

Direct Testimony and Schedules  
Paul B. Johnson

Before the North Dakota Public Service Commission  
State of North Dakota

Application of Northern States Power Company  
for an Advance Determination of Prudence for a Power Purchase Agreement with  
Aurora Distributed Solar, LLC for Up to 100 MW of Solar Generation

Case No. PU-15-\_\_\_\_\_  
Exhibit\_\_\_\_(PBJ-1)

**Resource Need and Geronimo Solar PPA Testimony**

February 13, 2015

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## Schedules

Resume	Schedule 1
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1 **I. INTRODUCTION**

2  
3 Q. PLEASE STATE YOUR NAME AND TITLE.

4 A. My name is Paul B. Johnson. I am Director of Resource Planning and  
5 Bidding for Xcel Energy.

6  
7 Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

8 A. I have worked for Xcel Energy since July 2014 in the area of resource  
9 planning. In my current role, I am responsible for the direction and oversight  
10 of electric Resource Planning for the five-state integrated Northern States  
11 Power Company system (NSP System), which provides electric service to  
12 customers in North Dakota, South Dakota, Minnesota, Wisconsin, and  
13 Michigan.

14  
15 My responsibilities include directing the development of resource plans,  
16 working closely with modeling to complete the analyses required for those  
17 plans. I also oversee the development and execution of Request for Proposals  
18 (RFP), the modeling for asset acquisition assessments, and provide long-term  
19 pricing guidance for purchased power negotiations. In addition, I lead the  
20 effort to provide resource analysis and planning guidance for regulatory  
21 filings, information requests needed by various departments, and NSP  
22 executives. My resume is provided as Exhibit\_\_\_(PBJ-1), Schedule 1.

23  
24 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

25 A. I discuss the capacity resource need that is the basis for the Company's  
26 proposal to enter into a 20-year power purchase agreement (PPA) with Aurora  
27 Solar, LLC, an affiliate of Geronimo Energy, LLC (Geronimo Solar PPA),

1 including the factors and analysis that went into determining the resource  
2 need. I also discuss the terms of the Geronimo Solar PPA, and our analysis of  
3 the PPA's costs and benefits for our ratepayers.

4  
5 Q. PLEASE SUMMARIZE YOUR TESTIMONY.

6 A. The Company performs a rigorous analysis to estimate its resource needs  
7 many years into the future, using econometric and other assumptions and  
8 variables a basis for its determinations. I identify in my testimony the  
9 challenges and difficulties in accurately assessing future generation capacity  
10 requirements, and provide the range of probable need we face based on the  
11 best available information we have. Company Witness Mr. Kurtis J. Haeger  
12 discusses in his Direct Testimony the variability in our demand forecasts that  
13 led to the Company's determination of a capacity need of 150-500 MW by the  
14 end of the decade.

15  
16 I then discuss the terms of the Geronimo Solar PPA, highlighting known risks  
17 and the steps taken to mitigate those risks. I also provide a detailed analysis of  
18 the costs and benefits of the PPA for our ratepayers to aid the Commission in  
19 its determination of the PPA's prudence.

20  
21 **II. RESOURCE NEED**

22  
23 Q. HOW IS THE COMPANY'S RESOURCE NEED DETERMINED?

24 A. The Company's assessment of resource need is based on three primary  
25 factors: (1) peak demand forecast; (2) required reserve margins; and (3) the  
26 maximum generation capability of existing resources. The peak demand  
27 forecast is based on an econometric model using a combination of variables,

1 including weather-normalized native energy requirements and peak producing  
2 weather by month. The reserve margins are based on the reserve margin  
3 calculations used by the Midwest Independent System Operator, Inc.,  
4 (MISO), the regional transmission organization to which the Company  
5 belongs. Finally, the maximum generation capability of existing resources is  
6 based on NSP System operational data.

7  
8 In addition to analyzing peak demand, we also forecast our total annual energy  
9 requirements based on projected sales and transmission line losses, which  
10 includes the impact of Demand-Side Management on our total sales. This not  
11 only contributes to our assessment of a capacity need, but also allows us to  
12 assess the type of resource that will best meet our energy needs, that is,  
13 whether the best option in light of capacity and energy needs is the addition of  
14 a baseload, intermediate, or peaking resource to our system or some  
15 combination of those types of resources.

16  
17 Q. WHAT IS THE COMPANY'S NEED?

18 A. The Company's need is 150-500 MW by 2019/2020, based on our updated  
19 Fall 2011 forecast (Fall 2011 Forecast). This forecast updated the initial  
20 forecasting included in our 2010 Resource Plan. Augmented with information  
21 from the Company's Spring 2013 forecast, the Fall 2011 Forecast is the  
22 forecast that was used in our advance determination of prudence application  
23 for Black Dog Unit 6 and Red River Valley Units 1 and 2 (Case No. PU-13-  
24 194 (Gas CT's Case)).

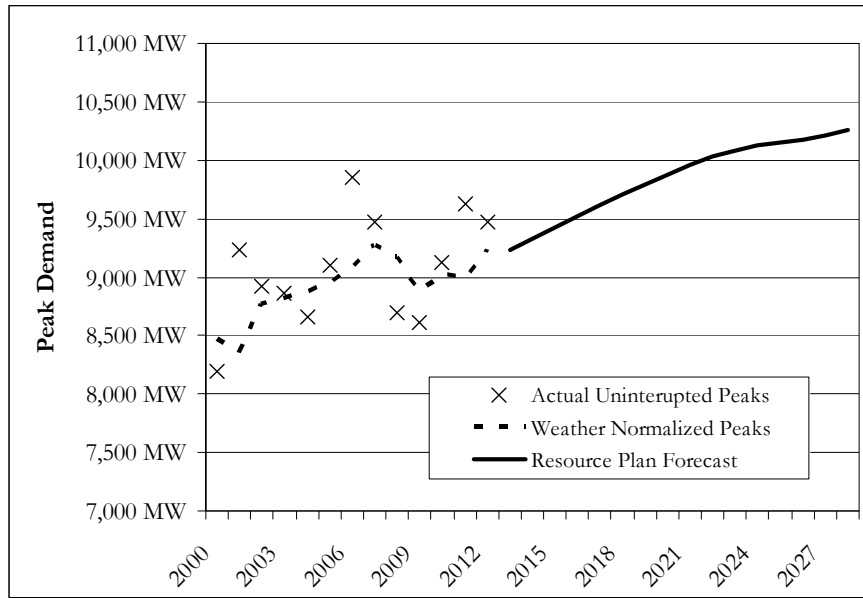
25  
26 Q. PLEASE DESCRIBE THE COMPONENTS OF THE FALL 2011 FORECAST.

27 A. Figure 1 provides the Fall 2011 Forecast's peak demands. As shown in Figure

1 1, from 2013 through 2020, the average rate of growth in our peak demand  
2 forecast is 1.0 percent.

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**Figure 1:  
NSP Historic and Forecasted Peak Demand**

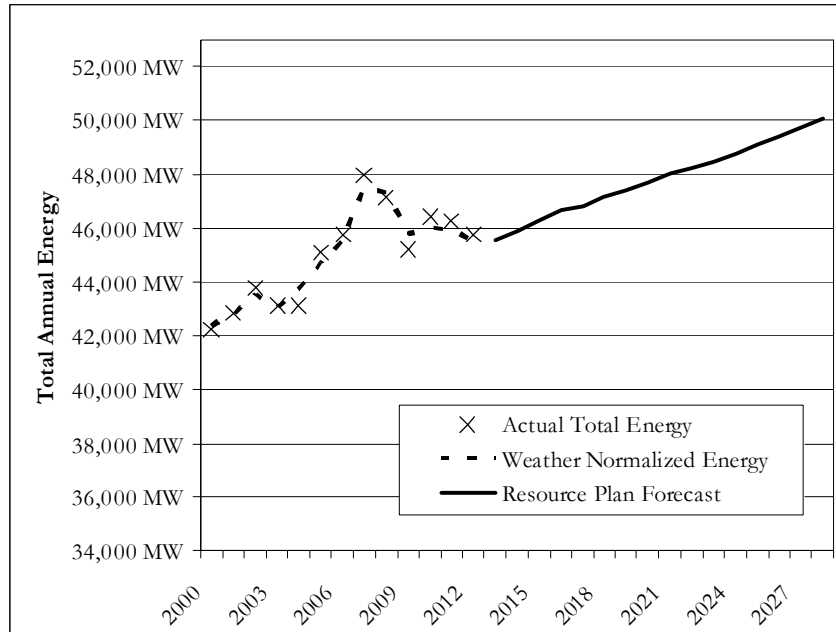


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Our total annual energy forecast is shown in Figure 2. The Fall 2011 Forecast assumed an average growth rate from 2013 to 2020 of 0.7 percent.

