1.38	$ 0.80	$ 0.34	$ 0.15	$ 0.06	$ 0.02
2017	**$ 9.81**	$ 9.93	$ 9.08	$ 7.18	$ 4.18	$ 2.43	$ 1.42	$ 0.82	$ 0.35	$ 0.15	$ 0.07	$ 0.02
2018	**$ 10.05**	$ 10.18	$ 9.31	$ 7.36	$ 4.29	$ 2.49	$ 1.45	$ 0.84	$ 0.36	$ 0.16	$ 0.07	$ 0.02
2019	**$ 10.31**	$ 10.43	$ 9.54	$ 7.55	$ 4.39	$ 2.56	$ 1.49	$ 0.87	$ 0.37	$ 0.16	$ 0.07	$ 0.02
2020	**$ 10.56**	$ 10.69	$ 9.78	$ 7.74	$ 4.50	$ 2.62	$ 1.53	$ 0.89	$ 0.38	$ 0.16	$ 0.07	$ 0.03
2021	**$ 10.83**	$ 10.96	$ 10.03	$ 7.93	$ 4.62	$ 2.69	$ 1.56	$ 0.91	$ 0.39	$ 0.17	$ 0.07	$ 0.03
2022	**$ 11.10**	$ 11.23	$ 10.28	$ 8.13	$ 4.73	$ 2.75	$ 1.60	$ 0.93	$ 0.40	$ 0.17	$ 0.07	$ 0.03
2023	**$ 11.38**	$ 11.51	$ 10.53	$ 8.33	$ 4.85	$ 2.82	$ 1.64	$ 0.96	$ 0.41	$ 0.18	$ 0.08	$ 0.03
2024	**$ 11.66**	$ 11.80	$ 10.80	$ 8.54	$ 4.97	$ 2.89	$ 1.68	$ 0.98	$ 0.42	$ 0.18	$ 0.08	$ 0.03
2025	**$ 11.95**	$ 12.10	$ 11.07	$ 8.75	$ 5.09	$ 2.96	$ 1.73	$ 1.00	$ 0.43	$ 0.18	$ 0.08	$ 0.03
2026	**$ 12.25**	$ 12.40	$ 11.34	$ 8.97	$ 5.22	$ 3.04	$ 1.77	$ 1.03	$ 0.44	$ 0.19	$ 0.08	$ 0.03
2027	**$ 12.56**	$ 12.71	$ 11.63	$ 9.20	$ 5.35	$ 3.11	$ 1.81	$ 1.06	$ 0.45	$ 0.19	$ 0.08	$ 0.03
20 Year Lev	**$4.34**	$4.39	$4.02	$3.18	$1.85	$1.08	$0.63	$0.36	$0.16	$0.07	$0.03	$0.01

