

MESABA ENERGY PROJECT

REPORT TO THE MINNESOTA PUBLIC UTILITIES COMMISSION

SECTION II

CLEAN ENERGY TECHNOLOGY DETERMINATION

EXCELSIOR ENERGY INC.

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INTRODUCTION

The IEP Statute provides a means to ensure that Mesaba One proceeds to construction and operation in a timely manner, by providing for the right for the IEP to contract for its output with Xcel Energy. The statute also provides a means to ensure that the benefits of IGCC are considered each time an alternative fossil generation proposal is brought to the Commission by any utility in the State.

The Clean Energy Technology Statute, set forth below, provides the Commission with an additional, proactive mechanism to ensure that adequate clean coal base load is added to the energy supply mix on behalf of NSP's ratepayers.

This Section II of the Mesaba Energy Project Report provides the information needed for the Commission to determine that the Mesaba Project uses Clean Energy Technology ("CET") that is or is likely to be a least-cost resource. This Section also provides the Commission with the information it needs to determine the percent of NSP's retail energy that must come from CET.

Minn. Stat. § 216B.1693 (the "CET Statute") provides:

- (a) If the commission finds that a clean energy technology is or is likely to be a least-cost resource, including the costs of ancillary services and other generation and transmission upgrades necessary, the utility that owns a nuclear generating facility shall supply at least two percent of the electric energy provided to retail customers from clean energy technology.
- (b) Electric energy required by this section shall be supplied by the innovative energy project defined in section 216B.1694, subdivision 1, unless the commission finds doing so contrary to the public interest.
- (c) For purposes of this section, "clean energy technology" means a technology utilizing coal as a primary fuel in a highly efficient combined-cycle configuration with significantly reduced sulfur dioxide, nitrogen oxide, particulate, and mercury emissions from those of traditional technologies.
- (d) This section expires January 1, 2012.

ANALYSIS

Subdivision (c) of the CET Statute defines CET as integrated gasification combined-cycle ("IGCC") technology. Minnesota law therefore directs the utility that owns a nuclear generating facility to supply a clean energy minimum ("CEM") of at least two percent of its retail energy from IGCC, subject to a finding by the Commission that IGCC is or is likely to

be a least-cost resource. The law also requires that an IEP supply the CEM to NSP unless the Commission finds that supply is contrary to the public interest.

As noted in Paragraphs 15-17 of the Petition, the Mesaba Project is an IEP that uses IGCC, and NSP is a public utility that owns a nuclear generating facility. The Mesaba Project is thus entitled to provide the CEM, subject to a finding by the Commission that IGCC is or is likely to be a least-cost resource, and a finding that it is not contrary to the public interest for the Mesaba Project to supply that energy. The information reported below demonstrates that IGCC is, under current market conditions or is likely to be, under future market conditions, a least-cost resource. The evaluation of the Mesaba Project in Section I of this Report demonstrates that the Mesaba Project is in the public interest. The factors relevant to making that determination also demonstrate that the supply of the CET by the Project is not contrary to the public interest as required by Subdivision (b) of the CET Statute.

A. IGCC IS OR IS LIKELY TO BE A LEAST-COST RESOURCE

In enacting the CEM, the Legislature directed the Commission to evaluate the costs and benefits of IGCC. The CET statute recognizes the tradeoff between cost and the environmental performance, flexibility and other benefits of the IGCC technology, and recognizes that many of the positive attributes of IGCC, as an advanced clean coal technology, may not lend themselves to precise quantification. The statutory language “is or is likely to be” also reflects the need to look at all plausible future scenarios in making resource decisions. Under different scenarios, different technologies may end up being least-cost. The CET Statute therefore does not require the Mesaba Project to prove that IGCC is the single least-cost resource, or that it is a least-cost resource under current regulations and market conditions. It does not require that the Commission conduct exhaustive analysis to pinpoint a single, precise cost comparison. Rather, the CET Statute tasks the Commission with determining whether IGCC brings the benefits described in the Statutes, and does so in a manner that balances the costs with those benefits.

1. IGCC IS LEAST-COST TODAY WHEN ALL COSTS ARE APPROPRIATELY CONSIDERED

Consensus is emerging that IGCC is a least-cost resource even if it appears more expensive than alternative conventional technologies on a direct cost comparison under current market and regulatory conditions. This analysis of the Project is simplified by the fact that the direct cost, from inception, of energy from the Project will in fact be competitive with the cost of energy from a utility-owned supercritical pulverized coal (“SPCP”) unit. This cost parity of the Project is afforded in part by the Federal incentives offered under the Energy Policy Act of 2005. These benefits are only available for a handful of “first mover” projects that will include the Project. When the other factors relevant to the determination of life-cycle costs are factored into the analysis, the Project’s cost advantage margin widens significantly. This cost advantage should be retained for subsequent Mesaba units as the learning curve for the technology reduces the capital costs of IGCC and improves its performance.

The analysis below focuses upon the cost of the IGCC technology in general.

Conventional coal technologies, such as SCPC plants, may be quoted at current installed prices that appear to be lower than IGCC based plants. This barrier to selection of IGCC was even more formidable at the time the CET Statute was adopted, explaining in part why “least-cost” alone is not the standard under the CET Statute.

a. Cost Estimates of Conventional Coal Are Outdated and Incomplete

Close scrutiny of current industry cost quotes for conventional coal plants reveals that many of these quotes are not based on the full, site-specific cost of the plant and often do not reflect current market data, including the recent across-the-board market increase in construction costs for infrastructure projects. In many cases, the proposals are preliminary in nature and do not include all the costs associated with the construction and operation of the facility. Xcel makes it clear that the self-build conventional alternatives presented in their resource planning document are of this preliminary and incomplete nature.¹

b. Cost Estimates of Conventional Coal Plants Are Based on Risky Assumptions

The up-front quotes for the price of power from a SCPC typically reflect two erroneous, implicit assumptions that must be true in order to justify building a new SCPC plant. The first assumption is that there will be no changes in emission limits over the life of the facility that will require significant capital and operating expenditures to achieve compliance, assuming compliance can even be achieved. The second is that a conventional coal alternative can be permitted and constructed in a timely manner and without last minute cost adders.

i. Emissions Limits Are Tightening

Sponsors of conventional coal proposals assume in their pricing that no changes in environmental laws will occur over the life of the plant. The prices quoted assume that it will suffice to meet the plant-specific emission limits in effect at the time the plant is proposed. These price quotes ignore the equipment costs and efficiency losses associated with the improved environmental controls that are likely to be imposed during or after the permitting process. In the case of utilities, the implicit assumption is that the actual, final costs will be considered after the initial plant proposal is approved at the lower cost, or that the retrofit costs will be considered after the investment is made and the plant is built, at which point the prudence discussion will be centered on approving the retrofit and the attendant cost increase in order to avoid stranding the initial investment, and to “keep the lights on.”

The State has a vested interest in scrutinizing the assumption that as-built costs tell the whole story. The selection by a project sponsor of a plant and a technology that marginally meet plant-specific emission requirements poses a significant threat to the economic well-being of the State.

¹ For an analysis of the current, actual cost of energy from a SCPC plant, see the Fluor Reports attached as Exhibits F and G of this Report.

The permits initially obtained by such a facility may allow the utility to run the plant, but the analysis should not end there. Tightening limits increasingly take the form of portfolio emission reduction requirements, which in many cases are imposed on a State and not a facility. Further, these requirements often must be met from all sources in the state, and not just power generation facilities. This means that a decision to build a marginally permissible plant when a much cleaner alternative exists puts pressure on other industries to shoulder more of the costs of future emission reduction initiatives. Therefore, the State has a direct interest in ensuring that generation capacity decisions are made with an eye toward maximizing the State's flexibility to meet more stringent requirements than those in place when the plant is first proposed.

Events are unfolding that illustrate the materiality of this risk. There have been substantial advances in air pollution epidemiology and damage cost estimation since the original study that formed the basis for the Minnesota externality values was completed. Since 1994, a large number of new studies have greatly expanded the state of scientific knowledge concerning the relationship between different measures of particulate matter ("PM"), sulfur dioxide ("SO₂"), nitrogen oxide ("NO_x"), ozone, and mercury and health effects. USEPA 2004 provides a comprehensive recent review of particulate health effects studies.