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**Figure 2:  
NSP Historic and Forecasts Total Annual Energy**



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5 Our Fall 2011 Forecast also took into consideration the reserve margin  
6 calculations specified by MISO using the criteria applicable at the time. MISO  
7 calculates the reserve margin percentage based on loss of load expectation  
8 (LOLE) studies that calculate how high the reserve margin must be to ensure  
9 that load will not have to be curtailed any more often than once in every ten  
10 years. Comparing the load forecast plus reserve margin to the capacity ratings  
11 of Xcel Energy-owned resources plus purchased power, our system's  
12 forecasted capacity need is around 500 MW by 2019-2020, as shown in Table  
13 1.

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2  
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**Table 1:  
System Capacity Need  
(Fall 2011 Forecast)**

	2015	2016	2017	2018	2019	2020
Peak Forecast	9,428	9,524	9,613	9,708	9,799	9,881
<u>x 1+RM%</u>	<u>3.8%</u>	<u>3.8%</u>	<u>3.8%</u>	<u>3.8%</u>	<u>3.8%</u>	<u>3.8%</u>
= Total Obligation	9,786	9,885	9,977	10,076	10,170	10,255
<b><u>Resources</u></b>	<b>2015</b>	<b>2016</b>	<b>2017</b>	<b>2018</b>	<b>2019</b>	<b>2020</b>
Coal	2,331	2,331	2,331	2,331	2,331	2,331
Nuclear	1,610	1,610	1,610	1,610	1,610	1,610
Gas	3,476	3,534	3,437	3,424	3,424	3,424
Renewable	1,288	1,289	1,287	1,238	1,212	1,213
Other	92	-	-	-	-	-
<u>Load Management*</u>	<u>1,145</u>	<u>1,153</u>	<u>1,157</u>	<u>1,153</u>	<u>1,149</u>	<u>1,145</u>
Total	9,943	9,917	9,823	9,757	9,727	9,724
<b>Long (Short)</b>	<b>157</b>	<b>32</b>	<b>(154)</b>	<b>(319)</b>	<b>(443)</b>	<b>(532)</b>

\* Includes reserves

4

As shown in Table 1, our Fall 2011 Forecast identified a capacity need of 153 MW in 2017, growing to 532 MW in 2020.

6

7

Q. PLEASE DESCRIBE THE UNCERTAINTY RELATING TO CHANGES IN HOW MISO CALCULATES RESERVE MARGINS.

9

A. The way MISO calculates the generation reserve margins necessary to ensure system reliability has been subject to on-going change. Starting in 2013, MISO's reserve margin calculation for individual utility systems will change to reflect the utility's peak demand *at the time of the region's peak*, rather than the utility's own peak. The Company's demand at the MISO peak has varied

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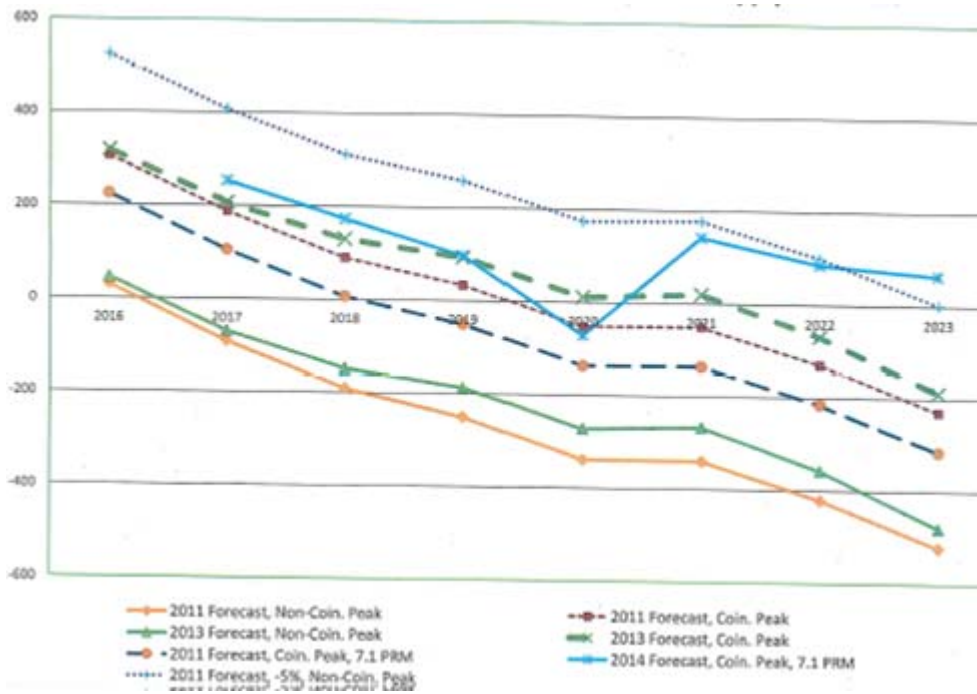
1 substantially, and has not been coincident with MISO's in five of the last eight  
2 summer seasons – averaging approximately five percent lower than our own  
3 peak.

4  
5 Because our peak has not been coincident with MISO's, this methodology  
6 change reduces our reserve obligation. For 2013, the Company's reserve  
7 margin was approximately 200-300 MW lower than what we used in 2010  
8 Resource Plan analysis. Relatively small changes in coincidence factors,  
9 combined with adjustments in MISO's UCAP capacity calculations and  
10 adjustments in MISO's annual loss of load expectation calculations, can swing  
11 reserve requirements on our system measurably. However, it is not clear at  
12 this time how reserve calculations might change between now and the 2017-  
13 2019 time period for which we currently have identified resource needs.

14  
15 Figure 3 below illustrates the impact of this uncertainty by applying the  
16 coincident and non-coincident methodologies to various demand forecasts  
17 considered during our 2010 Resource Plan proceedings. The figure shows  
18 that very small changes can result in material swings in the required amount of  
19 capacity.

20

1 **Figure 3:**  
 2 **Impact of Coincident and Non-Coincident Peak Methodologies on**  
 3 **Resource Plan Need Forecasts**



4 Source: Department of Commerce, Docket No. E002/CN-12-1240 (Dec. 10, 2014)

5  
 6  
 7 Q. WHAT IS THE MOST RECENT FORECAST OF THE COMPANY'S NEED IN ITS 2015  
 8 RESOURCE PLAN?

9 A. The Company's recently filed Resource Plan shows a modest amount of  
 10 excess capacity (between 1 and 2.5 percent) from 2015 through 2018 and  
 11 virtually no excess capacity on a system-wide basis in 2019 and 2020. In 2021,  
 12 the system then regains a small amount of excess capacity by increasing our  
 13 current Manitoba Hydro purchase with anticipated new capacity that is under  
 14 development. In 2024, however, we again show a system deficit of 234 MW.  
 15 This load balance profile suggests that we are at risk of capacity deficits  
 16 beginning in 2019 and 2020 if our projected loads change by even a very small  
 17 amount. Indeed, even the 0.5 to 2.5 percent excess capacity shown on our

1 assumed supply portfolio is modest given that normal forecast variability can  
2 result in demand swings of 200 MW (2 percent) or more.

