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APPENDIX 1
PRICE ELASTICITY OF DEMAND

Default Electric Supplier Procurement Guidelines, and more specifically ARM 38.5.8210(2), states that a utility's needs assessment under subpart (a) address price elasticity of demand. NorthWestern has not observed or determined, through review of customer usage history information, the extent to which electric rates and changes to rates have influenced consumption behavior. A number of factors are recognized as contributing to customer energy usage with electricity price being only one of multiple factors. The difficulty of isolating and measuring price elasticity effects is evident.

Northwestern will continue to monitor price elasticity of demand through the Smart Grid Demonstration Project (Project). The project objectives are to deploy, test, and evaluate various equipment, systems and customer services associated with emerging Smart Grid technology. A portion of the project involves testing consumer response to different electricity prices at different times of the day. This activity is an initial step toward gaining a better understanding of consumers' elasticity of demand through time of use (TOU) pricing. Based on the results obtained from this study Northwestern may be able to provide some meaningful information with regard to consumer response from this study. A final report by NorthWestern outlining its part of the Pacific Northwest Smart Grid Demonstration Project is scheduled for completion by December 2014.

APPENDIX 2
ABBREVIATIONS

A

ACC	Air-cooled Condenser
ACES	American Clean Energy & Security Act
ADI	Ace Diversity Interchange
AMI	Advanced Metering Infrastructure
aMW	Average megawatts
ARM	Administrative Rules of Montana
ARRA	American Recovery & Reinvestment Act

B

BAA	Balancing Authority Area
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BGI	Billings Generation Inc.
BOC	Building Operator Certification
BPA	Bonneville Power Administration
Btu/kWh	British thermal unit per kilowatt-hour

C

CC	Combined Cycle
CCCT	Combined Cycle Combustion Turbine
CCR	Coal combustion residuals
CCS	Carbon Capture and Sequestration
CDD	Cooling Degree Day(s)
CDP	Carbon Disclosure Project
CEIC	Census and Economic Information Center
CELP	Colstrip Energy Limited Partnership
CFLs	Compact Florescent Light Bulbs
CHP	Combined Heat and Power
CO_2	Carbon dioxide
CREP	Community Renewable Energy Project
CT	Combustion turbine
CU3	Colstrip Unit 3
CU4	Colstrip Unit 4

D

DA	Data Analytics
DGGS	Dave Gates Generating Station
DOE	Department of Energy
DSM	Demand Side Management

E

EIA	Energy Information Administration
EPA	Environmental Protection Agency
EPC	Engineering Procurement and Construction
ESB	Energy Supply Board
ESRPP	Electricity Supply Resource Procurement Plan
ETAC	Electric Technical Advisory Committee
EUI	Energy Use Intensity

F

FERC	Federal Energy Regulatory Commission
FIP	Federal Implementation Plan
FLISR	Fault Location Isolation and Service Restoration

G

GHG	Greenhouse gases
GWh	Gigawatt hour

H

HAN	Home Area Network
HAP	Hazardous Air Pollutant
HDD	Heating Degree Day(s)
HL	Heavy Load (on peak hours per Mid-Columbia definition)
HRSG	Heat Recovery Steam Generator
HVAC	Heating Ventilating and Air Conditioning

I

IC	Internal Combustion
IGCC	Integrated Gasification Combined Cycle
ITAP	Intra-hour Transaction Accelerator Platform

K

kW	Kilowatt
kWh	Kilowatt hour

L

LIEAP	Low Income Energy Assistance Program
LL	Light Load (off peak hours per Mid-Columbia definition)
LRAM	Lost Revenue Recovery Mechanism

M

MACT	Maximum Achievable Control Technology
MATL	Montana-Alberta Tie Line

MATS	Mercury and Air Toxics Standards
MCA	Montana Code Annotated
MCC	Montana Consumer Counsel
Mid-C	Mid-Columbia electric trading point
MMBtu	Millions of British thermal units
MPSC	Montana Public Service Commission
MSTI	Mountain States Transmission Intertie
MSW	Municipal Solid Waste
MW	Megawatt
MWh	Megawatt hour

N

NCAT	National Center for Appropriate Technology
NEEA	Northwest Energy Efficiency Alliance
NERC	North American Reliability Corporation
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NOx	Nitrous Oxide
NPDES	National Pollutant Discharge Elimination System
NPV	Net Present Value
NSPS	New Source Performance Standards
NWE	NorthWestern Energy or NorthWestern
NWPCC	Northwest Power and Conservation Council

O

OATT	Open Access Transmission Tariff
O&M	Operation & Maintenance

P

PEV	Plug-in electric vehicle
PM	Particulate Matter
PPA	Power Purchase Agreement
PRB	Powder River Basin
PTC	Production Tax Credit
PURPA	Public Utility Regulatory Policies Act
PV	Photovoltaic

Q

QF	Qualifying Facility

R

REC	Renewable Energy Credit associated with one megawatt hour of production
REMI	Regional Economic Models, Inc.
RCRA	Resource Conservation and Recovery Act
RFI	Request for Information
RFP	Request for Proposals
RPP	Resource Procurement Plan

RPS	Renewable Portfolio Standards

S

SCCT	Simple Cycle Combustion Turbine
SO_2	Sulfur Dioxide
SOx	Sulfur Oxide

T

TONNE	Metric Ton
TOU	Time of Use

U

USB	Universal System Benefits

V

VAR	Vector Auto-Regression

W

WACC	Weighted Average Cost of Capital
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council
WREGIS	Western Renewable Energy Generation Information System

Y

YELP	Yellowstone Energy Limited Partnership

CHAPTER 1

THE 2013 ELECTRIC SUPPLY RESOURCE PROCUREMENT PLAN

Electric Utility Transition

This planning document presents the results of electric resource planning and procurement activities by NorthWestern Energy ("NorthWestern") and the resulting proposed actions to reliably and cost-effectively meet the Montana retail load serving obligation over the 20 year planning horizon. In addition to satisfying the biennial regulatory filing requirement, the 2013 Electric Supply Resource Procurement Plan ("2013 Plan" or "Plan") documents resource acquisition and evaluation work, analyzes and defines load-serving needs and alternatives, examines changes effecting supply, addresses Montana Public Service Commission ("MPSC" or "Commission") comments on the 2011 Plan, and proposes appropriate courses of action.

On September 26, 2013, NorthWestern announced that it entered into an agreement to purchase the hydro assets of PPL Montana, LLC.

The timing of the 2013 Plan finds NorthWestern's portfolio in transition. On September 26, 2013, NorthWestern announced that it entered into an agreement to purchase the hydro assets of PPL Montana, LLC ("Hydro Acquisition" or "Hydros"). The Hydro Acquisition includes 11 hydroelectric facilities representing 633 MWs of generation, a storage reservoir, and other related assets (see Figure 1-1). The Hydro Acquisition clearly falls into the category of an "opportunity acquisition" as envisioned in NorthWestern's 2011 Electricity Supply Resource Procurement Plan ("2011 Plan"), and will be submitted for regulatory consideration, pursuant to 69-8-421 MCA. The 2011 Plan, while not specifically indentifying the Hydros,

contemplated similar resources in terms of availability for purchase, applicability in serving Montana retail load, portfolio value contribution, and cost effectiveness. If the Commission approves NorthWestern's Application to acquire the Hydros under satisfactory terms, NorthWestern will place the Hydros into its resource portfolio in the second half of 2014. A thorough description of the Hydros is presented in Chapter 5.

Figure No. 1-1

PPL Montana Hydroelectric Facilities

The 2011 Plan communicated that NorthWestern would continue to evaluate gas-fired resources and future opportunity resources (existing resources available for purchase); NorthWestern has done both in the 2013 Plan. The benchmark portfolio in the 2011 Plan was based upon the then current supply portfolio, and included future market transactions, but, except for potential opportunity acquisitions, no additional generation resources over the three year action period. The 2011 Plan compared alternative portfolios to the market portfolio to

determine if new resources would result in portfolios with lower costs and risks. The 2011 plan concluded through its evaluation of gas-fired resources that the addition of a combined cycle combustion turbine ("CCCT"), nominally sized at 300MW, as the preferred resource alternative because of the balance achieved between resulting portfolio cost and risk when compared to alternative portfolios, including market. The market case had the lowest cost portfolio, but was determined to be unacceptable because of the potential higher costs associated with market uncertainty.

The 2013 Plan builds upon conclusions reached in the 2011 Plan. Market assumptions have been brought forward in the 2013 Plan and have been updated to reflect current market expectations, including the recognition of carbon costs starting in 2021. Carbon costs are included in the 2013 Plan as a $/tonne cost adder and serve as a surrogate for whatever mechanism (fee, tax, penalty, or environmental compliance cost) is ultimately enacted with regard to carbon. Additionally, the resource definition for gas-fired resources has been further refined to include a detailed build-up of the operational characteristics and expected costs of ownership and operation for gas-fired resources sited in Montana, as opposed to more the generic resource assumptions employed in the 2011 Plan.

The 2013 Plan re-evaluates the current portfolio plus market transaction case (Current portfolio), refines the 2011 preferred resource option (CC portfolio), and includes an "opportunity resource" portfolio which is the Hydro Acquisition (Hydro portfolio). These three scenarios bracket the full range of portfolio compositions contemplated in the 2011 Plan. On a 30-year net present value comparison, the Hydro portfolio has the lowest expected cost when compared to the CC or Current portfolios as shown in the table below. The Hydro portfolio is the preferred resource option when compared to the CC portfolio or the Current

portfolio. The Hydro portfolio is the least cost portfolio (Table 1-1). Additionally, the Hydro portfolio achieves a lower total risk-adjusted cost than either the Current portfolio or the CC portfolio.

Table No. 1-1

Net Present Value of Portfolio Costs, 2015 - 2043 ($ Millions)

Portfolio	Total Cost Excluding Risk Premium	Risk Premium	Total Cost Including Risk Premium
Current portfolio	$5,778	$451	$6,229
CC portfolio	$5,854	$380	$6,234
Hydro portfolio	$5,609	$247	$5,856

The addition of the Hydros to NorthWestern's energy supply portfolio creates a unique set of circumstances in terms of the resource type and associated positive benefits to the load-serving capabilities of resources under NorthWestern's control. The Hydros will transform NorthWestern's resource portfolio from what was, until recently, a complete reliance upon market purchases and power purchase agreements, to a more balanced combination of traditional owned generation including hydro and thermal assets, renewable resources, legacy contracts, and market transactions. For planning purposes the Hydro Acquisition represents the largest set of physical assets considered for inclusion into the resource portfolio by NorthWestern to serve its customers in Montana. With the addition of the Hydros and, continued transformation of the portfolio's makeup, NorthWestern will focus on capacity-based planning as opposed to energy-based operations to support reliable

Transformation of NorthWestern's energy supply will focus on capacity-based as opposed to energy-based operations.

and cost-effective service according to time-tested utility standards.

The opportunity to manage a resource portfolio based primarily on electric generation resources rather than a portfolio weighted in favor of market products and purchases creates different responsibilities for electricity resource planning. These responsibilities will include scheduling and planning for resource output in conjunction with reduced market purchases. Thermal, hydro, and other assets interconnected within the NorthWestern balancing authority require planning and coordination between the three principle operating units within the utility; Generation, Supply, and Transmission. A natural outcome of coordinated planning and operation is the overall achievement of efficiency through cost-management, economic asset optimization of resources, reliable service, and regulatory oversight. Additionally, the Hydros will help mitigate the risks inherent in large open positions in the electricity market over the long-term and will help mitigate potential environmental risk. With the Hydro Acquisition, NorthWestern continues to transition from a planning paradigm that was the result of energy deregulation and sale of all generation assets, to a paradigm defined by utility controlled resources and more focused on capacity and operational planning.

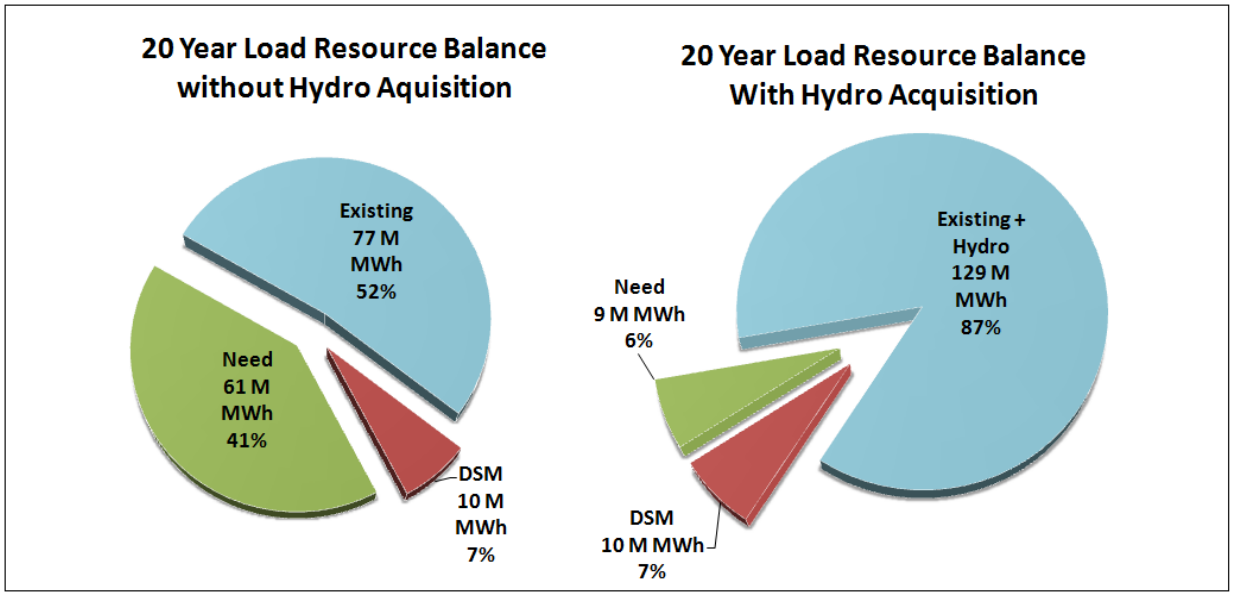
Fulfillment of Load-Serving Obligations

The retail load served by NorthWestern in Montana is comprised of multiple rate classes that on both a customer number and energy consumption basis are weighted heavily to retail and small commercial customers. The challenge posed by the retail load is its variability (hourly to seasonal) and the requirement to maintain and manage a portfolio of resources assembled to effectively meet the current and future needs of the retail Montana load. The 2013 Plan considers customer loads over multiple time periods for reliability, operational need, cost, and risk. NorthWestern continues to tailor its analytical examination of loads and resources to account for variability across all time periods within the 20-year

planning horizon to assure customer energy needs are met in a reliable and cost-effective manner.

During the 10-year period from 2003 through 2012 retail load grew from 5.5 million megawatt-hours per year to 6.4 million megawatt-hours per year. This included losses associated with transmission and distribution. Retail load is forecast to be 6.5 million megawatt-hours in 2014 and expected to increase to 7.6 million megawatt-hours per year by 2033. Over a 20-year resource planning horizon the total energy need of retail customers is expected to be approximately 148 million megawatt-hours, excluding the impacts of future energy savings associated with the Demand Side Management (DSM) program. Based on the expected output from the resources currently in the supply portfolio, representing an estimated 87 million megawatt-hours of production, the remaining un-secured resource need is 61 million megawatt-hours or approximately 41% of retail customer need (Figure 1-2). Over the next 20 years the Hydros (excluding Kerr Dam) are estimated to produce approximately 50 million megawatt-hours of power. This reduces future unsecured load-serving needs over the 20-year planning horizon to less than 10%; an amount far less than the current long-term deficit and more easily managed at lower risk to the portfolio.

Figure No. 1-2



Long-term energy volumes only provide a partial understanding of load and how best to meet it. The 2013 Plan also examines load over the 20-year planning horizon and includes modeling and analysis at the hourly level to inform the long-term resource planning process on a capacity basis (see Chapter 4).

Supply Costs and Risks

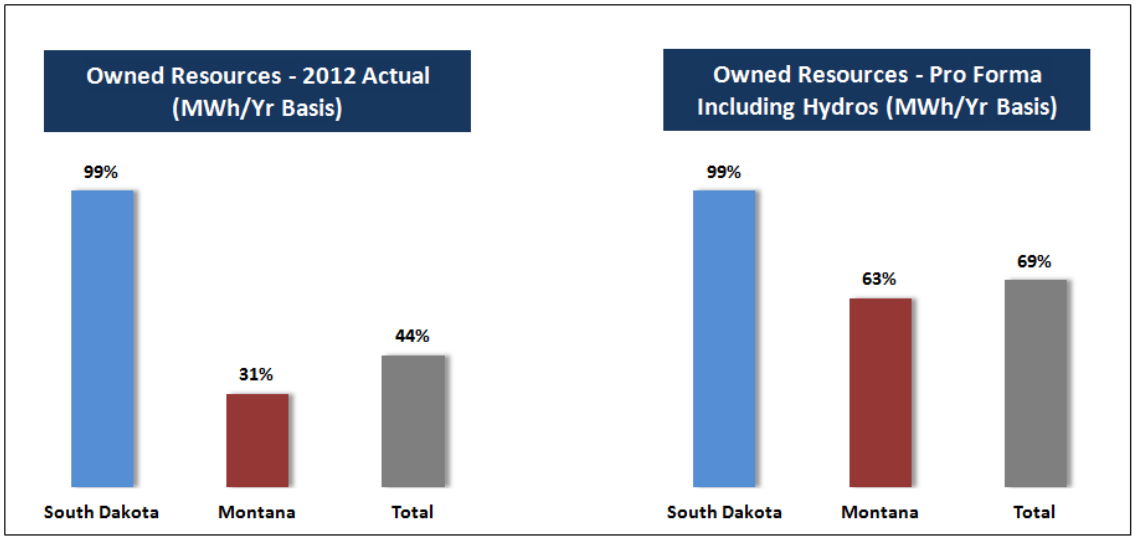
Retail supply costs result primarily from the costs associated with generating electricity from portfolio resources and from purchases of energy products. Electric commodity costs are aggregated, tracked, regularly reported to the MPSC, and included in customer rates. Sources of energy in the current resource portfolio have varying levels of future cost uncertainty. NorthWestern manages this uncertainty on behalf of its retail customers and reductions in risk usually include an accompanying cost. The cost of reducing this risk recognizes an element of time and often means that reduction of risk farther into the future includes a price premium to reflect future uncertainty.

NorthWestern currently relies heavily on market purchases in the wholesale electricity market to meet customers' energy requirements. NorthWestern's peer utilities meet 93% of their energy requirements from company-owned resources, while NorthWestern meets only 31% (pre-Hydros) of its customers' energy needs from company-owned resources. This means that any increase in market prices, or increased volatility in market prices, affects NorthWestern to a much greater degree than other regional utilities. As the region's surplus diminishes, NorthWestern's reliance on market transactions will be more costly, will be subject to more volatility, and could potentially increase the risk of physical delivery.

Hydro Acquisition

With the addition of the Hydros, NorthWestern will be able to meet 63% of its customers' energy needs from company-owned resources; a substantial increase over the current 31% (see Figure No. 1-3). Importantly, NorthWestern's load-serving obligation includes the obligation to provide service during all hours, including Peak load hours.

Figure No. 1-3



NorthWestern's current 20-year planning horizon shows a large unfilled resource need for both energy and peaking resources. Unlike other Pacific Northwest utilities and load-serving entities facing incremental resource additions, NorthWestern is confronted with large deficits in the portfolio that translate into risk and uncertainty. The Hydros will contribute significantly to meeting peak resource need and are expected to reduce portfolio risk, creating cost certainty and rate stability.

Resource Adequacy

NorthWestern currently relies heavily on market purchase in the wholesale electricity market to meet customers' needs at time of peak demand. NorthWestern's load and resource balance indicates that, absent the Hydros, it must plan to acquire 680 MW of power to meet a planned winter peak of 1,162 MW in 2014, increasing to 819 MW of power needed to meet a winter peak of 1,202 MW in 2018. While NorthWestern would use staged and planned RFPs and other short term market purchases to minimize market exposure, it would still be exposed to a great deal of market price risk.

In 2005, the Northwest Power and Conservation Council and Bonneville Power created the Pacific Northwest Adequacy Forum ("Adequacy Forum"). The Adequacy Forum was tasked with developing an adequacy standard for the regional power supply. In its 2012 forecast, the Adequacy Forum identified a 350 MW capacity deficit by 2017. While the study observed that utility planned resources exceed the identified deficit, the planned elimination of the Boardman and Centralia coal-fired plants and PPL Montana's announcement that the 153 MW J.E. Corette coal-fired generation plant will be placed in reserve status beginning April 2015, contribute to regional resource adequacy concerns.

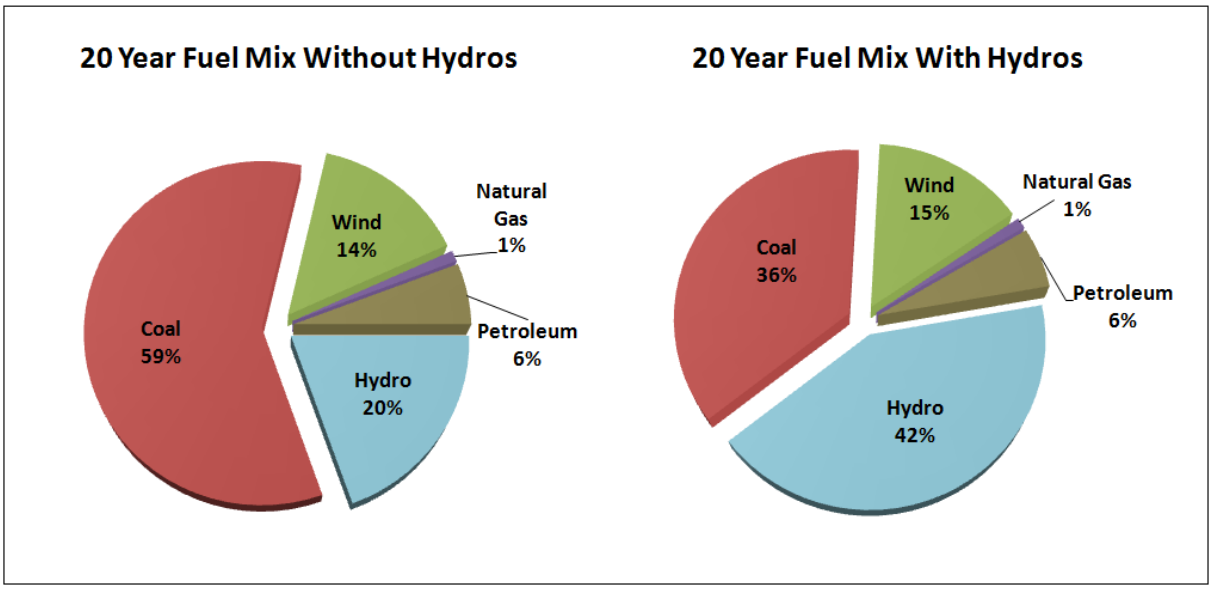
Additional resource adequacy concern arises over statements by other regional utilities that in the future they intend to rely more heavily on market purchases to meet their load and resource balance. Absent the addition of the Hydros or a CCCT, NorthWestern will be seeking a majority of its peak need through market purchases; 58% in 2014 increasing to 68% in 2018. The risk associated with market and market price volatility has a greater potential impact on NorthWestern's customers as a percentage of their total electric bill compared to other regional utilities. Adding the Hydros to the resource portfolio reduces the market risk for both peak and energy. A more thorough discussion of NorthWestern's resource needs is presented in the Chapter 4.

Environmental Risk

Montana is affected by environmental policies promulgated by the federal government and by other states residing in the Western Electricity Coordinating Council. Future environmental actions including taxing or regulating carbon emissions will impact NorthWestern because NorthWestern currently relies heavily on short-term to mid-term market purchases sourced both from hydroelectric and thermal generators. The Hydros (excluding Kerr) will provide 439 MW of long-term electric generation capacity and approximately 2.5 Million MWh per year of environmentally responsible baseload energy to the NorthWestern's resource portfolio, significantly changing the fuel-mix of NorthWestern's resource portfolio (see Figure 1-4) and reducing the risks of any future actions addressing emissions. A more thorough discussion of environmental risk is presented in Chapter 3.

Figure No. 1-4

2012 Portfolio Resource Mix versus Pro Forma Hydro Addition



2011 Action Plan & MPSC Comments

Resource procurement and planning undertaken by NorthWestern following the submission of the 2011 Plan addressed the initiatives and baseline activities identified and explained in the December 15, 2011 filing. Planning and procurement work has continued to focus on the needs of the portfolio and customers in terms of maintaining cost-effective and reliable service while considering how to meet changing needs and fulfill future load-serving obligations. The following discussion provides an explanation of activities that address what NorthWestern and its consultants have done to analyze and address key issues from the 2011 Action Plan. It is not intended to be a full and exhaustive accounting of all supply group planning and analysis work performed during the period 2011 – 2013.

Modeling and Software

NorthWestern engaged the services of Ascend Analytics ("Ascend") of Boulder, Colorado to apply new modeling approaches to long-term resource and supply portfolio evaluations for the 2013 Plan. When the Hydro Acquisition was announced, Ascend's scope of work was expanded to include supporting analysis and work products for the Hydros. Both of these tasks required a substantial level of detailed analysis and evaluation of risk.

Prior to selecting Ascend, NorthWestern researched several software vendors to determine software capabilities and the scope of vendor support. Ultimately, NorthWestern selected Ascend and the PowerSimm™ suite of products based on the ability to model the Montana supply portfolio, commodity prices, new resources, and an expanded set of variables. Migration to new resource modeling presented a number of challenges, but PowerSimm has proven to be a better model to analyze portfolio costs and risks and to develop a common understanding of portfolio costs and risks with stakeholders. A discussion of how the PowerSimm suite values risk is contained in Chapter 6.

Expiration of the PPL Agreement

The Hydro Acquisition has eliminated the need to replace power currently supplied under the 7-year agreement with PPL set to expire in 2014. The scale of the Hydros, when added to the existing portfolio, fulfills more than 90% of the retail load-serving obligation over the next 20 years. The expected annual production of approximately 2.5 million megawatt-hours from the Hydros (excluding Kerr Dam) exceeds the current annualized power delivery under the PPL 7-year agreement by approximately 1 million megawatt-hours.

In the 2011 Plan, opportunity resources were identified but not described in detail except to say that these resources would be evaluated and considered if they were determined to meet acceptable levels of portfolio energy, cost, and risk. NorthWestern concluded that the Hydro Acquisition meets all three of the opportunity resource criteria identified in the 2011 Plan.

NorthWestern has concluded that the Hydro Acquisition meets all three of the opportunity resource criteria identified in the 2011 Plan.

Gas-fired Resources

Prior planning cycles, including the 2011 Plan, identified natural gas fired generation resources as preferred resources based on their performance (cost and risk) in the simulated portfolio modeling environment. Absence the Hydros these resources are plausible additions to the supply portfolio based on their ability to provide cost-effective generation at acceptable levels of risk. NorthWestern currently possesses multiple sources of gas-fired resource experience which further adds to the plausibility of the gas-fired resource option. This experience includes development, construction, and operation of facilities in Montana and South Dakota for both internal combustion and simple cycle gas turbines.

During 2013, unit definitions such as size, combustion technology, and performance characteristics were developed in consultation with major electric generation equipment manufacturers under conditions expected for a Montana installation. This information was shared, presented, and discussed with the Electric Technical Advisory Committee during 2013 in anticipation of evaluating portfolios composed of different gas-fired technologies. Lands Energy Consulting developed a focused set of generation resources to evaluate in the Plan. The group of identified resources concentrates primarily on proven resource types including gas-fired technologies and renewables, and represents currently

plausible and commercially available new-build alternatives with known characteristics. Generic resource assumptions and definitions used in previous planning work were replaced with unit definitions developed specifically for installation and operation of gas units within Montana.

Following the announcement of the Hydro Acquisition, the gas-fired resource evaluation focused on CCCT technology because it represented the most plausible alternative to the Hydros. CCCT technology offers the best value gas-fired technology when placed in a baseload role in the supply portfolio because it has the lowest fuel consumption per unit of energy output (heat rate) of the gas-fired options and has low variable operating costs. As a baseload resource, the CCCT is the most appropriate new commercial-scale thermal generating resource for NorthWestern to compare to the Hydros. Finally, CCCT technology is readily available for commercial deployment by NorthWestern.

Resource Adequacy

Resource adequacy standards are typically defined within utility regulatory jurisdictions including NERC regions such as WECC, and are often prescriptive. The utility regulatory jurisdiction in which NorthWestern operates in Montana requires cost-effective and reliable retail service to customers under a set of rules that guide planning, cost reporting and recovery, and a regulatory framework. NorthWestern is therefore under a prudence demonstration obligation rather than a set of prescriptive resource adequacy standards.

The supply portfolio is evolving and changing in order to continue to satisfy multiple objectives such as low cost, low risk, renewable portfolio standards, demand side management energy savings, Public Utilities Regulatory Policy Act of 1978 ("PURPA") contracting

The supply portfolio is evolving and changing in order to continue to satisfy multiple objectives.

obligations, and more. Defining resource adequacy for NorthWestern and its customers involves balancing these multiple objectives while maintaining reliability at acceptable levels of cost and risk.

Renewable Portfolio Standards

The retail load-serving obligations of NorthWestern go beyond meeting the physical energy needs of retail customers. Renewable Portfolio Standards require the utility to supply a defined percentage of retail sales from eligible renewable sources. This requirement (currently 10%) is being adequately served from a fleet of wind and small hydroelectric projects that are either under contracted or under utility ownership and in both cases, directly interconnected within the NorthWestern balancing authority.

NorthWestern currently has four approved CREP qualified resources, and expects that the recently negotiated Sleeping Giant Power, LLC project will qualify for CREP status. The total installed capacity of these five projects is a little over 33 MW. When compared to NWE's estimate of its CREP obligation, NorthWestern is currently about 12 MW short of its 2012 CREP obligation and about 35 MW short of its 2015 CREP obligation. NorthWestern has found the CREP requirement difficult to achieve and is currently seeking a waiver for CREP compliance in 2013. A Request for Proposals (RFP) for up to 45 MW of CREP-eligible resources was issued on August 2, 2012. Any new CREP projects will contribute to meeting both Montana RPS and CREP requirements.

Intermittent Resource Integration

The portfolio includes eligible renewable resources comprised primarily of wind and small hydro facilities that contribute energy and in some cases renewable energy credits (RECs). The transmission business unit provides integration services, primarily regulation services from Dave Gates Generation Station

(DGGS) and imbalance services, to enable the safe and reliable operation of these and other generation resources within the NorthWestern balancing authority. The Supply operations group uses available resources, including market purchases and sales (day-ahead and hourly), to balance load with resources and while accounting for changing renewable energy output.

Supply operations perform specific functions in pursuit of creating balance between retail load and resources within the portfolio. Initiatives are being explored that may help to integrate intermittent resources in the region and NorthWestern is an active participant in these initiatives. Initiatives such as Ace Diversity Interchange (ADI) and I-TAP (Intra-hour Transaction Accelerator Platform) are examples of industry-sponsored programs envisioned to provide utilities with alternatives to more efficiently balance loads with variable resource output. NorthWestern's response to these changes has been to participate, provide input where appropriate, and to monitor development. Adoption of new protocols into supply operations is wholly reliant on the active participation of others. Market-based transformation has been slow to materialize in the northwest because of technical challenges and because participation has not materialized. However, the development of an energy imbalance market in the northwest may create new opportunities for NorthWestern to help cost-effectively manage the resources within the supply portfolio.

Conclusions

Resource planning informs NorthWestern's resource procurement strategies and decisions. The 2013 Electricity Resource Procurement Plan presents an up-to-date assessment of retail customer load, the current supply portfolio, projection of future needs, and actions to effectively manage the portfolio. NorthWestern's retail customers have long benefitted from available power supplies located within the state and in the region; historically purchased from third-party thermal

and hydro electric sources. However, the region is changing; excess resources and regional flexibility are declining and we must consider alternatives to prior resource procurement practices and strategies.

The 2013 Plan is a continuation of NorthWestern's previous planning efforts. The 2011 Plan contemplated that NorthWestern would continue to evaluate gas-fired resources and future opportunity resources (existing resources available for purchase). NorthWestern has done both in the 2013 Plan and has identified the Hydro Acquisition as the preferred resource portfolio. The Hydro Acquisition provides the opportunity to create a long-term, balanced portfolio to satisfy customer needs, substantially mitigate market price risk, substantially mitigate environmental risk, and ensure reliable capacity-based power delivery at lowest long-term risk-adjusted cost.

CHAPTER 2
CURRENT RESOURCES

CHAPTER 2

NorthWestern manages a portfolio of demand- and supply-side resources to serve the needs of its retail customers.

Existing Supply-Side Portfolio

NorthWestern's supply-side portfolio contains a diverse set of resources, including coal and natural gas thermal units, small hydro, wind generation, Purchased Power Agreements ("PPAs"), and Qualifying Facilities ("QFs") generating electricity using wind, water, waste coal and pet-coke. The location of the physical resources included in the resource portfolio is shown in Figure 2-1.

Figure No. 2-1

Existing Generation in Supply Portfolio

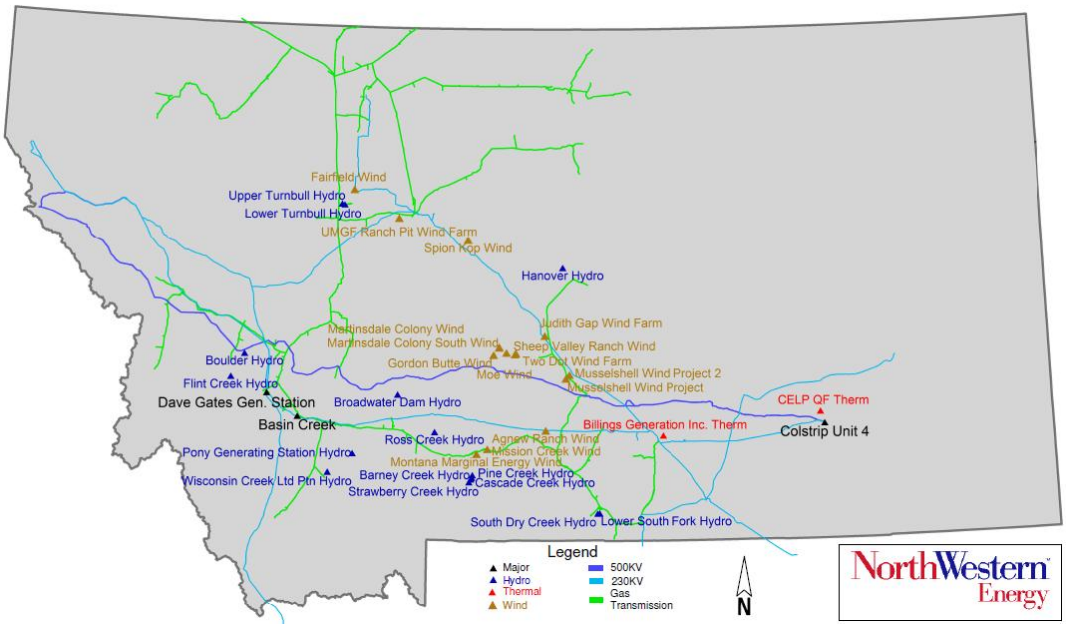


Table 2-1 lists each mid-to-long term resource in the supply-side portfolio along with their attributes; installed capacity, winter and summer peaking capability, annual energy production, load following capability (both up and down), spinning and non-spinning reserves, and expiration dates for PPA resources.

Table No. 2-1

NorthWestern Energy
Existing Energy Supply Peaking Resources
(as of January 1, 2013)

Resource	Nameplate [1] Capacity (MW)	Winter Peaking (MW)	Summer Peaking (MW)	Annual Energy (aMW)	Load Following Up (MW)	Load Following Down (MW)	Spinning Reserves (MW)	Non-Spinning Reserves (MW)	Contract Expiration Date
Colstrip 4	222	222	222	202	0	162	0	0	n/a
Basin Creek	52	35	35	2	35	35	0	17	07/01/26
QF Tier II	99.5	130.7	28.5	94	0	0	0	0	Various
Wind resources	218	0	5						
DGGS (Energy Supply)	7	7	7	7	0	0	0	0	n/a
Tiber Montana, LLC	7.5	4	-	2	0	0	0	0	06/01/24
PPL 7-Year (HL)	200	200	200	112	0	0	0	0	06/30/14
PPL '09 RFP (HL)	25	25	25	14	0	0	0	0	06/30/17
TransAlta '10 RFP (HL)	25	25	25	14	0	0	0	0	06/30/17
Credit Suisse	25	25	25	25	0	0	0	0	06/30/15
Total:	881	674	573	472	35	197	0	17	

[1] Nameplate capacity reflects NWE share only

The following is a description of each of the resource attributes listed in Table No. 2-1.

- **Nameplate capacity:** Nameplate capacity, or nameplate rating, is the maximum rated output of a generation facility under specific conditions defined by the manufacturer. The nameplate rating is usually displayed on a plaque or tag physically attached to the generator and contains additional data such as manufacturer and serial number. The nameplate capacity in Table 2-1 reflects NorthWestern's share of the

rated capability of the generation facility at point of delivery to NorthWestern.

- **Peaking capacity:** "Winter Peaking" and "Summer Peaking" capacities indicate the amount of electric power that can be reliably called upon by NorthWestern when the system is experiencing its highest levels of demand. Typically, baseload generation (like Colstrip Unit 4) and peaking resources (like Basin Creek) can be relied upon at time of system peak. Likewise, PPAs contracted for delivery during heavy load hours can be relied upon at time of system peak. Intermittent resources, like wind, cannot be relied upon to meet peak load. Peaking capacity is measured in Megawatts ("MW").

- **Annual energy:** The average annual energy, measured as Average Annual Megawatts ("aMW"), that a generation facility can reliably be forecast to produce on an annual basis. For example, a generation facility which produces 1 MW continuously for one full year would produce 8,760 MWh of energy, or 1 aMW.

- **Load following capability:** Load following measures a generation facility's capability to change electric generation output as system loads increase (following-up) or to reduce loads as system loads decrease (following-down). Load following is needed to maintain balance between generation, and system loads and changes in intermittent generation. NorthWestern generally uses market purchases, or in some instances sales, to meet its load following needs. Additionally, load-following resources are used to integrate intermittent resources like wind. Load following is measured as the maximum MW change in output that can be called upon from one hour to the next.

- **Contingency reserves:** Adequate generation capability must be maintained at all times to maintain scheduled frequency and to avoid loss of load due to forced outages of generation or transmission facilities. Contingency reserves are required by the Western Electricity Coordinating Council (WECC) to maintain the reliable operation of the interconnected power system. Contingency reserve requirements can be met with spinning reserves and non-spinning reserves, as well as by contracting for reserves from third parties that can be deliverable on Firm Transmission Service.
    - **Spinning reserves:** On-line generation that is capable of increasing power production within ten minutes and can sustain that change in output for a minimum of sixty minutes and can be used for meeting requirements for spinning reserves. Baseload generation is typically not used for spinning reserves.
    - **Non-spinning reserves:** Off-line generation that is capable of being fully deployed within ten minutes may be used to provide non-spinning reserves. Non-spinning reserves must be capable of maintaining their specified reserve level for at least sixty minutes.

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Existing Electric Supply Resources

Figure No. 2-2

Colstrip Generation Facilities

Colstrip Unit 4

Colstrip Unit 4 ("Colstrip 4") is the fourth unit of a 2,094 MW four unit baseload coal-fired steam electric plant located about 120 miles southeast of Billings, Montana. NorthWestern has 30% ownership of the 740 MW Colstrip 4, or 222 MW. NorthWestern also participates in a reciprocal sharing agreement with PPL Montana, who owns a similar share (30%) of the 740 MW Colstrip Unit 3. Under the Joint Ownership and Operation Agreement, PPL Montana and NorthWestern operate both of their shares of Colstrip Unit 3 and 4 as a single project, effectively providing an equivalent 15% of two separate units at the same net total of 222 MW. This agreement provides diversity in generating units that results in greater physical power reliability and availability, and ultimately reduced risk for NorthWestern's electric customers. Additionally, as a rate-based asset, Colstrip 4 provides long-term rate stability and reduced market exposure for customers.

NorthWestern's Colstrip 4 operations are driven by the baseload, multiple ownership characteristics of this facility. The variable cost of Colstrip 4 is relatively low so it is generally dispatched at its full capacity. Occasionally, market prices drop below Colstrip 4 variable cost. In these instances, NorthWestern has the ability to operated Colstrip 4 between the minimum operating level of 60 MW (NorthWestern's share of the minimum) and 222 MW (NorthWestern's share at full capacity). During spring runoff when the Pacific Northwest hydro system is operating at full capacity, it is common for NorthWestern to operate Colstrip 4 at maximum output during the day when loads and prices are high, and back the output down to minimum output at night when loads and prices are low. Occasionally, the Colstrip owners may agree to take the unit offline if low market prices are expected to persist for a week or more.

Figure No. 2-3

Spion Kop Wind Facility

Spion Kop Wind Generation Facility

Spion Kop is a 40 MW renewable wind generation facility that was developed and built by Spion Kop Wind, LLC and turned over to NorthWestern under an asset purchase agreement that was the result of a negotiated build-transfer agreement following a 2009 RFI competitive solicitation. The facility is located in the northwest corner of Judith Basin County, Montana near Raynesford. NorthWestern and retail customers will receive the benefits of energy production and associated renewable energy credits from this eligible renewable resource. Spion Kop consists of 25 General Electric 1.6 MW wind turbines that have been in commercial service since December of 2012 and has a capacity factor of just over 39% (December 2012 through November 2013).

Figure No. 2-4

Dave Gates Generating Station at Mill Creek

Dave Gates Generating Station at Mill Creek (DGGS)

NorthWestern constructed the DGGS gas-fired plant to provide regulation service and meet NERC Reliability as part of its Transmission Business Unit's duties as a

FERC Balancing Authority. This plant was built east of Anaconda, Montana in the Mill Creek area. DGGS was designed to provide sufficient regulating reserves to cover load and wind generation with the capability to quickly ramp to minimize Area Control Error and meet Reliability Standards. NorthWestern calculated a total regulation demand of 105 MW, with 45 MW reflecting the regulating reserves needed to integrate wind generation and 60 MW reflecting the regulating reserves historically required, prior to the addition of wind generation, necessary to regulate NorthWestern's system. The plant is comprised of three 50 MW units including 6 gas turbines with useable per unit output being typically less than 50 MW due to factors such as ambient air conditions, fuel type, air quality permit requirements, and equipment performance and availability. NorthWestern's operational plan was to keep two DGGS units in service at all times, with the third unit put into service during times of peak regulation demand but otherwise acting as an operational spare in case one of the other two units required maintenance. At minimum turndown, the two operating units generate an average of 7 MW per hour which is allocated to NorthWestern's Energy Supply Portfolio.

Figure No. 2-5

Basin Creek Plant

Basin Creek Equity Partners, LLC

Basin Creek is a 52 MW peaking facility that began operations in 2006. NorthWestern has operational control of Basin Creek and uses the facility for economic dispatch (serving load), peaking, and non-spinning reserves. This contract will expire on July 1, 2026, unless extended for a 5-year term in accordance with the contract. As discussed below, Basin operations have been somewhat modified to accommodate operational needs and market requirements.

Basin Creek is designed to be operated in a flexible manner. Each of its nine, 5.7 MW units can be dispatched individually, so the plant can be dispatched in 5.7 MW increments up to its full 52 MW capacity. Currently, NorthWestern uses about 17 MW (three units) of its nameplate capacity for non-spinning reserve requirements, leaving about 35 MW of capacity (six units) to be used to serve the peak and energy needs of retail customers. NorthWestern's schedulers dispatch the Basin Creek units on an hour-by-hour basis when the variable cost to generate is lower than the market price for energy. The variable cost of Basin Creek is high relative compared to baseload units, so it is typically dispatched in the hours when loads and prices are highest. During the 2012-2013 tracker-period, NorthWestern dispatched Basin Creek for 26,234 MWh for electricity supply.

Qualifying Facility and Renewable Power Purchase Agreements

NorthWestern has approximately 361MW of renewable generation by nameplate capacity in its Portfolio and interconnected within the Montana BA. NorthWestern's ownership of the 40 MW Spion Kop wind project represents approximately 11% of the renewable fleet. The remainder of the renewable sources is a mix of PPAs and QF PPAs consisting of wind, hydro and thermal

resources. Only a portion of the renewable sources are eligible under the rules for Montana RPS (renewable portfolio standards). QF PPAs consist of two main groups: older Tier II QF contracts signed prior to 1998 and newer QF contacts signed under the QF-1 Tariff on file with the MPSC.

Tier II consists of a group of QF contracts that were in place when the original default supply obligation was established under utility deregulation. The 10 Tier II contracts (originally 15) consist of thermal and hydro generation sources that provide NorthWestern with a reliable and schedulable source of energy. NorthWestern credits the Tier II contracts with energy and capacity based upon the historic operating performance of the resources. The contracts cannot be dispatched to follow load, nor do they provide spinning or non-spinning reserves.

The QF-1 Tariff contracts consist of any new QF contract or older QF renewal contract signed under a QF-1 Tariff approved by the MPSC. This group of 18 contracts consists of 13 wind (61 MW) and 5 hydro generation projects (5 MW) with an aggregate installed capacity of approximately 66 MW. Since 2011, NorthWestern has signed five QF-1 long-term wind contracts with nameplate capacity ranging from 9.5 MW to 10 MW. Approximately 61 MW of the 66 MW is from wind projects and except for the very limited curtailment provisions associated with a few contracts is non-dispatchable and intermittent.

Thermal QF Facilities

NorthWestern has QF contracts with two thermal plants; 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 facilities follow a standard schedulable unit contingent pattern with occasional outage variances. The pattern of normal summer outage schedules can be seen

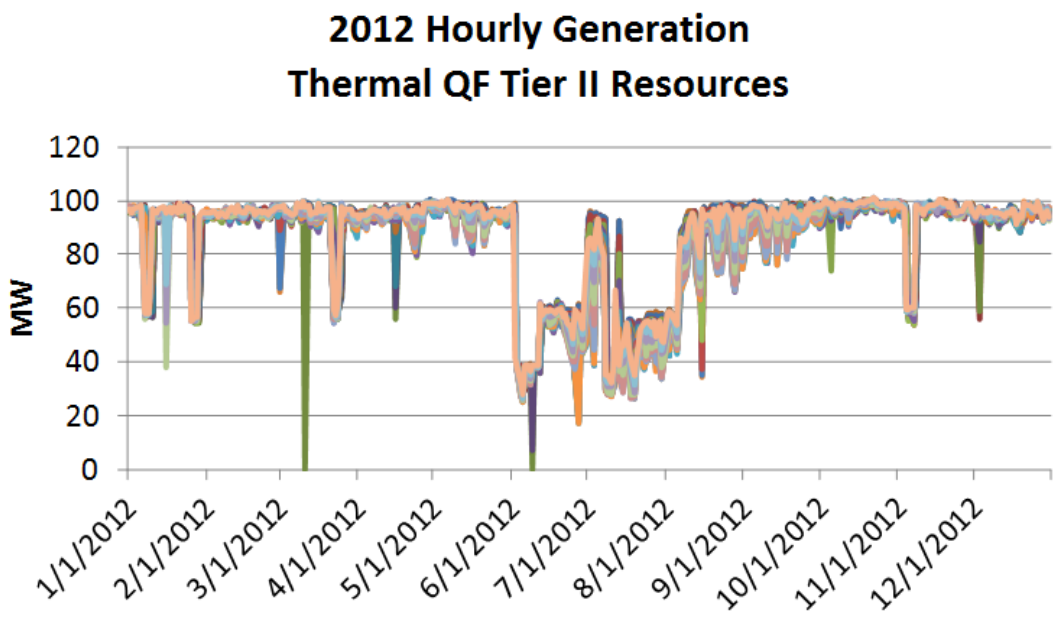
in Figure 2-6. Both of these facilities installed capacities are greater than the contracted capacity. Regulatory efforts to enforce the terms and conditions of the PPAs resulted in only slight modifications to annual energy limits and price terms. In the case of YELP the installed capacity is 61 MW and for CELP the installed capacity is 41.5 MW for an aggregated total of 102.5 MW.

Table No. 2-2

Thermal QF Tier II Resources					
Resource	Resource Type	Nameplate Capacity (MW)	Winter Peaking (MW)	Summer Peaking (MW)	Annual Energy (MWH)
Colstrip Energy Limited Partnership	Tier II	35	36	0	297,900
Yellowstone Energy Limited Partnership (BGI)	Tier II	52	91	22	433,400
		87	127	22	731,300

Note: Winter/Summer peaking based upon 2006-2012 production
Annual generation based on actual average

Figure No. 2-6



Hydro Facilities

NorthWestern has contracted with 15 renewable power producers for hydroelectric power output from facilities in our portfolio with an aggregate installed capacity of approximately 37 MW. Table 2-3 shows NorthWestern's QF hydro facilities.

Table No. 2-3

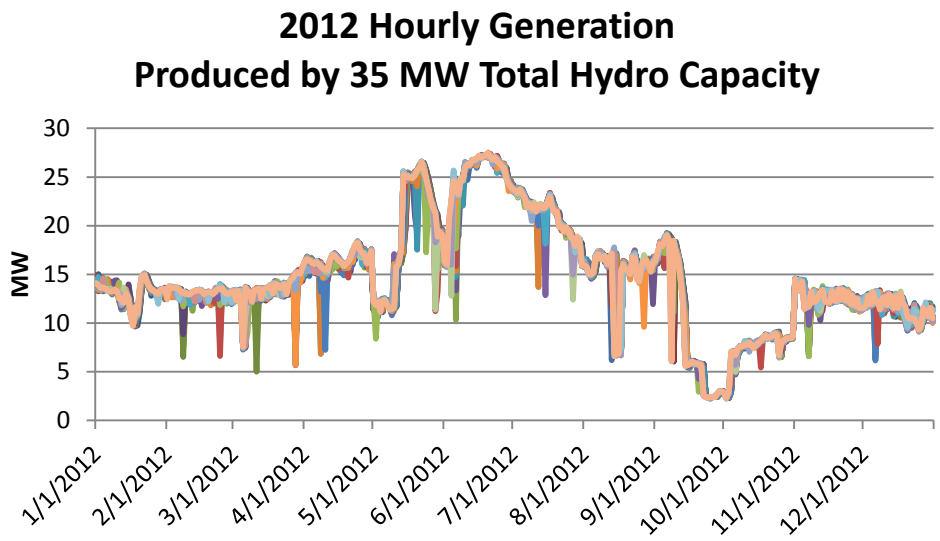
Renewable Hydro Resources

Resource	Resource Type	Nameplate Capacity (kW)	Winter Peaking (kW)	Summer Peaking (kW)	Annual Energy (MWH)
Donald Fred Jenni (Hanover Hydro)*	Tier II	240	25	33	220
Wisconsin Creek Limited Partnership*	QF-1	400	13	199	1,050
James Walker Sievers (Cascade Creek)*	Tier II	68	12	56	370
James Walker Sievers (Barney Creek)*	Tier II	60	0	11	110
Gerald Ohs (Pony Generating Station)*	QF-1	400	0	172	1,100
Hydrodynamics Inc (South Dry Creek)*	Tier II	1,200	0	1,988	2,700
Boulder Hydro Limited Partnership *	QF-1	510	96	236	1,670
Hydrodynamics Inc (Strawberry Creek)*	Tier II	190	48	300	1,450
State of MT DNRC (Broadwater Dam)*	Tier II	10,000	3,403	3,495	53,240
Estate of Howard Carter (Pine Creek)*	Tier II	300	1	243	1,170
Ross Creek Hydro LC*	Tier II	450	226	356	2,170
TurnBull Hydro, LLC*	PPA / CREP	13,000	0	5	35,000
Tiber Montana, LLC**	PPA	7,500	5,000	0	50,770
Flint Creek Hydroelectric LLC**	QF-1 / REC	2,000	1,000	2,000	8,000
Lower South Fork LLC**	QF-1 / REC	455	0	0	1,900
Total:		36,773	9,824	9,094	160,920

Note: *Winter/Summer peaking based upon 2010-2012 production
**Estimated peaking
Annual generation based on actual average

These hydro facilities are slightly more variability that the QF thermal facilities, and are also schedulable (within the seasonal flows determined by the weather (precipitation) and irrigation uses that determine production).

Figure No. 2-7



Wind Facilities

NorthWestern's portfolio includes 15 wind facilities; one company-owned, one PPA, and 13 QF-1 Wind facilities, with an aggregated installed capacity of approximately 237 MW. Table 2-4 shows the 15 wind facilities in NorthWestern's portfolio along with their installed capacity and forecast annual production.

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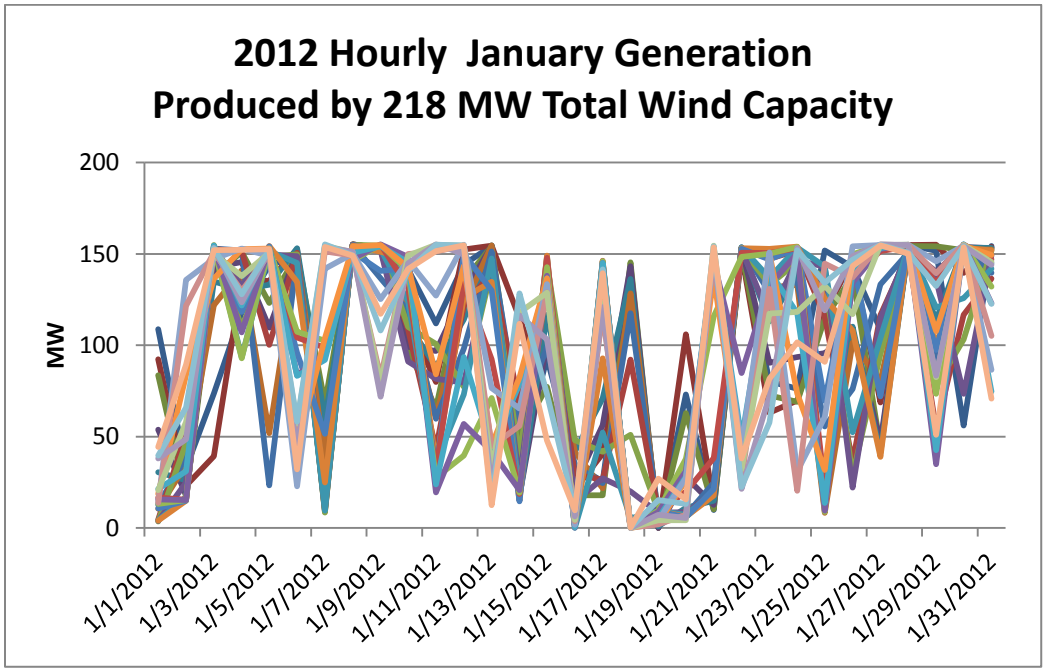
Table No. 2-4

Renewable Wind Resources				
Resource	**Resource Type**	**Nameplate Capacity MW**	**Peaking Capacity MW**	**Annual Energy MWh**
Judith Gap PPA*	PPA / REC	135.000	0	467,200
Spion Kop*	Owned / REC	40.000	0	138,400
Mr. Thomas G. Agnew (Agnew Ranch)*	QF-1	0.065	0	50
Two Dot Wind LLC (Martinsdale Colony)*	QF-1	0.750	0	1,700
Two Dot Wind LLC (Martinsdale Colony South)*	QF-1	2.000	0	90
Two Dot Wind LLC (Moe Wind)*	QF-1	0.450	0	630
Two Dot Wind LLC (Sheep Valley Ranch)*	QF-1	0.455	0	900
Fairfield Wind LLC**	QF-1 / REC	10.000	0	31,900
Gordon Butte Wind LLC*	QF-1 / CREP	9.600	0	33,750
Musselshell Wind Project LLC**	QF-1 / REC	10.000	0	28,600
Musselshell Wind Project Two LLC**	QF-1 / REC	10.000	0	28,000
Two Dot Wind Farm LLC**	QF-1 / REC	9.720	0	35,400
United Materials of Great Falls Inc.*	QF-1	9.000	0	16,360
Two Dot Wind Energy LLC (Mission Creek)*	QF-1	0.065	0	90
Two Dot Wind Energy LLC (Montana Marginal Energy)*	QF-1	0.195	0	170
Total:		237.300		783,240

Note: *Peaking capacity based upon 2010-2012 production
**Estimated peaking
Annual generation based on actual average

The generation from 13 of the 15 wind facilities on line in 2012 is highly variable when compared to the generation profiles of QF thermal or QF hydro as represented by the summer and winter 24 hour profiles in Figure 2-8. Table 2-4 shows the expected annual energy output of wind resources under contract to NorthWestern. Unlike NorthWestern's other resources, wind resources have not historically contributed materially to meeting peak load. When analyzed in aggregate, these 15 wind projects provide approximately 0.6 MW of peak capacity in winter (≈0.25%) and approximately 5.2 MW of peak capacity (≈2.2%) in summer.

Figure No. 2-8


2012 Hourly January Generation
Produced by 218 MW Total Wind Capacity
MW
200
150
100
50
0
1/1/2012
1/3/2012
1/5/2012
1/7/2012
1/9/2012
1/11/2012
1/13/2012
1/15/2012
1/17/2012
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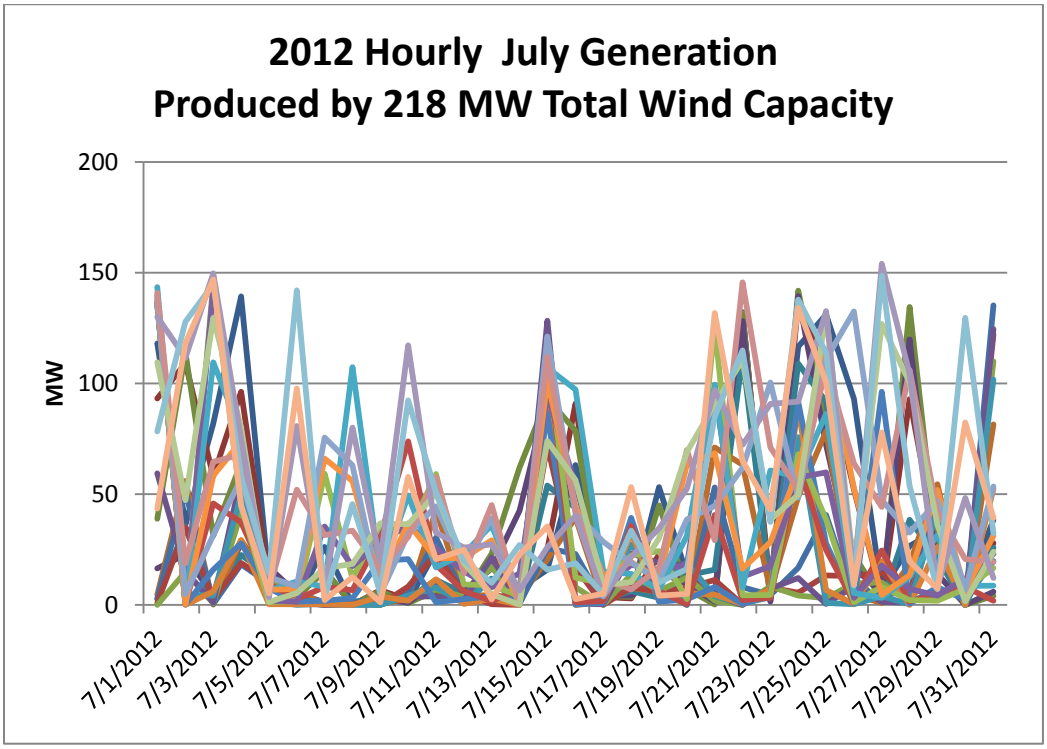
1/25/2012
1/27/2012
1/29/2012
1/31/2012


2012 Hourly July Generation
Produced by 218 MW Total Wind Capacity
MW
200
150
100
50
0
7/1/2012
7/3/2012
7/5/2012
7/7/2012
7/9/2012
7/11/2012
7/13/2012
7/15/2012
7/17/2012
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7/25/2012
7/27/2012
7/29/2012
7/31/2012

Figure No. 2-9

Judith Gap Facility

Judith Gap Energy, LLC

Judith Gap Energy, LLC, is a 135 MW nameplate capacity wind turbine facility comprised of 90, 1.5 MW wind turbines that are expected to contribute approximately 467,000 MWh per year based on historical performance. Judith Gap is located in Wheatland County, Montana north of Harlowton. Judith Gap provides NorthWestern with energy and Renewable Energy Credits ("RECs") which are used to help NorthWestern meet its obligation under the Renewable Portfolio Standard (RPS).

Tiber Montana, LLC

NorthWestern has a 7.5 MW unit-contingent energy contract with Tiber Montana, LLC, (Tiber) a small hydro facility located at the Tiber Dam on Lake Elwel (or Tiber Reservoir). Tiber began operations in June of 2004 and has a 20-year PPA to sell power to NorthWestern.

Figure No. 2-10

Turnbull Hydro

Turnbull Hydro, LLC

In 2009, NorthWestern entered into a 20-year contract with Turnbull Hydro LLC (Turnbull) with commercial service beginning in June 2011. Turnbull is a small hydroelectric project consisting of 2 generating units; Upper Turnbull and Lower Turnbull. Both Turnbull units were constructed on an existing irrigation canal on the Fairfield Bench in Teton County. Turnbull has a total nameplate capacity of 13 MW and has been approved as a CREP-eligible facility by the MPSC. Turnbull generation occurs in conjunction with the irrigation season, which normally occurs from late May through early September. Turnbull delivers an average of 35,000 MWh each irrigation season, but has a somewhat limited ability to contribute to summer peak because irrigation flows taper off during July and August.

PPL Montana, LLC

In 2007 NorthWestern began receiving 325 MW of firm heavy load (HL) power and 175 MW of light load (LL) power from PPL Montana, LLC (PPL) under a contract that runs from July 1, 2007 through June 30, 2014, when the contract expires. This contract with PPL has a fixed schedule of rates that is $52.70/MWh for the first quarter of 2013.

For the remainder of the PPL contract NorthWestern's Portfolio will receive 200 MW during HL hours and 125 MW during LL hours. The heavy load delivery of 200 MW contributes to the Portfolio's summer and winter peaking needs.

All-Source Competitive Solicitations

Market Operations conducted two all source competitive solicitations that were in addition to the contributions to the portfolio made under the 2011 Hedging Plan. The first was conducted in October 2011, and the second during May 2013.

The October 2011 RFP solicited up to 100 MW of baseload (around-the-clock) energy for calendar years 2013 and 2014, in part to help replace power under a PPL Montana contract that will be expiring on June 30, 2014. NorthWestern selected 100 MW of HL power and 100 MW of LL power at the Mid-C with an additional 50 MW of LL power delivered to NorthWestern's system in Montana.

The May 2013 RFP solicited up to 100 MW of firm supply for the period of January 1, 2015 through December 31, 2017 to be delivered at Mid-C or on NorthWestern's system. Separately in this RFP, NorthWestern sought up to 300 MW of firm supply for the period of July 1, 2014 through December 31, 2014 delivered on NorthWestern's system in Montana. This RFP also targeted replacement power under the previously mentioned expiring PPL contract. NorthWestern selected 100 MW of HL power delivered to Mid-C for calendar year

2015, 75 MW of HL power delivered to Mid-C for calendar year 2016, 50 MW of HL power delivered to Mid-C for calendar year 2017, and 200 MW of HL power delivered to NorthWestern's system in Montana.

Renewable Portfolio Standards

The Renewable Portfolio Standard (RPS) was established in 2005 by the Montana Legislature to promote the development of renewable resources, MCA 69-3-2004. NorthWestern is subject to the Renewable Portfolio Standard (RPS) which requires NorthWestern to purchase a portion of the electricity used to serve retail loads from eligible renewable resources built after January 1, 2005. RPS is a graduated standard and is currently set at 10% of prior year retail sales. NorthWestern has been able to meet its annual RPS obligation using a combination of renewable resources and "banked" Renewable Energy Credits (RECs). In 2015 the RPS standard increases to 15%. NorthWestern plans to meet its RPS obligation both now and into the future, taking steps to comply with all portions of RPS.

RPS Resources

NorthWestern uses a mix of wind and hydro projects to meet its RPS obligations. Judith Gap is NorthWestern's first and largest RPS resource. Several RPS resources, Fairfield Wind and Two Dot Wind, LLC, have been contracted for and are currently under construction. The resources used to meet RPS are shown in Table 2-5 along with the characteristics of the resource and NorthWestern's forecast of production. Forecast of production are either based upon developer-provided production numbers or based upon average historical performance. The use of historical production, however, does not provide full assurance that actual production will match forecast production values.

Table No. 2-5

Renewable Portfolio Standard (RPS) Resources				
Resource	Resource Type	Fuel	Nameplate Capacity MW	Annual Energy MWa
Judith Gap PPA*	PPA / REC	Wind	135	467,200
Gordon Butte Wind LLC*	QF-1 / CREP	Wind	9.6	33,750
Musselshell Wind Project LLC**	QF-1 / REC	Wind	10	28,600
Musselshell Wind Project Two LLC**	QF-1 / REC	Wind	10	28,000
Fairfield Wind LLC**	QF-1 / REC	Wind	10	31,900
Two Dot Wind Farm LLC**	QF-1 / REC	Wind	9.72	35,400
Spion Kop*	Owned / REC	Wind	40	138,400
2013 CREP RFP**	PPA / CREP	Wind	41	146,560
TurnBull Hydro, LLC**	PPA / CREP	Hydro	13	35,000
Flint Creek Hydroelectric LLC**	QF-1 / REC	Hydro	2	8,000
Lower South Fork LLC**	QF-1 / REC	Hydro	0.455	1,900
Sleeping Giant Power LLC**	QF-1 / CREP	Hydro	8	42,800
Total:			289	997,510

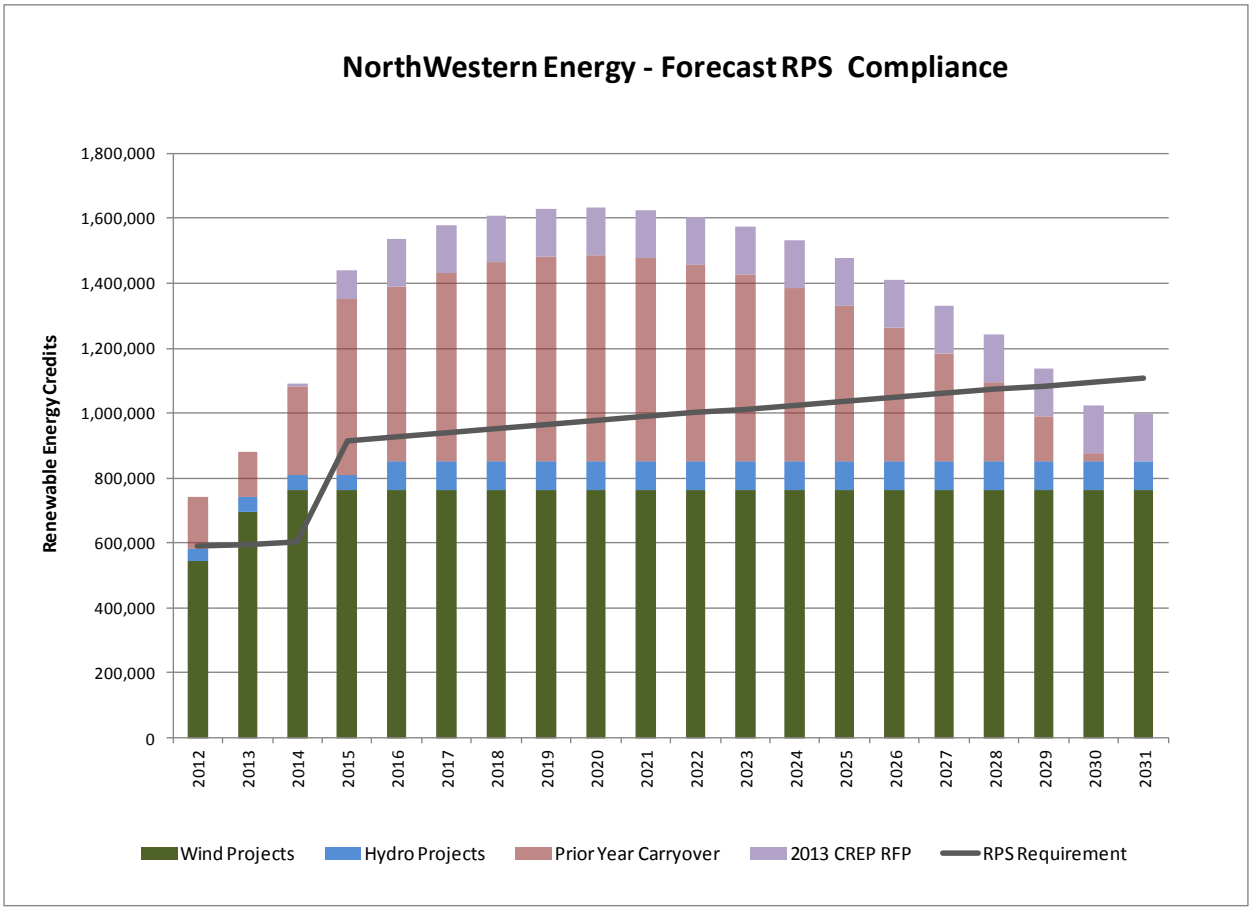
Note: *Average production
**Estimated production

NorthWestern is also planning to acquire up to approximately 43 MW of renewable resources to meet the Community Renewable Energy Project (CREP) requirement contained in the RPS legislation.

RPS Forecast

NorthWestern's forecast of RPS compliance is shown in Figure 2-11. The solid line depicts NorthWestern's RPS requirement for each compliance year and the green and blue bars show wind and hydro RECs. The pink bars show the REC amount carried over from the previous compliance year, and the light purple bars show the amount of RECs forecast to be produced if 40 MW of wind resources are added to the portfolio to fulfill NorthWestern's CREP obligation. Forecast CREP amounts are placed above the NorthWestern's RPS forecast to show that NorthWestern will have adequate RECs to meet RPS requirements through 2028 if it acquires CREP resources as required. The projected REC shortfall in 2031 is about 140,000 MWh, roughly equivalent to the production from a 47 MW wind facility. See Volume 2, Chapter 3 for annual RPS compliance forecast details.

Figure No. 2-11



CREP Resources

Community Renewable Energy Projects (CREPs) are a subset of the RPS requirement under MCA 69-3-2004. The CREP obligation is a state-wide target for eligible renewable resources, which is defined primarily project size and ownership. To be eligible for CREP Status, a project must have an installed capacity of 25 MW or less, and be owned by the utility or Montana entities. NorthWestern bears about 90 percent of the responsibility for meeting the statewide CREP mandate. Table 2-6 below shows the statewide requirement, which is capacity-based, and NorthWestern's estimate of its share of that requirement.

Table No. 2-6

RPS Requirement for Community Owned Energy Projects

Compliance Years	State-wide MW	NWE MW
2012 through 2014	50	45
2015 and Later	75	68

NorthWestern currently has four approved CREP qualified resources: Gordon Butte, Turnbull Hydro, Flint Creek, and Lower South Fork. Additionally, NorthWestern expects that the Sleeping Giant Power, LLC project will qualify for CREP status. The total installed capacity of these five projects is a little over 33 MW. When compared to NWE's estimate of its CREP obligation, NorthWestern is currently about 12 MW short of its 2012 CREP obligation and about 35 MW short of its 2015 CREP obligation.

NorthWestern issued a Request for Proposals (RFP) for up to 45 MW of CREP-eligible resources on August 2, 2012. New CREP projects will contribute to meeting both Montana RPS and CREP requirements. . Lands Energy (Lands), which is an independent entity from NorthWestern, conducted the solicitation process and the initial evaluation process for the RFP. Lands indicated that 30 responses were submitted by the September 28, 2012 deadline. Most of the responses (24) were for wind projects.

The viability scoring of all projects submitted in response to the 2012 CREP RFP included transmission criteria based on project location. NWE was concerned that individual CREP proposals might require transmission upgrades which could increase customer costs. Therefore, early in the RFP planning process, Energy Supply staff and Lands requested input and information from NorthWestern

Transmission Planning Department regarding transmission criteria based on project location. This information was incorporated into the scoring.

The federal Production Tax Credit (PTC) for wind projects was extended in early in January 2013. The PTC extension was significant because the original RFP requested bids without PTCs. NorthWestern and Lands interrupted the RFP process to allow all bidders the opportunity to re-price their bids based on the extension of the PTC. The deadline for the re-price was January 18, 2013. All projects were re-evaluated and scored by Lands and a list of 10 projects were selected and submitted to NorthWestern for further consideration. Two projects were selected from the group of 10 and NorthWestern began negotiations with the top "finalist."

The Compass Wind proposal, a 20 MW wind project located near Opheim, MT, was selected as the low-cost and low-risk alternative for retail customers. The long-term rate of $38.95/MWh for the Opheim project was the lowest-priced resource submitted in the RFP. Additionally and importantly, the Opheim project is located within the Western Area Power Administration ("WAPA") balancing authority ("BA") and the transmission service costs (current and future) would be borne by Compass as the project owner/operator. During final negotiations, WAPA determined that it would not be able to provide transmission balancing service to the Opheim project.

To meet its CREP obligation in 2014 and beyond, NorthWestern immediately took two actions. First, it notified the second-place respondent that it was moved up to the finalist position. However, the second-place project was also located within the WAPA BA and it too, was not able to obtain balancing service. Therefore, the 2012 CREP RFP was suspended.

Second, NorthWestern issued a new fast-track CREP PPA-only solicitation on October 14, 2013. The RFP was fast-tracked to allow developers to take advantage of the current PTC extension, which requires qualifying projects to achieve commercial operation date by the end of 2014. NorthWestern anticipates that it will be able to sign contracts for approximately 41 MW of CREP-eligible resources as a result of the RFP, and has included that estimate in its RPS forecast.

NorthWestern continues to monitor resource development in Montana, including renewable resources, and will continue to seek opportunities that will allow NorthWestern to meet its RPS obligations without paying a premium for those resources.

Energy Efficiency/DSM Discussion

A public utility must "conduct an efficient electricity supply resource planning and procurement process that evaluates the full range of cost-effective electricity supply and demand-side management options" per Section 69-8-419(2) (b), MCA, and thus NorthWestern intends to continue its DSM Programs, maintain its annual electric DSM goal of 6.0 aMW, and concentrate on the difficult-to-penetrate commercial/small industrial customer sectors. A comprehensive DSM program evaluation has been completed and modifications to DSM programs have been made. NorthWestern will continue to seek recovery of DSM Program Costs and DSM Lost Revenues.

Avoided costs remain central to energy supply DSM funded programs. This planning cycle will produce updated avoided costs that will be used to review and, if necessary, update certain elements and features of NorthWestern's DSM Programs.

In the current electric (and natural gas) avoided cost environment, NorthWestern is skeptical of the ability of benchmarking programs to produce cost-effective energy savings that persist for several years into the future, and to produce cost-effective DSM resource.

The Smart Grid Demonstration Project in Helena and Philipsburg, MT is in operation and completing its fourth year of the five year effort.

A new Battery Storage Project has been initiated in Helena, MT and operation is expected to begin in late 2013.

DSM Acquisition Plan and Programs

DSM Goals

NorthWestern is in the fourth year of its DSM Acquisition Plan set forth in the 2009 Electric Resource Procurement Plan. As of 2009, the amount of remaining achievable, cost-effective electric DSM was estimated to be 84.3 aMW. NorthWestern established its annual DSM acquisition goal at the level of 6.0 aMW. For the immediate future, NorthWestern intends to continue with that DSM Acquisition Plan and the annual goal of 6.0 aMW until a review of electric avoided costs resulting from this planning cycle can be completed. 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 avoided costs. It is expected that new electric avoided costs will be available to DSM planners in January 2014, and it appears that those new avoided costs will likely be lower than the avoided costs used in the previous planning cycle.

NorthWestern will, for now, stay with its annual electric DSM goal of 6.0 aMW. This annual goal remains aggressive given that legislative developments in the lighting sector continue to reduce the future contribution that energy efficient lighting can make to annual DSM results. New federal regulations relating to compact fluorescent lamps (CFLs) and other lighting technologies began phasing in over a three-year period beginning January 1, 2012. In certain applications, CFLs will continue as a cost-effective replacement lighting technology for certain applications (e.g., halogen lamps) but the amount of CFLs rebated through the DSM lighting programs will diminish significantly.

It is clear that in order to sustain a level of 6.0 aMW of DSM acquisition, additional energy savings must be captured from the commercial and small industrial sectors. NorthWestern has recently renewed contracts 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:

1. National Center for Appropriate Technology (NCAT)
2. McKinstry Essention (McKinstry)
3. Portland Energy Conservation, Inc. (PECI)
4. CTA Associates, Inc. (CTA)
5. Energy Resource Management, Inc. (ERM)

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. All contractors are expected to deliver to NorthWestern a minimum of 0.25 aMW per year of incremental DSM each year.

These contractors will continue to be supported by a three-member team of DNV-KEMA employees who have been given responsibility for direct contact, face-to-face marketing of DSM Programs to commercial/small industrial customers in an effort to identify, qualify and cultivate DSM projects for follow-up by the contractors listed above.

DSM Budget and Spending

The budget associated with the current DSM Acquisition Plan was developed using the then current 20-year levelized avoided costs 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 has met or exceeded its annual DSM goal, but actual spending has been less than this budgeted amount as summarized in Table 2-7.

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

Table No. 2-7

NorthWestern DSM Acquisition Plan and Budget 2010-2029

Year	Total (aMW)	Budget	Actual Spend*
1	5.5	$11,040,955	$7,108,435
2	6.0	$13,181,496	$9,185,261
3	6.0	$14,318,314	$10,836,590
4	6.0	$15,455,132	-
5	6.0	$16,440,140	-
6	6.0	$17,979,217	-
7	6.0	$19,518,294	-
8	6.0	$21,057,371	-
9	6.0	$22,596,448	-
10	6.0	$24,135,525	-
11	6.0	$25,884,476	-
12	6.0	$27,633,427	-
13	6.0	$29,382,378	-
14	6.0	$31,131,329	-
15	0.8	$4,334,800	-
16	-	-	-
17	-	-	-
18	-	-	-
19	-	-	-
20	-	-	-
	84.3	$294,089,302	

Note: *Figures for the 2010-11, 2011-12, and 2012-13 tracker periods.

The upcoming review of electric avoided costs resulting from this planning cycle, 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 the annual budget levels over the course of the DSM Acquisition Plan. NorthWestern notes that this DSM future budget is a long-term estimate 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 two years of data in the Actual Spend column of Table 2-7 above.

DSM Programs

NorthWestern Energy offers a variety of programs, services and resources to help our Montana customers to better manage energy costs. Consistent with plans for phasing out DSM Programs targeted at fluorescent lighting technologies, and pending completion of the avoided cost changes and subsequent review of all DSM Program measures, rebate levels and program designs, NorthWestern intends to continue offering the following electric DSM Programs that are funded through energy supply rates in 2014:

- **E+ Home Lighting Rebate** - Customers receive a REBATE of up to $2 or instant savings on ENERGY STAR® compact fluorescent light bulbs (CFLs). Rebates available for ENERGY STAR hard-wired lighting fixtures and wall-switched replacement occupancy sensors.
- **E+ Residential Existing Electric Rebate Program** - REBATES are available to electric space or water heat customers for qualifying electric measures.
- **E+ Residential New Construction Electric Rebate Program** - Customers building a new home may receive REBATES for qualifying ENERGY STAR appliances and qualifying electric conservation measures.
- **E+ Commercial Lighting Rebate Program** - Offers prescriptive 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 retrofit facilities are eligible.
- **Northwest Energy Efficiency Alliance** - 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 funded programs that will continue into the foreseeable future. The electric energy savings produced from these 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 the Low Income Energy Assistance Program (LIEAP) qualified space-heating customer of NorthWestern Energy.
- **E+ Energy Audit for the Home** - Free onsite energy audits and mail-in survey audits.

- **E+ Energy Appraisal for Businesses** - Free audit that focuses on identifying electric conservation opportunities for small commercial customers on NorthWestern Energy'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 (BOC) 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.
- **ENERGY STAR New Homes Program-** Northwest Energy Star homes are verified and savings claimed for all CFLs above 50% of sockets installed with CFLs and not rebated through any other E+ Residential Lighting program.
- **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 http://www.NorthWesternEnergy.com/eplus/.

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.

The potential for lost transmission and distribution revenues, and fixed costs associated with owned interest in Colstrip Unit #4 and the Dave Gates Generating Station, (DSM Lost Revenues) resulting from reduced volume sales caused by customer participation in DSM Programs remains a potential financial disincentive to continued operation of DSM Programs. For the past several years, this disincentive has been avoided through use of a Lost Revenue Recovery Mechanism (LRAM) that adjusts energy supply rates annually for estimated Lost Revenues. This mechanism also incorporates a self-correcting true-up feature with each successive annual electric tracker filing to adjust the prior year forward-looking Lost Revenues with observed results from DSM Programs. The true-up is again performed following a comprehensive DSM Program Evaluation performed every few years, and will be done again as part of the final phase of the Electric Supply Tracker Docket No. D2012.5.49.

NorthWestern believes that the LRAM currently in use, together with recovery of DSM Program costs, helps to mitigate financial disincentives to DSM Programs under current ratemaking practices, and NorthWestern will continue to seek recovery of Lost Revenues through the LRAM.

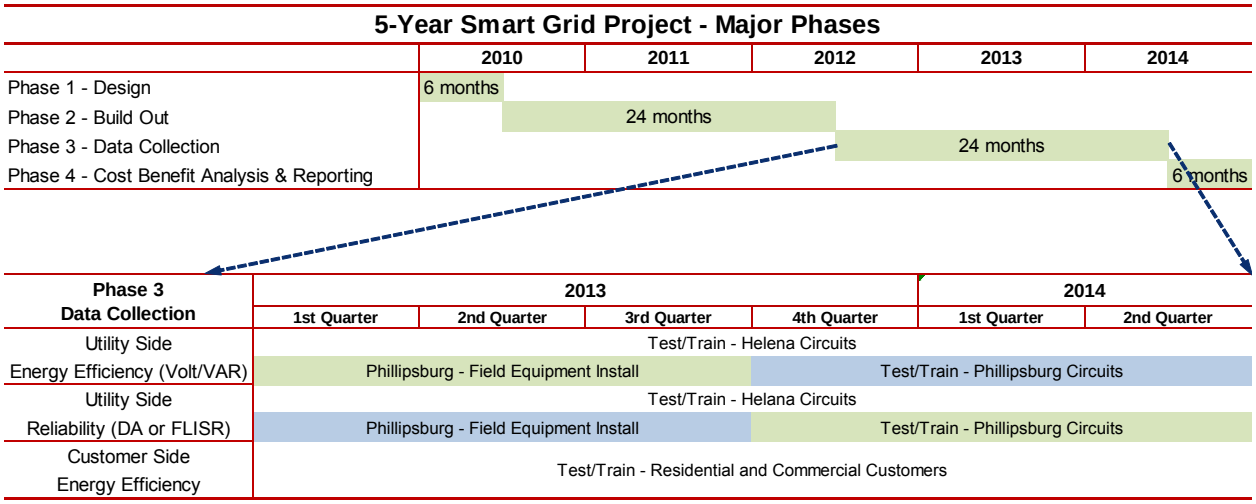
Smart Grid Demonstration Project

NorthWestern is completing year 4 of its 5-year (2010-2014) Smart Grid Demonstration Project (Project) as part of a larger, region-wide effort. NorthWestern's project objectives are to deploy, test, and evaluate various equipment, systems and customer services associated with emerging Smart Grid technology. The scope of this effort includes Smart Grid technologies at the electric utility substation, distribution circuit and customer levels of two unique NorthWestern locations in Western Montana, including "urban" circuits in the center of the City of Helena and a "rural" circuit located in the Philipsburg area. The estimated budget for the Project is approximately $4.3 million (50% cost-

shared with federal ARRA funds). The Project generally concentrates on the various aspects of advanced volt/VAR control, distribution automation, automated outage restoration, substation capacity, advanced metering infrastructure (AMI), and customer demand response, control and energy management.

There are four major Phases to the project, summarized in Figure 2-12. NorthWestern and the other partners and utilities in the Pacific Northwest Smart Grid Demonstration Project are in the middle of Phase 3 - Data Collection.

Figure No. 2-12



In the Project area concerned with Distribution Automation, all activities have been initiated and testing will be completed during the Data Collection Phase. Substation & Line Equipment installations are complete in Helena and Philipsburg. NorthWestern issued a Request for Proposals for control software/systems, subsequently received five proposals, and selected Cooper Power Systems as the winning bidder. The software and systems were purchased and installed and the system acceptance test was completed in the first and third quarters of 2013.

Energy Efficiency (Volt/VAR) substation and line equipment installations are complete in Helena and Philipsburg. S & C Electric software was chosen as the software vendor. The software and systems were purchased and installed and system acceptance test was completed in 2012. Testing on circuits in Helena started in fall, 2012 and is ongoing. Testing of circuits in Philipsburg started in fall 2013 and is ongoing.

Working with ITRON, Inc., NorthWestern completed all activities in Helena, MT that relate to the customer side of the meter. These included:

- Installation and testing of 200 CENTRON electric interval meters for project participants in the home area network and Time of Use (TOU) trial.
- Testing and ongoing maintenance of the fixed wireless network with the installation of 4 Cell Control Units and 10 communication repeaters. These units were installed to collect interval data from residential home area network customers for TOU billing purposes.
- Collection of 15-minute electric interval data and electronic transport of data to ITRON's data center in Spokane, WA where data hosting and meter data management services are performed by ITRON.
- Export and transport of meter data from ITRON to NorthWestern's MV-90 system on regular nightly intervals for further processing into billing determinants for project participants.
- Field installation and maintenance of Home Area Networks (HAN), supporting communications links and platforms, and training of participants on use of devices and equipment was completed at NorthWestern's direction. KEMA, Inc. was contracted to provide HAN installation and training.

TOU pricing has been established for residential participants in the project. NorthWestern met with MPSC staff to present derivation of the TOU rates and discuss this approach to experimental TOU pricing within the Project. Upon advice and guidance from MPSC staff, NorthWestern prepared and filed a TOU tariff for this Project. A Master Time of Use pricing table was established and is reviewed monthly. This table is updated with each monthly update of electric supply prices, and the table is integral to the hourly pricing signals sent to project participants with HAN equipment. Additional steps related to this portion of the Project that have been completed in the first half of 2012 include:

- Testing and debugging of all data pathways; Interval meters (Helena) – fixed network – ITRON hosting (Spokane) – MV 90 (Butte) – TOU calculator – NorthWestern billing system.
- Completion of automated extraction of monthly kWh from NorthWestern's MV-90 system that receives 15-minute interval data from ITRON's data center.
- Completion of a TOU energy cost calculator using MV-90 output and the Master TOU pricing table.
- Automated export of monthly TOU energy cost to utility billing system.
- Automated calculation of delta between TOU energy cost and normal non-TOU energy cost. This capability entails:
    - Posting of TOU "credit" to Smart Grid participants' monthly bill. Send appropriate message via HAN system.
    - Ensuring that no "debit" will be charged to customer if usage increases. Send appropriate message via HAN system.
- Automate "How am I doing" messages to residential participants based on results of their participation, operation of HAN, and TOU-induced energy usage changes.

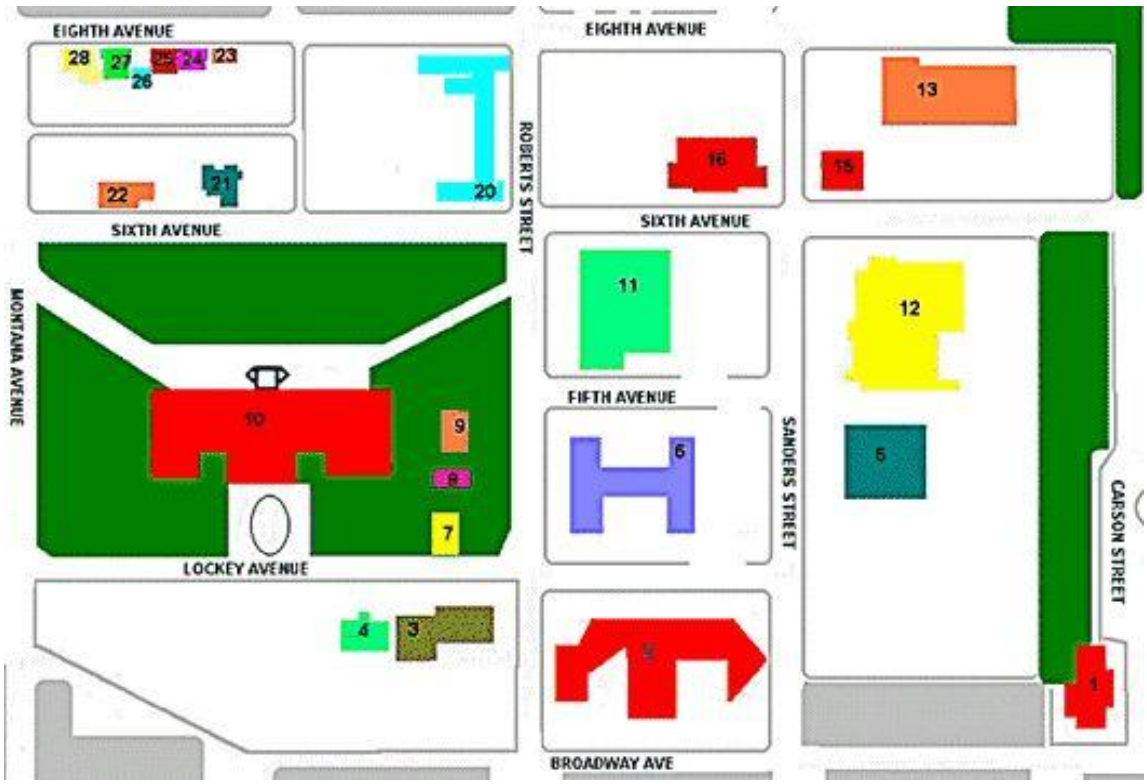
- Rigorous exercising of a Test case "customer" in Smart Grid Lab prior to rollout in Helena.

NorthWestern's Smart Grid Project also includes buildings at the Capitol Complex in Helena, MT. All equipment except 2 interval meters and 2 cell collection units have been installed in the Metcalf Building. Additional steps either now in process or planned for completion in the 2013 include:

- Integrate Lockheed Martin (LM) SeeLoad/SeeGrid demand response application to Metcalf head end building automation control system.
- Survey results of smart grid influence on business practices at periodic intervals throughout the study.

Figure No. 2-13

Helena Capital Complex Schematic



Building 13- Metcalf Building 3 - Walt Sullivan

Battery Storage Project

NorthWestern Energy has purchased and installed a battery to test using storage for feeder support. Although the source of funding for this project is in the Research and Development Category of the Universal System Benefit (USB) Program, it is worth noting here in the context of electric resource planning and distributed generation. The power conversion system is sized for 45 kW. The battery system uses advanced lead acid technology and is designed for 180 kWh of storage with 2,000 charge/discharge cycles at 50% depth of discharge/cycle. Included in the project is a 10.8 kW solar photovoltaic system coupled to the battery. The project features a web based hosted software that gives NorthWestern Energy remote control and operability of the system as well the opportunity to import or export information to other software systems within the NorthWestern operating system or smart grid project.

NorthWestern's objectives for the project are:

- Testing commercial scale viability – gain experience with a small system to evaluate the potential for larger scale energy storage.
- Testing potential for wind integration – analyze the operational model and benefits of having a dispatchable load as an integration resource for renewable energy.
- Testing direct solar photovoltaic system integration – directly integrate solar panels to provide integrated solar firming with the energy storage system.
- Examine and quantify the value streams of this form of distributed energy storage, including feeder support, reduced line loss, potential for transmission and distribution infrastructure upgrade deferral, passive demand response, energy efficiency, or other location-specific energy management solutions.
- Analyze project economics.

- Inform future decisions.

The battery storage system is a complete end-to-end distributed energy storage solution. The Joule.System™ is comprised of two main system components: the Grid.DNA™ and the Grid.Balancer™.

Joule.System™The distributed energy storage device (battery) creates load during off-peak times, stores the energy at the load site, and ultimately dispatches it on command or on a managed schedule. By storing and distributing the energy at the point of use, the total electrical energy inventory of stored energy and energy storage capacity can be monitored and dispatched within seconds. The Demand Shifter can potentially complement renewable generation sources, contribute to spinning reserves, reduce capital costs, and help avoid dispatching more costly incremental energy generation sources, especially during peak pricing periods.

The device is configured for NorthWestern Energy to test using storage for feeder support. Web based hosted software gives NorthWestern Energy the control and operability of the system as well the opportunity to import or export information to other software systems within the NorthWestern operating system or smart grid project.

Grid.DNA™The Grid.DNA™ (Disributed Network Architecture) is a comprehensive Graphical User Interface of the energy storage solution. The Grid.DNA™ system provides a user interface for real-time supervisory control and data acquisition of the Grid.Balancer™elements and other integrated components. Grid.DNA™ can be utilized to initiate Grid.Balancer™ operations on a pre-scheduled basis or can initiate operations on a manual basis from the browser based user interface. Any individual or selected groups of Grid.Balancer™can be instructed to override its

current schedule and operate as requested. Grid.DNA™ provides historical data archiving of all system data points, including a full system assurance package (alarming, events, status, etc). Grid.DNA™ utilizes the latest in distributed computing, cluster computing, and network security to create the most fault tolerant, scalable and secure environment possible.

The battery has been sited inside NorthWestern's Helena Division Operating Center yard and connected to both the distribution system and the Helena Operating Center Building. Communications to the device are operational and software loading and testing will be completed in the 4th quarter of 2013. Construction of the solar PV array will be completed by year end 2013 and the project will become fully operational.

Behavior Based DSM

In its written comments on NorthWestern's 2011 Electricity Supply Resource Procurement Plan (Docket No. N2011.12.96) the MPSC stated that NorthWestern should address the steps it is taking to monitor the economic potential of behavior-based DSM programs, and address the merits of conducting a pilot program to gather Company-specific data on potential savings and costs.

A pilot or demonstration project would be an appropriate methodology for testing the cost-effectiveness of a behavior-based DSM program, depending on the specific definition and elements of a behavior-based program, and whether there exists sufficient or compelling evidence to suggest such behavior-based DSM programs could ultimately be cost effective.

The term "behavior-based" can be ascribed to many different DSM program designs. Behavior-based programs focus on energy savings resulting from changes in individual or organizational behavior and decision making based on

new or additional data, and information and knowledge gained from external sources. These external sources may be the utility, government, mass media, or other public or private sources. Mechanisms used to influence consumer energy decisions include marketing, customer education, communications, tips and technical assistance, goal setting, rewards, recognition, and financial help in the form of loans, grants, incentives or rebates. All of this is intended to increase consumer awareness of and engagement in energy use decisions. In whole or in part, all of NorthWestern's DSM programs utilize these mechanisms and techniques to attempt to modify consumer behavior to reduce energy consumption. Therefore, all of NorthWestern's DSM programs have a behavior-based component. In particular, the Building Operator Certification Program is a good example of a program intended to result in reduced energy use through modification of building operator behavior.

The Smart Grid Pilot Demonstration Program now beginning to operate includes a customer behavior-modification feature based on regular provision of time of use energy consumption and time of use pricing. This pilot program will give NorthWestern additional insight into the effects of higher levels of detailed energy usage information on consumer energy decision-making and whether customer behavior can be changed through regular provision of energy use information. It remains to be determined whether the benefits of energy savings will offset the costs of providing the energy use information.

One category of programs currently being marketed by certain vendors (OPOWER, ACLARA) supplies consumers with billing and energy usage data from the utility billing system at regular intervals, along with comparative billing and usage data from other "neighboring" or "similar" facilities. This is generally referred to as benchmarking. Benchmarking programs calculate an Energy Use Index (EUI) and present it to participating consumers. Benchmarking programs

seek to inform consumers about their energy use (customer education), keep it raised in their consciousness (increased awareness and customer engagement), and create mild anonymous peer pressure and competition among participants to reduce their respective EUI. It is important to note that benchmarking programs of this type depend on vendor software integration with the utility billing system, and a sustained effort to recruit and sustain customer interest and participation. Both of these requirements, in particular the software integration (needed regardless of the size of the pilot program), translate into significant cost to introduce and operate such programs.

Programs of this design present certain challenges. The Regional Technical Forum informs NorthWestern that most other utilities have assigned a one-year measure life to benchmarking programs, indicating that the energy savings is not persistent into the future. There are questions about the wisdom of the utility company trying to use the techniques of peer pressure and competition, comparing an individual household's energy use to that of their neighbors, even if done anonymously. Even if they live in similar size and vintage dwellings, consumers have different personal situations, temperature tolerance levels, and working schedules. In a given neighborhood, some may be retirees or people with home-based businesses and may be more likely to be at home during the day and thus run their space heating/cooling more than peer participants. Comparing their power use to a neighborhood that is at work most of the day may falsely convey the impression that these people are not concerned about the many issues surrounding energy, the environment, or societal costs.

In 2011, NorthWestern evaluated a Behavior-based DSM program proposal from a vendor (OPOWER) selling its DSM benchmarking services. The results of this analysis concluded that there was a very low probability of that program meeting standard cost-effectiveness tests used to measure the success of utility DSM

programs. Since that time, electric and natural gas avoided costs (the primary determinant of benefits of all DSM programs including behavior-based programs), have decreased. Most of NorthWestern's residential customers use natural gas for space and water heating and natural gas supply costs have declined. We are currently in a period of low natural gas supply costs and prices are expected to remain at or near these levels for awhile. These lower natural gas costs translate into lower natural gas avoided costs, and therefore reduced benefits from such programs.

NorthWestern is skeptical of the ability of residential benchmarking programs to produce cost-effective energy savings that persist for several years into the future or produce a cost-effective DSM resource. At this time, NorthWestern is reluctant to introduce a pilot program of this kind. NorthWestern is not optimistic that a pilot program of this type would be cost-effective in the current avoided cost environment, and therefore the risk of not recovering program costs and associated DSM Lost Revenues is greater than the benefits that might be achievable.

Currently in the western U.S., NorthWestern is aware of pilot programs operated by Puget Sound Energy (PSE), the Energy Trust of Oregon (ETO), and Sacramento Municipal Utility District (SMUD) to examine the performance and cost-effectiveness of behavior-based DSM programs. NorthWestern intends to monitor the efforts and results of the PSE, ETO and SMUD pilot programs, and learn from results of its Smart Grid Pilot Program, and then decide whether it is prudent to conduct a behavior-based DSM pilot program of its own.

CHAPTER 3
ENVIRONMENTAL ISSUES

CHAPTER 3

NorthWestern is committed to environmental stewardship and compliance.

Environmental Discussion

Environmental factors are a key risk consideration in NorthWestern Energy's resource planning. For example, regulations to control or reduce greenhouse gas emissions (carbon dioxide) at thermal power plants are expected to affect the cost of electric supply resources and prices associated with market transactions.

Greenhouse Gas Emission Risks are Increasing

In "*The President's Climate Action Plan*" issued in June 2013, President Obama issued a Presidential Memorandum directing the Environmental Protection Agency ("EPA") to "work expeditiously to complete carbon pollution standards for both new and existing power plants." On September 20, 2013, the EPA proposed new source performance standards, setting aggressive greenhouse gas emission reduction requirements for new fossil fuel-fired plants. These standards are expected to be finalized in mid-2014. The proposed CO_2 emissions limit for new coal-fired generating units is 1,100 lb CO_2/MWh based on implementation of partial carbon capture and sequestration (CCS). Significant disagreement exists between EPA and industry about the availability of CCS for coal, with EPA contending that it has been adequately demonstrated and industry claiming that it has not. Litigation over the new source standards is expected to focus largely on

this dispute. The proposed CO_2 emissions limit for new larger natural gas-fired stationary turbines is 1,000 lb CO_2/MWh and for new smaller natural gas-fired stationary turbines is 1,100 lb CO_2/MWh. The EPA is not proposing to require CCS for gas-fired units, on the grounds that CCS has not been adequately demonstrated for gas units and because emissions from gas units are already "acceptably low."

The EPA is also in the process of preparing to publish proposed emission guidelines for existing power plants by June, 2014, with final guidelines for such facilities expected by June 2015. According to the Climate Change Action Plan and the Clean Air Act, individual States must then submit plans to implement those guidelines by July 2016. Based on public comments made by the EPA, CCS is not expected to be required for existing power plants. Instead the guidelines are likely to focus on alternatives such as incentives to reduce demand for electricity and promote the development of renewable energy capacity, and possibly a banking, averaging, and trading program for emission reduction credits.

NorthWestern Includes a Carbon Cost in its Planning

NorthWestern's planning includes a cost imposed on carbon emissions within the 2013 planning horizon. NorthWestern recognizes that the ultimate resolution of carbon emissions regulation may take the form of alternative carbon mitigation schemes but believes the carbon tax approach employed in this and previous plans is an adequate surrogate until greater clarity is obtained. NorthWestern's modeling of carbon costs has been modified from the 2011 Plan, incorporating MPSC comments. The 2013 Plan uses the Energy Information Administration's ("EIA") 2013 Annual Energy Outlook greenhouse gas case of $15 per metric ton (GHG15 case), which begins in 2014 and escalates at 5%. NorthWestern's price forecast includes the GHG15 case beginning in 2021 when the carbon penalty

has escalated to $21.11/metric ton. NorthWestern's incorporation of a price on carbon is an assumption shared by many utilities[1] and mainstream companies: according to Carbon Disclosure Project's (CDP) December 5, 2013 Report, 29 companies include a price on carbon in their business planning. These include Excel Energy, Inc. ($20); Ameren Corporation ($30); and Exxon Corporation ($60).[2]

NorthWestern is placing significant positive value on resources such as hydroelectric facilities, that do not emit carbon and that, therefore, eliminates the risks and costs associated with the regulation of carbon.

Other Environmental Considerations

Aside from potential greenhouse gas regulations, few of the environmental regulations under consideration are likely to materially impact Colstrip 3 & 4 operation, which supplies 27% of NorthWestern's energy portfolio (based on nameplate capacity). A brief discussion of regulations under consideration that could affect operation at Colstrip follows[3]:

Mercury and Air Toxics Standards

On February 16, 2012, EPA finalized the *National Emissions Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units.* These standards are commonly known as the Mercury and Air Toxics Standards ("MATS"). At the same time, EPA also signed revisions to the new source performance standards (NSPS) for fossil-fuel-fired electric generating

[1] See Chapter 6, page 6-27 for examples and ranges of various utilities' CO_2 penalty forecasts.

[2] "Use of internal carbon price by companies as incentive and strategic planning tool," A review of findings from CDP 2013 Disclosure (December 2013).

[3] See Volume 2, Chapter 2 for a table summarizing environmental regulations and Colstrip's compliance status.

units. This NSPS revises the standards that new coal- and oil-fired power plants must meet for particulate matter (PM), sulfur dioxide (SO2), and nitrogen oxides (NOx). While these new requirements provide some certainty concerning environmental requirements, individual compliance requirements for many power plants are still being evaluated and could involve a variety of technologies with different costs. Moreover, while compliance, generally, is required by 2015, state regulatory agency exceptions may extend the compliance deadline until 2016, while EPA administrative order exceptions may extend to 2017. Also, the MATS is presently under judicial review before the United States Court of Appeals for the District of Columbia Circuit, and it remains a possibility that the MATS could be vacated in whole or in part. A decision from the court is expected in the first half of 2014. However, assuming MATS is upheld, the operation of Colstrip 3 & 4 will not be affected by this regulation as emission standards can be met at Colstrip 3 & 4 without installation of additional emission control equipment, aside from some increased monitoring requirements.

In addition, Montana implemented a mercury standard in 2009 under Rule 17.8.771. This standard exceeds the most recently adopted federal mercury limit. Colstrip 3 & 4 has emissions controls that meet Montana's mercury emissions standard.

Regional Haze

On September 18, 2012, EPA published the Approval and Promulgation of Implementation Plans; State of Montana; State Implementation Plan and Regional Haze Federal Implementation Plan (FIP). The EPA promulgated the FIP to address regional haze in the State of Montana. This rule addresses visibility; it was established to increase visibility to that of natural conditions by the year 2064. To that end, the rule establishes limits for particulate matter, sulfur dioxide and nitrogen oxide emissions for stationary sources that may contribute to

visibility degradation in Class 1 airsheds, such as national parks and wilderness areas. Under this rule, plants built between 1962 and 1977 are subject to Best Available Retrofit Technology (BART) requirements and must meet emission limits that are attainable by installing those controls. Plants built after 1977 are subject to a review similar to BART that ensures "reasonable progress" is made toward the 2064 goal of natural visibility. Colstrip 3 & 4 are subject to "reasonable progress" requirements. During the first review period (2012 review – 2017 control), EPA did not mandate further reductions at Colstrip 3 & 4. As Reviews are conducted every 5 years with control required within 5 years following a review, Colstrip 3 & 4 will be reviewed again in 2017. Thus, the earliest any controls could be required for Colstrip 3 & 4 would be in 2022. However, at this time NorthWestern does not have any basis for assuming there will be additional controls.

Coal Ash Management

Coal combustion residuals (CCRs), including coal ash, are a byproduct of combustion of coal in power plants. CCRs are currently exempted wastes under the Resource Conservation and Recovery Act (RCRA); however, in 2010, the EPA proposed to regulate CCRs. The proposal included two options to regulate CCRs under RCRA. Under the first option, EPA would list these residual materials as special wastes (a category of hazardous wastes) subject to regulation under Subtitle C of RCRA with significant requirements from the point of generation to disposition including the closure of disposal units. Under the second option, EPA would regulate coal combustion residuals as nonhazardous waste under Subtitle D of RCRA and establish minimum nationwide standards for the disposal of coal combustion residuals. Under either option for regulation, surface impoundments utilized for coal combustion byproducts such as the fly ash and bottom ash ponds at Colstrip would have to be closed unless they could meet more stringent regulatory requirements.

In October 2011, the EPA issued a Notice of Data Availability inviting comments on chemical constituent data from coal combustion residuals; facility and waste management unit data; information on additional alleged damage cases; adequacy of State programs; and beneficial uses of CCRs. The comment period closed November 14, 2011. The EPA has not yet indicated when the rule will be finalized, and the substance of the final rule is not known. EPA's most recent regulatory agenda lists the CCR rule as a long-term item with no specific deadline. However, in a recent decision, *Appalachian Voices v. McCarthy*, No. 12-0523 (RBW) (D.D.C.) (Oct. 29, 2013), a federal district judge ordered the EPA to develop and submit a schedule for finalizing the CCR rule. The order makes it more likely that the EPA will work to finalize the rule by the end of 2014.

Earlier in 2013, the EPA also announced plans to coordinate its eventual regulation of CCRs with its proposed rule establishing effluent limitation guidelines for the steam electric power generating category. EPA must take final action on its proposed effluent limitation guidelines by May 22, 2014, under a consent decree that EPA has entered. EPA has also indicated that its proposed effluent limitations guidelines, if finalized, are likely to lead many power plants to dry-handling of coal ash. This, in EPA's view, would reduce the risks associated with storage of coal ash and is likely to lead it, in a final Coal Ash Rule, to treat coal combustion residuals as non-hazardous municipal and solid waste rather than as hazardous substances and consequently to be subject to less stringent regulation than would be required for hazardous wastes. Colstrip 3 & 4 are zero-discharge facilities and thus operate without a NPDES permit. Because the effluent limitation guidelines, if finalized, would only regulate facilities that discharge, they should not apply to Colstrip 3&4. Thus, since Colstrip 3 & 4, are zero-discharge facilities and it is likely that CCRs will be regulated as a municipal and solid waste, the CCR rule and the effluent limitation guidelines for power

plants should have little to no effect on the future cost of handling CCRs at Colstrip 3 & 4.

Summary

While there are environmental risks, we do not expect that the MATS, regional haze requirements, and coal ash regulations individually or in the aggregate will negatively affect Colstrip 3 & 4 operations within the planning horizon. However, the next phase of environmental regulations, such as the Regional Haze regulations, will need to be closely monitored. The Administration's Climate Action Plan, when implemented, is assumed to increase market prices which are already factored into NorthWestern's electricity price forecast. The forecast uses a carbon tax as a surrogate for a broad range of potential carbon mitigation efforts. For these reasons, it is prudent to invest in utility owned generation resources, especially those such as the Hydros, which emit no carbon. This investment will protect customers from both market price and environmental risks.

NORTHWESTERN ENVIRONMENTAL POLICY

NorthWestern places the environment directly in its corporate vision, mission, and value statement. Its value acronym SERVICE, has Environment as the last lettered statement that reads as follows; "We are committed to providing all customers with utility services that meet their current and future needs, while protecting and enhancing the quality of the environment. We utilize our limited natural resources wisely and act responsibly to limit impacts on our air, water, and land resources". NorthWestern recognizes its obligation to be a good steward of the natural resources entrusted to it. The newly established Environmental Department is creating environmental performance goals and will continue work toward written procedures, standards, guidelines, or policies for

protecting and maintaining the environment, and for environmental compliance. It will then communicate these established procedures, standards, guidelines, and policies to all employees.

CHAPTER 4
RESOURCE NEEDS ASSESSMENT

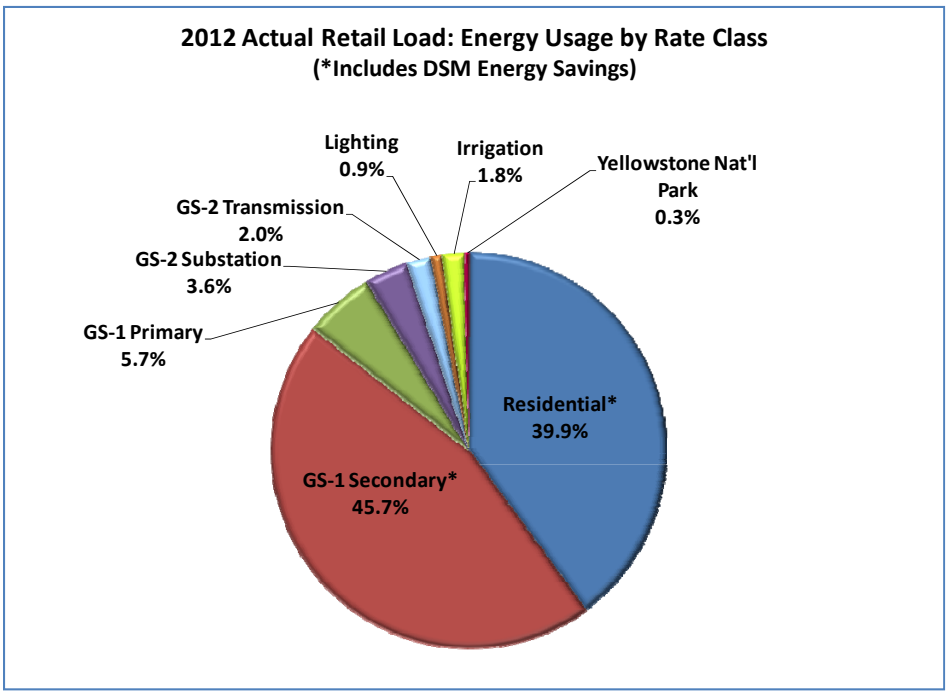
CHAPTER 4

Load - resource balance and the need for additional resources determines the scope and timing of NorthWestern's resource planning and procurement activities

Load Forecast

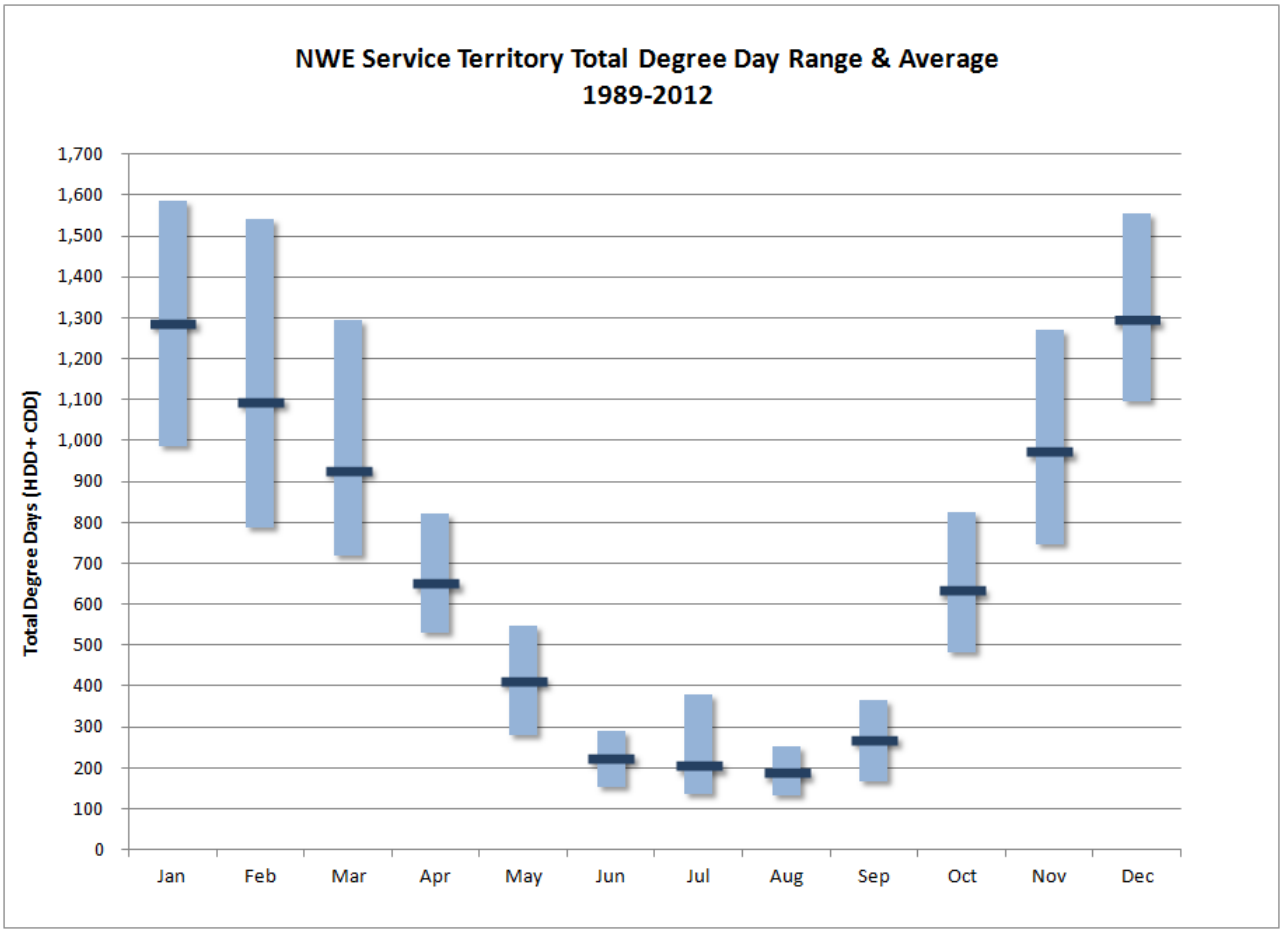
NorthWestern develops its 20-year long-term load forecast using a regression model with two explanatory variables; a forecast of customer count and normalized weather. Residential and GS-1 Secondary (small commercial) loads represent approximately 85% of the total energy load-serving obligation (see Figure 4-1) so much of the load forecast focuses on these customer classes.

Figure No. 4-1



Weather is normalized by using average historical total degree days per year, heating degree days (HDDs) plus cooling degree days (CDDs). 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 HDDs; if a negative value is derived, the value is recorded as CDDs. Figure 4-2 illustrates the average and wide ranges in weather in terms of degree days that the service territory has experienced since 1989.

Figure No. 4-2

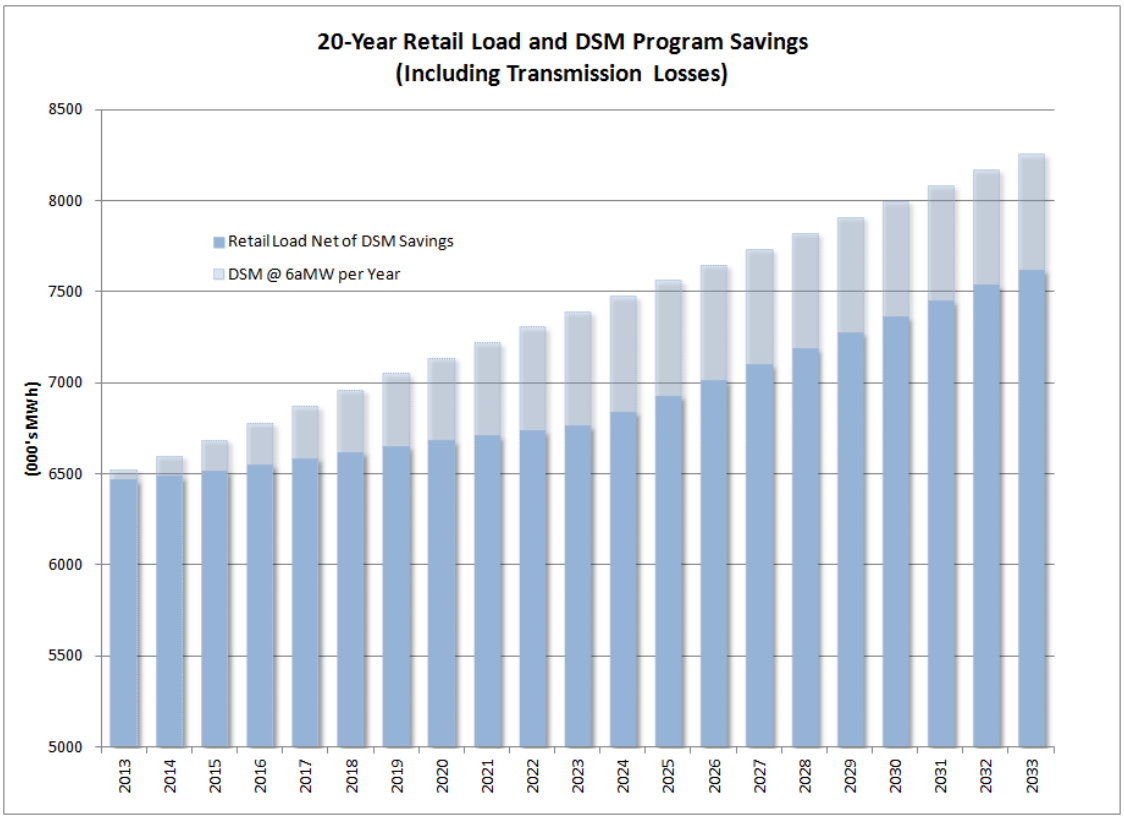


Other variables that may impact customer loads, including economic conditions, DSM activity, and distributed generation, are not included in the forecast. NorthWestern understands that several economic business cycles will likely

occur over the course of the 20-year planning horizon, but it does not adjust specific periods for expected up- or down-turns in the economy; rather it integrates the long-term historical average annual growth, which does include the impacts of several economic business cycles, into its long-term load forecast.

NorthWestern acquires about one-percent 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 4-3 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 benefit of DSM.

Figure No. 4-3



DSM is an important long-term component in NorthWestern's supply stack. The long-term projected growth rate of load is 1.2% per year excluding DSM and 0.8% including DSM energy savings. By 2024, NorthWestern is expected to have to procure approximately 750,000 fewer MWh per year that it would otherwise have to procure without the DSM programs. DSM programs are discussed further in Chapter 2.

Peak Demand Forecast

The peak demand forecast is prepared by the Energy Supply group using hourly load data for the retail customer class supplied by NorthWestern's Load Research Department. Energy Supply analyzes this data for patterns of use and peak demand. 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 4-1 for the period 2002 – 2012. The annual peak load forecast presented in Table 4-2, 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.

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Table No. 4-1

Historical Peak Demand (MW)		
Year	Winter	Summer
2002	892	958
2003	912	1,078
2004	1,096	1,000
2005	1,096	1,026
2006	1,085	1,122
2007	1,100	1,177
2008	1,165	1,071
2009	1,225	1,059
2010	1,219	1,045
2011	1,139	1,091
2012	1,106	1,133
Averge Growth Rate	2.17%	1.69%

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Table No. 4-2

1 in 2 Peak Demand Forecast Excluding DSM (MW)			Peak Demand DSM Savings Forecast (MW)			1 in 2 Peak Demand Forecast Including DSM (MW)		
Year	Winter	Summer	Year	Winter	Summer	Year	Winter	Summer
2013	1,161	1,087	2013	10	10	2013	1,152	1,078
2014	1,182	1,105	2014	21	20	2014	1,162	1,086
2015	1,202	1,122	2015	30	28	2015	1,171	1,093
2016	1,222	1,140	2016	40	38	2016	1,182	1,102
2017	1,241	1,158	2017	50	48	2017	1,191	1,110
2018	1,261	1,176	2018	60	58	2018	1,201	1,119
2019	1,281	1,193	2019	69	66	2019	1,212	1,126
2020	1,301	1,211	2020	79	76	2020	1,222	1,135
2021	1,322	1,229	2021	89	86	2021	1,233	1,144
2022	1,342	1,248	2022	99	95	2022	1,243	1,152
2023	1,363	1,265	2023	109	104	2023	1,254	1,161
2024	1,386	1,286	2024	118	114	2024	1,268	1,172
2025	1,400	1,298	2025	118	114	2025	1,282	1,184
2026	1,415	1,310	2026	118	114	2026	1,297	1,196
2027	1,427	1,319	2027	118	114	2027	1,309	1,205
2028	1,439	1,329	2028	118	114	2028	1,321	1,215
2029	1,451	1,339	2029	118	114	2029	1,333	1,225
2030	1,463	1,349	2030	118	114	2030	1,345	1,235
2031	1,476	1,359	2031	118	114	2031	1,358	1,245
2032	1,488	1,369	2032	118	114	2032	1,370	1,255
2033	1,501	1,379	2033	118	114	2033	1,382	1,265
Averge Growth Rate	1.29%	1.19%	Averge Growth Rate	13.28%	13.07%	Averge Growth Rate	0.92%	0.80%

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 ("CEIC") publishes Montana's population forecast on its website. The forecast is constructed using an independent econometric

model developed by Regional Economic Models, Inc. (REMI), and provides county population projections through 2060. As shown in Table 4-3, 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.

Table No. 4-3

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*	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	989,415	*1.1%*	773,713	*1.1%*	338,804	*1.4%*	270,571	*1.3%*	60,872	*1.9%*
2015	1,041,128	*1.0%*	813,876	*1.0%*	359,037	*1.2%*	285,980	*1.1%*	65,578	*1.5%*
2020	1,103,993	*1.2%*	862,580	*1.2%*	385,857	*1.5%*	306,323	*1.4%*	72,055	*1.9%*
2025	1,165,500	*1.1%*	910,245	*1.1%*	412,063	*1.3%*	327,130	*1.3%*	77,454	*1.5%*
2030	1,230,432	*1.1%*	960,544	*1.1%*	439,071	*1.3%*	348,232	*1.3%*	83,360	*1.5%*

Energy Load - Resource 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) must also be considered. Simply averaging or ignoring the differences in HL and LL would not balance either load-serving period and would likely lead to energy deficits during HL hours and energy surpluses during LL hours.

Figures 4-4 and 4-5 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.

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Figure No. 4-4

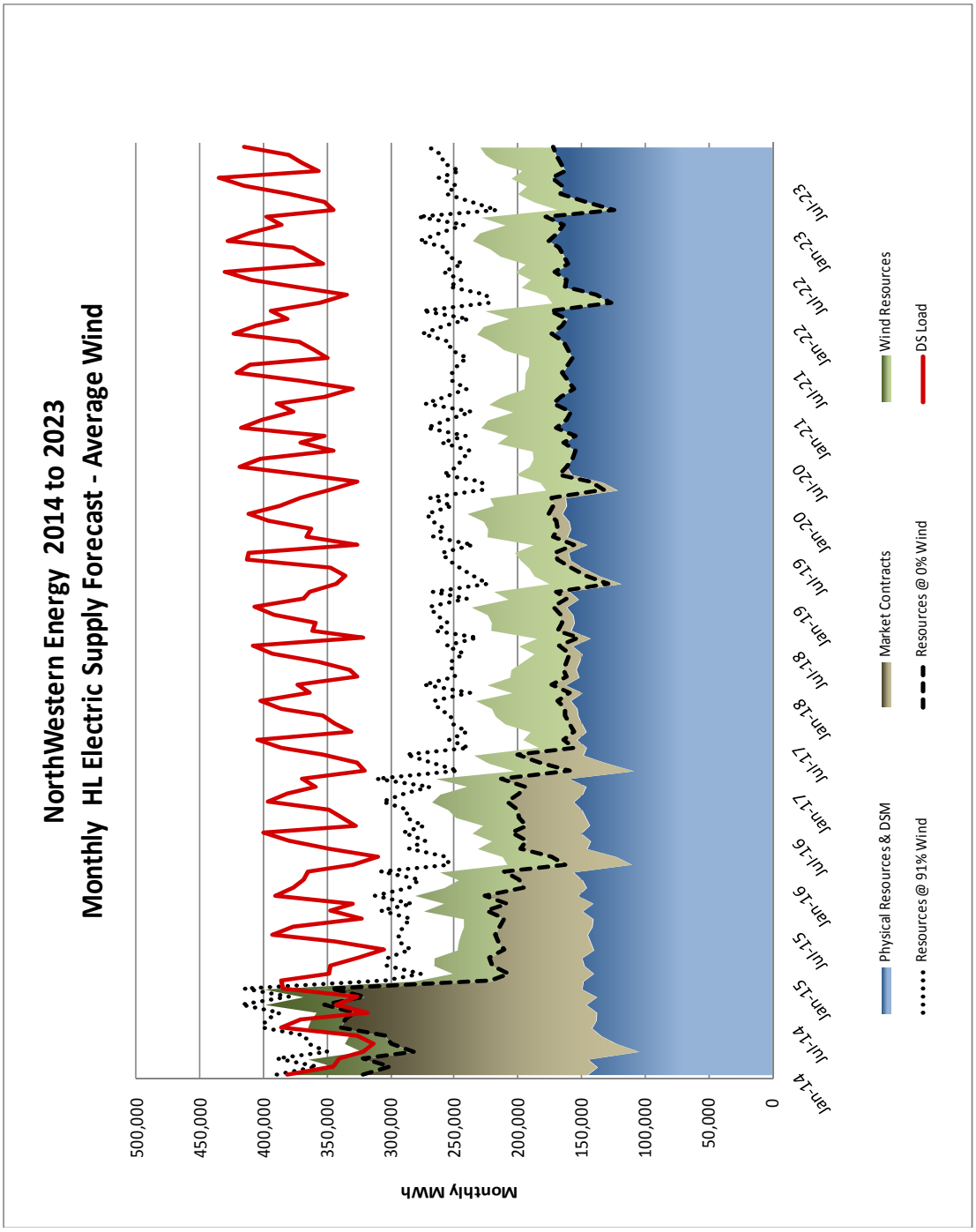
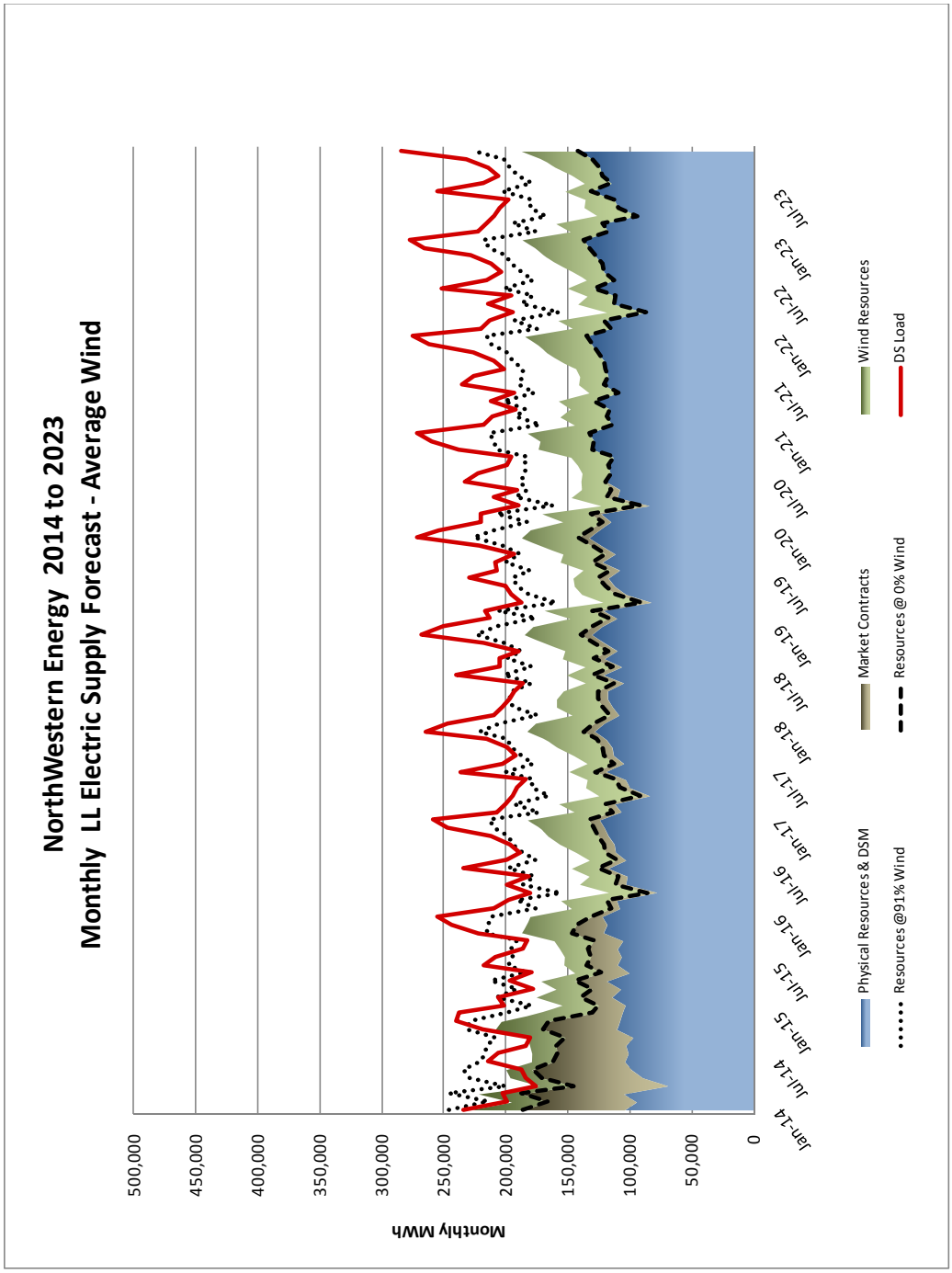

NorthWestern Energy 2014 to 2023
Monthly HL Electric Supply Forecast - Average Wind
Monthly MWh
500,000
450,000
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
Jan-14
Jul-14
Jan-15
Jul-15
Jan-16
Jul-16
Jan-17
Jul-17
Jan-18
Jul-18
Jan-19
Jul-19
Jan-20
Jul-20
Jan-21
Jul-21
Jan-22
Jul-22
Jan-23
Jul-23
Physical Resources & DSM
Market Contracts
Wind Resources
Resources @ 91% Wind
Resources @ 0% Wind
DS Load

Figure No. 4-5


NorthWestern Energy 2014 to 2023
Monthly LL Electric Supply Forecast - Average Wind
Monthly MWh
500,000
450,000
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
Jan-14
Jul-14
Jan-15
Jul-15
Jan-16
Jul-16
Jan-17
Jul-17
Jan-18
Jul-18
Jan-19
Jul-19
Jan-20
Jul-20
Jan-21
Jul-21
Jan-22
Jul-22
Jan-23
Jul-23
Physical Resources & DSM
Market Contracts
Wind Resources
Resources @91% Wind
Resources @ 0% Wind
DS Load

Peak Demand – Resource Balance

Resource Adequacy

Resource adequacy refers to the ability of a utility, or electricity supplier, to meet the peak load requirements of the customers its serves for each hour of the forecast period. At the time NorthWestern purchased the transmission and distribution assets from Montana Power Company, NorthWestern had to rely entirely upon market purchases to meet both the capacity and energy needs of its customers. Since that time, NorthWestern has taken steps towards providing resource adequacy, but still relies heavily upon market purchases to meet its peak load obligations. In fact, NorthWestern's long-term capacity deficit, as a percentage of forecast peak load, greatly exceeds the forecast capacity deficits of other investor-owned utilities in the Pacific Northwest.

Regional Resource Adequacy

Resource adequacy planning at the regional level is changing. Over the past decade the Pacific Northwest region was capable of producing more energy than the region consumed, even during times of peak load. This has kept market prices low and has allowed NorthWestern to take advantage of market purchases to serve its peak load obligations, rather than building and owning new generation.

In 2005, the Northwest Power and Conservation Council ("NWPCC") and Bonneville Power created the Pacific Northwest Adequacy Forum (Adequacy Forum). The Adequacy Forum was tasked with developing an adequacy standard for the regional power supply. The purpose of the standard is to provide an early warning to the region should resource development fail to keep pace with demand growth. This warning is designed to "notify" utilities that they may

need to reconsider their individual plans for meeting their own resource adequacy.

In its 2012 forecast, the Adequacy Forum identified a 350 MW capacity deficit by 2017. The forecast also observed that the region will develop adequate resources to meet that capacity need. However, the planned elimination of the Boardman and Centralia coal-fired plants and PPL Montana's announcement that the 153 MW J.E. Corette coal-fired generation plant will be placed in reserve status beginning April 2015 contribute to regional resource adequacy concerns.

Boardman: Portland General Electric (PGE) has announced that it will close the 650 MW Boardman coal-fired generation plant in 2020. PGE plans to replace it with new natural gas-fired generation.

Centralia: TransAlta's 670 MW Centralia Unit 1 is scheduled to be shut down in 2020 and the 670 MW Centralia Unit 2 is scheduled to shut down in 2025.

J.E. Corette: PPL Montana has announced that it will place the J.E. Corette, a 153 MW coal-fired power plant, in reserve status beginning in April 2015, when the requirements for Mercury and Air Toxics Standard take effect (reserve status is also commonly called "mothballing").

At present, NorthWestern relies heavily on purchases in the wholesale electricity market to meet peak demand at variable market rates. This has proven to be a sound near-term strategy, but as the region's surplus diminishes NorthWestern's ability to rely on the market to meet peak demand will become more costly and

the risk to physical reliability will become greater. Additionally, the market may become tighter as other changes to the resource mix in northwest unfold.

Economic Recovery: Loads could rebound due to increases in construction of new facilities, particularly data centers, and the potential for restart of industrial facilities.

Electricity Exports to Canada: BC Hydro recently filed its Integrated Resource Plan with the provincial government. The plan projects a 40 percent increase in electricity demand over the next 20 years. BC Hydro is looking at a variety of ways to meet its growth, including market purchases.

DSM Underperformance: Most regional utilities plan to meet a significant portion of their load growth with DSM measures. DSM is a mature market strategy in the Pacific Northwest. Additional DSM may prove more difficult to develop than anticipated by utility planners, which would result in faster load growth than currently forecast.

Montana-Alberta Tie Line: The newly energized Montana-Alberta Tie Line ("MATL") will, for the first time, provide a south-to-north path from NorthWestern's BA to the higher-priced Alberta Electric System. MATL will likely compete for the same resources that have traditionally been available to serve NorthWestern's peak load.

Reduced New Capacity Construction: Some regional utilities have determined that investment in transmission and distribution upgrades (which may allow for greater imports) presents a lower risk investment strategy than does investment in new generation.

Other regional utilities have recently indicated that they intend to rely more heavily on market purchases to meet their load and resource balance. Table 4-4 shows several regional utilities and their future plans to depend on wholesale market purchases to balance loads and resources.

Table No. 4-4

Regional Investor-Owned Utilities' Reliance on Market to Meet Peak Load

Utility	Date of Resource Plan	2018 Resource Balance
Avista	2013	110 MW Surplus
Puget Sound Energy	2013	2,188 MW Deficit
Seattle City Light	2010	800 MW Deficit
Portland General Electric	2012 Update	294 MW Deficit
Idaho Power	2013	none
Pacificorp (scope)	2013	1,888 MW Deficit

All of the factors discussed above could cause the WECC capacity loads and resources balance to tighten significantly in the next three to seven years.

NorthWestern Resource Adequacy

Table 4-5 below shows the resources NorthWestern has procured to help meet customer capacity requirements at time of peak load. Additionally the table shows the winter peaking capability and the summer peaking capability for the years 2014, 2016 and 2018. In addition, customer capacity requirements at peak are shown with the load and resource balance.

Table No. 4-5

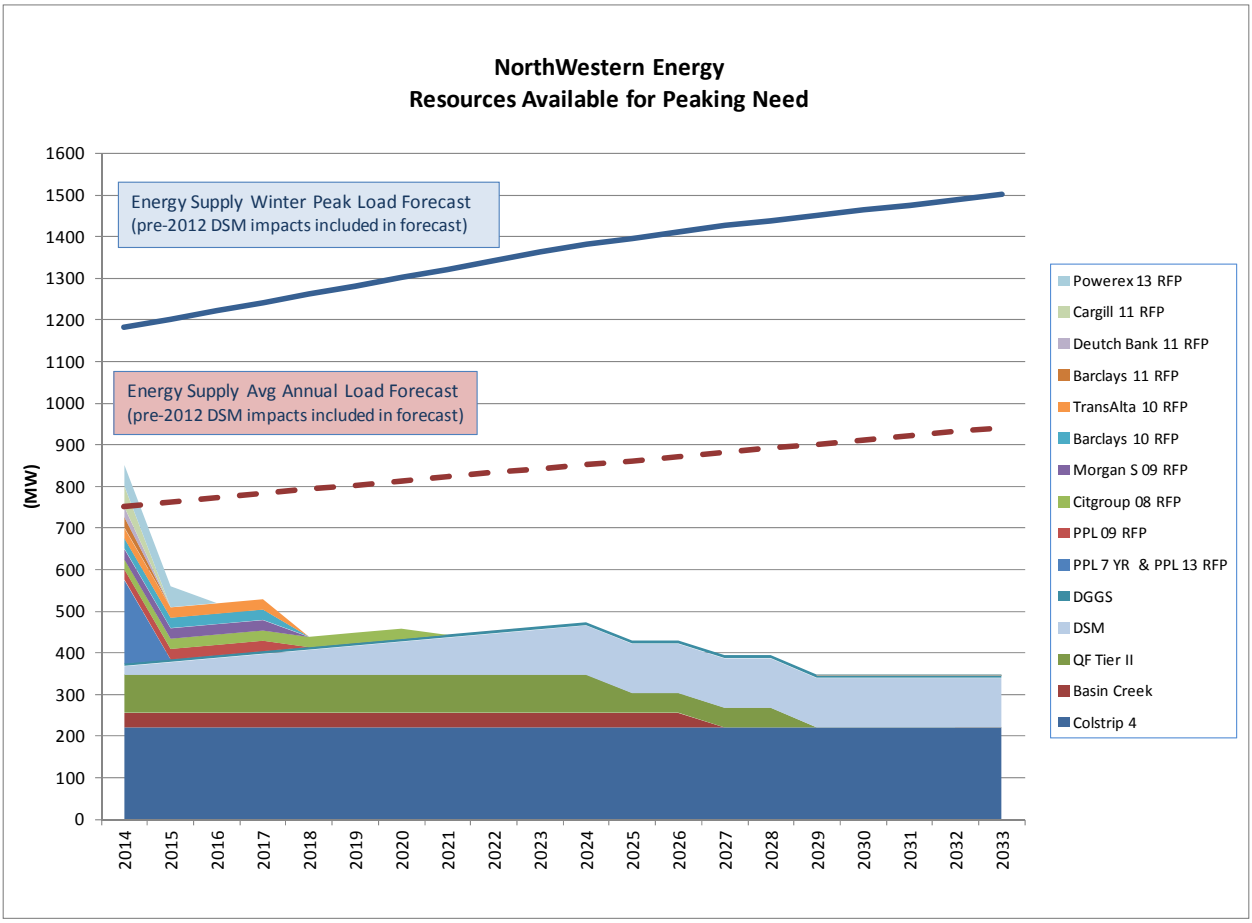
NorthWestern Energy Load and Resource Balance

		2014		2016		2018	
Resource	**Nameplate MW**	**Winter MW**	**Summer MW**	**Winter MW**	**Summer MW**	**Winter MW**	**Summer MW**
Colstrip 4	222	222	222	222	222	222	222
Basin Creek	52	35	35	35	35	35	35
DGGS	150	7	7	7	7	7	7
Wind	237	0	0	0	0	0	0
Misc QF	143	93	36	93	36	93	36
Off-System Positions	150	100	100	75	75	25	25
Purchased Power Agreements	25	25	25	25	25	0	0
Total	979	482	425	457	400	382	325
Customer Capacity Requirement		1,162	1,086	1,182	1,102	1,201	1,119
Load and Resource Balance		**-680**	**-661**	**-725**	**-702**	**-819**	**-794**

Negative "Loads and Resource Balance" in the previous Table represents a shortage and means that NorthWestern must plan to acquire short-to-intermediate term power to meet peak. For example, NorthWestern must plan to acquire 680 MW of power to meet the planned winter peak in 2014, increasing to 819 MW in the 2018 planning year. NorthWestern minimizes market exposure through use of staged and planned RFPs and other short term market purchases.

NorthWestern prepares a 20-year forecast of default supply loads. Figure 4-6, is a graphical representation of NorthWestern's load and resource balance for over the planning horizon. The forecast assumes a 50 percent expected probability of occurrence, meaning that half of the futures would have higher peak loads and be higher and half of the years would have lower peak loads. The solid line depicts NorthWestern's forecast of peak winter load from 2013 through 2033. The solid bars reflect mid-to-long term resources that NorthWestern has acquired to meet that need.

Figure No. 4-6



Planning Margin

A key concept to capacity planning, as employed by most utilities, is the concept of capacity "planning margin". Planning margin provides added capacity above the anticipated need to serve customers. This margin or "buffer" provides protection against unforeseen circumstances that affect load; extreme weather, low stream flows, unplanned resource outages, and unexpected transmission outages, or a combination of these factors. A utility with a diverse set of resources in its portfolio may be able to adopt smaller planning margins than a utility with relatively few, and larger, generation units. However, NorthWestern does not have any planning margin because NorthWestern still relies on the

wholesale energy market to provide a significant portion of its energy supply portfolio. As NorthWestern continues to build its portfolio of resources, its capacity resource deficit will diminish to the point where it will make sense to revisit the issue of capacity planning margin. As referred to within this Plan, reserves cover balance of the hour needs if a unit trips while planning margin covers longer duration events. The primary difference is that we are required to carry reserves and we are not required to hold or demonstrate margin. NorthWestern will consider inclusion of an appropriate capacity margin in future planning processes.

Steps to Achieve Resource Adequacy

Early in this planning cycle NorthWestern commissioned Lands Energy ("Lands") to compare NorthWestern's load-serving resources to the portfolio composition of other regional utilities to draw conclusions concerning resource adequacy. The work was commissioned prior to the announcement of the Hydro Acquisition, but the conclusions of the Lands' report supports the acquisition. The report is included in Volume 2, Chapter 2.

NorthWestern has carefully and deliberately moved toward achieving physical resource adequacy, but has a long way to go to cover its future open positions (or resource needs). The acquisition of Colstrip 4 and Basin Creek added both baseload and peaking/flexible capability, respectively, to NorthWestern's energy supply portfolio. Additionally, NorthWestern has covered a large portion of its open position with Purchased Power Agreements ("PPAs") from PPL Montana, which has physical resources located in NorthWestern's Balancing Authority ("BA"). The acquisition of the Hydros will more than displace the current PPL Montana contract which is a continuation of NorthWestern's focus on achieving physical resource adequacy and long term price certainty.

Resource adequacy as defined by the needs of the load being served, usually requires a variety of resource types; baseload, intermediate, flexible/dispatchable, and peak serving resources:

Baseload Resources: Generation units with high average annual capacity factor resources historically comprised of large thermal and hydro.

Intermediate Load Resources: Generation units capable of cycling to meet daily load increases associated with heavy load with moderate annual capacity factors.

Peaking Resources: Dispatchable generation units that run only during short duration, high loading periods with low annual capacity factors and often represent the incremental portfolio additions by integrated utilities.

Flexible /Dispatchable Resources: Generation units that can be effectively used to meet changing supply needs because of renewable resource production attributes and uncertainty.

CHAPTER 5
MODELING INPUTS

CHAPTER 5

Forecasts of retail loads, commodity prices, resource costs, and environmental costs and potential resources, including the Hydros, are presented in this chapter.

Forward Price Projections

Natural Gas Price Forecast

Natural gas prices are a major determinant of electric market prices. In the Pacific Northwest electric market, a natural gas unit is often the marginal unit of production, and hence it establishes the marginal cost for market power for those time periods. Therefore, a lower natural gas price forecast drives a lower electric price forecast and impacts the economic dispatch of gas units.

Unlike prior resource plans, NorthWestern has not constructed, weighted, and selected various natural gas cases, such as high market and low market cases, which can be evaluated under a deterministic modeling approach. This approach has lead to "selecting" the best forward price strip and weighting modeling results in an attempt to chose the "best" results that are perceived to more accurately represent the future. This type of post-modeling decision making does not provide more conclusive results or promote better decision making.

Rather, natural gas prices, as well as many other variables, have been subjected to hundreds of simulations through an integrated stochastic modeling approach using Ascend Analytic's energy resource planning tool, PowerSimm, with the

idea that creating hundreds of possible future states in which to evaluate portfolios presents a more robust planning process than constructing a few future cases. A more detailed discussion on portfolio modeling is included in Chapter 6.

PowerSimm relies on historical spot prices to determine implied market volatility in the forecast, as well as forward price curves to factor in current expectations of market conditions in the future. In other words, even though historical volatility plays a significant role in the development of the future model states, current market data constrains the variability and assists in correlating the simulation of prices through time.

Figure 5-1 displays the natural gas price forecast results from PowerSimm, along with comparisons to the Northwest Power and Conservation Council's (NPCC) medium case as of July 2013, and the Energy Information Administration's (EIA) reference case issued April 2013. The mean outcome of the simulations (solid red line) is bounded by the 5th percentile (lower dotted red line) and the 95th percentile (upper dotted red line) of the distribution of model outcomes, which encompass both the EIA and NPCC cases.

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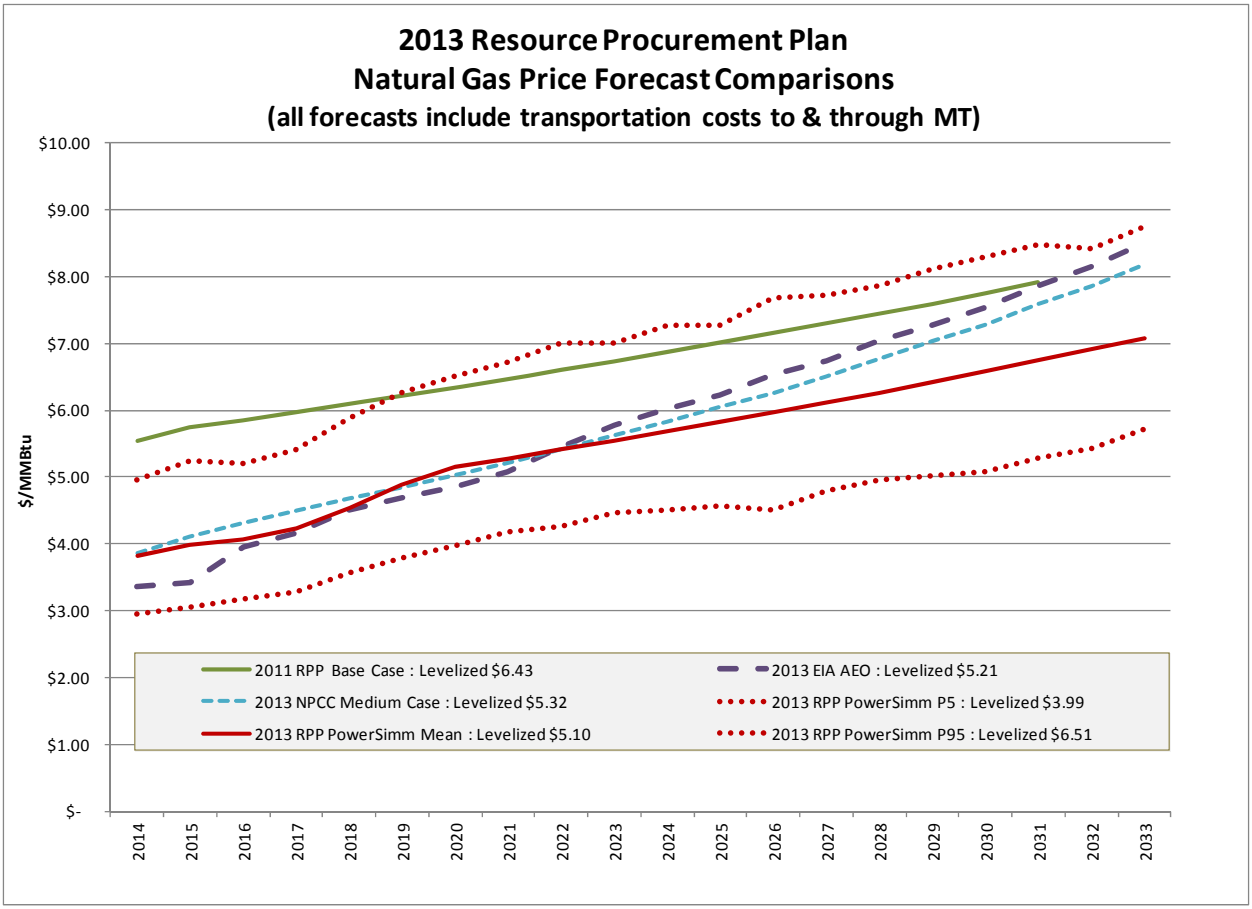
Figure No. 5-1



Electric Price Forecast

As with the natural gas price forecast, NorthWestern has not constructed various electricity price cases, such as high market and low market cases. Wide ranges of possible electricity price trajectories will be examined via PowerSimm stochastic modeling through hundreds of simulations that maintain the structural relationship between natural gas and electricity.

Figure 5-2 illustrates the mean electricity price forecast along with a comparison to the NPCC's carbon impacted electricity price forecast. The NPCC's Federal CO_2 case contains a higher carbon penalty and earlier implementation year (2015 versus 2021) than NorthWestern's forecast. But, as with the comparison

forecasts in the natural gas chart, the NPCC forecast is within the bounds created by the 5th and 95th percentile forecasts.

Figure No. 5-2

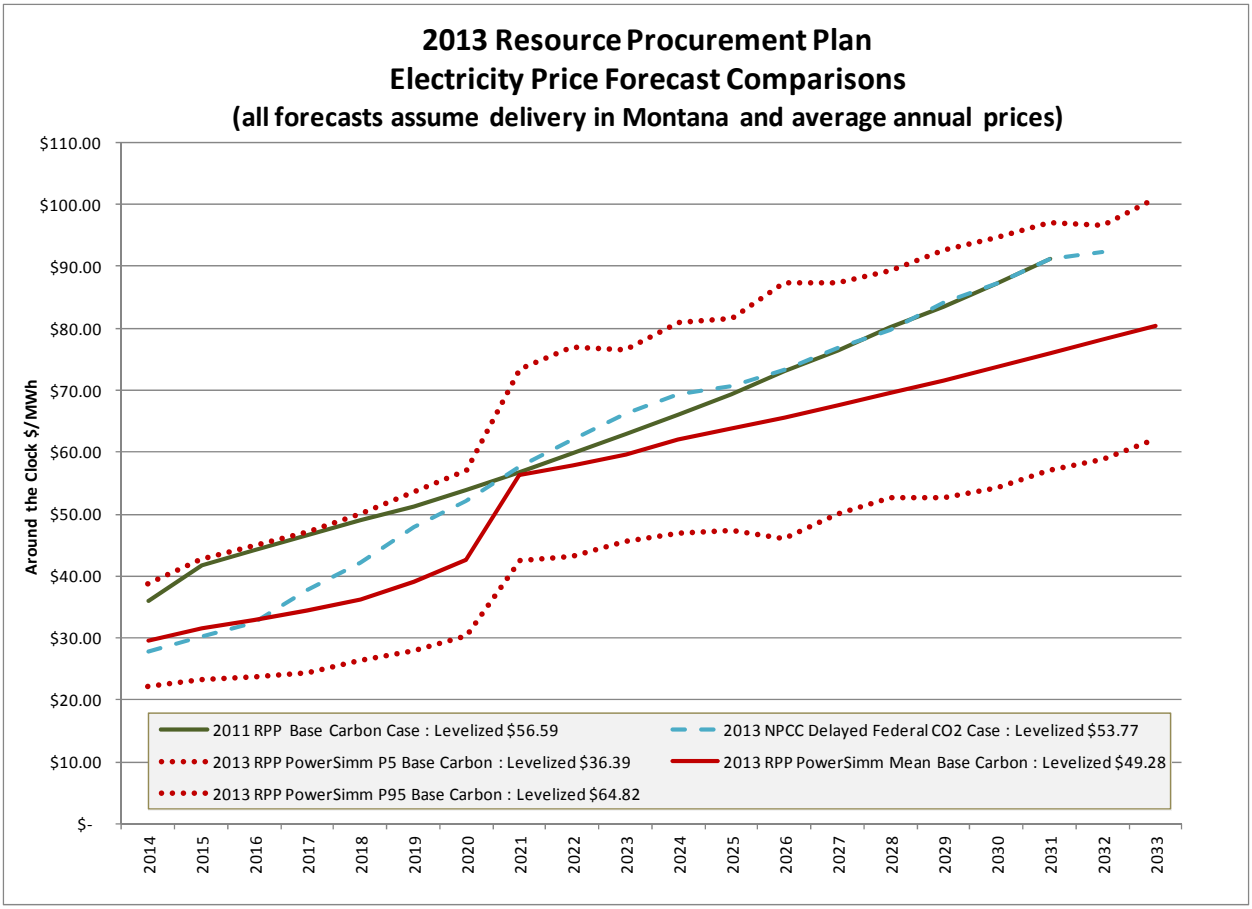


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Table 5-1 presents the mean electricity and natural gas price forecasts by year.

Table No. 5-1

Ascend Mean Electricity & Natural Gas Price Forecasts Montana Delivery				
Year	HL On-Peak ($/MWh)	LL Off-Peak ($/MWh)	Around the Clock ($/MWh)	Natural Gas ($/MMBtu)
2014	$33.55	$24.35	$29.50	$3.82
2015	$35.91	$26.04	$31.57	$3.98
2016	$37.68	$27.02	$32.99	$4.07
2017	$39.45	$27.87	$34.36	$4.23
2018	$41.62	$29.55	$36.31	$4.54
2019	$44.79	$32.02	$39.17	$4.88
2020	$48.10	$35.45	$42.53	$5.16
2021	$62.01	$49.15	$56.35	$5.28
2022	$63.74	$50.60	$57.96	$5.41
2023	$65.50	$52.10	$59.60	$5.54
2024	$68.49	$53.65	$61.96	$5.68
2025	$70.44	$55.25	$63.75	$5.82
2026	$72.46	$56.91	$65.61	$5.96
2027	$74.53	$58.62	$67.53	$6.11
2028	$76.66	$60.40	$69.51	$6.26
2029	$78.88	$62.23	$71.56	$6.42
2030	$81.17	$64.13	$73.67	$6.58
2031	$83.54	$66.10	$75.86	$6.74
2032	$85.98	$68.13	$78.12	$6.91
2033	$88.51	$70.24	$80.47	$7.08
20-Year Lev	$55.01	$41.98	$49.28	$5.10

Carbon Adjustment

Consistent with prior resource plans, NorthWestern incorporates a carbon penalty forecast into its planning work and views it as a proxy for the eventual form of greenhouse gas regulation implemented. The cost of thermal generating resources includes a carbon penalty as does the marginal generating resource

that sets the market-clearing price and no adjustment was made for carbon emission allowances. NorthWestern's carbon penalty is based upon the EIA Annual Energy Outlook GHG15 case, greenhouse gas penalty of $15/metric ton, as published in April 2013. The GHG15 case is constructed in a manner that begins with a penalty of $15/metric ton in 2015 and escalates at 5% thereafter. However, NorthWestern's electric price forecast and generating resource assessment does not consider a carbon penalty until 2021 when it "picks up" the escalated forecast and incorporates it into its planning. Every thermal resource is assigned a carbon emissions factor based on its expected CO_2 emissions per unit of production, which, when multiplied by the annual penalty, results in additional cost of dispatching the resource. The adjustment to the price curve is accomplished by applying the annual carbon penalty to the implied marginal operating unit. The carbon projections that were used as inputs for this adjustment are shown in Table 5-2 below. The Flat Market Adder column illustrates the impact of the carbon penalty on flat (average) electricity market prices due to the higher cost of dispatching the marginal unit, which is assumed to be a natural gas-fired resource.

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Table No. 5-2

Carbon Penalty Forecast		
Year	Carbon Penalty ($/ton)	Flat Market Adder ($/MWh)
2014	$0.00	$0.00
2015	$0.00	$0.00
2016	$0.00	$0.00
2017	$0.00	$0.00
2018	$0.00	$0.00
2019	$0.00	$0.00
2020	$0.00	$0.00
2021	$21.11	$13.52
2022	$22.16	$14.19
2023	$23.27	$14.90
2024	$24.43	$15.65
2025	$25.66	$16.44
2026	$26.94	$17.26
2027	$28.28	$18.12
2028	$29.70	$19.02
2029	$31.18	$19.98
2030	$32.74	$20.98
2031	$34.38	$22.02
2032	$36.10	$23.12
2033	$37.90	$24.28
20-Year Lev	$12.87	$8.25

Colstrip Coal Price Forecast

Coal used as fuel for the Colstrip plant is obtained from an open-pit mine owned and operated by Western Energy Company. The Rosebud Coal Seam, which lies 50 to 100 feet below the surface, serves as the source of coal that fuels the plant. Coal is delivered to Units 3 and 4 via a 4-mile, covered, overland conveyor system. The projected cost of the coal used in Units 3 and 4 is presented in Table 5-3.

Table No. 5-3

Colstrip Coal Price Forecast	
Year	($/ton)
2014	$21.49
2015	$21.87
2016	$23.21
2017	$23.16
2018	$24.11
2019	$24.61
2020	$25.12
2021	$25.64
2022	$26.17
2023	$26.71
2024	$27.27
2025	$27.83
2026	$28.41
2027	$29.00
2028	$29.60
2029	$30.21
2030	$30.84
2031	$31.48
2032	$32.13
2033	$32.80

Renewable Energy Credits

The market for renewable energy credits (RECs) in Montana is very latent and illiquid. The demand for RECs is created by entities that are required to meet renewable portfolio standards (RPS) such as NorthWestern Energy. Historically, NorthWestern has met annual RPS requirements through the purchase of bundled products comprised of both energy and the associated renewable energy credits. NorthWestern has not yet been in the position where it has had to pursue the purchase of REC-only products, but it would be considered if an attractive opportunity was presented or if a shortfall of RECs was encountered.

The supply of RECs for meeting Montana RPS is dependent on eligible renewable generators. As previously stated, bundled contracts are the norm, but there are situations where producers sell only the energy produced to buyers, such is the case with many existing QF contracts, and are able to sell the RECs to potential buyers in the market for REC-only products. NorthWestern's forecast of REC prices is based on regional REC quotes provided by an independent broker and is presented in Table 5-4.

Table No. 5-4

REC Price Forecast	
Year	**($ / REC)**
2014	$1.00
2015	$1.25
2016	$1.50
2017	$1.75
2018	$2.00
2019	$2.25
2020	$2.50
2021	$2.75
2022	$3.00
2023	$3.25
2024	$3.50
2025	$3.75
2026	$4.00
2027	$4.25
2028	$4.50
2029	$4.75
2030	$5.00
2031	$5.25
2032	$5.50
2033	$5.75
20-Yr Lev	$2.76

Industry Developments

In the two years since NorthWestern filed its last resource procurement plan ("2011 Plan"), significant changes have occurred in the electric utility industry. Many of these changes have an impact on the 2013 Plan:

- **EPA tightens regulations on GHG emissions.** In September 2013, and after considering 2.5 million public comments, the EPA proposed setting CO_2 emissions limits for new coal and natural gas power plants at approximately 1,000 pounds per MWh produced. This will require that new coal plants sequester approximately half of their CO_2 emissions. Without breakthroughs in carbon sequestration technologies that make it feasible and economical at large scales, the order effectively prevents the construction of any new coal plants. For further environmental discussion, refer to the Environmental chapter of the Plan.

- **The Federal Production Tax Credit Extended.** The Production Tax Credit ("PTC") for renewable resources was extended, and is now set to expire at the end of 2013. PTC rules allow projects that have commenced construction prior to the deadline but don't achieve commercial operation until later to maintain eligibility. This expiration, combined with the leveling of the RPS requirements in many states has led to a slowing of renewable energy development in the U.S. Congress has in the past extended the PTC rather than allow it to expire, and the industry believes it will extend the PTC again. However, no specific legislation for any further extension has been proposed by the time this Plan was prepared. The expiration of the PTC will make renewable power considerably more expensive on a comparative basis to other non-renewable resources.

- **Solar Panels.** Solar panel prices have dropped, but not enough to be economical at utility scale without significant government incentives. The U.S. Energy Information Administration (EIA) currently estimates the long-term levelized cost of solar photovoltaic (PV) at $144/MWh and the cost of solar thermal projects at $261/MWh. Continued growth in solar installations is fueled mainly by state incentives (including RPS targets) and the Federal PTC that allow the installation of solar generation at competitive prices. Despite the incentives, installed solar capacity lags other renewable sources. In 2012, solar represented only 2% of the annual total renewable generation, which included wind, biomass and geothermal. Despite lagging the other technologies, solar generation did see significant growth with 2012's total generation of 496 aMW representing a 258% increase over 2010's total generation of 138 aMW. Without significant incentives, major technology breakthroughs or major reductions in manufacturing and installation costs, solar will not be competitive with other forms of renewable generation.

- **Capacity and Energy Constraints.** The Pacific Northwest continues to recognize that it is a capacity and flexibility constrained region. The region produces adequate energy to serve load, even under low stream flow conditions. However, regional resources may not be able to match loads and resources at all hours during extreme load and/or under resource underperformance conditions.

- **Distributed Generation.** Distributed generation technologies (especially roof top solar) and aggressive demand side management have begun to disrupt sales volumes for higher cost utilities in California and the Desert Southwest.

Resource Descriptions

Discussion of Future Resources

As explained in Chapter One, the timing of the 2013 Plan is coincidental with the Hydro Acquisition. Because the Hydro Acquisition represents a very large acquisition, 633 MW and over 400 aMW, and consistent with the conclusions of the 2011 Plan, NorthWestern is focusing its model analysis on three portfolios; 1) the current portfolio plus market transactions, 2) the current portfolio plus a CCCT acquisition and market transactions, and 3) the current portfolio plus the Hydro Acquisition and market transactions. However, in all three portfolios projected levels of DSM acquisition, (6 aMW per year), are maintained and wind resources are only added in sufficient quantities to meet RPS. The remainder of this chapter discusses each hydro generation facility included in the Hydro Acquisition and discusses a number of natural gas generation technologies. Although NorthWestern has decided to focus its natural gas resource modeling on a CCCT, the natural gas generation technology that figured most prominently in the 2011 Plan preferred portfolios and that most closely matches the operating characteristics of the Hydros, several other gas-fired generation technologies are also discussed. Much of this work was completed prior to the Hydro-Acquisition. Additionally, these resource definitions may also prove to be useful in the upcoming avoided cost filing.

Summary of Hydro Resources - Hydro Acquisition

The Hydro Acquisition dominates the 2013 Plan as the fulfillment of the opportunity resources identified for potential acquisition in the 2011 Plan. The PPLM hydro system is comprised of 11 hydroelectric generating plants and one water storage reservoir facility. The facilities are located in Montana on the Clark

Fork, Flathead, Missouri and Madison Rivers and on West Rosebud Creek. The total capacity of the assets is 633 MW. The location of each of the hydro facilities is shown in Figure 5-3, and a general description of each facility is shown in Table 5-5.

Figure No. 5-3

Hydro Acquisition Locations

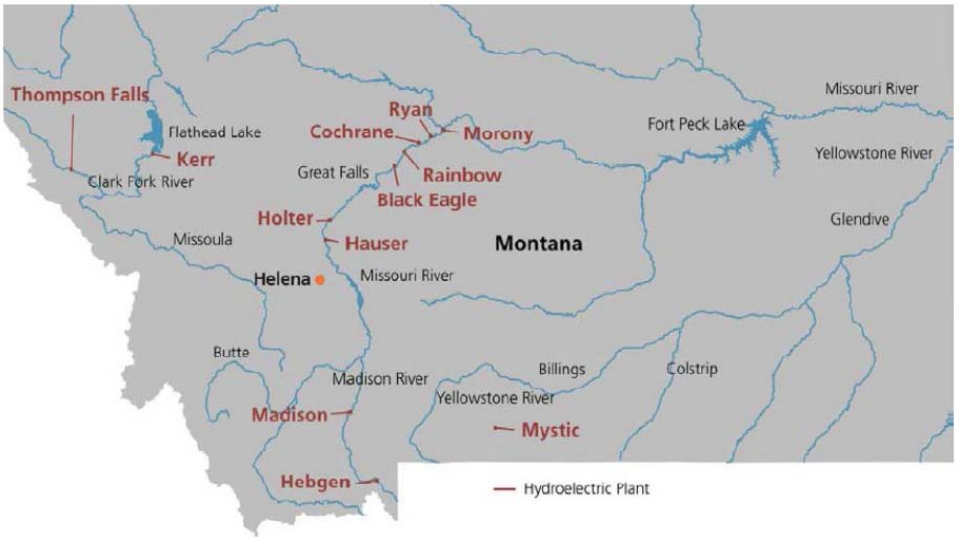

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Table No. 5-5

Hydro Acquisiiton - Resources				
Facility	Nameplate Capacity (MW)	25-Year Average Generation (MWH)*	2012 Generation Actual (MWH)	2013 Generation Actual (MWH)**
Thompson Falls	94	493,000	522,124	493,972
Mystic	12	46,000	49,084	48,367
Kerr	194	1,085,000	1,128,646	1,090,958
Madison	8	61,000	66,415	59,481
Hauser	19	124,000	129,008	121,939
Holter	48	269,000	283,213	243,341
Black Eagle	21	128,000	120,683	117,830
Rainbow	60	382,000	241,199	307,620
Cochrane	69	296,000	227,886	240,420
Ryan	60	414,000	390,454	407,896
Morony	48	273,000	284,608	233,508
Total:	633	3,571,000	3,443,320	3,365,332

* Calculated using 25 years historic production

** Actuals through Aug, and budget values for Sept. through Dec.

Figure No. 5-4

Thompson Falls Dam

Thompson Falls Dam is a seven-unit hydroelectric plant on the Clark Fork River in Thompson Falls. The facility was built in 1915 and consists and six older (1915) generation units with a combined capacity of 44 MW and a newer (1995)

powerhouse with one generation unit with 50 MW capacity. The facility has a total generating capacity of 94 MW and is classified as a "run-of-river" project. Thompson Falls is one of two hydro facilities in the Hydro Acquisition located west of the Continental Divide, the other is Kerr.

Figure No. 5-5

Kerr Dam

Kerr is a three-unit hydroelectric facility located on the Flathead River 5 miles southwest of Polson on the natural outlet of Flathead Lake. The units have a total generation capacity of 194 MW (1938/1954). Kerr Dam is operated under a joint license with PPL Montana and the Confederated Salish and Kootenai Tribes of the Flathead Indian Nation ("CSKT"). The CSKT have the option of purchasing and taking over the operation of Kerr Dam in 2015 and are currently negotiating the purchase price with PPLM. Kerr dam is classified as a "storage generation" facility because it uses the water stored in its reservoir to generate electricity.

Figure No. 5-6

Mystic Lake Dam

Mystic Lake is a hydroelectric plant located on West Rosebud Creek in the Beartooth Mountains, about 75 miles southwest of Billings. The powerhouse contains two turbine-generators installed in 1925 and has a total capacity of 12 MW. After exiting the powerhouse, water re-enters West Rosebud Creek and flows for a distance of about one mile to West Rosebud Lake where the flow is re-regulated.

The Madison-Missouri River hydro generation facilities consist of one reservoir and eight generation facilities. In order from upstream to downstream the order is; Hebgen (the only reservoir) Madison, Hauser, Holter, Black Eagle, Rainbow, Cochrane, Ryan and Morony. All eight Madison-Missouri facilities are classified as “run of river” projects and are managed under the terms and conditions of the FERC license. The ability to draft and refill some of the project reservoirs in the Great Falls area for generation is available under the terms of the license. Project reservoirs can be drafted for maintenance purposes under the relevant license articles and related specific plans

Hebgen Lake is the most upriver structure the Madison-Missouri River hydro system and is located on the Madison River, 25 miles north of West Yellowstone.

The facility consists of a 88-foot-high, 721-foot-long earth embankment dam and does not contain provide any generation. Instead, Hebgen is used to manage the flow of water into the Madison-Missouri system.

Figure No. 5-7

Madison Dam

Madison Dam is a four-unit hydroelectric plant on the Madison River at the head of Bear Trap Canyon which is about 10 miles north of Ennis, Montana. The four units were placed in service 1905-06 and have a total generating capacity of 9 MW.

Figure No. 5-8

Hauser Dam

Hauser Dam is a six-unit hydroelectric plant located on the Missouri River, about 14 miles northeast of Helena, Montana. The powerhouse contains six turbine-generator units with combined capacity of 19 MW (1911/1914). The dam is 720 feet long and 111 feet high. Its reservoir is 14 miles long and has a storage capacity of 64,253 acre-feet.

Figure No. 5-9

Holter Dam

Holter Dam is located on the Missouri River, about 43 miles northeast of Helena, Montana. Holter consist of four generation units with a total generating capacity of 48 MW. The dam became operational in 1918, is 1,364 feet long and 124 feet high. Its reservoir is 27 miles long and has a storage capacity of 240,000 acre-feet.

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Figure No. 5-10

Black Eagle Dam

Black Eagle Dam is a three-unit hydroelectric plant located about two miles downstream from Great Falls, Montana, at Black Eagle Falls on the Missouri River. The three generation units have a total generating capacity of 21 MW and were placed in service in 1927.

Figure No. 5-11

Rainbow Dam

Rainbow is located at Rainbow Falls in Great Falls, Montana, and began commercial operation in 1910. A new single-unit powerhouse was completed in early 2013. The new powerhouse replaced an eight-unit, 35 MW facility and increased the facility's generating capacity to 60 MW.

Figure No. 5-12

Cochrane Dam

Cochrane Dam is a two-unit hydroelectric plant located on the Missouri River about eight miles downstream from Great Falls, Montana. The two generation units began commercial operation in 1958, and have a combined capacity of 64 MW.

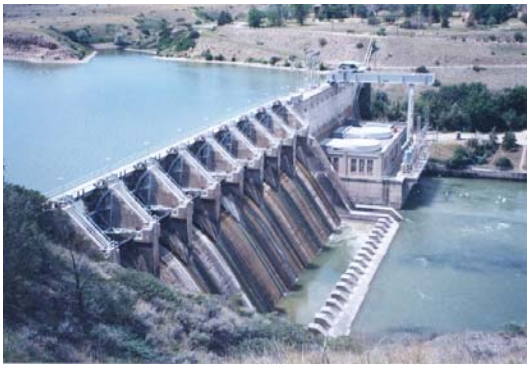
Figure No. 5-13

Ryan Dam

Ryan Dam is a six-unit hydroelectric plant located on the Missouri River about 10 miles downstream from Great Falls, Montana. The powerhouse was built in 1915/16 and contains six generation units with a total capacity of 60 MW.

Figure No. 5-14

Morony Dam



Morony is the last in the chain of Madison-Missouri River hydro facilities included in Hydro Acquisition and is located 15 miles northeast of Great Falls, Montana. Morony is a two-unit hydroelectric plant on the Missouri River. Built in 1930, the powerhouse contains two generation units with a combined capacity of 48 MW.

Natural Gas-fired Generation

Natural gas-fired generation offers a number of advantages when compared to other new resource alternatives:

- **Environmental.** Modern natural gas-fired power plants are designed with highly effective emission control technologies and produce minimal amounts of atmospheric pollutants (compounds of sulfur oxides, nitrogen oxides, and suspended particulates). In fact, the most efficient gas-fired generators produce approximately 40% of the carbon dioxide (on a per MWh basis as a coal-fired power plant.
- **Flexibility.** Natural gas-fired generators can quickly change loading levels to meet changing loads and wind output levels. However, this flexibility does cause loss of efficiency because highest efficiency occurs at full output levels.

- **Land Use.** A 20-30 acre parcel of land can accommodate as much as 600 MW of natural gas-fired generation whereas a similarly sized wind farm would require thousands of acres of land; although it would have little effect on agricultural uses, such as livestock grazing.
- **Infrastructure Utilization.** Natural gas-fired generators can be sited near population centers or existing electric or natural gas transmission facilities.
- **Construction and Technology Risk.** Modern natural-gas fired generation is a mature technology and is based on a limited number of gas turbine designs. Although soil conditions and local permitting requirements may dictate variations in equipment selection and project design, the power train (turbine, generator, piping, wiring, and control equipment) of a new natural gas-fired generator changes little from facility to facility. As a result, major Engineering Procurement and Construction (EPC) firms have acquired significant experience in the design and construction of these facilities.
- **Schedule Certainty.** If a site has adequate transmission and pipeline capacity available, permitting, design and construction of a new natural gas-fired generation facility can occur in 4-5 years following site selection.

Siting Considerations

Significant supplies of natural gas lie in close proximity to NorthWestern's service territory. These supplies include both traditional supply basins, as well as new sources of supply from shale formations. Shale gas and oil supplies, which are extracted through the process of hydraulic fracturing (or "fracking"), have transformed the US natural gas and electric markets. When compared to the 2011 Plan, natural gas prices in the 2013 Plan are approximately 20% lower, primarily due to the emerging influence of shale gas on forward market prices.

The natural gas pipelines that serve NorthWestern's service territory are near full capacity. These constraints necessitated installation of dual-fuel capability at the nominally natural gas-fueled DGGS. Installation of significant new natural-gas fired generation anywhere in the NorthWestern service territory will likely require pipeline capacity upgrades or interruptible pipeline service with diesel fuel back-up.

Electricity transmission constraints also influence natural gas-fired generation siting. Some generation sites with close proximity to major natural gas pipelines, particularly sites close to the Montana-Alberta border, suffer from significant transmission constraints that would require construction of major new transmission facilities to integrate the output of new generation. The cost and likely schedule for such transmission upgrades (8-20 years for permitting and eventual construction) renders these sites unsuitable for construction of new gas-fired generation.

Topography also affects the desirability of generation sites in the NorthWestern service territory. Every 1,000 feet of increased elevation above sea level reduces the capacity of natural gas-fired generators by about 3%. For example, a gas turbine rated at 200 MW at sea level would only produce about 170 MW at 5,000 feet (the approximate elevation of DGGS). Assuming construction costs were equal, a generator located at 5,000 feet would cost 15% more, on a dollars per kW basis, than a generator located at sea level. Most feasible sites for construction of new gas-fired generation in Montana lie at elevations between 2,500 and 5,500 feet.

Finally, the availability of cooling water affects the economics of a given site. Depending on the equipment configuration (CCCT or SCCT) and unit size, a gas-fired generator can use considerable amounts of water for cooling. Although a

generator can use an air-cooled condenser for cooling, this equipment adds capital cost and results in lower efficiency and output.

Equipment

Natural gas-fired generators can meet almost any type of load service and generation following requirement. Selection of a particular turbine technology depends on the expected role of the unit in the resource portfolio. In general, the high efficiency/low heat rate (6,600-7,200 Btu/kWh[1]) and slower ramp rate characteristics of combined cycle combustion turbines ("CCCTs") tend to work best in a baseload or intermediate load application. Aero-derivative, hybrid combustion turbines, and internal combustion engines (ICs), which have fast ramp rates and attractive heat rates (8,700-9,400 Btu/kWh), often provide fast response capacity required to follow load and generation swings. These units can also meet intermediate load service requirements. Finally, Frame combustion turbines operating in a simple cycle combustion turbine ("SCCT") configuration often provide peaking capacity for only a few hours a year during extreme loading and/or high wholesale market price conditions. Frame SCCT units have relatively high heat rates (11,000 Btu/kWh and greater) and slower ramp rates than aero-derivative machines (but ramp faster than CCCTs). However, they are somewhat less expensive (on a $/kW of installed capacity basis) than other gas generation technologies.

Internal Combustion (IC) Engines

IC engines, similar to those installed at the Basin Creek facility, utilize a reciprocating engine technology that evolved from diesel engine technology. Caterpillar, Wartsila, and other heavy equipment manufacturers make ICs. Most IC alternatives employ a dual-fuel capability, which allows the operator to switch

[1] All heat rates are expressed in terms of higher heating value ("HHV"). However, turbine manufacturers specify heat rates in lower heating value ("LHV") terms. In general HHV = LHV*1.105.

to on-site diesel fuel in the event of curtailment of natural gas pipeline supply during winter peak load conditions. These units operate at heat rates in the range of 9,000 Btu/kWh. ICs can start quickly and ramp up to full output in minutes. When deployed as multiple units, the units can be "staged" using a staggered or sequential firing control scheme that balances generation efficiency with usable operating range. ICs work well for peaking; load and generation following; and ancillary service needs. Individual units range in size from 5-20 MW. The modular nature of ICs allow for rapid installation upon completion of permitting activities (assuming a site with adequate pipeline and transmission support). Although capital costs and heat rates associated with ICs compare favorably to SCCTs, variable operation and maintenance costs are roughly double the equivalent cost for a larger SCCT. NorthWestern evaluated an IC equivalent to the Caterpillar G16CM34 (the machines installed at Basin Creek).

Simple Cycle Combustion Turbine (SCCT)

Larger Frame SCCTs (e.g. GE 7EA or 7FA gas turbines) are used by utilities to meet peak load and local reliability obligations. These units can start and reach full generation on relatively short notice and offer dispatch flexibility that typically exceeds that associated with large baseload CCCTs or units fueled by coal. SCCTs also require less capital investment (on a $/kW basis) than IC units, aero-derivative SCCTs, or CCCT's. With a fairly high heat rate of over 11,000 Btu/kWh for the least expensive Frame SCCT, (GE Frame 7EA), the wholesale market heat rate rarely reaches levels that justify running these units. Because of this, Frame SCCTs may go for months (or even years) without operating to serve load. NorthWestern evaluated the GE Frame 7EA SCCT in its planning work.

Aero-derivative SCCT

Aero-derivative SCCT units are available in a range of unit sizes from less than 10 MW to over 100 MW. The aero-derivative name reflects the aviation jet engine application which drove the original development of the technology. Aero-

derivative units are low-maintenance cost, high-efficiency units designed to operate on natural gas and diesel fuel. Utilities generally utilize aero-derivative SCCTs as peaking and fast response units. The larger units, such as the GE LMS 100, use inter-cooled gas turbine technology, resulting in lower heat rates than smaller units.

NorthWestern installed three Pratt & Whitney FT-8 aero-derivative units at DGGS to enable the NorthWestern Transmission function to follow load and wind generation deviations for the entire Balancing Authority. NorthWestern also installed an FT-8 unit in Aberdeen, SD to meet the peaking needs of its South Dakota service territory. These units have full load heat rates of 9,500 Btu/kWh and a unique turbine configuration that supports lower heat rate operation across a broad range of the output curve.

The smaller size and modular design of units such as the GE LM6000 permit rapid construction and siting close to load centers, albeit at a premium capital cost. The LM6000 exhibits slightly better full load heat rate characteristics (9,100 Btu/kWh) when compared to the FT-8. NorthWestern used the LM 6000 as the smaller aero-derivative alternative in its 2011 Plan portfolio model. However, due to its experience with construction and operation of the Pratt & Whitney FT-8, NorthWestern elected to include the cost and operating characteristics of this unit in its portfolio model, rather than the LM 6000. NorthWestern evaluated a 90 MW/8,700 Btu/kWh GE LMS 100 in its planning work.

Combined Cycle Combustion Turbine (CCCT)

CCCTs combine gas turbine and steam turbine technology to achieve the best gas-fired heat rates of any gas-fired generation option. A CCCT may utilize one, two, or three gas turbines that exhaust into a single heat recovery steam generator (HRSG). Waste heat from the gas turbines creates steam in the HRSG,

which in turn drives an additional generator. CCCTs achieve optimal performance when the units operate at full load over longer periods of time. CCCTs demonstrate heat rates below 7,000 Btu/kWh (assuming conventional water cooling). CCCTs can follow load and generation swings, but incur heat rate penalties for operation below the maximum efficiency point.

The standard manufacturer-supplied CCCT package includes 22 MW (and up to 60 MW) of supplemental firing capacity, often referred to as "duct-firing". Duct-firing involves burning natural gas and injecting the heat directly into the HRSG. Duct-firing requires little incremental investment in the CCCT installation and provides rapid ramping at a heat rate of 9,000-9,500 Btu/kWh.

NorthWestern included a single GE Frame 7FA.04 gas turbine-generator on one steam turbine-generator CCCT configuration (a "one-on-one configuration" or "1x1") for evaluation in its portfolio model. NorthWestern elected not to evaluate a 600 MW a two-on-one CCCT configuration even though it would be slightly more efficient, because it would produce much more annual energy than required to meet the needs of its customers.

Table No. 5-6

Gas Unit Comparison Table

	Provide Capacity	Standby Peaking	Integration	Heatrate
Internal Combustion	Yes	Yes	Yes	9,000
SCCT	Yes	Yes	Partial	11,000
Aero Derivative	Yes	Yes	Yes	9,500
CCCT	Yes	No	Partial	<7,000

NorthWestern Energy Siting Analysis

Since adoption of the 2011 Plan, NorthWestern has undertaken a structured effort to identify feasible sites for new gas-fired generation. This siting effort centered on finding locations in the NorthWestern service territory that will provide access to electric transmission, natural gas pipeline, water, and land use attributes necessary to successfully permit and build a new unit (or units) using the technologies identified above.

Pipeline Considerations

NorthWestern owns the intrastate pipeline infrastructure that serves natural gas load in its service territory. The NorthWestern intrastate system generally serves the same major communities as the NorthWestern electric system. Table 5-7 shows the locations where NorthWestern's intrastate gas pipeline connects to the interstate/interprovincial gas transportation system and pipeline capacity at those locations.

Table No. 5-7

NorthWestern Pipeline Connections

Pipeline	Connection Point	Nearest City	Capacity MMBtu/day
TransCanada	Carway	Cut Bank	81,600
Aden	Aden Border	Cut Bank	50,000
Havre	Blaine County #3/#1	Havre	30,000
Colorado Interstate	Grizzley	Billings	40,000*
Williston Basin	Warren	Billings	20,000*

Note: * Interruptible

The natural gas-fired generator modeled in the Plan, a 270 MW CCCT, would consume approximately 45,000 MMBtu/day at full load. A natural gas load of this size would approach or exceed the capacity of existing NorthWestern pipeline connections. NorthWestern and its direct access gas supply customers use most

of the capacity of these connections to meet existing natural gas load needs. Furthermore, the natural gas load peaks during the winter on the NorthWestern natural gas system at the same time the electric system peaks.

In addition to interstate/interprovincial pipeline delivery constraints, the NorthWestern intrastate pipeline system has significant internal constraints, particularly between Great Falls and Deer Lodge, and between Billings and Bozeman. As a result, NorthWestern will likely need to upgrade both the pipeline connections and its intrastate pipeline system to firm transportation service for any new natural gas-fired generator located in its service territory.

Water and Waste Water Treatment Availability

Cooling and cooling tower blow-down of a gas-fired generator may require significant supplies of water, as well as waste water treatment capacity. Where an IC could use closed-loop cooling requiring minimal amounts of make-up water, a conventionally-cooled CCCT (1x1) could consume up to 3 million gallons of water per day. Aero-derivative equipment suppliers can provide water-based supplemental cooling capability in order to eke out additional capacity on hot days.

As an alternative to using water to cool a CCCT, NorthWestern is considering using an air-cooled condenser ("ACC") to cool the facility. An ACC uses a large bank of electric-powered fans to provide cooling. Because of the amount of power used to operate the fans and the fact that an ACC doesn't cool a CCCT as effectively as water cooling, a CCCT with an ACC generates slightly less power at a higher heat rate than a conventionally-cooled machine. Additionally, an ACC increases the capital cost of a CCCT as compared to a conventionally cooled CCCT that uses a cooling tower. However, the ACC does require much less

waste water treatment than the water discharge from a conventionally-cooled CCCT.

Elevation

As indicated earlier, a gas-fired generator loses about 3% of its capacity for every 1,000' above sea level. By virtue of its mountainous terrain and inland location, most of the cities in Montana lie well above sea level. Havre, at approximately 2,500' is one of the lower elevation cities in Montana, while Butte and Anaconda lie above 5,000', which is where Basin Creek and DGGS are located. Billings and Great Falls, with approximate elevations of 3,100', represent typical elevations for the state's population centers.

Land Use

The physical profile of gas-fired generators blends well with an industrial landscape. In many cases, these so-called "brownfield" sites also provide good access to transmission, natural gas, and water infrastructure. Existing generation sites, such as DGGS, may also provide for easy site expansion and shared maintenance and operations services.

Equipment Operation Characteristics and Portfolio Modeling Parameters

The expected application of the gas-fired generation – SCCT for low capacity factor peak load service or higher capacity factor CCCT base/intermediate load service – could dictate site selection.

SCCT Peaking

As discussed above, NorthWestern expects the SCCT types of gas-fired generators (ICs, Frame machines, and aero-derivatives) to operate primarily to

serve winter and summer peak load. Incurring significant costs to upgrade pipeline capacity to supply peaking units for a few hours a year – in addition to the cost of firm transportation - would be prohibitively expensive for NorthWestern. As an alternative, NorthWestern may consider a strategy similar to the interruptible gas transportation/back-up fuel strategy for DGGS.

Because NorthWestern may be able to add an SCCT unit in either the Butte/Anaconda area at approximately 5,000' elevation, or the Billings (or Great Falls) area at approximately 3,500' elevation, NorthWestern elected to evaluate all SCCT alternatives at both 5,000' and 3,500' elevation for analysis purposes.

CCCT Base/intermediate Load

Even if there was no other load on the NorthWestern intrastate pipeline system, NorthWestern couldn't supply the 45,000 MMBtu daily natural gas requirement for a fully-loaded 1x1 CCCT located near existing generation in the Butte/Anaconda area. Furthermore, pipeline reinforcement costs from either the Great Falls area to the north or the Billings area to the east would make siting a CCCT in the Butte/Anaconda area prohibitively expensive. Given the significant transmission congestion south of Great Falls (and the number of MW of competing generation projects ahead of NorthWestern in the OATT interconnection and transmission service study queue), a CCCT in the Billings area may be the only feasible location for connection of this technology to the NorthWestern electric system. For these reasons, a CCCT was modeled only at the 3,500' elevation in the Billings area. Additionally, because of the uncertainty surrounding the availability of water, modeling was limited to ACC units.

Resource Cost Summary

Table 5-8 is a summary of resource costs developed for consideration in the 2013 Plan. As discussed in other places in the Plan, many of these resources

have not been carried forward into the portfolio analysis due to the Hydro Acquisition.

Table No. 5-8

Resource Cost Summary
($2013)

Resource Description	Fuel Source	Technology	Nameplate Capacity (MW)	Net Capacity @ 3,500 feet (MW)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Heat Rate (Btu/kWh)
CCCT (1x1)	Natural Gas	GE 7FA.04 ACC[1]	270	239	$1,425	$13.94	$3.60	6,660
SCCT - Small Aeroderivative	Natural Gas	PW FT8	60	53	$917	$6.05	$4.60	10,500
SCCT - Large Aeroderivative	Natural Gas	GE LMS100	110	97	$1,087	$17.06	$3.47	8,722
SCCT - Frame	Natural Gas	GE 7EA	90	78	$897	$11.73	$3.20	11,289
Internal Combustion - Recips	Natural Gas	CAT G16CM34	54	52	$1,402	$18.39	$8.15	9,078
Solar PV	Solar		10	10	$3,136	$27.00	$0.00	n/a
Wind[2]	Wind		25	25	$1,524	$49.18	$0.00	n/a
Hydro - Montana Large Scale[3]	Water		439	439	$1,982	$52.58	$0.00	n/a

1 ACC = Air Cooled Condenser
2 Based on build-transfer bids received in NWE's 2012 CREP RFP
3 Excludes KERR costs and capacity

CHAPTER 6
PORTFOLIO MODELING AND ANALYSIS

CHAPTER 6

Ascend's analysis identifies the Hydro Acquisition as the preferred resource portfolio. The Hydros provide a balanced supply portfolio at the lowest long-term risk-adjusted cost.

Background

In prior resource plans, NorthWestern used GenTrader® to model resource portfolios. The MPSC, when commenting on the 2009 Plan and 2011 Plan, requested that NorthWestern explore alternatives to GenTrader. Early in the 2013 Plan cycle, NorthWestern contacted several software vendors to determine the capabilities of their models and the scope of vendor support for the use of their models in developing the 2013 Plan. NorthWestern selected Ascend Analytics ("Ascend") of Boulder, Colorado, to model the Montana supply portfolio, commodity prices, new resources, and an expanded set of variables using its PowerSimm suite of products. Simply purchasing a license agreement from Ascend was not an option based on the work product delivery schedule for the 2013 Plan. PowerSimm is a useful tool for analyzing portfolio costs and risks, and for developing a common understanding of costs and risks with stakeholders. When the Hydro Acquisition[1] was announced, Ascend's scope of work was expanded to include supporting analysis and work products for the Hydro Acquisition, adding a third resource portfolio to the 2013 Plan.

[1] See Chapter 5 for a description of the resources included in the Hydro Acquisition.

Prior planning analysis constructed an "efficiency frontier" rather than quantifying risk. Ultimately, the choice of a portfolio involved subjective choices. Instead of subjective measures, PowerSimm quantifies portfolio risk as a value in a non-subjective manner. Although NorthWestern selected Ascend prior to any discussion of the Hydro Acquisition, this feature is proving to be useful in comparing the costs and risks (in total) of various resource planning scenarios. This chapter describes the results of the PowerSimm analysis, including; the underlying simulation and validation methodology, the approach used to value and monetize risk, and the portfolio- and unit-level results from the simulations. More technical results are included in Volume 2, including detailed simulation results, generating asset performance outputs, and validation results.

At NorthWestern's direction, Ascend modeled the short-term and long-term cost and risk implications of three portfolios over the planning horizon. The first portfolio is referred to as the "Current" portfolio and consists of NorthWestern's currently-owned and contracted generating assets, and quantifies the costs and risks of relying on market purchases to meet the utility's electricity supply obligations into the future. This portfolio is referred to as the Current portfolio because without the acquisition of physical resources, these are the resources NorthWestern would depend on to meet customer loads. The second portfolio adds the 633 MW Hydro Acquisition to the Current portfolio beginning in October of 2014 and is called "Hydro" portfolio. This portfolio adds substantial energy and capacity to NorthWestern's resource portfolio and reduces the exposure to gas and power market prices. The third portfolio adds an un-sited, 239 MW (adjusted for elevation) gas-fired combined-cycle generator to the NorthWestern Current portfolio in 2018 and is called the "CC" portfolio. This portfolio represents the most likely alternative to the Hydro Acquisition and would also reduce NorthWestern's market exposure to market power purchases.

Ascend has designed its modeling approach to incorporate best practices in resource modeling. The PowerSimm software platform used in this analysis explicitly captures the impact of load variability, renewable generation, and market prices on the distribution of possible portfolio-level costs. PowerSimm models the operation of NorthWestern's resources in the context of a validated regional market simulation, capturing the costs and net position of the portfolio across a wide range of possible futures. The analysis is performed at an hourly time-step in order to capture the unique operating characteristics of renewable resources and flexible resources able to respond rapidly to changing market prices.

Ascend's modeling approach focuses on introducing "meaningful uncertainty" into simulations of the future, capturing both the expected value and the risk value associated with the three portfolios. The simulation engine models both physical and financial uncertainty, with defined structural and covariate relationships between variables that adhere to rigorous validation requirements. The variables represented by the model include financial components of forward/forecast price simulations for major commodities. The physical dimension of spot energy include critical structural relationships driven initially from the central risk factor of weather, which then drives load, wind generation, and hydro production, and then spot prices for gas. Spot power prices are a function of load, wind, hydro generation, and spot gas prices. These simulated variables, in turn, drive operationally-based models of the hourly generation of the current and future resource options available to NorthWestern, leading to an economically optimized dispatch of generation costs for each portfolio. This stochastic simulation approach is superior to traditional methods, which generally run deterministic simulations on expected values of input variables and thus miss out on the range of possible outcomes of portfolio costs.

The use of stochastic analysis allows for a full characterization of the expected costs and uncertainty surrounding the costs of each portfolio. For this Plan, the economic comparison between the divergent risk profiles of the portfolio choices becomes equalized through the monetization of the of the value risk. Ascend denotes the value of uncertainty in costs by calculating the "risk premium" associated with each portfolio. This captures the likely magnitude of costs above the expected value. By adding each portfolio's risk premium to its expected levelized annual cost of energy, the analysis quantifies risk using a single number that is more directly comparable across portfolios than traditional approaches such as cost-at-risk or efficient frontier analysis. This approach streamlines the decision-making process, allowing both cost and risk to be quantified on an expected-value basis and allowing direct comparison between portfolio options of different risk profiles.

The results of the analysis indicate that the Hydro Acquisition, modeled in the Hydro portfolio, has an approximately 6% lower NPV over the study horizon than either the Current portfolio or the CC portfolios, albeit with a slightly higher costs in the 2014-2020 timeframe due to the fixed costs of the investment in hydro generation. Importantly, the Hydro Acquisition also has substantially less exposure to gas and power market price increases than either the Current or the CC portfolios. The Hydro portfolio has a net present value of risk premium of $245 million versus $451 million for the Current portfolio. The annual costs to NorthWestern's ratepayers, therefore, are likely to be much more stable with Hydro Acquisition in the portfolio than without it.

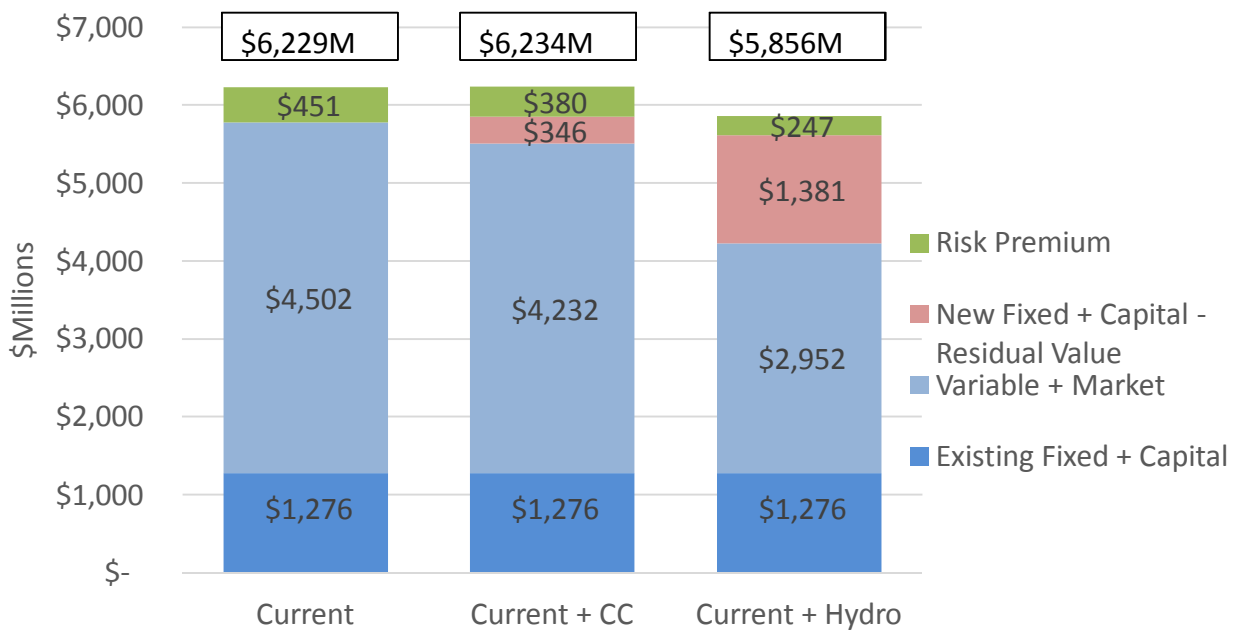
Summary of Results

The net present value (NPV) cost of energy service over the study horizon is presented below in Figure 6-1. Costs are broken down by current portfolio fixed costs, variable operating costs including market purchases and sales, and

annualized capital expenses and fixed operating costs added in the CC and Hydro portfolios. The risk premium adder on top of the portfolio costs is significantly smaller for the Hydro portfolio than the other two, and together, the analysis shows that the Hydro Acquisition will reduce risk. The residual values of the hydro and CC assets are accounted for in the model and represent the present value of their residual worth at the end of the study horizon, under the assumption that hydro generation rights and land ownership do not depreciate in the future. The NPV of the residual value for the CC and Hydro resources is $9 million and $212 million respectively, and is subtracted from the NPV of the new fixed plus capital costs of the assets in Figure 6-1.

Figure 6-1

Net Present Value of Portfolio Costs, 2015-2043

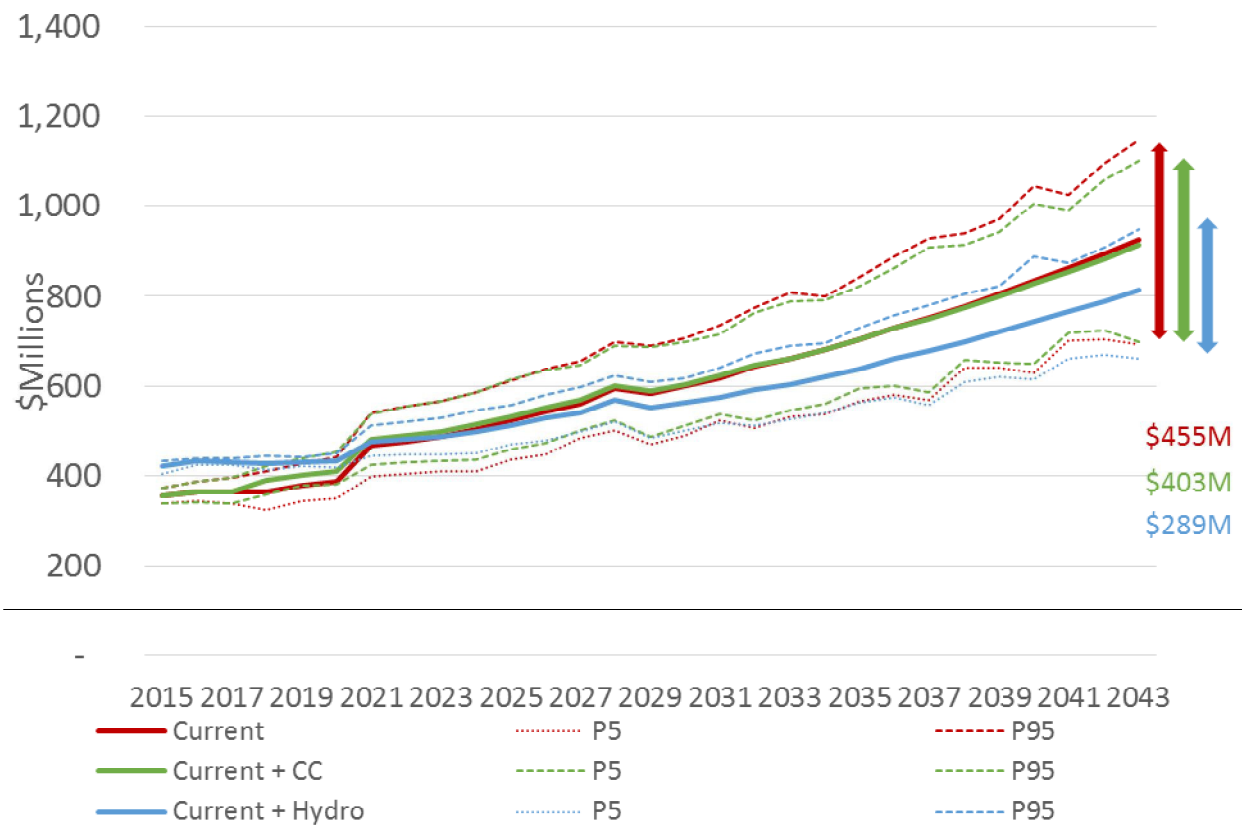


The estimated annual cost streams of the three portfolios are markedly different. Figure 6-2 shows the modeled mean costs of each portfolio in each year of the study, as well as the 5th and 95th percentile bounds on the costs. The Hydro portfolio is higher cost in the early years of the study, due to the capital

investment required, but then declines below market portfolio costs in the early 2020's, as hydro generation makes up for its higher fixed costs by offsetting high-cost market purchases. The costs of all portfolios increase in 2021 because of the cost of CO_2 emissions, discussed below. Figure 6-2 reflects revenue requirements related to the wholesale cost of power and include power purchases and sales, fixed and operating costs from existing and new generation assets, but excludes transmission, distribution, and other indirect delivery components of NorthWestern's annual revenue requirement.

Figure 6-2

Annual Portfolio Cost Confidence Intervals



The arrows and numbers shown on the right of Figure 6-2 represent the spread in annual costs between the 5th and 95th percentile at the end of the study period. As is visually apparent, the spread in cost between the 5th and 9th percentiles of the Hydro portfolio is much narrower than the spread of the other two portfolios' distributions, representing the reduced exposure to market price increases that the Hydro Acquisition offers.

While the economics of the hydro generation portfolio are compelling relative to the other two portfolio options evaluated, the addition of the hydro assets to NorthWestern's current portfolio fulfills a critical need for capacity to economically serve load obligations. The current supply portfolio of NorthWestern leaves the company short of resources relative to load obligations. The average annual net position of NorthWestern's current energy supply position shows a deficit in Figure 6-3 of approximately three million MWh in 2017, of which the hydro assets could supply more than 80%. The hydro assets fulfill a core obligation of physical supply and substantially reduce the large open position exposure in NorthWestern's supply portfolio.

