414 Nicollet Mall
Minneapolis, MN 55401

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May 27, 2009

- VIA E-MAIL & U.S. MAIL -

Darrell Nitschke, Executive Director
North Dakota Public Service Commission
State Capitol Building, Dept 408
600 East Boulevard
Bismarck, ND 59505-0480

Re: APPLICATION OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION, FOR AN ADVANCED DETERMINATION OF PRUDENCE FOR THE 20 MW BAY FRONT PROJECT

Dear Mr. Nitschke:

Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company"), is pleased to offer this Application for an Advanced Determination of Prudence ("ADP") for our proposed 20 megawatt ("MW") Bay Front Project located in Northern Wisconsin. The purpose of this ADP filing is to provide the Commission with information about this proposed Project. While the size of this facility falls below the commitment threshold for an ADP filing established in our recent rate case settlement, this filing is part of our on-going efforts to fully inform the Commission of facilities that will affect electric rates for our North Dakota customers in the future.

The Project will consist of installing a biomass gasification system to convert waste wood to synthetic gas ("syngas") and modifying the existing boiler #5 at Bay Front to burn the gas effectively to produce steam for electric power generation. In addition, we will increase the biomass receiving, storage and handling capabilities and add enhanced flue gas filtering equipment to capture residual particulates.

After examining existing fuel costs and identifying the investments necessary to meet emerging air quality requirements for boiler #5 we concluded it is not prudent to continue to operate the boiler on the current fuel mix of coal and pet coke. The conversion of boiler # 5 to utilize biomass helps us meet the renewable energy objectives in all of our jurisdictions, including North Dakota's renewable and recycled energy objective contained in NDCC Section 49-02-28.

The size and location of Bay Front provides a unique opportunity to expand the utilization of biomass in our portfolio of renewable-based generation, and the repowering of boiler #5 as a biomass resource provides benefits at a reasonable cost other alternatives cannot. After considering the benefits and potential risks of the Project, we believe that its implementation is prudent and in the best interest of our North Dakota customers, and customers throughout our system.

After receiving all necessary approvals for this Project, we anticipate we will begin engineering and procurement in 2010. Primary construction is planned to begin no later than mid- 2011 with commercial operation targeted for October 2012.

We believe the Project is necessary to meet our states' renewable energy policies and to serve the energy needs of our customers as part of an integrated and diversified portfolio of resources. As a result, we believe the project meets the standard for the Commission to make an advance determination of prudence and reasonableness. In the enclosed application, we provide analyses that confirm the project is a cost effective undertaking that will help meet renewable policies and provide a hedge against fuel price increases in the future.

We look forward to working with the Commission in the review of this filing and respectfully request that the Commission make a determination that the Bay Front Project meets the Advance Determination of Prudence requirement of NDCC Section 49-05-16.

SINCERELY,

/S/

JAMES R. ALDERS
DIRECTOR, REGULATORY ADMINISTRATION

Enclosures

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STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

NORTHERN STATES POWER COMPANY,
A MINNESOTA CORPORATION

CASE NO. PU-_____

IN THE MATTER OF AN APPLICATION
FOR ADVANCE DETERMINATION OF
PRUDENCE FOR THE BAY FRONT
BIOMASS GASIFICATION PROJECT

INTRODUCTION

Northern States Power Company, a Minnesota Corporation operating in North Dakota ("Xcel Energy" or the "Company"), respectfully submits to the North Dakota Public Service Commission (the "Commission") this Application for an Advance Determination of Prudence ("ADP") pursuant to North Dakota Century Code ("NDCC") Section 49-05-16. This ADP application is for a proposed Biomass Gasification Project at the Bay Front Plant in northwestern Wisconsin ("Bay Front Project" or "Project").

The Bay Front Plant is owned by Northern States Power Company, a Wisconsin Corporation ("NSP-WI"), and a portion of the costs of the Project will be shared by the Company through the Federal Energy Regulatory Commission ("FERC") approved Interchange Agreement[1], and ultimately allocated to the North Dakota jurisdiction.

[1] NSP-WI and the Company plan and operate their electric production and transmission systems on an integrated basis to affect the most economical and reliable supply of energy to meet their combined electric load. This integrated system is commonly referred to as the "NSP System", and the Company and NSP-WI are collectively referred to as the "NSP Companies" or simply "NSP." Because of the integrated nature of their systems, the Company and NSP-WI entered into an agreement for the sharing of all costs of generating and transmission facilities, including capital costs. This agreement is generally referred to as the Interchange Agreement.

OVERVIEW

The purpose of this ADP filing is to seek the Commission's determination that our investment in the proposed Bay Front Project is prudent. This filing is part of our on-going efforts to fully inform and engage the Commission in resource decisions that will affect electric rates for our North Dakota customers in the future.[2]

The Project consists of: 1) retrofitting the existing Boiler #5 at Bay Front in Ashland, Wisconsin with state of the art biomass gasification technology and 2) making other improvements to convert Boiler #5's fuel source from coal and petroleum coke to biomass. Once completed, Boiler #5's fuel source will be wood waste from northwestern Wisconsin's forest industries.

After examining existing fossil fuel costs and identifying the investments necessary to meet emerging air quality requirements for Boiler #5, we concluded it is not prudent to continue to operate on the current fuel mix of coal and petroleum coke.

