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BEFORE THE
MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
100 Washington Square, Suite 1700
Minneapolis, Minnesota 55401-2138

FOR THE
MINNESOTA PUBLIC UTILITIES COMMISSION
127 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

In the Matter of the Petition of Excelsior Energy Inc. and Its Wholly-Owned Subsidiary MEP-I, LLC For Approval of Terms and Conditions For The Sale of Power From Its Innovative Energy Project Using Clean Energy Technology Under Minn. Stat. § 216B.1694 and a Determination That the Clean Energy Technology Is Or Is Likely To Be a Least-Cost Alternative Under Minn. Stat. § 216B.1693

PREPARED REBUTTAL TESTIMONY AND EXHIBITS OF EXCELSIOR ENERGY INC. AND MEP-I LLC

MARIA F. SCHELLER

OCTOBER 10, 2006

DIRECT TESTIMONY OF
MARIA F. SCHELLER

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BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

PREPARED REBUTTAL TESTIMONY OF

MARIA F. SCHELLER

I. INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

Q Please state your name and business address?

A My name is Maria F. Scheller and I am employed by ICF International ("ICF"). My business address is 9300 Lee Highway, Fairfax, VA 22031.

Q Please describe your background as it relates to this proceeding.

A I am currently a Vice President in the Energy and Resources practice area of ICF and I am head of the Modeling practice area in this practice. Over the past 13 years while at ICF I have had extensive experience in assessing generation and wholesale power markets issues. This work addresses both regulatory and commercial issues. In addition, I have had extensive experience developing models and analyzing modeling techniques and approaches, particularly in the area of price forecasting and resource planning. My resume is attached as Exhibit MFS-1 to this testimony.

Q How does this experience relate to this proceeding?

A The consideration of all elements of integrated resource planning is essential to this proceeding, including the understanding of optimization approaches and the relationship of input assumptions to modeling results. I have developed or been involved in the development of numerous least cost planning modeling tools including ICF's Integrated Planning Model™ (IPM®) and further have utilized these tools for analysis for both private and public sector clients. Hence, my expertise born by experience is precisely focused on this particular area of inquiry.

II. SCOPE OF TESTIMONY AND SUMMARY OF FINDINGS

Q On whose behalf is your testimony submitted?

A My testimony is submitted on behalf of MEP-I LLC and Excelsior Energy Inc. (collectively "Excelsior"), the developers of the Mesaba Energy Project ("Mesaba" or the "Project").

Q What is the scope of your testimony?

A The scope of my testimony falls into two areas, both rebutting testimony of NSP witnesses. The first is attempting to provide Excelsior a modeling framework comparable to that used by Northern States Power Company ("NSP") d/b/a Xcel Energy even though neither Excelsior nor ICF was provided access either to the Strategist model generally or to the NSP version of the model. This was done by calibrating the ICF IPM® modeling software to the Strategist analysis of NSP. This is important because NSP relies on forecasts of the Present Value of its Revenue Requirement (PVRR) for the NSP system from the Strategist model in assessing the Mesaba PPA. The second was to use the IPM® run model to conduct analyses using alternative input assumptions as directed by Andrew Weissman of FTI.

Q What have you done to prepare your testimony?

A I have reviewed the material prepared by NSP including the testimony of Elizabeth M. Engelking and Mark Hervey filed under this docket, as well as several sets of input and output data for the Strategist model which was provided by NSP as responses to IR Nos. 4, 5 and 10, received input assumptions from Andrew Weissman of FTI Energy and Excelsior, and conducted modeling analyses of my own using ICF's IPM® software.

Q Please summarize your findings.

A ICF was able to calibrate the IPM® model sufficiently to provide a modeling framework for FTI to use to do an independent analysis of the resource planning efforts of NSP, compensating in part for the inability to use the Strategist model.

In the effort to understand NSP's model and calibrate to it, I identified several instances where the NSP model had not achieved proper optimization, and that, even under the single case presented by NSP, with all of NSP's assumptions remaining unchanged, the difference between the PVRR of NSP with and without the Mesaba PPA is not $1.6 billion, but rather it is a difference of $0.9 billion.

Once calibrated using NSP's assumptions I then analyzed a new reference scenario and a number of scenarios using FTI's recommended assumptions.

I found that when incorporating changes to only three key inputs, gas prices, capital costs, and load growth, the difference between the PVRR of NSP with and without the Mesaba PPA is $0.1 billion. I also found that the Mesaba PPA is actually preferred and offers lower PVRR versus the non-Mesaba case when another scenario with higher natural gas prices is evaluated. The purpose of this effort was to rebut the notion that the Mesaba PPA adds net costs to the system, and no effort was undertaken to scrutinize each assumption employed by NSP and model a comprehensive suggested alternative case that would reflect the net benefits of the Mesaba PPA to the NSP system.

Q How is your testimony organized?

A Section I presents my qualifications. Section II describes the scope of my testimony and summarizes my findings. Section III describes ICF's calibration of its IPM® model to the Strategist model used by NSP including a review of the assumptions. Section IV presents the results of IPM® modeling using NSP assumptions but correcting for apparent bias against the Mesaba PPA option. Section VI presents the results of IPM® modeling using alternate assumptions under several sensitivity cases.

III. ICF'S CALIBRATION TO NSP'S STRATEGIST MODEL

Q Please describe the NSP IRP expansion plan development process as you understand it.

A NSP utilizes a least cost system expansion planning modeling tool called "Strategist" to establish system expansion plans. Strategist is a third-party software product used by utilities throughout the country. It is dependent, as is our own IPM® tool, on a user to provide specific assumptions and to analyze and confirm the validity of output forecasts. NSP inputs assumptions into the Strategist software, and then utilizes Strategist to produce system expansion plans. Strategist calculates a present value for each and produces a plan with the lowest present value for each set of assumptions, with a goal of formulating a least cost approach to meeting the expanding electricity demands on the NSP system.

Q Did you have access to the Strategist Model or the version of the model created by NSP?

A No. As a result, I used ICF's own modeling system, IPM® and calibrated it to the NSP assumptions. IPM® is a widely used and accepted model. For example it is used by the US Environmental Protection Agency for assessing future conditions in the electric power sector, and is widely used by utilities and other private sector companies both domestically and internationally.

Q Have you reviewed the assumptions used by NSP in Strategist?