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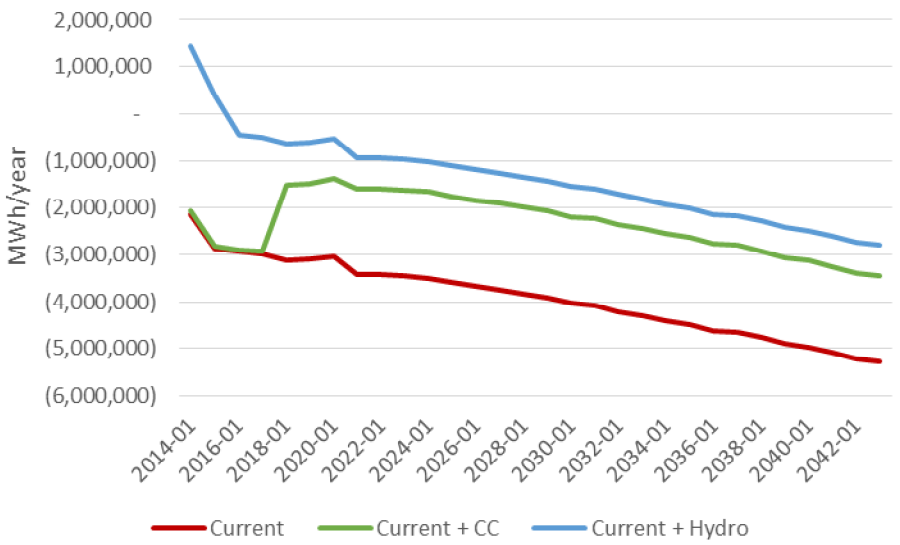
Figure 6-3

Annual Net Position by Portfolio



Planning Under Uncertainty

For this analysis, Ascend used a systematic approach to derive probabilistic distributions for uncertain future conditions. To support the notion of "meaningful" uncertainty, Ascend has developed a broad set of validation reports for each risk factor and their covariate or structural relationships to other risk factors The end result probabilistically envelopes the uncertainty in future market price paths and physical conditions. The generation supply portfolio is economically dispatched to these market conditions. The approach of this analysis represents a significant improvement over traditional resource planning methodologies, by emphasizing several current best practices of resource planning centered around the use of stochastic modeling and the introduction of meaningful uncertainty into the planning process. These considerations and their advantages are discussed briefly in the following sections.

Stochastic Versus Deterministic Modeling

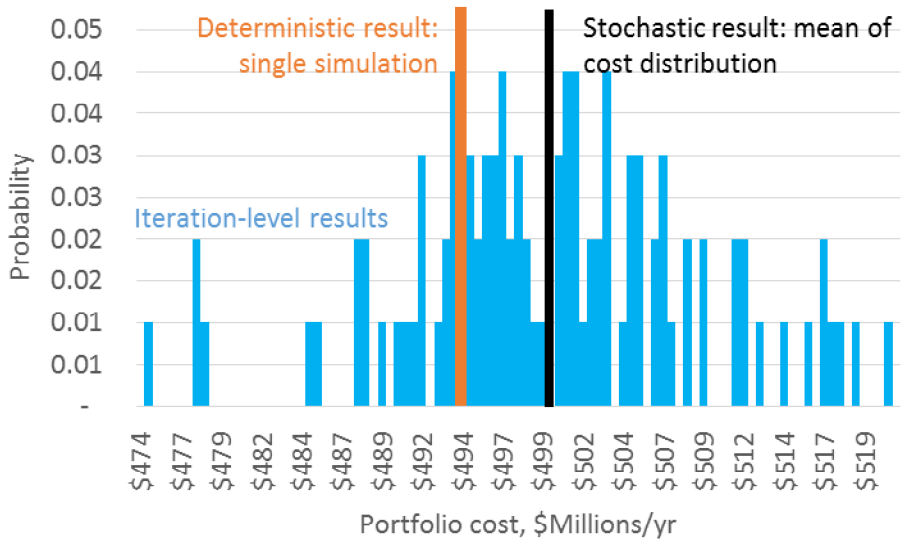
In the past, utility planning has often been performed using deterministic or scenario analysis. This methodology can often miss important aspects of long-term analysis that are associated with uncertainty of future conditions or the correlation of simulated commodity prices and physical conditions (weather) that drive load and renewable generation. Combining risk-based analysis with discrete portfolio investment choices (i.e. the Hydro Acquisition) supports an integrated view of operational and financial analysis.

Traditional scenario analysis provides insight into planning choices, but the nature of a scenario-based, deterministic view of future conditions introduces inherent biases and inconsistencies. Figure 6-4 illustrates the differences between using a deterministic versus a stochastic approach to estimating portfolio costs. Each blue bar represents the aggregation of costs into probability bins. Realizations of future conditions with similar total portfolio costs are aggregated into the same blue cost bins (rectangular bars). Higher probability costs bins occur at the center of the distribution and lower probability events occur at the tails of the distribution. Each cost bin represents the probability of obtaining levelized annual portfolio costs for the "Current" portfolio option within a given range, under the full spectrum of uncertainty of future conditions. The orange bar is an illustrative deterministic result, showing the output of a single cost simulation that only uses expected values for uncertain variables. The black bar, representing the average of all possible outcomes, is the expected value of costs (mean costs) from the stochastic analysis. The mean costs from the simulated values is a more robust and accurate estimate of future costs than a single deterministic simulation. The difference between the mean of annual costs for all simulated input values versus the deterministic run shown in Figure 6-4 differ by $5 M per year, or more than $60 M NPV over the course of the study.

This large cost difference is a result of the natural variability in commodity prices, weather, load, wind, and hydro being larger than can be reflected in a single future scenario designed to reflect "normal" conditions.

Figure 6-4

Distribution of Annual Portfolio Costs – Current Portfolio



The inherent importance of input assumptions in a deterministic analysis can create conditions where each stakeholder has their own preferred set of inputs. The determination of an optimal Plan becomes a direct function of the selected inputs. Thus, each stakeholder may see a different preferred plan. Sorting through the diverging views becomes akin to selecting the true image from a Rorschach diagram in psychology. By using a stochastic simulation approach, the current analysis probabilistically envelopes the full range of expected future conditions in order to arrive at a robust estimate of portfolio costs, and avoids the problem of portfolio selection based on a limited, deterministic representation of possible future conditions.

The nature of deterministic scenarios also tends to limit the extent of extreme cases. For example, a "high price gas" scenario or sensitivity test in a traditional planning study may increase gas prices by 50%. However, commodity prices for power and gas have shown the potential to increase several hundred percent, but are commonly followed by a rapid retreat back to the long-run mean. Disequilibrium events and scarcity shocks in prices are generally followed by a sharp mean reversion as demand abates, and supplies increase, with higher prices. The common whipsaw pattern of commodity price shocks often diverges from the monotonic nature of traditional scenarios runs. The inability of scenario runs to capture the shape of individual commodity price patterns further limits the use of scenarios to capture the integrated dimension of uncertainty. This realistic representation of commodity price patterns produces a "normal" shaped distribution of levelized costs. While the distribution of costs for a select year may be positively skewed, the levelized cost distribution over the full simulation horizon has the combined effects of: 1) mean reversion, which limits the duration of extreme events to generally less than a year, and 2) the rule of large numbers, which averages away the upper tail of costs.

The integrated dimensions of uncertainty commonly compound risk. For example, sharp increases in gas prices are commonly followed jointly by increases in the price of power and coal. Additionally, low water supply years on the Columbia system are often accompanied by high electricity prices, further exacerbating the drop in hydroelectric production for utilities dependent on the Columbia system. A traditional, deterministic analysis typically models portfolio costs assuming one trajectory for important system drivers like load, market and fuel prices, and renewable generation; often, the values used are the expected values. However, it is generally not the case that for complicated systems such as utility resource portfolios, the expected value of portfolio costs under a wide

range of uncertain inputs is the same as the portfolio cost assuming the expected value of each input. In other words, representing future conditions with single, deterministic trajectories can yield different cost estimates than taking the average of portfolio costs over the full range of future conditions, as illustrated in Figure 6-4.

Traditional resource planning studies have been limited, for computational reasons, to a scenario framework for modeling different trajectories for commodity prices or load into the future. For example, traditional resource plans commonly model "low" and "high" gas or market price scenarios, holding price trajectories low or high for the duration of the study. As discussed above, this approach can lead to unrealistic representations of market prices relative to expected trajectories of market prices. The present study, instead of relying on price scenarios with distinct price trajectories, simulates realistic price trajectories using forward/forecast prices, with time series models that capture volatilities of prices and correlations based on observed and expected price uncertainty, observed patterns and covariate relationships. In doing so, this analysis introduces meaningful uncertainty into price simulations, rather than just introducing noise into expected value forecasts, and produces price trajectories whose variability conforms to current market expectations.

CO_2 Price Simulation

The present analysis treats the uncertain future price of CO_2 emissions stochastically. As a participant in the multi-state regional market in the Northwest, NorthWestern is exposed to risk not just from a Montana-specific CO_2 emission penalty, but also a potential federal tax or cap-and-trade system, as well as other state-specific or regional CO_2 emission reduction policies. Any such policy will likely impact the price of electricity in the regional market, as well as the effective

production cost of NorthWestern's owned or contracted generating assets. Even if such a policy is not enacted for environmental reasons, recent experience has proven that a price on CO_2 can be a politically palatable alternative to other means of raising revenue in states with budget imbalances. Because this revenue is raised via electricity bills and not direct taxation, such a policy redirects the public resistance inherent in introducing new taxes, and places blame on utilities instead of policymakers. California, for example, expects to generate $500 million in 2013 with its emission permit auctions, rising significantly in coming years[1], and has joined with several other Western states and provinces in a commitment to a regional CO_2 emissions abatement plan[2]. Oregon and Washington announced this past October their intent to join California in adopting carbon emissions legislation.

Given the regional nature of the wholesale power market and the revenue impact a price on CO_2 may have on Montana or neighboring states, NorthWestern has found it prudent to model a conservative price of CO_2, lower than many regional utilities' projection, in this analysis. The price of CO_2 is simulated by drawing from a triangular distribution, centered around the expected CO_2 cost used elsewhere in NorthWestern's valuation and planning studies, with trajectories rising and falling year-to-year to represent the expected volatility of emission permit prices. This volatility has been observed in other regional carbon markets (Europe and California) and is an important driver of the overall uncertainty in portfolio costs. A stochastic representation of the price of CO_2 emissions fully captures the impact of this volatility on NorthWestern's portfolio costs, versus a deterministic price simulation which would leave out this important dimension of risk.

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[1] http://online.wsj.com/news/articles/SB10001424127887323734304578541822111512316

[2] http://www.bloomberg.com/news/2013-10-28/western-u-s-states-british-columbia-sign-climate-change-pact.html

Risk-based Decision Analysis

Stochastic models can improve the accuracy of estimated future costs, and provide a fuller picture of the range of possible outcomes. The next step is to integrate a quantification of risk into the portfolio selection process. Traditional planning approaches, if they deal with uncertainty at all, typically quantify risk using metrics such as cost-at-risk, and use both this risk metric and expected costs to drive the resource selection decision process. This places the burden of weighing the value of risk on the planner, and can encourage multiple interpretations of the results and different rank ordering of portfolio options. The current analysis integrates the measure of risk into the portfolio cost results by calculating a "risk premium," described in detail later in this document, allowing a single rank ordering of portfolio costs and thus streamlining the decision analysis process.

Table 6-1 outlines some of the important sources of uncertainty present in utility planning. The effect of each risk factor on its own may be limited relative to the integrated dimensions of risk. For example, causal effects such as weather on load and wind generation and correlated effects such as gas and coal prices can exacerbate the portfolio-wide risks beyond uncertainties realized through single-variable sensitivity analysis. Traditional planning tools such as production cost models and/or load duration curve-based expansion planning models effectively limit decision analysis to sensitivities. In contrast, best practices in planning today seek to integrate the central risk factors into a unified simulation framework with verifiable simulations. This more robust treatment of uncertainty in an integrated risk modeling platform is used by Ascend in the present study. The simulation methodologies of integrating the risk factors listed in Table 6-1 are

discussed later in this chapter. All three portfolios are evaluated against the same set of simulated future conditions.

Table 6-1

Treatment Of Uncertainty In Resource Planning Modeling Tools		
Uncertainty Factor	**Traditional Tools**	**Integrated Risk Planning Models**
Load growth	Fixed	Simulated uncertainty
Load patterns	"Typical" profile	Uncertainty in profile and usage pattern
Weather	Fixed	Weather drives demand and causes renewable generation
Hydro	Fixed	Simulated seasonal, daily operations
Wind	Fixed	Simulated with weather
CO_2 emissions	Fixed	Simulated based on uncertainty in costs
Gas & power prices	Fixed	Simulated monthly, daily & hourly prices
Transmission	Fixed Input/Output	Variable flow contingent factors
Forward/Forecast prices	N/A	Simulated forward curves

Modeling Framework

Ascend's modeling process proceeds in two broad steps. First, the PowerSimm simulation engine uses physical relationships of energy supply and observed price patterns to build trajectories of future forward and spot prices. By maintaining the fundamental structural relationship between weather, load, wind and hydro generation, and then market prices, PowerSimm develops realistic simulations of future conditions to probabilistically envelope the expected value and range of potential future scenarios. Second, PowerSimm simulates the operation of all generating units and use of instruments in each of the three portfolios, each using the same realizations of future variable values, in order to calculate the range of portfolio costs. Figure 6-5 shows the overall process flow for the PowerSimm simulation framework.

The simulation of future conditions is initiated with prior-to-delivery simulations of forward/forecast prices and regional hydro conditions shown in the lower left of Figure 6-5. Upon evolution of the forward/forecast prices to the final evolved monthly price expiration, the during-delivery simulations of spot conditions are initiated with the simulation of weather shown in the upper right box of Figure 6-5. The weather simulations then drive renewable generation and load. Spot prices are then simulated as a function of load, renewable generation, and other potential variables of supply. For each iteration, the simulated hourly spot prices for the month are scaled to be consistent with the final evolved heavy load and light load forward/forecast price simulation. Generation dispatch is optimized to the calibrated spot price simulations shown in the lower right of Figure 6-5. Further detail about each step is described in the following sections.

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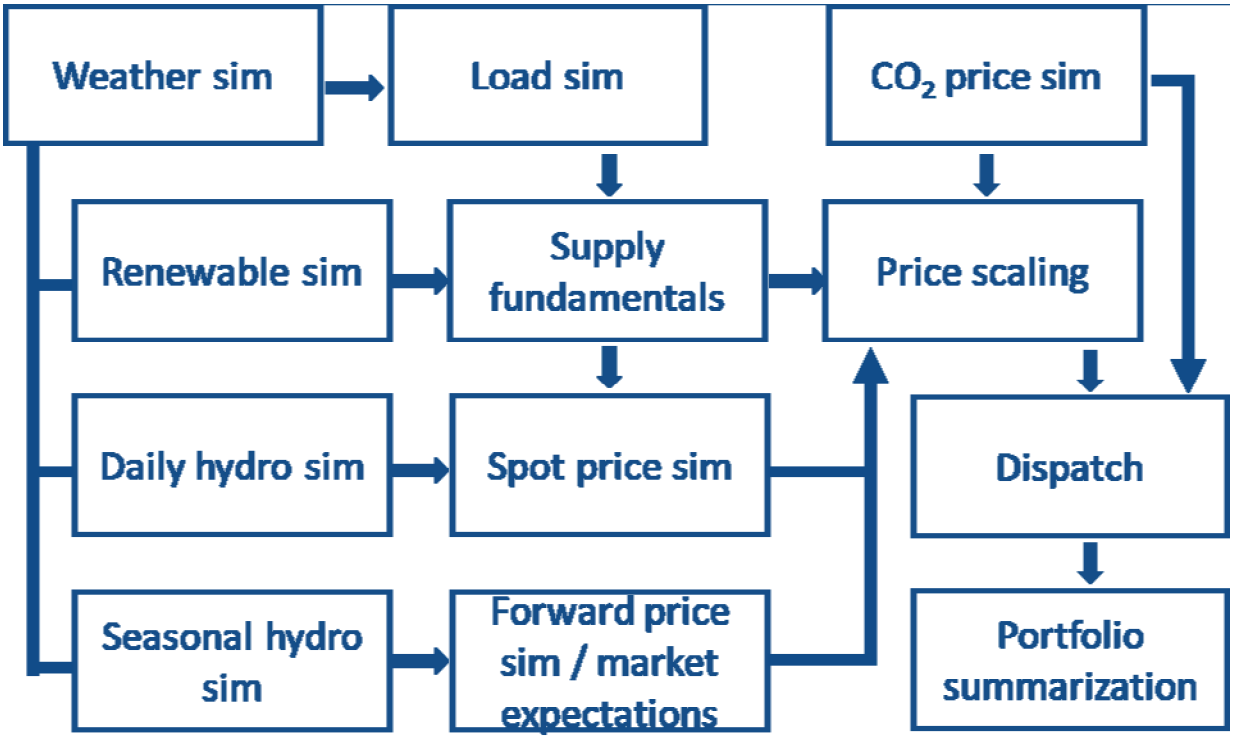
Figure 6-5

PowerSimm Process Flow Diagram



The simulation framework of PowerSimm addresses uncertainty as viewed through today's market expectations (forward/forecast prices) and the future realized delivery conditions for load, spot prices, and generation. The framework to simulate physical and financial uncertainty follows the process flow of Figure 6-5. The simulation of spot market prices further extends the simulation of forward/forecast prices to model spot price conditions based on structural relationships such as weather on load, load on market prices (gas), and then gas and load on electric prices.

Simulation of Commodity Prices and Physical Components

Simulation of electric system and customer loads follows from a common analytical structure that seeks to preserve the fundamental relationship between

demand and price. The simulation process is divided into two separate components: 1) prior to delivery and 2) during delivery. The prior-to-delivery simulation of forward/forecast prices shown in Figures 6-6 through 6-9 evolves current expectations through time from the start date to the end of the simulation horizon. The simulations during delivery capture the relationship of physical system conditions (i.e., weather, load, wind, run-of-river hydro, unit outages, and transmission) on market prices. The inter-relationship between prior-to-delivery and during-delivery simulations is central to linking expectations to realized observations.

For forward/forecast prices representing prior-to-delivery simulations, monthly prices are evolved into the future from the current forward/forecast prices through expiration of each contract or forecast month. This process of evolving forward/forecast prices into the future draws on the observed behavior of forward contract variability and covariate relationships to create future monthly price projections. Within each prior-to-delivery simulation, observed commodity prices behavior, volatility, rate of reversion, and covariate relationships across commodities drive price movements to ultimately arrive at a final evolved price at delivery. The average of these final evolved prices across all simulations for each monthly price will equal the current forecast expectation of the price at delivery. Similarly, the average of the simulated electric spot prices for a given month will equal the current forecast price for that month. Seasonal hydro conditions are also correlated with the simulated forward/forecast prices.

The during-delivery simulation process begins with simulation of weather. PowerSimm simulates minimum and maximum temperature for Montana weather stations using a cascading Vector Auto-Regression (VAR) approach. This approach maintains both the temporal and spatial correlations of weather

patterns for the region. Ascend applies a cascading VAR approach to maintain inter-month temperature correlations consistent with the historical data. For example, if a hot July day is likely to be followed by another hot July day, the cascading VAR method captures this effect. The application of weather simulations supports the analysis of uncertainty through hundreds of weather scenarios without the limitation of the pure historical record where extreme weather events beyond observed conditions may occur (but with a low probability). The second step of the process combines these weather simulations with other factors in the load simulation process, described in the next section.

Load and Price Simulation

PowerSimm uses the weather simulations as well as forecasted input load values, scaling and shaping the simulated load shapes to match forecasted monthly demand and peak demand values. The simulations of electric load use a state-space modeling framework to estimate seasonal patterns, daily and hourly time series patterns, and the impact of weather. The state-space framework of PowerSimm produces results that reflect the explained effects of weather and time-series patterns and the unexplained components of uncertainty.

The during-delivery simulation of prices addresses the more intuitive simulations of system conditions and spot prices. System conditions of unit outages, supply stack composition, system imports and exports, and transmission outages are separated independent of weather but can also serve as determinants to the spot price of electricity. The stochastic simulation approach of PowerSimm applies a random component to capture the uncertainty in hourly prices and their covariate relationship, which yields better benchmark results than a fixed profile with variable daily levels.

Hourly Analysis

Many utility resource planning studies have used capacity expansion optimization heuristics based on load duration curves or other methods that approximate operational characteristics and costs of resources without explicitly modeling the hourly attributes of generation. However, these simplifications fail to capture several important aspects of resource performance characteristics, such as the intermittent nature of renewable generation and the differences in flexibility between traditional generating assets. PowerSimm performs the simulation of system variables described above and optimizes the operation of each resource at hourly resolution over the course of the study horizon in order to fully capture the operational details that drive total portfolio cost.

Market-based Operational Modeling

The present analysis models NorthWestern's resources as price-takers in a validated simulation of the larger Northwestern market. By modeling NorthWestern's portfolio in the broader context of regional market dynamics, the analysis better captures operational flexibility and the potential for economic purchases and sales. While this approach may be distinct from a planning process where resources are optimized to meet load obligations, the inclusion of market interactions provides a more accurate representation of operating economics and position management.

Renewable Generation

Montana's renewable resources requirement to serve 15 percent of load obligations with renewable generation by 2015 makes renewable resources a substantive and core component of NorthWestern's future supply portfolio. The renewable resources modeled in the analysis consisted of three wind generation projects: 1) Judith Gap, 2) Gordon Butte, and 3) Spion Kop. The wind generation

from these projects is grown annually to be consistent with load growth, net of demand-side management, to meet the 15 percent requirement. The simulation of hourly and daily pattern of wind follows directly from the historic relationship of wind generation and weather conditions. By capturing the dynamic relationship of wind with weather, the Ascend modeling approach provides a dynamic representation of the physical drivers underlying system operation, including load and renewable generation. By explicitly modeling weather, a fundamental driver of both load and renewable generation, as well as the relationship of load and wind with market prices, the analysis captures a critical dynamic of weather, load, renewables, and prices that drives the operating characteristics of electric power systems. This structural modeling approach supports the study goal of introducing "meaningful" uncertainty in future load, price, and renewable generation simulations.

Forecasted Model Inputs

The forecasted inputs into PowerSimm consist of forward prices, general economic modeling assumptions and load growth, and the cost of CO_2 emissions. These are described in more detail in the following sections.

Commodity Forward Prices

In order to capture meaningful uncertainty in its simulation of future states, PowerSimm relies on current expectations of forward/forecast prices, market expectations of price volatility, fundamental market relationships, rate of mean reversion, and correlations of simulated prices through time. The simulated forward/forecast commodity prices include power at the Mid-Columbia hub (Mid-C), natural gas at AECO delivery, and Powder River Basin (PRB) coal. For each commodity, current monthly forward prices through 2020 are combined with forecast values thereafter to generate forward/forecast prices that rise at inflation

through the end of the study horizon. During the simulation of potential future states, prices are scaled such that the mean of all iterations' results match the expected prices given by the forward curve value for each month.

Forward curves and price projections in nominal dollars covering the study horizon for each commodity are shown in the charts below.

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Figure 6-6

Mid-C Heavy Load Hour Price Forecast

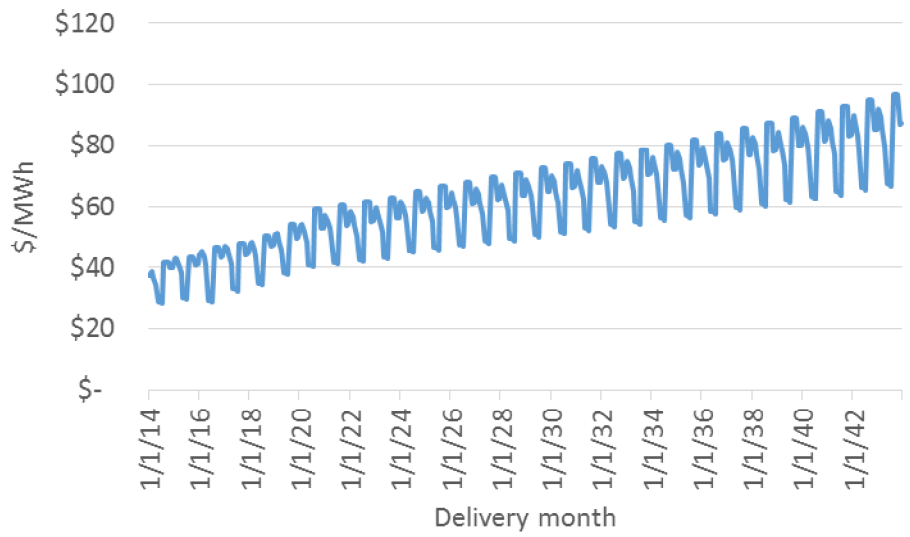


Figure 6-7

Mid-C Light Load Hour Price Forecast

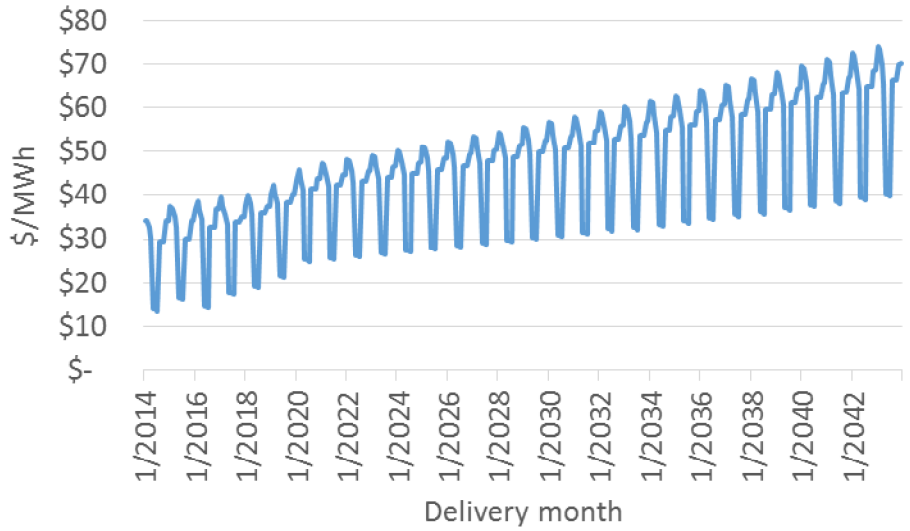


Figure 6-8

AECO Gas Price Forecast

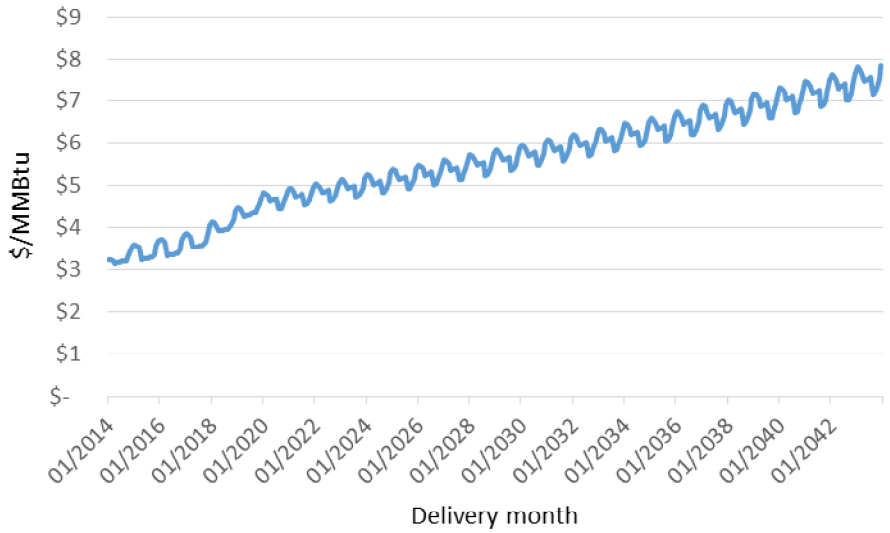
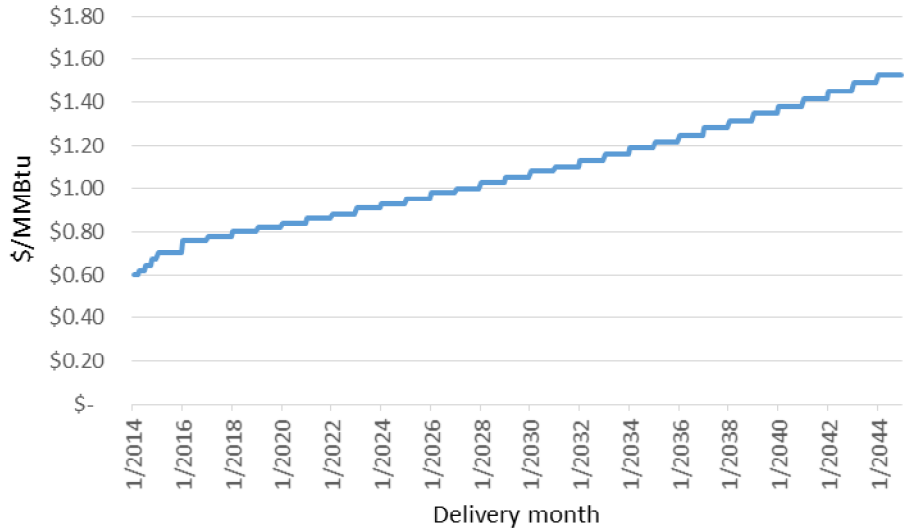


Figure 6-9

PRB Coal Price Forecast



Economic Inputs & Load Forecasts

Besides commodity prices, other inputs to the PowerSimm analysis for NorthWestern are shown in Table 6-2 below. An inflation rate of 2.1% per year is used to scale current costs (e.g. generator variable operating costs) to future year (nominal) values, and also used to scale commodity price inputs after 2020. 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. Load growth, including the impact of demand-side management (DSM), is shown in Figure 6-10.

Table 6-2

Fundamental Inputs to PowerSimm Analysis for NorthWestern Energy

Input	Value
Inflation	2.1%/year
Weighted average cost of capital (WACC)	7.14%
RPS compliance	15% of energy from wind from 2015 onwards
Load growth	~1.07%/year

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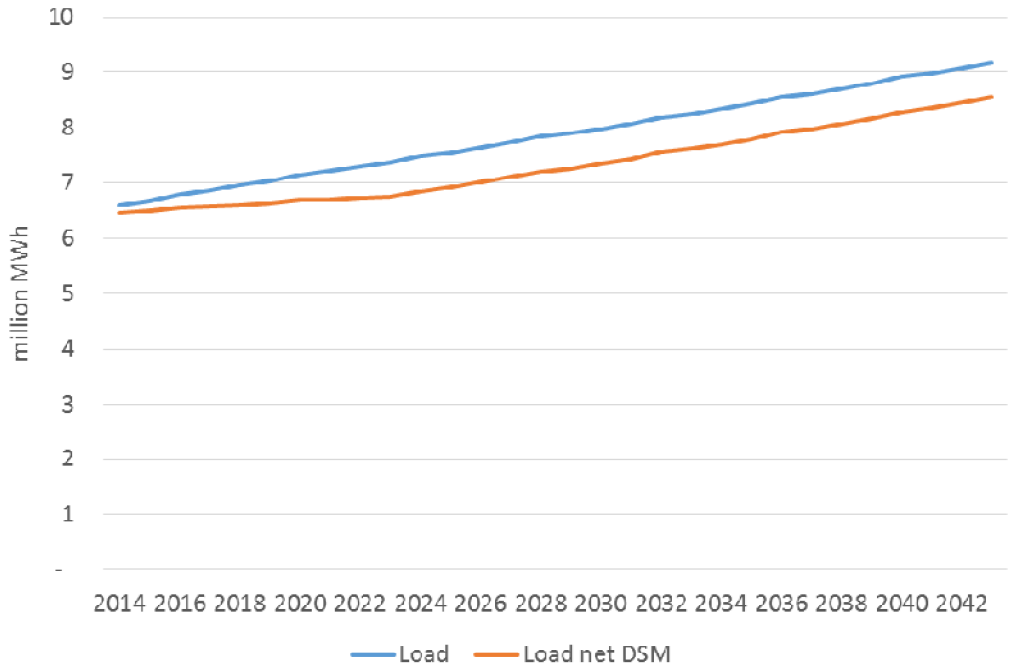
Figure 6-10

NorthWestern Retail Load Forecast



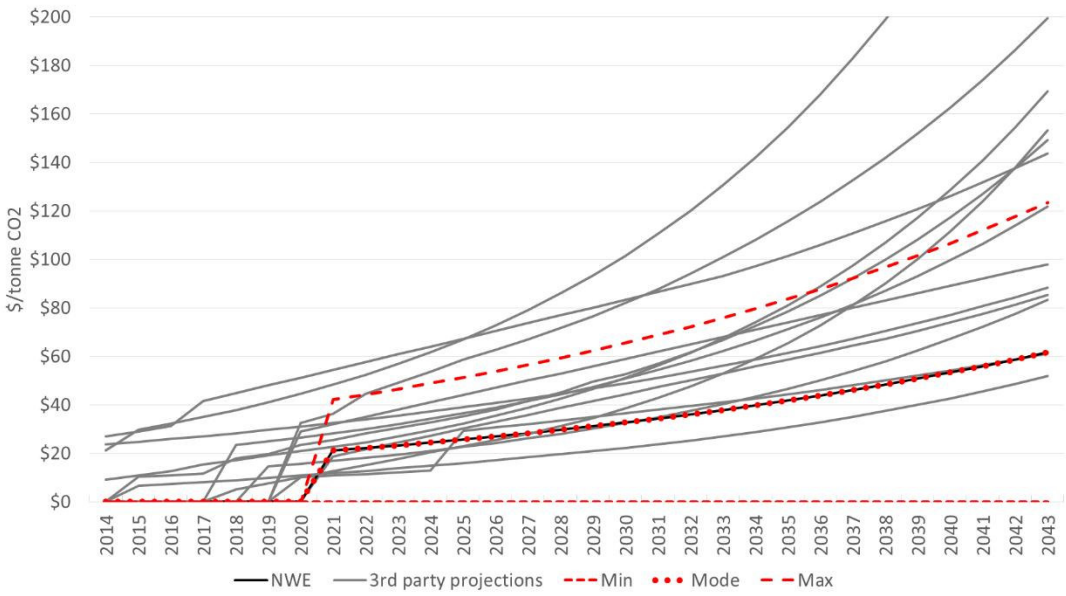
CO_2 Price Projections

The uncertain price of CO_2 through the study horizon introduces considerable risk to NorthWestern's costs in future years. For this analysis, Ascend defined a cost distribution centered around NorthWestern's pre-existing forecast cost of CO_2 emissions explained in Chapter 5. PowerSimm used a triangular distribution with a minimum value of zero, a mode and mean of NorthWestern's expected CO_2 price, and a maximum value of twice the mode. These projections of CO_2 price are shown by year in Figure 6-11, and the probability density for 2021 is shown in Figure 6-12. The expected cost starts at $21.11/tonne (nominal) in 2021, escalating each year at 5%. The grey lines in Figure 6-11 represent the cost

forecasts published and used for planning at other regional utilities[3]. These curves are drawn from publically-available regional utility planning studies, converted to nominal dollars when necessary, and scaled out to 2043 at the annual rate of growth present at the end of each utility's published projections. The assumed distribution of future CO_2 costs captures a majority of the cost forecasts of other regional utilities and forecasting bodies, but falls well short of many of the higher CO_2 price forecasts. As such, the cost distribution used in this analysis represents a conservative estimate of the likely future price of CO_2, as seen by other stakeholders in the Western market.

Figure 6-11

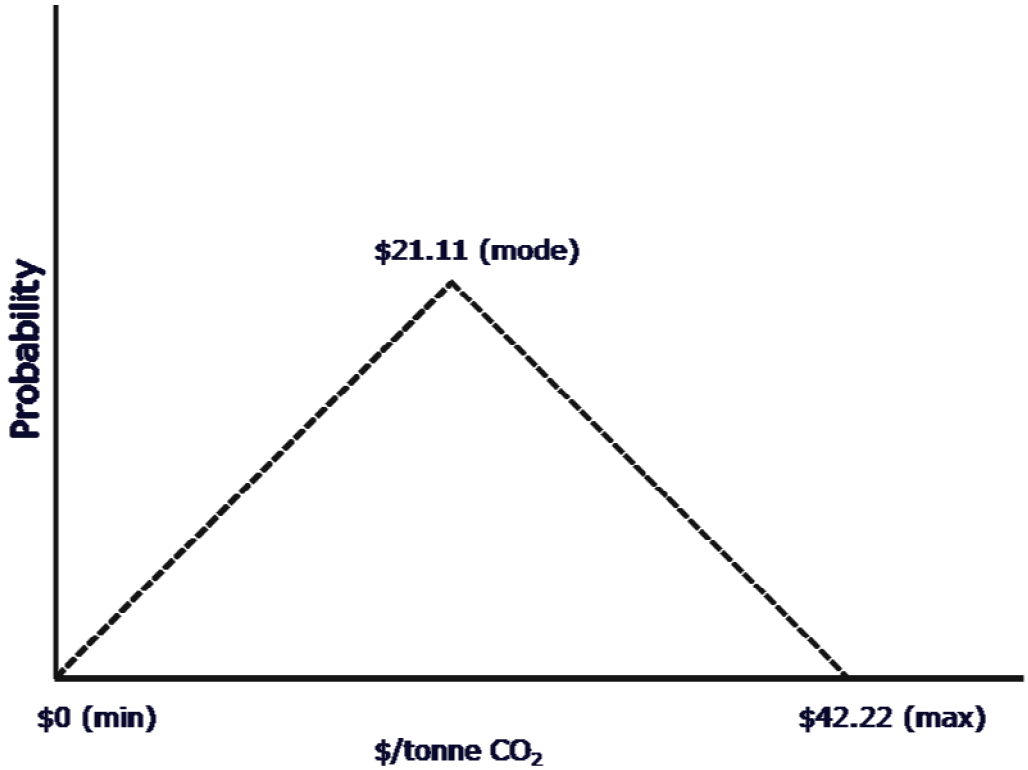
CO_2 Price Projections & Assumed Triangular Distribution



[3] Utility documents analyzed include: Arizona Public Service (2012), Avista (2013), Idaho Power (2012), PacifiCorp (2013), Portland General Electric (2012), Puget Sound Energy (2013), Seattle City Light (2012), Tacoma Public Utilities (2012), Tucson Electric Power (2012), Xcel Energy - NM (2012), Snohomish County PUD (2012), and Tri-State G&T (2010).

Figure 6-12

CO_2 Price Triangular Distribution Example: 2021



The CO_2 price realized in each year of each iteration affects the market price of power at Mid-C as well as the production cost of NorthWestern's owned resources. CO_2 costs are added to the electricity price by multiplying by 0.6, a common industry assumption that reflects the emissions factor of the marginal unit. The production costs of NorthWestern's thermal resources incorporate the price of CO_2 multiplied by each unit's emissions factor.

Summary of Simulation Validation Results

Model validation and benchmarking is an essential part of the risk management and planning process. Ascend has developed tests designed to verify model calibration to the input data and ensure accuracy and consistency of the

PowerSimm simulation output. These validation tests provide insight into the simulations and build confidence in using the results as tools for informed decision making.

Apart from routine checks of the input data for outliers or other anomalies, the majority of the validation effort is focused on ensuring that the model output is appropriately calibrated to the historical input data. The stochastic simulation methodology used by PowerSimm generates trajectories of future conditions of weather, load, and market prices, which define ranges of potential future states over which generation, cost of supply, and other important planning variables are optimized. To make sure the future states modeled by PowerSimm are feasible, the simulated distributions of weather, load, forward market prices, and daily and hourly spot prices are examined in detail to verify consistency with the body of available historical data. Several additional validation tests also make sure that important historically-observed relationships, such as the relationships between weather and load and between load and spot prices, are captured in the model output.

Validation of Simulated Commodity Prices

PowerSimm's forward price module simultaneously simulates multiple commodity price forecasts into the future, estimating parameters for the stochastic processes and the covariate factors. The forward price module in PowerSimm builds a system of simultaneous equations that captures the stochastic component of each individual forward contract while maintaining structural and covariate relationship between neighboring contract months, other commodities, and other factors. Table 6-3 lists the tests performed to validate forward price simulation output.

Table 6-3

Forward Price Simulation Validation Criteria

Test No.	Market Attribute	Information Used to Evaluate	Expectation
1	Uncertainty in Future Prices	Forward Price Confidence Intervals (mean, P5, P95)	▪ Uncertainty grows over time with a conical shape. ▪ Width of confidence intervals will grow for a period and then level off (should not grow indefinitely). ▪ Ranges of prices are consistent with market expectation and historic perspective of forward price uncertainty.
2	Mean Reversion of Prices	Simulated Price Paths	Simulated price paths match the historically observed mean reversion behavior over the estimated date ranges used to parameterize the model.
3	Correlation of Related Commodities	Heat Rate Confidence Intervals (mean, P5, P95)	▪Heat rates derived from simulated forward prices have limited growth in uncertainty over time. ▪The on peak heat rate is greater than or equal to off peak heat rate for all months. ▪The heat rate distributions change mean and/or spread from month to month due to seasonality.

Uncertainty in forward price simulations is examined by computing the mean and the 5th and 95th percentiles for the distributions of simulated final evolved forward/forecast prices at each delivery date. Figure 6-13 and Figure 6-14 show these confidence intervals for monthly Mid-C Heavy Load electricity and AECO gas prices, respectively. These plots reflect a number of historically observed phenomena regarding the forward/forecast price of both electricity and gas. For example, strong seasonal components in both contract price and contract volatility can readily be seen in the simulated output, and are consistent with observed market trends. A sharp increase in the price of electricity is observed around the year 2021, reflecting the distribution of future carbon penalties and their effect on electricity prices. Additionally, uncertainty in the simulated

forward/forecast prices grows as delivery dates range further into the future, a phenomenon consistent with historical market behavior. Overall, the confidence interval plots in Figure 6-13 and Figure 6-14 indicate that forward price simulations in PowerSimm capture an appropriate range of future states of the market.

Reversion of forward contract prices toward the mean is another important market phenomenon, and can be seen in the forward price simulation confidence interval plots discussed above, as well as in plots of the final evolved forward price paths for individual iterations of the forward price simulation. Five such price paths are plotted by simulation iteration in Figure 6-15, and spikes in the contract price across neighboring delivery dates can be observed, followed by reversion of the prices toward the mean.

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Figure 6-13

Mid-C Heavy Load Price Confidence Intervals

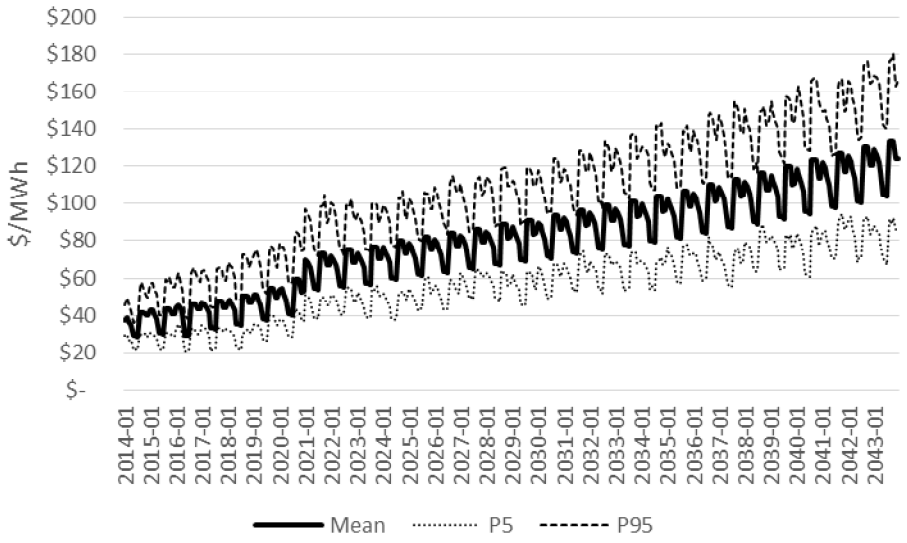


Figure 6-14

AECO Price Confidence Intervals

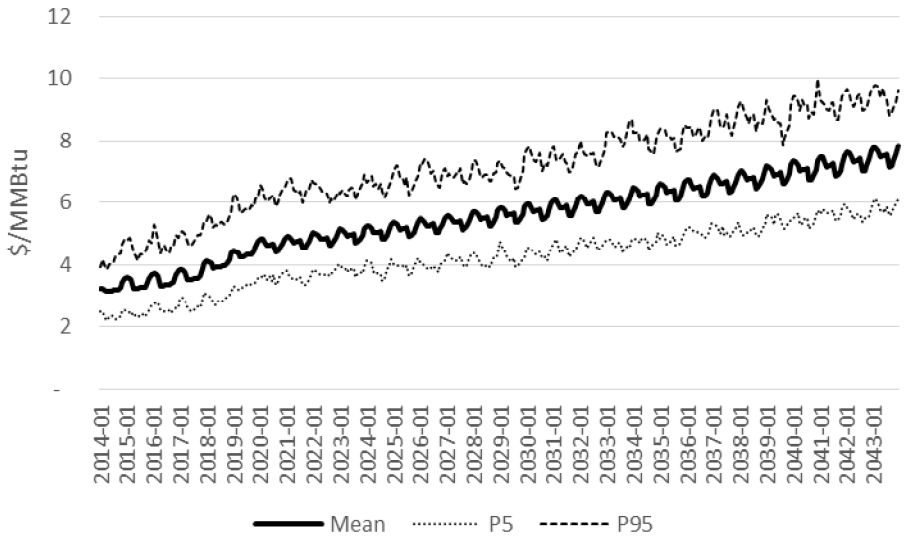
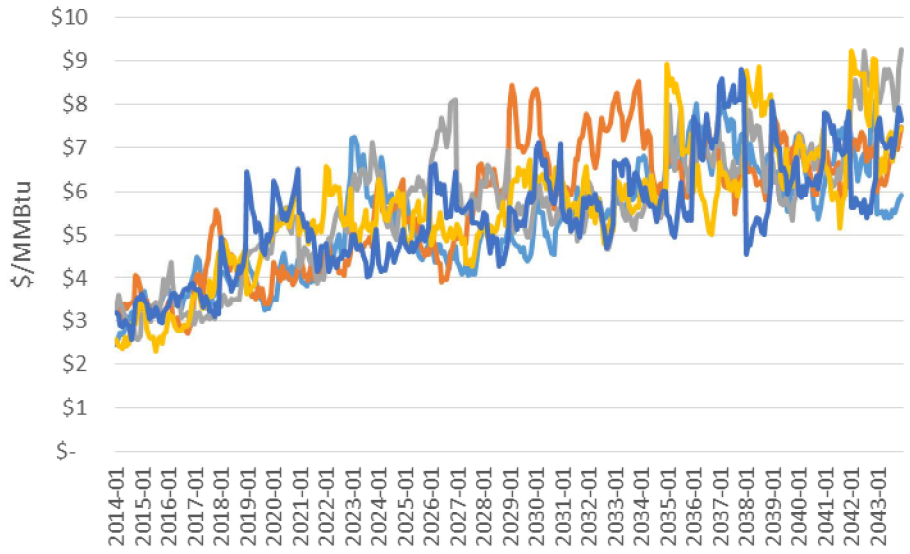


Figure 6-15

Five Example Paths for AECO Gas Price



Finally, the structural relationship of forward/forecasted prices for power and gas is investigated via plots of the market implied heat rates.[4] Figure 6-16 and Figure 6-17 show the simulated mean and the 5th and 95th percentiles for the forward market implied heat rates for Mid-C heavy load and light load, respectively. These heat rates are computed by dividing the forward market price of Mid-C electricity, excluding the impact of any CO_2 price, by the forward price of AECO gas. Notably, despite growth in uncertainty of the individual contract prices, growth in uncertainty of the implied heat rates is limited. Heat rate plots with the impact of CO_2 price added to the power price are shown in Volume 2, Chapter 4. The simulations also show that the implied heat rates for Mid-C heavy load are

[4] The market implied heat rate is the ratio of power prices ($/MWh) to gas prices ($/MBtu) and yields units of generation heat rates of MBtu/MWh.

greater than those for Mid-C light load, which is consistent with market expectations.

Figure 6-16

Heavy Load Implied Market Heat Rate Confidence Interval

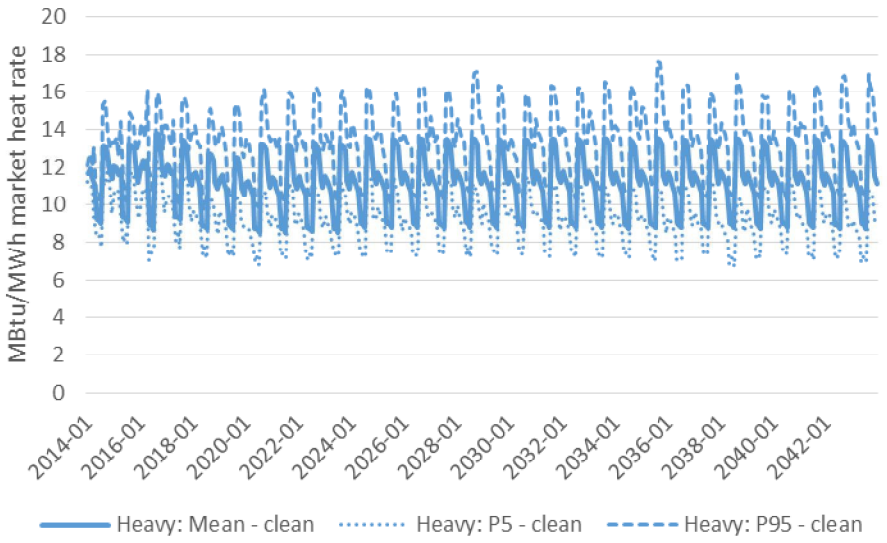
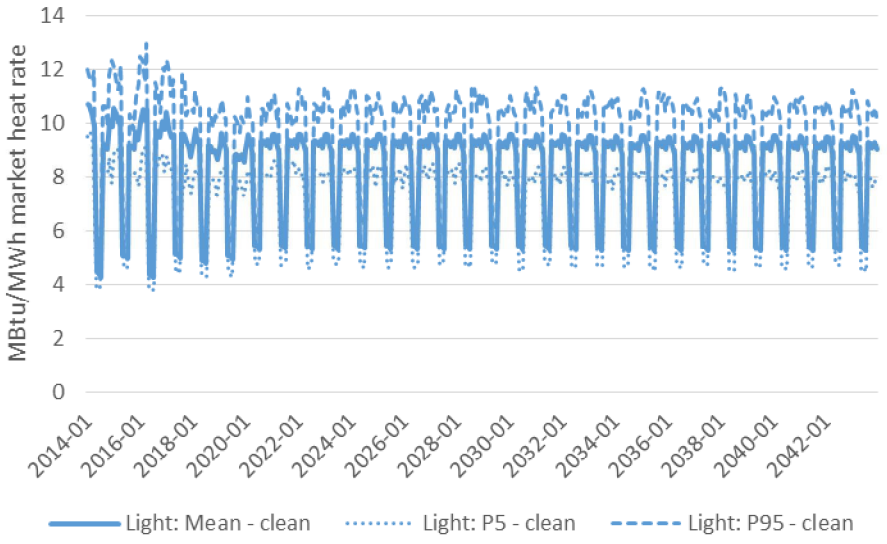


Figure 6-17

Light Load Implied Market Heat Rate Confidence Interval



Validation of Simulated Weather

Weather forecasts are used as inputs into a data preparation procedure that transforms weather into probability distributions that are fed into the overall forecasting simulations. The purpose of weather simulation is to provide a set of outcomes for simulated daily and hourly weather variables across weather stations in Montana. The criteria used to validate the distributions generated by PowerSimm weather simulations are summarized in Table 6-4 below.

Table 6-4

Weather Simulation Validation Criteria

Test No.	Attribute	Information Used to Evaluate	Expectation
1	Seasonal Fluctuation in Temperature	Maximum dry bulb temperature confidence intervals by month	Simulated values match historical values, for mean, P5, and P95
2		Maximum dry bulb temperature confidence intervals by day of the year	Simulated values match historical values, for mean, P5, and P95

Checking the simulated dry bulb temperature distributions on both a monthly and a daily basis provides verification that the simulations align with historical distributions across multiple time scales. In particular, these checks ensure that important monthly and daily variations in weather patterns, which have significant effects on load and market prices, are present in the simulation output. Validation plots for the monthly and daily simulated dry bulb temperature confidence intervals are shown in Figure 6-18 and Figure 6-19, respectively. Simulated values are shown in blue and historical values in red. These plots illustrate the excellent agreement between simulated weather output and historical data at the mean and the 5th and 95th percentiles.

Figure 6-18

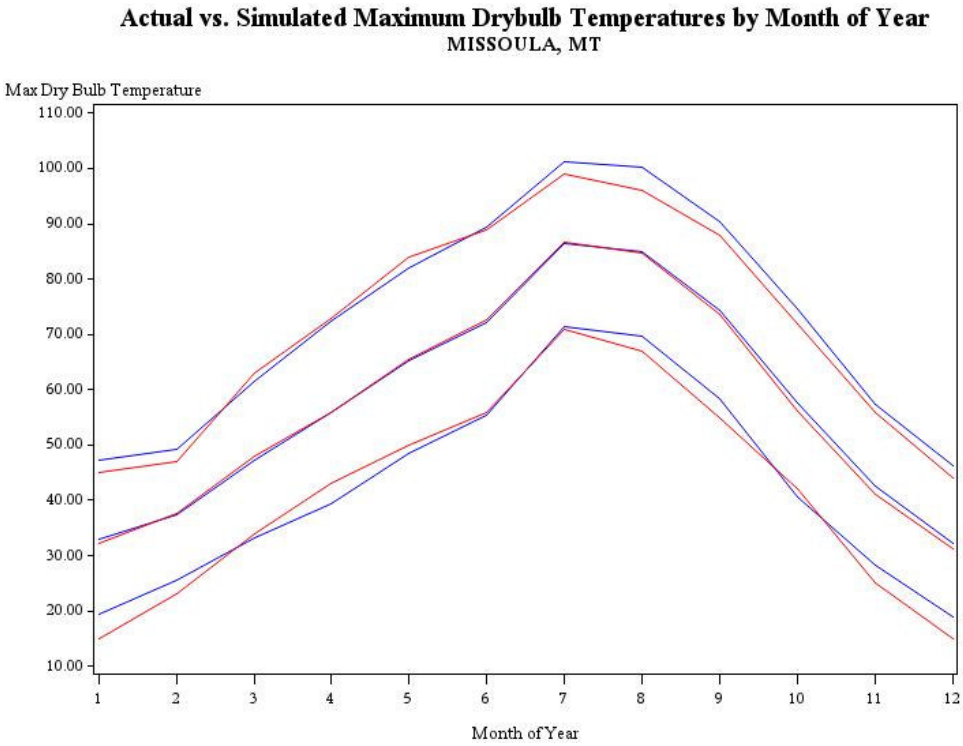
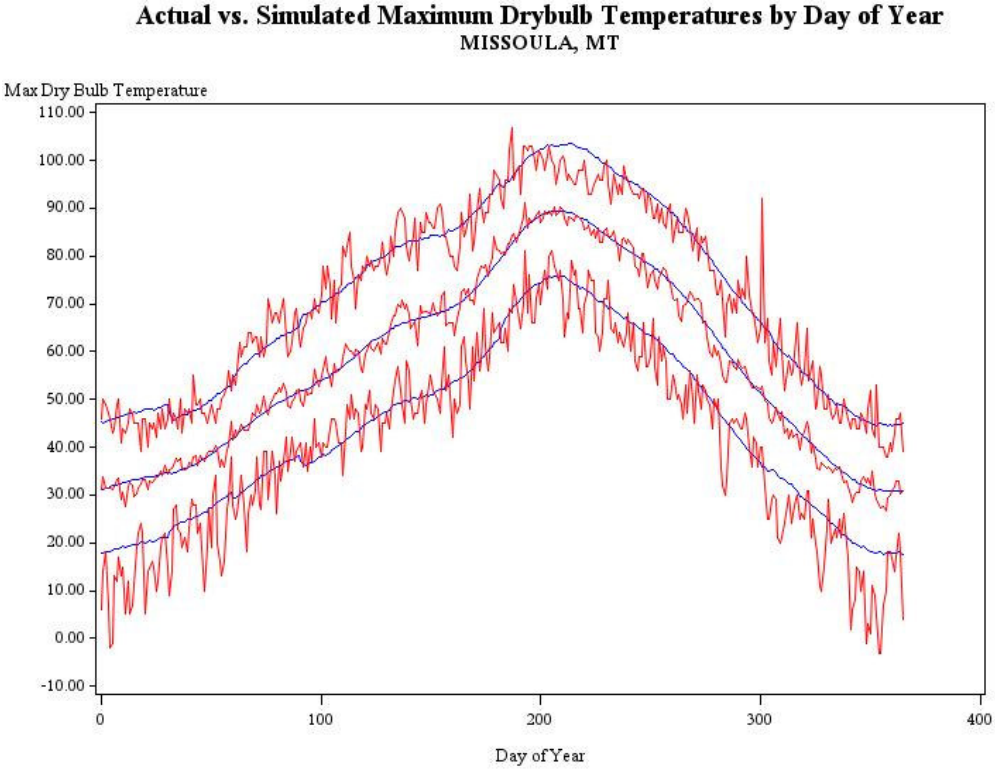


Figure 6-19



Validation of Simulated Load

Developing accurate electricity load simulations is critical for determining cost of service, associated risks, and appropriate hedging strategies. In addition, load simulation has significant bearing on electricity prices because of the strong non-linear relationship between electricity load and prices. The validation tests listed in Table 6-5 are designed to verify accuracy of the load simulations and their calibration to the historical data.

Table 6-5

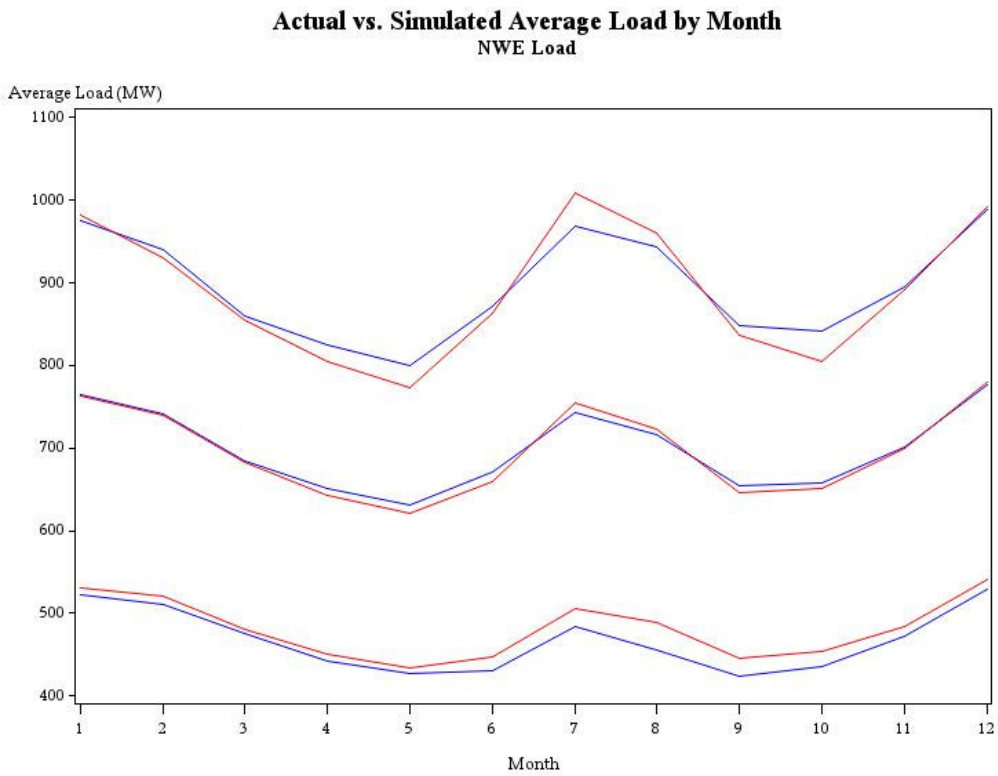
Load Simulation Validation Criteria

Test No.	Attribute	Information used to evaluate	Expectation
1	Seasonal Fluctuation in Load	Confidence intervals by month (backcast mode)	Simulated values match historical values for mean, P5, and P95
2	Hourly Fluctuation in Load	Confidence intervals by hour (backcast mode)	Simulated values match historical values for mean, P5, and P95
3	Seasonal Fluctuation in Daily Load Profile	Confidence intervals by hour and by month (backcast mode)	Simulated values match historical values for mean, P5, and P95
4	Correlation Between Load and Weather	Weather-Load Scatterplot	Heating and/or cooling loads are demonstrated as applicable for the markets simulated.

As with weather, simulated loads are examined across a range of time scales. The monthly confidence intervals at the mean, the 5th, and 95th percentiles, shown in Figure 6-20, display seasonal variability in the average load; namely, load is generally higher in both the summer and winter than in the spring and fall. This test is run in “backcast mode”, in which simulations are performed over a historical time period for comparison with the original historical data. Figure 6-20

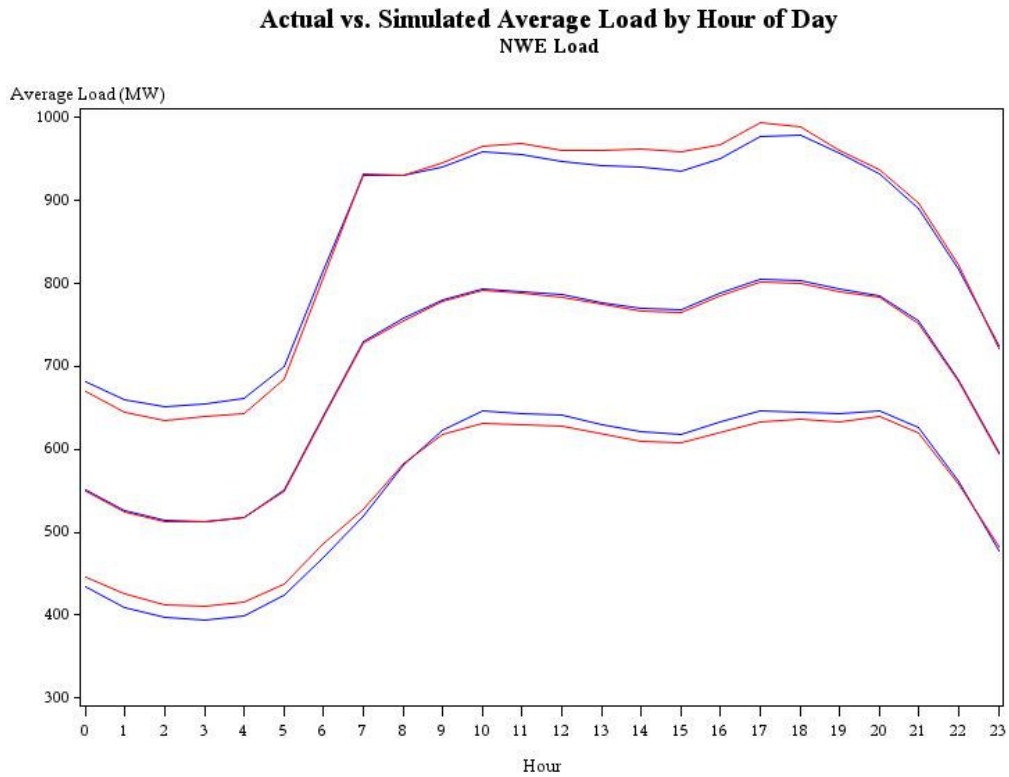
demonstrates the excellent agreement between simulated and historical load distributions on a monthly timescale.

Figure 6-20



Confidence intervals are also examined for hourly load over the course of a day. Figure 6-21 shows the mean and the 5th and 95th percentiles of both the historical (red) and simulated (blue) hourly loads. The daily peaking behavior of electric loads is readily observed in this plot. Again, excellent agreement is achieved between the historical data and the simulation output.

Figure 6-21



A third confidence interval plot captures the changes in daily peaking behavior on a monthly basis. Figure 6-22 and Figure 6-23 show the historical (red) and simulated (blue) mean and the 5th and 95th percentiles for hourly load by month. Importantly, the shape of the daily load profile can be seen to change dramatically by month. In cold months, there is a peak in the early morning hours, followed by a second peak in the evening, as seen in Figure 6-22 for the month of February. In warm months, there is a single elongated peak that reaches a maximum during the hottest hours of the day, as seen Figure 6-23 for the month of August. Again, simulations match the historical data sets very closely at the mean, the 5th, and 95th percentiles.

Finally, the nonlinear relationship between load and temperature is maintained in the simulation output; electric load typically becomes elevated when the

temperature is either low or high. This relationship is readily observed in both the historical data and the simulated output for load and weather, as shown in Figure 6-24. Historical data points are shown in red and simulations are shown in blue. The plot shows that the observed historical relationship is accurately captured by the simulation output.

Figure 6-22

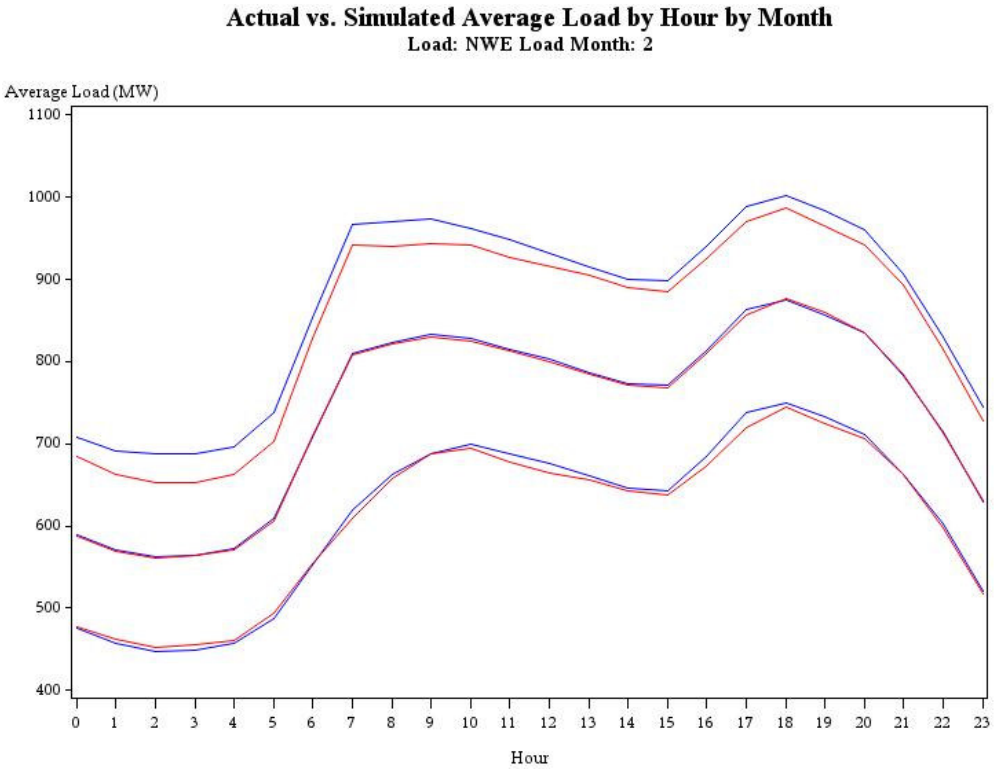


Figure 6-23

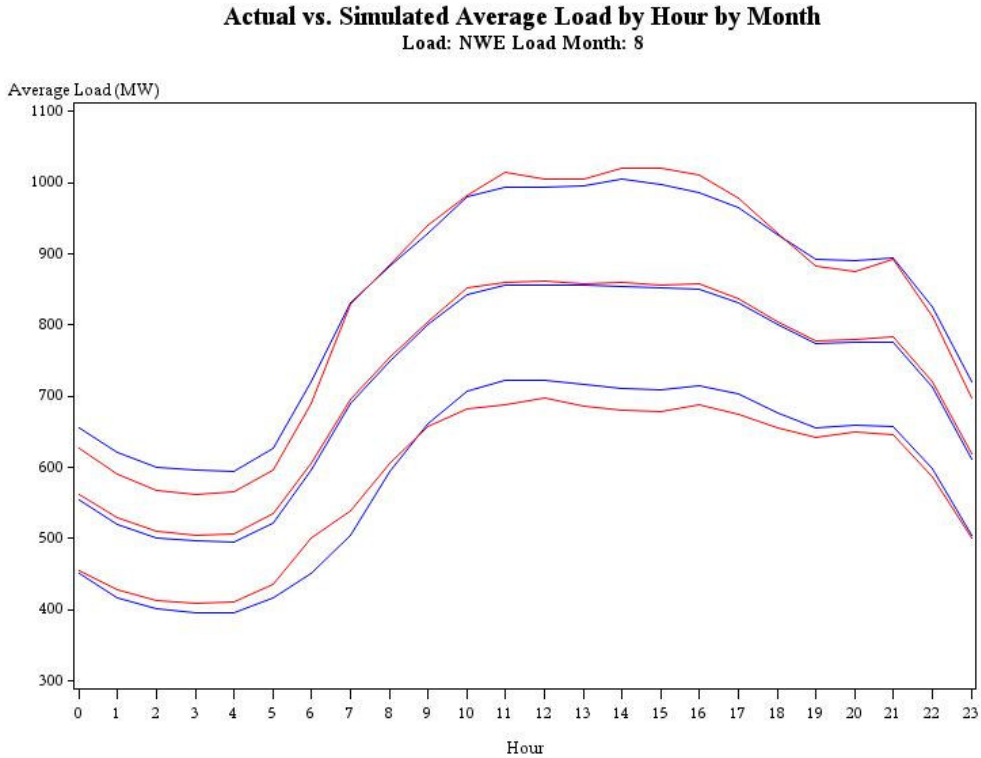
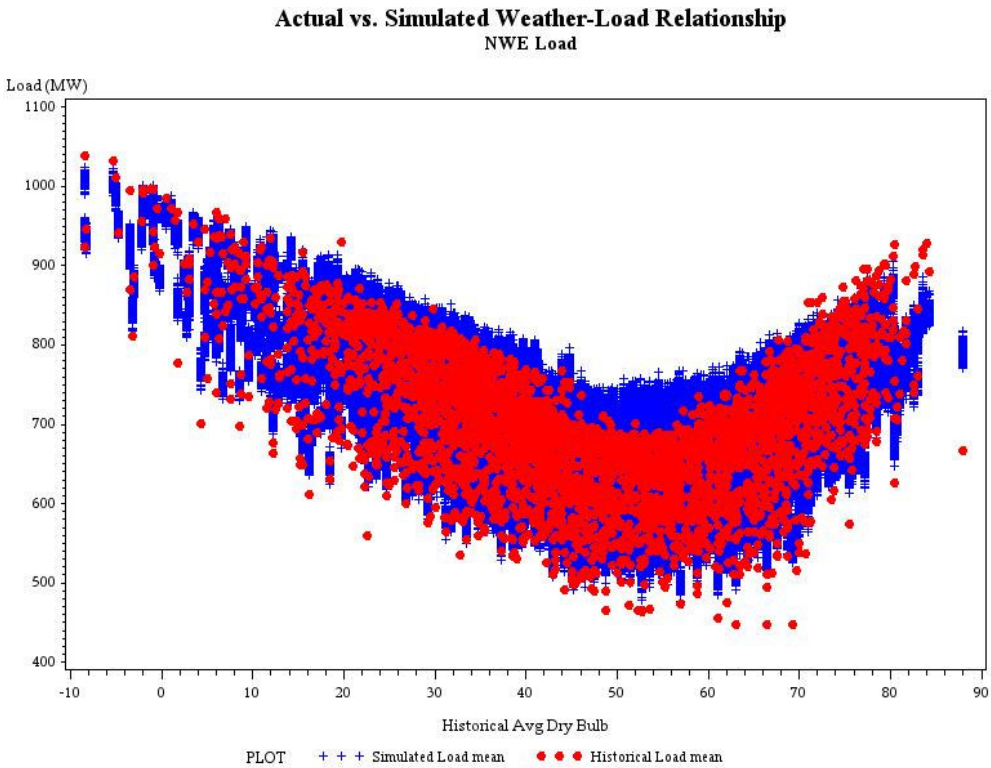


Figure 6-24



Validation of Simulated Spot Prices

Simulations of spot prices in PowerSimm incorporate the results of the various simulations discussed above, allowing these related model components to affect electricity and gas prices on daily and hourly time scales. Relationships between fundamental input variables and electricity prices are measured from historical data, and simulated variables such as load, hydro generation, imports/exports, reserve margins, supply stack, and gas prices are used as explanatory variables for the electricity prices through a structural state space model. Table 6-6 lists the tests performed to validate the spot price simulation output and ensure its consistency and accuracy compared to historical data.

Table 6-6

Forward Price Simulation Validation Criteria

Test No.	Market Attribute	Information Used to Evaluate	Expectation
1	Uncertainty in Electric Prices	Hourly confidence intervals for electric prices by month (mean, P10, P90)	Simulated values consistent with historical values for mean, P10, P90
2	Uncertainty in Gas Prices	Monthly confidence intervals for natural gas (mean, P10, P90)	Simulated values consistent with historical values for mean, P10, P90
3	Electricity Spot Prices Correlate with Load	Load-Spot Scatter Plot	Spot prices increase with system load, in a manner consistent with historical data

Similar to the hourly peaking behavior observed for load above, electricity spot prices also display a significant hourly shape. Figure 6-25 gives an example of this hourly price shape for Mid-C electricity spot prices for the months of February and August, showing the mean and the 10th and 90th percentiles of both the

historical data (red) and the simulation output (blue). The figure illustrates a stark difference between the hourly Mid-C electricity price profiles during the winter and summer: a slight double peak exists in February, as in other cold months, and a single elongated evening peak exists in August, as in other warmer months. The figure further illustrates that, in both cases, the simulation output accurately captures both the shape and magnitude of hourly prices for Mid-C electricity. Similar validation plots for additional months are included in Volume 2, Chapter 4.

For natural gas, important price variations occur on a monthly basis. These seasonal components of natural gas prices are the result of both simple supply and demand fundamentals as well as complex interactions between related commodities and markets. Seasonal components of natural gas prices are the result of both simple supply and demand fundamentals as well as complex market and commodity interactions. Figure 6-26 shows the mean and the 10th and 90th percentiles for the price of AECO natural gas by month of the year. A slight increase in the price of gas during late fall and winter can be observed in both the historical data (red) and the simulation output (blue). Again, the confidence intervals of the simulations are consistent with those from the historical data.

Figure 6-25

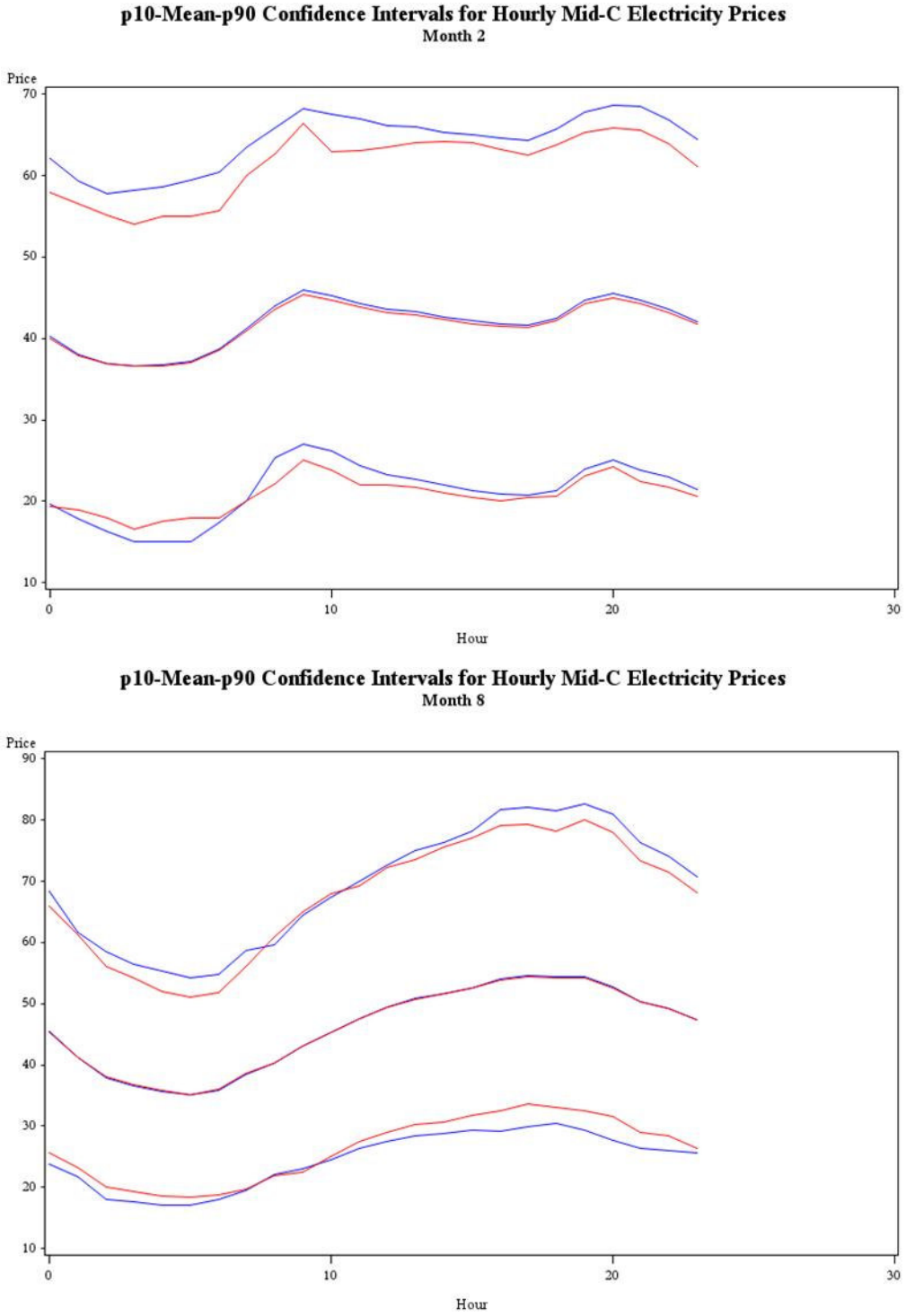
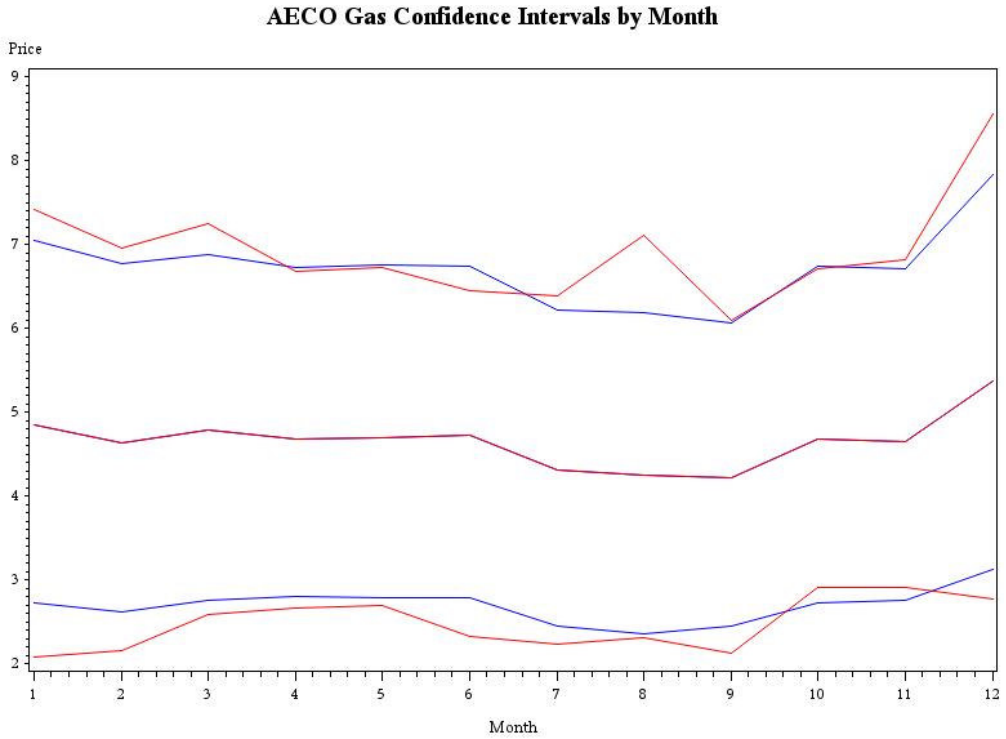

p10-Mean-p90 Confidence Intervals for Hourly Mid-C Electricity Prices
Month 2
Price
70
60
50
40
30
20
10
0
10
20
30
Hour
p10-Mean-p90 Confidence Intervals for Hourly Mid-C Electricity Prices
Month 8
Price
90
80
70
60
50
40
30
20
10
0
10
20
30
Hour

Figure 6-26

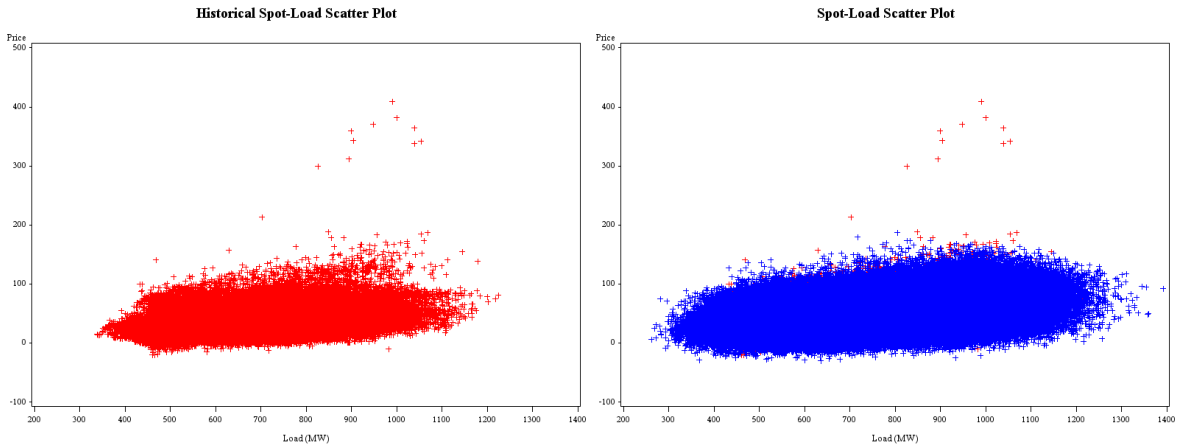


Finally, historical data indicate that there is a significant correlation between the spot price of electricity and system load. The correlation is generally positive, though the exact relationship may vary widely by market. For this reason, it is important to verify that the relationship captured in the simulation output is consistent with the particular market being modeled. Figure 6-27 shows the price of Mid-C electricity plotted against the system load, with historical values shown in red and simulated values in blue. The left pane depicts historical prices only, and the right pane shows an overlay of historical and simulated prices. The scatter plot shows that the simulations accurately capture the relationship between Mid-C electricity prices and load.

Figure 6-27

(Left) Historical Mid-C Spot Price vs. System Load.

(Right) Overlay of Historical (Red) and Simulated (Blue) Mid-C Spot Price vs. System Load



Validation of Renewable Generation Levels

Since PowerSimm simulates renewable (hydro and wind) generation along with weather, load, and prices, it is necessary to validate these simulated outputs as well. Figure 6-28 shows historical monthly capacity factors for Hydro Acquisition assets in black, and the mean, P5, and P95 simulation results from the PowerSimm hydro realizations. The red confidence interval largely encompasses the historical data, indicating good agreement between the simulation results and prior years' generation.

Figure 6-28

Historical (Black) and Simulated (Red) Confidence Intervals for Monthly Hydro Capacity Factor

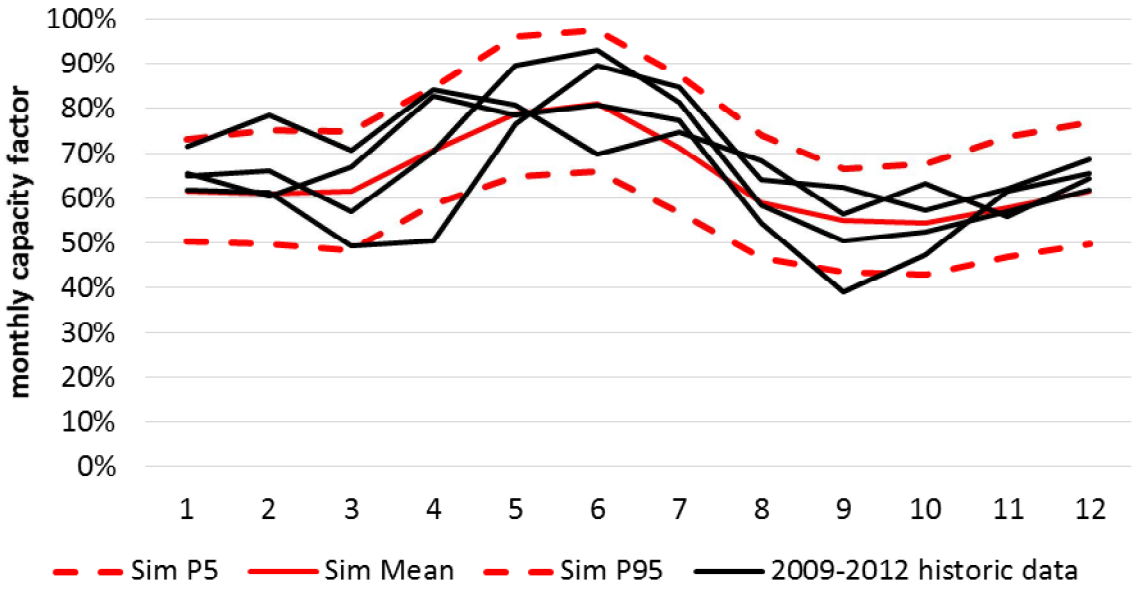
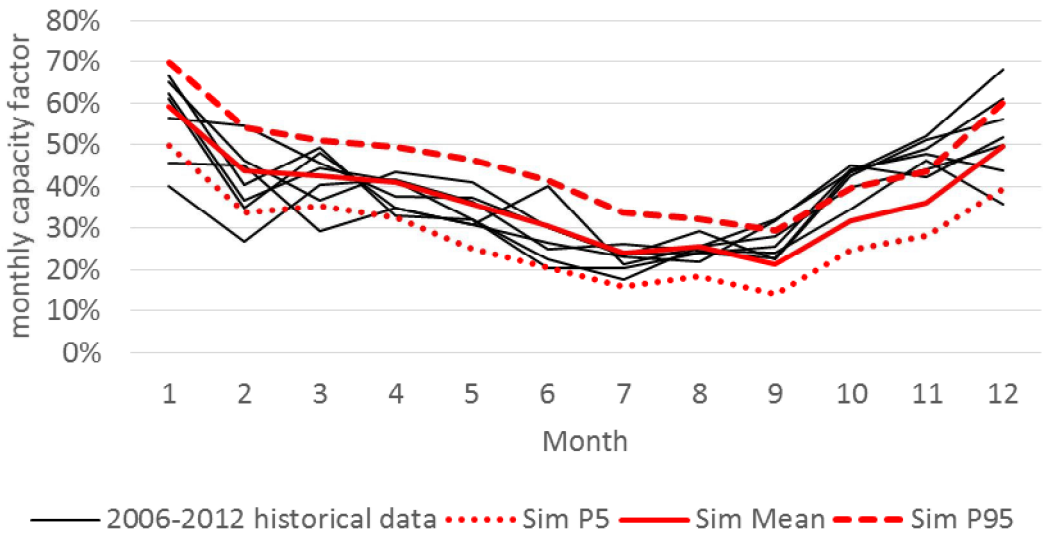


Figure 6-29 shows the equivalent monthly energy validation results for NorthWestern's wind asset generation. Historic monthly capacity factors are largely contained within the P5 and P95 confidence intervals (red) calculated by the PowerSimm simulation engine.

Figure 6-29

Historical (Black) and Simulated (Red) Monthly Wind Capacity Factors



Valuation of Risk

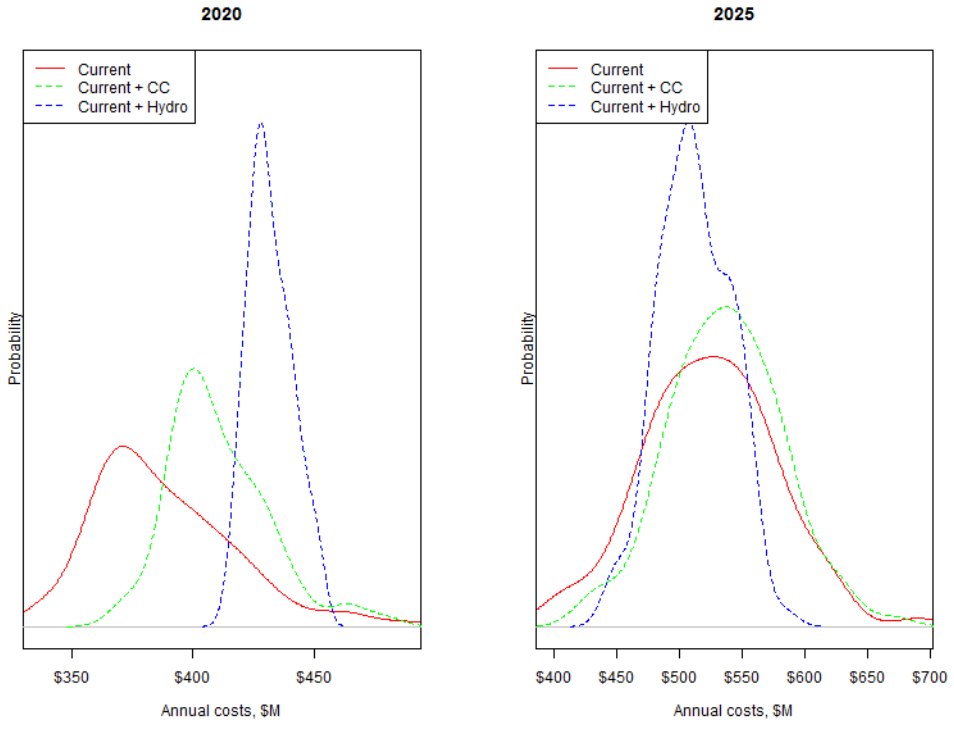
Given the validated simulation engine results, PowerSimm dispatches NorthWestern's resources each iteration for all years of the study horizon in order to arrive at a distribution of future costs. The expected value of portfolio costs is therefore a robust metric to determine the cost ranking of the different portfolio options, but it does not capture the large differences in risk between the portfolios. Given the substantial uncertainty in future prices of fuel, wholesale power, and CO_2, derived from current market data as described in the above sections, and the difference in long/short positions between the portfolios, the distributions of costs around each portfolio's expected value are significantly different. The following sections illustrate the key differences in portfolio cost distributions and the methodology by which Ascend places a monetary value on these differences.

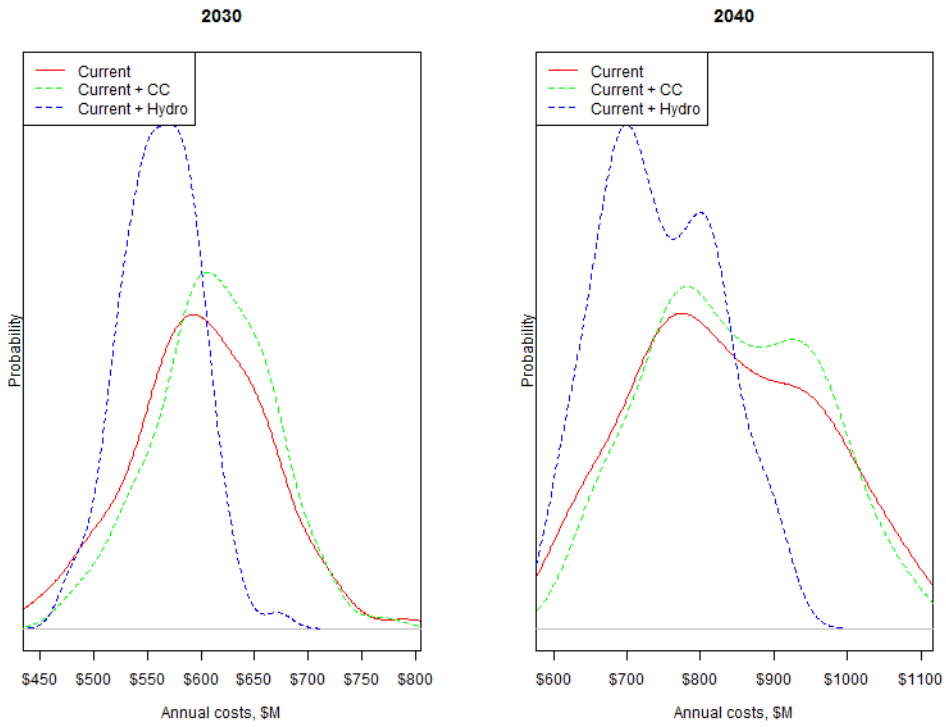
Portfolio Cost Distributions

The differences in the future cost distributions of the three portfolios are illustrated in Figure 6-30, with four graphs showing the distribution of simulated portfolio costs in 2020, 2025, 2030, and 2040 for each portfolio. These distributions represent the total spread of annual costs experienced in the PowerSimm iterations performed for this analysis, capturing the variability in hydro resource, gas price, load, market price, etc., with simulation results validated as described above. The simulations thus probabilistically envelope possible future states and capture the likely range of future costs.

Figure 6-30

Distributions of Annual Costs by Portfolio





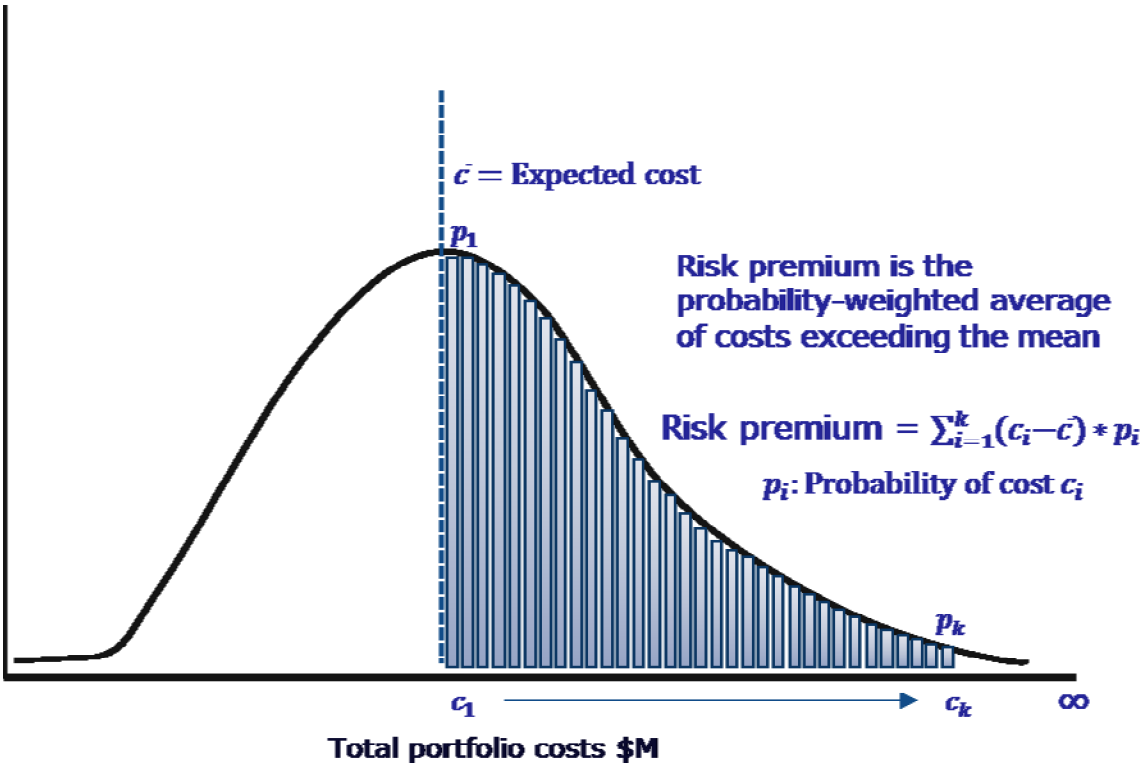
In 2020, the costs of the hydro portfolio are higher in nearly all simulations, due to the substantial fixed costs associated with the acquisition, but the distribution of cost outcomes is much tighter, reflecting the lower exposure to market price increases. In later years, including 2025 and later as illustrated above, the cost advantage has reversed, and the hydro portfolio maintains a much tighter distribution around the expected value of cost.

Risk Premium Definition

PowerSimm monetizes the difference in the shapes of these distribution 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 6-31.

Figure 6-31

Illustration of Risk Premium Concept



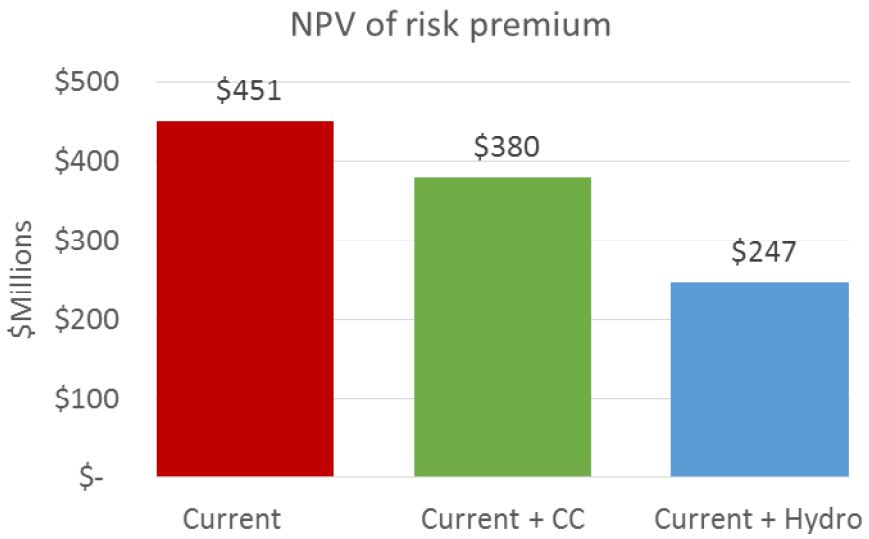
The risk premium can be added to the expected value to better approximate the full distribution of costs, and portfolios can be directly compared based on the sum of expected cost plus the risk premium. This risk metric improves upon traditional planning approaches such as cost-at-risk or efficient frontier 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 the NorthWestern portfolio options are shown below in Figure 6-32. 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 portfolio has a risk premium of $451 M, or 8% of total NPV of costs, versus $247 M (4% of NPV costs) for the hydro

portfolio. The difference between the risk premiums of these portfolios, $204 M, is the NPV of the risk reduction value of the Hydro Acquisition assets. This value, approximately 23% of the purchase price of the assets, illustrates the monetary value of decreased uncertainty of future costs with the Hydro portfolio.

Figure 6-32

Values of Risk Premium for NorthWestern's Portfolios



Portfolio and Asset Operations

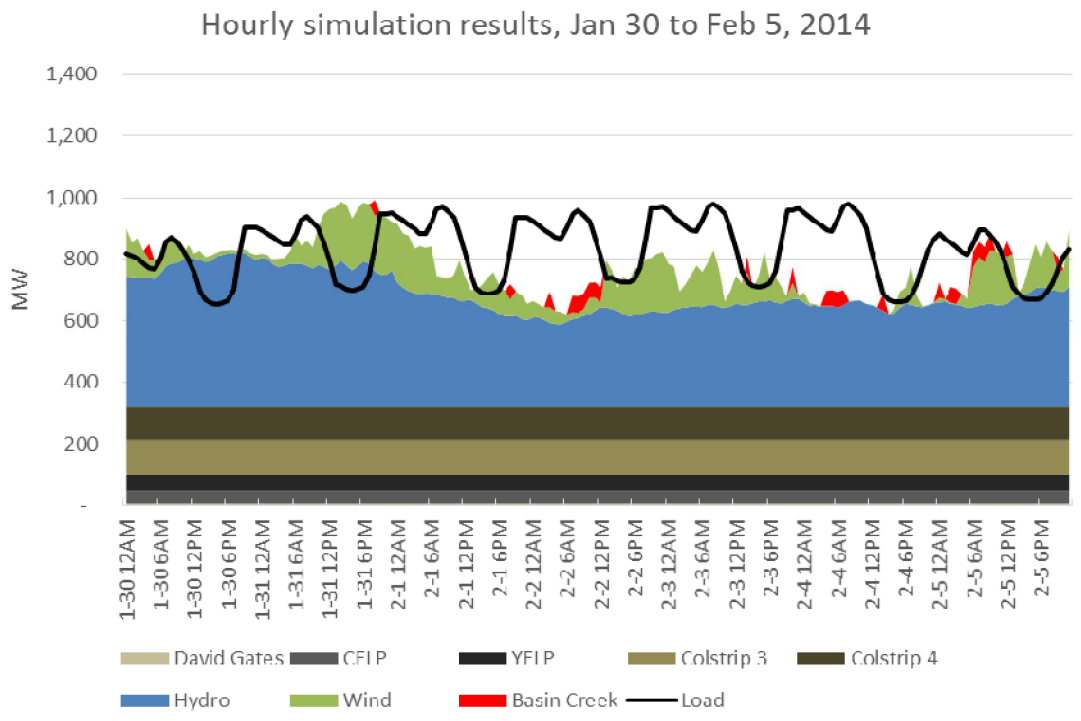
The PowerSimm dispatch engine outputs a broad set of results that can be used to examine and validate the operational characteristics of the portfolios under consideration. Results including costs, fuel use, outages, generation, etc. are reported at time-frames ranging from hourly interval data to study horizon totals. In addition, several input datasets constrain the future variable simulations and illustrate some key aspects of the assets analyzed in this report. The following sections summarize some of these input data relationships and outputs for portfolio comparison, and more detailed results are contained in Volume 2, Chapter 4.

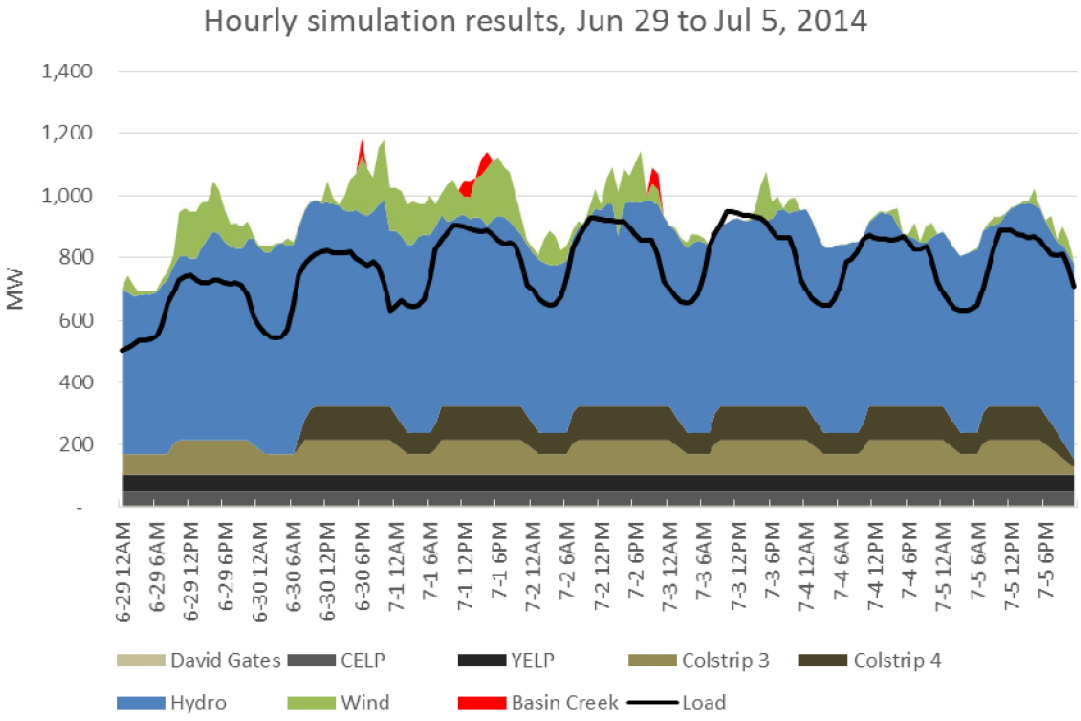
Hourly Operations

Simulations based on the historical data reveal an expected hourly operating pattern for wind, hydro, and thermal assets. Wind generation varies substantially on an hourly basis, while hydro follows a more regular and consistent generation profile. Because hydro generation has been modeled to replicate the observed seasonal and hourly operating pattern, opportunities to optimize generation have not been modeled. For example, spilling or banking hydro flows during negative spot price conditions, which could raise the hydro assets' net revenues, has not been modeled. Thermal generation generally dispatches when its operating costs are below the market price, subject to operating constraints. Figure 6-33 below illustrates asset operating during two sample periods of a single iteration of dispatch simulation. In these results, the variable nature of renewable resources as well as the economic operation of the thermal generators is apparent. Colstrip 3 & 4 (browns) operate constantly in the winter (top pane), and cycle based on market price and forced outages in the summer months (bottom pane), when prices are lower. Basin Creek (red) operates during peak periods, when prices are high.

Figure 6-33

Illustration of Hourly Portfolio Operations with Hydro





Relationships of Risk Factors

Figure 6-34 shows the correlation between hydro generation of the proposed asset and market prices, using historical data. In total (blue dots), the hydro portfolio's output is negatively correlated to market price, which acts to reduce the value of the portfolio. This follows expectations – dams on the Columbia are a large part of the Mid-C market, and thus their production is expected to be inversely related to market price. However, the output of the Missouri river system portion of the proposed Hydro Acquisition (orange dots; all facilities except Kerr and Thompson) is much less correlated with Mid-C price than the Columbia portion, and with Kerr leaving the portfolio in 2015, most of NorthWestern's hydro generation will be on the Missouri. The hydro asset's low correlation with market prices suggests that purchases and sales will be spread more evenly across low- and high-price hours than if the resources were on the Columbia River system. Figure 6-35 illustrates this another way by showing the low correlation between generation at the Missouri and the Columbia system hydro stations.

Figure 6-34

Historical Daily Average Mid-C Price Versus Total and Missouri System Hydro

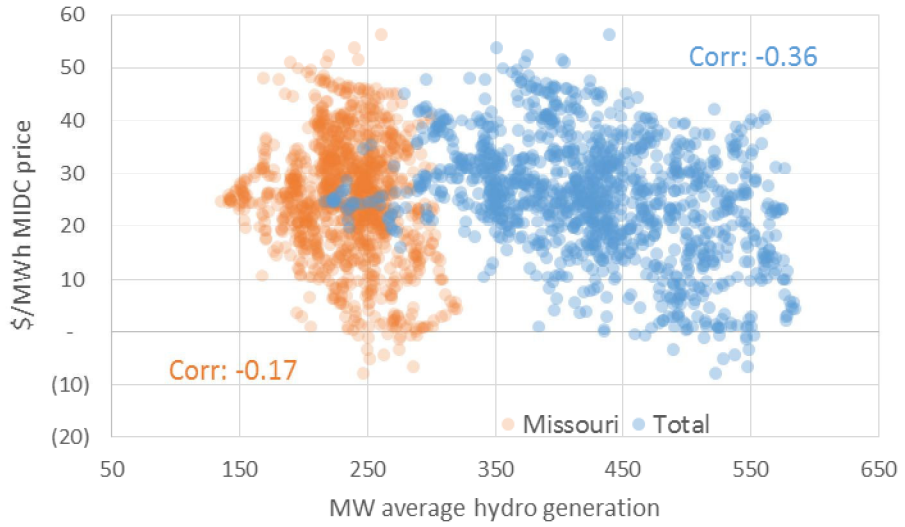


Figure 6-35

Historical Daily Average Missouri Versus Columbia System Hydro

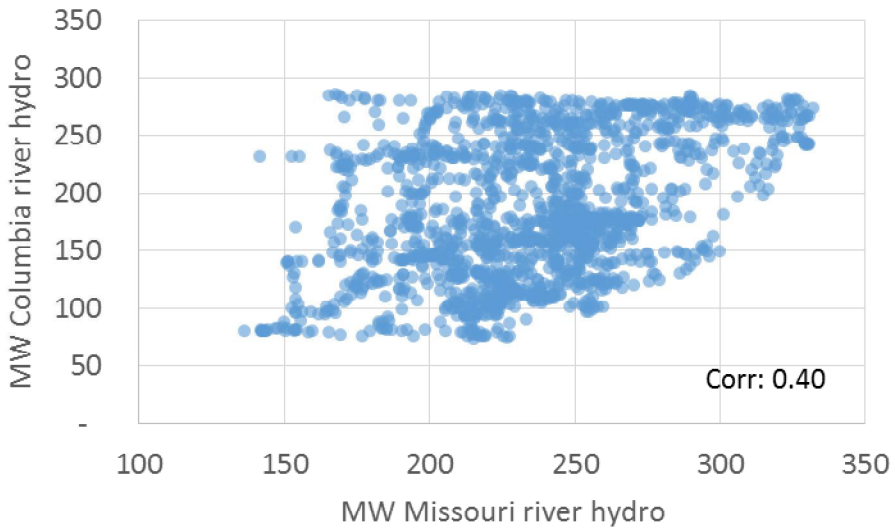
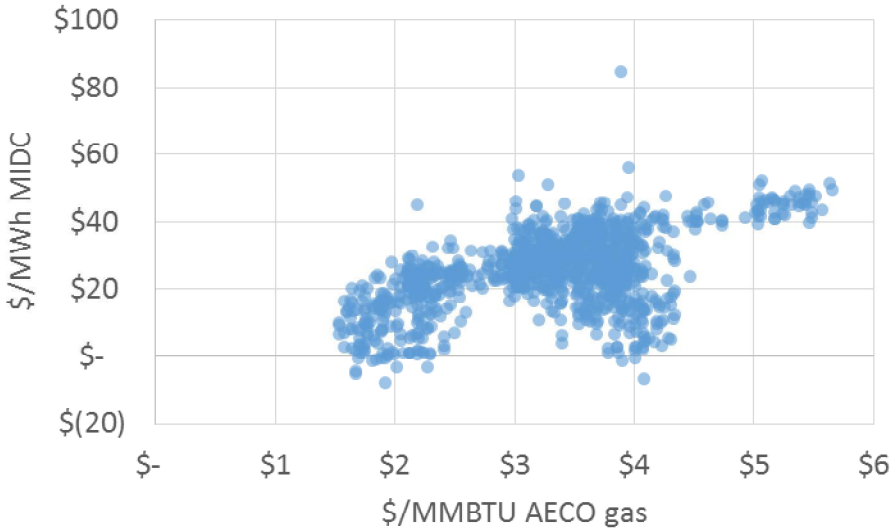


Figure 6-36 shows the low positive correlation between gas and power prices. This relationship is preserved through PowerSimm's simulation engine and impacts dispatch operations and market purchases and sales in each portfolio simulation.

Figure 6-36

Historical Daily Average Mid-C Versus AECO Price



Monthly Net Position

NorthWestern Energy's portfolio is variable in its monthly energy output, with seasonal fluctuations in load, wind, hydro, and thermal planned outages impacting production during each month of the year. Figure 6-37 shows the expected value of NorthWestern's net position, or the sum of its supply resources minus load, during each month of the study horizon, by portfolio. Figure 6-38 shows the same data for just 2018, to better illustrate the seasonal pattern. NorthWestern's portfolio with the hydro addition is long in the spring months, when hydro flow is at its highest, and short in the summer months when prices are low and it is most economical to buy from the market. In all months, the proposed hydro and CC asset acquisitions add significant energy to the current portfolio.

Figure 6-37

Monthly Net Position by Portfolio

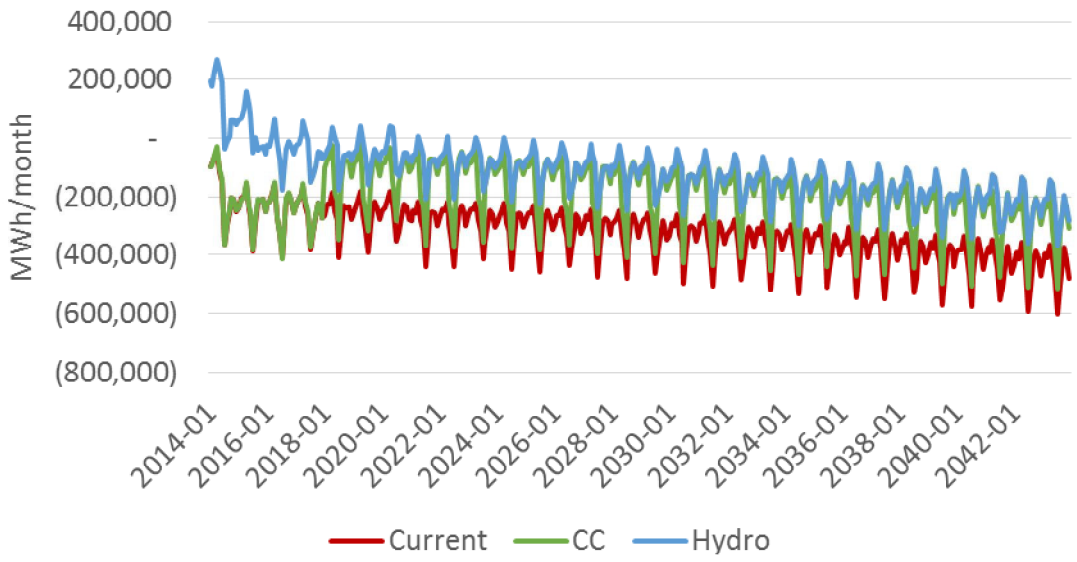
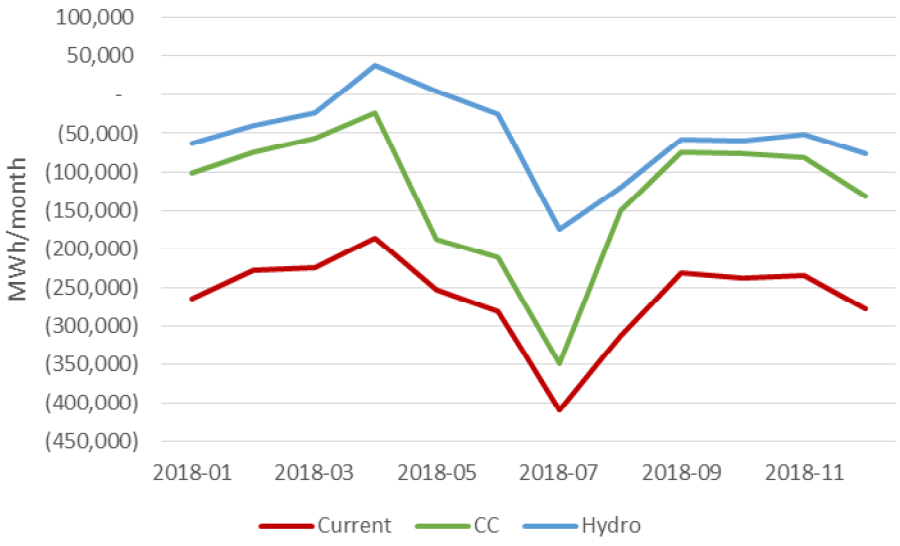


Figure 6-38

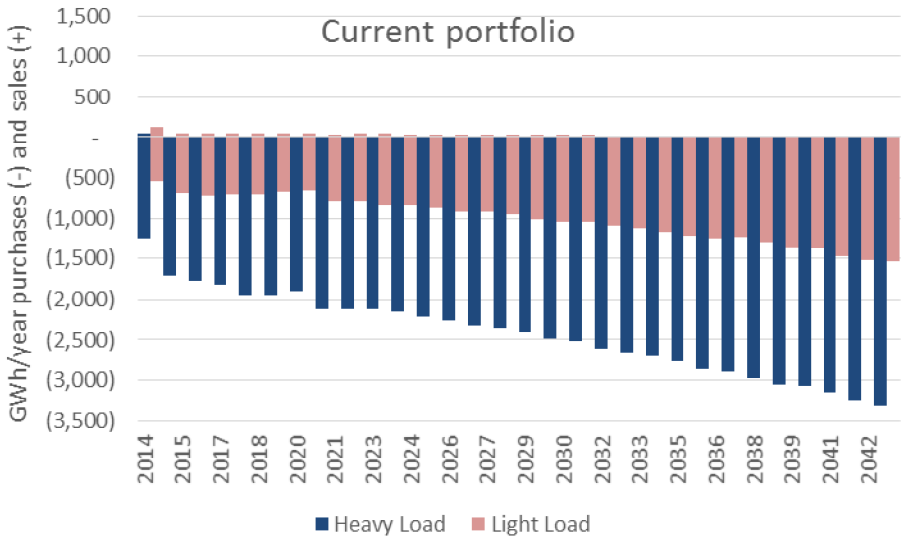
Monthly Net Position: 2018

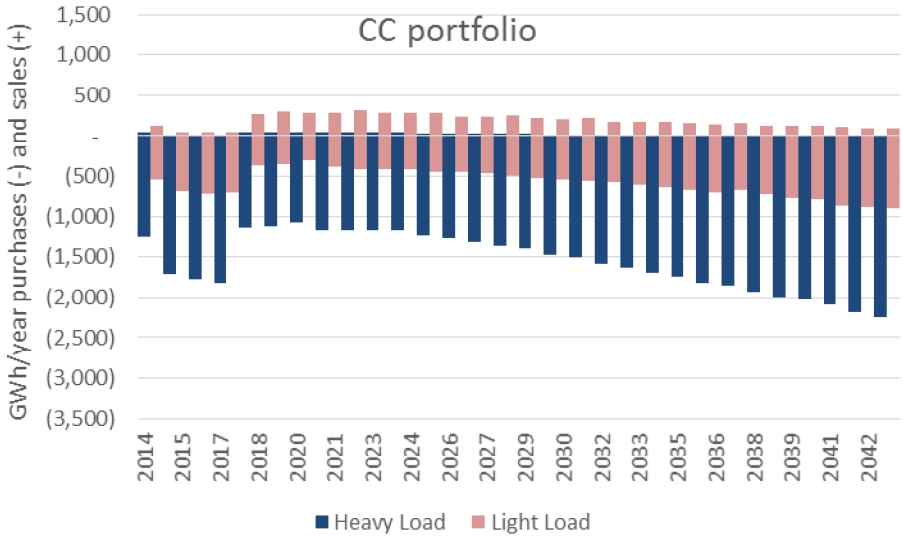


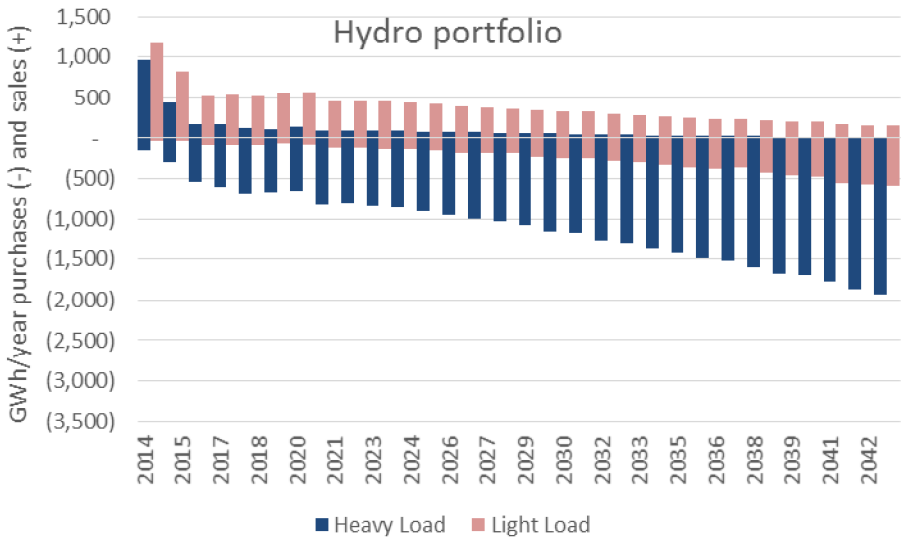
NorthWestern's modeled position is different between heavy load and light load periods for each of the modeled portfolios. When NorthWestern loads are higher, during heavy load hours in the broader market, NorthWestern tends to purchase more energy than during light load hours. For similar reasons, market sales are lower during heavy load hours. Figure 6-39 illustrates this phenomenon with the mean results from each year of the study horizon. Sales (above the X-axis) and purchases (below the X-axis) are plotted for both heavy load (blue) and light load (red) hours, for each portfolio. Both the CC and hydro assets would reduce net purchases during heavy load (i.e. high-price) hours.

Figure 6-39

Annual Market Purchases and Sales by Portfolio






Hydro portfolio
GWh/year purchases (-) and sales (+)
1,500
1,000
500
-
(500)
(1,000)
(1,500)
(2,000)
(2,500)
(3,000)
(3,500)
2014
2015
2017
2018
2020
2021
2023
2024
2026
2027
2029
2030
2032
2033
2035
2036
2038
2039
2041
2042
Heavy Load
Light Load

CHAPTER 7
ACTION PLAN

CHAPTER 7

The Hydro Acquisition will fundamentally alter the focus of NorthWestern's future resource planning and procurement activities, and heavily influences this action plan.

2013 Action Plan Overview

The successful acquisition and integration of the Hydros will have long-term implications for planning and post-acquisition work. The Hydro Acquisition (633 MW) will alter NorthWestern's approach to electricity planning and procurement activities. This acquisition also provides significant benefits to the resource portfolio. The Hydros will greatly reduce market and fuel price exposure, lower portfolio risk, provide resource reliability, and represents a major step toward capacity-based operations and planning. With the Hydros in mind, NorthWestern proposes the following Action Plan.

Action Items

The 3-year action plan addresses issues facing the resource portfolio from both a planning perspective and operations perspective assuming the Hydro Acquisition is granted satisfactory regulatory approvals. During 2014, NorthWestern continues to prepare for the smooth integration of the Hydros into NorthWestern's organization and the resource portfolio. The following action items are tasks to be addressed by NorthWestern and its advisors to support continued cost effective and reliable service to retail customers, and to inform NorthWestern's

supply operations, resource procurement, service reliability, and the fulfillment of utility load-serving obligations:

1. Following the execution of the Hydro asset purchase and sale agreement, NorthWestern immediately began preparing for the addition of the Hydros into its resource portfolio. The Generation and Supply business units will continue this planning activity throughout much of 2014, in anticipation of owning and operating the Hydros. For the Generation Group, hydro operations will include assumption of day-to-day activities, short to long-term planning, and management of the assets according to the terms and conditions in the FERC licenses. For the Energy Supply business unit, the Hydros will be integrated into market operations and resource planning. This planning will address short to medium-term hydroelectric resource production scheduling, outage scheduling, and overall coordination to ensure effective utilization of the hydro resources.

   With the addition of the Hydros, NorthWestern will be capable of serving the majority of the retail load with physical resources, reducing its reliance on market transactions. Future plans will concentrate on specific resource needs, such as heavy load hours and times of peak demand. This change in focus represents a logical progression in resource planning and Supply operations.

   Energy Supply will evaluate, and where necessary, adjust its market strategies. Procurement strategies will be adjusted to account for changes to heavy and light load needs based on estimates of total output from all supply resources including Colstrip 4, the Hydros, Basin Creek, Spion Kop, contracted sources and projected energy savings from DSM. With the addition of the Hydros, light load and flat products will have a

much more limited role in the supply portfolio. Variable output from renewable sources such as wind projects will also be recognized in the examination of portfolio market operations and procurement. The changes described above will also be reflected in future avoided cost QF-1 Tariff filings.

2. If the Commission fails to approve the Hydro Acquisition on satisfactory terms, the CC portfolio will advance to "preferred portfolio" status. In the short term, NorthWestern must fill its immediate energy deficits with market purchases. For long term needs, NorthWestern would focus on filling the capacity deficit identified in its loads and resources analysis with alternative long-term physical resources, most likely a CCCT with an on-line date possibly as early as 2018, as identified in this Plan.

3. In Docket D2012.5.49, the 2011/2012 Electric Tracker Docket, the MPSC stated that within 90 days of the date of its Final Order in that docket it would open a new docket to investigate possible mechanisms to better align the goals of rate stability and risk mitigation with the goal of providing service at the lowest long term total cost. NorthWestern anticipates that hedging issues will be fully vetted in that yet-to-be opened docket. NorthWestern will continue to adhere to the monthly hedging targets from the hedging strategy described in its 2011 Electricity Supply Procurement Plan until the Commission issues a final order in that docket.

4. During 2014, NorthWestern will review the Basin Creek facility to determine whether further changes in operating protocols could provide greater overall value to the utility. When considering changes to Basin Creek's operations, NWE recognizes that during 2013 Basin Creek's

economic dispatch increased significantly compared to prior years. NorthWestern's Energy Supply, Generation and Transmission business units will participate in the study and a consultant will be retained to design and execute the study. Among other issues, the continued use of Basin Creek for contingency reserves will be examined. The study is exploratory and should not be considered as a commitment by NorthWestern to change the current operations of Basin Creek.

5. NorthWestern will continue to monitor changes in the northwest electricity market. Intra-hour scheduling and potential trading alternatives may develop which are intended to make more efficient use of the flexibility that is already available in the region. The opportunity to develop an Energy Imbalance Market (EIM) to better utilize regional flexibility is being studied for possible deployment in the northwest. NorthWestern is funding and participating in the study process. NorthWestern will continue to study this, and any other regional initiative, to determine whether it makes sense to participate and, if so, at what level.

6. NorthWestern will continue to diligently pursue the acquisition and integration of renewable resources in the Supply portfolio necessary to meet its annual RPS and CREP obligations and will continue to seek refinements to efficiently integrate and utilize intermittent resources in light of the Hydro Acquisition. The scope of future CREP and other renewable resource acquisition activity may be impacted by renewable contract negotiations performed during the fourth quarter of 2013. If negotiations are successful and long-term PPAs are executed with CREP-eligible projects NorthWestern projects that it will meet both the future 15% annual RPS requirement and the CREP obligation until the late 2020s. CREP acquisition has proven challenging over the last

several years for NorthWestern. Developers of these projects are confronted with financing hurdles, development uncertainties, and other issues that have impeded their ability to enter into long-term CREP purchase power agreements.

7. NorthWestern will continue to develop internal modeling capabilities and expertise in resource planning, portfolio optimization and resource selection through the deployment of the PowerSimm™ software as provided and supported by Ascend Analytics. As NorthWestern improves its PowerSimm usage proficiency during 2014 it will communicate progress to stakeholders such as ETAC and provide opportunities for stakeholders to become more familiar with the software, its functionality, and the results it produces.

8. Even in light of the recent Commission decision on DSM lost revenue recovery, NorthWestern intends to continue its DSM Programs and, for now, maintain its annual electric DSM goal of 6.0 aMW and continue to seek recovery of DSM Program Costs and DSM Lost Revenues. In addition, NorthWestern will continue to concentrate on the difficult-to-penetrate commercial/small industrial customer sectors to help achieve future annual DSM targets.

   Updated electric avoided costs to be produced in conjunction with the 2013 electric resource planning process will be used to review and, if necessary, update certain elements and features of NorthWestern's DSM Programs. NorthWestern will continue to monitor the efforts and results of the PSE (Puget Sound Energy), ETO (Energy Trust of Oregon), and SMUD (Sacramento Municipal Utility District) pilot DSM programs. The Smart Grid Demonstration Project will be completed in 2014 and a final

report will be completed and the results communicated to the Commission and stakeholders. NorthWestern will complete installation and integration of the Battery Storage Project at the Helena Service Center and place it into operation.

9. Regulation of power plant emissions at the state and federal levels will continue to be monitored and evaluated for potential impacts on existing resources and potential supply resources. NorthWestern anticipates working with appropriate state agencies in the development of state implementation programs in response to federal requirements. Any proposed standards will be reviewed and evaluated to determine how they could impact market transactions and the economics and operation of NorthWestern's current fleet of thermal resources. Following the review of the draft standards NorthWestern will determine necessary actions.

10. The natural gas generating plant siting study that began in 2012 under the direction of the Generation Group will be completed in 2014. This study will be used to determine the feasibility of locating new natural gas-fired generation facilities within NorthWestern's BA. Planning for additions to the existing gas-fired fleet (Basin Creek and Dave Gates Generating Station) will include determinations of total project feasibility, schedule, and associated infrastructure needs as informed by the study.

11. NorthWestern will continue to use ETAC in an advisory role for electric resource planning and procurement and carefully consider its comments and input in its planning process. In addition to supplying resource planning information to ETAC, NorthWestern will provide retail customers and other stakeholders with electric resource information as part of its annual strategic communications plan. The strategic communications

plan uses multiple forms of information dissemination to customers and includes the use of bill inserts, and direct communications with the media and NorthWestern staff located in the Montana service territory. Additionally, enhanced communications are planned in connection with the 2014 upgrade to the NorthWestern Energy website, which will further enable consumers and stakeholders access to posted information (including resource planning materials) and as well as the capability to interact directly with the company through electronic inquiry.

Volume 2

Chapter 1

Background

1) 2012 - 2013 ETAC Meeting Minutes & Materials 1

NorthWestern Energy

ETAC Meeting Agenda

Meeting Location

Northwest Power and Conservation Council – Helena
1301 Lockey (South of Capitol Building)

Friday April 6, 2012 – 9:00 AM

Conference Call-In: 877 273-4202 Conference Room (Access Code): 7656120

Agenda:

MPSC - NARUC Capacity Assistance Grant: Consultant review of electric resource planning and procurement rules (Will Rosquist / Dennis Lopach)

Dave Gates Generating Station discussion (Jim Williams via conf call)

2011 Renewable energy production and RPS compliance (NWE)

2011 Electricity Resource Procurement Plan discussion (All)

- 2011 process check
- 3-Year Action Plan

(Lunch will be provided)

Meeting Summary
NorthWestern Energy Electricity Technical Advisory Committee
April 6, 2012

Attendance
Those participating in the Energy Electricity Technical Advisory Committee (ETAC) meeting in person and via telephone included:

Name	Organization
In Person	
Paul Schulz	Montana Consumer Counsel (MCC)
John Hines	NorthWestern Energy (NWE)
Diego Rivas	Northwest Energy Coalition
Thomas M. Power	District XI Human Resource Council
Lauren Casey	Northwest Power and Conservation Council (NPCC)
Dennis Lopach	Montana Public Service Commission (MPSC)
Mike Dalton	MPSC
Todd Guldseth	NWE
Will Rosquist	MPSC
Larry Nordell	MCC
Chuck Magraw	Natural Resources Defense Council
Paul Cartwright	Montana Department of Environmental Quality (DEQ)
Patrick Barkey	UM Bureau of Business and Economic Research
Pat Corcoran	NWE
John Bushnell	NWE
Kyla Wiens	Montana Energy Information Center (MEIC)
Dave Fine	NWE
Gerald Mueller	Consensus Associates
Via Telephone	
Jim Williams	NWE
Joe Schwartzenberger	NEW
Dan Strizic	NWE

Agenda
- MPSC - NARUC Capacity Assistance Grant: Consultant review of electric resource planning and procurement rules
- Dave Gates Generating Station discussion
- 2011 Renewable energy production and RPS compliance
- 2011 Electricity Resource Procurement Plan discussion
- Next meeting

MPSC - NARUC Capacity Assistance Grant: Consultant Review of Electric Resource Planning and Procurement Rules
Dennis Lopach, MPSC Chief Legal Counsel, provided background for and summarized the MPSC activities related to this topic. The existing procurement rules were adopted by the MPSC in

2002-03. Mr. Lopach asked MPSC staff person Jason Brown to review other state procurement rules, including those of Colorado, Utah, and Oregon, with particular attention to utility self-bidding and third party monitoring and evaluation of request for proposals (RFPs). Before Mr. Brown had gotten far in his analysis, MPSC became aware of a National Association of Regulatory Utility Commissioners (NARUC) grant program. The MPSC applied for and was awarded an $85,000 grant to review the MPSC procurement guidelines and integrated resource planning (IRP) rules and those of other states and recommend draft rules to the MPSC. Through a competitive solicitation, the MPSC selected two contractors, Graceful Systems LLC and Bench Mark Heuristic LLC, to conduct this work. The individuals involved are Pam Morgan, a former regulatory director for Portland General Electric (PGE), and Marty Howard, who formerly worked in the PGE rate department. Prior to this meeting, Will Rosquist provided Mr. Mueller a work plan and statement of work for the NARUC grant which was forwarded to ETAC members via email. Copies of these documents are attached below in Appendices 1 and 2.

Ms. Morgan and Mr. Howard have reviewed NWE's procurement plans, MPSC's procurement guidelines and IRP rules, and other state public utility commission rules. They have also begun interviewing individuals knowledgeable about utility planning in Montana. Ms. Morgan and Mr. Howard will consider merging the MPSC procurement guidelines and IRP rules. This study is scheduled be completed by September 15, 2012.

Mr. Lopach asked for ETAC member comments on the work plan and statement of work.

Comment by Pat Corcoran - The IRP and procurement guidelines have different regulatory frameworks. IRP addresses traditional utility resource acquisition in which the resources are included in the utility rate base after application of the used-and-useful test. The procurement guidelines followed restructuring which required the utility to rely on market purchases rather than owning and rate basing resources. Market purchases have been subject to a prudency and public interest test. Montana Dakota Utilities (MDU) was not subject to restructuring and has followed the IRP process. As a successor to MPC, NWE was subject to restructuring and the procurement guidelines. As a result of the Electric Utility Industry Generation Reintegration Act (Reintegration Act), NWE has been re-integrating utility-owned resources along with making market purchases. NWE is not convinced that combining the IRP rules and the procurement guidelines will be as easy as this effort assumes. The company is also concerned that a combination of the two will result in another regulatory layer and/or a regulatory reset. Except for the length of the planning cycle, which should be extended, NWE is not convinced that the current system is broken and requires a fix.

Comment by John Hines - The context for our resource planning and acquisition is critical. By 2002, it was evident that restructuring was a poor decision. Returning to the used-and-useful IRP approach may undermine our work to recover from restructuring. 75% of NWE's electricity resources are still not utility-owned. MDU is not acquiring resources and faces a minimal capital risk. Task 3 of the statement of work (see Appendix 2) directs the consultants to "Develop options for a single, revised set of supply planning and procurement rules for Montana that provide for third-party evaluation and a more structured competitive solicitation process." This Task indicates a prejudged outcome, perhaps in response to a few complaints by small number of unsuccessful resource developers.
Response by Will Rosquist - The MPSC has not prejudged the outcome of the study. The Commission can revisit Task 3 in light of this concern.

Comment - The current planning cycle is not working, and I am not sure that the current procurement planning process is as useful as it should be. These guidelines originated in a regulatory environment, restructuring, that no longer exists.

Comment - The MPSC understands the structural differences between the MDU and NWE processes. The Commission leaned heavily on the IRP process in developing the procurement guideline rules. The objective in both is to ensure the lowest possible resource costs recognizing risk and environmental costs.

Question - What is the difference between used-and-useful and prudency/public interest tests?
Answer by Pat Corcoran and John Hines - In the first, a utility builds an asset in response to a need and comes to the commission for a used-and-useful approval. The second involves a net present analysis against a market price defined via a RFP process.

Question - Is the difference one of building and an after-the-fact review for cost recovery versus the pre-approval allowed in Title 69?
Answer - The Reintegration Act which was passed to allow recovery from restructuring requires a balance of ownership versus the market. IRP focuses on the least cost resource.

Comment - In my view the IRP requires the same analysis as the market test.
Response by John Hines - The procurement guideline approach requires addressing multiple sources of risk. Utility resource ownership requires a showing of how ownership balances risk and value versus market acquisition.
Response by Dennis Lopach - Within the current framework the utility must justify a decision to build a resource within the RFP context.

Comment - The utility needs certainty as to the rules. The current procurement guidelines provide the process and regulatory certainty within side boards.

Comment - I am comfortable with the current regulatory guidelines for resource acquisition decisions. The role of the resource plan visa vie acquisitions is important. The utility needs to identify and value risk and show how it forecasts market price. In the past, there was suspicion that the utility was manipulating assumptions to drive a specific outcome. The current guidelines accommodate opportunity acquisitions and utility built resources.

Comment - We have discussed before the role of the plan which is a time consuming forward looking process versus opportunity acquisitions. In my mind the overriding issue appears to be whether pre-approval will go away.

Comment - We should work from where we are and seek to make the planning and resource acquisition process more useful and less burdensome.

Comment - I agree that we should recognize where we are and seek to streamline the process. I think there is an opportunity to have similar rules for NWE and MDU and ensure that resources benefit customers.

Comment - It appears that an assumption has been made because the NARUC money is available, we should find some way to spend it. I am concerned that using the money on this study may increase uncertainty in the regulatory process. All of us, the utility included, will have to devote time and resources to changing the rules, when a clear need to do so has not been identified.

Comment - I do not see this study as a criticism of NWE. Good regulation and improvements in the rules will lead to more regulatory certainty. Utility-owned assets and ad hoc approvals are a source of uncertainty.

Comment by John Hines - I am concerned about the political context. I do not want this process to lead to an acrimonious legislative session in response to a few disgruntled parties. I do not see the current process as fundamentally broken.

Question - A primary concern that I am hearing is returning to the IRP context. Because of a possible share holder incentive to favor utility-owned resources over market purchases, we need an objective look at all resource alternatives. Do the rules need to be changed to ensure against a bias for utility-owned resources?

Comment - The consultant's scope of work should be narrowed to compiling information about other state processes and stakeholder views of Montana's current process. Given their lack of experience in Montana, consultant recommendations are problematic.

Next Steps - At its next meeting, in light of its members experience with NWE's electricity resource planning and acquisition, the ETAC will review the existing procurement guideline rules to seek ways they can be improved.

Dave Gates Generating Station Discussion

Jim Williams, a manager in NWE's generation group, and John Hines summarized the status of the outage of the Dave Gates Generating Station (DGGS), and NWE's response to it. In January, the plant had a failure in the power turbines which are still under warrantee by their manufacturer, Pratt and Whitney. The DGGS has six turbines, two connected to one of three electric generators . The manufacturer recommended that the plant be shut down pending identification and correction of the problem causing the failure. On January 31, the DGGS was shut down, and its power turbines were shipped to Pratt and Whitney in Connecticut for repair. On February 18, one turbine had been repaired and was back in service. Pratt and Whitney also loaned three power turbines from its lease fleet so that four power turbines are currently available to run at DGGS, the repaired turbine and the three loaners. Two additional turbines have been shipped from Connecticut for repair by April 13. These turbines should be installed and ready to be put into service at the DGGS by May 1st.. At that time, the DGGS will be fully operational utilizing a combination of DGGS and Loaned turbines.

For the first 48 hours after the plant outage, NWE relied upon Colstrip Unit 4 and the Basin Creek plant to meet the North American Electric Reliability Corporation's (NERC's) CPS2 power balancing control performance balancing standard. NWE was able to use information from a recent RFP to contract with Avista and Powerex to provide 85 MW of regulation through February and March to replace the DGGS capability. NWE currently has under contract 25 MW

of regulation through April 15. This contracting confirmed NWE's view that, at best, contracting for regulation services is uncertain.

Question - Is Pratt and Whitney liable for consequential damages?
Answer - NWE is not looking at this issue now. The immediate focus is working with Pratt and Whitney to restore service as soon as possible. Pratt and Whitney has provided the three loaner turbines at no cost and moved the DDGS Gates turbines to the front of its repair queue. NWE intends to maintain its relationship with Pratt and Whitney.

Question - What is your level of confidence that Pratt and Whitney will address the turbine problem?
Answer - It is high over the long-term. Pratt and Whitney has a vested interest in not getting a black mark in the utility community to protect the marketability of its products.

Question - Do you expect that this problem will change turbine manufacturing for any future Dave Gates units?
Answer - Engineering is constantly evolving. While we and the manufacturer are learning from this situation, we do not see a specific manufacturing change resulting from it.

Question - What part failed?
Answer - The DGGS consists of three units. Each unit has two turbines turning one electric generator. The combustion turbine produces the air flow that turns the power turbine. The power turbine is coupled to the electric generator. The failure was in the power turbine, not the combustion turbine. Bolts were backing out and a bearing support was cracking on the power turbine. Whether the bolt backing out caused the support cracking or visa versa is not clear.

2011 Renewable Energy Production and RPS Compliance

Todd Guldseth and Dave Fine reviewed the Judith Gap wind energy production in 2011 and NWE's projected compliance with the Montana Renewable Portfolio Standard (RPS) using two documents entitled, respectively, Judith Gap Wind Energy Production and Summary and Montana Renewable Portfolio Standard Compliance Projection. These documents were passed out at this meeting and will be available on the ETAC web page at the following web address.

http://www.northwesternenergy.com/display.aspx?Page=Electric_Technical_Advisory_Committee_%28ETAC%29

2011 was the best year for wind energy production at Judith Gap, whereas the preceding year, 2010, was the worst year. Wind production varied by 100,000 MWH between the two years. The capacity factor for 2011 was 43% compared to the 2010 value of 35-36%. As has been discussed in past ETAC meetings, maintenance at the Judith Gap project was previously conducted by the turbine manufacturer, GE, with the objective of meeting its contractual obligation of 96% mechanical availability annually for the wind generators. In 2011 with the expiration of the GE contract, Invenergy assumed responsibility for maintenance with the objective of maximizing wind generation. Invenergy does not take turbines out of service for maintenance when the wind is blowing unless necessary. NWE selected GE turbines for the Spion Kop project. NWE will be responsible for maintenance at Spion Kop and intends to incorporate lessons learned at Judith Gap.

NWE's projection of RPS compliance includes Qualifying Facility (QF) projects under contract but which have not yet been constructed and in operation. One of these, Fairfield, recently defaulted on its contract, but under MPSC QF rules was first to enter into a new contract. QF performance and variation in the annual production of the Judith Gap project introduce uncertainty into the RPS compliance forecasts. Reducing QF or Judith Gap annual production by 10 MW shifts the date by which NWE would need additional renewable resources to comply with RPS by one year.

Question - What is the Gordon Butte capacity factor for this year?
Answer - I haven't seen the monthly production from this project, so I don't know the answer.

Question - Has NWE adjusted the projected wind energy production at Spion Kop based on the lessons learned at Judith Gap?
Answer - We are working with the Spion Kop contractor, but have not yet adjusted production estimates.

Question - Do you have sufficient confidence in the Spion Kop meteorology data so that you won't need to adjust the production forecast?
Answer - The meteorology data we use is based on the industry standard.

Question - Can you use a past breech of contract as a reason to deny a QF contract?
Answer - No, under MPSC rules, NWE cannot refuse a QF contract based on a past contract default.

Question - Is a wind developer liable for transmission costs?
Answer - The developer is responsible for transmission interconnection costs.

Question - High pressure systems can result in low wind speeds and high temperature during the summer and low temperatures during the winter. Are electric loads and wind production negatively correlated?
Answer - Hourly wind speeds and loads have a zero correlation. I don't know what the correlation would be on an annual basis.

Question - Does your RPS compliance projection assume current law?
Answer - Yes. Whether the wind production tax credits (PTCs) or some other tax credit is continued is an important issue.

Question - The MPSC is presently considering storage and cost caps. Would the proposals affect your RPS compliance projection?
Answer - We are not aware of these proposals.

Question - Purchase of Renewable Energy Credits (RECs) may be an option for short-term RPS compliance. How do the costs of RECs compare to the wind PTCs?
Answer - RECs are about a $1/MWH whereas the PTC is about $22/MWH.

2011 Electricity Resource Procurement Plan discussion

Dave Fine introduced this topic. He thanked those who made comments on the draft plan. NWE considered the comments in finalizing the 2011 plan. Mr. Fine stated that the plan incorporates

NWE's thinking and sets out what the company plans to do regarding resource acquisition. A gas-fired resource again bubbled to the top in balancing cost and risk. The 2009 resource plan action plan included further development of a site for a gas-fired generating plant. The 2011 plan continues this initiative with actions to narrow possible site alternative considering gas and electric transmission and water availability for cooling. A total of five to six years is projected to be required to develop a gas-fired plant from start to finish. NWE has added personnel to its generation group with gas plant competency. Executive leadership including the vice presidents for transmission (Mike Cashell) and energy supply (John Hines) have bought into the gas plant planning and site banking activity. Under current market conditions with low electricity prices, NWE would not build a new gas-fired plant. However, in 2014 the PPL Montana contract expires so planning for possible acquisition of a gas-fired plant continues. Opportunity acquisitions resulting from other entity bankruptcies or specific conditions will also be considered.

Mr. Fine asked for comments on the 2011 plan and topics that the next planning cycle, which has begun, should address.

Mr. Mueller summarized his February 9, 2012 memo discussing two types of risk which in his view the 2011 plan did not address and which might be considered in the next planning cycle. This memo was shared with the ETAC and NWE prior to this meeting and is attached below in Appendix 3.

Question - During the last planning cycle, NWE indicated that its generation group was conducting a fleet optimization study which would address use of gas-fired resources. Has this study been completed?
Answer - It has not because of other priorities but remains an objective.

Question - Has the internal momentum locked in acquisition of a gas-fired generating plant?
Answer - No, a gas-fired plant continues to be subject to an economic decision involving both company and customer interests. The gas-fired plant planning process has a number of decision points including plant costs and market prices. There is never a perfect moment for a plant acquisition decision. Market price forecasts are just one source of uncertainty. In the past, utilities planned for energy and peak. Today, we must also consider resource flexibility.

Question - Would NWE's gas supply group sell gas to the electric supply group?
Answer - This is not an issue today. NWE has made one small acquisition of a gas supply.

Comment - The last two years have seen big changes in the domestic energy industry.
Response - We are aware of this change particularly in terms of the supply and cost of natural gas; however there are also factors such as environmental regulations and the possible export of liquid natural gas that might cause gas markets to tighten.
Question - Does NWE expect Colstrip Unit 4 to operate for another 20 years?
Answer - We look at resources on an individual basis. Colstrip Units 3 and 4 do not need upgrades to meet recent federal air quality regulations.

Comment - Two other issues raised during the last planning cycle that the ETAC may wish to consider during this cycle are utility-owned resources versus market purchases and siting or acquiring a gas-fired generating plant outside of Montana west of the Mid-Columbia trading hub.

Response - NWE agrees that these are both issues that may benefit from additional ETAC consideration. Risk arising from QF acquisitions is another.

Question - What is the significance of the Mid-Columbia trading hub.
Answer - The hub is located in the Spokane area and is a common delivery point for electricity transactions. If NWE had a source of electricity west of this hub, it could sell electricity to the owners of the Colstrip plants and avoid transmission costs by displacing Colstrip generation.

Comment - I would also like an expanded look at energy efficiency programs, including NWE's strategy for responding to the pending change in lighting standards.

Next Meetings

The next meeting was scheduled for Monday, April 30, 2012 in Butte.

Disclaimer

Committee members provide advice to NWE as individual professionals; the advice they provide does not bind the agencies or organizations that the members serve.

Appendix 1

Montana Public Service Commission Update
of Integrated Resource Planning and Resource Procurement Rules
High-Level Work Plan

Kick-Off: The consultants will begin the project with a series of in-person meetings with the Commissioners, Commission staff and planning and procurement stakeholders to explore fully:

- The existing regulatory planning and procurement processes. This will include observations of experience over time with respect to:
    - Satisfaction with the process of IRP and procurement
        - Participation adequacy?
        - Appropriate level of effort?
        - Perceived value?
        - Indicators of success?
    - Satisfaction with the process of decision-making regarding planning and procurement with regard to:
        - Usefulness of IRP's in the ratemaking decision process following utility resource actions?
            - To the Commission?
            - To the stakeholders?
        - Usefulness of procurement practices in the ratemaking decision process following utility resource actions?
            - To the Commission?
            - To the stakeholders?
        - Indicators of success?
    - Post-decision-making
        - Indicators of success?
        - Observation and assessment of any gaps between:
            - Expected outcomes and actual outcomes?
            - Assumptions used and reality that unfolded?
        - Learning and action on the basis of such observations and assessments
- Aspirations for its future regulatory planning and procurement processes. These would be the same sets of observed outcomes expressed over time as listed above but forward- rather than backward-looking.
- Goals and objectives for the project.

Data-Gathering: The next steps in the process with be (1) gathering and review of publicly-available statutes/rules and IRP and procurement docket records from various states and, to the extent that it is useful, internationally, and (2) surveys and interviews to identify and describe the IRP/procurement practices currently found most effective, including the reasons why the practitioners believe them to be so. To assist this stage, the interviews in the kick-off stage will include stakeholders' views on state or utility planning/procurement processes they admire and why.

Preliminary recommended IRP/Procurement approach (with options as appropriate): Combining the learning from the data-gathering with the consultants' expertise and experience, the consultants will develop the key components of an integrated IRP and procurement process for the Commission's

preliminary review and consideration.

Stakeholder engagement: After making any modifications to reflect the Commission's preliminary review, the consultants will engage the key Montana stakeholders in dialogue around the components identified.

Final recommended IRP/Procurement approach in preparation for rulemaking: The consultants will prepare a report for the Commission specifying a final recommended approach. Upon request, they will also write a draft rule suitable for beginning a formal rulemaking process, such rule to incorporate any modifications the Commission suggests in response to the initial report and recommendations.

Appendix 2

Montana SERCAT SOW

2.4 STATEMENT OF WORK/ TECHNICAL PROGRAMMATIC AREAS

The Consultant, in accordance with high standards of professionalism and expertise, will act at the direction of the *NARUC* Director of Grants and Research in coordination with the designated representatives of *Montana Public Service Commission (MPSC)* in carrying out the tasks described below as adopted by the NARUC Executive Committee, and as they may be amended throughout the term of this Consulting Agreement.

While complying with all aspects of the Prime Agreement and the terms and conditions of this *Contract*, the *Sub-awardee* will accomplish a series of tasks and subtasks detailed below:

TASKS AND SUBTASKS TO BE PERFORMED

TASK 1. IN-PERSON KICK OFF MEETING

Graceful Systems LLS and Bench Mark Heuristics LLC shall attend an in-person kick off meeting to explore the Commission's existing regulatory planning processes and its aspirations for its future regulatory planning processes objectives. *Graceful Systems* will also reach out to major stakeholders in Montana and interview them regarding the existing IRP process.

This kick-off meeting will also provide the context to finalize the workplan, including defining in advance the number of hours and means by which *Graceful Systems LLS and Bench Mark Heuristics LLC* will be available to provide the MPSC with reasonable technical assistance by conference call or email during the rulemaking process, as delivered under Task 5 of this agreement.

Deliverables: Summary document of findings of kick off meeting and stakeholder interviews, delivered electronically to NARUC within 10 days of meetings. Finalized plan for consultant support to MPSC during rulemaking process.

ARRA Reporting Requirement for this task: Report all individuals working under this agreement whether fully or partially and the number of hours each of them has contributed to the performance of this task. Hours must be reported on the 3rd day following the end of the calendar quarter (April 3, July 3, October 3, and January 3).

TASK 2. GATHER AND COMPILE AN INTO A COMPREHENSIVE OVERVIEW STATE PROCUREMENT RULES AND BEST PRACTICES

Graceful Systems LLS and Bench Mark Heuristics LLC will access both publicly-available statues/rules and IRP and procurement docket records from various states and identify the practices currently found most effective, including the reasons why they are found so.

Deliverables: Deliver briefing of findings to the MPSC. Summary document of best practices and an overview of existing state procurement rules, including a bibliography, delivered electronically to NARUC staff within five days delivering briefing of compilation to MPSC.

ARRA Reporting Requirement for this task: Report all individuals working under this agreement whether fully or partially and the number of hours each of them has contributed to the performance of this task. Hours must be reported on the 3rd day following the end of the calendar quarter (April 3, July 3, October 3, and January 3).

TASK 3. DEVELOP OPTIONS FOR A SINGLE, REVISED SET OF SUPPLY PLANNING AND PROCUREMENT RULES FOR MONTANA THAT PROVIDE FOR THIRD-PARTY EVALUATION AND A MORE STRUCTURED COMPETITIVE SOLICITATION PROCESS

Graceful Systems LLS and Bench Mark Heuristics LLC will combine findings from Task 2 and their own expertise and develop the key components of an integrated IRP and procurement process for the MPSC to review.

Deliverables: A document with a single set of robust, comprehensive supply planning and procurement rules for Montana that provide for third-party evaluation and a more structured competitive solicitation process. Delivered electronically to NARUC staff within five days of delivering it, either in an in-person briefing or electronically, to MPSC.

ARRA Reporting Requirement for this task: Report all individuals working under this agreement whether fully or partially and the number of hours each of them has contributed to the performance of this task. Hours must be reported on the 3rd day following the end of the calendar quarter (April 3, July 3, October 3, and January 3).

TASK 4. STAKEHOLDER ENGAGEMENT

Graceful Systems LLS and Bench Mark Heuristics LLC will engage key Montana stakeholders in a dialog around the components identified in Task 3 as the revised planning and procurement rules.

Deliverable: Summary document of outcomes from stakeholders' dialogs delivered electronically to NARUC staff within 10 days of interviews.
ARRA Reporting Requirement for this task: Report all individuals working under this agreement whether fully or partially and the number of hours each of them has contributed to the performance of this task. Hours must be reported on the 3rd day following the end of the calendar quarter (April 3, July 3, October 3, and January 3).

TASK 5. DEVELOP FINAL RECOMMENDATIONS AND DRAFT FINAL RULE; ADVISE COMMISSION IN RULEMAKING

Graceful Systems LLS and Bench Mark Heuristics LLC will use all available resources to compile a report specifying a final comprehensive recommended approach to planning and procurement rules for Montana. *Graceful Systems LLS and Bench Mark Heuristics LLC* will write a draft rule in order to begin a formal rulemaking process, incorporating any modifications the Commission suggests in response to the initial report and recommendations.

In addition, *Graceful Systems LLS and Bench Mark Heuristics LLC* will be available to provide the MPSC with reasonable technical assistance by conference call or email during the rulemaking process, within parameters defined in Task 1.

Deliverables: Final written recommendations delivered to MPSC at the conclusion of this project and to NARUC staff electronically by September 15, 2012.

ARRA Reporting Requirement for this task: Report all individuals working under this agreement whether fully or partially and the number of hours each of them has contributed to the performance of this task. Hours must be reported on the 3rd day following the end of the calendar quarter (April 3, July 3, October 3, and January 3).

TASK 6. FINAL WRITTEN REPORT

Graceful Systems LLS and Bench Mark Heuristics LLC will draft a report summarizing tasks 1-5, including a bibliography and citations, so that other states entering a similar examination might benefit from the process.

Deliverables: Final written report summarizing tasks 1 through 5 and analyzing the results, delivered to MPSC at the conclusion of this project and to NARUC staff electronically by September 15, 2012.

ARRA Reporting Requirement for this task: Report all individuals working under this agreement whether fully or partially and the number of hours each of them has contributed to the performance of this task. Hours must be reported on the 3rd day following the end of the calendar quarter (April 3, July 3, October 3, and January 3).

Appendix 3

Memorandum

Date: February 9, 2012
To: Files
From: Gerald Mueller
RE: NWE Procurement Plan and Risk

NWE's 2011 Plan appropriately defines risk as "...the relative uncertainty associated with an outcome or value." It goes on to say, "Here we define risk that is associated with the estimated future cost of the supply Portfolio..." and "NorthWestern addresses risk through stochastic modeling and the use of stochastic model results to quantitatively assess risk relative to total Portfolio cost." The plan also states that "The primary drivers of risk that are defined and examined in this Plan are electricity price and natural gas price." I am concerned that this assessment of risk may be too limited because it does not address improbable but catastrophic outcomes or the uncertainty of the wind resource.

Unfortunately, utilities in our region and in Montana, both publically- and investor-owned, have experienced or come close to experiencing improbable but catastrophic outcomes. Recently, Southern Montana Electric (SME) contracted for power assuming significant load growth and/or high electricity prices. Neither occurred and SME was forced to declare bankruptcy. In the 1970's, the Montana Power Company (MPC) and three other investor-owned utilities built Colstrip Units 3 & 4. MPC's share of these plants would have essentially doubled its rate base. Loads did not grow as the company forecasted due in part to the shut down of Anaconda Company smelting and refining operations. When the Montana Public Service Commission failed to allow MPC's investment in Colstrip Unit 4 into rate base in the early 1980s, MPC faced bankruptcy until it was able to sell its Colstrip Unit 4 power to a southern California utility. Regionally, publically- and investor-owned utilities spent literally billions of dollars in the 1980s on unneeded nuclear plants that were not completed: Washington Public Power Supply System Units 1, 3, 4, & 5 and the Skagit-Hanford and Pebble Springs projects. Whether this outcome was as improbable as the utilities thought when the plants were planned may be debatable, but its cost was nearly catastrophic.

While I do not see the NWE Plan action plan as presenting significant risk of improbable, catastrophic outcomes, I suggest that NWE explicitly consider whether any portfolios present this kind of risk in future plans.

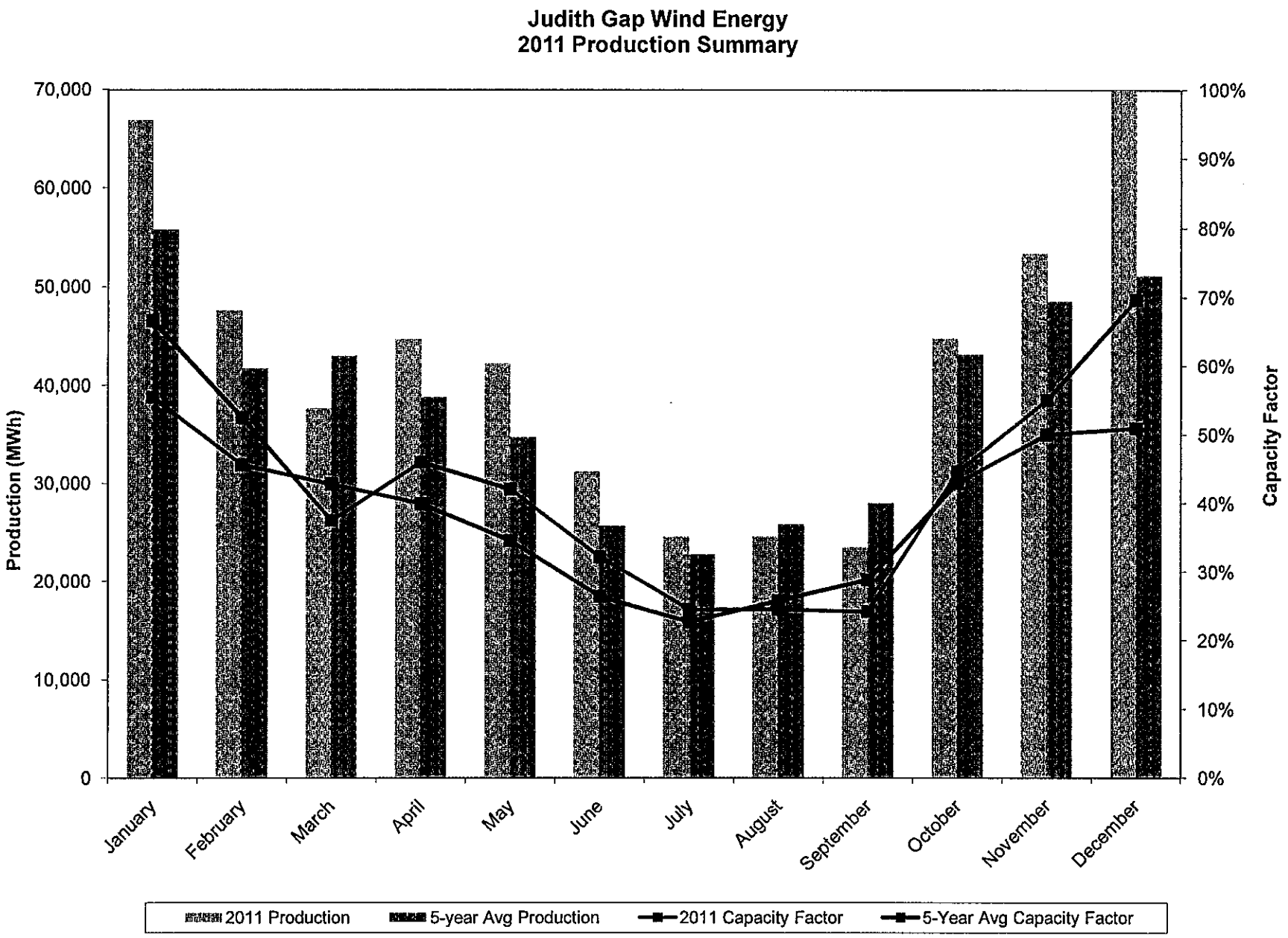
NWE has experienced unexpected outcomes regarding generating resources it has acquired. Both Colstrip Unit 4 and the Dave Gates Generating Station have suffered extended and unplanned outages. Through market purchases, NWE has been able to respond to these outages successfully so that they apparently did not significantly harm the company or its customers.

Another source of risk is the uncertainty inherent in wind generation. The 2011 Plan discusses but does not assess this risk. According to the Plan, wind is playing an increasingly significant role in NWE's resource portfolio. On the present course, by the end of this year, NWE will be integrating approximately 237 MW of wind into its energy supply portfolio, compared to 368 MW of thermal generation. The Northwest Power Planning Council analyzes wind stochastically in a manner similar to water availability. My understanding is that the Council constructs a distribution of wind production and makes draws of "wind years" as it does water years in each stochastic model run. In my opinion, NWE should consider assessing the risk posed by wind in a manner similar to the Council or through some other approach in future plans.

Judith Gap Wind Energy Production Summary

2011	Total MWH	HL[1] MWH	LL[2] MWH	Peak MW	Maximum 15-Minute Change MW	Average MW	Standard Deviation MW	Capacity Factor[3]	2006-2010 Average Total MWH	2006-2010 Average Capacity Factor
January	66,855	34,304	32,552	133.4	-58.2	89.9	47.5	67%	55,782	55%
February	47,622	29,347	18,274	135.8	-94.2	70.9	53.6	52%	41,742	46%
March	37,661	23,934	13,727	136.0	85.2	50.6	52.9	37%	42,999	43%
April	44,721	26,527	18,194	136.0	82.4	62.1	52.1	46%	38,820	40%
May	42,238	27,208	15,030	136.0	76.3	56.8	49.0	42%	34,707	35%
June	31,259	20,776	10,483	135.9	84.3	43.4	47.5	32%	25,699	26%
July	24,609	15,494	9,115	135.9	-112.0	33.1	40.1	25%	22,796	23%
August	24,633	15,948	8,685	135.9	77.2	33.1	39.4	25%	25,871	26%
September	23,516	14,777	8,739	136.0	97.6	32.7	42.9	24%	28,068	29%
October	44,792	27,770	17,022	136.0	90.5	60.2	52.5	45%	43,171	43%
November	53,496	31,863	21,633	136.0	-90.2	74.3	52.9	55%	48,660	50%
December	69,959	44,694	25,265	136.1	74.6	94.0	52.7	70%	51,187	51%
Total YTD	511,362	312,644 61%	198,719 39%	136.1	-112.0	58.4	52.9	43%	459,501	39%

1 - Heavy load hours Monday - Saturday HE 7 - 22
2 - Light load hours Monday - Saturday HE 1 - 6, 23, 24; all day Sunday
3 - Calculated capacity factor based on 135 MW installed capacity


Judith Gap Wind Energy
2011 Production Summary
Production (MWh)
Capacity Factor
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
January
February
March
April
May
June
July
August
September
October
November
December
2011 Production
5-year Avg Production
2011 Capacity Factor
5-Year Avg Capacity Factor

Montana Public Service Commission Update
of Integrated Resource Planning and Resource Procurement Rules
High-Level Work Plan

Kick-Off: The consultants will begin the project with a series of in-person meetings with the Commissioners, Commission staff and planning and procurement stakeholders to explore fully:

- The existing regulatory planning and procurement processes. This will include observations of experience over time with respect to:
    - Satisfaction with the process of IRP and procurement
        - Participation adequacy?
        - Appropriate level of effort?
        - Perceived value?
        - Indicators of success?
    - Satisfaction with the process of decision-making regarding planning and procurement with regard to:
        - Usefulness of IRP's in the ratemaking decision process following utility resource actions?
            - To the Commission?
            - To the stakeholders?
        - Usefulness of procurement practices in the ratemaking decision process following utility resource actions?
            - To the Commission?
            - To the stakeholders?
        - Indicators of success?
    - Post-decision-making
        - Indicators of success?
        - Observation and assessment of any gaps between:
            - Expected outcomes and actual outcomes?
            - Assumptions used and reality that unfolded?
        - Learning and action on the basis of such observations and assessments
- Aspirations for its future regulatory planning and procurement processes. These would be the same sets of observed outcomes expressed over time as listed above but forward- rather than backward-looking.
- Goals and objectives for the project.

Data-Gathering: The next steps in the process with be (1) gathering and review of publicly-available statutes/rules and IRP and procurement docket records from various states and, to the extent that it is useful, internationally, and (2) surveys and interviews to identify and describe the IRP/procurement practices currently found most effective, including the reasons why the practitioners believe them to be so. To assist this stage, the interviews in the kick-off stage will include stakeholders' views on state or utility planning/procurement processes they admire and why.

Preliminary recommended IRP/Procurement approach (with options as appropriate): Combining the learning from the data-gathering with the consultants' expertise and experience, the consultants will develop the key components of an integrated IRP and procurement process for the Commission's preliminary review and consideration.

Stakeholder engagement: After making any modifications to reflect the Commission's preliminary review, the consultants will engage the key Montana stakeholders in dialogue around the components identified.

Final recommended IRP/Procurement approach in preparation for rulemaking: The consultants will prepare a report for the Commission specifying a final recommended approach. Upon request, they will also write a draft rule suitable for beginning a formal rulemaking process, such rule to incorporate any modifications the Commission suggests in response to the initial report and recommendations.

2.4 STATEMENT OF WORK/ TECHNICAL PROGRAMMATIC AREAS

The Consultant, in accordance with high standards of professionalism and expertise, will act at the direction of the *NARUC* Director of Grants and Research in coordination with the designated representatives of *Montana Public Service Commission (MPSC)* in carrying out the tasks described below as adopted by the NARUC Executive Committee, and as they may be amended throughout the term of this Consulting Agreement.

While complying with all aspects of the Prime Agreement and the terms and conditions of this *Contract*, the *Sub-awardee* will accomplish a series of tasks and subtasks detailed below:

TASKS AND SUBTASKS TO BE PERFORMED

TASK 1. IN-PERSON KICK OFF MEETING

Graceful Systems LLS and Bench Mark Heuristics LLC shall attend an in-person kick off meeting to explore the Commission's existing regulatory planning processes and its aspirations for its future regulatory planning processes objectives. *Graceful Systems* will also reach out to major stakeholders in Montana and interview them regarding the existing IRP process.

This kick-off meeting will also provide the context to finalize the workplan, including defining in advance the number of hours and means by which *Graceful Systems LLS and Bench Mark Heuristics LLC* will be available to provide the MPSC with reasonable technical assistance by conference call or email during the rulemaking process, as delivered under Task 5 of this agreement.

Deliverables: Summary document of findings of kick off meeting and stakeholder interviews, delivered electronically to NARUC within 10 days of meetings. Finalized plan for consultant support to MPSC during rulemaking process.

ARRA Reporting Requirement for this task: Report all individuals working under this agreement whether fully or partially and the number of hours each of them has contributed to

the performance of this task. Hours must be reported on the 3rd day following the end of the calendar quarter (April 3, July 3, October 3, and January 3).

TASK 2. GATHER AND COMPILE AN INTO A COMPREHENSIVE OVERVIEW STATE PROCUREMENT RULES AND BEST PRACTICES

Graceful Systems LLS and Bench Mark Heuristics LLC will access both publicly-available statues/rules and IRP and procurement docket records from various states and identify the practices currently found most effective, including the reasons why they are found so.

Deliverables: Deliver briefing of findings to the MPSC. Summary document of best practices and an overview of existing state procurement rules, including a bibliography, delivered electronically to NARUC staff within five days delivering briefing of compilation to MPSC.

ARRA Reporting Requirement for this task: Report all individuals working under this agreement whether fully or partially and the number of hours each of them has contributed to the performance of this task. Hours must be reported on the 3rd day following the end of the calendar quarter (April 3, July 3, October 3, and January 3).

TASK 3. DEVELOP OPTIONS FOR A SINGLE, REVISED SET OF SUPPLY PLANNING AND PROCUREMENT RULES FOR MONTANA THAT PROVIDE FOR THIRD-PARTY EVALUATION AND A MORE STRUCTURED COMPETITIVE SOLICITATION PROCESS

Graceful Systems LLS and Bench Mark Heuristics LLC will combine findings from Task 2 and their own expertise and develop the key components of an integrated IRP and procurement process for the MPSC to review.

Deliverables: A document with a single set of robust, comprehensive supply planning and procurement rules for Montana that provide for third-party evaluation and a more structured competitive solicitation process. Delivered electronically to NARUC staff within five days of delivering it, either in an in-person briefing or electronically, to MPSC.

ARRA Reporting Requirement for this task: Report all individuals working under this agreement whether fully or partially and the number of hours each of them has contributed to

the performance of this task. Hours must be reported on the 3rd day following the end of the calendar quarter (April 3, July 3, October 3, and January 3).

TASK 4. STAKEHOLDER ENGAGEMENT

Graceful Systems LLS and Bench Mark Heuristics LLC will engage key Montana stakeholders in a dialog around the components identified in Task 3 as the revised planning and procurement rules.

Deliverable: Summary document of outcomes from stakeholders' dialogs delivered electronically to NARUC staff within 10 days of interviews.

ARRA Reporting Requirement for this task: Report all individuals working under this agreement whether fully or partially and the number of hours each of them has contributed to the performance of this task. Hours must be reported on the 3rd day following the end of the calendar quarter (April 3, July 3, October 3, and January 3).

TASK 5. DEVELOP FINAL RECOMMENDATIONS AND DRAFT FINAL RULE; ADVISE COMMISSION IN RULEMAKING

Graceful Systems LLS and Bench Mark Heuristics LLC will use all available resources to compile a report specifying a final comprehensive recommended approach to planning and procurement rules for Montana. *Graceful Systems LLS and Bench Mark Heuristics LLC* will write a draft rule in order to begin a formal rulemaking process, incorporating any modifications the Commission suggests in response to the initial report and recommendations.

In addition, *Graceful Systems LLS and Bench Mark Heuristics LLC* will be available to provide the MPSC with reasonable technical assistance by conference call or email during the rulemaking process, within parameters defined in Task 1.

Deliverables: Final written recommendations delivered to MPSC at the conclusion of this project and to NARUC staff electronically by September 15, 2012.

ARRA Reporting Requirement for this task: Report all individuals working under this agreement whether fully or partially and the number of hours each of them has contributed to

the performance of this task. Hours must be reported on the 3rd day following the end of the calendar quarter (April 3, July 3, October 3, and January 3).

TASK 6. FINAL WRITTEN REPORT

Graceful Systems LLS and Bench Mark Heuristics LLC will draft a report summarizing tasks 1-5, including a bibliography and citations, so that other states entering a similar examination might benefit from the process.

Deliverables: Final written report summarizing tasks 1 through 5 and analyzing the results, delivered to MPSC at the conclusion of this project and to NARUC staff electronically by September 15, 2012.

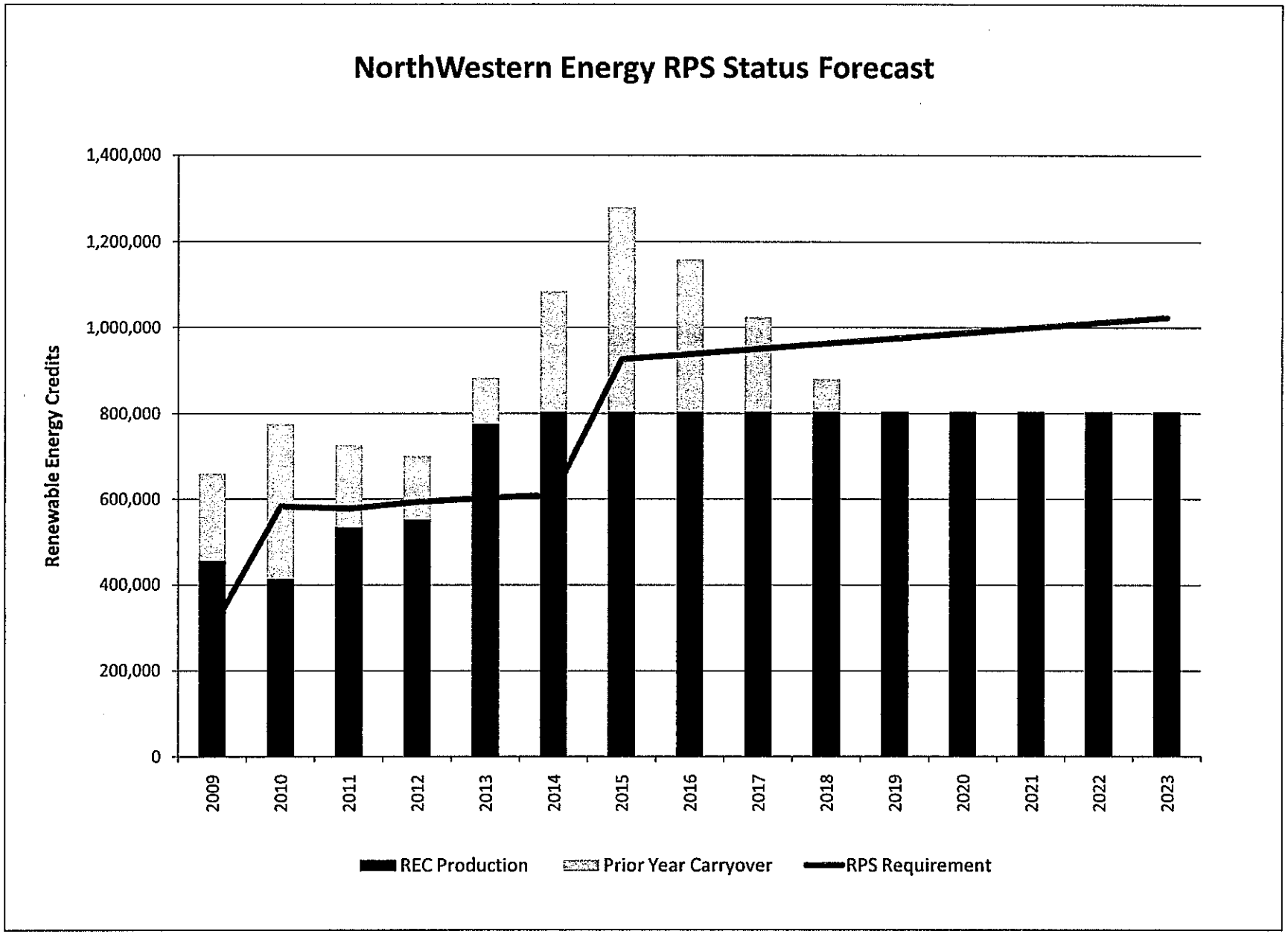
ARRA Reporting Requirement for this task: Report all individuals working under this agreement whether fully or partially and the number of hours each of them has contributed to the performance of this task. Hours must be reported on the 3rd day following the end of the calendar quarter (April 3, July 3, October 3, and January 3).

Montana Renewable Portfolio Standard Compliance Projection

One Renewable Energy Credit (REC) generated for each Megawatt-Hour of Approved Renewable Generation
April 2012 Update

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Retail Load (sales) MWH	5,834,029	5,775,605	5,932,810	6,024,562	6,097,846	6,174,666	6,253,776	6,334,403	6,416,151	6,498,765	6,582,096	6,666,023	6,749,435	6,833,174	6,916,944
RPS (%)	5%	10%	10%	10%	10%	10%	15%	15%	15%	15%	15%	15%	15%	15%	15%
RPS (based on prior year load)	298,759	583,403	577,561	593,281	602,456	609,785	926,200	938,066	950,160	962,423	974,815	987,314	999,903	1,012,415	1,024,976
Operating Projects:															
Judith Gap (135 MW)	455,985	414,004	511,362	473,805	473,805	473,805	473,805	473,805	473,805	473,805	473,805	473,805	473,805	473,805	473,805
Turnbull (13MW)			22,459	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000
Gordon Butte (9.6 MW)			747	33,750	33,750	33,750	33,750	33,750	33,750	33,750	33,750	33,750	33,750	33,750	33,750
Construction Projects:															
Spion Kop (40MW)				11,534	138,408	138,408	138,408	138,408	138,408	138,408	138,408	138,408	138,408	138,408	138,408
Musselshell (10 MW)				2,288	28,600	28,600	28,600	28,600	28,600	28,600	28,600	28,600	28,600	28,600	28,600
Musselshell 2 (10 MW)				2,240	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000
Two Dot Wind Farm (10 MW)				2,832	35,400	35,400	35,400	35,400	35,400	35,400	35,400	35,400	35,400	35,400	35,400
Fairfield (10 MW)					2,552	31,900	31,900	31,900	31,900	31,900	31,900	31,900	31,900	31,900	31,900
Flint Creek (2 MW)				640	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000
Lower South Fork (0.5 MW)				152	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Total RECs Generated	455,985	414,004	534,568	552,241	775,415	804,763	804,763	804,763	804,763	804,763	804,763	804,763	804,763	804,763	804,763
Current Yr REC	455,985	414,004	534,568	552,241	775,415	804,763	804,763	804,763	804,763	804,763	804,763	804,763	804,763	804,763	804,763
Prior Yr Carry-Over REC	204,132	361,359	191,960	148,967	107,927	280,886	475,865	354,428	221,124	75,727	0	0	0	0	0
Total Available REC	660,117	775,363	726,528	701,208	883,342	1,085,649	1,280,628	1,159,191	1,025,887	880,490	804,763	804,763	804,763	804,763	804,763
RPS	298,759	583,403	577,561	593,281	602,456	609,785	926,200	938,066	950,160	962,423	974,815	987,314	999,903	1,012,415	1,024,976
Carry-Over REC	361,359	191,960	148,967	107,927	280,886	475,865	354,428	221,124	75,727	0	0	0	0	0	0
Annual RPS Met?	YES	YES	YES	YES	YES	YES	YES	YES	YES	NO	NO	NO	NO	NO	NO
Additional RECs needed to meet RPS										81,933	170,052	182,551	195,140	207,652	220,213

Load based on April 2011 long-term load forecast update


NorthWestern Energy RPS Status Forecast
Renewable Energy Credits
1,400,000
1,200,000
1,000,000
800,000
600,000
400,000
200,000
0
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
REC Production
Prior Year Carryover
RPS Requirement

ETAC Meeting Agenda

NorthWestern Energy
General Office 4th Floor Boardroom

Monday April 30, 2012 – 9:00 AM

Conference Call-In: 877 273-4202 Conference Room (Access Code): 7656120

Agenda:

This meeting is a follow-up to the April 6th meeting to offer an opportunity for the ETAC to comment to NorthWestern on planning rules and process

- Owned versus contracted electric supply resources
- Resource Plan submission cycle
- Other topics

Bill Thomas can be available for additional discussion concerning the future of the DSM program if requested

(Lunch will be provided)

Meeting Summary
NorthWestern Energy Electricity Technical Advisory Committee
April 30, 2012

Attendance
Those participating in the Energy Electricity Technical Advisory Committee (ETAC) meeting in person and via telephone included:

Name	Organization
In Person	
Thomas M. Power	District XI Human Resource Council
Pat Corcoran	NorthWestern Energy (NWE)
Chuck Magraw	Natural Resources Defense Council
Diego Rivas	Northwest Energy Coalition
Kyla Wiens	Montana Energy Information Center (MEIC)
John Hines	NWE
John Bushnell	NWE
Mark Stauffer	NWE
Frank Bennett	NWE
Dave Fine	NWE
Todd Guldseth	NWE
Joe Schwartzenberger	NWE
Bill Thomas	NWE
Gerald Mueller	Consensus Associates
Via Telephone	
Kate Whitney	Montana Public Service Commission (MPSC)
Will Rosquist	MPSC
Lauren Casey	Northwest Power and Conservation Council (NPCC)
Larry Nordell	Montana Consumer Counsel

Agenda
- ETAC Discussion of NWE Planning Rules and Process
- Future of the DSM Program
- Next meeting

ETAC Discussion of NWE Planning Rules and Process
Highlights of the group's discussion of this topic follows. Prior to this meeting, John Bushnell provided ETAC members with copies of two statutes related to resource planning and acquisition, Title 69, Chapter 3, Sub-Chapter 12 MCA and Title 69, Chapter 8 MCA, and the corresponding MPSC administrative rules, 38.5.20 ARM and 38.5.82 ARM. These documents are included below in Appendices 1 and 2.

Comment - I am confused about how the statutes and rules fit together.

Response by Pat Corcoran - In general, statutes set forth statewide, public policy, and agency rules provide details for implementing the policy. The statute addressing integrated least cost planning (IRP), Title 69, Chapter 3, Sub-Chapter 12, goes back to 1993. The second statute, the reintegration statute, applies only to NWE (a utility that removed its generation assets from its rate base pursuant to this chapter prior to October 1, 2007). A utility such as Montana Dakota Utilities that is subject to the IRP statute services its load by purchasing or building a resource and then submits the acquisition to the MPSC for rate approval. The test applied by the MPSC to these acquisitions is the used-and-useful test. The reintegration statute allowed NWE to recreate a vertically integrated utility by rate-basing electric resources and to seek MPSC approval before the resource is acquired. To give pre-acquisition approval, the MPSC must find that the acquisition would be in the public interest. Thus the two statutes have different contexts and provide different legal tests. NWE understands that the MPSC may be considering merging its rules for IRP and resource procurement. We believe that such a merger would require statutory change. NWE also believes that the current framework is working so we do not see a need to expend resources to consider changes to it.

Mr. Mueller asked if any ETAC member see a need to change the basic framework under which NWE is planning and acquiring resources and about specific changes that would improve the MPSC rules guiding resource procurement (38.5.82 ARM). Mr. Mueller pointed out two specific potential changes, requiring an independent, third party to administrate request-for-resource processes (RFP), and lengthening the resource planning cycle, which current rules set at two years. He also noted that the IRP rules 38.5.2001(8) provide that "...utility investment in conservation measures installed on the customer's side of the meter should be considered cost effective up to 115 percent of the utility's long-term avoided cost." The procurement guidelines do not have a similar reference. Mr. Mueller asked if ETAC members see a need to include such a requirement in the procurement guideline rules.

Comment by Bill Thomas - The 115% was set to acknowledge externalities that are too difficult to quantify. Two points are important regarding demand-side management (DSM) resources. First, there needs to be agreement regarding DSM acquisition rules. Second, DSM should be treated as a resource to which a cost effective test must be applied.

Comment - The 115% is usually justified in terms of market barriers rather than costs of externalities.

Question - Does the IRP statute also apply to NWE?
Answer - No. The MPSC rules at 38.5.8201(5), which apply to NWE, provide that:

> These guidelines supersede the commission's electric least cost planning rules (ARM 38.5.2001 through 38.5.2012) solely with respect to electricity supply resource planning and procurement functions.

Comment - In theory, NWE could purchase or build a resource and take it to the MPSC for approval under the used-and-useful test.

Comment - Both the IRP rules (38.5.20 ARM) and the procurement guidelines (38.5.82 ARM) are good rules, and NWE is doing a good job implementing the latter. However, I believe that

too much emphasis is being given to a potential effect resulting from combining the two. NWE's concern that combining the rules would subject it to the used-and-useful test could be addressed in an explicit statement that any utility that was restructured could continue to seek a pre-acquisition approval subject to the public interest test.

Comment - I have two comments regarding specific changes to the current resource procurement guidelines. First, while NWE could have been more transparent in its explanation of how and why it made decisions in the Spion Kop acquisition, I would not require a fully independent RFP administrator. Secondly, changes may be needed setting forth clear standards regarding utility-owned versus purchased resource acquisitions.
Response by John Hines - The biggest transparency obstacle in Spion Kop would not be resolved by requiring a third party administrator. The obstacle arises from confidentiality issues. NWE cannot disclose why we shifted from one resource to another.

Question - In the section of resource acquisition [38.5.8212(d)], the current procurement guideline rules require the utility to:

> *analyze the feasibility and economic costs, risks, and benefits of rate basing versus alternative electricity supply arrangements.*

This requirement relates to acquisition, not planning. Is utility ownership built into the current NWE resource plan?
Answer by John Hines - No. Under the old IRP framework, utilities such as the Montana Power Company (MPC) spent money siting and designing specific resources pursuant to an acquisition schedule. MPC acquired resources in a different environment than exists today. Utilities owned a fleet of resources and needed to acquire increments to it. A robust resource market did not exist, nor did were opportunity resources such as the bankrupt Southern Montana Utility gas plant available. In its current planning, NWE develops an acquisition road map using generic resource costs. The cost of specific resources are addressed when an acquisition occurs. For example, for the Spion Kop acquisition, we looked at the range of currently available resource alternatives. Spion Kop was cheaper than all alternatives except for the market, but a market purchase would not have addressed risk or the value of renewable resource credits. The 2011 resource plan identifies a gas-fired resource as the preferred option, but in today's market, with lower gas and electricity prices, we would not acquire a gas resource. In considering changes to the rules regarding owned versus purchases, we should be careful not to undermine the policy of recreating a vertically-owned utility.

Comment - Looking at the entire set of rules including acquisition filing requirements, the utility is clearly on notice that it will have to justify its decision to own rather than purchase a resource using modeling, market price forecasts and risk analysis. I do not hear NWE seeking to change the rules regarding standards for owned versus purchased resources. I do not have specific suggestions for changing the rules to address this issue.

Comment - There has been frustration that NWE has not implemented the action plan as set out in past resource plans. Rather than as a detailed schedule for acquiring specific resources, plans today have a different purpose. Now plans provide information about resource technologies and electric and gas markets and assess risk to provide a context for evaluating specific resource acquisition opportunities.

Response by John Hines - The plan allows us to understand resource portfolio needs. We currently face decisions about how to respond to the expiration of the PPL contracts. We analyze gas and electric price forecasts, compare market and alternative generic resource costs, and assess external factors such as environment and carbon costs. In the present plan, we are looking at a decision in the 2015-16 time frame to acquire a combined cycle, gas-fired plant. From beginning to commercial start, acquiring a combined cycle plant would take five years. We are taking actions to reduce this lead time to three years by site banking, assessing infrastructure and permitting.

Comment - I am not convinced that the utility would plan differently today under the IRP or default procurement guideline rules. Under both the utility should test the market by issuing an RFP for resources with the characteristics of the identified preferred resource.
Response by John Hines - NWE will issue an RFP to replace the PPL contracts seeking the combination of base load and callable resource products so that we can demonstrate and document alternatives to building and operating a plant.

Comment by Dave Fine - For the plan, we must make assumptions such as the presence of a market providing for within-the-hour scheduling and dispatchable resources. If this market does not develop, the plan would not reflect actual acquisition conditions.

Comment by John Bushnell - Another such assumption is whether Congress will extend production tax credits for renewable resources.

Comment by Mark Stauffer - In an IRP, variables are defined within study parameters. It is not clear if an IRP would capture externalities such as whether the region is energy surplus but peak deficient as has recently been found by the Pacific Northwest Utilities Conference Committee (PNUCC).

Question - If the region is peak short, why build a combined cycle plant?
Answer by John Hines - We may at some point need to reassess the identification of a combined cycle plant as the preferred resource.

Comment - I am concerned that site banking and internal planning for a combined cycle plant would create momentum that would lock in an acquisition of this resource.
Response by John Hines - The steps we are taking have costs that are small compared to a acquiring a plant and are not locking in a gas resource. If market prices remain as low as they are now, we will not acquire a new gas-fired resource. However, we do not want to be in a position of having to rely on the market. At some point, which we cannot predict with certainty, market prices may increase and exceed the costs of a new resource. By taking steps now to enhance the ownership option, we may protect customers from higher market costs.

Comment - I agree that the utility should be taking initial steps now to preserve utility ownership as an option should market prices increase.
Response by Pat Corcoran - NWE is setting out milestones that can lead to utility ownership.

Comment - I do not know how to change the procurement rules at this point, but we should think more about recommendations regarding the tradeoff between utility ownership and flexibility afforded by shorter term purchases. Management decisions to acquire a resource are driven by more than resource planning.
Response by Pat Corcoran - NEW management decisions are informed by planning, which is in turn informed by ETAC discussions. Planning recommendations go to the Energy Supply Board and then to the executive supply team. We are careful to document the factors and steps in the company's decisions before making filings.

Question - How would a three year planning cycle link to MPSC avoided cost determinations?
Answer by Will Rosquist - The utility must now file avoided costs within 30 days of the procurement plan filing. If we moved to a three-year planning cycle, there could be an intermediate update or status report to inform an avoided cost proceeding. The avoided cost would stand on the evidence in the avoided cost case.

Question - Can a utility file qualifying facility (QF) rates at any time?
Answer by Will Rosquist - The utility can initiate a QF rate filing at any time; however, FERC rules require filing QF tariffs every two years.

Question - Isn't the FERC two-year filing requirement informational rather than to set QF tariffs?
Answer by Will Rosquist - The information may initiate a tariff change.

Comment - A three year period is needed to receive and respond to comments on the resource procurement plan.

Question by Gerald Mueller - Does anyone see drawbacks to a planning cycle longer than three years?
Answer by John Hines - If we went to longer than three years, the utility would likely be doing plan revisions in response to changes.

Question - What is the current planning cycle for natural gas?
Answer by Will Rosquist - Two years in even number years.

Question - Has there been discussion of eliminating the gas procurement planning requirement?
Answer by John Hines - While gas planning is simpler than for electricity, planning for gas acquisitions should not be eliminated.

Question - What is the schedule for the work of the MSPC consultants concerning the IRP/procurement rules?
Answer by Will Rosquist - The consultants have completed the initial phase of the work which involved interviewing stakeholders. They are now compiling a report on other state rules and should have a preliminary report with their recommendations about best practices and changes to current MPSC rules in June.

Question - Is there time frame for action by MPSC on rule changes?
Answer by Will Rosquist - No; once a draft rule is published, the Commission has six months to act on it.

Question - Will the consultants seek comments from stakeholders before submitting their draft report?
Answer by Will Rosquist - The contract does not require such action by the consultants but the Commission will be interested in stakeholder comments on it.

Question - Who are the stakeholders?
Answer by Will Rosquist - Anyone interested in utility resource planning in Montana is a potential stakeholder

Comment - MPSC should invite comments from NWE and the other stakeholders before initiating action on the rule changes.

Next Steps - Once the draft plan is submitted by the consultants to the MSPC, a discussion of it will be included on an ETAC meeting agenda.

Future of the DSM Program

At its last meeting, ETAC members asked for information about how NWE is planning to respond in its Demand Side Management (DSM) programs to the implementation of federal lighting standards. Bill Thomas provided the following information.

Federal standards require phasing out 100 watt incandescent light bulbs in 2012, 75 watt incandescent bulbs in 2013, and 60 watt incandescent bulbs in 2014. These standards are in effect, but currently there are no funds for the Department of Energy to enforce them.

In their analysis of NWE DSM programs, Nexant and Cadmus incorporated implementation the federal lighting standards so that after five years no more savings were assumed due to the compact fluorescent light (CFL) bulb lighting rebate program. However, as has previously been discussed with the ETAC, abrupt changes to NWE DSM programs due to factors such as implementation of federal lighting standards do not work. Because of contractor, trade ally and customer response considerations, DSM program objectives should have continuity.

Experience indicates that as the federal standards are implemented, retailers will dump incandescent bulbs in jurisdictions with weaker enforcement. To protect against such dumping in Montana, NWE plans to maintain its CFL rebate program for one year past the federal standard implementation date.

The three-year phase out of incandescent bulbs may coincide with increased market penetration of light- emitting diode (LED) lighting. If this occurs, NWE may shift its rebate programs from CFL to LED lighting. NWE will likely conduct another DSM assessment before significant LED technology market penetration occurs and will base LED lighting acquisition program decisions on the assessment.

Making up for the implementation of federal lighting standards will require replacing the lighting savings with other DSM, particularly in the commercial sector. This in turn will require more contacts with commercial customers. NWE issued a RFP for commercial DSM contractors and was able to retain two additional contractors, bringing its total to seven contractors. The seven include:

1. KEMA - This contractor runs NWE lighting rebate program which to date has partially funded customer purchase of over 1 million CFL bulbs; KEMA has a new commercial outreach team seeking new customer leads in the commercial sector;
2. National Center for Appropriate Technology (NCAT) - NCAT is compensated on a performance basis;
3. McKinstry - McKinstry is a Seattle based energy service company which implements performance based contracts to provide energy efficiency improvements such as building control management on a shared savings basis;
4. CTA Associates - CTA is a Montana architect and engineering firm;
5. Portland Energy Conservation, Inc (PECI) - PECI is a private, non-profit firm that provides energy conservation services;
6. ECOVA - ECOVA was formerly ECOS and is focused on grocery stores for NWE;
7. Energy Resource Management - This is a small, one person firm in Butte that focuses on small industrial and commercial energy efficiency projects such as BN shops, lumber and saw mills, and hospitals.

   [Note: contractors #2-7 are all compensated on a performance basis in the same manner that NCAT has been for several years.]

NWE DSM programs attempt to maximize the difference between resource value and what the cost of the DSM acquisition is (including utility program costs and customers contributions), while reaching or exceeding its annual DSM acquisition targets. This difference is the net customer benefit of the DSM program. About 9-11% of the value is allocated to a finder's fee for DSM contractors, 9-11% is allocated to payments for completing projects, and up to 50% for cash payments to customers such as lighting rebates. A small amount is spent for program marketing by the contractors. Contractors use direct face-to-face contract with prospective customers as the primary means of developing and completing projects. Raising program rebates lowers the net benefit to the utility and its customers.

In the 2009 resource procurement plan, the avoided cost was $70.12 per MWh. In the Spion Kop filing, the avoided cost was $53.85 per MWh, a 23% reduction. As a result of this decrease, some measures formerly in NWE DSM programs are no longer cost effective. The commercial new construction program lost four measures, the existing commercial program lost 7 measures, the residential new construction program lost 5 out of 27 measures, and the existing residential lost 8 out of 33 measures. The total average measure loss is 19.7%.

NWE is retaining its 6 average Mw annual acquisition target for its DSM programs. NWE is reluctant to raise this target because of the decreased avoided cost, pending implementation of federal lighting standards, and concern whether any higher targets are sustainable going forward.

Question - Is the commercial program operating on a project-by-project basis?

Answer - Yes, except for the easy measures such as lighting tubes. There are prescriptive rebates for certain common measures such as lamp replacements.

Question - You mentioned that the different contractors focus on different areas. Are you trying to maximize the efficiency of how they work together?
Answer - We are trying to achieve both cooperation and competition. We keep all of our contractors informed about customer contacts made by all of them. We have received only one complaint of customer confusion caused by multiple contacts.

Comment - In your tracker filing, you might emphasize the performance basis of your contracts and analyze the contractor results.

Question - Are you running the Green Block Program in cities other than Missoula?
Answer - We offered it in Helena with help from Paul Cartwright. We did not have stimulus funds for the Helena effort. We are not now running the program in other locations.

Question - Will you be conducting another DSM potential assessment in two or three years?
Answer - We are targeting conducting assessments in five year intervals. If LED use expands rapidly, we may do so sooner. The assessments require a significant effort from NWE staff above their normal activities.

Question - How do you expect the drop off due to implementation of the federal lighting standards to occur by customer sector?
Answer - We expect the impact to be proportional to our customer count, about two-thirds in residential and one-third commercial.

Question - Is the loss of stimulus funds also a factor?
Answer - Yes. Our motor efficiency program is an example of the importance of stimulus funding. This funding encouraged customers to implement air and frequency motor drives. However, as the economy has tightened, customers have paid closer attention to energy efficiency. Participation in the lighting rebate programs increased with the economic downturn.

Next Meeting

The date of the next meeting was not set. It will likely be in June after the MSPC consultants issue their draft report on the MPSC IRP/Procurement Guidelines. A discussion of the report will be included on the meeting agenda.

Disclaimer

Committee members provide advice to NWE as individual professionals; the advice they provide does not bind the agencies or organizations that the members serve.

ETAC Meeting Agenda

NorthWestern Energy
Missoula Division Office
1801 South Russell Street

Thursday July 26, 2012 – 9:00 AM

Conference Call-In: 877 820-7831 (Access Code): 555256

Agenda:

2012 Community Renewable Energy Project: RFP and viability scoring review

(Morning snack and lunch will be provided)

Meeting Summary
NorthWestern Energy Electricity Technical Advisory Committee
July 26, 2012

Attendance
Those participating in the Energy Electricity Technical Advisory Committee (ETAC) meeting in person and via telephone included:

Name	Organization
In Person	
Lauren Casey	Northwest Power and Conservation Council (NPCC)
Frank Bennett	NorthWestern Energy (NWE)
Thomas M. Power	District XI Human Resource Council
Paul Cartwright	Montana Department of Environmental Quality
Todd Guldseth	NWE
Patrick Barkey	University of Montana Bureau of Business and Economic Research
Paul Schulz	Montana Consumer Counsel (MCC)
Dave Fine	NWE
John Bushnell	NWE
Diego Rivas	Northwest Energy Coalition
Steve Lewis	Lands Energy
Gerald Mueller	Consensus Associates
Via Telephone	
Chuck Magraw	Natural Resources Defense Council
Will Rosquist	Montana Public Service Commission (MPSC)
Mike Dalton	MPSC
Kyla Wiens	Montana Energy Information Center (MEIC)
Larry Nordell	MCC

Agenda
2012 Community Renewable Energy Project: RFP and Viability Scoring Review

2012 Community Renewable Energy Project: RFP and Viability Scoring Review
Dave Fine provided background for the actions leading up to development of the draft Request-for-Resources (RFP) for Community Renewable Energy Projects (CREP). Steve Lewis then led a discussion of the RFP using the outline included below in Appendix A. Note that while the price benchmarks in item 5)c were discussed with the ETAC, the values are redacted from Appendix A. The price information is redacted to prevent its disclosure to potential bidders which may skew responses to the RFP. The draft of the RFP including a cover letter and two appendices, Appendix C, Terms and Conditions for Power Purchase Agreement, and Appendix D, Terms and Conditions for Build - Transfer Agreement, were provided to ETAC members via email prior to today's meeting.

Background
For 2012, the MPSC granted NWE a partial waiver from CREP acquisition requirements, but also indicated that a waiver for 2013-14 would be unlikely. Through 2014, NWE needs to acquire an approximate total of 45 megawatts (MW) of installed capacity of CREP. In 2015, this requirement increases approximately to 65 MW of installed capacity, so an additional CREP RFP is likely.

NWE began working with Lands Energy on development of this CREP RFP two months ago. As it has done in the past, Lands is developing the RFP and will solicit and score responses to it. Lands will conduct the initial screening of the responses in a manner blind to NWE. Lands Energy will recommend a short-list of proposals to NWE, and will at that time disclose to NWE the identity of those on the short-list.

Question - How blind do you want to be? Doesn't blinding NWE prevent it from applying its incites to the evaluation of RFP responses, such as public support or opposition, that might be better than that of Lands Energy?
Answer - Conducting the initial screening on a blind basis is meant to eliminate any NWE bias regarding the RFP responses. Lands Energy will receive and score the RFP responses in an initial screen. It will then recommend a short-list to NWE and provide the company with the details of and explanation for the screening. After this step, NWE will conduct its due diligence of the short-list and make its decision regarding acquisition.

Comment - CREP acquisitions are made to satisfy legal requirements. They are not aimed at the overall resource portfolio. These are small projects and responsibility for their acquisition is shared between NWE and the MPSC.

Comment - My problem is more with the statute than NWE's CREP process. It is not clear why NWE should be acquiring projects with little or no capacity.

Comment - In the past, planning was focused on energy rather than capacity.

RFP Topics
Expectations - Nationally, utilities are meeting their renewable resource portfolio standard (RPS) requirements so renewable resource acquisitions have slowed. However, because of the slow down, wind developers have access to equipment at distressed prices. Also the pending expiration of the production tax credits (PTC) for wind generation would raise wind costs and further slow wind development. NWE has heard optimism from the wind development community that Congress may act to extend the PTC. Lands has had contacts from over 20 potential RFP respondents. Overall, NWE is optimistic about the potential of the RFP to result in CREP acquisitions.

Major Points for RFP - This RFP solicits only CREP as defined by state statute. NWE would acquire the projects through either a power purchase agreement (PPA) or a Build-Transfer agreement (the developer would build the project and then transfer ownership of it to NWE). NWE has no preference between the PPA and build-transfer option. Unlike the past Request-for-Information (RFI) for renewable resources, this solicitation will seek all information to be provided up-front. To facilitate this objective, two months will be provided prior to the

solicitation deadline so that responders have sufficient time to develop the requested project information. NWE does intend, however, to keep the process moving so that PPAs might be finalized with a commercial operation date by the end of 2013. NWE does not intend to seek approval from the MPSC before finalizing the PPAs. The target for build-transfer agreements is 2014. The additional year is allowed because NWE would seek advanced approval of Build-Transfer agreements. Two conference calls with bidders will be held prior to the solicitation deadline to address bidder questions.

Question - What bottle necks occurred in past renewable resource acquisitions?
Answer - Developing a memorandum of understanding with short-listed proposers prior to the full contract has been a bottle neck. This step included negotiating and exchanging red-line versions of the proposed substantial commercial terms required significant time. For this RFP, NWE is providing contract templates building on what we have learned in past renewable resource solicitations.

Comment - One Montana Public Service Commissioner is concerned that restricting the RFP to CREP instead of all resources will limit NWE's ability to demonstrate what is required under the statutory cost cap. Under the CREP-only approach, it is not clear how NWE will compare renewable costs to those of other resources.

Question - Do you have existing Qualifying Facilities (QFs) that might seek CREP designations?
Answer - For an existing QF to seek a CREP contract under this solicitation, it would have to void its existing QF contract and participate in this RFP. Two new hydroprojects, Lower South Fork, which has reported initial operation, and Flint Creek, which is contracted and under development, might seek CREP designations.

Changes to Approach - Changes to this RFP from past solicitations address speeding the administrative process, the confidentiality of respondent's material, and a requirement for finalist earnest money.

To speed the administrative process, in addition to pre-specifying the contract terms, the scoring rules for project viability will be pre-defined and the scoring categories will be included in the RFP. The viability scoring is based on the California viability scorecard. Mr. Lewis reviewed application of the current viability scoring applied to three projects considered by NWE in past renewable resource acquisitions and one hypothetical "perfect wind" project. The past projects, Spion Kop and Big Otter wind and Turnbull hydropower, were finalists in the last renewable resource acquisition solicitation. The "perfect wind" project was created to consider the maximum score that a wind project might achieve.

Comment - The MPSC procurement guidelines require the utility to communicate the scoring system to potential respondents.
Response - We are including in the RFP the areas to be scored but are not including the actual scoring to prevent gaming the responses.

Question to Will Rosquist - Is this approach consistent with the MPSC guidelines?
Answer - The utility should develop and document systematic ranking/scoring criteria, but it need not disclose actual scoring.

Question - Are there any ranking categories that are not disclosed to respondents in the RFP?
Answer - No.

Question - In the scoring, failure to provide some information results in an "F" rather than a numerical score. Does this mean that the application would be rejected?
Answer - Yes.

Question - Is there a reason not to pre-disclose the actual scoring in the RFP?
Answer - We don't want proposals written to hit the scoring targets.

Comment - The scoring criteria appear to be heavy on engineering and light on financing. For example, you do not consider whether respondents have defaulted in provide resources in the past.
Response - Contracts will provide default provisions to protect the utility against them. We do assess the availability of either a letter of credit or guarantee by a parent company with significant financial capability. We assume that a financing entity such as a bank would properly cost providing financing.

Question - Does this mean that you are outsourcing the financial assessment to a bank?
Answer - We will review the financial scoring in light of your comments.

Question - If a respondent does not provide information in a category, will you substitute NWE's experience?
Answer - We may ask for clarification; however, the failure to provide information or providing false information will be grounds for terminating the application.

Question - You consider local support/opposition to the project. How will you assess the responses?
Answer - We ask the project developer to discuss its plans to engage stakeholders and obtain support for the project. Perhaps we should more clearly ask for evidence of support or opposition.