These circumstances provide us with a unique opportunity to utilize existing generating infrastructure, take advantage of gasification technology, and increase the use of the indigenous fuel source of northwestern Wisconsin to help meet the renewable energy goals of the states we serve at a reasonable cost.

We believe the conversion of Bay Front Boiler #5 to Biomass satisfies the ADP standards for the following reasons:

- *The Project enhances energy diversity.* The project will help diversify the mix of renewables-based generation we operate to meet the renewable energy goals in the states we serve. The Bay Front Plant's renewables-based generation will increase by approximately 124,000 MWh per year. Bay Front is a dispatchable resource that will operate at a high capacity factor and complement the more intermittent nature of wind power.

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[2] In our recent rate case settlement (Docket PU-07-776, *Order Adopting Settlement*, Dec. 31, 2008), the Company committed to make an ADP filing for any capacity acquisition of at least 50 MW. The Bay Front Project, while smaller than this commitment, we believe is appropriate for the Commission's ADP consideration.

- *The Project is a cost effective biomass resource.* The conversion of Boiler # 5 provides a unique opportunity to utilize significant parts of the existing plant infrastructure to keep the cost low while adding state-of-the-art gasification technology to our system. Other approaches to increasing the use of biomass are more costly.

- *The Project is reasonable when compared to alternatives.* Our analysis examined several options for replacing the electricity generated using Boiler #5 and found the Project compares favorably. An additional renewables based generation resource provides a hedge against potentially volatile market or natural gas prices.

- *The Project provides environmental and economic benefits.* Given emerging air quality regulations, NSP must significantly modify or shut down Boiler #5 at Bay Front. Not only will the Project enable us to achieve compliance with applicable air quality regulations, but will do so with a dispatchable renewable resource utilizing existing infrastructure. In addition, the Project will utilize biomass from the forest industries of northwestern Wisconsin, thereby contributing to the economic health of our service territory.

After considering the benefits and potential risks of the Project, we believe that its implementation is prudent and in the best interest of customers throughout our system.

We have organized the remainder of this application into the following sections:

- Description of the Applicant
- Request for an ADP
- Description of the Bay Front Project
- Assessment of Prudence and Reasonableness
- Communications and Service List

DESCRIPTION OF THE APPLICANT

Xcel Energy is a Minnesota corporation duly authorized to conduct business in the State of North Dakota as a public utility subject to the jurisdiction and regulation of the Commission pursuant to Title 49 of the NDCC. The full name and address of the Company is:

> Northern States Power Company,
> a Minnesota corporation
> 414 Nicollet Mall
> Minneapolis, Minnesota 55401

The Company also operates in North Dakota from the following address:

> Northern States Power Company
> 2302 Great Northern Drive
> Fargo, ND 58102

Xcel Energy's Certificate of Incorporation and amendments were filed with the Commission on May 31, 2001 and are incorporated herein by reference.

Xcel Energy has service territory in three upper Midwest states including North Dakota. NSP-WI has service territory in Wisconsin and Michigan. The Company presently serves approximately 87,000 retail electric customers in and around Fargo, Grand Forks, and Minot, North Dakota. Xcel Energy owns approximately 250 miles of transmission lines and 12 substations in North Dakota.

REQUEST FOR AN ADVANCE DETERMINATION OF PRUDENCE

It is important to involve the Commission in key energy policy decisions that will affect rates. North Dakota statues provide that a utility proposing an energy facility may seek an Advanced Determination of Prudence. Specifically, North Dakota law provides:

> **Section 49-05-16. Advance Determination of Prudence.** A public utility proposing to construct, lease, or make improvements to an energy conversion facility, renewable energy facility, transmission facility, or proposed energy purchase contract from another entity or person for the purpose of ensuring reliable electric service to its customers may file an application with the commission for advance determination of prudence regarding the proposal…

Under NDCC Section 49-05-16, the Commission may issue an order approving the prudence of an electric resource addition if three conditions are met:

a. The public utility files with its application a projection of costs to the date of the anticipated commercial operation of the electric resource addition;

b. The commission provides notice and holds a hearing, if appropriate, in accordance with Section 49-02-02; and

c. The commission determines that the resource addition is reasonable and prudent.

As demonstrated in this Application, the Bay Front Project is a reasonable and prudent investment for the purpose of providing electric service to our customers. We will file testimony and exhibits to further support this Application if the Commission deems a formal hearing appropriate for this filing. If appropriate, we will work with the Commission's staff to determine a schedule to submit testimony expeditiously. The testimony and exhibits would further support the prudence of the Bay Front Project, provide additional support for choosing the Bay Front Project as a good resource for meeting customers' needs, and expand on the Project development process including cost projections.

DESCRIPTION OF THE BAY FRONT PROJECT

A. Background

The Bay Front Plant is located on approximately 50 acres of land on the shores of Lake Superior's Chequamegon Bay in Ashland, WI. The plant was originally constructed and began operation in 1916 as a coal-fired plant. In 1960, it consisted of five boilers and six turbines. Two of the boilers and three of the turbines have since been retired. The three remaining boilers feed into a combined steam heater system that can support three turbine-generator sets. The Bay Front Plant has become a model for the creative use of fuels, including renewable fuels. The boilers burn a variety of fuels including coal, waste wood, railroad ties, tire-derived fuel, natural gas and petroleum coke to produce steam that drives the three turbine/generators to produce electricity.

