STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

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In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota

Docket No. E015/GR-16-664

MINNESOTA POWER'S PETITION FOR RECONSIDERATION AND REQUEST FOR CLARIFICATION

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INTRODUCTION AND IMPORTANT CONTEXT FOR REQUEST

On March 12, 2018, the Minnesota Public Utilities Commission ("Commission") issued its Findings of Fact, Conclusions, and Order ("March 12, 2018 Order") in the general electric rate case for ALLETE, Inc., doing business as Minnesota Power ("Minnesota Power" or the "Company"). Minnesota Statutes section 216B.27, subdivision 1, and Minnesota Rule 7829.3000 provide that any party to a proceeding may request rehearing on any order within 20 days after service of the Commission's decision. Minnesota Power respectfully requests that the Commission reconsider the matters set forth in this Petition for Reconsideration ("Petition"). The Commission has stated that it will reconsider an order when (1) new issues it has not yet considered are raised; (2) new facts not yet in evidence are presented for consideration; (3) there are errors or ambiguities in the Commission's order; or (4) the Commission is otherwise persuaded to reconsider an order.[1] The basis of the Company's request for reconsideration is discussed in conjunction with each of the issues detailed below.

Before turning to the individual issues, Minnesota Power offers some broader context for its Petition. The Company appreciates the Commission's thoughtful review of the record in this proceeding and the positions of the parties, and recognizes that this case has presented some unusual circumstances and complexities. The Company has limited its requests for reconsideration or clarification to those items where the Commission's decision is fundamentally in conflict with the overall record in this rate case or may have unintended consequences that may not have been foreseen due to the variety of issues in the case. And while the Company supports many of the decisions made by the Commission, the Commission's decisions, in total, have already begun to result in real and significant financial injury to the Company and its

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[1] *In the Matter of Detailing Criteria and Standards for Measuring an Elec. Util.'s Good Faith Efforts in Meeting the Renewable Energy Objectives Under Minn. Stat. § 216B.1691*, Docket No. E999/CI-03-869, ORDER AFTER RECONSIDERATION at 9 (Aug. 13, 2004).

operations. This is in large part because certain expense reductions advocated by other parties and accepted by the Commission necessitate cuts to core utility functions. Combined with the rejection of recovery of these expenses, the lower rate of return on equity ("ROE") adopted by the Commission has resulted in determinations by Standard & Poor's ("S&P") Global Ratings and Moody's that the rate case outcome (both on its own and in combination with recent tax reform) is "credit negative" to the utility and has resulted in changes in the Company's outlook from "stable" to "negative" with a downgrade expected.[2] Due to the combined impact of the Commission's decisions, the Company has announced the need for layoffs and is looking at other expense reductions.[3]

The Company filed this rate case on November 2, 2016, requesting operations and maintenance ("O&M") expenses for rate recovery at nearly the same level as its 2010 expenses, but for additional expenses associated with the since-added Bison Wind Farms.[4] Despite proactive cost-containment measures implemented by the Company in advance of filing this rate case, the Commission has cut into critical O&M expenses with its decisions in the March 12, 2018 Order. The result, after reflecting that certain revenues are being attributed to the EITE docket rather than the rate case, is a determination that the Company had a revenue surplus. This decision comes even though Minnesota Power's initial request was based on O&M at 2010 levels. As discussed in testimony and throughout the record in this case, Minnesota Power takes Commission decisions on what are reasonable costs seriously and as directives of how the Company should utilize resources, and therefore is reacting accordingly in the operation of its business. However, these decisions have real impacts on the Company's ability to fulfill other

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[2] eDockets ID Nos. 20182-139884-01, 20182-139884-02; 20182-139910-01; and 20192-139910-02.

[3] ALLETE mulls layoffs, leaving jobs open, DULUTH NEWS TRIBUNE (Feb. 22, 2018), *available at* https://www.duluthnewstribune.com/business/energy-and-mining/4407843-allete-mulls-layoffs-leaving-jobs-open#.WrFKE9h5bqw.email (*last accessed* Mar. 22, 2018).

[4] Ex. 53 at 9 (Morris Direct).

directives of the Commission, including continuing its efforts to be forward-thinking in its resource plans and keeping Minnesota ahead of the energy markets curve. In other words, the Commission decision effectively directs the Company to cut expenses below 2010 O&M levels, even though market indices and inflation make such an approach untenable.

As previously noted, this confluence of factors has also resulted in real impacts in the financial markets as well. Other parties and the Commission debated whether approving a low ROE would create impacts for the Company in the financial markets. Minnesota Power advised the Commission that it depends on constructive regulatory outcomes to assure capital markets that Minnesota Power is a worthwhile investment.[5] The historical investment by shareholders in the stock of the Company has allowed Minnesota Power to support some of the lowest Residential rates in the nation while also performing as a good partner with the regulatory community in implementing the strategic energy policies of the State of Minnesota. There was debate before the Commission on whether any of its decisions would result in negative impacts to the Company's financial markets performance.[6] Minnesota Power expressed serious concerns, backed by objective metrics, regarding the impacts of positions supported by the parties.[7] Minnesota Power also explained that as a company dominated by its Minnesota regulatory environment, it does not have the opportunity to make up for lost costs or too-low ROEs in other jurisdictions. This debate has now been settled and the outcomes the Company

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[5] Jan. 11, 2018 Commission Deliberation Transcript at 83:13-16 (McMillan).

[6] Jan. 11, 2018 Commission Deliberation Transcript at 266:12-19 (Department witness Amit) ("I say that a typical investor would not pay attention to an ROE that's been determined a year ago. . . . And typical investor would not look back at what was the cost of this particular stock a year ago, because this cost is irrelevant today."); *Id.* at 268:21-269:5 (Company witness Hevert) ("I disagree with Dr. Amit. . . . And I think part of the reason we can easily conclude the information is important to the financial community, to investors, to rating agencies, is because they are disclosed in SEC form 10k. . . . If they were not important information to investors, they would not be disclosed, but they are."); *Id.* at 290:1-4 (Department representative O'Connell) ("[W]e would never recommend a return on equity if we didn't think that it would ensure that the Company has a reasonable opportunity to be financially viable. . . . And that's why our recommendations have always looked at what is the market telling us right now, . . . where else can investors take their money.").

[7] Ex. 38 at 24 (Cutshall Rebuttal).

feared have come to fruition in the financial markets. Based on this new information, which further underscores that a different view of the facts in the record is warranted, the Company asks the Commission to reconsider certain decisions in this proceeding.

An additional impact of the reduced expense recovery is that the Company does not have a reasonable and realistic opportunity to earn even its authorized ROE. As Minnesota Power explained in its Initial Filing in the Commission's Investigation into the Effects of the 2017 Federal Tax Act, Docket No. E,G999/CI-17-895, "While the Commission approved an allowed ROE of 9.25% . . . many costs were disallowed, including recovery of pre-paid pension. . . Minnesota Power has calculated that the effective ROE based on the outcome of the rate case for the 2017 test year is only 8.14%. Consequently, the Company has recently announced cost-cutting plans in an attempt to earn its 9.25% allowed ROE."[8] Among those efforts, on February 19, 2018, the Company announced that staff reductions through a combination of attrition and layoffs would begin immediately and in the upcoming months.[9] Minnesota Power is committed to taking all steps available to continue the quality and affordability of service, environmental stewardship, and community partnership for which it is known in Minnesota and throughout the region. Ultimately, however, the Company asks the Commission to reconsider certain decisions so that it can also remain a vibrant utility without cutting too far into the core of its operations.

Minnesota Power recognizes that while the impacts of the Commission's decisions on these key rate case items were debatable at the time the decisions were made, the fall out demonstrates the real impact the Commission's decisions have had on the overall financial market perceptions of the Company. Support from these markets is essential to raise the capital

[8] *See In the Matter of a Comm'n Investigation into the Effects on Elec. and Nat. Gas Util. Rates and Servs. of the 2017 Federal Tax Act*, Docket No. E,G999/CI-17-895, MINNESOTA POWER'S INITIAL FILING at 5 (Mar. 2, 2018).
[9] *See In the Matter of a Comm'n Investigation into the Effects on Elec. and Nat. Gas Util. Rates and Servs. of the 2017 Federal Tax Act*, Docket No. E,G999/CI-17-895, MINNESOTA POWER'S INITIAL FILING at 5 (Mar. 2, 2018).

necessary to continue providing reliable service to our customers while still maintaining some of the lowest Residential rates in the country. The Company respectfully requests the Commission reconsider its March 12, 2018 Order with respect to the revenue requirement issues and cost of equity outlined below. The Company also includes minor requests for clarification on certain items later in this Petition.

PETITION FOR RECONSIDERATION

I. Test Year Sales Forecast

The reasonableness of a test year sales forecast must be judged holistically, as the purpose of a test year sales forecast is to accurately forecast overall customer sales and ultimately revenue. The Commission's March 12, 2018 Order with respect to a reasonable 2017 test year sales forecast errs in that it focuses on the sales to only one of Minnesota Power's customers—Keetac. The Commission's March 12, 2018 Order on the test year sales forecast is premised on the following finding:

> Because the evidence in the record supports the conclusion that sales to Keetac will continue for the foreseeable future, the Company will be required to reflect 12 months of sales, and a corresponding $1.8 million revenue increase, in its test year calculations.[10]

The Commission's finding is in error in that it ignores the broader goal of sales forecasting – to ensure a reasonable test year forecast for all of the Company's system. As discussed in the testimony of Company witness Ms. Julie Pierce, the Company's objective in updating its test year sales forecast for Keetac sales was to ensure that the overall sales forecast for its Industrial customers was reasonable after the Keetac restart.[11] It was never intended to match the expected sales to Keetac. By requiring 12 months of sales to Keetac to be included in

[10] March 12, 2018 Order at 51.
[11] Ex. 69 at 3 (Pierce Supplemental Direct).

the test year sales forecast without adjusting sales elsewhere, the Commission's March 12, 2018 Order sets an unreasonably high sales level because it assumes nearly full production at all six of Minnesota Power's taconite customers or a utilization rate of over 93 percent. This assumption is not representative of the historic trends for sales in Minnesota over the last 10 years due to the cyclical and often volatile taconite industry, which is closer to 84 percent.[12] By adopting a sales forecast that is higher than actual sales, the rates set by the Commission are too low for the Company to recover its cost of service. To correct this error, the Commission should adopt the Company's updated test year retail sales forecast of 9,212,383 MWh that relies on a 90 percent utilization rate for Minnesota Power's six taconite plants.[13]

A. Reasonableness of Test Year Sales Forecast Must be Judged Holistically

The Company filed its initial test year sales forecast on November 2, 2016.[14] This forecast assumed nearly full production from five of Minnesota Power's taconite customers and assumed that the Keetac facility, idle since April 2015, would remain idle.[15] Even with the idling of Keetac, the Company's test year sales forecast projected a dramatic and pronounced increase in sales to Minnesota Power's Industrial customers as compared to 2016.[16] Specifically, for the Company's mining and metals customers, the test year sales forecast was an over 20 percent increase from the 2016 Annual Utility Forecast Review ("AFR").[17]

After Keetac announced its restart plans in late 2016, the Company updated the test year sales forecast to reflect nine months of sales to Keetac while leaving the remainder of the already

[12] Ex. 65 at 6-7 (Perala Rebuttal). If 2009 is excluded due to its low production amounts, the 10-year average utilization rate is 89 percent and the Minnesota Power utilization rate of 90 in its sales forecast is slightly optimistic.
[13] Ex. 69 at 5 (Pierce Supplemental Direct).
[14] Ex. 67 at Schedule 1 (Pierce Direct).
[15] Ex. 64 at 5 (Perala Second Supplemental Direct).
[16] Ex. 67 at 6 (Pierce Direct).
[17] Ex. 67 at Schedule 1 (Pierce Direct).

optimistic Industrial test year sales forecast unchanged.[18] The purpose of incorporating nine rather than 12 months of sales to Keetac was two-fold. First, Keetac was anticipated to restart in the month of March 2017 and nine months of sales matched this expectation.[19] Second, and more importantly, incorporating only nine months of sales was the best way to approximate overall sales to the taconite customers.[20] Including a full year of production at Keetac would overstate 2017 sales to this customer class and would not be representative of future sales given the already optimistic outlook contained in the original sales forecast for these Large Industrial customers.[21] The Company's resulting updated test year sales forecast was 31.8 percent higher for mining and metals customers compared to the 2016 AFR.[22] Specific to the taconite customers, Minnesota Power's updated 2017 Industrial sales forecast correlated to approximately 37 million tons of taconite production or a 90 percent utilization rate.[23]

The 90 percent utilization rate utilized by the Company to update its test year sales forecast is consistent with historic trends and helps smooth out the often dramatic year-to-year fluctuations that are common to this industry, including data on the taconite utilization rates for 2006 to 2016, as shown in Table 1, below.

[18] Ex. 69 at 4 (Pierce Supplemental Direct).
[19] Ex. 64 at 4 (Perala Second Supplemental Direct).
[20] Ex. 65 at 5 (Perala Rebuttal); Ex. 69 at 3 (Pierce Supplemental Direct).
[21] Ex. 65 at 5 (Perala Rebuttal).
[22] Ex. 68 at Schedule 1 (Pierce Supplemental Direct).
[23] Ex. 65 at 6 (Perala Rebuttal); Ex. 64 at 5 (Perala Supplemental Direct).

Table 1. Minnesota Taconite Utilization Rates[24]

Year	Utilization Rate
2016	68%
2015	76%
2014	95%
2013	90%
2012	95%
2011	95%
2010	85%
2009	41%
2008	95%
2007	93%
2006	95%
Source: Minnesota Department of Revenue	

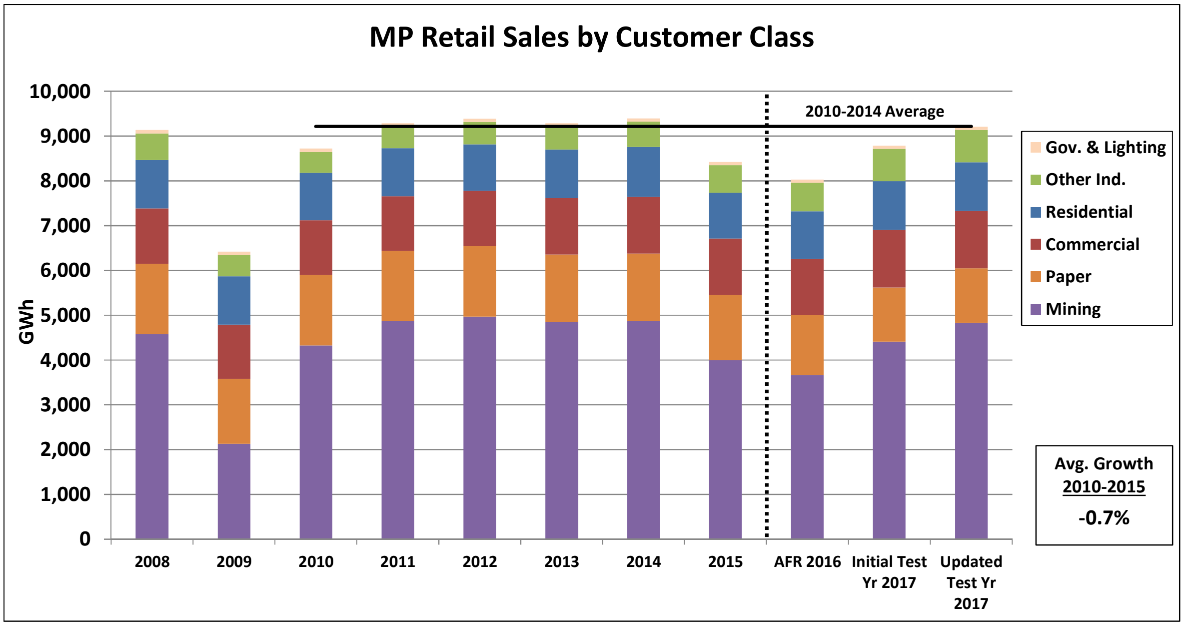
Based on this data, the ten-year average (2006-2016) utilization rate for taconite customers is 84 percent or, if 2009 is excluded from this calculation, the ten-year average is 89 percent. As a result, the 90 percent utilization rate that underpins the Company's updated test year forecast is consistent with this ten-year average. In contrast, the Commission-ordered test year sales forecast that includes 12 months of Keetac sales is equivalent to a much higher utilization rate of 93 percent. This level is inconsistent with this ten-year average. Furthermore, if a five-, four-, or three-year average is calculated, similar to the methodology approved for some expense adjustments in this case, the utilization rates are 85 percent, 82 percent, and 80 percent, respectively. The utilization rate of 93 percent consistent with the Commission-ordered test year sales forecast is significantly higher than all of these averages.

