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CHAPTER 1
PLAN OVERVIEW

The 2015 Electricity Supply Resource Procurement Plan

Portfolio Transformation

NorthWestern's acquisition of the Montana hydroelectric facilities marks a major step in the continuing transformation of the electric supply portfolio towards a more efficient, stably priced, reliable, and lower carbon intensity portfolio. The acquisition of the hydro facilities also includes high priority value-added opportunities at the existing dams. These opportunities would result in increased installed generation capacity at multiple dams on the Montana hydroelectric system by a total of approximately 40 megawatts ("MW").

The establishment of a diversified generation fleet under its ownership and control further solidifies both NorthWestern's and Montana's goal of owning generation, creating more vertically integrated utility operations, and transitioning to capacity-based resource planning to meet critical customer needs while maintaining a low-carbon emission footprint. The resource initiatives and actions developed in this 2015 Electricity Supply Resource Procurement Plan ("2015 Plan" or "Plan") identify the critical future needs of our portfolio including addressing significant capacity shortages. The Plan identifies how to best meet the large capacity needs of the supply portfolio with least-cost, low-risk resources and includes a set of action plans which the utility will implement on a going forward basis. Key focus areas identified and developed in the Plan include:

- *Capacity-based planning and determination of resource adequacy*
- *Co-optimization of hydroelectric and thermal resources*
- *Optimized new resource selection*

- *Resource flexibility, dispatch, and ramping capability*
- *Cost-effective integrated utility operations and planning*

Reducing Resource Deficits Since 2002

NorthWestern has relied on the actions and capabilities of others to meet its load-serving obligations through the use of market products at prevailing levels of price and availability. Although the Supply portfolio has grown through resource acquisitions over the preceding ten years (Table 1-1), a significant capacity resource deficit persists, resulting in long-term supply uncertainty associated with the cost and availability of market products and resulting reliability concerns.

Table 1-1 Utility Owned and Controlled Resources in Montana

Utility Owned and Controlled Resources			
	Installed Capacity (MW)	Fuel / Resource Type	In-Service Year by NorthWestern
Hydroelectric Facilities	442	Hydro	2014
Spion Kop	40	Wind	2012
Dave Gates Generating Station	150	Natural Gas	2011
Colstrip Unit 4	222	Coal	2008
Basin Creek (under contract)	52	Natural Gas	2006
Total	906		

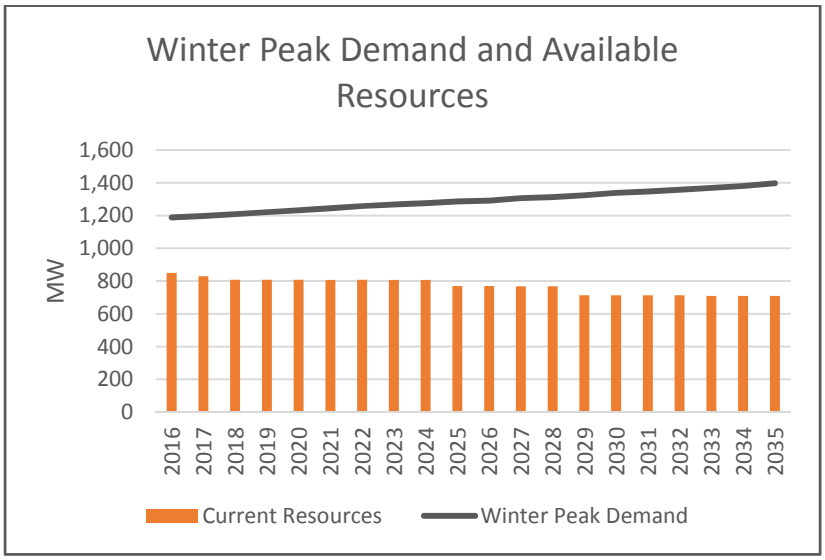
Capacity Needs and Planning

Regional supply conditions have changed; continued load growth, substantial additions of intermittent wind resources, hydrologic flow restrictions, and planned coal retirements have reduced and restricted electric generation capacity to the point that the region now faces increasing capacity constraints. Based on the findings of the Northwest Power and Conservation Council ("NWPCC") and its Resource Adequacy Advisory Committee ("RAAC"), NorthWestern has adopted a strategy to achieve minimal resource adequacy in

ten years – about the same time frame that 2,400 MW of coal-fired generation is scheduled to retire in this region. Additionally, the NWPCC 7th Plan is the first plan to focus on how the region will meet peak capacity requirements, instead of focusing on energy needs. NorthWestern has adopted a "capacity first" planning strategy as well in this planning cycle.

For NorthWestern, the addition of physical resources increased our capability to more reliably meet customer needs, provide stable rates, and reduce risk by lowering market exposure. Concurrent with the growth of NorthWestern's generation fleet, a large amount of intermittent wind generation entered the portfolio to meet Renewable Portfolio Standards ("RPS") and mandatory QF purchases. Today, including NorthWestern's 2014 acquisition of hydroelectric facilities, the portfolio is energy and capacity deficit during Heavy Load ("HL") hours and slightly energy surplus during Light Load ("LL") hours. Significant peak capacity needs remain unfulfilled. The large 20-year peak load deficit is illustrated by the widening gap between capacity delivery capability of the current energy supply portfolio and winter peak demand (Figure 1-1).

Figure 1-1 Winter Peak Demand and Available Resources



Retail loads at winter peak demand are forecast to grow from approximately 1,200 MW in 2016 to roughly 1,400 MW in 2035. The projected peak demand deficit for 2016 is 338 MW and forecast to grow to 688 MW, representing only half of peak demand needs, over the 20-year planning period unless additional capacity sources are secured. The peak load forecast includes reductions to peak demand associated with energy conservation measures from the 2009 Demand Side Management ("DSM") assessment update.

Capacity needs are also increasing for NorthWestern as a result of the adoption and implementation of new operating requirements in the regional utility industry. Reliability Based Control ("RBC"), as required by the North American Electric Reliability Corporation ("NERC"), is altering how NorthWestern and its utility neighbors will be required to meet operational performance criteria beginning July 1, 2016. Compliance with RBC is not optional. Compulsory standards of performance defined under RBC require NorthWestern to respond within 30 minutes to change of generation notifications. In order to comply, NorthWestern must continuously reserve generation capacity and be capable of increasing or decreasing output as directed. RBC represents a capacity need that will be better defined for NorthWestern after the 4-month test period which began in March 2016.

Preferred Resources

The evaluation of resource alternatives using a combination of optimal capacity expansion methods and 20-year Net Present Value ("NPV") of portfolio cost simulations has produced a resource capacity plan to meet minimum levels of adequacy calculated through loss of load probability analysis (Chapter 11). The Economically Optimal Portfolio ("EOP") is comprised of gas-fired capacity resources utilizing multiple technologies that provide economy, flexibility, environmental compatibility, and reliability. Resource selections include flexible reciprocating gas-fired engines, a high thermal efficiency combined cycle combustion turbine with duct firing, and low capital cost simple cycle combustion turbines (Table 1-2). When added to the existing portfolio, the resulting

combination of multiple gas-fired technologies, hydroelectric, thermal, wind and limited solar sources creates a cost-effective and diverse portfolio with the capability to deliver sustainable and needed levels of resource reliability and adequacy while further reducing an already low carbon emission footprint (Figure 1-2). Compared to the market alternative, the 20-year NPV of portfolio cost for the EOP is roughly 7% lower:

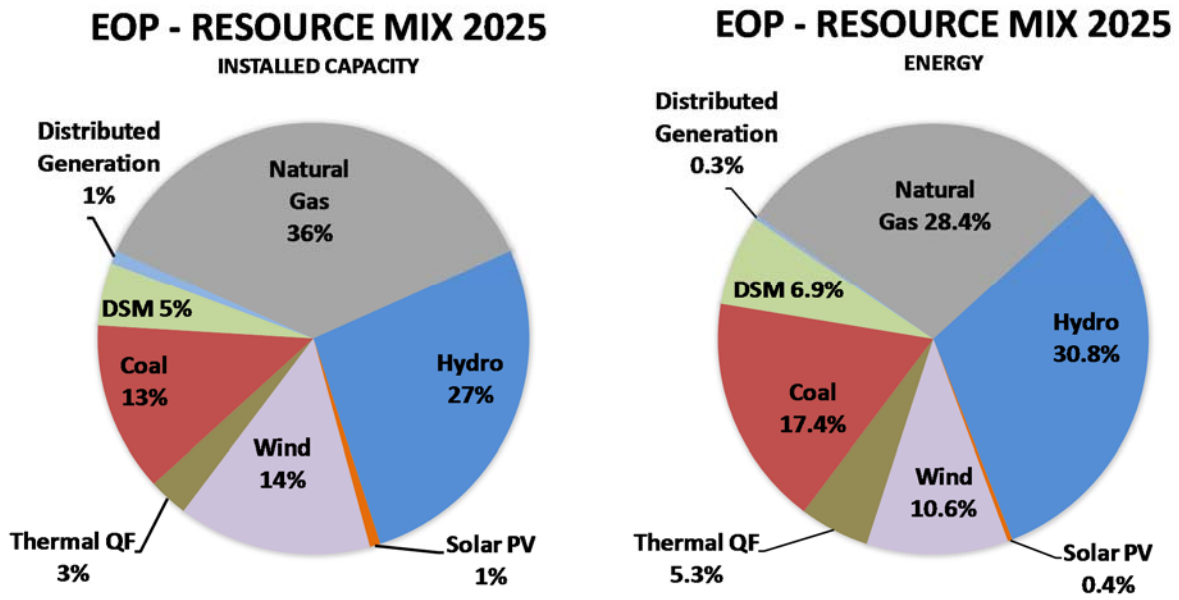
- EOP $5.5 billion
- Current Portfolio + Market $5.9 billion

Table 1-2 EOP Resources

PREFERRED PORTFOLIO RESOURCES			
TYPE	NUMBER OF UNITS	CAPACITY (MW)	YEAR ADDED TO PORTFOLIO
Internal Combustion Engine	3	55	2019
Internal Combustion Engine	1	18	2021
Internal Combustion Engine	1	18	2024
Combined Cycle Combustion Turbine	1	348	2025
Internal Combustion Engine	5	92	2028
Frame Combustion Turbine	1	79	2028
Frame Combustion Turbine	1	79	2029

Optimal capacity expansion planning evaluated whether wind and solar photovoltaic ("PV") resource options could contribute to meeting winter peak demand. In the case of both solar PV and wind generation, neither resource was determined to be an economic alternative to gas-fired generation options because of low (including zero) capacity contribution, inability to dispatch, and resource cost. Renewable energy resources such as wind and solar PV are not an economically viable alternative to capacity resources which have the capability to meet time sensitive load-serving needs.

Figure 1-2 EOP– Resource Mix 2025



The 2015 Plan identifies needs over a 20-year planning horizon and evaluates how these needs can be best satisfied using proven and reliable natural gas-fired generation technologies. Siting gas-fired generation on the Montana natural gas transmission system will require a comprehensive evaluation of infrastructure alternatives. The development of natural gas transportation infrastructure is a particularly critical component of the EOP strategy since it will ultimately determine where and when new generation resources can be added. The costs of necessary new natural gas transmission have been evaluated and estimated only at a high level.

Estimated costs for the resources identified in the EOP are included in Table 1–3. These costs, while useful for long-term planning and resource evaluation purposes, should be considered feasibility level estimates that will be further studied and refined as part of pre-development decision analysis.

Table 1-3 Estimated EOP Costs

ESTIMATED OVERNIGHT CAPITAL COSTS ($ Million, nominal dollars)			
	Project Cost	Infrastructure Costs	Total Costs
2019	76.5	22.0	98.4
2021	26.5	7.6	34.1
2024	28.1	8.1	36.2
2025	593.9	59.5	653.4
2028	254.2	83.7	337.9
2029	103.9	40.8	144.7
Total	1,083.2	221.7	1,304.8

Hydro Potential

The hydroelectric generation group operates 37 individual generating units across its ten generation facilities. The Hebgen project does not currently have generation installed at its location. The ten facilities' generation units, turbines, and generators have been refurbished or replaced to varying levels across the system. The potential exists to increase the system's capacity through further upgrades of existing units and the addition of new capacity at the Hebgen and Ryan plants. The replacement of a vintage turbine or generator results in greater long-term reliability and incremental capacity gain from current design and fabrication processes. A baseline life extension evaluation has been performed on all of the projects to evaluate current condition, upgrade requirements, and incremental generation benefit applicable to each facility. The baseline assessments indicate that, in addition to improved reliability, the system has a potential capacity increase of approximately 40 MW through existing unit upgrades. Engineering evaluations have been performed that define the scope of generation potential at Hebgen with a new generating facility and the addition of a seventh unit at the Ryan facility. The potential capacity increase of these two projects is 46 MW. These potential capacity increases have been assessed on a baseload evaluation. Modified system operations could provide additional incremental value.

NorthWestern is currently performing upgrades at its Hauser facility including upgrades to the six turbine generator units which will result in a total generating capacity increase of 2.5 MW. The first unit will be completed in 2016 and the second unit upgrade has started followed by one unit per year until completed. The hydroelectric engineering staff is currently reviewing the baseline evaluations performed at the other facilities where potential capacity increases are possible. This work will update project scopes, associated costs, schedules, and viability to include in our future business plans. The inherent value of the hydroelectric system upgrades to existing and new facilities is that there is no or minimal fixed and variable costs associated with the additional projects. The upgrades would continue to be operated with the existing staff and carbon-free fuel.

Demand Side Management

This Plan includes a description of electric efficiency programs available to residential, commercial, industrial, and irrigation electric supply customers. NorthWestern recently contracted for an updated Electric Efficiency Potential Assessment ("2016 Efficiency Assessment") to determine the amount of remaining achievable, cost effective electric DSM available in its Montana service territory. NorthWestern will maintain the current annual DSM acquisition goal of 6.0 average megawatts ("aMW") established from its 2009 Energy Efficiency Assessment until the 2016 Efficiency Assessment based on new avoided electric costs from this Plan is available, which NorthWestern expects will be completed during the second quarter of 2016. Among other things, the 2016 Efficiency Assessment will evaluate compact fluorescent lamps ("CFLs"), light emitting diodes ("LEDs") and behavioral based energy efficiency programs. NorthWestern will then determine whether revision to the current 6.0 aMW annual DSM acquisition goal is necessary and will adjust program offerings based upon the results.

NorthWestern has completed its 5-year (2010-2014) commitment to the Pacific Northwest Smart Grid Demonstration Project. A summary of NorthWestern's two geographically unique projects and related findings, as well as insights from projects implemented by other utilities in the Pacific Northwest Smart Grid Demonstration Project, are included in Volume 2, Chapter 3.

NorthWestern continues to investigate electric distribution system applications for battery technology and completed the installation of a second project near Deer Lodge during 2015 (Volume 1, Chapter 9). A summary of the status of NorthWestern's first battery storage project in Helena is included in Volume 2, Chapter 3.

NorthWestern continues to explore the potential value of behavior-based DSM. The Pacific Northwest Smart Grid Demonstration Project included some behavior-modification features. To date, NorthWestern's review of a variety of programs offered by vendors that benchmark customers' energy usage and provide education to influence energy reduction behaviors has not shown such programs to be cost effective. Such behavior-based programs will be evaluated in the 2016 Efficiency Assessment.

While NorthWestern initially anticipated that its Smart Grid Demonstration Time-Of-Use study would provide insight into customer price elasticity of demand, the small sample of NorthWestern's retail electric customers and lack of baseline data did not support definitive price elasticity of demand calculations.

Renewable Portfolio Standards

NorthWestern continues to meet its annual obligation to purchase 15% of its energy from eligible renewable resources under the Montana Renewable Power Production and Rural Economic Development Act, § 69-3-2001, MCA, *et. Seq*. (generally known as the

"Renewable Portfolio Standard", or "RPS"). Wind resources, and to a lesser extent small-scale hydro, are yielding sufficient annual volumes of renewable energy credits ("RECs") to enable us to meet the Montana 15% renewable portfolio requirement through 2026, assuming contracted sources are built and achieve the contract commercial operation dates. As detailed in Chapter 8, NorthWestern has integrated a significant amount of intermittent resources – approximately 240 MW of wind and roughly 40 MW of small-scale hydro for a combined total of roughly 280 MW. Unfortunately, not all of these resources qualify as eligible renewable resources and only a few are Community Renewable Energy Project ("CREP") qualified because of size and strict, limiting ownership requirements. Additionally, state statute does not recognize that eligible renewable resources are not all carbon emission free.

Resource Adequacy

Although the addition of thermal and hydroelectric facilities have greatly reduced NorthWestern's dependence on wholesale markets to supply capacity and energy, supply operations must still rely on significant wholesale market transactions to provide necessary capacity during peak load events. In addition, NorthWestern does not currently maintain planning reserves and instead relies on other parties or the market. Figure 1-3 below shows a range of planning reserve margins for selected utilities. The 2015 Plan incorporates Loss of Load Probability analysis to quantitatively assess the ability of the portfolio to meet peak demand (Chapter 11).

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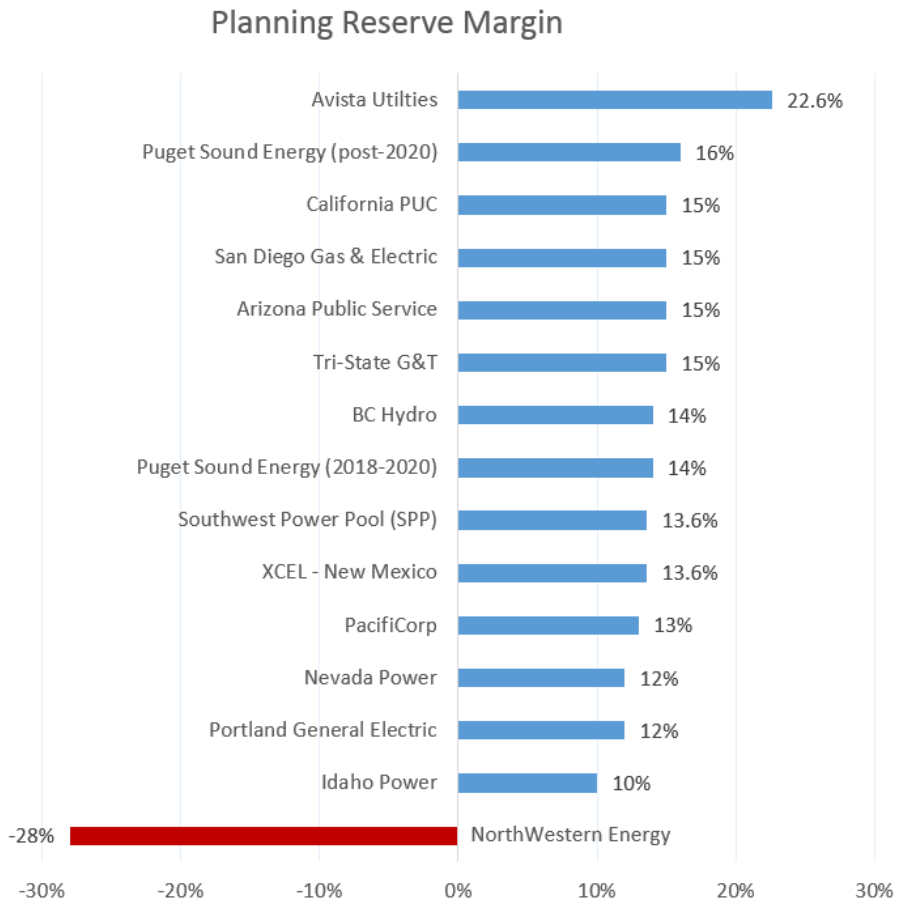
Figure 1-3 Planning Reserve Margins for Selected Power Companies



In 2005, the NWPCC and the Bonneville Power Administration ("BPA") created the Pacific Northwest Adequacy Forum ("Forum") to produce an adequacy standard for the regional power supply. In May of 2015, the NWPCC adopted the Forum's most recent forecast, which shows that the likelihood of a power supply shortage in 2020 is just under the 5% Loss-of-load Probability ("LOLP") standard set by the NWPPC in 2011. By 2021, the LOLP jumps to over 8% due to the planned retirements of Washington and Oregon coal-fired generation plants. The region would need to add 1,150 MW of gas-fired generation by 2021 to reduce the LOLP back to 5% or face a planning reserve margin deficit. Based on this projection of regional resource adequacy NorthWestern cannot assume that the region will be capable of meeting its capacity requirements.

Market Operations

Supply Market Operations conducts hourly, daily, and short-term deployment of portfolio resources to balance load with available energy and load-serving capacity. This function is performed through day-ahead and 24-hour desks where schedulers monitor electric generation production, dispatch resources, react to changes in intermittent wind energy production, and execute market purchases and sales.

In additional to hourly market purchases and sales for balancing, real time operators have the option to use the dispatch capability of certain supply resources including the 52-MW Basin Creek Equity Partners, LLC Plant ("Basin Creek") to meet load-serving needs. Using a defined dispatch protocol that determines the economics of using Basin Creek, real time operators evaluate and determine the use of the resource. The dispatch protocol considers the market price of electricity and the cost of natural gas to fuel the plant to determine economics of running the plant compared to alternatives including market purchases. In addition, a portion of the Basin Creek capacity is dedicated to providing non-spinning contingency reserves, and ancillary service required to schedule and serve load on all transmission systems. The self-provision of non-spinning contingency reserves from Basin Creek eliminates the need to purchase this product from the market.

In Final Order No. 7219h in Docket No. D2012.5.49, the Montana Public Service Commission ("MPSC" or "Commission") ordered NorthWestern to perform analysis of the Basin Creek gas-fired facility to determine if the plant is being utilized effectively. The Commission further required NorthWestern to report the results of this work. NorthWestern engaged the services of Energy and Environmental Economics, Inc. ("E3"), a California-based consultancy, to independently evaluate NorthWestern's use of Basin Creek during 2013. The results of the E3 study are noted in item 20 of NorthWestern's response to Commission comments on the 2013 Plan as well as in Volume 2, Chapter 5 of this Plan.

Since the 2013 Plan was filed, market operations has continued to evaluate and improve upon its capabilities to efficiently use the generation fleet. The integration of the hydroelectric system involved changes to planning and personnel to coordinate business activities necessary to incorporate hydro planning and operations with other supply functions including market operations. The hydro integration process has gone smoothly, including the successful transfer of Kerr Dam to the Confederated Salish and Kootenai Tribes of the Flathead Reservation on September 5, 2015.

Higher levels of integration and coordination between supply, generation, and transmission business units represent an opportunity to operate more efficiently and more cost-effectively. For example, the imbalance service function has returned to utility control. In its role as the imbalance scheduler and resource manager for the Montana system, market operations provides necessary services through the coordinated and cost-effective use of available resources and market purchases and sales.

Regional Electricity Market Development

Energy Imbalance Markets

Efforts to develop Energy Imbalance Markets ("EIMs") in the West have been underway for several years. Like Regional Transmission Organizations ("RTOs") and Independent System Operators ("ISOs"), EIMs accept offers and dispatch resources on a sub-hourly basis to meet load requirements. Unlike RTOs and ISOs, EIMs do not provide ancillary services, manage congestion, or administer an Open Access Same-Time Information System ("OASIS") site, and they do not take on reliability responsibility.

Over the last two years, there has been some progress in the development of these markets. Most notably, PacifiCorp and the California ISO ("CAISO") announced, developed, and on October 1, 2014, implemented an EIM for their Balancing Authority Areas (now called

the "Western EIM"). Several other investor-owned utilities ("IOUs") subsequently began the process to join this market. Separately, the Northwest Power Pool ("NWPP") worked toward the development of an EIM for a number of years before pulling back from these efforts in late 2015.

Regional Transmission Organizations / Independent System Operators

Development of full regional markets has also begun to progress in the West. Currently, there are two ISOs in the Western Electricity Coordinating Council ("WECC"): the CAISO and the Alberta Electric System Operator ("AESO"). In 2015, CAISO and PacifiCorp announced a memorandum of understanding to explore the possibility of PacifiCorp becoming a full participating transmission owner in the CAISO, raising the possibility that what had previously been a California state market may develop into a regional entity.

Participation in Organized Markets

NorthWestern is assessing the development of these markets and the potential for future participation, and we intend to engage a third-party consultant to aid in our evaluation. There are potential benefits – more efficient dispatch, improved reliability, and intermittent renewable (primarily wind) integration – but there are also challenges for NorthWestern's participation, including connectivity, implementation costs, and capacity requirements.

NorthWestern will need to assess how its resources would fit with the requirements of these markets. Such participation would potentially place additional requirements on NorthWestern from a resource adequacy and capacity perspective and could change the timing of the addition of resources to the portfolio. Participation in an EIM or ISO would also significantly change both market operations and transmission operations for NorthWestern.

Because a significant number of utilities are moving to organized markets, NorthWestern must also be aware of the potential consequences of not joining. Most notably, NorthWestern is evaluating the potential effects on the real-time bilateral markets as more entities join the Western EIM and potentially other markets. The implications could be significant for NorthWestern. Currently, NorthWestern relies heavily on the real-time market, particularly in times of peak load. A substantial decline in liquidity in the bilateral markets would increase the risk of not becoming an organized market member.

Colstrip Unit 4 Value

The 2015 Plan examines Colstrip Unit 4 ("CU4") from a cost, capacity, environmental, and resource adequacy perspective to assess the value and longevity of the resource for portfolio planning and resource adequacy purposes. Our assessment incorporates carbon costs as well as the potential for different carbon pricing trajectories to determine a range of potential impacts to the portfolio. Based on the results of our analysis we conclude that CU4 provides long-term value to the portfolio, especially when it is considered in the context of the portfolio's capacity requirements.

Introduction to 2015 Plan Document

The Plan is presented in two volumes with Volume 1 separated into primary topical chapters addressing fundamental resource planning components such as load, the current portfolio, resources, model inputs and analysis, and results and conclusions. Volume 2 is a compilation of supporting documentation, references, and technical materials that are too voluminous to be reasonably included in Volume 1. A detailed table of contents for both volumes is provided to help readers quickly and easily locate materials of interest. Discussion of resource topics and analytical methods often leads to the use of technical terminology and acronyms that may not be familiar to all readers. Appendix 1 (Abbreviations) and Appendix 2 (Glossary) to Volume 1 are included as reference aids to

support more effective communication of resource planning work and promote a shared understanding of NorthWestern's electric supply business unit.

Volume 1

The first volume is designed to provide a full accounting of the work performed by NorthWestern and its advisors, including Electric Technical Advisory Committee ("ETAC"), to inform electric generation resource procurement. As a planning and information road map, it is a guide that explains the steps taken to craft the EOP and explains how it was determined to be the low-cost, low-risk resource strategy. NorthWestern will show that it has conducted a careful examination of the factors relevant to the retail load-serving obligation and that it has employed methods of evaluation that are appropriate, thorough, and complete.

Volume 2

Seven chapters are included in the second volume which is being supplied in electronic format with printed versions of Volume 1 due the large amount and nature of the information presented. References to the materials found in Volume 2 are found throughout Volume 1 and provide background, source information, and a detailed tabular accounting of modeling results and output. Additional background information is also provided on topics relevant to the Plan in Volume 2 that is not explicitly cited in Volume 1.

CHAPTER 2
LOAD FORECAST

NorthWestern's 2015 Forecast of Customer Loads

Peak Demand Forecast

Peak demand drives and defines the need for capacity resources, establishes resource adequacy benchmarks, and comprises a key planning variable in the 2015 Plan. The analysis of peak demand is prepared by the Energy Supply group in coordination with NorthWestern's Load Research Department using historical hourly load data for the retail customer rate classes. Energy Supply analyzes this data for patterns of use, peak demand, and sensitivity to weather. NorthWestern's loads exhibit dual-peaks, meaning that maximum annual peak demand has occurred in both winter and summer. Actual peak demand for winter and summer, including line losses, is presented in Table 2-1 for the period 2002–2014. The annual peak load forecast presented in Table 2-2, is a 1 in 2 forecast, meaning that there is a 50% probability that forecast peak will be less than actual peak load, and a 50% probability that the forecast peak will be greater than actual peak load. The forecast of peak demand is presented with and without the estimated impacts of DSM measures as noted in the title of each of the tables.

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Table 2-1 Historical Peak Demand

	Historical Peak Demand (MW)		
	Year	Winter	Summer
Actual	2002	892	958
	2003	912	1078
	2004	1096	1000
	2005	1096	1026
	2006	1085	1122
	2007	1100	1177
	2008	1165	1071
	2009	1225	1059
	2010	1219	1045
	2011	1139	1091
	2012	1106	1133
	2013	1074	1162
	2014	1272	1115
2002-2014 CAGR		3.00%	1.27%

Table 2-2 Peak Demand 1 in 2

	1 in 2 Peak Demand Forecast Excluding DSM (MW)		
	Year	Winter	Summer
Forecast	2016	1224	1154
	2017	1244	1177
	2018	1264	1200
	2019	1285	1222
	2020	1305	1245
	2021	1325	1267
	2022	1344	1289
	2023	1363	1310
	2024	1382	1333
	2025	1390	1344
	2026	1398	1356
	2027	1405	1368
	2028	1413	1379
	2029	1423	1393
	2030	1433	1406
	2031	1443	1420
	2032	1453	1434
	2033	1463	1448
	2034	1473	1462
	2035	1484	1477
2016-2035 CAGR		1.02%	1.31%

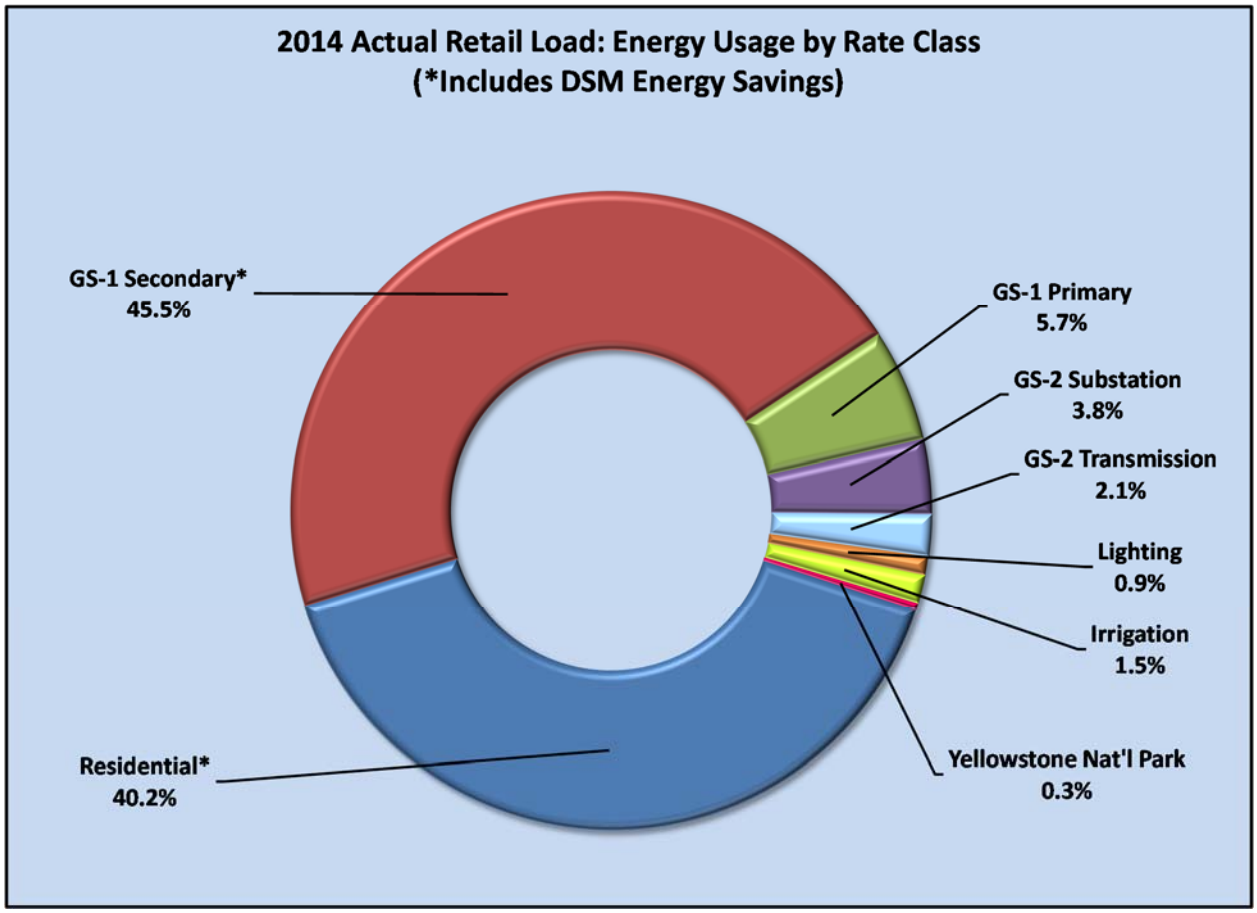
	Peak Demand DSM Savings Forecast (MW)		
	Year	Winter	Summer
Forecast	2016	40	38
	2017	50	48
	2018	60	58
	2019	69	66
	2020	79	76
	2021	89	86
	2022	99	95
	2023	109	104
	2024	118	114
	2025	118	114
	2026	118	114
	2027	118	114
	2028	118	114
	2029	118	114
	2030	118	114
	2031	118	114
	2032	118	114
	2033	118	114
	2034	118	114
	2035	118	114
2016-2035 CAGR		5.85%	5.95%

	1 in 2 Peak Demand Forecast Including DSM (MW)		
	Year	Winter	Summer
Forecast	2016	1184	1116
	2017	1195	1129
	2018	1205	1143
	2019	1216	1156
	2020	1226	1169
	2021	1236	1181
	2022	1246	1194
	2023	1254	1206
	2024	1263	1219
	2025	1272	1231
	2026	1280	1242
	2027	1287	1254
	2028	1295	1265
	2029	1304	1279
	2030	1314	1292
	2031	1324	1306
	2032	1335	1320
	2033	1345	1334
	2034	1355	1348
	2035	1365	1363
2016-2035 CAGR		0.75%	1.06%

Energy Usage and Needs

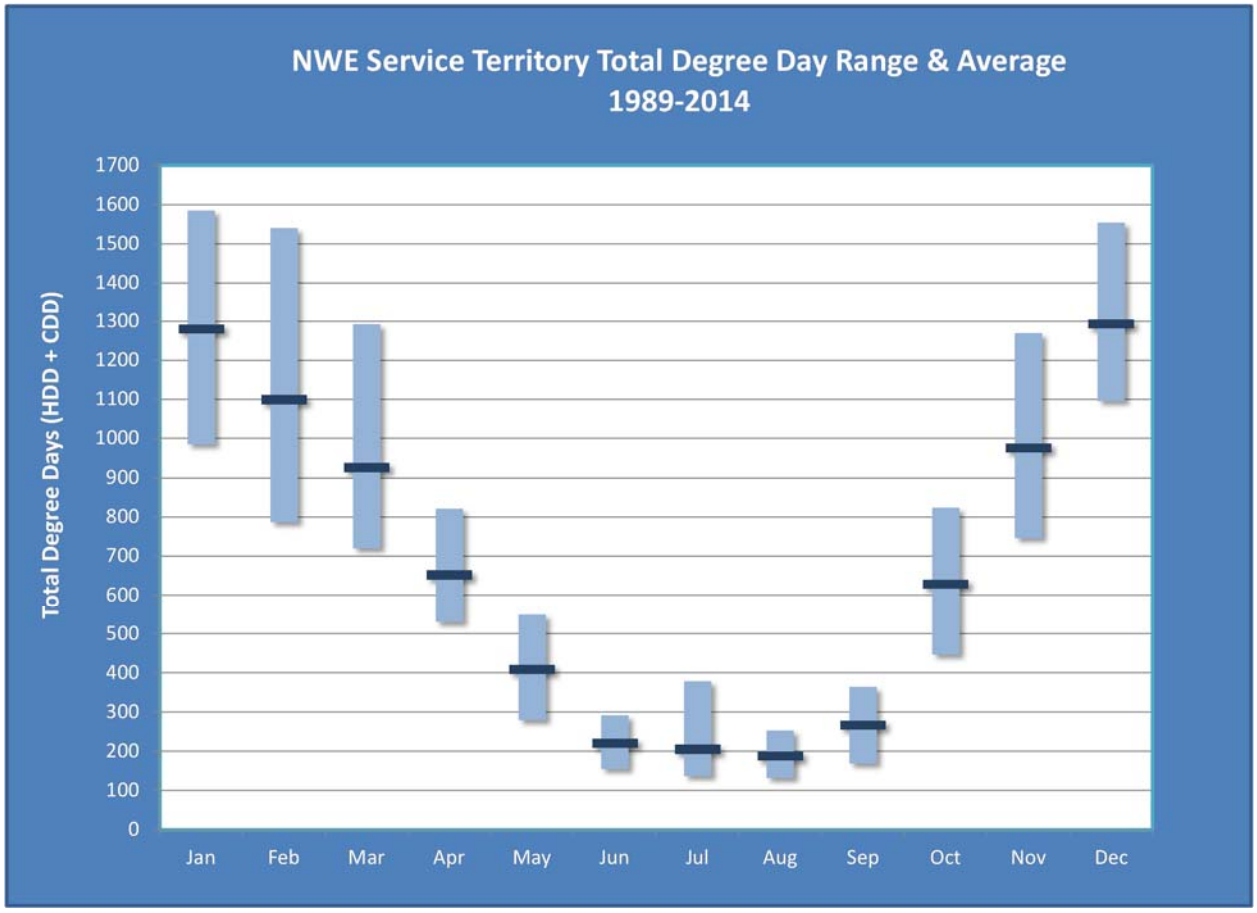
NorthWestern develops its 20-year long-term energy forecast using a regression model with two explanatory variables: a forecast of customer count and degree days. Residential and GS-1 Secondary (small commercial) rate classes represent approximately 85% of the total energy load-serving obligation (see Figure 2-1) so much of the energy usage and peak demand forecasting work focuses on these customer classes. Additionally, these two classes of retail customers are weather sensitive and respond quickly and predictably to temperature changes.

Figure 2-1 2014 Actual Retail Load Energy Usage by Rate Class



Weather is normalized by using average historical total degree days per year, heating degree days ("HDD") plus cooling degree days ("CDD"). Degree days are calculated according to the average daily temperature compared to 65° (Fahrenheit). If 65° minus the average daily temperature equals a positive value, the value is recorded as HDD; if a negative value is derived, the value is recorded as CDD. Figure 2-2 illustrates the monthly average and total range in weather variability in terms of degree days that have been recorded in the NorthWestern Montana service territory since 1989.

Figure 2-2 NorthWestern Service Territory Total Degree Day Range and Average 1989-2014



Other variables that may impact customer loads, such as economic conditions and DSM activity, are not included in the forecast. Several economic business cycles could occur over the course of the 20-year planning horizon, but NorthWestern has no practical way or predicting and measuring such cycles. However, the use of a long-term historical average annual growth rate, which does include the impacts of several economic business cycles, is incorporated in the long-term load forecast.

NorthWestern acquires about 1% of retail sales, or 6 aMW, of energy efficiency each year through its DSM programs. Over time, accumulated DSM reduces NorthWestern's load-serving obligation significantly and acts to dampen load growth that would otherwise occur. Figure 2-3 below provides the long-term load-serving obligation projection (blue) and expected DSM energy efficiency savings (gray) over the planning horizon; the stacked components illustrate what the load-serving obligation would otherwise be without the energy-reducing benefit of DSM.

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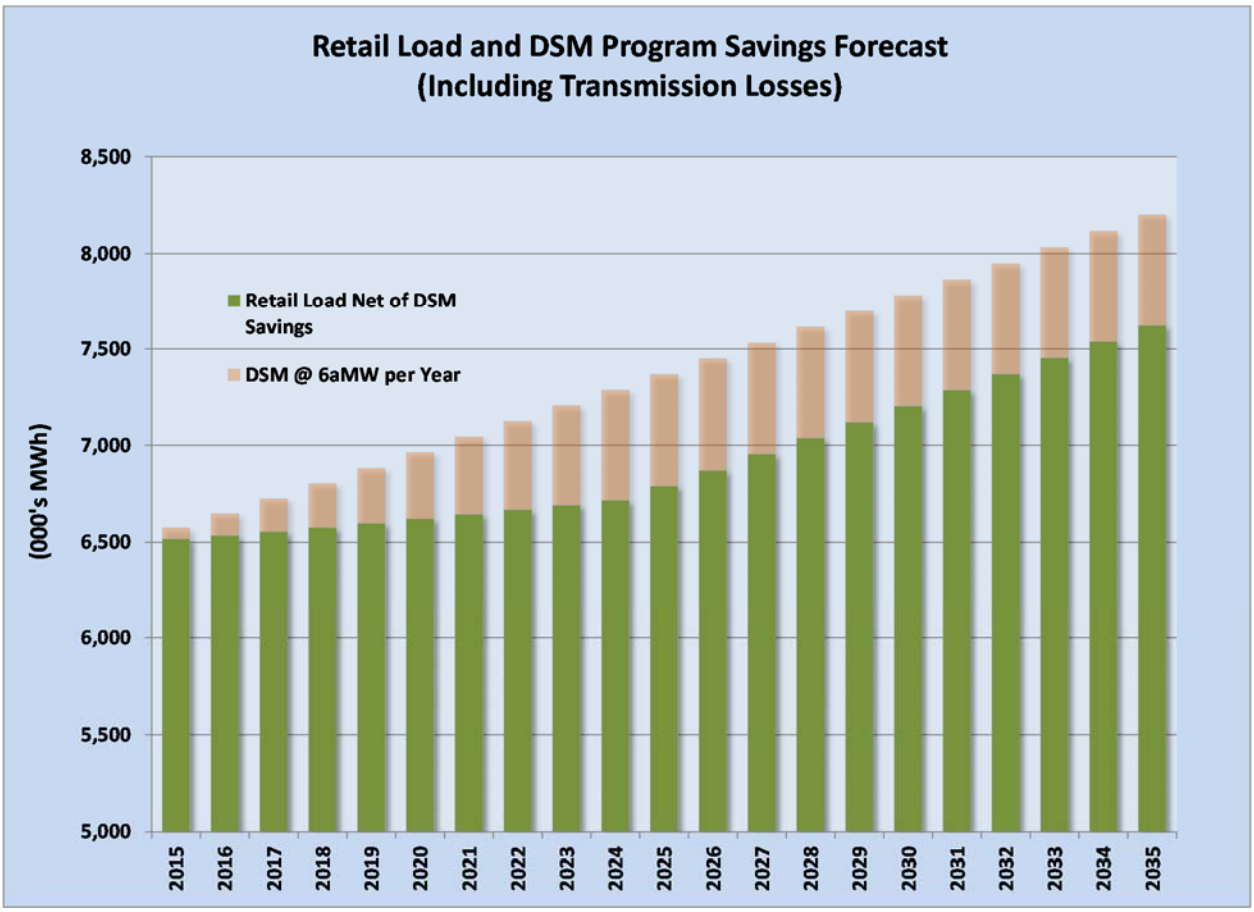
Figure 2-3 Retail Load and DSM Program Savings Forecast



DSM is an important long-term component in NorthWestern's supply stack. Currently, the long-term projected average annual growth rate of load is 1.1% per year excluding DSM and 0.8% net of DSM energy savings. The compounding growth of energy savings measures can be observed from 2016 through 2024. Based on the DSM acquisition assessment conducted in 2009, NorthWestern anticipates procuring approximately 750,000 fewer megawatt-hours ("MWh") per year by 2024 than it would otherwise have needed to procure without the energy savings from DSM program measures. DSM programs are discussed further in Chapter 3.

Customer Forecast

Residential and GS-1 Secondary (small commercial) customers make up 85% of NorthWestern Energy's load-serving obligation but they make up 98% of the Company's electric customers or accounts. The primary driver of the customer forecast is the projected population in NorthWestern's service territory, which is comprised of 37 of Montana's 56 counties. The State of Montana's Census and Economic Information Center publishes Montana's population forecast on its website and NorthWestern uses this in its forecasting work. The forecast is constructed using an independent econometric model developed by Regional Economic Models, Inc. that provides county population projections through 2060. As shown in Table 2-3, actual and expected population growth for the state of Montana and NorthWestern's service territory is about the same – approximately 1%. Total Accounts are expected to grow at about a 1.3% annual rate, greater than population growth because of total new connects in residential single and multi-family housing units and commercial buildings.