The capacity equivalent of the existing boilers are 22 MW each for Boilers #1 and #2, and 28 MW for Boiler #5. Since 1979, the Bay Front Plant has converted more than four million tons of biomass, largely waste material (wood and sawdust) from local timber processing firms, into electricity. In 2007, Boilers #1 and #2 consumed approximately 200,000 tons of biomass, and in 2008 Boilers #1 and #2 consumed approximately 210,000 tons of biomass.

Boiler #5 uses cyclone combustion technology to generate the necessary steam levels to generate electricity. As a result, the type and quality of coal and its mixing ratio with petroleum coke is very important to ensure proper operation of Boiler #5. Locating an acceptable coal with the proper characteristics can be difficult and can result in increased delivery costs. In addition, because of the size and location of Boiler #5, the opportunity for price discounts on coal do not exist and extra handling of the coal is required, resulting in higher costs. Currently, coal prices for Boiler #5 exceed the cost of biomass for the Plant on a per million Btu basis.

In 1991 Bay Front was equipped with an upgraded air quality control system, which includes two gravel bed filters. The gravel bed filters are designed to remove more than 98% of the particulate matter. The system contains more than 300 tons of gravel bits, which are electrically charged to collect particulates from flue gas. In 1999, the plant was equipped with auxiliary natural gas burners to improve operating efficiency while firing on wood.

In 2008, NSP installed oxides of nitrogen ("NOx") emission control equipment on Bay Front Boilers #1 and #2. These investments will allow the continued use of biomass in Boilers #1 and #2 well into the future. However, NSP cannot economically continue to rely on coal and petroleum coke to power Boiler #5 due to long-term coal availability and cost issues, and significant costs relating to compliance with the recently reinstatement of the Clean Air Interstate Rule ("CAIR") and the pending federal mercury rules.

With the re-instatement of CAIR, additional environmental regulations apply to Boiler #5. CAIR will require Boiler #5 to further reduce its NOx and sulfur dioxide ("SO_2") emissions in 2009. Using banked SO_2 allowances will help minimize the cost of satisfying the SO_2 emission reduction targets in 2010. However, federal NOx emission reduction targets will require additional investments in NOx control equipment or the purchase of NOx allowances. In addition, some of the NOx emission reductions or allowance purchases must be seasonally specific, resulting in higher costs. Utilizing biomass as a fuel will result in at least a 60 percent reduction in NOx emissions from Boiler #5.

The U.S. Environmental Protection Agency has indicated that it plans to replace its Clean Air Mercury Rule ("CAMR") with new mercury rules requiring Maximum Achievable Control Technology ("MACT"). We do not expect the new rule to include exemptions for low-emitting boilers such as Boiler #5 or contain cap and trade provisions. We expect the new mercury rules will require a 90 percent mercury

emission reduction target for Boiler #5. Activated carbon injection with a baghouse collection system is likely to achieve a 90 percent reduction in mercury emissions at a significant annual operating cost. Switching to biomass fuel with natural gas as an alternative fuel, while eliminating the ability to burn coal, will remove Boiler #5 from regulation under the new federal mercury rules.

A promulgation date for the new federal mercury rules is still uncertain. However, there is talk within the industry that rulemaking could be completed in 2011 with implementation necessary sometime between mid-2012 and the end of 2015. If the new federal rules are not in place prior to 2015, a Wisconsin mercury rule, (NR 446, Wisconsin Administrative Code) has a compliance deadline of January 1, 2015.

Since Boiler #5's coal and petroleum coke fuel sources are more expensive than local biomass fuel and significant plant investments would be necessary in the near term to continue to operate the boiler on fossil fuels, we concluded it was prudent to pursue conversion of the facility.

B. Project Description

The major components of the Project include installing a biomass gasification system to convert waste wood to synthetic gas ("syngas") and modifying the existing Boiler #5 to burn the gas effectively to produce steam for electric power generation. Boiler #5 will also have the capability to burn natural gas. In addition, we will increase the biomass receiving, storage, and handling capabilities, and add enhanced flue gas filtering equipment to capture residual particulate emissions.

1. Gasifier

Biomass gasification has been studied and developed over the past half century and continues to grow due to interest in clean, renewable energy. To date, biomass gasification installations in the U.S. have predominantly been small-scale (less than 5 MW) plants, however, some larger-scale plants have been installed in recent years.

The process of biomass gasification involves the heating of biomass in the presence of a limited proportion of air or oxygen to generate a gas made up primarily of carbon monoxide ("CO"), carbon dioxide ("CO_2"), methane ("CH_4"), longer chain hydrocarbons, and hydrogen ("H_2"). The syngas can then be fired in a traditional boiler. Syngas burns more efficiently and cleanly than solid fuel, including the biomass from which it was made.

Gasification takes place in a heated chamber. Fluidized bed media, cleaning and reinjection systems, fuel metering and air delivery systems will be an integral part of controlling the output of the gasifier. The gasifier project will also address char and ash handling needs and will include control system logic that can be integrated into the existing plant control system.

