OTP/MDU EXHIBIT 341

CASE NOS. PU-06-481 & PU-06-482

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION BY OTTER TAIL POWER CORPORATION D/B/A

OTTER TAIL POWER COMPANY

AND

MONTANA-DAKOTA UTILITIES CO., A DIVISION OF MDU RESOURCES GROUP, INC.

FOR AN ADVANCED DETERMINATION OF PRUDENCE

FOR THE BIG STONE II GENERATING PLANT

PREFILED REBUTTAL TESTIMONY

OF

DANIEL KLEIN

PRESIDENT

TWENTY-FIRST STRATEGIES, LLC

APRIL 23, 2008

BIG STONE II
PARTNERS IN GENERATION

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PREFILED REBUTTAL TESTIMONY OF DANIEL KLEIN

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BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

PREFILED REBUTTAL TESTIMONY OF DANIEL KLEIN

I. INTRODUCTION

Q: Please state your name and business address.

A: My name is Daniel E. Klein, and my business address is Twenty-First Strategies, LLC, 6595 Terri Knoll Court, McLean, VA 22101.

Q: By whom are you employed, and in what capacity?

A: I am President of Twenty-First Strategies, LLC, a consulting firm founded in 1995 to offer energy and environmental consulting services to electric power companies, industry associations, government agencies, NGOs, and others

Q: What is your educational background?

A: In 1973, I received a bachelor's degree in Urban Studies from the Massachusetts Institute of Technology. In 1975, I received a Masters of Business Administration from the Stanford University Graduate School of Business.

Q: What is your employment history?

A: In the 30-plus years since I completed my graduate studies, I have been a consultant specializing in energy, environmental, and economic analysis. Beginning in 1975, I was employed for over twenty years by the consulting firm ICF Resources Incorporated (originally ICF Inc.), where for several years I was a Senior Vice President and Director. I founded Twenty-First Strategies in 1995 to offer energy and environmental consulting services to electric power companies, industry associations, government agencies, NGOs, and others.

Over the course of my consulting career, I have conducted hundreds of projects related to energy and environmental concerns, energy markets, electric utility fuel use, coal supply, transportation, and antitrust issues. My work in recent years has focused primarily on energy, climate change, and related issues, both on policy issues from the government side as well as strategies for the private sector.

Attached as OTP/MDU Exhibit 349 to this Testimony is my resume, which presents my qualifications and experience in greater detail.

Q: Did you previously submit testimony in this proceeding?

A: This is my first testimony before the North Dakota Public Service Commission. However, related to the Big Stone II project, I submitted testimony before both South Dakota and Minnesota public utility commissions.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q: What is the purpose of your testimony today?

A: My testimony relates to the supplemental direct testimony of David A. Schlissel of Synapse Energy Economics, Inc., on behalf of Mark Trechock and Dakota Resource Council, filed on April 9, 2008. Mr. Schlissel has suggested that as an alternative to Big Stone II, a combination of new natural gas capacity, renewable resources, and energy efficiency could possibly present a less expensive and lower risk option (Schlissel, pp. 4-5). While he agrees that "over-reliance on natural gas can be a concern" (Schlissel, p. 8), he does not see this as a problem of particular concern "in this specific instance and in this specific area of the nation."

In this testimony, I address the following points:

- If Big Stone II is not built, an alternative means of acquiring baseload resources will be required. Likely alternatives to supply 500 MW of baseload power are few, and increased natural gas generation would be a probable result, either as a primary or backup fuel supply, or as power purchased from the pool.
- Natural gas (and petroleum) prices are much more volatile than coal prices. Because of this, regions with more coal-fired power in their generation mix tend to have more stable power rates.
- Natural gas markets are increasingly becoming international, and increasingly subject to many of the same types of price spikes and volatility as seen with petroleum.
- While CO_2 requirements and/or pricing would affect the costs of using coal at Big Stone II, it would also affect the costs of using natural gas. Gas costs would be affected both by the direct effect of CO_2 pricing on natural gas' CO_2 emissions, and also by the potential rise in market price and volatility for the fuel.
- The volatility of natural gas prices creates a highly significant risk factor for an electric generation resource that relies on natural gas. If Big Stone II were replaced with gas-fired capacity, an increase in gas prices of only $1/MMBtu would increase generation costs by as much as $28,000,000 in a single year.
- North Dakota's participation in the Midwest ISO exposes it to a natural gas price volatility risk that is much larger than its actual percentage of generation.
- North Dakota households are at greater risk from natural gas price spikes than most other states. Non-electric residential energy uses in North Dakota indicate higher than average natural gas and petroleum consumption, even while household income is lower than average.

