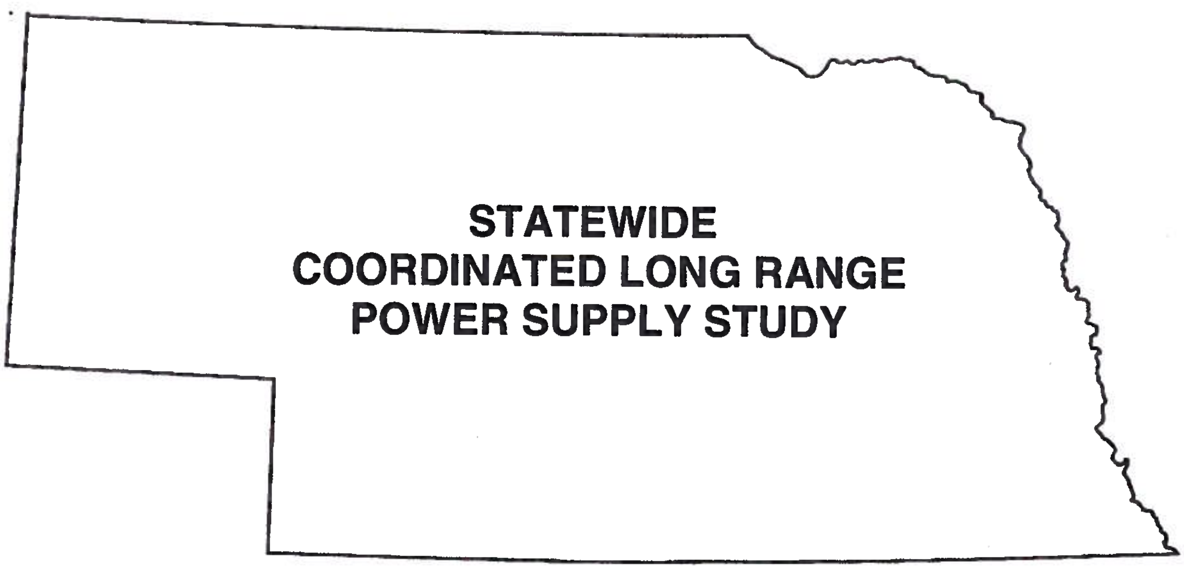
NEBRASKA POWER ASSOCIATION

Nebraska Power Association



STATEWIDE COORDINATED LONG RANGE POWER SUPPLY STUDY

July 2012

Nebraska Power Association

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Prepared by: NPA Joint Planning Subcommittee

Grand Island Utilities
Hastings Utilities
Lincoln Electric System
Loup River Public Power District
Nebraska Electric G&T
Nebraska Public Power District
Municipal Energy Agency of Nebraska
Omaha Public Power District
Niobrara Valley Electric Membership Corporation
Tri-State G&T Association

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List of Acronyms

ACI	Activated Carbon Injection
BACT	Best Available Control Technology
CAA	Clean Air Act
CC	Combined Cycle
CCR	Coal Combustion Residuals
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CCS	Carbon Capture and Sequestration
CEII	Critical Energy Infrastructure Information
CO	Carbon Monoxide
CSAPR	Cross-State Air Pollution Rule
CT	Combustion Turbine
DSM	Demand-Side Management
EGU	Electric Generating Units
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
FGD	Flue-Gas Desulfurization
FRET	Fremont Utilities
GHG	Greenhouse Gases
GRIS	Grand Island Electric Department
HAP	Hazardous Air Pollutants
HCl	Hydrochloric Acid
HF	Hydrofluoric Acid
HU	Hastings Utilities
ICR	Information Collection Request
IRP	Integrated Resource Plan
ITP	Integrated Transmission Plan
JPS	Joint Planning Subcommittee (of NPA)
LES	Lincoln Electric System
MACT	Maximum Achievable Control Technology
MAPP	Mid-Continent Area Power Pool
MATS	Mercury and Air Toxics Standard
MEAN	Municipal Energy Agency of Nebraska
MSA	Metropolitan Statistical Area
MRO	Midwest Reliability Organization
MW	Megawatt (1,000 kilowatts or 1,000,000 watts)
NAAQS	National Ambient Air Quality Standards
NDEQ	Nebraska Department of Environmental Quality
NEG&T	Nebraska Electric G&T
NMPP	Nebraska Municipal Power Pool
NSPS	New Source Performance Standards
NOx	Nitrogen Oxide
NO2	Nitrogen Dioxide
NPA	Nebraska Power Association

List of Acronyms (continued)

NPPD	Nebraska Public Power District
NRC	Nuclear Regulatory Commission
NSR	New Source Review
OPPD	Omaha Public Power District
PM	Particulate Matter
PRB	Power Review Board
PSD	Prevention of Significant Deterioration
PURPA	Public Utilities Regulatory Policies Act of 1978
PSD	Prevention of Significant Deterioration
RCRA	Resource Conservation and Recovery Act
REC	Renewable Energy Credit
RICE	Reciprocating Internal Combustion Engines
RSG	Reserve Sharing Group
RTO	Regional Transmission Organization
SPG	Subregional Planning Group
SPP	Southwest Power Pool
SO2	Sulfur Dioxide
TRC	Tradable Renewable Certificate
TSGT	Tri-State G&T Association
VOC	Volatile Organic Compounds
WAPA	Western Area Power Administration

1.0 EXECUTIVE SUMMARY

The purpose of this plan is to comply with the Nebraska Power Review Board (PRB) June 2011 request as provided by Nebraska State Statute 70-1025 to prepare a coordinated long-range power supply plan which would inform the PRB as to the status of future electrical loads and resources on a statewide basis. The method of compiling this plan is to summarize the combined results of individual Nebraska utility Integrated Resource Plans (IRPs) into a statewide plan following the scope of work which is similar to the methodology used in the 2003 plan. The resulting statewide coordinated long-range power supply plan considers both demand side management programs and supply side resources including renewable resources. Data is reported over the next 20 years and, as such, fulfills the requirements of State Statutes 70-1025 and 70-1026 for both the annual load and capability report and the coordinated long-range power supply plan.

The Nebraska statewide forecast of non-coincident peak demand is 6,810 MW in 2012, increasing to 8,719 MW in 2031. This is a compounded annual growth rate of 1.3% through 2031 which is essentially the same as the 2011 Load and Capability Report. Load growth in urban areas continues to be higher than rural areas. In addition to the peak load requirements, utilities are required to maintain a 12% capacity margin which in total is the Minimum Obligation. This reserve capacity amounts to significant resource capability over and above the Nebraska load requirement, 791 MW in 2012 and 1049 MW in 2031.

Nebraska currently has 8,066 MW of existing generation, and no conventional committed generation additions; however, there are 195 MW of wind projects that are committed resources to be on line by the end of 2012 and available for 2013. These wind resources are assumed to not add significant capacity value due to SPP rules as they are normally not operating during peak hours. LES is adding 4 MW of capacity in 2013 with the addition of a landfill gas generator. There are 243 MW of planned resources and 1,591 MW of studied resources through 2031. The planned resources include a 75 MW extended power uprate from Fort Calhoun Station in 2016, a 146 MW extended power up rate from Cooper Nuclear Station in 2019, and 22 MW from changes in operation at LES peaking units in 2020. The studied resources include 655 MW of nameplate wind energy, 166 MW of baseload capacity, 450 MW of intermediate capacity, and 320 MW of peaking capacity.

Committed resources are those approved by the PRB, planned resources are those that utilities have authorized expenditures but have not had PRB approvals, and studied resources are those additional resources needed to meet the Minimum Obligation. A portion of the existing and committed resources are renewable, including the existing 341 MW nameplate (wind and landfill gas) in service for the summer of 2012. A methane landfill gas project by Omaha Public Power District (OPPD) is 6 MW. An additional 199 MW nameplate is committed for the summer of 2013, increasing the total renewable resources to 540 MW nameplate. An additional 655 MW is being studied by NPPD Public Power District (NPPD) and OPPD to meet their 10% renewable energy goal by 2020.

A capacity deficit for Nebraska, with committed resources, is not expected until 2024 based on the Minimum Obligation including the SPP minimum capacity margin of 12%. With the studied resources of 1,591 MW, a capacity deficit is not expected through the study period of 2031.

The planning methodology used was the same as that used for the 2003 plan. Each electric supplier indicated their load pattern and any expected changes to that pattern. These were summed to indicate a statewide total. Power resource screening curves for typical resources indicating total bus bar cost for that resource were applied to the load pattern curve to determine the approximate resource type and quantity – base, intermediate or peaking – that would be required.

There are significant environmental rules and regulations that are in various stages of implementation. Many are proposed but it is not certain as to the impact on existing or future generating resources. Because of these rules and regulations, there is a great deal of uncertainty as to future supply resources and the potential for the retirement of units as they become uneconomical to continue operation. The plan describes many of these rules and regulations.

Sensitivities to the base case of all existing fossil facilities remaining in operation through the study period were made. Depending on age and size of units assumed to be retired, the first year of deficit could be advanced from 2024 to 2019 or possibly 2015.

NPPD, OPPD, and LES are voting members of SPP. SPP has an Integrated Transmission Plan that identifies needs in the near term, 10-year, and 20-year time frame. SPP transmission plan maps with the planned transmission additions are included.

The electric industry is facing many other possible considerations. Many of these are listed and discussed.

2.0 INTRODUCTION AND PURPOSE

2.1 Introduction

The Nebraska electric utility joint planning efforts date back to the late 1970s. The current Joint Planning Subcommittee (JPS) of the Nebraska Power Association (NPA) was formed in 1980.

Nebraska State Statute 70-1024 provides that the Nebraska Power Review Board (PRB) designate a representative organization to be responsible for preparing reports and studies for their use. The PRB has designated the NPA as the representative organization and the NPA has given the responsibility to the JPS as the NPA subcommittee that accumulates and prepares these reports and studies.

The JPS is made up of ten member companies with expertise in electric utility planning, representing the major electric suppliers in Nebraska.

The JPS has prepared over 25 various joint reports and studies through the years for the industry and for the PRB. The most recent report for the PRB was the 2011 Research and Conservation Report dated December, 2011. The last coordinated long-range power supply plan which included a research and conservation report was completed in 2003.

The PRB can request, but no more often than biennially, the NPA to prepare a coordinated long-range power supply plan (State Statue 70-1025) and a research and conservation report (State Statute 70-1026).

In addition, State Statute 70-1025 requires that an annual load and capability report be prepared by NPA and filed with the PRB.

The NPA utilized a methodology similar to that used on the 2003 Coordinated Long-Range Power Supply Plan and annual load and capability reports of recent years to meet the requirements for a coordinated long-range power supply plan and provide the annual load and capability report. The requested research and conservation report was completed in December, 2011, and presented to the PRB. This document completes the request for a long-range power supply plan and also satisfies the required annual load and capability report.

2.2 Purpose of Plan

The purpose of this plan is to meet the PRB June 2011 request of the NPA for a coordinated long-range power supply plan as provided by State Statute 70-1025. A Research and Conservation Report was completed in December 2011 per State Statue 70-1026. Additionally, this report includes the statewide annual load and capability report as required by State Statute 70-1025.

This plan was prepared utilizing a scope of work to meet the requirements of State Statue 70-1025:

- The plan will cover loads over a 20-year period beginning with the year the report is prepared and will be prepared to provide information for power resource addition approval decisions by the Board as well as each electric supplier and will contain at least the following items:

- An estimate of the electric power requirements for each electric supplier operating in Nebraska for each year of the 20-year period based on their 50/50 load forecasts (i.e. 50% probability that forecast will be exceeded due to hotter than normal weather), net of demand side resources, and the minimum 12% capacity margin requirements (minimum obligation) and then summed for a statewide total minimum obligation for each year

- An estimate of electric power requirements for each electric supplier operating in Nebraska for each year of the 20-year period that includes any additions to the minimum obligation due to analysis based on risk assessment of items such as weather, electric markets or other items that each electric supplier uses as their load obligation for planning purposes (load obligation) and then summed for a statewide total load obligation for each year

- Identification of all existing power supply resources and an indication as to whether they are expected to continue for the 20-year period, including unit retirement sensitivities such as age, size, regulations, RTO assumptions, fuel type and others

- A list of new power supply resources that are committed (approved by Board, if required) for each year by each electric supplier and a statewide total

- A list of new power supply resources that are planned (approved by electric supplier) for each year by each electric supplier and a statewide total

- A list of power supply resources studied beyond those committed and planned that are required by each electric supplier (for each year) to meet their load obligation for each year and by each generation type (peaking-intermediate-base) along with a summation for the state for each year

- Discuss approved and pending environmental legislation, regulations, and rules and where possible identify their potential impacts

- An indication for each electric supplier of their load pattern (shape) used for power resource planning purposes for the past year and for any future expected changes and a summation to indicate a statewide total

- A power resource screening curve indicating total bus bar cost for that resource at all capacity factors for all typical resources as well as specific curves for each committed and planned resource

- A map showing all committed and planned transmission lines 115KV and above as well as an indication of any transmission lines required to meet the load obligation for the state based on SPP studies (Note: A detailed Nebraska transmission map cannot be provided in a public document per FERC's rules regarding Critical Energy Infrastructure Information (CEII).

Using the information in the items previously mentioned, the plan will indicate on a statewide basis the best estimate of the power resource type and timing including sensitivities that could best meet the load obligation of the total state for the 20-year period.

The plan will also discuss what renewable type resources electric suppliers are currently using and are planning to use.

Any other significant considerations that impact the existing or future power supply resources will also be discussed.

3.0 STATEWIDE LOAD OBLIGATION

A discussion of Demand-side Management (DSM) programs is not included in this report but can be found in the 2011 Research and Conservation Report. DSM programs are included in the peak demand forecasts contained within this report to the extent that the programs impact peak demand.

3.1 Base Load Forecast

The current combined statewide forecast of non-coincident peak demand is derived by summing the demand forecasts for each individual utility. Each utility supplied a peak demand forecast net of demand-side management programs based on the loads having a 50/50 probability of being higher or lower as shown in Exhibit 3.1-1 for selected years 2012, 2022, and 2031. Over the twenty-year period of 2012 through 2031, the average annual compounded load growth rate for the State is projected at 1.3% per year. This growth rate does however vary greatly from utility to utility. The lowest annual compounded growth rate is 0.3% per year and the highest is 1.8% per year. Urban areas continue to show a higher forecasted rate of demand load growth than rural areas. This growth rate is the same as the 2011-2030 growth rate from the 2011 Load and Capability Report.

Exhibit 3.1-1

Peak Demand

	2012	2022	2031	Average Annual Increase
Auburn	3	3	3	0.0%
Falls City Utilities	14	16	17	1.0%
Fremont Department of Utilities	96	106	115	1.0%
Grand Island Utilities	170	192	214	1.2%
Hastings Utilities	100	117	135	1.6%
Lincoln Electric System	758	862	1,009	1.5%
Municipal Energy Agency Of Nebraska	206	240	274	1.5%
Nebraska City Utilities	38	40	42	0.5%
Nebraska Public Power District **	2,698	2,946	3,188	0.9%
Omaha Public Power District	2,353	2,822	3,322	1.8%
Tri-State G&T *	372	397	397	0.3%
Wahoo	2	2	2	0.0%
STATEWIDE	6,810	7,742	8,719	1.3%

* Nebraska's portion only.

** NPPD's 2012 actual peak demand has significantly surpassed this projection as of the date of this report.

3.2 Minimum Obligation

In addition to the load requirements of our customers, the State utilities that are Southwest Power Pool (SPP) Members must also maintain a 12% capacity margin (equivalent to 13.64% reserve margin) above their peak demand forecast ("Minimum Obligation"). This is the planning (or installed) reserve requirement of the SPP Reserve Sharing Group (RSG). All SPP RSG members must maintain this in order to assist each other in case of emergencies such as unit outages, fuel disruptions, etc. By having a reserve sharing "pool", instead of individually carrying reserves to protect from the loss of the largest unit on their system, the planning reserve requirement for all members of the "pool' is reduced. A 12% capacity margin is adequate in a pool but individually it would be much higher. This 12% capacity margin is also used for State utilities that are not in SPP.

This reserve capacity amounts to significant resource capability over and above the Nebraska load requirement, 791 MW in 2012 and increasing to 1,049 MW by 2031 due to load growth.

4.0 EXISTING GENERATING CAPABILITY

The State has an "Existing" in-service accreditable generating resource capability of 8,066 MW. Each unit is detailed in Appendix A.

4.1 Age of Existing Fleet

Exhibit 4.1-1 shows the age of the fleet by type of unit. About 9% of the generating fleet is greater than 50 years old today. These old units tend to be small coal (< 200 MW), diesels, and hydro. Another 10% of the generating fleet is 41 to 50 years old today. About 70% of the generating fleet is at least 31 years old today.

Exhibit 4.1-1

Age of Existing Generating Fleet (MW)

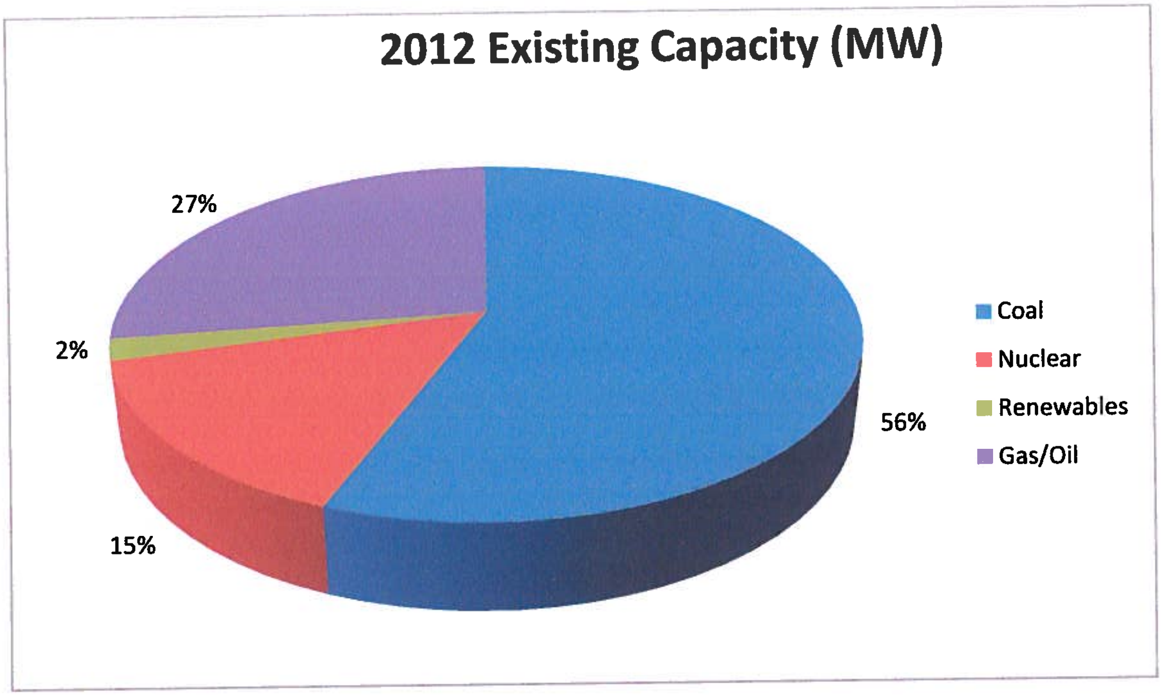
Years	Small Coal	Large Coal	Oil/Gas	Nuclear	Renewable*	Total
0-20	280	836	1,234	0	6	2,356
21-30	0	0	5	0	38	43
31-40	262	2,215	359	1,245	0	4,081
41-50	483	0	358	0	0	841
50+	405	0	216	0	126	746
Total	1,430	3,051	2,171	1,245	169	8,066

*Accredited Capacity (does not include wind)

4.2 Fuel Resource Mix

Exhibit 4.2-1 is a pie chart that illustrates the Existing capacity mix by fuel type. Coal is the predominate fuel type in Nebraska by a wide margin.

Exhibit 4.2-1
Fuel Source Mix



Since wind does not have much, if any, accreditable capacity value in SPP, the renewables in the exhibit above only include the hydro capacity that is accreditable. The existing energy mix would show larger percentages for coal and nuclear, renewables increasing and gas/oil a significant reduction to about 1-2%.

4.3 Retirements

A key consideration in power supply planning is the retirement of existing generating plants. Most new thermal generating plants are built for a normal useful life of at least 40 years. Approximately 70% of the existing generation in Nebraska has been in service for more than 30 years, and it will be approaching the end of its original planned useful life by the end of this study period. In addition, there is 1,587 MW of generation that is more than 40 years old now and will be over 60 years old by the end of the study period.

With proper operating and maintenance practice, older generating units are capable of continued reliable operations. However, it can be expected that some older generating units will be retired over the study period. As components of older generating units fail, it is increasingly difficult to procure replacement parts and, in some cases, it is not cost effective to repair the generating units.

A part of long-term resource planning could include studies that provide management with some analytical information regarding the long-term use of resources. As the age of units approach 40 years old and greater, and even if they have been well maintained, at some point in the future it may be more economical to retire the units vs. continued operation. This is especially true if new environmental measures are enacted, which may require additional expenditures to allow these units to comply. Long-term engineering studies are typically required to confidently predict: 1) remaining life, and 2) if expenditures above & beyond those expected are needed to maintain the units in their present state. Studies of this type may become more prevalent as units age and resource planning horizons extend, and new environmental regulations are implemented.

A main factor that could cause older generating units to be retired is the compliance cost of new environmental regulations. Changing interpretations of existing Clean Air Act provisions relating to New Source Review (NSR) as well as new legislation, such as the Mercury and Air Toxics Standard (MATS), could force older generating units to install expensive environmental control equipment to remain in service. For some older generating units, installing expensive environmental control equipment could be cost prohibitive relative to the value of keeping the generating unit in service. In some cases, building a new generating plant may be more cost effective than retrofitting an existing plant with the best available retrofit technology. These are economic decisions that Nebraska utilities will be making in the future as circumstances warrant.

During the 20-yr forecast period, only 94 MW of capacity was removed from service:

- 18 MW of diesel engines removed due to Reciprocating Internal Combustion Engines (RICE) rules that limit generation
- 22 MW derate of coal units due to the retrofit of back-end environmental equipment
- 54 MW removal of hydro facilities that were sold out of state

As planning horizons extend beyond 2031, and other business influences are determined, it is not unreasonable to assume that other generating unit potential retirement dates, unit derates, and fuel switching will be determined as part of future long-range power supply studies.

The impact of early retirements based on age is described in Section 8.7.

5.0 NEW POWER SUPPLY RESOUCES

Appendix B summarizes the committed, planned, and studied resources.

- "Committed" resources are those units that have been approved by the PRB if required. PURPA qualifying projects do not need PRB approval.
- "Planned" resources are those units that utilities have authorized expenditures for engineering analysis, architect/engineer, or permitting, but do not have PRB approval if required.
- "Studied" resources are those units that are needed to meet the utility's Planned Obligation. These studied resources are specified based on the theoretically ideal split between baseload, intermediate, and peaking types considering existing and projected needs.

5.1 Committed Resources

The State has no conventional (such as nuclear, coal, gas/oil) committed resources for this plan.

There are 195 MW of wind projects that are committed resources projected to be on line by the end of 2012 and available for the 2013 summer peak. This includes the 80 MW Broken Bow I Wind Farm, 75 MW Broken Bow II Wind Farm, and the 40 MW Crofton Bluffs Wind Farm. These wind resources are not expected to add significant capacity (less than 3%) using the SPP Criteria.

LES has a committed landfill gas generator project that is projected to be on-line for the 2013 summer peak. This project will add 4 MW of capacity.

5.2 Planned Resources

There are 243 MW of planned resources for this plan. Planned Resources include 75 MW extended power uprate of Ft. Calhoun Station in 2016, 146 MW extended power uprate of Cooper Nuclear Station in 2019, and 22 MW from changes in operation at LES peaking units in 2020.

5.3 Studied Resources

Resources identified as studied for this report were not based on the traditional method but in a way specifically for the statewide plan. For years beyond the point when existing, committed, and planned resources would meet a utility's minimum obligation, each utility would establish studied resources in a quantity to meet this deficit gap. These studied resources are identified based on renewable, baseload, intermediate, and peaking resources considering current and future needs. The result is a listing of the preferable mix of renewable, baseload, intermediate and peaking resources for each year. The summation of studied resources will provide the basis for the PRB and the State utilities to understand the forecasted future need by year and by resource type. This can be used as a joint planning document and a tool for a coordinated long-range power supply plan.

There are 1,591 MW of studied resources that include 655 MW of nameplate renewable (wind) resources, 166 MW of baseload capacity, 450 MW of intermediate capacity, and 320 MW of peaking capacity by 2031.

6.0 RENEWABLE RESOURCES

Both NPPD and OPPD have a renewable energy goal of 10% of native load sales by 2020. This would translate to approximately 900 MW of wind nameplate capacity by 2020. LES recently adopted a sustainability target that sets a goal of supplying its 2011 to 2016 demand growth with either sustainable generation or demand reduction resources.

As shown in Appendix C, the State has 341 MW nameplate of existing renewable resources (wind and landfill gas) in-service for the summer of 2012. Recently proposed national renewable portfolio standards generally do not allow existing hydro units to count towards renewable energy goals and therefore are not included in Appendix B but are identified in Appendix A, although LES does count its existing hydro contracts with WAPA in its internal renewable reporting. An additional 199 MW nameplate is committed for the summer of 2013 (Broken Bow I Wind, Broken Bow II Wind, Crofton Bluffs Wind, and the LES Landfill Gas Generator) increasing the total renewable resources to 540 MW nameplate. An additional 655 MW is being studied by NPPD and OPPD to meet their 10% of native load sales renewable energy goals.

The State is projected to have 1,039 MW nameplate of renewable resources in the year 2027 when the total renewable resources are projected to decrease as older wind farms are retired after 20-years service.

The renewable resources in the State are wind energy except for 10 MW of landfill gas. Because of the intermittent nature of wind energy, typically less than 3% of the nameplate capacity is accreditable under the SPP Criteria for intermittent accreditation. For this plan, the summer accreditable capacity is assumed at zero.

7.0 STATEWIDE CAPABILITY VS. OBLIGATION

7.1 Committed Resources

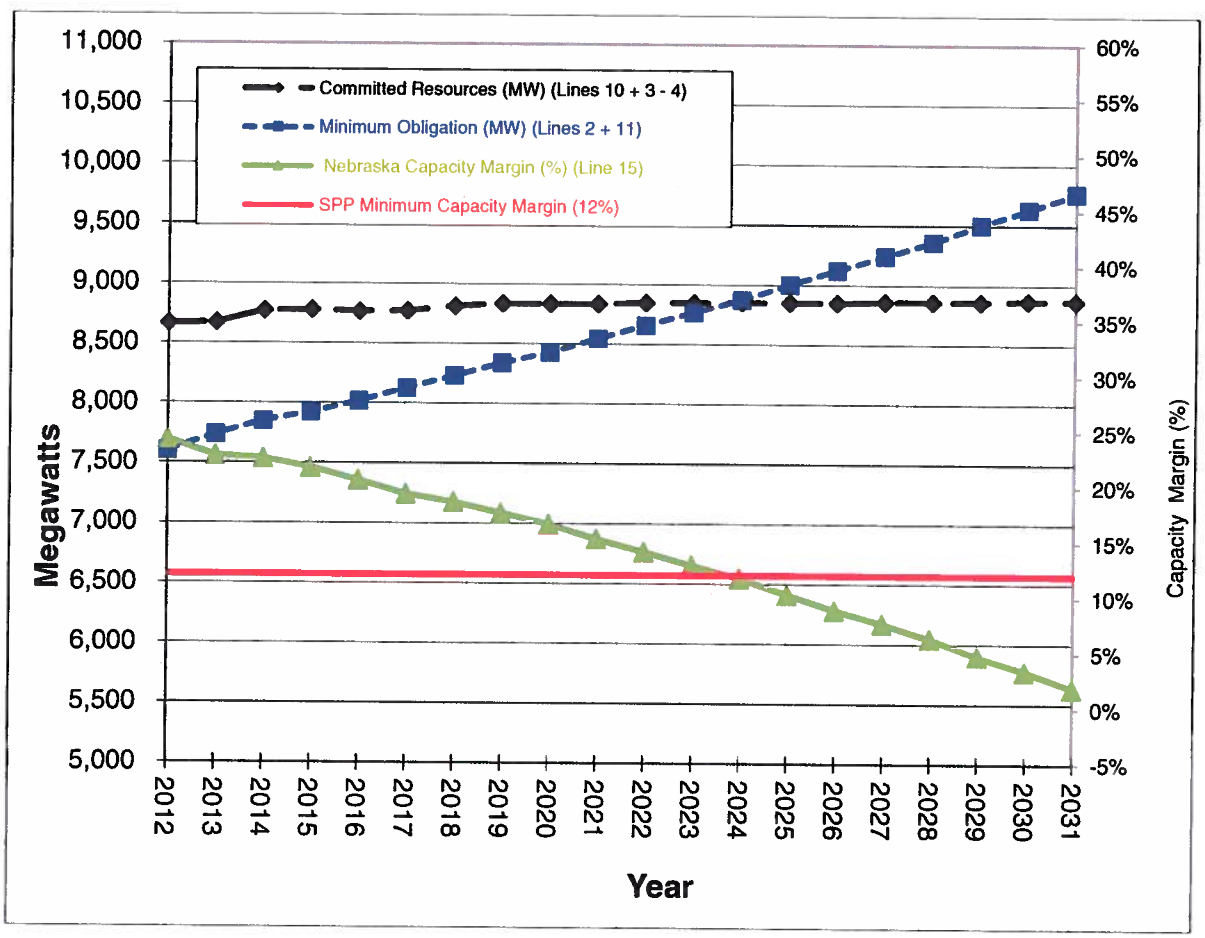
Exhibit 7.1-1 is the load and capability chart based on existing and committed resources and Appendix D contains the corresponding load and capability table. The "Minimum Obligation" line is the statewide obligation based on the 50/50 forecast (normal weather) and the 12% capacity margin of the SPP RSG. Based on the existing and committed resources, the statewide deficit occurs in 2024.

The statewide deficit year has advanced 2 years (from 2026 to 2024) as compared to the 2011 Load and Capability Report.

EXHIBIT 7.1-1

Statewide Capability vs. Obligation

Committed Resources



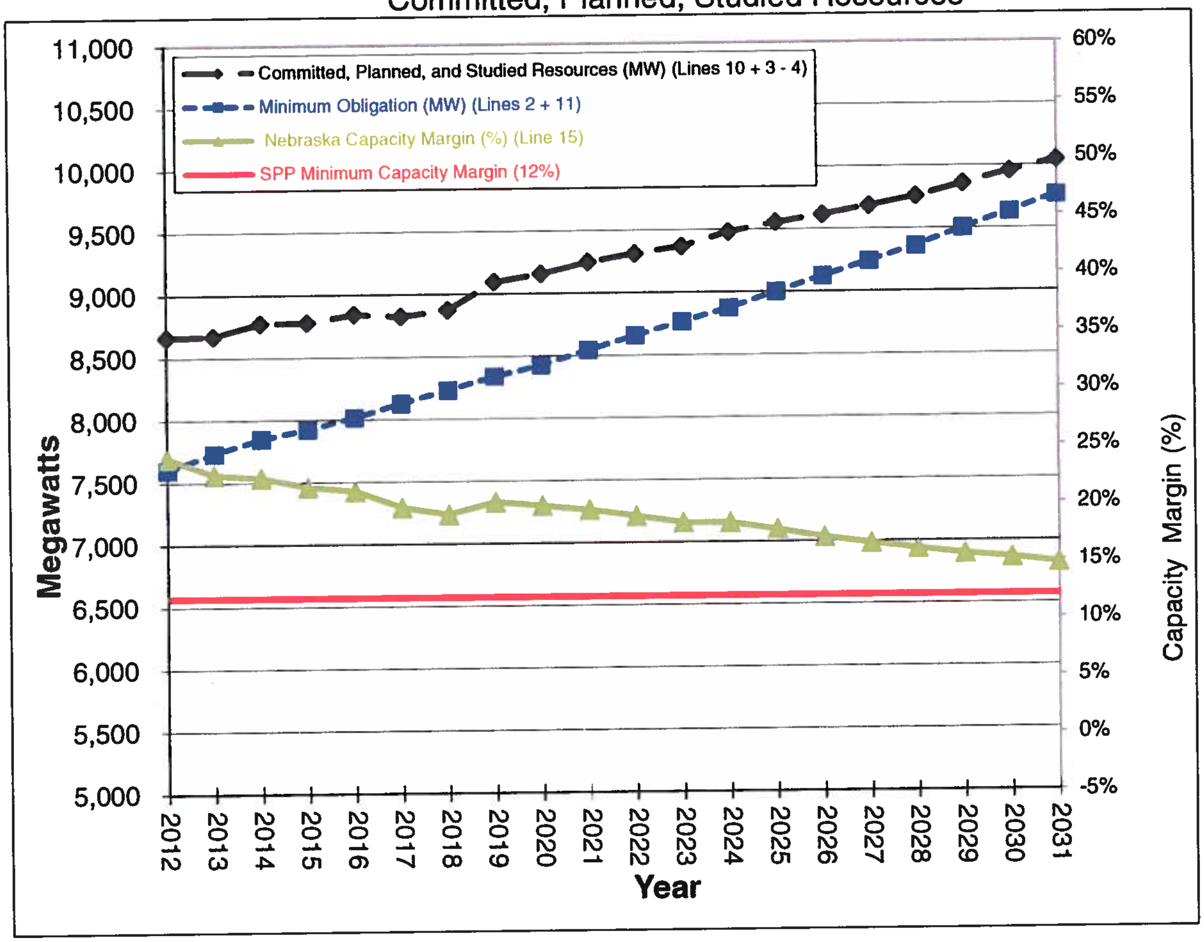
7.2 Committed, Planned, and Studied

Exhibit 7.2-1 shows the statewide load and capability chart considering 8,066 MW of Existing, 199 MW of Committed, 243 MW of Planned, and 1,591 MW of Studied resources. Appendix D contains the corresponding load and capability tables for the State and each individual utility. As intended, these exhibits show how the Minimum Obligation can be met with the addition of the Studied resources.

EXHIBIT 7.2-1

Statewide Capability vs. Obligation

Committed, Planned, Studied Resources



8.0 ENVIRONMENTAL

8.1 Cross State Air Pollution Rule

The Cross State Air Pollution Rule (CSAPR), formerly the Transport Rule, is the replacement to the Clean Air Interstate Rule (CAIR) that was remanded by the courts in December 2008. The goal of the CSAPR is to reduce emissions contributing to downwind fine particle ($PM_{2.5}$) and ozone nonattainment areas that are often caused by pollutants traveling across state lines. The proposed CSAPR was issued in June 2010 and the final CSAPR was issued on July 6, 2011. In the final rule the EPA significantly reduced the number of allowances allocated to Nebraska utilities. The final rule would have required Nebraska utilities to reduce sulfur dioxide (SO_2) emissions by approximately 14% and nitrogen oxides (NO_x) emissions by approximately 40%. Numerous states and utilities filled suit over the rule which led to the courts staying the rule on December 30, 2011. Until the courts rule on the merits of the rule, the impacts to Nebraska utilities are unknown. A final decision from the courts is expected by August 2012. It is expected that the earliest the CSAPR requirements could be reinstated would be January 2013 but could be much later if the courts mandate significant changes to the rule.

8.2 National Ambient Air Quality Standards

The Clean Air Act (CAA) requires the EPA to set National Ambient Air Quality Standards (NAAQS) for pollutants considered harmful to public health and the environment. The primary NAAQS standards are intended to protect the public health, particularly the health of sensitive populations such as children and the elderly. There are NAAQS for six criteria pollutants: Carbon Monoxide (CO), Lead, Nitrogen Dioxide (NO_2), Particulate Matter (PM), Ozone and SO_2. The CAA requires the EPA to reevaluate each NAAQS every five years and determine if it is necessary to set a new standard.

8.2.1 SO_2 NAAQS

The new SO_2 NAAQS was finalized in June 2010. The new 1-hour standard is 75 parts per billion (ppb). EPA revoked the 24-hour standard of 140 ppb and the annual standard of 30 ppb when it issued the new standard. Due to the 1-hour averaging period it will be very difficult for facilities to meet the new standard. States will have to perform dispersion modeling on stationary sources and may be required to install new monitoring sites in order to determine non-attainment areas. A source will need to meet the new standard in both modeling and monitoring in order to be designated as in attainment. States will be required to submit state implementation plans (SIPs) by June 2013 that will detail all nonattainment areas and how the state plans to bring those sites into attainment. The latest deadline to comply with the standard will be 2017. Once the EPA and the Nebraska Department of Environmental Quality (NDEQ) finalize the modeling protocol major SO2 sources in Nebraska will be required to model the SO2 emissions from those sources. However, due to delays in the EPA finalizing the modeling protocol the EPA has stated that the initial SIP submittal need not require modeling results. It is not known at this time when the EPA will finalize the modeling protocol. It is possible that many power plants in Nebraska may not meet the modeling requirements of the new standard and would be designated as nonattainment areas. If declared in non-attainment, options for Nebraska utilities that could bring them into attainment could include building taller stacks, burning lower sulfur coal or installing pollution control equipment.