3  
4 Q. WHAT ARE THE COMPANY'S OPTIONS FOR MANAGING THIS RISK OF CHANGES  
5 IN CUSTOMER LOAD FROM WHAT IS FORECASTED?

6 A. The normal variability we have experienced between load projections and  
7 actual results in recent years indicates it is appropriate to acquire additional  
8 generation as a hedge. While we recognize that we could potentially purchase  
9 short-term capacity from the MISO voluntary capacity market at then-  
10 prevailing rates for any capacity shortfall, we must also consider that existing  
11 and proposed retirements of baseload units in the MISO footprint may result  
12 in a shortfall of capacity across the footprint leading to higher capacity prices  
13 in the MISO voluntary short-term capacity market. Prudent planning includes  
14 balancing the risk of exposure to the capacity market in the next five years  
15 against the cost of building additional capacity in the 2019/2020 time-frame,  
16 which will be necessary by 2024 in any event.

17  
18 Our 2015 Resource Plan includes a scenario that reflects all of our currently  
19 contemplated resources. This includes: (1) the 98 MW creditable capacity  
20 (187 MW nameplate) of the solar portfolio which is the subject of Case No.  
21 PU-14-810; (2) the 278 MW creditable capacity (345 MW nameplate) of the  
22 Calpine Project PPA; (3) the up-to 71 MW creditable capacity (100 MW  
23 nameplate) of the Geronimo Solar PPA; (4) the 207 creditable capacity of  
24 the Black Dog 6 combustion turbine unit (215 MW nameplate); (5) a new  
25 short-term (four-year) 75 MW capacity exchange with Manitoba Hydro; and  
26 (6) additional resources contemplated in our 2015 Resource Plan. If all of this  
27 contemplated new generation is deployed, it will result in a system surplus in

1 the 2019-2020 timeframe of about 6 to 7 percent (550 MW in 2019 and 685  
 2 MW in 2020) and address our resource need in 2024.

3  
 4 Table 2 provides a summary of this analysis on a system-wide basis:

5  
 6 **Table 2:**  
 7 **System Capacity Forecast (MW)**  
 8 **(2014 Forecast)**

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Long/(Short) (existing system)	177	142	242	91	8	0	231	182	163	(234)
Resources Approved by the MPUC	-	-	-	71 <sup>3</sup>	278 <sup>4</sup> 71 <sup>3</sup>	207 <sup>5</sup> 278 <sup>4</sup> 71 <sup>3</sup>	556 <sup>6</sup>	556 <sup>6</sup>	556 <sup>6</sup>	556 <sup>6</sup>
Proposed Additional Resources	-	73 <sup>1</sup>	73 <sup>1</sup>	98 <sup>2</sup> 73 <sup>1</sup>	98 <sup>2</sup> 73 <sup>1</sup>	98 <sup>2</sup>	98 <sup>2</sup>	98 <sup>2</sup>	98 <sup>2</sup>	98 <sup>2</sup>
Resources in the 2016 IRP Preferred Plan	-	-	-	-	-	-	89	89	118	171
Aggregate Additional Resources	-	73	73	243	551	684	773	773	803	855
Long/(Short) Position (assumes all additions)	<b>177</b>	<b>216</b>	<b>315</b>	<b>334</b>	<b>529</b>	<b>685</b>	<b>1,004</b>	<b>956</b>	<b>965</b>	<b>621</b>
<b>Notes</b>	1- Manitoba Hydro 75 MW additional capacity exchange (four years). 2- 187 MW Solar portfolio (98 MW accreditation) 3- Geronimo Solar Project PPA (2016 in-service; 2018 MISO accreditation) 4- Calpine Project PPA 5- Black Dog Unit 6 6- Geronimo PPA + Calpine Project PPA + Black Dog Unit 6									

9  
 10 Q. WHAT IS THE IMPACT IN NORTH DAKOTA?

11 A. We prepared a similar analysis showing the same information on a North  
 12 Dakota load-allocated basis. The following Table 3 provides the output of  
 13 that analysis:  
 14

**Table 3:  
North Dakota Allocated System Capacity Forecast (MW)  
(2014 Forecast)**

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ND as a Percentage of NSP System	4.94	4.99	5.01	5.05	5.08	5.13	5.19	5.22	5.34	5.38
Long/(Short) (existing system)	9	7	7	5	0	0	12	10	9	(13)
ND Allocation of Additional Resources	-	4	4	12	28	35	40	40	43	46
Long/(Short) (assumes all additions)	9	11	11	17	28	35	52	50	52	33

This shows that on a North Dakota allocated basis, there is no statistical excess capacity in 2019 and 2020. While the number increases again in 2021 due to the addition of new capacity from Manitoba Hydro, it is appropriate to plan the system to include additional capacity that addresses the 2019 and 2020 ‘pinch point’ and remains available in 2024 when we begin to experience forecasted capacity deficits.

### III. GERONIMO SOLAR PPA

Q. PLEASE DESCRIBE THE GERONIMO SOLAR PPA?

A. The 20-year Geronimo Solar PPA will provide up to 100 MW of nameplate capacity from distributed solar facilities located at up to 24 sites in Minnesota, and ranging in size from 2 to 10 MW. Each solar facility will interconnect to the Company’s distribution substations, utilizing excess available transfer capability to inject power into the system at distribution voltage.

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The PPA is based upon the Company’s Model Solar PPA, which has been used in several jurisdictions to procure solar energy. This allowed the Company to utilize standardized terms and conditions that it has used with other solar generation, resulting in enhanced certainty and consistency with other Company contracts.

Q. WHAT ARE THE PRINCIPAL TERMS OF THE GERONIMO SOLAR PPA?

A. The Geronimo Solar PPA has a single bundled per MWh capacity/energy price structure. This means that all payments to Geronimo are on a per-MWh basis, with no separate payment for capacity. Geronimo is contractually committed to obtain approximately 71 percent capacity accreditation for the total nameplate capacity it achieves under the PPA. This means that if the nameplate capacity of the project is 100 MW, the Company will obtain about 71 MW of accredited capacity pursuant to the MISO accreditation process. The PPA contains a mechanism to compensate the Company if the capacity level is less than Geronimo has committed to in the PPA.

To accommodate tax equity financing, the parties negotiated a single PPA structure covering all of the solar facility sites (each site referred to as a “phase”), with the possibility of the PPA being split into a maximum of three separate PPAs as needed post-COD for tax equity financing purposes. As a result of this structure, each phase is treated as a separate project pre-COD, and the Company cannot terminate the single PPA because of any action or inaction with respect to a particular phase that occurs prior to COD. The Company retains, however, pre-COD global default and termination rights for bad acts and defaults by Geronimo. This structure also provides Geronimo

1 the flexibility to reduce the aggregate size of the nameplate capacity of the  
2 PPA if circumstances warrant. The maximum nameplate capacity that may be  
3 delivered under the PPA is capped at 100 MW.

4  
5 Geronimo is also entitled to a 30 percent investment tax credit (ITC) for all  
6 project phases that achieve commercial operation by the end of 2016. The  
7 30 percent ITC will automatically reduce to 10 percent absent Congressional  
8 action for projects going into service beginning in 2017. This means that  
9 development and construction decisions are time-sensitive for Geronimo to  
10 ensure that all the phases covered by the PPA will timely qualify for the  
11 available ITC at the end of 2016.

12  
13 Q. PLEASE DESCRIBE THE RISKS OF THE PPA.

14 A. The Geronimo Solar PPA had risks with respect to (1) potential delay; (2)  
15 transmission interconnection; (3) total capacity and capacity accreditation; (4)  
16 curtailment costs; (5) environmental costs; (6) financial security; (7)  
17 construction and operational issues; and (8) the phase-in approach to the  
18 distributed facility sites.