The chart above is also evidence of the cyclical and unpredictable nature of the taconite industry. In 2008, the utilization rate was at an all-time high of 95 percent only to plummet the very next year to an all-time low of 41 percent. These dramatic swings in taconite production translate into similar dramatic swings in Minnesota Power's retail sales given that sales to Large

[24] Ex. 65 at 7 (Perala Rebuttal).

Industrial customers, including mining, paper, and pipeline industries make up approximately 72 percent of the Company's total energy sales.[25] As shown in Figure 1 below, in 2009, 2014, and 2015, when taconite production was down, Minnesota Power's retail sales were similarly markedly lower.

Figure 1[26]



These dramatic year-to-year fluctuations are another reason that a singular focus on one customer's sales is not appropriate here. In other ratemaking circumstances (including in many decisions in this rate proceeding), the Commission has adopted the use of averages to smooth out year-to-year fluctuations, a similar approach is warranted here as a test year sales forecast that is too high prevents Minnesota Power from recovering its cost of service.

It also bears noting that Minnesota Power's taconite customers are not the only customers that are prone to dramatic downturns. In October 2017, for example, one of Minnesota Power's large paper customers, UPM Blandin, announced plans to permanently close one of its paper

[25] Ex. 67 at 3 (Pierce Direct).
[26] Ex. 69 at 5-6 (Pierce Supplemental Direct) ("The updated 2017 test year retail sales outlook of 9,212,383 MWh is very similar to recent historical sales years, and differs just 0.3% from a 2010-2014 average (9,214,807 MWh).").

machines at its Grand Rapids plant in the first quarter of 2018.[27] While this particular closure was not part of the Company's 2017 sales forecast, its overall forecast was realistic because it accounted for just such closures, idling, and downturns that are regular occurrences on the Minnesota Power system. These cyclical downturns have been recognized by the Commission in Minnesota Power's last rate case where a Margin Impact Analysis was approved that allowed for rates to potentially adjust if load increased or decreased due to a large customer.[28] Likewise, in Minnesota Power's Boswell Energy Center ("BEC") Unit 4 Environmental Rider, the Commission, on the recommendation of Large Power Intervenors, required the Company to adjust allocation factors if a large customer adds or loses 10 MW of load.[29]

B. Test Year Forecast Should Reasonably Reflect Actual Sales

The Commission-ordered test year sales forecast is also in conflict with the actual sales data on the record for 2017. The Company provided actual sales data through May 31, 2017.[30] As of May 31, 2017, total retail sales for 2017 were approximately 3.5 percent lower than Minnesota Power's updated test year sales forecast.[31] Even after weather-normalizing and non-levelizing[32] these actual sales, the sales as of May 31, 2017 were still about 1.5 percent below the Company's updated test year forecast.[33] In contrast, the Commission-ordered sales forecast would be approximately 6 percent higher than these actual sales figures through May 2017.

[27] *See* Letter – Notice of Blandin Service Change (Oct. 25, 2017) (eDockets ID No. 201710-136825-01).
[28] *In the Matter of the Application of Minn. Power for Auth. to Increase Rates for Elec. Serv. in Minn.*, Docket No. E015/GR-09-1151, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 18 (Nov. 2, 2010).
[29] *In the Matter of Minn. Power's Petitions for approval of its Boswell Energy Center Unit 4 Envt'l Retrofit Project and Boswell 4 Envt'l Improvement Rider*, Docket No. E015/M-12-920, ORDER at Order Point 4 (November 5, 2013).
[30] Ex. 71 at 5 (Pierce Rebuttal).
[31] Ex. 71 at 3 (Pierce Rebuttal).
[32] The Company's updated test year forecast included a "levelized" sales outlook for sales to Keetac. This means that nine months of sales were levelized across all twelve months to avoid biasing the cost allocation functions. Ex. 71 at 5 (Pierce Rebuttal).
[33] Ex. 71 at 5 (Pierce Rebuttal).

The goal of a test year sales forecast is to provide a reasonable approximation of actual sales to all customers for purposes of setting rates.[34] By focusing solely on the sales to Keetac, the Commission's March 12, 2018 Order overlooks the cyclical and volatile nature of the taconite industry as a whole and its pronounced impact on Minnesota Power's retail sales and risk. To properly account for the instability in this large segment of Minnesota Power's customers, the Commission should reconsider its finding to include 12 months of sales to Keetac and instead adopt the Company's updated test year sale forecast. The Company's updated test year sales forecast is consistent with the ten-year average utilization rate for the industry, and use of this average will even out year-to-year fluctuations in sales to this volatile industry.

II. <u>Capital and O&M Costs</u>

A. <u>Generation Supervision & Engineering and Distribution Meter Reading</u>

The Commission's March 12, 2018 Order requires a $6.781 million (MN Jurisdictional) reduction to the test year O&M expenses for Minnesota Power's generation and distribution functions.[35] This is a significant and duplicative reduction to expenses that are at the core of Minnesota Power's mission: providing safe and reliable electric service to its customers. To reach this decision, the Commission erred by adopting the Minnesota Department of Commerce, Division of Energy Resources' ("Department") recommendation to utilize a five-year historical average based solely on the examination of seven selected O&M FERC accounts, without regard to the Company's reasonable budgeting process or a significant reduction that the Company already made to these same expenses.

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[34] *In the Matter of an Application by CenterPoint Energy for Auth. to Increase Nat'l Gas Rates in Minn.*, Docket No. G008/GR-08-1075, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 51 *adopting* ALJ FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION at Finding 410 (Nov. 2, 2009) ("[T]he purpose of the test year is to represent expected sales under normal conditions.").
[35] March 12, 2018 Order at 19.

1. Minnesota Power's budgeting process is reasonable and sound

The fundamental flaw with the Department's examination of Minnesota Power's Generation and Distribution O&M expenses is that it utilized a different budgeting protocol than the one used by the Company and was too narrowly focused. If either one of these flaws is corrected, the reasonableness of Minnesota Power's test year budget is apparent.

There is no specific budgeting methodology required by law. Rather, the budget methodology employed by a utility must result in a request for recovery that is just and reasonable. Thus the question is not whether a utility budgets in the manner the Department prefers and leads to the outcome the Department wants, but whether the utility's approach is reasonable.[36] Nor must the Company prove that its approach is the ideal method as, by definition, there may be more than one reasonable approach to a variety of operational processes.

The Commission's March 12, 2018 Order found that "in response to Department's information requests, Minnesota Power provided only a high-level description of its budgeting process, and the Department was left unable to determine the basis for or reasonableness of Company's budgets."[37] This finding is contrary to the evidence. Minnesota Power provided testimony from its controller as to the overall budgeting process used by the Company, as well as testimony from each of its vice presidents for Generation and Distribution as to the budgeting process employed by these business units to develop the test year budget.[38] The testimony of these witnesses describes the methodical approach used by the Company to develop its O&M

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[36] For example, the Commission declined to adopt the Department's recommended adjustment to Transmission O&M expenses, as the Department's methodology in determining a historic average was flawed. There, the Department considered the test year amount to be too high because the historic average was lower, but the Department failed to acknowledge that the difference was the jurisdictional allocator – not the underlying expense levels. Similarly, here the Department rejected the Company's approach simply because it did not utilize the sole methodology supported by the Department, even though that methodology did not fit the circumstances.
[37] March 12, 2018 Order at 19.
[38] Ex. 53 at 2-10 (Morris Direct); Ex. 44 at 45-49 (Skelton Direct); Ex. 49 at 68-72 (Fleege Direct).

budgets. This approach includes an examination of historic trends and accounts for changes in employee counts and known operational changes.[39]

Specifically, Minnesota Power budgets for its O&M expenses by identified and carefully managed Responsibility Centers ("RCs"). These RCs correlate to specific departments and, in the case of Generation, specific generation units. Rather than examining the reasonableness of the Company's O&M budgets using this same RC methodology, the Department's analysis examined the budgets by FERC account. While the Company does not dispute that a FERC account review may be most appropriate in some circumstances, Minnesota Power explained that such a review is problematic here because budgets developed by RC do not perfectly translate into FERC accounts. For example, Company witness Josh Skelton explained that the FERC Account definitions do not exactly match the Company's RC-level budgets such that an expense may be budgeted to a specific account but then the actual cost may be recorded to a different FERC account.[40] Thus, an examination of budget to actual O&M on a FERC account level, such as that done by the Department, will result in discrepancies.

Not only did the Department's analysis fail to utilize an approach consistent with the Company's budgeting methods, but the Department only examined seven selected FERC accounts for both Generation and Distribution.[41] Such a narrow view does not provide an accurate or complete picture of these expenses when, for example, the O&M budget for Generation is made up of over 28 different FERC accounts.[42] A more holistic review of the Company's FERC accounts provides evidence of the reasonableness of the test year budgets.

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[39] Ex. 53 at 4-5 (Morris Direct).
[40] Ex. 46 at 8-9 (Skelton Rebuttal).
[41] The Department also admitted that its examination was limited to these FERC accounts because these accounts had the highest year-over-year increases since 2012. Ex. 624 at 30 (Ouanes Direct) ("Initially, I selected three accounts (FERC account Nos. 535, 546, and 902), that had among the highest year-over-year dollar increases between 2012-2015 actuals and 2016-2017 budget….").
[42] Ex. 46 at 10 (Skelton Rebuttal).

For instance, if all RCs that utilize FERC Account No. 902 are examined, <u>the test year budget is $3 million lower than 2016 actuals and also lower than the five-year average for these expenses</u>.[43] Similarly, during the evidentiary hearing, the Department admitted that it failed to examine other FERC accounts with similar names as the seven under its scrutiny. In particular, while the Department examined FERC Account 902 "Meter Reading Expenses," the Department did not examine FERC Account 586 "Meter Expense" even though the actual expenses for Account 586 trended higher than budget.

> Q. I'd like to turn your analysis related to FERC account 902. And FERC account 902 is the meter reading expense; is that correct?
>
> A. Correct …
>
> Q. And I want to look at another FERC account, FERC account 586. Can you tell me the name of that FERC account?
>
> A. Meter expenses …
>
> Q. A one-word difference. Given the similarities of these two accounts, did you also examine the budget to actual variances associated with this account in your analysis? …
>
> A. No …
>
> Q. If you look at the actual to budget variance amount for 2016 for this FERC account, FERC account 586, the actuals are actually above the budget by 23 percent.
>
> A. Yes, that's what it shows there.[44]

As this exchange demonstrates, if the Department had examined more than just seven select FERC accounts, the variances between these particular accounts is balanced by other accounts where actuals trend higher than budget.

Further, the Commission's nearly $7 million reduction to the Company's O&M expenses is excessive when considering that the Company's total O&M test year budget is essentially the

[43] Ex. 50 at Schedule 7, p. 4 (Fleege Rebuttal); Evidentiary Hearing Transcript, Volume 4 at 62-64 (Ouanes).
[44] Evidentiary Hearing Transcript, Volume 4 at 58-59 (Ouanes).

same as the Company's actual O&M expenses in 2010.[45] As explained by Company witness Steven Morris:

> but for the addition of the Bison Wind Farm, the Company's 2017 unadjusted O&M [test year] budget is largely equivalent to 2010 levels. Notably, the difference between our unadjusted 2017 O&M budget and our 2010 actual O&M is approximately $13.7 million, and our budgeted 2017 O&M for the Bison Wind Farm totals $14.5 million.[46]

Thus, despite transformations to its generation portfolio due to Energy*Forward* and rising health care and other employee costs, the Company's cost control measures have managed to keep overall O&M expenses steady.[47] Requiring the Company to reduce its O&M expenses even further is fundamentally unreasonable and will impact the Company's ability to serve its customers.

2. *Ordered adjustment is duplicative*

The Commission's adoption of the Department's recommended adjustment to Generation Supervision & Engineering and Distribution Meter Reading is also in error as it results in a double counting of a payroll adjustment made during Rebuttal Testimony that impacts two of the same FERC accounts at issue. The Commission's March 12, 2018 Order states that the rationale for not taking into account this adjustment was "the Company has not shown that the Department's proposed adjustment overlaps with the adjustment already made . . . ."[48] However, the Company provided the evidence that the payroll adjustment impacts two of the same FERC accounts that were subject to the Department's examination.[49]

[45] Ex. 53 at 9 (Morris Direct).
[46] Ex. 53 at 9 and Schedule 13 (Morris Direct).
[47] Ex. 53 at 9 (Morris Direct).
[48] March 12, 2018 Order at 19-20.
[49] Ex. 46 at 13-14 (Skelton Rebuttal).

As the Company noted in Rebuttal Testimony, the test year budget for BEC was developed prior to Minnesota Power's decision to close BEC Units 1&2 at the end of 2018.[50] After the Company made this decision, it put a hold on hiring for these units resulting in 23 fewer employees at BEC than was assumed in developing the 2017 test year budget.[51] In Rebuttal, the Company proposed a significant $2,969,621 (MN Jurisdictional) adjustment to account for reduced Generation salaries and benefits in the test year and beyond due to the pending retirement of Units 1&2.[52] The Company also explained that this adjustment impacted two of the same FERC accounts that were subject to the Department's adjustment: FERC accounts 500 and 510.[53] The title of FERC account 500 is "Operation Supervision" for Steam Power Production and the title of account 510 is "Maintenance Supervision and Engineering" for Steam Power Production.[54]

Both the Department and the Commission's March 12, 2018 Order failed to take into account this adjustment because "the Company has not shown that the Department's proposed adjustment overlaps with the adjustment already made."[55] However, the Department's recommended adjustment included six Generation FERC accounts (Account Nos. 500, 510, 535, 541, 546, and 551) and the Company's adjustment impacted two of these accounts, 500 and 510. Given the Department's averaging methodology, it is impossible to show specifically which dollars would overlap, which further underscores the unreasonableness of the Department's approach in this area. But given the undisputed overlap, adopting the Department's full

[50] Ex. 58 at 7 (Johnson Rebuttal); Ex. 46 at 13 (Skelton Rebuttal).
[51] Ex. 58 at 3 (Johnson Rebuttal).
[52] Ex. 58 at 7 (Johnson Rebuttal).
[53] Ex. 46 at 13 (Skelton Rebuttal).
[54] Ex. 46 at Schedule 4 (Skelton Rebuttal).
[55] March 12, 2018 Order at 19-20.

adjustment necessarily results in double counting and prevents Minnesota Power from recovering its cost of service.

Minnesota Power recognizes that the Commission opted not to adopt the Administrative Law Judge's ("ALJ") Report in many respects and understands the reasoning behind this overall approach. In this area, however, the ALJ provided a clear view of the utility's and Department's respective positions and reached the appropriate conclusions.[56] Given that the Company's budgeting process is consistent, reasonable, and traceable, the focus on FERC account averaging creates a dangerous result that cuts into core utility services and undermines the Company's ability to provide those services and also earn its authorized return.