Table 2-3 Actual and Expected Population Growth

Year	Montana Population	*Annual Growth Rate*	NWE Srvc Territory Population	*Annual Growth Rate*	NWE Total Accounts	*Annual Growth Rate*	NWE Residential Accounts	*Annual Growth Rate*	NWE GS1-Secondary Accounts	*Annual Growth Rate*
2000	903,293		705,330		292,437		235,784		49,759	
2005	934,801	*0.7%*	731,505	*0.7%*	315,755	*1.5%*	253,124	*1.4%*	55,491	*2.2%*
2010	990,575	*1.2%*	774,891	*1.2%*	338,804	*1.4%*	270,571	*1.3%*	60,872	*1.9%*
2015	1,033,902	*0.9%*	807,496	*0.8%*	357,897	*1.1%*	286,311	*1.1%*	64,183	*1.1%*
2020	1,087,097	*1.0%*	848,406	*1.0%*	381,736	*1.3%*	304,800	*1.3%*	69,533	*1.6%*
2025	1,143,030	*1.0%*	891,388	*1.0%*	406,685	*1.3%*	324,206	*1.2%*	75,076	*1.5%*
2030	1,201,841	*1.0%*	936,547	*1.0%*	432,453	*1.2%*	344,454	*1.2%*	80,596	*1.4%*
2035	1,263,677	*1.0%*	983,995	*1.0%*	459,108	*1.2%*	365,556	*1.2%*	86,149	*1.3%*

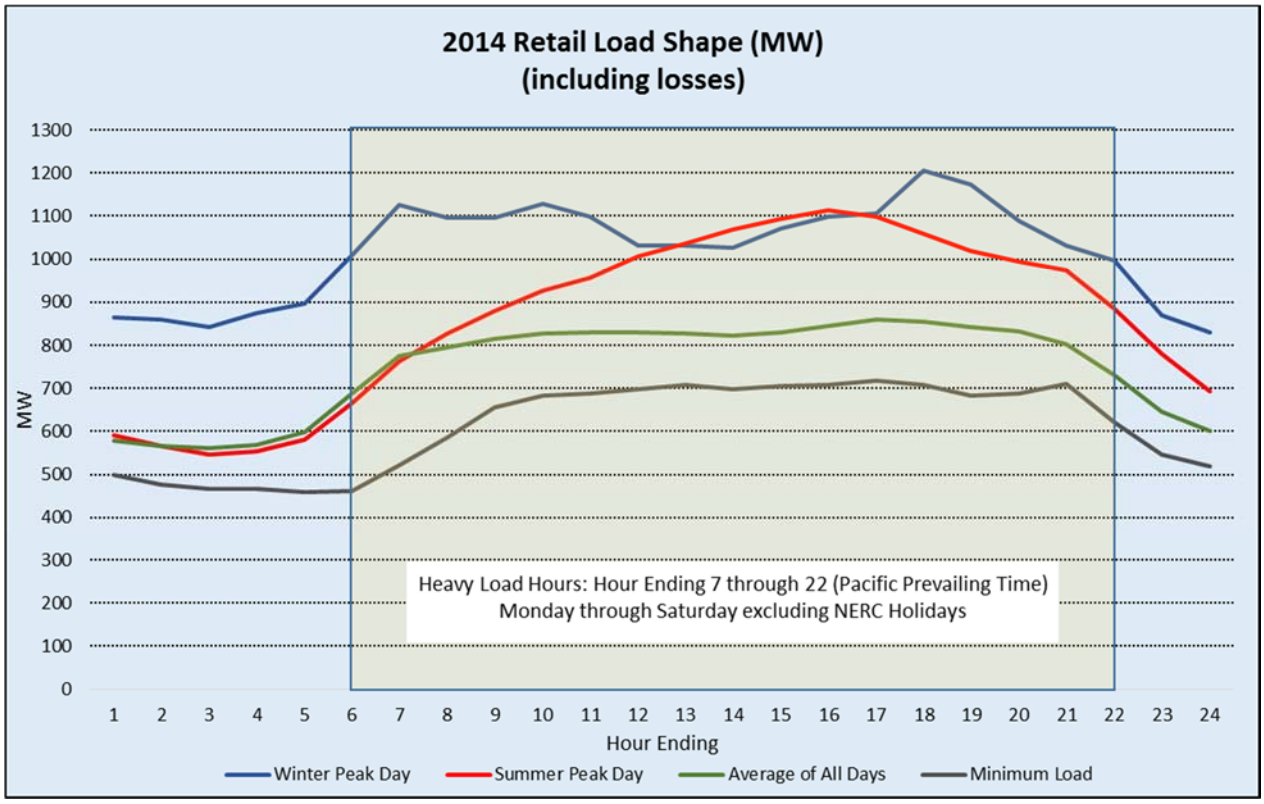
In addition to the information presented on peak demand and load forecasting in this chapter, supporting data and load analysis can be found in Volume 2, Chapter 2.

Retail Load Shape

The retail load shape is driven primarily by the energy consumption patterns from two rate classes: residential and GS-1 secondary. The pattern of retail consumption is seasonal and weather sensitive according to changes in outside air temperatures which span a range from over 100 degrees Fahrenheit to double digit negative values in a typical year.

Figure 2-4 illustrates the range of hourly retail load including losses for 2014. The blue and red lines show the peak winter and summer load days while the black line illustrates a minimum load day from May. The green line was created by averaging the hourly load values for individual hours of the day.

Figure 2-4 2014 Retail Load Shape



The gray shaded area represents HL hours defined as hour ending 6 – 22 on Monday through Saturday (Pacific Prevailing Time ("PPT")) and excluding NERC holidays. Remaining hours are defined as LL hours.

From the load-serving perspective it is critically important to account for load changes in order to reliably meet load by matching resource accordingly. Reviewing the winter peak day shown in Figure 2-4, loads varied from approximately 830 MW to a maximum of 1,200 MW – a range of approximately 370 MW. In the summer the range of load is much greater where the minimum load of roughly 550 MW doubles to 1,100 MW over a 24-hour period.

Energy Load – Balance

NorthWestern's load-serving obligation requires that Energy Supply acquire resources sufficient to achieve a balance between loads and resources. Load-resource balance is achieved when resources equal loads. The amount and timing of resource acquisitions is determined by comparing the existing supply portfolio to forecast need. Additionally, differences in need between heavy-load and light-load (also referred to as on- and off-peak) periods must also be considered. Simply averaging or ignoring these differences would not balance either load-serving period and would likely lead to energy deficits during HL hours and energy surpluses during LL hours.

Figures 2-5 and 2-6 illustrate NorthWestern's HL and LL load-resource balance over the next 10 years using forecast loads and existing resources. Each figure is compiled using monthly load values and reflects the seasonality of loads, resulting in a "spiky" appearance. The red line represents loads, while NorthWestern's existing resources are shown as a resource stack. Comparing forecast loads to the existing resource stack in each figure indicates the volume of resource needed to meet forecast loads.

The resource stack in each figure is constructed using average annual energy production for each existing resource. Existing wind resources are shown in the resource stack at their average annual energy production, which is equal to about 38% of generation at full capacity (also known as capacity factor). However, in any one hour cumulative wind may vary between 0% and 91% of total installed capacity. The area between the dotted lines in each figure represents the variability in wind that may occur from hour to hour (wind variability band). This band of variability represents uncertainty that NorthWestern must manage when procuring resources to serve loads.

Several conclusions can be drawn from Figures 2-5 and 2-6. First, NorthWestern has some ongoing need for resources that produce, or can be called on to produce, during HL hours. Second, NorthWestern has no need for resources that produce during LL hours. This category of resources generally includes must-take resources like non-curtailable intermittent wind. NorthWestern's wind at 0% and wind at 91% have been included in the figures (black dashed lines) to graphically portray the potential swing in wind resources that NorthWestern must be able to deal with in any one hour. The potential swing in wind production from hour to hour requires flexible, or ramping, resources. NorthWestern has modeled this need and presents the results of that analysis in Chapter 12.

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Figure 2-5 Current plus Market 5-Year HL MWh

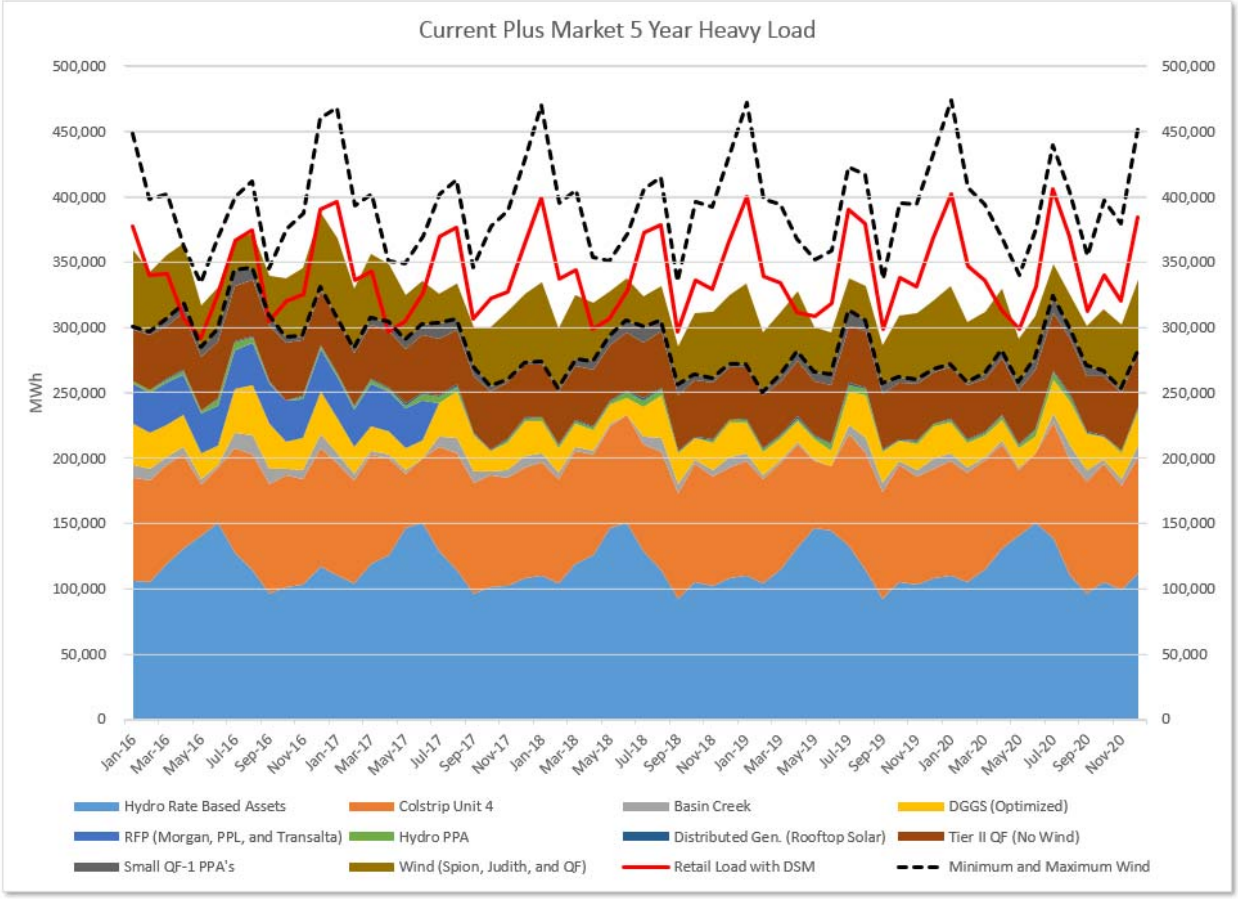

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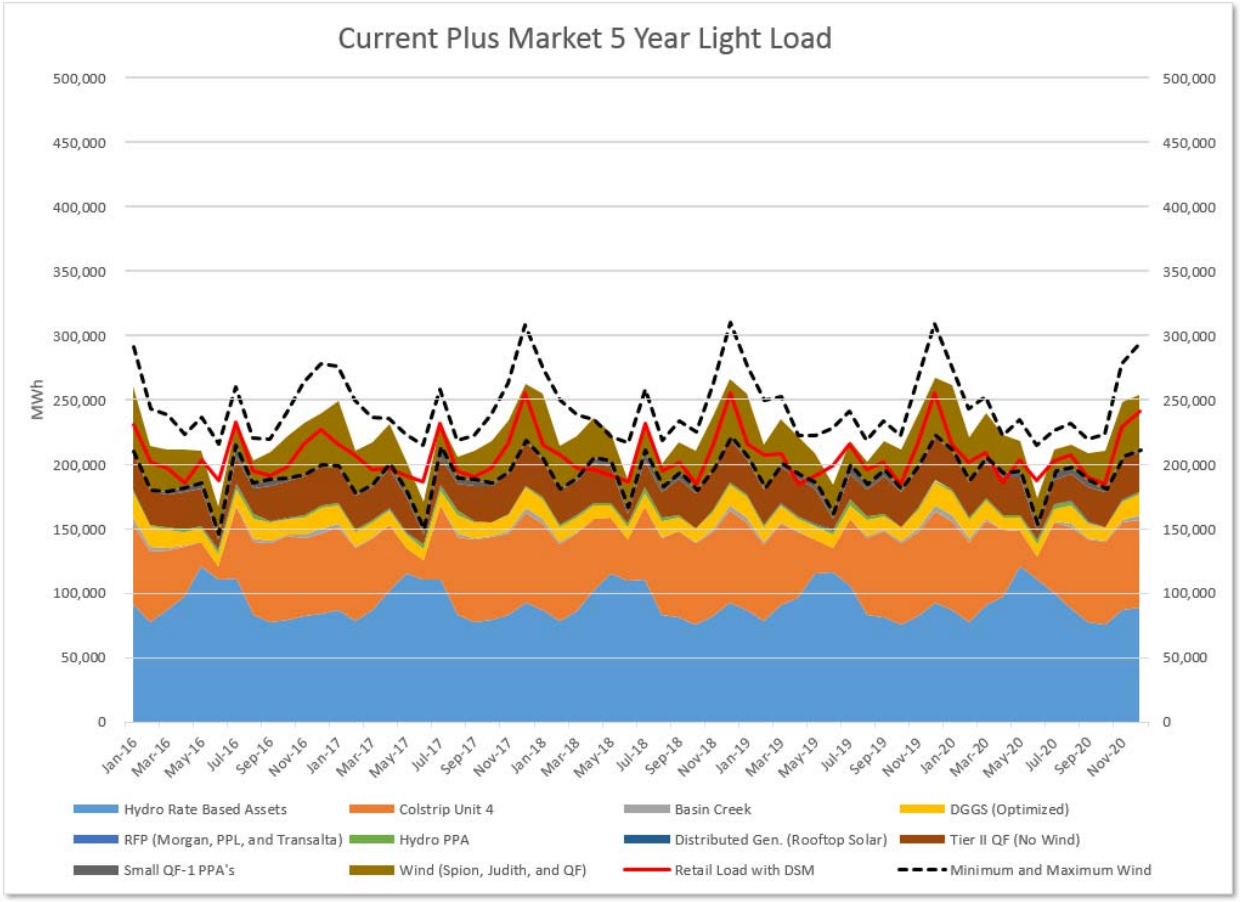
Figure 2-6 Current plus Market 5-Year LL MWh



Conclusion

NorthWestern is short on the physical capacity needed to meet peak loads and has some need for additional heavy load hour resources, but has little to no need for additional light load hour resources. Therefore, NorthWestern's first priority resource need is for dispatchable peaking resources and, on a much lower priority, some need for dispatchable heavy load hour resources. Specifically, NorthWestern has little to no need for additional intermittent renewable resources like wind, except to meet Renewable Portfolio Standards ("RPS") as required by law.

NorthWestern's resource needs assessment, combined with its current portfolio of resources, drives the selection of resources as presented in Chapter 12. Other factors driving resource selection are the integration of system operations (presented in Chapter 10) and ancillary services (Chapter 11).

CHAPTER 3
DEMAND SIDE MANAGEMENT

DSM Acquisition Plan and Programs

DSM Goals

NorthWestern has recently contracted with Nexant Consulting Inc. ("Nexant") for an updated Electric Efficiency Potential Assessment ("2016 Efficiency Assessment") which will provide information as to the amount of remaining achievable, cost-effective electric DSM available in NorthWestern's Montana service territory. The most recent Efficiency Assessment was conducted in 2009 and this value was estimated to be 84.3 aMW. Based on that value, NorthWestern established its annual DSM acquisition goal at the level of 6.0 aMW after an initial year target of 5.5 aMW. NorthWestern intends to continue implementing the annual goal of 6.0 aMW until a review of electric avoided costs resulting from this planning cycle can be completed and the 2016 Efficiency Assessment is available.

Electric avoided costs are a primary determinant of DSM cost-effectiveness. Therefore, eligible DSM measures, achievable cost-effective DSM potential, proper DSM Program rebate/incentive levels, and expenditure levels for various other DSM Program activities such as marketing and outreach must be evaluated against the most recent avoided costs. NorthWestern expects the results of the 2016 Efficiency Assessment based on new electric avoided costs from this planning cycle will be available to DSM planners in second quarter of 2016. The new avoided costs are expected to be lower than those applied in the previous planning cycle.

NorthWestern recognizes that the annual goal of 6.0 aMW is aggressive given lower

avoided costs and the federal legislative developments in the lighting sector that have reduced the contribution that energy efficient lighting can make to annual DSM results. Federal regulations relating to CFLs and other lighting technologies began phasing in over a three-year period starting January 1, 2012. NorthWestern started using halogen incandescent lamps as the baseline lamps beginning January 1, 2015. Despite these changes CFLs continue to be a cost-effective DSM measure and NorthWestern continues to incent customers to purchase and install the higher cost but more efficient CFLs.

In February 2015, NorthWestern contracted for a CFL lighting market study (Refer to Volume 2, Chapter 3) that was designed to help the Company better understand the current state of the market for energy efficient lighting products in Montana, with specific focus on awareness, installation, and saturation of CFLs in the residential sector for both general and specialty lighting. This study concluded that the residential CFL lighting market is not transformed and NorthWestern should continue to include CFLs in its programs through at least the 2015-2016 tracker period while continuing to monitor developments and changes in the market during the next few years. The study recommended continued evaluation of LEDs for future DSM offerings. CFLs and LEDs will be evaluated as part of the 2016 Efficiency Assessment.

NorthWestern has also continued its focus on acquiring energy efficiency in the commercial sector and has contracts in place with several firms for services in support of the E+ Business Partners Program, the E+ Commercial Lighting Rebate Program, the E+ Commercial Electric Rebate Program for New Construction, and the E+ Commercial Electric Rebate Program for Existing Facilities. The firms are:

- National Center for Appropriate Technology
- McKinstry Essention
- CTA Associates, Inc.

- Energy Resource Management, Inc.
- CLEAResult Consulting, Inc. (formerly Portland Energy Conservation, Inc.)
- Associated Construction Engineering, Inc.

These contractors are compensated by NorthWestern on a performance basis, with payment based on a percentage of the energy conservation resource value of each individual DSM project that is completed with the contractor's involvement. Each contractor is expected to deliver to NorthWestern a minimum estimated 0.25 aMW per year of incremental energy savings each year.

These contractors continue to be supported by a two- to three-member team of DNV GL (formerly KEMA, Inc.) employees who have responsibility for direct contact, face-to-face marketing of E+ Programs to commercial/small industrial customers in an effort to identify, qualify, and cultivate DSM projects for follow-up by DSM staff and the contractors listed above.

DSM Budget and Spending

The budget associated with the 2009 DSM Acquisition Plan was developed using the 2010 20-year levelized avoided cost of approximately $70/MWh.[1] Annual spending estimates were based on a percentage of total resource value of the annual DSM target of 5.5-6.0 aMW at this level of avoided cost. NorthWestern on average has exceeded its annual DSM goal, and actual spending has been less than this budgeted amount as summarized in Table 3-1.

[1] The planning process culminating in the 2011 Electricity Supply Resource Procurement Plan produced a 20-year levelized electric avoided cost of approximately $54/MWh for use in DSM planning and analysis; the 2013 Electricity Supply Resource Procurement Plan produced a 20-year levelized electric avoided cost of approximately $44/MWh for use in DSM planning and analysis.

Table 3-1 DSM Acquisition Plan and Budget

NorthWestern DSM Acquisition Plan and Budget 2010-2029					
Plan Year	Tracker Year	Total (aMW) Acquisition Plan	Total (aMW) Acquisition Reported	Budget	Actual Spend
1	2010-2011	5.5	5.6	$ 11,040,955	$ 7,108,435
2	2011-2012	6.0	6.9	$ 13,181,496	$ 9,185,261
3	2012-2013	6.0	7.8	$ 14,318,314	$ 10,836,590
4	2013-2014	6.0	6.9	$ 15,455,132	$ 9,339,577
5	2014-2015	6.0	5.9	$ 16,440,140	$ 5,414,378
6	2015-2016	6.0		$ 17,979,217	$ -
7	2016-2017	6.0		$ 19,518,294	$ -
8	2017-2018	6.0		$ 21,057,371	$ -
9	2018-2019	6.0		$ 22,596,448	$ -
10	2019-2020	6.0		$ 24,135,525	$ -
11	2020-2021	6.0		$ 25,884,476	$ -
12	2021-2022	6.0		$ 27,633,427	$ -
13	2022-2023	6.0		$ 29,382,378	$ -
14	2023-2024	6.0		$ 31,131,329	$ -
15	2024-2025	0.8		$ 4,334,800	$ -
16	2025-2026	-		$ -	$ -
17	2026-2027	-		$ -	$ -
18	2027-2028	-		$ -	$ -
19	2028-2029	-		$ -	$ -
20	2029-2030	-		$ -	$ -
	Total	**84.3**	**33.2**	**$ 294,089,303**	**$ 41,884,240**

The upcoming review of electric avoided costs resulting from this planning cycle, the results of the 2016 Efficiency Assessment, and the effects of new avoided costs on remaining achievable cost-effective DSM potential, rebate/incentive levels, and other spending plans will necessarily include revisiting annual acquisition targets and budget levels and will likely require revision to the 2009 DSM Acquisition Plan. NorthWestern notes that a future DSM budget is a long-term estimate that may be used for long range resource planning. Each year as part of the annual electric tracker filing, NorthWestern

provides an updated short-term, next-year budget estimate for the immediately following tracker period. That one-year budget forecast is based on current year results and knowledge gained from past program operation and is likely to deviate from the values established in the long range budget forecast presented above, and as evidenced by the five years of data in the Actual Spend column of Table 3-1 above.

DSM Programs

NorthWestern continues to offer a variety of programs, services and resources to help our Montana customers to better manage energy costs. The following are electric DSM Programs funded through energy supply rates during the 2015-2016 tracker period:

- **E+ Home Lighting Rebate** – Rebates available to residential customers for ENERGY STAR® hard-wired CFL lighting fixtures and wall-switched replacement occupancy sensors in existing or new construction homes. This program also offers several other mechanisms to either distribute or encourage purchase and use of ENERGY STAR CFLs including: free CFL with mail-in home audits, in-store instant rebates with redeemed coupons, the Simple Steps Program which is a buy-down of CFL prices for residential customers at retailers through a regional campaign facilitated by the Bonneville Power Administration, and non-retailer special events (trade shows).
- **E+ Commercial Lighting Rebate Program** – Offers prescriptive and custom rebates for the replacement of less efficient lighting products with high efficiency technologies.
- **E+ Commercial Existing Electric Rebate Program** – Rebates are available to electric customers for qualifying electric measures.
- **E+ Commercial New Construction Electric Rebate Program** – Rebates are available to electric customers for qualifying electric measures.

- **E+ Business Partners Program** – Provides customized incentives to commercial and industrial customers for electric and natural gas conservation. Examples of projects include measures to improve lighting, heating, ventilating and cooling ("HVAC") systems, refrigeration, air handling, and pumping systems. New and existing facilities are eligible.
- **Northwest Energy Efficiency Alliance ("NEEA")** – NEEA is a regional non-profit organization supported by electric utilities, public benefits administrators, state governments, public interest groups, and energy efficiency industry representatives. Through regional leveraging, NEEA encourages "market transformation" or the development and adoption of energy efficient products and services in Montana, Washington, Idaho, and Oregon. NEEA's regional market transformation activities target the residential, commercial, industrial and agricultural sectors.

Additional electric energy savings are produced from Universal System Benefits ("USB") funded programs that will continue into the foreseeable future. The electric energy savings produced from these USB programs are counted toward annual DSM goals. The costs to operate these programs are not included in the energy supply resource planning process:

- **E+ Free Weatherization Program** – Provides insulation and other efficiency improvements at no cost to Low Income Energy Assistance Program ("LIEAP") qualified space-heating customers of NorthWestern.
- **E+ Energy Audit for the Home** – Free onsite energy audit and mail-in survey audit.
- **E+ Energy Appraisal for Businesses** – Free onsite energy audit that focuses on identifying electric conservation opportunities for small commercial customers on NorthWestern's electric distribution system. A report with recommendations

customized to the facility is provided. Some energy saving measures may be installed as appropriate.

- **E+ Irrigator Program** – Provides financial incentives for the installation of energy efficient electric conservation in irrigation systems.
- **Building Operator Certification** – Building Operator Certification is an international professional development program for managers and operating engineers of commercial and public facilities and is available to commercial customers in partnership with the Northwest Energy Efficiency Council.
- **E+ Renewable Energy Program –** Provides incentive funds to electric customers for qualifying small-scale solar photovoltaic, wind, and hydroelectric systems in Montana.

Additional information on these programs is available at NorthWestern's web site at www.NorthWesternEnergy.com/Eplus.

Upon completion of the 2016 Efficiency Assessment, avoided cost changes, and subsequent review of all DSM Program measures, rebate levels and program designs, NorthWestern will adjust programs offered in the 2016-2017 tracker period accordingly.

DSM Program Costs & Lost Revenue Recovery

DSM Program costs have been included in annual electric tracker filings as a line item in the electric supply portfolio, and NorthWestern will continue this approach to seeking full cost recovery on an annual basis for this portion of the overall expenses associated with its electric supply DSM activity. Final Order No. 7375a issued by the MPSC in Docket No. D2014.6.53 terminated NorthWestern's ability to recover cumulative and forecasted lost revenues through electric and natural gas supply rates effective December 1, 2015. Consequently, while NorthWestern recognizes the least-cost nature of DSM measures, they

must also be considered in the context of the future risk associated with program cost recovery by the utility.

The following DSM projects and topics are discussed in Volume 2, Chapter 3:

- Smart Grid Demonstration Project
- Battery Storage Project
- Behavior Based DSM, Time of Use ("TOU"), and Price Elasticity of Demand

CHAPTER 4
KEY MODEL INPUTS

Commodity Price Forecasts Used in the 2015 Plan

Forecast commodity prices represent the market price NorthWestern will pay for energy purchased to balance its portfolio. There is significant risk and volatility associated with reliance on the market, and while the energy procured from the market can meet short-term energy requirements, it does not contribute to peak capacity needs. NorthWestern requires a significant amount of capacity to meet its peak load, and new thermal resources can provide both energy and capacity.

Commodity Forward Prices

NorthWestern relies on current expectations of forward/forecast prices, market expectations of price implied volatility, fundamental market relationships, rate of mean reversion, and correlations of simulated prices through time in order to capture variability in the simulation of commodity prices. The simulated forward/forecast commodity prices include power at the Mid-Columbia trading hub ("Mid-C"), natural gas at the Alberta Energy Company Trading Hub ("AECO"), and coal used for generation at Colstrip. The forecasted commodity prices provide the expected values from the average of simulation results. The forecasts that are used in this plan will be utilized in evaluation of other potential future resources.

Natural Gas Price Forecast

NorthWestern's long-term natural gas forecast is a combination of current forward market prices and the application of long-term price escalation factors. The near-term Henry Hub and AECO basis forward prices are obtained from New York Mercantile Exchange ("NYMEX"), Intercontinental Exchange ("ICE"), and Natural Gas Exchange ("NGX"). These sources are used to compose a forward price curve for AECO from January 2016

until July 2020, at which time liquidity is deemed insufficient to support the extension of forward price quote information. The forward curve is then escalated after July 2020 through the remainder of the planning horizon at the average escalation rate from the Energy Information Administration ("EIA") 2015 Annual Energy Outlook nominal Henry Hub gas price projection.

Natural gas prices have declined substantially since the filing of the 2013 Electricity Supply Resource Procurement Plan ("2013 Plan"). Figure 4-1 reflects the mean, P5, and P95 natural gas price forecasts simulated in PowerSimm for the 2015 Plan (in black), along with comparisons from the EIA Annual Energy Outlook for 2015, the NWPCC Medium price forecast update in December 2015, and the mean natural gas price from the 2013 Plan.

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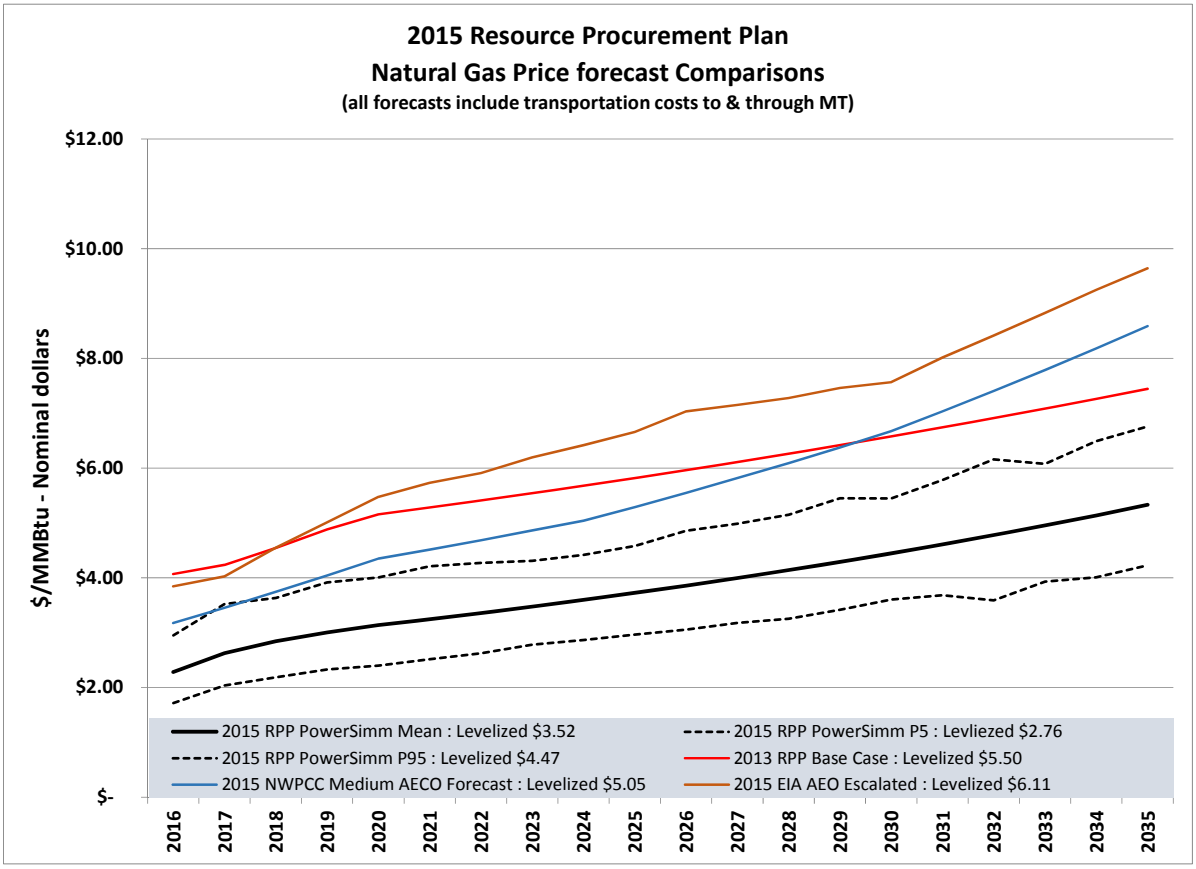
Figure 4-1 Natural Gas Price Forecast Comparisons



Electricity Price Forecast

NorthWestern uses the same methodology for its electricity price forecast that it is used for its natural gas forecast. Forward market electricity prices are provided by ICE and utilized through the same time period as in the natural gas forecast. The electricity price is then escalated using the same escalation rate as the natural gas forecast in order to maintain the structural relationship between natural gas and electricity going forward through time.

Figure 4-2 details NorthWestern's average annual electricity price forecast along with the December 2015 Medium price forecast update provided by the NWPCC and the 2013 average annual electricity forecast. NWPCC does not include a carbon price in its 2015

electric forecast. For comparison purposes, NorthWestern removed carbon from the electricity forecast from both the 2013 and 2015 Plans.

Figure 4-2 Electricity Price Forecast Comparisons

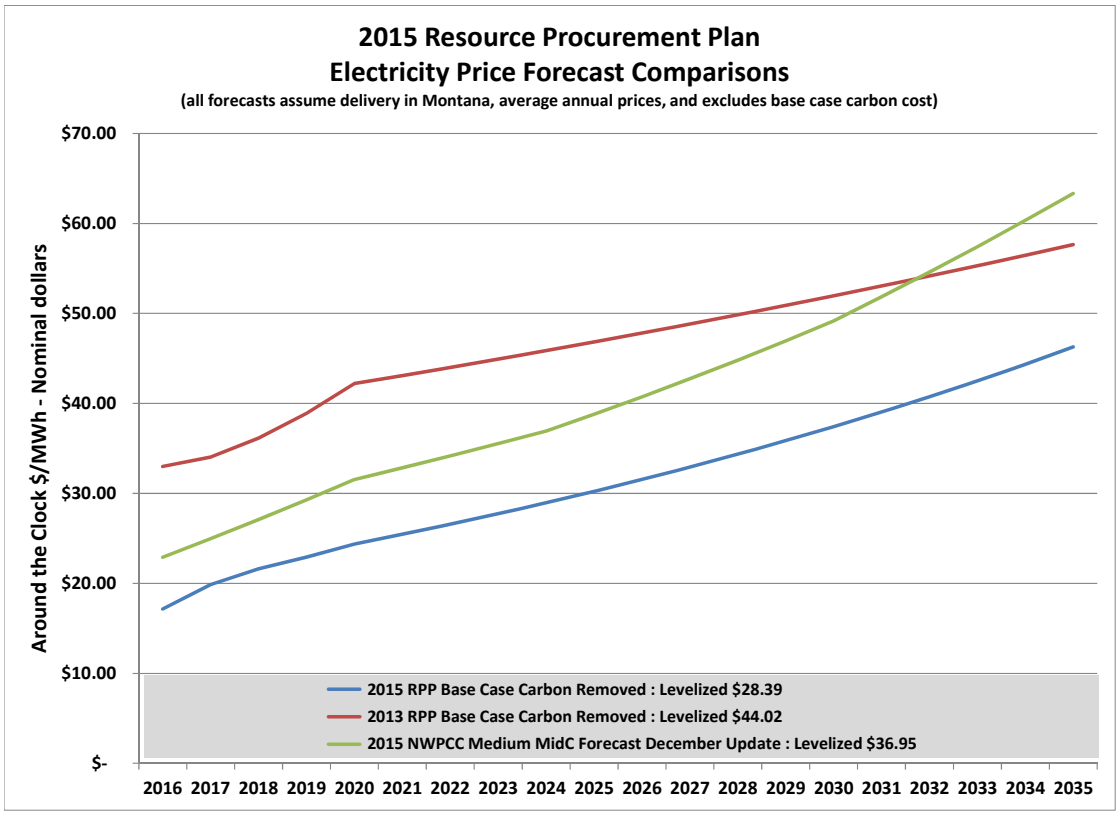


Table 4-1 details the mean heavy load, light load, and around the clock electric and natural gas price forecasts that are modeled in PowerSimm. The electricity prices include the base carbon price forecast that begins in 2022 and results in a significant increase in market prices for electric power and no impact to natural gas prices. The carbon price forecast is discussed in greater detail in Chapter 6.

Table 4-1 Base Case Electricity and Natural Gas Price Forecasts (Including base case carbon price for electricity)

Mean Electricity & Natural Gas Price Forecasts				
Montana Delivery (includes base case carbon cost for electricity)				
	HL - On Peak	LL - Off Peak	Around the Clock	Natural Gas
Year	($/MWh - Nominal)	($/MWh - Nominal)	($/MWh - Nominal)	($/MMBTu - Nominal)
2016	$19.38	$14.19	$17.10	$2.28
2017	$22.27	$16.91	$19.91	$2.63
2018	$24.18	$18.66	$21.75	$2.84
2019	$25.73	$19.85	$23.14	$3.00
2020	$27.34	$21.30	$24.68	$3.14
2021	$28.60	$22.31	$25.83	$3.24
2022	$41.91	$35.36	$39.03	$3.36
2023	$43.78	$36.95	$40.77	$3.47
2024	$45.72	$38.60	$42.59	$3.60
2025	$47.74	$40.33	$44.48	$3.72
2026	$49.85	$42.13	$46.45	$3.86
2027	$52.04	$44.01	$48.51	$4.00
2028	$54.33	$45.96	$50.65	$4.14
2029	$56.71	$47.99	$52.88	$4.29
2030	$59.19	$50.11	$55.19	$4.45
2031	$61.77	$52.31	$57.61	$4.61
2032	$64.46	$54.61	$60.12	$4.78
2033	$67.26	$57.00	$62.75	$4.95
2034	$70.18	$59.49	$65.48	$5.14
2035	$73.21	$62.08	$68.32	$5.33
20-Year Lev	$40.43	$33.32	$37.30	$3.52

Colstrip Coal Price Forecast

The Colstrip coal price forecast used estimated prices for 2016 through 2021. After 2021, the coal price is escalated throughout the remainder of the planning horizon using the 20-year average inflation escalation for Gross Domestic Product ("GDP") as provided by the U.S. Bureau of Economic Analysis ("BEA"). Table 4-2 details the projected coal forecast. Coal price was escalated using GDP because coal prices from the Rosebud mine are tied more closely to costs of production under provisions of a negotiated term contract spanning multiple years.

Table 4-2 Colstrip Coal Price Forecast

Colstrip Coal Price Forecast	
Year	($/ton - Nominal)
2016	$23.60
2017	$23.47
2018	$22.52
2019	$24.61
2020	$23.80
2021	$27.60
2022	$24.07
2023	$24.55
2024	$25.04
2025	$25.55
2026	$26.06
2027	$26.58
2028	$27.11
2029	$27.65
2030	$28.20
2031	$28.77
2032	$29.34
2033	$29.93
2034	$30.53
2035	$31.14
20-Year Lev	$25.64

Renewable Energy Credits

The Montana Renewable Resource Standard, commonly referred to as RPS, requires that NorthWestern procure 15% of its annual supply from eligible renewable resources, such as wind, solar, biomass, and small hydroelectric. NorthWestern utilizes the renewable energy credits from these eligible renewable resources to satisfy its RPS obligation.

To date, NorthWestern has fulfilled its obligation through the use of RECs from owned and contracted resources. However, NorthWestern expects that it will need to acquire additional resources or RECs to meet its obligations under the RPS within the 20-year

planning horizon. Contracted resources provide both energy and associated environmental attributes, and NorthWestern has not needed to purchase additional RECs to satisfy its RPS obligation. The market for RECs in Montana is illiquid, with limited information, and few market participants due to the fact that NorthWestern bears primary responsibility for Montana renewable standards. NorthWestern's forecast of future prices for RECs is provided in Table 4-3.

It is difficult to construct a long-term estimate of REC prices with a high level of confidence. Estimates of REC prices are based upon broker quotes that do not extend more than a couple years into the future. An REC price increase of $0.25/REC/year was employed where we assumed an annual increase to provide a modest level of price escalation over the 20-year planning horizon. If a more active market for RECs develops, NorthWestern will presumably be in a better position to forecast REC prices applicable to RECs for use in Montana with a higher level of confidence.

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Table 4-3 Renewable Energy Credit Price Forecast

REC Price Forecast	
Year	($ / REC - Nominal)
2016	$0.65
2017	$0.90
2018	$1.15
2019	$1.40
2020	$1.65
2021	$1.90
2022	$2.15
2023	$2.40
2024	$2.65
2025	$2.90
2026	$3.15
2027	$3.40
2028	$3.65
2029	$3.90
2030	$4.15
2031	$4.40
2032	$4.65
2033	$4.90
2034	$5.15
2035	$5.40
20-Yr Lev	$2.48

Besides commodity prices, other inputs to the PowerSimm analysis for NorthWestern are shown in Table 4-4 below. An inflation rate of 2.0% per year is used to scale current costs (e.g. generator variable operating costs) to future year (nominal) values. This is provided by the BEA and is the average of the 20-year quarterly percentage changes in GDP. NorthWestern's nominal weighted average cost of capital ("WACC") is used to discount all costs back to present value, in order to compare portfolio cash flows in the future.

Table 4-4 Fundamental Inputs to PowerSimm Analysis

Fundamental Inputs to PowerSimm Analysis for NorthWestern Energy

Input	Value
Inflation	2.0%/year
Weighted average cost of capital (WACC)	7.03%
RPS compliance	15% of retail sales
Load growth	0.8%/year average (net of DSM)

Table 4-5 provides the WACC used in this Plan. NorthWestern is maintaining the same capital structure (48% debt and 52% equity) and cost of equity (10%) that was used in the 2013 Plan. The incremental cost of debt is updated at 4.29% to reflect current financial conditions.

Table 4-5 Weighted Average Cost of Capital

NorthWestern WACC			
	Rate	Structure	Weighted Cost
Cost of Equity	10.00%	48.00%	4.80%
Incremental Cost of Debt	4.29%	52.00%	2.23%
		WACC / ROR	7.03%

CHAPTER 5
ENVIRONMENTAL

Environmental Trends that Influence the 2015 Plan

Introductory Statement

Environmental considerations continue to be a critical aspect of NorthWestern's resource planning process. We are committed to providing utility services that cost-effectively meet our customer's needs, while protecting the quality of the environment. We are vigilant in monitoring the impacts of our operations on the environment, in complying with the spirit, as well as the letter, of environmental laws and regulations, and in responsibly managing the natural resources under our stewardship.

The electric utility sector is heavily regulated by state and federal environmental laws such as the Clean Air Act, the Clean Water Act, the Endangered Species Act, the Migratory Bird Treaty Act, and laws regulating waste generation and disposal. Title 69, Chapter 8 of the Montana Code, Electric Utility Industry Generation Reintegration, also includes environmental requirements we must consider.

Greenhouse Gas Emissions

No single law or public policy issue has had as great an influence on resource planning as the Clean Air Act. The current attempt to regulate greenhouse gas ("GHG") emissions from existing electric generating units vividly demonstrates the potential impacts of the Act and has injected substantial uncertainty into the planning process. Efforts by the U.S. Environmental Protection Agency ("EPA"), states, and others to regulate GHGs have created risks which our planning processes have prudently incorporated in past planning cycles. For example, in 2013, NorthWestern's planning included a proxy cost for carbon emissions, specifically a carbon tax, implemented within the planning horizon.

Coal-fired generating plants are under particular scrutiny due to their level of GHG emissions. In Montana, we have a 30% joint ownership interest in Unit 4 of the coal-fired Colstrip electric generating plant. Talen Energy has a 30% joint ownership interest in Colstrip Unit 3. We have a risk sharing agreement with Talen Energy regarding the operation of Colstrip Units 3 and 4, in which each party receives 15% of the respective combined output and is responsible for 15% of the respective operating and construction costs, regardless of whether a particular cost is specified to Unit 3 or Unit 4. Three carbon price scenarios were modeled as part of this Plan to incorporate the risk associated with GHG emissions and the possible associated effect on resource optimization. Colstrip is assumed economically viable under the modeling scenarios.

On October 23, 2015, the final standards of performance to limit GHG emissions from new, modified, and reconstructed fossil fuel generating units and from newly constructed and reconstructed stationary combustion turbines were published in the Federal Register ("FR"). The standards reflect the degree of emission limitations EPA believes are achievable through the application of their best systems of emission reduction which EPA determined have been demonstrated for each type of unit.

In a separate action that dramatically affects existing power plants, the final rule titled, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Generating Units" was published in the FR on the same day. This rule establishes guidelines for states to follow in developing plans to reduce GHG emissions from existing electric generating units under Section 111(d) of the Clean Air Act. EPA refers to this rule as the Clean Power Plan ("CPP"). The CPP specifically establishes carbon dioxide ("CO_2") emission performance rates for fossil-fuel fired electric utility steam generating units and stationary combustion turbines. States have the option to develop their own implementation plans or adopt a federal implementation plan. The EPA gave states the

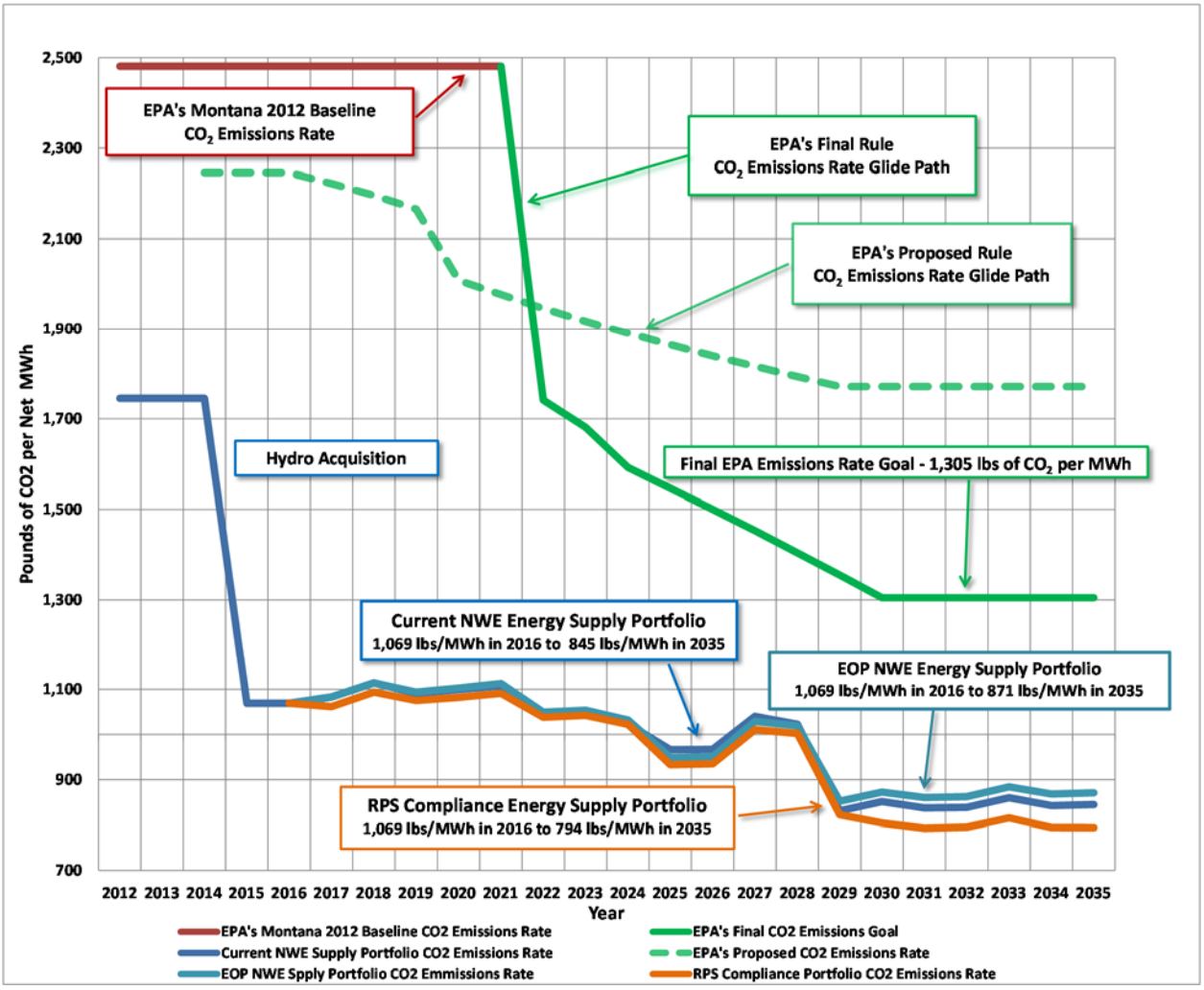
option to develop compliance plans based on CO_2 emissions rates (pounds ("lbs.") of CO_2 per MWh) or CO_2 mass (tons) emissions. The CPP establishes dates by which states are required to submit plans with initial plans due to EPA by September 2016, with the option to seek additional time to finalize state plans by September 2018.

