TO: VERMONT SENATE COMMITTEE ON NATURAL RESOURCES AND ENERGY

FROM:
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RE: S. 230

Thank you for the opportunity to provide comment to your committee regarding S.230, specifically Net Metering and the Grid Impact of Renewable Generation.

Summary

We need to dampen the rapid growth of solar net metering by ending incentives for large projects remotely located from customers' electric load sites. If growth is not dampened, electric rates will rise to unacceptable levels. Stopping the momentum will be become even more difficult in future years. Remote projects increase line losses and require more grid infrastructure than roof mounted projects.

Interconnecting additional renewable generation to the grid in some areas will require substantial costs. Neither the PSD nor utilities have provided studies to quantify these interconnection costs. Adding the grid impact costs to the other siting problems, it seems prudent to temporarily stop development of large renewable projects. The time out can be used to perform detailed analysis, review the results and consider a new renewable energy policy.

Qualifications

I retired in November 2013 from Green Mountain Power (GMP). I had worked since 1987 for Central Vermont Public Service (CVPS) until acquisition by GMP. In 2011 GMP officers replaced those of CVPS and I began working under GMP management at that time. The acquisition was effective in 2013. At CVPS/GMP I first worked in generation and integrated resource planning. I later was assigned the role of a senior internal consultant-power engineering, where I worked for various departments such as power supply, finance, accounting, rates and legal. I provided support for major CVPS filings to the Vermont Public Service Board ("Board"). Prior to CVPS I worked for another utility and several utility consultants, which included transmission and distribution circuit analysis and generation interconnection. I graduated from Iowa State University with a Bachelor of Science in electrical engineering, power specialty in 1973. I was a registered professional engineer in Iowa and Nebraska.

I testified before the Senate Committee on Natural Resources and Energy on April 22, 2015 and two other committees in 2015. Since that time I testified at the Vermont PSB for two solar projects proposed for location in New Haven: the 350 kW net metered SSE New Haven II project (CPG NMP-5978, to be added at site of existing 150 kW project) and the 2,200 kW Standard Offer Next Generation project (Docket 8523). I also provided a memo in support of comments filed by the Wind Action Group, concerning the Deerfield Wind Project (Docket 7250).

General Comments on Renewable Energy Generation Facility Siting in Vermont

I think it's important to consider S.230 in the context of Vermont's energy policy. The reason for S.230 is that there are major concerns from an increasing share of Vermonters about the siting of renewable energy projects, particularly solar projects. S.230 by itself cannot change Vermont's energy policy, which I think is misguided. However, S.230 can alleviate some of the problems of major concern to Vermonters.

The recent article from the VTDigger by Hans Ohanian, a Vermont physicist and physics book author, provides a critique of the 2016 Vermont Comprehensive Energy Plan and the state's energy policy. Except for the part on fast nuclear reactors with which I'm not familiar, I agree with all the points Mr. Ohanian made. However, I think that new technology nuclear units should be considered as a viable alternative to solve climate change.

http://vtdigger.org/2016/02/07/hans-ohanian-the-vermont-energy-plan-vs-the-paris-climate-accord/

I will expand upon two specific points of Mr. Ohanian: Vermont suffers from a lack of quantitative analysis of its energy policy and faces future problems from high electric rates due to net metering.

In the area of grid impacts from the current high growth of solar generation in Vermont, I have found a lack of quantitative analysis. In my work as an engineering consultant for the Town of New Haven, I submitted testimony that raised questions about the impact on reliability and power quality of solar projects connected to the Weybridge substation, in Addison County. The two projects are listed in my qualifications. The installation of solar photovoltaic generation capacity that is sufficiently large relative to the distribution circuit upon which it is interconnected can reduce reliability and reduce power quality, if mitigating system upgrades are not completed. Power quality impacts are based on the distribution circuit voltage being outside of acceptable limits, or voltage going quickly up or down within those limits ("Voltage flicker").

New Haven filed at the PSB to join GMP to the two proceedings because there was a problem with New Haven solar projects violating a criterion contained in PSB rules governing interconnection of solar projects in Vermont. GMP stated in a report for each project that one of the interconnection rule criterea was violated but that the criterion was no longer relevant. However, GMP did not provide any explanation for why the criterion was no longer relevant. The criterion states that the ratio of total distributed generation capacity to peak load cannot exceed 15%. The ratio for one of the New Haven project was 521%. New Haven was justifiably concerned.