Accordingly, if natural gas supplies are constrained in supply and/or subjected to price spikes, residences can be hit twice – once in their direct consumption of fuel, and again in their use of natural gas-fueled electricity.

III. NATURAL GAS AS A LIKELY ALTERNATIVE TO BIG STONE II

Q: Is increased natural gas use a likely alternative if Big Stone II is not built?

A: Yes. As I understand it, the Big Stone II owners have determined there is a need for baseload resources. Big Stone II has been proposed to meet this increasing demand, and would be a 500-megawatt (MW), coal-fired electric generation plant. The plant's dispatchable, baseload power would increase reliability in the region, as well as add diversity and reduce single-outage risks for the participants.

If Big Stone II is not built, an alternative means of acquiring baseload resources will be required. Likely alternatives to supply 500 MW of baseload power are few, and would likely entail dependence upon expensive and risky supplies of natural gas and/or petroleum fuels. In most parts of the U.S., the primary alternative to a new coal-fired plant would be construction of a large combined cycle natural gas plant. While nuclear energy is edging closer to again becoming a viable option for new capacity, it cannot yet be considered "available" with respect to licensing, timing, and costs. The other primary source of baseload power, large hydroelectric plants, offers no reasonable opportunities for large-scale additions.

In theory, renewable resources such as wind power could substitute for some of the generation that Big Stone II would produce. But because these resources are intermittent and not dispatchable, they make only a limited contribution to meeting peak load capacity needs. These intermittent renewable resources would require back-up capabilities such as natural gas-fired turbines before most of the capacity could be considered dependable. And, because wind power has a capacity factor of about 30% to 40%, some other resource would be needed to provide energy during the other 60% to 70% of the time.

Energy efficiency measures and demand-side management measures may also have potential to substitute for some of the needed generation. However, DSM is typically most cost-effective when peak loads are reduced, lessening the need for building additional peak load capacity. Further, because of the low load factors, the energy savings tend to be relatively low relative to capacity savings. These savings are less applicable to a baseload project such as Big Stone II.

Accordingly, capacity alternatives to Big Stone II entail utilization of natural gas (or petroleum fuels), either as a primary or backup fuel supply. If this capacity is not built and operated by these utilities, it will most likely be in the form of natural gas-fired power purchased from the pool instead.

IV. GREATER VOLATILITY OF NATURAL GAS PRICES

Q: Why is fuel price volatility a concern?

A: Increased reliance on natural gas power entails substantial price and supply availability risks. Oil and natural gas prices have increased sharply in recent years, and now the incremental cost relative to coal is far higher than levels seen in the 1990s. We are also observing much greater volatility in oil and natural gas prices, relative to both earlier years and to coal. The inherent volatility in natural gas prices creates a significant risk factor for an electric generation resource that relies on natural gas. Because of this, regions with more coal-fired power in their generation mix usually have more stable electric power rates.

Q: Are coal price risks significant?

A: Fuel prices are a large part of power generation costs. As such, changes in current and projected fuel prices are important considerations. In recent years, coal prices have risen significantly on a percentage basis. However, since the coal prices are so much lower than natural gas prices, this percentage increase is small in absolute terms relative to the changes seen in the highly volatile natural gas market.

Q: How have forecast prices for natural gas changed?

A: Natural gas (and petroleum) prices have increased sharply in recent years, and now the incremental cost relative to coal is far higher than levels seen in the 1990s. Additionally, the outlook for natural gas supplies has been worsening for consumers. In the last few years, available supplies for both natural gas and petroleum fuels have been much tighter, resulting in sharply higher market prices, volatile price patterns, and rapidly increasing expectations for higher prices well into the future.

Natural gas prices remain high and volatile. While today's prices have eased off some from their highest prices seen in late 2005, they remain at levels far higher than seen just a few years ago. Since the beginning of 2006, the U.S. average price of natural gas delivered to the electric power sector has ranged between $5.76 and $9.15 per thousand cubic feet (mcf).[1] During this brief period there have been at least four months in which the average price rose or fell by over $1.00 per mcf from the previous month.

