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TESTIMONY
JAMES A HEIDELL

STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

NORTHERN STATES POWER COMPANY

CASE NO. PU-21-152

ADVANCE DETERMINATION OF PRUDENCE – 460 MW SHERCO SOLAR FACILITY

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1 **I. Introduction**

2 **Q. Would you please state your name, affiliation, and address?**

3 **A.** My name is James A. Heidell and I work as a Director for PA Consulting Group, Inc.
4 (PA). My business address is 1700 Lincoln Street, Suite 3550, Denver, CO 80203.

5
6 **Q. On whose behalf are you filing this testimony?**

7 **A.** I am filing this testimony on behalf of the Advocacy Staff of the North Dakota Public
8 Service Commission (Commission or NDPSC).

9
10 **Q. Please summarize your qualifications and experience.**

11 **A.** I have worked in the energy industry for the past 40 years, primarily specializing in
12 electricity and utilities. I have worked on issues related to resource planning, rates,
13 analysis of electricity markets, and analysis of the economics of financial transactions for
14 utilities and wholesale generation owners. My academic background includes a BSE in
15 civil engineering from Tufts University, a MS in engineering economics from Stanford
16 University, and an MBA in finance from the University of Washington. I am a CFA
17 Charterholder. My CV is provided in Exhibit JAH-1.

18
19 **Q. Have you testified before the North Dakota Public Service Commission previously?**

20 **A.** Yes, I have submitted testimony on behalf of Advocacy Staff in numerous dockets
21 including the following:

- 22 • Northern States Power Company's request for an ADP for the Heartland Divide II
23 Wind Project (Case Number PU-20-433);
- 24 • Montana-Dakota Utilities' 2020 Natural Gas Rate Increase Application (Case
25 Number PU-20-379);
- 26 • Montana-Dakota Utilities' request for an ADP and Certificate of Public
27 Convenience and Necessity for an 88 MW Simple Cycle Combustion Turbine
28 (CT) (Case Number PU-19-307);

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- 1 • Northern States Power Company’s request for an ADP for the Dakota Range III
- 2 Wind Facility (Case Number PU-18-430);
- 3 • Northern States Power Company’s request for an ADP for the Dakota Range
- 4 Wind Project (Case Number PU-17-372);
- 5 • Northern States Power Company’s request for an ADP for 1,550 MW of Wind
- 6 (Case Number PU-17-120);
- 7 • Otter Tail Power Company’s Request for an ADP for the Astoria CT and
- 8 Merricourt Wind Project (Case Nos. PU-17-140, PU-17-141, and PU-17-143);
- 9 • Advance Prudence – Biomass Application for deferred accounting Northern
- 10 States Power Company (Case Nos. PU-17-270, PU-17-271, and PU-17-322); and
- 11 • Northern States Power Company Resource Treatment Framework (Case Nos. PU-
- 12 12-813 et al.).

13
14 **Q. What is the purpose of your testimony?**

15 A. The purpose of my testimony is to provide the Commission with my assessment of the
16 Northern States Power Company’s (NSP or Company) Application for an Advanced
17 Determination of Prudence (the Application) for the 460 MW grid-scale solar
18 photovoltaic (PV) facility at the Company’s Sherburne County (Sherco) Generation
19 Station site (Sherco Solar, or the Project). The Project consists of two distinct large solar
20 facilities in Becker, Minnesota adjacent to the existing Sherco coal plant. This Advanced
21 Determination of Prudence (ADP) request is unique in that the Company is not asking the
22 Commission for an ADP of the solar project, but rather to approve a proxy pricing
23 scheme developed by NSP. According to the Company, its proposed proxy pricing will
24 result in a lower cost to North Dakota ratepayers than obtaining an equivalent amount of
25 energy and accredited Midcontinent Independent System Operator (MISO) capacity. NSP
26 contends the Project is the least cost option when incorporating Minnesota’s assumptions
27 related to the social cost of carbon; however, when the social cost of carbon is not
28 included the analysis, per the requirements of North Dakota, the lowest cost capacity
29 resource is a CT.

1
2 The Company indicates that its 2020-2040 Upper Midwest Resource Plan Supplement
3 (IRP) identified the need for new capacity in 2026 due in part by the need to replace the
4 capacity from the Sherco Unit 2 coal plant scheduled for retirement in 2023.¹ The IRP's
5 Preferred Plan, based upon Minnesota planning criteria, identified a solar resource as the
6 most cost-effective resource; however, the IRP's North Dakota Scenario – the “North
7 Dakota Plan” – identifies a 374 MW CT in 2025 as the most cost-effective resource.^{2 3}
8

9 **II. Organization of the Testimony**

10 **Q. Would you please summarize the organization of your testimony?**

11 A. Yes. I start with presenting my recommendations and findings followed by a detailed
12 discussion of my supporting analysis and additional factors considered. Finally, I propose
13 conditions for the Commission to consider imposing if it approves the Company's request
14 for a proxy pricing treatment. My testimony is separated into eleven sections:

- 15 • A summary of my recommendations (Section III);
- 16 • A summary of my findings (Section IV);
- 17 • An overview of the Project (Section V);
- 18 • An overview of the requested proxy pricing treatment (Section VI);
- 19 • An assessment of the need for additional capacity (Section VII);
- 20 • An evaluation of the economics of the Project (Section VIII);
- 21 • An evaluation of the economics of the proxy pricing (Section IX);
- 22 • Consideration of additional issues (Section X), and
- 23 • My conclusions and recommendations (Section XI)

24
25 **Q. Are you sponsoring any exhibits to your testimony?**

¹ Application Page 1.

² Upper Midwest Integrated Resource Plan 2020 -2034 Supplement, Northern States Power Company,
Docket No. E0002/RP-19-368

³ The Preferred Plan identifies 500 MW of new solar on-line in 2025 (3-2)

1 A. Yes, I am sponsoring two exhibits:

- 2 • Exhibit JAH-1: James Heidell CV; and
- 3 • Exhibit JAH-2: Forecast of Net Energy Margins from a CT.

4 **III. Summary of Recommendations**

5 **Q. Do you recommend the Commission approve the Company's request for approving**
6 **proxy pricing in place of the Project?**

7 A. No, I recommend disapproval of the ADP with regard to either the Company's request
8 for proxy pricing, or for acquiring the Sherco Solar project in lieu of proxy pricing.

9
10 **Q. If the Commission were to approve the Company's request for approving proxy**
11 **pricing, are you recommending modifications?**

12 A. Yes, as conditions to any Commission approval of proxy pricing, I recommend that the
13 Commission:

- 14 • Set the proxy cost of capacity equal to the cost of a brownfield CT assumption as
15 defined in the most recent Supplemental IRP;
- 16 • Adjust the proxy capacity cost to reflect an offset for the expected energy market
17 margins the brownfield CT would earn in the MISO energy markets.
- 18 • If the Commission accepts NSP's recommendation to base capacity cost on the
19 MISO Cost of New Entry (CONE), the MISO CONE should be adjusted
20 downward to reflect the gross margins that the CT would earn in the energy and
21 ancillary services market as those margins would be credited to customers (Net-
22 CONE).
- 23 • Clarify that ND customers will only pay for the actual accredited capacity that is
24 relevant to the Project as determined by the MISO and adjust ND customers'
25 share based upon the prevailing cost allocation factors;
- 26 • Explicitly exclude ND customers from any future renewable integration costs
27 assigned to the Project by MISO;
- 28 • Require periodic review of the commitment for ND customers to pay a load-based
29 share of the energy from the Project at MISO rates; and

- Establish that the approval is non-precedential.

IV. Summary of Findings

Q. Would you please provide a summary of the findings you believe the Commission should consider as it determines whether to approve NSP's Application for an ADP?

A. My conclusion is that the Company is offering a false choice to the Commission. The Commission is not being offered the choice of selecting between the Project or a CT; NSP's intention is to add 460 MW of solar to its resource portfolio, regardless of the Commission's ADP decision. NSP anticipates the Commission will reject sharing in the cost of the Project but is nonetheless requesting the Commission resolve the accounting for a disputed resource through a potentially precedent setting ADP decision. While it is the prerogative of the Commission to establish the accounting in conjunction with rejecting an ADP, I am not aware of instances in prior ADP requests where this Commission has ordered an accounting treatment for a disputed resource.

Q. If the Commission concurs with your recommendation to reject the ADP for the Project, why should the Commission also reject the proxy pricing proposal?

A. My understanding is that this Commission's precedent is that if it rejects an ADP for a company-owned renewable resource, that those costs should not be recovered through the Renewable Energy Rider and capacity cost recovery is explicitly excluded in the Fuel Cost Rider.

Q. Do you have additional specific findings?

A. Based upon my review and analysis of the testimony filed in the Application, the exhibits contained within the Application, and the information produced in discovery, I find the following relevant in determining whether to approve the ADP for the Project and/or the proposed proxy pricing:

- If the Commission approves a proxy pricing mechanism, it should require NSP to modify its proposed methodology.

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- 1 ○ The basis for the proxy price should be the cost of the combustion turbine less
- 2 the energy and ancillary margins (Net CONE).
- 3 ○ The Company should allocate North Dakota's share of capacity costs based
- 4 upon the Project's accredited capacity in each year and that year's prevailing
- 5 inter-jurisdictional capacity allocation factor.
- 6 ○ North Dakota customers should not be allocated a share of the transmission
- 7 costs used to connect the two solar facilities to the existing substation.

- 8
- 9 • NSP's need for additional capacity is based upon its load forecast, the end of the
- 10 Manitoba Hydro contract, and decision to retire the Sherco coal units early.
- 11 However, absent the Company's decision to retire the Sherco coal units early, the
- 12 need for the capacity would be delayed for years;
- 13 • NSP does not have a retail load need in this decade for the energy the Project will
- 14 generate;
- 15 • There is no benefit to North Dakota customers associated with a long-term
- 16 commitment to purchase electricity at volumes tied to the Project's output and costs
- 17 based on MISO market pricing. The Company can purchase power for ND customers
- 18 from MISO at the prevailing market price without any long-term contractual
- 19 commitment.
- 20

21 **V. Overview of the Project**

22

23 **Q. Would you please provide an overview of the Company's plan to construct Sherco**

24 **Solar?**

25 **A.** The Company plans to build 460 MW of solar adjacent to the existing Sherco coal plant.

