BEFORE THE PUBLIC SERVICE COMMISSION OF WISCONSIN

Joint Application of American Transmission Company LLC, ITC Midwest LLC, and Dairyland Power Cooperative, for Authority to Construct and Operate a New 345 kV Transmission Line from the Existing Hickory Creek Substation in Dubuque County, Iowa, to the Existing Cardinal Substation in Dane County, Wisconsin, to be Known as the Cardinal-Hickory Creek Project.	**5-CE-146**

SOUL OF WISCONSIN'S MOTION FOR ORDER COMPELLING DISCOVERY FROM APPLICANTS

INTRODUCTION

Intervenor S.O.U.L. of Wisconsin Inc. (SOUL) hereby moves for an order compelling discovery of material responsive to Request 15A (and related Requests 15B and 59) made to American Transmission Company LLC ("ATC"), ITC Midwest LLC ("ITC"), and Dairyland Power Cooperative ("Applicants"). Wis. Admin. Code PSC 2.23, 2.24; Wis. Stat. § 804.12.

S.O.U.L. of Wisconsin Inc. (SOUL) respectfully submits a Motion to Enlarge Time in this Motion 3 more days as per Wis. Admin. Code PSC PSC 2.23(3) dating from the Applicants Objection of March 25, 2019 (see ATTACHMENT J). The reason for the delay is the insertion of additional work involved with re-submitting many rephrased requests to Applicants. Applicant's Objections to SOUL's Third Set of Discovery Requests (see ATTACHMENT I), indicated they were unable to respond to a large number of requests as stated and as some pertain to the motion, SOUL felt that it was in the best interest of all parties to pursue this opportunity for increased clarity but it strained our volunteer staff resources to maximum. SOUL's Third Set of Discovery Requests is included as

ATTACHMENT H.

SOUL has been engaged in a lengthy exchange with the Applicants explaining the importance of the information we have requested. We have responded to issues the Applicants have raised by rephrasing requests and we and suggesting ways to make the analysis we request more encompassing and clear. The Applicants have offered little in return and recently concluded, "This is not an analysis the Applicants are capable of conducting.[1]"

SOUL also discussed the request on phone on April 1, 2019 with Applicant legal counsel, David Zoppos. SOUL stressed the importance of enabling Wisconsin ratepayers to understand the scale of the financial impacts the Project would entail. Applicants did not wish to discuss the interests of ratepayers. They did not wish to elaborate on complexities they feel would make the requested calculations difficult.

It is difficult to identify any information more salient. The PSC's central obligation is to ratepayers: "We have noted that a prevailing purpose of Wisconsin public utility laws is to protect the consuming public, i.e., ratepayers." (Citation omitted). ***Wis. Indus. Energy Grp., Inc. v. Pub. Serv. Comm'n of Wis.***, 342 Wis.2d 576, 819 N.W.2d 240, 2012 WI 89 (Wis., 2012). All affected ratepayers will experience the impacts of the project through rates. Without ratepayer impact information for the proceeding, the Commission will lack basic information that it needs to evaluate the Application.

Applicants seek approval for a high-voltage transmission line for which partial costs and benefits would be distributed across Wisconsin retail ratepayers over period of 30 or more years. The reduction in Project costs to Wisconsin electric customers are due to regional cost-sharing as a Multi Value designated Project. We note in passing that this structure mismatches costs against claimed benefits because, while, all potential benefits are claimed, all related costs are not recognized. MVP projects come the caveat that ratepayers will be made liable for costs of portions of other MVP transmission projects. These costs, along with costs of new generation that is encouraged, are categorically excluded from Applicants' analysis.

Applicants estimated potential net benefits for all Wisconsin retail electric customers under a "wide range" of putatively "robust[2]" economic planning futures range from $22.7 to $349.3 million

1 See Attachment C. Direct-Applicants-Degenhardt-9, PSC REF# PSC REF#:358849

2 See Direct-Applicants-Dagenais-8, "The Applicants conducted a robust economic analysis of the Project, modeling it against three different alternatives in a total of eight different, plausible futures for the electric industry… the eight futures in which the Project was analyzed included wide-ranging assumptions about key factors that could affect the future of the electric power sector."

dollars over a period of 40 years[3].

Dispersed over 40 years and all three sectors of Wisconsin retail customers, the largest potential benefit under the most advantageous future appears to be around 12/100th of one percent of an average monthly electric bill, or pennies per month for the average 660 kWh of residential use based on 2017 EIA data[4].

SOUL'S QUESTIONS TO APPLICANTS

SOUL sought two critical pieces of information: i) an estimate of benefits to ratepayers and ii) an estimate of benefits that have materialized from the stream of approved projects that were promoted under the same kinds of claims the Applicants are making here. If Applicants can use analytical tools to confidently predict the future, they can certainly use tools to see whether past predictions have panned out. This is critical information for the Commission, and for ratepayers.

SOUL's request for average impacts on monthly electric bills included calculations as a starting point for Applicants. Applying 2017 EIA Form 861 data for Wisconsin with exact numbers of residential, commercial and industrial retail customers and sector usage amounts, the Applicants' range of $22.7 to $350 million dollars computes to one-half cent to six cents per month for the average residential customer, from five cents to fifty-one cents per month for the average commercial customer and from $3 to $32 per month for average industrial customers.

On a related question, SOUL asked Applicants to share estimated, historical benefits from 345 kV expansion transmission lines that have been in service, some as long as 12 years. Applicants refused to provide this accountability[5].

Applicants argue that the requested information is too complex to calculate, that benefits from utilities and coops accessing different generation resources over time would not be included in simple calculations and that the Commission supported the Applicants' position in the Badger-Coulee decision finding that, "...quantifying the projected net benefits of the project in terms of a per-retail-customer economic benefit" [would be] "misleading, inaccurate, and unnecessary."

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3 See Direct-Applicants-Dagenais-45, *Table 12: Monetized Net Benefits of Alternatives to Wisconsin ($M – 2018 PV)*

4 EIA Form 861 data. Estimates based on sector percentage of total Wisconsin use divided by the number of customers for average monthly use. Least benefit amount is about .5 cents on a $94 monthly average residential bill to $32 on a $26,600 monthly average bill for industrial customers. Applicants have suggested there are other benefits these amounts are not accounting for but will not state how they would compare to these amounts.

5 See SOUL REQUEST 10D(a), p.22-23, *Applicants' Responses to SOUL of Wisconsin's Second Set of Discovery Requests* (PSC REF#- 360493 and SOUL REQUEST NO. 26, p.8, *Applicants' Objections to SOUL's Third Set of Data and Document Requests.*

It is unclear to SOUL why applicants would be hesitant to calculate and show customers the additional benefits they observe simple calculations would not include. The Applicants' economic futures contain a range of assumptions about generation changes in Wisconsin and the PSC staff encouraged them develop them further.

Applicants are suggesting that cost distribution formulas to customers through changing tariffs could collectively result in lower electric bills over time but they refuse to substantiate whether this factor or adjustments in transmission charges are significant (ATTACHMENT I-Excerpts)[6]. This seems to be a central crux.

That Applicants are providing information that contains potential shortfalls does not relieve our collective responsibilities. That information must be on the table and debated before the commission can make a decision in the best interest of customers. Whether the factors the applicants have cited will have a significant impact on future electric bills is not known, but the request has established that information is missing and this forces intervenors and the commission to find remedy.

Great reliance on elaborate projections and assumptions creates vulnerability, but this reliance has been set forth applicants, without using other checks and balances[7], not by the commission or intervenors. Intervenors like SOUL are simply requesting the Applicants to make their trajectories consistent and conclude with improved clarity and greatly improved usefulness. SOUL's request does not ask for definitive, future precision; it asks for *significance* in terms that all Wisconsin electric customers can see: potential impacts on future monthly electric bills.

Applicants are able to communicate with Wisconsin utilities in estimating the factors and significance they have raised. We also note that collectively, Applicants have a great deal of experience with creating tariffs (Dairyland Power Cooperative) and making adjustments in transmission charges.

The Commission is urged to elevate transparency over concerns that known, complete, information might "confuse" ratepayers.

In refusing to reply to the requests, Applicants cite the Commission's Badger-Coulee decision.

6 See p 4-6, Requests 54R(a), 54R(b), 57R(a) and 57R(b) in SOUL REPHRASED, *SOUL's Third Discovery Requests for the Joint Applicants* encouraging applicants to explore the relevance of prior data in existing economic planning and experiences with tariffs, (ATTACHMENT I-Excerpts)

7 In response to SOUL Request 10D, Second Set Discovery Requests, PSC REF#:360493 and ATTACHMENT C, p. 25, Applicants ignored SOUL's suggestion of examining actual benefits from past 345 kV transmission cases and compare old projections and outcomes to those being projected for Project. They replied, "It [is] not feasible to separate the impacts of a single project from the performance of the system as a whole..."

The requests were made to secure for the record information of a type the PSC did not have in that case, and for which no methodologies were presented until late in the case. The first observation in the case that benefits on a per customer basis could be very small, "about nine cents per customer per month," was made in direct testimony of SOUL's expert witness Peter Lanzalotta[8]. There was no follow-up by any parties in discovery which the requests are trying to remedy.

While in 2015, the Commission found that ratepayer level impacts could be misleading to electric customers in the Badger-Coulee decision, in 2001, the Arrowhead-Weston Final Order (Attachment F -EXCERPTS)[9] cites an independent study (Attachment G-Excerpt)[10] done by the Commission concluding with three tables showing cost per kWh impacts on residential, commercial and industrial customers under three electricity market futures and "...demonstrated that expanding transfer capability by means of a new extra-high voltage line would help foster a more competitive market structure in Wisconsin. The Arrowhead-Weston project is such a transmission line."

SOUL REQUESTS 15A, 15B, and 59, OBJECTIONS, APPLICANT RESPONSES, CITATIONS

The following is excerpts of correspondence from large documents in chronological order. Complete documents are Attached except for cases where relevant sections are small in large documents and so marked.

On February 27, 2019, SOUL emailed the data requests 15A and 15B (Attachment A) to Applicants:

15. **Ratepayer friendly account of the Monetized Range of Net Benefits of Alternatives to Wisconsin** Please refer to the data in Table 2.1-1: Monetized Range of Net Benefits of Alternatives to Wisconsin from p. 2 of the "Applicants' Supplemental Response to PSCW Data Request 1.169," REF#:358840 or more recent estimates provided by the Applicants.

02-SOUL-ATC-15A: In order to assess the monetary significance of the Project and

8 See Direct-CETF/SOUL-Lanzalotta-7, PSC REF# 229027

9 See p.30, Arrowhead-Weston Final Order Oct 30, 2001, 05-CE-113 http://apps.psc.wi.gov/pages/viewdoc.htm?docid=3817 (ATTACHMENT F-EXCERPTS)

10 See p.52-54, *Horizontal Market Power in Wisconsin Electricity Market,* Tabors Caramis and Associates, 2000 http://www.utilityregulation.com/content/reports/WImktstudy.pdf (ATTACHMENT G-EXCERPTS)

Alternatives, please provide rough estimates of the economic benefits for each Alternative under each planning Future for an average residential Wisconsin electric customer on a per month basis over the 40 year period.

The purpose of this request is to provide average benefit distributions to Wisconsin Electric customers over 40 years in 2018 dollars in terms that typical ratepayers can understand. It is not a request for utility-specific, detailed information. It is understood that benefits from the Alternatives would not be spread uniformly across Wisconsin utilities (and their customers) and that calculations based on averaged state wide figures will not account for all distinctions.

The below reference table may help clarify the kind of information that is being requested.

(See table on following page)

APPROXIMATIONS OF WISCONSIN ELECTRIC CUSTOMER SHARE OF ECONOMIC BENEFITS^^								
Economic Future	40 Year Net Benefits of Evaluated Alternatives (Includ. Costs; $Millions – 2018 PV)	40 Year Average Annual Benefits For Wisconsin Customers (Losses in Red)	2017 Average Residential Customer Monthly Share^	2017 Average Commercial Customer Monthly Share^	2017 Average Industrial Customer Monthly Share^	2027 Average Residential Customer Monthly Share*	2027 Average Commercial Customer Monthly Share*	2027 Average Industrial Customer Monthly Share*
	Estimated Cardinal Hickory Creek Economic Benefits							
Existing Fleet (EF)	22.7	$567,500	$0.005	$0.05	$2.92	$0.01	$0.04	$2.95
Policy Regulations with Low Energy (PRLE)	156.1	$3,902,500	$0.04	$0.32	$20.11	$0.04	$0.31	$20.31
Policy Regulations (PR)	105.5	$2,637,500	$0.03	$0.21	$13.59	$0.02	$0.21	$13.73
Policy Regulations with Foxconn (PRFoxconn)	129.2	$3,230,000	$0.03	$0.26	$16.65	$0.03	$0.25	$16.81
Accelerated Alternative Technologies (AAT)	249.3	$6,232,500	$0.06	$0.51	$32.12	$0.06	$0.49	$32.44
	Estimated Low Voltage Transmission Alternative Benefits							
Existing Fleet (EF)	-132.4	-$3,310,000	-$0.03	-$0.27	-$17.06	-$0.03	-$0.26	-$17.23
Policy Regulations with Low Energy (PRLE)	-18.6	-$465,000	-$0.004	-$0.04	-$2.40	-$0.004	-$0.04	-$2.42
Policy Regulations (PR)	-47.4	-$1,185,000	-$0.01	-$0.10	-$6.11	-$0.01	-$0.09	-$6.17
Policy Regulations with Foxconn (PRFoxconn)	-15.3	-$382,500	-$0.004	-$0.03	-$1.97	-$0.003	-$0.03	-$1.99
Accelerated Alternative Technologies (AAT)	270.4	$6,760,000	$0.06	$0.55	$34.84	$0.06	$0.53	$35.19
	Estimated Non-Transmission Alternative Benefits							
Existing Fleet (EF)	-5.4	-$135,000	-$0.001	-$0.01	-$0.70	-$0.001	-$0.01	-$0.70
Policy Regulations with Low Energy (PRLE)	3.7	$92,500	$0.001	$0.01	$0.48	$0.001	$0.01	$0.48
Policy Regulations (PR)	-6	-$150,000	-$0.001	-$0.01	-$0.77	-$0.001	-$0.012	-$0.78
Policy Regulations with Foxconn (PRFoxconn)	-19.9	-$497,500	-$0.005	-$0.04	-$2.56	-$0.004	-$0.04	-$2.59
Accelerated Alternative Technologies (AAT)	29.7	$742,500	$0.007	$0.06	$3.83	$0.01	$0.06	$3.87

^ Based on 2017 EIA Form 861 data: 3,038,715 WI Total Retail Customers; Consumption: 31% Residential; 34% Commercial and 35% Industrial
* 2027 figures based on 6.3% increase in Residential customers, 3% increase in Commercial customers and 1% decrease in Industrial customers of 2017 figures.
^^Benefit data from Table 2.1-1: Monetized Range of Net Benefits of Alternatives to Wisconsin" on p. 34 of the Cardinal Hickory Creek Application.

02-SOUL-ATC-15B: If Applicants observe other, significant, losses or gains that would occur on average Wisconsin electrical bills that would not be sufficiently accounted for in the approximation method described above in 15A, please describe them and quantify the extent of their financial impact on bills. Please state the changes as a range of possible percentage adjustments made to the 40 year approximate economic distributions from the Project as estimated in response to 02-SOUL-ATC-15A or using the sample computations in 02-SOUL-ATC-15A as a reference.

On February 14, 2019, Applicants provided, *Applicants' Objections to SOUL of Wisconsin's Second Set of Discovery Requests* (Attachment B, Excerpt) with responses to Requests 15A and 15B on p. 38-39.

OBJECTIONS TO REQUEST 15A: The Applicants object to this Request as vague, overbroad, and unduly burdensome. The Applicants also object to this Request to the extent that it seeks information or documents that are not in the Applicants' possession, custody, or control and to the extent it would require the Applicants to perform studies, gather information, or undertake other tasks that the Applicants have not completed.

OBJECTIONS TO REQUEST 15B: The Applicants object to this Request as vague, overbroad, and unduly burdensome. The Applicants also object to this Request to the extent that it seeks information or documents that are not in the Applicants' possession, custody, or control and to the extent it would require the Applicants to perform studies, gather information, or undertake other tasks that the Applicants have not completed.

On February 28, 2019, Applicants provided, *Applicants' Responses to SOUL of Wisconsin's Second Set of Discovery Requests,* PSC REF#- PSC 360493 (Attachment C) with responses to Requests 15A and 15B on p. 49:

"**RESPONSE TO REQUEST 15A:** The Applicants object to this Request as vague, overbroad, and unduly burdensome. The Applicants also object to this Request to the extent that it seeks information or documents that are not in the Applicants' possession, custody, or control and to the extent it would require the Applicants to perform studies, gather information, or undertake other tasks that the Applicants have not completed. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows: *See Direct-Applicants-Degenhardt* for an explanation of why the Applicants cannot determine individual ratepayer impacts. In addition, the Applicants do not have enough detailed information to define an "average residential customer."

<u>"RESPONSE TO REQUEST 15B</u>: The Applicants object to this Request as vague, overbroad, and unduly burdensome. The Applicants also object to this Request to the extent that it seeks information or documents that are not in the Applicants' possession, custody, or control and to the extent it would require the Applicants to perform studies, gather information, or undertake other tasks that the Applicants have not completed. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

See Response to Request 15A. "

The section referenced in Response to 15A, *Direct-Applicants-Degenhardt-8* (Attachment D) starting on line 18, reads:

"Q: Did the Applicants calculate the impact that the Project would have on electric bills for individual retail electric ratepayers?

A: No. As the Commission has recognized, in a docket where the proposed transmission project brings economic benefits (in addition to reliability and policy benefits), calculating the impact of a project on individual retail ratepayers would be extremely difficult, would not yield useful information, and could perhaps result in misleading data.[Footnote 1] ATC, ITC, and Dairyland do not directly serve retail electric customers. Rather, they serve local distribution companies (LDCs) or (in the case of Dairyland) member cooperatives, which in turn serve retail customers. Therefore, to determine the Project's impacts to individual retail electric ratepayers, one would have to determine (for example) the benefits of accessing different sources of generation for each Wisconsin LDC and cooperative, how each Wisconsin LDC and cooperative would incorporate these benefits into its retail tariffs for each customer class, and then those benefits would have to be compared to the changes in transmission charges. This is not an analysis the Applicants are capable of conducting."

The referenced 2015 *Badger-Coulee Final Decision* [Footnote 01], is PSC REF#: 235295 (Attachment E EXCERPT) and reads at p.14:

> "Opposing intervenors also criticize the applicants for not quantifying the projected net benefits of the project in terms of a per-retail-customer economic benefit, and for not providing guarantees of the magnitude of the benefit.[Footnote 35]. Calculation of a per-retail-customer economic benefit would require a complex analysis of many individual transmission customers' allocation of costs to retail customers and rate classes, considering each local distribution company's (LDC) individual rate structure. The proposed project is anticipated to provide economic benefits to transmission customers as a whole, which in turn will be passed along to transmission customers and subsequently retail customers. As such, the Commission finds the intervenors' criticism as misleading, inaccurate, and unnecessary."

The 2015 proceeding documents referenced in the Badger-Coulee Final Decision {Not Attached) [Footnote 35] are:

> I*ntervenor Save Our Unique Lands of Wisconsin, INC.'s Initial Brief In Opposition to the Application* (PSC REF# 231947) at p. 1-12
>
> *Intervenor Citizens Energy Task Force, INC.'s Initial Brief in Opposition to the Application* (PSC REF# 231948) at p. 28-30

On March 29, 2019, in *S.O.U.L. of Wisconsin's Third Set of Document and Data Requests to the Joint Applicants* emailed to Applicants (ATTACHMENT H - EXCERPTS), SOUL encouraged the Applicants to consider a more comprehensive but still ratepayer-friendly description of impacts in Request No. 59, on p.13 that reads,

> **REQUEST NO. 59:** "Using EIA Form 861 data from 2017 with Wisconsin-wide totals for customer usage and customer counts for all sectors (see Request 15A from SOUL's second set of Discovery Requests), please comment on whether the following two sentences are factually correct: Simple averaged distributions of the $22.7 to $349.3 million in potential transmission congestion and reliability net benefits from Cardinal Hickory Creeks transmission line would range from .5 cents to 6 cents per month per average residential customer, from 5 cents to 51 cents per month for the average commercial customer and from $3 to $32 per month for the average industrial customer. Applicants have suggested that benefits could be larger based on actual

changes in power purchases that materialize."

On March 25, 2019, in *Applicants' Objections to SOUL's Third Set of Data and Document Requests,* (ATTACHMENT J - EXCERPT) on p. 13, the Applicants reply:

> RESPONSE: The Applicants object to this Request as argumentative, compound, and vague. The Applicants further object to this Request to the extent it would require the Applicants to function as consultants for SOUL by gathering information, conducting studies, or undertaking other tasks that the Applicants have not yet completed. The Applicants further object to this Request to the extent it mischaracterizes the Applicants' prior statements regarding the need for and benefits of the Project. The Applicants further object to this Request to the extent it is premised on, or presupposes the existence of, inaccurate or incorrect assumptions or factual assertions. [Partial response to be separately provided in accordance with the timeframes established by the Administrative Law Judge.]

On March 29, 2019, in *S.O.U.L. of Wisconsin's Rephrased Requests in our Third Set of Document and Data Requests to the Joint Applicants emailed* to the Applicants (ATTACHMENT I - EXCERPTS) , SOUL made data four, rephrased, requests regarding Mr. Degenhardt's concern that ratepayer level impacts could include benefits from different future generation used by Wisconsin utilities: 54R(a); 54R(b); 57R(a) and 57R(b) in SOUL's Third of Discovery Requests which starts on p. 4 and reads,

> **"Re: Direct-Applicants-Degenhardt-8, Question posed "Did the Applicants calculate the impact that the Project would have on electric bills for individual retail electric ratepayers?" Degenhardt Reponse: "No. As the Commission has recognized, in a docket where the proposed transmission project brings economic benefits (in addition to reliability and policy benefits), calculating the impact of a project on individual retail ratepayers would be extremely difficult, would not yield useful information, and could perhaps result in misleading data.**[footnote 1] **ATC, ITC, and Dairyland do not directly serve retail electric customers. Rather, they serve local distribution companies (LDCs) or (in the case of Dairyland) member cooperatives, which in turn serve retail customers. Therefore, to determine the Project's impacts to individual retail electric ratepayers, one would have to determine (for example) the benefits of accessing different sources of generation for each**

Wisconsin LDC and cooperative, how each Wisconsin LDC and cooperative would incorporate these benefits into its retail tariffs for each customer class, and then those benefits would have to be compared to the changes in transmission charges. This is not an analysis the Applicants are capable of conducting.”

[SOUL carried forward two prior citations in rephrasing the requests:]

Related Citation #1 Direct-Applicants-Dagenais-52

> “...the Project will increase the transfer capability of the transmission system between Wisconsin and Iowa, which will increase the availability of low-cost wind energy and reduce energy costs for Wisconsin customers

Related Citation #3, Applicants’ Analysis of WI Utility Future Generation Sources: Direct-Applicants-Dagenais-8,

> “The Applicants conducted a robust economic analysis of the Project, modeling it against three different alternatives in a total of eight different, plausible futures for the electric industry. In the Application, the Applicants submitted modeling results for five futures. After the Application was filed, at the Commission staff’s request, the Applicants made numerous changes to their models and evaluated the Project under three new futures, resulting in a total of eight futures being studied.[Footnote 1] As shown in Table 1, below, the eight futures in which the Project was analyzed included wide-ranging assumptions about key factors that could affect the future of the electric power sector.”

[SOUL provided new background in rephrasing the requests:]

Additional Background: In Re: Direct-Applicants-Degenhardt-8, Applicants mention three, additional factors they feel need to be considered in order to provide an estimate of ratepayer level impacts which we have italicized and underlines the following, excerpted, statement:

> “Therefore, to determine the Project’s impacts to individual retail electric ratepayers,

> one would have to determine (for example) the benefits of accessing different sources of generation for each Wisconsin LDC and cooperative, how each Wisconsin LDC and cooperative would incorporate these benefits into its retail tariffs for each customer class, and then those benefits would have to be compared to the changes in transmission charges."

REQUEST NO. 54R(a) REPHRASED: Please explain if the Applicants' economic modeling that produced monetized net saving estimates for the Project under several economic planning futures makes assumptions about "different sources of [future] generation" for ATC's local distribution companies, Northern States Power and Dairyland Power Cooperative. If, not please explain why the economic planning futures did not make assumptions about "different sources of [future] generation" for these parties.

REQUEST NO. 54R(b) REPHRASED: If the applicants' economic planning did estimate "different sources of [future] generation," for the above, cited, parties, please explain why these estimates, or others similar to them, could not be used to resolve this changing generation variable which applicants suggest is necessary to provide SOUL an estimate of the average "impacts [on] individual retail electric ratepayers," for all three retail sectors in Wisconsin.

[SOUL provided addition background in rephrasing the requests:]

Additional Background: For clarity, SOUL has divided former Request No 57 into two parts, (a) and (b).

REQUEST NO. 57R(a) REPHRASED: Please explain why Co-Applicant Dairyland Power Cooperative, who creates tariffs for a wide range renewable and non renewable generation, would not be able to provide Applicants as a whole a range of sample tariffs to apply in estimates of the benefits for electric customers from placing different, accessed "sources of generation... into retail tariffs."

Additional Background Comment: The above requests hope to account for the feasibility of Applicants addressing the first two of the three, additional factors Applicants feel need to be considered in order to provide an estimate of ratepayer level impacts. The remaining factor pertains to the need to account for changes in benefits resulting from "changes in transmission charges" as a result of ATC's local distribution companies, Northern States Power and Dairyland Power Cooperative "accessing different sources of [future] generation."

REQUEST NO. 57R(b) REPHRASED: Please discuss use of the Applicants' economic modeling that produced monetized net saving estimates for the Project under several economic planning futures to estimate "changes in transmission charges" associated with the "different sources of [future] generation" modeled under Applicants' economic planning futures. If the economic modeling used to determine "changes in transmission charges" cannot be adapted to provide estimated changes in benefits from this, third, factor, please explain why.

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RELEVANCE

Contrary to Applicants' responses thus far, this data request seeks clear information that is extraordinarily challenging for Applicants to produce and it would provide an essential ability in the proceeding of enabling Wisconsin ratepayers the ability to assess the proposal's potential net benefits in familiar terms: potential savings on monthly electric bills. As described earlier, in 2000, a consultant estimated impacts on residential, commercial and industrial rates for IOU's and Cooperatives to assist the Commission in considerations of the Arrowhead-Weston proposal, using readily available, "data reported by the utilities in their 1998 FERC Form 1 reports.[11]"

In regard to the Applicants challenging relevance by stating our Requests are, " vague, overbroad, and unduly burdensome," SOUL's intent is to provide the public with concise and inclusive descriptions of monetary benefits. Applicants understand how important costs and benefits are to electric customers. They have featured monetary aspects in three, concise press releases in 2018[12] in

11 See p. 48, Horizontal Market Power in Wisconsin Electricity Market, Tabors Caramis and Associates, 2000 http://www.utilityregulation.com/content/reports/WImktstudy.pdf (ATTACHMENT G-EXCERPTS)

12 See three Applicant press releases from 4-25-18 to 10-5-2018: https://www.cardinal-hickorycreek.com/wp-content/uploads/2018/04/Cardinal-Hickory-Creek-CPCN-filing-process-release-4.25.18.pdf https://www.cardinal-

this format:

example of misleading customers

> • Provide $23.5 million to $350.1 million in net economic benefits to Wisconsin electric consumers
>
> • Avoid the need to spend $87.2 million to $98.8 million on transmission line and asset renewal projects that would otherwise be needed if the project is not constructed.

We note that this description does not explain to electric customers that cited dollars would be over 40 years. Nor is it clear in these bullets that the $87.2 to $98.8 million referenced as, "...transmission line and asset renewal projects" are being double-counted, also included in the figures in the first bullet.

Applicants also objects to the data request " to the extent that it seeks information or documents that are not in the Applicants' possession, custody, or control and to the extent it would require the Applicants to perform studies, gather information, or undertake other tasks that the Applicants have not completed." The Applicants' primary objection is that some benefits from the Project are missing in the simplest calculations. Given the small amounts of the Applicants' $22.7 to $349.3 million when divided over 40 years, there is reason for Applicants to calculate and add significant benefits.

As for the requests forcing Applicants to "perform studies, gather information, or undertake other tasks that the Applicants have not completed, " Applicants do not state that the analysis requires, *new* studies or tasks, or information that applicants would have to create from scratch. As SOUL attempts to outline in requests, 54R(a), 54R(b), 57R(a) and 57R(b), there is strong likelihood that the most time consuming "information gathering" Applicants suggest is present in the economic planning futures each containing, "different sources of [future] generation," ready to be combined with tariffs DPC can provide and transmission charges inherent in economic modeling.

Finally, in regard to relevance, it is important to consider the relative scale of the potential benefits involved. If unaccounted for benefits from the Project were determined to be several times larger, ratepayers might feel the amount is still insignificant compared to the many drawbacks of sitig a high profile transmission facility. This is the right of ratepayers to judge and they cannot without a clear picture of what the potential benefits might be.

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hickorycreek.com/wp-content/uploads/2018/05/ATC-ITC-Dairyland-Power-receive-incompleteness-determination-from-the-PSCW.5.25.18.pdf https://www.cardinal-hickorycreek.com/wp-content/uploads/2018/10/ATC-ITC-Dairyland-Power-receive-completeness-determination-from-the-PSCW-10-5-18.pdf

SOUL observes that Applicants could be over-stressing the degree of nuance required to produce sufficiently accurate numbers for ratepayers. SOUL request 15B asks Applicants to consider adding a range of possible adjustments that could occur on top of the existing figures produced thus far.

IMPORTANCE OF THE ISSUES AT STAKE, IMPORTANCE OF DISCOVERY, PROPORTIONALITY, AND ACCESS TO INFORMATION

In addition to adding a major, potentially under-utilized transmission line across communities in Wisconsin that are voicing wide and loud objection, the direction of Wisconsin future energy spending will be influenced by this case.

The prospect of accelerating generation costs in Wisconsin is high without the high capacity addition to our transmission system. Wisconsin utilities are looking increasingly in-state for utility-scale renewable development. The looming costs of keeping Wisconsin's lower voltage transmission and distribution lines in good maintenance are very real. By lowering demand and placing stabilizing generation, load management and storage behind meters, the Non-Transmission Alternatives path increasingly lowers grid related maintenance costs. The substantial costs of building and connecting, large, utility-scale generation facilities are increase demand on the grid adding more upgrade and maintenance costs over time.

CONCLUSION

Data Requests 15A (or alternately, 15B or 59) seek information that is of extreme value to the ratepayers of Wisconsin. It can be efficiently produced, will avoid confusions and set invaluable example for straight-forwardness and clarity in this proceeding.

Dated April 2, 2019.

S.O.U.L of Wisconsin, Inc.
/s/ Rob Danielson

Rob Danielson

Rob Danielson Secretary/Treasurer, Registered Agent,
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BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Joint Application of American Transmission Company, ITC Midwest LLC, and Dairyland Power Cooperative, for Authority to Construct and Operate a New 345 kV Transmission Line from the Existing Hickory Creek Substation in Dubuque County, Iowa, to the Existing Cardinal Substation in Dane County, Wisconsin, to be Known as the Cardinal-Hickory Creek Project.

Docket No. 5-CE-146

S.O.U.L. OF WISCONSIN'S SECOND SET OF DOCUMENT AND DATA REQUESTS TO THE JOINT APPLICANTS

Intervenor S.O.U.L of Wisconsin, Inc.. (SOUL) requests that joint applicants American Transmission Company LLC, ITC Midwest LLC and Dairyland Power Cooperative answer the following document and data requests (collectively, the "Discovery Requests) within twenty-one (21) days of service pursuant to section IV(A)(2)(a).

DEFINITIONS

1. The term, "Project," means the high-voltage transmission option in the Cardinal Hickory Creek docket.

2. The term, "significant improvements" means physical modification made to the facility in question whose purpose or effect was to increase the efficiency, effectiveness, reliability or safety of the facility in question.

3. The term, "NERC violation" means any deviation from the North American Electric Reliability Corporation Critical Infrastructure Protection standards in effect at the timeframe each data or document request addresses.

4. The term "document" means a copy in whatever format of the PDF electronic file that corresponds to the ERF reference number the given data or document request addresses.

5. The term, "provide" means to email copies of the document addressed to the undersigned intervenor[1].

6. The terms, "summer peak load" and" winter peak load" mean the maximum load for the facility for the summer period and the maximum load for the winter period.

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1 Please see email address in the signature of this document.

7. The term, "summer off peak load" means 70% of summer peak load.

8. The term, "energy efficiency" means any utility programs that provide rebates for appliances, equipment and improvements to buildings to lower energy consumption by lowering the amount of energy required to provide services.

9. The term "demand response" of utility programs that control time of use of end users especially during periods of high demand.

10. The term, "generation retirements, conversions and additions" means power plants that are taken out of service, converted to another type of fuel and/or power plants that are placed in service.

11. The term, "recovery costs" means recoupment of the purchase price of a capital asset and associated expenses through depreciation over a prescribed period.

12. The term, "asset renewal projects" means the transmission facilities in Southwest Wisconsin applicants have specified as having issues requiring replacement and/or rebuilding.

13. The term, "reliability projects" means the transmission facilities in Iowa and Wisconsin applicants have specified as having potential thermal overloads under NNL contingencies.

14. The term, "Critical Electric Infrastructure Information (CEII) is defined[2] by FERC as, "[I]nformation related to or proposed to critical electric infrastructure, generated by or provided to the Commission or other Federal agency other than classified national security information, and that is designated as critical electric infrastructure information by the Commission or the Secretary of the Department of Energy pursuant to section 215A(d) of the Federal Power Act."

15. The term, "commercial market competition" means rivalry between companies selling similar products and services in the MISO market with the goal of achieving revenue, profit, and market share growth.

16. The term, "base power transfer" is the initial loading in the load flow case from network resources serving load, plus schedules to external areas based on net firm transmission service rights.[3]"

DOCUMENT REQUESTS

Please note that the below, updated documents requests are being made following SOUL's January 10, 2019, First Document Request *Revision* and a phone discussion with Mr. Brian Potts on January 11, 2019. Please provide the following documents:

2 https://www.ferc.gov/legal/ceii-foia/ceii.asp

3 p.2, *Treatment of Capacity Exports from Local Reserve Zones* by David Patton, Potomac Economics https://www.ferc.gov/CalendarFiles/20151020085636-Patton,%20MISO%20IMM-Local%20Rqmts%20Session%202_10-20-2015.pdf

1. The document identified as Appendix D, Exhibit 1 Planning Analysis Document CEII C27841 (PSC Ref# 341713) to the extent the below sections contain publicly accessible information that is not protected as Critical Energy Infrastructure Information or commercial market competition information.

   p. 24, Figure 6: CHC Diagram labeled as, "CEII." Please provide access to this diagram or explain why the entire diagram is redacted.

   p. 26, Figure 7 LVA Diagram labeled as, "CEII." Please provide access to this diagram or explain why the entire diagram is redacted.

   p. 46-47, Tables 9-12. Please redact the names of the LBA's and provide the data in the other columns, or provide totals for each column in all tables, or explain why it is necessary to redact the information in each of the columns or not provide the totals for all columns in Tables 9-12.