A Yes, I viewed those that where made available. NSP provided inputs and outputs for several Strategist cases. The input and output files NSP provided for the Strategist cases redacted natural gas prices on the grounds that they are trade secrets. I focused on the cases that NSP described as their Resource Plan Case and their Mesaba 1 PPA Case. Most of the other cases provided analyzed different variations on the Mesaba 1 PPA Case with different capital cost assumptions for the Mesaba facility in each; no alterative cases were provided by NSP utilizing any sensitivities to (1) capital costs for all new plant construction available, (2) fuel costs, (3) load growth, (4) carbon policy changes, or (5) some combination of the above alternatives.

Q Are these cases consistent with the current NSP IRP plan?

A The Resource Plan Case does not appear to be consistent with the IRP case submitted last year by NSP and differs both on demand and sales information, as well as a number of other assumptions to which modeling outcomes are generally sensitive. The planned capacity additions are also different than those indicated in the IRP. I have not reviewed the difference in any detail. Mr. A. Joseph Cavvichi has submitted testimony on behalf of Excelsior discussing the apparent differences. My focus was on comparing the Strategist cases provided by NSP.

Q What material used for the Strategist modeling did you review in particular?

A I reviewed NSP assumptions addressing: existing power plants, power purchases, electricity demand after DSM, delivered coal costs, non-fuel O&M, options for up-rates at existing plants, financing and discounting assumptions, parameters for new power plant options including capital costs, unit characteristics, plans for additional wind resources, and other parameters. The initial purpose of this review was solely to allow for calibration of the IPM® model, and I did not critique or change any assumption made by NSP. A secondary purpose for review was to identify inconsistencies in treatment of assumptions across the NSP "no Mesaba" case and the NSP Mesaba 1 PPA case. These inconsistencies were corrected in an exercise to properly optimize the Mesaba case under the NSP assumptions.

I also reviewed the outputs provided including resulting capacity expansion and retirement decisions by case, resulting annual reserve margins by case, facility output by case, transaction data by case, and other parameters.

I was not able to review the natural gas price inputs or outputs due to the confidentiality of the data[1].

Q Can you describe the assumptions you relied on?

[1] Natural gas price information was redacted by NSP as trade secret information.

A For the most part, for purposes of calibrating the IPM® model I accepted assumptions provided in Ms. Engelking's testimony. However, there were instances where the assumptions relied on by NSP as identified either based directly on the Strategist inputs or on conversations with Ms. Engelking which occurred after the testimony was filed, seemed to deviate from Ms. Engelking's stated assumptions, Exhibit MFS-2 provides an overview of the key assumptions as per Ms. Engelking's testimony as well as any modifications made to match the actual assumptions embedded in the Strategist runs that were provided by NSP.

Q How do the Strategist inputs vary from the Engelking testimony?

A Although I have not exhaustively checked all assumptions, differences appear to exist in the DSM treatment, the capacity of uprates at Sherco, the MERP unit characterization, and the Mesaba characterization among other things. These differences are outlined in Exhibit MFS-3.

Q How did you ensure that your models were calibrated to the Strategist modeling with out the gas price data?

A While being able to calibrate on an annual basis would have been ideal, we could not accomplish this without having access to NSP's trade secreted gas forecast; thus, the alternative was to ensure that over the planning horizon, our present value for non-gas costs was equal to that of the Strategist forecasts. Excelsior, who could view the data, developed a 'placeholder' 2005 dollar gas price that would yield the same present value of total gas revenues as that in the Strategist forecast. Excelsior gave us a natural gas price of $5.37/MMBtu on a delivered basis in 2005 dollars for all forecast years. This price assumption yielded the same present value of total gas costs over the forecast horizon, while preserving the confidentiality of the actual gas forecast used in Strategist.

The weakness of this approach is obvious, since we are modeling this placeholder gas price as a level real price, when in fact, the actual gas forecasts used in Strategist may have been at very different levels in each individual year. When running the generation plan utilized by Strategist, we end up at a comparable PVRR, but the annual gas expenses for any given year could be very different. While effective in calibrating, we can not represent that the placeholder gas forecast would have yielded the same generation or dispatch choices as that in the Strategist run. In effect, the approach uses a levelized gas price over the forecasting horizon over the modeling period, rather than a precise prediction of different gas price levels for each year.

However, we did examine alternate gas price projections when considering alternate scenarios to evaluate the resulting system PVRR when including or excluding Mesaba.

Q What did you assume for environmental costs?

A I relied on NSP's assumption of a $9 carbon tax beginning in 2010. NSP indicated that no other environmental costs were added.

Q What is the impact of NSP's environmental assumptions?

A They significantly disadvantage the profile of IGCC, compared to conventional coal additions – by excluding meaningful externality values for the lower emitting profile of IGCC. Further, the IGCC profile tends to have lower actual compliance costs for existing environmental programs than conventional pulverized coal facilities. By excluding these costs, NSP disadvantages the Mesaba facility.

Q Is NSP's use of a $9 carbon tax assumption sound?

A No. Any such assumption would have to be part of a comprehensive carbon tax scenario where the impacts of the tax on the cost and availability of other resources are taken into account as well. In Europe, carbon dioxide limits have driven up natural gas prices significantly. In California, large energy users are alarmed at the new carbon dioxide limits because of the significant impact they will have on natural gas prices. NSP did not assume any change in natural gas prices as part of its modeling. Increases in natural gas prices in such a situation would likely more than offset the differential between the impact of such a tax on an IGCC facility and on a natural gas-fired facility. In addition, construction costs for all forms of infrastructure would likely rise in the event of a carbon constraint imposed in the U.S., given the national and global efforts to meet the new limits that would ensue. In such a scenario, coal base load facilities that were built prior to the imposition of the carbon constraint would be very inexpensive by comparison to any other alternative.

Q What value do you attach to the Strategist modeling results in terms of building this record?

A Very little, given the deficiencies described above in the NSP modeling and the fact that NSP applied only a carbon tax and did not apply the correct statutory standards or externality values for any other pollutants. This is discussed in detail in Section IV: Environmental Risks below.

Q What are some of the noteworthy features of the NSP analysis using Strategist?

A NSP's analysis is clear regarding the need for additional coal-power plant capacity; NSP concludes that its forward resource plan should include 4500 MWs of additional coal fired capacity between 2015 and 2033—a massive expansion that would roughly include a 600MW plant coming on line every two and one-half years during this entire eighteen year period . In NSP's analysis the issue analyzed is whether the proposed Mesaba IGCC (Integrated Gasification Combined Cycle) coal plant with a generation capacity of approximately 600 MW should be one of the new coal plants and if so the timing of that addition, which are traditional "size, type and timing" factors considered in certificate of need proceedings.