Longer-term, the price outlook for natural gas consumers continues to worsen. Using the Energy Information Administration's (EIA) *Annual Energy Outlook (AEO)* projections, I

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[1] U.S. Department of Energy, Energy Information Administration, *Monthly Energy Review March 2008*, Table 9.11, "Natural Gas Prices", http://www.eia.doe.gov/emeu/mer/pdf/pages/sec9_17.pdf.

compiled a retrospective of several years' worth of natural gas price forecasts that they had made for the years 2010-2020. In MDU/OTP Exhibit 342, I have taken the *AEO* price forecasts for natural gas delivered to the electric power sector in 2010 through 2030. I have done this for 11 consecutive *AEO* forecasts, extending back to the 1998 *AEO*. Because the forecasts are presented in different year dollars, I have converted all prices into constant year 2000 dollars, using the GDP Implicit Price Deflator. As MDU/OTP Exhibit 342 shows, eleven years' worth of price forecasts have become year-by-year progressively higher, with future prices now more than half again as pricey as had been expected only a few years ago.

Q: In the forecasts, how does natural gas price volatility compare to that of coal?

A: Natural gas price forecasts show far more price volatility compared to coal. This can be seen by examining the absolute changes in future price projections when the forecasts are updated each year.

OTP/MDU Exhibit 343 shows how much more substantial the price changes are for natural gas relative to coal. OTP/MDU Exhibit 343 examines the forecast prices for coal and for natural gas for the forecast years 2010, 2015, and 2020. The price forecasts are drawn from ten years' worth of *AEO* price forecasts, beginning with *AEO 1998* which was the first time 2020 forecasts were published. Part A of OTP/MDU Exhibit 343 shows the coal and natural gas price forecasts as they were published in the respective *AEO*s. I have converted here into real 2000$ for comparability; these year 2000$ prices are shown in Part B of OTP/MDU Exhibit 343. Then, Part C of OTP/MDU Exhibit 343 shows the changes in price forecasts relative to the previous year's *AEO* forecasts.

OTP/MDU Exhibit 343 shows dramatically how very much more volatile the price forecasts are for natural gas compared to coal. With three price forecast years (2010, 2015, and 2020) and nine sets of AEO forecasts after 1998, there are 27 price forecast changes shown for both coal and natural gas. As can be seen (in Part C of OTP/MDU Exhibit 343), of the 27 coal-related price changes, 19 are less than $0.10 per MMBtu, and the maximum change is only $0.18 per MMBtu. In sharp contrast, only 7 of the natural gas-related price changes are less than $0.10 per MMBtu, and the maximum change is $0.98 per MMBtu, over five times that of any of the coal price changes. In fact, of the 14 biggest year-to-year price changes in the table (either up or down), all 14 relate to natural gas.

V. INTERNATIONAL TRENDS IN NATURAL GAS SUPPLY AND PRICING

Q: How do international trends affect natural gas supply availability and prices?

A: For many years, the U.S. viewed natural gas mainly as a domestic fuel, insulated from world pressures. For much of the world, that is already no longer the case. For the U.S., those days are rapidly coming to a close. The increasing U.S. reliance on natural gas imports, the growing world trade in liquefied natural gas (LNG), and the tighter linkages to oil prices are making natural gas forecasting an increasingly uncertain exercise.

Q: What risks do we incur by becoming more dependent on imported LNG?

A: As the U.S. comes to rely more and more on LNG to meet its demand for natural gas, market prices will increasingly be set in a world context. In a global market with little excess capacity, a supply disruption anywhere affects prices everywhere.

LNG is a relatively recent addition to the U.S. natural gas supply. Up until the 1990s, domestic production accounted for more than 90 percent of total supplies to the U.S., with pipeline imports from Canada and Mexico comprising most of the rest. High transportation costs and limited pipeline capacities led to widely varying regional patterns of both consumption and prices.

More recently, net pipeline imports of natural gas (mostly from Canada and Mexico) have been declining, and the outlook is for continuing declines. Instead, it is projected that overseas LNG will grow rapidly and offset these projected declines in both domestic production and pipeline imports. These dramatic trends in past and projected U.S. imports of natural gas are shown in OTP/MDU Exhibit 344.