B. Employee and Retiree Benefits

1. *Prepaid Pension Asset*

In its March 12, 2018 Order, the Commission ordered the Company to remove the prepaid pension asset, along with the associated tax savings, from test year rate base. The Commission primarily relied on the reasoning provided in previous Commission decisions for other utilities denying a return on the prepaid pension asset, adopting the same rationale for excluding the asset and citing to the two most recent Minnesota Energy Resources Corporation rate case decisions.[57] The Commission further highlighted three additional reasons for denying Minnesota Power's request for recovery of the Company's prepaid pension asset in this particular proceeding: Minnesota Power recovers its allowable pension expense from ratepayers and is not denied recovery of this operating cost; the accounting asset identified by the Company is distinct from assets that typically are included in rate base and does not reflect the funded

[56] ALJ Report at 23, 46, 100-103.

[57] *See, e.g.*, *In the Matter of the Application of Minn. Energy Res. Corp. for Auth. to Increase Rates for Nat. Gas Serv. in Minn.*, Docket No. G011/GR-15-736, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 8-11 (Oct. 31, 2016); *In the Matter of a Petition by Minn. Energy Res. Corp. for Auth. to Increase Nat. Gas Rates in Minn.*, Docket No. G011/GR-13-617, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 22-24 (Oct. 28, 2014).

status of the pension plan; and pension plan assets and benefit obligations fluctuate up and down, depending on funding or market conditions and are temporary, making it impractical to equitably separate the prepaid amount attributable solely to Minnesota Power's contributions from that attributable to ratepayer contributions and market returns.[58] As detailed more fully below, the record in this proceeding conflicts with the Commission's reasoning for denying recovery of the prepaid pension asset, and Minnesota Power respectfully requests that the Commission reconsider the issue to address these errors and ambiguities in the Commission's March 12, 2018 Order.[59]

First, given the conflicting history of Commission decisions regarding ratemaking for pension accounts, it is inequitable to conclude that certain prior Commission decisions, but not others, govern or even particularly inform the determination in this proceeding. As demonstrated during this proceeding, Minnesota Power differs from other Minnesota electric utilities, particularly in that the Company is so heavily reliant on sales to a small number of Large Industrial customers who operate in highly-cyclical taconite and paper industries.[60] Minnesota Power is, therefore, subject to much greater volatility due to its Industrial load than other comparable Minnesota utilities.[61] Because Minnesota Power is unique when considering the Minnesota utility landscape, reliance on an unrelated gas utility's recent Commission determinations excluding the asset from rate base is imbalanced.

[58] March 12, 2018 Order at 16-17.
[59] Minnesota Power also wishes to clarify the actual amount of the prepaid pension asset it seeks to include in rate base. Page 15 of the Commission's March 12, 2018 Order states that "[t]he Company seeks to include approximately $60 million in pension funds in rate base, offset by some $31.9 million in associated tax savings, for a net after-tax increase to rate base of approximately $27.8 million." These numbers are incorrect. As provided in Schedule 2, page 2 of the Company's ALJ Compliance filing filed on November 17, 2017, Minnesota Power seeks to include $60,041,948 in pension funds in rate base, offset by $31,487,190 in associated tax savings, for a net after-tax increase to rate base of $28,554,758.
[60] Ex. 38 at 12 (Cutshall Rebuttal).
[61] Ex. 38 at 12 (Cutshall Rebuttal).

Further, there is a divergence in Commission precedent on this issue that the Commission's March 12, 2018 Order wholly ignores. Minnesota Power does not dispute that the Commission has recently rejected similar prepaid pension asset recovery proposals, but the Commission has also recently and expressly, with both settlement approvals and a deciding order point where the issue was not settled, granted recovery to Xcel Energy's Minnesota electric utility.[62] Nothing in the record of this proceeding demonstrates that Xcel Energy's prepaid pension asset itself was materially different than Minnesota Power's. If anything, the fact that Xcel Energy was specifically allowed recovery of the prepaid pension asset in an ALJ finding and Commission order point, outside a settlement, in a prior rate case order,[63] supports Minnesota Power's request for the asset's inclusion in the Company's rate base. In sum, it appears that the Commission defers to only certain prior orders, without explaining why it is fair to apply a different outcome to Minnesota Power than it offered to Xcel Energy on a specifically-decided issue. This divergence and lack of explanation renders the Commission's decision here arbitrary and inequitable.

While the Commission also notes that it agrees with the ALJ's "findings" regarding the prepaid pension asset, the March 12, 2018 Order unfortunately appears to misstate the ALJ's recommendation. The Commission states that:

> The Administrative Law Judge recommended that the prepaid pension asset not be included in the test-year rate base. He reached this conclusion based on prior Commission rate-case decisions, and in particular based on his finding that it would be impracticable, if not impossible, to tease out the prepaid amount attributable solely to the Company's contributions.[64]

[62] *In the Matter of the Application of N. States Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, Docket No. E002/GR-13-868, FINDINGS OF FACT, CONCLUSIONS, AND ORDER (May 8, 2015).
[63] *Id.*
[64] March 12, 2018 Order at 16.

However, the ALJ did not make such a recommendation; rather, his recommendation to exclude the prepaid pension asset from rate base noted that the Company "makes some compelling arguments for including the prepaid pension asset in its rate base" and was explicitly based solely on prior Commission determinations about the asset:

> While Applicant makes some compelling arguments for including the prepaid pension asset in its rate-base, this case is not significantly different from prior cases in which the PUC has considered this issue. Applicant argues that it is incorrect to state that the prepaid pension asset is temporary and that it is actually one of the most permanent assets a utility can have, outside of unimproved land.[65] <u>But the substance of the PUC's previous rulings against recovery for prepaid pension assets</u> is that the asset, unlike plant, oscillate in value from year to year and it is next to impossible to discern whether the changes in value come from shareholder dollars, marketplace returns, or changes in actuarial accounting.[66]

In other words, the Commission's statement that the ALJ's factual findings support exclusion of the asset from rate base is incorrect; rather, the ALJ found the Company's arguments to be compelling, but relied instead on Commission precedent to recommend against recovery. As such, the Commission's statement that it agrees with the ALJ, who based his recommendation on certain prior Commission reasoning, does not relate to specific factual findings but instead reverts to prior, inconsistent Commission reasoning for some (but not all) Minnesota utilities.

Second, the Commission's reasoning that the Company recovers its allowable pension expense from ratepayers and is not denied recovery of this operating cost is inaccurate and based on a fundamental misstatement of the nature of the asset. The Company does not dispute that the Commission has consistently approved recovery of a certain level of expense – namely, an

[65] ALJ Report at 85 (citing Ex. 38 at 38 (Cutshall Rebuttal)).
[66] ALJ Report at 86 (emphasis added) (citing *In re Application of Otter Tail Power Co. for Auth. To Increase Rates for Elec. Serv. in Minn.*, Docket No. E017/GR-15-1033, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 25 (May 1, 2017)).

amount of benefits based on what must be paid to employees in a given year. However, annual expense is not the full cost of employee pensions. Rather, the Pension Protection Act of 2006 and ERISA require the Company to invest amounts into a pension trust fund that exceed the amounts included in expense each year.[67] This additional amount is deposited based on actuarial determinations of future pension benefits that will have to be paid to employees, and is the prepaid pension asset for which the Company seeks recovery. Such additional contributions are required by law and are necessary to provide employees with reasonable retirement benefits in consideration of their work providing electric service to the Company's customers. Company witness Mr. Patrick Cutshall, in Rebuttal Testimony, provided the calculation showing that ratepayers are not making these additional contributions; the Company is doing so.[68] As explained by Mr. Cutshall, Minnesota Power's 2017 MN Jurisdictional pension expense for the test year is $5,200,194 (total plan expense is $8,376,836), but the 2017 MN Jurisdictional pension contribution (which was made in the first quarter of this year) allocated in the same manner is $10,183,969 (total plan contribution in 2017 is $15,150,000).[69] The difference between the MN Jurisdictional contribution and expense is $4,983,775, which is the incremental addition to the prepaid pension asset for the year 2017 that is presently funded entirely by shareholders.[70] Therefore, by law, Minnesota Power should earn a return on amounts it or its shareholders are making to provide a benefit to customers.[71] The rationale that the Company is

[67] Ex. 37 at 40 (Cutshall Direct).
[68] Ex. 38 at 36 (Cutshall Rebuttal).
[69] Ex. 38 at 35 (Cutshall Rebuttal).
[70] Ex. 38 at 35-36 (Cutshall Rebuttal).
[71] Excluding these Company contributions to providing a pension benefit to employees from rates is directly contrary to the requirement in Minn. Stat. § 216B.16, subd. 6 that :

> The commission, in this exercise of its power under this chapter to determine just and reasonable rates for public utilities, shall give due consideration to the public need for adequate, efficient, and reasonable service <u>and to the need of the</u>

already recovering pension expense actually does not address whether a utility should also be able to earn a return on annual contributions to the pension trust fund that exceed the expense amount.

Furthermore, this rationale unfortunately ignores that the Company's contributions to the pension trust benefit customers by directly reducing the amount of pension expense that is included in rates. Like a personal savings account in which a deposited amount earns interest to pay a future household expense, the earnings on the amounts included in the pension trust account are – and must be, pursuant to law[72] – used to pay for the annual pension benefits provided to customers. Since customers are typically responsible for the annual pension expense, these earnings from the Company's pension trust contributions actually reduce the expense that the customer needs to pay, as shown in Figure 2 below.[73]

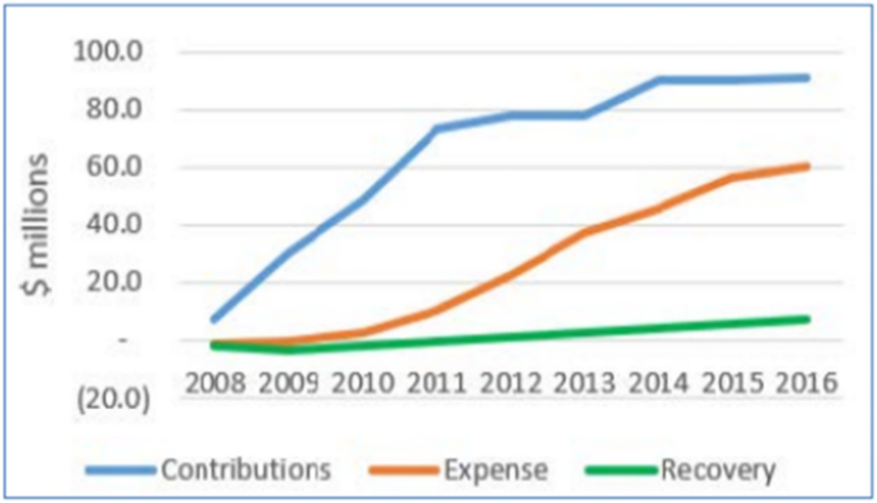
> public utility for revenue sufficient to enable it to meet the cost of furnishing the service.

Minn. Stat. § 216B.16, subd. 6 (emphasis added).

[72] *See* Pension Protection Act of 2006 (requiring Minnesota Power to estimate on a rolling basis the level of future benefits it will have to pay employees, and then make contributions to the pension fund to ensure adequate amounts will be available to pay employees when their benefit payouts are triggered and establishing certain minimum funding requirements for plan years beginning in 2008 through the present).

[73] Ex. 37 at 62-63 (Cutshall Direct).

Figure 2[74]
Cumulative Pension Contributions, Expense, and Recovery Since 2008
MN Jurisdiction



Moreover, compounded earnings on these contributions go even further to reduce pension expense. It is fundamentally not fair to the utility to provide such a benefit to customers without earning any compensation for "lending" these amounts to the customer. Conversely, if at some point the pension trust balance declines to the point where the pension asset becomes a liability, presumably customers would want the balance to be included in rate base to decrease it. Excluding the amounts from rate base now mean that the existence of a prepaid pension asset (or liability) is essentially ignored in ratemaking.

Third, the record demonstrates that the Commission's reasoning that the accounting asset identified by Minnesota Power is distinct from assets that typically are included in rate base and is "misleading in that it does not account for the funding status of the entire pension plan"[75] is fundamentally incorrect. Standard ratemaking laws and requirements establish that all reasonable assets used to provide retail electric service to Minnesota Power's customers should

[74] Ex. 37 at 62 (Cutshall Direct).
[75] March 12, 2018 Order at 16.

be included in rate base.[76] Notably, the legal precedent for this proposition does not distinguish between assets and liabilities that are changing, and the Commission has not identified a legal exception to this fundamental and critical legal principle. If funded assets are not included in rate base, investors are financing an asset utilized for the delivery of electric service for the benefit of customers without meeting the second half of the regulatory compact: that they will have the opportunity to earn a fair return on those reasonable investments. The fact that the prepaid pension asset is reserved to pay for utility employee pension benefits – and only pension benefits –underscores that it is dedicated to the provision of utility service.

Further, the prepaid pension asset is no different from other, similar assets that are included in rate base. There are many situations in which contributions and expenses differ significantly for an expenditure, resulting in a prepaid asset or liability that is included in rate base. One example is deferred tax assets and liabilities, which result from customers paying taxes to the utility before they must be paid to the government. These deferred tax assets/liabilities have been part of ratemaking, and included in rate base, for decades and, therefore, are now also the subject of significant revaluations in light of the Tax Cuts and Jobs Act of 2017.[77] Another example is working capital, which is included in rate base and results from investors providing/receiving funds in excess/under expense. The fact that prepaid pension assets are no different from these kinds of assets is further exemplified by the fact that many United States utilities currently are allowed to include prepaid pension assets in their rate base.[78]

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[76] *See Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679, 689-93 (1923); *Fed. Power Comm'n v. Hope Nat. Gas Co.*, 320 U.S. 591, 603 (1944).

[77] *See In the Matter of a Comm'n Investigation into the Effects on Elec. and Nat. Gas Util. Rates and Servs. of the 2017 Federal Tax Act*, Docket No. E,G999/CI-17-895, NOTICE OF COMMISSION INVESTIGATION INTO THE EFFECT OF THE 2017 FEDERAL TAX ACT ON UTILITY RATES AND SERVICES (Dec. 29, 2017); *see also* Ex. 19, Supplemental Direct Schedule C-1 at 27 (deferred tax asset line item).

[78] *See* Ex. 37 at 70 (Cutshall Direct) (citing to the Oregon Public Utility Commission Pension Survey, Pension Treatment in Rate Making Survey, Summary Report (Mar. 28, 2013)). As discussed below, this also includes the Commission allowing Xcel Energy to include the prepaid pension asset in its rate base. *See In the Matter of the*

And "[t]he rate case outcome also points to a less constructive regulatory relationship between MP and the MPUC. The MPUC's decision to deny pre-paid pension cost recovery when other utilities in the state recover those same costs appears inconsistent."[79] Moreover, Moody's February 8, 2018, Issuer Comment addressed the Commission's disallowance of recovery of prepaid pension expenses in this case, noting the allowed recovery of the prepaid pension asset for Xcel Energy and highlighting the difficulty Minnesota Power will have earning its below-average ROE due to the Company's inability to recover already-incurred expenses like the prepaid pension asset.[80]

In addition, the conclusion that the request for recovery of the prepaid pension asset is "misleading in that it does not account for the funding status of the entire pension plan"[81] is based on a fundamental misunderstanding of the prepaid pension asset and GAAP that has been promulgated by the Department over several rate cases. This misunderstanding was specifically identified and walked through in detail in the evidentiary hearings of this proceeding. In particular, Mr. Cutshall's Rebuttal Schedule 8, which is PricewaterhouseCoopers' confirmation that Minnesota Power's accounting and reporting regarding its prepaid pension asset is correct, is key to understanding the Department's errors. Mr. Cutshall's Rebuttal Schedule 8, page 3, reproduced below, presents a Reconciliation that shows how the various components of the prepaid pension asset are indeed included in the Company's 2016 Annual Report as shown in Table .