The U.S. Supreme Court issued a stay of the implementation of the final CPP on February 9, 2016. The stay will remain in effect until the U.S. Court of Appeals enters a decision on the substantive challenges to the CPP and the Supreme Court either denies a petition for certiorari following that decision or enters a judgment following grant of a petition for certiorari. We are monitoring this situation closely and are hopeful EPA takes this opportunity to address Montana's serious concerns with the 47% reduction required in the final CPP and recognize the low carbon intensity of the portfolio we have assembled and reward rather than punish our customers for their low carbon energy use. The stay does not however alleviate uncertainty from a planning perspective.

The 2030 rate-based requirement in the CPP for Montana is 1,305 lbs. CO_2/MWh resulting in about a 47% CO_2 emissions rate reduction from the 2012 baseline emissions rate calculated by EPA. A mass-based plan would require a reduction of about 41% from the 2012 baseline mass emissions level calculated by EPA for Montana.

The figure below depicts the changes from the draft and final versions of the CPP and a comparison of EPA's requirements for "existing sources" (those that commenced construction on or before January 8, 2014) to NorthWestern's estimate of CO_2 emissions from our existing resource supply portfolio, EOP, and RPS Compliance portfolio.

Figure 5-1 Implications of the CPP



Unlike many other states, Montana's obligation to reduce carbon emissions dramatically increased from the draft to the final CPP, an increase from about 21% to 47%. As is indicated in the figure, with the acquisition of the hydro units, the carbon emissions rate of our Montana supply portfolio fell significantly. The CO_2 emissions rates of our existing portfolio, EOP, and RPS Compliance portfolios are currently well below the 2030 requirement for Montana established by EPA in the CPP. The following table shows the estimates of CO_2 emissions from the Current plus Market, EOP, and RPS Compliance scenarios. Estimated variations from year to year are due to maintenance cycles at Colstrip,

market purchases, and the expiration of contracts with fossil-fueled facilities in 2024 and 2028 and Judith Gap in 2026.

Table 5-1 Estimated EOP Carbon Emissions with CPP Regulated Sources

NorthWestern Estimated Carbon Emissions ($lbs\ of\ CO_2$ per MWh)			
YEAR	Current plus Market	EOP	RPS Compliance
2016	1069	1069	1069
2017	1083	1083	1061
2018	1114	1114	1094
2019	1091	1094	1075
2020	1099	1103	1082
2021	1108	1112	1091
2022	1043	1049	1038
2023	1047	1054	1042
2024	1023	1032	1022
2025	966	949	933
2026	967	951	935
2027	1040	1029	1011
2028	1022	1019	1002
2029	831	852	822
2030	852	873	805
2031	838	860	793
2032	839	862	795
2033	860	884	816
2034	843	868	794
2035	845	871	794

In its current form, the CPP does not recognize portfolio-based carbon emissions rates. The CPP instead focuses on unit specific emissions rates to calculate state emissions requirements.

On October 23, 2015, EPA also published in the FR a proposed rule titled, "Federal Plan Requirements for Greenhouse Gas Emissions from Electric Utility Generating Units Constructed on or Before January 8, 2014; Model Trading Rules; Amendments to Framework Regulations". In this action, EPA proposed a federal plan that would be imposed if a state fails to submit a satisfactory plan under the CPP. The federal plan proposal includes a "model trading rule" that describes how the EPA would establish an emissions trading program as part of the federal plan to allow affected units to comply with the emission rate requirements. EPA proposed both an emission rate trading plan and a mass-based trading plan and indicated that the final federal rule will elect one of the two options. We are working with other industry leaders and have filed comments on these draft regulations.

Despite the Supreme Court's decision to stay the CPP, there remains significant risk regarding the uncertainty of Montana's ultimate disposition of carbon emissions reductions. This risk is prudently included in the modeling scenarios used in the Plan for determining future portfolio needs.

Summary of Key Colstrip Environmental Risks

Regional Haze Rule

The EPA's regional haze rule, finalized in 1999, requires states to develop and implement plans to improve visibility in certain national park and wilderness areas. On June 15, 2005, the EPA issued final amendments to its Regional Haze Rule. These amendments require emission controls known as the Best Available Retrofit Technology ("BART") for emissions of certain pollutants that have the potential to impact visibility. These pollutants include fine particulate matter ("PM"), nitrogen oxides ("NO_X"), sulfur dioxide ("SO_2"), certain volatile organic compounds, and ammonia. States were given until December 2007 to develop implementation plans to comply with the Regional Haze Rule. Montana did not

develop a plan to comply, and EPA subsequently developed a Federal Implementation Plan ("FIP") for Montana in September of 2012. The FIP included requirements for upgrades to Colstrip Units 1 &2 but did not include immediate requirements for Units 3 & 4.

The Regional Haze Rule, which requires "reasonable progress" analyses every 5 years, may drive incremental SO_2 and NOx reductions at Colstrip in the future. We assume Colstrip Units 3 and 4 will not require additional material upgrades to comply with the Regional Haze Rule during the 20-year planning period. This information was factored in to the modeling scenarios for this Plan.

Mercury and Air Toxics

The Mercury and Air Toxics Rule ("MATS") became effective April 16, 2012. The MATS rule requires that new and existing coal-fueled facilities achieve emissions standards for mercury, acid gases, and other hazardous pollutants. Existing sources were required to comply with the new standards by April 16, 2015. The Colstrip facility requested a one-year extension to become compliant as allowed by the rule to allow time for all the units at Colstrip to become compliant as a facility. That request was granted, and the Colstrip facility needs to be compliant by April 16, 2016.

The existing mercury control system at the Colstrip facility was installed to comply with Montana's mercury rule, which is more stringent than the federal rule. Additional equipment on Units 1 and 2 was required to comply with the particulate matter requirements of the rule, and installation of this equipment will be complete prior to the April 16, 2016 compliance deadline. Units 3 and 4 did not require additional equipment. Therefore, we assume in the Plan there will be no additional material upgrades required for additional MATS compliance obligations for Colstrip.

Coal Combustion Residuals

Coal Combustion Residuals ("CCRs") including coal ash, are byproducts from the combustion of coal in power plants. CCRs have historically been considered exempt wastes under an amendment to the Resource Conservation and Recovery Act ("RCRA"). However, the EPA issued a final rule in April 2015 to regulate CCRs as a nonhazardous waste under Subtitle D of RCRA and establish minimum nationwide standards for the disposal of coal combustion residuals.

A plan is being developed by Talen Energy to comply with the CCR Rule within the required timeframes. The compliance plan will involve closing some ponds, installing liners, separating solids from slurry, ongoing monitoring, and a final remedial plan.

NorthWestern's share of the estimated capital costs for compliance is expected to be approximately $27 million, a significant portion of which will be incurred over seven or more years depending on the amount of ash waste. These costs were incorporated in the cost structure for Colstrip in this Plan.

New Source Review ("NSR") / Prevention of Significant Deterioration ("PSD")

There is ongoing litigation regarding alleged Clean Air Act violations at Colstrip. The Plaintiffs allege some equipment changes made at Colstrip between 2001 and 2012, (a) have increased emissions of SO_2, NO_x and particulate matter and (b) were "major modifications" subject to permitting requirements under the Clean Air Act (New Source Review). On December 1, 2015, the U.S. Magistrate Judge Jeremiah C Lynch heard oral arguments in the U.S. District Court for the District of Montana on motions for summary judgment pending before that court on Case 1:13-cv-00032-DLC-JCL which involves a Sierra Club and Montana Environmental Information Center case against the Colstrip Owners. The pending motions are as follows: (1) Plaintiffs' Motion for Partial Summary

Judgment Regarding Routine Maintenance, Repair and Replacement; (2) Plaintiffs' Motion for Partial Summary Judgment that the redesign Projects for the Unit 1 and 4 Turbines and the Unit 1 Economizer Were Not "Like-Kind Replacements"; (3) Defendants' Motion for Partial Summary Judgment Regarding Use of "Actual-To-Potential" Emissions Test; (4) Plaintiffs' Motion for Partial Summary Judgment Regarding the Allowable Period From Which to Select a Baseline for the Unit 3 Reheater Project; (5) Defendants' Motion for Partial Summary Judgment on Baseline Selection; (6) Defendants' Motion for Partial Summary Judgment on Emissions Calculation for Alleged Aggregated Turbine and Safety Valve Project. Judge Lynch issued a proposed decision in December 2015. The proposed decision found as follows on each of the motions identified above: (1) Denied, (2) Denied, (3) Granted, (4) Granted in Part and Denied in Part, (5) Granted in Part and Denied in Part, and (6) Granted. A final decision is expected in the near future. Due to these rulings, NorthWestern did not feel it was appropriate to include any additional material cost-related impacts for NSR/PSD related issues in our modeling scenarios. Should the final decision vary significantly from the proposed decision, we will review our modeling and determine if any changes are necessary.

National Ambient Air Quality Standards ("NAAQS")

The Clean Air Act sets allowable ambient air quality standards for six "criteria" pollutants. The rule requires periodic review of the science used to establish the standards and the standards themselves. With each review, the standards are compared to ambient air quality in each state or part of each state to determine if the state or part of each state is in "attainment" or "non-attainment." If a state contains any areas of "non-attainment", the state must propose a plan and schedule to reduce emissions to achieve attainment. Currently, the Colstrip area of Montana is in attainment for all criteria pollutants. Further reductions in emissions resulting from compliance with MATs are expected to keep the Colstrip area in attainment with future NAAQS reviews/revisions. NorthWestern does not

expect additional material cost impacts related to NAAQS compliance. Therefore, we did not include any additional costs related to NAAQS compliance in our modeling scenarios.

Wastewater

In August 2012, Talen Energy, the Colstrip Plant Operator, and the Montana Department of Environmental Quality ("MDEQ") signed an Administrative Order of Consent Regarding Impacts from Wastewater Facilities ("AOC"). The AOC sets up a comprehensive program for investigation, interim response, and remediation of any wastewater seepage or spills, and closure of the holding ponds. The AOC provides for preparation of a Site Report for any identified area of the plant site where seepage or spills have occurred. A separate plan for closure of the wastewater ponds must be prepared and submitted by August 2017. This closure plan will include requirements for wastewater pond closure which must be completed when operations cease. No additional costs associated with the AOC for Colstrip 4 are included in our modeling scenarios in this Plan. Costs associated with compliance with the CCR Rule, which addresses the same facilities associated with the AOC, are discussed in the CCR section above.

Summary of Key Hydro Risks

Hydroelectric License Compliance

NorthWestern's hydroelectric facilities consist of ten generating plants and one storage reservoir that are operated under three licenses from the Federal Energy Regulatory Commission ("FERC"). FERC typically issues licenses for 40 to 50 years. The nine developments on the Missouri and Madison Rivers operate under one license: FERC Project #2188 which has a term through 2040. The Mystic Project (FERC #2301) license expires in 2050, and the Thompson Falls Project (FERC #1869) expires in 2025.

For the purpose of long-term resource planning, NorthWestern does not assume material changes to the licenses, such as changes in ownership or operational changes affecting generation output, over the planning period.

Relicensing

The FERC licenses require that the hydroelectric projects be operated to reflect the Federal Power Act's mandate to give equal consideration to generation and non-power benefits including fisheries, wildlife, public recreation, flood control, cultural resources, and water quality. NorthWestern's licenses have specific parameters regarding reservoir elevations, minimum downstream river flows, and river flow rate changes. In addition, extensive environmental Protection, Mitigation, and Enhancement ("PM&E") programs must be implemented over the terms of the licenses. NorthWestern complies with these obligations through a collaborative and consultative strategy with the resource agencies and other stakeholders which involves funding Technical Advisory Groups, monitoring studies, effects assessments, and mitigation projects. All costs associated with license compliance are incorporated in the planning process.

The listing of bull trout under the Endangered Species Act in 1999 led to the installation of a fish ladder at Thompson Falls in 2010 (after numerous years of required consultation and study) and ongoing monitoring and evaluation of project impacts on fisheries. Relicensing of the Thompson Falls Project will involve a new and focused examination of power generation and all non-power benefits to reassess the aforementioned "equal consideration" balance. NorthWestern anticipates initiating this process in the 2018-2020 timeframe. It will involve various studies with significant agency and public input. While the relicensing process has the potential to decrease available generation capacity and increase requirements for proposed measures and plans to protect, mitigate, or enhance environmental resources, no reduction of the available capacity or operational flexibility

has been assumed in this planning effort since the primary resource potentially affected by operations (fisheries) has already been mitigated for and actively managed.

River Flow and Reservoir Management

For purposes of this planning process, NorthWestern used the 2010 to 2014 historical five year average as the basis for projecting monthly hydroelectric generation.

The FERC licenses have various requirements for river flows and reservoir levels. NorthWestern operates the hydro facilities to maximize generation within the conditions and constraints of the FERC hydro licenses and in pursuing required protection, mitigation, and enhancement of river and public recreation resources. An example is the Lower Madison River Pulse Flow Protocol, which affects Hebgen and Madison developments.

The pulse flow protocol requirement is designed to protect lower Madison River fisheries. It involves releasing water from Ennis Lake (Madison Dam) at specified times based on a predictive model that projects the temperature of the water at Blacks Ford in the lower Madison River. There is documented fish mortality if the river temperature reaches 82.5 degrees Fahrenheit. The goal of the Pulse Flow Protocol is to maintain the lower Madison River below 80 degrees Fahrenheit during the summer months while balancing the need to keep upstream Hebgen Reservoir (which supplies water for Ennis Lake refill and downstream minimum pulse flows) at a level suitable for recreation and maintaining FERC license-required downstream minimum flows. The Madison Plant hydraulic capacity is approximately 1,400 cubic feet per second (about 8 MW). When pulse flow requirements are above that level, the excess water is spilled. The pulse flow protocol is constantly monitored and updated for fisheries protection while maximizing water conservation. The pulse flow program has been very effective in protecting the lower Madison River trout fishery while not negatively impacting generation output.

Hydrologic Uncertainty

Hydrologic characteristics (e.g., runoff rate and timing, precipitation events, weather conditions) vary from year to year and may differ from the assumptions used in this Plan. For example, 2012 was an exceptional hydro generation year due to above average precipitation. While 2015 was a low water year, output from the hydro assets slightly exceeded forecasted output as set forth in the hydro filing. Low precipitation will, at times, cause hydro generation to be less than average.

Diversification in different watersheds over a large geographic area and conservative assumptions regarding generation output can help reduce risks associated with changes in hydrologic characteristics. The modeling scenarios in the Plan incorporate risk associated with varying hydrologic characteristics.

Other Environmental Considerations

Wind Generation

In order to comply with Renewable Portfolio Standards, NorthWestern has a substantial amount of intermittent renewable generation in its portfolio, including owned wind generation (Spion Kop), qualifying facilities, and power purchase agreements with wind facilities.

Intermittent resources create environmental risks, including impacts to wildlife and wildlife habitat. Intermittent resources also require backup from dispatchable fossil-based generation which also has environmental risk.

In the development and management of the Spion Kop Wind Farm, NorthWestern follows the U.S. Fish and Wildlife Service's ("USFWS") Land-Based Wind Energy Guidelines which are voluntary guidelines for addressing wildlife conservation concerns. The Bird

and Bat Conservation Plan for the project is being implemented through coordination and consultation with the Spion Kop Technical Advisory Committee ("TAC") made up of representatives of Montana Fish, Wildlife and Parks, the USFWS, Montana Audubon, the University of Montana, and NorthWestern. Post construction monitoring is underway to determine impacts of operations on birds and bats. Results of the monitoring will help inform the TAC of any operational or other mitigation that may be necessary. At this time we do not foresee additional material mitigation at our wholly owned wind facility. NorthWestern does not assume environmental liabilities or responsibilities associated with Qualifying Facilities ("QFs") and other non-owned wind resources.

The USFWS has regulatory authority to administer the following regulations that could affect siting or operating a wind farm in Montana: the Migratory Bird Treaty Act, the Bald and Golden Eagle Protection Act, the Endangered Species Act as amended, the National Wildlife Refuge System Improvement Act of 1997, and the National Environmental Policy Act. Siting and operating wind generation facilities in Montana are also subject to the Management Plan and Conservation Strategies for Sage Grouse. While NorthWestern does not assume environmental liabilities or responsibilities associated with QFs and other non-owned wind resources, new wind generation will be subject to the aforementioned regulations.

Dave Gates Generating Station ("DGGS")

NorthWestern operates DGGS under a Title V Operating Permit (Montana Air Quality Permit) and associated Acid Rain Permit. NorthWestern operates water injection and selective catalytic reduction ("SCR") as NO_X control equipment for the combustion turbine generating units. Catalytic oxidizers are used for carbon monoxide ("CO") control equipment. A Continuous Emission Monitoring System ("CEMS") is installed at the combined stacks for each generating unit. The CEMS measures NO_X and CO concentrations and the Data Acquisition and Handling System ("DAHS") calculates

lbs./hour of each pollutant. This information is used to assure proper SCR, water injection, and catalytic oxidizer operation and to assess compliance with the applicable standards.

Basin Creek

The nine natural gas-fired Caterpillar reciprocating internal combustion engines ("RICE") at Basin Creek totaling 52.5 MW of generating capacity are permitted under a Title V Permit and a Montana Air Quality Permit. Emission limits apply to NO_X, CO and volatile organic compounds ("VOC"). The engines combust pipeline-quality natural gas and incorporate an oxidation catalyst for control of CO, VOC, and Hazardous Air Pollutant ("HAP") emissions. Combustion of pipeline quality natural gas in lean-burn RICE inherently results in low NO_X emissions, and the limit of 34,200 combined operating hours during any 12-month rolling period also limits NO_X emissions. Further, add-on controls for SO_2 and particulate matter less than 10 microns aerodynamic diameter ("PM_{10}") emissions are not required as Basin Creek is combusting only pipeline quality natural gas, which, similar to the previously discussed inherent NO_X control, results in reduced SO_2 and PM_{10} emissions. NorthWestern does not own the Basin Creek facility. However, dispatch of the units is controlled by NorthWestern under a long-term contract. We do not expect any material environmental costs associated with the long-term Basin Creek contract.

Transmission Line Permitting

New generation sources or changes to customer load may require new natural gas pipeline construction and/or new or upgraded electric transmission lines. NorthWestern is in the third year of a five-year project to upgrade a 69-kilovolt ("kV") transmission line to 161 kV to serve the ever-expanding load in the Big Sky, Montana area. The project took almost eight years to permit even though it was an existing line because the U.S. Forest Service required an Environmental Impact Statement.

Customer load in Stillwater County, Montana requires additional transmission. A new 100-kV transmission line from Chrome Junction to a substation near Nye is expected to be constructed under an exemption to the Montana Major Facility Siting Act as 75% of the landowners have already granted easements for the 54-mile project. Permits to cross public lands have been acquired from the State of Montana, U.S. Forest Service, and the Bureau of Land Management. Construction on the line is planned to begin in 2016.

CHAPTER 6
CARBON IMPACTS

Carbon Scenarios Included in Modeled Portfolios

Carbon Costs

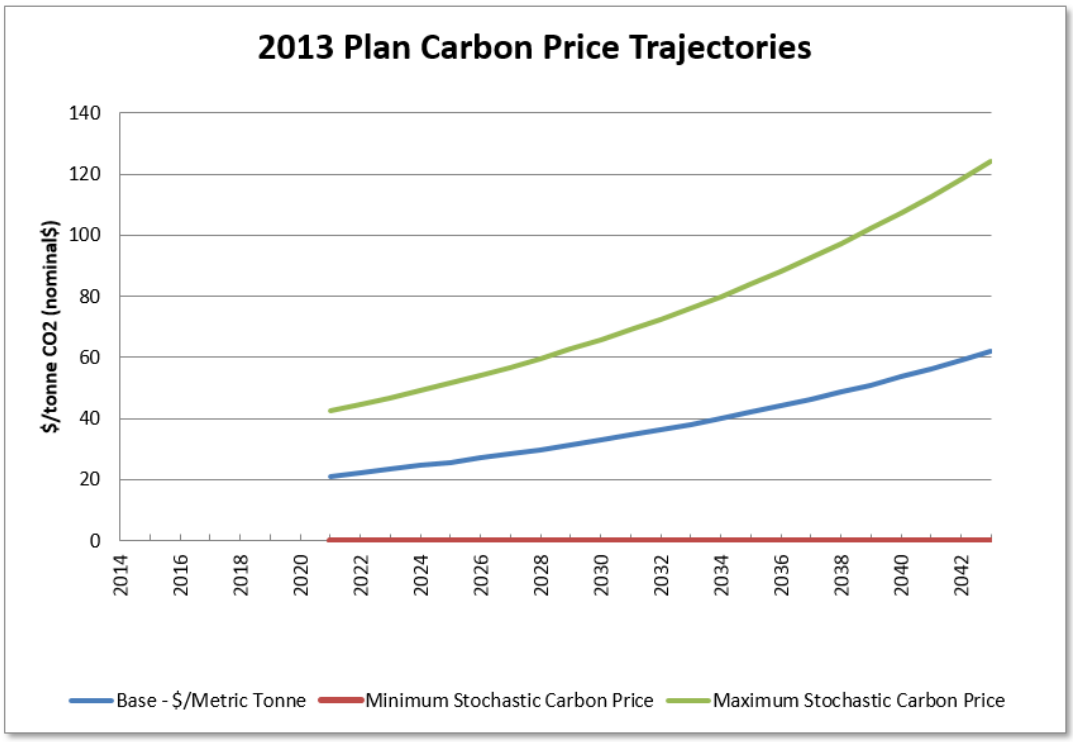
Estimates of future costs associated with regulation of CO_2 emissions from thermal power plants is an important consideration in terms of analyzing potential changes to resource costs, electricity market prices, and portfolio risk. Most electric utilities, including NorthWestern, consider future carbon cost uncertainty as a significant risk variable that should be considered and assessed through modeling. NorthWestern incorporates carbon risk in the evaluation of resource alternatives.

NorthWestern does not know the future costs of carbon emissions, as they will be largely dependent on what regulatory measures might be imposed as a means of controlling them. However, carbon cost estimates can be formulated from a diverse range of analytically supported opinions that are found in other utility resource plans, government proposals, and academic literature. The best approach to estimating the effects of carbon risks is to evaluate current and potential resource portfolios over a range of plausible futures to determine which resource portfolio(s) achieve a balance of acceptable cost and risk.

The 2013 Plan considered carbon costs in the context of the information provided in the 2013 EIA Annual Energy Outlook and in advance of the EPA 111(d) proposed rules for existing CO_2 emitting sources. In selecting the EIA GHG15 carbon case as the base carbon assumption, NorthWestern derived a base set of carbon pricing assumptions of $21.22/tonne ($/metric tonne - nominal) starting in 2021 and escalating annually at 5% over the 20-year planning horizon and through 2043. For stochastic modeling purposes, carbon price was varied above and below the annual base value according to a triangular

distribution in recognition of the high degree of uncertainty associated with the carbon price variable and how it might actually materialize over time (Figure 6-1). One hundred iterations of the model were executed to create a distribution of total portfolio cost where carbon cost, like other stochastic variables such as electricity and natural gas price, varied above and below the starting value defined by the forecast schedule. Values never went below zero.

Figure 6-1 2013 Plan Carbon Price Trajectories



The final EPA rules for implementation of the CPP were published August 3, 2015, and the schedule for states to submit implementation plans was set. States were required to submit initial plans for achieving GHG emission standards to EPA by September 2016. However, the U.S. Supreme Court recently issued a stay of the final rule to remain in effect until the challenge to the rule is either appealed and decided by the U.S. Supreme Court or

the U.S. Supreme Court declines to hear the appeal (see Volume 2, Chapter 4 for final CPP goals and NorthWestern's Motion to Stay).

NorthWestern relies on outside sources of carbon cost estimates to inform its planning and modeling. Prior resource planning cycles have recognized the Annual Energy Outlook as a guiding source of carbon cost planning information. The 2015 Annual Energy Outlook excluded projections of carbon prices, however. This left NorthWestern, its advisors, and its advisory group to identify and select carbon cost estimates without the use of information from EIA. The following sources were reviewed to inform NorthWestern's 2015 Plan:

- CO_2 Price Report, January, 2016 (Synapse Energy Economics, Inc.)
- PacifiCorp 2015 Integrated Resource Plan
- Xcel Energy 2015 IRP (Preferred PF)
- Puget Sound Energy 2015 IRP (low, mid, and high case)
- Portland General Electric 2015 Update

The carbon cost values from the reference list above plus NorthWestern's three projections of carbon costs are presented in Table 6-1.

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Table 6-1 CO_2 Cost Forecasts

Forecast Source	$/Short Ton CO_2 (Nominal $)																
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
NWE - Base				20.00	20.83	21.69	22.59	23.53	24.51	25.53	26.59	27.69	28.84	30.03	31.28	32.58	33.93
NWE - Low				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NWE - High				40.00	41.66	43.39	45.19	47.06	49.02	51.05	53.17	55.38	57.68	60.07	62.56	65.16	67.86
PacifiCorp - 2015		22.39	26.20	30.02	33.83	37.64	41.45	45.27	49.08	52.89	56.71	60.52	64.33	68.14	71.96	75.77	79.58
PGE - 2015 Update		12.04	12.78	13.66	14.68	15.84	17.13	18.57	20.14	21.85	23.69	25.68	27.80	30.06	32.46	34.99	37.67
PSE - 2015 Low	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PSE - 2015 Mid	16.59	17.85	19.22	20.68	22.26	23.96	25.78	27.75	29.86	32.14	34.59	37.23	40.07	43.12	46.41	49.95	53.76
PSE - 2015 High		34.79	37.80	41.07	44.62	48.48	52.68	57.23	62.18	67.56	73.41	79.76	86.65	94.15	102.29	111.14	120.76
Synapse - 2016 High				28.72	30.46	32.27	34.13	36.06	38.05	44.31	50.80	57.54	64.52	71.76	79.27	87.04	95.10
Synapse - 2016 Med				22.97	24.31	25.69	27.12	28.60	30.12	31.69	33.32	34.99	39.81	44.81	49.99	55.36	60.92
Synapse - 2016 Low				17.23	18.45	19.72	21.03	22.38	23.78	25.23	26.72	28.26	29.86	31.51	33.21	34.96	36.78
Xcel - 2015	21.50	22.15	22.81	23.49	24.20	24.92	25.67	26.44	27.24	28.05	28.89	29.76	30.65	31.57	32.52	33.50	34.50

To aid in the comparison of NorthWestern's three carbon price cases to other utility values, the pricing information from several recent utility planning documents shown in Table 6-1 has been plotted in Figure 6-2. NorthWestern has supplied three carbon price trajectories with carbon costs beginning in 2022 (Table 6-2). Each year after 2022 non-zero values were escalated using the same escalation rate that has been employed for other commodities in this Plan. The purpose of three pricing cases is to evaluate cost and risk over a plausible range of potential carbon price futures. Figure 6-2 illustrates the forecasted trajectories of NorthWestern's three pricing cases (in black) in comparison to other utility and non-utility values.

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Figure 6-2 CO_2 Cost Forecast Comparison

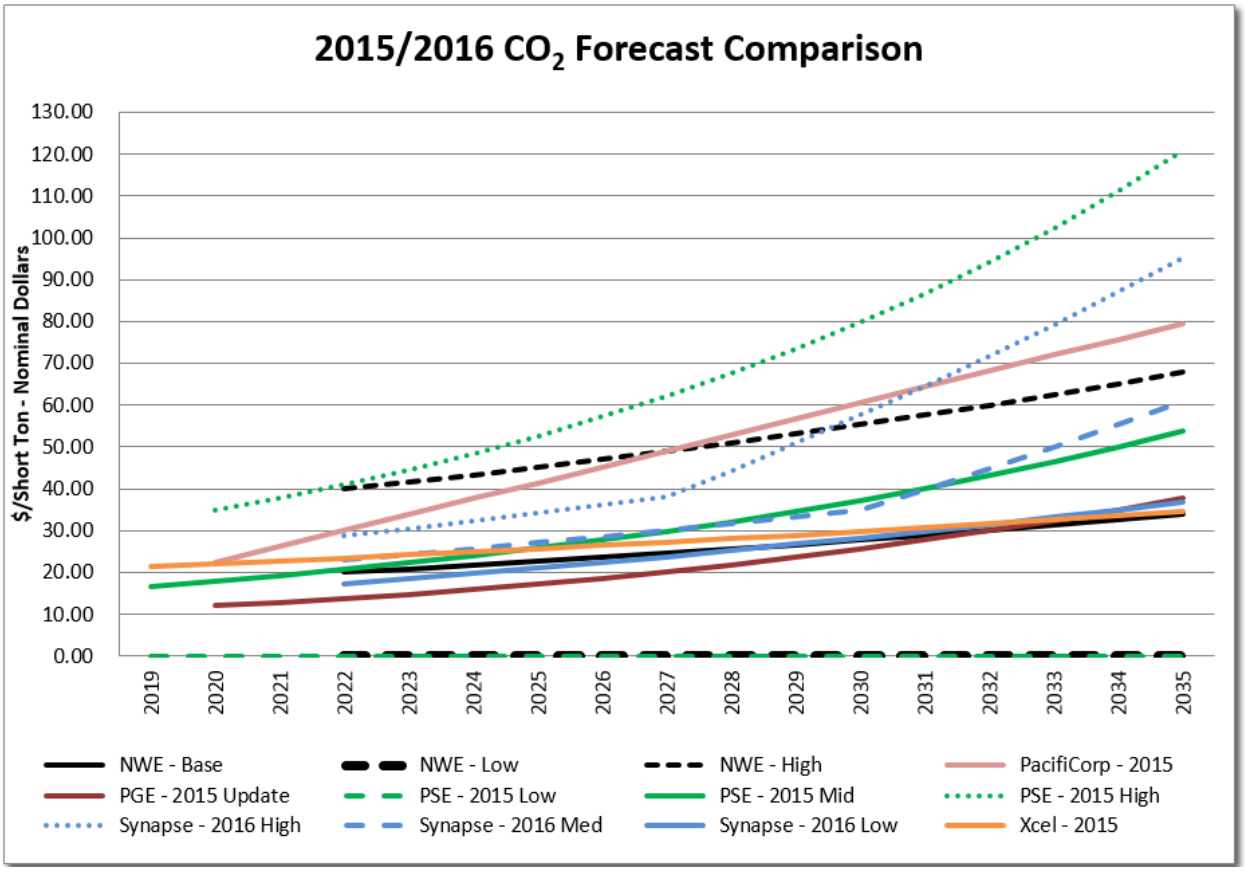

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Table 6-2 2015 Plan Carbon Price Forecast

2015 Plan Carbon Price Forecast			
	Carbon Penalty ($/ton - Nominal)	Carbon Penalty ($/ton - Nominal)	Carbon Penalty ($/ton - Nominal)
Year	base case	high case	low case
2016	$0.00	$0.00	$0.00
2017	$0.00	$0.00	$0.00
2018	$0.00	$0.00	$0.00
2019	$0.00	$0.00	$0.00
2020	$0.00	$0.00	$0.00
2021	$0.00	$0.00	$0.00
2022	$20.00	$40.00	$0.00
2023	$20.83	$41.66	$0.00
2024	$21.69	$43.39	$0.00
2025	$22.59	$45.19	$0.00
2026	$23.53	$47.06	$0.00
2027	$24.51	$49.02	$0.00
2028	$25.53	$51.05	$0.00
2029	$26.59	$53.17	$0.00
2030	$27.69	$55.38	$0.00
2031	$28.84	$57.68	$0.00
2032	$30.03	$60.07	$0.00
2033	$31.28	$62.56	$0.00
2034	$32.58	$65.16	$0.00
2035	$33.93	$67.86	$0.00
20 -Year Levelized:	$13.87	$27.75	$0.00

The application of the carbon cost adder in modeling is again defined as a stochastic variable in the PowerSimm software using a triangular distribution. Recognition of the uncertainty associated with carbon value is captured in the Monte Carlo routine which stresses the carbon value above and below the annual price projection over the 20-year simulation horizon. This allows us to observe portfolio performance over a plausible set of carbon price paths to evaluate a range of outcomes rather than simply choosing a single set of prices.

The carbon price trajectories shown in Table 6-2 are one of many possible price paths that could materialize. Carbon pricing is included as a risk variable in the portfolio simulations presented in Chapter 12 and is considered a base assumption in the 2015 Plan. In order to better understand the impact of this carbon pricing variable, two alternative carbon pricing cases have been included for comparison purposes to the base case. They include a zero carbon cost adder "low case" and a doubling of the base case value as a "high" carbon cost case. Specialty case portfolio runs were performed using the zero and high case carbon prices, and the results of these models are presented in Chapter 12.

In its comments to the 2013 Plan, the Commission directed NorthWestern to make changes to its methods and scope of evaluation of future carbon costs. Specifically, the Commission requested the following:

- A more rigorous evaluation of potential CO_2 costs in future filings;
- Evaluation of alternative CO_2 price trajectories;
- Alternative ways of defining the CO_2 price distribution; and
- Receipt of specific guidance on CO_2 from ETAC.

Based on these comments NorthWestern did the following:

1. NorthWestern solicited input from ETAC during 2015 for CO_2 pricing including the cost, timing, and methods of including carbon costs and received comments to address the use of a triangular distribution in the stochastic simulations;
2. NorthWestern identified and considered additional sources of price forecasts for CO_2 and shared them with ETAC;
3. NorthWestern employed a base case carbon pricing assumption and two alternatives including a zero carbon cost case and a high carbon cost case in the 2015 Plan; and
4. NorthWestern completed portfolio simulations for the base capacity plan using all three carbon pricing trajectories.

It should be noted that neither NorthWestern nor Ascend Analytics nor ETAC identified an appropriate alternative to the triangular distribution of carbon price in the stochastic models. However, the use of multiple pricing scenarios provides modeling results that allow an understanding of the impacts under different carbon price assumptions.

CHAPTER 7
RESOURCE ADEQUACY – REGIONAL MARKET

Resource Adequacy and the Regional Market Impacts

Background

On February 15, 2002 NorthWestern began providing service to retail customers without any owned generation assets to supply energy and load-serving capacity. Since NorthWestern did not own any generation resources at the time, it was forced to manage a market-based strategy based on purchase power agreements. A concerted program of resource acquisition over the past eight years has greatly reduced our reliance on the market and led to our current focused planning to address specific capacity needs and resource adequacy. Historically the Pacific Northwest has been dominated by excess capacity. However, continued load growth, substantial additions of intermittent wind resources, hydrologic flow restrictions, and planned coal retirements in the Pacific Northwest have reduced reserve margins to the point that the regional planning bodies are now concerned about meeting future capacity needs.

NorthWestern's previous resource plans did not directly address resource adequacy or planning reserve margins for several reasons. First, surplus capacity in the region was available to serve peak needs. Second, prior to the acquisition of the hydro assets, the gap between physical resource peaking capability and peaking resource need was so wide that it would have made the use of traditional capacity planning metrics of resource adequacy essentially meaningless. With the addition of the hydro assets to the resource portfolio, NorthWestern has reduced market dependence, and the gap between physical resource capability and peaking resource needs has been narrowed substantially. However, NorthWestern must still rely upon the market to meet its customers' needs during certain

hours, including peak load hours. Use of this strategy in light of current and forecast capacity conditions within the region requires reexamination.

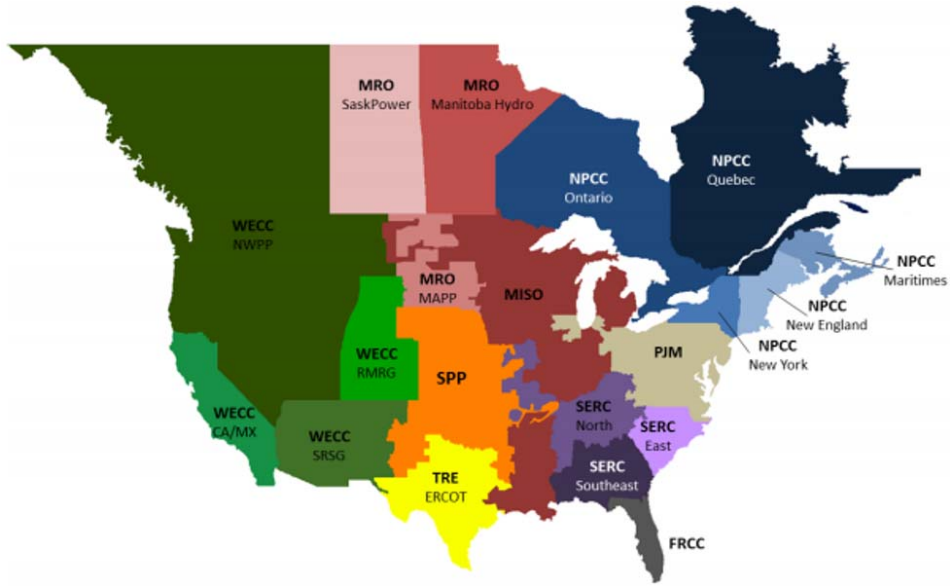
NERC Resource Adequacy

Within the WECC, there is no industry standard for the level of planning reserve margin a utility must carry, and an examination of different utilities reveals widely varying levels of reserve margins. However, it is clear that nearly all utilities possess at least some level of planning reserve margin. NERC develops and enforces reliability standards and annually assesses seasonal reliability for the North American bulk power system.

NERC Reference Reserve Margin

NERC's Reference Reserve Margin is equivalent to the Target Reserve Margin Level provided by the Regional/sub-regional's own specific margin based on load, generation, and transmission characteristics as well as regulatory requirements. If not provided, NERC assigned 15 percent Reserve Margin for predominately thermal systems and 10 percent for predominately hydro systems.[1]

Figure 7-1 NERC Reliability Assessment Areas



[1] http://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx

As shown in Table 7-1, the NERC reference margin level for NWPP-US, the region that includes NorthWestern, is 16.6%.

Table 7-1 NERC Reference Reserve Margin Levels

NERC ASSESSMENT AREA	NERC Reference Margin Level
WECC - Western Electricity Coordinating Council	
WECC-NWPP - United States	16.6%
WECC-NWPP - Canada	11.6%
WECC-RMRG	11.9%
WECC-SRSG	12.3%
WECC-CAMX	13.5%
MRO - Midwest Reliability Organization	
MISO	14.3%
MRO - Manitoba	12.0%
MRO - MAPP	15.0%
MRO - SaskPower	11.0%
SPP - Southwest Power Pool	13.6%
TRE - Texas Reliability Entity	
TRE-ERCOT	13.8%
NPCC - Northeast Power Coordinating Council	
Maritimes	15.0%
New England	16.7%
New York	17.0%
Ontario	19.0%
Québec	11.7%
RF - Reliability First - PJM	16.0%
SERC Reliability Corporation	
SERC-E	15.0%
SERC-N	15.0%
SERC-SE	15.0%
FRCC - Florida Reliability Coordinating Council	15.0%

Regional Resource Adequacy

In 2013, the NWPCC re-formed the Pacific Northwest Adequacy Forum into the Resource Adequacy Advisory Committee ("RAAC"). The RAAC produces an annual report on the adequacy of the Pacific Northwest power supply. The RAAC's most recent report shows that the region has adequate resources to meet its capacity needs through 2020. RAAC

estimates that the likelihood of a power supply shortage in 2020 is just under the 5% LOLP standard set by the NWPPC in 2011. By 2021, the LOLP jumps to over 8% due to the planned retirements of the Boardman and Centralia-1 coal plants (1,330 MW nameplate capacity). The implication of the 8% LOLP is that the region will need to add peaking resources to maintain regional resource adequacy. The NWPCC concluded that the region would have to add 1.15 gigawatts ("GW") of gas-fired generation by 2021 to bring the LOLP back to 5%. Alternatively, the region could add 12.7 GW[2] of solar PV which, when combined with the storage capability of the Pacific Northwest hydropower system, would also bring the LOLP back to 5%. No amount of wind power, even in combination with the Columbia River hydropower system, was found to achieve a 5% LOLP.[3] The work of the RAAC feeds directly into the NWPCC's power planning efforts.

The NWPCC recently adopted the 7th Plan[4]. In prior plans, the primary emphasis was to meet the annual energy requirements of the region. In the 7th Plan, the NWPCC has switched the focus from energy to capacity planning. The future needs of the region can no longer be adequately addressed by only evaluating average annual energy requirements. Planning for capacity to meet peak load and flexibility to provide within-hour load-following and regulation services must also be evaluated and addressed regionally and by NorthWestern specifically.

Historically, NorthWestern has been able to take advantage of regional surplus capacity to maintain resource adequacy. However, as discussed above, the regional capacity surplus is expected to diminish over time and directly impact the supply-demand relationship in the region. NorthWestern as a market taker is at greater risk as the regional capacity surplus

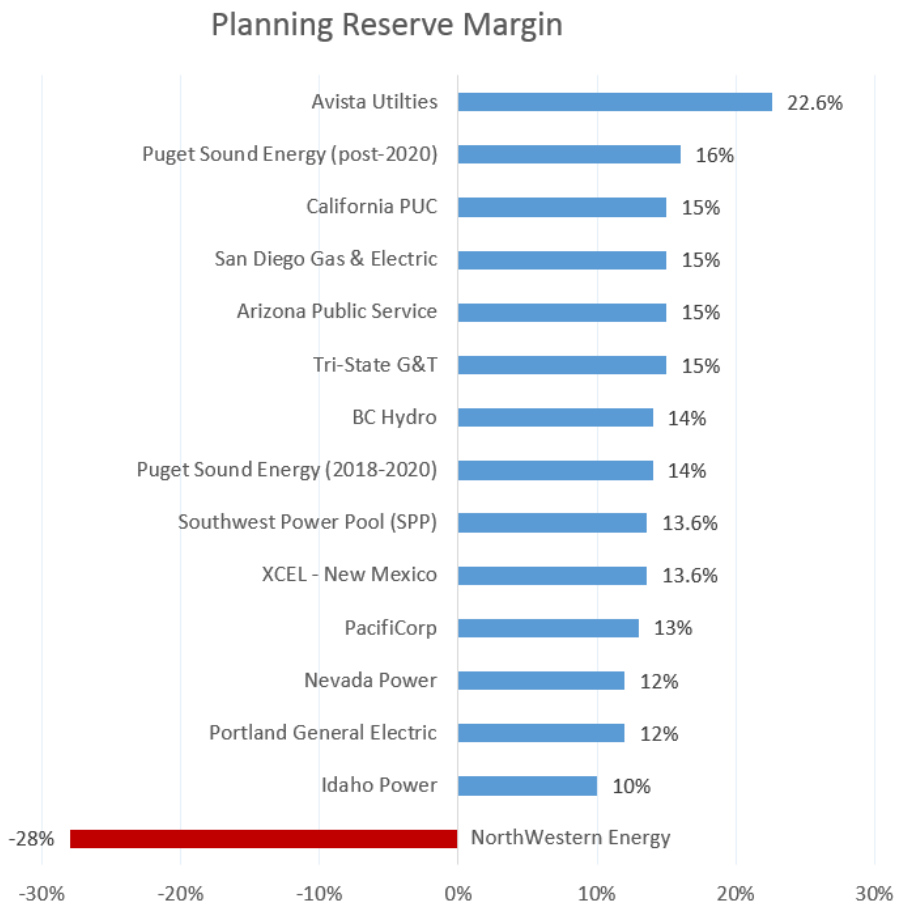
[2] The NWPCC estimated that total installed capacity of solar PV in the U.S. is currently 15.9 GW.

[3] 10 GW of wind power achieved a 6.9% LOLP.

[4] http://www.nwcouncil.org/energy/powerplan/7/plan/

diminishes. Figure 7-2 below shows a range of planning reserve margins for regional utilities and other select entities. NorthWestern's current physical reserve margin, which excludes market, is significantly less than zero. This is not new information, but it does highlight NorthWestern's need to address its current lack of capacity.

Figure 7-2 Planning Reserve Margins for Selected Power Companies



Regional Market Development and Regulatory Change

Energy Imbalance Markets

The development of EIMs in the West has been a topic of discussion and analysis for several years. Despite the reference to "Imbalance," resources in an EIM are dispatched economically regardless of whether there is an imbalance to correct. EIMs share some characteristics of RTOs and ISOs, but there are key differences. The major similarity is that all of these entities operate markets which accept offers and dispatch resources on a sub-hourly basis to meet load requirements. Unlike RTOs and ISOs, EIMs do not provide ancillary services, manage congestion, or administer an OASIS site, and they do not take on reliability responsibility.