In 2005, net LNG imports to the U.S. amounted to 0.57 trillion cubic feet, about 2.6 percent of the total U.S. supply.[2] But EIA's latest projections point to a fivefold growth in LNG imports in 2030 (to 2.84 trillion cubic feet) while domestic production remains basically flat and pipeline imports decrease, such that by 2030, LNG imports account for 12.5 percent of total U.S. supply.

As dramatic as this growth in LNG is, it was not anticipated just a few years ago. In OTP/MDU Exhibit 345, I have charted gas supply forecasts as developed in EIA's *Annual Energy Outlooks* published between 1998 and 2008. The top half of OTP/MDU Exhibit 345 shows how the forecasts for 2010 have changed over the years, while the bottom half does the same thing for EIA's 2020 forecasts. Several trends can be observed in OTP/MDU Exhibit 345. First, future expectations of total gas supply and demand have generally declined in recent years, especially in the past few years as price expectations have been rising. Second, expectations of

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2 Source: Energy Information Administration, *Annual Energy Outlook 2008*, Release date March 2008 (Revised to include the impact of H.R.6, Energy Independence and Security Act of 2007 enacted in December 2007), Reference Case Forecast, Table A13, "Natural Gas Supply and Disposition", http://www.eia.doe.gov/oiaf/aeo/pdf/aeotab_13.pdf.

gas supplies from the U.S. and pipeline imports from Canada and Mexico have been falling, even though prices are higher. This leads to a rapidly growing expectation of future LNG exports. Just a few years ago LNG imports were not forecasted to rise much above then-current levels.

Q: How is global competition for LNG showing up in market prices?

A: As LNG grows as a world-traded commodity, its price will become more determined by worldwide supply and demand factors, particularly the price of oil.

A page 1 story in the April 18, 2008 edition of *The Wall Street Journal* describes at length some of these interactions and concerns. In "Surge in Natural Gas Stoked by New Global Trade,"[3] the reporters' lead sentence states that "Americans feeling the pain of record gasoline prices now face the likelihood of another fuel shock, from natural gas." The story continues with the troubling observations that prices in the U.S. have risen 93% since late August as power-hungry nations such as South Korea and Japan compete in a global natural-gas market that scarcely existed a half-decade ago, and that the global appetite for natural gas has profound implications for a U.S. economy already tipping toward recession and struggling against inflation pressures. A copy of the WSJ article is attached as OTP/MDU Exhibit 350.

VI. NATURAL GAS PRICING VOLATILITY FROM CO_2 REQUIREMENTS

Q: How could requirements to reduce CO_2 emissions affect natural gas demand and prices?

A: CO_2 requirements and/or pricing would affect the costs of using both coal and natural gas. Per million Btu, natural gas produces a little more than half the CO_2 emissions that a million Btu of coal does. Pricing these CO_2 emissions would also add to the cost of consuming

[3] "Surge in Natural Gas Stoked by New Global Trade," by Ann Davis and Russell Gold, *The Wall Street Journal*, April 18, 2008, page 1, http://online.wsj.com/article/SB120847521878424735.html.

natural gas, though by a lesser amount than for coal. Gas costs could also be affected by the potential rise in market price and volatility for the fuel

Q: How could requirements to reduce CO_2 emissions affect the demand for natural gas?

A: For many electric power companies, shifting to natural gas may be the only suitable CO_2 reduction strategy that can be implemented on a large scale. While nuclear energy is edging closer to again becoming a viable option for new capacity, it cannot yet be considered as a dependable near-term strategy because of licensing, timing, and cost factors. The other primary source of baseload power, large hydroelectric plants, offers no reasonable opportunities for large-scale additions. While renewable resources such as wind power might be able to substitute for some of the fossil-fueled generation, they are intermittent and not dispatchable. To some degree, energy conservation can slow the growth in electric power demand, but such energy conservation is unlikely to fully offset the need for new baseload power generation.

Q: What is the net effect of these changes in demand on natural gas prices?

A: When there are more near-term shifts to natural gas than there are defections from natural gas to other emission-reducing activities, the aggregate near-term consumption of natural gas is more likely to rise relative to a scenario not requiring CO_2 reductions. It follows that near-term prices for natural gas could also rise, both in absolute terms and relative to coal prices. The amount that natural gas prices could rise in the near-term is dependent upon a number of factors, in particular the timing and magnitude in which CO_2 emissions reduction requirements are phased in, and the price of natural gas vis-à-vis coal.