Application of N. States Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn., Docket No. E002/GR-13-868, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 20 (May 8, 2015).
[79] eDockets ID No. 20182-140359-01.
[80] eDockets ID No. 20182-0139910-01 (public), 20182-139910-02 (trade secret).
[81] March 12, 2018 Order at 16.

Table 2

Reconciliation of ALLETE, Inc.'s 2016 Form 10-K to Minnesota Power's Accumulated Contributions in Excess of Net Periodic Benefit Cost
(dollars in millions)

Pension Funded Status per ALLETE, Inc.'s 2016 Form 10-K	$	(185.8)	A
Unrecognized Pension Costs in Accumulated Other Comprehensive Income per Allete, Inc.'s 2016 Form 10-K		250.4	B
Total Accumulated Contributions in Excess of Net Periodic Benefit Cost		64.6	C
Subtract SERP Plan Accumulated Contributions in Excess (Short) of Net Periodic Benefit Cost		(12.6)	D
Subtract EIP Plan Accumulated Contributions in Excess (Short) of Net Periodic Benefit Cost		(2.2)	E
Pension Plan Accumulated Contributions in Excess of Net Periodic Benefit Cost		79.4	F
Subtract SWL&P Pension Plan 12/31/16 Accumulated Contributions in Excess of Net Periodic Benefit Cost		6.9	G
Minnesota Power 12/31/16 Pension Plan Accumulated Contributions in Excess of Net Periodic Benefit Cost	$	72.5	H

The accompanying Notes are an integral part of this Reconciliation of ALLETE, Inc.'s 2016 Form 10-K to Minnesota Power's Accumulated Contributions in Excess of Net Periodic Benefit Cost

Line A in this Reconciliation (which confirms that ALLETE does follow GAAP in its pension accounting) first shows the funded status/pension fund liability of ($185.8) million. This funded status, as stated in the Reconciliation and on page 123 of the ALLETE 2016 10-K, is the pension portion of the "Defined Benefit Pension and Other Postretirement Benefit Plans" line item of the Consolidated Balance Sheet.[82] But this is only part of the story. The ($185.8) million funded status is found in Note 15 to the financial statements, page 123, which Department witness Ms. Campbell acknowledged at hearing is "an integral part of [the Company's financial] statements."[83] Turning to the next page of the 2016 ALLETE annual report, Note 15 continues on by explaining that <u>there is an offsetting $250.4 million net loss</u> contained in the Consolidated Balance Sheet under Accumulated Other Comprehensive Income (in this case, a loss).[84] This $250.4 million is set forth on Line B of Mr. Cutshall's Rebuttal Schedule 8,[85] which further explained that it represents "the total unrecognized pension costs in accumulated other comprehensive income as of December 31, 2016 as disclosed on page 124 of

[82] Evidentiary Hearing Transcript, Volume 4 at 138 (Campbell); Ex. 88 at 71, 123 (ALLETE 2016 Form 10-K).
[83] Evidentiary Hearing Transcript, Volume 4 at 139:15-16 (Campbell); Ex. 88 at 71 (ALLETE 2016 Form 10-K).
[84] Ex. 88 at 124 (ALLETE 2016 Form 10-K).
[85] Ex. 38 at Rebuttal Schedule 8, p. 3 (Cutshall Rebuttal).

ALLETE's 2016 Form 10-K. This amount includes ALLETE's Pension Plan, Supplemental Executive Retirement Plan, and EIP]."[86]

The net of Lines A and B (Line C) is the Total ALLETE Accumulated Contributions in Excess of Net Periodic Benefit Cost.[87] Because the Company is not seeking rate recovery of amounts related to its Supplemental Executive Retirement Plan or EIP, or of amounts related to ALLETE subsidiary Superior Water, Light & Power plans, they are subtracted out in lines D-G – establishing that Minnesota Power's 12/31/16 pension plan accumulated contribution in excess of net periodic benefit cost was in fact an asset of $72.5 million.[88] This 2016 year-end balance differs somewhat from the amount Minnesota Power is requesting in this proceeding because, for ratemaking, the appropriate amount is the MN Jurisdictional 2017 13-month average balance, estimated at the time of filing to be $59,707,183.[89] The Commission's statement that the Company's request ignores the funding status of the prepaid pension asset overlooks this detailed dialogue in the record.[90] In essence, the Commission's conclusion merely repeats a fundamental misunderstanding of the asset, even though this misunderstanding apparently began in the MERC and Otter Tail Power Company ("Otter Tail") rate cases and was debunked in this proceeding.

Fourth, the Commission disallows recovery of the prepaid pension asset in rate base by reasoning that pension plan assets and benefit obligations fluctuated up and down, depending on funding or market conditions, and the balances in the asset are temporary, making it impractical to equitably separate the prepaid amount attributable solely to Minnesota Power's contributions from that attributable to ratepayer contributions and market returns. At the outset, there is

[86] Ex. 38 at Rebuttal Schedule 8, p. 4 (Cutshall Rebuttal).
[87] Ex. 38 at Rebuttal Schedule 8, p. 3-4 (Cutshall Rebuttal).
[88] Ex. 38 at Rebuttal Schedule 8, p. 3-4 (Cutshall Rebuttal).
[89] Ex. 37 at 63 (Cutshall Direct).
[90] *See* Minnesota Power Initial Brief at 26-28.

nothing uniquely temporary about the prepaid pension asset. All items in rate base can be considered temporary, including assets like buildings and equipment that depreciate over time, depending on the definition of "temporary." And as previously noted, assets like deferred tax assets can change significantly at any time when tax rates change. In this case, the prepaid pension asset/liability has been around since 1987 and will be in existence until the pension fund is gone, which is no time in the foreseeable future.[91] This is arguably as permanent as any utility asset other than perhaps unimproved land.

Even if the asset were not "permanent," the solution is not to disallow recovery when the asset exists but to update the status of the asset (or liability) in a future rate case, as with all assets and liabilities. There was no evidence that the amount in the 2017 test year was likely to disappear shortly after the test year; thus, there is no "known and measurable" change outside the test year[92] that would warrant excluding the asset from rate base for purposes of the test year revenue requirement.

Further, the Commission's explanation that it is impractical to equitably separate the prepaid amount attributable solely to Minnesota Power's contributions from that attributable to ratepayer contributions and market returns ignores that the record in this case does just this in several independent ways. First, Company witness Mr. Cutshall demonstrated that the Company contributed $103 million to the pension trust from 1994 through 2016 on a MN Jurisdictional basis, while pension expense was only $58 million and customers have only paid $14 million through rates over the same period.[93] Second, the shareholder contributions to the prepaid

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[91] Ex. 38 at 38 (Cutshall Rebuttal).
[92] *See, e.g.*, *In the Matter of the Application of N. States Power Co. d/b/a Xcel Energy for Auth. to Increase Rates for Elec. Serv. in Minn.*, Docket No. E002/GR-05-1428, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER; ORDER OPENING INVESTIGATION at 7-12(Sept. 1, 2006) (agreeing with the ALJ that known and measurable changes can occur immediately after the close of the test year and the exclusion of which would make the test year process unreliable).
[93] *See* Ex. 38 at Schedule 10 (Cutshall Rebuttal) (attached to this filing as **Attachment 1**).

pension fund and the amount of the asset the Company is seeking to include in rate base for the 2017 test year were independently confirmed in the record through submissions by Minnesota Power's actuary, Mercer.[94] Third, ALLETE's independent auditor, PricewaterhouseCoopers, further confirmed the amount of the asset for the Minnesota Power jurisdiction, and verified that the Company's recovery proposal was stated in accordance with Generally Accepted Accounting Principles.[95] Put simply, these contributions are a real, physical cost that have been funded completely by investors while the benefits have flowed to ratepayers through reduced pension expense, as explained above.

With respect to the impact of market returns on the prepaid pension asset, it is important to remember that the historical prepaid pension asset is a result of historical contributions and historical expense. Investors must still contribute the same amount regardless of market returns, as any reduction in required contributions is completely absorbed by the ratepayers through reduced pension expense. Since customers pay solely for expense that is already reduced by earnings on pension fund contributions, and since customers do not contribute to pension funding beyond annual expense, it is only appropriate to compensate investors for the funds that constitute the prepaid pension asset and in turn reduce expense.

Based on the foregoing and the additional support provided in testimony and briefing during this proceeding and due to the errors in the Commission's March 12, 2018 Order, the Company respectfully requests that the Commission reconsider its decision to deny Minnesota Power recovery of the prepaid pension asset in rate base and instead include the net after-tax MN Jurisdictional amount of $27,816,947 for the asset in rate base.

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[94] Ex. 38 at Schedule 11 (Cutshall Rebuttal) (attached to this filing as **Attachment 2**).
[95] *See* Ex. 38 at Schedule 8 (Cutshall Rebuttal) (attached to this filing as **Attachment 3**).

2. *Retirement Savings and Stock Ownership Plan*

The Company next asks the Commission to reconsider its averaging of historical Retirement Savings and Stock Ownership Plan ("RSOP") expense levels to set the test year expense because use of averaging in this instance is an error. This is because there was a one-time event in 2016 that drastically reduced actual expenses such that the use of averaging will result in under-recovery of these retirement expenses.

Certain retirement benefits for Minnesota Power employees are funded through Company contributions to the RSOP. To establish the test year RSOP expense, the Commission utilized a three-year average of historic expenses or $6.43 million as opposed to the Company's requested $7.148 million, shown in Table .[96]

Table 3[97]

RSOP Expenses	2014 Actuals	2015 Actuals	2016 Actuals	2017 Test Year Budget
	$6,407,565	$6,686,868	$6,196,551	$7,148,064

The basis for the Commission's decision was that a dividend credit[98] that occurred in 2016, and reduced RSOP expenses by 10 percent[99] in that year, "could reoccur" because "dividend credits are often difficult to predict" and thus the use of a three-year average was appropriate to smooth year-to-year fluctuations.[100] However, the evidence on the record shows that this 2016 dividend credit was a one-time event related to the closure of another retirement plan, the employee stock ownership plan ("ESOP").[101] The closure of the plan means this one-

[96] March 12, 2018 Order at 35.
[97] Ex. 58 at Schedule 5 at p. 6 (Johnson Rebuttal).
[98] A dividend credit results when a corporation declares a dividend and then credits a current liability account, in this instance, its RSOP expenses.
[99] Ex. 58 at 27 (Johnson Rebuttal).
[100] March 12, 2018 Order at 36.
[101] *See* Ex. 58 at 27-28 (Johnson Rebuttal).

time credit cannot recur.[102] Further, the March 12, 2018 Order does not address uncontested record evidence that RSOP expenses will be higher in future years due to a fundamental change in the way the Company provides retirement benefits to its employees.[103] As a result, the use of a three-year average is in error as it will intentionally result in underestimation of actual RSOP expenses.

Specifically, the dividend credit that reduced RSOP expenses in 2016 resulted from closing Minnesota Power's leveraged ESOP. Minnesota Power's now expired ESOP was supported by a loan, payments to which were made from ALLETE's stock dividends. This loan was paid off in full in December 2015 and, as a result, the December 1, 2015 ALLETE stock dividend was not used to pay the final December 2015 loan payment. Rather, this dividend was used to make the Company's contribution to the Company's remaining defined contribution retirement plan, the RSOP, in 2015. As a result, the RSOP expense for the first quarter of 2016 was reduced by this dividend amount. Given that this dividend payment was the result of the expiration of the ESOP plan, this dividend credit will not occur in the future. Thus, the record evidence is that it is impossible for the dividend credit to reoccur, whereas the argument that they may reoccur is speculation without a basis in fact.

In addition, the current plan design for the RSOP requires that all dividend credits be paid directly to participants and cannot be used to reduce plan expenses.[104] As a result, even if such a dividend credit were to reoccur, it would not result in a reduction in Minnesota Power's future RSOP expenses.[105] In sum, this dividend credit was a one-time event because (1) the ESOP plan

[102] Ex. 58 at 27-28 (Johnson Rebuttal).
[103] *See* Ex. 58 at 28 (Johnson Rebuttal).
[104] Ex. 58 at 27-28 (Johnson Rebuttal).
[105] Ex. 58 at 28 (Johnson Rebuttal).

and loan that yielded this credit is no longer in existence, and (2) the current RSOP plan requires a dividend credits to be provided to participants.[106]

Moreover, the use of an historic average is unreasonable because it is not disputed that in recent years Minnesota Power has been moving away from defined benefit plans (i.e., pension) to defined contribution plans (i.e., RSOP) such that historic costs are not reflective of current or future expenses.[107] Due to this transition, Minnesota Power's RSOP costs have increased for two primary reasons. First, given that defined benefit (pension) plans are closed to new hires, all new hires accrue 100 percent of their retirement benefits from the RSOP, resulting in increasing future expenses for this plan.[108] For example, the retirement benefit for a bargaining unit employee hired prior to 2011 consists mostly of their defined benefit with the Company contributing only one percent of the employee's salary to RSOP.[109] In contrast, all new hires rely solely on the RSOP for their retirement benefit, which results in a material increase in RSOP costs as compared to prior years.[110] Second, the use of historic averages does not account for annual salary increases that impact Minnesota Power's required RSOP contributions.[111] While these annual salary increases are discretionary for non-bargaining unit employees, the labor contract for bargaining unit employees requires three percent annual salary increases for the test year.[112]

In this instance, averaging is not reasonable because the cause of these year-to-year fluctuations are known not to reoccur and the record demonstrates that future expenses will be higher than prior years. As a result, use of a three-year average will inevitably result in the

[106] Ex. 58 at 27-28 (Johnson Rebuttal).
[107] Ex. 56 at 39 (Johnson Direct).
[108] Ex. 56 at 39 (Johnson Direct); Ex. 58 at 28 (Johnson Rebuttal).
[109] Ex. 71 at 28 (Johnson Rebuttal).
[110] Ex. 71 at 28 (Johnson Rebuttal).
[111] Ex. 71 at 28-29 (Johnson Rebuttal).
[112] Ex. 71 at 28-29 (Johnson Rebuttal).

Company's under recovery of expenses for retirement funds for Minnesota Power employees. Minnesota Power respectfully requests that the Commission reconsider its initial decision with respect to the RSOP, and adopt the Company's proposed test year expenses of $7.188 million in full as opposed to the historic three-year average amount of $6.43 million.

3. *Other Employee Benefits*

Similar to its decision on RSOP expenses, the Commission adopted the Department's recommendation to utilize a three-year historical average to set the "Other Benefits" test year expense.[113] The test year expenses in the "Other Benefits" category are another key component of Minnesota Power's employee compensation and benefits package. These are expenses associated with essential employee benefits: life insurance, flexible compensation plan, tuition reimbursement, EIP survivor benefits, long-term disability plan, self-insured worker's compensation, and other miscellaneous expenses such as the costs to administer benefit plans.[114] These expenses are a necessary and important aspect of Minnesota Power's employee benefit package and are crucial to retaining and recruiting qualified employees. The decision to use a three-year average for these expenses is in error as it fails to account for the events that resulted in unusually low 2015 and 2016 actuals for these expenses.

For instance, the Company provided undisputed evidence that in 2015 there was a large number of retirements, such that benefit expenses tied to employee headcount (as for flexible compensation and long-term disability) were unusually low in 2015.[115] And as new employees were hired to replace these retirees, expenses for long-term disability rebounded in 2016 but flexible compensation did not.[116] This is because employees must have one year of service to be

[113] March 12, 2018 Order at 37.
[114] Ex. 58 at 29-30 (Johnson Rebuttal).
[115] Ex. 58 at 31 (Johnson Rebuttal).
[116] Ex. 58 at 31 (Johnson Rebuttal).

eligible for this benefit.[117] Thus, while 2015 and 2016 flexible compensation spending declined, the 2017 test year amount was similar to 2014 actual expenses and more accurately reflects actual and future costs. No party disputed the facts provided by Minnesota Power to explain the increases in "Other Benefit" expenses. The Company asks the Commission to reconsider its initial decision reducing Minnesota Power's recovery of these employee benefit costs by $0.503 million,[118] and adopt the Company's proposed test year "Other Benefit" expenses of $2.167 million (MN Jurisdictional) as representative of the actual costs incurred by the Company.