Developments in the understanding of PM emissions are one example of the changing regulatory landscape for generation resources. A number of recent risk assessments have concluded that PM-associated adverse effects tend to dominate overall impacts associated with a range of fossil fuel burning power generation facilities, and that the bulk of the health effects (both mortality and morbidity) tend to be associated with exposures to the "fine" fraction particulate matter having an aerodynamic diameter less than or equal to 2.5 microns (PM_{2.5}).² Epidemiological studies of both short-term and long-term PM exposures have led to a growing consensus that the adverse effects of ambient particulate matter exposures tend to be much better correlated with PM_{2.5} levels than other measures of PM exposure (PM₁₀ and PM_{10-2.5}). In addition, it appears that a large proportion of health effects previously attributed to gaseous pollutants may actually be caused by fine particles.

PM_{2.5} is currently regulated by the EPA under the National Ambient Air Quality Standards ("NAAQS"). Numerous Federal regulatory programs are now in place that will address, either directly or indirectly, the transport of fine particulate matter across state boundaries in amounts that could cause or contribute to violations of the NAAQS. These programs include the Clean Air Interstate Rule ("CAIR"), the Clean Air Visibility Rule, the Acid Rain Program, and the NO_x State Implementation Plan ("SIP") Call. These emission limits will soon tighten for Minnesota under CAIR because the precursors to PM_{2.5} originating in Minnesota are contributing to non-attainment of air quality standards in the Chicago area.

² U.S. ENVTL. PROT. AGENCY, OFFICE OF AIR AND RADIATION, THE BENEFITS AND COSTS OF THE CLEAN AIR ACT: 1990 TO 2010, (1999), *available at* <http://www.epa.gov/air/sect812/1990-2010/fullrept.pdf>; JI LEVY, ET AL., THE IMPORTANCE OF POPULATION SUSCEPTIBILITY FOR AIR POLLUTION RISK ASSESSMENT: A CASE STUDY OF POWER PLANTS NEAR WASHINGTON, D.C., (2002), *available at* http://www.cleartheair.org/reports/dc_study.pdf; ABT ASSOC., PARTICULATE MATTER HEALTH RISK ASSESSMENT FOR SELECTED URBAN AREAS: DRAFT REPORT, *prepared for* U.S. Env'tl. Prot. Agency, Office of Air Quality Planning and Standards, (2003), *available at* http://www.epa.gov/ttn/naaqs/standards/pm/data/pm_risk_tsd_finalreport_2005_mainbody.pdf.

As individual states prepare, via SIP revisions, to reduce their contributions to such violations, sources within the state must reduce actual emissions. As scientific understanding of the damages from these emissions is refined, emissions controls will be required to the point where plants internalize these costs which are presently treated as externalities.

PM_{2.5} emissions are dramatically higher for even the most advanced combustion technologies, compared to the very tight emission controls achieved by the Project. Excelsior has conducted state-of-the-art health benefits modeling in an effort to identify such damages caused by PM_{2.5}. For a detailed analysis of the costs imposed on Minnesota and the nation by the PM_{2.5} associated with the Mesaba Project as compared to a new SCPC plant located in Central Minnesota, see the ICF Health Benefits Report attached as Exhibit D of this Report.

IGCC brings the State two important benefits in terms of emissions flexibility. First, criteria pollutant emissions from an IGCC plant are generally 60% less than emissions from a state-of-the-art SCPC coal facility. See Section I, at Subsection E for more details on the Mesaba Project's low emission rates. Second, the technology is inherently more flexible in accommodating emission-reducing retrofits as even better control technologies develop. This is due to the low volumes of syngas that are cleaned in the IGCC process prior to combustion, compared to the very large volumes of flue gases that must be scrubbed post-combustion in order for a conventional technology to achieve emission reductions. Pre-combustion clean up equipment is modular and much smaller than scrubbing facilities for combustion technologies, further contributing to IGCC's flexibility. While conventional technologies are being stretched to their limits to meet existing criteria pollutant emission requirements, IGCC is in a position to improve significantly from its profile today.

In addition to considering tightening emission limits for criteria pollutants, a decision-maker must also weigh the likelihood of carbon constraints in judging the soundness of looking solely to initial capital costs in making base load power generation technology selections. In the event of limits on greenhouse gases, Minnesota will be required to reduce overall carbon dioxide emissions from all sources, while meeting ever-increasing growth in demand for energy to fuel economic growth. It is important for the State to lay the groundwork for responding to this challenge in the resource decisions it makes now, in order to avoid potentially severe consequences to the State's economy when the limits are imposed.

It has become clear that some form of greenhouse gas regulation and limits are likely in the future. As described in Section I of this Report, the Project's IGCC technology represents the technological path for the Nation to begin to address carbon management in electricity production from its abundant, domestic resources of coal. The U.S. Department of Energy sees the Mesaba Project as a key stepping-stone in its development of FutureGen, a coal-fired IGCC electric generation plant with near-zero emissions.

When carbon limits occur, they may sound the death-knell for conventional coal-fired generating plant technology, which cannot support cost-effective carbon capture.³ Assuming limits are imposed in the next decade, any SCPC plant on the drawing board now would have virtually its entire useful life in jeopardy or subject to a significant economic penalty. This is true because the only identified technology path for carbon capture from a SCPC boiler technology is post-combustion scrubbing of a very large volume of flue gas, which is a capital and energy intensive proposition, as well as being technologically unproven. This is one of the signature differences in combustion technologies and the IGCC technology, which can cost-effectively capture carbon from the concentrated, pre-combustion syngas.

The National Commission on Energy Policy, in its December 2004 report entitled “Ending the Energy Stalemate: A Bipartisan Strategy to Meet America’s Energy Challenges,” describes the critical role of IGCC in providing policy flexibility in this way:

Coal-based integrated gasification combined cycle (IGCC) technology, which – besides having lower pollutant emissions of all kinds – can open the door to economic carbon capture and storage, holds great promise for advancing national as well as global economic, environmental, and energy security goals. The future of coal and the success of greenhouse gas mitigation policies may well hinge to a large extent on whether this technology can be successfully commercialized and deployed over the next 20 years.⁴

In the case of carbon management, American Electric Power (“AEP”) has analyzed the cost of capturing carbon dioxide from IGCC and other technologies and concluded that the cost advantage of IGCC from this feature alone is a sufficient rationale to select the technology, as is reflected in their expert testimony in the Ohio Public Utilities Commission with respect to their proposed IGCC plant:

The Companies issue one final caution regarding the intervenors’ collective arguments about IGCC technology. In virtually every concern expressed by the various parties, whether the point is the availability, capacity or cost of the plant, comparisons are made between an IGCC plant and pulverized coal plants. Those comparisons are in most cases skewed and in all cases invalid.

The point is, that this case is not about choosing between IGCC and pulverized coal technologies. AEP has made a decision, based on its engineering knowledge, its belief in the likelihood of a carbon constrained future, and its belief regarding the difficulty of adapting pulverized coal units to a carbon constrained future, that IGCC technology will play a prominent role in its new plants. Consequently, it is not relevant to the outcome of this case what a pulverized coal plant can and cannot do (other than the

³ See, e.g. American Electric Power, “An Assessment of AEP’s Actions to Mitigate the Economic Impacts of Emissions Policies,” Annex D, (2004), attached to Section VII of this Report at Tab 1, and Cinergy Corp., “Air Issues: Report to Stakeholders,” December 2004, attached to Section VII of this Report at Tab 3.