26 The Project consists of: (1) a 230 MW solar project under development by National Grid

27 Renewables located to the west of the coal plant (National Grid project) and (2) a 230

28 MW solar project being developed by NSP on the east side of the coal plant (NSP

29 project). The Company will also build two short high-voltage transmission lines to

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1 connect the projects to the existing Sherco substation. The west block will be on land
2 leased by National Grid and the east block is on land leased by Xcel. The Company
3 plans to acquire the National Grid project through a build-own-transfer arrangement. The
4 anticipated COD for the Project's full capacity is projected to occur in the fourth quarter
5 of 2024 with an estimated cost of \$622M (\$586M without AFUDC).⁴
6

7 **Q. Will NSP have to build new transmission facilities to connect the Project?**

8 A. Yes, the Company will need to make a relatively small investment to interconnect each of
9 the Project's two solar facilities to the Sherco substation.⁵ Contingent upon NSP
10 interconnecting alternative generation within three years of the date that Sherco Unit 2
11 ceases operation, however, MISO rules permit NSP to retain Sherco's existing
12 transmission interconnection rights.⁶
13

14 **Q. What is the Company's estimate of Project cost?**

15 A. The Company estimates total cost including AFUDC will be [Trade Secret Begins] [REDACTED]
16 [REDACTED] [Trade Secret Ends]. Based upon Company modeling, this
17 translates to [Trade Secret Begins] [REDACTED] [Trade Secret Ends]. The Company
18 expects that based upon current rules, the Project will also qualify for an Investment Tax
19 Credit (ITC) of [Trade Secret Begins] [REDACTED] [Trade Secret Ends].
20

21 **Q. Does the Company's capital cost estimate include transmission costs?**

22 A. Yes, the estimate includes [Trade Secret Begins] [REDACTED] [Trade Secret Ends]
23 excluding AFUDC. The cost is for two short connection lines and interconnection to the
24 existing substation.
25

26 **Q. Is the Company requesting that the NDPSC approve the Project?**

27 A. No. The Company is *not* asking the Commission to approve the Project because its

⁴ NSP Public response to IR No. 2, E002/M-20-891.

⁵ Direct Testimony of Chamberlain p 12 line 20.

⁶ MISO Tariff, Attachment X, Section 3.7.1.

1 analysis does not identify the Project as the least cost capacity resource addition when the
2 analysis excludes an assumed social cost of carbon.⁷ The Company is instead asking the
3 Commission to “institute a cost assignment methodology”⁸ that permanently approves a
4 specific proxy pricing methodology for valuing the energy and accredited capacity
5 associated with the Project.
6
7

8 **VI. Summary of the Proxy Pricing Proposal**
9

10 **Q. Would you please provide an overview of NSP’s proposal for assigning North
11 Dakota a share of the energy and capacity from the Project using proxy pricing?**

12 **A.** Yes, the Company is proposing that North Dakota’s pro rata share of the MISO
13 accredited capacity from the Project be based upon the cost of a CT as defined by MISO
14 in its published CONE as of 2023/24.⁹ North Dakota’s pro rata share of the energy cost
15 would be recovered through the Fuel Cost Rider (FCR) based upon the hourly nodal price
16 that the resource is paid by MISO.
17

18 **Q. Is there a North Dakota precedent for the Company’s proposal for allocating the
19 energy cost of the Project?**

20 **A.** No, not that I am aware of. I note that there is precedent for the Company recovering
21 disallowed PPAs. As I discuss below, there is precedent for using proxy pricing to
22 recover an equivalent amount of energy from disallowed PPAs in the FCR. In this
23 instance the Project is not a PPA, and the Company is proposing to recover capacity costs
24 through the FCR.
25

⁷ The assumed social cost of carbon is established by the PUC in Minnesota Public Utilities Commission’s Order Updating Environmental Cost Values in Docket No. E999/CI-14-643 issued January 3, 2018

⁸ Direct Testimony of Chamberlain p 15 line 18.

⁹ The Company uses the MISO CONE cost as of 2020/21 in this filing, but the proposal is to use the 2023/24 cost when that is determined.

1 **Q. Is the Company's proposal similar to the approach the Commission has addressed**
2 **prior disputed resources?**

3 A. With respect to the energy costs, the Company's proposal is similar to – but not exactly
4 the same as – the approach that has been used for the treatment of the Minnesota
5 Community Solar Gardens disputed resources in the FCR. While I am not aware of the
6 Commission explicitly approving the approach for those disputed resources, it has been
7 the practice for years. The Company's proposal is different in that the Community Solar
8 Gardens disputed resources are priced at MISO average costs for the month but not tied
9 to the disputed resource's nodal price.

10
11 **Q. Is there a North Dakota precedent for the Company's proposal for allocating the**
12 **capacity cost of the Project in the FCR?**

13 A. No, not that I am aware of. However, I note that a reading of the FCR explicitly includes
14 PPAs and explicitly excludes recovery of capacity costs.

15 **QUALIFYING SYSTEM COST OF FUEL**

16 The qualifying system cost of fuel includes:

17 1. The cost of fuels consumed in the Company's generating stations as recorded in Federal Energy
18 Regulatory Commission (FERC) Accounts 151 and 518;

19 2. The cost of energy purchases, exclusive of capacity or demand charges, as recorded in FERC
20 Account 555 including but not limited to:

21 a) Energy that is purchased on an economic dispatch basis;

22 b) Energy purchased from a renewable energy source with the exception of the Purchased
23 Power Agreement (PPA) Cost Exclusion defined below. The energy that would have been
24 provided to North Dakota customers from these excluded PPAs will be repriced at the
25 Qualifying System Cost of Fuel absent these contracts;

26 [Tariff Section 5 5th Revision Sheet No. 76]
27

28 **Q. Is there a North Dakota precedent for the Company's proposal for allocating the**
29 **capacity cost of the Project in the Renewable Energy Rider (RER)?**

30 A. No, not that I am aware of. My understanding is that the RER is used for approved
31 Company-owned renewable resources that are not included in rates. I am not aware of a
32 precedent for using proxy pricing in the RER for disallowed Company-owned resources.
33

34 **Q. Does the Company's proposal for proxy pricing in the RTF Proceeding create a**
35 **precedent for the Company's current proposal?**

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1 A. No. Mr. Chamberlin notes the Company's current proposal is consistent with its proposal
2 for proxy pricing in the RTF filing;¹⁰ however, neither Advocacy Staff nor the
3 Commission accepted the Company's proposal. Furthermore, Advocacy Staff highlighted
4 numerous concerns with the Company's RTF filing.

5
6 **Q. If the Commission approves including capacity cost recovery in either the RER, or
7 FCR, is basing the proxy cost for capacity based upon a CT reasonable?**

8 A. Yes, if the Commission is considering a mechanism for proxy capacity pricing where
9 there is a legitimate demonstration of need for additional capacity resources but not
10 additional energy resources. The Company uses the CT as its firm dispatchable peaking
11 resource in its EnCompass modeling for its IRP. As the CT would be the alternative
12 capacity resource, it is a reasonable proxy for the cost of acquiring additional capacity.

13
14 **Q. How does the Company propose to estimate the proxy capacity cost based upon a
15 CT?**

16 A. The Company is proposing to use the CONE, as defined by MISO in the 2024-2025
17 planning year. The Company considered four options for the proxy cost of capacity:
18

- 19 • MISO CONE;
- 20 • A generic brownfield CT;
- 21 • The Mankato Energy Center II PPA (MEC II PPA); and
- 22 • Estimated cost of maintaining the Sherco II coal plant and keeping it in service
23 through 2024 and then constructing a CT.

24 The Company concluded that MISO CONE is the best option.

25 **Q. Do you agree with the Company's recommendation?**

26 A. No. If the Commission allows the use of a proxy, my recommendation is that the
27 Company use the brownfield CT cost, as estimated in the Supplemental IRP.

¹⁰ Direct testimony of Mr. Chamberlin p 19, lines 25 – 26.

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Q. How does MISO determine the CONE?

A. MISO bases its estimate for a CT on an estimate from the U.S. Department of Energy’s (DOE) Energy Information Administration (EIA) as part of its annual long-term Annual Energy Outlook. MISO then scales the cost for each Local Resource Zone (LRZ) using a regional factor. The MISO tariff states:

[C]onsider factors, including, but not limited to: (1) physical factors (such as, the type of Generation Resource that could reasonably be constructed to provide Planning Resources, costs associated with locating the Generation Resource within the Transmission Provider Region, the estimated costs of fuel for the Generation Resource); (2) financial factors (such as, the hypothetical debt/equity ratio for the Generation Resource, the cost of capital, a reasonable return on equity, applicable taxes, interest, insurance); and (3) other costs (such as, costs related to permitting, environmental compliance, operating and maintenance expenses). In calculating the CONE, the Transmission Provider and the IMM shall not consider the anticipated net revenue from the sale of capacity, Energy or Ancillary Services. CONE values will be calculated for each LRZ.¹¹

Q. What are some of the issues with using the MISO estimate of CONE costs?

A. There are a number of issues with using the MISO cost estimate as the proxy cost for North Dakota. These issues include:

- The EIA cost estimate is based upon a November 2016 study using April 2016 data. Ignoring inflation, it does not necessarily reflect current costs;¹²

¹¹ MISO FERC Electric Tariff, 69.A.8, Calculation of CONE, 33.0.0 Tariff (misoenergy.org)

¹² https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf

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- 1 • The regional adjustment factors used by MISO refer to the EIA adjustment factors
- 2 from the November 2016 study;
- 3 • MISO bases CONE on a greenfield project; however, NSP has not demonstrated
- 4 why a brownfield project is not a reasonable capacity proxy;
- 5 • In the past the Company has identified the Sherco site as a brownfield site for a
- 6 combined cycle and NSP has identified multiple other sites as a possibility for a
- 7 brownfield CT;
- 8 • The estimate uses a hypothetical capital structure and not NSP's capital structure,
- 9 and
- 10 • The estimate excludes the MISO energy and ancillary service margins that North
- 11 Dakota customers would have otherwise received if the CT were constructed.

12
13 **Q. What capital structure is incorporated into the MISO CONE analysis?**

14 A. MISO's CONE analysis uses the following assumptions regarding capital structure: a
15 55/45 debt to equity ratio; a 20-year project life and loan term; a 6.20 % debt interest rate;
16 and a 13.4% after tax internal rate of return on equity.¹³ This results in a weighted
17 average cost of capital (WACC) of 8.52%.

18
19 **Q. What WACC does the Company assume in its analysis of options in the IRP?**

20 A. The Company uses a 6.47% WACC.¹⁴ My recommendation is that the levelization of the
21 CT cost use the Company's currently approved WACC.

22
23 **Q. How did the Company determine the capital cost of the brownfield CT?**

24 A. The Company based the brownfield CT capital costs on the assumptions for an advanced
25 7H turbine in the IRP. The brownfield CT has a capital cost of \$467/kW (\$2018)
26 compared to \$517/kW (\$2018) for a greenfield CT. A brownfield CT has a \$50/kW

¹³ Filing for Midcontinent Independent System Operator, Inc. Regarding Local Resource Zone CONE Calculation, Docket No. ER19-2781, p 5.