The efforts to develop these markets have occurred for both reliability and economic reasons. Both the reliability and economic aspects are driven in large part by the need to integrate increasing amounts of intermittent generation into the portfolios of virtually all utilities in the region. An energy imbalance market would be expected to improve reliability by providing increased region-wide situational awareness to Balancing Authorities ("BAs") and making better use of available generating capacity in the region. It would also be expected to improve economics by efficiently dispatching generators to meet loads across a regional footprint rather than within BAs.

While the individual BAs would retain their reliability responsibility, EIMs typically have resource sufficiency requirements that obligate participating BAs to carry enough capacity to meet their own internal needs. These requirements are designed to keep a participating BA from entering an hour in a capacity- or energy-short position and relying on the EIM to meet its load-serving obligations. Participation in an EIM would help make efficient use of resources, but it would not reduce a BA's need for capacity. Depending on the

specifics of the resource sufficiency requirement, participation could drive the need for additional capacity.

Over the last two years, there has been significant progress in the development of these markets. Most notably, PacifiCorp and the California ISO announced, developed, and on October 1, 2014, implemented an EIM for their Balancing Authority Areas (now called the "Western EIM"). NV Energy began participating in the market on December 1, 2015. The CAISO/Pac EIM has reported benefits to customers in excess of $20 million over the first three quarters of the market operation. As of this writing, Arizona Public Service and Puget Sound Energy have plans to join that market in late 2016, and Portland General Electric expects to begin participating in 2017. The NWPP worked toward the development of an EIM for a number of years before pulling back from these efforts in late 2015.

Regional Transmission Organizations / Independent System Operators

Development of full regional markets has materialized in the West. Currently, there are two ISOs in the WECC: the CAISO and the AESO. CAISO manages the transmission system owned by three large investor-owned utilities in California and operates full day-ahead and real-time markets. In April of 2015, CAISO and PacifiCorp announced a memorandum of understanding to explore the possibility of PacifiCorp becoming a full participating transmission owner ("PTO") in the CAISO.

PacifiCorp engaged a consultant to estimate the benefits of this integration. The benefits were studied in the areas of more efficient unit commitment and dispatch, more efficient over-generation management, lower peak capacity needs, and renewable procurement savings. The preliminary results of the study show the present value of these benefits over a 20-year period of between $3 billion and $9 billion for CAISO and PacifiCorp customers.

Another development of note is related to the Southwest Power Pool ("SPP"). NorthWestern's South Dakota utility, along with a number of other entities including the portion of the Western Area Power Administration's ("WAPA") Upper Great Plains entity located in the Eastern Interconnection joined SPP in October of 2015. NorthWestern's South Dakota operations, WAPA, and several other entities fully participate in the day-ahead and real-time SPP markets (the "Integrated Marketplace"), and their transmission systems are now operated by SPP.

In addition, SPP now acts as the Transmission Service Provider ("TSP") for the portion of WAPA's system located in the Western Interconnection in Montana. The Integrated Marketplace does not extend to this portion of the system, and it is not clear whether an extension of the market footprint to this area would be feasible given the limited transfer capability between the Eastern and Western Interconnections. However, the full implications of SPP's presence in Montana are not known at this time.

Participation in Organized Markets

NorthWestern continues to assess the development of these markets and the potential for future participation. There are potential benefits – more efficient dispatch, improved reliability and renewable integration – but there are also challenges for NorthWestern's participation. Some of these challenges are as follows:

- Connectivity with the markets;
- Resource sufficiency and resource adequacy requirements;
- Implementation costs and staffing (software, metering, etc.);
- Development risk; and
- Regulatory risk.

NorthWestern must assess if and how its resources would fit with the requirements of these markets. The portfolio optimization efforts that NorthWestern has undertaken (as described elsewhere in this Plan) are aligned with potential participation in an EIM or ISO. However, such participation would potentially place additional requirements on NorthWestern from a resource adequacy perspective and could change the timing of the addition of resources to the portfolio. Participation in an EIM or ISO would also significantly change both market operations and transmission operations for NorthWestern.

Because a significant number of utilities are moving to organized markets, NorthWestern must also be aware of the potential consequences of not joining. Most notably, NorthWestern is evaluating the potential effects on the real-time bilateral markets as more entities join the Western EIM and potentially other markets. While the effects are difficult to measure at this time due to a limited number of parties currently participating in the Western EIM, the results could be significant for NorthWestern. Currently, NorthWestern relies heavily on the real-time market, particularly in times of peak load. A substantial decline in liquidity in the bilateral markets would increase the risk of this approach.

Real Power Balancing and Reliability Based Control

NorthWestern is also facing changes with regard to reliability standards. In April of 2015, FERC approved NERC Standard Bal-001-2 – Real Power Balancing Control Performance, which replaces Standard Bal-001-1. This standard eliminates Control Performance Standard 2 ("CPS2") and replaces it with what is sometimes referred to as Reliability Based Control ("RBC").

Under CPS2, a BA is required to keep its Area Control Error ("ACE") between bounds in 90% of the 10-minute periods during a calendar month. For NorthWestern, these bounds are approximately +/- 23 MW, so NorthWestern transmission operators need to control the system such that its ACE stays between -23 MW and +23 MW 90% of the time. The new

RBC standard requires a BA to operate such that its clock-minute average of ACE does not exceed its clock-minute Balancing Authority ACE Limit ("BAAL") for more than 30 consecutive clock minutes. Unlike the limits under CPS2, BAALs are not static; they vary based on the frequency in the interconnection.

Beginning on July 1, 2016, NorthWestern will be required to operate to the new standard, with potential penalties for failing to do so. NorthWestern has begun to participate in a field trial, which will allow the company to gain a better understanding of the requirements prior to the July 1 effective date. Based on our analysis to date, we expect that compliance with the new standard will require less frequent intra-hour ramping of generators than was required under CPS2. However, because of the nature of the standard, we expect that our need for capacity – particularly flexible capacity that can ramp up and down on short notice – will be greater than it was under CPS2.

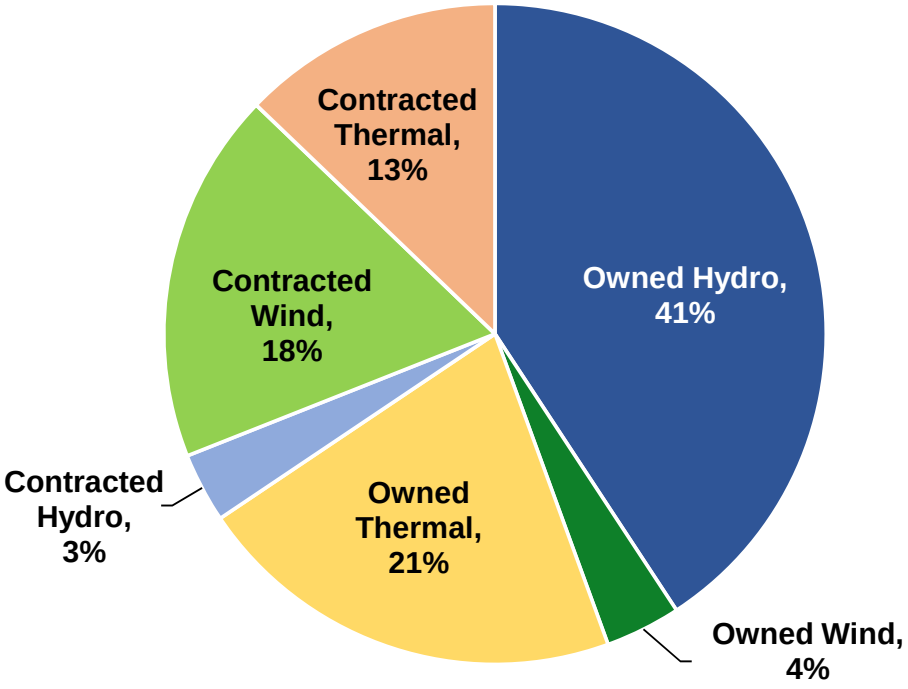
CHAPTER 8
EXISTING RESOURCES

Existing Resources Included in Modeled Portfolios

Introduction

NorthWestern serves retail loads using company-owned generation, a number of generation facilities under power purchase agreements ("PPAs"), and wholesale market purchases. Figure 8-1 summarizes the nameplate capacity percentages of owned and contracted resource types currently supplying energy to NorthWestern's Montana customers in 2016.

Figure 8-1 2016 Electricity Supply Portfolio
(Based on nameplate capacity)



NorthWestern's current resource portfolio consists of 1,084 MW of generation capacity. On an installed capacity basis, 66% of NorthWestern's current resources are renewable. However, because of the intermittent nature of wind, the realized capacity at time of peak loads is substantially less than nameplate for wind.

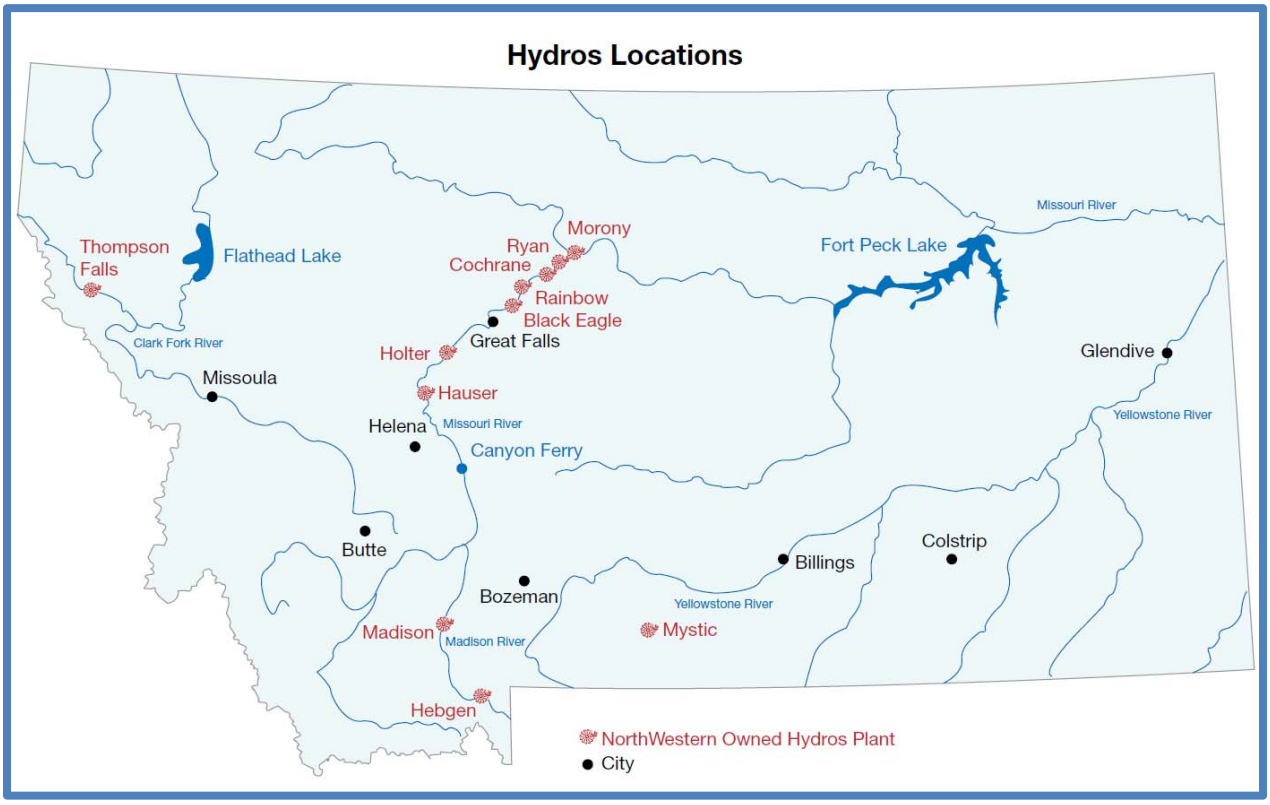
Figure 8-2 NorthWestern Energy Hydro Facilities

Utility Hydroelectric Resources

NorthWestern's rate base hydroelectric resources consist of 10 hydroelectric generating facilities. Kerr Dam, while included in the Hydros purchase, was transferred to the Confederated Salish and Kootenai Tribes on September 5, 2015, reducing the Hydros

nameplate capacity from 633 MW to 442 MW.[1] Figure 8-3 shows the location of the Hydros. Nine of these facilities, including the storage reservoir at Hebgen Dam, are located on the Madison-Missouri River system. The Mystic generation facility is located on West Rosebud Creek, 75 miles southwest of Billings, Montana, and the Thompson Falls facility is located on the Clark Fork River in Thompson Falls, Montana. NorthWestern's Hydro Operations Control Center is located at the new Rainbow Dam power house in Great Falls. The control center monitors and controls most operations at all of the hydro facilities, including the storage facility at Hebgen Lake.

Figure 8-3 Hydros Locations



[1] The capacity value of the hydros without Kerr Dam has been upgraded from 439 MW to 442 MW. Capacity at Ryan increased by 3 MW due to two generator rewinds and three turbine replacements.

Table 8-1 below lists all 10 rate-based hydroelectric facilities and provides key characteristics of the facilities.

Table 8-1 NorthWestern Owned Hydro Resources

NorthWestern Owned Hydro Resources								
Resource	Nameplate Capacity (MW)	River System	Designated Run-of-the-River (ROTR)	Storage Capacity (acre-ft)	First Year in Service	Number of Units	Turbine Types	Historical Capacity Factor
Thompson Falls	94	Clark Fork	Yes	0	1916	7	Francis, Kaplan	60%
Mystic	12	Rosebud Creek	No	0	1925	2	Pelton	48%
Hebgen Lake	0	Madison	No	386,845	1915	0	N/A	N/A
Madison	8	Madison	Yes	27,200	1906	4	Francis	89%
Hauser	19	Missouri	Yes	64,200	1911	6	Francis	75%
Holter	48	Missouri	Yes	243,000	1918	4	Francis	65%
Black Eagle	21	Missouri	Yes	1,710	1891	3	Propeller	72%
Rainbow	60	Missouri	Yes	0	1910	1	Kaplan	70%
Cochrane	69	Missouri	No	0	1958	2	Kaplan	43%
Ryan	63	Missouri	No	5,000	1915	6	Francis	78%
Morony	48	Missouri	No	3,000	1930	2	Francis	61%
Total	**442**			**730,955**		**37**		

Licenses and Agreements

NorthWestern's Hydro projects on the Madison-Missouri River are operated jointly under one FERC license (Project No. 2188), which sets tolerances of associated reservoir levels, downstream flow rates, and maximum daily flow variation for each dam. Six of these facilities are considered "run-of-the-river", meaning that they must be operated in a manner that generally minimizes changes between upstream and downstream flow rates while maintaining reservoir levels at elevations specified by the license. Thompson Falls Dam (Project No. 1869) and Mystic Dam (Project No. 2301) each operate under their own FERC licenses. Additionally, there are hydro operating provisions requiring concurrence from the following agencies prior to any intentional deviation from the proposed operations, (refer to Volume 2, Chapter 5):

- Montana Fish Wildlife and Parks;
- U.S. Bureau of Land Management;
- Montana Department of Environmental Quality;
- U.S. Fish and Wildlife Service;
- Montana Department of Natural Resources and Conservation, and
- U.S. Bureau of Reclamation.

Altogether, these agreements serve to balance power generation with other resource needs, including flood control, preservation of wildlife, and recreational use of the rivers. Under the Federal Power Act, changes from licensed operations require agency approval and formal license amendment at FERC. The NorthWestern Energy Hydropower Operational Plan, included in Volume 2 of this Plan, is a summary of the operational constraints of these agreements and licenses that are the result of years of relicensing and post-license study, consultation, negotiations, and balancing of power generation with other interests.

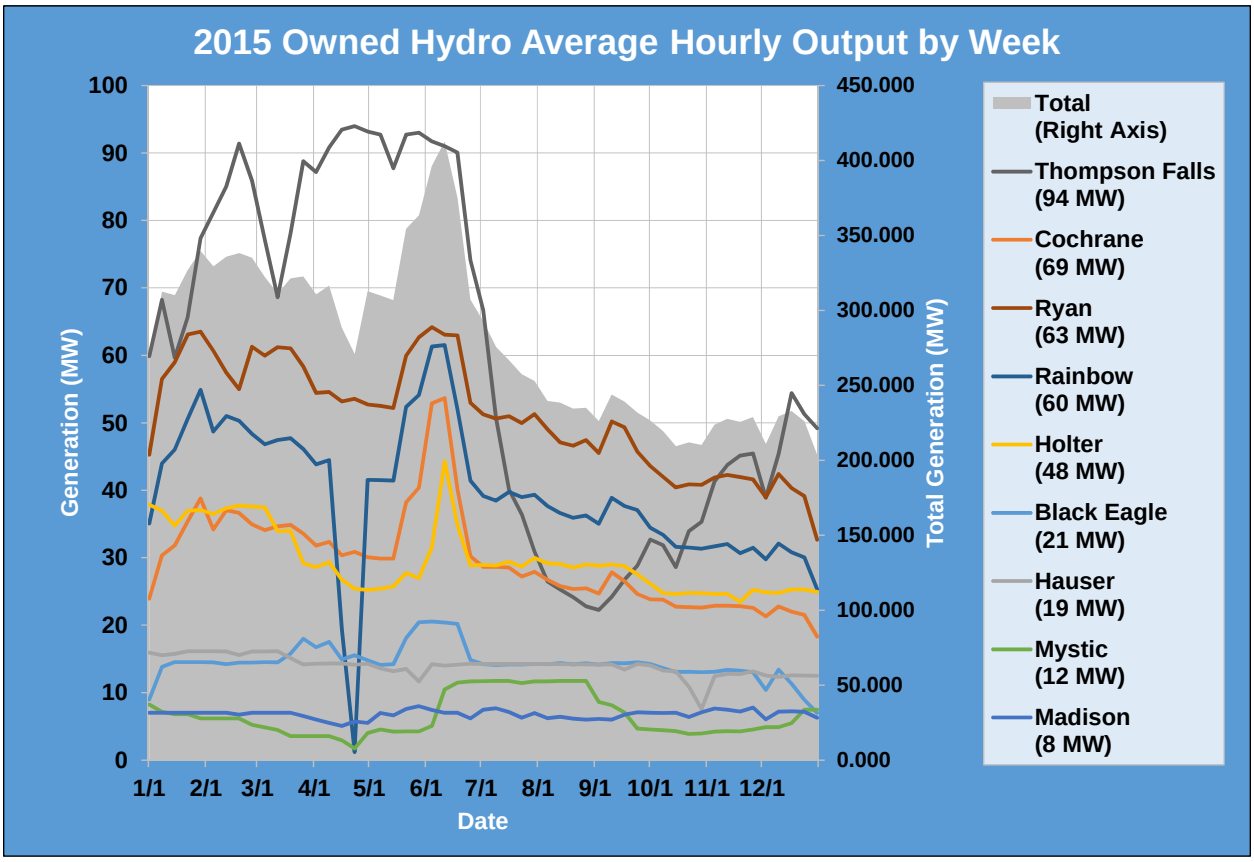
Hydroelectric Operations

With a few exceptions, the hydroelectric system is primarily a run-of-river system, as mentioned above. Inflow behind the dams is directed through the turbine units to produce power or, if conditions require, spilled without generating power. Mystic, Thompson Falls, Black Eagle, Rainbow, Cochrane, and Ryan facilities have traditionally been used to provide spinning reserves. The ability to provide spinning reserves depends upon license restrictions, current flow conditions, reservoir levels, and turbine unit availability. These conditions can change daily.

Mystic has traditionally been used as a peaking operation throughout the year with considerable restrictions in the spring and summer, maximizing generation during high load hours and minimizing generation during low load hours. Mystic's ability to provide

peaking service is dependent upon reservoir elevations and inflows. Conducted on a pre-scheduled, 24-hour cycle, peaking operations are restricted to the same volume of water that would have been available for baseload operations.

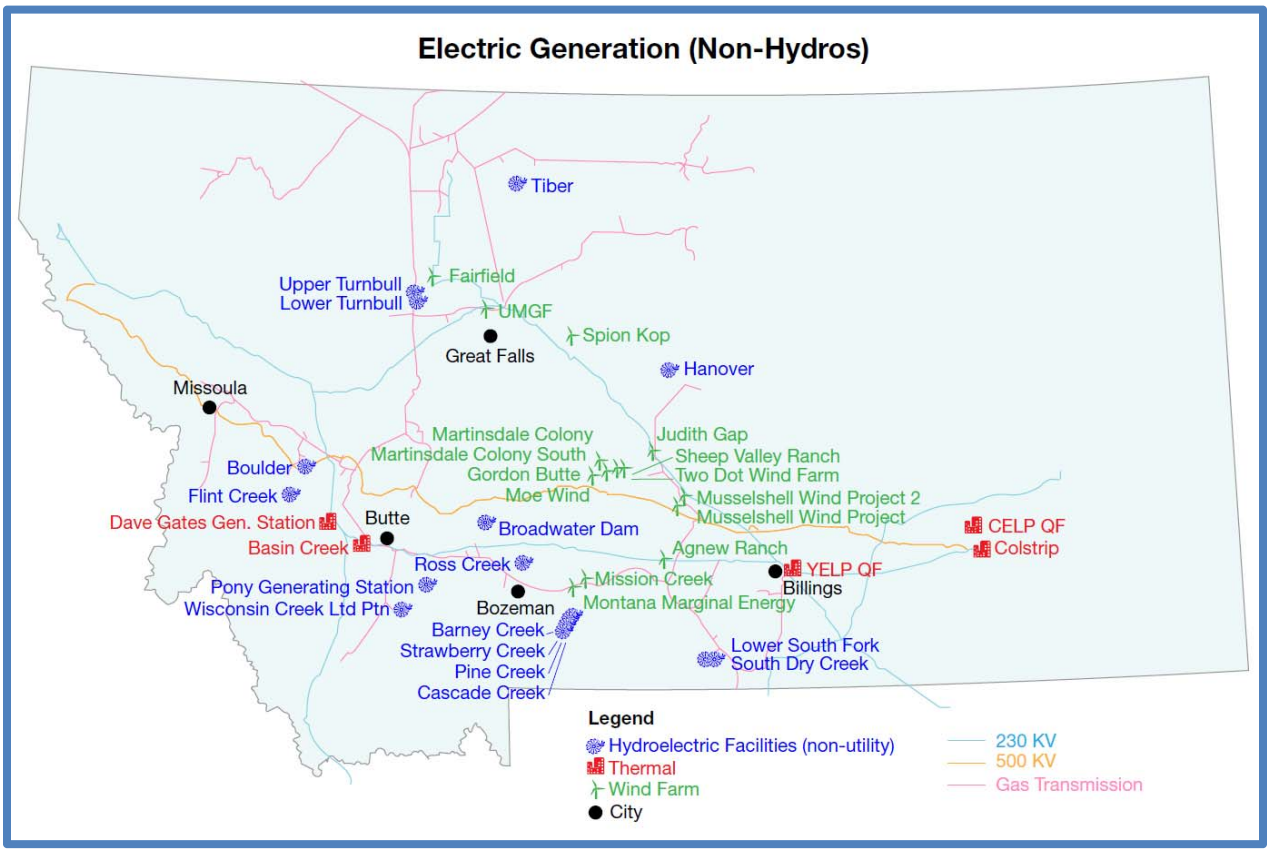
Figure 8-4 2015 Owned Hydro Average Hourly Output by Week



The average hourly output by week (MW) for each of the owned Hydros during 2015 is plotted in Figure 8-4, referenced to the left axis. The total combined output (gray area referenced to the right axis) shows the seasonality of hydroelectric power with the spring run-off months having the most production potential, and summer and fall having lower production. Hydraulic capacity of the hydro system determines the amount and timing of available production capability. The Hydro system has historically operated in the range of roughly 200 to 400 MW. The seasonality of the resource and the run-of-river

characteristics including flow and river elevation are captured in the portfolio modeling. Although the amount of hydroelectric system production changes during the year, it does not have the intermittent power production characteristics of resources such as wind and solar that react very quickly to changes in the weather. As a result, when scheduling output of the Hydros in the hourly, day-ahead, and longer timeframes, there is a high degree of certainty associated with the power delivery schedule.

Figure 8-5 Electric Generation (Non-Hydros)



Thermal Generation Resources

NorthWestern owns or controls the generation of three thermal resources: 30% of Colstrip Unit 4, DGGS, and Basin Creek Equity Partners LLC (tolling agreement). Additionally, NorthWestern purchases energy from two thermal QFs: Colstrip Energy Limited Partnership and Yellowstone Energy Limited Partnership – Billings Generation Inc. These

resources are listed in Table 8-2, and the locations of all thermal and other non-Hydros resources are shown in the map of Figure 8-5 above.

Table 8-2 NorthWestern Thermal Generation

NorthWestern Energy Thermal Resources				
Resource	**Nameplate Capacity (MW)**	**2015 Generation (MWh)**	**Ownership / Contract Type**	**Fuel**
Colstrip Unit 4	222	1,610,151	Rate-based	Coal
Basin Creek	52	62,770	Tolling PPA	Natural Gas
DGGS (Energy Supply)	7	61,313	Rate-based	Natural Gas
Colstrip Energy Limited Partnership - MT1 (CELP)	35	294,033	Tier II	Waste Coal
Yellowstone Energy Limited Partnership - BGI (YELP)	52	500,087	Tier II	Waste Coke
Total	**368**	**2,528,354**		

Colstrip Unit 4

NorthWestern's ownership interest in CU4 provides our Montana electric customers with low-cost, baseload electricity. Colstrip Steam Electric Station ("CSES") consists of four separate coal-fired generating units ("CU 1, 2, 3, and 4") capable of nearly 2100 MW of net generation. CSES is jointly owned by NorthWestern, Talen Energy LLC ("Talen"), Puget Sound Energy, Portland General Electric, Avista Corp., and PacifiCorp. CU 1&2 are capable of producing 307 MW each, and CU 3&4 are capable of producing 740 MW each. CU 1&2 and CU 3&4 are operated as separate projects under separate operating agreements. Talen is the operator on behalf of all owners of all units at CSES. Table 8-3 below summarizes the ownership of all four Colstrip Units, CU1 - CU4.

Through contractual arrangements with Talen, which owns a 30% share of CU3, NorthWestern and Talen share their respective ownership of the CU 3&4 project equally. Through this arrangement, NorthWestern and Talen act as one 30% owner, each of which has the rights to 15% of the output from both CU 3&4; both owners are also responsible for 15% of the costs for operation, maintenance, and capital improvements. This

arrangement results in reduced risk as the impacts of an outage are spread across both units for NorthWestern.

Table 8-3 Colstrip Generation, Ownership

Colstrip Units 1 - 4 Ownership					
Unit Owners	CU1 (307 MW)	CU2 (307 MW)	CU3 (740 MW)	CU4 (740 MW)	Total Net Capacity (MW)
Puget Sound Energy	50%	50%	25%	25%	677
Talen Energy, LLC	50%	50%	30%	0%	529
Portland General Electric	0%	0%	20%	20%	296
Avista Corp.	0%	0%	15%	15%	222
NorthWestern Energy	0%	0%	0%	30%	222
PacifiCorp	0%	0%	10%	10%	148
Total	**100%**	**100%**	**100%**	**100%**	**2,094**

The operation of the CU 3&4 project is governed by the Colstrip Unit 3&4 Ownership and Operation Agreement ("OOA"). An operating committee, comprised of representatives from each owner, votes to approve operations, maintenance, and capital budgets and operation strategy.

Some key conditions of the OOA are listed below:

- The term of the agreement continues as long as CU 3&4 operate and only concludes when salvage is complete and all requirements of law are met.
- Each owner must be prepared to take, at a minimum, their share of generation necessary to keep the plant on-line (CU 3&4 each require 200 net MW) and must be prepared to provide sufficient fuel to operate at minimum levels. An owner can take less than minimum generation and provide less than minimum fuel so long as other owners requiring operation of the unit(s) in the aggregate are operating the unit(s) at a level high enough to meet the minimum generation required to keep the unit(s) on-line.

- The duties, obligations, and liabilities of the owners are intended to be several and not joint or collective and no owner shall be jointly or severally liable for the acts, omissions, or obligations of any other owner.
- An owner wanting to sell its interest in CU3 or CU4 must first offer to sell to other current owners at fair market value based on current ownership percentage.
- Until such time that ownership is transferred to another party, an owner is obligated to pay for its share of costs to operate & maintain CU 3&4 as well as its share of capital additions.
- There must be 100% owner consensus to shut down CU3 or CU4 either temporarily or permanently.

CSES is located adjacent to the Rosebud coal mine. The Rosebud mine is located on the north end of the Powder River Basin, the largest coal producing region in the United States. At the Rosebud Mine, coal is taken from the Rosebud coal seam of the Fort Union formation. This low-sulfur sub-bituminous coal is supplied to all four units by Western Energy Company, a subsidiary of Westmoreland Coal Company.

CU 3&4 receive coal under a cost-plus contract with Western Energy Company. The current contract will end in 2019 unless amended, restated, or extended. Negotiations are underway to extend the contract term. Coal reserve estimates indicate that sufficient coal exists to operate CSES for 25+ years.

Typical Rosebud coal quality is 25% moisture, 10% ash, and less than 1% sulfur. The coal has a heating value of approximately 8,500 Btu/lb. CU 3&4 collectively average 6.3 million tons of coal consumption per year.

The coal is mined from areas west of the plants and is crushed into smaller chunks (2-3 inch) and then transported via conveyor (about 4 miles) where it is stored in bunkers and piles at the plant site. Coal is transferred into the plant via conveyor into silos located within the plants.

Planned maintenance outages are normally scheduled for spring time to coincide with elevated hydro conditions in the Northwest that typically produce surplus power conditions, favorable market prices, and the opportunity to make economy purchases. CU 3&4 are each on a separate 3-year planned outage schedule where every third year the units typically do not experience a planned outage and are available to operate.

CU4 historically has been used to provide baseload power, with generation being reduced during periods where more economical energy sources are available. Typically, CU4 capacity is scheduled by NorthWestern to meet load on a seasonal-to-day-ahead basis. However, updated system generation and load levels, weather conditions, and market prices are reviewed hourly by the real-time desk, and adjustments from the previous hour's generation are made as necessary. During periods of low electricity market prices, CU4's output is sometimes reduced so that lower-cost market purchases can be made as a benefit to customers. Generation is also reduced when load can be satisfied without full output from CU4. This often occurs during the spring when hydro output is higher due to increased snowmelt and load is lower due to milder weather conditions.

Exportation of excess generation to other markets is generally not cost effective due to the added transmission costs for delivery which include energy losses. Furthermore, other Colstrip owners may experience similar conditions such as low load and excess generation due to increased hydro production and therefore have no interest in purchasing NorthWestern's excess generation. In these cases, the output is reduced until conditions

change significantly enough such that increasing production is economical. This "economic de-rate" of CU4 generation is subject to limitations covered in the OOA outlined above. Alternately, if electricity market prices are high enough, then excess generation is sold on an hour-by-hour determination and the profits are returned to customers in the form of revenue credits, which helps reduce overall supply costs.

NorthWestern, consistent with the terms of the OOA, has the right to make adjustments to the generation output. Generally, when requests are made to change generation levels, CU 3 & 4 generation changes at a ramp rate of +/- 8 MW per minute per unit with NorthWestern's share being 15% of 8 MW or 1.2 MW per minute per unit.

Colstrip generation has historically resulted in Montana being a net exporter of power because the amount of generating capability greatly exceeded native load. Other Northwest utilities and large customers in Montana who purchase their power from non-utility sources have been able to avoid transmission costs associated with importing power from other states because of Colstrip generation.

The Colstrip resource has characteristics that provide many positive benefits to NorthWestern's supply portfolio and the customers we serve:

- Baseload power – one of only two NorthWestern baseload assets;
- Load-serving capacity and a reliable source of capacity at times of peak demand;
- Reliability and price stability;
- Component of portfolio optimization plan;
- Complements baseload hydro: reduced production during high hydro and low load conditions; and
- Stable fuel pricing; low price volatility.

Dave Gates Generating Station

DGGS is a NorthWestern-owned and operated natural gas-fired plant located near Anaconda, Montana that has traditionally provided regulation service for the NorthWestern BA. Market operations historically scheduled 7 MW of generation each hour into the portfolio to account for the minimum level of output from the plant. DGGS is comprised of three 50-MW generation units powered by six Pratt & Whitney FT8 simple-cycle combustion turbines ("SCCT"). NorthWestern typically operates two units at a time, reserving the third unit to be utilized during maintenance outages or during periods of elevated regulation demand. The DGGS facility was constructed to physically accommodate a fourth unit.

DGGS has the ability to quickly ramp (30 MW/minute per unit), providing regulation through automatic generation control and electronic signals from the NorthWestern Operations Center in Butte. The control signal, a number representing the needed increase or decrease in generation to keep system load and generation in balance, is generated in sub-minutely time increments based on these signals. Typically, the facility generates between 7 MW and 100 MW. Regulation service is a capacity-based product that creates energy as a byproduct of the balancing service it performs. DGGS produced approximately 428,000 MWh of energy in 2015.

Basin Creek Equity Partners, LLC

Basin Creek is a 52-MW natural gas plant located in Butte, Montana. It is composed of nine 5.7 MW Caterpillar 16GCM34 reciprocating internal combustion engines ("IC") that are designed for flexible operation and can be started and ramped to full capacity in less than ten minutes. Basin Creek has been used historically for serving load and peak demand, and to provide non-spinning reserves. With a heat rate near 9,000 Btu/kWh, it is often dispatched in times of high market prices when the variable cost to generate is lower than the market price for electricity. NorthWestern staff at the Market Operations Real-Time

Desk schedule and dispatch energy and reserves from this resource on a day-ahead and hourly basis depending on needs and market conditions. Additionally, energy and non-spinning reserves may be sold to the market on an hourly basis when economical to do so. Basin Creek produced approximately 63,000 MWh in 2015 and has been used to supply non-spinning reserves from up to three units to meet Energy Supply's transmission reserve requirements. NorthWestern has operational control of this facility under a tolling agreement that will expire in July 2026, with an option to extend the agreement for another five years.

Thermal QF Resources

NorthWestern is contractually obligated to purchase energy from two thermal QF resources: Yellowstone Energy Limited Partnership ("YELP") and Colstrip Energy Limited Partnership ("CELP"). YELP is a 52-MW facility using waste petroleum coke as its primary fuel source. CELP is a 35-MW facility using waste coal as its primary fuel source. Both of these facilities' installed capacities are greater than the contracted capacity. In the case of YELP the installed capacity is 61 MW and for CELP the installed capacity is 41.5 MW for an aggregated total of 102.5 MW. The CELP contract ends June 30, 2024 and the Yelp contract ends December 31, 2028. For purposes of modeling in this plan, it is not assumed that either of these contracts will be renewed after contract expiration.

Wind Generation

NorthWestern receives the power generated from 237 MW of wind projects delivering energy to the supply portfolio. The 40-MW Spion Kop Wind Project is the only company-owned project and the remaining 197 MW are under purchase power contracts with third parties. Table 8-4 is a listing of all wind projects currently delivering energy to NorthWestern. The Greenfield project (25 MW) is not listed, but is expected to be built and enter commercial production during 2016, raising the total wind installed production capability to 262 MW.

Table 8-4 Renewable Wind Resources

Renewable Wind Resources					
Resource	**Nameplate Capacity (kW)**	**2015 Generation (MWh)**	**Ownership / Contract Type**	**Renewable Energy Credits**	**Historical Capacity Factor**
Spion Kop	40,000	127,662	Rate-based	REC	40%
Musselshell	10,000	24,055	QF-1	REC	30%
Musselshell Two	10,000	28,257	QF-1	REC	35%
Fairfield Wind	10,000	31,605	QF-1	REC	38%
Two Dot Wind Farm	9,720	29,845	QF-1	REC	38%
Gordon Butte	9,600	36,651	QF-1	CREP	49%
United Materials of Great Falls Inc.	9,000	3,460	QF-1	N/A	4%
Two Dot Wind LLC (Martinsdale Colony South)	2,000	759	QF-1	N/A	8%
Two Dot Wind LLC (Martinsdale Colony)	750	1,235	QF-1	N/A	20%
Two Dot Wind LLC (Sheep Valley Ranch)	455	611	QF-1	N/A	19%
Two Dot Wind LLC (Moe Wind)	450	620	QF-1	N/A	15%
Two Dot Wind Energy LLC (Montana Marginal Energy)	195	0	QF-1	N/A	0%
Mr. Thomas G. Agnew (Agnew Ranch)	65	21	QF-1	N/A	1%
Two Dot Wind Energy LLC (Mission Creek)	65	21	QF-1	N/A	1%
Judith Gap	135,000	455,389	PPA	REC	40%
Total	**237,300**	**740,191**			

When considered in the context of NorthWestern's load-serving obligation and the other resources that comprise the supply portfolio, the scale of wind power, much of it required purchases from QFs, is very large. NorthWestern's retail load averages approximately 750 MW for all hours over the calendar year with a minimum load of about 450 MW. The current installed wind capacity represents just over one-third of our average load and about 60% of minimum load. When the intermittency of wind power is taken into account, it is clear that this resource has a significant impact on the management of the supply portfolio and poses challenges unlike other resources such as thermal and hydro. Also, NorthWestern has limited real time operating information on QF wind projects.

Figure 8-6 Net Wind Generation Hourly Output – Daily Examples

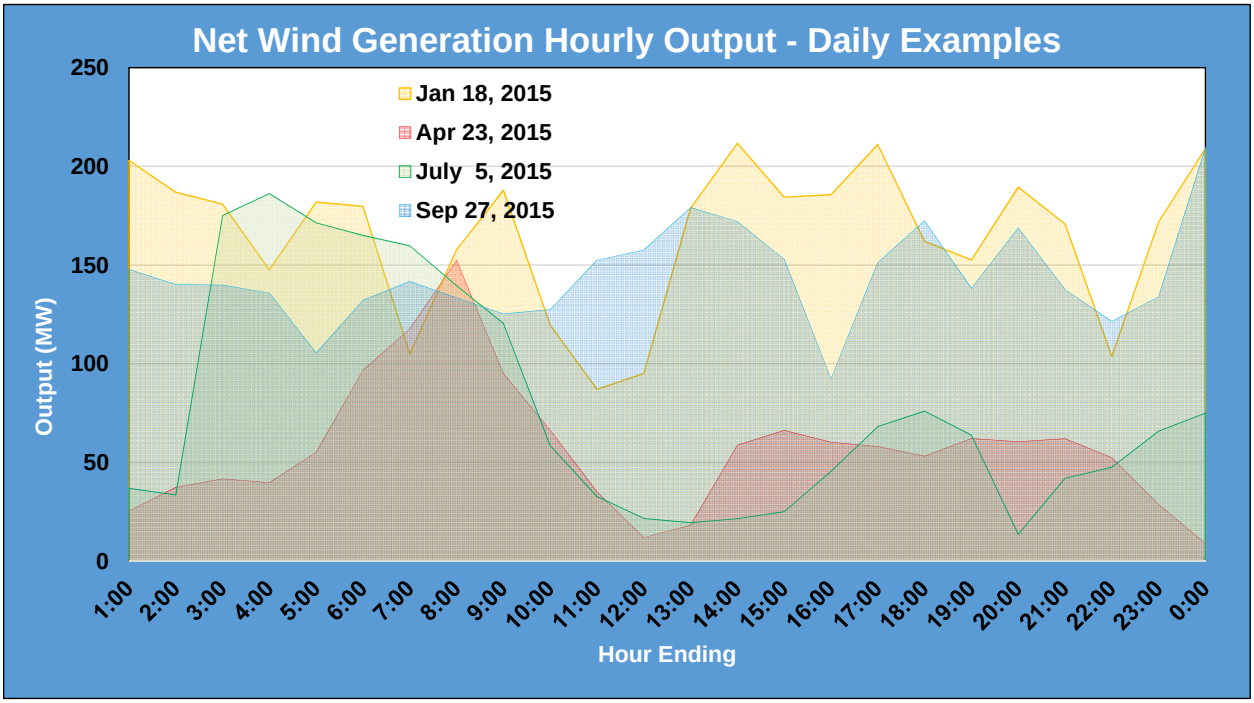


Figure 8-6 shows examples of the variability of hourly wind output of the current wind fleet on four different days in 2015. One aspect of wind that is evident in this figure is the magnitude of hourly change in output. For example, on July 5th (green), the net wind output changes from 34 MW in hour ending 2:00am to 175 MW in hour ending 3:00am, only to drop back to near 20 MW by noon. These drastic fluctuations can also happen many times in a day, as shown on January 18th (yellow) when 14 separate hourly changes exceeded 30 MW. Planning and scheduling for those periods using weather and wind forecasts includes uncertainty. Lastly, Figure 8-6 illustrates days when wind generation was changing throughout the day. NorthWestern also experiences days when wind has a high average daily capacity factor, but more days when wind has a low average daily capacity factor – 27 days greater than 80% and 130 days less than 20%. Although not depicted on Figure 8-6, wind power production also varies substantially within the hourly timeframe with equivalent levels of intermittency.

Small Hydroelectric Generation

NorthWestern is currently purchasing energy from 13 small QF and two small PPA hydroelectric projects with total nameplate capacities of 16.423 and 20.5 MW, respectively. Table 8-5 lists these small hydro facilities which include three CREP-qualifying resources.

Table 8-5 Small Hydro Resources

Small Hydro Resources					
Resource	Nameplate Capacity (kW)	2015 Generation (MWh)	Ownership / Contract Type	Renewable Energy Credits	Historical Capacity Factor
Turnbull	13,000	25,124	PPA	CREP	9%
Tiber	7,500	21,953	PPA	N/A	8%
State of MT DNRC (Broadwater Dam)	10,000	47,296	Tier II	N/A	59%
Hydrodynamics Inc - South Dry Creek	1,200	9,276	Tier II	N/A	74%
Ross Creek Hydro LLC	450	2,274	Tier II	N/A	62%
Estate of Howard Carter (Pine Creek)	300	1,307	Tier II	N/A	29%
Hydrodynamics Inc. (Strawberry Creek)	190	1,700	Tier II	N/A	91%
James Walker Sievers (Cascade Creek)	68	436	Tier II	N/A	65%
James Walker Sievers (Barney Creek)	60	109	Tier II	N/A	27%
Flint Creek Hydroelectric, LLC	2,000	10,165	QF-1	CREP	68%
Wisconsin Creek Limited Partnership	550	720	QF-1	N/A	18%
Boulder Hydro Limited Partnership	510	1,484	QF-1	N/A	38%
Lower South Fork, LLC	455	1,292	QF-1	CREP	20%
Gerald Ohs (Pony Generating Station)	400	1,384	QF-1	N/A	39%
Donald Fred Jenni (Hanover Hydro)	240	252	QF-1	N/A	12%
Total	**36,923**	**124,772**			

Qualifying Facility Power Purchase Agreements

NorthWestern's QF contracts consist of two main groups: older Tier II QF contracts under Final Order Nos. 5986w and 6353c under combined Docket Nos. D97.7.90 and D2001.1.5 and newer or renewal of older QF contracts executed under the QF-1 Tariff. QF wind resources are listed in Table 8-4; QF hydro resources are listed in Table 8-5, and QF thermal resources are shown in Table 8-2 above. In total, NorthWestern is currently purchasing approximately 166 MW of QF resources from 28 projects with annual production of about 900 MWh. At the time of preparing this Plan, NorthWestern had

executed contracts for 47 MW of new QF-1 projects since November 2013 which have not been included in this discussion.

Like all QF contracts, the Tier II QF contracts cannot be dispatched by NorthWestern to follow load or to provide reserves. For planning purposes, the energy and capacity of these contracts are based upon the historical operating performance of the facilities. NorthWestern has made no assumptions in this planning cycle concerning the longevity of QF projects beyond the term of the current agreements. This means NorthWestern must plan for resources to replace them.

NorthWestern recently signed two QF contracts for future wind and hydro resources totaling 33 MW and five QF contracts for future solar PV resources totaling 14 MW. A summary of these facilities is given in Table 8-6. At the time of writing this plan, six solar PV generation developers had expressed an interest in negotiating additional QF contracts. Five of these developers have submitted requests for multiple locations, and in some cases, a definitive number of locations has not yet been specified.

Table 8-6 Future Renewable Resources

Future Renewable Resources						
Resource	**Nameplate Capacity (MW)**	**Contract COD Date**	**Contract Expiration Date**	**Ownership / Contract Type**	**Renewable Energy Credits**	**Fuel**
Greenfield Wind, LLC	25.0	2016	2041	QF-1	TBD	Wind
Sleeping Giant Hydro	8.0	2016	2042	QF-1	TBD	Hydro
Green Meadow Solar LLC	3.0	2016	2041	QF-1	TBD	Solar
Deer Creek	3.0	2016	2041	QF-1	TBD	Solar
Ragen Ranch	3.0	2016	2041	QF-1	TBD	Solar
South Mills	3.0	2016	2041	QF-1	TBD	Solar
River Bend Solar LLC	2.0	2016	2041	QF-1	TBD	Solar
Total	**47.0**					

TBD – To Be Determined by Montana Public Service Commission

Renewable Portfolio Standards

Under Montana's Renewable Power Production and Rural Economic Development Act, NorthWestern is subject to § 69-3-2004, MCA, Renewable Resource Standard, generally known as the Renewable Portfolio Standard ("RPS"). NorthWestern is required to purchase a portion of the electricity used to serve retail loads from eligible renewable resources built after January 1, 2005. For 2015 and subsequent years, the RPS requirement is set at 15% of the previous year's retail sales. Unused renewable energy credits ("RECs") may be carried forward or "banked" for up to two years. NorthWestern's RPS-eligible resources are listed at the bottom of Table 8-7 below and denoted as "REC" to identify them as eligible renewables as determined by the Commission.

