STATE OF MAINE PUBLIC UTILITIES COMMISSION

DOCKET NO. 2008-255

CENTRAL MAINE POWER COMPANY
Request for Certificate of Public Convenience
and Necessity for the Maine Power Reliability Program
Consisting of the Construction of Approximately
350 miles of 345 kV and 115 kV Transmission Lines ("MPRP")

Central Maine Power
Your Electricity Delivery Company

VOLUME VII

REBUTTAL TESTIMONY
Of
BRIAN CONROY

GRIDSOLAR INTERCONNECTION

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REBUTTAL TESTIMONY OF BRIAN CONROY

GridSolar Interconnection Docket No. 2008-255

This rebuttal testimony is offered by Brian Conroy. Please *see* Exhibit 1 to this testimony for Mr. Conroy's credentials.

The purpose of this testimony is to show that the GridSolar proposal, as presented in the testimony submitted by Richard Silkman and Mark Isaacson in this case, ignores important technical issues with respect to interconnecting the proposed GridSolar generation facilities with the CMP system, and also ignores the substantial costs of those interconnections. These factors, when properly taken into account, provide further support for the conclusion that the GridSolar testimony provides no basis at all upon which to conclude that a solar distributed generation alternative could serve as a practical or cost effective alternative to any part of the Maine Power Reliability Program ("MPRP").

Technical Concerns with Interconnecting GridSolar Generation Facilities

Contrary to the implication through the GridSolar testimony, solar distributed *generation cannot be sprinkled randomly throughout the CMP system.* For example, with respect to the bulk power system:

1. Location of solar installations in relation to load. In order to function as a true load reduction and avoid the need for transmission, the solar installations need to be located adjacent to the load. If not, the installations would be like newly installed generation, and additional transmission may be needed to move the

power from the installations to the load. As an example, consider the Portland area. It is difficult to imagine significant solar installations adjacent to the load due to the lack of availability of land. Therefore, the installations may be located outside of this area, potentially requiring the need for transmission to move it into Portland. As a general concept, one would expect that the higher the concentration of load, the less land there is available for the solar installations.

2. Location of the backup generation. The backup generation must be located next to or near the solar generation. For example, if the transmission related upgrades in Western Maine that are part of MPRP were not installed due to solar installations in the area, the backup generation would also need to be in the same area to manage load when the solar output is decreased. An example of this could occur at 7 pm on a summer peak load day. The output of the solar panels would be expected to be reduced, yet load may not decline at that time. If the backup generation is installed remotely, additional transmission may be needed to supply the load from the remotely located generation when the solar is unavailable.
3. Light load conditions. During light load conditions in the spring and fall, the solar installations likely would continue to supply power. This could result in loads in Maine (net of the solar generation) of only a few hundred MW. This may cause new system operating concerns, including voltage control on the transmission system. Lower loads on the transmission system could result in high voltages and stability concerns for other generators as these other generators will tend to have less reactive output.

4. Harmonics. While each site may meet IEEE-392 (addressing the permitted level of harmonic distortion) requirements, the total contribution of harmonic distortion to the system may be large when there are 400 solar installations. This concern may be exacerbated by the fact that there may be fewer conventional generators running in Maine due to the fact that the solar installations are supplying the load "locally." This has the potential to result in a much weaker system with a number of injections of harmonics, which could cause customer issues with power quality and may also cause relay challenges on the transmission system.

5. Other bulk power system issues. Like other NTAs, GridSolar would not improve the transfer capability of the interfaces in the Maine system. It would also introduce greater load forecasting error. Moreover, GridSolar is entirely unproven as a reliability substitute for transmission.

The GridSolar testimony similarly fails to address how, or if, the following distribution system issues would or could be addressed:

1. Required distribution upgrades. The impact of interconnecting GridSolar generation facilities must be analyzed at heavy load/low generation levels as well as light load/high generation levels to determine the local distribution system's capacity to handle these situations and the reliability implications of these extreme situations;

2. Voltage regulation. The system would need to be upgraded to accommodate bi-directional power flow, as power can flow in either direction with the GridSolar generation facilities located on distribution circuits;

3. <u>Protection systems.</u> These would need to be upgraded to accommodate bi-directional power flow. All reclosers and sectionalizers in the path to the GridSolar generation facilities would likely have to be upgraded to electronic controls with the capability to sense flow direction and voltage, and to change settings and actions based on direction and loss of potential. This would likely require an extra (external) set of potential transformers;

4. <u>Distribution lines</u> may have to be upgraded to accommodate generation resources located off distribution circuit branches because of capacity issues;

5. <u>Disturbance response.</u> Islanding, low and high voltage ride through, low and high frequency response, fault duty contribution and harmonic output of inverter facilities all would be required to meet UL-1741 ("Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources") and IEEE-1547 ("Standard for Interconnecting Distributed Resources with Electric Power Systems") standards. The unit response to multiple reclosing events would need to be determined and analyzed to ensure the appropriate system design. These same items would have to be addressed for behind-the-meter back-up generation as well as if the generation is to run in parallel with the utility. If the generation is to be run in both parallel and stand-alone modes, this would impact requirements, as synchronizing, protection systems, and metering upgrade may be required;

6. <u>Ramp rates</u>. The on and off ramp rates of each installation would need to be analyzed to ensure that the 3% feeder voltage rise and dip requirement is maintained; and

7. <u>Other distribution system issues</u> include power quality (due to intermittence and otherwise), possible need for dedicated feed, islanding, control design, resynchronization after generator stops generating, motor start issues, distance from substation making issues more acute, and the need to run backup generation in parallel if it is used for peak shaving.