¹⁴ EO-6-10-21 – ND Plan.xlsb

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1 (2018) cost reduction compared to the greenfield CT.¹⁵ The driver of the cost differential
2 is that the greenfield CT has an interconnection cost of \$200/kW over the planning period
3 whereas a brownfield CT has none.
4

5 **Q. Is it reasonable to assume that the Company can build a CT at a brownfield site?**

6 A. Yes, the Company notes that the retirement of the Sherco coal plant will create 700 MW
7 of interconnection capacity that can be reassigned to new units at the site if a new
8 resource is constructed within three years. In its IRP, the Company identified the Sherco
9 site as a potential brownfield construction site for a combined cycle project and assumes
10 no electric transmission costs. Alternatively, the Company has identified three alternative
11 sites with interconnection rights.¹⁶
12

13 **Q. How did the Company determine the capital cost of capacity based upon the**
14 **Mankato Energy Center (MEC) II PPA?**

15 A. The Company developed the cost estimate based upon the MEC II PPA. The MEC II
16 project consisted of the installation of an additional CT at the existing combined cycle
17 facility. The Company notes; “the MEC II PPA provides a reasonable baseline for the
18 Company’s actual costs of firm dispatchable capacity.”¹⁷ The Company’s estimate for
19 MEC II costs (on a \$/kW basis) is above the Company’s estimate for a brownfield CT but
20 still below the MISO CONE cost.¹⁸ This further demonstrates that using MISO CONE as
21 a proxy capacity cost overstates the cost of incremental CT capacity developed by / for
22 NSP.
23

24 **Q. How did the Company determine the cost of capacity based upon the continued**
25 **operation of Sherco Unit 2 and switching to a CT in 2035?**

¹⁵ 2020-2034 Upper Midwest Resource Plan Supplement, p 69.

¹⁶ NSP response to Advocacy Staff 3-1 C.

¹⁷ Direct testimony of Ms. Mandich, p 9 lines 25 – 26.

¹⁸ NSP response to Advocacy Staff 2-004 Attachment B TRADE SECRET, tab “Capacity Pricing Options.”

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1 A. The Company calculated the levelized cost of Sherco Unit 2 capacity over the period of
2 2020 – 2034 incorporating the revenue requirement associated with the invested capital
3 plus the assumptions about the fixed O&M costs. The Company assumed the cost of a
4 brownfield CT starting in 2035.¹⁹

5
6 **Q. Do you agree with the Company’s recommendation to use MISO CONE as an
7 estimate for the capital cost to be used in the proxy pricing calculation?**

8 A. No, the more appropriate proxy is the brownfield CT cost identified in the Upper
9 Midwest IRP. The Company has developed a specific cost estimate in its IRP based upon
10 its expertise, and presumably the expertise of its consultants. There is no reason to
11 assume that the EJA’s national cost estimate – dating back to 2006 – is a more reasonable
12 basis. In addition, use of the Company’s cost of capital is more appropriate.

13
14 **Q. Why do you recommend use of the brownfield CT?**

15 A. The Company has identified the Sherco site as a location for a brownfield gas generation
16 project and noted the Company can use the available transmission capacity resulting from
17 the coal plant retirement without incurring additional expenses. Furthermore, the IRP cost
18 assumptions reflect the Company’s estimate of costs using the Company’s cost of capital,
19 which is lower than that assumed in the MISO’s CONE calculations.

20
21 **Q. Do you agree with the Company’s proposal to base the proxy cost on the estimated
22 cost in 2024 - 2025?**

23 A. No. My recommendation is to estimate cost at the time the resource would have been
24 constructed – not a forward-looking estimate at the time the unit will be in service. I do
25 not know whether using the current cost will ultimately be higher or lower than the
26 estimated cost in 2024 - 2025.

27

¹⁹ NSP response to Advocacy Staff 2-4.

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1 **Q. If the Company were to build a CT would it provide benefits in addition to**
 2 **capacity?**

3 A. Yes, the CT would be dispatched into the MISO market to provide energy and ancillary
 4 services. Furthermore, the CT provides a hedge against high energy costs in hours of
 5 scarcity. In addition, it can provide other grid services including frequency regulation,
 6 spinning reserves, voltage control, and potentially black start capability. The Company
 7 notes the difference in the resource attributes between a CT and solar in the following
 8 graphic.²⁰

Figure VI-1: Resource Attributes Mapped to Resource Types

		Resource Types	Firm Traditional – Baseload	Firm Traditional – Intermediate or Peaking	Variable Renewables	Fast-Burst Balancing
Resource Attributes	Response Duration & (Frequency of Need)	Examples	Coal, Nuclear, Biomass, Run-of-river, Hydro	CC, CT	Standalone Wind, Solar	DR, Standalone Battery Storage
Essential Reliability Services	Minutes – Milliseconds (Continuous)	Spinning reserve, inertial response, frequency regulation, voltage control	Nuclear Non-nuclear	●	○	◐
Flexibility	Minutes – Hours (Daily)	Ramp rate, cycling, minimum runtime	◐	◑	○	●
Energy Availability	Hourly – Multiday (Continuous)	Long duration availability, secure fuel supply	●	●	●	◐
Black Start	Minutes – Hours (Infrequent, emergency only)	Starts and runs on zero load, secure fuel supply	Nuclear Non-nuclear	◑	●	●

9
10
11 **Q. Would the CT earn positive margins in the MISO market from selling energy and**
 12 **ancillary services?**

13 A. Yes, it is reasonable to expect the Company would earn revenues from dispatching a CT
 14 into the MISO market. Those revenues would offset the cost of fuel and variable non-fuel

²⁰ 2020-2034 Upper Midwest Resource Plan Supplement, P 94, June 30, 2020.

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1 operating expenses as well as a portion of the fixed cost of owning and operating the CT.
2 The offsetting gross margins subtracted from the fixed cost is referred to as the Net
3 CONE.

4
5 **Q. Does the Company's proxy pricing proposal incorporate the concept of Net Cone?**

6 **A.** No, the Company's estimate of the brownfield CT cost does not include an offset for
7 margins in the MISO energy and ancillary services markets. As a result, the Company
8 overstates the net cost of the proxy capacity resource.

9
10 **Q. How would the energy and ancillary services margins be recognized if the Company**
11 **were to build a CT?**

12 **A.** My assumption is associated fuel cost and MISO revenues would flow through the FCR,
13 which would result in a net reduction to fuel costs needing to be recovered in rates.

14
15 **Q. If the Commission does not reject the ADP and accepts your recommendation to use**
16 **Net CONE as the proxy cost of a CT, how should the offset for energy and ancillary**
17 **services margins be calculated?**

18 **A.** My recommendation is to deduct the annual forecast of margins on a \$/kW basis from the
19 annual levelized Gross CONE.

20
21 **Q. How would the annual forecast be established?**

22 **A.** My recommendation, which would be administratively efficient, is to base the forecast on
23 PA's forecast of gross margins on a \$/kW basis.

24
25 **Q. Did you consider using the estimate of gross margins for the CT from the**
26 **Company's EnCompass Modeling?**

27 **A.** I evaluated that option and rejected it because the Company's modeling of revenues is
28 based upon the dispatch of the Company's resources and not all of the MISO resources.
29 The market price that the CT would receive in each hour of operation is based upon the

1 marginal unit dispatched in MISO to serve the MISO zone and not the marginal unit in
2 NSP's portfolio.

3
4 **Q. Have you developed the forecast of the CT gross margins based upon participation
5 in the MISO market?**

6 A Yes, it is provided in Exhibit JAH-2. I recognize that as a forecast, it would inevitably be
7 different than what would have occurred had the CT been constructed. However, I note
8 that the adjustment to the gross CONE value is relatively small – on the order of 0.1% –
9 and the alternative of monthly adjustments in the FCR would be overly burdensome.

10
11 **VII. Demonstration of Need**

12
13 **Q. Has NSP demonstrated a need for the capacity from the project?**

14 A. The Supplemental 2020-2034 Upper Midwest IRP identifies a need for 92 MW of
15 capacity in 2026, 334 MW in 2027 and growing to 1,016 MW in 2030.²¹ It should be
16 noted that a significant portion of the need for capacity is a result of the Company's
17 decision to retire Sherco Units 1 and 2 early.

18
19 **Q. In the North Dakota plan what was the in-service year for the CT?**

20 A. The North Dakota plan indicated that a 374 MW CT would be in-service no later than
21 December 31, 2025. I note that in the EnCompass run provided by NSP, the in-service
22 year is 2027 for 374 MW of capacity.²² The bulk of the accredited capacity from Sherco
23 Solar will not be needed until 2027 or two years after the expected in-service date for the
24 full capacity of the Project.

25
26 **Q. What is your understanding of the driver of the need for additional capacity?**

²¹ 2020-2034 Upper Midwest Resource Plan Supplement, p 25, June 30, 2020.
Supplemental IRP Table 2-2, p 25 of 78.

²² EO -6-10-21 – ND Pln.xlsb

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1 A. The Company's Supplemental Preferred Plan has several changes to the resource
2 portfolio besides the Project. The driver of the need for new capacity is primarily the
3 expiration of a 450 MW hydro contract with Manitoba Hydro and retirement of
4 resources, including the Sherco coal units, as opposed to load growth. For example, the
5 Preferred Plan includes the retirement of all coal generation by 2030 (i.e., 682 MW of
6 Sherco 2 at the end of 2023 and 680 MW of Sherco 1 at the end of 2026).²³

7
8 **Q. Did you independently evaluate the need for new capacity?**

9 A. No, I did not; however, I reviewed the Supplemental IRP and its assumptions and
10 concluded that the need is driven primarily by the expiration of PPAs and retirement of
11 the Sherco units.

12
13 **Q. Is there a need for an additional energy resource to meet retail load?**

14 No. The Company's analysis estimates the Project will generate [Trade Secret Begins]
15 [REDACTED] [Trade Secret Ends] MWh/year. The Company's modeling shows it has a net
16 long energy position on an annual basis through the remainder of the decade based upon
17 its Preferred Plan and excluding Sherco Solar. The Company will have net generation in
18 excess of sales on the order of [Trade Secret Begins] [REDACTED] [Trade Secret Ends]
19 in the 2025 – 2030 period.

20
21 **VIII. Evaluation of Project Economics**

22
23 **Q. Did the Company develop a forecast for of the Project's cost?**

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1 A. Yes, the Company developed a revenue requirement analysis for each of the solar fields,
2 resulting in a combined levelized cost of [Trade Secret Begins] [REDACTED] [Trade
3 Secret Ends].