⁴ NAT’L COMM’N ON ENERGY POLICY, ENDING THE ENERGY STALEMATE: A BIPARTISAN STRATEGY TO MEET AMERICA’S ENERGY CHALLENGES, p. 51, (2004), available at <http://www.energycommission.org/>.

inability to efficiently and cost effectively retrofit a pulverized coal plant to capture and sequester carbon).⁵

In commencing IGCC pre-engineering work in Indiana, Cinergy also emphasized the need to plan now for carbon constraints:

[T]he signs are all pointing to the reality that we will live in a carbon-constrained world in the future. Although we don't know exactly when and how, we believe it is inevitable that carbon dioxide (CO₂) and other greenhouse gases will be regulated in the future. Consequently, we must continue to make long-term investment decisions that will ensure affordable and reliable supplies of power for our customers while reducing those and other environmental impacts of generating electricity with coal.⁶

While Commission Staff in Ohio cautiously noted that they could not “know for certain whether carbon sequestration regulations will be passed during the operational life of the plant,” and that “[o]nly time will tell if IGCC or some other technology is the better hedge against carbon rules,” they essentially arrived at the same conclusion:

While it is apparent that there are significant risks to Ohio's generation currently, there is an even more dire possibility. Even if our old coal plants can be patched together for decades more, and we can afford to retrofit mercury and sulfur controls on them, and even if there is natural gas to burn, and even if we can afford the natural gas to burn, the largest risk remains. Judging from the level of interest both in the United States and beyond, it appears that some sort of carbon sequestration will be required in the timeframe about which we are concerned. Europe already has a trading regime for carbon allowances, several U.S. states are considering carbon restriction measures, and many businesses are altering there [sic] operations to anticipate a carbon constrained environment. While it is uncertain when such limitations might be enforced, generating assets are very long lived (that is of course one of the problems here, our plants are very old) and it is a virtual certainty that restrictions will be imposed over the life of the assets.

All fossil generation, both pulverized coal and natural gas, are vulnerable to carbon emission limitations. Both produce large volumes of carbon dioxide. At this point there is no hedge for this risk. The vast majority of generation in the Midwest, and the country generally, is fossil-fueled. Thus, there is no

⁵ American Electric Power, Reply Brief of Columbus S. Power Co. and Ohio Power Co., p. 37-38, Oct. 11, 2005, Case No. 05-376-EL-UNC.

⁶ Cinergy, Testimony of Kay Pashos, Verified Joint Petition of PSI Energy, Inc. and Southern Indiana Gas and Electric Company d/b/a/ Vectren Energy Delivery of Indiana, Inc. for Authority Pursuant to an Alternative Regulatory Plan Authorized Under Ind. Code § 8-1-2.5 et seq. to Defer and Subsequently Recover the Feasibility Study, Engineering, and Preconstruction Costs Associated With the Consideration and Exploration of Constructing an Integrated Coal Gasification Combined Cycle Electric Generating Facility, and Approval of Confidential Treatment of Certain Information to Be Presented in this Cause, p. 7, Nov. 18, 2005, Cause No. 42894.

practical way to buy a hedge from any supplier. All other suppliers are in the same position. Their plants produce carbon dioxide as well. The only practical hedge against this large risk is to build a new facility which anticipates carbon sequestration.

* * *

An examination of the state of the electric market then shows consumers in Ohio in a position of great, but not immediate, vulnerability. This vulnerability is not today and not tomorrow and not even within four years. It should not cause panic but it should engender sober, thoughtful planning. The facts are clear. Our coal fleet is aged and needs large new investment to run at all. Our natural gas fleet is economically hobbled currently and may not have fuel to burn at some point. Both kinds of plants are threatened by the possibility of carbon restrictions. Existing markets and bi-lateral transactions can do nothing for these risks. The only alternative is to evaluate the possibility of construction of new facilities which anticipate carbon controls.⁷

IGCC technology is on the DOE Roadmap that culminates in FutureGen, a near zero-emission coal-fueled plant.⁸ The significant research and development funding and attention that the technologies to be incorporated in the FutureGen design will enjoy will provide a constant technological means to improve every other IGCC facility in the nation's fleet in a cost effective manner. The Roadmap includes extensive research and development focused on further reducing the cost of carbon capture from IGCC facilities. The identified improvement targets for all aspects of IGCC's cost and performance will provide powerful policy tools that State regulators can use to address the challenge of supplying ever more electric power at ever-reducing overall emissions limits. Not only is this important from a cost and compliance perspective, it is also crucial for the long-term health and economic growth of the State's economy.

In Minnesota, the importance of IGCC technology was recognized by the Legislature, the Governor and other policymakers, rather than utility executives, shareholders or boards of directors. Minnesota saw the challenges posed by the State's growing energy needs and responded in 2003. While the foremost challenges identified by the Legislature stem from the need to reduce criteria pollutants, the Legislature also recognized that IGCC might play a role in managing greenhouse gas emissions.⁹

⁷ Post-Hearing Brief Submitted on Behalf of the Staff of the Public Utilities Commission of Ohio, Case No. 05-376-EL-UNC, Sep. 20, 2005

⁸ For an overview of the DOE's Roadmap, culminating in near zero emission technologies from coal, see www.fossilenergy.gov/programs/powersystems/publications/clean_coal_topical_reports/CCT-Roadmap.pdf.

⁹ The IEP Statute contains a requirement that the Project seek to obtain funding to conduct carbon sequestration research and development funding. The Project is participating in the Plains Carbon Dioxide Regional Partnership, which has been awarded funding to identify the sources and sinks of carbon dioxide in the plains states, and as part of its effort will identify the most promising means to mitigate the carbon dioxide emissions of the Project.

Because of the significant likelihood of changes in environmental law, IGCC is likely to be a least-cost resource.

ii. There Are Implementation Risks Associated With Conventional Technologies

The second assumption made in the pricing of conventional coal proposals is that a pulverized coal plant can be permitted on schedule and without significant feasibility risks. The Commission should weigh the validity of this assumption, particularly in light of the sizable opposition faced by these technologies. Given the long lead time necessary to plan and permit a coal plant, and the ability of stakeholders to raise concerns at any stage in the process, this assumption is likely to lead to delays of needed base load generation and thereby increase actual plant costs significantly beyond the original cost estimate. Recent efforts to build pulverized coal plants in Florida, Texas, and Illinois have all met with significant opposition from local residents and environmental groups who promote the use of IGCC technology as a better alternative.¹⁰

Many project sponsors have sought to avoid this delay by entering into settlement agreements with groups opposing conventional coal projects.¹¹ These costs are typically incurred late in the licensing process, and also have the effect of driving up the final cost of the plant to consumers from the original estimates.

While perhaps initially alluring, the preliminary price quotes for pulverized coal facilities do not, therefore, reflect the true cost of selecting a conventional alternative, particularly at a time when IGCC has arrived as a commercially viable alternative. Conventional facilities will lose any initial price parity during their early years of operation, due to the increased cost of operating those facilities that will occur in any scenario where emission limits and other environmental requirements tighten.

c. The Technology Learning Curve Will Give IGCC an Additional Edge

Even if the initial commercial IGCC plants did prove to be slightly more costly to construct, expert analysts believe that the installed cost of IGCC will reduce very rapidly following the installation of the next round of IGCC projects due to a phenomenon commonly known as the technology curve (also called the learning curve or experience curve). The International Energy Agency explains

¹⁰ In November of this year, the St. Lucie, Florida, County commission voted 5-0 against re-zoning a 3,000 acre tract of land that would have allowed Florida Power and Light to construct an 850 MW SCPC plant there. Environment and Energy Daily reported that while the Executive Director of the Southern Alliance for Clean Energy, Stephen Smith, “encouraged FPL to adopt coalbed gasification technology for the St. Lucie County plant, the company refused on grounds that IGCC was unproven and that the same environmental protection could be achieved with pulverized coal. ‘They made this [conventional plant] sound like the Maserati of coal plants,’ Smith said, ‘But clearly, a large number of citizens and a majority of the commission agreed it wasn’t what they touted it to be.’” See “In Florida, Residents Stop Proposed Power Plant,” Environment and Energy Daily, Nov. 8, 2005, available at <http://www.nrdc.org/news/newsDetails.asp?nID=1910>. See also “Upcoming Texas Decision Could Boost Push for IGCC in State Air Permits,” EnergyWashington Week, Dec. 14, 2005.