We focused on fluidized bed gasification technology due to the advantages it offers at this scale. Gasifying biomass in the fluidized bed configuration combines partial oxidation of hydrocarbons and de-volatilization of fuel. Biomass is introduced into a heated, fluidized bed furnace in the presence of less than 50% of the air necessary for combustion. At temperatures between 1,000°F and 1,600°F, most of the volatiles and water within the fuel are driven off as syngas, leaving ash and carbon. The energy content of the syngas is typically in the range of 100 to 200 BTU[3] per standard cubic foot (BTU/scf). While significantly lower in heating value than natural gas, oil or propane, this syngas compares favorably with pulverized coal in temperature and excess air requirements and contains much lower levels of sulfur and nitrogen.

The lower heat energy content of the syngas and the physical characteristics of the existing boiler will reduce the steam generating capacity of the boiler when burning 100 percent syngas. Ultimately, the reduced steam capacity will decrease the amount of electric generating capacity from the current rating of approximately 28 MW to an estimated 20 MW. The boiler will still retain the ability to generate 28 MW of electricity when burning 100 percent natural gas. As a result, the Project is not expected to impact the plant's total summer accredited capacity.

2. Modifications to balance of plant

To construct the Project, we will need to perform several modifications to the Bay Front Plant. Specifically, we will retire or remove the equipment currently used to process the coal fuel for Boiler #5 including the coal crusher; the crusher reversing switch; the coal feeder system; and the dewatering bin which is used to cool the slag. In addition, certain air quality control equipment, multiclone separators and collectors will be removed. We will modify Boiler #5 so that it can burn the syngas and effectively produce steam for electric power generation, and add enhanced flue gas filtering equipment to capture residual particulates. Because the gasifier will be installed in the area currently occupied by the plant's weld and maintenance shops,

[3] British Thermal Unit

those two building will be removed and replaced. NSP will also increase the Bay Front Plant's biomass receiving, storage and handling capabilities to accommodate the additional biomass that will be used at the plant upon completion of the Bay Front Project.

3. Implementation Schedule

Table 1 provides a high-level implementation schedule for the Project. After receiving all necessary approvals for this project, engineering and procurement will occur in 2010. Primary construction is planned to begin no later than mid-2011, with commercial operation planned for October 2012.

Table 1
Summary of Project Milestones

Description	Estimated Completion Date
Award Study Contract	April 23, 2009
Begin RFPs for Major Components	October 13, 2009
Receive Air/Water Permit	February 11, 2010
All Contracts Awarded	June 25, 2010
Engineering Complete	July 6, 2011
Major Components delivered to Site	August 31, 2011
Start Construction	September 1, 2011
Foundation Complete	December 16, 2011
Construction Complete	August 15, 2012
Provisional Acceptance	September 21, 2012
Commercial Operation	October 12, 2012
Project Closeout	January 30, 2013

4. Projected Costs

NDCC Section 49-05-16 1.a requires a projection of costs to the date of the anticipated commercial operation of the electric resource. The project is currently estimated to cost $58.1 million. Table 2 provides an estimate of project costs. Attachment A, a Trade Secret attachment, contains more details on the project costs.

Table 2
Bay Front Boiler #5 Gasifier Project
Summary Cost Estimate

Major Equipment/Systems	Cost
Mechanical System	**$29,053,250**
Electrical and Controls	**$ 2,010,500**
Civil/Structural	**$ 3,758,250**
Design & Engineering & Field Engineering	**$ 3,140,000**
Indeterminates and Contractor OH	**$ 4,474,700**
Sub Total Directs	**$42,436,700**
Indirects	**$ 6,657,650**
Escalation	**$ 3,740,623**
Contingency, 10%	**$ 5,283,497**
Project Total	**$58,118,470**

5. Energy Production

The Project is expected to generate approximately 124,000 MWh of electricity annually, approximately the same level of energy production as the current Boiler # 5. The unit will be operated as a must-run resource to maximize energy production and minimize the overall cost of energy produced. Energy production at the Bay Front Plant currently averages around 325,000 MWh annually and is currently forecast to produce just under 300,000 MWh annually after conversion of Boiler #5. The lower forecast is dependent on a number of variables including energy market conditions, gasifier start-up period, and potential increases in maintenance time as the new and existing equipment ages.

C. Biomass Fuel Source

The Bay Front Plant currently utilizes approximately 200,000 to 210,000 tons of biomass annually. As a result, we have significant experience with the sourcing and handling of biomass fuel. The proposed gasifier is expected to consume as much as 200,000 to 250,000 additional green tons of locally available biomass each year.

The existing biomass fueled boilers at the Bay Front Plant are supplied by a mixture of waste wood from wood products firms in the area and underutilized woody biomass that is typically left behind at existing forest harvest sites. This material includes treetops, logging slash, damaged trees, underutilized species and mortality classed trees.

After installation of the gasifier, the total fuel requirement of the plant will increase to approximately 400,000 to 460,000 tons of biomass. This fuel requirement will be satisfied with the use of waste wood from existing, new and expanding wood products firms in northern Wisconsin, Michigan, and Minnesota and the underutilized woody biomass described above. Based on information from the United States Forest Service, less than 15% of this underutilized woody biomass available within 100 miles of the Bay Front Plant will be needed to help satisfy Bay Front's total fuel requirements.[4]

The availability of an adequate supply of woody biomass for the Project will be reflected to a certain degree by the price. We have estimated the price for woody biomass in 2012 between **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. Because of uncertainty surrounding fuel cost forecasts, NSP also ran sensitivity analyses with prices at ±20 percent of the baseline price, and at ±40 percent of the baseline price.

