STATE OF MINNESOTA
BEFORE THE
PUBLIC UTILITIES COMMISSION

Beverly J. Heydinger	Chair
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
John Tuma	Commissioner
Betsy L. Wergin	Commissioner

In the Matter of the Petition of Northern States Power Company for Approval of Cost Recovery of the Aurora PPA Pursuant to Minn. Stat. § 216B.1645

Docket No. E002/M-15-330

REPLY COMMENTS

I. INTRODUCTION

Aurora Distributed Solar, LLC ("Aurora") respectfully submits these reply comments in response to the Minnesota Department of Commerce, Division of Energy Resources Department Comments and Addendum filed on December 4, 2015 and December 8, 2015, respectively, recommending the Commission reject the Petition of Northern States Power Company d/b/a Xcel Energy ("Xcel's Petition") for recovery of the North Dakota portion of the costs of the Aurora power purchase agreement (the "Aurora PPA").

The Department's Comments proffer three reasons to reject Xcel's Petition: (1) the Aurora PPA was not studied to determine if it was a cost effective resource for meeting the energy and capacity needs of only Minnesota ratepayers; (2) the Letter Agreement between Xcel and Aurora provides a market solution to address the effects of North Dakota's decision to deny cost recovery; and (3) the Aurora PPA provides "only a minimal incremental impact" for meeting Xcel's Solar Energy Standard and Renewable Energy Standard requirements. These arguments ignore important legal, factual and policy issues that support approval of Xcel's Petition.

II. RESPONSE

A. The Department Cites No Authority Prohibiting Commission Approval of Xcel's Petition.

As an initial matter, the Department did not argue or provide any legal analysis suggesting that the Commission lacks the legal authority to approve Xcel's Petition. As Aurora discussed in its Initial Comments, while traditionally multi-state jurisdictional allocations have been utilized, Minn. Stat. § 216B.1645, subd. 2, does not require it. Just as the Commission did in the case of the legislatively-mandated Renewable Development Fund ("RDF") allocation, the Commission has discretion, where appropriate, to allocate costs to Minnesota ratepayers that would have otherwise been borne by North Dakota ratepayers, particularly when, as here, the measure fulfills Minnesota statutory and policy objectives and there is unique benefit to Minnesota ratepayers in doing so.[1] The Department does not argue that the Commission lacks such authority or that the statute prohibits such approval.

B. The Commission's Approval of the Aurora PPA Relied on Factors Beyond the Department's Cost Benefit Analysis.

The Department argues that the administrative record does not contain an analysis of the cost effectiveness of the Aurora PPA for only Minnesota ratepayers. While that is true, the Commission's selection of resources, including the Aurora PPA, from the competitive acquisition process, did not rely on any one cost analysis. Rather, the Commission's resource selection was based on the record as a whole, including a number of factual, legal and policy considerations.

[1] Order After Reconsideration Modifying March 17, 2011 Order and Reallocating Expenses, *In the Matter of a Petition by Northern States Power d/b/a Xcel Energy for Approval of a 2011 Renewable Development Fund Rate Rider Factor*, Docket No. E-002/M-10-1054 (June 6, 2011) (the "RDF Rate Rider").

Moreover, the administrative record does not contain a cost benefit analysis evaluating *any* of the bidding proposals for only Minnesota. As the Department points out in Attachment 1 to its Comments, the North Dakota Public Service Commission ("NDPSC") staff and counsel have also recommended denial of Xcel's request for Advanced Determination of Prudence ("ADP") for the 345 MW power purchase agreement with Mankato Energy Center, LLC (the "Calpine PPA"). If the Department's argument regarding the cost effectiveness comparison prevailed, the entirety of the competitive bidding process could be undone by another state commission's decision to deny cost recovery. The Commission found that the selected resources were needed to ensure the reliability of Xcel's system. In a case such as this, where the Minnesota portion of Xcel's system load is approximately 75% of the total, allowing another state to essentially veto the Commission's action would put Minnesota ratepayers at great risk.

The Commission did not rely solely on the Department's analysis in selecting the Aurora PPA, and the scope of the Department's prior analysis should not be relied upon as justification for denying Xcel's Petition.