Q What are the key differences in reported results between the NSP Resource Plan Case and NSP Mesaba 1 PPA Case?

A NSP's analysis shows that the PVRR under its single model run without the Mesaba plant ("no Mesaba") is $1.5 billion to $1.6 billion lower (4%) than when the proposed Mesaba IGCC coal power plant is considered (See Tables 1 and 2 of the testimony of Elizabeth Engelking, page 6).

Q Were you able to verify the Strategist results under NSP's assumptions using IPM®?

A Yes. IPM results were within 5 percent on a PVRR basis for the NSP "no Mesaba" model run. ICF was able to calibrate a model run using IPM that tied to an NPV of revenue requirements (i.e. PVRR) to be $33.5 billion versus a reported $35.4 billion as reported in the testimony of Elizabeth Engelking (Table 1 of her testimony). Also, NSP informed us that their $35.4 billion PVRR of the Mesaba model run includes costs not in the Strategist outputs or apparent on any of the worksheets provided to us. Hence, it is expected for our modeling results to be below those of NSP. More importantly, we were even closer on recreating the differences between the NSP model runs with and without the Mesaba PPA. That is, after running the NSP "no Mesaba" case, we ran the NSP Mesaba PPA Case as proposed and as characterized by NSP itself, and were able to calibrate to the costs differences that NSP derived from their two model runs.

Q How was you able to verify the Strategist results if you did not have access to the model?

A As mentioned, ICF received files created by NSP which contained inputs and outputs of the Strategist model. We also received some limited and incomplete explanations of the NSP modeling from NSP staff. At that time we were informed that there were differences between the model results and the filed testimony but the explanation was insufficient for us to include these add-ons to the modeling. Using the available information, we set as many of the inputs in IPM® to be consistent with NSP assumptions including notably the capacity expansion plan of NSP (i.e. the specific power plant additions and the specific timing of these additions).

IV. RERUNNING WITH NSP ASSUMPTION'S

Q **In your review of the NSP analysis, what did you notice that caused you to believe that even using their assumptions, additional analysis was necessary in order for their runs to be principled and make analytical sense?**

A In the modeling run with Mesaba included, NSP did not allow the model to fully re-optimize its decisions but rather, outside the workings of Strategist, forced in or removed from the model key, sub-optimal decisions in addition to Mesaba. For example, in the Strategist run that was intended to calculate the costs and benefits of including Mesaba, rather than allowing the model to consider uprates to existing facilities in combination with Mesaba—which were included in the model in the "no Mesaba" run—NSP removed these options completely from the model, leaving only more expensive options for capacity expansion.

Q **What are the implications of this forced changed?**

A It is possible that had NSP allowed the model to optimize between uprates and timing of new construction, Strategist would have chosen more cost effective options that would place the Resource Plan with Mesaba to be more on par with their Resource Plan without Mesaba Case.

Q **What do you mean?**

A As is discussed below, we believe the increase in PVRR due to adding the Mesaba plant would be less if the optimization in the "with Mesaba" case was on par with the "no Mesaba" case. In other words, to conduct modeling runs to compare two alternatives, NSP should have left all other assumptions constant, including those relating to demand, fuel, new unit capital costs, etc. Of course, correcting other assumptions and factoring in the consideration of other benefits from Mesaba might cause the PVRR of the "with Mesaba" model run to be even lower, but I am focusing here on just the issue of at a minimum having a "level playing field for Mesaba" in the context of NSP's analysis.

Q Are the resource plan selections shown by NSP in the Mesaba 1 PPA case, on their face, rational?

A No. In the Mesaba 1 PPA scenario, NSP shows more gas-fired generation coming online before 2011 than the scenario where Mesaba is not added to the mix at all. That is, in the "no Mesaba" case, NSP includes baseload uprates of 52 MW at Sherco and allows the Strategist model to add two combustion turbines in 2010, one in 2011, and one in 2012 at 160 MW each for a total of 692 MW (excluding wind) by 2012. In the Mesaba 1 PPA case, NSP manually removed all uprates which had been included in the Resource Plan, and allows for the inclusion of two combined cycles at 250 MW each in 2010, one combustion turbine in 2011 at 160 MW in addition to the nearly 600 MW for the Mesaba facility for a total of 1260 MW by 2012. 600 MW of new coal capacity should reduce the amount of combined cycle gas-fired capacity being added to the system, not increase it. Instead, NSP shows that adding Mesaba results in 469 MW of excess capacity in 2012.[2]

Q With such an illogical result, what would sound resource planning practice require the system analyst to do?

[2] Note that on a firm summer capacity basis, the difference in new unit construction (including uprates) results in an addition of 531 MW in the Mesaba case; however the results in Strategist indicate a difference in summer firm capacity of 469 MW. This difference has not been accounted for.

A A system analyst seeking to minimize costs would apply judgment to the modeling result and understand which of the myriad of assumptions embedded in the analysis were causing this sub-optimal result.

Q Did NSP apply this kind of judgment?

A No. Based upon conversations with Ms. Engelking of NSP, she simply took the results that Strategist produced and accepted them for purposes of her analysis.

Q Did NSP make any manual adjustments to the model results?

A Yes, NSP indicated that they did not use optimization methods for such things as the timing and quantity of wind additions or to determine the optimality of the Sherco, Prairie Island or Monticello uprates.

Q What modeling analysis was performed by ICF for purposes of demonstrating that NSP's two model runs did not offer Mesaba a "level playing field," which had the effect of disadvantaging the Mesaba case beyond the disadvantages embedded in the assumptions that were consistent in both cases?

A Two additional cases were considered. These cases involved using IPM® to optimize the NSP capacity expansion plan under the basic NSP assumptions and the $5.37 (real 2005$) gas price for the "no Mesaba" case and the Mesaba 1 PPA cases. In other words, while accepting for purposes of analysis all of NSP's inputs and assumptions provided to Strategist in conducting its two runs, rather than mimic the NSP determined expansion paths under these two cases, the new cases reflected optimal expansion decisions using the IPM model. I should point out that in these two cases, our IPM model optimized based on the $5.37 (real 2005$) gas price and the resource plan generated may or may not have been optimized if one were have used the exact gas price forecasts used in the Strategist runs.

Q What did you find when you optimized the NSP capacity expansion plan to properly accommodate Mesaba?