Question - Since the responsibility for transmission interconnection remains with the responder, do you provide with the RFP information about transmission congestion?
Answer - Yes. We are providing a map showing zones of transmission congestion developed by the NWE Transmission Group. The transmission folks also identified possible mitigation costs associated with the zones.

Comment - Eastern Montana does not appear to be a zone.
Response - The portion of eastern Montana not in a zone is not connected to the Montana NWE transmission system. Respondents seeking do develop projects not connected to the NWE system must provide a means to deliver energy to us.

Question - Will Lands Energy work with NWE Transmission personnel to determine the status of a project in NWE's transmission interconnection queue?
Answer - Transmission queue information is available on the NWE OASIS web site.

Question - The zones appear to be set up by county. Will a county-by-county ranking provide adequate information?
Answer - We will also have the best judgment by the Transmission Group.

Question - How do you weigh qualitative viability scoring against project price?
Answer - We are evaluating viability separately from price and are considering mechanisms for combining the two numerically. For example, we have discussed with NWE valuing a viability score increment in dollars per MW.

Comment - Rather than attempting a numerical combination of the viability scores and price, you might set a viability threshold, rank those projects passing the threshold by price, and document company decisions. (Note: No one participating in this meeting argued against this approach.)

Regarding the confidentiality of respondent's material, this RFP is a change from past solicitations. In this case, the respondent rather than NWE is clearly assigned the responsibility of protecting information she or he deems confidential. The RFP puts respondents on notice that while NWE would not seek to disclose information submitted in this process publicly, it will share the information with the ETAC and the MPSC. Information supplied will therefore likely be disclosed in the public MPSC process.

Question - Do you have concerns that other bidders will challenge MPSC decisions using the information provided in RFP responses?
Answer - Such suits have happened in the past in other solicitation processes.

Question - What is the standard practice regarding confidentiality in other regulatory jurisdictions?
Answer - In some jurisdictions, price information is disclosed only under confidentiality agreements. The middle of the road practice is to disclose prices but blind them as to their sources.

Comment - Another approach is to disclose price information after a certain time period.

Regarding earnest money, NWE will in this RFP process require finalists to deposit earnest funds in an amount that would get a proposer's attention but not so high as to discourage them from participating in the process. Deposits would be included in final contracts, so that successful contractors would not lose the money.

Question - What amount of earnest money are you considering?
Answer - We have not a set amount. It should be comparable to the requirements of generation interconnection deposits. We would want to scale the amount depending on project size and technology. For Spion Kop, we might have required an earnest money amount of $100,000 to $200,000. Additional work by Lands Energy and NorthWestern has resulted in selecting $2,500 per megawatt as the level of deposit for bidders who are selected for contract negotiations.

Comment - Interconnection agreement deposits are meant to recover study costs, not recoup lost opportunity costs.

Question - Have other utilities required earnest money deposits in renewable energy acquisitions?
Answer - Yes, other utilities have had "pay-to-play" requirements.

Question - Do you anticipate multiple finalists required to make these deposits?
Answer - Yes. The company intends to designate as finalists proposals with which we intend to execute contracts.

Question - Would there be circumstances in which a contract would not be completed but the finalist could recoup the earnest money?
Answer - Earnest money is generally intended to keep either party from moving away from the original proposal. If NWE decides to move away, then earnest money should be returned.

Question - After finalists are designated, how much remains to be negotiated?
Answer - Details such as equipment orders, transmission integration, land lease agreements, etc., may remain.

Comment - The RFP states that NWE reserves the right to change the evaluation but not tell the respondent why. This provision does not appear to be consistent with the MPSC disclosure requirement.
Response - The evaluation caveat is meant to provide utility flexibility if a proposal contains something the company has not previously thought about. We will look at the language to make sure it accomplishes what we want. In past negotiations, contracts were finalized with over 50% of the finalists (the Judith Gap, Spion Kop, and Turnbull projects). NorthWestern does not plan to withhold information. If the RFP somehow changes materially we will communicate with the RFP participants.

PTC Expiration - The RFP assumes that the PTC will not be extended. If they are, the RFP process will be reopened to all respondents so they can address their proposals accordingly. NWE may reopen the process if it judges that extension is imminent.

Disclaimer

Committee members provide advice to NWE as individual professionals; the advice they provide does not bind the agencies or organizations that the members serve.

ETAC Meeting Agenda

NorthWestern Energy
General Office
40 East Broadway

Wednesday December 19, 2012 – 9:30 AM

Conference Call-In: 877 820-7831 (Participant Code): 555256

Agenda:

Update on DSM program assessment

2012 renewable energy production and RPS compliance status

- Spion Kop status

QF-1 Final Order

CREP RFP status update

2013 Electricity Resource Procurement Plan discussion

- ETAC process and input
- Issues of interest & concern
- Schedule

Next meeting

(Lunch will be provided)

Meeting Summary
NorthWestern Energy Electricity Technical Advisory Committee
December 19, 2012

Attendance
Those participating in the Energy Electricity Technical Advisory Committee (ETAC) meeting in person and via telephone included:

Name	Organization
In Person	
Thomas M. Power	District XI Human Resource Council
Diego Rivas	Northwest Energy Coalition
Kyla Maki	Montana Energy Information Center (MEIC)
Brian Spangler	Montana Department of Environmental Quality
Bill Thomas	NorthWestern Energy (NWE)
Todd Guldseth	NWE
John Bushnell	NWE
Frank Bennett	NWE
Dave Fine	NWE
Paul Schulz	Montana Consumer Counsel (MCC)
Jamie Stamatson	MCC
Gerald Mueller	Consensus Associates
Via Telephone	
Chuck Magraw	Natural Resources Defense Council
Will Rosquist	Montana Public Service Commission (MPSC)
Patrick Barkey	University of Montana Bureau of Business and Economic Research

Agenda
- Update on DSM program assessment
- 2012 renewable energy production and RPS compliance status
  - Spion Kop status
  - Dave Gates Generation Station status
  - QF-1 Final Order
- CREP RFP status update
- Resource planning model review
- 2013 Electricity Resource Procurement Plan discussion
  - ETAC process and input
  - Issues of interest and concern
  - Schedule
- Next meeting

Update on DSM Program Assessment
Bill Thomas provided an update on the impact and process evaluations of NWE's 2007-2011 electricity, demand-side, natural gas, and Universal System Benefits demand-side-management (DSM) programs. Renewable energy programs that result in energy savings are also included in

the evaluations. As discussed previously with the ETAC, NWE selected two contractors to conduct the evaluation, SBW Consulting and Research into Action. The contractors have been working for one year. The contract tasks proved to be larger and more complicated than the contractor anticipated because of the number and scope of the NWE demand-side resource programs. The contractors missed their deadlines for providing the draft and final report on the evaluations. The final report will be provided to NWE on January 11, 2013. NWE intends to have the contractors provide their results to the ETAC at its January 2013 meeting.

In reviewing early versions of the contractors' draft report, NWE staff found problems with the spread sheet calculation of program costs, the calculation of life cycle costs, the allocation of costs to specific programs, and the application of the total resource cost test. For example, some appliance costs in the cost effectiveness calculation included the total appliance cost rather than the cost above what appliance efficiency codes require. NWE has had to educate consultant analysts about the cost allocations. NWE has not sought to challenge the consultants' findings; it has sought to understand the consultants' methodologies and ensure that they are correctly applied to NWE program data.

Some of the consultants' findings are interesting:

- DSM costs - DSM measure costs continue to be low compared to supply-side electricity source costs.
- Compact florescent lighting (CFL) burn hours - The burn hours for CFLs in homes in NWE service territory have decreased to 2 hours per day from the 3.7 hours per day determined in the last program evaluation in 2007. The 2012 burn hours were measured using data logging. This result is not unexpected because customers are now installing CFLs in lower use lighting applications.
- NWE weatherization events - For the last five years, NWE has given away weatherization kits at weatherization events held in communities in its service territories. The consultants' evaluation determined the savings realization from these events to be low because people are not installing the weatherization measures. Since the events have now reached about 50% of its service territory population, the company faces the question of whether to continue them.
- Process evaluation - The most cost effective method for contacting customers about their use of NWE DSM programs is the telephone survey. Customers, however, were less willing this year to participate in telephone surveys than during the 2007 DSM program evaluation.

Question - Instead of a telephone survey, have you considered surveying by computer?
Answer - This is a good question to ask the consultants at the January meeting. Surveying by computer and email would sub-stratify the sampling because not all customers have computers or use email.

Question - Are the costs of lighting using CFLs and light-emitting diodes (LEDs) crossing?
Answer - LED lights are cool, safe, and long-lived, and their cost is dropping. My guess is that LEDs may be cost competitive with CFLs in about two years. However, the incremental savings from the switch from CFLs to LEDs will be significantly less than from incandescent lighting to CFLs. We see nothing on the technology horizon beyond LEDs. Two disadvantages of LEDs are that people have concerns about the color of light they produce, and they require rare earth phosphors, 90% of the supply of which is controlled by China.

2012 Renewable Energy Production and RPS Compliance Status

Dave Fine and Todd Guldseth reported on these topics.

Judith Gap, Gordon Butte, and Spion Kop Production - The production from these three projects is summarized in the handout included below in Appendix 1.

Question - Energy production at Judith Gap during June was significantly higher this year than past year averages. Was this due to weather or something about the project?
Answer - The higher production was due to weather which produced more wind. Maintenance at this project was performed as normal during July and August, the low wind months. It is interesting to note that the Gordon Butte project outperformed Judith Gap during almost all months and for the year as a whole. This may be due to lower turbulence at the Gordon Butte site. Both the Judith Gap and Gordon Butte projects have capacity factors higher than typical wind projects in the northwest. Both projects use GE turbines which have a higher than usual Ride Through Capability so the machines need not shut down as often with high winds.

Spion Kop Status - The Spion Kop project went into NWE's rate base on December 1, 2012. Ownership of the project transferred to NWE on November 15. The project will be managed by Jim Williams and Dusty Rhodes with the NWE Generation Group. GE will operate the project under a 10-year full service agreement (FSA) with NWE. The FSA covers each wind generator at the project from the bolts which hold the tower to the foundation upward including the turbine. GE has five people at Spion Kop, a site manager and four technicians.

RPS Compliance Status - Dave Fine provided a handout summarizing NWE's past and projected compliance with the Montana Renewable Portfolio Standards (RPS). The handout in included below in Appendix 2. The numbers reported for 2009-2011 are actual production and numbers for 2012-2030 are projections. Projections for Judith Gap are based on the average of the past years of production. NWE will get renewable energy credits (RECs) for all energy produced by the Spion Kop project after commercial operation commences. The Musselshell and Musselshell 2 projects are on schedule; energy delivery is anticipated to begin about Christmas day and commercial operation should begin by December 31, 2012. Commercial operation of the Flint Creek project should begin in February 2013.

As the Appendix 2 table indicates, NWE should be in compliance with the RPS through 2017, although the margin in that year is small compared to the annual variation in energy production of the Judith Gap project. Compliance in 2017 will, therefore, depend on actual production at Judith Gap and the other listed projects.

Question - How many years can RECs be carried over?
Answer - Two years.

Question - What order does NWE use the carry-over RECs?
Answer - We use the oldest first, based on the calendar year.

Dave Gates Generation Station Status - The Dave Gates Generating Station (DGGS) consists of three units with two turbines each for a total capacity of 150 MW. As reported previously to the ETAC, in January 2011, the power turbines at this plant experienced a failure. As the turbines were under warrantee, their manufacturer, Pratt and Whitney, removed them from DGGS and

shipped them to Connecticut for repair. Pratt and Whitney replaced the damaged turbines temporarily with loaned machines. All repairs have been completed and the repaired machines have been shipped to Anaconda for re-installation. The DGGS will be at full plant capacity by the end of this week. Pratt and Whitney has installed sensors with the turbines and is completing an analysis of the data gathered from them. A final fix with all issues resolved is expected in early 2013.

Question - What is meant by a final fix?
Answer - The component engineering including the analysis of the sensor data will be completed.

Question - Is Pratt and Whitney developing a root cause analysis and will it be included in the final fix?
Answer - Yes.

QF-1 Final Order

John Bushnell reported on this topic. MPSC rules require NWE to update its Qualifying Facility (QF) tariffs after filing its resource plan. In January 2012, NWE filed revised QF tariffs, basing them on the methodology prescribed in the previous MPSC order. The filing included a blended market and combined cycle generation price with market prices through 2017 and a combined cycle price beginning in 2018. The tariff levels set by the MPSC in its order responding to the NWE 2012 filing are shown in the table in Appendix 3 below.

Three issues were controversial in this filing: the natural gas price forecast, the capacity value of wind generation, and the limit on NWE QF wind acquisitions. In the filing, NWE incorporated the natural gas price forecast used in its 2011 resource plan. In the 2012 final order, the MPSC used NWE's proposed forward market price curve until 2015, then escalated using information from the US Energy Information Administration's Energy Annual Energy Outlook. Regarding the wind generation capacity, NWE used a 0% value in its filing, a reduction from the 15% value set in the previous 2010 QF order. In the final order, the MPSC approved a 5% capacity contribution for wind generation, the value adopted by the Northwest Power and Conservation Council. The wind integration rate in effect prior to the recent MPSC order was $2.35 per kilowatt month. In its pre-filed testimony, NWE proposed a wind integration rate of $1.48 per kilowatt month. The company reduced this amount in its rebuttal testimony to $1.46 per kilowatt month. The MPSC adopted in the final order a zonal approach to the wind integration rate. For zone 1 which is defined as less than 25 miles from the Judith Gap project, the rate was set at $1.09 per kilowatt month. Zone 2 was defined as from 25 to 60 miles from the Judith Gap project, and its rate was set at $.40 per kilowatt month. Zone 3 was defined to include areas greater than 60 miles from the Judith Gap project, and the corresponding rate was set at $.15 per kilowatt month. The MPSC final order set the long term wind integration WI-1 rates based off the long-term levelized value of $4.15 /kW-month with Zone 1 rate set to $1.58/kW-month, zone 2 set to $0.58/kW-month and Zone 3 set to $0.21/kW-month. The most controversial issue in this proceeding was the 50 MW limit on QF wind acquisitions that the MPSC had set in the 2006 QF tariff. NWE is bumping up against this limit. In the 2-12 order, the MPSC removed any limit on wind acquisition by NWE.

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NWE has requested the MPSC to reconsider three issues, the zonal wind integration tariffs, the long-term levelized tariff, and the dropping of the 50 MW cap on QF acquisitions. NWE has also asked the MPSC to clarify to whom the QF tariff applies.

Dave Fine discussed why NWE supports a limit on QF wind acquisitions at present. NWE's resource portfolio includes the Judith Gap, Spion Kop, and three QF wind projects, Musselshell, Musselshell 2, and Gordon Butte. These projects total 205 MW of capacity. Two other QF projects for which NWE has contracted but which have not yet been built total an additional 20 MW. The Horse Shoe Bend project for which NWE must provide regulation adds another 10 MW of wind. During light load hours in the, NWE's load totals about 450 MW. The 225-235 MW of wind generation capacity total poses a significant challenge for NWE's market operations during the light load hours. Also, NWE does not yet have real operating experience with the DGGS including all the intermittent wind resources listed above, so that we do not know what the operational limit on self-supply of regulating resources will be. NWE Transmission which regulates our balancing area, intends to run DGGS with two units (95-100 MW) operating and one unit (50 MW) spare. Historically, 60 MW was required for load regulation on the MPC and NWE systems. Based on this value, experience with the Judith Gap wind production, and the assumed 100 MW of the two operating units of DGGS, NWE uses a regulation requirement for all wind projects at 18% of their nameplate capacity.

Question - What was the origin of the QF wind acquisition cap?
Answer by Will Rosquist - The 50 MW cap was set by the MSPC in the 2006 QF tariff order due to uncertainty about resource avoided cost and wind integration cost. The order stated that the MPSC would reconsider the cap when NWE bumped up against it.

Question - Is NWE reluctant to acquire more non-QF wind?
Answer - We would like to get more experience managing the wind resources in the portfolio before acquiring more wind. Without the QF cap, we cannot limit QF wind acquisitions.

Comment - The MSPC QF decision appears to create an incentive to locate projects farther from Judith Gap.
Response - The GENIVAR Study found that locating new wind farther from Judith Gap reduced regulation requirements, but the relationship was not linear.

Question - What is Plan B for providing regulation other than the DGGS?
Answer - NWE Transmission conducts the planning for regulation resources. We assume that Transmission will use market resources in addition to DGGS.

Comment - Providing regulation is a growing concern in California and the northwest.

Question - What are the analytical implications of the large amount of wind resources on NWE's system for this planning cycle?
Answer - At a minimum, we must plan to ensure compliance with the RPS. As discussed above, NWE has sufficient resources through 2017 with uncertainty about 2017 depending on production at Judith Gap and other existing projects. We will have limited real experience with DGGS operation and wind integration requirements for this planning cycle.

Question - Can you model the interaction between fluctuating loads and intermittent resources? I am concerned about pancaking uncertainty.
Answer - In the GENIVAR study, all model runs used the same load information. The interaction between load fluctuation and intermittent resources is therefore buried in the results, and the wind in these studies captured the load diversity benefit. We cannot replicate the GENIVAR modeling in-house.

Comment - No one has figured out how to address all of the challenges due to integration of intermittent resources. Ideally, NWE would lay out the regulation costs of Plan B and take them to the MPSC for a policy decision.
Response - The Kenmile decision in which the MSPC ordered that 10 MW wind projects cannot be built one mile or less apart to take advantage of QF tariffs provides NWE some protection. Also, given the low level of QF rates in the recent order, if production tax credits (PTC) for wind are not extended by the Congress, we see few new wind generation projects in the near term so that the wind integration issue may not be large for this planning cycle.

Question - What are the prospects for QF development? Will it be more of an issue if the PTC are extended for wind generation? At what price point will QF become more of a concern?
Answer - NWE does not have access to wind developers' business plans, and we don't have a good forecast of the REC market; hence we can't answer the price point question. If the PTC are not extended, wind developers will have to shave their profit margins. 100 MW of new QF wind is possible.

Comment - I assume that the utility will not end up in crisis because of wind development. Historically, utilities have been good at stalling if faced by a stampede of wind development. I assume that you will not sign contracts if they would be too risky.
Response - Under the QF tariffs, we do not have a choice about signing qualified QF contracts.

Comment - The MPSC expects NWE to monitor the rate of new wind development on its system, ensure FERC standards are met, and report to it if problems develop.

CREP RFP Status Update

Dave Fine provided the update about NWE's request for proposal (RFP) for community renewable energy projects (CREP). Responses to the RFP were due on September 28. NWE received 30 responses with total project capacity totaling over 500 MW, some for more than one technology at the same location. Most proposals were for wind projects that would be developed and sold to NWE. These projects are called build-transfer projects. Lands Energy has evaluated the responses ranking them by price and project attributes. The scoring system was previously discussed with ETAC. Lands has provided NWE a summary of the proposals and their scoring without identifying the project sponsor and a recommended short-list of projects that should be considered for acquisition. On December 4, Lands sent notices to all those submitting proposals notifying them of their proposal status. Since December 4, Lands has sought additional information from the short-listed projects so that they can be evaluated and modeled by NWE.

Question - What is the time line for a NWE decision on the proposals?
Answer - NWE does not have a specific schedule. The projects are being discussed internally and additional information has been requested of the project proposers so that the modeling can

be finalized. NWE anticipates seeking a memorandum of understanding with those proposals the company wishes to acquire in February. No decision has been made to acquire any project.

Question - How are you addressing the extension of the wind generation PTC?
Answer - The RFP anticipated this question. If the PTC are extended, NWE will allow proposers to rebid their projects.

Question - You said that most of the proposals involved wind projects. I evaluated biomass projects for DOE in light of the availability of federal stimulus funding. Combined heat and power may make the biomass projects more viable. Are you looking at biomass projects?
Answer - Yes.

Question - What did Flathead Electric pay Stoltze Lumber for its biomass project?
Answer - $90 per megawatt hour.

Question - How would the build-transfer option affect the CREP requirements?
Answer - NWE would have to be the sole project owner for it to qualify as a CREP.

Resource Planning Model Review

Todd Guldseth provided a handout summarizing his review of possible alternatives to the GenTrader model used by NWE in its resource planning and acquisitions. The handout is included below in Appendix 4. About three to six months would be required to select a model vendor and an equal time to prepare the new model for use by NWE.

Question - Why are you looking at models other than GenTrader?
Answer - NWE has conducted this review in response to MPSC comments on NWE's 2011 resource plan.

Question - What capabilities would the other models have that GenTrader does not?
Answer - GenTrader was designed as an hourly dispatch model rather than a long-term resource planning tool. Other models may better analyze different resources and tie them to the existing resource portfolio and have shorter run times for stochastic studies. NWE now has its own computer servers and has developed the inputs necessary to run GenTrader in the stochastic mode. We have become efficient in using GenTrader.

Comment - My experience is that GenTrader was built for dispatch rather than long-term planning studies.
Response - We augment GenTrader with spread sheet models. As is the case with GenTrader, the other models we have examined do not have modules for intermittent resources that can directly address wind integration.

Comment - The MPSC does not have anything against GenTrader, although NWE had difficulty applying it at our request in the context of a specific docket. The Commission's main objective is for the company to stay apprized of other models and their uses.

Question - Has the Northwest Power and Conservation Council made progress in documenting its planning models and making them available to utilities?
Answer - We are not aware of progress in this regard.

Electricity Resource Procurement Plan Discussion

Dave Fine led a discussion of the following topics.

ETAC Process and Input - The process issue that we are aware of from past planning cycles is providing adequate time for the ETAC to review the draft plan. Are there others?

Comment - Our past pattern has been for ETAC members to respond to technical issues cold at meetings. If materials were provided prior to meetings, we could review them before hand and be better prepared to discuss issues. Breaking this pattern would require scheduling meetings and the issues they would address ahead of time and members setting aside time to review the supplied materials.
Response - We are discussing how we can better forecast planning activities and do things differently including supplying agenda materials advance of meetings.

Comment - The interaction between the resource plan and acquisition of opportunity resources has also been an issue in the past. For example, I have heard rumors that Pennsylvania Power and Light (PPL) is seeking to sell its Montana assets.
Response - The resource plan provides a foundation for several needs including acquiring new resources via contracts or building them. NWE focuses on meetings its customer's needs rather than merchant activities. Our planning is informed by power marketing activities and prices, including electricity, natural gas and RECs. The best we can do is analyzing the middle-of-the-road with higher and lower scenarios to identify a range of outcomes.

Issues of Interest and Concern - Dave Fine handed out a list of issues for the current planning cycle. This list is included below as Appendix 5.

Question - Will you consider siting a natural gas-fired generating plant during this cycle?
Answer - Acquiring a plant prior to 2017-18 is unlikely so that siting a plant will probably not be urgent. NWE's generation group is focused on the DGGS and Spion Kop projects.

Comment - The primary impact of the adder is to make coal plants more or less cost effective. No US utility is building a coal plant.
Response - Some northwestern utilities are removing a carbon adder from its base planning.

Comment - It may be useful to bring to the ETAC aspects of integrated resource planning such as transmission constraints.

Comments - We may also want to consider physical and financial hedges to accommodate uncertainty.

Schedule - Dave Fine passed out a draft schedule for ETAC meetings with topics. See Appendix 6 below. The ETAC agreed to target meeting the fourth Wednesday of the month during this planning cycle.

Next Meeting

The next meeting was scheduled for Wednesday, January 23, 2013 at a location in Helena to be determined. NWE will send out copies of the MPSC on the 2011 resource plan. These comments will be reviewed at the January meeting.

Disclaimer

Committee members provide advice to NWE as individual professionals; the advice they provide does not bind the agencies or organizations that the members serve.

Appendix 1

Judith Gap Wind Energy Production Summary

2012	Total MWH	HL[1] MWH	LL[2] MWH	Peak MW	Maximum 15-Minute Change MW	Average MW	Standard Deviation MW	Capacity Factor[3]	2006-2011 Average Total MWH	2006-2011 Average Capacity Factor
January	61,881	34,286	27,594	136.0	81.5	83.2	54.1	62%	57,628	57%
February	34,979	19,957	15,022	136.0	78.5	50.3	52.5	37%	42,722	47%
March	48,500	30,601	17,899	136.4	99.3	65.2	53.8	48%	42,109	42%
April	35,386	20,415	14,970	136.6	72.1	49.1	50.5	36%	39,803	41%
May	30,985	20,364	10,621	136.4	-76.8	41.6	44.6	31%	35,962	36%
June	40,798	24,126	16,672	136.4	81.2	56.7	52.4	42%	26,626	27%
July	21,604	10,480	11,124	136.2	102.9	29.0	40.1	22%	23,098	23%
August	26,452	18,289	8,163	136.2	97.8	35.6	44.3	26%	25,665	26%
September	28,382	17,523	10,859	136.2	94.3	39.4	45.1	29%	27,309	28%
October	40,055	26,113	13,942	136.2	84.5	53.8	51.5	40%	43,441	43%
November	43,662	26,319	17,343	136.3	95.8	60.6	51.9	45%	49,466	51%
December										
Total YTD	412,682	248,472	164,210	136.6	102.9	51.3	51.5	38%	413,828	38%
		60%	40%							

1 - Heavy load hours Monday - Saturday HE 7 - 22
2 - Light load hours Monday - Saturday HE 1 - 6, 23, 24; all day Sunday
3 - Calculated capacity factor based on 135 MW installed capacity

Gordon Butte
9.6 MW QF

Total MWH	Capacity Factor
5,179	73%
3,501	52%
4,525	63%
3,055	44%
3,094	43%
3,242	47%
1,807	25%
1,810	25%
2,441	35%
3,906	55%
4,824	70%
37,386	48%

Spion Kop
40 MW

Total MWH	Capacity Factor
400	1%
10,221	34%
16,058	56%
26,680	30%

*Sep - Nov is Test Energy
*Commercial Operation Date Dec 1, 2012

Appendix 2

Montana Renewable Portfolio Standard Compliance Projection
One Renewable Energy Credit (REC) generated for each Megawatt-Hour of Approved Renewable Generation
December 2012 Update

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2020	2022	2024	2026	2028	2030
Retail Load (sales) MWH	5,834,029	5,775,605	5,932,810	6,025,826	6,090,031	6,161,279	6,237,014	6,315,649	6,396,193	6,478,062	6,644,508	6,811,437	6,978,488	7,146,014	7,314,318	7,483,441
RPS (%)	5%	10%	10%	10%	10%	10%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
RPS (based on prior year load)	298,759	583,403	577,561	593,281	602,583	609,003	924,192	935,552	947,347	959,429	984,136	1,009,199	1,034,239	1,059,325	1,084,509	1,109,817
Judith Gap (135 MW)	455,985	414,004	511,362	462,000	473,805	473,805	473,805	473,805	473,805	473,805	473,805	473,805	473,805	473,805	473,805	473,805
Turnbull (13MW)			22,459	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000
Spion Kop (40MW)				41,560	138,408	138,408	138,408	138,408	138,408	138,408	138,408	138,408	138,408	138,408	138,408	138,408
Gordon Butte (9.6 MW)			747	40,366	33,750	33,750	33,750	33,750	33,750	33,750	33,750	33,750	33,750	33,750	33,750	33,750
Musselshell (10 MW)				0	28,600	28,600	28,600	28,600	28,600	28,600	28,600	28,600	28,600	28,600	28,600	28,600
Musselshell 2 (10 MW)				0	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000
Two Dot Wind Farm (10 MW)				0	5,900	35,400	35,400	35,400	35,400	35,400	35,400	35,400	35,400	35,400	35,400	35,400
Fairfield (10 MW)				0	5,317	31,900	31,900	31,900	31,900	31,900	31,900	31,900	31,900	31,900	31,900	31,900
Flint Creek (2 MW)				0	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000
Lower South Fork (0.5 MW)				152	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Total RECs Generated	455,985	414,004	534,568	569,078	748,680	804,763	804,763	804,763	804,763	804,763	804,763	804,763	804,763	804,763	804,763	804,763
Current Yr REC	455,985	414,004	534,568	569,078	748,680	804,763	804,763	804,763	804,763	804,763	804,763	804,763	804,763	804,763	804,763	804,763
Prior Yr Carry-Over REC	204,132	361,359	191,960	148,967	124,764	270,862	466,621	347,193	216,403	73,819	0	0	0	0	0	0
Total Available REC	660,117	775,363	726,528	718,045	873,444	1,075,625	1,271,384	1,151,956	1,021,166	878,582	804,763	804,763	804,763	804,763	804,763	804,763
RPS	298,759	583,403	577,561	593,281	602,583	809,003	924,192	935,552	947,347	959,429	984,136	1,009,199	1,034,239	1,059,325	1,084,509	1,109,817
Carry-Over REC	361,359	191,960	148,967	124,764	270,862	466,621	347,193	216,403	73,819	0	0	0	0	0	0	0
Annual RPS Met?	YES	YES	YES	YES	YES	YES	YES	YES	YES	NO	NO	NO	NO	NO	NO	NO
Additional RECs needed to meet RF										80,847	179,373	204,436	229,476	254,562	279,746	305,054

Load based on April 2012 long-term load forecast update

Appendix 3

	Existing	NWE Prefiled		HYDRO Prefiled		UMG Prefiled		NWE Rebuttai		Order	
Option 1(a)	$ 62.92	$ 55.92	-11.1%	$ 62.92	0.0%	$ 58.46	-7.1%	$ 44.52	-29.2%	$ 56.18	-10.7%
Off-Peak	$ 54.44	$ 46.92	-13.8%	$ 54.44	0.0%	$ 49.61	-8.9%	$ 35.31	-35.1%	$ 46.97	-13.7%
On-Peak	$ 90.87	$ 85.61	-5.8%	$ 90.87	0.0%	$ 87.65	-3.5%	$ 74.90	-17.6%	$ 86.56	-4.7%
Option 1(b)	$ 54.44	$ 33.49	-38.5%	$ 54.44	0.0%	$ 33.49	-38.5%	$ 22.02	-59.6%	$ 31.00	-43.1%
Option 1 (c)	$ 57.87	$ 46.92	-18.9%	$ 57.87	0.0%	$ 49.61	-14.3%	$ 35.31	-39.0%	$ 48.22	-16.7%
Off-Peak										$ 46.97	
On-Peak										$ 52.33	

Appendix 4

Power Planning Model Review

ETAC December 19, 2012

Mod& Vendor Contacts (2012)

2. Ascend Analytics
2. Aurora
3. OATI
4. Ventyx (late 2010)

Ascend Analytics

- Short, medium, and long-term power planning capabilities
- Power price curve development product
- Northwest presence (Denver and Bozeman)

Aurora

- Fundamentals based, hourly dispatch model
- Power price curve development capability
- Northwest presence
- Used by several utilities in Pacific Northwest

Next Steps

- Find time
- Draft a scorecard/desired attribute document to evaluate products and focus search
    - Interface with existing NWE power market departments and platforms (Market Ops, WebTrader, etc...)
    - ETAC input
- Determine how to proceed in researching products
    - RFP
    - Solicit individual vendors for information and demos
    - Interview counterparts for pros and cons of various products
- Compare alternatives to GenTrader
- Determine time and resource requirements of implementing a new product, if desired

Appendix 5

2013 Electricity Resource Procurement Plan Issues

Carbon uncertainty

Market transformation in the northwest and US

- Natural gas market / electricity market

- Depressed utility load growth
- Mid-C basis differential with Montana market

Renewables integration and sources of integration resources

Capacity planning

Integrated utility planning

RPS compliance

Renewable energy credit (REC) value

Resource selection and portfolio composition (RPP alternatives)

Gas-fired resources _New build timing and infrastructure needs

Appendix 6

DRAFT 2013 Electric Resource Procurement Plan Work Schedule and Deliverables

	2013
Portfolio and Plan Review - DSM Plan Review Results Presentation - Existing Portfolio Review and Needs - MPSC Comments on 2011 Plan (N2011.12.96)	January
Planning Methods and Scope - Planning Rules - Capacity Planning & Market - Distributed Generation	February
Forecasting and Resources - Load & Resource Balance - Load Forecast Update including Peak Demand - Existing Resources	March
Resource Definitions, Carbon, and Renewables - New Resource Costs and Attributes - Carbon/Environmental Costs & Issues - Renewables/RPS/Integration	April
Price Forecasts, Volatility - Peak Period Definitions & Price Volatility - Fuel and Electricity Prices	May
Scenarios and Portfolios - Review and Discussion on all Model Inputs & Portfolios - Scenario definitions	June
Intrinsic Analysis - Modeling Results and Iterative Model Runs - Ranking of Results - Volatility and Risk Review	July
Stochastic Analysis - Modeling Results - Efficiency Frontier - Preferred Portfolio(s) and Resources	August/September
RPP Conclusions and Action Plan	September
Draft RPP – Prepare and Release for Review	September/October
ETAC Meeting – Review of Draft RPP	November
Energy Supply Board Meeting – Review Draft RPP	November 15, 2013
ETAC Meeting – Final Comments due	November
ESB Plan Approval	December
Submit Plan	December 16, 2013

ETAC Meeting Agenda

Oriental Room
Best Western Great Northern Hotel
835 Great Northern Boulevard
Helena, Montana

Thursday January 24, 2013 – 1:00 PM

Audio Conference Call-In: 877 820-7831 (Participant Code): 555256

To participate via the web using GoToMeeting please use the following link:
https://www1.gotomeeting.com/join/858457152

Agenda:

DSM Program Evaluation presentation by SBW

- The SBW final report is contained in two documents that have been posted to the NorthWestern Energy website at:

  http://www.northwesternenergy.com/display.aspx?Page=Studies_and_Reports

CREP RFP status update following extension of Federal Production Tax Credit

2013 Electricity Resource Procurement Plan discussion

- Review of existing resource portfolio and future needs
- MPSC Comments on 2011 Plan (N2011.12.96)

Meeting Summary
NorthWestern Energy Electricity Technical Advisory Committee
January 24, 2013

Attendance
Those participating in or attending the Energy Electricity Technical Advisory Committee (ETAC) meeting in person and via telephone and GoToMeeting included:

Name	Organization
In Person	
Diego Rivas	Northwest Energy Coalition
Brian Spangler	Montana Department of Environmental Quality (DEQ)
Mike Dalton	Montana Public Service Commission (MPSC)
Will Rosquist	MPSC
Neil Templeton	MPCS
Pat Corcoran	NorthWestern Energy (NWE)
Chuck Magraw	Natural Resources Defense Council
Dan Yoeman	NWE
David Bausch	NWE
June Pusich-Lester	NWE
Connie Moran	NWE
Betsy Pahut	NWE
Danie Williams	NWE
Brandy Powers	NWE
Lou Moore	DEQ
Bob Decker	MPSC
Deb Young	NWE
Jamie Stamatson	Montana Consumer Counsel (MCC)
Bill Thomas	NWE
Joe Schwartzenberger	NWE
Frank Bennett	NWE
John Bushnell	NWE
Todd Guldseth	NWE
Dave Fine	NWE
Marjorie McRae	Research into Action
Mike Baker	SBW
Kyla Maki	Montana Environmental Information Center (MEIC)
Gerald Mueller	Consensus Associates
Via Telephone	
Clauda Rapkoch	NWE
Thomas M. Power	District XI Human Resource Council
Larry Nordell	MCC

Agenda
- DSM Program Evaluation presentation by SBW
- CREP RFP status update following extension of Federal Production Tax Credit

- 2013 Electricity Resource Procurement Plan discussion
  - Review of existing resource portfolio and future needs
  - MPSC Comments on 2011 Plan (N2011.12.96)
- Next meeting

DSM Program Evaluation Presentation

Pat Corcoran introduced this topic noting that the evaluation allows NWE to look backward at the performance of its demand side management (DSM) programs, determine how it stacks up with other utility DSM programs, and calculate lost revenues due to the DSM acquisitions.

Michael Baker of SBW Consulting and Dr. Marjorie McRae of Research into Action used a PowerPoint presentation to report on the impact and process evaluation that their firms conducted of NWE's 2007-2011 demand side management programs. A copy of the presentation was supplied to the ETAC prior to this meeting and is posted on the ETAC web page at:
http://www.northwesternenergy.com/documents/etac/2013/SBW_Presentation_24_JAN_2013.pdf

Dr. McRae elaborated on concepts discussed on page 8 of the PowerPoint presentation, including net-to-gross ratio, leakage, spillover, and free ridership. A copy of her notes is included below in Appendix 1.

Copies of the full evaluation reports are available on the NWE web page at:
http://www.northwesternenergy.com/display.aspx?Page=Studies_and_Reports.

Question - You recommend that while the programs should be designed to avoid free-ridership, i.e. savings that would have occurred with the utility programs, no quantitative adjustments to the program impacts should be made for free-ridership. If NWE had not offered DSM programs, would not the private sector marketed DSM?
Answer - We can't know what the private sector would have done, absent NWE's programs. For example, without the utility lighting rebates and marketing program, manufactures may have brought their less efficient lighting stock into Montana.

Question - Did NWE's marketing efforts displace private sector marketing?
Answer - It is possible that displacement occurred; however, acquiring DSM reflects a societal goal and therefore utilities such as NWE are directed to pursue it.

Question - Is the realization rate different than the combined affects of spill over, free-ridership, and leakage?
Answer - Yes. The realization rate is determined via field tracking of program performance. The realization rate reflects errors in documentation, actual measure installation rates, and energy calculations that do not reflect actual savings.

Comment - The table shown on page 10 of your presentation differs from the similar table in the report executive summary.
Response - We will check this. Thank you for pointing it out.

Question - You mentioned that the lighting data logging was limited to the summer. Do you need to adjust the burn rate determined from the data logging to reflect day length?

Answer - Yes, and we did make an adjustment based on a regression analysis of the logging data to see if day length mattered and on the results of other studies which had a longer logging period. The most comprehensive data logging study of lighting was conducted in California. This study determined that latitude was not significant in determining the burn rate but the day of the year was.

Comment - At the last ETAC meeting, a member asked if the low telephone survey participation rate might be improved by using email and survey devices such as SurveyMonkey to contact customers. Bill Thomas suggested that we pose this question to you.
Response - Surveying via email may have higher participation rates than telephone contacts, but it would not be a panacea. One would have to consider the percentage of NWE customers that use email. Participation rates via telephone were definitely lower than five years ago.

Comment - For this evaluation, telephone survey attempts were made during the election season, when people were flooded with election surveys.
Response - The combination of the election season and the small number of DSM program participants combined to produce a "perfect storm" for the current evaluation.

Question - Are the actual spread sheets used to calculate the program savings available?
Answer by Bill Thomas - While the spread sheets are not in the reports, they are available to anyone wishing to examine them.

Community Renewable Energy Project Request-for-Proposal Status Update

Dave Fine provided the update. Lands Energy has evaluated twenty-eight responses to the Community Renewable Energy Project (CREP) Request-for Proposal (RFP). Lands has not yet revealed the identity of those making the proposals to NWE. The responses included one solar, one hydro, one waste gas, three biomass, and twenty-three wind project proposals. One proposal not included in the twenty-eight total was withdrawn by the proposer. The initial proposals did not reflect extension of the federal wind production tax credits (PTC). A PTC extension for renewable projects that begin construction during 2013 was recently signed into federal law. The original RFP stated that if the PTC was extended all project proposals, not just wind, could be repriced. Other aspects of the proposal cannot be changed. Lands has received 17 repriced proposals.

The RFP allowed proposals to be submitted either as build-transfer projects in which ownership would be transferred to NWE or as Power Purchase Agreements (PPAs) in which NWE would purchase the project output. Build-transfer proposals bid a total project price, while the PPA price is in dollars per megawatt-hour (MWh). Lands will update the project screening based on the new price submittals.

NWE has not made any conclusions to date regarding moving forward with any of the proposals.

Question - Did the PTC extension impact pricing for all RFP projects or just the wind projects?
Answer - All projects could be repriced.

Question - Are you comfortable sharing the range of RFP project prices?
Answer - We are not comfortable doing so now because negotiations have not occurred. We do not want a price range to influence the proposals or potential negotiations with developers.

Question - Did the repricing result in lower prices?
Answer - Yes. In more than one case, the price was reduced by about 40%. In at least some cases, the reductions appear to exceed the impact of the PTC extension.

2013 Electricity Resource Procurement Plan Discussion

Dave Fine, Todd Guldseth, and Frank Bennett discussed this topic using a PowerPoint presentation entitled, ETAC Update, January 24, 2013. This information had been provided to the ETAC prior to this meeting and is available on the NWE web site at the following web address:

http://www.northwesternenergy.com/documents/etac/2013/Materials_24_JAN_2013.pdf

Existing Resources

Question - The list of energy supply resources includes the Two Dot and Fairfield wind projects. What is going on with these projects?
Answer - As noted on the list, both of these projects are Qualifying Facility (QF) projects under contract to NWE. Neither project is under construction, but both have operational dates by the end of this year. Because they are QF projects, NWE does not have the interaction with their developers that we have with that of other projects. NWE also does not have the ability to enforce the terms and conditions of the contracts. We include the Two Dot and Fairfield wind projects in our list of existing resources because we expect them to perform under the terms of the executed contract.

We should also note that NWE has appealed the MPSC decision in the QF docket to Montana District Court.

NWE recently has received requests by developers representing QF contracts totaling 70 MW of new-build capacity.

Heavy and Light Load and Supply Forecasts

The load forecast shown in the red lines is not yet updated. The white area on the two graphs, the area between the resource stack and the red line forecast, is the area that must be filled with new supplies. The information shown illustrates the difference in our heavy and light load and supply positions. The supply deficit for heavy load hours is on the order of 150,000 monthly MWh or 200 average MW and under light load hours is on the order of 100,000 monthly MWh or 140 average MW. If we acquire a 300 MW flat resource, i.e. the same production during heavy and light hours, we would be long during light hours. NWE has a policy of not being in a long position because of the market exposure that results. Another marketing challenge facing NWE is the lack of firm transmission capacity, particularly during light load hours. Because marketing takes place on Pacific Time, NWE has made swaps because our load ramps start an hour earlier than the utilities that are on Pacific time. More information will be provided at the next ETAC meeting on the load-resource balance.

Comment - Graphically showing the frequency of light loads would be useful.

Question - What about replacing the PPL contract with a flat resource when it expires in 2014?
Answer - The PPL contract is for 200 MW during heavy loads and 125 MW during light load hours. A flat resource sized to meet our light load needs would be beneficial. A dispatchable resource would tend to have a higher value to our portfolio than a flat resource.

Question - As mentioned at the last meeting, rumors have been reported that PPL is seeking to sell its Montana generation resources. Also, the Confederated Salish and Kootenai Tribes will take ownership of Kerr Dam in 2015 and will be seeking a purchaser of Kerr power. Does your heavy and light load and supply profiles mean that NWE would not have an interest in purchasing PPL's hydropower resources or contracting for Kerr power?
Answer by John Hines - We may consider these resources if their price adequately reflected discounting during periods when we would be long.

Preliminary Annual Portfolio Forecast
The units of this table are in MWh. This table lists no production for QF Tier II resources after 2028, even though the existing Tier II contracts do not expire until 2032 (volumes past 2028 are less than 1 MW and cannot be scheduled in real time). We assume that these generators would still have economic capability and viability and that as contracts expire, these projects would apply for new QF contracts based either on a standard or negotiated rate. Therefore, as the volumes associated with these contracts roll-off Tier II, they are reflected in the QF-1 category.

Renewables by RPS/REC (Capacity and Energy)
Question - What is the message here? Does it relate to the difference between PURPA and Montana's Resource Portfolio Standard (RPS)?
Answer - We are trying to illustrate the high percentage of intermittent resource compared to our light load levels as well as the challenge in meeting the RPS. New wind may currently be the least cost alternative for complying with the RPS, but we cannot take more intermittent resources without the accompanying Renewable Energy Credits (RECs). As discussed at the last ETAC meeting; our current wind generation capacity under contract/owned is about 238 MW. Historically, much of the installed wind generation tends to produce at the same time and if this continues to be the case then our wind generation alone will cover over 50% of our light load. Additionally, if we are forced to acquire QF projects without RECs, it could affect our ability to meet the RPS in the future.

Question - As more and more wind generation is developed, what are RECs worth?
Answer - We are rethinking the value of RECs. Current REC offers are not long-term. When we first started purchasing the Judith Gap wind, RECs sold for $4/MWhr. Short-term REC prices are now on the order $1.50/MWhr. The bid/ask spread on MWhr RECs is on the order of $.50-$1.00.

Comment - When California closed the door on purchasing out-of-state renewable resources, the market for RECs crashed.

Comment - Washington statues have tied up the availability of REC through 2016-17.

Comment - PPL has historically had difficulty purchasing RECs to meet their Montana RPS.

Question - What about biofuels?
Answer - NWE studies indicate that the price of biofuel renewable energy resource is in the $115-118 per MWh range which would not be cost effective even with high value RECs.

Next Meeting
The next meeting was scheduled for Wednesday, February 27, 2013 at the NWE Division offices in Helena.

Disclaimer

Committee members provide advice to NWE as individual professionals; the advice they provide does not bind the agencies or organizations that the members serve.

Appendix 1
Dr. McRae's Notes

I am going to start my discussion with some definitions. And then I will discuss the concepts on the slide from the bottom up!

Gross savings are the savings accruing to all of the measures installed through the program.

Net Savings is the term used by the efficiency community to denote the savings that would not have happened in the absence of the program. The notion is one of attribution—if the savings would not have happened in the absence of the program, then it is assumed the program caused the savings or these savings are attributable to the program.

The net-to-gross ratio (or NTG ratio) is calculated by dividing net savings by gross savings, or expressing net savings as some percentage of gross savings. Net can be less than or greater than gross, so the net to gross ratio can commonly take values of 0.8 or 1.2 or whatever.

For this evaluation, we estimated three factors that commonly are used to derive net savings. These factors are leakage, spillover, and free ridership.

Leakage estimates the proportion of savings that leaves or leaks out of the service territory. We surveyed participants, asked them if their efficiency measures were stilt in place and, if not, where they were. We found zero leakage. The very few folks that reported they had given the measure -say, a tank wrap—to someone else, such as a family member, reported where the recipient lived and we determined that all measures remained within NWE's service territory—electric for electric measures and gas territory for gas measures. NWE assumes a leakage rate for its CFL buy-down program, on the assumption that some of these buy-down stores' customers live outside of the service territory. We believe NWE made a good assumption, and we used that value for the buy-down program.

Spillover estimates savings resulting from the program that NWE doesn't know about, savings from measures other than those NWE paid a customer a rebate for, or provided to the customer. For example, a participant receives two CFLs from the program, decides CFLS are a good product, and purchases additional CFLs without any rebate or discount from NWE. Or a nonparticipant purchases an Energy Star appliance based on the NWE promotion, yet doesn't submit the rebate application form. We estimated spillover using standard, respected evaluation practices. We first asking surveyed customers about any non-program energy efficiency actions they took, asking whether the program influenced this action, and for those that did, investigated the action on-site or, if that wasn't possible, through a subsequent follow-up phone interview.

Free ridership estimates the proportion of program savings that customers would have acquired without the program. They would have been willing to buy the energy efficiency measure without a rebate. We followed standard, respected evaluation practices to estimate this. We asked surveyed customers a series of questions to understand the influence of the program and what they would have done had they not received a rebate. We estimated free ridership *for* each program and obtained results comparable to the results of other program administrators, as we illustrate in the report.

Free ridership, spillover, and leakage estimates get rolled up into a net savings estimates as follows: free ridership counts against the utility as savings that would have happened anyway, with no program; leakage counts against the utility as savings that occur outside the service territory; spillover counts for the utility as additional savings beyond those tracked for program participants.

Now the interesting thing is that at a policy level, there is very little agreement around this whole net savings issue, or NIG. There is little agreement across jurisdictions on (1) whether to calculate net savings, (2) how to calculate net savings, and (3) what use to make of any net savings estimate.

In a recent *Public Utilities Fortnightly* article, Sami Khawaja and Hossein Haeri report on a study The Cadmus Group conducted of 39 jurisdictions with active energy efficiency efforts. 42% of the jurisdictions -nearly half— had no NTG requirement in assessing program performance. An equivalent way to express this is these jurisdictions assumed or used an NTG value of 1.0. A value of 1.0 means that net savings equals gross savings. It also means that spillover -the savings that add to the utility's tracked savings -are assumed to be equal to free ridership and leakage - the savings that subtract from the utility's tracked savings.

In other words, that these unobservable phenomenon of spillover and free ridership are offsetting.

So nearly half of the jurisdictions effectively assume spillover equals free ridership— a wash. In addition to these jurisdictions, another handful that require an estimated NTG use the NTG value for program planning and design activities. Combining these two groups, the result is that *less than half* of the jurisdictions use an estimated NTG value in retrospective assessments of program and portfolio cost-effectiveness.

We concur with this majority of jurisdictions and recommended to NWE that it use an NTG value of 1.0 for its cost-effectiveness analyses, and that's the approach we used in this evaluation study. Thus, the gross and net savings estimates we generated are equal.

Now let's look at the underpinnings of this recommendation. Further supporting the common policy practices that do not use NTG in cost-effectiveness calculations, there are concerns raised in the evaluation community with the estimated free ridership and spillover values, which I will next discuss.

The problems with any estimates of spillover and free ridership are those of asymmetric information, as well as false measurement.

Our ways of estimating spillover very likely underestimate it, and our ways of estimating free ridership very likely overestimate it.

Let's think for a moment about the goals of NWE's energy efficiency portfolio, which has concluded its tenth year- First and foremost, the portfolio seeks to acquire energy savings today. But almost as importantly, it seeks to lay the groundwork for savings acquisitions in subsequent years. NWE activities ensure that customers are aware that energy efficient options exist, are aware that these options offer energy and money savings, comfort, high quality, and other non-energy benefits. NWE activities ensure there is ready-availability of energy efficient options, that

distributors provide them and vendors and contractors stock or order them. That vendors and contractors are aware of the benefits these energy efficient options offer consumers, are familiar with the quality of the products, how to spec them, install them, and service them. NWE activities lay the ground work for future increases in the energy efficiency requirements in building codes. NWE's efficiency activities increase the number of people who are always deliberating whether the energy-efficient alternative is the right choice in any given situation.

Now think for a moment about the paradox of this policy goal -moving consumers to cost-effective, quality energy efficiency actions -and the estimation of free ridership as an adjustment that debits from the utility'S claimed energy savings. As the portfolio reaps success from year to year and increasingly motivates consumers and suppliers to engage in energy efficiency -that is, as the *actual* effectiveness of the portfolio increases -the estimated free ridership value goes up - because participants say, "oh, I would have done that anyway"— and the *estimated* effectiveness of the portfolio decreases. Let'S hear that again: as the *actual* effectiveness of the portfolio increases, a free ridership adjustment used in the calculation of cost-effectiveness generates a *declining* indicator of portfolio success.

It is impossible for consumers -residential and nonresidential -to know of all of NWE'S program activities and interventions in the market. They can't know all the ways NWE's actions have influenced them, from increased awareness of product existence and product benefits to increased supply and proper installation and maintenance, to lower costs -not just through rebates, the only part of NWE's activities that is really obvious to consumers -but also lower costs through increased supply and increased supplier familiarity, skills and lower administrative costs. So when participants are asked "did the program influence you" and "would you have done this without a rebate", they say "no, would have done this anyway."

As Haeri and Khawaja put it, "Could it be that what's being measured in free ridership surveys is, in fact, the opposite: spillover? What's being measured, it appears, are the effects of the program -not what would be expected in its absence. In areas with long histories of conservation programs and activities, it's no longer possible to parse out who is a free rider from who was influenced by the program."

So free ridership estimates are undoubtedly overestimates, due to the confounding with spillover. And spillover estimates are underestimated, in part because part of the spillover methodology includes asking the free ridership questions about any discovered non-tracked efficiency -"did the program influence this?" Spillover customers, like participants, say "no," when in fact they have no way of knowing the program activities and implications.

Spillover is also underestimated due to what is termed in statistics "type II errors." When a customer reports in a survey that they did an efficiency action, we went on-site and confirmed or disconfirmed the action. Disconfirmation reveals a type I error. But studies have shown that customers also *underreport* efficiency actions. That is, they say that what they have is not efficient when it is. This is a type II error. Our methods don't uncover these errors. To do so would require on-site visits of a large stratified random population to obtain measure saturation data.

So our methods underestimate spillover, because it includes a free ridership component that undercounts NWE's influence and it can't be corrected for type II errors.

And our methods overestimate free ridership, also for two reasons. One, because it counts spillover as free ridership, as discussed. Secondly, because we have only limited means of assessing the validity of our estimation approach.

To be a good estimator, a method must be reliable and valid. Reliable means the repeated applications of the method yields the same results. Valid means the method is estimating what it says it is. Our free ridership methods appear to be fairly reliable, as illustrated by the fact that NWE's estimates are similar to those of other program administrators. But what is it measuring? There are three different elements that are simultaneously measured in free ridership estimates. The first is true free ridership. It exists, of course, and our methods capture that, as well as quantities owing two other phenomenon. The second thing that is rolled into the free ridership estimate is spillover, as we discussed.

And there is a third thing that it is simultaneously measuring: multiple psychological phenomena that lead people to respond in predictable ways and ways contrary to the facts—ways that overestimate free ridership. All of these responses have been proven empirically to exist -repeated empirical studies show the same effects.

One of these is loss aversion. People will pay more to avoid a loss than to reap a gain. When a customer is contemplating a higher cost efficiency item he or she might indeed be persuaded by the rebate. But after living with the item for a while, the researcher asks the participant to consider a loss -life without the item. The participant now values this item more than he did prior to purchasing and says "of course I'd pay the higher cost for it."

Another one of these psychological phenomena is attribution theory. Again, this has been proven repeatedly be researchers in experimental settings. But this phenomenon has long been immortalized in the culture at large in the aphorism "success has a thousand fathers, failure is an orphan" -or, in the case of failure, the colorful "the devil made me do it." Attribution theory states that everyone likes to attribute a successful idea to their own good sense; everyone likes to attribute failure to some external circumstance. Energy efficiency is a successful idea that people take credit for, and are reluctant to credit to the utility.

Another one of these phenomena is referred to as "choice-induced preference change." Experimental studies have shown that the very act of making a decision, a choice, changes one's preferences, and that these changes are long lasting. Prior to purchasing the energy efficient item, the customer may have been indecisive and the rebate may have been influential. Subsequent to the purchase, the participant's preferences have changed in favor of the item and they report to researchers "no, it wasn't the utility, this is what I preferred."

Let's finish up by recapping. Spillover underestimates non-tracked energy savings because customers make type II errors and because, when they have invested in efficiency, they are not aware of or they underestimate the utility's influence. Free ridership overestimates what would have happened in the absence of the utility portfolio because people are not aware of the utility's influence and because of psychological effects that lead people to say that what they did is what they wanted to do and nobody influenced them.

For welt designed and implemented efficiency portfolios that have been operating continuously for a decade or more, we can expect spillover is large - energy efficiency is becoming more top-of-mind and easier to do.

And this is what policy is aiming at: a more energy-efficient economy.

It doesn't make sense to penalize the utility for its very success. More than half of the jurisdictions with active energy efficiency efforts do not use an NTG adjustment in the calculation of program cost-effectiveness, and we recommended and implemented this approach for NWE.

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Impact and Process Evaluation of NorthWestern Energy 2007–2011 Demand Side Management Programs

January 24, 2013

Presentation to: NorthWestern Energy
Electric Technical Advisory Committee

Presented by: Michael Baker, SBW Consulting, Inc.
Dr. Marjorie McRae, Research Into Action

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Research Objectives

- Impact
  - Gas and electric gross savings
  - Net savings
  - Measure persistence
  - Installation vs. measure rebate date
- Economic Analysis
  - Benefits, costs and cost-effectiveness
- Process
  - Program planning, design, and management
  - Branding, marketing, outreach, and media use
  - Quality control, data tracking, and evaluation
  - Free ridership, spillover, leakage

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Evaluation Timing and Scope

- Evaluation work conducted from Jan – Oct 2012
- Portfolio of 24 programs (DSM and USB)
- Evaluation covered all program activity from 7-1-2006 thru 12-31-2011
- Standardized program tracking database, covering all programs, all years, >300,000 records
- Samples drawn from the most recent two years of program activity and results applied to the entire period
- Gross and net savings (kWh, dkt) and cost-effectiveness evaluated by Calendar and Tracker Year
- 1,416 process evaluation with participants, non-participants, trade allies, and program staff
- Compared with more than 50 program best practices
- Formulated 239 program-specific recommendations for improvements

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24 Programs Evaluated

- Building Operator Certification
- DEQ Appliance
- E+ Audit Home or Business
- E+ Building Blocks Pilot
- E+ Business Partners
- E+ Commercial Existing Electric Rebate
- E+ Commercial Existing Gas Rebate
- E+ Commercial Lighting
- E+ Commercial New Electric Rebate
- E+ Commercial New Gas Rebate
- E+ Electric Motor/Rewind Rebate
- E+ Free Weatherization/Fuel Switch
- E+ Irrigation
- E+ New Homes
- E+ Renewable
- E+ Residential Existing Electric Rebate
- E+ Residential Existing Gas Rebate
- E+ Residential Lighting
- E+ Residential New Electric Rebate
- E+ Residential New Gas Rebate
- Low Income Appliance
- NEEA Initiatives
- Vending Miser
- Motor Management Training

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Some Have More Than One Component

- E+ Audit Home or Business
  - Home Electric Survey
  - Home On-site Audit
  - Small Business Electric Appraisal
- E+ Commercial Lighting
  - Commercial CFL Direct Install
  - Commercial Lighting Rebate
- E+ Renewable
  - Business Renewable
  - Residential Renewable
- E+ Residential Lighting
  - In-Store Coupon
  - Trade Show
  - Mail-In
  - Mail-Out
  - Residential CFL Direct Install
  - Upstream CFL Buy-down

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NEEA Had Many

- 80 Plus Power Supply
- Commercial Commissioning Public Buildings
- Commercial Verdiem
- Energy Codes 1997-2004
- Energy Codes 1997-2011
- Irrigation Soil Moisture Data Logger
- Residential Ductless Heat Pump
- Residential Energy Star CFL Bulbs
- Residential Energy Star CFL Fixtures
- Residential Energy Star Clothes Washers
- Residential Energy Star Dishwashers
- Residential Energy Star New Construction
- Residential Energy Star Refrigerators
- Residential Energy Star Specialty CFL Bulbs
- Residential Energy Star TVs
- Residential Energy Star Windows
- Residential Multi-Family Codes > 2004
- Residential Single-Family Codes > 2004

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Data Collection – Samples and Methods

- Participant Samples
  - 2007-09
    - File-Review Only – 1,181
  - 2010-11
    - Site Visit – 638
    - Light Loggers – 76 residences and 220 loggers
    - Telephone
      - Free-Ridership – 922
      - Spillover – 508
- Non-Participant Samples
  - Telephone – 231
  - Residential, Irrigation, Other Small and Other Larger
- Trade Ally Samples
  - Telephone – 228
  - Residential, Commercial, Irrigation, Renewables, CFL Retailers
- Program Staff
  - In-Person and Telephone – 35
  - Corporate DSM staff, other NWE staff, implementation contractors, low income free weatherization

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Free Ridership, Spillover, and Net-to-Gross Adjustments

- Challenges in Estimating Free Ridership
  - The Measurement Issues: Reliability and Validity
  - Established Approaches to Validity
    - Face Validity
    - Internal Consistency
  - Doubts about the Face Validity of Self-Reported Free Ridership
- Challenges in Estimating Spillover
  - The Measurement Issues: Identifying Its Occurrence and Quantifying Its Savings
  - Spillover and the Confounding of Free Ridership Estimators
  - Relative Magnitudes of Spillover and Free Ridership Effects
- Estimated Leakage by NWE Program
  - None reported
- Net-to-Gross Recommendations
  - Program design should seek to avoid free-ridership
  - However, no quantitative adjustment to impacts should be made for free ridership or spillover

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Final Products of the Evaluation

- Report Volume 1
  - Vol 1 NWE 2007-11 Impact and Process Evaluation.docx
    - Executive Summary and overall methodology, findings and recommendations
    - Individual chapters for 24 programs
    - Chapters on special studies
      - CFL operating hours
      - Savings persistence
      - Installation vs. rebate date
  - Impact Result Tables - Calendar.xlsm
    - Portfolio tabulations of savings, costs, cost-effectiveness tests and levelized costs
    - Individual sheets by program, including lifetime savings
  - NWE Recommendations Master Matrix.xlsx
    - 239 program-specific recommendations
- Report Volume II
  - Vol II NWE 2007-11 Impact and Process Evaluation.docx
- Tracker Year Results
  - Impact Result Tables - Tracker.xlsm

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Portfolio Impact (kWh and dkt) – Calendar Years (2007-11)

All Programs

	Units	Reported Energy Savings	Evaluation Energy Savings	Net Savings Adjustment Rate
Electric				
Electric Supply - DSM	kWh	275,073,686	248,463,014	0.90
Electric - USB	kWh	34,262,001	22,101,125	0.65
All Programs Electric	**kWh**	**309,335,688**	**270,564,139**	**0.87**
Natural Gas				
Natural Gas Supply - DSM	dkt	548,774	343,421	0.63
Natural Gas - USB	dkt	325,536	233,824	0.72
All Programs Natural Gas	**dkt**	**874,310**	**577,245**	**0.66**

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Portfolio Impact (kWh and dkt) – Tracker Years (2006-07 thru 2010-11)

All Programs

	Units	Reported Energy Savings	Evaluation Energy Savings	Net Savings Adjustment Rate
Electric				
Electric Supply - DSM	kWh	255,525,303	235,093,603	0.92
Electric - USB	kWh	35,163,422	23,038,815	0.66
All Programs Electric	**kWh**	**290,688,725**	**258,132,418**	**0.89**
Natural Gas				
Natural Gas Supply - DSM	dkt	559,072	348,641	0.62
Natural Gas - USB	dkt	332,990	245,223	0.74
All Programs Natural Gas	**dkt**	**892,062**	**593,864**	**0.67**

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Portfolio Cost-Effectiveness – Calendar Years (2007-11)

All Programs

	Units	TRC B/C Ratio	PAC B/C Ratio	RIM B/C Ratio	Societal Cost B/C Ratio
Electric					
Electric Supply - DSM	kWh	2.14	3.66	1.81	2.36
Electric - USB	kWh	0.28	0.52	0.45	0.31
All Programs Electric	**kWh**	**1.41**	**2.49**	**1.46**	**1.56**
Natural Gas					
Natural Gas Supply - DSM	dkt	1.00	1.46	1.10	1.10
Natural Gas - USB	dkt	1.77	1.77	1.32	1.95
All Programs Natural Gas	**dkt**	**1.28**	**1.60**	**1.20**	**1.41**

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Levelized Cost of Energy – Calendar Years (2007-11)

All Programs	Units	Net Adjusted Energy Savings	Cost of Saved Energy (CSE) Based on Total Resource Costs (TRC)	Cost of Saved Energy (CSE) Based on Program Administrator Costs (PAC)
Electric				
Electric Supply - DSM	kWh	248,463,014	0.028	0.016
Electric - USB	kWh	22,101,125	0.21	0.113
All Programs Electric	**kWh**	**270,564,139**	**0.042**	**0.024**
Natural Gas				
Natural Gas Supply - DSM	dkt	343,421	6.605	4.508
Natural Gas - USB	dkt	233,824	3.971	3.971
All Programs Natural Gas	**dkt**	**577,245**	**5.303**	**4.242**

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Findings from Special Studies of CFLs

- Operating hours
  - Residential
    - Light Logger study
      - 76 residences and 220 light loggers
      - Sample represents 2010-11 program activity
      - Average of 2.02 hours per day
    - Hours before 2010 adjusted based on earlier metering studies
    - Hours for each program based on bulb count by year
      - E+ New Homes - 2.24
      - E+ Residential Lighting - 2.30
      - NEEA Initiatives - 2.4
  - Non-residential
    - Hours per day from Commercial CFL Direct Install - 6.14
- Non-residential share of "Buy-Down" bulbs from Trade Ally surveys
  - 19.4% - Applied to E+ Residential Lighting and NEEA CFL initiatives

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Savings Persistence

- Methodology
  - Site visit sample selected from 2007-08 installations in 17 programs
  - 119 projects inspected / surveyed to determine if still operational and saving energy
  - Literature review conducted for a set of measures not included in site visit sample
- Findings and Recommendations
  - Evidence that EULs should be re-examined or changed for certain measures in 8 programs
  - EULs should be standardized across programs for the same technologies and sectors, such as residential CFLs
  - Consider creating separate EULs for the direct-installed and owner-installed elements of audits
  - Reassess EULs for commercial CFLs and unconventional renewable energy projects.

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Impact of Install vs. Rebate Date

- Methodology
  - Obtained rebate date from program tracking data
  - Install date either from tracking data or project files
  - Computed number of days between install and rebate
  - Noted when that interval crossed into new tracker year
- Findings and Recommendations
  - Comparison possible for 14 programs, as some delivery methods, e.g., CFL buy-down do not allow for recording install date
  - Savings weighted average days between install and rebate – 115 days
  - 28% of measures tested crossed June 30th into new tracker year
  - Recommend continuing to use rebate date as it is the only date readily available across all programs

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Process Finding

- Activity Areas
  - Program Planning and Design
  - Management
  - Branding, Marketing, Outreach, and Media Use
  - Quality Control and Data Tracking
  - Evaluation
- Nonparticipant Findings

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Program Planning and Design

- Service Territory Context
  - Rural, mountainous, noncontiguous, "islands" of communities
  - 75% of customers are residential, but little electric space heating load
  - Large C&I on Choice
- Program Planning and Design
  - Conducts independent assessments of efficient potential
  - Annually updates available measures and incentives
  - Uses variety of distribution channels, incentive approaches, services
- Follows More than 12 Best Practices for Planning and Design
  - Develops sound program plans, responsive to market conditions, HTR
  - Encourages contractor participation
  - Keeps programs and funding stable

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Program Management and Administration

- Program Management and Administration
  - Program staff *extremely* lean compared to 39 program administrators (LBNL study)
  - Efficiency staff supported by Corp Communications, Community Relations
  - Experienced program implementation contractor
    - Frequent communication, collaboration
- Follows more than 12 Best Practices for Management and Administration
  - Program roles, responsibilities clear
  - Processes in place for systematic inspections, verification
  - Program processes simple, assistance available
  - Single-point of contact for participants
  - Uses well-qualified engineering staff for technical programs

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Branding, Marketing, Outreach, and Media Use

- Branding, Website, and Other Services
  - Careful branding, use of logos
  - Corporate Communications staff are valued members of efficiency team
  - Website evolution; in 2010 efficiency pages reworked with ad agency
- Marketing and Outreach
  - Extensive outreach to customers and trade allies through multiple channels
  - Frequently hosting or participating in events, often distributing measures
  - Nonresidential one-on-one and small group outreach
  - Trade allies supported with newsletters, facilitated network, annual meetings
- Community Relations
  - NWE's CR managers provide outreach to multiple communities (based in 6 major cities)
  - Discuss efficiency with individual customers and at events
- Follows More than 8 Best Practices for Marketing and Outreach
  - Communicates with customers through multiple media
  - Uses website to attract and inform
  - Uses Energy Start products and logo
  - Leverages marketing dollars (trade ally relationships, co-hosting events)
  - Conducts cross program marketing

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Quality Control and Data Tracking

- Quality Control
  - Automated and manual checking of application forms, invoices, incentives
  - Audit results reviewed by technical staff
  - Inspections in all programs
- Follows More than 9 Best Practices for Quality Control
  - Sample-based post-installation inspections
  - Inspects all large projects and uncertain savings estimates
  - Assesses customer satisfaction
  - Preferred contractors
- Data Tracking and Reporting
  - 30 databases, including cross-program databases that interact with other files
  - Databases, purpose, variables are documented
  - All participants checked for eligibility
  - Payments tracked together
  - Consistent reports generated
- Follows More than 15 Best Practices for Data Tracking and Reporting
  - Functions – including QC – are automated
  - Databases dynamically linked
  - Algorithms validated
  - Tracking reports used to manage programs

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Evaluation

- Data Tracking for Evaluability
  - Recommendations offered for:
    - Date tracking – savings start date
    - Cost tracking – measure & participant costs
    - Unique identifiers – file naming conventions, grouping of project-specific files
- Evaluation Practices
  - Conducts regular, independent evaluations
  - NWE supportive of evaluation needs
  - Culture of receptivity to new ideas and research
  - Staff want to improve programs
  - Program evolution from 2007 in response to prior evaluation findings
- Follows More than 15 Best Practices for Evaluation
  - Obtains market baselines
  - Conducts detailed ex post impact evaluations
  - Conducts comprehensive evaluations
  - Estimates realization rates
  - Estimates measure lives
  - Fosters a culture that values and uses evaluation findings

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Nonparticipant Findings

- Residential, Small Commercial, Large Commercial, Irrigation nonparticipants
- High awareness of Energy Star
- Most contacts knew about pertinent qualifying measures
- Most learned about NWE programs through publications and advertisements
- In general, majorities aware of rebates and audits
  - Fewer aware of renewables
- The few using the website did so for contact information or to pay bill
- Under half think they are likely to participate in future

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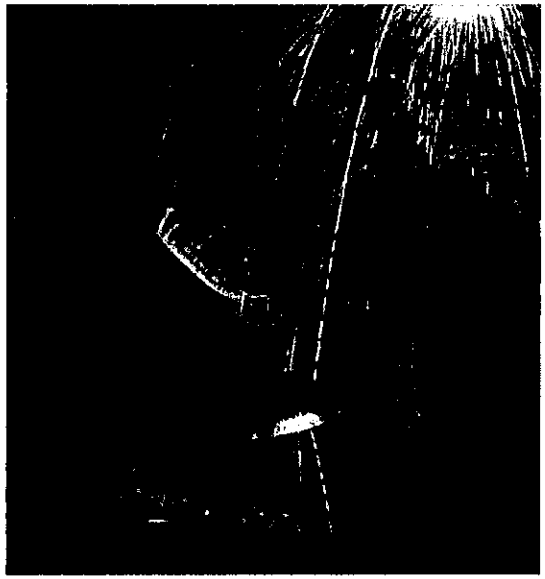
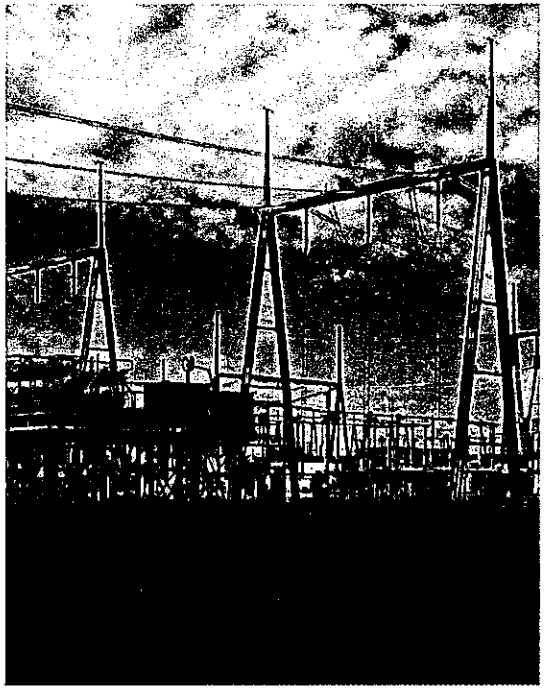
Portfolio Recommendations

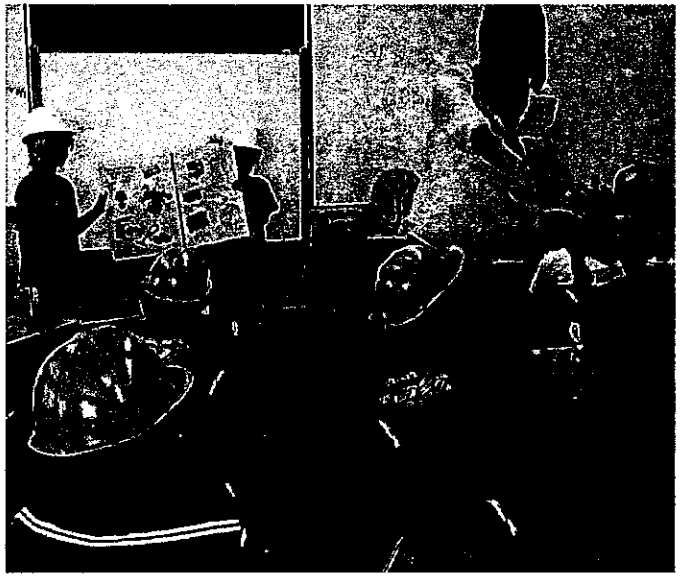
- Impact
  - Increase marketing to make customer more aware of NWE offerings
  - Collect customer e-mail addresses for future evaluations
  - Use consistent program names
  - Update UES values
- Process
  - Planning and design
    - Prepare written program plans
    - Reduce the frequency of updates
    - Update customers about program changes
  - Management and administrative
    - Write down process plans
    - Solicit program feedback from trade allies
    - Increase use of internet tools
  - Marketing and outreach
    - Provide more information about efficiency opportunities through mail
    - Notify participating trade allies by email of all Montana-based efficiency related workshops, seminars, and training opportunities
    - Recruit additional trade allies as preferred contractors
    - Incorporate additional non-energy benefits and marketing messages
  - Quality control
    - Consider project inspection costs when setting ongoing inspection rates
  - Evaluation
    - Adopt a fast-feedback evaluation approach
    - Monitor product markets and conduct market saturation studies
    - Conduct more frequent, smaller-scope evaluations

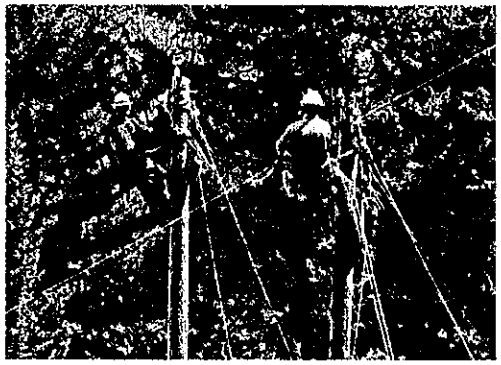


ETAC UPDATE

January 24, 2013







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EXISTING ENERGY SUPPLY RESOURCES

NorthWestern Energy
Existing Energy Supply Resources
(as of January 1, 2013)

Resource	Nameplate [1] Capacity (MW)	Peaking Capacity (MW)	Annual Energy (aMW)	Load Following Up (MW)	Load Following Down (MW)	Spinning Reserves (MW)	Non-Spinning Reserves (MW)	Expiration Date
Colstrip 4	222.0	222.0	202.0	0.0	222.0	0.0	0.0	n/a
Basin Creek	52.0	35.0	2.0	35.0	0.0	0.0	17.0	7/1/2026
Spion Kop	40.0	0.0	16.0	0.0	0.0	0.0	0.0	n/a
QF Tier II	99.9	91.0	93.0	0.0	0.0	0.0	0.0	Various
QF-1 Tariff	4.0	0.0	0.1	0.0	0.0	0.0	0.0	Various
Gordon Butte	9.6	0.0	4.0	0.0	0.0	0.0	0.0	3/21/2036
Musselshell 1	10.0	0.0	3.0	0.0	0.0	0.0	0.0	3/24/2036
Musselshell 2	10.0	0.0	3.0	0.0	0.0	0.0	0.0	3/24/2036
Two Dot [2]	9.7	0.0	3.0	0.0	0.0	0.0	0.0	8/31/2037
Fairfield Wind [2]	9.5	0.0	3.0	0.0	0.0	0.0	0.0	8/31/2037
Turnbull	13.0	0.0	3.0	0.0	0.0	0.0	0.0	12/31/32
DSM [3 & 4]	n/a	9.0	6.0	0.0	0.0	0.0	0.0	n/a
DGGS (Energy Supply)	7.0	7.0	7.0	0.0	0.0	0.0	0.0	n/a
Judith Gap	135.0	0.0	53.0	0.0	0.0	0.0	0.0	12/31/2026
Tiber	7.5	5.0	2.0	0.0	0.0	0.0	0.0	6/1/2024
PPL 7 YR (HL)	200.0	200.0	112.0	0.0	0.0	0.0	0.0	6/30/2014
PPL 7 YR (LL)	125.0	0.0	55.0	0.0	0.0	0.0	0.0	6/30/2014
PPL 09 RFP (HL)	25.0	25.0	14.0	0.0	0.0	0.0	0.0	6/30/2017
Citgroup 08 RFP	25.0	25.0	25.0	0.0	0.0	0.0	0.0	6/30/2020
Morgan S 09 RFP (HL)	25.0	25.0	14.0	0.0	0.0	0.0	0.0	6/30/2017
TransAlta 10 RFP (HL)	25.0	25.0	14.0	0.0	0.0	0.0	0.0	6/30/2017
Powerex (LL)	50.0	0.0	22.0	0.0	0.0	0.0	0.0	12/31/2014
Credit Suisse	25.0	25.0	25.0	0.0	0.0	0.0	0.0	6/30/2015
TOTAL:	1,129.2	694.0	681.1	35.0	222.0	0.0	17.0	n/a

1. Nameplate capacity reflects NWE share only
2. Under QF contract but not yet under construction
3. Pre-existing DSM embedded in load forcast
4. Estimated on non-coincident peak basis

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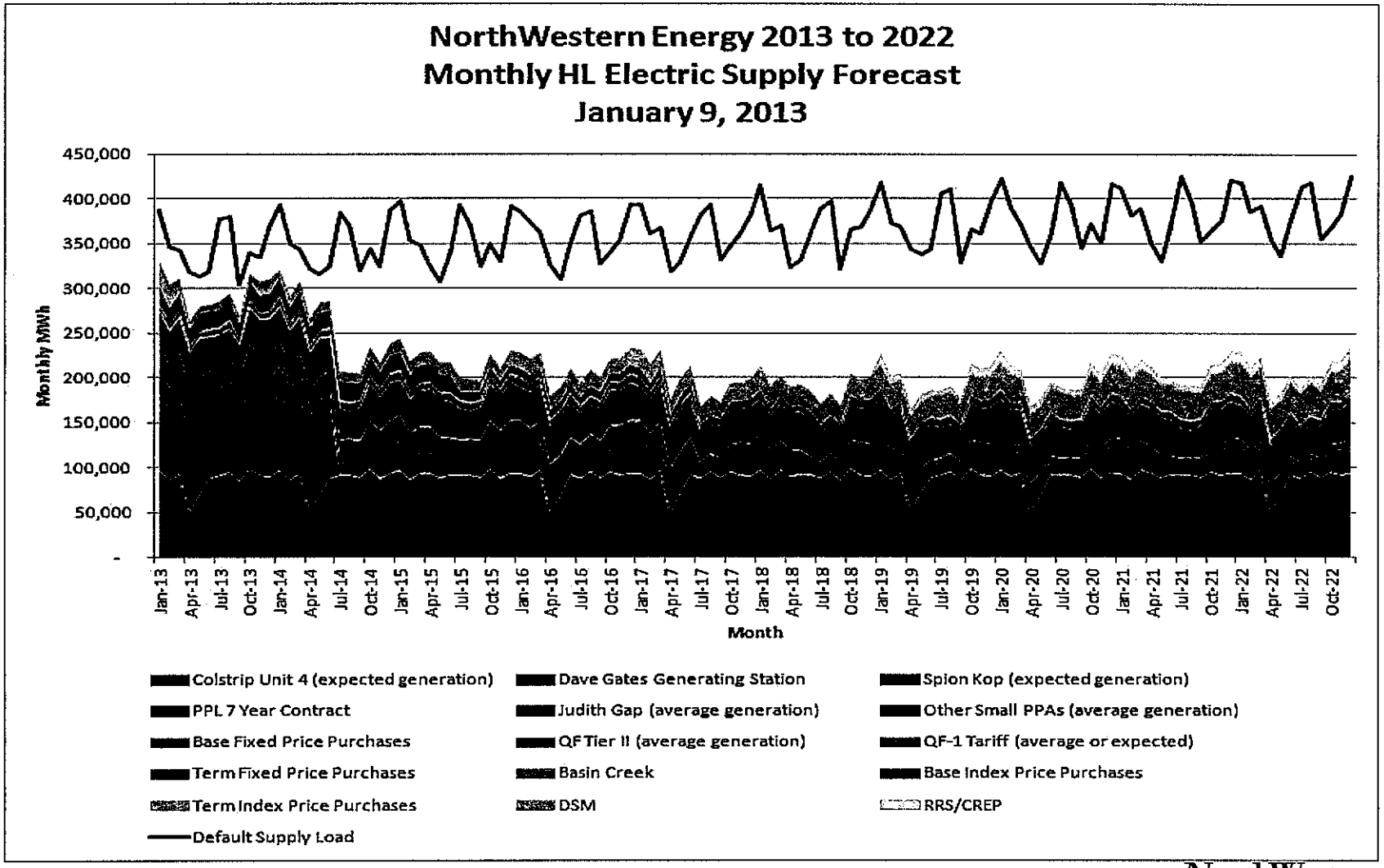
HEAVY LOAD & SUPPLY FORECAST



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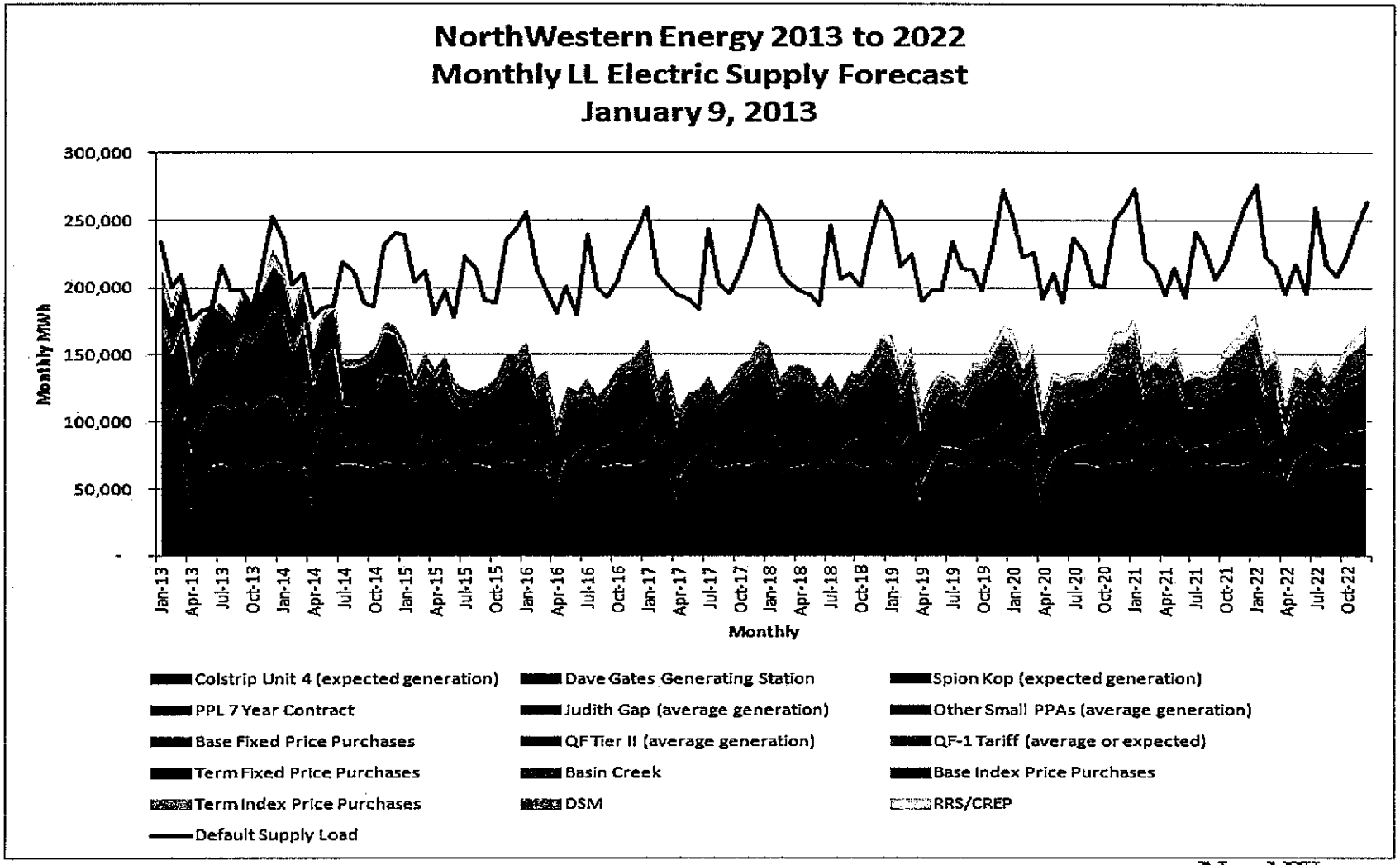
LIGHT LOAD & SUPPLY FORECAST



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PRELIMINARY ANNUAL PORTFOLIO FORECAST

NWE
2013 RPP
Preliminary Annual Portfolio Forecast

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Colstrip Unit 4 (expected generation)	1,659,600	1,659,600	1,769,520	1,664,448	1,659,600	1,769,520	1,659,600	1,664,448	1,769,520	1,659,600	1,659,600	1,774,368	1,659,600	1,659,600	1,769,520	1,664,448	1,659,600	1,769,520	1,659,600	1,659,600	1,769,520
Dave Gates Generating Station	61,320	61,320	61,320	61,488	61,320	61,320	61,320	61,488	61,320	61,320	61,320	61,488	61,320	61,320	61,320	61,488	61,320	61,320	61,320	61,320	61,320
Spion Kop (expected generation)	136,451	135,752	135,752	136,136	135,752	135,752	135,752	136,136	135,752	135,752	135,752	136,136	135,752	135,752	135,752	136,136	135,752	135,752	135,752	136,136	135,752
PPL 7 Year Contract	1,463,400	726,475	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Judith Gap (average generation)	459,464	459,560	459,416	460,624	459,064	459,272	459,464	460,928	459,192	459,112	459,064	460,976	459,560	459,800	459,192	460,576	459,272	457,672	457,672	457,672	457,672
Other Small PPAs (average generation)	117,096	126,768	126,768	127,200	126,768	126,768	126,768	127,200	126,768	126,768	126,768	127,200	126,768	113,880	113,880	114,192	113,880	113,880	0	0	0
Base Fixed Price Purchases	245,600	245,600	245,600	246,400	122,400	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
QF Tier II (average generation)	811,224	811,224	811,224	813,576	811,224	811,224	811,224	813,576	805,344	803,160	803,160	634,680	448,416	448,416	448,416	449,784	0	0	0	0	0
QF-1 Tariff (average or expected)	138,794	176,282	176,282	176,798	176,282	176,282	176,282	176,798	182,162	184,346	184,346	355,029	538,406	538,406	538,406	539,913	985,595	985,595	985,595	987,902	952,695
Term Fixed Price Purchases	23,025	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Basin Creek	15,680	15,616	15,712	15,696	15,632	15,664	15,680	15,728	15,664	15,680	15,632	15,696	15,616	15,744	15,664	15,648	15,664	14,944	14,944	14,944	14,944
Base Index Price Purchases	534,200	534,200	231,375	123,200	61,200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Term Index Price Purchases	84,752	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DSM	157,992	207,912	263,936	317,384	368,568	422,264	475,232	530,256	581,016	633,584	685,680	696,576	694,256	695,136	693,920	695,920	694,304	690,368	690,368	696,208	694,000
RRS/CREP	0	0	0	0	0	23,352	162,648	175,608	188,208	199,128	213,720	224,664	237,792	249,432	275,016	275,904	287,376	301,968	313,680	327,120	337,008
Forecast Need	672,966	1,498,567	2,444,151	2,683,433	2,915,971	3,001,200	3,008,539	3,021,062	2,948,871	3,085,913	3,109,914	3,058,817	3,258,943	3,349,926	3,307,521	3,496,029	3,588,924	3,562,535	3,865,745	3,934,440	3,935,184
Default Supply Load	6,581,564	6,658,876	6,741,055	6,826,382	6,913,781	7,002,617	7,092,509	7,183,228	7,273,816	7,364,362	7,454,555	7,545,629	7,636,428	7,727,411	7,818,607	7,910,038	8,001,687	8,093,554	8,184,677	8,275,342	8,358,095

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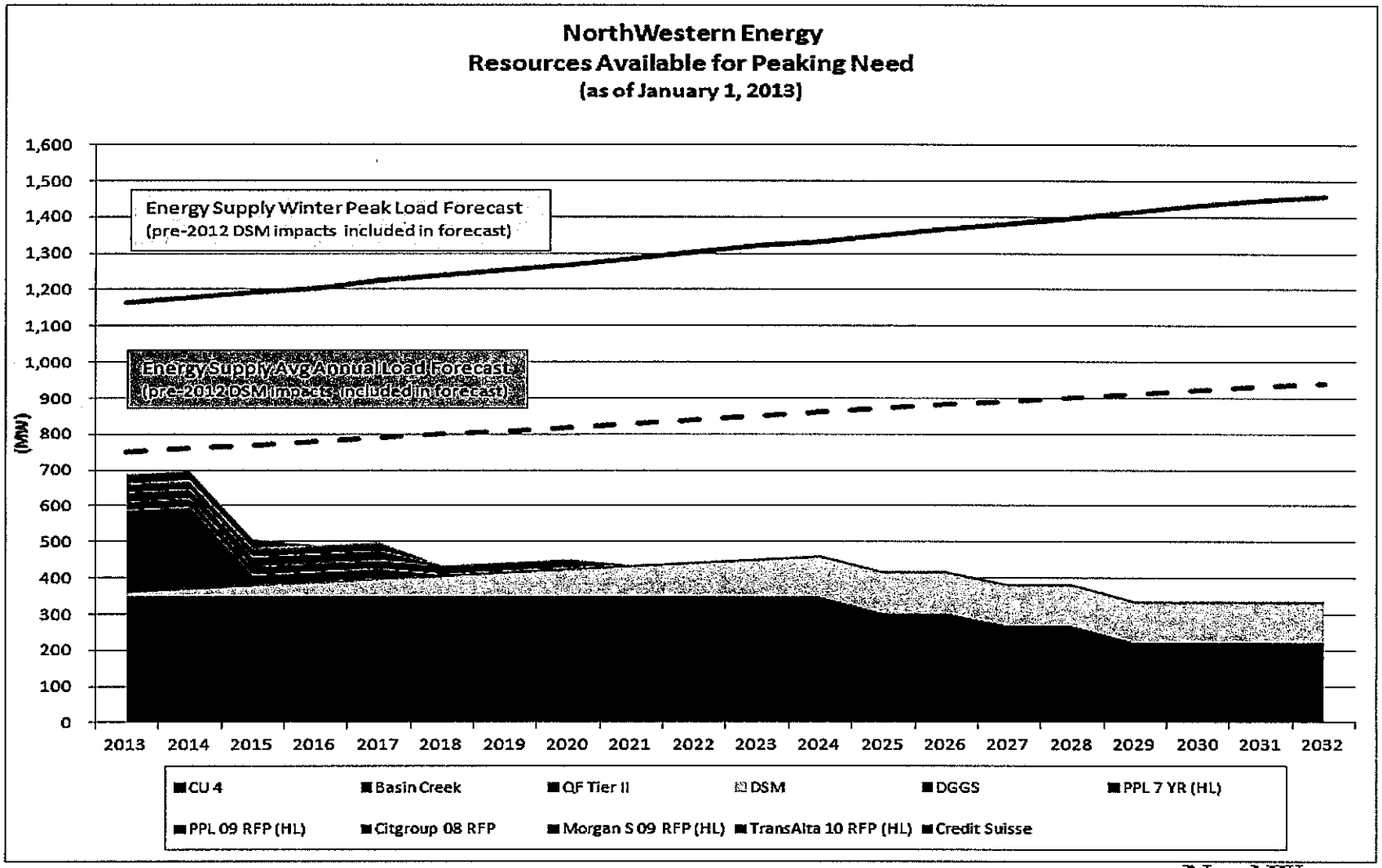
RESOURCES AVAILABLE FOR PEAKING NEED



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RENEWABLES BY GEN TYPE (CAPACITY)

Contracted Capacity 2012
for Supply Portfolio Renewable Resources
by Generation Type
(Montana RPS and non-RPS Combined)

WIND	kW
Mr. Thomas G. Agnew (Agnew Ranch)	65
Two Dot Wind LLC (Martinsdale Colony)	750
Two Dot Wind LLC (Martinsdale Colony South)	2,000
Two Dot Wind Energy LLC (Mission Creek)	65
Two Dot Wind LLC (Moe Wind)	450
Two Dot Wind Energy LLC (Montana Marginal Energy)	195
Two Dot Wind LLC (Sheep Valley Ranch)	455
United Materials of Great Falls Inc	9,000
Musselshell Wind Project LLC	10,000
Musselshell Wind Project Two LLC	10,000
Two Dot Wind Farm LLC	9,720
Fairfield Wind LLC	9,500
Gordon Butte Wind LLC	9,600
WPSA Judith Gap 1 LLC (Judith Gap)	135,000
Spion Kop Wind	40,000
Total Wind:	236,800

THERMAL	kW
Yellowstone Energy Limited Partnership (BGI)	52,000
Celstrip Energy Limited Partnership	35,000
Total Thermal:	87,000

Total Installed Capacity: 353,073

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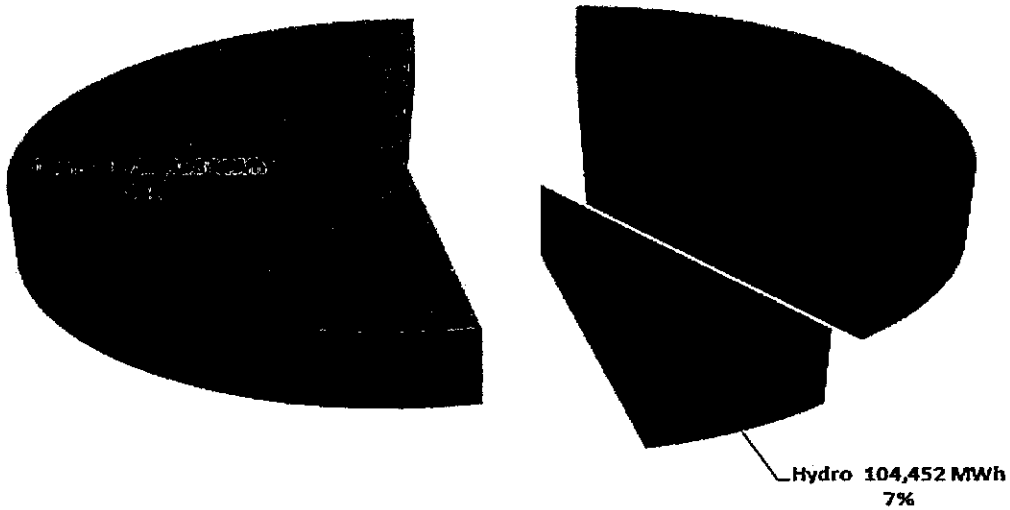
RENEWABLES BY GEN TYPE (ENERGY)

2012 Supply Portfolio
Renewable Energy Generation
by Generation Type
(Montana RPS and non-RPS Combined)



WIND	MWh
Mr. Thomas G. Agnew (Agnew Ranch)	39.1
Two Dot Wind LLC (Martinsdale Colony)	1,334.3
Two Dot Wind LLC (Martinsdale Colony South)	1,183.4
Two Dot Wind Energy LLC (Mission Creek)	119.8
Two Dot Wind LLC (Moe Wind)	580.0
Two Dot Wind Energy LLC (Montana Marginal Energy)	335.9
Two Dot Wind LLC (Sheep Valley Ranch)	884.0
United Materials of Great Falls Inc	4,056.5
Musselshell Wind Project LLC	-
Musselshell Wind Project Two LLC	-
Two Dot Wind Farm LLC	-
Fairfield Wind LLC	-
Gordon Butte Wind LLC	43,007.2
WPSA Judith Gap 1 LLC (Judith Gap)	461,276.0
Spion Kop Wind	42,251.0
Total Wind:	555,067.3

THERMAL:	MWh
Yellowstone Energy Limited Partnership (BGI)	454,803.7
Colstrip Energy Limited Partnership	301,694.0
Total Thermal:	756,497.7

Total Renewble MWh Purchases in 2012: 1,415,927

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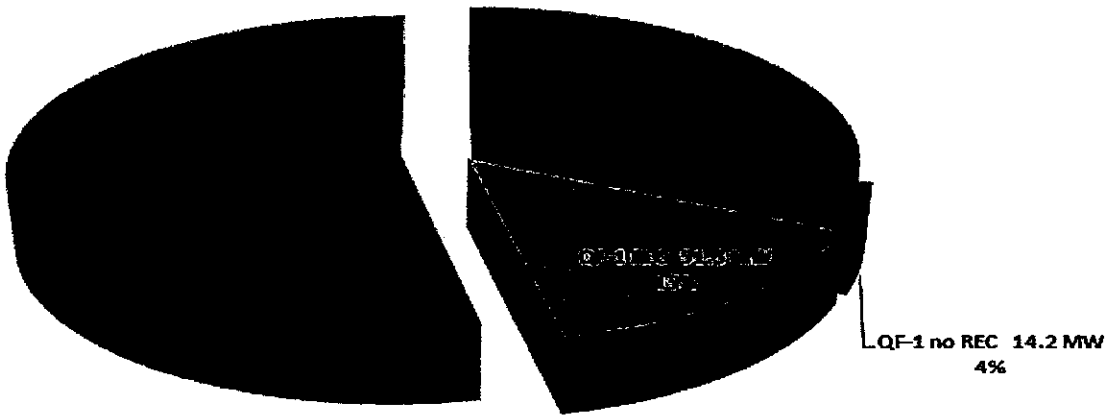
RENEWABLES BY RPS/REC (CAPACITY)

Contracted Capacity 2012
for Supply Portfolio Renewable Resources
by Renewable Category
(Montana RPS and non-RPS Combined)



REC's PPA	kW
WPSA (Judith Gap) LLC (Judith Gap)	135,000
Turnbull Hydro LLC	13,000
Spion Kop Wind	40,000
Total REC's PPA	188,000

QF-1 REC	kW
Flint Creek Hydroelectric LLC	2,000
Lower South Fork LLC	455
Musselshell Wind Project LLC	10,000
Musselshell Wind Project Two LLC	10,000
Two Dot Wind Farm LLC	9,720
Fairfield Wind LLC	9,500
Gordon Butte Wind LLC	9,600
Total QF-1 REC	51,275

Tier II no REC	kW
James Walker Sievers (Barney Creek)	60
State of MT DNRC (Broadwater Dam)	10,000
Yellowstone Energy Limited Partnership (BOI)	52,000
Colstrip Energy Limited Partnership	35,000
James Walker Sievers (Cascade Creek)	65
Donald Fred Jenni (Hanover Hydro)	240
Estate of Howard Carter (Pine Creek)	300
Ross Creek Hydro LC	450
Hydrodynamics Inc (South Dry Creek)	1,200
Hydrodynamics Inc (Strawberry Creek)	190
Total QF-1 REC	99,508

Total Installed Capacity:	353,073

NorthWestern Energy
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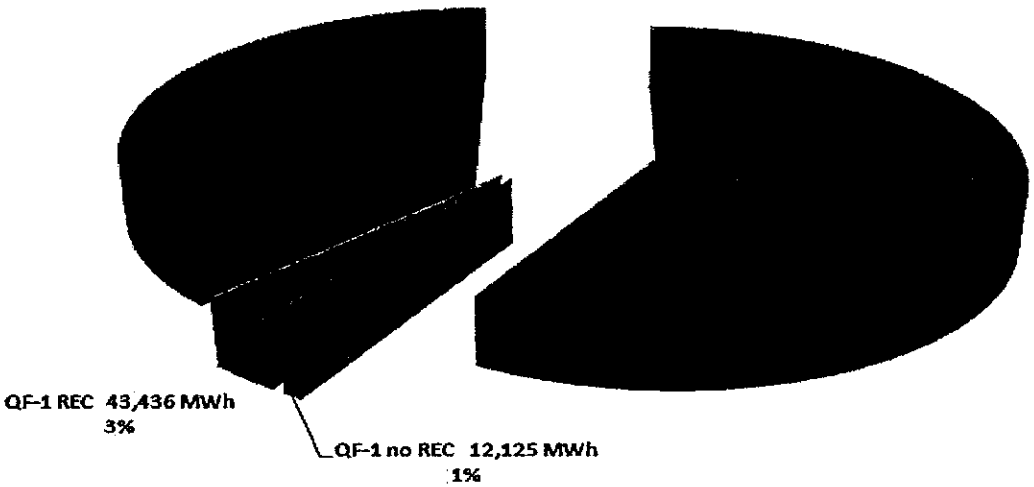
RENEWABLES BY RPS/REC (ENERGY)

2012 Supply Portfolio
Renewable Energy Generation
by Renewable Category
(Montana RPS and non-RPS Combined)



REC - PPA	MWh
WPSA Judith Gap I LLC (Judith Gap)	461,276.0
Turnbull Hydro LLC	53,019.0
Spion Kop Wind	42,251.0
Total REC - PPA	536,546.0

QF-1 REC	MWh
Flint Creek Hydroelectric LLC	-
Lower South Fork LLC	426.9
Musselshell Wind Project LLC	-
Musselshell Wind Project Two LLC	-
Two Dot Wind Farm LLC	-
Fairfield Wind LLC	-
Gordon Butte Wind LLC	43,007.2
Total QF-1 REC	43,436.1

Tier II	MWh
James Walker Sievers (Barney Creek)	133.5
Yellowstone Energy Limited Partnership (BOI)	454,803.7
State of MT DNRC (Broadwater Dam)	53,500.1
James Walker Sievers (Cascade Creek)	383.5
Colstrip Energy Limited Partnership	301,604.0
Donald Fred Jenni (Hanover Hydro)	248.7
Estate of Howard Carter (Pine Creek)	1,000.4
Rass Creek Hydro LC	2,435.5
Hydrodynamics Inc (South Dry Creek)	8,319.8
Hydrodynamics Inc (Strawberry Creek)	1,390.6
Total Tier II	823,819.7

Total Renewble MWh Purchases in 2012: 1,415,927

NorthWestern Energy
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ETAC Meeting Agenda

NorthWestern Energy Bull Room
Helena Division Office
1315 North Last Chance Gulch

Wednesday February 27, 2013 – 9:00 AM

Conference Call-In: 877 820-7831 (Participant Code): 555256

Please Note: No GoToMeeting this time

Agenda:

NWE Battery Storage Project Overview & Update – June Pusich-Lester

NWE Transmission Planning – Don Bauer/John Leland

Discussion of Montana Public Service Commission on NWE 2011 Electricity Resource Procurement Plan

Confirm March Meeting Schedule and Location

(Lunch will be provided)

Meeting Summary
NorthWestern Energy Electricity Technical Advisory Committee
February 27, 2013

Attendance
Those participating in or attending the Energy Electricity Technical Advisory Committee (ETAC) meeting included:

Name	Organization
Brian Spangler	Montana Department of Environmental Quality (DEQ)
Mike Dalton	Montana Public Service Commission (MPSC)
Dave Fine	NorthWestern Energy (NWE)
Kyla Maki	Montana Environmental Information Center (MEIC)
Paul Schultz	Montana Consumer Counsel (MCC)
Jamie Stamatson	MCC
June Pusich-Lester	NWE
Bill Thomas	NWE
Chuck Magraw	Natural Resources Defense Council
Thomas M. Power	District XI Human Resource Council
Diego Rivas	NW Energy Coalition
Will Rosquist	MPSC
Patrick Barkey	University of Montana - Bureau of Business and Economic Research
John Leland	NWE
Don Bauer	NWE
Al Brogan	NWE
Lou Moore	DEQ
Frank Bennett	NWE
John Bushnell	NWE
Todd Guldseth	NWE
Larry Nordell	MCC
Gerald Mueller	Consensus Associates

Agenda
- NWE Battery Storage Project Overview and Update
- Distributed Generation Experience
- NWE Transmission Planning
- Discussion of MPSC on NWE 2011 Electricity Resource Procurement Plan
- Next meeting

NWE Battery Storage Project Overview & Update
June Pusich-Lester, an engineer in NWE's DSM group, used a PowerPoint presentation entitled "ETAC Presentation - NorthWestern Energy Battery Storage Project" to provide an overview and update of a project testing battery storage connected to an intermittent renewable electricity resource, a photovoltaic array, and to review NWE's ongoing Smart Grid project. The presentation is available on the ETAC's web page at the following web address.

http://www.northwesternenergy.com/documents/etac/2013/NorthWestern_Energy_Battery_Storage_Project_ETAC.pdf

Question - What are the battery storage volume and duration and the cost of the system?
Answer - The battery volume will be 30 kilowatts (kW) and will be able to provide power for four hours. The system cost will be about $198,000.

Question - What technology will the batteries use?
Answer - The batteries will be lead acid, not lithium-ion. The latter technology has a higher energy density and recharge rate, but is more costly than the lead acid battery. The lithium-ion battery also has heat related safety issues.

Question - What will be the capacity of the photovoltaic system that will be installed with the batteries?
Answer - The photovoltaic system will have a capacity of 10 kW and will be connected to the batteries.

Question - Will the solar photovoltaic system be the only feed to the batteries?
Answer - In addition to the photovoltaic array, the batteries will be connected to a transformer on the Helena distribution system to provide the 480 volts necessary to run the system electronics.

Question - What is the estimate of the system losses?
Answer - We will be measuring the losses.

Question - Will the system be behind the meter at the distribution center?
Answer - The system will be net metered and will be dispatched into the distribution center circuit.

Question - What will be the useful life of the batteries based on cycling?
Answer - The manufacturer is providing a five-year warrantee for the system based on an assumed 4,000 charge/discharge cycles.

Question - Would the rate and amount of discharges of a lead acid battery system be a good match with wind generation?
Answer - The battery management system will prevent damage to the battery, but we do not know its compatibility with wind. The manufacturer will teach us how to operate the system. We will control the schedule of the battery discharge and will work with the Energy Supply group in scheduling.

Question - You mentioned that Idaho Falls Power has a similar battery and photovoltaic system in place. Will you be talking to Idaho Falls Power about its system operation?
Answer - Yes.

Question - Did you consider using the Zinc Air battery developed by a firm at Columbia Falls?
Answer - We did, but are not sure that the membrane it uses can meet the manufacturer's claims.

Question - What does integrating a photovoltaic system add?

Answer - We may be able to charge the system during high prices and discharge during low prices.

Distributed Generation Experience

Dave Fine stated that the battery project just discussed will not be the first test of distributed generation by NWE and the Montana Power Company (MPC). MPC tested a 20 kW gas-fired micro turbine on the company's headquarters building in Butte. The system ran successfully but was removed. We have not seen a report on how well it worked. NWE planned to install a flywheel system at the Dave Gates Generating Station (DGGS); however, it failed prior to final installation. NWE also currently has in its service territory small hydropower facilities. NWE acquires the output of these facilities via Qualifying Facility (QF) contracts and does not control or schedule their output.

NWE Transmission Planning

Don Bauer, Manager of Transmission and Distribution Planning and Capacity West, provided an overview of local transmission planning, and John Leland, Manager of Regional Transmission Planning, covered subregional and regional transmission planning.

Don Bauer used a PowerPoint presentation entitled "NWE Transmission System Overview." The presentation is available at the following web address.

http://www.northwesternenergy.com/display.aspx?Page=Electric_Technical_Advisory_Committee_%28ETAC%29

This presentation was developed for meetings held on the local transmission plan which Mr. Bauer's group develops in consultation with NWE's Transmission Advisory Committee (TRANSAC). NWE recently reorganized its transmission and distribution functions so that local transmission planning and distribution planning occur in the same group, thereby ensuring better coordination between the two. Local transmission planning refers to transmission facilities within NWE's service territory. Mr. Bauer's group analyzes customer-driven requests for new load and transmission interconnections.

Subregional planning involves the Northern Tier Transmission Group (NTTG), whose members deliver electricity in the northwest and mountain states. Regional planning involves the Western Electricity Coordinating Council (WECC) which includes the western US and the provinces of British Columbia and Alberta. Subregional and regional planning is governed by Federal Regulatory Commission (FERC) orders, including FERC 890 and 1000. Pursuant to these orders, transmission owners must provide open access to their transmission systems.

Question - When the Montana-Alberta Tie Line (MATL) project is completed, will it create a fourth transmission path for transmitting electricity out of state?

Answer - Yes. It will provide a 300 megawatt (MW) path north of Great Falls into Alberta. The three existing paths are labeled Montana to Northwest (Path 8), Montana to Idaho (Path 18), and Montana Southeast (Path 80). Path 8 is in northwestern Montana. Path 18 is south of Butte. Path 80 is southeast of Billings. MATL will have about the same path rating as the Montana to Idaho path.

Question - What is the significance of MATL for resource planning?

Answer - As just noted, MATL provides a 300 MW path from North of Great Falls to southern Alberta. The project has a phase shifting transformer to control flows on it. A new wind farm is located about half way from Great Falls to the border with Alberta. Customers wishing to use MATL to move power out of Montana to the west or south will require firm transmission service to and from Great Falls. We do not see MATL affecting the short-term electricity market. We are not sure how it will affect the long-term market.

Question - Could MATL be used to transmit power from the Mid-Columbia trading hub to southern Alberta?
Answer - Doing so would require three cost pancakes. Firm contractual transmission capacity is not available to move 300 MW between the BPA transmission system and Great Falls. A customer requesting such service would be subject to mitigation costs such as building a new transmission line. NWE would conduct a study to determine the amount of firm capacity available between the BPA system and Great Falls in response to such a request.

Question - We have discussed assessing transmission as a possible constraint in the electricity resource plan. Have or can you produce a histogram for the three existing transmission paths showing hourly import and export capacity?
Answer - Physical transmission capacity is not an issue because there is an excess of generation in NWE's load balancing area. Information regarding contracts is currently available on the NWE OASIS web site (http://www.oatioasis.com/NWMT/index.html). Customers requesting new generation or transmission requests will be subject to studies by Mr. Bauer's or Mr. Leland's group to identify mitigation required to address capacity, reliability, or stability issues. The resource planning models run by Todd Guldseth account for market conditions, so that portfolios that sell at low market price conditions take a cost hit.

Question - In your presentation you report that the queue of generation interconnection requests includes 44 projects totaling 1,700 MW of capacity. How many of these projects would trigger the need for new transmission lines?
Answer - Most of these projects are small and would be located so that only substation upgrades and not new transmission lines would be required. A couple of large project projects might require new lines. Demand-side management (DSM) resources are included in the load forecasts used in the transmission system studies. Mitigation decisions are made to ensure compliance with North American Electric Reliability Corporation (NERC) standards.

Question - You mentioned that transmission planning and operation is subject to FERC audits that occur every three years. When is the next audit scheduled?
Answer - 2015. We passed an audit in 2012 that focused on security.

Question - How are the transmission planning responsibilities divided within the company?
Answer - Local transmission is in Don Bauer's group. Subregional and regional planning is in John Leland's group. Planning for loads and resource balancing, including day-to-day and next day, is conducted by the Systems Operations Control Center (SOCC).

Question - Planning for resources necessary to balance loads and resources such as the DGGS are not part of the resource planning that comes before the ETAC. The MPSC is concerned with overall planning. Who or what group in NWE conducts integrated resource planning?
Answer - The transmission department is responsible for ensuring that sufficient facilities are available to provide a reliable, adequate, and safe transmission system. It includes the three groups mentioned above, local transmission and distribution, regional transmission, and system operations. We use customer supplied information on loads and resources to ensure that power can be moved on a point-to-point or network basis and that the system is regulated on a second-by-second basis. However, no integrated resource plan is developed as was the case in the days of the MPC Conservation and Least Cost Planning Advisory Committee.

Question - Under FERC rules, NWE is obligated to provide regulation (balancing) services when generation resources are connected to its transmission system. How does NWE acquire regulation resources?
Answer - NWE acquires regulation resources by analyzing the market and either building or acquiring them through request-for-proposals (RFP).

Question - What interaction occurs between the energy supply and transmission group?
Answer - The two groups work together; however, pursuant to FERC rules, transmission cannot provide energy supply market sensitive information.

Question - NWE develops local transmission and energy supply plans. Is a plan developed for providing regulation resources that the MPSC can interrogate?
Answer - We are not aware of such a plan.

Question - How would NWE assess the need for and cost of regulation resources if energy supply is considering acquisition of 10 MW of intermittent resources?
Answer - The transmission group would respond as if any customer within NWE's balancing area is building an intermittent resource. It would assess the impacts of the transmission interconnection and the need for system balancing resource.

Comment - Given the current situation, NWE would need a simulation in which wind is added that would push the DGGS beyond its capacity to assess the cost of additional required regulation resource.

Question - Given the stove pipe responsibilities for intermittent resources, how do we ensure good decisions that incorporate all factors influencing the utility, including transmission, regulation, and energy supply?
Answer - The stove pipe exists in the short-term because of market sensitivity concerns and FERC rules. In the long-term, more coordinated planning involving transmission and energy supply can occur.

Comment - NWE currently hires a consultant to address regulation supply issues on a sporadic basis.
Response - We have decades of experience in responding to supply issues. The regulation issue is new. We need to understand the issues that drive operation of the DGGS. Important variables include air temperature and the diversity of wind generation as a function of location.

Comment - For vertically integrated utilities, the initial cost of regulating intermittent resources was assumed to be zero. Today the bookends of the cost of regulation are zero and the cost of building a new project like the DGGS.
Comment - We need a systematic approach to determining the incremental cost of regulation.
Response - New generation projects seeking to connect to NWE's transmission system must supply the required regulation, supply it dynamically from anther balancing area, or pay NWE to provide it.

Question - Given FERC's recent ruling limiting NWE's ability to recover costs of the DGGS from its transmission customers, what is the status of the use of 60 MW of the DGGS for regulation?
Answer - There is an issue with FERC about definition of regulation and load-following. The definition will affect resource planning.

Question - The Corette Plant will apparently be moth balled by PPL. Operations of other coal plants such as the Colstrip units may be curtailed because of environmental regulations. Would these changes to the Montana generation mix affect NWE's transmission system?
Answer - Local transmission planning studies routinely include scenarios that include the loss of system elements such has hydropower or coal plant outages. These scenarios have not identified the need for new transmission lines. We have studied the loss of the Corette Plan and have identified mitigation measures needed to support the transmission system voltage. New transmission lines will not be required in response to the shut down of this plant.

Question - Would converting the Colstrip coal plants to natural gas be cheaper and faster?
Answer - We don't know.

Question - If the owner of firm transmission rights decided to release them, could NWE energy supply group purchase them?
Answer - We would have to conduct a study to answer this question.

Question - Could distributed generation be used to solve transmission issues?
Answer - Local transmission planning studies the system from border to border every two years. FERC orders require that we consider both transmission and non-transmission alternatives. When we have identified a transmission problem, we have backed off load until it went away to assess distributed generation and DSM. Both of these alternatives are generally more effective at addressing localized distribution problems rather than system transmission. As an example, our studies indicate the need for new transmission in the Columbus area. We looked at new gas-fired generation as an alternative to the new transmission. The new generation cost was double the transmission cost and a firm gas supply was not available.

Comment - In its comments on the most recent resource plan, the MPSC asked NWE to evaluate energy and capacity costs of distributed generation in relation to transmission and distribution enhancements.

Comment - When evaluating distributed generation as an alternative to new transmission, the cost comparison should take into account the value of the energy and capacity to energy supply.

Response - Transmission lines tend to be capital intensive. Distributed generation would have significant capital and operating costs. Also, in the case of some transmission problems such as the new line in the Columbus area, the distributed generation alternative would have to run and not be held in a stand-by mode, raising its costs in comparison to the new line.

Question - If energy supply is considering a 25 MW resource, could it ask the transmission group where best to locate the resource to reduce transmission costs?
Answer - No. We have to treat energy supply the same as any other transmission customer, and we can only provide very limited advice on suitable locations.

Comment - The economic analysis of a new transmission line is not complete without accounting for the value of energy that a distributed generation alternative would provide.
Response - To date, the costs of new transmission lines that we are considering to mitigate system problems are much less than the distributed generation costs, so we have not considered the value of energy to energy supply.

Question - If supply is considering a distributed generation resource, could you post an announcement on the NWE OASIS so that transmission could contribute to the cost of the project depending on the value it would provide to transmission?
Answer - The answer to this question would have to come through TRANSAC.

Comment - Transmission and distribution system elements have to be available mechanically more than generation.
Response - NERC reliability standards are currently based on consequence not probability.

Comment - NWE should find out if the National Renewable Energy Laboratory has modeled distributed generation to determine the settings in which it might be cost effective taking into account transmission and distribution effects.

Comment - Historically, small coal plants that might function as distributed generation were not available. Now gas-fired plants with efficiencies that do not drop significantly at small sizes are available.

MPSC Comments on NWE 2011 Electricity Resource Procurement Plan

Prior to this meeting NWE requested ETAC member review the MPSC's comments on the 2011 resource plan. Gerald Mueller led an ETAC discussion of the comments. Highlights of the discussion, including ETAC member comments or questions noted in bullet points and NWE's response in italics to some of them follow.

<u>MPSC Comment #13 - Resource adequacy standards</u>

- A resource adequacy standard would be different for the region than for an individual utility. The region is concerned with regional loads and instantaneous available capacity, supplemented by the ability to import power from adjacent regions. NWE has recourse to spot, short term and longer term market purchases. A shortfall for NWE occurring at a time when the region is not stressed should not lead to any curtailments. NWE would be at risk if it were short at a time the region is stressed.

- As the region approaches load-resource balance, NWE's access to or price of market purchases may be implicated.
  Response - NWE pays attention to the regional assessment of resource adequacy developed by the Northwest Power and Conservation Council and to the Pacific Northwest Utilities Conference Committee's forecast of the northwest regional load resource balance. Regional utilities presently plan to add 3,000 MW of generating capacity. Without this additional resource, the region's load-resource balance will tighten in about five years.
- This issue has bothered me since utility restructuring. Utilities are not all autonomous. How reliable is the sum of all individual plans for determining the region's load -resource balance?
- The value of capacity depends on the region's loss of load probability; hence NWE depends on the regional loss of load probability.
- If there is an increasing risk that the market would tighten, would NWE have sufficient lead time to do something?
- The issue is how much of the resource portfolio should be tied to the market and how much should be utility owned.
- QF developers argue that NWE should be planning to acquire its own resources rather than relying on the market.
- Some utilities have reserve requirements. Should NWE be able to ride on the region's reserves?
- What are the reserve requirements for NWE?
  Answer - They vary by resource type.
- The company does not want to be explicit about resource standards.

MPSC Comment #17

- NWE might narrow down the list of portfolios and then test them using the alternate natural gas price forecasts.
  Response - This would be a good approach.

MPSC Comment #25 - Rate based resources versus power purchase agreements

- NWE should set forth the advantages and disadvantages of owning resources.
- It is analytically difficult to assess the risks posed by owning versus contracting for resources.
- The MPSC rules require comparison of a utility's preferred resource acquisition with the available alternatives.
  Response - NWE is aware of this requirement. The previous resource plans have identified a gas-fired generating plant as the preferred resource. Before we move to acquire one, we would explain how such a plant would address resource portfolio needs and conduct a competitive resource solicitation and compare the responses to a utility owned plant.
- NWE should provide a full discussion of the benefits to the customer of owning a resource versus acquiring its output via a power purchase agreement.
  Response - The Spion Kop wind resource provides an example of NWE's conservative approach to resource acquisition. The project developer, Compass Wind, urged us to approve use of a new carbon turbine blades that would have increased the generation capacity. However, because the carbon blades were not a proven technology, we declined in favor of the standard blade. It turned out that using the carbon blades would have substantially delayed the project, so Compass was glad we did not take its original advice.

Next Steps

NWE will prepare a response to each MPSC comment and review the responses with the ETAC at its next meeting.

Next Meeting

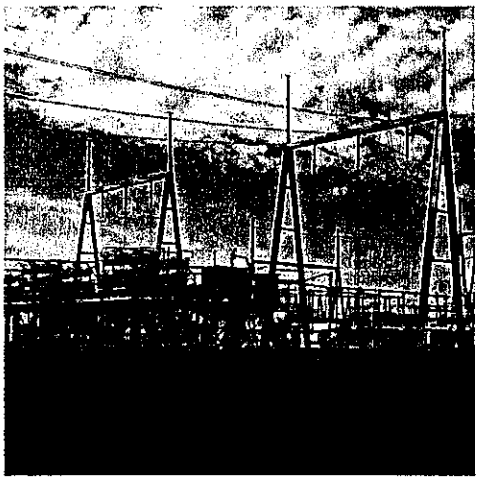
The next meeting was scheduled for Wednesday, March 27, 2013 at the NWE Division Office in Helena.

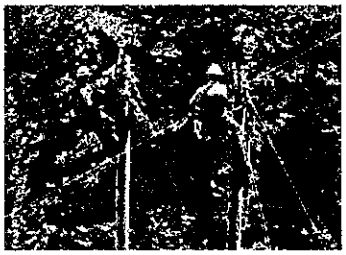
Disclaimer

Committee members provide advice to NWE as individual professionals; the advice they provide does not bind the agencies or organizations that the members serve.

ETAC Presentation - NorthWestern Energy Battery Storage Project

June Pusich-Lester
NorthWestern Energy - DSM Engineer





NorthWestern Energy
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Today's Presentation

- Battery Storage Project
  - Project Description
  - System Description
  - Installation
  - Testing
  - Integration
- Distributed Generation
  - Smart Grid Project

NorthWestern Energy

Project Description

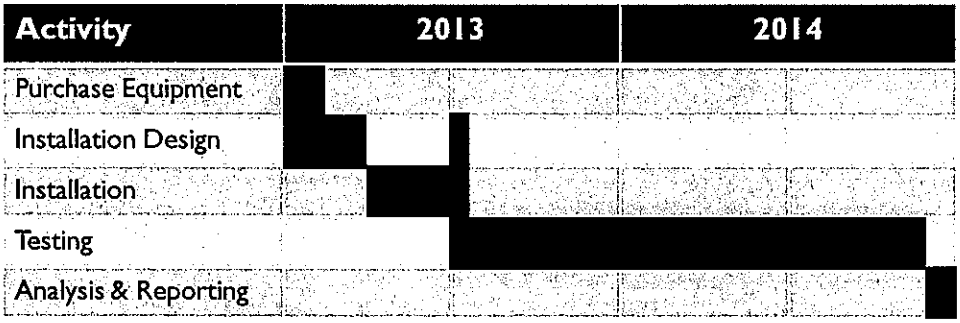
Battery Storage Project with Renewables Integration

- Purchase, install and test small scale battery storage system
- Project funded with USB $ in 2011 & 2012
- 30 kW system with 4 hour battery backup
- Install on NorthWestern Energy distribution line

NorthWestern Energy

Project Description

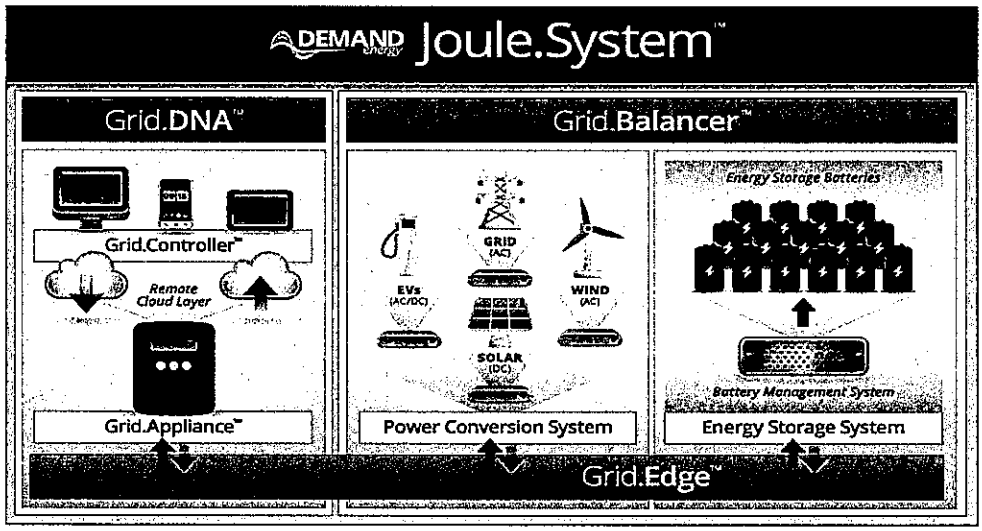
- Schedule
- Status
  - Installation location selected – Helena Service Center Yard
  - Equipment purchase and delivered (Butte warehouse)



NorthWestern Energy

System Description

- Technology - *Joule.System*™



NorthWestern Energy

System Description

- Manufacturer
  - Demand Energy Networks
    - Headquartered in Liberty Lake, WA
    - Launched business in 2008
    - First commercial deployment in 2011
    - Funded by private investors
      - Senior team of professionals from utility and telecom fields (Itron and World Wide Packets/Ciena)

NorthWestern Energy

System Description

- Manufacturer
  - Demand Energy Networks
    - 7 patents/patents pending in the core areas of power/energy conversion, power switching, batteries, battery management and network management
    - Successful commercial systems
      - several electric utilities in Pacific NW
      - high rise buildings in NYC
      - China

NorthWestern Energy

System Description

- Grid.DNA™
  - Distributed Network Architecture
    - Manages load to and from storage devices
      - No matter where located
    - Detects frequency fluctuations and reacts
    - Millisecond response
    - Instantly releasing or absorbing power to regulate load and transmission capacity
    - Cloud Based Managed Service
      - Provides infinite scalability
      - Minimizes IT infrastructure and OA&M costs
      - No software upgrades to manage
    - Open source Infrastructure
      - No time spent building core functionality
      - Speeds up development time while minimizing the size of team required
      - Multiple options allow for best of breed components when assembling the system
    - Fresh Software Approach
      - No legacy "baggage" to prevent embracing emerging technologies and solutions

NorthWestern Energy

System Description

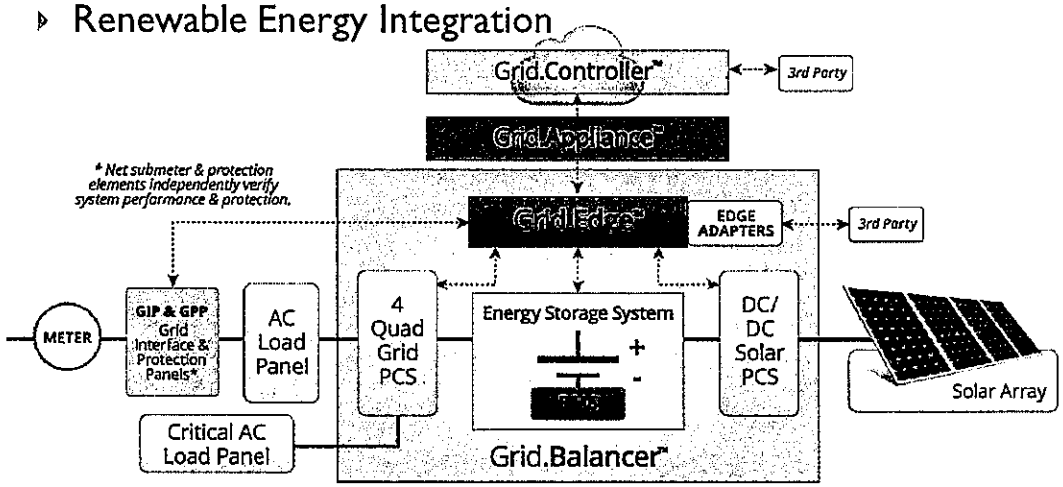
- Grid.Balancer™
  - 30 kW Power Conversion System (PCS) & 4 Hour Energy Storage System (ESS)
    - Other sizes available
    - System size can increase down the road

Available System Sizes			
PCS	30 kW	100 kW	500 kW
ESS	60-120+ kWh	200-400+ kWh	1000+ kWh

NorthWestern Energy

System Description

- Grid.Balancer™
  - Solid state converter system (DC → AC and DC →DC)
  - Renewable Energy Integration



NorthWestern Energy

System Description

- Grid.Balancer™
  - Modular, scalable energy storage
  - Advanced battery technologies with innovations in power conversion and battery management
    - Lead acid batteries (VRLA)
      - low energy density, lower cycle life, established supply chain, 98% recyclable, and proven safety record
    - Lithium (LiFe)
      - great energy density, rare earth metal with supply chain constraints, thermal concerns in multi-cell-higher voltage applications, unknown recycling, with increasingly problematic safety record. Highest lifecycle costs

NorthWestern Energy

System Description

- Grid.Balancer™
  - Batteries Will Be Lead Acid

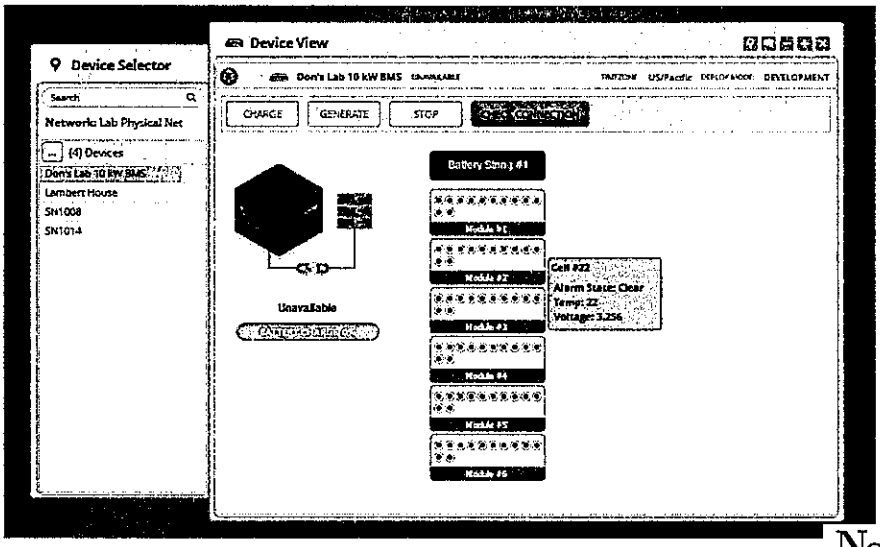
	Lead Acid (VRLA)	Lithium-Iron Phosphate (LiFe) *
Wh/kg	23	100
Cycle Life at 50% DoD	1800	3600
Charge Efficiency	85%	95%
$/KWh	$328	$900
$/KWh/ Cycle	$0.18	$0.25

* Does not include weight or cost of required safety monitoring equipment (BMS)

NorthWestern Energy

System Description

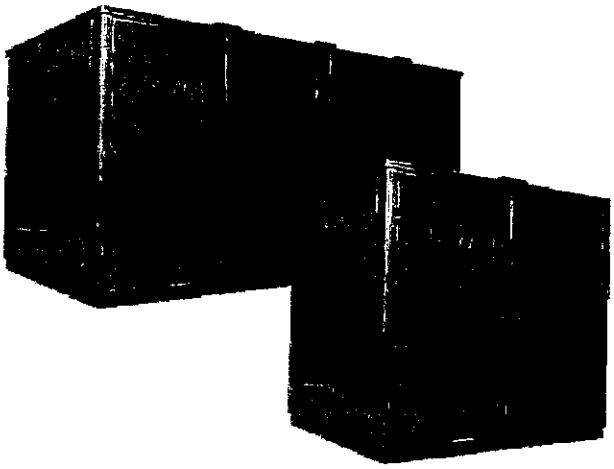
- Grid.Balancer™
  - Battery Management Interface



NorthWestern Energy

Installation

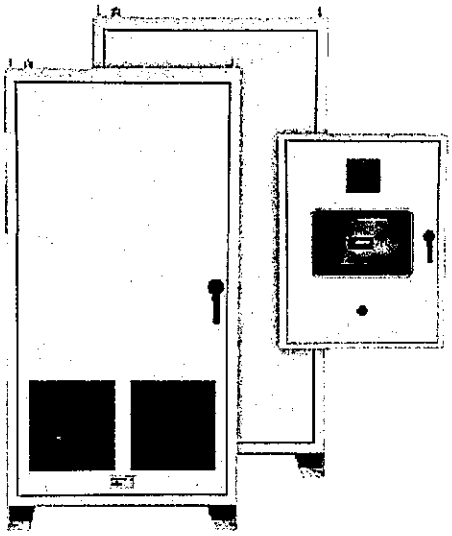
- Helena Service Center Yard
  - 2 Control Cabinets and 4 Battery Cabinets



NorthWestern Energy

Installation

- Connected to distribution line in yard – 480V secondary from new transformer
- Mounted on concrete pad
- Local control system and operator interface
- Net metered
- Install 10 kW solar array in Fall 2013
- Additionally - Cooper Recloser for distribution system interruption when required



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Testing

- ~ 18 month test period
  - Purpose: Test performance of system over different conditions
  - Automated control
    - Schedule Charge/Discharge Cycles via Software
      - Select duration and start/stop day & time
    - Real Time Monitoring for Load and Generation
      - Conduct Load Following
    - Firing of Renewables
      - Frequency of Solar PV and Frequency of Grid
  - Manual control
    - Start a charge or discharge immediately

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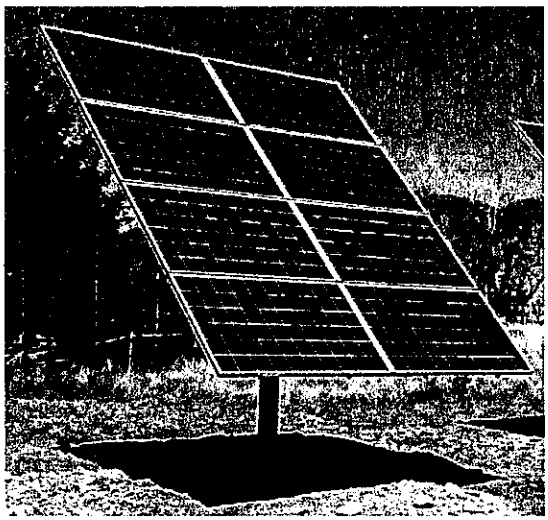
Testing

- What will this tell us?
- Real performance data
  - Measurements included in system
    - How they relate to performance
    - Measured kW on feeder
    - Adjusted Demand
    - Ramp up/down cycle and repetition of cycles
    - Battery measurements

NorthWestern Energy

Renewable Integration

- Installation of small scale solar PV - fall 2013
  - 10 kW solar array
  - Used to charge batteries
  - Net metered



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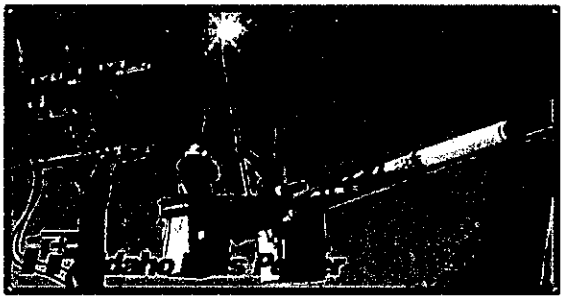
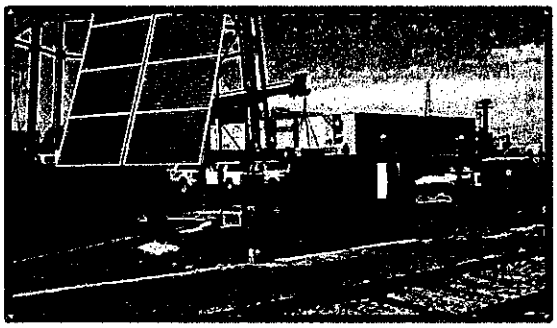
Idaho Falls Power -10 kW Solar Support





NorthWestern Energy

Distributed Generation

- Pacific Northwest Smart Grid Demonstration Project
  - One of 16 smart grid demonstration projects funded by U.S. DOE under ARRA
  - 11 utility representatives across 5 states in Pacific Northwest
  - Chance for NorthWestern Energy to learn about distributed generation from other project participants

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Distributed Generation

- Pacific Northwest Smart Grid Demonstration Project
  - Portland General Electric - test how smart grid technologies can help maintain and improve the electrical system's reliability
    - Integrating variable renewable power resources such as wind and solar – compensation methods only
    - Creating a high-reliability zone for customers using a 5-MW (1.25 MWh battery) energy storage system in concert with customers' back-up generators
    - Oldest DG with over 75 MW

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Distributed Generation

- Pacific Northwest Smart Grid Demonstration Project
  - City of Ellensberg - Renewables Park
    - Help mitigate regional over-generation (high-wind, high-water events) by using the project's transactive control system to automatically take the Park off and on-line as necessary
    - Test of centralized small renewables verses dispersed small renewables
  - Benton PUD (Washington State) - small-scale distributed energy storage and generation
    - Demonstrate how devices could be dispatched to firm intermittent wind generation and to reduce peak electrical demand

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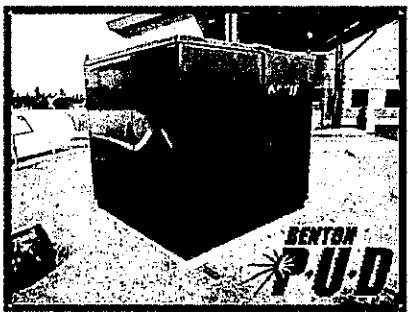
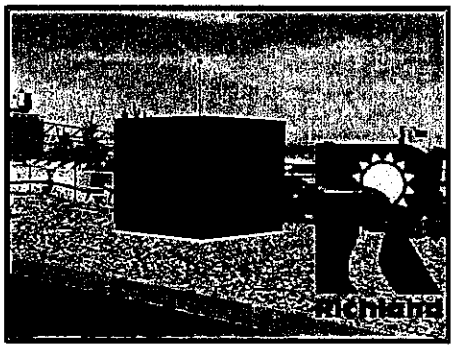
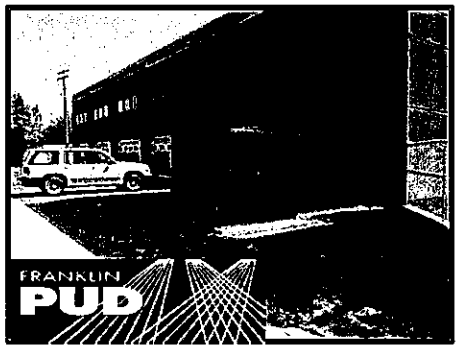
Wind Integration Project

- Pacific Northwest Utilities
  - 3 - 10 kW / 40 kWh Systems
  - Coordinated operation across 3 local utilities to use storage to balance wind integration







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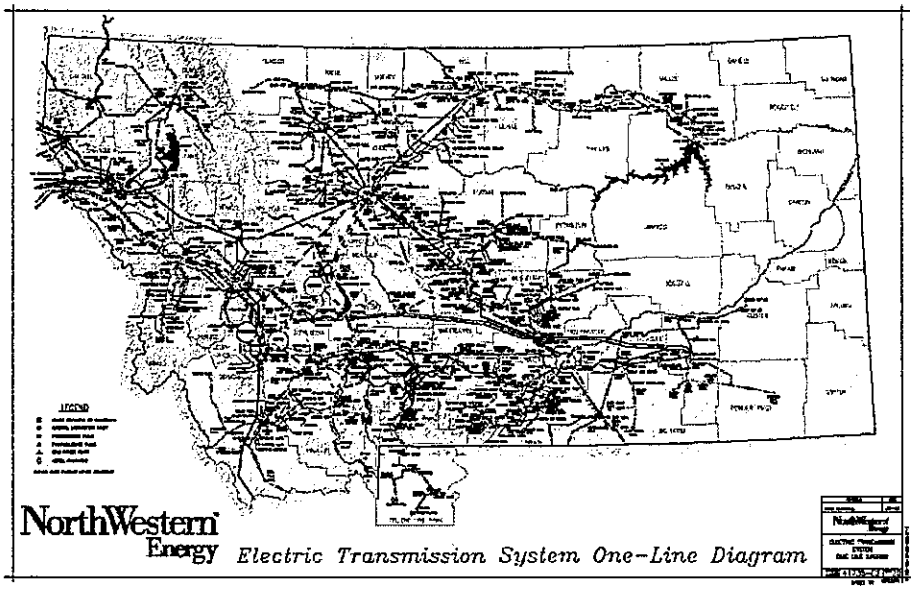
NWE Transmission System Overview

NWE Electric System

7000 miles transmission line from 50 to 500 kV

Serving over 300,000 customers



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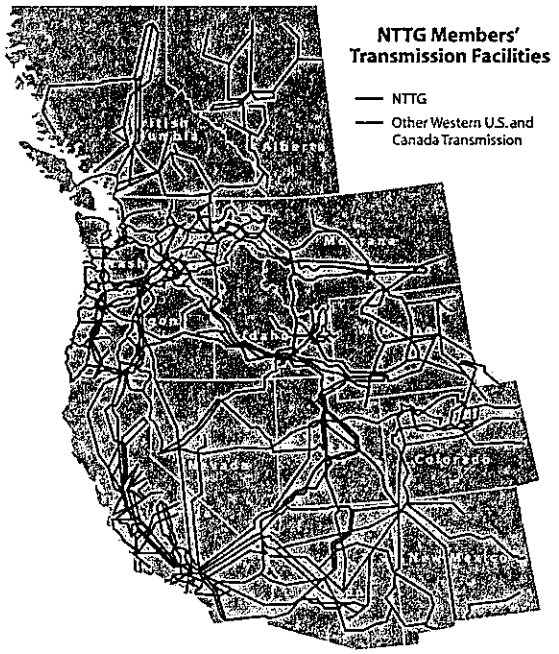
System Overview Continued…

NWE is a member of:

WECC-Regional Planning Western Grid – Reliability

NTTG – Sub-Regional Planning and Coordination

Three Major Paths to Other Systems With Interconnections to Five Other Utilities



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Electric Transmission Planning

- Our Mission: To Assure the Adequacy and Security of the Electric Transmission System under Normal and Adverse Conditions while meeting FERC, NERC, WECC, and other regional, state, and internal standards…
  - » Provide a RELIABLE, ADEQUATE, and SAFE transmission system.
  - » Voltage, Power Capacity, and System Stability
  - » Internal, Local, and Regional (Western or WECC "Grid") Coordination with Others
- Considering the future: load growth, new generation, imports and exports, and other system changes…

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Electric Transmission Planning

- **Major Tasks and Responsibilities**
  - » **Local Area Planning (in state, 15 – year plan)**
    - ♦ **TRANSAC**
    - ♦ **Budget Recommendations and Justifications**
  - » **Regional Planning (WECC/NTTG region)**
    - ♦ **Path Ratings, Transfer Capacity**
  - » **Transmission Service Requests (internal/external)**
  - » **Generation Interconnection Requests**
    - ♦ **44 active projects and almost 1700 MW in queue, over 800 MW in service**
      - • **3100 MW existing (pre-2000 generation), 1800 MW peak load**
    - ♦ **Feasibility, System Impact, and Facility Studies**
  - » **Growth Projects (external path upgrades)**
  - » **Operational Studies (Planned outages, other contingencies)**
  - » **Compliance Justification and Documentation (NERC)**

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4

Electric Transmission Planning

Ranking System Deficiencies

- Overall Risk = Consequences X Probability
  - » Highest Risk gets Highest Priority
- Consequences:
  - » Voltage, Thermal, Stability Problems
  - » Amount of Load Affected (customers)
- Probability:
  - » Normal or Outage Condition (1:1, 1:10, 1:100...)
  - » Seasonal Conditions – How often?
  - » Other Exposure – Long Line, short line
- Evaluate Mitigation Options
- Submit Budget Recommendations and Justifications

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Electric Transmission Planning

Major Projects Recommended:

- Three Rivers – Jackrabbit 161 kV Transmission Line
- Jackrabbit Auto Transformer Upgrade
- Jackrabbit – Big Sky 161 kV Transmission Line
- Missoula #4 Substation Transformer Upgrade
- Billings Steamplant Sub Upgrades
- Mill Creek Substation Upgrades
- Columbus Area 100 kV Transmission Line
- Bitterroot Area Improvements…

NorthWestern Energy
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ETAC Meeting Agenda

NorthWestern Energy
General Office
40 East Broadway

Wednesday April 24, 2013 – 9:00 AM

Conference Call-In: 877 820-7831 (Participant Code): 555256

Agenda:

Generation Group – Gas-fired Generation Siting Activities
Spion Kop Operations Update
DGGS Operations Update

Environmental Group- Overview
2013 Resource Plan Involvement & Scoping

Long-term Load Forecast Discussion – Review of Methods
Changes and Improvements Discussion

2013 Resource Plan – Work with Ascend Analytics
Expanded Resource Detail (existing and new)
Additions/Changes to Planning Work

MPSC Comments on 2011 Resource Plan

Update on CREP RFP

(Lunch will be provided)

Meeting Summary
NorthWestern Energy Electricity Technical Advisory Committee
April 24, 2013

Attendance
Those participating in or attending the Energy Electricity Technical Advisory Committee (ETAC) meeting included:

Name	Organization
Thomas M. Power	District XI Human Resource Council
Diego Rivas	NW Energy Coalition
Brian Spangler	Montana Department of Environmental Quality (DEQ)
Kyla Maki	Montana Environmental Information Center (MEIC)
Chuck Magraw	Natural Resources Defense Council
Todd Guldseth	NorthWestern Energy (NWE)
Frank Bennett	NWE
Jim Williams Jr.	NWE
Dave Fine	NWE
Mary Gail Sullivan	NWE
Patrick Barkey	University of Montana - Bureau of Business and Economic Research
Jamie Stamatson	MCC
Larry Nordell	Montana Consumer Counsel (MCC)
Will Rosquist	MPSC (via telephone)
Gerald Mueller	Consensus Associates

Agenda
- Generation Group
  - Gas-fired Generation Siting Activities
  - Spion Kop Operations Update
  - DGGS Operations Update
- Environmental Group
  - Overview
  - 2013 Resource Plan Involvement & Scoping
- Long-term Load Forecast Discussion
  - Review of Method
  - Changes and Improvements Discussion
- 2013 Resource Plan
  - Work with Ascend Analytics
- All Source Request for Resources
- Update on CREP RFP
- MPSC Comments on 2011 Resource Plan
- Trading Floor Visit
- Next meeting

Generation Group

Dave Fine introduced Jim Williams Jr., a Project Manager in NWE's Generation Group. The Generation Group manages NWE's generation assets and some of its contracts and will provide input and analysis for the 2013 resource plan, including the action plan. The generation assets managed by this group includes the Colstrip 4, Basin Creek, and Spion Kop plants, but not the Dave Gates Generation Station (DGGS). The DGGS is managed by the Transmission Group.

Gas-fired Generation Siting Activities - Mr. Williams is acting as a third party contractor for NWE's Supply Group to analyze the siting and technology alternatives for a natural gas-fired generation plant. The 2011 resource plan included a generic 250 megawatt (MW) gas-fired plant. Mr. Williams' work will advance the gas-fired option by matching the costs, heat rates, and operational characteristics of gas-fired plant options with the Supply Group planning needs. Two types of combustion turbines are used in electric generation, a frame unit and an aeroderivative unit. Frame units are large industrial turbines used in applications where size and weight are not a concern. Aeroderivative units are smaller and historically have had lower efficiencies than frame units; however, the efficiency of aeroderivative units is improving. Combined cycle combustion turbine technology is also advancing. Mr. Williams and Bill Thompson, who is with the NWE Environmental Group, and a consulting engineer have just completed an on-the-ground survey of possible sites for a 250 MW combined cycle plant. The siting study is scheduled to be completed and the technology choice to be made late in the third quarter of this year.

Question - Are you considering sites outside of Montana?
Answer - The gas-fired plants in the 2011 plan were modeled as Montana plants. Our present analysis is looking only at Montana sites.

Question - Is the efficiency of technologies you are considering in the 70-90% range?
Answer - The efficiency is not that high. By adding shafts, 2-on-1, we may reach 57%.

Question - Are you assessing the availability of a firm gas supply?
Answer - Yes.

Question - Are you having trouble finding firm gas supplies?
Answer - Firm electricity and gas transmission are considerations in the siting study. We are also involving an attorney to look at Federal Energy Regulatory Commission issues.

Question - Is the siting study similar to that conducted for the DGGS?
Answer - Yes.

Question - Are you looking at the same sites?
Answer - Some are the same, but changes have occurred to the electric and gas transmission system. We started with 14 sites and have narrowed our ongoing analysis to 8.

Question - For the DGGS, linking a new gas resource and intermittent resources turned out to be controversial in Montana and with FERC. Have you settled how regulators will treat this issue?
Answer - DGGS is NWE's sole regulating facility. The issue with regulators is not settled. Technology is changing so that larger gas-fired plants have greater ramping capabilities. I have presented information about the DGGS at a power generation conference. We are incorporating regulation into the design of the new gas-fired plant.

Comment by Dave Fine - Our goal is to include in this plan more information about a gas-fired plant. We will include siting and infrastructure costs if they are available.

Question - For this plan, will NWE attempt to analyze operating coordination between the new gas-fired plant and the DGGS so that the regulation responsibility might be shared between them?
Answer - The DGGS provides 7 average megawatts each hour to energy supply. This will not change prior to a FERC ruling on the cost allocation for this plant. We do not see coordination between the DGGS and a new gas-fired plant in this plan.

Question - Is this a strategic decision based on decisions by regulators?
Answer - Until FERC rules, we cannot develop a strategy for coordinating gas-fired resources. DGGS consists of single cycle combustion turbines. We cannot compare single cycle and combined cycle plants because of their different heat rates and operational characteristics. For this plan, our goal is to pick the best gas-fired plant.

Comment - I am concerned about boxing-off the DGGS in integrated resource planning.
Response - We are moving towards integrated planning, but integrating the work of the Supply and Generation Groups in resource planning is not there yet.

Question by Jim Williams Jr. - How do ETAC members feel about natural gas?
Answers by ETAC members:

- It is currently the most cost effective electric generation technology for base load. New coal plants are too expensive and risky.
- Natural gas is the correct fuel for a transitional strategy to move to a lower carbon energy supply. I have lingering concerns about the environmental impacts of fracking. Price volatility may occur due to interaction with international gas markets. I do not know if gas is as cheap as it appears. The experience in the 1980s and 1990s demonstrate the difficulties in forecasting gas prices.

Question - Are siting costs materially significant when comparing resource options including contracts?
Answer - Siting costs are generally not 1% of total resource costs and are not a factor when choosing between contracts and utility built resources.

Comment - Planning has been based on generic resources. New build plants have siting costs. After identifying the preferred resource, then a different level of planning should occur that considers specific technology and infrastructure cost.
Response - Siting does not occur in the abstract but rather informs utility decisions about specific resources. New build resources must beat market resources, but determining where the lines cross is problematic. Consideration of specific resources must address operational issues.

Question - How do the pieces fit together? Having identified a gas-fired plant as the preferred resource, do you analyze the siting and infrastructure costs by including them in the modeling?
Answer - Yes; however, simple cycle and combined cycle costs require similar infrastructure. We may use both simple and combined cycle plants on the same site.

Question - Is air versus water cooling a consideration?

Answer - Yes. Combined cycle plants require more water for cooling, and water use is a sensitive issue. Air cooling generally requires more land and more energy. Increased energy use reduces plant efficiency.

Spion Kop Operations Update - Jim Williams Jr. discussed the operation of Spion Kop and the other wind generation projects providing electricity to NWE using the table and chart included below in Appendix 1. Spion Kop has a net capacity factor for this year of 54%, which exceeds the planned factor. NWE has a full service agreement with GE for Spion Kop so GE provides operation and maintenance of this project full time. GE trouble shoots the generators at this project from Schenectady, New York.

Question - What was the annual capacity factor last year for the Gordon Butte wind project?
Answer - 54%.

Question - Where is this project located?
Answer - Near Martinsdale.

Question - Are wind Qualifying Facility (QF) projects integrated in your Real Time Trading desk?
Answer - Gordon Butte and the Musselshell projects are not being forecast by 3TIER. We are grouping the projects with Judith Gap for now and using real-time production information for the projects to inform the hour-ahead estimates.

Question - What is the source of the difference between the capacity factors of the two Musselshell projects?
Answer - I am not sure. They use the same generation technology and are located near each other.

Question - Is a wind capacity factor less than 100% due to lack of wind or generation outages or both?
Answer - Both. At Spion Kop, GE uses a software package that can adjust the operation of individual turbines so that the total generation from the project cannot exceed the sum of the name plate rating of the individual generators. The name plate capacity is therefore determined by the control system capacity.

Question - Can you aggregate all of the small wind farms to improve efficiency?
Answer - No. Individual projects are subject to generation interconnection and transmission service agreements which limit how much they can deliver to our system. North American Reliability Corporation (NERC) standards also limit our ability to aggregate the small wind farms.

Question - Do you have information about the diversity between the wind projects on your system?
Answer - We are developing this information. We are getting 15 minute wind data from the projects so that we can develop empirical correlation factors. Spion Kop appears to be in the same wind regime as Judith Gap with a time delay. Although they are located only 15 miles apart, wind at the Musselshell projects can be different than at the Judith Gap project.

DGGS Operations Update - Jim Williams Jr. also provided this update. As discussed at the April 4, 2012 ETAC meeting, the DGGS had a failure in the power turbines in January 2012. The turbines were under warrantee by their manufacturer, Pratt and Whitney, when the failure occurred. On December 19, 2012, the three unit capability at the DGGS was restored. Pratt and Whitney has installed a power turbine with 250 monitoring points and continues modeling and testing. The fix to the turbine should be completed some time this year.

DGGS consists of three 50 MW units. Each unit has two combustion turbines and two power turbines driving one generator. Two of the units are available or operating and one is in reserve. The available capacity 24 hours per day and 7 days per week is therefore not 3X 50 MW = 150 MW. The total output is instead 100 MW, of which 7 MW is provided to NWE Energy Supply. The 7 MW is twice the minimum output of each of the two operating units. The total capacity available for regulation is therefore 100 MW - 7 MW = 93 MW. Actual output from the two units is affected by temperature and humidity. In the summer, the maximum output may be approximately94 MW rather than 100 MW so the regulation is limited to 87 MW (94 MW - 7 MW). If necessary, the third unit held in reserve can be operated to provide additional regulation. Thus real conditions make the integration of the DGGS with another gas-fired unit more complex than assumed in planning models.

Question - Did Pratt and Whitney provide replacement turbines while the DGGS turbines were being repaired?
Answer- While DGGS was waiting for Pratt and Whitney Power Systems (PWPS) to perform the repairs to our power turbines PWPS utilized turbines from their Lease fleet to allow the DGGS to return to operations. The DGGS is currently running with 4 of our original repaired power turbines and 2 PWPS lease pool power turbines. PWPS covers the cost of the lease pool turbines under the warranty. The two leased power turbines will be replaced once the Power Turbine modification is finalized.

Question - What modifications were made?
Answer - More cooling was provided and the configuration of the #7 bearing support was changed.

Question - Since the DGGS must move both up and down to regulate intermittent generation such as wind, is not the regulation capacity less than 100 MW, the sum of the two 50 MW units?
Answer - The DGGS' regulation band is roughly 93MW. 100MW max with 2 unit operation minus 7mw allocated to energy supply. That 93MW number is always fluctuating as Combustion Turbines are mass flow device and as humidity and temperature dictate the more or less mass in the air will drive that 93MW up or down respectively. If the regulation band with 2 Units is too low we can bring on the 3rd "operational spare unit" to provide the differential need. The DGGS is not biased at some load point as to be able to regulate up and down as the DGGS reacts close enough to real time that it is always where the system operators need it to be to balance the system. In short the DGGS does not wait in standby mode at some calculated load. It is always responding to the SOCC signal to balance the system.

Question - How did you size the plant?
Answer - The DGGS was sized to provide NWE's regulation need. The old regulation contracts included a band width. The DGGS acts as a spring to provide the required variation in regulation. We are gaining operational experience with the wind generation on our system.

Environmental Group

Dave Fine introduced Mary Gail Sullivan, the Manager of NWE's Environmental Group, who discussed her group staff and function. This group will also be providing input to the resource the 2013 resource plan, including the action plan.
The Montana Power Company had a robust environmental group with over 20 staff. NWE initially decentralized the environmental function so that its different groups provided their own environmental expertise. After an independent compliance audit, NWE decided to centralize this function, hired Ms. Sullivan as the group's manager, and developed an environmental system plan. Currently, in addition to Ms. Sullivan, the group includes Bill Thompson, a senior engineer who addresses land and permit issues, and Sam Milodragovitch, a wildlife biologist who also covers water issues. The group will be adding two staff, an environmental engineer and an environmental specialist.

Ms. Sullivan asked ETAC members about their environmental concerns. Highlights of ETAC member responses follow.

- In the past, ETAC wrestled with carbon issues including possible implementation of the approach in the Waxman-Markey legislation which passed the US House of Representatives but died in the US Senate. Carbon adders do not appear to be a pressing issue now.
- One way to approach incorporating environmental costs into resource planning would be by examining how high environmental costs assigned to various resources would have to be to change the composition of the resource portfolio.
- We should consider the implications of existing policies and policy uncertainty in portfolio selection. For example, what does the cost of environmental compliance mean for market resources?

Question - What are the priorities for the Environmental Group?
Answer - Besides getting a more robust environmental management system in place, we are addressing day-to-day system operations, for example, ensuring compliance with storm water and other construction-related or operational permits and siting initiatives.

Question - Does the Environmental Group work on transmission line siting?
Answer - Yes. We support permitting and siting needs associated with electricity and gas supply and delivery.

Long-term Load Forecast Discussion

Todd Guldseth reviewed the method used to develop the load forecast for the 2011 resource plan using materials provided under the headings April 24, 2013, ETAC Meeting, Meeting Materials at the following web address.

http://www.northwesternenergy.com/display.aspx?Page=Electric_Technical_Advisory_Committee_%28ETAC%29

He then asked for ETAC member concerns about the forecast methodology and for possible improvements to it. Highlights of the ETAC member discussion follow.

Question - Do you look for trends in the degree days?
Answer - We have plotted the historical degree day data. Variability has been greater recently.

Question - Have you done a time series regression on the degree day data?
Answer - No.

Question - Are the changes to customer accounts net or gross?
Answer - Net.
Question - In Helena, Staples moved to a new building, and the old building is vacant. Are both buildings treated as separate accounts and included in the data base?
Answer - Yes.

Comment - In the bar graph of NWE residential and GS-1 accounts versus year, there appears to be a significant discontinuity between 2012, the last year of historical data, and 2013, the first year of the forecast data.
Response - This discontinuity is an artifact of the methodology. We always see an apparent discontinuity between the last historical data and the first forecast year.

Question - What software do you use to make your forecast?
Answer - Forecast Pro.

Comment - If you exclude the ten years of the housing bubble, then customer accounts would not grow as rapidly. However, NWE will not be building or acquiring a new electric generation plant in the near term, so the company will have time to adjust the forecast.

Question - Have you attempted to forecast the business cycle?
Answer - No.

Comment - The load forecast is based on a single variable - population. As a result, you do not see a smooth transition from actual to forecasted data, and the model does not include electrical uses. Recessions kill jobs and long term electricity usage.

Comment - You assume constant electricity use per customer.
Response - Customer account growth rate has grown faster than electricity usage growth. Actual usage drives the load growth forecast.

Question - Suppose no growth in customers. Since the model uses normalized weather, how could the forecast change?
Answer - The modeling incorporates change in customer usage per account.

Question - Can you add electricity use per customer as a regression variable?
Answer - We can look at doing so.

Comment - Electric load growth has been slow enough that change in usage per customer account is a resource scheduling issue rather than a portfolio issue. Actual weather appears to make more of a difference than use per customer.

Comment - The big driver on resource timing is contract expiration and NWE's desire to become an integrated utility.

Question - For past plans, system capacity needs were calculated from the energy forecast. Given the changes to the regional system, should you make an independent capacity forecast?
Answer - We are looking at doing so.

Comment - I am concerned about the complacent attitude about the significance of the load forecast. A small change in the rate of growth may have a large impact at the end of the forecast period. Getting the trend in the forecast right is what matters.

Question - What is the total increase in electricity demand over the forecast period in the forecast shown on the graphs?
Answer - About 200 MW.

Comment - The load forecast provides a guide for near-term resource decisions and allows us to keep an eye on the factors important for the long term.
Response - The load forecast provides a spring board for the resource portfolio. The demand-side resource program is not accounted for in the forecast and acquires about 10% of our system load over a ten-year period. Portfolio decision making should be based on a range of load forecasts rather than just the base case load forecasts. An important issue is whether we have a plausible forecast range.

Comment - The past practice of increasing or decreasing the forecast rate of growth by 50% is arbitrary. The trend rate of load growth will matter if not for the choice of resources, then for the timing of resources in the preferred portfolio. The current forecast methodology does not provide a tool for analyzing policy changes that affect energy usage. NWE should consider incorporating into its forecast methodology additional explanatory variables that could impact customer energy use.

Comment - NWE might test the preferred resource portfolio to see how much change in demand would be required to change it and then judge whether the change would be plausible.

2013 Resource Plan

Todd Guldseth provided an update on discussions with Ascend Analytics regarding the resource planning modeling for the 2013 resource plan. Since 2003, NWE has used the GenTrader® modeling system for intrinsic and stochastic resource portfolio modeling. Stochastic modeling using GenTrader® relies upon gas and electricity prices as variables to assess portfolio cost and risk. This methodology drops the tails of the portfolio cost distribution and calculates a risk parameter by subtracting the mean portfolio cost from the 95% confidence interval of the distribution of the costs calculated from the stochastic variation of electricity costs. The output of this modeling is plotted and an efficiency frontier curve is fitted by eye to the data to determine which portfolios represented the least combined cost and risk. No assignment of probability is made to any outcome. Ascend Analytics has a modeling system that uses probability to calculate a numerical risk adjusted portfolio cost. For the 2013 plan, NWE will use Ascend Analytics to conduct a shadow analysis to the GenTrader® portfolio analysis.

Mr. Guldseth is also continuing to discuss with his peers in other utilities about other modeling systems such as Aurora.

All Source Request for Resources

Dave Fine stated that Kevin Markovich's group (market operations) will soon, perhaps by next week, be issuing an all-source request for resource proposals (RFP) for a specific product for 2015-2017: up to 100 MW of firm heavy load only power. NWE would decide among the bids one hour after they are due.

Question - What would be the point of delivery for this power?
Answer - Somewhere on NWE's system.

Question - Why the one hour decision time?
Answer - Bidders are likely to hold open their offer only for a short time.

Question - Would this product replace other resources such as the PPL contract?
Answer - The PPL contract which provides 200 MW of peak power and 125 MW off-peak during expires in 2014.

Question - Would this RFP require a transmission service contract?
Answer - No new agreement would be required. NWE Supply Group has an existing network service transmission request. Pursuant to it, NWE specifies points for receipt of power every year.

Update on CREP RFP

In response to the Community Renewable Energy Project (CREP) RFP, NWE has identified two 20 MW project finalists. NWE has changed its intentions and now seeks only one 20 MW project. The two finalists have been so notified. We continue to have locational issues with wind on our system. Once we have a contract signed with a project developer, we will have to apply for a transmission service agreement. The need for this agreement makes this RFP challenging.

Question - Is CREP unique for transmission service?
Answer - No. A CREP does not receive special treatment for transmission.

Question - What is the time frame for completing the contract for this project?
Answer - As soon as possible.

MPSC Comments on 2011 Resource Plan

NWE provided the response to some of the MPSC comments at this meeting. Written responses to all comments are being prepared and will be discussed with ETAC.

Trading Floor Visit

ETAC members visited the NWE day-ahead and real time trading desks.

Next Meeting

The next meeting was scheduled for the fourth Wednesday in May. This week will not work for NWE. Mr. Mueller will poll ETAC members about an alternative date, perhaps in the last week of May. The meeting will be in Butte.

Disclaimer

Committee members provide advice to NWE as individual professionals; the advice they provide does not bind the agencies or organizations that the members serve.

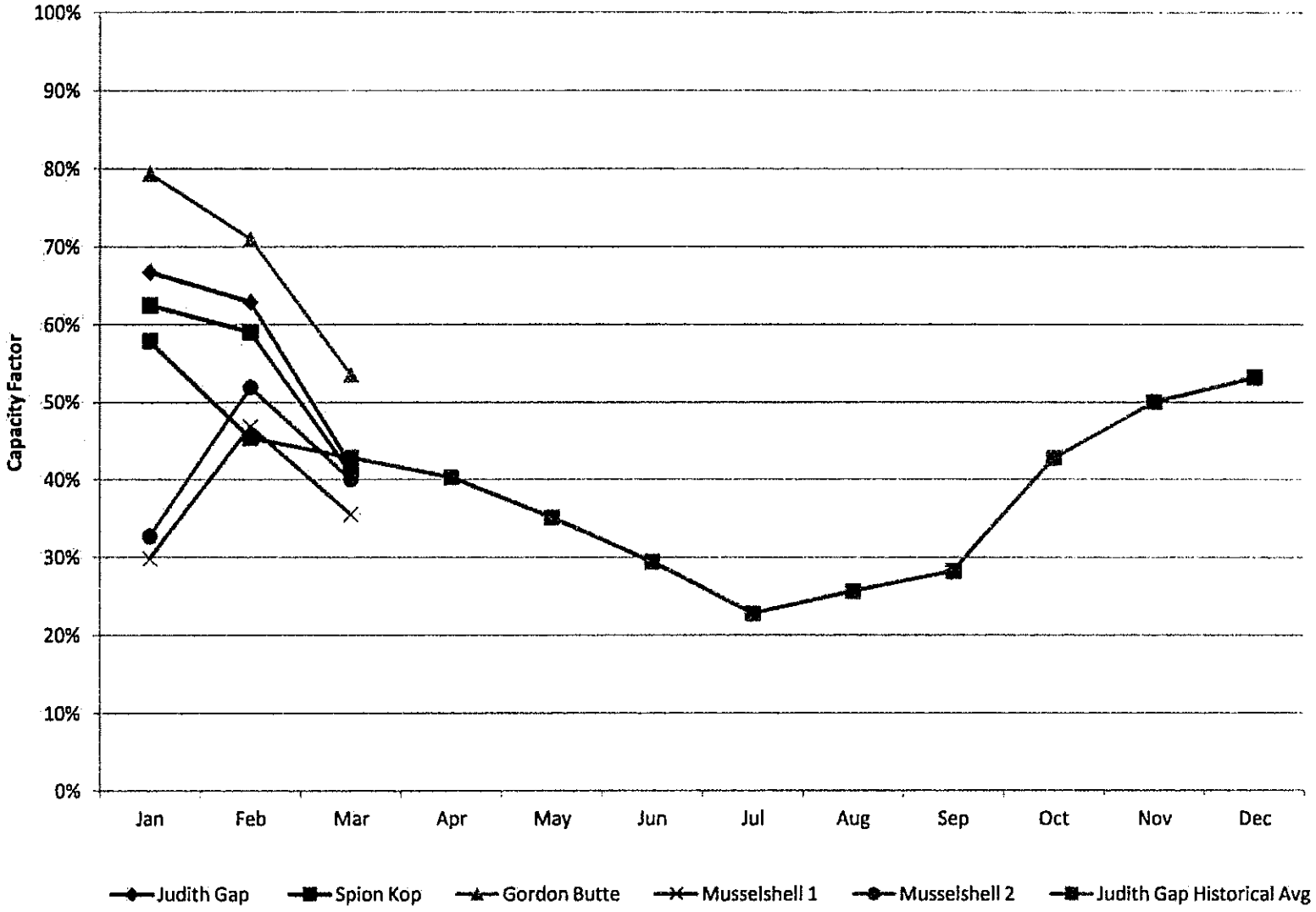
Appendix 1

NorthWestern Energy
2013 Wind Resource Capacity Factors

	Judith Gap 135 MW		Spion Kop 40 MW		Gordon Butte 9.6 MW QF		Musselshell 1 10 MW QF		Musselshell 2 10 MW QF	
	2013 Capacity Factor	2006-2012 Capacity Factor	2013 Capacity Factor	JG Hist. Capacity Factor[1]	2013 Capacity Factor	2012 Capacity Factor	2013 Capacity Factor	JG Hist. Capacity Factor[1]	2013 Capacity Factor	JG Hist. Capacity Factor[1]
Jan	67%	58%	63%	58%	79%	73%	30%	58%	33%	58%
Feb	63%	45%	59%	45%	71%	52%	47%	45%	52%	45%
Mar	42%	43%	41%	43%	54%	63%	36%	43%	40%	43%
Apr										
May										
Jun										
Jul										
Aug										
Sep										
Oct										
Nov										
Dec										
	=======	=======	=======	=======	=======	=======	=======	=======	=======	=======
Total YTD	57%	49%	54%	49%	68%	63%	37%	49%	42%	49%

1-Using historical Judith Gap capacity factor (annual 39.5%) as comparison point until Spion Kop and the two Musselshell projects have their own history.

Comparison of 2013 Capacity Factors



ETAC Meeting Agenda

NorthWestern Energy
General Office
40 East Broadway

Wednesday April 24, 2013 – 9:00 AM

Conference Call-In: 877 820-7831 (Participant Code): 555256

Agenda:

Generation Group – Gas-fired Generation Siting Activities
Spion Kop Operations Update
DGGS Operations Update

Environmental Group- Overview
2013 Resource Plan Involvement & Scoping

Long-term Load Forecast Discussion – Review of Methods
Changes and Improvements Discussion

2013 Resource Plan – Work with Ascend Analytics
Expanded Resource Detail (existing and new)
Additions/Changes to Planning Work

MPSC Comments on 2011 Resource Plan

Update on CREP RFP

(Lunch will be provided)

NorthWestern Energy
2013 Wind Resource Capacity Factors

	Judith Gap 135 MW		Spion Kop 40 MW		Gordon Butte 9.6 MW QF		Musselshell 1 10 MW QF		Musselshell 2 10 MW QF	
	2013 Capacity Factor	2006-2012 Capacity Factor	2013 Capacity Factor	JG Hist. Capacity Factor[1]	2013 Capacity Factor	2012 Capacity Factor	2013 Capacity Factor	JG Hist. Capacity Factor[1]	2013 Capacity Factor	JG Hist. Capacity Factor[1]
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Feb	63%	45%	59%	45%	71%	52%	47%	45%	52%	45%
Mar	42%	43%	41%	43%	54%	63%	36%	43%	40%	43%
Apr										
May										
Jun										
Jul										
Aug										
Sep										
Oct										
Nov										
Dec										
	=======	=======	=======	=======	=======	=======	=======	=======	=======	=======
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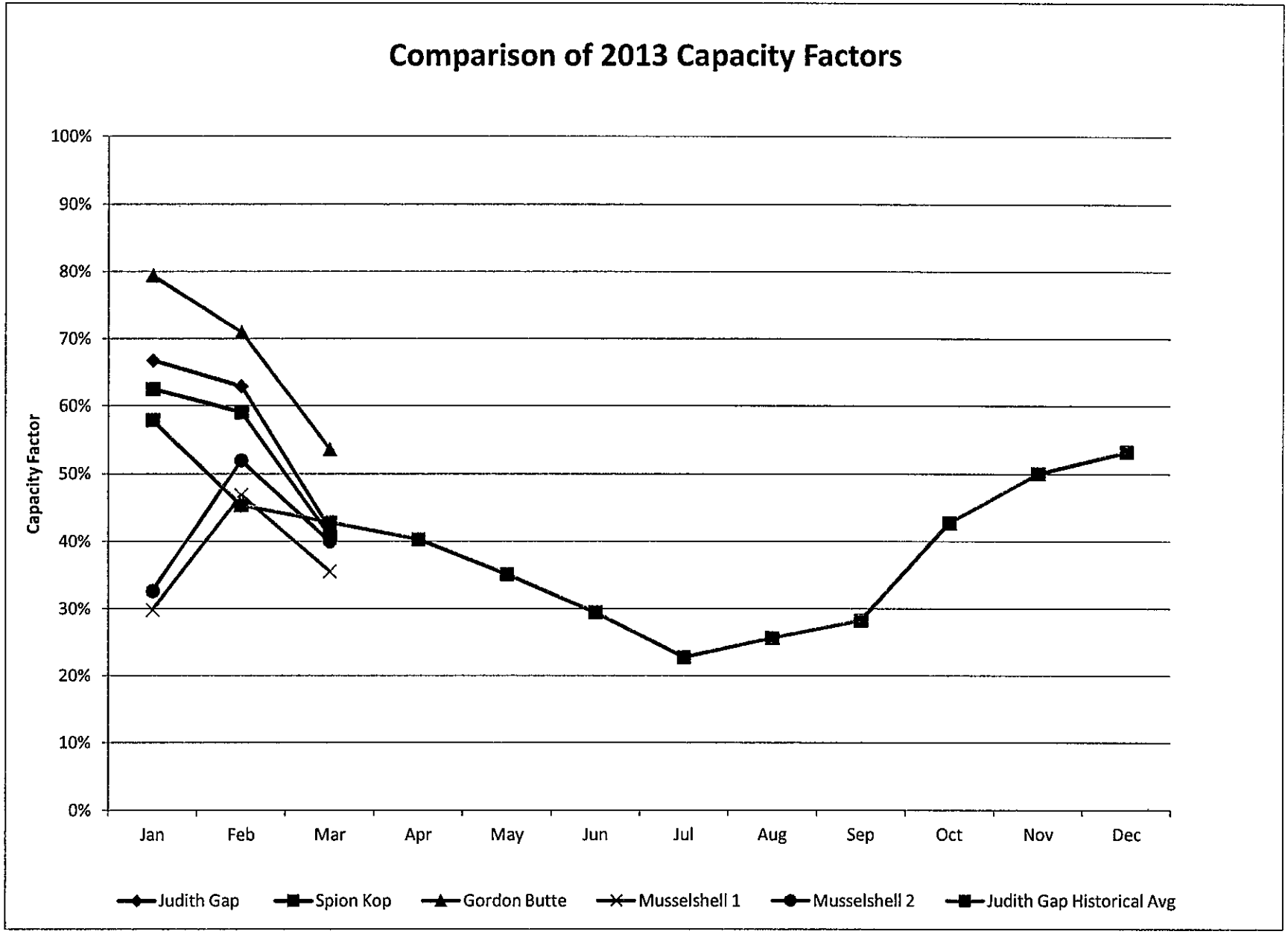

Comparison of 2013 Capacity Factors
Capacity Factor
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Judith Gap
Spion Kop
Gordon Butte
Musselshell 1
Musselshell 2
Judith Gap Historical Avg

NorthWestern Energy
2013 Long-Term Load Forecast Discussion
ETAC 4-24-13

Load Forecast Methodology

1. Residential & GS1 Secondary (small commercial) customer forecast
    a. Montana population forecast (Montana State Government CEIC site)
        i. NWE service territory population forecast
    b. Historical customer counts (1980 – 2012)
    c. Regression model to develop customer forecast

2. Total Degree Days (HDD + CDD)
    a. Historical total degree days (1980 – 2012)
    b. Normal forecasted degree days equals average of historical degree days

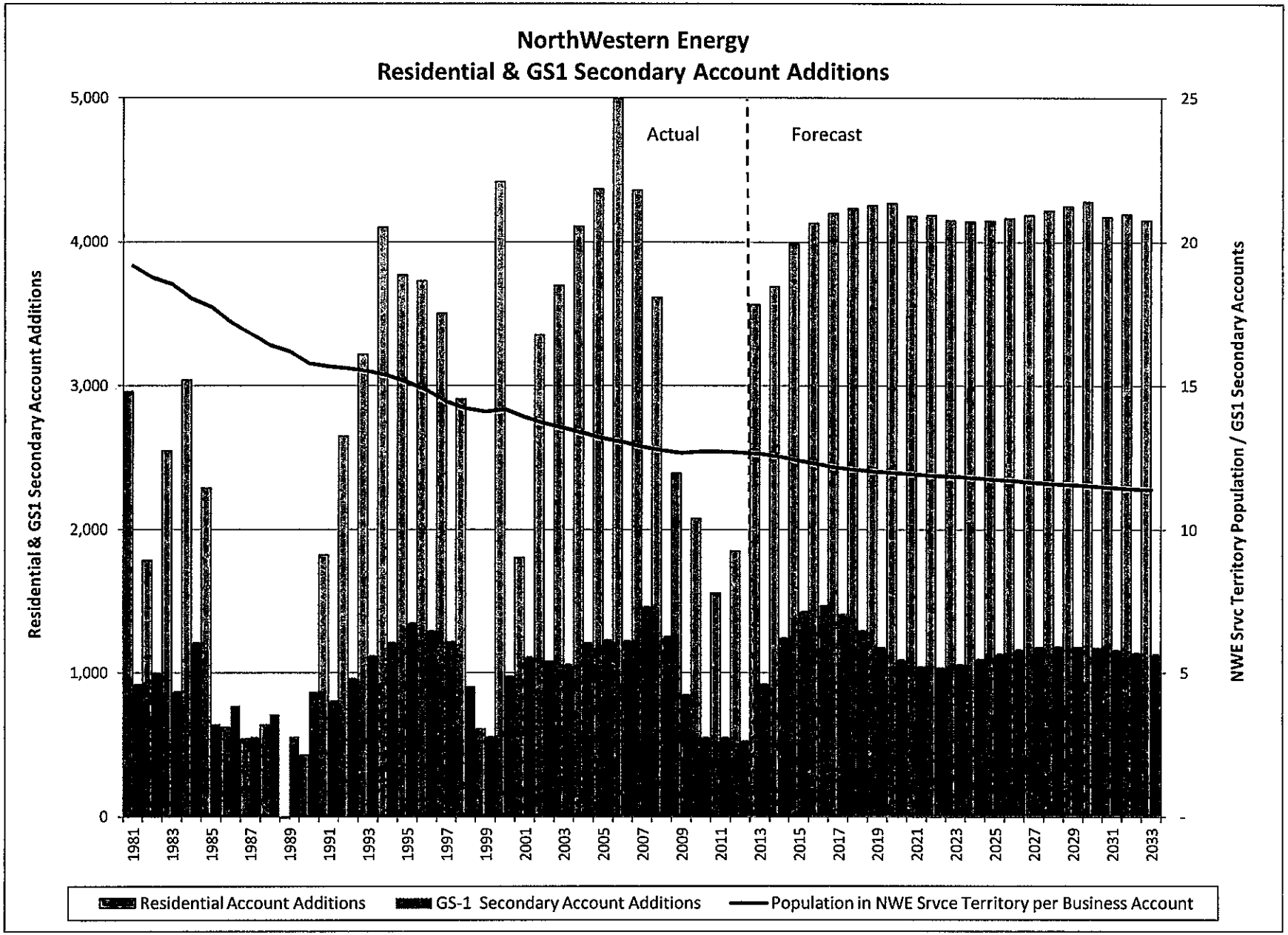
3. Residential & GS1 Secondary load forecast
    a. Historical and forecasted customer counts
    b. Historical and forecasted total degree days
    c. Historical Residential and GS1 Secondary loads (energy usage 1980 - 2012)
    d. Regression model to develop load forecast

4. Thoughts on improving/enhancing the load forecast process and results

Load Forecast Sensitivities

1. The practice has been to construct a high load case and a low load case by increasing/decreasing the forecast growth rate by 50%. That is, if the base case load forecast growth rate is 1.2%, the high load case growth rate would be 1.8% and the low load case would be 0.6%.

2. Thoughts on selecting drivers or using other methods to develop alternative load scenarios and sensitivities


NorthWestern Energy
Residential & GS1 Secondary Account Additions
Residential & GS1 Secondary Account Additions
NWE Srvc Territory Population / GS1 Secondary Accounts
Actual
Forecast
5,000
4,000
3,000
2,000
1,000
0
25
20
15
10
5
-
1981
1983
1985
1987
1989
1991
1993
1995
1997
1999
2001
2003
2005
2007
2009
2011
2013
2015
2017
2019
2021
2023
2025
2027
2029
2031
2033
Residential Account Additions
GS-1 Secondary Account Additions
Population in NWE Srvce Territory per Business Account

Forecast Pro Version 4.3 Extended Edition 2013 Res Load Frcst

Database H:\2013 Resource Procurement Plan\Load Forecast\!FP Res MWH b4 losses 1980-2033.xls i:

Forecast Model for ResMWHb4loss
Regression(2 regressors, 0 lagged errors)

Term	Coefficient	Std. Error	t-Statistic	Significance
RESCUSTCOUNT	8.049008	0.329829	24.403555	1.000000
DEGDAYS	12.955781	9.303518	1.392568	0.826341 <-

Marked regressors are insignificant.

Within-Sample Statistics

Sample size 33	Number of parameters 2
Mean 1.937e+006	Standard deviation 2.348e+005
R-square 0.943	Adjusted R-square 0.9411
Durbin-Watson 1.035	Ljung-Box(18)=22.13 P=0.7735
Forecast error 5.697e+004	BIC 6.139e+004
MAPE 0.02383	RMSE 5.522e+004
MAD 4.483e+004	

Variable specification test battery

RESCUSTCOUNT[-1]	Chi Square(1)=2.44	Percentile=0.8817	
DEGDAYS[-1]	4.36	0.9632	*
_CONST	8.65	0.9967	**
_TREND	5.71	0.9831	*

Try adding _CONST to model.
Forecast Model for ResMWHb4loss
Regression(3 regressors, 0 lagged errors)

Term	Coefficient	Std. Error	t-Statistic	Significance
RESCUSTCOUNT	8.603631	0.324493	26.514079	1.000000
DEGDAYS	68.568409	17.833392	3.844945	0.999416
_CONST	-579054.939787	166069.699678	-3.486819	0.998471

Within-Sample Statistics

Sample size 33	Number of parameters 3
Mean 1.937e+006	Standard deviation 2.348e+005
R-square 0.9594	Adjusted R-square 0.9567
Durbin-Watson 0.6532	** Ljung-Box(18)=71.01 P=1
Forecast error 4.886e+004	BIC 5.461e+004
MAPE 0.02139	RMSE 4.658e+004
MAD 4.051e+004	

Variable specification test battery

RESCUSTCOUNT[-1]	Chi Square(1)=6.59	Percentile=0.9898	*
DEGDAYS[-1]	0.34	0.4384	
_TREND	0.53	0.5316	

Variable specification tests successful.

Dynamics test battery

RESMWHB4LOSS[- 1]	Chi Square(1)=7.76	Percentile=0.9947	**
RESMWHB4LOSS[- 2]	5.48	0.9807	*
_AUTO[- 1]	Chi Square(1)=11.91	Percentile=0.9994	**
_AUTO[- 2]	6.82	0.9910	**

Try adding _AUTO[-1] to model.
Forecast Model for ResMWHb4loss
Regression(3 regressors, 1 lagged errors)

Term	Coefficient	Std. Error	t-Statistic	Significance
RESCUSTCOUNT	8.528263	0.691473	12.333465	1.000000
DEGDAYS	71.852518	11.111757	6.466351	0.999999
_CONST	-577392.239445	190643.773208	-3.028645	0.994768
_AUTO[- 1]	0.647603	0.143217	4.521825	0.999898

Within-Sample Statistics

Sample size 32	Number of parameters 4
Mean 1.95e+006	Standard deviation 2.26e+005
R-square 0.9763	Adjusted R-square 0.9738
Durbin-Watson 2.24	Ljung-Box(18)=25.6 P=0.8909
Forecast error 3.662e+004	BIC 4.254e+004
MAPE 0.01313	RMSE 3.425e+004
MAD 2.57e+004	

Dynamics test battery

RESMWHB4LOSS[- 1]	Chi Square(1)=0.65	Percentile=0.5785
RESMWHB4LOSS[- 2]	0.47	0.5084
_AUTO[- 2]	Chi Square(1)=0.86	Percentile=0.6466
Common factor test	Chi Square(2)=1.59	Percentile=0.7925

Dynamics tests successful.

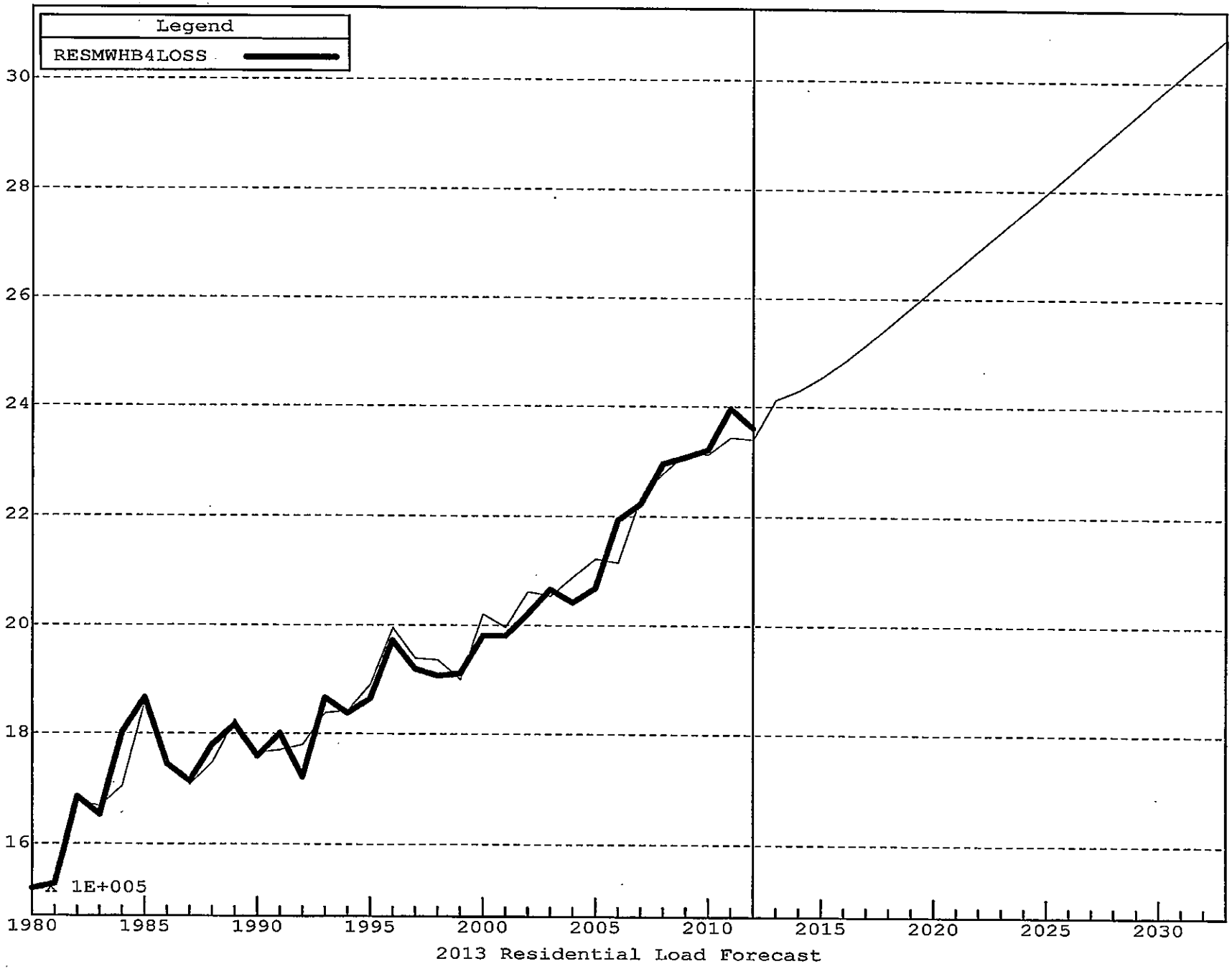
Forecast Report
Wed Apr 17 15:06:29 2013
Dynamic Regression model for ResMWHb4loss
Analysis of Historic Fit Set

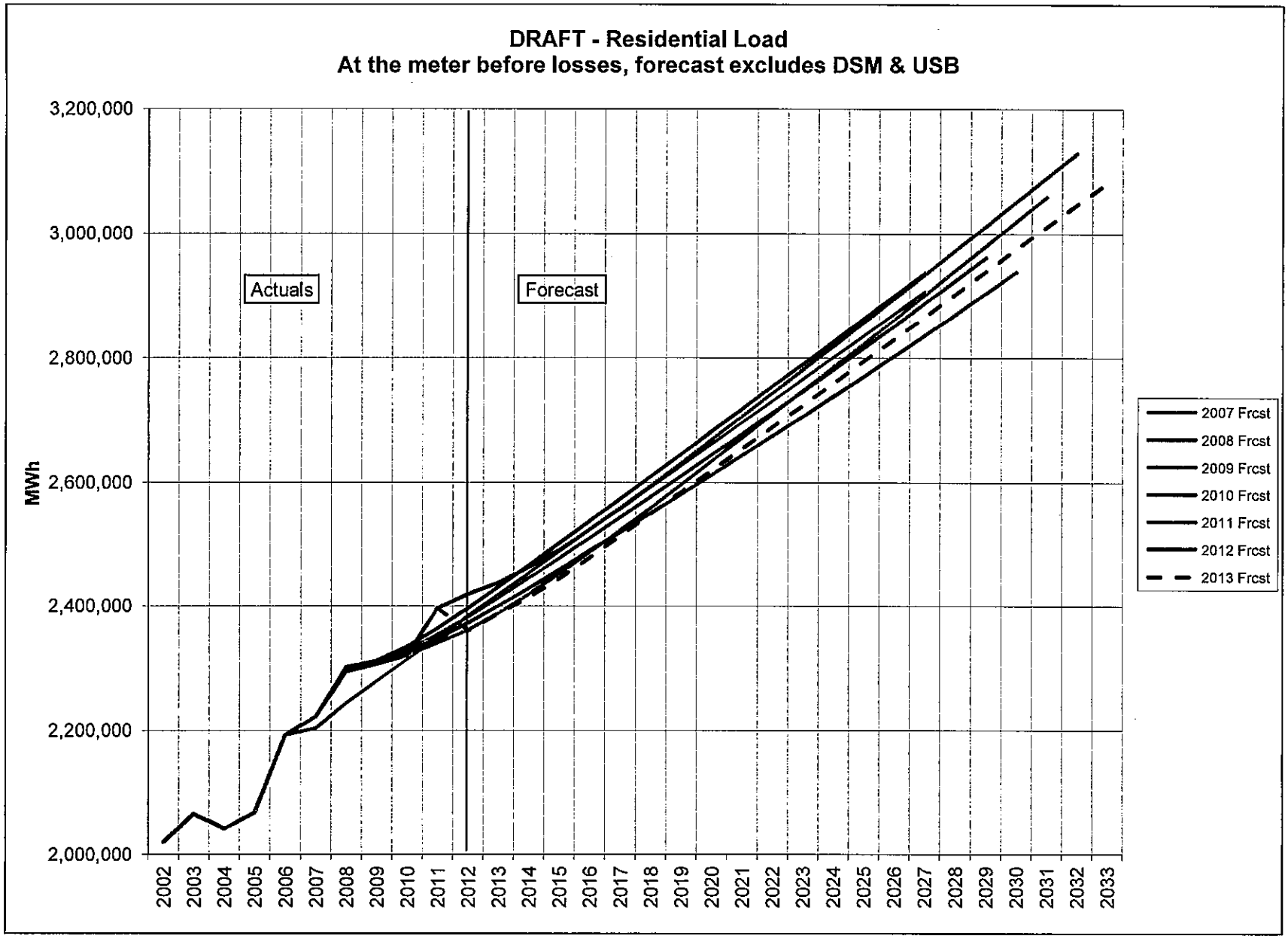
Date	Historic	Fitted
1980	1518703	
1981	1527055	1536861
1982	1684474	1677439
1983	1652559	1667028
1984	1801859	1704094
1985	1865405	1859137
1986	1744131	1744765
1987	1712902	1706905
1988	1779941	1747036
1989	1816213	1824898
1990	1759377	1764335
1991	1800675	1769895
1992	1720884	1779165
1993	1865441	1837943
1994	1837957	1841337
1995	1863461	1889374
1996	1972187	1995168
1997	1918533	1938757
1998	1906541	1935309
1999	1910313	1899155
2000	1980795	2020944
2001	1980524	1996586
2002	2021156	2061395
2003	2066030	2053710
2004	2041803	2088287
2005	2068600	2122220
2006	2193452	2115181

2007	2222521	2234071
2008	2295070	2277977
2009	2307076	2312082
2010	2320737	2311969
2011	2396492	2342572
2012	2360453	2339022

Forecasted Values

Date	Forecast
2013	2412399
2014	2429879
2015	2454814
2016	2484176
2017	2516197
2018	2549849
2019	2584540
2020	2619922
2021	2654909
2022	2690184
2023	2725295
2024	2760429
2025	2795686
2026	2831139
2027	2866814
2028	2902754
2029	2938962
2030	2975458
2031	3011072
2032	3046825
2033	3082239


Legend
RESMWHB4LOSS
30
28
26
24
22
20
18
16
1E+005
1980
1985
1990
1995
2000
2005
2010
2015
2020
2025
2030
2013 Residential Load Forecast


DRAFT - Residential Load
At the meter before losses, forecast excludes DSM & USB
MWh
3,200,000
3,000,000
2,800,000
2,600,000
2,400,000
2,200,000
2,000,000
Actuals
Forecast
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
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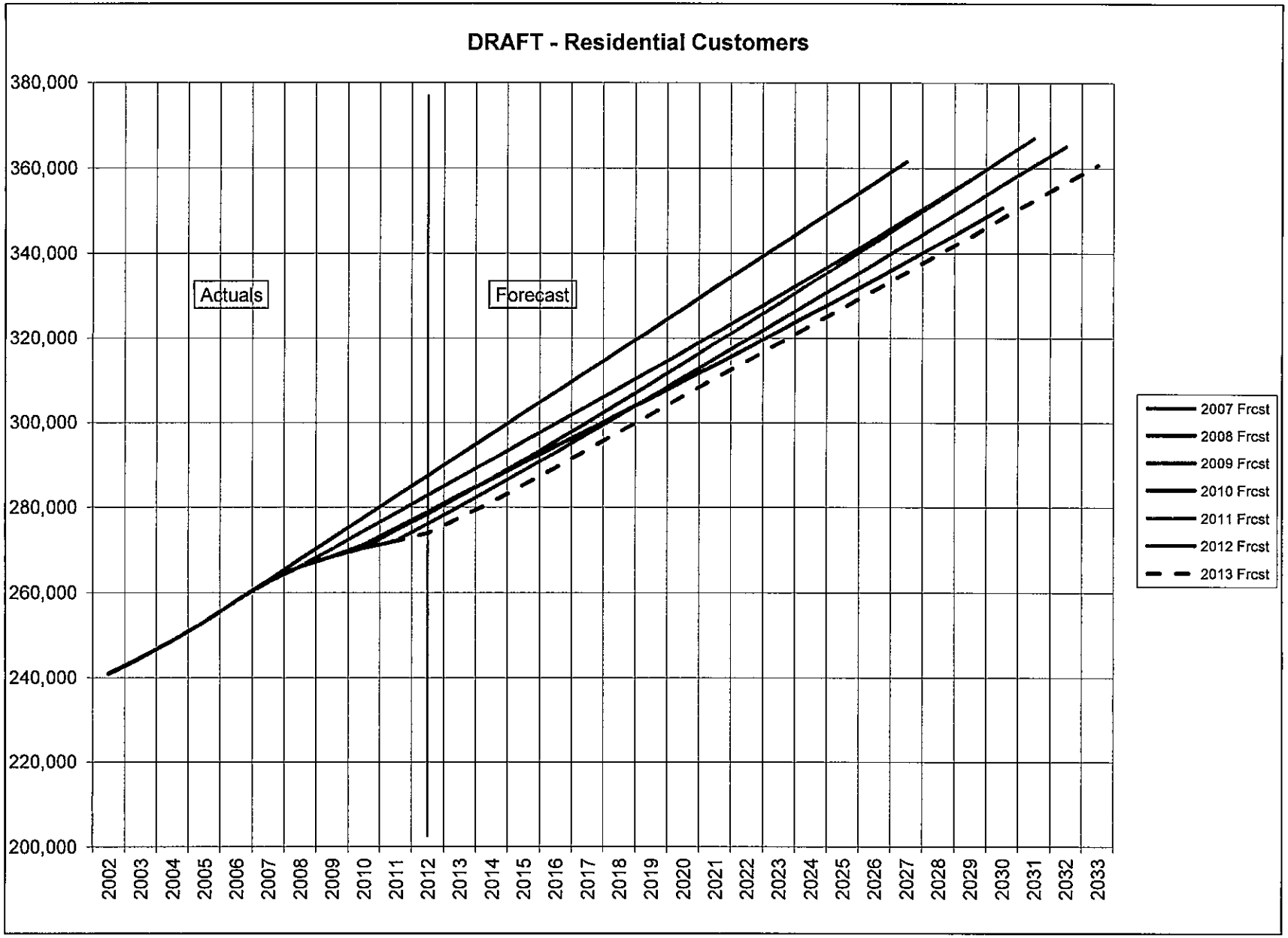
2008 Frcst
2009 Frcst
2010 Frcst
2011 Frcst
2012 Frcst
2013 Frcst


DRAFT - Residential Customers
380,000
360,000
340,000
320,000
300,000
280,000
260,000
240,000
220,000
200,000
Actuals
Forecast
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
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2019
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2021
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2008 Frcst
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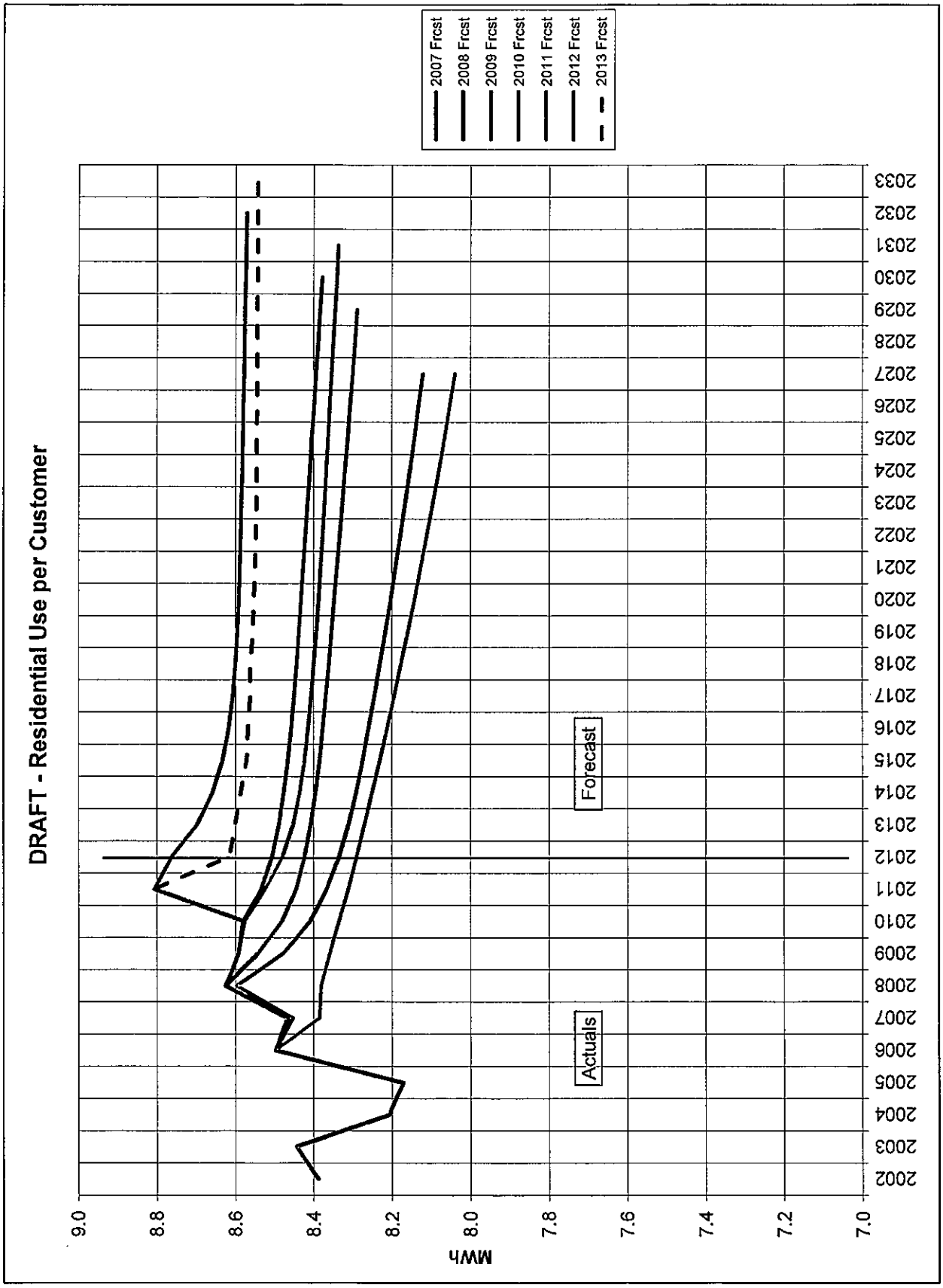
2010 Frcst
2011 Frcst
2012 Frcst
2013 Frcst


DRAFT - Residential Use per Customer
MWh
9.0
8.8
8.6
8.4
8.2
8.0
7.8
7.6
7.4
7.2
7.0
2002
2003
2004
2005
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Actuals
Forecast
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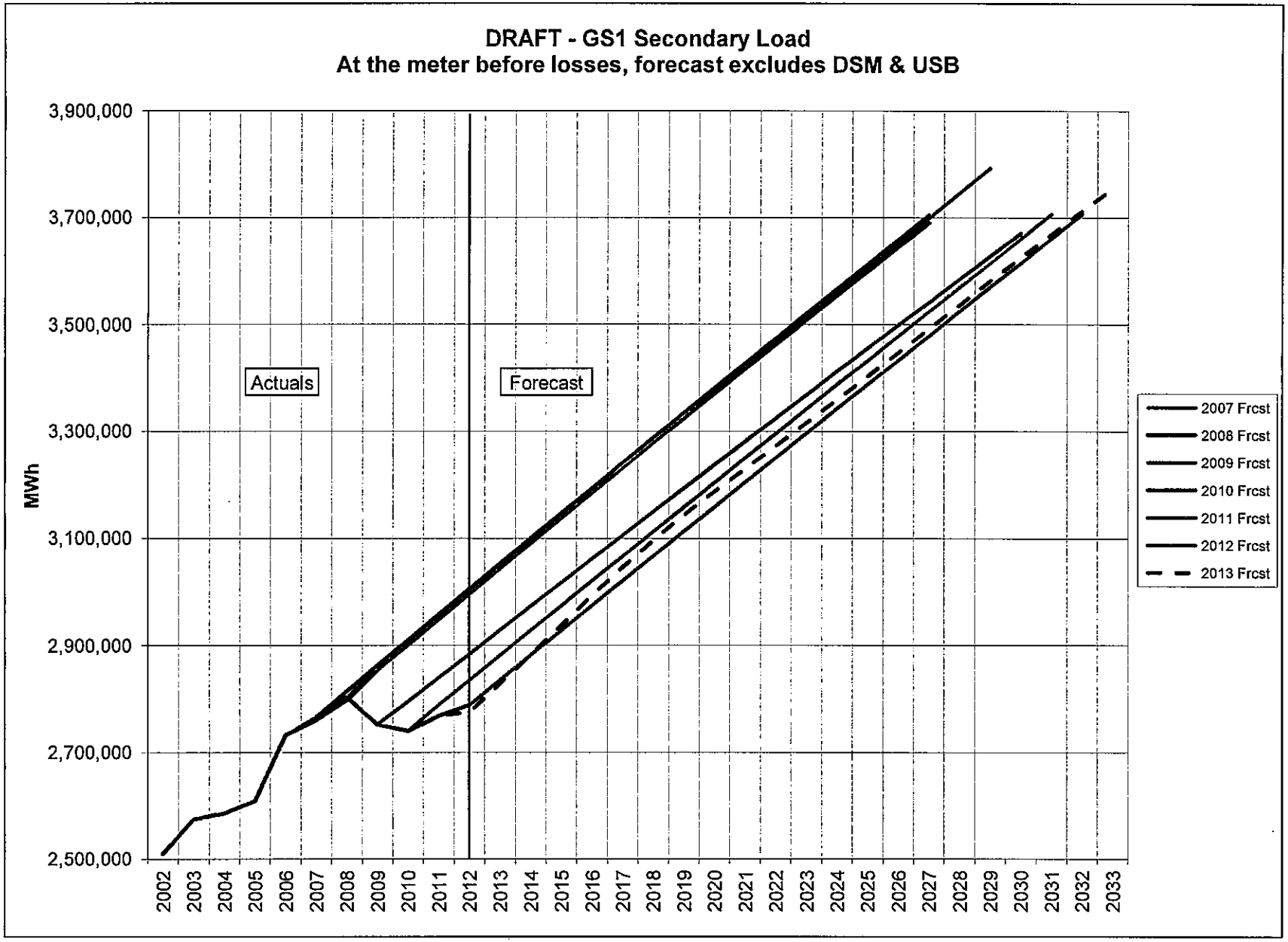
2008 Frcst
2009 Frcst
2010 Frcst
2011 Frcst
2012 Frcst
2013 Frcst


DRAFT - GS1 Secondary Load
At the meter before losses, forecast excludes DSM & USB
MWh
3,900,000
3,700,000
3,500,000
3,300,000
3,100,000
2,900,000
2,700,000
2,500,000
Actuals
Forecast
2002
2003
2004
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2011
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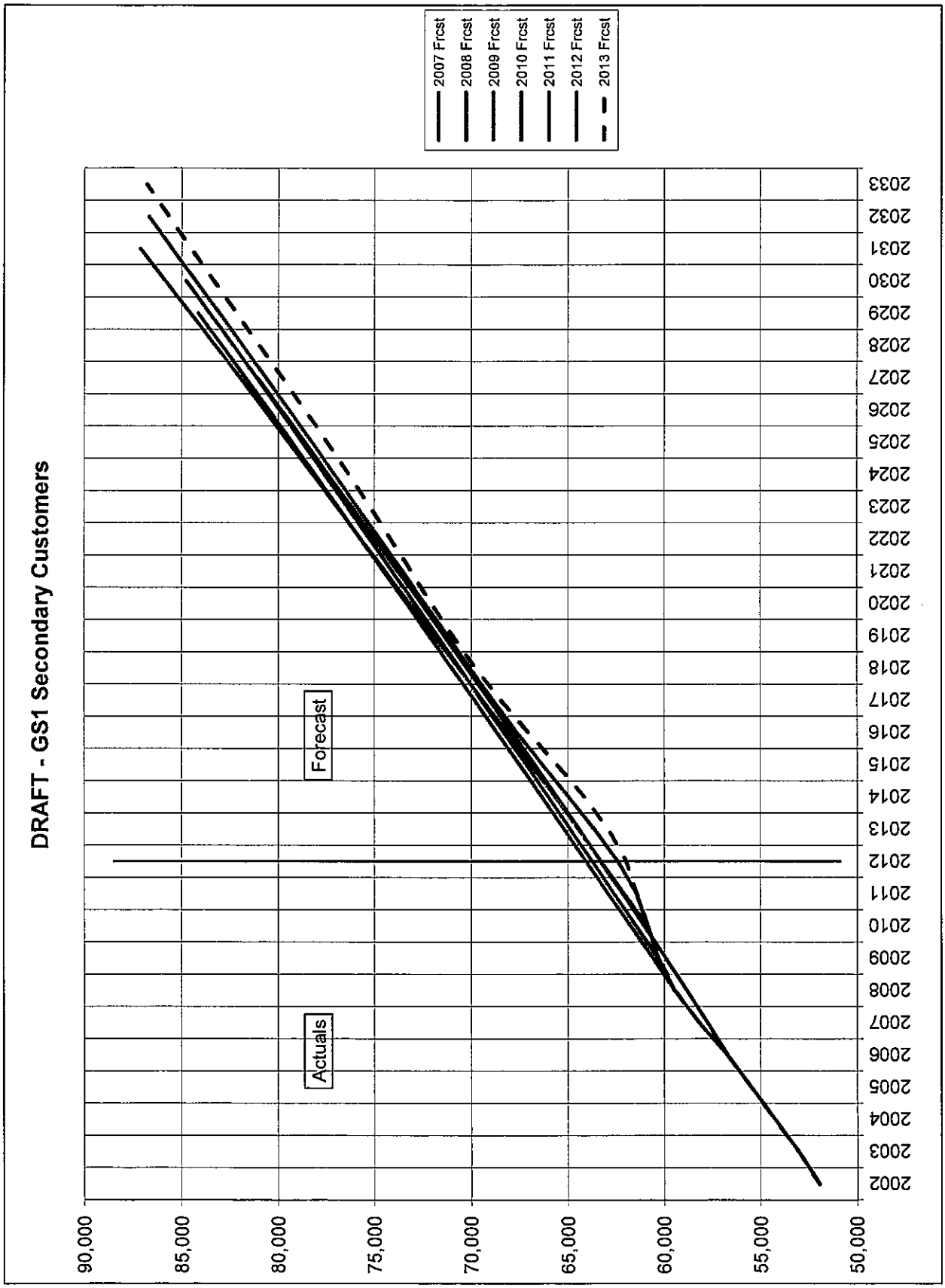
2009 Frcst
2010 Frcst
2011 Frcst
2012 Frcst
2013 Frcst


DRAFT - GS1 Secondary Customers
2007 Frcst
2008 Frcst
2009 Frcst
2010 Frcst
2011 Frcst
2012 Frcst
2013 Frcst
Actuals
Forecast
90,000
85,000
80,000
75,000
70,000
65,000
60,000
55,000
50,000
2002
2003
2004
2005
2006
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2008
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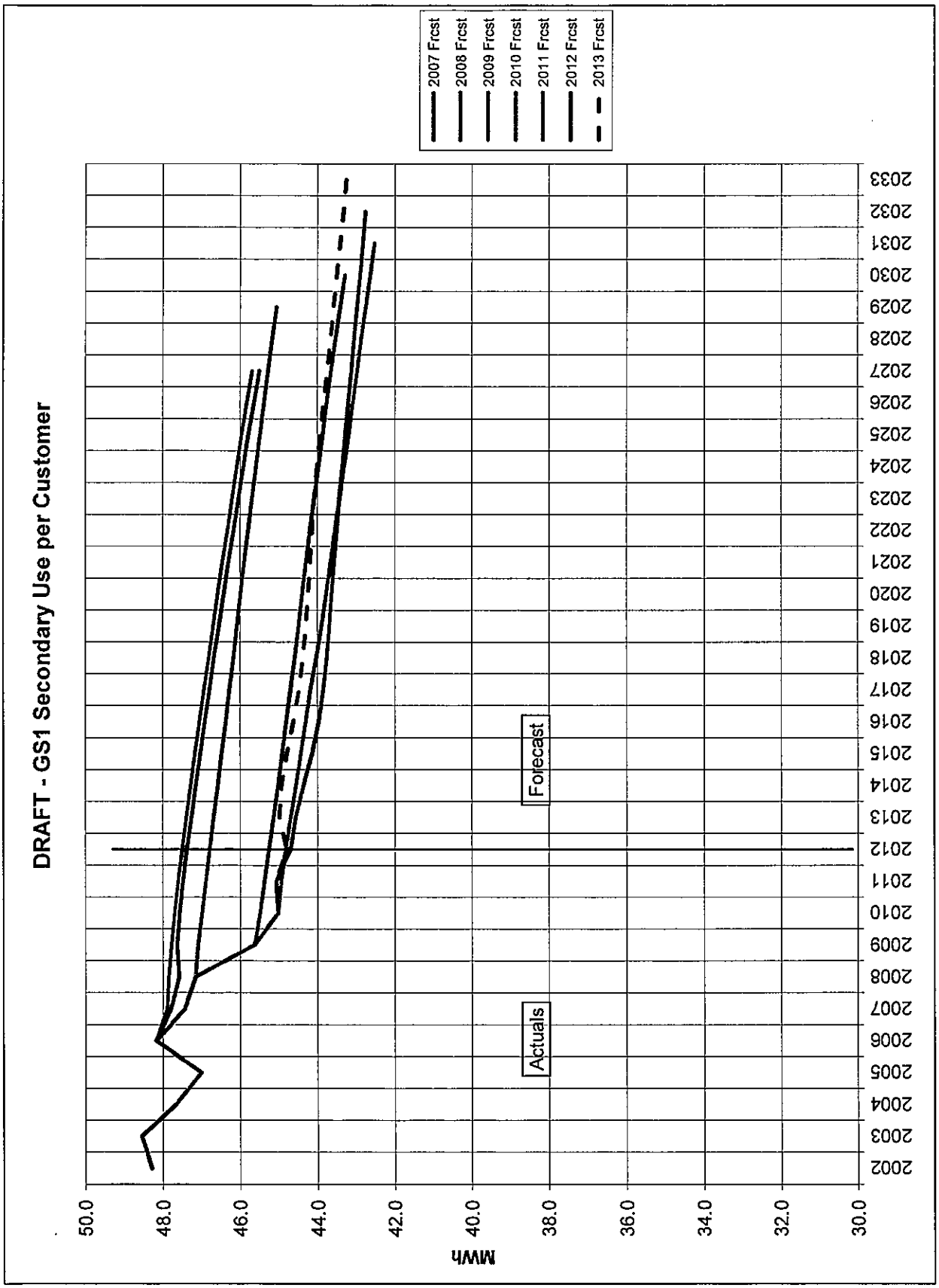
DRAFT - GS1 Secondary Use per Customer
MWh
50.0
48.0
46.0
44.0
42.0
40.0
38.0
36.0
34.0
32.0
30.0
2002
2003
2004
2005
2006
2007
2008
2009
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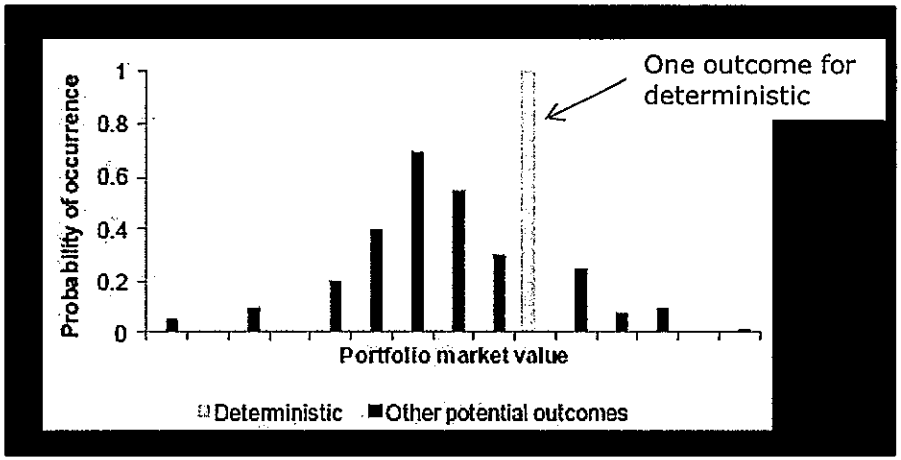
Actuals
Forecast
2007 Frcst
2008 Frcst
2009 Frcst
2010 Frcst
2011 Frcst
2012 Frcst
2013 Frcst

Phase 2 Deliverables

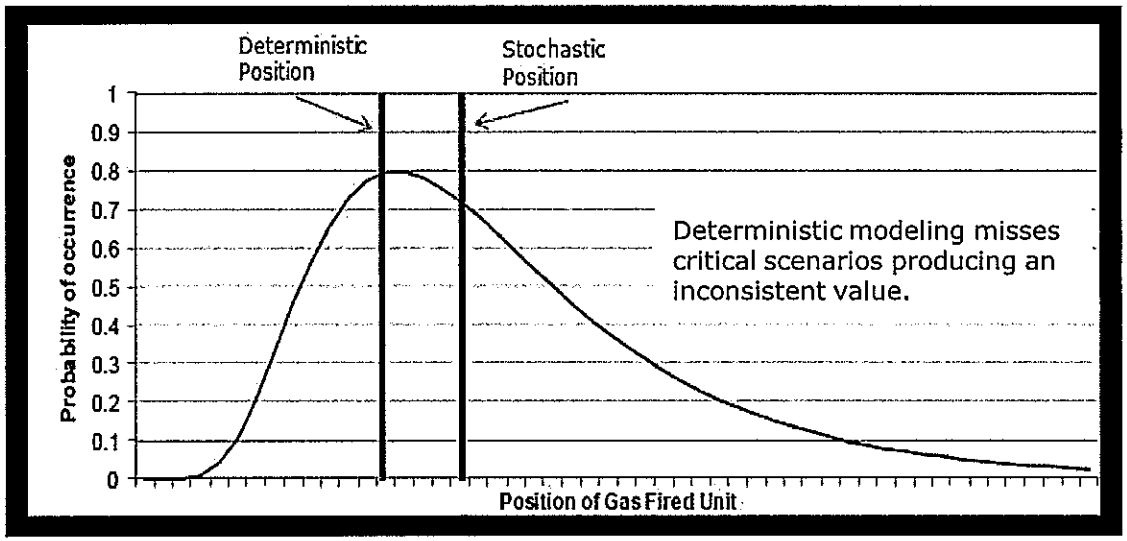
- Optimal Risk Based Long-term Resource Planning—Years 5-25
  - Develop a resource plan that systematically incorporates uncertainty into the planning process.
  - Simplify the presentation of results to minimize the number of scenario runs
  - Create a robust defensive shield for decision analysis that supports evaluation of future resource options:
    - Power purchase options
    - Power plant purchases
    - New construction
  - Address financial risk of forward prices and physical risk of spot delivery conditions
  - Meaningful uncertainty criterion. Probabilistically envelope future outcomes.
- Develop Portfolio Management Analytic—Years 1-5 (optional)
  - Evaluate near term portfolio management options
  - Select hedging/portfolio management strategy to minimize uncertainty in future cash flows
  - Budgeted cash flows equal realized cash flows

Deterministic vs. Stochastic Models

- Heavy dependence on deterministic results with scenarios
  - The likelihood of result is not understood
  - Model inputs are variable and interdependent

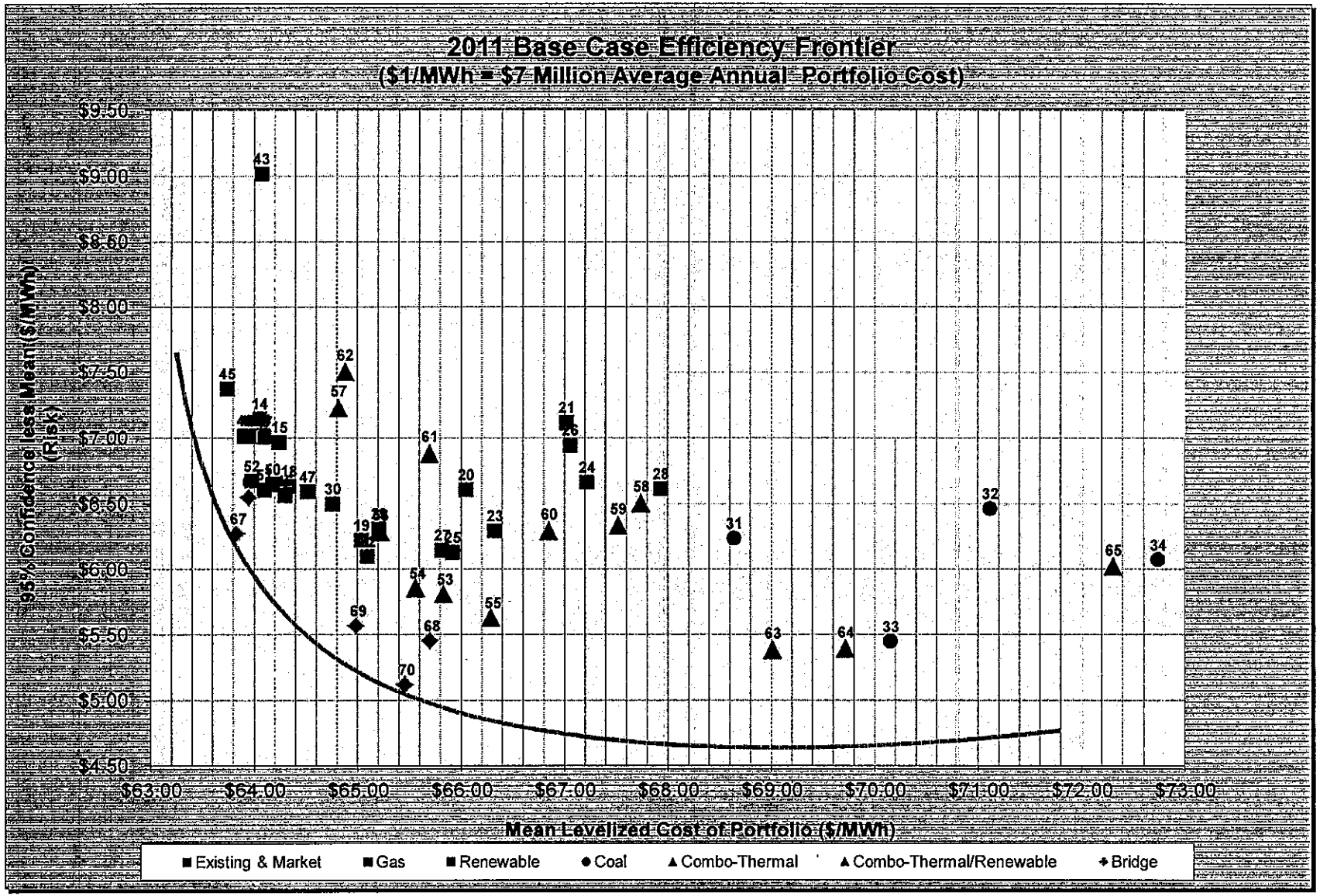


- What's the impact of unused information?
  - Inaccurate forecasting
  - Assessing risk becomes difficult



Ascend Analytics

Better Models. Better Decisions.