C. The Letter Agreement Provides Insufficient Cause to Deny the Petition.

The Department also argues that the Commission should deny Xcel's Petition because there is a "market solution" to address this issue in the form of the Letter Agreement between Xcel and Aurora. This argument overlooks the fact that the Letter Agreement is triggered only in the event that the Commission denies Xcel's Petition. Furthermore, the parties would not have needed to enter into the Letter Agreement if the Commission had acted on Aurora's earlier cost recovery request.[2] As Aurora discussed in its Intitial Comments, the Letter Agreement

[2] Geronimo Energy's Comments and Request for Approval of and Cost Recovery for the Aurora PPA, *In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for Approval of Competitive Resource*

served as the only available option Aurora had to ensure it could continue to meet its obligations under the Aurora PPA while waiting for this issue to come before the Commission again.

It could also be argued that there would also be a "market solution" if Xcel had simply waived the condition precedent in Section 6.1 of the Aurora PPA and not terminated the Aurora PPA despite the denial by the NDPSC. Calpine and Xcel still face that issue, since the conditions precedent have been extended in the Calpine PPA pending further regulatory processes. Similarly, the Solar RFP PPAs approved by the Commission[3] were also denied ADPs by the NDPSC[4] and, to Aurora's knowledge, those PPAs have not been terminated.

NDPSC staff recently filed testimony related to these cost recovery issues in the context of Xcel's North Dakota Negotiated Settlement Agreement.[5] In relevant part, NDPSC Staff stated:

> **Q: Why do you need more time to develop the RTF for allocating future generation resources to North Dakota?**
>
> A: The additional time is more for NSP than for staff. NSP sees the task of allocating resources in a non-traditional way to ND as daunting and nearly impossible to achieve. NSP's inability to develop a solution to date likely has more to do with its inability to accept a less integrated approach going forward. It takes time for a large utility to change direction but I recommend that the commission stand firm and require a less integrated approach going forward nonetheless. The state of Minnesota is not going back to least-cost planning for its generation resource additions anytime soon and North Dakota should not

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Acquisition Proposal, Docket No. E-002/CN-12-1240, and *In the Matter of a Draft Power Purchase Agreement with Geronimo Wind Energy, LLC d/b/a Geronimo Energy*, Docket No. E-002/M-14-788 (October 23, 2014).

[3] Order Approving Solar Portfolio, *In the Matter of Xcel Energy's Petition for Approval of a Solar Portfolio to Meet Initial Solar Energy Standard*, Docket No. E002/M-14-162 (March 24, 2015)

[4] Findings of Fact, Conclusions of Law and Order, *In the Matter of Northern States Power Company's Request for Advance Prudence for a 187 MW Solar Energy Portfolio Application*, Case No. PU-14-810 (June 17, 2015).

[5] Direct Testimony of Mike Diller, *In the Matter of Northern States Power Company's Application for Approval of a Negotiated Agreement Relating to North Dakota's Generation Resource Policy*, Case No. PU-12-813 et al (December 1, 2015). *See* **Attachment A**.

> acquiesce to building generation that is neither needed nor least-cost oriented. That said, the Negotiated Agreement gives NSP more time to plan for what in essence is already happening through the disallowance of existing CBED and the small solar units per the Negotiated Agreement; the already disallowed 100 MW Aurora Solar and 187 MW Solar Energy Portfolio projects; and hopefully the Calpine Energy Center purchase power agreement not yet decided by the commission. North Dakota's generation portfolio is indeed diverging from NSP's traditional allocation of integrated system costs.
>
> I think part of the transitional difficulties to a North Dakota specific energy plan is that the relatively simple approach of allocating a greater share of agreeable plants (energy and capacity) to ND and none of the objectionable resources likely increases the cost to Minnesota and lowers the cost to North Dakota.[6]

Thus, this issue is likely to come back to the Commission in a variety of forms, without a separate written agreement from the developer, and the Commission will need to undertake similar factual, legal and policy analyses to determine what happens when a resource approved in Minnesota is denied recovery by another state commission.