19  
20 Q. PLEASE DESCRIBE HOW THE DELAY RISK HAS BEEN MITIGATED?

21 A. Geronimo's pricing depends in part on its phases qualifying for the ITC.  
22 There is no mechanism to increase the price if phases go into service after  
23 expiration or reduction of the ITC (currently scheduled to reduce from 30 to  
24 10 percent at the end of 2016). However, the PPA allows Geronimo to stop  
25 development of phases and effectively reduce the size of the project if they are  
26 unable to complete them in time to qualify for the ITC.

27

1 Q. WHAT IS THE RISK WITH RESPECT TO TRANSMISSION INTERCONNECTION COST?

2 A. None of the Project's phases require interconnection to the transmission grid;  
3 they are all connected to the Company's system at the distribution level.  
4 Geronimo bears all distribution interconnection costs.

5

6 Q. WHAT ARE THE CAPACITY AND CAPACITY ACCREDITATION RISKS AND HOW  
7 HAVE THEY BEEN MITIGATED?

8 A. The PPA can deliver up to 100 MW of nameplate capacity. To incentivize  
9 Geronimo to deliver the highest possible capacity up to that cap, the PPA  
10 includes a scale of damage payments that escalates the further the aggregate  
11 MW level of the PPA falls short of the 100 MW cap. In addition, failure to  
12 obtain 71 percent accreditation of the actual nameplate capacity delivered  
13 under the PPA results in damages for the period of the accredited capacity  
14 shortfall.

15

16 Q. PLEASE DESCRIBE THE COMPANY'S MITIGATION OF THE CURTAILMENT RISK.

17 A. The PPA provides a mechanism to determine whether and under what  
18 circumstances the facility's output is curtailed. These provisions are similar to  
19 those typically included in our wind and other solar PPAs, modified only to  
20 account for technical differences related to the PPA's distributed solar facility  
21 sites. Curtailments arising out of the operation of the system are generally not  
22 compensable, while curtailments arising for economic reasons generally are  
23 compensable. This is because economic curtailments will be initiated when it is  
24 more economic for the Company to curtail the resource (due to negative  
25 LMPs, for example) than to let the resource continue to generate (at negative  
26 prices). Economic curtailment limits the total cost paid by customers. Unlike  
27 wind, solar is an "on-peak" resource and will likely experience fewer

1 curtailments due to negative LMPs or system balancing issues. This is true for  
2 both distribution and transmission interconnected resources.

3

4 Q. HOW DOES THE PPA MITIGATE THE RISK OF ENVIRONMENTAL COSTS?

5 A. Under the PPA, the Company will own the environmental and renewable  
6 energy credits.

7

8 Q. WHAT IS THE MITIGATION OF THE FINANCIAL RISK OF THE PPA?

9 A. The Company negotiated pre-COD and post-COD security fund amounts to  
10 protect the Company generally from the range of financial risks associated  
11 with the Geronimo Solar PPA. In addition, Geronimo takes all ITC  
12 qualification risks.

13

14 Q. PLEASE DESCRIBE THE MITIGATION OF THE PPA'S CONSTRUCTION AND  
15 OPERATIONAL RISKS.

16 A. The Company accepted Geronimo's proposal that completed phases can be  
17 recognized as having achieved COD in a 120-day window that begins  
18 September 1, 2016, and ends December 31, 2016. For each phase that fails to  
19 achieve COD by December 31, 2016, Geronimo will have the option to  
20 complete additional project phases, but will be required to pay liquidated  
21 damages until the phase achieves COD. The PPA also includes protective  
22 measures such as specific performance, step-in rights, actual damages, and  
23 termination.

24

25 Q. HOW HAVE THE RISKS ASSOCIATED WITH THE PHASE-IN APPROACH TO THE  
26 DISTRIBUTED SOLAR FACILITY SITES BEEN MITIGATED?

27 A. As I previously explained, the PPA has been negotiated to provide flexibility

1 both as to the timing of completing phases and the aggregate capacity of all  
2 completed phases. In order to stage construction and to maximize the  
3 potential for project phases to qualify for the ITC, we anticipate that some  
4 number of phases may be completed before September 1, 2016, when the PPA  
5 authorizes the project to commence commercial operation at the contract price.  
6 The PPA provides that the Company will take pre-COD energy produced by a  
7 phase before that date. However, the pricing for this pre-COD energy is  
8 based on the prevailing market rate. Conversely, as mentioned before, if  
9 circumstances warrant, the developer can reduce the aggregate nameplate  
10 capacity of the PPA by eliminating phases and making the agreed-upon  
11 capacity buy-down payment to the Company.

12  
13 Q. WHAT IS THE MITIGATION FOR THE RISKS ASSOCIATED WITH GOVERNMENTAL  
14 AND OTHER THIRD PARTY APPROVALS AND AUTHORIZATIONS?

15 A. These risks include obtaining required governmental permits and approvals,  
16 obtaining required third-party contracts that are necessary for the project to be  
17 completed, and internal approvals of regulatory revisions of the PPA's terms.  
18 The PPA's "conditions precedent" provide a mechanism for terminating the  
19 PPA if these are not obtained. There are two primary conditions that  
20 Geronimo must meet to perform under the PPA: (1) a master site permit for  
21 all the facility sites in the aggregate or individual site permits for each phase;  
22 and (2) satisfactory arrangements for the interconnection of the project  
23 phases.

24  
25 The Company has one important condition precedent. Within ten days after  
26 receipt of an order of the MPUC approving the PPA, The Company must  
27 request approval of the PPA from this Commission. The MPUC Order

1 approving the Geronimo Solar PPA was issued February 5, 2015. The present  
2 filing was made on February 13, 2015, within the ten day window.

3  
4 The Company's obligation under the PPA is to seek an order from the  
5 Commission that affirmatively states the Company's execution of the PPA is  
6 reasonable, in the public interest, and that all costs incurred under the PPA are  
7 recoverable from our customers subject to ongoing prudency review of  
8 Company's performance and administration of the PPA. The Company  
9 retains the right to terminate the PPA if the Commission does not approve  
10 the PPA, or denies the Company recovery of the costs incurred under the  
11 PPA as currently allocated to North Dakota customers by ratemaking  
12 mechanisms currently in effect.

#### 13 14 **IV. PRUDENCE OF GERONIMO SOLAR PPA**

15  
16 Q. WHAT FACTORS SHOULD BE CONSIDERED IN DETERMINING THE PRUDENCE OF  
17 THE GERONIMO SOLAR PPA?

18 A. The two principal factors are (1) whether the Geronimo Solar PPA is  
19 appropriate to meet the Company's identified need, and if so, (2) does it  
20 effectively meet the need at a reasonable cost. Mr. Haeger addresses how the  
21 addition of the up to 71 MW of capacity from the Geronimo Solar PPA meets  
22 our need, and I address how the PPA meets that need at a reasonable cost.

23  
24 Q. HOW DID THE COMPANY ANALYZE THE WHETHER THE GERONIMO SOLAR  
25 PPA MEETS THE COMPANY'S NEED AT A REASONABLE COST?

26 A. The Company used the Strategist resource planning model to evaluate the  
27 costs of the up-to-100 MW Geronimo Solar PPA. Strategist simulates the

1 operation of the NSP System and estimates the total cost of energy over the  
2 life of the project on a present value basis. We also used the model to test  
3 results under a range of input assumptions. To assess the impact on customer  
4 costs, we simulated the operation of the NSP System with and without the  
5 addition of the Geronimo Solar PPA. For purposes of this analysis we  
6 considered the PPA in isolation and not in combination with the other  
7 proposed new generators.