8.2.2 Ozone NAAQS

In 2008 the EPA reevaluated the ozone NAAQS and determined it was necessary to lower the ozone NAAQS from 80 ppb to 75 ppb. Due to numerous challenges to the new standard EPA proposed to strengthen the ozone standard in January 2010. EPA proposed to set the standard between 60 to 70 ppb. However, due to significant opposition the EPA decided to delay the new ozone standard until 2013 when it was scheduled to be reviewed. Ozone is created by the combination of NO_x and volatile organic compounds (VOCs) in the presence of sunlight and heat. Due for the need of both sunlight and heat the ozone season is from April 1 to October 31. If the ozone standard is set lower than 68 ppb it is possible the Omaha Metropolitan Statistical Area (MSA) may be designated as nonattainment for ozone. The nonattainment designation will require reductions of NO_x and VOCs from existing sources and any new increases in NO_x or VOC emissions will need to be offset by reductions at other facilities.

8.2.3 $PM_{2.5}$ NAAQS

In 2006 EPA lowered the 24-hour fine particle $PM_{2.5}$ NAAQS standard from 65 micrograms per cubic meter ($\mu g/m^3$) to 35 $\mu g/m^3$. The annual $PM_{2.5}$ standard of 15 $\mu g/m^3$ was retained. $PM_{2.5}$ are tiny particles less than 2.5 microns in diameter in the air that reduce visibility and cause the air to appear hazy. $PM_{2.5}$ particles are more than 30 times smaller than the width of a human hair. Because of the small size these particles are more likely to be lodged deeply into the lungs causing respiratory system problems. $PM_{2.5}$ is emitted primarily from vehicles, power plants, forest and grass fires and industrial facilities. $PM_{2.5}$ is also formed from the reaction in the atmosphere of gaseous emissions of NO_x and SO_2 from power plants. The EPA is required to reevaluate each NAAQS standard every 5 years and the EPA is planning on proposing changes to the $PM_{2.5}$ standard in sometime in 2012. There is currently no information available on what the new $PM_{2.5}$ standard will be set at or what the potential impact to Nebraska utilities may be. It is possible the new standard could require Nebraska utilities to install pollution control equipment to meet the standard.

8.3 Mercury and Air Toxics Standard

The EPA has traditionally regulated the criteria pollutants (CO, SO_2, NO_x, Lead, Ozone and PM) from power plants, but has not had standards for the numerous hazardous air pollutants (HAPs) that are also emitted from power plants. Common HAPs emitted from power plants include mercury, arsenic, chromium, formaldehyde, benzene, hydrochloric acid, hydrogen fluoride and dioxins. In 2010 the EPA sent out an Information Collection Request (ICR) to hundreds of power plants that required the facilities to perform stack testing for various HAPs. EPA used this information to set the Mercury and Air Toxics Standard (MATS) which sets the maximum achievable control technology (MACT) standards for many previously unregulated pollutants. The MACT standards are set by averaging the top 12% of the best performing plants for a particular pollutant.

In 2005 the EPA issued the Clean Air Mercury Rule (CAMR) which was a cap-and-trade style program intended to reduce the amount of mercury emitted from power plants. In February 2008 the CAMR was vacated by the courts. As a result of the vacatur the EPA reached legal settlement requiring the EPA to have a proposed mercury MACT standard issued by March 2011 with a final standard issued by November 2011. The proposed mercury MACT rule was issued on March 16, 2011 and was finalized in December 2011 as part of the MATS rule.

The MATS rule is intended to regulate HAPs from power plants that use a boiler to generate more than 25 megawatts of electricity. The proposed rule was issued on March, 16 2011 and the final rule issued on December 21, 2011. The final rule was published in the Federal Register on February 12, 2012 and became effective 60 days after it was published in the Federal Register. Facilities would then have 3 years from the effective date to become compliant with the standard. A one year compliance deadline extension may also be granted by the state. An additional one year extension could be granted if reliability of the grid is threatened. The rule is intended to reduce emissions of mercury, acid gases, hazardous air pollutants and dioxins and furans from new and existing coal- and oil-fired steam utility electric generating units (EGUs).

The rule would reduce emissions of heavy metals, (mercury, arsenic, chromium, nickel, etc), dioxins and furans, and acid gases, (hydrochloric acid (HCl) and hydrofluoric acid (HF)). For all existing and new coal-fired EGUs, the standards would establish numerical emission limits for mercury, particulate matter (PM), (as a surrogate for toxic non-mercury metals), and HCl (as a surrogate for acid gases). A range of technologies and compliance strategies are available to meet the emission limits. These technologies include wet and dry scrubbers, dry sorbent injection systems, activated carbon injection (ACI) systems, and baghouses. Nebraska utilities burn low sulfur Powder River Basin coal and it is possible Nebraska utilities may be able to meet the PM and HCl standards in the rule without additional pollution control equipment. Most Nebraska utilities will be required to install mercury removal equipment, such as coal additives and/or ACI, to reduce mercury emissions. Use of ACI will likely make the fly ash unsuitable for beneficial uses. This will result in lost revenue from selling some of the fly ash and increased landfill costs.

8.4 Greenhouse Gas Regulations

In December 2007 the EPA Administrator found that the current and projected concentrations of the six key well-mixed greenhouse gases (GHGs) in the atmosphere threaten the public health and welfare of current and future generations. The Administrator also found that the combined emissions of these well-mixed greenhouse gases from new motor vehicles and new motor vehicle engines contribute to the greenhouse gas pollution which threatens public health and welfare. These findings led to the light duty vehicle rule which regulated the emissions of GHGs from motor vehicles starting on January 2, 2011. The EPA ruled that since GHGs are subject to regulations in motor vehicles that GHGs are also subject to regulation for stationary sources. This ruling resulted in regulation of GHGs for EGUs.

8.4.1 Tailoring Rule

Starting January 2, 2011 the EPA began regulating GHGs from stationary sources. Since GHGs are emitted in much larger quantities than the criteria pollutants, GHGs could not be regulated like other pollutants. This approach would overwhelm state agencies with new sources requiring operating permits due to GHG emissions. This led the EPA to develop the Tailoring Rule which would gradually phase in regulations for GHGs starting with the largest emitters. The Tailoring Rule became effective on January 2, 2011 and requires any stationary source that emits more than 100,000 tons of GHGs to obtain a Title V Operating permit if the facility does not already have one. The Tailoring Rule also requires any facility emitting more than 100,000 tons of GHGs to obtain a prevention of significant deterioration (PSD) permit for any modification to the facility that results in an increase of more than 75,000 tons of GHGs. A PSD permit would require the installation of Best Available Control Technology (BACT) for GHGs. At this time since there does not exist any commercially available CO_2 capture and sequester technology, BACT would be some kind of facility efficiency requirements. These would have to be negotiated with the NDEQ and EPA and placed in the PSD permit. Starting in 2011 the EPA began a five year study to determine if smaller sources emitting less than 100,000 tons of GHGs should also be regulated. Potential regulation of these smaller sources would begin no earlier than 2016.

8.4.2 New Source Performance Standards for Power Plants

The EPA reached a legal settlement to establish new source performance standards (NSPS) for new and modified power plants and emission guidelines for existing power plants. EPA issued the proposed rule on March 27, 2012 and was published in the Federal Register on April 13, 2012. The proposed rule will regulate CO_2 emissions from new coal-fired and natural gas combined cycle combustion turbines. The EPA is proposing to limit CO_2 emission from new power plants to less than 1,000 pounds of CO_2 per gross megawatt-hour (MWh) of electricity output. The standard would apply at all times including periods of startups, shutdowns and malfunctions and would be calculated on a 12-month rolling average. Facilities that begin construction within 12 months of the publication of this rule in the Federal Register would not be subject to this standard. Currently only natural gas combined cycle combustion turbines, nuclear units, and renewable generation are capable of meeting this standard. New coal fired facilities would need to be equipped with carbon capture and sequestration (CCS) in order to meet this new standard. Since CCS is not yet a viable technology the EPA is proposing to allow a new coal facility to be constructed and operated for 10 years without CCS. The new coal facility would be allowed to emit 1,800 pounds of CO_2 per MWh for the first 10 years. However, the facility would be required to use CCS to reduce CO_2 emissions to less than 600 pounds per MWh for the next 20 years so that the facilities 30-year average CO_2 emissions meet 1,000 pounds of CO_2 per MWh standard. In the proposed rule the EPA exempts existing facilities that are modified or reconstructed from this standard. According to the EPA the installation of pollution control equipment at existing facilities would not result in a facility becoming subject to this standard. However, there have been differing opinions regarding the EPA's authority to issue a NSPS that only effects new sources and not modified or reconstructed sources. There are also differing opinions regarding the EPA's authority to exempt new pollution control equipment from triggering the modification or reconstructed thresholds.

If it is determined that the EPA has the authority to exempt modified, reconstructed and existing facilities from the GHG NSPS for new facilities, the EPA has committed to also establishing emission guidelines for CO_2 emissions from existing, modified and reconstructed sources. There is no information on what the standards for existing facilities may be or when the EPA will release a proposed rule covering existing facilities.

8.5 316(b) - Cooling Water Intake Structures

Section 316(b) of the Clean Water Act requires EPA to ensure that the location, design, construction and capacity of the cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts. Cooling water intake structures cause adverse environmental impact by entraining large numbers of fish and shellfish or their eggs into a power plant's cooling system where the organisms may be killed or injured by heat, physical stress, or by chemicals or impinging them on screens at the front of an intake structure.

The regulations to implement Section 316(b) were published February 16, 2004. These regulations were suspended as a result of a law suit in 2007. The EPA released the proposed rule March 28, 2011, and is scheduled to release the final rule by July 27, 2012.

The 316(b) regulations will affect several Nebraska utilities. Nebraska facilities covered by this rule would be subject to a limit on the number of fish and other aquatic organisms that are killed when they are pinned against the intake structures of the facility's cooling water system (impingement). The proposed rule would require facilities to have a fish survivability rate of at least 69% per month and at least 88% on an annual basis. Nebraska utilities will need to conduct studies and with the NDEQ to determine the best technology available to meet this impingement limit. The proposed regulations require the covered facilities to meet the impingement standard as soon as possible, but no later than eight years after the effective date of the rule.

Nebraska utilities will also be required to conduct studies to determine the appropriate controls to limit the number of aquatic organisms drawn into the facility's cooling water system (entrainment) and killed. The entrainment mortality control technology is determined on a case-by-case basis and is based on the results of data collected from the applicable water body and facility. The process for determining the appropriate entrainment controls also includes public participation. The proposed regulations provide that the schedule for implementing entrainment mortality controls will be determined by the NDEQ on a case-by-case basis.

Although the exact requirements to meet the rule are not known at this time, it is anticipated that fine mesh screens (2 mm), upgraded fish removal systems, closed cycle cooling (cooling towers), or some other equivalent technology may be required to be installed. As noted above, impingement and entrainment sampling will need to be conducted. The study results along with EPA and NDEQ criteria will determine site specific control technologies deemed to be best technology available.

8.6 EPA's Proposal to Regulate Coal Combustion Residuals

In 2008, a dam at a coal ash storage impoundment operated by the Tennessee Valley Authority failed, resulting in a significant spill. The integrity of the dam was determined to be the cause of the spill. Impoundments are one option for disposal of ash. Other options include storage in landfills or coal mines, or to beneficially reuse it. Based on this incident, EPA is reconsidering the regulatory classification of coal ash and designating it a hazardous waste.

The EPA has proposed two options to regulate the disposal of coal combustion residuals (CCR) under the Resource Conservation and Recovery Act (RCRA) but under different programs of RCRA. One option would regulate CCR as hazardous waste, the other option would regulate CCR as municipal or special waste.

Regulation as hazardous waste could result in significant economic impacts as utilities would most likely not be able to market CCR products for "beneficial use" (e.g., flyash as an aggregate in concrete or flue-gas desulfurization (FGD) solids for manufacture of wallboard). As less CCR materials could be marketed for use, greater volumes of CCR materials would be required to be stored in landfills. Regulation as hazardous waste would impose stringent regulatory requirements associated with the handling, storage and disposal of large volumes of hazardous wastes.

Regulation as a municipal or special waste would result in relatively minor impacts on Nebraska utility operations to dispose of CCR due to the stringency of the current Nebraska solid waste landfill requirements. Current Nebraska landfill regulations include location restrictions, standards for landfill liners, leachate collection and removal systems, as well as additional stringent permitting requirements such as groundwater monitoring, fugitive dust control, closure and post-closure care, and financial assurance. It is unknown at this time what the impacts to Nebraska utilities will be until the rule is finalized.

8.7 Sensitivity Analysis

The full impact of the above mentioned regulations on the viability of existing resources will be site and unit specific. Each utility will need to analyze their facilities on a case-by-case basis.

A breakdown of the age of the existing fossil generating fleet is provided in Exhibit 8.7-1.

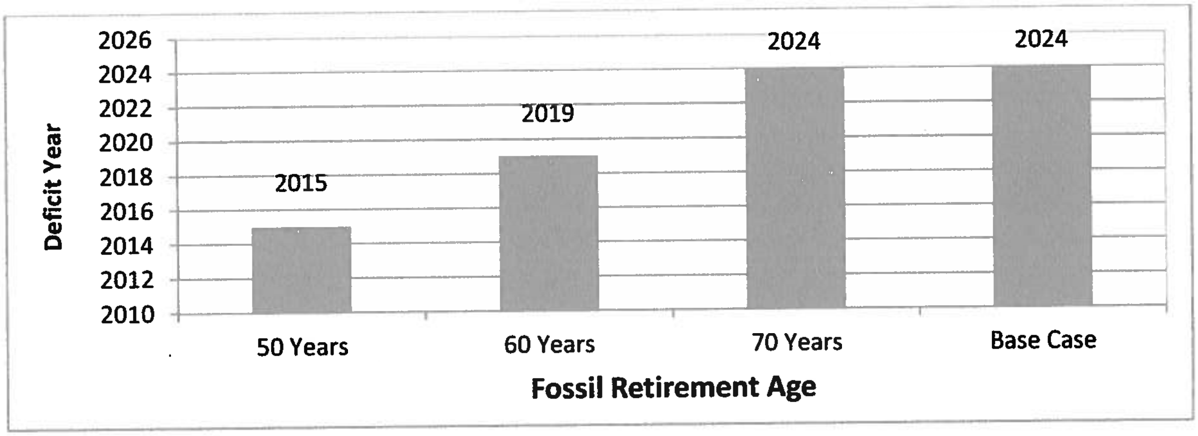
Exhibit 8.7-1

Existing Generating Fleet – Fossil Units (MW)

Years	Small Coal	Large Coal	Oil/gas	Total
0-20	280	836	1,234	2,349
21-30	0	0	5	5
31-40	262	2,215	359	2,836
41-50	483	0	358	841
50+	405	0	216	620
Total	1,430	3,051	2,171	6,652

It was assumed in the base case that all existing fossil facilities will remain operational throughout the study period. Simple scenarios were run to show the how the first year of a Nebraska wide deficit changed when the fossil units' retirement ages were varied as shown in Exhibit 8.7-2.

Exhibit 8.7-2
Deficit Load Year



9.0 LOAD PATTERN

9.1 Basic Definitions

When a customer flips a light switch and the light comes on, the electrical power required to turn on the bulb is considered "load".

The electrical power that serves the load is nearly instantaneously created at a power plant and transmitted through transmission and distribution lines to serve that particular customer.

The same electrical power that serves a given load over a specified time period (usually an hour) is called energy, and the standard unit of measure for electrical energy is the watt-hour. When dealing in large amounts of electrical energy the megawatt-hour (MWh) is preferred. 1 MWh is equal to 1,000,000 watt-hours.

So energy is different from capacity because energy is over a greater, more useful and easier measured unit of time such as a single hour.

By charting the energy used each hour in a year in chronological order (Hour 1, January 1 through Hour 24, December 31), a load pattern or load shape is created and because each utility has different types of customers, the annual load shape of each utility possess slightly different patterns. An example of a chronologically ordered hourly energy chart showing hourly energy for the coincident summer peak load week in 2011 is shown in Exhibits 9.3-1, 9.3-2 and 9.3-3.

If the hourly load shape data is sorted from highest load to lowest load, then a load duration curve is created. The load duration curve shows the relatively small number of hours a utility's peak load occurs.

Loads shown above the base load capacity are typically served by intermediate and peaking resources. An example of a load duration curve is shown in Exhibit 9.2-1.

The advantage of a load duration curve is that it helps visualize a cost-effective mix of resources (or capacity) by matching resource types to the expected level load duration and matching the percentage of time the load must be served.

9.2 Nebraska Statewide Load Duration Curves and Capacity Resources

Exhibit 9.2-1 below shows the actual 2011 load duration curve for the indicated Nebraska utilities, sorted in descending order to create a load duration curve. Super-imposed on that load duration curve is a representation of the existing baseload capacity resources utilized to meet the load obligation. The term Non-Coincident Peak means that the calculations were performed by sorting each utility's loads in descending order then summing.

Exhibit 9.2-1

2011 Load Duration Curve

Non-Coincident Peak

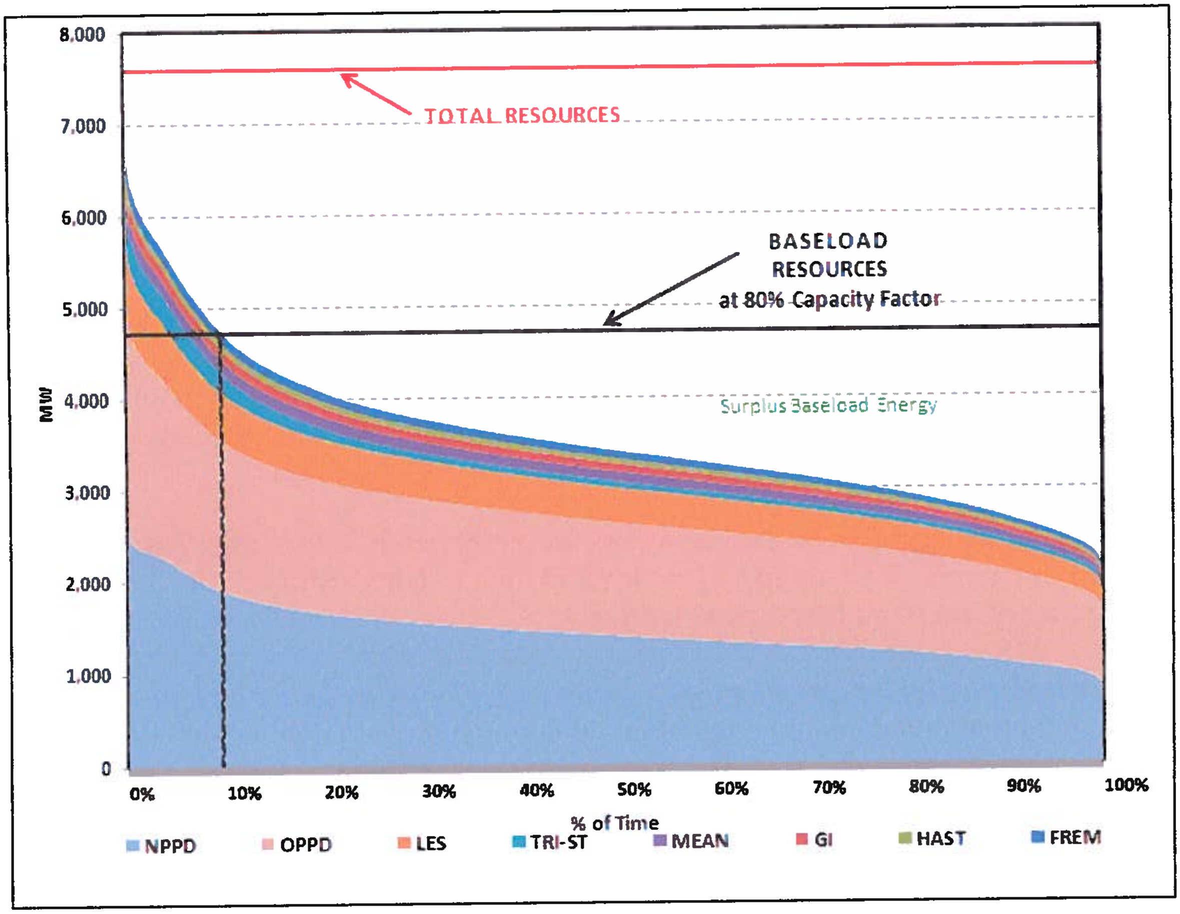
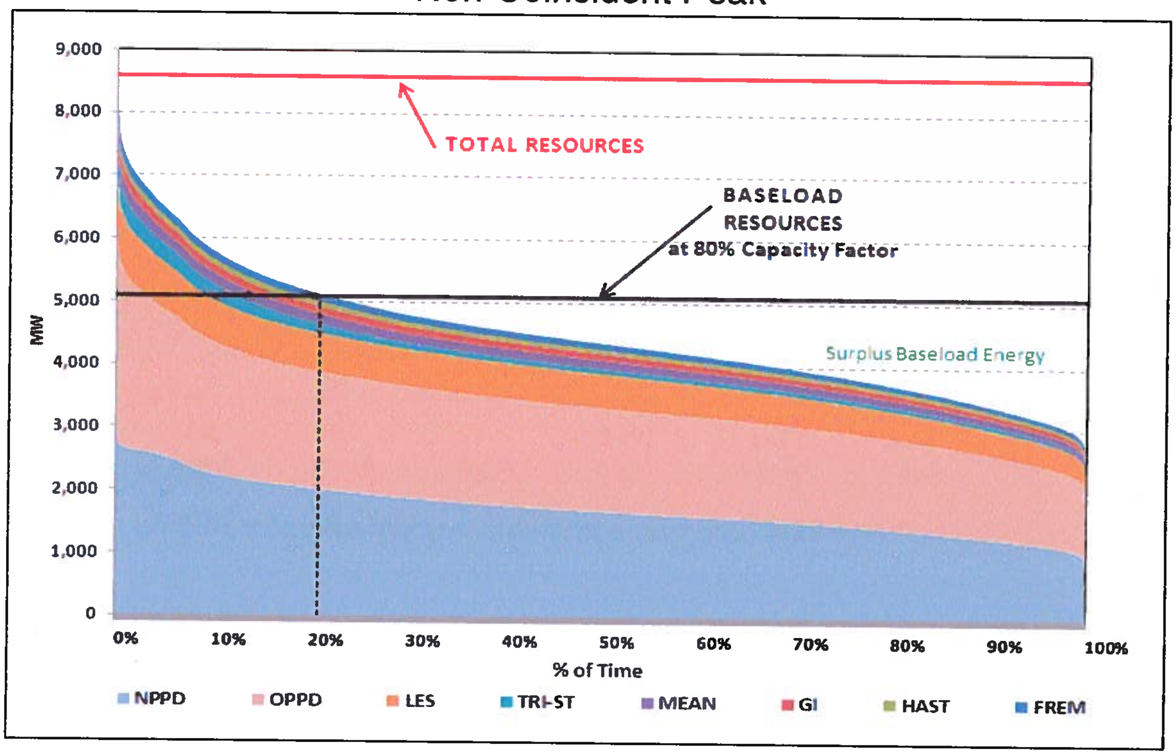


Exhibit 9.2-1 demonstrates the adequacy and effective matching of Nebraska capacity resources to the required load obligation while maintaining capacity reserves (12% SPP Capacity Margin) in case of unexpected unit outages. The State has adequate total resources (red line) to meet the non-coincident peak and minimum obligation (capacity reserves). The State has adequate baseload resources at an 80% capacity factor (typical capacity factor to account for planned and unplanned outages) to serve about 90% of the load hours. Peaking and intermediate resources are needed about 10% of the time. The baseload surplus

energy (area between the baseload resources line (black line) and the top of the load duration curve) is sold to the market if it can be done so cost effectively.

Exhibit 9.2-2 shows the expected 2026 load duration curves.

Exhibit 9.2-2
2026 Load Duration Curve
Non-Coincident Peak



This chart demonstrates that growth in load is matched with growth in resources to maintain adequate capacity reserves at peak. Baseload resources can serve about 80% of hours as compared to 90% in 2011. Peaking and intermediate resources are now needed about 20% of the hours. Increased load reduces the surplus baseload energy as compared to 2011.

9.3 Nebraska Statewide Load Shapes – Statewide Peak Week Basis (2011)

An analysis was completed to determine when the Nebraska State utilities set their highest coincident hourly peak load during the summer of 2011. In other words, the highest coincident peak is the hour in which the statewide load is at its peak for the year. In 2011 this hour occurred between 4:00 and 5:00 p.m., otherwise known as Hour Ending 17, Monday, August 1st. Exhibit 9.3-1 contains the weekly shape for State utilities with peak loads under 500 MW and Exhibit 9.3-2 contains the three State utilities with peak loads greater than 500 MW for the peak week of August 1.

Exhibit 9.3-3 uses the hourly data of the utility weekly load shapes in Exhibit 9.3-1 and Exhibit 9.3-2 and stacks all the individual utilities' loads to achieve a statewide load shape for the peak week of August 1.

Exhibit 9.3-1

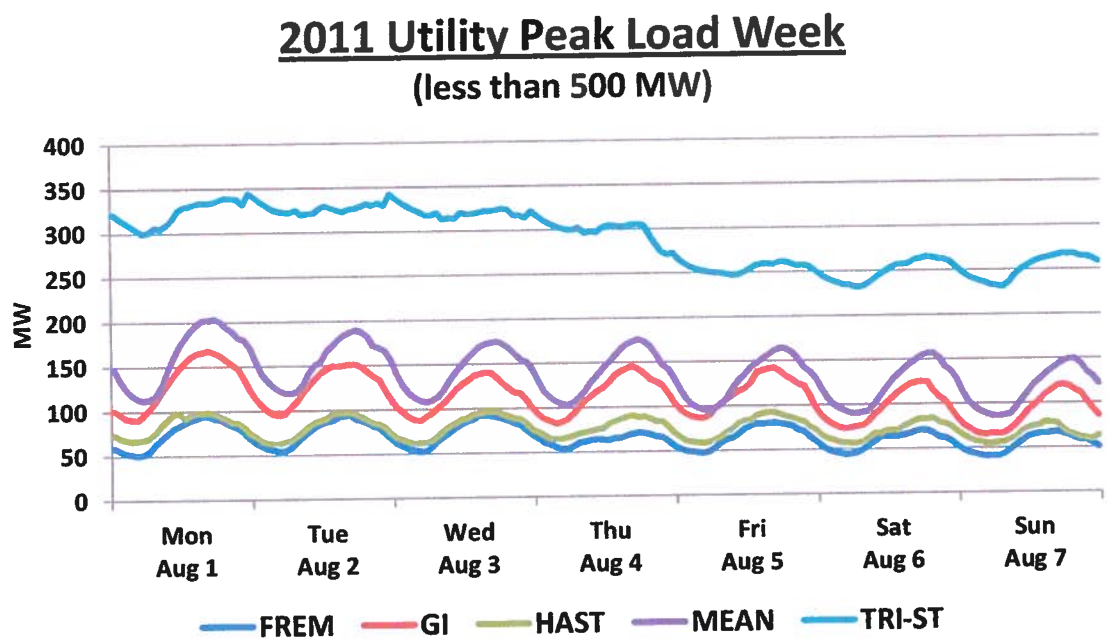


Exhibit 9.3-2

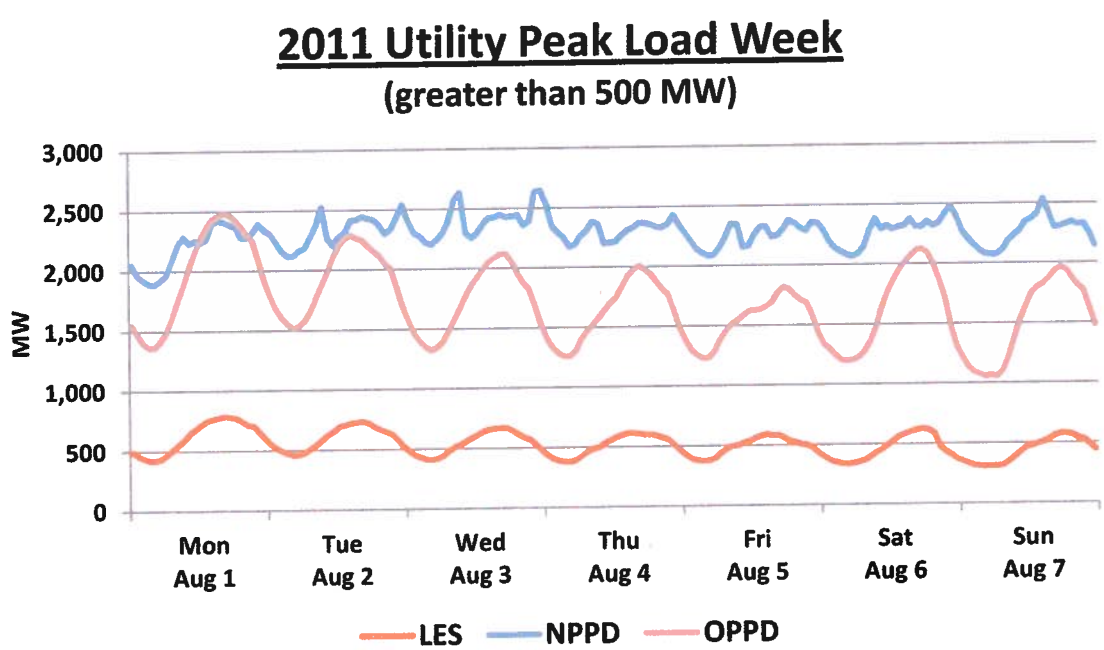
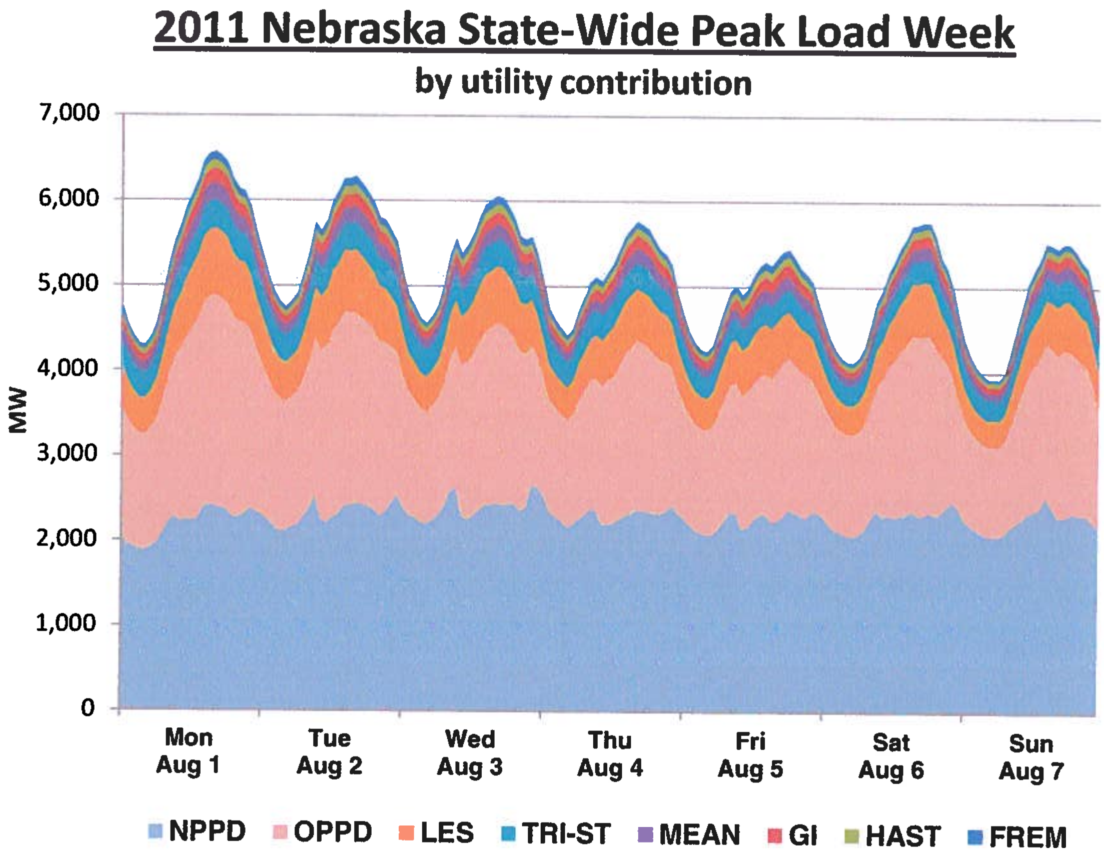


Exhibit 9.3-3



These charts were used to compare the energy profiles by utility. Load reduction strategies for utilities that serve more rural or irrigation loads that shift high demands to off-peak hours will show substantial variation from other utilities that serve more metropolitan loads and who may have different kinds of load reduction strategies. This supports the need for operational flexibility associated with capacity resources in order to effectively meet varying load patterns and diversity between rural and metropolitan loads across the state of Nebraska.

Exhibit 9.3-4 tabulates each State utility's non-coincident peak load, coincident load and coincidence factor percentage. The 2011 non-coincident peak load column is the utility peak loads regardless of day and time they were achieved, therefore they are non-coincident. The non-coincident statewide total of 6,822 MW is a summation of the utility non-coincident peak loads. Since it is non-coincident, this statewide total was not actually reached. The 2011 coincident peak load column results from a different approach. In this column the statewide peak hour is determined. In 2011 this statewide peak was 6,682 MW. Then each State utility load during that hour is tabulated, therefore these loads are coincident to the statewide peak. The 2011 coincidence factor is the coincident load divided by the non-coincident load. The statewide coincidence factor is 97.9% for 2011. A 97.9% coincidence factor demonstrates limited statewide diversity in the loads of the State utilities stemming from peak load being driven by hot summer days where the high temperatures stretch across the entire state. Simply put, most of the State utilities peak at the same time.

Exhibit 9.3-4

Coincidence Factor Calculation

	2011 Utility Non-Coincident Peak Load (MW)	2011 Utility Coincident Peak Load (MW)	2011 Coincidence Factor
Fremont	95	88	92.6%
Grand Island	168	168	100.0%
Hastings	99	97	98.0%
LES	786	786	100.0%
MEAN	203	202	99.5%
NPPD	2,646	2,526	95.5%
OPPD	2,481	2,481	100.0%
Tri-State	344	334	97.1%
Statewide Total	6,822	6,682	97.9%

10.0 POWER SUPPLY SCREENING CURVE

10.1 Discussion of Use of Curves

Power resources can be categorized into three different types of options: Baseload, Intermediate, and Peaking. Based on the number of hours of operation (or capacity factor) a given resource is expected to operate, the three types of resources could demonstrate enough flexibility to operate as shown below:

–Peaking Units:	**0 - 25% of the year**
–Intermediate Units:	**15 - 75% of the year**
–Baseload Units:	**60 - 100% of the year**

Some forms of generation, such as nuclear and large fossil steam units, are well suited for Baseload operation because of their relatively low operating cost, even though their installed capital cost may be higher. Conversely, other forms of generation that have a lower installed capital cost, such as Combustion Turbines, generally have a higher operating cost (principally due to fuel and heat rate), thus making them appropriate to utilize as Peaking units. An example of an Intermediate unit would be a Combined Cycle unit, which has the flexibility to run at lower or higher capacity factors.

10.2 Screening Curves

Capital cost, operating cost, and performance data for supply-side resources expected to be available during the twenty year study period of 2012-2031 are shown in Appendix E. These options include conventional methods of power supply, emerging technologies, storage technologies, and renewables. Each option was screened on a levelized busbar cost basis to determine the least-cost baseload, intermediate, and peaking options at various capacity factors.

The screening curve is used to determine the relative cost of each option. Those options with the highest construction and operating costs relative to other supply-side options with the same operational mode are eliminated. The screening curve analysis utilized is a plot of the levelized busbar costs versus capacity factor for each technology. The least expensive technologies are shown in Exhibit 10.2-1 and Exhibit 10.2-2.

It is difficult to compare the costs for dispatchable technologies to non-dispatchable technologies (i.e. wind, solar) in a screening curve analysis. To improve the screening curve analysis, wind energy includes the cost of combustion turbines as the backup resource. Exhibit 10.2-1 and Exhibit 10.2-2 show two wind backup cases (both cases shown in dotted lines). The lower cost case assumes 1 MW of natural gas for every 2 MW of wind. If wind is available at 40% capacity factor, then the gas can contribute another 20% (1 MW gas for every 2 MW wind), or a maximum of 60% capacity factor. The higher cost case assumes 2 MW of natural gas for every 1 MW of wind (i.e. lower availability of wind on-peak) which does result in higher costs but allows up to 100% capacity factor.

Appendix E also contains a graphical representation of the costs of each option by component: capital, operating, and fuel costs for 1%, 5%, 20%, 40%, 60%, and 80% capacity factors.

While screening curves are useful for comparing options they cannot be utilized as the sole means for making resource selections. That is because they do not contain some information that is necessary to making final resource selection.

Some of the items that cannot be evaluated with screening curves are:

- Non-dispatchable (wind, solar)
- Timing
- Effects on dispatch of other units.
- Forced outages
- Planned maintenance outages
- Coincidence of generation with load
- Existing resource mix

So while screening curves provide considerable insight for comparison of like resources, they are only one tool to be utilized in the resource planning process.