D. The Aurora PPA will Contribute to Xcel's Compliance with the SES.

The Department also argues that denying Xcel's Petition would have "little to no impact" on Xcel's compliance with the SES. Under this logic, any single project could be dropped after approval. It is important to note here that the 100 MW Aurora PPA is expected to be one of the largest solar projects in Minnesota when it goes into service at the end of 2016, and the approximately 200,000 MWh/year of solar energy it will provide is a substantial step toward implementing and complying with the SES. The record is clear that Xcel intends to use the solar energy from the Aurora PPA to comply with its SES requirements. Moreover, the record is clear that the Commission found that the 71 MWs of accredited capacity from the Aurora PPA are needed to ensure Xcel has access to reliable, clean and cost effective resources to meet its needs in the coming years.

[6] *Id*. at 3:18 - 4:13.

E. Policy Considerations Heavily Favor Approving Xcel's Petition.

As discussed in Aurora's Initial Comments, it is also worth underscoring again the precedent that would be created if the Commission denies Xcel's Petition. The competitive resource acquisition process already presents a high hurdle for participation by requiring bidders to undertake the remarkable and difficult steps of participating in a lengthy, expensive regulatory process, sharing sensitive business information with its competitors, and risking protracted contractual negotiations with a utility that is also competing against the developer. If the Commission were to create additional risk that portions of the reasonable and prudent expenses approved through this process may be denied rate recovery and be borne by either the utility or the developer, again the Commission would be creating an untenable risk that could eliminate robust developer participation in future proceedings and or ultimately result in developers having to increase their offered pricing in order to recognize this risk. The Commission should, consistent with its expectation that all parties be held accountable to the bid terms, take steps here to ensure that new, unanticipated regulatory costs arising through no fault of the parties are not shifted to the utility or developer.

III. CONCLUSION

Aurora respectfully requests that the Commission approve Xcel's request for approval of the North Dakota portion of the costs of the Aurora PPA in recognition of the benefits of the Project to Minnesota ratepayers and the unique procedural history of this case.

Dated: January 8, 2016

Respectfully submitted,

/s/ Christina K. Brusven

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December 1, 2015

Darrell Nitschke, Executive Secretary
North Dakota Public Service Commission
600 E Blvd Ave
Bismarck, ND 58505

Re: **Case No. PU-12-813**
Case No. PU-13-194
Case No. PU-13-195
Case No. PU-13-706
Case No. PU-13-707
Case No. PU-13-708
Case No. PU-13-742
Case No. PU-13-743
Case No. PU-15-096

Northern States Power Company
Staff Testimony Supporting Negotiated Agreement

Dear Mr. Nitschke:

Enclosed for filing is an original copy of Advocacy Staff's direct testimony supporting the Negotiated Agreement in the above captioned proceedings filed on September 30, 2015.

I look forward to testifying at the Hearing scheduled for December 15, 2015.

Sincerely,

Mike Diller
Director of Economic Regulation

Enclosure

C: Dave Sederquist, Zeviel Simpser, Alison Archer

111 PU-13-708 Filed 12/01/2015 Pages: 11
Pre-filed direct testimony of Mike Diller

112 PU-13-707 Filed 12/01/2015 Pages: 11
Pre-filed direct testimony of Mike Diller

112 PU-13-706 Filed 12/01/2015 Pages: 11
Pre-filed direct testimony of Mike Diller

90 PU-15-96 Filed 12/01/2015 Pages: 11
Pre-filed direct testimony of Mike Diller

130 PU-13-195 Filed 12/01/2015 Pages: 11
Pre-filed direct testimony of Mike Diller

123 PU-13-743 Filed 12/01/2015 Pages: 11
Pre-filed direct testimony of Mike Diller

113 PU-13-194 Filed 12/01/2015 Pages: 11
Pre-filed direct testimony of Mike Diller

115 PU-13-742 Filed 12/01/2015 Pages: 11
Pre-filed direct testimony of Mike Diller

251 PU-12-813 Filed 12/01/2015 Pages: 11
Pre-filed direct testimony of Mike Diller

BEFORE THE

NORTH DAKOTA PUBLIC SERVICE COMMISSION

In the Matter of Northern States Power Company's

Application for Approval of a Negotiated Agreement

Relating to North Dakota's Generation Resource Policy

Case No. PU-12-813
Case No. PU-13-194
Case No. PU-13-195
Case No. PU-13-706
Case No. PU-13-707
Case No. PU-13-708
Case No. PU-13-742
Case No. PU-13-743
Case No. PU-15-096

DIRECT TESTIMONY

OF

MIKE DILLER

ON BEHALF OF THE

NORTH DAKOTA PUBLIC SERVICE COMMISSION

ADVOCACY STAFF

December 1, 2015

Q: **Provide your name and qualifications.**

A: My name is Mike Diller. I am the Director of Economic Regulation for the North Dakota Public Service Commission (commission). I am a utility analyst and provide direction to a small staff. I have more than 30 years of utility regulatory experience including service to the Oklahoma Corporation Commission.

