

## 5 Preferred Resource Plan

The Preferred Resource Plan details the expected specific activities of Otter Tail with respect to the resources associated with the preferred plan in the 2011 – 2016 time period. It also identifies possible resources that could be used to serve customer loads over the entire 2011 – 2025 resource planning period. This section first discusses details associated with the preferred resource plan. Following that discussion, this section presents the results for the scenarios required by the Minnesota Rules for resource plan filings, including: high and low load growth scenarios, externality scenarios, and renewable and conservation scenarios. The Company’s specific resource plan, presented in Table 5-1, shows the estimated MW impact of each resource group by calendar year. Figure 5-1 shows the resource stack of new additions and existing resources compared to the resource adequacy obligation. The peak demand is shown net of new and existing DSM.

**Table 5-1: Annual Summer Accredited Capacity Values of Potential Future Resources for the Preferred Plan or Base Case (MW)**

Resource	2010	2011	2012	2013	2014	2015	2016	2017
1.2% MN CIP <sup>1</sup>	-2.6	-5.3	-8.3	-11.6	-14.8	-18.2	-21.5	-25.2
New Demand Response <sup>1</sup>	0.0	0.0	0.0	0.0	0.0	-5.0	-5.0	-5.0
Annual Bilateral Capacity	0.0	0.0	0.0	75.0	100.0	150.0	150.0	75.0
Wind Generation <sup>2</sup>	0.0	0.0	50.0	50.0	50.0	50.0	50.0	50.0
Frame 5s Peaker Project	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hoot Lake #3 Project	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hoot Lake #2 Project	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Aeroderivative NG CT	0.0	0.0	0.0	0.0	39.6	39.6	39.6	126.1
Big Stone Plant AQCS	0.0	0.0	0.0	0.0	0.0	0.0	229.7	229.7

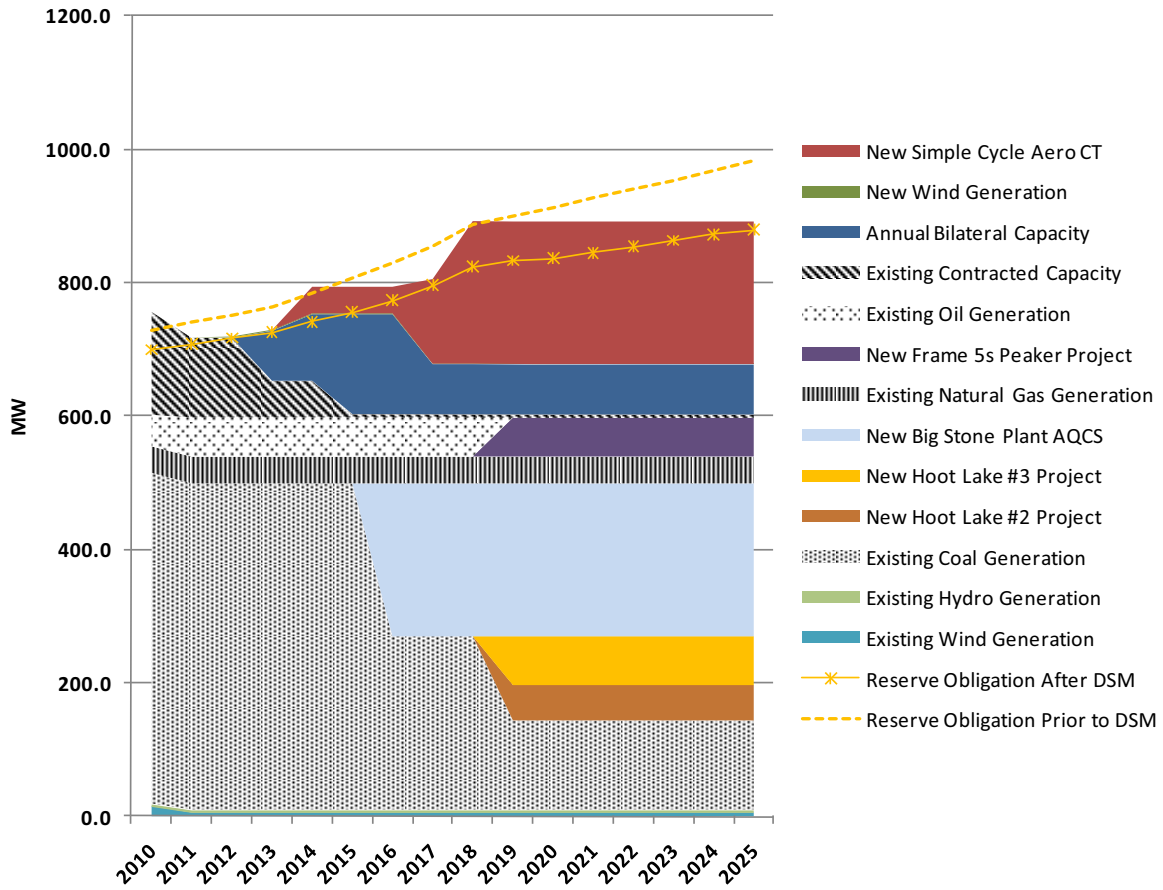
Resource	2018	2019	2020	2021	2022	2023	2024	2025
1.2% MN CIP <sup>1</sup>	-29.0	-32.9	-36.9	-41.2	-45.3	-49.5	-53.5	-55.1
New Demand Response <sup>1</sup>	-5.0	-5.0	-10.0	-10.0	-10.0	-10.0	-10.0	-15.0
Annual Bilateral Capacity	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
Wind Generation <sup>2</sup>	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Frame 5s Peaker Project	0.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
Hoot Lake #3 Project	0.0	73.6	73.6	73.6	73.6	73.6	73.6	73.6
Hoot Lake #2 Project	0.0	53.5	53.5	53.5	53.5	53.5	53.5	53.5
Aeroderivative NG CT	212.6	212.6	212.6	212.6	212.6	212.6	212.6	212.6
Big Stone Plant AQCS	229.7	229.7	229.7	229.7	229.7	229.7	229.7	229.7

<sup>1</sup>Conservation and demand response are netted from the peak demand forecast prior to calculation of the resource adequacy requirement.

<sup>2</sup>Wind generation is shown at nameplate capacity. Accredited capacity expected to be around 3% of nameplate.