[4] NSP is also working with the Wisconsin Office of Energy Independence, Wisconsin Department of Agriculture, Trade and Consumer Protection, University of Wisconsin - Madison and local agricultural experts to explore the feasibility of developing biomass plantations and grower cooperatives. The products of these initiatives would be chipped and used as fuel for the gasifier. Among other benefits, grower cooperatives could offer a centralized location(s) for the aggregation, processing and storage of the biomass, and provide just-in-time delivery to the Bay Front Plant.

Generally speaking, the lower end of the range corresponds to the continued use of wood and wood waste supplied by wood products firms in the area, while the higher end of the range corresponds to fuel from future energy plantations and grower cooperatives. Based on our efforts to develop multiple sources of biomass fuel, we expect the cost of biomass to fall within this price range. The baseline price for woody biomass delivered to Bay Front in 2012 was estimated at **[TRADE SECRET BEGINS TRADE SECRET ENDS]** and is based on the range of 2008 actual delivered cost of woody biomass to Bay Front, escalated to 2012 based at a compound annual rate of **[TRADE SECRET BEGINS TRADE SECRET ENDS]** escalation for each year after 2012.

In projecting future prices for woody biomass, we viewed the increases in biomass prices from 2005 to 2008 as anomalous, as those increases were primarily due to the increase in demand for biomass supplies resulting from a commitment to burn 100% biomass in Boilers # 1 and #2. Over the past two years, the demand for biomass for Boilers #1 and #2 has leveled off and is not expected to increase. As a result of demand stabilization, we expect annual price increases for biomass supplies to decline to the **[TRADE SECRET BEGINS TRADE SECRET ENDS]** (after 2012) levels identified above. In addition, our efforts to expand biomass markets in northern Wisconsin, including expanding supplies from existing sources, coordination with the WDNR on the development of biomass harvesting guidelines, and efforts to spur development of energy plantations have helped to stabilize prices.

The projected fuel costs as described above are shown in Figure 1 below.

Figure 1 [TRADE SECRET BEGINS

TRADE SECRET ENDS]

D. Cost to Customers

Table 3 provides the estimated annual revenue requirement associated with the Project that would be allocated to the North Dakota jurisdiction over the next five years. The calculation includes both capital and operating expenditure estimates. Table 3 also translates the revenue requirement impact into an estimate of the increased monthly cost to a typical residential customer using 750 kilowatt-hours.

Table 3
Revenue Requirements and Customer Impact of the Bay Front Project

	2010	2011	2012	2013	2014
Annual Revenue Requirement	$9,182	$89,660	$267,935	$533,587	$510,695
Typical Residential Monthly Bill Impact	$0.00	$0.03	$0.09	$0.18	$0.17

ASSESSMENT OF PRUDENCE AND REASONABLENESS

This Project provides a unique opportunity to use existing generating infrastructure, take advantage of gasification technology, and increase the use of the indigenous fuel source of northwestern Wisconsin to cost effectively meet the renewable energy goals of the states we serve.

A. Renewable Energy Goals

The Project will be primarily fueled with biomass, which is an eligible renewable fuel in all the states we serve. All of these states have implemented renewable energy standards or goals. Each jurisdiction has identified goals for energy production as a percentage of total sales within the state as shown below.

North Dakota	10 percent	2015	
South Dakota	10 percent	2015	
Wisconsin	13 percent	2015	
Michigan	10 percent	2015	
Minnesota	15 percent	2010	
	18 percent	2012	
	25 percent	2016	
	30 percent	2020	(25% wind power)

In aggregate, these goals represent on the order of 12 million MWh of renewable energy by 2020. Approximately 6 million MWh of eligible renewable energy is produced annually on the NSP System today. We estimate Boiler #5 will produce about 124,000 MWh of renewable energy annually and will contribute to the goals that have been established.

The increased use of biomass at Bay Front also helps us maintain fuel diversity in the production of renewable energy on our system. Currently Xcel Energy uses a mix of wind, biomass and water as renewable fuels to generate electricity. However, wind power has become the resource of choice in recent years and is projected to continue to grow on our system. North Dakota, South Dakota and western Minnesota have been favored with a bountiful wind resource. While wind power is a cost effective energy resource in today's market, production is variable, that is, it rises and falls as wind speeds vary. Intermittent resources like wind power require other dispatchable generating resources to ensure system reliability.

There are very few opportunities on our system to add dispatchable renewable resources. The region's hydro resources are essentially developed. Next to wind power, biomass from the forest industries of northwestern Wisconsin represents the next most available renewable resource on our system. With the conversion of Boiler #5, the Bay Front Plant will be one of the largest biomass fueled generators in the country. The Project will add 20 MW of dispatchable, biomass fueled, production capacity that will operate at a high capacity factor.

