**BEFORE THE PUBLIC UTILITIES COMMISSION**
**OF THE STATE OF SOUTH DAKOTA**

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| **IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY DBA XCEL ENERGY FOR AUTHORITY TO INCREASE ITS ELECTRIC RATES** | ) ) ) ) | **XCEL ENERGY PROPOSED FINDINGS OF FACT**<br><br>**EL11-019** |

# XCEL ENERGY PROPOSED FINDINGS OF FACT

**<u>Parties</u>**

1. The Applicant is Northern States Power Company dba Xcel Energy, a public utility as defined in SDCL 49-34A-1(12).

2. Commission Staff participated in this case as a full party.

**<u>Procedural Findings</u>**

3. Xcel Energy filed with the Public Utilities Commission (Commission) an application for approval to increase rates for electric service to customers in its South Dakota service territory by approximately $14.6 million annually or approximately 9.28% based on the Company's 2010 test year, on June 30, 2011.[1] In addition, Xcel Energy proposed to recover approximately $1 million of ongoing investments in its Monticello nuclear generating plant through a Nuclear Cost Recovery Rider intended to go into effect with final rates.[2] Under the requested increase, a residential electric customer using 750 kWh per month would have seen an increase of 9.48%, or $6.93 per month. The proposed rates would potentially affect approximately 84,000 customers in Xcel Energy's South Dakota service territory.

4. On July 7, 2011, the Commission officially took notice of the filing and set an intervention deadline of September 9, 2011, to interested individuals and

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[1] McCarten Direct at 3.
[2] McCarten Direct at 20.

entities. No persons requested intervention.

5. On July 20, 2011, the Commission issued an Order of Assessment of Filing Fee and Suspension of Imposition of Tariff and set an intervention deadline of September 9, 2011. No petitions to intervene were filed.

6. On November 4, 2011, the Company filed its Notice of Intent to Implement Interim Rates based on current rate design for service provided on and after January 2, 2012, pursuant to SDCL § 49-34A-17.

7. On January 2, 2012, Xcel Energy implemented an interim rate increase of approximately $12.7 million, or 8.09 percent, subject to refund.

8. On February 28, 2012, the Commission issued an Order for and Notice of Procedural Schedule and Notice of Hearing. On March 19, 2012, April 2, 2012, and April 9, 2012, the Company and Staff filed stipulations for extension of the procedural schedule deadline for filing and service of Staff's testimony to facilitate on-going settlement discussions.

9. On April 16, 2012, Staff filed its pre-filed testimony.

10. On April 19, 2012, the Company filed a letter to the Commission that settlement had been reached on all issues except two issues.

11. On April 27, 2012, the Company filed Rebuttal Testimony.

12. On May 8, 2012, the Company and the Commission Staff filed a Joint Motion For Approval Of Settlement Stipulation, which stated that the parties had resolved all issues except, (i) cost recovery for the Nobles wind plant and the adjustments associated with the level of the Nobles wind plant cost recovery allowed, and (ii) rate of return on equity, cost of debt, and capital structure ("Settlement").

13. The Commission considered the Settlement at its May 22, 2012 meeting in Pierre, South Dakota.

14. On May 23, 2012 Commission Staff filed Rebuttal Testimony on the remaining contested issues.

15. The Commission approved the Settlement in its May 24, 2012 order in this docket.

16. On June 4, 2012, the Company filed Surrebuttal Testimony on the remaining contested issues.

17. On June 6, the Company filed its brief and proposed findings of fact in this case.

18. On June 13 and 14, 2012 evidentiary hearings were held on the remaining contested issues.

19. The Commission has jurisdiction in this matter pursuant to SDCL Chapters 1-26 and 49-34A, specifically 49-34A-4,49-34A-6,49-34A-8,49-34A-I 0,49-34A-11,49-34A-12,49-34A-13,49-34A-13.1, 49-34A-17, 49-34A-19, and 49-34A-21.

