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December 29, 2011

Patricia Van Gerpen
Executive Director
SD Public Utilities Commission
500 E. Capitol Ave.
Pierre, SD 57501

RE: Docket EL08-028 – In the Matter of the Consideration of the New PURPA Standards Annual Report

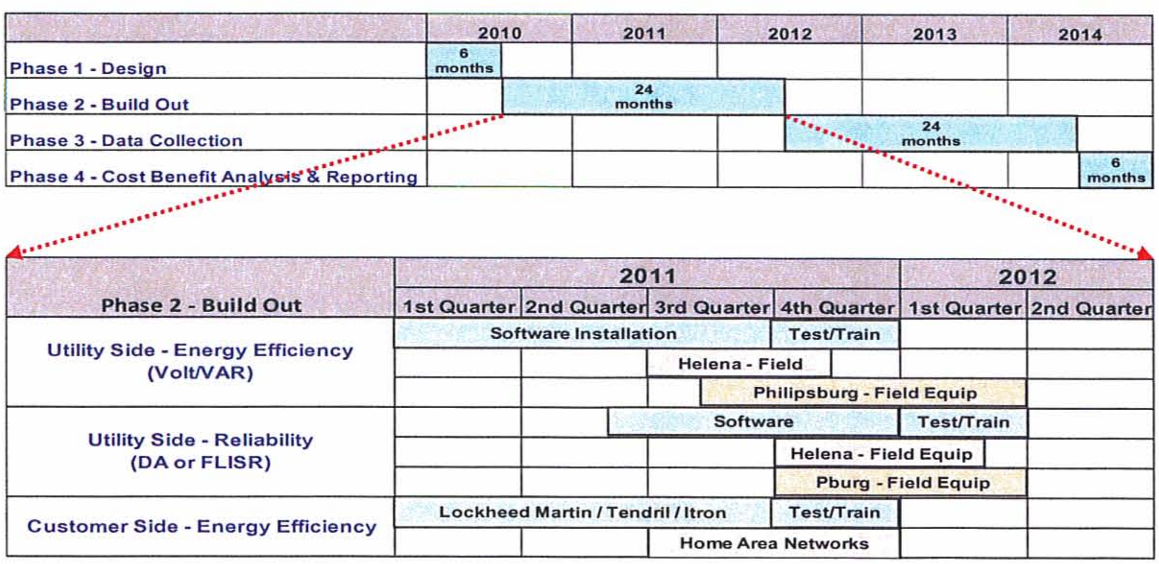
Dear Ms. Van Gerpen:

NorthWestern Corporation, d.b.a. NorthWestern Energy (NorthWestern), hereby submits its 2011 Annual Report regarding Smart Grid Investment Deployment Opportunities in compliance with the South Dakota Public Utilities Commission (Commission) order dated December 18, 2009 in the above referenced matter.

NorthWestern will describe our Smart Grid Deployment Opportunities in South Dakota and other areas of our service territory in relation to the questions presented in the Commission's order.

1. <u>Smart Grid Deployment Opportunities.</u>
NorthWestern is completing Year 2 of its 5-year project in partnership with many other entities in a larger, multi-utility Pacific Northwest Regional Smart Grid Demonstration Project (PNW-SGDP). The PNW-SGDP involves a portion of our Montana service area (Helena and Philipsburg, MT) and other utilities from the northwest region of the United States. Information gathered from this pilot program will be used by NorthWestern in evaluating appropriate Smart Grid technologies for future deployment in South Dakota and Nebraska. Figure 1 below provides a generalized timescale of major phases of the project in Montana.

Figure 1: NorthWestern Energy PNW-SGDP Project Schedule



2. <u>Why or why not was deployment made?</u>
As NorthWestern evaluates Smart Grid technologies, it must consider the cost of the technology versus the benefits to system operations or in providing better reliability and services to our customers. Additionally, if NorthWestern identifies a particular operational need that can be satisfied using more than one possible technology, we will use pilot programs to determine which technology meets our needs at the best cost before engaging in full scale deployment. Results from earlier Smart Grid project deployments around the country show mixed results (e.g., Smart Grid City in Boulder, CO) and suggest proceeding with caution is prudent. By utilizing this approach, we are able to avoid costly mistakes in adopting a technology that does not deliver as expected. Also, participation in the PNW-SGDP is an excellent opportunity for NorthWestern to learn from the many and varied other project participants (and their diverse Smart Grid projects) at a fraction of the cost if NorthWestern attempted all of same itself.

3. <u>The extent of deployment.</u>
NorthWestern's participation in the PNW-SGDP is a $4.2 million effort, termed a "subproject" within the larger regional project footprint. NorthWestern's subproject will test advanced metering infrastructure, demand response, time-of-use pricing and energy management systems for at least 200 residential electric customers and one to two state government buildings/facilities in its Montana service territory. In addition, the subproject will examine the costs and benefits of smart technologies on the electric distribution system, including conservation voltage reduction and Volt/VAR control. A total of four distribution feeder circuits will be fitted with the smart technology. The project will be built out in 2011 and operated in 2012-13. Evaluation of costs and benefits will occur in 2014.

During 2011, NorthWestern made the following investments in South Dakota:

- The installation and use of fault indicators on underground and overhead lines in several locations (transmission and distribution). Fault indicators are devices that are placed on lines and indicate a fault has occurred downstream of the fault indicator by a flashing strobe, a tripped flag, or other indication. Fault indicators assist in locating where a fault has occurred and reduce outage times

- Installing SCADA/RTU (equipment capable of remotely monitoring the status of electric system equipment and controlling the actions of such equipment). Examples of equipment where remote control was recently added include breakers, reclosers, substation power transformers, and switches. By being able to monitor and control the actions of equipment remotely, switching actions, outage restoration, workforce efficiency, and system response are improved.