B. Cost Effective Biomass Resource

Bay Front is uniquely situated to use biomass. The plant is located in northwestern Wisconsin, an area whose economy relies heavily on its forest resource. As discussed earlier, there are considerable sources of biomass fuel stock within a relatively short distance of the plant that can be used to produce electricity. Furthermore, the Bay Front Plant has considerable experience working with the existing biomass forestry market to obtain fuel supplies for Boilers #1 and #2.

In addition, the size of Boiler #5 lends itself to being utilized as a biomass generating resource. As noted previously, gasification technology has been utilized, for the most part, at scales smaller than would be required to repower Boiler #5. A repowering application much larger than Boiler #5 would present considerable technology risk, yet our technology investigations indicated that the application of gasification at the scale needed to repower Boiler #5 is feasible. Moreover, the total cost of power production can be kept lower to the extent existing infrastructure can be reused as part of the repowering effort. To the extent existing boiler, fuel handling, and other equipment can be recycled, power from biomass will be more cost effective than other biomass alternatives studied.

As part of our analysis, we undertook studies to examine the options for repowering Boiler #5 using gasification technology and compared them to completely replacing the unit with a new Circulating Fluidized Bed ("CFB") boiler utilizing biomass fuel. Babcock & Wilcox was retained to complete an initial evaluation of the boiler's capability to use syngas. Zachary Engineering conducted an initial feasibility study for use of biomass gasification technology at the Bay Front Plant and compared gasification to CFB technology.

The studies verified the relative benefits of a gasification approach to biomass expansion at Bay Front. A new CFB boiler option has the highest capital cost of the alternatives studied since it amounts in essence to replacing the existing boiler with nearly all new equipment. We rejected this option due to its very high costs and lack

of benefits relative to the gasification option. Clearly, repowering Boiler #5 in a way that takes advantage of as much of the existing plant infrastructure as possible represents the most cost effective approach to expanding the use of biomass fuel resources.

C. Compares favorably to other options

To further evaluate repowering Boiler #5, we investigated the relative merits of the Project compared to three other alternatives:

1) retiring the unit and replacing its energy with additional wind power, or
2) retiring the unit and making purchases from the market to replace its energy, or
3) operating Boiler #5 as a peaking resource with natural gas as its fuel.

Attachment B provides more information on the analysis of these alternatives including an examination of total system expansion and operating costs over an extended planning period using the Strategist model. The results of the analysis are expressed as the present value of revenue requirements ("PVRR") associated with each alternative. In each case the Strategist model found a slightly lower PVRR for the options examined. However, in each case, we believe there are other factors that favor biomass conversion. Following is a summary of the analysis for each option.

1. Wind Option

Wind was also considered as an alternative to this Project. The Wind Option assumes 33 MW of wind generation would be installed with an overall capacity factor in the range of 36%-40%. This generation would be accredited at only about 12% of nameplate capacity, or approximately 4 MW, for purposes of MISO mandated reserve margins. Because of the higher capacity rating of Boiler #5, additional output would still need to be purchased from the market. Considering the costs of ancillary services needed to integrate wind, the Gasifier Option costs virtually the same as this Wind Option, with only $0.03/MWh separating the two options. The gasification option provides the added benefit of further diversifying our renewable energy portfolio, which is already heavily weighted toward wind.

2. Market Purchase Option

Instead of repowering Boiler #5, we could retire the facility and replace its output from the wholesale market. As shown in Attachment B, the Strategist model predicts

only a slightly higher PVRR for the Project compared to market purchases over the planning period. The Market Option would appear to be the lowest cost option based on current planning assumptions. However, we do not believe it is reasonable to increase reliance on the market to meet resource needs long term. Planning models cannot adequately capture market volatility that could cause this option to be more costly with unforeseen variations from modeling assumptions. When we rely on market capacity and energy to meet resource needs, it results in a largely uncapped cost risk that could soar during extreme weather conditions and/or serious disruptions in fuel supply or generating capability. For long-term energy needs, such as that currently supplied by the Bay Front Plant, it is more reasonable to rely on our own generation that hedge against market volatility and consist largely of fixed or known costs.

Although the Project is projected to cost slightly more over the long run than the Market Option, it provides benefits that the Market Option does not, such as energy that can be used to meet state renewable energy objectives and a hedge against potential future, more stringent regulation of air emissions. In addition, it avoids market risk and allows us to utilize existing infrastructure, including transmission, which is not considered in the cost of the Market Option. In light of these benefits, we believe the costs of pursuing the gasification project are reasonable when compared to relying on the market.

3. Natural Gas Option

Instead of conversion to biomass, Boiler #5 could be converted to burn only natural gas. The capital costs of gas conversion is less but fuel costs are expected to be much higher. The Natural Gas Option would maintain the accredited capacity of Boiler #5, but the energy produced would be more expensive on a MWh basis. The high fuel costs would cause Boiler #5 to be dispatched only to provide peak energy during periods of high system demand. Boiler #5 would remain a steam-generator and would take longer to ramp up to full output capability compared to generation from a combustion turbine. Boiler #5 operated on gas alone would be a relatively inefficient peaking resource and would probably be dispatched even less than assumed in our modeling. Thus, the actual cost of a unit of energy would be higher. Furthermore, this option is subject to greater volatility in fuel costs as natural gas prices continue to fluctuate and be less predictable than historical costs.