2. The document identified as Appendix D, Exhibit 1 PAD Appendices CEII C27841 (PSC Ref# 341715). In particular, please provide the public accessible data in the following sections:

   Appendix D-6: Assumptions And Data Used In HHI Analysis, pdf p. 29. See redaction at the end of this statement, "Average import capability is the maximum 2016 imports of..." If this information is not publicly accessible, please explain the reason(s). If the redaction is numerical, please explain why the value and measured units should not be accessible to the public.

   Table D-8-1 – Historical Coincident Peak Load and Weather Normalized Forecasted Peak Load from 2007 to 2027 on .pdf pages 32-43 except for Critical Electric Infrastructure or commercial market competition information or explain why historical and forecasted substation loads should not be accessible to the public.

3. The .xls format document with calculations identified as Attachment to Response to Data Request 01.169. (PSC Ref# 347516) based on Schedule 9 and Schedule 26A data for American Transmission Company, Northern States Power and Dairyland Power Cooperative or explain which data in the schedules from which the spreadsheet calculations are derived cannot be made available to the public, and/or name and describe other sources of data used to generate this spreadsheet that cannot be made available to the public.

4. [SOUL is no longer requesting the document identified as Attachment to Response to Data Request 01.187 - C-27845. (PSC Ref# 347518).]

5. The 2017 and 2018 SW Wisconsin Operating Guides or document identified as Attachment to Response to Data Request 01.192 - C-27845. (PSC Ref# 347520). SOUL could not find reference to "Operating Guides" being protected as Critical Energy/Electric Infrastructure Information (CEII) in FERC Orders[4]. SOUL wishes to understand the nature of the 2017 and 2018 SW Wisconsin Operating Guides including their purpose and background, the geographic area(s) being monitored and affected, system re-configurations, the congestion

4 https://www.ferc.gov/legal//maj-ord-reg/land-docs/ceii-rule.asp?csrt=9891730892299641903

binding, associated generation commitments, conditions requiring load shed guidance and their revision history to the greatest extent granted to the public.

6. [SOUL is no longer requesting the document identified as Response to Data Request 2 (C 27846) PSC Ref# 348966]

7. [SOUL is no longer requesting the document identified as Supplemental to Second Group of Responses to PSCW's May 24, 2018 Incompleteness Letter (C 27847) PSC Ref# 350641]

8. The document identified as Supplemental Response to Data Request 1, Economic Analysis Update (C27849). (PSC Ref# 351942) including narrative and analysis accessible for public review in a format not requiring Ventyx or PowerWorld software to access.

9. The document identified as Response to Data Request 6 with Data Disc (C27850) (PSC Ref# 354246) including narrative and analysis accessible for public review in a format not requiring Ventyx or PowerWorld software to access.

10. [SOUL is no longer requesting the document identified as Response to Data Request 2 (C 27846) PSC Ref# 348966]

11. [SOUL is no longer requesting the document identified as Response to Data Request 4, Part 2, Planning Items with Data Disc (C 27852) PSC Ref# 354926]

12. The document identified as, "**Attachments 1 and 2"** part of the Applicants' Responses to DALC's First Set of Data Requests, PSC Ref # 35898. SOUL respectfully requests the Applicants to make this document publicly accessible on the docket for other parties to become aware of and use.

13. The document identified as, "**Attachment 1 to 01-DALC-ATC-06,**" part of the Applicants' Responses to DALC's First Set of Data Requests, PSC Ref # 358984. SOUL respectfully requests the Applicants to make this document publicly accessible on the docket for other parties to become aware of and use.

14. The document identified as, "**Attachment 2 to 01-DALC-ATC-06,**" part of the Applicants' Responses to DALC's First Set of Data Requests, PSC Ref # 358984. SOUL respectfully requests the Applicants to make this document publicly accessible on the docket for other parties to become aware of and use..

15. The document identified as, "**Attachments 3 and 4 to 01-DALC-ATC-06,**" part of the Applicants' Responses to DALC's First Set of Data Requests, PSC Ref # 358984. SOUL respectfully requests the Applicants to make this document publicly accessible on the docket for other parties to become aware of and use.

16. The document identified as, "**Attachment 9 to 01-DALC-ATC-06**" part of the Applicants' Responses to DALC's First Set of Data Requests, PSC Ref # 358984. Please selectively redact CEII information from this document in order to make the non-confidential part of it accessible on the docket.

17. The document identified as, "**1 to 7 01-DALC-ATC-07**" part of the Applicants' Responses to DALC's First Set of Data Requests, PSC Ref # 358984. SOUL respectfully requests the Applicants to make this document publicly accessible on the docket for other parties to become aware of and use.

18. The document identified as, "NTA analysis included in a .zip file labeled, "**Attachment 1 to 01-DALC-ATC-14.**" as part of the Applicants' Responses to DALC's First Set of Data Requests, PSC Ref # 358984. SOUL respectfully requests the Applicants to make this document publicly accessible on the docket for other parties to become aware of and use.

19. The document identified as, "Work papers related to energy cost savings.. in response to **01-DALC-ATC-33**" as part of the Applicants' Responses to DALC's First Set of Data Requests, PSC Ref # 358984. SOUL respectfully requests the Applicants to make this document publicly accessible on the docket for other parties to become aware of and use.

20. The document identified as, "**Attachment 1 to 01-DALC- ATC-16,**" as part of the Applicants' Responses to DALC's First Set of Data Requests, PSC Ref # 358984. SOUL respectfully requests the Applicants to make this document publicly accessible on the docket for other parties to become aware of and use.

21. The document identified as, "**Attachment 2 to 01-DALC-ATC-16**" as part of the Applicants' Responses to DALC's First Set of Data Requests, PSC Ref # 358984. SOUL respectfully requests the Applicants to make this document publicly accessible on the docket for other parties to become aware of and use.

22. The document identified as, "**Attachment 3 to 01-DALC-ATC- 16**" as part of the Applicants' Responses to DALC's First Set of Data Requests, PSC Ref # 358984. SOUL respectfully requests the Applicants to make this document publicly accessible on the docket for other parties to become aware of and use.

23. The document identified as, "**Attachment 3 to 01-DALC-ATC- 16**" as part of the Applicants' Responses to DALC's First Set of Data Requests, PSC Ref # 358984. SOUL respectfully requests the Applicants to make this document publicly accessible on the docket for other parties to become aware of and use.

24. The document identified as, "**Attachments 1 to 8 to 01-DALC-ATC-18.**" as part of the Applicants' Responses to DALC's First Set of Data Requests, PSC Ref # 358984. SOUL respectfully requests the Applicants to make this document publicly accessible on the docket for other parties to become aware of and use.

25. The document identified as, **"Attachment 1 to 01-DALC-ATC-20."** as part of the Applicants' Responses to DALC's First Set of Data Requests, PSC Ref # 358984. SOUL respectfully requests the Applicants to make this document publicly accessible on the docket for other parties to become aware of and use.

26. The document identified as, **"Attachments 1 to 3 to 01- DALC-ATC-21,"** as part of the Applicants' Responses to DALC's First Set of Data Requests, PSC Ref # 358984. Please

selectively redact CEII information from Attachment 3 in order to make the non-confidential part of it accessible on the docket. SOUL respectfully requests the Applicants to make this document publicly accessible on the docket for other parties to become aware of and use.

27. The document identified as, **"Attachment 1 to 01-DALC-ATC-25"** as part of the Applicants' Responses to DALC's First Set of Data Requests, PSC Ref # 358984. SOUL respectfully requests the Applicants to make this document publicly accessible on the docket for other parties to become aware of and use..

28. The document identified as, "**Attachment 1 to 01-DALC-ATC-14**" as part of the Applicants' Responses to DALC's First Set of Data Requests, PSC Ref # 358984. SOUL respectfully requests the Applicants to make this document publicly accessible on the docket for other parties to become aware of and use.

INSTRUCTIONS

1. Please use all information available to, or at the disposal of, you or any other parties that you either employ or contract in connection with the above-referenced docket.
2. Make a good faith, diligent inquiry into all information the data requests seek.
3. If any data or documents the data requests seek exist within a larger set of data or documents, produce only the relevant subset of data or documents. If separating the requested subset of data or documents is overly burdensome, make a good faith and diligent effort to create a clear indication or demarcation of the relevant data or documents subset within the larger set of data or documents produced.
4. Update and amend your answers to the data requests with any new information that you discover or to which you gain access in the future, or with any correction that comes to your attention in the future.
5. If you raise an objection to any particular data or document request, please provide an explanation of the objection and the grounds upon which you invoke it.

DATA REQUESTS

1. (Continuation of Question 1 from SOUL's first set of data requests regarding further substantiation of **potential electric market advantages of the Project and Alternatives.**)

   SOUL would like to thank the Applicants for referencing Section 6.8 (Improved Competitiveness) of the Appendix D Exhibit 1 Planning Analysis and the assumptions for this assessment of Market Power in Appendix D-6, Appendix D Exhibit 1 Planning Analysis Document Appendices. Below is a follow-up data request with labeling continuing the original alphabetical sequence. With this second set of requests, SOUL is adopting the request naming prefix used by DALC for consistency and convenience in future references.

02-SOUL-ATC-1C: On p. 69 in Section 6.8, of the Appendix D Exhibit 1 Planning Analysis, it states:

> "The Herfindahl-Hirschman Index (HHI) is used to evaluate the extent of competition in power markets. Markets in which the HHI is between 1000 and 1800 points are considered to be moderately concentrated and those in which the HHI is in excess of 1800 points are considered to be highly concentrated.
>
> The HHI can be calculated for expected market conditions with and without new transmission facilities, such as the Project. The competitiveness of a region varies with the assumed fraction of generation capacity available to the market by the suppliers that make up the market, as well as by the amount of summer on-peak and shoulder period incremental transfer capability that results from the construction of the proposed transmission facility.
>
> The competitiveness of the market is analyzed from two perspectives: Gross HHI and Net HHI. Gross HHI does not consider the suppliers' load obligations and exposes the entire generation capability to the market. The Net HHI subtracts the suppliers' load obligations from their supply portfolios. The residual generation capability represents the supplier-specific capacity that is available to the market.
>
> Since Wisconsin is not a retail choice state, the supplier (i.e., the state-based electric utility) has an obligation to serve its native load; as a result, the Net HHI is more relevant to the analysis than the Gross HHI."

Please explain how Applicants determined the estimated 2027 No-Action Summer Peak Gross HHI value of 2279. Identify the sources of the data utilized in making the estimate.

02-SOUL-ATC-1D: Please provide the calculations used to estimate the 2027 Net HHI figures for the No-Action cases in Tables 42-45 on p. 70-71 as derived from data described as, "suppliers' load obligations" (Wisconsin based utilities) and, "supply portfolios."

02-SOUL-ATC-1E: Please describe by generic name(s), what constitutes the "load obligations" that are subtracted from the Gross HHI values to derive the Net HHI values.

02-SOUL-ATC-1F: Please explain if and how these wind generators: Top of Iowa II, Top of Iowa III, Barton, Crane Creek and Bent Tree (from pdf p. 29, Appendix D-6, Appendix D Exhibit 1 Planning Analysis Document Appendices) are incorporated into the requested "load obligations" and/or other HHI calculations. It seems Wisconsin utilities either own these referenced generators or are contracted to purchase power from them.

02-SOUL-ATC-1G: Please explain the meaning of and the impact of note 1, "Generation Capacity assumes a 100 percent wind credit." on the data in Table D-6-1, pdf p. 29, Appendix D-6, Appendix D Exhibit 1 Planning Analysis Document Appendices.

02-SOUL-ATC-1H: Please describe what the expected impacts would be on the Applicants'

HHI calculations in Tables 42-45 on p. 70-71 of the Appendix D Exhibit 1 Planning Analysis if Dairyland Power Cooperative (DPC) and Northern States Power (NSP) utilities were included in the analysis. Would the estimated change in market concentration in 2027 due to the Project affect the economics of DPC and NSP and, if so, would including these utilities in the Applicants' HHI analysis cause the Net HHI values in Tables 42-45 on p. 70-71 to increase or descrease?

02-SOUL-ATC-1I: In response to question 1A in SOUL's first Discovery Requests, the Applicants explain:

> "First Contingency Incremental Transfer Capability (FCITC) was determined by transmission planning studies that increased generation output in Iowa and decreased generation output in Wisconsin until the first transmission element was loaded to 100 percent of the applicable rating with a full set of contingencies. The FCITC was identified in a shoulder and summer peak model for each of the alternatives. The difference between the FCITC of an alternative and the No Action Alternative were reported as *Incremental FCITC* and used in the calculations in Section 6.8 (Improved Competitiveness) of the Planning Analysis Document."

As FCITC values already include an *incremental* amount, specifically defined as the amount above normal base power transfers that can be transferred over the interconnected transmission systems in a reliable manner, please clarify if the "Incremental FCITC" figures provided for each of the Alternatives in Tables 42-45 on p. 70-71 of the Appendix D Exhibit 1 Planning Analysis include or do not include normal base power transfers.

02-SOUL-ATC-1J: Please provide the 2027 estimated base power transfer amounts[5] for each of the Alternatives in Tables 42-45 on p. 70-71 of the Appendix D Exhibit 1 Planning Analysis that were inherent in the Applicants' HHI analysis or in prior studies.

02-SOUL-ATC-1K: On p. 68 of the Appendix D Exhibit 1 Planning Analysis, the Applicant's state:

> "A new transmission facility can improve the market structure and competitiveness if the facility enables external suppliers to offer additional generation into a specifically-defined market. The increased generation alternatives will increase competition causing a reduction in market prices. To the extent that suppliers who participate in the market are exposed to such market prices through short-term purchases and the turnover of longer-term contracts, these reductions in market prices will also reduce end-user costs."

As charted below, the estimated 2027 changes in Net HHI values for all alternatives in Tables 43 and 45 range from 1.8-16.3%. Please elaborate on the economic benefits that Wisconsin electric customers could expect from the Project's 10.1% to 16.3% improvement in market competitiveness in 2027.

5 See definition 16 in this document.

Table 43: 2027 Summer Peak Net HHI

Alternative	Incremental FCITC (MW)	NA	Net HHI w/Alternative	Change in Net HHI	Percentage Change
CHC	1382	1011	918	-93	**10.1%**
LVA	980.3	1011	935	-76	**8.1%**
NTA	170	1011	993	-18	**1.8%**

Table 45: 2027 Shoulder Net HHI

CHC	1231	1652	1421	-231	**16.3%**
LVA	784.9	1652	1492	-160	**10.7%**
NTA	334.2	1652	1578	-74	**4.7%**

02-SOUL-ATC-1L: If spread across 40 years, how would these economic benefits from improved market competitiveness compare to the benefits in Table 46: Monetized Range of Net Benefits of Alternatives to Wisconsin on p. 84 of the Appendix D Exhibit 1 Planning Analysis?

02-SOUL-ATC-1M: Please provide Applicants' calculations used to produce the 2027 Incremental FCITC value of 170 MW used for the NTA Alternative in Tables 42-45 on p. 70-71 of the Appendix D Exhibit 1 Planning Analysis. For purposes of clarity, please explain the relation of this estimated increase in Incremental FCITC in 2027 and the 2023 On Peak Capacity total of 66.1 MW in Table 2: NTA Components on p. 28 of the Appendix D Exhibit 1 Planning Analysis.

2. (Continuation of Question 2 from SOUL's first set of data requests regarding expenses contained in the Applicants' estimated **Project Costs**.) Below is a follow-up data request with labeling continuing alphabetical sequence:

02-SOUL-ATC-2B: In response to Request 2A on p. 10, of Applicants' Response to S.O.U.L. of Wisconsin, Inc.'s First Document and Data Requests, it is stated, "40 year Hardening, cyber and other Security expenses: assumed to be included in the remaining $500M (cost)." Please provide a more detailed estimate of hardening, cyber and other security expense costs that can be expected for the Project over 40 years based on studies or other reliable sources.

02-SOUL-ATC-2C: Please provide documentation that hardening, cyber and other security expenses have been observed by the Public Service Commission of Wisconsin (PSCW) as expenses expected to be paid for by Transmission Operators in Wisconsin in previous permits for 345 kV transmission lines or other arrangements with PSCW?

02-SOUL-ATC-2D: Also in response to Request 2A on p. 10,of Applicants' Response to S.O.U.L. of Wisconsin, Inc.'s First Document and Data Requests, when accounting for Project expenses over 40 years, the Applicants observe that revenue requirements, operation and maintenance expenses would total $100M:

> "Revenue Requirement Adders over 40 years: $100M; Construction Period costs: assumed to be included in the remaining $500M; 40 year Maintenance expenses: assumed to be included in the $100M of revenue requirement adders; 40 year Operation expenses: assumed to be included in the $100M of revenue requirement adders."

Please provide documentation that Revenue Requirement Adders, Maintenance and Operation expenses have averaged around $2.5M per year for a Wisconsin-based 345 kV transmission line in 2018 era dollars.

3. [No follow-up questions at this time.]

4. [No follow-up questions at this time.]

5. [No follow-up questions at this time.]

6. [No follow-up questions at this time.]

7. (Continuation of Question 7 from SOUL's first set of data requests regarding **Energy Cost Savings** and supplementing **Need for Overview Tables compiling significant drivers, sensitivities, policies and other assumptions for all Alternatives under all Futures.**) Below is a follow-up data request with labeling continuing alphabetical sequence:

02-SOUL-ATC-7B: Applicants have recently indicated they will be updating the Planning Analysis Document as stated on p. 2 of Applicants' Supplemental Response to PSCW Data Requests 1.172, 1.174, 1.195, 1.198, 1.200-1.206, 1.208, 1.209, 1.213-1.216, and 4.56 (PSC REF#358760):

> "In order to ensure that the Commission and all parties can easily obtain all of the modeling results in one location, the Applicants plan to file an update to the Planning Analysis Document that was filed with the Application which incorporates all of the changes described herein."

We note that, to date, the planning document and other application materials for this docket do not contain overview charts compiling and clarifying drivers, sensitivities and other key factors for all futures as was provided for the Badger-Coulee docket (see Tables 12-13, p. 38-39, Planning Analysis of the Badger-Coulee Transmission Project PSC Ref#204739).

We also note that the current docket does not yet contain an explanation of the estimated economic impacts for all alternatives based on ProMod and other analysis in language that electric customers and the public can easily understand.

Additionally, we note that narrative for Tables 37-41 on p. 66-67, Appendix D. Exhibit 1 Planning Analysis (which we assume will be updated in the new document) does not explain why Energy Cost Saving are so influential in Net Economic Benefit Calculations across the studied futures nor discuss factors that tend to cause the range in the estimated Energy Cost Saving benefits.

The Applicants' limited discussion of these economic factors can be found in Section 4.1.1 Energy Cost Savings, p. 20, Appendix D. Exhibit 1 Planning Analysis:

> "When a new transmission line or non-transmission alternative is added to the electric system, this often impacts the competitiveness of the energy market and can lower market prices in certain locations... the energy market becomes more robust as energy from different generators can now travel to different load points more efficiently and without congestion, thereby increasing competition and driving down locational marginal prices (LMP) in the market."

Please create table(s) similar to Tables 12-13, p. 38-39 of the Planning Analysis for the Badger-Coulee proposal to provide electric customers an overview of the most influential drivers, sensitivities and other assumptions for each Alternative and each Future in this docket. As a unifying factor, feature drivers, sensitivities and other assumptions that primarily affect **Energy Cost Savings** in the Applicants Net Economic Benefit Calculations. For example, influential factors in the ranking might involve:

- Study year(s)
- Drivers/Bounds (Low Medium & High)
- The Futures subcategorized for Each Alternative

  For each Future and Alternative provide/chart drivers, sensitivities and other assumptions with expected greatest influence on **Energy Cost Savings** which may include:

- Assumed load growth rate inside of Wisconsin^
- Assumed load growth rate outside of Wisconsin^
- Assumed energy growth rate inside of Wisconsin^
- Assumed energy growth rate outside of Wisconsin^
- Incremental FCITC created from added transmission facilities
- Incremental FCITC created from reducing customer demand such as targeted energy efficiency, load management and distributed generation (NTA's)
- Total Capacity Coal Retirements with Wisconsin^
- Total Capacity Coal Retirements outside of Wisconsin^
- Total Generation Additions in Wisconsin^
- Total Generation Additions outside of Wisconsin^
- Total Renewable Generation Additions in Wisconsin^
- Total Renewable Generation Additions outside of Wisconsin^
- Percent of Energy from Renewables for Wisconsin^
- Revenue from Wisconsin^ utilities selling power from generation

assets out of state
- Natural gas prices
- Necessary policy changes
- Carbon Taxes/Dividends

^ Or ATC's service territory if more accurately represented by the modeling.

8. (Continuation of Question 8 from SOUL's first set of data requests regarding **Calculations of Benefits from the Applicants' Non-Transmission Alternative.**) Below is a follow-up data request with labeling continuing the original alphabetical sequence:

02-SOUL-ATC-8C: In response to Request 3B. on p. 11, of Applicants' Response to S.O.U.L. of Wisconsin, Inc.'s First Document and Data Requests, it is stated:

> "The Applicants performed a similar benefit/cost analysis for all of the alternatives (i.e., the Project, LVA and NTA). The costs of energy efficiency and load management investments, for example, were compared to those investments' benefits, assuming a 40-year life of the investments. Thus, the Applicants assumed that the investment in energy efficiency and load management would occur in 2023, such that the benefits of those investments would be carried and measured throughout the study-term (40 years)."

In response to Request 8A. on p. 17, of Applicants' Response to S.O.U.L. of Wisconsin, Inc.'s First Document and Data Requests, it is stated:

> "The benefits of the NTA included the avoided electricity use due to energy efficiency, avoided electricity use due to residential renewables, energy sales from the utility-scale solar facility, and the energy savings from the demand response."

Did the Applicants only account for the transmission-associated avoided electricity benefit from energy efficiency, residential solar arrays and the utility-scale solar facility?

02-SOUL-ATC-8D: Did the Applicants account for energy savings the large users would realize from participating in 31.5 MW of Demand Response?

9. [No follow-up questions at this time]. Thank you for the explanation of Capacity Loss Savings.

10. (Continuation of Question 10 from SOUL's first set of data requests concerning the **Use of Net Savings Records from seven prior 345 kV expansion transmission lines in economic projections for the Project.)** Below is a follow-up data request with labeling that continuing the original alphabetical sequence:

02-SOUL-ATC-10D: On p. 22 of Appendix D Exhibit 1 Planning Analysis, the Applicants discuss the importance of the Project to enhance WUMS transfer,

> "New transmission can improve competitiveness if it enables external suppliers to offer additional generation into the relevant market... The competitiveness of WUMS is reviewed instead of all of Wisconsin because WUMS has been and will likely continue to

be designated as an area with market constraints. Hence improving the competitiveness of WUMS would be particularly beneficial to customers."

Since 2007, seven expansion transmission lines have been added in Wisconsin. All were justified, in considerable part, to address WUMS marketing constraints with economic benefits to Wisconsin ratepayers:

WI PSC Docket	Year Installed	Expansion Transmission Line	Location
137-ce-113	2007	Arrowhead-Weston	Superior – Wausau
05-ce-142	2018	Badger-Coulee	La Crosse -Madison
137-ce-149	2010	Paddock-Rockdale	IL- Madison
05-ce-136	2016	CapX2020	MN – La Crosse
137-ce-147	2012	Madison Beltline	Rockdale– Middleton
137-ce-166	2018	Bay Lake	Appleton-Morgan
137-ce-161	2013	Pleasant Valley- Zion	Kenosha – IL

MISO and Transmission Operators have access to voluminous electric market records. That past data can be used to forecast the potential economics of an 8th line for Wisconsin ratepayers to better evaluate the Project.

Using all means at the Applicants' disposal, please provide for Wisconsin electric customers these assessments:

(a) Document, quantitatively, the net savings in electricity costs due to the presence of the seven, prior 345 kV transmission expansion lines added in Wisconsin since 2007; and,

(b) From these historical records, estimate the economic value of adding an 8th line.

02-SOUL-ATC-10E: To what extent has the Applicants' economic planning for the Project, to date, used past performance records of prior 345 kV transmission lines in Wisconsin to make economic projections for the Project?

02-SOUL-ATC-10F: With energy use leveling off, wouldn't an economic projection for the Project based on established performance of the past seven lines provide highly relevant modeling data? If not, what are the major economic differences in the Project compared to Badger-Coulee, for example? Is there more economic impact from reliability projects and renewal assets with the Project than with Badger-Coulee? Are the estimated net energy savings from the Project and Badger-Coulee about the same?

02-SOUL-ATC-10G: Please provide a list all, other, 161 kV, or larger, transmission line improvements or new additions that have been announced to the Public Service Commission of Wisconsin that, if realized, would tend to reduce the Project's ability to provide net savings to Wisconsin electric customers.

11. (Continuation of Question 11 from SOUL's first set of data requests concerning the **economic impact on the Project from potential, additional generation in the vicinity of the 138/345 kV "Eden" substation at Montfort, WI.**) Below are follow-up data requests with labeling continuing alphabetical sequence:

02-SOUL-ATC-11F: The Applicants write on p. 41 of Appendix D Exhibit 1 Planning Analysis:

> "The fact that the LVA performed comparably to the Project was unexpected and prompted further analysis... the Applicants analyzed the PROMOD results and realized that the Project was almost too effective at bringing power into Wisconsin. Under certain conditions, the Project allowed too much power to flow into the south-central Wisconsin system, and under some outages, this could lead to congestion on the system east of the Eden Substation....Having the Hill Valley – Cardinal 345 kV line constructed as 345/138 kV double circuit capable will give the system planners increased flexibility to meet the changing needs of the system such as: • the potential need for the transmission system to handle increased generation in southwest Wisconsin including but not limited to recent generator interconnection requests at Eden 138 kV: J712 – 200 MW Wind, J855 – 100 MW Wind, J870 – 200 MW Solar, J871 – 100 MW Solar"

In response to Request 11A. on p. 23, of Applicants' Response to S.O.U.L. of Wisconsin, Inc.'s First Document and Data Requests, the Applicants describe:

> "The following conditions can contribute to higher levels of energy import into Wisconsin:
> - Scenarios with increased development of renewables in wind rich areas west of Wisconsin;
> - Unplanned and maintenance outages of larger generators in Wisconsin during high wind periods; and
> - Increased retirement of fossil fuel generation in Wisconsin."

When the Applicants wrote in April, 2018 that, "the Project allowed too much power to flow into the south-central Wisconsin system," was the recognition of the possibility of an additional, approximate 600 MW (faceplate) of generation in the vicinity of the Eden a key factor in making this statement?

02-SOUL-ATC-11G: Please characterize the impact on Energy Cost Savings this addition of approximately 400-600 MW (faceplate) of generation at the Eden 138/345 kV substation would have on the Applicants most recent economic modeling (Applicants' Supplemental Response to PSCW Data Requests 1.172, 1.174, 1.195, 1.198, 1.200-1.206, 1.208, 1.209, 1.213-1.216, and 4.56, PSC REF#358760).

02-SOUL-ATC-11H: Would the 400-600MM of power intake at the Eden substation tend to increase or decrease the Energy Cost Saving Benefits for the CHC Project during the window of years studied?

02-SOUL-ATC-11I: Would 400-600MM of power intake to the Project at the Eden substation make generators in wind rich area west of Wisconsin less competitive or more competitive if inserted into the economic planning the Applicants have conducted thus far?

02-SOUL-ATC-11J: We note the Applicants included potential natural gas generation in their economic planning that we cannot find in the MISO queue (see Response to PSCW Data Request 01.210 and Response to PSCW Data Request 01.211 in Response to Data Request 1, Part 2 – Supplement, PSC REF#-347526. Generators that could be located in the vicinity of the Eden Substation, J870, J871, J947 and J855 were introduced to the MISO queue in July, 2017 before the cut off dates for PROMOD models used for Project analysis in October, 2017. Please explain why this potential of 400-600MM of generation in the vicinity of the Eden substation was not incorporated into the economic planning for the Project and other alternatives.

02-SOUL-ATC-11K: Would 400-600MM of power introduced at the Eden substation lower the Incremental FCITC Summer and Shoulder ratings that the Applicants have assumed in their economic planning to date? If so, roughly how much?

We note that even though the 200MW J712 wind project has been (temporarily?[6]) withdrawn from the MISO queue, another, 200 MW solar facility, J947, is in queue in the Grant County that was not included in the Applicants /Eden Substation accounting. Below are rough estimates created to help clarify our question. We could not summer or shoulder credit percentages for solar.

Rough Estimate C-HC Incremental FCITC from New Generation Introduced at or near EDEN Substation

Eden Area Interconnection Project	Type	Rating MW Faceplate	Capacity Factor	SUMMER PEAK Credit (Solar est)	SHOULDER PEAK Credit (Solar est)	Rough Estimate Percentage CHC Incremental FCITC Shoulder Peak (MW)	Rough Estimate Percentage CHC Incremental FCITC Shoulder Peak (MW)	APPLICANT CHC INCREMENTAL FCITC SUMMER PEAK (MW)	APPLICANT CHC INCREMENTA L FCITC SHOULDER PEAK (MW)
J855	Wind	100	0.36	0.14	0.4	**1%**	**3%**	1382	1231
J947	Solar	200	0.94	0.9	0.7	**13%**	**11%**	1382	1231
J870	Solar	200	0.94	0.9	0.7	**13%**	**11%**	1382	1231
J871	Solar	100	0.94	0.9	0.7	**7%**	**6%**	1382	1231
Totals		**600**				**34%**	**32%**		

12. (Continuing Question 12 from SOUL's first set of data requests concerning the **Policy Regulation Future and Project CO2 Emission Reduction potential**.) Below are new, follow-up data requests with labeling that continues the original alphabetical sequence:

SOUL's first set of data requests, Request 12B reads:

> "Including the Project and all Alternatives, figures in Table 4, p. 41 of Appendix D Exhibit 1 Planning Analysis forecast an average 26% increase in Energy Cost Savings for the Policy Regulation future with Limited Energy (PRLE) compared to the Policy Regulation (PR) future. Please explain how changing from a (higher) MISO "Mid" demand and energy sensitivity to a (lower) MISO "Low" demand forecast resulted in increased energy savings. Feel free to account

6 To the best of SOUL's knowledge, contracts with landowners still have active options.

for other factors as required"

To which the Applicants replied on p. 28:-29:

"The optimization of generation dispatch in the energy market is extremely complex. Any single change to an assumption can affect the results in several ways. It is important to note, regarding this future comparison, that the lower demand and energy forecasts were not limited to Wisconsin only. By lowering demand and energy throughout MISO, lower cost energy resources external to Wisconsin may become available. Improving the ability to access these lower cost resources, compared to available resources in Wisconsin, is one of the primary reasons Cardinal – Hickory Creek provides energy cost savings. As we assume lower or higher demand and energy levels, we are comparing different available resources, which have different costs.

02-SOUL-ATC-12H: In SOUL's first set of data requests, Request 12C reads:

Regarding the "renewable additions" assumed for the Policy Regulation future on p.38 of the Planning Analysis, please provide some specific examples of Wisconsin policy changes that applicants expect would stimulate these additions. Feel free to include changed policy examples outside of the categories described on p.38 as, "renewable portfolio standards and goals, economics, and business practices to meet carbon regulations."

The Applicants respond:

"Policy changes are not the only driver of renewable development. Market conditions can also drive renewable development. Nonetheless, below is a list of a few examples that could promote increased development of renewable resources:

- Continuation of renewable energy production tax credits beyond existing rules;
- Decreased costs for enrollment in utility renewable energy programs, such as Madison Gas and Electric's Green Power Tomorrow program; and
- Increases in Wisconsin's Renewable Portfolio Standard.

Below are observations concerning the three, possible policy improvements the Applicants have suggested.

In our reading, continuation of the renewable energy production tax credits beyond existing rules does not appear to be included in the "Policy Regulation" future. See p. 38 of the Planning Analysis, all of the Applicants' futures, including, Policy Regulation, "Tax credits for renewables continue until 2022 to model existing policy."

It appears that MGE's Green Power Tomorrow program's rate of $0.01 per kWh would not necessarily result in predictable, significant total increases as MGE customers can buy into the program from 1% to 100% of the energy use or choose to contribute a minimal monthly amount.

To the best of our knowledge, the last considered legislation effort to increase Wisconsin's RPS was tabled in committee in 2013.

Please provide further documentation of these and other Wisconsin policy changes that the Applicants assume are significant and appropriate to include in the "Policy Regulation" future.

02-SOUL-ATC-12I: Please provide documentation for all other, future, policy-driven enhancements that would occur in Wisconsin that Applicants consider to be part of the "Policy Regulation" future.

02-SOUL-ATC-12J: In SOUL's first set of data requests, Request 12G reads:

"Similarly, please provide data indicating forecasted CO2 emissions for the ATC and MISO footprints in 2026 and 2031with and without the Project in service for all five futures and, if possible, the Project with the Eden Outlet Restraint Resolved."

The Applicants responded:

"The Applicants estimated the reduction in CO2 emissions from Wisconsin power plants over the 40-year life of the Cardinal-Hickory Creek Project. The results of this analysis are shown in the table below:

Future	40-year CO2 Emissions Reduction in Wisconsin (Million Tons)
AAT	98
EF	20
PR	40
PR + Foxconn	42
PRLE	39

Please indicate if the above amounts would meet the CO2 reduction targets of the Futures in Figure 5.2-1 on p. 82 of MTEP17 Report Book, .pdf p. 303 in Appendix D Exhibit 1 Planning Analysis Document Appendices, PSC Ref 341716 as shown below. Please indicate the targeted year of compliance that MISO and the Applicants assume in Figure 5.2-1.

FUTURE	CARBON REDUCTION
Existing Fleet	-14% of current levels (2017)
Policy Regulations	-25% of 2005 levels
Accelerated Alternative Technologies	-35% of 2005 levels

02-SOUL-ATC-12K: Are the measure ton units, metric? Please characterize the estimated changes in these reduction amounts over time in these ways. Provide the expected reduction amounts for each future at the start and end of the 5 year economic planning window. For the 40 year duration, provide year by year amounts, or describe whether annual reduction amounts for each specified future steadily increase over 40 years, remain fairly steady over 40 years, steadily decrease over 40 years or assume trend different from these.

02-SOUL-ATC-12L: Would the total reduction amount for each future be entirely the result of estimated generation characteristics of the power being transported by the Project, combining Hickory Creek - Hill Valley and Hill Valley - Cardinal segments over 40 years?

02-SOUL-ATC-12M: In regard to the Applicants' CO2 Reduction calculations, With the Project conceived primarily as one integrated facility combining Hickory Creek - Hill Valley and Hill Valley – Cardinal segments, did Applicants assume the power being transported by the Project over 40 years would flow in both directions or primarily flow in one direction? If the later, would the assumed to be from west to east or east to west?

02-SOUL-ATC-12N: Assuming the Non-Fossil Fuel Generation transported by the Project to Cardinal substation would displace the Wisconsin fossil fuel generation mix at the current EPA CO2 reference displacement rate of .707 Metric Ton per MWH[7], how much transmission volume or capacity would be required on 365 day, 24 hour basis, without losses, to transport the amount of Non-Fossil Fuel Generation required to achieve the 40 year CO2 Emission reductions the Applicants have estimated for each future? The below sample calculations with EPA assumption may help clarify this request.