2011 Base Case Efficiency Frontier
($1/MWh = $7 Million Average Annual Portfolio Cost)
95% Confidence less Mean ($/MWh) (Risk)
$9.50
$9.00
$8.50
$8.00
$7.50
$7.00
$6.50
$6.00
$5.50
$5.00
$4.50
$63.00
$64.00
$65.00
$66.00
$67.00
$68.00
$69.00
$70.00
$71.00
$72.00
$73.00
Mean Levelized Cost of Portfolio ($/MWh)
Existing & Market
Gas
Renewable
Coal
Combo-Thermal
Combo-Thermal/Renewable
Bridge

ETAC Meeting Agenda

NorthWestern Energy
General Office Auditorium (downstairs)
40 East Broadway

Thursday June 6, 2013 – 9:00 AM

Conference Call-In: 877 820-7831 (Participant Code): 555256

Agenda:

May 2013 RFP Results – Kevin Markovich

Electricity Market Discussion
- Market flexibility
- Other utility activity

Electric Generation Resources for 2013 Plan
- Base load
- Intermediate/Peaking
- Renewable
- Other including distributed generation
- Resource/Fuel Diversity

Operational and Technology Considerations for Gas-Fired Resources
- Resource and portfolio flexibility
- On-peak & off-peak needs

(Lunch will be provided)

Meeting Summary
NorthWestern Energy Electricity Technical Advisory Committee
June 6, 2013

Attendance
Those participating in or attending the Energy Electricity Technical Advisory Committee (ETAC) meeting included:

Name	Organization
Diego Rivas	NW Energy Coalition
Thomas M. Power	District XI Human Resource Council
Steve Fisher	Lands Energy (for NWE)
Patrick Barkey	University of Montana - Bureau of Business and Economic Research
Brien DeKiep	Northwest Power and Conservation Council
Jamie Stamatson	Montana Consumer Counsel (MCC)
Paul Schultz	MCC
Larry Nordell	MCC
Garrett Martin	Montana Department of Environmental Quality (DEQ)
Jeff Blend	DEQ
John Bushnell	NorthWestern Energy (NWE)
Todd Guldseth	NWE
Frank Bennett	NWE
Dave Fine	NWE
Kevin Markovich	NWE
Doug Peoples	NWE
Joe Stimatz	NWE
Lisa Barkell	NWE
Chuck Magraw	Natural Resources Defense Council (via telephone)
Will Rosquist	MPSC (via telephone)
Jim Williams Jr.	NWE (via telephone)
Gerald Mueller	Consensus Associates

Agenda
- Market Operations
- Electricity Market Discussion
- Operational and Technical Considerations for Gas-Fired Resources
  - Resource and Portfolio Flexibility
  - On-peak and Off-peak Needs
- Electric Generation Resources for the 2013 Plan
  - Base Load
  - Intermediate/Peaking
  - Renewable
  - Other Including Distributed Generation
  - Resource/Fuel Diversity
- Other Topics
- Next Meeting

Market Operations

Kevin Markovich, Director of Energy Supply Market Operations at NorthWestern Energy, introduced three members of his Market Operations group: Joe Stimatz, Manager of Resource Optimization; Doug Peoples, Energy Scheduling and Imbalance Manager; and Lisa Barkell, Day Ahead Scheduler. He then discussed how NWE conducts market operations and summarized the May 2013 request-for-proposals (RFP) issued and transactions executed by his group. The Planning group develops a plan containing a resource portfolio for a 20-year period. The Market Operations group then contracts for specific resources pursuant to the plan and operates or manages them. The Day Ahead and Real-Time Desks schedule resources and make market purchases and sales to ensure that NWE's rate-based and contract resources balance load on a day ahead and hourly basis.

Lisa Barkell discussed her day-ahead marketing activities. For example, at 6:00 a.m. on Thursday, she schedules power for Friday and Saturday. She does so after considering the NWE load, weather (temperature), and 3-Tier wind forecasts and the electricity market. Pre-scheduling wind resources is challenging because of the disparity between forecast and actual wind and the operating environment. The wind may blow on Friday but not on Saturday. Because she must purchase a product for the two-day period, she faces the choice of pre-scheduling sufficient wind and purchases to cover both days or splitting the difference. The Real-Time desk must then adjust to the day-ahead schedule by either selling the excess power into or purchasing additional power from the market. NWE tries to avoid being long in the hourly market as re-marketing costs (transmission) can be substantial.

Comment - Even if both the Day Ahead and Real-Time desks had perfect knowledge of the future, pre-scheduling would still be challenging because standard power offers are marketed in 25 MW blocks.

Comment - Comment - You don't want to leave the Real-time desk in a long position because surplus wind in the region does not have a home, i.e., a firm contract, and often isn't sold into the day-ahead market. This situation results in low market prices and a disadvantage for sellers.

Question - Have the region's utilities and power marketers considered other periods for scheduling?
Answer by Lisa Barkell - The region has discussed moving scheduling to a seven day period, but has not done so because it would be more costly.

Comment - The blockiness of the market is advantageous for generation such as coal and natural gas that can be scheduled in blocks compared to intermittent resources such as wind.

May 2013 RFP - This past month, NWE issued an all-source request-for-proposals (RFP) for three products: up to 100 MW of fixed-price energy delivered at either the Mid-Columbia hub or to NWE's system for the years 2015-2017; up to 100 MW of index-priced energy delivered to NWE's system for the years 2015-2017; and up to 300 MW of index-priced energy delivered on NWE's system for Q3 and Q4 2014. The RFP was issued partly because the contracts with PPL Energy Plus (PPL) are expiring in the 2014 time frame. The PPL contracts currently provide 200 MW on-peak and 125 MW off-peak. NWE directly solicited responses from some 30 trading entities plus resource developers totaling 50-60 parties and issued a press release to reach additional entities. The RFP was conducted

in two phases. The first phase requested draft confirmation by May 22, 2013 setting forth contract conditions such as delivery points. The second phase was conducted from 2:00 p.m. to 4:00 p.m. on Thursday, May 30, and requested offers with specific amounts and prices. Ten entities made offers on May 30 for dozens of different product, term, and pricing combinations. More offers addressed the year 2015 than 2016 and more addressed 2016 than 2017. NWE entered into index-price contracts for 250 MW of on peak power delivered on system for July 1 through December 31, 2014 and another 50 MW for the 2015 calendar year. In addition, NWE entered into fixed-price contracts for delivery at Mid-Columbia totaling 100 MW on-peak and 75 MW off-peak for 2015; 75 MW on-peak and 50 MW off-peak for 2016; and 50 MW on-peak and 25 MW off-peak for 2017. The effect of the RFP acquisition on NWE's supply is shown in the second slide in the ETAC Materials 6-6-2013 presentation posted on the ETAC web page at:

http://www.northwesternenergy.com/display.aspx?Page=Electric_Technical_Advisory_Committee_%28ETAC%29

The title of the slide is "Monthly Average On-peak Resource Position - Physical System Position -6/3/2013."

Question - Why was the second phase of the RFP open for only two hours?
Answer - Market prices change quickly. Banks and speculators have specified risk parameters, so they will not hold bids for longer periods.

Question - Why not seek a deal for a longer period such as 15 years?
Answer - Not enough entities are willing to sell for a 5 to 15 year period to create a liquid market for electricity products for the longer periods. An efficient market exists typically for 18 months to 2 year periods.

Question - Did NWE receive more offers in the RFP for 2014 than 2015, more for 2015 than 2016, etc.?
Answer - Yes, both in terms of numbers of offers and the spread of prices.

Question - What is the point of entry for the power acquired pursuant to the RFP?
Answer - NWE Supply must have a transmission contract for 2014 so that it can receive the power on its system.

Question - You noted that even with the RFP acquisition, a short fall remains for the July through December 2014 period. How might this short-fall be hedged?
Answer - We can make bilateral purchases or transact through the Inter Continental Exchange.

Electricity Market Discussion

Kevin Markovich and his staff provided information about the electricity market and the pending electricity tracker proceeding before the MPSC. Data for the tracker was shown the table on the third slide entitled "Montana Regulated Electric Actual Tracker" in the ETAC Materials 6-6-2013 presentation. NWE uses hedges to fix electricity prices and thereby reduce its customers' exposure to the electricity and gas market price volatility. NWE does not use hedges to attempt to make a profit. The utility's use of hedges is an issue in the tracker proceeding. Mr. Markovich illustrated NWE's view of the value of hedges to its customers using the fourth slide in the aforementioned presentation, entitled "Analysis of Hedge Value During the California Energy Crises."

Comment - This example is a hedge created when the Montana Power Company (MPC) sold its generation to PPL. Hedges come at a cost. The issue is whether the cost is worth the price stability it affords.
Response - NWE hedges to provide price insurance against catastrophic events, not to make a profit.

Doug Peoples discussed the external and internal factors that affect market operations using slides 5 -14 in the ETAC Materials 6-6-2013 presentation. He stated that every two weeks, he briefs NWE management about the market. He noted that electricity at the Mid-Columbia trading hub and natural gas prices at the AECO hub in Alberta are strengthening. Gas prices are increasing because not as much has been stored. Gas demand and drilling rig count are also down.

Question - How were market operations handled by MPC?
Answer by Kevin Markovich - In 1996, MPC had a day-ahead scheduler at the Intercompany Pool. Because utility assets were rate-based, there was not a formal electricity market.

Question - How many people were involved with market operations in MPC?
Answer - Maybe a couple of people in the System Operations Control Center (SOCC).

Question - What is an Ice Settlement?
Answer - ICE is an acronym for Intercontinental Exchange which provides an electronic trading platform that shows amounts and prices of electricity market transactions. At 1:00 p.m. each day, brokers email reports to the ICE.

Question - What does ATC stand for?
Answer - Around the clock.

Question - Do the brokers report the market transactions voluntarily or in response to regulation?
Answer - They do so voluntarily.

Question - Is there an incentive for brokers to report accurate information?
Answer - Brokers need to be viewed as reliable to transact business.

Question - When NWE was evaluating the May RFP responses, did you look at the ICE information?
Answer - Yes, we factored into our decision the best information about the future electricity market.

Question - What is the use of your bi-weekly briefings of management if the market changes?
Answer - The briefing provides a snapshot of the market at the time of the meeting and two weeks previous.

Question - Does NWE acquire a separate gas supply for the Basin Creek plant operation?
Answer - Yes. John Smith is responsible for gas acquisitions.

Operational and Technical Considerations for Gas-Fired Resources

Steve Fisher with Lands Energy reported on this topic using a PowerPoint presentation entitled "Combustion Turbine Flexibility." This presentation is available on the ETAC web page.

Question - Are the gas-fired generators manufactured in the U.S.?
Answer - The GE, Siemens, Pratt and Whitney, and Caterpillar units are manufactured in the U.S. The Wärtsilä units are manufactured in Italy.

Question - Does the Dave Gates Generating Station (DGGS) rely on interruptible gas transmission?
Answer - Yes; it has the capability to switch to diesel fuel if gas is not available. Some natural gas generating stations, usually combined cycle plants, have firm gas transmission.

Question - You mentioned that a combined cycle combustion turbine operator needs access to liquid electricity and natural gas market hubs. Is there such a location on the NWE system?
Answer - No.

Question - Does a heat recovery steam generator (HRSG) improve air quality by lessening emissions?
Answer - Yes; using an HRSG increases generation without requiring extra fuel, except for duct firing. Water availability is another important environmental concern. Water cooling in a combined cycle plant evaporates about 2-3 million gallons per day. When water is not available, air cooling is used, but doing so requires 15 MW to run the cooling fans.

Electric Generation Resources for the 2013 Plan

Dave Fine reviewed the alternatives for electric generation resources for the 2013 resource plan using slides 15 -18 in the ETAC Materials 6-6-2013 presentation.

Question - What assumptions are you making regarding parasitic load and elevation for a gas-fired plant?
Answer - We are assuming a standard plant without duct firing.

Question - Does pollution control significantly degrade the capacity of gas-fired plants?
Answer - No.

Question - Are you looking for more regulation capacity?
Answer - Not currently.

Question - Depending on the Federal Energy Regulatory Commission (FERC), could the DGGS provide the regulation requirements for your system?
Answer – FERC's definition of regulation differs from NWE's. FERC assumes regulation to be moment-to-moment rather than larger movements such as load following.
Answer by Steve Fisher - There are four possible forms of regulation: four second load and generation matching; an ancillary service that California calls "flexible ramping," ten minute load and resource balancing, and operating reserves.

Question - Under FERC's definition, is DGGS sized to supply all regulation needs?

Answer - I don't know.

Question - Why do you need more shaping rather than just the lowest cost energy and capacity resources?
Answer - Because of the addition of intermittent wind resources, the needs of the portfolio have changed. We now need not only load shaping and peaking but also the ability to integrate wind generation on a minute-to-minute and hour-to-hour basis. Flexibility has value.
Answer by Steve Fisher - Generation is visible in real time; load is not. There is a clear advantage in the ability to dispatch generation into high priced markets. If the marginal unit is other than the highest priced unit, decision making becomes problematic.

Comment - In the MPC days, the utility used one unit of the Kerr hydropower plant to follow loads over short periods. One unit was operated at half of its capacity so that it could move up and down. Now NWE uses the DGGS to meet the load shape and short-term variations. A question is could NWE use blocks of other generation, such as the Basin Creek plant, to meet the load shape and save the DGGS for meeting the short-term variation.

Comment - We need to know the value of flexibility. A single cycle combustion turbine and a reciprocating engine plant such as the Basin Creek plant could move up and down quickly. There is a suite of types of flexibility.

Comment - Having just built the DGGS, NWE now needs to provide capacity and energy.
Response - We need both the capability to meet both light and heavy loads. We are not looking at regulation, but we are not disregarding the need for ancillary services such as reserves.

Question - It would be helpful to distinguish between the different types of flexibility. Is either portfolio model, GenTrader© or the Ascend model, sufficiently granular to make this decision?
Answer - For the portfolio, we are interested is assessing whether a resource fits in terms of load serving capability. For example, we want to assess if the portfolio would best be served with a simple cycle or combined cycle combustion turbine or a reciprocating engine plan or some combination of them.

Question - Can a combined cycle combustion turbine be operated as a single cycle turbine?
Answer by Steve Fisher - Doing so would not be efficient.

Question - Could several simple cycle aero-derivative turbines provide heat to a steam turbine?
Answer - Yes, but the heat rate would not be as good as a GE Frame 7F operating in combined cycle mode.

Comment - A key issue is whether using the model to select a natural gas-fired plant alternative depends on how the DGGS is operated.

Distributed Generation - An important issue in assessing the use of backup generation as distributed generation is whether it would be available when called on by the utility. The backup generation on NWE's system is not first-call to us so it cannot serve as reserves. The transactional costs of distributed generation such as hospital backup generation would be so high that building more Basin Creek type units would be cheaper.

Question - Is system reserves the only possible us of distributed generation?
Answer - No, it can also be used in a Smart Grid application.

Question - What about using interruptible rates in which the utility offers a payment or reduced rate for a load to either cut back or allow the utility to fire up the backup generation.
Answer - We must have the first call on the generation. I do not know the last time NWE used interruptible rates. Backup generation has two issues, control and start/stop limitations. The utility must be able to control starting backup generation.

Comment - Other utilities use interruptible rates for large industrial customers and for domestic water heating to avoid using expensive peaking resources.

Question - Are other utilities using backup generation as a resource?
Answer by Steve Fisher - Customers of some utilities are paid to have backup generation ready; however the operation of such resources would be complicated and high cost. This would be the last alternative given a functioning electricity market.

Comment - Kansas utilities negotiated with customers for a peak shaving rate for backup generation that could be started remotely and synchronized to the system.

Comment - I agree that distributed generation should not be used for this plan in portfolio modeling. The plan should, however, include a robust discussion of distributed generation because of its potential for disrupting the normal utility business model. NWE should begin considering distributed generation now.

Comment - The applicability of distributed generation depends on regulatory treatment.
Response - NWE is learning by observing the experience of other utilities and through its pilot battery storage/solar panel project.

Other Generation Technologies - Preliminary calculations indicate that combined cycle combustion turbine plants with carbon capture and sequestration would be so expensive that they would not dispatch.

Question - A company in Wyoming is building a pipeline to pump carbon dioxide a significant distance for enhanced oil recovery. What about doing so for the Sunburst oil fields?
Answer by Steve Fisher - The only electric generation plant that I am aware of using carbon capture and sequestration is the Summit project in Texas. Even with selling carbon dioxide, urea and electricity, this project is on the ragged edge of obtaining financing.

Question - What do you have in mind regarding gas-fired combined heat and power?
Answer - Some industrial customers use natural gas as a heat source, so a combined heat and power (cogeneration) plant might be feasible. We are evaluating combined heat and power purely as a generic resource.

Comment - Montana Dakota Utilities just installed a 5 MW generating plant fired by waste heat from a gas pipeline compressor station.

Response - NWE does not have a large enough gas pipeline in Montana to generate electricity in this way. We are, however, we have looked at capturing the energy that results from pressure drop on a gas pipeline in South Dakota.

Comment - Roof top solar is a potentially disruptive technology for utilities, but its cost needs to drop and more people need to be willing to install it.
Response by Steve Fisher - Roof top solar can be considered with a stand alone rather than a modeling analysis.
Response - To date NWE has about 880 roof top solar installations in its service territory.

Comment - Your slide with the viable supply options for the 2013 resource plan (slide 18 in the ETAC Materials 6-6-2013 presentation) does not use any fuel to provide a hedge against natural gas cost increases.
Response - This is correct, but we will examine a high cost gas scenario in the portfolio modeling.

Comment - The regulatory uncertainty is too high to consider coal as an alternative fuel to gas.

Comment by Steve Fischer - With its 11,400 MMBtu per MWh heat rate, 8,500 Btu per pound coal fuel source, the incremental cost of the Corette Plant is about $20 MW, but PPL has announced its intention to close this plant.

Comment - Given NWE's current fleet of electricity resources, new natural gas would increase fuel diversity.

Question - Why did you consider pump storage in the 2011 plan but are not considering it in this plan?
Answer - The cost and operation of a pump storage plant is site specific. We have asked developers about a plant on our system, but have not been offered any projects.
Answer by Steve Fisher - The current electricity market structure is not favorable for pump storage project. Prices of $4 on peak and $3 on peak would be necessary.

Other Topics

Question - What is the status of the Community Renewable Energy Project (CREP) RFP?
Answer by Dave Fine - NWE has selected a project entity that responded to the CREP RFP and is currently negotiating a contract for the project.

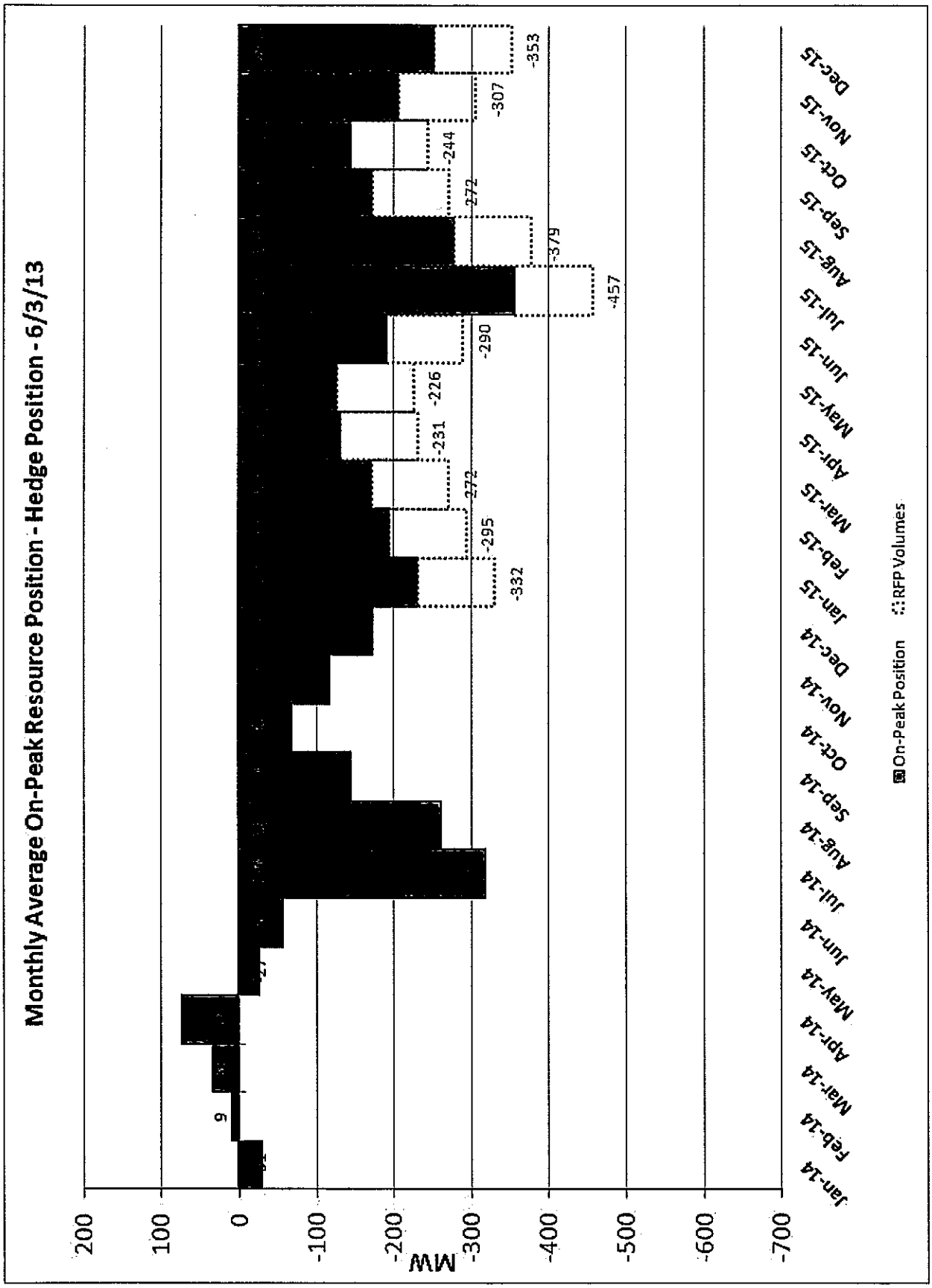
Question - What is the size of the project?
Answer by Dave Fine - The projects bid were generally about 20 MW, and the project in contract negotiations is for 20 MW. We are hopeful that we will secure a power purchase for this project.

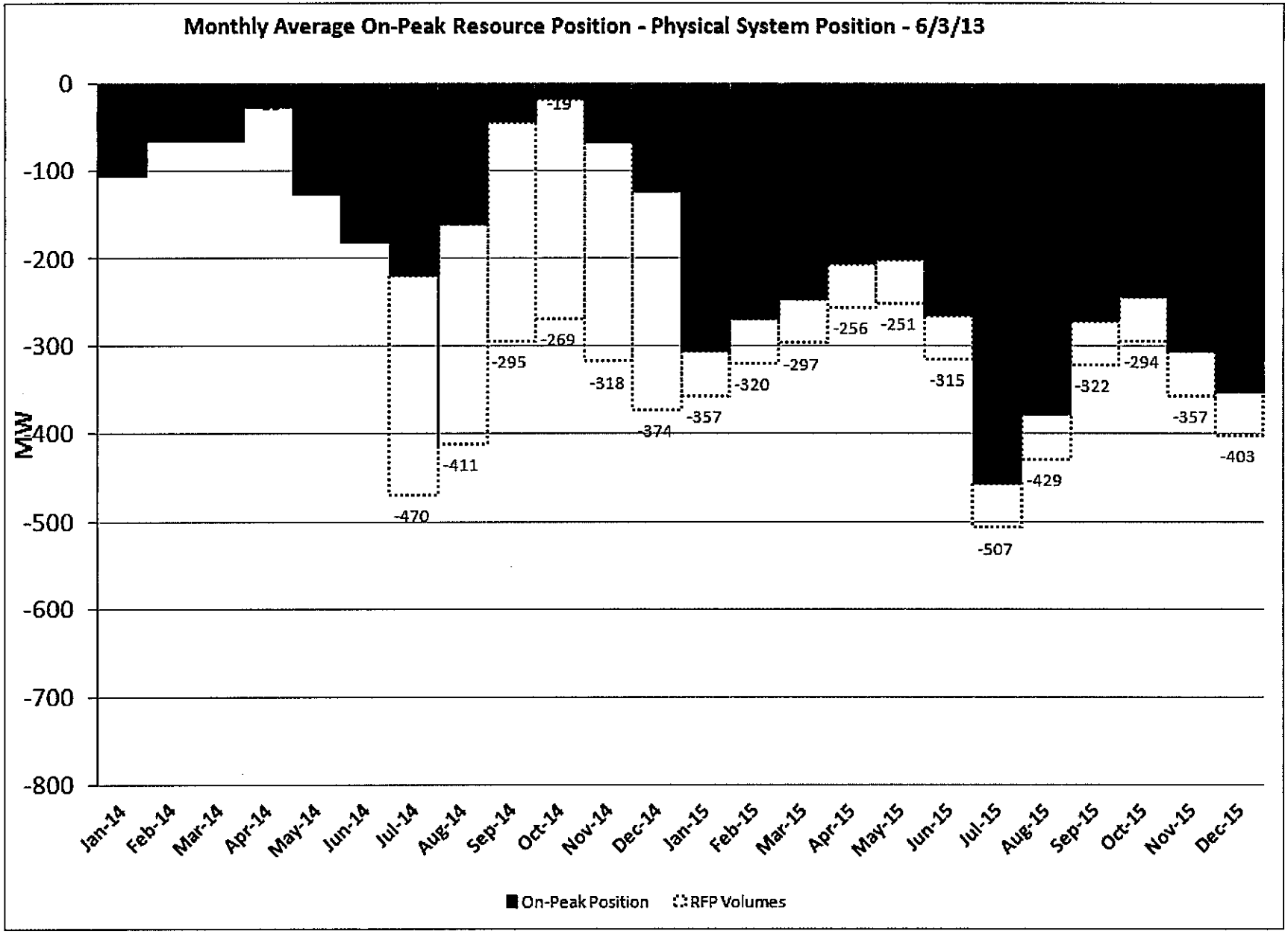
Next Meeting

The next meeting was scheduled for Wednesday, July 24, 2013. We expect to be discussing portfolio modeling results at this meeting.

Disclaimer

Committee members provide advice to NWE as individual professionals; the advice they provide does not bind the agencies or organizations that the members serve.


Monthly Average On-Peak Resource Position - Hedge Position - 6/3/13
MW
200
100
0
-100
-200
-300
-400
-500
-600
-700
Jan-14
Feb-14
Mar-14
Apr-14
May-14
Jun-14
Jul-14
Aug-14
Sep-14
Oct-14
Nov-14
Dec-14
Jan-15
Feb-15
Mar-15
Apr-15
May-15
Jun-15
Jul-15
Aug-15
Sep-15
Oct-15
Nov-15
Dec-15
9
-332
-295
-272
-231
-226
-290
-457
-379
-272
-244
-307
-353
On-Peak Position
RFP Volumes


Monthly Average On-Peak Resource Position - Physical System Position - 6/3/13
MW
0
-100
-200
-300
-400
-500
-600
-700
-800
-470
-411
-295
-269
-318
-374
-357
-320
-297
-256
-251
-315
-507
-429
-322
-294
-357
-403
Jan-14
Feb-14
Mar-14
Apr-14
May-14
Jun-14
Jul-14
Aug-14
Sep-14
Oct-14
Nov-14
Dec-14
Jan-15
Feb-15
Mar-15
Apr-15
May-15
Jun-15
Jul-15
Aug-15
Sep-15
Oct-15
Nov-15
Dec-15
On-Peak Position
RFP Volumes

MONTANA REGULATED ELECTRIC ACTUAL TRACKER

Electric Tracker Data	Actual 2009/10	Actual 2010/11	Actual[1] 2011/2012	Estimate[2] 2012/2013
Total Cost (millions)	$271.5	$247.1	$228.0	$226.4
Total Purchased/Owned Volume (millions)	6.4	6.5	6.5	6.6
Total Billed Volume (millions)	5.7	5.8	5.8	6.0
Supply Over/(Under) collection (millions)	($6.9)	($24.4)	($15.3)	$2.4
CU4 Over/(Under) collection (millions)	$7.9	$26.0	$5.2	($0.01)
DGGS Over/(Under) collection (millions)		($1.5)	($0.8)	($4.2)
Total Over/(Under) collection (millions)	$1.0	$0.5	($10.8)	($1.8)

[1] Prior tracker year
[2] Active tracker year - final through February 2013

NorthWestern Energy
Delivering a Bright Future

Analysis of Hedge Value During California Energy Crisis

	MWh	Hedged Price	Mid C Price	Actual Cost	Non-Hedged Cost	Difference
Jul-00	569,000	$ 22.85	$ 98.08	$ 13,001,650	$ 55,807,520	$ 42,805,870
Aug-00	614,000	$ 22.85	$ 166.06	$ 14,029,900	$ 101,960,840	$ 87,930,940
Sep-00	497,000	$ 22.85	$ 114.73	$ 11,356,450	$ 57,020,810	$ 45,664,360
Oct-00	480,000	$ 22.85	$ 96.81	$ 10,968,000	$ 46,468,800	$ 35,500,800
Nov-00	557,000	$ 22.85	$ 161.29	$ 12,727,450	$ 89,838,530	$ 77,111,080
Dec-00	615,000	$ 22.85	$ 524.64	$ 14,052,750	$ 322,653,600	$ 308,600,850
Jan-01	594,000	$ 22.85	$ 261.17	$ 13,572,900	$ 155,134,980	$ 141,562,080
Feb-01	545,000	$ 22.85	$ 275.21	$ 12,453,250	$ 149,989,450	$ 137,536,200
Mar-01	518,000	$ 22.85	$ 260.71	$ 11,836,300	$ 135,047,780	$ 123,211,480
Apr-01	496,000	$ 22.85	$ 289.74	$ 11,333,600	$ 143,711,040	$ 132,377,440
May-01	507,000	$ 22.85	$ 223.45	$ 11,584,950	$ 113,289,150	$ 101,704,200
Jun-01	538,000	$ 22.85	$ 62.00	$ 12,293,300	$ 33,356,000	$ 21,062,700
	6,530,000	$ 22.85	$ 211.16	$ 149,210,500	$ 1,404,278,500	$ 1,255,068,000

Increase in Supply Costs	841%
Increase in December Supply Costs	2196%

* Estimated monthly volumes. Actual Mid C prices.

May 29, 2012

- **External Factors**
  - Electric Pricing (Resources Brokers and TFS)
    - Current
    - Forward Strips
  - Gas Prices (Resources Brokers and Prophet X)
    - Current
    - Foreword Strips
  - Spring Snow Pack
  - Weather Telvent
  - Transmission Issues
    - Bonneville and NorthWestern
- **Internal Factors**
  - Portfolio Needs
    - On Peak, Off Peak
    - Shaped Products
    - Contracts
    - Generation Outages

Mid C Ice Settlements 5/28

Forecast Date 5/14	**On Peak**								
	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Average
	33.99	32.95	43.90	49.30	42.80	37.40	38.65	41.55	**40.07**
	Off Peak								
	9.72	12.35	28.65	35.05	34.30	32.90	33.70	35.75	**27.80**
	ATC								
	22.83	23.47	36.89	42.75	38.89	35.33	36.37	38.88	**34.43**
Forecast Date 5/28	**On Peak**								
	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	
	33.46	33.50	44.35	49.25	43.05	38.50	39.40	42.55	**40.51**
	Off Peak								
	13.05	14.50	28.55	34.85	35.20	33.25	33.65	36.55	**28.70**
	ATC								
	24.07	24.76	37.08	42.63	39.44	36.09	36.76	39.79	**35.08**
Forecast Date 5/28	**On Peak**								
	Q 3 2014	Q 4 2014							
	43.35	42.08							
	Off Peak								
	31.70	36.08							
	ATC								
	37.99	39.32							

Mid C Heavy Load Broker Quotes

Forecast Changes

Peak	May-13	Jun-13	Jul-13	Aug-13	Cal 13	Cal 14	Cal 15	Cal 16	Cal 17	Cal 18	Cal 19
06/01/10					51.65	54.50	57.35	60.35	63.40	66.35	
[redacted]					[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
01/06/11					47.20	51.10	54.45	57.45	59.45	61.45	
03/22/11					43.75	47.25	51.50	55.35	59.00	62.45	
08/05/11					42.00	46.35	50.45	53.85	57.10	60.20	
[redacted]					[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
11/18/11					36.75	41.50	45.20	48.95	52.90	56.25	
12/16/11					36.05	40.05	43.30	46.80	50.05	53.30	
01/10/12					34.80	38.65	41.80	45.80	49.55	52.75	
05/01/12					31.45	36.70	39.50	42.40	45.30	48.30	
07/20/12					33.80	39.05	42.05	44.60	47.60	50.45	
08/21/12					32.60	38.25	40.85	43.00	45.25	47.50	
10/02/12					34.35	38.65	41.35	43.45	45.45	47.70	
11/27/12					32.30	38.25	41.25	43.50	45.75	48.00	
12/31/12					30.25	36.05	40.15	42.80	45.55	48.30	
01/08/13						35.70	39.85	42.65	45.10	47.60	50.10
01/22/13						36.60	39.85	42.60	45.05	47.80	50.45
02/20/13	23.75					35.65	38.65	41.15	43.70	46.30	49.10
03/19/13	23.90					36.92	39.74	42.41	45.52	47.91	49.95
04/02/13	23.35	22.85				36.91	38.84	41.92	44.96	47.35	49.39
04/16/13	25.50	25.50				36.91	38.71	40.90	44.07	46.46	48.50
04/30/13	30.25	27.75	44.00			37.35	38.50	40.10	41.85	44.00	46.30
05/07/13	26.50	27.50	41.50			36.60	38.30	40.15	42.00	44.25	47.00
05/14/13	33.00	32.85	43.75	49.25		37.15	38.70	40.50	42.50	44.85	47.70
05/28/13	32.00	33.50	44.35	49.25		38.25	39.65	41.80	43.85	46.25	49.25

Mid C Light Load Broker Quotes

Forecast Changes

OFF-PEAK	Cal 13	Cal 14	Cal 15	Cal 16	Cal 17	Cal 18	Cal 19
06/01/10	39.85	41.50	43.50	45.50	47.50	49.45	
09/20/11	34.10	35.00	35.90	36.90	37.90	38.90	
01/06/11	36.25	37.75	39.00	40.10	41.10	42.10	
03/22/11	31.70	33.85	36.25	38.85	41.25	43.35	
08/05/11	30.60	33.35	35.65	37.55	39.35	41.15	
10/12/11	28.15	31.15	33.80	36.15	38.30	39.95	
11/18/11	26.80	29.55	31.90	34.00	36.10	37.95	
12/16/11	26.95	29.55	31.20	33.10	34.90	36.60	
01/10/12	25.95	28.85	30.25	32.00	33.90	35.65	
05/01/12	23.30	26.75	28.95	31.05	33.10	35.05	
07/20/12	24.90	28.50	30.75	32.75	34.60	36.60	
08/21/12	24.05	28.40	30.40	32.40	34.40	36.15	
10/02/12	24.95	29.45	31.50	33.15	35.00	36.90	
11/27/12	23.25	28.85	31.20	32.75	34.30	36.05	
12/31/12	21.50	27.20	30.00	31.95	33.95	35.95	
01/08/13		26.45	29.35	31.20	33.05	35.05	37.05
01/22/13		27.30	29.50	31.60	33.55	35.80	38.05
02/20/13		26.90	29.25	31.10	32.95	34.95	37.10
03/19/13		28.42	30.10	31.93	33.71	36.55	38.38
04/02/13		28.41	28.85	31.67	33.65	36.49	38.31
04/16/13		27.87	28.99	30.60	32.71	35.55	37.38
04/30/13		28.10	29.10	30.65	32.20	34.00	35.85
05/07/13		27.50	28.80	30.55	32.15	34.00	36.15
05/14/13		27.80	29.25	30.90	32.60	34.45	36.70
05/28/13		28.30	29.70	31.50	33.65	35.75	38.20

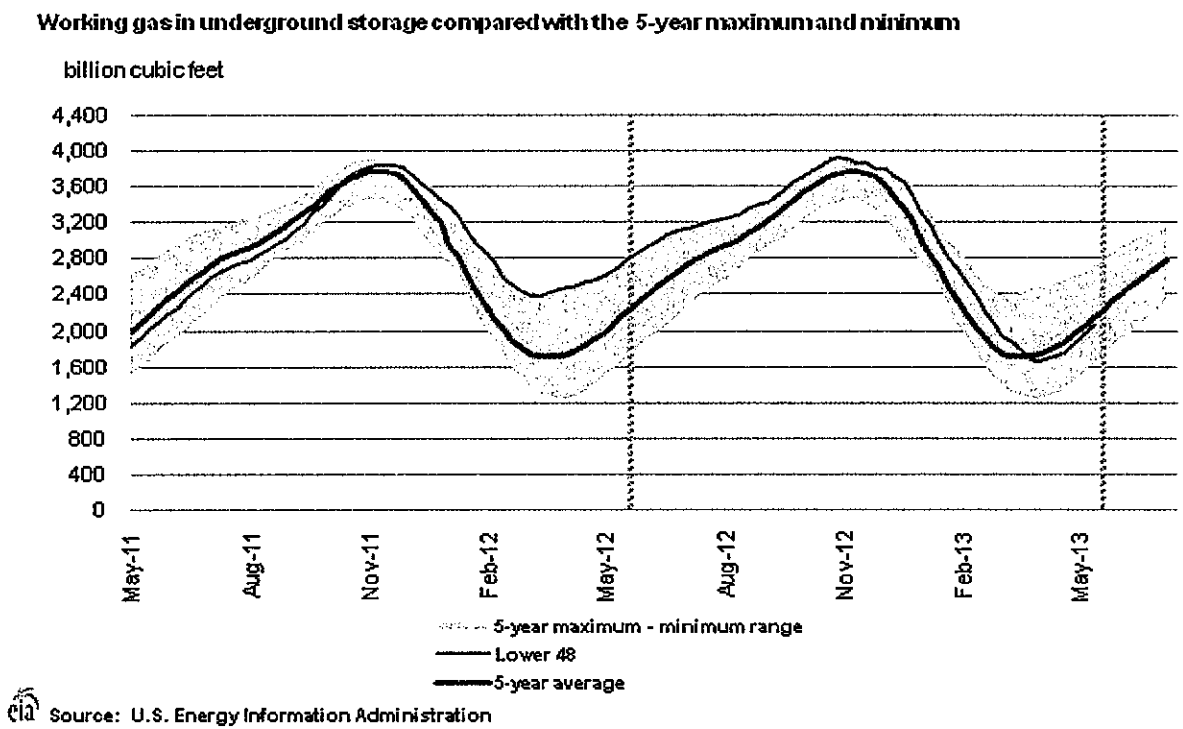
Basin Creek Estimated Dispatch						
As of:	5/28/2013					
	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
Mid-C On-Peak Price ($/MWh)	**$ 44.35**	**$ 49.25**	**$ 43.05**	**$ 38.50**	**$ 39.40**	**$ 42.55**
AECO Price ($US/MMBtu)	$ 3.648	$ 3.653	$ 3.658	$ 3.703	$ 3.870	$ 3.995
Dispatch Cost ($/MWh)	**$ 37.68**	**$ 37.72**	**$ 37.77**	**$ 38.17**	**$ 39.68**	**$ 40.81**
Spark Spread ($/MWh)	**$ 6.67**	**$ 11.53**	**$ 5.28**	**$ 0.33**	**$ (0.28)**	**$ 1.74**
Implied Heat Rate	12.2	13.5	11.8	10.4	10.2	10.7
Estimated Dispatch						
% of On-Peak Hours	78%	92%	65%	34%	32%	44%
Run Hours	323	400	250	148	129	178
Total MWh	11,312	13,983	8,766	5,180	4,503	6,227
2012 On-Peak Capacity Factor	15%	20%	8%	23%	9%	23%
2012 On Peak MWh	2,155	3,597	1,092	4,687	1,262	3,404

AECO

Forecast Changes

Forecast Date	M-May 13	M-Jun 13	M-Jul 13	M-Aug 13	M-Sep 13	M-Oct 13	M-Nov 13	M-Dec 13	M-Jan 14	M-Feb 14	M-Mar 14	M-Apr 14	M-May 14	M-Jun 14
Jan 6,2011	4.32	4.34	4.38	4.40	4.42	4.49	4.65	4.87	5.02					
August 31 2011	4.44	4.44	4.47	4.46	4.52	4.53	4.77	4.96	5.05	5.02	4.96	4.70	4.66	4.65
Oct. 18, 2011	3.99	3.99	4.02	3.99	4.06	4.07	4.30	4.49	4.58	4.55	4.49	4.33	4.28	4.28
Jan 10, 2012	3.40	3.40	3.45	3.43	3.48	3.59	3.70	3.87	3.95	3.93	3.88	3.85	3.81	3.81
Feb 7, 2012	3.14	3.19	3.17	3.21	3.33	3.47	3.62	3.69	3.68	3.64	3.58	3.55	3.54	3.56
March 6, 2012	2.97	2.98	3.00	2.98	2.98	2.97	3.13	3.42	3.56	3.52	3.42	3.29	3.30	3.41
April 17, 2012	2.74	2.75	2.80	2.80	2.84	2.96	3.12	3.29	3.35	3.33	3.27	3.23	3.22	3.21
May 1, 2012	2.98	3.03	3.03	3.07	3.15	3.32	3.49	3.56	3.53	3.47	3.40	3.38	3.38	3.40
June 12, 2012	2.84	2.86	2.89	2.90	2.94	3.00	3.20	3.40	3.46	3.44	3.37	3.33	3.31	3.31
July 10, 2012	3.03	3.04	3.08	3.09	3.12	3.17	3.36	3.56	3.64	3.62	3.58	3.46	3.44	3.44
August 7, 2012	3.07	3.09	3.12	3.14	3.17	3.21	3.38	3.57	3.66	3.66	3.62	3.52	3.49	3.48
September 4, 2012	2.98	2.99	3.02	3.04	3.06	3.09	3.27	3.46	3.54	3.53	3.49	3.39	3.36	3.35
October 30, 2012	3.42	3.43	3.46	3.49	3.51	3.56	3.70	3.86	3.95	3.93	3.88	3.70	3.70	3.71
November 28, 2012	3.49	3.50	3.52	3.55	3.57	3.64	3.76	3.92	4.00	3.99	3.94	3.75	3.75	3.75
December 11, 2012	3.14	3.15	3.17	3.21	3.24	3.29	3.44	3.60	3.67	3.67	3.64	3.49	3.49	3.50
December 31, 2012	3.03	3.04	3.08	3.12	3.14	3.21	3.40	3.57	3.64	3.65	3.62	3.53	3.51	3.52
January 8, 2013	2.94	2.96	2.99	3.03	3.06	3.13	3.33	3.51	3.58	3.58	3.56	3.48	3.48	3.49
January 22, 2013	3.19	3.19	3.22	3.26	3.28	3.36	3.56	3.71	3.77	3.77	3.75	3.60	3.60	3.60
February 5, 2013	3.09	3.10	3.14	3.18	3.21	3.27	3.48	3.61	3.68	3.68	3.65	3.53	3.54	3.55
February 20, 2013	2.99	2.99	3.02	3.06	3.09	3.15	3.35	3.51	3.56	3.57	3.54	3.46	3.47	3.48
March 19, 2013	3.52	3.54	3.57	3.57	3.63	3.75	3.88	3.88	3.86	3.81	3.60	3.58	3.58	3.58
April 2, 2013	3.48	3.49	3.51	3.54	3.54	3.60	3.74	3.86	3.88	3.87	3.85	3.57	3.55	3.55
April 16, 2013	3.62	3.62	3.64	3.67	3.68	3.74	3.88	4.02	4.03	4.00	3.94	3.65	3.62	3.62
April 30, 2013	3.71	3.71	3.74	3.76	3.77	3.84	3.99	4.15	4.14	4.12	4.06	3.72	3.68	3.70
May 14, 2013	3.48	3.50	3.51	3.51	3.52	3.56	3.72	3.87	3.87	3.86	3.83	3.60	3.58	3.60
May 28, 2013	3.65	3.65	3.65	3.65	3.66	3.70	3.87	4.00	3.99	3.99	3.96	3.74	3.72	3.73

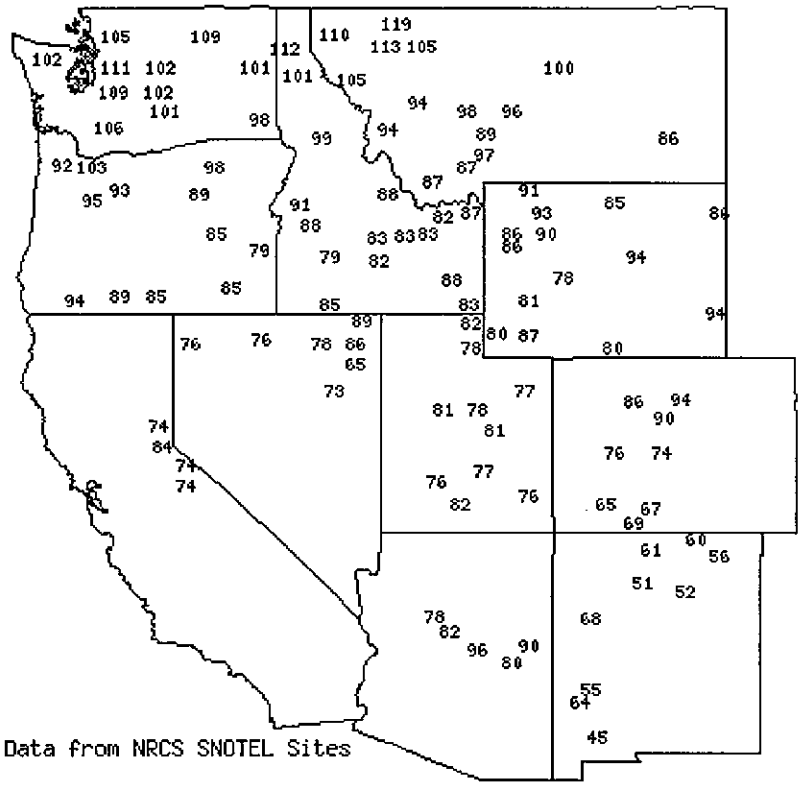
Gas Storage Levels



Note: The shaded area indicates the range between the historical minimum and maximum values for the weekly series from 2005 through 2009.
Source: Form EIA-912, "Weekly Underground Natural Gas Storage Report." The dashed vertical lines indicate current and year-ago weekly periods. Released May 23 2013

Basin Average Precipitation. (% of Average.)

OCTOBER 1 , 2011 thru MAY 28 , 2013



Report Date:

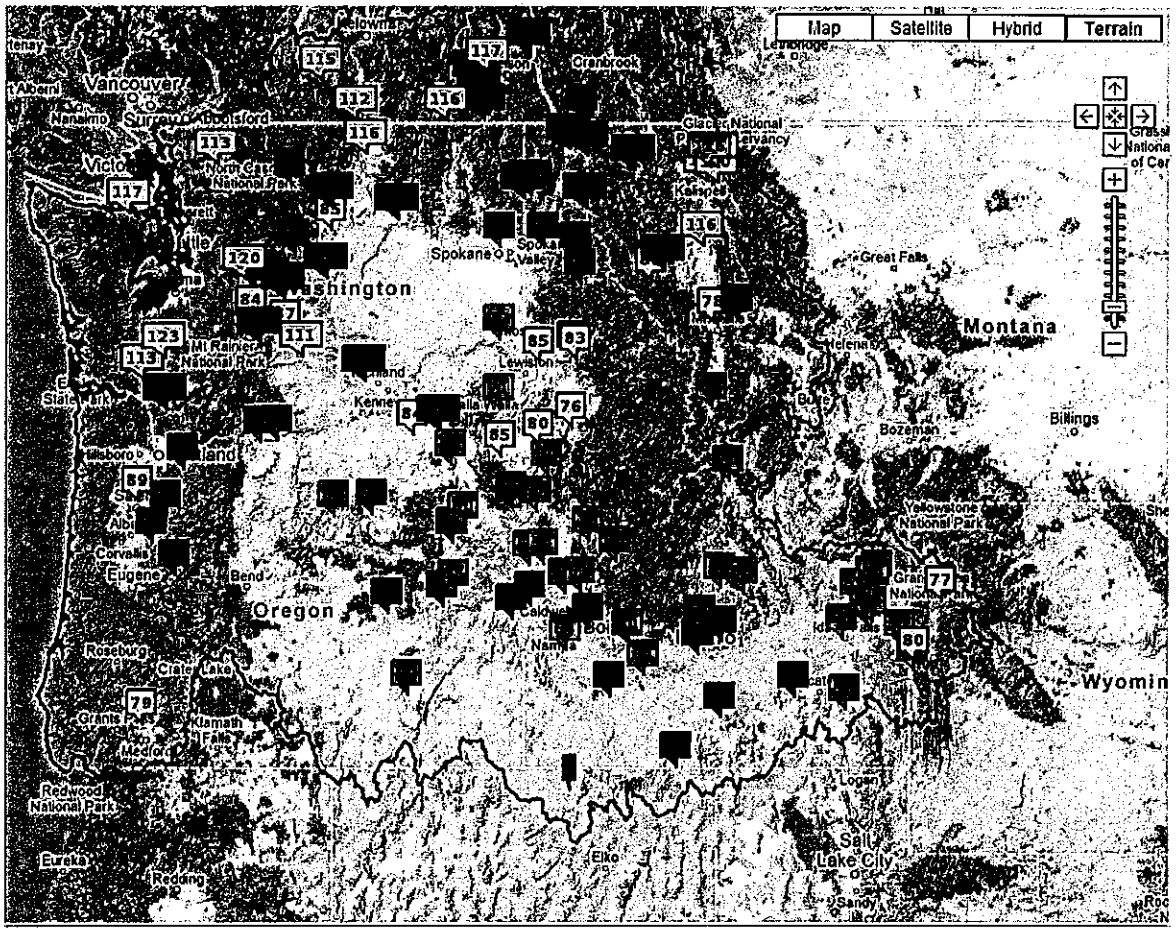
MAY 28 , 2013

Provisional Data
Based on Mountain Data from NRCS SNOTEL Sites

Data provided by
Water and Climate Center
Natural Resources Conservation Service
Portland, Oregon

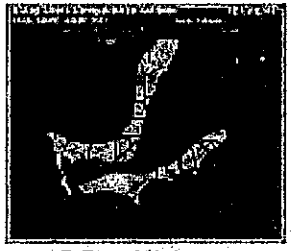
Western Regional Climate Center
Desert Research Institute
Reno, Nevada

Water Supply Forecast – May through September



Weather Forecasts

5 Day Maximum Temperatures



5 Day Minimum Temperatures

6-10 Day Mean Temperatures

8-14 Day Mean Temperatures

30 Day Temperature Outlook

90 Day Temperature Outlook

NorthWestern Energy
2013 Resource Procurement Plan
Electric Generation Resources

All single unit or 1x1 capacities

Resource	Start Date	Size (MW)
Baseload		
Combined Cycle (gas)		
GE 6FA		119
GE 7FA.05		290
Siemens STG6-5000F		293
Combined Cycle (gas) w/CCS		
Gas Combined Heat & Power (CHP)		
Supercritical Coal w/CCS		
IGCC		
IGCC w/CSS		
Intermediate/Peaking		
Aeroderivative Gas Turbine		
GE LM6000		43
GE LS100		103
P&W FT-8		52
Frame Gas Turbine		
GE 6F		77
GE 7EA		85
GE 7FA.05		211
Siemens STG6-5000F		208
Reciprocating Engine		
Wärtsillä 34SG		9
Wärtsillä 50SG		19
Caterpillar G16CM34		9
Renewable & Other		
Battery Storage		
Biomass Wood Products		
Distributed Generation		
Solar PV		
Geothermal		
Waste Water Treatment		
Landfill Gas		
Small Hydro		
Wind		
DSM		

Customer Segment	Technical Potential (kW in 2020)	Economic Potential (kW in 2020)
Wastewater	454	380
Chemicals	2,929	477
Metals	312	51
Timber	9,354	1,524
Airports	2,119	345
College/University	9,180	1,495
Golf/Country Club	4,583	747
Hotel & Motel	15,636	2,547
Laundry	913	149
Medical	26,832	4,371
Prisons	1,309	213
TOTAL	**73,621**	**12,299**

Note: Distributed Energy Resources as Regulating Resources.
Nexant, Inc from February 8, 2011.
No additional analysis updated.
Includes combined heat and power (CHP) and biogas recovery systems fed by anaerobic digesters.

Regional Gas Projects

Utility	Project	Status	Technology	Unit Description	Capacity (MW)	Cost	Cost ($/kW)
Portland General	Port Westward Unit 2	COD 2015	Reciprocating Engine	12 Wartsila 18.7 MW units	220	$300 M	$1,364
Portland General	Carty Generating Station	COD 2016	CCCT	Mitsubishi M501GAC gas turbine; SRT-50 reheat steam turbine; heat recovery steam generator	440	$455 M	$1,034
Idaho Power	Langley Gulch	COD July 2012	CCCT	Siemens 5000F combustion turbine generator; Siemens ST-700/900 reheat steam turbine generator; Vogt triple-pressure heat recovery steam generator	300	$400 M	$1,333
Pacificorp	Lake Side 2 (Utah)	COD 2014	CCCT	Two Siemens SGT6-5000F gas turbines; One SST6-5000 steam turbine; Two heat recovery steam generators	637	$756 M?	$1,187
Black Hills / Cheyenne Light	Cheyenne Prairie Generating Station	COD 2014	CCCT & SCCT	Three General Electric LM 6000 PF Sprint combustion turbine generators; two operating in CC, one in SC	SCCT - 37 CCCT - 95	$222 M	$1,682
NorthWestern Energy	Aberdeen Generating Station Unit #2	COD Spring 2013	SCCT	One Pratt & Whitney aeroderivative combustion turbine	60	$55 M	$917
Basin Electric Power Cooperative	Pioneer Generation Station Phase I (Williston, ND)	COD Summer 2013	SCCT	One General Electric LM 6000 combustion turbine generator	45	$64 M	$1,422
Basin Electric Power Cooperative	Pioneer Generation Station Phase II (Williston, ND)	COD 2014	SCCT	Two General Electric LM 6000 combustion turbine generators	90	$102 M	$1,133

NorthWestern Energy
2013 Energy Supply and Procurement Plan - Resource Options

	Leading Edge Technologies	In 2011 Preferred Portfolios	Proposed for Inclusion in 2013 Portfolios
Baseload			
Combined Cycle		Yes	Yes
Combined Cycle w/ CCS	Yes		
Gas Combined Heat & Power			Yes
Supercritical Coal	Yes		
IGCC no CCS	Yes		
IGCC with CCS	Yes		
Intermediate/Peaking			
Aeroderivative Gas Turbine		Yes	Yes
Frame Gas Turbine			Yes
Reciprocating Engine			Yes
Renewable & Other			
Distributed Generation (Rooftop Solar)			??
Waste Water Treatment			
Biomass Wood products			
Solar PV		Yes	Yes
Geothermal			
Landfill Gas		Yes	
Small Hydro		Yes	
Wind		Yes	Yes
Storage Devices			
Battery Storage			
Pump Storage		Yes	

Combustion Turbine Flexibility

Presentation to: NorthWestern Energy ETAC

June 6, 2013

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Why Does NWE Need Flexible Resources?

- Variations in load (within hour flexible capacity)
- Hour-to-hour ramp (10 minutes before to 10 minutes after the hour) to reflect schedule changes
- Forced outage response
- Variable Energy Resource (VER) following – primarily wind

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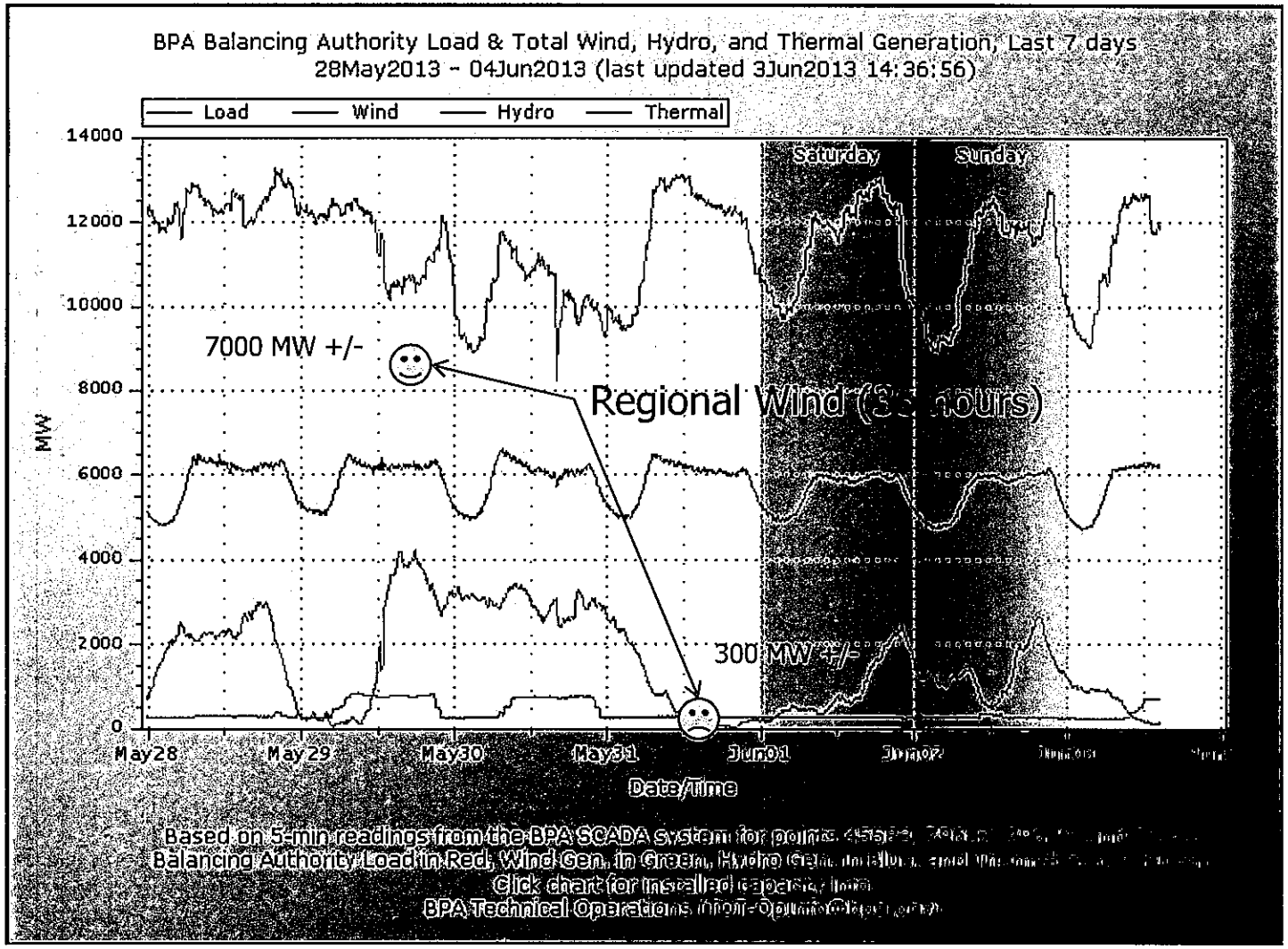
BPA Balancing Authority Load & Total Wind, Hydro, and Thermal Generation, Last 7 days
28May2013 - 04Jun2013 (last updated 3Jun2013 14:36:56)
Load
Wind
Hydro
Thermal
14000
12000
10000
8000
6000
4000
2000
0
MW
Saturday
Sunday
7000 MW +/-
Regional Wind (3
hours)
300 MW +/-
May28
May29
May30
May31
Jun01
Date/Time
Based on 5-min readings from the BPA SCADA system for points
Balancing Authority Load in Red, Wind Gen. in Green, Hydro
Click chart for installed capacity, info
BPA Technical Operations

Northwest Resource Flexibility

- Prior to 2003, NW IOUs (PacifiCorp, PGE, PSE, Avista, Idaho Power) enjoyed adequate resource flexibility from Mid C projects and/or utility-owned hydro resources
- BPA, BC Hydro, Mid C PUDs, Seattle, Tacoma operate hydro resources with significant flexibility – second-to-second, daily, seasonal
- The wind revolution and expiry of Mid C contracts (starting in 2004 with Priest Rapids) changed the regional flexibility landscape – PacifiCorp and PGE joined NWE as hydro flexibility "have-nots"

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Role of Gas Resources to Meet Flexibility Needs

- PGE, PacifiCorp, NWE, and (to a lesser extent) PSE use gas-fired generation to follow load and resource deviations
- Maintaining load resource balance can be particularly difficult in spring and over winter peak – may need to run gas out-of-merit for regulation margin
- Entities with surplus hydro flexibility (large publics, BC Hydro/Powerex) generally make more money from load factoring (LLH to HLH) than providing regulation service

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Types of Open Cycle Gas Turbines

- Frame SCCTs - Primarily capacity (large/fast w/controls)
  - GE 7EA, GE 7FA, Siemens 501G, etc.
  - 85-350 MW
  - Heat Rate = 9400-11,400 Btu/kWh – rarely dispatch (under 2% of hours)
- Reciprocating Engines - Primarily flexibility (small/fast)
  - 9-20 MW
  - Wärtsilä, Caterpillar (Basin Creek)
  - Heat Rate = 8500-9000 Btu/kWh – higher variable O&M limits dispatch
- Aero derivative SCCTs - Capacity and flexibility (fast)
  - GE LM6000 (Highwood), GE LS100, P&W FT-8 (DGGS)
  - 10-105 MW
  - Heat Rate = 8700-9500 Btu/kWh – infrequent dispatch (under 5% of hours)

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Open Cycle Turbine Dispatch

- Purchase spot market natural gas
- Infrequent dispatch complicates gas pipeline and transmission strategy – Firm transport way too expensive, but interruptible may be interrupted or reduced over winter peak
  - Avista Rathdrum – California storage and exchange via GTN
  - Back-up fuel (DGGS)
- Smaller unit size and flat HR curve may make reciprocating engines a better fit for flexibility requirements than other SCCT technologies
- Infrequent CT dispatch increases start-up forced outage risk

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Combined Cycle CT Basics

- CCCT utilizes two turbine generator sets, usually with separate shaft for each T-G:
  - Gas-turbine generator (GE Frame 7, MHI, or Siemens) – thermal energy from fuel combustion directly spins the turbine
  - Steam-turbine generator – uses heat energy from gas-turbine exhaust to create steam to spin a second turbine
- Add additional combustion capability after combustion turbine to increase steam-turbine output (duct-firing)

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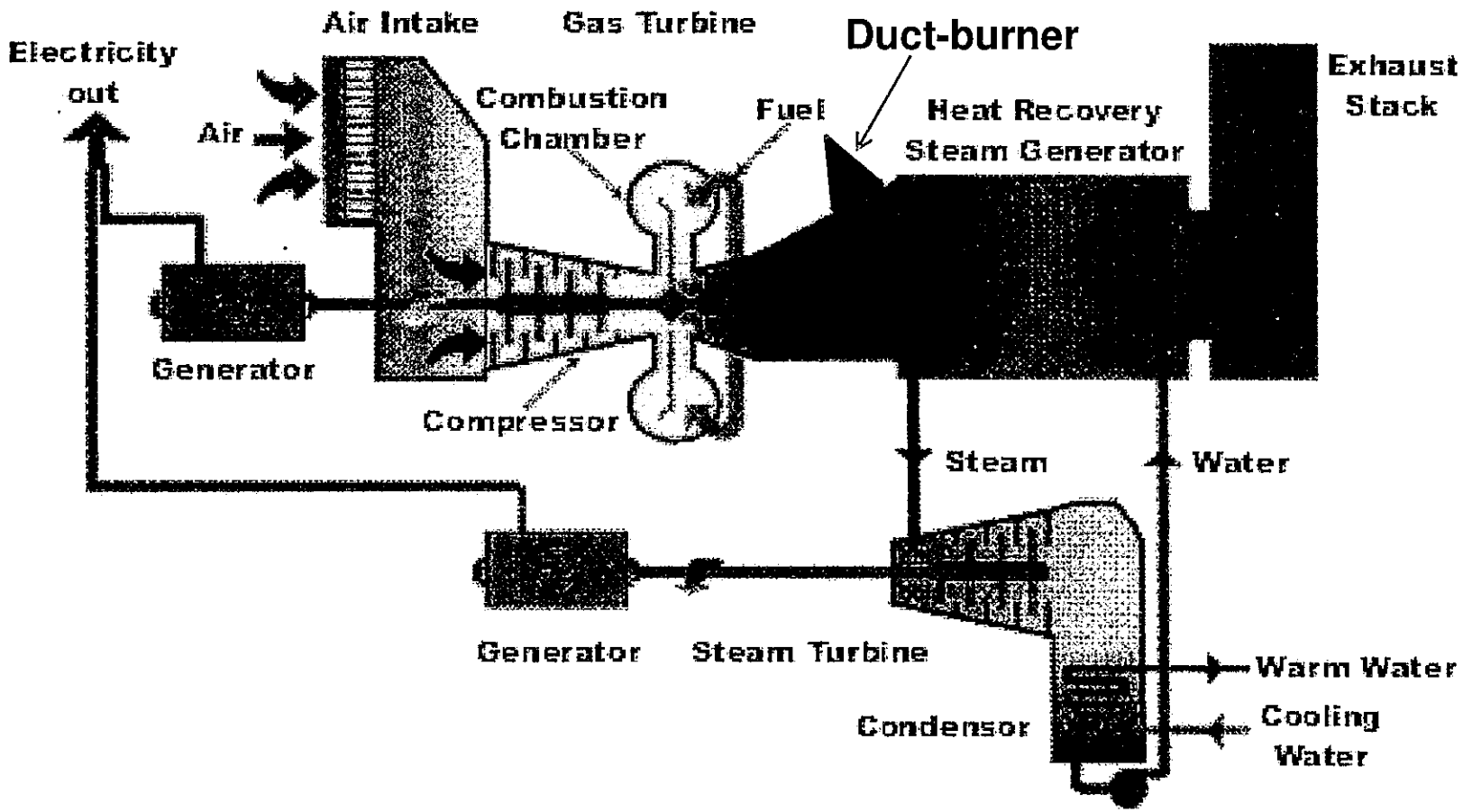
How a Combined Cycle Plant works



CCCT Math

- Large gas turbines have a "heat rate" under 7000 Btu/kWh - describes the conversion of thermal energy into electrical energy.
- Natural gas generally priced in $/MMBtu
- Incremental cost of production =

  Heat Rate/1000 x (Gas Price + Variable Transportation) x (1+ End Use Gas Tax Rate) + Variable O&M
- Depending on location of unit, may need to factor incremental transmission and losses into the calculation

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CCCT Incremental Cost Example

Heat Rate = 7000 Btu/kWh

Gas Price = $4/MMBtu

Variable Gas Transportation = $.10/MMBtu

WA Gas Tax Rate = .038 (allows me to make a point)

Variable O&M = $3.5/MWH

Incremental Cost = (7000 Btu/kwh) /1000 x ($4/MMBtu +$.10/MMBtu) x (1 + .038) + $3.5/MWH = $33.3/MWH

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But CCCT Dispatch Decisions Rarely Straight-forward

- NW CCCT fleet usually sets daily market-clearing price – wind and hydro push CCCTs in/out of the money
- CCCTs often economic HLH but uneconomic LLH - $1.5/MWH in-the-money HLH, -13.0/MWH LLH on 6/1/13
- Start-up requires multi-hour ramp-up/ramp-down – quick start package can shorten the ramp-up
- Maintenance contracts charge for starts after some maximum (around 50/yr) - $3000-$5000/start
- Best CCCT heat rate at full load
  - Heat rate increases 1% for every 5% of output reduction between 80% and 100% of rated capacity
  - Heat rate increases 2.7% for every 5% of output reduction thereafter to maximum turn-down of 50%

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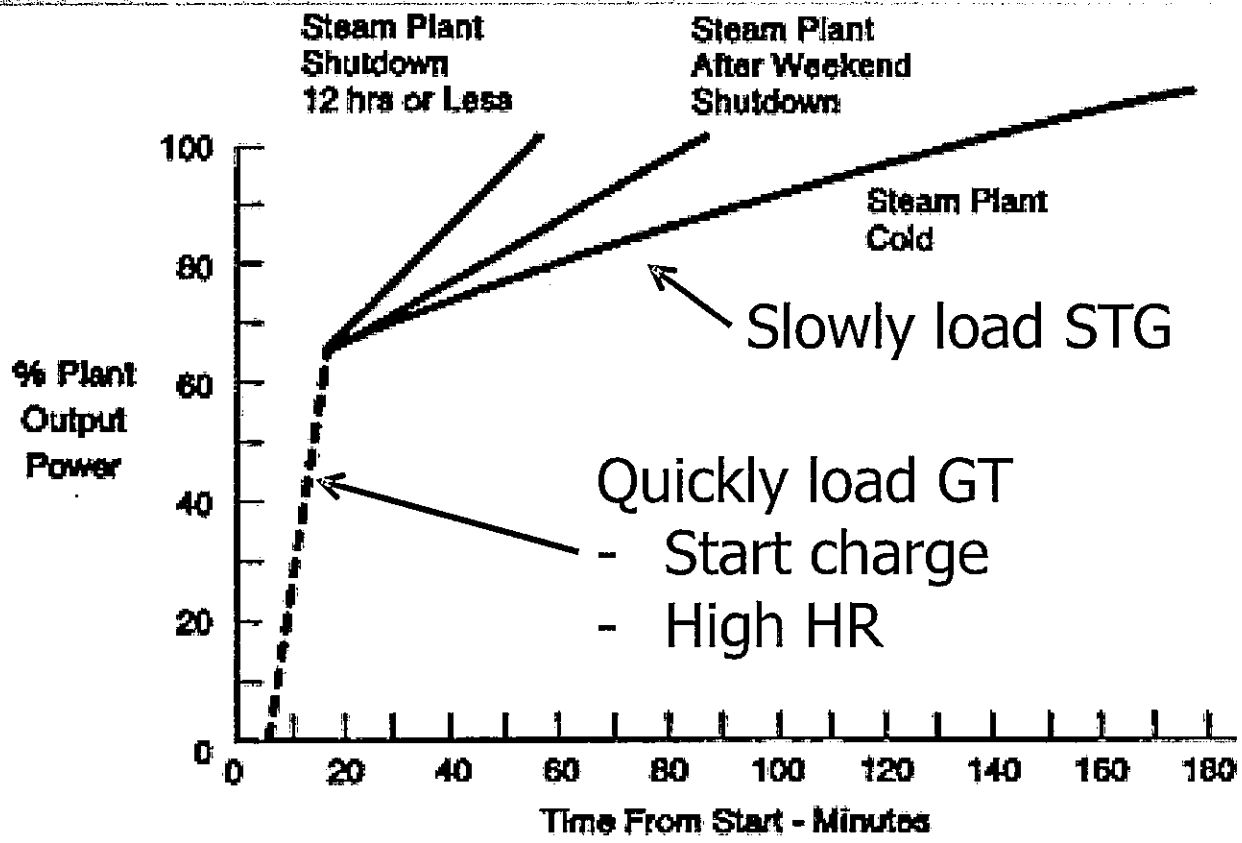
CCCT Ramp (GE Product)



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GE Part Load Performance

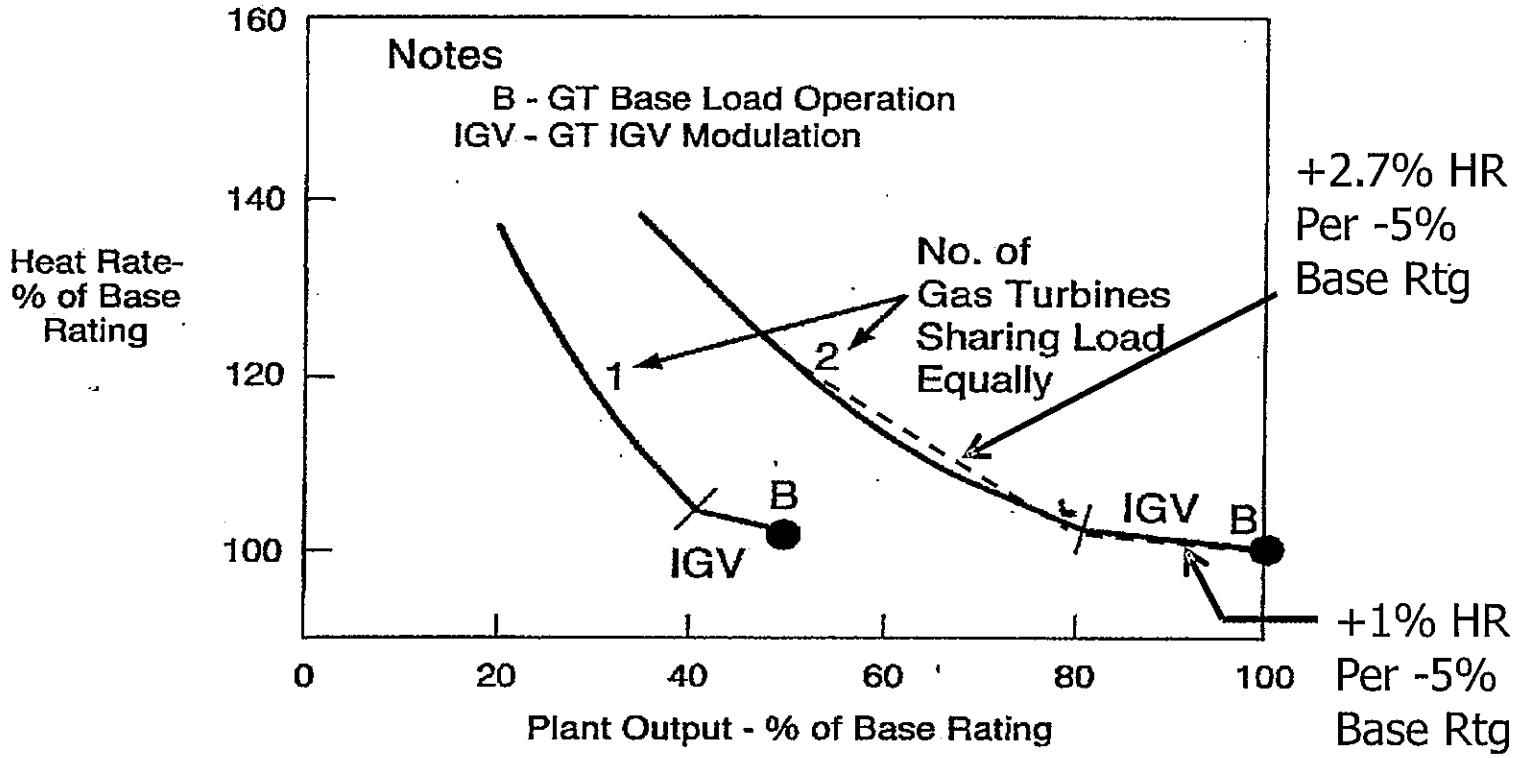

Figure 35. STAG 200 part-load performance

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CCCT Part-load Performance + LM6000

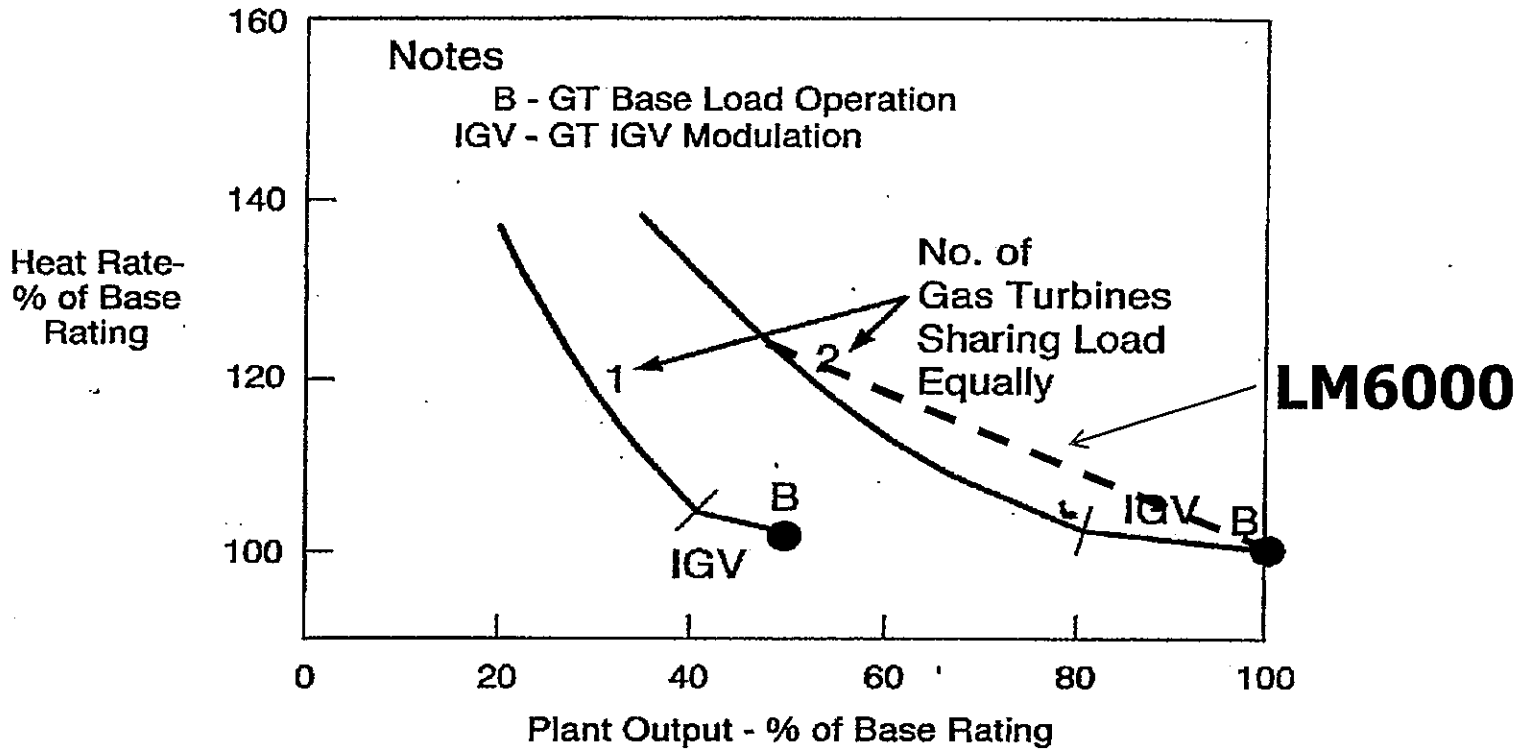

Figure 35. STAG 200 part-load performance

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But Wait, There's More

- Different schedule for gas day (9 AM – 9 AM PPT/MPT 8 AM – 8 AM) versus electric day (midnight to midnight) introduces additional uncertainty on CCCT economics
- Dispatching CCCT up/down to minimize electric imbalance charges could cause imposition of pipeline imbalance charges
- Location on transmission system could limit ability to dispatch on some hours

Note the number of discontinuities and uncertainties inherent in CCCT dispatch decisions!

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CCCT Duct-firing

- Standard GE Frame 7FA CCCT GT-STG package includes 22 MW of duct-firing – could be as much as 60 MW for a 1x1 CCCT configuration
- Duct-firing looks like a quick-start SCCT with 9400 Btu/kWh HR
- Duct-burner start and ramp to full output takes about 10 minutes due to need to have plant operator configure equipment
- On the ragged-edge of fast enough to use for spinning reserve.

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And Did I Mention Hedging?

- Once you sign the confirm to purchase forward gas, the unit price you paid has no bearing on dispatch decisions
- However, purchasing gas in the forward market at a price well above the ultimate market price will attract attention, and
- Not purchasing gas in the forward market at a price that turns out to be well below the ultimate market price will attract attention
- Depending on hydro conditions, load growth, coal/nuclear performance, etc, a CCCT could dispatch on as few as 30% of the hours in a year and as many as 80% of the hours in a year.

Regardless of hedging strategy deployed, a CCCT operator needs good access to liquid natural gas and electric market hubs and/or suppliers to sell excess and cover deficits

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Modeling Implications

- Hard to predict CT actual operation with a dispatch model (requires perfect knowledge)
- Many examples of out-of-merit dispatch – aware of one entity that won't turn CCCT on unless in the money on a multi-week basis, then doesn't adjust output until market indicates unit uneconomic on a multi-week basis
- Hydro flexibility often used to keep CCCTs either just in or just out of the money – some dispatch models handle hydro complexity better than others

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Integrated Uncertainty

- NWE Standards of Conduct limit ability of NWE Transmission to coordinate flexibility needs of the BAA with NWE Supply
- DGGS provides much of NWE's BAA balancing needs, with Shell Trading available to buy/sell real-time to "recenter" DGGS – NWE Supply currently receives no information on DGGS operation
- NWE Transmission called NWE Supply for Basin Creek support during DGGS outage as an emergency measure
- NWE would need to change current model for provision of balancing resources to fully utilize flexibility of Supply-controlled natural gas generation resources and to minimize NWE overall expense for natural gas

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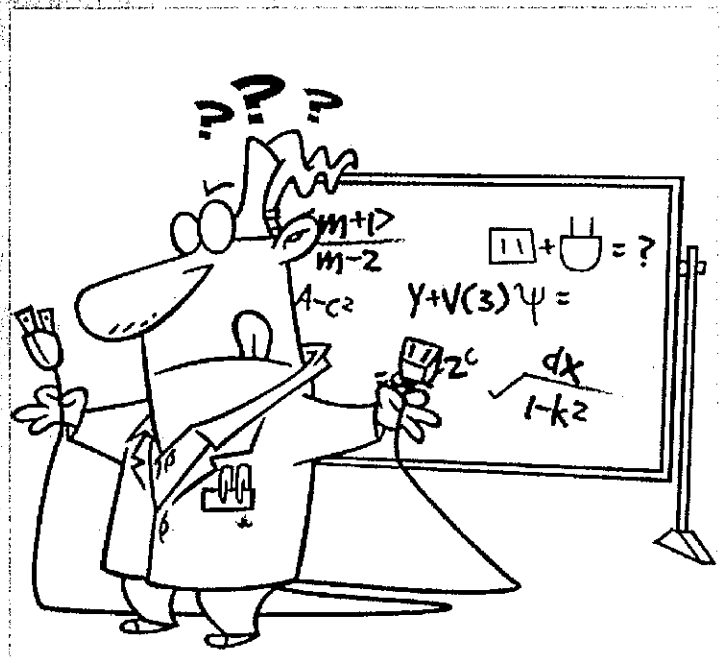
Final Points

CCCT Operation? Why, yes, it is rocket science!



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Lands Energy CONSULTING

Stephen V. Fisher

2017 Linville Drive
Wenatchee, WA 98801
www.landsenergy.com

(509) 888-0976
Cell: (509) 669-5101
Fax: (509) 888-0988
sfisher@landsenergy.com

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ETAC Meeting Agenda

NorthWestern Energy
General Office Auditorium (downstairs)
40 East Broadway

Wednesday July 24, 2013 – 9:00 AM

Conference Call-In: 877 820-7831 (Participant Code): 555256

Note: The conference call will not be used during the natural gas DSM bidder presentations

Agenda:

9:00 - 10:30 Cadmus Natural Gas DSM Resource Assessment Presentation

10:30 - 12:00 Nexant Natural Gas DSM Resource Assessment Presentation

12:00 - 1:00 Lunch (provided)

Afternoon:

Overview of Ascend Analytics – Gary Dorris to host web presentation

2013 Resource Procurement Plan inputs discussion-NWE

Capacity Planning & Resource Adequacy discussion – Steve Fischer

Meeting Summary
NorthWestern Energy Electricity Technical Advisory Committee
July 24, 2013

Attendance
Those participating in or attending the Energy Electricity Technical Advisory Committee (ETAC) meeting included:

Name	Organization
Thomas M. Power	District XI Human Resource Council
Diego Rivas	NW Energy Coalition
Brian Spangler	Montana Department of Environmental Quality (DEQ)
Kyla Maki	Montana Environmental Information Center (MEIC)
Chuck Magraw	Natural Resources Defense Council
Todd Guldseth	NorthWestern Energy (NWE)
Frank Bennett	NWE
Bill Thomas	NWE
Dave Fine	NWE
David Bausch	NWE
Danie Williams	NWE
Kevin Markovich	NWE
Patrick Barkey	University of Montana - Bureau of Business and Economic Research
Jamie Stamatson	MCC
Paul Schultz	Montana Consumer Counsel (MCC)
Will Rosquist	MPSC (via telephone)
Hossein Haeri	Cadmus
Travis Walker	Cadmus
Steve Fisher	Lands Energy
Lynn Roy	Nexant
Patrick Burns	Nexant

Agenda
- Regulatory Support Services
  - Cadmus Natural Gas DSM Resource Assessment Presentation
  - Nexant Natural Gas DSM Resource Assessment Presentation
- Energy Supply
  - Ascend Analytics
    - 2013 Resource Procurement Plan Inputs Discussion
  - Lands Energy Consulting
    - Capacity Planning & Resource Adequacy Discussion
- Energy Supply
  - 2013 Resource Procurement Plan inputs discussion
    (The inputs discussion was postponed until August 28, 2013 meeting due to lack of time)

Regulatory Support Services

Following a general discussion of Natural Gas DSM Potential Assessment the group had a question and answer session with Cadmus and Nexant.

[Cadmus]

Question – Please restate the NorthWestern project that Cadmus worked on in the past.
Answer – Cadmus completed a comprehensive market study (end use study) for NorthWestern.

Question – Did the earlier study cover natural gas?
Answer – Yes it did.

Question – You referred to electric utilities in your previous work…is that because most of this kind of work has been for electric utilities?
Answer – Through telephone surveys and on-site work, we collected saturations and estimated end-use covered by both electric and natural gas. We revisited the results and would need to update those for today's presentation, however the study is recent. Mid-American, Alliant Energy, Black Hills Power, Louisville Electric, and Puget are utilities that have completed this type of natural gas study.

Question – What has been the market for natural gas studies of this kind?
Answer – There has been more focus on electric. The methods of natural gas studies are the same as electric but natural gas has fewer methods with less complex interactions.

Question – When you go down the funnel from the technical to economical potential, I assume that is based on cost effectiveness, what is your explanation for why customers are not doing more energy conservation if it is cost effective?
Answer – It is an old question. It is observed that customers expect a higher return on economic investments than any other investment. It is at times a mystery. There is a market barrier used as an explanation for the perception of value for utilities working with customers on activity based programs.

Question – If you cannot explain the outcome you actually observe, how can you explain the method and incentives you offer?
Answer – There are studies and then there are evaluations.

Question – Would you agree that the adoption rate is fundamentally based on the customer's decisions? Where is that analysis?
Answer – Yes. There is not much literature on the social science aspect. There are different types of interactions with customers that do take into account activity based measures, for example the EMS, and when it comes to energy use behavior, we assume that utility marketing incentives and the like can increase awareness…and that translates (sometimes) into customer action and participation, and sometimes not.

Question – This goes back to an issue we had on the electric side related to calculating free-

riders and spillover and whether we can accurately calculate them separately. After decades of utility programs, can we accurately measure what the customer would have done absent the utility's DSM programs. I am not sure what the answer to the question of "people not behaving rationally" when it comes to energy saving programs is. In the end the question is what do we know about the effectiveness of utility programs is in changing customer behavior?
Answer – Utilities have fundamentally transformed the market through their presence in the market with DSM programs for many years. I will send the citation/article for "The Trouble with Free-riders" written for Utilities Fortnightly that relates to this subject that people want to answer that they look green or not answer yes, because they received a subsidy from the utility.

[Nexant]

Question – Is turnover rate a fixed rate?
Answer – Yes, to keep track of stock and the number of premises.

Question – Is there natural gas displacing electricity?
Answer – That is treated as new construction by adding load returning back into our market. Customers are likely to make the decision to switch fuel based on the cost of natural gas and not utility subsidies.

Question – Is there a concern with focusing on the short-term price movements, or if a utility should look longer term because of starting and stopping programs…and what timeframe of gas prices will you look at?
Answer – That depends on what NorthWestern's questions are if any, we would go back to our team for their expertise. This is partially a utilities call.

Question – Do utilities come up with avoided costs?
Answer – If a standard is set for the underlying gas cost base case and that would follow high regulatory scrutiny.

Question – Does it matter how utilities demand projection is looked at? It has been a long time since the econometric model has been looked at because of small demand and growth. Do you just need to understand?
Answer – We would need to add more assumptions for the forecast for load versus demand. We are accustomed to looking at different utilities projections. We will document any assumptions made by Nexant.

Energy Supply
Ascend Analytics

An overview of Ascend and its software was provided by Gary Dorris (Ascend CEO) via web presentation. There will be a focus on uncertainty within the resource planning effort. The use of RRV or risk reduction value and how it will be defined within the modeling software was explained. This concept incorporates fuel, reliability, markets, and uncertainty for the physical and environmental areas. Discussion was based on uncertainty with deterministic (formerly referred to as intrinsic in prior NWE planning work) and stochastic views that use a probabilistic determinant for modeling. This view stressed capturing the results of all scenarios rather than

being limited to outcomes within the range defined by 1 to 2 standard deviations. A formulaic expression to calculate the cost of a much wider area of risk was presented followed by a question and answer session.

Question – In your argument on risk premium calculations, can you provide a rational as to why the calculation is the change in the shape of the distribution?
Answer – Risk premiums are similar to stock and insurance actuarial calculations. Evaluating the efficiency frontier is ok but it is difficult to determine the best or preferred point on the frontier simply through observation. Ascend incorporates a numerical expression of risk (the risk premium) to show a change to the shape of distribution of stochastic outcomes.

Statement – The RPP will incorporate the Ascend weather, market, and renewable variability through their PowerSimm approach which is a different approach from the GenTrader modeling. NorthWestern will be migrating away from stochastic models feeding into a stand-alone efficiency frontier. The Ascend model will incorporate risk, mean value, and a probability function to measure preferred portfolios in a mathematical approach rather than an interpretation of a graphical representation of cost and risk.

Question – Doesn't the efficiency frontier have cost and risk?
Answer – Ascend looks at cost over a distribution, not at one point.

Question – How will it address weather?
Answer – Ascend will simulate weather peaks, both high and low, by probability and compare to a benchmark to allow it to fill out the upper and lower tails that will be validated historically. This goes directly to meaningful uncertainty validations of the market over time.

Question – What is ETAC's role in building the plan with Ascend?
Answer – NorthWestern will use Ascend to perform modeling. One of the goals in using the Ascend software is to remove the subjectivity of the efficiency frontier and instead use numerically derived results to directly compare modeling results. We will build common understand of modeling results with ETAC by sharing modeling results and explaining how values were derived using the PowerSimm model capability and add layers along the way through interactions with ETAC to avoid anxiety. We will use risk based planning in a way that is digestible.

Energy Supply
Lands Energy Consulting (Steve Fischer)

Steve Fischer talked about the history of the northwest electric market and his observations of how it has performed. The old focus on energy constrained planning has passed. The region is now a dual peaking (summer/winter) planning area. NorthWestern's capacity situation was analyzed for the 2018 time period to show potential deficits. Recent constrained outages were discussed. It was suggested that NorthWestern merge both the financial and physical into future planning to reliably serve load.

Statement – Regional announcements and speculation about plant closures and permanent mothballing will impact future markets.

Statement – It appears that the summer peaking in the region has about four times the risk of winter peaking.

Statement – NorthWestern is pleased to add Lands regional utility and market experience to our planning efforts.

Question – Is wind now credited with summer capacity but no winter capacity?
Answer – The references were using monthly averages but focusing on just peak days shows no capacity.

Question – Is there any wind to load analysis?
Answer – There was information provided in the electric tracker Docket but the specific analysis for wind was not done.

Next ETAC Meeting

August 28, 2013 was selected as the next meeting date for ETAC. It will be in Butte.

Resource Planning with Uncertainty for NorthWestern Energy

Ascend Analytics

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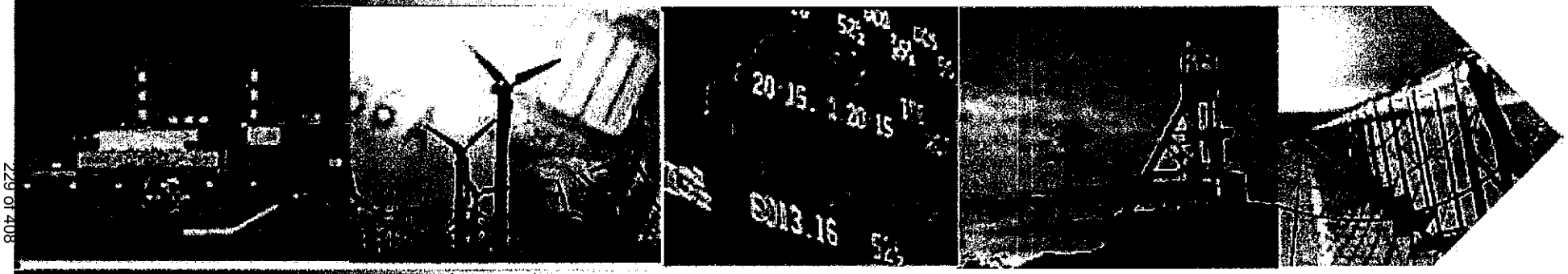


Selection of Optimal Resource Plan for 2013 Resource Procurement Plan

July 24, 2013

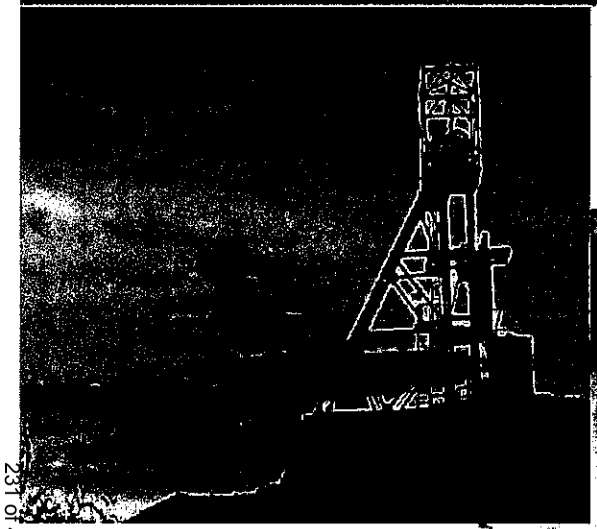
Gary Dorris, Ph.D.
Ascend Analytics, LLC

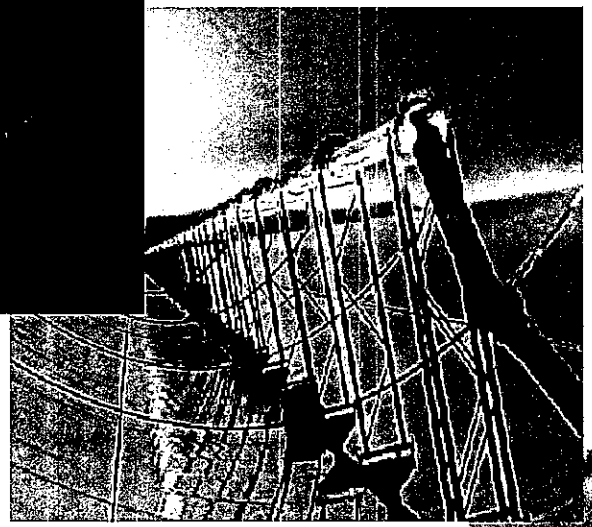
gdorris@ascendanalytics.com
303.415.0311
www.ascendanalytics.com

Outline

- Resource Planning Paradigms and Choices
- Resource Selection
- Best in Breed Resource Selection
- Best in Show Resource Selection
- Risk Reduction Value (RRV) for Renewables

Resource Planning Paradigms and Choices





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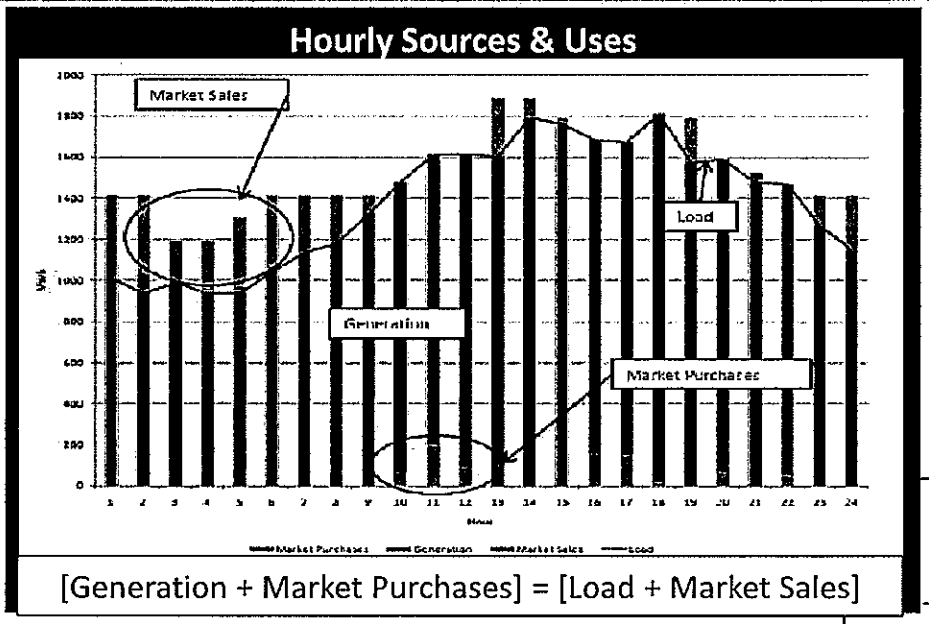
Planning in Transition

- Portfolio perspective
  - Fuel diversity
  - Reliability and intermittent resources
  - Uncertainty in fuel, emissions, and power
- Use of market for fuel and power
- Analyze generation resource options with respect to market dynamics
- Capture new dynamics
  - Weather
    - Load
    - Wind generation
  - Market conditions
    - Forward markets for fuel and power
    - Spot price dynamics
- Resource adequacy
  - Reliable service at cost effective rates
  - Market interactions

Central Tenants of Resource Selection Modeling

- Utilize All Available Information
  - Effectively capture all major elements of uncertainty
    - Markets
    - Physical
    - Environmental
  - Does the decision analysis process meet "include all the available information a reasonable person would use to make a decision"
- Balance Costs and Risks
  - Present value trade-off of capital and variable costs and associated risks
- Integrated Decision Framework
- Monetization of Risk

Economic Resource Dispatch

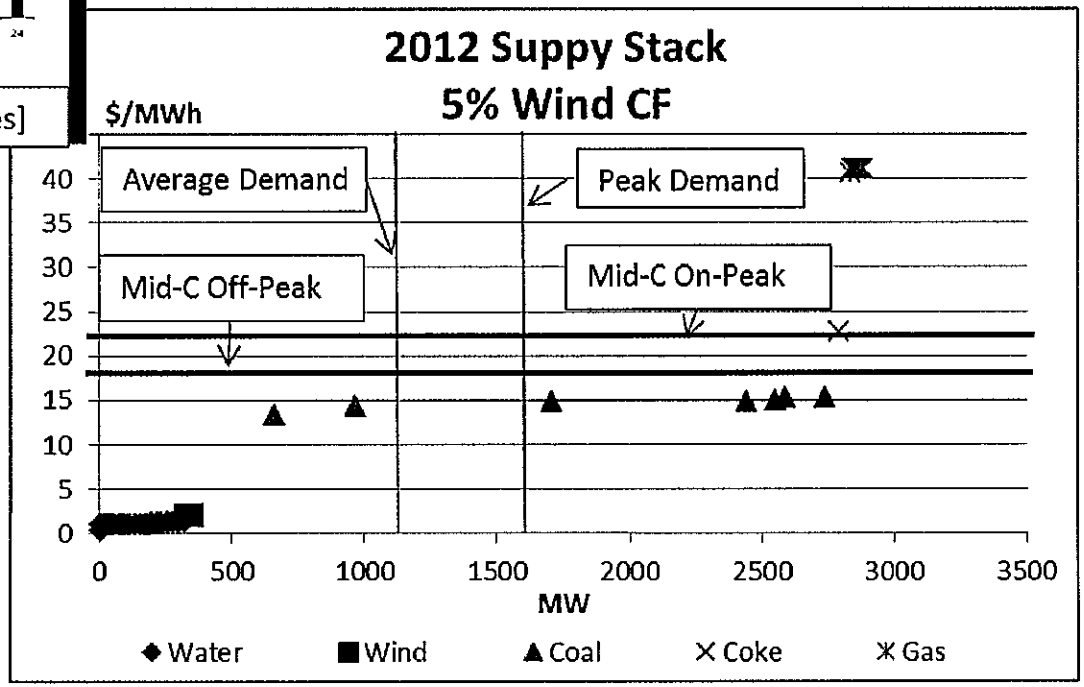


[Generation + Market Purchases] = [Load + Market Sales]

Liquid Market Utilities

- "Economic Dispatch" – Dispatch is determined by generation cost relative to market prices
- NorthWestern is a price taker

- Generation is not used solely to meet load – unit turn on when it is economical to do so relative to market prices
- Account for transmission constraints and costs on imports and exports



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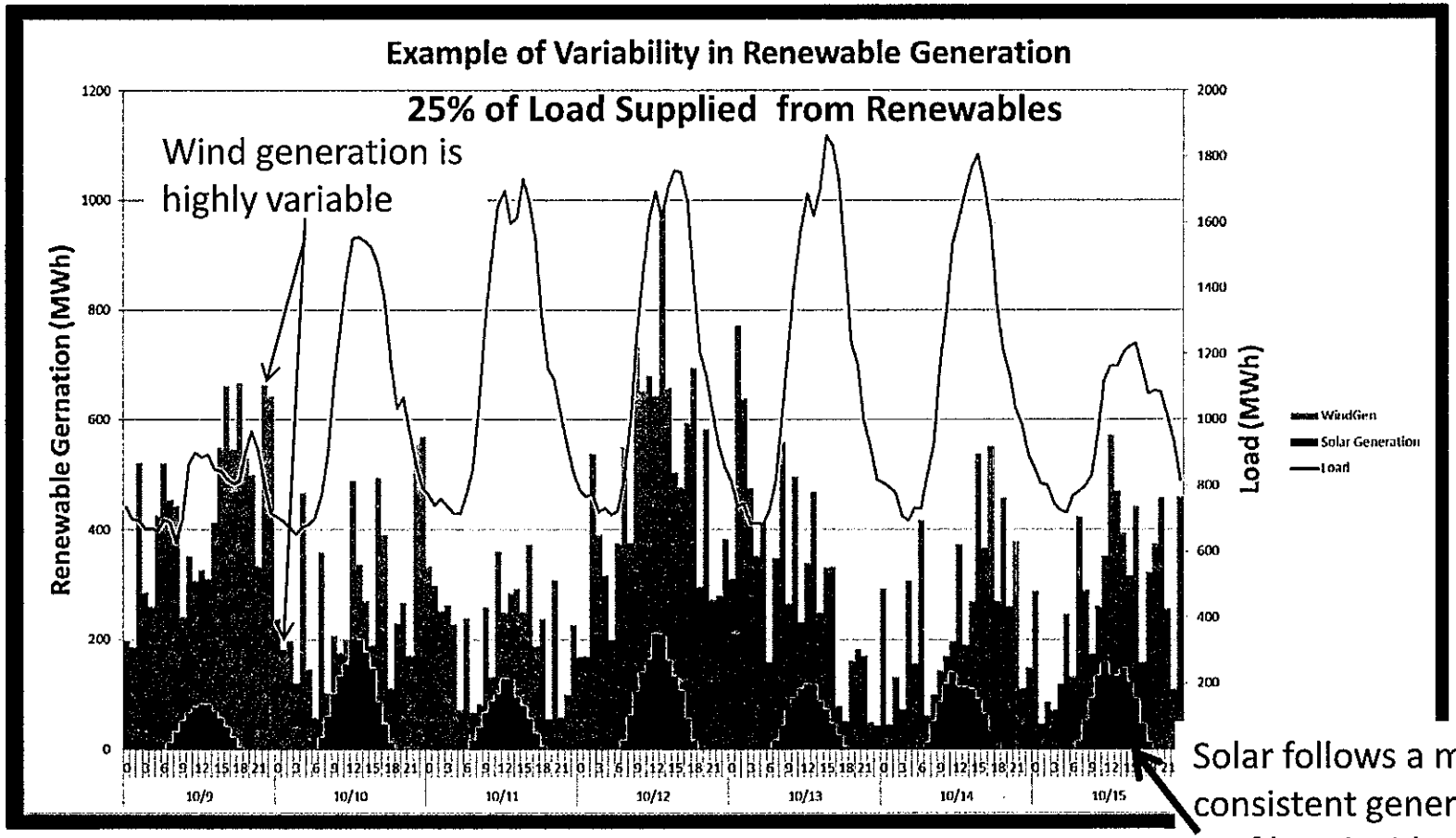
Renewable Portfolio Standard
Ancillary Service Implications

- Perception that increasing RPS creates value for flexible resources
  - Negative power prices
  - Large potential swings in supply→ greater demand for ancillary services and flexibility

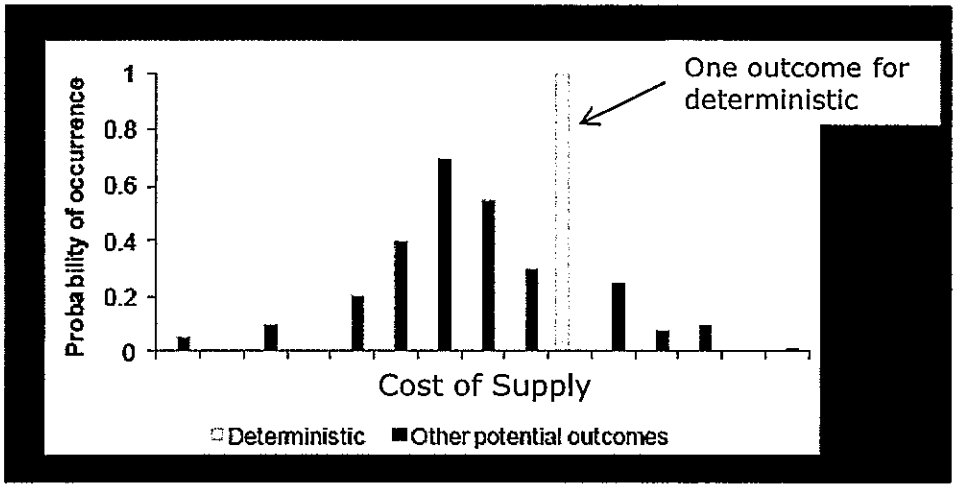


Solar follows a more consistent generation profile coincident with peak load

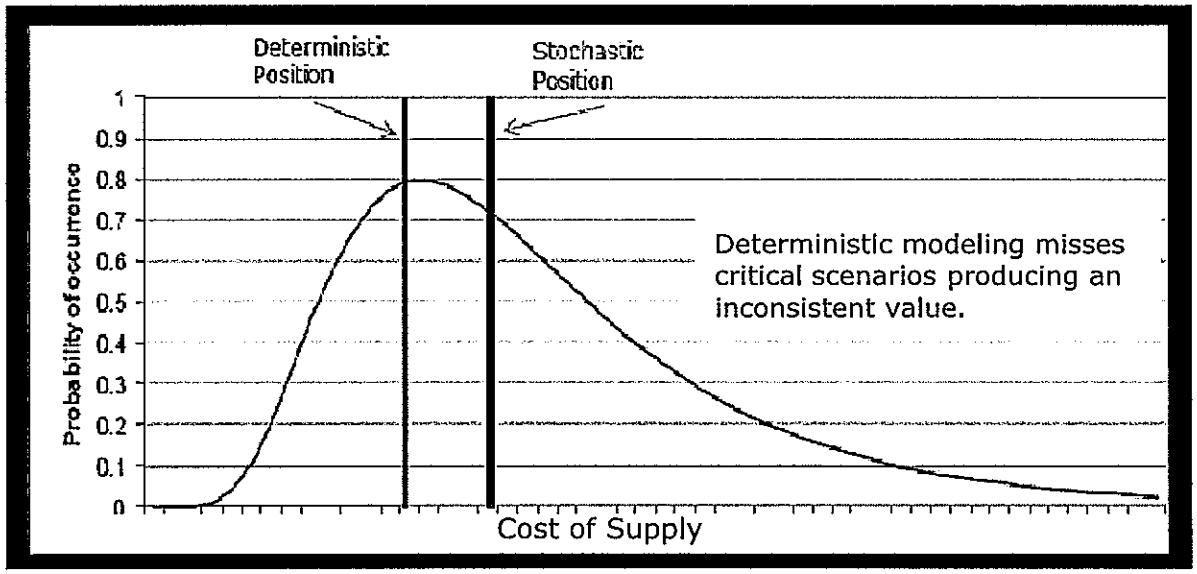
Question: How can Flexible Resource Adequacy address reliability and costs to integrate wind into the portfolio?

Deterministic vs. Stochastic Models

- Heavy dependence on deterministic results with scenarios
  - The likelihood of result is not understood
  - Model inputs are variable and interdependent
  - Inputs probabilistically envelopes future states
  - Simulations consistent with observe patterns



- What's the impact of unused information?
  - Inaccurate forecasting
  - Assessing risk becomes difficult
  - Missing information results in model biases



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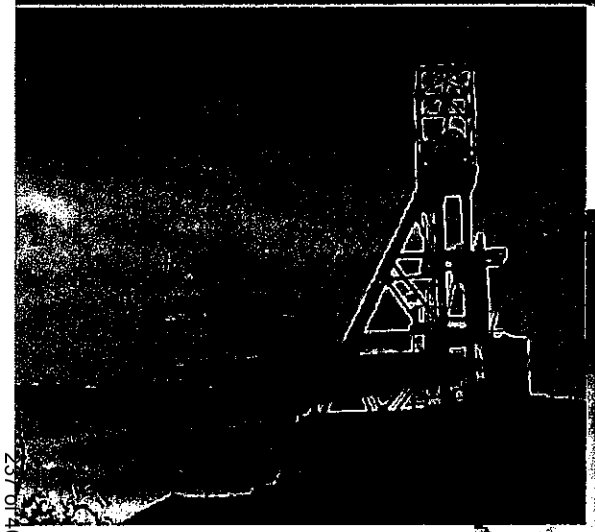
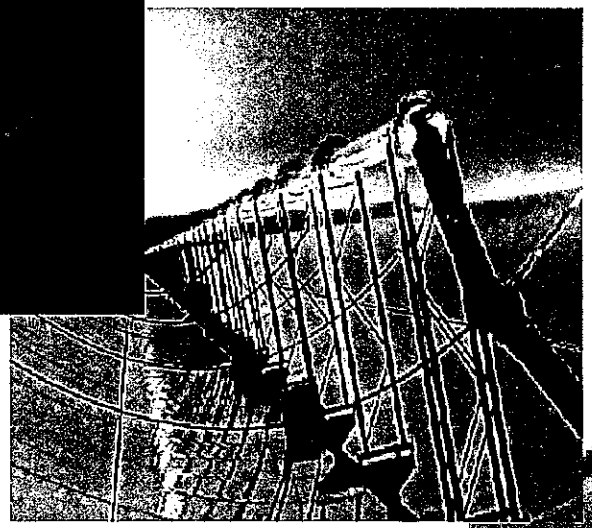
Resource Selection





Ascend Analytics

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Measure of Portfolio Costs

Costs = Net Power Costs (NPC) + Fixed Costs (FC)

- Net Power Costs (NPC)=

  Fuel + Variable O&M+ Purchase Power

  – Wholesale Sales + Hedge Payoffs

- NPC_{fpy}=

  Net Power Cost of portfolio p in year y of future f

  Calculated from dispatch model

- FC_{fpy}=

  Fixed revenue requirement of portfolio p in year y

  Calculated from financial model

- Portfolio Costs (PC)=PV(NPC_{fpy})+PV(FC_{fpy})
- Expected Costs =

  Mean (over all futures) of Present Value (over all years) of Costs

  - *Average Cost of Supply*

Best-In-Breed

Objective:

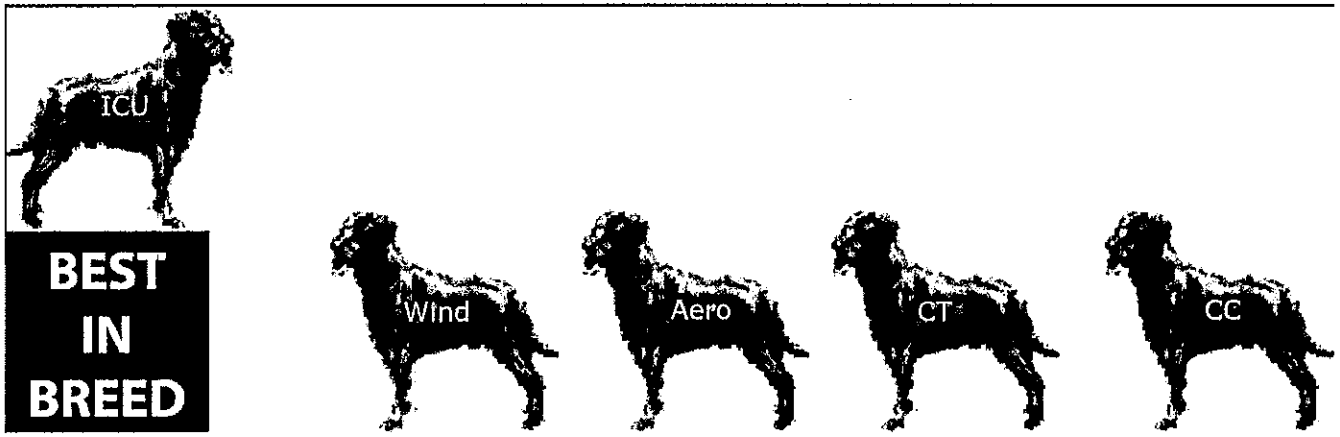
- Find the cheapest capacity expansion plan that satisfies the constraints
  - Cheapest is often defined as the net present value of the revenue requirements

Constraints :

- Renewables, RECs, limits on market sales and purchases,…

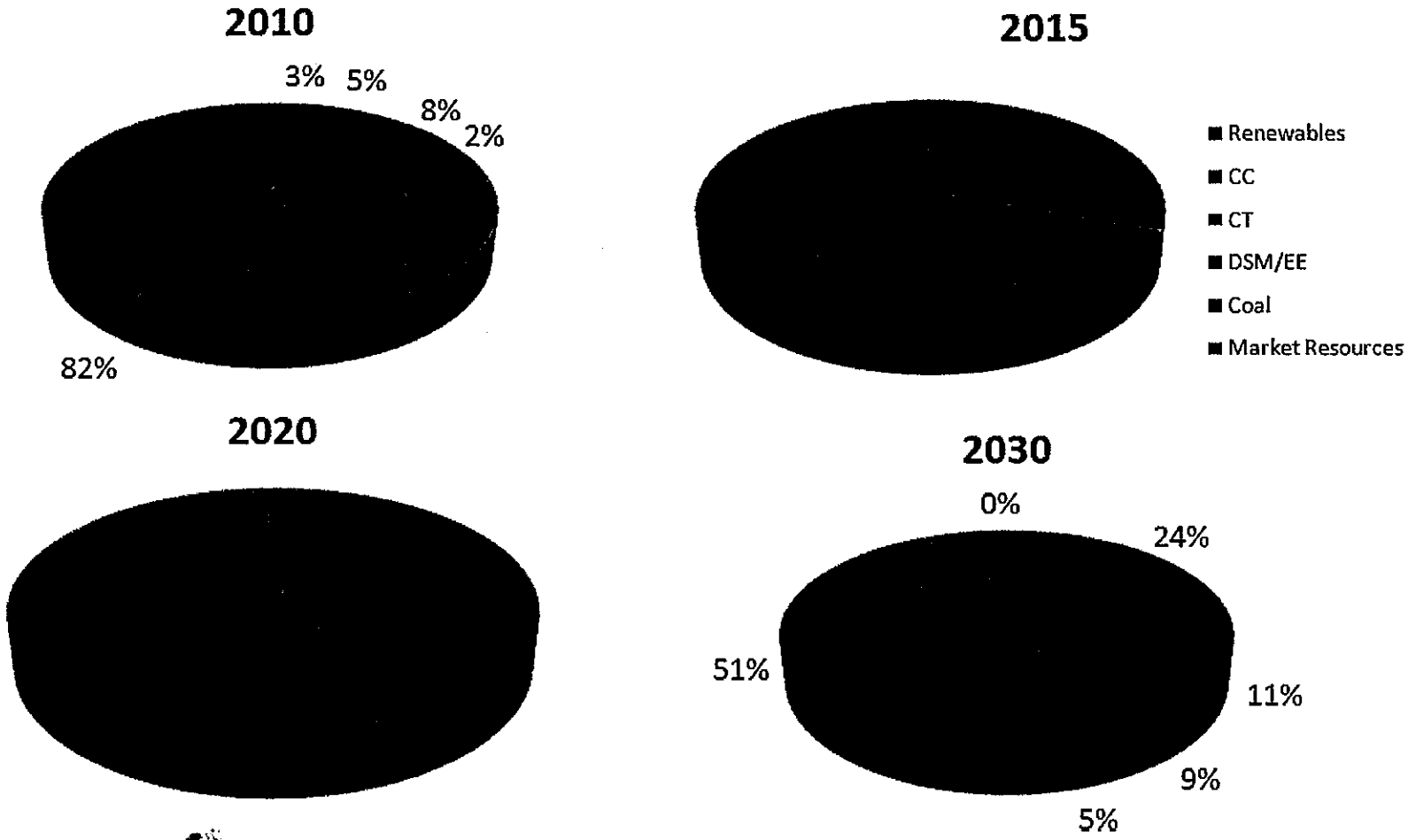
Result

- Optimal capacity expansion of generation resources and conservation options to minimize revenue requirements subject constraints.
- Breed is a dog show analogy referring to the best expansion plan from a deterministic run (single forecast) of simulated weather, load, and prices.



Best in Breed Expansion Plans
Growth of Renewables – 2030

Energy Through Time



PowerSimm™ Result

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Best-In-Breed

Question:

- How robust is the plan under variable conditions?
- Is this the breed for the future?

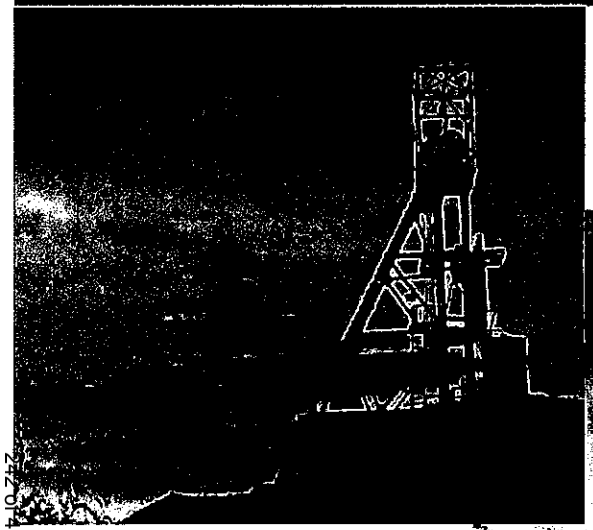
Issues:

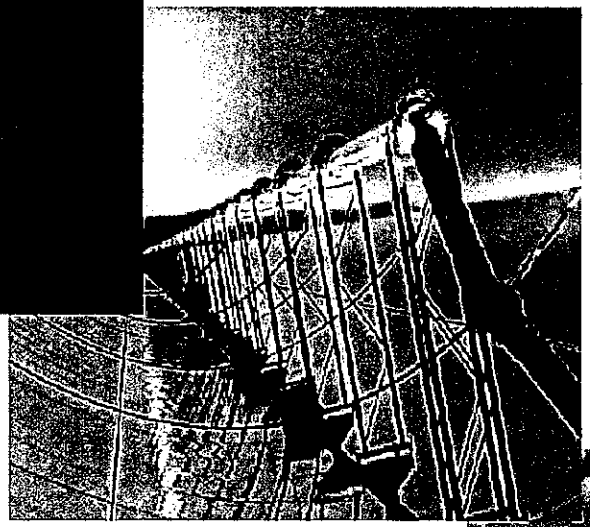
- Risks are unknown? Robustness of portfolio is unknown?
- What happens when gas prices spike up to 10 $/MBtu for six months?....

Limitations of Scenario Analysis:

- Too many views of the world
- No probability weighting to likelihood of outcomes
- Akin to Rorschach Test
  - Study in psychology – every interviewer sees only their preferred plan
- Need to account for uncertainty and probability of future states
- Assimilate broad set of prices, load, unit outages, etc. into the decision analysis → Risk-based decision analysis

Simulation Requirements





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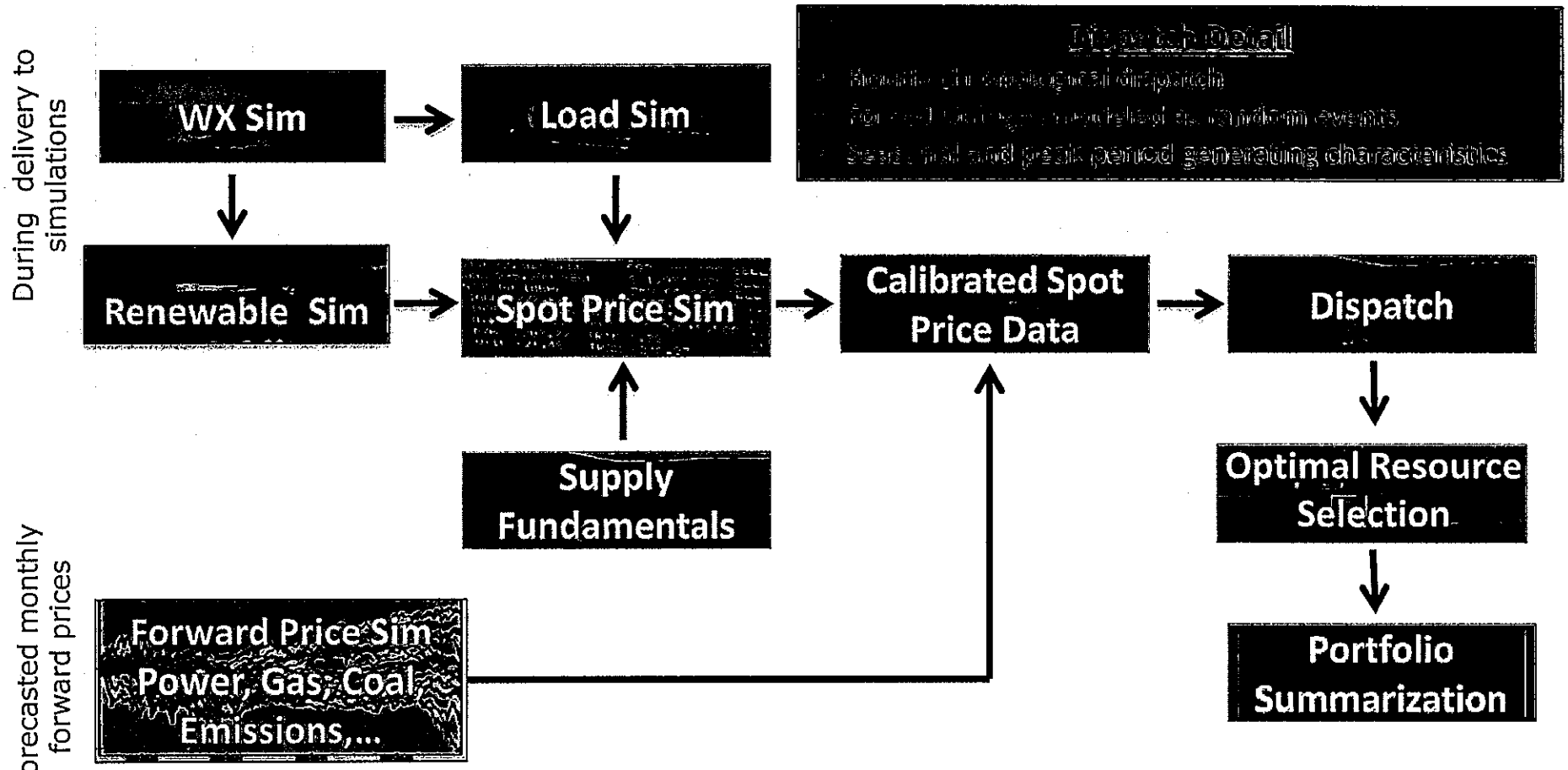
Integrating Physical and Financial Uncertainty



Unified simulation framework reflecting joint financial and physical uncertainty

- Rigorous validation
- Framework to assess Flexible Resource Adequacy (FRA)
- Capture of critical covariate relationships
- Frequency and magnitude of price spikes

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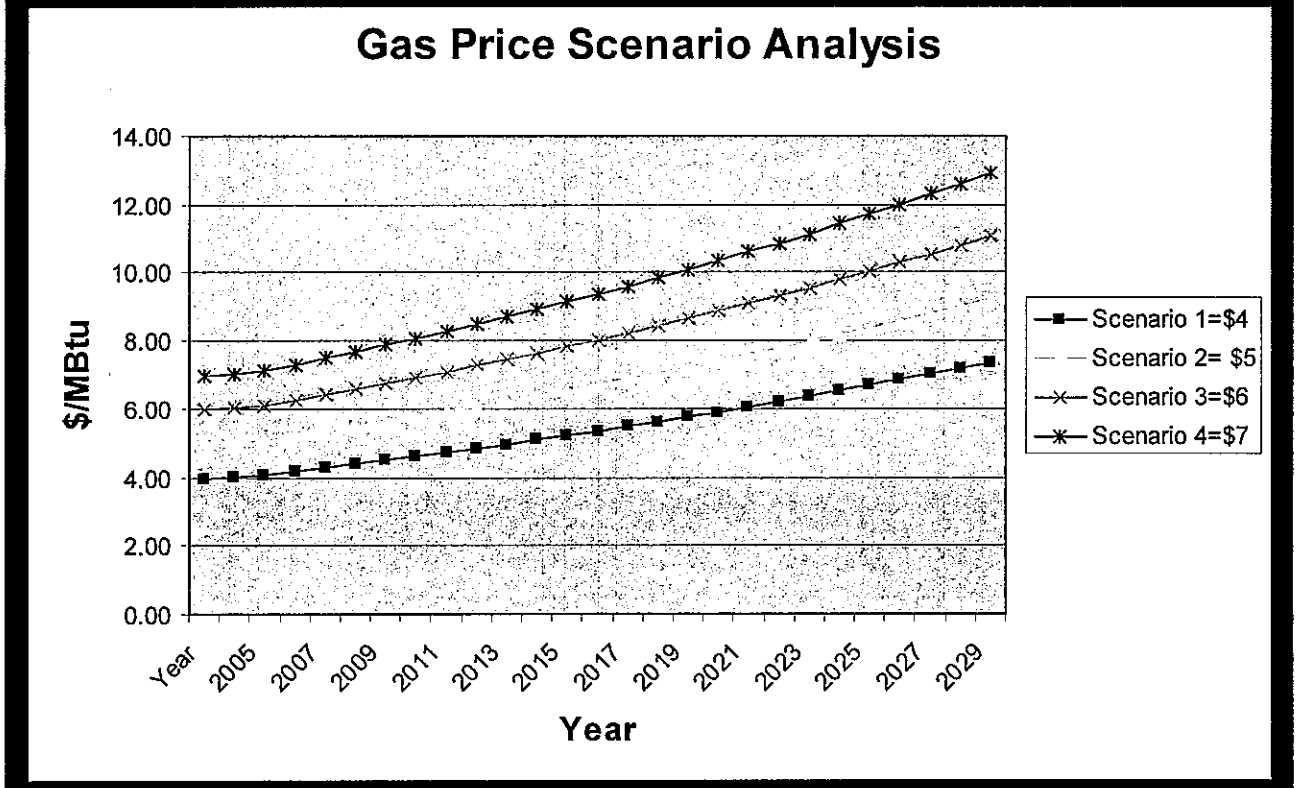
Scenario Analysis

Common Scenarios: High, Med, Low

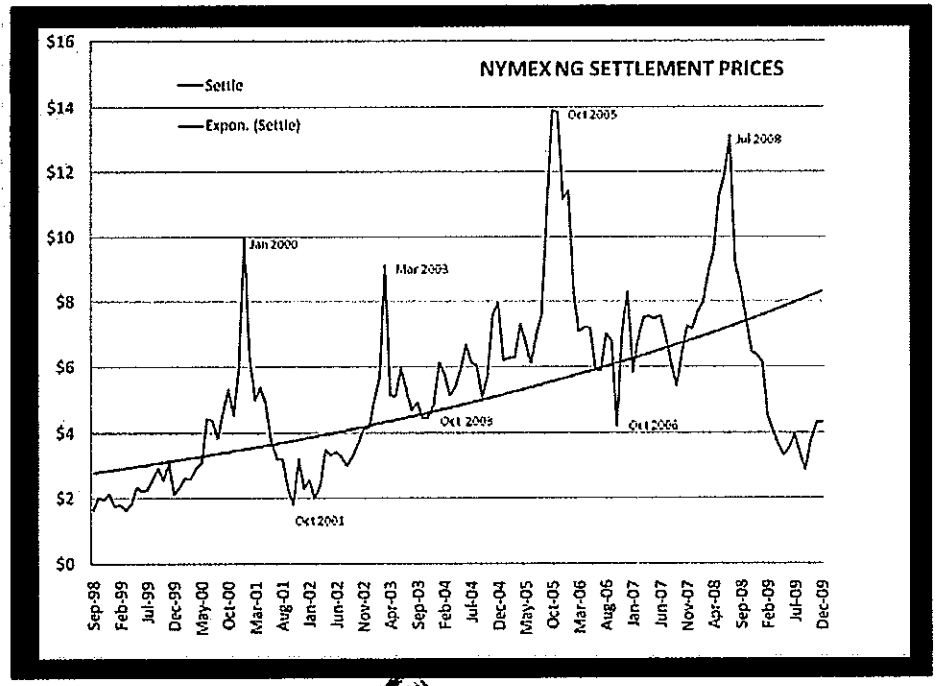


- Which forecast are the best?
- Scenarios with prices monotonically increasing over time.
- Are these prices consistent with observed patterns?
- What's the probability weight of being in scenario 1 or 4?
- Why is the max prix in 2025 less than historical prices observed 25 years prior?
- Can we capture probabilistically future states and a more market consistent pattern of gas prices?

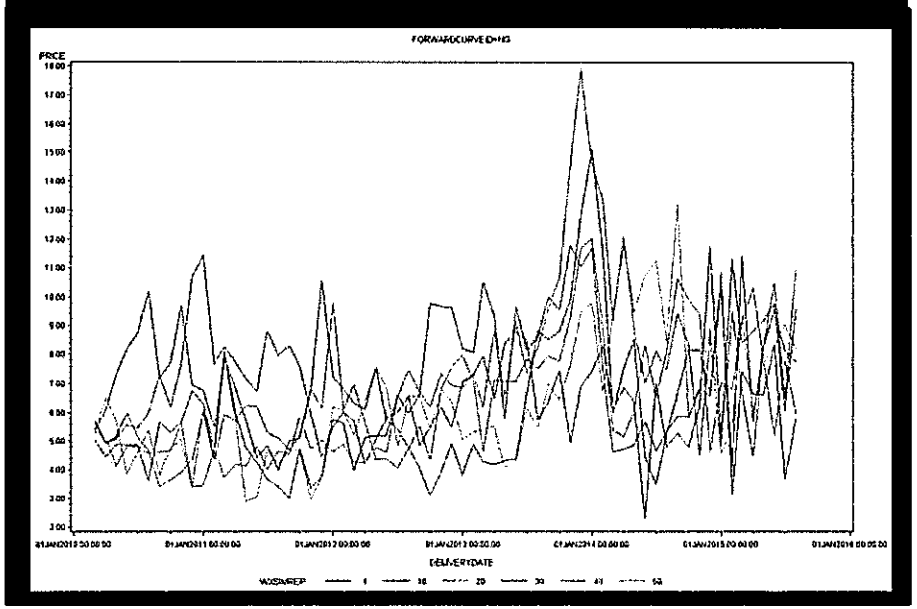
Forward Price Validation History and Simulations: Natural Gas

Simulated forward market prices for Henry Hub

- Large price spikes followed by mean reversion
- 2 to five year cycle
- Large volatility in prices followed by quiescent periods



Forward Price Validation-
Price Paths for Final Evolved Forward Curve Simulation



Historic prompt month prices for Henry Hub

- Large price spikes followed by mean reversion
- 2 to five year cycle
- Large volatility in prices followed by relative quiescent periods

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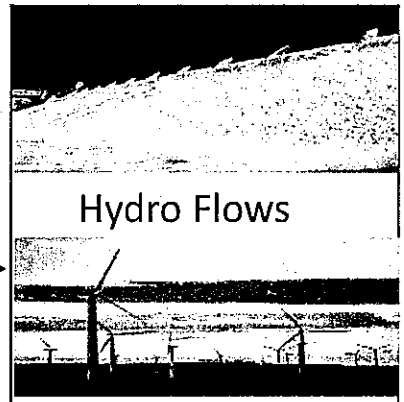
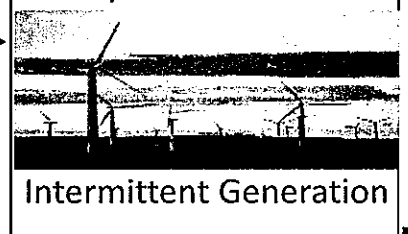
Weather → Hydro Flows → Load → Price Simulations

Weather

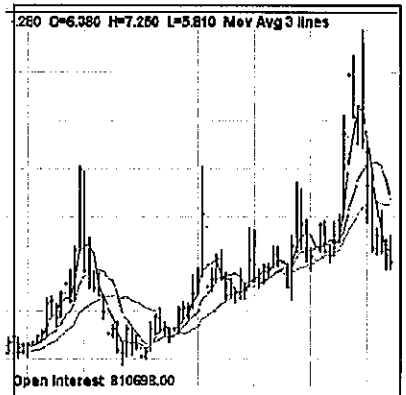


Hydro Flows

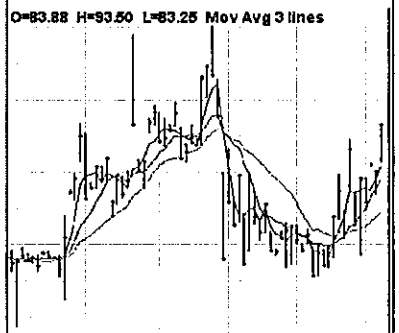


Intermittent Generation

Load



Gas



Electric

Price

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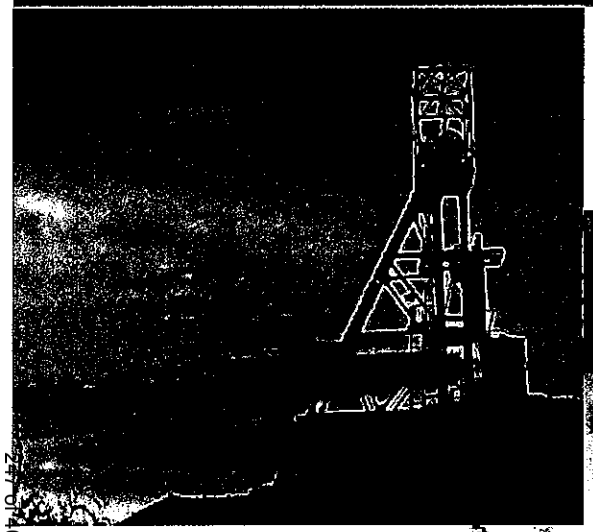
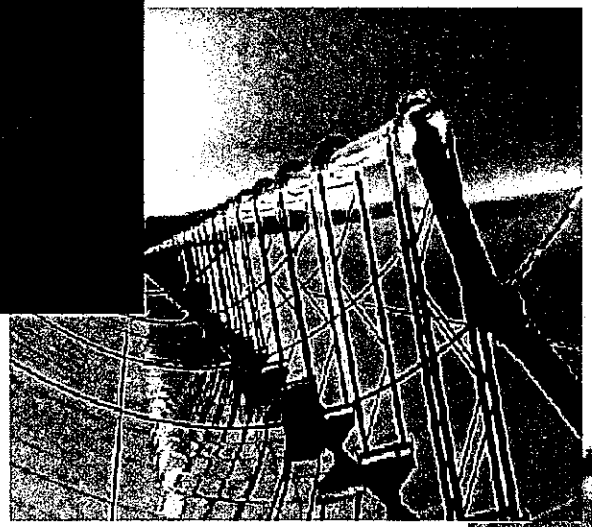
Best in Show





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Components of Uncertainty: Integrating Physical and Financial

Financial

- Fuel Prices
  - Gas (Monthly, Daily)
  - Coal
  - Emission Allowances
    - CO2, SO2, Nox
  - RECs
- Electric Prices
  - Supply Stack
  - Transmission
  - Hydro Levels
  - Load
  - Fuel and Emission Prices
- Interest Rates
- Construction Costs

Physical

- Load
  - Weather
  - Growth
    - Customer Mix
    - Energy Efficiency
- Wind
  - Weather→Load
- Hydro
  - Weather
- Unit Contingencies
  - Construction risk
  - Performance risk
- Transmission

Unified simulation framework reflecting joint financial and physical uncertainty

- Rigorous validation
- Capture of critical covariate relationships
- Frequency and magnitude of price spikes

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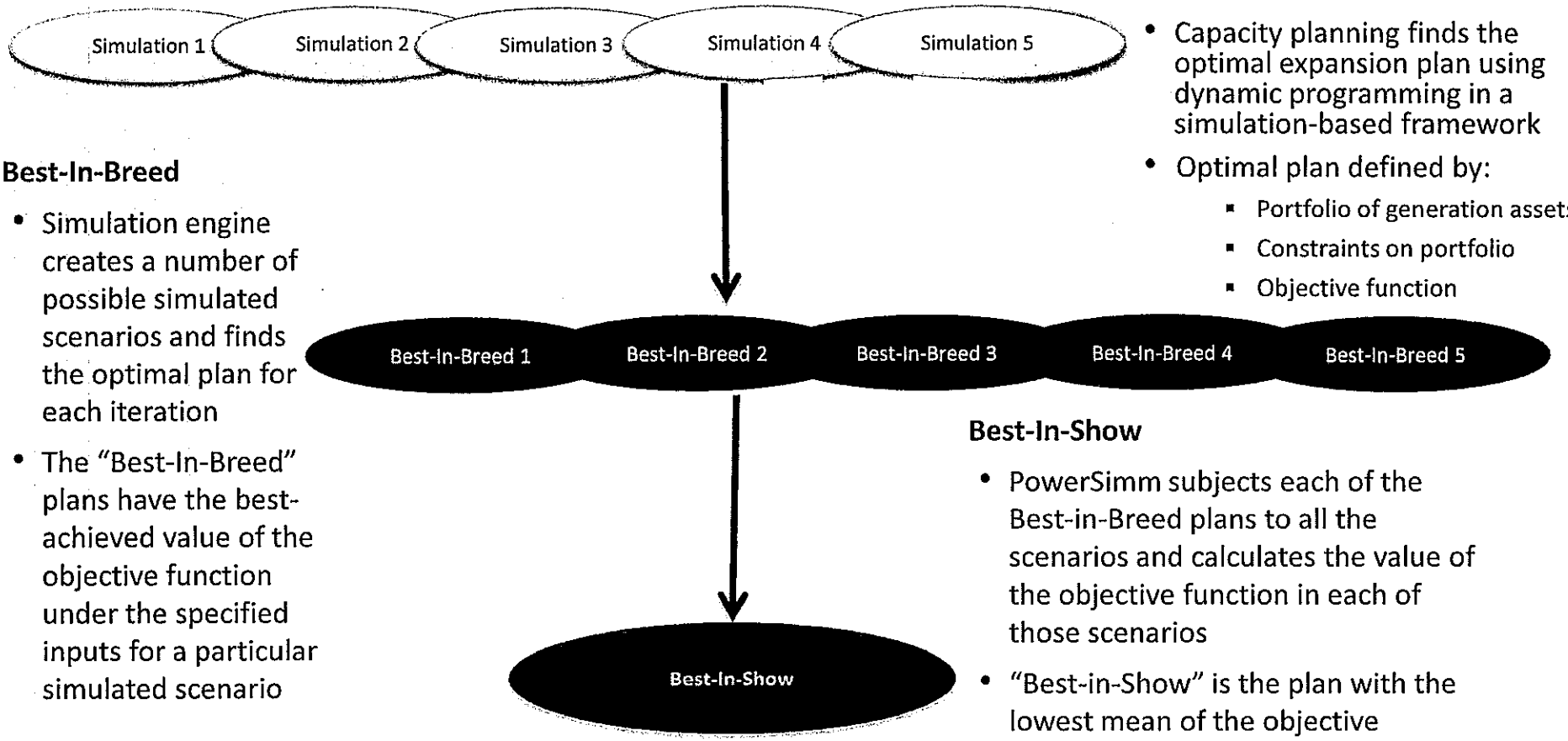
Tools of Supply Planning Model Attributes

Uncertainty Factor	Production Cost Models	Integrated Risk Based Planning Models
Load Growth	Fixed	Simulated Uncertainty
Load Patterns	"Typical" profile	Uncertainty in Profile and Usage Pattern
Conservation	Fixed	Weather Based Demand Response
Weather	Fixed	Weather Based Demand Response
Hydro	Fixed	Simulated Annual Daily Operations
Wind	Fixed	Simulated with Weather
Env. Hg, CO2, SO2, NOx	Fixed	Simulated Based on Uncertainty in Costs
Gas Prices	Fixed	Simulated Monthly and Daily Prices
Transmission	Fixed Input/Output	Variable Flow Contingent Factors
Financial Instruments	Modeled as Fixed Assets	Simulated Values
Reserve Margins	Fixed, Small Effect	Simulated and Key Driver of Prices
Integration of Elements	Cost Based	Linked Equations and Casual Effects
Capital Cost	Fixed	Simulated Interest Rates and Capital

Best-In-Breed & Best-In-Show



Simulations

- Capacity planning finds the optimal expansion plan using dynamic programming in a simulation-based framework
- Optimal plan defined by:
  - Portfolio of generation assets
  - Constraints on portfolio
  - Objective function

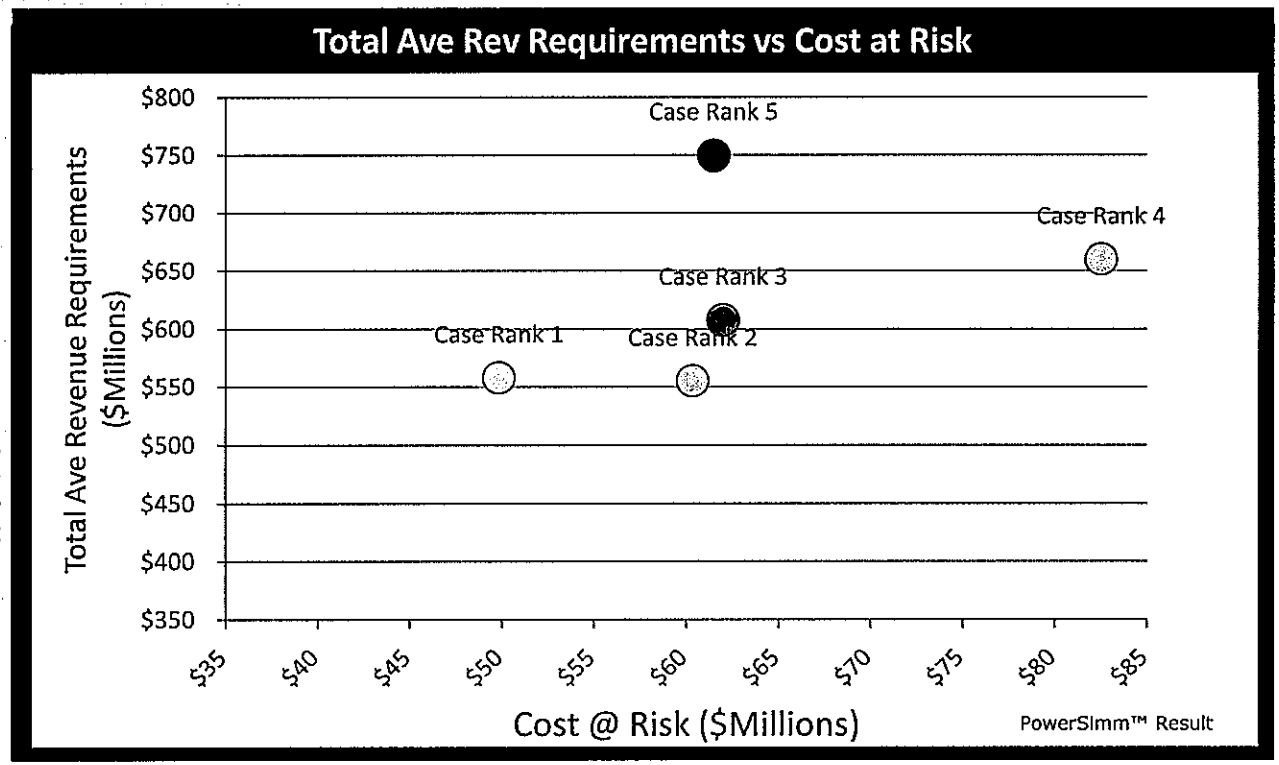
Best-In-Breed

- Simulation engine creates a number of possible simulated scenarios and finds the optimal plan for each iteration
- The "Best-In-Breed" plans have the best-achieved value of the objective function under the specified inputs for a particular simulated scenario

Best-In-Show

- PowerSimm subjects each of the Best-in-Breed plans to all the scenarios and calculates the value of the objective function in each of those scenarios
- "Best-in-Show" is the plan with the lowest mean of the objective function across all the scenarios
- This plan performed the **best** across a variety of scenarios

Best In Show



- How do environment controls on coal impact risks?
- What resources are more highly valued with growing percentage of renewables?
- How do I tie Best in Breed back to specific scenarios?

BEST IN SHOW

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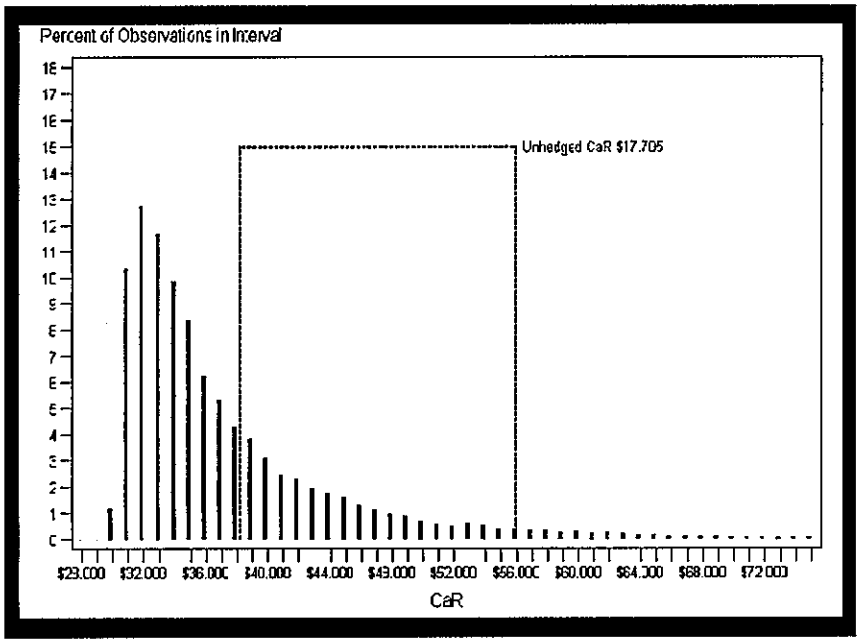
Definition of Common Planning Risk Metrics

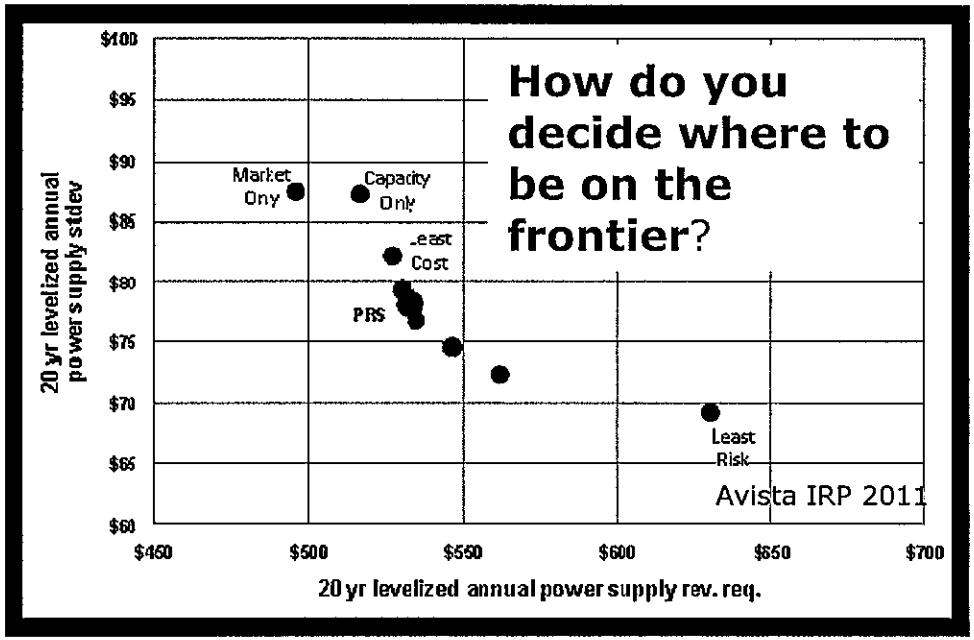
Cost at Risk (CaR) for Rev Req =

CaR = 95th percent costs – mean costs

Standard deviation (Std) of Ann Rev Req (ARR) =

Std = $\sqrt{E[ARR^2] - (E[ARR])^2}$





BEST IN SHOW

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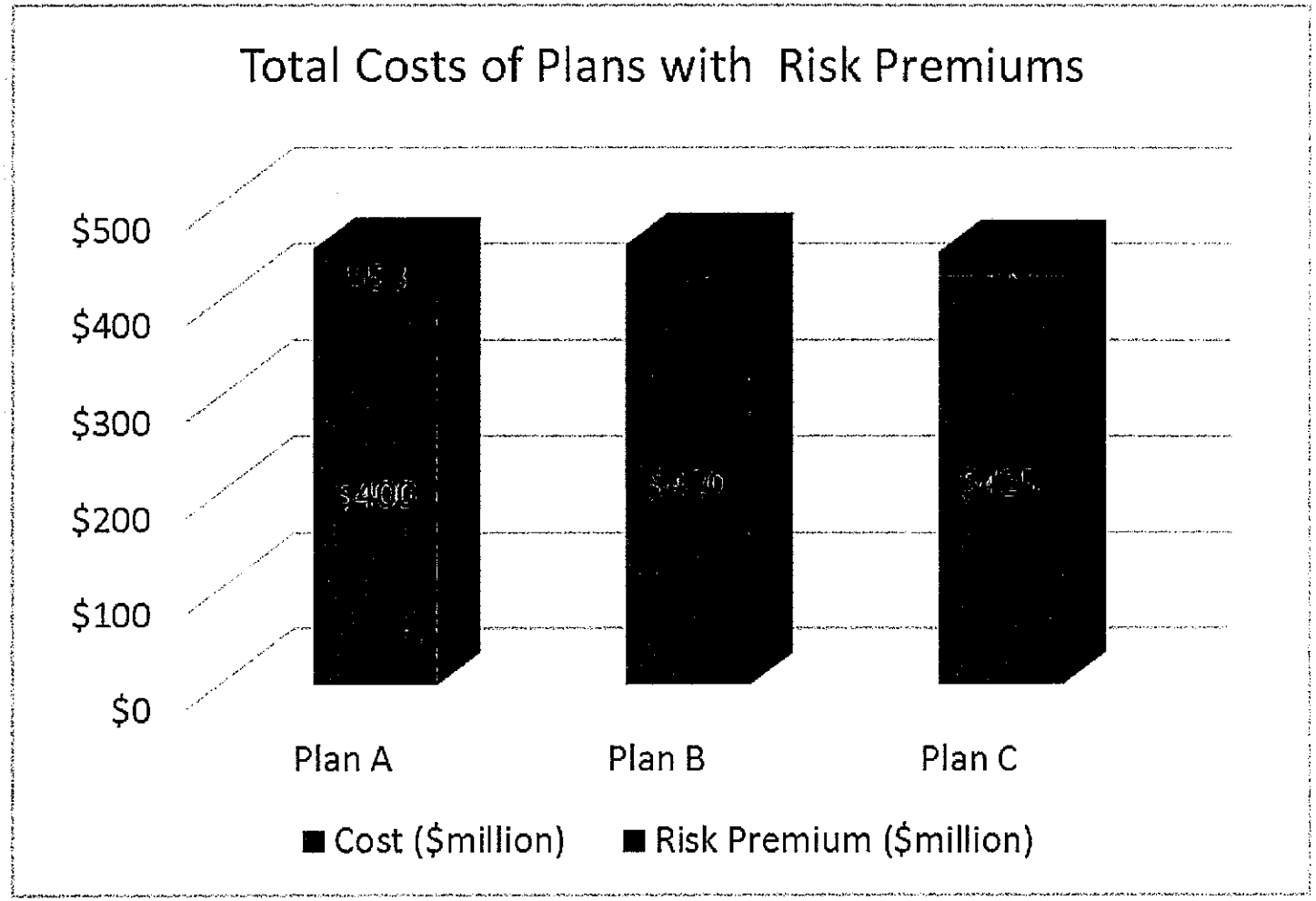
Total Cost Portfolio Selection



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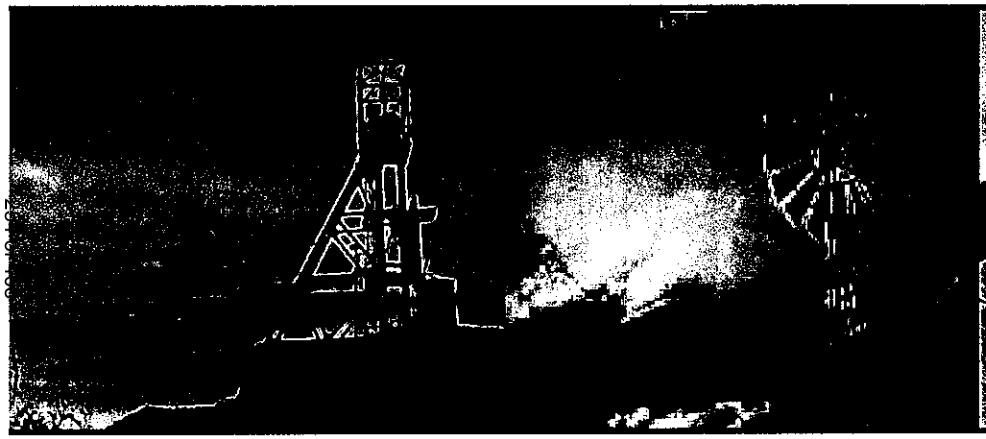
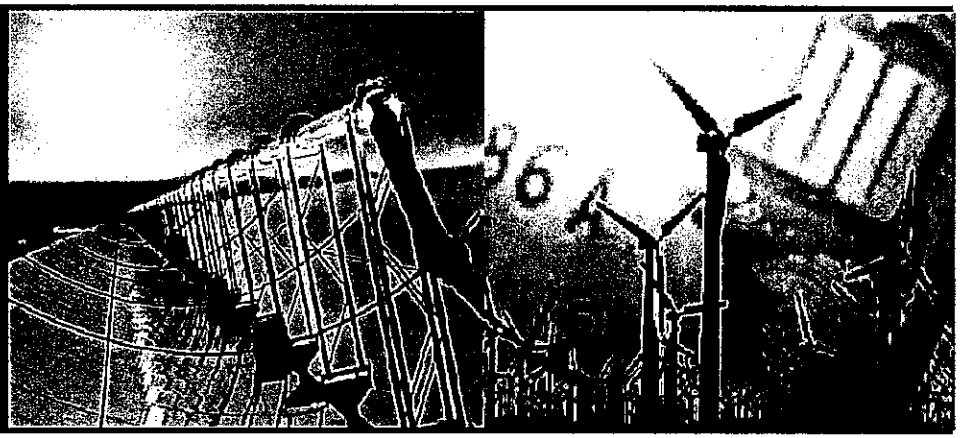
Risk Reduction Value (RRV)



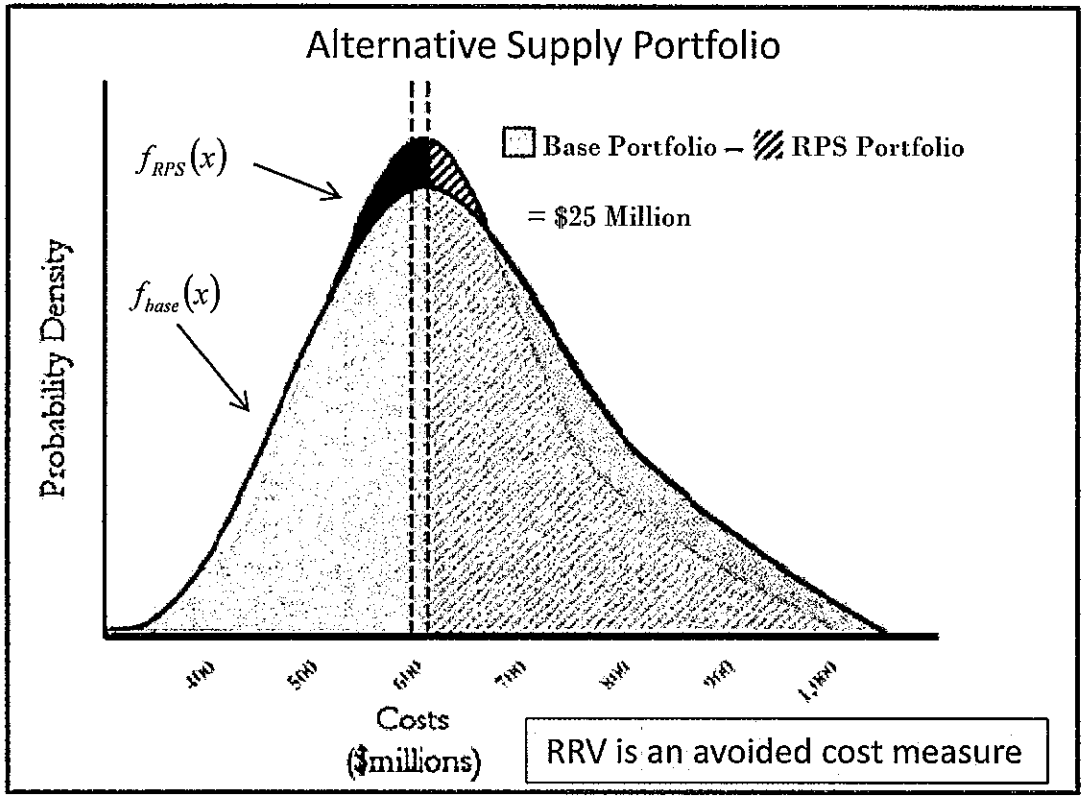


Net Benefits
Example Continued

What is the net benefit of new strategy?

- Cost increases of new strategy are mitigated by decrease in tail risk.
- Preference for lower cost base strategy reversed when net benefit in value is achieved.

Consider:
E["Base Rev Requirements"] = $600
E["RPS Rev Requirements"] = $615
RP("Base") = $100
RP("RPS") = $75
RRV = RP("Base") - RP("Hedged")
RRV = $25



"Net Benefits" = "Avoided Risk Costs" – "Difference in Program Costs"
= RRV + ΔCost
= $25 + ($600 – $615) = $25 – 15 = $10 million

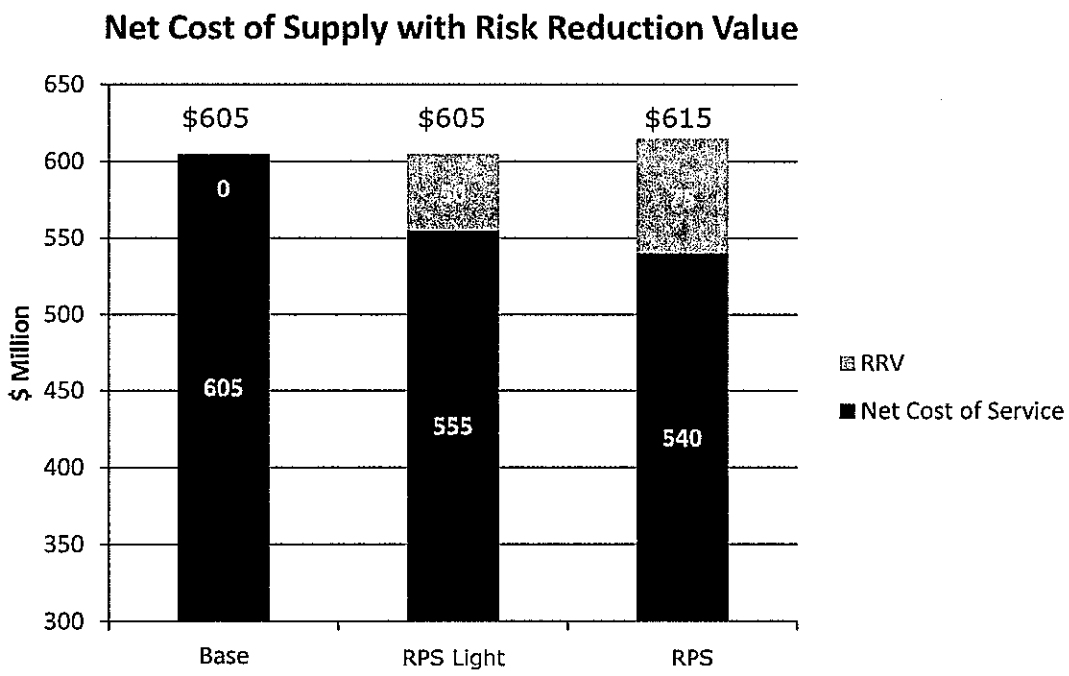
Risk Reduction Value of Renewables Example Continued

- Expected costs greater, but risk adjusted costs are less
- Value risk premium of renewables as insurance premiums that provide a hedge against potential losses. In this case, option premiums increase the expected value, but provide benefits greater than the value

- Base
  Total cost: $605 mm
  Effective cost: $605 mm

- RPS Light
  Total cost: 555 + 50 = $605 mm
  Effective cost: $555 mm

- RPS
  Total cost: 540 + 75 = $615 mm
  Effective cost: $540 mm



A portfolio with low cost renewables can have a lower effective cost than the base position.

Planning Steps

- Develop Model Inputs
  - Market prices
  - Load forecasts
  - Resource options
- Validate Model
  - Consistency of model
    - Historic values
    - Expectations
- Analyze Results
  - Least Cost Revenue Requirements
  - Flexible Resource Adequacy (FRA)

NorthWestern Energy Capacity Planning and Resource adequacy

ETAC Presentation

Steve Fisher
Lands Energy Consulting

July 24, 2013

Lands Energy CONSULTING

Historic Perspective

- Historically (pre-2000), the NWPP Region was the only energy-constrained region in the US Electric system
  - Critical water planning dictated need for new resources
  - Northwest peaks primarily in the winter, with California peaking capacity available in a pinch (February 1989)
  - Installed hydro capacity made peak load planning a cocktail napkin exercise.
- Things changed
  - Regional resource additions mostly non-hydro - either natural gas, or wind (energy w/o capacity) for RPS.
  - Flexibility to utilize hydro machine capacity declined.
  - Regional summer peak approaching winter peak
  - Regional entities recognize that peak load service and flexibility requirements now dictate resource additions
  - The cocktail napkin is no longer sufficient.

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The Complexity Continuum

- Initially, Default Supply load served by PPL requirements contract at a fixed price – fully hedged, with explicit PPL obligation to serve peak load. Simple!
- Today, mix of coal, wind, gas peaking resources, with majority of Default Supply MWH supplied by layers of wholesale market purchases – staggered hedges, with indeterminate obligation to serve peak load and follow wind. Anything but simple!
- Next 3 to 5 years, add more physical generation to serve Default Supply peak and energy load and to follow wind – hedge both gas and electric price, with clarified obligation to serve peak. Way complex!

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Northwest Power Planning

- Portland General Electric, Puget Sound Energy, Avista, PacifiCorp, Idaho Power all use a combined approach to power planning: peak load service (reliability) first/energy cost (financial risk management) second
- Hydro based public utilities (Seattle, Tacoma, Grant PUD, Chelan PUD) with high installed capacity to peak load ratios use energy cost planning similar to NWE
- NWPCC forecasts peak load service deficits starting in 2017
- Wind integration requirements influence IOU resource decisions – Mid C Purchaser "losers" in particular (those losing shares in the Mid-Columbia over time).
- Even BPA in the market looking for capacity resources

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2018 NWE Peak Load/Resource Balance

2018: The earliest feasible on-line date for a new peaking resource

NWE Firm Peaking Resources	432 MW
Less 2018 Peak Load (50% Probability)	(1201 MW)
Less Planning Margin (14% of load)	(168 MW)
Capacity L/R Deficit	(937 MW)

There is no crisis today, but the Western resource landscape continues to evolve – more intermittent renewables, less coal, less nuclear, less hydro flexibility

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NWE Current Load Service Strategy

- Acquire generation and generation-supported PPAs for peak load and energy service
- Purchase HLH Mid C-delivered contracts (WSPP Schedule C) to hedge a portion of energy obligation 18-48 months into the future – convert to NWE system delivered purchases a few months prior to delivery
- Purchase additional NWE system-delivered HLH energy on a quarterly or monthly basis (including replacement for generation forced outage) as delivery date approaches (1-18 months out)
- Preschedule generation and generation-backed PPAs (including hour-by-hour wind output estimates), including natural gas for Basin Creek if justified by market heat rates
- Purchase (and sell) additional energy in the day-ahead and hour-ahead markets as necessary to balance loads and resources

Forward market purchases are dictated by monthly energy requirements – not peak load service

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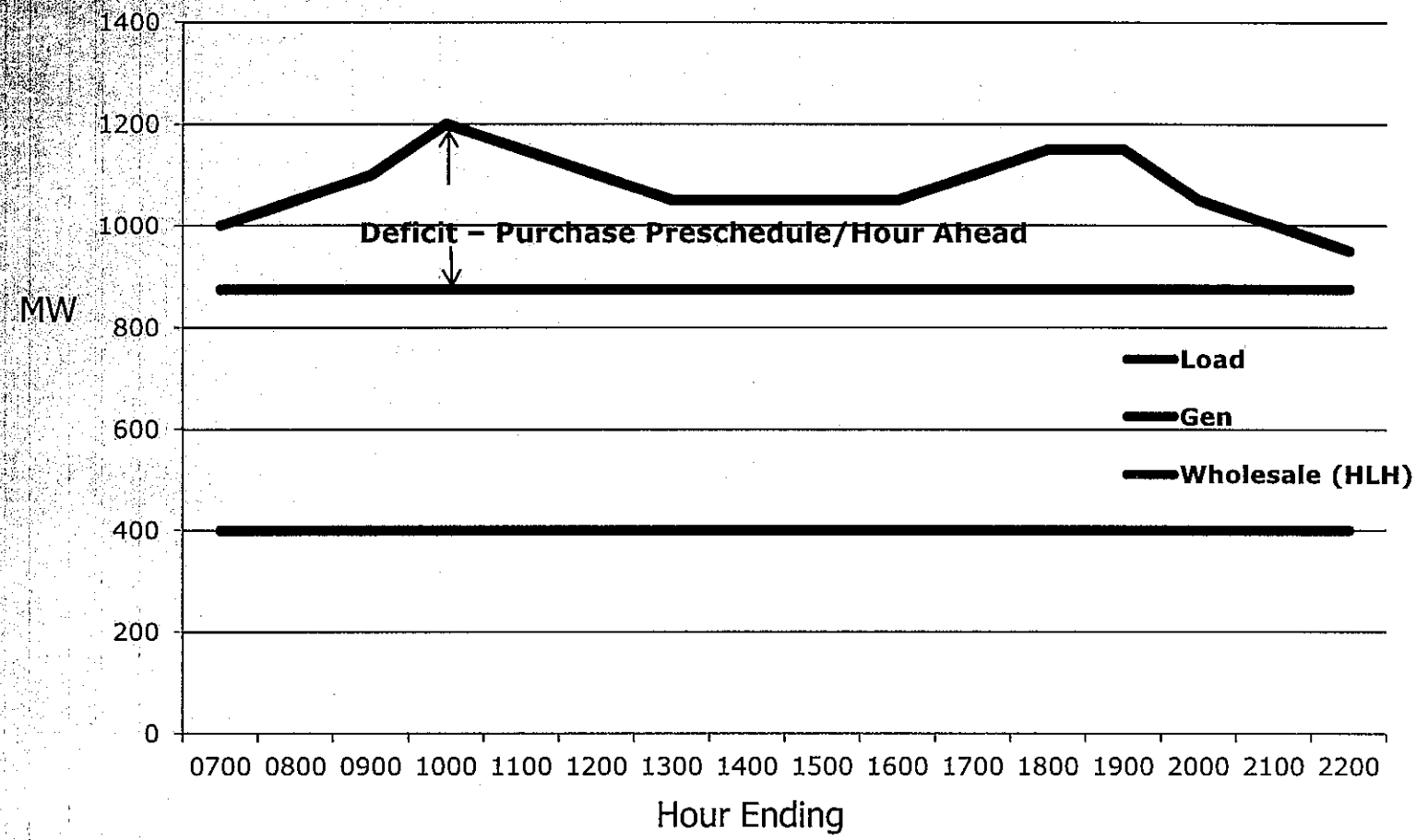
Peak Day HLH – Winter 2018



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Schedule C Purchases as a Capacity Resource

- Effective way to hedge energy price risk, and…
- Liquidated Damages provisions act as a good (albeit imperfect) deterrent to interruption by suppliers, but…
- Reliable electricity service depends on the continued operation of properly located generation (e.g. Colstrip, Corette, Montana hydro) to serve physical peak load
- Standard HLH product shape doesn't match daily load shape
- Risk that power unavailable at any price:
  - July 24, 2006
  - July 1, 2013

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Risks of Relying on Market Purchases

- Market purchases send price signals to generation owners regarding the financial feasibility of continued operation versus generating plant closures
- MATL provides access for in-state generators to a new, higher clearing price market in Alberta
- Colstrip 3/4 outage over peak forces NWE into the market with other owners also looking for replacement power
- Extreme cold and hot weather puts everyone in the market looking to cover peak load

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Conclusions

- 2013 NWE Procurement Plan should incorporate more rigorous capacity planning and analysis.
- The Plan should include a strategic plan to address near- and long-term capacity deficits.
- Addressing capacity deficits with generating resources could be more costly than continued reliance on market (for now)
- Western Systems Power Pool (WSPP) Schedule C contracts could prove inadequate for meeting peak load requirements (resource adequacy issue). Must balance cost with availability and interruption risk.
- Ensuring the continued operation of existing in-state resources that provide the voltage and current to support NWE peak load service should be part of the NWE strategy to address capacity deficits.

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ETAC Meeting Agenda

NorthWestern Energy
Conference Call & WebEx

Wednesday August 28, 2013
9:00 AM – 12:00 PM

WebEx Login
https://www1.gotomeeting.com/join/277099881

Conference Call Information
1-877-820-7831 pass code 555256

Agenda:

1. 2013 Resource Procurement Plan Model Inputs
    a. Load & customer forecast
    b. Peak demand forecast
    c. DSM forecast
    d. Existing resources
    e. Proposed new resources to model
    f. Natural gas price forecast
    g. Electricity price forecast
    h. Carbon penalty forecast
    i. REC forecast
    j. Wind integration & ancillary services costs

2. Ascend Analytics PowerSimm preliminary deterministic model results and discussion

Web Meeting Summary
NorthWestern Energy Electricity Technical Advisory Committee
August 28, 2013

Attendance
Those participating in the Energy Electricity Technical Advisory Committee (ETAC) meeting conducted via GoToMeeting and conference call included:

Name	Organization
Garrett Martin	Montana Department of Environmental Quality (DEQ)
Jamie Stamatson	Montana Consumer Counsel (MCC)
Will Rosquist	Montana Public Service Commission (MPSC)
Steve Fisher	Lands Energy
John Bushnell	NorthWestern Energy (NWE)
Thomas M. Power	District XI Human Resource Council
Make Dalton	MPSC
Brian Spangler	DEQ
Chuck Magraw	Natural Resources Defense Council
Paul Schultz	MCC
Diego Rivas	NW Energy Coalition
Brien DeKiep	Northwest Power and Conservation Council (NPCC)
Patrick Barkey	University of Montana - Bureau of Business and Economic Research
Jeff Blend	DEQ
Todd Guldseth	NWE
Frank Bennett	NWE
Dave Fine	NWE
Gary Dorris	Ascend Analytics
Gerald Mueller	Consensus Associates

Agenda
- 2013 Resource Procurement Plan Model Inputs
  - Load & customer forecast
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  - Existing resources
  - Proposed new resources to model
  - Natural gas price forecast
  - Electricity price forecast
  - Carbon penalty forecast
  - REC forecast
  - Wind integration & ancillary services costs
- Ascend Analytics PowerSimm Modeling Presentation
- Next Meeting

2013 Resource Procurement Plan Model Inputs

Dave Fine introduced this item stating that its goal was an understanding of the resource planning inputs for this plan's modeling. The inputs are provided graphically and include a comparison to the input values for past resource plans. Todd Guldseth discussed the specific model input topics using a presentation found under the August 28 meeting heading on the ETAC web page at:
http://www.northwesternenergy.com/our-company/regulatory-environment/etac
Highlights of points made by Mr. Guldseth that expand upon or clarify the presentation material and the meeting participant questions and comments by topic follow. Unless otherwise noted, answers and responses were provided by Mr. Guldseth or Mr. Fine.

Model Inputs (Presentation Page 1)
Past modeling using GenTrader® assumed normal weather. Ascend Analytics will conduct the 2013 modeling using its PowerSimm® model. In this model, weather will be a variable which drives loads and electricity prices. Also, modeling for past plans used a table of electricity and natural gas volatility developed by Lands Energy as an input. PowerSimm® will generate the price volatility used in the stochastic analysis from historic Mid-Columbia electricity and AECO gas price data. NWE is developing a summary of new resource production and cost characteristics which will include granular heat rate curves.

Load and Customer Forecast (Presentation Pages 2-10)
The electric load forecast for residential and GS1 customer classes, which together make up 85% of NWE's retail load, is based on the Montana Department of Commerce Census and Economic Information Center (CEIC) econometric population modeling. The number of residential and GS1 customers (each meter constitutes one customer) is growing faster than population. The forecast of loads for the large commercial and industrial customer classes, which constitute the remaining 15% of NWE's load, uses a known and measurable change methodology based on specific customer information provided by NWE Key Account Executives.

Comment - The load forecast does not incorporate economics such as electricity prices and the business cycle.
Response - The load forecast is based on an econometric population forecast. The economies of prior years are built into the regression.

Comment - The CEIC model is a reasonable model to use for demographics. However, the model does not understand business cycles. The residential and GS1 customer use graphs show the same trend taking off from different initial points for the different year forecasts. If the model knew about business cycles, the trend lines may be affected.
Response - The historic data includes 20 years of data, the same period as the planning horizon.
Response - We will look into incorporating customer use as a regression variable for the next resource planning cycle. The NPCC 7th Power Plan, which is under development, may help inform the next plan forecast.

Comment - This situation reminds me of the projections of gas prices during the 1980s and early 1990s. The forecasts were always wrong, and each year the curves were merely shifted forward. The forecasts of use per NWE customer are not encouraging in terms of reflecting reality.
Response - We need to weather normalize the historic load data so that forecast curve does not change abruptly at the transition from historic to projected data.

Comment - Weather will not shape the trend lines in the customer use forecasts. The graphs reveal a problem that should be addressed.

Comment - NWE and the ETAC have been wrestling with clarifying customer use trends for several years. The historic residential customer use data for 2007-2011 do not show the flattening and declining trends in the forecasts made during those years. The expected values may lie between the forecasted values for 2012 and 2013 and the forecasts made during the preceding years. This appears to be a weak point of the analysis.

Comment - The GS1 customer use forecast also did not foresee the Great Recession. The succeeding year forecasts keep the trend the same but use a different starting point. Unlike the residential use forecasts, the GS1forecast trends keep the same sign.

Peak Demand Forecast (Presentation Pages 11-13)
Question - This year's peak forecast will be independent of the energy forecast?
Answer - Yes.

Comment - The peak forecast also does not include economics so we don't know if the recession caused a temporary or permanent downward adjustment.
Response - The bump in the 2014 forecast relative to the 2013 actual represents economic recovery.

Comment - In planning for a 20-year period, the slope of the line is more important than its starting point.
Response - The business cycle impacts historical actual values. The extent of the discontinuity from actual to forecasted values is embedded in the forecast.

Comment - For the energy forecasts, several years of past forecasts are shown. The peak forecast shows only the current year. The information for past years helps one to assess what the forecast model reacts to.
Response - We should be able to provide past year forecasts for peak as we have for energy. The forecasted growth rates in the winter and summer peak values are the same as the energy forecast, even though the two were developed separately this year.

DSM Forecast (Presentation Pages 14-15)
Question - Could you provide a graph showing past DSM program savings projections versus actual savings?
Answer - Yes.

Comment - The MPSC recently conducted an evaluation/verification of the DSM program savings in the electric tracker proceeding.
Response - The evaluations of the DSM program have been based on a sampling of the DSM program measures rather than all measures. We will look into providing a summary of the evaluation results.

Existing Resources (Presentation Pages 16-17)

About 90 MW of the QF Tier II resources are made up of two projects, the Yellowstone Energy Limited Partnership or YELP project which is a petroleum coke fueled generating plant in Billings and the Colstrip Energy Limited Partnership or CELP project which is a waste coal fueled generating plant located near Colstrip.

Question - Are you accounting for the results of the resources acquired pursuant to the 2013 request-for-proposals (RFP) to partially replace the contracts with PPL that expire in 2014?
They do not provide volumes of physical power and therefore are not listed in the table of existing resources (page 17 of the presentation).

Question - On the existing resources table, Basin Creek is listed as providing 35 MW of capacity and 2 MW of average energy, and the Dave Gates Generation Station (DGGS) is listed as providing 7 MW of capacity and 7 MW of average annual energy. What will we see in the future for these plants?
Answer - The 2 MW average energy for the Basin Creek plant is the historical value. The model will dispatch this plant. Three of the plant's units are used for reserves. The 7 MW for the DGGS plant is the minimum turn-down value for the two units. This is the amount now dedicated to Energy Supply. When NWE determines the ultimate amount that Energy Supply will receive from this plant, it will be included in resource planning.

<u>Proposed New Resources to Model (Presentation Pages 18-19)</u>
For this plan, NWE has not included leading edge technologies, some which were included in past plans. Resources for this plan are limited to those that are commercially available.

Question - Given the concern about NWE interest in purchasing additional portions of the Colstrip plants, should you include in the portfolio modeling a purchase of existing base load resources?
Answer - Energy Supply has not been directed to do so. We are including in the portfolio modeling only plausible resources.

Comment - It would be good to know ahead of time how a purchase of existing baseload plants would compare to a new gas-fired resource.
Response - We do not know what the purchase price of the existing baseload plant would be. Without a price, we do not know how to model it.

Comment - The justification for any purchase of an existing baseload plant would have to be its low price. One could work backward and determine what the price would have to be to be competitive with a new gas-fired resource.
Response by Steve Fisher - Such a purchase would look like a wholesale market acquisition.

Question - Is the solar photovoltaic (SPV) resource listed in the table a utility scale resource?
Answer - Yes, it would be measured in megawatts rather than kilowatts.

Question - So it would not consist of distributed SPV installations?
Answer - Correct, it is a commercial scale project or projects.

Question - The utility faces a choice of supporting distributed customer-scale projects or commercial utility-scale projects. Could the modeling inform a debate about how much distributed projects should be subsidized by other customers?
Answer - This appears to be a spread sheet or policy issue rather than a resource supply issue.

Comment - Maybe this is a marketing issue. If solar resources look good, then the question of how to its acquisition should be pursued.
Response - For supply planning, the question is when SPV become attractive from a capital cost perspective.

Comment - Some people think that roof top solar installations prices may drop so that customer use will increase. Someone in NWE should be reading the literature and considering an appropriate strategy.
Response - Bill Thomas' group is likely following this issue.

Natural Gas Price Forecast (Presentation Pages 20-21)
Question - What is the delivered cost of gas to residential customers?
Answer - In July the delivered cost was $7.92 per dekatherm. The commodity cost was approximately $4.00 per dekatherm.

Comment - The prices in the chart on page 21 is the gas commodity plus the cost of moving it through the transmission system.

Question - I understand the historical use of AECO hub prices. However, NWE is using increasing amounts of gas from Havre and Wyoming. Should AECO prices be used for the future?
Answer - For now using AECO prices is appropriate. In the future, use of Rockies and Wyoming gas may increase. NWE's recent gas field purchases have been for gas customers not for fueling electricity generation.

Question - Given the use of the Gross Domestic Product based price deflator, are you assuming a constant real gas price beginning with the end of the AECO forward price curves?
Answer - No, the GDP Implicit Price Deflator is a measure of inflation and used for nominal escalation, not real price escalation.

Question - in the chart on page 21, what is the mix of real and nominal prices?
Answer - The dotted lines show real and nominal price escalations. The solid lines are nominally escalated only.

Question - The natural gas price projections are nominal. The solid line includes a 2% per year escalation because of inflation. The market has recently changed significantly. Many demand and supply factors could change the market in the future. Should price uncertainty be a point of emphasis in this plan?
Answer - Yes. The Ascend modeling will incorporate a range of prices. The price chart is the beginning point of the analysis. We don't expect actual prices to follow any specific line over the planning period.

Comment - NWE is talking about price volatility. I am concerned about the trend rate of growth. I would be more comfortable with price forecasts made by economic outfits such as Moody's Analytics rather than the Energy Information Administration (EIA).
Response - We want to rely on market prices and fundamentals. Historically, the GDP price deflator has served as a reasonable escalator for forecasting commodity prices. Four or five years ago, forecasting the downward adjustment in gas prices that has occurred would have been heretical. We use the forward market price curve as the starting point for the gas price forecasts.

Comment - The EIA provides comparisons of its past forecasts with other respected forecasters, so that we need not rely on EIA forecasts alone.

Electricity Price Forecast (Presentation Pages 22-23) and Carbon Penalty Forecast (Presentation Pages 24-25)
Question - You use forward electricity price forecasts for 2014 - 2020. Beginning in 2021, you appear to apply a carbon cost adder. Why the change in 2021?
Answer - Forward electricity prices at the Mid-Columbia trading hub are available through 2020. Beginning in 2021, we apply escalations including the carbon adder forecasts by the EIA.

Comment - You might add to the chart on page 23 an overlay of the Mid-C heat rate for the no carbon tax case. The existing green line appears to escalate the heat rate.
Response - Our objective is long-term equilibrium. We want to pay close attention to the heat rate because increased heat rates may imply an increased profitability of a gas-fired resource.

REC Forecast (Presentation Pages 26-27)
Mr. Fine receives a daily email from Karbone Inc. with price information about renewable energy credits (REC). Recently, we have not seen REC-only contracts, nor much volume in the REC markets. NWE and other utilities purchasing renewable resources have retained their RECs to meet renewable portfolio standards (RPS).

Question - What about the California market and Washington market for double RECs?
Answer - California has a limit of 25% for REC-only contracts to meet its RPS. This limit is apparently limiting the impact on REC prices. At some point the California market may increase purchases from Montana wind farms.
Answer by Steve Fisher - The Washington double REC applies only to small projects, not commercial wind farms.

Comment - I will send you the link to the Washington statute that addresses double RECs.

Ascend Analytics PowerSimm Modeling Presentation

Dr. Gary Dorris of Ascend Analytics gave a presentation entitled "Resource Planning with Uncertainty for NorthWestern Energy." A copy of this presentation is available on the ETAC web page at the address given above. The presentation provided an overview of Ascend's modeling approach and modeling activity plan for NWE's 2013 resource plan. Unlike past plans, NWE will not conduct modeling in-house but will rely on its contractor, Ascend Analytics.

Question - Will wind be treated as a variable in the stochastic analysis?
Answer - Yes.

Question - How will you handle wind?
Answer - The relationship between wind and load and market prices will be preserved. Simply drawing wind amounts from a random distribution is not acceptable. When it is very hot or very cold, the wind sometimes does not blow.

Question - Will you use Montana wind data?
Answer - Yes. We have data for a couple of wind sites.