The least cost options based on the screening curves are shown below:

Peaking:

Combustion Turbines
Combined Cycle

Intermediate:

8 Hour Battery
Gas Turbine
Pumped Storage
Combined Cycle
Compressed Air Energy Storage

Baseload:

Combined Cycle
Supercritical Pulverized Coal with CCS
Integrated Gasification Combined Cycle (IGCC)
Nuclear
Supercritical Pulverized Coal

Renewables:

Landfill Gas
Wind Turbines

Storage:

8 Hour Battery Storage
Pumped Storage
Compressed Air Energy Storage

Exhibit 10.2-1

Screening Curve - $/MW-Year

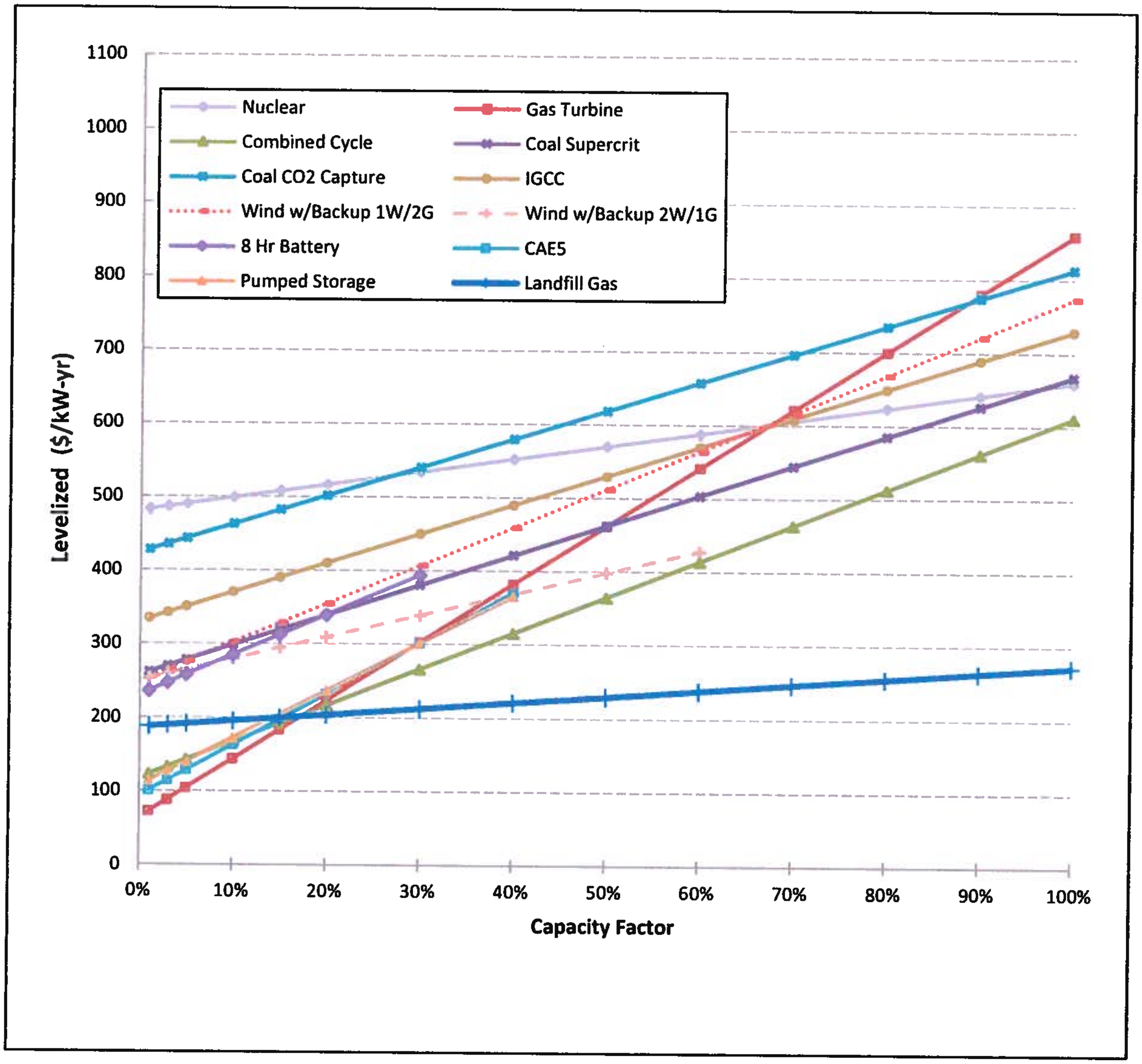
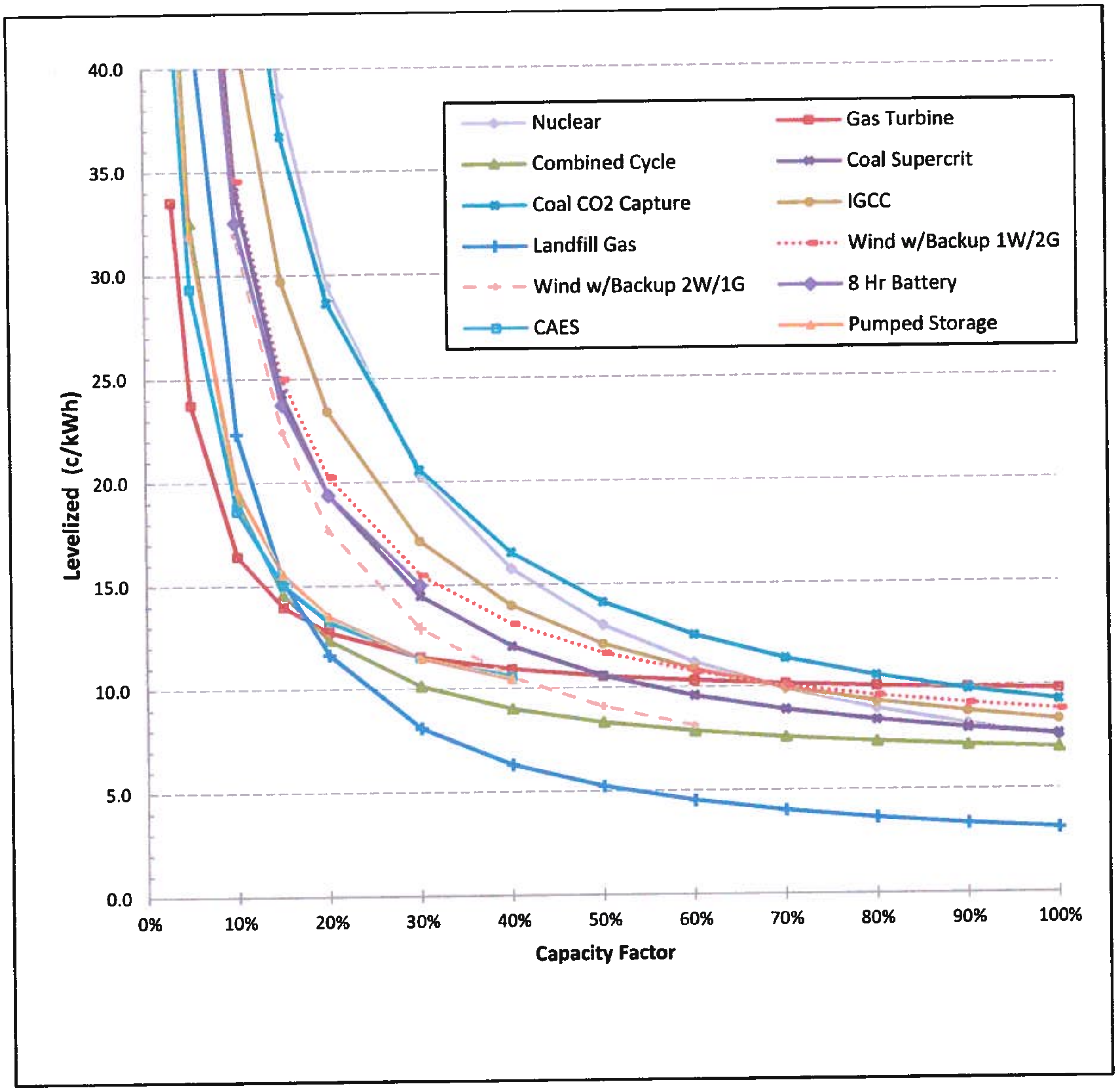


Exhibit 10.2-2

Screening Curve - $/MWh



11.0 TRANSMISSION

11.1 The Nebraska Subregional Planning Group (SPG)

The primary objective of the Nebraska SPG is to develop a coordinated ten-year transmission plan for the Nebraska subregion on an annual basis. The latest transmission plan is provided in Appendix F.

The Nebraska Transmission Plan shall be consistent with applicable standards and requirements established by North American Electric Reliability Corporation (NERC), Federal Energy Regulatory Commission (FERC), Midwest Reliability Organization (MRO), Mid-Continent Area Power Pool (MAPP), and Southwest Power Pool (SPP).

In 2009, LES, NPPD, and OPPD became Members of SPP and the SPP Regional Transmission Organization (RTO) is the Planning Coordinator for these entities. LES, NPPD, and OPPD coordinate their long term transmission expansion plans through the SPP Transmission Expansion Plan (STEP) and the Integrated Transmission Plan (ITP) processes.

All of the Nebraska SPG entities are Members of the MRO Regional Entity.

A detailed transmission map cannot be provided in a public document per FERC's rules regarding Critical Energy Infrastructure Information (CEII).

11.2 SPP Integrated Transmission Plan (ITP)

11.2.1 Overview

The ITP is SPP's approach to planning transmission needed to maintain reliability, provide economic benefits and achieve public policy goals to the SPP region in both the near and long-term. The ITP enables SPP and its stakeholders to facilitate the development of a robust transmission grid that provides regional customers improved access to the SPP region's diverse resources. Development of the ITP was driven by planning principles developed by the Synergistic Planning Project Team (SPPT), including the need to develop a transmission backbone large enough in both scale and geography to provide flexibility to meet SPP's future needs.

The ITP is an iterative three-year process that includes 20-Year, 10-Year, and Near-Term Assessments and targets a reasonable balance between long-term transmission investment and customer congestion costs (as well as many other benefits).
The ITP creates synergies by integrating existing SPP activities: the Extra High Voltage (EHV) Overlay, the Balanced Portfolio, and the SPP

Transmission Expansion Plan (STEP) Reliability Assessment. Consequently, and reaching the balance above, efficiencies are expected to be realized in the Generation Interconnection and Aggregate Transmission Service Request study processes. The ITP works in concert with SPP's existing sub-regional planning stakeholder process, and parallels the NERC TPL Reliability Standards compliance process.

The Economic Studies Working Group (ESWG) was also formed in conjunction with the development of the ITP and will maintain the processes and metrics on an ongoing basis for qualifying and quantifying the transmission projects for the 20-Year and 10-Year Assessments.

The Transmission Working Group (TWG) will maintain the process on an ongoing basis for qualifying and quantifying the transmission projects for the Near-Term Assessment. The TWG also provides technical oversight for the 20-Year & 10-Year Assessments.

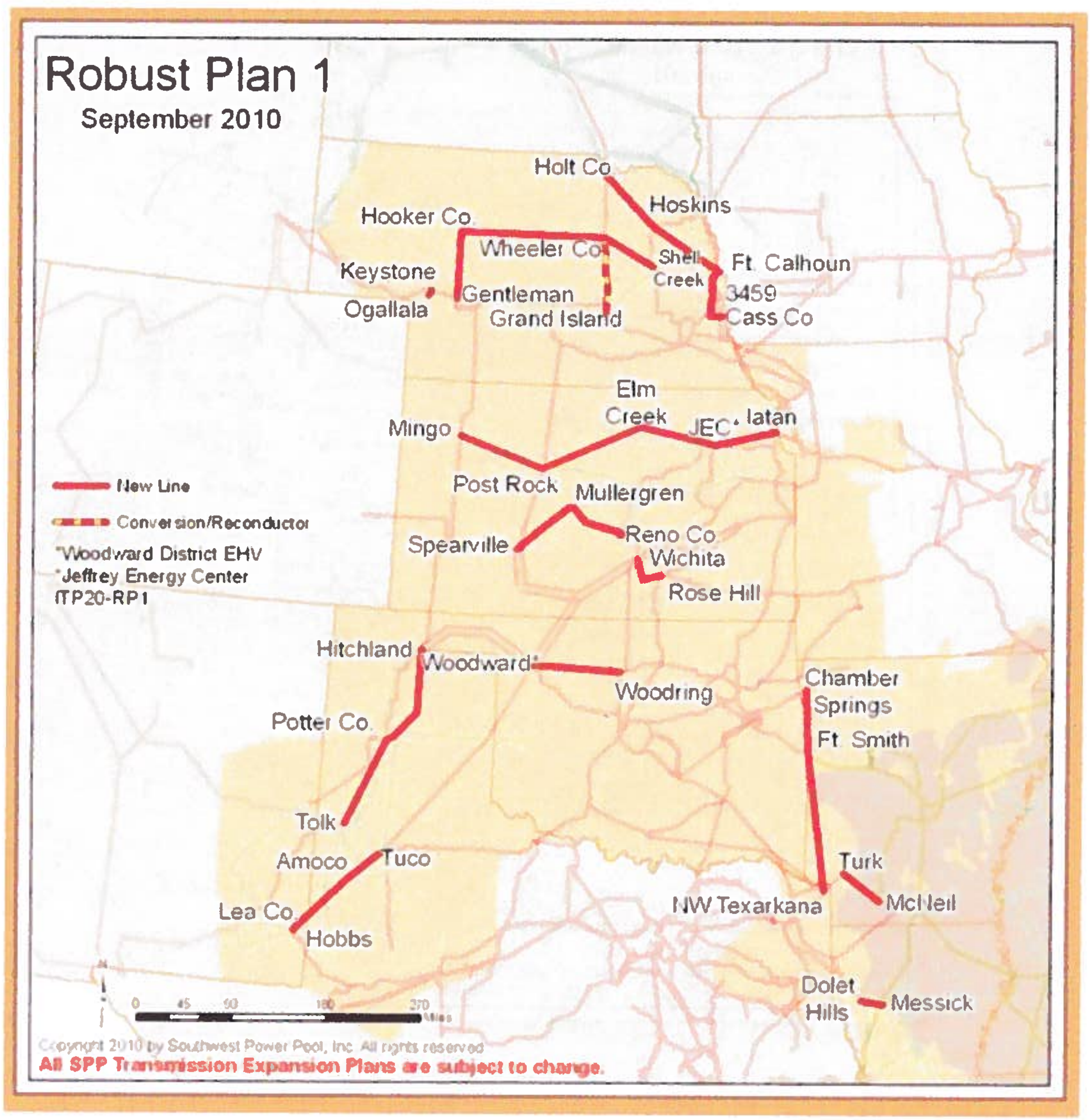
ITP recommendations that are reviewed by the Market Operations and Policy Committee (MOPC) and approved by the Board of Directors (BOD) will allow staff to issue Notification to Construct (NTC) letters for approved projects needed within the financial commitment horizon. An Authorization to Plan (ATP) will be issued for projects needed beyond the financial horizon.

Once an ATP is issued, the project will be reviewed annually to ensure the continued need for the project and the proper timing.

Successful implementation of the ITP will result in a list of transmission expansion projects, projected project costs and completion dates that facilitate the creation of a cost-effective, robust, and responsive transmission network in the SPP footprint.

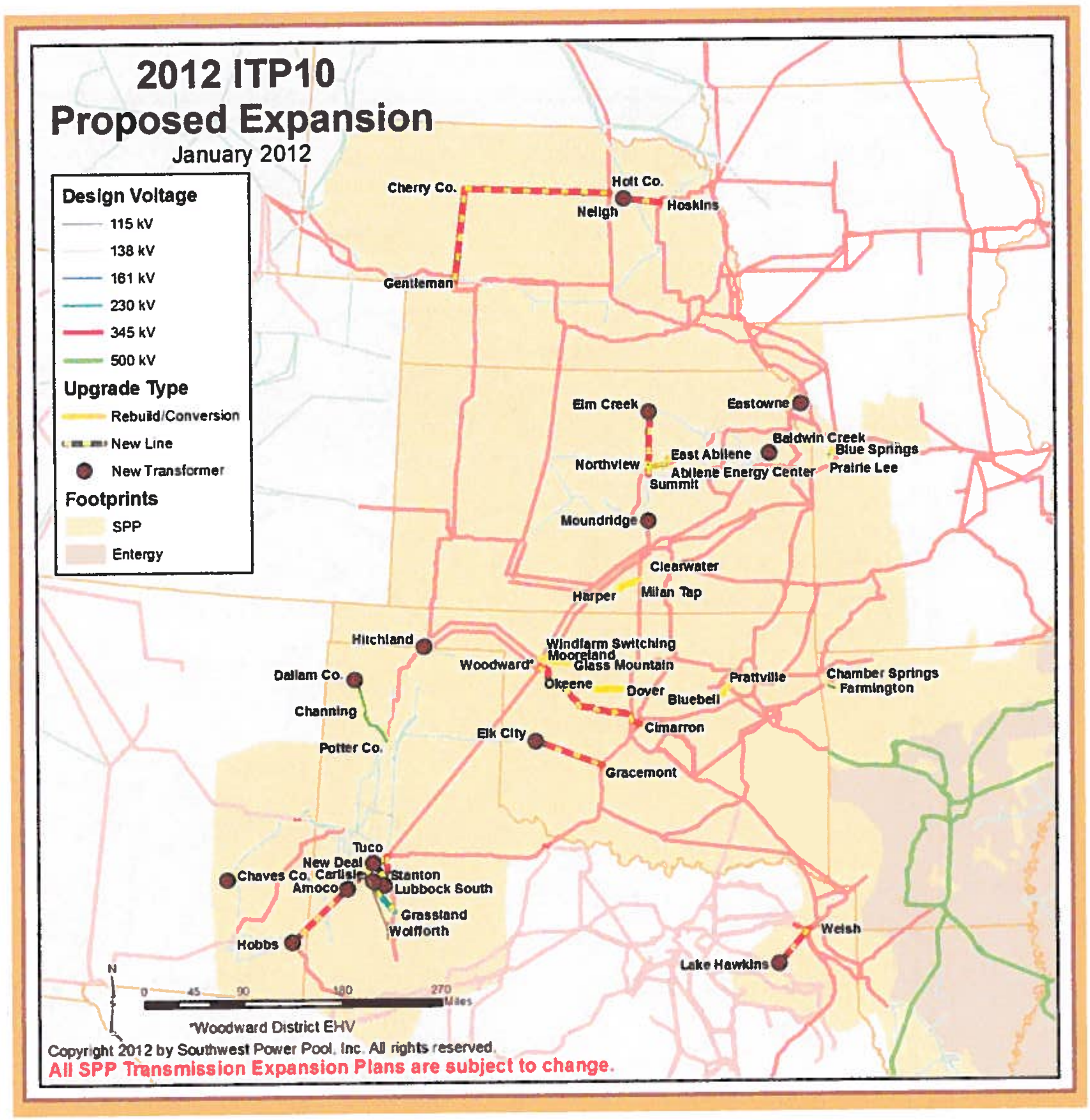
11.2.2 2010 ITP20 Results

The 2010 ITP20 work was completed during 2010 and the report approved by the SPP's Board of Directors on January 25, 2011. Four (4) futures were identified in the process: 1) Business-As-Usual, 2) Renewable Electricity Standard, 3) Carbon Mandate, and 4) Renewable Electricity Standard plus Carbon Mandate. Transmission projects were designed to overcome identified limits, allowing future requirements to be met. The transmission projects were then combined into different plans and analyzed. Robust Plan 1 was selected and is shown below. No notices to construct were issued based on this study. Refer to the ITP20 report for more details.



11.2.3 2012 ITP10 Results

The 2012 ITP10 work was completed during 2011 and the report approved by the SPP's Board of Directors on January 31, 2012. Two futures were studied in the process: 1) Business-As-Usual, and 2) EPA Rules with Additional Wind. The selected transmission plan is shown below. Notices to construct were issued for the proposed expansion plan. Refer to the 2012 ITP10 report for more details.



11.2.4 2013 ITP20 Study

The 2013 ITP20 Study has begun and is expected to be completed by July 2013.

Five futures have been identified for study:

1) Business as Usual
2) Additional Wind (20% RPS)
3) Additional Wind plus Exports (20% RPS and 10,000 MW wind export)
4) Combined Policy (20% RPS, load growth reduction, carbon tax)
5) Joint SPP/MISO Future

12.0 OTHER CONSIDERATIONS

Earlier sections of this plan discussed the challenges the electric utility industry faces with environmental regulations compliance, generating resource replacements, integrating renewable generation, and transmission expansion. Additionally, the industry is adapting its generating resource planning processes to incorporate a significant amount of input and feedback from the public. Electrical energy consumers and the public in general have taken a strong interest in energy sources and their potential environmental impacts. As a result, existing processes such as the WAPA Integrated Resource Plan have public input requirements, and NPPD's ongoing Generation Options Analysis also has a notable public comment component. A related WAPA process is the ongoing 2021 Power Marketing Initiative that seeks to develop updated Firm Electric Service agreements and the associated Contracted Rate of Delivery documents. Since several Nebraska utilities participate in WAPA contracts, this initiative will most likely represent a component of the State's future generating resource mix.

Although Federal legislative efforts to develop a national Renewable Portfolio Standard have waned and the President's proposal to implement a Federal Clean Energy Standard has made very little progress towards enactment, Nebraska's utilities continue to monitor and review these policies because of the significant impact they could have on utility operations. Another regulatory area that presents significant challenges to the electric utility industry is the regulation of greenhouse gases. The EPA has issued proposed rules that would require new intermediate and base load generating resources to emit no more carbon dioxide per MWh than what a modern natural gas fired combined cycle plant emits. Without a viable carbon capture and storage technology, this proposed rule could effectively stop the installation of new coal fired generating units. An additional challenge may be the EPA's pending proposal to limit greenhouse gas emissions from existing generating units. Depending on how this regulation is crafted, the electric utility industry may be driven towards significant generating resource infrastructure modifications.

With restrictions on the development of coal fired generation and the long lead times for engineering, procurement, and construction of nuclear generation, it appears natural gas will provide the only realistic option for dispatchable generation expansion in the near term. That expansion will drive a need for significant natural gas production and natural gas delivery infrastructure development.

A major factor in this needed expansion will be the ongoing regulatory uncertainty in the evolution of natural gas recovery through hydro-fracturing technology. The long-term environmental viability of hydro-fracturing may dampen the potential for recoverable natural gas supplies; however, recent information has indicated that environmental issues with hydro-fracturing stem from poor drilling practices and operational errors, not an inherent danger in the technology. Natural gas prices should remain relatively low for the next several years while hydro-fracturing makes natural gas supplies appear plentiful. It is quite possible, though, that a significant shift in the electric utility industry toward natural gas consumption will put pressure on natural gas production and cause increased pricing in the next decade. Historically, natural gas prices have been very volatile and have proven difficult to forecast.

There are certain long-range planning scenarios where nuclear generation as a base load resource appears financially attractive; however, regulatory uncertainty and public sentiment would make constructing new traditional nuclear projects in the Midwest region challenging. Modular nuclear energy resources continue to garner interest and the recent Nuclear Regulatory Commission's (NRC) approval of two new nuclear reactors in Georgia have increased the optimism level of nuclear energy's supporters. Last year's nuclear tragedy in Japan continues to heighten the scrutiny on all nuclear energy development, but the NRC's action provides some insight into the future of nuclear development in the U.S.

Another topic creating uncertainty for the electric utility industry is the pending expiration at the end of 2012 of energy production tax credits and investment tax credits for new wind generating projects. There is also the uncertain future of large scale consumer adoption of all-electric or plug-in hybrid electric vehicles. This market change could exercise the generation, transmission, and distribution system in unexpected ways.

In summary, while Nebraska's electric utilities attempt to consider and plan for a multitude of potential future events, there will always be new and unanticipated challenges needing creative solutions.

Appendix A: Statewide Existing Generating Capability Data

APPENDIX A

Statewide Existing Generating Capability Data

Utility	Unit Name	Duty Cycle	Unit Type	Fuel Type	Commercial Operation Date	Summer Accredited Capacity	Summer Utility Capacity
Falls City	Falls City #1	P	D	O	1930	0.70	
	Falls City #2	P	D	O	1937	1.00	
	Falls City #3	P	D	NG/O	1965	2.30	
	Falls City #4	P	D	NG/O	1946	0.80	
	Falls City #5	P	D	NG/O	1951	1.40	
	Falls City #6	P	D	NG/O	1958	2.00	
	Falls City #7	P	D	NG/O	1972	6.20	
	Falls City #8	P	D	NG/O	1981	6.00	
Falls City	**Total**						**20.4**
Fremont	Fremont #6	B	F	C/NG	1958	15.60	
	Fremont #7	B	F	C/NG	1963	20.50	
	Fremont #8	B	F	C/NG	1976	85.00	
	CT	P	CT	NG/O	2003	36.00	
Fremont	**Total**						**157.1**
Grand Island	Burdick #1	P	F	NG/O	1957	16.00	
	Burdick #2	P	F	NG/O	1963	22.00	
	Burdick #3	P	F	NG/O	1972	54.00	
	Burdick GT1	P	CT	NG/O	1968	13.00	
	Burdick GT2	P	CT	NG/O	2003	34.00	
	Burdick GT3	P	CT	NG/O	2003	34.00	
	Platte Generating Station	B	F	C	1982	100.00	
Grand Island	**Total**						**273.0**
Hastings	Whelan Energy Center #1	B	F	C	1981	77.00	
	Whelan Energy Center #2	B	F	C	2011	220.00	
	Hastings-NDS#4	P	F	NG/O	1957	15.00	
	Hastings-NDS#5	P	F	NG/O	1967	23.00	
	DHPC-#1	P	CT	NG/O	1972	18.00	
Hastings	**Total**						**353.0**
LES	Laramie River #1	B	F	C	1982	188.69	
	Walter Scott #4	B	F	C	2007	101.28	
	J St	P	CT	NG/O	1972	27.00	
	Rokeby 1	P	CT	NG/O	1975	63.00	
	Rokeby 2	P	CT	NG/O	1997	86.30	
	Rokeby 3	P	CT	NG/O	2001	89.00	
	Wind Turbines #1-2	I	R	W	1999	0.00	
	Rokeby Black Start	P	D	O	1997	3.00	
	Terry Bundy	P	CC	NG/O	2003	120.30	
	Terry Bundy	P	CT	NG/O	2003	47.10	
	Terry Bundy Black Start	P	D	O	2004	1.60	
LES	**Total**						**727.3**
MEAN	Ansley #1	P	D	NG/O	1972	0.40	
	Ansley #2	P	D	NG/O	1968	0.80	
	Arnold #1	P	D	NG/O	1960	0.40	
	Arnold #2	P	D	NG/O	1942	0.20	
	Arnold #3	P	D	NG/O	1946	0.30	
	Beaver City #1	P	D	NG/O	1958	0.40	
	Beaver City #2	P	D	NG/O	1961	0.30	
	Beaver City #4	P	D	NG/O	1968	0.45	
	Benkelman #1	P	D	NG/O	1968	0.75	
	Blue Hill#1	P	D	NG/O	1964	0.80	
	Blue Hill#2	P	D	O	1948	0.40	
	Broken Bow #1	P	D	O	1933	0.50	
	Broken Bow #2	P	D	NG/O	1971	3.20	
	Broken Bow #3	P	D	NG/O	1936	0.80	
	Broken Bow #4	P	D	NG/O	1949	0.80	
	Broken Bow #5	P	D	NG/O	1959	1.00	
	Broken Bow #6	P	D	NG/O	1961	2.00	
	Burwell#1	P	D	NG/O	1955	0.50	
	Burwell#2	P	D	NG/O	1962	0.70	
	Burwell#3	P	D	NG/O	1967	0.90	
	Burwell#4	P	D	NG/O	1972	0.90	
	Callaway #1	P	D	O	1936	0.18	
	Callaway #2	P	D	O	1948	0.18	
	Callaway #3	P	D	O	1958	0.50	
	Chappell #2	P	D	O	1945	0.30	
	Chappell #3	P	D	O	1982	0.90	
	Crete #1	P	D	NG/O	1939	0.50	
	Crete #2	P	D	NG/O	1955	1.10	
	Crete #3	P	D	NG/O	1951	0.90	
	Crete #4	P	D	NG/O	1947	0.90	
MEAN (contd)	Crete #5	P	D	NG/O	1962	2.70	
	Crete #6	P	D	NG/O	1965	3.50	
	Crete #7	P	D	NG/O	1972	6.07	
	Curtis #1	P	D	NG/O	1975	1.20	

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Statewide Existing Generating Capability Data

Utility	Unit Name	Duty Cycle	Unit Type	Fuel Type	Commercial Operation Date	Summer Accredited Capacity	Summer Utility Capacity
	Curtis #2	P	D	NG/O	1969	0.90	
	Curtis #3	P	D	NG/O	1955	0.90	
	Fairbury #2	P	F	NG/O	1948	4.30	
	Fairbury #4	P	F	NG/O	1966	11.00	
	Kimball #1	P	D	NG/O	1955	1.00	
	Kimball #2	P	D	NG/O	1956	0.90	
	Kimball #3	P	D	NG/O	1959	1.00	
	Kimball #4	P	D	NG/O	1960	0.90	
	Kimball #5	P	D	NG/O	1951	0.70	
	Kimball #7	P	D	NG/O	1975	3.50	
	Kimball Wind Turbines #1-7	I	R	W	2002	0.00	
	Oxford #1	P	D	O	1948	0.54	
	Oxford #2	P	D	NG/O	1952	0.53	
	Oxford #3	P	D	NG/O	1956	0.76	
	Oxford #4	P	D	NG/O	1956	0.47	
	Oxford #5	P	D	O	1972	1.00	
	Pender #1	P	D	O	1967	1.06	
	Pender #2	P	D	NG/O	1973	1.72	
	Pender #3	P	D	O	1953	0.44	
	Pender #4	P	D	O	1961	0.74	
	Red Cloud #2	P	D	NG/O	1953	0.50	
	Red Cloud #3	P	D	NG/O	1960	1.00	
	Red Cloud #4	P	D	NG/O	1968	1.00	
	Red Cloud #5	P	D	NG/O	1974	1.50	
	Sargent #1	P	D	NG/O	1963	0.00	
	Sargent #2	P	D	NG/O	1964	0.75	
	Sargent #3	P	D	NG/O	1966	0.25	
	Sidney #1	P	D	NG/O	1967	1.00	
	Sidney #2	P	D	NG/O	1973	2.50	
	Sidney #3	P	D	O	1953	0.65	
	Sidney #4	P	D	NG/O	1961	0.85	
	Sidney #5	P	D	NG/O	1939	2.65	
	Stuart #1	P	D	NG/O	1965	0.75	
	Stuart #2	P	D	NG/O	1996	0.75	
	Stuart #3	P	D	O	1954	0.28	
	Stuart #4	P	D	O	1946	0.28	
	West Point #1	P	D	NG/O	1950	2.10	
	West Point #2	P	D	NG/O	1959	1.10	
	West Point #3	P	D	NG/O	1965	0.71	
	West Point #5	P	D	NG/O	1971	0.00	
	Laramie River #1	B	F	C	1982	10.00	
	Walter Scott #4	B	F	C	2007	50.00	
MEAN	Total						146.4
NPPD	ADM	B	F	C	2009	59.80	
	Ainsworth Wind	I	R	W	2005	0.00	
	Auburn #1	P	D	NG/O	1982	2.10	
	Auburn #2	P	D	NG/O	1949	0.50	
	Auburn #4	P	D	NG/O	1993	3.30	
	Auburn #5	P	D	NG/O	1973	3.00	
	Auburn #6	P	D	NG/O	1967	2.20	
	Auburn #7	P	D	NG/O	1987	5.20	
	Beatrice Power Station	I	CC	NG	2005	217.00	
	Belleville 4	P	D	NG/O	1955	0.00	
	Belleville 5	P	D	NG/O	1961	1.40	
	Belleville 6	P	D	NG/O	1966	2.50	
	Belleville 7	P	D	NG/O	1971	3.30	
	Belleville 8	P	D	NG/O	2006	2.80	
	Broken Bow Wind	I	R	W	2013	0.00	
	Cambridge	P	D	NG	1972	3.00	
	Canaday	P	F	NG/O	1958	111.00	
	Columbus 1	B	H	HR	1936	15.00	
	Columbus 2	B	H	HR	1936	15.00	
	Columbus 3	B	H	HR	1936	12.00	
	Cooper	B	N	UR	1974	766.00	
	Crofton Bluffs Wind	I	R	W	2013	0.00	
	David City 1	P	D	NG/O	1960	1.30	
	David City 2	P	D	NG/O	1949	0.80	
	David City 3	P	D	NG/O	1955	0.90	
	David City 4	P	D	NG/O	1966	1.80	
	David City 5	P	D	O	1996	1.33	
NPPD (contd)	David City 6	P	D	O	1996	1.33	
	David City 7	P	D	O	1996	1.34	
	Deshler 1	P	D	NG/O	2001	0.27	
	Deshler 2	P	D	NG/O	1950	0.29	
	Deshler 3	P	D	NG/O	1998	1.10	
	Deshler 4	P	D	NG/O	1956	0.60	
	Elkhorn Ridge Wind Farm	I	R	W	2009	0.00	
	Emerson #2	P	D	NG/O	1968	1.20	

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Statewide Existing Generating Capability Data

Utility	Unit Name	Duty Cycle	Unit Type	Fuel Type	Commercial Operation Date	Summer Accredited Capacity	Summer Utility Capacity
	Emerson #3	P	D	NG/O	1948	0.00	
	Emerson #4	P	D	O	1958	0.40	
	Franklin 1	P	D	NG	1963	0.65	
	Franklin 2	P	D	NG	1974	1.35	
	Franklin 3	P	D	NG	1968	1.05	
	Franklin 4	P	D	NG	1955	0.70	
	Gentleman 1	B	F	C	1979	665.00	
	Gentleman 2	B	F	C	1982	700.00	
	Hallam (Black Start)	P	CT	NG/O	1973	45.00	
	Hebron	P	CT	NG/O	1973	41.00	
	Holdrege 1	P	D	O	1938	0.00	
	Holdrege 2	P	D	O	1952	0.00	
	Holdrege 3	P	D	O	1945	0.00	
	Jeffrey 1	B	H	HR	1940	9.00	
	Jeffrey 2	B	H	HR	1940	9.00	
	Johnson I 1	B	H	HR	1940	9.00	
	Johnson I 2	B	H	HR	1940	9.00	
	Johnson II	B	H	HR	1940	18.00	
	Kearney	B	H	HR	1921	1.00	
	Kingsley(Black Start)	B	H	HR	1985	37.50	
	Laredo Ridge Wind Farm	I	R	W	2011	0.00	
	Lodgepole 1	P	D	O	1934	0.00	
	Lodgepole 2	P	D	O	1947	0.00	
	Lyons 2	P	D	O	1953	0.20	
	Lyons 3	P	D	O	1960	0.30	
	Lyons 4	P	D	O	1967	0.60	
	Madison 1	P	D	NG/O	1969	1.70	
	Madison 2	P	D	NG/O	1959	0.95	
	Madison 3	P	D	NG/O	1953	0.85	
	Madison 4	P	D	O	1946	0.50	
	McCook(Black Start)	P	CT	O	1973	41.00	
	Monroe	B	H	HS	1936	3.00	
	Mullen #1	P	D	O	1958	0.35	
	Mullen #2	P	D	O	1966	0.00	
	North Platte 1(Black Start)	B	H	HR	1935	11.95	
	North Platte 2(Black Start)	B	H	HR	1935	11.95	
	Ord 1	P	D	NG/O	1973	5.00	
	Ord 2	P	D	NG/O	1966	1.00	
	Ord 3	P	D	NG/O	1963	2.00	
	Ord 4	P	D	O	1997	1.40	
	Ord 5	P	D	O	1997	1.40	
	Sheldon 1	B	F	C	1961	105.00	
	Sheldon 2	B	F	C	1965	120.00	
	Spalding 2	P	D	O	1955	0.40	
	Spalding 3	P	D	O	1975	1.40	
	Spalding 4	P	D	O	1999	0.20	
	Spalding 5	P	D	O	2001	0.25	
	Spencer 1	B	H	HS	1927	1.00	
	Spencer 2	B	H	HS	1952	0.80	
	Springview Wind	I	R	W	2012	0.00	
	Sutherland 1	P	D	O	1952	0.45	
	Sutherland 2	P	D	O	1959	0.85	
	Sutherland 3	P	D	O	1935	0.00	
	Sutherland 4	P	D	O	1964	1.35	
	Wahoo #1	P	D	NG/O	1960	1.70	
	Wahoo #3	P	D	NG/O	1973	3.60	
	Wahoo #5	P	D	NG/O	1952	1.80	
	Wahoo #6	P	D	NG/O	1969	2.90	
	Wakefield 2	P	D	NG/O	1955	0.54	
	Wakefield 4	P	D	NG/O	1961	0.69	
	Wakefield 5	P	D	NG/O	1966	1.08	
	Wakefield 6	P	D	NG/O	1971	1.13	
	Wayne 1	P	D	O	1951	0.75	
	Wayne 3	P	D	O	1956	1.75	
	Wayne 4	P	D	O	1960	1.85	
	Wayne 5	P	D	O	1966	3.25	
	Wayne 6	P	D	O	1968	4.90	
NPPD (contd)	Wayne 7	P	D	O	1998	3.25	
	Wayne 8	P	D	O	1998	3.25	
	Wilber 4	P	D	O	1949	0.78	
	Wilber 5	P	D	O	1958	0.59	
	Wilber 6	P	D	O	1997	1.57	
	York 1	P	D	O	1980	0.00	
	York 2	P	D	O	1996	0.00	
NPPD	Total						3,136.2
Nebraska City	Nebraska City #2 Black start	P	D	NG/O	1953	1.00	
	Nebraska City #3	P	D	NG/O	1955	2.00	
	Nebraska City #4	P	D	NG/O	1957	2.50	