**Return On Equity ("ROE"), Capital Structure and Cost of Debt**

20. Determining a reasonable ROE rests primarily on sound judgment looking at the overall results of the analysis. Under SDCL 49-34A-8 and relevant caselaw, rates set in this proceeding must be just and reasonable.[3]

21. The just and reasonable test focuses on whether the "total effect of the rate order [is] unreasonable."[4] Under the just and reasonable test "it is the result reached, not the method employed that is controlling" and "the impact of the rate order which counts."[5] The South Dakota Supreme Court recognized that rates that do not yield a fair return are unreasonable.[6] The rate of a return must be is "commensurate with returns on other investments of corresponding risks" and "be sufficient … to attract capital."[7]

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[3] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).
[4] *Duquesne Light Co. v. Barasch*, 488 U.S. 299, 310 (1989).
[5] *Hope Natural Gas*, 320 U.S. at 602.
[6] *In Re Northwestern Bell*, 43 N.W.2d 553, 555 (S.D. 1950).
[7] *Northwestern Public Service v. Cities of Chamberlain, etc.*, 265 N.W.2d 867, 873 (S.D. 1978), quoting *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944) (Emphasis added); the

22. The Company's proposed 10.65 percent ROE meets the standard of comparability to returns from other investments, and the related standard of sufficiency to attract capital and is appropriate based on South Dakota statutes and court decisions.

23. Staff witness Mr. Basil Copeland's recommendation of a 9.0 percent ROE and his 8.5 to 9.5 percent ROE range fail the standards of comparability and adequacy to attract capital. Mr. Copeland's 9.0 percent ROE recommendation is below every one of the 79 authorized ROEs for integrated electric utilities, from January 1, 2010 to March 31, 2012,[8] including 7 decisions in 2012.[9] There have been 6 additional decisions in 2012. The average of the 13 ROE decisions in 2012 is 10.15 percent.[10]

24. The Company is making substantial investments in its generation and transmission infrastructure. Between 2010 and 2016, the Company plans to invest approximately $7 billion in its system: more than $4 billion for all generating resources, nearly $2 billion in transmission investment, and another $1 billion in its distribution system.[11]

25. In South Dakota, nearly three quarters of the Company's revenue deficiency related to new investment, primarily in generation and transmission infrastructure. Of the original requested increase of $14.6 million, $11.8 million was due to the Company's infrastructure cost drivers.[12] The Company has demonstrated its investment needs, and has shown that it will have significant capital needs for the foreseeable future.[13] The harm from an ROE that is not reasonably comparable (and

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same quotation and standard was applied in *Application of Northwestern Bell Tel. Co.*, 98 N.W.2d 170, 179-180 (S.D. 1959.

[8] Coyne Rebuttal at p. 6. Source: Regulatory Research Associates.

[9] Coyne Surrebuttal at Schedule 1.

[10] *Id.*

[11] McCarten Direct at p. 5, 16.

[12] *Id.* at p. 4.

[13] Dane Direct at p. 23.

is therefore insufficient to attract capital) would be compounded by the very substantial investments being made by the Company.

26. The Company has experienced inadequate returns in prior years, and will also experience a return deficiency in 2012. With an authorized ROE of 10.65 percent, the Company is projected to have an ROE of 8.10 percent for 2012, including full recovery for the costs of the Nobles wind plant.[14]

27. The Company determined its proposed 10.65 percent ROE based on the constant growth Discounted Cash Flow ("DCF") model. The DCF model expresses the cost of equity as the sum of the expected dividend yield plus long-term growth rate.[15]

28. The Company's DCF model was applied to a comparable group of ten domestic electric utilities.[16] Mr. Copeland used the same comparable group.[17] The comparable group used to determine the ROE is appropriate.