My testimony raised many concerns about reliability and power quality that I had learned from studying the experience of other states and Germany, that have the same or more concentration of solar capacity than Vermont. Utilities in Hawaii, California and Germany have raised valid concerns about numerous problems caused when the amount of solar generation capacity is too large relative to the electric load. These problems can all be solved, but only with detailed engineering analysis, and with a significant cost. Cost varies based on the strength and other characteristics of the particular distribution circuit and associated substation, and the ratio of solar generation to load. Unfortunately, in the two dockets in which I testified, there was not sufficient evidence that the proper analysis was completed. The major part of my testimony in Docket 8523 is copied at end of this document.

For the substation and two circuits upon which the two New Haven projects would be interconnected, the ratio of distributed generation to load would be higher than currently exists for utilities in Hawaii and California. Thus, there were concerns about reliability and power quality impacts on customers in New Haven and other adjoining towns.

The impact on reliability and power quality can be classified into two categories: local and regional. Local impacts occur to the distribution circuit to which the solar generation is interconnected. These undesirable impacts are more frequent voltage surges, voltage flicker (lights dimming frequently), and outages from overloads caused by excessive generation. The regional impacts are potential reduction in reliability that can occur when a very large amount of load in Vermont or New England is being supplied by solar generation.

Reliable power system operation requires that at all times generation power output equals load power consumed. If a sufficiently large amount of the load is being supplied by solar generation, there are at least two problem situations that can occur. First, the amount of solar generation can be much lower than expected, due to unexpected changes in cloud cover. Second, a large solar generation output can aggravate regional power system conditions when major outages occur. As solar becomes a bigger and bigger share of the region's generation, there are reliability concerns due to its intermittent output and possibility of being completely lost in certain events.

Hawaii, California and Germany have experienced these problems and accordingly revised their interconnection rules and standards. From the testimony and discovery response of GMP in the two New Haven dockets, there has not been adequate evidence that Vermont has addressed these concerns as carefully as Hawaii, California and Germany. This should raise a big red flag to the framers of S.230. This new law could put the brakes on development of not only large net metered solar projects, but also the other large solar projects, until the cost of the grid impact is better understood.

As part of my New Haven work, I have analyzed the new GMP Solar Map. This map shows that Addison County contains a disproportionate share of the red colored distribution circuits, which are at or exceeding the allowed amount of distributed generation, most of which is solar. The Solar Map shows total distributed generation by circuit and substation. The map also shows that some large substation transformers are overloaded at the time of summer days when the solar output is the highest. The amount of generated energy is much greater than the load on the transformer, which exceeds the allowed maximum thermal rating of the transformer. Instead of power flowing from the transmission system to the customers, the load flows in reverse and overloads the transformer. The map shows that two substations at least have transformer overloads: Weybridge and Sharon substations. These overloads would occur if all the currently planned solar and other distributed generation is built.

GMP officials were asked at a recent Addison County Planning Commission meeting about whether or not there were specific plans to deal with the impending transformer overload at the Weybridge substation. GMP officials did not provide any specific plans based on analysis of that situation. In any case, the cost to fix this situation is at least in the millions of dollars for this substation. The Sharon substation transformer is smaller but will also likely cost millions to fix. Costs will increase as more transformers approach overloaded conditions.

The problem with the current PSB approval process is that each solar project is evaluated on its own, and there is no comprehensive, system-wide analysis of the cumulative impact of all new solar projects. There has been no system wide study that provides information relevant to grid interconnection costs for solar projects. The GMP Solar Map is a start, but it's still a rough tool. It does not contain any load data, which is critical to assessing impact. The ratio of generation to load is the critical screening criterion. Thus, Vermont needs more quantitative analysis to determine grid interconnection costs.

Addison County has become a mecca for solar projects because of relatively flat land, farmers willing to sell or lease their land and sufficient three phase distribution lines. Many of these projects are the large (150 to 500 kW) remote net metering solar projects. The "remote" refers to the current practice of allowing net metered projects on paper to allocate their output to any customer or group of customers at any remote location. That policy needs to be stopped. First, it allows an area like Addison County to be overrun with net metered projects, causing future electric system problems such as substation transformer overloads. Second, it increases energy losses in the electric system, because solar energy generated must travel long distances to reach the intended load it offsets on paper. Third, remote net metered solar projects require an additional transformer bank. If a rooftop solar project is installed, in almost all cases the existing distribution transformer can be used. Also the additional transformers installed at each remote solar project consume energy and produce losses, even when the project does not generate.

A fourth undesirable impact is that the large remote projects are sometimes owned by large, out of state investors. My experience with New Haven and other information provided by Vermonters for a Clean Environment lead me to that conclusion. It may be that most of such projects are financed by non-Vermonters. It doesn't make sense for Vermonters to provide incentives to wealthy non-Vermonters.

Fifth and finally, net metered solar is the most expensive solar energy. GMP claims to be now building solar projects with a levelized costs of under 10 cents/kWh. Then why are we paying 19 cents/kWh for net metered generation?