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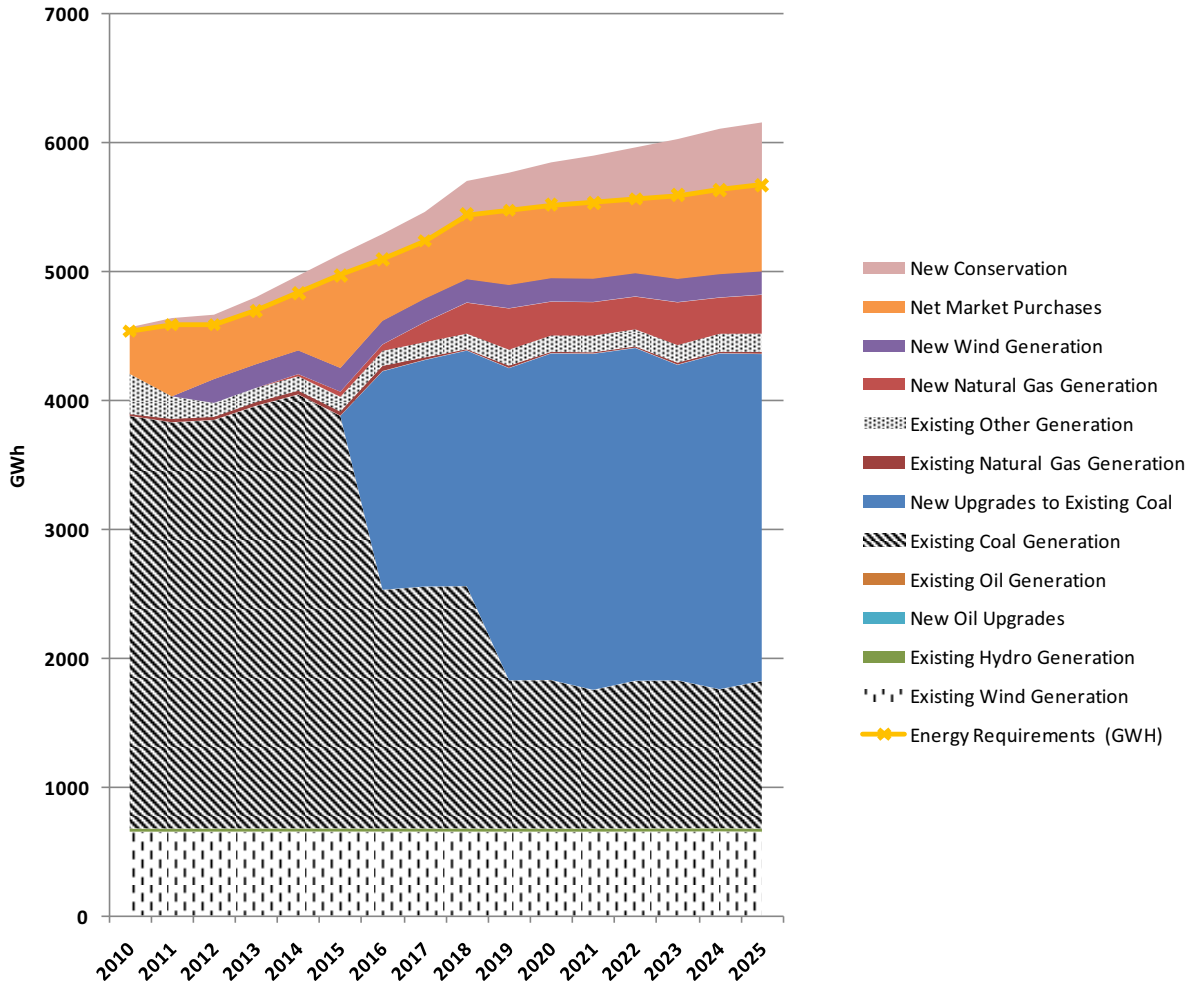
Figure 5-1: 2010-2025 Capacity Resources and Reserve Obligation for Preferred Plan (MW)



As Figure 5-1 shows, the new resource additions are added primarily above the 700 MW level. Below that level are upgrades to existing facilities and environmental projects, or existing levels of market purchases. New wind generation is barely visible due to its low capacity accreditation value. However, its impacts are better represented in Figure 5-2 which shows the energy sources in the preferred plan by fuel type. As in the capacity representation, new resource additions are primarily represented above the 4,000 GWh level. Below that level are upgrades to existing facilities. As shown in Figure 5-2, conservation contributes a significant portion to the Company's future energy needs, as do new wind generation and continued market purchases.

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**Figure 5-2: 2010-2025 Energy Resources and Energy Requirements for Preferred Plan (MW)**



### 5.1 Preferred Resource Plan Description

The Otter Tail preferred resource plan is the least cost plan selected by the Strategist model under the Company’s base case assumptions, totaling \$3.888B in NPVRR in 2010\$. The base case, or preferred plan, is the zero externality and zero CO<sub>2</sub> value scenario. It is important to recognize that the Midwest ISO reserve capacity obligation is a *minimum* obligation. It is quite likely that the Company will seek to have a small margin above the obligation to reduce the risk of falling below the requirement and being forced to purchase capacity at the Midwest ISO “Cost of Next Entry” rate, estimated to be \$90,000/MW-month. Following is a description and comment on each of the resources identified in Table 5-1.

- **1.2% CIP** – The model chose an annual energy efficiency and conservation alternative for Minnesota load that was 1.2% of average retail sales for the prior three years. By 2025, summer

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peak demand impacts from energy efficiency and conservation are expected to be 55.1 MW, not including the reserve margin savings. Winter peak demand impacts are expected to be 62.4 MW. Table 5-2 presents the expected annual savings due to energy efficiency for all jurisdictions Otter Tail serves by 2025. South Dakota has an approved energy efficiency goal of approximately 0.4% of retail sales, which is not reflected in Table 5-1, but included in the data presented in Table 5-2. The cumulative savings due to energy efficiency for all jurisdictions reaches just over 482 GWh by 2025 and reduces the average energy growth rate by 0.52% over the study period and the peak demand growth rate by 0.40%.

**Table 5-2: Estimated MWh Savings Due to Conservation in all Jurisdictions**  
(2009 CIP data is included since the impacts of those programs are not included in the load forecast)

Year	Incremental Annual Savings (GWh)	Cumulative Annual Savings (GWh)
2009	18.8	18.8
2010	23.3	42.1
2011	24.3	66.4
2012	26.7	93.1
2013	28.0	121.1
2014	28.4	149.5
2015	29.0	178.5
2016	30.3	208.8
2017	31.5	240.4
2018	32.8	273.2
2019	34.4	307.6
2020	35.6	343.1
2021	36.3	379.4
2022	36.3	415.7
2023	36.2	451.9
2024	36.2	469.2
2025	36.2	482.1

- Demand Response** – Demand response includes both load management capability and customer contracts that allow load shedding to a firm service level. In the preferred plan, demand response capability was selected to increase annually and reach 15 MW of additional summer season capability and 30 MW of additional winter season capability by 2025. To allow the Company time to confirm measurement and verification capability of incrementally new demand response, the new demand response was stair-stepped in every 5 years in 5 MW increments. Otter Tail has invested in and developed the demand response capability over many years. This resource is critical in reducing the Company’s peak demand and smoothing the peak demands between summer and winter. Because the Company has substantial winter demand response capability and is winter peaking, the winter peak demand obligations are reduced to a level more in line with summer peak demand. According to Midwest ISO Module E rules, the accredited capability is netted directly from the peak demand forecast prior to calculation of the resource adequacy obligation and thereby saves the Company not only the difference, but the reserve margin requirement as well.