C. Transmission Capital Projects

The Commission's March 12, 2018 Order requires removal of the costs of two deferred capital projects—the 5-Line Reconductor project and the Hoyt Lakes Ring Bus Reconfiguration project—from the test year revenue requirements.[119] However, the Company identified and provided support for replacement transmission projects completed for the benefit of customers and at a higher cost than the original projects[120] (although the Company did not seek increased cost levels) – and did so nearly two months before Rebuttal Testimony.[121] The Commission nonetheless states that the Company "has not met the standard for substituting new capital projects for the deferred projects removed from the test-year rate base."[122] The Company asks the Commission to reconsider this decision, consistent with its approach elsewhere in this and prior rate cases.

First, the Commission incorrectly states that Minnesota Power "made it impossible for the Department to review its requested transmission capital costs by filing, in rebuttal testimony,

[117] Ex. 58 at 31 (Johnson Rebuttal).
[118] March 12, 2018 Order at 37.
[119] March 12, 2018 Order at Order Point 10.
[120] The deferral of the 5-Line Reconductor and Hoyt Lakes Ring Bus Reconfiguration projects resulted in a plant-in-service reduction of approximately $2.2 million. The plant-in-service for the replacement projects totaled $4.7 million. Ex. 50 at Rebuttal Schedule 11, p. 10 (Fleege Rebuttal).
[121] Ex. 50 at Rebuttal Schedule 11 (Fleege Rebuttal).
[122] March 12, 2018 Order at 21.

a new proposal indicating there were now eight major capital projects… to be placed in service in 2017."[123] Nearly two months before Rebuttal Testimony, via a discovery response in early May 2017, the Company provided detailed information regarding the six projects (identified in summary in Table below) that the Company was substituting for the 5-Line Reconductor and Hoyt Lakes Ring Bus Reconfiguration projects.[124]

Table 4. Excerpt of 2017 Transmission Capital In-Service Dates for Key Projects[125]

	Project No.	Project Name	Project Start Date	Construction Phase Start Date	Estimated In-Service Date	Status	Reasonableness of In-Service Date
9	109253	ETCO Capacitor Bank	1/4/16	1/3/17	8/28/17	On Schedule	No material changes in original schedule.
10	109039	Forbes 3T Breaker & 3TR Panel	4/1/16	11/28/16	8/25/17	On Schedule	Short implementation schedule planned.
11	109047	Boswell 95 Line upgrade	11/3/16	1/19/17	10/10/17	On Schedule	No material changes in original schedule.
12	109052	Blackberry 95 Line Upgrade	11/3/16	3/10/17	10/17/17	On Schedule	No material changes in original schedule.
13	109176	Minntac 50L	8/1/16	12/15/16	2/6/17	**Completed**	**Completed**
14	109177	Minntac 54L	8/1/16	12/15/16	2/27/17	**Completed**	**Completed**

Notably, Table 4 above is merely a summary of the detailed information provided; the data regarding scope, cost, reason for moving the projects, construction status was much more extensive, as set forth in the Rebuttal Testimony and Schedules of Company witness, Mr. Christopher E. Fleege.

Minnesota Power also included this information in Rebuttal Testimony, along with the then-most recent costs and construction status of all six projects that, of course, evolve for any project being completed during a test year.[126] As such, the Department had several months,

[123] March 12, 2018 Order at 21.
[124] Ex. 50 at 22 and Rebuttal Schedule 11, p. 5-6 (Fleege Rebuttal). The "North Shore 115 kV Switch Station" project was included in both the original list of transmission capital projects exceeding $1 million (Part A of the response in Rebuttal Schedule 11) and the list of replacement projects (Rebuttal Schedule 11 at 5-6, 10-12) because the overall components and construction requirements of the project were revised from the Initial Filing to May 2017 so the Company could ensure safe and reliable operation of the transmission system.
[125] Ex. 50 at 22, Table 2 (Fleege Rebuttal).
[126] Ex. 50 at 21-22, 22 at Table 2, and Rebuttal Schedule 11, p. 5-6, 10-12 (Fleege Rebuttal). The only "new" information provided by the Company in Rebuttal Testimony was to update the list of transmission capital projects from the Company's initial filing that exceeded $1 million per project, to show that eight rather than six projects

including through Rebuttal, Surrebuttal, and August 2017 evidentiary hearings, to investigate these projects, each of which was short-term in length.

Second, the Commission's decision does not recognize the undisputed record evidence that the six replacement projects all served critical transmission system needs.[127] The detailed data provided in discovery and in Rebuttal, including scope, reason for accelerating projects into 2017, cost, and construction status,[128] underscore the need for these projects *and* are consistent with both the Commission's precedent from other rate cases[129] and its Generation capital decision in this case.[130] Likewise, the ALJ determined that "Applicant supplied substantial and credible evidence to support its claims for transmission capital projects, demonstrating they are all reasonable and necessary."[131] Ultimately, the scope and type of data provided, as well as its timing, align with the need for utilities to serve customers by exchanging projects when needed, rather than continuing projects simply to avoid changes in the test year project list.

Third, during Commission deliberations it turned out that the Decision Options did not include an alternative permitting both removal of the deferred transmission projects *and* inclusion of the added transmission projects.[132] Some discussion indicated the Commission may

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exceeded $1 million. Ex. 50 at Rebuttal Schedule 11 at 6 (Fleege Rebuttal). The Commission appears to have confused the list of projects in excess of $1 million with the six replacement projects.

[127] Ex. 50 at 26 and Rebuttal Schedule 11, p. 6-7, 10-12 (Fleege Rebuttal).

[128] Ex. 50 at Rebuttal Schedule 11 (Fleege Rebuttal).

[129] *In the Matter of the Application of N. States Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, Docket No. E002/GR-13-868, FINDINGS OF FACT, CONCLUSIONS, AND ORDER, at 26 (May 8, 2015).

[130] March 12, 2018 Order at 22-23.

[131] ALJ Report at ¶ 47.

[132] Staff Briefing Papers for January 11 and 18, 2018 Commission Meetings, Volume 1, p. 95:

1018. Require Minnesota Power to remove the two capital projects that it deferred and will not be in service in 2017, the 5-Line Re-conductor project and the Hoyt Lakes Ring Bus Reconfiguration projects, from the revenue requirements for the 2017 test year. (Department, OAG)

1019. Do not require Minnesota Power to remove the two capital projects that it deferred and will not be in service in 2017, the 5-Line Re-conductor project and the Hoyt Lakes Ring Bus Reconfiguration projects, from the revenue requirements for the 2017 test year. (MP, ALJ) have intended to both remove the old projects and approve the replacements.[133] An error may have occurred; correcting it would be consistent with the past policy decisions of this Commission and the record in this case.

Ultimately, the Commission has stated that substitutions in a utility's test year for capital investments are appropriate when the utility shows the replacement projects are necessary and other parties have sufficient time to review the proposed replacement projects.[134] The Company provided the required information a month before the Department's Direct Testimony was due and two months before Rebuttal. Such updates were identified at the same time and with the same level of detail (scope, impact, priority, and completion status) as the Generation capital project substitutions the Commission permitted.[135] The transmission capital adjustment does not comport with the record, the treatment of generation projects in this case, or with Commission precedent in other cases. For any or all of these reasons, the Company respectfully requests that the Commission reconsider the transmission capital test year adjustment.

D. Third-Party Transmission Revenue and Expenses

The Company asks the Commission to reconsider its March 12, 2018 Order rejecting the Company's updated information regarding transmission revenues, which will explicitly and unavoidably decline by the amounts shown in Table 5. The 2017 impact comes straight from Midcontinent Independent System Operator ("MISO") documentation provided to the Company in the summer of 2017, informing Minnesota Power of the redirection of a third party's 207 MW from the Minnesota Power system.

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[133] Commissioner Tuma questioned, "I thought the 1019 was this is where they took some projects out, but they put some projects that they're going to have used and useful and that it was a slight wash and so the ALJ said, look, it's not that big of a dollar amount, so . . . Is that the other one?" Commissioner Schuerger responded, "I believe that's a different . . . issue." *See* January 18, 2018 Commission Deliberation Transcript at 107:18-108:8. In fact, the ALJ did find that no adjustment was needed for Transmission Capital projects. ALJ Report at 74-75.

[134] March 12, 2018 Order at 21.

[135] *Compare* Ex. 46 at Rebuttal Schedule 1 and Rebuttal Schedule 2 (Skelton Rebuttal), *with* Ex. 50 at Rebuttal Schedule 11 (Fleege Rebuttal).

Table 5. Third-Party Transmission Revenue and Expense Impacts of 207 MW Redirection

2017 Impact (loss of 207 MW for seven months of year)		**Full-Year Impact (loss of 207 MW for twelve months of year)**	
Total Company	MN Jurisdictional	Total Company	MN Jurisdictional
$2.85 million	$2.357 million	$6.23 million	$5.15 million

The background on Third-Party Transmission Revenue is somewhat complex, but the record support for this background is clear. In Rebuttal Testimony, based on prior information request responses submitted to the parties, Minnesota Power corrected inadvertent errors to the statement of actual 2016 Third-Party Transmission Revenues and Expenses, and therefore agreed to increase Other Operating Revenues by $1.836 million related to Third-Party Transmission Revenue and Expenses.[136] This adjustment was ultimately included in the Commission's March 12, 2018 Order in this case.[137]

Three days before Surrebuttal Testimony, the Company received the unexpected and unwelcome information from MISO that a Transmission Service Request customer moved 207 MW worth of revenue to a different utility's transmission system.[138] The Company identified that this change resulted in a reduction to Transmission Revenues of $2.85 million (Total Company)/$2.357 million (MN Jurisdictional) for 2017 as the revenue for this 207 MW is lost for seven of the year's 12 months, or $6.23 million (Total Company)/$5.15 million (MN Jurisdictional) on a longer-term, annual basis.[139] In rejecting this offset to the $1.836 million approved adjustment, the Commission concluded that Minnesota Power "has not provided a sufficient factual basis for its $6.23 million adjustment" and that "the calculation used to convert $2.85 million to $6.23 million is not in the record nor is any explanation provided for how the

[136] Ex. 50 at 29-30 and Rebuttal Schedule 14 (Fleege Rebuttal).
[137] March 12, 2018 Order at Order Point 14.
[138] Ex. 51 at 2, 4 (Fleege Surrebuttal).
[139] Ex. 51 at 3-4 (Fleege Surrebuttal).

raw MISO data in the supporting schedules result in a $2.85 million revenue loss."[140] The Company respectfully disagrees with this conclusion.

The Company provided, in Surrebuttal Testimony, the MISO reports that explicitly show that 207 MW were redirected away from the Minnesota Power transmission system.[141] Concurrent with its Surrebuttal Testimony, the Company provided, to all parties, the "revenues data from which the adjustment to the impact of the 207 MW redirection on net revenues (expenses) analysis was developed," which included detailed information from MISO records.[142] This information from MISO is the same information that would have been available for the Company to provide if this redirection of 207 MW had occurred earlier in the year. In short, MISO identifies when Company revenues have changed, and the MISO data is what the Company provided here. More time would not have resulted in more or different data being available, nor in more "testing" of what is the proof of these redirected revenues. Further, in Surrebuttal Testimony, the Company detailed where the impacts of this loss of 207 MW were reflected in the Company's methodology.[143]

No party questioned the Company at the evidentiary hearing on how it converted the 207 MW loss to $2.85 million (Total Company)/$2.357 (MN Jurisdictional) Third-Party Transmission Expense for the 2017 actual revenue impact.[144] Indeed, the only questions related to the $2.357 (MN Jurisdictional) for the 2017 actual revenue impact were asked by the

[140] March 12, 2018 Order at 26.
[141] Ex. 52 at Surrebuttal Schedule 1 (Fleege Surrebuttal) (trade secret).
[142] Ex. 51 at 3 n.2 (Fleege Surrebuttal) (public). These data were provided to all parties in response to OAG IR 635, which requested "any and all information contained in or derived from spreadsheets . . . in live Excel format."
[143] Ex. 51 at 3 and Surrebuttal Schedule 2 (Fleege Surrebuttal) (public).
[144] *See* Evidentiary Hearing Transcript, Volume 1 at 130-35 (Fleege).

Department, and verified that the Company detailed (and the Department understood) where the changes in revenue occurred, as shown in Figure 3.[145]

Figure 3. Excerpt of Evidentiary Hearing Transcript, Volume 1[146]

Q Mr. Fleege, if you can now turn to Schedule 2 of
your surrebuttal testimony.
A Okay.
Q Would you agree that under the column for 2017,
rebuttal revenue -- rebuttal updated budget, excuse
me, at 10.82 percent ROE shows a net revenue for a
third-party transmission of 2.24 million?
A Yes.
Q And would you agree in the third column, 2017
surrebuttal updated budget at 10.82 percent ROE that
there is a .61 million net expense?
A Yes.
Q Mr. Fleege, is the difference between 2.24 million
and the .61 net expense is the 2.85 million figure
that you provide in your surrebuttal --
A That is correct.
Q -- on page 3?
A That's correct.
Q And that's your recommended adjustment for
third-party transmission revenues?

Page 134

A Is it at the top of page 4? Is it on 4 or is that
the trade secret version?
Q I think I'm working off of a rebuttal document, a
public document.
A Yeah, that must be. Okay. Gotcha. It's on 4 on
the other one. Okay.
Q Just to clarify, the 2.85 million adjustment is the
difference between the two figures we just
discussed, the 2.24 and the .61?
A Correct.
Q Okay. Thank you.

The support for the \$2.85 million (Total Company)/\$2.357 million (MN Jurisdictional) 2017 test year amount was, therefore, wholly clear in the record. At the same time, Minnesota Power also provided the revenue impact data from MISO to support the full-year amount of \$6.23 million (Total Company)/\$5.15 million (MN Jurisdictional) and requested the full-year amount in Surrebuttal Testimony. Minnesota Power requests the Commission reconsider its decision on these lost revenues, as these are actual costs that the Company experienced in 2017 (the \$2.357 MN Jurisdictional amount) and will experience in years after 2017 (\$5.15 million MN Jurisdictional).

While Minnesota Power understands the hesitancy to approve changes introduced to the record late in the proceeding, the specific revenue requirement adjustment requested in this

[145] Evidentiary Hearing Transcript, Volume 1 at 133:1-134:10 (Fleege); Ex. 51 at Surrebuttal Schedule 2 (Fleege Surrebuttal) (public). Although the Department did ask the Company how it calculated the addition \$3.38 million (Total Company) for a full year impact of the redirection, neither the Department nor any other party raised any issue on how the Company calculated the financial impact of the 207 MW redirection.

[146] Evidentiary Hearing Transcript, Volume 1 at 133:6-134:11 (Fleege by Madsen).

instance was requested as soon as the impact was known by the Company. Further, the Company provided proof of both the change in the 207 MW delivery and the detailed revenues data from which the Company calculated its adjustment to all parties immediately upon finding it. The parties did not contest its validity in the time available – which included the full timeframe after Surrebuttal and throughout the evidentiary hearings. Rather, they simply argued it was too late and that the Company should not recover the amount due to the timing. Where, as here, the supporting evidence is clear, comes from a FERC-regulated independent source (MISO), is not subject to judgment, discretion, or change, was shared with the parties immediately upon discovery by the Company, and will have a significant impact on the Company, Minnesota Power asks the Commission to reconsider its March 12, 2018 Order and approve the Company's demonstrated Third-Party Transmission Revenue loss.