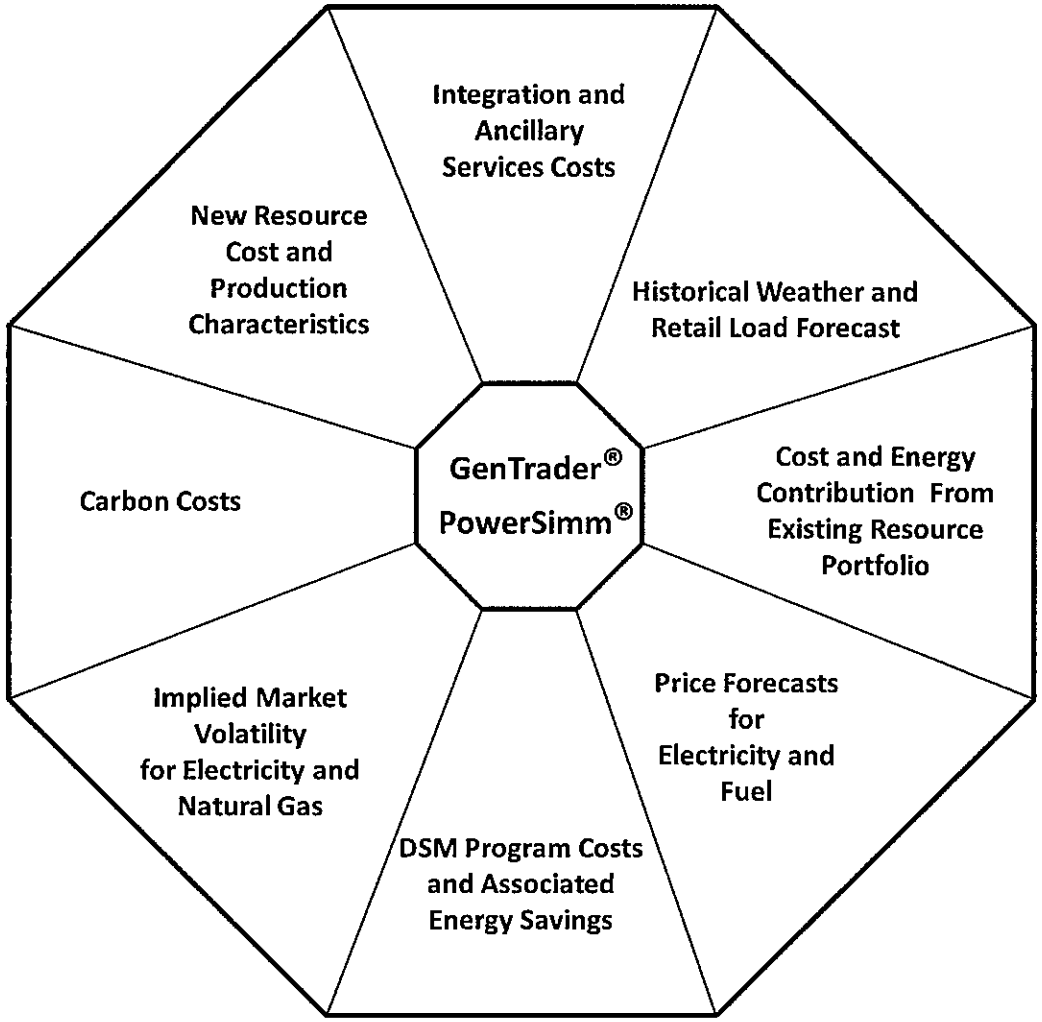
Next Meeting

The next meeting was scheduled for Wednesday, September 25, 2013 at the NWE General Headquarters in Butte.

Disclaimer

Committee members provide advice to NWE as individual professionals; the advice they provide does not bind the agencies or organizations that the members serve.

Model Inputs



NWE 2013 Resource Procurement Plan
Model Input Overview
Load Forecast

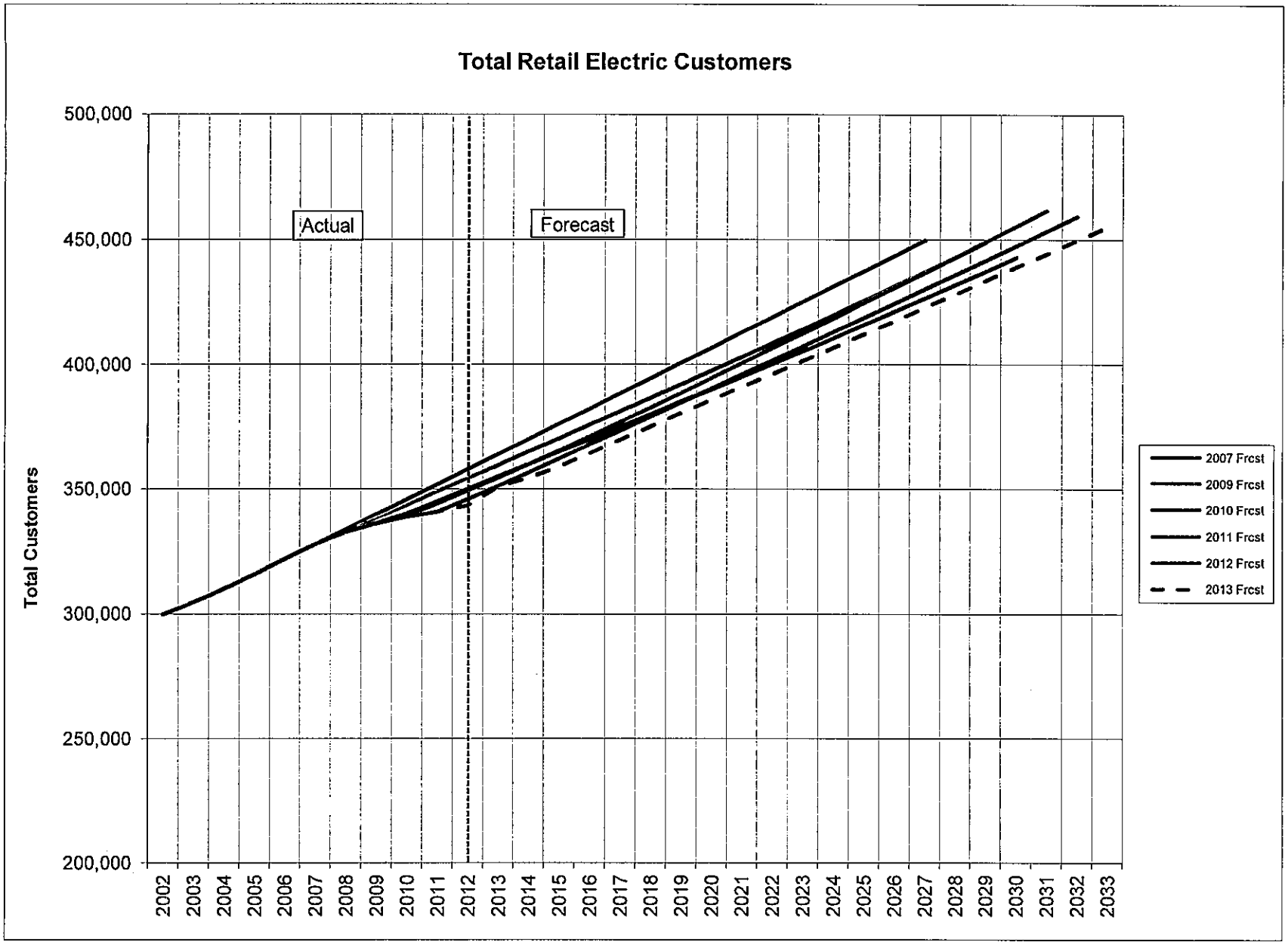
1. Residential & GS1 Secondary (small commercial) customer forecasts
    a. Montana state and county population forecasts (MT State Census & Economic Information Center (CEIC))
        i. Econometric model developed by Regional Economic Models, Inc. (REMI)
        ii. Drives NWE service territory population forecast
    b. Historical customer counts (1980 – 2012)
    c. Regression model to develop customer forecast

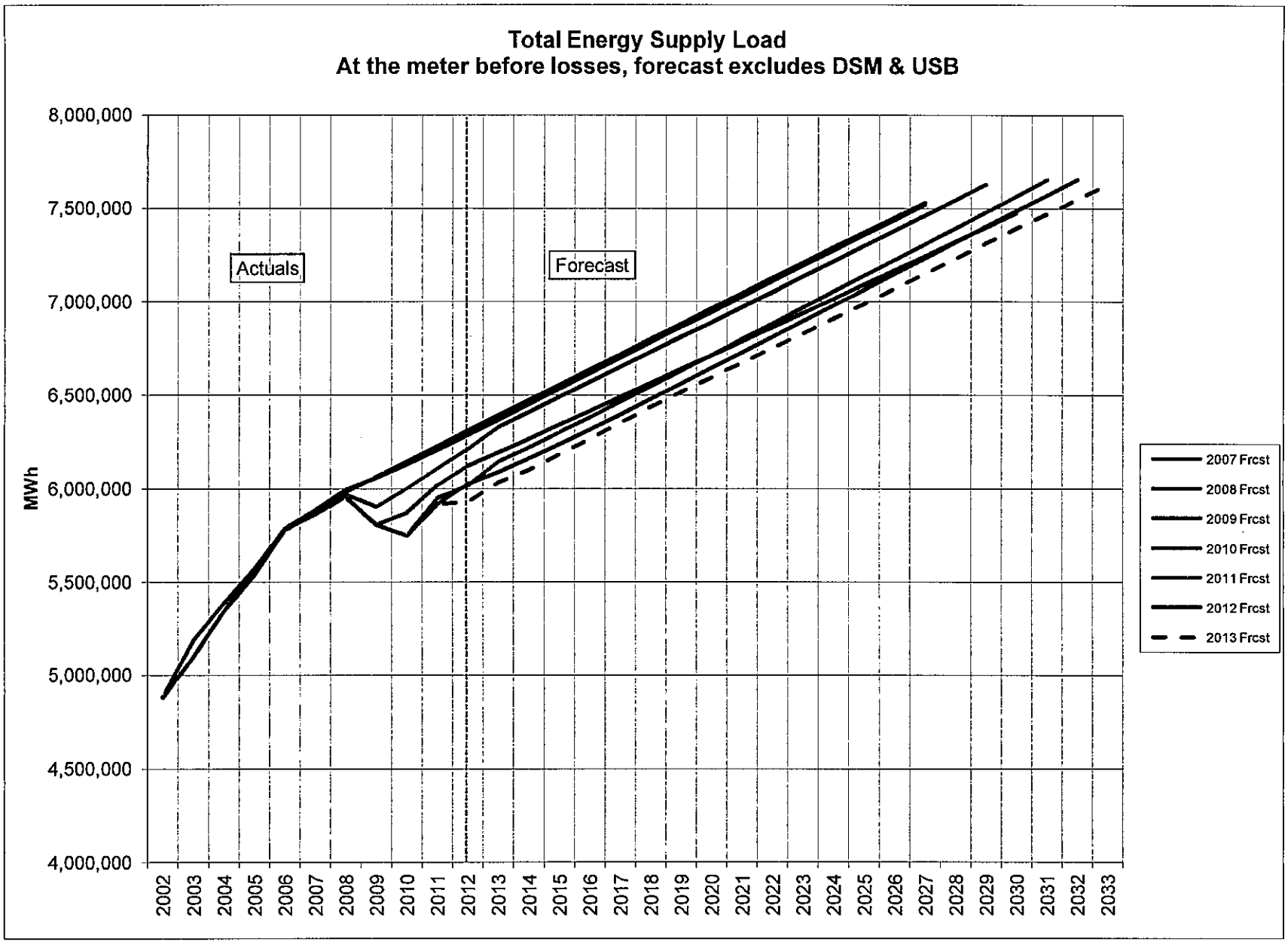
2. Total Degree Days (HDD + CDD)
    a. Historical total degree days (1980 – 2012)
    b. Normal forecasted degree days equals historical average

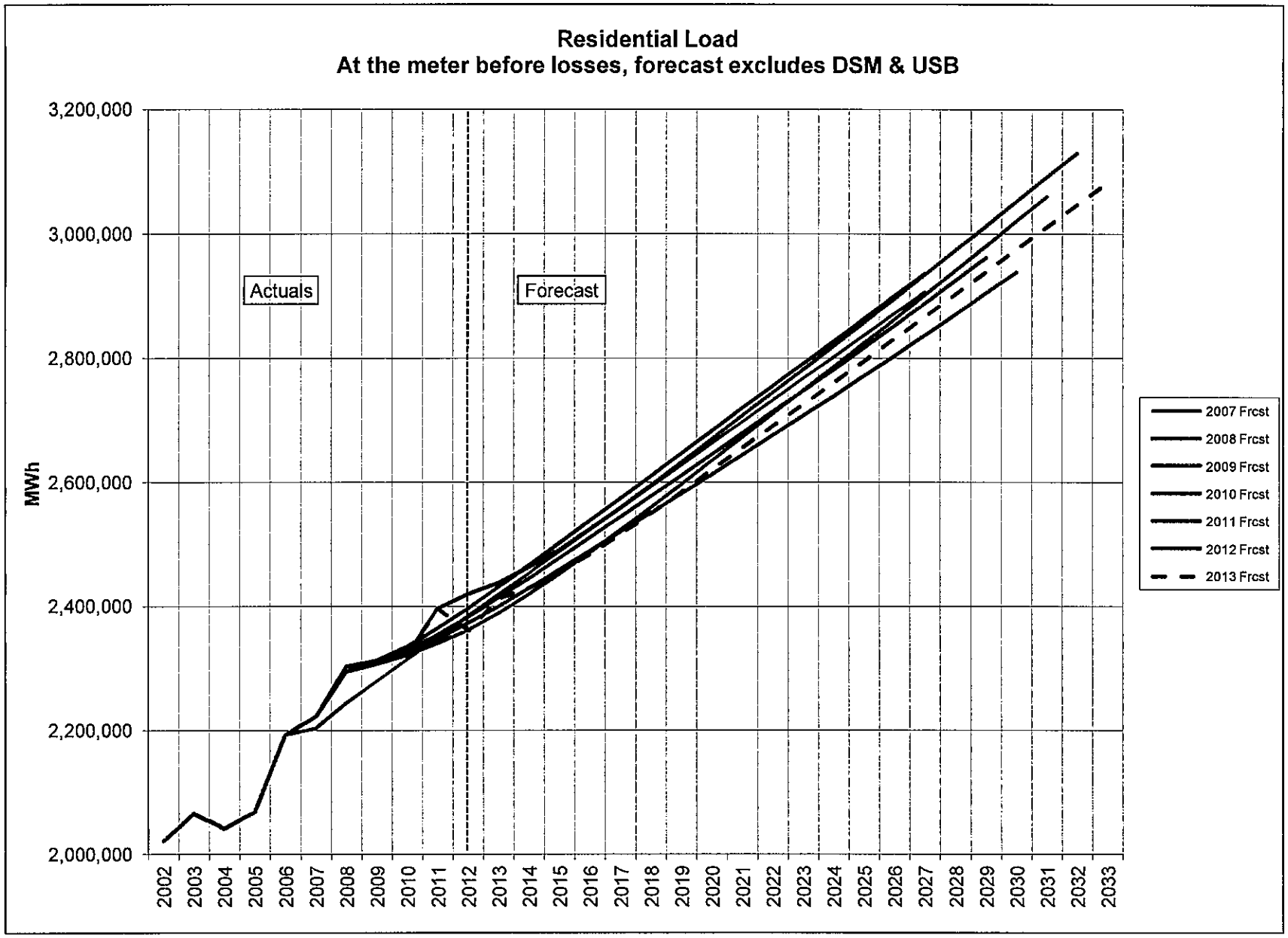
3. Residential & GS1 Secondary load forecast
    a. Historical and forecasted customer counts
    b. Historical and forecasted total degree days
    c. Historical Residential and GS1 Secondary loads (1980 - 2012)
    d. Regression model to develop load forecast

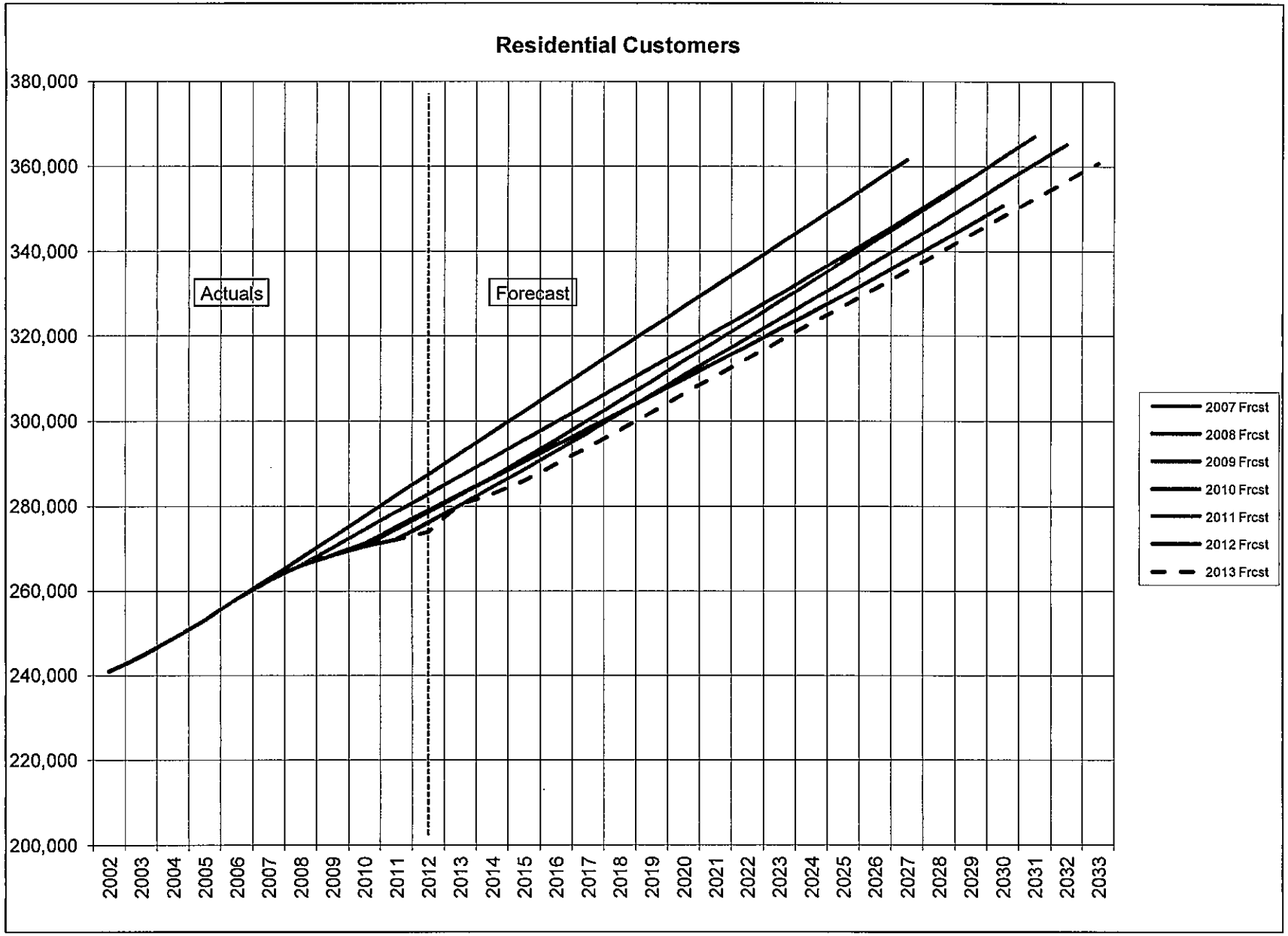
4. Customer forecast results reflect 1.3% growth in Residential, 1.6% growth in GS-1 Secondary, and 1.3% growth in Total customers, compared to 1.1% growth in both Montana and NWE service territory population. (20-year average annual growth rates)

5. Load forecast results reflect 1.2% growth in Energy Supply load for all rate classes excluding DSM and 0.8% growth including DSM.


Total Retail Electric Customers
Total Customers
500,000
450,000
400,000
350,000
300,000
250,000
200,000
Actual
Forecast
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2007 Frcst
2009 Frcst
2010 Frcst
2011 Frcst
2012 Frcst
2013 Frcst


Total Energy Supply Load
At the meter before losses, forecast excludes DSM & USB
MWh
8,000,000
7,500,000
7,000,000
6,500,000
6,000,000
5,500,000
5,000,000
4,500,000
4,000,000
Actuals
Forecast
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2007 Frcst
2008 Frcst
2009 Frcst
2010 Frcst
2011 Frcst
2012 Frcst
2013 Frcst


Residential Load
At the meter before losses, forecast excludes DSM & USB
MWh
3,200,000
3,000,000
2,800,000
2,600,000
2,400,000
2,200,000
2,000,000
Actuals
Forecast
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2007 Frcst
2008 Frcst
2009 Frcst
2010 Frcst
2011 Frcst
2012 Frcst
2013 Frcst


Residential Customers
380,000
360,000
340,000
320,000
300,000
280,000
260,000
240,000
220,000
200,000
Actuals
Forecast
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
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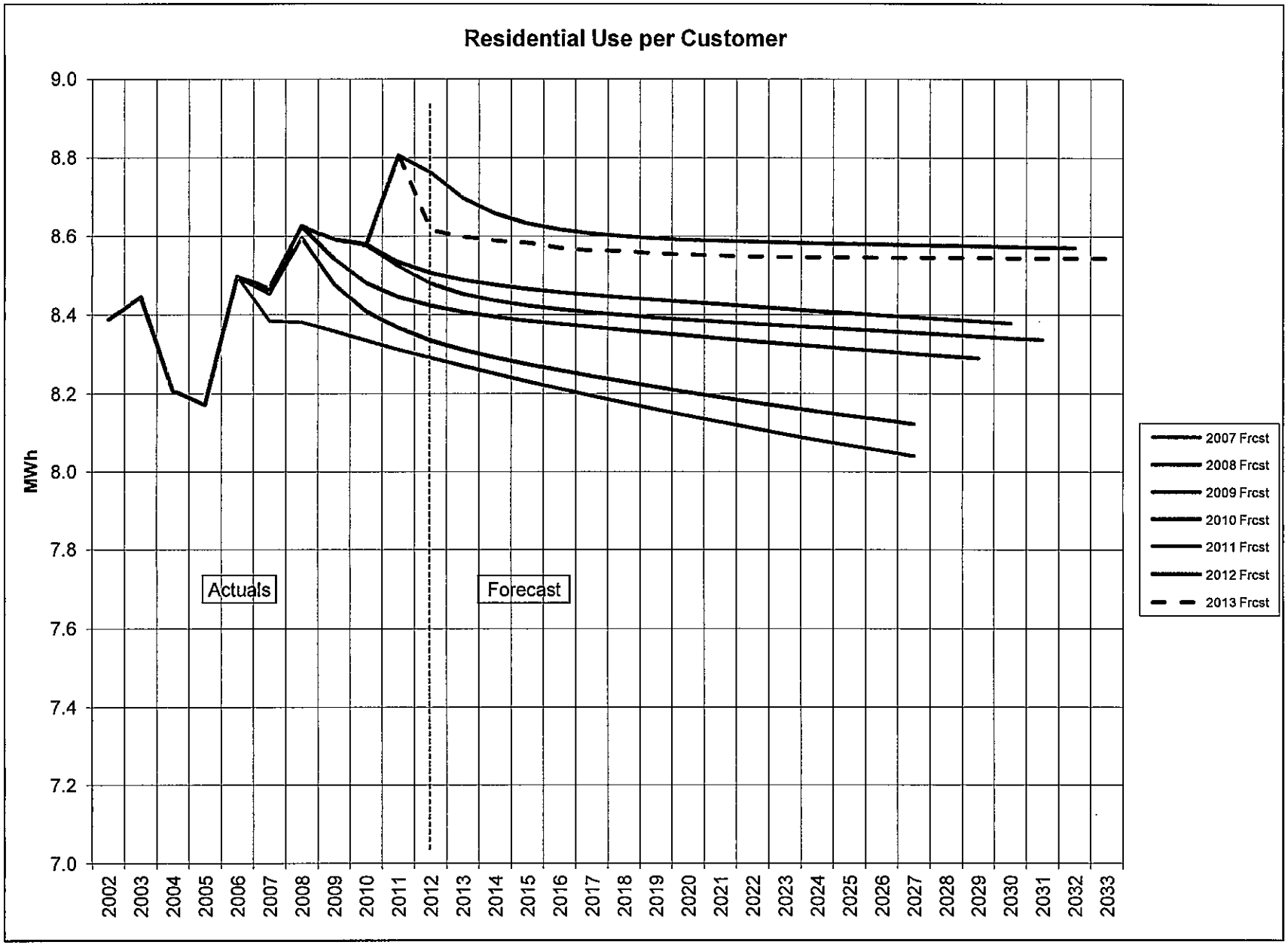
2027
2028
2029
2030
2031
2032
2033
2007 Frcst
2008 Frcst
2009 Frcst
2010 Frcst
2011 Frcst
2012 Frcst
2013 Frcst


Residential Use per Customer
MWh
9.0
8.8
8.6
8.4
8.2
8.0
7.8
7.6
7.4
7.2
7.0
Actuals
Forecast
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
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2023
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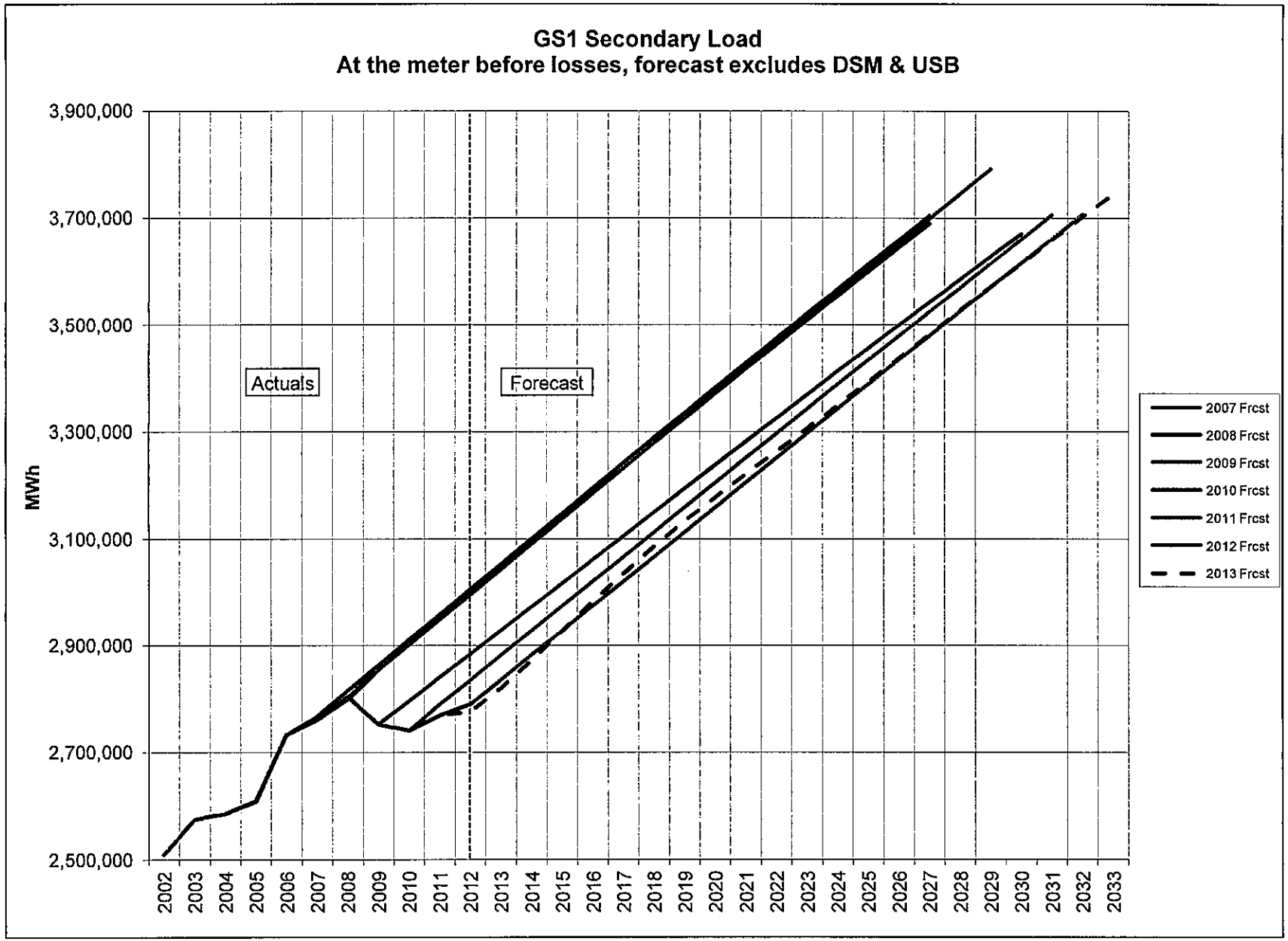
2007 Frcst
2008 Frcst
2009 Frcst
2010 Frcst
2011 Frcst
2012 Frcst
2013 Frcst


GS1 Secondary Load
At the meter before losses, forecast excludes DSM & USB
MWh
3,900,000
3,700,000
3,500,000
3,300,000
3,100,000
2,900,000
2,700,000
2,500,000
Actuals
Forecast
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
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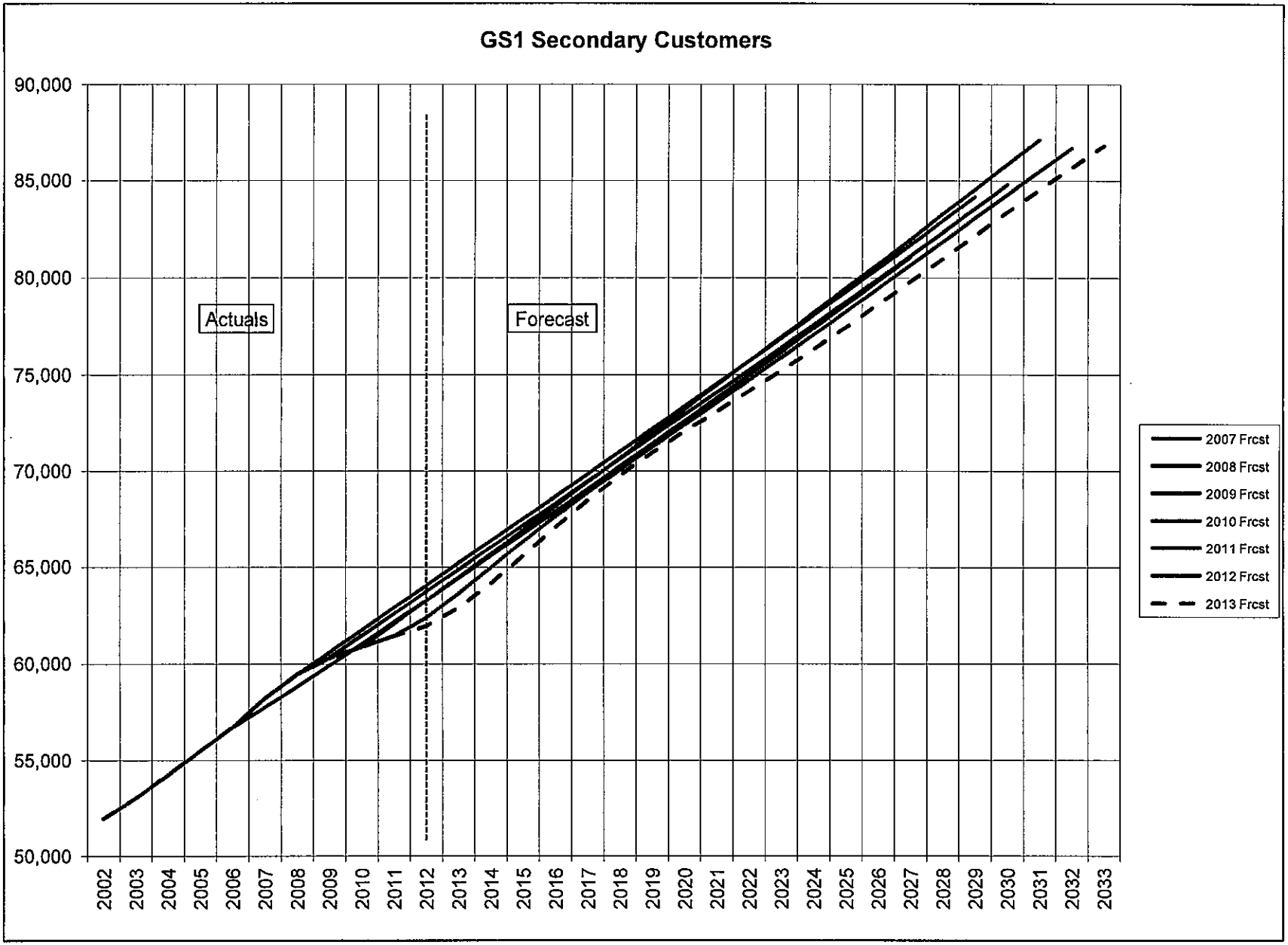
2032
2033
2007 Frcst
2008 Frcst
2009 Frcst
2010 Frcst
2011 Frcst
2012 Frcst
2013 Frcst


GS1 Secondary Customers
90,000
85,000
80,000
75,000
70,000
65,000
60,000
55,000
50,000
Actuals
Forecast
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
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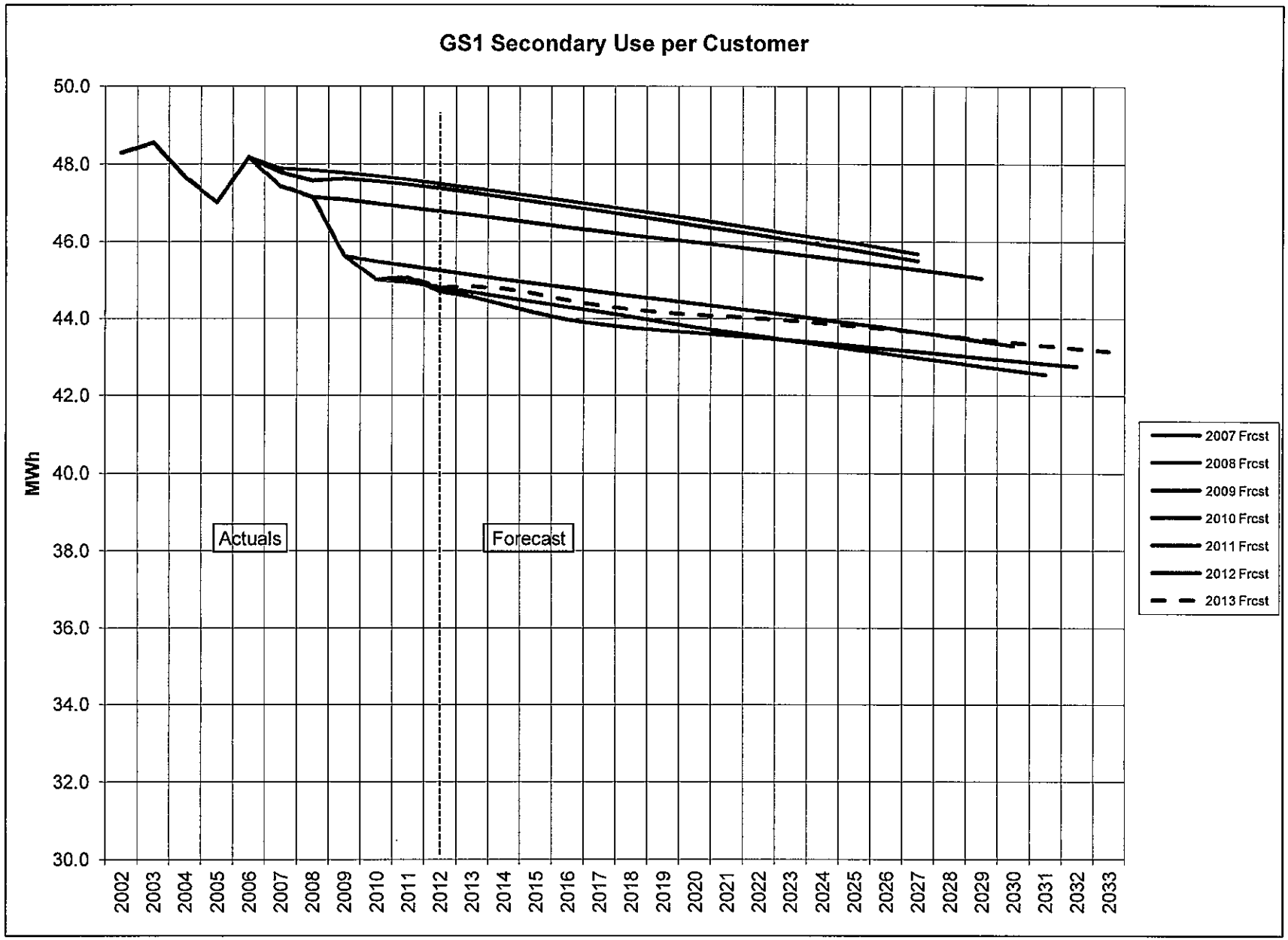
2007 Frcst
2008 Frcst
2009 Frcst
2010 Frcst
2011 Frcst
2012 Frcst
2013 Frcst

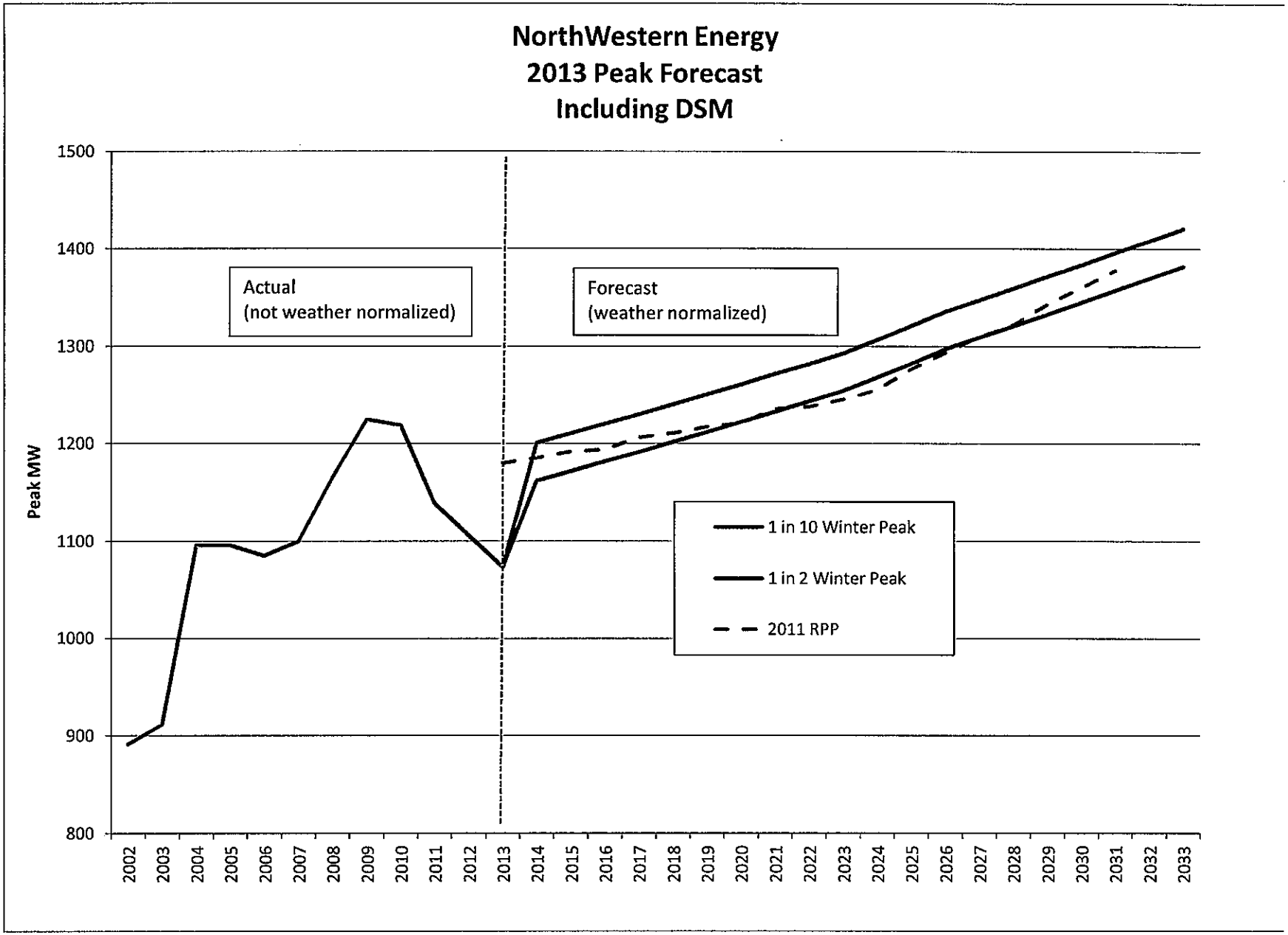

GS1 Secondary Use per Customer
MWh
50.0
48.0
46.0
44.0
42.0
40.0
38.0
36.0
34.0
32.0
30.0
Actuals
Forecast
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2007 Frcst
2008 Frcst
2009 Frcst
2010 Frcst
2011 Frcst
2012 Frcst
2013 Frcst

NWE 2013 Resource Procurement Plan
Model Input Overview
Peak Demand Forecast

1. Energy Supply is using a new method for developing the peak demand forecast – based on a percentage, or ratio, of the Balancing Authority Area (BAA) forecast.

2. Pros of this method include the NWE Transmission group uses linear regression with weather/temperature, loads, and population as the driving variables (so it is not a derivative of Energy Supply's load forecast); 1 in 2 (50% probability of being exceeded) and 1 in 10 (10% probability of being exceeded) forecasts are developed; and the ratio of Energy Supply peak demand to BAA peak demand has been reasonably consistent over the past ten years with winter peak averaging 68.3% with a 1.8% standard deviation and summer peak averaging 66.1% with a 2.3% standard deviation.

3. Cons of this method include the forecast could be skewed by large industrial load swings that are not relevant to Energy Supply. Energy Supply will have to monitor the BAA load forecast to make certain there are no such swings, which is the case in the most recent BAA load forecast.


NorthWestern Energy
2013 Peak Forecast
Including DSM
Peak MW
1500
1400
1300
1200
1100
1000
900
800
Actual
(not weather normalized)
Forecast
(weather normalized)
1 in 10 Winter Peak
1 in 2 Winter Peak
2011 RPP
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033

NWE Energy Supply Historical and Forecast Peaks
1 in 2 Peak Forecast - Including DSM

	2013 RPP Energy Supply Peak Forecast		
	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
Forecast	2013	1152	1078
	2014	1162	1086
	2015	1171	1093
	2016	1182	1102
	2017	1191	1110
	2018	1201	1119
	2019	1212	1126
	2020	1222	1135
	2021	1233	1144
	2022	1243	1152
	2023	1254	1161
	2024	1268	1172
	2025	1282	1184
	2026	1297	1196
	2027	1309	1205
	2028	1321	1215
	2029	1333	1225
	2030	1345	1235
	2031	1358	1245
	2032	1370	1255
	2033	1382	1265
2013-2033 CAGR		0.92%	0.80%

NWE 2013 Resource Procurement Plan
Model Input Overview
Demand Side Management (DSM) Forecast

1. Future DSM acquisition is considered a load-serving resource rather than a direct reduction on the load forecast. Prior year DSM acquisition is built into the load forecast as a result of being embedded in the actual historical load that drives the forecast.

2. The 2013 RPP DSM acquisition forecast is based on the 2009 DSM study and acquisition plan that produced a 15-year goal of 84 aMW (91 aMW including losses) in accumulated DSM energy savings by 2024.

3. The planned DSM contribution to serving peak load, including losses, is an accumulated 130 MW of winter peak savings and 125 MW of summer peak savings by 2024.

2009 15-Year DSM Plan

		Annual Cumulative Achievable			
Year	Year	Residential - non-CFL	Residential - CFL	Non-Residential	Total
1	2010	0.6	3.8	1.1	5.5
2	2011	1.4	7.7	2.4	11.5
3	2012	2.1	11.5	3.8	17.5
4	2013	2.9	15.4	5.2	23.5
5	2014	3.7	19.2	6.6	29.5
6	2015	5.8	19.2	10.5	35.5
7	2016	8.0	19.2	14.3	41.5
8	2017	10.1	19.2	18.2	47.5
9	2018	12.3	19.2	22.0	53.5
10	2019	14.4	19.2	25.9	59.5
11	2020	16.6	19.2	29.7	65.5
12	2021	18.7	19.2	33.6	71.5
13	2022	20.8	19.2	37.4	77.5
14	2023	23.0	19.2	41.3	83.5
15	2024	23.3	19.2	41.8	84.3

NWE 2013 Resource Procurement Plan
Model Input Overview
Existing Resources Assumptions

1. Existing resources include all owned, leased, and physical contracted energy supply resources that are at least 3 years in duration.

2. QF Tier II contracts will expire at various times throughout the planning horizon and are assumed to renew under QF1 tariffs.

3. Judith Gap and any QF1 contracts that expire are assumed to renew under estimated prevailing avoided cost rates.

NorthWestern Energy
Existing Energy Supply Resources
(as of June 26, 2013)

Resource	Nameplate [1] Capacity (MW)	Summer Peaking Capacity (MW)	Winter Peaking Capacity (MW)	Annual Energy (aMW)	Load Following Up (MW)	Load Following Down (MW)	Spinning Reserves (MW)	Non-Spinning Reserves (MW)	Expiration Date
Colstrip Unit 4	222.0	222.0	222.0	202.0	0.0	222.0	0.0	0.0	n/a
Basin Creek	52.0	35.0	35.0	2.0	35.0	0.0	0.0	17.0	7/1/2026
Spion Kop	40.0	0.0	0.0	16.0	0.0	0.0	0.0	0.0	n/a
QF Tier II	119.7	83.7	99.4	93.0	0.0	0.0	0.0	0.0	Various
QF-1 Tariff[5]	16.7	2.8	0.7	0.1	0.0	0.0	0.0	0.0	Various
Gordon Butte	9.6	0.0	0.0	4.0	0.0	0.0	0.0	0.0	3/21/2036
Musselshell	10.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	3/24/2036
Musselshell Two	10.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	3/24/2036
Two Dot [2]	9.7	0.0	0.0	3.0	0.0	0.0	0.0	0.0	8/31/2037
Fairfield Wind [2]	9.5	0.0	0.0	3.0	0.0	0.0	0.0	0.0	8/31/2037
Turnbull	13.0	9.5	0.0	3.0	0.0	0.0	0.0	0.0	12/31/1932
DSM (2010-2024 Total)[3 & 4]	n/a	124.8	130.2	91.5	0.0	0.0	0.0	0.0	n/a
DGGS (Energy Supply)	7.0	7.0	7.0	7.0	0.0	0.0	0.0	0.0	n/a
Judith Gap	135.0	0.0	0.0	53.0	0.0	0.0	0.0	0.0	12/31/2026
Tiber	7.5	0.0	5.0	2.0	0.0	0.0	0.0	0.0	6/1/2024
PPL 7 YR (HL)	200.0	200.0	200.0	112.0	0.0	0.0	0.0	0.0	6/30/2014
PPL 7 YR (LL)	125.0	0.0	0.0	55.0	0.0	0.0	0.0	0.0	6/30/2014
PPL 09 RFP (HL)	25.0	25.0	25.0	14.0	0.0	0.0	0.0	0.0	6/30/2017
Citgroup 08 RFP	25.0	25.0	25.0	25.0	0.0	0.0	0.0	0.0	6/30/2020
Morgan S 09 RFP (HL)	25.0	25.0	25.0	14.0	0.0	0.0	0.0	0.0	6/30/2017
TransAlta 10 RFP (HL)	25.0	25.0	25.0	14.0	0.0	0.0	0.0	0.0	6/30/2017
Powerex (LL)	50.0	0.0	0.0	22.0	0.0	0.0	0.0	0.0	12/31/2014
Credit Suisse	25.0	25.0	25.0	25.0	0.0	0.0	0.0	0.0	6/30/2015
TOTAL:	1,161.8	809.7	824.3	766.5	35.0	222.0	0.0	17.0	n/a

1. Nameplate capacity reflects NWE share only
2. Under QF contract but not yet under construction
3. Pre-existing DSM embedded in load forcast / values include losses
4. Estimated on non-coincident peak basis
5. QF-1 excludes wind contracts after 2011

NWE 2013 Resource Procurement Plan
Model Input Overview
Proposed New Resources to Assess

1. The number of proposed new resources that will be modeled in the 2013 RPP is trimmed down considerably from previous plans due to a focus on resources that are commercially viable and realistically plausible. Alternative resources that are excluded from modeling will still receive consideration in the body of the plan.

2. The group of resources that will be assessed via portfolio modeling include: various combined cycle and simple cycle techonologies, combined heat & power, solar pv, and wind.

3. Not including the total universe of generating resources in the modeling effort is consistent with practices exhibited by other utilities in the development of their IRPs, including Puget Sound Energy.

NorthWestern Energy
2013 Energy Supply and Procurement Plan - Resource Options

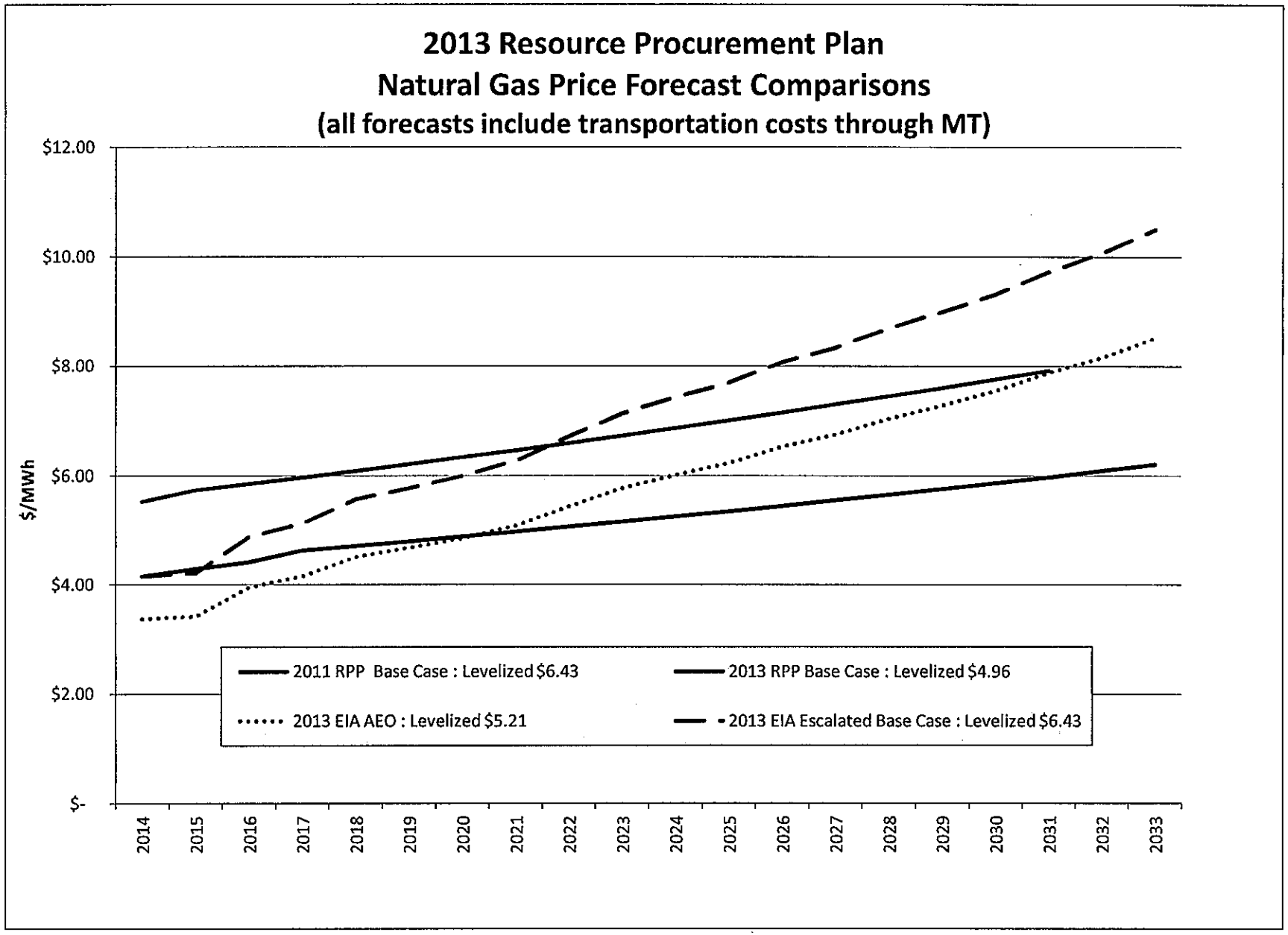
	Leading Edge Technologies	In 2011 Preferred Portfolios	Proposed for Inclusion in 2013 Portfolios
Baseload			
Combined Cycle		Yes	Yes
Combined Cycle w/ CCS	Yes		
Gas Combined Heat & Power			Yes
Supercritical Coal	Yes		
IGCC no CCS	Yes		
IGCC with CCS	Yes		
Intermediate/Peaking			
Aeroderivative Gas Turbine		Yes	Yes
Frame Gas Turbine			Yes
Reciprocating Engine			Yes
Renewable & Other			
Distributed Generation (Rooftop Solar)			
Waste Water Treatment			
Biomass Wood products			
Solar PV		Yes	Yes
Geothermal			
Landfill Gas		Yes	
Small Hydro		Yes	
Wind		Yes	Yes
Storage Devices			
Battery Storage			
Pump Storage		Yes	

NWE 2013 Resource Procurement Plan
Model Input Overview
Natural Gas Price Forecast

1. The natural gas price forecast is based on AECO forward market curve as of June 7, 2013.

2. An escalation rate of 2.07% based on the 20-year average Implicit Price Deflator (measure of average annual growth in GDP) was used to escalate prices beyond the forward curve.

3. Transportation charges of $0.17 (AECO to MT) and $0.4225 (delivery within MT) are added to the AECO forward market curve to create the delivered cost of fuel.

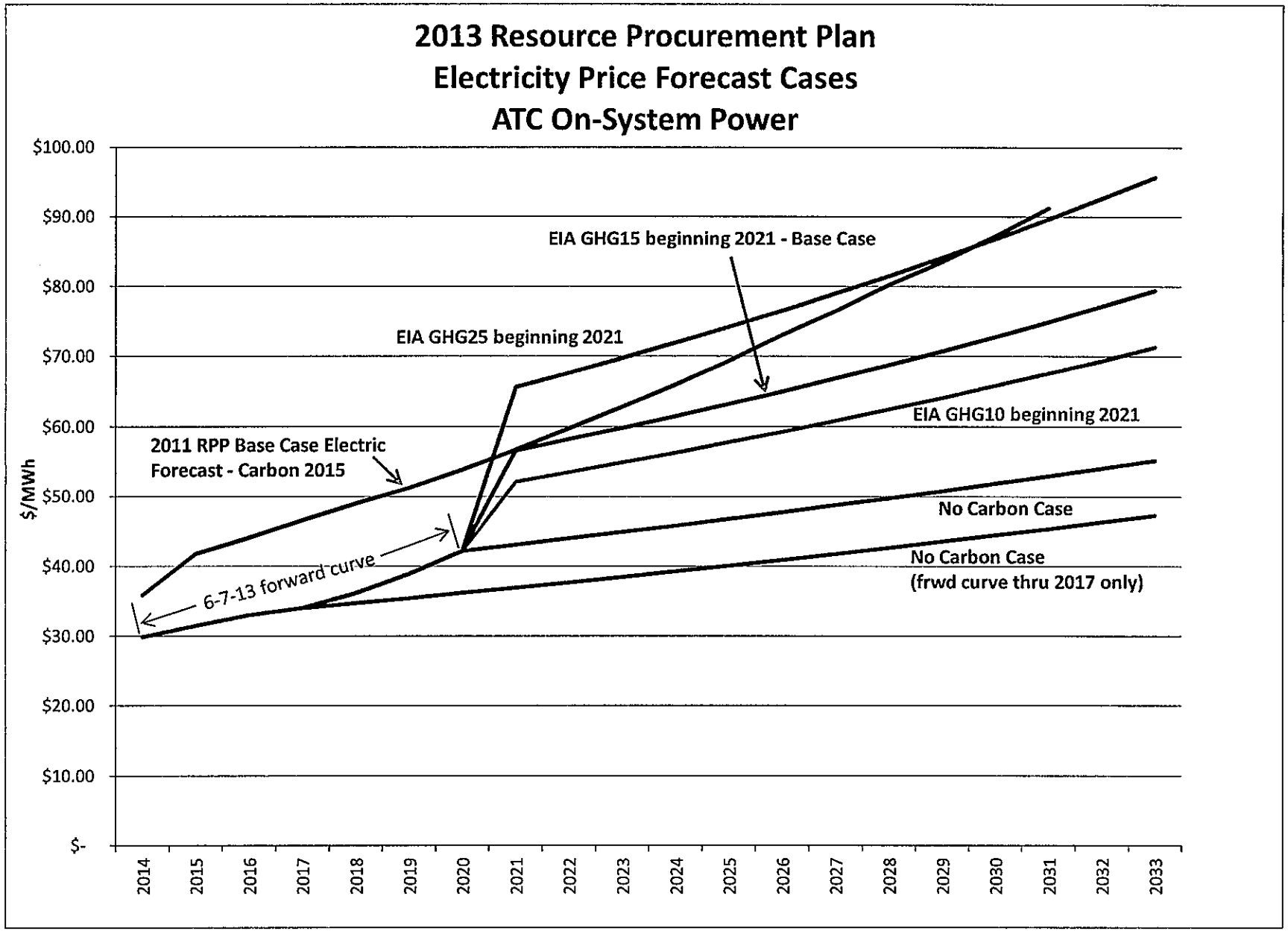

2013 Resource Procurement Plan
Natural Gas Price Forecast Comparisons
(all forecasts include transportation costs through MT)
$/MWh
$12.00
$10.00
$8.00
$6.00
$4.00
$2.00
$-
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2011 RPP Base Case : Levelized $6.43
2013 RPP Base Case : Levelized $4.96
2013 EIA AEO : Levelized $5.21
2013 EIA Escalated Base Case : Levelized $6.43

NWE 2013 Resource Procurement Plan
Model Input Overview
Electric Price Forecast

1. The electric price forecast is based on the Mid-C forward market curve as of June 7, 2013.

2. The electric price forecast cases include the EIA carbon penalty cases in 2021 as they would apply to the marginal unit (assumed to be a natural gas-fired resource).

3. An escalation rate of 2.07% based on the 20-year average Implicit Price Deflator (measure of average annual growth in GDP) was used to escalate prices beyond the forward curve.


2013 Resource Procurement Plan
Electricity Price Forecast Cases
ATC On-System Power
$/MWh
$100.00
$90.00
$80.00
$70.00
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$-
2014
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2019
2020
2021
2022
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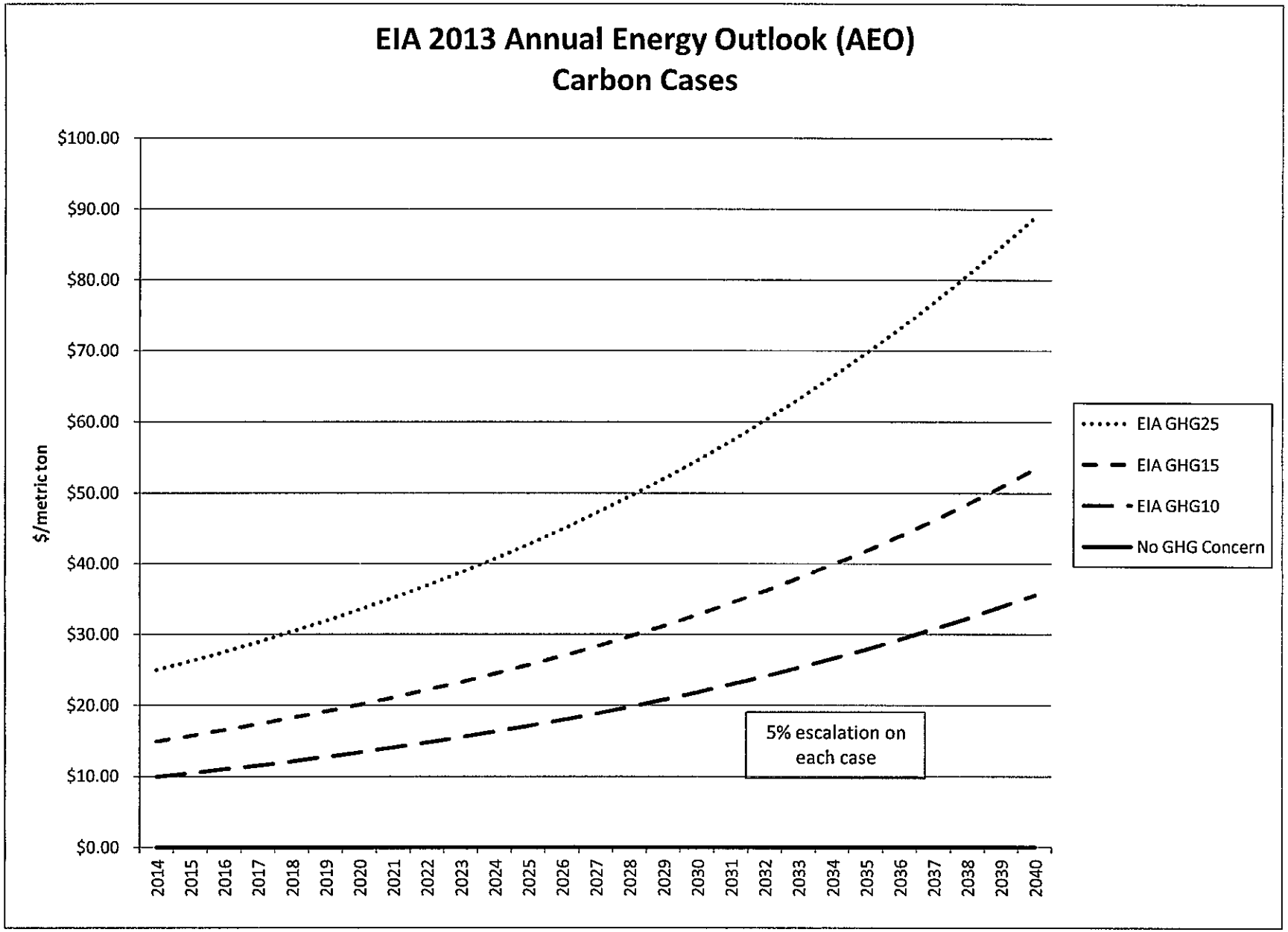
2032
2033
EIA GHG15 beginning 2021 - Base Case
EIA GHG25 beginning 2021
EIA GHG10 beginning 2021
2011 RPP Base Case Electric
Forecast - Carbon 2015
No Carbon Case
No Carbon Case
(frwd curve thru 2017 only)
6-7-13 forward curve

NWE 2013 Resource Procurement Plan
Model Input Overview
Carbon Penalty Forecast

1. The carbon penalty forecast was adopted from the Energy Information Administration's (EIA) 2013 Annual Energy Outlook (AEO).

2. EIA developed three carbon, or green house gas (GHG), cases in addition to its "No GHG Concern" case which was simply a no carbon penalty case:
    a. GHG10 case – carbon penalty beginning in 2014 at $10/metric ton and escalating at 5%
    b. GHG15 case – carbon penalty beginning in 2014 at $15/metric ton and escalating at 5%
    c. GHG25 case – carbon penalty beginning in 2014 at $25/metric ton and escalating at 5%

3. NWE intends to use these cases as well as any others that will help capture a variety of carbon futures and provide insight into how resources and portfolios will perform under the uncertain future of carbon legislation.


EIA 2013 Annual Energy Outlook (AEO)
Carbon Cases
$/metric ton
$100.00
$90.00
$80.00
$70.00
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$0.00
2014
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2037
2038
2039
2040
EIA GHG25
EIA GHG15
EIA GHG10
No GHG Concern
5% escalation on each case

NWE 2013 Resource Procurement Plan
Model Input Overview
Renewable Energy Credits (REC) Forecast

1. The Renewable Energy Credit (REC) forecast is based on broker quotes for RECs on July 24, 2013, provided by Karbone, Inc., a global firm focused on renewable energy and environmental markets operating from offices in New York, London and Istanbul.

2. The quotes cover three years, 2013-2015, and average $1.07 with the high occurring in 2015 at $1.25.

3. For the period 2016-2033, REC values increase by $0.25, which is the increase from 2014 to 2015 in the broker quotes. The 20-year levelized value of RECs is $2.76.

4. The 2011 RPP reflected a 20-year levelized REC value of $11.36 based on short-term broker quotes ($7.50) and actual long-term contract deals for RECs ($15.00) executed in the state of Washington.

Karbone Broker Quotes-Based Method
2013 RPP REC Forecast

highlighted = average bid/ask broker quotes

2016-2033 increased by $0.25 annually
(same as 2014 to 2015 increase)

	REC Forecast	Annual Growth
2013	$0.95	
2014	$1.00	5.3%
2015	$1.25	25.0%
2016	$1.50	20.0%
2017	$1.75	16.7%
2018	$2.00	14.3%
2019	$2.25	12.5%
2020	$2.50	11.1%
2021	$2.75	10.0%
2022	$3.00	9.1%
2023	$3.25	8.3%
2024	$3.50	7.7%
2025	$3.75	7.1%
2026	$4.00	6.7%
2027	$4.25	6.3%
2028	$4.50	5.9%
2029	$4.75	5.6%
2030	$5.00	5.3%
2031	$5.25	5.0%
2032	$5.50	4.8%
2033	$5.75	4.5%
20-Yr Lev	**$2.76**	

NWE 2013 Resource Procurement Plan
Model Input Overview
Wind Integration & Ancillary Services Costs

1. Wind integration costs are based on the wind integration tariff finalized in the 2011 RPP Avoided Cost docket, updated with the electricity and natural gas price forecasts developed with June 7, 2013 forward curve information.

2. The resulting integration adders applied to wind projects are as follows:
   a. Zone 1, < 25 miles from Judith Gap: $7.12/MWh
   b. Zone 2, 25-60 miles from Judith Gap: $2.62/MWh
   c. Zone 3, > 60 miles from Judith Gap: $0.96/MWh

3. Purchasing operating reserves is necessary for each generating resource, with thermal resources requiring 7% reserves, and wind and hydro resources requiring 5% reserves.

4. Based on the current operating reserve contract that NWE has with a third party, the operating reserve costs applied to each resource is as follows:
   a. Thermal resources: $0.77/MWh
   b. Wind & Hydro resources: $0.55/MWh

Cost of Regulation and WI-1 Tariff Rates, 25-Year Levelized Rate for New Wind (Revised)
(Updated with June 7, 2013 Electric and Natural Gas Price Forecasts)

	105 MW Regulation for Load and Wind as per PSC-002(a) with 25-yr levelized prices			60 MW Regulation for Load as per UMX-013(a) with 25-yr levelized prices			Change for 45 MW Additional Regulation
Fuel Expenses							
	Units	Price	Total	Units	Ave. Price	Total	Total
Natural Gas Fuel Costs (Dekatherms) /1	3,296,876	$6.45	$ 21,271,236	2,675,524	$6.45	$ 17,262,313	$ 4,008,923
Diesel Fuel Costs (Gallons) /2	1,293,569	$3.79	$ 4,902,628	1,049,774	$3.79	$ 3,978,643	$ 923,984
Compressor Electricity Bill /3			$ 559,177			$ 559,177	$ -
Total Fuel Expense			$ 26,733,040			$ 21,800,133	$ 4,932,907
Revenue Credits							
	Per NWE	Default Supply	Total	Per NWE	Default Supply	Total	Total
Mid-C Forward Market Price ($/MWh) /4	$34.90	$ 34.90	$ 34.90	$ 34.90	$ 34.90	$ 34.90	
Discount to Mid-C ($/MWh)	($7.00)	($7.00)	($7.00)	($7.00)	($7.00)	($7.00)	
Project Energy (aMW)	27	7	34	18	7	25	
Hours/Year	8,760	8,760	8,760	8,760	8,760	8,760	
Total Revenue Credits	$ 6,599,891	$ 1,711,083	$ 8,310,974	$ 4,399,927	$ 1,711,083	$ 6,111,010	$ 2,199,964
Cost of Regulation			$ 18,422,066			$ 15,689,123	$ 2,732,943

Cost of Regulation for New Wind	DGGS
Annual Net Variable Cost	$ 2,732,943
Regulation Required (MW)	45
Unit Cost ($/kw-month)	$ 5.06

WI-1 Tariff Rates		DGGS		
	Regulation as % of Nameplate Capacity	Rate ($/kw-month of Namplate Capacity)	Rate for 37% c.f. wind project ($/kwh)	Total annual cost for 10 MW project at 37% c.f.
Zone 1	38.0%	$ 1.92	$ 0.00712	$ 230,782
Zone 2	14.0%	$ 0.71	$ 0.00262	$ 85,025
Zone 3	5.1%	$ 0.26	$ 0.00096	$ 30,973

Resource Planning with Uncertainty for NorthWestern Energy

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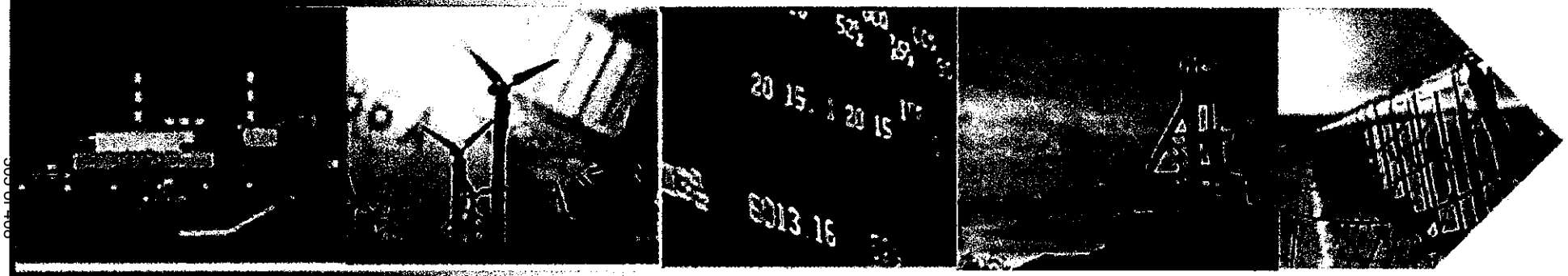
Better Models. Better Decisions.



Selection of Optimal Resource Plan for 2013 Resource Procurement Plan

August 28, 2013

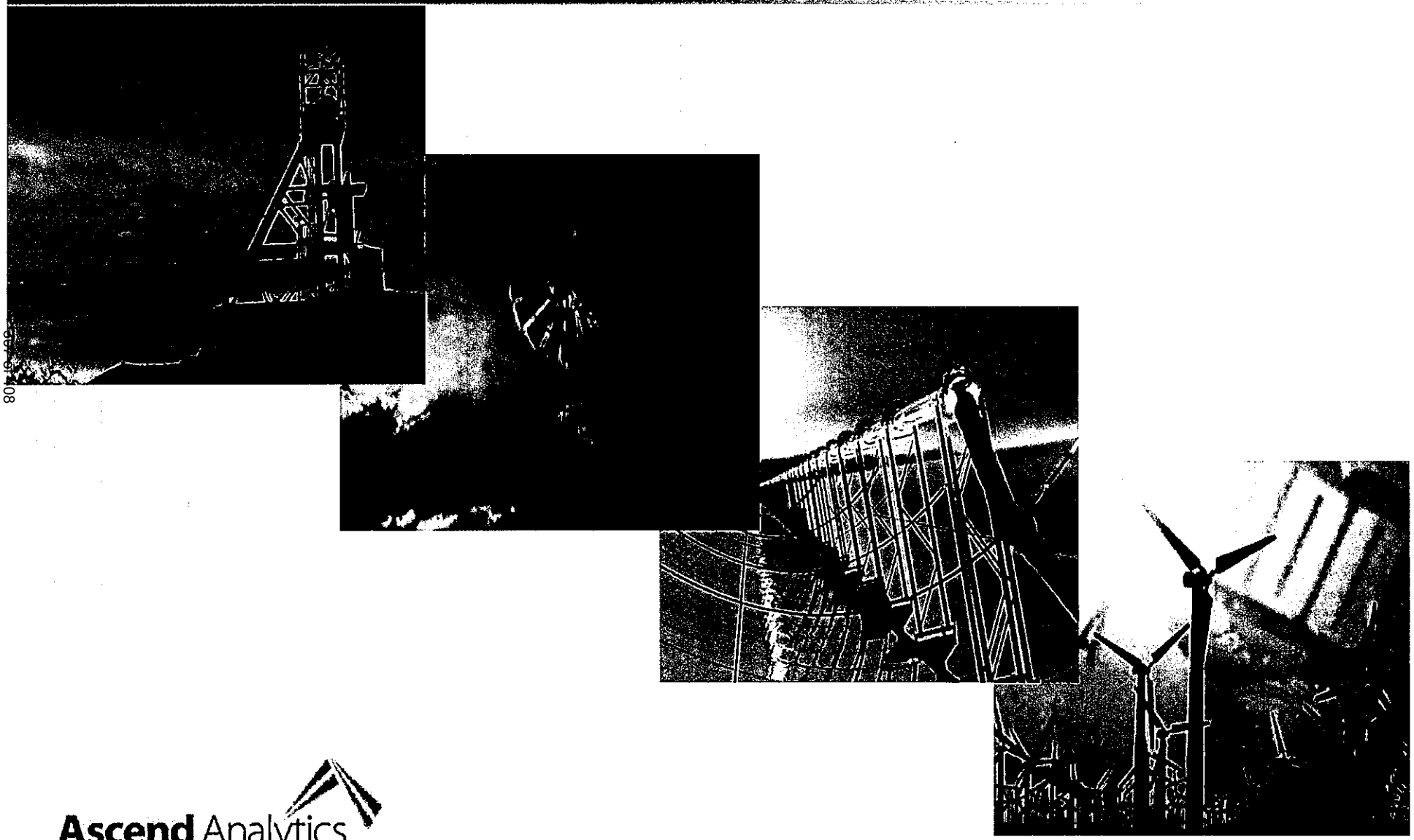
Gary Dorris, Ph.D.
Ascend Analytics, LLC

gdorris@ascendanalytics.com
303.415.0311
www.ascendanalytics.com

Outline

- Resource Planning Paradigms and Choices
- Resource Selection
- Best in Breed Resource Selection
- Best in Show Resource Selection
- Risk Reduction Value (RRV) for Renewables

Activity Plan



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Planning Steps

1. Develop Model Inputs (August)
    1. Market prices
    2. Load forecasts
    3. Resource options
2. Validate Model (August)
    1. Consistency of model
        1. Historic values
        2. Expectations
3. Resource Selection (September)
    1. Deterministic Models
    2. Stochastic Models
4. Automatic Resource Selection (October)
    1. Deterministic Models
    2. Stochastic Models
5. Project Finalization (November)
    1. Full Resource Plan(s)
    2. Technical Write-up

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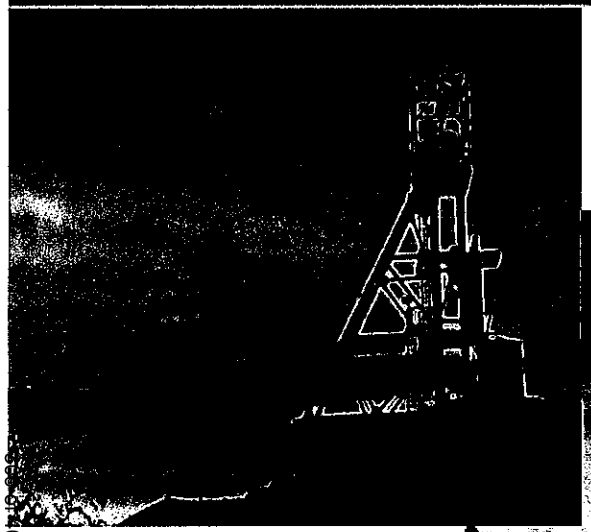
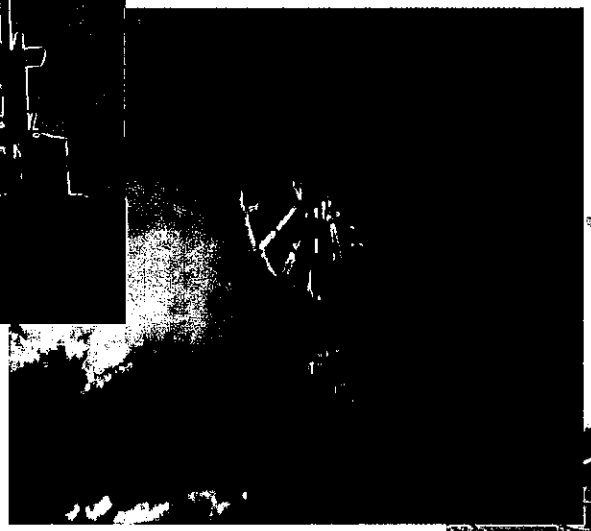
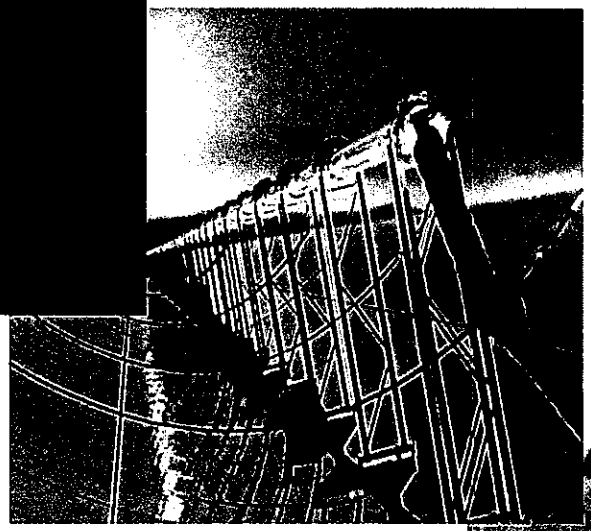
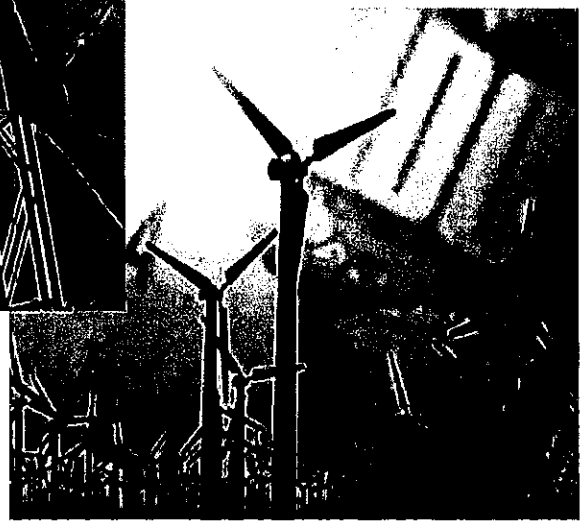
Resource Planning Paradigms and Choices









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Planning in Transition

- Portfolio perspective
  - Fuel diversity
  - Reliability and intermittent resources
  - Uncertainty in fuel, emissions, and power
- Use of market for fuel and power
- Analyze generation resource options with respect to market dynamics
- Capture new dynamics
  - Weather
    - Load
    - Wind generation
  - Market conditions
    - Forward markets for fuel and power
    - Spot price dynamics
- Resource adequacy
  - Reliable service at cost effective rates
  - Market interactions

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Best-In-Breed

Objective:

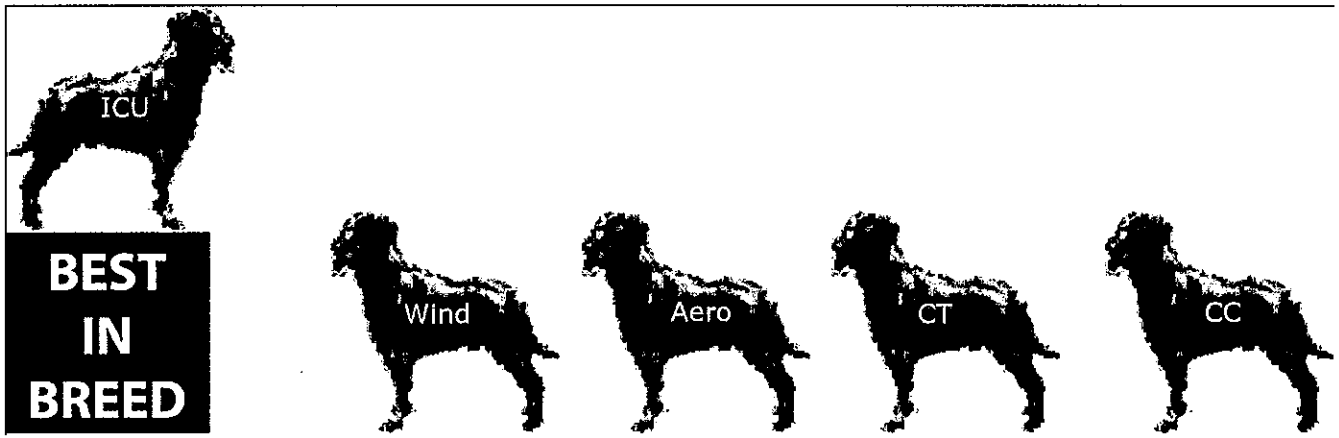
- Find the cheapest capacity expansion plan that satisfies the constraints
  - Cheapest is often defined as the net present value of the revenue requirements

Constraints :

- Renewables, RECs, limits on market sales and purchases,…

Result

- Optimal capacity expansion of generation resources and conservation options to minimize revenue requirements subject constraints.
- Breed is a dog show analogy referring to the best expansion plan from a deterministic run (single forecast) of simulated weather, load, and prices.



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Components of Uncertainty: Integrating Physical and Financial

Financial

- Fuel Prices
  - Gas (Monthly, Daily)
  - Coal
  - Emission Allowances
    - CO2, SO2, Nox
  - RECs
- Electric Prices
  - Supply Stack
  - Transmission
  - Hydro Levels
  - Load
  - Fuel and Emission Prices
- Interest Rates
- Construction Costs

Physical

- Load
  - Weather
  - Growth
    - Customer Mix
    - Energy Efficiency
- Wind
  - Weather→Load
- Hydro
  - Weather
- Unit Contingencies
  - Construction risk
  - Performance risk
- Transmission

[redacted]

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Tools of Supply Planning Model Attributes

Uncertainty Factor	Production Cost Models	Integrated Risk Based Planning Models
Load Growth	Fixed	Simulated Uncertainty
Load Patterns	"Typical" profile	Uncertainty in Profile and Usage Pattern
Conservation	Fixed	Weather Based Demand Response
Weather	Fixed	Weather Based Demand Response
Hydro	Fixed	Simulated Annual Daily Operations
Wind	Fixed	Simulated with Weather
Env. Hg, CO2, SO2, NOx	Fixed	Simulated Based on Uncertainty in Costs
Gas Prices	Fixed	Simulated Monthly and Daily Prices
Transmission	Fixed Input/Output	Variable Flow Contingent Factors
Financial Instruments	Modeled as Fixed Assets	Simulated Values
Reserve Margins	Fixed, Small Effect	Simulated and Key Driver of Prices
Integration of Elements	Cost Based	Linked Equations and Casual Effects
Capital Cost	Fixed	Simulated Interest Rates and Capital

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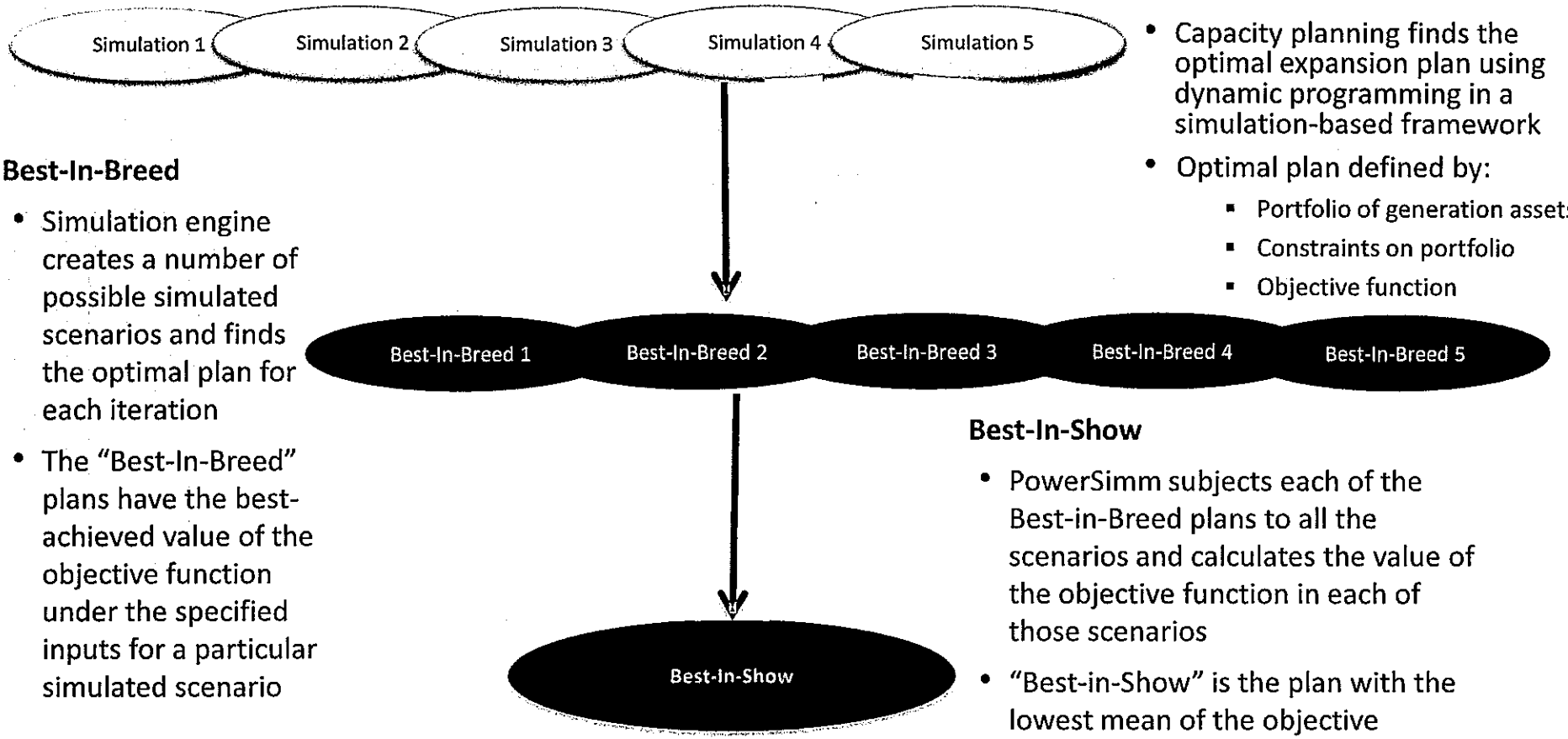
Best-In-Breed & Best-In-Show



Simulations

- Capacity planning finds the optimal expansion plan using dynamic programming in a simulation-based framework
- Optimal plan defined by:
  - Portfolio of generation assets
  - Constraints on portfolio
  - Objective function

Best-In-Breed

- Simulation engine creates a number of possible simulated scenarios and finds the optimal plan for each iteration
- The "Best-In-Breed" plans have the best-achieved value of the objective function under the specified inputs for a particular simulated scenario

Best-In-Show

- PowerSimm subjects each of the Best-in-Breed plans to all the scenarios and calculates the value of the objective function in each of those scenarios
- "Best-in-Show" is the plan with the lowest mean of the objective function across all the scenarios
- This plan performed the **best** across a variety of scenarios

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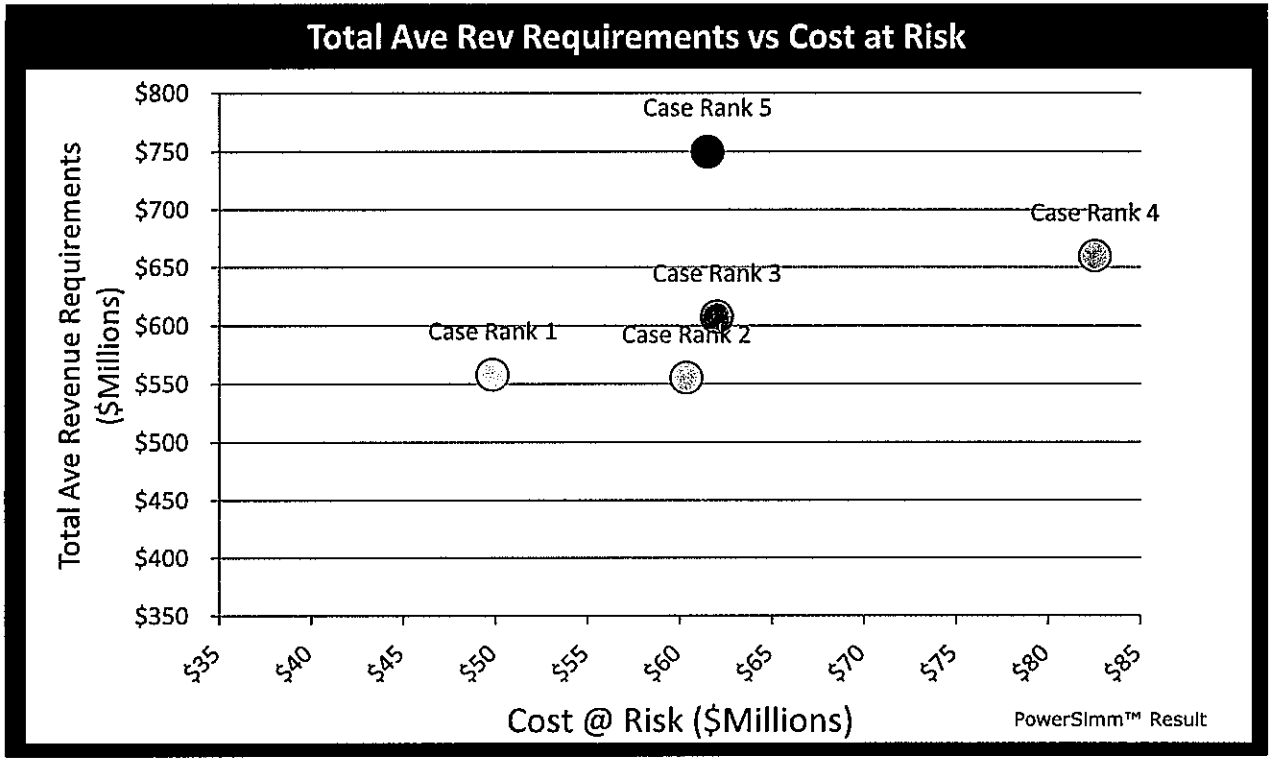
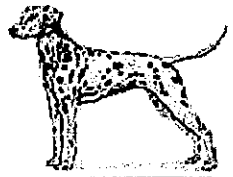
Best In Show



- How do environment controls on coal impact risks?
- What resources are more highly valued with growing percentage of renewables?
- How do I tie Best in Breed back to specific scenarios?



BEST IN SHOW

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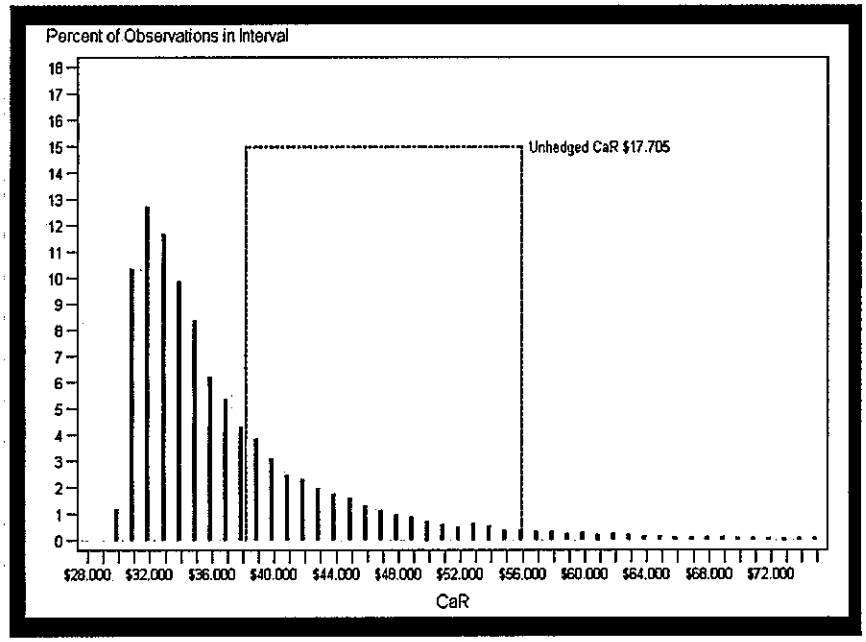
Definition of Common Planning Risk Metrics

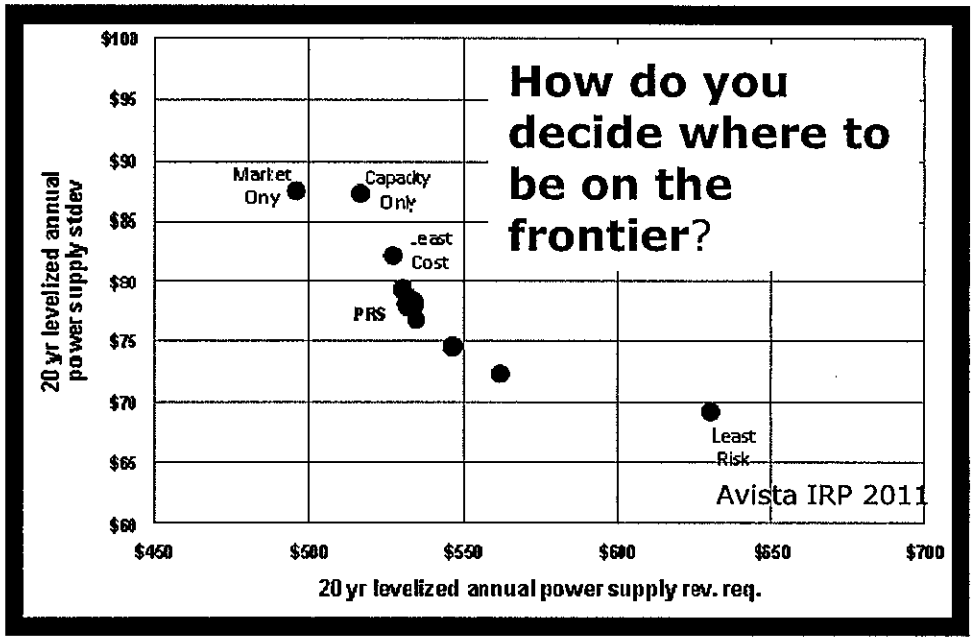
Cost at Risk (CaR) for Rev Req =

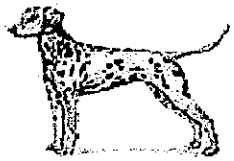
CaR = 95th percent costs – mean costs

Standard deviation (Std) of Ann Rev Req (ARR) =

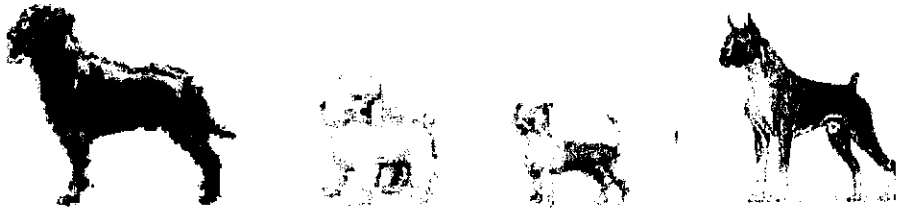
Std = $\sqrt{E[ARR^2] - (E[ARR])^2}$







BEST IN SHOW



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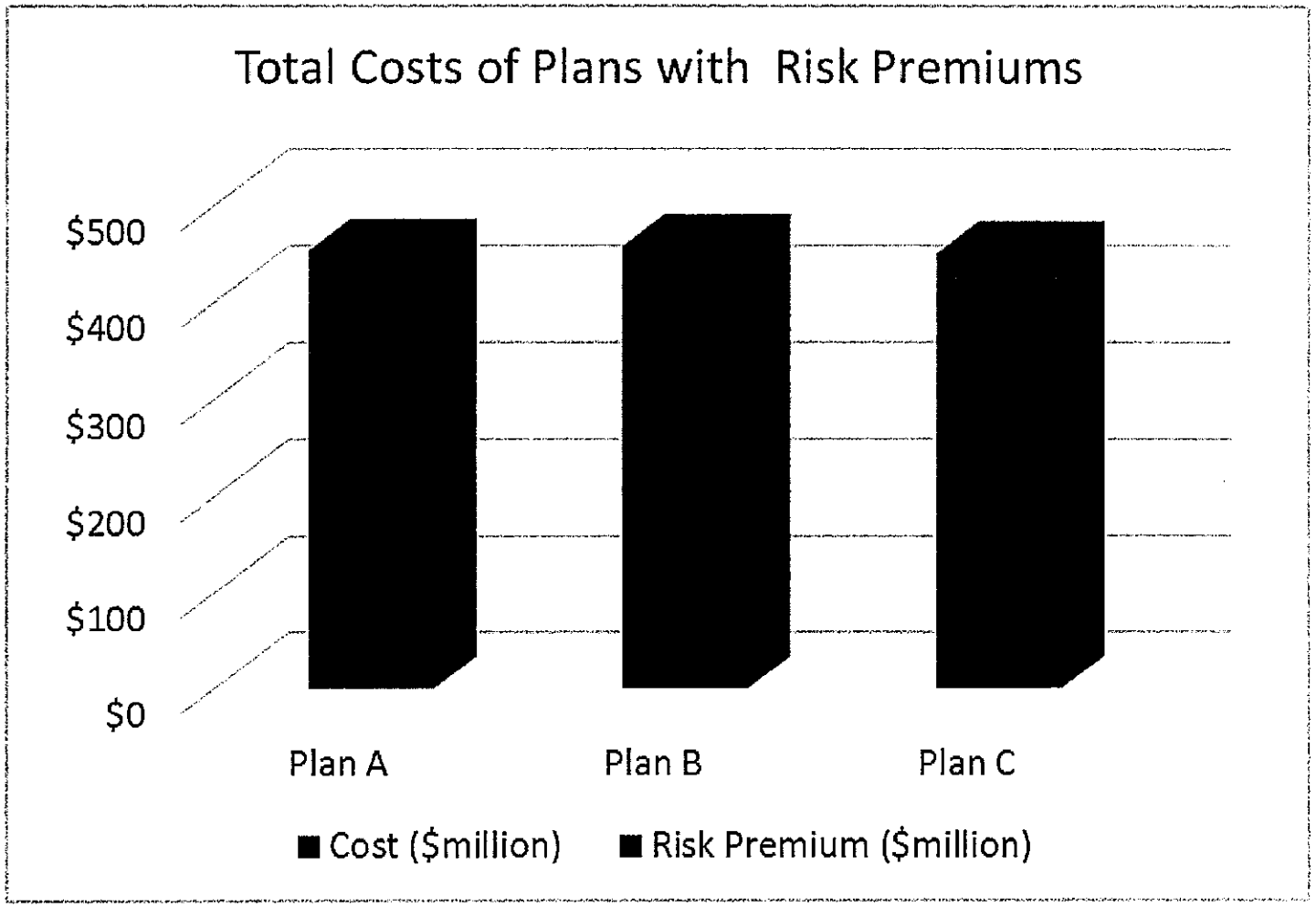
Total Cost Portfolio Selection



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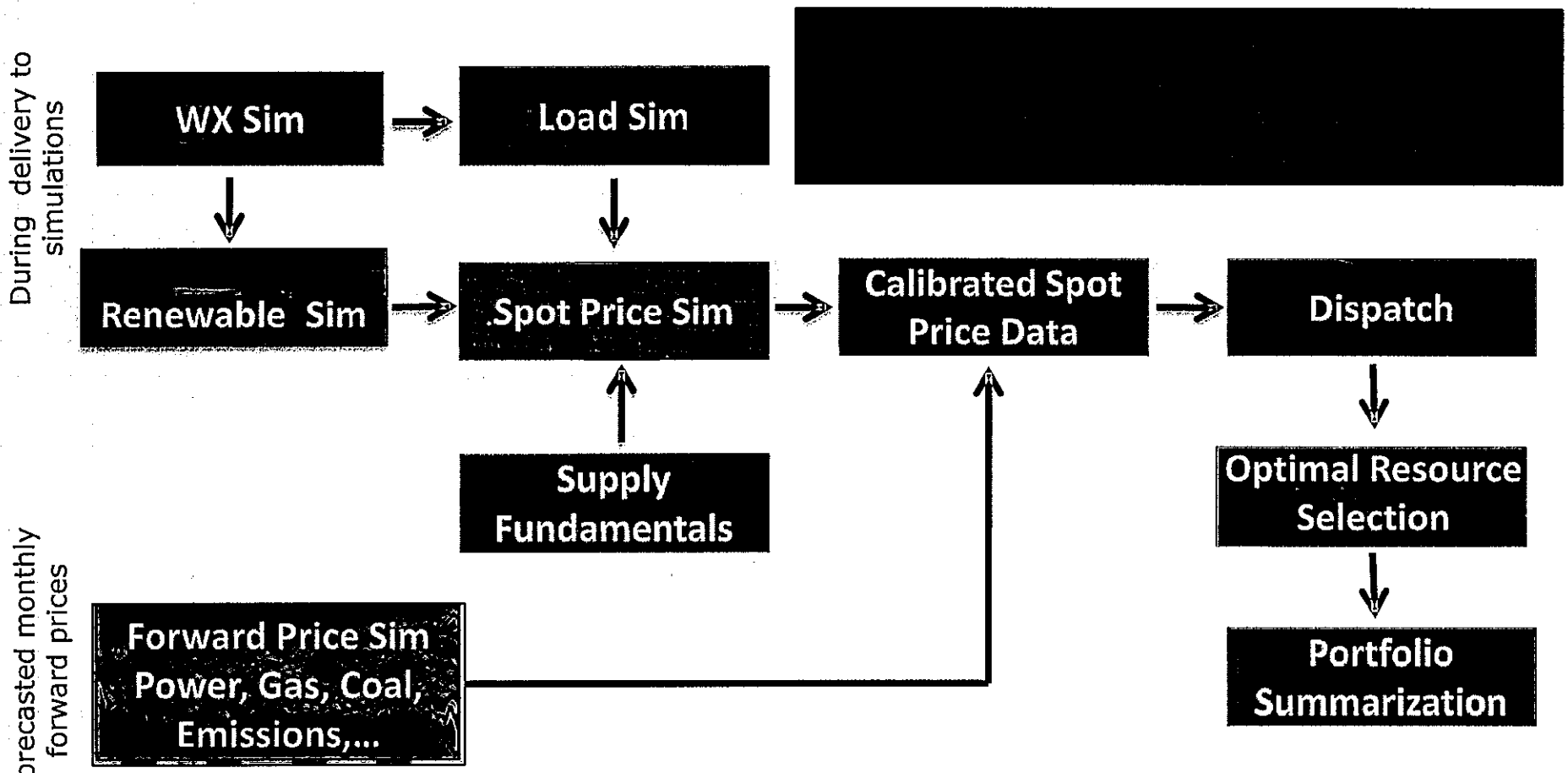
Integrating Physical and Financial Uncertainty



Unified simulation framework reflecting joint financial and physical uncertainty

- Rigorous validation
- Framework to assess Flexible Resource Adequacy (FRA)
- Capture of critical covariate relationships
- Frequency and magnitude of price spikes

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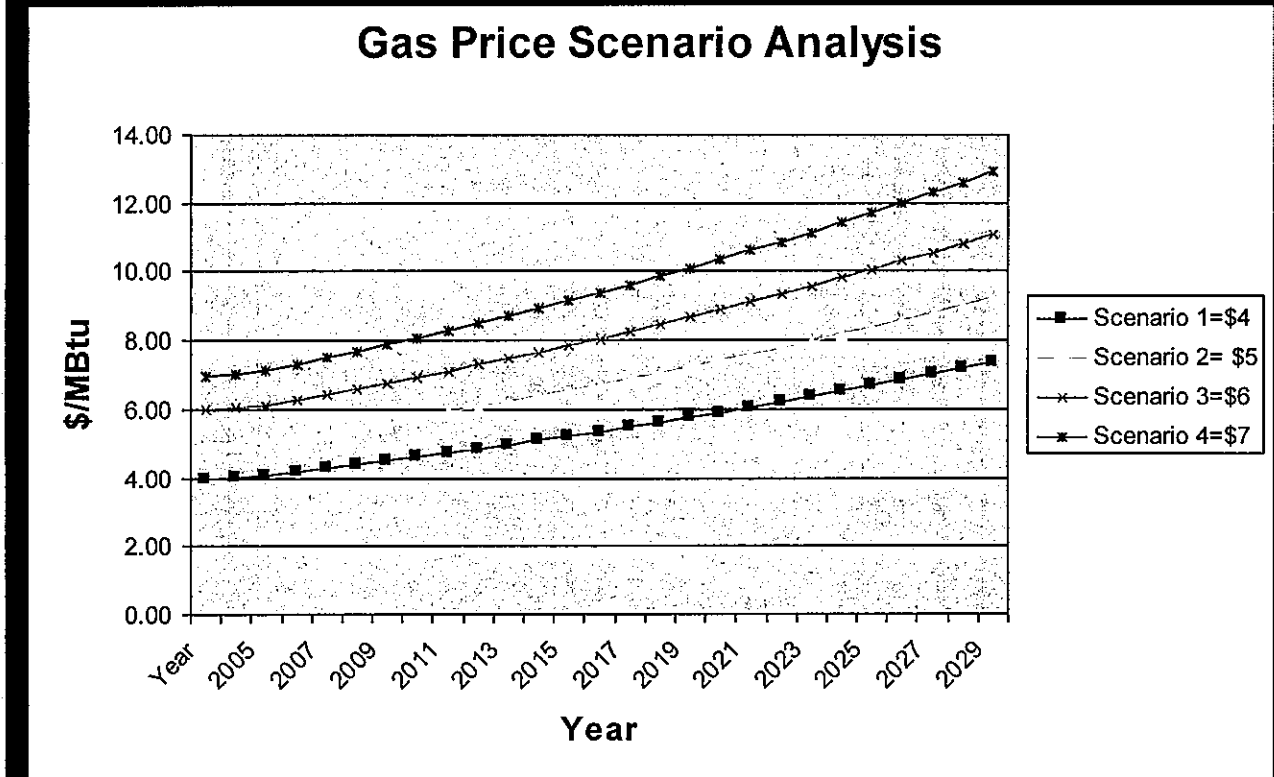
Scenario Analysis

Common Scenarios: High, Med, Low



- Which forecast are the best?
- Scenarios with prices monotonically increasing over time.
- Are these prices consistent with observed patterns?
- What's the probability weight of being in scenario 1 or 4?
- Why is the max prix in 2025 less than historical prices observed 25 years prior?
- Can we capture probabilistically future states and a more market consistent pattern of gas prices?

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Validation Tests

Simulation Module	Statistical Test	Purpose
Power Spot Daily	5th, mean, 95th	Simulation calibration to observed data
	Autocorrelation within month	Time series pattern of movement in prices
	Correlation between on/off peak	Time series pattern of movement in prices
	Daily option quotes at a strike price for each month	Measures fit to market data
	Spark spread to price fit	Consistency of gas to electric price relationship
	Visual inspection of continuous price paths over a year	Heuristic interference of model performance
Spot Basis Gas and Elect	5th, mean, 95th by month	Simulation calibration to observed data
	Temp and gas basis structural relationship	Maintain relationship where gas price mean and variance are a function of temperature
	Load and power basis structural relationship	Maintain relationship where power price mean and variance are a function of load and gas prices
	Autocorrelation	Time series pattern of movement in prices
Spot Hourly	5th, mean, 95th by month	Simulation calibration to observed data
	Autocorrelation	Time series pattern of movement in prices
	Correlation to load	Comparison of relationship of hourly simulated prices and load to actual values
Spot Basis Hourly	5th, mean, 95th by month	Simulation calibration to observed data
	Autocorrelation	Time series pattern of movement in prices
	5th, mean, 95th by hour	Simulation calibration to observed data

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Validation Tests (continued)

Simulation Module	Statistical Test	Purpose
Weather	5th, mean, 95th actual vs. simulated	Simulation calibration to observed data
	Autocorrelation	Time series pattern of weather
	Correlation between stations	Spatial correlation of weather
Load	5th, mean, 95th by monthly summary	Simulation calibration to observed data
	Autocorrelation	Time series pattern of load
	5th, mean, 95th by month	Simulation backtest to observed data
	5th, mean, 95th by hour	Simulation backtest to observed data
	equation fit, parameter estimates, p values, F-test, DW, CP, White, correlation matrix of parameters and residuals	Measures of statistical fit, parameter robustness, and assessment of model performance
Forward price	5th, mean, 95th	Simulation calibration to observed data
	Volatility consistency	Simulated output realizes vols consistent with input values and/or constraints
	Autocorrelation	Time series pattern of movement in prices
	Correlation between commodities	Measures coincident movement of commodities and neighboring months consistent with input correlations and pos definate transformed correlation values
	Monthly option quotes at multiple strikes prices	Measures fit to market data
	Clean spark spread at 5th, mean, 95th	Measures consistency of forward electric and gas price simulations
	Brown spark spread at 5th, mean, 95th	Measures consistency of forward electric and gas price simulations

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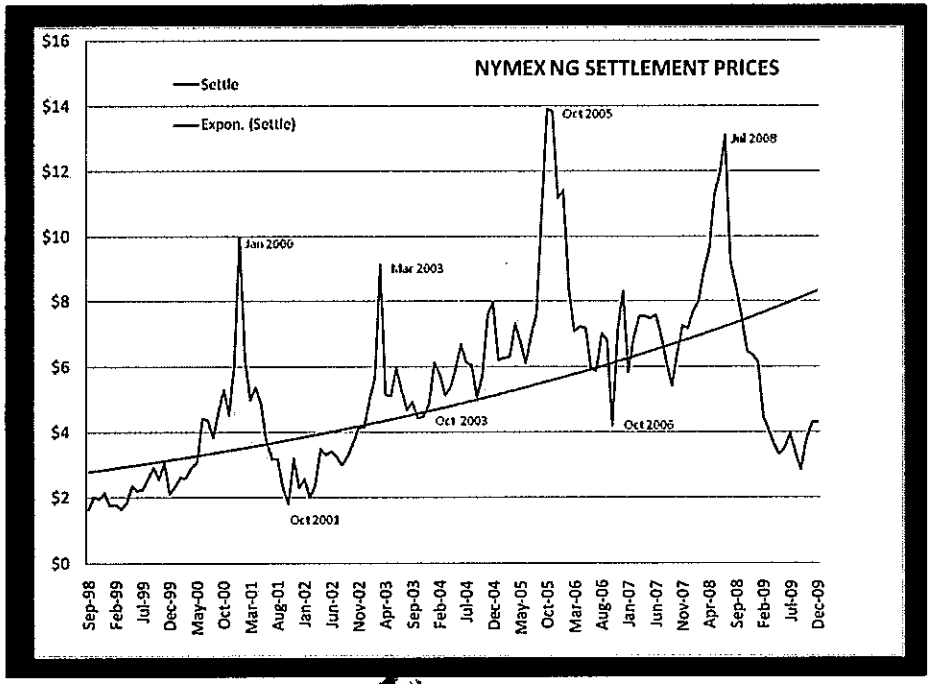
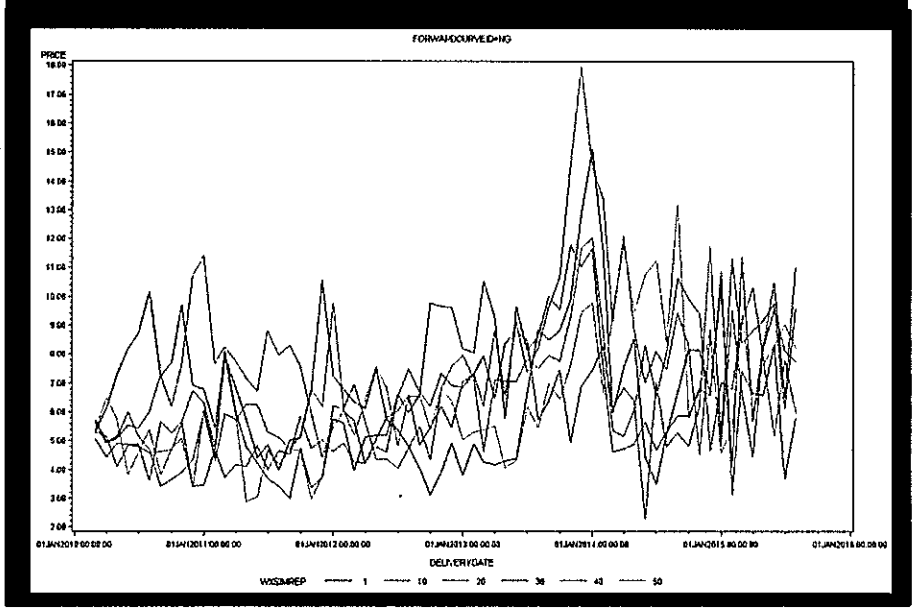
Forward Price Validation History and Simulations: Natural Gas

Simulated forward market prices for Henry Hub

- Large price spikes followed by mean reversion
- 2 to five year cycle
- Large volatility in prices followed by quiescent periods



Forward Price Validation-
Price Paths for Final Evolved Forward Curve Simulation



Historic prompt month prices for Henry Hub

- Large price spikes followed by mean reversion
- 2 to five year cycle
- Large volatility in prices followed by relative quiescent periods

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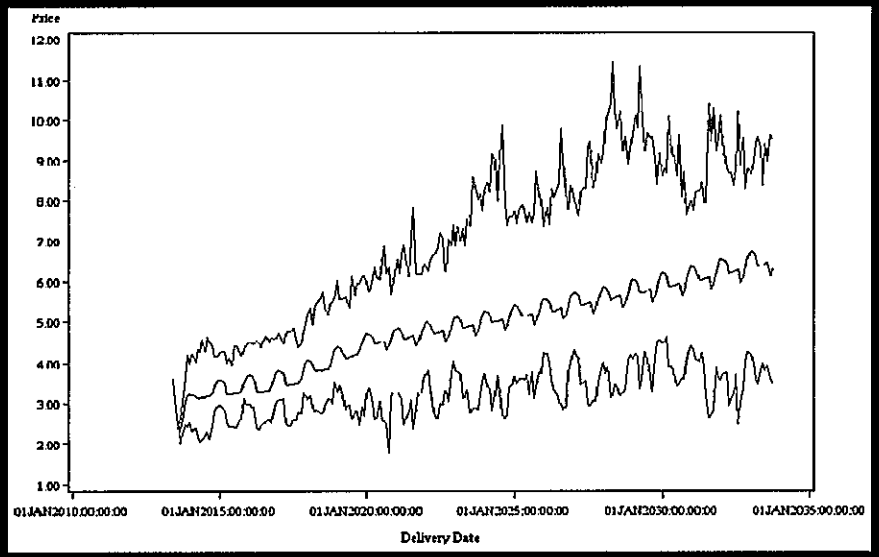
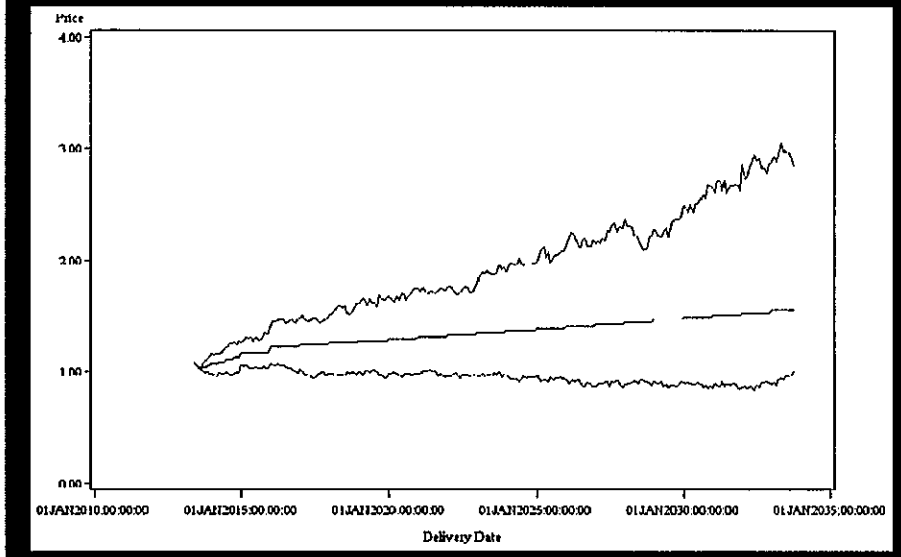
Fuel Price Simulations

AECO Gas



PRB Coal



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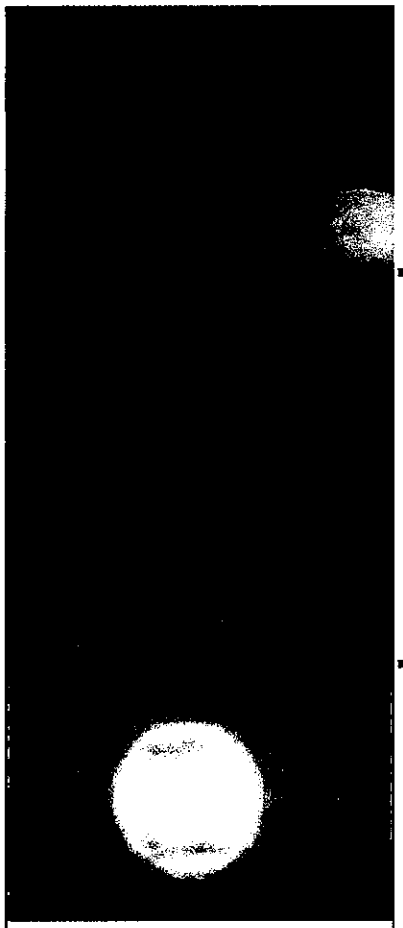
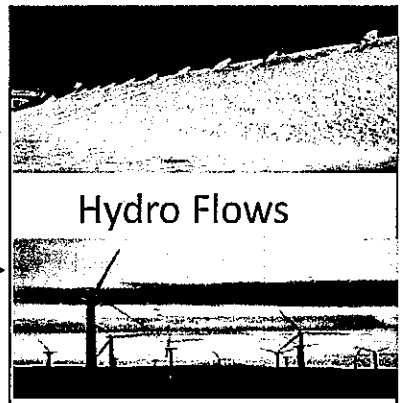
Weather → Hydro Flows → Load → Price Simulations

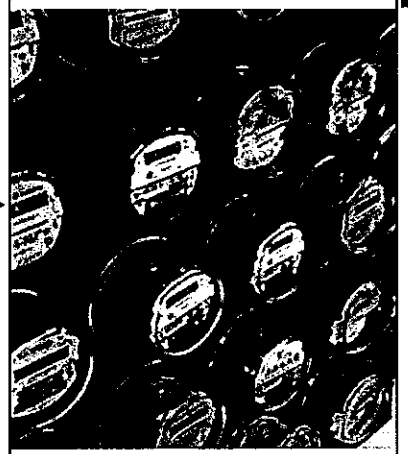


Weather

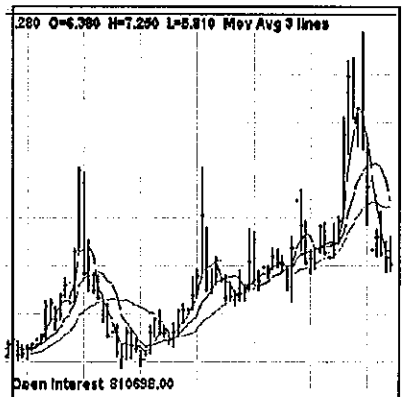


Hydro Flows

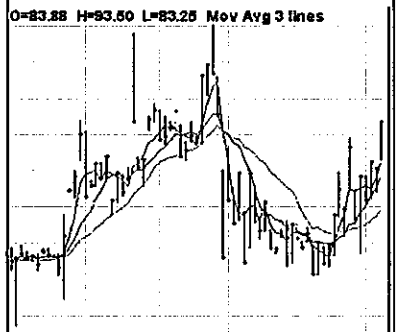
Intermittent Generation



Load



Gas



Electric

Price

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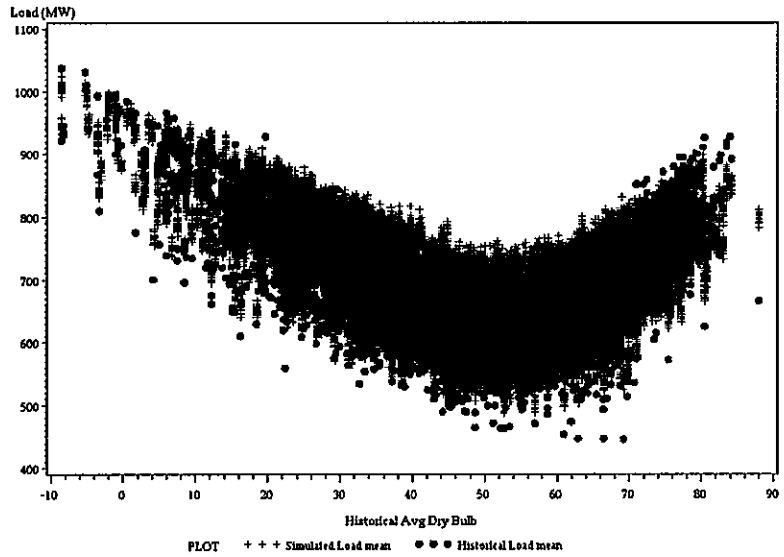
Preserving Relationship and Dependency

Weather-Load Validation

Simulated vs. Historical



Maintaining Correlations

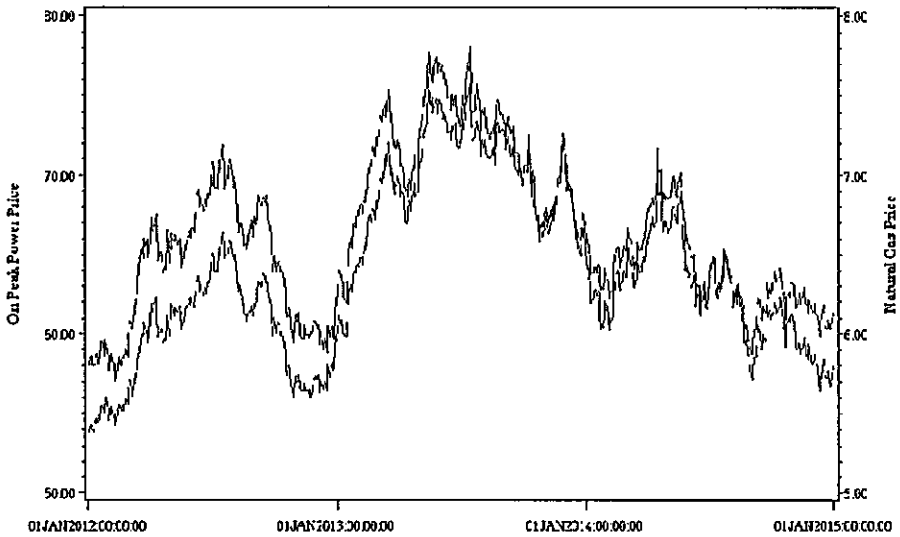
- Incorporating weather into the load model maintains integrity in the weather – load relationship
- Simulations nicely smooth out "bumps" of historical weather record
- Simulations provide for new extreme values to exceed historic record

Validating Relationship

- Validate by capturing the weather – load relationship in the historical period and simulated backcast
- The structural state space modeling captures the changes in shape with changes in load

Inter-Commodity Price Relationship

External Market



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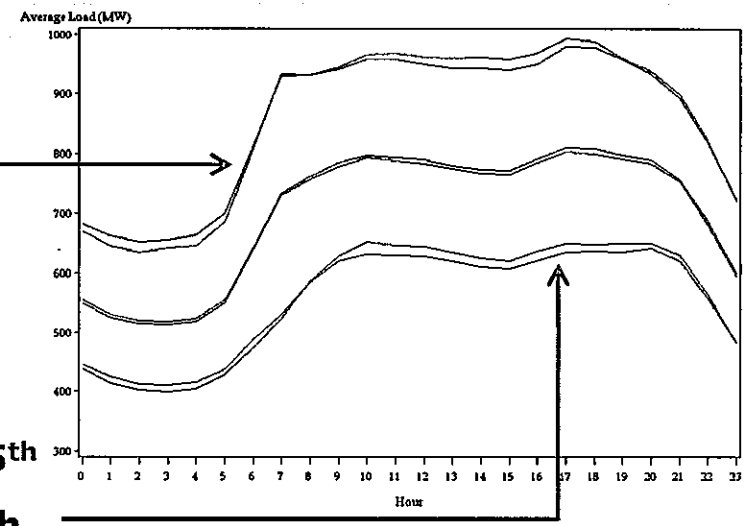
Load – Evaluating Difference 5th, Mean, 95th

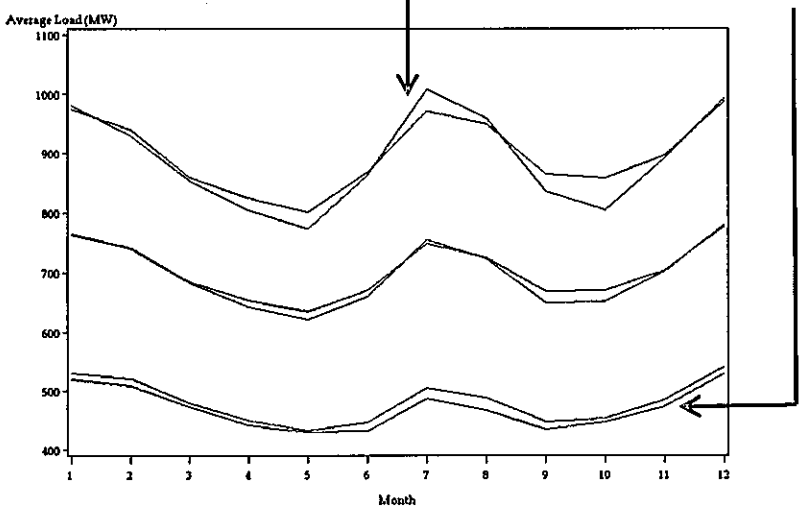
Load Simulation Validation Results

- Demonstrate a robust model to simulate future load
- Capture uncertainty in load growth with extreme weather scenarios validated prior to a load simulation
- Validated monthly load values
- Validated hourly load values for hours 1-24



Steeper load change at 95th

Flatter load pattern at 5th



Load Simulation Modeling

- Developed through a structural state-space model integrating weather as a dependant variable
- Weather effects modeled through a fourth order polynomial that reflects load/temperature relationships
- Calendar structure in terms of month, weekday and hour
- Autocorrelation effects where extreme load conditions are measured

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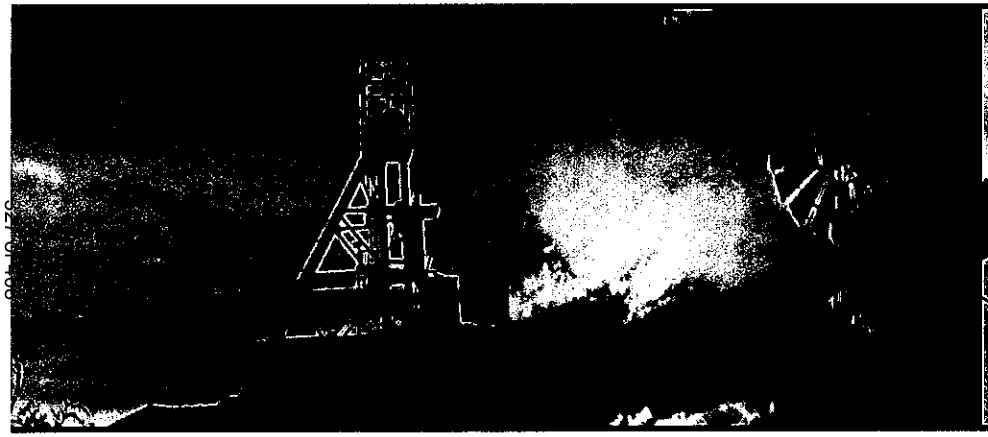
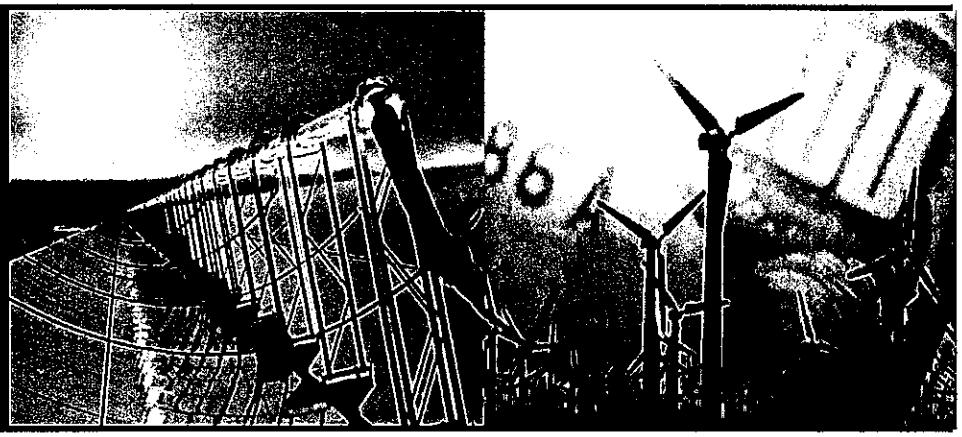
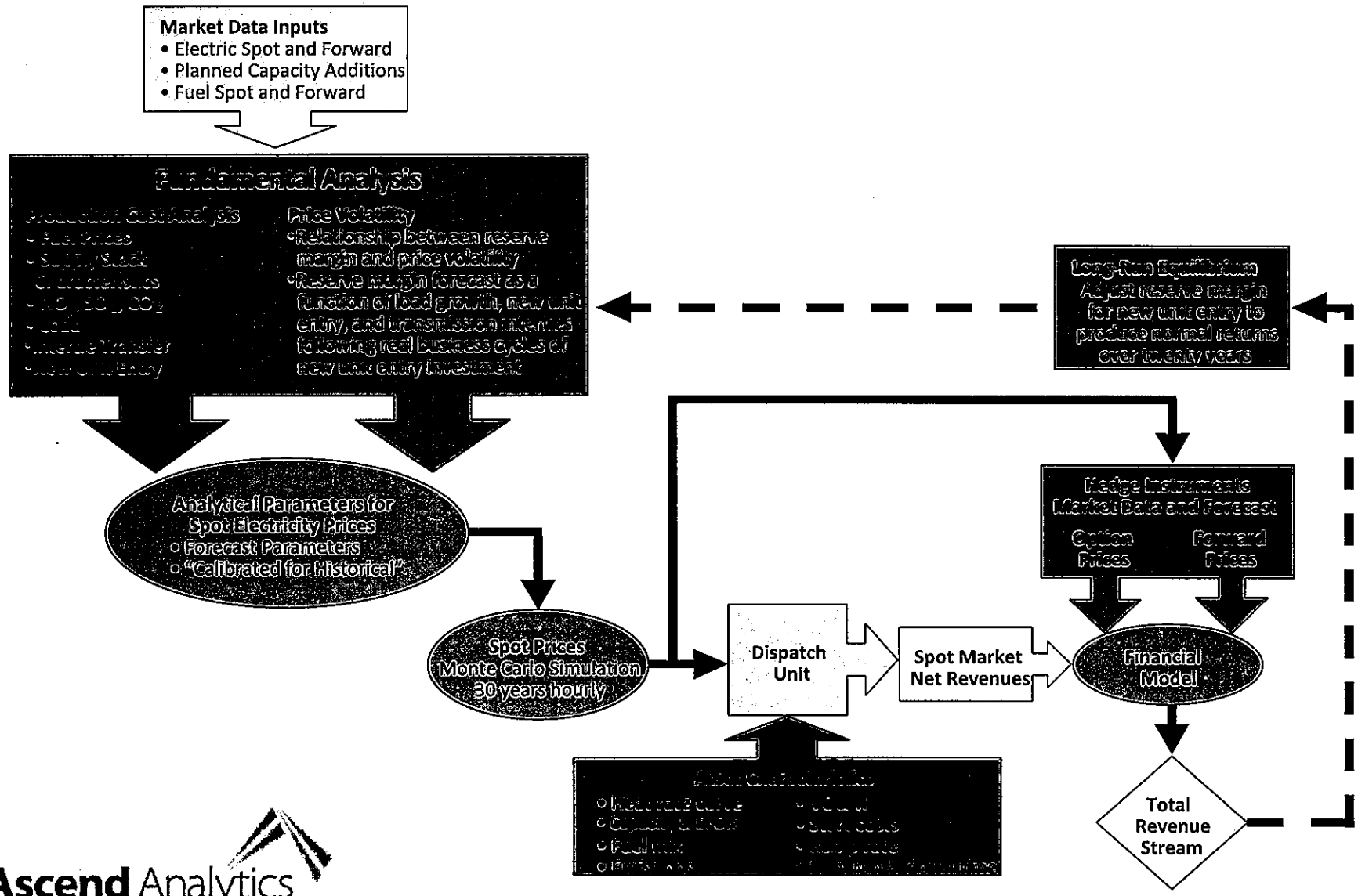
Long-run Market Price Forecasting





Power 2020 Years 4-30
Overview of Modeling Market Price



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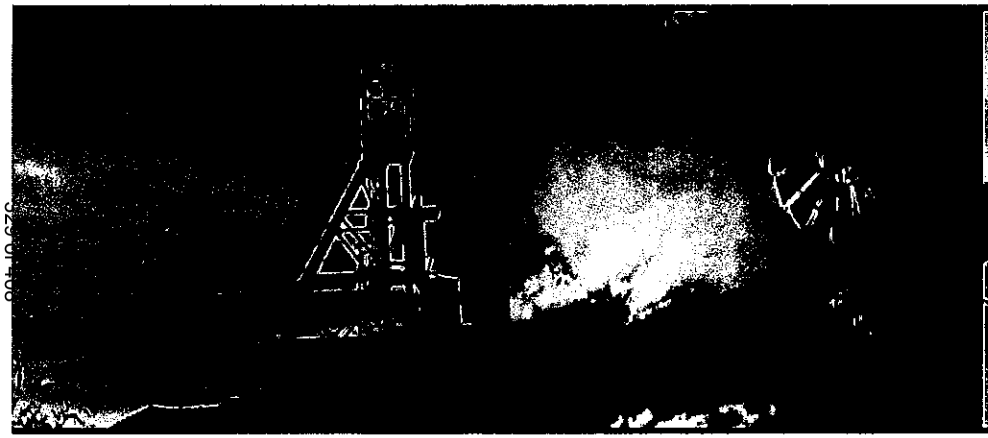
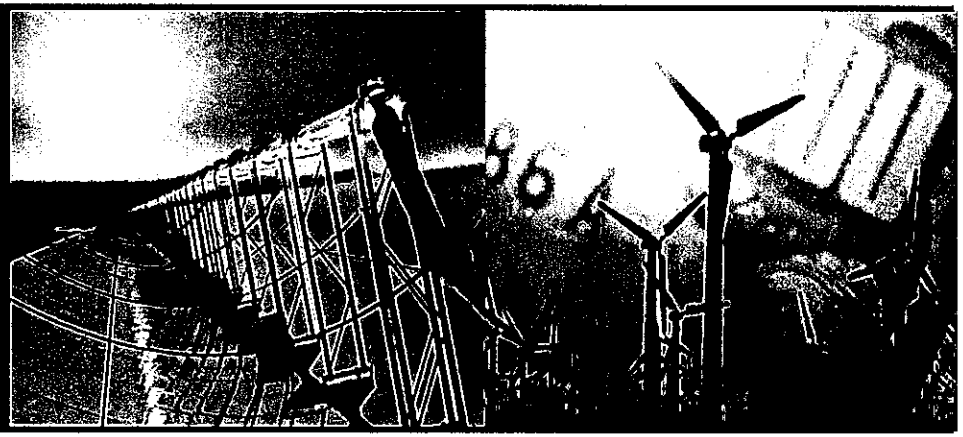
Automatic Resource Selection

1. Dynamic Optimization for Resource Selection
2. Structural State Space Modeling to Capture Uncertainty
3. Hedge Instrument Payoffs
4. Ancillary Services





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Deterministic Optimization

- Choose values for decision variables to minimize an objective function (e.g., cost), subject to constraints

$$\min_{\mathbf{u}} \text{NPV Revenue Requirement} = f(\mathbf{u})$$

s.t.

$$\text{Reliability imports } \mathbf{g}(\mathbf{u}) \leq 1.2 \text{ load}$$

$$\text{Reliability exports } \mathbf{g}(\mathbf{u}) > 0.8 \text{ load}$$

$$\text{RPS } \mathbf{h}(\mathbf{u}) \geq 15\% \text{ of load}$$

- The values of objective function *f* and constraints **g** and **h** are calculated for decision variables **u**(resource mix).
- One "realization" (i.e., predicted future)

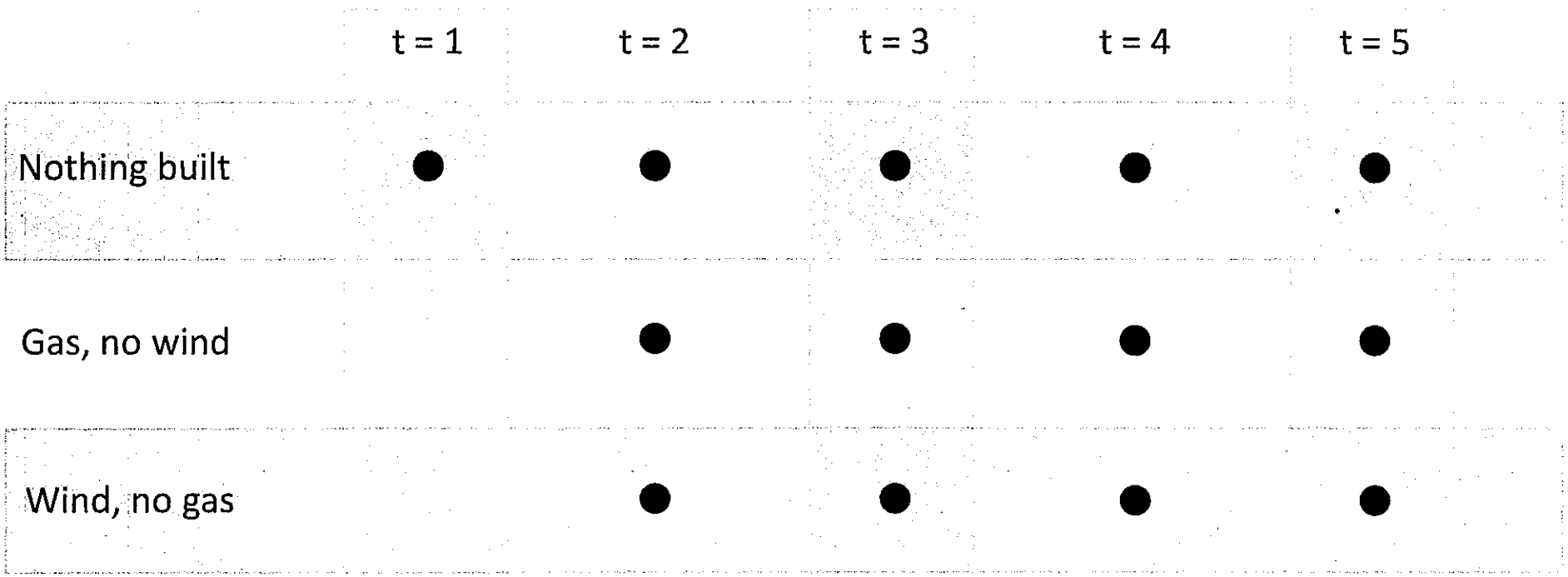
Solved using dynamic programming

Example: portfolio can build CC, wind, or both

- Load increases in t = 3
- RPS takes force in t = 5

State space including infeasible states shown here

● Represents a portfolio configuration ('state')



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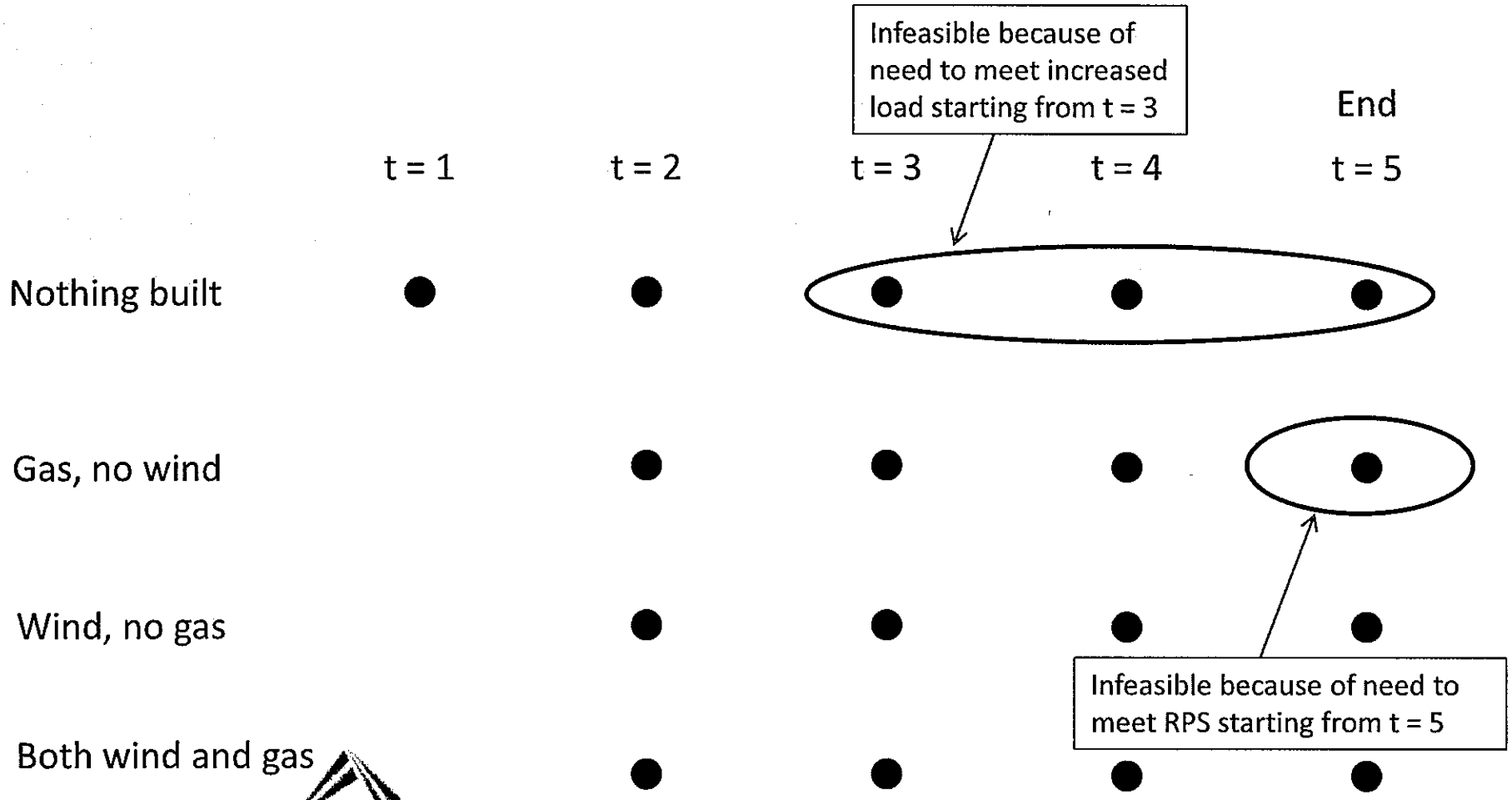
Solved using dynamic programming

Identify and remove infeasible states



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Enumerate costs for states

Variable costs shown in green

- CC makes a profit
- Wind (contract with independent generator) makes a loss
- Variable costs sums linearly

	t = 1	t = 2	t = 3	t = 4	t = 5	End
Nothing built	0	0				
Gas, no wind		-100	-100	-100		
Wind, no gas		150	150	150	150	
Both wind and gas		50	50	50	50	

Negative cost indicates operating profit for CC

Wind contract makes an operating loss

Wind + CC combination operating economics sum linearly

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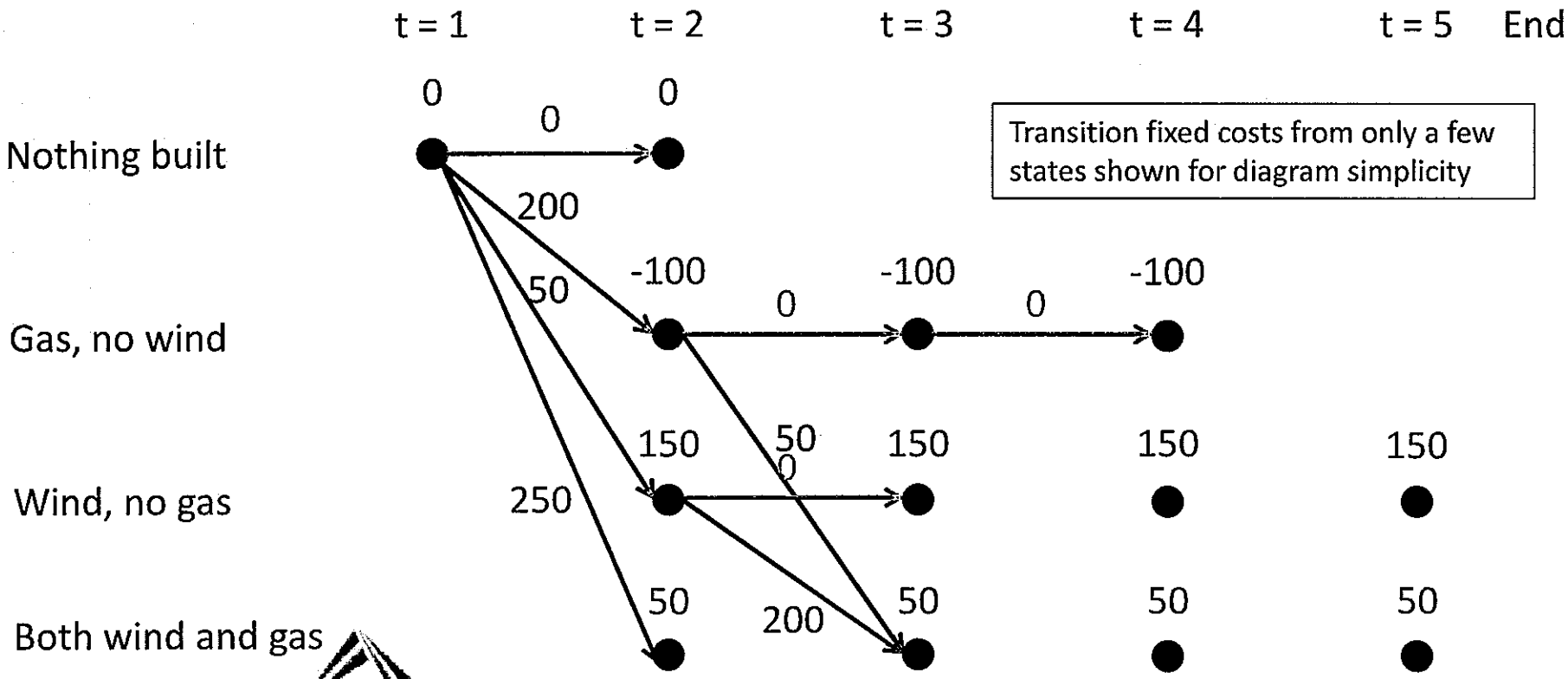
Enumerate fixed costs for transitions between states

Fixed costs sum linearly

- Building a CC is 200
- Wind contract has up-front cost of 50

Allowable transition (e.g., build an asset) – 'feasible action'



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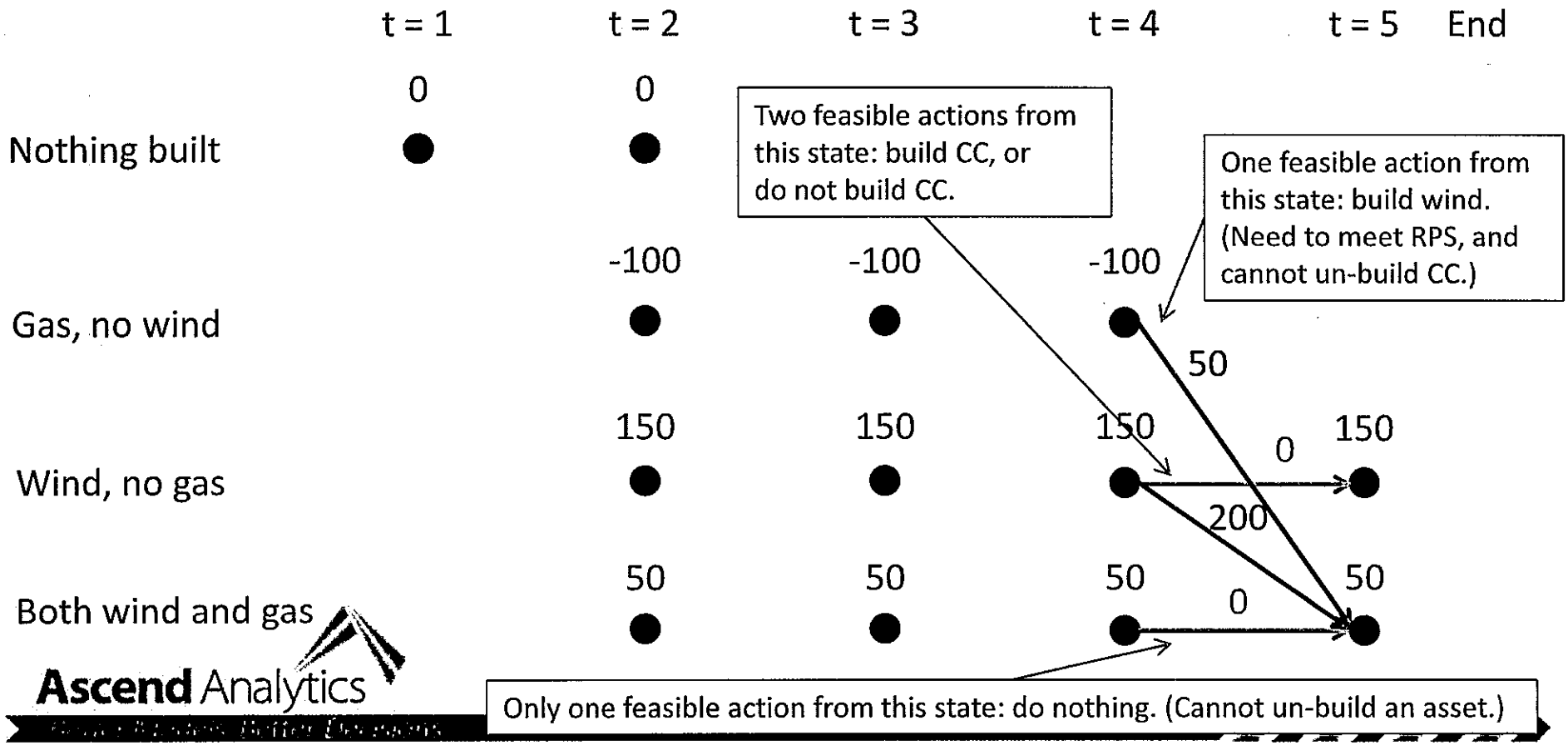
Backward pass

Start from next-to-last time period (t = 4)

Begin by enumerating feasible action set for each state



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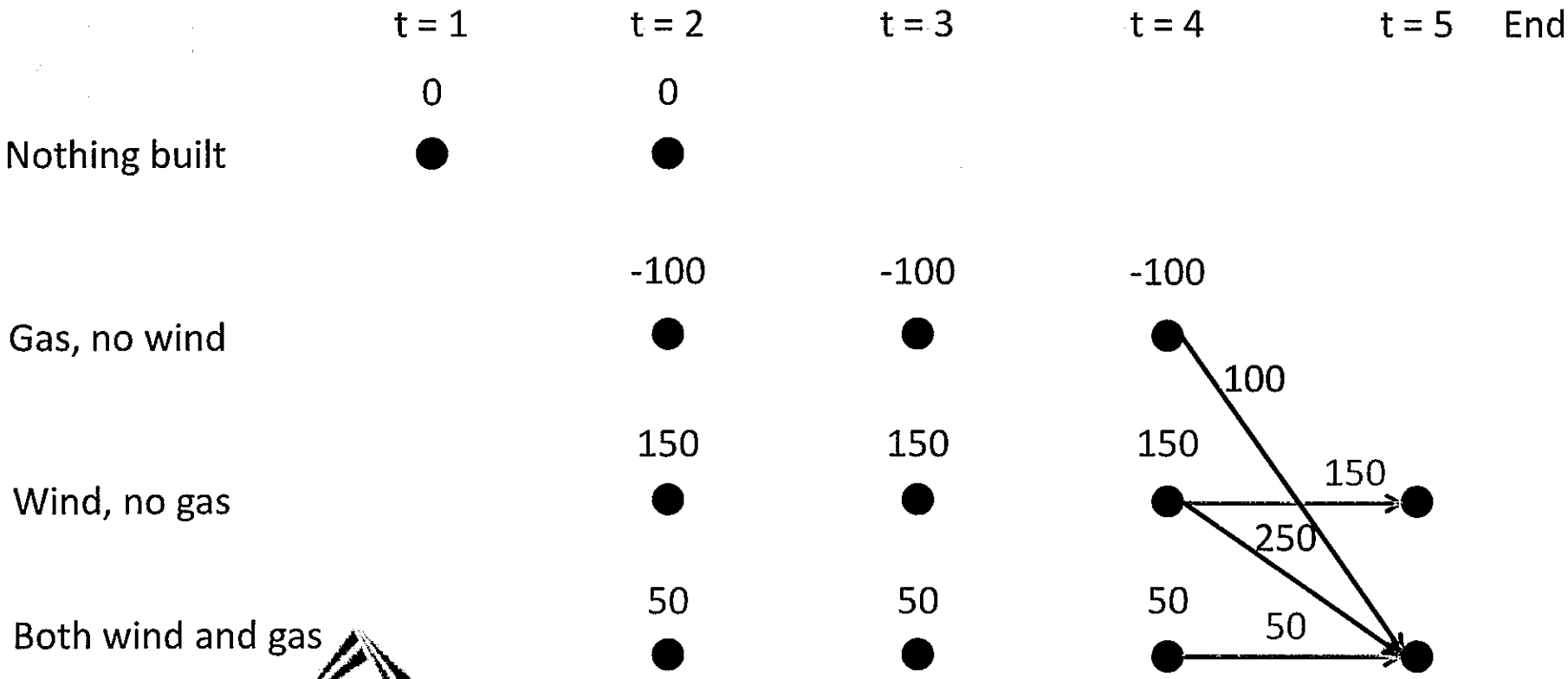
Backward pass

Calculate cost associated with each feasible action

- Quantity includes both fixed cost of this action, and future costs



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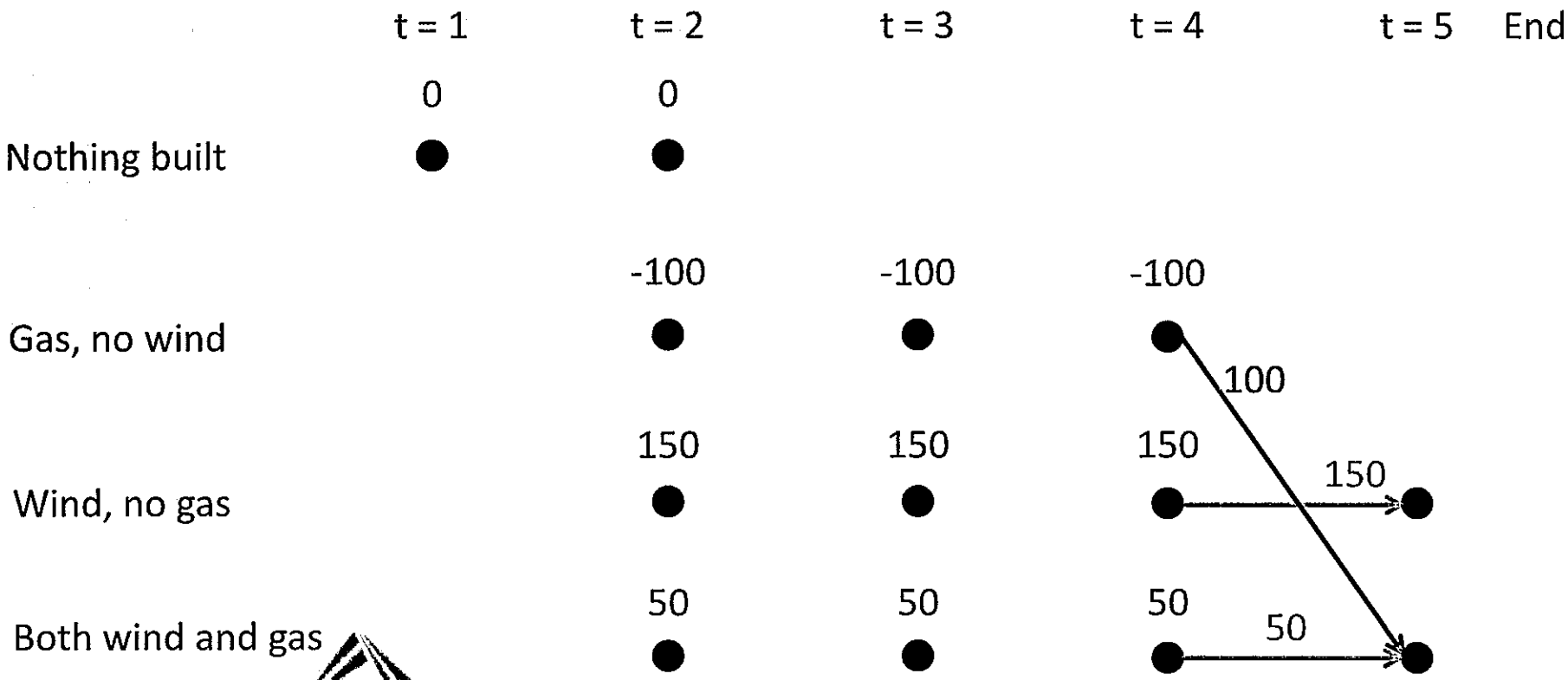
Backward pass

Select lowest-cost action from each state in t = 4

- Retain lowest cost action, and discard suboptimal actions



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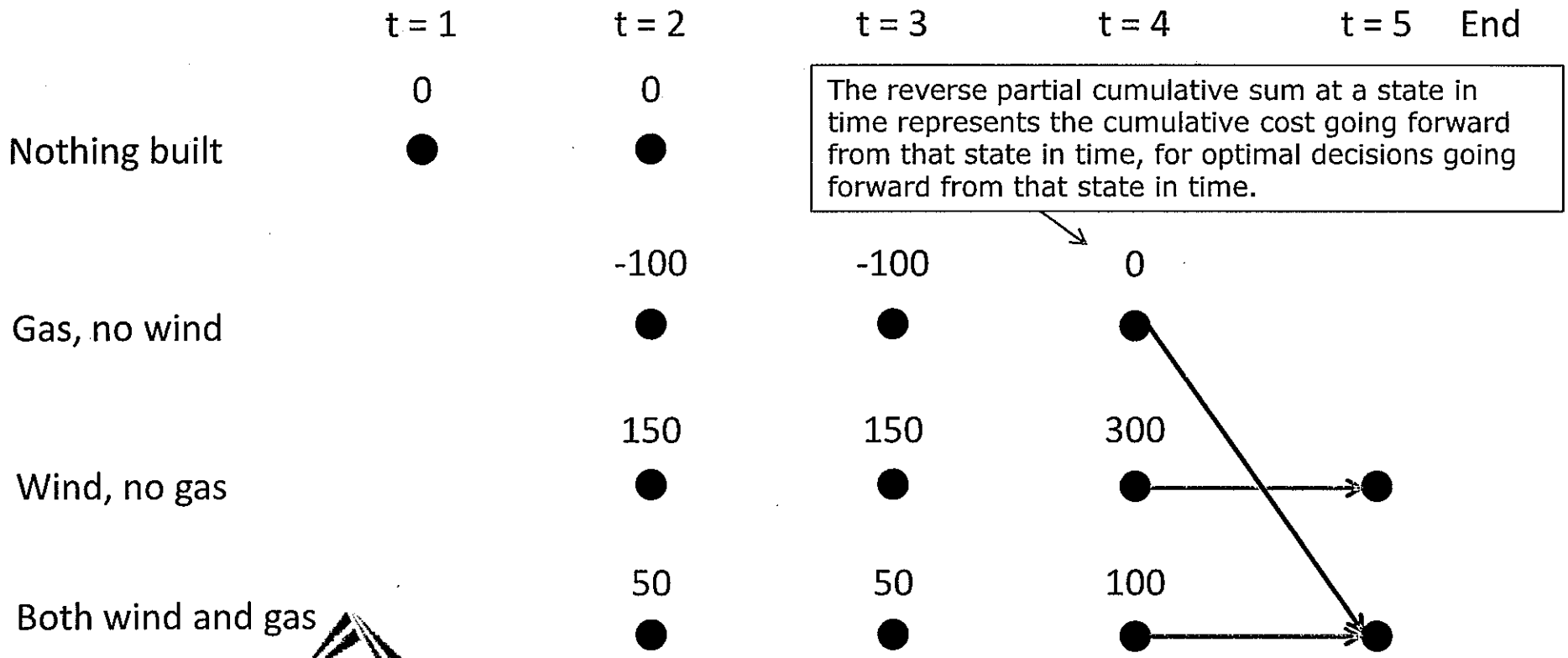
Backward pass

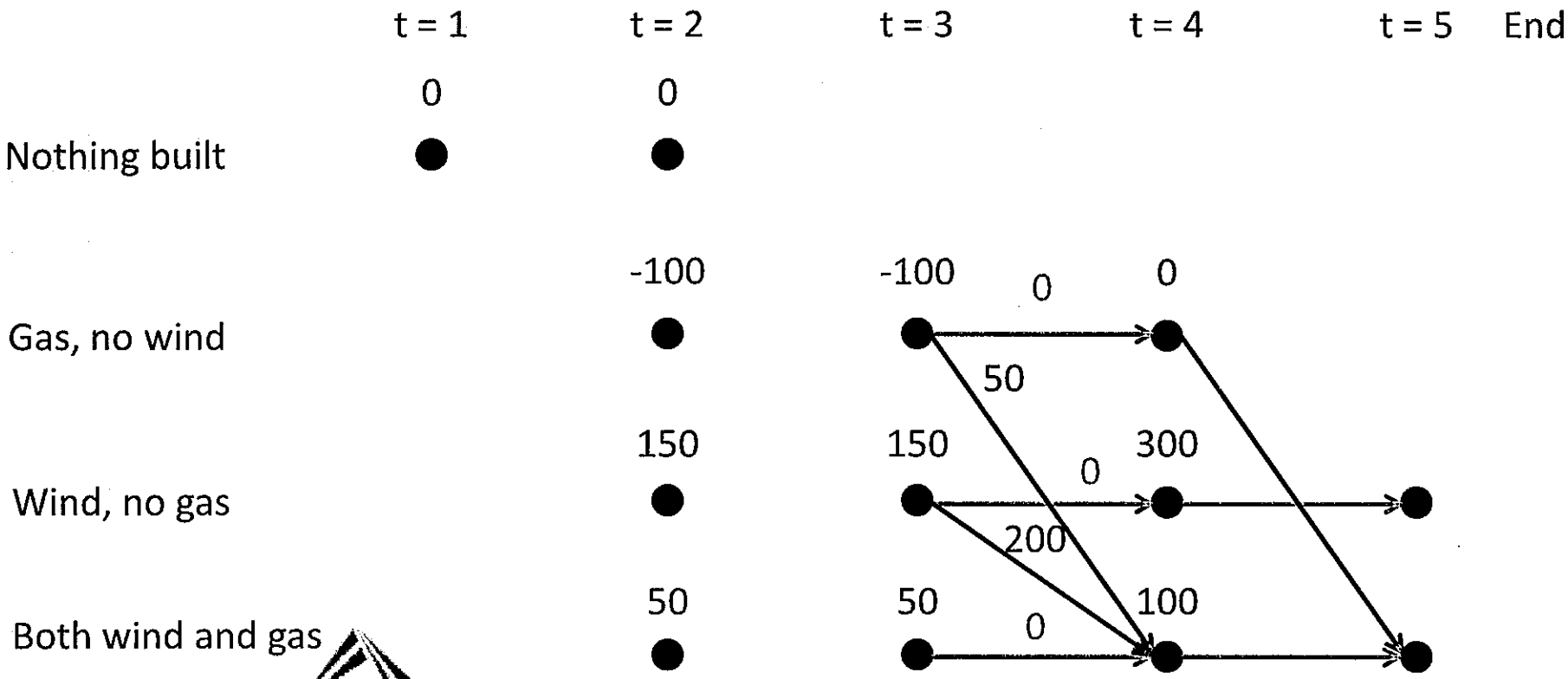
The reverse partial objective function sum is calculated for each of the states in the t = 4 time period.



Ascend Analytics

Backward pass

The process is repeated, starting from the previous time period.



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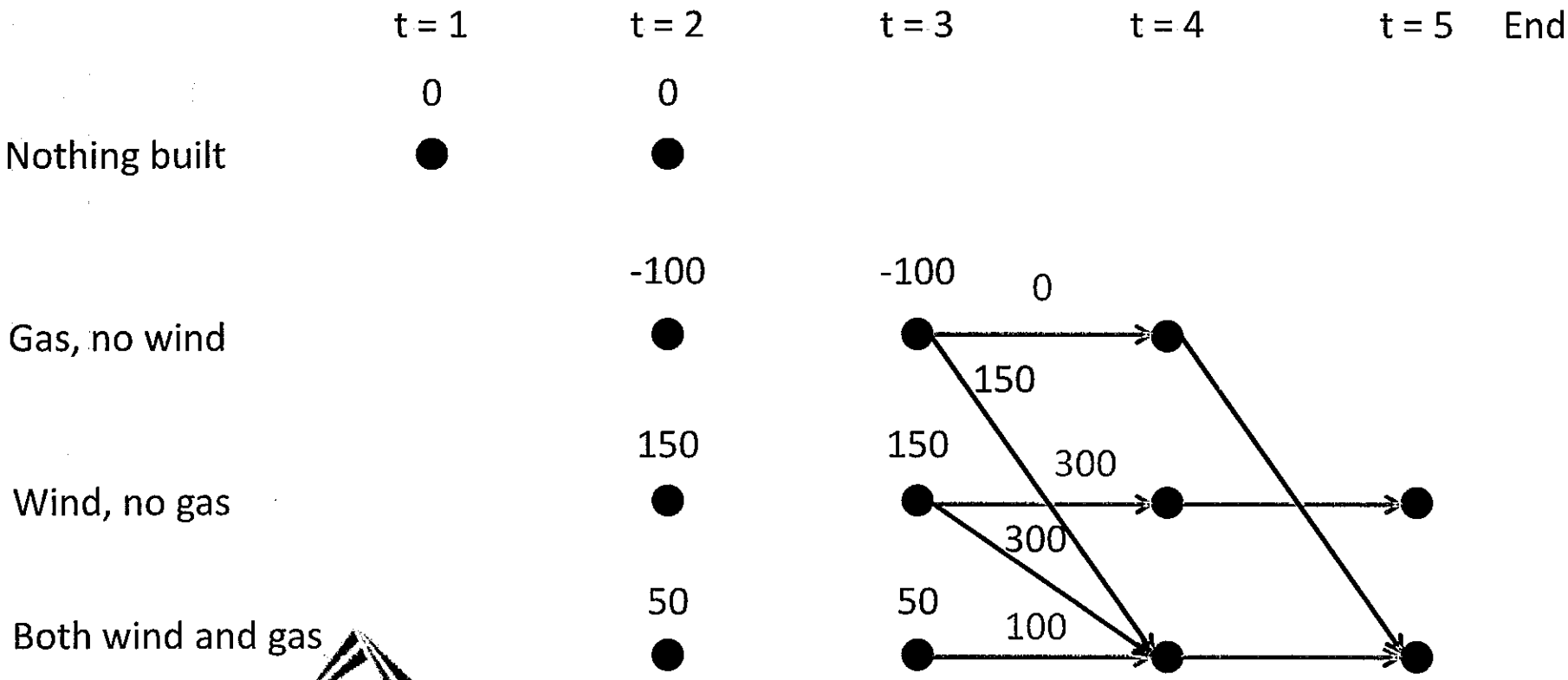
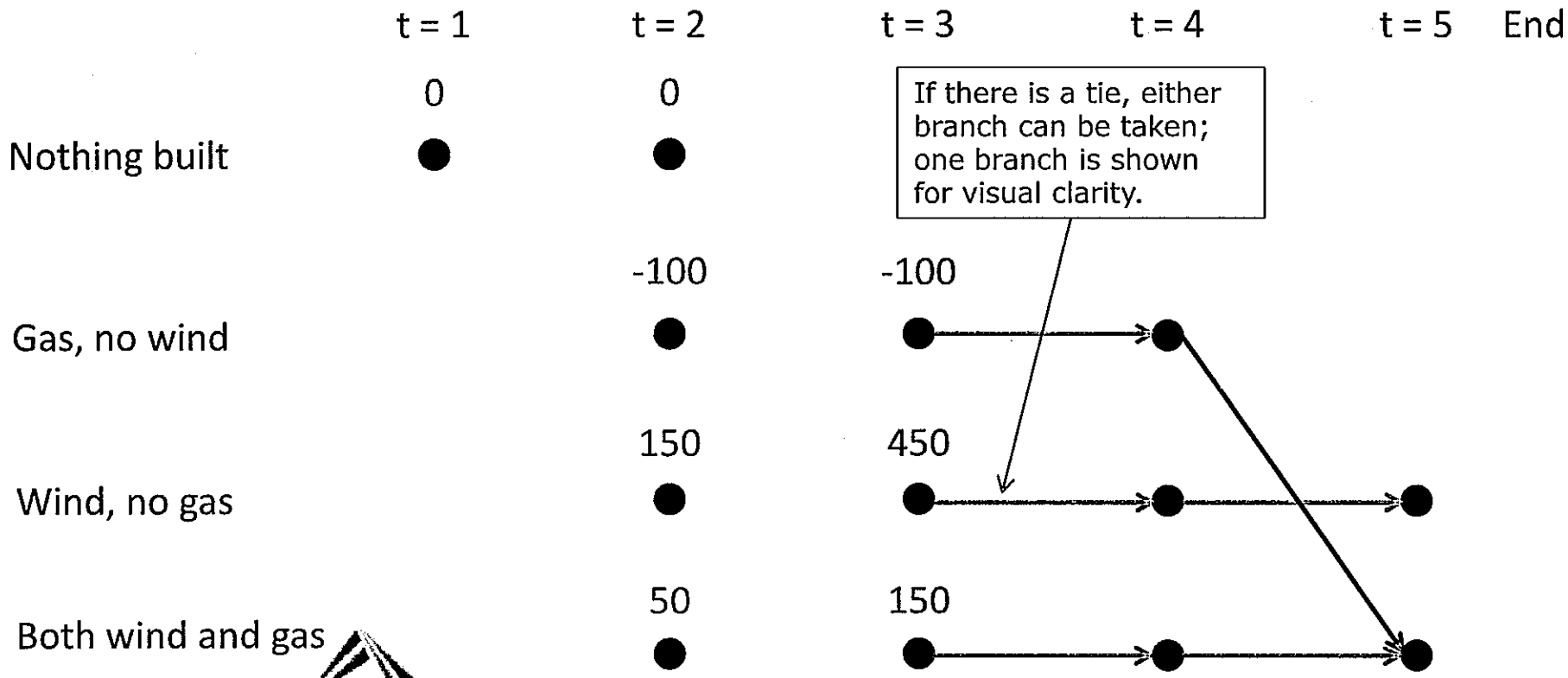


Ascend Analytics

Backward pass

All time periods are iterated through reverse sequentially (backward in time).



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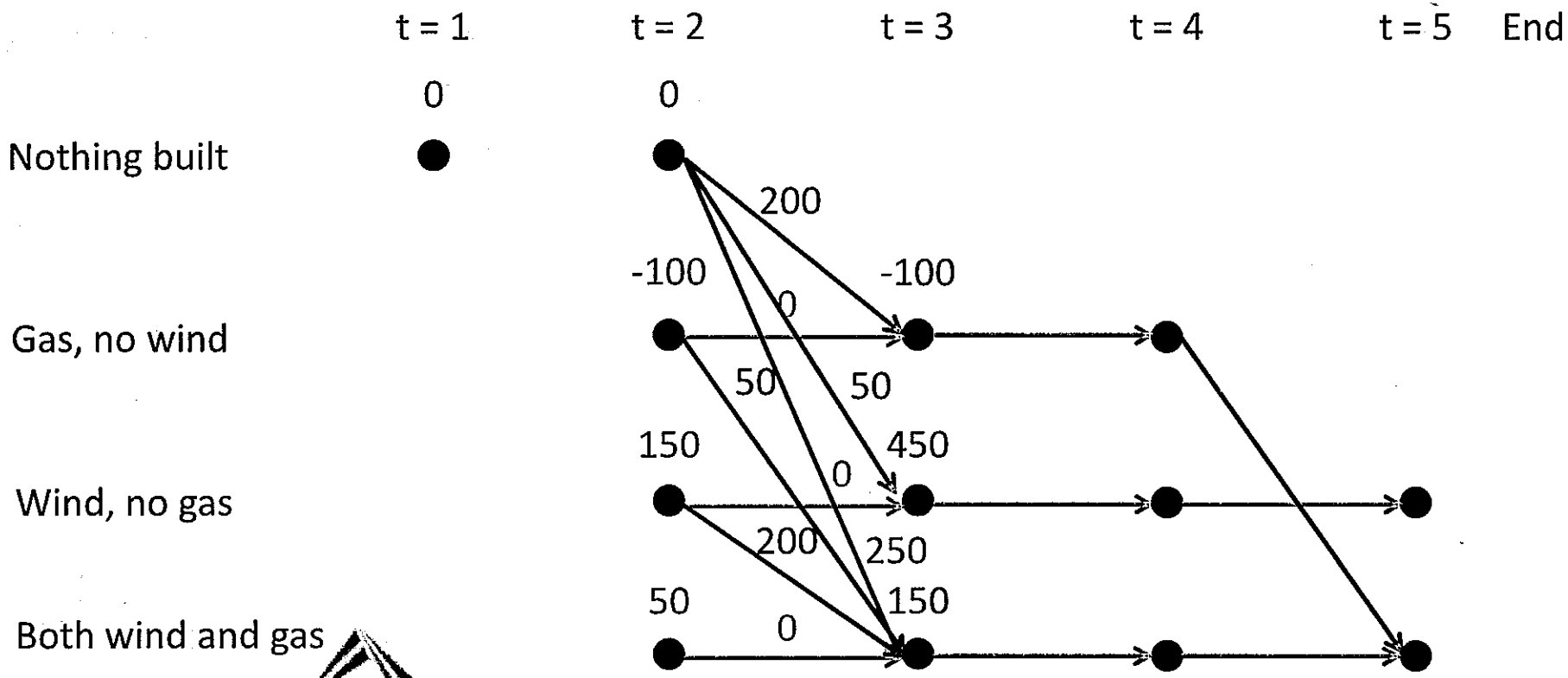

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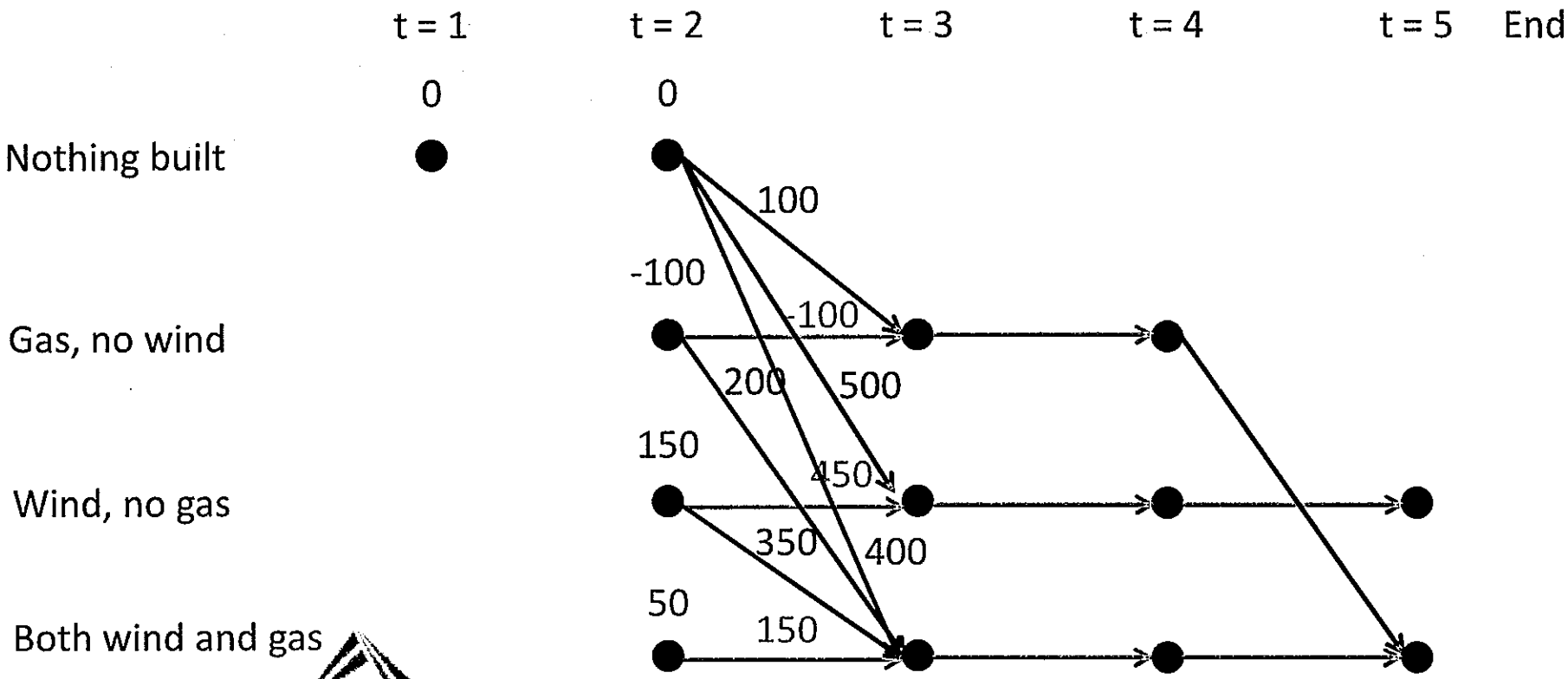

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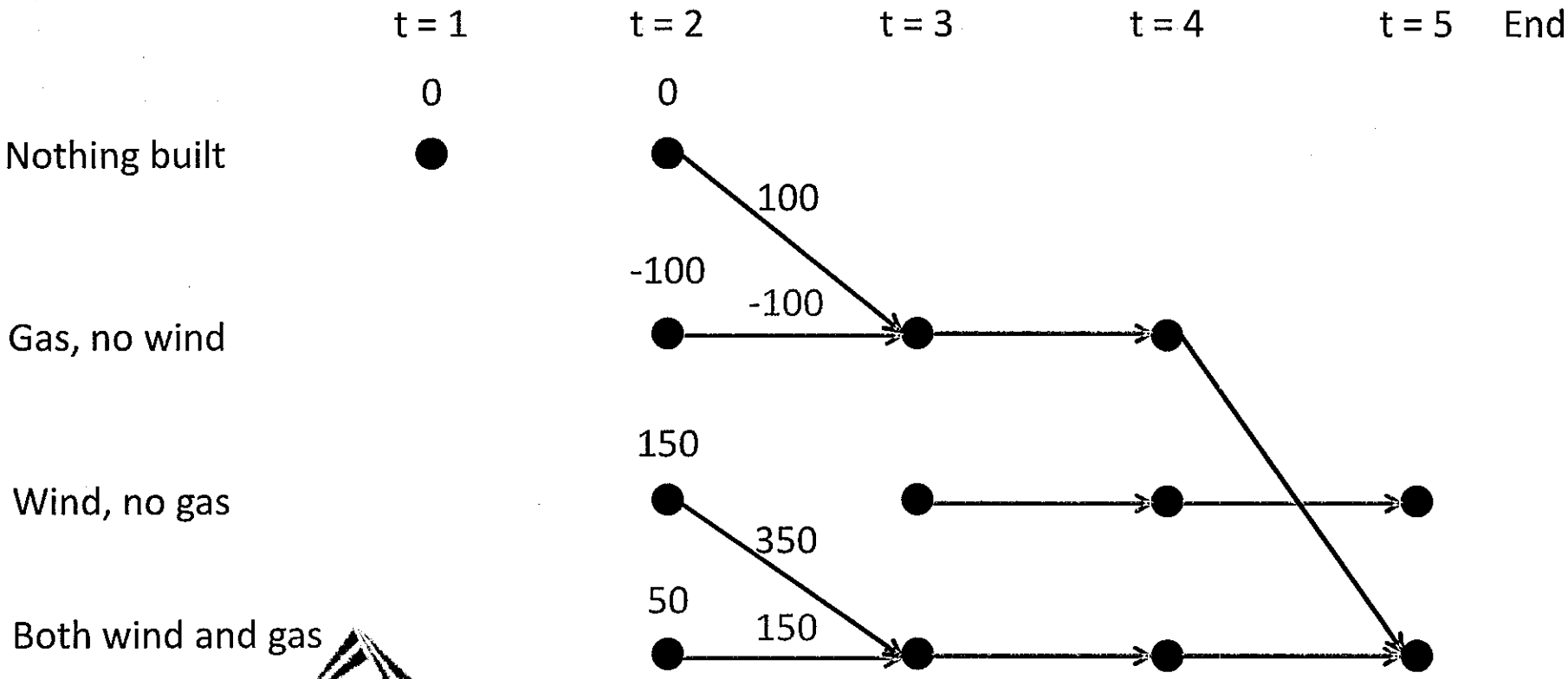

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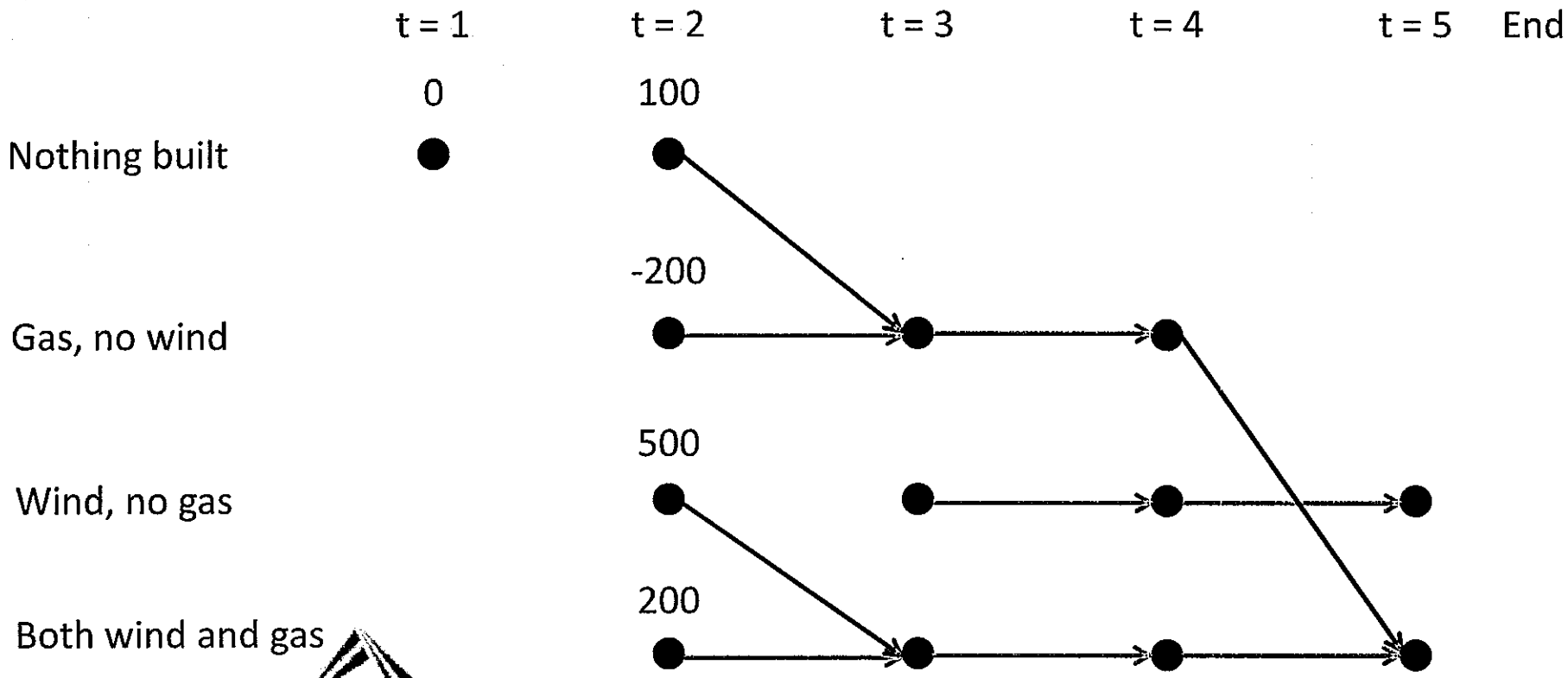

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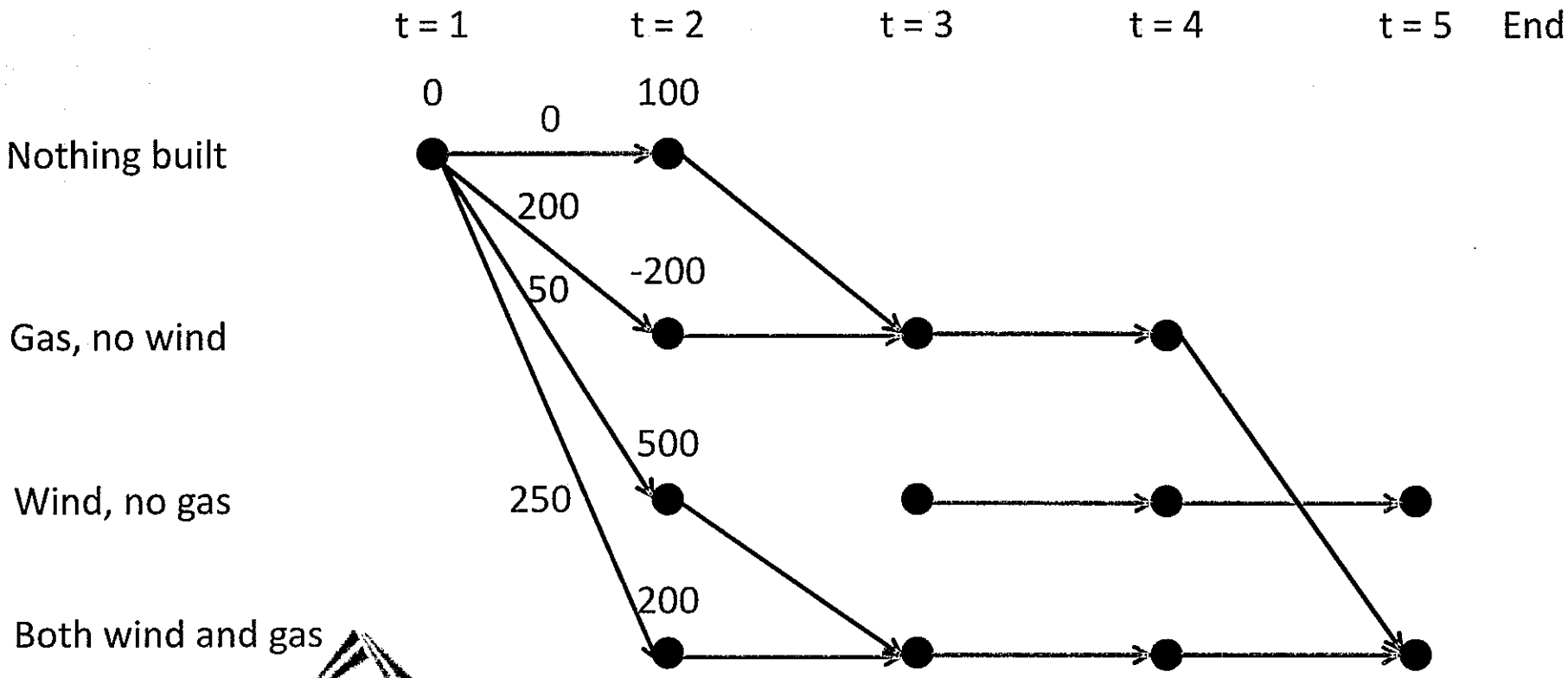

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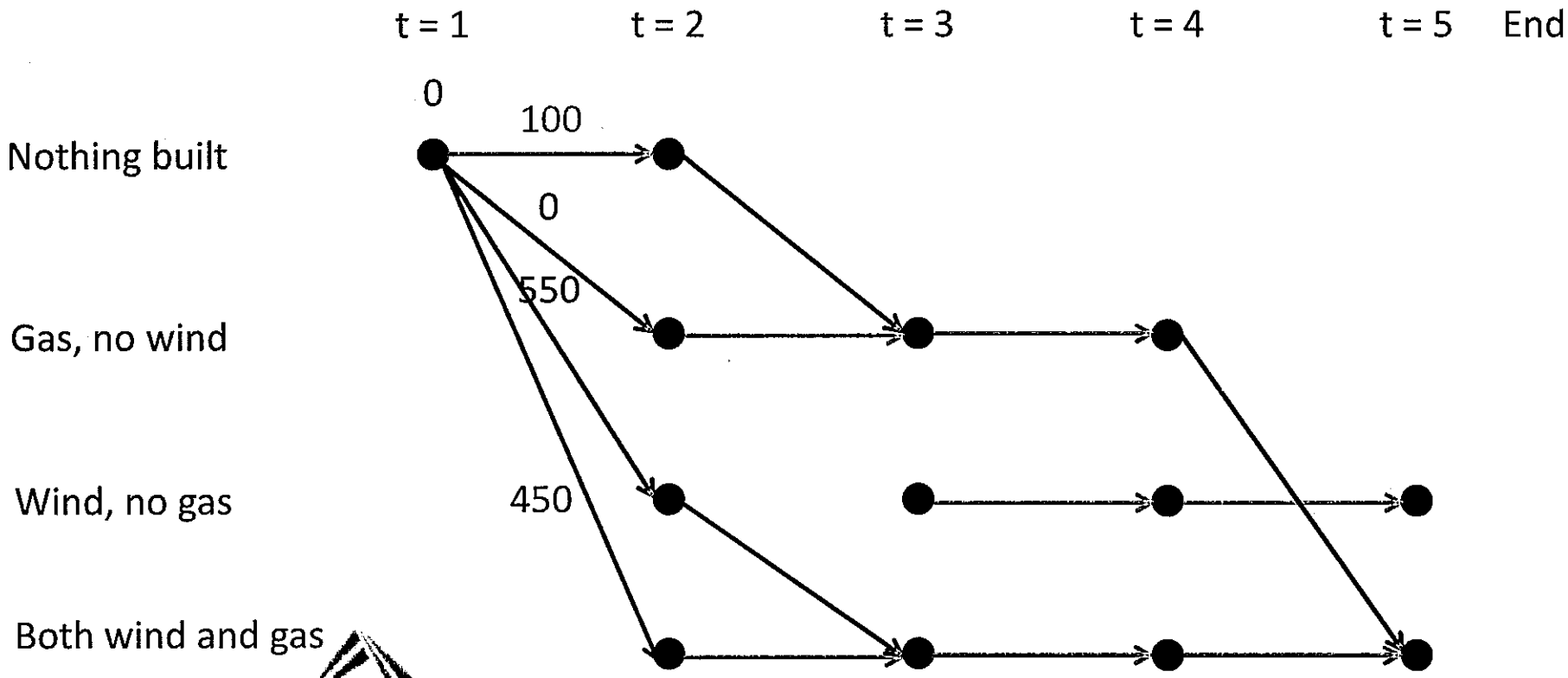
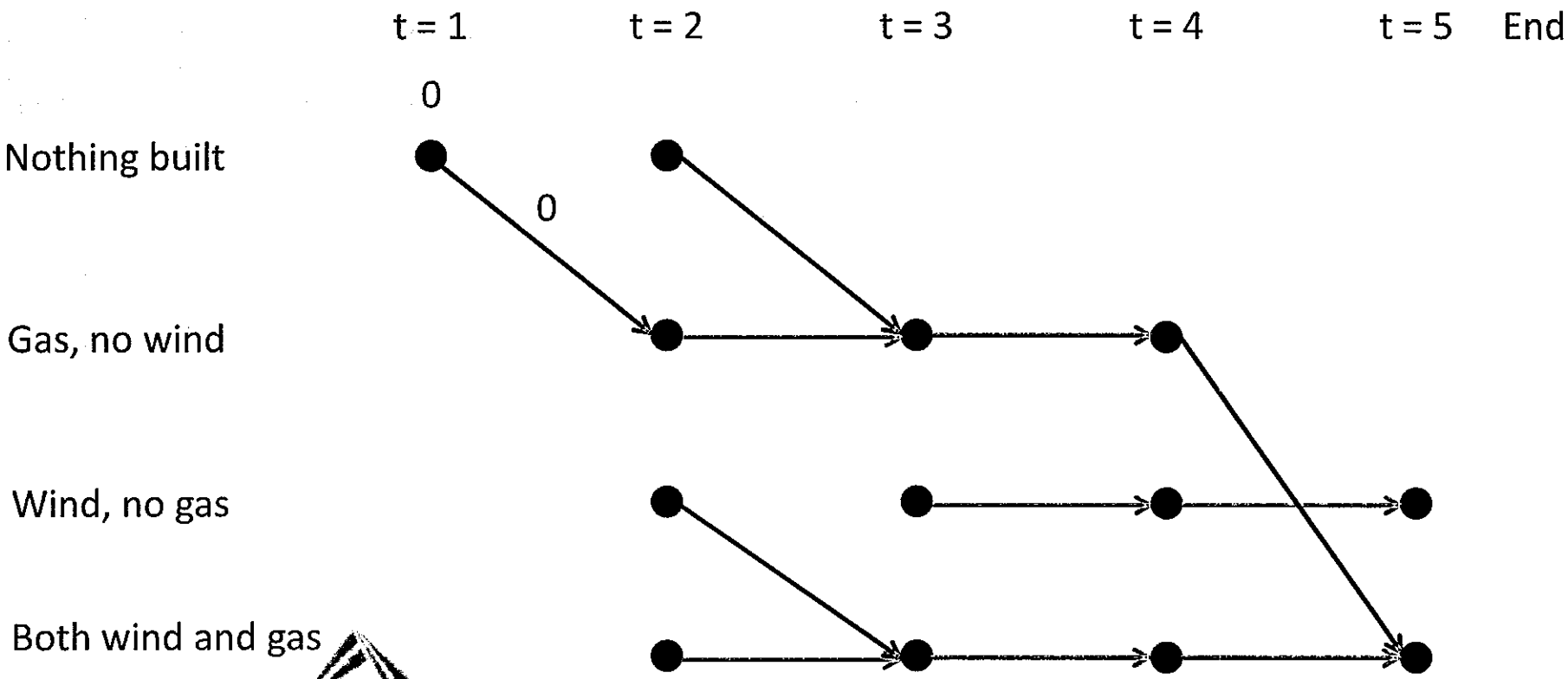


Ascend Analytics

Backward pass

All time periods are iterated through reverse sequentially (backward in time).



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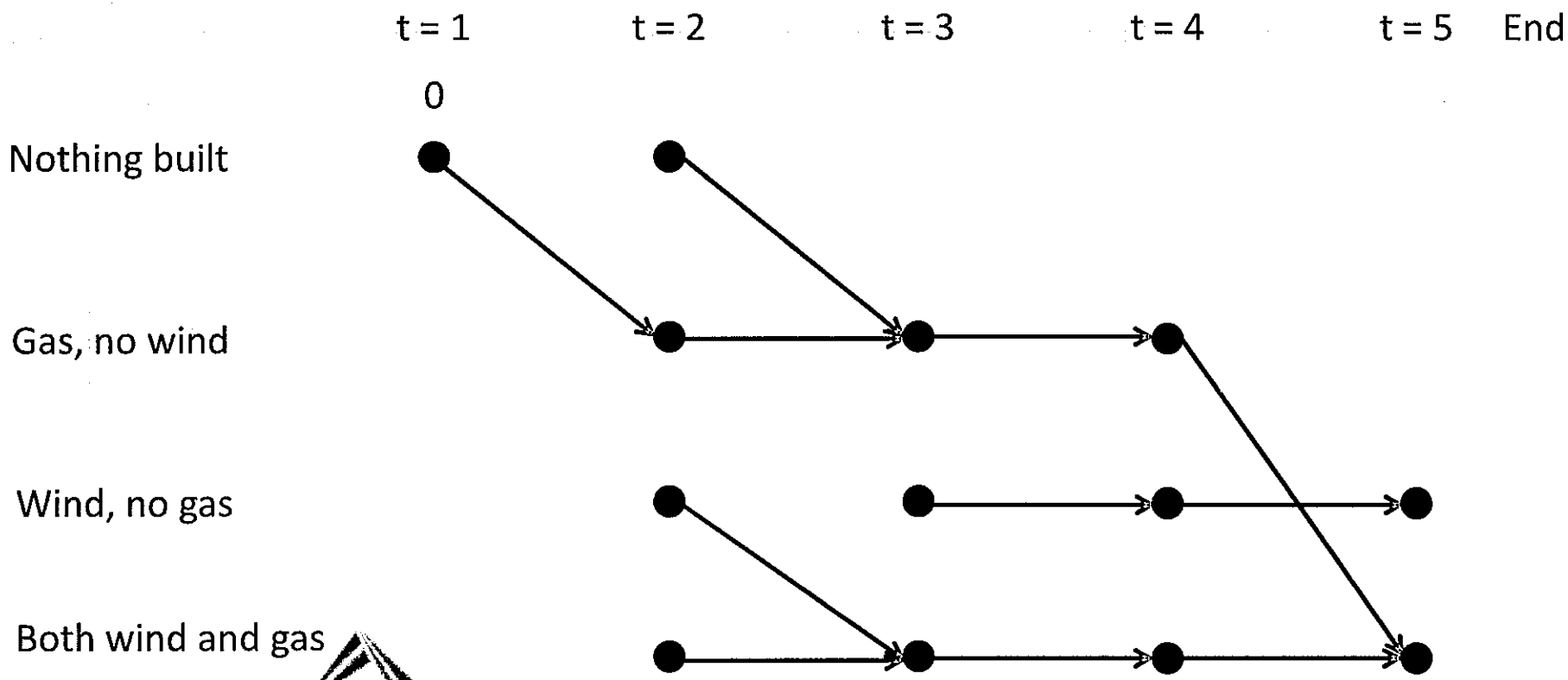
Backward pass completed



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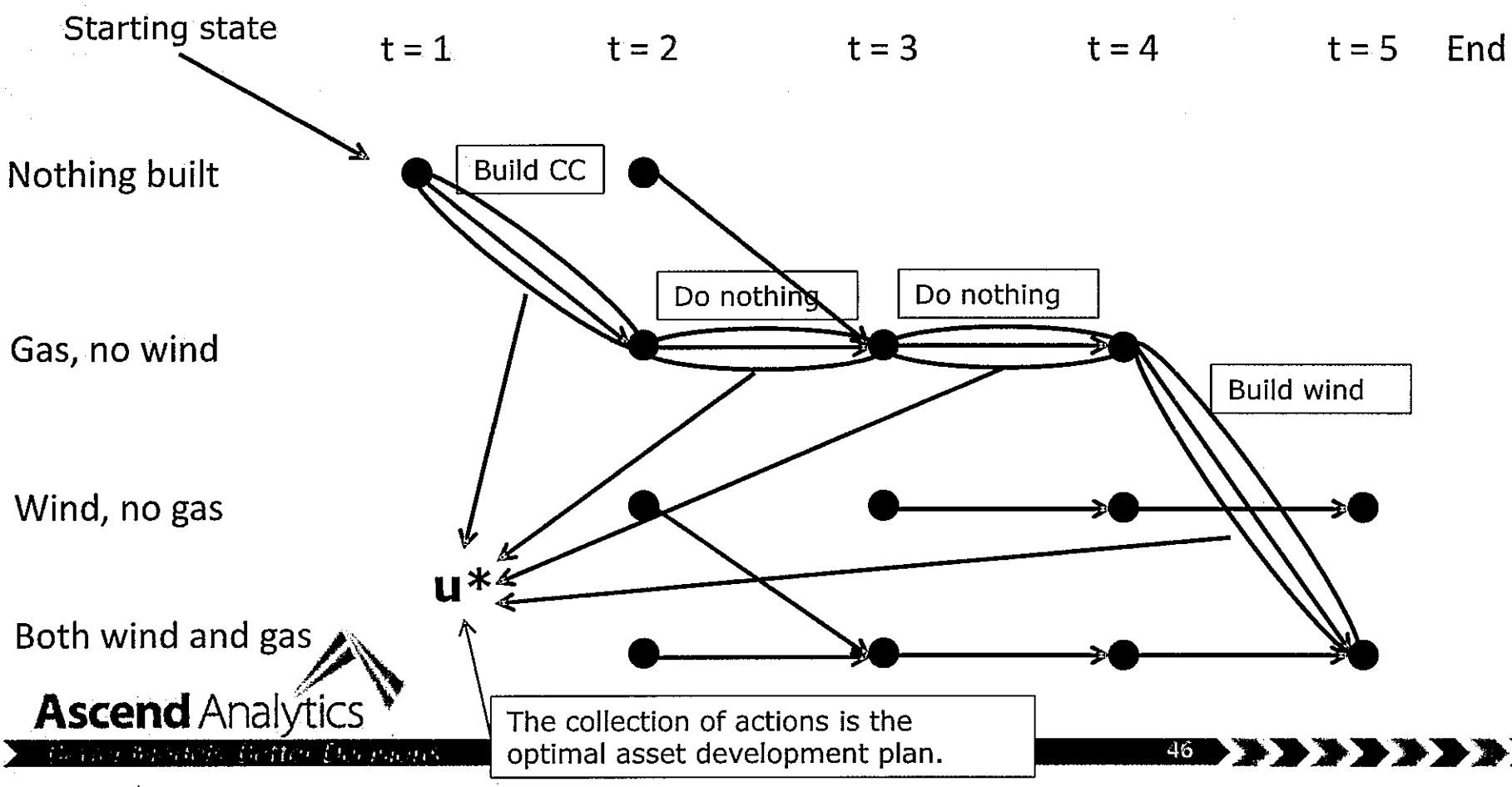
Forward pass

After the backward pass is completed, the optimal path is found by iterating forward through time from the starting state.