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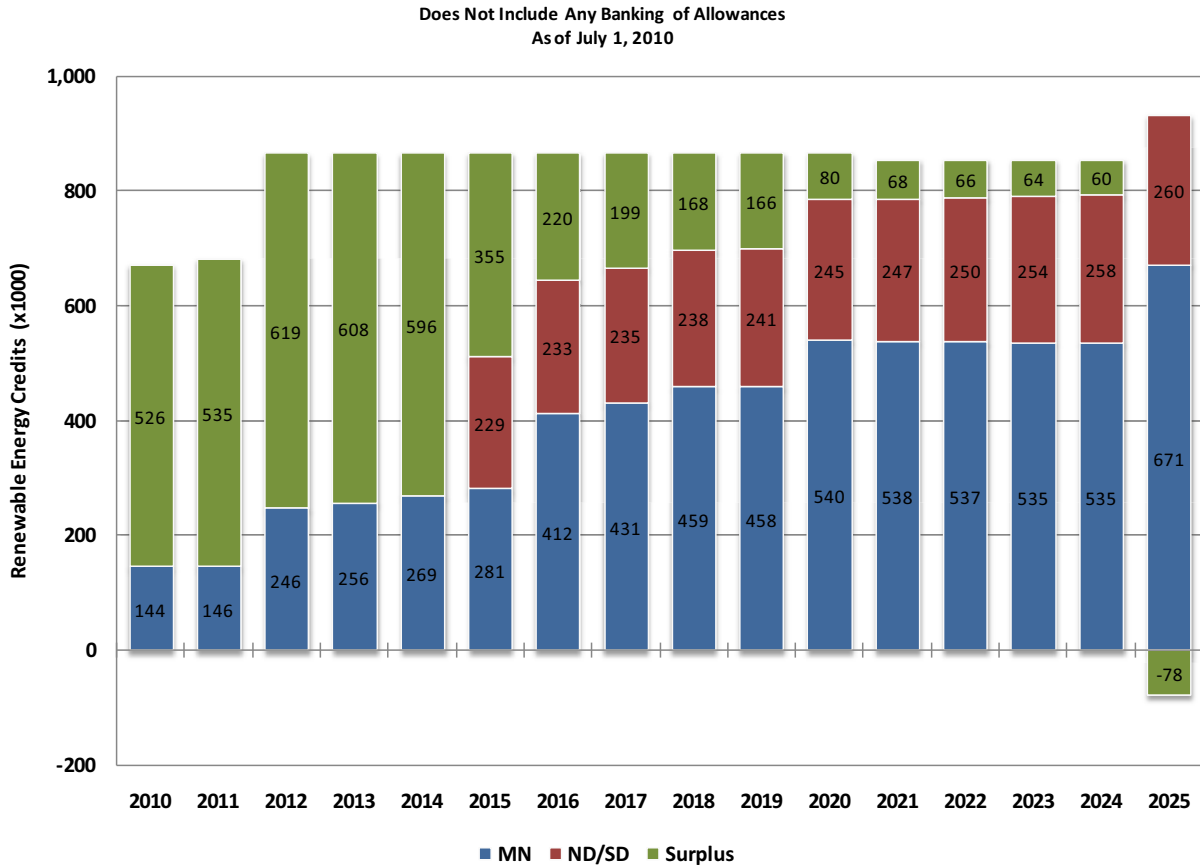
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- **Bilateral Capacity Purchases** – The model was able to select annual bilateral capacity contracts in 75 MW blocks. It is not necessarily the case that the Company will require exact multiples of that much capacity. Rather, these block purchases should be viewed as a purchase “up to the stated amount.” The block size was selected to compete with the natural gas combustion turbine alternatives which were between 69.2 MW and 86.5 MW of accredited capacity. Due to the favorable capacity market prices, the model relied on annual bilateral capacity contracts as much as it was allowed throughout the study period. Capacity purchases will be used up to the amount shown to meet the balance of resource adequacy obligations in any month of each respective year.
- **Wind Generation** - The model selected 50 MW of wind generation in 2012, assuming an ownership cost that incorporates the federal PTC and North Dakota state incentives. Accredited capacity of wind generation was set at 8% for the 2010 planning year, but dropped to roughly 3% for the remaining years of the study period. This accreditation level is assumed for all wind generation resources in that time frame, recognizing that the accreditation levels for wind generation will likely drop as greater amounts of wind generation penetrate the region. Annual energy from the new wind generation resources is expected to be based on a capacity factor of approximately 41%.
- **Combustion Turbines** – Three aeroderivative simple cycle, natural gas-fired combustion turbines were selected in the preferred plan. These turbines included 39.6 MW of accredited capacity in 2014, 86.5 MW of accredited capacity in 2017, and 86.5 MW of accredited capacity in 2018.
- **Existing Plant Projects** – Several projects on existing baseload and peaking resources were selected in the preferred plan. These upgrades are expected to be necessary for continued operation of these facilities and were included in the analysis to determine if these upgrades are economic when compared to other available alternatives. The projects totaled roughly 417 MW of accredited capacity and included:
  - Environmental upgrades for an Air Quality Control System (AQCS) at Big Stone Plant (229.7 MW accredited capacity) using Best Available Retrofit Technology (BART) was selected in 2016 and included installation of flue gas desulfurization equipment and a selective catalytic reduction system for control of NO<sub>x</sub> emissions. Plant efficiency was assumed to be reduced by 1.5% and costs for operations and maintenance were assumed to increase. These assumptions are provided in Appendix F.
  - Environmental and plant upgrades at Hoot Lake Plant Units #2 and #3 (127 MW accredited capacity) are expected to continue operations as long as it remains cost effective to do so. The preferred plan selected environmental and plant upgrade capital projects to maintain this facility in 2019. Similar to the Big Stone Plant environmental project, it was assumed that plant efficiency would decrease by 1.5% and costs for operations and maintenance would increase. A more thorough evaluation of specific Hoot Lake Plant options will be conducted and factored into Otter Tail’s next IRP filing.
  - Jamestown and Lake Preston oil-fired peaking units (about 60 MW accredited capacity) are also expected to continue operations as long as it remains cost effective. Capital projects to continue operations of these units were selected in the preferred plan in 2019.

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Figure 5-3 represents the planned compliance with REO/RES regulation in all jurisdictions under the preferred plan.

**Figure 5-3: Planned Compliance with REO/RES Regulation in All Jurisdictions**



As shown, Otter Tail expects to be surplus renewable energy credits through 2024. The addition of 50 MW of wind generation in the preferred plan provides Otter Tail sufficient renewable generation to meet the RES in Minnesota through 2025 (assuming banking of RECs) and the REO in both North Dakota and South Dakota through 2025.

The federal PTC and other North Dakota state financial incentives available to wind generation development help to make wind generation an economic alternative. The renewable generation shown in the figure assumes certain levels of wind generation performance annually, which is subject to fluctuations. Smaller wind generation installations and additional renewable energy projects are likely to take place so that renewable energy generation for the Company may increase above what the Company is projecting.

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### 5.2 Load Growth Scenarios

The base case was executed assuming a low load growth scenario and a high load growth scenario. Table 5-3 presents a comparison of these two runs with the base case. As shown, the low load growth scenario results in lower total revenue requirements and fewer resource additions and the high load growth scenario results in higher total revenue requirements and more resource additions.

**Table 5-3: Comparison of Load Growth Scenarios to Base Case**

Scenario	Base Case	High Load Growth	Low Load Growth
NPVRR (\$000)	\$3,888,399	\$4,882,855	\$3,326,266
<b>Resource Plan (MW) - Based on Summer Ratings, except Wind which is shown as Nameplate</b>			
2010	1.2% MN CIP	1.2% MN CIP	1.2% MN CIP
2011	New Demand Response	<50 MW 1-Yr Capacity	
2012	50 MW Wind	50 MW Wind <50 MW 1-Yr Capacity	
2013	<75 MW 1-Yr Capacity	<100 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2014	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	<100 MW 1-Yr Capacity
2015	<150 MW 1-Yr Capacity	<175 MW 1-Yr Capacity	<150 MW 1-Yr Capacity
2016	229.7 MW BSP AQCS Project <150 MW 1-Yr Capacity	229.7 MW BSP AQCS Project <100 MW Capacity 86.5 MW Aero NG CT	229.7 MW BSP AQCS Project <150 MW Capacity
2017	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity
2018	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity
2019	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity	92.4 MW Combined Cycle 60.0 MW Frame 5s Project	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity
2020	<75 MW 1-Yr Capacity	55 MW Supercritical Coal <75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2021	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2022	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2023	<75 MW 1-Yr Capacity	55 MW Supercritical Coal <75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2024	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2025	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
<b>New Resources by Category (MW)</b>			
Conservation	-55	-62	-50
Demand Response	-15		
Wind	50	50	
Existing Baseload Upgrades	357	230	357
Coal		110	
Gas	213	305	173
Existing Peaking Upgrades	60	60	60
Capacity Purchase	75	75	75

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Neither of the load growth sensitivity scenarios selected additional demand response capability. This is likely due to the lumpiness of additions and inability of the model to add exact measures of resources as needed. The demand response resource is unable to displace a whole combustion turbine or large capacity purchase due to its relatively smaller size. The high load growth scenario added 110 MW of new baseload coal-fired generation accredited capacity and replaced the Hoot Lake Project with combined cycle generation. The low load growth scenario did not add any wind and added slightly less simple cycle combustion turbine capacity than the preferred plan. Like the preferred plan, both the high and low load growth scenarios selected the 1.2% CIP level, the Big Stone Plant AQCS project, the Frame 5 oil-fired peaking project, and significant amounts of combustion turbine capacity.