A Under the "no Mesaba" case, the IPM® model resulted in the same PVRR, $33.5 billion, as when replicating the expansion decisions in NSP's Strategist runs. In the "with Mesaba" case where the model was allowed to choose from the same alternative as used in the "no Mesaba" case, the differential between the two cases was $0.7 billion less than that reflected in the NSP analysis.

Q What is the significance of this result?

A The fact that NSP presented an optimized "no Mesaba" case and did not allow the model to optimize the "with Mesaba" case calls into question the validity of the methodology employed by NSP. The corrections implemented by ICF correct problems that are apparent on the face of NSP's results. Given that we cannot access and vet the Strategist model itself, there is nothing in the record to support the proposition that there are not other deficiencies embedded in the model that would further call into question the value of NSP's analysis to this proceeding.

V. ICF MODELING ANALYSIS OF EXCELSIOR REFERENCE CASE SCENARIO

Q Did you analyze any cases with alternate market assumptions?

A Yes. I considered a scenario which modified assumptions in three general areas: 1) load growth; 2) fuel prices; and 3) capital costs. This case also included the Mesaba PPA. I refer to this as the Excelsior Mesaba Reference Case. FTI Consulting provided the gas price and capital costs assumptions for the Excelsior Mesaba Reference Case. The load growth was based on work in which ICF was directly involved as described below.

Q Please elaborate on the alternate assumptions in the Excelsior Mesaba Reference Case.

A First, the NSP assumptions for annual average peak demand and energy growth after accounting for DSM were 1.58 and 1.68% respectively. After reviewing actual realized growth in the NSP area based on data NSP has filed in its IRP case, historical FERC Form 1 filings by NSP, historical hourly nodal load data for the NSP area available from the Midwest Independent System Operator (MISO), NSP's proposed DSM savings, and information available from the Minnesota Department of Commerce, I found the growth rate to be unreasonably low and inconsistent with NSP's actual experience. I considered the impact of normalization on historical data. Based on this analysis, an annual average growth rate of 2.0% was used for energy while the load factor relationship assumed by NSP was maintained to determine the peak demand. I did not consider a higher confidence interval, such as a 90:10 confidence interval; this would have resulted in an even higher growth expectation.

Second, Andy Weissman of FTI provided assumptions that that are more reflective of current market conditions—both on fuel pricing and on the capital costs of new build generation. I utilized a gas price of $7.67/mmBTU (real 2007$) for all years. This is the equivalent of the NYMEX futures price strip for 2007 based on prices quoted in 2006. The capital cost assumptions for the cost of building new coal or gas fired generation were modified according to the assumptions below.

- New Pulverized Coal—Instead of the NSP assumption of approximately $1748/kW (2005$), new pulverized coal plants were assumed to cost $2769/kW (2005$). This cost is consistent with costs currently reported for an actual unit, Big Stone II, currently under construction in South Dakota.
- New Natural Gas Combined Cycles—Instead of the NSP assumption of $690/kW (2005$ including estimated AFUDC), new combined cycle plants were assumed to cost $1148/kW (2005$).
- New Natural Gas Simple Cycles (Combustion Turbines) —Instead of the NSP assumption of $574/kW (2005$), new combustion turbine plants were assumed to cost 15% above this or $660/kW (2005$). The 15% was added to account for recent increases in commodity and EPC contracting costs. This assumption is conservative when compared to actual increases realized in recent years.

Q What did you find?

A I found that the PVRR for the "with Mesaba" case would be $42.6 billion (2005$).

Q Did you examine comparison scenarios that did not include Mesaba?

A Yes. I found that the PVRR of the "with Mesaba" case was lower at $42.7 billion (2005$), just slightly above the case including the Mesaba PPA.

Q What is the significance of this finding?

A Whereas NSP found that the Mesaba PPA added $1.5-1.6 billion over their proposed capacity expansion plan under the "no Mesaba" case, under the reference case assumptions described, the Mesaba PPA would be slightly better than break-even.

Q Why is there this difference?

A The most important explanations for this difference are: (1) putting Mesaba on a level playing field alone decreases the Mesaba cost disadvantage reported by NSP by $0.7 billion, (2) updated capital costs reduces the cost disadvantage approximately $0.5-$0.7 billion, and (3) the net of demand and gas price changes account for the remainder.

Q Under these alternate assumptions did you consider options for any resources other than the uprates, the combined cycle, the coal, or the combustion turbine units?

A Yes. I considered a case which included the Manitoba Hydro 500 MW contract was extended in 2015.

Q What were the results of this case?

A I found that there was no significant cost difference if Mesaba were added or not should the Manitoba Hydro contract be extended at the same terms. I found the PVRR for both cases (with and without Mesaba) to be $41.9 billion (2005$).

VI. ENVIRONMENTAL RISKS

Q Are there issues with the NSP's assumptions regarding air emissions and externalities?

A In a phone conversation to discuss the application of the Strategist model in determining the system PVRR, NSP indicated that they did not include the costs of SO2, HG, NOx in their analysis. NSP did not include any environmental air quality control programs or air emission externalities in their Strategist modeling except CO2 even in their High Externality case.

Q Why is that inappropriate?

A This is inappropriate for several reasons. Title IV of the federal Clean Air Act and the Clean Air Interstate Rule and the Clean Air Mercury Rule (CAIR and CAMR, respectively) air emission regulatory programs require large reductions in SO2, and HG emissions. These programs impose very significant SO2 and HG emission allowance costs on a $/ton basis that all US coal power plants currently or will soon face. In addition, it is my understanding that Minnesota has identified externalities appropriate for consideration and provided externality values in $/ton of emissions.

Q Why is this significant?

A The emissions from the Mesaba plant are lower than for conventional new coal power plants, and the NSP plan in Minnesota (note NSP is proposing IGCC instead of conventional coal power plant technology in Colorado) proposes large amounts of conventional (i.e. non-IGCC) coal power plant construction. This result is directly due to the technology of gasification, gas clean up and the combustion of these coal-derived gases using combined cycle technology. Thus a failure to account for these factors biases the results against the Mesaba plant.

Q What should NSP have done?

A NSP should have compared the NSP Resource Plan without Mesaba and the ICF assessment of the optimal NSP plan including Mesaba.

Q Did NSP take into account the fact that the Mesaba plant is better suited to CO2 capture and sequestration than a conventional plant?

A No. Hence, the externality advantage estimated for Mesaba could be even greater if this feature was accounted for in the analysis.

Q What is your understanding of NSP's treatment of CO2 capture and lower CO2 emissions potential of IGCC?