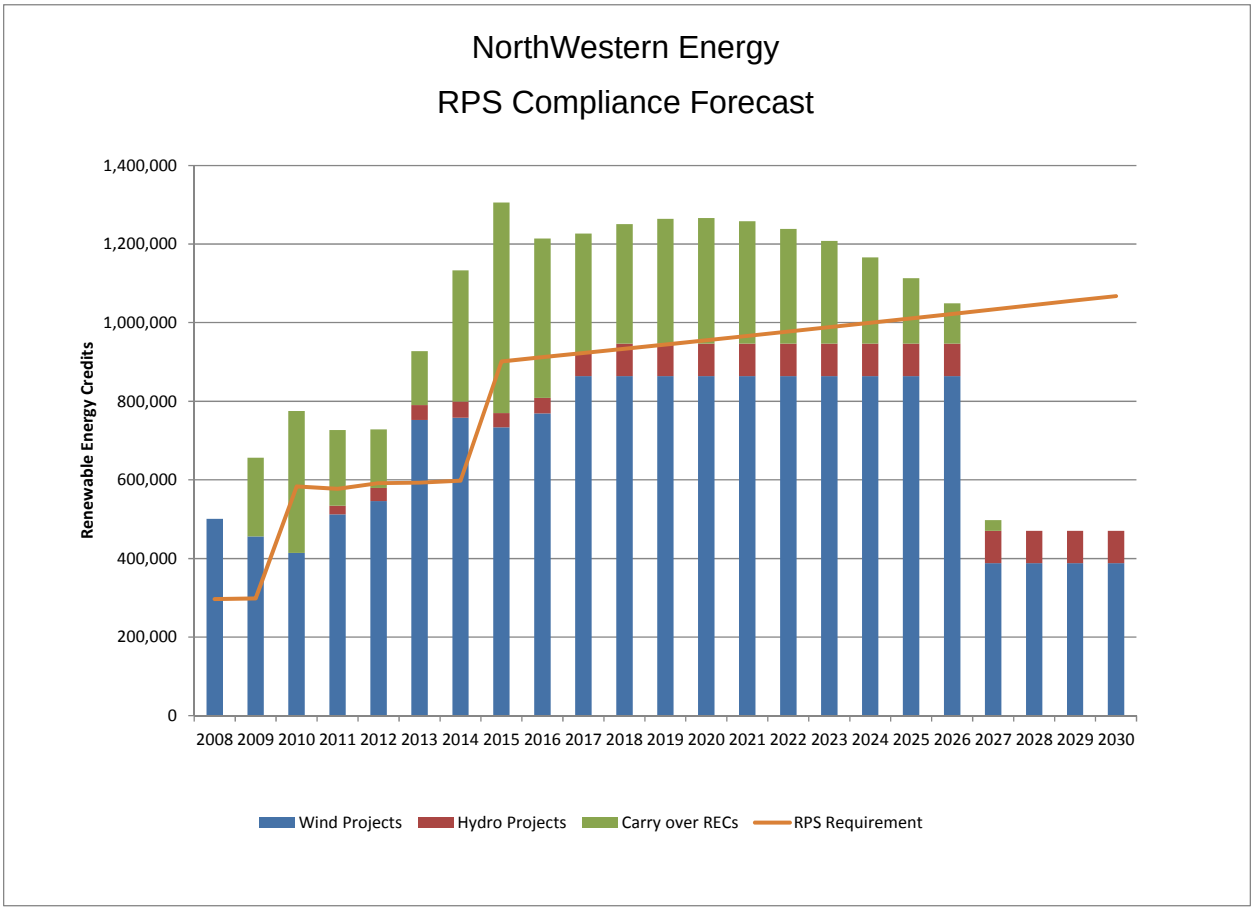
Table 8-7 RPS Eligible Renewable Resources

Eligible Renewable Resources					
Resource	**Nameplate Capacity (MW)**	**2015 Generation (MWh)**	**Ownership / Contract Type**	**Renewable Energy Credits**	**Fuel**
Turnbull	13.000	25,124	PPA	CREP	Hydro
Flint Creek Hydroelectric, LLC	2.000	10,165	QF-1	CREP	Hydro
Lower South Fork, LLC	0.455	1,292	QF-1	CREP	Hydro
Gordon Butte	9.600	36,651	QF-1	CREP	Wind
Judith Gap	135.000	455,389	PPA	REC	Wind
Spion Kop	40.000	127,662	Rate-based	REC	Wind
Musselshell	10.000	24,055	QF-1	REC	Wind
Musselshell Two	10.000	28,257	QF-1	REC	Wind
Fairfield Wind	10.000	31,605	QF-1	REC	Wind
Two Dot Wind Farm	9.720	29,845	QF-1	REC	Wind
Total	**239.775**	**770,045**			

NorthWestern's historical and forecasted RPS compliance is shown in Figure 8-7. The orange line depicts NorthWestern's historic actual and estimated RPS requirement for each compliance year and the blue and red bars show estimated wind and hydro RECs. The

green bars show the REC amount carried over from the previous compliance year. This forecast only depicts current RPS resources. NorthWestern is projected to meet its RPS requirement through 2026 with currently contracted and owned eligible renewable resources. If contracted resources including Greenfield wind and Sleeping Giant hydroelectric are delayed or do not achieve commercial operation, future compliance with renewable requirements will change significantly. Without these resources, NorthWestern will only meet its RPS obligation through 2018.

Figure 8-7 Forecast RPS Compliance



CREP Resources

Since 2012, the RPS law has also included a Community Renewable Energy Project ("CREP") requirement. CREPs are locally owned eligible renewable resources that have a generation capacity of up to 25 MW (15 MW for small hydroelectric facilities). For 2015, RPS requires Montana public utilities to make CREP-eligible purchases of RECs and electricity output that total at least 75 MW of nameplate capacity (previously 50 MW for the years 2012-2014). The vast majority of the CREP requirement is borne by NorthWestern. Based on 2014 electric energy retail sales, NorthWestern's share of the 2015 CREP requirement is estimated to be around 65.4 MW. NorthWestern currently has four contracts for CREP-eligible resources totaling about 25 MW of capacity and is deficient in meeting its current CREP obligation.

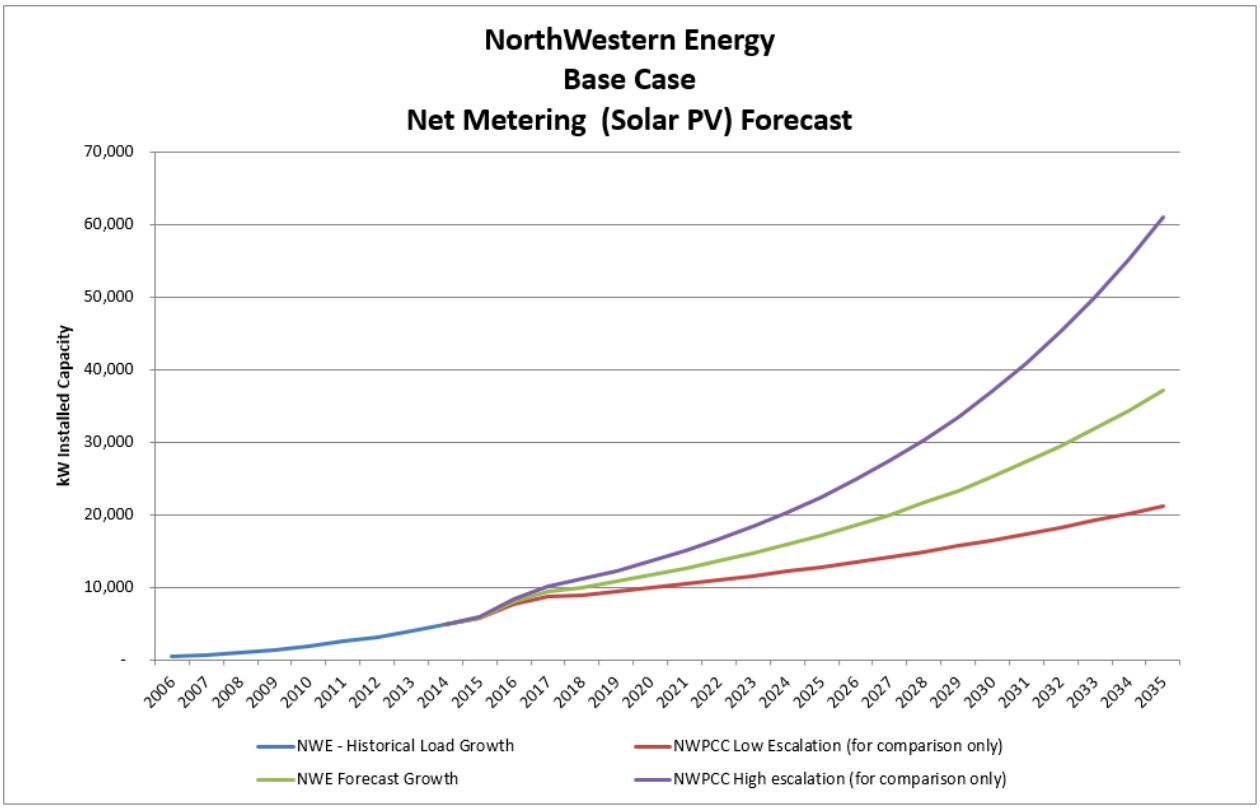
Distributed Energy Resources

Customer-driven Distributed Energy Resources ("DER") development is subsidized by funding mechanisms such as the Universal System Benefits Charge and through the net metering tariffs that allow behind-the-meter generation.[2] Projecting additional DER by project resource growth based on historical values is difficult because it relies, at least in part, on customer behavior and investment. During the period 1999-2014, approximately 5 MW of solar PV has been added and two small-scale hydroelectric projects totaling 7.5 kW have been added. For purposes of modeling future growth in DER, NorthWestern assumes that it all will come from net-metered rooftop solar PV.

Figure 8-8 shows the forecast growth in net metering on NorthWestern's system. Also shown, for informational purposes only, is what the growth in net metering would look like when escalated by the NWPCC's low and high growth rates for rooftop solar PV. Forecast growth in net metering is included in all modeling scenarios.

[2] Installations up to 50 kW.

Figure 8-8 Forecast Growth in Net Metering



CHAPTER 9
NEW RESOURCES

New Resources Evaluated for the 2015 Plan

New Resources Overview

The 2015 Plan focuses on thermal, hydro capacity upgrades, wind and solar PV resources as plausible additions to the resource portfolio. The planning process involved analysis and contributions from outside consultants (Lands Energy Consulting ("Lands"), Ascend Analytics, LLC ("Ascend")) and other sources, and input from members of ETAC[1].

Thermal Resources

Natural gas-fired generation has the capability to operate with flexibility, and the selection of the type of unit depends on the need of the portfolio. The thermal resource analysis for this Plan considered baseload, intermediate, and peaking operations. One key operating characteristic of thermal units is heat rate, a measure of thermal energy required to produce electrical energy, expressed in this Plan as the higher heating value ("HHV") heat rate. Internal combustion engines ("ICEs") provide the ability to ramp quickly and have heat rates in the range of 8,500-10,500 Btu/kWh. Combined cycle combustion turbines ("CCCTs") provide better efficiency, with a heat rate around 6,500-7,000 Btu/kWh, but have slower ramp rates and are best used in baseload functions. Simple cycle combustion turbines ("SCCTs") have the ability to ramp quickly yet are not as efficient as CCCTs. Aero-derivative SCCTs have heat rates in the range of 8,500-10,500; while frame SCCT heat rates are above 11,000 and are dispatched only in hours of high market prices. The quick ramp capability allows SCCTs and ICEs to provide response to generation and load changes.

[1] Materials from ETAC meetings and contracted studies are included in Volume 2.

Internal Combustion Engines

ICEs are analogous to diesel engines and use the combustion of natural gas to drive pistons, turning a generator to create electricity. ICEs have the ability to ramp quickly to full output and can be used for intermittent resource and load following functions. NorthWestern modeled the Wartsila 18V50SG reciprocating engine for the 2015 Plan. The Wartsila engine has a heat rate of 8,300 with capital costs of $1,280 $/kilowatt ("kW") and variable Operation and Maintenance ("O&M") costs of $5/MWh. Basin Creek utilizes nine Caterpillar ICEs for peaking, supplying reserves, and serving load.

Combined Cycle Combustion Turbines

CCCTs are turbines which ignite natural gas to produce electricity and waste heat. The waste heat is injected into a heat recovery steam generator to create additional electricity. The combined use of natural gas and waste heat increases efficiency. NorthWestern modeled the GE 7F.05 for a CCCT. The 7F.05 is the latest in the series of CCCT units and offers a better heat rate and higher capacity than the 7F.03 and 7F.04. The costs modeled for the 7F.05 and the duct firing are shown in Table 9-1 below.

Simple Cycle Combustion Turbines

SCCTs are natural gas turbines that rely on combustion alone to produce power and cannot generate electricity from waste heat. SCCTs have the ability to start and ramp quickly to full output. This flexibility provides for use during peak times and during changes in load and generation. The SCCTs that NorthWestern analyzed in the 2015 Plan were the GE LMS 100, GE Frame 7EA, and the Pratt & Whitney FT-8. The LMS100 provides the most efficiency, but has the highest capital and fixed O&M costs. The Frame 7EA has the lowest capital costs, but has a heat rate above 11,000. The Pratt & Whitney FT-8 turbines have the lowest variable and fixed O & M charges, but are not as efficient as the LMS100. All of these are available today with no major product improvements or cost changes since the 2013 Plan. DGGS features three generating units that utilize a total of six aero-derivative SCCTs to meet regulation requirements.

Defining New Gas-Fired Resources

As part of the due diligence process in determining the best alternatives for new generation in the portfolio, NorthWestern has taken steps toward defining the most suitable equipment, location, and implementation for new gas-fired plants.

Lands was contracted to analyze natural gas-fired resources and develop equipment parameters for inclusion in the modeling for this Plan. They provided a summary of operating characteristics, costs, and suggested dispatch scenarios for several current technology models. Results presented to ETAC on June 4, 2015 (see Volume 2, Chapter 1) included recommended manufactured units for Aero-derivative and Frame SCCT, CCCT, and ICE generator types. NorthWestern used Lands' recommendations to narrow the scope of stochastic modeling, utilizing the most suitable technology currently available. In addition, these units were used as examples in additional pre-feasibility studies. Table 9-1 below details the resource cost and descriptions for all resources that were modeled.

Table 9-1 Resource Cost Summary (2015$)

Resource Description	Fuel Source	Technology	Net Capacity (MW)	Capital Cost ($ / kW)	Fixed O&M ($ / kW-yr)	Variable O&M ($ / MWh)	HHV Heat Rate (Btu/kWh)	Escalation Rate (%/year)
CCCT (1x1)	Natural Gas	GE 7FA.05 ACC[1]	308	$1,400	$10	$3	6,528	2.0%
CCCT (Duct Firing)	Waste Heat	GE 7FA.05 ACC[1]	40	$0	$12	$0	8,546	2.0%
SCCT - Small Aeroderivative	Natural Gas	PW FT8	53	$1,017	$6	$5	10,500	2.0%
SCCT - Large Aeroderivative	Natural Gas	GE LMS100	93	$1,187	$17	$3	8,867	2.0%
SCCT - Frame	Natural Gas	GE 7EA	79	$997	$12	$3	11,286	2.0%
ICE - Internal Combustion Engine	Natural Gas	Wartsila 18V50SG	18	$1,280	$11	$5	8,314	2.0%
Utility Scale Solar PV[2]	Solar		25	$3,176	$43	$1		-1.0%
Wind[3]	Wind		40	$1,980	$38	$2		-0.5%

Table Notes:
Capacity for natural gas-fired resources estimated at 3,500 ft. elevation
[1] ACC = Air Cooled Condenser
[2] Solar fixed O&M is priced in $/kWdc.
[3] Based on build-transfer bids received in NWE's 2015 CREP RFP

Natural Gas-Fired Resource Siting

CB&I Stone & Webster, Inc. ("CBI") was contracted in 2013 to provide a site study (Volume 2, Chapter 6) for a new CCCT plant of about 250 MW[2] capacity to handle future load growth. These analyses provide input into the modeling. However, this information will be updated with much more detail for any actual development.

Table 9-2 CBI Study Potential Locations

CBI Study Potential Locations	
Anaconda (existing Mill Creek site)	Highwood
Big Sandy (Verona sub)	Kalispell
Billings Area	Main Line 1 / Cut Bank
Corette	Missoula
Dry Creek Storage	Silver Bow
Great Falls/ MFM	Telstad/Shelby
Havre Pipeline	Warren
Helena	

NorthWestern supplied a list of 15 potential locations throughout Montana based on current gas supply and electric transmission capabilities, load centers, and population/load growth which are listed in Table 9-2. Site-specific attributes considered include availability of NorthWestern property (Anaconda Mill Creek site, Dry Creek, Main Line 1/Cut Bank, Telstad/Shelby), proximity to existing generation infrastructure (Corette, Great Falls, Highwood), and proximity to major gas pipelines (Havre, Warren).

[2] Prior to the Lands Energy Consulting study on thermal resource specifications, NorthWestern supplied a general estimate of 250 MW in nameplate capacity for a potential gas-fired plant to CBI for siting considerations.

Table 9-3 CBI Study Scoring

CBI Study Scoring	
Selection Category / Criteria	**Weighting Factor**
System electric transmission	20
Gas supply	20
Water supply	15
Air quality issues	15
Local stakeholder support	5
Land use/ setting	10
Constructability	5
Ecology	10
Total	**100**

CBI performed a preliminary screening based on eight weighted criteria shown in Table 9-3. For each category, a value from "1" to "5" was assigned indicating the suitability of that location ranging from "complications for site development" up to "favorable development conditions" respectively. A comparison of the highest total weighted scores resulted in a short list of the five most attractive sites. These sites were further evaluated on a basis of an expanded, more detailed set of criteria that included assigning a degree of potential costs for some criteria. This analysis resulted in a list of the three most favorable locations: Billings, Anaconda/Mill Creek, and Great Falls.

NorthWestern continued this analysis by determining infrastructure requirements, issues, and associated costs for natural gas supply and transmission, and electric transmission and interconnection at each location. To provide a more focused study, the potential plants were restricted to a 50-MW ICE plant and a 250-MW CCCT plant. Choosing a conservatively high heat rate among models recommended from the Lands report, gas supply and transmission requirements were established including identification of a suitable supply connection point, installation of pipeline from this point to the new facility, and construction of compressor stations. On the electric side, determinations were made

regarding the need to re-conductor existing lines or construct new 230-kV transmission lines as well as modifying or building new associated substations. Pre-feasibility-level cost estimates associated with these infrastructure requirements were supplied by NorthWestern's Transmission department (Volume 2, Chapter 6). Using these infrastructure cost estimates, a corresponding levelized cost of natural gas ($/dekatherm) and levelized cost of electricity ($/kWh) were determined for each location. The results suggest that, on a gas and electric infrastructure cost-basis, the Billings area is the least-costly location for new gas generation, at a 50-MW or 250-MW capacity.

A second pre-feasibility cost-estimate study was conducted between the following two scenarios: building one 308-MW GE 7FA.05 CCCT facility located in the Billings area, or building five smaller Wartsila 18V50SG-B facilities geographically dispersed around the state (Billings, Butte, Great Falls, Havre, and Warren). These locations were selected primarily on the results of the above study with the added intent to minimize costs related to gas and electric transmission limitations and provide greater system reliability. Recommended units and costs from the Lands report were used to provide a more accurate representation of capital costs, fuel use, annual generation, variable and fixed costs, and carbon emissions-related costs. Infrastructure requirements and costs from the previous study were adjusted to more accurately reflect the operational characteristics of the units used in each of these plants. The resulting costs (found in Volume 2, Chapter 6) were used to calculate potential levelized costs ($/MWh). This study suggests that one CCCT facility in the Billings area would be much less costly to build and operate than five separate smaller plants dispersed around Montana.

These ongoing studies in conjunction with stochastic modeling results will be used to help define the most appropriate choices for developing new gas-fired resources in the supply portfolio. The next steps being taken are discussed in the Action Plan in Chapter 14.

Renewable Resources

Wind and small hydroelectric projects are the principle non-utility-owned renewable resources currently in the resource portfolio. Commercial scale solar PV resources have not been in operation yet in Montana, but have experienced both a decline in costs and development throughout the region. NorthWestern includes this resource for consideration in the 2015 Plan, but it is not selected in the optimization.

Hydroelectric Upgrades

Hydroelectric generation is the ultimate renewable resource; not only does it use a renewable form of energy, but the fuel (water) has the potential to be used many times over in a system of resources, as occurs on the Madison- Missouri River system. In the 1990s and early 2000s previous owners of the Hydros system (PPL and Montana Power) identified opportunities to increase the generating capacity at facilities throughout the system. Certain projects, including the Rainbow Dam powerhouse and the Mystic turbine replacement project, were successfully completed and entered service prior to NorthWestern ownership. Additional opportunities remain. NorthWestern is evaluating these projects in the context and scope of the Supply resource portfolio and the utility system needs these resources would serve. This requires complete legacy study updates. These potential projects were not assigned any value in the analyses of the Hydros purchase.

Optimization

Timing and sequencing of resource development and optimization activities has been a key consideration of NorthWestern throughout the 2015 planning cycle. Beginning in 2014, after the purchase of the Hydros was approved, NorthWestern considered initiatives to identify and develop operational alternatives for specific hydroelectric facilities as part of a broader resource fleet optimization program. One goal of the optimization is to identify and evaluate the use of all Hydros to expand their operating role in providing additional

ancillary services while continuing to provide reliable baseload generation, while operating within all fish and wildlife parameters. In the context of developing a resource procurement plan, these activities needed to be advanced before embarking on the work to evaluate new resources, including those represented by capacity expansion at existing facilities. By assessing existing capabilities NorthWestern is able to establish the proper foundation of future economic and operational efficiency and properly define future resource needs accordingly.

The scope of the capacity expansion plan for the hydroelectric system includes the rehabilitation and development projects shown in Table 9-4 below. For each project, the generating capacity increase has been reasonably defined. The energy values shown represent historic estimates that are under review and consideration by the generation staff and are subject to revision and update. NorthWestern anticipates completing the re-evaluation of project costs and subsequent assignment of priority in 2016. The seven rehabilitation projects will not trigger FERC license amendments, but the two development projects will be required to go through the process of obtaining FERC license amendments which can take several years.

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Table 9-4 Hydroelectric Capacity Expansion Potential

Hydroelectric Capacity Expansion Potential		
Development Projects	**Additional Capacity (MW)**	**Additional Energy (MWh)**
Hebgen	6.0	38,000
Ryan Unit 7	40.0	120,000
Rehabilitation Projects		
Black Eagle	1.8	3,000
Cochrane	6.0	24,000
Hauser	2.5	8,000
Holter	8.0	14,000
Morony	8.0	23,000
Ryan	8.0	37,000
Thompson Falls	4.0	15,000
Net Total	84.3	282,000

NorthWestern will place a high priority on additional work to define costs, timing, and size of these renewable resource expansion projects due to their potential to provide increased capacity and generation. The generation group is currently performing operational testing of hydro system capabilities and defining a work plan to review, evaluate, and update previous studies of the hydroelectric system.

Utility Scale Solar PV

Solar energy technologies capture energy from the sun and convert it to usable energy. One form of solar technology is photovoltaic technology that converts the sun's energy directly into electricity through the use of solar panels. Solar PV technology has been around for many years, but has not been widely adopted at least in Montana due to its intermittent nature and the high cost of the technology. The Department of Energy developed the SunShot initiative in an effort to make solar energy cost-competitive with other forms of electricity by the end of the decade. The reduction in costs and improvements in technology will make solar PV more competitive with other resources in the future.

At the time of writing this plan, six solar PV generation developers have expressed an interest in negotiating multiple QF contracts. A definitive number of locations has not yet been specified.

Solar resources are intermittent in nature. The movement of clouds can change solar production from maximum output to zero production in a matter of seconds. Solar resources also do little to provide peak capacity for NorthWestern's winter peak days as the peak occurs after the sun has set during the winter. They do provide some capacity during NorthWestern's summer peak. However, this peak occurs late in the day and the contribution is only a small percentage of its installed capacity. To develop a greater understanding of solar PV resources, NorthWestern contracted with DNV KEMA Renewables, Inc. ("DNV-GL") and Clean Power Research ("CPR").

CPR provided weather data for seven sites in Montana. The sites cover all six NorthWestern operating divisions and were selected to develop a greater understanding of the diversity of solar PV generation in Montana and the regulation required to integrate solar PV. The seven sites are located near Anaconda, Bozeman, Broadview, Great Falls, Missoula, Moore and Townsend.

DNV-GL supplied NorthWestern with a generic scalable solar PV resource designed to be suitable for Montana locations. Other than specifying that the proxy resource be sized somewhere around 3 MW, DNV-GL was left to determine the appropriate size, components, etc. Lastly, NorthWestern asked DNV-GL to model annual production using hourly Anaconda weather data supplied by CPR.

DNV-GL's indicative design is a 3.02 MW_{DC} (2.5 MW_{AC}) solar PV project using Canadian Solar polycrystalline silicone-based modules and SMA Sunny Central inverters. The

design uses single-axis tracking with conventional backtracking. DNV-GL also applied estimates for soiling losses (which includes snow cover), shading losses, and energy losses associated with equipment failures, unplanned outages, planned downtime, and solar PV degradation over time. DNV-GL provided NorthWestern with capital cost estimates for the indicative design and modeled the first year production using PVsyst and hourly weather data provided by CPR. The modeled cost of utility scale solar PV is shown in Table 9-1. The DNV-GL report, "Indicative Design, Energy, and Cost Estimation for 2.5 MW_{AC} Photovoltaic Project" is provided in Volume 2, Chapter 5. NorthWestern will also gain additional information on solar costs, output, and the intermittent nature of the output with the proposed commercial projects discussed earlier.

Wind

Wind is an intermittent generation resource, meaning that generation levels fluctuate greatly in a short time period. It is not uncommon for actual generation to deviate considerably from forecasted generation within the hour. Wind provides little peaking resource capacity as the turbines are not rated to operate during the winter peak period and during the summer peak there is normally very little wind.[3] The modeled cost of wind is shown in Table 9-1.

Small Hydroelectric

Small hydroelectric projects have been in NorthWestern's portfolio for many years. NorthWestern has over 44 MW nameplate capacity of small hydro in its portfolio. Some of the small hydro facilities are schedulable resources with very little hour-to-hour or day-to-day variability. There is some variability around yearly precipitation and seasonal water flows. Some of the small hydroelectric facilities contribute winter and summer peaking capacity.

[3] As noted in NorthWestern's 2013 Electricity Supply Resource Procurement Plan, the combined wind resources at that time (237.3 MW nameplate capacity) provided approximately 0.6 MW (0.25%) of peak capacity in winter and 5.2 MW (2.2%) of peak capacity in summer.

Research and Development

Demand Response

Demand Response ("DR") is a voluntary and temporary reduction in electricity consumption by customers during periods when the power system is stressed and in need of additional peaking resources. DR is technically not considered a "resource" but essentially fulfills the same purpose as a physical peaking resource such as an internal combustion peaking unit. DR can, therefore, offset or defer the need for new peaking resources. DR programs are not new.[4] What is new is the recent surge of interest in DR programs as the region becomes increasingly capacity constrained.

The NWPCC's 7th Plan identifies 3,500 MW of DR savings for winter peak and 3,300 MW for summer peaks by the end of the study period. Of the DR savings identified for 2035, 48% of the achievable savings are from residential, 8% from commercial, and 44% from agricultural and industrial consumers. A simple extrapolation of the regional DR savings to NorthWestern would indicate that NorthWestern can achieve significant peak savings through DR. However, NorthWestern has significantly different retail load characteristics when compared to the region or other regional utilities.

NorthWestern has a limited ability to take advantage of DR. Forty-eight percent of the DR savings that NWPCC identified is obtained from Residential DR programs, with the largest percentages obtained by controlling electric space heating and electric water heaters. However, the penetration rates for these two uses of electricity differ widely between the region as a whole and NorthWestern's service area. The Council identifies a 33% penetration rate for residential electric space heat, while NorthWestern estimates an overall penetration rate of about 3% for residential electric space heat. Similarly, the Council

[4] The Montana Power Company received approval for an Electric Industrial Retention/Interruptible Rate for Stauffer Chemical Company in the mid-1980s (Docket No. 85.9.40).

assumes a 57% penetration rate for residential electric water heat, while NorthWestern end-use studies show a 21% penetration rate for residential electric water heat.

Forty-four percent of the 2021 savings identified by the NWPCC were from the agricultural and industrial customer classes. Most of the industrial customers in NorthWestern's Balancing Authority are "choice" customers and do not purchase electricity from NorthWestern, and thus NorthWestern has a very limited resource within their customer group from which to purchase DR.

In July of 2015, NorthWestern surveyed 54 large key account customers regarding their ability, and willingness, to participate in a DR program[5]. The surveyed customers represented a combined non-coincident peak of over 550 MW. Of those surveyed, eighteen were choice customers. The respondents estimated that a cumulative total of between 34 MW and 36 MW may be subject to interruption for any one load reduction event. NorthWestern will follow up on this survey with these customers, but for the reasons above has no other current plans to implement DR.

Microgrid

NorthWestern is piloting a Microgrid project comprised of 80 kVA/183.4 kWh of battery storage and 40.26 kW of solar PV generation. A description of this project and related costs is included in Volume 2, Chapter 5.

[5] The Survey and Survey Results are included in Chapter 3, Volume 2 of the 2015 Plan.

CHAPTER 10
INTEGRATED GENERATION SYSTEM

The integrated generation system combines operation of Dave Gates Generating Station with the Hydros and Thermals to jointly manage system operations. Exploring the potential value of an integrated system follows from NorthWestern's operating objectives of maintaining a high level of performance and identifying opportunities for improvement.

Background

The first step in the 2015 planning process, begun shortly after the Hydro transaction closed, was to examine how the fleet of hydroelectric, thermal, and intermittent wind resources could be used as a system to maximize economic and operational efficiency. In 2015, HDR Engineering, Inc. ("HDR") completed an enhanced operations capability study of the recently acquired hydroelectric facilities. The study provided information needed to create the foundation upon which the 2015 Plan is built. This plan seeks to leverage the capabilities and value of the Hydros beyond that set forth in the Hydros docket – establishing integrated operations for ancillary services and load following.

In prior plans, generation asset operations were generally segregated into two categories: 1) DGGS providing primarily regulation services and 2) all other generation (Basin Creek, Colstrip, Hydros, and PPAs) providing hourly energy and contingency reserves. The EOP in the 2015 Plan has the Hydros contributing approximately half of the necessary regulation services requirement with the balance supplied by DGGS. Basin Creek and Colstrip are also integrated into the resource optimization to enhance system economics, providing additional load following and contingency reserves. DGGS, in addition to regulation services, helps optimize the portfolio by providing peak demand capacity, flexibility, and other needed ancillary services.

DGGS, consisting of a series of 6 Pratt-Whitney FT8 combustion turbines (150 MW total), and three hydro resources, 1) Thompson Falls (94 MW), 2) Rainbow (60 MW) and 3) Mystic (12 MW), were pooled to jointly manage intra-hour system responses for regulation. The Hydros' relatively low operating cost coupled with the capability to rapidly cycle up and down are characteristics that enable them to perform multiple roles; however, they have estuary and physical system constraints that limit their abilities to assume more than about half of the system obligations for regulation and load following.

The integrated system further combines the thermal resources of Basin Creek (52 MW) and Colstrip (222 MW) to provide contingency reserves. The relative contribution of each resource toward regulation and contingency reserves is shown in Figure 10-1. The Hydros and DGGS nearly equally share the responsibility for regulation. For contingency reserves, about half is carried by DGGS and a third by Basin Creek with the balance provided by the Hydros.

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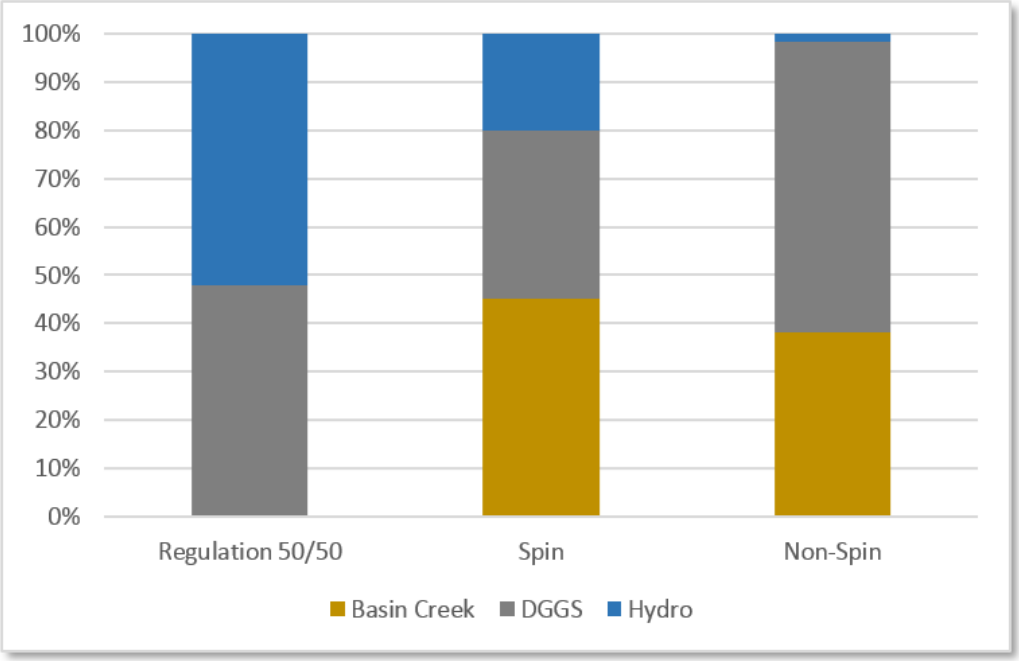
Figure 10-1 Integrated System Economic Sharing of Contingency Reserves and Regulating Requirements



Hydro Optimization

NorthWestern engaged the services of HDR in 2015 to perform a "Flexibility Operations Model Study" of the hydroelectric assets. This study represented the first phase of work to define the operational capabilities of the existing fleet and evaluate the possibilities of expanded operating roles. This work was accomplished using HDR's proprietary Computer Hydro Electric Operations and Planning Software ("CHEOPS") under conditions and constraints defined by project licenses, hydrologic conditions, and the physical characteristics of the hydroelectric fleet.

HDR customized the CHEOPS model for NorthWestern using historical operating and hydrological data from the projects comprising the Montana hydroelectric fleet. Natural groupings of projects were determined according to facility locations, major drainages, and

the licenses under which they are operated. The three generalized groupings of the resources comprising the hydroelectric system are:

- Missouri – Madison Projects (including Canyon Ferry)
- Thompson Falls Project
- Mystic – West Rosebud Projects

HDR's modeling of the hydro assets included benchmarking of model performance to represent operational conditions and compared against historical values. CHEOPS uses facility specific system conditions and constraints including flow, reservoir elevations, equipment capability, storage, and operating criteria to calculate energy production across the different systems and for individual dams.

A simple overview of the HDR work is that they evaluated different "peaking scenarios" whereby different generating schedules could be used to produce at elevated and reduced levels of generation. The context of peaking for the purpose of evaluating flexibility is the amount and timing of available hydro generation to operate in a flexible rather than a run-of-river mode. HDR determined that peaking flexibility can be available and operationally consistent with FERC licenses.

Reservoir elevations and flow requirements are two metrics that must be properly managed according to FERC licensing requirements, operational requirements, and good utility resource management practices. The result of more flexible operation is a small reduction in total annual energy production. Reduced energy production occurs when reservoir levels are lowered, hydrologic head diminishes, and individual turbines operate at a lower point on their efficiency curves. A full presentation of the analytical approach, technical considerations, and results of the HDR work are presented in the "NorthWestern Energy

Hydro Fleet CHEOPS Model Operations/Verification Report (February 2015)" which can be found in Volume 2, Chapter 5.

HDR's analysis focused on operational effects, within existing operational constraints, and did not include the analysis of the economic benefits or costs associated with flexible operation and did not capture some of the more complex operational constraints. However, HDR's modeling served as the foundational analysis and initial conditions to support Ascend in the development of a more detailed model of co-optimized hydro and thermal operations. This analysis is presented in Chapter 12.

CHAPTER 11
ANCILLARY SERVICES
LOSS OF LOAD PROBABLILITY

Introduction

Ancillary services are needed to correct for minutely and intra-hour changes in loads and generation. Loss of Load Probability ("LOLP") determines the amount of capacity that needs to be available to meet the desired or required reliability target.

Contingency Reserves

Contingency reserves must be maintained to ensure reliability under normal and abnormal conditions as part of WECC requirements.[1] For NorthWestern, this minimum amount is equal to the sum of 3% of hourly combined load and 3% of hourly combined generation. Of this minimum, at least 50% must be spinning reserves, which are on-line generators synchronized with the grid. The rest can be supplied by non-spinning reserves, which are off-line generators. Both types must be capable of responding within ten minutes and maintaining specified levels for at least sixty minutes. Table 11-1 shows the approximate minimum and maximum amount of reserves required during 2015.

Table 11-1 2015 Contingency Reserve Requirements

2015 Contingency Reserve Requirements		
	Min (MW)	**Max (MW)**
Spinning	14	35
Non-Spinning	13	34
Total Reserves	**27**	**69**

[1] Except within the first sixty minutes following an event requiring the activation of Contingency Reserves (WECC Standard BAL-002-WECC-2 – Contingency Reserve).

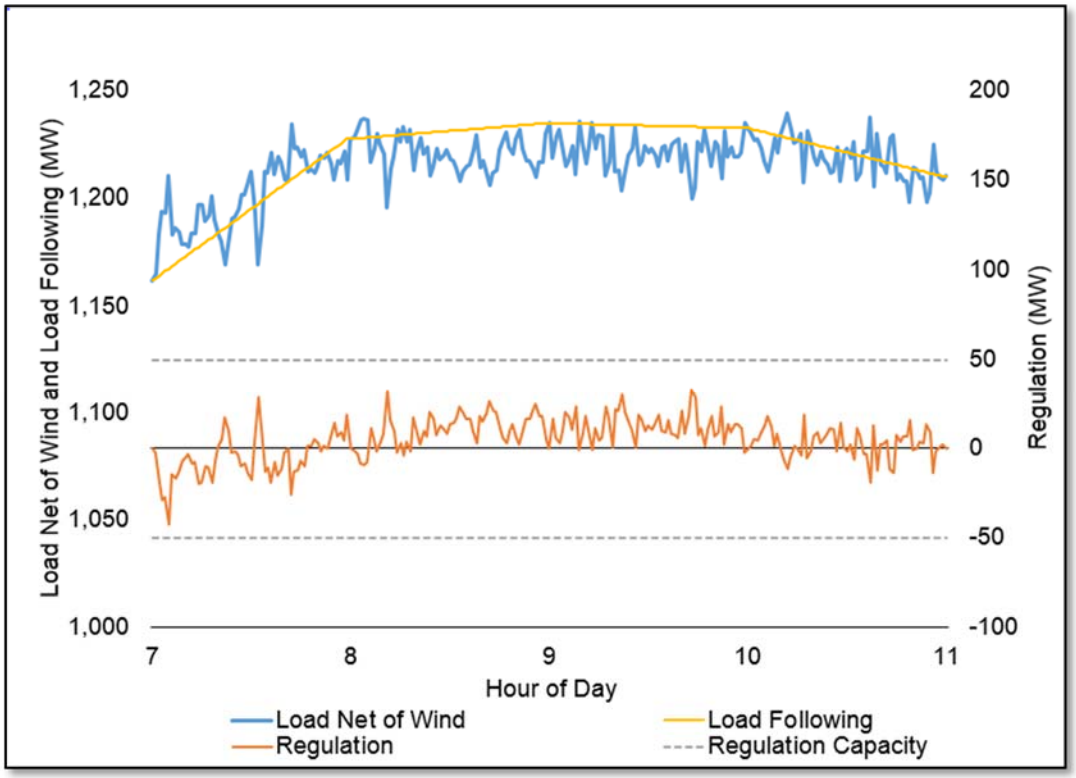
In 2015, spinning reserves were supplied by the Hydros, and a portion of Basin Creek's capacity was allocated for non-spinning reserves.

Ancillary Services

Historically, utilities were able to provide ancillary services from existing resources far in excess of their need. NorthWestern had no ability to self-provide ancillary services after purchasing the electric transmission and distribution system from Montana Power, but was able to purchase ancillary services from other regional utilities. However, as these utilities added intermittent renewable generation to their portfolios, they ended their sales of ancillary services to NorthWestern. Still lacking the resources necessary to provide its own ancillary services, NorthWestern constructed and placed DGGS into service in 2011 expressly for the provision of ancillary services. In 2015, NorthWestern acquired 442 MW of hydroelectric resources that have some ability to provide ancillary services.

Ancillary services provide fast and flexible response to keep the supply system in balance. There are two major components to ancillary services: 1) regulating reserves and 2) contingency reserves. Figure 11-1 illustrates the difference between regulation and load following services. The linear ramp between hours, designated by the yellow line, is primarily served using load following and base energy resources. Regulation, shown as the small deviations in load, is designated by the blue line, which varies around the yellow line. Regulation uses generators equipped with automatic generation control ("AGC") to quickly change output, on the order of megawatts per minute (MW/min), to correct for moment-to-moment fluctuations in customer loads and generation – particularly variations in generation of intermittent renewable resources. Regulation (right side scale) required is shown by the orange line and varies between positive and negative, netting to zero over the course of several hours.

Figure 11-1. Illustration of Regulation Compared to Load Following

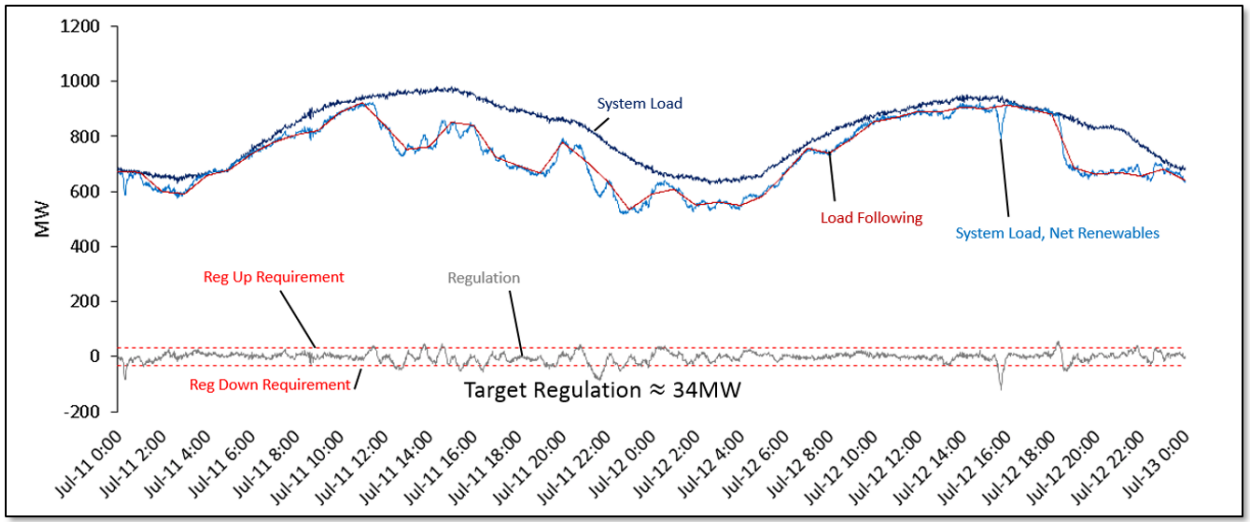


The 2015 Plan optimizes hydro and thermal resources to meet NorthWestern's regulation and load following needs. Thermal and hydro resources jointly share responsibility to meet load following and regulation requirements. Using minutely level dispatch that is co-optimized between thermal and hydro resources accurately portrays the operating patterns and resource cycles of the resources used to meet the minutely level fluctuations in net load. This analysis is performed using PowerSimm at a minutely level time step and analyzes regulation and flexibility needs and costs[2].

[2] This level of analysis is not possible with simplified spreadsheet models.

Figure 11-2 shows minutely load and intermittent renewable generation scaled to expected load and intermittent renewable generation for July 11th and 12th in 2022. System load is depicted by the relatively stable dark blue line at the top of Figure 11-2.