29. The Company's proposed dividend yield was adjusted to reflect one-half of the expected annual dividend growth in order to reflect the expected dividend yield in the coming twelve-month period.[18] Mr. Copeland used the same approach to determine dividend yield.[19]

30. The Company's growth rate was based solely on investment analysts' forecasted growth in earnings per share for each comparable group company. The use of earnings growth is appropriate because: (i) investors look to earnings growth as the primary source of estimates for long term growth; (ii) earnings growth data is the only consensus data that is widely reported and available to investors; and (iii) the use of earnings growth as a measure of long term growth is supported by academic

[14] McCarten Rebuttal at p. 6.
[15] Dane Direct at p. 16-17.
[16] Id. at p. 15.
[17] Copeland Direct, Schedule 4; Dane Direct at p. 15.
[18] Dane Direct at pp. 18-19.
[19] Copeland Direct at p. 24.

analysis. Earnings growth for the comparable companies is reported by three separate investment analyst services, Zack's, First Call, and Value Line.[20] Investors use these services to make investment decisions, and the connection between earnings growth projections and stock prices has been demonstrated by independent research.[21] Because the Commission is trying to determine these investor expectations of growth, the use of earnings growth forecasts is appropriate.[22]

31. Staff witness Mr. Copeland's growth rate is skewed downwards as the result of giving 3/4[ths] weighting to Value Line's estimates of dividend per share growth, book value per share growth, and % Retained to Common Equity.[23] Growth rates for dividend per share and book value per share are not reliable long-term growth rates, because both are largely affected by short-term management decisions that reflect short-term cash needs.[24] The % Retained to Common Equity understates growth by failing to consider the additional growth from externally generated funds (new equity issuances).[25] In addition, dividend per share growth, book value per share growth, and % Retained to Common Equity growth rates are not reported by most analysts, making it not likely these rates are relied upon by investors in making investment decisions.[26]

32. Mr. Copeland also used a dividend discount model ("DDM") which includes multiple growth rates. The 8.42 percent median and 8.54 percent mean results of Mr. Coyne's DDM model provide the bottom of his range.[27]

33. Mr. Copeland used the % Retained to Common Equity as the long term growth rate in his DDM, but did not consider the additional source of growth from

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[20] Dane Direct at p. 20.
[21] *Id.* at p. 19.
[22] *Id.* at pp. 15-19.
[23] Copeland Direct at p. 25.
[24] Coyne Rebuttal at pp. 15-16.
[25] *Id.* at 17
[26] *Id.* at pp. 15-16.
[27] *Id.* at p. 18.

externally generated funds (new equity issuances) that should be included in this model.[28] As a result, Mr. Copeland's % Retained to Common Equity growth rate understates the prospective earnings growth rates for the comparison group.[29]

34. Mr. Copeland's 4.00 percent long term growth rate is significantly lower than most estimates of nominal long term GDP growth (4.93 percent as determined by Mr. Coyne),[30] which are the generally used for the long term estimate in a multiple growth rate model.[31]

35. The Company provided a multistage DCF model that indicated an average result of 10.00 percent.[32] The Company's multistage DCF model used forecasted nominal growth in GDP for the long term growth rate. The 4.93 percent forecasted nominal GDP rate used by the Company includes: 2.27 percent (for inflation) + 2.60 percent real GDP growth. The forecasted inflation rate and real GDP rates are based on well recognized forecasting and reporting services.[33] The Company's use of the long-term average payout ratio in the multistage DCF model was appropriate. While the current level of utility investment may lower payout ratios in the short-term, it is incorrect to assume that level of earnings retention will last indefinitely.[34]

36. The forecasted nominal GDP growth (used by the Company in its multistage model) is appropriate in the multi-stage DCF model. The use of long-term nominal GDP growth is well accepted by experts and regulators in determining the ROE for regulated utilities. Utility commissions in Alabama, Arizona, Illinois, Missouri, Montana, New York, Pennsylvania, Washington, and the Federal Energy Regulatory Commission have all considered or relied on growth in GDP in their

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[28] *Id.* at p. 17.
[29] *Id.* at p. 17.
[30] *Id.* at pp. 20-21.
[31] *Id.* at p. 20.
[32] *Id.* at 23
[33] *Id.* at 20-21.
[34] Coyne Surrebuttal at p. 9.

evaluations of the cost of equity.[35] As stated by the Pennsylvania Public Utility Commission:

> We can think of no other industry that is more closely and inexorably linked to the long-term growth of our economy, and therefore GDP, as is the electric utility industry.[36]

37. Flotation costs for stock issuances are the costs of issuing stock, which include underwriter discounts and out-of-pocket costs. These costs are actual costs, and decrease the amount of capital the Company received from issuing equity. Flotation costs are a part of a utility's cost of capital, and are appropriately recovered in rates. The 10.65 percent ROE includes the Company's flotation costs.