¹¹ See, e.g. Xcel Energy’s Settlement Agreement in Colorado in Connection with Its Comanche Self-Build Project, available at: http://www.xcelenergy.com/XLWEB/CDA/0,3080,1-1-1_1875_15056_15473-13518-0_0_0,00.html#

the technology curve as representing the cost reduction benefits a technology will experience as new plants or products are built. For a typical technology, the first few projects will allow future projects to benefit in reduced costs of capacity installations. The learning curve is a declining linear line. After the first projects are realized, the next groups of subsequent projects receive a tremendous price advantage by shifting downward on the experience curve.¹² Minnesota will benefit directly from this reduction in installed cost, as the “technology curve” benefits will ensure that IGCC preserves and improves its position as a least-cost resource.

d. Conventional Coal Plants May Not Be an Option

Leadership of some of the largest coal utilities in the U.S. have, during the past year, called into question the very viability of conventional coal technologies. The analysis conducted by AEP’s Board of Directors concluded that the company must take a leadership position in driving IGCC into the mix. The Report of AEP’s Board of Directors¹³ reflects the Board’s conclusion that investing wholly in conventional coal technologies would be ill-advised from the perspective AEP’s shareholders, due to the significant risk that those investments will be stranded when conventional technologies cannot meet reasonably foreseeable emission control requirements. AEP has therefore been at the national forefront in removing barriers to deployment of IGCC. AEP sums up the challenge as follows:

The central challenge the company faces is that of making decisions about large investments in long-lived assets in a setting of uncertain public policy and rapidly evolving technology. The dilemma is that requirements and technology that can change fairly rapidly increase the risk of making an investment that fails to remain productive over its useful life. For the reasons summarized below, we believe that this situation is likely to persist for a considerable time.¹⁴

AEP has taken a leadership position to ensure market and regulatory conditions address any remaining concerns about IGCC. AEP summarizes the costs and benefits of IGCC, and their impact on AEP’s decision to lead the industry’s transition to IGCC, as follows:

Integrated gasification combined cycle (IGCC) is of particular interest to AEP, in light of the abundance, accessibility, and affordability of high rank coals for the company. IGCC also appears well-positioned for integration of carbon capture and sequestration technologies, which will be a critical measure in mitigating greenhouse gas emissions. While technology risks, performance uncertainties, and capital costs remain formidable at this early state in IGCC’s development, AEP also recognizes sizable operational, policy, and economic benefits that this technology potentially could deliver as the next generation of power generation assets. Weighing these costs and

¹² INT’L ENERGY AGENCY, EXPERIENCE CURVES FOR ENERGY TECHNOLOGY POLICY, (2000).

¹³ The Report is attached to Section VII of this Report and is available at www.AEP.com.

¹⁴ American Electric Power, “An Assessment of AEP’s Actions to Mitigate the Economic Impacts of Emissions Policies,” (2004), p. 12, *available at* <http://www.aep.com/environmental/performance/emissionsassessment/docs/FullReport.pdf>.

benefits, the company has committed to emerging as a leader and first-mover in advancing IGCC into the mainstream of power generation.¹⁵

According to Cinergy's CEO, James E. Rogers, Cinergy must develop IGCC, and it must act immediately. In May of 2005, he told the New York Times, "I'm making a bet on gasification . . . I don't see any other way forward,"¹⁶ and months earlier, during a roundtable at the Edison Electric Institute, he said, "I have a sense of urgency . . . We need gasification now."¹⁷

In 2004, Mr. Rogers announced the development of an IGCC plant that is described in more detail in a letter to stakeholders that accompanies Cinergy's 2004 Annual Report.¹⁸ The report states Cinergy's position on the importance of leadership in driving technological change:

We must act now. Around the world today, at least 850 coal-burning power plants are on the drawing board. Once built, these plants will operate for between 60 and 80 years. Will they be designed with new technologies that burn coal more efficiently and with significantly fewer emissions, or will they be built using existing combustion technology? The need to accelerate the commercialization of new technologies is critical. We put a man on the moon because we had leadership and public support for this mission. This same focused "can-do" leadership and public support are needed now.¹⁹

In short, these major coal-based U.S. utilities have essentially concluded that pulverized coal technologies are not a least-cost resource because they are no longer a viable option for new resources.

A Commissioner from Indiana captures the risks associated with indecision and delay in choosing IGCC:

Ever hear the proverb: "A day late and a dollar short"? The German's version of this proverb goes like this: "A little too late is much too late." Perhaps the East African proverb might leave you with a visual image that will be a take-away from this talk: "He who waits for the whole animal to appear will only spear its tail." Rather than taking a risk by building an IGCC now and gaining the benefits of being an early adaptor, the real risk taker might actually be the company that waits too long to choose IGCC.²⁰

¹⁵ American Electric Power, "An Assessment of AEP's Actions to Mitigate the Economic Impacts of Emissions Policies," (2004), p. 6, *available at*

<http://www.aep.com/environmental/performance/emissionsassessment/docs/FullReport.pdf>.

¹⁶ Dirty Secret: Coal Plants Could Be Much Cleaner, New York Times, May 22, 2005, Kenneth J. Stier.

¹⁷ Craig Canine, How to Clean Coal, OnEarth, Fall 2005, *available at* www.nrdc.org/onearth/o5fal/coal5.asp.

¹⁸ The Letter to Stakeholders is attached to Section VII.

¹⁹ Cinergy Corp., Annual Report 2004, Global Warming: Can We Find Common Ground?, p.14, (2004), *available at* http://www.cinergy.com/pdfs/reports/04sar/04AR01_Complete.pdf.

²⁰ Remarks of David Hadley, Commissioner, Indiana Utility Regulatory Commission, Gasification Technologies 2004 Conference, Oct. 4, 2004, *available at* www.gasificatoin.org/DOCS/2004_Papers/03HHDL_Paper.pdf.

In sum, IGCC is or is likely to be a least-cost resource as the costs rapidly converge with those of coal combustion technologies. The technology's flexibility and identified improvement path positions it to remain cost-effective under all plausible scenarios. As the very viability of conventional technologies is openly questioned by leading coal utilities, IGCC provides a means to ensure that coal remains in the mix.

e. Additional Project Features Add to IGCC's Cost Advantage

While the Commission need not conclude that the Project or IGCC is the least-cost alternative in order to approve the supply of the CEM, the cost of the Project's output is certainly important to many stakeholders in this docket. Therefore, Excelsior has provided a detailed cost comparison of the actual tariff under the Mesaba PPA with the tariff from a utility-owned conventional coal (SCPC) alternative plant. This comparison is provided in Section III of this Report. The report by Fluor Enterprises entitled "Independent Analysis of Generation Technologies for a 600 MW Coal-Fired Power Plant in Minnesota" (the "Fluor Report") attached as Exhibit F to this Report, provides expert analysis of the installed costs, operation and maintenance costs and total tariff of a utility-owned SCPC.²¹

Section III of this Report demonstrates that Mesaba One's cost of energy is actually on par with that of a utility-owned SCPC plant, due in part to the Federal benefits available to the Project. Quantifiable externality values further contribute to the overall cost advantage that the Mesaba Project has when compared to a SCPC plant. Additional qualitative factors further advantage IGCC in the comparison to the cost of a utility-owned SCPC unit. These include the timely 2011 in-service date and the reduced risks to ratepayers of a PPA structure, versus a utility cost of service structure. See Section III of this Report.

f. Transmission and Ancillary Costs Improve IGCC's Competitive Profile

Transmission and ancillary costs associated with IGCC are required to be considered by the Commission in making its determination that IGCC is or is likely to be a least-cost resource. The requirement that these costs associated with IGCC be considered is consistent with the requirement that such costs be considered for wind resources, which have indirect system costs relating to their intermittent nature. In general, the transmission and ancillary costs associated with IGCC will be comparable to other base load alternatives. Energy delivery from base load facilities requires lower transmission and ancillary costs, compared to intermediate, peaking and intermittent technologies. This is due to the fact that base load facilities fully utilize the transmission associated with those facilities. Therefore, the transmission and ancillary costs of IGCC generation will be comparable to other base load alternatives, and less than intermediate, peaking and intermittent alternatives.

²¹ Fluor is a recognized national engineering and construction firm that has built more than 120,000 MW of coal-fired and natural gas-fired capacity in recent years, and distinguishes itself as the EPC firm that has constructed more new power plants in the United States than any other firm. Fluor has currently been retained to engineer and construct SCPC plants in other jurisdictions, and therefore has the expertise to provide current information to the Commission about the costs of generation from SCPC plants. For more information about Fluor, see Section III of this Report.