APPENDIX A

Statewide Existing Generating Capability Data

Utility	Unit Name	Duty Cycle	Unit Type	Fuel Type	Commercial Operation Date	Summer Accredited Capacity	Summer Utility Capacity
	Nebraska City #5 Black start	P	D	NG/O	1964	1.60	
	Nebraska City #6	P	D	NG/O	1967	1.50	
	Nebraska City #7	P	D	NG/O	1969	1.50	
	Nebraska City #8	P	D	NG/O	1970	3.50	
	Nebraska City #9	P	D	NG/O	1974	5.60	
	Nebraska City #10	P	D	NG/O	1979	5.80	
	Nebraska City #11	P	D	NG/O	1998	3.80	
	Nebraska City #12	P	D	NG/O	1998	3.80	
	Nebraska City #13	P	D	O	1998	4.50	
Nebraska City	Total						37.1
OPPD	Fort Calhoun #1	B	N	UR	1973	478.60	
	Nebraska City #1	B	F	C	1979	651.50	
	Nebraska City #2	B	F	C	2009	684.60	
	North Omaha #1	B	F	C/NG	1954	79.30	
	North Omaha #2	B	F	C/NG	1957	96.20	
	North Omaha #3	B	F	C/NG	1959	108.40	
	North Omaha #4	B	F	C/NG	1963	138.40	
	North Omaha #5	B	F	C/NG	1968	204.40	
	Jones St. #1	P	CT	O	1973	61.50	
	Jones St. #2	P	CT	O	1973	61.20	
	Cass County #1	P	CT	NG	2003	161.90	
	Cass County #2	P	CT	NG	2003	161.30	
	Sarpy County #1	P	CT	NG/O	1972	55.50	
	Sarpy County #2	P	CT	NG/O	1972	55.70	
	Sarpy County #3	P	CT	NG/O	1996	105.10	
	Sarpy County #4	P	CT	NG/O	2000	47.60	
	Sarpy County #5	P	CT	NG/O	2000	48.00	
	Sarpy Co. Black Start	P	D	O	1996	3.40	
	Elk City Station #1-4	B	R	L	2002	3.13	
	Elk City Station #5-8	B	R	L	2006	3.11	
	Flat Water Wind Farm	I	R	W	2011	0.00	
	Petersubrg Wind Farm	I	R	W	2012	0.00	
	Valley Wind Turbine #1	I	R	W	2001	0.00	
	Tecumseh #1	P	D	O	1949	0.60	
	Tecumseh #2	P	D	O	1968	1.40	
	Tecumseh #3	P	D	O	1952	1.00	
	Tecumseh #4	P	D	O	1960	1.20	
	Tecumseh #5	P	D	O	1993	2.40	
OPPD	Total						3,215.4
Nebraska Grand Total						TOTAL	8,065.9

Duty Cycle	Unit Type	Fuel type	
B-Base	H-Hydro	HS-Run of River	HR- Reservoir
I-Intermediate	D-Diesel	NG-Natural Gas	UR-Uranium
P-Peaking	N-Nuclear	O-Oil	L=Landfill Gas
	CT-Comb Turbine	C-Coal	W-Wind
	CC-Comb Cycle		
	F-Fossil		
	R-Renewable		

Appendix B: Committed, Planned, and Studied Resources

APPENDIX B

Committed, Planned and Studied Resources

Utility	Unit Name	New Existing	Committed	Planned	Studied	Duty Cycle	Unit Type	Fuel Type	Accredited Capacity	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Fremont	Future Base				S	B			24.0	0	0	0	0	0	0	0	0	0	24	24	24	24	24	24	24	24	24	24	24
Fremont	Total								24.0	0	0	0	0	0	0	0	0	0	24	24	24	24	24	24	24	24	24	24	24
LES	J St Uprate			P		P	CT	NG	3.3	0	0	0	0	0	0	0	0	3	3	3	3	3	3	3	3	3	3	3	3
	Rokeby Uprate			P		P	CT	NG	18.7	0	0	0	0	0	0	0	0	19	19	19	19	19	19	19	19	19	19	19	19
	Landfill Gas Generator		C			B	R	L	4.0	0	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	Future Base				S	B			82.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	19	39	59	82
LES	Total								108.0	0	4	4	4	4	4	4	4	26	26	26	26	26	26	26	26	45	65	85	108
MEAN	Future Base				S	B			60.0	0	0	0	0	0	0	0	0	0	0	0	0	60	60	60	60	60	60	60	60
MEAN	Total								60.0	0	0	0	0	0	0	0	0	0	0	0	0	60	60	60	60	60	60	60	60
NPPD	Broken Bow I		C			R	R	W	0.0	0	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
	Broken Bow II		C			R	R	W	0.0	0	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
	Crofton Bluffs		C			R	R	W	0.0	0	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
	CNS HP Turbine Replacement			P		B	N	UR	5.0	0	0	0	0	0	-22	-22	5	5	5	5	5	5	5	5	5	5	5	5	5
	CNS Extended Power Uprate			P		B	N	UR	141.0	0	0	0	0	0	0	0	141	141	141	141	141	141	141	141	141	141	141	141	141
	Future Renewable				S	R	R	W	0.0	0	0	0	0	0	100	100	200	200	200	200	200	200	250	250	250	250	250	250	250
	Future Peak				S	P			0.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Future Intermediate				S	I			0.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Future Base				S	B			0.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NPPD	Total								146.0	0	195	195	195	195	273	273	541	541	541	541	541	541	591	591	591	591	591	591	591
OPPD	Ft. Calhoun Uprate			P		B	N	UR	75.0	0	0	0	0	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
	Future Renewable				S	R	R	W	0.0	0	0	0	0	20	20	100	100	180	180	180	180	180	180	250	320	320	345	345	405
	Future Peak				S	P			320.0	0	0	0	0	1	0	7	41	81	145	199	255	304	320	320	320	320	320	320	320
	Future Intermediate				S	I			450.0	0	0	0	0	0	0	0	0	0	0	0	0	0	57	118	178	232	312	381	450
OPPD	Total								845.0	0	0	0	0	96	95	182	216	336	400	454	510	559	632	763	893	947	1052	1121	1250
	Nebraska Grand Total								1183	0	199	199	199	295	372	459	761	903	991	1045	1101	1210	1333	1464	1594	1667	1792	1881	2033

Unit Type	Fuel type
H-Hydro	HS-Run of River
D-Diesel	NG-Natural Gas
N-Nuclear	O-Oil
CT-Combustion Turbine	Coal-Coal
CC-Combined Cycle	HR-Reservoir
C-Pulverized Coal	UR-Uranium
R-Renewable	Wind-Wind
	L-Landfill Gas

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
New Existing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Committed	0	199	199	199	199	199	199	199	199	199	199	199	199	199	199	199	199	199	199	199
Planned	0	0	0	0	75	53	53	221	243	243	243	243	243	243	243	243	243	243	243	243
Future Renewable	0	0	0	0	20	120	200	300	380	380	380	380	380	430	500	570	570	595	595	655
Future Peak	0	0	0	0	1	0	7	41	81	145	199	255	304	320	320	320	320	320	320	320
Future Intermediate	0	0	0	0	0	0	0	0	0	0	0	0	0	57	118	178	232	312	381	450
Future Base	0	0	0	0	0	0	0	0	0	24	24	24	84	84	84	84	103	123	143	166
TOTAL	0	199	199	199	295	372	459	761	903	991	1045	1101	1210	1333	1464	1594	1667	1792	1881	2033

Appendix C: Renewable Resources

APPENDIX C
Renewable Resources

Utility	Unit Name	Existing	Committed	Planned	Studied	Unit Type	Fuel Type	Nameplae	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
LES	Lincoln	E				R	Wind	1.3	1.32	1.32	1.32	1.32	1.32	1.32	1.32	0	0	0	0	0	0	0	0	0	0	0	0	0
LES	Landfill Gas		C			R	L	4.0	0	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
MEAN	Kimball	E				R	Wind	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	0	0	0	0	0	0	0	0	0	0
NPPD	Ainsworth	E				R	Wind	59.4	59.4	59.4	59.4	59.4	59.4	59.4	59.4	59.4	59.4	59.4	59.4	59.4	59.4	59.4	0	0	0	0	0	0
NPPD	Elkhorn Ridge	E				R	Wind	80.0	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	0	0	0
NPPD	Laredo Ridge	E				R	Wind	80.0	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	0
NPPD	Springview	E				R	Wind	3.0	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
NPPD	Broken Bow I		C			R	Wind	80.0	0	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
NPPD	Broken Bow II		C			R	Wind	75.0	0	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
NPPD	Crofton Bluffs		C			R	Wind	40.0	0	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
NPPD	Future Renewable				S	R	Wind	250.0	0	0	0	0	0	100	100	200	200	200	200	200	200	250	250	250	250	250	250	250
OPPD	Elk City Landfill	E				R	L	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1
OPPD	Valley Wind Turbine	E				R	Wind	0.7	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0	0	0	0	0	0	0	0	0	0
OPPD	Flat Water Wind	E				R	Wind	60.0	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	0
OPPD	Petersburg Wind	E				R	Wind	40.5	40.5	40.5	40.5	40.5	40.5	40.5	40.5	40.5	40.5	40.5	40.5	40.5	40.5	40.5	40.5	40.5	40.5	40.5	40.5	40.5
OPPD	Future Renewable				S	R	Wind	405.0	0	0	0	0	20	20	100	100	180	180	180	180	180	180	250	320	320	345	345	405
	Nebraska Grand Total							1038.6	341	540	540	540	560	660	740	839	919	919	908	908	908	958	969	1039	1039	984	984	904

Unit Type	Fuel type
R-Renewable	Wind-Wind
	L-Landfill Gas

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Existing	341	341	341	341	341	341	341	340	340	340	329	329	329	329	270	270	270	190	190	50
Committed	0	199	199	199	199	199	199	199	199	199	199	199	199	199	199	199	199	199	199	199
Planned	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Studied	0	0	0	0	20	120	200	300	380	380	380	380	380	430	500	570	570	595	595	655
TOTAL	341	540	540	540	560	660	740	839	919	919	908	908	908	958	969	1039	1039	984	984	904

Appendix D: Statewide Capability vs. Obligation Tables

APPENDIX D
NEBRASKA STATEWIDE
Committed Load & Generating Capability in Megawatts
Summer Conditions (May 1 to October 31)

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	
1 Seasonal System Demand	6,810	6,929	7,029	7,097	7,177	7,276	7,366	7,462	7,539	7,642	7,742	7,838	7,932	8,046	8,154	8,258	8,362	8,487	8,601	8,719	1.31%
2 Annual System Demand	6,810	6,929	7,029	7,097	7,177	7,276	7,366	7,462	7,539	7,642	7,742	7,838	7,932	8,046	8,154	8,258	8,362	8,487	8,601	8,719	
3 Firm Purchases - Total	1,124	1,130	1,135	1,138	1,141	1,144	1,147	1,149	1,149	1,149	1,150	1,150	1,153	1,154	1,153	1,152	1,152	1,151	1,150	1,149	
4 Firm Sales - Total	117	117	117	117	117	117	117	118	118	118	118	118	118	119	119	119	119	119	119	120	
5 Seasonal Adjusted Net Demand (1-3+4)	5,803	5,916	6,011	6,076	6,153	6,249	6,336	6,431	6,508	6,611	6,711	6,806	6,897	7,010	7,120	7,225	7,329	7,455	7,570	7,690	
6 Annual Adjusted Net Demand (2-3+4)	5,803	5,916	6,011	6,076	6,153	6,249	6,336	6,431	6,508	6,611	6,711	6,806	6,897	7,010	7,120	7,225	7,329	7,455	7,570	7,690	
7 Net Generating Capability (owned)	8,066	8,052	7,994	7,994	7,976	7,976	7,976	7,976	7,976	7,976	7,986	7,986	7,986	7,986	7,986	7,996	7,996	7,996	8,006	8,006	
8 Participation Purchase -Total	659	656	655	653	650	648	646	647	647	647	648	648	599	599	599	600	600	601	601	602	
9 Participation Sales -Total	1,069	1,049	894	889	884	879	839	819	819	819	819	819	769	769	769	769	769	769	769	769	
10 Adjusted Net Capability (7+8-9)	7,656	7,659	7,754	7,757	7,742	7,744	7,783	7,803	7,803	7,804	7,815	7,815	7,815	7,816	7,816	7,827	7,827	7,828	7,838	7,838	
11 Net Reserve Capacity Obligation (6 x 0.136)	791	807	820	828	839	852	864	877	888	902	915	928	941	956	971	985	999	1,017	1,032	1,049	
12 Total Firm Capacity Obligation (5+11)	6,594	6,723	6,831	6,904	6,992	7,101	7,200	7,308	7,396	7,513	7,626	7,734	7,838	7,966	8,091	8,210	8,328	8,472	8,602	8,739	
13 Surplus or Deficit (-) Capacity @ Minimum Obligation (10-12)	1,062	936	923	853	750	643	583	495	407	291	189	81	-23	-150	-275	-383	-501	-644	-764	-901	
14 Reserve Margin ((10-6)/6)	31.9%	29.5%	29.0%	27.7%	25.8%	23.9%	22.8%	21.3%	19.9%	18.0%	16.5%	14.8%	13.3%	11.5%	9.8%	8.3%	6.8%	5.0%	3.5%	1.9%	
15 Capacity Margin ((10-6)/10)	24.2%	22.8%	22.5%	21.7%	20.5%	19.3%	18.6%	17.6%	16.6%	15.3%	14.1%	12.9%	11.7%	10.3%	8.9%	7.7%	6.4%	4.8%	3.4%	1.9%	

APPENDIX D
NEBRASKA STATEWIDE
Committed, Planned & Studied Load & Generating Capability in Megawatts
Summer Conditions (May 1 to October 31)

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1 Seasonal System Demand	6,810	6,929	7,029	7,097	7,177	7,276	7,366	7,462	7,539	7,642	7,742	7,838	7,932	8,046	8,154	8,258	8,362	8,487	8,601	8,719
2 Annual System Demand	6,810	6,929	7,029	7,097	7,177	7,276	7,366	7,462	7,539	7,642	7,742	7,838	7,932	8,046	8,154	8,258	8,362	8,487	8,601	8,719
3 Firm Purchases - Total	1,124	1,130	1,135	1,138	1,141	1,144	1,147	1,149	1,149	1,149	1,150	1,150	1,153	1,154	1,153	1,152	1,152	1,151	1,150	1,149
4 Firm Sales - Total	117	117	117	117	117	117	117	118	118	118	118	118	118	119	119	119	119	119	119	120
5 Seasonal Adjusted Net Demand (1-3+4)	5,803	5,916	6,011	6,076	6,153	6,249	6,336	6,431	6,508	6,611	6,711	6,806	6,897	7,010	7,120	7,225	7,329	7,455	7,570	7,690
6 Annual Adjusted Net Demand (2-3+4)	5,803	5,916	6,011	6,076	6,153	6,249	6,336	6,431	6,508	6,611	6,711	6,806	6,897	7,010	7,120	7,225	7,329	7,455	7,570	7,690
7 Net Generating Capability (owned)	8,066	8,052	7,994	7,994	8,052	8,029	8,036	8,238	8,300	8,388	8,452	8,508	8,617	8,690	8,751	8,821	8,894	8,994	9,093	9,185
8 Participation Purchase -Total	659	656	655	653	650	648	646	647	647	647	648	648	599	599	599	600	600	601	601	602
9 Participation Sales -Total	1,069	1,049	894	889	884	879	839	819	819	819	819	819	769	769	769	769	769	769	769	769
10 Adjusted Net Capability (7+8-9)	7,656	7,659	7,754	7,757	7,818	7,797	7,843	8,065	8,127	8,216	8,281	8,337	8,446	8,520	8,581	8,652	8,725	8,826	8,925	9,017
11 Net Reserve Capacity Obligation (6 x 0.136)	791	807	820	828	839	852	864	877	888	902	915	928	941	956	971	985	999	1,017	1,032	1,049
12 Total Firm Capacity Obligation (5+11)	6,594	6,722	6,831	6,904	6,992	7,101	7,200	7,308	7,396	7,513	7,626	7,734	7,838	7,966	8,090	8,210	8,329	8,472	8,602	8,738
13 Surplus or Deficit (-) Capacity @ Minimum Obligation (10-12)	1,062	936	923	853	826	696	642	757	731	703	655	603	609	554	491	441	397	354	323	279
14 Reserve Margin ((10-6)/6)	31.9%	29.5%	29.0%	27.7%	27.1%	24.8%	23.8%	25.4%	24.9%	24.3%	23.4%	22.5%	22.5%	21.5%	20.5%	19.7%	19.0%	18.4%	17.9%	17.3%
15 Capacity Margin ((10-6)/10)	24.2%	22.8%	22.5%	21.7%	21.3%	19.9%	19.2%	20.3%	19.9%	19.5%	19.0%	18.4%	18.3%	17.7%	17.0%	16.5%	16.0%	15.5%	15.2%	14.7%

Auburn Board of Public Works

Committed, Planned & Studied Load & Generating Capability in Megawatts

Summer Conditions (May 1 to October 31)

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	
1 Seasonal System Demand	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	0.00%
2 Annual System Demand	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	
3 Firm Purchases - Total	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	
4 Firm Sales - Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Seasonal Adjusted Net Demand (1-3+4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
6 Annual Adjusted Net Demand (2-3+4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
7 Net Generating Capability (owned)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
8 Participation Purchase -Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
9 Participation Sales -Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
10 Adjusted Net Capability (7+8-9)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
11 Net Reserve Capacity Obligation (6 x .136)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
12 Total Firm Capacity Obligation (5+11)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
13 Surplus or Deficit (-) Capacity @ Minimum Obligation (10-12)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	

Auburn Board of Public Works
Seasonal Purchases and Sales in Megawatts
Summer Conditions (May 1 to October 31)

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
FIRM PURCHASES																				
WAPA Firm	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Total Firm Purchases	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
FIRM SALES																				
none	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PARTICIPATION PURCHASES																				
None	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Participation Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PARTICIPATION SALES																				
None	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Participation Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Falls City Utilities
Committed, Planned & Studied Load & Generating Capability in Megawatts
Summer Conditions (May 1 to October 31)

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	
1 Seasonal System Demand	14	14	15	15	15	15	15	15	15	16	16	16	16	16	16	17	17	17	17	17	1.00%
2 Annual System Demand	14	14	15	15	15	15	15	15	15	16	16	16	16	16	16	17	17	17	17	17	
3 Firm Purchases - Total	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	
4 Firm Sales - Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Seasonal Adjusted Net Demand (1-3+4)	11	11	11	12	12	12	12	12	12	13	13	13	13	13	13	13	14	14	14	14	
6 Annual Adjusted Net Demand (2-3+4)	11	11	11	12	12	12	12	12	12	13	13	13	13	13	13	13	14	14	14	14	
7 Net Generating Capability (owned)	20	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	
8 Participation Purchase -Total	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	
9 Participation Sales -Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
10 Adjusted Net Capability (7+8-9)	26	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	
11 Net Reserve Capacity Obligation (6 x .136)	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	
12 Total Firm Capacity Obligation (5+11)	13	13	13	13	13	14	14	14	14	14	14	15	15	15	15	15	16	16	16	16	
13 Surplus or Deficit (-) Capacity @ Minimum Obligation (10-12)	13	5	5	5	5	4	4	4	4	4	3	3	3	3	3	3	2	2	2	2	
14 Reserve Margin (10/6)	133.1%	57.8%	55.8%	53.9%	51.9%	50.1%	48.2%	46.4%	44.5%	42.8%	41.0%	39.3%	37.6%	35.9%	34.3%	32.6%	31.0%	29.4%	27.9%	26.3%	
15 Capacity Margin ((10-6)/10)	57.1%	36.6%	35.8%	35.0%	34.2%	33.4%	32.5%	31.7%	30.8%	30.0%	29.1%	28.2%	27.3%	26.4%	25.5%	24.6%	23.7%	22.7%	21.8%	20.8%	

Falls City Utilities
Seasonal Purchases and Sales and Generation in Megawatts
Summer Conditions (May 1 to October 31)

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Firm Purchases																				
WAPA Firm	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Total Firm Purchases	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Firm Sales																				
none	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Participation Purchases																				
OPPD NC#2 Purchase	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Total Participation Purchases	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Participation Sales																				
OPPD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peaking Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Participation Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION																				
Existing	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Emergency	0	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2
Future Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Intermediate	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Baseload	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Generation	20	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12

Fremont Department of Utilities
Committed, Planned & Studied Load & Generating Capability in Megawatts
Summer Conditions (May 1 to October 31)

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	
1 Seasonal System Demand	96	97	97	98	99	100	101	102	103	104	106	107	108	109	110	111	112	113	114	115	1.00%
2 Annual System Demand	96	97	97	98	99	100	101	102	103	104	106	107	108	109	110	111	112	113	114	115	
3 Firm Purchases - Total	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	
4 Firm Sales - Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Seasonal Adjusted Net Demand (1-3+4)	91	92	93	94	95	96	97	98	99	100	101	102	103	104	105	106	107	109	110	111	
6 Annual Adjusted Net Demand (2-3+4)	91	92	93	94	95	96	97	98	99	100	101	102	103	104	105	106	107	109	110	111	
7 Net Generating Capability (owned)	157	157	153	153	153	153	153	153	153	177	177	177	177	177	177	177	177	177	177	177	
8 Participation Purchase -Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
9 Participation Sales -Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
10 Adjusted Net Capability (7+8-9)	157	157	153	153	153	153	153	153	153	177	177	177	177	177	177	177	177	177	177	177	
11 Net Reserve Capacity Obligation (6 x .136)	12	13	13	13	13	13	13	13	13	14	14	14	14	14	14	14	15	15	15	15	
12 Total Firm Capacity Obligation (5+11)	103	104	106	107	108	109	110	111	112	114	115	116	117	118	120	121	122	123	125	126	
13 Surplus or Deficit (-) Capacity @ Minimum Obligation (10-12)	54	53	48	46	45	44	43	42	41	64	62	61	60	59	58	56	55	54	52	51	
14 Reserve Margin (10/6)	72.7%	70.9%	64.9%	63.1%	61.5%	59.8%	58.1%	56.5%	54.9%	77.3%	75.4%	73.6%	71.8%	70.1%	68.3%	66.6%	64.8%	63.1%	61.5%	59.8%	
15 Capacity Margin ((10-6)/10)	42.1%	41.5%	39.3%	38.7%	38.1%	37.4%	36.8%	36.1%	35.4%	43.6%	43.0%	42.4%	41.8%	41.2%	40.6%	40.0%	39.3%	38.7%	38.1%	37.4%	

Fremont Department of Utilities
Seasonal Purchases and Sales and Generation in Megawatts
<u>Summer Conditions (May 1 to October 31)</u>

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
FIRM PURCHASES																				
WAPA Firm	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Total Firm Purchases	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
FIRM SALES																				
none	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PARTICIPAITON PURCHASES																				
none	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Participation Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PARTICIPAITON SALES																				
none	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Participation Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION																				
Fremont Unit 6	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Fremont Unit 7	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
Fremont Unit 8	85	85	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81
Fremont CT	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
Future Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Intermediate	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Baseload	0	0	0	0	0	0	0	0	0	24	24	24	24	24	24	24	24	24	24	24
Total	157	157	153	153	153	153	153	153	153	177	177	177	177	177	177	177	177	177	177	177

Grand Island Utilities
Committed, Planned & Studied Load & Generating Capability in Megawatts
Summer Conditions (May 1 to October 31)

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	
1 Seasonal System Demand	170	172	174	176	179	181	183	185	187	190	192	194	196	199	201	204	206	209	211	214	1.21%
2 Annual System Demand	170	172	174	176	179	181	183	185	187	190	192	194	196	199	201	204	206	209	211	214	
3 Firm Purchases - Total	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	
4 Firm Sales - Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Seasonal Adjusted Net Demand (1-3+4)	161	163	165	167	169	172	174	176	178	180	183	185	187	190	192	195	197	200	202	205	
6 Annual Adjusted Net Demand (2-3+4)	161	163	165	167	169	172	174	176	178	180	183	185	187	190	192	195	197	200	202	205	
7 Net Generating Capability (owned)	273	273	273	273	273	273	273	273	273	273	273	273	273	273	273	273	273	273	273	273	
8 Participation Purchase -Total	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	
9 Participation Sales -Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
10 Adjusted Net Capability (7+8-9)	322	322	322	322	322	322	322	322	322	322	322	322	322	322	322	322	322	322	322	322	
11 Net Reserve Capacity Obligation (6 x .136)	22	22	23	23	23	23	24	24	24	25	25	25	26	26	26	27	27	27	28	28	
12 Total Firm Capacity Obligation (5+11)	183	185	188	190	192	195	197	200	202	205	208	210	213	216	218	221	224	227	230	233	
13 Surplus or Deficit (-) Capacity @ Minimum Obligation (10-12)	139	137	135	132	130	127	125	122	120	117	115	112	109	107	104	101	98	95	92	89	
14 Reserve Margin (10/6)	100.1%	97.6%	95.1%	92.7%	90.3%	87.9%	85.5%	83.2%	80.9%	78.7%	76.4%	74.2%	72.1%	69.9%	67.7%	65.6%	63.4%	61.4%	59.3%	57.3%	
15 Capacity Margin ((10-6)/10)	50.0%	49.4%	48.7%	48.1%	47.4%	46.8%	46.1%	45.4%	44.7%	44.0%	43.3%	42.6%	41.9%	41.1%	40.4%	39.6%	38.8%	38.0%	37.2%	36.4%	

Grand Island Utilities
Seasonal Purchases and Sales and Generation In Megawatts
Summer Conditions (May 1 to October 31)

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Firm Purchases																				
WAPA	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Total Firm Purchases	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Firm Sales																				
None	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Participation Purchases																				
OPPD NC#2 Purchase	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
Hastings WEC#2 Purchase	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Total Participation Purchases	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49
Participation Sales																				
Peaking Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Participation Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION																				
Existing	273	273	273	273	273	273	273	273	273	273	273	273	273	273	273	273	273	273	273	273
Future Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Intermediate	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Baseload	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	273	273	273	273	273	273	273	273	273	273	273	273	273	273	273	273	273	273	273	273

Hastings Utilities
Committed, Planned & Studied Load & Generating Capability in Megawatts
Summer Conditions (May 1 to October 31)

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	
1 Seasonal System Demand	100	102	103	105	107	108	110	112	114	115	117	119	121	123	125	127	129	131	133	135	1.6%
2 Annual System Demand	100	102	103	105	107	108	110	112	114	115	117	119	121	123	125	127	129	131	133	135	
3 Firm Purchases - Total	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	
4 Firm Sales - Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Seasonal Adjusted Net Demand (1-3+4)	89	90	92	94	95	97	99	100	102	104	106	108	110	112	114	116	118	120	122	124	
6 Annual Adjusted Net Demand (2-3+4)	89	90	92	94	95	97	99	100	102	104	106	108	110	112	114	116	118	120	122	124	
7 Net Generating Capability (owned)	353	353	353	353	353	353	353	353	353	353	353	353	353	353	353	353	353	353	353	353	
8 Participation Purchase -Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
9 Participation Sales -Total	220	215	210	205	200	195	190	190	190	190	190	190	190	190	190	190	190	190	190	190	
10 Adjusted Net Capability (7+8-9)	133	138	143	148	153	158	163	163	163	163	163	163	163	163	163	163	163	163	163	163	
11 Net Reserve Capacity Obligation (6 x .136)	12	12	13	13	13	13	13	14	14	14	14	15	15	15	15	16	16	16	17	17	
12 Total Firm Capacity Obligation (5+11)	101	103	104	106	108	110	112	114	116	118	120	122	125	127	129	131	134	136	138	141	
13 Surplus or Deficit (-) Capacity @ Minimum Obligation (10-12)	32	35	38	41	44	48	51	49	47	44	42	40	38	36	34	31	29	27	24	22	
14 Reserve Margin (10/6)	49.6%	52.5%	55.3%	57.9%	60.3%	62.7%	64.9%	62.0%	59.2%	56.4%	53.6%	51.0%	48.3%	45.8%	43.2%	40.8%	38.3%	36.0%	33.6%	31.3%	
15 Capacity Margin ((10-6)/10)	33.2%	34.4%	35.6%	36.7%	37.6%	38.5%	39.4%	38.3%	37.2%	36.1%	34.9%	33.8%	32.6%	31.4%	30.2%	29.0%	27.7%	26.4%	25.2%	23.8%	

Hastings Utilities
Seasonal Purchases and Sales and Generation in Megawatts
Summer Conditions (May 1 to October 31)

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Firm Purchases																				
WAPA Firm	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Total Firm Purchases	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Firm Sales																				
None	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Participation Purchases																				
None	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Participation Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Participation Sales																				
MEAN	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
NPPD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MEAN WEC#2	95	92	90	88	85	82	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Grand Island WEC#2	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Nebraska City Utilities WEC#2	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Out of State-WEC#2	95	93	90	87	85	83	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Total Participation Sales	220	215	210	205	200	195	190	190	190	190	190	190	190	190	190	190	190	190	190	190
GENERATION																				
Existing	133	133	133	133	133	133	133	133	133	133	133	133	133	133	133	133	133	133	133	133
Whelan Energy Center #2	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220
Future Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Intermediate	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Baseload	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	353	353	353	353	353	353	353	353	353	353	353	353	353	353	353	353	353	353	353	353

Lincoln Electric System
Committed, Planned & Studied Load & Generating Capability in Megawatts
Summer Conditions (May 1 to October 31)

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	
1 Seasonal System Demand	758	769	786	792	797	807	814	826	834	846	862	873	885	898	917	933	953	971	988	1,009	1.52%
2 Annual System Demand	758	769	786	792	797	807	814	826	834	846	862	873	885	898	917	933	953	971	988	1,009	
3 Firm Purchases - Total	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	
4 Firm Sales - Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Seasonal Adjusted Net Demand (1-3+4)	631	642	659	665	670	680	687	699	707	719	735	746	758	771	790	806	826	844	861	882	
6 Annual Adjusted Net Demand (2-3+4)	631	642	659	665	670	680	687	699	707	719	735	746	758	771	790	806	826	844	861	882	
7 Net Generating Capability (owned)	727	731	731	731	731	731	731	731	753	754	754	754	754	754	754	754	773	793	813	836	
8 Participation Purchase -Total	227	227	227	227	227	227	227	227	227	227	227	227	227	227	227	227	227	227	227	227	
9 Participation Sales -Total	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	
10 Adjusted Net Capability (7+8-9)	894	898	898	898	898	898	898	898	920	920	920	920	920	920	920	920	939	959	979	1,002	
11 Net Reserve Capacity Obligation (6 x .136)	86	88	90	91	91	93	94	95	96	98	100	102	103	105	108	110	113	115	117	120	
12 Total Firm Capacity Obligation (5+11)	718	730	749	756	762	773	781	795	804	818	836	848	862	877	898	916	939	960	979	1,003	
13 Surplus or Deficit (-) Capacity @ Minimum Obligation (10-12)	176	168	149	142	136	125	117	103	116	103	85	72	59	44	22	4	0	0	0	0	
14 Reserve Margin (10/6)	41.6%	39.8%	36.2%	35.0%	33.9%	32.0%	30.6%	28.4%	30.0%	27.9%	25.1%	23.3%	21.4%	19.3%	16.4%	14.1%	13.7%	13.6%	13.7%	13.6%	
15 Capacity Margin ((10-6)/10)	29.4%	28.5%	26.6%	25.9%	25.3%	24.2%	23.4%	22.1%	23.1%	21.8%	20.1%	18.9%	17.6%	16.2%	14.1%	12.4%	12.0%	12.0%	12.0%	12.0%	

Lincoln Electric System
Seasonal Purchases and Sales in Megawatts
Summer Conditions (May 1 to October 31)

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
FIRM PURCHASES																				
WAPA Firm	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33
WAPA Peaking	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
WAPA Class II	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
Total Firm Purchases	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127
FIRM SALES																				
None	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PARTICIPATION PURCHASES																				
NPPD - GGS	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109
NPPD - SHELDON	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68
NPPD - ELKHORN RIDGE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NPPD - LAREDO RIDGE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NPPD - BROKEN BOW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NPPD - CROFTON HILLS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MEC - WSEC3	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Total Participation Purchases	227	227	227	227	227	227	227	227	227	227	227	227	227	227	227	227	227	227	227	227
PARTICIPATION SALES																				
Los Alamos	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
MEC - WSEC4	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Total Participation Sales	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60

Lincoln Electric System
Generation in Megawatts
Summer Conditions (May 1 to October 31)

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
GENERATION																				
Laramie	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189
J St	27	27	27	27	27	27	27	27	30	30	30	30	30	30	30	30	30	30	30	30
Rokeby 1	63	63	63	63	63	63	63	63	74	74	74	74	74	74	74	74	74	74	74	74
Rokeby 2	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86
Rokeby 3	89	89	89	89	89	89	89	89	97	97	97	97	97	97	97	97	97	97	97	97
TBS CT1/CC1	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120
TBS CT 3	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47
WSEC4	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101
Rokeby Black Start	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
TBS Black Start	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Landfill Gas Generator	0	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Future Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Intermediate	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Baseload	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	19	39	59	82
Total	727	731	731	731	731	731	731	731	753	754	754	754	754	754	754	754	773	793	813	836
Change in Existing		0	0	0	0	0	0	0	22	0	0	0	0	0	0	0	0	0	0	0

Municipal Energy Agency Of Nebraska
Committed, Planned & Studied Load & Generating Capability in Megawatts
Summer Conditions (May 1 to October 31)

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	
1 Seasonal System Demand	206	210	213	216	219	222	226	229	233	236	240	243	247	250	254	258	262	266	270	274	1.50%
2 Annual System Demand	206	210	213	216	219	222	226	229	233	236	240	243	247	250	254	258	262	266	270	274	
3 Firm Purchases - Total	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	
4 Firm Sales - Total	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	
5 Seasonal Adjusted Net Demand (1-3+4)	259	262	265	268	271	274	278	281	285	288	292	295	299	303	306	310	314	318	322	326	
6 Annual Adjusted Net Demand (2-3+4)	259	262	265	268	271	274	278	281	285	288	292	295	299	303	306	310	314	318	322	326	
7 Net Generating Capability (owned)	146	146	146	146	146	146	146	146	146	146	156	156	216	216	216	226	226	226	236	236	
8 Participation Purchase -Total	194	191	190	188	185	183	181	181	182	182	183	183	134	134	134	135	135	136	136	137	
9 Participation Sales -Total	30	30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
10 Adjusted Net Capability (7+8-9)	310	308	336	334	332	329	328	328	328	329	339	340	350	350	351	361	362	362	373	373	
11 Net Reserve Capacity Obligation (6 x .136)	35	36	36	37	37	37	38	38	39	39	40	40	41	41	42	42	43	43	44	44	
12 Total Firm Capacity Obligation (5+11)	294	297	301	305	308	312	316	320	323	327	331	336	340	344	348	352	357	361	366	370	
13 Surplus or Deficit (-) Capacity @ Minimum Obligation (10-12)	17	10	35	30	24	17	12	8	5	1	8	4	10	6	3	9	5	1	7	3	
14 Reserve Margin (10/6)	20.0%	17.6%	26.9%	24.8%	22.3%	19.9%	17.9%	16.6%	15.3%	14.1%	16.3%	15.0%	17.1%	15.8%	14.5%	16.5%	15.2%	13.9%	15.7%	14.4%	
15 Capacity Margin ((10-6)/10)	16.7%	15.0%	21.2%	19.9%	18.3%	16.6%	15.2%	14.2%	13.3%	12.3%	14.0%	13.0%	14.6%	13.6%	12.7%	14.1%	13.2%	12.2%	13.6%	12.6%	

Municipal Energy Agency Of Nebraska
Seasonal Purchases and Sales and Generation in Megawatts
Summer Conditions (May 1 to October 31)

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
FIRM PURCHASES																				
WAPA - UGPR	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
WAPA - LAP	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32
Total Firm Purchases	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
FIRM SALES																				
WAPA Swap	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
CB4 Iowa Loads	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
Total Firm Sales	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104
PARTICIPATION PURCHASES																				
MEAN Wside Import	44	44	44	45	45	45	46	46	47	47	47	48	48	49	49	50	50	50	51	51
Hastings	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Hastings WEC#2 Purchase	95	92	90	88	85	82	80	80	80	80	80	80	80	80	80	80	80	80	80	80
NPPD	50	50	50	50	50	50	50	50	50	50	50	50	0	0	0	0	0	0	0	0
Total Participation Purchases	194	191	190	188	185	183	181	181	182	182	183	183	134	134	134	135	135	136	136	137
PARTICIPATION SALES																				
Basin Electric Power Cooperative	30	30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Participation Sales	30	30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Municipal Energy Agency Of Nebraska
Seasonal Purchases and Sales and Generation in Megawatts
Summer Conditions (May 1 to October 31)

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
GENERATION																				
Ansley	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Arnold	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Beaver City	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Benklemen	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Blue Hill	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Broken Bow	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Burwell	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Callaway	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Chappell	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Crete	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Curtis	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Fairbury	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Kimball	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Oxford	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Pender	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Red Cloud	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Sargent	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Sidney	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Stuart	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
West Point	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
LRS	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
CB4	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Future Peaking	0	0	0	0	0	0	0	0	0	0	10	10	10	10	10	20	20	20	30	30
Future Intermediate	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Baseload	0	0	0	0	0	0	0	0	0	0	0	0	60	60	60	60	60	60	60	60
Total	146	146	146	146	146	146	146	146	146	146	156	156	216	216	216	226	226	226	236	236

Nebraska Public Power District
Committed, Planned & Studied Load & Generating Capability in Megawatts
Summer Conditions (May 1 to October 31)