38. The recovery of flotation costs does not require a stock issuance in the test year because flotation costs are not fully recovered in the year of issuance, but rather are recovered over the long term, similar to the costs of issuing debt.[37] As a result, flotation costs should be recovered even if there is no debt or stock issuance in the test year. The Company's large investment plan will necessitate additional share issuances in the future.[38]

39. The Company's calculation of flotation costs was based on the Company's historical costs for the Company's public issuances. Mr. Copeland argued that no flotation costs should be recovered and also argued that the lower costs of non-public issuances should be reflected in the Company's flotation costs. Including the costs of non-public issuances would reduce the flotation cost by 0.11 percent (from 0.25 percent to 0.14 percent).[39] Basing the Company's flotation costs on its historical costs for public issuances is appropriate because the Company will require public issuances to finance its investment plans.

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[35] *Id.* at p. 8.
[36] *Pennsylvania Public Utility Com'n v. West Penn Power Co. et al.*, Docket Nos. R-00942986, *et al.*, 1994 WL 932287 (Pennsylvania P.U.C., December 29, 1994).
[37] Dane Direct at pp. 21-23.
[38] *Id.* at p. 23.
[39] Coyne Rebuttal at p. 26.

40. The appropriate ROE includes flotation costs, and the proposed 10.65 ROE includes flotation costs.

41. Policy initiatives by the Federal Reserve since September, 2008 have led to the continuation of artificially low interest rates. In addition, many investors have left the equity market for the security of Treasuries. As a result, there is far less current demand for stocks (because investors are averse to risk) and far more current demand for Treasuries than is typical over time. The result is that the lower demand for equities and the higher demand for Treasuries has increased the current spread between equities and Treasuries beyond historic average spread between equities and Treasuries.[40]

42. Mr. Copeland argued that effective regulation would lead to a market to book ratio of just over 1 over long periods of time.[41] However, regulation of electric utilities across the U.S. has not led to the market-to-book ratios of just over 1.0 over long periods of time. Since the year 2000, the companies in the comparable group had an average market-to-book ratio of approximately 1.47, and the broader electric utility group averaged approximately 1.57. For the market as a whole (as indicated by the companies in the S&P 500 index), the current 30-day average market-to-book ratio as of March 31, 2012 is 2.25. The only time that market-to-book ratios were close to 1.0 was during the financial crisis of 2009.[42]

43. Investors would not invest in utility stocks if they believed that utility commissions would set rates in an effort to move the market-to-book ratio to 1.0 or just over 1.0. Ratemaking policy designed to cause a decrease in the market–to-book ratio would impede a utility's ability to attract the capital required to support its operations, and conflicts with ratemaking capital attraction standards.[43]

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[40] Dane Direct at p. 8; Coyne Rebuttal at p. 32.
[41] Copeland Rebuttal at pp. 8-9.
[42] Coyne Surrebuttal at p. 6-7.
[43] *Id.* at p. 7.