The transmission costs generally associated with base load facilities are further reduced in the context of an IEP, because of the regulatory benefits conferred by the Statutes. Under the IEP Statute all transmission infrastructure associated with the Mesaba Project is exempt from state certificate of need requirements. The IEP's exemption from certificate of need will reduce lead-time and uncertainty, and will speed implementation of critically needed transmission infrastructure.

The specific transmission plan for the Project will positively impact the performance of the grid, bringing material benefits to ratepayers, currently estimated at \$59 million annually.²² The transmission and ancillary costs associated with Units One and Two of the Mesaba Project are analyzed in Section IV of this Report.

The analysis above demonstrates that IGCC is or is likely to be a least-cost resource. This conclusion is underscored by the fact that the Mesaba Project is in fact, the least-cost alternative for NSP's current needs. Externality values, IGCC's flexibility to address future carbon constraints, the transmission and timing benefits of the Project, the risk mitigation benefits of the PPA structure, further add to the cost advantages the Project brings to NSP ratepayers.

B. THE COMMISSION MUST DETERMINE THE APPLICABLE CEM PERCENTAGE

Although the CET Statute creates a two percent floor for the amount of NSP's total retail sales that must come from IGCC, the Legislature required the Commission to analyze and determine the appropriate percentage to establish as the clean energy minimum ("CEM") in order to ensure that coal-based generation would continue to play a prominent role in the energy supply mix.²³ The Legislature's directive to the Commission was to confirm that IGCC addressed the concerns historically associated with coal-based generation before adopting a mechanism to ensure that the technology would serve as an important component of the mix.

Establishing the CEM at a percentage higher than the 2% minimum is important, in light of events since the passage of the CET Statute. Natural gas prices, reserve margins, transmission constraints, and the likelihood of changes in environmental laws were factors that the Legislature sought to address with the passage of the CET Statute in 2003. With natural gas prices now nearly triple the price that caused the Legislature concern,²⁴ and given even tighter reserve margins and transmission constraints, the imperative for policy makers and regulators to step in to assure Minnesota's energy security has intensified. In addition, many of the changes in environmental law that were only a possibility when the Legislature considered the CEM are now probable, or a given. These market

²² See the ICF Draft Transmission Report, attached as Exhibit H. This is a conservative estimate of the annual savings to consumers in the cost of power production, based upon very low natural gas price assumptions contained in the transmission system model used by ICF. This annual savings is in addition to the savings represented by deferred capital investments in transmission facility upgrades that would otherwise be necessary as the Project's transmission upgrades provide a net reduction in the number of hours of congestion across many important 345kV MAPP transmission facilities.

²³ The CEM applies to NSP-North energy.

²⁴ According to the U.S. Energy Information Administration's "Natural Gas Weekly Update" for the week ending May 29, 2003, the spot-market at Henry Hub closed at \$5.91 per MMBtu on May 23, 2003, the day that the Minnesota Legislature passed the bill. On Tuesday, December 13, 2005, the market closed at \$15.40 per MMBtu.

conditions are an important backdrop to the determination of what constitutes an optimal amount of IGCC in NSP's portfolio.

The purpose of the CEM is similar to the Renewable Energy Objective ("REO"). The CEM provision was added by the authors of the CET Statute as a means to ensure that the optimal level of IGCC, as determined by the Commission, would be added to the resource mix in Minnesota. While the Legislature left it to the Commission to set the CEM, the legislative record clearly reflects that the CEM was substituted for another provision that would also have made IGCC a central feature of Minnesota's energy future. The earlier provision, which was included in versions of the bill which passed in both chambers of the Legislature, made IGCC eligible to count toward the REO. Under the provision that was replaced with the CEM, every three megawatt hours of IGCC energy would have counted as one megawatt hour of renewable energy under the REO. The substitution of the CEM was made because the Governor and the Legislature wanted to ensure IGCC was made a significant part of the mix in addition to, but not in competition with, renewable energy technologies acquired in accordance with the REO. Letters from key policy makers involved in the decision to substitute the CEM requirement for the REO provision are attached to this Report as Exhibit E.

Minnesota has a history of benefiting from policymakers' decisions to ensure that adequate coal base load is included in the resource mix. The energy crisis currently affecting all sectors of the economy is in many ways similar to the situation in the late 1970s when the decision to build Sherco 3 was made. Concerns about volatile, foreign sources of fuel underscored the importance of maintaining coal's percentage in the mix.²⁵

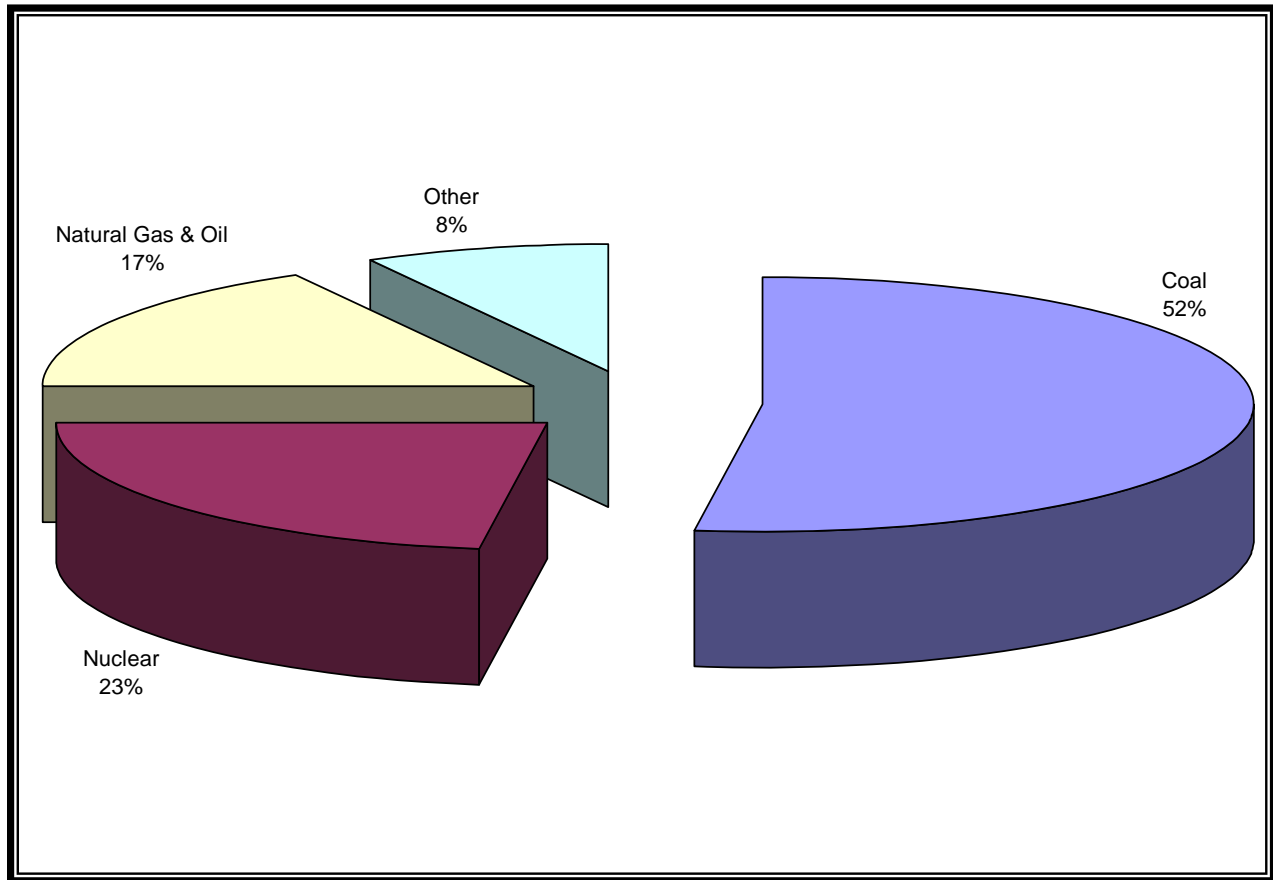
One of the chief criticisms of Sherco was that the plant was not needed to maintain reserve margins. As it turned out, Minnesota benefited from the decision to build Sherco, in the form of low and stable power prices over the past decades. In contrast to the overcapacity concerns critics raised in the Sherco approval process, reserve margins are tight today and forecasted to drop as low as 11% in the current planning horizon.²⁶ The capacity associated with the Mesaba Project units is therefore much more critical to ensuring overall energy security from a pure capacity perspective than was Sherco.