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	
1 Seasonal System Demand	2,698	2,721	2,747	2,771	2,795	2,819	2,842	2,868	2,894	2,920	2,946	2,973	2,999	3,026	3,053	3,079	3,106	3,134	3,161	3,188	0.88%
2 Annual System Demand	2,698	2,721	2,747	2,771	2,795	2,819	2,842	2,868	2,894	2,920	2,946	2,973	2,999	3,026	3,053	3,079	3,106	3,134	3,161	3,188	
3 Firm Purchases - Total	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	
4 Firm Sales - Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Seasonal Adjusted Net Demand (1-3+4)	2,247	2,270	2,296	2,321	2,344	2,368	2,392	2,418	2,444	2,470	2,496	2,522	2,549	2,575	2,602	2,629	2,656	2,683	2,710	2,738	
6 Annual Adjusted Net Demand (2-3+4)	2,247	2,270	2,296	2,321	2,344	2,368	2,392	2,418	2,444	2,470	2,496	2,522	2,549	2,575	2,602	2,629	2,656	2,683	2,710	2,738	
7 Net Generating Capability (owned)	3,136	3,136	3,082	3,082	3,082	3,060	3,060	3,228	3,228	3,228	3,228	3,228	3,228	3,228	3,228	3,228	3,228	3,228	3,228	3,228	
8 Participation Purchase -Total	162	162	162	162	162	162	162	162	162	162	162	162	162	162	162	162	162	162	162	162	
9 Participation Sales -Total	347	347	227	227	227	227	227	227	227	227	227	227	177	177	177	177	177	177	177	177	
10 Adjusted Net Capability (7+8-9)	2,952	2,952	3,018	3,018	3,018	2,996	2,996	3,164	3,164	3,164	3,164	3,164	3,214	3,214	3,214	3,214	3,214	3,214	3,214	3,214	
11 Net Reserve Capacity Obligation (6 x .136)	306	310	313	316	320	323	326	330	333	337	340	344	348	351	355	358	362	366	370	373	
12 Total Firm Capacity Obligation (5+11)	2,553	2,580	2,610	2,637	2,664	2,691	2,718	2,747	2,777	2,806	2,836	2,866	2,896	2,926	2,957	2,987	3,018	3,049	3,080	3,111	
13 Surplus or Deficit (-) Capacity @ Minimum Obligation (10-12)	398	372	408	380	353	304	277	416	387	357	327	297	317	287	257	226	195	165	133	102	
14 Reserve Margin (10/6)	31.4%	30.0%	31.4%	30.0%	28.7%	26.5%	25.2%	30.8%	29.5%	28.1%	26.8%	25.4%	26.1%	24.8%	23.5%	22.2%	21.0%	19.8%	18.6%	17.4%	
15 Capacity Margin ((10-6)/10)	23.9%	23.1%	23.9%	23.1%	22.3%	20.9%	20.1%	23.6%	22.8%	21.9%	21.1%	20.3%	20.7%	19.9%	19.0%	18.2%	17.4%	16.5%	15.7%	14.8%	

Nebraska Public Power District
Seasonal Purchases and Sales and Generation in Megawatts
Summer Conditions (May 1 to October 31)

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
FIRM PURCHASES																				
Tribal	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07
BEAT	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75
WALM	3.85	3.85	3.85	3.81	3.81	3.81	3.81	3.81	3.81	3.81	3.81	3.81	3.81	3.81	3.81	3.81	3.81	3.81	3.81	3.81
WAPA Pattern	152.30	152.30	152.30	152.30	152.30	152.30	152.30	152.30	152.30	152.30	152.30	152.30	152.30	152.30	152.30	152.30	152.30	152.30	152.30	152.30
WAPA Peaking	287.53	287.53	287.53	287.53	287.53	287.53	287.53	287.53	287.53	287.53	287.53	287.53	287.53	287.53	287.53	287.53	287.53	287.53	287.53	287.53
Total Firm Purchases	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451	451
FIRM SALES																				
none	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PARTICIPATION PURCHASES																				
OPPD NC#2 Purchase	162	162	162	162	162	162	162	162	162	162	162	162	162	162	162	162	162	162	162	162
Total Participation Purchases	162	162	162	162	162	162	162	162	162	162	162	162	162	162	162	162	162	162	162	162
PARTICIPATION SALES																				
NPPD - CNS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NPPD - GGS	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109
NPPD - SHELDON	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68
Out of State - CNS	120	120	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Out of State - Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Out of State - GGS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
System Sales	50	50	50	50	50	50	50	50	50	50	50	50	0	0	0	0	0	0	0	0
Total Participation Sales	347	347	227	227	227	227	227	227	227	227	227	227	177	177	177	177	177	177	177	177
GENERATION																				
Existing	3,136	3,136	3,082	3,082	3,082	3,060	3,060	3,228	3,228	3,228	3,228	3,228	3,228	3,228	3,228	3,228	3,228	3,228	3,228	3,228
Future Renewable	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Intermediate	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Baseload	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	3,136	3,136	3,082	3,082	3,082	3,060	3,060	3,228	3,228	3,228	3,228	3,228	3,228	3,228	3,228	3,228	3,228	3,228	3,228	3,228

Nebraska City Utilities
Committed, Planned & Studied Load & Generating Capability in Megawatts
Summer Conditions (May 1 to October 31)

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1 Seasonal System Demand	38	38	38	39	39	39	39	39	39	40
2 Annual System Demand	38	38	38	39	39	39	39	39	39	40
3 Firm Purchases - Total	8	8	8	8	8	8	8	8	8	8
4 Firm Sales - Total	0	0	0	0	0	0	0	0	0	0
5 Seasonal Adjusted Net Demand (1-3+4)	30	30	30	30	30	31	31	31	31	31
6 Annual Adjusted Net Demand (2-3+4)	30	30	30	30	30	31	31	31	31	31
7 Net Generating Cap-ability (owned)	37	27	27	27	27	27	27	27	27	27
8 Participation Purchase -Total	21	21	21	21	21	21	21	21	21	21
9 Participation Sales -Total	0	0	0	0	0	0	0	0	0	0
10 Adjusted Net Capability (7+8-9)	59	49	49	49	49	49	49	49	49	49
11 Net Reserve Capacity Obligation (6 x .136)	4	4	4	4	4	4	4	4	4	4
12 Total Firm Capacity Obligation (5+11)	34	34	34	34	35	35	35	35	36	36
13 Surplus or Deficit (-) Capacity @ Minimum Obligation (10-12)	25	15	14	14	14	14	13	13	13	13
14 Reserve Margin (10/6)	97.1%	62.4%	61.4%	60.3%	59.3%	58.3%	57.3%	56.3%	55.3%	54.4%
15 Capacity Margin ((10-6)/10)	49.3%	38.4%	38.0%	37.6%	37.2%	36.8%	36.4%	36.0%	35.6%	35.2%

Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	
1 Seasonal System Demand	40	40	40	40	41	41	41	41	42	42	0.50%
2 Annual System Demand	40	40	40	40	41	41	41	41	42	42	
3 Firm Purchases - Total	8	8	8	8	8	8	8	8	8	8	
4 Firm Sales - Total	0	0	0	0	0	0	0	0	0	0	
5 Seasonal Adjusted Net Demand (1-3+4)	32	32	32	32	32	33	33	33	33	33	
6 Annual Adjusted Net Demand (2-3+4)	32	32	32	32	32	33	33	33	33	33	
7 Net Generating Cap-ability (owned)	27	27	27	27	27	27	27	27	27	27	
8 Participation Purchase -Total	21	21	21	21	21	21	21	21	21	21	
9 Participation Sales -Total	0	0	0	0	0	0	0	0	0	0	
10 Adjusted Net Capability (7+8-9)	49	49	49	49	49	49	49	49	49	49	
11 Net Reserve Capacity Obligation (6 x .136)	4	4	4	4	4	4	4	5	5	5	
12 Total Firm Capacity Obligation (5+11)	36	36	36	37	37	37	37	38	38	38	
13 Surplus or Deficit (-) Capacity @ Minimum Obligation (10-12)	13	12	12	12	12	11	11	11	11	11	
14 Reserve Margin (10/6)	53.4%	52.4%	51.5%	50.5%	49.6%	48.7%	47.7%	46.8%	45.9%	45.0%	
15 Capacity Margin ((10-6)/10)	34.8%	34.4%	34.0%	33.6%	33.2%	32.7%	32.3%	31.9%	31.5%	31.0%	

Nebraska City Utilities
Seasonal Purchases and Sales and Generation in Megawatts
Summer Conditions (May 1 to October 31)

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
FIRM PURCHASES																				
WAPA Firm	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Total Firm Purchases	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
FIRM SALES																				
none	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PARTICIPATION PURCHASES																				
OPPD NC#2 Purchase	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Hastings WEC#2 Purchase	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Total Participation Purchases	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
PARTICIPATION SALES																				
none	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Participation Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATION																				
Existing	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37
Emergency	0	-10	-10	-10	-10	-10	-10	-10	-10	-10	-10	-10	-10	-10	-10	-10	-10	-10	-10	-10
Future Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Intermediate	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Baseload	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Generation	37	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27

Omaha Public Power District
Committed, Planned & Studied Load & Generating Capability in Megawatts
Summer Conditions (May 1 to October 31)

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1 Seasonal System Demand	2,353	2,424	2,468	2,494	2,534	2,588	2,636	2,683	2,718	2,774
2 Annual System Demand	2,353	2,424	2,468	2,494	2,534	2,588	2,636	2,683	2,718	2,774
3 Firm Purchases - Total	82	82	82	82	82	82	82	82	82	82
4 Firm Sales - Total	13	13	13	13	13	13	13	14	14	14
5 Seasonal Adjusted Net Demand (1-3+4)	2,284	2,355	2,399	2,425	2,465	2,519	2,567	2,615	2,650	2,706
6 Annual Adjusted Net Demand (2-3+4)	2,284	2,355	2,399	2,425	2,465	2,519	2,567	2,615	2,650	2,706
7 Net Generating Cap-ability (owned)	3,215	3,215	3,215	3,215	3,273	3,272	3,279	3,313	3,353	3,417
8 Participation Purchase -Total	0	0	0	0	0	0	0	0	0	0
9 Participation Sales -Total	412	397	397	397	397	397	362	342	342	342
10 Adjusted Net Capability (7+8-9)	2,803	2,818	2,818	2,818	2,876	2,875	2,917	2,971	3,011	3,075
11 Net Reserve Capacity Obligation (6 x .136)	311	321	327	331	336	344	350	357	361	369
12 Total Firm Capacity Obligation (5+11)	2,595	2,676	2,726	2,756	2,801	2,863	2,917	2,972	3,011	3,075
13 Surplus or Deficit (-) Capacity @ Minimum Obligation (10-12)	208	142	92	62	75	13	0	(0)	(0)	0
14 Reserve Margin (10/6)	22.7%	19.7%	17.5%	16.2%	16.7%	14.1%	13.6%	13.6%	13.6%	13.6%
15 Capacity Margin ((10-6)/10)	18.5%	16.4%	14.9%	14.0%	14.3%	12.4%	12.0%	12.0%	12.0%	12.0%

Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	
1 Seasonal System Demand	2,822	2,871	2,914	2,977	3,031	3,084	3,131	3,202	3,262	3,322	1.83%
2 Annual System Demand	2,822	2,871	2,914	2,977	3,031	3,084	3,131	3,202	3,262	3,322	
3 Firm Purchases - Total	82	82	82	82	82	82	82	82	82	82	
4 Firm Sales - Total	14	14	14	15	15	15	15	15	15	16	
5 Seasonal Adjusted Net Demand (1-3+4)	2,754	2,803	2,846	2,910	2,964	3,017	3,064	3,135	3,195	3,256	
6 Annual Adjusted Net Demand (2-3+4)	2,754	2,803	2,846	2,910	2,964	3,017	3,064	3,135	3,195	3,256	
7 Net Generating Cap-ability (owned)	3,471	3,527	3,576	3,649	3,710	3,770	3,824	3,904	3,973	4,042	
8 Participation Purchase -Total	0	0	0	0	0	0	0	0	0	0	
9 Participation Sales -Total	342	342	342	342	342	342	342	342	342	342	
10 Adjusted Net Capability (7+8-9)	3,129	3,185	3,234	3,307	3,368	3,428	3,482	3,562	3,631	3,700	
11 Net Reserve Capacity Obligation (6 x .136)	376	382	388	397	404	411	418	428	436	444	
12 Total Firm Capacity Obligation (5+11)	3,130	3,185	3,234	3,307	3,368	3,428	3,482	3,563	3,631	3,700	
13 Surplus or Deficit (-) Capacity @ Minimum Obligation (10-12)	(0)	(0)	0	0	(0)	(0)	0	(0)	0	0	
14 Reserve Margin (10/6)	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.7%	13.6%	
15 Capacity Margin ((10-6)/10)	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	

Omaha Public Power District
Seasonal Purchases and Sales and Generation in Megawatts
Summer Conditions (May 1 to October 31)

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
FIRM PURCHASES																				
WAPA	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82
Total Firm Purchases	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82
FIRM SALES																				
Wholesale Towns	13	13	13	13	13	13	13	14	14	14	14	14	14	15	15	15	15	15	15	16
Total Firm Sales	13	13	13	13	13	13	13	14	14	14	14	14	14	15	15	15	15	15	15	16
PARTICIPATION PURCHASES																				
NPPD Wind (accredited)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Participation Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PARTICIPATION SALES																				
Western Area Power Administration	50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
City of Gardner Kansas	20	20	20	20	20	20	20	0	0	0	0	0	0	0	0	0	0	0	0	0
MJMEUC	0	35	35	35	35	35	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NPPD NC#2 Sale	162	162	162	162	162	162	162	162	162	162	162	162	162	162	162	162	162	162	162	162
Grand Island NC#2 Sale	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
Falls City Utilities NC#2 Sale	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Nebraska City Utilities NC#2 Sale	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Out of State NC#2 Sale	129	129	129	129	129	129	129	129	129	129	129	129	129	129	129	129	129	129	129	129
Total Participation Sales	412	397	397	397	397	397	362	342	342	342	342	342	342	342	342	342	342	342	342	342
GENERATION																				
Fort Calhoun	479	479	479	479	554	554	554	554	554	554	554	554	554	554	554	554	554	554	554	554
Nebraska City #1	652	652	652	652	634	634	634	634	634	634	634	634	634	634	634	634	634	634	634	634
Nebraska City #2	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685
North Omaha	627	627	627	627	627	627	627	627	627	627	627	627	627	627	627	627	627	627	627	627
Sarpy County	315	315	315	315	315	315	315	315	315	315	315	315	315	315	315	315	315	315	315	315
Jones Street	123	123	123	123	123	123	123	123	123	123	123	123	123	123	123	123	123	123	123	123
Cass County	323	323	323	323	323	323	323	323	323	323	323	323	323	323	323	323	323	323	323	323
Douglas County Landfill	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Tecumseh (leased)	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Future Peaking	0	0	0	0	1	0	7	41	81	145	199	255	304	320	320	320	320	320	320	320
Future Intermediate	0	0	0	0	0	0	0	0	0	0	0	0	0	57	118	178	232	312	381	450
Future Baseload	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	3,215	3,215	3,215	3,215	3,273	3,272	3,279	3,313	3,353	3,417	3,471	3,527	3,576	3,649	3,710	3,770	3,824	3,904	3,973	4,042

Tri-State G&T*

Committed, Planned & Studied Load & Generating Capability in Megawatts

Summer Conditions (May 1 to October 31)

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	
1 Seasonal System Demand	372	377	383	386	389	391	394	396	396	396	397	398	401	402	401	400	400	398	398	397	0.34%
2 Annual System Demand	372	377	383	386	389	391	394	396	396	396	397	398	401	402	401	400	400	398	398	397	
3 Firm Purchases - Total	372	377	383	386	389	391	394	396	396	396	397	398	401	402	401	400	400	398	398	397	
4 Firm Sales - Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Seasonal Adjusted Net Demand (1-3+4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
6 Annual Adjusted Net Demand (2-3+4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
7 Net Generating Cap-ability (owned)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
8 Participation Purchase -Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
9 Participation Sales -Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
10 Adjusted Net Capability (7+8-9)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
11 Net Reserve Capacity Obligation (6 x .136)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
12 Total Firm Capacity Obligation (5+11)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
13 Surplus or Deficit (-) Capacity (10-12)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	

* Only Tri-State's load in Nebraska is shown and is covered by firm purchases of an equal amount.

Tri-State G&T*

Seasonal Purchases and Sales in Megawatts

Summer Conditions (May 1 to October 31)

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
FIRM PURCHASES																				
LAP Nebr	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83
Basin Electric Power Coopera	289	294	300	303	306	308	311	314	313	313	314	315	318	319	318	317	317	316	315	314
Total Firm Purchases	372	377	383	386	389	391	394	396	396	396	397	398	401	402	401	400	400	398	398	397
FIRM SALES																				
none	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PARTICIPATION PURCHASES																				
none	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Participation Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PARTICIPATION SALES																				
none	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Participation Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Wahoo Utilities
Committed, Planned & Studied Load & Generating Capability in Megawatts
Summer Conditions (May 1 to October 31)

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	
1 Seasonal System Demand	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0.00%
2 Annual System Demand	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	
3 Firm Purchases - Total	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	
4 Firm Sales - Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Seasonal Adjusted Net Demand (1-3+4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
6 Annual Adjusted Net Demand (2-3+4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
7 Net Generating Capability (owned)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
8 Participation Purchase -Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
9 Participation Sales -Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
10 Adjusted Net Capability (7+8-9)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
11 Net Reserve Capacity Obligation (6 x .136)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
12 Total Firm Capacity Obligation (5+11)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
13 Surplus or Deficit (-) Capacity @ Minimum Obligation (10-12)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	

Wahoo Utilities
Seasonal Purchases and Sales in Megawatts
Summer Conditions (May 1 to October 31)

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
FIRM PURCHASES																				
WAPA Firm	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Total Firm Purchases	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
FIRM SALES																				
none	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PARTICIPATION PURCHASES																				
none	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Participation Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PARTICIPATION SALES																				
none	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Participation Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Appendix E: Screening Curves

Appendix E

Supply-Side Screening Curve Data

2012$

Coal / Natural Gas/Oil

Inputs:	Units	Coal Supercritical 800 MW	Coal CO2 Capture 800 MW	Integrated Gasification Comb Cicle 600 MW	Frame Gas Turbine	Aero LM 6000	Aero LMS 100	Combined Cycle	Ph Acid Fuel Cell	Diesel
Size	MW	1x800	1x800	600	160	43	90	460	100	5
Production Plant	$/kW	2,352	4,099	3,523	719	1,489	1,336	1,181	5,268	875
Transmission	$/kW	231	231	88	50	50	50	174	0	50
Subtotal	$/kW	2,583	4,330	3,611	769	1,539	1,385	1,355	5,268	925
Escalation,Interest Factor	$/kW	250	387	332	0	0	0	55	0	0
Total Installed Cost	$/kW	2,833	4,717	3,944	769	1,539	1,385	1,410	5,268	925
Wind MWs										
Gas MWs										
Real Fuel Cost	$/MBtu	2.23	2.23	2.23	5.30	5.30	5.30	5.30	5.30	33.63
Heat Rate	Btu/kWh	9,290	13,250	8,300	10,220	9,840	9,260	7,000	9,760	8,740
Fixed O&M	$/kW-yr	50.00	81.80	49.60	8.60	16.10	15.40	17.00	14.24	30.76
Decommissioning	$/kW-yr	0.87	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
A&G & Insurance	$/kW-yr	3.50	5.09	3.48	1.63	1.63	1.77	1.85	1.71	2.54
TOTAL O&M	$/kW-yr	54.37	86.89	53.08	10.23	17.73	17.17	18.85	15.95	33.30
Variable O&M	$/MWh	2.10	3.90	4.88	10.30	5.00	4.10	2.30	2.85	5.58
Environmental *	$/MWh	15.18	2.60	13.55	9.22	8.88	8.35	6.31	8	12.58
Efficiency Ratio	O/I	0	0	0	0	0	0	0	0	0
Pumping Cost	$/MWh	0	0	0	0	0	0	0	0	0
Tipping Fee	$/Ton	0	0	0	0	0	0	0	0	0
Conversion Tons/MW-Day		0	0	0	0	0	0	0	0	0
Life	Years	30	30	30	30	30	30	30	30	30
Maintenance Outage Rate	%	4.8	4.8	6.5	4.0	3.0	3.0	6.9	1.1	5
Forced Outage Rate	%	3.7	3.7	6.0	3.0	2.0	2.0	4.6	1.8	1
Equivalent Availability	%	91.7	91.7	87.9	93.1	95.1	95.1	88.8	97.1	94.1
SO2 Emissions	lb/MBtu	0.095	0.095	0.060	0	0	0	0	0	0.056
NOx Emissions	lb/MBtu	0.070	0.070	0.050	0.030	0.030	0.030	0.010	0	2.900
CO2 Emissions	lb/MBtu	213	21	213	120	120	120	120	108	162
Part Emissions	lb/MBtu	0.018	0.018	0.010	0	0	0	0	0	0
HG Emissions	lb/MBtu	.000002	.000002	.000003	0	0	0	0	0	0
Real Fixed Charge Rate		5.454%	5.454%	5.454%	5.454%	5.454%	5.454%	5.454%	5.454%	5.454%
Levelized Fixed Charge Rate		6.720%	6.720%	6.720%	6.720%	6.720%	6.720%	6.720%	6.720%	6.720%
Preconst, License Design	years	1	3	3	1	1	1	2	2	1
Idealized Plant Construction	years	3	3	3	1	1	1	2	2	1
AFUDC/Escalation Adder		10.7%	9.4%	9.4%	0%	0%	0%	4.7%	0%	0%
Cost Confidence	+	10%	25%	25%	20%	20%	20%	30%	30%	10%
	-	10%	25%	25%	15%	15%	15%	20%	30%	10%
Fixed Costs	$/kw-yr	208.90	344.12	268.15	52.15	101.67	92.72	95.74	303.22	83.75
Variable Costs	$/MWh	37.99	36.04	36.93	73.66	66.00	61.51	45.69	62.43	312.07

Nuclear/Renewables/Distributed Generation

Inputs:	Units	AP 1200 Nuclear	Whole Tree	Biomass Fluidized Bed	Solar Thermal	Solar Photo Voltaic	Wind Turbine w/Backup 1W for 2G	Wind Turbine w/Backup 1W for 1G	Wind Turbine w/Backup 2W for 1G	Wind Turbine w/o Backup	Landfill Gas	Bio-Diesel Gen	Micro Turbine
Size	MW	1x1200	100	50	100	25	100	100	100	100	3	5.0	0.060
Production Plant	$/kW	3,994	3,614	5,234	5,161	5,333	2,106	2,106	2,106	2,106	2,171	875	1,500
Transmission	$/kW	412	88	88	50	50	50	50	50	50	50	50	0
Subtotal	$/kW	4,406	3,702	5,322	5,211	5,383	2,156	2,156	2,156	2,156	2,220	925	1,500
Escalation,Interest Factor	$/kW	1,471	204	344	0	0	0	0	0	0	0	0	0
Total Installed Cost	$/kW	5,877	3,906	5,666	5,211	5,383	2,156	2,156	2,156	2,156	2,220	925	1,500
Wind MWs							1	1	2				
Gas MWs							2	1	1				
Real Fuel Cost	$/MBtu	0.89	5.19	3.32	0	0	0	0	0	0	0.41	31.04	5.30
Heat Rate	Btu/kWh	10,710	12,894	14,119	0	0	0	0	0	0	10,000	8,740	12,186
Fixed O&M	$/kW-yr	93.08	64.51	116.74	72.37	15.36	8.24	8.24	8.24	8.24	28.42	30.76	0
Decommissioning	$/kW-yr	18.30	0.44	0.44	0	0	0	0	0	0	0	0	0
A&G & Insurance	$/kW-yr	5.65	4.23	6.84	4.62	1.77	4.65	4.65	4.65	4.65	2.42	2.54	0
TOTAL O&M	$/kW-yr	117.03	69.17	124.01	76.98	17.13	12.89	12.89	12.89	12.89	30.84	33.30	0
Variable O&M	$/MWh	5.68	5.20	5.99	3.07	0	6.74	6.74	6.74	6.74	3.77	5.58	0
Environmental *	$/MWh	0	0.08	0	0	0	0	0	0	0	0	12.58	0
Efficiency Ratio	O/I	0	0	0	0	0	0	0	0	0	0	0	0
Pumping Cost	$/MWh	0	0	0	0	0	0	0	0	0	0	0	0
Tipping Fee	$/Ton	0	0	0	0	0	0	0	0	0	0	0	0
Conversion Tons/MW-Day		0	0	0	0	0	0	0	0	0	0	0	0
Life	Years	60	30	30	25	25	20	20	20	20	30	30	30
Maintenance Outage Rate	%	3.0	4.0	4.0	2.0	1.0	0.75	0.75	0.75	0.75	0.0	5	
Forced Outage Rate	%	3.0			2.0	2.0	2.25	2.25	2.25	2.25	20.0	1	
Equivalent Availability	%	94.1	96.0	96.0	96.0	97.0	97.0	97.0	97.0	97.0	80.0	94.1	
SO2 Emissions	lb/MBtu	0	0.003	0.003	0	0	0	0	0	0	0	0.056	
NOx Emissions	lb/MBtu	0	0.018	0	0	0	0	0	0	0	0	2.900	
CO2 Emissions	lb/MBtu	0	0	0	0	0	0	0	0	0	0	162	
Part Emissions	lb/MBtu	0	0.02	0	0	0	0	0	0	0	0	0	
HG Emissions	lb/MBtu	0	0	0	0	0	0	0	0	0	0	0	
Real Fixed Charge Rate		4.119%	5.454%	5.454%	6.053%	6.053%	6.979%	6.979%	6.979%	6.979%	5.454%	5.454%	5.454%
Levelized Fixed Charge Rate		5.518%	6.720%	6.720%	7.254%	7.254%	8.107%	8.107%	8.107%	8.107%	6.720%	6.720%	6.720%
Preconst, License Design	years	5	2	1	1	1	2	2	2	2	2	1	
Idealized Plant Construction	years	5	2	2	1	1	1	1	1	1	1	1	
AFUDC/Escalation Adder		36.8%	5.7%	6.6%	0%	0%	0%	0%	0%	0%	0%	0%	
Cost Confidence	+	30%	30%	40%	30%	30%	30%	30%	30%	30%		10%	
	-	20%	20%	25%	20%	20%	20%	20%	20%	20%		10%	
Fixed Costs	$/kw-yr	359.07	282.19	433.00	392.40	342.96	215.52	215.52	215.52	163.37	151.93	83.75	81.80
Variable Costs	$/MWh	15.19	72.23	52.91	3.07	0.00	51.35	40.20	29.05	6.74	7.86	289.48	64.55

Storage

Inputs:	Units	Pumped Storage	CAES	Adv Battery 7.2 hr
Size	MW	1050	350	12
Production Plant	$/kW	1,312	1,020	3,361
Transmission	$/kW	88	88	50
Subtotal	$/kW	1,400	1,108	3,411
Escalation,Interest Factor	$/kW	296	161	0
Total Installed Cost	$/kW	1,696	1,269	3,411
Wind MWs				
Gas MWs				
Real Fuel Cost	$/MBtu	0	5.30	0
Heat Rate	Btu/kWh	0	4,050	0
Fixed O&M	$/kW-yr	5.45	5.76	0.00
Decommissioning	$/kW-yr	0	0	0
A&G & Insurance	$/kW-yr	1.27	1.29	1.00
TOTAL O&M	$/kW-yr	6.72	7.05	1.00
Variable O&M	$/MWh	5.45	11.53	0.00
Environmental *	$/MWh	0	3.65	0
Efficiency Ratio	O/I	0.77	1.39	0.75
Pumping Cost	$/MWh	49.39	27.35	50.53
Tipping Fee	$/Ton	0	0	0
Conversion Tons/MW-Day		0	0	0
Life	Years	50	30	30
Maintenance Outage Rate	%	5	2.3	1.9
Forced Outage Rate	%	5.0	0.5	4.0
Equivalent Availability	%	90.3	97.2	94.2
SO2 Emissions	lb/MBtu	0	0	0
NOx Emissions	lb/MBtu	0	0.030	0
CO2 Emissions	lb/MBtu	0	120	0
Part Emissions	lb/MBtu	0	0	0
HG Emissions	lb/MBtu	0	0	0
Real Fixed Charge Rate		4.352%	5.454%	5.454%
Levelized Fixed Charge Rate		5.830%	6.720%	6.720%
Preconst, License Design	years	2	2	1
Idealized Plant Construction	years	6	2	1
AFUDC/Escalation Adder		22.6%	15.7%	0.0%
Cost Confidence	+		30%	100%
	-		25%	30%
Fixed Costs	$/kw-yr	80.53	76.26	187.00
Variable Costs	$/MWh	54.84	63.99	50.53

SOURCES: EPRI: Technical Assessment Guide (TAG).
VENTYX: Power Reference Case

SO2 Emission Cost	250	$/ton
NOx Emission Cost	150	$/ton
CO2 Emission Cost	15	$/ton
Particulate Emission Cost	461	$/ton
HG (Mercury) Emission Cost	15,000,000	$/ton

Inflation Rate	1.90%	2012 Forecast
Interest Rate	5.80%	
Real Disc Rate	3.83%	
Administrative & General Expense	5.00%	(of Fixed O&M)
Insurance ($/kW-yr)	1.000	
Escalation Rate	1.90%	

* Encompasses the residual gases CO2, SO2, NOx, and particulates.

Supply Side Screening Curve Analysis

2012

Real - $/kW-year

Capacity Factor	Coal Supercritial 800 MW	Coal CO2 Capture 800 MW	Integrated Gasification Comb Cicle 600 MW	Frame Gas Turbine	Aero LM 6000	Aero LMS 100	Combined Cycle	Ph Acid Fuel Cell	Diesel	AP 1200 Nuclear	Whole Tree	Biomass Fluidized Bed	Solar Thermal	Solar Photo Voltaic	Wind Turbine w/Backup 1W for 20	Wind Turbine w/Backup 1W for 10	Wind Turbine w/Backup 2W for 10	Wind Turbine w/o Backup	Landfill Gas	Bio-Diesel Gen	Micro Turbine	Pumped Storage	CAES	Adv Battery 7.2 hr
0%	209	344	268	52	102	93	96	303	84	359	282	433	392	343	216	216	216	163	152	84	82	81	76	187
1%	212	347	271	59	107	98	100	309	111	360	289	438	393	343	220	219	218	164	153	109	87	85	82	191
3%	219	354	278	72	119	109	108	320	166	363	301	447	393	343	229	226	223	165	154	160	99	95	93	200
5%	226	360	284	84	131	120	116	331	220	366	314	456	394	343	238	233	228	166	155	211	110	105	104	209
10%	242	376	301	117	159	147	136	358	357	372	345	479	395	343	261	251	241	169	159	337	138	129	132	231
15%	259	391	317	149	188	174	156	385	494	379	377	503	396	343	283	268	254	172	162	464	167	153	160	253
20%	275	407	333	181	217	200	176	413	631	386	409	526	398	343	305	286	266	175	166	591	195	177	188	276
30%	309	439	365	246	275	254	216	467	904	399	472	572	400	343	350	321	292	181	173	845	251	225	244	320
40%	342	470	398	310	333	308	256	522	1177	412	535	618	[redacted]	[redacted]	395	356	317	187	179	1098	308	273	300	[redacted]
50%	375	502	430	375	391	362	296	577	1451	426	599	665	[redacted]	[redacted]	440	392	343	[redacted]	186	1352	365	[redacted]	[redacted]	[redacted]
60%	409	534	462	439	449	416	336	631	1724	439	662	711	[redacted]	[redacted]	485	427	368	[redacted]	193	1605	421	[redacted]	[redacted]	[redacted]
70%	442	565	495	504	506	470	376	686	1997	452	725	757	[redacted]	[redacted]	530	462	[redacted]	[redacted]	200	1859	478	[redacted]	[redacted]	[redacted]
80%	475	597	527	568	564	524	416	741	2271	466	788	804	[redacted]	[redacted]	575	497	[redacted]	[redacted]	207	2112	534	[redacted]	[redacted]	[redacted]
90%	508	628	559	633	622	578	456	795	2544	479	852	850	[redacted]	[redacted]	620	[redacted]	[redacted]	[redacted]	214	2366	591	[redacted]	[redacted]	[redacted]
100%	542	660	592	697	680	632	496	850	2818	492	915	897	[redacted]	[redacted]	665	[redacted]	[redacted]	[redacted]	221	2620	647	[redacted]	[redacted]	[redacted]

Real - c/kWh

Capacity Factor	Coal Supercritial 800 MW	Coal CO2 Capture 800 MW	Integrated Gasification Comb Cicle 600 MW	Frame Gas Turbine	Aero LM 6000	Aero LMS 100	Combined Cycle	Ph Acid Fuel Cell	Diesel	AP 1200 Nuclear	Whole Tree	Biomass Fluidized Bed	Solar Thermal	Solar Photo Voltaic	Wind Turbine w/Backup 1W for 20	Wind Turbine w/Backup 1W for 10	Wind Turbine w/Backup 2W for 10	Wind Turbine w/o Backup	Landfill Gas	Bio-Diesel Gen	Micro Turbine	Pumped Storage	CAES	Adv Battery 7.2 hr
1%	242.3	396.4	309.8	66.9	122.7	112.0	113.9	352.4	126.8	411.4	329.4	499.6	448.3	391.5	251.2	250.1	248.9	187.2	174.2	124.5	99.8	97.4	93.5	218.5
3%	83.3	134.5	105.7	27.2	45.3	41.4	41.0	121.6	63.1	138.2	114.6	170.1	149.6	130.5	87.1	86.0	84.9	62.8	58.6	60.8	37.6	36.1	35.4	76.2
5%	51.5	82.2	64.9	19.3	29.8	27.3	26.4	75.5	50.3	83.5	71.6	104.1	89.9	78.3	54.3	53.2	52.1	38.0	35.5	48.1	25.1	23.9	23.8	47.7
10%	27.6	42.9	34.3	13.3	18.2	16.7	15.5	40.9	40.8	42.5	39.4	54.7	45.1	39.2	29.7	28.6	27.5	19.3	18.1	38.5	15.8	14.7	15.1	26.4
15%	19.7	29.8	24.1	11.3	14.3	13.2	11.9	29.3	37.6	28.8	28.7	38.2	30.2	26.1	21.5	20.4	19.3	13.1	12.3	35.3	12.7	11.6	12.2	19.3
20%	15.7	23.2	19.0	10.3	12.4	11.4	10.0	23.5	36.0	22.0	23.3	30.0	22.7	19.6	17.4	16.3	15.2	10.0	9.5	33.7	11.1	10.1	10.8	15.7
30%	11.7	16.7	13.9	9.4	10.5	9.7	8.2	17.8	34.4	15.2	18.0	21.8	15.2	13.1	13.3	12.2	11.1	6.9	6.6	32.1	9.6	8.5	9.3	12.2
40%	9.8	13.4	11.3	8.9	9.5	8.8	7.3	14.9	33.6	11.8	15.3	17.6	[redacted]	[redacted]	11.3	10.2	9.1	5.3	5.1	31.3	8.8	7.8	8.6	[redacted]
50%	8.6	11.5	9.8	8.6	8.9	8.3	6.8	13.2	33.1	9.7	13.7	15.2	[redacted]	[redacted]	10.1	8.9	7.8	[redacted]	4.3	30.9	8.3	[redacted]	[redacted]	[redacted]
60%	7.8	10.2	8.8	8.4	8.5	7.9	6.4	12.0	32.8	8.4	12.6	13.5	[redacted]	[redacted]	9.2	8.1	7.0	[redacted]	3.7	30.5	8.0	[redacted]	[redacted]	[redacted]
70%	7.2	9.2	8.1	8.2	8.3	7.7	6.1	11.2	32.6	7.4	11.8	12.4	[redacted]	[redacted]	8.7	7.5	[redacted]	[redacted]	3.3	30.3	7.8	[redacted]	[redacted]	[redacted]
80%	6.8	8.5	7.5	8.1	8.1	7.5	5.9	10.6	32.4	6.6	11.2	11.5	[redacted]	[redacted]	8.2	7.1	[redacted]	[redacted]	3.0	30.1	7.6	[redacted]	[redacted]	[redacted]
90%	6.4	8.0	7.1	8.0	7.9	7.3	5.8	10.1	32.3	6.1	10.8	10.8	[redacted]	[redacted]	7.9	[redacted]	[redacted]	[redacted]	2.7	30.0	7.5	[redacted]	[redacted]	[redacted]
100%	6.2	7.5	6.8	8.0	7.8	7.2	5.7	9.7	32.2	5.6	10.4	10.2	[redacted]	[redacted]	7.6	[redacted]	[redacted]	[redacted]	2.5	29.9	7.4	[redacted]	[redacted]	[redacted]