A These advantages are not accounted for, though they seem to have contributed to a different conclusion in Colorado.

Q What do you conclude from this?

A The PVRR increases due to the Mesaba 1 PPA, as estimated by NSP, may overstate the cost disadvantage of the facility.

Q Did you attempt to quantify this?

A No. Given inconsistencies in the testimony of Engelking and responses provided by NSP in a conference call which we scheduled to discuss assumptions, further time would be required to try to understand these inconsistencies, their environmental assumptions and correct for errors.

VII. NATURAL GAS PRICE RISK SHOULD BE CONSIDERED IN A RESOURCE PLANNING EXERCISE

Q How did you examine the likelihood that natural gas prices would differ from those assumed in the Excelsior reference cases?

A I examined a higher gas price projection where a $14/mmBTU (real 2006$) was assumed. Under this gas price projection, I considered 2 sensitivities, the first included the Mesaba PPA (“with Mesaba”) while the second did not allow any coal construction in the NSP system (‘no Mesaba no coal”).

Q What is the source of these assumptions?

A The assumptions for these scenarios were provided by Andrew Weissman at FTI Consulting.

Q What did you find under these scenarios?

A The PVRR under the “with Mesaba” case under a $14 gas price case was $45.9 billion (2005$). The PVRR in the “no Mesaba no coal” case is $49.2 billion. This result clearly indicates that higher gas prices can potentially have a large impact on overall system costs and hence rates in the absence of units such as Mesaba.

VIII. CONCLUSIONS

Q Do you have an exhibit summarizing your results?

A Yes, see Exhibit MFS-4.

Q Please summarize your conclusions.

A First, even when calibrating to NSP's assumptions, NSP's modeling on its face overstates by $0.7 billion the costs of the "with Mesaba" case. Second, under the Mesaba Base Case, the Mesaba PPA does not cost ratepayers more than NSP's "no Mesaba" case in which increased demand is met with natural gas-fired generation at a base gas price. In that scenario, Mesaba is essentially breakeven vis-à-vis excluding it. Third, all cases involving Mesaba would better reflect true costs if the emission allowance and environmental externalities values were fully incorporated. Finally, because the gas prices assumed in the "no Mesaba" case are not hedged or guaranteed by NSP, the addition of the Mesaba unit provides ratepayers with a hedge against scenarios where actual natural gas prices are higher than assumed in the Mesaba Base Case.

Q Does this conclude your rebuttal testimony in this case?

A Yes.

MARIA FUSCO SCHELLER — ICF INTERNATIONAL

Vice President

EDUCATION

Successfully completed all coursework in Masters Program, Virginia Polytechnical University, Department of Economics (degree pending thesis)

B.S., Economics with honors, The Pennsylvania State University, University Scholars Program, 1992

EXPERIENCE OVERVIEW

Ms. Scheller joined ICF Resources in 1994 as an Analyst and is currently serving as a Vice President of the company and Director in the Wholesale Power Market Practice. Ms. Scheller manages work in the areas of wholesale power market assessments, regulatory support, asset valuation, due diligence, litigation, and strategic studies. This work involves review and creation of economic and technical aspects of power supply including: avoided energy supply cost determination; forward price curve analysis; plant dispatch analysis; power sector restructuring; power plant siting, evaluation of power purchase and tolling agreements; revenue forecasts and financial performance of assets in competitive and deregulating markets; expansion planning for generation companies; environmental compliance; financial impact of regulatory programs, and transmission flow and congestion analysis. Further, Ms. Scheller assisted in analysis of coal mining and transportation issues, gas market pricing issues, and oil and by-product pricing. She has also co-authored several articles appearing in Public Utilities Fortnightly and the Electricity Journal.

Ms. Scheller is also Product and Development Manager for the Integrated Power Model (IPM®), a detailed analytical tool simulating the fundamental operation of the electric power system. Under her guidance, this model has developed into a integrated modeling software which is regularly applied in public sector environmental compliance analysis (federal, regional and state level), forward power pricing, forward fuel pricing, DSM analysis, and resource (generation and transmission) planning. The tool is now used in all public and private sector wholesale price analysis and environmental cost and compliance analysis performed for North American, European, and Asian markets by the ICF Energy and Resources Group. Prior to taking on management of the IPM® tool, Ms. Scheller led the development of the Wholesale Power Market Model (WPMM™) and has conducted both on- and off-site training sessions for users of both models.

While at ICF, Ms. Scheller has achieved a high degree of accomplishments and responsibilities. Ms. Scheller’s focus has been broad, covering a range of economic and technology assignments. Her experience includes:

- Managing studies on the wholesale power marketplaces including valuation of generating assets, power marketing, due diligence, short-term volatility analysis, litigation, strategic positioning, and fuel market analysis.
    - Leading due diligence financial review for multiple power plant transactions
    - Valuing power plant and transmission assets
    - Assessing risk for generation providers
    - Evaluating financial impact of energy efficiency programs in the electricity market
    - Analyzing power purchase agreement contract structure
    - Creating regulated cost of service filing
    - Performing a detailed review of the industry financial status in the US marketplace
- Directing product design and development for the Integrated Planning Model (IPM®) and other analysis tools for the electrical power markets.

In these areas, Ms. Scheller has consistently been recognized for high quality work product and client support.

PROJECT EXPERIENCE

Wholesale Power Market Analysis: Ms. Scheller has performed analyses of many projects for utility and the non-utility power generation sector clients. Her work has involved dispatch assessment, energy price, capacity price and revenue forecasting. Scenario analyses, including probabilistic assessments, were performed as part of these assignments.

Resource Planning: Ms. Scheller has been led numerous long-term resource planning exercises. Many of these projects included components related to resource adequacy to meet the load expectations in developing and developed systems. For example, in developing countries, issues which Ms. Scheller addressed include providing cost / benefit assessments of the trade offs between early expansion to reduce unforced outages and development of resources that will provide greater long-term benefits. For developed systems, where outages were not an immediate concern, Ms. Scheller has provided assessments of issues such as wind and hydro ability to serve peak demand reliably.

Loss of Load Probability Analysis: Ms. Scheller recently managed a projected to assess the loss of load probability in the southwest. To perform this work, Ms. Scheller applied an approach to approximate the probability density function around system resources and the system load. This assessment was submitted in testimony to FERC. Ms. Scheller has also been involved in LOLP assessments of the midwest and southeast markets. Ms. Scheller managed an effort to develop a linear approximation of the probability density function for system resources which has been incorporated into a linear optimization model which targets minimizing system production (fixed and variable) costs including the costs of unserved energy.