### 5.3 Environmental Externality Scenarios

The base case optimization model was executed assuming no environmental externality values and no CO<sub>2</sub> tax values. This case is the zero externality scenario. Additional scenarios were evaluated assuming low, mid, and high environmental externality values and CO<sub>2</sub> values. The environmental externality scenarios changed the results of the model in total revenue requirements of the plan and in resources selected as shown in Table 5-4.

The assumptions for the high and low environmental externality values were taken from the June 1, 2010 *Notice of Revised Updated Environmental Externality Values* as provided by the Commission for rural MN. The high and low CO<sub>2</sub> tax values were \$34 and \$9, respectively. For the mid-externality scenario, an average of the high and low values was used. In all externality scenarios, externality and tax values were escalated 3% for inflation and the CO<sub>2</sub> tax began in 2012, replacing the externality value.

As shown, the externality scenarios add significant cost. The low externality scenario was approximately \$707M higher than the preferred plan, however, was identical to the preferred plan in resource selection. The mid and high externality scenarios both replaced the Hoot Lake Project with combined cycle generation. These two plans cost roughly \$1.8B and \$2.0B more than the preferred plan, respectively, due to the impacts of the higher CO<sub>2</sub> tax as well as higher capital costs for new, lower-emitting resources to replace existing resources.

Customers benefit from one uniform plan across the jurisdictions through (1) economy of scale, (2) reduced administrative and ratemaking burden by not having to “jurisdictionalize” the plan, and (3) reduced operational complexity in operating the system. The Company recognizes that the preferred plan may change as CO<sub>2</sub> regulation becomes defined and expiration or extension of the federal PTC for wind generation is determined. The preferred plan provides the greatest flexibility in meeting those changes going forward.

### 5.4 50% and 75% Conservation and Renewable Scenarios

Minnesota Statutes §216B.2422, Subd. 2 states that "a utility shall include the least cost plan for meeting 50 and 75 percent of all new and refurbished capacity needs through a combination of conservation and renewable energy resources." The calculation is based on the energy from future conservation and renewable resources compared to the total growth in energy requirements for Otter Tail's Minnesota load.

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**Table 5-4: Comparison of Externality Scenarios to Base Case**

Scenario	Base Case	Low Externalities	Medium Externalities	High Externalities
NPVRR (\$000)	\$3,888,399	\$4,595,128	\$5,720,206	\$5,931,129
<b>Resource Plan (MW) - Based on Summer Ratings, except Wind which is shown as Nameplate</b>				
2010	1.2% MN CIP	1.2% MN CIP	1.2% MN CIP	1.2% MN CIP
2011	New Demand Response	New Demand Response	New Demand Response	New Demand Response
2012	50 MW Wind	50 MW Wind	50 MW Wind	50 MW Wind
2013	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2014	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	<100 MW 1-Yr Capacity
2015	<150 MW 1-Yr Capacity	<150 MW 1-Yr Capacity	<150 MW 1-Yr Capacity	50 MW Wind <150 MW 1-Yr Capacity
2016	229.7 MW BSP AQCS Project <150 MW 1-Yr Capacity	229.7 MW BSP AQCS Project <150 MW Capacity	229.7 MW BSP AQCS Project <150 MW Capacity 46.2 MW Combined Cycle	229.7 MW BSP AQCS Project <75 MW Capacity 92.4 MW Combined Cycle
2017	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity
2018	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2019	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity	92.4 MW Combined Cycle 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity	92.4 MW Combined Cycle 60.0 MW Frame 5s Project
2020	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	69.2 MW Frame NG CT <75 MW 1-Yr Capacity	69.23 MW Frame NG CT <75 MW 1-Yr Capacity
2021	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2022	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2023	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2024	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2025	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
<b>New Resources by Category (MW)</b>				
Conservation	-55	-55	-55	-55
Demand Response	-15	-15	-15	-15
Wind	50	50	50	100
Existing Baseload Upgrades	357	357	230	230
Coal				
Gas	213	213	334	341
Existing Peaking Upgrades	60	60	60	60
Capacity Purchase	75	75	75	75

Table 5-5 presents the energy calculation for determining whether the conservation and renewable energy target was met. The 50% scenario is identical to the preferred plan. The 50% and 75% scenarios are shown in Table 5-6 as compared to the base case. Otter Tail's commitment to conservation assists the Company in achieving the 50% target, contributing nearly 44% of the future resources' energy by 2025. The additions of CIP and wind combined in the preferred plan meet 52% of the Company's future energy needs in the Minnesota jurisdiction, assuming only 50% of new wind resources are allocated to Minnesota load. As stated previously this plan's NPVRR was approximately \$3.888B.

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**Table 5-5: 50% and 75% Renewable and Conservation as Percent of Total New MN Energy Requirements**

	50% Renewable and Conservation Scenario			75% Renewable and Conservation Scenario		
	1.2% Conservation (GWh)	MN 50% Share of 50 MW Wind (GWh)	Total (GWh)	1.2% Conservation (GWh)	MN 100% Share of 100 MW Wind (GWh)	Total (GWh)
<b>New MN CIP</b>	482	-	482	482	-	482
<b>New Wind</b>	-	92	92	-	368	368
<b>Total</b>	482	92	574	482	368	850
<b>Percent of Total New MN Energy Requirements (= 1101.341 GWh)</b>	44%	8%	52%	44%	33%	77%

The 75% scenario required forcing the model to select a 1.2% CIP goal in Minnesota and adding 50 MW more wind generation than was selected in the preferred plan. This additional wind was added in 2013 after the expiration of the federal PTC. This plan was more expensive than the base case, reaching \$3.940B. Together, the additional CIP and wind achieve 77% of future energy needs in MN.

Otter Tail strives to develop a preferred plan that freely selects least-cost resources and allows Otter Tail to plan and operate the Company as one system that reliably and economically meets the electric needs of its customers and shares the burden of both those costs and benefits among all customers. It is important to recognize in the 75% scenario that the costs for all wind generation additions would be allocated to Minnesota customers to meet this objective. In such a case, the increased revenue requirements would be borne by Minnesota ratepayers.

### 5.5 Additional Sensitivity Scenarios

Otter Tail evaluated additional sensitivity scenarios in the process of selecting a preferred plan. These scenarios included variations in fuel prices, CO<sub>2</sub> reductions, capital costs, and policy or regulation changes. A comparison of the net present value of revenue requirements for all scenarios is provided in Figure 5-4. While some of the sensitivity scenarios are less expensive than the preferred plan, relying on those plans exposes the customer to unacceptable levels of risk. For example, heavy reliance on market purchases and assumptions of low load growth or low fuel and/or capital costs that do not materialize may actually result in higher costs to the customer. Some of the sensitivity scenarios are more expensive than the preferred plan but result in significantly reduced amounts of CO<sub>2</sub>. Again, Otter Tail believes that choosing one of these plans as the preferred plan subjects the customer to unacceptable risk levels. Taking actions to attempt to meet uncertain legislative or regulatory requirements could result in the Company taking unnecessary or incorrect actions for which customers are ultimately required to pay.