Lowest Cost

Supply Side Screening Curve Analysis

2012

Levelized - $/kW-year

Capacity Factor	Coal Supercritial 800 MW	Coal CO2 Capture 800 MW	Integrated Gasification Comb Cicle 600 MW	Frame Gas Turbine	Aero LM 6000	Aero LMS 100	Combined Cycle	Ph Acid Fuel Cell	Diesel	AP 1200 Nuclear	Whole Tree	Biomass Fluidized Bed	Solar Thermal	Solar Photo Voltaic	Wind Turbine w/Backup 1W for 2G	Wind Turbine w/Backup 1W for 1G	Wind Turbine w/Backup 2W for 1G	Wind Turbine w/o Backup	Landfill Gas	Bio-Diesel Gen	Micro Turbine	Pumped Storage	CAES	Adv Battery 7.2 hr
0%	257	424	330	64	125	114	118	374	103	481	348	534	470	411	250	250	250	190	187	103	101	108	94	230
1%	262	428	334	72	132	121	123	380	137	483	356	539	471	411	256	254	253	190	188	134	108	114	101	236
3%	270	436	342	88	147	134	133	394	204	486	371	551	471	411	266	263	259	192	190	197	122	127	115	247
5%	278	443	350	104	161	147	143	407	272	490	387	562	472	411	276	271	265	193	191	259	136	140	129	258
10%	298	463	370	144	197	181	167	441	440	499	426	591	473	411	303	291	280	197	196	416	170	172	163	285
15%	319	482	390	184	232	214	192	475	609	508	465	619	475	411	329	312	295	200	200	572	205	204	198	312
20%	339	502	410	223	268	247	217	508	777	517	504	648	477	411	355	332	309	203	204	728	240	237	232	340
30%	380	541	450	303	339	313	266	576	1114	535	582	705	480	411	407	373	339	210	213	1041	310	301	301	394
40%	421	580	490	382	410	380	315	643	1451	552	660	762			459	414	369	217	221	1353	380	365	370	
50%	462	619	530	462	482	446	365	711	1788	570	738	819			512	455	398		230	1666	449			
60%	503	657	570	541	553	513	414	778	2124	588	816	876			564	496	428		238	1978	519			
70%	544	696	610	621	624	579	463	845	2461	606	894	933			616	537			247	2291	589			
80%	586	735	649	700	695	645	513	913	2798	624	972	991			668	578			255	2603	658			
90%	627	774	689	780	767	712	562	980	3135	641	1049	1048			721				264	2916	728			
100%	668	813	729	859	838	778	611	1048	3472	659	1127	1105			773				272	3228	798			

Levelized - c/kWh

Capacity Factor	Coal Supercritial 800 MW	Coal CO2 Capture 800 MW	Integrated Gasification Comb Cicle 600 MW	Frame Gas Turbine	Aero LM 6000	Aero LMS 100	Combined Cycle	Ph Acid Fuel Cell	Diesel	AP 1200 Nuclear	Whole Tree	Biomass Fluidized Bed	Solar Thermal	Solar Photo Voltaic	Wind Turbine w/Backup 1W for 2G	Wind Turbine w/Backup 1W for 1G	Wind Turbine w/Backup 2W for 1G	Wind Turbine w/o Backup	Landfill Gas	Bio-Diesel Gen	Micro Turbine	Pumped Storage	CAES	Adv Battery 7.2 hr
1%	298.5	488.5	381.8	82.4	151.2	138.0	140.3	434.2	156.3	551.2	405.9	615.6	537.2	469.2	291.8	290.5	289.2	217.4	214.7	153.5	123.0	130.5	115.2	269.3
3%	102.6	165.8	130.3	33.5	55.8	51.1	50.5	149.9	77.7	185.1	141.2	209.6	179.3	156.4	101.2	99.9	98.6	73.0	72.2	74.9	46.3	48.4	43.6	93.9
5%	63.5	101.3	80.0	23.7	36.7	33.7	32.6	93.0	62.0	111.9	88.3	128.3	107.7	93.8	63.1	61.8	60.5	44.1	43.7	59.2	31.0	32.0	29.3	56.8
10%	34.1	52.8	42.3	16.4	22.4	20.6	19.1	50.3	50.2	56.9	48.6	67.4	54.0	46.9	34.5	33.3	32.0	22.4	22.3	47.5	19.5	19.7	18.6	32.5
15%	24.3	36.7	29.7	14.0	17.7	16.3	14.6	36.1	46.3	38.6	35.4	47.1	36.2	31.3	25.0	23.7	22.4	15.2	15.2	43.5	15.6	15.6	15.0	23.8
20%	19.4	28.6	23.4	12.7	15.3	14.1	12.4	29.0	44.3	29.5	28.7	37.0	27.2	23.5	20.3	19.0	17.7	11.6	11.7	41.6	13.7	13.5	13.2	19.4
30%	14.5	20.6	17.1	11.5	12.9	11.9	10.1	21.9	42.4	20.3	22.1	26.8	18.3	15.6	15.5	14.2	12.9	8.0	8.1	39.6	11.8	11.5	11.5	15.0
40%	12.0	16.5	14.0	10.9	11.7	10.8	9.0	18.4	41.4	15.8	18.8	21.7			13.1	11.8	10.5	6.2	6.3	38.6	10.8	10.4	10.6	
50%	10.6	14.1	12.1	10.5	11.0	10.2	8.3	16.2	40.8	13.0	16.8	18.7			11.7	10.4	9.1		5.2	38.0	10.3			
60%	9.6	12.5	10.8	10.3	10.5	9.8	7.9	14.8	40.4	11.2	15.5	16.7			10.7	9.4	8.1		4.5	37.6	9.9			
70%	8.9	11.4	9.9	10.1	10.2	9.4	7.6	13.8	40.1	9.9	14.6	15.2			10.0	8.8			4.0	37.4	9.6			
80%	8.4	10.5	9.3	10.0	9.9	9.2	7.3	13.0	39.9	8.9	13.9	14.1			9.5	8.2			3.6	37.1	9.4			
90%	7.9	9.8	8.7	9.9	9.7	9.0	7.1	12.4	39.8	8.1	13.3	13.3			9.1				3.3	37.0	9.2			
100%	7.6	9.3	8.3	9.8	9.6	8.9	7.0	12.0	39.6	7.5	12.9	12.6			8.8				3.1	36.9	9.1			
Levelization Factor	1.232	1.232	1.232	1.232	1.232	1.232	1.232	1.232	1.232	1.340	1.232	1.232	1.198	1.198	1.162	1.162	1.162	1.162	1.232	1.232	1.232	1.340	1.232	1.232

Lowest Cost

Busbar Costs By Component

Real - cents/kWh

	Coal Supercrital 800 MW	Coal CO2 Capture 800 MW	Integrated Gasification Comb Cicle 600 MW	Frame Gas Turbine	Aero LM 6000	Aero LMS 100	Combined Cycle	Ph Acid Fuel Cell	Diesel	AP 1200 Nuclear	Whole Tree	Biomass Fluidized Bed	Solar Thermal	Solar Photo Voltaic	Wind Turbine w/Backup 1W for 2G	Wind Turbine w/Backup 1W for 1G	Wind Turbine w/Backup 2W for 1G	Wind Turbine w/o Backup	Landfill Gas	Bio-Diesel Gen	Micro Turbine	Pumped Storage	CAES	Adv Battery 7.2 hr
Capacity	176.4	293.6	245.5	47.9	95.8	86.2	87.8	327.9	57.6	276.3	243.2	352.7	360.1	372.0	219.6	219.6	219.6	171.8	138.2	57.6	93.4	84.3	79.0	212.3
Fixed O&M	62.1	99.2	60.6	11.7	20.2	19.6	21.5	18.2	38.0	133.6	79.0	141.6	87.9	19.6	26.4	26.4	26.4	14.7	35.2	38.0	0.0	7.7	8.1	1.1
Environmental	1.5	0.3	1.4	0.9	0.9	0.8	0.6	0.8	1.3	0.0	0.0	0.0	0.0	0.0	0.6	0.5	0.3	0.0	0.0	1.3	0.0	0.0	0.4	0.0
Variable	2.3	3.3	2.3	6.4	5.7	5.3	3.9	5.5	29.9	1.5	7.2	5.3	0.3	0.0	4.5	3.6	2.6	0.7	0.8	27.7	6.5	5.5	6.0	5.1
Total - 1% CF	242.3	396.4	309.8	66.9	122.7	112.0	113.9	352.4	126.8	411.4	329.4	499.6	448.3	391.5	251.2	250.1	248.9	187.2	174.2	124.5	99.8	97.4	93.5	218.5
Capacity	35.3	58.7	49.1	9.6	19.2	17.2	17.6	65.6	11.5	55.3	48.6	70.5	72.0	74.4	43.9	43.9	43.9	34.4	27.6	11.5	18.7	16.9	15.8	42.5
O&M	12.4	19.8	12.1	2.3	4.0	3.9	4.3	3.6	7.6	26.7	15.8	28.3	17.6	3.9	5.3	5.3	5.3	2.9	7.0	7.6	0.0	1.5	1.6	0.2
Environmental	1.5	0.3	1.4	0.9	0.9	0.8	0.6	0.8	1.3	0.0	0.0	0.0	0.0	0.0	0.6	0.5	0.3	0.0	0.0	1.3	0.0	0.0	0.4	0.0
Fuel	2.3	3.3	2.3	6.4	5.7	5.3	3.9	5.5	29.9	1.5	7.2	5.3	0.3	0.0	4.5	3.6	2.6	0.7	0.8	27.7	6.5	5.5	6.0	5.1
Total - 5% CF	51.5	82.2	64.9	19.3	29.8	27.3	26.4	75.5	50.3	83.5	71.6	104.1	89.9	78.3	54.3	53.2	52.1	38.0	35.5	48.1	25.1	23.9	23.8	47.7
Capacity	8.8	14.7	12.3	2.4	4.8	4.3	4.4	16.4	2.9	13.8	12.2	17.6	18.0	18.6	11.0	11.0	11.0	8.6	6.9	2.9	4.7	4.2	4.0	10.6
O&M	3.1	5.0	3.0	0.6	1.0	1.0	1.1	0.9	1.9	6.7	3.9	7.1	4.4	1.0	1.3	1.3	1.3	0.7	1.8	1.9	0.0	0.4	0.4	0.1
Environmental	1.5	0.3	1.4	0.9	0.9	0.8	0.6	0.8	1.3	0.0	0.0	0.0	0.0	0.0	0.6	0.5	0.3	0.0	0.0	1.3	0.0	0.0	0.4	0.0
Fuel	2.3	3.3	2.3	6.4	5.7	5.3	3.9	5.5	29.9	1.5	7.2	5.3	0.3	0.0	4.5	3.6	2.6	0.7	0.8	27.7	6.5	5.5	6.0	5.1
Total - 20% CF	15.7	23.2	19.0	10.3	12.4	11.4	10.0	23.5	36.0	22.0	23.3	30.0	22.7	19.6	17.4	16.3	15.2	10.0	9.5	33.7	11.1	10.1	10.8	15.7
Capacity	4.4	7.3	6.1	1.2	2.4	2.2	2.2	8.2	1.4	6.9	6.1	8.8	[redacted]	[redacted]	5.5	5.5	5.5	4.3	3.5	1.4	2.3	2.1	2.0	[redacted]
O&M	1.6	2.5	1.5	0.3	0.5	0.5	0.5	0.5	1.0	3.3	2.0	3.5	[redacted]	[redacted]	0.7	0.7	0.7	0.4	0.9	1.0	0.0	0.2	0.2	[redacted]
Environmental	1.5	0.3	1.4	0.9	0.9	0.8	0.6	0.8	1.3	0.0	0.0	0.0	[redacted]	[redacted]	0.6	0.5	0.3	0.0	0.0	1.3	0.0	0.0	0.4	[redacted]
Fuel	2.3	3.3	2.3	6.4	5.7	5.3	3.9	5.5	29.9	1.5	7.2	5.3	[redacted]	[redacted]	4.5	3.6	2.6	0.7	0.8	27.7	6.5	5.5	6.0	[redacted]
Total - 40% CF	9.8	13.4	11.3	8.9	9.5	8.8	7.3	14.9	33.6	11.8	15.3	17.6	[redacted]	[redacted]	11.3	10.2	9.1	5.3	5.1	31.3	8.8	7.8	8.6	[redacted]
Capacity	2.9	4.9	4.1	0.8	1.6	1.4	1.5	5.5	1.0	4.6	4.1	5.9	[redacted]	[redacted]	3.7	3.7	3.7	[redacted]	2.3	1.0	1.6	[redacted]	[redacted]	[redacted]
O&M	1.0	1.7	1.0	0.2	0.3	0.3	0.4	0.3	0.6	2.2	1.3	2.4	[redacted]	[redacted]	0.4	0.4	0.4	[redacted]	0.6	0.6	0.0	[redacted]	[redacted]	[redacted]
Environmental	1.5	0.3	1.4	0.9	0.9	0.8	0.6	0.8	1.3	0.0	0.0	0.0	[redacted]	[redacted]	0.6	0.5	0.3	[redacted]	0.0	1.3	0.0	[redacted]	[redacted]	[redacted]
Fuel	2.3	3.3	2.3	6.4	5.7	5.3	3.9	5.5	29.9	1.5	7.2	5.3	[redacted]	[redacted]	4.5	3.6	2.6	[redacted]	0.8	27.7	6.5	[redacted]	[redacted]	[redacted]
Total - 60% CF	7.8	10.2	8.8	8.4	8.5	7.9	6.4	12.0	32.8	8.4	12.6	13.5	[redacted]	[redacted]	9.2	8.1	7.0	[redacted]	3.7	30.5	8.0	[redacted]	[redacted]	[redacted]
Capacity	2.2	3.7	3.1	0.6	1.2	1.1	1.1	4.1	0.7	3.5	3.0	4.4	[redacted]	[redacted]	2.7	2.7	[redacted]	[redacted]	1.7	0.7	1.2	[redacted]	[redacted]	[redacted]
O&M	0.8	1.2	0.8	0.1	0.3	0.2	0.3	0.2	0.5	1.7	1.0	1.8	[redacted]	[redacted]	0.3	0.3	[redacted]	[redacted]	0.4	0.5	0.0	[redacted]	[redacted]	[redacted]
Environmental	1.5	0.3	1.4	0.9	0.9	0.8	0.6	0.8	1.3	0.0	0.0	0.0	[redacted]	[redacted]	0.6	0.5	[redacted]	[redacted]	0.0	1.3	0.0	[redacted]	[redacted]	[redacted]
Fuel	2.3	3.3	2.3	6.4	5.7	5.3	3.9	5.5	29.9	1.5	7.2	5.3	[redacted]	[redacted]	4.5	3.6	[redacted]	[redacted]	0.8	27.7	6.5	[redacted]	[redacted]	[redacted]
Total - 80% CF	6.8	8.5	7.5	8.1	8.1	7.5	5.9	10.6	32.4	6.8	11.2	11.5	[redacted]	[redacted]	8.2	7.1	[redacted]	[redacted]	3.0	30.1	7.6	[redacted]	[redacted]	[redacted]
Capacity	1.8	2.9	2.5	0.5	1.0	0.9	0.9	3.3	0.6	2.8	2.4	3.5	[redacted]	[redacted]	2.2	[redacted]	[redacted]	[redacted]	1.4	0.6	0.9	[redacted]	[redacted]	[redacted]
O&M	0.6	1.0	0.6	0.1	0.2	0.2	0.2	0.2	0.4	1.3	0.8	1.4	[redacted]	[redacted]	0.3	[redacted]	[redacted]	[redacted]	0.4	0.4	0.0	[redacted]	[redacted]	[redacted]
Environmental	1.5	0.3	1.4	0.9	0.9	0.8	0.6	0.8	1.3	0.0	0.0	0.0	[redacted]	[redacted]	0.6	[redacted]	[redacted]	[redacted]	0.0	1.3	0.0	[redacted]	[redacted]	[redacted]
Fuel	2.3	3.3	2.3	6.4	5.7	5.3	3.9	5.5	29.9	1.5	7.2	5.3	[redacted]	[redacted]	4.5	[redacted]	[redacted]	[redacted]	0.8	27.7	6.5	[redacted]	[redacted]	[redacted]
Total - 100% CF	6.2	7.5	6.8	8.0	7.8	7.2	5.7	9.7	32.2	5.6	10.4	10.2	[redacted]	[redacted]	7.6	[redacted]	[redacted]	[redacted]	2.5	29.9	7.4	[redacted]	[redacted]	[redacted]

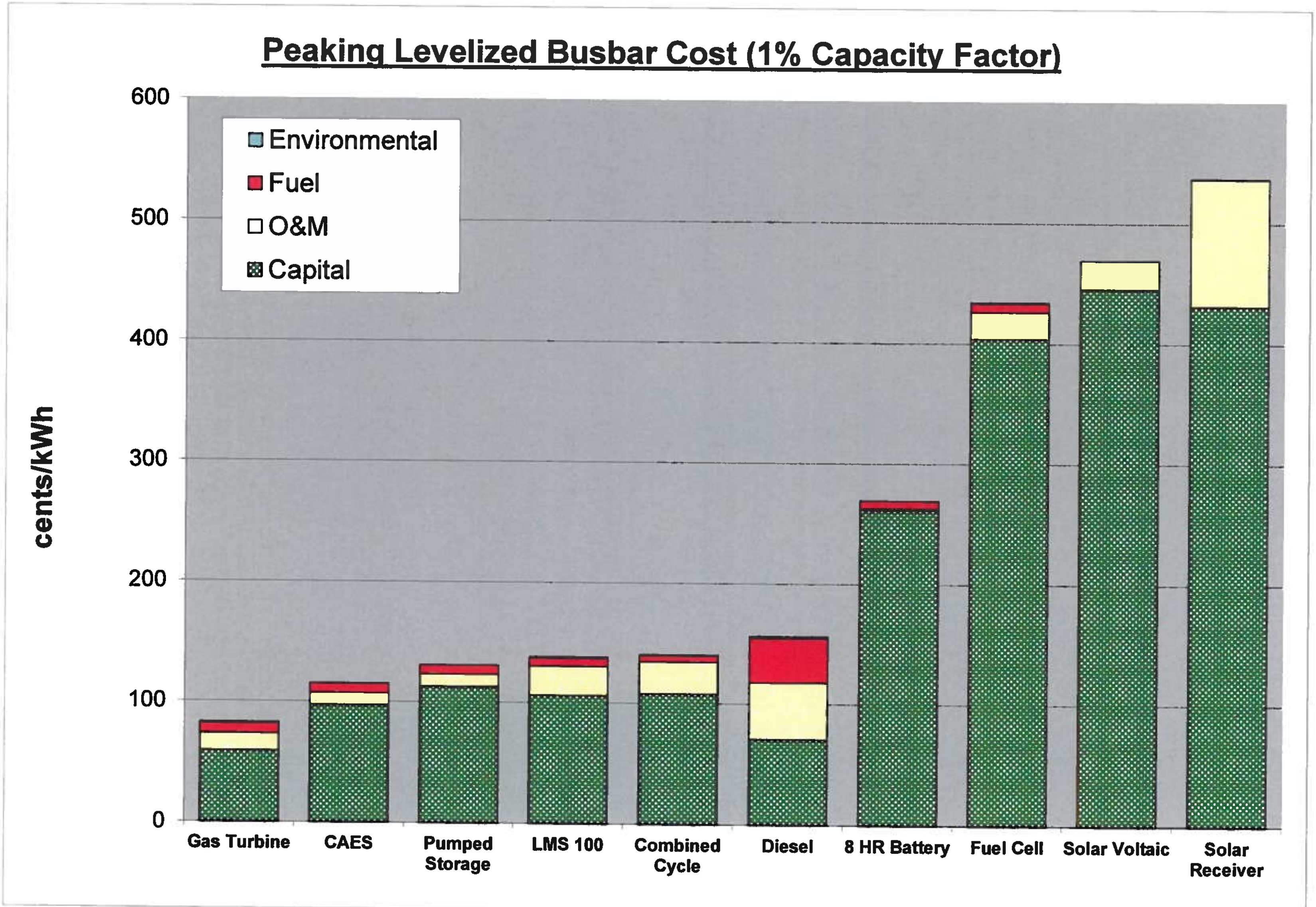
Busbar Costs By Component

Levelized - cents/kWh

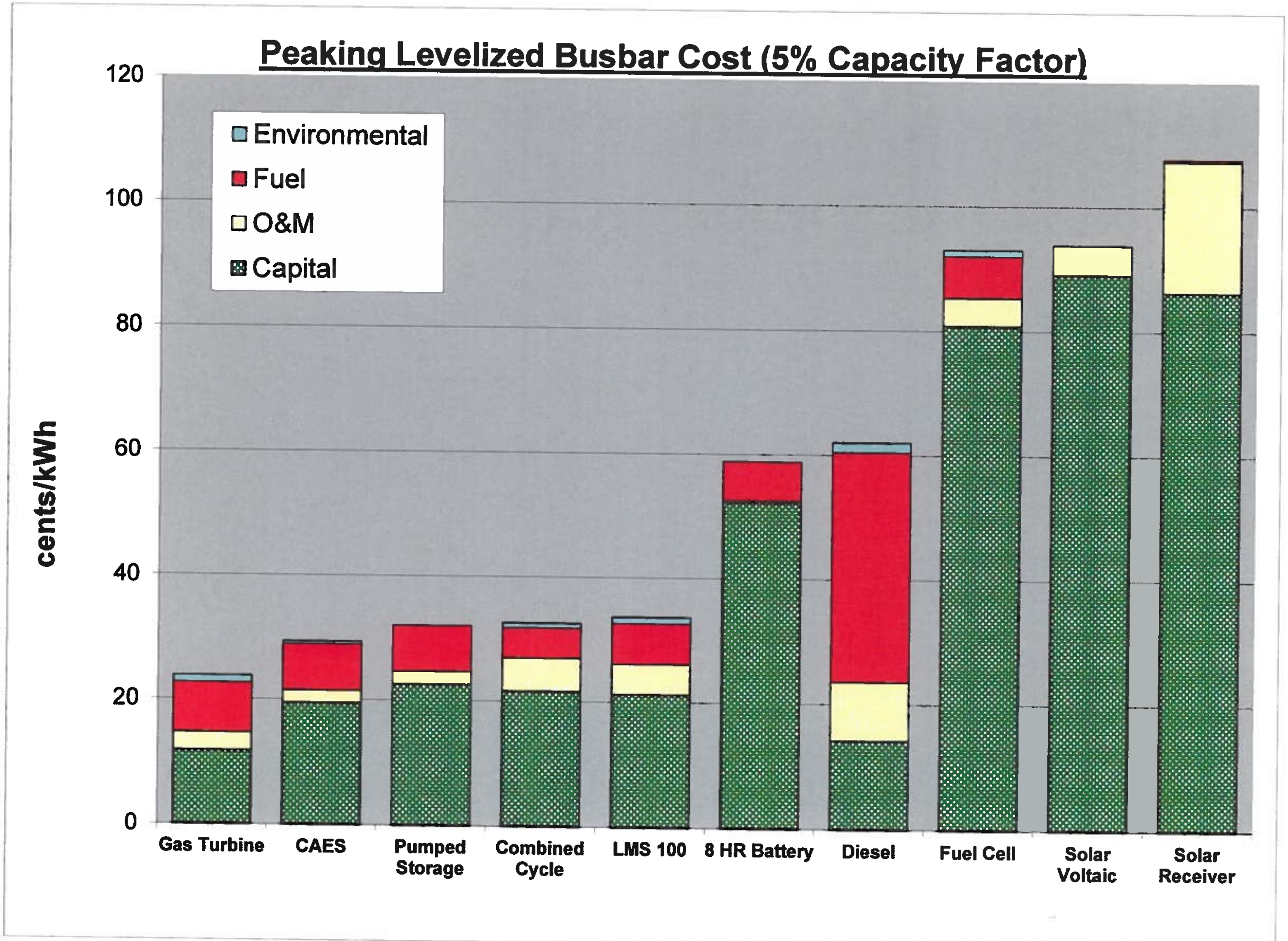
	Coal Supercritical 800 MW	Coal CO2 Capture 800 MW	Integrated Gasification Comb Cicle 800 MW	Frame Gas Turbine	Aero LM 6000	Aero LMS 100	Combined Cycle	Ph Acid Fuel Cell	Diesel
Capacity	217.4	361.8	302.5	59.0	118.1	106.3	108.2	404.1	71.0
Fixed O&M	76.5	122.2	74.7	14.4	24.9	24.2	26.5	22.4	46.8
Environmental	1.9	0.3	1.7	1.1	1.1	1.0	0.8	1.0	1.6
Variable	2.8	4.1	2.9	7.9	7.0	6.6	4.9	6.7	36.9
Total - 1% CF	298.5	488.5	381.8	82.4	151.2	138.0	140.3	434.2	156.3
Capacity	43.5	72.4	60.5	11.8	23.6	21.3	21.6	80.8	14.2
O&M	15.3	24.4	14.9	2.9	5.0	4.8	5.3	4.5	9.4
Environmental	1.9	0.3	1.7	1.1	1.1	1.0	0.8	1.0	1.6
Fuel	2.8	4.1	2.9	7.9	7.0	6.6	4.9	6.7	36.9
Total - 5% CF	63.5	101.3	80.0	23.7	36.7	33.7	32.6	93.0	62.0
Capacity	10.9	18.1	15.1	2.9	5.9	5.3	5.4	20.2	3.5
O&M	3.8	6.1	3.7	0.7	1.2	1.2	1.3	1.1	2.3
Environmental	1.9	0.3	1.7	1.1	1.1	1.0	0.8	1.0	1.6
Fuel	2.8	4.1	2.9	7.9	7.0	6.6	4.9	6.7	36.9
Total - 20% CF	19.4	28.6	23.4	12.7	15.3	14.1	12.4	29.0	44.3
Capacity	5.4	9.0	7.6	1.5	3.0	2.7	2.7	10.1	1.8
O&M	1.9	3.1	1.9	0.4	0.6	0.6	0.7	0.6	1.2
Environmental	1.9	0.3	1.7	1.1	1.1	1.0	0.8	1.0	1.6
Fuel	2.8	4.1	2.9	7.9	7.0	6.6	4.9	6.7	36.9
Total - 40% CF	12.0	16.5	14.0	10.9	11.7	10.8	9.0	18.4	41.4
Capacity	3.6	6.0	5.0	1.0	2.0	1.8	1.8	6.7	1.2
O&M	1.3	2.0	1.2	0.2	0.4	0.4	0.4	0.4	0.8
Environmental	1.9	0.3	1.7	1.1	1.1	1.0	0.8	1.0	1.6
Fuel	2.8	4.1	2.9	7.9	7.0	6.6	4.9	6.7	36.9
Total - 60% CF	9.6	12.5	10.8	10.3	10.5	9.8	7.9	14.8	40.4
Capacity	2.7	4.5	3.8	0.7	1.5	1.3	1.4	5.1	0.9
O&M	1.0	1.5	0.9	0.2	0.3	0.3	0.3	0.3	0.6
Environmental	1.9	0.3	1.7	1.1	1.1	1.0	0.8	1.0	1.6
Fuel	2.8	4.1	2.9	7.9	7.0	6.6	4.9	6.7	36.9
Total - 80% CF	8.4	10.5	9.3	10.0	9.9	9.2	7.3	13.0	39.9
Capacity	2.2	3.6	3.0	0.6	1.2	1.1	1.1	4.0	0.7
O&M	0.8	1.2	0.7	0.1	0.2	0.2	0.3	0.2	0.5
Environmental	1.9	0.3	1.7	1.1	1.1	1.0	0.8	1.0	1.6
Fuel	2.8	4.1	2.9	7.9	7.0	6.6	4.9	6.7	36.9
Total - 100% CF	7.6	9.3	8.3	9.8	9.6	8.9	7.0	12.0	39.6

	AP 1200 Nuclear	Whole Tree	Biomass Fluidized Bed	Solar Thermal	Solar Photo Voltaic	Wind Turbine w/Backup 1W for 2G	Wind Turbine w/Backup 1W for 1G	Wind Turbine w/Backup 2W for 1G
Capacity	370.2	299.6	434.7	431.5	445.7	255.1	255.1	255.1
Fixed O&M	179.0	97.3	174.4	105.3	23.4	30.7	30.7	30.7
Environmental	0.0	0.0	0.0	0.0	0.0	0.7	0.5	0.4
Variable	2.0	8.9	6.5	0.4	0.0	5.3	4.1	3.0
Total - 1% CF	551.2	405.9	615.6	537.2	469.2	291.8	290.5	289.2
Capacity	74.0	59.9	86.9	86.3	89.1	51.0	51.0	51.0
O&M	35.8	19.5	34.9	21.1	4.7	6.1	6.1	6.1
Environmental	0.0	0.0	0.0	0.0	0.0	0.7	0.5	0.4
Fuel	2.0	8.9	6.5	0.4	0.0	5.3	4.1	3.0
Total - 5% CF	111.9	88.3	128.3	107.7	93.8	63.1	61.8	60.5
Capacity	18.5	15.0	21.7	21.6	22.3	12.8	12.8	12.8
O&M	8.9	4.9	8.7	5.3	1.2	1.5	1.5	1.5
Environmental	0.0	0.0	0.0	0.0	0.0	0.7	0.5	0.4
Fuel	2.0	8.9	6.5	0.4	0.0	5.3	4.1	3.0
Total - 20% CF	29.5	28.7	37.0	27.2	23.5	20.3	19.0	17.7
Capacity	9.3	7.5	10.9			6.4	6.4	6.4
O&M	4.5	2.4	4.4			0.8	0.8	0.8
Environmental	0.0	0.0	0.0			0.7	0.5	0.4
Fuel	2.0	8.9	6.5			5.3	4.1	3.0
Total - 40% CF	15.8	18.8	21.7			13.1	11.8	10.5
Capacity	6.2	5.0	7.2			4.3	4.3	4.3
O&M	3.0	1.6	2.9			0.5	0.5	0.5
Environmental	0.0	0.0	0.0			0.7	0.5	0.4
Fuel	2.0	8.9	6.5			5.3	4.1	3.0
Total - 60% CF	11.2	15.5	16.7			10.7	9.4	8.1
Capacity	4.6	3.7	5.4			3.2	3.2	
O&M	2.2	1.2	2.2			0.4	0.4	
Environmental	0.0	0.0	0.0			0.7	0.5	
Fuel	2.0	8.9	6.5			5.3	4.1	
Total - 80% CF	8.9	13.9	14.1			9.5	8.2	
Capacity	3.7	3.0	4.3			2.6		
O&M	1.8	1.0	1.7			0.3		
Environmental	0.0	0.0	0.0			0.7		
Fuel	2.0	8.9	6.5			5.3		
Total - 100% CF	7.5	12.9	12.6			8.8		

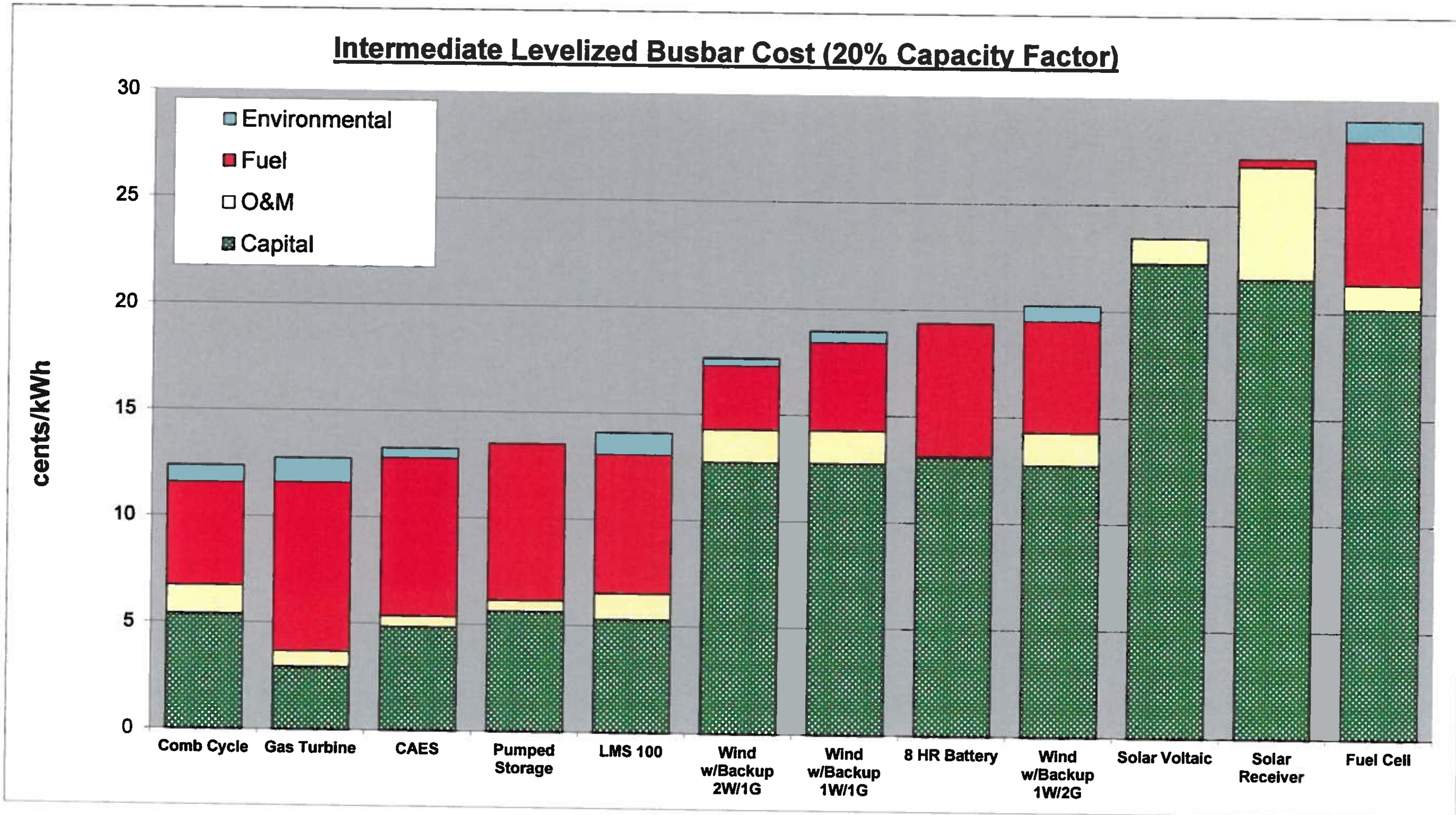
	Wind Turbine w/o Backup	Landfill Gas	Bio-Diesel Gen	Micro Turbine	Pumped Storage	CAES	Adv Battery 7.2 hr
Capacity	199.6	170.3	71.0	115.1	112.9	97.4	261.6
Fixed O&M	17.1	43.4	46.8	0.0	10.3	9.9	1.4
Environmental	0.0	0.0	1.6	0.0	0.0	0.5	0.0
Variable	0.8	1.0	34.1	8.0	7.3	7.4	6.2
Total - 1% CF	217.4	214.7	153.5	123.0	130.5	115.2	269.3
Capacity	39.9	34.1	14.2	23.0	22.6	19.5	52.3
O&M	3.4	8.7	9.4	0.0	2.1	2.0	0.3
Environmental	0.0	0.0	1.6	0.0	0.0	0.5	0.0
Fuel	0.8	1.0	34.1	8.0	7.3	7.4	6.2
Total - 5% CF	44.1	43.7	59.2	31.0	32.0	29.3	58.8
Capacity	10.0	8.5	3.5	5.8	5.6	4.9	13.1
O&M	0.9	2.2	2.3	0.0	0.5	0.5	0.1
Environmental	0.0	0.0	1.6	0.0	0.0	0.5	0.0
Fuel	0.8	1.0	34.1	8.0	7.3	7.4	6.2
Total - 20% CF	11.6	11.7	41.6	13.7	13.5	13.2	19.4
Capacity	5.0	4.3	1.8	2.9	2.8	2.4	
O&M	0.4	1.1	1.2	0.0	0.3	0.2	
Environmental	0.0	0.0	1.6	0.0	0.0	0.5	
Fuel	0.8	1.0	34.1	8.0	7.3	7.4	
Total - 40% CF	6.2	6.3	38.6	10.8	10.4	10.6	
Capacity		2.8	1.2	1.9			
O&M		0.7	0.8	0.0			
Environmental		0.0	1.6	0.0			
Fuel		1.0	34.1	8.0			
Total - 60% CF		4.5	37.6	9.9			
Capacity		2.1	0.9	1.4			
O&M		0.5	0.6	0.0			
Environmental		0.0	1.6	0.0			
Fuel		1.0	34.1	8.0			
Total - 80% CF		3.6	37.1	9.4			
Capacity		1.7	0.7	1.2			
O&M		0.4	0.5	0.0			
Environmental		0.0	1.6	0.0			
Fuel		1.0	34.1	8.0			
Total - 100% CF		3.1	36.9	9.1			