Relationship Between Deterministic and Stochastic Problems

- Stochastic problem consists of several parallel deterministic problems
- Different realizations will have different objective and constraint function values for a given plan u*
  - **u*** may be non-optimal or infeasible for realizations other than the one optimized for
- We want to find a plan u** that is good across the whole space of plausible futures
  - *Compromise plan* that works well in all realizations

Mathematical Formulation

$$\min_{\mathbf{u}} F(\mathbf{u})$$

$$\text{s.t.} \quad \mathbf{G}(\mathbf{u}) \leq 0$$

$$\mathbf{H}(\mathbf{u}) = 0$$

Upper case – stochastic
Lower case – deterministic

Arithmetic average used for stochastic objective function

$$F(\mathbf{u}) = \frac{1}{N}\sum_{n=1}^{N} f^n(\mathbf{u})$$

Some constraints need to satisfied for all realizations, e.g. physical characteristics of asset need to be respected

Certain other constraints need only be satisfied 50% or 95% of the time, e.g., reserve margin

$$\mathbf{G}(\mathbf{u}) = \frac{1}{N}\sum_{n=1}^{N} \max\left(0, \mathbf{g}^n(\mathbf{u})\right) \quad \mathbf{H}(\mathbf{u}) = \frac{1}{N}\sum_{n=1}^{N} |\mathbf{h}^n(\mathbf{u})|$$

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Constraints

- Christy Dunn produced a word document illustrating constraints in deterministic vs. stochastic case
- For constraints that must be satisfied in all simreps, determining feasibility is simple

$$\mathbf{G}(\mathrm{u}) = \frac{1}{N}\sum_{n=1}^{N} \max\left(0, \mathbf{g}^n(\mathbf{u})\right) \qquad \mathbf{H}(\mathrm{u}) = \frac{1}{N}\sum_{n=1}^{N} \left|\mathbf{h}^n(\mathbf{u})\right|$$

- Major difference between deterministic and stochastic cases is that stochastic case may want to allow a state to violate a constraint in some simreps but still be feasible in the overall stochastic problem
  - Grouped approach – each state has an error bar, and each bound has an error bar, and to determine feasibility we can choose which comparisons to make
  - Simrep-by-simrep counting approach – evaluate feasibility for each simrep as in deterministic case, and then evaluate feasibility of state in stochastic space by counting – e.g., 95% feasible threshhold means that < 5 out of 100 simreps are infeasible

Constraints

Consider the constraint of the form

$$Q \leq Q_{max},$$

where Q is a quantity calculated within the optimization and Q_{max} is a bound. Q is the value of some constrained quantity that depends upon the simrep simulated parameters and planning decisions (e.g., total reserve available), and Q_{max} is the bound that may depend on some simrep simulated values (e.g., if the reserve margin is a proportion of load, which differs from simrep to simrep).

Then in the equation, both Q and Q_{max} will have a distribution of values. In some cases these are correlated.

The grouped way to evaluate constraint satisfaction is to compare some statistical measures of Q and Q_{max} with each other using a feasibility rule that gives the desired feasibility threshold.

The simrep-by-simrep way is to compare Q and Q_{max} with each other for each simrep, and then count the number of simreps that are feasible or infeasible. The feasibility threshold is implemented using this count of simreps.

Constraints

- The group approach is faster, but less rigorous if uncertainty in the constrained quantity and the constraint are correlated. The simrep-by-simrep approach requires a large number of evaluations (one for each simrep), but is mathematically rigorous
- For some constraints, the error bar on the states will have zero width, that is, all the simreps will have the same quantity (e.g., for reserve margin constraint, a state will have the same capacity in every simrep). These constraints can be evaluated using the group approach without any loss of rigor
- For other constraints, the error bar on the states will have some width, and the constrained quantity and constraint will be correlated. These constraints should be evaluated, if computationally possible, using the simrep-by-simrep method.

Relationship between stochastic and deterministic objective functions

F : Stochastic objective function evaluation over whole time period

F_t : Stochastic objective function evaluation for a single time step

$$F(\mathbf{u}) = F_T\ (\mathbf{u}) + F_{T-1}(\mathbf{u}) + \cdots + F_1\ (\mathbf{u})$$

$f_t{}^n$: Single realization objective function evaluation for a single time step

$$F_t\ (\mathrm{u}) = \frac{1}{N}\left[f_t{}^N(\mathbf{u}) + f_t{}^{N-1}(\mathbf{u}) + \cdots + f_t{}^1\ (\mathbf{u})\right]$$

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Meeting Summary
NorthWestern Energy Electricity Technical Advisory Committee
October 18, 2013

Attendance
Those participating in or attending the Energy Electricity Technical Advisory Committee (ETAC) meeting included:

Name	Organization
Patrick Barkey	University of Montana - Bureau of Business and Economic Research
Pat Corcoran	NorthWestern Energy (NWE)
Kate Whitney	Montana Public Service Commission (MPSC)
Al Brogan	NWE
Diego Rivas	NW Energy Coalition
John Bushnell	NWE
Thomas M. Power	District XI Human Resource Council
Kyla Maki	Montana Environmental Information Center (MEIC)
Brian Spangler	Montana Department of Environmental Quality (DEQ)
John Hines	NWE
Brian DeKiep	Northwest Power and Conservation Council
Paul Schultz	Montana Consumer Counsel (MCC)
Jamie Stamatson	MCC
Larry Nordell	MCC
Bob Rowe	NWE
John VanDaveer	NWE
Neil Templeton	NWE
Mike Dalton	MPSC
Mary Gail Sullivan	NWE
Bill Rhoads	NWE
Jeff Blend	DEQ
Garrett Martin	DEQ
Will Rosquist	MPSC
Gerald Mueller	Consensus Associates

Agenda
John Hines stated that this meeting is a follow-on to NWE's presentation to the MPCS that preceded the ETAC meeting and will allow ETAC members to ask questions and make observations about NWE's acquisition of the PPL Montana hydro plants in Montana. NWE will also discuss its planning process and modeling in light of the acquisition. Highlights of the ETAC discussion follows.

ETAC Discussion
Comment - The presentation to the MPSC indicated that the hydro acquisition would result in a long-term risk reduction and a short-term rate increase for customers. The presentation specified a 5% rate increase in the first year. I would like to see the rate impact for each year of the 30-year planning horizon.

Response - We will provide this information. Comparing the market prices with the hydro acquisition costs, we don't see a cross over point until the 2020s, i.e., power costs with the hydro acquisition do not drop below market prices until that time. The acquisition offers a policy choice of paying a little more now for long-term certainty.

Question - NWE has said that negotiations culminated in an agreement in June with PPL Montana to acquire the hydro plants. Did you consider issuing a request-for-proposal (RFP) to solicit resources prior to reaching the agreement?
Answer - No, we did not consider an RFP. Had we done so, PPL Montana would have sold the hydro plants to someone else. PPL viewed a sale to NWE as risky. We saw the acquisition as a once-in-a-lifetime opportunity.

Question - With the commitment to acquire the hydro plants in place, what is NWE's ability to conduct a resource solicitation now?
Answer - We do not see a solicitation as viable. Responding to an RFP imposes costs on responding entities, and they would need to see NWE as seriously soliciting resources. We want to close on the hydro plant acquisition.

Comment - The MPSC is now the decision maker regarding the acquisition. By not soliciting for resources, NWE does not appear to have followed the MPSC rules for utility acquisitions.
Response - The MPSC rules set forth a preferred path for resource acquisition, but also allow for an alternative path with the onus on the utility to demonstrate why an opportunity resource is the appropriate choice. The hydro plant acquisition was not considered in the previous resource plan. NWE was surprised and pleased that PPL Montana agreed to sell the plants to us.

Question - The MPSC has argued that the Federal Energy Regulatory Commission (FERC) should uphold qualifying facility (QF) tariffs because NWE has not acquired a large amount of resources outside of the RFP process. The hydro acquisition is a massive acquisition outside of an RFP. Are you concerned about the implications of this acquisition to the FERC QF ruling?
Answer - NWE has used the RFP process to acquire resources. The hydro acquisition is a once-in-a-lifetime opportunity. PPL would not have bid its hydro plants into a competitive solicitation. It would have sold them directly to a merchant entity or another utility to meet its loads.

Comment - I assume that for this planning cycle, NWE will analyze the resource portfolio with a new alternative, with and without the hydro plants.
Response - We see three scenarios, with the hydro plants, without the hydro plants, and with new combined cycle gas-fired unit(s).

Comment - Representatives of Ascend Analytics have made two presentations of its modeling approach and its model, PowerSimm to ETAC. I and other ETAC members still do not understand how PowerSimm works.
Response - For the model used in previous plans, GenTrader ®, we pre-specified the risk band, which introduced bias. Ascend's PowerSimm model provides a better method for the stochastic analysis and increased clarity regarding risk.

Comment - I am not arguing that PowerSimm is not a better model, just that ETAC members do not understand how it works.

Response - We will arrange for presentations to help ETAC members understand how PowerSimm works. We can provide details either to the full group or to a modeling subgroup.

Comment - I would like to review the actual equations used in PowerSimm.

Comment - I think a face-to-face meeting of ETAC to discuss the PowerSimm model would be beneficial.
Response - We will arrange for such a meeting.

Comment - The problem facing ETAC and NWE's modeling group is understanding what we are doing. The resource plan including a short-term action plan is created using hypothetical resources and a projected market. Acquiring actual resources with real costs in a real power market then shifts to the regulatory environment. Thus planning does not select actual resources, and some may see the resource plan as a sham to fulfill MPSC requirements. The regulatory consideration of an actual resource encourages hindsight analysis. I see developing the plan as an exercise which creates an understanding about how the existing utility system works, about electricity demand, about electricity market forces, and about how alternative supply and demand resources would fit into the utility's system.

Comment - Planning is a complex tool for evaluating resource alternatives. Planners do not make actual resource decisions.
Response by Pat Corcoran - Planning helps inform resource acquisition decisions, which are guided by the costs and resources set forth in the resource plan.

Comment - To evaluate the proposed hydro plant acquisition, regulators will need to decide if its price is right, including how much customers would pay up front for risk abatement and how long they will be paying for future risk abatement. These are not long-term planning issues. I agree that planning has not driven major resource acquisition decisions such as Colstrip.

Comment - John Hines stated earlier that the hydro plant-market price cost curves will cross in the 2020s. It would be useful for NWE to present to ETAC its cost analysis including the risk that the hydro plant acquisition will abate.

Question - Regarding the hydro plant acquisition, did NWE analyze how future fish-related concerns may impact plant operations?
Answer by Mary Gail Sullivan - Yes. Our review of the projects indicates that PPL Montana has integrated into its project operation and planning future fish concerns. FERC licences for the projects require adaptive management which incorporates current technology and understanding of the fish resource. For example, the Thompson Falls plant has a state of the art passage system for bull trout.
Answer by Bill Rhoads - Next to nuclear plants, hydro is the most heavily regulated form of electric generation.

Question - What is the likelihood that the Confederation Salish and Kootenai Tribes will make a competing application for the Thompson Falls plant when the FERC license must be renewed?
Answer by Bill Rhoads - Such a competing application is possible. NWE has the responsibility of demonstrating that its maintenance and operation of the plant is the best it can be.

Question - Regarding NWE's due diligence for the acquisition, did you conduct an in-house valuation and then have an outside look?
Answer by Bill Rhoads - Shaw/CB&I conducted an independent review with NWE input. Our transition team included years of experience in operating these plants, and this experience informed the decision to acquire them. Our team observed that the plants have been well-maintained by PPL Montana, and that PPL has made substantial improvements to them after acquiring them from Montana Power Company.

Question - Can you make the due diligence documents available to the MPSC before the filing for acquisition approval?
Answer by Pat Corcoran - PPL Montana owns the data that would be reviewed.

Question - What is the firm generation capacity of the hydro plants?
Answer by Bill Rhoads - The installed capacity is 633 megawatts (MW) and the critical water generation is 435 MW.

Question - How does PowerSimm model water years and electricity prices?
Answer by John Bushnell - The model incorporates Mid Columbia electricity prices. We will discuss how the model's stochastic feature incorporates weather with the ETAC at a future meeting.

Question - Did you incorporate climate change in your evaluation of the hydro plants?
Answer by Mary Gail Sullivan - No. The FERC license controls flows.

Comment - Climate studies indicate a shifting pattern of precipitation across time. Runoff will occur earlier. Whether there will be more or less total precipitation is not known.

Question - Are major upgrades planned for any of the hydro plants?
Answer by Bill Rhoads - PPL Montana has a five-year plan for generation upgrades. It has invested $400 million in plant improvements including $280 at Rainbow Dam. We are not aware that PPL Montana had planned major upgrades similar to Rainbow at its other dams.

Next Steps

Gerald Mueller will discuss with Dave Fine possible dates for an ETAC meeting focused on the Ascend model, PowerSimm, and will poll ETAC members to identify the best date among the possibilities.

Disclaimer

Committee members provide advice to NWE as individual professionals; the advice they provide does not bind the agencies or organizations that the members serve.

ETAC Meeting Agenda

NorthWestern Energy
General Office Auditorium (downstairs)
40 East Broadway

Wednesday November 13, 2013 – 9:00 AM

Conference Call-In: 877 820-7831 (Participant Code): 555256

Agenda:

Ascend Analytics presentation of PowerSimm model

- Gary Doris, Sean Burrows, and Mark Dyson will be in Butte to present the PowerSimm model built for NorthWestern and to answer questions
- Discussion will include: Input Parameters
  PowerSimm Results
  Validation Results & Methods
  Additional results; Risk Premium, Net Position
- Models to be discussed and viewed include the base model, base model + combined cycle, base model + hydro generation

We will plan to have the Ascend team available until approximately 1:45PM.

(Lunch will be provided)

REVIEW DRAFT

Meeting Summary
NorthWestern Energy Electricity Technical Advisory Committee
November 13, 2013

Attendance
Those participating in or attending the Energy Electricity Technical Advisory Committee (ETAC) meeting in person or via the web and by teleconference included:

Name	Organization
Jaime Stamatson	Montana Consumer Council (MCC)
Kyla Maki	Montana Environmental Information Center (MEIC)
Diego Rivas	NW Energy Coalition
Jeff Blend	Montana Department of Environmental Quality (DEQ)
Thomas M. Power	District XI Human Resource Council
Brian DeKiep	Northwest Power and Conservation Council
Neil Templeton	Montana Public Service Commission (MPSC)
Will Rosquist	MPSC
Mike Dalton	MPSC
Frank Bennett	NorthWestern Energy (NWE)
Dave Fine	NWE
John Bushnell	NWE
Al Brogan	NWE
Chuck Magraw	Natural Resource Defense Council
Steve Fisher	Lands Energy
Todd Guldseth	NWE
Joe Stimatz	NWE
Joe Schwartzenberger	NWE
Patrick Barkey	University of Montana - Bureau of Business and Economic Research (via telephone)
Gerald Mueller	Consensus Associates

Agenda
The agenda for this meeting focused on a presentation by representatives of Ascend Analytics of its PowerSimm resource planning model and its application to NWE resource planning and acquisition. The specific topics to be addressed include:
- Portfolio characteristics and valuation results;
- Quantifying the value of risk;
- Market inputs;
- Simulation validation;
- Operating dynamics and detailed results; and
- Quantification and monetization.

Introduction
Dave Fine introduced the meeting. He noted that modeling discussed at previous ETAC meetings did not incorporate NWE's proposed acquisition of the PPL Montana hydroelectric

facilities in Montana because of NWE's non-disclosure agreement with PPL Montana during the negotiation. NWE planning staff work has shifted from a planning focus to analyzing the pending hydro facility acquisition. Today's meeting will continue the process of providing education about Ascend Analytics' model and its application to NWE's planning and hydro acquisition. The results presented today are preliminary. Final results will be presented to the ETAC when NWE files its application with the MPSC in December for pre-approval of the hydro acquisition.

Gary Doris, Sean Burrows, and Mark Dyson with Ascend Analytics used a PowerPoint presentation to cover the specific topics listed above in under the agenda heading. A version of the PowerPoint with modeling results redacted will be posted on the ETAC web site at the following address:

http://www.northwesternenergy.com/docs/default-source/documents/etac/2013/ascend_presentation_13_nov_13_without_prelim_results.pdf

Gary Doris stated that PowerSimm provides a Monte Carlo framework to construct resource portfolios using simulations of forward markets and during delivery conditions of weather, load, wind, hydropower, and spot market conditions to conduct a risk analysis. Uncertainty is introduced following a highly structured process producing "meaningful" risk analysis that probabilistically envelopes future outcomes. Risk is quantified and monetized using an actuarial approach to help level the economic playing field between different portfolio choices. The monetization approach is more transparent than the efficiency frontier approach to comparing the risk and cost of portfolio alternatives. Ascend's modeling incorporates information about NWE's existing generation assets and loads. Load data is combined for all customer sectors; individual load sectors are not broken out.

Highlights of the ETAC discussion during the presentation follows.

ETAC Discussion

Comment - The Ascend approach is not necessarily superior to displaying the modeling analysis in an efficiency frontier, but aids the decision maker in resolving the value of risk. Decision makers will continue to use their judgment in selecting the resource portfolio and making resource acquisitions.

Question - How is the Dave Gates Generation Station treated in the modeling?
Answer - It is modeled as a must-run plant with a constant 7 megawatt (MW) output. It may be possible to address the ancillary services potential of this plant in the future.

Question - Is the combined cycle gas-fired plant assumed to be water or air cooled?
Answer - Air cooled. We recognize that air cooling is a conservative assumption but seems appropriate for MT given the limited availability of water rights.

Question - One of the parameters you use to compare resources is maximized revenue. Why did you choose this parameter rather than minimizing cost?
Answer - Maximizing revenues reflects the fact that NWE can sell into the market. However, maximizing revenues minimizes costs by default.

Question - What time period do you use looking back?
Answer - We start with a monthly period to allow for adjustments to resource operation, e.g. heat rates, with time.
Question - What portfolios did you examine to analyze the hydro acquisition?
Answer - A base or market case, a combined cycle plant case, and the hydro case.

Question - What data was used for the hydro plants?
Answer - We used historic hydro plant data and replicated it through time. We have five years of monthly data augmented with five years of hourly data. We did a statistical analysis of the Rainbow plant to see how it would have operated given its upgrade from 30 MW to 60 MW.

Question - So the historic data were extrapolated into the future?
Answer - We used historic relationships between generation, prices and load to do so.

Question - How did you calculate the 439 MW capacity for the hydro plants?
Answer - We summed the total of the individual plants and subtracted the Kerr capacity because its ownership will shift to the Confederated Salish and Kootenai Tribes in 2015.

Question - Will the modeling for the advanced approval application to the MPSC dispatch the hydro?
Answer - The hydro plants will not be dispatched directly; their capability will be offset.

Question - Does each of the stochastic runs draw from a distribution of water years?
Answer - Yes.

Question - Given the fact that precipitation changes and the hydro plants do not last for ever, how do planners typically value hydro assets?
Answer - Necessary maintenance is included in the operation budget. Water rights are assumed in perpetuity.

Comment -Hydro plant operation is subject to Federal Energy Regulatory Commission (FERC) licenses which are of finite duration.
Response - Economic analysis assumes that the water right is perpetual. Because of the hydro plants' large residual value at the end of the planning period, one should change their discount rate. We did not do so, which makes the analysis of the hydro value conservative, i.e., it under values it.

Comment - You quantify the value of risk by integrating under the cost distribution curve determined from compiling the results of all of the individual stochastic PowerSimm runs. For past plans, NWE assessed risk by calculating the 5th and 95th percentile of the curve. We need to understand which variables you perturb in the individual model runs.

Question - Is the mid-point of the distribution near the quantified risk value?
Answer - Close. The risk premium corresponds approximately to the difference between the mean cost and one standard deviation up in costs. We add the risk premium to the total cost of the portfolio.

Question - There is a change in the distribution of costs at 2021. What happened then?

Answer - Carbon costs are added in 2021.

Question - Have you considered examining the impact on the portfolio if carbon costs are not added?
Answer - No. Not adding carbon costs would be imprudent as other utilities in the region include carbon costs in their planning. The value we added, $20 per ton of CO_2, is at the lower of the range of values used by the other regional utilities.

Question - How much does the electricity price change when carbon costs are incorporated?
Answer - It increases by about $12 per ton of CO_2 emitted, calculated by multiplying the carbon cost by 0.6.

Question - Does this mean that electricity customers will pay 60% of the carbon costs?
Answer - The calculation is 0.6 X $20 per ton of CO_2. The 0.6 is the conversion factor.

Question - Shouldn't the conversion factor decrease with time as electricity generation becomes less carbon intensive?
Answer - The conversion factor is based on gas-fired plants as the marginal generation unit. This is a conservative assumption, i.e. it lessons the value of the hydro plants over time. A higher carbon charge would be required to push existing plants fueled with Powder River Basin coal to the margin and cause them to be retired because of costs.

Question - Does the cost of carbon assume that utilities receive carbon emission allowances?
Answer - No, it is based on opportunity costs.

Question - How is the 0.6 conversion factor derived?
Answer by Todd Guldseth - The Energy Information Administration gives a carbon cost of $15 per ton of CO_2 in 2015. A combined cycle gas-fired plant produces 0.4 tons of CO_2 per megawatt hour (MWh) of electricity production. A simple cycle plant produces 0.6 tons of CO_2 per MWh. A coal plant produces a little over one ton of CO_2 per MWh.

Question - What is the experience with other emission costs?
Answer - Ascend has been modeling carbon costs in Europe for 18 years. Carbon costs have come down somewhat. For criteria pollutants such as SO_2 and NO_x, the costs were initially high but dropped as control technology cost dropped.

Question - How did you determine a distribution of gas costs?
Answer - The distribution was created using historic future price curves and option price quotes. We do not simply make random draws of gas prices because it would not result in meaningful price changes over time. Instead we use a mean reversion component of 0.998 to capture price changes in succeeding modeling time steps. We also maintain the cost relationship between electricity and gas costs, i.e. the heat rate.

Question - Is carbon cost the major driver of risk reduction resulting from the acquisition of the hydro plants?
Answer - Simulating carbon costs would increase uncertainty and hence the risk premium. We add the carbon cost in 2021 which makes hydropower cost effective compared to the market or

combined cycle alternative portfolios. However, we use a deterministic carbon cost and do not directly assign uncertainty to it. Thus, the risk premium from carbon emitting electricity generation does not grow. This assumption reduces the benefit of the hydro acquisition.

Question - Have you run other dates than 2021 for imposing the carbon costs?
Answer - No. We could do so. We could for example use a 2019 date.

Comment - The political viability of a $50/Mwh carbon tax is uncertain.

Comment - We do not need a carbon tax for carbon to affect regional power prices.

Comment - NWE must make a reasoned and prudent business decision based on what we know now. Utilities are not building coal plants because of regulatory risk associated with doing so. Other pollutants such as sulfur and mercury are subject to emission standards rather than emission taxes. The question is not whether we will have a carbon tax but whether emitting carbon will raise generation costs.

Question - In addition to the deterministic carbon cost scenario which you are now using, when the advanced approval application for the hydro plant acquisition, could you also include a sensitivity case for carbon costs?
Answer - PowerSimm could do so.

Question - Does the Basin Creek plant run only when it is in the money?
Answer – Generally yes. Updated answer: Basin Creek is also called on for reserves and when it is called on it may or may not be in the money.

Question - Why does the net revenue from the Yellowstone Energy Limited Partnership (YELP) and the Colstrip Energy Limited Partnership (CELP) qualifying facility projects drop off beginning in 2017?
Answer - The net revenue drops with the decline in the implied heat rate.

Question - Do you model Colstrip Units 3 and 4 separately taking into account the reciprocal ownership agreement?
Answer - We scale the full unit amounts based on the ownership shares. When the units make money, they run.

Question - You said that generation is displaced when it is not in the money. Is the net position based on theoretical capability?
Answer - The plants are run based on a market rather than a system reliability perspective. Subject to operational constraints, units are run in the model when they make money, i.e., when market prices exceed generation variable cost of production.

Question - Why is exposure to the market a bad thing?
Answer - With and without the hydro plants, NWE resources do not meet loads, i.e. NWE is short. Exposure to market prices can result in rate shocks.

Question - Why do you use the net present value of risk to judge the value of market exposure?

Answer - One cannot beat the forward price curve. If you could lock in $30 power for 30 years, then you could beat the forward price curve. Such contracts are generally not available because producers would generally prefer to receive higher returns consistent with the market.

Comment - NWE also faces counter party risk when contracting for power. If the counter party defaults then you don't get the MWs.
Response - Sophisticated utilities factor in credit risk.

Comment - You list the capacity factor of a combined cycle plant in the high 50% range. In the last resource plan, the capacity factor was in the high 80% range.
Response - The baseload capacity factor realized in PowerSimm increases with carbon costs. We also constrain the combined cycle plant operation as follows: two hour cold start, 4 hour run time, 1 hour shut down time, and four hour down time.

Question - Does the load forecast include economic development and energy efficiency?
Answer by Todd Guldseth - As we have previously discussed with the ETAC, the load forecast does not include business cycles. It is based on historic growth.

Question - The analysis you are presenting today focuses on the hydro plant acquisition. What will be in the resource plan?
Answer - We are focused on completing the work that supports the hydro plant asset purchase. We will also address in the plan resource adequacy, compliance with the renewables portfolio standard, as well as the selection of the preferred resource portfolio using PowerSimm.

Comment - The proposed asset purchase allows this plan to focus on an actual resource, the PPL Montana hydro plants, with specific cost and operational characteristics.

Comment - The resource plan question brings to mind something we discussed at the last ETAC meeting, what is planning all about. The plan is built using generic resources. Deciding whether to acquire a specific resource is analyzed a different way. Acquiring the hydro plants raises issues such as the plant ages and climate change which may change flows. NWE will have to show why this specific acquisition is a good idea. Other factors may influence business and corporate decision makers such as the logic in reclaiming part of Montana's heritage. The planning process does not replace business decisions.
Response by Dave Fine - We are examining whether the hydro plants fulfill NWE's resource needs and fit into our resource portfolio. The hydro plants have known cost and performance.

Question - What are the independent variables distributions of which are drawn from in individual PowerSimm stochastic runs?
Answer - Each run draws from distributions of weather (temperature), water year, and gas prices.

Next Steps

NWE will complete its advanced approval filing and resource plan. A date for the next ETAC meeting to review the resource plan was not set.

Disclaimer

Committee members provide advice to NWE as individual professionals; the advice they provide does not bind the agencies or organizations that the members serve.

Portfolio Valuation of PPL Hydro Asset Acquisition

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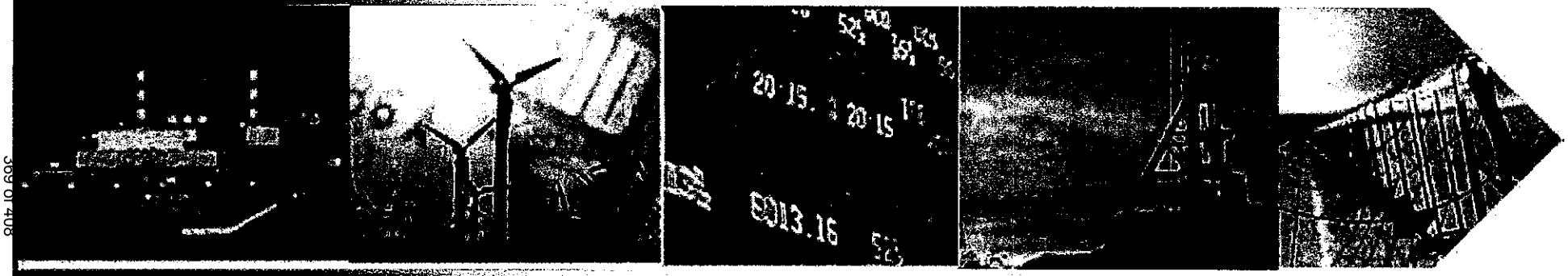

Understanding the Latent Value of Hydro Generation

November 13, 2013

Gary Dorris, Ph.D.
Sean Burrows, Ph.D.
Mark Dyson
Alex Lauderbaugh
Brock Mosovsky, Ph.D.

gdorris@ascendanalytics.com
303.415.0311

www.ascendanalytics.com

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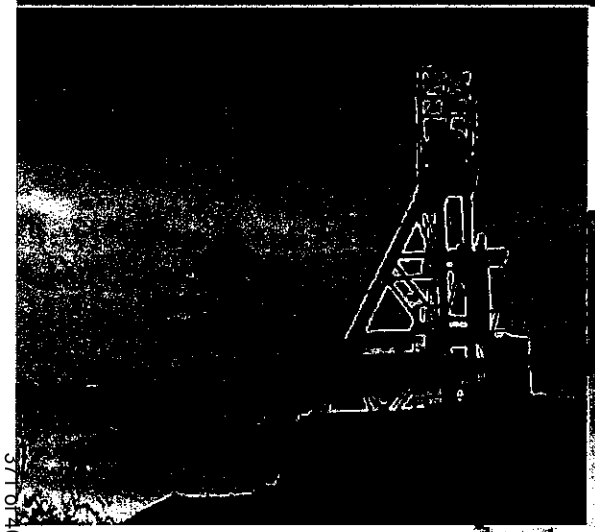
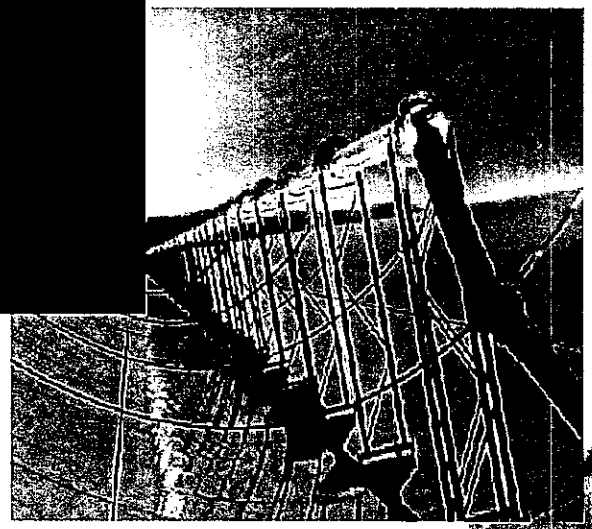
Outline

- Portfolio Characteristics and Valuation Results
- Quantifying the Value of Risk
- Market Inputs
- Simulation Validation
- Operating Dynamics and Detailed Results

Preliminary Results of Hydro Acquisition Analysis





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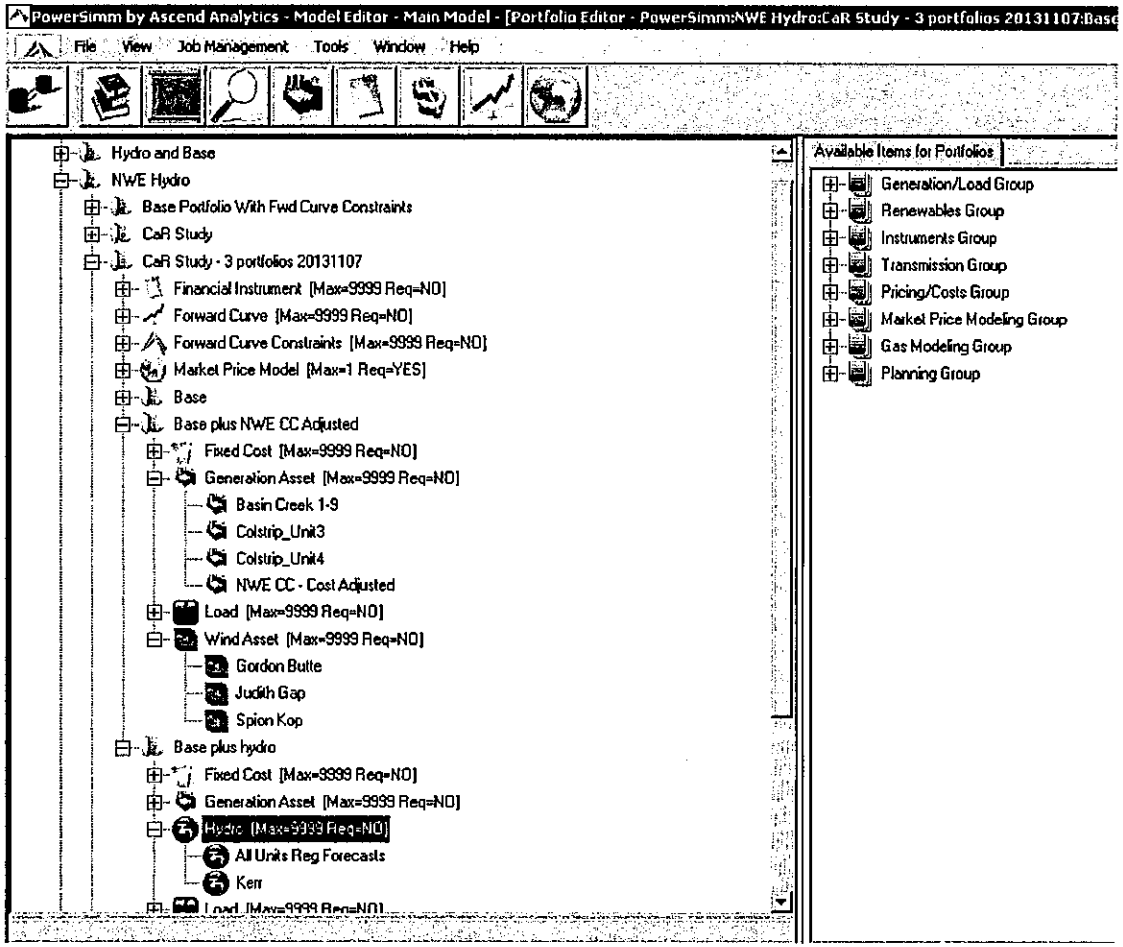
Best Practices in Resource Analysis

- Portfolio perspective
  - Fuel diversity
  - Reliability and intermittent resources
  - Uncertainty in fuel, emissions, and power
- Use of market for fuel and power
- Analyze generation resource options with respect to market dynamics
- Capture new dynamics
  - Weather
    - Load
    - Wind generation
  - Market conditions
    - Forward markets for fuel and power
    - Spot price dynamics
- Resource adequacy
  - Reliable service at cost effective rates
  - Market interactions

Key Points of Analysis

- Supply Cost and Risk = costs and uncertainty in energy supply costs (fixed and variable)
- Risk Premium = monetized value of risk—uncertainty in supply costs
- Net Position Exposure = balance of NWE resources relative to load obligations

- Supply portfolios to be assessed:
  - Market purchases
  - Purchase of PPL hydro (439 MW)
  - Combined cycle (239 MW)
- Optional Analysis
  - Reliability of supply
  - Flexibility function



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Tools of Supply Planning Model Attributes

Uncertainty Factor	Production Cost Models	Integrated Risk Based Planning Models
Load Growth	Fixed	Simulated Uncertainty
Load Patterns	"Typical" profile	Uncertainty in Profile and Usage Pattern
Conservation	Fixed	Weather Based Demand Response
Weather	Fixed	Weather Based Demand Response
Hydro	Fixed	Simulated Annual Daily Operations
Wind	Fixed	Simulated with Weather
Env. Hg, CO2, SO2, NOx	Fixed	Simulated Based on Uncertainty in Costs
Gas & Power Prices	Fixed	Simulated Monthly, Daily & Hourly Prices
Transmission	Fixed Input/Output	Variable Flow Contingent Factors
Forward Contracts	N/A	Simulated Forward Curves
Financial Instruments	N/A	Simulated Values
Integration of Elements	Cost Based	Linked Equations and Casual Effects

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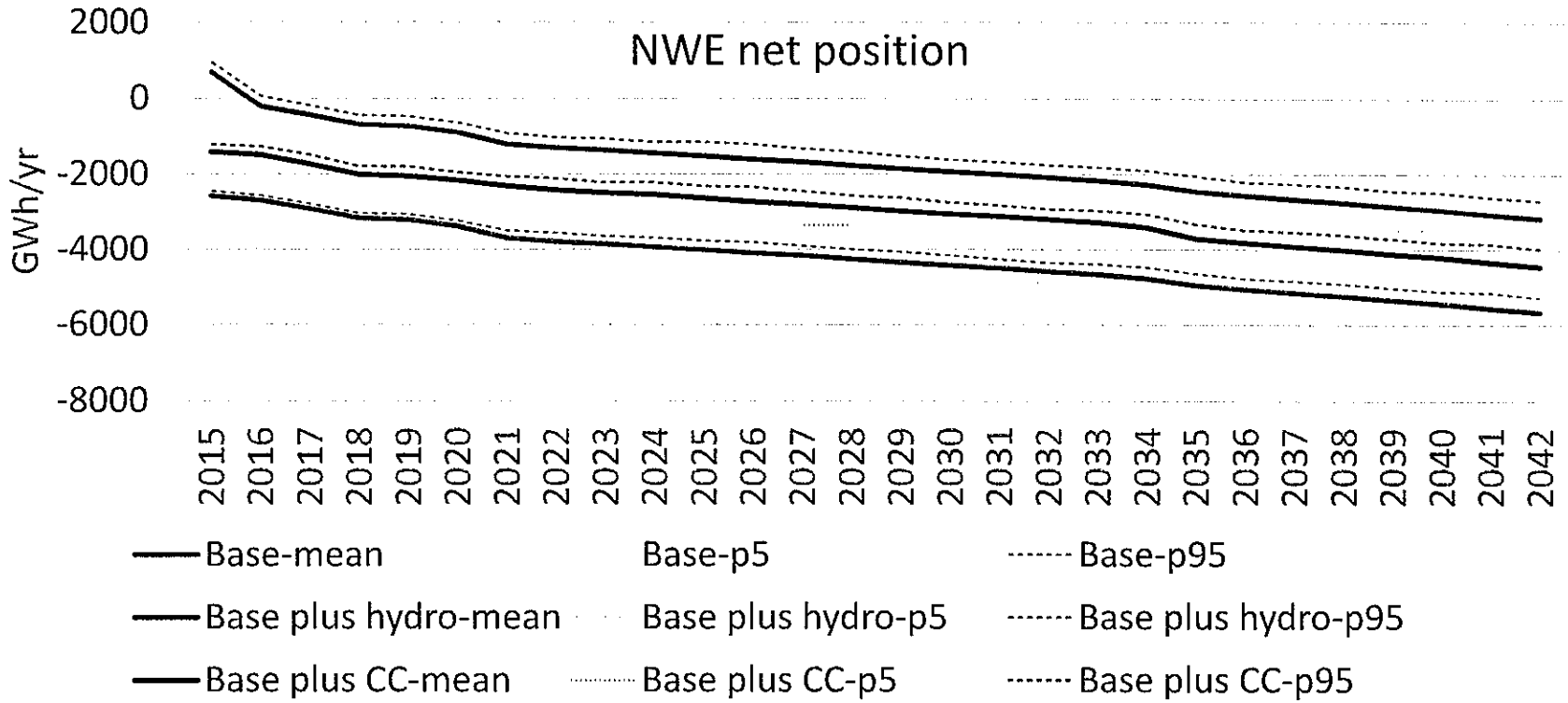
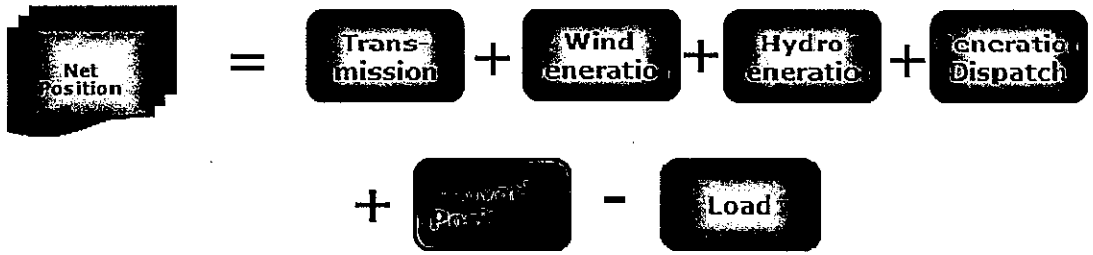
Net Position Report





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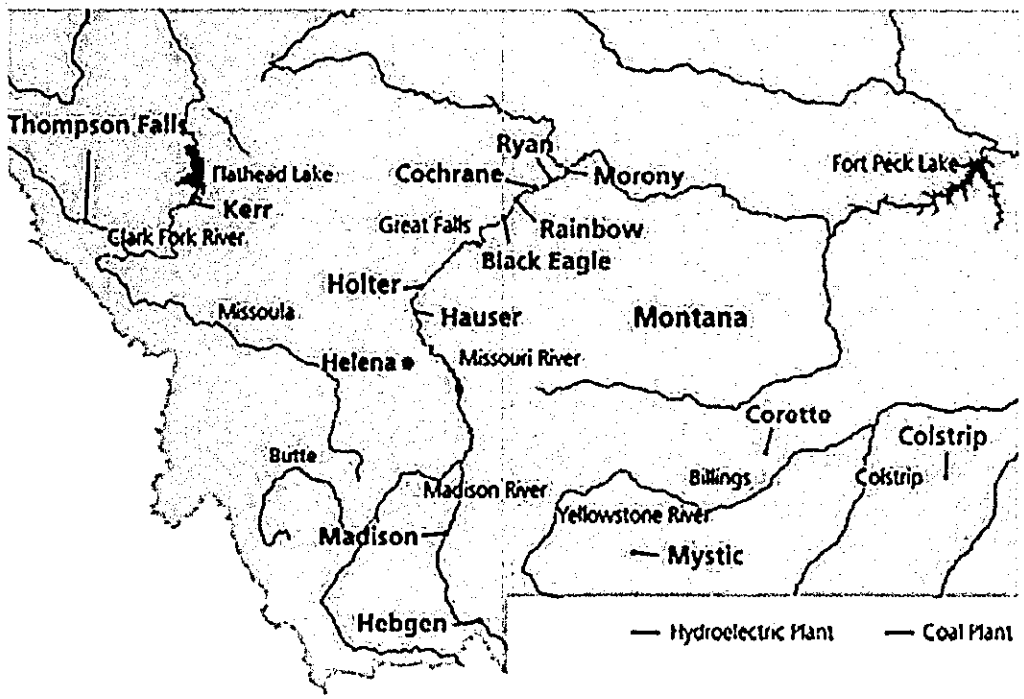
PPL Hydro Assets



Generator	MW Net	Capacity Factor (%)	Storage (A/F)
Thompson Falls	94	60	14,970
Mystic Lake	12	50	
Kerr*	194	64	200,000
Madison	8	85	27,200
Hebgen	-	-	386,000
Hauser Lake	19	81	64,253
Holter	48	75	82,000
Black Eagle	21	73	1,820
Rainbow	60	60	1,050
Cochrane	69	50	2,700
Ryan	60	80	5,000
Morony	48	68	2,700
Total	**633**	**65**	**787,693**

*Kerr generation rights end in 2015

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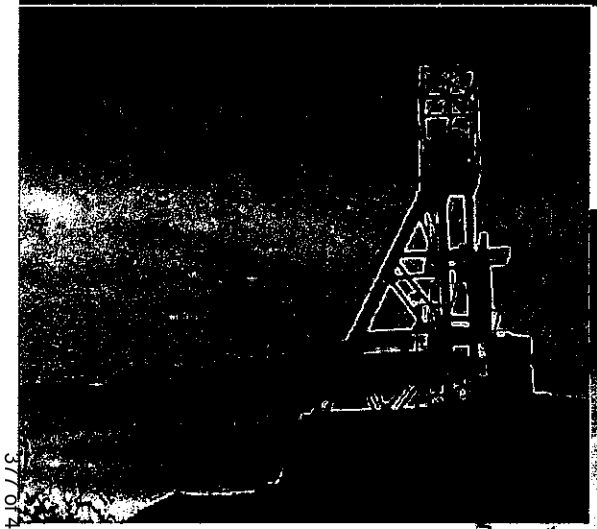
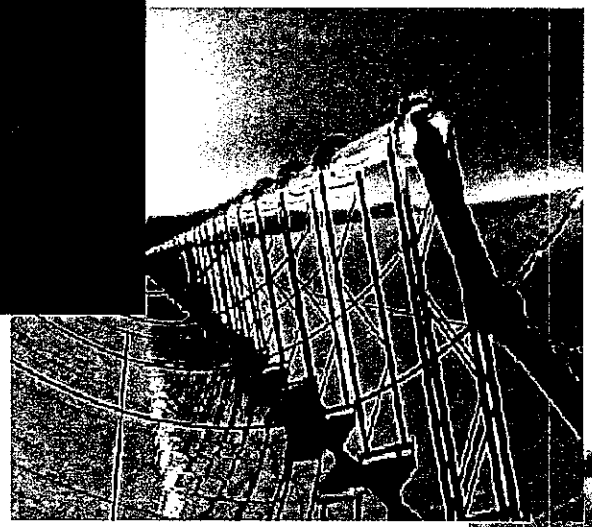
Quantifying the Value of Risk





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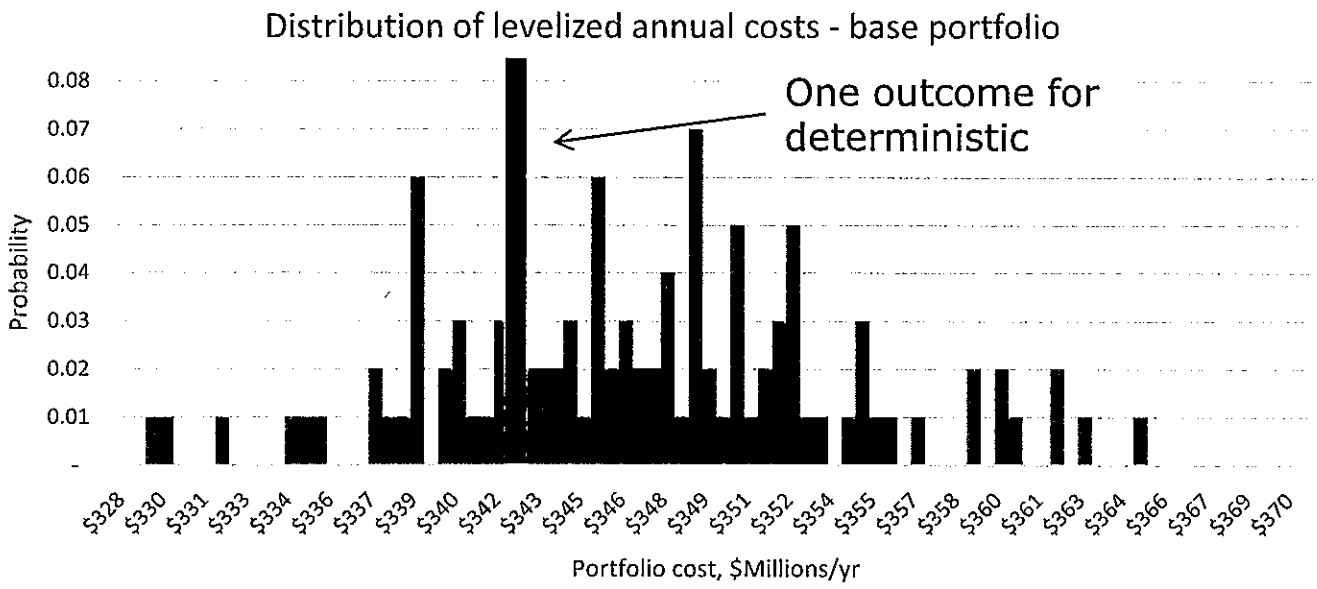
Deterministic vs. Stochastic Models

- Heavy dependence on deterministic results with scenarios
  - Excessive focus over input forecasts
  - The likelihood of result is not understood
  - Model inputs are variable and interdependent
- What's the impact of unused information?
  - Inaccurate forecasting
  - Assessing risk becomes difficult



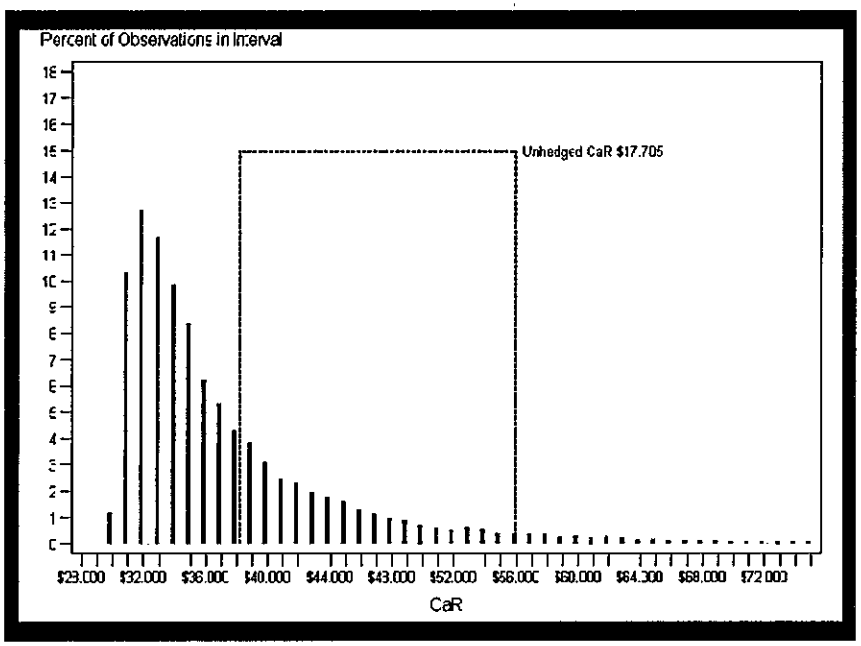
Definition of Common Planning Risk Metrics

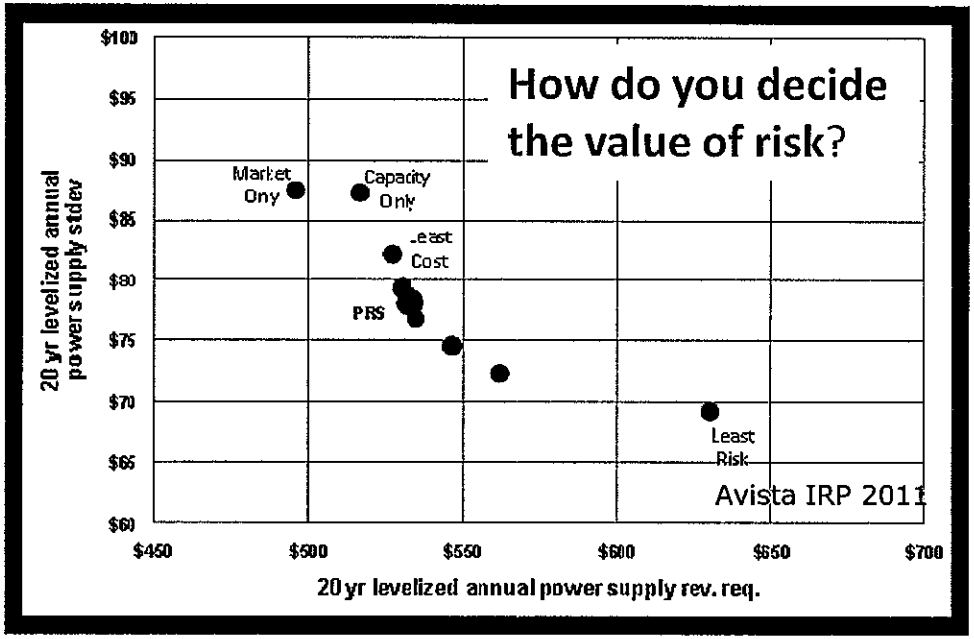
Cost at Risk (CaR) for Rev Req =

CaR = 95th percent costs – mean costs

Standard deviation (Std) of Ann Rev Req (ARR) =

Std = $\sqrt{E[ARR^2] - (E[ARR])^2}$



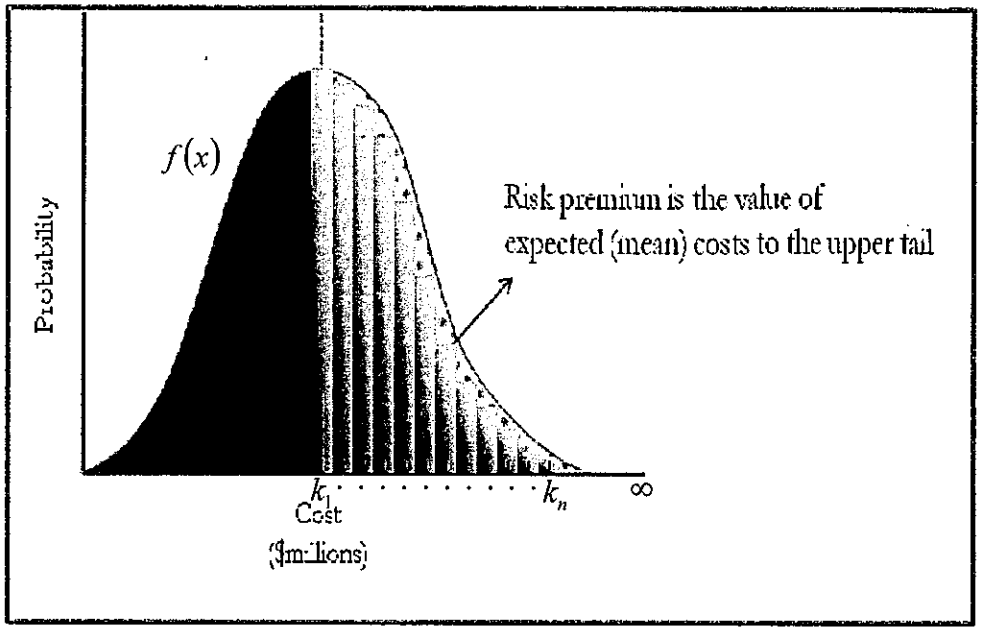


- Risk metrics are useful but need to be translated into a monetary value by quantifying the value of uncertainty

Risk Premium (RP)

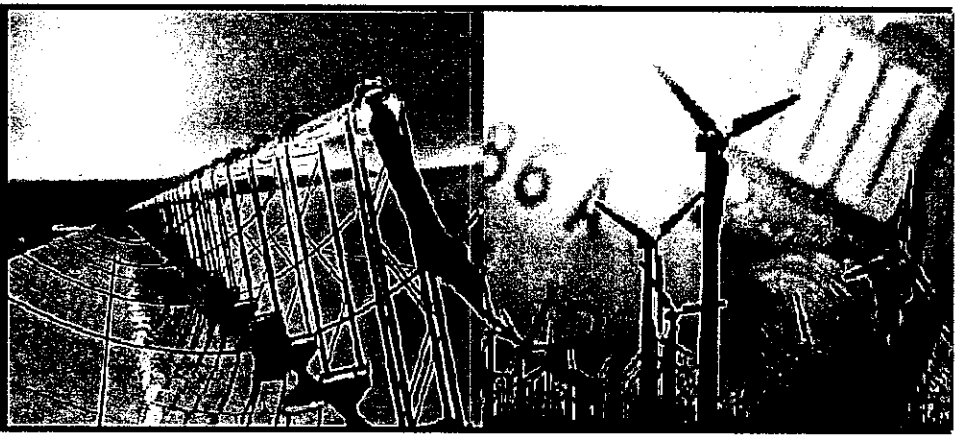
How to calculate the RP in discrete time?

- Calculate the area under the cost distribution curve.
- The orange dotted section has been overlaid with rectangles to reflect this discretized area.
- RP calculation is the same calculation used to value options or assess actuarial values (insurance premiums)

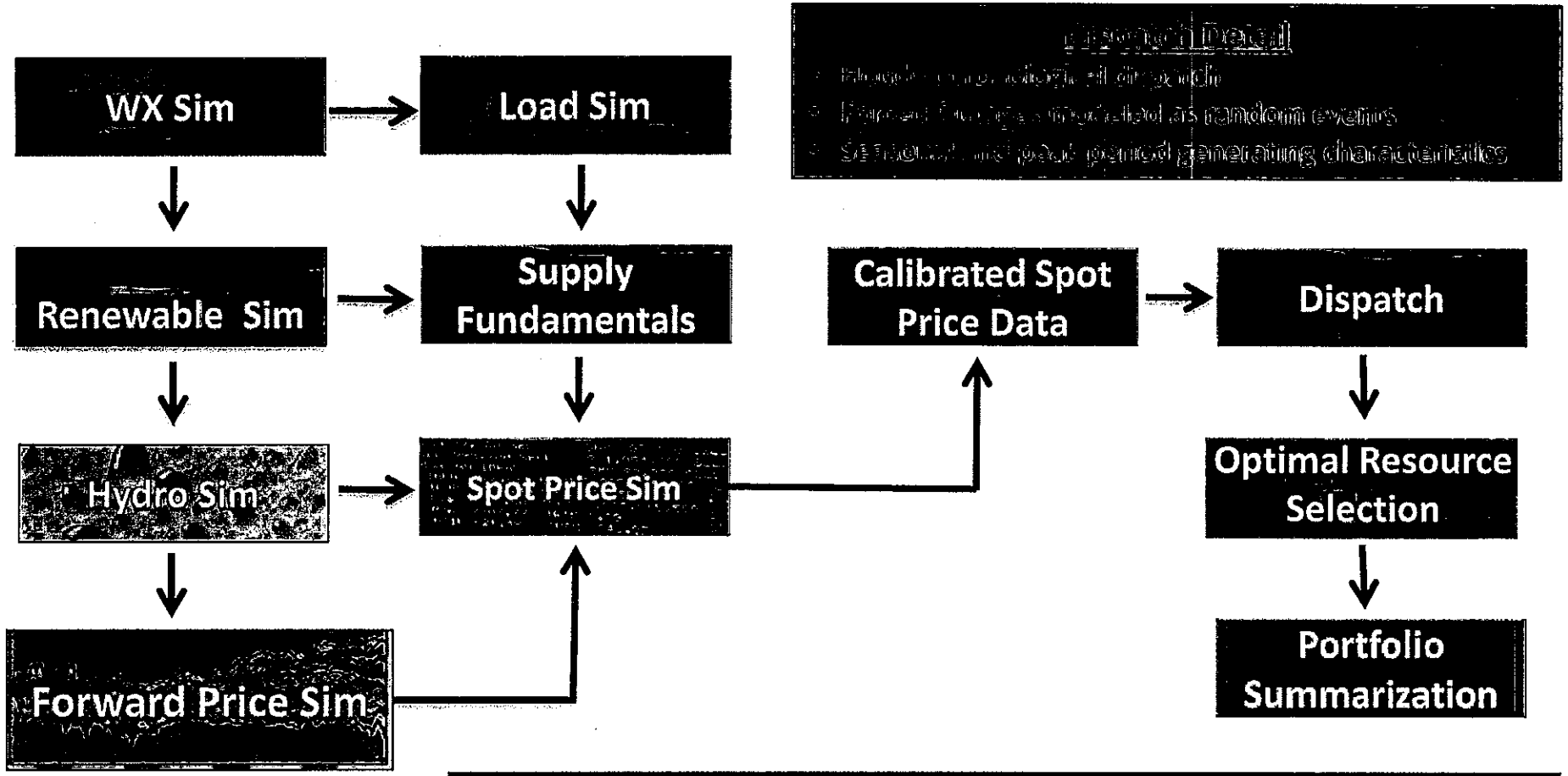


$$"Risk\ Premium" = \sum_{i=1}^{n} k_i \cdot Prob_i$$

Simulation Validation



Integrating Physical and Financial Uncertainty



Unified simulation framework reflecting joint financial and physical uncertainty

- Rigorous validation
- Capture of critical covariate relationships
- Frequency and magnitude of price spikes

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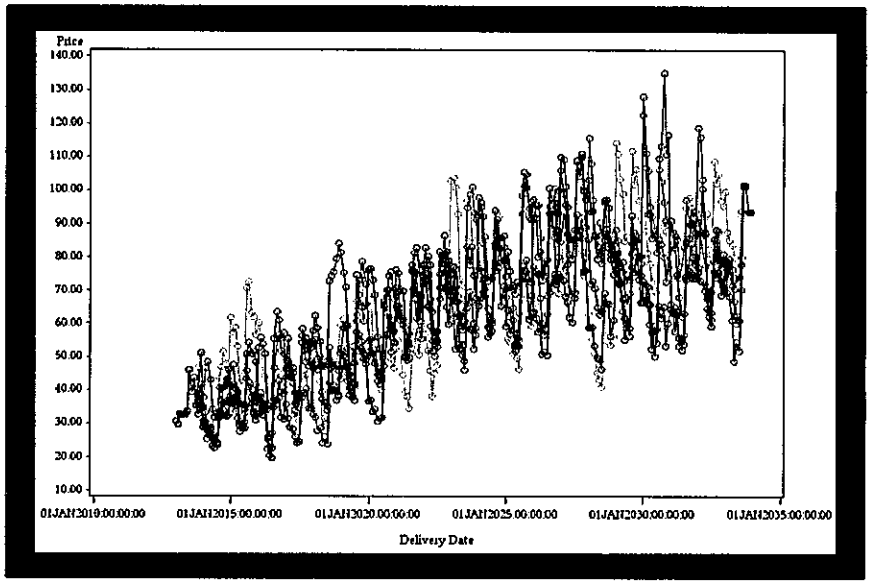
Confidence Intervals and Simulation Spread

Forward Price Simulations

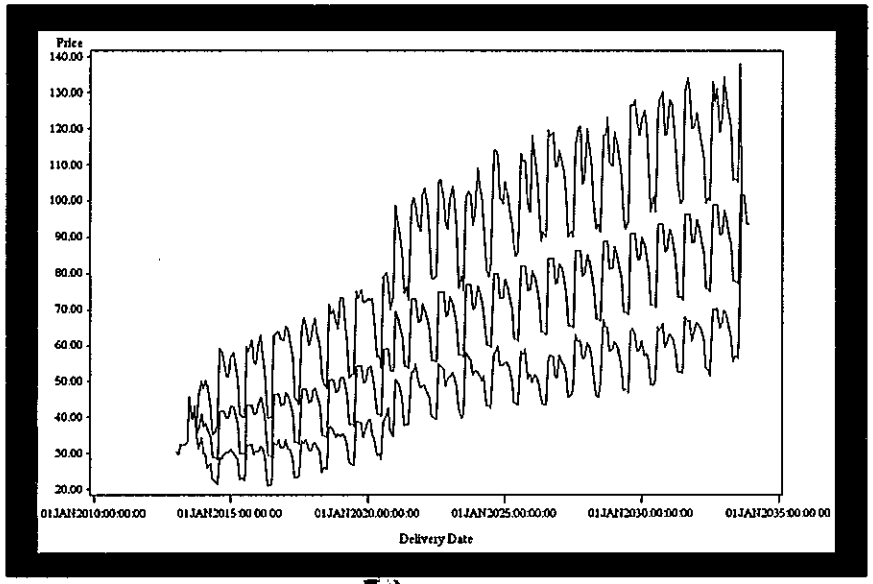
- Simulated forward prices are plotted over time for the mean, 5th, and 95th percentiles
- Expect that uncertainty will grow with time

$$F_0=E(F_t)=E(F_T)=E(S_t)$$

Mid-C Heavy price simulations spread from the mean



Confidence Intervals for Mid-C Heavy price simulations 5th, mean, 95th



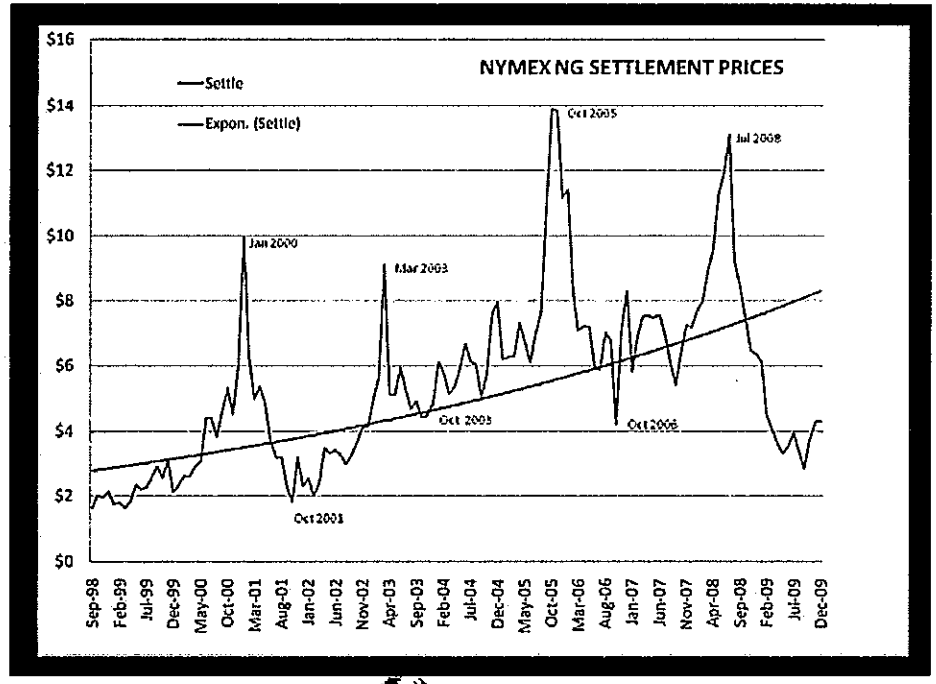
Forward Price Validation

- Tests uncertainty in the distribution of simulated forward prices
- Uncertainty grows over time
- Ranges of prices are consistent with market expectations and historic perspectives of forward price uncertainty

Forward Price Validation History and Simulations: Natural Gas

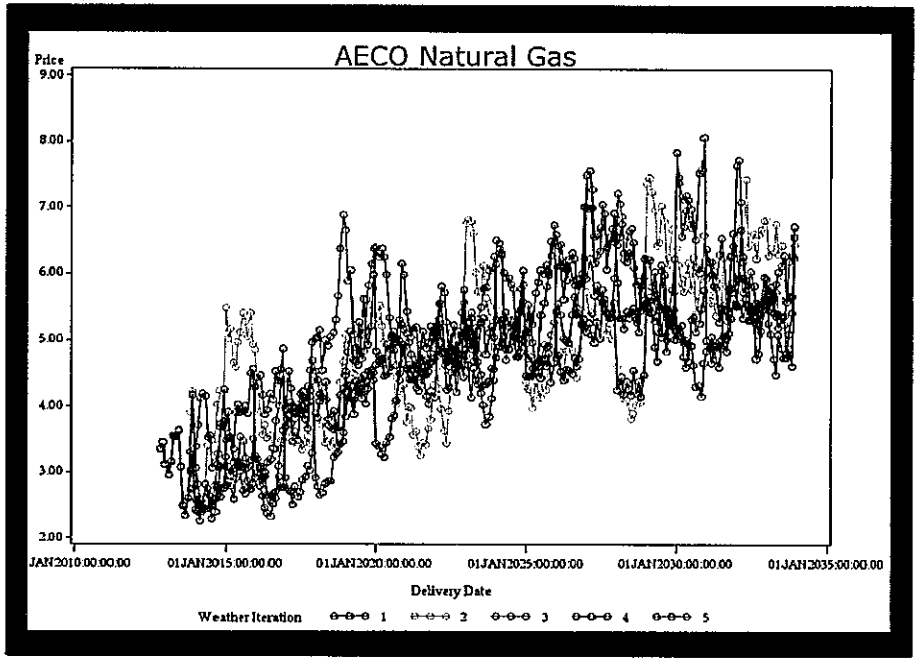
Historic prompt month prices for Henry Hub

- Large price spikes followed by mean reversion
- 2 to five year cycle
- Large volatility in prices followed by relative quiescent periods



Forward Price Validation

Price Paths for Final Evolved Forward Curve Simulation



Simulated forward market prices for AECO

- Price spikes followed by mean reversion
- 2 to 6 year cycle
- Large volatility in prices followed by quiescent periods

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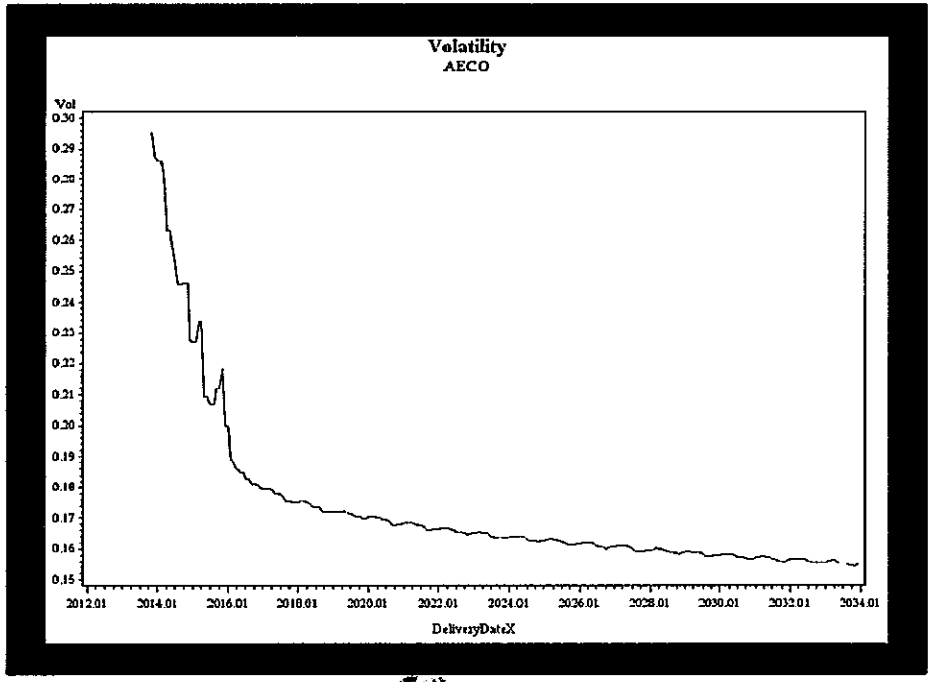
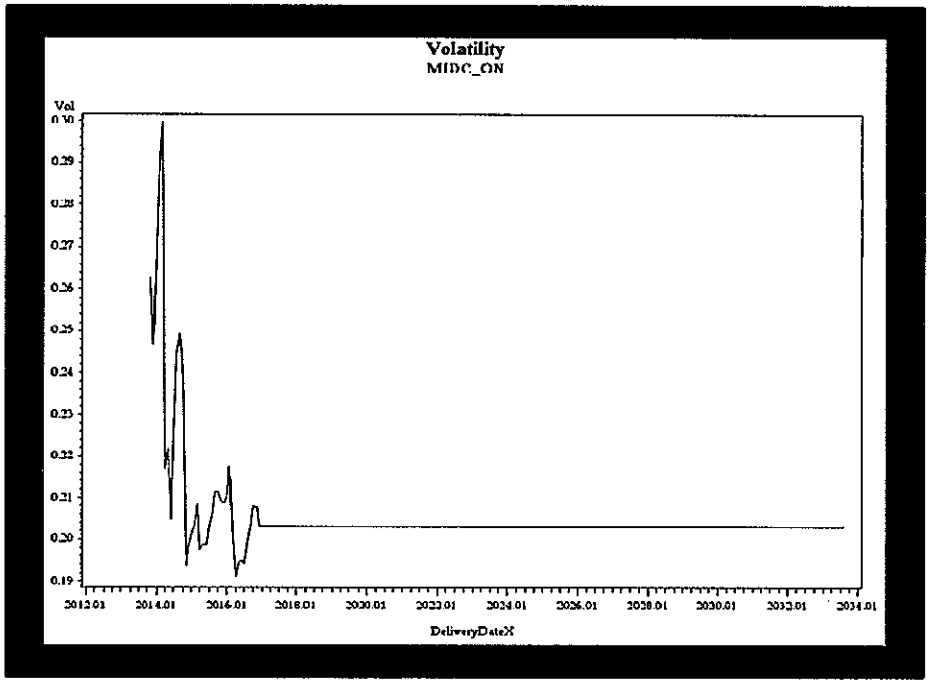
Volatilities

Volatility in Forward Contracts by Delivery Date

- Calculated from recent forward market transactions
- Controls the amount of uncertainty in simulated forward prices

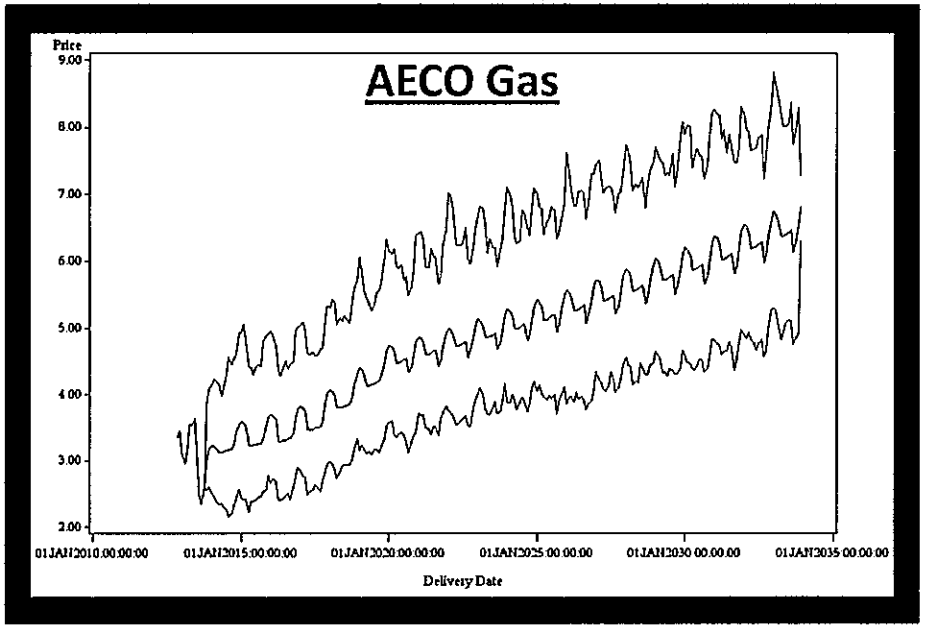


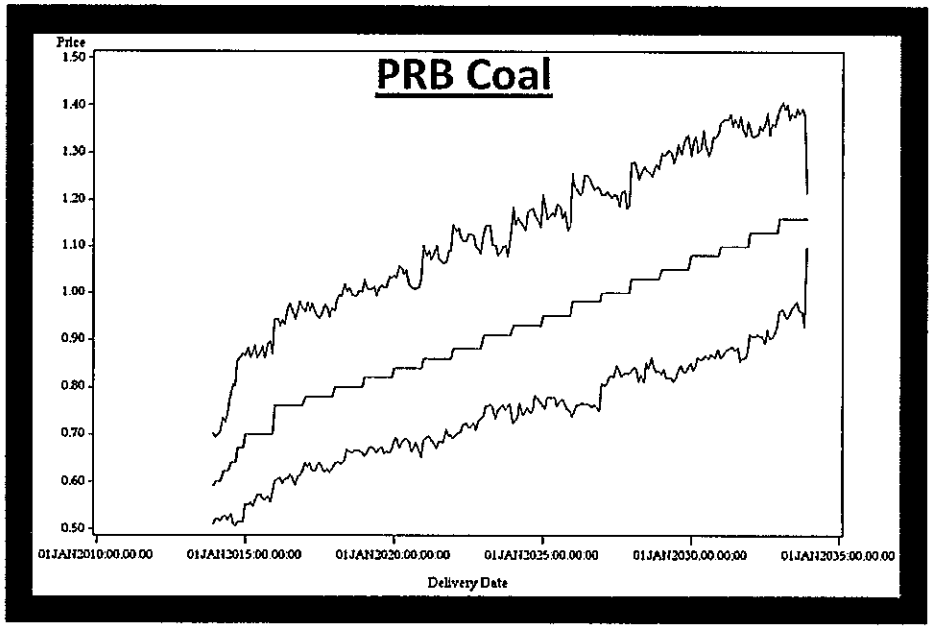


- Decreases exponentially through time
- Displays seasonal trends
- Distinct patterns observed by commodity

Fuel Price Simulations

- Simulated forward prices are plotted over time for the mean, 5th, and 95th percentiles
- Seasonal changes in price and uncertainty

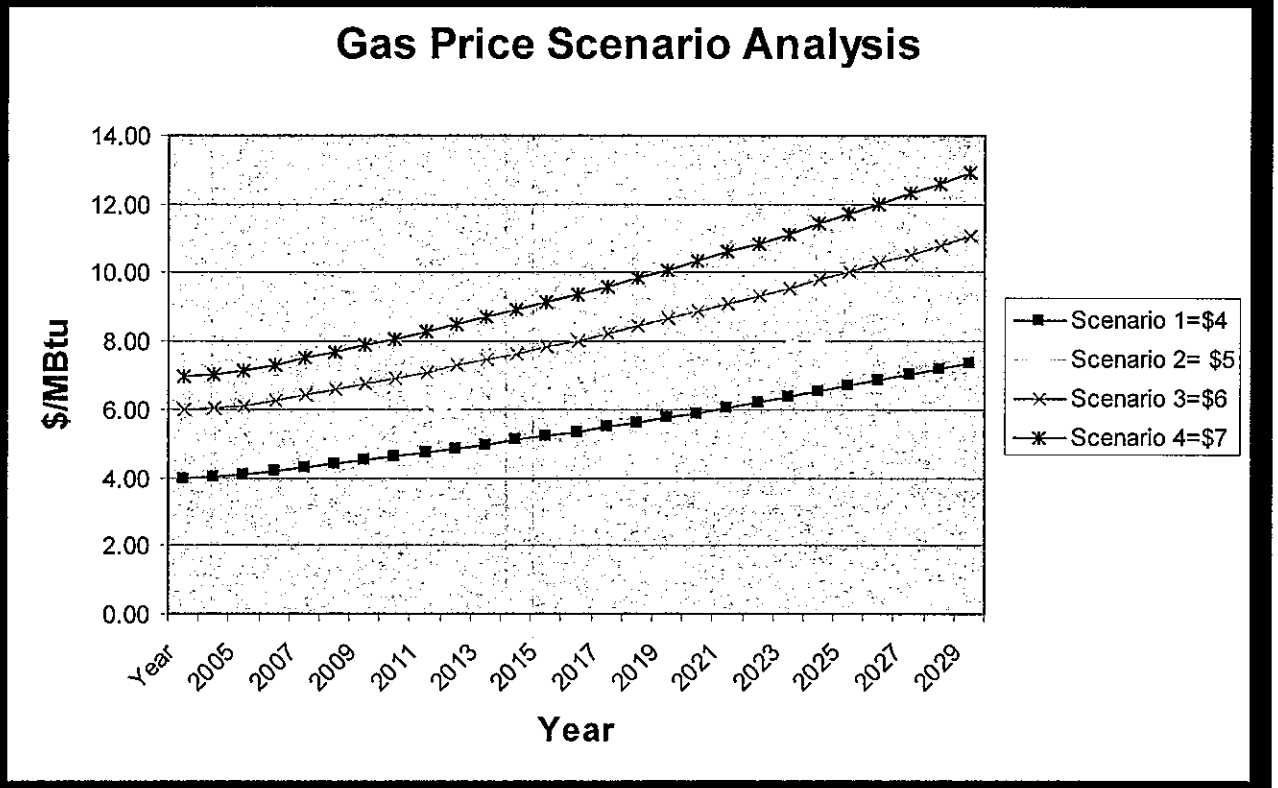




- Uncertainty grows with time
- Average price increases to account for inflation

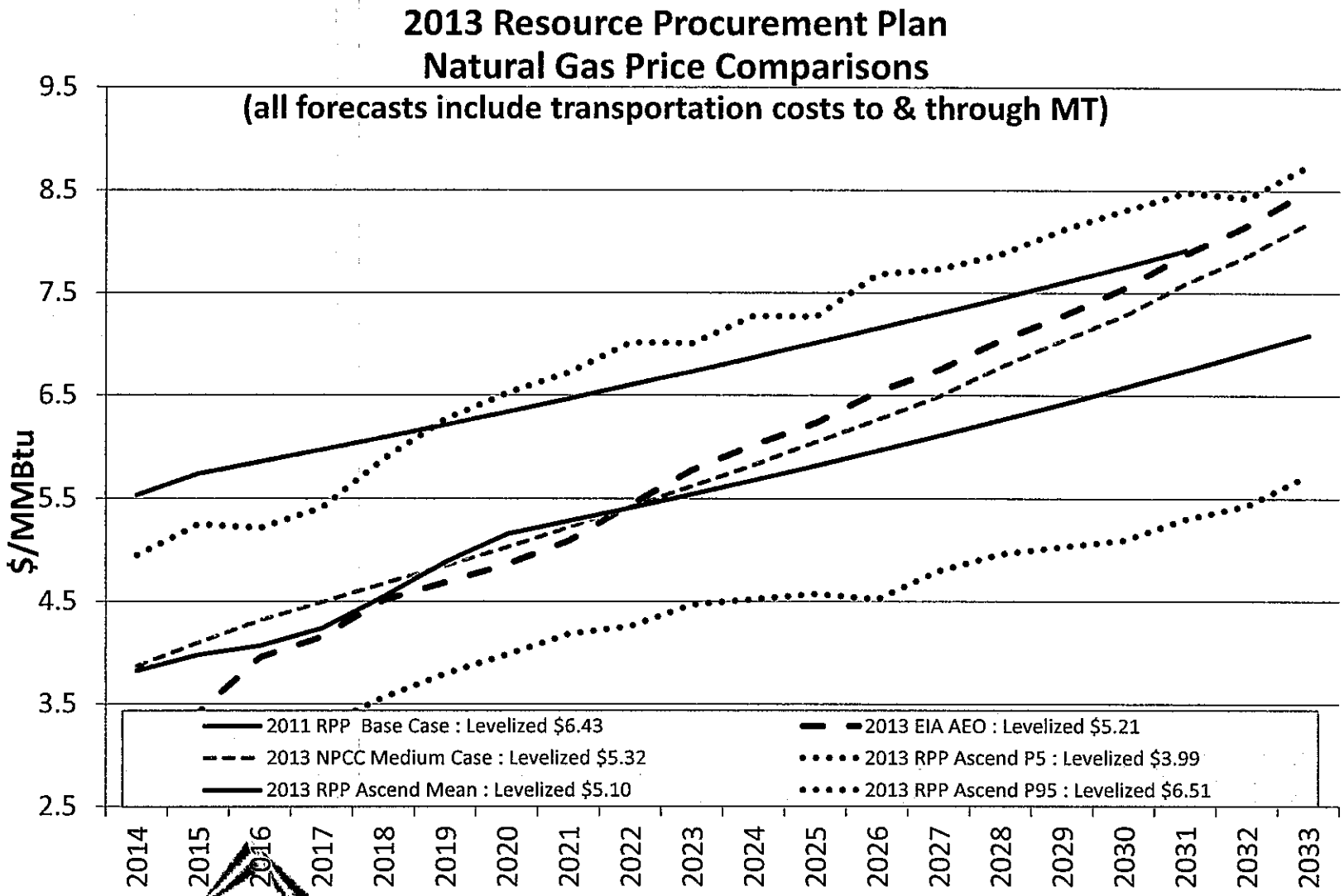
Scenario Analysis

Common Scenarios: High, Med, Low



- Which forecast are the best?
- Scenarios with prices monotonically increasing over time.
- Are these prices consistent with observed patterns?
- What's the probability weight of being in scenario 1 or 4?
- Why is the max prix in 2025 less than historical prices observed 25 years prior?
- Can we capture probabilistically future states and a more market consistent pattern of gas prices?

Gas Price Simulation



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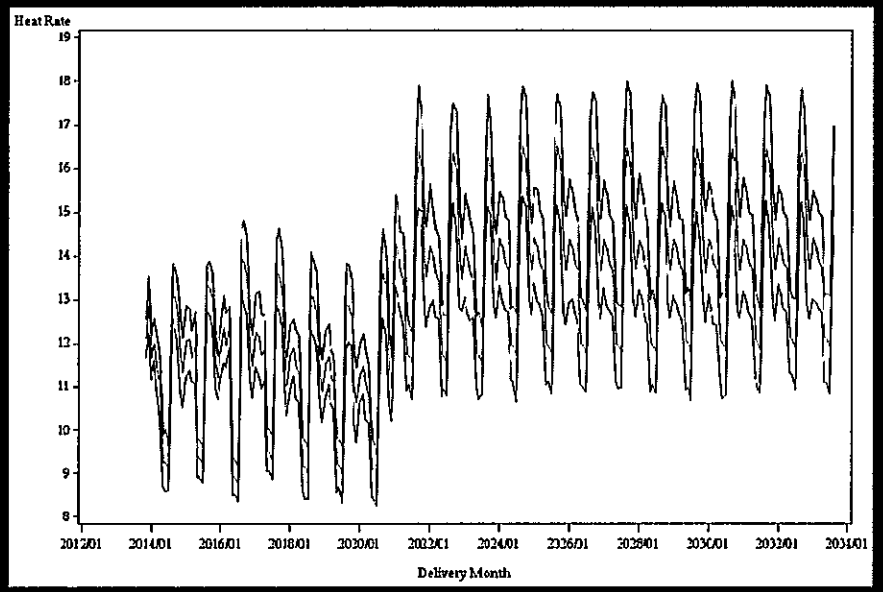
Forward Price Validation

Risk Bands for Implied On-Peak Heat Rates

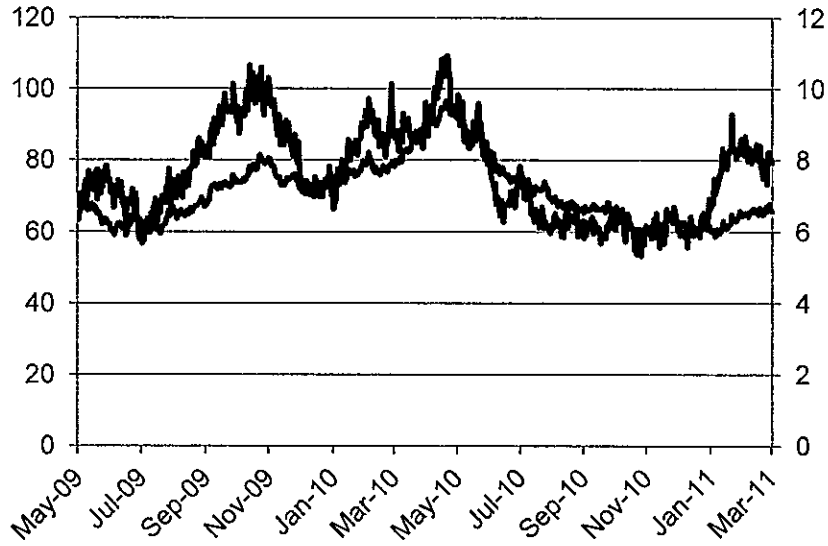


Maintaining Correlations

- Simulations maintain implied heat rate distributions
- Correctly value generation assets
- Preserve proper value of portfolio risks
- Enables proper value of cross hedges

Simulated forward market prices

- Large price spikes followed by mean reversion
- 2 to five year cycle
- Large volatility followed by quiescent periods



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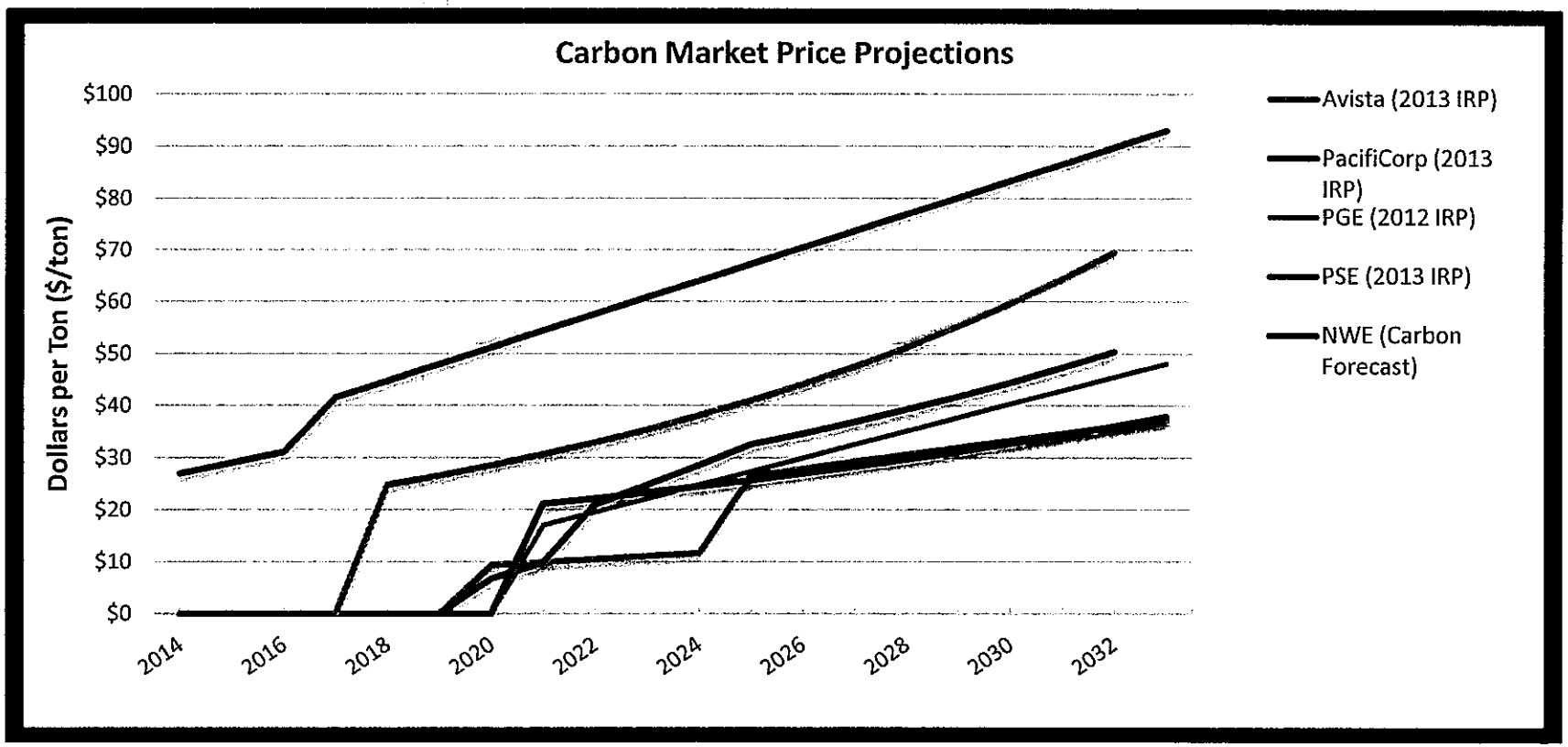
Carbon Penalty Effect

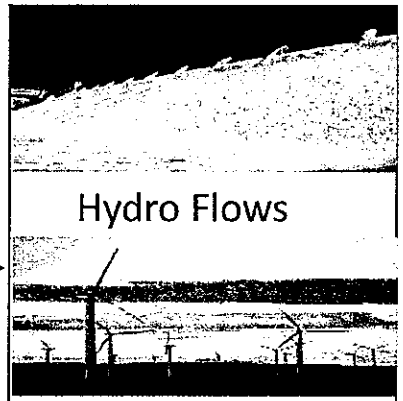
Forecasting Carbon Costs

- In 2021, a carbon penalty is priced in to both generation and forward curves.



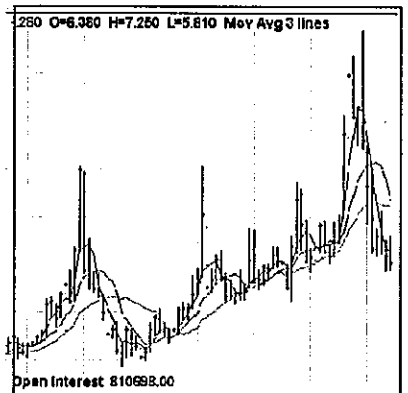
Weather → Hydro Flows → Load → Price Simulations

Weather

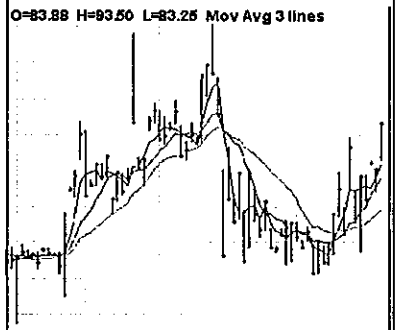


Intermittent Generation

Load



Gas



Electric

Price

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Weather-Load-Price Paradigm

Weather

- Weather is a stochastic input–so an appropriate range of future states must be simulated based on historical observations.

Load

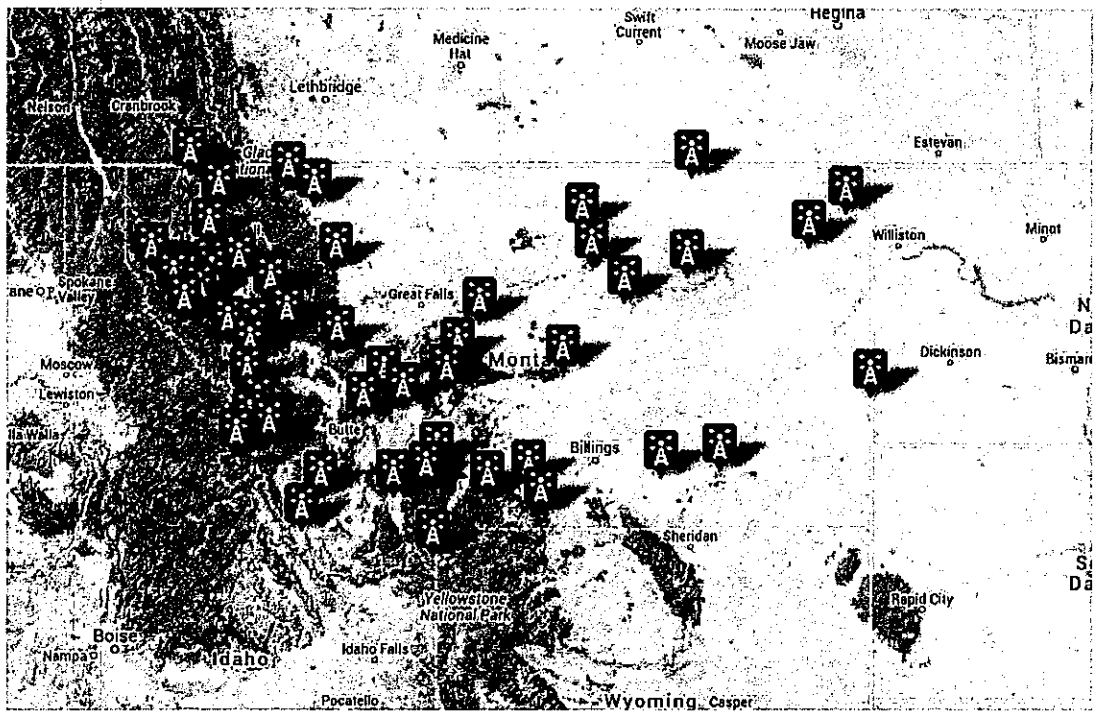
- Load is driven primarily by weather—high and low temperatures increase the demand for electricity.

Price

- Electricity price is predominantly driven by load, though other factors contribute (coal and gas price, regulations, etc.).

Weather Overview

- Weather data taken from the National Climatic Data Center
  - Publicly available at http://ncdc.noaa.gov
  - 10+ years of historical data
  - More than 30 weather stations across Montana



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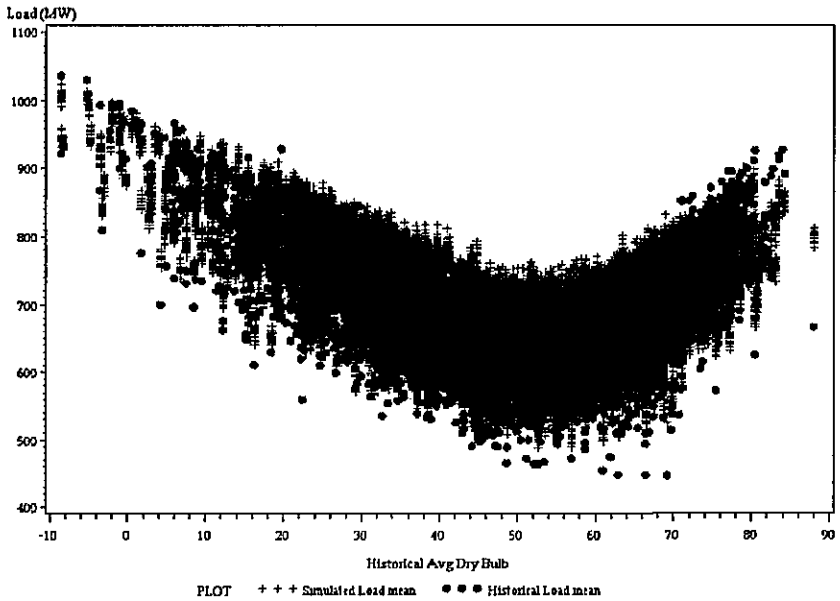
Weather Load Relationship

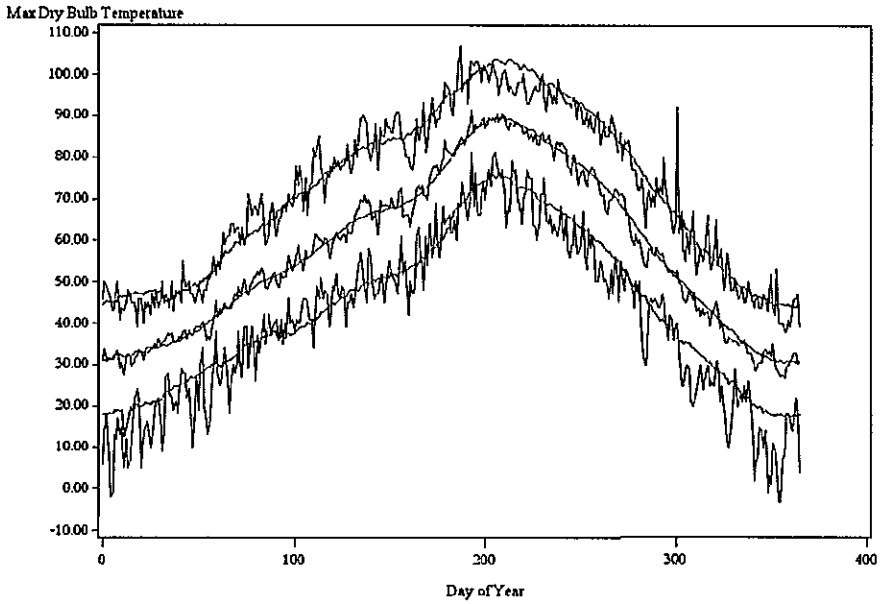
Weather-Load Validation

Simulated vs. Historical



Maintaining Correlations

- Incorporating weather into the load model maintains integrity in the weather – load relationship
- Simulations nicely smooth out "bumps" of historical weather record
- Simulations provide for new extreme values to exceed historic record



Validating Relationship

- Validate by capturing the weather – load relationship in the historical period and simulated back cast
- The structural state space modeling captures the changes in shape with changes in load

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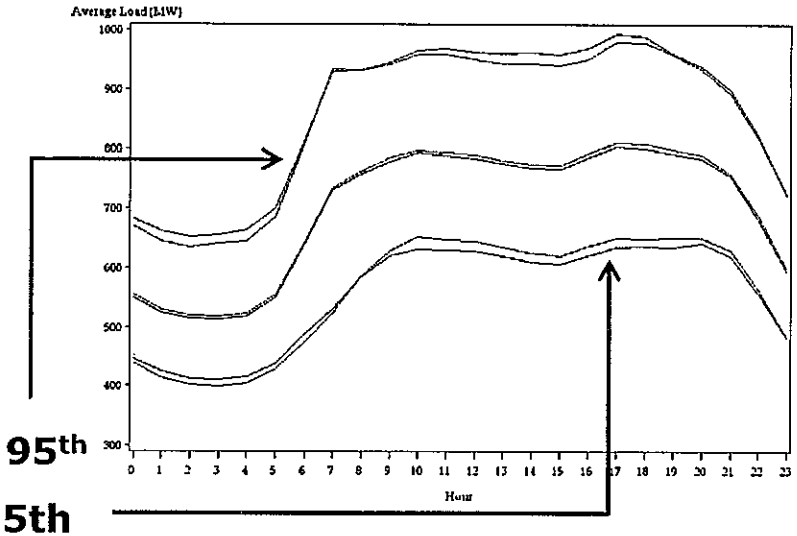
Load – Evaluating Difference 5th, Mean, 95th

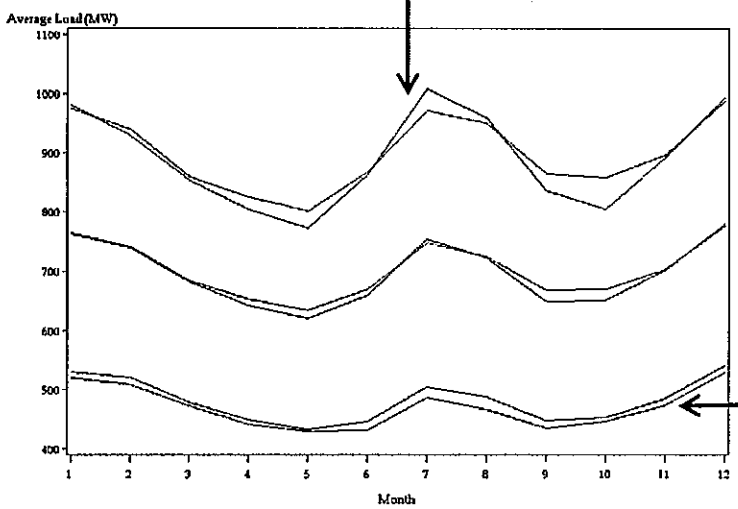
Load Simulation Validation Results

- Demonstrate a robust model to simulate future load
- Capture uncertainty in load growth with extreme weather scenarios validated prior to a load simulation
- Validated monthly load values
- Validated hourly load values for hours 1-24



Steeper load change at 95th

Flatter load pattern at 5th



Load Simulation Modeling

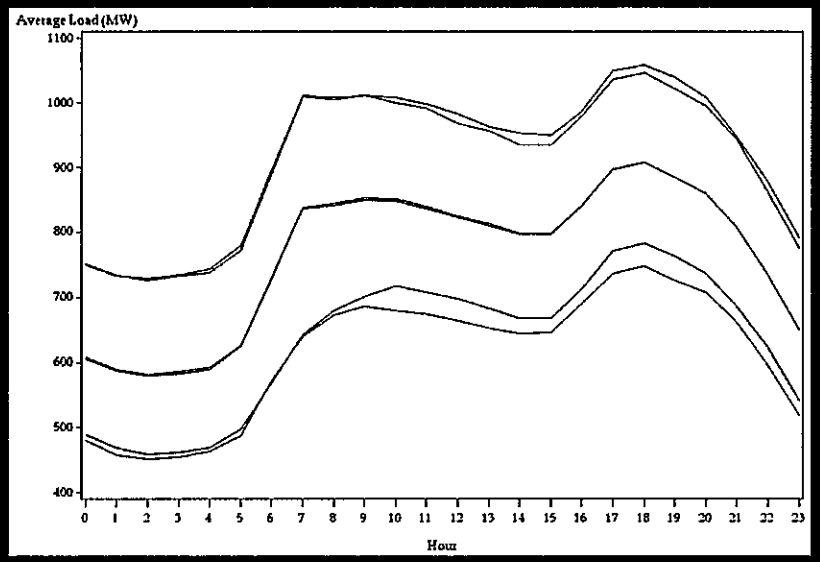
- Developed through a structural state-space model integrating weather as a dependant variable
- Weather effects modeled through a fourth order polynomial that reflects load/temperature relationships
- Calendar structure in terms of month, weekday and hour
- Autocorrelation effects where extreme load conditions are measured

Load Validation

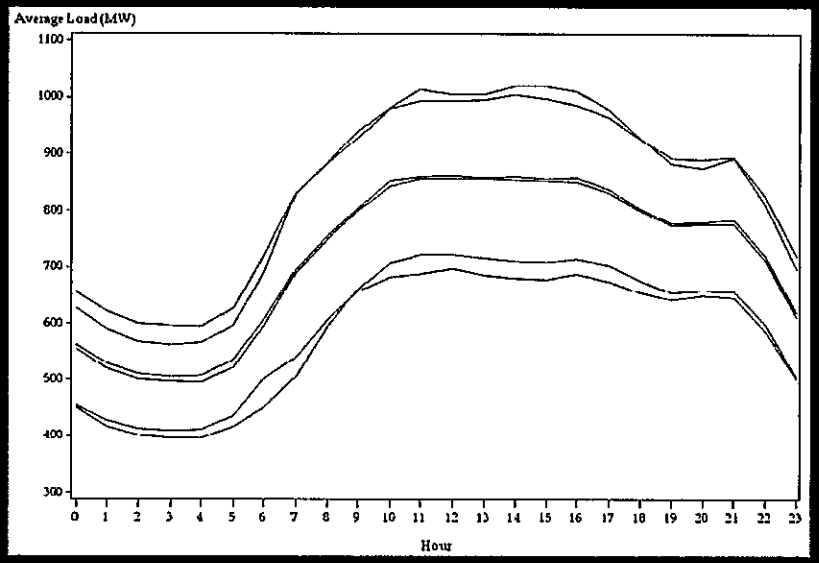
Load Confidence Intervals

- Confidence intervals for hourly load by month at the mean, 5th, and 95th percentiles
- Alignment of simulations with historical data

January



August



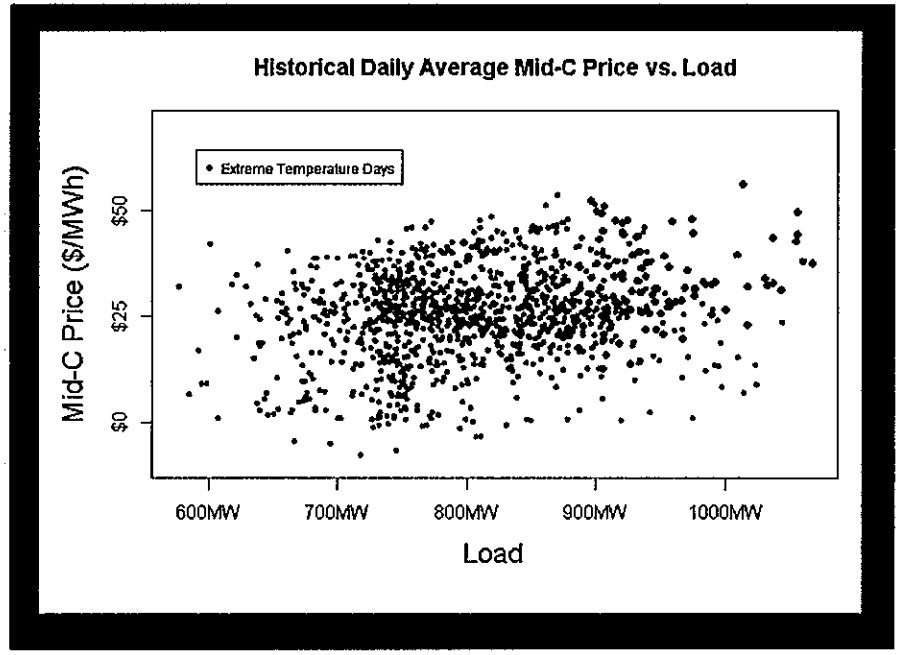
Daily Load Shape

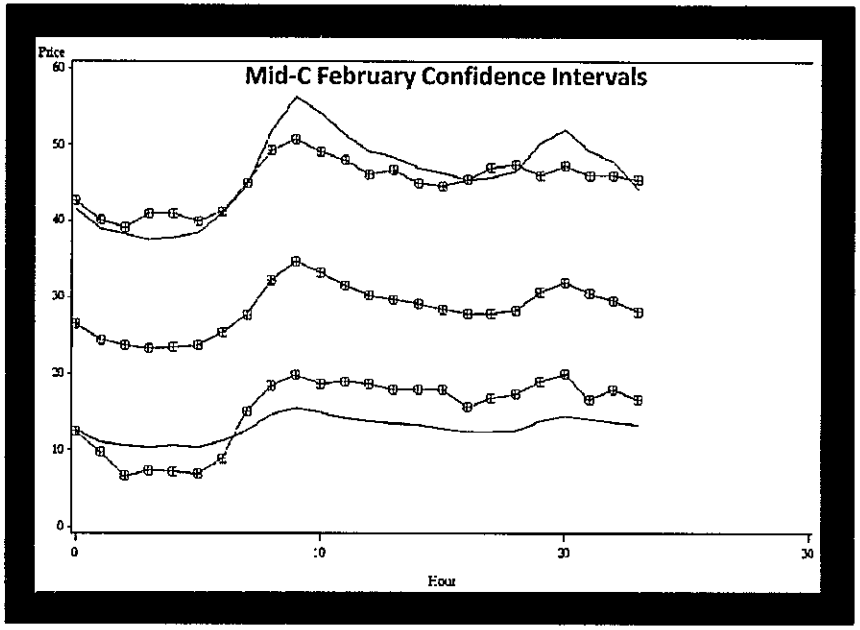
- Morning and evening peak during cold months
- Single afternoon peak during warm months

Spot Price Simulations

Daily historical market prices for Mid-C Heavy compared to NWE load

- Low correlation between NWE load and power prices.





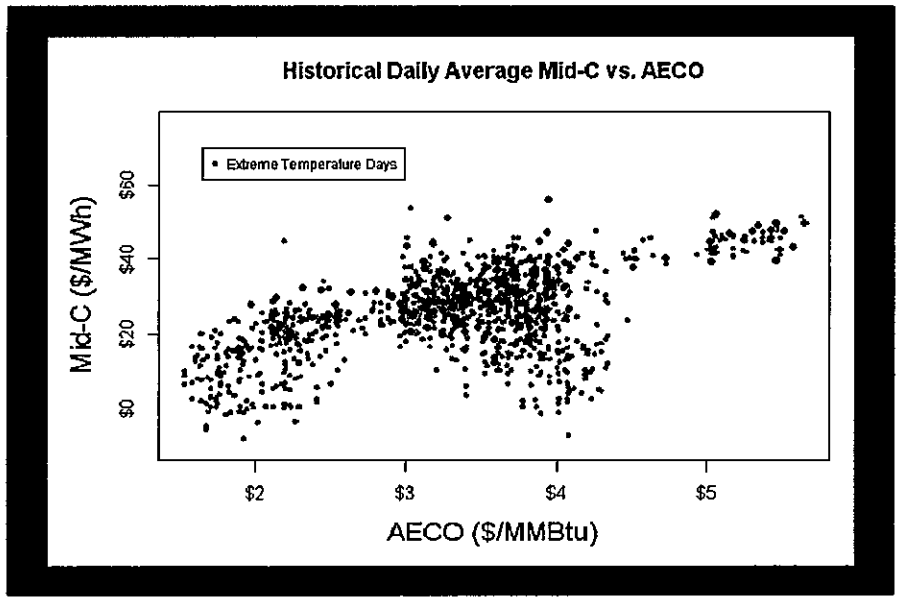
Hourly P10-Mean-P90 Confidence Intervals for February Mid-C power prices

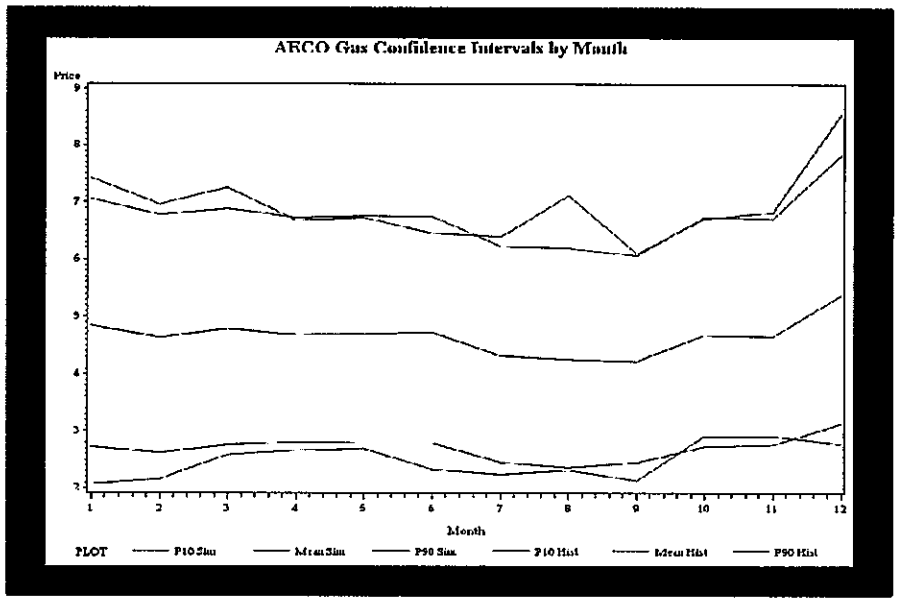
- Historical in red, simulation in blue
- Good distributional agreement between simulated and historical data

Comparisons of Hydro Generation, Load, Prices, & Weather

Daily market prices for Mid-C heavy compared to AECO gas

- Power shows a positive correlation with gas
- Extreme weather days (below 10th percentile of average temp) highlighted in orange





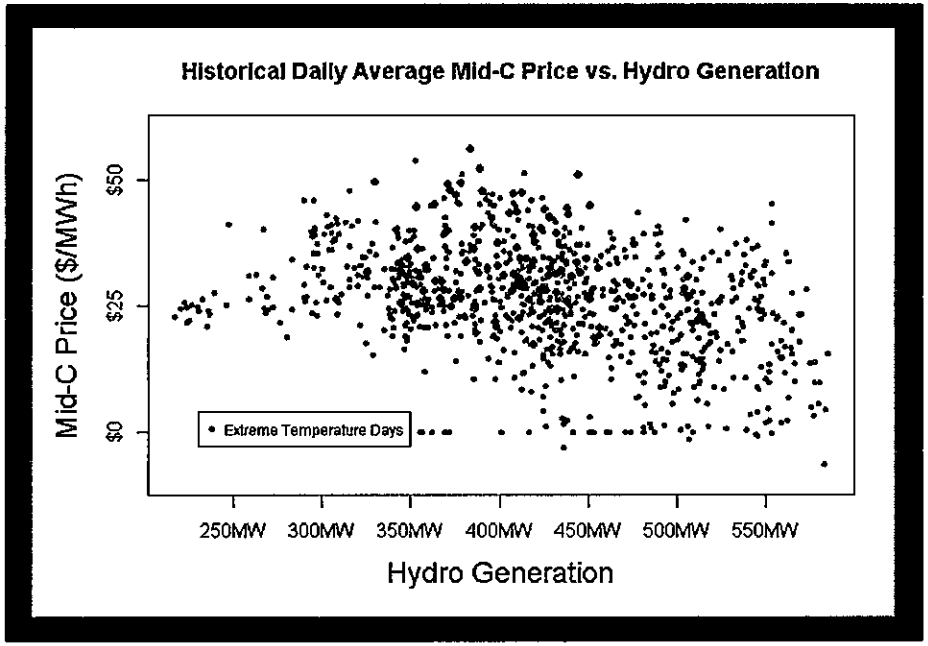
AECO Gas confidence Intervals

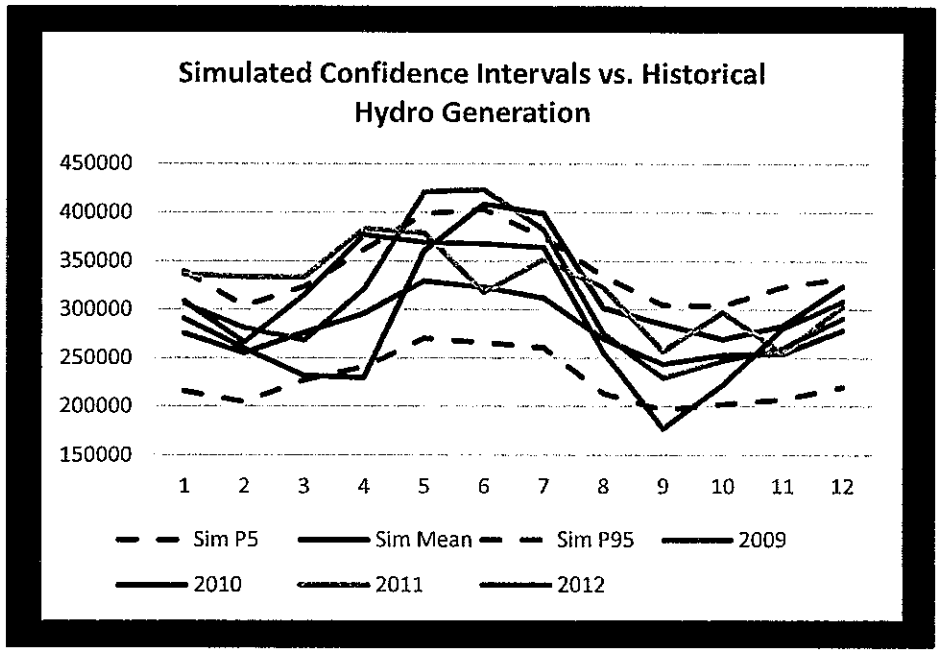
- Historical in red, simulation in blue
- Relatively little seasonal shape
- Excellent distributional agreement between simulation output and historical data

Comparisons of Hydro Generation, Load, Prices, & Weather

Daily historical Mid-C vs. Hydro generation

- Meaningful negative correlation between power prices and hydro generation.
- Extreme weather days (below 10th percentile of average temp) highlighted in red.





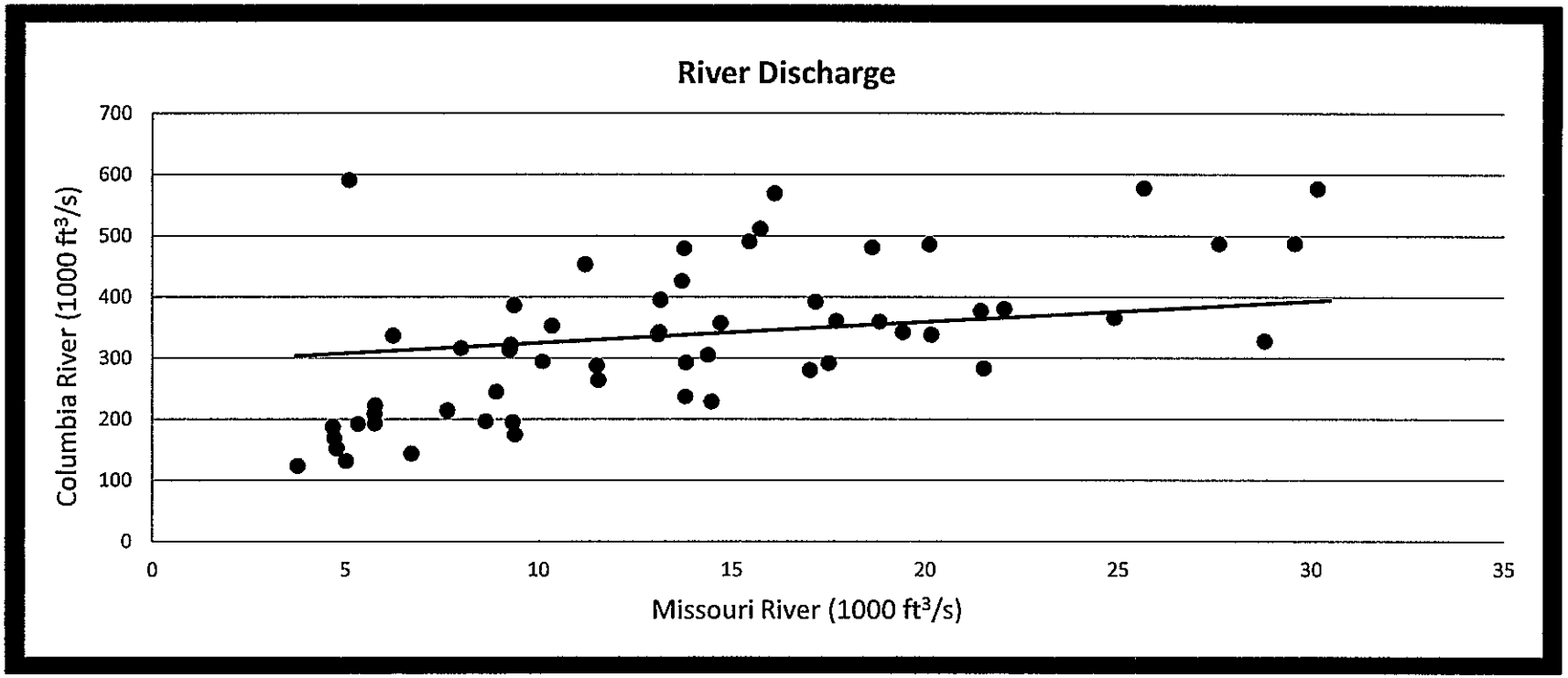
Monthly P5-Mean-P95 for Simulated Hydro

- Simulation confidence intervals bracket historical observations
- Seasonal shape observed both in historical data and simulations

Historical River Flows

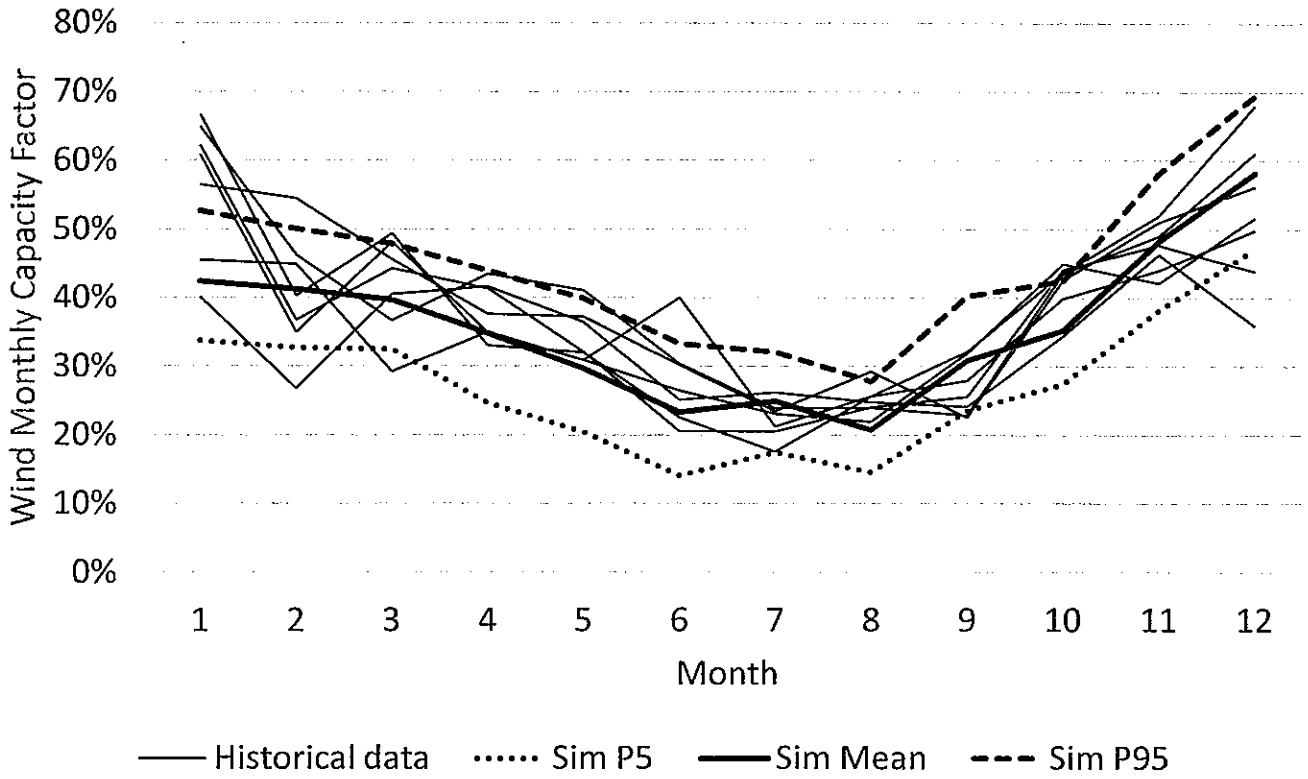
River Discharge

- June river discharge for years 1957-2012.
- Notice negligible correlation between river systems.



Wind Generation Validation

- Simulated wind production matches the historical behavior of NWE wind assets
- Wind is scaled to meet 15% of load in 2015 onwards



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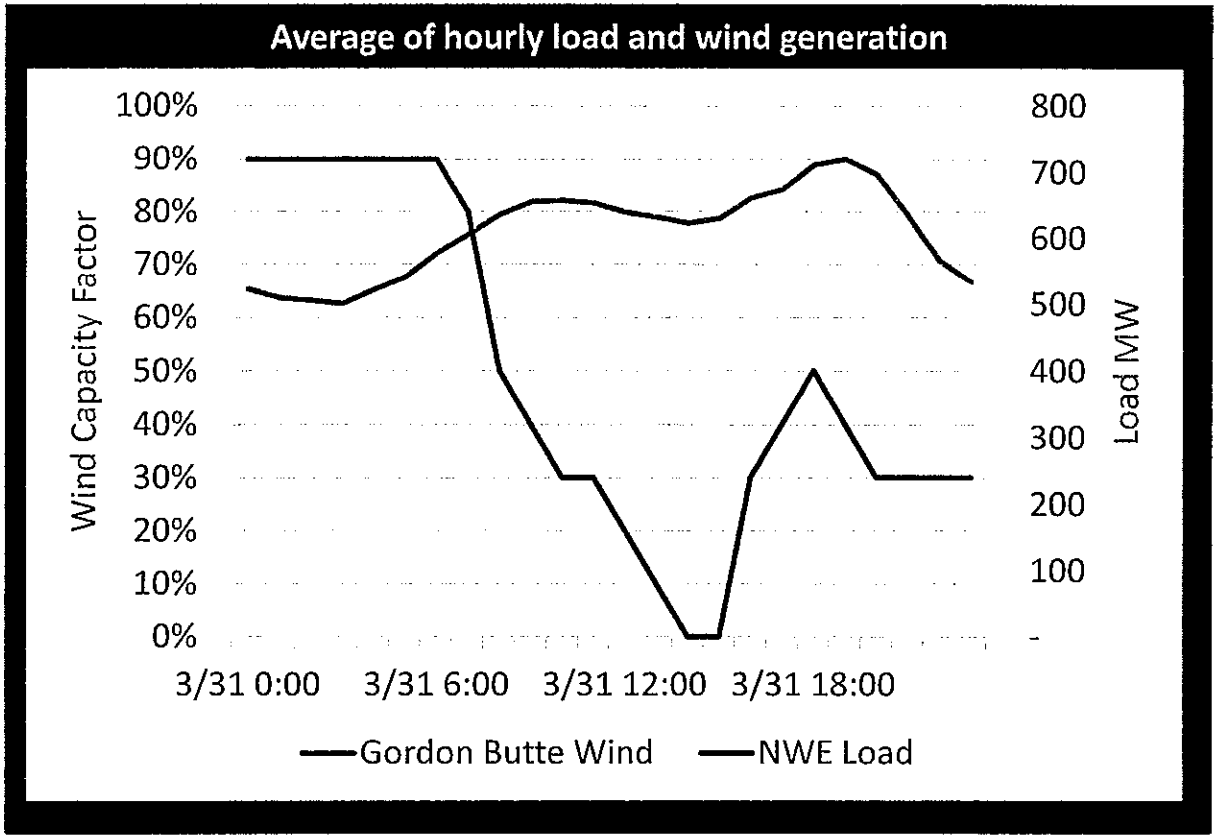
Site A: Hourly Wind and Load



- Wind generation declines as system load peaks
- Wind doesn't blow when you need it to

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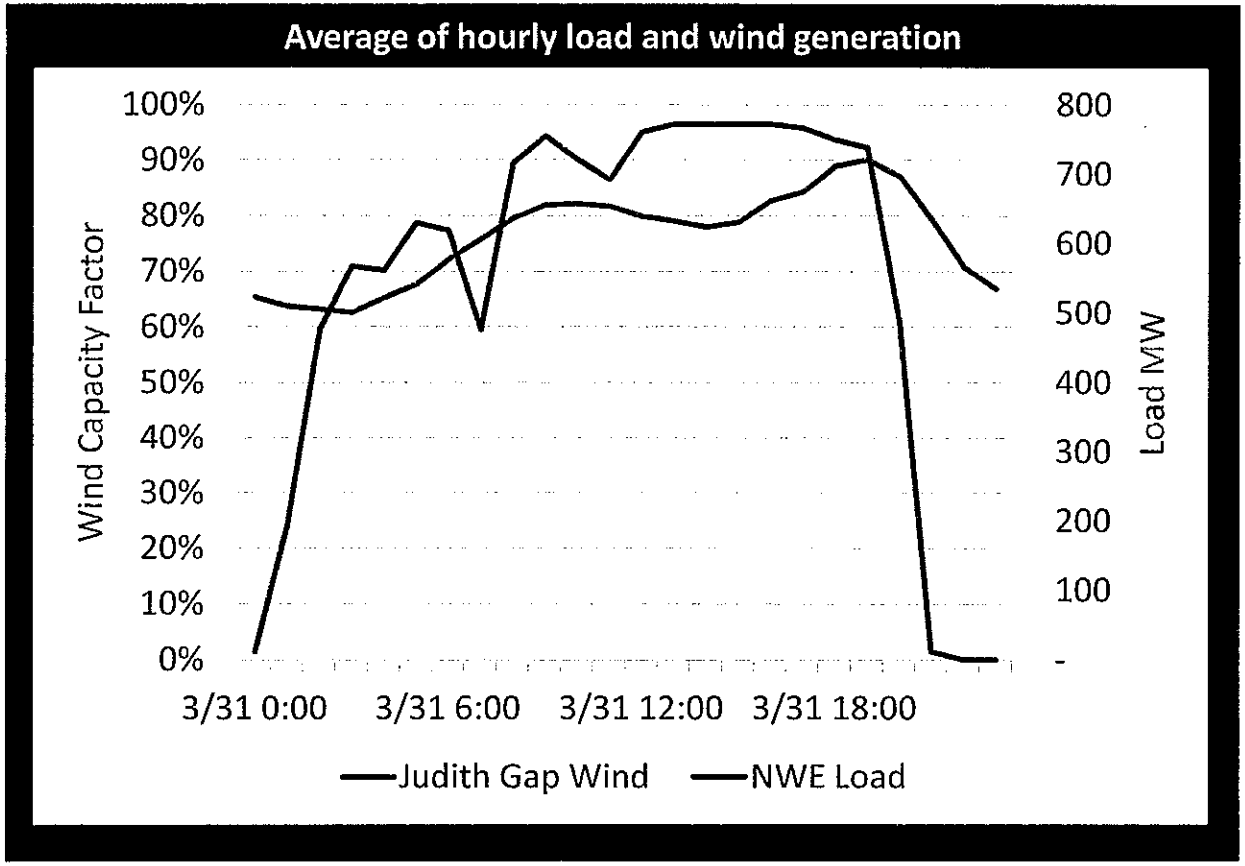
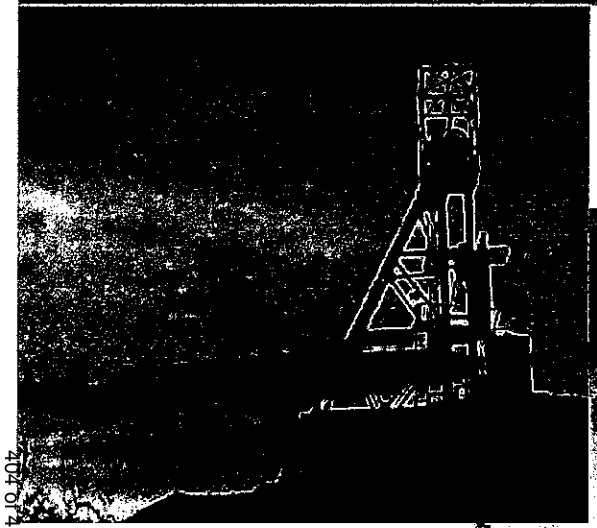
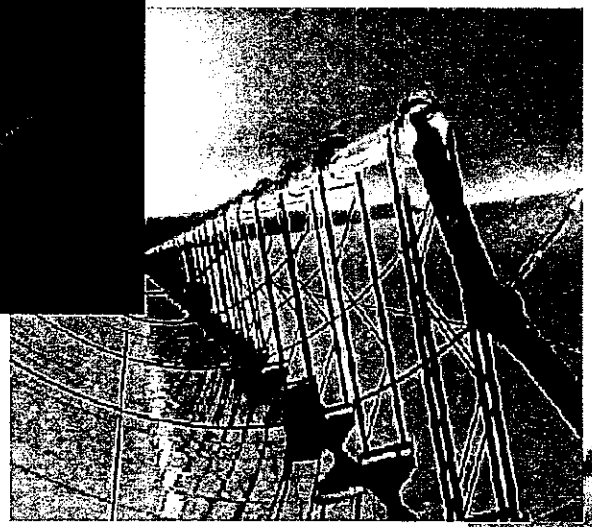
Site B: Hourly Wind and Load



- Diversifying wind portfolio can "make the wind blow when you need it to"
- Adding more wind farms in the vicinity of wind rather than just one wind farm in the place where wind is most likely

Hourly Portfolio Attributes





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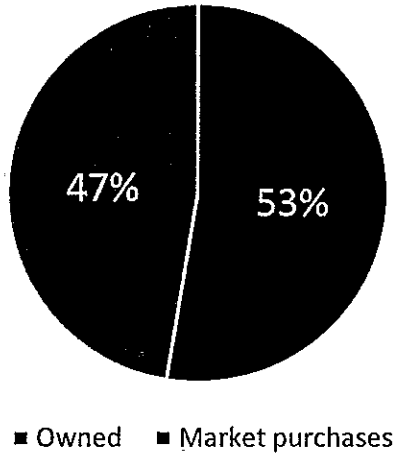
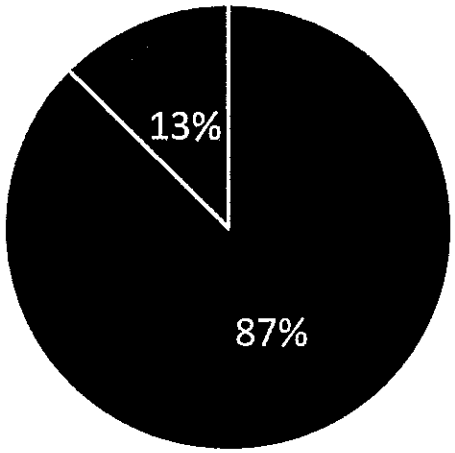
Net Energy Position

Current supply portfolio: 2020

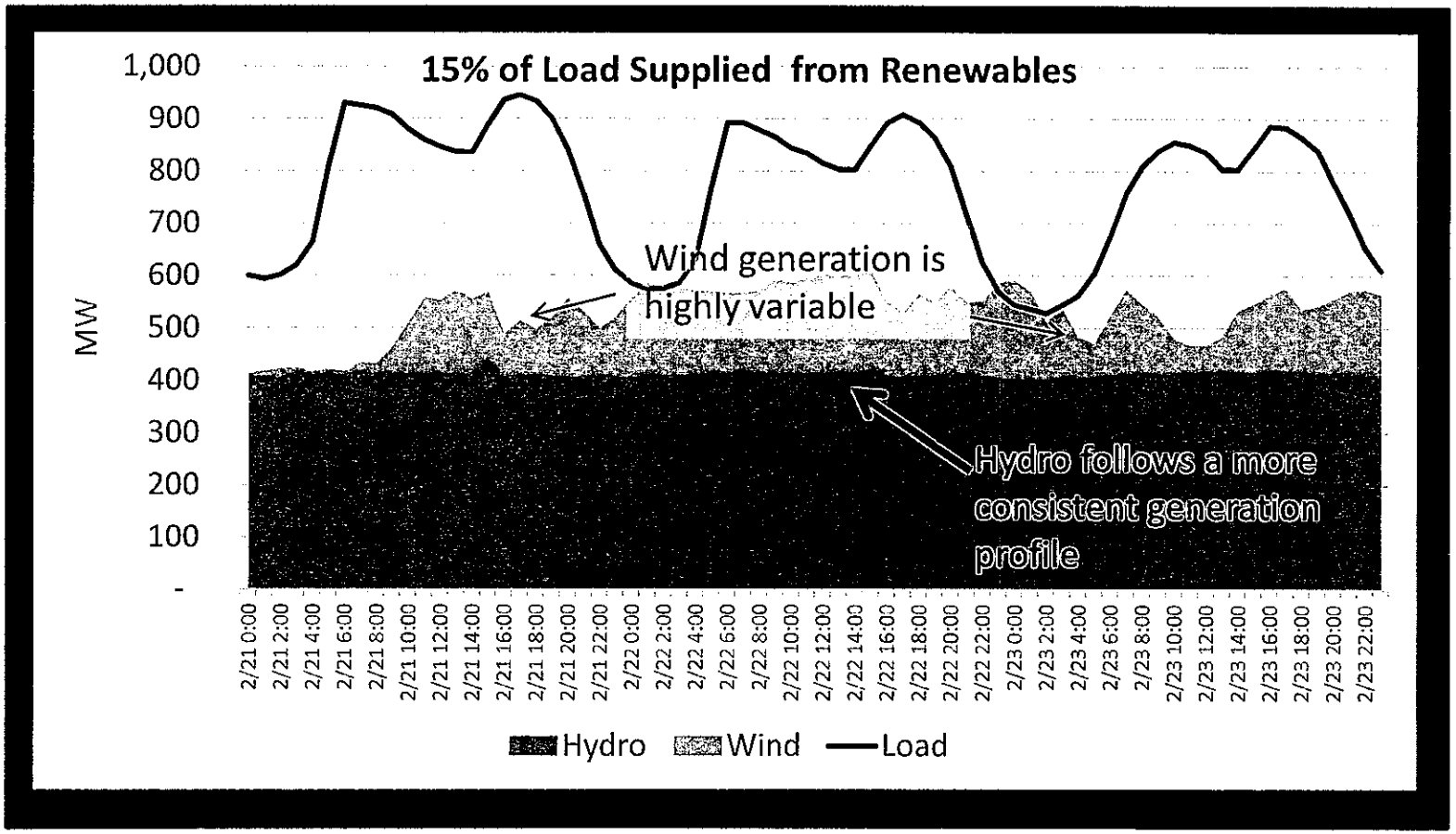


Hydro added to portfolio: 2020



Resource Integration
Ancillary Service Implications

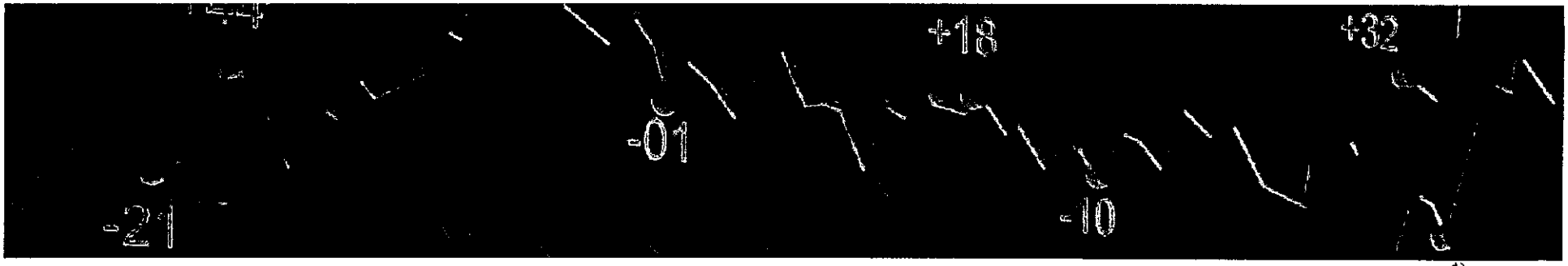
- Perception that increasing RPS creates value for flexible resources
  - Negative power prices
  - Large potential swings in supply→ greater demand for ancillary services and flexibility



Question: Will the cost of ancillary services increase with higher penetration of renewables?

Generation Stations Report

- Net Position Report
  - Portfolios
    - Generation
    - Load
- Stations Report
  - Capacity factor
  - Fuel consumed
  - Generation
  - Emissions (CO2)



Contact Information

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U.S. Offices

Headquarters:

1877 Broadway St
Suite 706
Boulder, CO 80302
(303) 415-1400

Other Offices:

Berkeley, CA
Bozeman, MT

Gary Dorris | 303.415.0311
President
gdorris@ascendanalytics.com

Volume 2

Chapter 2

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4) Wind Resource Pricing 27

5) Thermal and Renewable Resource Cost Data 29

December 12, 2013

Mr. David Fine
Director – Energy Supply Planning
NorthWestern Energy
40 East Broadway Street
Butte, Montana 59701-9394

Subject: Transmittal of Resource Adequacy Evaluation and Recommendation Report

Dear Dave:

Lands Energy Consulting, Inc. is pleased to submit the attached Resource Adequacy Evaluation and Recommendation Report to NorthWestern Energy. It's been a pleasure to work with you and your staff on the Report. Good luck with the completion of your 2013 Procurement Plan.

If you would like to discuss the Report further, please contact me at sfisher@landsenergy.com or via office phone at (509) 888-0976.

Sincerely,

Stephen V. Fisher
Principal Consultant - Lands Energy Consulting, Inc.

Resource Adequacy Evaluation and Recommendation

A Report Prepared for

NorthWestern Energy Supply Group

by

Lands Energy CONSULTING

D e c e m b e r 2 0 1 3

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Attachment A – Survey of Utility Power Planning Practices

I. Introduction

Northwestern Energy ("NWE") retained Lands Energy Consulting, Inc. ("LEC") to perform a Resource Adequacy Evaluation ("Evaluation") for its Montana service territory. The results of the Evaluation will provide conclusions and analysis that NWE intends to incorporate into the 2013 Resource Procurement Plan. LEC will evaluate NWE's electric capacity planning and procurement methodology and make recommendations to improve the methodology and enhance the ability of NWE to serve winter and summer peak load. The Evaluation will:

- Evaluate NWE's current peak load planning methodology and critique NWE's current strategy for meeting peak loads.
- Summarize the current practices and strategies of Pacific Northwest investor owned utilities and larger public utilities (e.g., Seattle City Light and Tacoma Power) in the region for meeting peak load obligations.
- Describe alternative strategies for meeting NWE's peak load obligations and the pros/cons of each of the alternatives.

II. Study Conclusions

Based on the results of this Evaluation, LEC submits to NWE the following conclusions regarding the adequacy of NWE's capacity planning methodology and a recommended strategy for peak load service:

1. NWE hasn't explicitly evaluated its capacity load/resource balance in prior versions of its bi-annual Procurement Plan. All other Pacific Northwest investor-owned utilities (plus some publicly-owned utilities, such as Clark PUD) determine a capacity load/resource balance and develop strategies – including resource acquisition and development – to reliably serve capacity obligations.
2. NWE's long-term capacity deficit (2014-2018), as a percentage of forecast peak load, greatly exceeds forecast capacity deficits of other Pacific Northwest investor owned utilities. Furthermore, each of these utilities incorporate a planning margin of 13-14% of forecast peak load to account for operating reserve requirements, forced outages, and extreme load conditions. Including a planning margin of 14% of forecast peak load in the calculation of NWE's capacity load/resource balance would increase the deficit by about 170 MW.

3. Although all other Pacific Northwest investor owned utilities develop strategies to reliably serve peak load, three of these utilities – PacifiCorp, Puget Sound Energy, and Idaho Power – consider firm transmission rights and interconnection capacity to liquid market hubs as equivalent to generating capacity resources.

4. NWE Energy Supply relies on third party-owned generating resources to provide the electrical support to reliably serve peak load. However, NWE contracts with the owners of this generation for only a portion of its peak load service requirement.

5. The continuing trend in the Western Electricity Coordinating Council ("WECC") of premature retirement of existing resources (coal, nuclear, and gas-fired peaking generators), coupled with the operational demands of wind generation facilities and the recently completed transmission interconnection with the Alberta System Operator, will combine to reduce the amount of generation available to NWE under peak load conditions. These factors could threaten NWE's ability to acquire resources on a "just-in-time" basis to serve peak load.

6. Wind generation projects that deliver energy to NWE's Energy Supply group provide little or no generation during winter and summer extreme peak load hours. Furthermore, thermal constraints and fuel availability reduce the capability of some NWE-contracted resources (thermal and hydro) during summer and winter peak load hours.

7. Infrastructure costs, including electric and natural gas transmission, are an integral component of new generation total cost. In determining the economic viability of new resource alternatives, NorthWestern must consider the range of potential development options for locating new generation to properly identify and select least cost, low risk projects. Constraints on the electric transmission and natural gas pipeline systems in the State of Montana will create unique challenges to the successful siting of new resources in the state.

III. Recommendations

Based on the Conclusions contained in this Evaluation, LEC recommends that NWE immediately commence the following activities to address power planning deficiencies and forecast peak load/resource balance deficits:

1. Move towards a Procurement Plan that utilizes a "capacity first/energy second" planning approach. The 2013 Procurement Plan should at a minimum contain the following elements:

- Formalize ETAC involvement in the review and adoption of Procurement Plan capacity study methodology, key assumptions, planning margin, alternate resource portfolios, and action plans. Such involvement will enable NWE to build support for the action plan contained in the final draft of the 2013 Procurement Plan.

- Prepare a monthly forecast of capacity load/resource balance.

2. Continue the process to evaluate and acquire resources that could address winter and summer capacity deficits:

    - Wholesale Market – Acquire additional firm, on-peak energy to cover anticipated 2014-18 winter energy deficits.. Obtain bids from wholesale market participants for cost-effective, structured, physically delivered products (e.g., daily call options)[1]. DSM – Evaluate proposed DSM programs for peak load-reducing benefits and timing.

    - Generation Development - Perform conceptual level development activities for 100-300 MW of simple cycle or combined cycle combustion turbine capacity. Potential sites should include both Montana (first priority) and outside of Montana locations (second priority). This effort should focus on equipment configurations, pipeline transportation strategies, transmission interconnection requirements, and siting process/issues.

    - Resource Acquisition – Consider opportunities to purchase existing generation resources that could more immediately provide flexible capacity to serve peak load.

IV. NWE's Electric System

A. Utility Description

NWE serves approximately 342,000 electric customers in the State of Montana and approximately 62,000 customers in South Dakota and Nebraska. NWE also provides natural gas

[1] NWE could encounter difficulty from over-reliance on wholesale market purchases to serve peak load obligations, especially during extreme winter load peaks. NWE could fail to cover its peak load due to transmission constraints or wholesale market suppliers that are forced to invoke the liquidated damages provisions of the supply contracts in lieu of delivering contracted capacity and energy to NWE.

retail service to customers in Montana, South Dakota, and Nebraska. Unless indicated otherwise, this Assessment addresses NWE's Montana operation only.

NWE secures power supply for the Montana service territory separately from the South Dakota service territory. While the South Dakota electric service territory is structured as a traditional vertically-integrated utility, Montana industrial and large commercial customers retain the right to acquire power supply from third party suppliers, while receiving transmission and distribution service from NWE. NWE refers to retail customers served by utility-owned and purchased resources as "Energy Supply Customers" and industrial/large commercial customers served by third-party supply as "Choice Customers". NWE's 2012 Energy Supply Customers' load was 6,437,668 MWh, with a winter peak demand of 1,106 MW. NWE's 2013 summer peak demand was 1,162 MW.

B. Existing Resources

NWE currently meets its Energy Supply obligation with a combination of short-term and long-term power purchase agreements, wholesale market purchases, the 40 MW Spion Kop wind generation project, the 52 MW Basin Creek reciprocating engine, and its 222 MW ownership share of the Colstrip 4 power plant[2].

The long-term power purchase agreements include a combination of resource-specific agreements and market-sourced agreements. The resource specific agreements include output from wind generators, small hydro projects, and thermal resources that use a variety of fuel sources (natural gas, waste coal, petroleum coke). The earliest contract expiration for these resources occurs in 2026.

NWE acquires two types of market-sourced resources: shorter-term (next hour to 18 months out) wholesale market purchases that generally specify delivery points on the NWE transmission system (either specific generators or points of interconnection between NWE and other BAs); and longer-term transactions with delivery periods starting 18 months in the future, with terms of one to ten years. NWE sources these longer-term products from the more liquid Mid-Columbia trading hub, with the intent to "buy back" these transactions ahead of initial delivery in favor of energy delivered to the NWE transmission system[3]. All but one of NWE's longer-term market

[2] 15% of the 1,480 MW capability of Colstrip 3 & 4.

[3] NWE could use the Mid C-sourced purchases to serve firm load, but would have to purchase transmission service from BPA to enable deliveries to the NWE electric system.

sourced agreements[4] expire on or before June 30, 2017. Table 1 provides a summary of the capacity value of NWE supply resources for 2014, 2016, and 2018.

Energy Supply receives a fixed allocation of 7 MW of output each hour from the NWE Transmission function-operated David Gates Gas-fired Generation Station ("DGGS") to serve Energy Supply load. (Note: 7 MW is the minimum generation level for DGGS and represents the portion of DGGS available to serve Energy Supply. The remainder of DGGS is dedicated to serving the balancing and regulation requirements of the entire NWE Balancing Authority).

Table 1
Capacity Value of NWE Resources

Resource	Nameplate HLH Capacity	Summer 2014	Winter 2014	Summer 2016	Winter 2016	Summer 2018	Winter 2018
Colstrip 4	222.0	222.0	222.0	222.0	222.0	222.0	222.0
Basin Creek[5]	52.0	35.0	35.0	35.0	35.0	35.0	35.0
DGGS	150.0	7.0	7.0	7.0	7.0	7.0	7.0
Wind	237.3	0.6	5.2	0.6	5.2	0.6	5.2
Misc QF	123.7	38.2	99.1	38.2	99.1	38.2	99.1
Hedge Contracts (Mid-C POD)	NA	100.0	100.0	125	125.0	25.0	25.0
Physical Supply Contracts	NA	350.0	350.0	75.0	75.0	0.0	0.0
Total		**752.8**	**818.3**	**502.8**	**568.3**	**327.8**	**393.3**

[4] A 25 MW all hours purchase from Citigroup that expires June 30, 2020.

[5] 17 MW of Basin Creek is used to fulfill a portion of NWE's non-spinning contingency reserve requirements.

C. Energy Supply Capacity Forecast

NWE prepares a 20 year forecast of Energy Supply-related peak loads. This forecast assumes a 50% expected probability of occurrence (half of all years show higher peaks and half of all years show lower peaks). The forecast of NWE Energy Supply peak loads exhibits slightly higher peaks in the winter than in the summer[6]. Table 2 provides summer and winter peak load requirements for 2014, 2016, and 2018. NWE experienced its highest summer peak demand for the period 2002-13 of 1177 MW in 2007 and its highest winter peak demand for the same period of 1225 MW in 2009. Both of these demands exceed the peak demand forecast for 2018.

Table 2
Energy Supply Capacity Requirement
(1 in 2 Expected)

Year	Summer	Winter
2014	1086	1162
2016	1102	1182
2018	1119	1201

V. NWE Capacity Load/Resource Balance

Combining Table 1 and Table 2 allows LEC to construct a load/resource balance for the NWE Default Supply customer load. This data yields the following winter capacity load/resource balance for NWE:

[6] Actual summer peak load has exceeded winter peak for the calendar year on multiple occasions over the past few years.

Table 3
NWE Winter Capacity Load/Resource Balance

Year	Winter Peak Load	Controlled Resources	Generation-Sourced PPAs	NWE System POD Purchases	Mid-C POD Purchases	Net Position	Net Position as a % of Peak Load
2014	1162	229	139	350	100	(344)	30%
2016	1182	229	139	75	125	(614)	52%
2018	1201	229	139	0	25	(808)	67%

And a summer capacity load resource balance:

Table 4
NWE Summer Capacity Load/Resource Balance

Year	Summer Peak Load	Controlled Resources	Generation-Sourced PPAs	NWE System POD Purchases	Mid-C POD Purchases	Net Position	Net Position as a % of Peak Load
2014	1086	229	74	350	100	(333)	31%
2016	1102	229	74	75	125	(599)	54%
2018	1119	229	74	0	25	(791)	71%

NWE exhibits significant capacity load/resource deficits in both the summer and the winter. Although the winter deficits exceed the summer deficits, covering summer deficits could prove more difficult due to the fact that during an extreme summer load event, most of the load in the WECC would likely peak at about the same time. During the winter, however, while the Pacific Northwest region experiences extreme cold weather, California and the Desert Southwest would probably experience milder weather and thereby have surplus generation capacity available for sale into the Pacific Northwest.

Although NWE is currently exploring construction of new generation resources, 2018 is probably the earliest a new-build generation project could be completed and available to serve peak load requirements. However, as compared to new-build generation, NWE could more expeditiously arrange for new market purchases (either on-peak firm, structured products, or an asset-based PPA), or acquire existing generation assets to cover peak load deficits.

VI. Power Planning Considerations

A. Planning Margin

A key concept common to the capacity planning methodology employed by most utilities is the inclusion of a "planning margin" in the determination of capacity and energy resource requirements. Planning margin provides a mechanism to allow for unexpected events, including weather extremes affecting load, low stream flow, resource outage (or underperformance), DSM underperformance, transmission curtailment, etc. A utility with a diversified resource portfolio consisting of smaller generating units may prudently adopt a smaller planning margin, whereas a utility with a reliance on a unit that is large compared to load obligations may need to adopt a higher planning margin.

B. Power Planning

As demonstrated in Tables 3 and 4 above (NWE Capacity Load/Resource Balance), the post-2013 resource portfolio doesn't produce enough capacity to serve all NWE load obligations during all months and all hours without significant augmentation from wholesale market purchases, DSM, or new/acquired generating resources.

Load growth increases these deficits. While the NWE risk management process will identify market solutions to near term energy and capacity deficits (Next day to 48 months out), a longer-term power planning effort will provide a strategic path for identifying supply-side resource and DSM strategies that meet future load obligations under various load growth scenarios. This planning effort also needs to account for various regulatory and legal factors, including retirement of regional generating resources (particularly coal-fired generation) that could affect the availability of on-peak wholesale market supplies to serve future NWE capacity obligations.

A well-researched and thoroughly-debated capacity planning study forms the cornerstone for identifying long-lead time strategies (DSM programs, new generating resources, power purchase agreements, etc.) for meeting future capacity and energy requirements. Given the size of projected monthly capacity deficits identified in Tables 3 and 4, NWE needs to incorporate capacity planning into its 2013 Procurement Plan in order to provide an action plan to guide

resource acquisition/development and DSM/DR program design for the 2014 and beyond time period.

Preparation of capacity studies and analyses for the 2013 Procurement Plan requires significant conceptual upgrade from that contained in the 2011 Procurement Plan. The 2013 Procurement Plan will contain significant recommendations (in the form of an action plan) that affect NWE's power costs, resource mix, and DSM programs. These recommendations should consider both the energy and capacity capabilities of these resources.

C. Resource Procurement

The action plan contained in the 2013 Procurement Plan will identify resource types to target for acquisition. The NWE Energy Supply group will, depending on the types of resources contained in the action plan, provide input to the conceptual specifications for proposed generating assets, DSM programs, or power purchase arrangements.

VII. Resource Adequacy

Resource adequacy refers to the ability of an electric supplier to match physical generation to the peak load requirements of the load it serves, plus a planning margin, for each hour of the forecast period. Some regions of the US, including California, require that energy suppliers demonstrate control of enough physical generating capacity to serve their load obligations. Suppliers must demonstrate control of capacity for a specified period, where the demonstration occurs months, weeks, or hours ahead of the initial delivery date. California limits the use of firm power purchase agreements as a resource adequacy-compliant source of supply. In addition, the CAISO tariff requires that the purchaser of a resource adequacy capacity resource surrender control of the dispatch of the resource to the California ISO.

A. NWE Energy Supply Operation

The NWE Energy Supply function focuses its efforts on managing the cost of power supply to serve its Energy Supply Customers. The Energy Supply function operates a generation portfolio that includes a share of Colstrip Unit 4 and power purchase agreements with a variety of generation technologies, including wind, hydro, petroleum coke, and reciprocating engines. Energy Supply also acquires firm power for both price hedging and service to Default Supply customers.

NWE Energy Supply acquires significant amounts of power from the wholesale market to augment its controllable generation and resource-specific PPAs. Energy Supply arranges for some of these wholesale supplies well ahead of the delivery period, while serving a portion of its load during many hours with power purchases secured in the day-ahead and hour-ahead markets.

Energy Supply purchases standard Heavy Load Hour ("HLH") and Light Load Hour ("LLH") electricity products.

The NWE Energy Supply function only receives real-time information on output from generation owned by NWE or generation committed to NWE pursuant to a unit-specific PPA and located within the NWE BA. During the active day, NWE's real-time desk buys and sells power as required to match resources to forecast load. The real-time desk also receives telemetered information on resource performance and may buy or sell energy in the wholesale market as necessary to better match scheduled output to actual output trends.

Energy Supply receives no real-time information on its customers' loads, since many substations (including Choice Customer and other third-party load delivery points) don't provide real-time telemetry of load quantities to the NWE System Operations Center. As a result, NWE calculates transmission customer hourly imbalance amounts at the end of the billing cycle, which doesn't enable transmission customers (including NWE Energy Supply) to accurately determine schedule-to-actual load imbalances in real-time.

VIII. Power Planning Process Comparison to Peer Organizations

LEC performed a high-level evaluation of power planning studies of the following seven Pacific Northwest utilities:

- Avista Utilities
- Idaho Power
- PacifiCorp
- Portland General Electric
- Puget Sound Energy
- Chelan PUD
- Seattle City Light
- Tacoma Power

The utilities on the list include both public and investor owned utilities. Attachment A contains a summary of key elements of these utilities' integrated resource plans[7]. The utilities operate

[7] The list also includes results for NWE's 2011 Procurement Plan

resource portfolios that contain a range of technologies and fuel sources. On one end of the fuel spectrum, PacifiCorp operates a predominantly thermal generation fleet, while Tacoma Power meets its load obligations with a mix of BPA contractual supply and its own hydro projects. All of these utilities have been preparing power planning studies for 100 years or longer. Over the years, these studies and the analytical methodologies used to forecast load and evaluate comparative resource performance have evolved to reflect the political, regulatory, and business environment affecting each utility. As a result, no two utility plans employ the same set of assumptions and planning tools. However, they all attempt to quantify the effects to the financial performance of their respective resource portfolios due to electric and natural gas market prices, proposed greenhouse gas regulations, demand side management programs, renewable resource operational characteristics (especially wind integration requirements), etc.

One key concept common to most integrated resource plans is the inclusion of a "planning margin" in the determination of capacity and energy resource requirements. Planning margin provides a mechanism to allow for unexpected events, including weather extremes affecting load, low stream flow, resource outage (or underperformance), DSM underperformance, transmission curtailment, etc. A utility with a diversified resource portfolio consisting of smaller generating units may prudently adopt a smaller planning margin, whereas a utility with a reliance on a unit that is large compared to load obligations may need to adopt a higher planning margin.

In general, the utility power planning approaches fall into two categories: capacity first (energy cost second) and energy balance methodologies. For prior Procurement Plans, NWE employed an energy balance planning methodology, with no explicit acknowledgement of physical capacity load/resource deficits.

A. Capacity First Planning

The capacity first power planning approach treats peak load service as a reliability obligation of the system. Although a given plan may include some level of reliance on shorter-term market purchases, the utility generally assembles resource portfolios that are designed to cover forecast firm one-hour peak obligations[8]. The peak hour obligation includes retail load, wholesale sales obligations, and system losses, as well as operating reserve requirements and some level of planning margin to account for weather that is colder than normal (or hotter than normal for a summer-peaking utility) and resource outage/underperformance. Portfolios that demonstrate acceptable peak obligation service characteristics move on to some form of hourly portfolio cost

[8] Because hydro projects can experience operating limitations due to reservoir draft rates/limits, inflow freeze-up, downstream hydraulic limitations, etc. during peak load hours, most hydro-generation owning utilities will determine the "sustained peaking capability" of their hydro assets. These utilities will generally evaluate the ability of the hydro generators to meet load requirements for periods of 4 hours to 3 days given these operating limitations.

modeling analysis, which usually involves testing portfolios against different permutations of load, natural gas price, carbon cost, etc. The energy analysis also evaluates whether a given portfolio contains an adequate amount of renewable resource output to meet state Renewable Portfolio Standards. Avista Utilities, Idaho Power, PacifiCorp, Portland General Electric, and Puget Sound Energy all use a variation of capacity first planning. These utilities all operate electric systems that contain a mix of coal, combined cycle combustion turbine ("CCCT"), simple cycle combustion turbine ("SCCT"), hydro, and wind resources.

B. Energy Balance Planning

For much of the history of the Pacific Northwest electric power industry, most utilities relied on energy balance power planning methodologies. The economics of hydro project construction favored installed capacity to annual average energy production ratios of 1.6 to 3.0. As a result, a predominantly hydro-based utility usually had adequate capacity to meet peak load obligations under all conditions, but needed to worry about the ability to meet customer energy requirements during extended low stream flow conditions. Theoretically, seasonal reservoir storage projects and hydro coordination (through the Pacific Northwest Coordination Agreement) allowed utilities to move generation from periods of surplus to periods of deficit. While most utilities looked at capacity load/resource balances as part of their planning process, satisfaction of their energy obligations usually resulted in installation of adequate capacity to serve peak load.

Today, only a handful of hydro-reliant public utilities still use an energy balance planning methodology. This list includes Seattle City Light and Tacoma Power. Both utilities look at monthly load/resource balances more closely than annual balances. This monthly approach recognizes the fact that environmental constraints limit the ability of project operators to store and release water based on power needs alone[9]. Both the Seattle City Light and Tacoma Power Integrated Resource Plans evaluate various portfolios for monthly energy adequacy, Renewable Portfolio Standard compliance, and total cost in order to create resource acquisition recommendations.

IX. Regional Capacity Planning and Load Service Trends

Appendix A provides a survey of capacity planning methodologies and load/resource balance for all investor owned utilities and select public utilities in the Pacific Northwest. Some utilities, particularly Portland General Electric and Avista Utilities, have acquired firm resources to serve peak load requirements over the 5 year planning horizon, with limited reliance on wholesale market purchases to meet firm load needs during cold weather events. Others, such as

[9] Seattle City Light's Procurement Plan contains no capacity planning analysis whatsoever. The Seattle City Light capacity surplus equals approximately 40% of installed generation capacity.

PacifiCorp, Idaho Power, and Puget Sound Energy, consider transmission access to the Mid-Columbia and other trading points as a surrogate for generation and firm long-term purchase agreements sourced from generation. These utilities intend to rely on the market for significant amounts of power to serve peak load. Two large public utilities, Snohomish PUD and Clark PUD would likely also need to purchase significant amounts of power to serve load in the event of an extreme winter peak load condition.

The Northwest Power and Conservation Council ("NWPCC") performs periodic resource adequacy assessments for the Pacific Northwest region. These assessments look at the entire WECC when evaluating generation available to serve summer and winter peak load. The NWPCC's most recent assessment of resource adequacy (December 2012) determined that the Pacific Northwest region is close to capacity load/resource balance when taking into account uncommitted generation from merchant generation projects. These projects include the PPL Montana generation facilities, TransAlta's Centralia Coal-Fired Generation Project, a portion of the output from the Grant PUD and Chelan PUD Mid-Columbia hydro projects, and a number of merchant CCCT projects constructed between 2000 and 2009. However, this determination occurred prior to the announcement of the closure of the 2000 MW San Onofre Nuclear Generation Project, and continued thermal resource retirement announcements throughout the WECC.

NWE has successfully served peak load for many years, despite its reliance on some amount of short-term (day-ahead and hour-ahead) market purchases to serve load over peak hours. This strategy worked due to the large amount of uncommitted resource capacity available in the Pacific Northwest market. In particular, the proximity of PPL Montana generation assets helped NWE provide the electrical support required to reliably serve NWE's retail load obligations. Slack regional electric load growth also contributed to the availability of power during winter heavy load hours.

However, the region could see reductions in available generation due to:

- Resource retirements – Corette 154 MW in 2014, one 700 MW Centralia unit in 2020, Boardman 600 MW in 2020, San Onofre 2000 MW in 2013, California "once-through cooling" gas-fired units, and numerous Desert Southwest coal plants.

- Economic Recovery – Loads rebound due to increases in new construction, data center construction, and restart of industrial facilities.

- Reduced New Capacity Construction – Many utilities have determined investment in transmission and distribution upgrades present a lower-risk investment strategy than does investment in new generation.

- DSM Underperformance – Most regional utilities plan to meet a significant portion of future load growth with DSM measures. DSM is a mature strategy in the Pacific Northwest – additional DSM may prove difficult to develop, resulting in faster load growth than currently forecast.

These factors could cause the WECC capacity load/resource balance to tighten significantly in the next 3-7 years. In addition, the newly-energized Montana-Alberta Tie Line ("MATL") will provide a south-to-north path from NWE's BA to the higher-priced Alberta Electric System Operator market[10]. MATL could likely increase the cost to NWE of Montana resources that had heretofore been available to serve NWE load during peak load hours.

X. NWE Peak Load Service Strategies

Up until recently, most Pacific Northwest utilities relied on hydro generation to respond to and serve peak load. As wind generation proliferated and utilities saw their ability to flexibly utilize hydro diminish (due to environmental constraints and expiry of Mid-Columbia Purchaser Agreements), many utilities have had to rely on output from higher heat rate SCCTs and reciprocating natural gas engines to integrate wind and to serve peak load.

As detailed in Tables 3 and 4 above, NWE's capacity load resource balance for 2014 shows a deficit (without planning margin) equal to 31% of forecast summer peak load and 30% of winter peak load. The projected 2018 deficit increases to 71% of forecast summer peak load and 67% of winter peak load. The capacity deficit increases by approximately 170 MW in 2018 after adding in a 14% planning margin[11].

In order to serve these forecast peak loads, NWE could (in order of ascending complexity and time to acquire):

- Continue to rely on HLH standard product (term and day-ahead) and real-time market purchases
- Acquire structured products (e.g., call options or super-peak hour energy purchases)
- Acquire existing generation
- Implement demand response measures

[10] The Alberta Electric System Operator permits market clearing prices up to $1000/MWh. During extreme summer and winter peak load events, the Alberta Electric System Operator market clears at prices well in excess of Mid-Columbia market prices.

[11] Most Pacific Northwest investor-owned utilities use a 13-14% planning margin when conducting capacity planning studies.

- Develop generation – CCCT (w/duct-firing), SCCT, reciprocating engines

As a practical matter, NWE will likely use a combination of the above measures to enhance its ability to meet peak load obligations.

1. Standard HLH Products and Real-time Purchases – NWE has relied on this strategy to serve the bulk of its capacity peak load obligation. Term HLH purchases allow NWE to meet monthly energy deficits as well. Implementing this strategy requires little execution time or transaction complexity, except for credit terms for long-dated transactions. Risks to this strategy include scarcity or unavailability of supply at the time of peak. Under such circumstances NWE may not be able to find supply to serve load. If the region faced an inadequate supply situation, NWE's suppliers could face the same difficulty and be forced to invoke the liquidated damages provisions of the WSPP Contract and provide NWE with payment in lieu of energy to serve load. Please note that NWE currently purchases term HLH products to meet projected energy deficits for periods of a month or greater. Such purchases would still leave significant load to serve over peak hours. NWE would have to purchase significant amounts of what could be scarce energy in the day ahead and real-time markets to cover the peaks.

2. Structured Products – NWE should evaluate purchasing structured products to meet peak load obligations. These products take a variety of forms, including daily or hourly call options and purchases of super-peak energy (hours ending 1300-2000). Such products can allow NWE to better match the purchase to the actual daily load shape[12]. This flexibility comes at a cost, and also carries the risk the supplier can't find supply to fulfill their obligations during extreme load conditions. Although somewhat more complicated to arrange than standard HLH purchases, NWE could contract for structured products fairly quickly. As a practical matter, these products are often available only a few months ahead of the delivery period, if they are even available at all.

3. Acquire Existing Generation – A number of independent power producers ("IPPs") operate generating facilities in the Pacific Northwest. Many of these entities (particularly thermal plant owners, but some wind generation owners as well) have struggled to arrange for power sale transactions that cover the cost of operation, debt service, and provide an adequate return on invested capital. Other entities have shown an interest in divesting merchant generation assets in order to concentrate on other business opportunities, including investment in regulated utility assets. Assets potentially available for sale include coal-fired and hydro

[12] NWE should consider participating in the periodic auctions of Mid-Columbia hydro capacity conducted by Grant PUD, Chelan PUD, and the Confederated Tribes of the Colville Indian Reservation. These so-called "Slice Auctions" could provide NWE with flexible capacity to meet both peak load and energy load requirements at costs reflective of wholesale electric market prices.

power plants in Montana, CCCTs and SCCTs in Oregon and Washington, and renewable resource facilities (mostly wind) located in the Columbia Gorge.

4. Construct New Generation – Finally, NWE could construct new controllable (non-intermittent) generation to meet its Energy Supply peak load obligations. Feasible technologies include[13]:

    a. CCCT - In addition to covering energy deficits, a CCCT would operate at a high annual capacity utilization factor (35-85%) and provide additional flexibility to meet peak load excursions, particularly if NWE equipped the CCCT with duct-firing capability[14].

    b. SCCT and Reciprocating Engines - An SCCT or reciprocating engine would operate at a much lower annual capacity factor than a CCCT (0-10%) and would only operate during peak load and high market heat rate conditions.

    c. Hydro - Hydro generation with at-site or upstream reservoir storage can provide flexible peak load service (with attractive ramp rates and limited loss of efficiency over a range of operating conditions), and cover energy load deficits. However, most of the feasible Pacific Northwest sites for hydro generation have already been developed.

Natural gas pipeline and electric transmission constraints into and within Montana will complicate (if not delay and/or frustrate) NWE's efforts to develop new generation connected directly to the NWE electric system. Even under favorable circumstances, 2018 is likely the earliest date that NWE could energize a new gas-fired generating facility in a location that provides adequate existing transmission and gas pipeline infrastructure.

Given the challenges of implementing demand response strategies and finding adequate in-state sites for construction of new generating projects, NWE will likely continue to rely on standard product and structured wholesale market purchases to serve peak load for the foreseeable future. Acquisition of existing generating assets, or PPAs from existing assets (either in Montana or elsewhere in the Pacific Northwest), provides the most immediate opportunity for NWE to cover peak load deficits with company-owned generating assets or a PPA with an asset dedicated to NWE delivery. NWE could consummate acquisition of an existing resource (including obtaining regulatory approvals), or complete a PPA within 12-18 months of initiating transaction discussions.

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[13] NWE isn't considering construction of new coal, nuclear, or pumped storage hydro due to cost and permitting uncertainty.

[14] Duct-firing involves a supplemental natural gas burner that injects additional heat into the HRSG of a CCCT to produce peaking power from the steam turbine generator. Duct-firing operation results in incremental heat rates and ramp rates equivalent to an SCCT (8800-9400 Btu/kWh and 4-10 MW/minute).

Appendix A

NWE - Capacity Planning
Survey of Utility IRP Planning Methodologies and Identified Open Positions

	Utility	Version	IRP Release Date	Historic Peak Load	Peak Load Probability	Expected Case Peak Load Growth Rate	Planning Margin	Capacity L/R Balance - 2014	Capacity L/R Balance - 2018	Capacity L/R Balance - 2020	New Capacity Resources - 2018	Planned Capacity Deficit - 2018
1	**Puget Sound Energy**	2013	5/31/2013	4905 MW	One-in-two (23 degrees F)	1.90%	Target 13.5% 2014-15 and 14% 2018-19, plus operating reserves - corresponds to 5% LOLP	671 MW Deficit	2188 MW Deficit	2238 MW Deficit	Peakers - 221 MW DSM - 423 MW	1600 MW + 600 MW PM Cover with Transmission Contracts to Mid-C
2	**Tacoma Power**	2012	8/25/2011	1055 MW	Calculated for January 2012 assuming coldest 3 day cold snap between 1998 and 2008 and critical water	N/A - Didn't forecast beyond 2012 due to uncertainty of modeling BPA Slice capacity	26% - Which is the result of the capacity analysis, not the design target. After adding operating and regulating reserves to peak load, the planning margin is closer to 11%	172 MW Surplus in 2012	Not Forecast	Not Forecast	Surplus with existing resources for study period.	0 MW
3	**Chelan PUD**	2012	8/31/2012	442 MW	Expected temp and one-in-twenty year temp	1.45%	Not explicitly used to assess resource adequacy	N/A	N/A	N/A	None	0 MW
4	**Avista Utilities**	2013	8/31/2013	1821	One-in-two	0.84%	Target 14.0% plus operating reserves	17 MW Surplus	110 MW Surplus	42 MW Deficit	None	0 MW
5	**NorthWestern Energy**	2011	Dec-11	1219 MW	Historical extreme (2003-10)	1.30%	Not explicitly used to assess resource adequacy	Not calculated	Not calculated	Not calculated	Evaluate CCCT	Not calculated

Appendix A

NWE - Capacity Planning
Survey of Utility IRP Planning Methodologies and Identified Open Positions

	Utility	Version	IRP Release Date	Historic Peak Load	Peak Load Probability	Expected Case Peak Load Growth Rate	Planning Margin	Capacity L/R Balance - 2014	Capacity L/R Balance - 2018	Capacity L/R Balance - 2020	New Capacity Resources - 2018	Planned Capacity Deficit - 2018
6	**Portland General Electric**	2012 Update to 2009	11/5/2012	4073 MW (1998)	One-in-two	1.5% 2010-15 in 2009, reduced in update	Calculates LOLP, other reliability metrics to compare portfolios. No explicit reference to Planning Margin other than to ensure Operating Reserves maintained at 6% of resource capacity and contingency reserves maintained at 6% of load.	300 MW Deficit	294 MW Deficit	600 MW Deficit	2015 - CCCT (441 MW), DSM (141 aMW), RPS (wind at 15 MW), seasonal capacity purchases (354 MW), peaker (200 MW), customer generation and demand response (97 MW), ETO Savings (270 MW)	0 MW
7	**PacifiCorp**	2013	5/30/2013	10,000 MW	Based on historical average weather conditions for the prior 20 years of record. Summer peak in PACE, winter peak in PACW.	1.20%	13% target plus operating reserves, less firm purchases, less direct load reduction measures	986 MW Deficit	1888 MW Deficit	2100 MW Deficit	Market Purchases and new DSM through 2021	Despite significant new resources and demand response, PacifiCorp anticipates 1050 MW of market purchases in 2018.
8	**Idaho Power**	2013	6/1/2013	3407 MW (summer)	Median, 90% confidence, and 95% confidence based on the prior 30 years of weather records	1.8% (summer)	10%, although best described as a "soft target"	507 MW Surplus (includes 237 MW of import capability from the Pacific Northwest)	788 MW Surplus (includes 237 MW of import capability from the Pacific Northwest plus 500 MW from Hemingway-Boardman)	693 MW Surplus (includes 237 MW of import capability from the Pacific Northwest plus 500 MW from Hemingway-Boardman)	Hemingway-Boardman 500 MW (essentially relies on market purchases)	None summer (Even after removing PNW import capability and Boardman-Hemingway from L/R balance)
9	**Seattle City Light**	2010		2059 MW	Not modeled	No forecast	Not explicitly used to assess resource adequacy	800 MW (est.)	800 MW (est.)	800 MW (est.)	N/A	N/A

Appendix A

NWE - Capacity Planning
Survey of Utility IRP Planning Methodologies and Identified Open Positions

	Utility	Energy Load	Energy Planning Methodology	Energy L/R Balance - 2018	New Supply Side Energy Resources - 2018	Target DSM - 2018	Comments
1	**Puget Sound Energy**	2450 aMW	Aurora Portfolio Analysis - Find the least cost portfolio	689 aMW Deficit - Aurora uses market purchases or PSE resources, whichever is cheaper	None - Deficits covered by PSE resources, new DSM, market purchases	400 aMW	PSE considers meeting capacity obligations as the primary planning objective (reliability measure). Portfolio modeling is used to identify a least cost resource mix. PSE uses a power cost adjustment mechanism to track purchase power and gas costs, so there's little risk to their shareholders from actual results that deviate from the plan.
2	**Tacoma Power**	580 aMW	Critical Water and Average Water Planning, Monthly L/R with Vista LT	Balanced on a Critical Water Basis	None Required other than DSM	63 aMW	Tacoma Power serves a low growth service territory with a stable portfolio of hydro and contract resources. A hyper-conservative planning approach still shows no need for new resources. Tacoma Power relies on surplus power sales to offset power costs to retail customers. Rate increases require governing board approval (no power cost tracker or surcharge mechanism).
3	**Chelan PUD**	185 a MW	Critical Water and portfolio modeling for calculating revenue from surplus sales	115 aMW Surplus on an Average Water Basis.	None Required for load service. DSM implemented to satisfy state statute. RPS covered by qualifying hydro upgrades and Nine Canyon wind	14 aMW	Chelan PUD has rights to approximately half of the Rock Island and Rocky Reach projects for the next 17 years, with some ability to use Alcoa's share of project output to serve peaks. Chelan PUD carries extraordinary levels of financial reserves and the Commissioners have adopted a surcharge formula (that they are reluctant to use) to respond to poor stream flow and market conditions.
4	**Avista Utilities**	1050 MW	PRiSM (in-house model) used to select preferred resource strategy, with Aurora generating Mid C prices	147 aMW Surplus	DSM	77 aMW	Avista will release the new IRP 8/31/11. Except for RPS required wind (100 MW Palouse Project and Reardan) DSM, and hydro upgrades, the new IRP forecasts no new supply side resources until 2018 (peaker). Performs all resource planning in-house. Like PSE, Avista relies on a power cost adjustment mechanism to buffer shareholders from actual power and fuel costs.
5	**NorthWestern Energy**	743 aMW	GenTrader Portfolio Analysis	305 MW Deficit	Evaluate CCCT, Market Purchases, DSM, wind	56 a MW	Planning to evaluate capacity L/R balance in 2013 Procurement Plan

Appendix A

NWE - Capacity Planning
Survey of Utility IRP Planning Methodologies and Identified Open Positions

	Utility	Energy Load	Energy Planning Methodology	Energy L/R Balance - 2018	New Supply Side Energy Resources - 2018	Target DSM - 2018	Comments
6	**Portland General Electric**	2138 aMW	AURORAxmp Portfolio Analysis - Find the least cost portfolio for 16 pre-determined portfolios	46 aMW Deficit	2015 - CCCT (406 aMW), DSM (214 aMW), RPS (wind at 122 aMW), contract renewals (66 a MW), market purchases (100 aMW)	141 aMW	Planning methodology overly complex and difficult to interpret - not easy to understand by people outside of power supply.
7	**PacifiCorp**	6300 aMW	Portfolios modeled using proprietary System Optimizer.	None	DSM, Market Purchases	625 MW - Both capacity and energy measures	Planning complicated by operation of two separate (but connected by transmission and wheeling contracts) Balancing Authority Areas, with each BAA having very different load and resource characteristics. Planning looks at monthly energy load/resource balance, as well as capacity requirements and overall portfolio costs. The PacifiCorp planning methodology is much more straight-forward than Portland General Electric.
8	**Idaho Power**	1745 aMW	AURORAxmp Portfolio Analysis - uses average water hydro conditions in calculating an expected case NPV for various portfolios. Risk analysis looks at performance of the portfolios for various variations of fuel price, load, carbon cost, etc. Finally, use stochastic analysis to look at portfolio performance for various combinations of risks.	No months with deficits (70th percentile energy load and 70th percentile hydro generation, but including transmission import capability)	Boardman-Hemingway (market purchases) and DSM	150 MW (mostly demand reduction)	Capacity needs drive resource additions. Energy a financial issue. Hydro flexibility allows for LLH purchases when energy from the system not available due to low stream flow. Boardman-Hemingway delay could force construction of additional SCCT
9	**Seattle City Light**	1126 aMW	AURORAxmp Portfolio Analysis - Look at various combinations of gas prices, hydro performance, and load growth	Annual balance but 100 aMW winter deficit requiring "exchanges" or market purchases	DSM plus limited new renewables	100 aMW	Resource decisions driven by winter average energy requirements and I-937 requirements.

NorthWestern Energy
2013 Resource Procurement Plan
Colstrip Units 3 & 4 Environmental Regulation Compliance Status

Environmental Regulation			Colstrip Units 3 & 4
Standard	**Purpose**	**Enforcement Status**	**Compliance Status**
Mercury Air Toxics Standard (MATS)	Set limits on acid gases, non-mercury heavy metals, organics, PCB's, and mercury	Rule was finalized in 2012 and compliance is required by 2015	Already in compliance with emission limits, but may incur minimal costs to make enhancements to monitoring system
Regional Haze	Eliminate all man-made visibility impacts to Class I air sheds by 2064 by limiting NOx, SOx, and particulate matter	Limits are source specific defined age: 1. Sources constructed between 1962 and 1977 are subject to Best Available Retrofit Technology (BART) analysis 2. Sources constructed after 1977 are subject to "Reasonable Progress" analysis	Subject to "Reasonable Progress" analysis: 1. First review in 2012 revealed achievement of reasonable progress 2. Next review scheduled for 2017, and, if necessary, compliance will be required by 2022
Coal Combustion Residue (CCRs)	Establish national rules to ensure the safe disposal and management of coal ash from coal-fired power plants	Two proposals: 1. Regulate as hazardous waste 2. Regulate as non-hazardous waste	Regulation as non-hazardous waste has been indicated, the impact to Colstrip 3&4 will not be material
Effluent Guidelines - Clean Water Act Section 304(m)	Regulate effluents including: 1. Once-through cooling water 2. Cooling tower blow down 3. Ash transport water discharge 4. Run off	Final rule expected in 2014 or 2015 This rule is expected to affect facilities with an NPDES (discharge) permit	Not expected to be affected by this regulation as it is a zero-discharge facility that does not require a discharge permit
Intake Structures – Clean Water Act 316(b)	Reduce environmental and aquatic life impacts associated with drawing cooling water from bodies of water	Regulation deadline is Jan 14, 2014. Will require NPDES (discharge) permit holders to install Best Available Control Technology to minimize environmental impacts	Not expected to be affected by this regulation as it is a zero-discharge facility that does not require a discharge permit
Cross State Air Pollution Rule (CSAPR) & Clean Air Interstate Rule (CAIR): regulation applies to 27 states	Intended to provide relief to states that are receiving power plant pollution drift (SO2 & NOx) from another state	Currently CAIR is the regulating rule since CSAPR was stayed by the US Court of Appeals while merits of challenges are being considered	Colstrip is not expected to be affected as Montana is not one of the states being regulated under these rules
NAAQS – National Ambient Air Quality Standards	Establishes emission standard criteria for several pollutants with area categories of attainment or non-attainment	-Sources within a non-attainment area may have control measures imposed on them to get the area into attainment status -Sources within an attainment area cannot have significant increases in emissions as a result of "major modifications"	-There is argument that Colstrip has undergone "major modifications" without acquiring the necessary permits -Colstrip maintains those modifications were routine repair and maintenance and no new permits are required

Wind Integration Price Signal (WIPS)

For the 2013 Resource Procurement Plan, NorthWestern adopted the Wind Integration tariff (Schedule WI-1) set by the Montana Public Service Commission in Docket No. D2012.1.3, updated with electricity and natural gas forward price information as of June 7, 2013. The market price update and subsequent compliance filing of revised Schedule WI-1 rates was a requirement of the docket's final order (Order No. 7199d).

Schedule WI-1 bases wind integration rates on two premises; 1) Dave Gates Generating Station ("DGGS") incremental net variable costs of regulating wind, and 2) a MPSC-approved zonal methodology in allocating regulating requirements to wind projects. Incremental net variable costs associated with regulating wind include the variable costs of increasing regulation service from 60 MW (the required legacy regulation capacity of system load) to 105 MW (DGGS regulating capacity, of which 45 MW is wind regulating capacity), offset by revenue credits created by the sale of electricity generated as a result of running DGGS.

The zonal approach in allocating regulating requirements is based largely on the GENIVAR Study conducted in June 2011. The zonal approach assigns regulation requirements as a percentage of a wind project's capacity depending on the project's proximity to the 135 MW Judith Gap Wind Farm located in Wheatland County. Zone 1 includes the area less than 25 miles from Judith Gap and assigns a regulation requirement of 38.0% of installed capacity; Zone 2 includes the area 25 – 60 miles from Judith Gap and assigns a regulation requirement of 14.0% of installed capacity; Zone 3 includes any location greater than 60 miles from Judith Gap and assigns a regulation requirement of 5.1% of installed capacity.

Based on the two premises described in the preceding two paragraphs, wind integration rates for each zone are calculated as follows:

1. Zone 1: $1.92 / kW-month
2. Zone 2: $0.71 / kW-month
3. Zone 3: $0.26 / kW-month

Cost of Regulation and WI-1 Tariff Rates, 25-Year Levelized Rate for New Wind
(Updated with June 7, 2013 Electric and Natural Gas Price Forecasts)

	105 MW Regulation for Load and Wind as per PSC-002(a) with 25-yr levelized prices			60 MW Regulation for Load as per UMX-013(a) with 25-yr levelized prices			Change for 45 MW Additional Regulation
Fuel Expenses							
	Units	Price	Total	Units	Ave. Price	Total	Total
Natural Gas Fuel Costs (Dekatherms) /1	3,296,876	$6.45	$ 21,271,236	2,675,524	$6.45	$ 17,262,313	$ 4,008,923
Diesel Fuel Costs (Gallons) /2	1,293,569	$3.79	$ 4,902,628	1,049,774	$3.79	$ 3,978,643	$ 923,984
Compressor Electricity Bill /3			$ 559,177			$ 559,177	$ -
Total Fuel Expense			$ 26,733,040			$ 21,800,133	$ 4,932,907
Revenue Credits							
	Per NWE	Default Supply	Total	Per NWE	Default Supply	Total	Total
Mid-C Forward Market Price ($/MWh) /4	$34.90	$ 34.90	$ 34.90	$ 34.90	$ 34.90	$ 34.90	
Discount to Mid-C ($/MWh)	($7.00)	($7.00)	($7.00)	($7.00)	($7.00)	($7.00)	
Project Energy (aMW)	27	7	34	18	7	25	
Hours/Year	8,760	8,760	8,760	8,760	8,760	8,760	
Total Revenue Credits	$ 6,599,891	$ 1,711,083	$ 8,310,974	$ 4,399,927	$ 1,711,083	$ 6,111,010	$ 2,199,964
Cost of Regulation			$ 18,422,066			$ 15,689,123	$ 2,732,943

Cost of Regulation for New Wind	DGGS
Annual Net Variable Cost	$ 2,732,943
Regulation Required (MW)	45
Unit Cost ($/kw-month)	$ 5.06

WI-1 Tariff Rates		DGGS		
	Regulation as % of Nameplate Capacity	Rate ($/kw-month of Namplate Capacity)	Rate for 37% c.f. wind project ($/kwh)	Total annual cost for 10 MW project at 37% c.f.
Zone 1	38.0%	$ 1.92	**$ 0.00712**	$ 230,782
Zone 2	14.0%	$ 0.71	**$ 0.00262**	$ 85,025
Zone 3	5.1%	$ 0.26	**$ 0.00096**	$ 30,973

/1 - based on Docket D2012.1.3 QF-1 Compliance Filing updated AECO natural gas price curve as of 6-7-13
/2 - price as per EIA 2012 AEO Early Release
/3 - 2012 expenses as per PSC-002(a) escalated 2.16% per year
/4 - based on Docket D2012.1.3 QF-1 Compliance Filing updated Mid-C price curve as of 6-7-13

Northwestern Energy 2013 RPP
Projected Wind Costs
Base Case Integration Rate: Updated QF1 WI Rate

Spion Kop

Discount Rate 7.92%
Escalation Rate 2.07%

Year	Energy + RECs	RECs	QF1 WI Zone 2	Operating Reserves	Wind Cost
2014	$50.39	($1.00)	$2.62	$0.55	**$52.56**
2015	$50.39	($1.25)	$2.62	$0.56	**$52.32**
2016	$50.39	($1.50)	$2.62	$0.57	**$52.09**
2017	$50.39	($1.75)	$2.62	$0.58	**$51.85**
2018	$50.39	($2.00)	$2.62	$0.60	**$51.61**
2019	$50.39	($2.25)	$2.62	$0.61	**$51.37**
2020	$50.39	($2.50)	$2.62	$0.62	**$51.14**
2021	$50.39	($2.75)	$2.62	$0.63	**$50.90**
2022	$50.39	($3.00)	$2.62	$0.65	**$50.66**
2023	$50.39	($3.25)	$2.62	$0.66	**$50.42**
2024	$50.39	($3.50)	$2.62	$0.68	**$50.19**
2025	$50.39	($3.75)	$2.62	$0.69	**$49.95**
2026	$50.39	($4.00)	$2.62	$0.70	**$49.72**
2027	$50.39	($4.25)	$2.62	$0.72	**$49.48**
2028	$50.39	($4.50)	$2.62	$0.73	**$49.25**
2029	$50.39	($4.75)	$2.62	$0.75	**$49.01**
2030	$50.39	($5.00)	$2.62	$0.76	**$48.78**
2031	$50.39	($5.25)	$2.62	$0.78	**$48.54**
2032	$50.39	($5.50)	$2.62	$0.80	**$48.31**
2033	$50.39	($5.75)	$2.62	$0.81	**$48.08**
NPV	$497.70	($27.31)	$25.91	$6.32	**$502.62**
Levelized	$50.39	($2.76)	$2.62	$0.64	**$50.89**

Gordon Butte

Discount Rate 7.92%
Escalation Rate 2.07%

Year	Energy + RECs	RECs	QF1 WI Zone 2	Operating Reserves	Wind Cost
2014	$69.21	($1.00)	$2.62	$0.55	**$71.38**
2015	$69.21	($1.25)	$2.62	$0.56	**$71.14**
2016	$69.21	($1.50)	$2.62	$0.57	**$70.91**
2017	$69.21	($1.75)	$2.62	$0.58	**$70.67**
2018	$69.21	($2.00)	$2.62	$0.60	**$70.43**
2019	$69.21	($2.25)	$2.62	$0.61	**$70.19**
2020	$69.21	($2.50)	$2.62	$0.62	**$69.96**
2021	$69.21	($2.75)	$2.62	$0.63	**$69.72**
2022	$69.21	($3.00)	$2.62	$0.65	**$69.48**
2023	$69.21	($3.25)	$2.62	$0.66	**$69.24**
2024	$69.21	($3.50)	$2.62	$0.68	**$69.01**
2025	$69.21	($3.75)	$2.62	$0.69	**$68.77**
2026	$69.21	($4.00)	$2.62	$0.70	**$68.54**
2027	$69.21	($4.25)	$2.62	$0.72	**$68.30**
2028	$69.21	($4.50)	$2.62	$0.73	**$68.07**
2029	$69.21	($4.75)	$2.62	$0.75	**$67.83**
2030	$69.21	($5.00)	$2.62	$0.76	**$67.60**
2031	$69.21	($5.25)	$2.62	$0.78	**$67.36**
2032	$69.21	($5.50)	$2.62	$0.80	**$67.13**
2033	$69.21	($5.75)	$2.62	$0.81	**$66.90**
NPV	$683.58	($27.31)	$25.91	$6.32	**$688.50**
Levelized	$69.21	($2.76)	$2.62	$0.64	**$69.71**

Two Dot Wind

Discount Rate 7.92%
Escalation Rate 2.07%

Year	Energy + RECs	RECs	QF1 WI Zone 1	Operating Reserves	Wind Cost
2014	$59.00	($1.00)	$7.12	$0.55	**$65.67**
2015	$59.00	($1.25)	$7.12	$0.56	**$65.43**
2016	$59.00	($1.50)	$7.12	$0.57	**$65.19**
2017	$59.00	($1.75)	$7.12	$0.58	**$64.96**
2018	$59.00	($2.00)	$7.12	$0.60	**$64.72**
2019	$59.00	($2.25)	$7.12	$0.61	**$64.48**
2020	$59.00	($2.50)	$7.12	$0.62	**$64.24**
2021	$59.00	($2.75)	$7.12	$0.63	**$64.01**
2022	$59.00	($3.00)	$7.12	$0.65	**$63.77**
2023	$59.00	($3.25)	$7.12	$0.66	**$63.53**
2024	$59.00	($3.50)	$7.12	$0.68	**$63.30**
2025	$59.00	($3.75)	$7.12	$0.69	**$63.06**
2026	$59.00	($4.00)	$7.12	$0.70	**$62.82**
2027	$59.00	($4.25)	$7.12	$0.72	**$62.59**
2028	$59.00	($4.50)	$7.12	$0.73	**$62.35**
2029	$59.00	($4.75)	$7.12	$0.75	**$62.12**
2030	$59.00	($5.00)	$7.12	$0.76	**$61.88**
2031	$59.00	($5.25)	$7.12	$0.78	**$61.65**
2032	$59.00	($5.50)	$7.12	$0.80	**$61.42**
2033	$59.00	($5.75)	$7.12	$0.81	**$61.18**
NPV	$582.74	($27.31)	$70.33	$6.32	**$632.07**
Levelized	$59.00	($2.76)	$7.12	$0.64	**$64.00**

Musselshell

Discount Rate 7.92%
Escalation Rate 2.07%

Year	Energy + RECs	RECs	QF1 WI Zone 1	Operating Reserves	Wind Cost
2014	$69.21	($1.00)	$7.12	$0.55	**$75.88**
2015	$69.21	($1.25)	$7.12	$0.56	**$75.64**
2016	$69.21	($1.50)	$7.12	$0.57	**$75.40**
2017	$69.21	($1.75)	$7.12	$0.58	**$75.17**
2018	$69.21	($2.00)	$7.12	$0.60	**$74.93**
2019	$69.21	($2.25)	$7.12	$0.61	**$74.69**
2020	$69.21	($2.50)	$7.12	$0.62	**$74.45**
2021	$69.21	($2.75)	$7.12	$0.63	**$74.22**
2022	$69.21	($3.00)	$7.12	$0.65	**$73.98**
2023	$69.21	($3.25)	$7.12	$0.66	**$73.74**
2024	$69.21	($3.50)	$7.12	$0.68	**$73.51**
2025	$69.21	($3.75)	$7.12	$0.69	**$73.27**
2026	$69.21	($4.00)	$7.12	$0.70	**$73.03**
2027	$69.21	($4.25)	$7.12	$0.72	**$72.80**
2028	$69.21	($4.50)	$7.12	$0.73	**$72.56**
2029	$69.21	($4.75)	$7.12	$0.75	**$72.33**
2030	$69.21	($5.00)	$7.12	$0.76	**$72.09**
2031	$69.21	($5.25)	$7.12	$0.78	**$71.86**
2032	$69.21	($5.50)	$7.12	$0.80	**$71.63**
2033	$69.21	($5.75)	$7.12	$0.81	**$71.39**
NPV	$683.58	($27.31)	$70.33	$6.32	**$732.92**
Levelized	$69.21	($2.76)	$7.12	$0.64	**$74.21**

Musselshell 2

Discount Rate 7.92%
Escalation Rate 2.07%

Year	Energy + RECs	RECs	QF1 WI Zone 1	Operating Reserves	Wind Cost
2014	$69.21	($1.00)	$7.12	$0.55	**$75.88**
2015	$69.21	($1.25)	$7.12	$0.56	**$75.64**
2016	$69.21	($1.50)	$7.12	$0.57	**$75.40**
2017	$69.21	($1.75)	$7.12	$0.58	**$75.17**
2018	$69.21	($2.00)	$7.12	$0.60	**$74.93**
2019	$69.21	($2.25)	$7.12	$0.61	**$74.69**
2020	$69.21	($2.50)	$7.12	$0.62	**$74.45**
2021	$69.21	($2.75)	$7.12	$0.63	**$74.22**
2022	$69.21	($3.00)	$7.12	$0.65	**$73.98**
2023	$69.21	($3.25)	$7.12	$0.66	**$73.74**
2024	$69.21	($3.50)	$7.12	$0.68	**$73.51**
2025	$69.21	($3.75)	$7.12	$0.69	**$73.27**
2026	$69.21	($4.00)	$7.12	$0.70	**$73.03**
2027	$69.21	($4.25)	$7.12	$0.72	**$72.80**
2028	$69.21	($4.50)	$7.12	$0.73	**$72.56**
2029	$69.21	($4.75)	$7.12	$0.75	**$72.33**
2030	$69.21	($5.00)	$7.12	$0.76	**$72.09**
2031	$69.21	($5.25)	$7.12	$0.78	**$71.86**
2032	$69.21	($5.50)	$7.12	$0.80	**$71.63**
2033	$69.21	($5.75)	$7.12	$0.81	**$71.39**
NPV	$683.58	($27.31)	$70.33	$6.32	**$732.92**
Levelized	$69.21	($2.76)	$7.12	$0.64	**$74.21**

Fairfield Wind

Discount Rate 7.92%
Escalation Rate 2.07%

Year	Energy + RECs	RECs	QF1 WI Zone 3	Operating Reserves	Wind Cost
2014	$66.10	($1.00)	$0.96	$0.55	**$66.61**
2015	$66.10	($1.25)	$0.96	$0.56	**$66.37**
2016	$66.10	($1.50)	$0.96	$0.57	**$66.13**
2017	$66.10	($1.75)	$0.96	$0.58	**$65.89**
2018	$66.10	($2.00)	$0.96	$0.60	**$65.65**
2019	$66.10	($2.25)	$0.96	$0.61	**$65.42**
2020	$66.10	($2.50)	$0.96	$0.62	**$65.18**
2021	$66.10	($2.75)	$0.96	$0.63	**$64.94**
2022	$66.10	($3.00)	$0.96	$0.65	**$64.70**
2023	$66.10	($3.25)	$0.96	$0.66	**$64.47**
2024	$66.10	($3.50)	$0.96	$0.68	**$64.23**
2025	$66.10	($3.75)	$0.96	$0.69	**$63.99**
2026	$66.10	($4.00)	$0.96	$0.70	**$63.76**
2027	$66.10	($4.25)	$0.96	$0.72	**$63.52**
2028	$66.10	($4.50)	$0.96	$0.73	**$63.29**
2029	$66.10	($4.75)	$0.96	$0.75	**$63.05**
2030	$66.10	($5.00)	$0.96	$0.76	**$62.82**
2031	$66.10	($5.25)	$0.96	$0.78	**$62.59**
2032	$66.10	($5.50)	$0.96	$0.80	**$62.35**
2033	$66.10	($5.75)	$0.96	$0.81	**$62.12**
NPV	$652.86	($27.31)	$9.44	$6.32	**$641.31**
Levelized	$66.10	($2.76)	$0.96	$0.64	**$64.93**

Northwestern Energy 2013 RPP
Projected Wind Costs
Base Case Integration Rate: Updated QF1 WI Rate

Generic QF Zone 1

Discount Rate 7.92%
Escalation Rate 2.07%

Year	Energy + RECs	RECs	QF1 WI Zone 1	Operating Reserves	Wind Cost
2014	$54.39		$7.12	$0.55	**$62.06**
2015	$54.39		$7.12	$0.56	**$62.07**
2016	$54.39		$7.12	$0.57	**$62.08**
2017	$54.39		$7.12	$0.58	**$62.09**
2018	$54.39		$7.12	$0.60	**$62.10**
2019	$54.39		$7.12	$0.61	**$62.12**
2020	$54.39		$7.12	$0.62	**$62.13**
2021	$54.39		$7.12	$0.63	**$62.14**
2022	$54.39		$7.12	$0.65	**$62.16**
2023	$54.39		$7.12	$0.66	**$62.17**
2024	$54.39		$7.12	$0.68	**$62.18**
2025	$54.39		$7.12	$0.69	**$62.20**
2026	$54.39		$7.12	$0.70	**$62.21**
2027	$54.39		$7.12	$0.72	**$62.23**
2028	$54.39		$7.12	$0.73	**$62.24**
2029	$54.39		$7.12	$0.75	**$62.26**
2030	$54.39		$7.12	$0.76	**$62.27**
2031	$54.39		$7.12	$0.78	**$62.29**
2032	$54.39		$7.12	$0.80	**$62.30**
2033	$54.39		$7.12	$0.81	**$62.32**
NPV	$537.18	$0.00	$70.33	$6.32	**$613.82**
Levelized	$54.39	$0.00	$7.12	$0.64	**$62.15**

Generic QF Zone 2

Discount Rate 7.92%
Escalation Rate 2.07%

Year	Energy + RECs	RECs	QF1 WI Zone 2	Operating Reserves	Wind Cost
2014	$54.39		$2.62	$0.55	**$57.56**
2015	$54.39		$2.62	$0.56	**$57.57**
2016	$54.39		$2.62	$0.57	**$57.58**
2017	$54.39		$2.62	$0.58	**$57.60**
2018	$54.39		$2.62	$0.60	**$57.61**
2019	$54.39		$2.62	$0.61	**$57.62**
2020	$54.39		$2.62	$0.62	**$57.63**
2021	$54.39		$2.62	$0.63	**$57.65**
2022	$54.39		$2.62	$0.65	**$57.66**
2023	$54.39		$2.62	$0.66	**$57.67**
2024	$54.39		$2.62	$0.68	**$57.69**
2025	$54.39		$2.62	$0.69	**$57.70**
2026	$54.39		$2.62	$0.70	**$57.71**
2027	$54.39		$2.62	$0.72	**$57.73**
2028	$54.39		$2.62	$0.73	**$57.74**
2029	$54.39		$2.62	$0.75	**$57.76**
2030	$54.39		$2.62	$0.76	**$57.77**
2031	$54.39		$2.62	$0.78	**$57.79**
2032	$54.39		$2.62	$0.80	**$57.81**
2033	$54.39		$2.62	$0.81	**$57.82**
NPV	$537.18	$0.00	$25.91	$6.32	**$569.40**
Levelized	$54.39	$0.00	$2.62	$0.64	**$57.65**

Generic QF Zone 3

Discount Rate 7.92%
Escalation Rate 2.07%

Year	Energy + RECs	RECs	QF1 WI Zone 3	Operating Reserves	Wind Cost
2014	$54.39		$0.96	$0.55	**$55.89**
2015	$54.39		$0.96	$0.56	**$55.90**
2016	$54.39		$0.96	$0.57	**$55.92**
2017	$54.39		$0.96	$0.58	**$55.93**
2018	$54.39		$0.96	$0.60	**$55.94**
2019	$54.39		$0.96	$0.61	**$55.95**
2020	$54.39		$0.96	$0.62	**$55.96**
2021	$54.39		$0.96	$0.63	**$55.98**
2022	$54.39		$0.96	$0.65	**$55.99**
2023	$54.39		$0.96	$0.66	**$56.00**
2024	$54.39		$0.96	$0.68	**$56.02**
2025	$54.39		$0.96	$0.69	**$56.03**
2026	$54.39		$0.96	$0.70	**$56.05**
2027	$54.39		$0.96	$0.72	**$56.06**
2028	$54.39		$0.96	$0.73	**$56.08**
2029	$54.39		$0.96	$0.75	**$56.09**
2030	$54.39		$0.96	$0.76	**$56.11**
2031	$54.39		$0.96	$0.78	**$56.12**
2032	$54.39		$0.96	$0.80	**$56.14**
2033	$54.39		$0.96	$0.81	**$56.16**
NPV	$537.18	$0.00	$9.44	$6.32	**$552.93**
Levelized	$54.39	$0.00	$0.96	$0.64	**$55.98**

NorthWestern Energy 2013 Resource Procurement Plan
Resource Cost Summary
(2013$)

Resource Description	*Fuel Source*	*Technology*	*Nameplate Capacity (MW)*	*Net Capacity @ 3,500 feet (MW)*	*Capital Cost $ / kW*	*Fixed O&M $ / kW-yr*	*Variable O&M $ / MWh*	*Heat Rate Btu / kWh*
CCCT (1x1)	Natural Gas	GE 7FA.04 ACC[1]	270	239	$1,425	$13.94	$3.60	6,660
SCCT - Small Aeroderivative	Natural Gas	PW FT8	60	53	$917	$6.05	$4.60	10,500
SCCT - Large Aeroderivative	Natural Gas	GE LMS100	110	97	$1,087	$17.06	$3.47	8,722
SCCT - Frame	Natural Gas	GE 7EA	90	78	$897	$11.73	$3.20	11,289
Internal Combustion - Recips	Natural Gas	CAT G16CM34	54	52	$1,402	$18.39	$8.15	9,078
Solar PV	Solar		10	10	$3,136	$27.00	$0.00	n/a
Wind[2]	Wind		25	25	$1,524	$49.18	$0.00	n/a
Hydro - Montana Large Scale[3]	Water		439	439	$1,982	$52.58	$0.00	n/a

[1] ACC = Air Cooled Condenser

[2] Based on build-transfer bids received in NWE's 2012 CREP RFP

[3] Excludes KERR costs and capacity

ANNUAL NOMINAL LEVELIZED RESOURCE FIXED COSTS
$/KW INSTALLED

Resource	MW	Life	TPVRR Factor	LVLCR Factor	Carrying Charge	2013$ Capital/kW	Annual Nominal Levelized Cost: Inflation = 2.1%										
							2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Combined Cycle (natural gas)	270	30	1,248	0.08172	10.20%	$ 1,425	$ 148	$ 151	$ 155	$ 158	$ 161	$ 164	$ 168	$ 171	$ 175	$ 178	$ 182
Small Aeroderivative (natural gas)	60	30	1,248	0.08172	10.20%	$ 917	$ 95	$ 97	$ 99	$ 101	$ 104	$ 106	$ 108	$ 110	$ 112	$ 115	$ 117
Large Aeroderivative (natural gas)	110	30	1,248	0.08172	10.20%	$ 1,087	$ 113	$ 115	$ 118	$ 120	$ 123	$ 125	$ 128	$ 131	$ 133	$ 136	$ 139
Frame Turbine (natural gas)	90	30	1,248	0.08172	10.20%	$ 897	$ 93	$ 95	$ 97	$ 99	$ 101	$ 103	$ 106	$ 108	$ 110	$ 112	$ 115
IC - Recip Engine (natural gas)	54	30	1,248	0.08172	10.20%	$ 1,402	$ 146	$ 149	$ 152	$ 155	$ 158	$ 162	$ 165	$ 168	$ 172	$ 176	$ 179
Solar PV	10	20	1,212	0.09542	11.56%	$ 3,136	$ 370	$ 378	$ 386	$ 394	$ 402	$ 410	$ 419	$ 427	$ 436	$ 445	$ 454
Wind	25	20	1,212	0.09542	11.56%	$ 1,524	$ 180	$ 184	$ 187	$ 191	$ 195	$ 199	$ 203	$ 208	$ 212	$ 216	$ 221
Hydro - Montana Large Scale	439	40	1,244	0.07623	9.48%	$ 1,982	$ 192	$ 196	$ 200	$ 204	$ 208	$ 213	$ 217	$ 221	$ 226	$ 231	$ 235

NorthWestern 2013 RPP
Thermal Resource Heat Rate and Generation
by Elevation and Technology

Resource	Technology	Elevation	Nameplate Capacity	Fuel Type	Min HR	Med Low HR	Med Pre HR	Med Post HR	Med High HR	Max HR	Min Gen	Med Low Gen	Med Pre Gen	Med Post Gen	Med High Gen	Max Gen
CCCT (1x1)	7FA.04_Water Cooled	1500	270	Gas	7276	7047	6865	6717	6640	6597	151	173	194	215	237	260
CCCT (1x1)	7FA.04_Air Cooled Condenser	1500	270	Gas	7436	7162	6963	6799	6703	6647	148	171	191	212	235	258
CCCT (1x1)	7FA.04_Water Cooled	3500	270	Gas	7289	7058	6873	6726	6649	6602	141	161	180	199	220	241
CCCT (1x1)	7FA.04_Air Cooled Condenser	3500	270	Gas	7450	7194	6988	6810	6724	6660	137	158	177	197	217	239
CCCT (1x1)	7FA.04_DF_Water Cooled	1500	40	Gas	8749	8749	8749	8749	8749	8749	40	40	40	40	40	40
CCCT (1x1)	7FA.04_DF_Air Cooled Condenser	1500	40	Gas	8952	8952	8952	8952	8952	8952	40	40	40	40	40	40
CCCT (1x1)	7FA.04_DF_Water Cooled	3500	40	Gas	8813	8813	8813	8813	8813	8813	40	40	40	40	40	40
CCCT (1x1)	7FA.04_DF_Air Cooled Condenser	3500	40	Gas	9072	9072	9072	9072	9072	9072	40	40	40	40	40	40
SCCT - Small Aero	PWFT8	3500	60	Gas	14400	11700	11300	11000	10700	10500	10	19	26	35	42	53
SCCT - Small Aero	PWFT8	5000	60	Gas	14400	11700	11300	11000	10700	10500	10	18	25	33	40	50
SCCT - Large Aero	LMS100	1500	110	Gas	9979	9518	9173	8884	8746	8722	52	63	73	84	94	105
SCCT - Large Aero	LMS100	3500	110	Gas	9979	9518	9173	8884	8746	8722	49	58	68	78	87	97
SCCT - Large Aero	LMS100	5000	110	Gas	9979	9518	9173	8884	8746	8722	46	55	64	73	83	92
SCCT - Frame	7EA	3500	90	Gas	12917	12320	11873	11499	11320	11289	39	47	54	62	70	78
SCCT - Frame	7EA	5000	90	Gas	12940	12342	11894	11520	11341	11309	37	44	51	59	66	73
Internal Combustion	Reciprocating Engine	5000	52	Gas	11000	10616	10231	9847	9462	9078	0	10	21	31	41	52

NorthWestern 2013 RPP
Thermal Resource Operating Parameters
by Elevation and Technology

Resource	Technology	Elevation	Nameplate Capacity	Fuel Type	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Min. Up Time (hrs)	Min. Down Time (hrs)	Ramp Up Rate (MW/hr)	Ramp Down Rate (MW/hr)	EFOR (%)	CO2 Emissions (lbs/MMBtu)
CCCT (1x1)	7FA.04_Water Cooled	1500	270	Gas	$1,323	$7.73	$2.58	16	7	260	480	3	117
CCCT (1x1)	7FA.04_Air Cooled Condenser	1500	270	Gas	$1,332	$12.55	$3.24	16	7	260	480	3	117
CCCT (1x1)	7FA.04_Water Cooled	3500	270	Gas	$1,418	$8.58	$2.87	16	7	260	480	3	117
CCCT (1x1)	7FA.04_Air Cooled Condenser	3500	270	Gas	$1,425	$13.94	$3.60	16	7	260	480	3	117
CCCT (1x1)	7FA.04_DF_Water Cooled	1500	40	Gas	$0	$0	$0.08	1	1	240	240	3	117
CCCT (1x1)	7FA.04_DF_Air Cooled Condenser	1500	40	Gas	$0	$0	$0.08	1	1	240	240	3	117
CCCT (1x1)	7FA.04_DF_Water Cooled	3500	40	Gas	$0	$0	$0.08	1	1	240	240	3	117
CCCT (1x1)	7FA.04_DF_Air Cooled Condenser	3500	40	Gas	$0	$0	$0.08	1	1	240	240	3	117
SCCT - Small Aero	PWFT8	3500	60	Gas	$917	$6.05	$4.60	8	7	300	300	2	120
SCCT - Small Aero	PWFT8	5000	60	Gas	$917	$6.35	$4.83	8	7	300	300	2	120
SCCT - Large Aero	LMS100	1500	110	Gas	$1,034	$15.67	$3.19	8	7	600	600	2	116
SCCT - Large Aero	LMS100	3500	110	Gas	$1,087	$17.06	$3.47	8	7	600	600	2	116
SCCT - Large Aero	LMS100	5000	110	Gas	$1,140	$17.90	$3.64	8	7	600	600	2	116
SCCT - Frame	7EA	3500	90	Gas	$897	$11.73	$3.20	8	7	240	240	2	120
SCCT - Frame	7EA	5000	90	Gas	$949	$12.42	$3.39	8	7	240	240	2	120
Internal Combustion	Reciprocating Engine	5000	52	Gas	$1,402	$18.39	$8.15	1	1	312	312	1	118

Volume 2

Chapter 3

Forecasts

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Load , Customer, and Peak Demand Forecasts Overview

As a supplement to the load, customer, and peak forecasts presented in Volume 1, Chapter 4 of the 2013 Electricity Supply Resource Procurement Plan, NorthWestern has prepared additional charts and tables to provide more detail.