44. The cost of equity of the Company's parent (Xcel Energy Inc. or "XEI") is the result of a number of investments it has made in utilities in other states and through other operating companies. The risks of those investments may be higher or lower than the Company's South Dakota operations. Further, a parent company may invest in a range of regulated and non-regulated businesses that impact its cost of capital, as XEI has done in the past. The cost of providing electric service in South Dakota is separate from those risks. As a result, the Commission focuses on the cost of equity for the Company's South Dakota operations.[44]

45. The Company's proposed capital structure is based on a 13-month average capital structure, ending December 31, 2011. The Company's method is appropriate because it matches the capital structure to the Company's rate base, which was similarly based on a 13-month average.[45] Staff witness Mr. Copeland recommended using a year-end 2010 capital structure and a 13-month average rate base. This approach is inappropriate because it involves a mismatch between the capital structure and the rate base. This mismatch is inappropriate because the capital structure provides the funding that results in the rate.[46] The Company's 8.52 percent overall ROR, incorporating the proposed 10.65 percent ROE, reflects a 13-month average capital structure and a 6.13 percent cost of long-term debt.[47]

46. Mr. Coyne's rebuttal testimony explains the negative impact on earnings caused by a combination of: (i) substantial new annual investments; (ii) historic test years and the resulting regulatory lag; and (iii) prior low authorized returns.[48] The harm from an ROE that is not reasonably comparable (and is therefore insufficient to attract capital) would be compounded by the very substantial investments being made

[44] *Id.* at pp. 10-11.
[45] Coyne Rebuttal at p. 42.
[46] *Id.* at p. 22.
[47] *Id.* at p. 5.
[48] *Id.* at pp. 7-10.

by the Company.[49]

47. The Company's cost of long-term debt of 6.13 percent is appropriate. There is no remaining dispute regarding the Company's cost of long-term debt.[50]

48. The Company's capital structure and cost of capital is as follows:

**Overall Cost of Capital for Xcel Energy**

| | Percent | Cost Rate | Weighted Cost |
|---|---|---|---|
| Common Equity | 52.90% | 10.65% | 5.63% |
| Long-term debt | 47.10% | 6.13% | 2.89% |
| Total Capitalization | 100.00% | | 8.52% |

**<u>Nobles Wind Plant Cost Recovery</u>**

49. The Nobles wind project is a 201 MW project located in nobles County, Minnesota, and consists of 134 1.5 MW wind turbines. Nobles became operational in December 2010.[51]

50. The Company conducts its resource planning on a system wide basis. It does not select resources to meet individual jurisdictional needs. The Company believes that using an integrated system provides all of its customers with significant benefits. In particular, the Company explained that its integrated system allows it to: reduce the total amount of generating resources used to reliably serve customers; diversify the fleet of generating resources required to meet customer needs, lowering costs and risks; and lowers costs by spreading costs over a substantially larger customer base.[52]

51. Based on its resource planning process, the Company determined that there was a system need for additional wind generation. As a result, the Company

[49] McCarten Direct at p. 5.
[50] Copeland Rebuttal at p. 30.
[51] McCarten Direct at p. 6.
[52] Alders Rebuttal at p. 4.

initiated a competitive bidding process in 2007. The Nobles wind project was selected pursuant to this process during which the Company evaluated 30 proposals submitted in response to a request for proposal ("RFP") for up to 500 MW of wind energy generation.[53]

52. Before proceeding with the project, the Company conducted two Strategist modelings and determined that: "In the case of Nobles, we were able to add a generating resource that will lower the production cost of electricity and comply with the policies set by all of the States in which we provide service."[54]

53. Commission Staff questioned the correctness of allowing full cost recovery for Nobles. Ms. Kavita Maini, on behalf of Staff, argued that Nobles was selected to meet Minnesota resource requirements and was not needed to serve South Dakota customers. She further stated that the costs of Nobles exceeded the value of its benefits. She also disputed the Company's use of $17 per ton for carbon regulation costs in its Strategist modeling, and advocated using $4 per ton in the absence of specific legislation establishing a different cost. Finally, because the actual cost of bringing Nobles on line was greater than the Company estimated in an earlier Minnesota proceeding, she advocated disallowing the incremental actual investment costs. In combination, Ms. Maini recommended disallowing 30 percent of the Company's requested cost recovery, or $612,000.[55]

54. The Company testified that Nobles was not selected just because of Minnesota requirements and that it does not consider the South Dakota goal of serving 10 percent of the retail load using renewable resources with wind as either a floor or as a ceiling.[56] The Company's position is that if the wind generation is cost effective it should be allowed to recover its costs. The Commission agrees. In

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[53] McCarten Direct at p. 7.
[54] Alders Rebuttal at p. 10.
[55] Maini Direct at pp. 13-19.
[56] Alders Rebuttal at p. 10.

addition, the benefits to South Dakota of participating in the Company's integrated system significantly lowers the cost of service to South Dakota. The Commission has approved cost recovery based on allocations of system costs in each of the Company's prior rate cases.