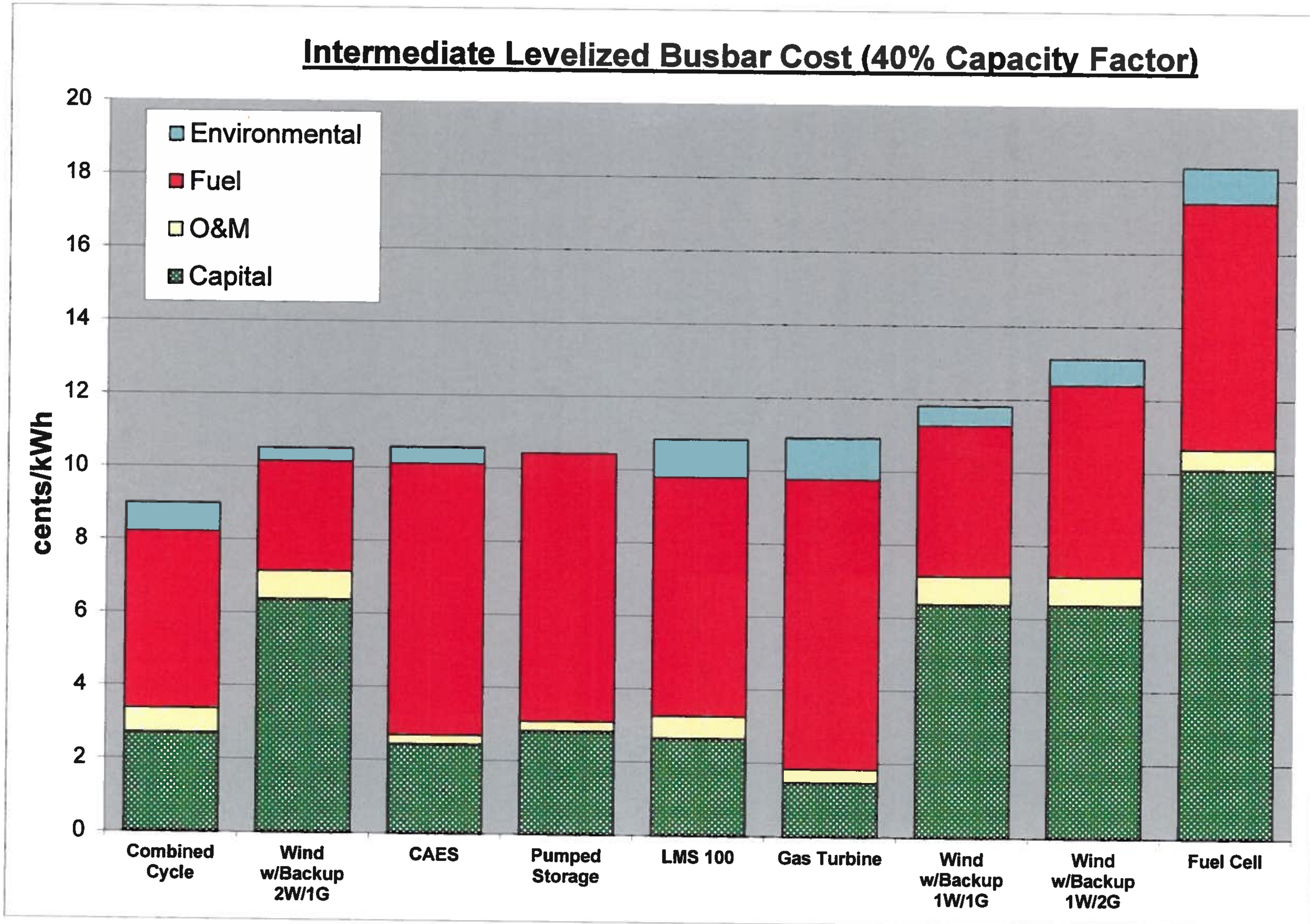
c/kWh	Gas Turbine	CAES	Pumped Storage	LMS 100	Combined Cycle	Diesel	8 HR Battery	Fuel Cell	Solar Voltaic	Solar Receiver
Capital	59.0	97.4	112.9	106.3	108.2	71.0	261.6	404.1	445.7	431.5
O&M	14.4	9.9	10.3	24.2	26.5	46.8	1.4	22.4	23.4	105.3
Environmental	1.1	0.5	0.0	1.0	0.8	1.6	0.0	1.0	0.0	0.0
Fuel	7.9	7.4	7.3	6.6	4.9	36.9	6.2	6.7	0.0	0.4
TOTAL	82.4	115.2	130.5	138.0	140.3	156.3	269.3	434.2	469.2	537.2



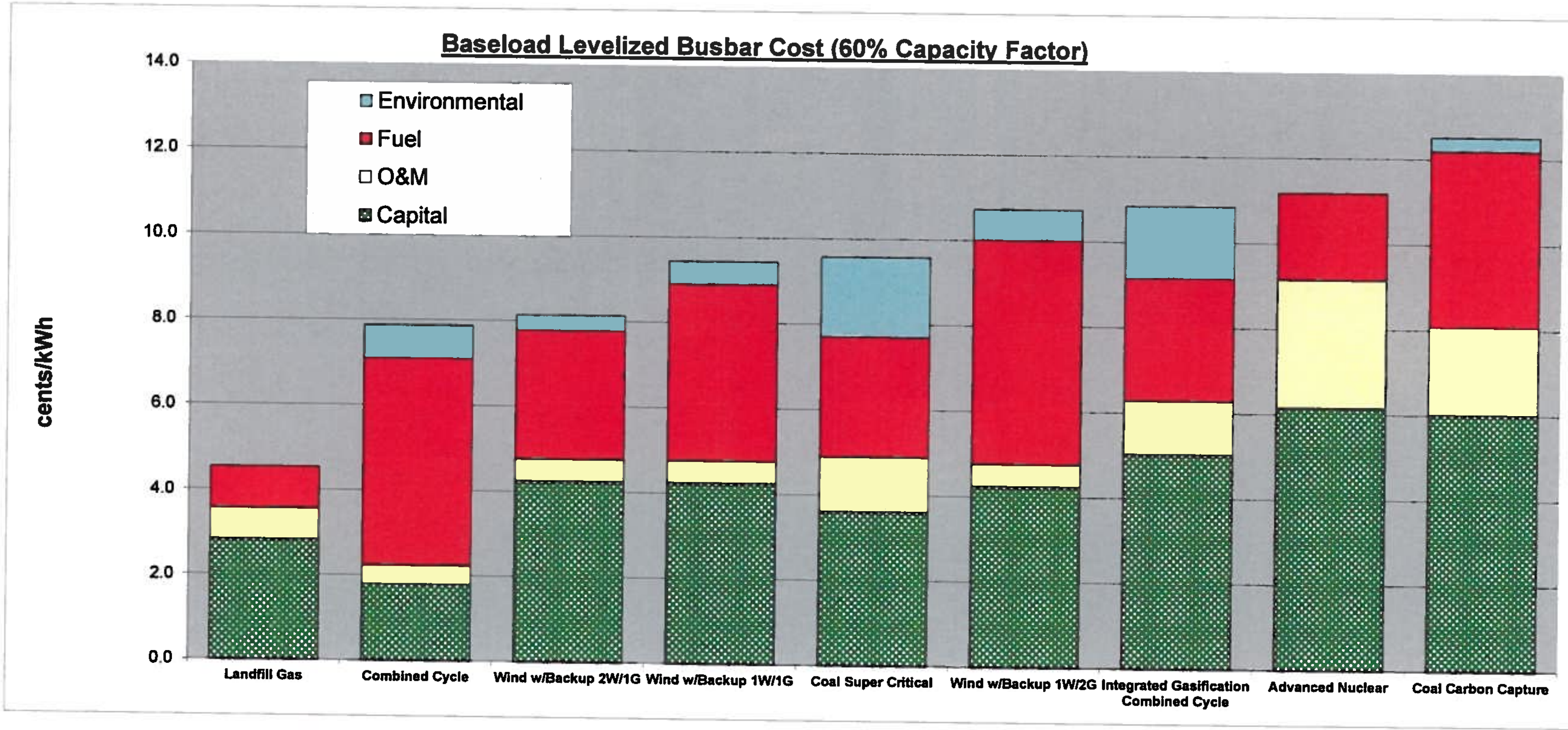
c/kWh	Gas Turbine	CAES	Pumped Storage	Combined Cycle	LMS 100	8 HR Battery	Diesel	Fuel Cell	Solar Voltaic	Solar Receiver
Capital	11.8	19.5	22.6	21.6	21.3	52.3	14.2	80.8	89.1	86.3
O&M	2.9	2.0	2.1	5.3	4.8	0.3	9.4	4.5	4.7	21.1
Environmental	1.1	0.5	0.0	0.8	1.0	0.0	1.6	1.0	0.0	0.0
Fuel	7.9	7.4	7.3	4.9	6.6	6.2	36.9	6.7	0.0	0.4
TOTAL	23.7	29.3	32.0	32.6	33.7	58.8	62.0	93.0	93.8	107.7



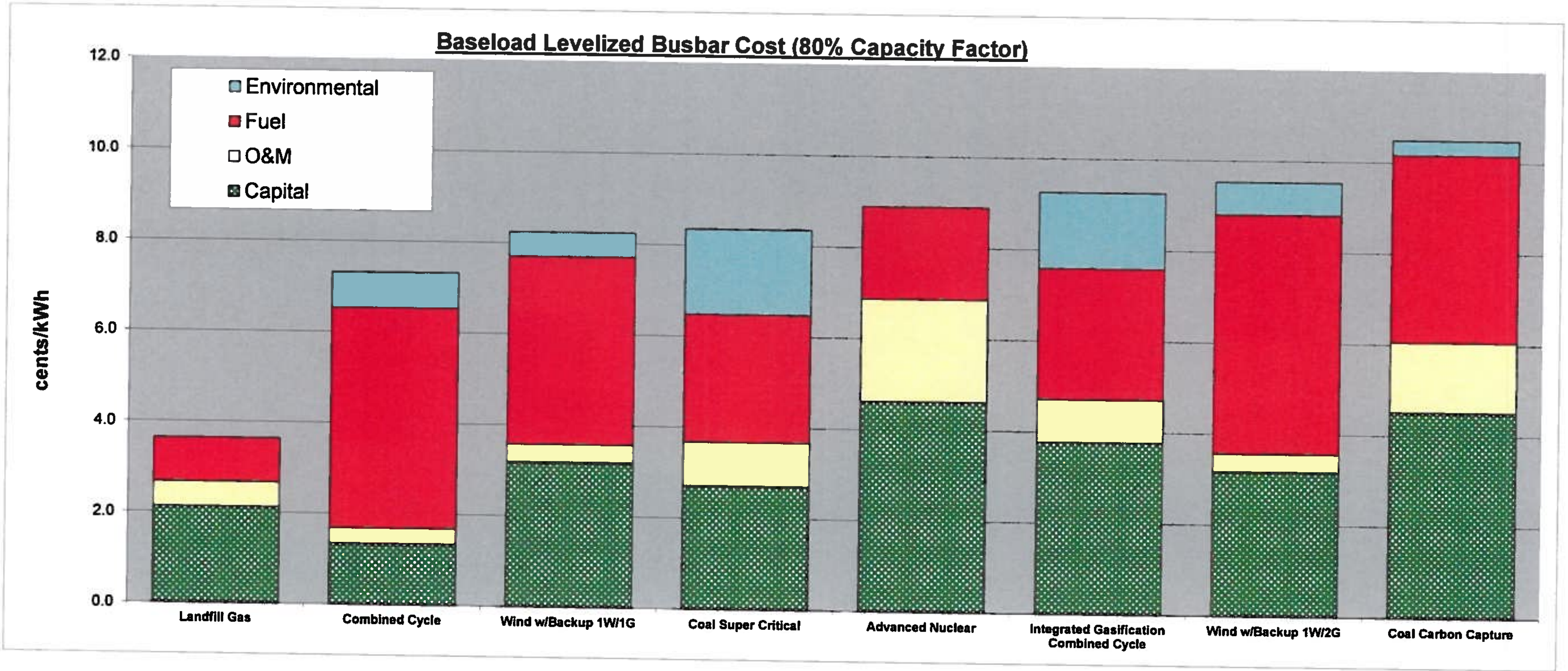
c/kWh	Comb Cycle	Gas Turbine	CAES	Pumped Storage	LMS 100	Wind w/Backup 2W/1G	Wind w/Backup 1W/1G	8 HR Battery	Wind w/Backup 1W/2G	Solar Voltaic	Solar Receiver	Fuel Cell
Capital	5.4	2.9	4.9	5.6	5.3	12.8	12.8	13.1	12.8	22.3	21.6	20.2
O&M	1.3	0.7	0.5	0.5	1.2	1.5	1.5	0.1	1.5	1.2	5.3	1.1
Environmental	0.8	1.1	0.5	0.0	1.0	0.4	0.5	0.0	0.7	0.0	0.0	1.0
Fuel	4.9	7.9	7.4	7.3	6.6	3.0	4.1	6.2	5.3	0.0	0.4	6.7
TOTAL	12.4	12.7	13.2	13.5	14.1	17.7	19.0	19.4	20.3	23.5	27.2	29.0



c/kWh	Combined Cycle	Wind w/Backup 2W/1G	CAES	Pumped Storage	LMS 100	Gas Turbine	Wind w/Backup 1W/1G	Wind w/Backup 1W/2G	Fuel Cell
Capital	2.7	6.4	2.4	2.8	2.7	1.5	6.4	6.4	10.1
O&M	0.7	0.8	0.2	0.3	0.6	0.4	0.8	0.8	0.6
Environmental	0.8	0.4	0.5	0.0	1.0	1.1	0.5	0.7	1.0
Fuel	4.9	3.0	7.4	7.3	6.6	7.9	4.1	5.3	6.7
TOTAL	9.0	10.5	10.6	10.4	10.8	10.9	11.8	13.1	18.4



c/kWh	Landfill Gas	Combined Cycle	Wind w/Backup 2W/1G	Wind w/Backup 1W/1G	Coal Super Critical	Wind w/Backup 1W/2G	Gasification Combined Cycle	Advanced Nuclear	Coal Carbon Capture
Capital	2.8	1.8	4.3	4.3	3.6	4.3	5.0	6.2	6.0
O&M	0.7	0.4	0.5	0.5	1.3	0.5	1.2	3.0	2.0
Environmental	0.0	0.8	0.4	0.5	1.9	0.7	1.7	0.0	0.3
Fuel	1.0	4.9	3.0	4.1	2.8	5.3	2.9	2.0	4.1
TOTAL	4.5	7.9	8.1	9.4	9.6	10.7	10.8	11.2	12.5



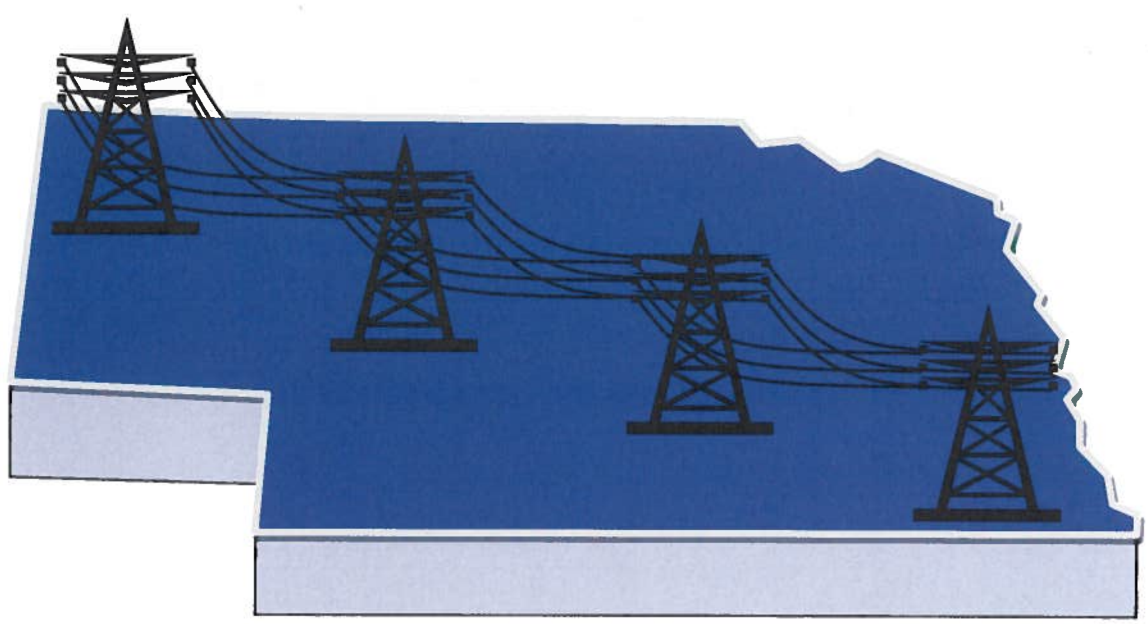
c/kWh	Landfill Gas	Combined Cycle	Wind w/Backup 1W/1G	Coal Super Critical	Advanced Nuclear	Integrated Gasification Combined Cycle	Wind w/Backup 1W/2G	Coal Carbon Capture
Capital	2.1	1.4	3.2	2.7	4.6	3.8	3.2	4.5
O&M	0.5	0.3	0.4	1.0	2.2	0.9	0.4	1.5
Environmental	0.0	0.8	0.5	1.9	0.0	1.7	0.7	0.3
Fuel	1.0	4.9	4.1	2.8	2.0	2.9	5.3	4.1
TOTAL	3.6	7.3	8.2	8.4	8.9	9.3	9.5	10.5

Appendix F: Nebraska Subregional Transmission Plan

Nebraska Subregional Transmission Plan (2011 – 2021)

Developed By:
Nebraska Subregional Planning Group

Final Report
September 2011



NEBRASKA SUBREGIONAL TRANSMISSION PLAN
(2011 - 2021)

This Nebraska Subregional Transmission Plan documents the results of a coordinated study and evaluation of the Nebraska Subregional Transmission System. The following individuals contributed to this effort and the development of the Final Report:

Travis Burdett	Grand Island Electric Department
Allen Meyer	Hastings Utilities
Alan Burbach	Lincoln Electric System
Billy Cutsor	Municipal Energy Agency of Nebraska
Dustin Betz	Nebraska Public Power District
Randy Lindstrom	Nebraska Public Power District (Chairman)
Dan Lenihan	Omaha Public Power District
Jon Shipman	Omaha Public Power District
Bruce Mitchell	Tri-State G&T Association
Dan Belk	Western Area Power Administration

Nebraska Subregional Planning Group
MAPP 2011 Regional Plan
(2011 through 2021)

1.0 Introduction

The Nebraska Subregional Planning Group (SPG) was originally formed under the Mid-continent Area Power Pool (MAPP) Transmission Planning Subcommittee (TPSC) in 1997. The primary objective of the Nebraska SPG is to develop a coordinated ten-year transmission plan for the Nebraska subregion on an annual basis. The Nebraska SPG develops coordinated transmission plans for the facilities located in the state of Nebraska and coordinates those plans with regional Planning Coordinators. The Member participants of the Nebraska SPG and those engaged in the development of the 2011 Nebraska SPG 10 Year Plan:

Grand Island Electric Department (GRIS)
Hastings Utilities (HU)
Lincoln Electric System (LES)
Municipal Energy Agency of Nebraska (MEAN)
Nebraska Public Power District (NPPD)
Omaha Public Power District (OPPD)
Tri-State G & T Association (TSGT)
Western Area Power Administration (WAPA)

The Nebraska Transmission Plan shall be consistent with applicable standards and requirements established by North American Electric Reliability Corporation (NERC), Federal Energy Regulatory Commission (FERC), Midwest Reliability Organization (MRO), MAPP, and Southwest Power Pool (SPP). In 2009, LES, NPPD, and OPPD became Members of SPP and the SPP Regional Transmission Organization (RTO) is the Planning Coordinator for these entities. LES, NPPD, and OPPD coordinate their long term transmission expansion plans through the SPP Transmission Expansion Plan (STEP) and the Integrated Transmission Plan (ITP) processes. All of the Nebraska SPG entities are Members of the MRO Regional Entity. NPPD's and OPPD's membership in the MAPP Regional Transmission Committee (RTC) will expire during the last week of September, 2011. As such, the Nebraska SPG will no longer be a formal Subregional Planning Group under the recently approved MAPP Second Restated Agreement. All of the Nebraska SPG Members recognize the importance of ongoing subregional transmission planning coordination activities within the state and the Nebraska SPG will continue as an independent Subregional Planning Group.

The Members of the Nebraska SPG have reviewed the 2011 MAPP System Performance Assessment and have incorporated the latest SPP STEP analysis into the facility plans submitted in this 2011 Nebraska SPG Plan. The Nebraska SPG has also included new facility plan details for facilities which have been recently identified through other Generator Interconnection, Transmission Service, and local area planning studies. The detailed listing of all planned transmission lines, transformers, devices, and generators for the Nebraska subregion is contained in Appendix A: Forms 1-3 of this 2011 Plan. The following subsections provide a summarized overview of the 2011 Ten-Year Plan involving the members of the Nebraska SPG.

2.0 Grand Island Electric Department

Planned Transmission Facilities

New Line into Substation F – A new 115 kV transmission line will be constructed to connect Grand Island's Substation F to NPPD's St. Libory Junction Substation approximately 7 miles north of Grand Island. The St. Libory Junction Substation currently consists of three circuit switchers mounted on wood poles. A new 115 kV substation is currently under construction in its place to accommodate the new transmission line. The new substation is scheduled for an in-service date later this year. The current schedule projects a completion date for the new transmission line by the end of 2012.

Re-conductor two 115 kV lines – Following the addition of the new transmission line into Substation F, the transmission line between Grand Island's Substation A and Substation B as well as the line between Substation B and Substation F will be re-conductored from 477 MCM ACSR to T-2 336.4 MCM ACSR to carry anticipated load currents. The current schedule projects a completion date of 2014.

Planned Substation Facilities

Addition of Substation J – Due to increased load growth in the southwest area of Grand Island, specifically the industrial park, additional substation capacity is needed. Substation J will be installed on the northwest corner of the Platte Generating Station property beneath the 115 kV transmission line between Substation D and Substation A. The current schedule projects a completion date of 2013.

Whelan Energy Center Unit #2 Participation

Grand Island entered into a power purchase agreement with Public Power Generation Agency (PPGA) for 6.82% of the capacity and energy from the Whelan Energy Center Unit # 2 (WEC2) power plant project. WEC2 is a 220 MW coal-fired power plant which began commercial operation in May of 2011.

3.0 Hastings Utilities

Whelan Energy Center Unit #2

Public Power Generation Agency (PPGA), a nonprofit entity formed under the Interlocal Cooperation Act of the State of Nebraska, has completed construction of a second coal-fired generating unit at the Whelan Energy Center Station. Whelan Energy Center Unit 2 (WEC2) began commercial operation on May 1, 2011 with a nominal net output of 220 MW. WEC2 is owned by PPGA which consists of Grand Island Utilities, Hastings Utilities, Heartland Consumers Power District (Madison, SD), MEAN, and Nebraska City Utilities. Hastings Utilities is acting on behalf of PPGA as Project Construction Manager and Project Operating Agent. The output of WEC2 will be allocated to the members of PPGA as follows:

Member	% Output	MW Output
Grand Island Utilities	6.82	15
Hastings Utilities	15.91	35
Heartland Consumers PD	36.36	80
MEAN	36.36	80
Nebraska City Utilities	4.55	10
Total	100.00	220

NPPD and PPGA in cooperation prepared the Whelan Energy Center Unit 2 Interconnection, Delivery, and Facilities Study dated November 2006. The WEC2 Study was presented by PPGA, in December 2006, to the MAPP DRS (Design Review Subcommittee) for approval. The MAPP DRS approved the WEC2 Study contingent upon the following items:

1. Whelan Energy Center 115 kV Substation Expansion to an eight terminal breaker-and-a-half scheme.
2. New 2.5 Mile Energy Center – Hastings (NPPD) 115 kV Transmission Line
3. Re-conductor existing Energy Center – Hastings (City) 115 kV Transmission Line (4.5 miles)
4. Re-conductor existing Energy Center – Sutton – Geneva 115 kV transmission line sections (35 miles)
5. City of Hastings 115 kV Ring Substation Equipment Upgrades (1200 Amp Minimum)
6. Re-conductor Grand Island – Aurora 115 kV transmission line section (13.8 Miles).
7. Construct Hastings Bypass – North Hastings (Doniphan/Prosser Tap) 115 kV line and substation (3.5 miles).
8. Hastings 230/115 kV transformer re-termination, breaker replacements, and other identified 115 kV overloads and voltage violations.

All items identified above were completed in advance of WEC2 commercial operation.

4.0 Lincoln Electric System

The Lincoln Electric System (LES) Service Area covers approximately 200 square miles within Lancaster County and includes the communities of Waverly, Prairie Home, Walton, Cheney, and Emerald. The LES system comprises 76 miles of 345 kV lines, 12 miles of 161 kV lines, and 197 miles of 115 kV lines. LES set a new peak load of 786 MW in July 2011.

LES is participating or planning to participate in several wind farm developments in the NPPD area, which include the following wind sites and the LES capacity amount:

- Elkhorn Ridge 6 MW
- Crofton Bluffs 3 MW
- Laredo Ridge 10 MW
- Broken Bow 10 MW

Transmission Projects Expected In-Service In the Next Ten Years

LES will be rebuilding the 2.1-mile 57th & Garland to 84th & Leighton 115 kV line to a higher thermal capacity. The project has an anticipated completion date of May 1, 2012. This 115 kV line will be rebuilt using bundled T2 397.5 MCM ACSR phase conductors.

LES will be replacing 5.6-miles of 115 kV underground cables with a combination of 115 kV overhead and underground line segments. The existing cable, installed in the year 1976, is approaching the end of its 40-year life. This project has an expected completion date of August 2013, and includes construction of a new 115 kV line from 17th & Holdrege to 21st & N (new sub) to 30th & A to 56th & Everett. The new 21st & N substation includes a 115/12 kV, 39.2 MVA transformer and associated switchgear.

LES plans to rebuild the 16-mile Sheldon to Folsom & Pleasant Hill 115kV line (LN-1099) by the 2013 summer. In December 2010, this 115kV line had its thermal rating reduced to 43 MVA due to line clearance issues, and was taken out of service for an extended period over the 2011 summer. SPP's ITPNT study includes a rebuild of this 115kV line as a project, and LES expects a NTC to be issued in January 2012.

LES plans to add a new 5.5-mile 115 kV line from a new SW 7th & Bennet substation to the existing 40th & Rokeby substation. The proposed in-service date is 2015. The new SW 7th & Bennet substation will tap the recently rebuilt Sheldon to Folsom & Pleasant Hill (LN-1197). This substation will be a three terminal 115kV switching substation, and will be configured to accommodate the addition of a 115-12kV transformer and associated switchgear in the future. The 40th & Rokeby substation will have installed two additional 115kV breakers, switches, associated bus and relaying to convert it to a ring-bus configuration.

LES plans to install a second 336 MVA 345/115 kV autotransformer at the NW68th & Holdrege Substation, with an expected in-service date of 2022. The proposed in-service date has slipped by two years.

Future 115 kV Substations Expected In-Service In the Next Ten Years

The proposed NW 70th & Fairfield substation has a planned in-service date of 2012, and will tap into the existing NW68th & Holdrege - NW12th & Arbor 115 kV line. The surrounding load will initially be supplied by a 115/12 kV, 39.2 MVA transformer, with the transformer protected by a circuit switcher. This plan also has LES retiring both 115/35 kV transformers located at the West Lincoln substation. Transformers T082 and T083 are scheduled to be retired by 2015.

5.0 Municipal Energy Agency of Nebraska

Municipal Energy Agency of Nebraska (MEAN) is a transmission customer of NPPD. In general, transmission improvements necessary to serve MEAN load in the Nebraska area are planned and constructed by NPPD. MEAN's loads are included in NPPD's transmission planning analyses and studies. MEAN recognizes the need for their members to generate under certain conditions.

On February 1, 2010, MEAN began taking network service from SPP. MEAN projects their loads within the Nebraska / Iowa area to increase by approximately 15% over the next ten years.

Whelan Energy Center 2

MEAN is part of the Whelan Energy Center Unit 2 (WEC2) project that began commercial operation on May 1, 2011 with a nominal net output of 220 MW.

6.0 Nebraska Public Power District

The Nebraska Public Power District (NPPD) transmission system encompasses 4401 miles of high voltage transmission lines in the state of Nebraska. This is comprised of 1015 miles of 345 kV, 643 miles of 230 kV and 2743 miles of 115 kV facilities. NPPD established an all-time native peak load level of 2671 MW which occurred in July of 2006. NPPD's current accredited total generation is 3157 MW which is comprised of coal, nuclear, gas, oil, and renewable resources such as hydro and wind. The NPPD Balancing Area encompasses a significant portion of the state of Nebraska and also includes transmission facilities and load owned by Grand Island, Hastings, MEAN, Tri-State, and WAPA. The all-time NPPD Balancing Area peak load reached 3226 MW in August of 2010. The NPPD system is characterized by summer peak irrigation loads, considerable seasonal load level variations, western Nebraska stability limitations, and four regional constrained transmission interfaces. The following subsections describe current planned major projects and facility plans for the NPPD system.

Bloomfield Wind Generation Interconnection, Delivery & Facilities
NPPD Energy Supply has executed Generator Interconnection Agreements and Power Purchase Agreements with two wind project developers for two new wind generation projects which interconnect at NPPD's Bloomfield 115 kV Substation. The 123 MW wind generation project includes the 81 MW Elkhorn Ridge Wind Project and the 42 MW Crofton Bluffs Wind Project. NPPD completed the Bloomfield Wind Generation Interconnection, Delivery & Facilities Study to establish the transmission facility requirements necessary for the interconnection and delivery of these new wind generation projects. The following is a summarized list of the transmission facility plan:

- +/- 5 MVAR Dynamic Reactive Power Compensation
- Upgrade Gavins Point – Bloomfield 115 kV Line to 159 MVA
- Upgrade Bloomfield – Creighton 115 kV Line to 159 MVA
- Upgrade Creighton – Neligh 115 kV Line to 143 MVA
- Upgrade Neligh – Petersburg 115 kV Line to 113 MVA
- Upgrade Petersburg – Albion 115 kV Line to 113 MVA
- Upgrade Battle Creek – County Line Tilden 115 kV Line to 120 MVA

NPPD has completed all of the facility upgrades associated with the NPPD owned facilities required for the interconnection and delivery of the Elkhorn Ridge and Crofton Bluffs wind generation projects. The Elkhorn Ridge DVAR system has also been installed and commissioned. The Elkhorn Ridge 81 MW wind project went into commercial operation in March of 2009. The Crofton Bluffs 42 MW wind project is currently in the engineering design phase and it has a current projected in-service date of December 2012.

Cooper 345/161 kV Transformer Addition
During the past ten years, there have been significant changes to the regional grid conditions which have resulted in a continued degradation of the off-site grid capacity associated with NPPD's Cooper Nuclear Station (CNS). As a result of diminished reliability margins affecting the Cooper area, NPPD is executing a plan to improve the off-site grid capacity for CNS. This plan involves the addition of a second 300 MVA 345/161 kV transformer at Cooper along with 161 kV and 69 kV facility additions to improve the off-site grid backup capability at CNS. These facilities are currently planned for a May 2012 in-service date.

Ogallala 230/115 kV Transformer Replacement
Due to load growth in the NPPD / Tri-State (NETS) region, there are first contingency thermal overloads of the existing 187 MVA 230/115 kV transformer at Ogallala during summer peak load conditions. This first contingency transformer overload condition was identified in the MAPP TRAWG Assessment and the SPP STEP. NPPD and Tri-State have evaluated this region through multiple joint planning study efforts over the past few years. They have recently documented the results of these joint planning efforts in the Southwest Nebraska NETS Transmission Planning Study. As a result of this study, NPPD

is planning to replace the existing 187 MVA unit with a new 336 MVA 230/115 kV transformer. The in-service date for this project is currently June 2014.

Twin Church / South Sioux City Area

The Twin Church / South Sioux City area is experiencing substantial load growth due to new industrial plants and planned expansions at existing plants. As a result of this rapid load growth, a long term transmission planning study was performed to establish the most effective transmission expansion plan to meet the local area load delivery requirements. The Twin Church / South Sioux City Transmission Study recommended the construction of the following new facilities:

- Construct new South Sioux City 115/69 kV Substation
- Install a New 70 MVA 115/69 kV Transformer
- Install Two 69 kV 10.8 MVAR cap banks
- Rebuild Existing Twin Church 115 kV substation to a breaker and a half scheme
- Construct a New 7-mile 115 kV transmission line (Circuit 1 / South Route) from the Twin Church Substation to the new South Sioux City Substation
- Construct a New 10-mile 115 kV transmission line (Circuit 2 / North Route) from the Twin Church Substation to the new South Sioux City Substation

The current planned in-service date for the Twin Church / South Sioux City Transmission Expansion Project is September 2012.

Keystone Pipeline

TransCanada has completed construction of Phase 1 of their Keystone oil pipeline from Alberta, Canada to Illinois. Phase 1 resulted in five new pumping station load additions throughout the eastern Nebraska area. NPPD and our wholesale partners have completed construction of the transmission, sub-transmission, and distribution facilities at these five locations to serve the new pumping station loads. The initial pumping station loads are in-service with expansion up to full capacity currently planned for 2012.

TransCanada is also planning Phase 2 of a pipeline project which will encompass a new pipeline from Alberta, Canada down to the Gulf of Mexico refinery region. The Keystone XL Phase 2 project will involve another five new pumping station load additions in the NPPD service area. NPPD has completed the Keystone XL Phase 2 Radial Transmission Analysis Study and the NPPD / Steele City – Westar / Knob Hill 115 kV Interconnection Project Study. As a result of this study-work, the following Keystone XL Transmission Expansion Plan facilities have been recommended:

- *Pump Station 22 (Stuart South)*
    - New 28 Mile 115 kV line from O'Neill – PS 22 Stuart South
    - New 18 MVAR 115 kV Capacitor Bank at O'Neill
    - New 9 MVAR Capacitor Bank at O'Neill 69 kV
    - Expand Ainsworth 9 MVAR 115 kV Capacitor Bank to 15 MVAR
    - New 15 MVAR 115 kV Capacitor Banks at Pump Station 22

- *Pump Station 23 (Ericson)*
  - New 37 Mile 115 kV line from Petersburg – PS 23 Ericson
  - New 15 MVAR Capacitor Bank at Petersburg North 115 kV
  - New 6 MVAR Capacitor Bank at Ericson 115 kV
- *Pump Station 24 (Central City North)*
  - New Clarks 115 kV Substation (Between Central City and Silver Creek)
  - New 9 Mile 115 kV line from Clarks 115 kV – PS 24 Central City North
  - New 18 MVAR 115 kV Capacitor Bank at Clarks
- *Pump Station 25 (McCool)*
  - No transmission additions necessary
- *Pump Station 26 (Steele City)*
  - New 115 kV line from Steele City – Kansas Border – Knob Hill (WERE)
    - NPPD responsible for 2 Miles from Steele City – Kansas Border
  - New 115 kV line from Steele City – Keystone PS 26

The new Steele City – Knob Hill 115 kV transmission line interconnection was energized in September of 2010. The 15 MVAR Capacitor bank at Petersburg North was energized in January of 2011. All of the other Keystone XL Phase 2 facilities are currently planned to be in-service in November of 2012.

Axtell - Spearville 345 kV Transmission Project

NPPD has been working with SPP, SPP Member Utilities, and ITC (Independent Transmission Company) Great Plains to further develop the Axtell – Spearville 345 kV Transmission Line Project. NPPD has been promoting the Axtell – Spearville 345 kV Project as a solution to the growing congestion associated with the current Western Nebraska – Western Kansas Flowgate (Gentleman – Red Willow – Mingo 345 kV path). The Axtell – Spearville 345 kV project was identified by KETA (Kansas Electric Transmission Authority) for further development as an economic project to enhance the ability to interconnect wind generation in the state of Kansas. SPP performed economic planning studies associated with this project and it was subsequently included as a Balanced Portfolio project in SPP. SPP Board of Directors approved the Balanced Portfolio in April of 2009 and SPP has issued a Notice To Construct to NPPD to construct the Axtell – Kansas Border portion of the Axtell – Spearville Balanced Portfolio Project. This new line is essentially a parallel path to the existing Western Nebraska – Western Kansas Flowgate. NPPD has performed FCITC analysis associated with this new line project and it shows significant positive impacts on the regional transfer capability currently constrained by the Western Nebraska – Western Kansas Flowgate. The new Axtell – Spearville 345 kV line project would involve approximately 226 miles of new 345 kV transmission line from Axtell, Nebraska to Spearville, Kansas. There is also a planned interconnection of this line at a new Post Rock Substation, located next to the Knoll Substation near Hays, Kansas. NPPD is responsible for approximately 53 miles of the new 345 kV line from Axtell to the Kansas border. ITC Great Plains will construct the two Kansas segments of this line project which is approximately 173 miles from the Nebraska/Kansas border to Post Rock to Spearville. SPP, ITC, and NPPD are currently planning an in-service date of June 2013 for this Balanced Portfolio Project.

Laredo Ridge (Petersburg) 80 MW Wind Project
NPPD Energy Supply has executed a SPP LGIA (Large Generator Interconnection Agreement) and PPA (Power Purchase Agreement) for the Laredo Ridge 80 MW Wind generating facility located near Petersburg, NE. NPPD performed generation interconnection, delivery, and facility studies for a new 80 MW wind generation facility near the existing Petersburg 115 kV tap substation. These studies were approved through the MAPP processes in 2008. The new Petersburg North 115 kV Substation was energized in October of 2010. The Laredo Ridge Wind Farm went commercial in February 2011.

Broken Bow 80 MW Wind Project
NPPD Energy Supply has executed a SPP LGIA and PPA for the development of a new 80 MW wind project near Broken Bow, NE. NPPD Transmission Planning performed generation interconnection, delivery, and facility studies for a new 80 MW wind generation facility located near the existing Broken Bow 115 kV substation. These studies were approved through the MAPP processes in 2008. The existing Canaday 100 MVA 230/115 kV Transformer was identified in the delivery studies as a limiting facility. A new Canaday 336 MVA 230/115 kV Transformer upgrade was constructed and was placed in-service in October of 2010. The new Broken Bow North 115 kV Substation will be constructed as the point of interconnection between the wind farm and the NPPD 115 kV transmission system. A new 9-Mile 115 kV line will be constructed to tie the Broken Bow North Substation and Broken Bow Wind Farm into NPPD's Broken Bow 115 kV Substation. The new Broken Bow 80 MW Wind Project and required transmission interconnection facilities are currently planned to be in-service in December of 2012.

Stegall 345/230 kV Transformer Addition
To mitigate emergency voltage violations for the contingent loss of the existing Stegall 345/230 kV transformer, a second Stegall 345/230 kV transformer is identified in the SPP STEP. The 2011 MAPP System Performance Assessment documents 17 bus voltage violations in western Nebraska for this single contingency during the 2016 Winter Peak analysis. NPPD, Tri-State, BEPC and WAPA are coordinating on a joint project to add a second Stegall 345/230 kV 400 MVA transformer at the Stegall MBPP (Missouri Basin Power Project) Substation and a second 230 kV transmission line from the Stegall MBPP Substation to the Stegall WAPA Substation. The current projected in-service date for this project is June 2015.