GridSolar Would Not Avoid Investment in Feeder Components

GridSolar asserts that it could eliminate over $350 million of expected CMP investment in the "feeder components" of its system that serves sub areas. That is not the case. The $350 million, noted by David Conroy at the technical conference, upon which GridSolar relies for this estimate, refers to the costs of the FERC "bright line" order RC-09-3 and NERC proposed Standard TPL-001. These costs are to upgrade 115 kV substations to eliminate certain extreme contingencies. These upgrades would not be avoided by the GridSolar generation facilities, because the investments would have to be made irrespective of peak loads. GridSolar's inclusion of $300 million of "avoided" costs in its financial analysis is thus simply wrong.

GridSolar has ignored or understated the substantial costs required to interconnect GridSolar Generation Facilities

Exhibit 2 to this testimony provides an estimate of the costs involved in interconnecting one GridSolar generation project onto a CMP distribution circuit. These costs are nearly $300,000 for each facility. Included in the cost estimate are the following:

1. A small number of distribution substations have small capacity transformers. They would need to be upgraded to larger transformers. CMP included a weighted estimate for this item;
2. All distribution substation reclosers would need upgraded to accommodate bi-directional flow;
3. CMP would need to upgrade the voltage regulator banks or load tap changers at each distribution substation impacted by a GridSolar generation facility;
4. CMP would need to upgrade distribution circuits with 336AL three phase conductors on which is located a GridSolar generation project. CMP includes a probabilistic estimate for this item;
5. CMP would need to upgrade its distribution reclosers (from mechanical to electronic) on all circuits on which a GridSolar generation facility is located;
6. CMP would need to upgrade its distribution voltage regulators (to install electronic controls) on all circuits on which a GridSolar generation facility is located; and
7. Direct interconnection costs.

GridSolar has included an estimate of $50,000 for each interconnection,[1] thus understating its costs by nearly $250,000 for each.

[1] *See* Nov. 18 Tr. at 46.

GRIDSOLAR INTERCONNECTION EXHIBIT 1

BRIAN A. CONROY, P.E.

EDUCATION & TRAINING

Masters Degree in Business Administration
Thomas College; Waterville, Maine
June 1992

Bachelor of Science in Electrical Engineering
University of Maine; Orono, Maine
May 1986
Graduated with High Distinction

Registered Professional Engineer in the State of Maine
Registered since 1990

NERC System Operator Certification for Reliability Operator function

Senior Member, IEEE

PROFESSIONAL EXPERIENCE

Manager – Dispatch & Energy Control Center, Central Maine Power Company; Augusta, Maine. Manager responsible for Maine Local Control Center which oversees the electric transmission operations the 345 kV and 115 kV systems in Maine, along with the 34 kV sub-transmission system for Central Maine Power Company. (7/2006 – present)

Lead Electrical Engineer, Distribution Engineering Department, Central Maine Power Company; Augusta, Maine. Electrical engineer responsible for the planning, design, construction, operation and maintenance of the distribution system, including underground network system. (7/1995 – 6/2006)

Engineer, Load Management Operations Department, Central Maine Power Company; Augusta, Maine. Project engineer responsible for specification, bid review, technical design review, and acceptance testing of real-time computer system. Also responsible for the design and installation of substation, communications (telecommunications and power line carrier), and metering equipment for Load Management System. (12/1988 - 7/1995)

Engineer, Meter Operations Department, Central Maine Power Company; Augusta, Maine. Designed metering installations, equipment specifications, and construction standards. (6/1986 - 12/1988)

GRIDSOLAR INTERCONNECTION EXHIBIT 2

Grid Solar Interconnection Estimate

Assuming a 2 MW Solar Farm

Substation Transformer Upgrade			
Number of Substation Transformers < 2 MVA:	6		
Total Number of Substation Transformers:	250		
Percentage of Substation Transformers < 2 MVA:	2.4%		
Cost of Substation Transformer Upgrade:	$600,000		
Weighted Cost of Transformer Upgrade:			$14,400
Substation Recloser Upgrade			
Cost of Substation Recloser Upgrade:			$40,000
Substation Regulator Bank/LTC Upgrade			
Percentage of Substation Regulator Bank/LTC Upgrade:	50%		
Cost of Substation Regulator Bank/LTC Upgrade:	30000		
Weighted Cost of Substation Regulator Bank/LTC Upgrade:			$15,000
Distribution Conductor Upgrade			
Miles of 336AL 3-phase Conductors:	1,239	mi.	
Total Miles of 3-phase Distribution:	3,369	mi.	
Percentage of 336AL 3-phase Construction:	36.8%		
Cost of Reconductoring to 336AL Conductors:	$150,000	/mi.	
Average Interconnection Distance from Substation:	2	mi.	
Weighted Cost of Reconductoring:			$110,329
Distribution Recloser Upgrade			
Number of Distribution Reclosers in Interconnection Path:	1		
Cost of Distribution Recloser Upgrade:	$40,000		
Weighted Cost of Distribution Recloser Upgrade:			$40,000
Distribution Regulator Bank Upgrade			
Number of Distribution Regulator Banks in Interconnection Path:	1		
Cost of Distribution Regulator Bank Upgrade:	$21,000		
Weighted Cost of Regulator Bank Upgrade:			$21,000
Service Interconnection			
Cost of 2 MVA Service Connection (3PH TO, riser, Pad):			$55,000
Total Cost per Interconnection			**$295,729**