STATE OF MINNESOTA
BEFORE THE PUBLIC UTILITIES COMMISSION

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In the Matter of the Review of the 2011-2012 Annual Automatic Adjustment Reports for All Electric Utilities	DOCKET NO. E999/AA-12-757
In the Matter of the Review of the 2012-2013 Annual Automatic Adjustment Reports for All Electric Utilities	DOCKET NO. E999/AA-13-599

COMMENTS OF THE OFFICE OF THE ATTORNEY GENERAL – RESIDENTIAL UTILITIES AND ANTITRUST DIVISION

The Office of the Attorney General – Residential Utilities and Antitrust Division ("OAG") submits the following comments in response to the Commission's Notice of Additional Comment Period for the above-captioned matters regarding the annual review of electric utility fuel costs and recovery. The OAG addresses the need for a modified fuel clause adjustment ("FCA") mechanism to incentivize active management of fuel costs by utilities, recommends protecting ratepayer interests by deferring action on Northern States Power Company's (doing business as Xcel Energy) ("Xcel Energy") request for recovery of replacement power costs related to the extended plant outage at the Sherburne County Generating Station Unit 3 ("Sherco 3"), [1] and addresses the issue of business interruption insurance for utilities.

[1] Other than the replacement power costs related to Sherco 3, the OAG takes no position on the Department's review and recommendations or the utilities' requests for recovery of energy costs during the review period.

Annual automatic adjustments are permitted under Minnesota Statutes section 216B.16, subdivision 7, which allows for monthly adjustments for utilities to recover their fuel and purchased power costs ("energy costs") incurred to generate electricity.[2] The energy cost adjustment for each billing period is computed in accordance with Minnesota Rules parts 7825.2390 to 7825.2920. Each utility must submit an annual report detailing its energy costs for the period from July 1 to June 30 each year.[3] Each utility must also submit an independent auditor's report evaluating the accounting for automatic adjustments for the reporting period.[4] The Minnesota Department of Commerce ("DOC") thereafter provides its evaluation of energy cost adjustments for each utility, and the Commission considers each utility's report.

The annual evaluation of automatic adjustments has grown to be a significant task for a number of reasons. First, the types of costs that are permitted recovery as energy costs has expanded to include such items as Midwest Independent System Operator ("MISO") costs, asset based and non-asset based margins, purchased wind contract and curtailment costs, and other items for which the Commission has granted specific authority for recovery. Second, the scope and type of generation costs has expanded to include costs related to renewable energy resources such as wind and solar. More recently, new legislation has also expanded utilities' obligations to purchase distributed solar energy from customers or their designated provider of solar power. Third, the annual evaluation processes have been complicated by recent events, including the catastrophic failure of Sherco 3, because of extended plant outages. Unplanned outages typically

[2] *See* Minn. Stat. § 216B.16, subd. 7 (2014) (specifying the types of costs allowed for monthly adjustments). The Commission has the authority to permit the use of automatic adjustments for energy cost; alternatively, the Commission may deny this recovery method.
[3] *See* Minn. Rule 7825.2810.
[4] *See* Minn. Rule 7825.2820.

result in the utility incurring additional costs to generate electricity from more expensive sources of generation.

Stakeholders and the Commission have raised questions about the current automatic energy cost recovery mechanism. The current system requires a lengthy process to explore whether the energy costs were reasonable and necessary, and whether they justify recovery from ratepayers. The current mechanism also fails to adequately incentivize utilities to minimize fuel costs.

I. THE COMMISSION SHOULD CONSIDER IMPLEMENTING A FCA INCENTIVE MECHANISM TO MANAGE FUEL COSTS.

Modifications to the FCA mechanism in Minnesota should attempt to address the need to manage this substantial category of costs. Rather than an automatic recovery mechanism, an incentive mechanism, which has the potential for financial impacts on the utility, will help focus management's attention on the need to manage its costs for the mutual benefit of the utility and ratepayers. Parties have raised concerns with the FCA mechanism dating back more than 10 years.[5] These concerns have been addressed in various dockets, including rate cases and annual evaluation dockets. OAG witness Mr. John Lindell first proposed a FCA incentive mechanism to address these concerns in Xcel's 2009 rate case and again in Xcel's 2011 and 2013 rate cases.[6] Other parties have also identified the need for a FCA incentive mechanism and offered or discussed various incentive proposals.[7] There are various ways to provide some level of financial incentive for electric utilities in Minnesota to manage their energy costs on behalf of their ratepayers, and the Commission should further consider the matter.

[5] Docket No. E999/CI-03-802.
[6] *See* Lindell testimony in Docket Nos. E002/GR-08-1065, E002/GR-10-971 and E002/GR-12-961.
[7] *See*, *e.g.* DOC's June 5, 2013 Comments in Docket No. E999/AA-12-757.