The power supply mix immediately after Sherco came online is instructive for policymakers interested in replicating the positive impact of stable power prices on Minnesota's economy. In 1990, total capacity on NSP's system was approximately 7200 MW. This capacity consisted of approximately 52% coal, 23% nuclear, and 25% gas, oil and other resources. Figure 1 depicts this mix.

²⁵ It is noteworthy that in response to this previous energy crisis, Congress banned the use of natural gas as a utility fuel in the Fuel Use Act. Some industrial leaders today are calling for the reinstatement of that ban to help counter the current natural gas crisis.

²⁶ In its Reliability Assessment 2005-2014, the newly formed Midwest Reliability Organization (MRO) reported that the "summer capacity reserve margin is forecast to decline from a high of 18.0% in 2005 to 11.2% in 2011 and 6.7% in 2014." See Midwest Reliability Organization, Reliability Assessment 2005-2014, p. 1, (2005), available at http://www.midwestreliability.org/Committees/Reliability%20Assessment%20Committee/2005/Agenda/May%2017,%202005/da_RAC050517_w-attachements.pdf.

Figure 1. NSP Generation Capacity, 1990



Coal represented 61% of the energy mix in 1990.²⁷ Gas, oil and other resources accounted for only 4% in total of the overall energy mix.

Today, coal represents 39% of Xcel's available capacity.²⁸

Taking into account only Xcel's existing, approved capacity additions through 2012, coal's proportion of the mix will be reduced to 29% (2,869 MW) by that date, a reduction by nearly half of the proportion coal represented in 1990.²⁹

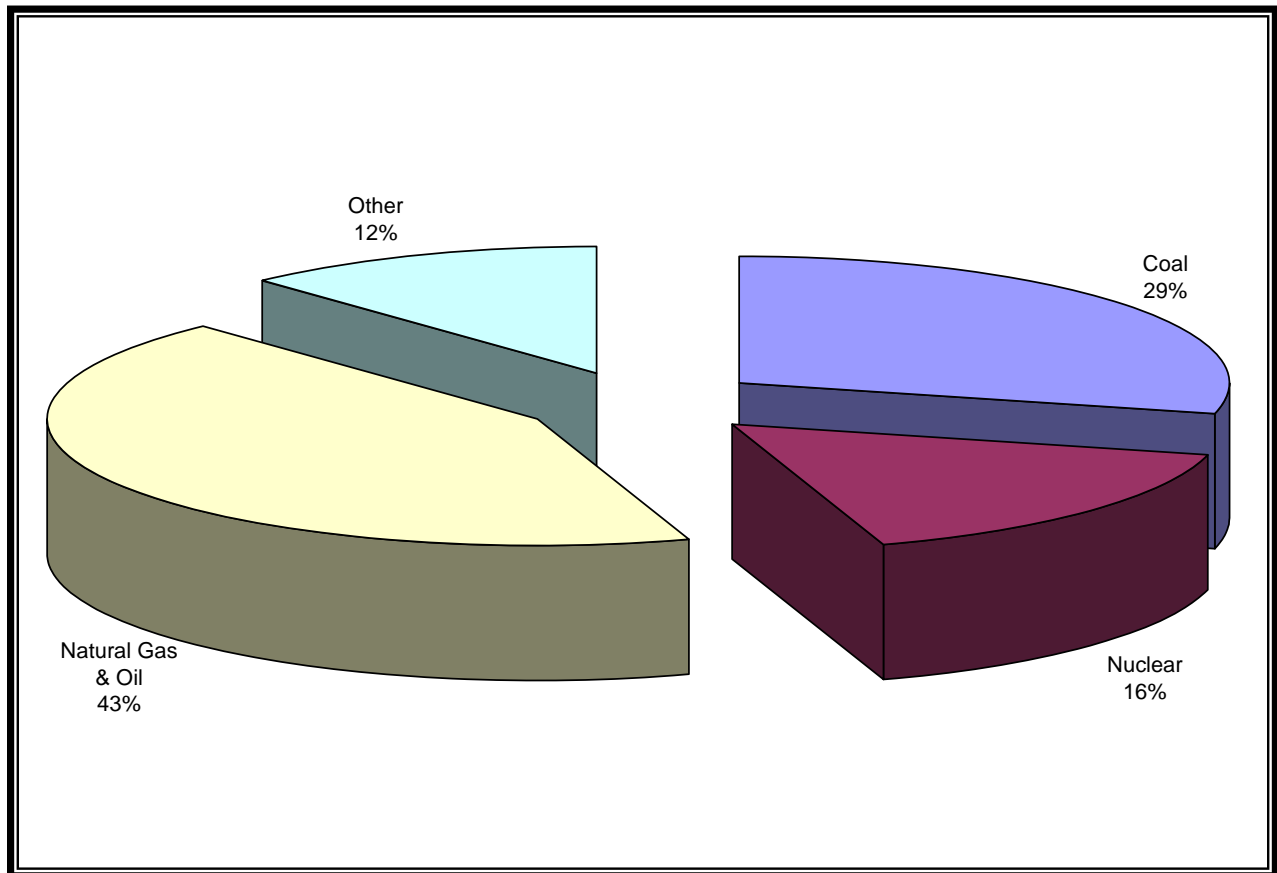
²⁷ Energy production in 1990 (including 6 terawatt hours of purchases) was 40 terawatt hours. One terawatt hour equals 1,000 gigawatt hours. On an energy production basis, 50% was from coal plants, 30% was from nuclear plants, 16% was purchased energy production (which was also 69% coal-based, representing an additional 11% of total energy) and the remaining 4% was gas, oil and other resources. Because the purchased energy was 69% coal, this represents an additional 11% that coal-based generation represented of the total mix, making the total energy provided by coal 61%.

²⁸ Xcel Energy, Response to Department of Commerce Information Request No. 34, Table: NSP Adjusted Net Capacity, Nov. 29, 2004.

²⁹ By 2012, NSP-North forecasts that it will have total installed capacity and long-term purchased power of 10,057 MW.

Taking into account only these approved additions, oil and gas-fired capacity will increase to 43% (4,296 MW) of the total capacity on the system. Figure 2 depicts Xcel's existing capacity together with these approved capacity additions, as of 2012.

Figure 2. NSP-North Generation Capacity, 2012



While the forecasted utilization of Xcel's natural gas-fired units is a trade secret, it can be surmised from the information that the public is able to access that the utilization of the gas-fired facilities is forecasted to be much greater than the 4% of total energy that Xcel produced from the 25% of its capacity represented by oil, gas and other resources in 1990.³⁰ Implicitly, this will make energy derived from natural gas a healthy majority of total power production on Xcel's system.

The advanced age of the remaining coal and nuclear base load fleet that have served as the backbone to Minnesota's low-cost energy strategy and the trend toward reductions in the total hydro electric energy available to meet Minnesota's needs will further skew the portfolio, over time, without active planning to avert this result.

³⁰ For example, the MERP facilities have been projected to have a 62% capacity factor, and the Calpine Mankato facility is projected to have a 60% capacity factor.

Xcel's shrinking coal base load capacity stands in stark contrast to the 50% that coal accounts for in the national generation mix. Xcel's proposed portfolio is an even more dramatic deviation from the energy mix in the Midwest. According to Cinergy:

Coal fuels more than 80 percent of the Midwest electric market. We do not see it being displaced as the main fuel source for electric production without what we believe would be unacceptable economic and social consequences, not only to the region, but to the entire nation.³¹

Cinergy further explains its decision to focus on maintaining this high ratio of coal in the mix:

Abandoning coal and moving to another fuel source, such as natural gas, is not a viable economic option for the company. Neither is it a socially responsible option because by shifting to natural gas fuel, the increased demand would cause electricity and home heating prices to dramatically increase in all regions of the country. Our views on climate change, therefore, reflect the need to ensure a role for coal in a carbon-constrained world.³²

Cinergy arrived at the conclusion that relying on natural gas for power generation was not socially responsible a year ago, in December of 2004, *before* the nearly 75% increase in natural gas prices that occurred in 2005.³³

AEP, another benchmarking peer company for Xcel, maintained 90% of its total portfolio in coal resources, prior to its merger with Central and South West Corporation, which brought coal to 65% of the combined utility's fleet.³⁴

In each of its resource plans since 2000, NSP has identified significant base load needs but has not ever provided any concrete coal-fueled resource to meet that identified need. Even the recently announced "three-pronged approach" to base load acquisitions in NSP's pending 2004 resource plan does not provide a specific, fully developed proposal.