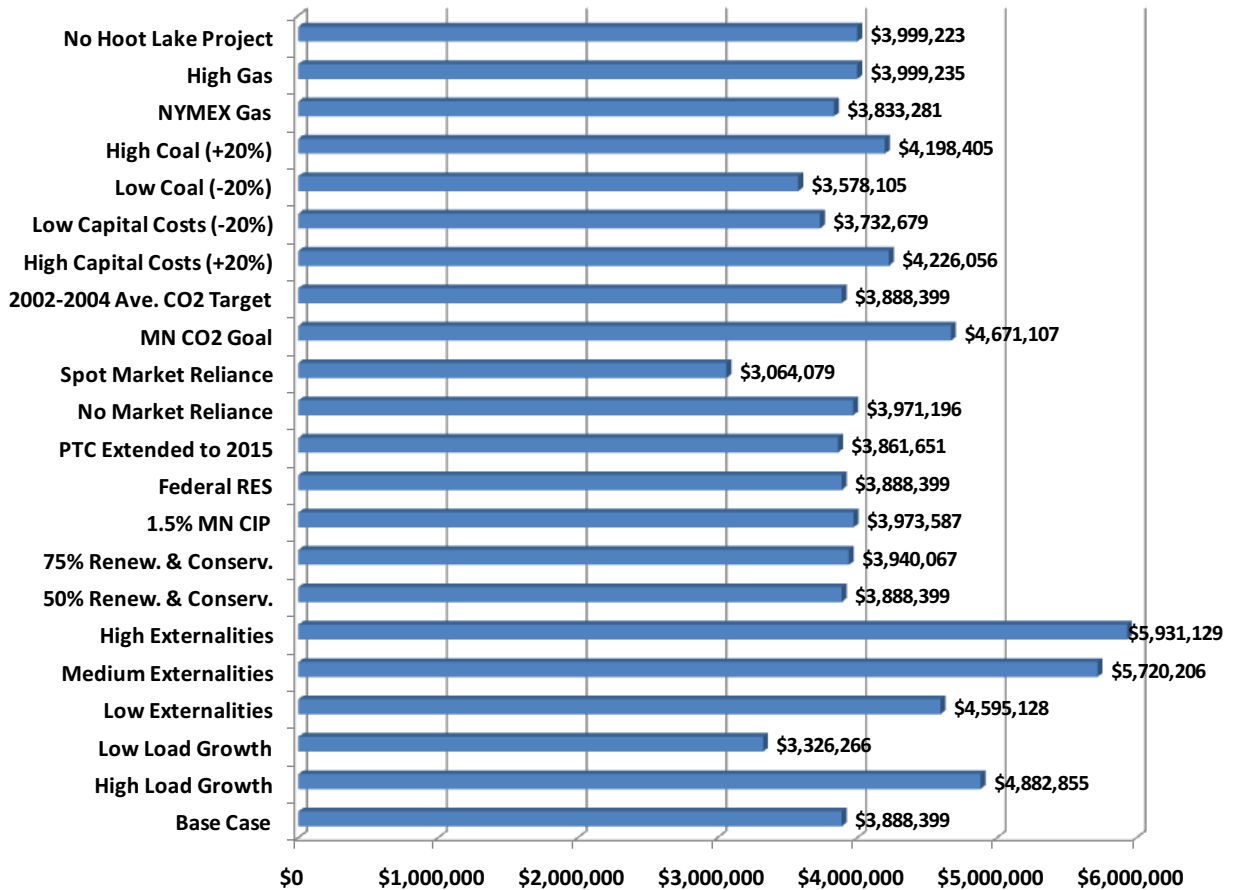
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**Table 5-6: Comparison of 50% and 75% Renewable and Conservation Scenarios to Base Case**

Scenario	Base Case	50% Renew. & Conserv.	75% Renew. & Conserv.
<b>NPVRR (\$000)</b>	\$3,888,399	\$3,888,399	\$3,940,067
<b>Resource Plan (MW) - Based on Summer Ratings, except Wind which is shown as Nameplate</b>			
2010	1.2% MN CIP	1.2% MN CIP	1.2% MN CIP
2011	New Demand Response	New Demand Response	New Demand Response
2012	50 MW Wind	50 MW Wind	50 MW Wind
2013	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	50 MW Wind <75 MW 1-Yr Capacity
2014	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	39.6 MW Aero NG CT <100 MW 1-Yr Capacity
2015	<150 MW 1-Yr Capacity	<150 MW 1-Yr Capacity	<150 MW 1-Yr Capacity
2016	229.7 MW BSP AQCS Project <150 MW 1-Yr Capacity	229.7 MW BSP AQCS Project <150 MW 1-Yr Capacity	229.7 MW BSP AQCS Project <150 MW 1-Yr Capacity
2017	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity
2018	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity
2019	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity
2020	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2021	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2022	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2023	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2024	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2025	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
<b>New Resources by Category (MW)</b>			
Conservation	-55	-55	-55
Demand Response	-15	-15	-15
Wind	50	50	100
Existing Baseload Upgrades	357	357	357
Coal			
Gas	213	213	213
Existing Peaking Upgrades	60	60	60
Capacity Purchase	75	75	75

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Figure 5-4: Comparison of Net Present Value of Revenue Requirements for All Sensitivity Scenarios

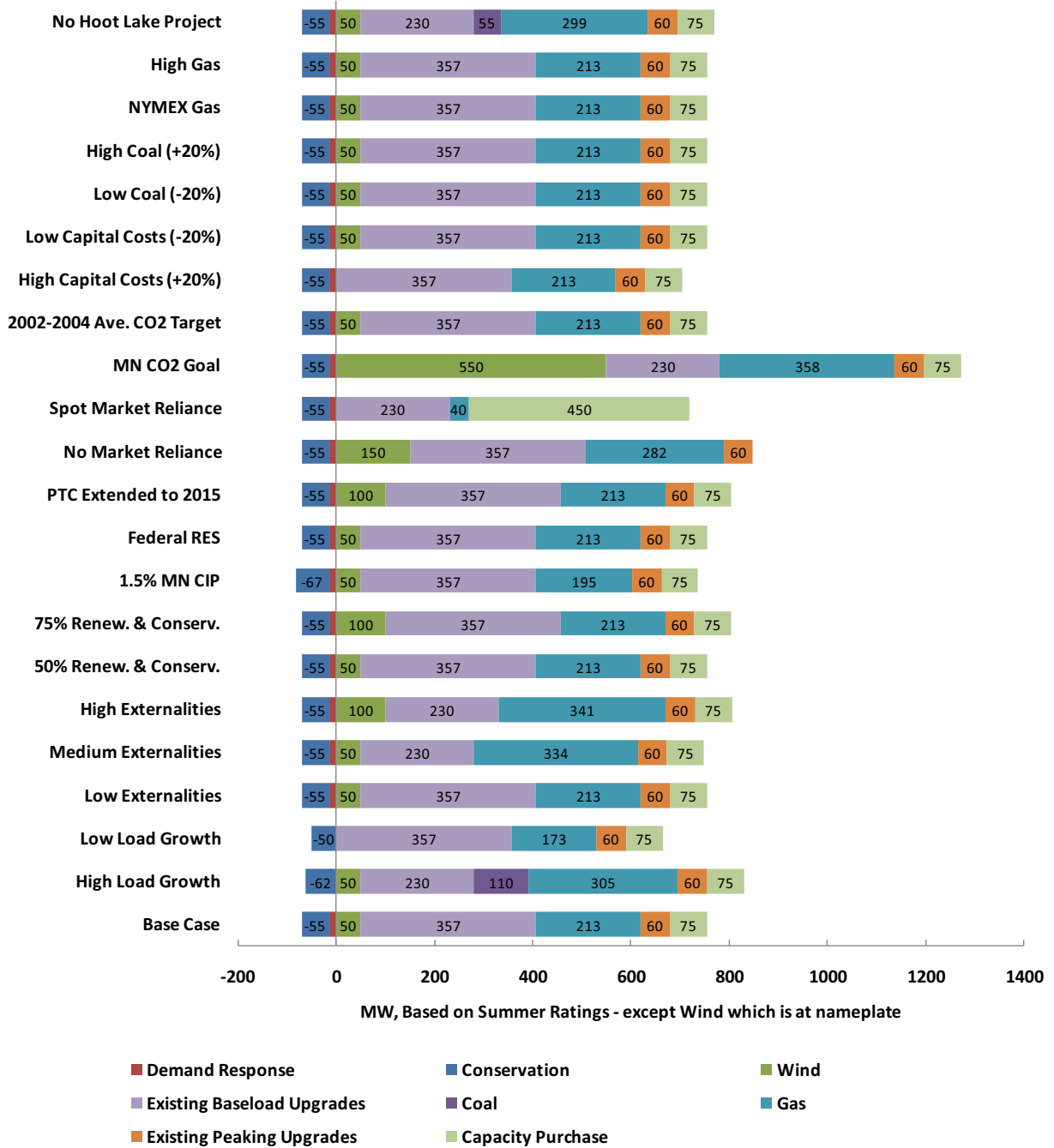


Comparisons of capacity additions by resource type for all scenarios is presented in Figure 5-5 and Figure 5-6 shows the energy side of the scenarios, presenting GWh by source in the year 2025 for all resources, including new and existing.