Future	40-year CO2 Emissions Reductions in Wisconsin	Metric Ton CO2 Avoided Per MWH of Non-Fossil Fuel Generation	40-year Total Required MWH of 100% Non-Fossil Fuel Generation for CO2 Reductions	Annual Average Required 100% Non-Fossil Fuel Generation (MWH)	Estimated Required Transmission Volume on a 365 day 24 hour basis over 40 years (MW)
AAT	98,000,000	0.7070	138,613,861	3,465,347	395.59
EF	20,000,000	0.7070	28,288,543	707,214	80.73
PR	40,000,000	0.7070	56,577,086	1,414,427	161.46
PR+Foxconn	42,000,000	0.7070	59,405,941	1,485,149	169.54
PRLE	39,000,000	0.7070	55,162,659	1,379,066	157.43

02-SOUL-ATC-12O: Please provide the effective (EPA-like) CO2 emission displacement rate(s) Applicants used to estimate displacement of Fossil Fuel Generation and corresponding CO2 reduction in Wisconsin generation -or- other calculation used to estimate the how much Non-Fossil Generation would have to introduced by the Project at the Cardinal

7 https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator

substation to achieve the CO_2 reduction estimates the Applicants have provided.

02-SOUL-ATC-12P: If applicable, please describe other ways the Project would reduce CO_2 Emissions other than the transporting power with inherently lower C02 Emission content compared to the average fossil fuel generation power mix in Wisconsin.

02-SOUL-ATC-12Q: Applicants have included nuclear power plant located in the Quad Cities in their economic modeling, (see 6.5.1 Modeling Assumptions p.47 "Turned on the Quad Cities power plant in Illinois and set the dispatch consistent with Multiregional Modeling Working Group (MMWG) models." Appendix D Exhibit 1 Planning Analysis Document) At least one Wisconsin utility contracts power from this ~1800 MW facility. Please provide an estimate of the 40-year power transfer amount from this plant for all futures that would be part of the Non-Fossil Generation transported by the Project into Wisconsin. Please provide this volume amount either as MWH over the 40 year planning period, or as an average percentage of estimated Non-Fossil Generation that would be transported by the Project in all futures.

02-SOUL-ATC-12R: Please provide the assessment, study or assumptions and calculations used to produce the CO_2 reduction amounts the Applicants have provided in the above chart from p. 32 of the Applicants' Responses to SOUL of Wisconsin's First Set of Discovery Requests (PSC REF#- 357719).

13. (Continuing Question 13 from SOUL's first set of data requests concerning **Low Voltage Asset Renewals.**) Below are follow-up data requests with labeling continuing the alphabetical sequence:

02-SOUL-ATC-13E: In SOUL's first set of data requests, Request 13A included this table with Asset Renewal projects:

Data from Revised Table 34: Southwest Wisconsin Asset Renewal Issues Response to Data Request No. 01.189

Transmission Line	Renewal Capital Cost ($M – 2018)	Avoided Renewal Benefit ($M – 2018)	Avoided Benefit Percentage of Renewal Capital Costs ($M – 2018)	Avoided Renewal Benefit @ 95% Marginal Cost ($M – 2018)
Nelson Dewey – Eden 138 kV (1st Upgrade)	28.9	22.1	76%	21.0
Nelson Dewey – Eden 138 kV (2nd Upgrade)	16	3.8	24%	3.6
Eden – Dodgeville 69 kV	31.5	9.1	29%	8.6
Wally Road – Stagecoach 69 kV	13	9.9	76%	9.4
Stagecoach – West Middleton 69 kV (Preferred Route)	5	2.5	50%	2.4
Total Preferred Route	**94.4**	**47.4**	50%	**45.0**
Stagecoach – West Middleton 69 kV (Alternate Route)	6.4	3.2	50%	3.0
Nelson Dewey – Hillman 138 kV	34.6	23.6	68%	22.4
Hillman – Falcon 138 kV	7.6	7.2	95%	6.8
Eden – Spring Green 138 kV	15.2	10.4	68%	9.9
Hillman – Eden 69 kV	24.6	15.2	62%	14.4
Total Alternate Route	**88.4**	**59.6**	67%	**56.6**

The Applicants note in response to SOUL's first set of data requests request 11D on p.25:

> "As described in the August 2017 Wisconsin Area Phase 1 System Impact Study (link below), the Eden – Wyoming Valley – Spring Green 138 kV line is presently a required Network Upgrade."

If by, "required Network Upgrade" the Asset Renewal project will be done as part of ATC's scheduled rebuilds, please explain if the $9.9M cost of rebuilding the Eden – Wyoming Valley 138 kV segment will be removed as an avoided cost benefit for the Project?

02-SOUL-ATC-13F: In SOUL's first set of data requests, Request 13A reads:

> "For each of the 10 Renewal Asset Projects in Revised Table 34, please provide estimates of the avoided costs for the following categories: Pole Replacements; Conductors; Substation Transformers; Other Substation Components; Other Expenses."

The Applicants responded to 13A as follows:

> The cost estimates were prepared without detailed scoping, engineering, site investigation, or risk assessment. The estimates were not provided on a cost per pole or cost per conductor basis; rather, the estimates were developed considering the line segments as whole. Each line was individually reviewed along with its local terrain to determine the total estimated cost to renew the asset. The total cost includes typical project costs such as the capital cost of the equipment as well as labor, taxes, etc.
>
> The cost estimates assumed that the lines will be upgraded on a like-for-like basis for structures (i.e. the same number and type of poles would be used to replace the aging poles), twisted pair phase conductors would be used on all lines, using T2- 4/0 Penguin for 69 kV lines and T2-477 Hawk for 138 kV lines (twisted pair phase conductor is the ATC standard due to conductor galloping concerns in the region). Optical Ground Wire (OPGW) was assumed on all lines. No substation components, including transformers, were included in the Avoided Asset Renewal Costs."

02-SOUL-ATC-13G: Please explain the reason for rebuilding Nelson Dewey – Eden 138 kV (X-16) in two separate steps/upgrades. We are aware that some of the wooden poles have already been replaced with steel poles.

02-SOUL-ATC-13H: Please explain why the Applicants feel it is mandatory to replace the conductors on all of the Asset Renewal projects? If possible, when illustrating your answer, please refer to the X-16 and Wally Road – Stagecoach 69 kV rebuild projects.

02-SOUL-ATC-13I Using figures from past, similar, Asset Renewal rebuild projects in the Applicants' records, please provide cost per mile estimates for the 138 kV and 69 kV rebuild initiatives described in the below table.

Assume terrain of the type found in the Project study area and include costs for equipment, materials, expenses and labor.

Facility Size	Asset Renewal Rebuilding Task	Typical Cost Per Mile
138 kV	Only replacing conductors and communication wires for a single circuit facility.	
138 kV	Only replacing the wooden poles with new wood poles for a single circuit facility.	
138 kV	Replacing wooden poles with wood poles and installing conductor for a single circuit at the same time.	
138 kV	Replacing wooden poles with steel poles and installing conductor for a single circuit at the same time.	
69 kV	Only replacing conductors and communication wires for a single circuit facility.	
69 kV	Only replacing the wooden poles with new wood poles for a single circuit facility.	
69 kV	Replacing wooden poles with wood poles and installing conductor for a single circuit at the same time.	
69 kV	Replacing wooden poles with steel poles and installing conductor for a single circuit at the same time.	

02-SOUL-ATC-13J: In SOUL's first set of data requests, Request 13A, the Applicants responded to 13A as follows:

> "No substation components, including transformers, were included in the Avoided Asset Renewal Costs."

Does this mean that <u>none</u> of the transformers in the Asset Renewal Project substations are expected to require age-related or precautionary replacement over the next 40 years?

02-SOUL-ATC-13K: If some of the transformers associated with the Asset Renewal Project substations are expected to require age-related or other precautionary replacement over the next 40 years, please list their associated substations and cost for each including equipment, materials, labor and revenue requirement. The below reference table may help clarify this request.

Southwest Wisconsin Asset Renewal Projects – Substations Expecting Transformers Over Next 40 Years

		Transformer(s) likely to be replaced and cost		Transformer(s) likely to be replaced and cost
Preferred Route				
Nelson Dewey – Eden 138 kV (1st Upgrade)	Nelson Dewey 138kV		Eden 138 kV	
Nelson Dewey – Eden 138 kV (2nd Upgrade)	"		"	
Eden – Dodgeville 69 kV	Eden 69 kV (#1)		Dodgeville 69 kV	
Wally Road – Stagecoach 69 kV	Wally Road 69 kV		Stagecoach 69 kV	
Stagecoach – West Middleton 69 kV (Preferred Route)			West Middleton 69 kV	
Alternate Route				
Stagecoach – West Middleton 69 kV (Alternate Route)				
Nelson Dewey – Hillman 138 kV			Hillman 138 kV	
Hillman – Falcon 138 kV			Falcon 138 kV	
Eden – Spring Green 138 kV ??			Spring Green 138 kV ??	
Hillman – Eden 69 kV	Hillman 69 kV		Eden 69 kV (#2)	

14. (Continuing Question 14 from SOUL's first set of data requests concerning **Wind Facilities Explicitly Conditioned on CHC** from Table D-4-1, pdf p. 18, Appendix D Exhibit 1 Planning Analysis Document Appendices CEII C27841 RE 341716. Below are follow-up data requests with labeling continuing the original alphabetical sequence:

02-SOUL-ATC-14B: (Thank you for providing links to the GIA's.)

Please help us clarify which wind farm projects the Applicants have determined are explicitly conditional on the Project. The facilities were initially provided in Table D-4-1. After confirming Project conditionality in the GIA's, please provide an updated list and links to GIA's not previously provided (such as G858 and J278, if applicable). The below reference table may help clarify this request:

Projects in Current Table D-4-1: GIAs Explicitly Conditioned on CHC

Project Number	MTEP Cited	Contingency
H096	B-C Only	(4) NRIS 0 until study made
J091	B-C Only	(4) NRIS 0 until study made
J870	B-C Only	(4) NRIS 0 until study made
G735	B-C Only	Contingency Restudy
H071	B-C and CHC	(4) NRIS 0 until study made
H008	B-C and CHC	Contingency Restudy
R39	B-C and CHC	Contingency Restudy
G826	B-C and CHC	Minimal Language
J395	CHC Only	(4) NRIS 0 until study made
H081	CHC Only	Contingency Restudy
G858	GIA Link Needed	?
J278	GIA Link Needed	?

02-SOUL-ATC-14C: The factors that are limiting the wind facilities are difficult to determine with the information provided in the GIA's. Please further describe the limiting factors hat are currently in place on the wind projects explicitly conditional on the construction of the Project. In non-technical language, what would effectively change with the operation of these facilities after the construction of the Project?

02-SOUL-ATC-14D: Please briefly describe the hardships of the alternative actions the wind facilities would be forced to consider if the Project was not added to the transmission system as the Applicant's propose?

02-SOUL-ATC-14E: To assess the monetary and environmental significance of the potential wind farm GIA compliances if the Project is built, please provide estimates of the annual MWH that is not currently not being delivered to the grid by the restricted wind facilities. If this data is too challenging to produce, please provide an estimate of the percentage of the potential total generation that is not being delivered to the grid from a typical facility that is experiencing comparable restrictions. The annual percentage estimate should reflect only the portion that would be enabled with GIA compliance from the Project being built.

15. **Ratepayer friendly account of the Monetized Range of Net Benefits of Alternatives to Wisconsin** Please refer to the data in Table 2.1-1: Monetized Range of Net Benefits of Alternatives to Wisconsin from p. 2 of the "Applicants' Supplemental Response to PSCW Data Request 1.169" REF#:358840 or more recent estimates provided by the Applicants.

02-SOUL-ATC-15A: In order to assess the monetary significance of the Project and Alternatives, please provide rough estimates of the economic benefits for each Alternative under each planning Future for an average residential Wisconsin electric customer on a per month basis over the 40 year period.

The purpose of this request is to provide average benefit distributions to Wisconsin Electric customers over 40 years in 2018 dollars in terms that typical ratepayers can understand. It is not a request for utility-specific, detailed information. It is understood that benefits from the Alternatives would not be spread uniformly across Wisconsin utilities (and their customers) and that calculations based on averaged state wide figures will not account for all distinctions.

The below reference table may help clarify the kind of information that is being requested.

APPROXIMATIONS OF WISCONSIN ELECTRIC CUSTOMER SHARE OF ECONOMIC BENEFITS^^

Economic Future	40 Year Net Benefits of Evaluated Alternatives (Includ. Costs; $Millions – 2018 PV)	40 Year Average Annual Benefits For Wisconsin Customers (Losses in Red)	2017 Average Residential Customer Monthly Share^	2017 Average Commercial Customer Monthly Share^	2017 Average Industrial Customer Monthly Share^	2027 Average Residential Customer Monthly Share*	2027 Average Commercial Customer Monthly Share*	2027 Average Industrial Customer Monthly Share*
	Estimated Cardinal Hickory Creek Economic Benefits							
Existing Fleet (EF)	22.7	$567,500	$0.005	$0.05	$2.92	$0.01	$0.04	$2.95
Policy Regulations with Low Energy (PRLE)	156.1	$3,902,500	$0.04	$0.32	$20.11	$0.04	$0.31	$20.31
Policy Regulations (PR)	105.5	$2,637,500	$0.03	$0.21	$13.59	$0.02	$0.21	$13.73
Policy Regulations with Foxconn (PRFoxconn)	129.2	$3,230,000	$0.03	$0.26	$16.65	$0.03	$0.25	$16.81
Accelerated Alternative Technologies (AAT)	249.3	$6,232,500	$0.06	$0.51	$32.12	$0.06	$0.49	$32.44
	Estimated Low Voltage Transmission Alternative Benefits							
Existing Fleet (EF)	-132.4	-$3,310,000	-$0.03	-$0.27	-$17.06	-$0.03	-$0.26	-$17.23
Policy Regulations with Low Energy (PRLE)	-18.6	-$465,000	-$0.004	-$0.04	-$2.40	-$0.004	-$0.04	-$2.42
Policy Regulations (PR)	-47.4	-$1,185,000	-$0.01	-$0.10	-$6.11	-$0.01	-$0.09	-$6.17
Policy Regulations with Foxconn (PRFoxconn)	-15.3	-$382,500	-$0.004	-$0.03	-$1.97	-$0.003	-$0.03	-$1.99
Accelerated Alternative Technologies (AAT)	270.4	$6,760,000	$0.06	$0.55	$34.84	$0.06	$0.53	$35.19
	Estimated Non-Transmission Alternative Benefits							
Existing Fleet (EF)	-5.4	-$135,000	-$0.001	-$0.01	-$0.70	-$0.001	-$0.01	-$0.70
Policy Regulations with Low Energy (PRLE)	3.7	$92,500	$0.001	$0.01	$0.48	$0.001	$0.01	$0.48
Policy Regulations (PR)	-6	-$150,000	-$0.001	-$0.01	-$0.77	-$0.001	-$0.012	-$0.78
Policy Regulations with Foxconn (PRFoxconn)	-19.9	-$497,500	-$0.005	-$0.04	-$2.56	-$0.004	-$0.04	-$2.59
Accelerated Alternative Technologies (AAT)	29.7	$742,500	$0.007	$0.06	$3.83	$0.01	$0.06	$3.87

^ Based on 2017 EIA Form 861 data: 3,038,715 WI Total Retail Customers; Consumption: 31% Residential; 34% Commercial and 35% Industrial
* 2027 figures based on 6.3% increase in Residential customers, 3% increase in Commercial customers and 1% decrease in Industrial customers of 2017 figures.
^^Benefit data from Table 2.1-1: Monetized Range of Net Benefits of Alternatives to Wisconsin" on p. 34 of the Cardinal Hickory Creek Application.

02-SOUL-ATC-15B: If Applicants observe other, significant, losses or gains that would occur on average Wisconsin electrical bills that would not be sufficiently accounted for in the approximation method described above in 15A, please describe them and quantify the extent of their financial impact on bills. Please state the changes as a range of possible percentage adjustments made to the 40 year approximate economic distributions from the Project as estimated in response to 02-SOUL-ATC-15A or using the sample computations in 02-SOUL-ATC-15A as a reference.

Respectfully submitted on February 7, 2018.

S.O.U.L of Wisconsin, Inc.

/s/ Rob Danielson

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BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Joint Application of American Transmission Company, ITC Midwest LLC, and Dairyland Power Cooperative, for Authority to Construct and Operate a New 345 kV Transmission Line from the Existing Hickory Creek Substation in Dubuque County, Iowa, to the Existing Cardinal Substation in Dane County, Wisconsin, to be Known as the Cardinal-Hickory Creek Project.	Docket No. 5-CE-146

APPLICANTS' OBJECTIONS TO S.O.U.L. OF WISCONSIN'S SECOND SET OF DISCOVERY TO AMERICAN TRANSMISSION COMPANY LLC, ITC MIDWEST LLC, AND DAIRYLAND POWER COOPERATIVE

Pursuant to Section E.1.d of the Prehearing Conference Memorandum in the above-captioned proceeding (*see* PSC REF#: 357500), Wis. Admin. Code § PSC 2.24, and Wis. Stat. ch. 804, American Transmission Company LLC, by and through its corporate manager ATC Management, Inc., ITC Midwest LLC, and Dairyland Power Cooperative (collectively, Applicants) provide the following written objections to the S.O.U.L. of Wisconsin's (Intervenor) Second Set of Document and Data Requests to the Applicants (Requests), which were served on February 7, 2019.

GENERAL OBJECTIONS

1. Hearing preparation and factual investigation are ongoing in this proceeding. The Applicants' responses and objections will therefore be based on and necessarily limited by the records and information in existence, presently recollected, and thus far discovered in the course of preparation of the responses and objections. Consequently, the Applicants reserve the right to make any changes in these objections or their responses if it appears at any time that omissions or errors have been made or that more accurate information becomes available. By this reservation,

the Applicants do not in any way assume a continuing responsibility to update their responses to the Requests.

2. The Applicants object to these Requests to the extent that they seek production of information protected by the attorney work product doctrine, the attorney-client privilege, joint defense/prosecution privilege, common interest doctrine, or any other applicable privilege. Nothing contained in the responses will be intended to, or shall in any way be deemed, a waiver of any such privilege or doctrine.

3. The Applicants object to each and every one of the Requests to the extent that it seeks documents or information that are not in the Applicants' possession, custody, or control.

4. The Applicants object to each and every one of the Requests to the extent it seeks documents or information equally or more readily available to Intervenor.

5. The Applicants object to each and every one of the Requests to the extent that the information has already been provided in the Applicants' filings in this case and is already available to Intervenor.

6. The Applicants object to the instructions as an attempt to impose obligations on them beyond what is required when responding to discovery by Chapter 804 of the Wisconsin Statutes, and PSC 2.24, Wis. Admin. Code.

7. The Applicants object to each and every Request to the extent that it is vague, ambiguous, overly broad, unduly burdensome, or not reasonably calculated to lead to the discovery of relevant information or admissible evidence.

8. The Applicants object to each and every Request to the extent that it seeks information that is confidential. The Applicants' production of such information is limited to those

individuals that have signed and submitted the necessary exhibits required pursuant to the confidentiality agreement between the parties and otherwise complied with the terms of such confidentiality agreement.

9. The Applicants object to each and every Request to the extent that it is unduly burdensome and seeks to make the Applicants function as consultants for Intervenor in that the Requests would require the Applicants to perform studies, gather information, or undertake other tasks that the Applicants have not completed.

10. The Applicants object to each and every Request to the extent that it seeks information that the Applicants did not use in analyzing the need for the Project and such information is not relevant to the issues in this docket.

11. The Applicants object to each and every Request to the extent that the burden and expense of producing the requested information far exceeds its probative value to any issue in this case or is disproportionate to the needs of the case.

12. The Applicants object to the requests to the extent they violate Wis. Stat. § 804.08(1)(am), which provides that a party cannot ask more than 25 interrogatories, including subparts, without advance consent from the judge.

13. The fact that the response to a particular Request may repeat one or more of these General Objections is not a waiver of the other General Objections, each and all of which are incorporated into the responses to each specific Request.

14. By submitting responses, the Applicants do not in any way adopt Intervenor's purported definitions of words and phrases.

SPECIFIC OBJECTIONS TO DOCUMENT REQUESTS

REQUEST FOR PRODUCTION NO. 1: The document identified as Appendix D, Exhibit 1 Planning Analysis Document CEII C27841 (PSC Ref# 341713) to the extent the below

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The below reference table may help clarify the kind of information that is being requested.

APPROXIMATIONS OF WISCONSIN ELECTRIC CUSTOMER SHARE OF ECONOMIC BENEFITS^^

Economic Future	40 Year Net Benefits of Evaluated Alternatives (Includ. Costs; $Millions – 2018 PV)	40 Year Average Annual Benefits For Wisconsin Customers (Losses in Red)	2017 Average Residential Customer Monthly Share^	2017 Average Commercial Customer Monthly Share^	2017 Average Industrial Customer Monthly Share^	2027 Average Residential Customer Monthly Share*	2027 Average Commercial Customer Monthly Share*	2027 Average Industrial Customer Monthly Share*
	Estimated Cardinal Hickory Creek Economic Benefits							
Existing Fleet (EF)	22.7	$567,500	$0.005	$0.05	$2.92	$0.01	$0.04	$2.95
Policy Regulations with Low Energy (PRLE)	156.1	$3,902,500	$0.04	$0.32	$20.11	$0.04	$0.31	$20.31
Policy Regulations (PR)	105.5	$2,637,500	$0.03	$0.21	$13.59	$0.02	$0.21	$13.73
Policy Regulations with Foxconn (PRFoxconn)	129.2	$3,230,000	$0.03	$0.26	$16.65	$0.03	$0.25	$16.81
Accelerated Alternative Technologies (AAT)	249.3	$6,232,500	$0.06	$0.51	$32.12	$0.06	$0.49	$32.44
	Estimated Low Voltage Transmission Alternative Benefits							
Existing Fleet (EF)	-132.4	-$3,310,000	-$0.03	-$0.27	-$17.06	-$0.03	-$0.26	-$17.23
Policy Regulations with Low Energy (PRLE)	-18.6	-$465,000	-$0.004	-$0.04	-$2.40	-$0.004	-$0.04	-$2.42
Policy Regulations (PR)	-47.4	-$1,185,000	-$0.01	-$0.10	-$6.11	-$0.01	-$0.09	-$6.17
Policy Regulations with Foxconn (PRFoxconn)	-15.3	-$382,500	-$0.004	-$0.03	-$1.97	-$0.003	-$0.03	-$1.99
Accelerated Alternative Technologies (AAT)	270.4	$6,760,000	$0.06	$0.55	$34.84	$0.06	$0.53	$35.19
	Estimated Non-Transmission Alternative Benefits							
Existing Fleet (EF)	-5.4	-$135,000	-$0.001	-$0.01	-$0.70	-$0.001	-$0.01	-$0.70
Policy Regulations with Low Energy (PRLE)	3.7	$92,500	$0.001	$0.01	$0.48	$0.001	$0.01	$0.48
Policy Regulations (PR)	-6	-$150,000	-$0.001	-$0.01	-$0.77	-$0.001	-$0.012	-$0.78
Policy Regulations with Foxconn (PRFoxconn)	-19.9	-$497,500	-$0.005	-$0.04	-$2.56	-$0.004	-$0.04	-$2.59
Accelerated Alternative Technologies (AAT)	29.7	$742,500	$0.007	$0.06	$3.83	$0.01	$0.06	$3.87

^ Based on 2017 EIA Form 861 data: 3,038,715 WI Total Retail Customers; Consumption: 31% Residential; 34% Commercial and 35% Industrial
* 2027 figures based on 6.3% increase in Residential customers, 3% increase in Commercial customers and 1% decrease in Industrial customers of 2017 figures.
^^Benefit data from Table 2.1-1: Monetized Range of Net Benefits of Alternatives to Wisconsin" on p. 34 of the Cardinal Hickory Creek Application.

Request 15B: If Applicants observe other, significant, losses or gains that would occur on average Wisconsin electrical bills that would not be sufficiently accounted for in the approximation method described above in 15A, please describe them and quantify the extent of their financial impact on bills. Please state the changes as a range of possible percentage adjustments made to the 40 year approximate economic distributions from the Project as estimated in response to 02-SOUL-ATC-15A or using the sample computations in 02-SOUL-ATC-15A as a reference.

OBJECTIONS TO REQUEST 15A: The Applicants object to this Request as vague, overbroad, and unduly burdensome. The Applicants also object to this Request to the extent that it seeks information or documents that are not in the Applicants' possession, custody, or control and to the extent it would require the Applicants to perform studies, gather information, or undertake other tasks that the Applicants have not completed.

OBJECTIONS TO REQUEST 15B: The Applicants object to this Request as vague, overbroad, and unduly burdensome. The Applicants also object to this Request to the extent that it seeks information or documents that are not in the Applicants' possession, custody, or control and to the extent it would require the Applicants to perform studies, gather information, or undertake other tasks that the Applicants have not completed.

DATED: February 14, 2019

As to objections:

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BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Joint Application of American Transmission Company, ITC Midwest LLC, and Dairyland Power Cooperative, for Authority to Construct and Operate a New 345 kV Transmission Line from the Existing Hickory Creek Substation in Dubuque County, Iowa, to the Existing Cardinal Substation in Dane County, Wisconsin, to be Known as the Cardinal-Hickory Creek Project.	Docket No. 5-CE-146

APPLICANTS' RESPONSES TO S.O.U.L. OF WISCONSIN'S SECOND SET OF DOCUMENT AND DATA REQUESTS

Pursuant to Section E.1.d of the Prehearing Conference Memorandum in the above-captioned proceeding (*see* PSC REF#: 357500), Wis. Admin. Code § PSC 2.24, and Wis. Stat. ch. 804, American Transmission Company LLC, by and through its corporate manager ATC Management, Inc., ITC Midwest LLC, and Dairyland Power Cooperative (collectively, Applicants) provide the following written responses to S.O.U.L. of Wisconsin's (Intervenor) Second Set of Document and Data Requests to the Applicants (Requests), which were served on February 7, 2019.

GENERAL OBJECTIONS

1. Hearing preparation and factual investigation are ongoing in this proceeding. The Applicants' responses and objections will therefore be based on and necessarily limited by the records and information in existence, presently recollected, and thus far discovered in the course of preparation of the responses and objections. Consequently, the Applicants reserve the right to make any changes in these responses if it appears at any time that omissions or errors have been made or that more accurate information becomes available. By this reservation, the Applicants do not in any way assume a continuing responsibility to update their responses to the Requests.

2. The Applicants object to these Requests to the extent that they seek production of information protected by the attorney work product doctrine, the attorney-client privilege, joint defense/prosecution privilege, common interest doctrine, or any other applicable privilege. Nothing contained in these responses is intended to, or shall in any way be deemed, a waiver of any such privilege or doctrine.

3. The Applicants object to each and every one of the Requests to the extent that it seeks documents or information that are not in the Applicants' possession, custody, or control.

4. The Applicants object to each and every one of the Requests to the extent it seeks documents or information equally or more readily available to Intervenor.

5. The Applicants object to each and every one of the Requests to the extent that the information has already been provided in the Applicants' filings in this case and is already available to Intervenor.

6. The Applicants object to the instructions as an attempt to impose obligations on them beyond what is required when responding to discovery by Chapter 804 of the Wisconsin Statutes, and PSC 2.24, Wis. Admin. Code.

7. The Applicants object to each and every Request to the extent that it is vague, ambiguous, overly broad, unduly burdensome, or not reasonably calculated to lead to the discovery of relevant information or admissible evidence.

8. The Applicants object to each and every Request to the extent that it seeks information that is confidential. The Applicants' production of such information is limited to those individuals that have signed and submitted the necessary exhibits required pursuant to the confidentiality agreement between the parties and otherwise complied with the terms of such confidentiality agreement.

9. The Applicants object to each and every Request to the extent that it is unduly burdensome and seeks to make the Applicants function as consultants for Intervenor in that the Requests would require the Applicants to perform studies, gather information, or undertake other tasks that the Applicants have not completed.

10. The Applicants object to each and every Request to the extent that it seeks information that the Applicants did not use in analyzing the need for the Project and such information is not relevant to the issues in this docket.

11. The Applicants object to each and every Request to the extent that the burden and expense of producing the requested information far exceeds its probative value to any issue in this case.

12. The Applicants object to the requests to the extent they violate Wis. Stat. § 804.08(1)(am), which provides that a party cannot ask more than 25 interrogatories, including subparts, without advance consent from the judge.

13. The fact that the response to a particular Request may repeat one or more of these General Objections is not a waiver of the other General Objections, each and all of which are incorporated into the responses to each specific Request.

14. By submitting responses, the Applicants do not in any way adopt Intervenor's purported definitions of words and phrases.

DOCUMENT REQUESTS

REQUEST FOR PRODUCTION NO. 1:. The document identified as Appendix D, Exhibit 1 Planning Analysis Document CEII C27841 (PSC Ref# 341713) to the extent the below sections contain publicly accessible information that is not protected as Critical Energy Infrastructure Information or commercial market competition information.

p. 24, Figure 6: CHC Diagram labeled as, "CEII." Please provide access to this diagram or explain why the entire diagram is redacted.

p. 26, Figure 7 LVA Diagram labeled as, "CEII." Please provide access to this diagram or explain why the entire diagram is redacted.

p. 46-47, Tables 9-12. Please redact the names of the LBA's and provide the data in the other columns, or provide totals for each column in all tables, or explain why it is necessary to redact the information in each of the columns or not provide the totals for all columns in Tables 9-12.

RESPONSE TO REQUEST FOR PRODUCTION NO. 1: The Applicants object to this Request to the extent it would require the Applicants to produce confidential information without a confidentiality agreement in place. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

This information is all confidential. If the Intervenor would like to sign a confidentiality agreement as other intervenors in this docket have done, it can do so and obtain this information. The Applicants cannot further redact the requested CEII. The entire diagrams are CEII. As for the data in the columns in Tables 9-12, this also cannot be redacted without giving away the confidential information. Because there are so few LBAs, revealing the data without the names would allow the public to figure out which data applies to which LBA.

REQUEST FOR PRODUCTION NO. 2: The document identified as Appendix D, Exhibit 1 PAD Appendices CEII C27841 (PSC Ref# 341715). In particular, please provide the public accessible data in the following sections:

Appendix D-6: Assumptions And Data Used In HHI Analysis, pdf p. 29. See redaction at the end of this statement, "Average import capability is the maximum 2016 imports of..." If this information is not publicly accessible, please explain the reason(s). If the redaction is numerical, please explain why the value and measured units should not be accessible to the public.

Table D-8-1 – Historical Coincident Peak Load and Weather Normalized Forecasted Peak Load from 2007 to 2027 on .pdf pages 32-43 except for Critical Electric Infrastructure or commercial market competition information or explain why historical and forecasted substation loads should not be accessible to the public.

RESPONSE TO REQUEST FOR PRODUCTION NO. 2: The Applicants object to this Request as vague and ambiguous and because it seeks confidential information without a confidentiality agreement in place. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

The redacted portion cited in Appendix D-6 should not have been marked confidential. The full sentence reads: "Average import capability is the maximum 2016 imports of 2687 MW."

The remaining information is all business confidential. If the Intervenor would like to sign a confidentiality agreement as other intervenors in this docket have done, it can do so and obtain this information. Historical and forecasted substation loads are business confidential information for each specific LBA. This information could be used by the LBAs and others to, among other things, obtain a competitive advantage in the energy market.

REQUEST FOR PRODUCTION NO. 3: The .xls format document with calculations identified as Attachment to Response to Data Request 01.169. (PSC Ref# 347516) based on Schedule 9 and Schedule 26A data for American Transmission Company, Northern States Power and Dairyland Power Cooperative or explain which data in the schedules from which the spreadsheet calculations are derived cannot be made available to the public, and/or name and describe other sources of data used to generate this spreadsheet that cannot be made available to the public.

RESPONSE TO REQUEST FOR PRODUCTION NO.3: The Applicants object to this Request as being vague and overbroad and to the extent it would require the Applicants to produce confidential information without a confidentiality agreement in place. The Applicants further object to this Request to the extent it seeks data or information that is equally or more readily available to the Intervenor. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

This information is all business confidential. If the Intervenor would like to sign a confidentiality agreement as other intervenors in this docket have done, it can do so and obtain this information. The spreadsheet includes tools developed by the Applicants that are business confidential and could be used by competitors.

REQUEST FOR PRODUCTION NO. 5: The 2017 and 2018 SW Wisconsin Operating Guides or document identified as Attachment to Response to Data Request 01.192 - C-27845. (PSC Ref# 347520). SOUL could not find reference to "Operating Guides" being protected as Critical Energy/Electric Infrastructure Information (CEII) in FERC Orders[1]. SOUL wishes to understand the nature of the 2017 and 2018 SW Wisconsin Operating Guides including their purpose and background, the geographic area(s) being monitored and affected, system re-configurations, the congestion binding, associated generation commitments, conditions requiring load shed guidance and their revision history to the greatest extent granted to the public.

RESPONSE TO REQUEST FOR PRODUCTION NO. 5: The Applicants object to this Request as vague, overbroad, and unduly burdensome, and to the extent that the burden of producing the requested information outweighs its probative value to any issue in this case. The Applicants further object to this Request to the extent it would require the Applicants to produce confidential information without a confidentiality agreement in place. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

Operating Guides describe real-world conditions and contingencies that could occur which would result in severe reliability issues. Operating Guides also describe the detailed step-by-step processes that are implemented to eliminate these potential issues. The detailed description of system vulnerabilities and detailed design information included in Operating Guides is CEII. The Applicants cannot redact these Operating Guides and produce them, as the entire Operating Guides are considered CEII. In other words, this information is all confidential. If the Intervenor would like to sign a confidentiality agreement as other intervenors in this docket have done, it can do so and obtain this information.

REQUEST FOR PRODUCTION NO. 8: The document identified as Supplemental Response to Data Request 1, Economic Analysis Update (C27849). (PSC Ref# 351942) including narrative and analysis accessible for public review in a format not requiring Ventyx or PowerWorld software to access.

[1] https://www.ferc.gov/legal//maj-ord-reg/land-docs/ceii-rule.asp?csrt=9891730892299641903

RESPONSE TO REQUEST FOR PRODUCTION NO. 8: The Applicants object to this Request as vague, overbroad, and unduly burdensome. The Applicants further object to this Request to the extent it seeks information from the Applicants that is equally or more readily available to Intervenor, to the extent it would require the Applicants to produce confidential information, and to the extent it seeks to make the Applicants function as consultants for Intervenor in that the Request would require the Applicants to perform studies, gather information, or undertake other tasks that the Applicants have not completed. The Applicants further object to this Request to the extent it asks for further redactions because performing such redactions would be unduly burdensome and not likely to lead to the discovery of admissible evidence. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

This information is all confidential. If the Intervenor would like to sign a confidentiality agreement as other intervenors in this docket have done, it can do so and obtain this information.

REQUEST FOR PRODUCTION NO. 9: The document identified as Response to Data Request 6 with Data Disc (C27850) (PSC Ref# 354246) including narrative and analysis accessible for public review in a format not requiring Ventyx or PowerWorld software to access.