Value of Lost Load Assessments: Ms. Scheller has participated on projects to estimate the value of loss load based on the costs to consumers of such outages. The analysis included literature review and actual observations to assess the willingness to pay for reliable power supply.

Asset Valuation: Ms. Scheller managed projects focusing specifically on the valuation of generating assets including cogeneration, steam (coal / oil-gas), turbine based, hydro, gasification, and renewables, in various marketplaces. These analyses include research into the various marketplaces to gain knowledge of current market conditions and the potential for change in the market conditions. Probabilistic forecast assessments were conducted to derive expected marketplace prices for energy and capacity prices. Unit performance was then analyzed under given scenarios in order to conduct financial analysis on the generating units.

Renewable Market Analysis: Ms. Scheller recently led a project to support the financing of two merchant wind development projects. The analysis included a detailed review of the transmission network and potential issues resulting from the development of the facilities. Further, the analysis considered the potential capacity value associated with the variability of the system. In addition, Ms. Scheller has in numerous analysis considered the impact of renewable generation portfolio standards in various power markets.

Fuel Market Analysis: Ms. Scheller has led efforts to determine natural gas, oil, and petroleum coke price forecasts for the US markets. These forecasts include detailed review of the transportation networks and availability of supply sources.

Transmission Analysis: Ms. Scheller has assisted in designing an approach for use in the SUPERGEN project related to sustainable power generation and supply in the United Kingdom. The component of the analysis focuses specifically on the effect of development of intermittent power supply sources such as wind on the reliability of the power system. Further, the analysis will examine the possible evolution paths of the generation mix and the associated transmission issues. In addition to forward planning exercise, Ms. Scheller has managed several projects focusing on the impact of physical transmission constraints on the dispatch of power facilities in various markets in the US. This work has included detailed location marginal price forecasting and congestion analysis.

International Analysis: Ms. Scheller has led projects focused on integrated resource planning in several developing countries including Armenia, Azerbaijan, and the Republic of Georgia. Analysis included detailed review of the power grid and steam demand and supply capabilities for several of these markets with large combined heat and power needs. Ms. Scheller also recently served as Project Director on an assignment for the Polish Power Grid Company. The overall assignment included a review of the regulatory and market risks faced by PPGC and provided options on how to evaluate and plan for these risk elements.

Product and Development Management: Ms. Scheller has overseen the development of ICF Resources Wholesale Power Market Model (WPMM™). She has developed enhanced capabilities within the model to allow users to perform analysis on individual generating units (e.g. Pro forma Module, Generation Module) and has created significant advancements in the user interface with the model. In addition, she has conducted training sessions for individual clients and organized User's Groups that have been attended by representatives from over 30 companies.

RELATED PROJECT EXPERIENCE

- Assisted in the analysis of coal transportation costs via rail lines to utilities in select areas. The analysis is to be used in a coal contract dispute to be heard by the Interstate Commerce Commission.
- Involved in the preparation of ICF Resources' Energy Service. Responsibilities included collecting and analyzing data on issues such as current developments in the oil, gas and coal industries, oil production in OPEC and Non-OPEC countries, oil demand, coal mining productivity trends, acid rain regulation, and electricity and non-utility demand for coal and gas. Analyzed the potential effects of such issues on the demand for energy.
- Assisted in the development of a model to determine the effect of delivered fuel prices on electricity system dispatch. The model was prepared to assist a rail carrier develop a strategic pricing policy and analyzed six different electric utility systems in the rail lines' area of operation.
- Assisted in developing and modifying a model to estimate the hourly marginal energy prices for utilities operating in various regions of the country. The model allows for variations in transmission capacities across regions, demand, fuel prices and transportation costs, and several other variables.
- Prepared a report on produced water treatment technologies including detailed explanations of new technologies available to petroleum producers. Broad topics discussed included characteristics of produced water, current treatment and disposal technologies, major technical and economic issues concerning produced water treatment, and opportunities for future research and development. The report also characterized the capital and operating costs of the various treatment technologies.
- Assisted in preparing a report of environmental costs that have not been traditionally reflected in oil prices. The paper included analysis of approaches used for quantifying unincluded costs (externalities), estimates of the value of unincluded costs, potentially unincluded costs and benefits, and trends that may affect unincluded costs.
- Assisted in preparing a report outlining the effects of oil imports on the domestic oil industry. This report included an analysis of the impact on imports on domestic production, employment, earnings, and exploration trends over time. The report also

included analysis of the implications of foreign incentives, resource requirements, technology, and undeveloped supply locations on domestic production and refining.

- Examined trends in coal prices, sulfur content, and energy capacities for various grades of coal supplied from different locations across the nation. She developed and managed a database of coal buyers and suppliers, prices, grades, heat content, and other relevant information to assist expert staff in developing evidence to be used in testimony.
- Assisted in research to determine if proposals to expand the list of chemicals required to be reported under the Toxic Release Inventory Act (TRI) would be beneficial. Research included determining the quantity and strength of emissions from various sources.

PREVIOUS EXPERIENCE

Prior to joining ICF, Ms. Scheller assisted expert economists in analyses of public policy issues, antitrust and other commercial litigation matters. She conducted research on markets and industries using sources such as government agencies, trade associations and on-line databases, and developed and managed databases used in economic damage models. Highlights of her work experience include:

- Economic analysis of environmental damage due to illegal dumping under Section 106 of CERCLA;
- Impact analysis of proposed changes to business tax incentives in Puerto Rico;
- Impact analysis of proposed policy changes on employees in the maritime industry.

COMPUTER KNOWLEDGE

-Experienced in many industry models and databases: IPM®, WIPM™, WPMM™, DARWIN, NERC ES&D, CEMS, BaseCase, NewGen, UDI, Energy Velocity, SNL Energy, Bloomberg Energy.
-Proficient in Microsoft Office Professional Edition. Experienced user of WordPerfect, Freelance, MapInfo, Lotus 1-2-3.
-Background using Windows XP/2003/NT/2000, Windows 9x, DOS, UNIX, CMS, VAX, LAN, and Macintosh.
-Programming in SAS, dBase, FoxPro, MSAccess Basic, SPSS, MINITAB, and Turbopascal.

PUBLISHED PAPERS AND CONFERENCE ENGAGEMENTS

"Transmission and Capacity Pricing Constraints," presentation at conference: ENERDAT's GasFair & PowerMart, Toronto, Ontario, April 20, 1999.