D. Environmental and Economic benefits

The conversion of Boiler #5 will help us meet renewable energy requirements at reasonable cost. It also will reuse existing infrastructure and result in environmental and socio- economic benefits.

1. Existing infrastructure benefits

The Project has the distinct advantage of being a dispatchable, high capacity factor, renewable resource, without the need for greenfield development and the associated financial, environmental or societal impacts of such development. The Project will use existing infrastructure and land resources, including: 1) the existing boiler and turbine/generator sets; 2) the existing plant site; 3) the existing transmission and substation; and 4) as a base for expansion within the plant footprint, the existing fuel procurement system.

2. Air Emissions

The Project brings environmental benefits because it is displacing a resource powered by coal and petroleum coke. The table below demonstrates air emission benefits associated with the conversion.

Table 4

Emission	Current Permitted or Actual Emission Rate	Post-project Emission Rate	% Reduction
NOx	0.80 lb/mmbtu	< 0.30 lb/mmbtu	> 60%
PM	0.60 lb/mmbtu	< 0.10 lb/mmbtu	> 80%
SO_2	3.20 lb/mmbtu	< 1.20 lb/mmbtu	> 80%
Mercury	0.000003572 lbs/mbtu	< .0000008 lb/mmbtu	> 80%
CO_2	213 lb/mmbtu (coal)	NET 0	100%
Opacity	40%	< 20%	>50%

If Boiler #5 is converted to the gasifier technology, up to 100,000 tons of coal and 4,000 tons of petroleum coke would no longer be burned in Boiler #5. Displacing coal with sustainable harvested biomass will reduce net CO_2 emissions from Boiler #5 to zero, contributing to NSP carbon reduction goals.

3. *Socio- economic benefits*

The conversion of Boiler #5 will increase the amount of biomass used at Bay Front substantially, which in turn will increase the demand for by-products of the forest industries in northwestern Wisconsin. Increased biomass fuel demand will help create and maintain jobs. The expansion in the local economy will benefit local workers in the forest industries many of whom are also our customers.

COMMUNICATIONS AND SERVICE LIST

We respectfully request that the following persons be placed on the Commission's official service list for all official communications in this case:

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CONCLUSION

The Bay Front Project provides a unique opportunity to utilize existing generating infrastructure, take advantage of gasification technology, and increase the use of the indigenous fuel source of northwestern Wisconsin to cost effectively meet the renewable energy goals of the states we serve. Comparative analyses confirm the Project's costs are reasonable and will have a minimal impact on customers' bills. In addition, the Project is a dispatchable, high capacity factor biomass resource that will displace the use of coal and gas, thereby reducing air emissions and the risk of future environmental regulatory costs and market volatility.

Based on the information contained in this Application, Xcel Energy respectfully requests that the Commission make an advanced determination of prudence regarding the Bay Front Project pursuant to NDCC Section 49-05-16.

Dated: May 27, 2009
Northern States Power Company,
a Minnesota Corporation and
wholly owned subsidiary of Xcel Energy Inc.

RESPECTFULLY SUBMITTED,

/s/

JAMES R. ALDERS
DIRECTOR, REGULATORY ADMINISTRATION

ATTACHMENT A
Public Document
Trade Secret Data Has Been Removed

ATTACHMENT A
Bay Front Boiler #5 Gasifier Project
Summary Cost Estimate

Major Equipment/Systems	Cost

This document is Trade Secret

ATTACHMENT B
Bay Front Boiler #5 Gasifier Project
Alternatives Analysis

In preparing this Application, the economic and qualitative analysis included a review of the following Project alternatives using our strategist model:

1) CFB Option: Replace boiler #5 with a boiler using circulating fluidized bed ("CFB") technology,

2) Market Purchase Option: Continue to burn coal in boiler #5 until 2015, then retire boiler #5 and replace it with market-based energy and capacity;

3) Wind Option: Retire boiler #5 and replace it with comparable wind resources located in Minnesota or the Dakotas; and

4) Natural Gas Conversion Option: Continue burning coal in boiler #5 until 2015 then switch to 100 percent natural gas for the remaining life of the boiler;

Strategist

To evaluate the economic costs and benefits of the alternatives, NSPW utilized the Strategist resource-planning model. Xcel Energy uses Strategist to model the load and generation resources for the entire NSP System, in Resource Planning and Certificate of Need proceedings. The model produces a long-range forecast of total system costs. Planners then compare the forecast costs for the various alternatives under consideration.

The Strategist model consists of four primary components:

Load Module: This module contains NSP's load forecast, load management resources, and conservation programs. It produces long-range estimates of the Company's hourly load, net energy requirements, and annual peak load.

Generation Module: This module contains the operating costs and performance characteristics for our thermal units, renewable resources, and energy transactions. It uses an hourly dispatch simulation to estimate how customer demand will be met and what the associated costs and emissions will be.

Capital Project Module: This module estimates the revenue requirements for capital projects. It keeps track of rate base, depreciation, taxes, and rate of return.