Annual load history and forecast tables begin on page 4. The Energy Supply Group is charged with the coordination and preparation of Supply load forecasts. The long-term forecasting work is done for each NWE customer rate class on a calendar year basis for a 20-year period (2014-2033). These rate classes include; 1) Residential; 2) GS-1 Secondary; 3) GS-1 Primary; 4) Irrigation; 5) Lighting; 6) GS-2 Substation; and 7) GS-2 Transmission. Although the Supply customer group is comprised of all rate classes, it consists primarily of Residential and GS-1 Secondary customers. On an annual energy consumption basis, Residential and GS-1 Secondary customers currently account for approximately 85 percent of the Supply load obligation. GS-1 Secondary customers are described as small commercial accounts. Examples of a GS-1 Secondary customer would be a small retail store, a convenience store and gas station, or a restaurant.

Customer data is collected by NWE key account representatives for many of the larger commercial and industrial customers from the GS-1 Primary and GS-2 Substation and Transmission rate classes. This information typically consists of near-term operating information and estimated energy usage that is then employed in the load forecast. The information gathered by the key account representatives can include business expansion plans, business startups, closures, and in some cases, detailed energy usage forecasts for energy intensive industries.

The methods of estimating future energy usage are rate class specific. Residential and GS-1 Secondary usage forecasts are based on regression models using the customer forecast and normal weather, defined as average historical total degree days (heating plus cooling), as the explanatory variables. Charts depicting the dynamic regression results for each of these two classes are on pages 10 and 11. GS-I Primary, GS-2 Substation and GS-2 Transmission rate class forecasts are based on the "known

changes" methodology. Simply put, when a customer-specific known change occurs, prior year energy usage is adjusted up or down to reflect the known changes. Irrigation and Lighting rate classes do not display a growth pattern or trend as in the case of the Residential and GS-1 Secondary rate classes. In the absence of a historical growth trend, NWE has employed the known changes methodology in this forecast by using the 2012 energy consumption value for the Lighting rate class and a historical 5-year average usage rate for the Irrigation rate class as estimates for the period 2014-2033. In addition, transmission line losses are included in all customer class's forecasts. Losses must be included because metered usage plus losses equals the amount of energy that must be generated (or supplied) to meet the Supply energy serving obligation.

The "Totals" table on page 9 illustrates the impact of DSM on the annual load forecast totals; the forecasted average annual growth rate for the Supply load obligation including future DSM energy conservation impacts is 0.8%, while the average annual growth rate for the 20-year period increases to 1.2% when future DSM impacts are excluded. Future new increments of energy savings attributed to DSM are handled outside of the forecasting models. For PowerSimm™ modeling purposes, future DSM measures and associated energy savings are treated as an energy "purchase" and have the effect of lowering the Supply load obligation and contribute to the total portfolio cost. All resource portfolios employ the same set of DSM inputs and assumptions. Historic DSM energy savings are inherent in the load forecast in that they are included in historic load figures, the basis for predicting future loads, and are explicitly included in all forecast values.

Because customer count is an explanatory variable in the regression simulations, it must be estimated for the forecast period (2014-2033). The estimate of average annual customer count (see customer count forecast tables beginning on page 12) for the residential and GS-I Secondary rate classes were derived by relating customer count values to the population within the counties served by NWE. The population forecast used by NorthWestern was developed by Regional Economic Models, Inc. ("REMI") and made available by the State of Montana Census and Economic Information Center ("CEIC") on its website. Population and customer count charts have been included as a

graphical representation of the historic and forecast data contained in the customer count tables.

Charts that combine historical customer counts, load use, and weather (heating and cooling degree days) to illustrate actual and weather normalized use-per-customer activity follow on page 21.

Historic heating degree day ("HDD"), cooling degree day ("CDD"), and temperature values from the 9 largest Montana cities in NWE's service territory are presented beginning on page 25. Normal weather conditions, as defined for the dynamic regression modeling, are the average of the total number of annual HDD and CDD for the period 1980 through 2012. The numeric average for HDD and CDD is employed in the dynamic regressions to create a weather normal annual energy forecast. The degree day charts include one that demonstrates the historic range of annual HDD and CDD in the form of a stacked histogram.

NorthWestern's Energy Supply peak demand "1-in-10" forecast is on page 30. The "1-in-2" peak demand forecast is presented in Volume 1, Chapter 4. Both forecasts were developed in conjunction with NorthWestern's balancing authority peak demand forecast process performed by the NorthWestern Transmission group. This process employs a linear regression model with weather (CDD and HDD), temperature, loads, and population serving as the driving variables. Hence, Energy Supply's peak demand forecast is not a derivative of its load forecast; rather, it can be more accurately defined as a subset NorthWestern's total balancing authority peak demand forecast. The "1-in-10" forecast means that there is a 10% probability that the forecast will be exceeded by an actual peak in any given year. Charts that depict historical winter and summer peaks and historical ranges in load by month are also included.

20-Year Load Forecast
Annual Energy Consumption Estimate
MWH including Losses
Base Case Forecast
Updated 30April 2013
Residential loss factor 1.0851

Forecast values for Residential and GS-1 Secondary rate classes are weather normalized

Actual historical energy values in **BOLD**

	Residential Total Excluding DSM & USB	Residential Default Supply	Residential Default Supply Including Future DSM & USB	Residential Choice	Future Residential DSM+USB Energy Savings	Total Residential Including DSM+USB Energy Savings
2003	**2,241,849**	**2,241,158**		**691**		**2,241,849**
2004	**2,215,560**	**2,215,540**	**2,215,540**	**21**		**2,215,560**
2005	**2,244,640**	**2,244,638**	**2,244,638**	**2**		**2,244,640**
2006	**2,380,123**	**2,380,115**	**2,380,115**	**9**		**2,380,123**
2007	**2,411,659**	**2,411,628**	**2,411,628**	**30**		**2,411,659**
2008	**2,490,380**	**2,490,234**	**2,490,234**	**146**		**2,490,380**
2009	**2,503,408**	**2,503,271**	**2,503,271**	**137**		**2,503,408**
2010	**2,518,232**	**2,518,102**	**2,518,102**	**130**		**2,518,232**
2011	**2,600,433**	**2,600,300**	**2,600,300**	**133**		**2,600,433**
2012	**2,561,328**	**2,561,198**	**2,561,198**	**129**		**2,561,328**
2013	2,617,694	2,617,694	2,573,333	0	44,362	2,573,333
2014	2,636,662	2,636,662	2,548,142	0	88,520	2,548,142
2015	2,663,719	2,663,719	2,543,037	0	120,681	2,543,037
2016	2,695,579	2,695,579	2,546,138	0	149,441	2,546,138
2017	2,730,325	2,730,325	2,554,237	0	176,088	2,554,237
2018	2,766,841	2,766,841	2,565,507	0	201,334	2,565,507
2019	2,804,484	2,804,484	2,578,883	0	225,602	2,578,883
2020	2,842,877	2,842,877	2,593,717	0	249,161	2,593,717
2021	2,880,842	2,880,842	2,608,653	0	272,189	2,608,653
2022	2,919,119	2,919,119	2,624,308	0	294,810	2,624,308
2023	2,957,218	2,957,218	2,640,106	0	317,112	2,640,106
2024	2,995,342	2,995,342	2,675,310	0	320,032	2,675,310
2025	3,033,599	3,033,599	2,713,567	0	320,032	2,713,567
2026	3,072,069	3,072,069	2,752,037	0	320,032	2,752,037
2027	3,110,780	3,110,780	2,790,748	0	320,032	2,790,748
2028	3,149,778	3,149,778	2,829,747	0	320,032	2,829,747
2029	3,189,068	3,189,068	2,869,036	0	320,032	2,869,036
2030	3,228,669	3,228,669	2,908,638	0	320,032	2,908,638
2031	3,267,314	3,267,314	2,947,282	0	320,032	2,947,282
2032	3,306,110	3,306,110	2,986,078	0	320,032	2,986,078
2033	3,344,538	3,344,538	3,024,506	0	320,032	3,024,506
Forecasted Growth Rate	**1.2%**	**1.2%**	**0.8%**		**10.4%**	**0.8%**

20-Year Load Forecast
Annual Energy Consumption Estimate
MWH including Losses
Base Case Forecast

GS-1 Secondary loss factor 1.0851

	GS-1 Secondary Total Excluding DSM & USB	GS-1 Secondary Default Supply	GS-1 Secondary Default Supply Including Future DSM & USB	GS-1 Secondary Choice	GS-1 Secondary Future DSM+USB Energy Savings	Total GS-1 Secondary Including DSM+USB Energy Savings
2003	**2,794,459**	**2,404,061**		**390,398**		
2004	**2,806,179**	**2,687,250**	**2,687,250**	**118,929**		**2,806,179**
2005	**2,831,105**	**2,787,422**	**2,787,422**	**43,683**		**2,831,105**
2006	**2,965,333**	**2,899,025**	**2,899,025**	**66,308**		**2,965,333**
2007	**2,996,060**	**2,922,255**	**2,922,255**	**73,805**		**2,996,060**
2008	**3,042,807**	**2,947,597**	**2,947,597**	**95,210**		**3,042,807**
2009	**2,986,731**	**2,894,430**	**2,894,430**	**92,301**		**2,986,731**
2010	**2,973,871**	**2,883,696**	**2,883,696**	**90,175**		**2,973,871**
2011	**3,004,086**	**2,915,383**	**2,915,383**	**88,704**		**3,004,086**
2012	**3,012,497**	**2,928,740**	**2,928,740**	**83,757**		**3,012,497**
2013	3,059,830	2,976,073	2,963,402	83,757	12,671	3,047,159
2014	3,116,683	3,032,927	3,007,381	83,757	25,546	3,091,138
2015	3,176,753	3,092,996	3,042,579	83,757	50,417	3,126,336
2016	3,236,835	3,153,079	3,074,388	83,757	78,691	3,158,145
2017	3,294,558	3,210,802	3,101,726	83,757	109,076	3,185,482
2018	3,348,838	3,265,082	3,124,218	83,757	140,863	3,207,975
2019	3,399,716	3,315,959	3,142,331	83,757	173,628	3,226,088
2020	3,448,050	3,364,293	3,157,191	83,757	207,102	3,240,948
2021	3,494,804	3,411,047	3,169,940	83,757	241,107	3,253,697
2022	3,540,999	3,457,243	3,181,724	83,757	275,518	3,265,481
2023	3,587,410	3,503,653	3,193,404	83,757	310,250	3,277,160
2024	3,634,418	3,550,662	3,235,813	83,757	314,849	3,319,570
2025	3,682,113	3,598,357	3,283,508	83,757	314,849	3,367,265
2026	3,730,313	3,646,556	3,331,708	83,757	314,849	3,415,464
2027	3,778,761	3,695,004	3,380,156	83,757	314,849	3,463,912
2028	3,827,172	3,743,415	3,428,566	83,757	314,849	3,512,323
2029	3,875,374	3,791,618	3,476,769	83,757	314,849	3,560,526
2030	3,923,340	3,839,583	3,524,735	83,757	314,849	3,608,492
2031	3,970,843	3,887,086	3,572,238	83,757	314,849	3,655,995
2032	4,017,872	3,934,116	3,619,267	83,757	314,849	3,703,024
2033	4,064,582	3,980,826	3,665,977	83,757	314,849	3,749,734
Forecasted Growth Rate	**1.4%**	**1.5%**	**1.1%**	**0.0%**	**17.4%**	**1.0%**

20-Year Load Forecast
Annual Energy Consumption Estimate
MWH including Losses
Base Case Forecast

GS-1 Primary Loss factor 1.0554 GS-2 Sub Loss factor 1.0463

GS-1 Primary assumes that usage continues until a known change occurs

GS-2 Substation forecast based on "known changes"

	GS-1 Primary Total	GS-1 Primary Default Supply	GS-1 Primary Choice	GS-2 Substation Total	GS-2 Substation Default Supply	GS-2 Substation Choice
2003	**377,727**	**303,937**	**73,789**	**1,887,950**	**273,108**	**1,614,842**
2004	**385,325**	**310,992**	**74,334**	**2,226,943**	**273,059**	**1,953,884**
2005	**399,734**	**316,653**	**83,081**	**2,294,539**	**342,953**	**1,951,586**
2006	**426,753**	**331,594**	**95,159**	**2,252,968**	**290,040**	**1,962,929**
2007	**446,133**	**351,673**	**94,460**	**2,250,194**	**317,226**	**1,932,968**
2008	**425,802**	**343,644**	**82,159**	**2,324,550**	**324,439**	**2,000,111**
2009	**423,747**	**338,877**	**84,870**	**2,070,694**	**214,705**	**1,855,989**
2010	**427,602**	**341,837**	**85,765**	**1,883,732**	**165,545**	**1,718,188**
2011	**444,780**	**364,127**	**80,654**	**1,891,633**	**214,615**	**1,677,018**
2012	**441,203**	**366,461**	**74,741**	**1,889,172**	**229,072**	**1,660,100**
2013	441,203	366,461	74,741	1,941,854	245,509	1,696,345
2014	441,203	366,461	74,741	1,941,854	245,509	1,696,345
2015	441,203	366,461	74,741	1,941,854	245,509	1,696,345
2016	441,203	366,461	74,741	1,941,854	245,509	1,696,345
2017	441,203	366,461	74,741	1,941,854	245,509	1,696,345
2018	441,203	366,461	74,741	1,941,854	245,509	1,696,345
2019	441,203	366,461	74,741	1,941,854	245,509	1,696,345
2020	441,203	366,461	74,741	1,941,854	245,509	1,696,345
2021	441,203	366,461	74,741	1,941,854	245,509	1,696,345
2022	441,203	366,461	74,741	1,941,854	245,509	1,696,345
2023	441,203	366,461	74,741	1,941,854	245,509	1,696,345
2024	441,203	366,461	74,741	1,941,854	245,509	1,696,345
2025	441,203	366,461	74,741	1,941,854	245,509	1,696,345
2026	441,203	366,461	74,741	1,941,854	245,509	1,696,345
2027	441,203	366,461	74,741	1,941,854	245,509	1,696,345
2028	441,203	366,461	74,741	1,941,854	245,509	1,696,345
2029	441,203	366,461	74,741	1,941,854	245,509	1,696,345
2030	441,203	366,461	74,741	1,941,854	245,509	1,696,345
2031	441,203	366,461	74,741	1,941,854	245,509	1,696,345
2032	441,203	366,461	74,741	1,941,854	245,509	1,696,345
2033	441,203	366,461	74,741	1,941,854	245,509	1,696,345
Forecasted Growth Rate	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**

20-Year Load Forecast
Annual Energy Consumption Estimate
MWH including Losses
Base Case Forecast

GS-2 Trans Loss Factor 1.0400 Lighting Loss Factor 1.0851

GS-2 Transmission forecast based on "known changes"

	GS-2 Transmission Total	GS-2 Transmission Default Supply	GS-2 Transmission Choice	Lighting Total	Lighting Default Supply	Lighting Choice
2003	**675,095**	**108,892**	**566,203**	**68,478**	**54,892**	**13,587**
2004	**771,020**	**100,978**	**670,042**	**68,457**	**67,684**	**773**
2005	**874,141**	**122,498**	**751,642**	**65,871**	**61,214**	**4,657**
2006	**882,403**	**163,468**	**718,934**	**65,974**	**61,230**	**4,744**
2007	**873,063**	**155,047**	**718,016**	**66,244**	**61,458**	**4,786**
2008	**936,703**	**154,180**	**782,523**	**66,421**	**61,597**	**4,824**
2009	**955,832**	**151,221**	**804,611**	**65,915**	**61,158**	**4,757**
2010	**987,020**	**151,045**	**835,975**	**65,776**	**61,020**	**4,756**
2011	**1,062,994**	**140,512**	**922,482**	**65,363**	**60,607**	**4,756**
2012	**1,118,207**	**128,098**	**990,109**	**65,419**	**60,678**	**4,741**
2013	1,147,157	140,023	1,007,134	65,419	60,678	4,741
2014	1,147,157	140,023	1,007,134	65,419	60,678	4,741
2015	1,147,157	140,023	1,007,134	65,419	60,678	4,741
2016	1,147,157	140,023	1,007,134	65,419	60,678	4,741
2017	1,147,157	140,023	1,007,134	65,419	60,678	4,741
2018	1,147,157	140,023	1,007,134	65,419	60,678	4,741
2019	1,147,157	140,023	1,007,134	65,419	60,678	4,741
2020	1,147,157	140,023	1,007,134	65,419	60,678	4,741
2021	1,147,157	140,023	1,007,134	65,419	60,678	4,741
2022	1,147,157	140,023	1,007,134	65,419	60,678	4,741
2023	1,147,157	140,023	1,007,134	65,419	60,678	4,741
2024	1,147,157	140,023	1,007,134	65,419	60,678	4,741
2025	1,147,157	140,023	1,007,134	65,419	60,678	4,741
2026	1,147,157	140,023	1,007,134	65,419	60,678	4,741
2027	1,147,157	140,023	1,007,134	65,419	60,678	4,741
2028	1,147,157	140,023	1,007,134	65,419	60,678	4,741
2029	1,147,157	140,023	1,007,134	65,419	60,678	4,741
2030	1,147,157	140,023	1,007,134	65,419	60,678	4,741
2031	1,147,157	140,023	1,007,134	65,419	60,678	4,741
2032	1,147,157	140,023	1,007,134	65,419	60,678	4,741
2033	1,147,157	140,023	1,007,134	65,419	60,678	4,741
Forecasted Growth Rate	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**

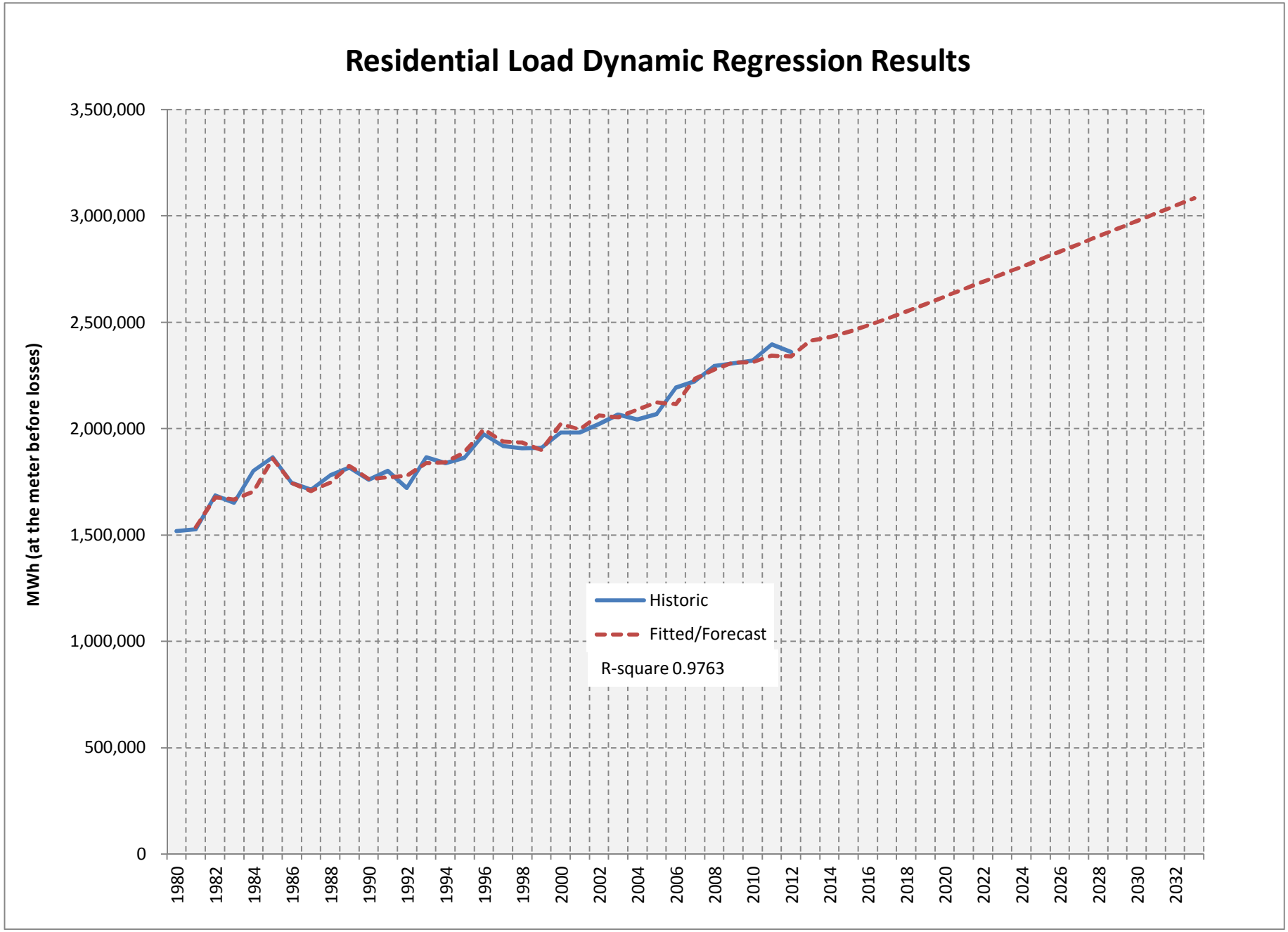
20-Year Load Forecast
Annual Energy Consumption Estimate
MWH including Losses
Base Case Forecast

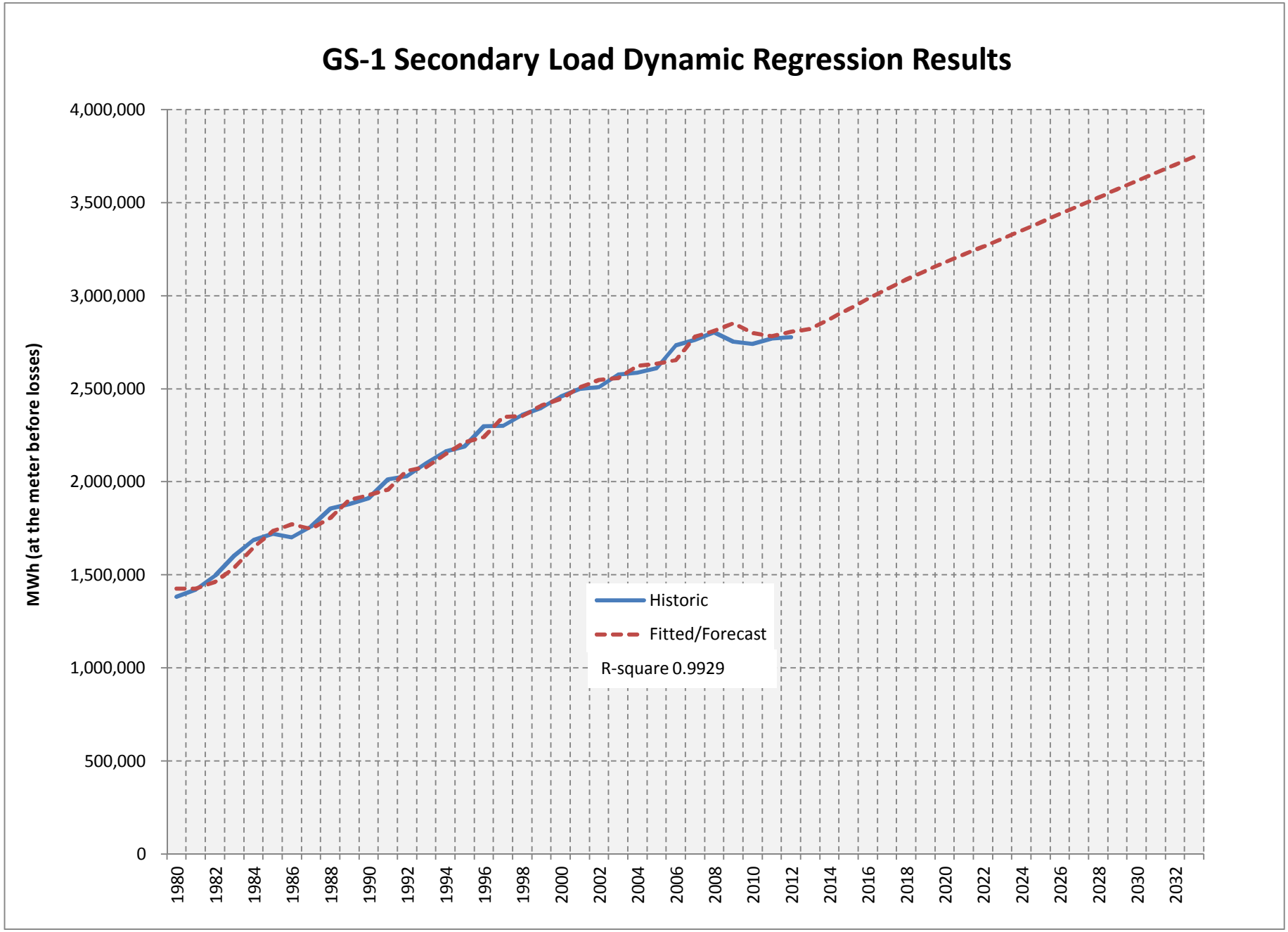
Irrigation Loss Factor 1.0851 DSM Loss Fa 1.0851

	Irrigation Total	Irrigation Default Supply	Irrigation Choice	YNP Loss factor 1.0851 YNP Default Supply	Load Reduction From Future USB + DSM (MWH)
2003	**104,867**	**104,867**	**0**	**20,054**	
2004	**97,664**	**97,647**	**17**	**20,279**	
2005	**84,405**	**84,187**	**217**	**20,808**	
2006	**100,029**	**99,837**	**192**	**20,416**	
2007	**95,057**	**94,808**	**248**	**20,039**	
2008	**95,279**	**95,040**	**240**	**20,285**	
2009	**94,357**	**94,149**	**208**	**20,226**	
2010	**75,631**	**75,456**	**176**	**21,533**	
2011	**84,192**	**83,994**	**197**	**20,034**	
2012	**116,914**	**116,695**	**219**	**20,860**	
2013	93,275	93,067	208	20,860	57,033
2014	93,275	93,067	208	20,860	114,066
2015	93,275	93,067	208	20,860	171,099
2016	93,275	93,067	208	20,860	228,131
2017	93,275	93,067	208	20,860	285,164
2018	93,275	93,067	208	20,860	342,197
2019	93,275	93,067	208	20,860	399,230
2020	93,275	93,067	208	20,860	456,263
2021	93,275	93,067	208	20,860	513,296
2022	93,275	93,067	208	20,860	570,329
2023	93,275	93,067	208	20,860	627,361
2024	93,275	93,067	208	20,860	634,880
2025	93,275	93,067	208	20,860	634,880
2026	93,275	93,067	208	20,860	634,880
2027	93,275	93,067	208	20,860	634,880
2028	93,275	93,067	208	20,860	634,880
2029	93,275	93,067	208	20,860	634,880
2030	93,275	93,067	208	20,860	634,880
2031	93,275	93,067	208	20,860	634,880
2032	93,275	93,067	208	20,860	634,880
2033	93,275	93,067	208	20,860	634,880
Forecasted Growth Rate	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**12.8%**

20-Year Load Forecast
Annual Energy Consumption Estimate
MWH including Losses
Base Case Forecast

	Historic Default Supply Useage (MWH)	Total Projected Default Supply Including DSM (MWH)	Default Supply Load Change Including Future DSM Impacts	Total Projected Default Supply Excluding DSM (MWH)	Default Supply Load Change Excluding Future DSM Impacts
2003	**5,510,969**				
2004	**5,773,429**				
2005	**5,980,373**				
2006	**6,245,724**				
2007	**6,334,134**				
2008	**6,437,015**				
2009	**6,278,039**				
2010	**6,218,232**				
2011	**6,399,572**				
2012	**6,411,802**				
2013		6,463,332	0.8%	6,520,365	1.7%
2014		6,482,120	0.3%	6,596,186	1.2%
2015		6,512,214	0.5%	6,683,312	1.3%
2016		6,547,124	0.5%	6,775,255	1.4%
2017		6,582,560	0.5%	6,867,724	1.4%
2018		6,616,323	0.5%	6,958,520	1.3%
2019		6,647,811	0.5%	7,047,041	1.3%
2020		6,677,505	0.4%	7,133,768	1.2%
2021		6,705,190	0.4%	7,218,486	1.2%
2022		6,732,630	0.4%	7,302,958	1.2%
2023		6,760,107	0.4%	7,387,468	1.2%
2024		6,837,720	1.1%	7,472,600	1.2%
2025		6,923,672	1.3%	7,558,553	1.2%
2026		7,010,342	1.3%	7,645,222	1.1%
2027		7,097,501	1.2%	7,732,381	1.1%
2028		7,184,910	1.2%	7,819,790	1.1%
2029		7,272,402	1.2%	7,907,283	1.1%
2030		7,359,970	1.2%	7,994,850	1.1%
2031		7,446,118	1.2%	8,080,998	1.1%
2032		7,531,942	1.2%	8,166,823	1.1%
2033		7,617,080	1.1%	8,251,960	1.0%
Forecasted Growth Rate		**0.8%**		**1.2%**	


Residential Load Dynamic Regression Results
MWh (at the meter before losses)
3,500,000
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
Historic
Fitted/Forecast
R-square 0.9763


GS-1 Secondary Load Dynamic Regression Results
MWh (at the meter before losses)
4,000,000
3,500,000
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
Historic
Fitted/Forecast
R-square 0.9929

Long-Term (20-Year) Customer count Forecast
Calendar Year Basis
Montana population and population within NorthWestern service territory from CEIC website/Regional Economic Models Inc. (REMI)
Dynamic Regression - Residential cust count, Dynamic Regression - GS-1 Secondary cust count
Updated April 13, 2013

	Montana Population History/Forecast	Montana Average Annual Growth (%)	Population within NWE Service Territory	NWE Average Annual Growth (%)	% of Population within N.W.E. Service Territory	Average Annual Residential Accounts	Residential Account Additions	Residential Average Annual Growth (%)	Residential Accounts as % of Population within N.W.E. Service Territory
1982	805,257	1.2%	620,030	0.9%	77.0%	195,095	1,791	0.9%	31.5%
1983	815,926	1.3%	628,893	1.4%	77.1%	197,646	2,551	1.3%	31.4%
1984	823,433	0.9%	634,142	0.8%	77.0%	200,686	3,040	1.5%	31.6%
1985	825,472	0.2%	635,324	0.2%	77.0%	202,974	2,288	1.1%	31.9%
1986	817,480	-1.0%	629,765	-0.9%	77.0%	203,600	626	0.3%	32.3%
1987	809,395	-1.0%	624,319	-0.9%	77.1%	204,144	544	0.3%	32.7%
1988	805,149	-0.5%	621,322	-0.5%	77.2%	204,788	644	0.3%	33.0%
1989	805,100	0.0%	621,925	0.1%	77.2%	204,602	-186	-0.1%	32.9%
1990	799,065	-0.7%	619,715	-0.4%	77.6%	205,035	433	0.2%	33.1%
1991	808,230	1.1%	628,076	1.3%	77.7%	206,858	1,824	0.9%	32.9%
1992	823,287	1.9%	640,662	2.0%	77.8%	209,509	2,650	1.3%	32.7%
1993	841,188	2.2%	654,381	2.1%	77.8%	212,727	3,219	1.5%	32.5%
1994	856,519	1.8%	666,350	1.8%	77.8%	216,832	4,104	1.9%	32.5%
1995	870,351	1.6%	676,898	1.6%	77.8%	220,605	3,774	1.7%	32.6%
1996	879,372	1.0%	683,712	1.0%	77.8%	224,339	3,733	1.7%	32.8%
1997	878,810	-0.1%	682,888	-0.1%	77.7%	227,845	3,506	1.5%	33.4%
1998	880,453	0.2%	685,233	0.3%	77.8%	230,751	2,906	1.3%	33.7%
1999	882,779	0.3%	687,224	0.3%	77.8%	231,365	614	0.3%	33.7%
2000	903,293	2.3%	705,330	2.6%	78.1%	235,784	4,419	1.9%	33.4%
2001	905,873	0.3%	707,844	0.4%	78.1%	237,591	1,807	0.8%	33.6%
2002	909,868	0.4%	711,656	0.5%	78.2%	240,944	3,353	1.4%	33.9%
2003	916,750	0.8%	717,128	0.8%	78.2%	244,645	3,701	1.5%	34.1%
2004	925,887	1.0%	724,327	1.0%	78.2%	248,756	4,111	1.7%	34.3%
2005	934,801	1.0%	731,505	1.0%	78.3%	253,124	4,368	1.7%	34.6%
2006	946,801	1.3%	740,888	1.3%	78.3%	258,123	4,999	1.9%	34.8%
2007	957,225	1.1%	749,792	1.2%	78.3%	262,481	4,358	1.7%	35.0%
2008	968,035	1.1%	758,565	1.2%	78.4%	266,099	3,618	1.4%	35.1%
2009	974,989	0.7%	764,028	0.7%	78.4%	268,492	2,393	0.9%	35.1%
2010	989,415	1.5%	773,713	1.3%	78.2%	270,571	2,079	0.8%	35.0%
2011	997,667	0.8%	780,807	0.9%	78.3%	272,131	1,560	0.6%	34.9%
2012	1,005,141	0.7%	785,984	0.7%	78.2%	273,984	1,853	0.7%	34.9%
2013	**1,016,996**	**1.2%**	**795,173**	**1.2%**	**78.2%**	***280,549***	**6,565**	**2.4%**	**35.3%**
2014	**1,028,992**	**1.2%**	**804,470**	**1.2%**	**78.2%**	***282,892***	**2,343**	**0.8%**	**35.2%**
2015	**1,041,128**	**1.2%**	**813,876**	**1.2%**	**78.2%**	***285,980***	**3,088**	**1.1%**	**35.1%**
2016	**1,053,408**	**1.2%**	**823,392**	**1.2%**	**78.2%**	***289,862***	**3,882**	**1.4%**	**35.2%**
2017	**1,065,833**	**1.2%**	**833,019**	**1.2%**	**78.2%**	***293,813***	**3,951**	**1.4%**	**35.3%**
2018	**1,078,404**	**1.2%**	**842,758**	**1.2%**	**78.1%**	***297,798***	**3,985**	**1.4%**	**35.3%**
2019	**1,091,124**	**1.2%**	**852,611**	**1.2%**	**78.1%**	***302,053***	**4,255**	**1.4%**	**35.4%**
2020	**1,103,993**	**1.2%**	**862,580**	**1.2%**	**78.1%**	***306,323***	**4,270**	**1.4%**	**35.5%**
2021	**1,116,029**	**1.1%**	**871,909**	**1.1%**	**78.1%**	***310,504***	**4,181**	**1.4%**	**35.6%**
2022	**1,128,196**	**1.1%**	**881,339**	**1.1%**	**78.1%**	***314,691***	**4,187**	**1.3%**	**35.7%**
2023	**1,140,496**	**1.1%**	**890,871**	**1.1%**	**78.1%**	***318,841***	**4,150**	**1.3%**	**35.8%**
2024	**1,152,930**	**1.1%**	**900,506**	**1.1%**	**78.1%**	***322,982***	**4,141**	**1.3%**	**35.9%**
2025	**1,165,500**	**1.1%**	**910,245**	**1.1%**	**78.1%**	***327,130***	**4,148**	**1.3%**	**35.9%**
2026	**1,178,206**	**1.1%**	**920,089**	**1.1%**	**78.1%**	***331,296***	**4,166**	**1.3%**	**36.0%**
2027	**1,191,051**	**1.1%**	**930,040**	**1.1%**	**78.1%**	***335,485***	**4,189**	**1.3%**	**36.1%**
2028	**1,204,036**	**1.1%**	**940,099**	**1.1%**	**78.1%**	***339,703***	**4,218**	**1.3%**	**36.1%**
2029	**1,217,163**	**1.1%**	**950,267**	**1.1%**	**78.1%**	***343,951***	**4,248**	**1.3%**	**36.2%**
2030	**1,230,432**	**1.1%**	**960,544**	**1.1%**	**78.1%**	***348,232***	**4,281**	**1.2%**	**36.3%**
2031	**1,242,587**	**1.0%**	**969,960**	**1.0%**	**78.1%**	***352,409***	**4,177**	**1.2%**	**36.3%**
2032	**1,254,861**	**1.0%**	**979,469**	**1.0%**	**78.1%**	***356,602***	**4,193**	**1.2%**	**36.4%**
2033	**1,267,257**	**1.0%**	**989,070**	**1.0%**	**78.0%**	***360,755***	**4,153**	**1.2%**	**36.5%**

Average Growth Rates

2008-2012	1.0%		0.9%
2003-2012	1.0%		1.0%
1998-2012	0.9%		0.9%
2013-2033	**1.1%**		**1.1%**

Average Growth Rates

2008-2012	0.9%
2003-2012	1.3%
1998-2012	1.2%
2013-2033	**1.3%**

Long-Term (20-Year) Customer count Forecast
Calendar Year Basis

	Average Annual GS-1 Secondary Accounts	GS-1 Secondary Account Additions	GS-1 Secondary Average Annual Growth (%)	GS-1 Secondary Accounts as % of Population within N.W.E. Service Territory	Population in NWE Srvce Territory per Business Account	Average Annual GS-1 Primary Accounts
1982	33,049	1,008	3.0%	5.3%	19	134
1983	33,926	878	2.6%	5.4%	19	135
1984	35,145	1,219	3.5%	5.5%	18	136
1985	35,796	651	1.8%	5.6%	18	138
1986	36,571	775	2.1%	5.8%	17	139
1987	37,132	561	1.5%	5.9%	17	140
1988	37,846	715	1.9%	6.1%	16	140
1989	38,406	559	1.5%	6.2%	16	142
1990	39,277	872	2.2%	6.3%	16	144
1991	40,090	813	2.0%	6.4%	16	145
1992	41,061	970	2.4%	6.4%	16	144
1993	42,187	1,126	2.7%	6.4%	16	146
1994	43,407	1,220	2.8%	6.5%	15	148
1995	44,764	1,357	3.0%	6.6%	15	154
1996	46,066	1,302	2.8%	6.7%	15	157
1997	47,294	1,228	2.6%	6.9%	14	158
1998	48,207	913	1.9%	7.0%	14	155
1999	48,771	564	1.2%	7.1%	14	146
2000	49,759	988	2.0%	7.1%	14	152
2001	50,881	1,122	2.2%	7.2%	14	152
2002	51,967	1,086	2.1%	7.3%	14	154
2003	53,035	1,068	2.0%	7.4%	14	156
2004	54,251	1,216	2.2%	7.5%	13	158
2005	55,491	1,240	2.2%	7.6%	13	162
2006	56,724	1,233	2.2%	7.7%	13	164
2007	58,195	1,471	2.5%	7.8%	13	163
2008	59,458	1,263	2.1%	7.8%	13	161
2009	60,314	856	1.4%	7.9%	13	162
2010	60,872	558	0.9%	7.9%	13	165
2011	61,430	558	0.9%	7.9%	13	167
2012	61,963	533	0.9%	7.9%	13	168
2013	***62,893***	**930**	**1.5%**	**7.9%**	13	168
2014	***64,143***	**1,250**	**2.0%**	**8.0%**	13	168
2015	***65,578***	**1,435**	**2.2%**	**8.1%**	12	168
2016	***67,056***	**1,478**	**2.3%**	**8.1%**	12	168
2017	***68,471***	**1,415**	**2.1%**	**8.2%**	12	168
2018	***69,772***	**1,301**	**1.9%**	**8.3%**	12	168
2019	***70,956***	**1,184**	**1.7%**	**8.3%**	12	168
2020	***72,055***	**1,099**	**1.5%**	**8.4%**	12	168
2021	***73,106***	**1,051**	**1.5%**	**8.4%**	12	168
2022	***74,149***	**1,043**	**1.4%**	**8.4%**	12	168
2023	***75,214***	**1,065**	**1.4%**	**8.4%**	12	168
2024	***76,315***	**1,101**	**1.5%**	**8.5%**	12	168
2025	***77,454***	**1,139**	**1.5%**	**8.5%**	12	168
2026	***78,622***	**1,168**	**1.5%**	**8.5%**	12	168
2027	***79,807***	**1,185**	**1.5%**	**8.6%**	12	168
2028	***80,996***	**1,189**	**1.5%**	**8.6%**	12	168
2029	***82,181***	**1,185**	**1.5%**	**8.6%**	12	168
2030	***83,360***	**1,179**	**1.4%**	**8.7%**	12	168
2031	***84,523***	**1,163**	**1.4%**	**8.7%**	11	168
2032	***85,669***	**1,146**	**1.4%**	**8.7%**	11	168
2033	***86,804***	**1,135**	**1.3%**	**8.8%**	11	168

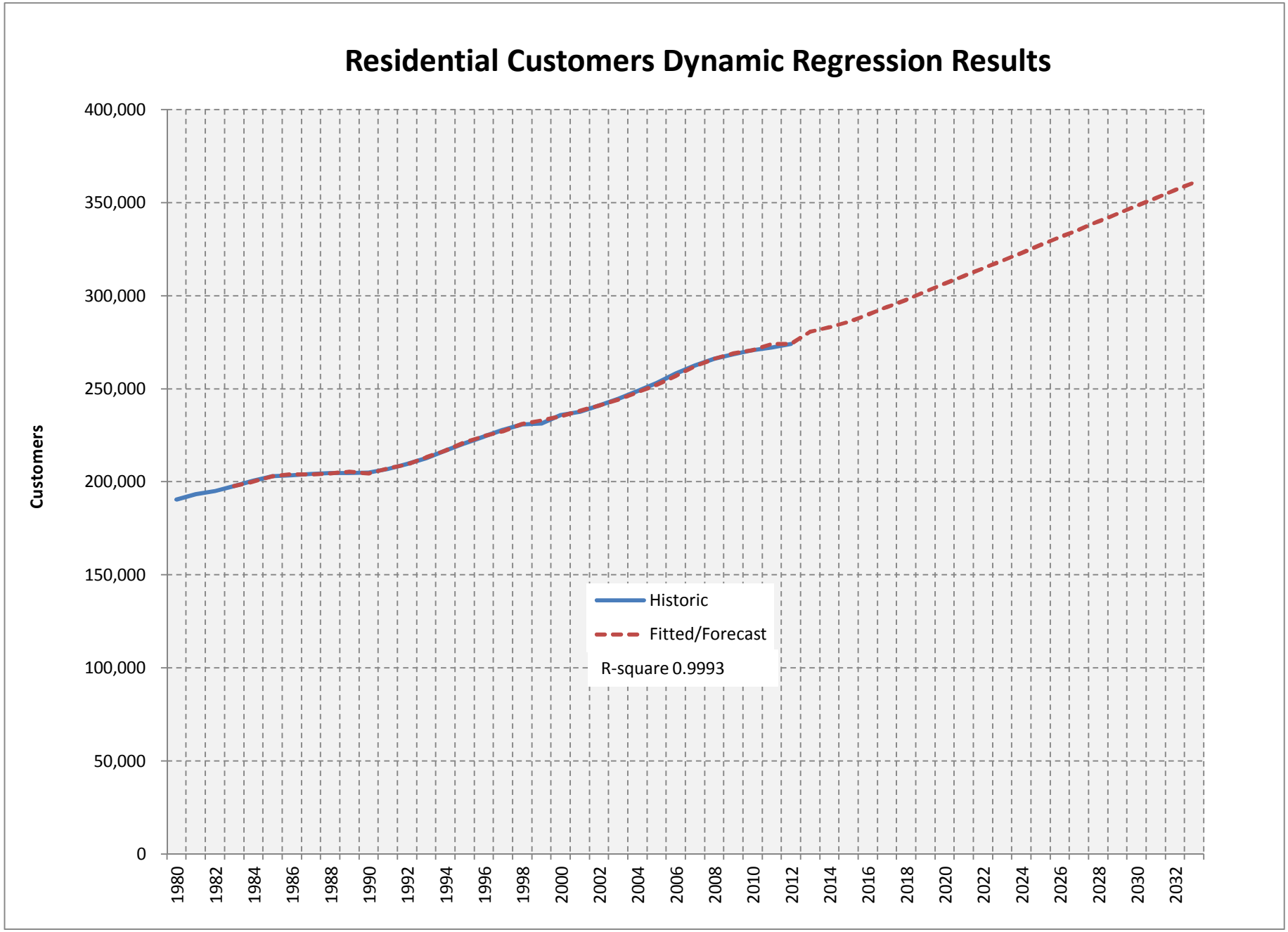
Average Growth Rates

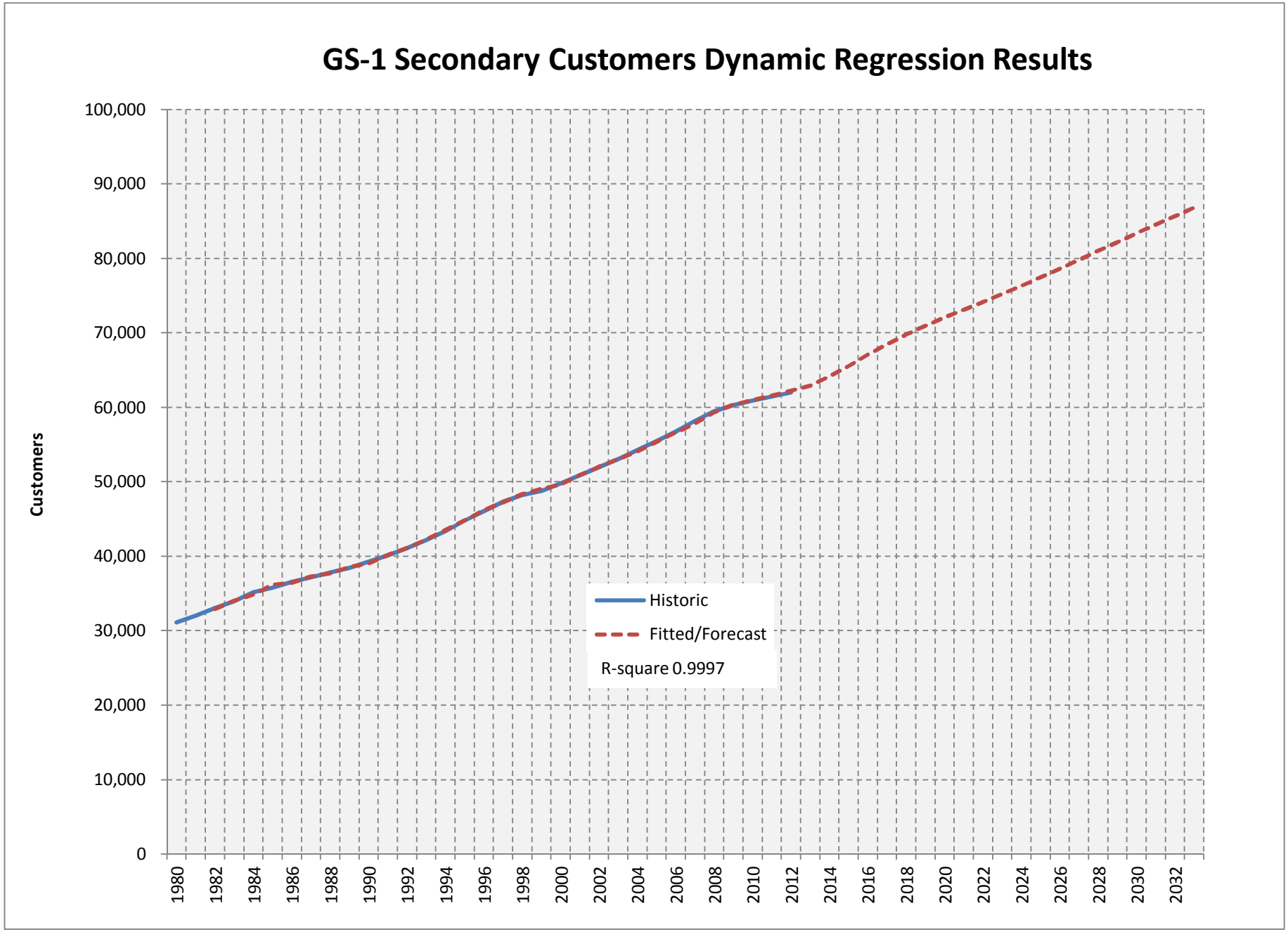
2008-2012	1.2%
2003-2012	1.7%
1998-2012	1.8%
2013-2033	**1.6%**

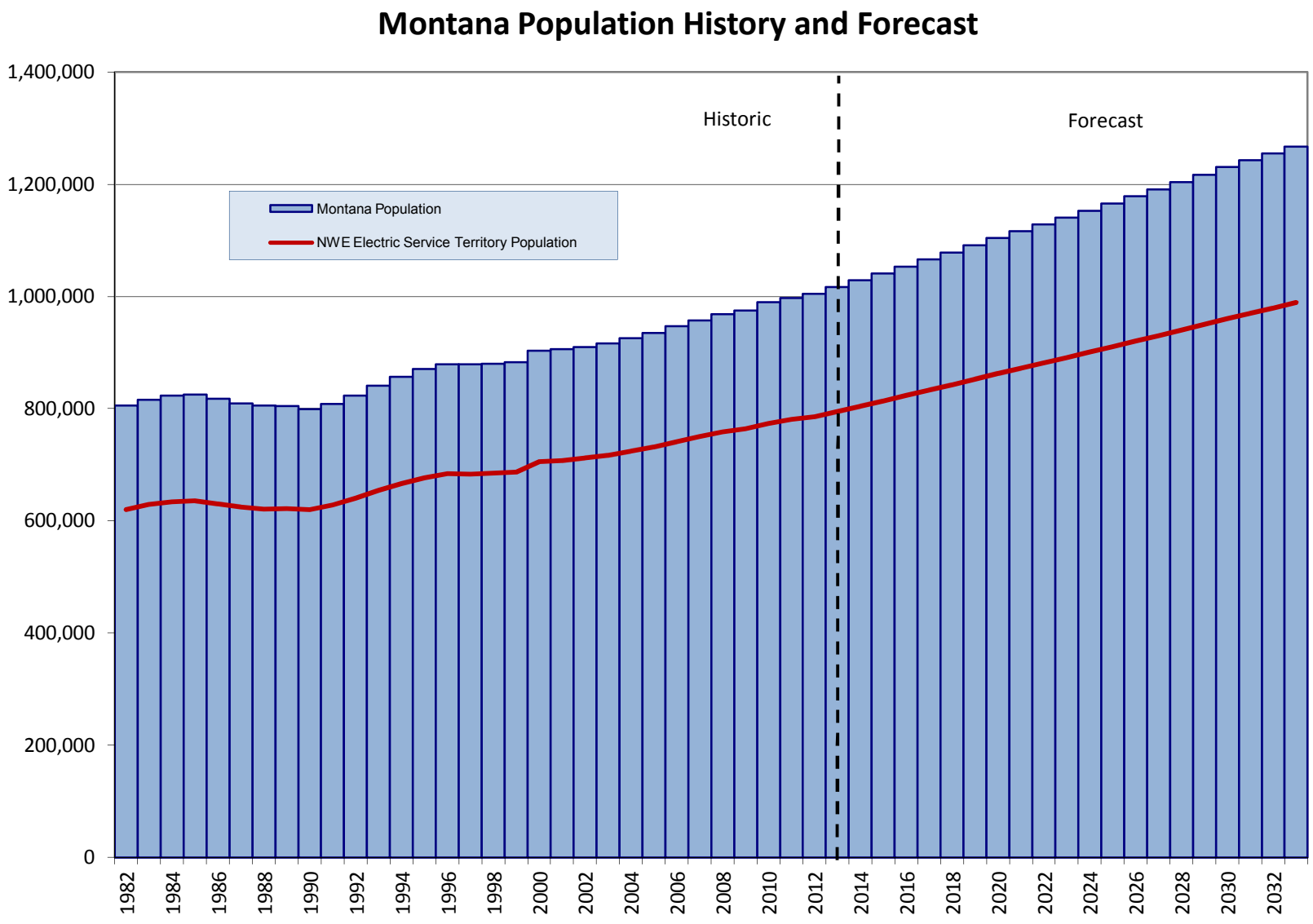
Long-Term (20-Year) Customer count Forecast
Calendar Year Basis

	Average Annual GS-2 Sub Accounts	Average Annual GS-2 Trans Accounts	Maximum Irrigation Accounts	Average Annual Lighting Accounts	**Average Annual Total NWE Accounts**	Annual Growth (%)
1982	57	4	2,757	1,648	232,743	1.3%
1983	57	4	2,825	1,701	236,294	1.5%
1984	57	4	2,910	1,731	240,669	1.9%
1985	57	4	2,860	2,579	244,408	1.6%
1986	57	4	2,830	2,700	245,901	0.6%
1987	58	4	2,742	2,745	246,964	0.4%
1988	58	4	2,870	2,769	248,476	0.6%
1989	60	5	2,713	2,750	248,677	0.1%
1990	62	5	2,817	2,833	250,173	0.6%
1991	59	6	2,678	2,841	252,677	1.0%
1992	57	6	2,787	2,875	256,438	1.5%
1993	59	6	2,114	2,914	260,153	1.4%
1994	60	6	2,759	2,949	266,161	2.3%
1995	58	7	2,566	2,999	271,154	1.9%
1996	59	7	2,712	3,104	276,443	2.0%
1997	59	10	2,544	2,819	280,729	1.6%
1998	53	11	2,695	2,864	284,736	1.4%
1999	47	7	2,757	3,295	286,388	0.6%
2000	58	8	2,697	3,979	292,437	2.1%
2001	57	8	2,791	3,706	295,186	0.9%
2002	56	9	2,903	3,758	299,791	1.6%
2003	55	9	3,060	3,810	304,770	1.7%
2004	54	9	3,044	3,818	310,090	1.7%
2005	53	11	3,102	3,812	315,755	1.8%
2006	53	16	3,152	3,792	322,024	2.0%
2007	53	16	3,162	3,794	327,864	1.8%
2008	53	16	3,326	3,818	332,931	1.5%
2009	53	16	3,356	3,795	336,188	1.0%
2010	53	16	3,345	3,782	338,804	0.8%
2011	53	18	3,334	3,771	340,904	0.6%
2012	52	20	3,468	3,771	343,426	0.7%
2013	52	20	3468	3771	**350,921**	**2.2%**
2014	52	20	3468	3771	**354,514**	**1.0%**
2015	52	20	3468	3771	**359,037**	**1.3%**
2016	52	20	3468	3771	**364,397**	**1.5%**
2017	52	20	3468	3771	**369,763**	**1.5%**
2018	52	20	3468	3771	**375,049**	**1.4%**
2019	52	20	3468	3771	**380,488**	**1.5%**
2020	52	20	3468	3771	**385,857**	**1.4%**
2021	52	20	3468	3771	**391,089**	**1.4%**
2022	52	20	3468	3771	**396,319**	**1.3%**
2023	52	20	3468	3771	**401,534**	**1.3%**
2024	52	20	3468	3771	**406,776**	**1.3%**
2025	52	20	3468	3771	**412,063**	**1.3%**
2026	52	20	3468	3771	**417,397**	**1.3%**
2027	52	20	3468	3771	**422,771**	**1.3%**
2028	52	20	3468	3771	**428,178**	**1.3%**
2029	52	20	3468	3771	**433,611**	**1.3%**
2030	52	20	3468	3771	**439,071**	**1.3%**
2031	52	20	3468	3771	**444,411**	**1.2%**
2032	52	20	3468	3771	**449,750**	**1.2%**
2033	52	20	3468	3771	**455,038**	**1.2%**

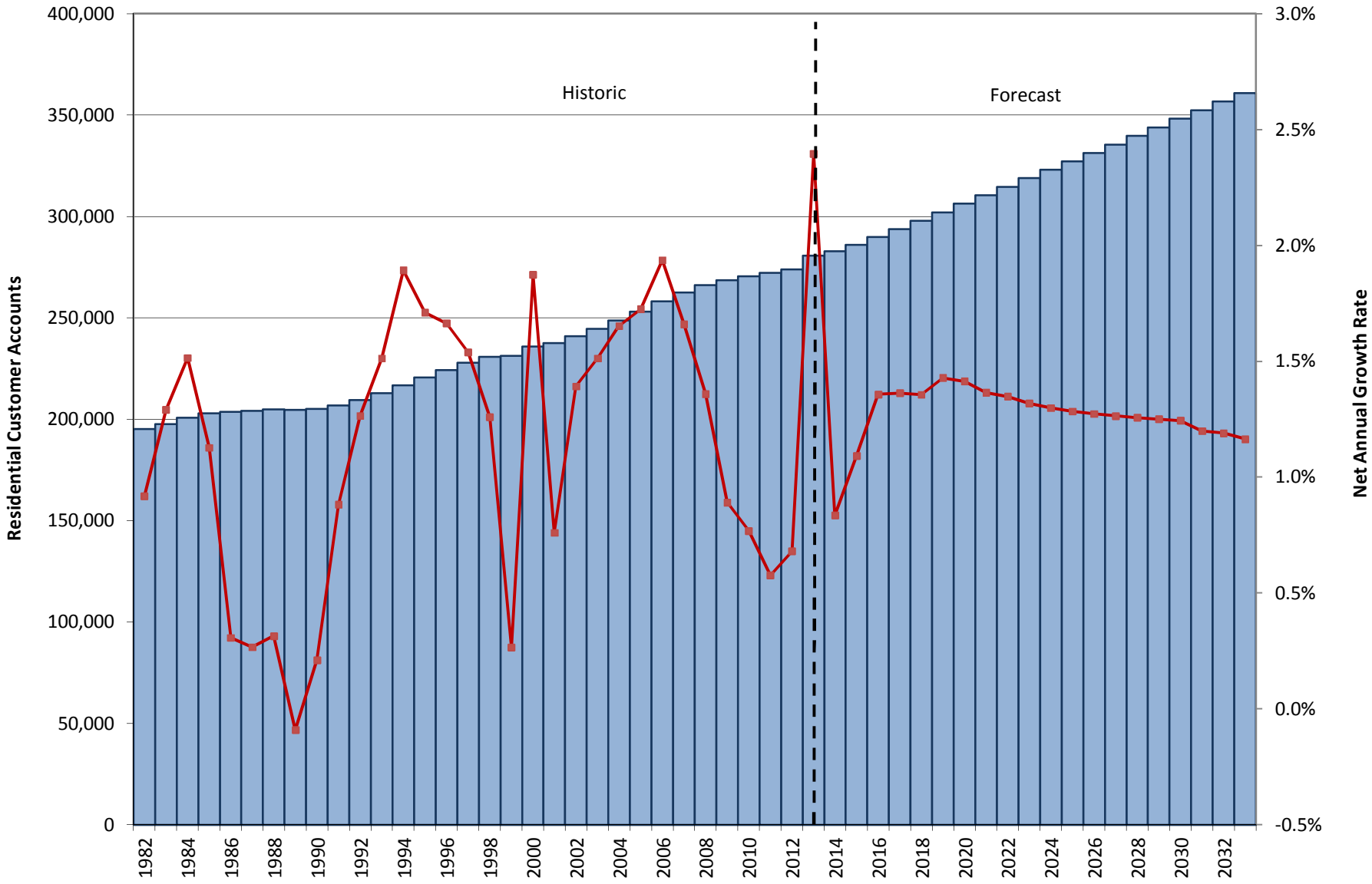
Average Growth Rates	
2008-2012	0.9%
2003-2012	1.4%
1998-2012	1.4%
2013-2033	**1.3%**


Residential Customers Dynamic Regression Results
Customers
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
Historic
Fitted/Forecast
R-square 0.9993

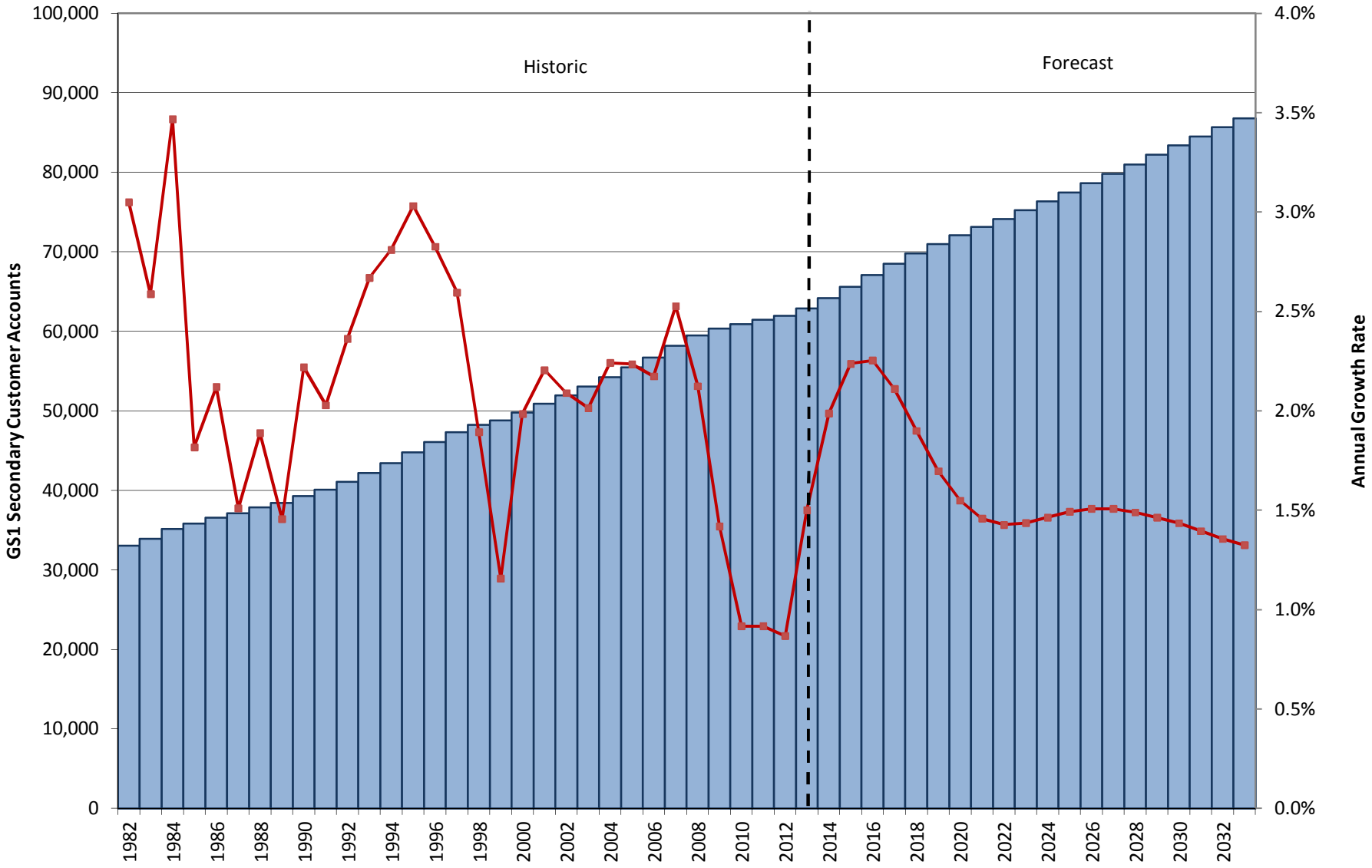

GS-1 Secondary Customers Dynamic Regression Results
Customers
100,000
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
Historic
Fitted/Forecast
R-square 0.9997

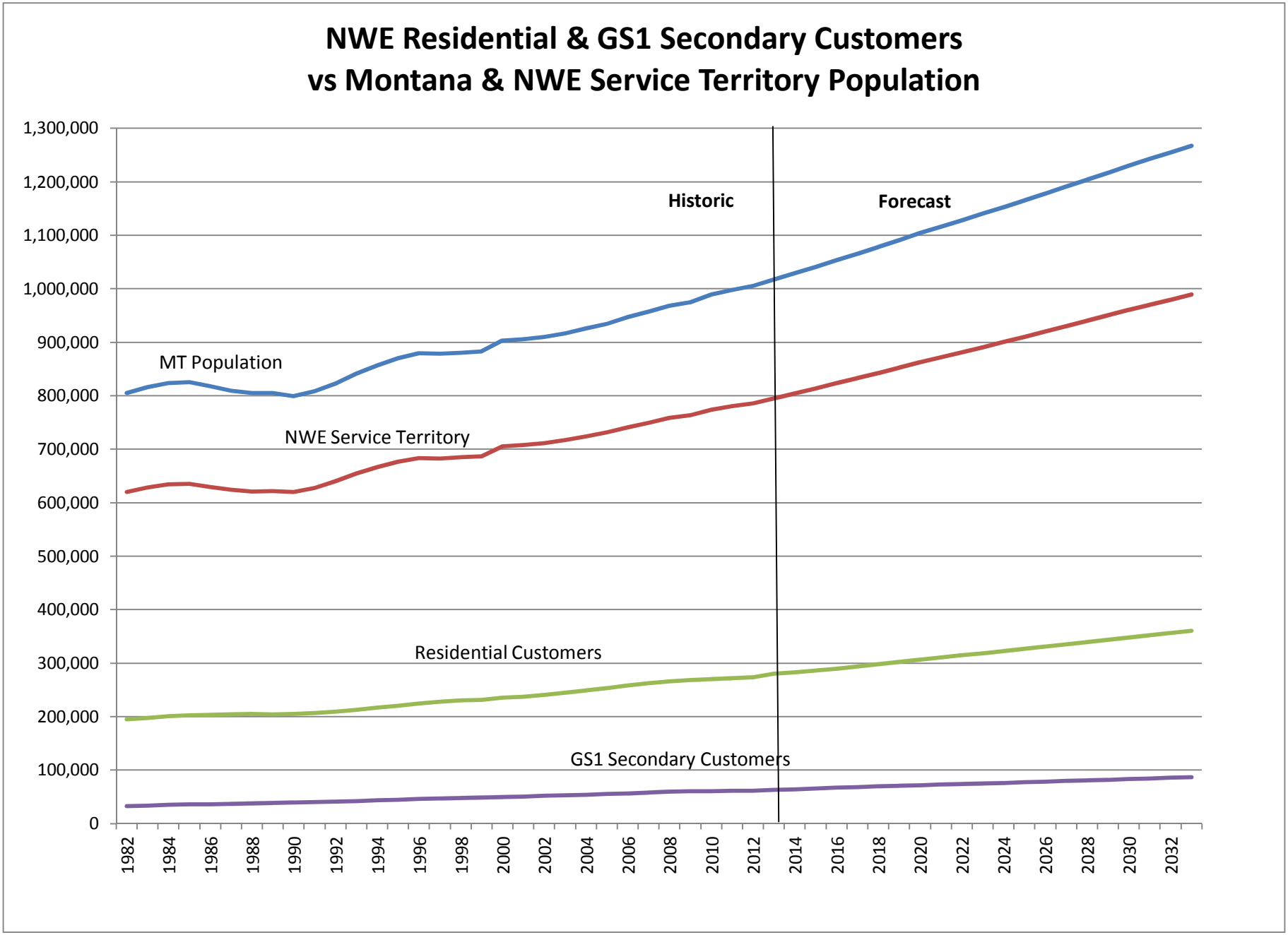

Montana Population History and Forecast
1,400,000
1,200,000
1,000,000
800,000
600,000
400,000
200,000
0
Historic
Forecast
Montana Population
NWE Electric Service Territory Population
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032

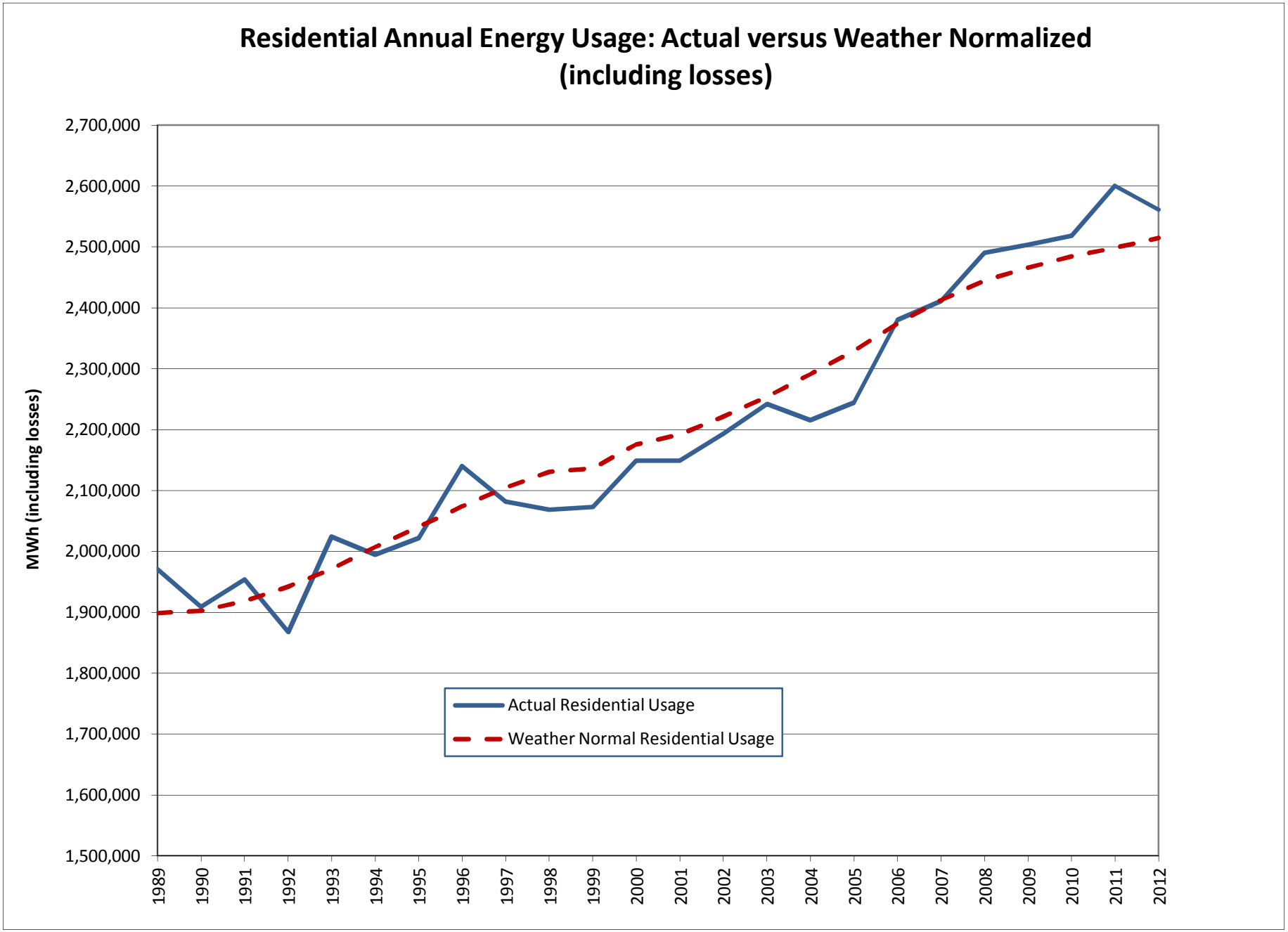
NorthWestern Energy Residential Customer Account History & Forecast

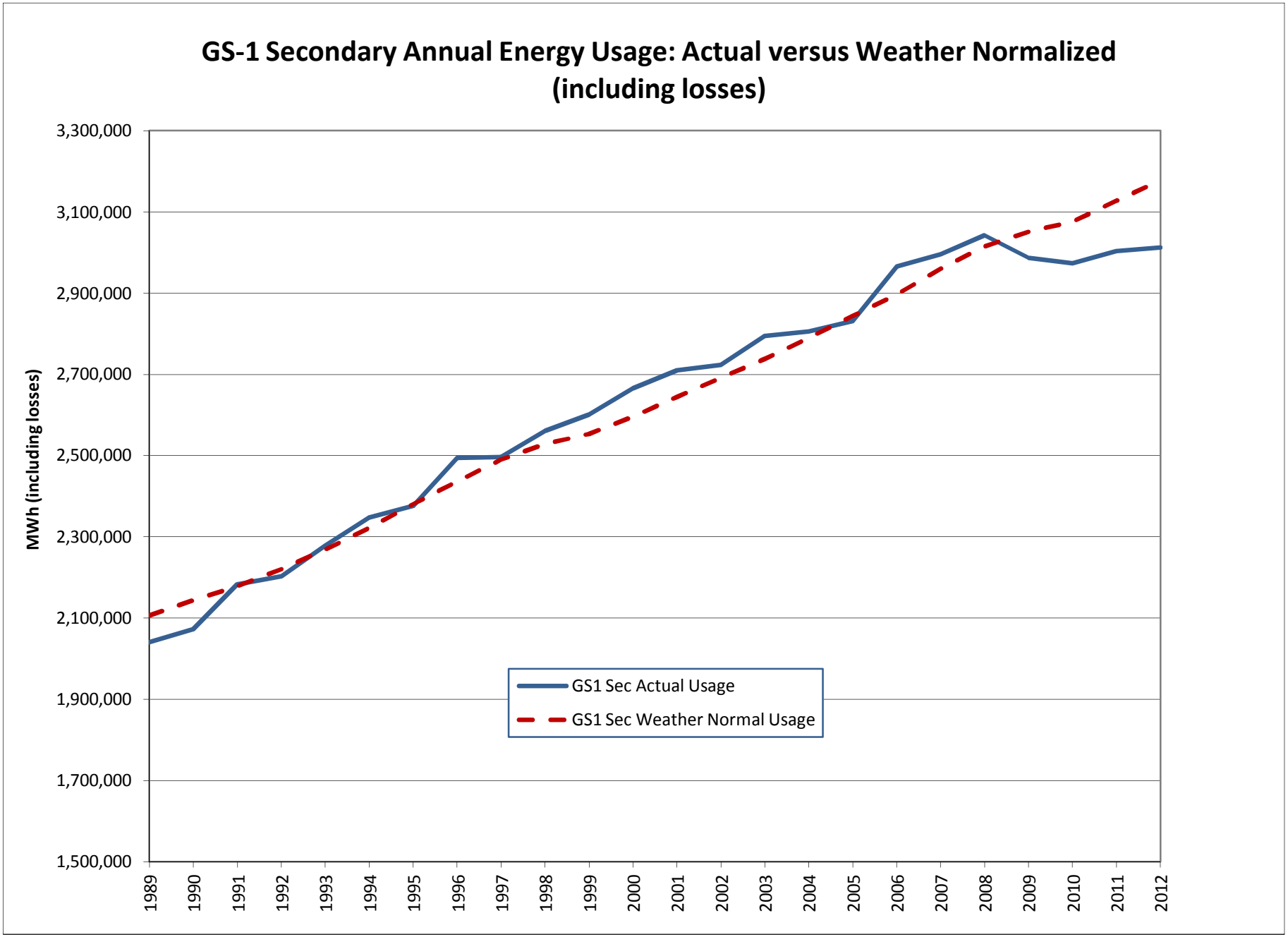


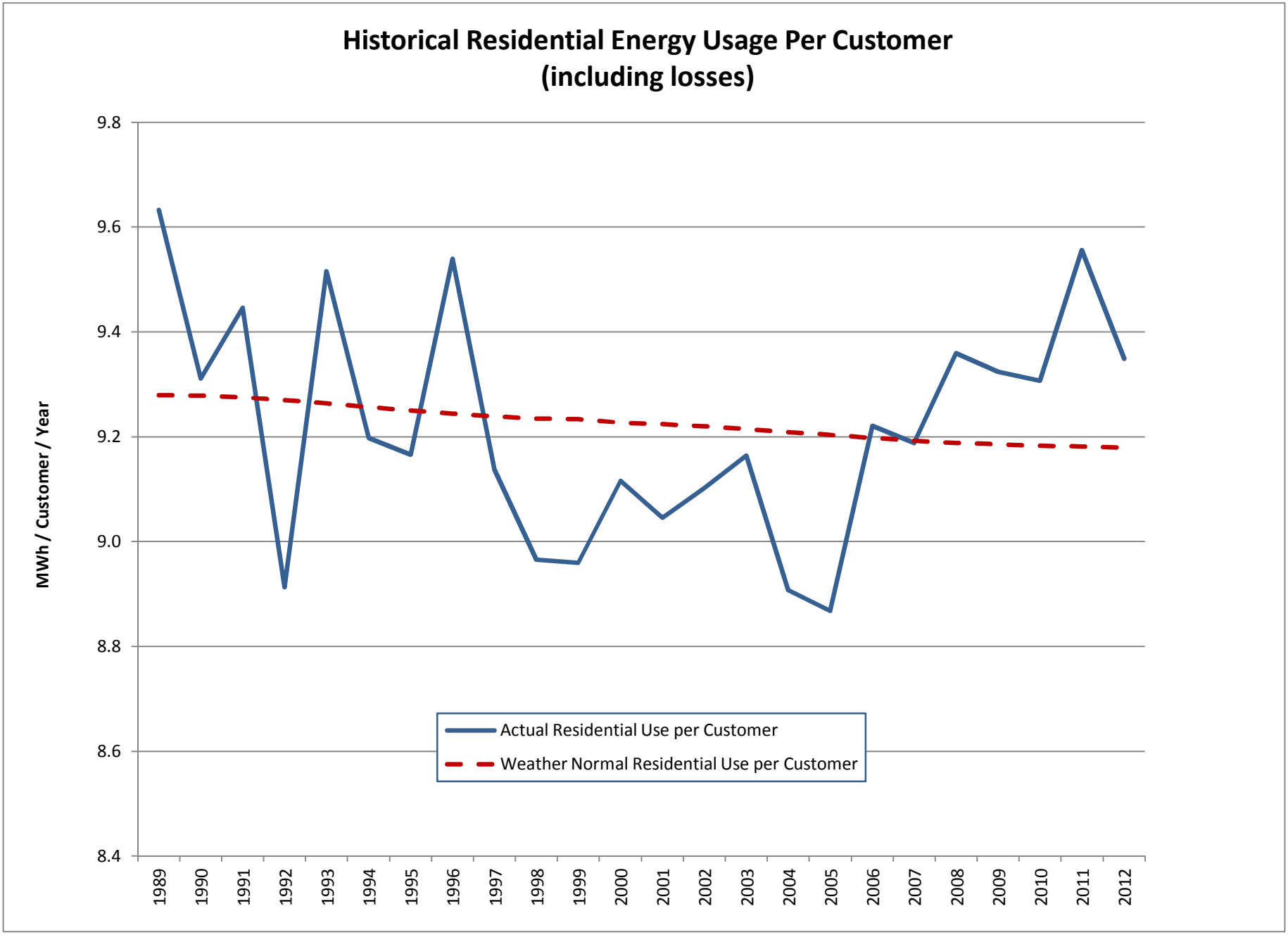
NorthWestern Energy GS-1 Secondary Customer Account History & Forecast

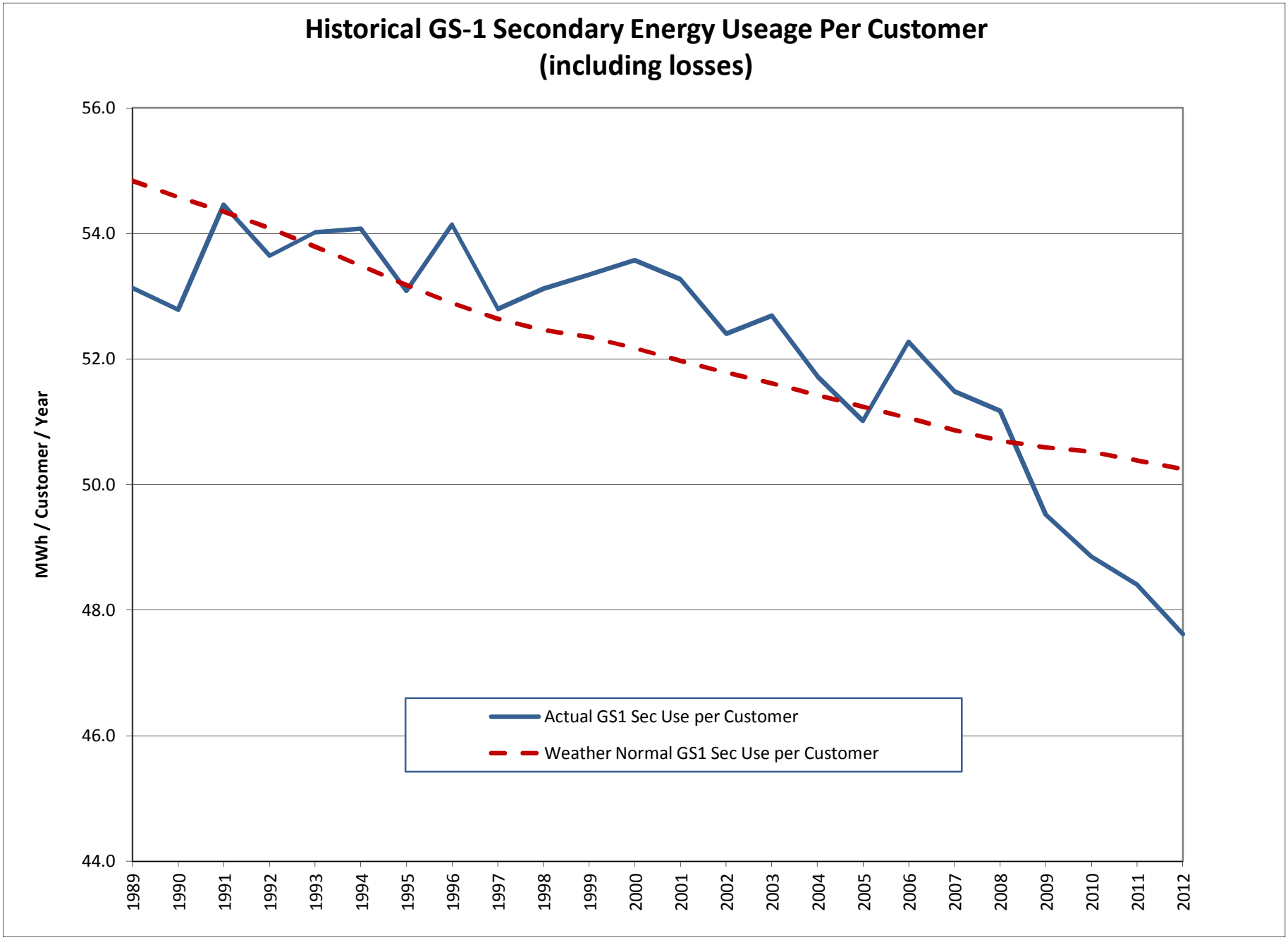



NWE Residential & GS1 Secondary Customers
vs Montana & NWE Service Territory Population
1,300,000
1,200,000
1,100,000
1,000,000
900,000
800,000
700,000
600,000
500,000
400,000
300,000
200,000
100,000
0
Historic
Forecast
MT Population
NWE Service Territory
Residential Customers
GS1 Secondary Customers
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032


Residential Annual Energy Usage: Actual versus Weather Normalized
(including losses)
MWh (including losses)
2,700,000
2,600,000
2,500,000
2,400,000
2,300,000
2,200,000
2,100,000
2,000,000
1,900,000
1,800,000
1,700,000
1,600,000
1,500,000
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
Actual Residential Usage
Weather Normal Residential Usage


GS-1 Secondary Annual Energy Usage: Actual versus Weather Normalized (including losses)
MWh (including losses)
3,300,000
3,100,000
2,900,000
2,700,000
2,500,000
2,300,000
2,100,000
1,900,000
1,700,000
1,500,000
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
GS1 Sec Actual Usage
GS1 Sec Weather Normal Usage


Historical Residential Energy Usage Per Customer
(including losses)
MWh / Customer / Year
9.8
9.6
9.4
9.2
9.0
8.8
8.6
8.4
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
Actual Residential Use per Customer
Weather Normal Residential Use per Customer


Historical GS-1 Secondary Energy Useage Per Customer
(including losses)
MWh / Customer / Year
56.0
54.0
52.0
50.0
48.0
46.0
44.0
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
Actual GS1 Sec Use per Customer
Weather Normal GS1 Sec Use per Customer

Degree Day Data for NWE Service Territory
Source: NWE Load Research
9 Weather Stations

Monthly Heating Degree Days

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
1993	1585	1356	873	643	270	240	207	151	344	629	1141	1135	8573
1994	1134	1249	814	599	296	168	45	33	158	652	1067	1257	7472
1995	1268	959	1007	723	470	229	57	81	295	694	896	1255	7934
1996	1559	1297	1169	625	549	147	31	62	331	682	1205	1441	9097
1997	1506	1057	944	822	376	160	81	67	207	637	1001	1266	8122
1998	1348	973	1017	599	341	288	9	23	164	638	886	1307	7591
1999	1171	907	873	728	471	217	84	29	362	592	747	1096	7275
2000	1256	1025	848	583	380	166	27	38	304	655	1270	1477	8028
2001	1316	1327	925	664	317	195	32	9	165	622	826	1264	7660
2002	1229	1054	1293	758	478	188	23	101	261	824	928	1138	8274
2003	1152	1172	980	600	432	176	9	22	269	511	1158	1187	7667
2004	1437	1098	752	574	467	215	36	76	312	629	914	1111	7619
2005	1401	961	876	646	441	227	34	79	268	554	939	1380	7806
2006	985	1095	978	564	345	93	4	51	256	692	973	1195	7229
2007	1279	1073	720	636	333	117	1	35	268	566	960	1224	7213
2008	1358	1014	942	751	401	198	15	46	273	591	767	1442	7798
2009	1213	964	1034	668	356	191	32	49	121	783	868	1555	7833
2010	1276	1078	782	629	501	183	50	71	235	479	1112	1386	7780
2011	1269	1273	954	757	480	223	22	16	144	543	997	1190	7867
2012	1142	1072	729	526	435	145	7	30	150	657	879	1240	7012
20 yr Avg	1294	1100	925	655	407	188	40	53	244	631	977	1277	7793

Monthly Cooling Degree Days

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
1993	0	0	0	0	10	26	17	40	6	0	0	0	98
1994	0	0	0	1	3	53	156	170	20	0	0	0	403
1995	0	0	0	0	1	17	80	89	23	1	0	0	210
1996	0	0	0	0	0	39	138	127	8	0	0	0	311
1997	0	0	0	0	3	22	76	88	21	2	0	0	211
1998	0	0	0	0	2	4	173	144	82	0	0	0	405
1999	0	0	0	0	3	16	101	136	2	0	0	0	258
2000	0	0	0	0	2	30	191	146	21	0	0	0	389
2001	0	0	0	1	19	50	169	205	38	1	0	0	482
2002	0	0	0	0	8	54	218	30	23	0	0	0	333
2003	0	0	0	0	19	47	266	224	28	3	0	0	586
2004	0	0	0	0	0	21	153	95	10	1	0	0	280
2005	0	0	0	0	1	29	180	119	21	1	0	0	351
2006	0	0	0	0	18	62	280	118	22	0	0	0	499
2007	0	0	0	0	5	64	378	146	39	0	0	0	632
2008	0	0	0	0	9	42	168	155	4	0	0	0	378
2009	0	0	0	1	15	29	136	116	75	0	0	0	371
2010	0	0	0	0	1	28	119	109	11	2	0	0	271
2011	0	0	0	0	0	20	147	157	34	5	0	0	362
2012	0	0	0	3	5	60	252	162	19	1	0	0	501
20 yr Avg	0	0	0	0	6	36	170	129	25	1	0	0	367

Degree Day Data for NWE Service Territory
Source: NWE Load Research
9 Weather Stations

Total Degree Days (HDD + CDD)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
1993	1585	1356	873	643	279	265	224	191	350	630	1141	1135	8671
1994	1134	1249	814	599	299	222	201	204	178	652	1067	1257	7875
1995	1268	959	1007	723	471	246	137	170	318	695	896	1255	8144
1996	1559	1297	1169	625	549	185	169	188	339	682	1205	1441	9408
1997	1506	1057	944	822	379	181	156	155	228	638	1001	1266	8333
1998	1348	973	1017	599	343	292	182	166	246	638	886	1307	7996
1999	1171	907	873	728	474	234	184	165	364	592	747	1096	7534
2000	1256	1025	848	583	382	195	218	184	325	655	1270	1477	8417
2001	1316	1327	925	665	336	244	201	214	203	623	826	1264	8142
2002	1229	1054	1293	758	486	242	241	131	284	824	928	1138	8606
2003	1152	1172	980	600	451	222	275	246	297	514	1158	1187	8253
2004	1437	1098	752	574	467	237	189	170	321	630	914	1111	7899
2005	1401	961	876	646	442	256	214	198	289	556	939	1380	8158
2006	985	1095	978	564	363	154	284	169	277	692	973	1195	7728
2007	1279	1073	720	637	338	181	379	181	307	566	960	1224	7844
2008	1358	1014	942	751	410	240	183	201	278	591	767	1442	8175
2009	1213	964	1034	668	371	220	168	165	196	783	868	1555	8205
2010	1276	1078	782	629	502	211	169	180	246	482	1112	1386	8051
2011	1269	1273	954	757	480	242	168	173	178	548	997	1190	8229
2012	1142	1072	729	529	441	205	259	192	168	658	879	1240	7513
20 yr Avg	1294	1100	925	655	413	224	210	182	270	632	977	1277	8159

Temperature Data for NWE Service Territory

9 Weather Stations

Average Minimum Temperature

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
1993	-23	-22	1	24	31	35	40	34	26	13	-16	4	12
1994	-8	-28	11	18	32	33	40	40	32	19	-3	-9	15
1995	-14	-11	-9	14	24	33	40	36	21	10	-1	-16	11
1996	-30	-34	-14	22	23	35	40	38	24	5	-11	-23	6
1997	-32	2	-6	4	25	33	36	39	29	15	0	-1	12
1998	-25	5	-5	22	29	31	47	41	31	18	10	-25	15
1999	-10	5	6	12	24	32	36	41	26	18	11	8	17
2000	-8	-2	13	14	28	33	40	38	19	15	-6	-20	14
2001	-4	-14	6	18	24	35	46	42	34	19	3	-5	17
2002	-11	-14	-18	4	20	35	41	35	29	-4	-1	0	10
2003	-5	-22	-10	16	26	34	43	39	27	2	-10	-9	11
2004	-28	-6	7	22	24	35	41	41	-13	21	9	-13	12
2005	-25	3	7	18	21	37	41	37	30	23	1	-19	15
2006	14	-21	9	23	27	42	48	40	32	3	-13	-1	17
2007	-13	-9	7	17	31	37	49	42	30	22	-6	-5	17
2008	-22	-1	11	8	27	34	42	42	33	17	14	-23	15
2009	-16	-1	-10	17	23	33	43	43	31	8	12	-24	13
2010	-19	-3	14	19	24	37	43	40	35	23	-17	-14	15
2011	-18	-22	2	20	29	37	44	44	33	21	-4	-3	15
2012	-13	2	10	20	26	37	46	39	34	14	-1	-8	17
20 yr Avg	-15	-10	2	17	26	35	42	40	27	14	-1	-10	14

Average Maximum Temperature

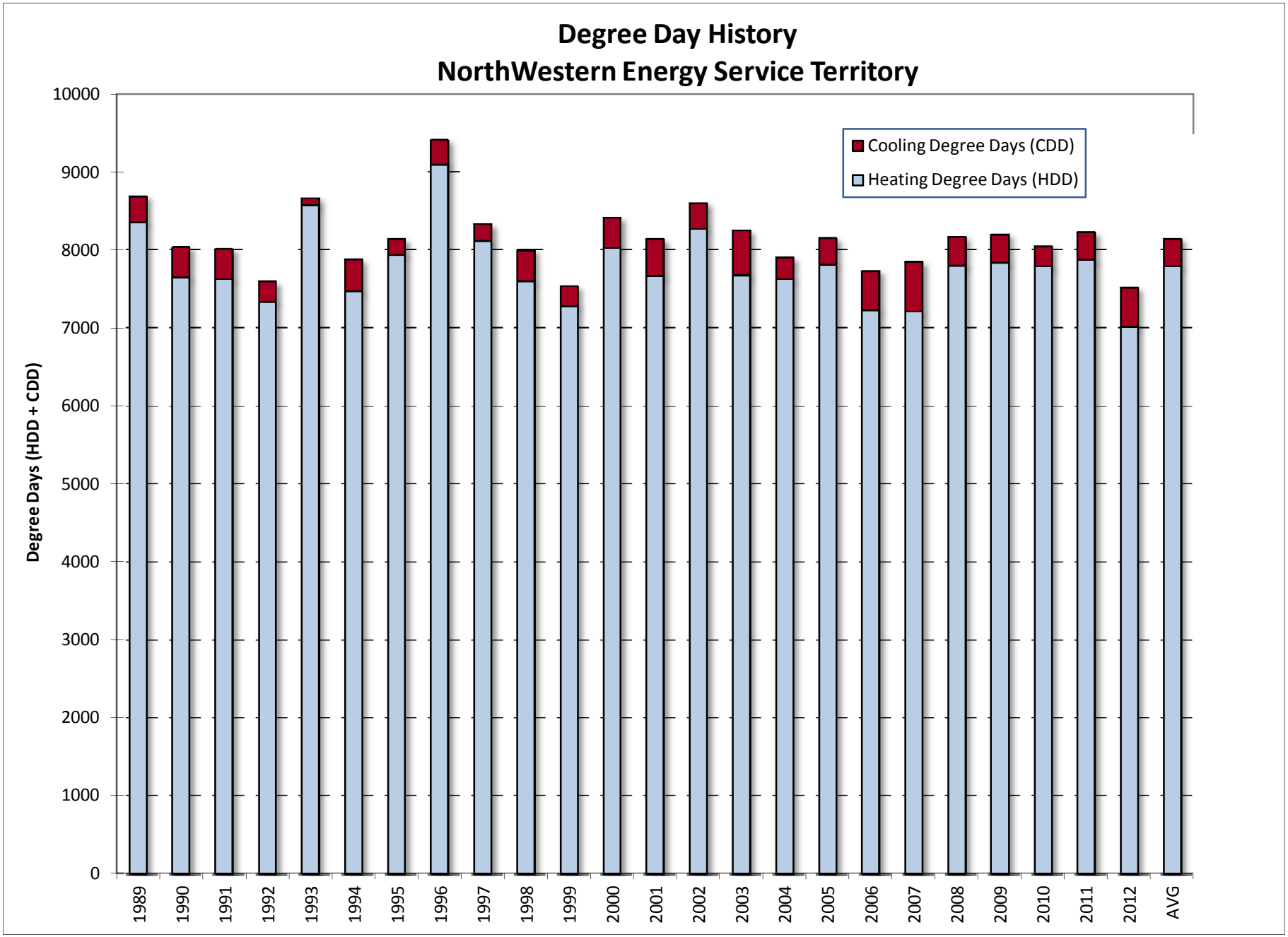
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
1993	49	48	71	66	87	89	93	90	84	81	55	55	72
1994	53	52	71	79	83	90	96	96	92	75	55	54	75
1995	53	67	64	69	81	84	92	95	91	77	63	53	74
1996	53	59	59	79	70	91	95	98	84	82	60	50	73
1997	53	52	69	72	83	87	90	94	87	83	65	52	74
1998	53	53	60	79	84	81	97	97	96	76	62	56	74
1999	52	58	72	73	86	86	99	95	85	76	75	54	76
2000	52	56	66	75	81	92	100	99	93	75	59	47	75
2001	53	44	62	81	90	91	96	101	93	83	66	49	76
2002	57	58	59	71	85	94	102	88	90	71	62	55	74
2003	58	48	67	75	89	93	102	100	92	82	62	55	77
2004	49	50	77	77	79	86	98	93	89	78	67	59	75
2005	59	60	68	75	77	91	98	97	90	77	65	52	76
2006	54	57	59	71	86	89	96	92	86	73	67	52	73
2007	53	54	68	75	80	91	100	93	90	74	61	52	74
2008	49	51	56	74	83	91	93	94	81	79	64	53	72
2009	51	51	60	74	84	86	92	90	89	70	65	42	71
2010	47	47	63	70	78	85	89	94	83	81	67	45	71
2011	47	54	56	61	70	87	94	92	86	82	57	50	70
2012	54	47	67	80	83	88	94	94	85	75	69	53	74
20 yr Avg	52	53	65	74	82	89	96	95	88	77	63	52	74

Temperature Data for NWE Service Territory

9 Weather Stations

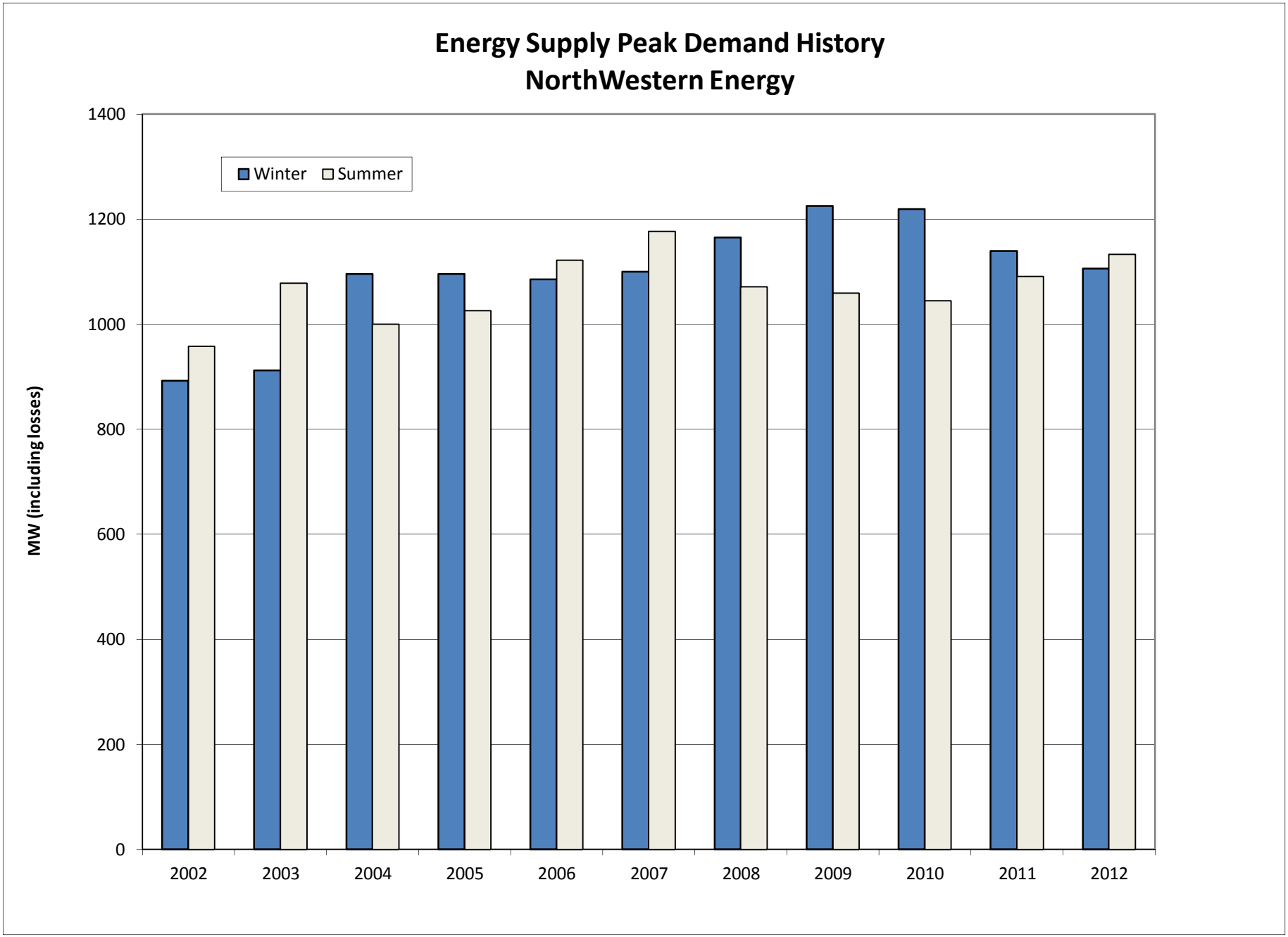
Average Temperature

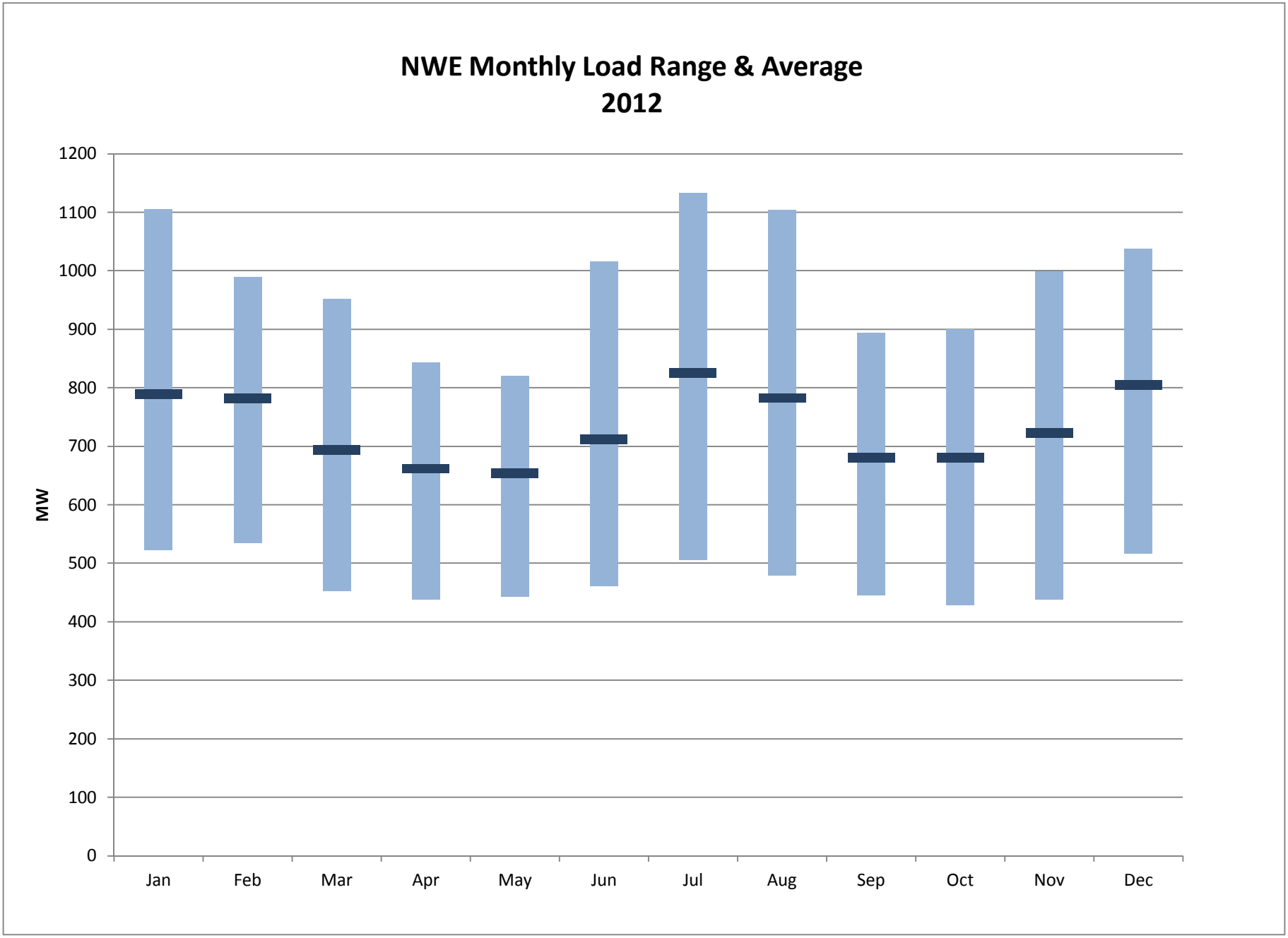
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
1993	12	16	37	43	56	58	59	61	53	45	27	29	41
1994	27	18	38	45	55	61	68	68	60	44	29	25	45
1995	24	30	32	40	50	58	65	64	56	42	34	24	43
1996	13	22	26	44	47	61	67	67	54	43	24	17	40
1997	16	28	34	37	53	60	65	65	59	45	31	25	43
1998	20	31	31	45	54	56	70	69	62	45	35	23	45
1999	26	33	37	41	50	58	65	68	53	46	40	31	46
2000	24	29	37	45	53	60	70	68	56	44	23	17	44
2001	24	17	35	43	56	60	69	71	60	45	38	24	45
2002	25	28	21	39	49	60	70	62	57	38	35	28	43
2003	27	23	32	45	51	60	72	71	56	49	26	27	45
2004	18	27	40	46	49	58	68	65	55	44	35	29	44
2005	19	31	36	43	51	58	69	65	56	48	34	21	44
2006	34	25	33	46	54	63	72	66	57	42	32	26	46
2007	23	25	40	43	54	62	75	67	56	46	33	24	46
2008	21	28	33	39	52	59	68	67	55	45	38	17	43
2009	24	28	31	42	52	59	67	66	62	39	36	15	43
2010	23	24	38	43	48	59	66	65	56	49	28	20	43
2011	22	19	32	40	49	58	68	68	60	47	32	26	43
2012	27	27	40	46	50	61	71	68	59	43	34	23	46
20 yr Avg	22	25	34	43	52	59	68	67	57	44	32	24	44

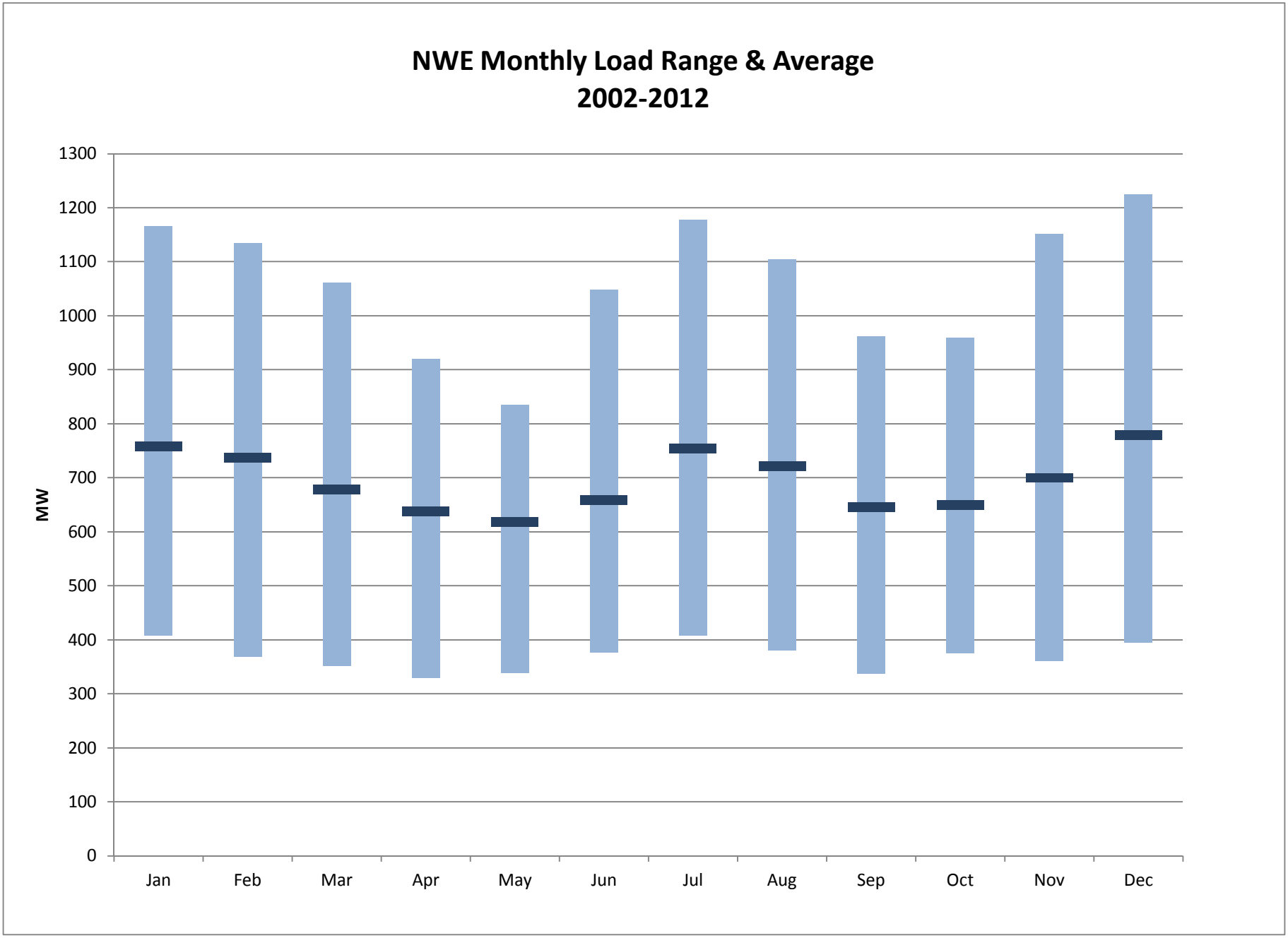

Degree Day History
NorthWestern Energy Service Territory
Cooling Degree Days (CDD)
Heating Degree Days (HDD)
Degree Days (HDD + CDD)
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
AVG

NorthWestern Energy
2013 Resource Procurement Plan
1 in 10 Peak Demand Forecast

1 in 10 Peak Demand Forecast Excluding DSM (MW)			Peak Demand DSM Savings Forecast (MW)			1 in 10 Peak Demand Forecast Including DSM (MW)		
Year	Winter	Summer	Year	Winter	Summer	Year	Winter	Summer
2013	1,200	1,108	2013	10	10	2013	1,190	1,098
2014	1,221	1,126	2014	21	20	2014	1,200	1,106
2015	1,240	1,142	2015	30	28	2015	1,210	1,114
2016	1,260	1,161	2016	40	38	2016	1,220	1,123
2017	1,280	1,179	2017	50	48	2017	1,230	1,131
2018	1,300	1,197	2018	60	58	2018	1,240	1,139
2019	1,320	1,213	2019	69	66	2019	1,250	1,147
2020	1,340	1,232	2020	79	76	2020	1,261	1,156
2021	1,361	1,250	2021	89	86	2021	1,272	1,164
2022	1,381	1,269	2022	99	95	2022	1,282	1,173
2023	1,401	1,286	2023	109	104	2023	1,293	1,182
2024	1,425	1,307	2024	118	114	2024	1,306	1,193
2025	1,439	1,319	2025	118	114	2025	1,321	1,205
2026	1,454	1,331	2026	118	114	2026	1,336	1,217
2027	1,466	1,340	2027	118	114	2027	1,348	1,226
2028	1,478	1,350	2028	118	114	2028	1,360	1,236
2029	1,490	1,360	2029	118	114	2029	1,372	1,246
2030	1,502	1,369	2030	118	114	2030	1,384	1,256
2031	1,514	1,379	2031	118	114	2031	1,396	1,265
2032	1,527	1,389	2032	118	114	2032	1,408	1,275
2033	1,539	1,399	2033	118	114	2033	1,421	1,286
Averge Growth Rate	1.25%	1.17%	Averge Growth Rate	13.28%	13.07%	Averge Growth Rate	0.89%	0.79%


Energy Supply Peak Demand History
NorthWestern Energy
Winter
Summer
MW (including losses)
1400
1200
1000
800
600
400
200
0
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012


NWE Monthly Load Range & Average
2012
MW
1200
1100
1000
900
800
700
600
500
400
300
200
100
0
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec


NWE Monthly Load Range & Average
2002-2012
MW
1300
1200
1100
1000
900
800
700
600
500
400
300
200
100
0
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec

NorthWestern Energy
2013 Resource Procurement Plan
PowerSimm Mean Monthly Market Price Forecast
Mid-C / AECO / Montana Delivered

Nominal Mid-C/Montana Basis Differential:	($3.00)
Nominal AECO into Montana Transportation:	$0.5925

Month	AECO Mean NG $/Dkt	Mid-C Mean HL $/MWh	Mid-C Mean LL $/MWh	MT Mean NG $/Dkt	MT Mean HL $/MWh	MT Mean LL $/MWh
2014-01	3.22	37.46	33.99	3.81	34.46	30.99
2014-02	3.22	38.55	33.98	3.81	35.55	30.98
2014-03	3.19	36.69	32.67	3.78	33.69	29.67
2014-04	3.14	34.43	30.41	3.73	31.43	27.41
2014-05	3.15	28.89	13.77	3.74	25.89	10.77
2014-06	3.16	28.89	13.77	3.75	25.89	10.77
2014-07	3.18	28.49	13.36	3.77	25.49	10.36
2014-08	3.19	41.80	29.30	3.79	38.80	26.30
2014-09	3.20	41.80	29.30	3.80	38.80	26.30
2014-10	3.28	41.80	29.30	3.87	38.80	26.30
2014-11	3.42	39.85	34.10	4.02	36.85	31.10
2014-12	3.55	40.00	34.25	4.14	37.00	31.25
2015-01	3.59	43.05	37.30	4.18	40.05	34.30
2015-02	3.57	42.81	36.65	4.16	39.81	33.65
2015-03	3.52	40.75	34.88	4.11	37.75	31.88
2015-04	3.24	38.24	32.73	3.83	35.24	29.73
2015-05	3.24	30.19	16.38	3.84	27.19	13.38
2015-06	3.25	30.19	16.38	3.84	27.19	13.38
2015-07	3.27	29.77	16.15	3.86	26.77	13.15
2015-08	3.28	43.35	29.95	3.87	40.35	26.95
2015-09	3.29	43.35	29.95	3.88	40.35	26.95
2015-10	3.36	43.35	29.95	3.95	40.35	26.95
2015-11	3.55	40.86	34.00	4.14	37.86	31.00
2015-12	3.68	41.01	34.13	4.27	38.01	31.13
2016-01	3.72	44.14	36.73	4.32	41.14	33.73
2016-02	3.71	45.56	38.39	4.30	42.56	35.39
2016-03	3.65	43.36	36.53	4.24	40.36	33.53
2016-04	3.33	40.69	34.28	3.92	37.69	31.28
2016-05	3.33	29.44	14.37	3.93	26.44	11.37
2016-06	3.34	29.44	14.37	3.93	26.44	11.37
2016-07	3.36	29.03	14.17	3.95	26.03	11.17
2016-08	3.37	46.45	32.60	3.97	43.45	29.60
2016-09	3.38	46.45	32.60	3.97	43.45	29.60
2016-10	3.45	46.45	32.60	4.05	43.45	29.60
2016-11	3.68	43.48	36.72	4.27	40.48	33.72
2016-12	3.81	43.65	36.86	4.40	40.65	33.86
2017-01	3.86	46.97	39.67	4.45	43.97	36.67

NorthWestern Energy
2013 Resource Procurement Plan
PowerSimm Mean Monthly Market Price Forecast
Mid-C / AECO / Montana Delivered

Nominal Mid-C/Montana Basis Differential:	($3.00)
Nominal AECO into Montana Transportation:	$0.5925

Month	AECO Mean NG $/Dkt	Mid-C Mean HL $/MWh	Mid-C Mean LL $/MWh	MT Mean NG $/Dkt	MT Mean HL $/MWh	MT Mean LL $/MWh
2017-02	3.84	46.24	37.38	4.43	43.24	34.38
2017-03	3.78	44.01	35.58	4.37	41.01	32.58
2017-04	3.52	41.30	33.39	4.11	38.30	30.39
2017-05	3.53	33.05	17.78	4.12	30.05	14.78
2017-06	3.53	33.05	17.78	4.12	30.05	14.78
2017-07	3.55	32.59	17.53	4.14	29.59	14.53
2017-08	3.57	47.80	33.80	4.16	44.80	30.80
2017-09	3.58	47.80	33.80	4.17	44.80	30.80
2017-10	3.66	47.80	33.80	4.25	44.80	30.80
2017-11	3.90	44.31	34.92	4.49	41.31	31.92
2017-12	4.06	44.48	35.05	4.65	41.48	32.05
2018-01	4.13	47.87	37.73	4.72	44.87	34.73
2018-02	4.10	48.30	39.86	4.70	45.30	36.86
2018-03	4.04	45.97	37.94	4.63	42.97	34.94
2018-04	3.91	43.13	35.60	4.50	40.13	32.60
2018-05	3.92	35.01	19.04	4.51	32.01	16.04
2018-06	3.92	35.01	19.04	4.51	32.01	16.04
2018-07	3.95	34.52	18.77	4.54	31.52	15.77
2018-08	3.96	50.40	35.95	4.55	47.40	32.95
2018-09	3.98	50.40	35.95	4.57	47.40	32.95
2018-10	4.07	50.40	35.95	4.66	47.40	32.95
2018-11	4.19	47.13	37.31	4.78	44.13	34.31
2018-12	4.37	47.31	37.45	4.96	44.31	34.45
2019-01	4.46	50.91	40.30	5.05	47.91	37.30
2019-02	4.44	51.36	42.39	5.03	48.36	39.39
2019-03	4.38	48.88	40.35	4.97	45.88	37.35
2019-04	4.26	45.87	37.86	4.86	42.87	34.86
2019-05	4.28	38.18	21.50	4.88	35.18	18.50
2019-06	4.29	38.18	21.50	4.89	35.18	18.50
2019-07	4.33	37.65	21.20	4.92	34.65	18.20
2019-08	4.35	54.30	38.20	4.94	51.30	35.20
2019-09	4.36	54.30	38.20	4.96	51.30	35.20
2019-10	4.45	54.30	38.20	5.05	51.30	35.20
2019-11	4.58	49.66	40.17	5.17	46.66	37.17
2019-12	4.76	49.84	40.33	5.35	46.84	37.33
2020-01	4.84	53.65	43.40	5.43	50.65	40.40
2020-02	4.82	54.31	45.98	5.41	51.31	42.98

NorthWestern Energy
2013 Resource Procurement Plan
PowerSimm Mean Monthly Market Price Forecast
Mid-C / AECO / Montana Delivered

Nominal Mid-C/Montana Basis Differential:	($3.00)
Nominal AECO into Montana Transportation:	$0.5925

Month	AECO Mean NG $/Dkt	Mid-C Mean HL $/MWh	Mid-C Mean LL $/MWh	MT Mean NG $/Dkt	MT Mean HL $/MWh	MT Mean LL $/MWh
2020-03	4.75	51.69	43.76	5.35	48.69	40.76
2020-04	4.63	48.50	41.06	5.22	45.50	38.06
2020-05	4.65	40.89	25.22	5.24	37.89	22.22
2020-06	4.66	40.89	25.22	5.25	37.89	22.22
2020-07	4.69	40.32	24.87	5.29	37.32	21.87
2020-08	4.44	59.05	41.45	5.03	56.05	38.45
2020-09	4.46	59.05	41.45	5.05	56.05	38.45
2020-10	4.55	59.05	41.45	5.14	56.05	38.45
2020-11	4.67	52.82	43.68	5.27	49.82	40.68
2020-12	4.86	53.02	43.84	5.45	50.02	40.84
2021-01	4.94	69.73	59.85	5.53	66.73	56.85
2021-02	4.92	68.10	59.60	5.51	65.10	56.60
2021-03	4.85	65.43	57.34	5.44	62.43	54.34
2021-04	4.73	62.18	54.58	5.32	59.18	51.58
2021-05	4.75	54.41	38.41	5.34	51.41	35.41
2021-06	4.76	54.41	38.41	5.35	51.41	35.41
2021-07	4.79	53.82	38.05	5.39	50.82	35.05
2021-08	4.53	72.94	54.98	5.13	69.94	51.98
2021-09	4.55	72.94	54.98	5.14	69.94	51.98
2021-10	4.64	72.94	54.98	5.24	69.94	51.98
2021-11	4.77	66.58	57.25	5.36	63.58	54.25
2021-12	4.96	66.79	57.42	5.55	63.79	54.42
2022-01	5.05	71.54	61.46	5.64	68.54	58.46
2022-02	5.02	69.88	61.20	5.62	66.88	58.20
2022-03	4.95	67.15	58.90	5.55	64.15	55.90
2022-04	4.83	63.84	56.08	5.42	60.84	53.08
2022-05	4.85	55.90	39.57	5.44	52.90	36.57
2022-06	4.86	55.90	39.57	5.45	52.90	36.57
2022-07	4.89	55.30	39.21	5.49	52.30	36.21
2022-08	4.63	74.82	56.49	5.22	71.82	53.49
2022-09	4.64	74.82	56.49	5.24	71.82	53.49
2022-10	4.74	74.82	56.49	5.33	71.82	53.49
2022-11	4.87	68.33	58.80	5.46	65.33	55.80
2022-12	5.07	68.54	58.98	5.66	65.54	55.98
2023-01	5.15	73.41	63.12	5.74	70.41	60.12
2023-02	5.13	71.71	62.85	5.72	68.71	59.85
2023-03	5.06	68.93	60.50	5.65	65.93	57.50

NorthWestern Energy
2013 Resource Procurement Plan
PowerSimm Mean Monthly Market Price Forecast
Mid-C / AECO / Montana Delivered

Nominal Mid-C/Montana Basis Differential:	($3.00)
Nominal AECO into Montana Transportation:	$0.5925

Month	AECO Mean NG $/Dkt	Mid-C Mean HL $/MWh	Mid-C Mean LL $/MWh	MT Mean NG $/Dkt	MT Mean HL $/MWh	MT Mean LL $/MWh
2023-04	4.93	65.55	57.63	5.52	62.55	54.63
2023-05	4.95	57.44	40.77	5.54	54.44	37.77
2023-06	4.96	57.44	40.77	5.55	54.44	37.77
2023-07	5.00	56.83	40.41	5.59	53.83	37.41
2023-08	4.73	76.75	58.04	5.32	73.75	55.04
2023-09	4.74	76.75	58.04	5.33	73.75	55.04
2023-10	4.84	76.75	58.04	5.43	73.75	55.04
2023-11	4.97	70.13	60.40	5.57	67.13	57.40
2023-12	5.17	70.34	60.59	5.76	67.34	57.59
2024-01	5.26	76.50	64.84	5.85	73.50	61.84
2024-02	5.24	74.77	64.56	5.83	71.77	61.56
2024-03	5.16	71.93	62.16	5.76	68.93	59.16
2024-04	5.03	68.48	59.23	5.62	65.48	56.23
2024-05	5.05	60.20	42.03	5.65	57.20	39.03
2024-06	5.07	60.20	42.03	5.66	57.20	39.03
2024-07	5.10	59.58	41.66	5.69	56.58	38.66
2024-08	4.83	79.91	59.65	5.42	76.91	56.65
2024-09	4.84	79.91	59.65	5.43	76.91	56.65
2024-10	4.94	79.91	59.65	5.53	76.91	56.65
2024-11	5.08	73.15	62.06	5.67	70.15	59.06
2024-12	5.28	73.37	62.26	5.87	70.37	59.26
2025-01	5.37	78.56	66.62	5.96	75.56	63.62
2025-02	5.35	76.79	66.33	5.94	73.79	63.33
2025-03	5.27	73.89	63.88	5.87	70.89	60.88
2025-04	5.14	70.37	60.89	5.73	67.37	57.89
2025-05	5.16	61.92	43.34	5.75	58.92	40.34
2025-06	5.17	61.92	43.34	5.76	58.92	40.34
2025-07	5.21	61.29	42.96	5.80	58.29	39.96
2025-08	4.93	82.04	61.32	5.52	79.04	58.32
2025-09	4.94	82.04	61.32	5.54	79.04	58.32
2025-10	5.05	82.04	61.32	5.64	79.04	58.32
2025-11	5.19	75.14	63.78	5.78	72.14	60.78
2025-12	5.39	75.36	63.99	5.98	72.36	60.99
2026-01	5.48	80.67	68.44	6.08	77.67	65.44
2026-02	5.46	78.87	68.15	6.05	75.87	65.15
2026-03	5.38	75.91	65.64	5.98	72.91	62.64
2026-04	5.25	72.31	62.59	5.84	69.31	59.59

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Nominal Mid-C/Montana Basis Differential:	($3.00)
Nominal AECO into Montana Transportation:	$0.5925

Month	AECO Mean NG $/Dkt	Mid-C Mean HL $/MWh	Mid-C Mean LL $/MWh	MT Mean NG $/Dkt	MT Mean HL $/MWh	MT Mean LL $/MWh
2026-05	5.27	63.69	44.68	5.86	60.69	41.68
2026-06	5.28	63.69	44.68	5.87	60.69	41.68
2026-07	5.32	63.05	44.29	5.91	60.05	41.29
2026-08	5.03	84.23	63.03	5.62	81.23	60.03
2026-09	5.05	84.23	63.03	5.64	81.23	60.03
2026-10	5.15	84.23	63.03	5.74	81.23	60.03
2026-11	5.29	77.18	65.54	5.89	74.18	62.54
2026-12	5.50	77.41	65.76	6.10	74.41	62.76
2027-01	5.60	82.84	70.33	6.19	79.84	67.33
2027-02	5.57	81.00	70.04	6.17	78.00	67.04
2027-03	5.50	77.98	67.48	6.09	74.98	64.48
2027-04	5.36	74.31	64.36	5.95	71.31	61.36
2027-05	5.38	65.51	46.08	5.97	62.51	43.08
2027-06	5.39	65.51	46.08	5.98	62.51	43.08
2027-07	5.43	64.85	45.68	6.02	61.85	42.68
2027-08	5.14	86.47	64.81	5.73	83.47	61.81
2027-09	5.15	86.47	64.81	5.75	83.47	61.81
2027-10	5.26	86.47	64.81	5.85	83.47	61.81
2027-11	5.41	79.28	67.37	6.00	76.28	64.37
2027-12	5.62	79.51	67.60	6.21	76.51	64.60
2028-01	5.72	85.10	72.29	6.31	82.10	69.29
2028-02	5.69	83.22	71.99	6.28	80.22	68.99
2028-03	5.61	80.14	69.38	6.20	77.14	66.38
2028-04	5.47	76.39	66.19	6.06	73.39	63.19
2028-05	5.49	67.41	47.53	6.09	64.41	44.53
2028-06	5.50	67.41	47.53	6.10	64.41	44.53
2028-07	5.54	66.73	47.12	6.14	63.73	44.12
2028-08	5.24	88.80	66.65	5.84	85.80	63.65
2028-09	5.26	88.80	66.65	5.85	85.80	63.65
2028-10	5.37	88.80	66.65	5.96	85.80	63.65
2028-11	5.52	81.46	69.26	6.11	78.46	66.26
2028-12	5.74	81.70	69.50	6.33	78.70	66.50
2029-01	5.84	87.42	74.31	6.43	84.42	71.31
2029-02	5.81	85.51	74.00	6.40	82.51	71.00
2029-03	5.73	82.36	71.34	6.32	79.36	68.34
2029-04	5.58	78.53	68.08	6.18	75.53	65.08
2029-05	5.61	69.37	49.04	6.20	66.37	46.04

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Nominal AECO into Montana Transportation:	$0.5925

Month	AECO Mean NG $/Dkt	Mid-C Mean HL $/MWh	Mid-C Mean LL $/MWh	MT Mean NG $/Dkt	MT Mean HL $/MWh	MT Mean LL $/MWh
2029-06	5.62	69.37	49.04	6.21	66.37	46.04
2029-07	5.66	68.67	48.62	6.25	65.67	45.62
2029-08	5.35	91.20	68.55	5.95	88.20	65.55
2029-09	5.37	91.20	68.55	5.96	88.20	65.55
2029-10	5.48	91.20	68.55	6.08	88.20	65.55
2029-11	5.63	83.71	71.22	6.23	80.71	68.22
2029-12	5.86	83.95	71.46	6.45	80.95	68.46
2030-01	5.96	89.82	76.39	6.55	86.82	73.39
2030-02	5.93	87.87	76.08	6.53	84.87	73.08
2030-03	5.85	84.66	73.36	6.44	81.66	70.36
2030-04	5.70	80.75	70.03	6.29	77.75	67.03
2030-05	5.73	71.40	50.60	6.32	68.40	47.60
2030-06	5.74	71.40	50.60	6.33	68.40	47.60
2030-07	5.78	70.68	50.17	6.37	67.68	47.17
2030-08	5.47	93.68	70.51	6.06	90.68	67.51
2030-09	5.48	93.68	70.51	6.08	90.68	67.51
2030-10	5.60	93.68	70.51	6.19	90.68	67.51
2030-11	5.75	86.04	73.24	6.35	83.04	70.24
2030-12	5.98	86.28	73.48	6.57	83.28	70.48
2031-01	6.08	92.31	78.56	6.68	89.31	75.56
2031-02	6.06	90.32	78.24	6.65	87.32	75.24
2031-03	5.97	87.05	75.46	6.57	84.05	72.46
2031-04	5.82	83.05	72.06	6.41	80.05	69.06
2031-05	5.85	73.51	52.23	6.44	70.51	49.23
2031-06	5.86	73.51	52.23	6.45	70.51	49.23
2031-07	5.90	72.78	51.79	6.49	69.78	48.79
2031-08	5.58	96.25	72.55	6.17	93.25	69.55
2031-09	5.60	96.25	72.55	6.19	93.25	69.55
2031-10	5.72	96.25	72.55	6.31	93.25	69.55
2031-11	5.87	88.45	75.34	6.47	85.45	72.34
2031-12	6.11	88.70	75.59	6.70	85.70	72.59
2032-01	6.21	94.87	80.79	6.80	91.87	77.79
2032-02	6.18	92.84	80.46	6.78	89.84	77.46
2032-03	6.10	89.50	77.63	6.69	86.50	74.63
2032-04	5.94	85.42	74.16	6.54	82.42	71.16
2032-05	5.97	75.68	53.91	6.56	72.68	50.91
2032-06	5.98	75.68	53.91	6.57	72.68	50.91

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Nominal AECO into Montana Transportation:	$0.5925

Month	AECO Mean NG $/Dkt	Mid-C Mean HL $/MWh	Mid-C Mean LL $/MWh	MT Mean NG $/Dkt	MT Mean HL $/MWh	MT Mean LL $/MWh
2032-07	6.02	74.94	53.47	6.62	71.94	50.47
2032-08	5.70	98.89	74.66	6.29	95.89	71.66
2032-09	5.72	98.89	74.66	6.31	95.89	71.66
2032-10	5.84	98.89	74.66	6.43	95.89	71.66
2032-11	6.00	90.93	77.50	6.59	87.93	74.50
2032-12	6.24	91.19	77.76	6.83	88.19	74.76
2033-01	6.34	97.26	82.85	6.93	94.26	79.85
2033-02	6.31	95.18	82.51	6.91	92.18	79.51
2033-03	6.23	91.77	79.62	6.82	88.77	76.62
2033-04	6.07	87.61	76.08	6.66	84.61	73.08
2033-05	6.09	77.65	55.39	6.69	74.65	52.39
2033-06	6.11	77.65	55.39	6.70	74.65	52.39
2033-07	6.15	76.90	54.94	6.74	73.90	51.94
2033-08	5.82	101.36	76.59	6.41	98.36	73.59
2033-09	5.84	101.36	76.59	6.43	98.36	73.59
2033-10	5.96	101.36	76.59	6.55	98.36	73.59
2033-11	6.12	93.23	79.49	6.72	90.23	76.49
2033-12	6.37	93.50	79.75	6.96	90.50	76.75
2034-01	6.47	99.96	85.25	7.07	96.96	82.25
2034-02	6.45	97.84	84.91	7.04	94.84	81.91
2034-03	6.36	94.36	81.95	6.95	91.36	78.95
2034-04	6.19	90.11	78.33	6.79	87.11	75.33
2034-05	6.22	79.94	57.21	6.81	76.94	54.21
2034-06	6.24	79.94	57.21	6.83	76.94	54.21
2034-07	6.28	79.17	56.75	6.87	76.17	53.75
2034-08	5.94	104.15	78.86	6.53	101.15	75.86
2034-09	5.96	104.15	78.86	6.55	101.15	75.86
2034-10	6.08	104.15	78.86	6.68	101.15	75.86
2034-11	6.25	95.85	81.82	6.84	92.85	78.82
2034-12	6.50	96.12	82.09	7.09	93.12	79.09
2035-01	6.61	102.75	87.73	7.20	99.75	84.73
2035-02	6.58	100.59	87.38	7.18	97.59	84.38
2035-03	6.49	97.03	84.37	7.08	94.03	81.37
2035-04	6.33	92.69	80.67	6.92	89.69	77.67
2035-05	6.35	82.31	59.11	6.95	79.31	56.11
2035-06	6.37	82.31	59.11	6.96	79.31	56.11
2035-07	6.41	81.53	58.64	7.00	78.53	55.64

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Month	AECO Mean NG $/Dkt	Mid-C Mean HL $/MWh	Mid-C Mean LL $/MWh	MT Mean NG $/Dkt	MT Mean HL $/MWh	MT Mean LL $/MWh
2035-08	6.07	107.03	81.20	6.66	104.03	78.20
2035-09	6.09	107.03	81.20	6.68	104.03	78.20
2035-10	6.21	107.03	81.20	6.80	104.03	78.20
2035-11	6.38	98.55	84.23	6.98	95.55	81.23
2035-12	6.64	98.83	84.50	7.23	95.83	81.50
2036-01	6.75	105.63	90.30	7.34	102.63	87.30
2036-02	6.72	103.43	89.94	7.31	100.43	86.94
2036-03	6.63	99.80	86.86	7.22	96.80	83.86
2036-04	6.46	95.36	83.09	7.05	92.36	80.09
2036-05	6.49	84.77	61.07	7.08	81.77	58.07
2036-06	6.50	84.77	61.07	7.09	81.77	58.07
2036-07	6.55	83.97	60.59	7.14	80.97	57.59
2036-08	6.19	110.00	83.64	6.79	107.00	80.64
2036-09	6.21	110.00	83.64	6.81	107.00	80.64
2036-10	6.34	110.00	83.64	6.93	107.00	80.64
2036-11	6.52	101.35	86.72	7.11	98.35	83.72
2036-12	6.78	101.64	87.00	7.37	98.64	84.00
2037-01	6.89	108.62	92.96	7.48	105.62	89.96
2037-02	6.86	106.36	92.59	7.45	103.36	89.59
2037-03	6.77	102.65	89.45	7.36	99.65	86.45
2037-04	6.59	98.13	85.60	7.19	95.13	82.60
2037-05	6.62	87.31	63.12	7.21	84.31	60.12
2037-06	6.64	87.31	63.12	7.23	84.31	60.12
2037-07	6.68	86.49	62.63	7.28	83.49	59.63
2037-08	6.32	113.08	86.15	6.92	110.08	83.15
2037-09	6.34	113.08	86.15	6.94	110.08	83.15
2037-10	6.47	113.08	86.15	7.07	110.08	83.15
2037-11	6.65	104.24	89.31	7.25	101.24	86.31
2037-12	6.92	104.53	89.59	7.51	101.53	86.59
2038-01	7.04	111.70	95.71	7.63	108.70	92.71
2038-02	7.01	109.40	95.34	7.60	106.40	92.34
2038-03	6.91	105.61	92.13	7.50	102.61	89.13
2038-04	6.73	100.99	88.20	7.32	97.99	85.20
2038-05	6.76	89.94	65.24	7.35	86.94	62.24
2038-06	6.78	89.94	65.24	7.37	86.94	62.24
2038-07	6.82	89.11	64.75	7.42	86.11	61.75
2038-08	6.46	116.25	88.76	7.05	113.25	85.76

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Month	AECO Mean NG $/Dkt	Mid-C Mean HL $/MWh	Mid-C Mean LL $/MWh	MT Mean NG $/Dkt	MT Mean HL $/MWh	MT Mean LL $/MWh
2038-09	6.48	116.25	88.76	7.07	113.25	85.76
2038-10	6.61	116.25	88.76	7.20	113.25	85.76
2038-11	6.79	107.23	91.98	7.39	104.23	88.98
2038-12	7.06	107.53	92.28	7.66	104.53	89.28
2039-01	7.18	114.88	98.57	7.78	111.88	95.57
2039-02	7.15	112.54	98.18	7.75	109.54	95.18
2039-03	7.05	108.67	94.91	7.65	105.67	91.91
2039-04	6.87	103.95	90.89	7.47	100.95	87.89
2039-05	6.90	92.67	67.46	7.50	89.67	64.46
2039-06	6.92	92.67	67.46	7.51	89.67	64.46
2039-07	6.97	91.82	66.95	7.56	88.82	63.95
2039-08	6.59	119.53	91.47	7.18	116.53	88.47
2039-09	6.61	119.53	91.47	7.21	116.53	88.47
2039-10	6.75	119.53	91.47	7.34	116.53	88.47
2039-11	6.94	110.32	94.76	7.53	107.32	91.76
2039-12	7.21	110.63	95.05	7.80	107.63	92.05
2040-01	7.33	118.18	101.52	7.93	115.18	98.52
2040-02	7.30	115.78	101.13	7.90	112.78	98.13
2040-03	7.20	111.83	97.78	7.79	108.83	94.78
2040-04	7.02	107.02	93.68	7.61	104.02	90.68
2040-05	7.05	95.50	69.76	7.64	92.50	66.76
2040-06	7.06	95.50	69.76	7.66	92.50	66.76
2040-07	7.11	94.63	69.23	7.71	91.63	66.23
2040-08	6.73	122.93	94.27	7.32	119.93	91.27
2040-09	6.75	122.93	94.27	7.34	119.93	91.27
2040-10	6.89	122.93	94.27	7.48	119.93	91.27
2040-11	7.08	113.52	97.63	7.67	110.52	94.63
2040-12	7.36	113.83	97.93	7.96	110.83	94.93
2041-01	7.49	121.59	104.58	8.08	118.59	101.58
2041-02	7.46	119.14	104.18	8.05	116.14	101.18
2041-03	7.35	115.11	100.76	7.95	112.11	97.76
2041-04	7.17	110.19	96.58	7.76	107.19	93.58
2041-05	7.20	98.44	72.15	7.79	95.44	69.15
2041-06	7.21	98.44	72.15	7.80	95.44	69.15
2041-07	7.26	97.55	71.62	7.86	94.55	68.62
2041-08	6.87	126.44	97.18	7.46	123.44	94.18
2041-09	6.89	126.44	97.18	7.49	123.44	94.18

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2041-10	7.04	126.44	97.18	7.63	123.44	94.18
2041-11	7.23	116.84	100.61	7.82	113.84	97.61
2041-12	7.52	117.15	100.92	8.11	114.15	97.92
2042-01	7.65	125.11	107.75	8.24	122.11	104.75
2042-02	7.61	122.62	107.34	8.21	119.62	104.34
2042-03	7.51	118.50	103.85	8.10	115.50	100.85
2042-04	7.32	113.48	99.58	7.91	110.48	96.58
2042-05	7.35	101.48	74.64	7.94	98.48	71.64
2042-06	7.36	101.48	74.64	7.96	98.48	71.64
2042-07	7.42	100.57	74.09	8.01	97.57	71.09
2042-08	7.02	130.06	100.19	7.61	127.06	97.19
2042-09	7.04	130.06	100.19	7.63	127.06	97.19
2042-10	7.18	130.06	100.19	7.78	127.06	97.19
2042-11	7.38	120.26	103.69	7.98	117.26	100.69
2042-12	7.68	120.59	104.01	8.27	117.59	101.01
2043-01	7.81	128.76	111.03	8.40	125.76	108.03
2043-02	7.77	126.21	110.61	8.37	123.21	107.61
2043-03	7.67	122.01	107.05	8.26	119.01	104.05
2043-04	7.47	116.88	102.69	8.06	113.88	99.69
2043-05	7.50	104.63	77.22	8.09	101.63	74.22
2043-06	7.52	104.63	77.22	8.11	101.63	74.22
2043-07	7.57	103.70	76.67	8.16	100.70	73.67
2043-08	7.16	133.82	103.32	7.76	130.82	100.32
2043-09	7.19	133.82	103.32	7.78	130.82	100.32
2043-10	7.33	133.82	103.32	7.93	130.82	100.32
2043-11	7.54	123.81	106.89	8.13	120.81	103.89
2043-12	7.84	124.14	107.22	8.43	121.14	104.22

NorthWestern Energy
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Nominal Mid-C/Montana Basis Differential:	($3.00)
Nominal AECO into Montana Transportation:	$0.5925

Month	AECO P95 NG $/Dkt	Mid-C P95 HL $/MWh	Mid-C P95 LL $/MWh	MT P95 NG $/Dkt	MT P95 HL $/MWh	MT P95 LL $/MWh
2014-01	3.94	45.48	37.56	4.54	42.48	34.56
2014-02	4.18	50.08	39.85	4.77	47.08	36.85
2014-03	4.02	47.24	38.15	4.61	44.24	35.15
2014-04	3.87	41.87	34.49	4.46	38.87	31.49
2014-05	4.02	35.93	16.06	4.61	32.93	13.06
2014-06	4.05	36.63	16.76	4.65	33.63	13.76
2014-07	4.04	35.76	16.06	4.63	32.76	13.06
2014-08	4.29	54.77	37.23	4.89	51.77	34.23
2014-09	4.35	57.67	38.17	4.94	54.67	35.17
2014-10	4.39	53.85	35.70	4.98	50.85	32.70
2014-11	4.69	50.11	40.05	5.28	47.11	37.05
2014-12	4.82	50.06	40.60	5.42	47.06	37.60
2015-01	4.79	57.17	44.62	5.38	54.17	41.62
2015-02	4.90	57.36	45.68	5.49	54.36	42.68
2015-03	4.74	53.87	42.45	5.33	50.87	39.45
2015-04	4.44	51.90	41.07	5.03	48.90	38.07
2015-05	4.26	40.15	20.30	4.86	37.15	17.30
2015-06	4.14	40.28	20.64	4.74	37.28	17.64
2015-07	4.34	39.83	20.33	4.94	36.83	17.33
2015-08	4.33	59.67	39.77	4.92	56.67	36.77
2015-09	4.41	58.04	38.72	5.00	55.04	35.72
2015-10	4.52	60.30	38.95	5.11	57.30	35.95
2015-11	4.78	55.29	43.24	5.37	52.29	40.24
2015-12	4.73	55.23	43.10	5.33	52.23	40.10
2016-01	5.30	58.15	44.19	5.90	55.15	41.19
2016-02	5.15	62.86	46.74	5.75	59.86	43.74
2016-03	4.82	56.32	44.49	5.41	53.32	41.49
2016-04	4.39	53.82	41.93	4.99	50.82	38.93
2016-05	4.63	39.21	18.14	5.22	36.21	15.14
2016-06	4.63	38.74	18.37	5.23	35.74	15.37
2016-07	4.44	37.66	17.62	5.03	34.66	14.62
2016-08	4.37	62.58	42.38	4.97	59.58	39.38
2016-09	4.57	65.79	43.90	5.17	62.79	40.90
2016-10	4.59	63.22	41.25	5.18	60.22	38.25
2016-11	4.97	59.93	47.28	5.56	56.93	44.28
2016-12	4.89	58.17	46.18	5.48	55.17	43.18
2017-01	5.05	63.32	49.53	5.65	60.32	46.53

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Nominal AECO into Montana Transportation:	$0.5925

Month	AECO P95 NG $/Dkt	Mid-C P95 HL $/MWh	Mid-C P95 LL $/MWh	MT P95 NG $/Dkt	MT P95 HL $/MWh	MT P95 LL $/MWh
2017-02	5.07	64.14	47.39	5.66	61.14	44.39
2017-03	5.01	60.75	44.87	5.61	57.75	41.87
2017-04	4.75	58.15	42.72	5.34	55.15	39.72
2017-05	4.64	44.65	22.16	5.24	41.65	19.16
2017-06	4.64	43.99	22.21	5.23	40.99	19.21
2017-07	4.75	44.85	22.33	5.35	41.85	19.33
2017-08	4.87	65.13	42.04	5.46	62.13	39.04
2017-09	4.97	65.75	42.77	5.57	62.75	39.77
2017-10	4.97	64.60	42.68	5.57	61.60	39.68
2017-11	5.21	59.37	42.94	5.80	56.37	39.94
2017-12	5.41	58.61	43.06	6.00	55.61	40.06
2018-01	5.40	68.38	48.70	5.99	65.38	45.70
2018-02	5.64	66.68	50.58	6.23	63.68	47.58
2018-03	5.46	65.50	49.78	6.05	62.50	46.78
2018-04	5.22	59.79	45.23	5.81	56.79	42.23
2018-05	5.31	49.08	24.41	5.90	46.08	21.41
2018-06	5.23	48.32	24.27	5.83	45.32	21.27
2018-07	5.36	48.72	23.96	5.95	45.72	20.96
2018-08	5.36	72.11	46.71	5.96	69.11	43.71
2018-09	5.29	72.50	46.80	5.88	69.50	43.80
2018-10	5.39	69.89	46.16	5.98	66.89	43.16
2018-11	5.58	65.60	47.50	6.17	62.60	44.50
2018-12	5.66	69.18	49.27	6.25	66.18	46.27
2019-01	6.30	72.36	52.45	6.89	69.36	49.45
2019-02	6.21	75.29	56.45	6.80	72.29	53.45
2019-03	5.99	72.47	53.90	6.58	69.47	50.90
2019-04	5.66	66.41	49.47	6.25	63.41	46.47
2019-05	5.71	54.11	28.03	6.30	51.11	25.03
2019-06	5.80	53.42	27.43	6.39	50.42	24.43
2019-07	5.79	51.58	26.56	6.38	48.58	23.56
2019-08	5.75	73.73	48.04	6.35	70.73	45.04
2019-09	5.92	77.13	49.71	6.51	74.13	46.71
2019-10	5.89	75.59	48.64	6.48	72.59	45.64
2019-11	6.11	66.77	49.91	6.70	63.77	46.91
2019-12	6.14	65.38	49.15	6.73	62.38	46.15
2020-01	6.56	78.27	58.18	7.15	75.27	55.18
2020-02	6.42	76.28	59.17	7.01	73.28	56.17

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Nominal AECO into Montana Transportation:	$0.5925

Month	AECO P95 NG $/Dkt	Mid-C P95 HL $/MWh	Mid-C P95 LL $/MWh	MT P95 NG $/Dkt	MT P95 HL $/MWh	MT P95 LL $/MWh
2020-03	6.17	76.29	57.23	6.76	73.29	54.23
2020-04	6.03	70.53	53.78	6.62	67.53	50.78
2020-05	6.11	57.07	31.62	6.70	54.07	28.62
2020-06	6.21	57.05	32.46	6.80	54.05	29.46
2020-07	6.26	57.67	32.07	6.85	54.67	29.07
2020-08	5.86	81.68	52.43	6.45	78.68	49.43
2020-09	6.04	84.58	54.04	6.63	81.58	51.04
2020-10	6.26	83.43	53.90	6.85	80.43	50.90
2020-11	6.39	74.18	56.21	6.98	71.18	53.21
2020-12	6.50	75.50	56.48	7.09	72.50	53.48
2021-01	6.70	97.07	77.27	7.30	94.07	74.27
2021-02	6.79	94.48	77.04	7.39	91.48	74.04
2021-03	6.77	91.09	72.37	7.36	88.09	69.37
2021-04	6.42	85.07	69.04	7.01	82.07	66.04
2021-05	6.34	74.97	50.26	6.94	71.97	47.26
2021-06	6.27	72.83	48.95	6.86	69.83	45.95
2021-07	6.37	71.66	48.20	6.96	68.66	45.20
2021-08	5.99	98.64	68.15	6.58	95.64	65.15
2021-09	6.27	98.90	68.25	6.87	95.90	65.25
2021-10	6.43	104.54	72.63	7.03	101.54	69.63
2021-11	6.45	89.86	72.08	7.05	86.86	69.08
2021-12	6.74	92.92	73.18	7.33	89.92	70.18
2022-01	6.66	100.64	79.70	7.25	97.64	76.70
2022-02	6.60	99.40	79.64	7.19	96.40	76.64
2022-03	6.57	92.19	75.93	7.16	89.19	72.93
2022-04	6.46	84.64	71.88	7.06	81.64	68.88
2022-05	6.37	75.83	50.56	6.96	72.83	47.56
2022-06	6.35	74.65	49.82	6.95	71.65	46.82
2022-07	6.26	72.30	49.73	6.86	69.30	46.73
2022-08	6.01	99.51	71.25	6.60	96.51	68.25
2022-09	6.13	97.84	70.73	6.72	94.84	67.73
2022-10	6.03	102.32	72.66	6.63	99.32	69.66
2022-11	6.18	95.42	75.75	6.78	92.42	72.75
2022-12	6.36	90.71	74.46	6.96	87.71	71.46
2023-01	6.29	94.29	78.87	6.88	91.29	75.87
2023-02	6.41	93.16	79.38	7.00	90.16	76.38
2023-03	6.26	90.30	76.43	6.85	87.30	73.43

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Month	AECO P95 NG $/Dkt	Mid-C P95 HL $/MWh	Mid-C P95 LL $/MWh	MT P95 NG $/Dkt	MT P95 HL $/MWh	MT P95 LL $/MWh
2023-04	6.20	84.36	71.89	6.80	81.36	68.89
2023-05	6.39	75.06	52.24	6.98	72.06	49.24
2023-06	6.49	75.38	52.46	7.08	72.38	49.46
2023-07	6.46	73.53	51.64	7.05	70.53	48.64
2023-08	6.10	100.09	72.12	6.69	97.09	69.12
2023-09	6.27	100.32	71.88	6.86	97.32	68.88
2023-10	6.47	99.29	72.76	7.06	96.29	69.76
2023-11	6.66	89.88	74.19	7.26	86.88	71.19
2023-12	6.91	92.69	75.52	7.50	89.69	72.52
2024-01	6.65	99.53	79.05	7.24	96.53	76.05
2024-02	6.72	98.80	80.78	7.31	95.80	77.78
2024-03	6.88	95.34	79.08	7.47	92.34	76.08
2024-04	6.54	89.28	74.42	7.13	86.28	71.42
2024-05	6.60	78.07	54.46	7.19	75.07	51.46
2024-06	6.47	77.14	54.05	7.06	74.14	51.05
2024-07	6.62	76.61	53.92	7.21	73.61	50.92
2024-08	6.36	103.01	75.39	6.95	100.01	72.39
2024-09	6.18	102.29	75.59	6.77	99.29	72.59
2024-10	6.35	106.68	76.64	6.94	103.68	73.64
2024-11	6.48	93.19	78.98	7.07	90.19	75.98
2024-12	6.71	91.93	77.47	7.31	88.93	74.47
2025-01	7.00	102.31	83.24	7.60	99.31	80.24
2025-02	7.17	100.67	82.98	7.77	97.67	79.98
2025-03	7.17	96.97	78.36	7.76	93.97	75.36
2025-04	6.82	91.36	74.73	7.42	88.36	71.73
2025-05	6.83	81.75	56.79	7.42	78.75	53.79
2025-06	6.52	80.46	56.06	7.11	77.46	53.06
2025-07	6.80	80.03	56.44	7.39	77.03	53.44
2025-08	6.26	106.14	77.35	6.85	103.14	74.35
2025-09	6.35	105.44	77.11	6.94	102.44	74.11
2025-10	6.57	105.23	77.74	7.16	102.23	74.74
2025-11	6.69	96.90	80.04	7.28	93.90	77.04
2025-12	6.84	97.14	79.83	7.43	94.14	76.83
2026-01	7.26	108.66	85.60	7.86	105.66	82.60
2026-02	7.23	105.12	85.93	7.83	102.12	82.93
2026-03	7.38	101.37	84.70	7.98	98.37	81.70
2026-04	7.39	96.37	81.67	7.98	93.37	78.67

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Month	AECO P95 NG $/Dkt	Mid-C P95 HL $/MWh	Mid-C P95 LL $/MWh	MT P95 NG $/Dkt	MT P95 HL $/MWh	MT P95 LL $/MWh
2026-05	7.16	89.79	59.56	7.75	86.79	56.56
2026-06	6.95	86.92	57.98	7.54	83.92	54.98
2026-07	7.03	83.11	58.75	7.62	80.11	55.75
2026-08	6.63	110.84	79.40	7.23	107.84	76.40
2026-09	6.53	114.71	80.16	7.12	111.71	77.16
2026-10	6.50	112.14	79.33	7.09	109.14	76.33
2026-11	6.98	106.43	85.76	7.58	103.43	82.76
2026-12	7.11	105.75	84.90	7.70	102.75	81.90
2027-01	6.86	110.58	87.52	7.45	107.58	84.52
2027-02	6.95	104.23	86.77	7.54	101.23	83.77
2027-03	6.82	99.04	82.37	7.41	96.04	79.37
2027-04	6.81	95.17	79.02	7.40	92.17	76.02
2027-05	6.94	84.56	58.34	7.54	81.56	55.34
2027-06	6.89	85.16	58.84	7.48	82.16	55.84
2027-07	7.10	85.98	58.21	7.69	82.98	55.21
2027-08	6.61	112.34	81.53	7.20	109.34	78.53
2027-09	6.67	113.29	80.79	7.27	110.29	77.79
2027-10	6.62	114.03	81.49	7.22	111.03	78.49
2027-11	6.71	104.56	84.72	7.31	101.56	81.72
2027-12	7.01	107.00	85.19	7.61	104.00	82.19
2028-01	7.36	114.55	91.37	7.95	111.55	88.37
2028-02	7.37	113.05	89.97	7.96	110.05	86.97
2028-03	7.13	110.91	88.92	7.73	107.91	85.92
2028-04	6.83	100.09	82.97	7.43	97.09	79.97
2028-05	6.81	87.29	60.94	7.40	84.29	57.94
2028-06	6.91	88.99	62.18	7.50	85.99	59.18
2028-07	6.90	88.47	62.36	7.50	85.47	59.36
2028-08	6.71	118.08	83.53	7.31	115.08	80.53
2028-09	6.69	119.25	85.39	7.28	116.25	82.39
2028-10	6.93	119.40	85.78	7.52	116.40	82.78
2028-11	6.96	109.68	88.85	7.55	106.68	85.85
2028-12	7.26	109.67	89.83	7.85	106.67	86.83
2029-01	7.34	112.57	92.27	7.93	109.57	89.27
2029-02	7.15	111.62	91.74	7.75	108.62	88.74
2029-03	7.12	105.25	87.52	7.71	102.25	84.52
2029-04	6.96	101.74	84.22	7.56	98.74	81.22
2029-05	6.90	88.41	63.05	7.49	85.41	60.05

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Month	AECO P95 NG $/Dkt	Mid-C P95 HL $/MWh	Mid-C P95 LL $/MWh	MT P95 NG $/Dkt	MT P95 HL $/MWh	MT P95 LL $/MWh
2029-06	6.84	90.35	63.46	7.44	87.35	60.46
2029-07	6.87	90.13	62.50	7.46	87.13	59.50
2029-08	6.45	119.36	85.85	7.04	116.36	82.85
2029-09	6.49	118.89	87.03	7.08	115.89	84.03
2029-10	6.76	115.99	85.63	7.35	112.99	82.63
2029-11	7.03	109.36	90.22	7.62	106.36	87.22
2029-12	7.56	110.23	90.00	8.15	107.23	87.00
2030-01	7.73	117.68	94.18	8.32	114.68	91.18
2030-02	7.79	112.81	92.68	8.38	109.81	89.68
2030-03	7.65	107.97	88.90	8.24	104.97	85.90
2030-04	7.37	102.65	86.08	7.97	99.65	83.08
2030-05	7.33	94.33	65.70	7.92	91.33	62.70
2030-06	7.49	95.71	66.28	8.08	92.71	63.28
2030-07	7.61	95.75	64.51	8.20	92.75	61.51
2030-08	7.02	123.76	88.63	7.61	120.76	85.63
2030-09	7.26	123.73	90.80	7.85	120.73	87.80
2030-10	7.17	124.09	88.46	7.77	121.09	85.46
2030-11	7.37	111.64	91.66	7.96	108.64	88.66
2030-12	7.72	111.94	92.16	8.32	108.94	89.16
2031-01	7.82	118.56	96.67	8.41	115.56	93.67
2031-02	7.37	117.28	96.95	7.96	114.28	93.95
2031-03	7.41	112.27	93.48	8.00	109.27	90.48
2031-04	7.43	109.91	91.30	8.02	106.91	88.30
2031-05	7.56	98.41	68.72	8.15	95.41	65.72
2031-06	7.29	96.09	67.88	7.89	93.09	64.88
2031-07	7.28	93.98	67.86	7.87	90.98	64.86
2031-08	6.99	128.33	91.03	7.58	125.33	88.03
2031-09	7.01	127.74	91.43	7.61	124.74	88.43
2031-10	7.19	125.95	91.97	7.78	122.95	88.97
2031-11	7.55	117.43	94.71	8.14	114.43	91.71
2031-12	7.64	117.31	94.27	8.24	114.31	91.27
2032-01	8.01	127.29	102.81	8.60	124.29	99.81
2032-02	7.71	123.21	101.99	8.30	120.21	98.99
2032-03	7.54	117.72	98.35	8.13	114.72	95.35
2032-04	7.52	115.14	95.45	8.11	112.14	92.45
2032-05	7.59	99.73	71.20	8.18	96.73	68.20
2032-06	7.55	101.30	71.34	8.15	98.30	68.34

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Month	AECO P95 NG $/Dkt	Mid-C P95 HL $/MWh	Mid-C P95 LL $/MWh	MT P95 NG $/Dkt	MT P95 HL $/MWh	MT P95 LL $/MWh
2032-07	7.61	97.46	71.14	8.20	94.46	68.14
2032-08	7.21	133.46	92.59	7.80	130.46	89.59
2032-09	7.13	131.07	92.64	7.72	128.07	89.64
2032-10	7.29	129.16	92.67	7.88	126.16	89.67
2032-11	7.49	117.04	95.82	8.08	114.04	92.82
2032-12	7.74	120.75	95.92	8.33	117.75	92.92
2033-01	8.26	129.61	107.59	8.85	126.61	104.59
2033-02	8.29	126.38	106.68	8.89	123.38	103.68
2033-03	8.31	121.98	101.51	8.90	118.98	98.51
2033-04	8.14	118.23	99.16	8.73	115.23	96.16
2033-05	8.19	106.07	74.86	8.78	103.07	71.86
2033-06	8.13	105.08	76.55	8.72	102.08	73.55
2033-07	8.05	102.68	74.62	8.64	99.68	71.62
2033-08	7.80	136.25	97.95	8.39	133.25	94.95
2033-09	7.90	137.86	99.80	8.49	134.86	96.80
2033-10	8.24	135.97	98.98	8.84	132.97	95.98
2033-11	8.63	123.95	101.46	9.22	120.95	98.46
2033-12	8.68	126.41	100.70	9.27	123.41	97.70
2034-01	8.26	130.28	106.76	8.86	127.28	103.76
2034-02	8.25	129.53	107.89	8.85	126.53	104.89
2034-03	8.29	128.45	104.99	8.89	125.45	101.99
2034-04	8.02	125.52	98.04	8.62	122.52	95.04
2034-05	8.01	111.27	74.60	8.60	108.27	71.60
2034-06	8.07	107.28	73.71	8.66	104.28	70.71
2034-07	8.21	107.53	73.07	8.80	104.53	70.07
2034-08	7.70	141.90	99.66	8.30	138.90	96.66
2034-09	7.63	140.12	98.54	8.22	137.12	95.54
2034-10	7.57	142.95	98.48	8.16	139.95	95.48
2034-11	8.06	129.17	104.00	8.65	126.17	101.00
2034-12	8.20	124.54	100.77	8.79	121.54	97.77
2035-01	8.37	131.95	111.77	8.96	128.95	108.77
2035-02	8.39	131.03	109.73	8.98	128.03	106.73
2035-03	8.34	126.94	106.05	8.93	123.94	103.05
2035-04	8.19	122.91	101.96	8.78	119.91	98.96
2035-05	8.18	108.73	78.78	8.78	105.73	75.78
2035-06	8.05	108.59	78.90	8.64	105.59	75.90
2035-07	8.08	108.70	77.56	8.67	105.70	74.56

NorthWestern Energy
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PowerSimm P95 Monthly Market Price Forecast
Mid-C / AECO / Montana Delivered

Nominal Mid-C/Montana Basis Differential:	($3.00)
Nominal AECO into Montana Transportation:	$0.5925

Month	AECO P95 NG $/Dkt	Mid-C P95 HL $/MWh	Mid-C P95 LL $/MWh	MT P95 NG $/Dkt	MT P95 HL $/MWh	MT P95 LL $/MWh
2035-08	7.64	139.09	101.93	8.23	136.09	98.93
2035-09	7.69	138.52	101.01	8.28	135.52	98.01
2035-10	7.73	141.70	102.57	8.32	138.70	99.57
2035-11	8.19	129.61	105.53	8.78	126.61	102.53
2035-12	8.51	127.21	106.64	9.10	124.21	103.64
2036-01	8.41	139.06	113.71	9.00	136.06	110.71
2036-02	8.43	134.34	113.64	9.03	131.34	110.64
2036-03	8.45	134.51	110.60	9.04	131.51	107.60
2036-04	8.14	126.23	107.34	8.73	123.23	104.34
2036-05	8.24	111.55	81.32	8.83	108.55	78.32
2036-06	8.43	110.74	81.79	9.02	107.74	78.79
2036-07	8.42	114.03	79.84	9.01	111.03	76.84
2036-08	8.02	147.51	105.70	8.62	144.51	102.70
2036-09	8.14	148.70	106.58	8.74	145.70	103.58
2036-10	8.09	145.65	106.15	8.68	142.65	103.15
2036-11	8.28	137.21	111.39	8.87	134.21	108.39
2036-12	8.76	134.09	110.14	9.35	131.09	107.14
2037-01	9.00	147.15	115.48	9.59	144.15	112.48
2037-02	8.97	142.92	117.19	9.57	139.92	114.19
2037-03	8.94	136.19	113.98	9.53	133.19	110.98
2037-04	8.47	130.05	109.26	9.06	127.05	106.26
2037-05	8.42	113.89	84.91	9.01	110.89	81.91
2037-06	8.53	114.67	84.53	9.12	111.67	81.53
2037-07	8.84	114.32	84.50	9.43	111.32	81.50
2037-08	8.38	154.65	110.75	8.97	151.65	107.75
2037-09	8.19	152.11	112.79	8.78	149.11	109.79
2037-10	8.37	150.32	112.51	8.96	147.32	109.51
2037-11	8.68	138.62	113.46	9.27	135.62	110.46
2037-12	9.07	137.90	112.73	9.67	134.90	109.73
2038-01	9.23	150.67	120.30	9.83	147.67	117.30
2038-02	9.18	143.13	119.26	9.78	140.13	116.26
2038-03	8.87	139.72	114.99	9.46	136.72	111.99
2038-04	8.71	134.34	111.71	9.30	131.34	108.71
2038-05	8.55	118.44	83.87	9.15	115.44	80.87
2038-06	8.81	121.54	84.56	9.41	118.54	81.56
2038-07	8.83	116.10	84.34	9.42	113.10	81.34
2038-08	8.30	149.61	111.36	8.89	146.61	108.36

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Nominal AECO into Montana Transportation:	$0.5925

Month	AECO P95 NG $/Dkt	Mid-C P95 HL $/MWh	Mid-C P95 LL $/MWh	MT P95 NG $/Dkt	MT P95 HL $/MWh	MT P95 LL $/MWh
2038-09	8.55	150.02	110.92	9.15	147.02	107.92
2038-10	8.62	152.30	110.09	9.22	149.30	107.09
2038-11	8.54	141.84	111.00	9.13	138.84	108.00
2038-12	8.95	144.45	116.20	9.55	141.45	113.20
2039-01	9.28	154.79	125.03	9.88	151.79	122.03
2039-02	8.99	148.72	126.20	9.58	145.72	123.20
2039-03	8.84	143.63	122.04	9.43	140.63	119.04
2039-04	8.66	140.68	117.17	9.26	137.68	114.17
2039-05	8.73	127.42	88.92	9.32	124.42	85.92
2039-06	8.61	124.46	88.68	9.20	121.46	85.68
2039-07	8.56	120.85	87.92	9.15	117.85	84.92
2039-08	7.84	157.40	115.77	8.43	154.40	112.77
2039-09	8.09	157.04	115.95	8.68	154.04	112.95
2039-10	8.29	154.82	115.71	8.88	151.82	112.71
2039-11	8.52	143.19	119.08	9.11	140.19	116.08
2039-12	9.11	144.48	119.12	9.71	141.48	116.12
2040-01	9.40	158.17	134.08	9.99	155.17	131.08
2040-02	9.42	162.90	136.05	10.01	159.90	133.05
2040-03	9.22	154.22	128.70	9.82	151.22	125.70
2040-04	8.96	145.91	124.67	9.55	142.91	121.67
2040-05	9.28	129.40	95.42	9.87	126.40	92.42
2040-06	9.09	128.52	95.60	9.68	125.52	92.60
2040-07	9.13	128.30	95.85	9.73	125.30	92.85
2040-08	8.70	166.08	124.46	9.29	163.08	121.46
2040-09	8.91	167.46	125.00	9.51	164.46	122.00
2040-10	8.84	167.05	124.37	9.44	164.05	121.37
2040-11	9.48	154.55	127.43	10.07	151.55	124.43
2040-12	10.00	152.39	129.47	10.59	149.39	126.47
2041-01	9.29	149.52	125.34	9.88	146.52	122.34
2041-02	9.21	149.83	128.42	9.81	146.83	125.42
2041-03	9.17	144.96	126.77	9.76	141.96	123.77
2041-04	9.00	142.78	121.77	9.60	139.78	118.77
2041-05	8.97	125.00	91.84	9.56	122.00	88.84
2041-06	9.22	126.22	92.74	9.82	123.22	89.74
2041-07	9.20	125.72	93.15	9.79	122.72	90.15
2041-08	8.68	162.60	121.45	9.27	159.60	118.45
2041-09	8.67	166.72	122.55	9.26	163.72	119.55

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Nominal Mid-C/Montana Basis Differential:	($3.00)
Nominal AECO into Montana Transportation:	$0.5925

Month	AECO P95 NG $/Dkt	Mid-C P95 HL $/MWh	Mid-C P95 LL $/MWh	MT P95 NG $/Dkt	MT P95 HL $/MWh	MT P95 LL $/MWh
2041-10	9.17	166.68	122.50	9.77	163.68	119.50
2041-11	9.39	149.44	126.22	9.98	146.44	123.22
2041-12	9.52	149.86	124.65	10.12	146.86	121.65
2042-01	9.67	165.56	132.58	10.27	162.56	129.58
2042-02	9.45	163.86	131.05	10.04	160.86	128.05
2042-03	9.24	156.62	128.10	9.84	153.62	125.10
2042-04	9.10	152.35	124.58	9.69	149.35	121.58
2042-05	9.25	137.82	98.07	9.85	134.82	95.07
2042-06	9.40	133.94	97.46	9.99	130.94	94.46
2042-07	9.50	135.85	98.51	10.10	132.85	95.51
2042-08	8.95	173.81	128.01	9.55	170.81	125.01
2042-09	9.01	174.53	131.00	9.60	171.53	128.00
2042-10	8.99	176.06	130.56	9.58	173.06	127.56
2042-11	9.33	164.25	133.84	9.93	161.25	130.84
2042-12	9.64	165.92	133.67	10.24	162.92	130.67
2043-01	9.73	168.66	141.42	10.33	165.66	138.42
2043-02	9.77	167.62	141.56	10.36	164.62	138.56
2043-03	9.74	164.98	138.31	10.33	161.98	135.31
2043-04	9.39	158.61	133.59	9.98	155.61	130.59
2043-05	9.69	142.60	105.40	10.28	139.60	102.40
2043-06	9.45	140.07	103.93	10.04	137.07	100.93
2043-07	9.28	140.33	104.47	9.87	137.33	101.47
2043-08	8.81	175.99	135.39	9.40	172.99	132.39
2043-09	8.92	177.53	135.36	9.51	174.53	132.36
2043-10	9.03	180.52	136.90	9.62	177.52	133.90
2043-11	9.19	162.81	139.87	9.78	159.81	136.87
2043-12	9.62	166.49	140.67	10.21	163.49	137.67

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Nominal Mid-C/Montana Basis Differential:	($3.00)
Nominal AECO into Montana Transportation:	$0.5925

Month	AECO P5 NG $/Dkt	Mid-C P5 HL $/MWh	Mid-C P5 LL $/MWh	MT P5 NG $/Dkt	MT P5 HL $/MWh	MT P5 LL $/MWh
2014-01	2.48	29.36	29.98	3.08	26.36	26.98
2014-02	2.48	29.81	28.68	3.07	26.81	25.68
2014-03	2.34	26.52	26.93	2.93	23.52	23.93
2014-04	2.22	27.17	26.15	2.81	24.17	23.15
2014-05	2.34	21.89	11.40	2.93	18.89	8.40
2014-06	2.37	22.61	11.33	2.96	19.61	8.33
2014-07	2.33	21.86	10.49	2.93	18.86	7.49
2014-08	2.24	30.21	21.78	2.83	27.21	18.78
2014-09	2.32	29.32	21.55	2.91	26.32	18.55
2014-10	2.33	29.76	22.44	2.92	26.76	19.44
2014-11	2.54	30.44	27.40	3.13	27.44	24.40
2014-12	2.52	28.21	26.67	3.11	25.21	23.67
2015-01	2.53	30.77	30.50	3.12	27.77	27.50
2015-02	2.46	29.86	27.14	3.05	26.86	24.14
2015-03	2.49	29.41	27.71	3.08	26.41	24.71
2015-04	2.34	27.66	25.92	2.93	24.66	22.92
2015-05	2.40	21.95	12.92	2.99	18.95	9.92
2015-06	2.37	21.53	12.42	2.96	18.53	9.42
2015-07	2.33	21.50	12.23	2.92	18.50	9.23
2015-08	2.40	30.76	22.10	2.99	27.76	19.10
2015-09	2.33	30.45	22.07	2.93	27.45	19.07
2015-10	2.39	30.60	22.90	2.98	27.60	19.90
2015-11	2.55	28.82	25.68	3.14	25.82	22.68
2015-12	2.71	28.19	25.66	3.30	25.19	22.66
2016-01	2.74	32.82	30.29	3.33	29.82	27.29
2016-02	2.79	35.07	32.57	3.38	32.07	29.57
2016-03	2.76	32.73	30.14	3.35	29.73	27.14
2016-04	2.54	30.13	27.76	3.14	27.13	24.76
2016-05	2.51	20.98	10.88	3.10	17.98	7.88
2016-06	2.50	21.07	10.83	3.09	18.07	7.83
2016-07	2.50	20.71	10.55	3.09	17.71	7.55
2016-08	2.51	32.70	23.75	3.11	29.70	20.75
2016-09	2.44	33.12	24.21	3.03	30.12	21.21
2016-10	2.52	32.13	24.77	3.12	29.13	21.77
2016-11	2.63	29.92	26.72	3.22	26.92	23.72
2016-12	2.63	30.41	27.82	3.22	27.41	24.82
2017-01	2.91	34.89	32.05	3.50	31.89	29.05

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Month	AECO P5 NG $/Dkt	Mid-C P5 HL $/MWh	Mid-C P5 LL $/MWh	MT P5 NG $/Dkt	MT P5 HL $/MWh	MT P5 LL $/MWh
2017-02	2.92	33.09	29.87	3.52	30.09	26.87
2017-03	2.87	32.79	28.86	3.46	29.79	25.86
2017-04	2.62	28.61	25.67	3.21	25.61	22.67
2017-05	2.56	21.04	12.87	3.15	18.04	9.87
2017-06	2.48	22.48	13.55	3.08	19.48	10.55
2017-07	2.52	22.10	13.41	3.11	19.10	10.41
2017-08	2.65	32.90	26.47	3.24	29.90	23.47
2017-09	2.64	33.09	25.91	3.23	30.09	22.91
2017-10	2.63	32.69	25.98	3.22	29.69	22.98
2017-11	2.90	31.34	27.14	3.49	28.34	24.14
2017-12	3.13	32.88	28.15	3.72	29.88	25.15
2018-01	3.02	32.23	28.69	3.61	29.23	25.69
2018-02	2.99	31.68	29.54	3.58	28.68	26.54
2018-03	2.88	30.71	28.41	3.48	27.71	25.41
2018-04	2.76	28.75	26.78	3.36	25.75	23.78
2018-05	2.70	22.85	13.96	3.29	19.85	10.96
2018-06	2.81	22.54	13.84	3.40	19.54	10.84
2018-07	2.84	21.77	13.60	3.44	18.77	10.60
2018-08	2.80	30.54	25.25	3.39	27.54	22.25
2018-09	2.84	30.73	25.86	3.44	27.73	22.86
2018-10	2.97	32.33	26.08	3.56	29.33	23.08
2018-11	3.03	30.89	27.76	3.63	27.89	24.76
2018-12	3.12	30.78	27.70	3.71	27.78	24.70
2019-01	3.33	35.47	31.29	3.92	32.47	28.29
2019-02	3.27	35.59	33.76	3.86	32.59	30.76
2019-03	3.19	34.61	31.58	3.78	31.61	28.58
2019-04	3.18	33.20	30.13	3.77	30.20	27.13
2019-05	3.27	27.25	17.15	3.86	24.25	14.15
2019-06	3.30	27.84	17.12	3.90	24.84	14.12
2019-07	3.36	26.69	17.04	3.96	23.69	14.04
2019-08	3.31	40.31	31.02	3.90	37.31	28.02
2019-09	3.40	39.87	30.64	3.99	36.87	27.64
2019-10	3.42	39.99	30.41	4.01	36.99	27.41
2019-11	3.42	35.91	32.07	4.01	32.91	29.07
2019-12	3.58	34.56	31.05	4.17	31.56	28.05
2020-01	3.66	37.27	33.22	4.25	34.27	30.22
2020-02	3.61	37.87	35.94	4.20	34.87	32.94

NorthWestern Energy
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Nominal AECO into Montana Transportation:	$0.5925

Month	AECO P5 NG $/Dkt	Mid-C P5 HL $/MWh	Mid-C P5 LL $/MWh	MT P5 NG $/Dkt	MT P5 HL $/MWh	MT P5 LL $/MWh
2020-03	3.67	36.47	34.66	4.27	33.47	31.66
2020-04	3.52	33.61	31.95	4.12	30.61	28.95
2020-05	3.63	28.58	19.63	4.22	25.58	16.63
2020-06	3.47	28.13	19.24	4.06	25.13	16.24
2020-07	3.69	28.24	19.57	4.28	25.24	16.57
2020-08	3.36	43.28	33.56	3.95	40.28	30.56
2020-09	3.49	42.65	32.34	4.09	39.65	29.34
2020-10	3.63	42.19	33.07	4.23	39.19	30.07
2020-11	3.72	37.74	34.66	4.32	34.74	31.66
2020-12	3.83	36.94	34.35	4.42	33.94	31.35
2021-01	3.80	50.91	47.53	4.39	47.91	44.53
2021-02	3.70	50.47	47.35	4.29	47.47	44.35
2021-03	3.58	48.33	44.04	4.17	45.33	41.04
2021-04	3.57	44.25	42.58	4.17	41.25	39.58
2021-05	3.52	38.28	29.17	4.11	35.28	26.17
2021-06	3.61	38.64	29.58	4.20	35.64	26.58
2021-07	3.62	37.78	27.93	4.21	34.78	24.93
2021-08	3.34	49.71	41.58	3.93	46.71	38.58
2021-09	3.37	50.03	41.43	3.97	47.03	38.43
2021-10	3.41	49.75	41.03	4.00	46.75	38.03
2021-11	3.54	45.30	42.12	4.13	42.30	39.12
2021-12	3.74	45.89	42.87	4.33	42.89	39.87
2022-01	3.87	51.05	46.47	4.46	48.05	43.47
2022-02	3.79	50.30	46.48	4.39	47.30	43.48
2022-03	3.72	48.33	45.27	4.32	45.33	42.27
2022-04	3.67	46.83	42.61	4.26	43.83	39.61
2022-05	3.69	40.84	29.02	4.28	37.84	26.02
2022-06	3.70	40.25	29.06	4.29	37.25	26.06
2022-07	3.71	40.76	28.49	4.31	37.76	25.49
2022-08	3.66	54.79	43.63	4.25	51.79	40.63
2022-09	3.73	55.07	43.42	4.33	52.07	40.42
2022-10	3.79	53.83	43.17	4.38	50.83	40.17
2022-11	3.88	49.35	45.11	4.47	46.35	42.11
2022-12	4.03	46.86	43.48	4.63	43.86	40.48
2023-01	4.03	52.76	47.39	4.62	49.76	44.39
2023-02	3.88	51.24	47.07	4.47	48.24	44.07
2023-03	3.89	47.64	46.41	4.49	44.64	43.41

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Nominal AECO into Montana Transportation:	$0.5925

Month	AECO P5 NG $/Dkt	Mid-C P5 HL $/MWh	Mid-C P5 LL $/MWh	MT P5 NG $/Dkt	MT P5 HL $/MWh	MT P5 LL $/MWh
2023-04	3.75	43.81	41.43	4.34	40.81	38.43
2023-05	3.90	39.26	27.65	4.49	36.26	24.65
2023-06	3.86	39.05	27.81	4.45	36.05	24.81
2023-07	3.87	38.78	28.51	4.47	35.78	25.51
2023-08	3.62	54.78	43.72	4.21	51.78	40.72
2023-09	3.72	54.06	43.12	4.31	51.06	40.12
2023-10	3.75	55.65	44.29	4.34	52.65	41.29
2023-11	3.73	51.11	45.89	4.33	48.11	42.89
2023-12	3.92	50.34	44.50	4.51	47.34	41.50
2024-01	4.13	51.72	47.11	4.72	48.72	44.11
2024-02	4.10	51.33	47.14	4.69	48.33	44.14
2024-03	4.08	47.95	44.95	4.67	44.95	41.95
2024-04	3.77	44.74	42.31	4.36	41.74	39.31
2024-05	3.82	38.78	28.45	4.41	35.78	25.45
2024-06	3.69	37.46	28.73	4.28	34.46	25.73
2024-07	3.70	37.88	28.82	4.29	34.88	25.82
2024-08	3.49	51.75	42.74	4.08	48.75	39.74
2024-09	3.54	51.84	42.21	4.14	48.84	39.21
2024-10	3.88	53.48	42.83	4.47	50.48	39.83
2024-11	3.89	50.11	45.30	4.49	47.11	42.30
2024-12	4.18	48.35	45.20	4.77	45.35	42.20
2025-01	4.00	54.80	48.85	4.59	51.80	45.85
2025-02	3.99	51.91	48.37	4.58	48.91	45.37
2025-03	3.97	50.33	45.51	4.56	47.33	42.51
2025-04	3.99	47.88	44.61	4.58	44.88	41.61
2025-05	3.98	42.82	30.04	4.57	39.82	27.04
2025-06	3.91	44.38	30.70	4.50	41.38	27.70
2025-07	3.97	43.43	30.58	4.56	40.43	27.58
2025-08	3.63	58.65	46.18	4.22	55.65	43.18
2025-09	3.73	59.93	47.23	4.32	56.93	44.23
2025-10	3.97	60.59	45.67	4.56	57.59	42.67
2025-11	4.04	51.53	47.01	4.63	48.53	44.01
2025-12	4.20	52.77	48.32	4.80	49.77	45.32
2026-01	4.04	55.97	49.93	4.63	52.97	46.93
2026-02	4.06	55.75	51.15	4.65	52.75	48.15
2026-03	3.99	52.82	48.68	4.58	49.82	45.68
2026-04	3.88	48.86	45.51	4.47	45.86	42.51

NorthWestern Energy
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Nominal Mid-C/Montana Basis Differential:	($3.00)
Nominal AECO into Montana Transportation:	$0.5925

Month	AECO P5 NG $/Dkt	Mid-C P5 HL $/MWh	Mid-C P5 LL $/MWh	MT P5 NG $/Dkt	MT P5 HL $/MWh	MT P5 LL $/MWh
2026-05	3.86	43.01	31.41	4.45	40.01	28.41
2026-06	3.88	43.44	30.47	4.47	40.44	27.47
2026-07	3.99	43.63	30.02	4.58	40.63	27.02
2026-08	3.84	59.18	45.01	4.43	56.18	42.01
2026-09	3.76	57.70	44.99	4.35	54.70	41.99
2026-10	4.02	56.97	44.03	4.61	53.97	41.03
2026-11	4.05	53.05	47.58	4.64	50.05	44.58
2026-12	4.12	51.57	46.48	4.71	48.57	43.48
2027-01	4.40	62.61	55.89	5.00	59.61	52.89
2027-02	4.31	61.01	54.92	4.90	58.01	51.92
2027-03	4.23	57.42	52.55	4.82	54.42	49.55
2027-04	4.14	55.17	49.97	4.74	52.17	46.97
2027-05	4.12	49.16	34.72	4.72	46.16	31.72
2027-06	4.12	50.32	34.68	4.71	47.32	31.68
2027-07	4.27	49.38	34.41	4.87	46.38	31.41
2027-08	4.07	65.12	51.26	4.66	62.12	48.26
2027-09	3.94	64.48	50.61	4.53	61.48	47.61
2027-10	3.97	64.21	49.93	4.56	61.21	46.93
2027-11	4.21	60.93	53.78	4.80	57.93	50.78
2027-12	4.39	61.19	53.96	4.98	58.19	50.96
2028-01	4.40	63.01	55.02	4.99	60.01	52.02
2028-02	4.38	62.01	55.97	4.98	59.01	52.97
2028-03	4.16	58.51	52.62	4.75	55.51	49.62
2028-04	4.07	56.04	52.45	4.67	53.04	49.45
2028-05	3.96	49.63	34.51	4.55	46.63	31.51
2028-06	3.94	49.03	34.38	4.53	46.03	31.38
2028-07	4.03	47.65	34.20	4.62	44.65	31.20
2028-08	3.93	64.34	52.27	4.52	61.34	49.27
2028-09	4.03	63.03	50.57	4.63	60.03	47.57
2028-10	4.20	62.98	50.43	4.79	59.98	47.43
2028-11	4.24	55.82	51.32	4.83	52.82	48.32
2028-12	4.34	56.60	50.99	4.93	53.60	47.99
2029-01	4.75	62.40	53.77	5.34	59.40	50.77
2029-02	4.56	59.26	52.63	5.15	56.26	49.63
2029-03	4.44	55.81	51.16	5.04	52.81	48.16
2029-04	4.31	53.84	49.24	4.90	50.84	46.24
2029-05	4.19	46.98	31.86	4.78	43.98	28.86

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Month	AECO P5 NG $/Dkt	Mid-C P5 HL $/MWh	Mid-C P5 LL $/MWh	MT P5 NG $/Dkt	MT P5 HL $/MWh	MT P5 LL $/MWh
2029-06	4.09	45.00	31.48	4.68	42.00	28.48
2029-07	4.21	46.09	31.78	4.80	43.09	28.78
2029-08	3.91	63.54	49.52	4.50	60.54	46.52
2029-09	3.97	62.92	49.11	4.56	59.92	46.11
2029-10	4.12	63.09	48.36	4.71	60.09	45.36
2029-11	4.17	56.96	51.28	4.77	53.96	48.28
2029-12	4.21	53.69	49.01	4.80	50.69	46.01
2030-01	4.54	65.97	59.55	5.13	62.97	56.55
2030-02	4.56	64.25	59.00	5.15	61.25	56.00
2030-03	4.56	61.53	56.37	5.15	58.53	53.37
2030-04	4.41	55.87	51.06	5.00	52.87	48.06
2030-05	4.36	48.91	34.36	4.95	45.91	31.36
2030-06	4.41	49.91	34.74	5.01	46.91	31.74
2030-07	4.43	49.47	34.66	5.03	46.47	31.66
2030-08	4.24	67.89	52.70	4.83	64.89	49.70
2030-09	4.27	66.65	52.07	4.86	63.65	49.07
2030-10	4.16	66.85	51.53	4.75	63.85	48.53
2030-11	4.34	60.52	53.49	4.93	57.52	50.49
2030-12	4.57	61.84	54.33	5.16	58.84	51.33
2031-01	4.70	67.60	58.82	5.30	64.60	55.82
2031-02	4.83	65.87	60.27	5.42	62.87	57.27
2031-03	4.69	63.46	58.39	5.28	60.46	55.39
2031-04	4.41	59.92	55.23	5.00	56.92	52.23
2031-05	4.48	53.15	37.97	5.08	50.15	34.97
2031-06	4.59	53.95	38.23	5.19	50.95	35.23
2031-07	4.61	52.50	37.42	5.21	49.50	34.42
2031-08	4.27	71.76	55.98	4.87	68.76	52.98
2031-09	4.38	73.87	56.10	4.97	70.87	53.10
2031-10	4.41	74.29	56.90	5.00	71.29	53.90
2031-11	4.46	63.96	57.37	5.05	60.96	54.37
2031-12	4.69	62.90	57.25	5.28	59.90	54.25
2032-01	4.87	69.19	61.88	5.46	66.19	58.88
2032-02	4.87	66.80	61.67	5.46	63.80	58.67
2032-03	4.76	65.07	59.34	5.35	62.07	56.34
2032-04	4.56	64.05	55.31	5.15	61.05	52.31
2032-05	4.71	53.88	35.31	5.31	50.88	32.31
2032-06	4.75	53.72	34.50	5.34	50.72	31.50

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Nominal AECO into Montana Transportation:	$0.5925

Month	AECO P5 NG $/Dkt	Mid-C P5 HL $/MWh	Mid-C P5 LL $/MWh	MT P5 NG $/Dkt	MT P5 HL $/MWh	MT P5 LL $/MWh
2032-07	4.89	51.78	34.62	5.48	48.78	31.62
2032-08	4.62	73.20	54.42	5.21	70.20	51.42
2032-09	4.46	72.64	54.44	5.05	69.64	51.44
2032-10	4.55	72.69	54.21	5.15	69.69	51.21
2032-11	4.62	67.26	57.84	5.22	64.26	54.84
2032-12	4.77	68.28	57.35	5.36	65.28	54.35
2033-01	4.81	69.04	61.86	5.40	66.04	58.86
2033-02	4.84	67.39	62.13	5.43	64.39	59.13
2033-03	4.80	65.62	58.95	5.39	62.62	55.95
2033-04	4.60	61.54	56.80	5.19	58.54	53.80
2033-05	4.60	53.41	38.21	5.19	50.41	35.21
2033-06	4.71	54.69	37.66	5.30	51.69	34.66
2033-07	4.73	55.11	36.29	5.33	52.11	33.29
2033-08	4.40	73.58	56.61	5.00	70.58	53.61
2033-09	4.55	72.84	56.08	5.14	69.84	53.08
2033-10	4.59	73.65	56.33	5.19	70.65	53.33
2033-11	4.55	67.77	60.30	5.14	64.77	57.30
2033-12	4.82	68.76	60.88	5.42	65.76	57.88
2034-01	4.84	69.04	62.96	5.44	66.04	59.96
2034-02	4.82	68.31	63.57	5.42	65.31	60.57
2034-03	4.79	66.05	60.51	5.38	63.05	57.51
2034-04	4.69	62.97	58.32	5.29	59.97	55.32
2034-05	4.89	54.04	38.26	5.48	51.04	35.26
2034-06	4.82	56.10	38.79	5.42	53.10	35.79
2034-07	4.83	53.75	38.38	5.42	50.75	35.38
2034-08	4.48	67.56	55.03	5.08	64.56	52.03
2034-09	4.60	68.69	54.72	5.19	65.69	51.72
2034-10	4.70	71.14	54.99	5.29	68.14	51.99
2034-11	4.74	66.86	60.08	5.33	63.86	57.08
2034-12	5.04	68.32	60.78	5.63	65.32	57.78
2035-01	4.85	76.22	66.63	5.44	73.22	63.63
2035-02	4.95	72.48	65.77	5.54	69.48	62.77
2035-03	4.86	71.38	63.27	5.45	68.38	60.27
2035-04	4.69	67.15	58.19	5.29	64.15	55.19
2035-05	4.69	58.34	41.24	5.29	55.34	38.24
2035-06	4.82	57.29	40.80	5.41	54.29	37.80
2035-07	4.92	57.04	40.15	5.52	54.04	37.15

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Nominal AECO into Montana Transportation:	$0.5925

Month	AECO P5 NG $/Dkt	Mid-C P5 HL $/MWh	Mid-C P5 LL $/MWh	MT P5 NG $/Dkt	MT P5 HL $/MWh	MT P5 LL $/MWh
2035-08	4.64	77.56	59.28	5.23	74.56	56.28
2035-09	4.62	77.55	59.94	5.22	74.55	56.94
2035-10	4.72	78.12	62.08	5.31	75.12	59.08
2035-11	4.82	72.31	63.68	5.41	69.31	60.68
2035-12	5.03	71.76	63.80	5.62	68.76	60.80
2036-01	5.20	73.16	65.82	5.79	70.16	62.82
2036-02	5.22	73.40	65.80	5.82	70.40	62.80
2036-03	5.20	69.27	62.06	5.79	66.27	59.06
2036-04	5.09	64.88	59.94	5.68	61.88	56.94
2036-05	5.08	58.48	42.25	5.68	55.48	39.25
2036-06	5.03	59.51	42.53	5.62	56.51	39.53
2036-07	5.05	60.31	42.39	5.64	57.31	39.39
2036-08	4.96	82.31	62.61	5.55	79.31	59.61
2036-09	4.87	78.48	61.22	5.46	75.48	58.22
2036-10	4.96	77.41	61.42	5.55	74.41	58.42
2036-11	5.03	69.39	63.37	5.62	66.39	60.37
2036-12	5.34	70.44	61.94	5.93	67.44	58.94
2037-01	5.29	73.82	64.81	5.89	70.82	61.81
2037-02	5.30	69.45	63.35	5.90	66.45	60.35
2037-03	5.21	67.01	61.10	5.80	64.01	58.10
2037-04	5.01	63.19	57.05	5.60	60.19	54.05
2037-05	5.24	56.31	38.04	5.83	53.31	35.04
2037-06	4.97	56.10	38.05	5.56	53.10	35.05
2037-07	5.03	55.13	37.57	5.62	52.13	34.57
2037-08	4.93	74.37	58.27	5.52	71.37	55.27
2037-09	4.96	74.07	58.11	5.55	71.07	55.11
2037-10	5.08	76.05	58.65	5.67	73.05	55.65
2037-11	5.16	67.73	61.56	5.76	64.73	58.56
2037-12	5.38	69.35	61.12	5.97	66.35	58.12
2038-01	5.08	79.54	69.97	5.68	76.54	66.97
2038-02	4.97	78.02	70.19	5.56	75.02	67.19
2038-03	4.95	76.49	68.26	5.54	73.49	65.26
2038-04	5.06	73.74	67.16	5.66	70.74	64.16
2038-05	5.13	64.59	47.45	5.72	61.59	44.45
2038-06	5.11	63.39	48.25	5.70	60.39	45.25
2038-07	5.23	63.93	46.20	5.82	60.93	43.20
2038-08	4.95	85.50	67.15	5.54	82.50	64.15

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Month	AECO P5 NG $/Dkt	Mid-C P5 HL $/MWh	Mid-C P5 LL $/MWh	MT P5 NG $/Dkt	MT P5 HL $/MWh	MT P5 LL $/MWh
2038-09	4.91	88.58	67.84	5.50	85.58	64.84
2038-10	4.98	86.25	68.38	5.57	83.25	65.38
2038-11	5.20	79.50	70.22	5.80	76.50	67.22
2038-12	5.25	80.40	70.50	5.85	77.40	67.50
2039-01	5.64	82.99	74.82	6.23	79.99	71.82
2039-02	5.52	81.43	73.37	6.11	78.43	70.37
2039-03	5.53	78.54	70.61	6.13	75.54	67.61
2039-04	5.31	75.05	67.35	5.90	72.05	64.35
2039-05	5.60	63.87	45.30	6.20	60.87	42.30
2039-06	5.61	65.72	46.04	6.20	62.72	43.04
2039-07	5.46	65.45	45.58	6.05	62.45	42.58
2039-08	5.20	83.25	66.22	5.80	80.25	63.22
2039-09	5.15	80.56	67.46	5.75	77.56	64.46
2039-10	5.30	83.36	66.77	5.89	80.36	63.77
2039-11	5.35	76.16	69.19	5.94	73.16	66.19
2039-12	5.47	77.93	70.39	6.06	74.93	67.39
2040-01	5.51	83.82	73.80	6.11	80.82	70.80
2040-02	5.56	81.74	72.58	6.16	78.74	69.58
2040-03	5.67	78.40	69.58	6.26	75.40	66.58
2040-04	5.27	72.02	63.89	5.87	69.02	60.89
2040-05	5.33	61.86	44.12	5.93	58.86	41.12
2040-06	5.49	62.06	42.80	6.08	59.06	39.80
2040-07	5.50	60.73	42.38	6.09	57.73	39.38
2040-08	5.18	84.85	64.86	5.77	81.85	61.86
2040-09	5.24	85.17	66.00	5.83	82.17	63.00
2040-10	5.34	88.04	66.32	5.94	85.04	63.32
2040-11	5.60	77.05	67.97	6.20	74.05	64.97
2040-12	5.73	79.72	68.61	6.32	76.72	65.61
2041-01	5.62	84.88	78.73	6.22	81.88	75.73
2041-02	5.78	85.33	79.34	6.37	82.33	76.34
2041-03	5.73	80.90	76.42	6.32	77.90	73.42
2041-04	5.68	76.24	71.77	6.27	73.24	68.77
2041-05	5.66	70.52	53.32	6.25	67.52	50.32
2041-06	5.72	70.15	53.22	6.31	67.15	50.22
2041-07	5.75	70.06	52.44	6.34	67.06	49.44
2041-08	5.41	88.99	74.47	6.00	85.99	71.47
2041-09	5.46	92.00	75.56	6.05	89.00	72.56

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2041-10	5.57	94.62	75.92	6.16	91.62	72.92
2041-11	5.84	86.03	78.53	6.43	83.03	75.53
2041-12	5.93	86.60	78.73	6.52	83.60	75.73
2042-01	5.82	91.14	80.80	6.41	88.14	77.80
2042-02	5.75	92.76	82.04	6.35	89.76	79.04
2042-03	5.68	86.86	79.42	6.27	83.86	76.42
2042-04	5.46	82.31	76.03	6.05	79.31	73.03
2042-05	5.63	68.50	53.16	6.22	65.50	50.16
2042-06	5.63	70.34	53.05	6.22	67.34	50.05
2042-07	5.63	70.17	52.99	6.22	67.17	49.99
2042-08	5.38	92.33	75.59	5.97	89.33	72.59
2042-09	5.49	92.31	74.14	6.08	89.31	71.14
2042-10	5.54	92.70	72.07	6.13	89.70	69.07
2042-11	5.52	83.52	74.84	6.12	80.52	71.84
2042-12	5.83	86.37	76.60	6.42	83.37	73.60
2043-01	6.08	88.00	78.84	6.67	85.00	75.84
2043-02	6.13	85.62	76.91	6.73	82.62	73.91
2043-03	6.01	84.48	74.10	6.60	81.48	71.10
2043-04	5.76	78.14	70.59	6.35	75.14	67.59
2043-05	5.78	70.16	46.89	6.37	67.16	43.89
2043-06	5.66	69.18	46.38	6.25	66.18	43.38
2043-07	5.88	66.67	45.33	6.48	63.67	42.33
2043-08	5.58	91.69	70.71	6.17	88.69	67.71
2043-09	5.65	89.16	72.30	6.25	86.16	69.30
2043-10	5.81	92.29	71.22	6.40	89.29	68.22
2043-11	5.94	86.39	74.03	6.53	83.39	71.03
2043-12	6.12	86.62	74.96	6.71	83.62	71.96

NorthWestern Energy
RPS Compliance Forecast

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Annual RPS Requirement Calculation											
Supply Load (2013 20-year forecast)	5,931,402	6,032,489	6,102,363	6,182,657	6,267,389	6,352,606	6,436,281	6,517,860	6,597,785	6,675,859	6,753,707
RPS (%)	10%	10%	10%	15%	15%	15%	15%	15%	15%	15%	15%
RPS MWH based on prior yr load	**592,007**	**593,140**	**603,249**	**915,355**	**927,399**	**940,108**	**952,891**	**965,442**	**977,679**	**989,668**	**1,001,379**
Wind Resource REC Generation											
Judith Gap (135 MW)	461,276	467,163	467,163	467,163	467,163	467,163	467,163	467,163	467,163	467,163	467,163
Spion Kop (40MW)	42,647	138,408	138,408	138,408	138,408	138,408	138,408	138,408	138,408	138,408	138,408
Musselshell (10 MW)		28,600	28,600	28,600	28,600	28,600	28,600	28,600	28,600	28,600	28,600
Musselshell 2 (10 MW)		28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000
Two Dot Wind Farm (10 MW)			35,400	35,400	35,400	35,400	35,400	35,400	35,400	35,400	35,400
Fairfield (10 MW)			31,900	31,900	31,900	31,900	31,900	31,900	31,900	31,900	31,900
Gordon Butte (9.6 MW)	42,251	33,750	33,750	33,750	33,750	33,750	33,750	33,750	33,750	33,750	33,750
Wind Resource RECs	**546,174**	**695,921**	**763,221**	**763,221**	**763,221**	**763,221**	**763,221**	**763,221**	**763,221**	**763,221**	**763,221**
CREP Resource REC Generation											
2013 CREP RFP (40.75 MW Wind)			6,816	87,760	146,560	146,560	146,560	146,560	146,560	146,560	146,560
2013 CREP RFP RECs			**6,816**	**87,760**	**146,560**	**146,560**	**146,560**	**146,560**	**146,560**	**146,560**	**146,560**
Hydro Resource REC Generation											
Turnbull (13MW)	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000
Flint Creek (2 MW)	640	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000
Sleeping Giant Power LLC (8 MW)					42,766	42,766	42,766	42,766	42,766	42,766	42,766
Lower South Fork (0.5 MW)	152	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Hydro Resource RECs	**35,792**	**44,900**	**44,900**	**44,900**	**87,666**	**87,666**	**87,666**	**87,666**	**87,666**	**87,666**	**87,666**
Total RECs Generated	**581,966**	**740,821**	**814,937**	**895,881**	**997,447**	**997,447**	**997,447**	**997,447**	**997,447**	**997,447**	**997,447**
Annual RPS Compliance Determination											
Current Yr REC	581,966	740,821	814,937	895,881	997,447	997,447	997,447	997,447	997,447	997,447	997,447
Prior Yr Carry-Over REC	158,507	138,466	276,147	544,172	539,367	582,086	612,095	629,322	633,997	626,436	606,886
Total Available REC	730,473	869,287	1,147,421	1,454,721	1,509,485	1,552,204	1,582,213	1,599,440	1,604,115	1,596,554	1,577,003
RPS Requirement	592,007	593,140	603,249	915,355	927,399	940,108	952,891	965,442	977,679	989,668	1,001,379
REC Balance / RPS Compliance Determination	**138,466**	**276,147**	**544,172**	**539,367**	**582,086**	**612,095**	**629,322**	**633,997**	**626,436**	**606,886**	**575,625**

NorthWestern Energy
RPS Compliance Forecast

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Annual RPS Requirement Calculation											
Supply Load (2013 20-year forecast)	6,831,589	6,910,044	6,989,256	7,069,128	7,149,452	7,230,006	7,310,636	7,391,336	7,470,728	7,549,822	7,628,282
RPS (%)	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
RPS MWH based on prior yr load	**1,013,056**	**1,024,738**	**1,036,507**	**1,048,388**	**1,060,369**	**1,072,418**	**1,084,501**	**1,096,595**	**1,108,700**	**1,120,609**	**1,132,473**
Wind Resource REC Generation											
Judith Gap (135 MW)	467,163	467,163	467,163	467,163	467,163	467,163	467,163	467,163	467,163	467,163	467,163
Spion Kop (40MW)	138,408	138,408	138,408	138,408	138,408	138,408	138,408	138,408	138,408	138,408	138,408
Musselshell (10 MW)	28,600	28,600	28,600	28,600	28,600	28,600	28,600	28,600	28,600	28,600	28,600
Musselshell 2 (10 MW)	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000
Two Dot Wind Farm (10 MW)	35,400	35,400	35,400	35,400	35,400	35,400	35,400	35,400	35,400	35,400	35,400
Fairfield (10 MW)	31,900	31,900	31,900	31,900	31,900	31,900	31,900	31,900	31,900	31,900	31,900
Gordon Butte (9.6 MW)	33,750	33,750	33,750	33,750	33,750	33,750	33,750	33,750	33,750	33,750	33,750
Wind Resource RECs	**763,221**	**763,221**	**763,221**	**763,221**	**763,221**	**763,221**	**763,221**	**763,221**	**763,221**	**763,221**	**763,221**
CREP Resource REC Generation											
2013 CREP RFP (40.75 MW Wind)	146,560	146,560	146,560	146,560	146,560	146,560	146,560	146,560	146,560	146,560	146,560
2013 CREP RFP RECs	**146,560**	**146,560**	**146,560**	**146,560**	**146,560**	**146,560**	**146,560**	**146,560**	**146,560**	**146,560**	**146,560**
Hydro Resource REC Generation											
Turnbull (13MW)	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000
Flint Creek (2 MW)	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000
Sleeping Giant Power LLC (8 MW)	42,766	42,766	42,766	42,766	42,766	42,766	42,766	42,766	42,766	42,766	42,766
Lower South Fork (0.5 MW)	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Hydro Resource RECs	**87,666**	**87,666**	**87,666**	**87,666**	**87,666**	**87,666**	**87,666**	**87,666**	**87,666**	**87,666**	**87,666**
Total RECs Generated	**997,447**	**997,447**	**997,447**	**997,447**	**997,447**	**997,447**	**997,447**	**997,447**	**997,447**	**997,447**	**997,447**
Annual RPS Compliance Determination											
Current Yr REC	997,447	997,447	997,447	997,447	997,447	997,447	997,447	997,447	997,447	997,447	997,447
Prior Yr Carry-Over REC	575,625	532,686	478,065	411,676	333,406	243,154	140,854	26,471	-100,007	-138,583	-150,492
Total Available REC	1,545,742	1,502,804	1,448,183	1,381,794	1,303,523	1,213,272	1,110,972	996,588	970,118	970,118	970,118
RPS Requirement	1,013,056	1,024,738	1,036,507	1,048,388	1,060,369	1,072,418	1,084,501	1,096,595	1,108,700	1,120,609	1,132,473
REC Balance / RPS Compliance Determination	**532,686**	**478,065**	**411,676**	**333,406**	**243,154**	**140,854**	**26,471**	**-100,007**	**-138,583**	**-150,492**	**-162,356**

Volume 2

Chapter 4

Supplementary PowerSimm Results

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VOLUME 2 CHAPTER 4—SUPPLEMENTARY POWERSIMM RESULTS

Detailed Simulation Validation

The figures in this section are provided as a supplement to those provided in the Volume 1, Chapter 6 section entitled Summary of Simulation Validation Results. The included plots demonstrate the rigorous validation of weather, load, forward/forecast price, and spot price simulations in PowerSimm, and their appropriate calibration to historical data. Some figures are reproduced here from Volume 1 for completeness.