- Replacing high voltage system switches that must be operated manually with switches that can be operated remotely. Replacing manually operated switches with switches capable of being operated remotely improves outage restoration, workforce efficiency, and system reactions. One example of this type of installation was made in Aberdeen where a circuit-switcher was installed ahead of the primary substation transformer. This installation allows safe and efficient switching for the large transformer. Another example is the installation of two additional SCADA-mate switches at a transmission tap in Scotland. These controlled switches are capable of indicating if a fault has occurred beyond the switch and allows remote operation of the switch. This installation will improve outage restoration and workforce efficiency.

- Adding "sectionalizing" reclosers on existing electric distribution circuits. By adding "sectionalizing" reclosers, portions of existing distribution circuits will "disconnect" from an overall circuit should a fault be present downstream of the "sectionalizing" recloser. By "disconnecting" that part of a circuit where a fault is present, the balance of the circuit stays on. This application reduces the number of customers affected by a problem on a circuit, improving overall reliability.

- The installation of 485 electric meters capable of being read remotely (from the meter location to a hand-held device pointed at the meter from a truck) in Aberdeen. We were able to purchase used meters at a cost slightly less than new non-automated meters. They were placed in locations where access was an issue (dogs or inside facilities/buildings) and meters were being replaced in a cycle-replacement program. This technology is not likely to be the technology of choice for future SD/NE automatic meter reading applications, but provided a quick return on investment and reduced overall workforce costs associated with reading meters in locations where access is an issue.

4. <u>Possible deployments that could be made in the forthcoming year.</u>
See item Number 3 above. NorthWestern's control systems are now in place at the Montana data center (Montana Call and Computer Center) and are communicating with the PNW-SGDP control center in Richland, WA at the Pacific Northwest National Laboratory. "Go-live" of this control system is happening now in planned stages. To date, 90 residential customers have been recruited, enrolled and are receiving installation of and training on Home Area Network (HAN) systems. Interval metering is being installed at the time installations are scheduled, and the fixed meter reading network has been designed, equipment ordered and received, and installation will be completed in first quarter 2012. NorthWestern will continue recruiting efforts until a total of 200 residential participants is reached. Home installation and training of residential participants is expected to be complete during the second quarter of 2012. Following that, the systems, including Time of Use (TOU) energy pricing, will be placed into full operation. Deployment, testing and operation of the distribution system smart technologies will begin in the first quarter of 2012.

Additional steps related to this portion of the Project that are either now in process or planned for completion in 2012 include:

- Testing and debugging of all data pathways; Interval meters (Helena) – fixed network – ITRON hosting (Spokane) – MV 90 (Butte) – TOU calculator – NorthWestern billing system
- Completion of automated extraction of monthly kWh from NorthWestern's MV-90 system that receives 15-minute interval data from ITRON's data center.
- Complete the building of a TOU energy cost calculator using MV-90 output and the Master TOU pricing table.
- Automated export of monthly TOU energy cost to utility billing system.
- Automated calculation of delta between TOU energy cost and normal non-TOU energy cost. This capability entails:
    - Posting of TOU "credit" to Smart Grid participants' monthly bills and sending appropriate messages via HAN system (and possibly billing statement).
    - Ensuring that no "debit" will be charged to customer if usage increases. Send appropriate messages via HAN system (and possibly billing statement).
- Automate "How am I doing" messages to residential participants based on results of their participation, operation of HAN, and TOU-induced energy usage changes.
- Rigorous exercising of a Test case "customer" in Smart Grid Lab prior to rollout in Helena.

NorthWestern's Smart Grid Project also includes buildings at the Capitol Complex in Helena, MT. After initial delays by the state of Montana, significant progress has been made in the last few months, and plans and specific actions are now falling into place for equipment installation in the Metcalf Building. Additional steps either now in process or planned for completion in the 2012 include:

- Review existing lighting plan and installed systems (NCAT retained by NorthWestern to perform this study).
- Upgrade lighting equipment with controls, communications and other equipment as needed. Install control areas along outside windows – both overhead lights and possibly automatic window shades. Install occupancy sensors. Install diming control in other areas.
- Integrate Lockheed Martin (LM) SeeLoad/SeeGrid demand response application to Metcalf head end building automation control system.
- Survey results of smart grid influence on business practices at periodic intervals throughout the study.

5. <u>What considerations will determine whether or not Smart Grid applications will be deployed, including costs and potential cost savings of deployment?</u>
The main considerations remain the same as before; the cost of a technology and the benefits of what that technology can provide to the company and its customers are the two primary considerations for whether or not to deploy a larger Smart Grid application. Secondary but contributing factors include customer acceptance of home energy management technology, level of response to changing energy prices, level of change of those energy prices, cost, performance and reliability of smart grid systems and equipment, and the level of scale needed to support a satisfactory business case for Smart Grid.

NorthWestern appreciates this opportunity to update the Commission on Smart Grid activities in South Dakota or other applicable projects in our three state service area. If you, or any of your staff, have additional questions, please do not hesitate to contact me.

Sincerely,

Pamela A Bonrud

Pamela A. Bonrud
Director – Government and Regulatory Affairs

Cc: Brian Rounds, Staff Analyst, SD PUC