Expansion Planning Module (Proview ™): This module uses a dynamic programming algorithm to derive the least-cost combination of possible new generation resources. It calculates the ratepayer and societal costs for thousands of different resource combinations to arrive at a least-cost plan.

a. Strategist Input Assumptions

The inputs used in Strategist represent the Company's best estimate of future conditions at the time of the filing. By their nature, forecasts are imprecise and can be the subject of reasonable disagreement. To mitigate forecast and assumption uncertainty, the Company employs sensitivity analyses to test the impacts of input. Each of the major inputs and how the Company employed them in the analysis are discussed next.

(1) Generation Resources

In Strategist, the Company models all the generation resources in the NSP System. The operating characteristics are based on historical data and modified to reflect any planned changes to the units.

(2) Load Forecast

The load forecast used in the Company's analysis is based on historical data but also integrates the expected impact of the recent economic contraction on consumer demand. Both a low load growth and a high load growth scenario were used to test the sensitivity of the model results to the load forecast.

(3) Fuel Cost Forecasts

The Company uses a variety of resources to develop our long-range fuel cost forecast, including both publicly available data and competitively sensitive information not available to the public. In Strategist, the Company varied its natural gas and coal forecasts by plus and minus 20% to test model sensitivity. For the biomass alternatives at Bay Front, the Company varied the cost of biomass fuel by +40%, +20%, -20% and –40% to test the impact of the fuel cost assumption on the overall economics of the alternatives.

(4) Other Input Assumptions

Other Strategist inputs that are important to the evaluation of the Project are future CO_2 regulation and the renewal of the federal production tax credit ("PTC") for renewable energy resources. Strategist models a cap and trade program for CO_2 where the allocations are based on estimated 1990 emission levels and gradually decrease towards a target of 80% in 2050. Sensitivities were performed with no CO_2 regulation and with allowance costs of $40/ton and $60/ton. The PTC for biomass is assumed to be $20/MWh escalating at 2% and extended through 2015. As a sensitivity, the Company also ran the model with the PTC expiring in 2009.

One of NSP's resource planning philosophies is to plan for future needs as if the NSP System were a stand-alone system. This approach ensures that the Company will meet the needs of our customers regardless of developments elsewhere in the market. However, since the launch of the MISO energy market, the operation and costs of the NSP System have been intertwined with all of the NSP System's neighboring utilities. Thus, when the Company ran the Strategist model, all interactions with the MISO market were turned off, and only NSP units and firm bilateral transactions were used to meet customer demand. As a sensitivity, market interactions were turned on and the model was allowed to purchase energy from or sell excess energy to the market.

Strategist Results

The following tables summarize the strategist results for the baseline assumptions and the sensitivity analysis. Among the alternatives analyzed, the CFB Option is the most costly alternative.

The Market Purchase Option was used as our baseline. However, we cannot capture some of the inherent difficulties associated with market purchases because Strategist is not an hourly dispatch model. Both the Market Purchase and Natural Gas Conversion Options have relatively lower up-front capital costs but depend on natural gas or market energy to meet customer needs. These alternatives can make economic sense when using current economic forecasts, but actual costs will be higher than expected if natural gas and market energy prices spike or grow faster than expected.

Table 1 - Strategist Results - Baseline Assumptions

	Market Purchase	CFB	Wind	Natural Gas Conversion	Gasifier Option
PVRR ($millions)	$57,525	$57,633	$57,559	$57,526	$57,563
Difference From Status Quo		+ $107	+ $34	+ $0	+ $38
Gasifier Plus 10% Capital Cost					+ $46
Gasifier Plus 20% Capital Cost					+ $54

Table 2 - Strategist Sensitivity Analysis

PVRR ($millions)	Market Purchase	CFB	Wind	Natural Gas Conversion	Gasifier Option
Baseline Assumptions	$57,525	+ $107	+ $34	+ $0	+ $38
Gasifier Plus 10% Capital Cost	$57,525	+ $107	+ $34	+ $0	+ $46
Gasifier Plus 20% Capital Cost	$57,525	+ $107	+ $34	+ $0	+ $54
Low Load Growth	$54,944	+ $108	+ $36	- $(6)	+ $39
High Load Growth	$60,215	+ $107	+ $32	- $(5)	+ $38
Gas + 20%	$59,446	+ $93	+ $27	- $(6)	+ $32
Gas - 20%	$55,580	+ $122	+ $40	- $(6)	+ $44
Coal + 20%	$58,633	+ $102	+ $32	- $(7)	+ $34
Coal - 20%	$56,430	+ $113	+ $36	- $(5)	+ $41
B.F. Biomass + 40%	$57,525	+ $146	+ $34	+ $0	+ $57
B.F. Biomass + 20%	$57,525	+ $127	+ $34	+ $0	+ $47
B.F. Biomass - 20%	$57,525	+ $88	+ $34	+ $0	+ $28
B.F. Biomass - 40%	$57,525	+ $68	+ $34	+ $0	+ $19
MISO ON	$57,155	+ $109	+ $31	- $(7)	+ $40
CO2 $0/ton	$55,867	+ $144	+ $49	- $(4)	+ $58
CO2 $40/ton	$59,041	+ $72	+ $18	- $(6)	+ $18
CO2 $60/ton	$60,046	+ $35	+ $4	- $(7)	- $(1)
CO2 PSCW	$59,325	+ $98	+ $30	- $(5)	+ $49
PTC Expire EOY 2009	$57,986	+ $107	+ $56	- $(5)	+ $51