The OAG's previous proposals for a FCA incentive mechanism were structured to incentivize utilities to manage their costs for energy. Currently, under a direct cost recovery model, there are no financial incentives to control energy costs because the costs are automatically recovered from ratepayers each month. While utilities may argue that they have incentive to control their energy costs based on potential disallowance (whether recommended by DOC or other parties), the bottom line is that the utilities have not been denied recovery for these costs. A FCA incentive mechanism should be structured to accomplish the goal of providing a financial incentive for the utilities to *manage* their energy costs.[8] The incentive mechanism should be easy to administer and should comply with Minnesota law.

Mr. Lindell's proposal in Xcel's last rate case was to establish a 3% cap above the base cost of energy, as established in the rate case.[9] If the utility's cost per megawatt hour for the year exceeded the 3% cap, it would not be able to recover the amount above the cap. Under this proposal, utilities would have incentive to manage their costs throughout the year because any excess costs above the cap in the beginning of the year could potentially be offset by keeping costs below the cap during the remainder of the year. Similarly, if a utility were to manage its costs and keep the cost per megawatt hour below the cap at the beginning of the year, it would still have incentive to manage its costs during the remainder of the year to limit its exposure to unforeseen high costs later in the year. The OAG also offered an alternative to this proposal in response to any concern that the utility was exposed to excessive cost disallowance.[10] The

[8] The proposal recognized that the goal of such a mechanism should not simply be to *minimize* energy costs because such an approach could cause unintended consequences where a utility's other costs of providing service increase as a result of focusing solely on minimizing energy costs. The mechanism should not create a high probability of cost disallowance. The goal is to provide a utility with the incentive to manage its energy costs in conjunction with other costs to provide service, not to disallow legitimate and well-managed energy costs.
[9] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service Minnesota,* Docket No. E002/GR-12-961, Lindell Direct at 12-18 (February 28, 2013).
[10] *Id.*

alternative proposal would establish a 2% cap with a limit on total disallowance equal to the amount of Conservation Improvement Program ("CIP") bonus[11] that the utility earned during the year.

The proposal previously offered by the OAG would be authorized by existing Minnesota law. Because the FCA is a discretionary tool that allows the automatic pass through of energy costs, establishing a cap in conjunction with the FCA would be similar to not allowing any automatic pass-through of energy costs. Absent the FCA, a fixed level of energy costs would be used for recovery and operate as both a cap and a floor for cost recovery. Therefore, the proposal would not violate existing statutes or rules governing energy cost recovery. The Commission will need to proceed with caution if any proposed incentive mechanism contains both a cap and a floor that would allow a utility to profit by reducing costs below the base cost of energy. Minnesota law provides only limited opportunities for utilities to earn above their authorized rate of return.[12] In addition to carefully considering the policy of any such mechanism, the Commission would also need to ensure that Minnesota law allows a utility to profit from reducing its energy costs.

Other states use different fuel cost incentive mechanisms. In Wisconsin, for example, adjustments for the actual cost of energy are prohibited in a range around the base cost of fuel as established in a Commission proceeding.[13] Wisconsin's band is 2% above and below the base cost of fuel, which is established annually. If actual costs for fuel exceed the base cost plus 2%, the utility is permitted to defer those costs for future recovery (subject to objections from other parties who may oppose cost recovery in excess of the 2% band). Similarly, if actual costs for

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[11] CIP bonuses are authorized by statute and allow the utility to earn above its authorized rate of return as an incentive to implement effective conservation programs.
[12] The CIP bonus, for example, is authorized by statute. *See* Minn. Stat. §216B.16, Subd. 6c (2014).
[13] *See* Wisconsin Public Service Administrative Code Ch. 116.

fuel are more than 2% below the base cost, the utility defers the difference for a future adjustment, resulting in a rebate to ratepayers. This band mechanism provides incentive to manage the cost of fuel and also limits the exposure for the utility and its ratepayers from excessive fluctuations in the cost of fuel. Any time the actual costs for fuel exceed or fall below the base cost of fuel plus the allowable variation, a Commission proceeding is necessary to establish the amount to rebate or surcharge ratepayers.