Figure 11-2 NorthWestern Load, Intermittent Renewable Generation, and Regulation Requirements



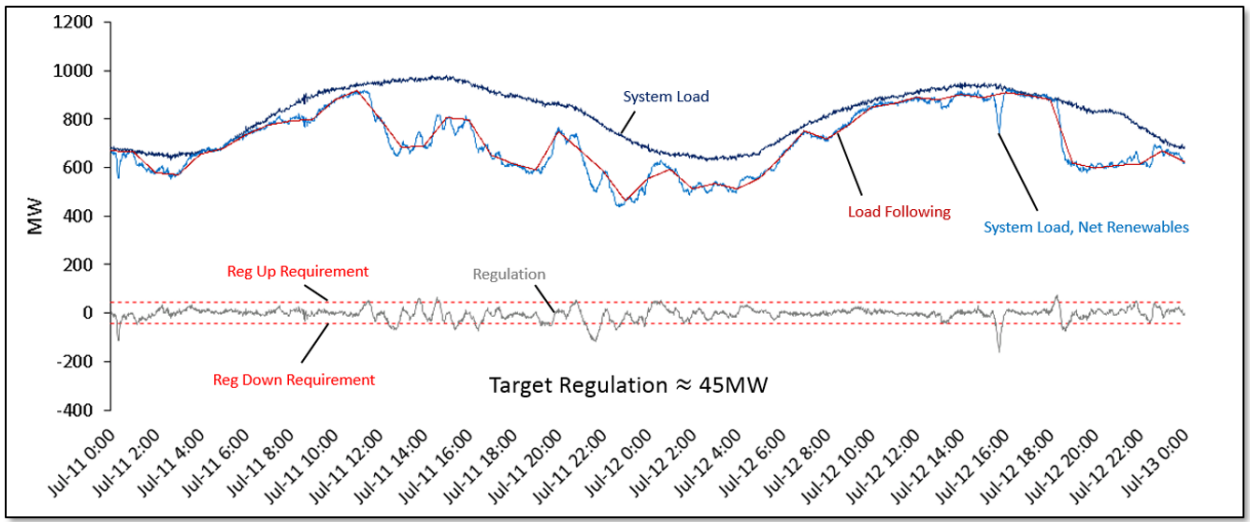
Load less intermittent renewable generation follows the light blue net load line, which moves above and below the red load following line. The difference between the red load following line and the light blue net load line represents the amount of system regulation, shown as the gray line, which is bounded by the 95th percentile confidence interval above and below.

Regulation Requirements for Wind and Solar PV

Running PowerSimm on a minutely time-step, the model is used to measure NorthWestern's ability to maintain acceptable CPS2 scores. The minutely level optimization in PowerSimm accounts for physical system limits, such as generation ramp rates needed to respond to system imbalances. The average monthly CPS2 score from

PowerSimm minutely dispatch for load and wind and solar PV for 2015 was 92[3]. The calculated regulation value required for NorthWestern is 34 MW in 2022, which consists of 12 MW of regulation required for load and 22 MW of regulation required for wind and solar PV. Figure 11-3 illustrates the impact of adding 100 MW of wind generation capacity on NorthWestern's minutely level operations.

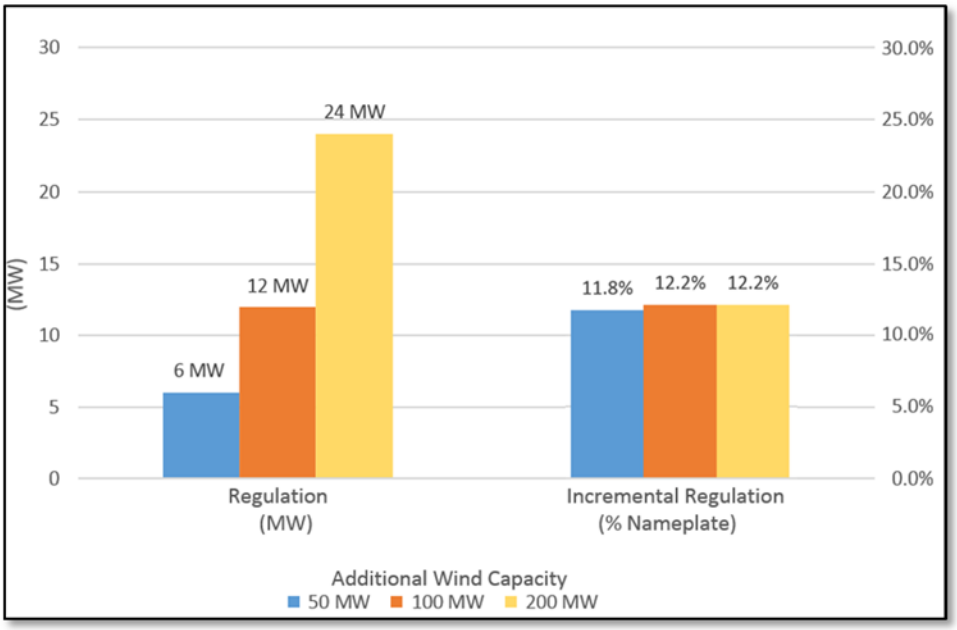
Figure 11-3 Impact of Adding 100 MW of Wind Generation on Regulation Requirements



NorthWestern's future incremental regulation requirements will be driven primarily by the amount of wind and, to a lesser extent, solar PV present on its system. The additional regulation needed to regulate an additional 50 MW, 100 MW and 200 MW of wind generation in 2022 is shown in Figure 11-4.

[3] 90 is the minimum score needed to satisfy CPS2.

Figure 11-4 Regulation Requirements for 2022 with Additional Wind Generation (Excludes Load Following Component)



NorthWestern's current resource portfolio contains relatively small amounts of solar PV. In order to gain a better understanding of solar PV resources, NorthWestern contracted with CPR and DNV-GL to provide solar irradiance data and an indicative design for solar PV facilities located in Montana. Production was modeled on a minutely basis using CPR solar data and DNV-GL's indicative design.

Figure 11-5 illustrates the impact of adding 100 MW of solar PV capacity on NorthWestern's minutely level operations. While solar PV generation does exhibit some erratic generation, the profile is generally smoother and better behaved than wind generation.

Figure 11-5 Impact of Adding 100 MW of Solar PV Generation on Regulation Requirements

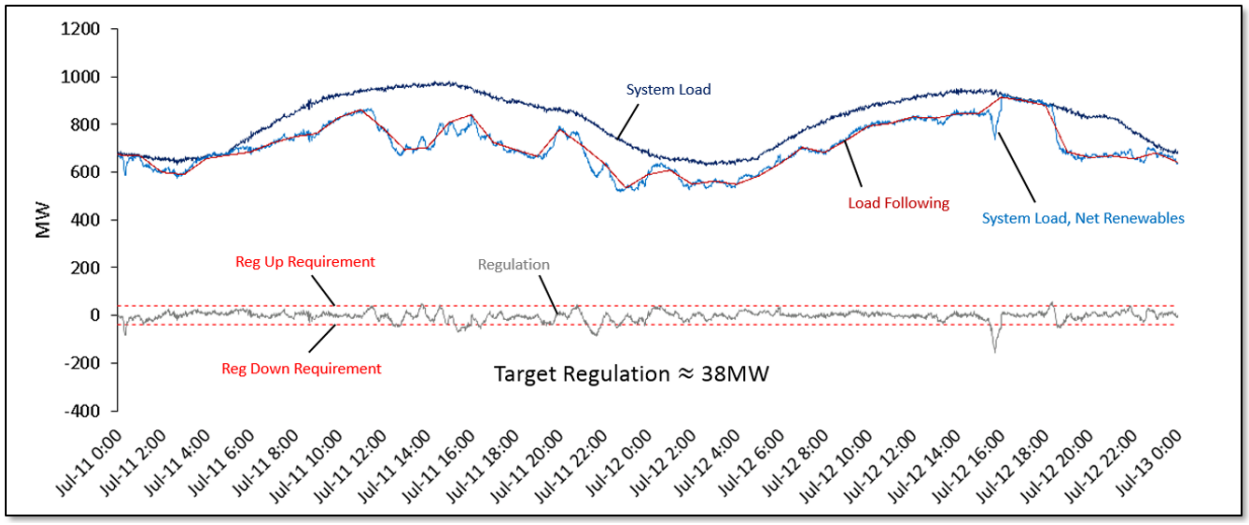


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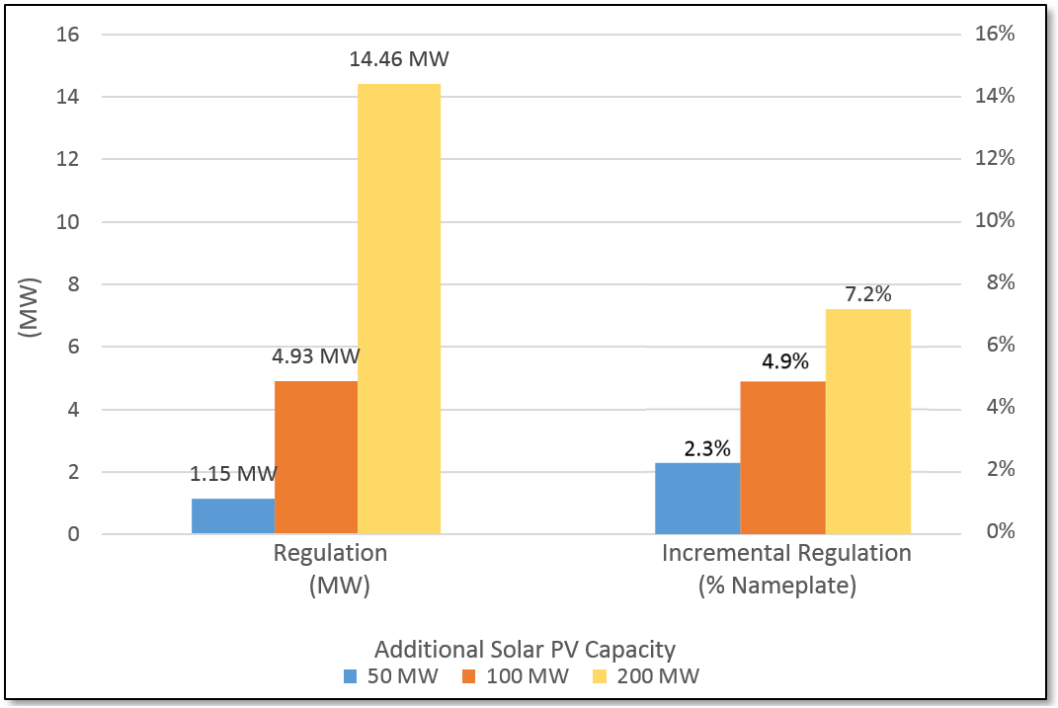
Figure 11-6 shows the small increases in regulation needed to accommodate the addition of 50, 100, and 200 MW of solar PV generation. The addition of 100 MW of solar PV generation in 2022 increases the regulation requirement by about 4 MW.

Figure 11-6 Regulation Requirements for 2022
With Additional Solar PV Generation
(Excludes Load Following Component)



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Flexibility Requirements for Wind and Solar PV

This section evaluates the level of flexible resources needed to balance loads and generation on NorthWestern's electric system. Figure 11-7 shows the hourly differential in load for NorthWestern over the two day period of July 11th and 12th, 2022. Total ramp (in red) is composed of the ramp needed for load, wind and solar. The figure illustrates that much of NorthWestern's current ramping need is caused by variations in wind generation.

Figure 11-7 One-hour Ramp Requirements with Current Resources

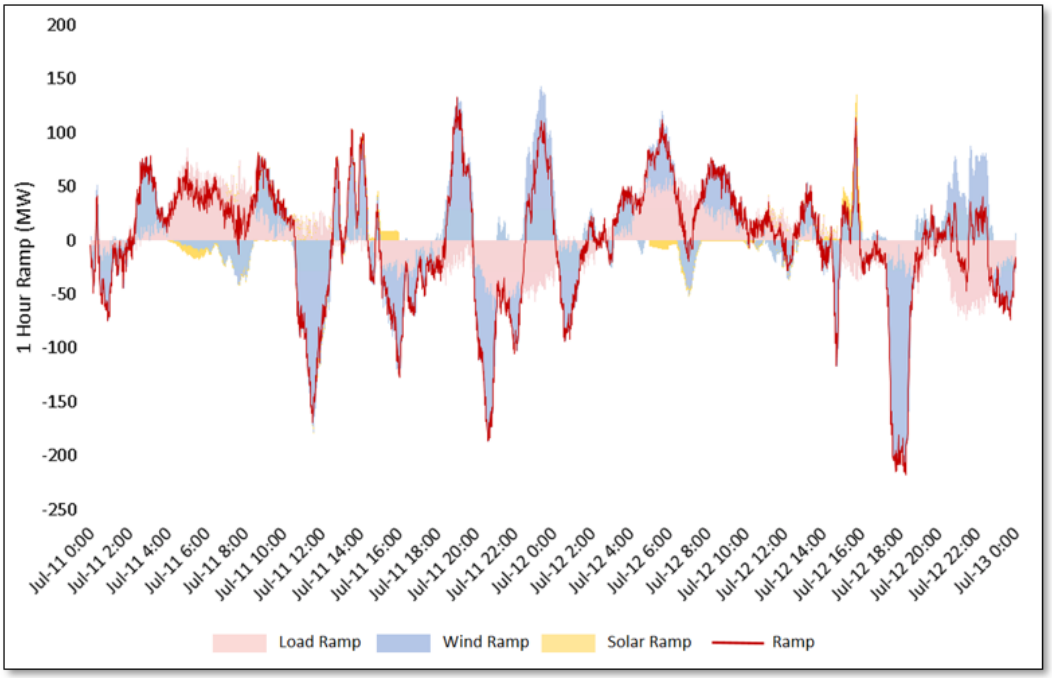

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Figure 11-8 shows the effect on ramp rates of adding 100 MW of wind generation for the same period. With the addition of 100 MW of wind, 1-hour ramp rates increase to 372 MW up and 376 MW down (increases of 85 MW up and 84 MW down). This analysis illustrates that additional intermittent wind generation cannot be added to NorthWestern's system without making sure that it has, or acquires, sufficient flexible generation.

Figure 11-8 One-hour Ramp Requirements with Additional 100 MW Wind

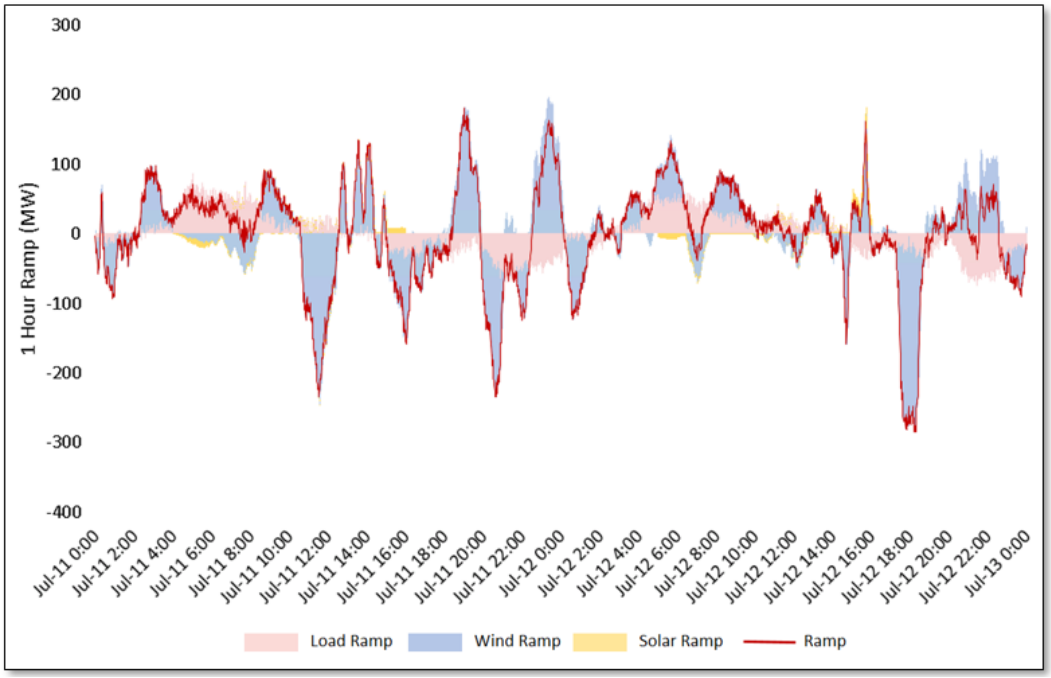

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Figure 11-9 shows effect on ramp rates of adding 100 MW of solar PV generation for the same period. With the addition of 100 MW Solar PV, 1-hour ramp rates increase by about 11 MW ramp up and no appreciable change in ramp down. While this analysis used the best data available, it used estimated solar production data and these results should be verified with actual solar PV production data to establish definitive conclusions.

Figure 11-9 One-hour Ramp Requirements with Additional 100 MW Solar

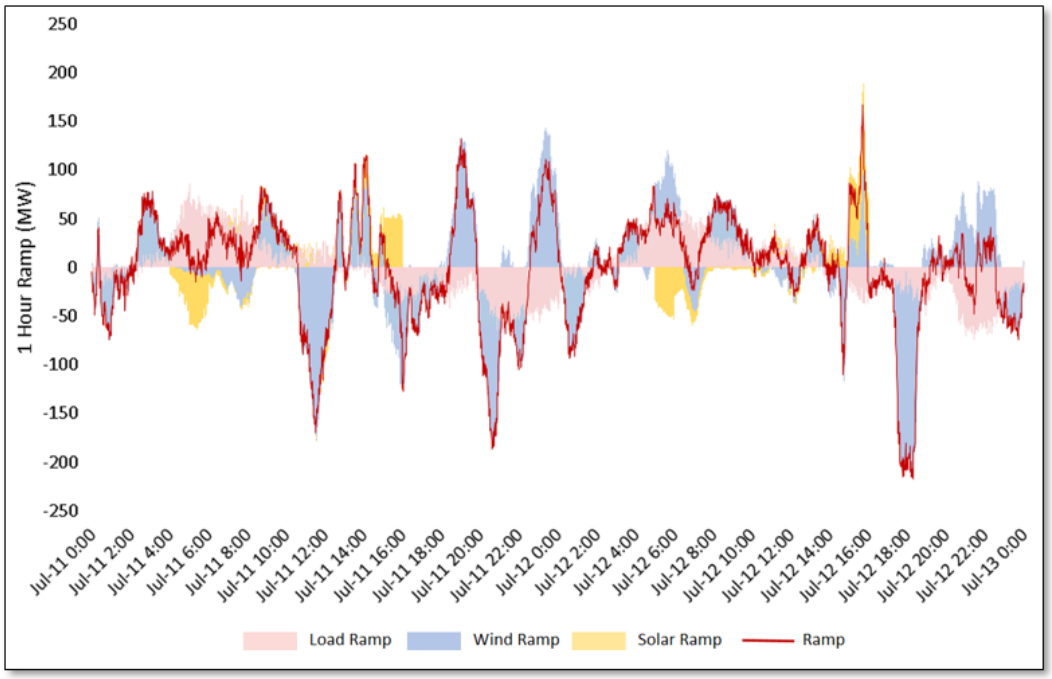

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Table 11-2 below summarizes the maximum 1-hour ramp up and maximum 1-hour ramp down for the planning year 2022. Maximum ramp rates are shown for the Economically Optimal Portfolio ("EOP"), the EOP plus 100 MW of incremental wind, and the EOP plus 100 MW solar PV. While 100 MW of incremental wind requires about 85 MW of ramping, an incremental 100 MW of solar PV has much less effect on ramping.

Table 11-2 2022 Ramp Requirements with Additional Wind and Solar PV

Year 2022 Ramp Requirement	Economically Optimal Portfolio	+100 MW Wind	Increment	+ 100 MW Solar PV	Increment
Solar PV Added	-	-	-	100 MW	100 MW
Wind Added	-	100 MW	100 MW	-	-
Regulation Requirement	34 MW	45 MW	12 MW	38 MW	1 MW
Total Solar Capacity	40 MW	40 MW	-	140 MW	100 MW
Total Wind Capacity	266 MW	366 MW	100 MW	266 MW	-
1-Hour Ramp-Up	287 MW	372 MW	85 MW	298 MW	11 MW
1-Hour Ramp-Down	292 MW	376 MW	84 MW	292 MW	-

Ramping capability is the key component of load following which has been mathematically identified and separated from regulation in the modeling analysis. While distinctly different from regulation, it is more challenging to isolate and evaluate independently because it is supplied concurrently from the same resources that are providing load-serving capacity and energy to the portfolio. In addition, load following is dynamic because conditions for generation resources change based on available physical capabilities (e.g. hydro conditions), unit outages, and economics.

The co-optimization of hydro and thermal resources to provide needed ancillary services shows cost savings opportunities. The reduced reliance on thermal units such as DGGS to provide regulation services lowers fuel and other costs of operation. This means that the capacity of DGGS units not being used to provide regulation services are economically

deployed to provide other services such as load following, peaking and reserves. The inherent flexibility of DGGS allows it to perform multiple roles and to readily change operation because of its high level of dispatch capability over a wide operating range.

Cost of Regulation

The Hydros have been modeled to furnish up to 50% of the regulation requirements of the 33 MW needed for NorthWestern's current portfolio, decreasing the cost of regulation. For the Load + Existing Wind & Solar (Base) case, shown in Figure 11-10, the 20-year NPV of variable costs for regulation decrease from $14.3 million to $7.2 million when DGGS and the Hydros share regulation service responsibility. Regulation costs decrease by $4.4 million from DGGS to 50/50 in the case when an additional 200 MW of wind is added to the current resource portfolio, and by $2.8 million when an additional 200 MW of wind is added to the current resource portfolio.

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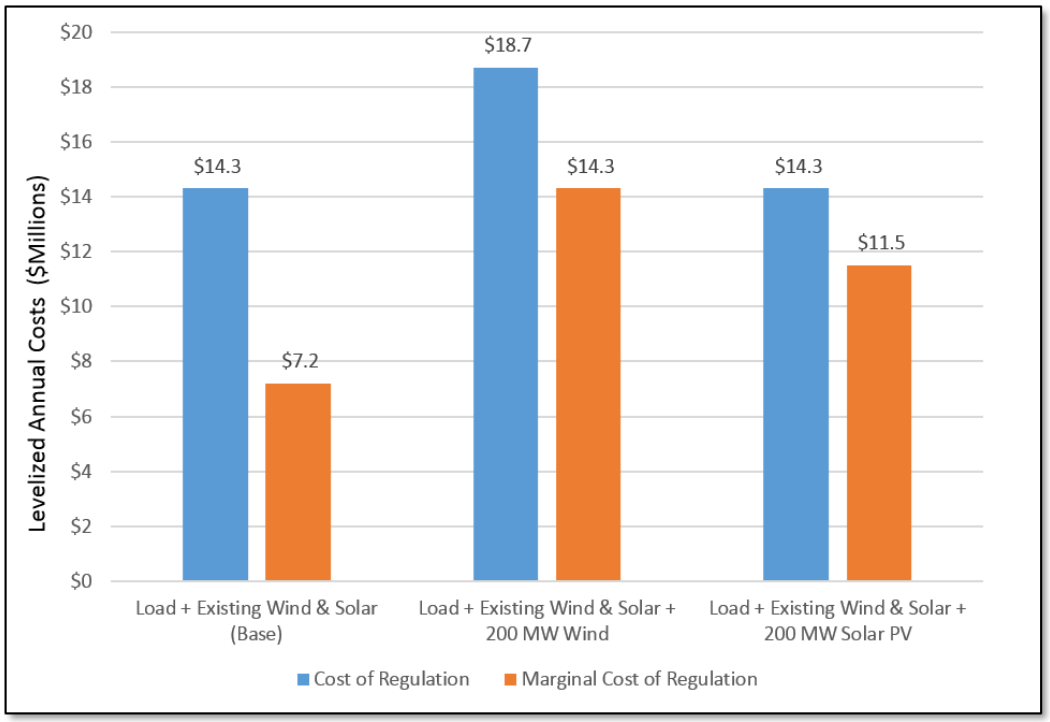
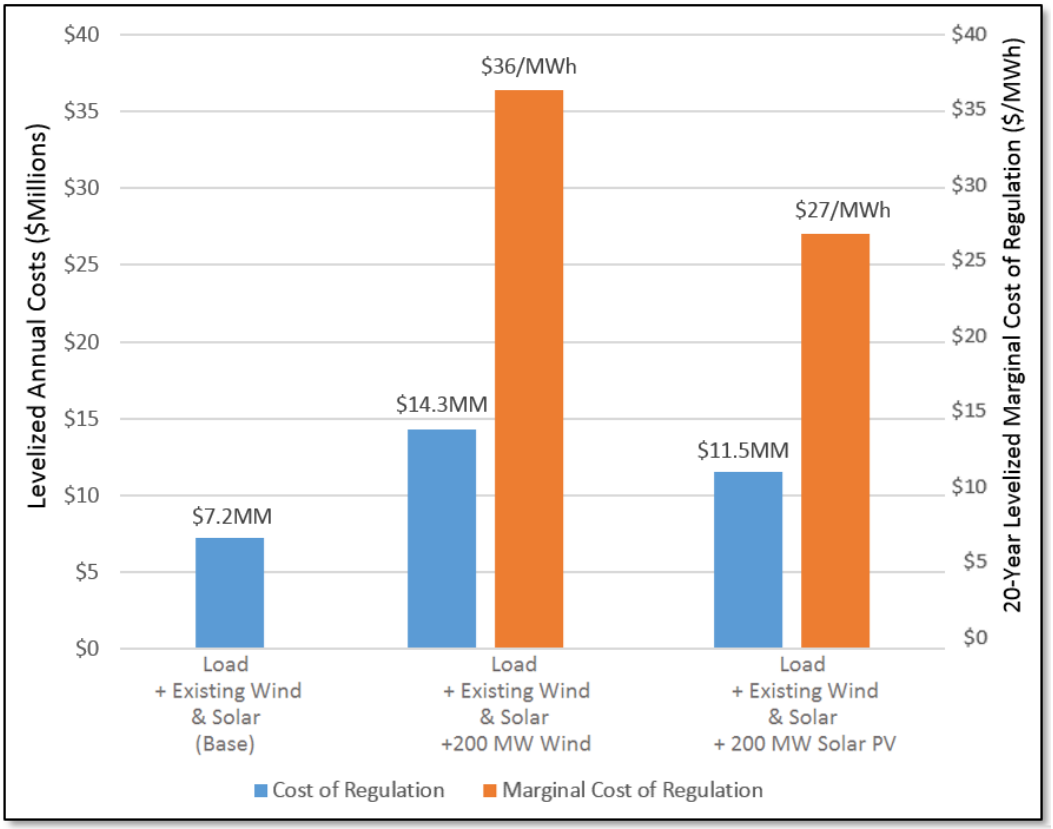
Figure 11-10 DGGS Regulation vs. 50/50 Regulation



NorthWestern is currently taking steps to enable implementing the 50/50 regulation operations that are modeled in PowerSimm. Successful completion of resource testing and updated operations are anticipated to lead to costs of regulation declining substantially. Figure 11-11 shows the regulation costs of serving loads at current levels of wind and solar PV, and the costs and marginal costs of serving loads at current levels of wind and solar PV and with additional amounts of wind and solar PV. Assuming 50/50 regulation, the cost of regulation needed to serve the current level of loads and wind and solar PV in NorthWestern's supply portfolio is approximately $7.2 million. Adding another 200 MW of wind roughly doubles the cost of regulation to $14.3 million, at a marginal cost of $36 per MWh. With the addition of 200 MW of wind, the regulation requirement increases by 12 MW, surpassing the Hydros' ability to continue to contribute 50% of the regulation, which drives the incremental cost of regulation higher. Adding another 200 MW of solar

PV increases regulation costs from $7.2 million to $11.5 million, at a marginal cost of $27 per MWh.

Figure 11-11 Cost of Supply Regulation 50% Hydros - 50% DGGS



Loss of Load Probability

LOLP or Loss of Load Expectation ("LOLE") is typically performed on an integrated utility system to determine the amount of capacity that needs to be installed to meet the desired reliability target. For planning purposes, NorthWestern does not need LOLP or LOLE to arrive at the conclusion that the physical resources in its resource portfolio fall far short of peak retail loads. However, LOLP analysis informs us of the amount of capacity additions necessary to maintain system reliability, and the supporting analysis also assesses the peak capacity contribution from intermittent resources, such as wind and solar

PV. Therefore, NorthWestern worked with Ascend to develop an LOLP metric for use in the 2015 Plan and other NorthWestern proceedings.

Traditional LOLP / LOLE analysis considers the peak hour of the days that have significant LOLP, which are generally peak demand days. Ascend calculates NorthWestern's LOLP using Load Hours ("LOLH") analysis, which jointly values the volumetric uncertainty of demand and supply to assess resource adequacy. The LOLH metric considers all hours during which there may be a risk of insufficient generation. According to NERC, LOLH is the more appropriate measure for resource adequacy, but its translation into a standard LOLP metric requires additional research.[4] In support of using LOLH, NERC states the following:

> *"With high penetrations of variable generation, this may be an advantageous metric because of the variability of these resources. The daily LOLE metric is coarse: it only considers one hour a day. The LOLH metric looks at each hour. This provides a more accurate assessment of adequacy in the sense that all hours are examined by the metric. However, unlike the daily LOLE, there is no generally accepted hourly target. For example, 2.4 hours/year is not the same as 0.1 days/year. Additional analysis is required to determine the relationship between LOLE and LOLH reliability targets."*[5]

To measure NorthWestern's LOLP, Ascend calculates the total annual LOLH from the simulations of net load and generating resource availability. Total annual LOLH is converted to the "LOLH in 10-years" metric by multiplying total annual LOLH by 10. NERC suggests that translating LOLH into LOLP "requires additional research". An industry standard LOLP metric is one day in ten years.

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[4] NERC, *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning*. March, 2011. http://www.nerc.com/files/ivgtf1-2.pdf (Volume 2, Chapter 7)

[5] Ibid pp. 28.

The analysis uses an advanced integrated simulation framework that captures the joint probability of load and intermittent renewable generation over 100 simulated weather conditions. The net load follows from a simulated set of meteorological conditions that drive load, wind, and solar generation. Generation resource availability is simulated from plant generation data based on an expected outage rate distribution and outage duration.

Table 11-3 portrays the LOLP metrics for NorthWestern's 2016 portfolio of physical resources, which has a physical reserve margin of -28%. To realize the industry standard LOLP of one day in ten years for 2016, NorthWestern would need to add 500 MW of capacity. This corresponds to an expected reserve margin of 14%. The current reliability planning criteria of the NWPCC of a 5% outage limit corresponds to 1.5 days in ten years.[6] Under the NWPCC criteria, NorthWestern would carry a reserve margin of 13% and need to add 487 MW of capacity.

Expected LOLH per 10 years is converted to Expected LOLD per 10 years by looking at the expected duration of the hourly level events per day. In this study the average expected loss of load event was 2 hours in duration, so expected LOLH hours are converted to days (dividing by 24), and then scaled by the expected event duration (multiplying by 2).

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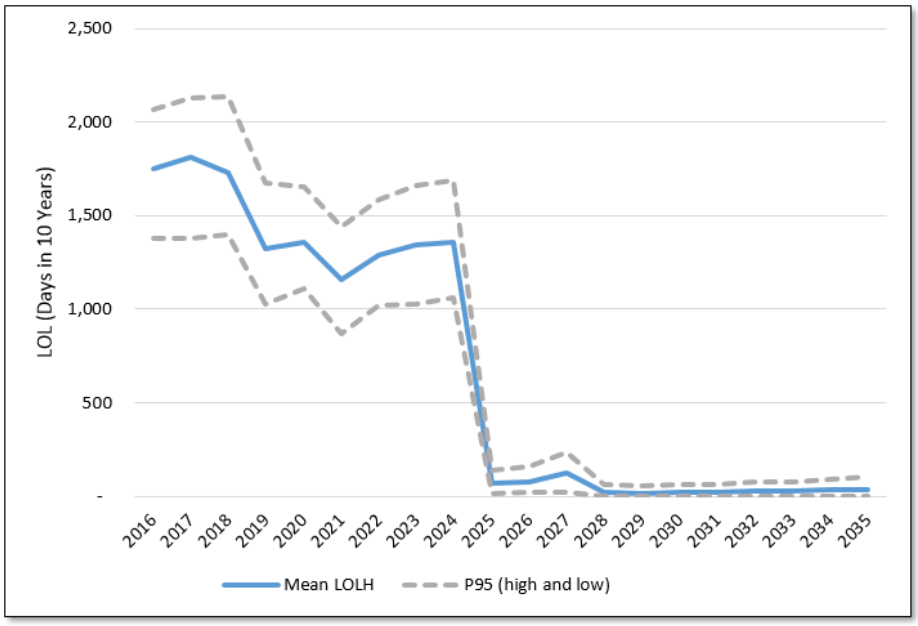
[6] Phone conversation with NWPCC staff, March 8, 2016.

Table 11-3 2016 Reserve Margins and LOLP with Capacity Resource Additions

Reserve Margin (%)	MW Additions	Expected LOLH in 10 years	Expected LOL Days in 10 years
-28%	0	21,020	1,752
-26%	25	17,382	1,449
-24%	50	14,075	1,173
-22%	75	11,167	931
-20%	100	8,692	724
-18%	125	6,618	551
-16%	150	4,921	410
-14%	175	3,608	301
-12%	200	2,571	214
-10%	225	1,804	150
-7%	250	1,236	103
-5%	275	833	69
-3%	300	532	44
-1%	325	332	28
1%	350	202	17
3%	375	116	10
5%	400	63	5
7%	425	36	3.0
9%	450	20	1.7
12%	475	10	0.8
14%	500	5	0.4
16%	525	1.2	0.1
18%	550	0.4	0.0

NorthWestern's optimal expansion planning analysis adds resources to increase the portfolio capacity level to a reserve margin of 0% in 2028, but still falls short of the normative planning capacity additions needed to realize an LOLP equal to one day in 10 years. Figure 11-12 shows the LOLP of the optimal expansion for the EOP. With capacity additions, the LOL Days in ten years falls to 16 days in 2029 and the rises to 36 days by the end of the planning period.

Figure 11-12 LOL Days in Ten Years – Economically Optimal Portfolio



As discussed previously, the wholesale market currently has an abundance of low-cost energy and a small surplus in capacity relative to load which is forecast to be deficit by 2021. NorthWestern can currently capitalize on these market conditions to meet its energy and capacity needs. Finding resources that are capable of meeting NorthWestern's future capacity requirements, as this surplus diminishes due in part to regional coal plant retirements and loss of flexibility in the region, while providing the most economic value to its customers, is a focus of this Plan.

CHAPTER 12
RESULTS AND CONCLUSIONS

Ascend's analysis identifies flexible capacity as the economically optimal near term resource additions. The addition of flexible capacity in the form of Internal Combustion Engines provides reliable capacity at the lowest cost.

Introduction

This chapter discusses NorthWestern's optimal capacity expansion analysis and the results and conclusions of NorthWestern's portfolio analysis. Several conclusions are evident from the analysis:

1. NorthWestern cannot continue to rely upon the market or other utilities to meet such a large percentage of NorthWestern's capacity requirements. Prudency in this context means customers will pay higher costs coupled with higher risks
2. Applying the results from PowerSimm and PowerSimm Planner will lead to a more efficient and lower cost portfolio of resources at lower risk than relying upon market purchases.
3. Carbon cost is a significant risk factor in NorthWestern's portfolio analysis.
4. NorthWestern's resource portfolio, already low carbon, remains low carbon when current RPS requirements are added to the Economically Optimal Portfolio ("EOP").
5. Intermittent renewable resources, like wind and solar, do not address NorthWestern's need for capacity resources and are not selected.
6. Adding wind and solar PV resources to the EOP increases NPV cost.

7. Additional wind and solar PV beyond RPS requirements further lowers carbon, but at significantly higher costs.
8. CPS2 compliance was the basis for determining regulation need in this Plan. RBC is the new compliance standard and requires flexible resources.
9. The EOP does not address NorthWestern's need for additional capacity resources to provide a minimal level of planning reserve margin.
10. NorthWestern's fleet of generation resources will be operated for additional and varied purposes, lowering overall costs to consumers.
11. DGGS will no longer be used exclusively as a regulation resource, but will be used to provide a variety of generation services.

Options for Capacity Expansion

The evaluation of near-term capacity resource additions considers both the potential for new generation assets to reduce NorthWestern's capacity deficit while also addressing system needs for flexible generation to integrate current and additional intermittent renewable resources. PowerSimm Planner was used to perform optimal capacity expansion planning and to assess the long-term path toward resource adequacy.

As discussed in Chapter 7, NorthWestern has a physical resource adequacy of -28% for 2016, which is equivalent to being 338 MW short. Unconstrained, PowerSimm Planner would fill this gap in a single year, creating an impossible build-out schedule. To create a more realistic and manageable schedule, NorthWestern constrained PowerSimm Planner such that it achieves minimum levels of resource adequacy over approximately ten years. NorthWestern selected ten years based upon the work of the NWPCC Resource Adequacy Advisory Committee ("RAAC"). Ten years allows NorthWestern to achieve minimal resource adequacy in about the same time frame that 2,400 MW coal-fired generation is

scheduled to retire in this region, which was the principle driver of regional resource need in the RAAC's analysis. NorthWestern also considered the potential impacts of the Clean Power Plan on the Colstrip facilities. This extended time frame also contains an inherent flexibility in resource timing and acquisition, as opposed to a "build-it-all-at-once" strategy. Not considered at the time the decision was made to achieve minimal resource adequacy in ten years was the current legislative efforts underway in Oregon and Washington to end "coal-by-wire" purchases from Colstrip. Those efforts underscore the need for NorthWestern to proactively address and resolve its current capacity deficit.

Constrained to achieve minimal resource adequacy in ten years, PowerSimm Planner determined timing and types of resource additions from a range of available supply options.[1] The key characteristics of generic generating units evaluated for capacity expansion planning are summarized in Table 12-1.

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[1] Although demand side resource options were not considered, these resources have value and will be considered in future analysis with the development of demand side programs.

Table 12-1 Summary of Resource Inputs for Capacity Expansion Planning

Resource Description	Fuel Source	Technology	Net Capacity (MW)	Capital Cost ($ / kW)	Fixed O&M ($ / kW-yr)	Variable O&M ($ / MWh)	HHV Heat Rate (Btu/kWh)	Escalation Rate (%/year)
CCCT (1x1)	Natural Gas	GE 7FA.05 ACC[1]	308	$1,400	$10	$3	6,528	2.0%
CCCT (Duct Firing)	Waste Heat	GE 7FA.05 ACC[1]	40	$0	$12	$0	8,546	2.0%
SCCT - Small Aeroderivative	Natural Gas	PW FT8	53	$1,017	$6	$5	10,500	2.0%
SCCT - Large Aeroderivative	Natural Gas	GE LMS100	93	$1,187	$17	$3	8,867	2.0%
SCCT - Frame	Natural Gas	GE 7EA	79	$997	$12	$3	11,286	2.0%
ICE - Internal Combustion Engine	Natural Gas	Wartsila 18V50SG	18	$1,280	$11	$5	8,314	2.0%
Utility Scale Solar PV[2]	Solar		25	$3,176	$43	$1		-1.0%
Wind[3]	Wind		40	$1,980	$38	$2		-0.5%

Table Notes:
Capacity for natural gas-fired resources estimated at 3,500 ft. elevation
[1] ACC = Air Cooled Condenser
[2] Solar fixed O&M is priced in $/kWdc.
[3] Based on build-transfer bids received in NWE's 2015 CREP RFP

Dynamic programming for automatic resource selection determines the optimal expansion path. The optimization routine does this through a two-pass process. The first pass is a backward pass that determines the number of feasible resource additions that satisfy the reserve margin constraints. After determining the feasible sets of generating resources that satisfy the constraints, the dynamic optimization proceeds forward in time selecting the addition of resources that minimizes the NPV of fixed and variable operating costs (second pass).

The reserve margin constraints specified for this analysis start with the current portfolio as it exists today, adds resources to achieve an intermediate requirement of 82% of expected peak load in 2025, then further adds capacity resources to achieve a final requirement of 100% of expected peak load required in 2028. The constraints allow the model to select reasonable levels of generation additions while satisfying the extended multi-year schedule.

Resource additions incorporated in this analysis have specified capital costs, escalation rates, reserve margin contributions, and annual fixed operating costs. These additions are valued against the stochastic simulations so that their values are estimated across the potential future conditions. This variable costs valuation is added to the other inputs, and the sum of these fixed, variable, and capital costs are used to calculate the NPV.

Portfolio Analysis

NorthWestern's portfolio analysis assesses a wide range of potential conditions for load growth, market prices for gas and emissions, and also shows the impact of environmental policies. Table 12-2 shows the input assumptions for each portfolio of resources analyzed. NorthWestern's base case scenario labeled "Current plus Market" captures NorthWestern's current set of resources and relies on market to meet current and future needs. The Current plus Market portfolio also uses NorthWestern's base case carbon scenario and a forecast average annual load growth of 0.8% over 20 years. In addition to the Current plus Market portfolio, other load growth scenarios include a "Low Load Growth" portfolio (0.4% average annual growth rate) and a "High Load Growth" portfolio (1.2% average annual rate).

The base assumption for carbon has an expected price of $20/ton for CO_2 in 2022 and a price distribution range of minimum value of $0/ton and maximum value of $40/ton. A "Low Carbon Cost" portfolio and a "High Carbon Cost" portfolio were also evaluated with a deterministic price at the minimum and maximum of the base case triangular distribution ($0 and $40/ton). Because carbon cost is defined as a variable in the stochastic model without the benefit empirical data, the triangular distribution creates a component of randomness that appropriately reflects the level of uncertainty associated with future implementation of carbon emissions regulations.

Table 12-2 Resource Plan Portfolio Assumptions

	Regulation	Assets	Load	Carbon Price	Fuel/Power Forecast
Current plus Market	50% Hydros 50% DGGS	Basin Creek Colstrip 3&4 Hydros DGGS	Grows by ~0.8%/year	Triangular distribution Mode = $20/ton Max=Roughly 2xMode. Starts in 2022 and escalates	Simulated monthly forwards from current CME market curves out to July 2020. Extended to 2035 by escalating both gas and power at 4% from July 2020 on.
Economically Optimal	Same as Current plus Market	Current plus Market +308MW CCCT +10x18MW ICEs +80 MW Frame CT	Same as Current plus Market	Same as Current plus Market	Same as Current plus Market
Preferred with Frame CT substituted for Wartsilas in 2019	Same as Current plus Market	Economically Optimal -4x18MW ICEs +80MW Frame CT	Same as Current plus Market	Same as Current plus Market	Same as Current plus Market
Low Load Growth	Same as Current plus Market	Economically Optimal -80MW Frame CT	Grows by ~0.4%/year (50% of Base Case)	Same as Current plus Market	Same as Current plus Market
High Load Growth	Same as Current plus Market	Economically Optimal +2x80MW Frame CTs	Grows by ~1.2%/year (150% of Base Case)	Same as Current plus Market	Same as Current plus Market
Low Carbon	Same as Current plus Market	Economically Optimal	Same as Current plus Market	Zero Carbon Costs	Same as Current plus Market
High Carbon	Same as Current plus Market	Economically Optimal	Same as Current plus Market	Carbon Cost = Maximum of Base Case triangular distribution	Same as Current plus Market
High Gas and Power Market	Same as Current plus Market	Economically Optimal	Same as Current plus Market	Same as Current plus Market	Natural Gas and Electric Prices increased by 22% over Base Case
Double Wind & Solar	Same as Current plus Market	Current plus Market +18x18MW ICEs +5x80 MW Frame CT	Same as Current plus Market	Same as Current plus Market	Same as Current plus Market
Triple Wind & Solar	Same as Current plus Market	Current plus Market +16x18MW ICEs +6x80 MW Frame CT	Same as Current plus Market	Same as Current plus Market	Same as Current plus Market
RPS Compliance	Same as Current plus Market	Economically Optimal	Same as Current plus Market	Same as Current plus Market	Same as Current plus Market

The EOP portfolio includes the all of the assumptions in the Current plus Market portfolio, but adds resources to achieve resource adequacy in approximately ten years. PowerSimm Planner selected capacity resource additions from the resources listed in Figure 12-2.

In all resource portfolio scenarios a GE 7FA.05 CCCT is added in 2025. With a capacity of 308 MW plus an additional 40 MW of duct firing capacity, this unit rapidly and cost-

effectively addresses a majority of NorthWestern's capacity needs. PowerSimm Planner "fills in the corners" with a mix of more flexible ICEs and later frame CTs to meet NorthWestern's future capacity and flexibility requirements. Table 12-3 shows unit build-outs by portfolios and scenarios.