I received a Bachelor of Science Degree in Accounting from Oklahoma Christian College in Edmond, Oklahoma in 1981. I am a Certified Public Accountant and member of the American Institute of Certified Public Accountants. I have testified before the commission on numerous occasions including acquisition and merger proposals, rate cases, settlements, advance determination of prudence requests and rule changes.

The commission appointed me to advocacy staff (staff) in NSP's last rate increase application (PU-12-813) and other consolidated cases that resulted in a multi-year rate plan settlement approved by the commission. The Comprehensive Settlement Agreement adopted by the commission on February 26, 2014 also required, among other things, continued good faith negotiations to develop long-term solutions to energy policy differences that exist between Minnesota and North Dakota. I have been the principal negotiator for staff and have testified previously in these proceedings.

Q: Provide a summary of the 2014 Comprehensive Settlement Agreement (CSA) as it pertains to generation resources.

A: The CSA was negotiated to implement a framework to reflect North Dakota's energy policy priorities as expressed by the commission. The commission has been resolute in its support for least cost planning and so any framework for handling future additions to the generation resource mix must incorporate that concept. A hard deadline of June 30, 2015 was established for the development of the Resource Treatment Framework (RTF) with a significant penalty for failure to establish such a plan. The RTF was to address the long-term interest of the commission in exerting more control over the energy resource mix serving North Dakota.

The CSA developed a framework for developing the RTF so that existing resources deemed inconsistent with North Dakota energy policies would be repriced based on "like" replacements using real or proxy pricing and that any future resources would be priced to reflect marginal pricing for a similar type of resource. In the end, the goal was to have a generation resource mix that would be a reasonable approximation of what would have occurred had NSP historically developed its overall resource mix consistent with North Dakota policy.

The CSA also required that staff consider the financial impact to NSP of the RTF including reasonable and mutually agreeable implementation schedules and deadlines.

The CSA acknowledged that having generation located closer to NSP's load centers in North Dakota provides benefits to both North Dakota customers as well as NSP's other customers served by the Company.

The CSA included a commitment by NSP to build "up to 400 MW" of thermal generation in North Dakota no later than 2036, consistent with the principles of orderly development and least-cost planning so that any new generation would be both cost effective and needed.

Q: **What is the purpose of your testimony in this proceeding?**
A: To support the September 30, 2015 Negotiated Agreement between NSP and staff.

Q: Provide a brief summary of this new Negotiated Agreement.
A: The Negotiated Agreement provides 6 major agreements:

1. Provides additional time to develop a long-term RTF for handling energy resource policy differences that will continue to occur between Minnesota and North Dakota.
2. Changes the overall thermal generation commitment in North Dakota from "up to 400 MW" to "at least 200 MW" and moves the completion time frame from 2036 to no later than December 31, 2025, including a sizable penalty for non-compliance.
3. Provides a rate freeze for one additional year through the end of 2017.
4. Allows cost recovery for the biomass purchase power agreements and the Pleasant Valley and Odell wind projects.
5. Removes from cost recovery all existing high cost Community Based Energy Development (CBED) and small solar projects on January 1, 2016 or the date the Negotiated Agreement is adopted by the commission, whichever is later.
6. Supports the use of the 12 coincident peak (12 CP) jurisdictional allocation method for purposes of assigning generation and transmission costs through December 31, 2025.

Q: Why do you need more time to develop the RTF for allocating future generation resources to North Dakota?