4
5 **Q. Did you review the Company's cost analysis for the Project?**

6 A. Yes, I reviewed the Company's Excel models, which includes a revenue requirement
7 model and a levelized cost calculation.²⁴ The Company prepared separate models for the
8 East and West blocks of the project and a combined analysis. The Company assumes that
9 both blocks will qualify for the Production Tax Credit (PTC). The levelized cost is as of
10 2021 and assumes the West Block is on-line in 2024 and the East Block is on-line in
11 2025. Each block assumes [Trade Secret Begins] [REDACTED] [Trade Secret Ends] to
12 connect each solar field to the Sherco substation.

13
14 **Q. Did the Company develop any sensitivities around the Project cost estimate?**

15 A. Yes, the Company's estimate, as explained in testimony, reflects current tax laws and the
16 expected construction schedule. The Company also developed a scenario assuming
17 changes in tax laws that would allow the Project to choose tax credits in the form of the
18 PTC versus the ITC as well as restore the PTC to its full value, which resulted in a
19 levelized cost of [Trade Secret Begins] [REDACTED] [Trade Secret Ends] \$/MWh.²⁵

20
21 **Q. Did the Company evaluate the cost of the Project as compared to market purchases
22 of energy?**

23 A. The Company's revenue requirement model did not include that analysis; however, in a
24 separate spreadsheet model the Company compared the levelized cost of the Project with
25 the cost of purchasing an equivalent amount of capacity and energy from MISO. Because

²⁴ NSP Response to NDPSC 2-002 Trade Secret

²⁵ PU-21-152 NDPSC-3-006 Trade Secret.

1 the Project provides both energy and capacity, the Company included the cost of
2 equivalent capacity using an assumed accredited capacity rating for the Project.
3

4 **Q. How did the Company forecast the market price for electricity?**

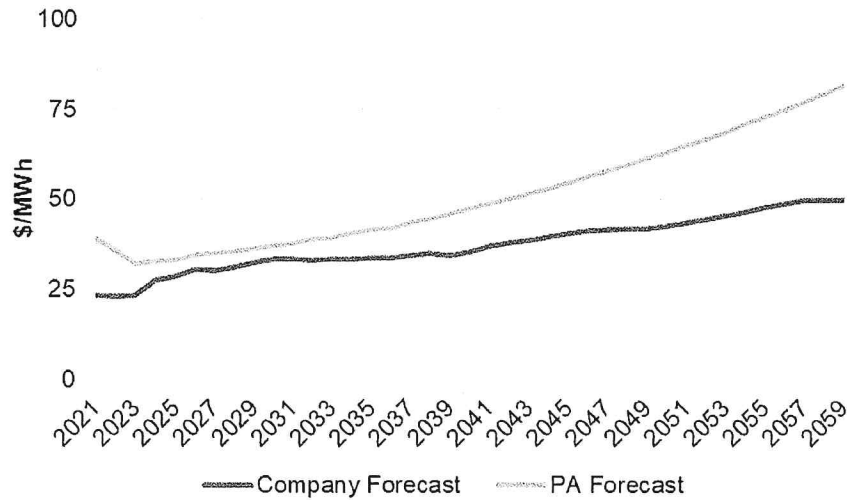
5 A. The Company applies a simple average of long-term implied heat rate forecasts from
6 various proprietary market vendors to the Company's forecast of delivered natural gas
7 prices. To derive natural gas forecast prices for Henry Hub, the Company uses the
8 NYMEX forward curve for the first few years of their forecast period, at which point it
9 transitions to an average of four price streams: the NYMEX forwards and three different
10 vendor-supplied fundamental forecasts. The Henry Hub forecast is then adjusted for
11 regional basis differentials, with the relevant natural gas hub for MISO Zone 1 being the
12 Ventura hub in Iowa. The Company updates their energy price forecast biannually; the
13 energy price forecast underlying the analysis put forth in the ADP is from the first half of
14 2021.
15

16 **Q. Is the Company's forecast of the market price of electricity reasonable and how
17 does it compare to PA Consulting's forecast?**

18 A. I compared it to PA's forecast and determined that the Company's forecast is reasonable
19 although appreciably lower than PA's forecast, particularly beyond 2030. *See* Figure 1.
20 The combination of the Company's and PA's forecast constitutes a reasonable range for
21 the long-term forecast.
22

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1 **Figure 1. PA Minnesota Hub On-Peak Forecast vs. NSP Forecast**



2
3 **Q. What accounts for the difference between the Company's and PA's forecasts?**

4 A. The main driver for the difference between the Company's forecast and PA's is likely the
5 underlying natural gas price forecast. PA uses a similar methodology to the Company in
6 that we use NYMEX forwards for the near-term; however, the PA forecast then switches
7 to PA's fundamental forecast for the remainder of the study period. The Company's
8 forecast for power prices was made in the first half of 2021. During this time, natural gas
9 prices were appreciably lower than they have been during the second half of 2021. PA's
10 proprietary fundamental forecast, on the other hand, was created in late July 2021 and
11 reflects higher underlying natural gas prices, both in the forwards market, and in the long-
12 term fundamental forecasts. The Company's forecast is not unreasonable; however,
13 because it relies on underlying natural gas prices that are materially lower than PA's, the
14 overall resulting price is lower.

15
16 **Q. Did the Company provide any alternatives scenarios around the cost of energy?**

17 A. No. In a decision to select between a fossil fuel resource (the CT), market purchases, and
18 a solar resource, the Company should have shown sensitivity of the results to alternative
19 market price forecasts and natural gas price forecasts.

1 **IX. Review of the Company's Proxy Pricing Proposal**
2

3 **Q. How did the Company evaluate the cost of the four alternative proposals for proxy**
4 **pricing?**

5 A. The Company developed a spreadsheet model for each of the four proxy costs analyzed.
6 Each case used the same assumptions for the Equivalent Load Carrying Capability
7 (ELCC) of the proxy CT, solar production profile, and market energy cost forecast. The
8 four cases vary from one another based on how the Company calculated the levelized
9 cost of proxy capacity.
10

11 **Q. How did the Company account for the equivalent MISO capacity value of the**
12 **Project?**

13 A. The Company relied upon the MISO MTEP19 Report – Appendix E.²⁶ The Company
14 developed two scenarios: (1) capacity value determined using a constant ELCC for solar
15 at the currently established 50% and (2) capacity value determined by using the currently
16 established 50% ELCC, but decreasing ELCC by two percent per year until it reaches
17 30% in 2033 and thereafter assuming the ELCC will remain at 30%.²⁷ The Company
18 confirms recovery of cost under its proxy pricing proposal should reflect the ELCC that
19 MISO attributes to the Project in each year.²⁸
20

21 **Q. Do you agree with the Company's assumption regarding the rate of decline in the**
22 **ELCC?**

23 A. I have not conducted a separate study of the likely annual ELCC of solar in MISO. After
24 reviewing the 2021 MISO Renewable Integration Assessment,²⁹ however, I caution that

²⁶ Appendix E: MTEP19 EGEAS Assumptions Document, p 28, Table 10.

²⁷ Company response to NDPSC DR 1-001_Alt A Trade Secret in Entirety.xlsx

²⁸ Company response to NDPSC DR 3-005.

²⁹ MISO's Renewable Integration Impact Assessment (RIIA) Summary Report – February 2021, Figure RA-3, p 29.

1 as utilities and merchant developers continue to build solar in MISO, its accredited ELCC
2 may decline more quickly and/or end at a lower value than the Company's assumption.
3

4 **Q. What would be the impact of a lower ELCC value for solar than what the Company**
5 **assumes?**

6 A. From the physical resource standpoint, NSP would have to add additional capacity
7 resources in the future to fulfill the same capacity requirement. The estimated
8 incremental cost of the Project compared to the savings based upon proxy pricing would
9 increase. The Company's proposal to adjust the ELCC to actual annual ELCC means the
10 annual cost paid by North Dakota customers will reflect the actual accredited capacity as
11 opposed to the assumed accredited capacity in the Company's model.
12

13 **Q. Did you review the Company's EnCompass modeling?**

14 A. Yes. Specifically, I reviewed:

- 15 • The assumptions about loads;
- 16 • The supply / demand balance (i.e., the need for new capacity);
- 17 • The forecast of net energy sales / purchases into the MISO market;
- 18 • The selection of the CT in the scenario excluding externality costs; and
- 19 • The energy margins forecast for the new CT.
20

21 **Q. Is the modeled load forecast consistent with the assumptions in the Supplemental**
22 **IRP?**

23 A. While I did not get the two sales forecasts to line up, both demonstrate minimal annual
24 load growth over the 2020 – 2034 period with the IRP having a compound annual load
25 growth of 0.3% and the Encompass model having 0.6%. In either case, the Company is
26 not forecasting significant load growth.
27

28 **Q. Does the EnCompass modeling confirm the need for capacity identified by Mr.**
29 **Chamberlin?**

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1 A. Yes.

2
3 **Q. If the Company were to build the CT instead of the Project, would the Company**
4 **need to secure an additional energy source to meet retail load?**

5 A. No, the Company's resource portfolio has a long energy position; the forecast generation
6 from its resources will exceed its retail load obligation on the order of 20% through the
7 end of the decade and beyond. The Company is therefore not only hedging the cost of its
8 retail load obligation, but also relying on the wholesale market prices to recover the cost
9 of the procured resources that collectively provide generation in excess of the load
10 obligation. In short, the energy produced by the Project is not needed to hedge the cost of
11 the retail load obligation.

12
13 **Q. Are the market energy pricing assumptions critical to the evaluation of benefits of**
14 **the Project?**

15 A. Yes, the Project's incremental levelized cost compared to the brownfield CT option is not
16 only dependent on the tax benefits associated with constructing a solar project but is also
17 a function of the benchmark - the market energy pricing assumptions.

18
19 **Q. Are the MISO market electricity prices impacted by natural gas prices?**

20 A. Yes. When the marginal unit setting the overall market price is a natural gas-fired
21 generation unit, there will be a strong relationship between gas and power prices. The
22 MISO Market Monitor has reported a strong correlation between natural gas prices and
23 wholesale market prices.³⁰ Notably, in 2019, coal units set the market clearing price 47%
24 of the time whereas natural gas units set the clearing price 51% of the time.³¹ I therefore
25 suspect natural gas will continue to set the market price in most hours.

26

³⁰ 2019 State of the Market Report, Midwest ISO p 4.

³¹ 2019 State of the Market Analytic Report, Midwest ISO, Table A1.

<https://cdn.misoenergy.org/2019%20State%20of%20the%20Market%20Analytical%20Appendix455180.pdf>

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1 **Q. Is the Company’s forecast of natural gas prices reasonable?**

2 A. The NSP reference case natural gas prices is dated May 2020. While gas prices have
3 increased dramatically since then, PA’s fundamental forecast shows an easing of gas
4 prices and the long-run PA and NSP forecasts are similar.