RESPONSE TO REQUEST FOR PRODUCTION NO. 9: The Applicants object to this Request as vague, overbroad, and unduly burdensome. The Applicants further object to this Request to the extent it seeks information from the Applicants that is equally or more readily available to Intervenor, to the extent it would require the Applicants to produce confidential information, and to the extent it seeks to make the Applicants function as consultants for Intervenor in that the Request would require the Applicants to perform studies, gather information, or undertake other tasks that the Applicants have not completed. The Applicants further object to this Request to the extent it asks for further redactions because performing such redactions would be unduly burdensome and not likely to lead to the discovery of admissible evidence. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

This information is all confidential. If the Intervenor would like to sign a confidentiality agreement as other intervenors in this docket have done, it can do so and obtain this information.

REQUEST FOR PRODUCTION NO. 12: The document identified as, "**Attachments 1 and 2"** part of the Applicants' Responses to DALC's First Set of Data Requests, PSC Ref # 35898. SOUL respectfully requests the Applicants to make this document publicly accessible on the docket for other parties to become aware of and use.

REQUEST FOR PRODUCTION NO. 13: The document identified as, "**Attachment 1 to 01-DALC-ATC-06,**" part of the Applicants' Responses to DALC's First Set of Data Requests, PSC Ref # 358984. SOUL respectfully requests the Applicants to make this document publicly accessible on the docket for other parties to become aware of and use.

REQUEST FOR PRODUCTION NO. 14: The document identified as, "**Attachment 2 to 01-DALC-ATC-06,**" part of the Applicants' Responses to DALC's First Set of Data Requests, PSC Ref # 358984. SOUL respectfully requests the Applicants to make this document publicly accessible on the docket for other parties to become aware of and use.

REQUEST FOR PRODUCTION NO. 15: The document identified as, "**Attachments 3 and 4 to 01-DALC-ATC-06,**" part of the Applicants' Responses to DALC's First Set of Data Requests, PSC Ref # 358984. SOUL respectfully requests the Applicants to make this document publicly accessible on the docket for other parties to become aware of and use.

REQUEST FOR PRODUCTION NO. 16: The document identified as, "**Attachment 9 to 01-DALC-ATC-06**" part of the Applicants' Responses to DALC's First Set of Data Requests, PSC Ref # 358984. Please selectively redact CEII information from this document in order to make the non-confidential part of it accessible on the docket.

REQUEST FOR PRODUCTION NO. 17: The document identified as, "**1 to 7 01-DALC-ATC-07**" part of the Applicants' Responses to DALC's First Set of Data Requests, PSC Ref # 358984. SOUL respectfully requests the Applicants to make this document publicly accessible on the docket for other parties to become aware of and use.

REQUEST FOR PRODUCTION NO. 18: The document identified as, "NTA analysis included in a .zip file labeled, "**Attachment 1 to 01-DALC-ATC-14.**" as part of the Applicants' Responses to DALC's First Set of Data Requests, PSC Ref # 358984. SOUL respectfully requests the Applicants to make this document publicly accessible on the docket for other parties to become aware of and use.

REQUEST FOR PRODUCTION NO. 19: The document identified as, "Work papers related to energy cost savings. in response to **01- DALC-ATC-33**" as part of the Applicants' Responses to DALC's First Set of Data Requests, PSC Ref # 358984. SOUL respectfully requests the Applicants to make this document publicly accessible on the docket for other parties to become aware of and use.

REQUEST FOR PRODUCTION NO. 20: The document identified as, "**Attachment 1 to 01-DALC- ATC-16,**" as part of the Applicants' Responses to DALC's First Set of Data Requests, PSC Ref # 358984. SOUL respectfully requests the Applicants to make this document publicly accessible on the docket for other parties to become aware of and use.

REQUEST FOR PRODUCTION NO. 21: The document identified as, "**Attachment 2 to 01-DALC-ATC-16**" as part of the Applicants' Responses to DALC's First Set of Data Requests, PSC Ref # 358984. SOUL respectfully requests the Applicants to make this document publicly accessible on the docket for other parties to become aware of and use.

REQUEST FOR PRODUCTION NO. 22: The document identified as, "**Attachment 3 to 01-DALC-ATC- 16**" as part of the Applicants' Responses to DALC's First Set of Data Requests, PSC Ref # 358984. SOUL respectfully requests the Applicants to make this document publicly accessible on the docket for other parties to become aware of and use.

REQUEST FOR PRODUCTION NO. 23: The document identified as, "**Attachment 3 to 01-DALC-ATC- 16**" as part of the Applicants' Responses to DALC's First Set of Data Requests, PSC Ref # 358984. SOUL respectfully requests the Applicants to make this document publicly accessible on the docket for other parties to become aware of and use.

REQUEST FOR PRODUCTION NO. 24: The document identified as, "**Attachments 1 to 8 to 01-DALC-ATC-18.**" as part of the Applicants' Responses to DALC's First Set of Data Requests, PSC Ref # 358984. SOUL respectfully requests the Applicants to make this document publicly accessible on the docket for other parties to become aware of and use.

REQUEST FOR PRODUCTION NO. 25: The document identified as, **"Attachment 1 to 01-DALC-ATC-20."** as part of the Applicants' Responses to DALC's First Set of Data Requests, PSC Ref # 358984. SOUL respectfully requests the Applicants to make this document publicly accessible on the docket for other parties to become aware of and use.

REQUEST FOR PRODUCTION NO. 26: The document identified as, **"Attachments 1 to 3 to 01- DALC-ATC-21,"** as part of the Applicants' Responses to DALC's First Set of Data Requests, PSC Ref # 358984. Please selectively redact CEII information from Attachment 3 in order to make the non-confidential part of it accessible on the docket. SOUL respectfully requests the Applicants to make this document publicly accessible on the docket for other parties to become aware of and use.

REQUEST FOR PRODUCTION NO. 27: The document identified as, **"Attachment 1 to 01-DALC-ATC-25"** as part of the Applicants' Responses to DALC's First Set of Data Requests, PSC Ref # 358984. SOUL respectfully requests the Applicants to make this document publicly accessible on the docket for other parties to become aware of and use.

REQUEST FOR PRODUCTION NO. 28: The document identified as, "**Attachment 1 to 01-DALC-ATC-14**" as part of the Applicants' Responses to DALC's First Set of Data

Requests, PSC Ref # 358984. SOUL respectfully requests the Applicants to make this document publicly accessible on the docket for other parties to become aware of and use.

COMBINED RESPONSES TO REQUESTS FOR PRODUCTION 12-28: These Requests seek numerous attachments to the Applicants' recently filed Responses to DALC's First Set of Data Requests. The Applicants will produce all non-confidential attachments to you in conjunction with their responses to these Requests. In the future, and as discussed at the second prehearing conference in this docket, the Applicants will either ERF attachments or provide a link to all parties where the attachments can be downloaded.

As SOUL is aware, numerous of the DALC discovery response attachments include confidential information, which the Applicants can only release to Intervenor after the Intervenor signs a confidentiality agreement. After consultation with SOUL's representative, it is the Applicants' understanding that SOUL is not willing to enter into a confidentiality agreement to receive such information. As such, the Applicants object to this Request to the extent it would require the Applicants to produce confidential information without a confidentiality agreement in place. The Applicants further object to this Request to the extent it asks for further redactions because performing such redactions would be unduly burdensome and not likely to lead to the discovery of admissible evidence--particularly given that the Intervenor could receive such information if it would agree to sign a reasonable confidentiality agreement.

DATA REQUESTS

DATA REQUEST NO. 1: (Continuation of Question 1 from SOUL's first set of data requests regarding further substantiation of **potential electric market advantages of the Project and Alternatives.**)

SOUL would like to thank the Applicants for referencing Section 6.8 (Improved Competitiveness) of the Appendix D Exhibit 1 Planning Analysis and the assumptions for this assessment of Market Power in Appendix D-6, Appendix D Exhibit 1 Planning Analysis Document Appendices. Below is a follow-up data request with labeling continuing the original alphabetical sequence. With this second set of requests, SOUL is adopting the request naming prefix used by DALC for consistency and convenience in future references.

Request 1C: On p. 69 in Section 6.8, of the Appendix D Exhibit 1 Planning Analysis, it states:

> "The Herfindahl-Hirschman Index (HHI) is used to evaluate the extent of competition in power markets. Markets in which the HHI is between 1000 and 1800 points are considered to be moderately concentrated and those in which the HHI is in excess of 1800 points are considered to be highly concentrated.
>
> The HHI can be calculated for expected market conditions with and without new transmission facilities, such as the Project. The competitiveness of a region varies with the assumed fraction of generation capacity available to the market by the suppliers that make up the market, as well as by the amount of summer on-peak and shoulder period incremental transfer capability that results from the construction of the proposed transmission facility.
>
> The competitiveness of the market is analyzed from two perspectives: Gross HHI and Net HHI. Gross HHI does not consider the suppliers' load obligations and exposes the entire generation capability to the market. The Net HHI subtracts the suppliers' load obligations from their supply portfolios. The residual generation capability represents the supplier-specific capacity that is available to the market.
>
> Since Wisconsin is not a retail choice state, the supplier (i.e., the state-based electric utility) has an obligation to serve its native load; as a result, the Net HHI is more relevant to the analysis than the Gross HHI."

Please explain how Applicants determined the estimated 2027 No-Action Summer Peak Gross HHI value of 2279. Identify the sources of the data utilized in making the estimate.

Request 1D: Please provide the calculations used to estimate the 2027 Net HHI figures for the No-Action cases in Tables 42-45 on p. 70-71 as derived from data described as, "suppliers' load obligations" (Wisconsin based utilities) and, "supply portfolios."

Request 1E: Please describe by generic name(s), what constitutes the "load obligations" that are subtracted from the Gross HHI values to derive the Net HHI values.

Request 1F: Please explain if and how these wind generators: Top of Iowa II, Top of Iowa III, Barton, Crane Creek and Bent Tree (from pdf p. 29, Appendix D-6, Appendix D Exhibit 1 Planning Analysis Document Appendices) are incorporated into the requested "load obligations" and/or other HHI calculations. It seems Wisconsin utilities either own these referenced generators or are contracted to purchase power from them.

Request 1G: Please explain the meaning of and the impact of note 1, "Generation Capacity assumes a 100 percent wind credit." on the data in Table D-6-1, pdf p. 29, Appendix D-6, Appendix D Exhibit 1 Planning Analysis Document Appendices.

Request 1H: Please describe what the expected impacts would be on the Applicants' HHI calculations in Tables 42-45 on p. 70-71 of the Appendix D Exhibit 1 Planning Analysis if Dairyland Power Cooperative (DPC) and Northern States Power (NSP) utilities were included in the analysis. Would the estimated change in market concentration in 2027 due to the Project affect the economics of DPC and NSP and, if so, would including these utilities in the Applicants' HHI analysis cause the Net HHI values in Tables 42-45 on p. 70-71 to increase or decrease?

Request 1I: In response to question 1A in SOUL's first Discovery Requests, the Applicants explain:

> "First Contingency Incremental Transfer Capability (FCITC) was determined by transmission planning studies that increased generation output in Iowa and decreased generation output in Wisconsin until the first transmission element was loaded to 100 percent of the applicable rating with a full set of contingencies. The FCITC was identified in a shoulder and summer peak model for each of the alternatives. The difference between the FCITC of an alternative and the No Action Alternative were reported as *Incremental FCITC* and used in the calculations in Section 6.8 (Improved Competitiveness) of the Planning Analysis Document."

As FCITC values already include an *incremental* amount, specifically defined as the amount above normal base power transfers that can be transferred over the interconnected transmission systems in a reliable manner, please clarify if the "Incremental FCITC" figures provided for each of the Alternatives in Tables 42-45 on p. 70-71 of the Appendix D Exhibit 1 Planning Analysis include or do not include normal base power transfers.

Request 1J: Please provide the 2027 estimated base power transfer amounts[2] for each of the Alternatives in Tables 42-45 on p. 70-71 of the Appendix D Exhibit 1 Planning Analysis that were inherent in the Applicants' HHI analysis or in prior studies.

Request 1K: On p. 68 of the Appendix D Exhibit 1 Planning Analysis, the Applicant's state:

> "A new transmission facility can improve the market structure and competitiveness if the facility enables external suppliers to offer additional generation into a specifically-defined market. The increased generation alternatives will increase competition causing a reduction in market prices. To the extent that suppliers who participate in the market are exposed to such

[2] See definition 16 in this document.

market prices through short-term purchases and the turnover of longer-term contracts, these reductions in market prices will also reduce end-user costs."

As charted below, the estimated 2027 changes in Net HHI values for all alternatives in Tables 43 and 45 range from 1.8-16.3%. Please elaborate on the economic benefits that Wisconsin electric customers could expect from the Project's 10.1% to 16.3% improvement in market competitiveness in 2027.

Table 43: 2027 Summer Peak Net HHI

Alternative	Incremental FCITC (MW)	NA	Net HHI w/Alternative	Change in Net HHI	Percentage Change
CHC	1382	1011	918	**-93**	**10.1%**
LVA	980.3	1011	935	**-76**	**8.1%**
NTA	170	1011	993	**-18**	**1.8%**
Table 45: 2027 Shoulder Net HHI					
CHC	1231	1652	1421	**-231**	**16.3%**
LVA	784.9	1652	1492	**-160**	**10.7%**
NTA	334.2	1652	1578	**-74**	**4.7%**

Request 1L: If spread across 40 years, how would these economic benefits from improved market competitiveness compare to the benefits in Table 46: Monetized Range of Net Benefits of Alternatives to Wisconsin on p. 84 of the Appendix D Exhibit 1 Planning Analysis?

Request 1M: Please provide Applicants' calculations used to produce the 2027 Incremental FCITC value of 170 MW used for the NTA Alternative in Tables 42-45 on p. 70-71 of the Appendix D Exhibit 1 Planning Analysis. For purposes of clarity, please explain the relation of this estimated increase in Incremental FCITC in 2027 and the 2023 On Peak Capacity total of 66.1 MW in Table 2: NTA Components on p. 28 of the Appendix D Exhibit 1 Planning Analysis.

RESPONSE TO REQUEST 1C: Subject to the General Objections identified above, the Applicants respond as follows:

If the Intervenor signs a confidentiality agreement, the Applicants will supply a spreadsheet showing all calculations made to calculate this figure. For a more general description of how this figure was calculated, please see pages 69 through 72 of the Planning Analysis Document.

RESPONSE TO REQUEST 1D: The Applicants object to this request as vague. The Applicants further object to this Request to the extent it would require the Applicants to produce confidential information without a confidentiality agreement in place. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

See Response to Request 1C.

RESPONSE TO REQUEST 1E: The Applicants object to this Request as vague. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

"Load obligations" are the amount of load projected to be served by the market participant.

RESPONSE REQUEST 1F: Subject to the General Objections identified above, the Applicants respond as follows:

That is correct. Wisconsin utilities either own these generators or have a contract for a portion of their power. The owned capacity and contracted capacity is used to meet the Wisconsin utilities' load obligations.

RESPONSE TO REQUEST 1G: Subject to the General Objections identified above, the Applicants respond as follows:

Note 1 means that the Generation Capacity (MW) column in Table D-6 counts 100% of the capacity from each wind plant for the purpose of summing the total generation capacity of each Market Participant. As noted in the Key Assumptions used in the analysis, the HHI calculations assumed the capacity credit for wind generators is 15.6 percent on summer peak and 40.0 percent on shoulder.

RESPONSE TO REQUEST 1H: The Applicants object to this request as vague and overbroad. The Applicants also object to this Request as unduly burdensome to the extent it would require the Applicants to perform studies, gather information, or undertake other tasks the Applicants have not completed. The Applicants further object to this Request to the extent it would require the Applicants to produce confidential information without a confidentiality agreement in place. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

The Applicants did not perform the analysis that would be needed to answer this question. The following information is only intended to explain why DPC and NSP were not included.

The Herfindahl-Hirschman Index (HHI) is used to evaluate the extent of competition in power markets. The ATC service area is the power market assumed in the calculation of the HHI given the established geographical and transmission system limitations; as a result, DPC and NSP have been excluded from the analysis.

<u>RESPONSE TO REQUEST 1I</u>: Subject to the General Objections identified above, the Applicants respond as follows:

The Incremental FCITC is the FCITC calculated for each alternative minus the No Action Alternative FCITC. The definition of "base transfer" in the Request is unclear, but The No Action Alternative can be considered the "base case" and the Incremental value reported is the amount of transfer enabled above and beyond this "base case".

<u>RESPONSE TO REQUEST 1J</u>: Subject to the General Objections identified above, the Applicants respond as follows:

The definition of "base power transfer" in the Request is unclear but the Applicants are interpreting it to mean the pre-transfer, post-contingent flow on the limiting element. This information is shown as the "PreShift" in Attachment 1 of 01-DALC-ATC-21 and in the table below.

Model	Alternative	PreShift (MW)	Rating (MVA)
Shoulder	NA	187.6	221.0
Shoulder	CHC	132.6	221.0
Shoulder	LVA	152.8	221.0
Shoulder	NTA	171.3	221.0
Summer Peak	NA	233.9	221.0
Summer Peak	CHC	183.9	221.0
Summer Peak	LVA	194.5	221.0
Summer Peak	NTA	227.0	221.0

RESPONSE TO REQUEST 1K: The Applicants object to this request as vague, overbroad, and unduly burdensome. The Applicants also object to this Request to the extent it would require the Applicants to perform studies, gather information, or undertake other tasks that the Applicants have not completed. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

The Applicants have not calculated economic benefits using the HHI. Please see the Planning Analysis Document for a description of how the Applicants have calculated the Project's net economic benefits.

RESPONSE TO REQUEST 1L: The Applicants object to this request as vague and overbroad. The Applicants also object to this Request as unduly burdensome to the extent it would require the Applicants to perform studies, gather information, or undertake other tasks the Applicants have not completed. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

This comparison can't be made. See Response to Request 1K.

RESPONSE TO REQUEST 1M: The Applicants object to this request as vague and overbroad. The Applicants also object to this Request to the extent it would require the Applicants to perform studies, gather information, or undertake other tasks the Applicants have not completed. The Applicants further object to this Request to the extent it would require the Applicants to produce confidential information without a confidentiality agreement in place. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

NTA Incremental FCITC is the amount of additional transfer enabled in the NTA models beyond the No Action Alternative models. The FCITC for the most limiting element is defined as:

FCITC = (Rating – PreShift)/TDF

Incremental FCITC = Alternative FCITC – No Action Alternative FCITC

The change in FCITC from a base model to a project model is a result of the effect on the PreShift flow and the Transfer Distribution Factor (TDF). The PreShift flow is the pre-transfer, post-contingent flow on the limiting element. The TDF is the portion of the transferred power that flows through the limiting element. The major effect of the NTA is a reduction of the PreShift flow which is mainly a result of the location of the utility-scale solar plant at the Nelson Dewey 138 kV Substation.

DATA REQUEST NO. 2: (Continuation of Question 2 from SOUL's first set of data requests regarding expenses contained in the Applicants' estimated **Project Costs**.) Below is a follow-up data request with labeling continuing alphabetical sequence:

Request 2B: In response to Request 2A on p. 10, of Applicants' Response to S.O.U.L. of Wisconsin, Inc.'s First Document and Data Requests, it is stated, "40 year Hardening, cyber and other Security expenses: assumed to be included in the remaining $500M (cost)." Please provide a more detailed estimate of hardening, cyber and other security expense costs that can be expected for the Project over 40 years based on studies or other reliable sources.

Request 2C: Please provide documentation that hardening, cyber and other security expenses have been observed by the Public Service Commission of Wisconsin (PSCW) as expenses expected to be paid for by Transmission Operators in Wisconsin in previous permits for 345 kV transmission lines or other arrangements with PSCW?

Request 2D: Also in response to Request 2A on p. 10,of Applicants' Response to S.O.U.L. of Wisconsin, Inc.'s First Document and Data Requests, when accounting for Project expenses over 40 years, the Applicants observe that revenue requirements, operation and maintenance expenses would total $100M:

> "Revenue Requirement Adders over 40 years: $100M; Construction Period costs: assumed to be included in the remaining $500M; 40 year Maintenance expenses: assumed to be included in the $100M of revenue requirement adders; 40 year Operation expenses: assumed to be included in the $100M of revenue requirement adders."

Please provide documentation that Revenue Requirement Adders, Maintenance and Operation expenses have averaged around $2.5M per year for a Wisconsin-based 345 kV transmission line in 2018 era dollars.

RESPONSE TO REQUEST 2B: The Applicants object to this Request as overbroad and unduly burdensome. The Applicants also object to this Request to the extent that it seeks to make the Applicants function as consultants for Intervenor in that the Request would require the Applicants to gather information or undertake other tasks that the Applicants have not completed. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

The initial planning-level estimates of the cost of Cardinal-Hickory Creek did not include detailed estimates of each project component. The final detailed estimate of $492M (year of occurrence dollars) included with the CPCN application does include these details. The planning-level estimate of $500M (2023 dollars) was made so that the NTA could be sized and studied while work outside of the Planning Analysis Document was being completed.

RESPONSE TO REQUEST 2C: The Applicants object to this Request as vague and overbroad. The Applicants also object to this Request to the extent that it is unduly burdensome and seeks to make the Applicants function as consultants for Intervenor in that the Request would require the Applicants to gather information or undertake other tasks that the Applicants have not completed and to the extent that the Requests seeks information from the Applicants that is equally or more readily available to Intervenors. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

ATC has installed appropriate fences, walls, cameras, and lighting at various substations. As stated in Response to 02-SOUL-ATC-2B, the Planning Analysis Document did not include the final cost estimates of the Project. See Response to Request 2B.

RESPONSE TO REQUEST 2D: The Applicants object to this Request as overbroad, not likely to lead to the discovery of admissible evidence, unduly burdensome and to the extent it seeks information or documents that are not in the Applicants' possession, custody, or control. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

The Applicants are not claiming an annual expense of $2.5M per year. The $100M is a planning-level estimate of the 2023 present value of the annual revenue requirements over forty years. The combined assumptions of $500M capital cost, 20% present value revenue requirements, and 15% MVP cost sharing appear to be reasonable based on the 2018 PV of $66.0M and final calculation by ATC finance specialists of a 2018 PV of $67.0M. As mentioned in previous responses, the initial planning-level estimates of $500M and $100M were only used to size the NTA.

DATA REQUEST NO. 7: (Continuation of Question 7 from SOUL's first set of data requests regarding **Energy Cost Savings** and supplementing **Need for Overview Tables compiling significant drivers, sensitivities, policies and other assumptions for all Alternatives under all Futures.**) Below is a follow-up data request with labeling continuing alphabetical sequence:

Request 7B: Applicants have recently indicated they will be updating the Planning Analysis Document as stated on p. 2 of Applicants' Supplemental Response to PSCW Data Requests 1.172, 1.174, 1.195, 1.198, 1.200-1.206, 1.208, 1.209, 1.213-1.216, and 4.56 (PSC REF#358760):

> "In order to ensure that the Commission and all parties can easily obtain all of the modeling results in one location, the Applicants plan to file an update

> to the Planning Analysis Document that was filed with the Application which incorporates all of the changes described herein."

We note that, to date, the planning document and other application materials for this docket do not contain overview charts compiling and clarifying drivers, sensitivities and other key factors for all futures as was provided for the Badger-Coulee docket (see Tables 12-13, p. 38-39, Planning Analysis of the Badger-Coulee Transmission Project PSC Ref#204739).

We also note that the current docket does not yet contain an explanation of the estimated economic impacts for all alternatives based on ProMod and other analysis in language that electric customers and the public can easily understand.

Additionally, we note that narrative for Tables 37-41 on p. 66-67, Appendix D. Exhibit 1 Planning Analysis (which we assume will be updated in the new document) does not explain why Energy Cost Saving are so influential in Net Economic Benefit Calculations across the studied futures nor discuss factors that tend to cause the range in the estimated Energy Cost Saving benefits.

The Applicants' limited discussion of these economic factors can be found in Section 4.1.1 Energy Cost Savings, p. 20, Appendix D. Exhibit 1 Planning Analysis:

> "When a new transmission line or non-transmission alternative is added to the electric system, this often impacts the competitiveness of the energy market and can lower market prices in certain locations... the energy market becomes more robust as energy from different generators can now travel to different load points more efficiently and without congestion, thereby increasing competition and driving down locational marginal prices (LMP) in the market."

Please create table(s) similar to Tables 12-13, p. 38-39 of the Planning Analysis for the Badger-Coulee proposal to provide electric customers an overview of the most influential drivers, sensitivities and other assumptions for each Alternative and each Future in this docket. As a unifying factor, feature drivers, sensitivities and other assumptions that primarily affect **Energy Cost Savings** in the Applicants Net Economic Benefit Calculations. For example, influential factors in the ranking might involve:

- Study year(s)
- Drivers/Bounds (Low Medium & High)
- The Futures subcategorized for Each Alternative

For each Future and Alternative provide/chart drivers, sensitivities and other assumptions with expected greatest influence on **Energy Cost Savings** which may include:

- Assumed load growth rate inside of Wisconsin^
- Assumed load growth rate outside of Wisconsin^
- Assumed energy growth rate inside of Wisconsin^
- Assumed energy growth rate outside of Wisconsin^
- Incremental FCITC created from added transmission facilities
- Incremental FCITC created from reducing customer demand such as targeted energy efficiency, load management and distributed generation (NTA's)
- Total Capacity Coal Retirements with Wisconsin^
- Total Capacity Coal Retirements outside of Wisconsin^
- Total Generation Additions in Wisconsin^
- Total Generation Additions outside of Wisconsin^
- Total Renewable Generation Additions in Wisconsin^
- Total Renewable Generation Additions outside of Wisconsin^
- Percent of Energy from Renewables for Wisconsin^
- o Revenue from Wisconsin^ utilities selling power from generation assets out of state
- Natural gas prices
- Necessary policy changes
- Carbon Taxes/Dividends
  ^ Or ATC's service territory if more accurately represented by the modeling.

RESPONSE TO REQUEST 7B: The Applicants object to this Request as vague, overbroad, and unduly burdensome. The Applicants further object to this Request to the extent it seeks to make the Applicants function as consultants for the Intervenor in that the Request would require the Applicants to perform studies, gather information, or undertake other tasks that the Applicants have not yet completed, or collect data or information that is not in the Applicants' possession, custody or control. The Applicants further object to this Request to the extent it would require the Applicants to produce confidential information without a confidentiality agreement in place. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

Additional detailed information regarding the Applicants' planning analysis and the need for the Project can be found in Direct-Applicants-Dagenais.

Regarding the request for a table(s) similar to Tables 12-13, p. 38-39 of the Planning Analysis for the Badger-Coulee, the Applicants have not created a similar table in this case because the futures in this case came from MISO's stakeholder process. Tables 12-13 in the Badger Coulee Planning Analysis were developed by ATC for the Badger Coulee project. Since that time, MISO has developed robust and well vetted futures for the region. As noted in the Planning Analysis Document for this Project, the Applicants are using the MISO futures to better align with regional transmission planning processes. MISO discusses all drivers and assumptions for each future in the MTEP17 study report.

Regarding the request to provide insight on which drivers, sensitivities, and other assumptions could have the greatest influence on Energy Cost Savings, this analysis is not done by ATC.

DATA REQUEST NO. 8: (Continuation of Question 8 from SOUL's first set of data requests regarding **Calculations of Benefits from the Applicants' Non-Transmission Alternative.**) Below is a follow-up data request with labeling continuing the original alphabetical sequence:

Request 8C: In response to Request 3B. on p. 11, of Applicants' Response to S.O.U.L. of Wisconsin, Inc.'s First Document and Data Requests, it is stated:

> "The Applicants performed a similar benefit/cost analysis for all of the alternatives (i.e., the Project, LVA and NTA). The costs of energy efficiency and load management investments, for example, were compared to those investments' benefits, assuming a 40 year life of the investments. Thus, the Applicants assumed that the investment in energy efficiency and load management would occur in 2023, such that the benefits of those investments would be carried and measured throughout the study-term (40 years)."

In response to Request 8A. on p. 17, of Applicants' Response to S.O.U.L. of Wisconsin, Inc.'s First Document and Data Requests, it is stated:

> "The benefits of the NTA included the avoided electricity use due to energy efficiency, avoided electricity use due to residential renewables, energy sales from the utility-scale solar facility, and the energy savings from the demand response."

Did the Applicants only account for the transmission-associated avoided electricity benefit from energy efficiency, residential solar arrays and the utility-scale solar facility?

Request 8D: Did the Applicants account for energy savings the large users would realize from participating in 31.5 MW of Demand Response?

RESPONSE TO REQUEST 8C: The Applicants object to this request as vague. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

The definition of "transmission-associated avoided electricity benefit" in the Request is unclear. Energy efficiency and residential solar arrays were represented as decreased loads in the planning models. These load-associated changes contribute to the overall benefits of the NTA.

RESPONSE TO REQUEST 8D: The Applicants object to this request as vague. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

In general, large energy users that are impacted by demand response events don't experience a net economic benefit from the event, since business activities and revenue streams are significantly adversely impacted by the loss of power during the event. As an offset to those possible impacts, those customers typically receive a discounted energy rate from their electric provider.

DATA REQUEST NO. 10: (Continuation of Question 10 from SOUL's first set of data requests concerning the **Use of Net Savings Records from seven prior 345 kV expansion transmission lines in economic projections for the Project.)** Below is a follow-up data request with labeling that continuing the original alphabetical sequence:

Request 10D: On p. 22 of Appendix D Exhibit 1 Planning Analysis, the Applicants discuss the importance of the Project to enhance WUMS transfer,

> "New transmission can improve competitiveness if it enables external suppliers to offer additional generation into the relevant market... The competitiveness of WUMS is reviewed instead of all of Wisconsin because WUMS has been and will likely continue to be designated as an area with market constraints. Hence improving the competitiveness of WUMS would be particularly beneficial to customers."

Since 2007, seven expansion transmission lines have been added in Wisconsin. All were justified, in considerable part, to address WUMS marketing constraints with economic benefits to Wisconsin ratepayers:

WI PSC Docket	Year Installed	Expansion Transmission Line	Location
137-ce-113	2007	Arrowhead-Weston	Superior – Wausau
05-ce-142	2018	Badger-Coulee	La Crosse -Madison
137-ce-149	2010	Paddock-Rockdale	IL- Madison
05-ce-136	2016	CapX2020	MN – La Crosse
137-ce-147	2012	Madison Beltline	Rockdale– Middleton
137-ce-166	2018	Bay Lake	Appleton-Morgan
137-ce-161	2013	Pleasant Valley- Zion	Kenosha – IL

MISO and Transmission Operators have access to voluminous electric market records. That past data can be used to forecast the potential economics of an 8^{th} line for Wisconsin ratepayers to better evaluate the Project.

Using all means at the Applicants' disposal, please provide for Wisconsin electric customers these assessments:

(a) Document, quantitatively, the net savings in electricity costs due to the presence of the seven, prior 345 kV transmission expansion lines added in Wisconsin since 2007; and,

(b) From these historical records, estimate the economic value of adding an 8^{th} line.

Request 10E: To what extent has the Applicants' economic planning for the Project, to date, used past performance records of prior 345 kV transmission lines in Wisconsin to make economic projections for the Project?

Request 10F: With energy use leveling off, wouldn't an economic projection for the Project based on established performance of the past seven lines provide highly relevant modeling data? If not, what are the major economic differences in the Project compared to Badger-Coulee, for example? Is there more economic impact from reliability projects and renewal assets with the Project than with Badger-Coulee? Are the estimated net energy savings from the Project and Badger-Coulee about the same?

Request 10G: Please provide a list all, other, 161 kV, or larger, transmission line improvements or new additions that have been announced to the Public Service Commission of Wisconsin that, if realized, would tend to reduce the Project's ability to provide net savings to Wisconsin electric customers.

RESPONSE TO REQUEST 10D: The Applicants object to this Request as vague and overbroad. The Applicants also object to this request to the extent it seeks documents or information that are not in the Applicants' possession, custody, or control. The Applicants further object to this request to the extent it would require the Applicants to function as consultants for the Intervenor, in that the Request would require the Applicants to perform studies, gather information, or undertake other tasks that the Applicants have not completed. The Applicants further object to the Request to the extent that it seeks information from the Applicants that is equally or more readily available to Intervenors and to the extent the Request would require the Applicants to produce confidential information without a confidentiality agreement in place. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

It not feasible to separate the impacts of a single project from the performance of the system as a whole, since there are a multitude of variables at play. The best way to estimate the economic value of a new project is to perform a detailed analysis using the PROMOD software package modeling multiple, plausible futures. The Applicants have done this and have provided results in Appendix D, Exhibit 1, Planning Analysis.

RESPONSE TO REQUEST 10E: The Applicants object to this Request as vague and overbroad. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

The Applicants have not used past performance records to make economic projections for this Project.

RESPONSE TO REQUEST 10F: The Applicants object to this Request as vague, compound, overbroad, and argumentative. The Applicants further object to the extent that the burden of producing the requested information outweighs its probative value to any issue in this case. The Applicants also object to the Request to the extent it seeks data or information that is equally or more readily available to the Intervenor and to the extent the Request would require the Applicants to perform studies, gather information, or undertake other tasks that Applicants have not completed. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

An economic projection for the Project based on performance of past projects would not provide relevant data. Significant system changes, such as the retirement of approximately 1,500 MW of coal-fired generation capacity in the state of Wisconsin in 2018 and the addition of new renewable resources throughout the region, make past system performance an unreliable indicator of future impacts of projects. In addition, the Applicants planning analysis in this case did not directly compare the benefits of the Badger-Coulee project with the Cardinal-Hickory Creek project.

RESPONSE TO REQUEST 10G: The Applicants object to this Request as vague, compound, overbroad, and argumentative. The Applicants further object to the extent that the burden of producing the requested information outweighs its probative value to any issue in this case. The Applicants also object to the Request to the extent it seeks data or information that is equally or more readily available to the Intervenor and to the extent the Request would require the Applicants to perform studies, gather information, or undertake other tasks that Applicants have not completed. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

The Applicants have not analyzed if any newly announced 161 kV or larger proposals would impact the benefits of Cardinal Hickory Creek. Generally speaking, however, new projects are designed and studied with the presumption that Cardinal Hickory Creek will be in-service.

DATA REQUEST NO. 11. (Continuation of Question 11 from SOUL's first set of data requests concerning the **economic impact on the Project from potential, additional generation in the vicinity of the 138/345 kV "Eden" substation at Montfort, WI.**) Below are follow-up data requests with labeling continuing alphabetical sequence:

Request 11F: The Applicants write on p. 41 of Appendix D Exhibit 1 Planning Analysis:

> "The fact that the LVA performed comparably to the Project was unexpected and prompted further analysis... the Applicants analyzed the PROMOD results and realized that the Project was almost too effective at bringing power into Wisconsin. Under certain conditions, the Project allowed too much power to flow into the south-central Wisconsin system, and under some outages, this could lead to congestion on the system east of the Eden Substation....Having the Hill Valley – Cardinal 345 kV line constructed as 345/138 kV double circuit capable will give the system planners increased flexibility to meet the changing needs of the system such as: • the potential need for the transmission system to handle increased generation in southwest Wisconsin including but not limited to recent generator interconnection requests at Eden 138 kV: J712 – 200 MW Wind, J855 – 100 MW Wind, J870 – 200 MW Solar, J871 – 100 MW Solar"

In response to Request 11A. on p. 23, of Applicants' Response to S.O.U.L. of Wisconsin, Inc.'s First Document and Data Requests, the Applicants describe:

> "The following conditions can contribute to higher levels of energy import into Wisconsin:
>
> - Scenarios with increased development of renewables in wind rich areas west of Wisconsin;
> - Unplanned and maintenance outages of larger generators in Wisconsin during high wind periods; and
> - Increased retirement of fossil fuel generation in Wisconsin."