8  
9 MISO generally dispatches solar production ahead of other generation such as  
10 gas and coal-based generation. Consequently, the more solar energy  
11 produced, the less fossil generation is operated. And when the energy from  
12 solar resources is produced, it displaces a similar amount of energy that would  
13 either have been produced by the Company or purchased elsewhere. The  
14 Strategist analysis identifies a displacement of approximately 200,000 MWh of  
15 fossil generation, which accounts for the differences in the cost of system  
16 operation with and without the Geronimo Solar PPA.

17  
18 We also conducted various “sensitivity tests” to evaluate how the Geronimo  
19 Solar PPA will affect system costs under different circumstances. The  
20 sensitivities analyzed include the effect on system costs if one assumes (1) the  
21 Fall 2011 Forecast of capacity need of 150-500 MWs in the 2017-2019  
22 timeframe), (2) no MISO market purchases available to supplement system  
23 resources (Markets Off), and (3) higher and lower gas costs. Table 4 below  
24 provides the results of these analyses.

25

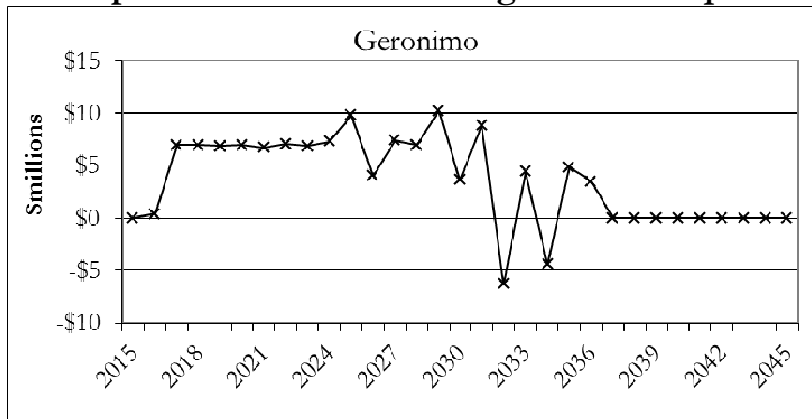
1 **Table 4:**  
 2 **Net PVRR Cost/Savings of Geronimo PPA for Key Sensitivities**

<u>Sensitivities</u> =>	Base	2012 Load Forecast	Low Gas	High Gas	Markets Off	MN Assumptions (PVSC)
Geronimo PPA vs Base Case with ND Assumptions	\$62	\$71	\$76	\$44	\$49	\$35

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 5 Q. HOW ARE THE GERONIMO SOLAR PPA COSTS SPREAD OVER TIME?

6 A. Figure 4 below illustrates annual net costs or savings over the 20-year life of  
 7 the PPA for the Geronimo Solar Project that lead to the \$62 million PVRR  
 8 impact. As shown over the term, the Geronimo Solar Project moves from net  
 9 cost to net savings on an annual basis in the out years due to the displacement  
 10 of thermal energy resources.

11  
 12 **Figure 4:**  
 13 **Annual Net Costs (Savings)**  
 14 **Compared to Base Case Using ND Assumptions**

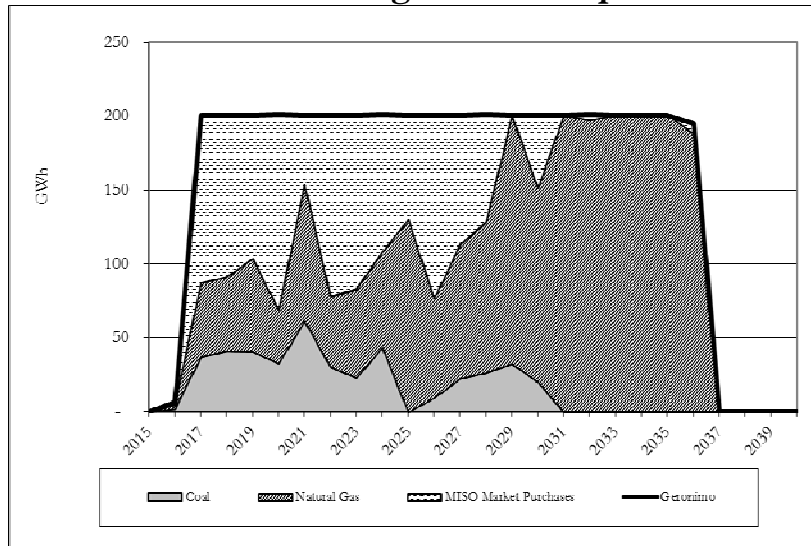


15  
 16  
 17 Q. WHAT IS THE PROFILE OF THE MORE EXPENSIVE GENERATION THAT THE  
 18 CALPINE PROJECT PPA DISPLACES?

19 A. Figure 5 below illustrates the results of the Strategist dispatch simulations  
 20 using the Base Case under North Dakota assumptions (i.e., a “Markets On”  
 21 scenario with no additional renewable generation and no externalities or

1 carbon cost). In this scenario Strategist may choose to purchase market  
2 energy to meet system need. Approximately 60 percent of the solar  
3 generation displaces natural gas-based generation, 10 percent displaces coal,  
4 and 30 percent displaces market energy.

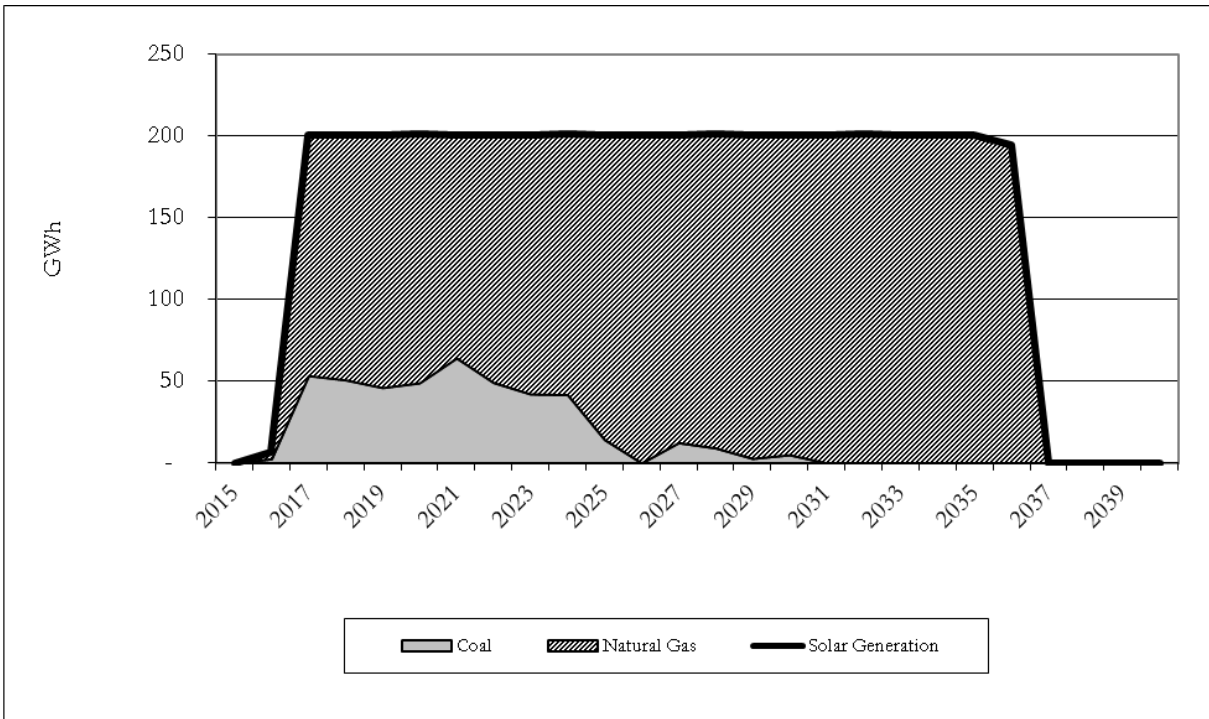
5  
6 **Figure 5:**  
7 **Strategist Simulations – Displaced Energy**  
8 **Base Case Using ND Assumptions**



9  
10  
11 Figure 6 below illustrates the results of the Strategist dispatch simulations  
12 under the Markets Off scenario, when just the NSP System is analyzed and  
13 only the Company's native generation is displaced by the Geronimo Solar  
14 Project. In this scenario, the majority of the solar generation (approximately  
15 89 percent) displaces natural gas-based generation, with the remaining 11  
16 percent is expected to displace coal generation.