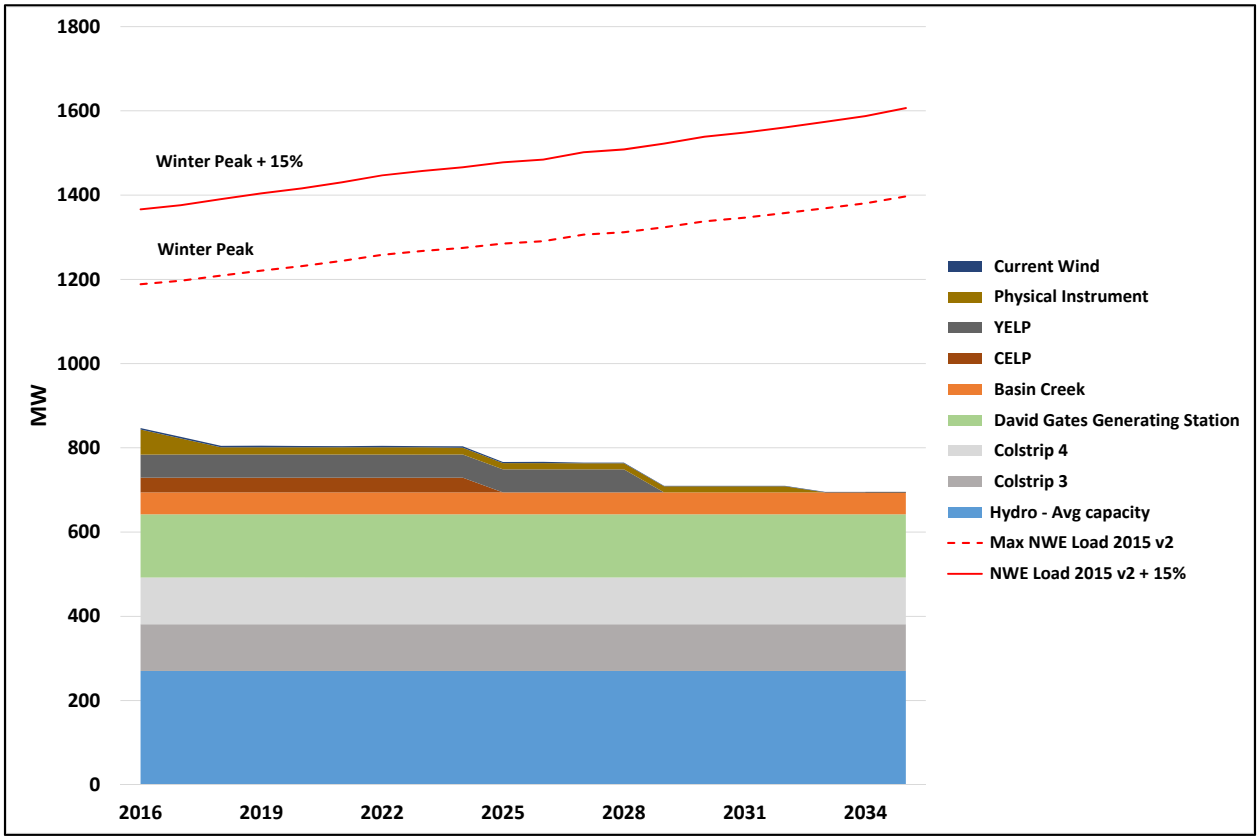
Table 12-3 Description of New Units by Portfolio

Portfolio	2016-2019	2020-2025	2026-2029	2030-2035
Current plus Market	No Additions	No Additions	No Additions	No Additions
Economically Optimal **High Carbon** **Low Carbon** **High Gas & Power**	3xICE	2xICE CCCT	5xICE 2xFrameCT	No Additions
Frame CT in 2019	FrameCT	2xICE CCCT	5xICE 2xFrameCT	No Additions
Low Load Growth	2xICE	ICE CCCT	6xICE FrameCT	No Additions
High Load Growth	4xICE	3xICE CCCT	3xICE 2xFrameCT	No Additions
RPS Compliance	3xICE	2xICE CCCT	5xICE 2xFrameCT	No Additions
Double Wind & Solar	2xICE 1xFrameCT	6xICE 2xFrameCT	10xICE 2x FrameCT	No Additions
Triple Wind & Solar	4xICE 2xFrameCT	12xICE 4xFrameCT	No Additions	No Additions

Capacity Expansion Charts

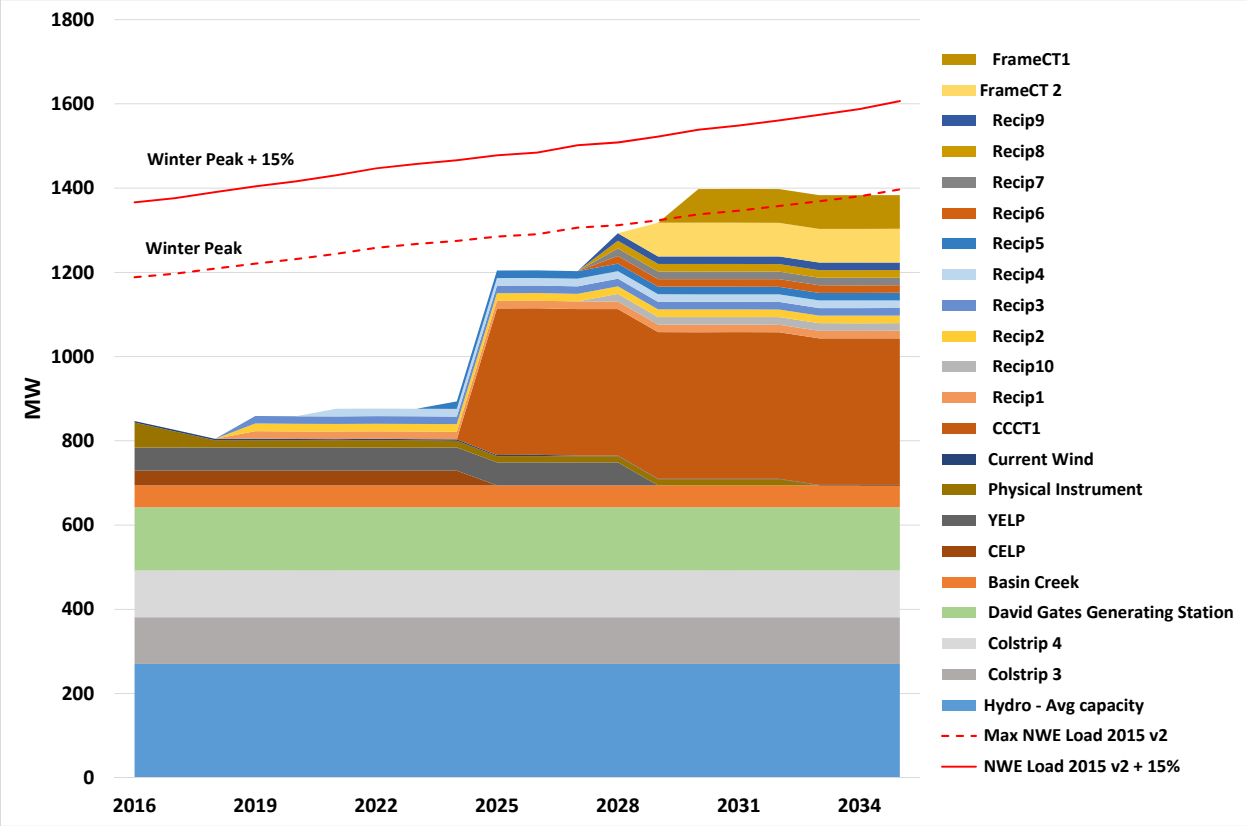
The following capacity expansion charts illustrate the growth in capacity over time of the Current plus Market and Preferred portfolios. Figure 12-1 shows the available winter capacity of all generation assets in NorthWestern's current resource portfolio. The dashed red line represents NorthWestern's winter peak demand forecast, while the solid red line represents winter peak demand plus a 15% reserve planning margin. The gap between the resource stack and the winter peak demand forecast represents NorthWestern's current resource adequacy deficit, which is substantial.

Figure 12-1 Current Plus Market Portfolio



The capacity expansion and resource adequacy of the EOP is shown in Figure 12-2. The EOP begins with the addition of three 18-MW ICEs in 2019 and continues to add a total of 10 ICEs by 2028. The flexibility of ICEs yields substantial value in a market that is short of flexible and fast ramping resources. The largest resource addition occurs in 2025 with a 348-MW CCCT (including 40 MW of duct firing). The CCCT plant substantially addresses NorthWestern's capacity deficit. The addition of two Frame CTs in 2028 and 2029 brings NorthWestern's reserve margin slightly above 100% physical resource adequacy, but still short of a minimal planning reserve margin.

Figure 12-2 EOP Capacity Expansion



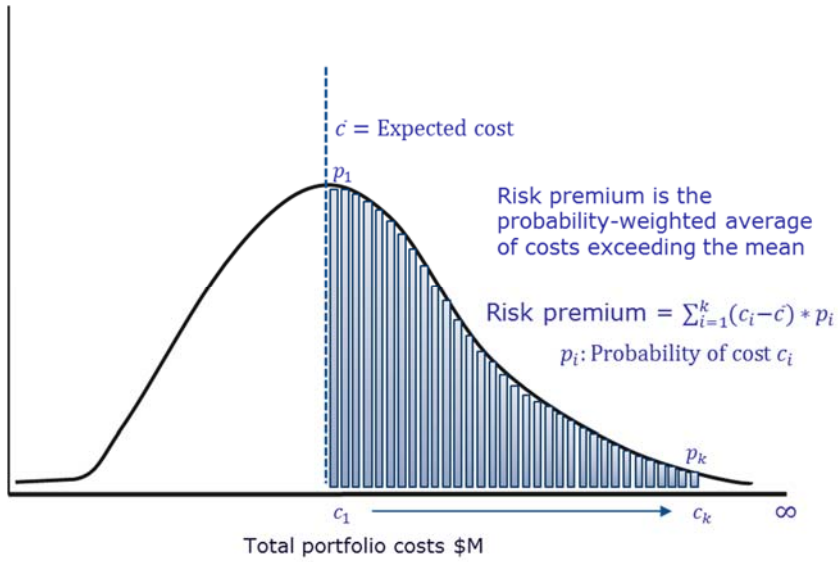
Valuation of Risk

PowerSimm dispatches NorthWestern's resources iteratively for all years of the study horizon in order to arrive at a distribution of future costs. The expected value of portfolio costs is therefore a robust metric to determine the cost ranking of the different portfolio options, but it does not capture the differences in risk between the portfolios. Given the substantial uncertainty in future prices of fuel, wholesale power costs, and carbon costs between portfolios, the distributions of costs around each portfolio's expected value are significantly different.

PowerSimm monetizes the difference in the shapes of these distributions by use of the *risk premium*, defined as the integral of the cost distribution above the mean. This is similar to

the approach taken by traders to evaluate the value of an option, or by insurance companies in valuing a policy. The derivation of the risk premium is illustrated graphically in Figure 12-3 below.

Figure 12-3 Illustration of Risk Premium Concept

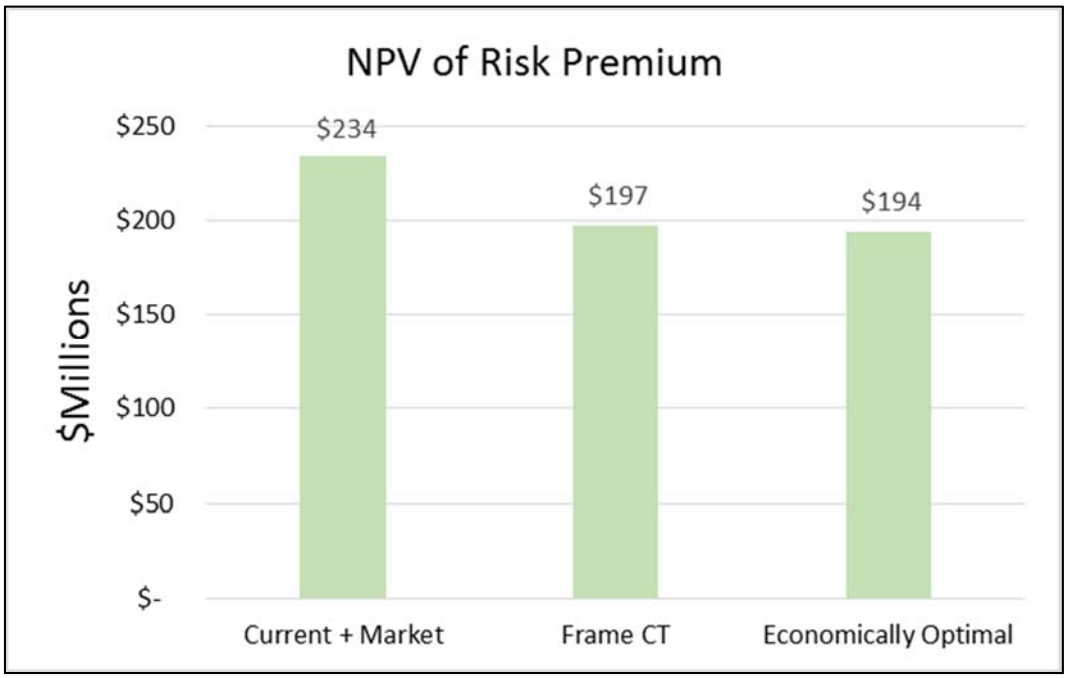


The risk premium is added to the expected value to better approximate the full distribution of costs. This risk metric improves upon traditional planning approaches such as cost-at-risk or efficient frontier analysis by providing a single number by which to compare portfolios, rather than requiring a planner to decide on a weighting between cost and risk.

The risk premiums of annual levelized cost for select portfolio options are shown below in Table 12-4. The bars represent the risk premium calculated by applying the method shown above to total portfolio costs realized for different simulated future states. The Current + Market portfolio has a risk premium of $234 million, or 4% of total NPV of costs, versus $194 million (3.5% of NPV of costs) for the EOP and $197 million (3.6% of NPV of costs) for the Frame CT Portfolio. The difference between the risk premiums of Current + Market and the EOP, $40 million, is the NPV of the risk reduction value of the EOP. The risk

value illustrates the monetary value of decreased uncertainty of future costs with the expansion plans.

Figure 12-4 Values of Risk Premium for Select Portfolios



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Net Present Value of Portfolio Costs

PowerSimm produces a NPV of the long-term costs of each portfolio. These costs are presented in Table 12-5 below, in terms of NPV. Total NPV is broken out into components of existing fixed and capital costs, variable costs and market, fixed and capital costs plus infrastructure costs less the residual value of new resources, and risk premium.

Table 12-4 Net Present Value of Portfolio Costs by Scenario and Category

Resource Portfolio	Total	Existing Fixed & Capital Costs	Generation Costs + Market Costs	New Fixed Capital and Infrastructure Costs	Risk Premium
Low Carbon Cost	$5,007 M	$2,797 M	$1,718 M	$407 M	$85 M
Low Load Growth	$5,323 M	$2,797 M	$2,033 M	$341 M	$181 M
Frame CT	$5,462 M	$2,797 M	$2,078 M	$391 M	$197 M
Economically Optimal	$5,482 M	$2,797 M	$2,085 M	$407 M	$194 M
High Gas & Power Prices	$5,549 M	$2,797 M	$2,144 M	$407 M	$202 M
High Load Growth	$5,624 M	$2,797 M	$2,170 M	$452 M	$204 M
High Carbon Cost	$5,720 M	$2,797 M	$2,378 M	$407 M	$138 M
Current plus Market	$5,944 M	$2,797 M	$2,913 M	$0 M	$234 M
Double Wind and Solar	$5,957 M	$2,797 M	$2,152 M	$839 M	$170 M
RPS Compliance	$6,146 M	$2,797 M	$2,648 M	$537 M	$163 M
Triple Wind and Solar	$6,340 M	$2,797 M	$2,084 M	$1,300 M	$159 M

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Figure 12-5 Net Present Value of Portfolio Costs Plus Carbon Footprint

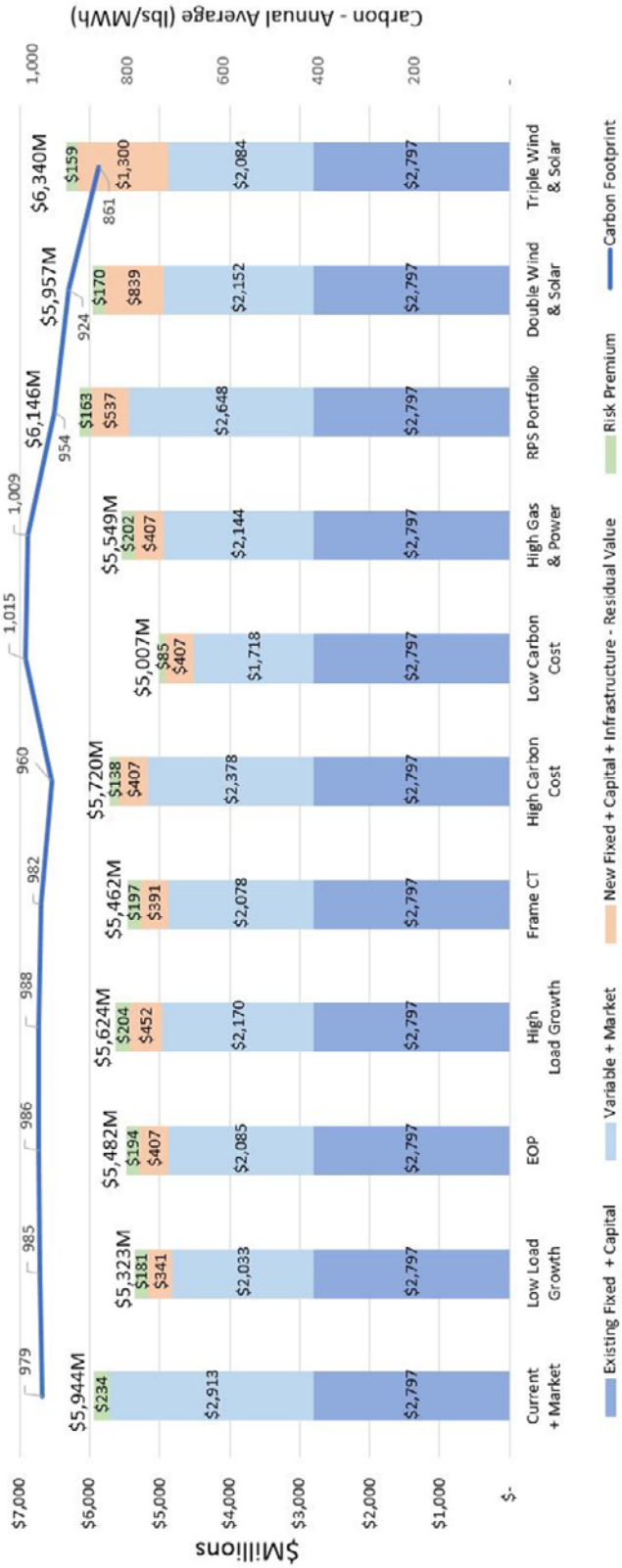

Figure 12-5 is a graphical illustration showing the NPV of all portfolio model runs and cost components: existing fixed and capital costs, variable costs and market, fixed and capital costs plus infrastructure costs less the residual value of new resources and risk premium. A comparison of carbon emissions rates is also included. Carbon emissions rates are addressed in greater detail at the end of this chapter. Comparisons between groups of portfolios follow.

Figure 12-6 shows a graphical representation of the costs of the Current plus Market, the EOP, and the EOP plus Frame CT portfolios. The Frame CT portfolio is the same as the EOP, but with a frame CT substituted for the ICEs in 2019. The Frame CT portfolio is included to illustrate the difference in technology cost only. The substitution of Frame CT for ICE technology as a near-term resource choice achieves lower cost but does not achieve needed resource flexibility capability of the ICE.

Figure 12-6 Net Present Value Costs of Current + Market, Frame CT, and EOP

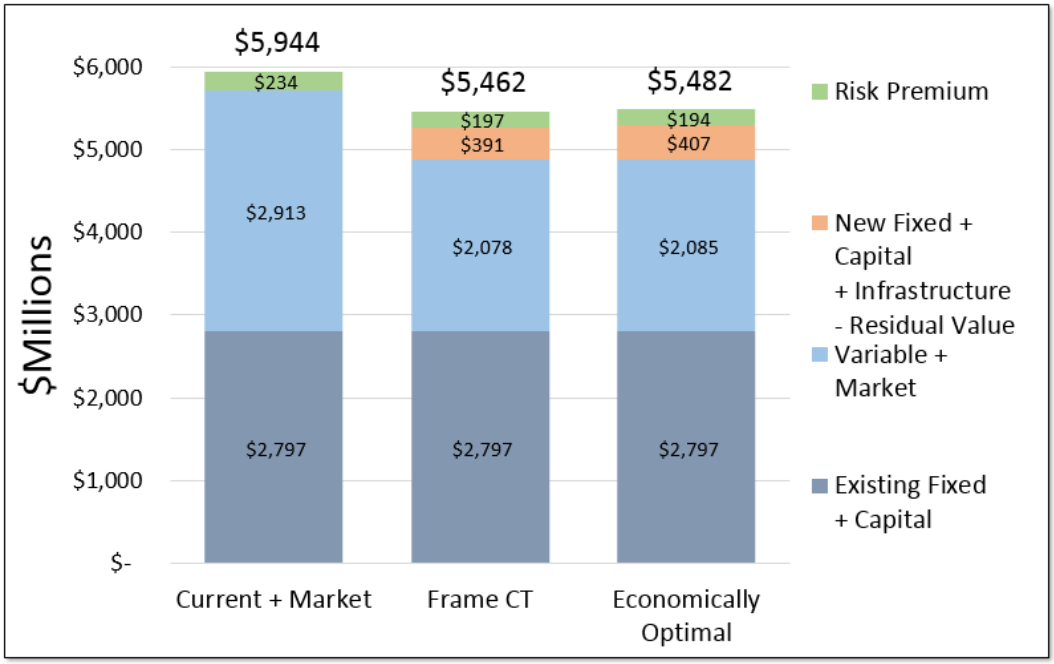

Figure 12-7 below is a similar illustration but compares the EOP to Low Load Growth and High Load Growth. As shown in Table 12-2 above, loads grow at 0.4% per year in the Low Growth portfolio, 1.2% per year in the High Growth portfolio, and at 0.8% per year in all other portfolios.

Figure 12-7 Net Present Value Cost of EOP Under Alternative Load Growth Scenarios

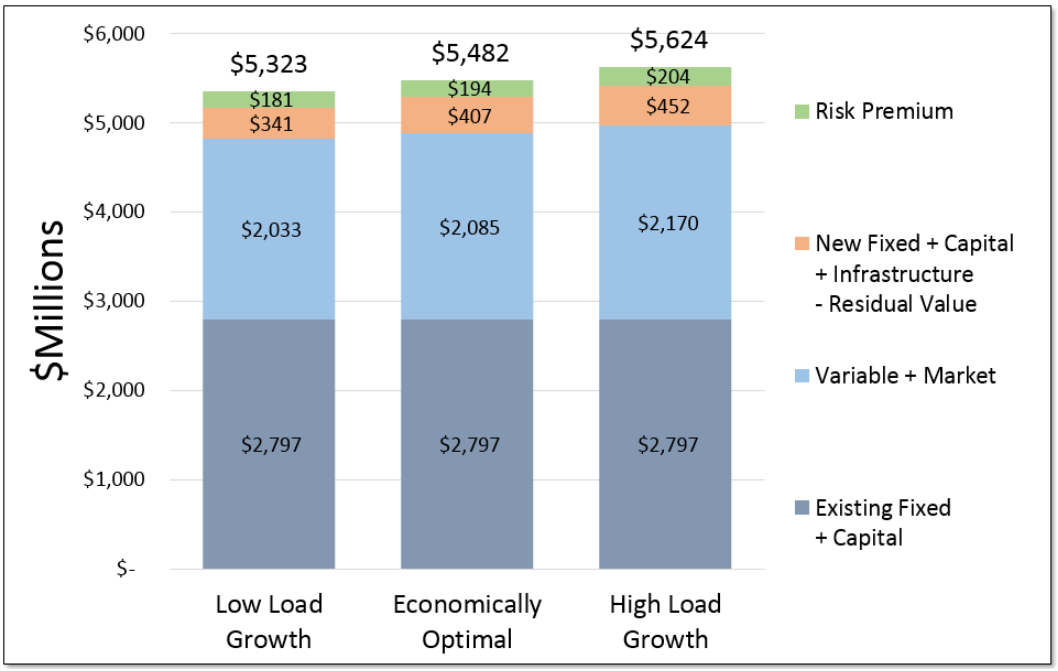

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Figure 12-8 below shows the NPV of the EOP under alternate price sensitivities: High Carbon Cost, Low Carbon Cost, and "High Gas and Power". As described earlier, the Low Carbon Cost portfolio assigns no cost to carbon, and the High Carbon Cost portfolio assigns a carbon cost of $40/ton. The High Gas and Power portfolio increases natural gas and wholesale electric power prices by 22%, while maintaining the pricing relationships (heat rate) established in the Current plus Market portfolio.

Figure 12-8 Net Present Value Cost of EOP Price Sensitivities

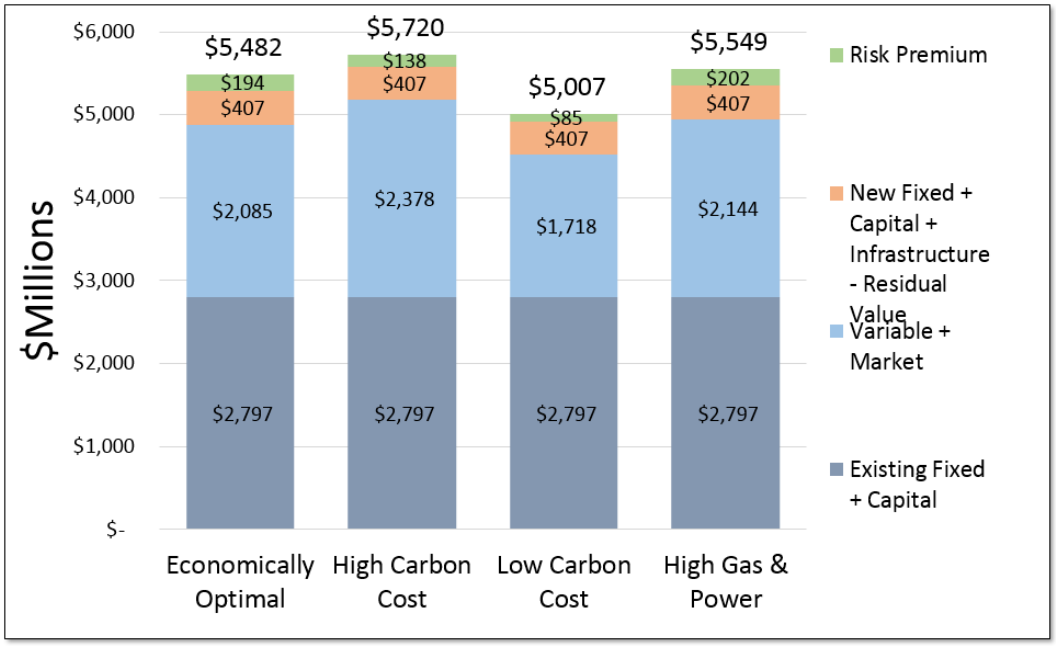

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Figure 12-9 shows the NPV of the EOP and three portfolios in which additional wind and solar PV are forced into the model. The RPS Compliance portfolio assumes company ownership of all wind resources needed to meet NorthWestern's RPS requirement through the 20-year planning horizon. The second portfolio, Double Wind & Solar, nearly "doubles" NorthWestern's current portfolio of wind and solar PV, adding 224 MW of wind and 24 MW of solar PV. The third portfolio, Triple Wind & Solar, nearly "triples" the current portfolio of wind and Solar PV, adding 448 MW of wind and 42 MW of solar PV.

The Double Wind & Solar portfolio and the Triple Wind & Solar portfolio are based off the Current plus Market portfolio. However, flexible gas-fired resources are added to each portfolio to meet ancillary service requirements and also to meet minimal resource adequacy in approximately ten years. The three portfolios meet the same capacity adequacy standard as the EOP so all four portfolios are comparable.

NorthWestern has limited transportation ability to export excess energy to sell to counterparties. The inclusion of the additional wind and solar resources generates significant surplus energy, so much so that NorthWestern would have challenges selling surplus energy in a market that is already long energy. To account for this, NorthWestern models surplus energy in the following manner: Surplus sales up to 20% of load receive market price; all remaining sales receive only 20% of the market price.

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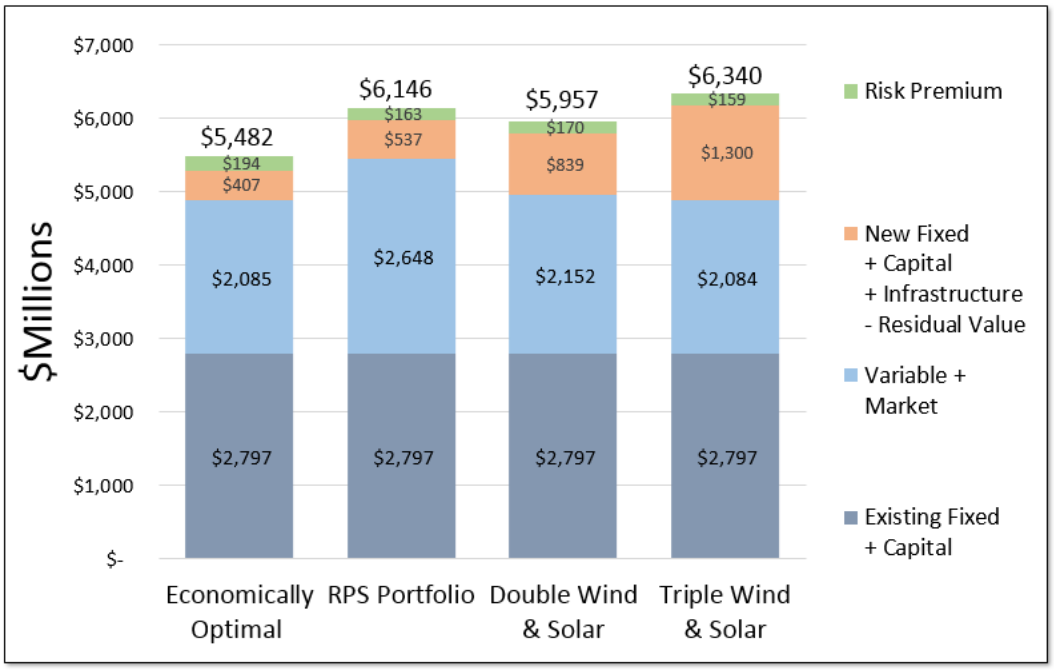
Figure 12-9 Net Present Value Cost of EOP, and EOP with Additional Wind



Carbon Footprint

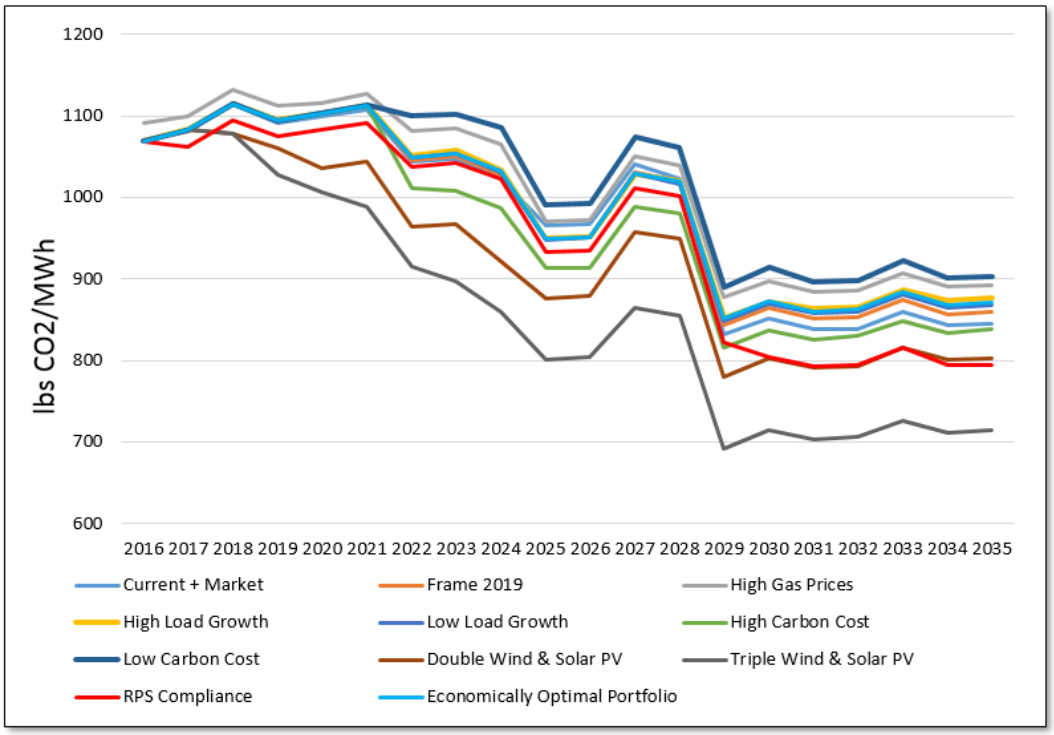
Table 12-5 shows carbon emissions rates for each resource portfolio, and Figure 12-10 shows carbon emissions rates for each resource portfolio over the 20-year planning horizon. All resource portfolios have relatively low carbon emissions; all are under 1,000 lbs./MWh except for the Low Carbon Cost and High Gas Cost portfolios. As expected, the Low Carbon Cost portfolio has the highest rate of carbon emissions, while the Triple Wind & Solar portfolio has the lowest carbon emissions. The EOP is a relatively low carbon emission portfolio while achieving minimal resource adequacy in approximately ten years. However, the EOP does not meet NorthWestern's current RPS obligation. The RPS Compliance portfolio meets NorthWestern's goals of meeting minimal resource adequacy in approximately ten years at lowest cost and meeting NorthWestern's future 15% RPS obligations. It also achieves the second lowest carbon footprint by the end of the planning horizon.

Table 12-5 Carbon Footprint (20-Year Average Annual)

Portfolio	Average Annual (lbs/MWh)	Percent of Current + Market
Low Carbon Cost	1,015	103.7%
High Gas Prices	1,009	103.0%
High Load Growth	988	100.9%
Economically Optimal	986	100.8%
Low Load Growth	985	100.6%
Frame CT	982	100.3%
Current + Market	979	100.0%
High Carbon Cost	960	98.1%
RPS Compliance	954	97.4%
Double Wind & Solar PV	924	94.3%
Triple Wind & Solar PV	861	87.9%

The variations in carbon emissions rates shown in Figure 12-9 occur because NorthWestern assumes all resources drop out of the resource portfolio after their contracts expire. The CELP contract expires in 2024, the Judith Gap wind energy PPA contract expires at the end of 2026, and the YELP contract expires at the end of 2028. These expiring contracts have a significant impact on the portfolio's estimated carbon emissions.

Figure 12-10 Carbon Emission Rates by Portfolio
(lbs CO2/MWh)



Conclusions

The EOP meets minimum resource adequacy and incorporates the co-optimization of hydroelectric and thermal resources to achieve low-cost and efficient generation operations. Resources including DGGS, Basin Creek, and Colstrip will be used in both load-serving and ancillary services roles. DGGS will no longer be used exclusively as a regulation service resource, but will also be used to provide contingency reserves and load-following services, and to provide peaking capacity at times of peak demand.

The EOP provides a least-cost and least-risk mix of resources needed to meet the capacity and ancillary service needs associated with loads and generation. However, NorthWestern must also comply with RPS. Therefore, RPS requirements are forced into the EOP in the RPS Compliance portfolio, albeit at higher NPV cost.

CHAPTER 13
RESPONSES TO MPSC COMMENTS ON 2013 PLAN

Commission 2013 Plan Comments

NorthWestern considered comments by the Commission on the 2013 Plan and addressed those comments in the 2015 planning cycle. In addition to addressing Commission comments, written stakeholder comments submitted to the Commission were reviewed within the context and scope of resource procurement planning. NorthWestern used the input from advisors and the Electric Technical Advisory Committee ("ETAC") to guide planning work to make it comprehensive and responsive to stakeholders while meeting the planning requirements contained within § 69-8-419, MCA, and ARM 38.5.8201 through 38.5.8229. The Commission comments on the 2013 Plan were issued on May 26, 2015 in Docket No. N2013.12.84 and the complete document is provided in Volume 2, Chapter 1 for reference. The following responses address Commission comment numbers 12 – 23:

12. The 2013 Plan fell short of the comprehensive resource planning described in the Commission's planning and procurement rules. See e.g. ARM 38.5.8213(f) (requiring scenario and sensitivity analyses); see also Notice of Commn. Action, Dkt. D2013.12.85 (Feb. 5, 2014) (determining hydro application was inadequate). NorthWestern initially analyzed market purchases and a combined cycle combustion turbine in 2018 as alternatives to the hydro facilities in the 2013 Plan, but questioned the viability of relying on market purchases for long term resource adequacy due to risk. 2013 Plan at ch. 4, pp. 12-13; see also Direct Test. of Joseph Stimatz, Dkt. D2013.12.85, p. 42 (Dec. 20, 2013). Such limited analysis does not help NorthWestern "explore a wide variety of alternative electricity supply resources" as is required under Commission rules. ARM 38.5.8212(1). In fact, NorthWestern eventually supplemented its 2013 Plan with additional portfolio modeling analysis that revealed two lower-cost alternatives to the 2018 combined cycle alternative. The Commission expects future plans to compare more than three scenarios and to include sensitivity analysis for variables such as CO_2 costs and market prices.

Response: The 2015 Plan is a comprehensive assessment of plausible resource alternatives evaluated under multiple future conditions of load, market prices, carbon costs, and resource selection. Use of capacity optimization techniques has eliminated the need to

iteratively examine resource selection alternatives and instead focuses on a more efficient methodology to address resource adequacy using economic criteria that are applied by using the capabilities of PowerSimm Planner's optimal resource selection module.

13. The Commission is not convinced that the stochastic modeling approach alone adequately captures future uncertainty and risk. Although stochastic modeling is useful, NorthWestern's results appear dependent on subjective judgments regarding key inputs, such as forward market price escalation and the timing and cost of CO2 emissions regulation. According to Evergreen: "[S]tochastic modeling and deterministic sensitivity analysis need not be mutually exclusive. Instead, we believe careful use of both approaches can produce better insight into risk than using one or the other alone." Evergreen Assessment at p. 22. The Commission agrees with Evergreen's assessment of stochastic modeling, and anticipates that NorthWestern will complement stochastic analysis with scenario analysis in future plans based on input from ETAC.

Response: NorthWestern has incorporated scenario analysis in the 2015 Plan in response to Commission comments and requests, and based on ETAC suggestions. Rather than running deterministic studies that do not incorporate measurements of risk, NorthWestern elected to perform multiple, full stochastic evaluations that address different trajectories of 1) load growth; 2) natural gas market price; 3) carbon price; and 4) variations on the EOP. Using this approach, analytical results are directly comparable and account for both cost and risk that are included in the NPV of total portfolio costs.

14. The 2013 Plan assumed that existing resources include 41 MW of community renewable energy project (CREP) capacity that had not been acquired, in anticipation that it would be acquired. 2013 Plan at ch. 2, pp. 20-24. The 2013 Plan did not separately analyze the portfolio cost and risk impacts of this CREP resource compared to the status quo or other resource alternatives. This approach is not consistent with Commission rules, which require NorthWestern to make RPS compliance an integral part of the overall resource planning and procurement process. ARM 38.5.8301(1); see also Written Comments, Dkt. N2010.6.57, ¶ 95 (Nov. 22, 2011) (NorthWestern should not hard-wire resources into portfolios to model RPS compliance). In future plans, NorthWestern should assess the possible portfolio cost and risk impacts of RPS compliance. If such an assessment is not possible, it should explain why.

Response: Solar and wind resources have been assessed using the PowerSimm model to determine resource costs and the value to the portfolio. NorthWestern has eliminated

assumptions regarding the inclusion of additional future renewable resources for the purpose of meeting annual RPS and CREP requirements. As a result of using capacity optimization, neither wind nor solar energy resources were selected through resource optimization to fulfill portfolio capacity resource requirements.

NorthWestern estimates that it will meet the 15% annual RPS requirement through the mid-2020s with currently contracted-for resources. Because no renewables were selected by the capacity optimizer, future resource planning cycles will address the actions necessary to meet RPS in the second half of the current 20-year planning period. Given this 10-year timeframe, the ability to consider and acquire additional eligible renewable resources in the future will afford the advantage of making resource decisions and selections based on technology improvements and associated resource costs that may offer more attractive choices than are otherwise available today.

15. The Commission's comments on the 2011 Plan urged NorthWestern to evaluate preferred portfolios under alternative long-term market price forecasts, such as those developed by the Northwest Power and Conservation Council or Energy Information Administration. Written Comments, Dkt. N2011.12.96, ¶ 17 (Sept. 28, 2012). The Commission has twice rejected NorthWestern's in-house forecasting methods. Or. 7108e ¶¶ 65-70, Dkt. D2010.7.77 (Oct. 13, 2011); Or.7199d ¶¶ 24-28, Dkt. D2012.1.3 (Nov. 20, 2012); see also Or. 7338b, Dkt. D2014.1.5, ¶ 37 (Apr. 24, 2015). The Commission renews its comment on the 2011 Plan and cautions against ignoring multiple Commission orders and comments in future filings.

Response: Long-term commodity price forecasts used in the 2015 Plan include the use of EIA annual escalation values in response to Commission comments. NorthWestern preserves the protocol of using the forward market price strip on the front end of the 20-year forward price curve as a best practice for constructing natural gas and electricity forecasts for long-term planning purposes.

16. The mean CO_2 cost projection and its associated triangular probability distribution were key assumptions in the 2013 Plan and significantly impacted the selection of preferred resources. Even with stochastic modeling, however, the single CO_2 price trajectory scenario did not adequately

account for the uncertainty of this key input, and did not demonstrate the sensitivity of modeling results to the assumed CO_2 prices. Given ongoing uncertainty regarding the timing and effect of CO_2 regulations on regional wholesale markets – and the fact that NorthWestern's management routinely relies on the preapproval process to make resource decisions – the Commission expects a more rigorous evaluation of potential CO_2 costs in future filings. Specifically, evaluating alternative CO_2 price trajectories and alternative ways of defining the price distribution is essential; NorthWestern should consult with ETAC for specific guidance in this regard.

Response: The 2015 Plan employs multiple (3) carbon cost scenarios to expand its analysis of potential carbon cost futures. The results of the three scenarios allows a comparison of the EOP under different trajectories of carbon pricing and thus, the sensitivity of the portfolio to different carbon prices can be observed.

NorthWestern considered alternatives to a triangular distribution method for determining long-term carbon price trajectories. Discussions with ETAC and Ascend did not yield an appropriate alternative that would produce a more instructive price distribution curve or mechanism. NorthWestern was careful not to use inappropriate distribution types that could produce misleading results or change results to the point of making them meaningless. Thus, NorthWestern attempted but did not find an appropriate alternative. The triangular distribution also includes an element of randomness without becoming totally random as would be the case if a uniform distribution, which is analogous to simply pulling numbers out of a hat, were used.

17. The PowerSimm model is capable of defining an optimal capacity expansion plan, but NorthWestern did not use this capability to develop the 2013 Plan. In retrospect it is clear that NorthWestern's 2013 Plan failed to identify the best alternatives to the current + hydro portfolio, based on the net present value of risk-adjusted total portfolio costs. First, its Supplement to the 2013 Plan revealed two portfolios with lower costs than the current + CC alternative. A separate analysis also indicated that adding a CC resource in 2033 would actually reduce the total cost of the current + hydro portfolio. Direct Test. of John Bushnell, Dkt. D2014.1.5 (Jan. 22, 2014); Data Response PSC-003d, Dkt. 2014.1.5 (May 2, 2014). These subsequent analyses underscored how much the timing of resource acquisitions can affect the value of a portfolio. Unless the costs are prohibitive, NorthWestern should use PowerSimm's optimal capacity expansion planning capabilities in its next plan.

Response: Optimized capacity expansion has been used effectively in the 2015 Plan to reflect the incorporation of capacity-based planning and the transition from energy-based planning metrics. PowerSimm Planner's optimal resource selection module was employed to determine the type and timing of capacity resource additions needed to satisfy peak demand. A two-step process determines the least-cost resource addition matrix by first assessing individual resource costs followed by an iterative system of resource elimination to arrive at resource selection.

18. In order to adequately assess resource needs, NorthWestern's ongoing planning and procurement activities should account for net metering, as well as other forms of distributed generation. ARM 38.5.8210(2)(a). Nevertheless, and despite the company's arguments in other venues that it is a major public policy dilemma, the 2013 Plan did not address the impacts of distributed generation technologies in NorthWestern's service area. Many proposals were submitted in the 64th session of the Montana Legislature to expand net metering. That debate has resulted in a study of the Energy and Telecommunications Interim Committee. In order to facilitate that legislative initiative and the Commission's own ratemaking and planning obligations, the Commission expects NorthWestern to perform a far more detailed analysis of existing and potential issues in the next plan, as well as a discussion of ways to remedy any concerns. Such an analysis will require detailed and current information, including participant demographics and the mix of generating technologies, their installed capacity and production patterns. Such an analysis should compare load factors, coincident peak demand, noncoincident peak demand, and regulation service demand for net metered customers and non-net metered customers. The analysis should attempt to quantify not only costs but also benefits, such as avoidable line losses and other delivery costs. The analysis should be transparent, and any given type of cost or benefit should be isolable, and supported by clear citations to source information in order to ensure the analysis can be meaningfully scrutinized. The analysis should consider the potential for different rate designs depending on a net metered customer's size and location. In its work with Powersimm, NorthWestern should consider modeling several resource portfolios in its next plan with an aggregate net metering capacity of two to three percent of system peak load (e.g., 25 to 45 MW) by the end of the planning horizon, based on input from ETAC. Depending on the quality of NorthWestern's analysis and the direction of the legislative process, the Commission may consider using its statutory authority to hire professional services related to net metering as a topic within the plan.

Response: Estimates of future net metering resource installations and energy production are included as a base set of assumptions in the 2015 Plan and described in Chapter 8. These assumptions reflect historical net metering installation levels by customers as well

as future projections of net metering resources comprised of rooftop solar resources. For purposes of estimating future net metering production NorthWestern relied on the 7th Power Plan to inform NorthWestern's installation growth projections over the 20-year planning horizon. Net metering and net metering growth were the subject of multiple ETAC discussions during 2015.

19. In response to the 2011 Plan, the Commission specifically endorsed two actions that NorthWestern identified in its three-year action plan: Defining resource adequacy and improving strategies for wind integration. With respect to resource adequacy, the Commission "strongly endorse[d] its commitment to define its own system-specific resource adequacy standards," and recommended exploring this issue with ETAC. Comments, Dkt. N2011.12.96, ¶ 13. With respect to wind integration, the Commission urged NorthWestern to "describe how it is promoting efficient use of limited Dave Gates Generating Station (DGGS) wind integration capacity," and "attempt a more sophisticated representation of the regulation needs that may result from diverse generators and loads." Id. at ¶ 22 ("avoid one-dimensional representations of regulation needs."). The 2013 Plan demonstrates little, if any, progress on these action items. NorthWestern's inability to demonstrate the amount of capacity needed to integrate its existing wind fleet is not acceptable. Now that it owns most of the resources used to serve load – including DGGS – NorthWestern should conduct the kind of integrated planning that recognizes interactions between transmission and supply assets in order to minimize the total, integrated cost of service. Integrated resource planning should measure resource capacity value in various ways (e.g., effective load carrying capability, exceedance, etc.).