When the Applicants wrote in April, 2018 that, "the Project allowed too much power to flow into the south-central Wisconsin system," was the recognition of the possibility of an additional, approximate 600 MW (faceplate) of generation in the vicinity of the Eden a key factor in making this statement?

Request 11G: Please characterize the impact on Energy Cost Savings this addition of approximately 400-600 MW (faceplate) of generation at the Eden 138/345 kV substation would have on the Applicants most recent economic modeling (Applicants' Supplemental Response to PSCW Data Requests

1.172, 1.174, 1.195, 1.198, 1.200-1.206, 1.208, 1.209, 1.213-1.216, and 4.56, PSC REF#358760).

Request 11H: Would the 400-600MM of power intake at the Eden substation tend to increase or decrease the Energy Cost Saving Benefits for the CHC Project during the window of years studied?

Request 11I: Would 400-600MM of power intake to the Project at the Eden substation make generators in wind rich area west of Wisconsin less competitive or more competitive if inserted into the economic planning the Applicants have conducted thus far?

Request 11J: We note the Applicants included potential natural gas generation in their economic planning that we cannot find in the MISO queue (see Response to PSCW Data Request 01.210 and Response to PSCW Data Request 01.211 in Response to Data Request 1, Part 2 – Supplement, PSC REF#-347526. Generators that could be located in the vicinity of the Eden Substation, J870, J871, J947 and J855 were introduced to the MISO queue in July, 2017 before the cut off dates for PROMOD models used for Project analysis in October, 2017. Please explain why this potential of 400-600MM of generation in the vicinity of the Eden substation was not incorporated into the economic planning for the Project and other alternatives.

Request 11K: Would 400-600MM of power introduced at the Eden substation lower the Incremental FCITC Summer and Shoulder ratings that the Applicants have assumed in their economic planning to date? If so, roughly how much?

We note that even though the 200MW J712 wind project has been (temporarily?[3]) withdrawn from the MISO queue, another, 200 MW solar facility, J947, is in queue in the Grant County that was not included in the Applicants /Eden Substation accounting. Below are rough estimates created to help clarify our question. We could not summer or shoulder credit percentages for solar.

Rough Estimate C-HC Incremental FCITC from New Generation Introduced at or near EDEN Substation

Eden Area Interconnection Project	Type	Rating MW Faceplate	Capacity Factor	SUMMER PEAK Credit (Solar est)	SHOULDER PEAK Credit (Solar est)	Rough Estimate Percentage CHC Incremental FCITC Shoulder Peak (MW)	Rough Estimate Percentage CHC Incremental FCITC Shoulder Peak (MW)	APPLICANT CHC INCREMENTAL FCITC SUMMER PEAK (MW)	APPLICANT CHC INCREMENTAL FCITC SHOULDER PEAK (MW)
J855	Wind	100	0.36	0.14	0.4	1%	3%	1382	1231
J947	Solar	200	0.94	0.9	0.7	13%	11%	1382	1231
J870	Solar	200	0.94	0.9	0.7	13%	11%	1382	1231
J871	Solar	100	0.94	0.9	0.7	7%	6%	1382	1231
Totals		600				34%	32%		

[3] To the best of SOUL's knowledge, contracts with landowners still have active options.

RESPONSE TO REQUEST 11F: Subject to the General Objections identified above, the Applicants respond as follows:

No, the 600 MW of Eden-area generation was not modeled in the economic planning studies.

RESPONSE TO REQUEST 11G: The Applicants object to this Request as vague and overbroad. The Applicants also object to this Request as unduly burdensome to the extent that it is unduly burdensome and seeks to make the Applicants function as consultants for Intervenor in that the Request would require the Applicants to gather information or undertake other tasks that the Applicants have not completed. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

The Applicants do not have this information. Further, this analysis can't be performed until the required Network Upgrades of the generator interconnection requests are known. According to the most recent DPP Schedule, the August 2017 Phase 3 studies will be completed in June 2020. https://cdn.misoenergy.org/Definitive%20Planning%20Phase%20Estimated%20Schedule106547.pdf

RESPONSE TO REQUEST 11H: The Applicants object to this Request as vague, speculative, overbroad, and unduly burdensome. The Applicants also object to this Request to the extent that it seeks information or documents that are not in the Applicants' possession, custody, or control and to the extent it would require the Applicants to perform studies, gather information, or undertake other tasks that the Applicants have not completed. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

Please see the Response to Request 11G.

RESPONSE REQUEST 11I: The Applicants object to this Request as vague, speculative, overbroad, and unduly burdensome. The Applicants also object to this Request to the extent that it seeks information or documents that are not in the Applicants' possession, custody, or control and to the extent it would require the Applicants to perform studies, gather information, or undertake other tasks that the Applicants have not completed. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

The Applicants have not performed this analysis.

RESPONSE TO REQUEST 11J: Subject to the General Objections identified above, the Applicants respond as follows:

The J870, J871, J947 and J855 were generator interconnection requests that had not started the interconnection study process, still haven't completed that study process, and are unlikely to have signed GIAs until 2020. A signed GIA is the typical requirement to be included in planning models. The withdrawal of J712 in 2018, after the February 2017 Phase 1 DPP study was complete, is an example of why having a signed GIA is the typical requirement for inclusion in the models.

RESPONSE TO REQUEST 11K: The Applicants object to this Request as vague, overbroad, and unduly burdensome. The Applicants also object to this Request to the extent that it seeks information or documents that are not in the Applicants' possession, custody, or control and to the extent it would require the Applicants to perform studies, gather information, or undertake other tasks that the Applicants have not completed. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

The Applicants do not have this information. As discussed in the previous responses, these generator interconnection requests have not completed the queue process. Until the queue process is completed, the final generator capacity and required Network Upgrades are unknown. Also, the effect on FCITC depends on ownership of the plants and/or contracts to purchase the power because including these plants in models will result in other plants' output being reduced.

DATA REQUEST NO. 12: (Continuing Question 12 from SOUL's first set of data requests concerning the **Policy Regulation Future and Project CO2 Emission Reduction potential**.) Below are new, follow-up data requests with labeling that continues the original alphabetical sequence:

SOUL's first set of data requests, Request 12B reads:

> "Including the Project and all Alternatives, figures in Table 4, p. 41 of Appendix D Exhibit 1 Planning Analysis forecast an average 26% increase in Energy Cost Savings for the Policy Regulation future with Limited Energy (PRLE) compared to the Policy Regulation (PR) future. Please explain how changing from a (higher) MISO "Mid" demand and energy sensitivity to a (lower) MISO "Low" demand forecast resulted in increased energy savings. Feel free to account for other factors as required"

To which the Applicants replied on p. 28:-29:

> "The optimization of generation dispatch in the energy market is extremely complex. Any single change to an assumption can affect the results in several ways. It is important to note, regarding this future comparison, that the lower demand and energy forecasts were not limited to Wisconsin only. By lowering demand and energy throughout MISO, lower cost energy resources external to Wisconsin may become available. Improving the ability to access these lower cost resources, compared to available resources in Wisconsin, is one of the primary reasons Cardinal – Hickory Creek provides energy cost savings. As we assume lower or higher demand and energy levels, we are comparing different available resources, which have different costs.

Request 12H: In SOUL's first set of data requests, Request 12C reads:

> Regarding the "renewable additions" assumed for the Policy Regulation future on p.38 of the Planning Analysis, please provide some specific examples of Wisconsin policy changes that applicants expect would stimulate these additions. Feel free to include changed policy examples outside of the categories described on p.38 as, "renewable portfolio standards and goals, economics, and business practices to meet carbon regulations."

The Applicants respond:

> "Policy changes are not the only driver of renewable development. Market conditions can also drive renewable development. Nonetheless, below is a list of a few examples that could promote increased development of renewable resources:
>
> - Continuation of renewable energy production tax credits beyond existing rules;
> - Decreased costs for enrollment in utility renewable energy programs, such as Madison Gas and Electric's Green Power Tomorrow program; and

- Increases in Wisconsin's Renewable Portfolio Standard.

Below are observations concerning the three, possible policy improvements the Applicants have suggested.

In our reading, continuation of the renewable energy production tax credits beyond existing rules does not appear to be included in the "Policy Regulation" future. See p. 38 of the Planning Analysis, all of the Applicants' futures, including, Policy Regulation, "Tax credits for renewables continue until 2022 to model existing policy."

It appears that MGE's Green Power Tomorrow program's rate of $0.01 per kWh would not necessarily result in predictable, significant total increases as MGE customers can buy into the program from 1% to 100% of the energy use or choose to contribute a minimal monthly amount.

To the best of our knowledge, the last considered legislation effort to increase Wisconsin's RPS was tabled in committee in 2013.

Please provide further documentation of these and other Wisconsin policy changes that the Applicants assume are significant and appropriate to include in the "Policy Regulation" future.

Request 12I: Please provide documentation for all other, future, policy-driven enhancements that would occur in Wisconsin that Applicants consider to be part of the "Policy Regulation" future.

Request 12J: In SOUL's first set of data requests, Request 12G reads:

> "Similarly, please provide data indicating forecasted CO2 emissions for the ATC and MISO footprints in 2026 and 2031with and without the Project in service for all five futures and, if possible, the Project with the Eden Outlet Restraint Resolved."

The Applicants responded:

> "The Applicants estimated the reduction in CO2 emissions from Wisconsin power plants over the 40-year life of the Cardinal-Hickory Creek Project. The results of this analysis are shown in the table below:

Future	40-year CO2 Emissions Reduction in Wisconsin (Million Tons)
AAT	98
EF	20
PR	40
PR + Foxconn	42
PRLE	39

Please indicate if the above amounts would meet the CO2 reduction targets of the Futures in Figure 5.2-1 on p. 82 of MTEP17 Report Book, .pdf p. 303 in Appendix D Exhibit 1 Planning Analysis Document Appendices, PSC Ref 341716 as shown below. Please indicate the targeted year of compliance that MISO and the Applicants assume in Figure 5.2-1.

FUTURE	**CARBON REDUCTION**
Existing Fleet	-14% of current levels (2017)
Policy Regulations	-25% of 2005 levels
Accelerated Alternative Technologies	-35% of 2005 levels

Request 12K: Are the measure ton units, metric? Please characterize the estimated changes in these reduction amounts over time in these ways. Provide the expected reduction amounts for each future at the start and end of the 5 year economic planning window. For the 40 year duration, provide year by year amounts, or describe whether annual reduction amounts for each specified future steadily increase over 40 years, remain fairly steady over 40 years, steadily decrease over 40 years or assume trend different from these.

Request 12L: Would the total reduction amount for each future be entirely the result of estimated generation characteristics of the power being transported by the Project, combining Hickory Creek - Hill Valley and Hill Valley - Cardinal segments over 40 years?

Request 12M: In regard to the Applicants' CO2 Reduction calculations, With the Project conceived primarily as one integrated facility combining Hickory Creek - Hill Valley and Hill Valley – Cardinal segments, did Applicants assume the power being transported by the Project over 40 years would flow in both directions or primarily flow in one direction? If the later, would the assumed to be from west to east or east to west?

Request 12N: Assuming the Non-Fossil Fuel Generation transported by the Project to Cardinal substation would displace the Wisconsin fossil fuel generation mix at the current EPA CO2 reference displacement rate of .707 Metric Ton per

MWH[4], how much transmission volume or capacity would be required on 365 day, 24 hour basis, without losses, to transport the amount of Non-Fossil Fuel Generation required to achieve the 40 year CO2 Emission reductions the Applicants have estimated for each future? The below sample calculations with EPA assumption may help clarify this request.

Future	40-year CO2 Emissions Reductions in Wisconsin	Metric Ton CO2 Avoided Per MWH of Non-Fossil Fuel Generation	40-year Total Required MWH of 100% Non-Fossil Fuel Generation for CO2 Reductions	Annual Average Required 100% Non-Fossil Fuel Generation (MWH)	Estimated Required Transmission Volume on a 365 day 24 hour basis over 40 years (MW)
AAT	98,000,000	0.7070	138,613,861	3,465,347	395.59
EF	20,000,000	0.7070	28,288,543	707,214	80.73
PR	40,000,000	0.7070	56,577,086	1,414,427	161.46
PR+Foxconn	42,000,000	0.7070	59,405,941	1,485,149	169.54
PRLE	39,000,000	0.7070	55,162,659	1,379,066	157.43

Request 12O: Please provide the effective (EPA-like) CO2 emission displacement rate(s) Applicants used to estimate displacement of Fossil Fuel Generation and corresponding CO2 reduction in Wisconsin generation -or- other calculation used to estimate the how much Non-Fossil Generation would have to introduced by the Project at the Cardinal substation to achieve the CO2 reduction estimates the Applicants have provided.

Request 12P: If applicable, please describe other ways the Project would reduce CO2 Emissions other than the transporting power with inherently lower C02 Emission content compared to the average fossil fuel generation power mix in Wisconsin.

Request 12Q: Applicants have included nuclear power plant located in the Quad Cities in their economic modeling, (see 6.5.1 Modeling Assumptions p.47 "Turned on the Quad Cities power plant in Illinois and set the dispatch consistent with Multiregional Modeling Working Group (MMWG) models." Appendix D Exhibit 1 Planning Analysis Document) At least one Wisconsin utility contracts power from this ~1800 MW facility. Please provide an estimate of the 40-year power transfer amount from this plant for all futures that would be part of the Non-Fossil Generation transported by the Project into Wisconsin. Please provide this volume amount either as MWH over the 40 year planning period, or as an average percentage of estimated Non-Fossil Generation that would be transported by the Project in all futures.

Request 12R: Please provide the assessment, study or assumptions and calculations used to produce the CO2 reduction amounts the Applicants have provided in the

[4] https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator

above chart from p. 32 of the Applicants' Responses to SOUL of Wisconsin's First Set of Discovery Requests (PSC REF#- 357719).

RESPONSE TO REQUEST 12H: The Applicants object to this Request as vague, overbroad, and unduly burdensome. The Applicants also object to this Request to the extent it seeks data or information that is equally or more readily available to Intervenor. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

The Applicants did not create the Policy Regulation future or the assumptions contained within it. The MISO stakeholders created all of the MTEP17 futures. Since the future is unknown, rather than speculate on specific, individual policy changes the stakeholder-driven MISO model development process builds in broad overarching assumptions on policy direction to develop multiple plausible futures. For further information regarding what was included or assumed in these futures, please refer to the MISO MTEP 17 information already provided.

RESPONSE TO REQUEST 12I: The Applicants object to this Request as vague, overbroad, and unduly burdensome. The Applicants also object to this Request to the extent it seeks information or documents that are not in the Applicants' possession, custody, or control and to the extent that it seeks data or information that is equally or more readily available to Intervenor. The Applicants further object to this Request to the extent it would require the Applicants to perform studies, gather information, or undertake other tasks that the Applicants have not completed. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

Please see Response to Request 12H.

RESPONSE TO REQUEST 12J: The Applicants object to this Request as vague, speculate, overbroad, and unduly burdensome. The Applicants also object to this Request to the extent it would require the Applicants to perform studies, gather information, or undertake other tasks that the Applicants have not completed. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

This request appears to be confusing the development of the MISO MTEP futures with the analysis of alternatives in the Planning Analysis Document. Figure 5.2-1 of the MTEP17 report discusses the design of the MTEP17 futures. MISO and stakeholders agreed to build the models around these assumptions. For the models to be built in a manner that is in accordance with the agreed upon assumptions, the model must produce base case results with emissions levels at the targets. Those targets must be met by 2030 and are based on emissions levels from 2005 (505 million tons). Those targets are as follows:

- Existing Fleet 2031 MISO-Wwde emissions must be lower than 434.3 million tons
    - (505 – (505 * 0.14)) = 434.4
- Policy Regulation 2031 MISO-wide emissions must be lower than 378.75 million tons
    - (505 – (505 * 0.25)) = 378.75
- Accelerated Alternative Technology 2031 MISO-wide emissions must be lower than 328.25 million tones
    - (505 – (505 * 0.35)) = 328.25

The reduction of emissions is inherent in the design of the future. It is completely independent of any alternative analysis.

The Applicants' response states the estimated impact of the Cardinal Hickory Creek Project on emissions in Wisconsin.

RESPONSE TO REQUEST 12K: The Applicants object to this Request as vague. The Applicants also object to this Request to the extent it would require the Applicants to perform studies, gather information, or undertake other tasks that the Applicants have not completed. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

The PROMOD software reports the data with the units as lbs. The Applicants converted this to tons (1 ton = 2,000 lbs).

Similar to the energy cost savings analysis, the Applicants only modeled 5, 10, and 15-year models. For years between 5, 10, and 15, the Applicants interpolated results. For years beyond year 15, the Applicants assumed increasing emissions at the rate of inflation.

See Attachment 1 to Response to Request 12k for all emissions data used to create the table.

RESPONSE TO REQUEST 12L: The Applicants object to this Request as vague. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

The reduction in emissions is based on the results of the PROMOD analysis. The ability of Wisconsin customers to access lower cost renewable energy results in the reduction of generation from higher CO_2 emission generation sources in Wisconsin.

RESPONSE TO REQUEST 12M: The Applicants object to this Request as vague. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

The Applicants did not assume a direction of flow of power across the Cardinal – Hickory Creek Project. As the Applicants have stated, this Project allows Wisconsin customers to access lower cost renewable energy by importing that energy into the state from areas west of Wisconsin. However, depending on system conditions, power could flow in either direction.

RESPONSE TO REQUEST 12N: The Applicants object to this Request as vague, speculative, argumentative, overbroad, and unduly burdensome. The Applicants also object to this Request to the extent it would require the Applicants to perform studies, gather information, or undertake other tasks that the Applicants have not completed. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

The Applicants have not performed this calculation. The EPA assumptions are based on a U.S. national weighed average CO_2 marginal emission rate. The analysis the Applicants provided is based on analysis specific to this Project and may not align with the assumptions used by the EPA tools.

RESPONSE TO REQUEST 12O: The Applicants object to this Request as vague. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

CO_2 reduction calculations were performed by the PROMOD software package based on the amount of annual energy produced by fossil fuel plants for each alternative studied combined with modeling information on emissions for those fossil fuel plants.

RESPONSE TO REQUEST 12P: The Applicants object to this Request as vague. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

Not applicable.

RESPONSE TO REQUEST 12Q: The Applicants object to this Request as vague, overbroad, and unduly burdensome. The Applicants also object to this Request to the extent it seeks information or documents that are not in the Applicants' possession, custody, or control and to the extent it would require the Applicants to perform studies, gather information, or undertake other tasks that the Applicants have not completed. The Applicants further object to this Request to the extent it would require the Applicants to produce confidential information without a confidentiality agreement in place. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

The stated modeling assumptions were specific to the reliability analysis which was not used in the calculation of emissions impacts.

RESPONSE TO REQUEST 12R: The Applicants object to this Request as vague, overbroad and unduly burdensome. The Applicants further object to this Request to the extent it would require the Applicants to produce confidential information without a confidentiality agreement in place. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

See Response to Request 12O.

DATA REQUEST NO. 13: (Continuing Question 13 from SOUL's first set of data requests concerning **Low Voltage Asset Renewals.**) Below are follow-up data requests with labeling continuing the alphabetical sequence:

Request 13E: In SOUL's first set of data requests, Request 13A included this table with Asset Renewal projects:

Data from Revised Table 34: Southwest Wisconsin Asset Renewal Issues

Response to Data Request No. 01.189

Transmission Line	Renewal Capital Cost ($M – 2018)	Avoided Renewal Benefit ($M – 2018)	Avoided Benefit Percentage of Renewal Capital Costs ($M – 2018)	Avoided Renewal Benefit @ 95% Marginal Cost ($M – 2018)
Nelson Dewey – Eden 138 kV (1st Upgrade)	28.9	22.1	76%	21.0
Nelson Dewey – Eden 138 kV (2nd Upgrade)	16	3.8	24%	3.6
Eden – Dodgeville 69 kV	31.5	9.1	29%	8.6
Wally Road – Stagecoach 69 kV	13	9.9	76%	9.4
Stagecoach – West Middleton 69 kV (Preferred Route)	5	2.5	50%	2.4
Total Preferred Route	**94.4**	**47.4**	50%	**45.0**
Stagecoach – West Middleton 69 kV (Alternate Route)	6.4	3.2	50%	3.0
Nelson Dewey – Hillman 138 kV	34.6	23.6	68%	22.4
Hillman – Falcon 138 kV	7.6	7.2	95%	6.8
Eden – Spring Green 138 kV	15.2	10.4	68%	9.9
Hillman – Eden 69 kV	24.6	15.2	62%	14.4
Total Alternate Route	**88.4**	**59.6**	67%	**56.6**

The Applicants note in response to SOUL's first set of data requests request 11D on p.25:

> "As described in the August 2017 Wisconsin Area Phase 1 System Impact Study (link below), the Eden – Wyoming Valley – Spring Green 138 kV line is presently a required Network Upgrade."

If by, "required Network Upgrade" the Asset Renewal project will be done as part of ATC's scheduled rebuilds, please explain if the $9.9M cost of rebuilding the Eden – Wyoming Valley 138 kV segment will be removed as an avoided cost benefit for the Project?

Request 13F: In SOUL's first set of data requests, Request 13A reads:

> "For each of the 10 Renewal Asset Projects in Revised Table 34, please provide estimates of the avoided costs for the following categories: Pole Replacements; Conductors; Substation Transformers; Other Substation Components; Other Expenses."

The Applicants responded to 13A as follows:

> The cost estimates were prepared without detailed scoping, engineering, site investigation, or risk assessment. The estimates were not provided on a cost per pole or cost per conductor basis; rather, the estimates were developed considering the line segments as whole. Each line was individually reviewed along with its local terrain to determine the total estimated cost to renew the asset. The total cost includes typical project costs such as the capital cost of the equipment as well as labor, taxes, etc.
>
> The cost estimates assumed that the lines will be upgraded on a like-for-like basis for structures (i.e. the same number and type of poles would be used to replace the aging poles), twisted pair phase conductors would be used on all lines, using T2- 4/0 Penguin for 69 kV lines and T2-477 Hawk for 138 kV lines (twisted pair phase conductor is the ATC standard due to conductor galloping concerns in the region). Optical Ground Wire (OPGW) was

> assumed on all lines. No substation components, including transformers, were included in the Avoided Asset Renewal Costs."

Request 13G: Please explain the reason for rebuilding Nelson Dewey – Eden 138 kV (X-16) in two separate steps/upgrades. We are aware that some of the wooden poles have already been replaced with steel poles.

Request 13H: Please explain why the Applicants feel it is mandatory to replace the conductors on all of the Asset Renewal projects? If possible, when illustrating your answer, please refer to the X-16 and Wally Road – Stagecoach 69 kV rebuild projects.

Request 13I: Using figures from past, similar, Asset Renewal rebuild projects in the Applicants' records, please provide cost per mile estimates for the 138 kV and 69 kV rebuild initiatives described in the below table.

Assume terrain of the type found in the Project study area and include costs for equipment, materials, expenses and labor.

Facility Size	Asset Renewal Rebuilding Task	Typical Cost Per Mile
138 kV	Only replacing conductors and communication wires for a single circuit facility.	
138 kV	Only replacing the wooden poles with new wood poles for a single circuit facility.	
138 kV	Replacing wooden poles with wood poles and installing conductor for a single circuit at the same time.	
138 kV	Replacing wooden poles with steel poles and installing conductor for a single circuit at the same time.	
69 kV	Only replacing conductors and communication wires for a single circuit facility.	
69 kV	Only replacing the wooden poles with new wood poles for a single circuit facility.	
69 kV	Replacing wooden poles with wood poles and installing conductor for a single circuit at the same time.	
69 kV	Replacing wooden poles with steel poles and installing conductor for a single circuit at the same time.	

Request 13J: In SOUL's first set of data requests, Request 13A, the Applicants responded to 13A as follows:

> "No substation components, including transformers, were included in the Avoided Asset Renewal Costs."

Does this mean that none of the transformers in the Asset Renewal Project substations are expected to require age-related or precautionary replacement over the next 40 years?

Request 13K: If some of the transformers associated with the Asset Renewal Project substations are expected to require age-related or other precautionary replacement over the next 40 years, please list their associated substations and cost for each including equipment, materials, labor and revenue requirement. The below reference table may help clarify this request.

Southwest Wisconsin Asset Renewal Projects – Substations Expecting Transformers Over Next 40 Years

Preferred Route		Transformer(s) likely to be replaced and cost		Transformer(s) likely to be replaced and cost
Nelson Dewey – Eden 138 kV (1st Upgrade)	Nelson Dewey 138kV		Eden 138 kV	
Nelson Dewey – Eden 138 kV (2nd Upgrade)	"		"	
Eden – Dodgeville 69 kV	Eden 69 kV (#1)		Dodgeville 69 kV	
Wally Road – Stagecoach 69 kV	Wally Road 69 kV		Stagecoach 69 kV	
Stagecoach – West Middleton 69 kV (Preferred Route)			West Middleton 69 kV	
Alternate Route				
Stagecoach – West Middleton 69 kV (Alternate Route)				
Nelson Dewey – Hillman 138 kV			Hillman 138 kV	
Hillman – Falcon 138 kV			Falcon 138 kV	
Eden – Spring Green 138 kV ??			Spring Green 138 kV ??	
Hillman – Eden 69 kV	Hillman 69 kV		Eden 69 kV (#2)	

RESPONSE TO REQUEST 13E: The Applicants object to this Request as vague. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

The Applicants used the term "required Network Upgrade" to mean that one or more generator interconnection requests are shown to be required to finance an upgrade to the Eden – Wyoming Valley – Spring Green 138 kV line. The upgrade is shown as an uprate on page 65 of 85 of the August 2017 Phase 1 study report. Since this is not a complete rebuild, the avoided asset renewal benefit will still apply. The amount of the avoided asset renewal benefit could be reduced depending on the exact method of uprating the line. If a complete rebuild of this line is identified in the Phase 3 study report and the affected requests continue in the process to sign a GIA and finance this project, then the $9.9M avoided cost should be removed from the avoided asset renewal benefit of the Alternate Route only.

RESPONSE TO REQUEST 13G: The Applicants object to this Request as vague. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

Only the original vintage structures on the line are assumed to be replaced with the first upgrade. During the second upgrade, other structures are assumed to be replaced based on their expected condition and performance.

RESPONSE TO REQUEST 13H: Subject to the General Objections identified above, the Applicants respond as follows:

Asset renewals are meant to meet long-term system needs. The ATC standard is to install twisted pair conductors to avoid transmission line galloping. In addition, standard shield wires are replaced with optical ground wires for communication needs.

RESPONSE TO REQUEST 13I: The Applicants object to this Request as vague, speculative, overbroad, and unduly burdensome. The Applicants also object to this Request to the extent it seeks information or documents that are not in the Applicants' possession, custody, or control and to the extent it would require the Applicants to perform studies, gather information, or undertake other tasks that the Applicants have not completed. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

The Applicants do not have this summarized data.

RESPONSE TO REQUEST 13J: The Applicants object to this Request as vague, speculative, overbroad, and unduly burdensome. The Applicants also object to this Request to the extent it seeks information or documents that are not in the Applicants' possession, custody, or control and to the extent it would require the Applicants to perform studies, gather information, or undertake other tasks that the Applicants have not completed. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

No. The Applicants did not determine whether substation components would be replaced in the next forty years because the Cardinal-Hickory Creek project is unable to prevent the need for these upgrades.

RESPONSE TO REQUEST 13K: The Applicants object to this Request as vague. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

Not Applicable. Please see Response to Request 13J.

DATA REQUEST NO. 14: (Continuing Question 14 from SOUL's first set of data requests concerning **Wind Facilities Explicitly Conditioned on CHC** from Table D-4-1, pdf p. 18, Appendix D Exhibit 1 Planning Analysis Document Appendices CEII C27841 RE 341716. Below are follow-up data requests with labeling continuing the original alphabetical sequence:

Request 14B: (Thank you for providing links to the GIA's.)

Please help us clarify which wind farm projects the Applicants have determined are explicitly conditional on the Project. The facilities were initially provided in Table D-4-1. After confirming Project conditionality in the GIA's, please provide an updated list and links to GIA's not previously provided (such as G858 and J278, if applicable). The below reference table may help clarify this request:

Projects in Current Table D-4-1: GIAs Explicitly Conditioned on CHC

Project Number	MTEP Cited	Contingency
H096	B-C Only	(4) NRIS 0 until study made
J091	B-C Only	(4) NRIS 0 until study made
J870	B-C Only	(4) NRIS 0 until study made
G735	B-C Only	Contingency Restudy
H071	B-C and CHC	(4) NRIS 0 until study made
H008	B-C and CHC	Contingency Restudy
R39	B-C and CHC	Contingency Restudy
G826	B-C and CHC	Minimal Language
J395	CHC Only	(4) NRIS 0 until study made
H081	CHC Only	Contingency Restudy
G858	GIA Link Needed	?
J278	GIA Link Needed	?

Request 14C: The factors that are limiting the wind facilities are difficult to determine with the information provided in the GIA's. Please further describe the limiting factors that are currently in place on the wind projects explicitly conditional on the construction of the Project. In non-technical language, what would effectively change with the operation of these facilities after the construction of the Project?

Request 14D: Please briefly describe the hardships of the alternative actions the wind facilities would be forced to consider if the Project was not added to the transmission system as the Applicant's propose?

Request 14E: To assess the monetary and environmental significance of the potential wind farm GIA compliances if the Project is built, please provide estimates of the annual MWH that is not currently not being delivered to the grid by the restricted wind facilities. If this data is too challenging to produce, please provide an estimate of the percentage of the potential total generation that is not being delivered to the grid from a typical facility that is experiencing comparable restrictions. The annual percentage estimate should reflect only the portion that would be enabled with GIA compliance from the Project being built.

<u>RESPONSE TO REQUEST 14B</u>: Subject to the General Objections identified above, the Applicants respond as follows:

The Applicants believe that all GIAs listed in the Response to Request 14A are conditional on Cardinal-Hickory Creek. Some of the GIAs don't specifically list "Cardinal-Hickory Creek" but do include MTEP Project 3127 with an ISD of 12/31/2020. Project 3127 is the combination of the Badger Coulee and Cardinal-Hickory Creek projects. The 12/31/2020 ISD was previously shown as the Cardinal-Hickory Creek project ISD. The Badger Coulee project ISD was 12/31/2018.

As stated in the Response to 01-SOUL-ATC-14A, the Applicants reviewed the J278 GIA and believe that it is not conditional on Cardinal-Hickory Creek.

The link to the G858 GIA as provided in the Response to Request 14A:

https://cdn.misoenergy.org/Northern%20States%20Power%20Company-Black%20Oak%20Wind%20Farm,%20LLC%20GIA%203rd%20Rev%20G858-H071%20SA2693%20ER15-2296%20PUBLIC%20VER55320.pdf

If any of the links are modified, the requestors can review the Interconnection Agreements at:

https://www.misoenergy.org/legal/service-agreements

RESPONSE TO REQUEST 14C: The Applicants object to this Request as vague, overbroad, and unduly burdensome. The Applicants also object to this Request to the extent that it seeks information or documents that are not in the Applicants' possession, custody, or control and to the extent it seeks information from the Applicants that is equally or more readily available to Intervenors. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

GIAs that are conditional on a transmission project are subject to Quarterly Operating Limit studies until that project is completed. These studies could require that the generating plants operate at a reduced capacity.

RESPONSE TO REQUEST 14D: The Applicants object to this Request as vague, overbroad, and unduly burdensome. The Applicants also object to this Request to the extent that it seeks information or documents that are not in the Applicants' possession, custody, or control and to the extent it seeks information from the Applicants that is equally or more readily available to Intervenors. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

If the Cardinal-Hickory Creek Project is not constructed, then MISO would need to perform new analysis to determine what transmission upgrades would need to be constructed to allow each plant to operate at its requested capacity.

RESPONSE TO REQUEST 14E: The Applicants object to this Request as vague, overbroad, and unduly burdensome. The Applicants also object to this Request to the extent that it seeks information or documents that are not in the Applicants' possession, custody, or control and to the extent it would require the Applicants to perform studies, gather information, or undertake other tasks that the Applicants have not completed. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

The Applicants do not have this information. Moreover, each facility is unique. Therefore, there is no such thing as a typical operating restriction.

DATA REQUEST NO. 15: Ratepayer friendly account of the Monetized Range of Net Benefits of Alternatives to Wisconsin Please refer to the data in Table 2.1-1: Monetized Range of Net Benefits of Alternatives to Wisconsin from p. 2 of the "Applicants' Supplemental Response to PSCW Data Request 1.169" REF#:358840 or more recent estimates provided by the Applicants.

Request 15A: In order to assess the monetary significance of the Project and Alternatives, please provide rough estimates of the economic benefits for each Alternative under each planning Future for an average residential Wisconsin electric customer on a per month basis over the 40 year period.

The purpose of this request is to provide average benefit distributions to Wisconsin Electric customers over 40 years in 2018 dollars in terms that typical ratepayers can understand. It is not a request for utility-specific, detailed information. It is understood that benefits from the Alternatives would not be spread uniformly across Wisconsin utilities (and their customers) and that calculations based on averaged state wide figures will not account for all distinctions.

The below reference table may help clarify the kind of information that is being requested.

APPROXIMATIONS OF WISCONSIN ELECTRIC CUSTOMER SHARE OF ECONOMIC BENEFITS^^

Economic Future	40 Year Net Benefits of Evaluated Alternatives (Includ. Costs; $Millions – 2018 PV)	40 Year Average Annual Benefits For Wisconsin Customers (Losses in Red)	2017 Average Residential Customer Monthly Share^	2017 Average Commercial Customer Monthly Share^	2017 Average Industrial Customer Monthly Share^	2027 Average Residential Customer Monthly Share*	2027 Average Commercial Customer Monthly Share*	2027 Average Industrial Customer Monthly Share*
	Estimated Cardinal Hickory Creek Economic Benefits							
Existing Fleet (EF)	22.7	$567,500	$0.005	$0.05	$2.92	$0.01	$0.04	$2.95
Policy Regulations with Low Energy (PRLE)	156.1	$3,902,500	$0.04	$0.32	$20.11	$0.04	$0.31	$20.31
Policy Regulations (PR)	105.5	$2,637,500	$0.03	$0.21	$13.59	$0.02	$0.21	$13.73
Policy Regulations with Foxconn (PRFoxconn)	129.2	$3,230,000	$0.03	$0.26	$16.65	$0.03	$0.25	$16.81
Accelerated Alternative Technologies (AAT)	249.3	$6,232,500	$0.06	$0.51	$32.12	$0.06	$0.49	$32.44
	Estimated Low Voltage Transmission Alternative Benefits							
Existing Fleet (EF)	-132.4	-$3,310,000	-$0.03	-$0.27	-$17.06	-$0.03	-$0.26	-$17.23
Policy Regulations with Low Energy (PRLE)	-18.6	-$465,000	-$0.004	-$0.04	-$2.40	-$0.004	-$0.04	-$2.42
Policy Regulations (PR)	-47.4	-$1,185,000	-$0.01	-$0.10	-$6.11	-$0.01	-$0.09	-$6.17
Policy Regulations with Foxconn (PRFoxconn)	-15.3	-$382,500	-$0.004	-$0.03	-$1.97	-$0.003	-$0.03	-$1.99
Accelerated Alternative Technologies (AAT)	270.4	$6,760,000	$0.06	$0.55	$34.84	$0.06	$0.53	$35.19
	Estimated Non-Transmission Alternative Benefits							
Existing Fleet (EF)	-5.4	-$135,000	-$0.001	-$0.01	-$0.70	-$0.001	-$0.01	-$0.70
Policy Regulations with Low Energy (PRLE)	3.7	$92,500	$0.001	$0.01	$0.48	$0.001	$0.01	$0.48
Policy Regulations (PR)	-6	-$150,000	-$0.001	-$0.01	-$0.77	-$0.001	-$0.012	-$0.78
Policy Regulations with Foxconn (PRFoxconn)	-19.9	-$497,500	-$0.005	-$0.04	-$2.56	-$0.004	-$0.04	-$2.59
Accelerated Alternative Technologies (AAT)	29.7	$742,500	$0.007	$0.06	$3.83	$0.01	$0.06	$3.87

^ Based on 2017 EIA Form 861 data: 3,038,715 WI Total Retail Customers; Consumption: 31% Residential; 34% Commercial and 35% Industrial
* 2027 figures based on 6.3% increase in Residential customers, 3% increase in Commercial customers and 1% decrease in Industrial customers of 2017 figures.
^^Benefit data from Table 2.1-1: Monetized Range of Net Benefits of Alternatives to Wisconsin" on p. 34 of the Cardinal Hickory Creek Application.