Table 6-8

NorthWestern Energy

Dollar Impact of Carbon Adders on Resources

Medium Carbon Adder

Year	Carbon Tax/Adder	Coal - PV Subcritical 1.012	Coal - PV Supercritical 0.9149	Coal - IGCC 0.791	Gas - SCCT Aero 0.582	Gas - Internal Combustion 0.582	Gas - LMs 0.582	Generic Regulating Resource 0.582	Gas - CCCT 0.429	Gas - CHP 0.429	Gas - Oil Sands 0.429	Gas - SCCT Frame 0.365
	($/ton)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)
2008	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2009	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2010	**$ 9.57**	$ 9.68	$ 8.86	$ 7.01	$ 4.08	$ 2.37	$ 1.38	$ 0.80	$ 0.34	$ 0.15	$ 0.06	$ 0.02
2011	**$ 9.81**	$ 9.93	$ 9.08	$ 7.18	$ 4.18	$ 2.43	$ 1.42	$ 0.82	$ 0.35	$ 0.15	$ 0.07	$ 0.02
2012	**$ 10.05**	$ 10.18	$ 9.31	$ 7.36	$ 4.29	$ 2.49	$ 1.45	$ 0.84	$ 0.36	$ 0.16	$ 0.07	$ 0.02
2013	**$ 10.31**	$ 10.43	$ 9.54	$ 7.55	$ 4.39	$ 2.56	$ 1.49	$ 0.87	$ 0.37	$ 0.16	$ 0.07	$ 0.02
2014	**$ 10.56**	$ 10.69	$ 9.78	$ 7.74	$ 4.50	$ 2.62	$ 1.53	$ 0.89	$ 0.38	$ 0.16	$ 0.07	$ 0.03
2015	**$ 10.83**	$ 10.96	$ 10.03	$ 7.93	$ 4.62	$ 2.69	$ 1.56	$ 0.91	$ 0.39	$ 0.17	$ 0.07	$ 0.03
2016	**$ 11.10**	$ 11.23	$ 10.28	$ 8.13	$ 4.73	$ 2.75	$ 1.60	$ 0.93	$ 0.40	$ 0.17	$ 0.07	$ 0.03
2017	**$ 11.38**	$ 11.51	$ 10.53	$ 8.33	$ 4.85	$ 2.82	$ 1.64	$ 0.96	$ 0.41	$ 0.18	$ 0.08	$ 0.03
2018	**$ 11.66**	$ 11.80	$ 10.80	$ 8.54	$ 4.97	$ 2.89	$ 1.68	$ 0.98	$ 0.42	$ 0.18	$ 0.08	$ 0.03
2019	**$ 11.95**	$ 12.10	$ 11.07	$ 8.75	$ 5.09	$ 2.96	$ 1.73	$ 1.00	$ 0.43	$ 0.18	$ 0.08	$ 0.03
2020	**$ 12.25**	$ 12.40	$ 11.34	$ 8.97	$ 5.22	$ 3.04	$ 1.77	$ 1.03	$ 0.44	$ 0.19	$ 0.08	$ 0.03
2021	**$ 12.56**	$ 12.71	$ 11.63	$ 9.20	$ 5.35	$ 3.11	$ 1.81	$ 1.06	$ 0.45	$ 0.19	$ 0.08	$ 0.03
2022	**$ 12.87**	$ 13.03	$ 11.92	$ 9.43	$ 5.49	$ 3.19	$ 1.86	$ 1.08	$ 0.46	$ 0.20	$ 0.09	$ 0.03
2023	**$ 13.19**	$ 13.35	$ 12.21	$ 9.66	$ 5.62	$ 3.27	$ 1.90	$ 1.11	$ 0.48	$ 0.20	$ 0.09	$ 0.03
2024	**$ 13.52**	$ 13.68	$ 12.52	$ 9.90	$ 5.76	$ 3.35	$ 1.95	$ 1.14	$ 0.49	$ 0.21	$ 0.09	$ 0.03
2025	**$ 13.86**	$ 14.03	$ 12.83	$ 10.15	$ 5.91	$ 3.44	$ 2.00	$ 1.16	$ 0.50	$ 0.21	$ 0.09	$ 0.03
2026	**$ 14.21**	$ 14.38	$ 13.15	$ 10.40	$ 6.06	$ 3.52	$ 2.05	$ 1.19	$ 0.51	$ 0.22	$ 0.09	$ 0.03
2027	**$ 14.56**	$ 14.74	$ 13.48	$ 10.66	$ 6.21	$ 3.61	$ 2.10	$ 1.22	$ 0.52	$ 0.23	$ 0.10	$ 0.04
20 Year Level	**$9.17**	$9.29	$8.49	$6.72	$3.91	$2.28	$1.32	$0.77	$0.33	$0.14	$0.06	$0.02