Q: How could CO_2 prices affect natural gas price volatility?

A: Natural gas (and petroleum) prices are already much more volatile than coal prices, and this price volatility creates a highly significant risk factor for an electricity generation resource that relies on natural gas. With the introduction of GHG reduction requirements and CO_2 prices, I would expect natural gas price volatility to increase significantly more. Even prior to CO_2 pricing, we have seen that relatively modest changes in the supply and/or the demand for natural gas can trigger large movements in market prices. Under a future with mandatory GHG reductions and CO_2 prices, energy consumers will face a new and different set of costs, and will need to reassess their fuels and process strategies.

The extent of shifts toward or away from gas will depend upon the relative fuel prices, technology costs and availability, extent of required GHG reductions, and CO_2 price levels. Many of these factors will in turn depend upon all the others. With so many changes in the marketplace, and with so much uncertainty as to how others will respond, we can expect to see a very uncertain and volatile market for natural gas for several years as transitions are made to the new GHG requirements.

VII. ENERGY SUPPLY AND SECURITY RISKS OF NATURAL GAS RELIANCE

Q: Does our increasing dependence on foreign supplies of natural gas present energy supply and security risks?

A: Yes. Our increasing reliance on natural gas supplies from overseas sources introduces geopolitical risks that are not seen with coal, an almost entirely domestic fuel source.

It is well known that most of the world's oil reserves are found in the Middle East. As seen in OTP/MDU Exhibit 346, 729 billion of the world's 1,277 billion barrels, or 57 percent, are located in Middle East countries.[4] North America is shown having 215 billion barrels, but over 80 percent of this is noted as being oil sands in western Canada, where extraction poses high costs.

A map of proven world gas reserves, shown in the bottom half of OTP/MDU Exhibit 346, shows a similarly worrisome situation for natural gas. Out of 6,044 trillion cubic feet of proven gas reserves, over 80 percent are located in the Middle East, Eastern Europe and former USSR countries, and Africa. In fact, a look at natural gas reserves by country shows that at the beginning of this year, the U.S. ranked sixth in world gas reserves, with 3.1 percent of proven reserves.[5] The nine other top-ten countries in gas reserves are Russia, Iran, Qatar, Saudi Arabia, Abu Dhabi, Nigeria, Algeria, Venezuela, and Iraq. These other nine countries, several of whom at best are reluctant business partners with the U.S., hold gas reserves that collectively account over three-fourths of the world's total.

With the bulk of world gas reserves concentrated in a few key countries, many of whom are not especially friendly to U.S. interests, this growing dependence poses both economic and national security risks. Added to that the fact that China, India, Japan, and Western Europe are *not* among the large holders of oil and gas reserves, and we can easily appreciate how global competition for oil and natural gas will continue to underlie international trade and security concerns.

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[4] Source: Adapted from Kevin R. Petak, Energy and Environmental Analysis, Inc., *Oil and Gas Prices: Will They Stay Linked?*, presented at 2006 EIA Energy Outlook and Modeling Conference, Washington DC, March 27, 2006, http://www.eia.doe.gov/oiaf/aeo/conf/pdf/petak.pdf. Original data source is *Oil and Gas Journal.*

[5] Oil and Gas Journal, "Worldwide Natural Gas Reserves by Country (annual) – data thru 2006", http://ogjresearch.stores.yahoo.net/wornatgasres.html. Estimated at January 1, 2006, U.S. reserves totaled 192,513 billion cubic feet, 3.15 percent of the world's total of 6,112,144 billion cubic feet. The other nine top-ten countries held 4,610,020 billion cubic feet, 75.42 percent of the world's total.

VIII. NATURAL GAS RISKS IN THE MIDWEST ISO

Q: What did Mr. Schlissel say regarding over-reliance on natural gas?

A: Mr. Schlissel stated that he agreed "that over-reliance on natural gas can be a concern." (Schlissel, p. 8) However, he stated that "in this specific instance and in this specific area of the nation, it does not appear that the MRO would be overly reliant on natural gas if the Commission rejected OTP and MDU request to build the Big Stone II Project."

Mr. Schlissel's conclusion seems to be based on figures drawn from the NERC *2007 Long-Term Assessment Reliability Assessment 2007-2016*. Those figures showed little projected change in the shares of coal and gas-fired capacity over the next few years, and that the replacement of Big Stone II by natural gas would not significantly change those figures. He concludes that "there is no real danger of over-reliance on natural gas in the upper Midwest. There could be a concern in other regions of the nation but not in the upper Midwest."