III. <u>Cost of Equity</u>

As with many rate cases, one of the primary issues in this proceeding has been Minnesota Power's ROE. ROE is traditionally a rate case issue that elicits differences of opinion between the utility, other parties to the proceeding, and regulatory decision-makers. The Company's ROE is an important financial piece to Minnesota Power's success and, if set reasonably, is the key to the Company's many positive relationships with investors. Further, Minnesota Power is a Minnesota utility that solely serves electric customers in this state. It also comprises more than 60 percent of ALLETE. As such, the Company cannot offset a lower Minnesota ROE through ROEs in other states, a gas division, or through different operating companies. During the pendency of this case, the Company consistently explained that ROE is of particular importance in this rate case due to the sizeable impact a low ROE would have on Minnesota Power's overall revenues, weakening an otherwise strong Minnesota utility.

That has, in fact, already come to pass in part. As discussed earlier in this Petition, the Company's concerns associated with a lower-than-anticipated ROE have materialized and already resulted in employee lay-offs, a credit outlook downgrade, and other very unfortunate, but real, impacts.

In this Petition, Minnesota Power respectfully requests that the Commission reconsider its decision to set the Company's ROE at 9.25 percent and increase the ROE to a percentage that will bring Minnesota Power's Funds from Operation to Debt ("FFO to Debt") ratio back to a workable level, particularly in light of the new facts presented by Minnesota Power's current credit negative outlook, discussed more fully below. Minnesota Power believes that an increased ROE, coupled with a positive outcome with respect to the other matters raised in this Petition, will help put the Company back in a more financially stable position and allow it to work back some of the employee cuts and credit rating impacts it has begun to experience.

The extent to which Minnesota Power (or ALLETE as a whole) is equally or more risky than other comparable companies is an important concept to the overall ROE determination here. The return ROE investors require is tied to the risk they are taking by investing in a particular utility. The higher the risk, the higher the required return. While it appears that the Commission did consider the Company's risk profile when coming to its overall ROE determination,[147] it is unclear the extent to which an adjustment to the ROE was made for Minnesota Power's business risk. This risk needs to be reflected in an ROE that is not materially below average ROEs for vertically integrated electric utilities in the United States (approximately 9.66 percent),[148] and is not materially below the ROE awarded to Otter Tail (9.41 percent) less than one year ago.

[147] *See* March 12, 2018 Order at 61 ("Most importantly, the approved ROE must adequately assure a fair and reasonable return in light of the Company's risk profile and costs of obtaining equity investment.").
[148] Evidentiary Hearing Transcript, Volume 3 at 184 (Amit).

Throughout this proceeding, the Company demonstrated that its risk levels are materially higher than those of comparable entities. For example, the record supports determinations that Minnesota Power's concentration of sales revenues to its Industrial customers is significantly higher than comparable utilities; the Company is heavily reliant on sales to a small number of Large Industrial customers who operate in highly-cyclical taconite and paper industries; Minnesota Power's small size, particularly when determining a credit rating[149]; the need for ALLETE to maintain a higher FFO to Debt ratio (18 percent) than certain peers to avoid a credit rating downgrade; and Minnesota Power has a larger portion of debt equivalents as a percentage of total capitalization. In fact, Minnesota Power has been recognized as "a company that has a significantly different risk profile than other companies" when considering the Company's equity ratio.[150]

During the Commission's deliberations, the Commission also highlighted how Minnesota Power's risk profile differs from that of other, comparable utilities. It was noted that Minnesota Power has "comparatively higher risk characteristics… relative to other utilities, in particular other utilities used as proxies in all of the various [Discounted Cash Flow ("DCF")] analysis on the record..."[151] There are also significant differences in Minnesota Power's capitalization ($2.9 billion) when compared to the average capitalization of the proxies used in the Department's DCF analysis of $15.3 billion.[152] In addition, "[w]e also have in Minnesota Power a much small geographic service area than the proxies with whom MP is matched in the DCF proxy groups. And we have a much higher concentration of Large Industrial customers for Minnesota Power, in

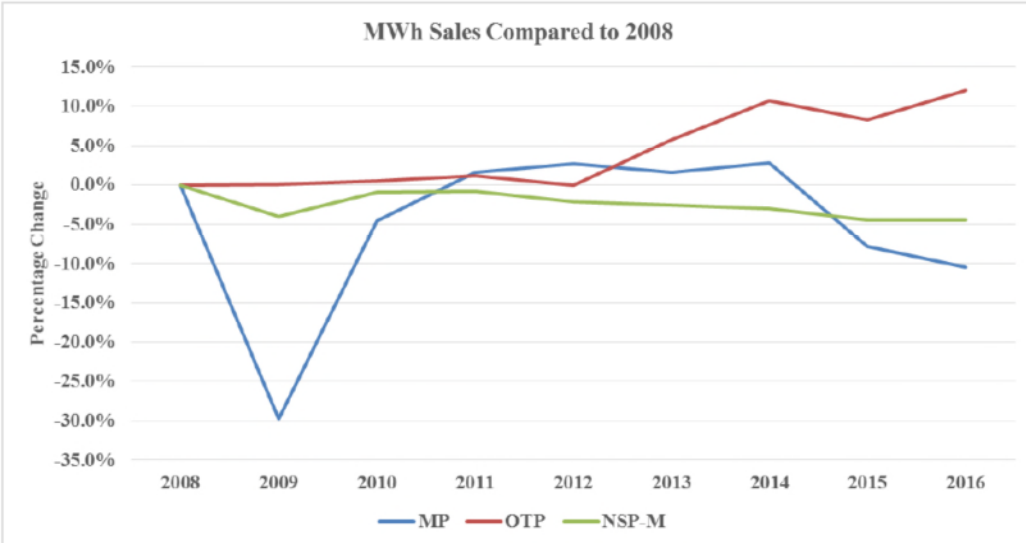
[149] As explained in the Company's Initial Brief, Moody's emphasized in its 2013 Rating Methodology Report, *Regulated Electric and Gas Utilities*, that a company will generally score lower if it provides services to a small area with an increased dependence on one or two highly-cyclical industries. Minnesota Power Initial Brief at 113.
[150] *In the Matter of the Application of CenterPoint Energy Res. Corp. d/b/a CenterPoint Energy Minn. Gas for Auth. to Increase Nat. Gas Rates in Minn.*, Docket No. G008/GR-15-424, INITIAL BRIEF OF THE OFFICE OF THE ATTORNEY GENERAL – RESIDENTIAL UTILITIES AND ANTITRUST DIVISION at 67 (Feb. 8, 2016).
[151] Jan. 18, 2018 Commission Deliberations Transcript at 152:21-25 – 153:1.
[152] Jan. 18, 2018 Commission Deliberations Transcript at 153:1-12.

comparison to the other utilities in the proxy group used. And as we heard and as we know from the record, approximately 70 percent of Minnesota Power's revenue comes from a very small group of Large Industrial customers who are not only a small group, but who are subject to highly cyclical economic forces in the industries in which they operate.[153] The Commission may have sought to capture these considerations in its ROE determination; however, the ROE outcome has nonetheless led to the harmful consequences outlined in this Petition.

The risk presented by Minnesota Power's unique load profile is also evidenced when comparing Minnesota Power to Otter Tail, a neighboring Minnesota electric utility. Otter Tail faces comparable levels of competition, operates in the same Minnesota regulatory environment, and is allowed the same cost recovery riders. Otter Tail's load profile, however, is much different because it is not so heavily reliant on sales to a small number of Large Industrial customers who operate in highly-cyclical taconite and paper industries. Figure 4 below illustrates the level of volatility of Minnesota Power's MWh sales to ultimate customers, comparing it to the relative stability of Otter Tail's and Northern States Power Company – Minnesota's MWh sales on a percentage of 2008 sales.

[153] Jan. 18, 2018 Commission Deliberations Transcript at 153:13-25 – 154:1-9.

Figure 4[154]



Despite this significant difference between Otter Tail and Minnesota Power (a difference that increases Minnesota Power's risk levels above Otter Tail's), Otter Tail, in its most recent rate case (Docket No. E017/GR-15-1033), was allowed a 9.41 percent ROE.[155] This is 16 basis points above the currently-ordered ROE for Minnesota Power. But Minnesota Power, while similarly situated in many ways with Otter Tail, demonstrably carries more risk than Otter Tail. The Commission's recent ROE determination in the Otter Tail rate case, coupled with Minnesota Power's unique risk profile, support an ROE for the Company significantly above 9.25 percent and more in, at a minimum, the 9.41 percent (OTP) to 9.66 percent (average vertically-integrated electric utilities) range.

[154] Exhibit 38 at Figure 1 (Cutshall Rebuttal).

[155] *In the Matter of the Application of Otter Tail Power Co. for Auth. to Increase Rates for Elec. Serv. in Minn.*, Docket No. E017/GR-15-1033, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 55 (May 1, 2017). In its Otter Tail order, the Commission specifically acknowledged Otter Tail's unique characteristics and circumstances in comparison to other utilities, but failed to provide such a discussion in its March 12, 2018 Order for Minnesota Power.

It is also worth highlighting that S&P provides a stringent FFO to Debt threshold for ALLETE of 18 percent, with a preferred threshold in the 20-22 percent range.[156] S&P also expects a Debt to Earnings Before Interest, Taxes, Depreciation, and Amortization ("EBITDA") ratio of less than 4.5x (i.e., 4.5:1).[157] The calculation of this ratio, as well as the methodology and appropriate inputs, were provided by Company witness Mr. Cutshall in this proceeding. Using this same approach, as well as the capital structure, ROE, and revenue requirement established by the Commission in its March 12, 2018 Order, results in the FFO to Debt and Debt to EBITDA ratios shown in Table 6 below, even <u>before</u> the impacts of the Tax Cuts and Jobs Act that serves to further reduce utility credit metrics.

Table 6

Minnesota Power & ALLETE			
S&P Credit Metric Comparison - with 2016 actual adjustments			
2017 with Impacts of General Rates (Based on Ending Balances)			
($ in millions)			
	Minnesota Power MPUC Order	**ALLETE Consolidated MPUC Order**	**S&P Required**
FFO/Debt Adjusted (E/F)	**15.7%**	**16.8%**	**18-22%**
Debt/EBITDA Adjusted (F/A)	**4.8**	**4.5**	**< 4.5**

See **Attachment 4** to this Petition for the calculation of these outcomes, consistent with the methodology Minnesota Power utilized throughout this proceeding.[158]

Consistent with these metrics and the concerns Minnesota Power expressed throughout this proceeding, after the conclusion of the Commission's deliberations on January 30, 2018,

[156] Ex. 38 at 6 (Cutshall Rebuttal).
[157] Ex. 38 at 6 (Cutshall Rebuttal).
[158] Attachment 4 also shows the impacts with tax reform – which further reduce the Minnesota Power FFO/Debt ratio to below 14 percent and the ALLETE FFO/Debt ratio to roughly 15 percent. All of these numbers are well below established investor expectations.

Moody's issued a rating action, changing the credit agency's outlook for ALLETE from stable to negative. As explained in the rating action, "[t]he negative outlook results from [Moody's] expectation that ALLETE's financial ratios will weaken following the adverse general rate case outcome at the company's primary business, Minnesota Power, as well as the negative cash flow impact associated with federal tax reform."[159] The rating action further explained that "ALLETE could be downgraded if it continues to experience a decline in the credit supportiveness of the Minnesota regulatory framework." In a separate February 8, 2018, Issuer's Comment, Moody's further concluded that Minnesota Power's general rate case outcome is credit negative even without considering the additional negative cash flow impacts stemming from federal tax reform.[160] In coming to this conclusion, Moody's called out that Minnesota Power's ROE of 9.25 percent is well below the national average of 9.66 percent despite its higher risk profile.[161] S&P took fundamentally the same approach.[162] The ROE determination in this case, together with other financial determinations, have plummeted the Company's FFO to Debt ratio and have impacted the way the Company is viewed from a credit ratings perspective. An increase in the Company's ROE is unlikely to fully cure Minnesota Power's current credit negative outlook or mitigate the expense reductions that still will likely be required, but will certainly help.

To determine an appropriate increase in Minnesota Power's ROE, consideration of the DCF analysis included in the record of this proceeding is helpful. Due to Minnesota Power's aforementioned risk profile, a reasonable return would be set at the upper end of a reasonable range. The Department, in Surrebuttal Testimony, recommended an ROE within a range of 7.64 to 9.66 percent based primarily on its DCF analyses. Minnesota Power's DCF analysis shows

[159] eDockets ID No. 20182-140359-01.
[160] eDockets ID No. 20182-139910-01 (public), 20182-139910-02 (trade secret).
[161] eDockets ID No. 20182-139910-01 (public), 20182-139910-02 (trade secret).
[162] eDockets ID No. 20182-139884-01 (public), 20182-139884-02 (trade secret).

that a DCF of 9.25 is below the mean growth rate under any Constant Growth DCF analysis – and this is before the Tax Cuts and Jobs Act was passed, further eroding utility credit metrics:[163]

Table 11a: Summary of DCF-Based ROE Results[165]

	Low Growth Rate	***Mean Growth Rate***	***High Growth Rate***
Constant Growth DCF			
30-Day Average	8.39%	9.33%	10.40%
90-Day Average	8.44%	9.38%	10.46%
180-Day Average	8.52%	9.47%	10.54%

While the Company appreciates the comprehensive ROE analysis provided by the Commission, an ROE set at 9.25 percent is simply not sufficient to help ensure stability for Minnesota Power – an historically strong Minnesota utility. The many negative impacts resulting from the collection of decisions made by the Commission in this rate case are significant for the Company. In an effort to help reverse, at least in part, the detrimental financial impacts of the current rate case outcome and in light of the new issues presented by the Company's current credit negative outlook, Minnesota Power respectfully requests that the Commission reconsider its ROE determination and increase the Company's ordered ROE.

REQUEST FOR CLARIFICATIONS

I. Annual Rate Review Mechanism ("ARRM")

In this proceeding, Minnesota Power proposed a new mechanism to address significant changes in retail and resale sales between rate cases – the Annual Rate Review Mechanism or "ARRM." The Commission did not approve the proposal, determining that while it values innovative approaches to improve the regulatory process, it was not established on the record in

[163] Ex. 35 at 65 (Hevert Rebuttal) (partial view of table, limited to DCF analyses).

this proceeding that Minnesota Power's ARRM proposal would properly align the Company's incentives with the public interest or result in just and reasonable rates.[164]

The Company is not requesting the Commission reconsider its ARRM decision in this Petition, but rather seeking clarification on the matter. While the Company supported the approval and implementation of the ARRM in this proceeding, it also suggested consideration of the ARRM in a separate docket. However, the March 12, 2018 Order does not discuss addressing the ARRM in a separate, miscellaneous proceeding, as it did in the order point requiring the Company to develop a demand response rider in a separate docket.[165] Minnesota Power seeks clarification that it may propose the ARRM, with additional evidence or modifications that may aid in evaluation and acceptance of the mechanism, in a separate, miscellaneous docket instead of waiting until the next rate case.

II. <u>Large Power Service</u>

Minnesota Power requests clarification with respect to several inconsistencies the Company identified throughout the March 12, 2018 Order, particularly related to Large Power standard service. On page 89 of the Commission's March 12, 2018 Order, the Commission approves the Company's proposed tariff changes concerning Large Power standard service and several other changes. However, there are several inconsistencies with respect to approval of specific items that are listed on page 87 of the Commission's March 12, 2018 Order. Due to the base cost of fuel upward adjustment and other revenue allocation decisions for Large Power, Minnesota Power assumes that those decisions supersede any specific tariff language as set forth on page 87 of the Commission's March 12, 2018 Order. To ensure that the decisions for Large

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[164] March 12, 2018 Order at 62.