Request 15B: If Applicants observe other, significant, losses or gains that would occur on average Wisconsin electrical bills that would not be sufficiently accounted for in the approximation method described above in 15A, please describe them and quantify the extent of their financial impact on bills. Please state the changes as a range of possible percentage adjustments made to the 40 year approximate economic distributions from the Project as estimated in response to 02-SOUL-ATC-15A or using the sample computations in 02-SOUL-ATC-15A as a reference.

RESPONSE TO REQUEST 15A: The Applicants object to this Request as vague, overbroad, and unduly burdensome. The Applicants also object to this Request to the extent that it seeks information or documents that are not in the Applicants' possession, custody, or control and to the extent it would require the Applicants to perform studies, gather information, or undertake other tasks that the Applicants have not completed. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

See Direct-Applicants-Degenhardt for an explanation of why the Applicants cannot determine individual ratepayer impacts. In addition, the Applicants do not have enough detailed information to define an "average residential customer."

RESPONSE TO REQUEST 15B: The Applicants object to this Request as vague, overbroad, and unduly burdensome. The Applicants also object to this Request to the extent that it seeks information or documents that are not in the Applicants' possession, custody, or control and to the extent it would require the Applicants to perform studies, gather information, or undertake other tasks that the Applicants have not completed. Subject to this specific objection and to the General Objections identified above, the Applicants respond as follows:

See Response to Request 15A.

DATED: February 28, 2019

As to objections:

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BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Joint Application of American Transmission Company LLC, ITC Midwest LLC, and Dairyland Power Cooperative, for Authority to Construct and Operate a New 345 kV Transmission Line from the Existing Hickory Creek Substation in Dubuque County, Iowa, to the Existing Cardinal Substation in Dane County, Wisconsin, to be Known as the Cardinal-Hickory Creek Project

Docket No. 5-CE-146

DIRECT TESTIMONY OF MIKE DEGENHARDT
IN SUPPORT OF THE APPLICATION

INTRODUCTION

Q. Please state your name, employer, title, and business address.

A. My name is Mike Degenhardt. I am employed by ATC Management, Inc., the corporate manager of American Transmission Company LLC (collectively, ATC). My job title is Corporate Planning Consultant, and my business address is W234 N2000 Ridgeview Parkway Court, Waukesha, WI 53188-1022.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of ATC in support of ATC, ITC Midwest LLC (ITC Midwest), and Dairyland Power Cooperative (Dairyland) (collectively, Applicants) and their Application for a Public Service Commission of Wisconsin (PSCW or Commission) Certificate of Public Convenience and Necessity (CPCN) and Wisconsin Department of Natural Resources Utility Permit for the Cardinal-Hickory Creek Transmission Line Project (Application).

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

A. I have a Bachelor's degree in Finance from UW-Milwaukee (1998) and have been with ATC for 13 years in the Financial Planning Department.

Q. What are your responsibilities at ATC?

A. My primary responsibilities include developing and using the corporate pro-forma financial models (which are used in the monthly forecasting and annual financial planning processes), performing other strategic financial analysis, and providing ad-hoc financial analysis services to ATC personnel.

Q. What role have you played studying and planning for the Cardinal-Hickory Creek Transmission Line Project (Cardinal-Hickory Creek Project or Project)?

A. I calculated the net present value revenue requirement (PVRR) of the Project to determine the estimated impact to customers in Wisconsin. I provided this information to the planners to conduct the Applicants' planning analysis, which is described in more detail in Ex.-Applicants-Application-Section 2.0 and Appx. D and Direct-Applicants-Dagenais.

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to describe how the Applicants calculated the net PVRR for the Project, and to describe the impact of the Midcontinent Independent System Operator's (MISO) Multi-Value Project (MVP) cost allocation process on ATC's, Dairyland's, and Northern States Power Company, Wisconsin's (NSPW) customers.

Q. Are you sponsoring any exhibits in support of your testimony?

A. Yes, I am sponsoring Ex.-Applicants-Degenhardt-1.

OVERVIEW OF PVRR ANALYSIS

Q. What is net PVRR and how was it used in the Applicants' planning analysis?

A. The net PVRR is a calculation of the overall cost of the Project to Wisconsin electric customers. When projects like the Cardinal-Hickory Creek Project are built, customers pay for them through increased transmission charges. The annual revenue requirement of a project represents the change in the total amount of annual transmission charges to be billed to a defined customer group as the result of the addition of the Project. The net PVRR represents the cumulative expected change in transmission charges to the customer group over the project's expected life, discounted for the time value of money.

Q. Why is it important to calculate the net PVRR of a project?

A. Knowing the net PVRR allows the Applicants (and ultimately, the Commission) to more accurately compare the costs and benefits of the Project to Wisconsin customers. Because the net PVRR represents the present value of the change in transmission charges to ATC's, NSPW's, and Dairyland's customers as a result of the addition of the Project, it represents the Project's true cost to Wisconsin customers.

The net PVRR for the Project can also be compared directly against the present values of its economic benefits. As explained in Direct-Applicants-Dagenais, the Applicants' planning analysis calculates various categories of economic benefits for ATC's, NSPW's and Dairyland's Wisconsin customers. To provide an accurate comparison of the Project's total, overall costs and benefits to Wisconsin customers, the costs must reflect the Wisconsin customer impact of the Project, which is what the net PVRR represents.

Q. Why didn't the Applicants use the total construction cost of the Project in their planning analysis?

A. Because, generally speaking, the amount Wisconsin customers pay for a major infrastructure project, like the Cardinal-Hickory Creek Project, is not the same as the construction cost. There are several reasons for this. For example, the Applicants are allowed to earn a rate of return on the capital they spend, which must be included to obtain the true cost of the Project to Wisconsin customers. This return is not reflected in the construction cost.

Moreover, as discussed in Direct-Applicants-Dagenais, the Project will qualify as a Multi-Value Project, meaning that its costs will be shared by customers across the entire MISO North region and not paid for entirely by ATC's, NSPW's, and Dairyland's customers. In other words, because the Project is an MVP, MISO will use the formulas in Attachment O and Attachment MM of the MISO Transmission and Energy Market Tariff (TEMT) to allocate the Project's costs across the MISO North system, only a portion of which will actually accrue to ATC's, NSPW's and Dairyland's Wisconsin customers. The MVP cost allocation is generally based on each utility's load share of energy (MWh) withdrawals from the MISO market across the relevant MISO North region. As a result, although the Project will cost approximately $492 million in year-of-occurrence dollars to construct, it will only cost ATC's, NSPW's, and Dairyland's Wisconsin customers approximately $67.0 million on a net PVRR basis. This is because the majority of the costs will be paid for through MISO cost-sharing by customers in other states.

Q. Which of the studied alternatives did the Applicants assume would be subject to cost-sharing under the MISO MVP Tariff?

A. As described in the Application and in Direct-Applicants-Dagenais, the Cardinal-Hickory Creek Project was the only alternative the Applicants assumed would be subject to cost-sharing under the MISO MVP Tariff.

PVRR ANALYSIS OF THE PROJECT

Q. Please describe in detail how you calculated the net PVRR of the Project.

A. A detailed spreadsheet showing my calculations is attached as Ex.-Applicants-Degenhardt-1.

The first step in my analysis was to calculate the Project's total incremental change in the Annual Revenue Requirement (ARR) to be billed by MISO under Schedule 9 and Schedule 26A. To calculate this total incremental change in ARR, I needed to calculate the incremental change in allocated amounts for each of the three proposed Project owners: ATC, ITC Midwest, and Dairyland. For the analysis presented in Ex.-Applicnats-Degenhardt-1, I used the costs associated with the Applicants' proposed Preferred Route.

For ATC, I started out by calculating the estimated incremental change to ATC's ARR for the years 2017 to 2063, which includes pre-certification costs and the 40-year depreciable life of the Project (assuming a 2023 in-service date), under ATC's Attachment O of the MISO TEMT with the addition of the Project. I then calculated the incremental change in the allocation of ATC's total ARR to MISO for recovery under Attachment MM with the addition of the Project. Next, I deducted the incremental change in the allocation to Attachment MM from the incremental ARR, and this resulted in the net total incremental annual Schedule 9 Network Service transmission charge to ATC's network customers.

I then calculated the incremental change in the amount allocated to Attachment MM for the Dairyland portion of the Project, using data from Dairyland's published Attachment O. For ITC Midwest's portion of the Project, I used projected allocation factors that ITC Midwest provided to me to calculate ITC Midwest's incremental change in the allocation to Attachment MM.

The total incremental change in the ARR to be billed by MISO under Attachment MM is the sum of the incremental change in allocated amounts for ATC, ITC Midwest, and Dairyland, as described above.

Once I knew this amount, I could then calculate the impact to ATC's, NSPW's and Dairyland's Wisconsin customers from the Project.

To determine the impact to ATC's Wisconsin customers, I took the sum of the change in the total allocation to Attachment MM, as described above, and multiplied it by 13.42 percent, which represents the share of Schedule 26A charges billed to ATC customer groups. I then added the incremental change in the annual Schedule 9 Network Service transmission charge and the ATC customer group share of Schedule 26A charges together and multiplied that value by 92.04 percent, which represents the share of ATC's customers in Wisconsin.

Similarly, to determine the impact to NSPW's Wisconsin customers I took the sum of the change in the total allocation to Attachment MM, as described above, and multiplied it by 10.16 percent, which represents the share of Schedule 26A charges billed to NSP customer groups. I then multiplied that value by 15.00 percent, which represents the share of NSPW customers, and multiplied that by 98.00 percent, which represents NSPW's customers in Wisconsin.

To determine the impact to Dairyland's Wisconsin customers, I took the sum of the change in the total allocation to Attachment MM, as described above, and multiplied it by 0.10 percent, which represents the share of Schedule 26A charges billed to Dairyland's customer groups. I then multiplied that value by 58.05 percent, which represents the share of Dairyland's customers in Wisconsin.

I then added the incremental change for ATC, NSPW, and Dairyland customers in Wisconsin, as described above, resulting in the total incremental change to customers in Wisconsin. I then discounted this total incremental change for the period of 2017 to 2063 to get the net PVRR of the incremental change to customers in Wisconsin. This resulted in a net PVRR of $67.0 million.

Q. Did your analysis change from what was included in the Application?

A. Yes, I revised my original analysis slightly to account for two minor changes. The first correction was to the calculation of Dairyland's allocation to Attachment MM. One of the input values was incorrectly entered. This correction amounted to a decrease in the net PVRR of less than $100,000. The second correction was to resolve a discrepancy in the end year of the analysis. Components of the original analysis ended between 2063 and 2065. This has been revised so all components of the analysis end in 2063. The result of this second change is an increase in the net PVRR of approximately $900,000. As a result of these two changes, the net PVRR changed from $66.2 million in the Application to $67.0 million in Ex.-Applicants-Degenhardt-1.

Q. Why did the Applicants use a discount rate of 6.4 percent in their calculation of the net PVRR?

A. The discount rate is the interest rate that is used to determine the present value of future cash flows and reflects the time value of money. The "FERC Interest Rate" of 6.4 percent was used as a long-term estimate of the interest rate used by the Federal Energy Regulatory Commission (FERC) to compensate utility customers in refund situations for their time value of money. This discount rate is used to calculate the present value of the benefits received by customers and the annual revenue requirements paid by customers.

Q. Why was the weighted cost of capital not selected as the discount rate?

A. The ATC weighted cost of capital (which includes costs financed with equity) was not selected because it is solely the prevailing rate needed to attract capital for the Project and does not reflect customers' applicable time value of money. The cost of financing the project, including debt and equity, was included in the annual revenue requirements calculation.

Q. Based on the Applicants' calculations, what is the net PVRR of the Project?

A. The Preferred Route for the Project has net PVRR to Wisconsin customers of $67.0 million. I performed the same type of calculations described above for the Applicants proposed Alternate Route and determined that route has net PVRR to Wisconsin customers of $72.7 million.

Q. Did the Applicants calculate the impact that the Project would have on electric bills for individual retail electric ratepayers?

A. No. As the Commission has recognized, in a docket where the proposed transmission project brings economic benefits (in addition to reliability and policy benefits), calculating the impact of a project on individual retail ratepayers would be extremely difficult, would not yield useful information, and could perhaps result in misleading data.[1] ATC, ITC, and Dairyland do not directly serve retail electric customers. Rather, they serve local distribution companies (LDCs) or (in the case of Dairyland) member cooperatives, which in turn serve retail customers. Therefore, to determine the Project's impacts to individual retail electric ratepayers, one would have to determine (for example) the benefits of accessing different sources of generation for each Wisconsin LDC and cooperative, how each Wisconsin LDC and cooperative would incorporate these benefits into its retail tariffs for each customer class, and then those benefits would have to be compared to the changes in transmission charges. This is not an analysis the Applicants are capable of conducting.

Q. Does this conclude your pre-filed direct testimony?

A. Yes.

[1] *In Re Joint Application of American Transmission Co. LLC and Northern States Power Co.-Wisconsin, as Electric Public Utilities, for Authority to Construct and Operate a New Badger-Coulee 345 kV Transmission Line from the La Crosse Area, in La Crosse County, to the Greater Madison Area in Dane County, Wisconsin,* Docket No. 05-CE-142, *Final Decision*, at 14 (Apr. 23, 2015) (PSC REF#: 235295).

PUBLIC SERVICE COMMISSION OF WISCONSIN

Joint Application of American Transmission Company LLC and Northern States Power Company-Wisconsin, as Electric Public Utilities, for Authority to Construct and Operate a New Badger-Coulee 345 kV Transmission Line from the La Crosse Area, in La Crosse County, to the Greater Madison Area in Dane County, Wisconsin

5-CE-142

FINAL DECISION

On October 22, 2013, pursuant to Wis. Stat. § 196.491 and Wis. Admin. Code chs. PSC 4 and 111, American Transmission Company LLC and Northern States Power Company-Wisconsin (ATC, NSPW, and together as applicants) filed with the Commission an application for a Certificate of Public Convenience and Necessity (CPCN) to construct new 345 kilovolt (kV) electric transmission facilities. (PSC REF#: 226510.) The project, known as the Badger-Coulee project, includes construction of a new 345 kV transmission line and related facilities from the Briggs Road Substation in the town of Onalaska, Wisconsin to the North Madison Substation, northeast of Waunakee, Wisconsin, then extending further south and west to the Cardinal Substation, in the town of Middleton, Wisconsin. (PSC REF#: 204860 at 1-5.) Subsequent to their initial interventions, Dairyland Power Cooperative (DPC), SMMPA Wisconsin, LLC (SMMPA Wisconsin), and WPPI Energy (WPPI) became co-applicants as tenants-in-common for the 345 kV transmission line segment from the Briggs Road Substation to the North Madison Substation with their respective ownership interests derived from NSPW's ownership share.[1] The CPCN application is APPROVED subject to conditions and as modified by this Final Decision.

[1] (PSC REF#: 205969, PSC REF#: 206586, PSC REF#: 224186, PSC REF#: 224187.)

The applicants' analysis included a "Slow Growth" future which included a 0.2 percent load growth rate for which the resulting projected net benefits are still positive. (*See, e.g.*, PSC REF#: 204739 at 35, 38.) The opposing intervenors did not provide credible evidence that a near-zero or negative load growth scenario would be a reasonable future for the applicants to consider.

Opposing intervenors also criticize the applicants for not quantifying the projected net benefits of the project in terms of a per-retail-customer economic benefit, and for not providing guarantees of the magnitude of the benefit.[35] Calculation of a per-retail-customer economic benefit would require a complex analysis of many individual transmission customers' allocation of costs to retail customers and rate classes, considering each local distribution company's (LDC) individual rate structure. The proposed project is anticipated to provide economic benefits to transmission customers as a whole, which in turn will be passed along to transmission customers and subsequently retail customers. As such, the Commission finds the intervenors' criticism as misleading, inaccurate, and unnecessary.

The Commission is persuaded that applicants' economic analysis is robust and more than sufficient for purposes of this proceeding.

Reliability Benefits

The transmission system in the western Wisconsin, eastern Iowa, and eastern Minnesota area includes primarily 69 kV, 138 kV and 161 kV transmission lines and related facilities.[36] Scheduled for completion by late 2015, this area will also include the 345 kV transmission line known as the CapX line, authorized by the Commission in docket 5-CE-136. (*See,*

[35] (*See, e.g.*, PSC REF#: 231947 at 1-12, PSC REF#: 231948 at 28-30.)
[36] (*See, e.g.*, PSC REF#: 218099 at 14-15, PSC REF#: 218100 at 28-29.)

included in this Final Decision. For any account or category where actual cost deviates significantly from those authorized, the final cost report shall itemize and explain the reasons for the deviation.

28. The CPCN is valid only if construction commences no later than one year after the latest of the following dates:

a. The date this Final Decision is served.

b. The date when applicants have received every federal and state permit, approval, and license that is required prior to commencement of construction by construction spread under the CPCN.

c. The date when the deadlines expire for requesting administrative review or reconsideration of the CPCN and of the permits, approvals, and licenses described in par. (b.)

d. The date when the applicants receive the Final Decision, after exhaustion of judicial review, in every proceeding for judicial review concerning the CPCN and the permits, approvals, and licenses described in par. (b.)

29. This Final Decision takes effect one day after the date of service.

Dated at Madison, Wisconsin, this 23rd day of April, 2015.

By the Commission:

Sandra J. Paske

Sandra J. Paske
Secretary to the Commission

SJP:JAL:jlt:DL:00970863

See attached Notice of Rights

Date Mailed
October 30, 2001

BEFORE THE

PUBLIC SERVICE COMMISSION OF WISCONSIN

Joint Application of Minnesota Power Company and Wisconsin Public Service Corporation for Authority to Construct and Place in Service Electric Transmission Lines and Other Electric Facilities for the Arrowhead-Weston Project, Located in St. Louis County in Minnesota, and Chippewa, Clark, Douglas, Lincoln, Marathon, Oneida, Price, Rusk, Sawyer, Taylor, and Washburn Counties in Wisconsin

05-CE-113

FINAL DECISION

Introduction

Background

From the origin of the electric utility industry more than a century ago, the growth in electricity demand and the resulting increase in generation has been matched by ever-increasing need for interconnection of electric power systems. The first power plants served only a few city blocks. The development of electric transmission systems, however, allowed power plants to be linked to serve entire cities, states, and ultimately, large multistate regions. Between 1950 and 1970 many miles of high-voltage transmission lines were constructed within and between regions, ultimately encompassing virtually all electrical loads in the contiguous United States and Canada within four interconnected systems. Wisconsin is within the Eastern Interconnection, extending from Saskatchewan to Florida and New Mexico to Nova Scotia.

The growth of interconnections within the power system allows ever-larger transfers of power between areas and enables utilities to take advantage of distant lower-cost generation. More importantly, it also permits utilities to take advantage of the diversity of electricity demand to the electric system than is currently possible. Accordingly, this project will enhance and not impair the efficiency of service of ATC and WPSC and all of the other utilities in Wisconsin.

The project, as approved by the Commission, will not provide facilities unreasonably in excess of the probable future requirements of ATC and WPSC. As has been discussed above, the project enables an increase of simultaneous import capability to 3,000 MW into eastern Wisconsin. The Commission has found that the 3,000 MW target is a reasonable planning target for transmission capability into eastern Wisconsin and that this project, when constructed and placed into operation, will enhance the reliability of electric service for all customers in Wisconsin.

Finally, when placed in operation, the Arrowhead-Weston project will not add to the cost of service without proportionately increasing the value or available quantity of service. As discussed above, this project will enhance the reliability of electric service for all customers in Wisconsin and the region. This project enhances both the value of the committed generating capacity as well as the quantity of service, which can be delivered to customers in eastern Wisconsin.

E. Impact on Wholesale Competition and Customer Benefits

Under Wis. Stat. § 196.941(3)(d)7., one of the findings the Commission must make in order to issue a CPCN is that "[t]he proposed facility will not have a material adverse impact on competition in the relevant wholesale electric service market." By definition, an extra-high voltage line that expands transfer capability and facilitates commerce will promote, not adversely affect, competition in electric markets in eastern Wisconsin. In addition, the Arrowhead-Weston project will help address horizontal market power issues in WUMS. By increasing transfer capacity, the Arrowhead-Weston project will allow more buyers and sellers to participate in electricity markets and help prevent generators from selling at excessive prices. These market forces can discipline or eliminate higher cost competitors. An independent study performed for the Commission and introduced into the record demonstrated that expanding transfer capability by means of a new extra-high voltage line would help foster a more competitive market structure in Wisconsin.[8] The Arrowhead-Weston project is such a transmission line.

Wis. Stat. § 196.491(3)(d)3t. imposes an additional requirement upon the issuance of a CPCN for this project. Under that statute, the Commission may not approve the CPCN application for an extra-high voltage line unless it finds that the line "provides usage, service or increased regional reliability benefits to the wholesale and retail customers or members in this state and the benefits of the high-voltage transmission line are reasonable in relation to the cost of the high-voltage line."

As noted above, the proposed Arrowhead-Weston project will provide significant benefits to both wholesale and retail customers in Wisconsin by substantially increasing the transfer capability into eastern Wisconsin. By increasing transfer capability, the Arrowhead-Weston project will allow more competition in wholesale electricity markets and help prevent generators from selling at excessive prices. The project will address existing transmission system operational problems such as the Arpin phase angle limitation and the current need to rely upon transmission system operating guides, and will improve both dynamic and voltage stability on the system. This, in turn, will permit the transmission system in

[8] "Horizontal Market Power in Wisconsin Electricity Market," Tabors Caramis and Associates (2000). Introduced as Exh. 244.

Wisconsin to operate more securely at higher power transfer levels, thereby enhancing the reliability of the system. Utilities in eastern Wisconsin, as wholesale customers using the Arrowhead-Weston project, will benefit from enhanced reliability of the electric system in eastern Wisconsin. The fact that all forms of generation would be significantly more expensive alternatives than the construction of the Arrowhead-Weston project demonstrates that the project's benefits are reasonable in relation to its cost.

F. EMF, Earth Currents, Stray Voltage, and Property Value Impacts

Opponents of the Arrowhead-Weston project argued that construction of such a transmission line could harm people or farm animals, because of the presence of EMF and because of earth currents. Others contended that the Arrowhead-Weston project would increase stray voltage on neighboring farms.

A significant body of research has studied whether EMF from electrical lines adversely affects human health or the health of agricultural animals; scientific evidence does not support such a conclusion. The project opponents relied upon the testimony of Dr. Duane Dahlberg when arguing that EMF and ground currents are a health risk. Dr. Dahlberg failed to offer credible testimony on these subjects. The better evidence in the record demonstrates that his theories are discredited, outdated, and not supported by scientific research. The overwhelming weight of scientific evidence indicates that exposure to EMF is extremely unlikely to result in any meaningful health impact. This conclusion is supported by the weak epidemiological evidence of any link to childhood leukemia, by the lack of a plausible biological mechanism that would explain how exposure to EMF could cause disease, and by the fact that the magnetic fields produced by electric power lines do not have enough energy to break chemical bonds or cause

c. Identify and provide very specific information about the environmentally sensitive resources located on the route, and how these resources will be protected.

d. Identify the location of each transmission structure using global positioning system technology and transfer this data to a geographic information systems database, using software compatible with state government standards.

6. The applicants shall work with Commission staff to prepare an RFP to hire environmental inspectors and an environmental manager. The RFP shall include the scope of duties, responsibilities, and authority of each position. The applicants shall hire enough environmental inspectors so that inspectors can be present at every construction spread where work is occurring. The inspectors and manager shall be independent and have the authority to stop work at any construction spread if they identify a violation of the Construction and Mitigation Plan or of any regulatory permit conditions. The inspectors and manager shall also have an active role in the final design, siting, and construction of the Arrowhead-Weston project. The environmental manager shall oversee all aspects of environmental compliance.

7. The applicants shall promptly stop work on a construction spread if directed to do so by an environmental inspector or the environmental manager.

8. The applicants shall comply with all requirements described in the Opinion above for known areas of special concern along the Oliver 1 Modified and Owen 4 routes.

9. The 115 kV transmission line currently located in the Three Lakes Mitigation Site shall be moved to segment 205, rebuilt to its current 161 kV standard and installed on double-circuit structures with the 345 kV transmission line portion of the Arrowhead-Weston project.

10. In areas inhabited by the threatened species wood turtle and Blanding's turtle, construction activities shall cease during the egg-laying and hatching period of June to late September.

11. The applicants shall promptly correct any stray voltage problems that are created by the construction or operation of the Arrowhead-Weston project.

12. WPSC's request for a CPCN to construct a 42-mile, 115 kV transmission line from a new Tripoli Substation to the Highway 8 Substation in Rhinelander is denied. WPSC or ATC may file an application for an alternate means of serving need in the Upper West area.

13. This order takes effect on the day after issuance. The CPCN for the Arrowhead-Weston project does not take effect until the DNR has issued all necessary permits and approvals that are required prior to construction.

14. Jurisdiction is retained.

Dated at Madison, Wisconsin, ______________________________

By the Commission:

____
Lynda L. Dorr
Secretary to the Commission

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See attached Notice of Appeal Rights

Horizontal Market Power in Wisconsin Electricity Markets:

A Report to
The Public Service Commission of Wisconsin

Submitted by

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Executive Summary

The Public Service Commission of Wisconsin (PSCW) has identified the development of a robust wholesale electric market as one of its primary policy objectives in the electric restructuring process underway in Wisconsin.

Market power

Market power has been defined by the PSCW as the ability of a seller to maintain prices above competitive levels for a significant period of time. The Wisconsin Legislature has identified the potential for generation owners to exercise horizontal market power, and thereby "…frustrate the creation of an effectively competitive retail electricity market", as a concern in any restructuring of the state's electric markets. In response to that concern, the PSCW retained Tabors Caramanis & Associates (TCA) to analyze the potential for the exercise of horizontal market power during the period 2001 through 2007, to evaluate potential measures to prevent that market power and to assess the impacts of those mitigation measures on stakeholders.

The study used both structural analysis and behavioral analysis to assess the potential for the exercise of market power, and further used behavioral analyses to evaluate measures for preventing that market power. The study also assessed the measures for preventing or mitigating market power in terms of their impacts on retail rates, stranded costs and employment in the generation sector.

Baseline market simulation

The study began with a simulation of market conditions and prices under perfect competition over the study period. The outputs of this baseline market simulation, prepared using a production cost model, provided the foundation for the structural and behavioral analyses as well for the assessment of rate impacts and stranded costs.

The baseline market simulation was based on a comprehensive set of assumptions regarding such key factors as the future structure of the Wisconsin wholesale electricity market, the on-line dates of new generating units, scheduled retirements of existing generating units, an assumed increase in transmission system capacity effective 2004, fuel prices and other operating costs. The baseline market simulation developed hourly, locational marginal prices that were then averaged across two distinct wholesale markets, the Wisconsin Upper Michigan System or WUMS and Northern States Power Wisconsin (NSPW).

Structural analysis

The structural analysis determined market concentration, a standard measure of the potential for exercise of market power. The markets considered for this analysis were defined in terms of utility service territories, season and load levels within each season. Market concentration was measured using the Herfindahl-Hirschman Index (HHI), an indicator that has been applied to analyses of the electric industry by the Federal Energy Regulatory Commission (FERC) in two tests, Economic Capacity (EC) and Available Economic Capacity (AEC). The EC test assumes that generator owners have no obligation to reserve their least-cost generation to serve native load, while the AEC test assumes that some generator owners have such an obligation.

Behavioral Analysis

While the structural analysis provides a measurement of market concentration but provides no indication of the actual exercise of market power or its impacts on stakeholders, the behavioral analysis simulates the exercise of market power directly. The behavioral analysis addresses two key policy questions:

- What is the potential increase in wholesale electricity prices resulting from strategic behavior on behalf of generators?
- How effective are market power mitigation options in preventing and/or reducing the impact of strategic behavior on wholesale electricity prices?

The behavioral analysis was prepared by simulating two types of strategic behavior generation owners could pursue in a deregulated generation market. The first behavior, strategic bidding, involves generating firms bidding prices above the variable production costs of their units, with the intent of forcing the market clearing price above competitive levels. Generating companies may be able to bid their units into the market at prices significantly above the variable production costs, while maintaining the merit order and often at no risk of being undercut by competitors. The second behavior, capacity withholding, involves firms removing some of their capacity from the bidding process or from the market for a certain period of time, in an effort to cause more expensive units in the system to set the market clearing price. As is the case with strategic bidding, capacity withholding strives to increase the market-clearing price. Unlike strategic bidding, capacity withholding changes the merit order in which units are dispatched. Both of these have the effect of increasing the market price of electricity.

The behavioral analysis was performed using COMPEL, a computer model developed at TCA based on Supply Function Equilibrium (SFE) and the Cournot methodology. Simulations were run for a Base Case, in which the market was deregulated without changes in the current structure or policy framework, and for three cases testing potential mitigation measures: Contracts Case, Divestiture Case, and Contracts plus Divestiture Case.

Impacts on rates

The impact of mitigation measures on public utility customers and electric cooperative members was assessed in terms of changes in unit revenues, a proxy for retail rates. Unit revenues by rate class were calculated for each utility each year as the sum of two unbundled components, the average unit cost of transmission, distribution and customer services by major customer class and the system-wide unit cost of generation.

Impacts on shareholders, electric cooperative members and employees

The impact of mitigation measures on public utility shareholders, electric cooperative members and employees was assessed in terms of stranded costs as well as qualitatively. Stranded costs equal the value of existing generating units in the restructured market less their book value. If that difference is positive, and the resulting stranded costs are not fully recoverable from ratepayers, utility shareholders and cooperative members will view this as an adverse financial impact. In contrast, if market value exceeds book value the stranded costs are negative and are, in effect, stranded benefits. The study estimated the market values for each generating plant using an asset valuation model and data from the baseline market simulation, i.e., a perfectly competitive market.

Conclusions.

The structural analysis indicates that

- Potential exists for the exercise of market power by generation owners within WUMS over the study period;
- This potential is greatest under existing transmission limitations, but potential remains even after transmission capacity is assumed to increase to 3,000 MW effective 2004.
- Wisconsin Electric Power (WEPCO) has the largest market share in all geographic and product markets within WUMS.

The behavioral analysis indicates that:

- Under the current market structure, the level of market power in the WUMS region would prevent the creation of an effectively competitive retail electricity market;
- A workably competitive retail market could be achieved by implementing two changes to the current market structure. These are:
  (1) require divestiture of WEPCO generation assets among three independent owners and thereby reduce market concentration, and
  (2) require owners of existing generation to commit a significant portion of their capacity under fixed price contracts, for example as the source of generation for retail customers on standard offer service.

The assessment of mitigation measure impacts indicates that

- Using fixed price contracts and divestiture to achieve workably competitive retail markets will result in significantly lower rates than would prevail if market power was not mitigated;
- Workably competitive retail markets would not result in positive stranded costs but instead would result in significant stranded benefits;
- Workably competitive retail markets should not have adverse effects on employees of existing generating units since those units will remain profitable.

Recommendations.

To ensure an effectively competitive electricity market, the deregulation of electric markets in Wisconsin should include the combination of mitigation measures modeled in the study. Specifically:

- WEPCO generation assets should be divested among three independent owners, and
- A significant portion of existing generation capacity should be committed under fixed price contracts. One option for accomplishing this would be to contract for generation from this capacity to be used as the source of generation for retail customers on standard offer service.

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5 Impacts on Stakeholders

The study assessed the impacts of market power and market power mitigation measures on three major categories of stakeholders: customers, utility shareholders and workers. The impact of mitigation measures on public utility customers and electric cooperative members was assessed in terms of changes in unit revenues, a proxy for retail rates. The impact of mitigation measures on public utility shareholders and electric cooperative members was assessed in terms of stranded costs. The impact of mitigation measures on public utility and electricity coop workers was assessed qualitatively.

5.1 Rate Impacts

The impact of the proposed mitigation measures on public utility customers and electric cooperative members was analyzed in terms of the effect on electricity rates. Retail rates for electric service provided by utilities are subject to approval by the PSCW. Those rates are set at levels that give the utility or cooperative an opportunity to recover its costs of providing that service, including a reasonable return on its investments, based on data for a representative time period. Those costs can be grouped according to the major distinct functions or services involved in providing traditional, "bundled" electric service i.e., generation, transmission, distribution and customer. If the cost of generation changes, up or down, materially from the level being recovered in current rates, utilities and cooperatives typically file for a corresponding change in their retail rates. Ratepayers generally view an increase in rates as a negative impact and a reduction in rates as a positive impact.

5.1.1 Analysis

The study assessed the impact of mitigation measures on ratepayers in each of the four largest Wisconsin utilities WEPCO, WP&L, WPSC and NSPW. The impact was assessed by comparing the unit revenues (cents/kwh) in each mitigation case to the unit revenues in the Base Case (no market power mitigation.) Unit revenues per rate class were used as a proxy for retail rates. Mitigation measures that result in a reduction in unit revenues relative to the Base Case have a positive impact on ratepayers.

Unit revenues were calculated for each of the four utilities under the Base Case, and under each of the mitigation cases, by major customer class by year. (See Table 5.1, below.) Unit revenues for each utility are the sum of its average unit cost of transmission, distribution and customer services (TDC) for each major customer class and its average system-wide cost of generation. The unit revenues by major customer class are reasonable estimates for the purpose of assessing the impact of mitigation measures on rates; they should not be interpreted as definitive calculations of rates. For example, the study uses the system-wide cost of generation as the generation cost component of unit revenues for each customer class whereas the generation cost component of rates typically varies by major customer class.

The TDC component remains constant across all scenarios since it would not affected by the deregulation of the generation market. The TDC component was estimated for each rate class by subtracting the utility's annual system-wide unit cost of generation in 1998 from its average annual unit revenue by rate class in that year. These estimates were prepared using data reported by the utilities in their 1998 FERC Form 1 reports.[15] The results of the unbundling[16] for each of the four utilities are presented in Appendix E and summarized in Table 5.1.