A: The additional time is more for NSP than for staff. NSP sees the task of allocating resources in a non-traditional way to ND as daunting and nearly impossible to achieve. NSP's inability to develop a solution to date likely has more to do with its inability to accept a less integrated approach going forward. It takes time for a large utility to change direction but I recommend that the commission stand firm and require a less integrated approach going forward nonetheless. The state of Minnesota is not going back to least-cost planning for its generation resource additions anytime soon and North Dakota should not acquiesce to building generation that is neither needed nor least-cost oriented. That said, the Negotiated Agreement gives NSP more time to plan for what in essence is already happening through the disallowance of existing CBED and the small solar units per the Negotiated Agreement; the already disallowed 100 MW Aurora Solar and 187 MW Solar Energy Portfolio projects; and hopefully the Calpine Energy Center purchase power agreement not yet decided by the commission. North Dakota's generation portfolio is indeed diverging from NSP's traditional allocation of integrated system costs.

I think part of the transitional difficulties to a North Dakota specific energy plan is that the relatively simple approach of allocating a greater share of agreeable plants (energy and capacity) to ND and none of the objectionable resources likely increases the cost to Minnesota and lowers the cost to North Dakota.

Q: Why would it be fair to allocate more of the legacy plants that are largely depreciated and cheaper to North Dakota while allocating all of the Minnesota green initiative resources to Minnesota?

A: If Minnesota desires green electrons for its ratepayers without any apparent regard for cost, then Minnesota ratepayers should pay for it. Whatever capacity is assigned to the objectionable units and whatever energy is generated from these units should come off the top of Minnesota's capacity and energy requirements before allocating the rest of the system capacity and energy costs to its other jurisdictions. Doing so assures MN of receiving the green electrons and capturing the Renewable Energy Credits for its ratepayers. It avoids assigning objectionable costs to North Dakota. It avoids creating the potential for stranded costs or the potential for recovering more or less than 100% of the costs through proxy pricing. Of course this straight-up simple approach doesn't work if Minnesota will not pay for the cost of its own green initiatives; but that is not a burden placed on NSP by North Dakota and we should not feel the urge to bear it.

Q: Why did staff agree to the term of adding "at least 200 MW's" of thermal generation to the Eastern side of North Dakota?

A: After giving consideration to the size of NSP's load requirements in North Dakota, staff reasoned that NSP's future ownership of 350 MW's of wind generation plus at least 200 MW's of thermal generation in North Dakota was a reasonable start towards providing local generation. For perspective, North Dakota makes up about 5% of NSP's regional capacity requirements and 200 MW's of thermal generation represents about 2% of NSP's system wide capacity needs. When combining the wind and thermal generation, these local generation facilities will provide the capability of producing the energy needed for NSP's North Dakota operations. Overall, the Negotiated Agreement will continue to promote local grid stability and reliability and provide a platform for future generation development in North Dakota.

Q: What is the value of one additional year of rate moratorium?

A: It is difficult to estimate given the multitude of variables to consider between now and 2018. I think a $10 million value is not unrealistic given NSP's recent multi-year rate increases. If nothing else, it gives ratepayers assurance, outside of some unforeseen or extraordinary event, that NSP's base rates will remain stable through 2017.

Q: Why did you agree to cost recovery for the biomass generation facilities and two large wind farms located in MN?

A: The CSA adopted by the commission in 2014 excluded these costs from rate recovery beginning January 1, 2016 absent an RTF agreement between NSP and staff for dealing with cost recovery of future generation resources. The recent Negotiated Agreement removes that obligation of mutual agreement between NSP and staff and places that burden of framework development more squarely on NSP. Still, staff will remain an active partner and provide guidance until the framework is established and approved. More than that, we will adamantly oppose any framework developed by NSP that is not fair and reasonable to its North Dakota ratepayers.

As NSP points out in its testimony, the biomass facilities have come about through negotiations with its Minnesota stakeholders in order to ensure continued operation of its low cost nuclear generation facilities. I think it would have been interesting to see the outcome had NSP decided to not be taken hostage by the environmental community and simply moved forward to close its low cost carbon free nuclear plants. Nevertheless, North Dakota ratepayers have been paying for biomass electricity for many years and have enjoyed its share of NSP's low cost nuclear power.

Staff's decision to allow biomass cost recovery was a hard decision but a choice that we had to make. The nuclear plants are located in MN and so MN requirements to keep them open and operating are unavoidable. It is this kind of history that the commission should consider before granting ADP to generation facilities located in other states. The commission has little control and influence over generation facilities located in another state.