Response: New analytical methods have been used in the 2015 planning cycle to incorporate and address resource adequacy. Optimized capacity planning, referenced in the response to Commission Comment No. 17, directly addresses Commission comments regarding resource adequacy. Peak demand service, a primary measure of resource adequacy, is analyzed in the 2015 Plan and is a key driver in the identification and selection of the EOP.

Wind integration requirements, including regulation and load following, have been modeled and analyzed in this Plan. Analysis and results provided in Chapter 11 demonstrate the amount and cost of regulation service needed for load and intermittent renewables integration. In addition, regulation and load following have been separated

into two distinctly different services in the evaluation of potential future ancillary services requirements and costs.

20. At the public meeting on the 2013 Plan, NorthWestern described on-going work on two separate studies, each of which involves evaluating the service capabilities of existing resources and how to optimize those capabilities. The next plan should thoroughly describe these studies, their methods, and how results affect system planning and operations. All written reports, such as the E3 study of Basin Creek's energy and capacity capabilities, should be attached to the next plan. NorthWestern should also provide a status report on the load variability study the Commission required in Order 6943e and whether results from that study have any planning impacts. Or. 6943e, Dkt. D2008.8.95, ¶ 94 (Mar. 20, 2012).

Response: The 2015 Plan explores opportunities to co-optimize hydroelectric and thermal resources in the portfolio (refer to Chapters 10, 11, and 12) and how to possibly operate efficiently and economically together to provide needed amounts of ancillary services. Supporting studies by HDR and Ascend provide the information used to construct the resource co-optimization scenarios developed and analyzed in the Plan. In addition, the Plan provides an overview and scope of evaluation work being performed by the hydro generation group for the Montana hydroelectric system. Although the results of this work was not available for incorporation in this planning cycle, it will be used in the future to inform resource decisions.

NorthWestern's consultant E3 has completed and reported on two phases of the Basin Creek operational analysis to assess historical use of the facility and answer Commission questions regarding operational decisions and dispatch. The results of the E3 studies are contained in a report titled "Basin Creek Dispatch Study" which is included in Volume 2, Chapter 5 to provide a full and detailed explanation of the independent analysis performed by E3 and their conclusions.

In summary, E3 concluded that "*Existing dispatch of the Basin Creek units is consistent with the Energy Supply Function's directive to minimize customer costs*." The context of

the conclusion was made with reference to the evaluation of Basin Creek operations during 2013 and the structure of the supply portfolio, operational protocols, and market conditions at that time. Phase 2 of the evaluation determined that while there could be opportunity to "relax restrictions" on the products provided by Basin Creek such as regulation services, the opportunity to reduce costs are limited due to the amount of time that Basin Creek can operate according to its air quality permit.

Related to the load variability study required in Order No. 6943e ("Order"), Docket No. D2008.8.95, as discussed in Chapter 11, NorthWestern has conducted considerable analysis and modeling for this plan to identify the overall system load following and regulation requirements. This work uses an estimate of the respective load following and regulation requirement responsibilities for retail and wholesale customers based on transmission system level data. NorthWestern has identified interval electric load data available at the substation level, as well as the composition of customer class electric usage served by the substations. The Company is currently considering opportunities to use this substation load data to leverage the work completed for this plan to further evaluate the relative contribution of retail and wholesale customers to the within-hour load fluctuations that drive regulation capacity needs.

21. In addition to the changing nature of NorthWestern's asset portfolio, the way in which energy, capacity, and ancillary services are procured in the wholesale market is evolving. One example is the centrally dispatching real-time energy market that PacifiCorp has joined, which NV Energy, Puget Sound Energy, and Arizona Public Service Corp. also intend to join. NorthWestern should study the benefits and costs of joining this market, in addition to explaining the findings and results of the Northwest Power Pool Market Assessment and Coordination Initiative in which it is engaged. These initiatives not only involve the ways that assets are dispatched into the market (as well as related tariff issues that could impact NorthWestern's business), but also the ways that an entity's resource sufficiency is measured. PacifiCorp, additionally, has indicated that it may join as a full Participating Transmission Owner of the California ISO. This would have even farther-reaching implications. In its next plan, NorthWestern should more closely examine how changes in the wholesale market affect its retail business.

Response: Chapter 7 provides a review of NorthWestern's participation in and understanding of market developments in the WECC. NorthWestern staff have attended regional meetings and participated in utility forums to stay apprised of the progress and status of utility initiatives. NorthWestern has not yet reached decisions concerning participation in any of the developing markets.

22. The 2013 Plan maintains NorthWestern's 6 aMW annual DSM acquisition goal, which was set following an energy efficiency potential study completed in 2009. Energy efficiency technologies, markets, and NorthWestern's avoided costs have changed since 2009. NorthWestern should consider reassessing energy efficiency potential in its service area, including the reasonableness of its annual 6 aMW DSM acquisition goal. In addition, NorthWestern's DSM programs should be responsive to changing markets and avoided costs even if overall acquisition goals remain appropriate. In that regard, NorthWestern should reassess whether residential lighting has been transformed by federal lighting standards for alternative bulb types, and consider whether the utility's role in continuing to incent this technology is useful.

Response: In 2016, Nexant will complete an assessment of remaining cost effective DSM potential in NorthWestern's Montana service territory based on avoided costs derived from the 2015 Plan. The results of this assessment will inform program design and DSM savings targets starting in 2016/2017 program year. The program assessment will include evaluation of federal lighting standards and potential impacts to DSM programs.

23. The Commission's planning and procurement rules emphasize transparency, stakeholder involvement, and diligent documentation of decision-making. Admin. R. Mont. 38.5.8201 et seq. Future plans should include a glossary of key terms included in the plan, especially terms used in PowerSimm reports and used to explain PowerSimm operations and outputs. Additionally, future plans should contain key model input and output data electronically, including forward price information, simulated monthly electricity and natural gas prices, CO2 costs or adders, resource production, and average and peak demand information with and without DSM impacts. Finally, stakeholders should have reasonable opportunities to test NorthWestern's modeling assumptions and results, both before a plan is filed (through ETAC) and subsequently where NorthWestern seeks to recover costs, obtain preapproval or set avoided cost rates (through data requests). Ideally, robust analysis preceding a resource plan will reduce the need for subsequent analysis in contested cases.

Response: NorthWestern and its advisors have endeavored to present a resource planning document using language and references that are less technical and more readable for all stakeholders and interested parties. The use of utility and modeling terminology and acronyms is unavoidable so NorthWestern has included a glossary of terms to help readers. The more technical analytical and modeling components of the Plan are found in Volume 2 and are being made available in electronic form on NorthWestern's website and on a CD to be included with printed versions of Volume 1. Twenty-year portfolio simulations produce enormous amounts of output data. The output data for all portfolios simulated in PowerSimm and presented in the Plan are included in Volume 2, Chapter 7.

CHAPTER 14
ACTION PLAN

Implementation and Next Steps

Moving Forward

Transitioning from planning to implementation requires the successful completion of additional tasks by NorthWestern. The 2015 Plan establishes target levels of additional electric generation resources in the Economically Optimal Portfolio to achieve minimum levels of resource adequacy. The analysis of resource alternatives and the selection of preferred resources leads us to the next steps to move from an analytical and planning framework to a set of specific activities intended to more fully inform resource procurement decisions and portfolio planning.

In addition to the information, analysis, and results presented in this planning document, NorthWestern identifies specific actions to address the issues and challenges facing the Supply Portfolio and the delivery of services to retail customers. This three-year action plan will address:

1. Resource Optimization – NorthWestern is committed to the efficient and cost-effective operation and management of the utility generation fleet. A testing program to determine the scope of operational capabilities at select hydroelectric facilities began in 2015 following the purchase and integration of the hydro assets. This high priority program will continue, and the results will be used to determine how alternative modes of operation can benefit the portfolio by reducing overall supply costs and improving the production and delivery of load-serving capacity and necessary services.

Prior to Northwestern taking ownership and operation of the hydroelectric facilities, previous owners assessed a number of potential facility upgrades including projects such as turbine replacements and generator rewinds. NorthWestern has already initiated work to update the results of these studies and anticipates completing a Phase 2 level of engineering and cost estimation by the end of 2016. This work will be considered in conjunction with the co-optimization initiative which addresses a combination of hydro and thermal resources providing regulation services and additional ancillary services to reduce total resource costs.

2. Gas-fired Resource Technology – Additional and detailed evaluation of gas-fired resources will be performed to inform and refine resource costs and the operational capabilities of the resource types identified in the 2015 Plan. The use of generic resources defined by certain manufacturer specifications helped to identify resource technology types; however, it does not represent a final model or manufacturer selection. Although internal combustion engine technology was identified in the Plan, the initial work will include an evaluation of a variety of highly flexible gas turbine technologies. NorthWestern intends to refine the analysis of costs and operating assumptions to enable more detailed planning leading to potential project identification and development. NorthWestern will issue a Request for Proposal ("RFP") for the identified capacity need. In parallel with the RFP, a siting, technology, and cost study will be performed by an independent engineer for a utility-build option. The siting study will evaluate an optimal site or sites addressing the future needs of net capacity. The technology study will use multiple generation configurations as proxies for input into the PowerSimm model. The PowerSimm model results will be used to determine the potential capacity factor and operating profile of a proposed facility/facilities. Once a type of technology has been defined as the most appropriate for the desired application, multiple manufacturers of the

selected technology will be further evaluated to determine the final equipment to be utilized. The cost study will utilize the results of the siting and technology studies to develop a net present value financial model. The responses to the RFP will then be compared to the results of the siting, technology, and cost study to evaluate all of the alternatives. If the NorthWestern self-build option has the greatest long-term benefit to customers when compared to the responses to the RFP, NorthWestern will proceed with building the needed capacity. If the RFP results are more financially and commercially acceptable compared to a self-build option, NorthWestern's plan would be to negotiate for the requested capacity with a third party or parties.

3. Infrastructure Planning and Evaluation – Initial high level assessments of natural gas and electricity transmission infrastructure will be advanced through a more detailed evaluation of the Montana systems to support additional electric generation. The goal of this work will be the definition and refinement of infrastructure costs and feasibility, and it is expected to lead to the submission of project study requests to the NorthWestern transmission planning staff.

4. Clean Power Plan – The U.S. Supreme Court issued a stay of the implementation of the final CPP on February 9, 2016. The stay will remain in effect until the U.S. Court of Appeals enters a decision on the substantive challenges to the CPP and the Supreme Court either denies a petition for certiorari following that decision or enters a judgment following grant of a petition for certiorari. The D.C. Circuit has set an accelerated briefing schedule, with oral argument scheduled for June 2 and June 3, 2016. A final decision could come as early as mid-summer 2017 or as late as 2018. NorthWestern is included in the group of utilities, trade groups, coal producers, and labor and business organizations that filed a Petition for Review and requested a stay of the CPP. NorthWestern also filed an administrative Petition for

Reconsideration with EPA, requesting EPA reconsider the CPP on the grounds that the CO_2 reductions in the CPP were substantially greater in the final rule than in the proposed rule. At this time EPA has taken no action on the Petition for Reconsideration. The timeline for a final disposition of the CPP in Montana is difficult to forecast as it depends on which side prevails before the D.C. Circuit, the timing of that court's decision, the schedule for subsequent processes and appeals, and changes to compliance deadlines should the CPP survive the legal challenges in its entirety. NorthWestern will continue to monitor the situation closely and consider the impacts of the final Court decisions on our resource plan.

The EPA's emissions target for Montana is 1,305 lbs. CO_2/MWh in 2030. NorthWestern already out-performs that standard with 1,069 lbs. CO_2/MWh. Under the EOP scenario set out in this Plan, NorthWestern's emissions would further decline to 794 lbs. CO_2/MWh. Further, this Plan includes many steps such as evaluating the feasibility of adding carbon-free generation at existing hydro facilities with potential to reduce CO_2 emissions even further.

5. Utility Integration – Utility industry changes are demanding that NorthWestern plan for and adopt a higher level of operational integration by the Supply and Transmission business units. A current example of this is the adoption and implementation of RBC where generation resources under the control and management of the Supply Group must be available to respond to generation change requests from the Electric Transmission business unit. RBC will go into full effect on July 1, 2016, and NorthWestern is taking the steps necessary to accomplish the transition and conversion to the RBC standard.

During the period March through June 2016, NorthWestern is participating in the

RBC testing program in advance of the July 1, 2016 implementation deadline. The test period allows NorthWestern the opportunity to gain necessary operational experience in the RBC environment prior to July 1st. It will also enable Supply operations to establish the operational protocols to respond to requests for generation output changes.

6. EIM/ISO/Organized Market Planning & Participation – NorthWestern has formed an internal group to examine the potential benefits and costs of joining an organized market. We intend to contract with a third-party consultant to help evaluate the potential of joining the Western EIM as well as any other alternatives that might be identified. We expect the evaluation to include a gap analysis with regard to hardware, systems, and staffing as well as a detailed study of potential customer benefits that could be achieved with participation in a market. NorthWestern will also assess the risks that may be associated with continuing to operate outside organized markets while several neighboring utilities move toward organized market participation.

   In South Dakota, NorthWestern conducted cost/benefit analysis prior to making the decision to join the Southwest Power Pool ("SPP"). That process and the operational knowledge gained from being an SPP member will help us make fully informed decisions concerning the organized market alternative that would be best suited to meet operational and portfolio needs in Montana.

7. Distributed Resource Integration & Planning – Based on projections of growth of roof top solar PV installations and utility-scale solar projects defined in the 2015 planning cycle, NorthWestern will monitor and refine its understanding and forecasting of the impacts of these resources on the utility. As penetration levels of

distributed resources increase over time, NorthWestern will observe and track changes to load net of solar production to understand and plan for the impacts to serving load based on empirical information acquired over time.

8. Long-Term RPS Planning – Estimates of production from current eligible renewable resources and volumes necessary to meet annual RPS requirements suggests NorthWestern will have adequate renewable energy credits through the mid-2020s. NorthWestern will continue to monitor renewable energy production and use the carry-over provisions of the Renewable Portfolio Standard to meet the 15% renewable standard.

   NorthWestern will continue to work to secure additional CREP resource to meet the annual capacity requirement. Competitive solicitations will continue to be used as the primary mechanism to identify and evaluate CREP opportunities including the evaluation of costs and risks of securing eligible resources. If potential CREP resources are identified outside of competitive processes, NorthWestern will consider an appropriate course of action based on the specific circumstances at that time. This may include petitioning the Commission for a CREP eligibility determination in association with future hydro upgrade projects for owned assets.

9. DSM Electric Potential Assessment ("Assessment") – In 2016, Nexant will complete an Assessment quantifying the remaining achievable cost-effective electric DSM potential in NorthWestern's Montana service territory, based on avoided costs derived from the 2015 Plan. NorthWestern will use the Assessment results to inform program design, update individual measure costs and savings, identify new program measures, and determine DSM annual savings targets starting in the 2016/2017 program year. Nexant will also prepare an analysis comparing the

2016 Assessment results with the Northwest Power and Conservation Council's 7th Plan's electric conservation projections for Montana.

NorthWestern intends to use the capability of the PowerSimm long-term portfolio simulation model to determine avoided costs to be used in the evaluation and determination of future energy savings measures. The use of PowerSimm and the methodology of avoided cost calculation will produce results consistent for planning and regulatory filing purposes.

10. NorthWestern will follow up on the demand response survey of large key account customers to further develop the availability and cost of DR from these customers.

11. The results of the 2015 Plan will be communicated to customers and stakeholders including the Commission, the Montana Consumer Counsel, and other interested parties. The goal is to inform, educate, and use transparent processes so planning and actions are presented clearly and made easy to understand. The use of ETAC will continue, and it is NorthWestern's hope that members of the advisory committee will continue to participate and provide feedback and constructive advice on resource planning and energy supply matters.

12. Electric generation and energy storage technology advancements may produce economically viable resource alternatives for NorthWestern to consider in future planning cycles especially if technological improvements are made and costs decline. NorthWestern will continue to monitor and assess the potential application of developing technologies, their capabilities, and the costs to purchase, operate, and integrate them. Battery and solar demonstration projects installed and operating on the Montana electric system are already being evaluated by our staff.

APPENDIX 1

ABBREVIATIONS

2015 Plan	2015 Electricity Supply Resource Procurement Plan
2016 Efficiency Assessment	2016 Updated Efficiency Potential Assessment provided by Nexant

A

AC	Alternating current
ACE	Area Control Error
AECO	Alberta Energy Company
AESO	Alberta Electric System Operator
AGC	Automated generation control
AMI	Advanced Metering Infrastructure
aMW	Average megawatts, a unit of energy
AOC	Administrative Order of Consent Regarding Impacts from Wastewater Facilities
ARM	Administrative Rules of Montana
Ascend	Ascend Analytics, LLC
ATC	Around-the-clock
ATC	Available Transfer Capability, a measure of remaining power transmission capability over and above already committed use (MW)
ATR	Acceleration Trend Relay

B

BA	Balancing Authority
BAAL	Balancing Authority ACE limit

BART	Best available retrofit technology
Basin Creek	Basin Creek Equity Partners, LLC
BBER	University of Montana – Bureau of Business and Economic Research
BEA	U.S. Bureau of Economic Analysis
BLM	U.S. Bureau of Land Management
BOR	U.S. Bureau of Reclamation
BPA	Bonneville Power Administration
Btu/kWh	British thermal unit per kilowatt-hour, typical unit for heat rate

C

CAA	Clean Air Act
CAISO	California Independent System Operator
CBI	CB&I Stone & Webster, Inc.
CCCT	Combined cycle combustion turbine
CCR	Coal combustion residuals
CDD	Cooling Degree Days
CELP	Colstrip Energy Limited Partnership
CEMS	Continuous Emission Monitoring System
CFLs	Compact florescent lamps
CHEOPS	Computer Hydro Electric Operations and Planning Software
CIG	Colorado Interstate Gas
CO	Carbon monoxide
CO_2	Carbon dioxide
COD	Commercial operation date
CPP	Clean Air Act Section 111(d) or Clean Power Plan
CPR	Clean Power Research
CPS2	NERC Control Performance Standard 2
CREP	Community Renewable Energy Project

CSES	Colstrip Steam Electric Station
CSP	Concentrating solar power
CT	Combustion turbine
CU1	Colstrip Unit 1
CU2	Colstrip Unit 2
CU3	Colstrip Unit 3
CU4	Colstrip Unit 4

D

DAHS	Data acquisition and handling system
DC	Direct current
DER	Distributed energy resource
DGGS	Dave Gates Generating Station
DHI	Diffuse horizontal insolation
Dkt	Dekatherm, a unit of energy (1 dkt = 1 MMBtu)
DOE	U.S. Department of Energy
DR	Demand response
DSM	Demand-side management
DNV-GL	DNV KEMA Renewables, Inc.

E

E3	Energy and Environmental Economics, Inc.
EE	Energy efficiency
EFOR	Equivalent forced outage rate
EIA	U.S. Energy Information Administration
EIM	Energy Imbalance Market
ELCC	Effective load-carrying capacity
EOP	Economically Optimal Portfolio

EPA	U.S. Environmental Protection Agency
ESB	Energy Supply Board
ETAC	Electric Technical Advisory Committee
EUI	Energy use index

F

FERC	Federal Energy Regulatory Commission
FIP	Federal Implementation Plan
FOM	Fixed operating and maintenance costs
Forum	Pacific Northwest Adequacy Forum
FR	Federal Register
Frame CT	Frame Simple Cycle Combustion Turbine
FWS	U.S. Fish and Wildlife Service

G

GCR	Ground cover ratio
GDP	Gross domestic product
GHG	Greenhouse gases
GHI	Global horizontal insolation
GW	Gigawatt, a unit of power (1,000,000,000 Watts)
GWh	Gigawatt-hour, a unit of energy (1,000 MWh)

H

HAN	Home area networks
HAP	Hazardous air pollutant
HDD	Heating Degree Days
HDR	HDR Engineering, Inc.
HHV	Higher Heating Value

HL	Heavy Load (on peak hours per Mid-Columbia definition)
HP	Horsepower, a unit of power (1 HP is approximately 746 Watts)
HVAC	Heating, ventilating and air conditioning
Hydros	NorthWestern's 2014 acquisition of hydroelectric generation plants and dams
Hz	Hertz, a unit of frequency

I

ICE	Intercontinental Exchange
ICE	Internal combustion engine
IEEE	Institute of Electrical and Electronics Engineers
IGCC	Integrated gasification combined cycle
IOU	Investor-owned utility
ISO	Independent system operator

K

kV	Kilovolt, a unit of voltage (1,000 Volts)
kVA	Kilovolt-ampere, a unit of apparent power (1,000 Volt-Amperes)
kW	Kilowatt, a unit of power (1,000 Watts)
kWh	Kilowatt-hour, a unit of energy

L

Lands	Lands Energy Consulting
Lb.	Pound, a unit of weight
LEDs	Light-emitting diodes
LID	Light induced degradation
LIEAP	Low Income Energy Assistance Program
LL	Light Load (off peak hours per Mid-Columbia definition)

LM	Lockheed Martin
LOL	Loss of load
LOLD	Loss of load days
LOLE	Loss of load expectation
LOLH	Loss of load hours
LOLP	Loss of load probability

M

Maf	Million acre-feet, a unit of volume used for reservoirs
MATL	Montana Alberta Tie Line
MATS	Mercury and Air Toxic Rule
MCA	Montana Code Annotated
MCC	Montana Consumer Counsel
Mcfh	Thousand cubic feet per hour, a unit of volumetric flow rate
MDDQ	Maximum daily delivery quantity
MDEQ	Montana Department of Environmental Quality
MDNRC	Montana Department of Natural Resources and Conservation
MFWP	Montana Fish Wildlife and Parks
Mid-C	Mid-Columbia River electric trading hub
MMBtu	Million British thermal units, a unit of energy
MMcfd	Million cubic feet per day, a unit of volumetric flow rate
MPSC	Montana Public Service Commission
MPT	Mountain Prevailing Time
MW	Megawatt, a unit of power (1,000,000 Watts)
MW_{AC}	Megawatt of power with alternating current, commonly used to describe solar PV power after DC-to-AC conversion
MW_{DC}	Megawatt of power with direct current commonly used to describe battery or solar PV power before DC-to-AC conversion

MWh	Megawatt hour, a unit of energy (1,000 kWh)
MW_P	Megawatts (peak), a measure of the rated DC power output of a solar PV system

N

NAAQS	National Ambient Air Quality Standards
NAESB	North American Energy Standards Board
NCAT	National Center for Appropriate Technology
NEEA	Northwest Energy Efficiency Alliance
NERC	North American Electric Reliability Corporation
Nexant	Nexant Consulting Inc.
NGX	NGX, owned by TMX Group Limited
Non-Spin	Non-spinning contingency reserves
NO_X	Nitrous oxide
NPV	Net present value
NREL	National Renewable Energy Laboratory
NRF	Northwest Regional Forecast
NSR	New Source Review
NW	Northwest
NWE	NorthWestern Energy
NWPCC	Northwest Power and Conservation Council
NWPP	Northwest Power Pool
NYMEX	New York Mercantile Exchange, Inc.

O

O&M	Operation & maintenance
OASIS	Open Access Same-Time Information System
OOA	Colstrip Unit 3 & 4 Ownership and Operation Agreement

P

Plan	2015 Electricity Supply Resource Procurement Plan
PM	Particulate Matter
PM_{10}	EPA air quality standard for particulate matter smaller than 10 microns in diameter
PM&E	Protection, mitigation, and enhancement
PNUCC	Pacific Northwest Utilities Conference Committee
PPA	Power purchase agreement
PPL	Pennsylvania Power & Light
PPT	Pacific Prevailing Time
PSC	Public Service Commission
PSD	Prevention of Significant Deterioration
PSIG	Pounds per square inch gauge, a unit of pressure relative to atmospheric pressure
PTC	Production Tax Credit
PTO	Participating Transmission Owner
PUC	Public utility commission
PUD	Public utility district
PURPA	Public Utility Regulatory Policies Act
PV	Photovoltaic

Q

QF	Qualifying Facility, as defined by PURPA

R

RAAC	NWPCC Resource Adequacy Advisory Committee
RAS	Remedial action scheme
RBC	Reliability-Based Control

RCRA	Resource Conservation and Recovery Act
REC	Renewable Energy Credit
REMI	Regional Economic Models, Inc.
RFP	Request for Proposal
RICE	Reciprocating internal combustion engine
ROTR	Run-of-the-river
RPS	Renewable Portfolio Standard (as defined by § 69-3-2004, MCA)
RTO	Regional transmission organization

S

SCADA	Supervisory control and data acquisition
SCCT	Simple cycle combustion turbine
SCR	Selective catalytic reduction, an NO_X emissions reduction process
SO_2	Sulfur dioxide
SOGF	South of Great Falls Cut Plane
SO_X	Sulfur oxide
Spin	Spinning contingency reserves
SPP	Southwest Power Pool
Synapse	Synapse Energy Economics, Inc.

T

TAC	Technical advisory committee
Talen	Talen Energy LLC
TIFID	Butte Tax Increment Financing Industrial District
TOU	Time of use
Ton	A unit of weight (1 ton = 2,000 lbs.)
Tonne	Metric ton, a unit of weight (1 tonne = 1,000 kg = 2,204.6 lbs.)
TPVRR	Total present value of revenue requirements

TRC	Total resource cost
TSP	Transmission service provider
TTC	Total transfer capability, a measure of power transmission (MW)

U

USB	Universal System Benefits
USFWS	U.S. Fish and Wildlife Services

V

VA	Volt-Ampere, a unit of apparent power
VAR	Volt-Ampere reactive, a unit of reactive power
VOC	Volatile organic compound
VOM	Variable operating and maintenance costs

W

WACC	Weighted average cost of capital
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council
Western EIM	CAISO/PacifiCorp EIM

Y

YELP	Yellowstone Energy Limited Partnership

APPENDIX 2

GLOSSARY

A

Acre-foot	A unit of volume used for reservoirs (1 acre-foot = 43,560 cubic feet).
Albedo	The ratio of reflected radiation from a surface to the incidental radiation upon it.
Area Control Error	The difference between scheduled and actual generation; positive values indicate over-generation.
Attainment	A (NAAQS) air quality status for an area with concentrations of criteria pollutants that are below levels established by NAAQS.
Average Annual Energy	The total amount of energy, measured in kWh or MWh, delivered over a period of one year divided by 8,760 hours per year.
Avoided Costs	Incremental cost for energy generated or acquired from another source.

B

Backward pass	Dynamic programming for automatic resource selection determines the optimal expansion path. The optimization routine does this through a two-pass process. The first pass is a backward pass that determines the number of feasible resource additions that satisfy the reserve margin constraints.
Balancing Authority	The responsible entity that maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

Balancing Authority Area	The collection of generation, transmission, distribution infrastructure, and load-resource balance within the metered boundaries of the Balancing Authority.
Baseload	The minimum amount of electric power delivered or required over a given period at a constant rate.
Bottom Ash	The waste mineral content found at the bottom of a boiler after complete combustion from burning pulverized coal.

C

Capacity	(Nameplate capacity) The maximum power output potential a machine or system can produce or carry under specified conditions generally expressed in kW or MW; (current capacity) instantaneous measurement of power delivery; (capacity resource) expression of capability to serve load.
Capacity Factor	The ratio of actual output to potential output over a period of time. Normally calculated by actual output in MWh divided by the product of nameplate capacity times 8,760 hours.
CapEx	Capital expenditure reflecting the cost of a resource, a project, or the expense to repair an asset.
Capital Structure	The mix of a company's long-term debt, specific short-term debt, common equity and preferred equity, which determines how a corporation finances assets.
Choice Customer	(NorthWestern) A NorthWestern electric service customer with an average monthly demand greater than or equal to 5,000 kW who chooses to buy power from a third party but uses NorthWestern transmission distribution, and other ancillary services (defined in § 69-8-201, MCA).

Community Renewable Energy Project	A Montana eligible renewable resource that is either owned by a public utility, or by specifically defined local owners that have a controlling interest, and is less than or equal to 25 MW in nameplate capacity, (defined in § 69-3-2003(4), MCA).
Confidence Interval	A range, calculated from a sample that likely contains the true value of a parameter, and is expressed with a confidence level. For example, there is 90% confidence that the interval from P5 to P95 will contain the mean if sampling is repeated.
Contingency Reserves	The provision of capacity deployed by the BA to meet the Disturbance Control Standard and other NERC and Regional Reliability Organization contingency requirements.
Cooling Degree Day	A measurement used to indicate a building's cooling (air conditioning) energy consumption, defined relative to an outside (base) temperature, below which the building needs no cooling.
Cost of Equity	The rate of return paid by a company to its equity investors.
CPS1	(NERC Control Performance Standard 1) A regulating standard for calculating the frequency error for a balancing authority.
CPS2	(NERC Control Performance Standard 2) A regulating standard for balancing authorities intended to minimize excessive power flows due to corrections to CPS1 scores.
Criteria Pollutants	EPA identified pollutants under the 1970 Clean Air Act amendments setting standards for total suspended particulates, sulfur dioxide, nitrogen oxide, ozone, carbon monoxide, and lead.
Cross-flow	Hydroelectric turbine design.

Customer-generator	A user of a net metering system.

D

Deterministic	Process or model in which the output is fully determined by inputs, thus containing no variability or risk.
Development	(Specifically as used in reference to Hydros projects) Refers to replacing units or adding new equipment, as defined by IEEE STD 1147-1991.
Diffuse Horizontal Insolation	The amount of insolation received by a surface that does not arrive directly from the sun but has been scattered by atmospheric particles and comes from all directions.
Dispatchability	The ability of a generating resource to deliver its output on demand.
Dynamic Programming	A method for solving a complex problem by breaking it down into smaller sub-problems, solving the sub-problems once and storing the solutions so that they can be looked up without resolving.

E

Economic Derate	A reduction in generation due to availability of cheaper energy.
Energy Use Index	The measure of a building's energy use as a function of size, typically expressed in units of (Btu/square feet).

F

Fish ladder	A structure to facilitate fish migration over or around obstructions such as dams.
Flexible Resource	A generating plant that has the capability to handle fast start-up and ramping allowing it to handle multiple daily on and off cycles.

Fly Ash	Non-combustible residual particles from the combustion process carried by flue gas.
Francis	Hydroelectric turbine design.
Fundamental Market Relationships	The market price for electricity is governed by supply and demand economics, and is partially dependent on the market price of natural gas, through the spark spread and, more directly, the heat rate of natural gas-fired generation.

G

Gap analysis	A strategic planning process of determining and documenting the difference between business requirements, or desired performance, and current capabilities.
Geothermal Energy	Heat energy generated and stored in the Earth, which can potentially be converted to create steam to generate electricity.
Global Horizontal Insolation	The amount of insolation received by a surface parallel to the ground.
Grid.Balancer	Energy storage system from Demand Energy used with Joule.System.
Grid.DNA™	Graphical user interface from Demand Energy used by Joule.System.
Ground Cover Ratio	The ratio between the surface area of a collection of solar PV panels and the area on the ground occupied by the solar PV system.

H

Head	(Hydraulic head across a dam) A measure of water pressure based on height differences in water upstream and downstream of a dam.
Heating Degree Day	A measurement used to indicate a building's heating energy consumption, defined relative to an outside (base) temperature, above which the building needs no heating.
Heat Rate	The amount of thermal energy (Btus) required by a generating unit to produce 1 kWh of electrical energy, expressed in this Plan as the higher heating value heat rate.
Heavy Load Hours	(On-Peak Hours) The periods of the week designated as traditionally having higher energy use; defined as hour ending 7 through hour ending 22 (inclusive) from Monday – Saturday.
Henry Hub	Natural gas distribution pipeline hub in Louisiana referenced as the principle pricing reference point in North America.
Higher Heating Value	(Heat Rate) A specific measure of the heat of combustion, the total energy released as heat, which is determined by bringing all products of combustion back to pre-combustion temperature and condensing any vapor produced.
Hydraulic Capacity	(Hydroelectric dam reference) A measure of the potential power generation for a hydroelectric dam based on current head and flow conditions.
Hydros	The system comprised of 11 hydroelectric dams and 1 storage dam purchased by NorthWestern in 2014 from PPL Montana.

I

Integrated Gasification Combined Cycle	A technology that converts coal into a pressurized synthetic gas (syngas) which facilitates the removal of impurities before combustion for power generation.
Intercontinental Exchange	A trading platform that helps to define markets through an electronic exchange including energy commodities and other products.
Illiquid	(Market) Condition where commodities are not easily sold or exchanged for cash without significant loss in value or due to a lack of buyers and sellers.
Implied Volatility	A measure of future potential market price moves; high IV indicates large price swings (either positive or negative) while low IV indicates smaller price swings.
Insolation	The amount of solar radiation energy that reaches the earth's surface over a specified period of time, typically measured in units of (kWh/m^2).
Integration	(Resource use) The process of adding new generation resources and rebalancing the operations of existing resources in a portfolio to continue to meet load and other balancing authority requirements, including regulation reserves, imbalance service, and scheduling.
Interconnected	(Transmission Grid use) The condition of being electrically connected and in synchronous operation with the electric transmission system operated by a BA.
Intermittent	(Resource use) Not continuously available, random, or varying in output.
Inverter	An electronic device that converts direct current (DC) to alternating current (AC), i.e., solar PV generation to grid-compatible power.

J

Joule.System	Integrated energy storage and management system designed by Demand Energy.

K

Kaplan	Hydroelectric turbine design.

L

Light Induced Degradation	The initial process of declining efficiency in solar PV cells after first exposure to sunlight. It results in a permanent reduction in nameplate capacity.
Light Load Hours	(Off-Peak Hours) The periods of the week designated as traditionally having lower system demand; hours not included in the definition of Heavy Load Hours.
Liquid	(Market) Condition where many buyers and sellers exist and commodities can be easily exchanged for cash without significant loss in value.
Load Following	The use of on-line generation, storage, or load equipment to track the intra- and inter-hour changes in customer loads, similar to regulation, but over longer periods of time.
Load Shifting	Moving the time period of a portion of electricity demand from higher demand hours to lower demand hours.
Loss of Load Expectation	(as defined by NERC) The expected number of days per year for which available generating capacity is insufficient to serve the daily peak demand (load). The LOLE is usually measured in days/year or hours/year. The convention is that when given in days/year, it represents a comparison between daily peak values and available generation. When given in hours/year, it represents a comparison of hourly load to available

	generation. LOLE is sometimes referred to as loss of load probability (LOLP). Also see LOLP.
Loss of Load Probability	(as defined by NERC) The proportion (probability) of days per year, hours per year, or events per season that available generating capacity/energy is insufficient to serve the daily peak or hourly demand. This analysis is generally performed for several years into the future and the typical standard metric is the loss of load probability of one day in ten years or 0.1 day/year. Also see LOLE. The NWPCC uses a metric, which establishes a minimum threshold LOLP standard of 5% for the Columbia River Basin (Region).

M

Market Taker	An entity that must accept whatever price the market dictates.
Mass-based	EPA CPP methodology for reducing CO_2 emissions by using goals specifying the total weight of CO_2 emissions measured in tons of CO_2.
Mean	(Statistical) Average or expected value of a set of values.
Meaningful Uncertainty	A stochastic modeling term that recognizes the need to produce plausible ranges of results that inform rather than providing results which effectively have no useful application.
Mean Reversion	The assumption that prices will eventually move towards the average price over time.
Microgrid	A localized electrical grid that can be disconnected from the traditional grid.
Minimum Down Time	(Generator use) A constraint on the least amount of time that a generating unit must be off after shutdown, typically due to necessary maintenance.

Minimum Up Time	(Generator use) A constraint on the least amount of time that a generating unit must be on once it starts, typically to minimize thermal stresses in the equipment.
Mode	(Statistical) The most often occurring value in a set of values.
Model Trading Rule	EPA CPP-proposed trading plan for carbon credits.
Monte Carlo	Modeling method that uses probability distributions for input values that have uncertainty, and produces distributions of possible outcomes.
Mountain Prevailing Time	Time of day based on the Mountain Time Zone and either Standard or Daylight Saving Time, whichever is applicable.
Must-take	(Resource use) A plant that requires, by physical design or contractual agreement, that the owner or purchasing customer accept all power production as it is generated.

N

Nameplate Capacity	The maximum rated generating output of a facility under specific conditions defined by the manufacturer.
Net Metering	Measuring the difference between the electricity distributed to and the electricity generated by a customer-generator that is fed back to the distribution system during the applicable billing period.
Net Present Value	The present value of future cash flows at a determined rate of return, used to discount future values back to today's dollars for a cost comparison of multiple projects, for example, alternative energy supply portfolios.
New Source Review	A CAA permitting program that requires industrial facilities to install modern pollution control equipment

	when they are built or when making a change that increases emissions significantly (as defined by EPA).
NGX	(TMX Group Limited – NGX) A Canadian natural gas exchange, trading, and clearing market.
Nodal Prices	Prices for a commodity such as electricity and natural gas determined by location or supply (interconnect) points and conditions of supply and demand associated with that location.
Non-attainment	(NAAQS use) Air quality status for an area with concentrations of criteria pollutants that are above levels established by NAAQS.
Non-Spinning Reserves	Off-line generation that is capable of being fully deployed within ten minutes and maintaining specified levels for at least sixty minutes.

O

Off-Peak Hours	Those hours defined by NAESB business practices, contracts, agreements, or guides as periods of lower electric demand and also may be those hours not included in On-Peak Hours (as defined in the QF-1 Tariff).
On-Peak Hours	Those hours defined by NAESB business practices, contracts, agreements, or guides as periods of higher electric demand and also may be the Heavy Load hours for the months of January, February, July, August, and December (as defined in the QF-1 Tariff).
1 in 2 (One in two) Peak Demand Forecast	A forecast based on a 50% probability that the forecasted value will be less than the actual peak demand, and a 50% probability that the forecasted value will be greater than the actual peak demand.

Optimization	Process of determining the lowest NPV utilization of resources to reliably meet energy, capacity, and ancillary needs.

P

P5	The 5th percentile of a sample is the value below which 5% of all values within that sample occur.
P95	The 95th percentile of a sample is the value below which 95% of all values within that sample occur.
Pacific Prevailing Time	Time based on the Pacific Time Zone and either Standard or Daylight Saving Time, whichever is applicable.
Parasitic Load	The power consumed by a generating device or system for its own operation and/or when not generating, such as transformer losses in a solar PV system at night.
Particulate Matter	Microscopic solid or liquid particles suspended in the Earth's atmosphere.
Peak Demand	Historical high point of collective power consumption.
Peak Shaving	Process of reducing the amount of energy purchased from a utility company during peak demand hours.
Pelton	Hydroelectric turbine design.
Performance Ratio	(Solar PV system) Ratio between actual annual production of AC energy and the theoretical annual production of energy.
Pet Coke	(Petroleum coke) A solid by-product of oil refineries that can be used as a fuel.
Petition for Certiorari	A written application to the United States Supreme Court (USSCt) to consider a case, which is used by the

	USSCt as a discretionary device to choose the cases that it will hear.
Photovoltaic	An electricity generation system that converts sunlight (photons) into electric current (voltage) within a semiconductor panel.
Plane of Array Insolation	The amount of insolation received by a surface parallel to solar panels.
PM_{10}	Particulate matter smaller than 10 microns in diameter.
Power Purchase Agreement	A contract between the utility and generation facility owner that defines the terms of the purchase and sale of energy production.
Prevention of Significant Deterioration	(as defined by EPA) A CAA New Source Review permitting program that applies to new major sources or major modifications at existing sources for pollutants where the area in which the source is located is in attainment or unclassifiable with the NAAQS. It requires the following: 1. installation of the "Best Available Control Technology" (BACT); 2. an air quality analysis; 3. an additional impacts analysis; and 4. public involvement.
Price-Taker	Company or resource that is not significant enough to influence the price of a good or service.
Procurement	The process of acquiring new resources.
Pro Forma	(Accounting use) A statement of a company's financial activities excluding unusual or non-recurring transactions.
Propeller	Hydroelectric turbine design.

PVsyst	Photovoltaic generation modeling software designed by PVsyst SA.

Q

Qualifying Facility	A small-scale renewable power producer that meets the capacity, fuel source, and operational criteria set forth by PURPA, including all pertinent requirements of Code of Federal Regulations Title 18 Conservation of Power and Water Resources and state law corollaries.
QF-1 Tariff	A MPSC approved electric tariff schedule that specifies rates and conditions for contracted renewable generation (Qualifying Facilities or QFs) power purchase terms between the utility (NorthWestern Energy) and the QF owner.

R

Ramp Rate	Speed at which a generator can increase or decrease generation, typically measured in units of MW/minute during the ramp period.
Rate-based	(CO_2 Emissions use) EPA CPP methodology for reducing CO_2 emissions that uses goals specifying the ratio of pounds of CO_2 emissions to the net energy produced, measured in units of (lbs. CO_2/net MWh).
Rate-based	(Resource use) A utility-owned generation resource in which the costs to purchase or build the resource are paid by the utility's customers through billed electric rates.
Rate of Return	The profit on an investment over a period of time, expressed as a proportion of the original investment.
Re-conductor	Replacement of a transmission line within existing infrastructure.

Regression model	A technique to analyze a dependent variable's reaction to changes in other independent (explanatory) variables.
Regulation	An ancillary service consisting of maintaining interconnection frequency, managing differences between actual and scheduled power flows, and matching generation to load, tracking minute-to-minute fluctuations in the BA as specified by NERC.
Rehabilitation	(Hydro Project use) Remanufacturing or refurbishing existing units, as defined by IEEE STD 1147-1991.
Reliability-Based Control	Refers to NERC Standard BAL-001-2, Real Power Balancing Control Performance. Among other things, the Standard requires a Balancing Authority to operate such that its Area Control Error does not exceed defined limits for more than 30 consecutive clock minutes. The Standard becomes effective July 1, 2016.
Renewable	A type of energy, or resource that generates the energy, that is produced from essentially sustainable fuel, such as falling water, wind, geothermal, or solar radiation.
Renewable Energy Credit	One megawatt-hour of renewable energy generation from an eligible renewable resource (defined by § 69-3-2003, MCA).
Replacement	(Contingency Reserves) Same as Non-Spinning reserves except with a 30-60 minute response time, and used to restore other contingency reserves to their pre-contingency status.
Reserve margin	Excess generating capacity above expected peak demand normally used in recovering from contingencies within the BA.
Risk premium	A monetary value associated with the risk of a specific portfolio, defined as the integral of the cost distribution above the mean.

Run-of-the-river	A FERC designation for a hydroelectric dam that must maintain minimum differences in upstream and downstream flow rates, and minimum storage reservoir level fluctuations, so that only water from upstream is available for generation at that moment and any unused amount must be spilled.

S

Scrubbers	Systems that remove particles or gases from industrial exhaust streams.
Solar PV	(see Photovoltaic) An electricity generating resource that uses sunlight as fuel to create an electric charge in semiconductor panels.
Spark Spread	The gross-generation profit margin earned by buying natural gas and burning it to produce electricity (compared to purchasing electricity from the market), which depends on energy prices and generator efficiency (heat rate), measured in units of ($/MWh).
Specific Yield	A standardized measure of energy output for a solar PV system in reference to the rated (peak) power output, in units of (MWh/MWp).
Spinning Reserves	On-line generation that is synchronized and ready to serve additional demand within ten minutes and can sustain that change in output for a minimum of sixty minutes, and can meet other WECC requirements.
Stochastic	A process in which there is inherent randomness; where the same inputs will produce a distribution of outcomes through iterative sampling of variables.
Sub-bituminous	An intermediate coal with properties between lignite and bituminous coal.

SunShot Initiative	A DOE program to make solar energy cost-competitive with other forms of electricity by the end of the decade, announced in 2011.
Supervisory Control and Data Acquisition	A computer-based system for remotely monitoring and controlling processes, such as power generation, electric transmission, and distribution.

T

Tier II	QF power purchase agreements that stemmed from MPSC Docket Nos. D97.7.90 and D2001.1.5, Order Nos. 5986w and 6353c.
Time of Use	A variable rate structure that charges customers a rate dependent on the time of day and season the energy is used.
Tolling PPA	A power purchase agreement where the buyer provides fuel as needed to meet the generation which is controlled and purchased by the buyer.
Tracker Period	(Tracker Year) A fiscal year from July 1 through June 30 of the following calendar year, used by NorthWestern's Electric Supply Cost Tracker.
Triangular Distribution	A probability distribution typically used when sample data and knowledge is limited. This distribution is defined by a lower limit, upper limit, and mode.
Turbine	A rotary mechanical device that extracts energy from a fluid (i.e. water) or the wind and converts it into work, such as turning a rotor.
Turgo	Hydroelectric turbine design.

U

Utility System	The interconnected grid within the BA area consisting of generation, transmission, and distribution equipment.

V

Volatility	The degree of variation of a market price over a period of time.

W

Waste Coal	A usable material byproduct of a previous coal processing operation.
Waste Coke	(See Pet Coke).
Weighted Average Cost of Capital	The rate that a company is expected to pay on average to all its security holders to finance assets. It is used to discount all costs back to present value in order to compare portfolio cash flows in the future. At the time of this Plan, NorthWestern used a WACC of 7.03%.

Z

Zero discharge	Permit requirement prohibiting waste water discharge from a site.