NPPD MAPP TRAWG Assessment and SPP STEP Comments / Plans
NPPD has reviewed the 2011 MAPP System Performance Assessment which noted some additional areas of potential future thermal and voltage concerns. NPPD utilized this 2011 MAPP System Performance Assessment as input for the 2011 Nebraska SPG Plan. NPPD is also engaged in the SPP STEP (SPP Transmission Expansion Plan) and ITP10 (Integrated Transmission Plan) processes and some of these areas were also flagged in those long term planning processes. All of these issues are directly related to the projected load growth assumptions in the NPPD system. As such, the timing of the planned facility additions will be dependent on the most recent and most accurate load growth assumptions. The previously mentioned projects in this section were developed to address

previously identified voltage and thermal issues from prior Assessments. NPPD also has developed a list of smaller potential fixes for the voltage and thermal issues identified, but we have not committed to all of these, pending a review of the impacts of latest load forecasts on future year models. Further, NPPD will take these issues into our next long term planning cycle and perform much more detailed studywork to develop optimal solutions. Here is a list of smaller planned and proposed facilities to address all of the voltage and thermal issues identified in the MAPP 2011 System Performance Assessment and SPP STEP:

- Gordon 9 MVAR 115 kV Cap Bank – June 2012
- Kearney 36 MVAR 115 kV Cap Bank – June 2012
- North Platte – Maloney 115 kV Line Uprate – June 2012
- Loup City – North Loup 115 kV Line Uprate – June 2012
- Albion – Spalding 115 kV Line Uprate – June 2013
- Canaday – Lexington 115 kV Line Uprate – June 2013
- Albion – Genoa 115 kV Line Uprate – June 2015
- Holdrege 18 MVAR 115 kV Cap Bank – June 2015
- Cozad – Gothenburg 115 kV Line Uprate – June 2016
- Keystone – Ogallala 115 kV Line Uprate – June 2016
- Sheldon – Firth 115 kV Line Uprate – June 2017

The thermal overload violation for the Sheldon – Firth 115 kV uprate project is caused by an OPPD NERC Category B and C contingency. OPPD and NPPD will coordinate actions to mitigate high loading for this facility. NPPD has committed to the construction of the first six items in this list. Additional detailed information regarding these projects is contained in Appendix A: Forms 1 and 2.

7.0 Omaha Public Power District

The Omaha Public Power District (OPPD) transmission system consists of about 1,300 miles of transmission lines (69 kV, 161 kV, and 345 kV) and serves 343,000 customers (population of 754,000). The OPPD service area spans approximately 5000 square miles across 13 counties in Eastern Nebraska.

The following transmission and resource projects are planned in the OPPD service area over the 10 year planning horizon:

- An existing large OPPD retail customer located near Ft. Calhoun, NE significantly increased its electrical usage in 2009 & 2010. OPPD has built and rebuilt new 161 kV transmission (~5.5 miles) and constructed one new 161 kV substation (Sub 1305) to serve this additional load. OPPD will build another new 161 kV substation (Sub 1341) and build new 161 kV transmission (~1 mile) by fall 2011 to serve a new load addition in 2012.

- As part of OPPD's Transmission & Distribution Improvement Plan (TDIP) initiative to replace aging T&D infrastructure, OPPD is planning to rebuild / uprate some 69 kV transmission in the OPPD West Rural 69 kV system. Specifically, the 69 kV transmission line from Yutan, NE to Valley, NE (S983-S902) is planned for rebuild / uprate by winter 2012.

- OPPD is planning a new 161kV substation (Sub 1366) to serve future load growth in the Bellevue, NE area. S1366 will be cut into the existing S1244-S1258 161kV line with an expected in-service date of June 2013.

- OPPD is planning to take part in the joint construction of a new 345 kV line from Nebraska City (Sub 3458) to Maryville to Sibley, Missouri. This project was issued as a result of the SPP Priority Projects Study. The expected in-service date for this project will be summer 2017.

- OPPD completed its Interconnection and Facilities agreement with a customer for a new 60 MW wind farm (Flat Water Wind Farm) in Richardson County. This facility went in-service in fall 2010. This facility interconnects with OPPD at a newly built 161 kV substation (Sub 1399) tapped into the Humboldt – Kelly 161 kV line.

- OPPD completed a power purchase agreement to purchase the output of a new 40.5 MW wind farm in Boone County. The expected in-service date for this project will be winter 2011. This facility interconnects with NPPD's Petersburg North 115 kV Substation. A transmission service request for delivery to OPPD load is being processed in the SPP Aggregate Delivery Study process.

- OPPD is planning a power uprate of 67 MW at the Ft. Calhoun Nuclear Station (FCNS). OPPD plans to complete the uprate work at FCNS during the fall 2012 refueling and maintenance outage. The FCNS Uprate Interconnection, Delivery, & Facility Study has been completed. Substation modifications will be completed to increase capacity on a Central Omaha 161 kV transmission circuit (S1221-S1255).

- OPPD is planning to add Cass County Unit 3 (CC3) at Cass County Station. This unit is the combined cycle steam turbine portion for this station. This unit will have a net capability of 208 MW and an expected in-service date of summer 2021.

OPPD Transmission Assessment and Plans

NERC Category A: System intact

There were no thermal or voltage violations classified as NERC Category A in the power flow analysis for OPPD facilities.

NERC Category B: Single Contingencies

- ***Thermal violations***

S917 – S918 69kV line
Thermal violations on this facility show up in the ten year-out summer peak case for the loss of the S1209 T1 161/69kV autotransformer. This violation could be addressed by uprating the S917-S918 69 kV line.

S906 South – S924 69 kV line
Thermal violations on this facility show up in the ten year-out summer peak case for the loss of the S1201 T1 161/69kV autotransformer. This violation could be addressed in op guides by dispatching generation at Jones Street units 1 and/or 2 and backing down generation at Sarpy County 1 and/or 2 or by uprating the S906 South-S924 69 kV line.

S985 – Plattsmouth 69kV line
Thermal violations on this facility show up in the near-term and out-year summer peak cases when a large amount of load is left radial from S962 at Nebraska City Utilities. This violation could be addressed in op guides by redispatching generation at Nebraska City Utilities, by uprating the S985 – Plattsmouth 69 kV circuit or by the addition of a new 161/69 kV autotransformer at future Sub 1262.

S906 North – S928 69kV line
Thermal violations on this facility show up in the ten year-out summer peak for loss of S921-S942 69kV line. This violation could be addressed by uprating the S906 North – S928 69kV line.

S907 – S919 69kV line
Thermal violations on this facility show up in the ten year-out summer peak for loss of S919-S950 69kV line or the S1250 T1 autotransformer. This violation could be addressed in op guides by reducing generation at North Omaha unit 1 or by uprating the S907-S919 69kV line.

S921 – S942 69kV line
Thermal violations on this facility show up in the ten year-out summer peak for loss of S906 N-S928 69kV. This violation could be addressed by uprating the S921 – S942 69kV line.

Humboldt T4 161/69 kV autotransformer (S975 T4)
Thermal violations on this facility only showed up in both the five and ten year-out summer and winter peak conditions for loss of the S1263 T1 161/69 kV autotransformer. This violation could be addressed in operating guides by dispatching local area 69 kV generation or through facility additions involving installation of future S975 161/69 kV autotransformer or an addition of a new 161/69 kV autotransformer at future Sub 1262.

S1206 T2 161/69 kV autotransformer
The thermal violation on this facility only showed up in near-term summer peak. These violations were created due to the temporary installation of a lower rated spare autotransformer after the original autotransformer failed. This violation was addressed in operating guides by redispatching generation at Sarpy County units 1 and/or 2. The failed autotransformer is being refurbished and will be installed by summer 2012.

- ***Voltage violations***

Falls City 69 kV Area (S993)
The low voltages at these facilities show up during summer peak conditions for loss of the Humboldt 161/69 kV auto (S975 T4). These violations could be addressed by increasing var generation output at Falls City, capacitor bank additions at or near Falls City or by the addition of a new 161/69 kV autotransformer at S975.

Nebraska City Utilities 69 kV Area (NCU903 & S977)
The low voltages at these facilities show up in the ten year-out summer peak timeframe when a large amount of load is left radial from S962 at Nebraska City Utilities. This violation could be addressed by increasing var generation output at Nebraska City Utilities, capacitor bank additions at or near Nebraska City Utilities, or by the addition of a new 161/69 kV autotransformer at future Sub 1262.

Fremont 69kV Area (S992 & Fremont F)
The low voltages at these facilities show up in the ten year-out winter peak timeframe for loss of Fremont unit 8. These violations could be addressed by increasing var generation output from available Fremont units.

OPPD 69 kV system
69 kV buses with high voltage violations - 901, 906N, 906S, 910, 915T1, 915T2, 924, 963, 964, 965, 967, 968, 969, 970, 973, 974, 975, 977, Auburn, Cornfield, Enron, Magellan, and W. Brock (1263). There are various single contingencies that cause post-contingent high voltages in the OPPD 69 kV system. All post-contingent violations are within emergency high limits of 1.10 PU, therefore the violations could be addressed post-contingent by switching off capacitor banks, adjusting LTCs on autotransformers, or decreasing var generation output to get back within normal limits.

S1280 161 kV
The high voltage violations on this bus did not exceed the emergency high limit of 1.10 PU; therefore, the violations could be addressed post-contingent by decreasing var generation output at Nebraska City and Cooper Nuclear Station to get back within normal limits.

S3740 345 kV
The high voltage violations on this bus did not exceed the emergency high limit of 1.10 PU; therefore, the violations could be addressed post-contingent by decreasing var generation output at Cass County and/or Nebraska City generating stations to get back

within normal limits.

NERC Category C: Multiple Contingencies

- ***Thermal violations***

S917 – S918 69kV line
A thermal violation on this facility shows up in the five and ten year-out summer peak case when a circuit breaker at S909 fails to clear a fault and subsequently causes the loss of the entire bus. This violation could be addressed by uprating the S917-S918 69 kV line.

S906 South – S924 & S924 – S912 69 kV lines
Thermal violations on this facility show up in the ten year-out summer peak case when a circuit breaker at S901 fails to clear a fault and subsequently causes the loss of the entire bus. These violations could be addressed reducing generation at Sarpy County 1 and/or 2 or by uprating the S906 South-S924 & S924-S912 69 kV circuits.

S985 – Plattsmouth 69kV line
Thermal violations on this facility show up in the five year-out summer and ten year-out summer and winter peak cases when a large amount of load is left radial from S962 at Nebraska City Utilities. This violation could be addressed in op guides by redispatching generation at Nebraska City Utilities, by uprating the S985 – Plattsmouth 69 kV circuit or by the addition of a new 161/69 kV autotransformer at future Sub 1262.

S906 North – S928 69kV line
Thermal violations on this facility show up in the ten year-out summer peak when a circuit breaker at S921 fails to clear a fault and subsequently causes the loss of the entire bus or several 69kV lines. This violation could be addressed by uprating the S906 North – S928 69kV line.

S921 – S942 69kV line
Thermal violations on this facility show up in the ten year-out summer peak when a circuit breaker at S906 North fails to clear a fault and subsequently causes the loss of the entire bus. This violation could be addressed by uprating the S921 – S942 69kV line.

S909 – S939 69kV line
Thermal violations on this facility show up in the ten year-out summer peak for loss S930-S918 and S930-S919 due to a common tower contingency. This violation could be addressed by uprating the S909 – S939 69kV line.

Humboldt T4 161/69 kV autotransformer (S975 T4)
Thermal violations on this facility only showed up in both the five and ten year-out summer and winter peak conditions for loss of the S1263 161 kV bus. This violation could be addressed in operating guides by dispatching local area 69 kV generation, or through facility additions involving installation of future S975 161/69 kV autotransformer

or an addition of a new 161/69 kV autotransformer at future Sub 1262.

S1206 T2 161/69 kV autotransformer

Thermal violations on this facility showed up in near-term summer peak for a breaker failure at S1206 due to the temporary installation of a lower rated spare autotransformer after the original autotransformer failed. A thermal violation on this facility also shows up in the near-term and out year summer peak for the original autotransformer. Thermal violations in this area could be addressed in operating guides by redispatching generation at Sarpy County's Units 1 or 2 or through facility additions involving replacing the S1206 161/69 kV autotransformers with larger units or adding additional 161/69 kV autotransformer capacity in the South Omaha / Bellevue area.

S1221 T9 161/69 kV autotransformer

Thermal violations on this facility showed up for the out-year summer peak when a circuit breaker at S906 North fails to clear a fault and subsequently causes the loss of several 69kV lines. This violation could be addressed through controlled reduction of local area 69kV load.

- *Voltage violations*

Falls City 69 kV Area (S993 & Magellan)

The low voltages at these facilities show up during summer peak conditions for loss of the Humboldt 161/69 kV auto (S975 T4). These violations could be addressed by increasing var generation output at Falls City, capacitor bank additions at or near Falls City or by the addition of a new 161/69 kV autotransformer at S975. .

Nebraska City Utilities 69 kV Area (NCU903 & S977)

The low voltages at these facilities show up in the ten year-out summer peak case when a large amount of load is left radial from S962 at Nebraska City Utilities. These violations could be addressed by increasing var generation output at Nebraska City Utilities, capacitor bank additions at or near Nebraska City Utilities or by the addition of a new 161/69 kV autotransformer at future Sub 1262.

Fremont 69kV Area (S992, S976 & Fremont B, C, D E, F)

The low voltages at these facilities show up in the near-term and out-year summer peak timeframe for a breaker failure at Fremont A. These violations could be addressed by increasing var generation output from available Fremont units and/or through controlled reduction of local area 69kV load.

OPPD 69 kV system

69 kV buses with high voltage violations - 901, 906N, 906S, 915T1, 915T2, 924, 938, 963, 964, 965, 967, 968, 969, 970, 973, 974, 975, 977, Auburn, Cornfield, Enron, Magellan, Tecumseh and W. Brock (1263). There are various multiple contingencies that cause post-contingent high voltages in the OPPD 69 kV system. All post-contingent violations are within emergency high limits of 1.10 PU, therefore the violations could be addressed post-contingent by switching off capacitor banks, adjusting LTCs on

autotransformers, or decreasing var generation output to get back within normal limits.

S1280 & Humboldt 161 kV

The high voltage violations on this bus did not exceed the emergency high limit of 1.10 PU; therefore, the violations could be addressed post-contingent by decreasing var generation output at Nebraska City and Cooper Nuclear Station to get back within normal limits.

8.0 Tri-State G & T Association

NPPD and Tri-State have a contractual agreement to coordinate joint planning and operating activities for the NPPD/Tri-State Electric Transmission System (NETS). The joint NETS system includes the NPPD and Tri-State transmission facilities and loads served by the eastern interconnected system from transmission delivery points east of the 101st Meridian. In order to address low voltage scenarios impacting Tri-State Member systems and provide voltage support for the NETS region, Tri-State is planning to add 7.5 MVAR to an existing 115 kV capacitor bank at Red Willow Creek Substation. Tri-State is also proposing a 115 kV capacitor bank at the Wild Horse Substation. NPPD and Tri-State have reviewed alternatives in the Ogallala - North Platte area through a joint planning study of this area to determine the most cost effective and efficient long term transmission facility plan for the NETS region. Based upon this review, Tri-State is planning to rebuild its Ogallala – Roscoe – Elsie Tap 115 kV transmission line to eliminate potential overloads caused by single contingency outages in the NETS region.

9.0 Western Area Power Administration

Western Area Power Administration (WAPA), Basin Electric Power Cooperative (BEPC) and Heartland Consumers Power District (HCPD) are parties to the Integrated System (IS) and are designated as the Transmission Providers for the IS system. WAPA provides administration of the IS tariff on behalf of the other IS parties. IS members own transmission facilities in the state of Nebraska and have load delivery obligations to various entities in the state of Nebraska. IS members participated in the coordinated development of the Nebraska SPG Plan. Most of the IS facilities are located within the Missouri Basin Subregional Planning Group (MBSPG) and since reports from the Nebraska SPG and the MBSPG will be combined, the IS plans to report all of their specific plans through the MBSPG. For more information on the IS long term transmission plans, please review the MBSPG section of the MAPP Regional Plan.

10.0 Regionally Beneficial Projects

Sub 1226 - Tekamah Flowgate

The Sub 1226 – Tekamah Flowgate is an existing regional flowgate which is constrained during heavy South – North regional transfer conditions. The Sub 1226 – Tekamah Flowgate is defined by the thermal loading limits on the Sub 1226 – Tekamah 161 kV line For Loss Of (FLO) the Sub 3451 – Raun 345 kV line. OPPD owns the transmission facilities associated with this Flowgate. The Sub 1226 – Tekamah Flowgate has shown increasing congestion during the last four years as depicted in the 2009 Update to the 2008 MAPP Regional Plan.

During NPPD's evaluation of Options in the Columbus / Norfolk Area Transmission Study, NPPD performed extensive regional transfer capability analysis. The results of this analysis demonstrated that the final chosen ETR Option (Hoskins – Shell Creek – Columbus East – NW68th & Holdrege 345 kV Plan) would provide significant increases in regional transfer capability for North – South and South – North directions. Many of the recent Wind Farm additions in Iowa have utilized this new regional transfer capability to address previous mitigation requirements associated with the Sub 1226 - Tekamah Flowgate. The new ETR project completes a new low impedance 345 kV path which is parallel to the critical Raun – Ft.Calhoun 345 kV path and underlying Sub 1226 – Tekamah 161 kV facilities. Since the energization of the ETR project, there have been significant reductions in TLR congestion events associated with the Sub 1226 – Tekamah Flowgate.

Western Nebraska – Western Kansas Flowgate

The Western Nebraska – Western Kansas Flowgate is an existing regional Flowgate defined by the Gentleman – Red Willow – Mingo 345 kV interconnection between NPPD and Sunflower Electric. NPPD has been working with SPP, SPP Member utilities, and ITC Great Plains to further develop the proposed Axtell – Spearville 345 kV Transmission Line Project. The Axtell – Spearville 345 kV project was identified as a SPP Balanced Portfolio Project and it was subsequently approved as a Balanced Portfolio project by the SPP Board of Directors.

The Gentleman – Red Willow Flowgate (#6007) has shown increased congestion during the past four years of the MAPP congestion analysis as documented in the recent Regional Plans. Following the integration into SPP, NPPD has been experiencing trends of significant congestion periods associated with the WNE_WKS Flowgate. This growing congestion is a correlation to the substantial amount of new wind generation added in the upper Midwest region without any recognition of the cumulative impacts on regional flowgates. The current Generation Interconnection (GI) study processes utilized in this area do not account for any impacts of new GI facilities on external flowgates. Further, if a delivery study is ever performed, the dispatch assumptions are modified to show minimal impacts to external flowgates which are typically under existing thresholds requiring mitigation. As a result of these external GI's, the impacts have continued to accumulate to the point of increased firm congestion on this flowgate.

The new Axtell – Spearville 345 kV transmission line creates an essential parallel path to the existing Western Nebraska – Western Kansas Flowgate (Gentleman – Red Willow – Mingo 345 kV path). NPPD has performed FCITC analysis associated with this new line project and it shows very positive impacts on the Western Nebraska – Western Kansas Flowgate. The new Axtell – Spearville 345 kV line project would involve approximately 226 miles of new 345 kV transmission line from Axtell, Nebraska to Spearville, Kansas. There is also a planned interconnection of this line at a new Post Rock Substation, located next to the Knoll Substation near Hays, Kansas. NPPD is responsible for approximately 53 miles of the new 345 kV line from Axtell to the Kansas border. ITC Great Plains will construct the two Kansas segments of this line project which is approximately 173 miles from the Nebraska/Kansas border to Post Rock to Spearville. SPP, ITC, and NPPD are currently planning an in-service date of June 2013 for this Balanced Portfolio Project.

Cooper South Flowgate

The Cooper South Flowgate is an existing regional Flowgate defined at the Cooper 345 kV terminal by the Cooper – Fairport 345 kV and Cooper – St.Joe 345 kV transmission lines. The most limiting contingency involves the loss of the Cooper – Fairport – St.Joe 345 kV line with subsequent thermal overloads on the Cooper – St.Joe 345 kV line. The contingent loss of the Cooper – St.Joe 345 kV line is the next limiting contingency.

In 2007, a Cooper South upgrade project was completed to increase the capacity of the most limiting terminal and line facilities associated with Cooper South. This project resulted in an increased TTC for the Cooper South Flowgate and a corresponding drop in congestion associated with this Flowgate for a limited timeframe. The Cooper South Flowgate (#6009) has shown increased congestion during the past three years of the MAPP congestion analysis as documented in the recent Regional Plans. Following the integration into SPP, NPPD has been experiencing increased trends of significant congestion periods associated with the Cooper South Flowgate. Once again, this growing congestion is a correlation to the substantial amount of new wind generation facilities added in the upper Midwest region without any recognition of the cumulative impacts on external regional flowgates.

As a result of the SPP Priority Projects Study, a new 345 kV line project was approved which was focused on alleviating congestion on the Cooper South Flowgate. The Nebraska City – Maryville - Sibley 345 kV transmission line project creates an essential parallel path to the Cooper South Flowgate. SPP, NPPD and OPPD have performed FCITC analysis associated with this project and the results show very positive impacts on the Cooper South Flowgate as well as the Kansas City area flowgates. The new Nebraska City – Maryville – Sibley 345 kV project would involve approximately 175 miles of new 345 kV transmission from Nebraska City, Nebraska to Maryville, Missouri to Sibley, Missouri. OPPD is responsible for approximately 10 miles of new 345 kV from their Nebraska City Substation to the Missouri River Crossing and Missouri Border. KCPL is responsible for the remaining 165 miles of new 345 kV to Maryville and then on to Sibley. The current in-service date for this Priority Project is June 2017.

11.0 Stakeholder Input

Nebraska is a totally public power state and each of the public power districts are political subdivisions of the State of Nebraska. NPPD and OPPD are governed by a Board of Directors elected through a public election process. Whereas the MEAN members elect their Board of Directors and the LES Administrative Board Members are appointed by the Mayor and approved by the City Council. These respective Boards are responsible for their area and territory from which they were elected or appointed. This Report has been provided to the management of each entity and is intended to be presented to the respective Boards. This Report is also available on the MAPP web site and copies have been sent to the state regulatory bodies associated with the Nebraska sub region.

The Nebraska SPG has sought participation of regulatory bodies and other interested public entities in the transmission planning process. The Nebraska SPG meetings are open forum meetings. The Nebraska entities who are also SPP Members, participate in the annual SPP ITP processes. In accordance with the ITP process, SPP holds two annual Planning Summits which are open to any interested stakeholder. The Nebraska Subregion is a part of the SPP Footprint and is reviewed during these Summits. Open stakeholder feedback sessions are held during the semi-annual SPP Planning Summits.

12.0 Final Plan Summary

The Nebraska Subregional Transmission Plan (2011 - 2021) evaluated the future transmission needs of the Nebraska subregion and provided detailed plans to meet those needs. The 2011 Nebraska Subregional Transmission Plan provides updates to previously identified plans and presents new plans currently being developed. The specific details of each future planned facility addition are listed in Appendix A within the MAPP TPSC reporting Forms 1-3. The Nebraska Subregional Planning Group submits this information as our 2011 Nebraska SPG input to the MAPP 2011 Regional Plan.

13.0 References

1.) 2009 SPP Balanced Portfolio Report (June 2009)

2.) MAPP 2009 Update to the 2008 Regional Plan 2008 through 2019 (November 2009)

3.) 2009 SPP Transmission Expansion Plan (December 2009)

4.) SPP Priority Projects Phase II Report (April 2010)

5.) 2010 MAPP System Performance Assessment (NERC Planning Standards TPL-001-0 thru TPL-004-0) (June 2010)

6.) MAPP 2010 Regional Plan 2010 through 2020 (November 2010)

7.) 2010 SPP Transmission Expansion Plan (January 2011)

8.) 2010 Integrated Transmission Plan 20-Year Assessment (January 2011)

9.) 2011 MAPP System Performance Assessment (NERC Planning Standards TPL-001-0 thru TPL-004-0) (June 2011)

Form 2 for Reporting Substation Devices

2011 Nebraska Subregional Transmission Plan (2011-2021)

Note #1: PLANNED projects are the preferred solution to an identified issue.
PROPOSED projects are a tentative solution to an identified issue.

The projects in this list are projected for service on the date indicated. They are expected to be needed to meet existing committments including network and native load growth. Because there is always the possibility of delay in permitting and construction, or for modification or deferral of projects as system conditions change, Transmission Providers should not assume that these projects are in-service when selling new transmission service. New transmission service should be conditioned on the completion of these projects.

Note #3: According to FERC Order 890, Attachment K filings of the Transmission Providers' Tariffs 0n 12/7/08, the TPSC is responsible for identifying cost responsibility on a regional and subregional basis for Network Upgrades identified in the MAPP Regional Plan for reliability and economic projects. There are 3 categories for the projects: 1. Baseline Reliability Projects 2. New Transmission Access Projects - Generation Interconnection Projects or Transmission Service Projects 3. Regionally Beneficial Projects
Regionally Beneficial Projects are required to go through a subscriptions rights solicitation process to be further developed by MAPPCOR Staff and the TPSC

Devices (capacitors, reactors, breakers, FACTS, etc):

Note # 2 above													Status (Note #1 above)
Expected In Service Date (m/d/y)	SPG or Other Region	Reporting Source or Transmission Owner	Location:	Bus #:	Type Description:	Voltage(s) (kV)	Summer Rating (Various Units)	Native Network Load	Gen Interconnection	Transmission Service	Improvement (Losses, Maint, Availability, or Other)	Regionally Beneficial	In Service Planned Proposed
10/7/2010	Nebraska	NPPD	Petersburg North	640444	Substation	115			100				In-Service
1/5/2011	Nebraska	NPPD	Petersburg North	640444	Capacitor	115	15	100					In-Service
5/1/2011	Nebraska	LES	Folsom & Pleasant Hill	650242	Substation	115		100					In-Service
6/1/2011	Nebraska	NPPD	Valentine	640392	Capacitor	115	9	100					In-Service
10/1/2011	Nebraska	OPPD	Sub 1341	646341	Substation	161		100					Planned
5/1/2012	Nebraska	LES	NW70th & Fairfield	650210	Substation	115		100					Planned
6/1/2012	Nebraska	NPPD	South Sioux City	640424	Substation	115		100					Planned
6/1/2012	Nebraska	NPPD	South Sioux City	640425	Capacitor	69	21.6	100					Planned
6/1/2012	Nebraska	NPPD	Gordon	640192	Capacitor	115	9	100					Planned
6/1/2012	Nebraska	NPPD	Kearney	640250	Capacitor	115	36	100					Planned
6/1/2012	Nebraska	TSGT	Red Willow Creek	659162	Capacitor	115	7.5	100					Planned
11/1/2012	Nebraska	NPPD	O'Neill	640305	Capacitor	115	18	100					Planned
11/1/2012	Nebraska	NPPD	Ainsworth	640051	Capacitor	115	15	100					Planned
11/1/2012	Nebraska	NPPD	Stuart South (PS22)	640441	Substation	115		100					Planned
11/1/2012	Nebraska	NPPD	Stuart South (PS22)	640441	Capacitor	115	15	100					Planned
11/1/2012	Nebraska	NPPD	Ericson (PS23)	640437	Substation	115		100					Planned
11/1/2012	Nebraska	NPPD	Ericson (PS23)	640437	Capacitor	115	6	100					Planned
11/1/2012	Nebraska	NPPD	Clarks	640436	Substation	115		100					Planned
11/1/2012	Nebraska	NPPD	Clarks	640436	Capacitor	115	18	100					Planned
11/1/2012	Nebraska	NPPD	Central City North (PS24)	640434	Substation	115		100					Planned
6/1/2013	Nebraska	OPPD	Sub 1366	646366	Substation	161		100					Planned
12/31/2013	Nebraska	GRIS	Sub J	642076	Substation	115		100					Planned
5/1/2015	Nebraska	LES	SW 7th & Bennet	650246	Substation	115		100					Planned
5/1/2015	Nebraska	LES	21st & N	650248	Substation	115		100					Planned
6/1/2015	Nebraska	NPPD	Holdrege	640224	Capacitor	115	18	100					Planned
6/1/2015	Nebraska	NPPD	O'Neill	640306	Capacitor	69	9	100					Planned
6/1/2016	Nebraska	TSGT	Wild Horse	659193	Capacitor	115	15	100					Proposed

Form 3 for Reporting MAPP Generation Projects

2011 Nebraska Subregional Transmission Plan (2011-2021)

								Status
Expected In-service Date (m/d/y)	SPG or Other Region	Reporting Source or Transmission Owner	Name:	Location:	Bus #:	Grid Injection Voltage (kV)	Summer Rating (MW)	In Service Planned Proposed
11/26/2010	Nebraska	OPPD	Flat Water Wind Farm	Richardson County, NE	645061	161	60	In-Service
2/1/2011	Nebraska	NPPD	Laredo Ridge Wind Facility	Petersburg, NE	640431	115	80	In-Service
5/1/2011	Nebraska	MEAN/HU	Whelan Energy Center # 2	Hastings, NE	641089	115	220	In-Service
12/31/2011	Nebraska	OPPD	TPW Petersburg	Petersburg, NE		115	40.5	Planned
11/10/2012	Nebraska	OPPD	Ft. Calhoun Nuclear Station Uprate	Ft.Calhoun, NE	645001	345	559	Planned
12/31/2012	Nebraska	NPPD	Crofton Bluffs Wind Facility	Bloomfield, NE	640421	115	42	Planned
12/31/2012	Nebraska	NPPD	Broken Bow Wind Facility	Broken Bow, NE	640428	115	80	Planned
6/1/2021	Nebraska	OPPD	Cass County Unit 3	Cass County, NE	645043	345	208	Planned

Appendix A: FORMS 1 THROUGH 3

Form 1 for Reporting Lines and Transformers

2011 Nebraska Subregional Transmission Plan (2011-2021)

Note #1: PLANNED projects are the preferred solution to an identified issue. PROPOSED projects are a tentative solution to an identified issue. WITHDRAWN projects should be removed from the list as they are no longer PLANNED or PROPOSED. IN SERVICE projects were PLANNED or PROPOSED projects that are now IN SERVICE

Note #2: The projects in this list are projected for service on the date

Note #3: Projects with zero miles indicate various activities like a new substation inserted in a line, substation changes alone, or reconfiguring of lines.

Note #4: According to FERC Order 890, Attachment K filings of the Transmission Providers' Tariffs 0n 12/7/08, the TPSC is responsible for identifying cost responsibility on a regional and subregional basis for Network Upgrades identified in the MAPP Regional Plan for reliability and economic projects. There are 3 categories for the projects: 1. Baseline Reliability Projects
2. New Transmission Access Projects - Generation Interconnection Projects or Transmission Service Projects
3. Regionally Beneficial Projects
Regionally Beneficial Projects are required to go through a subscriptions

Transmission Lines and Transformers:

Note # 2 above														Need Estimate (SUM of Columns =100 %)					Status (Note #1 above)
Expected In Service Date (m/d/y)	SPG or Other Region	Reporting Source or Transmission Owner	From:	Bus #:	To:	Bus #:	Circuit #	High Voltage (kV)	Low Voltage (kV)	Summer Rating (MVA)	Rebuild or Upgrade	New	Total Miles	Native Network Load	Gen Interconnection	Transmission Service	Improvement (Losses, Maint, Availability, or Other)	Regionally Beneficial	In Service Planned Proposed
9/28/2010	Nebraska	NPPD	Steele City	640426	Kansas Border	533332	1	115		223		2	2	100					In-Service
10/25/2010	Nebraska	NPPD	Canaday	640102	transformer	640103	1	230	115	336					50	50			In-Service
12/23/2010	Nebraska	MEAN/HU	Whelan Energy Center	641087	Hastings City	641088	1	115		240	4.5		4.5		50	50			In-Service
5/1/2011	Nebraska	LES	Folsom & Pleasant Hill	650242	Rokeby	650290	1	115		378		0	0				100		In-Service
5/1/2011	Nebraska	LES	Folsom & Pleasant Hill	650242	20th & Pioneers	650238	1	115		348	0.5		0.5				100		In-Service
5/1/2011	Nebraska	LES	20th & Pioneers	650238	2nd & N	650230	1	115		139		0					100		In-Service
5/1/2011	Nebraska	LES	Sheldon	640278	Folsom & Pleasant Hill	650242	1	115		240		0.5	0.5				100		In-Service
5/1/2011	Nebraska	LES	Sheldon	640278	Folsom & Pleasant Hill	650242	2	115		139		0.5	0.5				100		In-Service
10/1/2011	Nebraska	OPPD	Sub 1251	646251	Sub 1341	646341	1	161		558		0.5	0.5	100					Planned
10/1/2011	Nebraska	OPPD	Sub 1341	646341	Sub 1305	646305	1	161		558		0.5	0.5	100					Planned
1/27/2012	Nebraska	OPPD	Sub 983	647983	Sub 902	647902	1	69		57	6.5		6.5				100		Planned
5/1/2012	Nebraska	NPPD	Cooper	640139	transformer	640140	2	345	161	300							100		Planned
5/1/2012	Nebraska	LES	57th & Garland	650262	84th & Leighton	650267	1	115		362	2.1		2.1	100					Planned
6/1/2012	Nebraska	NPPD	Twin Church	640387	South Sioux City	640424	1	115		240		7	7	100					Planned
6/1/2012	Nebraska	NPPD	Loup City	640259	North Loup	640284	1	115		137	20		20	100					Planned
6/1/2012	Nebraska	NPPD	North Platte	640287	Maloney	640265	1	115		155	3.2		3.2	100					Planned
9/1/2012	Nebraska	NPPD	Twin Church	640387	South Sioux City	640424	2	115		240		10	10	100					Planned
11/1/2012	Nebraska	NPPD	O'Neill	640305	Stuart South (PS22)	640441	1	115		80		28	28	100					Planned
11/1/2012	Nebraska	NPPD	Petersburg	640318	Ericson (PS23)	640437	1	115		80		37	37	100					Planned
11/1/2012	Nebraska	NPPD	Clarks	640436	Central City N (PS24)	640434	1	115		80		9	9	100					Planned
11/10/2012	Nebraska	OPPD	Sub 1255	646255	Sub 1221	646221	1	161		352	3.9		3.9			100			Planned
12/1/2012	Nebraska	NPPD	Gavins Point	652511	Bloomfield	640084	1	115		159	17		17		100				Planned
12/1/2012	Nebraska	NPPD	Broken Bow	640089	Broken Bow North	640445	1	115		233		9	9		100				Planned
12/31/2012	Nebraska	GRIS	Sub F	642073	St.Libory Jct.	640353	1	115		160		6.9	6.9	100					Planned
5/1/2013	Nebraska	LES	Folsom & Pleasant Hill	650242	Sheldon	640278	2	115		298	12		12				100		Planned
6/1/2013	Nebraska	NPPD	Albion	640054	Spalding	640347	1	115		174	21.4		21.4	100					Planned
6/1/2013	Nebraska	NPPD	Axtell	640065	Kansas Border	530583	1	345		1793		53	53					100	Planned
6/1/2013	Nebraska	NPPD	Canaday	640103	Lexington	640256	1	115		137	8.3			100					Planned
8/1/2013	Nebraska	LES	17th & Holdrege	650219	21st & N	650248	1	115		181	1.3		1.3				100		Planned
8/1/2013	Nebraska	LES	21st & N	650248	30th & A	650252	1	115		181	2.0		2.0				100		Planned
8/1/2013	Nebraska	LES	30th & A	650252	56th & Everett	650256	1	115		181	2.0		2.0				100		Planned
12/1/2013	Nebraska	TSGT	Ogallala	659132	Roscoe	659187	1	115		230	12.3			100					Planned
12/1/2013	Nebraska	TSGT	Roscoe	659187	Elsie Tap	659185	1	115		230	3			100					Planned
12/31/2013	Nebraska	GRIS	Sub A	642068	Sub B	642069	1	115		180	4.2		4.2	100					Planned
12/31/2013	Nebraska	GRIS	Sub B	642069	Sub F	642073	1	115		180	1.4		1.4	100					Planned
6/1/2014	Nebraska	NPPD	Ogallala	640302	transformer	659132	1	230	115	336				100					Planned
5/1/2015	Nebraska	LES	SW 7th & Bennet	650246	40th & Rokeby	650250	1	115		362		5.5	5.5	100					Planned
6/1/2015	Nebraska	NPPD	Albion	640054	Genoa	640181	1	115		137	21.6		21.6	100					Planned
6/1/2015	Nebraska	NPPD	Stegall	659135	transformer	659317	2	345	230	400				100					Planned
6/1/2015	Nebraska	NPPD	Stegall MBPP	659317	Stegall WAPA	652573	2	230		400		2.6	2.6	100					Planned
6/1/2016	Nebraska	NPPD	Cozad	640144	Gothenburg	640196	1	115		120	11.2			100					Proposed
6/1/2016	Nebraska	NPPD	Keystone	640253	Ogallala	659132	1	115		320	5.3			100					Proposed
6/1/2017	Nebraska	NPPD	Sheldon	640278	Firth	640171	1	115		113	12.7			100					Proposed
6/1/2017	Nebraska	OPPD	Sub 3458	645458	Missouri Border		1	345		1793		10	10					100	Planned
5/1/2022	Nebraska	LES	NW68th & Holdrege	650114	transformer	650214	2	345	115	336				100					Proposed