Figure 5-7 presents the CO<sub>2</sub> emission levels in tons for all sensitivity scenarios in 2020 as compared with the Company's average levels from 2002-2004. Since no CO<sub>2</sub> legislation with required CO<sub>2</sub> reductions has yet been passed, Otter Tail's strategic priority is to cost effectively plan for future emissions of CO<sub>2</sub> to be no more than the 2002-2004 average level by 2020. The Company's measure for this goal is based on Otter Tail's owned, or internal, emissions. It is assumed that ownership of emissions from purchases will reside with the generator under any type of cap and trade regulation and that the associated costs for those external emissions will be passed to the Company through the price of the energy. As shown in the base case scenario, the model projected emissions in 2020 to be slightly below the 2002-2004 average level. In all years of the study, the preferred plan provides the Company the appropriate resource mix and flexibility to achieve emissions at or below the average CO<sub>2</sub> level emitted from 2002-2004.

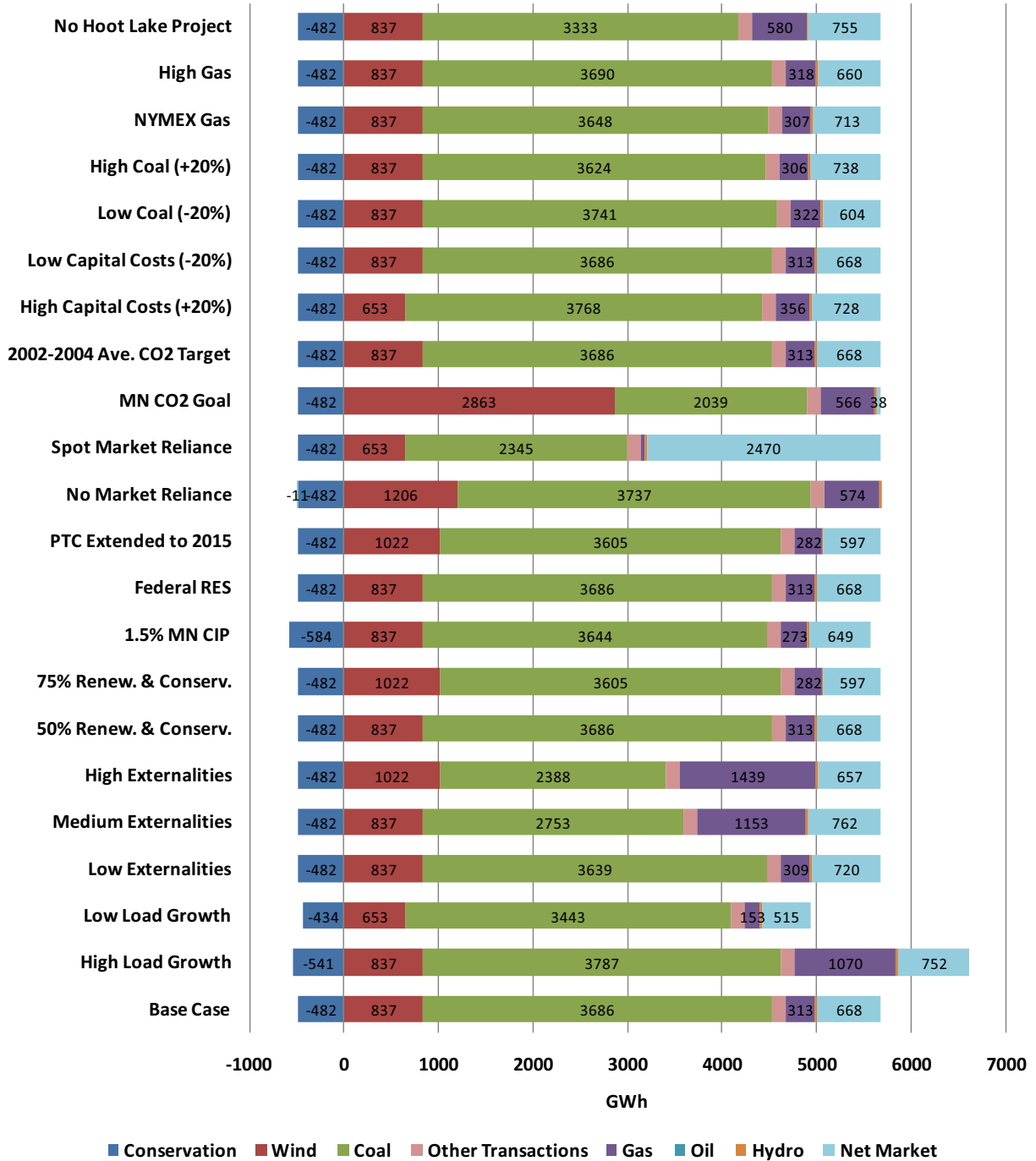
## Preferred Resource Plan 5-13

**Figure 5-5: Comparison of Resource Additions for All Scenarios (MW)**



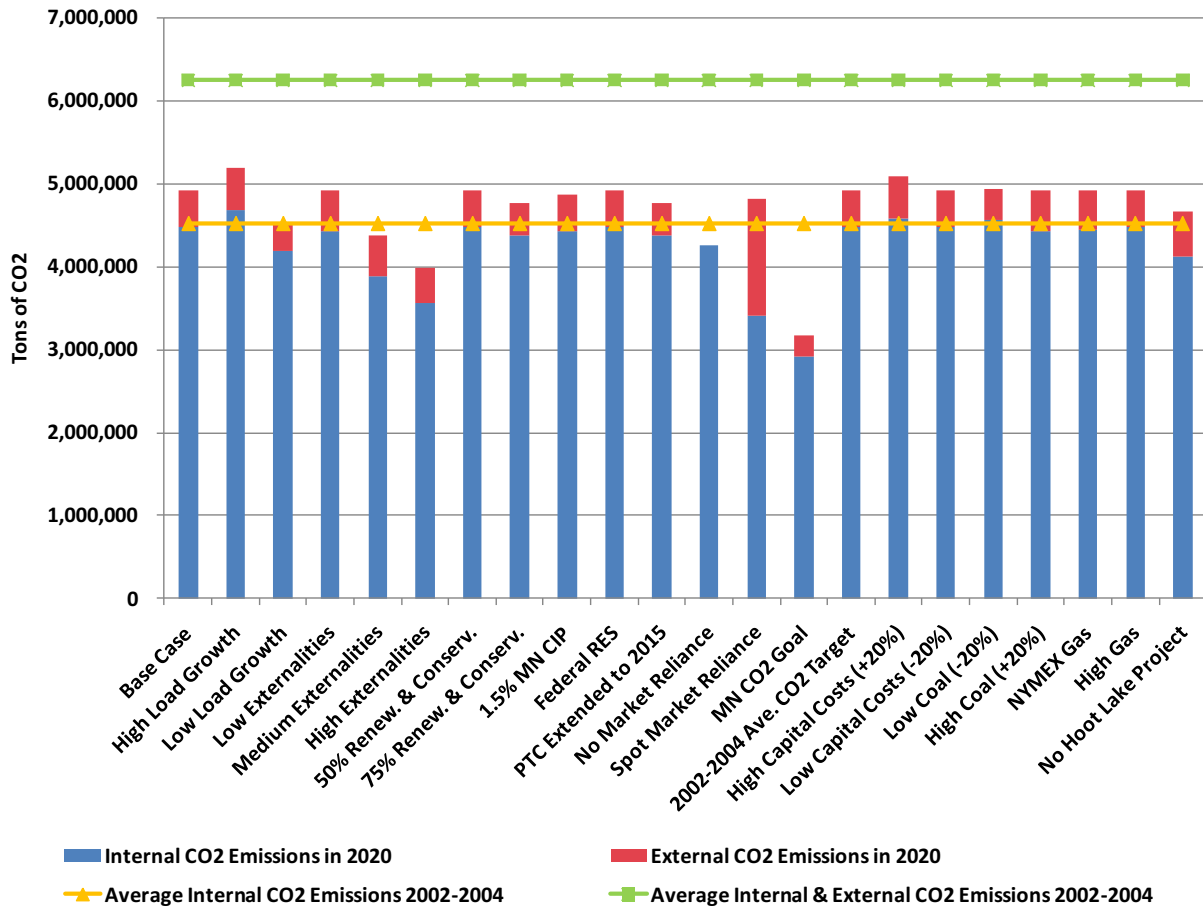
## 5-14 Preferred Resource Plan

Figure 5-6: Comparison of 2025 Generation (GWh) by Source for All Scenarios



## Preferred Resource Plan 5-15

Figure 5-7: Comparison of 2020 CO<sub>2</sub> Emission Levels to 2002-2004 Average for All Sensitivity Scenarios



The following bulleted list provides a brief discussion of each sensitivity scenario in comparison to the preferred plan.

- A 1.5% Minnesota CIP achievement scenario – By forcing the 1.5% Minnesota CIP goal into the model, the results showed additional costs of approximately \$85M over the preferred plan, or base case. This scenario added slightly less natural gas-fired peaking capacity, but otherwise was similar to the preferred plan.
- A 15% federal RES by 2025 –This scenario showed no difference from the preferred plan.
- Extension of the federal PTC through 2015 – This scenario showed a lower net present value of revenue requirements than the preferred plan by about \$27M and added an additional 50 MW of wind above the preferred plan. The rest of the resource additions in this plan were similar to those in the preferred plan.

## 5-16 Preferred Resource Plan

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- No market reliance – This scenario was about \$83M higher than the preferred plan. The Company has historically relied on the market, to some extent, to achieve savings and keep customer rates low. The Company can achieve lower costs for customers by relying on the market in a responsible manner as in the preferred plan. The energy import level in the preferred plan is 12% of total retail sales in 2025 and includes energy purchases to cover for major outages for maintenance of generation facilities.
- Unlimited spot market reliance – The price forecasts for capacity and energy indicate a surplus market. If the Company allowed unlimited spot market reliance, the reduction in net present value of revenue requirements from the preferred plan could be a significant \$824M. As shown, this plan would require Otter Tail to purchase capacity at a very high level throughout the study period and would import nearly half of the system's energy requirements by 2025. This plan would build about 40 MW of natural gas-fired simple cycle combustion turbine peaking capacity, pursue a 1.2% goal for CIP in Minnesota, implement new demand response programs, and upgrade Big Stone Plant. No wind or additional peaking capacity would be built, and the Hoot Lake Plant and Frame 5 facility upgrades would not occur. However, Otter Tail chooses to limit exposure to market fluctuations by limiting capacity and energy market reliance for reliability purposes and risk mitigation. The significance of the savings associated with this scenario support the Company's position to allow a prudent level of market reliance with the intent to minimize both cost and risk.
- Minnesota CO<sub>2</sub> Goal – According to Statute §216H.02, Minnesota has stated goals of achieving a 15% reduction in CO<sub>2</sub> emissions from 2005 levels by 2015, a 30% reduction by 2025, and an 80% reduction by 2050. This scenario would be roughly \$783M more expensive than the preferred plan, largely due to capital expenditures on wind and gas resources to replace baseload coal generation. The significance of the costs associated with this scenario support the Company's position to cost effectively plan for future internal CO<sub>2</sub> emissions to be no more than 2005 levels by 2020 until CO<sub>2</sub> regulation certainty exists.