Table 6-9

	NorthWestern Energy												
	Dollar Impact of Carbon Adders on Resources												
High Carbon Adder													
Year	Carbon Tax/Adder	Coal - PV Subcritical 1.012	Coal - PV Supercritical 0.9149	Coal - IGCC 0.791	Gas - SCCT Aero 0.582	Gas - Internal Combustion 0.582	Gas - LMs 0.582	Generic Regulating Resource 0.582	Gas - CCCT 0.429	Gas - CHP 0.429	Gas - Oil Sands 0.429	Gas - SCCT Frame 0.365	Coal - PV Sub w/ CCS 0.14
	($/ton)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)
2008	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2009	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2010	$ 9.65	$ 9.77	$ 8.93	$ 7.07	$ 4.11	$ 2.39	$ 1.39	$ 0.81	$ 0.35	$ 0.15	$ 0.06	$ 0.02	$ 0.00
2011	$ 10.37	$ 10.50	$ 9.60	$ 7.60	$ 4.42	$ 2.57	$ 1.50	$ 0.87	$ 0.37	$ 0.16	$ 0.07	$ 0.03	$ 0.00
2012	$ 11.15	$ 11.29	$ 10.32	$ 8.17	$ 4.75	$ 2.77	$ 1.61	$ 0.94	$ 0.40	$ 0.17	$ 0.07	$ 0.03	$ 0.00
2013	$ 11.99	$ 12.13	$ 11.10	$ 8.78	$ 5.11	$ 2.97	$ 1.73	$ 1.01	$ 0.43	$ 0.19	$ 0.08	$ 0.03	$ 0.00
2014	$ 12.89	$ 13.04	$ 11.93	$ 9.44	$ 5.49	$ 3.20	$ 1.86	$ 1.08	$ 0.46	$ 0.20	$ 0.09	$ 0.03	$ 0.00
2015	$ 38.99	$ 39.46	$ 36.10	$ 28.56	$ 16.62	$ 9.67	$ 5.63	$ 3.28	$ 1.41	$ 0.60	$ 0.26	$ 0.09	$ 0.01
2016	$ 41.53	$ 42.02	$ 38.45	$ 30.41	$ 17.70	$ 10.30	$ 6.00	$ 3.49	$ 1.50	$ 0.64	$ 0.28	$ 0.10	$ 0.01
2017	$ 44.23	$ 44.76	$ 40.95	$ 32.39	$ 18.85	$ 10.97	$ 6.39	$ 3.72	$ 1.59	$ 0.68	$ 0.29	$ 0.11	$ 0.01
2018	$ 47.10	$ 47.66	$ 43.61	$ 34.49	$ 20.08	$ 11.68	$ 6.80	$ 3.96	$ 1.70	$ 0.73	$ 0.31	$ 0.11	$ 0.02
2019	$ 50.16	$ 50.76	$ 46.44	$ 36.74	$ 21.38	$ 12.44	$ 7.24	$ 4.21	$ 1.81	$ 0.78	$ 0.33	$ 0.12	$ 0.02
2020	$ 53.42	$ 54.06	$ 49.46	$ 39.12	$ 22.77	$ 13.25	$ 7.71	$ 4.49	$ 1.93	$ 0.83	$ 0.35	$ 0.13	$ 0.02
2021	$ 56.89	$ 57.58	$ 52.68	$ 41.67	$ 24.25	$ 14.11	$ 8.21	$ 4.78	$ 2.05	$ 0.88	$ 0.38	$ 0.14	$ 0.02
2022	$ 60.59	$ 61.32	$ 56.10	$ 44.38	$ 25.83	$ 15.03	$ 8.75	$ 5.09	$ 2.18	$ 0.94	$ 0.40	$ 0.15	$ 0.02
2023	$ 64.53	$ 65.31	$ 59.75	$ 47.26	$ 27.51	$ 16.01	$ 9.32	$ 5.42	$ 2.33	$ 1.00	$ 0.43	$ 0.16	$ 0.02
2024	$ 68.73	$ 69.55	$ 63.63	$ 50.33	$ 29.29	$ 17.05	$ 9.92	$ 5.77	$ 2.48	$ 1.06	$ 0.46	$ 0.17	$ 0.02
2025	$ 73.19	$ 74.07	$ 67.77	$ 53.60	$ 31.20	$ 18.16	$ 10.57	$ 6.15	$ 2.64	$ 1.13	$ 0.49	$ 0.18	$ 0.02
2026	$ 77.95	$ 78.89	$ 72.17	$ 57.09	$ 33.23	$ 19.34	$ 11.25	$ 6.55	$ 2.81	$ 1.21	$ 0.52	$ 0.19	$ 0.03
2027	$ 83.02	$ 84.01	$ 76.86	$ 60.80	$ 35.38	$ 20.59	$ 11.99	$ 6.98	$ 2.99	$ 1.28	$ 0.55	$ 0.20	$ 0.03
20 Year Levelized	$ 28.92	$ 29.27	$ 26.78	$ 21.18	$ 12.33	$ 7.17	$ 4.18	$ 2.43	$ 1.04	$ 0.45	$ 0.19	$ 0.07	$ 0.01