Table 5.1: 1998 Unbundled Unit Revenues (cents/kwh)

Utility	Component	Residential	Commercial	Industrial
WEPCO	*Generation*	3.61	3.61	3.61
	TDC	3.81	2.48	0.15
WPL	*Generation*	2.80	2.80	2.80
	TDC	3.60	2.66	0.65
WPS	*Generation*	2.57	2.57	2.57
	TDC	3.41	1.90	0.29
NSPW	*Generation*	3.34	3.34	3.34
	TDC	3.42	2.97	1.14

The generation component of unit revenues varies by scenario according to the assumptions made regarding the price at which the utilities would acquire generation to serve their retail customers. In the Base Case and Divestiture Case the study assumed that utilities would acquire generation at the market price in effect when the generation was purchased. Thus the annual unit generation cost for those cases is based on the hourly market prices under each of those scenarios weighted by the quantity of generation acquired in each hour. In the Contracts Case, and Contracts plus Divestiture Case, the study assumed that utilities would acquire generation through "buy-back" or bilateral contracts at prices that would prevail under perfect competition. The annual unit generation cost for those cases is based on the hourly market prices under the simulation of perfect competition, again weighted by the quantity of generation acquired in each hour. The annual average unit cost of generation to utilities used to assess rate impacts are presented in Table 5.2 below.

[15] 1998 was the most recent year for which comprehensive data were available for all utilities.
[16] The estimates of unbundled costs are reasonable for the purpose of assessing the impact of mitigation measures on rates; they are not presented as a detailed or definitive unbundling of rates.

Table 5.2: Average Annual Cost of Electricity to Load Serving Entities (cents/kwh 1999$)

	WUMS				**MAPP**	
	Base Case	**Contracts Case**	**Divestiture**	**Contracts & Divestiture**	**Base Case**	**Contracts & Divestiture**
2001	3.78	2.36	2.51	2.36	2.09	1.97
2002	3.24	2.12	2.23	2.12	2.00	1.88
2003	2.99	2.09	2.19	2.09	2.40	2.27
2004	2.55	2.19	2.26	2.19	2.33	2.22
2005	2.55	2.18	2.25	2.18	2.21	2.10
2006	2.54	2.24	2.33	2.24	1.99	1.86
2007	2.79	2.37	2.44	2.37	2.59	2.44

5.1.2 Results

As shown in Table 5.2, the mitigation measures modeled in the study result in lower unit revenues by rate class than in the Base Case. The estimates of unit revenues for the residential, commercial and industrial rate classes in 2001 under each of the cases are presented in Figures 5.1 through 5.3 respectively. These results also indicate that the rates under the mitigation cases would be lower than the rates paid by customers in 1998.

5.2 Impact on Stranded Costs (Benefits)

The study assessed the impact of mitigation measures on public utility shareholders and electric cooperative members by estimating the impact of those measures on stranded costs. Stranded costs are embedded costs of utility investments that exceed market prices, exceed the amount that can be recovered through the sales of the assets underlying those costs and may not be fully recoverable from ratepayers after the assets are sold or divested. Thus, stranded costs equal the difference between the market value of the assets and their book value. Stranded costs that are not fully recoverable from ratepayers represent an adverse financial impact from the perspective of utility shareholders and cooperative members. In contrast, if stranded costs are negative they represent a positive impact or benefit from the perspective of utility shareholders and cooperative members.

5.2.1 Analysis

The level of stranded costs (benefits) resulting from deregulation of the wholesale generation market was estimated for the non-hydro units of the four largest Wisconsin utilities operating within WUMS - WEPCO, WP&L, WPSC and MGE. An estimate was not prepared for NSP because the capacity booked to NSPW in Wisconsin is not distinguished from the Minnesota capacity. Hydro units were excluded from the calculation because of insufficient data on their fixed costs available for the asset valuation model; however it is reasonable to assume that hydro units will have negative stranded costs.

Net book values of the non-hydro capacity of those utilities was obtained from Staff of the PSCW. Those values are presented in Appendix E.

Estimates of market values for each generating plant were calculated for a market with perfect competition using results from GE MAPS with a specialized asset valuation model. The model calculated the net present value of the income or profit of each generating unit in each year of the study period, 2001 through 2007. The net income each year is equal to the revenues received from selling into the deregulated wholesale market in that year less the operating costs and depreciation for the year. The forecasts of generation and annual revenues by generating unit were obtained from the simulation of the operation of a perfectly competitive wholesale market described in Section 2. The asset valuation model determines pretax revenues less expenses by subtracting variable expenses, fixed expenses and tax depreciation from the annual revenues. Assumptions regarding the level of depreciation of each unit each year were made from the perspective of a new owner, with the units fully depreciated over the lesser of 20 years or their economic life. The model determines after-tax cash flow by subtracting income taxes from pretax revenues, subtracting expenses and adding depreciation. The market value of each unit is the net present value of each year's after tax cash flow. Those estimates are presented in Appendix E.

5.2.2 Results

The study indicates that the market value of each utility's existing generating capacity exceeds the net book value under perfect competition. This implies that stranded costs will be negative even in a perfectly competitive market; in other words, they will be stranded benefits. As market prices under any market power or market power mitigation scenario may be expected to be equal to or greater than perfectly competitive prices, stranded benefits would be realized under any of those scenarios, as well.

The book values and market values under perfect competition of the generating capacity for the four major utilities in WUMS are presented in Figure 5.4. This Figure indicates that the ratios of market value under perfect competition to book value range from 2 to 5. The levels of stranded benefits under perfect competition are presented in Table 5.3.

Table 5.3: Stranded Benefits of Non-Hydro Units under Perfect Competition ($ million)				
	Net Book Value	**Market Value**	**Stranded Benefit**	**Market to Book**
WEPCO	1,295	2,847	1,552	2.2
WPL	195	1,069	874	5.5
WPS	291	874	583	3.0
MGE	65	277	214	4.3

5.3 Impact on Utility and Electricity Cooperative Employees

The study modeled mitigation measures designed to reduce, or eliminate, the potential for exercise of market power in the deregulated generation market. These measures should result in market conditions close to perfect competition. Mitigation measures should not have an adverse impact on public utility and electric cooperative employees relative to the Base Case.

The study found that there would be a significant level of stranded benefits under perfect competition, indicating that existing generating units will continue to be competitive and profitable even with the implementation of mitigation measures. Thus, the mitigation measures modeled in the study do not require power plant owners to reduce labor costs relative to levels in the Base Case. In addition, Wisconsin has passed legislation requiring new owners of generating units to offer employment to nonsupervisory employees for at least 30 months following the transfer at wages, terms and conditions comparable to those in effect prior to the transfer.

5.4 Impacts on Stakeholders: Figures

Figure 5.1: Unit Revenues - Residential

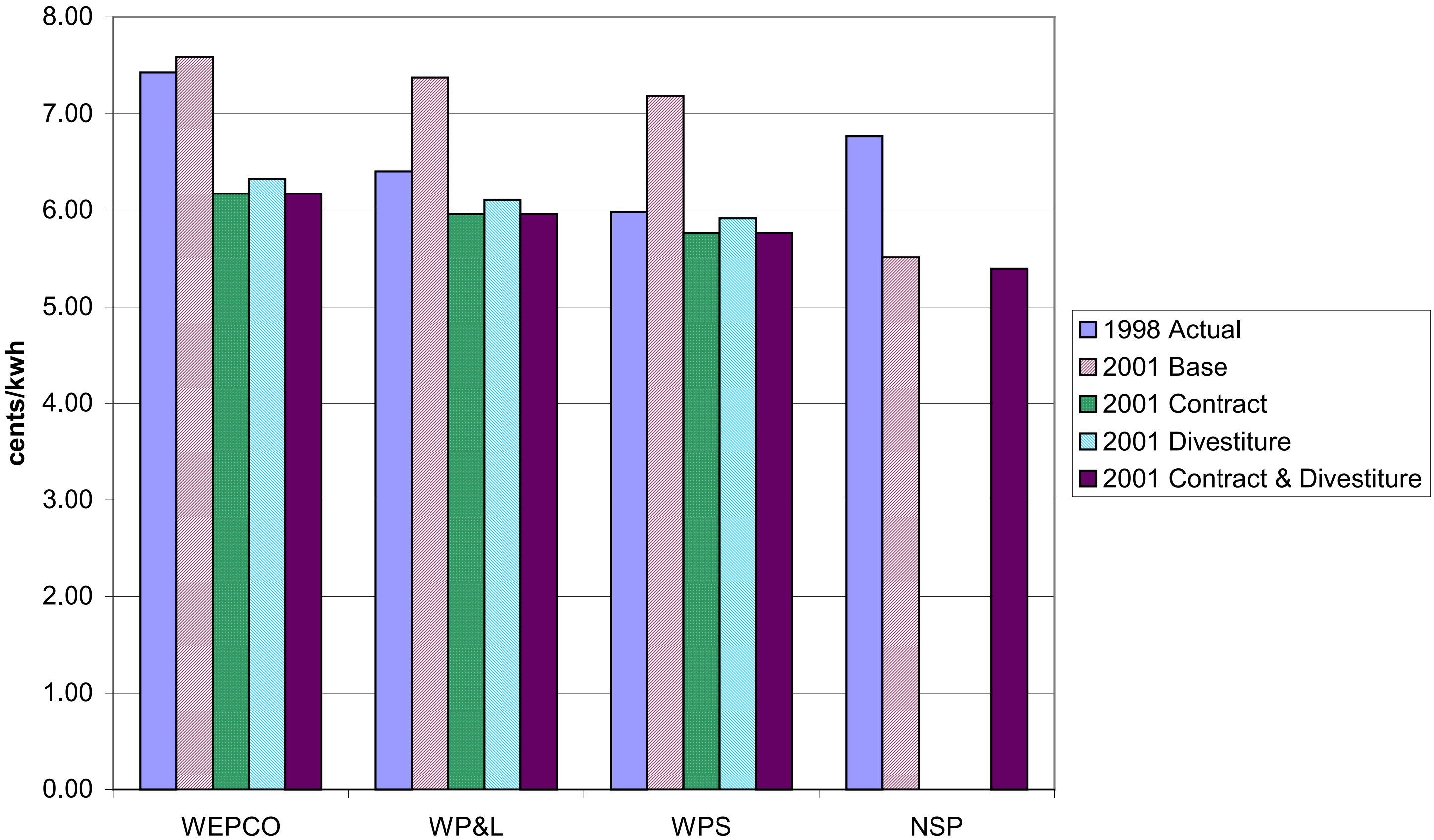


Figure 5.2: Unit Revenues - Commercial

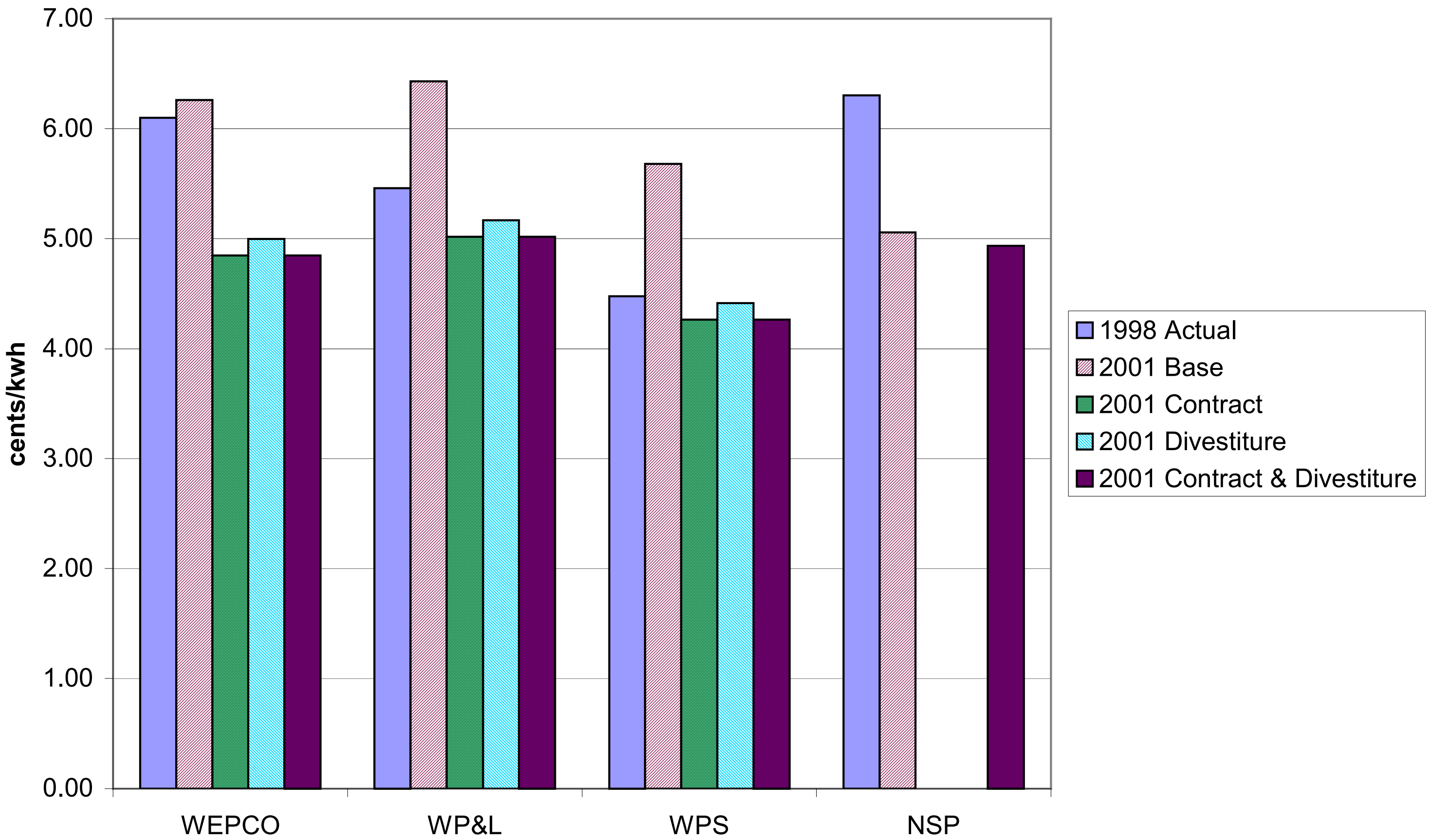


Figure 5.3: Unit Revenues - Industrial

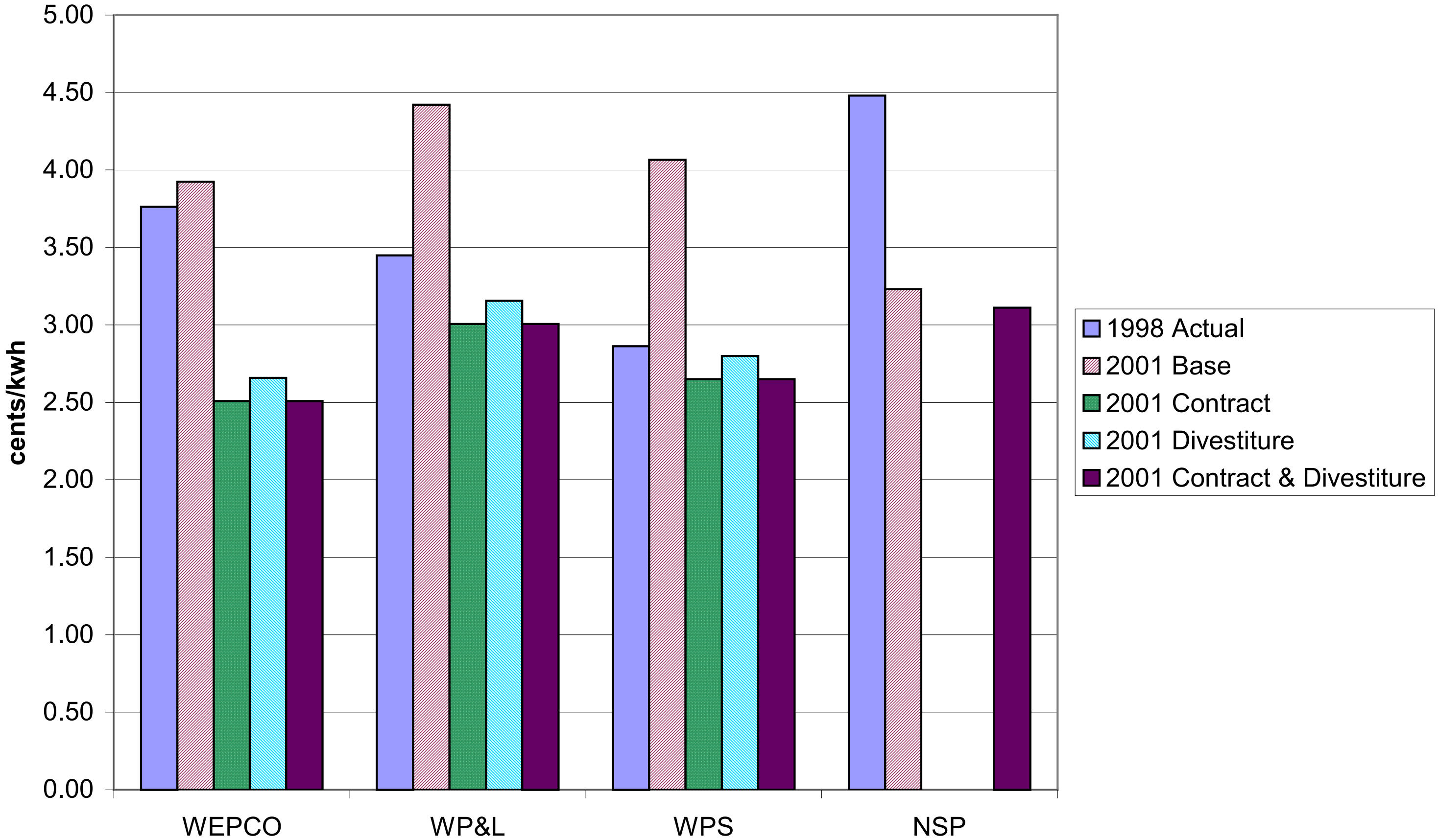
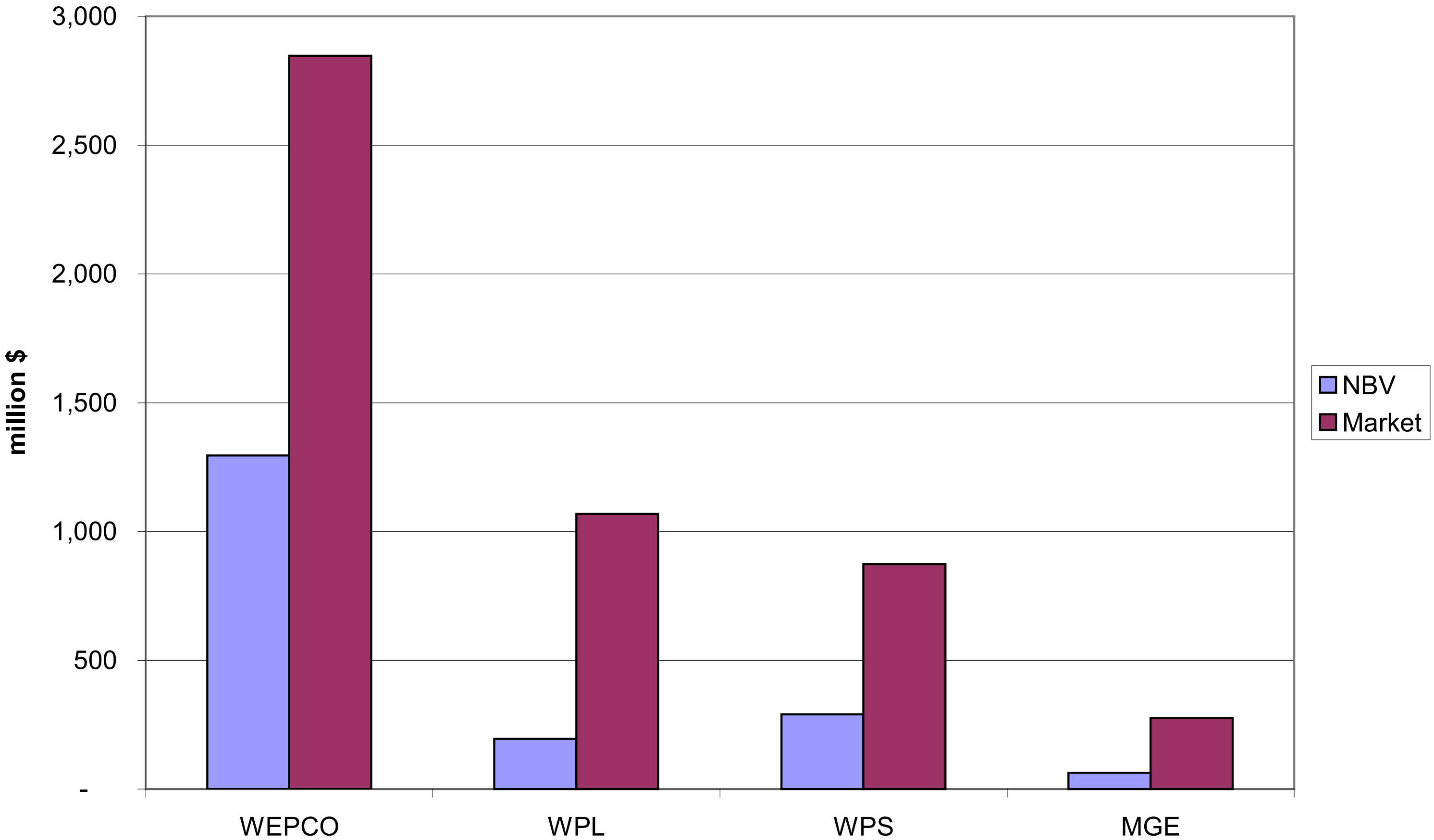


Figure 5.4: Market Value versus Net Book Value (NBV)



6 Conclusions and Recommendations

The Wisconsin Legislature has raised concerns regarding the ability of generator owners to exercise horizontal market power and thereby "…frustrate the creation of an effectively competitive retail electricity market."[17] In response to those concerns, the Public Service Commission of Wisconsin commissioned this study of the potential for the exercise of market power if Wisconsin's electricity markets were deregulated and of potential measures to eliminate that market power. The study assessed the potential for the exercise of market power over the period 2001 through 2007 using a structural analysis and a behavioral analysis.

The WUMS electricity markets are highly concentrated under all market conditions, suggesting that the potential exists for the exercise of market power by generator owners in this region. This potential is greatest under existing transmission limitations, but potential remains even after transmission capacity is assumed to increase to 3,000 MW in 2004. Wisconsin Electric Power (WEPCO) has the largest share of geographic and product markets within WUMS. The electricity market in NSPW region is not sufficiently concentrated to warrant market power concerns.

Under the current market structure, sufficient market power would exist within WUMS to elevate electricity prices significantly above competitive levels. The impact of this market power is reduced, but not eliminated, by expected new generation capacity and new transmission capacity during the study period.

A workably competitive retail market could be achieved in WUMS by changing the current market structure in a manner that eliminates undue market power. This study indicates that two changes, implemented in combination, would achieve this mitigation. The two changes are:

- require owners of existing generation to commit a significant portion of their capacity under fixed price contracts, for example as a source of generation for retail customers (contracts), and
- divestiture of WEPCO generation assets among three independent owners (divestiture).

Changing the current market structure in a manner that prevents undue market power will not have adverse effects on retail customers, public utility shareholders and workers or electric cooperative members and workers, because:

- Using contracts and divestiture to achieve workably competitive retail markets will result in lower rates than would otherwise prevail if market power is not mitigated, and
- Workably competitive retail markets result in stranded benefits, not stranded costs, suggesting that existing generating units will remain profitable in a restructured

[17] Wisconsin Act 9 (biennial budget), 196.025(5)(ar)

marketplace. The owners of those units will not be under undue pressure to reduce labor costs.

We recommend that these mitigation strategies be implemented as part of any electricity market deregulation initiative in Wisconsin.

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BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Joint Application of American Transmission Company, ITC Midwest LLC, and Dairyland Power Cooperative, for Authority to Construct and Operate a New 345 kV Transmission Line from the Existing Hickory Creek Substation in Dubuque County, Iowa, to the Existing Cardinal Substation in Dane County, Wisconsin, to be Known as the Cardinal-Hickory Creek Project.	Docket No. 5-CE-146

S.O.U.L. OF WISCONSIN'S THIRD SET OF DOCUMENT AND DATA REQUESTS TO THE JOINT APPLICANTS

Intervenor S.O.U.L of Wisconsin, Inc.. (SOUL) requests that joint applicants American Transmission Company LLC, ITC Midwest LLC and Dairyland Power Cooperative answer the following document and data requests (collectively, the "Discovery Requests) within twenty-one (21) days of service pursuant to section IV(A)(2)(a).

DEFINITIONS

1. The term, "Project," means the high-voltage transmission option in the Cardinal Hickory Creek docket.

2. The term, "significant improvements" means physical modification made to the facility in question whose purpose or effect was to increase the efficiency, effectiveness, reliability or safety of the facility in question.

3. The term, "NERC violation" means any deviation from the North American Electric Reliability Corporation Critical Infrastructure Protection standards in effect at the timeframe each data or document request addresses.

4. The term "document" means a copy in whatever format of the PDF electronic file that corresponds to the ERF reference number the given data or document request addresses.

5. The term, "provide" means to email copies of the document addressed to the undersigned intervenor[1].

6. The terms, "summer peak load" and" winter peak load" mean the maximum load for the facility for the summer period and the maximum load for the winter period.

1 Please see email address in the signature of this document.

7. The term, "summer off peak load" means 70% of summer peak load.

8. The term, "energy efficiency" means any utility programs that provide rebates for appliances, equipment and improvements to buildings to lower energy consumption by lowering the amount of energy required to provide services.

9. The term "demand response" of utility programs that control time of use of end users especially during periods of high demand.

10. The term, "generation retirements, conversions and additions" means power plants that are taken out of service, converted to another type of fuel and/or power plants that are placed in service.

11. The term, "recovery costs" means recoupment of the purchase price of a capital asset and associated expenses through depreciation over a prescribed period.

12. The term, "asset renewal projects" means the transmission facilities in Southwest Wisconsin applicants have specified as having issues requiring replacement and/or rebuilding.

13. The term, "reliability projects" means the transmission facilities in Iowa and Wisconsin applicants have specified as having potential thermal overloads under NNL contingencies.

14. The term, "Critical Electric Infrastructure Information (CEII) is defined[2] by FERC as, "[I]nformation related to or proposed to critical electric infrastructure, generated by or provided to the Commission or other Federal agency other than classified national security information, and that is designated as critical electric infrastructure information by the Commission or the Secretary of the Department of Energy pursuant to section 215A(d) of the Federal Power Act."

15. The term, "commercial market competition" means rivalry between companies selling similar products and services in the MISO market with the goal of achieving revenue, profit, and market share growth.

16. The term, "base power transfer" is the initial loading in the load flow case from network resources serving load, plus schedules to external areas based on net firm transmission service rights.[3]"

17. The term, "fuel mix" is the mixture of the fuels used to generate electricity, by percentage, for defined spatial and temporal contexts. Spatial examples include a state's electric generation supply, the generation content of a transmission facility or a utility's portfolio of generation sources. Time examples include instantaneous or "real time" percentages and durational measurements as averaged percentages over a specified time period such as a year, parts of year or other durations. EIA[4], MISO[5]

INSTRUCTIONS

2 https://www.ferc.gov/legal/ceii-foia/ceii.asp

3 p.2, *Treatment of Capacity Exports from Local Reserve Zones* by David Patton, Potomac Economics https://www.ferc.gov/CalendarFiles/20151020085636-Patton,%20MISO%20IMM-Local%20Rqmts%20Session%202_10-20-2015.pdf

4 https://www.eia.gov/todayinenergy/detail.php?id=13731

5 http://www.misomatters.org/2017/03/3-electricity-industry-issues-we-are-watching-in-2017/

1. Please use all information available to, or at the disposal of, you or any other parties that you either employ or contract in connection with the above-referenced docket.
2. Make a good faith, diligent inquiry into all information the data requests seek.
3. If any data or documents the data requests seek exist within a larger set of data or documents, produce only the relevant subset of data or documents. If separating the requested subset of data or documents is overly burdensome, make a good faith and diligent effort to create a clear indication or demarcation of the relevant data or documents subset within the larger set of data or documents produced.
4. Update and amend your answers to the data requests with any new information that you discover or to which you gain access in the future, or with any correction that comes to your attention in the future.
5. If you raise an objection to any particular data or document request, please provide an explanation of the objection and the grounds upon which you invoke it.

DATA REQUESTS

RE: RESPONSE TO REQUEST 12K , p.37, APPLICANTS' RESPONSES TO S.O.U.L. OF WISCONSIN'S SECOND SET OF DOCUMENT AND DATA REQUESTS, "Similar to the energy cost savings analysis, the Applicants only modeled 5, 10, and 15-year models. For years between 5, 10, and 15, the Applicants interpolated results. For years beyond year 15, the Applicants assumed increasing emissions at the rate of inflation.

REQUEST NO. 16 : Please clarify that the Applicants' CO2 reduction modeling/calculations for the Project assume that emissions would increase, annually at the rate of inflation (2.5% per year) for years 25 to 40.

REQUEST NO. 17: Please clarify whether the emission type being measured is CO2.

RE: RESPONSE TO REQUEST 12K , p.37, APPLICANTS' RESPONSES TO S.O.U.L. OF WISCONSIN'S SECOND SET OF DOCUMENT AND DATA REQUESTS, "However, depending on system conditions, power [in the Project] could flow in either direction."

REQUEST NO. 18: Please describe the most common system conditions that would result in power in the Project flowing from East to West in direction.

RE: RESPONSE TO REQUEST 12O, p.38, APPLICANTS' RESPONSES TO S.O.U.L. OF WISCONSIN'S SECOND SET OF DOCUMENT AND DATA REQUESTS, "CO2 reduction calculations were performed by the PROMOD software package based on the amount of annual energy produced by fossil fuel plants for each alternative studied combined with modeling information on emissions for those fossil fuel plants.

REQUEST NO. 19: Please provide the modeling information showing how CO2 reductions were estimated as a result of the Project affecting the amount of annual energy produced by Wisconsin fossil fuel generation power plants under all futures.

RE: RESPONSE TO REQUEST 12P, p.38, APPLICANTS' RESPONSES TO S.O.U.L. OF WISCONSIN'S SECOND SET OF DOCUMENT AND DATA REQUESTS, "Not applicable." SOUL Request 112P read, **"If applicable, please describe other ways the Project would reduce CO2 Emissions other than the transporting power with inherently lower C02 Emission content compared to the average fossil fuel generation power mix in Wisconsin."**

REQUEST NO. 20: Please clarify if Applicants mean by "Not applicable," they assume Project would reduce Wisconsin CO2 emissions primarily by transmitting power with inherently lower C02 emission content compared to the base case fossil fuel generation power "fuel mix[6]" for Wisconsin utilities in Wisconsin in 2026 and 2031.

REQUEST NO. 21: Please explain how the Applicants arrived at an estimate of Wisconsin generation CO2 reduction potential for the Project in 2026 and 2031 and provide associated, quantitative, documentation.

RE: RESPONSE TO REQUEST 11J, p.30, APPLICANTS' RESPONSES TO S.O.U.L. OF WISCONSIN'S SECOND SET OF DOCUMENT AND DATA REQUESTS, "The J870, J871, J947 and J855 were generator interconnection requests that had not started the interconnection study process, still haven't completed that study process, and are unlikely to have signed GIAs until 2020. A signed GIA is the typical requirement to be included in planning models. The withdrawal of J712 in 2018, after the February 2017 Phase 1 DPP study was complete, is an example of why having a signed GIA is the typical requirement for inclusion in the models." SOUL Request 112P read**, "We note the Applicants included potential natural gas generation in their economic planning that we cannot find in the MISO queue (see Response to PSCW Data Request 01.210 and Response to PSCW Data Request 01.211 in Response to Data Request 1, Part 2 – Supplement, PSC REF#- 347526. Generators that could be located in the vicinity of the Eden Substation, J870, J871, J947 and J855 were introduced to the MISO queue in July, 2017 before the cut off dates for PROMOD models used for Project analysis in October, 2017. Please explain why this potential of 400-600MM of generation in the vicinity of the Eden substation was not incorporated into the economic planning for the Project and other alternatives."**

REQUEST NO. 22: Please clarify whether the above referenced natural gas generation facilities mentioned in *Response to PSCW Data Request 01.210* are in the Applicants' economic planning studies. Please provide the relevant MISO project numbers so that more information can be found in the queue.

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6 See definition section.

REQUEST NO. 23: Please explain ATC's policy or criteria for including a MISO evaluated transmission proposal into ongoing economic planning studies

REQUEST NO. 24: If, as previously explained, new generation is not included in ATC planning studies for the Project and the LVA, please discuss how the combination of early economic planning incorporation of the Project and delayed or non-incorporation of new generation interconnection requests into economic planning affects the accuracy of Project and LVA economic planning.

REQUEST NO. 25: Also in regard to the combination of early planning incorporation of the Project and delayed or non-incorporation of new generation interconnection requests into the Applicants' economic planning, please assess the impact of these combined policies on the number of new generation interconnection requests that have materialized in Southwestern Wisconsin since 2017.

RE: RESPONSE TO REQUEST 10D, p.25, APPLICANTS' RESPONSES TO S.O.U.L. OF WISCONSIN'S SECOND SET OF DOCUMENT AND DATA REQUESTS, "It [is] not feasible to separate the impacts of a single project from the performance of the system as a whole, since there are a multitude of variables at play. The best way to estimate the economic value of a new project is to perform a detailed analysis using the PROMOD software package modeling multiple, plausible futures. The Applicants have done this and have provided results in Appendix D, Exhibit 1, Planning Analysis." Pertaining SOUL Request: **(a) Document, quantitatively, the net savings in electricity costs due to the presence of the seven, prior 345 kV transmission expansion lines added in Wisconsin since 2007; and, (b) From these historical records, estimate the economic value of adding an 8th line.**

Comment:

The request is to document past economic performance of Wisconsin expansion, 345 kV lines some that that have been in service from 6-12 years determine how they are performing-- not to conduct ProMod projections. For the sake of streamlining, it is logical to omit transmission projects with less than one year of economic activity to assess and lines that are co-owned leaving four,projects to assess.

As Transmission Operators, two of the Applicants have unique abilities to access usage records. This data can be analyzed generically without exposing the utilities involved. As part of normal record keeping, it seems likely that Transmission Operators carefully monitor and record MWH and MW values which can be used to calculate energy savings due to reduced congestion. The calculation, could for example, resemble a method similar to that used for PVRR for the Project.

REQUEST NO. 26: Quantitatively document the annual savings in electricity costs from reduced congestion from facility in-service dates to 2017 for these four 345 kV expansion lines: Arrowhead – Weston, 2007; Paddock-Rockdale, 2010; Rockdale - West Middleton, 2012; and Pleasant Valley – Zion, 2013

REQUEST NO. 27: Compare these results to energy savings ATC estimated in the original project application materials for each of the four lines. Please include associated, projected energy and demand growth rates with this data compilation.