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**Figure 6:  
Strategist Simulations – Displaced Energy  
Markets Off**



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To further illustrate the magnitude of the displacement of fossil fuel generation, we analyzed the impact of the Geronimo Solar PPA on our use of natural gas and energy market purchases to meet our customers’ demand. Table 5 below shows the levels of natural gas consumption and market purchases for the Base Case using North Dakota assumptions (i.e. the NSP System without the Geronimo Solar Project), and the reduction that would occur in those levels due to the addition of the Geronimo Solar PPA to the system. As shown in the table, the Geronimo Solar PPA is projected to displace 20 Bcf of natural gas and offset over 1.1 million MWhs of market purchases during its 20-year term. This provides the Company a hedge against increases in the costs of natural gas and market energy.

**Table 5:  
Hedge Value**

Total System 2017-2036	Natural Gas <i>bcf</i>	Market Purchases <i>GWh</i>
<b>Base Case Using ND Assumptions</b>	1,466	104,074
<b>Geronimo</b>	(20)	(1,138)

Q. WHAT IMPACTS WILL THE GERONIMO SOLAR PPA HAVE ON CUSTOMER RATES?

A. While the Geronimo Solar Project represents a large utility scale solar energy acquisition, we estimate that the customer rate impacts will be mitigated when spread across the entire system, because the NSP System is so large in comparison. As shown in Table 6 below, our Strategist dispatch simulation forecasts that for most years the rate impact of the Geronimo Solar Project will be nearly offset by decreases in the cost of fossil fuel and other purchased energy.

**Table 6:  
Geronimo Solar PPA Impacts  
(¢/kWh)**

GERONIMO	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Base Rates	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh
Fuel Clause	0.000¢/kWh	0.001¢/kWh	0.045¢/kWh	-0.045¢/kWh	0.046¢/kWh	0.048¢/kWh	0.049¢/kWh	0.050¢/kWh	0.051¢/kWh	0.052¢/kWh	0.053¢/kWh
Avoided Fuel & Purchased Power	0.000¢/kWh	0.000¢/kWh	-0.028¢/kWh	-0.029¢/kWh	-0.030¢/kWh	-0.031¢/kWh	-0.033¢/kWh	-0.033¢/kWh	-0.035¢/kWh	-0.035¢/kWh	-0.030¢/kWh

Table 7 below estimates how average rates will be affected by the Geronimo Solar PPA. The initial rate impact in 2017 is expected to be approximately 0.016¢ per kWh, or about 12¢ per month for a customer using 750 kWh, and stay relatively flat at that level through 2024. The net rate impact will increase somewhat in 2025 when the benefit of avoided fuel and purchased power decreases due to a shift in our mix of system resources and fixed PPA prices approaching the level of anticipated market energy prices.

**Table 7:  
Geronimo Solar Net Rate Impacts (10 Years)**

2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
0.000¢ /kWh	0.001¢ /kWh	0.016¢ /kWh	0.016¢ /kWh	0.016¢ /kWh	0.016¢ /kWh	0.016¢ /kWh	0.016¢ /kWh	0.016¢ /kWh	0.017¢ /kWh	0.023¢ /kWh

Q. DID THE COMPANY IDENTIFY ANY OTHER BENEFITS OF THE GERONIMO SOLAR PPA?

A. Yes. We identified two qualitative benefits of the Geronimo Solar PPA in addition to the quantifiable benefits identified above: (1) an environmental hedge benefit; and (2) the ITC qualification benefit.

Q. PLEASE DESCRIBE THE GERONIMO SOLAR PPA'S ENVIRONMENTAL HEDGE BENEFIT.

A. Solar generation provides an emissions-free energy source that can work well in combination with other capacity resources, such as natural gas facilities. Increasing carbon-free generation will further our goals of early compliance with new and emerging emissions requirements and targets.

As noted in our 2015 Resource Plan, this includes pending environmental regulation such as NOx regulations that may impact the continued use of our Sherco Units 1 and 2, as well as EPA's proposed Clean Power Plan. As part of that plan, the Company is proposing to add approximately 2,400 MW of utility-scale and customer-driven small solar resources over the next 15 years. This additional solar generation along with other resource choices should position us well for long-term compliance with greenhouse gas reductions. While our Resource Plan contemplates additional utility-scale solar being deployed in 2024 and beyond, we believe it is a reasonable policy choice to

1 advance 100 MW of that target and deploy the Geronimo Solar Project at this  
2 time.

3  
4 Furthermore, the Geronimo Solar PPA positions us to address known long-  
5 term changes to the NSP System beyond 2024. These changes will result in  
6 the Company needing to replace or extend the operating lives of nearly 75  
7 percent of the energy producing resources on the NSP System over the next  
8 20 years.

9  
10 Q. PLEASE EXPLAIN THE ITC QUALIFICATION BENEFIT OF THE GERONIMO  
11 SOLAR PPA.

12 A. The Geronimo Solar Project is dependent upon obtaining the 30 percent ITC  
13 to offset a significant proportion of the costs of the project. The 30 percent  
14 ITC applies to any project that goes into service by the end of 2016. The ITC  
15 automatically reduces to 10 percent for projects that go into service after 2016,  
16 and we are not assuming that the higher ITC rate will be renewed to prevent  
17 the imminent reduction in this significant generation subsidy.

18  
19 Our customers are increasingly interested in new energy choices, and state and  
20 federal policies are promoting solar as a way to reduce GHG emissions and  
21 support local economic development. Thus, there is a benefit in pursuing  
22 additional solar generation at this time to capture the higher ITC generation  
23 subsidy and realize the other benefits of solar generation on our integrated  
24 system.

25

**V. PRUDENCE OF PROPOSED RESOURCE PORTFOLIO  
(BLACK DOG, CALPINE, AND GERONIMO)**

Q. DID THE COMPANY ANALYZE THE COSTS AND BENEFITS OF THE ENTIRE RESOURCE PORTFOLIO IT IS PROPOSING?

A. Yes. To provide context for the Commission’s evaluation of this ADP request, we conducted modeling that identifies the costs of various combinations of the three resources we propose to acquire: Black Dog Unit 6, the Calpine Project PPA, and the Geronimo Solar PPA. Tables 8 and 9 below present the PVRR results of the specified combinations of resources, and the results of the same sensitivity tests that we conducted for the Calpine Project PPA.