"GenCo Opportunities- Developing A Successful GenCo," presentation at conference: IBC's Developing a Successful GenCo, Atlanta, Georgia, December 7, 1998.

"Using Modeling Tools for Market Price Forecasting," presentation at conference: IBC's Market Price Forecasting Conference, Baltimore, Maryland, August 26, 1998.

"Introduction to Short-Term Power Price Forecasting"; WPMM Advanced User Training; WPMM Introductory Session; WPMM User Group Houston, Texas, 1996.

"Using Price Forecasting Tools"; WPMM User Training; WPMM User Group, Fairfax, Virginia, 1996.

Financial Engineering in the Power Sector, Public Utilities Fortnightly: January 1, 1997, with Judah Rose and Shanthi Muthiah.

Lack of Competition in the Wholesale Marketplace for Power Generation: Does it Make a Difference, The Electricity Journal: Jan/Feb 1997, with Judah Rose and Shanthi Muthiah.

REGULATORY PRESENTATIONS AND TESTIMONY

"Avoided Costs of Energy in New England Due to Energy Efficiency Programs", State of Vermont Department of Public Service, August 25, 2006, with Leonard Crook.

Oral Testimony regarding Certificate of Need for the Warren County Transmission Expansion, Kentucky Public Service Commission, September 21, 2005.

"Analysis of an IGCC Coal Power Plant", Minnesota state house of representative committees, January 15, 2002, with Judah Rose.

Analysis Related to Merchant Plant Siting in South Carolina, Public Utilities Commission of South Carolina, Summer 2002, with Judah Rose and Kojo Ofori-Atta.

EMPLOYMENT HISTORY

ICF Resources Incorporated	Vice President	2001–Present
ICF Resources Incorporated	Principal	2000
ICF Resources Incorporated	Senior Project Manager	1999
ICF Resources Incorporated	Project Manager	1998
ICF Resources Incorporated	Senior Associate	1997
ICF Resources Incorporated	Associate	1996-1997
ICF Resources Incorporated	Analyst	1994-1996
Nathan Associates	Research Assistant	1992-1994
The Pennsylvania State University	Teaching Assistant	1991-1992

Modeling Assumptions

Parameter	Engelking testimony treatment	Comments on data or modifications made for calibration to Strategist	Changes for alternate scenarios
Load Forecast	Assumed NSP May 2006 forecast	No changes from NSP assumptions were made. ▪ Post DSM load growth assumes a 1.58% annual average peak demand growth and 1.68% annual average energy growth. ▪ Engelking indicated in one instance that demand for Flint Hills is included prior to the testimony. However, this has not been confirmed and it is inconsistent with the general testimony. We assume it is included. ▪ Graphic in Engelking testimony implies 90% load level used. However, the growth rate and starting points do not support this. We have this is the normal forecast is used.	Historical evidence including NSP historical Form 1 filings, MISO reported nodal load data, and NSP / DOC filings in the recent NSP IRP proceedings support and average annual growth rate of 2%. ICF has used this for the energy growth and relied on the load factors in Strategist to establish a comparable Peak demand level
DSM	Indicates 2004 Resource Plan Assumed: Energy savings of 3,950 MWhs and peak demand savings of 1,156 MW	We have relied on the Strategist characterization which appears to be more aggressive than the description. ▪ Actual levels realized in the Strategist modeling are 2,951 MW peak by 2033 and 7,205 GWH energy.	Inputs used in the IPM® modeling were post DSM.
Gas forecast	Aug 2006 - Dec 2008 NYMEX futures prices; Jan 2009 - Dec 2020 PIRA Midcon 6/15/06	The data on gas forecasts was not made available. ICF has assumed a $5.37 (real 2005$) for the forecast duration to calibrate.	FTI provided a Reference case forecast of $7.67 (real 2007$) for the Mesaba runs and an alternate scenario of $14/mmBtu (2006$)
Coal forecast	NSP 30 Year Forecast	ICF relied on forecast available in Strategist inputs. Verification of the Engelking testimony was not performed.	Same as calibration
Existing Generation Fleet	URGE rating used in 2004 IRP, West Fairbault and GRE/Basin 144 MW Flint Hills contract retired.	ICF relied on forecast available in Strategist inputs where possible. Verification of the Engelking testimony was not performed.	Same as calibration

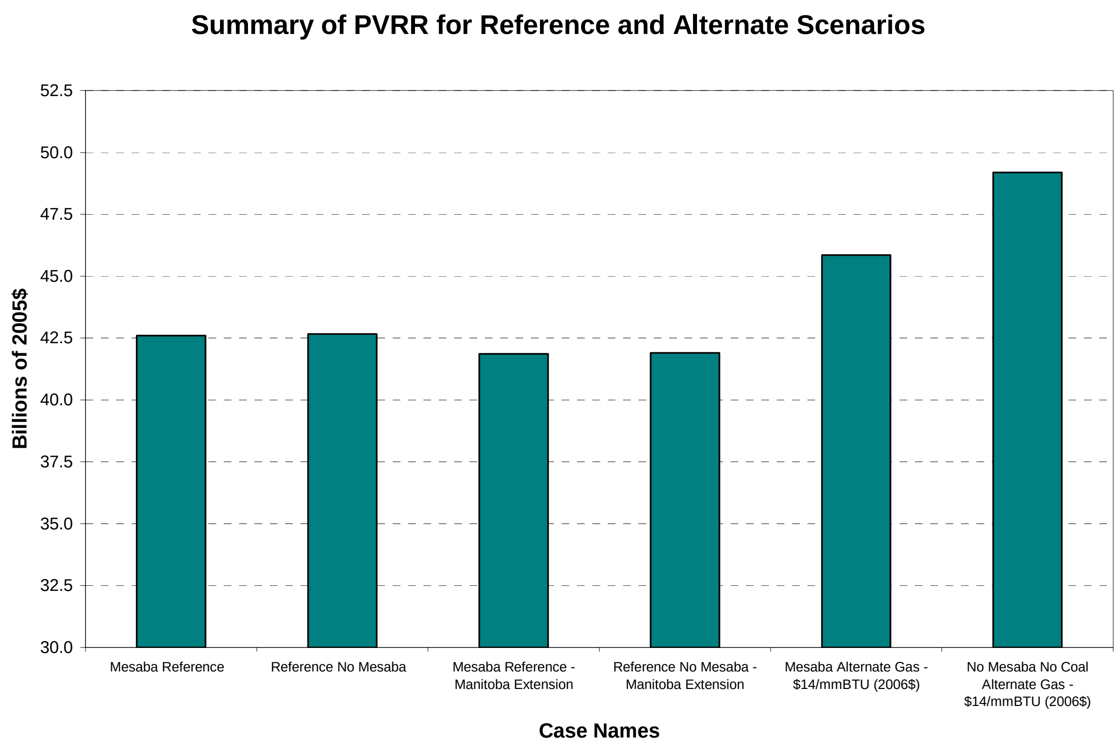
Parameter	Engelking testimony treatment	Comments on data or modifications made for calibration to Strategist	Changes for alternate scenarios
MERP	King 07, High Bridge 08, Riverside 09	ICF relied on forecast available in Strategist inputs ▪ Strategist does not appear to convert the King plant unit in 2007	Same as calibration
Upgrades	Sherco 48 MW 2010; PI 136 MW in 2015; Monti 66 MW in 2011	ICF relied on forecast available in Strategist inputs ▪ Strategist includes 52 for Sherco in 2010; 136 for PI in 2015; and 66 for Monticello in 2011	Rather than force in decisions through an external decision process, ICF allowed the uprate decision to be determined directly in the IPM® modeling exercise for all alternate scenarios
Wind	2,805 MW by 2019	ICF relied on forecast available in Strategist inputs ▪ Incremental wind additions account for 1.040 MW beginning in 2006. ▪ Total wind is 1,968 MW by 2019.	Same as calibration
Externalities	PUC values as of 4/17/05 in Docket No. E999/CI-00-1636	ICF relied on conversations with NSP staff to replicate the PVRR values. NSP indicated no externalities were included with the exception of a Carbon tax (below). NSP further indicated that the compliance costs for existing air pollutant control programs which affect the system (such as Title IV, CAMR and CAIR) are not included in the PVRR assessment.	Same as calibration
Carbon Tax	$9/ton starting in 2010 escalated by 2.5% thereafter	ICF was able to confirm this in the Strategist input files provided and relied on this assumption.	Same as calibration