The CEM is the tool the Minnesota Legislature provided to the Commission to address this inaction. The CEM established in this docket would be fed back into the 2004 NSP Integrated Resource Plan docket prior to its approval. This approach will accomplish the objective of the CET Statute of the giving the Commission the proactive tools it needs to ensure that adequate coal is in the mix.

³¹ Cinergy Corp., "Air Issues: Report to Stakeholders," p. 3, (2004), *available at* http://www.cinergy.com/pdfs/AIRS_12012004_final.pdf.

³² Cinergy Corp., "Air Issues: Report to Stakeholders," p. 9, (2004), *available at* http://www.cinergy.com/pdfs/AIRS_12012004_final.pdf.

³³ EIA reports that in December of 2004, prices ranged between \$5.98 per MMBtu and \$7.29 per MMBtu. Prices this December have yet to drop below \$12.59 per MMBtu. The difference between December 2005's minimum and December 2004's maximum is \$5.30 per MMBtu, which is an increase of 73%.

³⁴ AEP Report, attached to Section VII and available at www.aep.com.

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The Commission should set the CEM to ensure that NSP restores the coal balance to its portfolio, based on the projected total mix. In addition to reducing natural gas consumption, the staged introduction of Mesaba One and Mesaba Two will allow Xcel to avoid the perils associated with the forecasted significant capacity deficit in the MAPP region. As Xcel's expert stated in explaining why NSP's purchased power costs have skyrocketed in recent years, "short- and long-term purchases are being driven by gas prices due to lack of newly constructed coal or nuclear plants and the constant growth in load requirements across the MISO footprint."³⁵

This is only the beginning of the concerned testimony the Commission can expect from Xcel's experts over the coming decade who must justify the natural gas expenditures made by Xcel in order to obtain recovery from Xcel's ratepayers under the fuel adjustment clause. The testimony will certainly become much more dramatic over time, because this year's fuel clause testimony relates to a much smaller gas-fired fleet than the dramatically larger gas-fired fleet for which Xcel's ratepayers will be asked to foot the bill once the 2,041 additional MW of gas-fired capacity that Xcel is currently installing and the additional 349 - 562 MW of additional gas-fired capacity that Xcel is recommending in its current preferred plan are placed in service. The increase in fuel expense from this additional gas-fired capacity will be aggravated by the fact that all the gas-fired units will run at higher capacity factors over time without adequate coal in the mix.

A CEM of approximately 13% of NSP-North's retail sales would result in coal-fueled capacity supplying 36% of NSP's available capacity that is owned and available through long term purchases in 2013. This would nearly preserve the proportion of coal fueled capacity on the system today. This is still far below the 52% proportion of coal capacity and 61% proportion of coal energy on Xcel's system when Sherco came online. See Figure 1.

Even with the additional coal fueled resources added pursuant to a CEM of 13%, natural gas and oil based capacity would still compose 38% of the capacity resources of Xcel in 2013. This exceeds the proportion of 29% that natural gas and oil-based capacity represent today (see Figure 4), the 21% level of gas and oil based generation represented in 2003 when the CET Statute was enacted, and the 25% of oil, gas and other resources on the system in 1990.

If the CEM is not established at this level, coal's percentage will drop to 29% by 2013. See Figure 3.

³⁵ Testimony of Camille A. Abboud, Director of Generation Risk Services, Xcel Energy Services Inc., p. 16, Nov. 2, 2005, Docket No. E002/GR-05-1428, *available online at* <http://www.xcelenergy.com/docs/corpcomm/13FuelPurchasedPowerCosts20051102.pdf>.

Figure 3. NSP-North Generation Capacity, 2013 Without IGCC

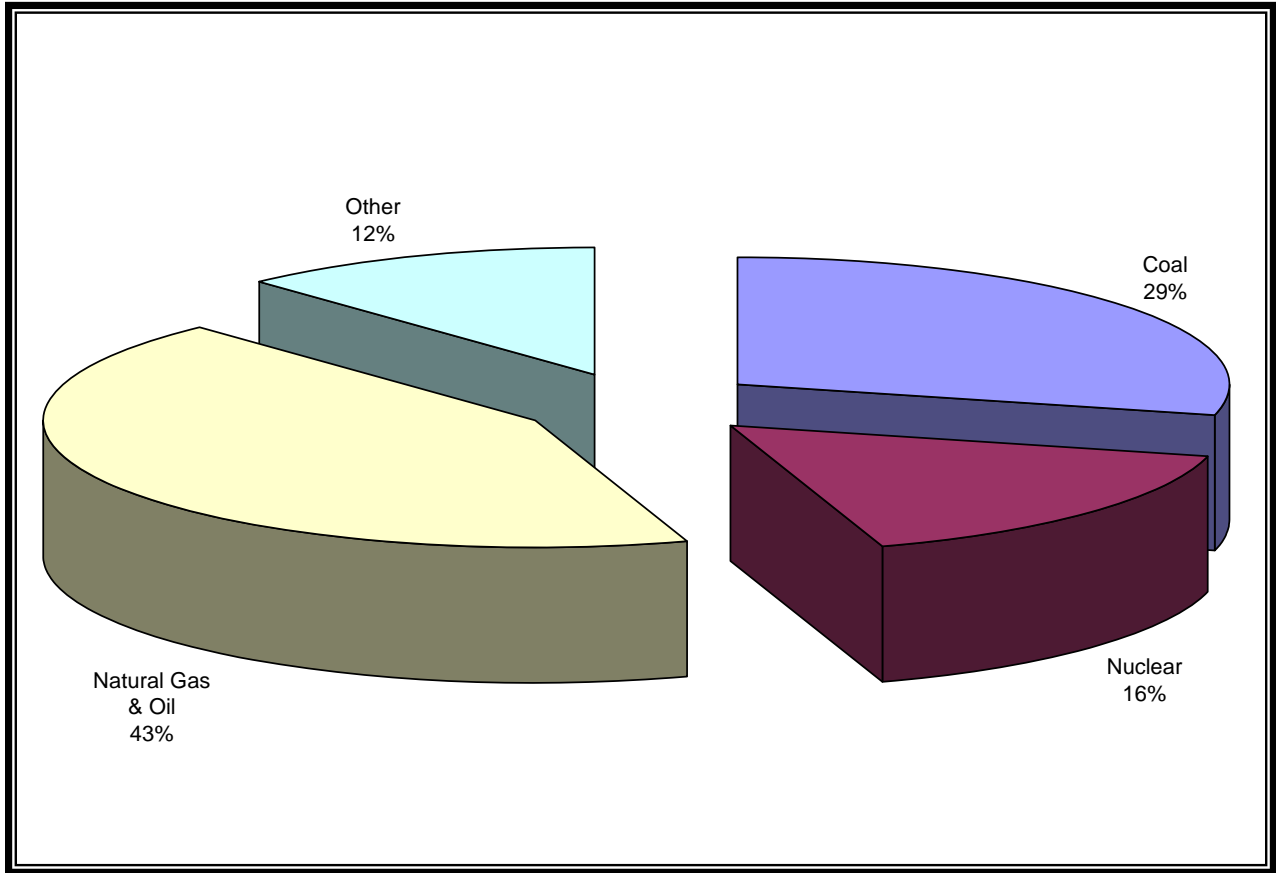
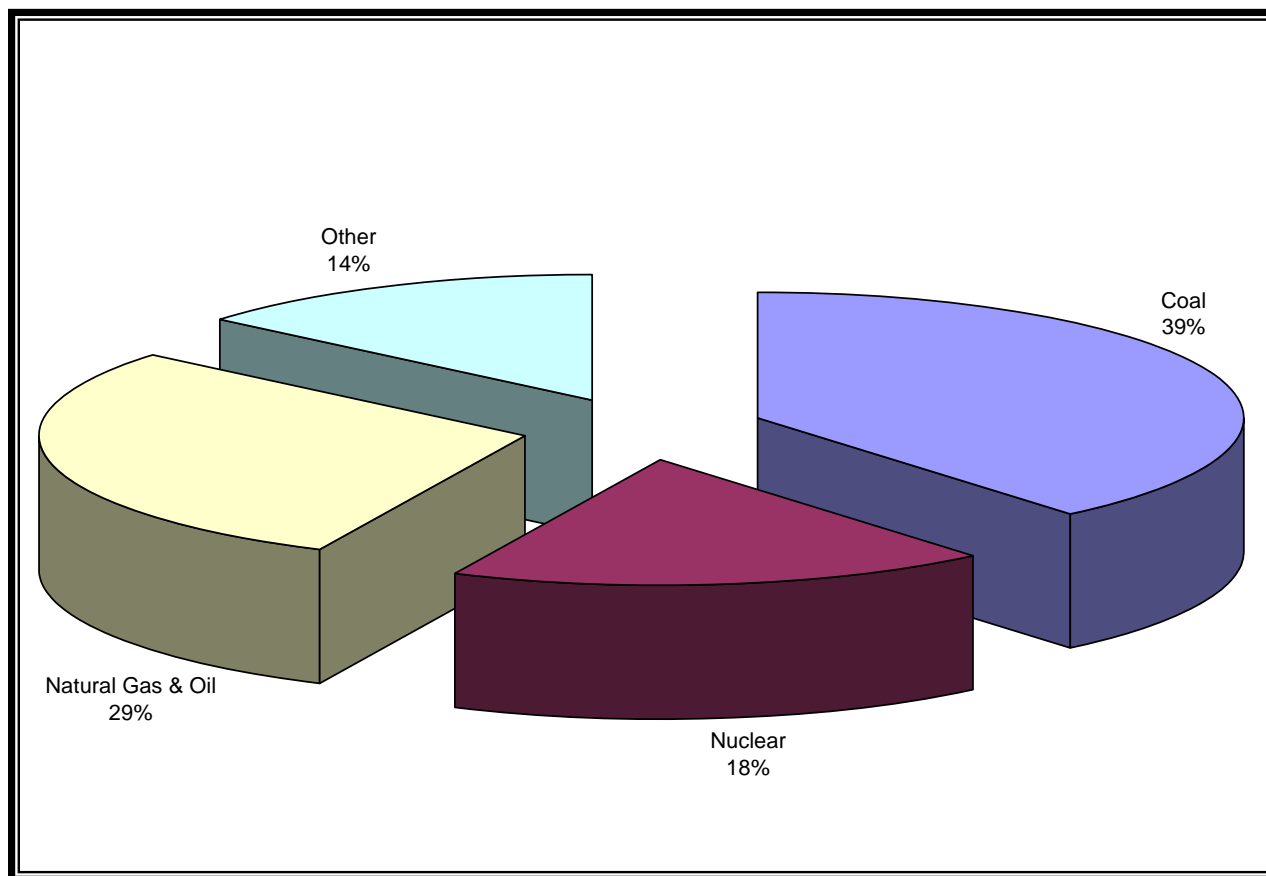