**Table 8:  
PVRR Results (\$millions)**

Scenarios	Base	2011 Load Forecast	Low Gas	High Gas	Markets Off	MN Assumptions (PVSC)
Base case using ND Assumptions	\$44,949	\$49,279	\$41,260	\$50,050	\$45,957	\$51,971
Add Geronimo Solar PPA	\$45,011	\$49,350	\$41,336	\$50,094	\$46,006	\$52,005
Add Calpine Mankato CC PPA	\$44,937	\$49,257	\$41,271	\$50,010	\$45,883	\$51,944
Add Black Dog 6	\$44,836	\$49,162	\$41,159	\$49,923	\$45,825	\$51,868
Add Geronimo & Calpine	\$45,012	\$49,328	\$41,358	\$50,070	\$45,947	\$51,992
Add Calpine & BD6	\$44,842	\$49,155	\$41,186	\$49,902	\$45,767	\$51,849
Add Geronimo & Calpine & Black Dog 6	\$44,929	\$49,219	\$41,286	\$49,974	\$45,842	\$51,908

**Table 9:  
Incremental PVRR from Base Case (\$millions)**

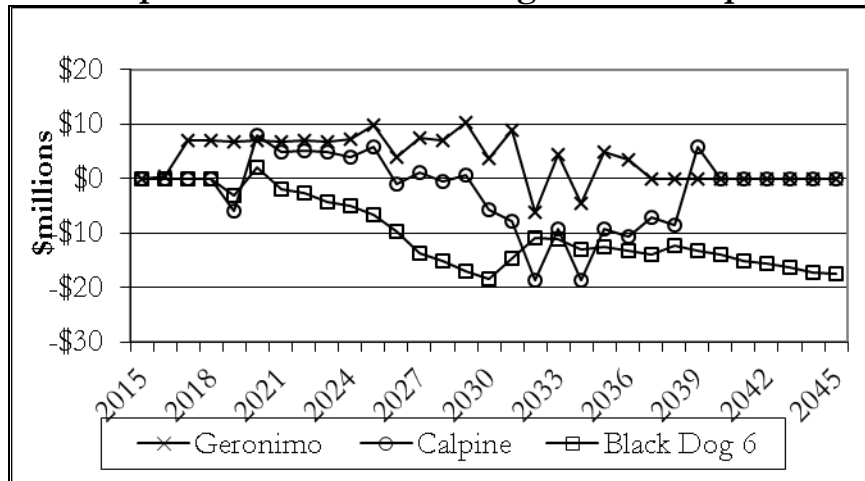
Scenarios	Base	2011 Load Forecast	Low Gas	High Gas	Markets Off	MN Assumptions
Base case using ND Assumptions	\$0	\$0	\$0	\$0	\$0	\$0
Add Geronimo Solar PPA	\$62	\$71	\$76	\$44	\$49	\$35
Add Calpine Mankato CC PPA	(\$11)	(\$22)	\$10	(\$40)	(\$74)	(\$27)
Add Black Dog 6 CT	(\$112)	(\$118)	(\$101)	(\$127)	(\$132)	(\$103)
Add Geronimo & Calpine	\$63	\$48	\$98	\$20	(\$10)	\$21
Add Calpine & Black Dog 6	(\$107)	(\$124)	(\$74)	(\$147)	(\$190)	(\$122)
Add Geronimo & Calpine & Black Dog 6	(\$20)	(\$60)	\$26	(\$76)	(\$115)	(\$63)

1 Notably, the addition of the Calpine Project PPA together with Black Dog  
 2 Unit 6 provides the most Present Value of Revenue Requirements (PVRR)  
 3 savings of the combinations provided. Further, including the Geronimo Solar  
 4 PPA in combination with the Calpine Project PPA and Black Dog Unit 6  
 5 provides a net reduction in the PVRR in all scenarios except the low gas case.

6  
 7 Q. WHAT IS THE AGGREGATE IMPACT OF ADDING THE THREE RESOURCES OVER  
 8 TIME?

9 A. Figure 7 below shows the aggregate impact of the Geronimo Solar PPA, the  
 10 Calpine Project PPA, and Black Dog Unit 6.

11  
 12 **Figure 7:**  
 13 **Annual Net Costs (Savings) (without CO2)**  
 14 **Compared to Base Case using ND Assumptions**

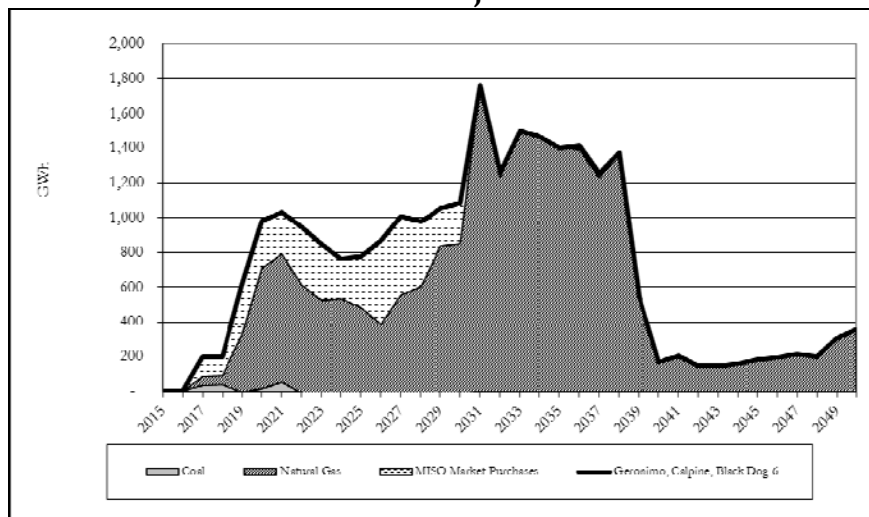


15  
 16  
 17 Q. WHAT IS THE PROFILE OF THE MORE EXPENSIVE ENERGY DISPLACED BY THE  
 18 ADDITION OF BLACK DOG UNIT 6, THE CALPINE PROJECT PPA, AND THE  
 19 GERONIMO PPA?

20 A. Figure 8 below illustrates the results of the Strategist dispatch simulations for  
 21 the Base Case using North Dakota assumptions (i.e., a “Markets On” scenario

1 with no additional renewable generation). In this scenario Strategist may  
 2 choose to purchase market energy to meet system need. Approximately 85  
 3 percent of the aggregate generation displaces natural gas-based generation, 16  
 4 percent displaces market energy, and coal generation has a net output increase  
 5 of 1 percent over the analysis period (2014-2053).

6  
 7 **Figure 8:**  
 8 **Strategist Simulations - Displaced Energy Base Case Using ND**  
 9 **Assumptions for combination of Geronimo, Calpine, and Black Dog 6**  
 10 **Projects**



11  
 12  
 13 As shown, the overall impact of adding all three resources on the operation of  
 14 the NSP System is displaced natural gas generation.

15  
 16 Q. WHAT IS THE AGGREGATE RATE IMPACT OF ADDING BLACK DOG UNIT 6, THE  
 17 CALPINE PROJECT PPA, AND THE GERONIMO PPA TO THE SYSTEM?

18 A. Table 10 below shows the rate impact of the various combinations.

19

1  
2

**Table 10:  
Annual Rate Impact Analysis**

GERONIMO	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Net Rate Impact	0.000¢/kWh	0.001¢/kWh	0.016¢/kWh	0.016¢/kWh	0.016¢/kWh	0.016¢/kWh	0.016¢/kWh	0.016¢/kWh	0.016¢/kWh	0.017¢/kWh	0.023¢/kWh
CALPINE	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Net Rate Impact	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	(0.014¢/kWh)	0.019¢/kWh	0.012¢/kWh	0.012¢/kWh	0.011¢/kWh	0.009¢/kWh	0.014¢/kWh
BLACK DOG 6	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Net Rate Impact	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	(0.007¢/kWh)	0.005¢/kWh	(0.004¢/kWh)	(0.006¢/kWh)	(0.010¢/kWh)	(0.011¢/kWh)	(0.015¢/kWh)
GERONIMO + CALPINE	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Net Rate Impact	0.000¢/kWh	0.001¢/kWh	0.016¢/kWh	0.016¢/kWh	0.003¢/kWh	0.035¢/kWh	0.027¢/kWh	0.028¢/kWh	0.026¢/kWh	0.032¢/kWh	0.023¢/kWh
CALPINE + BLACK DOG 6	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Net Rate Impact	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	(0.021¢/kWh)	0.018¢/kWh	0.029¢/kWh	0.019¢/kWh	0.009¢/kWh	0.006¢/kWh	0.003¢/kWh
GERONIMO + CALPINE + BLACK DOG 6	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Net Rate Impact	0.000¢/kWh	0.001¢/kWh	0.016¢/kWh	0.016¢/kWh	0.006¢/kWh	0.034¢/kWh	0.055¢/kWh	0.046¢/kWh	0.036¢/kWh	0.021¢/kWh	0.016¢/kWh

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5 Q. DOES THIS CONCLUDE YOUR TESTIMONY?