[165] "The Company shall work with LPI and other stakeholders to develop a demand response rider and corresponding methodology for cost recovery, based on stakeholder input, for submission to the Commission. The record to support the submission to the Commission may be developed in either Docket E015/AI-17-568 – OAH Docket 68-2500-34672 or a new miscellaneous docket." *See* March 12, 2018 Order at Order Point 72.

Power are properly addressed in the final outcome of this proceeding, Minnesota Power will provide the updated amounts in the Company's final rates compliance filing.

III. Changes to Various Class Rate Schedules

In Order Points 63 through 68 of the Commission's March 12, 2018 Order, the Commission approves changes to various class rate schedules either as proposed by the Company or with modifications. These order points, however, are void of language that allows the final rate component to be adjusted as needed to enable recovery of the revenue requirement allowed for each class. This language would be similar to that included in Order Point 57, where the Commission required Minnesota Power to implement a four block rate schedule "with adjustments to the rates for each block as needed to enable the Company to recover the full revenue requirement allowed by the Commission for the Residential class." Without this provision, it will be difficult to comply with the rate case apportionment decision. Minnesota Power, therefore, seeks clarification from the Commission that the language quoted above was intended to and should also be applied to the changes to various class rate schedules provided in Order Points 63 through 68.

IV. "Final Order" Clarification

Minnesota Power requests clarification from the Commission that any directive for the Company or another party to perform a task or submit a filing within a particular amount of time after a final order refers specifically to the final order issued after reconsideration. For example, Commission Order Point 5 requires Minnesota Power to file a securitization plan within two years of the date of the final order in this case and Commission Order Point 72 requires Minnesota Power to work with LPI and other stakeholders to develop a demand response rider and corresponding methodology for cost recovery, ordering that a filing be submitted for Commission approval "within six month after the date of the final written order in this proceeding."[166] Minnesota Power seeks clarification simply that "final written order" or "final order" refer to the final order issued after reconsideration in this case, as the final order after reconsideration may affect what actions the Company next takes and in what manner.

CONCLUSION

Minnesota Power respectfully requests that the Commission grant this Petition for Reconsideration and Request for Clarification in all respects.

Dated: April 2, 2018

Respectfully submitted,

MINNESOTA POWER

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BRIGGS AND MORGAN, P.A.

/s/ Elizabeth M. Brama

Elizabeth M. Brama
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[166] Additional filing requirements that should be required within a certain amount of time of the "final written order" in this case include: the requirement that Minnesota Power file a status report within six months of the date of the final written order in this proceeding addressing the transparency of the CCOSS (March 12, 2018 Order at 72); the directive that the Company file a Demand Response rider within six months of the date of the final written order (March 12, 2018 Order at 86); the Company must file a status report within six months of the final written order identifying Minnesota Power's efforts to facilitate review of its CCOSS model (Order Point 55); Minnesota Power shall work with Wal-Mart and other interested stakeholders to develop renewable programs suitable for large customers and report to the Commission the results of such development within six months of the date of the final written order (Order Point 81); and Minnesota Power shall make compliance filings within 30 days of the final written order (Order Point 88).

State of Minnesota

DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Nonpublic [ ]
Public [X]

Utility Information Request

Docket Number: E015/GR-16-664 Date of Request: 2/3/2017

Requested From: Minnesota Power Response Due: 2/15/2017

Analyst Requesting Information: Nancy Campbell/Dale Lusti/Lerma LaPlante/Samir Ouanes

Type of Inquiry: [X] Financial [ ] Rate of Return [ ] Rate Design
[ ] Engineering [ ] Forecasting [ ] Conservation
[ ] Cost of Service [ ] CIP [ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
1120	Reference: Vol. III, Direct Testimony of Patrick Cutshall p. 63 Subject: Pension Expense Recovery in Rates a) Please provide the MN jurisdictional pension expense rate recovery by year and in total for 1952 to 2016. b) Please provide pension contributions for 1952 to 2016 by year and in total, for both total ALLETE/MP and Minnesota Jurisdiction, including all applicable allocators and support for why allocators are reasonable. c) Please provide the pension expense reflected on MP's financials in 1952 to 2016 by year and in total, for both total ALLETE/MP and Minnesota Jurisdiction (regulated), including all applicable allocators and support for why allocators are reasonable.

RESPONSE:

a) Please see columns AF through AI of DOC IR 1120.01 Attach showing the pension cost recovery for the years 1994 through 2016. We were unable to find supportable pension recovery prior to 1994. Please see DOC IR 1120.02 Attach for the support.

Witness: Patrick L. Cutshall
Response by: Patrick L. Cutshall, Sara Carlson
Title: Treasurer
Department: Investments and Analysis
Telephone: (218) 723-3978

List sources of information:

b) The Company only maintains consistent actuarial statements for the total plan back to 1987. This essentially coincides with the adoption of SFAS No. 87 on January 1, 1986. This date also led to the initial balance of the prepaid pension asset at almost zero (actual is $1,645) on January 1, 1987, which is consistent with the fact that prior to adoption of SFAS No. 87 Minnesota Power funded expense. (Please see DOC IR 1118 for more detail.)

Please see the spreadsheet in DOC IR 1120.01 Attach, which shows by year and entity how contributions and expense would theoretically be allocated (since Minnesota Power does maintain financial statements in this manner). The following illustrates the allocation process:

	DOCI IR 1120.01 ATTACH Columns
Total Plan	A through E
Less subsidiaries directly billed (Superior Water Light & Power is ~ 98%)	G & H
= Total Minnesota Power	J through N
x allocation factor (to remove non regulated)	P
= Total Company	R through V
x Jurisdictional allocation factor	X
= Total MN Jurisdictional expense	Z through AD

DOC IR 1120.01 ATTACH ties to the rate case and provides support for the numbers as follows:

- Total Plan numbers tie to actuarial statements provided by Mercer (Hewitt prior to Mercer). The plan, ALLETE, and Superior Water & Light each have audited financial statements.
- In DOC IR 1119.01 Attach, we show how the total Minnesota Power prepaid balance of $78,195,165 (cell "N37" in DOC IR 1120.01 Attach) ties to the cost of service study.
- Columns J through N are the same numbers in Direct Schedule 4 of Patrick L. Cutshall's direct testimony.
- Column P (total MN power to total Company Allocator) allocators are supported by DOC IR 1120.03 Attach.
- Column X (Jurisdictional Allocator) allocators are supported by DOC IR 1120.04 Attach.

Although the expense, contributions, and prepaid asset balance are rolled forward by year in DOC IR 1120.01 Attach, we believe the correct way to calculate the MN Jurisdictional prepaid asset of $57,856,541 is by multiplying the current balance by the allocators. This is shown in Direct Schedule 4 of Patrick L. Cutshall's Direct Testimony and in cell "N42" of DOC IR 1120.01 Attach (although the roll forward Jurisdictional prepaid asset of $58,067,439 shown in cell "AD37" of DOC IR 1120.01 Attach is not materially different). This is the appropriate method to calculate 2017 prepaid expense because assets and liabilities that are included in calculating revenue requirements for ratemaking purposes are generally aggregated with activity over a period of time using Generally Accepted Accounting Principles and FERC Accounting Principles. When revenue requirements are calculated, the proper jurisdictional allocation is applied to the asset or liability for revenue requirement calculations. Utility assets and liabilities should not be aggregated over time using layers that have already had the jurisdictional allocation percentage applied. In the case of prepaid pension, it would be inappropriate to aggregate the prepaid balance using layers that already had the jurisdictional allocation applied.

c) Please see DOC IR 1120.01 Attach and the response to b) above.

Witness: Patrick L. Cutshall
Response by: Patrick L. Cutshall, Sara Carlson
Title: Treasurer
Department: Investments and Analysis
Telephone: (218) 723-3978

List sources of information:

Minnesota Power Petition for Reconsideration
Docket No. E015/GR-16-664
Attachment 1

MP Exhibit ____ (PLC)
Rebuttal Schedule 10
Docket No. E015/GR-16-664
Page 4 of 4

Total Pension Rollforward

A	B	C	D	E (E=B+C-D)	G	H
	total Plan				Less Subsidiary	
Year	Beginning Prepaid	Contributions	Expense	Ending Prepaid	Contributions	Expense
1987	1,645	4,053,454	4,053,454	1,645	559,999	457,574
1988	1,645	2,673,674	2,678,288	(2,969)	149,635	204,411
1989	(2,969)	2,466,133	2,466,133	(2,969)	102,421	169,626
1990	(2,969)	3,022,676	2,796,953	222,754	164,956	120,722
1991	222,754	5,724,650	2,321,988	3,625,416	258,884	67,754
1992	3,625,416	4,033,434	2,026,297	5,632,553	169,750	38,131
1993	5,632,553	4,008,886	1,904,872	7,736,567	62,510	105,189
1994	7,736,567	1,787,709	798,955	8,725,321	27,909	(113,184)
1995	8,725,321	3,621	2,323,762	6,405,180	-	13,352
1996	6,405,180	-	5,195,829	1,209,351	-	113,051
1997	1,209,351	-	4,596,632	(3,387,281)	-	109,340
1998	(3,387,281)	-	(459,478)	(2,927,803)	-	(171,476)
1999	(2,927,803)	-	(3,922,267)	994,464	-	(284,191)
2000	994,464	-	(8,497,214)	9,491,678	-	(411,904)
2001	9,491,678	-	(9,567,908)	19,059,586	-	(725,066)
2002	19,059,586	-	(6,975,895)	26,035,481	-	(379,100)
2003	26,035,481	-	(2,628,334)	28,663,815	-	(52,538)
2004	28,663,815	7,862,565	3,097,015	33,429,365	390,044	425,527
2005	33,429,365	-	4,951,308	28,478,057	-	547,212
2006	28,478,057	8,257,827	7,305,480	29,430,404	873,279	722,553
2007	29,430,404	187,819	1,096,191	28,522,032	-	389,871
2008	28,522,032	10,898,460	(577,913)	39,998,405	1,111,644	492,799
2009	39,998,405	32,900,000	764,042	72,134,363	3,355,820	306,228
2010	72,134,363	26,500,000	4,603,064	94,031,299	2,081,415	514,800
2011	94,031,299	33,819,786	11,486,072	116,365,013	2,289,883	991,698
2012	116,365,013	7,292,000	16,174,087	107,482,926	673,856	1,245,657
2013	107,482,926	-	20,670,516	86,812,410	-	1,529,187
2014	86,812,410	19,499,040	12,522,446	93,789,004	3,780,934	935,383
2015	93,789,004	-	15,304,684	78,484,320	-	1,562,991
2016 est	78,484,320	2,000,000	5,807,735	74,676,585	418,156	787,877
2017 est	74,676,585	19,700,000	8,760,000	85,616,585	1,693,600	1,029,800

J	K	L (L=C-G)	M (M=D-H)	N (N=K+L-M)	P
	total Minnesota Power				
Year	Beginning Prepaid	Contributions	Expense	Ending Prepaid	total MN Power to total Company Allocator
1987	1,645	3,493,455	3,595,880	(100,780)	76.70%
1988	(100,780)	2,524,039	2,473,877	(50,618)	76.70%
1989	(50,618)	2,363,712	2,296,507	16,587	76.70%
1990	16,587	2,857,720	2,676,231	198,076	76.70%
1991	198,076	5,465,766	2,254,234	3,409,608	76.70%
1992	3,409,608	3,863,684	1,988,166	5,285,126	76.70%
1993	5,285,126	3,946,376	1,799,683	7,431,819	76.70%
1994	7,431,819	1,759,800	912,139	8,279,480	76.70%
1995	8,279,480	3,621	2,310,410	5,972,691	76.70%
1996	5,972,691	-	5,082,778	889,913	76.70%
1997	889,913	-	4,487,292	(3,597,379)	76.70%
1998	(3,597,379)	-	(288,002)	(3,309,377)	76.70%
1999	(3,309,377)	-	(3,638,076)	328,699	76.70%
2000	328,699	-	(8,085,310)	8,414,009	76.70%
2001	8,414,009	-	(8,842,842)	17,256,851	76.70%
2002	17,256,851	-	(6,596,795)	23,853,646	76.70%
2003	23,853,646	-	(2,575,796)	26,429,442	76.70%
2004	26,429,442	7,472,521	2,671,488	31,230,475	76.70%
2005	31,230,475	-	4,404,096	26,826,379	77.12%
2006	26,826,379	7,384,548	6,582,927	27,628,000	82.96%
2007	27,628,000	187,819	706,320	27,109,499	83.66%
2008	27,109,499	9,786,816	(1,070,712)	37,967,027	85.94%
2009	37,967,027	29,544,180	457,814	67,053,394	87.42%
2010	67,053,394	24,418,585	4,088,264	87,383,715	89.22%
2011	87,383,715	31,529,903	10,494,374	108,419,244	88.83%
2012	108,419,244	6,618,144	14,928,430	100,108,958	89.60%
2013	100,108,958	-	19,141,329	80,967,629	89.69%
2014	80,967,629	15,718,106	11,587,063	85,098,672	88.66%
2015	85,098,672	-	13,741,693	71,356,979	87.12%
2016 est	71,356,979	1,581,844	5,019,858	67,918,965	85.68%
2017 est	67,918,965	18,006,400	7,730,200	**78,195,165**	85.51%

total MN Power to total Company Allocator	85.5100%
total Company	66,864,685
MN Jurisdictional Allocator	86.5278%
MN Jurisdictional (4)*(5)	**$ 57,856,541**

R	S	T (T=L* P)	U (T=M* P)	V (V=S+T-U)	X
	total Company				
Year	Beginning Prepaid	Contributions	Expense	Ending Prepaid	Jurisdictional Allocator
1987	1,645	2,679,480	2,758,040	(76,915)	92.1000%
1988	(76,915)	1,935,938	1,897,464	(38,441)	92.1000%
1989	(38,441)	1,812,967	1,761,421	13,106	92.1000%
1990	13,106	2,191,871	2,052,669	152,308	92.1000%
1991	152,308	4,192,243	1,728,997	2,615,553	92.1000%
1992	2,615,553	2,963,446	1,524,923	4,054,075	92.1000%
1993	4,054,075	3,026,870	1,380,357	5,700,589	92.1000%
1994	5,700,589	1,349,767	699,611	6,350,745	92.1000%
1995	6,350,745	2,777	1,772,084	4,581,437	92.1000%
1996	4,581,437	-	3,898,491	682,947	91.9200%
1997	682,947	-	3,441,753	(2,758,806)	91.9200%
1998	(2,758,806)	-	(220,898)	(2,537,909)	91.9200%
1999	(2,537,909)	-	(2,790,404)	252,496	91.9200%
2000	252,496	-	(6,201,433)	6,453,928	91.9200%
2001	6,453,928	-	(6,782,460)	13,236,388	91.9200%
2002	13,236,388	-	(5,059,742)	18,296,130	91.9200%
2003	18,296,130	-	(1,975,636)	20,271,765	91.9200%
2004	20,271,765	5,731,424	2,049,031	23,954,158	91.9200%
2005	23,954,158	-	3,396,439	20,557,719	89.4600%
2006	20,557,719	6,126,221	5,461,196	21,222,744	89.4600%
2007	21,222,744	157,129	590,907	20,788,966	87.4900%
2008	20,788,966	8,410,790	(920,170)	30,119,925	87.6767%
2009	30,119,925	25,827,522	400,221	55,547,227	87.6767%
2010	55,547,227	21,786,262	3,647,549	73,685,940	86.1672%
2011	73,685,940	28,008,013	9,322,152	92,371,800	86.1672%
2012	92,371,800	5,929,857	13,375,873	84,925,784	86.1672%
2013	84,925,784	-	17,167,858	67,757,926	86.1672%
2014	67,757,926	13,935,673	10,273,090	71,420,508	86.1672%
2015	71,420,508	-	11,971,763	59,448,745	86.5161%
2016 est	59,448,745	1,355,324	4,301,014	56,503,055	86.0536%
2017 est	56,503,055	15,397,273	6,610,094	**65,290,234**	86.5278%