RE: RESPONSE TO REQUEST 10F, p.26, APPLICANTS' RESPONSES TO S.O.U.L. OF WISCONSIN'S SECOND SET OF DOCUMENT AND DATA REQUESTS, "An economic projection for the Project based on performance of past projects would not provide relevant data. Significant system changes, such as the retirement of approximately 1,500 MW of coal-fired generation capacity in the state of Wisconsin in 2018 and the addition of new renewable resources throughout the region, make past system performance an unreliable indicator of future impacts of projects. In addition, the Applicants planning analysis in this case did not directly compare the benefits of the Badger-Coulee project with the Cardinal-Hickory Creek project."

Comment:

As forecasting is an imperfect art, SOUL is suggesting augmenting the Applicant's methodology with conventional business approach. It is based on examining existing records from four, prior Wisconsin-located 345 kV expansion lines, establishing economic performance data from each and comparing this with current ProMod estimations for the Project.

REQUEST NO. 28: In addition to the data compiled for Request 27, please include and present the historic, economic savings for each of the four projects as measured from in-service dates to 2017. Compare these four amounts to estimated ProMod economic savings for the Project over matching durations of time. These comparisons stand to provide valuable guides to understanding the reliabilities of the Applicants' past and present economic planning methodologies.

RE: RESPONSE TO REQUEST 8D, p.23, APPLICANTS' RESPONSES TO S.O.U.L. OF WISCONSIN'S SECOND SET OF DOCUMENT AND DATA REQUESTS, "In general, large energy users that are impacted by demand response events don't experience a net economic benefit from the event, since business activities and revenue streams are significantly adversely impacted by the loss of power during the event. As an offset to those possible impacts, those customers typically receive a discounted energy rate from their electric provider." Pertaining SOUL Request: **Did the Applicants account for energy savings the large users would realize from participating in 31.5 MW of Demand Response?**

Comment:

SOUL will assume the answer is "no" unless the Applicants want to modify their position. We agree there is "down time" that can bring economic loss and this is usually weighed when joining the DR program. The question is whether the value of the energy not used during down time was counted.

RE RESPONSE TO REQUEST 2B, p.18, APPLICANTS' RESPONSES TO S.O.U.L. OF WISCONSIN'S SECOND SET OF DOCUMENT AND DATA REQUESTS, "The initial planning-level estimates of the cost of Cardinal-Hickory Creek did not include detailed

estimates of each project component. The final detailed estimate of $492M (year of occurrence dollars) included with the CPCN application does include these details. The planning- level estimate of $500M (2023 dollars) was made so that the NTA could be sized and studied while work outside of the Planning Analysis Document was being completed." Pertaining SOUL Request: **"In response to Request 2A on p. 10, of Applicants' Response to S.O.U.L. of Wisconsin, Inc.'s First Document and Data Requests, it is stated, "40 year Hardening, cyber and other Security expenses: assumed to be included in the remaining $500M (cost)." Please provide a more detailed estimate of hardening, cyber and other security expense costs that can be expected for the Project over 40 years based on studies or other reliable sources."**

REQUEST NO. 29: If the Applicants do not intend to provide estimated hardening, cyber and other security expense costs over the 40 year lifespan of the Project and explain where the funds for these expenses would come from, please explain why.

RE; RESPONSE TO REQUEST 1F, p.14, APPLICANTS' RESPONSES TO S.O.U.L. OF WISCONSIN'S SECOND SET OF DOCUMENT AND DATA REQUESTS, "That is correct. Wisconsin utilities either own these generators or have a contract for a portion of their power. The owned capacity and contracted capacity is used to meet the Wisconsin utilities' load obligations." Pertinent SOUL Request: **"Please explain if and how these wind generators: Top of Iowa II, Top of Iowa III, Barton, Crane Creek and Bent Tree (from .pdf p. 29, Appendix D- 6, Appendix D Exhibit 1 Planning Analysis Document Appendices) are incorporated into the requested "load obligations" and/or other HHI calculations. It seems Wisconsin utilities either own these referenced generators or are contracted to purchase power from them."**

REQUEST NO. 30: Are any of the above wind facilities providing contracted power with Wisconsin utilities using the existing transmission system?

REQUEST NO. 31: Have the Applicants considered providing documentation of current transmission access costs for one or more of these (unnamed) contracted remote wind facilities and comparing these to estimated transmission access costs, post-Project, to substantiate Project economic potential?

RE: RESPONSE TO REQUEST 1H, p.14-15, APPLICANTS' RESPONSES TO S.O.U.L. OF WISCONSIN'S SECOND SET OF DOCUMENT AND DATA REQUESTS, "The Applicants did not perform the analysis that would be needed to answer this question. The following information is only intended to explain why DPC and NSP were not included.

The Herfindahl-Hirschman Index (HHI) is used to evaluate the extent of competition in power markets. The ATC service area is the power market assumed in the calculation of the HHI given the established geographical and transmission system limitations; as a result, DPC and NSP have been excluded from the analysis." Pertinent SOUL Request: **"Please describe what the expected impacts would be on the Applicants' HHI calculations in Tables 42-45 on p. 70-71 of the Appendix D Exhibit 1 Planning Analysis if Dairyland Power Cooperative (DPC) and**

Northern States Power (NSP) utilities were included in the analysis. Would the estimated change in market concentration in 2026 due to the Project affect the economics of DPC and NSP and, if so, would including these utilities in the Applicants' HHI analysis cause the Net HHI values in Tables 42-45 on p. 70-71 to increase or decrease?

REQUEST NO. 32: To the best of the Applicants' understanding of the use of the Herfindahl-Hirschman Index (HHI) and without conducting the analysis for comparison, please explain, in principle, whether the inclusion of Dairyland Power Cooperative (DPC) in the Applicants' IHH analysis would tend to increase or reduce the market competition performance of the Project? We note that DPC Member Distribution Coop is located in the Project study area and others are nearby.

Re: Ex-Applicants-Degenhardt-1, PSC REF# 358841, "NPV Table" with Schedule 9, Schedule 26A charges for ATC, NSP and DPC.

and

Re:Direct-Applicants-Degenhardt-3, "Knowing the net PVRR allows the Applicants (and ultimately, the Commission) to more accurately compare the costs and benefits of the Project to Wisconsin customers. Because the net PVRR represents the present value of the change in transmission charges to ATC's, NSPW's, and Dairyland's customers as a result of the addition of the Project, it represents the Project's true cost to Wisconsin customers."

This is challenging information for experienced financial analysts, not to mention non specialist electric customers.

REQUEST NO. 33: Please explain the dollar flow associated with Schedules 9 and 26A becoming charges that electric customers pay. Are they per MWH charges a customer's utility pays to the Transmission Operators for use of transmission facilities? Are these costs passed onto the customer?

REQUEST NO. 34: Please provide the energy and demand annual growth rate assumptions for all schedules used in the ex.1 Table.

REQUEST NO. 35: Please explain how often MISO updates the 26-A and 9 Schedules? Are these schedules considered to be estimates of future costs?

REQUEST NO. 36: If estimates, in Applicants' experiences, please describe the significance of inaccuracies they have exhibited in the past.

REQUEST NO. 37: Please provide links to the Schedule 9 and 26A schedule and associated spreadsheets, that applicants have used in creating the Table in Ex-Applicants-Degenhardt-1

REQUEST NO. 38: In the experiences of the Applicants, since the introduction of the use of the 26A schedule, have charges tended to remain steady, decline or increase?

REQUEST NO. 39: If charges in the 26A schedule have tended to change in one direction or another, have Applicants considered building in adjustments to economic planning to account for this factor?

REQUEST NO. 40: For ATC costs in ex.1 Table, the Project appears to result in progressingly lower Schedule 9 charges for ATC to pay from 2023 to 2063. Please explain whether the apparent, annual reductions in Schedule 9 charges after 2023 are the result of the Project being in service or another factor.

REQUEST NO. 41: Please explain if the projected, 2023 -2063 reductions in the ex.1 Table Schedule 9 charges that ATC is expected to pay are the result of less use of other transmission facilities in ATC's service territory. If so, please describe the types of transmission lines affected.

REQUEST NO. 42: If the decreasing Schedule 9 charges that ATC is expected to pay are associated with less use of transmission facilities, please characterize how the projected drop in usage would affect demand on ATC's lower voltage (69 kV-138 kV) transmission lines in Southwestern, Central and South-central Wisconsin.

REQUEST NO. 43: Please describe common factors that cause Schedule 9 charges to increase. For example, would introducing new generation into a transmission line with a Schedule 9 charge basis tend to increase those charges?

REQUEST NO. 44: Please explain why there are no Schedule 9 charges listed or adjusted made to them in the NSP and DPC sections.

REQUEST NO. 45: Regarding functions used in the ex.1 Table. In the value NPV row in Column G under ATC Net Charge of $62,162,880 the result of adding the values in the G column from 2017-2063 and applying the sub total to NPV calculation with a Discount Rate of 6.40%?

REQUEST NO. 46: Please explain the annual, net negative values in column "G," from row 2050 to 2063. Do these represent annual gains in this accounting beginning in 2050? If so, are these net gains in part or whole passed onto utilities and to their customers?

Re: Direct-Applicants-Degenhardt-3, "As explained in Direct-Applicants-Dagenais, the Applicants' planning analysis calculates various categories of economic benefits for ATC's, NSPW's and Dairyland's Wisconsin customers. To provide an accurate comparison of the Project's total, overall costs and <u>benefits</u> to Wisconsin customers, the costs must reflect the Wisconsin customer impact of the Project, which is what the net PVRR represents."

REQUEST NO. 47: Please clarify what type or types of benefits are referred to in the second, underlined usage of the term,"benefits," above. Do the referenced benefits include avoided reliability, asset renewal and other avoided costs?

Re:Direct-Applicants-Degenhardt-4, "...generally speaking, the amount Wisconsin customers pay for a major infrastructure project, like the Cardinal-Hickory Creek Project, is not the same as the construction cost. There are several reasons for this. For example, the Applicants are allowed to earn a rate of return on the capital they spend, which must be included to obtain the true cost of the Project to Wisconsin customers. This return is not reflected in the construction cost. "

REQUEST NO. 48: Please define and distinguish the terms, "return on the capital" and "Revenue Requirement Adders over 40 years." Please clarify if either are included in the construction period cost. We ask this because Applicants' response to Request 2A in SOUL's first set of Discovery Requests suggests that $100M of Revenue Requirement Adders over 40 years are included in the total ~$500M construction cost for the Project. (See PSC REF#- 357719, starting p. 9)

REQUEST NO. 49: Please provide the estimated value of the 40 year "return on the capital" for the Project and also that of the LVA.

Re: Direct-Applicants-Degenhardt-4, "The MVP cost allocation is generally based on each utility's load share of energy (MWH) withdrawals from the MISO market across the relevant MISO North region."

REQUEST NO. 50: Please describe the Applicants' awareness of how MISO predicts each utility's future load share of energy (MWh) withdrawals from the MISO market. Are annual growth rates used, and, if so, are rate refined on utility to utility basis or applied globally?

REQUEST NO. 51: To the best of the Applicants' awareness, what factors does MISO tend to base increasing annual growth rates on?

REQUEST NO. 52: To the best of the Applicants' awareness, does MISO refer to utilities' historical use and demand when projecting future energy and demand growth?

Re: Direct-Applicants-Degenhardt-6, "To determine the impact to ATC's Wisconsin customers, I took the sum of the change in the total allocation to Attachment MM, as described above, and multiplied it by 13.42 percent, which represents the share of Schedule 26A charges billed to ATC customer groups,"

REQUEST NO. 53: Please explain if the 13.42 percent share is subject to change. For example, would Wisconsin utilities' share of MVP costs increase if customers in other MISO states lower their reliance on power supplied by the MISO market at a faster rate than customers in Wisconsin?

Re: Direct-Applicants-Degenhardt-8, Question posed **"Did the Applicants calculate the impact that the Project would have on electric bills for individual retail electric ratepayers?"** Degenhardt Reponse: "**No. As the Commission has recognized, in a docket where the proposed transmission project brings economic benefits (in addition to reliability and policy benefits), calculating the impact of a project on individual retail ratepayers would be extremely difficult, would not yield useful information, and could perhaps result in misleading data.**[1] **ATC, ITC, and Dairyland do not directly serve retail electric customers. Rather, they serve local distribution companies (LDCs) or (in the case of Dairyland) member cooperatives, which in**

turn serve retail customers. Therefore, to determine the Project's impacts to individual retail electric ratepayers, one would have to determine (for example) the benefits of accessing different sources of generation for each Wisconsin LDC and cooperative, how each Wisconsin LDC and cooperative would incorporate these benefits into its retail tariffs for each customer class, and then those benefits would have to be compared to the changes in transmission charges. This is not an analysis the Applicants are capable of conducting."

Additionally,
Re: Direct-Applicants-Degenhardt-2, "I calculated the net present value revenue requirement (PVRR) of the Project to determine the estimated impact to customers in Wisconsin... The purpose of my testimony is to describe how the Applicants calculated the net PVRR for the Project, and to describe the impact of the Midcontinent Independent System Operator's (MISO) Multi-Value Project (MVP) cost allocation process on ATC's, Dairyland's, and Northern States Power Company, Wisconsin's (NSPW) customers."

Additionally,
Re: RESPONSE TO REQUEST 15A, p.49, APPLICANTS' RESPONSES TO S.O.U.L. OF WISCONSIN'S SECOND SET OF DOCUMENT AND DATA REQUESTS, "In addition, the Applicants do not have enough detailed information to define an "average residential customer."

Citation #1, Applicants' Analysis of WI Utility Future Generation Sources:
Direct-Applicants-Dagenais-52 "...the Project will increase the transfer capability of the transmission system between Wisconsin and Iowa, which will increase the availability of low-cost wind energy and reduce energy costs for Wisconsin customers

Citation #2, Applicants' Analysis of WI Utility Future Generation Sources:
Direct-Applicants-Dagenais-53, "...the Project provides the greatest amount of net benefits to Wisconsin customers. It is the most efficient means of improving the reliability of the transmission system and enabling Wisconsin customers to access a substantial amount of low-cost wind energy that is currently being developed in areas west of the state."

Citation #3, Applicants' Analysis of WI Utility Future Generation Sources:
Direct-Applicants-Dagenais-8, "The Applicants conducted a robust economic analysis of the Project, modeling it against three different alternatives in a total of eight different, plausible futures for the electric industry. In the Application, the Applicants submitted modeling results for five futures. After the Application was filed, at the Commission staff's request, the Applicants made numerous changes to their models and evaluated the Project under three new futures, resulting in a total of eight futures being studied.1 As shown in Table 1, below, the eight futures in which the Project was analyzed included *wide-ranging assumptions* about key factors that could affect the future of the electric power sector.

Citation #4, Applicants' Analysis of WI Utility Future Generation Sources:
RESPONSE TO REQUEST 12O, p.38, APPLICANTS' RESPONSES TO S.O.U.L. OF WISCONSIN'S SECOND SET OF DOCUMENT AND DATA REQUESTS, "CO2 reduction calculations were performed by the PROMOD software package based on the amount of annual energy produced by fossil fuel plants for each alternative studied combined with modeling information on emissions for those fossil fuel plants."

SOUL comment pertaining to Wisconsin electric customer rights to evaluate potential

monetary impacts in a way they are familiar with:

SOUL thoroughly agrees with the Applicants that it is not in the best interests of the public to misrepresent or mislead ratepayers about the facts in this case. As an organization representing Wisconsin electric customers, we have received many requests for concrete information concerning ratepayer level impacts from expansion transmission line proposals.

Knowledge of the potential impact on one's monthly electric bill is the only means a Wisconsin electric customer has to meaningfully evaluate the potential benefits and impacts of this proposal. It is widely acknowledged, if not legally protected in many instances, that a buyer has the right to know the cost of a considered purchase. When a purchase is based on, unknown, future conditions, it is standard practice to provided the buyer a good faith estimate, in dollars and cents, of the monetary consequences over time.

Transmission line additions <u>do have</u> direct, decades long impacts on electric customers' monthly electric bills.

To date, the Applicants' use of unfamiliar, financially sophisticated portrayals of cost impacts has prohibited electric customers from being able to meaningfully evaluate this proposal. Further, Mr. Degenhardt has observed that the Applicants' portrayal of monetized net benefits to Wisconsin electric customers may also be incomplete.

SOUL believes it is appropriate for the Applicants to provide the costs or at least a part of the costs portrayed as impacts on average, monthly residential, commercial and industrial customer electric bills-- the only context that Wisconsin electric customers can accurately weigh impacts.

The portrayal of Project cost as impacts on monthly electric bills begins to compensate for the fact that customers are only provided estimates about future monetary impacts whereas the transmission owner/operators/investors enjoy more or less guaranteed revenue with percentage point precision.

It is SOUL's estimation that benefits and adjustments coming from changes in Wisconsin utility generation sources, associated tariffs and altered transmission charges can be estimated from assumptions existing in the Applicants' futures, trends in tariffs and that transmission charge alterations that are standard fare calculations for ATC.

Following are several requests for clarification on this subject which conclude with a request to confirm Project costs in more precise yet, still familiar way for ratepayers.

REQUEST NO. 54: Please explain how the Applicants' economic planning with calculations of net benefits can be "robust" and <u>avoid</u> prediction and economic analysis of differing sources of generation for ATC's local distribution companies, Northern States Power and Dairyland Power Cooperative.

REQUEST NO. 55: Please discuss whether the ProMod software used by the Applicants to produce complex net benefit calculations is also used by utilities to help simulate cost impacts when considering new generation sources.

REQUEST NO. 56: Please explain whether the "robust," "wide-ranging" quantitative, future-based assumptions involving generation changes in Wisconsin utilities (ATC-LDC/NSP/DPC's) differs significantly from the "different sources of generation" that Wisconsin utilities would ultimately select. If so, please explain why this large difference in planning data exists.

REQUEST NO. 57: Please explain whether the Applicants' "robust" economic planning is able to accommodate commonly used tariffs and changes in transmission charges.

REQUEST NO. 58: Please comment on whether the following statement is factually correct: Applicants have estimated that potential, transmission congestion and reliability net benefits shared by approximately 3 million Wisconsin electric customers would range from $22.7 to $349.3 million over the 40 year projected lifespan of the proposed Cardinal Hickory Creek 345 kV transmission line.

REQUEST NO. 59 Using EIA Form 861 data from 2017 with Wisconsin-wide totals for customer usage and customer counts for all sectors (see Request 15A from SOUL's second set of Discovery Requests), please comment on whether the following two sentences are factually correct: Simple averaged distributions of the $22.7 to $349.3 million in potential transmission congestion and reliability net benefits from Cardinal Hickory Creeks transmission line would range from .5 cents to 6 cents per month per average residential customer, from 5 cents to 51 cents per month for the average commercial customer and from $3 to $32 per month for the average industrial customer. Applicants have suggested that benefits could be larger based on actual changes in power purchases that materialize.

Re: Direct-Applicants-Dagenais-7, "According to the MISO Generation Interconnection Queue, as of January 10, 2019, there are over 6.9 gigawatts (GW) of wind generation capacity installed or under construction in Iowa, as compared to just under 1.4 GW in Wisconsin."

REQUEST NO. 60: Is the 1.4 GW or 20% of MISO's new generation requests aimed at Wisconsin a substantial increase compared to recent years? If so, documenting some of the reasons would be helpful.

REQUEST NO. 61: What percentage interconnection requests for wind power are typically put into service?

REQUEST NO. 62: What are the most common reasons that utility-scale wind facilities are not put into service?

RE:Direct-Applicants-Dagenais-7, "However, Wisconsin customers do not receive the full benefits of this low-cost renewable generation to the west because of congestion on the transmission system between Iowa and Wisconsin. This congestion is not just causing Wisconsin to miss out on obtaining more renewable energy—it is also causing Wisconsin customers to pay more in the energy market as higher-cost-fuel resources are forced to dispatch east of the congestion. As future wind capacity is developed, economic planning models show that these market congestion issues will intensify.

REQUEST NO. 63: Please provide evidence such as quantitative congestion metrics showing the existence of a higher, persistent degree of transmission congestion in Southwest and South-central

Re: Direct-Applicants-Dagenais-52 Question posed: **"In your opinion, will the Project provide usage, service or increased regional reliability benefits to the wholesale and retail customers or members in this state, and are the benefits of the Project reasonable in relation to its costs?** Response: **"Yes, for all the reasons I discussed previously in my testimony."**

REQUEST NO 173: As Wisconsin statute does not specify, "net energy savings" in the list of considered benefits to judge whether benefits are reasonable in relation to Project costs, please explain how the Applicants consider net energy savings to be a benefit when assessing 345 kV transmission projects to help decision makers determine if the potential benefits are reasonable in relation to long term Project costs.

REQUEST NO 174: Please indicate whether the Applicants have estimated monetary values for each of these benefit types: "usage," "service," and "increased regional reliability."

REQUEST NO 175: If Applicant have determined, monetary values for "usage," "service," and "increased regional reliability." please provide the results with calculations for the Project and Alternatives.

REQUEST NO 176: If Applicants did not include "increased regional reliability." as a monetized, economic benefit in their current proposal, please explain how the Applicants concluded that the benefits from the Project are reasonable in relation to its costs .

Direct-Applicants-Dagenais-53. Question posed: **"In your opinion, will the Project have a material adverse impact on competition in the relevant wholesale market?"** Response: **"No. In fact, and as I noted earlier, the Applicants' HHI analysis indicates that the Project will actually improve competition in the ATC service area, and therefore actually benefit the competitiveness of the wholesale energy markets."**

REQUEST NO 177: In regard to evaluating market competition using HHI analysis, please list the new generation Applicants' assume in their HHI analysis and/or economic planning that would be located in Southwest and South-central Wisconsin.

REQUEST NO 178: Please describe the expected impact on HHI-analyzed *regional* competition if substantial amounts of new generation, such as the posed 600 MW of wind and solar generation being introduced into the Project at the Hill-Valley Substation? (See p. 42, 6.2.2 Energy Cost Saving Benefits with Future Constraints Resolved, Planning Analysis.)

Respectfully submitted on March 18, 2018.

S.O.U.L of Wisconsin, Inc.

/s/ Rob Danielson

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BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Joint Application of American Transmission Company, ITC Midwest LLC, and Dairyland Power Cooperative, for Authority to Construct and Operate a New 345 kV Transmission Line from the Existing Hickory Creek Substation in Dubuque County, Iowa, to the Existing Cardinal Substation in Dane County, Wisconsin, to be Known as the Cardinal-Hickory Creek Project.	Docket No. 5-CE-146

S.O.U.L. OF WISCONSIN'S REPHRASED REQUESTS IN OUR THIRD SET OF DOCUMENT AND DATA REQUESTS TO THE JOINT APPLICANTS

In the *Applicants' Objections to Intervenor S.O.U.L. of Wisconsin's Third Set of Document and Data Requests to the Joint Applicants Response*, the Applicants observe a number of times that, "The Applicants are unable to further respond to this Request as stated."

As part of our *Third Set of Document and Data Requests to the Joint Applicants,* S.O.U.L of Wisconsin, Inc.. (SOUL) has rephrased fourteen requests which are provided in this document submitted to Applicants American Transmission Company LLC, ITC Midwest LLC and Dairyland Power Cooperative for additional consideration and response.

DEFINITIONS

1. The term, "Project," means the high-voltage transmission option in the Cardinal Hickory Creek docket.

2. The term, "significant improvements" means physical modification made to the facility in question whose purpose or effect was to increase the efficiency, effectiveness, reliability or safety of the facility in question.

3. The term, "NERC violation" means any deviation from the North American Electric Reliability Corporation Critical Infrastructure Protection standards in effect at the timeframe each data or document request addresses.

4. The term "document" means a copy in whatever format of the PDF electronic file that corresponds to the ERF reference number the given data or document request addresses.

5. The term, "provide" means to email copies of the document addressed to the undersigned intervenor[1].

6. The terms, "summer peak load" and" winter peak load" mean the maximum load for the facility for the summer period and the maximum load for the winter period.

7. The term, "summer off peak load" means 70% of summer peak load.

8. The term, "energy efficiency" means any utility programs that provide rebates for appliances, equipment and improvements to buildings to lower energy consumption by lowering the amount of energy required to provide services.
9. The term "demand response" of utility programs that control time of use of end users especially during periods of high demand.
10. The term, "generation retirements, conversions and additions" means power plants that are taken out of service, converted to another type of fuel and/or power plants that are placed in service.
11. The term, "recovery costs" means recoupment of the purchase price of a capital asset and associated expenses through depreciation over a prescribed period.

12. The term, "asset renewal projects" means the transmission facilities in Southwest Wisconsin applicants have specified as having issues requiring replacement and/or rebuilding.

13. The term, "reliability projects" means the transmission facilities in Iowa and Wisconsin applicants have specified as having potential thermal overloads under NNL contingencies.

14. The term, "Critical Electric Infrastructure Information (CEII) is defined[2] by FERC as, "[I]nformation related to or proposed to critical electric infrastructure, generated by or provided to the Commission or other Federal agency other than classified national security information, and that is designated as critical electric infrastructure information by the Commission or the Secretary of the Department of Energy pursuant to section 215A(d) of the Federal Power Act."

15. The term, "commercial market competition" means rivalry between companies selling similar products and services in the MISO market with the goal of achieving revenue, profit, and market share growth.

16. The term, "base power transfer" is the initial loading in the load flow case from network resources serving load, plus schedules to external areas based on net firm transmission service rights.[3]"

17. The term, "fuel mix" is the mixture of the fuels used to generate electricity, by percentage, for defined spatial and temporal contexts. Spatial examples include a state's electric generation supply, the generation content of a transmission facility or a utility's portfolio of generation sources. Time examples include instantaneous or "real time" percentages and durational measurements as averaged percentages over a specified time period such as a year, parts of year or

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1 Please see email address in the signature of this document.
2 https://www.ferc.gov/legal/ceii-foia/ceii.asp
3 p.2, *Treatment of Capacity Exports from Local Reserve Zones* by David Patton, Potomac Economics https://www.ferc.gov/CalendarFiles/20151020085636-Patton,%20MISO%20IMM-Local%20Rqmts%20Session%202_10-20-2015.pdf

other durations. EIA[4], MISO[5]

INSTRUCTIONS

1. Please use all information available to, or at the disposal of, you or any other parties that you either employ or contract in connection with the above-referenced docket.
2. Make a good faith, diligent inquiry into all information the data requests seek.
3. If any data or documents the data requests seek exist within a larger set of data or documents, produce only the relevant subset of data or documents. If separating the requested subset of data or documents is overly burdensome, make a good faith and diligent effort to create a clear indication or demarcation of the relevant data or documents subset within the larger set of data or documents produced.
4. Update and amend your answers to the data requests with any new information that you discover or to which you gain access in the future, or with any correction that comes to your attention in the future.
5. If you raise an objection to any particular data or document request, please provide an explanation of the objection and the grounds upon which you invoke it.
6.

REPHRASED DATA REQUESTS

Re: Ex-Applicants-Degenhardt-1, PSC REF# 358841, "NPV Table" with Schedule 9, Schedule 26A charges for ATC, NSP and DPC.

and

Re:Direct-Applicants-Degenhardt-3, "Knowing the net PVRR allows the Applicants (and ultimately, the Commission) to more accurately compare the costs and benefits of the Project to Wisconsin customers. Because the net PVRR represents the present value of the change in transmission charges to ATC's, NSPW's, and Dairyland's customers as a result of the addition of the Project, it represents the Project's true cost to Wisconsin customers."

Additional Background: It is hoped the Applicants will soon provide SOUL the 26A schedule the Applicants used to make their net PVRR calculations in Ex-Applicants-Degenhardt-1. All of the 26A schedules that SOUL is able to access via MISO resources are labeled, "indicative." SOUL welcomes correction in our understanding. In addition changing energy and demand rate assumptions, actual project costs, actual in-service dates, and actual annual charge rates for transmission owners and other fluctuations, it is our understanding that the charges provided in 26A Schedules are subject to change and cannot be applied, without accounting for deviation, over the Applicants' PVARR calculation period. (Definition of "indicative," relating to, signifying, or pointing out) https://www.misoenergy.org/planning/planning-test/schedule-26-and-26a-indicative-reports/

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4 https://www.eia.gov/todayinenergy/detail.php?id=13731
5 http://www.misomatters.org/2017/03/3-electricity-industry-issues-we-are-watching-in-2017/

REQUEST NO. 39R (Re-Phrased): Please explain whether the data presented in Applicants' Table in Ex-Applicants-Degenhardt-1 accounts for future, potential changes in charges in the 26A schedule over the 40 year accounting period. If so, please explain how, future, potential charges in this Schedule are accounted for in the $66,957,498 estimated figure or explain why a potential deviation over the calculation period is considered to be insignificant.

Additional Background: SOUL does not have access to a functioning spreadsheet for table in Ex-Applicants-Degenhardt-1 ex.1

REQUEST NO. 45R (Re-Phrased): Regarding calculations used in producing the Applicants' Table in Ex-Applicants-Degenhardt-1 ex.1, please clarify how the value of $62,162,880 ("NPV" row / Column G "Net Charge") was derived. For example, is the $62,162,880 amount the mathematical result of the sum of values in Column G from 2017-2063 subjected to the Discount Rate of 6.40%? If not, please explain the other means Applicants used to derive the $62,162,880 figure.

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Re: Direct-Applicants-Degenhardt-8, Question posed **"Did the Applicants calculate the impact that the Project would have on electric bills for individual retail electric ratepayers?"** Degenhardt Reponse: "**No. As the Commission has recognized, in a docket where the proposed transmission project brings economic benefits (in addition to reliability and policy benefits), calculating the impact of a project on individual retail ratepayers would be extremely difficult, would not yield useful information, and could perhaps result in misleading data.[1] ATC, ITC, and Dairyland do not directly serve retail electric customers. Rather, they serve local distribution companies (LDCs) or (in the case of Dairyland) member cooperatives, which in turn serve retail customers. Therefore, to determine the Project's impacts to individual retail electric ratepayers, one would have to determine (for example) *the benefits of accessing different sources of generation* for each Wisconsin LDC and cooperative, how each Wisconsin LDC and cooperative would incorporate these benefits into its *retail tariffs* for each customer class, and then those benefits would have to be compared to the *changes in transmission charges*. This is not an analysis the Applicants are capable of conducting."**

Related Citation #1:
Direct-Applicants-Dagenais-52 "...the Project will increase the transfer capability of the transmission system between Wisconsin and Iowa, which will increase the availability of low-cost wind energy and reduce energy costs for Wisconsin customers

Related Citation #3, Applicants' Analysis of WI Utility Future Generation Sources:
Direct-Applicants-Dagenais-8, "The Applicants conducted a robust economic analysis of the Project, modeling it against three different alternatives in a total of eight different, plausible futures for the electric industry. In the Application, the Applicants submitted modeling results for five futures. After the Application was filed, at the Commission staff's request, the Applicants made numerous changes to their models and evaluated the Project under three new futures, resulting in a total of eight futures being studied.1 As shown in Table 1, below, the eight futures in which the Project was analyzed included *wide-ranging assumptions* about key factors that could affect the future of the electric power sector.

Additional Background: In **Re: Direct-Applicants-Degenhardt-8,** Applicants mention three, additional factors they feel need to be considered in order to provide an estimate of ratepayer level impacts which we have italicized and underlines the following, excerpted, statement:

"Therefore, to determine the Project's impacts to individual retail electric ratepayers, one would have to determine (for example) *the benefits of accessing different sources of generation for each Wisconsin LDC and cooperative*, how each Wisconsin LDC and cooperative would incorporate these *benefits into its retail tariffs* for each customer class, and then those benefits would have to be compared to the *changes in transmission charges*."

REQUEST NO. 54R(a) REPHRASED: Please explain if the Applicants' economic modeling that produced monetized net saving estimates for the Project under several economic planning futures makes assumptions about "*different sources of [future] generation*" for ATC's local distribution companies, Northern States Power and Dairyland Power Cooperative. If, not please explain why the economic planning futures did not make assumptions about "*different sources of [future] generation*" for these parties.

REQUEST NO. 54R(b) REPHRASED: If the applicants' economic planning did estimate "*different sources of [future] generation,*" for the above, cited, parties, please explain why these estimates, or others similar to them, could not be used to resolve this changing generation variable which applicants suggest is necessary to provide SOUL an estimate of the average "impacts [on] individual retail electric ratepayers," for all three retail sectors in Wisconsin.

Additional Background: For clarity, SOUL has divided former Request No 57 into two parts, (a) and (b)

REQUEST NO. 57R(a) REPHRASED: Please explain why Co-Applicant Dairyland Power Cooperative, who creates tariffs for a wide range renewable and non renewable generation, would not be able to provide Applicants as a whole a range of sample tariffs to apply in estimates of the benefits for electric customers from placing different, accessed *"sources of generation... into retail tariffs*."

Additional Background Comment: The above requests hope to account for the feasibility of Applicants addressing the first two of the three, additional factors Applicants feel need to be considered in order to provide an estimate of ratepayer level impacts. The remaining factor pertains to the need to account for changes in benefits resulting from "*changes in transmission charges"* as a result of ATC's local distribution companies, Northern States Power and Dairyland Power Cooperative "*accessing different sources of [future] generation."*

REQUEST NO. 57R(b) REPHRASED: Please discuss use of the Applicants' economic modeling that produced monetized net saving estimates for the Project under several economic planning futures to estimate "*changes in transmission charges"* associated with the "*different sources of [future] generation"* modeled under Applicants' economic planning futures. If the economic modeling used to determine "*changes in transmission charges"* cannot be adapted to provide estimated changes in benefits from this, third, factor, please explain why.

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RE:Direct-Applicants-Dagenais-7, "However, Wisconsin customers do not receive the full benefits of this low-cost renewable generation to the *west* because of congestion on the transmission system between Iowa and Wisconsin. This congestion is not just causing Wisconsin to miss out on obtaining more renewable energy—it is also causing Wisconsin customers to pay more in the energy market as higher-cost-fuel resources are forced to *dispatch east of the congestion*. As future wind capacity is developed, economic planning models show that these market congestion issues will intensify.

Additional Background: The Applicants describe an intensifying, location-based, economic opportunity that would be missed out on unless the Project is placed into service. The following request asks for the referenced "full benefits" stated in economic terms that electric customers can understand.

REQUEST NO. 68R(a) REPHRASED: Please explain if the Applicants' economic modeling that produced monetized net saving estimates for the Project and Alternatives under several economic planning futures can be used to produce an estimate of the annual, average difference in dollar cost, per MWH, for all types of generation at two dispatch locations qualifying as "*west [of Wisconsin]*" and "*east of the congestion.*" If it is not possible to use economic modeling to provide such annual difference in costs between two dispatch locations, please explain why.

REQUEST NO. 68R(b) REPHRASED: If produceable, please provide the estimated difference in average, annual cost of dispatched power, per MWH, at two locations fitting the Applicant's cited, "*west [of Wisconsin]*" and "*east of the congestion*" description for the year 2026 and 2031 or similar years for both the No Action Alternative, the Project and the LVA.

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Re: Direct-Applicants-Dagenais-16, "Essentially, MVPs are transmission projects that provide benefits in excess of their costs to customers across the entire MISO region."

Additional Background: SOUL interprets the above statement as the Applicants partially justifying the approval of the Project in the state of Wisconsin on the basis of the Project's ability to provide benefits across the MISO region. This is a challenging concept for Wisconsin electric customers to understand in concrete, economic terms.

REQUEST NO. 96R- REPHRASED: Please describe how MISO market monetary benefits are costs and cost allocations identified.

Respectfully submitted on March 29, 2018.

S.O.U.L of Wisconsin, Inc.

/s/ Rob Danielson

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