- 2002-2004 Average CO<sub>2</sub> Emission Target – Otter Tail's objective is to economically plan for internal emissions of CO<sub>2</sub> to not exceed the average level emitted from 2002-2004 by 2020. This scenario limited CO<sub>2</sub> emissions to the 2002-2004 average level throughout the study period and the results were identical to the base case.
- High capital costs (+20%) – Assuming that capital costs of wind generation and thermal resource alternatives were 20% higher than in the base case scenario resulted in a higher cost of roughly \$338M. The resources selected in this scenario were similar to the preferred plan except that this scenario did not add any wind generation.
- Low capital costs (-20%) – Assuming that capital costs of thermal resource alternatives were 20% lower than in the base case scenario resulted in a lower cost by approximately \$156M. The resources selected in this scenario were identical to the preferred plan.
- Low coal (-20%) – Assuming coal prices are 20% less than in the base case scenario resulted in a lower NPVRR by about \$310M. This scenario was identical to the preferred plan, or base case scenario, in resource selection.

## Preferred Resource Plan 5-17

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- High coal (+20%) – Assuming coal prices are 20% higher than in the base case scenario resulted in a higher cost by around \$310M. This scenario selected the same resources as the preferred plan.
- A NYMEX gas price scenario as provided by Wood Mackenzie – The gas prices in this scenario were based on an alternative gas price forecast that was slightly higher in the early years and lower in the majority of the outer years of the study period. This scenario was slightly less expensive than the preferred plan by about \$55M and selected the same resources as the preferred plan.
- High gas prices (+20%) – Assuming gas prices are 20% higher than in the preferred plan resulted in a cost increase of roughly \$111M over the preferred plan. This scenario selected the same resources as the preferred plan.
- The Hoot Lake Project is not available – If continued operation of Hoot Lake is not an option due to impacts of environmental regulation, project infeasibility, or other reasons, this plan selected 86.5 MW of additional simple cycle, natural gas-fired peaking capability and roughly 55 MW of accredited supercritical coal-fired generation capability. This scenario was approximately \$111M more expensive than the preferred plan.

Tables 5-7 through 5-11 show greater detail on the sensitivity scenarios discussed above. In each table the base case is presented on the left for ease in comparison between the sensitivity scenario and the base case.

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**Table 5-7: Additional Sensitivity Scenarios Compared with Base Case**

Scenario	Base Case	1.5% MN CIP	Federal RES	PTC Extended to 2015
NPVRR (\$000)	\$3,888,399	\$3,973,587	\$3,888,399	\$3,861,651
<b>Resource Plan (MW) - Based on Summer Ratings, except Wind which is shown as Nameplate</b>				
2010	1.2% MN CIP	1.5% MN CIP	1.2% MN CIP	1.2% MN CIP
2011	New Demand Response	New Demand Response	New Demand Response	New Demand Response
2012	50 MW Wind	50 MW Wind	50 MW Wind	
2013	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2014	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	39.6 MW Aero NG CT 50 MW Wind <100 MW 1-Yr Capacity
2015	<150 MW 1-Yr Capacity	<150 MW 1-Yr Capacity	<150 MW 1-Yr Capacity	50 MW Wind <150 MW 1-Yr Capacity
2016	229.7 MW BSP AQCS Project <150 MW 1-Yr Capacity	229.7 MW BSP AQCS Project <150 MW Capacity	229.7 MW BSP AQCS Project <150 MW Capacity	229.7 MW BSP AQCS Project <150 MW Capacity
2017	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity
2018	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	69.23 MW Frame NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity
2019	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity
2020	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2021	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2022	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2023	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2024	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2025	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
<b>New Resources by Category (MW)</b>				
Conservation	-55	-67	-55	-55
Demand Response	-15	-15	-15	-15
Wind	50	50	50	100
Existing Baseload Upgrades	357	357	357	357
Coal				
Gas	213	195	213	213
Existing Peaking Upgrades	60	60	60	60
Capacity Purchase	75	75	75	75