Z	AA	AB (AB=T * X)	AC (AC=U * X)	AD (AD=AA+AB-AC)
	MN Jurisdictional			
Year	Beginning Prepaid	Contributions	Expense	Ending Prepaid
1987	1,645	2,467,801	2,540,155	(70,709)
1988	(70,709)	1,782,999	1,747,564	(35,274)
1989	(35,274)	1,669,743	1,622,269	12,200
1990	12,200	2,018,713	1,890,508	140,405
1991	140,405	3,861,055	1,592,407	2,409,054
1992	2,409,054	2,729,333	1,404,454	3,733,933
1993	3,733,933	2,787,748	1,271,309	5,250,372
1994	5,250,372	1,243,135	644,341	5,849,166
1995	5,849,166	2,558	1,632,090	4,219,634
1996	4,219,634	-	3,583,493	636,141
1997	636,141	-	3,163,659	(2,527,518)
1998	(2,527,518)	-	(203,049)	(2,324,469)
1999	(2,324,469)	-	(2,564,940)	240,470
2000	240,470	-	(5,700,357)	5,940,827
2001	5,940,827	-	(6,234,437)	12,175,264
2002	12,175,264	-	(4,650,915)	16,826,179
2003	16,826,179	-	(1,816,004)	18,642,183
2004	18,642,183	5,268,325	1,883,470	22,027,038
2005	22,027,038	-	3,038,454	18,988,584
2006	18,988,584	5,480,517	4,885,586	19,583,515
2007	19,583,515	137,472	516,985	19,204,003
2008	19,204,003	7,374,303	(806,774)	27,385,080
2009	27,385,080	22,644,719	350,901	49,678,899
2010	49,678,899	18,772,612	3,142,991	65,308,520
2011	65,308,520	24,133,720	8,032,638	81,409,603
2012	81,409,603	5,109,592	11,525,615	74,993,579
2013	74,993,579	-	14,793,063	60,200,517
2014	60,200,517	12,007,979	8,852,034	63,356,462
2015	63,356,462	-	10,357,502	52,998,959
2016 est	52,998,959	1,166,305	3,701,178	50,464,087
2017 est	50,464,087	13,322,921	5,719,569	**58,067,439**

AF	AG	AH	AI
	TOTAL Recovery		
Year	O&M	Capital	Total
1987	n/a	n/a	n/a
1988	n/a	n/a	n/a
1989	n/a	n/a	n/a
1990	n/a	n/a	n/a
1991	n/a	n/a	n/a
1992	n/a	n/a	n/a
1993	n/a	n/a	n/a
1994	368,504	55,276	423,780
1995	368,504	55,276	423,780
1996	368,504	55,276	423,780
1997	368,504	55,276	423,780
1998	368,504	55,276	423,780
1999	368,504	55,276	423,780
2000	368,504	55,276	423,780
2001	368,504	55,276	423,780
2002	368,504	55,276	423,780
2003	368,504	55,276	423,780
2004	368,504	55,276	423,780
2005	368,504	55,276	423,780
2006	368,504	55,276	423,780
2007	368,504	55,276	423,780
2008	(1,566,373)	(234,956)	(1,801,329)
2009	(1,566,373)	(234,956)	(1,801,329)
2010	1,452,891	217,934	1,670,825
2011	1,452,891	217,934	1,670,825
2012	1,452,891	217,934	1,670,825
2013	1,452,891	217,934	1,670,825
2014	1,452,891	217,934	1,670,825
2015	1,452,891	217,934	1,670,825
2016 est	1,452,891	217,934	1,670,825
2017 est			
	12,196,547	1,829,482	14,026,029

MERCER
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Mr. Pat Cutshall
Treasurer
ALLETE, Inc.
30 West Superior Street
Duluth, MN 55802-2093

June 14, 2017

Subject: Explanation of Prepaid Pension Asset

Pat,

The terms "accrued pension liability" and "prepaid pension asset," or "accrued/prepaid" for short, are commonly used terms in regards to pension accounting. The accrued/prepaid is the difference between the accumulated contributions made to a plan and the accumulated pension expense recognized by the company as required by US GAAP. An accrued pension liability arises when the accumulated expense exceeds the accumulated contributions, and a prepaid pension asset arises when the accumulated contributions exceed the accumulated expense.

In the most recent ASC 715 actuarial valuation reports as of December 31, 2016 for ALLETE's pension plans, the accrued/prepaid is referred to as "accumulated contributions in excess of net periodic benefit cost," or "cumulative employer contributions in excess of net periodic benefit cost." While the terminology may differ, these amounts are one and the same, in amount and in concept. The accumulated contributions in excess of net periodic benefit cost can be found in Appendix A, page 3 of the actuarial valuation report, and Appendix B, page 3, and as of December 31, 2016 is $79,498,756.

Should you have any questions, please do not hesitate to call me at 612.642.8782.

Regards,

Scott Striegel

Scott Striegel, FSA, EA, MAAA
Senior Associate

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MARSH & McLENNAN COMPANIES

Report of Independent Accountants

To the Board of Directors and Management of ALLETE, Inc. and
Management of Minnesota Power

We have examined the accompanying management assertion of Minnesota Power that the Reconciliation of ALLETE, Inc.'s 2016 Form 10-K to Minnesota Power's Accumulated Contributions in Excess of Net Periodic Benefit Cost as of December 31, 2016 is a complete and accurate presentation of Minnesota Power's Accumulated Contributions in Excess of Net Periodic Benefit Cost based on the criteria set forth in Note 1. Minnesota Power's management is responsible for the assertion. Our responsibility is to express an opinion on management's assertion based on our examination.

Our examination was conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants. Those standards require that we plan and perform the examination to obtain reasonable assurance about whether management's assertion is fairly stated, in all material respects. An examination involves performing procedures to obtain evidence about management's assertion. The nature, timing and extent of the procedures selected depend on our judgment, including an assessment of the risks of material misstatement of management's assertion, whether due to fraud or error. We believe that the evidence we obtained is sufficient and appropriate to provide a reasonable basis for our opinion.

In our opinion, management's assertion that the Reconciliation of ALLETE, Inc.'s 2016 Form 10-K to Minnesota Power's Accumulated Contributions in Excess of Net Periodic Benefit Cost as of December 31, 2016 is a complete and accurate presentation of Minnesota Power's Accumulated Contributions in Excess of Net Periodic Benefit Cost based on the criteria set forth in Note 1 is fairly stated, in all material respects.

This report is intended solely for the information and use of ALLETE, Inc., Minnesota Power, the Minnesota Public Utilities Commission and other parties involved in Minnesota Power's currently ongoing rate case.

PricewaterhouseCoopers LLP

June 23, 2017

PricewaterhouseCoopers LLP, Suite 3400, 45 South 7th Street, Minneapolis, MN 55402
T: (612) 596 6000, F: (612) 373 7160, www.pwc.com/us

Minnesota Power
Management's Assertion on the Reconciliation of ALLETE, Inc.'s 2016 Form 10-K to Minnesota Power's Accumulated Contributions in Excess of Net Periodic Benefit Cost

Management of Minnesota Power, an operating division of ALLETE, Inc., has prepared the accompanying Reconciliation of ALLETE, Inc.'s 2016 Form 10-K to Minnesota Power's Accumulated Contributions in Excess of Net Periodic Benefit Cost as of December 31, 2016. Management asserts that the accompanying Reconciliation of ALLETE, Inc.'s 2016 Form 10-K to Minnesota Power's Accumulated Contributions in Excess of Net Periodic Benefit Cost as of December 31, 2016 is a complete and accurate presentation of Minnesota Power's Accumulated Contributions in Excess of Net Periodic Benefit Cost based on the criteria set forth in Note 1.

Minnesota Power
Reconciliation of ALLETE, Inc.'s 2016 Form 10-K to Minnesota Power's Accumulated Contributions in Excess of Net Periodic Benefit Cost
As of December 31, 2016

Reconciliation of ALLETE, Inc.'s 2016 Form 10-K to Minnesota Power's Accumulated Contributions in Excess of Net Periodic Benefit Cost
(dollars in millions)

Pension Funded Status per ALLETE, Inc.'s 2016 Form 10-K	$ (185.8)	**A**
Unrecognized Pension Costs in Accumulated Other Comprehensive Income per Allete, Inc.'s 2016 Form 10-K	250.4	**B**
Total Accumulated Contributions in Excess of Net Periodic Benefit Cost	64.6	**C**
Subtract SERP Plan Accumulated Contributions in Excess (Short) of Net Periodic Benefit Cost	(12.6)	**D**
Subtract EIP Plan Accumulated Contributions in Excess (Short) of Net Periodic Benefit Cost	(2.2)	**E**
Pension Plan Accumulated Contributions in Excess of Net Periodic Benefit Cost	79.4	**F**
Subtract SWL&P Pension Plan 12/31/16 Accumulated Contributions in Excess of Net Periodic Benefit Cost	6.9	**G**
Minnesota Power 12/31/16 Pension Plan Accumulated Contributions in Excess of Net Periodic Benefit Cost	$ 72.5	**H**

The accompanying Notes are an integral part of this Reconciliation of ALLETE, Inc.'s 2016 Form 10-K to Minnesota Power's Accumulated Contributions in Excess of Net Periodic Benefit Cost

Minnesota Power
Notes to the Reconciliation of ALLETE, Inc.'s 2016 Form 10-K to Minnesota Power's Accumulated Contributions in Excess of Net Periodic Benefit Cost
As of December 31, 2016

Note 1 – Basis of Presentation

ALLETE, Inc. (ALLETE) files its consolidated financial statements with the Securities and Exchange Commission on a quarterly (unaudited) and annual (audited) basis. ALLETE's consolidated financial statements include the operating results and financial position of Minnesota Power, an operating division of ALLETE, as well as other subsidiaries. ALLETE's consolidated financial statements include amounts and disclosures related to ALLETE's pension plan, including its funded status, which are based in part on an actuarial valuation report prepared by Mercer, ALLETE's independent actuary. ALLETE's consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America, and they have been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm.

On November 2, 2016, Minnesota Power filed a retail rate increase request with the Minnesota Public Utilities Commission. The Reconciliation of ALLETE, Inc.'s 2016 Form 10-K to Minnesota Power's Accumulated Contributions in Excess of Net Periodic Benefit Cost as of December 31, 2016 has been prepared to support management's rebuttal testimony in this ongoing rate case.

The Reconciliation of ALLETE, Inc.'s 2016 Form 10-K to Minnesota Power's Accumulated Contributions in Excess of Net Periodic Benefit Cost as of December 31, 2016 represents a reconciliation from ALLETE's 2016 Form 10-K pension amounts and disclosures to Minnesota Power's Accumulated Contributions in Excess of Net Periodic Benefit Cost as presented in the above-mentioned rate case.

Note 2 – Definition of Line Items in the Reconciliation of ALLETE, Inc.'s 2016 Form 10-K to Minnesota Power's Accumulated Contributions in Excess of Net Periodic Benefit Cost

The individual components of the Reconciliation of ALLETE, Inc.'s 2016 Form 10-K to Minnesota Power's Accumulated Contributions in Excess of Net Periodic Benefit Cost are as follows:

A – This amounts represents the total funded status of ALLETE's pension plans as of December 31, 2016, as disclosed on page 123 of ALLETE's 2016 Form 10-K. This amount includes ALLETE's Pension Plan, Supplemental Executive Retirement Plan, and EIP Plan.

B – This amount represents the total unrecognized pension costs in accumulated other comprehensive income as of December 31, 2016, as disclosed on page 124 of ALLETE's 2016 Form 10-K. This amount includes ALLETE's Pension Plan, Supplemental Executive Retirement Plan, and EIP Plan.

C – This amount represents the total accumulated contributions in excess of net periodic benefit cost as of December 31, 2016, and it is calculated as the sum of **A** and **B**. This amount includes ALLETE's Pension Plan, Supplemental Executive Retirement Plan, and EIP Plan.

D – This amount represents ALLETE's Supplemental Executive Retirement Plan accumulated contributions in excess (short) of net periodic benefit cost as of December 31, 2016. This amount agrees to ALLETE's actuarial valuation report as of December 31, 2016 prepared by Mercer, ALLETE's independent actuary, with minor differences due to rounding.

E – This amount represents ALLETE's EIP Plan accumulated contributions in excess (short) of net periodic benefit cost as of December 31, 2016. This amount agrees to ALLETE's actuarial valuation report as of December 31, 2016 prepared by Mercer, ALLETE's independent actuary, with minor differences due to rounding.

F – This amount represents the Pension Plan accumulated contributions in excess of net periodic benefit cost excluding the amounts related to ALLETE's Supplemental Executive Retirement Plan and EIP Plan as of December 31, 2016. It is calculated by subtracting **D** and **E** from **C**.

G – This amount represents Superior Water, Light and Power Company's Pension Plan accumulated contributions in excess of net periodic benefit cost as of December 31, 2016. This amount agrees to ALLETE's actuarial valuation report as of December 31, 2016 prepared by Mercer, ALLETE's independent actuary.

H – This amount represents Minnesota Power's Pension Plan accumulated contributions in excess of net periodic benefit cost as of December 31, 2016. It is calculated by subtracting **G** from **F**.

Minnesota Power Petition for Reconsideration
Docket No. E015/GR-16-664
Attachment 4

Minnesota Power & ALLETE
S&P Credit Metric Comparison - with 2016 actual adjustments
2017 with Impacts of General Rates (Based on Ending Balances)
($ in millions)

		Minnesota Power MPUC Order	Minnesota Power with Federal Tax Reform Impacts	ALLETE Consolidated MPUC Order	ALLETE Consolidated with Federal Tax Reform Impacts	S&P Required
	FFO/Debt Adjusted (E/F)	**15.7%**	≈ 13.7%	**16.8%**	≈ 15.0%	**18-22%**
	Debt/EBITDA Adjusted (F/A)	**4.8**	≈ 5.4	**4.5**	≈ 5.0	**< 4.5**
	FFO					
	EBITDA - Unadjusted	303.4		385.1		
	S&P EBITDA Adjustments:					
	Operating Leases	3.8		13.9		
	Asset Retirement Obligation	5.2		8.0		
	Purchased Power Agreements Depreciation	2.0		2.0		
	Purchased Power Agreements Interest Expense	6.1		6.1		
	Dividends Received from Equity Investments	-		12.8		
	Pension & Other Postretirement Expense	(5.6)		(7.4)		
	Stock Compensation Expense	2.2		2.6		
(A)	EBITDA - Adjusted	317.1		423.1		
	Interest Expense - Unadjusted	(55.3)		(70.0)		
	S&P Interest Expense Adjustments:					
	Operating Leases	(0.8)		(3.9)		
	Asset Retirement Obligation	(5.2)		(8.0)		
	Purchased Power Agreements Interest Expense	(6.1)		(6.1)		
	Pension & Other Postretirement Expense	(6.9)		(9.2)		
(B)	Interest Expense - Adjusted	(74.3)		(97.2)		
(C)	Interest and Dividend Income	-		-		
	Current Tax - Unadjusted	-		-		
	S&P Current Tax Adjustments:					
	Tax Effect on ARO	0.4		0.5		
	Tax Effect on Pension & Other Postretirement	(3.2)		(4.2)		
(D)	Current Taxes - Adjusted	(2.8)		(3.7)		
(E) = A+B+C+D	FFO (S&P Adjusted)	240.0		322.2		
	Debt					
	Debt - Unadjusted	1,247.4		1,567.0		
	S&P Debt Adjustments:					
	Operating leases	11.7		53.0		
	Post-retirement benefit obligation	100.2		133.2		
	Purchased power agreements	87.6		87.6		
	Asset retirement obligations	60.6		88.8		
	Accrued interest	17.1		17.6		
	Surplus Cash	-		(27.5)		
(F)	Debt - Adjusted	1,524.7		1,919.7		