55. In response to the assertion that Nobles costs more than the value of its benefits, the Company provided a number of responses. First, it cautioned against using the results of any single Strategist Model to determine the least cost alternative. Any modeling will necessarily depend on assumptions about the cost of alternatives including the cost of replacement energy over a 25 year period, where the change in one or more assumptions could change a least cost determination.[57] Second, the Company explained that it conducted three different cost/benefit analysis. Under the most conservative, worst case analysis relied upon by Ms. Maini, cost were competitive with the no build alternative, and under the other two analyses Nobles' benefits exceeded its costs.

56. The particular Strategist model relied upon by Ms. Maini, relied on conservative modeling filed in a Minnesota Commission proceeding. In that proceeding, the modeling was consistent with Minnesota renewable resource goals of serving up to 30 percent of Minnesota retail sales with renewable resources. Under that analysis, rather than look at Nobles as a standalone wind project, the Company modeled Nobles as if 2000 MW of additional wind generation had already been added and that the addition of 200 MW from Nobles would bring the total to 2200 MW need to need all State renewable obligations and objectives. Under that worst case scenario, Nobles was not strictly least cost, but it was cost effective (within 0.11 percent on a system basis) even before consideration of additional $600,000 in benefits from the bonus tax depreciation tax change.[58]

57. The Company's second Strategist analysis treated Nobles on a

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[57] *Id.* at p. 14.
[58] *Id.* at pp. 14-17.

standalone basis, where Nobles was the next wind generation unit added. Under that analysis, the benefits of Nobles (using $17 per ton carbon regulation) was the least cost, exceed costs by $80 million.[59]

58. The Company also compared the cost of Nobles against the cost of obtaining replacement energy from the MISO market. Wind provides little capacity, therefore, the MISO energy market comparison was a valid basis for comparison. The Company's comparison demonstrated that obtaining an equivalent amount of energy from the MISO market would have been $3.05/MWh more expensive.[60]

59. With respect to the issue of the appropriate level of regulatory cost of carbon to include in the modeling, it is not possible to determine the actual future cost of such regulation. That does not, however, justify ignoring an important and likely future cost. To ignore those future costs would result in resource decisions that adversely affect future ratepayers.

60. The Company picked $17 per ton based on two considerations. First, $17 per ton was the middle of the range developed in a Minnesota proceeding based on supporting testimony of expert witnesses.[61] Second, at the time the modeling was done there was legislation pending in Congress to establish a regulatory cost for carbon and $17 per ton represented a conservative mid-range value.[62] Ms. Maini's proposal to use $4 per ton fails to adequately reflect these potential future costs.

61. In her Rebuttal Testimony, Ms. Maini asserts that the Company should have supplemented its Strategist modeling with a chronological hourly production cost model to validate energy savings. The Company responded to this criticism by first explaining that production cost modeling is not appropriate for making long-term resource selection decisions. It further explained that the Company has incorporated

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[59] *Id.* at p. 16.
[60] Alders Rebuttal at p. 18; Alders Surrebuttal at p. 9.
[61] Alders Rebuttal at p. 19
[62] *Id.* at p. 20.

production costs into its Strategist modeling. In addition, the Company's Strategist model is also an hourly model.[63]

62. In her Rebuttal Testimony, Ms. Maini criticized the Company's use of forecasted MISO energy costs in its third analysis, stating that actual costs would be more accurate. However, the Company explained that a forward looking cost benefit analysis over a 25 year period must necessarily rely on forecasted costs.[64]