## Preferred Resource Plan 5-19

**Table 5-8: Additional Sensitivity Scenarios Compared with Base Case (continued)**

Scenario	Base Case	No Market Reliance	Spot Market Reliance	MN CO2 Goal
NPVRR (\$000)	\$3,888,399	\$3,971,196	\$3,064,079	\$4,671,107
<b>Resource Plan (MW) - Based on Summer Ratings, except Wind which is shown as Nameplate</b>				
2010	1.2% MN CIP	1.2% MN CIP	1.2% MN CIP	1.2% MN CIP
2011	New Demand Response	New Demand Response	New Demand Response	New Demand Response 50 MW Wind
2012	50 MW Wind	150 MW Wind		100 MW Wind
2013	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	150 MW Wind <75 MW 1-Yr Capacity
2014	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	<100 MW 1-Yr Capacity
2015	<150 MW 1-Yr Capacity	<150 MW 1-Yr Capacity	<150 MW 1-Yr Capacity	100 MW Wind <150 MW 1-Yr Capacity
2016	229.7 MW BSP AQCS Project <150 MW 1-Yr Capacity	229.7 MW BSP AQCS Project <150 MW Capacity	229.7 MW BSP AQCS Project <150 MW Capacity	229.7 MW BSP AQCS Project <150 MW 1-Yr Capacity 46.2 MW Combined Cycle
2017	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT 69.23 MW Frame NG CT	<300 MW 1-Yr Capacity	69.2 MW Frame NG CT 150 MW Wind <75 MW 1-Yr Capacity
2018	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT	<300 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity
2019	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project	<300 MW 1-Yr Capacity	60.0 MW Frame 5s Project <75 MW 1-Yr Capacity
2020	<75 MW 1-Yr Capacity		<450 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity
2021	<75 MW 1-Yr Capacity		<450 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2022	<75 MW 1-Yr Capacity		<450 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2023	<75 MW 1-Yr Capacity		<450 MW 1-Yr Capacity	69.2 MW Frame NG CT <75 MW 1-Yr Capacity
2024	<75 MW 1-Yr Capacity		<450 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2025	<75 MW 1-Yr Capacity		<450 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
<b>New Resources by Category (MW)</b>				
Conservation	-55	-55	-55	-55
Demand Response	-15	-15	-15	-15
Wind	50	150		550
Existing Baseload Upgrades	357	357	230	230
Coal				
Gas	213	282	40	358
Existing Peaking Upgrades	60	60		60
Capacity Purchase	75		450	75

## 5-20 Preferred Resource Plan

**Table 5-9: Additional Sensitivity Scenarios Compared with Base Case (continued)**

Scenario	Base Case	2002-2004 Ave. CO2 Target	High Capital Costs (+20%)	Low Capital Costs (-20%)
NPVRR (\$000)	\$3,888,399	\$3,888,399	\$4,226,056	\$3,732,679
<b>Resource Plan (MW) - Based on Summer Ratings, except Wind which is shown as Nameplate</b>				
2010	1.2% MN CIP	1.2% MN CIP	1.2% MN CIP	1.2% MN CIP
2011	New Demand Response	New Demand Response	New Demand Response	New Demand Response
2012	50 MW Wind	50 MW Wind		50 MW Wind
2013	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2014	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	39.6 MW Aero NG CT <100 MW 1-Yr Capacity
2015	<150 MW 1-Yr Capacity	<150 MW 1-Yr Capacity	<150 MW 1-Yr Capacity	<150 MW 1-Yr Capacity
2016	229.7 MW BSP AQCS Project <150 MW 1-Yr Capacity	229.7 MW BSP AQCS Project <150 MW 1-Yr Capacity	229.7 MW BSP AQCS Project <150 MW 1-Yr Capacity	229.7 MW BSP AQCS Project <150 MW Capacity 86.5 MW Aero NG CT
2017	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2018	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity
2019	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity
2020	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2021	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2022	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2023	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2024	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2025	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
<b>New Resources by Category (MW)</b>				
Conservation	-55	-55	-55	-55
Demand Response	-15	-15	-15	-15
Wind	50	50		50
Existing Baseload Upgrades	357	357	357	357
Coal				
Gas	213	213	213	213
Existing Peaking Upgrades	60	60	60	60
Capacity Purchase	75	75	75	75

## Preferred Resource Plan 5-21

**Table 5-10: Additional Sensitivity Scenarios Compared with Base Case (continued)**

Scenario	Base Case	Low Coal (-20%)	High Coal (+20%)
<b>NPVRR (\$000)</b>	\$3,888,399	\$3,578,105	\$4,198,405
<b>Resource Plan (MW) - Based on Summer Ratings, except Wind which is shown as Nameplate</b>			
2010	1.2% MN CIP	1.2% MN CIP	1.2% MN CIP
2011	New Demand Response	New Demand Response	New Demand Response
2012	50 MW Wind	50 MW Wind	50 MW Wind
2013	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2014	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	39.6 MW Aero NG CT <100 MW 1-Yr Capacity
2015	<150 MW 1-Yr Capacity	<150 MW 1-Yr Capacity	<150 MW 1-Yr Capacity
2016	229.7 MW BSP AQCS Project <150 MW 1-Yr Capacity	229.7 MW BSP AQCS Project <150 MW 1-Yr Capacity	229.7 MW BSP AQCS Project <150 MW 1-Yr Capacity
2017	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity
2018	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity
2019	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity
2020	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2021	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2022	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2023	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2024	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2025	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
<b>New Resources by Category (MW)</b>			
Conservation	-55	-55	-55
Demand Response	-15	-15	-15
Wind	50	50	50
Existing Baseload Upgrades	357	357	357
Coal			
Gas	213	213	213
Existing Peaking Upgrades	60	60	60
Capacity Purchase	75	75	75

## 5-22 Preferred Resource Plan

**Table 5-11: Additional Sensitivity Scenarios Compared with Base Case (continued)**

Scenario	Base Case	NYMEX Gas	High Gas	No Hoot Lake Project
NPVRR (\$000)	\$3,888,399	\$3,833,281	\$3,999,235	\$3,999,223
<b>Resource Plan (MW) - Based on Summer Ratings, except Wind which is shown as Nameplate</b>				
2010	1.2% MN CIP	1.2% MN CIP	1.2% MN CIP	1.2% MN CIP
2011	New Demand Response	New Demand Response	New Demand Response	New Demand Response
2012	50 MW Wind	50 MW Wind	50 MW Wind	50 MW Wind
2013	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2014	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	39.6 MW Aero NG CT <100 MW 1-Yr Capacity	39.6 MW Aero NG CT <100 MW 1-Yr Capacity
2015	<150 MW 1-Yr Capacity	<150 MW 1-Yr Capacity	<150 MW 1-Yr Capacity	<150 MW 1-Yr Capacity
2016	229.7 MW BSP AQCS Project <150 MW 1-Yr Capacity	229.7 MW BSP AQCS Project <150 MW 1-Yr Capacity	229.7 MW BSP AQCS Project <150 MW 1-Yr Capacity	229.7 MW BSP AQCS Project <150 MW 1-Yr Capacity
2017	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity
2018	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity
2019	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity	127.1 MW Hoot Lake Project 60.0 MW Frame 5s Project <75 MW 1-Yr Capacity	60.0 MW Frame 5s Project <75 MW 1-Yr Capacity
2020	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	86.5 MW Aero NG CT <75 MW 1-Yr Capacity
2021	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2022	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	55 MW Supercritical Coal <75 MW 1-Yr Capacity
2023	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2024	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
2025	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity	<75 MW 1-Yr Capacity
<b>New Resources by Category (MW)</b>				
Conservation	-55	-55	-55	-55
Demand Response	-15	-15	-15	-15
Wind	50	50	50	50
Existing Baseload Upgrades	357	357	357	230
Coal				55
Gas	213	213	213	299
Existing Peaking Upgrades	60	60	60	60
Capacity Purchase	75	75	75	75