5
6 **Q. Does the Project impact the Company’s energy mix from a resource diversity
7 perspective?**

8 A. No, the Preferred Plan retires all coal generation by 2030 and adds large amounts of
9 renewable energy to meet the Company’s stated goal of decarbonization. The resource
10 mix from the Encompass modeling of the Preferred plan includes large amounts of new
11 renewable resources; however, specific resources – including the Project – are not
12 identified for their individual contributions. *See* Table 1, below. Even if the Project is
13 included in the resource mix, removing its 460 MW does not significantly change the
14 overall resource mix (i.e., there would only be a 1% reduction in overall Solar PV).
15 Regardless of whether the Project is in the resource mix, the Company is taking a long
16 position and acquiring generation significantly in excess of its retail load obligations and
17 will be relying on the market sales to offset the costs of its excess generation.

18
19
20 **Table 1: Resource Mix with Sherco Solar* (GWh)**

Resource	2023	2024	2025	2026	2028	2030	2032
Coal	7,079	5,733	1,988	1,747	1,952	-	-
Energy Efficiency	8,771	9,202	9,471	9,849	10,461	11,477	12,323
Gas/Oil Combined Cycle	14,705	14,130	15,282	14,128	10,660	9,361	7,432
Gas/Oil CT	414	401	195	459	629	1,058	945

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Hydro	2,741	2,753	1,459	993	995	993	946
Nuclear	13,576	14,053	13,576	14,013	14,053	14,013	14,053
Biomass	648	611	367	368	232	166	166
Landfill	5	5	5	5	5	5	5
Solar PV	2,296	3,670	4,778	4,811	6,186	6,956	6,756
Wind	<u>16,343</u>	<u>16,224</u>	<u>16,352</u>	<u>16,273</u>	<u>16,932</u>	<u>20,739</u>	<u>23,110</u>
Total	66,578	66,783	63,473	62,645	62,104	64,767	65,737

* Table excludes system purchases

Table 2: Resource Mix (Percentages)*

Resource	2023	2024	2025	2026	2028	2030	2032
Coal	11%	9%	3%	3%	3%	0%	0%
Energy Efficiency	13%	14%	15%	16%	17%	18%	19%
Gas/Oil Combined Cycle	22%	21%	24%	23%	17%	14%	11%
Gas/Oil CT	1%	1%	0%	1%	1%	2%	1%
Hydro	4%	4%	2%	2%	2%	2%	1%
Nuclear	20%	21%	21%	22%	23%	22%	21%
Biomass	1%	1%	1%	1%	0%	0%	0%
Landfill	0%	0%	0%	0%	0%	0%	0%
Solar PV	3%	5%	8%	8%	10%	11%	10%

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Wind	<u>25%</u>	<u>24%</u>	<u>26%</u>	<u>26%</u>	<u>27%</u>	<u>32%</u>	<u>35%</u>
Total	100%	100%	100%	100%	100%	100%	100%

* Table excludes system purchases

1
2
3 **Q. Would you please summarize the results of your analysis of the proxy pricing and**
4 **cost of the Project?**

5 A. Table 3 shows a summary of the levelized cost of the Project compared to the Company's
6 recommendation to use the MISO Gross CONE value, the Company's estimate of a
7 brownfield CT, and my calculation of the Net CONE applied to the brownfield CT. The
8 table shows that under tax laws the Project is not a least cost solution to securing the
9 anticipated needed capacity. The differences between the levelized costs between using
10 the NSP and PA long term energy forecasts highlight that there is significant uncertainty
11 in future market prices. Within these bands, the Project is still not the least cost
12 alternative under current tax laws. The table also highlights how potential changes in tax
13 law could make the project look more favorable. However, approving the project would
14 unnecessarily expose North Dakota ratepayers to market risk.

15

1 **Table 3: Scenario Summary**

2 **[Trade Secret Begins]**

Scenario	Levelized Cost (\$/MWh)
Sherco Solar with Current Tax Laws	██████████
Sherco Solar with Potential Tax Law Change	██████████
MISO CONE	██████████
IRP Brownfield CT	██████████
IRP Brownfield with PA Energy prices	██████████
IRP Brownfield CT Less Energy Margins	██████████
IRP Brownfield CT Less PA Energy Margins	██████████

3 **[Trade Secret Ends]**

4

5

6 **X. Additional Issues**

7 **Q. Are there additional issues that the Commission should consider?**

8 A. Yes, the Commission may consider NSP's commitment to build a CT in North Dakota,
9 whether an ADP is an appropriate docket to establish a long-term commitment for proxy
10 pricing, and the potential for overpaying for capacity in conjunction with the treatment of
11 the early retirement of the Sherco coal units.

12

13 **Q. Is NSP's proposal consistent with the commitment to construct a CT in North
14 Dakota?**

15 A. My understanding is the Company committed to develop (or secure a PPA) of at least
16 200 MW of thermal generation in in eastern North Dakota no later than December 31,
17 2025.³² The Company can still fulfill the commitment; however, I note that cost
18 effectiveness appears to be a caveat to NSP's commitment in the settlement. The North

³² Order Approving Settlement, March 9, 2016, First Revised Negotiated Agreement Relating to North Dakota Generation Resource Policy, PU-12-813, p. 3.

1 Dakota Scenario in the Supplemental IRP identifies the CT as a cost-effective resource,
2 but this may not be the case in future scenarios when capacity is required.
3

4 **Q. Is it appropriate to make a permanent decision on proxy pricing should the**
5 **Commission deny an ADP for the Project but accept some form of proxy pricing?**

6 A. No. I note that Advocacy Staff and NSP never came to agreement in the RTF proceeding.
7 While NSP is not proposing the proxy pricing as a comprehensive approach to all future
8 disagreements regarding the prudence of new resources, the Commission may want to
9 avoid making a precedential decision and retain its ability to change how disputed
10 resources are recovered in rates. This is not an instance of whether NSP is making an
11 essentially irrevocable decision as to whether to build a CT or the Project. Rather, NSP
12 will proceed with the Project regardless of the Commission's decision and the matter at
13 hand is simply how ND customers should pay for its share of the resulting accredited
14 capacity and energy. The Commission should retain the flexibility to participate in the
15 Project to respond to any future changes that may occur (e.g., tax treatment of the
16 Project) and ensure that savings to North Dakota are offset by any losses prior to
17 modifying / abandoning the proxy pricing.
18

19 **Q. What is your concern regarding overpaying for capacity in conjunction with proxy**
20 **pricing for the Project and retirement of the Sherco coal units?**

21 A. As the Company points out in its proxy capacity options, the Sherco coal unit could be
22 one basis for determining the value of capacity provided by the Project. My
23 understanding is that North Dakota's cost recovery treatment of the early retirement of
24 the Sherco is yet to be determined and that the Company in the last rate case settlement
25 reserved the right to request stranded cost treatment.³³ If the Commission were to
26 approve both proxy pricing for the Project and also allow for stranded cost recovery of
27 the Sherco Coal plant, then North Dakota customers would effectively be paying for the
28 capacity twice.

³³ Case No. PU-20-441 Settlement Agreement, p. 4.

1
2 **XI. Conclusions and Recommendations**
3

4 **Q. Would you please summarize your conclusions?**

5 A. Yes.

- 6 • The Commission should deny the ADP for Sherco Solar on the basis that it would
7 raise costs for North Dakota customers and the Company does not need additional
8 energy to hedge its retail load obligations.
- 9 • The Commission should deny the Company's proposal for recovering the proxy
10 cost of capacity through the FCR. The Company's proposal creates a significant
11 precedent with regards to recovering capacity costs in the FCR or recovering the
12 cost of disallowed Company owned resources in the FCR.
- 13 • The rate recovery for this Project, which the Company admits is imprudent under
14 North Dakota standards, should be addressed in a future Company rate case.
- 15 • Should the Commission approve the Company's proxy pricing approach, subject
16 to conditions and recommendations as described below, it should be on an interim
17 basis.

18
19 **Q. What is your recommendation regarding proxy pricing if the Commission decides to**
20 **approve proxy pricing for the Project under the ADP?**

21 A. I recommend the Commission direct the Company to:

- 22 • Use the brownfield CT cost as identified in the IRP and defined in the Company's
23 response to Advocacy Staff 1-1 as the basis of the Gross CONE cost.
- 24 • The brownfield CT cost should not be updated at a later date. Updating the cost
25 at a later date creates potential controversy about what cost the Commission is
26 accepting. In addition, the cost presented by the Company is contemporaneous
27 with the alternative cost of participating in the Project.
- 28 • The brownfield CT cost as defined by NSP in the fore-mentioned data response
29 should be reduced by subtracting the energy margins I identify in my testimony
30 and Exhibit__JAH-2,

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- 1 • Annually adjust the system value of the proxy capacity based upon the MISO
- 2 accredited capacity of the Project,
- 3 • The share of the MISO based accredited capacity of the Project that is assigned to
- 4 ND should be based upon the capacity cost allocation factors annually updated
- 5 capacity allocation factors that reflect ND's share of system capacity.
- 6 • Exclude North Dakota from any allocation of the transmission cost associated
- 7 with interconnection of the Project, and
- 8 • Hold North Dakota customers harmless for any potential future intermittent
- 9 renewable generation integration charges.

10

11 **Q. Does this conclude your testimony?**

12 **A. Yes.**

JIM HEIDELL

DIRECTOR



Jim Heidell specializes in electric and gas utility regulation, distributed energy, evaluation of renewable energy technologies and financial analysis of complex investments. Mr. Heidell assists clients with due diligence associated with acquisition of natural gas and electric utilities and wholesale energy market transactions. He has extensive financial and energy market modeling experience coupled with a deep understanding of regulated and competitive markets that he applies to the valuation of energy assets. Mr. Heidell has prepared and submitted testimony in both regulatory proceedings and civil contract damages cases. His regulatory experience and testimony includes rate design, cost of service, resource planning, and merger conditions. Mr. Heidell also specializes in strategic analysis and evaluation of opportunities associated with renewable / alternative energy technologies. Prior to working at PA Consulting he held positions as the Director of Finance and Director of Federal and State Regulation at Puget Sound Energy. Mr. Heidell is a CFA and has an MBA in finance from the University of Washington, a MS in Engineering Economics from Stanford University, and a BSE in civil engineering from Tufts University.