Given the history behind the biomass facilities and the lack of NSP's success in convincing Minnesota regulators to pay for North Dakota's portion of the biomass facilities, staff does not believe NSP has a reasonable opportunity to recover these costs other than through North Dakota rate recovery. Staff agreed in the CSA to consider the financial impact to the Company in its future negotiations with NSP and therefore agreed to cost recovery for North Dakota's share of the biomass generation facilities.

The inclusion of the Pleasant Valley and Odell wind farms are a benefit to North Dakota ratepayers in terms of energy cost and environmental offsets for dealing with the Clean Power Plan. They were originally excluded from cost recovery, barring a framework agreement, in order to help NSP meet its renewable mandates in Minnesota and to offset some of the cost disallowances for the biomass facilities. Therefore, the inclusion of the biomass facilities for cost recovery in North Dakota as part of the Negotiated Agreement requires adding back the low-cost wind farms.

Q: If the non-recoverable biomass facilities in Minnesota argue for cost recovery in North Dakota, why did staff push for non-recovery of costs associated with NSP's CBED projects?

A: CBED projects are Minnesota programs for Minnesotans and were not required for the continued operation of economic and functional baseload generation facilities.

Q: Why did staff agree to use 12 CP through December 31, 2025 for allocating generation and transmission resources?

A: Staff worked with the company and independent consultant to evaluate the various methods used for allocating jurisdictional resources. The result of that effort was filed by NSP on April 27, 2015, Docket #228, Case No. PU-12-813. Of the 12 jurisdictional allocation methods evaluated, staff was partial to the Equivalent Peaker method using a single peak demand rather than the 12 CP Method currently used by all of NSP's regulatory jurisdictions.

As it turns out, staff's preference was quite comparable to the 12 CP in terms of stability and predictability. In terms of allocated cost to North Dakota, the Equivalent Peaker method allocated less cost to North Dakota in the earlier study years (2004-2013) but more cost to North Dakota two out of the last three years covered in the evaluation period. During the 10 year study period, the 12 CP allocated cost to North Dakota ranged from 5.63% to 6.11% whereas the Equivalent Peaker method ranged from 5.38% to 6.02%.

Because of the wide use of 12 CP among all of NSP's jurisdictions, changing the method of allocation for North Dakota should only be done when there is significant reason to do so. Given the results of the study, staff agreed to provide NSP with some long-term assurance that it would not advocate changing the method until after 2025 at the earliest. The 12 CP Method has been used for many years and a 10 year commitment to provide regulatory certainty is reasonable given the results of the study.

Q: Please summarize why you support the Negotiated Agreement?

A: The Negotiated Agreement is fair and reasonable for both NSP and its North Dakota customers. Following are the primary reasons for supporting the Negotiated Agreement.

- Provides additional time for NSP to develop an RTF responsive to North Dakota's energy policies.
- Continues North Dakota's practice of least cost planning.
- Secures one additional year of rate moratorium through 2017.
- Provides clarity and certainty as to how generation and transmission assets are to be allocated among NSP's various jurisdictions.
- Adds additional low cost wind resources useful in the implementation of the Clean Power Plan.
- Brings thermal generation to the Eastern part of North Dakota within the next 10 years.
- Adds security and stability to the local grid serving North Dakota's largest population segment.
- Allows ample time for planning the new thermal generation to coincide with NSP's need for additional capacity.
- Provides a greater impetus for natural gas development in the Eastern part of North Dakota.
- Provides a stronger opportunity for additional energy development in the future.

Q: What happens if the commission rejects the Negotiated Agreement?

A: If the commission were to reject the Negotiated Agreement without providing additional guidance, NSP could argue that it met its obligation to file a Negotiated Agreement. Therefore, the remedial action to disallow certain renewable energy costs on January 1, 2016 required in the original Comprehensive Settlement Agreement would no longer be required. This would result in North Dakota ratepayers continuing to pay for the Minnesota CBED and small solar projects.

Q: Do you have any recommendations for the commission if it chooses to reject the Negotiated Agreement?

A: Staff recommends that the commission provide some guidance for terms it finds objectionable so as to assist in further negotiations. Alternatively, I recommend that the commission order that the original remedial action be implemented for failure to develop an RTF for developing a resource mix consistent with North Dakota energy policies.

Q: Does this conclude your testimony?

A: Yes, it does.