Validation of Simulated Weather

PowerSimm uses weather data from six Montana weather stations, listed in Table 6-1, to calibrate future simulations of weather. Confidence intervals for the maximum simulated drybulb temperatures by month and by day of the year are plotted in Figure 6-1. Results for Billings and Missoula weather stations are shown. The simulated values (in blue) are overlayed with the historical values (in red) at the mean and the 5th and 95th percentiles. The plots illustrate the excellent agreement between the historical and simulated temperature distributions on both timescales.

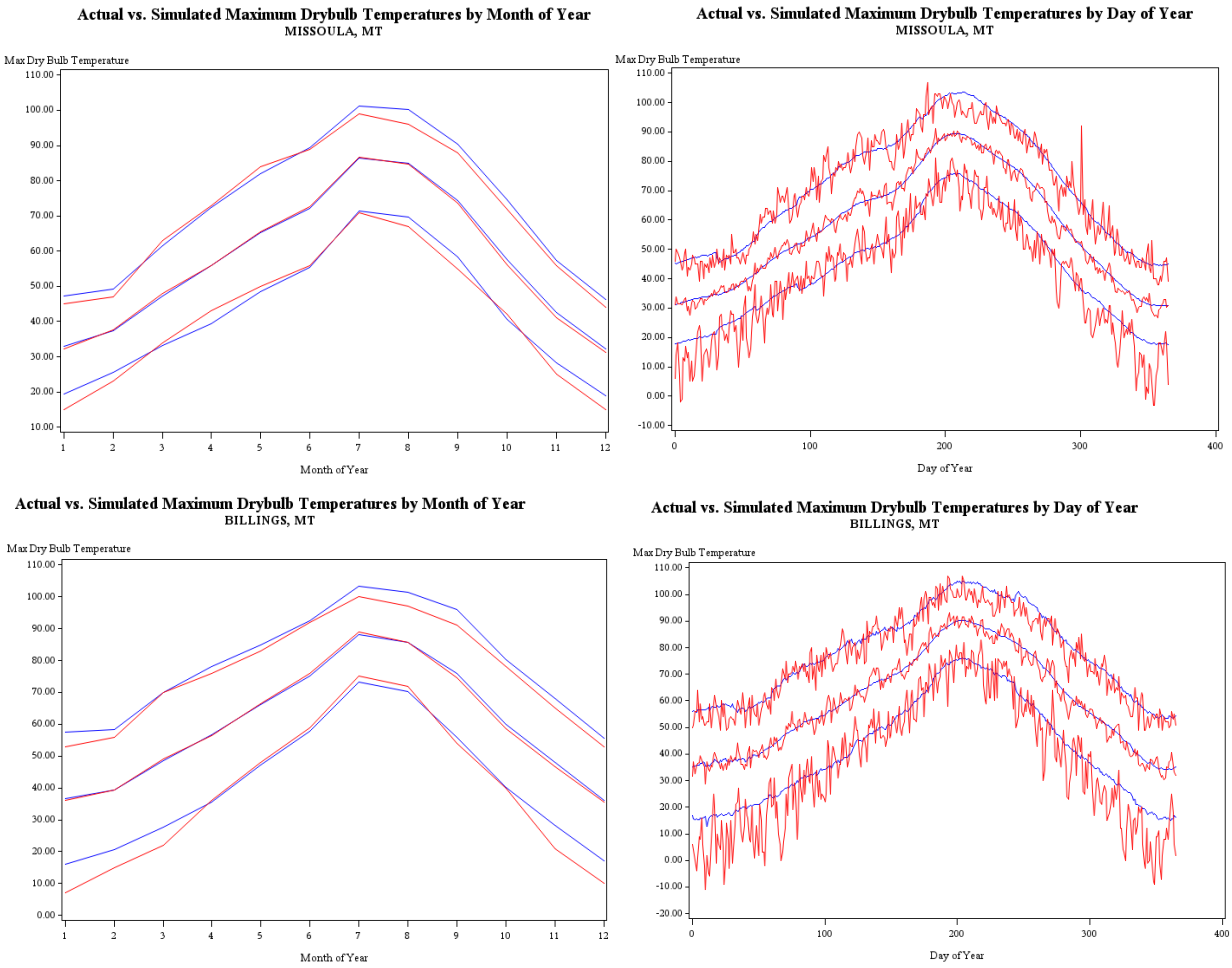
Table 6-1

Weather Stations Used in PowerSimm

NAME	LOCATION	CALLSIGN
BILLINGS, MT	INTERNATIONAL AIRPORT	BIL
BOZEMAN, MT	GALLATIN FIELD	BZN
BUTTE, MT	BERT MOONEY AIRPORT	BTM
GREAT FALLS, MT	INTERNATIONAL AIRPORT	GTF
HELENA, MT	HELENA AIRPORT	HLN
MISSOULA, MT	MISSOULA INT'L AIRPORT	MSO

Figure 6-1

Confidence intervals for maximum simulated (blue) and historical (red) drybulb temperature by month (left) and day (right) of the year



Validation of Simulated Load

Similarly to weather, validation of simulated load is performed across several time scales to ensure proper distributional agreement with historical data. Plots of confidence intervals for simulated and historical average load by month and hour are given in the main body of the report. Here, several additional plots are provided on a monthly-hourly time-scale to illustrate changes in the shape of the hourly load profile by month.

Figure 6-2 shows an overlay of simulated (blue) and historical (red) confidence intervals for hourly load by month, given in two-month increments. In all cases, simulations align well with the historical data at the mean and the 5th and 95th percentiles.

In addition to validation the simulated load itself, it is also important to validate that the simulations capture the observed historical relationship between temperature and load. Figure 6-3 illustrates the excellent agreement between the simulated (blue) and historical (red) temperature-load relationships within the Mid-C market.

Figure 6-2

Confidence intervals for average simulated (blue) and historical (red) hourly load for various months of the year

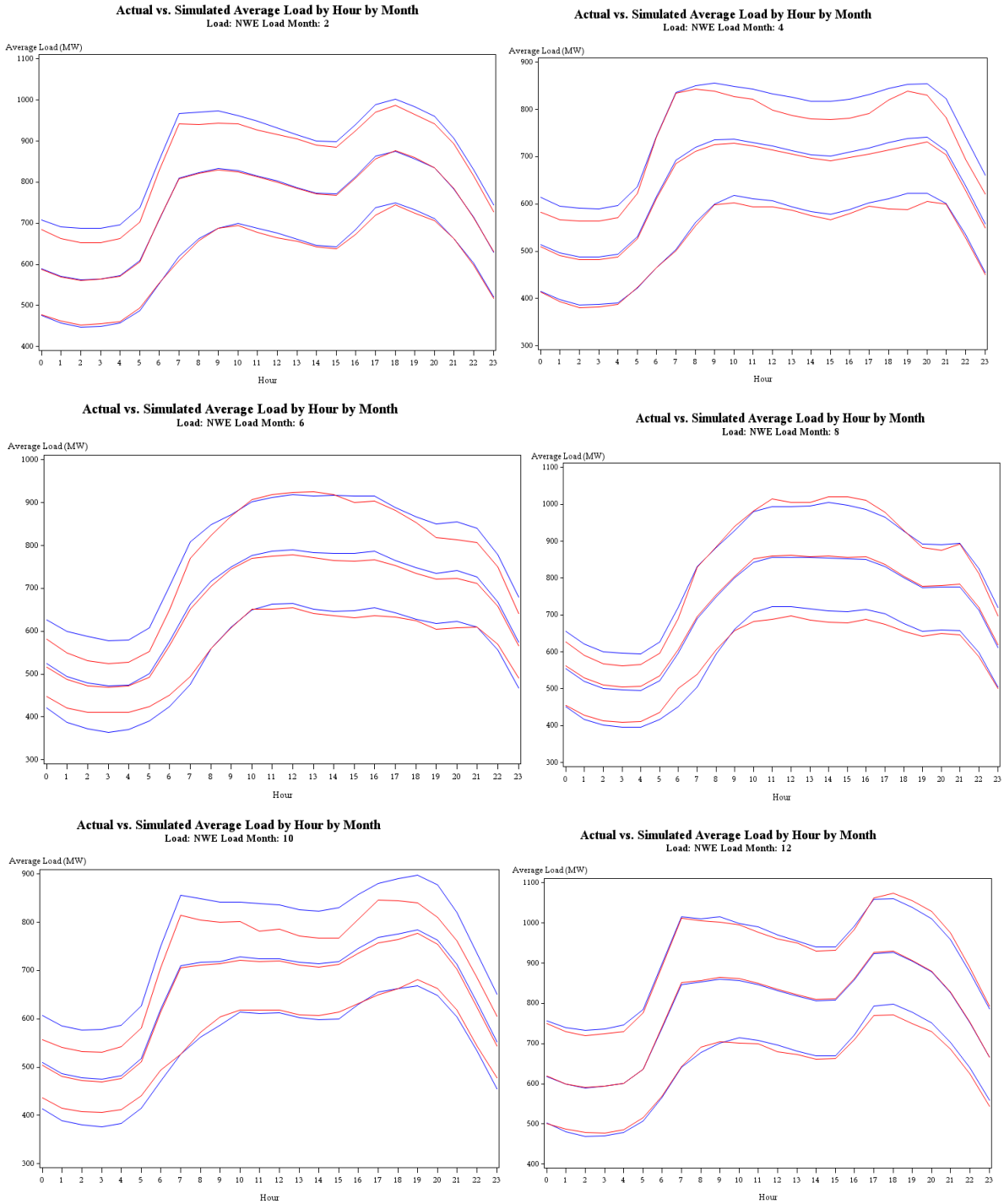
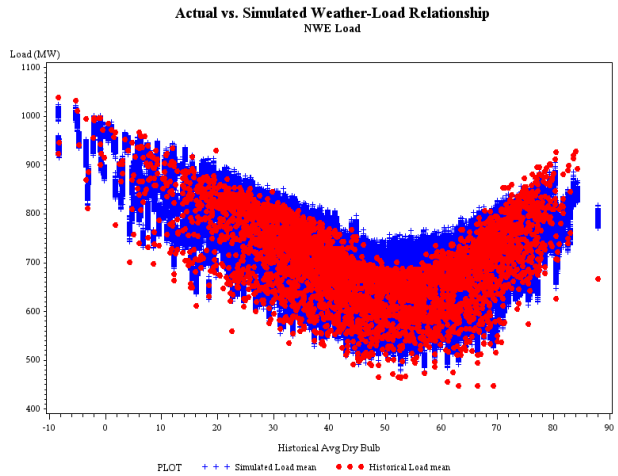


Figure 6-3

Simulated (blue) and historical (red) weather-load relationship



Validation of Market Heat Rates

Figure 6-4 and Figure 6-5 show the implied market heat rates obtained by dividing the forward\forecast price of power by the price of gas in each month. Figure 6-4 shows the implied heat rate with CO_2 incorporated into the price of power, and Figure 6-5 shows the heat rates with the CO_2 adder removed from the price of power. This “clean” heat rate stays constant over time, while the “dirty” heat rate rises slightly with the price of CO_2.

Figure 6-4

Heavy and Light Load “Dirty” Implied Market Heat Rates

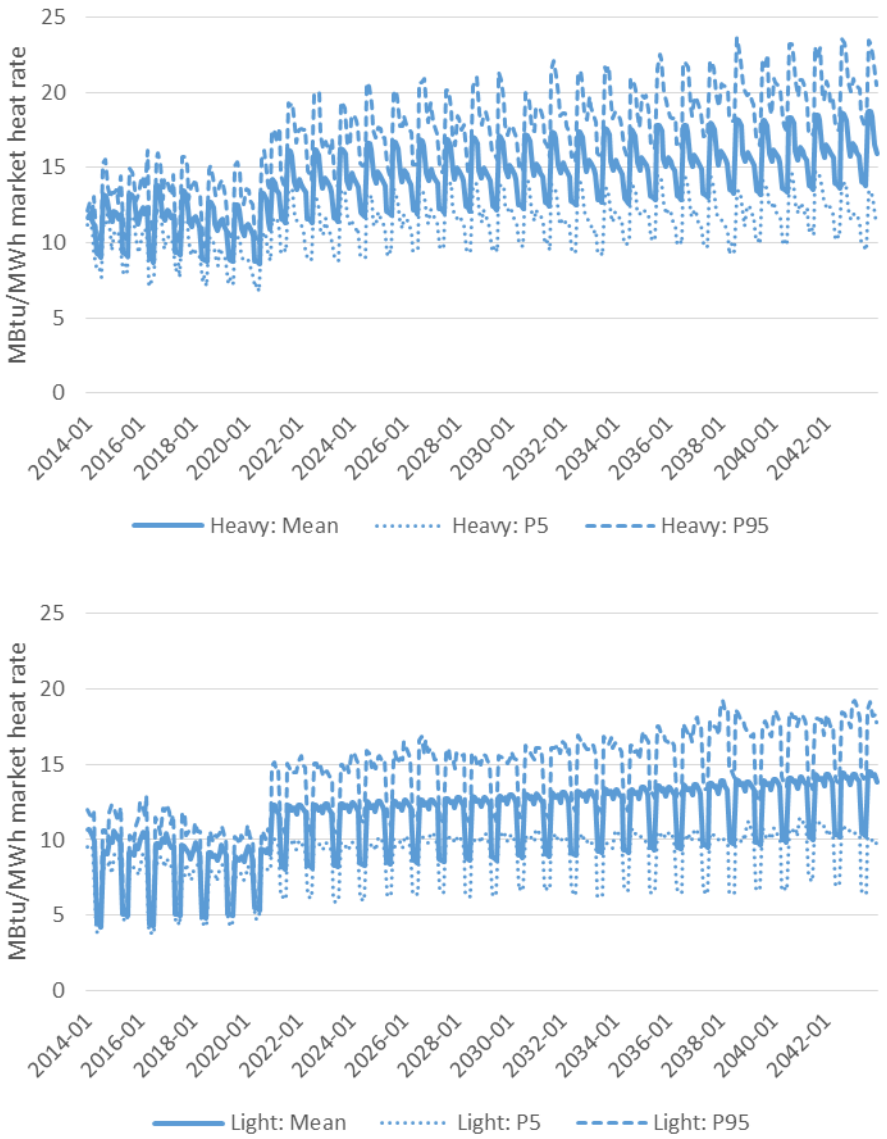
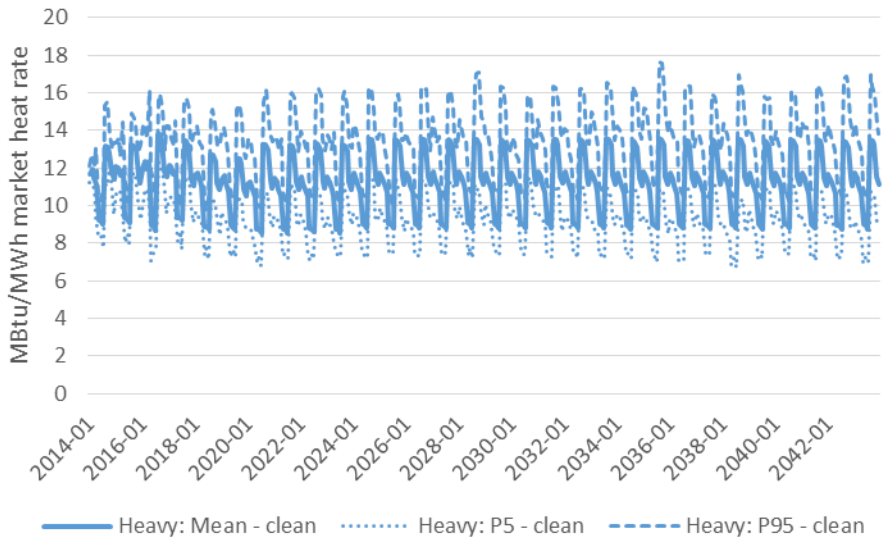
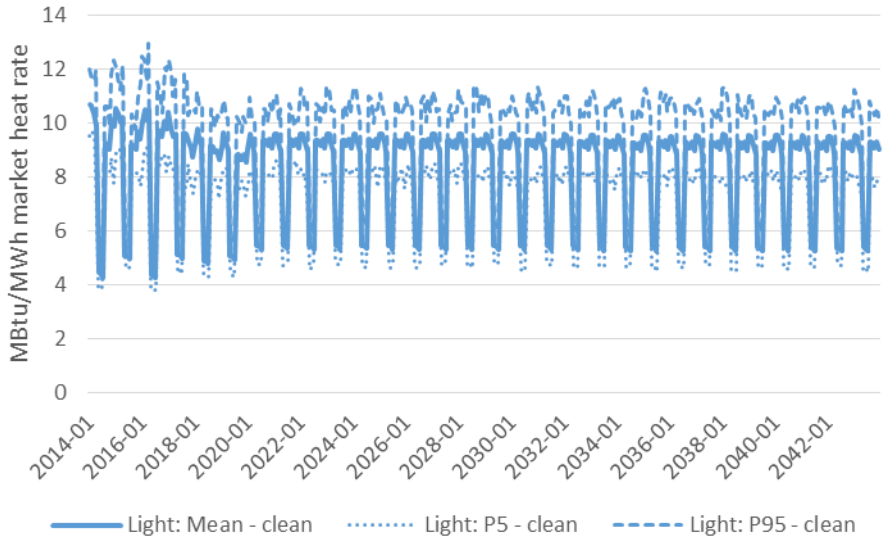


Figure 6-5

Heavy and Light Load "Clean" Implied Market Heat Rates





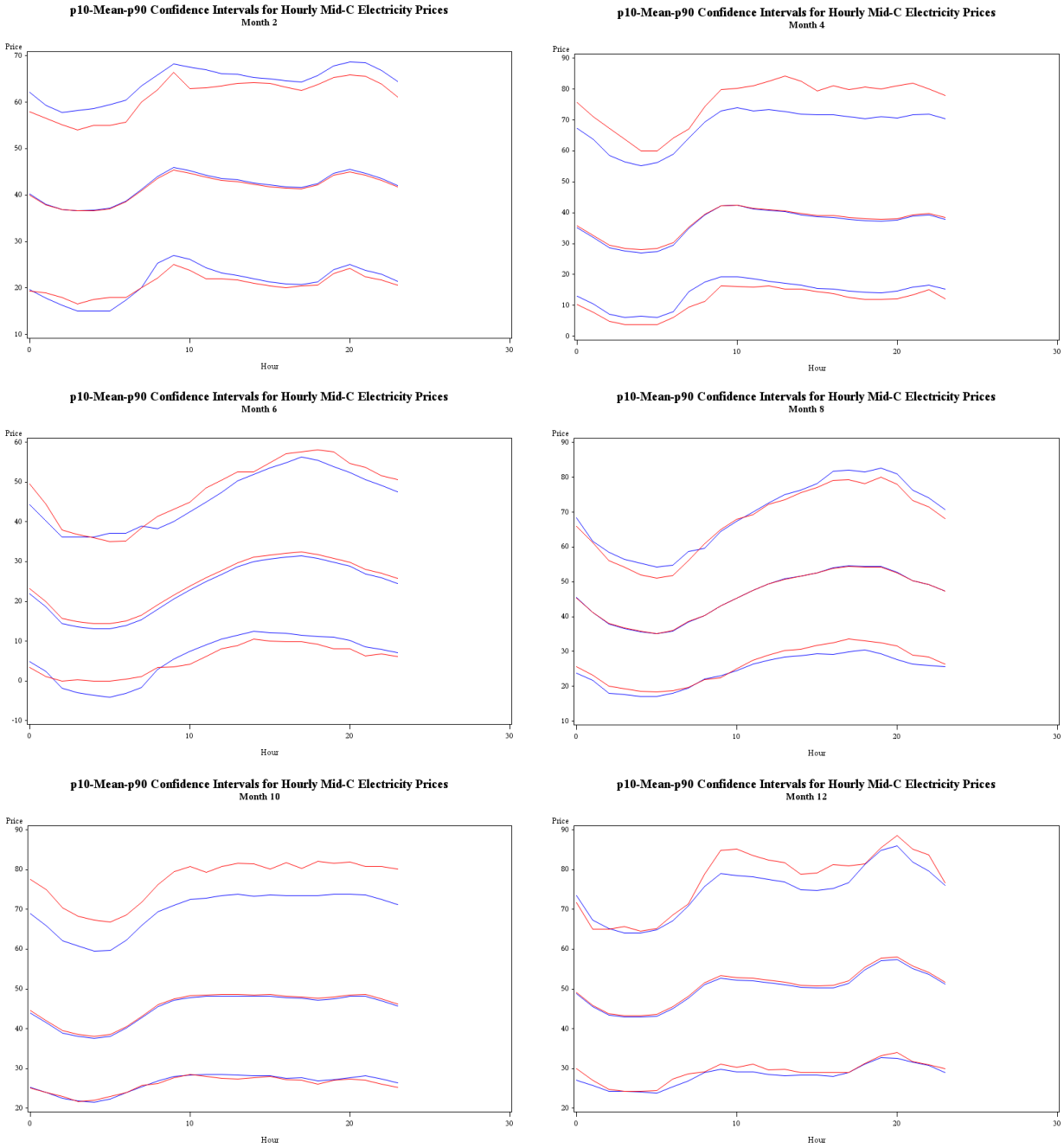
Validation of Simulated Spot Prices

As discussed in the body of the report, the hourly profile of electricity spot prices varies significantly by month. These monthly variations are closely related to the variation in hourly load profile by month, due to the high correlation between spot prices and system load. Figure 6-6 illustrates the simulated (blue) and historical (red) hourly spot price profiles for Mid-C electricity by month, for six months of the

year. The figure shows the excellent distributional agreement between the simulated and historical data, across all months.

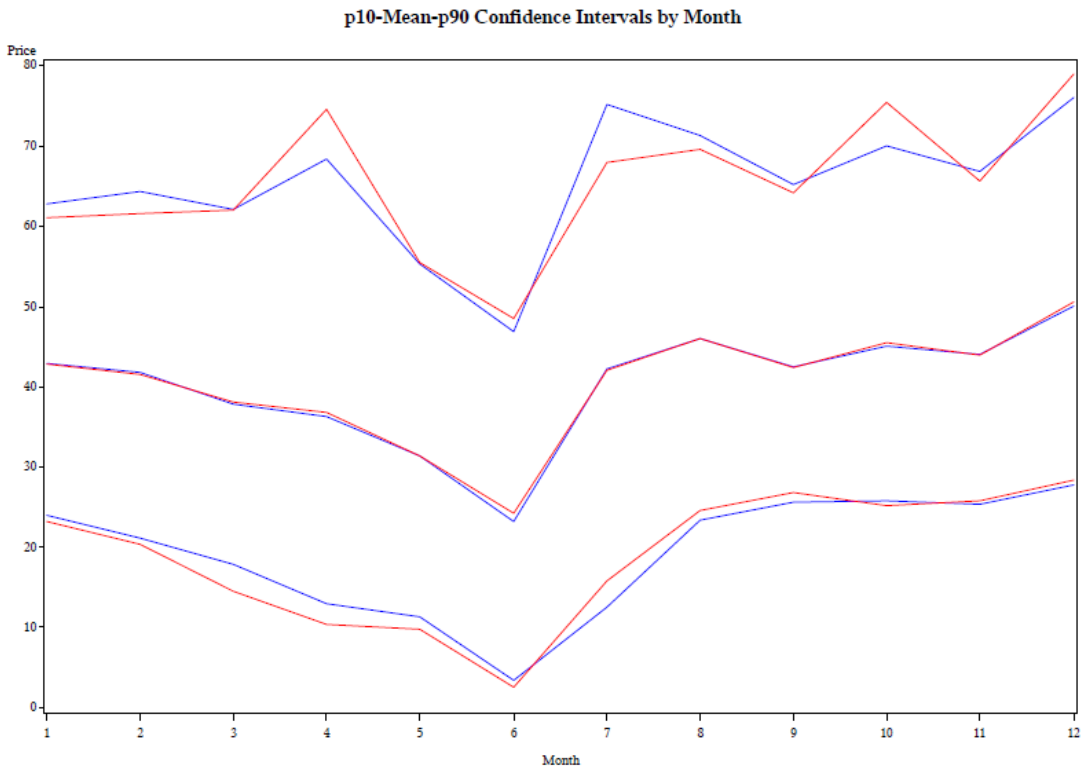
Figure 6-6

Historical and Simulated Spot Prices



In addition to the plots on the monthly-hourly timescale shown above, the simulated spot prices are also viewed across other scales to ensure robustness of the results. Plots of the simulated (blue) and historical (red) mean and the 10th and 90th percentiles for the spot price of Mid-C electricity by month and by hour are given in Figure 6-7 and Figure 6-8, respectively. These plots illustrate the excellent distributional agreement between simulated and historical spot prices across a very broad range of timescales.

Figure 6-7



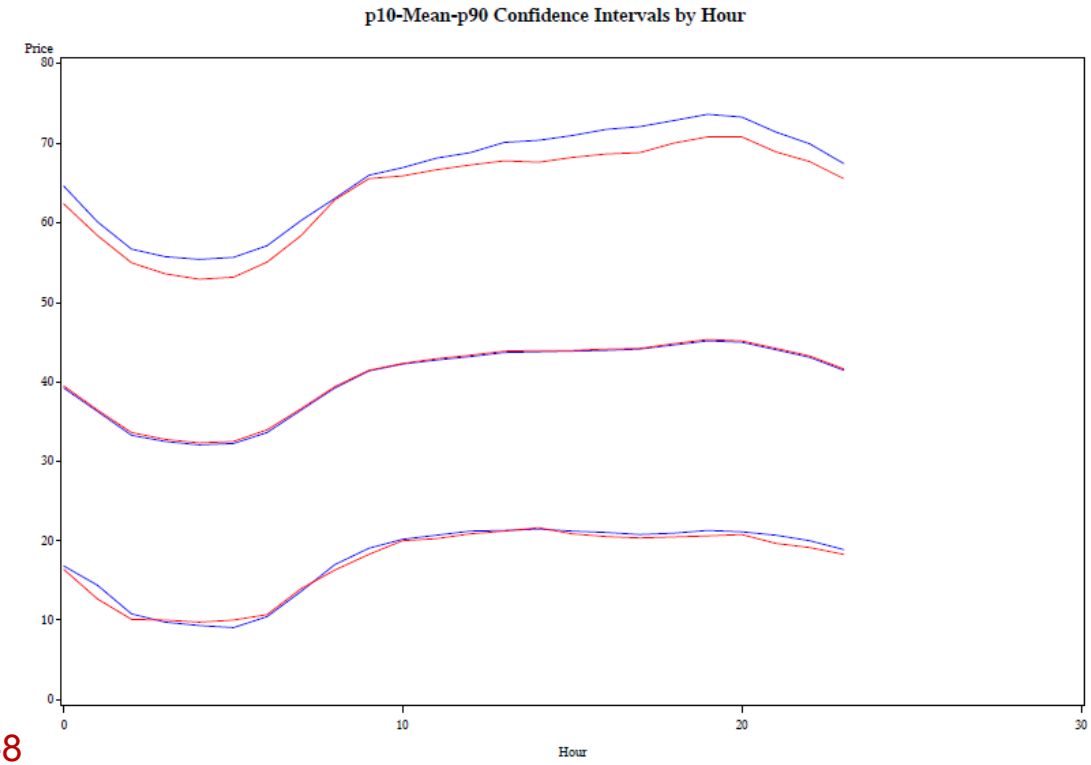
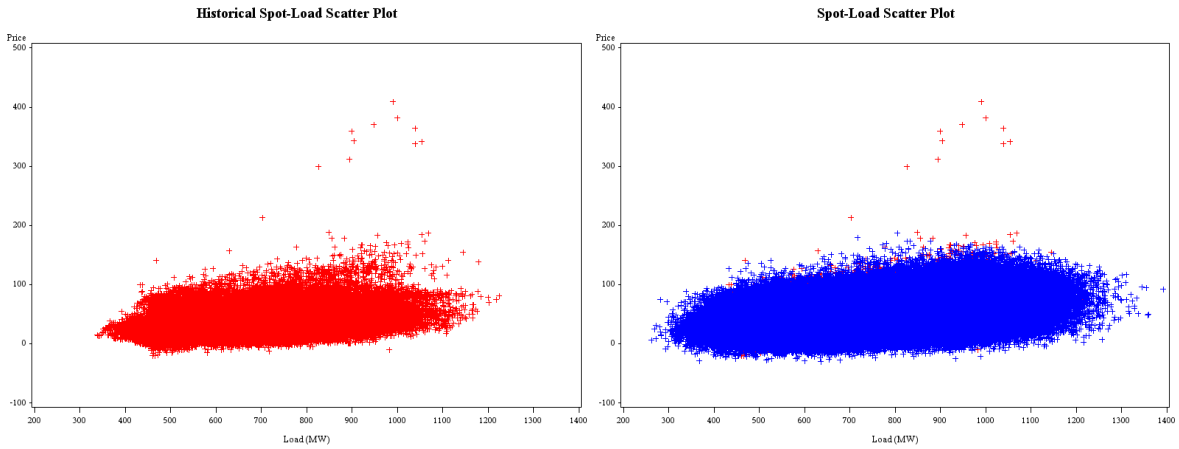


Figure 6-8

Lastly, as discussed in the body of the report, the simulation output accurately captures the relationship between Mid-C electricity spot prices and system load. Figure 6-9 illustrates this relationship; the left pane displays only historical prices, and the right pane displays an overlay of simulated (blue) and historical (red) prices, showing the excellent agreement between the two.

Figure 6-9

(Left) Historical Mid-C Spot Price vs. System Load;
(Right) Overlay of Historical (Red) and Simulated (Blue) Mid-C Spot Price vs. System Load



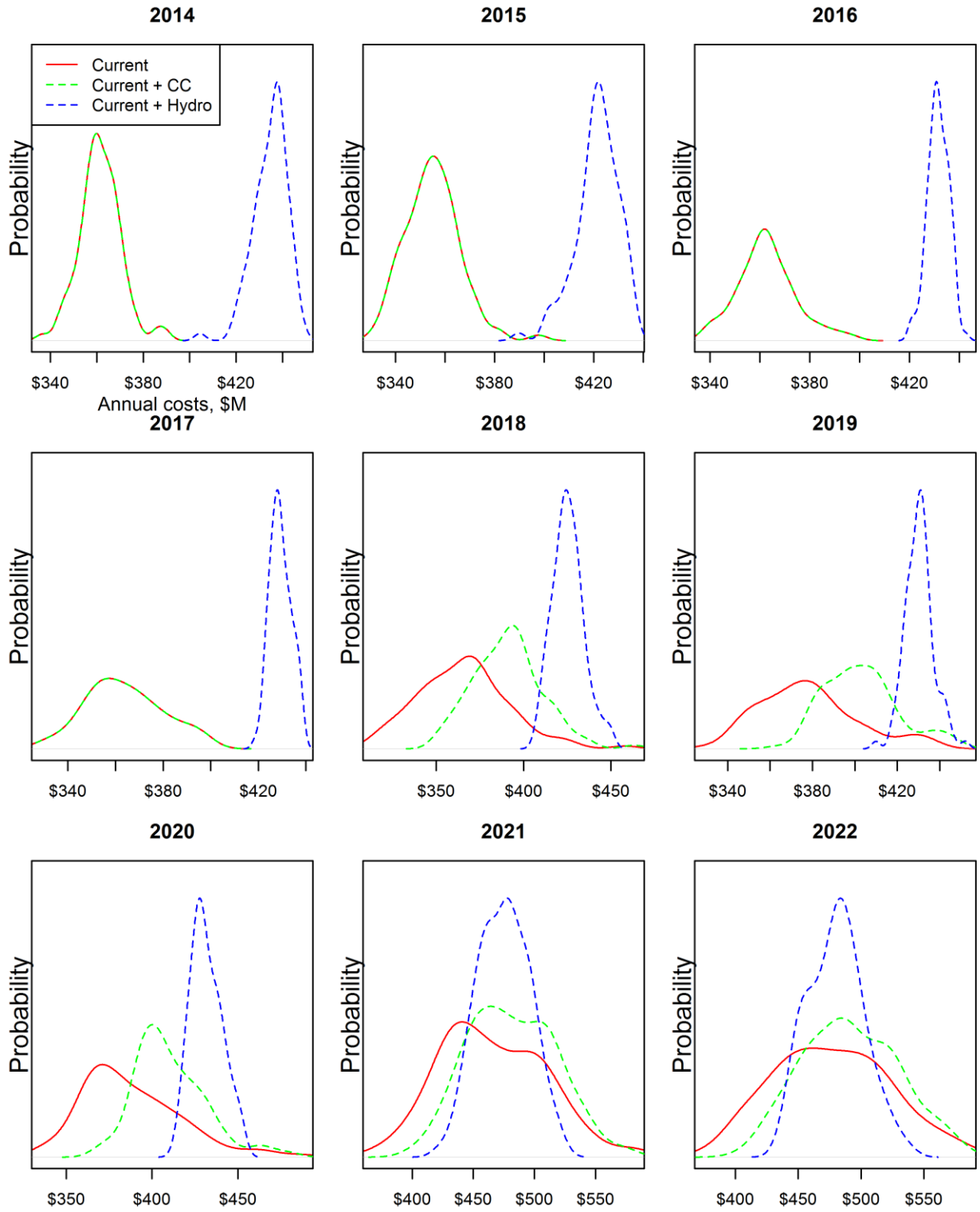
Modeling Results Annually

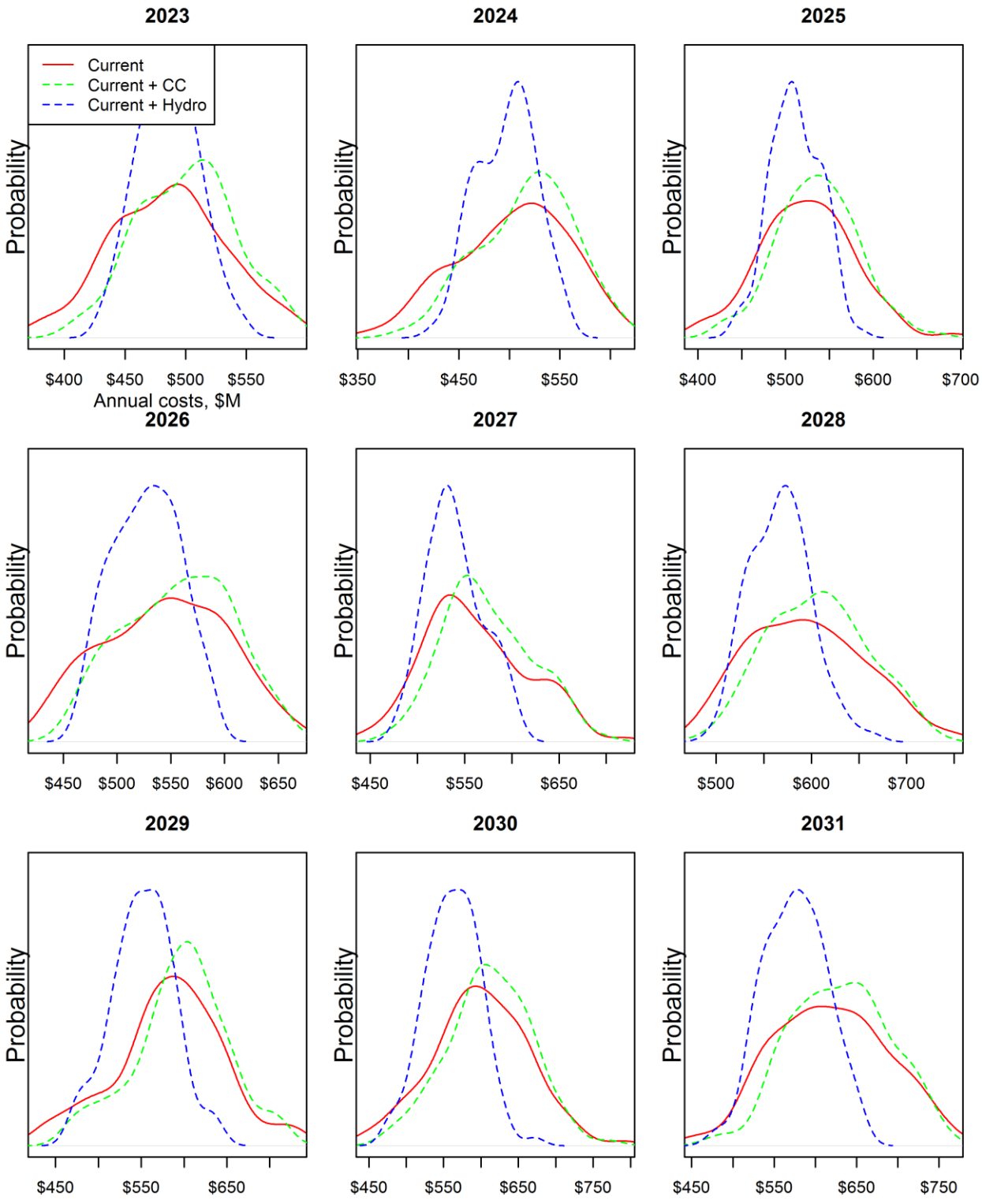
Portfolio cost distributions

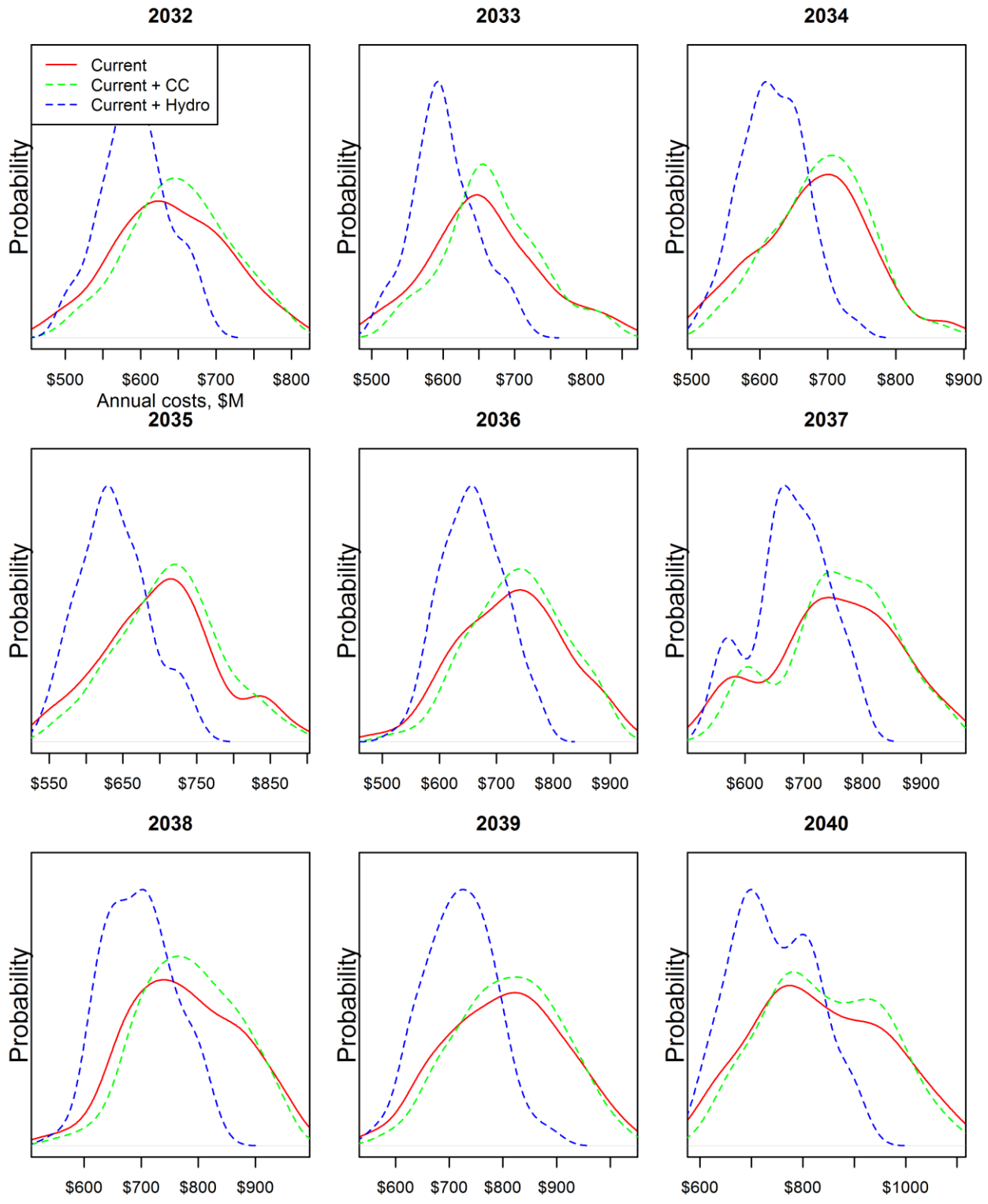
Figure 6-10 below shows the distribution of annual costs by portfolio for each simulated year. The X-axis represents the total annual portfolio costs, and the Y-axis represents the probability associated with that cost based on a kernel density estimator applied to the iteration-level cost realizations. The spread of the hydro portfolio in all years is tighter than the other two portfolio options, reflecting the lower exposure to variability in prices. For the first four years of the study, the curves for the current portfolio and the CC addition lie on top of each other, because the CC is assumed to come online in 2018.

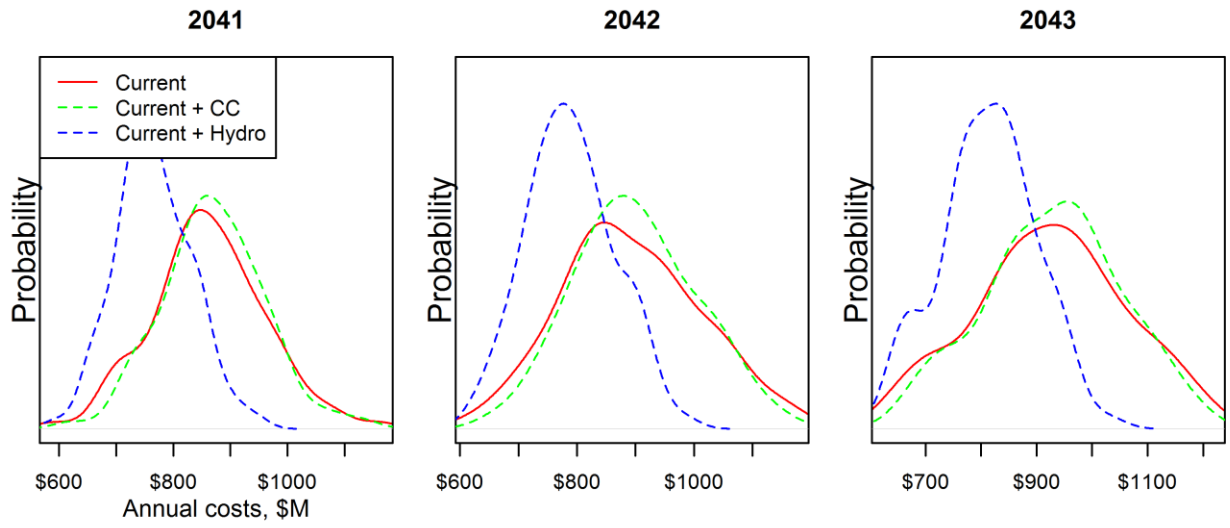
Figure 6-10

Distribution of Annual Cost by Portfolio for Each Year




2023
2024
2025
2026
2027
2028
2029
2030
2031
Current
Current + CC
Current + Hydro
Probability
Annual costs, $M
$400 $450 $500 $550
$350 $450 $550
$400 $500 $600 $700
$450 $500 $550 $600 $650
$450 $550 $650
$500 $600 $700
$450 $550 $650
$450 $550 $650 $750
$450 $550 $650 $750

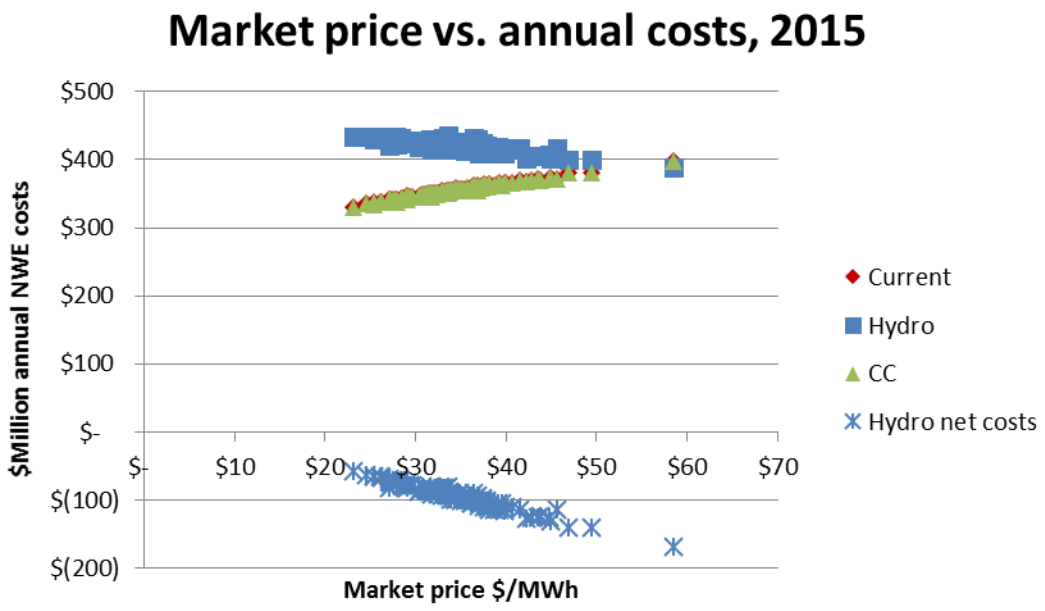

2032
2033
2034
2035
2036
2037
2038
2039
2040
Current
Current + CC
Current + Hydro
Probability
Annual costs, $M
$500
$600
$700
$800
$900
$1000
$550
$650
$750
$850

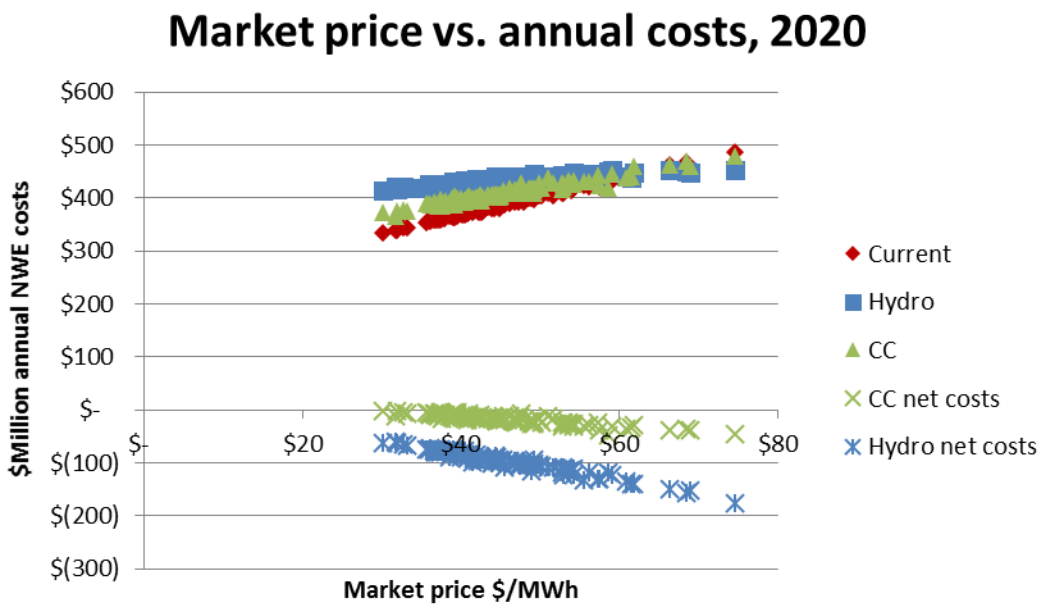


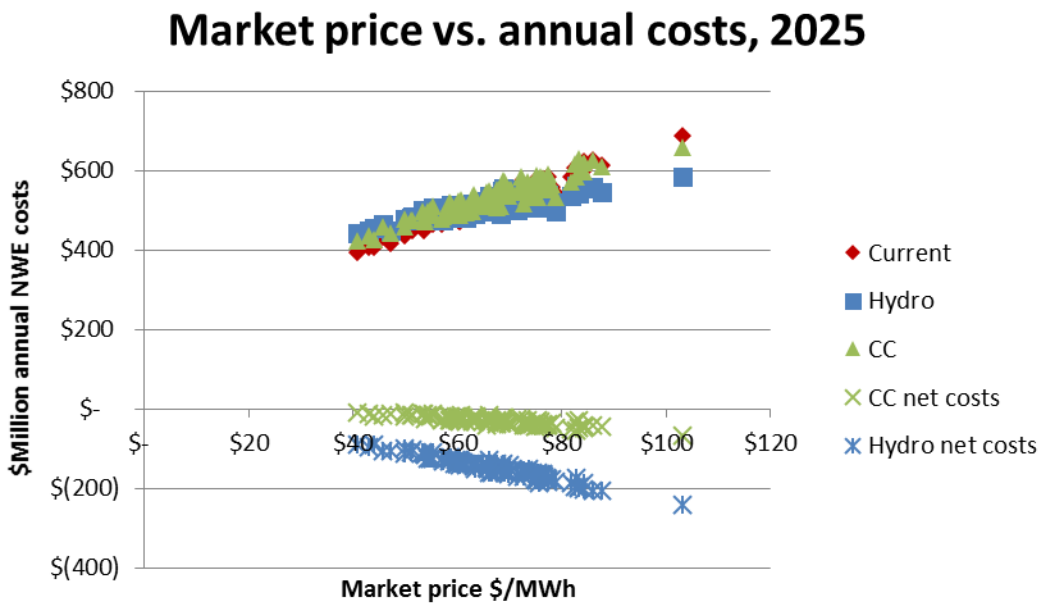
Payoff diagrams

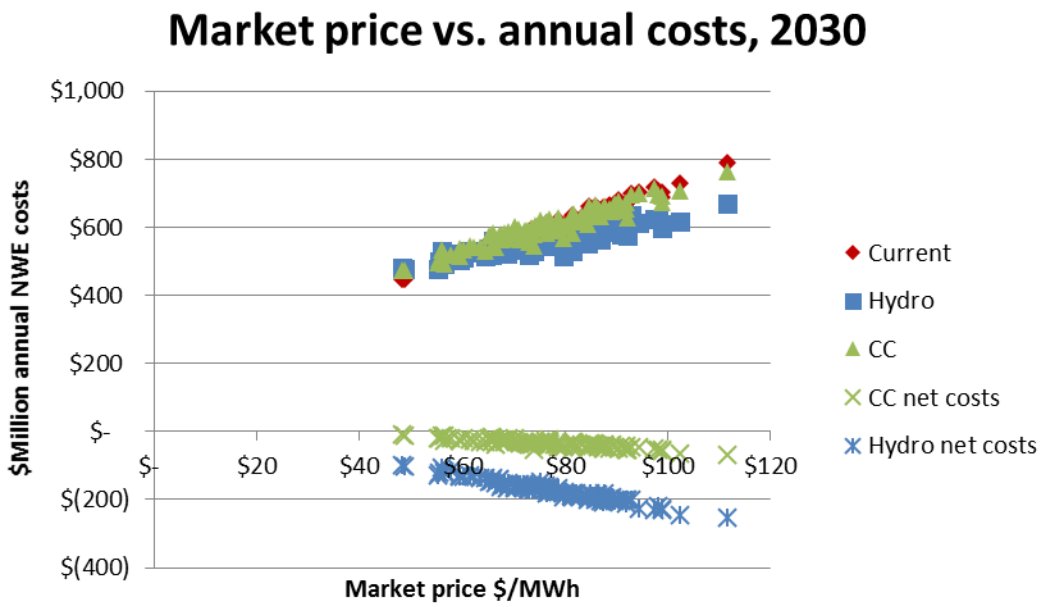
The charts in Figure 6-11 illustrate the differing sensitivity of the three portfolio options to changes in Mid-C market price. The X-axis of these charts shows the annual average Mid-C market prices, across all iterations of the price simulations. The Y-axis shows the total NorthWestern costs, including fixed costs of generation assets, variable costs, contracts, and purchases, netting out market sales from owned assets. A positive slope to the scatter of points for a given portfolio indicates a short position; i.e., as power prices increase, so do total costs. A negative slope indicates the opposite. Lines below the X-axis show the net costs (i.e. negative revenues) of the hydro and CC assets in their respective portfolios. Both of these lines show a negative slope, because as power costs increase, sales from these assets earn more revenue.

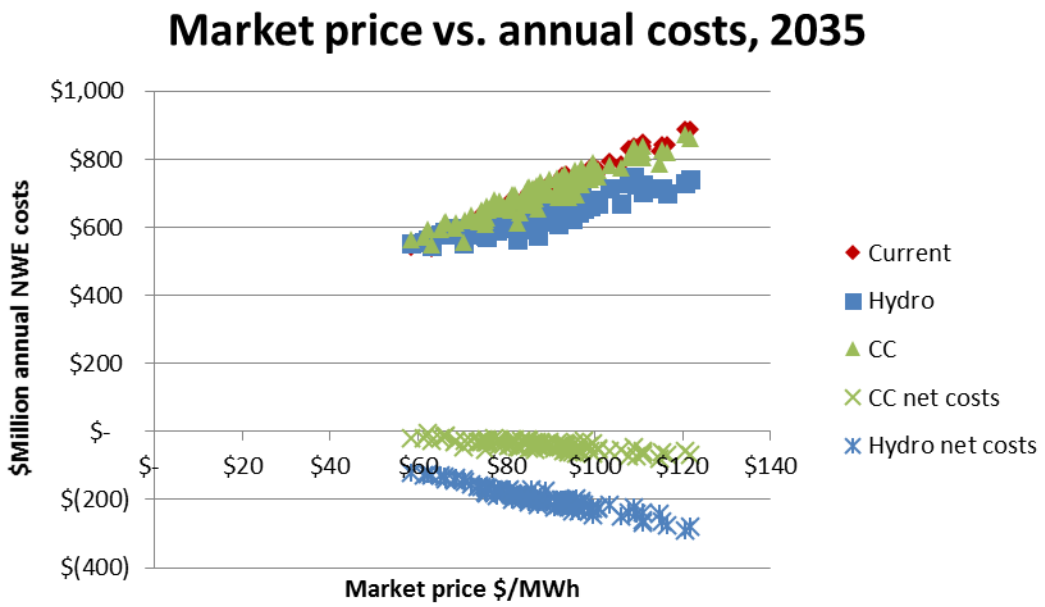
Figure 6-11

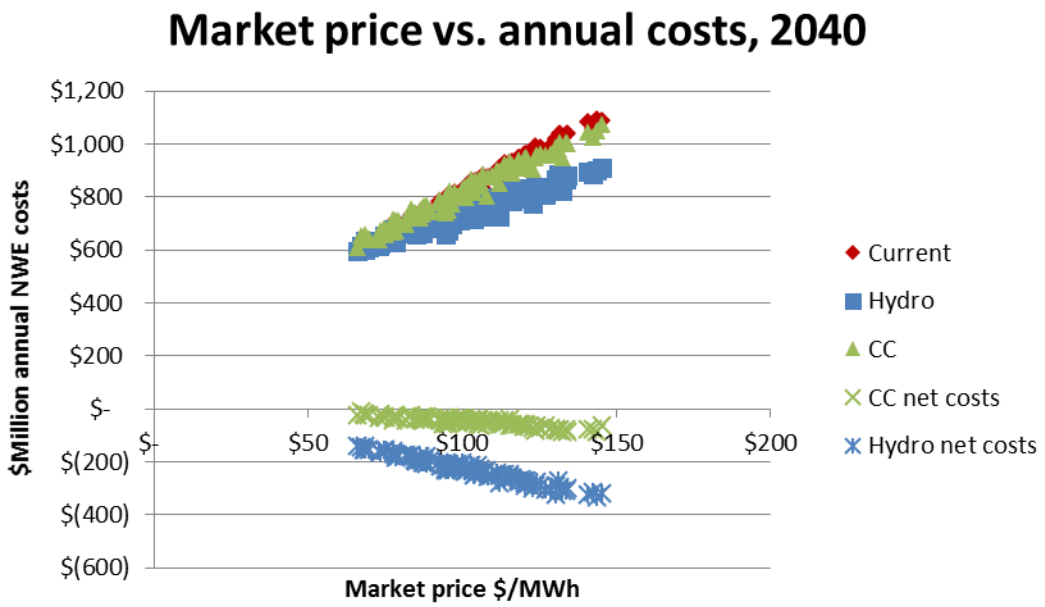

Market price vs. annual costs, 2015
$500
$400
$300
$200
$100
$-
$(100)
$(200)
$Million annual NWE costs
$-
$10
$20
$30
$40
$50
$60
$70
Market price $/MWh
Current
Hydro
CC
Hydro net costs


Market price vs. annual costs, 2020
$600
$500
$400
$300
$200
$100
$-
$(100)
$(200)
$(300)
$Million annual NWE costs
$-
$20
$40
$60
$80
Market price $/MWh
Current
Hydro
CC
CC net costs
Hydro net costs


Market price vs. annual costs, 2025
$800
$600
$400
$200
$-
$(200)
$(400)
$Million annual NWE costs
$-
$20
$40
$60
$80
$100
$120
Market price $/MWh
Current
Hydro
CC
CC net costs
Hydro net costs

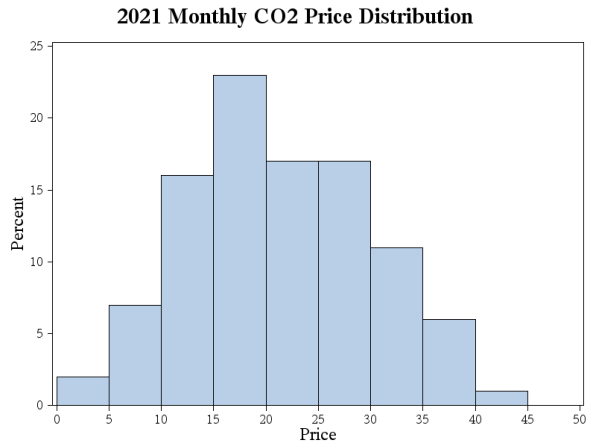

Market price vs. annual costs, 2030
$1,000
$800
$600
$400
$200
$-
$(200)
$(400)
$Million annual NWE costs
$-
$20
$40
$60
$80
$100
$120
Market price $/MWh
Current
Hydro
CC
CC net costs
Hydro net costs

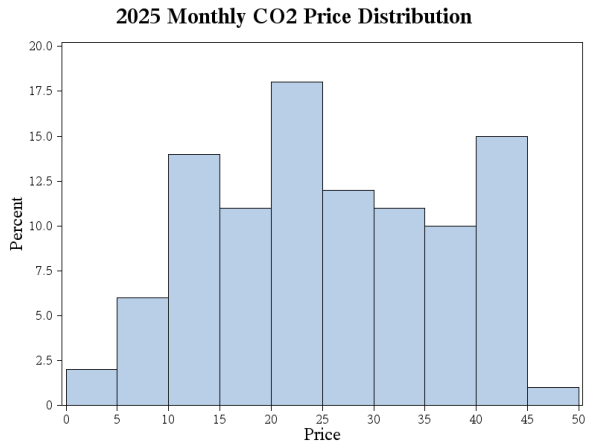

Market price vs. annual costs, 2035
$Million annual NWE costs
$1,000
$800
$600
$400
$200
$-
$(200)
$(400)
$-
$20
$40
$60
$80
$100
$120
$140
Market price $/MWh
Current
Hydro
CC
CC net costs
Hydro net costs

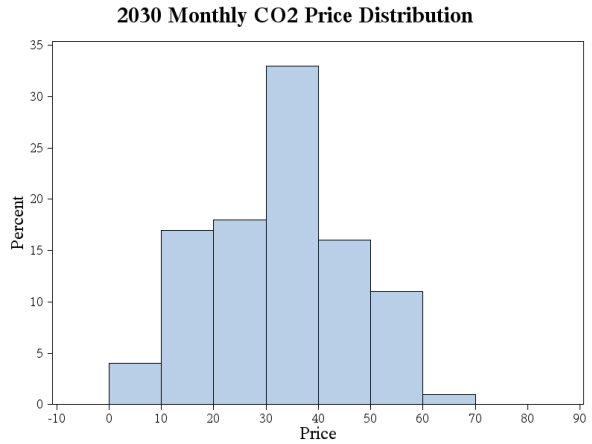

Market price vs. annual costs, 2040
$Million annual NWE costs
$1,200
$1,000
$800
$600
$400
$200
$-
$(200)
$(400)
$(600)
$-
$50
$100
$150
$200
Market price $/MWh
Current
Hydro
CC
CC net costs
Hydro net costs

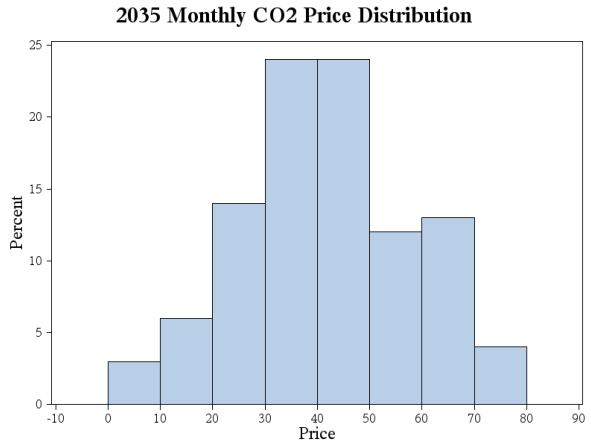
CO_2 Price Distributions

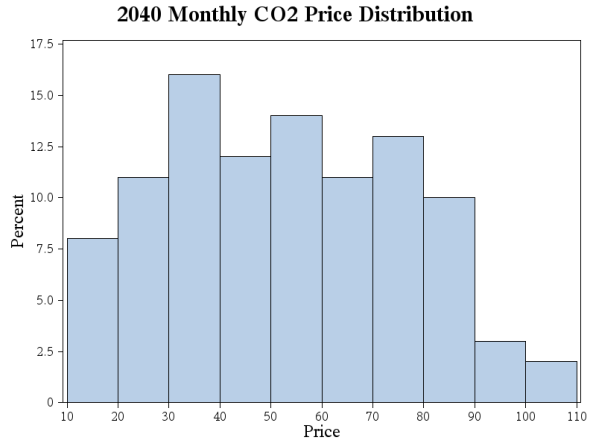
The forward price of CO_2 is simulated using a triangular distribution, with non-zero prices beginning in January of 2021. The simulated distribution of forward CO_2 prices is identical in all months of any given year, and the monthly distributions are shown in the chart below for select years. Note that the mean and variance of the monthly CO_2 price distributions both grow by year, and that the left endpoint of the triangular distribution for each year is anchored at zero. This allows the simulations to capture carbon scenarios that range from a minimal effect on electricity prices to a much more pronounced effect.

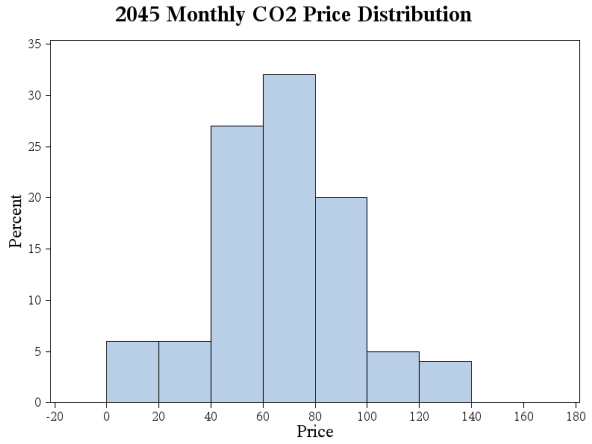

2021 Monthly CO2 Price Distribution
Percent
Price


2025 Monthly CO2 Price Distribution
Percent
Price


2030 Monthly CO2 Price Distribution
Percent
Price


2035 Monthly CO2 Price Distribution
Percent
Price


2040 Monthly CO2 Price Distribution
Percent
Price


2045 Monthly CO2 Price Distribution
Percent
Price

Detailed PowerSimm Results

Three spreadsheets with detailed, unit- and portfolio-level results from the PowerSimm dispatch simulations are included below. The net position report includes annual generation of each asset as well as load obligations during heavy load, light load, and all hours, with mean, 5th, and 95th percentile confidence intervals for each year. The generating stations report includes detailed dispatch results for each thermal and hydro asset in NorthWestern's portfolio, including capacity factor, emissions, and several cost categories, with expected values and confidence intervals for each year in the study horizon. Finally, the portfolio supply cost report includes annual, portfolio-level results for market purchases, sales, and fixed and operating costs, for each of the three portfolios analyzed in this study.

Net Position Report - Heavy Load Hours (GWh)

	Net Position, GWh		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Generating Assets		MEAN	6	9	17	17	18	20	29	33	37	37	42	42	44	43
		P5	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Basin Creek 1-9	P95	32	43	67	83	90	94	115	122	115	124	126	121	129	138
		MEAN	452	453	432	460	465	485	497	397	398	384	402	385	383	395
		P5	377	368	370	379	373	395	433	199	143	98	155	89	138	150
	Colstrip 3	P95	503	508	501	508	508	512	515	511	507	502	504	504	513	508
		MEAN	453	454	402	460	465	433	498	397	371	384	403	362	383	394
		P5	376	374	369	377	372	390	426	203	146	93	145	86	143	133
	Colstrip 4	P95	503	505	435	508	510	454	519	513	441	508	506	449	511	507
		MEAN	33	33	34	33	33	33	34	34	34	33	33	33	33	34
		P5	33	33	33	33	33	33	33	33	33	33	33	33	33	33
	David Gates	P95	34	34	34	34	34	34	34	34	34	34	34	34	34	34
		MEAN	0	0	0	0	975	994	981	1069	1068	1064	1071	1078	1075	1088
		P5	0	0	0	0	653	803	631	931	898	879	908	980	950	1015
	New CCCT	P95	0	0	0	0	1093	1088	1103	1121	1124	1113	1124	1118	1125	1122
		MEAN	606	446	0	0	0	0	0	0	0	0	0	0	0	0
		P5	566	403	0	0	0	0	0	0	0	0	0	0	0	0
	Kerr	P95	656	480	0	0	0	0	0	0	0	0	0	0	0	0
		MEAN	1392	1397	1396	1392	1392	1392	1398	1402	1401	1392	1393	1392	1397	1402
		P5	1293	1268	1280	1295	1293	1293	1292	1311	1317	1281	1291	1282	1279	1314
	Other Hydro	P95	1515	1493	1514	1482	1491	1486	1522	1502	1511	1500	1496	1490	1517	1522
		MEAN	1998	1843	1396	1392	1392	1392	1398	1402	1401	1392	1393	1392	1397	1402
		P5	1862	1685	1280	1295	1293	1293	1292	1311	1317	1281	1291	1282	1279	1314
	Total Hydro	P95	2171	1975	1514	1482	1491	1486	1522	1502	1511	1500	1496	1490	1517	1522
		MEAN	546	556	564	568	575	581	594	601	609	611	620	627	635	643
		P5	491	505	504	507	525	529	534	548	542	537	551	557	563	569
	Wind - Total	P95	607	607	612	623	627	631	652	664	661	663	695	692	699	714
Physical Instruments		MEAN	184	146	168	185	147	168	185	146	168	184	147	167	185	145
		P5	184	146	168	185	147	168	185	146	168	184	147	167	185	145
	CELP Contract	P95	184	146	168	185	147	168	185	146	168	184	147	167	185	145
		MEAN	123	123	124	62	0	0	0	0	0	0	0	0	0	0
		P5	123	123	124	62	0	0	0	0	0	0	0	0	0	0
	PPL 09 RFP (HL)	P95	123	123	124	62	0	0	0	0	0	0	0	0	0	0
		MEAN	490	0	0	0	0	0	0	0	0	0	0	0	0	0
		P5	490	0	0	0	0	0	0	0	0	0	0	0	0	0
	PPL 7 YR (HL)	P95	490	0	0	0	0	0	0	0	0	0	0	0	0	0

Net Position Report - Heavy Load Hours (GWh)

	Net Position, GWh		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	Small QF1	MEAN	6	6	6	6	6	6	6	6	6	6	6	6	6	6
		P5	6	6	6	6	6	6	6	6	6	6	6	6	6	6
		P95	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	Small QF2	MEAN	46	46	46	46	46	46	46	46	46	46	46	46	46	46
		P5	46	46	46	46	46	46	46	46	46	46	46	46	46	46
		P95	46	46	46	46	46	46	46	46	46	46	46	46	46	46
	Tiber	MEAN	14	14	14	14	14	14	14	14	14	14	14	14	14	14
		P5	14	14	14	14	14	14	14	14	14	14	14	14	14	14
		P95	14	14	14	14	14	14	14	14	14	14	14	14	14	14
	TransAlta 10 RFP (HL)	MEAN	123	123	124	62	0	0	0	0	0	0	0	0	0	0
		P5	123	123	124	62	0	0	0	0	0	0	0	0	0	0
		P95	123	123	124	62	0	0	0	0	0	0	0	0	0	0
	Turnbull	MEAN	18	19	19	19	19	19	19	19	19	19	19	18	19	19
		P5	18	19	19	19	19	19	19	19	19	19	19	18	19	19
		P95	18	19	19	19	19	19	19	19	19	19	19	18	19	19
	YELP Contract	MEAN	222	248	253	221	246	250	224	248	254	221	247	250	222	248
		P5	222	248	253	221	246	250	224	248	254	221	247	250	222	248
		P95	222	248	253	221	246	250	224	248	254	221	247	250	222	248
Load	NWE Load	MEAN	-3995	-4025	-4062	-4050	-4067	-4087	-4131	-4150	-4158	-4149	-4213	-4254	-4318	-4396
		P5	-4030	-4061	-4088	-4087	-4102	-4116	-4167	-4188	-4205	-4180	-4252	-4293	-4352	-4439
		P95	-3965	-3992	-4028	-4017	-4031	-4052	-4095	-4118	-4118	-4110	-4179	-4218	-4282	-4365
Total by Portfolio	Current Portfolio	MEAN	-1280	-1795	-1860	-1900	-2033	-2034	-1986	-2210	-2203	-2210	-2235	-2302	-2349	-2410
		P5	-1444	-2000	-1998	-2093	-2243	-2191	-2126	-2624	-2748	-2824	-2735	-2940	-2880	-2943
		P95	-1131	-1636	-1687	-1737	-1885	-1879	-1838	-1888	-1930	-1877	-1961	-2025	-1990	-2098
	Current + CC	MEAN	-1280	-1795	-1860	-1900	-1058	-1040	-1005	-1141	-1135	-1147	-1164	-1224	-1273	-1322
		P5	-1444	-2000	-1998	-2093	-1567	-1433	-1476	-1616	-1788	-1780	-1731	-1870	-1967	-1832
		P95	-1131	-1636	-1687	-1737	-798	-775	-745	-791	-835	-775	-858	-929	-889	-986
	Current Portfolio + Hydro	MEAN	718	48	-463	-507	-641	-642	-588	-808	-802	-819	-842	-910	-952	-1008
		P5	511	-198	-660	-736	-845	-835	-761	-1201	-1410	-1366	-1333	-1611	-1544	-1574
		P95	994	260	-244	-320	-453	-454	-405	-446	-533	-477	-551	-616	-566	-627

Net Position Report - Heavy Load Hours (GWh)

	Net Position, GWh		2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Generating Assets		MEAN	46	46	45	51	48	53	52	54	53	55	59	56	55	58	58	63
		P5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Basin Creek 1-9	P95	158	127	135	153	138	166	165	171	156	148	170	143	154	159	188	173
		MEAN	385	376	365	369	359	363	341	335	335	336	321	314	314	289	283	279
		P5	125	77	2	87	55	58	45	1	0	0	0	0	0	0	0	0
	Colstrip 3	P95	507	505	506	500	510	506	504	506	504	504	507	506	498	502	500	500
		MEAN	362	375	365	351	358	362	321	335	336	321	323	315	300	290	283	267
		P5	123	74	1	72	52	59	42	0	0	0	0	0	0	0	0	0
	Colstrip 4	P95	438	504	504	445	509	508	436	503	511	452	510	510	432	505	495	442
		MEAN	33	33	33	33	34	34	33	33	33	33	34	34	33	33	33	33
		P5	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33
	David Gates	P95	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
		MEAN	1083	1077	1083	1079	1093	1090	1082	1085	1086	1088	1089	1096	1093	1092	1088	1089
		P5	1009	963	1034	981	1008	983	978	1038	1018	1018	1009	1047	1025	1049	1010	972
	New CCCT	P95	1127	1121	1118	1122	1139	1135	1126	1125	1129	1131	1136	1134	1134	1128	1128	1133
		MEAN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		P5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Kerr	P95	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		MEAN	1393	1392	1392	1392	1403	1400	1392	1392	1393	1397	1402	1400	1393	1392	1392	1397
		P5	1278	1300	1302	1295	1286	1288	1268	1265	1274	1277	1289	1282	1286	1288	1277	1275
	Other Hydro	P95	1512	1499	1500	1492	1503	1502	1496	1515	1489	1480	1511	1510	1494	1499	1496	1497
		MEAN	1393	1392	1392	1392	1403	1400	1392	1392	1393	1397	1402	1400	1393	1392	1392	1397
		P5	1278	1300	1302	1295	1286	1288	1268	1265	1274	1277	1289	1282	1286	1288	1277	1275
	Total Hydro	P95	1512	1499	1500	1492	1503	1502	1496	1515	1489	1480	1511	1510	1494	1499	1496	1497
		MEAN	651	655	660	669	682	689	692	697	708	715	724	735	739	744	753	762
		P5	588	590	611	605	611	624	625	624	641	635	654	652	653	684	675	680
	Wind - Total	P95	729	731	726	757	766	765	764	768	782	789	800	825	823	827	842	850
Physical Instruments		MEAN	167	184	146	166	186	147	166	186	147	166	186	147	166	186	147	166
		P5	167	184	146	166	186	147	166	186	147	166	186	147	166	186	147	166
	CELP Contract	P95	167	184	146	166	186	147	166	186	147	166	186	147	166	186	147	166
		MEAN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		P5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	PPL 09 RFP (HL)	P95	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		MEAN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		P5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	PPL 7 YR (HL)	P95	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Net Position Report - Heavy Load Hours (GWh)

	Net Position, GWh		2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
	Small QF1	MEAN	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
		P5	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
		P95	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	Small QF2	MEAN	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46
		P5	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46
		P95	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46
	Tiber	MEAN	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
		P5	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
		P95	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
	TransAlta 10 RFP (HL)	MEAN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		P5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		P95	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Turnbull	MEAN	19	19	19	18	19	19	19	19	18	19	19	19	19	19	18	19
		P5	19	19	19	18	19	19	19	19	18	19	19	19	19	19	18	19
		P95	19	19	19	18	19	19	19	19	18	19	19	19	19	19	18	19
	YELP Contract	MEAN	253	221	247	251	224	248	251	224	248	251	224	248	251	224	248	251
		P5	253	221	247	251	224	248	251	224	248	251	224	248	251	224	248	251
		P95	253	221	247	251	224	248	251	224	248	251	224	248	251	224	248	251
Load	NWE Load	MEAN	-4426	-4464	-4519	-4574	-4682	-4718	-4737	-4807	-4885	-4936	-5009	-5070	-5101	-5137	-5215	-5288
		P5	-4462	-4499	-4561	-4620	-4722	-4759	-4780	-4853	-4926	-4971	-5043	-5110	-5147	-5181	-5262	-5335
		P95	-4388	-4423	-4480	-4537	-4633	-4681	-4698	-4771	-4843	-4896	-4975	-5029	-5050	-5088	-5173	-5250
Total by Portfolio	Current Portfolio	MEAN	-2445	-2489	-2573	-2600	-2706	-2739	-2796	-2858	-2941	-2975	-3053	-3137	-3159	-3230	-3325	-3382
		P5	-2964	-3154	-3273	-3188	-3315	-3429	-3431	-3577	-3631	-3690	-3735	-3804	-3787	-3871	-3965	-4028
		P95	-2150	-2180	-2211	-2299	-2366	-2386	-2428	-2428	-2519	-2599	-2614	-2736	-2776	-2673	-2779	-2922
	Current + CC	MEAN	-1361	-1413	-1491	-1520	-1613	-1649	-1715	-1773	-1855	-1887	-1965	-2041	-2066	-2138	-2237	-2293
		P5	-1908	-2072	-2199	-2096	-2179	-2298	-2339	-2481	-2522	-2570	-2642	-2699	-2673	-2777	-2896	-2935
		P95	-1047	-1073	-1114	-1204	-1258	-1283	-1309	-1344	-1418	-1507	-1511	-1638	-1672	-1575	-1665	-1807
	Current Portfolio + Hydro	MEAN	-1052	-1097	-1181	-1208	-1303	-1339	-1404	-1466	-1548	-1578	-1652	-1737	-1766	-1838	-1933	-1985
		P5	-1636	-1767	-1885	-1844	-1873	-1983	-2091	-2169	-2269	-2297	-2362	-2356	-2443	-2480	-2611	-2573
		P95	-722	-710	-779	-869	-888	-923	-988	-1013	-1102	-1191	-1176	-1269	-1317	-1228	-1393	-1525

Net Position Report - Light Load Hours (GWh)

			2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Generating Assets	Basin Creek 1-9	MEAN	0	0	0	0	0	0	1	1	1	1	1	1	1	1	2	1
		P5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		P95	0	0	1	1	1	1	3	5	5	6	5	5	8	7	13	8
	Colstrip 3	MEAN	318	329	308	334	342	357	368	290	288	285	295	284	281	286	283	276
		P5	288	285	284	290	290	303	321	144	94	71	111	57	94	93	79	49
		P95	351	370	343	373	376	379	385	374	368	372	373	375	375	368	376	372
	Colstrip 4	MEAN	318	328	299	335	341	327	369	291	274	286	295	272	282	285	271	275
		P5	288	281	284	293	290	298	316	149	104	67	102	57	100	83	83	46
		P95	355	369	317	371	375	342	387	377	323	378	376	337	377	368	333	371
	David Gates	MEAN	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
		P5	26	26	26	26	26	26	26	26	25	26	26	26	26	26	26	26
		P95	27	26	26	27	27	26	26	26	26	27	27	27	26	26	27	27
	New CCCT	MEAN	0	0	0	0	573	565	619	682	676	690	693	691	694	694	697	696
		P5	0	0	0	0	273	290	370	643	623	644	628	626	645	646	642	636
		P95	0	0	0	0	672	673	682	746	730	745	758	754	752	747	754	754
	Kerr	MEAN	472	341	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		P5	440	312	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		P95	509	368	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Other Hydro	MEAN	1095	1090	1091	1095	1095	1095	1090	1085	1086	1096	1094	1095	1090	1085	1095	1095
		P5	1016	990	999	1018	1018	1020	1008	1021	1023	1005	1012	1008	1002	1014	1010	1027
		P95	1187	1165	1183	1165	1175	1173	1188	1161	1169	1182	1176	1171	1178	1175	1185	1180
	Total Hydro	MEAN	1567	1431	1091	1095	1095	1095	1090	1085	1086	1096	1094	1095	1090	1085	1095	1095
		P5	1455	1308	999	1018	1018	1020	1008	1021	1023	1005	1012	1008	1002	1014	1010	1027
		P95	1695	1526	1183	1165	1175	1173	1188	1161	1169	1182	1176	1171	1178	1175	1185	1180
	Wind - Total	MEAN	393	396	404	410	415	422	425	427	431	441	447	448	454	458	466	471
		P5	351	358	362	368	371	381	382	384	382	396	399	410	404	407	422	428
		P95	432	438	436	451	458	465	467	463	474	493	486	493	498	511	505	516
Physical Instruments	CELP Contract	MEAN	147	115	133	146	114	133	146	115	132	147	115	134	146	116	134	147
		P5	147	115	133	146	114	133	146	115	132	147	115	134	146	116	134	147
		P95	147	115	133	146	114	133	146	115	132	147	115	134	146	116	134	147
	PPL 7 YR (LL)	MEAN	237	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		P5	237	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		P95	237	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Small QF1	MEAN	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
		P5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
		P95	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5

Net Position Report - Light Load Hours (GWh)

			2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
	Small QF2	MEAN	36	35	36	36	36	36	35	35	36	36	36	36	35	35	36	36
		P5	36	35	36	36	36	36	35	35	36	36	36	36	35	35	36	36
		P95	36	35	36	36	36	36	35	35	36	36	36	36	35	35	36	36
	Tiber	MEAN	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
		P5	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
		P95	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
	Turnbull	MEAN	15	14	15	15	15	15	14	14	15	15	15	15	14	14	15	15
		P5	15	14	15	15	15	15	14	14	15	15	15	15	14	14	15	15
		P95	15	14	15	15	15	15	14	14	15	15	15	15	14	14	15	15
	YELP Contract	MEAN	176	197	202	177	198	204	175	196	199	177	198	203	176	196	202	177
		P5	176	197	202	177	198	204	175	196	199	177	198	203	176	196	202	177
		P95	176	197	202	177	198	204	175	196	199	177	198	203	176	196	202	177
Load	NWE Load	MEAN	-2477	-2481	-2499	-2522	-2538	-2545	-2557	-2550	-2566	-2597	-2633	-2660	-2691	-2704	-2774	-2799
		P5	-2501	-2503	-2518	-2546	-2562	-2571	-2583	-2572	-2594	-2624	-2657	-2691	-2715	-2733	-2803	-2828
		P95	-2452	-2460	-2478	-2496	-2514	-2523	-2530	-2529	-2540	-2571	-2610	-2634	-2668	-2678	-2748	-2772
Total by Portfolio	Current Portfolio	MEAN	-796	-1025	-1061	-1028	-1035	-1011	-982	-1139	-1149	-1168	-1191	-1225	-1259	-1270	-1323	-1360
		P5	-875	-1137	-1127	-1126	-1155	-1111	-1086	-1414	-1542	-1601	-1549	-1666	-1649	-1696	-1718	-1813
		P95	-715	-940	-1002	-947	-934	-943	-922	-953	-1010	-968	-1021	-1058	-1037	-1078	-1158	-1172
	Current Portfolio + CC	MEAN	-796	-1025	-1061	-1028	-463	-445	-363	-457	-473	-478	-497	-534	-565	-576	-626	-664
		P5	-875	-1137	-1127	-1126	-822	-704	-632	-753	-869	-908	-861	-970	-994	-982	-1012	-1062
		P95	-715	-940	-1002	-947	-297	-287	-249	-267	-325	-273	-313	-365	-337	-372	-447	-479
	Current Portfolio + Hydro	MEAN	772	406	30	66	60	84	107	-54	-62	-72	-96	-130	-169	-185	-228	-265
		P5	629	252	-89	-67	-76	-45	-19	-331	-518	-452	-449	-616	-602	-632	-637	-723
		P95	963	548	146	181	181	203	223	159	114	150	106	68	78	70	-33	-29

Net Position Report - Light Load Hours (GWh)

			2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Generating Assets		MEAN	2	2	2	2	2	3	2	2	3	2	2	3	3	3
		P5	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Basin Creek 1-9	P95	9	9	9	9	12	15	11	8	14	9	14	11	20	18
		MEAN	269	272	263	260	249	244	246	245	230	223	228	209	201	200
		P5	1	49	35	37	29	1	0	0	0	0	0	0	0	0
	Colstrip 3	P95	374	371	371	367	368	372	373	367	362	367	353	370	362	367
		MEAN	268	262	262	260	240	244	246	238	231	223	222	210	201	196
		P5	0	43	33	39	28	0	0	0	0	0	0	0	0	0
	Colstrip 4	P95	370	337	373	370	322	372	376	336	367	373	320	373	363	329
		MEAN	26	26	26	26	26	26	26	26	26	26	26	26	26	26
		P5	26	26	26	25	26	26	26	26	26	26	26	26	26	26
	David Gates	P95	27	27	26	26	27	27	27	26	26	26	27	27	27	26
		MEAN	696	702	702	692	705	703	709	713	709	704	716	719	721	722
		P5	614	656	654	621	653	647	650	650	641	649	657	660	659	646
	New CCCT	P95	754	764	761	749	753	761	765	771	816	759	791	772	785	795
		MEAN	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		P5	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Kerr	P95	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		MEAN	1095	1095	1085	1087	1095	1095	1094	1090	1085	1087	1094	1095	1095	1090
		P5	1021	1018	990	1001	996	996	1004	997	995	991	1006	1012	999	999
	Other Hydro	P95	1176	1171	1163	1170	1181	1192	1170	1160	1173	1176	1171	1179	1175	1171
		MEAN	1095	1095	1085	1087	1095	1095	1094	1090	1085	1087	1094	1095	1095	1090
		P5	1021	1018	990	1001	996	996	1004	997	995	991	1006	1012	999	999
	Total Hydro	P95	1176	1171	1163	1170	1181	1192	1170	1160	1173	1176	1171	1179	1175	1171
		MEAN	478	481	484	486	496	503	509	512	515	518	532	537	540	546
		P5	435	436	427	437	442	456	455	462	461	464	472	483	488	474
	Wind - Total	P95	531	523	542	532	546	562	556	560	569	568	595	584	586	599
Physical Instruments		MEAN	115	134	146	114	134	146	114	134	146	114	134	146	114	134
		P5	115	134	146	114	134	146	114	134	146	114	134	146	114	134
	CELP Contract	P95	115	134	146	114	134	146	114	134	146	114	134	146	114	134
		MEAN	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		P5	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	PPL 7 YR (LL)	P95	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		MEAN	5	5	5	5	5	5	5	5	5	5	5	5	5	5
		P5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	Small QF1	P95	5	5	5	5	5	5	5	5	5	5	5	5	5	5

Net Position Report - Light Load Hours (GWh)

			2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
	Small QF2	MEAN	36	36	35	36	36	36	36	35	35	36	36	36	36	35
		P5	36	36	35	36	36	36	36	35	35	36	36	36	36	35
		P95	36	36	35	36	36	36	36	35	35	36	36	36	36	35
	Tiber	MEAN	11	11	11	11	11	11	11	11	11	11	11	11	11	11
		P5	11	11	11	11	11	11	11	11	11	11	11	11	11	11
		P95	11	11	11	11	11	11	11	11	11	11	11	11	11	11
	Turnbull	MEAN	15	15	14	15	15	15	15	14	14	15	15	15	15	14
		P5	15	15	14	15	15	15	15	14	14	15	15	15	15	14
		P95	15	15	14	15	15	15	15	14	14	15	15	15	15	14
	YELP Contract	MEAN	197	202	175	196	202	175	196	202	175	196	202	175	196	202
		P5	197	202	175	196	202	175	196	202	175	196	202	175	196	202
		P95	197	202	175	196	202	175	196	202	175	196	202	175	196	202
Load	NWE Load	MEAN	-2829	-2861	-2874	-2897	-2966	-2986	-3026	-3040	-3058	-3091	-3183	-3215	-3233	-3255
		P5	-2857	-2896	-2903	-2925	-2993	-3013	-3059	-3068	-3083	-3121	-3216	-3252	-3263	-3290
		P95	-2803	-2834	-2844	-2875	-2940	-2959	-2992	-3011	-3028	-3065	-3148	-3186	-3201	-3227
Total by Portfolio	Current Portfolio	MEAN	-1408	-1415	-1452	-1488	-1550	-1578	-1621	-1616	-1666	-1723	-1769	-1844	-1885	-1882
		P5	-1930	-1864	-1896	-1941	-1985	-2083	-2098	-2097	-2130	-2162	-2215	-2283	-2300	-2301
		P95	-1192	-1230	-1221	-1258	-1335	-1315	-1353	-1387	-1396	-1438	-1533	-1492	-1531	-1573
	Current Portfolio + CC	MEAN	-712	-713	-750	-796	-846	-876	-912	-903	-957	-1019	-1053	-1125	-1164	-1161
		P5	-1218	-1141	-1140	-1245	-1245	-1353	-1376	-1333	-1422	-1450	-1481	-1552	-1572	-1590
		P95	-493	-528	-541	-584	-623	-614	-653	-687	-695	-765	-818	-776	-818	-861
	Current Portfolio + Hydro	MEAN	-313	-320	-367	-400	-455	-483	-526	-526	-581	-636	-675	-748	-790	-793
		P5	-803	-822	-781	-862	-912	-986	-1018	-1032	-1069	-1039	-1155	-1200	-1243	-1220
		P95	-50	-123	-110	-140	-208	-181	-254	-268	-258	-340	-393	-338	-432	-476

Net Position Report - All Hours (GWh)

			2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Generating Assets	Basin Creek 1-9	MEAN	6	9	18	18	18	20	30	33	38	38	43	43	45	44
		P5	-	-	-	-	-	-	-	-	-	-	-	0	0	-
		P95	33	43	68	85	91	95	116	125	116	131	132	126	131	146
	Colstrip 3	MEAN	771	782	740	794	807	842	866	687	686	669	697	669	664	681
		P5	665	656	658	672	662	696	753	347	241	169	266	146	232	246
		P95	848	875	842	877	883	890	902	881	874	872	875	877	887	872
	Colstrip 4	MEAN	771	782	701	794	807	760	867	688	646	670	698	635	665	679
		P5	661	658	650	670	664	689	742	352	256	160	247	143	242	219
		P95	855	874	752	879	884	794	903	889	763	885	884	783	887	877
	David Gates	MEAN	59	59	60	59	59	59	60	59	59	59	60	59	59	59
		P5	59	59	59	59	59	59	59	59	59	59	59	59	59	59
		P95	60	60	60	60	60	60	60	60	60	60	60	60	60	60
	New CCCT	MEAN	-	-	-	-	1,547	1,559	1,600	1,752	1,744	1,753	1,765	1,769	1,769	1,782
		P5	-	-	-	-	930	1,173	1,014	1,587	1,529	1,540	1,541	1,642	1,597	1,656
		P95	-	-	-	-	1,765	1,764	1,776	1,864	1,848	1,853	1,878	1,873	1,878	1,866
	Kerr	MEAN	1,079	787	-	-	-	-	-	-	-	-	-	-	-	-
		P5	1,006	714	-	-	-	-	-	-	-	-	-	-	-	-
		P95	1,164	848	-	-	-	-	-	-	-	-	-	-	-	-
	Other Hydro	MEAN	2,487	2,487	2,487	2,487	2,487	2,487	2,487	2,487	2,487	2,487	2,487	2,487	2,487	2,487
		P5	2,308	2,257	2,277	2,313	2,311	2,313	2,300	2,333	2,339	2,286	2,304	2,293	2,282	2,328
		P95	2,702	2,660	2,697	2,648	2,666	2,660	2,713	2,663	2,678	2,682	2,670	2,660	2,696	2,697
	Total Hydro	MEAN	3,566	3,275	2,487	2,487	2,487	2,487	2,487	2,487	2,487	2,487	2,487	2,487	2,487	2,487
		P5	3,314	2,993	2,277	2,313	2,311	2,313	2,300	2,333	2,339	2,286	2,304	2,293	2,282	2,328
		P95	3,866	3,501	2,697	2,648	2,666	2,660	2,713	2,663	2,678	2,682	2,670	2,660	2,696	2,697
	Wind - Total	MEAN	939	952	968	978	991	1,003	1,019	1,028	1,040	1,052	1,067	1,076	1,089	1,101
		P5	851	871	877	883	902	925	937	934	929	934	956	973	997	976
		P95	1,030	1,040	1,040	1,063	1,084	1,086	1,101	1,114	1,127	1,139	1,172	1,186	1,196	1,216
Physical Instruments	CELP Contract	MEAN	331	261	302	331	261	301	332	261	301	331	262	301	331	261
		P5	331	261	302	331	261	301	332	261	301	331	262	301	331	261
		P95	331	261	302	331	261	301	332	261	301	331	262	301	331	261
	PPL 09 RFP (HL)	MEAN	123	123	124	62	-	-	-	-	-	-	-	-	-	-
		P5	123	123	124	62	-	-	-	-	-	-	-	-	-	-
		P95	123	123	124	62	-	-	-	-	-	-	-	-	-	-
	PPL 7 YR (HL)	MEAN	490	0	0	0	0	0	0	0	0	0	0	0	0	0
		P5	490	0	0	0	0	0	0	0	0	0	0	0	0	0
		P95	490	0	0	0	0	0	0	0	0	0	0	0	0	0
	PPL 7 YR (LL)	MEAN	237	0	0	0	0	0	0	0	0	0	0	0	0	0
		P5	237	0	0	0	0	0	0	0	0	0	0	0	0	0
		P95	237	0	0	0	0	0	0	0	0	0	0	0	0	0
	Small QF1	MEAN	10	10	10	10	10	10	10	10	10	10	10	10	10	10
		P5	10	10	10	10	10	10	10	10	10	10	10	10	10	10
		P95	10	10	10	10	10	10	10	10	10	10	10	10	10	10
	Small QF2	MEAN	81	81	81	81	81	81	81	81	81	81	81	81	81	81
		P5	81	81	81	81	81	81	81	81	81	81	81	81	81	81
		P95	81	81	81	81	81	81	81	81	81	81	81	81	81	81

Net Position Report - All Hours (GWh)

			2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	Tiber	MEAN	25	25	25	25	25	25	25	25	25	25	25	25	25	25
		P5	25	25	25	25	25	25	25	25	25	25	25	25	25	25
		P95	25	25	25	25	25	25	25	25	25	25	25	25	25	25
	TransAlta 10 RFP (HL)	MEAN	123	123	124	62	0	0	0	0	0	0	0	0	0	0
		P5	123	123	124	62	0	0	0	0	0	0	0	0	0	0
		P95	123	123	124	62	0	0	0	0	0	0	0	0	0	0
	Turnbull	MEAN	33	33	33	33	33	33	33	33	33	33	33	33	33	33
		P5	33	33	33	33	33	33	33	33	33	33	33	33	33	33
		P95	33	33	33	33	33	33	33	33	33	33	33	33	33	33
	YELP Contract	MEAN	397	444	455	397	444	453	399	444	453	398	445	453	398	444
		P5	397	444	455	397	444	453	399	444	453	398	445	453	398	444
		P95	397	444	455	397	444	453	399	444	453	398	445	453	398	444
Load	NWE Load	MEAN	-6472	-6506	-6560	-6573	-6605	-6633	-6688	-6700	-6724	-6746	-6847	-6913	-7009	-7100
		P5	-6528	-6559	-6604	-6630	-6664	-6686	-6745	-6761	-6796	-6800	-6905	-6982	-7065	-7168
		P95	-6420	-6456	-6507	-6518	-6545	-6579	-6628	-6651	-6658	-6684	-6791	-6855	-6950	-7043
Total by Portfolio	Current Portfolio	MEAN	-2076	-2820	-2921	-2928	-3068	-3045	-2968	-3350	-3351	-3378	-3426	-3527	-3608	-3680
		P5	-2313	-3145	-3121	-3210	-3400	-3286	-3207	-4033	-4274	-4425	-4284	-4603	-4528	-4635
		P95	-1862	-2598	-2702	-2700	-2835	-2830	-2746	-2864	-2948	-2854	-3005	-3110	-3037	-3195
	Current Portfolio + CC	MEAN	-2076	-2820	-2921	-2928	-1521	-1485	-1368	-1598	-1608	-1625	-1661	-1758	-1839	-1898
		P5	-2313	-3145	-3121	-3210	-2356	-2104	-2089	-2370	-2657	-2660	-2603	-2845	-2975	-2814
		P95	-1862	-2598	-2702	-2700	-1105	-1064	-1000	-1061	-1161	-1050	-1175	-1303	-1257	-1368
	Current Portfolio + Hydro	MEAN	1490	455	-434	-441	-581	-557	-481	-863	-864	-891	-939	-1040	-1121	-1193
		P5	1155	40	-737	-801	-917	-882	-779	-1522	-1927	-1812	-1782	-2227	-2146	-2205
		P95	1957	811	-110	-142	-286	-261	-182	-315	-430	-309	-445	-538	-508	-558

Net Position Report - All Hours (GWh)

			2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Generating Assets	Basin Creek 1-9	MEAN	48	48	47	53	50	55	54	57	55	56	62	58	57	60	61	66
		P5	0	-	0	-	-	-	-	0	-	-	-	-	0	-	-	0
		P95	171	136	143	163	150	178	174	185	164	154	183	147	166	167	208	186
	Colstrip 3	MEAN	668	652	634	641	621	623	590	579	580	581	552	537	542	498	484	479
		P5	204	126	2	132	90	95	75	2	0	0	0	0	0	0	0	-
		P95	881	874	880	869	876	872	870	880	874	871	862	872	848	869	865	863
	Colstrip 4	MEAN	633	650	634	613	619	622	561	579	582	558	554	538	523	499	484	463
		P5	204	123	2	114	85	98	71	0	0	0	0	0	0	0	0	-
		P95	769	873	871	783	882	877	759	872	883	787	874	883	755	879	859	771
	David Gates	MEAN	60	59	59	59	60	59	59	59	60	59	59	59	60	59	59	59
		P5	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59
		P95	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
	New CCCT	MEAN	1,781	1,773	1,779	1,782	1,795	1,781	1,786	1,787	1,794	1,801	1,798	1,800	1,810	1,811	1,809	1,811
		P5	1,661	1,592	1,650	1,636	1,660	1,607	1,632	1,669	1,657	1,663	1,630	1,682	1,692	1,701	1,667	1,605
		P95	1,881	1,876	1,872	1,881	1,900	1,884	1,879	1,880	1,883	1,906	1,946	1,885	1,920	1,903	1,913	1,921
	Kerr	MEAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		P5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		P95	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Other Hydro	MEAN	2,487	2,487	2,487	2,487	2,487	2,487	2,487	2,487	2,487	2,487	2,487	2,487	2,487	2,487	2,487	2,487
		P5	2,289	2,329	2,323	2,310	2,276	2,291	2,265	2,262	2,279	2,274	2,284	2,273	2,292	2,298	2,275	2,272
		P95	2,701	2,681	2,677	2,663	2,664	2,675	2,677	2,706	2,656	2,640	2,681	2,684	2,664	2,678	2,672	2,668
	Total Hydro	MEAN	2,487	2,487	2,487	2,487	2,487	2,487	2,487	2,487	2,487	2,487	2,487	2,487	2,487	2,487	2,487	2,487
		P5	2,289	2,329	2,323	2,310	2,276	2,291	2,265	2,262	2,279	2,274	2,284	2,273	2,292	2,298	2,275	2,272
		P95	2,701	2,681	2,677	2,663	2,664	2,675	2,677	2,706	2,656	2,640	2,681	2,684	2,664	2,678	2,672	2,668
	Wind - Total	MEAN	1,117	1,126	1,138	1,150	1,166	1,175	1,188	1,200	1,217	1,227	1,240	1,253	1,271	1,280	1,294	1,307
		P5	1,023	1,033	1,060	1,052	1,049	1,077	1,074	1,100	1,098	1,108	1,113	1,123	1,146	1,169	1,174	1,178
		P95	1,227	1,219	1,256	1,263	1,301	1,282	1,300	1,322	1,324	1,318	1,357	1,377	1,392	1,408	1,425	1,436
Physical Instruments	CELP Contract	MEAN	302	331	261	301	332	261	301	332	261	301	332	261	301	332	261	301
		P5	302	331	261	301	332	261	301	332	261	301	332	261	301	332	261	301
		P95	302	331	261	301	332	261	301	332	261	301	332	261	301	332	261	301
	PPL 09 RFP (HL)	MEAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		P5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		P95	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	PPL 7 YR (HL)	MEAN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		P5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		P95	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	PPL 7 YR (LL)	MEAN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		P5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		P95	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Small QF1	MEAN	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
		P5	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
		P95	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
	Small QF2	MEAN	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81
		P5	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81
		P95	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81

Net Position Report - All Hours (GWh)

			2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
	Tiber	MEAN	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
		P5	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
		P95	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
	TransAlta 10 RFP (HL)	MEAN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		P5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		P95	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Turnbull	MEAN	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33
		P5	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33
		P95	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33
	YELP Contract	MEAN	455	398	444	453	399	444	453	399	444	453	399	444	453	399	444	453
		P5	455	398	444	453	399	444	453	399	444	453	399	444	453	399	444	453
		P95	455	398	444	453	399	444	453	399	444	453	399	444	453	399	444	453
Load	NWE Load	MEAN	-7200	-7263	-7348	-7435	-7556	-7615	-7703	-7792	-7911	-7976	-8067	-8160	-8284	-8352	-8448	-8544
		P5	-7261	-7328	-7407	-7511	-7627	-7680	-7766	-7858	-7984	-8042	-8120	-8232	-8356	-8431	-8524	-8621
		P95	-7137	-7195	-7290	-7371	-7479	-7554	-7643	-7732	-7834	-7909	-8005	-8102	-8202	-8280	-8377	-8487
Total by Portfolio	Current Portfolio	MEAN	-3768	-3849	-3981	-4014	-4158	-4226	-4347	-4436	-4562	-4591	-4720	-4860	-4928	-5074	-5211	-5265
		P5	-4642	-4967	-5193	-5051	-5210	-5388	-5421	-5662	-5748	-5778	-5882	-5962	-6011	-6126	-6265	-6321
		P95	-3310	-3366	-3397	-3551	-3600	-3650	-3767	-3785	-3886	-4036	-4021	-4178	-4300	-4180	-4321	-4506
	Current Portfolio + CC	MEAN	-1987	-2076	-2202	-2233	-2363	-2445	-2560	-2649	-2767	-2790	-2922	-3060	-3118	-3263	-3402	-3454
		P5	-2899	-3160	-3419	-3233	-3319	-3540	-3560	-3811	-3904	-3902	-4069	-4129	-4165	-4324	-4468	-4530
		P95	-1504	-1562	-1595	-1746	-1788	-1861	-1932	-1942	-2074	-2220	-2222	-2427	-2486	-2353	-2473	-2663
	Current Portfolio + Hydro	MEAN	-1281	-1362	-1494	-1527	-1671	-1739	-1860	-1949	-2075	-2104	-2232	-2373	-2441	-2587	-2723	-2778
		P5	-2269	-2490	-2699	-2659	-2654	-2860	-2994	-3153	-3286	-3329	-3421	-3391	-3605	-3685	-3857	-3816
		P95	-780	-761	-827	-988	-1027	-1077	-1194	-1244	-1392	-1473	-1435	-1649	-1735	-1559	-1873	-2019

			2014	2015	2016	2017	2018	2019	2020
Basin Creek 1-9: 51.75 MW	Fuel Consumed MMBtu	MEAN	53,039	86,206	159,577	159,774	161,029	179,139	267,525
		P5	-	-	-	-	-	-	-
		P95	295,496	388,279	616,595	770,215	827,999	838,334	1,048,798
	CO2 Emissions Tonnes	MEAN	2,845	4,624	8,559	8,570	8,637	9,608	14,349
		P5	-	-	-	-	-	-	-
		P95	15,849	20,826	33,072	41,312	44,411	44,965	56,254
	Generation MWh	MEAN	5,843	9,496	17,578	17,600	17,738	19,733	29,470
		P5	-	-	-	-	-	-	-
		P95	32,551	42,771	67,922	84,844	91,209	92,348	115,532
	Capacity Factor %	MEAN	1%	2%	4%	4%	4%	4%	6%
		P5	0%	0%	0%	0%	0%	0%	0%
		P95	7%	9%	15%	19%	20%	20%	25%
	Number of Starts	MEAN	18	32	51	51	53	55	69
		P5	-	-	-	-	-	-	-
		P95	61	139	189	190	247	245	280
	Fuel Cost $	MEAN	$ 190,483	$ 352,449	$ 620,540	$ 646,178	$ 762,922	$ 867,058	$ 1,371,694
		P5	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		P95	$ 952,568	$ 1,545,987	$ 2,617,377	$ 3,464,604	$ 3,568,632	$ 4,450,336	$ 6,257,974
	Carbon Emission Costs $	MEAN							
		P5							
		P95							
	VOM Costs $	MEAN	$ 23,861	$ 39,597	$ 74,837	$ 76,503	$ 78,723	$ 89,416	$ 136,337
		P5	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		P95	$ 132,937	$ 178,347	$ 289,166	$ 368,795	$ 404,789	$ 418,448	$ 534,493
	Net Revenue $	MEAN	$ 25,247	$ 36,207	$ 68,920	$ 81,638	$ 83,055	$ 106,936	$ 227,324
		P5	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		P95	$ 154,919	$ 143,830	$ 317,964	$ 513,060	$ 487,774	$ 640,789	$ 1,043,219

			2014	2015	2016	2017	2018	2019	2020
Colstrip 3: 111 MW	Fuel Consumed MMBtu	MEAN	8,178,511	8,297,328	7,849,148	8,430,836	8,556,530	8,931,652	9,187,005
		P5	7,047,863	6,910,763	6,954,186	7,028,630	7,102,573	7,438,908	8,002,716
		P95	9,013,498	9,290,513	9,009,723	9,306,954	9,368,088	9,413,165	9,500,029
	CO2 Emissions Tonnes	MEAN	762,089	773,160	731,398	785,601	797,313	832,268	856,062
		P5	656,733	643,957	648,004	654,941	661,831	693,171	745,708
		P95	839,894	865,707	839,542	867,239	872,935	877,136	885,230
	Generation MWh	MEAN	770,834	782,041	740,669	794,574	806,381	841,373	866,172
		P5	666,619	653,413	658,020	665,259	672,213	702,766	755,479
		P95	848,092	874,316	847,904	875,853	881,892	886,659	895,969
	Capacity Factor %	MEAN	79%	80%	76%	82%	83%	87%	89%
		P5	69%	67%	67%	68%	69%	72%	77%
		P95	87%	90%	87%	90%	91%	91%	92%
	Number of Starts	MEAN	41	38	38	38	38	39	39
		P5	28	28	26	28	27	31	31
		P95	53	48	50	49	48	48	48
	Fuel Cost $	MEAN	$ 5,220,454	$ 5,877,945	$ 6,024,618	$ 6,645,695	$ 6,927,850	$ 7,366,379	$ 7,746,038
		P5	$ 3,689,221	$ 3,865,439	$ 4,321,078	$ 4,596,786	$ 4,450,291	$ 5,129,693	$ 5,692,873
		P95	$ 6,589,910	$ 7,763,108	$ 8,724,546	$ 8,794,285	$ 9,131,223	$ 9,665,596	$ 10,082,741
	Carbon Emission Costs $	MEAN							
		P5							
		P95							
	VOM Costs $	MEAN	$ 787,021	$ 815,231	$ 788,318	$ 863,450	$ 894,682	$ 953,110	$ 1,001,807
		P5	$ 680,618	$ 681,145	$ 700,352	$ 722,925	$ 745,823	$ 796,095	$ 873,781
		P95	$ 865,902	$ 911,423	$ 902,451	$ 951,775	$ 978,462	$ 1,004,410	$ 1,036,271
	Net Revenue $	MEAN	$ 8,596,620	$ 9,491,131	$ 10,297,063	$ 10,719,349	$ 11,988,123	$ 13,884,253	$ 16,385,017
		P5	$ 4,310,104	$ 3,719,416	$ 4,575,184	$ 4,632,395	$ 3,334,331	$ 6,445,287	$ 7,934,900
		P95	$ 13,360,851	$ 17,049,519	$ 17,821,338	$ 18,971,427	$ 22,777,638	$ 25,520,676	$ 29,111,577

			2014	2015	2016	2017	2018	2019	2020
Colstrip 4: 111 MW	Fuel Consumed MMBtu	MEAN	8,181,089	8,291,938	7,405,853	8,438,618	8,565,615	8,034,539	9,185,181
		P5	7,053,172	6,895,756	6,885,859	6,987,797	7,039,973	7,280,037	7,894,901
		P95	9,051,609	9,299,574	7,903,687	9,397,546	9,381,436	8,385,705	9,586,053
	CO2 Emissions Tonnes	MEAN	762,329	772,658	690,091	786,326	798,160	748,673	855,892
		P5	657,227	642,559	641,637	651,136	655,997	678,367	735,661
		P95	843,445	866,551	736,480	875,680	874,179	781,395	893,246
	Generation MWh	MEAN	771,079	781,568	699,928	795,297	807,200	758,342	866,031
		P5	667,172	652,324	651,353	661,321	666,236	688,682	745,220
		P95	851,701	875,208	745,864	884,539	882,788	791,477	905,156
	Capacity Factor %	MEAN	79%	80%	72%	82%	83%	78%	89%
		P5	69%	67%	67%	68%	69%	71%	76%
		P95	88%	90%	76%	91%	91%	81%	93%
	Number of Starts	MEAN	40	37	33	37	36	34	37
		P5	27	24	23	25	24	26	29
		P95	51	49	44	49	48	44	47
	Fuel Cost $	MEAN	$ 5,220,522	$ 5,873,608	$ 5,658,337	$ 6,650,546	$ 6,934,614	$ 6,609,504	$ 7,750,600
		P5	$ 3,703,278	$ 3,899,331	$ 4,342,481	$ 4,534,439	$ 4,514,670	$ 5,064,800	$ 5,650,118
		P95	$ 6,580,085	$ 7,869,746	$ 7,601,008	$ 8,763,839	$ 9,130,906	$ 8,514,517	$ 10,047,536
	Carbon Emission Costs $	MEAN							
		P5							
		P95							
	VOM Costs $	MEAN	$ 787,272	$ 814,738	$ 744,956	$ 864,236	$ 895,591	$ 859,052	$ 1,001,644
		P5	$ 681,182	$ 680,010	$ 693,256	$ 718,646	$ 739,192	$ 780,141	$ 861,916
		P95	$ 869,586	$ 912,352	$ 793,847	$ 961,213	$ 979,456	$ 896,587	$ 1,046,896
	Net Revenue $	MEAN	$ 8,597,132	$ 9,502,728	$ 10,177,238	$ 10,742,560	$ 11,999,970	$ 13,355,775	$ 16,433,743
		P5	$ 4,247,797	$ 3,953,320	$ 4,553,831	$ 4,584,631	$ 3,180,967	$ 6,574,204	$ 7,880,432
		P95	$ 13,291,831	$ 17,113,842	$ 17,332,189	$ 19,192,256	$ 22,419,882	$ 24,191,237	$ 29,069,628

			2014	2015	2016	2017	2018	2019	2020
David Gates: 7 MW (constant)	Fuel Consumed MMBtu	MEAN	678,136	678,136	680,013	678,136	678,136	678,136	680,013
		P5	666,628	666,628	668,543	666,628	666,628	666,628	668,543
		P95	687,457	687,457	689,373	687,457	687,457	687,457	689,373
	CO2 Emissions Tonnes	MEAN	36,373	36,373	36,473	36,373	36,373	36,373	36,473
		P5	35,755	35,755	35,858	35,755	35,755	35,755	35,858
		P95	36,873	36,873	36,975	36,873	36,873	36,873	36,975
	Generation MWh	MEAN	59,480	59,480	59,645	59,480	59,480	59,480	59,645
		P5	58,471	58,471	58,639	58,471	58,471	58,471	58,639
		P95	60,298	60,298	60,466	60,298	60,298	60,298	60,466
	Capacity Factor %	MEAN	97%	97%	97%	97%	97%	97%	97%
		P5	95%	95%	95%	95%	95%	95%	95%
		P95	98%	98%	98%	98%	98%	98%	98%
	Number of Starts	MEAN	17	17	17	17	17	17	17
		P5	11	11	11	11	11	11	11
		P95	25	25	25	25	25	25	25
	Fuel Cost $	MEAN	$ 2,198,260	$ 2,307,103	$ 2,387,755	$ 2,506,669	$ 2,741,775	$ 2,991,219	$ 3,174,523
		P5	$ 1,678,046	$ 1,687,038	$ 1,800,026	$ 1,851,159	$ 1,997,352	$ 2,391,065	$ 2,521,160
		P95	$ 2,774,992	$ 2,918,511	$ 3,237,879	$ 3,366,530	$ 3,563,032	$ 3,976,984	$ 4,153,785
	Carbon Emission Costs $	MEAN							
		P5							
		P95							
	VOM Costs $	MEAN	$ 182,188	$ 186,014	$ 190,446	$ 193,909	$ 197,981	$ 202,139	$ 206,955
		P5	$ 179,097	$ 182,858	$ 187,234	$ 190,618	$ 194,621	$ 198,708	$ 203,464
		P95	$ 184,693	$ 188,571	$ 193,068	$ 196,574	$ 200,703	$ 204,917	$ 209,803
	Net Revenue $	MEAN	$ (791,861)	$ (788,808)	$ (793,829)	$ (848,040)	$ (982,207)	$ (1,077,128)	$ (1,067,767)
		P5	$ (1,052,165)	$ (1,070,903)	$ (1,070,706)	$ (1,232,069)	$ (1,349,928)	$ (1,531,866)	$ (1,529,688)
		P95	$ (555,427)	$ (555,379)	$ (421,057)	$ (525,978)	$ (638,312)	$ (705,822)	$ (677,691)

			2014	2015	2016	2017	2018	2019	2020
Generic CCCT: 239 MW (effective)	Fuel Consumed MMBtu	MEAN					10,311,874	10,393,320	10,658,984
		P5					6,196,206	7,816,607	6,755,728
		P95					11,755,539	11,753,124	11,831,316
	CO2 Emissions Tonnes	MEAN					553,091	557,460	571,709
		P5					332,342	419,254	362,353
		P95					630,524	630,395	634,589
	Generation MWh	MEAN					1,547,305	1,559,268	1,599,672
		P5					929,554	1,173,448	1,013,926
		P95					1,764,839	1,763,637	1,775,680
	Capacity Factor %	MEAN					74%	74%	76%
		P5					44%	56%	48%
		P95					84%	84%	85%
	Number of Starts	MEAN					97	113	80
		P5					35	67	34
		P95					204	204	108
	Fuel Cost $	MEAN					$ 42,173,999	$ 45,987,838	$ 49,871,624
		P5					$ 21,282,877	$ 32,673,771	$ 29,711,402
		P95					$ 59,965,069	$ 62,100,141	$ 72,069,359
	Carbon Emission Costs $	MEAN							
		P5							
		P95							
	VOM Costs $	MEAN					$ 3,090,133	$ 3,179,418	$ 3,330,303
		P5					$ 1,856,417	$ 2,392,714	$ 2,110,857
		P95					$ 3,524,570	$ 3,596,135	$ 3,696,726
	Net Revenue $	MEAN					$ 14,472,583	$ 14,898,224	$ 17,675,329
		P5					$ 2,009,571	$ 4,466,853	$ 4,416,405
		P95					$ 28,587,571	$ 31,280,503	$ 37,233,463

			2014	2015	2016	2017	2018	2019	2020
Kerr: 194 MW	Generation MWh	MEAN	1,078,625	787,464					
		P5	1,005,917	713,564					
		P95	1,164,493	847,681					
	Capacity Factor %	MEAN	63%	46%					
		P5	59%	42%					
		P95	69%	50%					
	Net Revenue $	MEAN	$ 30,038,976	$ 22,269,885					
		P5	$ 22,275,139	$ 15,288,686					
		P95	$ 36,949,320	$ 29,998,819					
Other Hydro: 439 MW	Generation MWh	MEAN	2,487,162	2,487,157	2,487,172	2,487,136	2,487,150	2,487,167	2,487,151
		P5	2,308,498	2,257,486	2,277,267	2,312,786	2,311,198	2,312,906	2,300,187
		P95	2,701,515	2,659,754	2,696,754	2,648,061	2,666,311	2,659,580	2,712,906
	Capacity Factor %	MEAN	65%	65%	64%	65%	65%	65%	64%
		P5	60%	59%	59%	60%	60%	60%	60%
		P95	70%	69%	70%	69%	69%	69%	70%
	Net Revenue $	MEAN	$ 67,649,505	$ 72,509,048	$ 75,130,512	$ 78,627,989	$ 82,901,493	$ 89,819,369	$ 97,726,969
		P5	$ 50,124,085	$ 51,234,094	$ 55,362,259	$ 54,445,173	$ 51,512,416	$ 64,639,904	$ 70,196,433
		P95	$ 83,682,808	$ 96,963,886	$ 99,468,699	$ 104,312,473	$ 114,195,447	$ 128,245,506	$ 140,401,205

			2021	2022	2023	2024	2025	2026	2027
Basin Creek 1-9: 51.75 MW	Fuel Consumed MMBtu	MEAN	304,088	343,179	342,742	391,783	391,844	409,311	398,604
		P5	-	-	-	-	235	235	-
		P95	1,126,783	1,057,724	1,189,969	1,202,653	1,158,494	1,198,190	1,333,489
	CO2 Emissions Tonnes	MEAN	16,310	18,407	18,383	21,014	21,017	21,954	21,380
		P5	-	-	-	-	13	13	-
		P95	60,437	56,732	63,826	64,506	62,137	64,267	71,523
	Generation MWh	MEAN	33,497	37,803	37,755	43,157	43,164	45,088	43,909
		P5	-	-	-	-	26	26	-
		P95	124,122	116,515	131,083	132,480	127,616	131,988	146,892
	Capacity Factor %	MEAN	7%	8%	8%	9%	10%	10%	10%
		P5	0%	0%	0%	0%	0%	0%	0%
		P95	27%	26%	29%	29%	28%	29%	32%
	Number of Starts	MEAN	78	87	85	100	99	102	99
		P5	-	-	-	-	1	1	-
		P95	251	248	303	275	267	298	294
	Fuel Cost $	MEAN	$ 1,618,952	$ 1,765,206	$ 1,832,437	$ 2,065,160	$ 2,136,940	$ 2,298,944	$ 2,274,779
		P5	$ -	$ -	$ -	$ -	$ 1,304	$ 922	$ -
		P95	$ 6,439,821	$ 6,410,716	$ 6,718,085	$ 6,362,117	$ 6,406,075	$ 8,077,386	$ 7,209,357
	Carbon Emission Costs $	MEAN	$ 387,509	$ 478,749	$ 450,822	$ 618,624	$ 610,187	$ 678,171	$ 696,568
		P5	$ -	$ -	$ -	$ -	$ 89	$ 595	$ -
		P95	$ 1,685,436	$ 1,687,990	$ 1,755,851	$ 2,016,202	$ 1,884,766	$ 2,328,466	$ 2,482,773
	VOM Costs $	MEAN	$ 158,225	$ 182,315	$ 185,907	$ 216,970	$ 221,560	$ 236,297	$ 234,948
		P5	$ -	$ -	$ -	$ -	$ 133	$ 136	$ -
		P95	$ 586,295	$ 561,919	$ 645,451	$ 666,030	$ 655,047	$ 691,720	$ 785,995
	Net Revenue $	MEAN	$ 257,670	$ 273,062	$ 266,777	$ 309,369	$ 326,431	$ 370,672	$ 365,659
		P5	$ -	$ -	$ -	$ -	$ 9	$ 12	$ -
		P95	$ 1,158,891	$ 1,149,542	$ 1,379,260	$ 1,184,147	$ 1,185,130	$ 1,515,308	$ 1,502,717

			2021	2022	2023	2024	2025	2026	2027
Colstrip 3: 111 MW	Fuel Consumed MMBtu	MEAN	7,282,300	7,265,385	7,084,158	7,397,610	7,079,442	7,021,934	7,223,150
		P5	3,697,397	2,497,681	1,751,448	2,403,057	1,477,701	2,566,525	2,294,641
		P95	9,314,855	9,278,906	9,306,917	9,306,957	9,333,166	9,367,573	9,274,227
	CO2 Emissions Tonnes	MEAN	678,578	677,002	660,115	689,323	659,675	654,317	673,066
		P5	344,530	232,738	163,203	223,921	137,695	239,153	213,819
		P95	867,975	864,625	867,235	867,239	869,681	872,887	864,189
	Generation MWh	MEAN	687,609	685,992	669,095	698,338	668,330	662,927	681,881
		P5	349,751	236,268	165,750	226,587	139,466	241,703	216,567
		P95	878,349	874,579	877,145	876,859	879,549	882,776	873,922
	Capacity Factor %	MEAN	71%	71%	69%	72%	69%	68%	70%
		P5	36%	24%	17%	23%	14%	25%	22%
		P95	90%	90%	90%	90%	90%	91%	90%
	Number of Starts	MEAN	33	33	32	34	32	32	33
		P5	15	12	8	14	8	9	14
		P95	47	48	50	51	50	49	47
	Fuel Cost $	MEAN	$ 6,432,996	$ 6,552,810	$ 6,610,348	$ 7,021,184	$ 6,892,050	$ 7,091,231	$ 7,388,621
		P5	$ 2,567,798	$ 2,091,101	$ 1,549,156	$ 2,052,466	$ 1,233,692	$ 1,992,033	$ 1,935,109
		P95	$ 10,384,548	$ 9,795,329	$ 10,111,357	$ 10,219,247	$ 10,341,052	$ 11,546,894	$ 10,821,094
	Carbon Emission Costs $	MEAN	$ 14,828,203	$ 15,510,785	$ 15,629,565	$ 17,452,870	$ 17,008,570	$ 17,739,574	$ 19,655,857
		P5	$ 5,297,226	$ 3,045,662	$ 3,405,547	$ 3,425,361	$ 3,804,289	$ 3,310,480	$ 6,573,957
		P95	$ 24,804,753	$ 25,831,586	$ 27,205,030	$ 29,970,294	$ 31,403,364	$ 31,182,313	$ 32,081,676
	VOM Costs $	MEAN	$ 811,984	$ 827,086	$ 823,655	$ 877,706	$ 857,630	$ 868,561	$ 912,156
		P5	$ 413,014	$ 284,864	$ 204,038	$ 284,785	$ 178,968	$ 316,678	$ 289,703
		P95	$ 1,037,225	$ 1,054,462	$ 1,079,763	$ 1,102,080	$ 1,128,676	$ 1,156,605	$ 1,169,050
	Net Revenue $	MEAN	$ 9,062,941	$ 9,093,053	$ 9,140,385	$ 9,464,807	$ 9,625,572	$ 9,682,490	$ 9,586,380
		P5	$ 505,745	$ 499,066	$ 229,960	$ 701,504	$ 166,158	$ 402,310	$ 266,651
		P95	$ 24,339,938	$ 20,423,402	$ 24,582,146	$ 21,038,473	$ 22,564,029	$ 23,843,712	$ 20,006,604

			2021	2022	2023	2024	2025	2026	2027
Colstrip 4: 111 MW	Fuel Consumed MMBtu	MEAN	7,279,613	6,816,613	7,082,957	7,389,705	6,682,478	7,032,893	7,210,677
		P5	3,495,954	2,493,541	1,695,171	2,269,741	1,612,280	2,384,606	2,432,224
		P95	9,332,862	8,149,463	9,291,928	9,312,694	8,207,459	9,358,941	9,282,903
	CO2 Emissions Tonnes	MEAN	678,328	635,184	660,003	688,586	622,685	655,338	671,904
		P5	325,759	232,353	157,959	211,499	150,235	222,202	226,639
		P95	869,653	759,382	865,839	867,774	764,786	872,083	864,998
	Generation MWh	MEAN	687,397	644,384	668,995	697,623	631,531	663,967	680,724
		P5	330,639	235,868	160,443	213,949	152,494	224,795	229,508
		P95	879,338	769,396	876,012	877,387	774,619	882,091	874,508
	Capacity Factor %	MEAN	71%	66%	69%	72%	65%	68%	70%
		P5	34%	24%	17%	22%	16%	23%	24%
		P95	90%	79%	90%	90%	80%	91%	90%
	Number of Starts	MEAN	31	29	31	32	29	30	32
		P5	14	9	5	14	7	11	11
		P95	48	42	46	48	44	47	52
	Fuel Cost $	MEAN	$ 6,424,545	$ 6,118,235	$ 6,607,157	$ 7,014,041	$ 6,485,474	$ 7,101,413	$ 7,376,392
		P5	$ 2,528,362	$ 2,092,968	$ 1,482,814	$ 1,848,615	$ 1,352,835	$ 1,895,610	$ 2,058,382
		P95	$ 10,464,073	$ 8,725,572	$ 10,154,501	$ 10,229,316	$ 9,131,138	$ 11,494,165	$ 10,806,396
	Carbon Emission Costs $	MEAN	$ 14,807,223	$ 14,765,661	$ 15,595,474	$ 17,421,506	$ 16,308,604	$ 17,737,544	$ 19,645,649
		P5	$ 5,635,584	$ 2,922,472	$ 3,374,075	$ 3,972,427	$ 3,946,111	$ 3,318,069	$ 6,225,471
		P95	$ 24,504,858	$ 25,226,722	$ 27,170,616	$ 29,899,659	$ 30,077,619	$ 30,802,061	$ 31,673,949
	VOM Costs $	MEAN	$ 811,734	$ 776,921	$ 823,531	$ 876,806	$ 810,408	$ 869,923	$ 910,608
		P5	$ 390,445	$ 284,381	$ 197,505	$ 268,901	$ 195,687	$ 294,525	$ 307,013
		P95	$ 1,038,394	$ 927,644	$ 1,078,369	$ 1,102,743	$ 994,025	$ 1,155,708	$ 1,169,834
	Net Revenue $	MEAN	$ 9,045,889	$ 8,880,275	$ 9,160,402	$ 9,490,937	$ 9,388,128	$ 9,713,866	$ 9,599,019
		P5	$ 569,914	$ 513,594	$ 233,501	$ 656,874	$ 149,858	$ 292,439	$ 303,075
		P95	$ 23,775,416	$ 19,109,379	$ 24,824,623	$ 21,153,194	$ 20,835,249	$ 23,962,389	$ 19,609,458

			2021	2022	2023	2024	2025	2026	2027
David Gates: 7 MW (constant)	Fuel Consumed MMBtu	MEAN	678,136	678,136	678,136	680,013	678,136	678,136	678,136
		P5	666,628	666,628	666,628	668,543	666,628	666,628	666,628
		P95	687,457	687,457	687,457	689,373	687,457	687,457	687,457
	CO2 Emissions Tonnes	MEAN	36,373	36,373	36,373	36,473	36,373	36,373	36,373
		P5	35,755	35,755	35,755	35,858	35,755	35,755	35,755
		P95	36,873	36,873	36,873	36,975	36,873	36,873	36,873
	Generation MWh	MEAN	59,480	59,480	59,480	59,645	59,480	59,480	59,480
		P5	58,471	58,471	58,471	58,639	58,471	58,471	58,471
		P95	60,298	60,298	60,298	60,466	60,298	60,298	60,298
	Capacity Factor %	MEAN	97%	97%	97%	97%	97%	97%	97%
		P5	95%	95%	95%	95%	95%	95%	95%
		P95	98%	98%	98%	98%	98%	98%	98%
	Number of Starts	MEAN	17	17	17	17	17	17	17
		P5	11	11	11	11	11	11	11
		P95	25	25	25	25	25	25	25
	Fuel Cost $	MEAN	$ 3,232,780	$ 3,299,379	$ 3,369,389	$ 3,450,006	$ 3,512,470	$ 3,585,476	$ 3,660,861
		P5	$ 2,466,062	$ 2,596,798	$ 2,622,749	$ 2,681,208	$ 2,729,345	$ 2,772,841	$ 2,932,817
		P95	$ 4,177,063	$ 4,248,124	$ 4,242,187	$ 4,426,774	$ 4,496,503	$ 4,631,657	$ 4,672,662
	Carbon Emission Costs $	MEAN	$ 844,166	$ 887,369	$ 931,061	$ 980,140	$ 1,025,646	$ 1,076,873	$ 1,131,025
		P5	$ 238,071	$ 278,944	$ 220,418	$ 263,484	$ 350,565	$ 260,380	$ 454,293
		P95	$ 1,471,463	$ 1,468,978	$ 1,659,235	$ 1,734,251	$ 1,704,086	$ 1,853,250	$ 1,836,026
	VOM Costs $	MEAN	$ 210,718	$ 215,143	$ 219,661	$ 224,894	$ 228,983	$ 233,792	$ 238,702
		P5	$ 207,142	$ 211,492	$ 215,933	$ 221,101	$ 225,098	$ 229,825	$ 234,651
		P95	$ 213,614	$ 218,100	$ 222,680	$ 227,990	$ 232,131	$ 237,006	$ 241,983
	Net Revenue $	MEAN	$ (1,167,194)	$ (1,195,236)	$ (1,225,129)	$ (1,218,743)	$ (1,243,916)	$ (1,270,704)	$ (1,301,189)
		P5	$ (1,602,083)	$ (1,725,285)	$ (1,705,429)	$ (1,741,897)	$ (1,711,731)	$ (1,786,966)	$ (1,754,628)
		P95	$ (734,353)	$ (742,413)	$ (719,070)	$ (747,345)	$ (811,352)	$ (777,742)	$ (805,287)

			2021	2022	2023	2024	2025	2026	2027
Generic CCCT: 239 MW (effective)	Fuel Consumed MMBtu	MEAN	11,667,761	11,613,713	11,677,202	11,753,524	11,783,324	11,784,213	11,868,441
		P5	10,568,744	10,184,584	10,256,070	10,271,433	10,940,908	10,634,868	11,031,566
		P95	12,416,368	12,308,823	12,338,918	12,505,505	12,474,853	12,507,117	12,430,694
	CO2 Emissions Tonnes	MEAN	625,816	622,917	626,323	630,416	632,015	632,062	636,580
		P5	566,869	546,264	550,098	550,922	586,831	570,416	591,693
		P95	665,969	660,201	661,815	670,750	669,106	670,836	666,737
	Generation MWh	MEAN	1,751,807	1,743,742	1,753,222	1,764,659	1,769,137	1,769,309	1,781,953
		P5	1,586,892	1,529,012	1,539,946	1,541,378	1,642,488	1,596,746	1,656,030
		P95	1,864,320	1,848,170	1,852,661	1,877,704	1,873,095	1,877,943	1,866,471
	Capacity Factor %	MEAN	84%	83%	84%	84%	85%	85%	85%
		P5	76%	73%	74%	73%	78%	76%	79%
		P95	89%	88%	88%	89%	89%	90%	89%
	Number of Starts	MEAN	86	85	86	90	94	91	92
		P5	51	42	20	50	66	54	70
		P95	102	101	104	106	107	106	106
	Fuel Cost $	MEAN	$ 55,688,622	$ 56,569,329	$ 58,131,314	$ 59,713,952	$ 61,013,103	$ 62,335,276	$ 64,070,750
		P5	$ 39,441,911	$ 42,393,605	$ 42,731,078	$ 43,062,389	$ 47,051,803	$ 45,634,210	$ 51,698,794
		P95	$ 74,302,034	$ 73,483,804	$ 72,341,551	$ 77,142,885	$ 77,734,858	$ 80,254,336	$ 80,230,740
	Carbon Emission Costs $	MEAN	$ 14,675,568	$ 15,301,797	$ 16,187,687	$ 17,184,622	$ 18,003,908	$ 18,929,337	$ 19,921,875
		P5	$ 4,017,783	$ 4,429,952	$ 3,565,653	$ 4,471,359	$ 5,506,007	$ 4,534,283	$ 7,194,033
		P95	$ 26,484,746	$ 25,347,923	$ 28,548,539	$ 31,139,569	$ 30,959,271	$ 33,291,792	$ 33,299,584
	VOM Costs $	MEAN	$ 3,723,615	$ 3,784,308	$ 3,884,783	$ 3,992,238	$ 4,086,419	$ 4,172,639	$ 4,290,710
		P5	$ 3,373,074	$ 3,318,295	$ 3,412,206	$ 3,487,103	$ 3,793,879	$ 3,765,675	$ 3,987,502
		P95	$ 3,962,769	$ 4,010,939	$ 4,105,120	$ 4,247,982	$ 4,326,544	$ 4,428,834	$ 4,494,217
	Net Revenue $	MEAN	$ 25,744,976	$ 26,547,659	$ 27,234,732	$ 29,448,062	$ 30,204,330	$ 31,159,138	$ 32,113,666
		P5	$ 11,195,342	$ 10,131,137	$ 10,724,957	$ 11,298,482	$ 12,927,620	$ 11,977,786	$ 16,004,282
		P95	$ 42,400,226	$ 45,712,392	$ 45,331,735	$ 47,039,897	$ 47,317,829	$ 50,913,021	$ 52,749,417

			2021	2022	2023	2024	2025	2026	2027
Kerr: 194 MW	Generation MWh	MEAN							
		P5							
		P95							
	Capacity Factor %	MEAN							
		P5							
		P95							
	Net Revenue $	MEAN							
		P5							
		P95							
Other Hydro: 439 MW	Generation MWh	MEAN	2,487,142	2,487,137	2,487,201	2,487,160	2,487,174	2,487,207	2,487,156
		P5	2,333,324	2,338,820	2,285,730	2,303,520	2,292,896	2,282,039	2,328,070
		P95	2,662,931	2,678,260	2,682,387	2,669,501	2,660,249	2,696,175	2,696,753
	Capacity Factor %	MEAN	65%	65%	65%	64%	65%	65%	65%
		P5	61%	61%	59%	60%	60%	59%	61%
		P95	69%	70%	70%	69%	69%	70%	70%
	Net Revenue $	MEAN	$ 131,638,968	$ 135,468,600	$ 138,942,385	$ 144,511,953	$ 148,671,172	$ 153,127,631	$ 157,487,145
		P5	$ 94,173,541	$ 93,667,784	$ 94,520,951	$ 93,326,814	$ 104,453,293	$ 103,561,414	$ 117,882,381
		P95	$ 177,764,882	$ 181,977,275	$ 180,191,222	$ 187,239,028	$ 199,067,396	$ 210,542,261	$ 203,231,123

			2028	2029	2030	2031	2032	2033	2034
Basin Creek 1-9: 51.75 MW	Fuel Consumed MMBtu	MEAN	440,265	431,386	425,401	479,929	451,066	498,880	493,234
		P5	235	-	940	-	-	-	-
		P95	1,557,107	1,237,418	1,303,423	1,489,928	1,353,690	1,586,704	1,593,516
	CO2 Emissions Tonnes	MEAN	23,614	23,138	22,817	25,742	24,194	26,758	26,455
		P5	13	-	50	-	-	-	-
		P95	83,518	66,371	69,911	79,914	72,607	85,105	85,470
	Generation MWh	MEAN	48,498	47,520	46,861	52,867	49,688	54,955	54,333
		P5	26	-	104	-	-	-	-
		P95	171,525	136,310	143,580	164,125	149,118	174,786	175,536
	Capacity Factor %	MEAN	11%	10%	10%	12%	11%	12%	12%
		P5	0%	0%	0%	0%	0%	0%	0%
		P95	38%	30%	32%	36%	33%	39%	39%
	Number of Starts	MEAN	102	107	107	115	114	119	118
		P5	1	-	1	-	-	-	-
		P95	297	299	304	310	306	317	327
	Fuel Cost $	MEAN	$ 2,513,018	$ 2,549,576	$ 2,620,315	$ 2,893,567	$ 2,827,317	$ 3,112,230	$ 3,311,555
		P5	$ 1,276	$ -	$ 4,057	$ -	$ -	$ -	$ -
		P95	$ 8,604,906	$ 7,969,332	$ 8,223,452	$ 8,592,309	$ 9,144,480	$ 9,388,335	$ 11,195,441
	Carbon Emission Costs $	MEAN	$ 835,358	$ 834,826	$ 841,097	$ 1,053,756	$ 966,650	$ 1,240,610	$ 1,193,694
		P5	$ 328	$ -	$ 1,379	$ -	$ -	$ -	$ -
		P95	$ 3,241,799	$ 2,701,294	$ 2,393,331	$ 3,662,179	$ 3,029,551	$ 4,665,104	$ 3,786,504
	VOM Costs $	MEAN	$ 264,954	$ 265,062	$ 266,874	$ 307,405	$ 294,984	$ 333,105	$ 336,251
		P5	$ 141	$ -	$ 589	$ -	$ -	$ -	$ -
		P95	$ 937,075	$ 760,323	$ 817,698	$ 954,330	$ 885,275	$ 1,059,450	$ 1,086,343
	Net Revenue $	MEAN	$ 452,260	$ 398,389	$ 389,958	$ 482,544	$ 458,540	$ 531,843	$ 583,211
		P5	$ 4	$ -	$ 39	$ -	$ -	$ -	$ -
		P95	$ 1,863,056	$ 1,516,492	$ 1,552,495	$ 1,782,766	$ 1,945,353	$ 2,095,188	$ 2,574,462

			2028	2029	2030	2031	2032	2033	2034
Colstrip 3: 111 MW	Fuel Consumed MMBtu	MEAN	7,076,790	6,884,133	6,704,191	6,775,494	6,585,995	6,584,234	6,236,884
		P5	2,110,396	1,217,874	21,746	1,422,609	912,933	902,053	652,326
		P95	9,273,777	9,225,678	9,337,427	9,270,693	9,343,196	9,230,309	9,110,389
	CO2 Emissions Tonnes	MEAN	659,428	641,476	624,709	631,353	613,695	613,531	581,164
		P5	196,651	113,484	2,026	132,561	85,069	84,055	60,785
		P95	864,147	859,665	870,078	863,860	870,616	860,097	848,923
	Generation MWh	MEAN	668,220	650,050	633,007	639,780	621,927	621,712	589,003
		P5	198,981	114,847	2,019	134,229	86,085	85,145	61,502
		P95	873,897	869,440	880,890	873,363	880,744	869,766	858,329
	Capacity Factor %	MEAN	69%	67%	65%	66%	64%	64%	61%
		P5	20%	12%	0%	14%	9%	9%	6%
		P95	90%	89%	91%	90%	90%	89%	88%
	Number of Starts	MEAN	32	32	31	31	30	30	29
		P5	11	7	1	6	5	5	5
		P95	47	53	48	49	47	51	47
	Fuel Cost $	MEAN	$ 7,449,412	$ 7,421,756	$ 7,472,107	$ 7,616,530	$ 7,643,481	$ 7,896,214	$ 7,734,075
		P5	$ 1,888,243	$ 1,007,121	$ 21,171	$ 1,415,927	$ 909,411	$ 1,046,795	$ 684,506
		P95	$ 11,131,344	$ 10,613,513	$ 11,672,872	$ 11,413,811	$ 11,739,489	$ 13,382,822	$ 13,170,506
	Carbon Emission Costs $	MEAN	$ 20,156,345	$ 20,412,158	$ 20,546,969	$ 21,864,374	$ 21,783,009	$ 23,859,969	$ 23,397,898
		P5	$ 4,975,401	$ 3,255,480	$ 113,756	$ 5,705,652	$ 2,206,252	$ 4,131,209	$ 3,324,261
		P95	$ 32,966,018	$ 33,971,010	$ 36,425,093	$ 38,777,970	$ 40,275,252	$ 43,299,861	$ 41,596,122
	VOM Costs $	MEAN	$ 912,653	$ 906,481	$ 901,251	$ 930,024	$ 923,057	$ 942,116	$ 911,293
		P5	$ 271,768	$ 160,151	$ 2,875	$ 195,124	$ 127,767	$ 129,024	$ 95,155
		P95	$ 1,193,566	$ 1,212,415	$ 1,254,179	$ 1,269,575	$ 1,307,191	$ 1,318,005	$ 1,327,989
	Net Revenue $	MEAN	$ 9,429,197	$ 9,532,463	$ 9,688,596	$ 9,476,657	$ 9,654,116	$ 9,240,389	$ 9,335,531
		P5	$ 596,571	$ 192,750	$ (2,485)	$ 250,124	$ 127,340	$ 133,878	$ 60,359
		P95	$ 24,785,809	$ 18,636,736	$ 24,946,124	$ 22,130,186	$ 25,924,549	$ 23,610,653	$ 25,553,835

			2028	2029	2030	2031	2032	2033	2034
Colstrip 4: 111 MW	Fuel Consumed MMBtu	MEAN	6,681,835	6,897,349	6,722,209	6,496,115	6,594,348	6,583,883	5,943,569
		P5	2,091,404	1,302,034	26,433	1,445,138	922,941	997,427	735,809
		P95	8,201,134	9,202,991	9,288,541	8,207,549	9,394,394	9,350,169	8,001,659
	CO2 Emissions Tonnes	MEAN	622,626	642,708	626,388	605,320	614,473	613,498	553,833
		P5	194,881	121,326	2,463	134,661	86,001	92,942	68,564
		P95	764,197	857,551	865,523	764,794	875,387	871,266	745,609
	Generation MWh	MEAN	631,608	651,284	634,730	613,957	622,716	621,684	561,866
		P5	197,158	122,768	2,463	136,227	87,042	94,158	69,414
		P95	774,246	866,802	875,418	774,647	885,092	880,991	755,456
	Capacity Factor %	MEAN	65%	67%	65%	63%	64%	64%	58%
		P5	20%	13%	0%	14%	9%	10%	7%
		P95	79%	89%	90%	80%	91%	91%	78%
	Number of Starts	MEAN	28	31	30	28	29	29	26
		P5	11	5	1	7	4	5	4
		P95	40	50	50	42	48	45	41
	Fuel Cost $	MEAN	$ 7,008,734	$ 7,437,153	$ 7,489,498	$ 7,288,716	$ 7,654,011	$ 7,900,421	$ 7,339,179
		P5	$ 1,845,132	$ 1,074,983	$ 25,763	$ 1,405,465	$ 921,126	$ 1,150,039	$ 764,395
		P95	$ 9,758,223	$ 10,768,458	$ 11,496,112	$ 10,252,476	$ 11,849,754	$ 13,325,229	$ 11,901,086
	Carbon Emission Costs $	MEAN	$ 19,401,658	$ 20,458,866	$ 20,624,013	$ 21,232,034	$ 21,794,120	$ 23,799,091	$ 22,531,897
		P5	$ 4,475,312	$ 3,205,758	$ 138,423	$ 4,794,169	$ 2,218,099	$ 4,738,789	$ 3,644,825
		P95	$ 32,143,343	$ 34,138,270	$ 35,386,452	$ 37,585,359	$ 40,356,622	$ 41,558,111	$ 40,075,576
	VOM Costs $	MEAN	$ 862,648	$ 908,202	$ 903,706	$ 892,486	$ 924,228	$ 942,074	$ 869,307
		P5	$ 269,278	$ 171,197	$ 3,507	$ 198,028	$ 129,186	$ 142,683	$ 107,395
		P95	$ 1,057,463	$ 1,208,737	$ 1,246,387	$ 1,126,074	$ 1,313,643	$ 1,335,015	$ 1,168,826
	Net Revenue $	MEAN	$ 9,218,828	$ 9,558,239	$ 9,697,933	$ 9,353,962	$ 9,671,407	$ 9,274,752	$ 9,158,700
		P5	$ 627,100	$ 230,882	$ (2,144)	$ 209,644	$ 162,367	$ 136,431	$ 96,359
		P95	$ 23,519,918	$ 19,112,765	$ 24,656,942	$ 21,714,060	$ 25,220,300	$ 24,015,036	$ 24,378,056

			2028	2029	2030	2031	2032	2033	2034
David Gates: 7 MW (constant)	Fuel Consumed MMBtu	MEAN	680,013	678,136	678,136	678,136	680,013	678,136	678,136
		P5	668,543	666,628	666,628	666,628	668,543	666,628	666,628
		P95	689,373	687,457	687,457	687,457	689,373	687,457	687,457
	CO2 Emissions Tonnes	MEAN	36,473	36,373	36,373	36,373	36,473	36,373	36,373
		P5	35,858	35,755	35,755	35,755	35,858	35,755	35,755
		P95	36,975	36,873	36,873	36,873	36,975	36,873	36,873
	Generation MWh	MEAN	59,645	59,480	59,480	59,480	59,645	59,480	59,480
		P5	58,639	58,471	58,471	58,471	58,639	58,471	58,471
		P95	60,466	60,298	60,298	60,298	60,466	60,298	60,298
	Capacity Factor %	MEAN	97%	97%	97%	97%	97%	97%	97%
		P5	95%	95%	95%	95%	95%	95%	95%
		P95	98%	98%	98%	98%	98%	98%	98%
	Number of Starts	MEAN	17	17	17	17	17	17	17
		P5	11	11	11	11	11	11	11
		P95	25	25	25	25	25	25	25
	Fuel Cost $	MEAN	$ 3,749,354	$ 3,816,552	$ 3,897,313	$ 3,978,785	$ 4,073,615	$ 4,147,450	$ 4,235,070
		P5	$ 2,822,002	$ 2,931,055	$ 3,096,944	$ 3,177,503	$ 3,236,663	$ 3,240,246	$ 3,295,720
		P95	$ 4,684,778	$ 4,509,209	$ 4,961,057	$ 4,764,075	$ 5,039,732	$ 5,444,569	$ 5,400,255
	Carbon Emission Costs $	MEAN	$ 1,191,639	$ 1,247,519	$ 1,309,072	$ 1,375,052	$ 1,448,224	$ 1,516,776	$ 1,592,662
		P5	$ 370,470	$ 402,945	$ 489,837	$ 599,599	$ 336,349	$ 594,656	$ 565,732
		P95	$ 2,064,621	$ 2,081,171	$ 2,151,878	$ 2,288,289	$ 2,481,239	$ 2,524,248	$ 2,616,605
	VOM Costs $	MEAN	$ 244,389	$ 248,832	$ 254,058	$ 259,393	$ 265,573	$ 270,402	$ 276,080
		P5	$ 240,267	$ 244,610	$ 249,746	$ 254,991	$ 261,094	$ 265,813	$ 271,395
		P95	$ 247,753	$ 252,253	$ 257,550	$ 262,959	$ 269,229	$ 274,119	$ 279,875
	Net Revenue $	MEAN	$ (1,336,199)	$ (1,365,598)	$ (1,396,912)	$ (1,431,301)	$ (1,462,952)	$ (1,511,127)	$ (1,550,734)
		P5	$ (1,909,994)	$ (1,888,026)	$ (1,870,306)	$ (2,093,755)	$ (2,078,110)	$ (2,169,001)	$ (2,084,307)
		P95	$ (636,122)	$ (864,759)	$ (901,635)	$ (845,043)	$ (917,528)	$ (869,637)	$ (933,701)

			2028	2029	2030	2031	2032	2033	2034
Generic CCCT: 239 MW (effective)	Fuel Consumed MMBtu	MEAN	11,860,807	11,807,875	11,847,393	11,866,246	11,954,919	11,865,541	11,897,248
		P5	11,066,277	10,603,493	10,993,509	10,894,147	11,060,416	10,702,081	10,874,870
		P95	12,529,870	12,495,545	12,464,916	12,529,381	12,653,537	12,546,891	12,513,464
	CO2 Emissions Tonnes	MEAN	636,171	633,331	635,451	636,462	641,218	636,424	638,125
		P5	593,555	568,733	589,652	584,322	593,240	574,021	583,289
		P95	672,057	670,216	668,573	672,030	678,690	672,970	671,177
	Generation MWh	MEAN	1,780,805	1,772,854	1,778,710	1,781,636	1,794,949	1,781,473	1,786,321
		P5	1,661,155	1,591,870	1,649,885	1,635,522	1,660,381	1,606,704	1,632,456
		P95	1,881,357	1,876,202	1,871,609	1,881,289	1,899,931	1,883,918	1,878,899
	Capacity Factor %	MEAN	85%	85%	85%	85%	85%	85%	85%
		P5	79%	76%	79%	78%	79%	77%	78%
		P95	90%	90%	89%	90%	90%	90%	90%
	Number of Starts	MEAN	93	91	96	91	92	92	91
		P5	63	67	81	59	68	55	61
		P95	106	103	112	106	104	104	107
	Fuel Cost $	MEAN	$ 65,273,438	$ 66,463,713	$ 68,065,608	$ 69,634,156	$ 71,634,540	$ 72,437,358	$ 74,382,429
		P5	$ 49,624,661	$ 47,555,485	$ 52,816,943	$ 55,595,548	$ 58,492,801	$ 57,059,173	$ 54,191,505
		P95	$ 82,540,045	$ 80,750,396	$ 86,568,766	$ 85,318,970	$ 89,414,321	$ 93,338,918	$ 95,250,105
	Carbon Emission Costs $	MEAN	$ 20,993,854	$ 21,985,984	$ 23,100,213	$ 24,317,216	$ 25,703,276	$ 26,841,075	$ 28,187,264
		P5	$ 5,873,259	$ 5,572,860	$ 7,697,326	$ 10,146,308	$ 5,803,691	$ 8,944,977	$ 9,614,508
		P95	$ 36,426,439	$ 37,470,443	$ 38,887,254	$ 41,385,608	$ 45,499,467	$ 46,178,896	$ 48,299,939
	VOM Costs $	MEAN	$ 4,377,993	$ 4,449,974	$ 4,558,429	$ 4,661,813	$ 4,795,277	$ 4,859,220	$ 4,974,765
		P5	$ 4,083,841	$ 3,995,692	$ 4,228,281	$ 4,279,491	$ 4,435,773	$ 4,382,513	$ 4,546,263
		P95	$ 4,625,193	$ 4,709,381	$ 4,796,509	$ 4,922,563	$ 5,075,739	$ 5,138,652	$ 5,232,586
	Net Revenue $	MEAN	$ 33,231,436	$ 34,172,722	$ 35,139,377	$ 36,312,637	$ 37,654,654	$ 38,411,462	$ 39,420,094
		P5	$ 15,925,646	$ 15,860,940	$ 17,832,034	$ 17,472,888	$ 16,968,577	$ 15,441,193	$ 15,029,834
		P95	$ 53,741,005	$ 54,902,861	$ 54,022,551	$ 61,743,335	$ 59,973,529	$ 65,627,758	$ 68,664,926

			2028	2029	2030	2031	2032	2033	2034
Kerr: 194 MW	Generation MWh	MEAN							
		P5							
		P95							
	Capacity Factor %	MEAN							
		P5							
		P95							
	Net Revenue $	MEAN							
		P5							
		P95							
Other Hydro: 439 MW	Generation MWh	MEAN	2,487,182	2,487,152	2,487,131	2,487,160	2,487,219	2,487,158	2,487,150
		P5	2,288,771	2,329,423	2,322,960	2,310,297	2,275,948	2,290,500	2,264,680
		P95	2,701,403	2,681,132	2,676,580	2,663,231	2,663,706	2,674,791	2,677,027
	Capacity Factor %	MEAN	64%	65%	65%	65%	64%	65%	65%
		P5	59%	61%	60%	60%	59%	60%	59%
		P95	70%	70%	70%	69%	69%	70%	70%
	Net Revenue $	MEAN	$ 162,192,302	$ 166,433,671	$ 171,426,513	$ 176,407,362	$ 181,805,606	$ 186,754,991	$ 192,166,218
		P5	$ 116,882,755	$ 110,339,208	$ 120,206,036	$ 129,285,129	$ 130,014,808	$ 129,776,553	$ 127,935,484
		P95	$ 218,184,943	$ 214,432,562	$ 226,921,274	$ 232,302,026	$ 242,707,782	$ 246,403,703	$ 261,628,986

			2035	2036	2037	2038	2039	2040	2041
Basin Creek 1-9: 51.75 MW	Fuel Consumed MMBtu	MEAN	515,403	500,097	510,926	559,210	526,664	520,359	547,583
		P5	235	-	-	-	-	4,463	-
		P95	1,663,279	1,471,606	1,403,487	1,676,198	1,343,354	1,493,686	1,511,773
	CO2 Emissions Tonnes	MEAN	27,644	26,823	27,404	29,994	28,248	27,910	29,370
		P5	13	-	-	-	-	239	-
		P95	89,212	78,932	75,278	89,905	72,053	80,116	81,086
	Generation MWh	MEAN	56,775	55,089	56,282	61,601	58,015	57,321	60,320
		P5	26	-	-	-	-	492	-
		P95	183,221	162,107	154,603	184,644	147,979	164,539	166,532
	Capacity Factor %	MEAN	13%	12%	12%	14%	13%	13%	13%
		P5	0%	0%	0%	0%	0%	0%	0%
		P95	40%	36%	34%	41%	33%	36%	37%
	Number of Starts	MEAN	121	121	125	131	126	124	132
		P5	1	-	-	-	-	5	-
		P95	327	314	322	329	303	315	316
	Fuel Cost $	MEAN	$ 3,334,646	$ 3,439,429	$ 3,586,869	$ 3,896,121	$ 3,848,297	$ 3,832,602	$ 4,067,988
		P5	$ 1,220	$ -	$ -	$ -	$ -	$ 24,069	$ -
		P95	$ 10,938,981	$ 10,504,749	$ 9,887,419	$ 11,869,349	$ 10,425,254	$ 11,920,943	$ 11,135,915
	Carbon Emission Costs $	MEAN	$ 1,234,758	$ 1,322,414	$ 1,504,696	$ 1,711,353	$ 1,643,476	$ 1,869,387	$ 1,763,768
		P5	$ 526	$ -	$ -	$ -	$ -	$ 8,973	$ -
		P95	$ 4,698,153	$ 4,180,488	$ 4,562,501	$ 5,504,969	$ 5,214,550	$ 7,245,225	$ 4,897,642
	VOM Costs $	MEAN	$ 358,743	$ 355,399	$ 370,719	$ 414,275	$ 398,357	$ 401,854	$ 431,758
		P5	$ 163	$ -	$ -	$ -	$ -	$ 3,447	$ -
		P95	$ 1,157,714	$ 1,045,812	$ 1,018,348	$ 1,241,763	$ 1,016,084	$ 1,153,518	$ 1,192,002
	Net Revenue $	MEAN	$ 602,963	$ 585,085	$ 549,747	$ 674,565	$ 621,941	$ 632,583	$ 702,877
		P5	$ 0	$ -	$ -	$ -	$ -	$ 303	$ -
		P95	$ 2,300,156	$ 2,065,903	$ 1,728,305	$ 2,627,788	$ 1,964,567	$ 2,200,797	$ 2,406,814

			2035	2036	2037	2038	2039	2040	2041
Colstrip 3: 111 MW	Fuel Consumed MMBtu	MEAN	6,130,971	6,155,346	6,141,964	5,845,586	5,694,306	5,750,854	5,285,374
		P5	29,210	1,300	722	486	1,628	722	2,030
		P95	9,317,925	9,339,563	9,249,802	9,161,600	9,253,614	9,112,226	9,253,374
	CO2 Emissions Tonnes	MEAN	571,295	573,566	572,319	544,702	530,606	535,875	492,501
		P5	2,722	121	67	45	152	67	189
		P95	868,261	870,277	861,913	853,695	862,269	849,094	862,246
	Generation MWh	MEAN	578,796	581,228	579,806	551,686	537,613	543,012	498,906
		P5	2,730	104	57	38	131	57	165
		P95	878,099	879,968	871,473	863,241	871,486	858,355	871,979
	Capacity Factor %	MEAN	60%	60%	60%	57%	55%	56%	51%
		P5	0%	0%	0%	0%	0%	0%	0%
		P95	90%	90%	90%	89%	90%	88%	90%
	Number of Starts	MEAN	29	28	28	27	27	27	25
		P5	1	-	-	-	-	-	-
		P95	49	51	47	52	48	47	46
	Fuel Cost $	MEAN	$ 7,823,047	$ 7,992,904	$ 8,169,306	$ 8,122,693	$ 8,031,305	$ 8,254,542	$ 7,942,703
		P5	$ 29,924	$ 1,535	$ 758	$ 417	$ 1,814	$ 887	$ 2,457
		P95	$ 13,563,311	$ 14,204,083	$ 14,082,712	$ 14,727,758	$ 13,890,554	$ 14,580,464	$ 15,979,216
	Carbon Emission Costs $	MEAN	$ 23,205,612	$ 24,321,132	$ 24,551,147	$ 24,874,142	$ 26,037,289	$ 26,632,417	$ 25,809,556
		P5	$ 120,055	$ 10,962	$ 5,012	$ 3,692	$ 11,751	$ 7,263	$ 16,880
		P95	$ 43,270,976	$ 44,876,767	$ 45,141,434	$ 48,100,200	$ 52,018,452	$ 51,884,802	$ 46,393,666
	VOM Costs $	MEAN	$ 914,306	$ 937,430	$ 954,774	$ 927,546	$ 922,866	$ 951,709	$ 892,769
		P5	$ 4,313	$ 167	$ 93	$ 64	$ 224	$ 99	$ 295
		P95	$ 1,387,107	$ 1,419,251	$ 1,435,065	$ 1,451,361	$ 1,495,993	$ 1,504,396	$ 1,560,367
	Net Revenue $	MEAN	$ 9,504,617	$ 9,311,102	$ 9,202,049	$ 9,352,329	$ 8,772,031	$ 8,644,811	$ 8,574,180
		P5	$ -	$ -	$ (2,781)	$ (3,555)	$ (3,714)	$ -	$ (7,685)
		P95	$ 26,616,694	$ 28,653,606	$ 24,291,486	$ 22,162,194	$ 24,092,973	$ 23,522,615	$ 31,702,505

			2035	2036	2037	2038	2039	2040	2041
Colstrip 4: 111 MW	Fuel Consumed MMBtu	MEAN	6,130,185	6,155,469	5,904,678	5,839,731	5,678,473	5,527,360	5,286,388
		P5	1,915	1,300	971	309	1,028	722	1,793
		P95	9,191,537	9,278,253	8,270,327	9,158,705	9,227,209	7,947,032	9,211,028
	CO2 Emissions Tonnes	MEAN	571,222	573,578	550,209	544,157	529,130	515,049	492,595
		P5	178	121	90	29	96	67	167
		P95	856,484	864,564	770,644	853,425	859,808	740,519	858,300
	Generation MWh	MEAN	578,727	581,276	557,882	551,158	536,109	522,335	498,980
		P5	154	104	77	24	82	57	146
		P95	865,614	873,901	780,653	862,819	869,228	750,355	867,535
	Capacity Factor %	MEAN	60%	60%	57%	57%	55%	54%	51%
		P5	0%	0%	0%	0%	0%	0%	0%
		P95	89%	90%	80%	89%	89%	77%	89%
	Number of Starts	MEAN	28	27	26	27	26	25	24
		P5	1	-	-	-	-	-	-
		P95	48	48	40	49	48	40	46
	Fuel Cost $	MEAN	$ 7,823,558	$ 7,988,714	$ 7,831,309	$ 8,114,089	$ 8,010,605	$ 7,919,174	$ 7,945,849
		P5	$ 2,004	$ 1,535	$ 1,038	$ 284	$ 1,244	$ 932	$ 2,223
		P95	$ 13,560,796	$ 14,105,760	$ 12,633,044	$ 14,399,798	$ 13,723,277	$ 13,081,840	$ 15,911,758
	Carbon Emission Costs $	MEAN	$ 23,254,620	$ 24,324,691	$ 24,053,243	$ 24,786,643	$ 26,008,845	$ 25,985,256	$ 25,843,179
		P5	$ 14,274	$ 10,962	$ 6,753	$ 2,472	$ 8,102	$ 7,263	$ 14,892
		P95	$ 43,782,014	$ 44,138,605	$ 45,122,746	$ 47,666,682	$ 51,755,356	$ 51,390,696	$ 46,607,746
	VOM Costs $	MEAN	$ 914,197	$ 937,507	$ 918,671	$ 926,659	$ 920,285	$ 915,469	$ 892,902
		P5	$ 244	$ 167	$ 126	$ 40	$ 141	$ 99	$ 262
		P95	$ 1,367,384	$ 1,409,465	$ 1,285,511	$ 1,450,653	$ 1,492,117	$ 1,315,109	$ 1,552,415
	Net Revenue $	MEAN	$ 9,497,586	$ 9,298,910	$ 9,035,390	$ 9,372,940	$ 8,726,856	$ 8,515,868	$ 8,572,038
		P5	$ (493)	$ -	$ (2,251)	$ (3,555)	$ (2,107)	$ (674)	$ (4,453)
		P95	$ 26,444,446	$ 28,202,744	$ 22,635,700	$ 22,090,993	$ 23,276,204	$ 22,781,790	$ 31,339,524

			2035	2036	2037	2038	2039	2040	2041
David Gates: 7 MW (constant)	Fuel Consumed MMBtu	MEAN	678,136	680,013	678,136	678,136	678,136	680,013	678,136
		P5	666,628	668,543	666,628	666,628	666,628	668,543	666,628
		P95	687,457	689,373	687,457	687,457	687,457	689,373	687,457
	CO2 Emissions Tonnes	MEAN	36,373	36,473	36,373	36,373	36,373	36,473	36,373
		P5	35,755	35,858	35,755	35,755	35,755	35,858	35,755
		P95	36,873	36,975	36,873	36,873	36,873	36,975	36,873
	Generation MWh	MEAN	59,480	59,645	59,480	59,480	59,480	59,645	59,480
		P5	58,471	58,639	58,471	58,471	58,471	58,639	58,471
		P95	60,298	60,466	60,298	60,298	60,298	60,466	60,298
	Capacity Factor %	MEAN	97%	97%	97%	97%	97%	97%	97%
		P5	95%	95%	95%	95%	95%	95%	95%
		P95	98%	98%	98%	98%	98%	98%	98%
	Number of Starts	MEAN	17	17	17	17	17	17	17
		P5	11	11	11	11	11	11	11
		P95	25	25	25	25	25	25	25
	Fuel Cost $	MEAN	$ 4,323,867	$ 4,427,413	$ 4,507,324	$ 4,602,003	$ 4,697,950	$ 4,811,458	$ 4,896,640
		P5	$ 3,322,121	$ 3,603,217	$ 3,602,212	$ 3,486,110	$ 3,780,813	$ 3,783,160	$ 3,940,505
		P95	$ 5,419,708	$ 5,569,769	$ 5,694,874	$ 5,897,013	$ 5,668,252	$ 6,231,238	$ 5,972,278
	Carbon Emission Costs $	MEAN	$ 1,671,484	$ 1,759,741	$ 1,842,741	$ 1,935,185	$ 2,031,923	$ 2,140,173	$ 2,239,610
		P5	$ 662,489	$ 504,775	$ 465,621	$ 775,060	$ 599,038	$ 702,745	$ 1,005,115
		P95	$ 2,795,085	$ 3,025,781	$ 3,138,903	$ 3,257,606	$ 3,390,587	$ 3,730,342	$ 3,604,010
	VOM Costs $	MEAN	$ 281,878	$ 288,594	$ 293,841	$ 300,012	$ 306,312	$ 313,611	$ 319,312
		P5	$ 277,095	$ 283,726	$ 288,855	$ 294,921	$ 301,114	$ 308,321	$ 313,894
		P95	$ 285,753	$ 292,566	$ 297,880	$ 304,136	$ 310,523	$ 317,927	$ 323,702
	Net Revenue $	MEAN	$ (1,586,376)	$ (1,629,244)	$ (1,663,528)	$ (1,703,843)	$ (1,746,416)	$ (1,795,362)	$ (1,836,649)
		P5	$ (2,306,519)	$ (2,263,714)	$ (2,257,510)	$ (2,554,679)	$ (2,279,238)	$ (2,489,782)	$ (2,589,228)
		P95	$ (731,912)	$ (922,011)	$ (1,044,090)	$ (986,808)	$ (1,108,971)	$ (1,104,175)	$ (1,057,095)

			2035	2036	2037	2038	2039	2040	2041
Generic CCCT: 239 MW (effective)	Fuel Consumed MMBtu	MEAN	11,904,320	11,951,196	11,993,419	11,974,363	11,985,962	12,052,236	12,060,554
		P5	11,114,114	11,039,082	11,080,717	10,858,177	11,209,947	11,269,054	11,335,417
		P95	12,522,707	12,543,298	12,690,943	12,964,139	12,556,930	12,791,355	12,676,615
	CO2 Emissions Tonnes	MEAN	638,504	641,019	643,283	642,261	642,883	646,438	646,884
		P5	596,121	592,096	594,329	582,393	601,261	604,431	607,991
		P95	671,672	672,777	680,696	695,349	673,508	686,082	679,928
	Generation MWh	MEAN	1,787,375	1,794,360	1,800,725	1,797,873	1,799,599	1,809,564	1,810,824
		P5	1,668,555	1,657,189	1,663,372	1,630,258	1,681,853	1,691,741	1,700,699
		P95	1,880,282	1,883,372	1,905,547	1,946,406	1,885,420	1,920,474	1,903,282
	Capacity Factor %	MEAN	85%	85%	86%	86%	86%	86%	86%
		P5	80%	79%	79%	78%	80%	81%	81%
		P95	90%	90%	91%	93%	90%	91%	91%
	Number of Starts	MEAN	94	93	91	92	92	93	94
		P5	74	70	51	41	73	71	72
		P95	106	106	105	107	105	104	105
	Fuel Cost $	MEAN	$ 75,821,544	$ 77,866,969	$ 79,735,909	$ 81,055,435	$ 83,109,241	$ 85,299,409	$ 87,067,404
		P5	$ 57,102,411	$ 60,055,789	$ 61,013,178	$ 62,771,839	$ 65,714,113	$ 65,544,322	$ 68,528,680
		P95	$ 94,689,181	$ 98,587,997	$ 101,915,472	$ 103,161,711	$ 100,584,156	$ 109,098,132	$ 106,066,143
	Carbon Emission Costs $	MEAN	$ 29,618,115	$ 31,286,674	$ 33,068,161	$ 34,703,555	$ 36,279,769	$ 38,479,435	$ 40,123,832
		P5	$ 10,321,696	$ 8,595,865	$ 7,496,007	$ 12,451,436	$ 10,090,404	$ 10,761,336	$ 17,575,032
		P95	$ 50,261,722	$ 54,397,850	$ 59,936,156	$ 59,418,555	$ 62,022,727	$ 68,144,383	$ 68,587,846
	VOM Costs $	MEAN	$ 5,082,232	$ 5,209,237	$ 5,337,499	$ 5,440,953	$ 5,560,548	$ 5,708,755	$ 5,832,699
		P5	$ 4,744,377	$ 4,811,014	$ 4,930,372	$ 4,933,695	$ 5,196,725	$ 5,337,050	$ 5,477,982
		P95	$ 5,346,403	$ 5,467,648	$ 5,648,199	$ 5,890,464	$ 5,825,724	$ 6,058,652	$ 6,130,506
	Net Revenue $	MEAN	$ 40,686,214	$ 42,165,133	$ 43,460,011	$ 44,873,692	$ 46,320,500	$ 47,989,190	$ 49,331,085
		P5	$ 19,800,673	$ 18,519,639	$ 17,462,586	$ 20,129,790	$ 19,594,180	$ 22,077,737	$ 23,348,861
		P95	$ 67,980,355	$ 65,738,780	$ 67,613,493	$ 76,579,484	$ 71,173,309	$ 79,523,089	$ 74,012,520

			2035	2036	2037	2038	2039	2040	2041
Kerr: 194 MW	Generation MWh	MEAN							
		P5							
		P95							
	Capacity Factor %	MEAN							
		P5							
		P95							
	Net Revenue $	MEAN							
		P5							
		P95							
Other Hydro: 439 MW	Generation MWh	MEAN	2,487,163	2,487,162	2,487,168	2,487,161	2,487,199	2,487,138	2,487,141
		P5	2,261,680	2,278,944	2,273,779	2,284,369	2,272,687	2,292,102	2,298,423
		P95	2,706,472	2,656,393	2,639,990	2,681,309	2,684,322	2,663,578	2,678,084
	Capacity Factor %	MEAN	65%	64%	65%	65%	65%	64%	65%
		P5	59%	59%	59%	59%	59%	59%	60%
		P95	70%	69%	69%	70%	70%	69%	70%
	Net Revenue $	MEAN	$ 197,943,478	$ 204,029,733	$ 209,894,819	$ 216,075,905	$ 223,022,220	$ 229,629,608	$ 236,882,069
		P5	$ 131,305,430	$ 140,182,391	$ 139,574,569	$ 155,429,566	$ 155,325,959	$ 153,502,288	$ 167,109,375
		P95	$ 261,852,167	$ 278,170,800	$ 279,810,055	$ 284,038,658	$ 293,658,587	$ 311,923,066	$ 304,851,853

			2042	2043
Basin Creek 1-9: 51.75 MW	Fuel Consumed MMBtu	MEAN	552,784	603,178
		P5	-	3,993
		P95	1,893,709	1,685,594
	CO2 Emissions Tonnes	MEAN	29,649	32,352
		P5	-	214
		P95	101,572	90,409
	Generation MWh	MEAN	60,893	66,444
		P5	-	440
		P95	208,604	185,679
	Capacity Factor %	MEAN	13%	15%
		P5	0%	0%
		P95	46%	41%
	Number of Starts	MEAN	126	140
		P5	-	4
		P95	336	329
	Fuel Cost $	MEAN	$ 4,362,868	$ 4,699,125
		P5	$ -	$ 24,290
		P95	$ 15,016,444	$ 13,868,793
	Carbon Emission Costs $	MEAN	$ 1,975,003	$ 2,339,170
		P5	$ -	$ 3,403
		P95	$ 6,411,647	$ 8,417,427
	VOM Costs $	MEAN	$ 445,012	$ 495,778
		P5	$ -	$ 3,282
		P95	$ 1,524,508	$ 1,385,463
	Net Revenue $	MEAN	$ 835,160	$ 813,160
		P5	$ -	$ 326
		P95	$ 3,864,437	$ 3,186,366

			2042	2043
Colstrip 3: 111 MW	Fuel Consumed MMBtu	MEAN	5,139,705	5,053,568
		P5	1,300	-
		P95	9,152,597	9,189,988
	CO2 Emissions Tonnes	MEAN	478,927	470,901
		P5	121	-
		P95	852,856	856,340
	Generation MWh	MEAN	484,899	477,006
		P5	104	-
		P95	862,382	866,094
	Capacity Factor %	MEAN	50%	49%
		P5	0%	0%
		P95	89%	89%
	Number of Starts	MEAN	25	24
		P5	-	-
		P95	47	45
	Fuel Cost $	MEAN	$ 8,001,079	$ 7,958,063
		P5	$ 1,582	$ -
		P95	$ 15,897,360	$ 15,736,590
	Carbon Emission Costs $	MEAN	$ 26,015,280	$ 25,610,012
		P5	$ 10,699	$ -
		P95	$ 51,660,429	$ 51,119,881
	VOM Costs $	MEAN	$ 885,928	$ 889,808
		P5	$ 189	$ -
		P95	$ 1,575,601	$ 1,615,612
	Net Revenue $	MEAN	$ 8,624,444	$ 8,475,648
		P5	$ (3,946)	$ (3,319)
		P95	$ 29,439,107	$ 26,824,664

			2042	2043
Colstrip 4: 111 MW	Fuel Consumed MMBtu	MEAN	5,133,605	4,883,309
		P5	1,300	-
		P95	9,209,901	8,178,478
	CO2 Emissions Tonnes	MEAN	478,359	455,036
		P5	121	-
		P95	858,195	762,085
	Generation MWh	MEAN	484,324	461,254
		P5	104	-
		P95	867,878	771,794
	Capacity Factor %	MEAN	50%	47%
		P5	0%	0%
		P95	89%	79%
	Number of Starts	MEAN	25	22
		P5	-	-
		P95	51	40
	Fuel Cost $	MEAN	$ 7,989,649	$ 7,663,730
		P5	$ 1,582	$ -
		P95	$ 15,704,936	$ 13,967,174
	Carbon Emission Costs $	MEAN	$ 25,968,370	$ 25,111,798
		P5	$ 10,699	$ -
		P95	$ 51,007,248	$ 50,610,387
	VOM Costs $	MEAN	$ 884,877	$ 860,423
		P5	$ 189	$ -
		P95	$ 1,585,641	$ 1,439,706
	Net Revenue $	MEAN	$ 8,637,581	$ 8,338,856
		P5	$ (3,946)	$ (2,955)
		P95	$ 29,816,743	$ 25,175,685

			2042	2043
David Gates: 7 MW (constant)	Fuel Consumed MMBtu	MEAN	678,136	678,136
		P5	666,628	666,628
		P95	687,457	687,457
	CO2 Emissions Tonnes	MEAN	36,373	36,373
		P5	35,755	35,755
		P95	36,873	36,873
	Generation MWh	MEAN	59,480	59,480
		P5	58,471	58,471
		P95	60,298	60,298
	Capacity Factor %	MEAN	97%	97%
		P5	95%	95%
		P95	98%	98%
	Number of Starts	MEAN	17	17
		P5	11	11
		P95	25	25
	Fuel Cost $	MEAN	$ 5,001,501	$ 5,106,133
		P5	$ 3,895,036	$ 4,053,125
		P95	$ 6,252,543	$ 6,380,952
	Carbon Emission Costs $	MEAN	$ 2,352,226	$ 2,469,947
		P5	$ 897,506	$ 615,553
		P95	$ 3,771,997	$ 4,178,376
	VOM Costs $	MEAN	$ 326,018	$ 332,864
		P5	$ 320,485	$ 327,216
		P95	$ 330,499	$ 337,440
	Net Revenue $	MEAN	$ (1,882,213)	$ (1,924,957)
		P5	$ (2,425,184)	$ (2,848,289)
		P95	$ (1,106,176)	$ (1,141,717)

			2042	2043
Generic CCCT: 239 MW (effective)	Fuel Consumed MMBtu	MEAN	12,048,022	12,063,757
		P5	11,105,057	10,693,458
		P95	12,739,409	12,792,970
	CO2 Emissions Tonnes	MEAN	646,212	647,056
		P5	595,635	573,558
		P95	683,296	686,168
	Generation MWh	MEAN	1,808,958	1,811,287
		P5	1,666,582	1,604,765
		P95	1,912,722	1,920,730
	Capacity Factor %	MEAN	86%	87%
		P5	80%	77%
		P95	91%	92%
	Number of Starts	MEAN	93	92
		P5	65	44
		P95	105	106
	Fuel Cost $	MEAN	$ 88,853,834	$ 90,805,821
		P5	$ 70,134,067	$ 69,458,413
		P95	$ 111,398,014	$ 112,539,941
	Carbon Emission Costs $	MEAN	$ 42,210,973	$ 44,625,024
		P5	$ 15,131,844	$ 9,916,264
		P95	$ 69,364,159	$ 78,154,378
	VOM Costs $	MEAN	$ 5,949,048	$ 6,081,798
		P5	$ 5,480,822	$ 5,388,353
		P95	$ 6,290,291	$ 6,449,276
	Net Revenue $	MEAN	$ 51,022,106	$ 52,859,281
		P5	$ 21,859,738	$ 17,907,249
		P95	$ 87,725,883	$ 85,032,036

			2042	2043
Kerr: 194 MW	Generation MWh	MEAN		
		P5		
		P95		
	Capacity Factor %	MEAN		
		P5		
		P95		
	Net Revenue $	MEAN		
		P5		
		P95		
Other Hydro: 439 MW	Generation MWh	MEAN	2,487,172	2,486,854
		P5	2,275,331	2,272,495
		P95	2,671,702	2,667,899
	Capacity Factor %	MEAN	65%	65%
		P5	59%	59%
		P95	69%	69%
	Net Revenue $	MEAN	$ 244,275,813	$ 252,197,148
		P5	$ 171,736,571	$ 164,564,919
		P95	$ 329,287,415	$ 336,783,272

Current Portfolio

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Market Sales $M	**MEAN**	$ 4.4	$ 1.1	$ 1.4	$ 1.3	$ 1.3	$ 1.6	$ 1.7	$ 1.9	$ 2.2	$ 2.1
	P5	$ 2.9	$ 0.7	$ 1.0	$ 0.9	$ 0.8	$ 1.1	$ 1.1	$ 0.8	$ 0.5	$ 0.5
	P95	$ 5.9	$ 1.5	$ 1.9	$ 1.8	$ 1.8	$ 2.3	$ 2.4	$ 3.0	$ 3.2	$ 3.1
Market Purchases $M	**MEAN**	$ 54.6	$ 76.6	$ 80.9	$ 88.9	$ 98.5	$ 104.9	$ 113.2	$ 164.9	$ 168.1	$ 177.0
	P5	$ 43.3	$ 60.3	$ 59.3	$ 66.8	$ 66.2	$ 82.7	$ 86.1	$ 124.4	$ 120.3	$ 124.7
	P95	$ 66.7	$ 97.0	$ 101.8	$ 113.3	$ 131.4	$ 143.2	$ 157.6	$ 221.4	$ 215.8	$ 240.6
Fixed Costs $M	**Total**	$ 112.9	$ 112.9	$ 112.9	$ 112.9	$ 112.9	$ 112.9	$ 112.9	$ 112.9	$ 112.9	$ 112.9
Generator Operating Costs $M	**MEAN**	$ 14.6	$ 16.3	$ 16.5	$ 18.4	$ 19.4	$ 19.9	$ 22.4	$ 50.6	$ 51.4	$ 53.1
	P5	$ 10.6	$ 11.0	$ 12.1	$ 12.6	$ 12.6	$ 14.6	$ 15.9	$ 20.3	$ 14.7	$ 13.7
	P95	$ 18.3	$ 22.2	$ 23.7	$ 25.5	$ 27.8	$ 28.6	$ 32.2	$ 86.4	$ 85.8	$ 90.9
Total Cost $M	**MEAN**	$ 361.7	$ 355.6	$ 362.9	$ 364.1	$ 365.3	$ 377.7	$ 388.1	$ 466.6	$ 476.1	$ 485.9
	P5	$ 346.0	$ 338.6	$ 342.8	$ 338.7	$ 325.1	$ 344.8	$ 350.0	$ 398.8	$ 404.5	$ 408.5
	P95	$ 375.7	$ 372.6	$ 385.7	$ 394.4	$ 410.9	$ 427.2	$ 441.3	$ 539.5	$ 555.9	$ 567.5

Current Portfolio + CC

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Market Sales $M	**MEAN**	$ 4.4	$ 1.1	$ 1.4	$ 1.3	$ 11.0	$ 12.6	$ 13.5	$ 17.7	$ 19.7	$ 18.5
	P5	$ 2.9	$ 0.7	$ 1.1	$ 0.9	$ 4.4	$ 7.2	$ 6.8	$ 8.5	$ 7.2	$ 6.1
	P95	$ 5.9	$ 1.6	$ 1.9	$ 1.8	$ 17.0	$ 19.5	$ 22.3	$ 27.3	$ 29.4	$ 27.8
Market Purchases $M	**MEAN**	$ 54.6	$ 76.6	$ 80.9	$ 88.9	$ 45.9	$ 49.0	$ 51.4	$ 77.8	$ 80.3	$ 84.6
	P5	$ 43.7	$ 60.0	$ 59.2	$ 67.4	$ 38.1	$ 39.4	$ 41.6	$ 56.6	$ 59.2	$ 59.1
	P95	$ 66.6	$ 96.4	$ 102.0	$ 113.3	$ 56.8	$ 64.1	$ 68.2	$ 105.5	$ 114.3	$ 125.5
Fixed Costs $M	**Total**	$ 112.9	$ 112.9	$ 112.9	$ 112.9	$ 152.1	$ 152.1	$ 152.2	$ 152.3	$ 152.4	$ 152.5
Generator Operating Costs $M	**MEAN**	$ 14.6	$ 16.3	$ 16.5	$ 18.4	$ 64.7	$ 69.1	$ 75.6	$ 124.6	$ 127.1	$ 131.4
	P5	$ 10.7	$ 11.1	$ 12.1	$ 12.6	$ 35.8	$ 49.5	$ 48.6	$ 69.7	$ 69.9	$ 69.6
	P95	$ 18.3	$ 22.4	$ 23.6	$ 25.3	$ 91.4	$ 93.2	$ 107.6	$ 184.6	$ 185.5	$ 189.9
Total Cost $M	**MEAN**	$ 361.7	$ 355.6	$ 362.9	$ 364.1	$ 390.0	$ 402.0	$ 409.7	$ 480.3	$ 489.1	$ 498.2
	P5	$ 346.2	$ 338.1	$ 342.7	$ 339.1	$ 359.3	$ 378.1	$ 382.0	$ 423.5	$ 429.9	$ 431.8
	P95	$ 375.9	$ 372.6	$ 386.1	$ 394.1	$ 421.2	$ 438.9	$ 453.2	$ 538.2	$ 555.7	$ 566.8

Current Portfolio + Hydro

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Market Sales $M	**MEAN**	$ 55.9	$ 34.6	$ 20.0	$ 20.3	$ 19.2	$ 21.5	$ 24.2	$ 27.3	$ 28.8	$ 28.6
	P5	$ 40.3	$ 21.7	$ 14.0	$ 11.9	$ 11.4	$ 14.9	$ 15.5	$ 14.5	$ 10.1	$ 11.5
	P95	$ 72.3	$ 50.1	$ 27.9	$ 28.5	$ 28.0	$ 31.4	$ 35.3	$ 43.7	$ 44.0	$ 42.2
Market Purchases $M	**MEAN**	$ 5.9	$ 12.1	$ 21.4	$ 26.3	$ 30.3	$ 31.6	$ 34.6	$ 55.1	$ 55.5	$ 60.7
	P5	$ 3.6	$ 8.8	$ 15.5	$ 18.9	$ 21.4	$ 25.0	$ 25.8	$ 37.5	$ 36.6	$ 38.8
	P95	$ 8.9	$ 17.2	$ 27.1	$ 33.5	$ 40.3	$ 41.3	$ 47.3	$ 76.4	$ 83.9	$ 92.2
Fixed Costs $M	**Total**	$ 284.3	$ 273.3	$ 256.8	$ 257.3	$ 256.7	$ 255.7	$ 254.7	$ 254.1	$ 253.2	$ 252.5
Generator Operating Costs $M	**MEAN**	$ 14.6	$ 16.3	$ 16.5	$ 18.4	$ 19.4	$ 19.9	$ 22.4	$ 50.6	$ 51.4	$ 53.1
	P5	$ 10.6	$ 11.0	$ 12.1	$ 12.6	$ 12.6	$ 14.6	$ 15.9	$ 20.3	$ 14.7	$ 13.7
	P95	$ 18.3	$ 22.2	$ 23.7	$ 25.5	$ 27.8	$ 28.6	$ 32.2	$ 86.4	$ 85.8	$ 90.9
Total Cost $M	**MEAN**	$ 435.4	$ 421.2	$ 431.6	$ 429.9	$ 426.2	$ 430.7	$ 432.2	$ 476.2	$ 480.9	$ 486.6
	P5	$ 422.9	$ 403.8	$ 425.0	$ 423.5	$ 412.3	$ 420.5	$ 419.3	$ 444.4	$ 447.0	$ 446.9
	P95	$ 444.7	$ 433.7	$ 437.7	$ 437.6	$ 443.4	$ 442.5	$ 449.2	$ 512.2	$ 519.5	$ 528.2

Current Portfolio

		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Market Sales $M	**MEAN**	$ 2.0	$ 2.2	$ 1.9	$ 1.8	$ 2.0	$ 1.7	$ 1.6	$ 1.9	$ 1.4	$ 1.4
	P5	$ 0.6	$ 0.5	$ 0.3	$ 0.5	$ 0.8	$ 0.2	$ 0.1	$ 0.5	$ 0.1	$ 0.2
	P95	$ 3.0	$ 3.3	$ 3.2	$ 2.5	$ 2.9	$ 2.6	$ 2.4	$ 2.9	$ 2.4	$ 2.3
Market Purchases $M	**MEAN**	$ 186.3	$ 196.7	$ 209.3	$ 219.1	$ 229.1	$ 244.3	$ 259.6	$ 268.4	$ 290.9	$ 301.2
	P5	$ 128.5	$ 137.6	$ 143.5	$ 166.5	$ 165.5	$ 164.2	$ 180.4	$ 192.3	$ 188.3	$ 205.1
	P95	$ 244.2	$ 264.9	$ 282.5	$ 287.2	$ 301.8	$ 318.8	$ 351.9	$ 356.2	$ 399.8	$ 395.9
Fixed Costs $M	**Total**	$ 112.9	$ 112.9	$ 112.9	$ 112.9	$ 112.9	$ 112.9	$ 112.9	$ 112.9	$ 112.9	$ 112.9
Generator Operating Costs $M	**MEAN**	$ 58.2	$ 56.1	$ 59.5	$ 64.1	$ 64.6	$ 66.5	$ 67.1	$ 69.7	$ 70.6	$ 76.0
	P5	$ 16.7	$ 15.2	$ 14.4	$ 22.0	$ 20.0	$ 13.2	$ 6.2	$ 19.3	$ 13.2	$ 18.3
	P95	$ 96.3	$ 96.7	$ 104.1	$ 102.8	$ 104.7	$ 108.9	$ 114.5	$ 118.2	$ 125.9	$ 134.1
Total Cost $M	**MEAN**	$ 503.5	$ 523.1	$ 544.0	$ 561.3	$ 594.3	$ 584.0	$ 599.3	$ 618.6	$ 641.9	$ 659.0
	P5	$ 410.3	$ 436.2	$ 448.1	$ 482.6	$ 499.6	$ 470.1	$ 488.8	$ 522.9	$ 507.3	$ 531.1
	P95	$ 587.2	$ 611.3	$ 636.7	$ 656.0	$ 697.0	$ 688.8	$ 704.7	$ 733.4	$ 773.5	$ 807.9

Current Portfolio + CC

		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Market Sales $M	**MEAN**	$ 18.5	$ 19.2	$ 16.8	$ 16.8	$ 17.9	$ 15.9	$ 14.9	$ 16.6	$ 13.9	$ 13.6
	P5	$ 6.0	$ 5.3	$ 4.2	$ 5.5	$ 7.8	$ 4.3	$ 2.8	$ 5.7	$ 4.0	$ 3.4
	P95	$ 27.1	$ 27.6	$ 28.2	$ 25.8	$ 28.3	$ 23.0	$ 23.2	$ 25.9	$ 21.5	$ 22.3
Market Purchases $M	**MEAN**	$ 89.2	$ 96.6	$ 104.0	$ 110.2	$ 117.2	$ 127.4	$ 138.0	$ 144.0	$ 159.6	$ 166.3
	P5	$ 60.5	$ 65.0	$ 68.1	$ 80.5	$ 82.5	$ 88.9	$ 93.0	$ 105.0	$ 102.3	$ 114.3
	P95	$ 129.6	$ 151.5	$ 164.4	$ 164.0	$ 163.1	$ 185.6	$ 205.5	$ 210.7	$ 241.0	$ 242.0
Fixed Costs $M	**Total**	$ 152.6	$ 152.7	$ 152.8	$ 152.9	$ 153.0	$ 153.1	$ 153.2	$ 153.3	$ 153.5	$ 153.6
Generator Operating Costs $M	**MEAN**	$ 139.0	$ 139.4	$ 145.0	$ 152.3	$ 155.3	$ 159.4	$ 162.8	$ 168.3	$ 172.5	$ 180.2
	P5	$ 76.7	$ 81.4	$ 77.7	$ 94.6	$ 85.0	$ 84.5	$ 91.3	$ 108.4	$ 93.7	$ 102.4
	P95	$ 202.3	$ 206.8	$ 219.0	$ 215.9	$ 220.6	$ 223.9	$ 239.1	$ 243.9	$ 253.0	$ 273.7
Total Cost $M	**MEAN**	$ 513.8	$ 532.7	$ 552.8	$ 569.2	$ 601.1	$ 590.1	$ 604.4	$ 622.8	$ 644.9	$ 661.3
	P5	$ 436.0	$ 459.4	$ 472.2	$ 501.9	$ 522.5	$ 485.8	$ 511.9	$ 539.2	$ 524.7	$ 546.0
	P95	$ 586.9	$ 613.7	$ 634.8	$ 646.5	$ 689.6	$ 686.3	$ 696.2	$ 715.2	$ 762.3	$ 787.4

Current Portfolio + Hydro

		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Market Sales $M	**MEAN**	$ 28.5	$ 28.2	$ 26.9	$ 26.5	$ 26.5	$ 25.3	$ 24.1	$ 24.9	$ 22.6	$ 22.2
	P5	$ 12.6	$ 9.8	$ 8.6	$ 10.1	$ 11.4	$ 9.1	$ 6.1	$ 8.9	$ 9.8	$ 6.4
	P95	$ 40.4	$ 41.3	$ 46.1	$ 42.3	$ 43.3	$ 38.9	$ 39.3	$ 39.9	$ 37.3	$ 37.3
Market Purchases $M	**MEAN**	$ 64.3	$ 69.9	$ 77.0	$ 82.0	$ 87.0	$ 96.8	$ 106.0	$ 110.1	$ 125.2	$ 130.1
	P5	$ 40.9	$ 44.0	$ 48.6	$ 53.6	$ 59.7	$ 61.6	$ 69.1	$ 73.5	$ 76.2	$ 85.4
	P95	$ 100.6	$ 121.8	$ 133.2	$ 127.6	$ 130.5	$ 151.5	$ 165.3	$ 174.1	$ 196.5	$ 200.8
Fixed Costs $M	**Total**	$ 252.0	$ 251.4	$ 250.3	$ 249.5	$ 248.7	$ 248.0	$ 247.2	$ 246.4	$ 245.7	$ 243.8
Generator Operating Costs $M	**MEAN**	$ 58.2	$ 56.1	$ 59.5	$ 64.1	$ 64.6	$ 66.5	$ 67.1	$ 69.7	$ 70.6	$ 76.0
	P5	$ 16.7	$ 15.2	$ 14.4	$ 22.0	$ 20.0	$ 13.2	$ 6.2	$ 19.3	$ 13.2	$ 18.3
	P95	$ 96.3	$ 96.7	$ 104.1	$ 102.8	$ 104.7	$ 108.9	$ 114.5	$ 118.2	$ 125.9	$ 134.1
Total Cost $M	**MEAN**	$ 498.1	$ 513.0	$ 528.3	$ 540.5	$ 567.9	$ 552.7	$ 562.2	$ 575.8	$ 592.9	$ 603.2
	P5	$ 450.9	$ 469.7	$ 479.1	$ 496.9	$ 520.8	$ 483.8	$ 502.2	$ 517.9	$ 512.5	$ 526.1
	P95	$ 546.6	$ 557.9	$ 581.7	$ 597.1	$ 622.5	$ 610.3	$ 617.0	$ 640.8	$ 671.1	$ 687.9

Current Portfolio

		2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Market Sales $M	**MEAN**	$ 1.6	$ 1.4	$ 1.2	$ 1.4	$ 1.1	$ 1.0	$ 1.2	$ 0.9	$ 0.9	$ 1.0
	P5	$ 0.3	$ 0.1	$ 0.1	$ 0.1	$ 0.0	$ 0.1	$ 0.1	$ 0.0	$ 0.1	$ 0.1
	P95	$ 2.7	$ 2.7	$ 2.2	$ 2.3	$ 2.2	$ 1.7	$ 2.3	$ 2.0	$ 1.9	$ 1.8
Market Purchases $M	**MEAN**	$ 316.7	$ 338.5	$ 358.9	$ 372.1	$ 396.4	$ 419.8	$ 438.7	$ 469.0	$ 495.9	$ 521.7
	P5	$ 221.5	$ 243.9	$ 240.4	$ 227.2	$ 277.4	$ 284.4	$ 270.5	$ 332.4	$ 328.5	$ 309.2
	P95	$ 422.0	$ 461.4	$ 513.8	$ 528.6	$ 539.9	$ 571.5	$ 624.0	$ 655.0	$ 672.0	$ 733.9
Fixed Costs $M	**Total**	$ 112.9	$ 112.9	$ 112.9	$ 112.9	$ 112.9	$ 112.9	$ 112.9	$ 112.9	$ 112.9	$ 112.6
Generator Operating Costs $M	**MEAN**	$ 73.7	$ 75.1	$ 78.1	$ 78.6	$ 80.6	$ 82.9	$ 84.0	$ 83.0	$ 84.2	$ 83.5
	P5	$ 14.8	$ 7.2	$ 9.6	$ 8.2	$ 7.4	$ 7.7	$ 9.3	$ 8.4	$ 7.9	$ 7.9
	P95	$ 133.3	$ 138.8	$ 140.2	$ 140.9	$ 150.6	$ 157.8	$ 160.0	$ 153.1	$ 167.0	$ 161.6
Total Cost $M	**MEAN**	$ 679.8	$ 703.0	$ 728.7	$ 751.3	$ 777.3	$ 804.5	$ 834.9	$ 862.7	$ 892.9	$ 923.9
	P5	$ 537.4	$ 566.9	$ 580.1	$ 568.5	$ 640.2	$ 641.3	$ 630.1	$ 699.0	$ 702.8	$ 691.7
	P95	$ 801.3	$ 842.3	$ 887.2	$ 928.6	$ 940.3	$ 970.6	$ 1,044.5	$ 1,025.7	$ 1,096.9	$ 1,146.8

Current Portfolio + CC

		2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Market Sales $M	**MEAN**	$ 14.4	$ 12.9	$ 12.0	$ 13.0	$ 11.5	$ 10.8	$ 11.4	$ 9.8	$ 9.2	$ 9.5
	P5	$ 3.4	$ 2.5	$ 2.4	$ 2.9	$ 2.1	$ 2.1	$ 2.7	$ 1.9	$ 1.9	$ 1.8
	P95	$ 23.9	$ 21.1	$ 19.5	$ 22.0	$ 19.9	$ 19.1	$ 19.6	$ 16.5	$ 18.5	$ 17.5
Market Purchases $M	**MEAN**	$ 178.1	$ 194.0	$ 208.6	$ 217.0	$ 235.4	$ 252.9	$ 266.3	$ 290.0	$ 310.7	$ 329.8
	P5	$ 125.0	$ 134.0	$ 130.0	$ 128.1	$ 159.2	$ 165.6	$ 165.4	$ 199.1	$ 203.4	$ 190.1
	P95	$ 252.9	$ 296.1	$ 335.9	$ 332.6	$ 335.4	$ 368.8	$ 407.4	$ 435.3	$ 441.7	$ 489.4
Fixed Costs $M	**Total**	$ 153.7	$ 153.8	$ 153.9	$ 154.1	$ 154.2	$ 154.3	$ 154.5	$ 154.6	$ 154.8	$ 154.5
Generator Operating Costs $M	**MEAN**	$ 181.2	$ 185.7	$ 192.3	$ 196.9	$ 202.0	$ 207.9	$ 213.4	$ 216.0	$ 221.2	$ 225.3
	P5	$ 98.3	$ 102.9	$ 110.5	$ 109.1	$ 114.0	$ 113.1	$ 120.9	$ 131.2	$ 132.3	$ 116.3
	P95	$ 269.8	$ 284.3	$ 287.9	$ 299.9	$ 308.4	$ 314.5	$ 332.0	$ 310.7	$ 334.8	$ 333.2
Total Cost $M	**MEAN**	$ 681.2	$ 703.2	$ 727.6	$ 749.1	$ 773.8	$ 799.6	$ 828.5	$ 855.1	$ 883.8	$ 912.9
	P5	$ 560.3	$ 594.8	$ 600.1	$ 586.3	$ 657.2	$ 652.7	$ 649.0	$ 716.9	$ 723.8	$ 697.3
	P95	$ 790.0	$ 822.8	$ 861.8	$ 909.6	$ 912.6	$ 943.2	$ 1,005.8	$ 991.6	$ 1,059.2	$ 1,100.5

Current Portfolio + Hydro

		2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Market Sales $M	**MEAN**	$ 22.4	$ 21.5	$ 19.9	$ 20.1	$ 19.5	$ 17.8	$ 18.0	$ 16.6	$ 15.6	$ 15.2
	P5	$ 6.5	$ 5.9	$ 5.2	$ 5.5	$ 5.0	$ 5.5	$ 5.6	$ 5.4	$ 4.9	$ 4.2
	P95	$ 39.3	$ 36.2	$ 36.5	$ 34.1	$ 33.2	$ 31.9	$ 30.0	$ 31.3	$ 32.4	$ 26.9
Market Purchases $M	**MEAN**	$ 139.9	$ 155.2	$ 168.0	$ 175.2	$ 192.8	$ 207.4	$ 219.6	$ 241.3	$ 259.7	$ 276.9
	P5	$ 96.7	$ 102.4	$ 102.1	$ 93.2	$ 116.3	$ 132.3	$ 127.6	$ 156.0	$ 154.3	$ 151.0
	P95	$ 220.5	$ 251.4	$ 285.1	$ 289.3	$ 299.7	$ 310.7	$ 354.1	$ 375.6	$ 386.0	$ 418.4
Fixed Costs $M	**Total**	$ 244.9	$ 246.9	$ 247.7	$ 248.7	$ 249.6	$ 250.7	$ 251.7	$ 252.8	$ 254.0	$ 254.5
Generator Operating Costs $M	**MEAN**	$ 73.7	$ 75.1	$ 78.1	$ 78.6	$ 80.6	$ 82.9	$ 84.0	$ 83.0	$ 84.2	$ 83.5
	P5	$ 14.8	$ 7.2	$ 9.6	$ 8.2	$ 7.4	$ 7.7	$ 9.3	$ 8.4	$ 7.9	$ 7.9
	P95	$ 133.3	$ 138.8	$ 140.2	$ 140.9	$ 150.6	$ 157.8	$ 160.0	$ 153.1	$ 167.0	$ 161.6
Total Cost $M	**MEAN**	$ 619.7	$ 639.0	$ 659.5	$ 677.2	$ 698.0	$ 719.2	$ 744.1	$ 765.8	$ 789.7	$ 813.6
	P5	$ 541.9	$ 564.8	$ 573.9	$ 558.1	$ 610.3	$ 620.7	$ 614.2	$ 659.5	$ 669.5	$ 660.1
	P95	$ 695.1	$ 729.2	$ 756.9	$ 778.6	$ 806.4	$ 821.6	$ 888.0	$ 873.8	$ 907.4	$ 949.3