PRIMARY EXPERTISE

- Electric and natural gas utility regulation and finance
- Analysis of wholesale electric markets
- Renewable Energy Technologies
- Asset valuation / M&A Advisor
- Damages estimation for civil litigation
- Strategic planning
- Financial modelling of complex investments
- Financial planning

CLIENTS

- Riverstone Holdings
- Puget Sound Energy
- Solarcity
- Comision Federal de Electricidad
- North Dakota Public Service Commission

QUALIFICATIONS

- 30-years' experience with electric & gas utilities and electricity markets
- MBA University of Washington
- MSE Engineering Economics, Stanford University
- BSE, Civil Engineering, Tufts University
- CFA

EXPERIENCE SUMMARY

- **Utility Regulatory Support** – Prepare expert testimony in regulatory hearings related to resource acquisition, QF issues, rate impacts, marginal and embedded cost of service, and rate design. Developing marginal and embedded cost studies for regulated utilities.
- **Financial Analysis** – Long-term modelling of utility finance. Analysis of major capital investments using a variety of tools to incorporate uncertainty and risk.
- **Analysis of Energy Markets** – Develop energy and capacity forecasts for U.S. power markets to support: strategic investments by utilities and major energy companies, development of utility risk management strategies, and corporate strategies for generation asset acquisition and disposition.

- **Evaluation of Distributed Energy and Behind the Meter Generation** – Forecast of margins of community solar projects, portfolios of customer sited PV projects, and analysis of regulatory policies and rules associated with community solar projects and behind the meter PV projects.
- **Renewable Energy Technologies** – Develop business plans, market positioning strategies, and financial analysis of renewable technologies including PV cell manufacturing, flywheels, and fuel cells along with renewable generation technologies including solar thermal, geothermal, wind, battery storage, and IGCC projects.
- **Asset Valuation / M&A Advisor** – Provide valuation advice for acquisition of electric generation portfolios, single power plants, transmission projects, electric utilities, and gas distribution companies. Work also included review of wholesale and retail regulatory pricing mechanisms and analysis of associated risk.
- **Damages Estimation for Civil Litigation Testimony** – Prepare expert witness testimony to support power contract litigation, property tax cases, power plant development agreements, and quantification of economic damages.

EXPERIENCE

CIVIL LITIGATION TESTIMONY & SUPPORT

Rebuttal of claims of economic damage associated with the cancellation of a water desalination project in Monterey California.

Prepared an analysis of claims of economic damage associated with the performance of an anaerobic digester designed to provide gas for an electric generation project. Analysis included evaluation of performance, revenues and costs, and cost of capital used to discount projected future earnings. Prepared expert report and testified in jury trial in federal district court.

Developed an analysis of material and labor cost increases on EPC costs for a natural gas fired power plant located in New Mexico. The analysis was used to refute a claim that cost overruns were not reasonable in a cost plus EPC contract. The analysis demonstrated how much of the total project cost increases was associated with labor and material costs beyond the control of the general contractor.

Prepared an analysis of loss of margins at two coal plants during periods when there were alleged violations of EPA opacity emission limits. The analysis demonstrated that client did not receive any economic benefit associated with the periods of alleged violations.

Prepared an analysis of the commercial distributed solar sector in the 2010 – 2011 time frame and demonstration of the unreasonableness of the plaintiff's claims for economic damages associated with the defendant's decision not to pursue participation in an equity fund.

Prepared an analysis of the U.S. wholesale electric power markets in the 2008 – 2010 time frame to demonstrate why the plaintiff's decision to terminate construction of a coal fired power plant was due to cost increases in the EPC contract and not due to the changing natural gas prices and emission laws.

Prepared an estimate of lost margins associated with the extended outage of a Canadian nuclear reactor. The analysis included an estimate of what Ontario wholesale power prices would have been but-for the outage and estimates of the total damages including repair and inspection costs.

Prepared an Expert Report regarding rate making and financial policies of the Southern Minnesota Municipal Power Agency in conjunction with a contract dispute regarding a power contract and investments in new generation resources to serve full requirements customers.

Assisted expert witness by the preparation of a report on how a third party would value the Trans-Alaska Pipeline as part of a property tax dispute with the municipality of Anchorage.

Prepared an analysis of damages associated with claims for losses associated with the interruption of business of a Texas gas-fired power plant as a result of the rupture of a natural gas pipeline use to supply the power plant.

Prepared of an analysis of the economic benefits that accrued to the defendant associated with the purported delay of implementation of measures to correct water pollution discharge violations associated with a power plant.

ANALYSIS OF RENEWABLE ENERGY INVESTMENTS

Preparation of multiple Independent Market Expert Reports to support financing of community solar projects in Illinois, Maine, Massachusetts, New York, New Jersey, and Maryland.

Prepared an Independent Market Expert Report to support the debt financing of BrightSource Energy's Ivanpah solar thermal projects with purchased power agreements with California investor owned utilities.

Prepared an Independent Market Expert Report to support the debt financing of Solona, a large solar thermal project with molten salt storage, with a purchased power agreement with an Arizona Public Service.

Prepared an Independent Market Expert Report to support the expansion of a CdTe PV manufacturing facility in Colorado including the analysis of the business plan and projection of long-term prices for the PV modules.

Prepared an Independent Market Expert Report to support the expansion of a c-Si PV manufacturing facility including the analysis of the business plan and projection of long-term prices for the PV modules.

Prepared an Independent Market Expert Report to support the expansion of a polysilicon manufacturing facility including the analysis of the business plan and projection of long-term prices for polysilicon and the associated raw materials.

Prepared an evaluation of the global market for concentrating solar power plants as of 2012 as part of a client analysis of a potential purchase of a solar mirror manufacturing company.

Prepared an evaluation of the U.S. solar PV market to support evaluation of a Japanese firm's potential expansion in the U.S. markets.

Assisted client with a bid into a utility's renewable energy procurement program. The analysis included an assessment of competitors and analysis of pricing to support the bid of a renewable energy resource into 2011 Entergy RFP for renewable resources.

Prepared long range forecasts of multiple wind portfolios with an emphasis on the valuation of post PPA revenues and the value of renewable energy credits.

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Prepared an Independent Market Expert Report to support the debt financing of the Beacon flywheel energy storage project in New York.

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Independent Market Report to support the refinancing of the Dynegy corporate revolver. The effort included analysis of multiple U.S. power markets, valuation of the fleet of generation assets and associated contracts, and review of regulatory conditions impacting the Company's ability to realize earnings in markets with competitive auctions to serve load.

Multiple forecasts of California power market prices including support of a bid for a cogeneration facility located in the San Francisco Bay area and sale of La Rosita.

Forecast of the New England power markets to support a bid for the First Light Generation Assets.

Forecast of the California and SPP power markets to support a bid for assets from the EIF portfolio.

Analysis of the ERCOT, PJM and MISO markets for multiple bids for merchant gas fired generation plants.

Development of multiple Confidential Information Memorandums to support the sale of power plants. CIMs included description of the wholesale power markets and summaries of the key attributes of the assets to be sold in auction.

Preparation of sale offering of the Audrain power plant in response to Ameren solicitation to acquire new resources. Effort included evaluation of likely competitors and the development of the bid strategy.

Advise on pricing for offering power contracts as well as the sale of gas-fired combined cycle power plant in the South-East. Pricing and sale price based upon projections of the value of the power plant as a merchant unit, assessment of potential competitors, and the analysis of transmission constraints.

ELECTRIC MARKETS RISK MODELING

Provided support to a bond insurance company to prepare an assessment of the distribution of income from a fleet of peaking power plants in the South-East. Analysis used to review the provision for loss reserves.

Supported a bond insurance agency in determining the probability that a fleet of Mid-West generation assets would generate insufficient cash to meet debt payments and reserve requirements.

Developed an Excel based model for a mid-west public utility to assist in developing annual targets for the amount of surplus generation capacity to be sold as merchant and in contracts of varying tenor. The model was integrated into the corporate financial model to assist in identifying the appropriate risk profile to support building the reserve fund and to delay future rate increases.

DSM ADVISORY SERVICES

Advised Con Edison on the status of electric decoupling and incentive mechanisms in the United States as part of the New York state initiative to reintroduce decoupling.

Advised a private equity fund on the status of demand side management in New England, likely projections of growth, and probability of successful implementation as part of an evaluation of long-term supply and demand conditions in the New England electric markets.

Worked with Montana-Dakota utilities regarding the incorporation of projections of demand side management potential into the utility's long-term resource plan.

ADDITIONAL EXPERIENCE – EXPERT TESTIMONY

Before the Louisiana Public Commission, Direct Testimony and Schedules of James A. Heidell in Re: Application of 1803 Electric Cooperative, Inc. For Approval of Power Purchase Agreements and For Cost Recovery, Docket No. U-35927.

Before the North Dakota Public Service Commission, Direct Testimony and Schedules of James A. Heidell, In the Matter of Northern States Power Company Advance Prudence – Heartland Divide II Wind Project, Case No. PU-20-433.

California-American Water Company, a California Corporation; Monterey County Water Resources Agency, Plaintiffs, vs. Marina Cos Water District; RMC Water and Environment, a California Corporation; and DOES 1 through 10, inclusive, Defendants, Case No. CGC-15-546632. Report and Deposition on behalf of RMC Water and Environment addressing alleged economic damages as a result of a cancelled desalination project.

Before the Hawaii Public Service Commission, Direct Testimony Of James A. Heidell, Docket No. 2017-0105 In The Matter Of The Application of Hawaii Gas Company Application for a General Rate Increase. Testimony on behalf of Hawaii Gas addressing rate spread and rate design.

Before the North Dakota Public Service Commission, Direct Testimony and Schedules of James A. Heidell, In the Matter Of Otter Tail Power Company Advance Determination of Prudence Astoria Natural Gas Project, Merricourt Wind Project and Certificate of Public Convenience and Necessity Merricourt Wind Project, Case Nos. PU-17-140, PU-17-141, & PU-17-143,

Before the North Dakota Public Service Commission, Direct Testimony and Schedules of James A. Heidell, In the Matter Of Northern States Power Company Advance Prudence – Dakato Range Wind Project, Case No. PU-17-372.

Before the North Dakota Public Service Commission, Direct Testimony and Schedules of James A. Heidell, In the Matter Of Northern States Power Company Advance Prudence – 1,550 MW Wind Portfolio, Case No. PU-17-120.

Before the North Dakota Public Service Commission, Direct Testimony and Schedules of James A. Heidell, In the Matter Of Northern States Power Company Advance Prudence – BIOMASS APPLICATION FOR DEFERRED ACCOUNTING, Case Nos. PU-17-270, PU-17-271, & PU-17-322.

Before the North Dakota Public Service Commission, Direct Testimony and Schedules of James A. Heidell, In the Matter Of Northern States Power Company A Minnesota Corporation D/B/A XCEL Energy Jurisdictional Cost Allocation Matters, Case Nos. PU-12-813 et. al.