Washington uses a FCA mechanism that is specific to each utility. Washington utility Avista, for example, uses a FCA mechanism with a so-called "dead band," with no sharing within the dead band. There is sharing of the costs or savings when energy costs fall outside of an allowable range.[14] This FCA mechanism, also known as an Energy Recovery Mechanism, is intended to stabilize earnings and cash flow for the utility, offers the potential for rebates to customers, and also reduces financing costs for customers. The mechanism establishes a dead band where no adjustments for cost recovery are made. Based on the OAG's calculations, the dead band appears to be in the range of 2% to 3%, which is $6 million above or below the base cost of energy for Avista. When costs or savings exceed the dead band range, the utility and ratepayers share the additional costs or savings, which are deferred and applied to rates only when the total deferral reaches a trigger amount. The shared cost or savings occur in different ratios depending on the magnitude of the variance. For 2012 the Washington Utilities and Transportation Commission approved the sharing of the 2012 savings of $14.7 million with Avista retaining the first $6 million plus 25% of the next $4 million or $1.5 million plus 10% of

[14] *See* In the Matter of Avista Energy Recovery Mechanism Annual Filing to Review Deferrals for Calendar Year 2012, ORDER AUTHORIZING ENERGY RECOVERY MECHANISM DEFERRALS FOR CALENDAR YEAR 2012, Docket UE-130438, Order 01 (July 11, 2013).

the savings above $10 million or approximately $470,000.[15] Avista retained approximately $8 million of the total $14.7 million of savings and ratepayers received credit for $6.7 million.

Utilities criticize incentive mechanisms for a number of reasons; primarily, utilities have argued that they have little control over the costs paid for fuel.[16] That should not stop the Commission from protecting ratepayer interests. Energy costs can be managed and minimized, and they are subject to some degree of control. The utility must be given some incentive to act prudently in incurring these costs, however. The Commission should consider implementing a FCA mechanism that provides sufficient incentive to Minnesota utilities to control these costs to the maximum extent possible.

II. THE COMMSSION SHOULD CONTINUE TO DEFER ACTION ON OR APPROVAL OF XCEL ENERGY'S REPLACEMENT POWER COSTS RELATED TO THE FAILURE OF SHERCO 3.

The OAG has previously made specific recommendations[17] as to why the Commission should continue to defer action on or approval of Xcel Energy's replacement power costs incurred after the catastrophic failure at Sherco 3. As explained in the OAG's Comments, Xcel Energy has taken the position in filings in Minnesota state court that third-parties are liable for the replacement power costs, which could make it appropriate in the future for the Commission to order modification of Xcel's automatic adjustment charges to balance and protect ratepayer interests.[18] The OAG does not agree with the DOC's conclusions regarding causation and foreseeability of the failure, which are based on premature analysis of inadequate information. In addition, the method of calculation and total amount of Xcel Energy's replacement power

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[15] *Id.*
[16] *See, e.g.* Rebuttal Testimony of Xcel witness Allan Krug, Docket No. E002/GR-12-961 at 22.
[17] *See* September 26, 2014 Comments in Docket No. E999/AA-13-599. These Comments are incorporated herein by reference.
[18] *See* Minn. R. 7825.2920 (2013).

costs are disputed. For these reasons, approval of the costs should continue to be deferred and the Commission should clarify that it may act in the future to remedy any inequities for ratepayers.

The Commission has requested that other parties provide comments regarding the OAG's proposal to defer consideration of this issue;[19] the OAG anticipates providing responsive comments to such analysis by other parties.

III. THE COMMISSION SHOULD CONSIDER REQUIRING UTILITIES TO OBTAIN BUSINESS INTERRUPTION INSURANCE POLICIES TO LIMIT THE RISK THAT RATEPAYERS WILL HAVE TO PAY SUBSTANTIALLY INCREASED COSTS FOR REPLACEMENT POWER.

It is important to ensure that ratepayers are receiving utility service at a reasonable rate. As Xcel Energy's experience with the long-term loss of Sherco 3 has shown, interruption in normal utility production can have significant financial consequences on fuel costs and charges for replacement power. Business interruption insurance ("BII") may have the potential to insulate ratepayers and utilities from excessive risk related to plant outages. In the context of automatic recovery of fuel costs, all Minnesota utilities essentially have a form of BII under the current system: either an insurance company has issued a policy for such insurance, or the ratepayers provide full coverage, with no deductible (and without even collecting a premium). The Commission should examine the equity of putting the ratepayers in the position of providing this coverage free of charge, and alternatives for shifting that risk off of ratepayers.

BII insures against lost cash flows for outages caused by severe weather, terrorism, fire, explosions, and other events that cause an outage to occur at a utility's generation facility. The DOC requested information from each utility regarding its efforts to obtain and use BII, and a

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[19] *See* In the Matter of the Review of the 2012-2013 Annual Automatic Adjustment Reports for All Electric Utilities, NOTICE OF ADDITIONAL COMMENT PERIOD, (November 19, 2014).

full explanation as to why the utility has not obtained BII.[20] Each utility filed comments that briefly explained each company's experience with BII. The utilities' responses to these questions were not satisfactory, especially in explaining why they have generally not obtained BII. This subject is not simple and answering these questions demands a certain amount of specificity and analysis; most utilities did not provide sufficient information to fully analyze this issue.