Figure 4. NSP-North Generation Capacity, 2005



A CEM of 15% would be similar in magnitude to the REO and would, as of 2012, establish coal's proportion of the capacity mix to 37%. In order to restore coal's percentage of the mix to the 52% that existed after Sherco, the required CEM would be 67%.

The Commission would need to determine that the CEM will be at least approximately 2.5%, in order to include the full 153 MW of capacity of the Mesaba Facility in excess of the 450 MW contemplated by the IEP Statute in its order with respect to the PPA.³⁶

An initial CEM of approximately 13% would require the addition of Mesaba Two in order to satisfy the CET Statute. This second unit is scheduled to be in service in 2013. NSP's ratepayers would benefit significantly from a decision to ensure the implementation of Mesaba Two by Commission action now. First, Unit Two would share site amenities with Unit One, resulting in cost savings.

³⁶ This calculation assumes a 90% capacity factor for the IGCC facilities, and is based on total expected retail energy sales for NSP-North in 2012, as reported in response to DOC Information Request 61 in NSP's pending IRP docket. Alternatively, the Commission could approve the additional 153 MW of capacity under the PPA under the language requiring the Commission to ensure a supply proposal from an innovative energy project is considered prior to approval of any alternative fossil proposal, such as NSP's pending proposal in its 2004 IRP to add 416 MW of new gas-fired intermediate capacity by 2013, as contemplated by the Section 2(a)(5) of the Innovative Energy Project Statute.

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Second, retaining the turnkey construction consortium onsite to begin construction of the Unit Two facilities would result in significant savings from keeping the skilled workforce and experienced project manager on site. Third, timely approval of Unit Two would allow the sponsors of the Project the ability to secure a loan guarantee for Unit Two under the recently enacted Federal Energy Policy Act. Fourth, and most critical, given the persistence of high natural gas prices, Unit Two will protect Minnesota ratepayers by displacing the merit order dispatch of an additional 4700 GWh of gas-fired generation, and would presumably displace the proposed 416 MW of intermediate capacity by 2013 included in NSP's preferred plan in its pending IRP. This would translate into 32,000,000 MMBtu per year of natural gas consumption that would be averted by the second unit, through 2015.³⁷

This CEM percentage could be automatically adjusted upward at any time in order to retain the mix in the face of any retirement of existing coal and nuclear facilities.

In order to assure the benefits of two IGCC units that come online by 2013, the Commission should set the minimum CET energy percentage at a level sufficient to support the addition of Unit Two.³⁸

In sum, the Commission should take the dramatic changes in market conditions, including the near tripling of natural gas prices since the enactment of the CET Statute, into account in setting the CEM. In order to protect Xcel's ratepayers, the Commission should establish the CEM in a manner that restores balance to NSP's supply portfolio.

C. IT IS NOT CONTRARY TO THE PUBLIC INTEREST FOR THE PROJECT TO SUPPLY THE CEM

Minnesota law directs that the CET energy must be supplied by an innovative energy project ("IEP") unless that supply is contrary to the public interest. Supplying the CEM from the Mesaba Project will be in the public interest, due to the optimal size and configuration of Unit I, and the site synergies of Unit II. Because of these cost advantages, and because the Project is an IEP that meets the public interest requirements of the IEP Statute, this requirement is met.

As for future CET energy to supply additional needs under a higher CEM, other IGCC facilities can be proposed as an alternative to a supply from an IEP.

CONCLUSION

IGCC is a CET. IGCC is or is likely to be a least-cost base load resource. Supply of the CET Energy by the Mesaba Project is not contrary to the public interest. Therefore, NSP must procure at least two percent of its total retail energy needs from a CET. If the CEM is

³⁷ This calculation assumes that all of the displaced natural gas dispatch would be higher efficiency combined cycle units. More likely, the displaced generation would be a mix of combined cycle and peaking units, resulting in even more dramatic cost savings than those represented.

³⁸ The Commission could increase this percentage at any time prior to 2012, the date by which the CET statute must be fully implemented.

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established at approximately 2.5%, then the Unit I PPA will allow NSP to meet this statutory requirement. If the CEM is increased by an additional 10% by 2013, then Unit Two of the Mesaba Project would meet that additional requirement.

In promoting the adoption of IGCC technology with the enactment of the IEP Statute and the CET Statute (the “Statutes”), the Legislature expressly endorsed IGCC technology as the State’s preferred source of base load power generation, subject to the Commission’s confirmation of its benefits and costs. In enacting the Statutes, the Legislature recognized the growing demand for new base load generation resources, and recognized that it was in Minnesota’s interest to add more IGCC to the mix than the 450 MW PPA mandated by the IEP Statute. The CET Statute provides one of the means by which the Commission is to address this need for additional IGCC capacity to optimize the State’s generation mix.