6 A. Yes, it does.



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## PROFESSIONAL EXPERIENCE

### **Director Resource Planning and Bidding**

**July 2014 –Present**

*Xcel Energy, Minneapolis, MN*

- Develop and direct the systems, processes and personnel required to prepare effective and prudent long term system plans for each of the four Xcel Energy operating utilities.
- Develop and direct the systems, processes and personnel required to conduct effective and fair power solicitation processes to procure needed power and energy to meet native load demand and energy requirements and achieve cost reductions in the Xcel supply portfolios.
- Direct acquisition of up to 800 MW per year of additional capacity and for management of the various state resource planning processes in a manner to fulfill requirements and meet company objectives meeting native load requirements and company asset growth goals.

### **Manager Power Supply Planning**

**March 2012—June 2014**

*Old Dominion Electric Cooperative (ODEC), Glen Allen, VA*, a large G&T Cooperative serving 11 distribution cooperative members located in VA, MD and DE who serve over 1.3 million customers with a peak load of about 3000 MW.

- Directed long term power supply area of ODEC managing all ongoing power supply analysis, requests for proposals, PPA negotiations for renewable and thermal resources and planning analysis and issue or hot topic updates responsive to ODEC Board requests which meets monthly.
- Directed selection, implementation and ongoing management and updates of all planning models and data sources used for long term planning.
- Worked effectively and collaboratively with all areas of ODEC to successfully fulfill corporate and business unit objectives for current budget year.
- Actively develop staff providing growth opportunities within power supply planning and with other areas of ODEC.
- Kept abreast of developments and trends in PJM and electric industry and evaluate potential impact as a part of long term planning efforts and updates to executive management and Board members.

### **President, S&P Energy, LLC**

**October 2011--February 2012**

I formed S&P Energy LLC October 2011 in response to interest by others in my network to work with other consulting firms and development companies with all aspects of renewable project development and marketing (permitting, interconnection, off-take prospects and contracting, RFP responses, etc.).

- Worked as contract consultant with Bridge Energy Group as key resource for interconnection report development and filing support for large Californian utility to the California ISO involving over 120 reports (November 2011 through January 2012)
- Pursued consulting contract negotiations for work with a couple renewable project developers and biomass fuel production facility developers.

### **Sr. Manager, Development North central and Eastern Regions**

**April 2009—May 2011**

*RES Americas, Minneapolis, MN*, a national wind and solar project development and construction company. I have management responsibility of regional office in Minneapolis under Regional Vice

President Minneapolis Office has active project pipeline of nearly 2000 MW.

- Direct project management responsibility for development and power marketing of 300 MW Wind Project in southeastern, MN Successfully initiated and navigated permitting to advanced stage resulting in MPUC unanimous October 2010 approval of site permit and certificate of need. Led effort to successfully gain unanimous Mower County Commissioner approval of permits for two transmission routes and three substation sites. Provided direction and support for project interconnection options and study evaluation and effective and timely interaction with Midwest Independent System Operator (MISO) staff.
- As member of company-wide management team participated in 2010 effort to evaluate and refine RES Americas business strategy and identify key implementation efforts.
- Established and maintained project marketing relationships and RFP follow-up with electric utilities in MN, WI, IA, OH and TN.
- Actively monitored renewable market project development and sale opportunities which resulted in relationships with new power purchase prospects in upper Midwest and Eastern US.
- Led effort to evaluate potential biomass fuel opportunity and led effort to develop a biomass fuel business plan for generation market in US and Europe. This effort relied on extensive biomass fuel and biomass power market research.
- Identified and completed initial due diligence for potential acquisition of biomass fuel planting, harvesting and combustion technologies for utility-scale greenfield and retrofit biomass power generation projects.
- Completed preliminary work on strategic approach for wind project development in eastern US based on current and projected changes in renewable market and electric utility generation plans.

**Several key positions with Minnesota Power, Duluth, MN** **June 1999—April 2009**

An 1800 MW investor-owned electric utility serving 140,000 customers.

**Renewable Energy Project Development Manager** **October 2006—April 2009**

- Developed and led turbine 2008 purchase solicitation, screening and contract negotiation process which resulted in executed contract for 33 turbine project in North Dakota.
- Developed and gained management support for capital budget and project development plan for several 100 MW of wind generation development. Supported executive management's effort to secure budget and initial project approval.
- Initiated and continued to direct multi-year wind prospecting effort which resulted in met tower siting and installation on several project site in northeastern Minnesota. Prospecting effort also identified large area with high average winds within economic distance of grid interconnection. Oversaw successful wind option acquisition effort with sufficient land and wind rights to support substantial wind project development.
- Provided site control and project information necessary to maintain interconnection study process and avoid higher study costs.
- Developed and directed 2004 and 2007 All Source Request for Proposals through bid completeness, evaluation, short-list, contract negotiation and filing with state public utilities commission (all filed contracts approved).
- Successfully led negotiation team for four wind-based power purchase agreements totally 156 MW.
- Developed, maintains and directs implementation of renewable strategy responsive to corporate strategy and direction of key state and federal policies.
- Developed and managed relationships with major wind developers, turbine suppliers and regulators essential for continuing to increase wind portion of Minnesota Power renewable power supply.
- Managed hand-off to project construction team of permitted, sited projects with turbines.
- Provided liaison as needed with MP executive management, outside consultants and key landowners to resolve issues and keep wind generation project progress on schedule.

### **Strategic Initiatives—Project Leader**

**September 2002—October 2006**

- Directed development and implementation of long term power supply request for proposals for renewable, bridge transactions and long term purchases; evaluation and PPA negotiation completion by mid-2005.
- Led multi-area effort to develop and maintain MP's long term plan and develop and defend MP's biennial 15-year Resource Plan filed in September 2004.
- Developed long term power sales responses to RFPs and manage post-bid submittal follow-up through buyer screening and short-list announcement
- Identified long term power market and generation technology developments, trends, events and provide assessment executive management.
- Led and manage multi-area generation strategy development to support executive management decisions.
- Managed long term generation asset sale process including buyer due diligence and definitive agreement development.
- Tracked and provided assessments of regional generation development and performance of existing regional generation.

### **Generation Development –Project Leader**

**June 1999—August 2002**

- Managed internal generation development agreement compliance.
- Identified and screened generation development opportunities as key member of generation development team and lead project due diligence under executive management direction.
- Led effort to deploy and integrate price forecasting and generation opportunity evaluation tools into management decision processes.
- Monitored electric industry and key data sources for competitive intelligence and use this information to improve timing and focus of generation development.

### **ELECTRIC UTILITY INDUSTRY COMMITTEE LEADERSHIP OPPORTUNITIES**

- Edison Electric Institute Renewables Committee. Committee developed policy proposals on federal renewable policy initiatives to reflect position of member investor-owned utilities)
- EPRI Storage and Renewables Task Force (Biomass/Waste Fuel Working Group Chair) Efforts resulted in gaining \$85 million DOE funding commitment to complete engineering and build first 100 MW biomass power using “whole tree energy” technology. Also chaired national biomass technology symposium jointly hosted by EPRI and DOE in Washington, DC.

### **EDUCATION**

**Bachelor of Science and Master of Arts** Environmental Studies

Bemidji State University. Bemidji, MN

Completed extensive graduate studies in organic chemistry, ecology, macro/micro economics, environmental law, politics of pollution and many special topic research papers requiring peer defense. Degree was designed to prepare students to understand industrial environmental issues and regulatory requirements, pollution control and renewable technologies, law and associated environmental impacts. Served as graduate assistant in library and physics lab. Completed graduate internship with regional development commission providing technical support to environmental projects.