Q: Do you agree with Mr. Schlissel that the Big Stone II partners have no real danger of over-reliance on natural gas?

A: No. In looking only at capacity shares by fuel, Mr. Schlissel ignores the Applicants' participation in coordinated regional operations, and how that already exposes them to larger gas risks. Further, this exposure is expected to grow dramatically.

The Midwest Independent Transmission System Operator, Inc. (Midwest ISO, or MISO) serves a large region that covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, Illinois, Indiana, Michigan and parts of Montana, Missouri, Kentucky, and Ohio. The Applicants are members of MISO.

Established in 2002 as a regional reliability organization, MISO provides a number of services that provide economic and reliability benefits to its members. Since April 2005, MISO has administered a two-settlement (day ahead and real-time) energy market known as the Day-2 market. As described by FERC, in real-time market operations MISO centrally dispatches wholesale electricity and transmission service throughout much of the Midwest.

Q: As members of MISO, are the Applicants exposed to natural gas availability and pricing?

Yes. The MISO market produces Locational Marginal Prices (LMP) for five-minute intervals in the MISO market footprint. Because of line losses and potential congestion, prices are set for five hubs, with the one in Minnesota being the closest one to North Dakota. Locational Marginal Pricing provides price transparency for users of the wholesale bulk electric system, and indicates the cost of conducting business based on current system conditions. If natural gas use is growing, it will more often be the marginal resource that sets the LMP price. And with the higher volatility seen in natural gas prices, both historically and projected, it is reasonable to expect that the LMP price would be similarly more volatile. Natural gas-fired generation is becoming a significant driver of the pricing in the MISO energy market.

Q: How will the region's increasing dependence on natural gas for power generation affect customers of Big Stone II?

A: As natural gas use for power generation increases, it will more often be the marginal resource that sets MISO's LMP price. Gas prices and price volatility will increasingly affect Big Stone II customers via the prices in MISO's wholesale power transactions.

If Big Stone II were to be replaced by a natural gas-fired alternative, this exposure to gas prices and price volatility would be further exacerbated. For Big Stone II customers, the exposure would now be in the generating mix as well as purchases in the MISO markets.

Further, when there are problems with the availability, deliverability, and/or price of natural gas, it will affect a broader portion of the area, and the diversity that coal would have provided would be lost. Accordingly, looking only at the generating assets of a single utility provides a misleading picture. It is appropriate to consider the mix of assets in the broader reliability system in which it operates.

IX. IMPACTS ON ELECTRICITY CONSUMERS AND HOUSEHOLDS

Q: What is the potential magnitude of price changes in the context of this project?

A: Since a 500 MW unit consumes such large quantities of fuel, even small changes in fuel prices amount to very large changes in annual costs. For illustration, assume that if instead of coal, a natural gas combined cycle (NGCC) plant was proposed. If the NGCC plant was 500 MW, had a 7200 Btu/kWh heat rate, and operated at an 88% capacity factor, then each year it would generate about 3.85 million MWh and consume about 28 million MMBtu of gas. For this single unit, then, a change in gas prices of only $0.01 per MMBtu over the course of a year would change total costs by about $280,000. If future natural gas prices are uncertain by $1.00 per MMBtu (or more), then total annual costs for a gas-fueled alternative to Big Stone II may vary by about $28 million dollars per year. And, as noted earlier, just since the beginning of 2006, there have been at least four months in which the U.S. average price of natural gas delivered to the electric power sector has risen or fallen by over $1.00 per mcf from the previous month.

Q: Are Big Stone II customers at greater than average risk for fuel price volatility?

A: Yes. In addition to electricity, we use substantial amounts of natural gas and petroleum in the residential sector. Nationally, this direct consumption of natural gas and petroleum in the residential sector is substantially greater than the electrical energy consumed. It follows that if this non-electric residential energy consumption is weighted heavily toward price-volatile energy sources, then the reliance upon those same energy sources for Big Stone II could exacerbate the overall volatility risks for the Applicants' customers.