Before the Arizona Corporation Commission, Direct and Settlement Testimony Of James A. Heidell, Docket No. E-01345A-16-0036 and Docket No. E-01345A-16-0123 In The Matter Of The Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, To Fix a Just and Reasonable Rate of Return Thereon, To Approve Rate Schedules Designed to Develop Such Return.

Before the Public Utilities Commission of Nevada, Direct and Rebuttal Testimony Of James A. Heidell, Docket No. 16-06006, In The Matter of the Application of Sierra Pacific Power Company, d/b/a NV Energy, Filed pursuant to NRS 704.110(3), addressing its annual revenue requirement for general rates charged to all classes of Electric customers.

Amana Society, Inc. and Amana Farms, Inc. v. GHD, Inc. and Excel Engineering, Inc. Testimony on behalf of GHD, INC regarding the economic performance of a manure digester and evaluation of claims of damages by Amana. Expert Report 2012, Jury Trial September 2012.

Affidavit of James A. Heidell & Mark Repsher, Appropriate Approach to Calculating the Weighted Cost of Capital, Docket No. ER14-2940-0000, U.S. Federal Energy Regulatory Commission, October 15, 2014.

Affidavit of James A. Heidell & Mark Repsher, on behalf of Peabody Energy Corporation to stay the final Clean Power Plan rule, September 9, 2015.

Declaration and report of James A. Heidell & Mark Repsher, Utility and Allied Petitioners' motion to stay the final Clean Power Plan rule, October 16, 2015.

City of Rochester, Minnesota v. Southern Minnesota, State of Minnesota, County of Olmsted File No: 55-C3-05-002712. Testimony on behalf of the City of Rochester regarding the interpretation of a power contract. Testimony and deposition 2008.

Before the Public Service Commission of Maryland, Rebuttal Testimony Of James A. Heidell, Case No. 9173, Phase II In The Matter Of The Current And Future Financial Condition Of Baltimore Gas And Electric Company.

Before the Indiana Utility Regulatory Commission, Rebuttal Testimony in Northern Indiana Public Service Company's request to raise rates in Cause No. 43526. Testimony on behalf of the utility related to ratchets and other mechanisms appropriate to recover costs allocated to large energy using customer classes.

Before Public Service Commission of the State of North Dakota, Direct and Rebuttal Testimony in Montana Dakota Utilities Co., and Otter Tail Corporation; Advance Determination of Prudence, Big Stone II Generating Station Case Nos. PU-06-481 and PU-06-482. On behalf of Montana-Dakota Utilities. 2007 & 2008. On behalf of Montana-Dakota Utilities.

Before the Public Service Commission of the State of Montana, Direct and Rebuttal Testimony in Montana-Dakota's General Rate Case – Marginal Cost of Service Study, Docket No. D2010.8.82. On behalf of Montana-Dakota Utilities.

Before the Public Service Commission of the State of Montana, Direct and Rebuttal Testimony in Montana-Dakota's General Rate Case – Marginal Cost of Service Study, Docket No. D2007.7.79. On behalf of Montana-Dakota Utilities.

Before the Minnesota Public Utilities Commission, Direct and Rebuttal testimony on behalf of Montana-Dakota Utilities regarding a Certificate of Need for the Big Stone II Power Plant, Docket No. CN-05-619. On behalf of Montana-Dakota Utilities.

Before the Ontario Electric Board, Expert Report regarding the 2006 Electric Rate Distribution Handbook and Rate Mitigation, on behalf of Hydro One Networks, Inc. January 2005.

Before the Washington Utilities and Transportation Commission, Direct Testimony in 2004 General Rate Case Regarding Electric Cost of Service & Rate Design and Gas Rate Design, April 2004. On behalf of Puget Sound Energy.

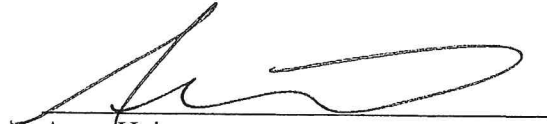
Before the Washington Utilities and Transportation Commission, Direct Testimony in 2001 General Rate Case Regarding Electric Cost of Service & Rate Design, November 2001. On behalf of Puget Sound Energy.

Before the Washington Utilities and Transportation Commission, Testimony Regarding the Need for a Special Competitive Rate for Intel. Docket No. UE-960299, 1996. On behalf of Puget Power.

Before the Washington Utilities and Transportation Commission, Rebuttal Testimony in the Merger of Puget Power and Washington Natural Gas Regarding Electric Rates, Docket Nos. UE-95-1270 & UE-960185, 1995. On behalf of Puget Power.

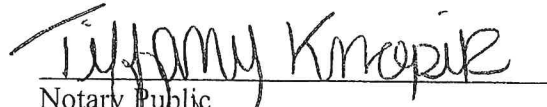
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CONFIDENTIAL-FILED AS TRADE SECRET


Anna Heinen

Subscribed and sworn before me this 17th day of December, 2021.

TIFFANY KNOPIK
Notary Public
State of North Dakota
My Commission Expires June 29, 2022


Notary Public
Burleigh County, North Dakota

JIM HEIDELL

DIRECTOR



Jim Heidell specializes in electric and gas utility regulation, distributed energy, evaluation of renewable energy technologies and financial analysis of complex investments. Mr. Heidell assists clients with due diligence associated with acquisition of natural gas and electric utilities and wholesale energy market transactions. He has extensive financial and energy market modeling experience coupled with a deep understanding of regulated and competitive markets that he applies to the valuation of energy assets. Mr. Heidell has prepared and submitted testimony in both regulatory proceedings and civil contract damages cases. His regulatory experience and testimony includes rate design, cost of service, resource planning, and merger conditions. Mr. Heidell also specializes in strategic analysis and evaluation of opportunities associated with renewable / alternative energy technologies. Prior to working at PA Consulting he held positions as the Director of Finance and Director of Federal and State Regulation at Puget Sound Energy. Mr. Heidell is a CFA and has an MBA in finance from the University of Washington, a MS in Engineering Economics from Stanford University, and a BSE in civil engineering from Tufts University.

PRIMARY EXPERTISE

- Electric and natural gas utility regulation and finance
- Analysis of wholesale electric markets
- Renewable Energy Technologies
- Asset valuation / M&A Advisor
- Damages estimation for civil litigation
- Strategic planning
- Financial modelling of complex investments
- Financial planning

CLIENTS

- Riverstone Holdings
- Puget Sound Energy
- Solarcity
- Comision Federal de Electricidad
- North Dakota Public Service Commission

QUALIFICATIONS

- 30-years' experience with electric & gas utilities and electricity markets
- MBA University of Washington
- MSE Engineering Economics, Stanford University
- BSE, Civil Engineering, Tufts University
- CFA

EXPERIENCE SUMMARY

- **Utility Regulatory Support** – Prepare expert testimony in regulatory hearings related to resource acquisition, QF issues, rate impacts, marginal and embedded cost of service, and rate design. Developing marginal and embedded cost studies for regulated utilities.
- **Financial Analysis** – Long-term modelling of utility finance. Analysis of major capital investments using a variety of tools to incorporate uncertainty and risk.
- **Analysis of Energy Markets** – Develop energy and capacity forecasts for U.S. power markets to support: strategic investments by utilities and major energy companies, development of utility risk management strategies, and corporate strategies for generation asset acquisition and disposition.

- **Evaluation of Distributed Energy and Behind the Meter Generation** – Forecast of margins of community solar projects, portfolios of customer sited PV projects, and analysis of regulatory policies and rules associated with community solar projects and behind the meter PV projects.
- **Renewable Energy Technologies** – Develop business plans, market positioning strategies, and financial analysis of renewable technologies including PV cell manufacturing, flywheels, and fuel cells along with renewable generation technologies including solar thermal, geothermal, wind, battery storage, and IGCC projects.
- **Asset Valuation / M&A Advisor** – Provide valuation advice for acquisition of electric generation portfolios, single power plants, transmission projects, electric utilities, and gas distribution companies. Work also included review of wholesale and retail regulatory pricing mechanisms and analysis of associated risk.
- **Damages Estimation for Civil Litigation Testimony** – Prepare expert witness testimony to support power contract litigation, property tax cases, power plant development agreements, and quantification of economic damages.

EXPERIENCE

CIVIL LITIGATION TESTIMONY & SUPPORT

Rebuttal of claims of economic damage associated with the cancellation of a water desalination project in Monterey California.

Prepared an analysis of claims of economic damage associated with the performance of an anaerobic digester designed to provide gas for an electric generation project. Analysis included evaluation of performance, revenues and costs, and cost of capital used to discount projected future earnings. Prepared expert report and testified in jury trial in federal district court.

Developed an analysis of material and labor cost increases on EPC costs for a natural gas fired power plant located in New Mexico. The analysis was used to refute a claim that cost overruns were not reasonable in a cost plus EPC contract. The analysis demonstrated how much of the total project cost increases was associated with labor and material costs beyond the control of the general contractor.

Prepared an analysis of loss of margins at two coal plants during periods when there were alleged violations of EPA opacity emission limits. The analysis demonstrated that client did not receive any economic benefit associated with the periods of alleged violations.

Prepared an analysis of the commercial distributed solar sector in the 2010 – 2011 time frame and demonstration of the unreasonableness of the plaintiff's claims for economic damages associated with the defendant's decision not to pursue participation in an equity fund.

Prepared an analysis of the U.S. wholesale electric power markets in the 2008 – 2010 time frame to demonstrate why the plaintiff's decision to terminate construction of a coal fired power plant was due to cost increases in the EPC contract and not due to the changing natural gas prices and emission laws.

Prepared an estimate of lost margins associated with the extended outage of a Canadian nuclear reactor. The analysis included an estimate of what Ontario wholesale power prices would have been but-for the outage and estimates of the total damages including repair and inspection costs.

Prepared an Expert Report regarding rate making and financial policies of the Southern Minnesota Municipal Power Agency in conjunction with a contract dispute regarding a power contract and investments in new generation resources to serve full requirements customers.

Assisted expert witness by the preparation of a report on how a third party would value the Trans-Alaska Pipeline as part of a property tax dispute with the municipality of Anchorage.

Prepared an analysis of damages associated with claims for losses associated with the interruption of business of a Texas gas-fired power plant as a result of the rupture of a natural gas pipeline use to supply the power plant.

Prepared of an analysis of the economic benefits that accrued to the defendant associated with the purported delay of implementation of measures to correct water pollution discharge violations associated with a power plant.

ANALYSIS OF RENEWABLE ENERGY INVESTMENTS

Preparation of multiple Independent Market Expert Reports to support financing of community solar projects in Illinois, Maine, Massachusetts, New York, New Jersey, and Maryland.

Prepared an Independent Market Expert Report to support the debt financing of BrightSource Energy's Ivanpah solar thermal projects with purchased power agreements with California investor owned utilities.