In general, most utilities stated that they found that BII was too expensive.[21] On the other hand, Xcel Energy has BII for its nuclear operations[22] and Minnesota Power has BII for its Bison Wind assets.[23] The fact that some utilities have found BII affordable and appropriate for some types of generation assets, while other utilities have found it unaffordable for other assets, demonstrates that simply stating that coverage is "too expensive" is not a sufficient answer to the question. Assuming Xcel Energy and Minnesota Power acted prudently in obtaining their coverage, this information demonstrates that for certain types of generation (*e.g.*, base load and low fuel cost generators), and under certain circumstances, BII is appropriate and affordable.

Utilities that found BII (other than pass-through of fuel costs to ratepayers) to be too expensive must provide sufficient explanation as to how they reached that conclusion. One company stated that an interruption of 60 days had never occurred previously in its system, so it did not find it financially feasible to purchase BII.[24] However, this is not an appropriate application of probability theory – the probability of an event occurring at a given generation

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[20] Department of Commerce Report at 15 (September 16, 2014).

[21] Of the four utilities that responded to the Department's request to provide information on their efforts to obtain business interruption insurance, none concluded that it was viable as a generalized solution. Xcel and Minnesota Power have BII for their nuclear and select wind assets, respectively. IPL and Otter Tail Power claimed that they do not have any form of BII and have concluded that it was not in their respective interest to acquire it.

[22] Xcel Energy Reply Comments at 9 (November 10, 2014).

[23] Minnesota Power Reply Comments at 3 (November 10, 2014).

[24] Otter Tail Power Reply Comments at 4 (November 10, 2014).

facility is not zero or reduced because such an event has not occurred in the past. By claiming that BII is too expensive, utilities are implicitly claiming that they have estimated the probability of the event occurring and the costs associated with each event. No such analysis was provided, and such an answer is far too simplistic for this complicated issue. Additionally, taking the utilities' claims at face value, if insurance companies have provided quotes for coverage that multiple utilities have deemed too expensive to accept, it could be that there is some type of risk that the insurance companies do not want to underwrite. The Commission should examine this risk and all options available to mitigate it because, under the current system, the ratepayers will bear that risk in the absence of any other arrangement.[25]

Deregulated electric generators have more of an incentive to purchase BII because they are not able to shift risk onto ratepayers through the regulatory structure. BII is common in the burgeoning solar generation market even though insurance premiums can make up to 25% of a solar system's annual operating expense.[26] For this reason, the OAG would like a much more rigorous explanation as to why utilities are not purchasing BII, especially on those facilities that would logically benefit most from it.

The OAG has requested additional analysis from each of the electric utilities[27] in order to explore this issue further. The OAG recommends that in reply comments each utility should submit a more detailed response to the initial questions posed by the DOC, and which responds to the following:

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[25] There may be disincentives influencing the utilities' willingness to purchase BII. First, the utilities likely consider themselves to have been adequately protected by using ratepayers as their insurance against unanticipated costs of this type. Second, utilities and their shareholders would bear the risk that an insurance company might not pay their claims if they were found to be negligent or otherwise culpable.

[26] National Renewable Energy Laboratory, *Insuring Solar Photovoltaics: Challenges and Possible Solutions*, at iv (Feb. 2010).

[27] Excluding Dakota Electric Association.

1. Given that Xcel Energy and Minnesota Power obtained BII for some generation facilities, there must exist some cost threshold or breakeven point for BII that depends on variables. More simply said, there is a price at which BII becomes affordable given the characteristics of a generation facility. Each utility should discuss this threshold and the variables considered to influence this threshold. The response should include quantification of the threshold and variables whenever possible.

    a. This response should include discussion of quotes from insurance companies, and an estimate of an "affordable" BII premium for a generation facility that uses cost-benefit principles, among other things.

    b. This response should include discussion of all underwriting criteria that are used by the insurance brokers that were contacted by each utility.

    c. This response should include an explanation as to why additional brokers were not contacted if the primary insurance broker for the utility did not offer BII, or it was deemed too expensive.

2. If a utility finds that BII is still too expensive once a more comprehensive analysis has been completed, it should discuss the characteristics that are causing the premiums and deductibles to be too high and how it plans to better insulate ratepayers from these risks without BII.[28]

3. The utilities should discuss the possibility of using other risk management instruments to control for price increases in the event of an outage. For example, what are the opportunities for the utilities to use call-put option collars, forward contracts, or other techniques and instruments to control for replacement power costs?

[28] Some risk will remain due to the expense of decreasing risk. The objective is to ensure that utilities are not shifting risk that would be cost effective to avoid and that the utility is identifying all relevant information.

IV. RECOMMENDATIONS

The OAG makes the following recommendations.

- establish an incentive mechanism for the recovery of fuel and purchased power costs:
- defer any decision on the recovery of Sherco 3 energy replacement costs until there is a sufficient record to determine if recovery is appropriate; and
- utilities should provide additional information and analysis as discussed above for the use of business interruption insurance.

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Respectfully submitted,

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