63. Ms. Maini also stated that the benefits from Nobles may have been overstated because the actual capacity factor for Nobles in 2011 was less than the projected 40 percent used in the Company's modeling. The Company responded by explaining that the lower capacity factor in 2011 was caused by transformer issues that have been resolved, and by MISO curtailing the output (lowering the capacity factor by 2 %). The Company does not believe either issue is indicative of future capacity factors.[65]

64. Ms. Maini argues that 30 percent of the cost of the Nobles project allocated to South Dakota customers should be recovered from Minnesota customers because Nobles was built to serve Minnesota customers under Minnesota policy. The Company answered by pointing out that the benefits associated with 30 percent of the costs should follow the cost recovery. Under that assumption, the benefits allocated to those states fully participating in Nobles cost recovery would exceed the costs. This further demonstrates that Nobles is a cost effective project.[66]

65. The Company's reliance on its studies for Nobles was reasonable and prudent. The Company's models considered Nobles both as the next resource added as if 2000 MW were already on the system, and on a "standalone basis." The Company's Strategist modeling evaluated Nobles as a resource under a variety of

[63] Alders Surrebuttal at pp. 4-6
[64] *Id.* at pp. 7.
[65] *Id.* at pp. 8.
[66] *Id* at pp. 11-12.

scenarios over a 25 year period. The Company included production costs in its Strategist modeling.[67] These models showed that Nobles is a cost effective resource.[68] The Commission concludes that there is adequate evidence that the benefits of Nobles exceed its costs.

66. In addition, the standard for testing cost recovery provided in Section 49-34A-8.4 is whether the expenditure was "efficient, and economical." That standard provides the Company with the necessary latitude to pick alternatives that are best for the overall system, not just the least-cost alternative. The facts demonstrate that the Company's selection of Nobles satisfies the "efficient and economical" component of that standard. Nobles is a system resource, and cost analysis should consider Nobles as a part of the Company's integrated system. Since the Company's South Dakota customers derive significant benefits from being customers of an integrated system, they should share in the costs of the integrated system.

67. Ms. Maini proposed that Nobles' cost recovery be limited to the Company's estimated cost presented to the Minnesota Commission in a proceeding that determined eligibility for cost recovery through a Minnesota special rate rider. Ms. Maini provided no evidence that the Company's actual incremental costs were not prudently incurred. The Company explained that these were necessary additional costs in addition to the costs of the developer that would have been incurred under any alternative project, including a power purchase agreement.[69]

68. The Commission will allow recovery of the Company's actual prudent costs. Cost recovery is determined based on the cost of service, and not based on cost estimates. Just as the Company must pass on any savings when a project comes on line below its estimated cost, the Company is entitled to recover its prudent costs

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[67] Alders Surrebuttal at p. 6.
[68] *Id.*
[69] *Id.* at pp. 12-13.

when actual costs exceed the preconstruction estimate.

69. The Company's full $2.039 million investment in Nobles[70] satisfies the standard established in Section 49-34A-8.4 for cost recovery of investment costs as "prudent, efficient, and economical, and are reasonable and necessary to provide service." Therefore, full cost recovery is approved.

**Conclusions**

1. Based the evidence in this case and the Commission's precedent for ratemaking, the Company's ROE of 10.65 percent, proposed 6.13 percent cost of long term debt and 13-month average capital structure, are reasonable and will be approved. These components lead to an overall ROR of 8.52 percent.

2. The evidence in this case and the ratemaking principles that guide the Commission in setting rates justify allowing full cost recovery for Nobles investment costs. Nobles provides cost-effective energy to the integrated system and South Dakota benefits from both Nobles and from participation in the Company's integrated system. The Commission finds that the Company's investment costs for Nobles were prudent, efficient, and economical, and are reasonable and necessary to provide service; and cost recovery will be approved.

Respectfully submitted,

By: /s/

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[70] Alders Rebuttal at p. 21.