Households in North Dakota and other West North Central states have higher than average consumption of natural gas and petroleum. This greater consumption is related to higher winter heating needs that largely utilize natural gas and petroleum fuels. Using data on heating and cooling degree-days, as reported by the Energy Information Administration, we can see that the West North Central region (comprised of Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, and South Dakota) is substantially colder than average in the winter, and somewhat cooler on average in the summer.[6] For heating degree-days over the 1971-2000 period, the West North Central region averaged more heating degree-days than any other Census region, 49.2 percent higher than the U.S. average. Conversely, the somewhat cooler-than-average summers led to the West North Central having 23.6 percent fewer cooling degree-days than the U.S. average.

Whereas summer cooling needs are typically met using electricity-driven air conditioners and fans, winter heating needs are more often met by direct household use of natural gas and

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[6] Energy Information Administration, *Annual Energy Review 2006*, Tables 1.9 and 1.10, at http://www.eia.doe.gov/emeu/aer/.

petroleum fuels. It would tend to follow that the colder regions of the country would have greater household consumption of natural gas and petroleum fuels.

The Energy Information Administration, in its periodic *Residential Energy Consumption Survey (RECS)*, develops state-wide estimates of energy consumption by type of fuel. EIA's most recent published estimates are for calendar year 2001. By dividing these estimates by the number of housing units in these states for 2001 (using Census Bureau data), we can attain per-household estimates of energy consumption, by state and by type of fuel.

OTP/MDU Exhibit 347 summarizes these per-household calculations of residential energy use. As can be seen, North Dakota had both a higher-than-average consumption of non-electrical residential energy consumption and a greater proportion of that as natural gas and petroleum fuels. For non-electric energy consumption, the average North Dakota household in 2001 consumed 76.3 MMBtu, thirty percent more than the national average of about 58.5 MMBtu per household. Nearly all of this was natural gas and petroleum fuels.

The heavy reliance on natural gas and petroleum fuels in the residential sector brings with it another risk of natural gas as a power plant fuel for North Dakotans. If natural gas is used as an energy source instead of coal at Big Stone II, there is an overall loss of fuel supply diversity. If natural gas supplies are constrained in supply and/or subjected to price spikes, residences can be hit twice – once in their direct consumption of fuel, and again in their use of natural gas-fueled electricity.

Q: Are Big Stone II customers exposed to relatively greater risk to electricity price increases?

A: Yes. Big Stone II customers are at relatively greater risk in two ways. First, they consume greater than average amounts of electricity. Second, household income is generally lower than average.

In OTP/MDU Exhibit 347, it was seen that North Dakota has a higher-than average per-household consumption of both electricity and non-electric energy. Electricity consumption, at 40.7 MMBtu per household in 2001, was 17 percent above the national average. It follows that an increase in the electricity rate will result in comparably higher monthly bills.

At the same time, North Dakota tends to have household incomes that are lower than the national average. In OTP/MDU Exhibit 348, I have compiled data from the U.S. Census Bureau on median household incomes for the U.S. and the North Dakota counties to be served by Big Stone II. The Census Bureau data consists of model-based estimates of poverty and income for states and counties, and is developed from its Small Area Income and Poverty Estimates (SAIPE) program. The latest estimates are for calendar year 2005, and can be referenced at http://www.census.gov/hhes/www/saipe/county.html. The staff at Otter Tail Power Company helped me to match the customers' communities to their respective counties. In all, Otter Tail will serve portions of 12 of North Dakota's 53 counties from Big Stone II, and for each I compared the median household income in 2005 to the U.S. average.

As seen in OTP/MDU Exhibit 348, U.S. median household income was $46,242 in 2005. North Dakota ranked 38th among states (including the District of Columbia); at $40,818 per household, North Dakotans' median household income was only 88 percent of the U.S average. And of the 12 North Dakota counties to be served by Otter Tail from Big Stone II, for instance, all but one were below the U.S. average, and nine were below the North Dakota average.

This combination of higher household energy use and lower household income is a risky situation for consumers. Higher electricity rates would be applied to more kWh, and with less disposable income to pay for it. Accordingly, the higher energy costs reduce the disposable income available for other purposes, and this impact would be disproportionately felt on higher consuming, lower income households.

X. CONCLUSION

Q: Does this conclude your testimony?

A: Yes.

APPENDIX A

EXHIBITS

PREFILED REBUTTAL TESTIMONY

OF

DANIEL KLEIN

PRESIDENT

TWENTY-FIRST STRATEGIES, LLC

APRIL 23, 2008