Prepared an Independent Market Expert Report to support the debt financing of Solona, a large solar thermal project with molten salt storage, with a purchased power agreement with an Arizona Public Service.

Prepared an Independent Market Expert Report to support the expansion of a CdTe PV manufacturing facility in Colorado including the analysis of the business plan and projection of long-term prices for the PV modules.

Prepared an Independent Market Expert Report to support the expansion of a c-Si PV manufacturing facility including the analysis of the business plan and projection of long-term prices for the PV modules.

Prepared an Independent Market Expert Report to support the expansion of a polysilicon manufacturing facility including the analysis of the business plan and projection of long-term prices for polysilicon and the associated raw materials.

Prepared an evaluation of the global market for concentrating solar power plants as of 2012 as part of a client analysis of a potential purchase of a solar mirror manufacturing company.

Prepared an evaluation of the U.S. solar PV market to support evaluation of a Japanese firm's potential expansion in the U.S. markets.

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Independent Market Expert Report to support the financing of Sequent Power's purchase of the Wolf Hollow 730 MW combined cycle power plant located in ERCOT. The report was used to support the syndication and rating of over \$400M of primary and mezzanine debt. The report incorporated forecast of gross margins for both the contracted and non-contracted portions of the facility as well as providing a detailed description of the ERCOT market conditions and key assumptions to the financial analysis.

Independent Market Expert Report to support the financing of Invenergy's purchase of the partially completed Grays Harbor 620 MW combined cycle power plant located in the Pacific Northwest. The report was used to support the syndication and rating of over \$100M of debt. The analysis included valuing both hedged and unhedged positions for the facility and conducting extensive due diligence regarding how NW power markets are likely to evolve and the role of independent power in a market dominated by vertically integrated public and investor-owned utilities.

Independent Market Report to support the refinancing of the Dynegy corporate revolver. The effort included analysis of multiple U.S. power markets, valuation of the fleet of generation assets and associated contracts, and review of regulatory conditions impacting the Company's ability to realize earnings in markets with competitive auctions to serve load.

Multiple forecasts of California power market prices including support of a bid for a cogeneration facility located in the San Francisco Bay area and sale of La Rosita.

Forecast of the New England power markets to support a bid for the First Light Generation Assets.

Forecast of the California and SPP power markets to support a bid for assets from the EIF portfolio.

Analysis of the ERCOT, PJM and MISO markets for multiple bids for merchant gas fired generation plants.

Development of multiple Confidential Information Memorandums to support the sale of power plants. CIMs included description of the wholesale power markets and summaries of the key attributes of the assets to be sold in auction.

Preparation of sale offering of the Audrain power plant in response to Ameren solicitation to acquire new resources. Effort included evaluation of likely competitors and the development of the bid strategy.

Advise on pricing for offering power contracts as well as the sale of gas-fired combined cycle power plant in the South-East. Pricing and sale price based upon projections of the value of the power plant as a merchant unit, assessment of potential competitors, and the analysis of transmission constraints.

ELECTRIC MARKETS RISK MODELING

Provided support to a bond insurance company to prepare an assessment of the distribution of income from a fleet of peaking power plants in the South-East. Analysis used to review the provision for loss reserves.

Supported a bond insurance agency in determining the probability that a fleet of Mid-West generation assets would generate insufficient cash to meet debt payments and reserve requirements.

Developed an Excel based model for a mid-west public utility to assist in developing annual targets for the amount of surplus generation capacity to be sold as merchant and in contracts of varying tenor. The model was integrated into the corporate financial model to assist in identifying the appropriate risk profile to support building the reserve fund and to delay future rate increases.

DSM ADVISORY SERVICES

Advised Con Edison on the status of electric decoupling and incentive mechanisms in the United States as part of the New York state initiative to reintroduce decoupling.

Advised a private equity fund on the status of demand side management in New England, likely projections of growth, and probability of successful implementation as part of an evaluation of long-term supply and demand conditions in the New England electric markets.

Worked with Montana-Dakota utilities regarding the incorporation of projections of demand side management potential into the utility's long-term resource plan.

ADDITIONAL EXPERIENCE – EXPERT TESTIMONY

Before the Louisiana Public Commission, Direct Testimony and Schedules of James A. Heidell in Re: Application of 1803 Electric Cooperative, Inc. For Approval of Power Purchase Agreements and For Cost Recovery, Docket No. U-35927.

Before the North Dakota Public Service Commission, Direct Testimony and Schedules of James A. Heidell, In the Matter of Northern States Power Company Advance Prudence – Heartland Divide II Wind Project, Case No. PU-20-433.

California-American Water Company, a California Corporation; Monterey County Water Resources Agency, Plaintiffs, vs. Marina Cos Water District; RMC Water and Environment, a California Corporation; and DOES 1 through 10, inclusive, Defendants, Case No. CGC-15-546632. Report and Deposition on behalf of RMC Water and Environment addressing alleged economic damages as a result of a cancelled desalination project.

Before the Hawaii Public Service Commission, Direct Testimony Of James A. Heidell, Docket No. 2017-0105 In The Matter Of The Application of Hawaii Gas Company Application for a General Rate Increase. Testimony on behalf of Hawaii Gas addressing rate spread and rate design.

Before the North Dakota Public Service Commission, Direct Testimony and Schedules of James A. Heidell, In the Matter Of Otter Tail Power Company Advance Determination of Prudence Astoria Natural Gas Project, Merricourt Wind Project and Certificate of Public Convenience and Necessity Merricourt Wind Project, Case Nos. PU-17-140, PU-17-141, & PU-17-143,

Before the North Dakota Public Service Commission, Direct Testimony and Schedules of James A. Heidell, In the Matter Of Northern States Power Company Advance Prudence – Dakato Range Wind Project, Case No. PU-17-372.

Before the North Dakota Public Service Commission, Direct Testimony and Schedules of James A. Heidell, In the Matter Of Northern States Power Company Advance Prudence – 1,550 MW Wind Portfolio, Case No. PU-17-120.

Before the North Dakota Public Service Commission, Direct Testimony and Schedules of James A. Heidell, In the Matter Of Northern States Power Company Advance Prudence – BIOMASS APPLICATION FOR DEFERRED ACCOUNTING, Case Nos. PU-17-270, PU-17-271, & PU-17-322.

Before the North Dakota Public Service Commission, Direct Testimony and Schedules of James A. Heidell, In the Matter Of Northern States Power Company A Minnesota Corporation D/B/A XCEL Energy Jurisdictional Cost Allocation Matters, Case Nos. PU-12-813 et. al.

Before the Arizona Corporation Commission, Direct and Settlement Testimony Of James A. Heidell, Docket No. E-01345A-16-0036 and Docket No. E-01345A-16-0123 In The Matter Of The Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, To Fix a Just and Reasonable Rate of Return Thereon, To Approve Rate Schedules Designed to Develop Such Return.

Before the Public Utilities Commission of Nevada, Direct and Rebuttal Testimony Of James A. Heidell, Docket No. 16-06006, In The Matter of the Application of Sierra Pacific Power Company, d/b/a NV Energy, Filed pursuant to NRS 704.110(3), addressing its annual revenue requirement for general rates charged to all classes of Electric customers.

Amana Society, Inc. and Amana Farms, Inc. v. GHD, Inc. and Excel Engineering, Inc. Testimony on behalf of GHD, INC regarding the economic performance of a manure digester and evaluation of claims of damages by Amana. Expert Report 2012, Jury Trial September 2012.

Affidavit of James A. Heidell & Mark Repsher, Appropriate Approach to Calculating the Weighted Cost of Capital, Docket No. ER14-2940-0000, U.S. Federal Energy Regulatory Commission, October 15, 2014.

Affidavit of James A. Heidell & Mark Repsher, on behalf of Peabody Energy Corporation to stay the final Clean Power Plan rule, September 9, 2015.

Declaration and report of James A. Heidell & Mark Repsher, Utility and Allied Petitioners' motion to stay the final Clean Power Plan rule, October 16, 2015.

City of Rochester, Minnesota v. Southern Minnesota, State of Minnesota, County of Olmsted File No: 55-C3-05-002712. Testimony on behalf of the City of Rochester regarding the interpretation of a power contract. Testimony and deposition 2008.

Before the Public Service Commission of Maryland, Rebuttal Testimony Of James A. Heidell, Case No. 9173, Phase II In The Matter Of The Current And Future Financial Condition Of Baltimore Gas And Electric Company.

Before the Indiana Utility Regulatory Commission, Rebuttal Testimony in Northern Indiana Public Service Company's request to raise rates in Cause No. 43526. Testimony on behalf of the utility related to ratchets and other mechanisms appropriate to recover costs allocated to large energy using customer classes.

Before Public Service Commission of the State of North Dakota, Direct and Rebuttal Testimony in Montana Dakota Utilities Co., and Otter Tail Corporation; Advance Determination of Prudence, Big Stone II Generating Station Case Nos. PU-06-481 and PU-06-482. On behalf of Montana-Dakota Utilities. 2007 & 2008. On behalf of Montana-Dakota Utilities.

Before the Public Service Commission of the State of Montana, Direct and Rebuttal Testimony in Montana-Dakota's General Rate Case – Marginal Cost of Service Study, Docket No. D2010.8.82. On behalf of Montana-Dakota Utilities.

Before the Public Service Commission of the State of Montana, Direct and Rebuttal Testimony in Montana-Dakota's General Rate Case – Marginal Cost of Service Study, Docket No. D2007.7.79. On behalf of Montana-Dakota Utilities.

Before the Minnesota Public Utilities Commission, Direct and Rebuttal testimony on behalf of Montana-Dakota Utilities regarding a Certificate of Need for the Big Stone II Power Plant, Docket No. CN-05-619. On behalf of Montana-Dakota Utilities.

Before the Ontario Electric Board, Expert Report regarding the 2006 Electric Rate Distribution Handbook and Rate Mitigation, on behalf of Hydro One Networks, Inc. January 2005.

Before the Washington Utilities and Transportation Commission, Direct Testimony in 2004 General Rate Case Regarding Electric Cost of Service & Rate Design and Gas Rate Design, April 2004. On behalf of Puget Sound Energy.

Before the Washington Utilities and Transportation Commission, Direct Testimony in 2001 General Rate Case Regarding Electric Cost of Service & Rate Design, November 2001. On behalf of Puget Sound Energy.

Before the Washington Utilities and Transportation Commission, Testimony Regarding the Need for a Special Competitive Rate for Intel. Docket No. UE-960299, 1996. On behalf of Puget Power.

Before the Washington Utilities and Transportation Commission, Rebuttal Testimony in the Merger of Puget Power and Washington Natural Gas Regarding Electric Rates, Docket Nos. UE-95-1270 & UE-960185, 1995. On behalf of Puget Power.

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