Parameter	Engelking testimony treatment	Comments on data or modifications made for calibration to Strategist	Changes for alternate scenarios
Cost of Capital	7.66% (after tax) from 2005 Minnesota Electric Rate Case - as proposed by NSP in filing and recommended by ALJ finding 122	ICF was able to confirm this in the Strategist input files provided and relied on this assumption.	Same as calibration
Capital Cost for New Units	Not discussed	ICF determined that costs used in Strategist were as follows: ▪ Combined cycles are $690/kW for 250 MW unit (derived from strategist inputs); ▪ CT $574/kW for 160 MW unit (derived from inputs); ▪ Coal $1748 for 375 MW unit (derived form inputs). All costs derivations include AFUDC. All costs in 2005$	These costs were updated by FTI per my testimony above.
New Unit Seasonal Derating	Not discussed	Combined cycles and combustion turbines dated by 15% in summer months; no derate on coal units, other than the Mesaba unit. This was derated to 566MW for the summer rating (597MW winter) in the NSP runs	Combined cycles, combustion turbines, and pulverized coal were treated the same as in the calibration. For Mesaba, the facility was modeled at 570MW summer and 598MW winter as specified by Excelsior
Existing Unit Seasonal Derating	Not discussed	Existing fossil units, both gas and coal, were found to be derated seasonally.	Same as calibration

Parameter	Engelking testimony treatment	Comments on data or modifications made for calibration to Strategist	Changes for alternate scenarios
New Unit Performance Character-istics	Not discussed	Strategist Assumptions: ▪ Coal units are modeled with a 4.9% annual derating with no near term penalty for start-up ▪ Combined cycles are modeled with a 4.6% annual derating with no near term penalty for start-up ▪ Combustion turbines are modeled with a 10.4% annual derating with no near term penalty for start-up	Same as calibration
Mesaba Cost Character-istics	Fixed and variable costs and capacity charges were described	ICF relied on forecast available in Strategist inputs ▪ The Engelking testimony could not be verified for fixed and variable O&M in the strategist runs. The capacity charge used in Strategist matched that in the Engelking testimony.	Same as calibration
Mesaba Performance Character-istics	Not discussed	Strategist assumes a forced outage rate of 35% in 2011, 33.5% in 2012, 23% in 2013, and 13% in 2014.	ICF relied on an annual average forced outage of 5% in all years. The single input value was used to compensate for NSP's aggressive treatment of all other new build options units versus Mesaba. This outage rate is above the long term expected forced outage of 4% for Mesaba.

Reference and Alternate Scenarios Modeled Using IPM®

Case Name	Gas	Mesaba Included	Coal Capital Cost	CC Capital Cost	CT Capital Cost	Load Growth	Additional Items	PVRR
	Assumption Description							
	2005 $/mmBtu			*2005 $/kWyr*				*billions of 2005$*
Mesaba Reference	$ 7.30	YES	$ 2,769	$ 1,148	$ 660	2% energy; consistent load factor with forecast used in Strategist run		42.6
Reference No Mesaba	$ 7.30	NO	$ 2,769	$ 1,148	$ 660	2% energy; consistent load factor with forecast used in Strategist run		42.7
Mesaba Reference with Manitoba Hydro Extension	$ 7.30	YES	$ 2,769	$ 1,148	$ 660	2% energy; consistent load factor with forecast used in Strategist run	Manitoba Hydro Contract Extension	41.9
Reference No Mesaba with Manitoba Hydro Extension	$ 7.30	NO	$ 2,769	$ 1,148	$ 660	2% energy; consistent load factor with forecast used in Strategist run	Manitoba Hydro Contract Extension	41.9
Mesaba Alternate Gas	$ 13.66	YES	$ 2,769	$ 1,148	$ 660	2% energy; consistent load factor with forecast used in Strategist run		45.9
No Mesaba No Coal Alternate Gas	$ 13.66	NO	NA	$ 1,148	$ 660	2% energy; consistent load factor with forecast used in Strategist run		49.2


Summary of PVRR for Reference and Alternate Scenarios
Billions of 2005$
52.5
50.0
47.5
45.0
42.5
40.0
37.5
35.0
32.5
30.0
Mesaba Reference
Reference No Mesaba
Mesaba Reference - Manitoba Extension
Reference No Mesaba - Manitoba Extension
Mesaba Alternate Gas - $14/mmBTU (2006$)
No Mesaba No Coal Alternate Gas - $14/mmBTU (2006$)
Case Names