If S.230 can effectively block development of the large remote net metered solar projects, the rate impacts of net metering can be reduced. I estimated that more than half of the growth in net metered solar projects is from the large remote projects. As I've testified previously, net metered renewable generation results in rate increases to those customers that do not install net metered generation projects. Ironically it results in a subsidy paid by non-participating customers, who tend to have lower incomes, to higher income participating customers that can afford the generation projects.

Vermont has had a net metering policy for many years, and it seems reasonable to continue it with limits on growth due to disallowance of large remote projects and reduced financial incentives. More and more customers expect to install solar projects at their homes and businesses, especially as solar costs have dropped. Solar firms start up and expand, expecting to stay in business installing solar projects. This is the net metering momentum problem. It is difficult to stop or change net metering policy. Customers expect the same subsidies to continue. Solar firm employees expect to continue their jobs. This expectation creates a momentum difficult to stop. But the net metering capacity and financial incentives need to be reduced over time, so that rate impacts are minimized.

Specific Comments on S.230 as presently drafted

S.230 contains the following section that I think should be deleted:

Sec. 5. 30 V.S.A. § 218. JURISDICTION OVER CHARGES AND RATES

(f) Regulatory incentives for renewable generation

"The Board is authorized to provide to an electric distribution utility subject to rate regulation under this chapter an incentive rate of return on equity [emphasis added] or other reasonable incentive on any capital investment made by such utility in a renewable energy generation facility sited in Vermont."

My rationale for deletion is that renewable energy already has too many financial incentives in Vermont. We need to review impact of existing incentives before adding more. An example of unintended effects of utility incentives is the huge increase in New

England transmission costs that has occurred in recent years. The reason for this increase is that Transmission Providers receive an incentive rate of return on equity and thus made huge investments in their transmission systems.

Excerpt from Amelang prefiled testimony in Docket 8623

2. System Reliability and Stability, Economic Impact, and Public Safety

Q.5. Please summarize any resources reviewed by you pertaining specifically to this project.

A.5. I reviewed testimony and discovery in Docket 8523, which included the Fast Track Analysis Supplemental Review Revision 1 for Next Gen, dated 8/25/2015. I reviewed the Fast Track Analysis report for the SSE New Haven Solar II project and the system impact study reports for the 4 MW Bennington, 0.5 MW Soveren Westminster Business Park and 0.5 MW BED Solar projects. I also reviewed materials posted on the ISO-NE public web site regarding distributed energy resources ("DER", also called distributed generation) and other web based material pertaining to power quality issues caused by solar photovoltaic ("Solar") based DER.

Q.6. How does the installation of Solar DER in general affect System Reliability and Stability?

A.6. The installation of Solar DER capacity that is sufficiently large relative to the distribution circuit upon which it is interconnected can reduce reliability and reduce power quality, if mitigating system upgrades are not completed. Power quality impacts are based on impact on distribution circuit voltage being outside of acceptable limits, or voltage going quickly up or down within those limits ("Voltage flicker"). Power quality also includes voltage waveform distortion, which is not significant in this proceeding. I am extending the meaning of "Stability" beyond the steady-state and transient stability of power systems, which is a regional system reliability issue, to include power quality.

Solar DER could result in a safety problem called "Islanding." Islanding could possibly occur when the distribution circuit source is disconnected and solar generation is sufficient to supply load. This is a safety problem because line crews might incorrectly expect the distribution line to be de-energized when it is now. However, Solar DER projects must use inverters that are designed to prevent this condition per Underwriters Laboratory and Institute of Electrical and Electronics Engineers standards (UL 1741 and IEEE 1547).

Solar DER can reduce reliability if there is sufficient generation output to result in thermal overloads can cause outages and from operation of protective devices caused by various factors.

The impact on reliability and power quality can be classified into two categories: local and regional. Local impacts occur to the distribution circuit to which the DER is interconnected. Since it's common for two adjacent distribution circuits to be temporarily connected, these impacts would in that case apply to any adjacent circuit(s). Local impacts affect both reliability and power quality.

The regional impacts are potential reduction in reliability that can occur when a very large amount of load in Vermont or New England is being supplied by Solar PV. Reliable power system operation requires that at all times generation power output equals load power consumed. If a sufficiently large amount of the load is being supplied by Solar DER, there are at least two problem situations that can occur. First, the amount of Solar DER can be much lower than expected, due to unexpected changes in cloud cover. Second, a large solar DER output can aggravate regional power system conditions when major outages occur. For example, when major outages occur such that generation output is reduced instantaneously, the grid frequency will drop temporarily.

There are inverters located at each Solar DER project, which allow operation of the solar panels with the interconnected distribution circuit. Each inverter is programmed to quickly shut off the solar generation output if frequency is lower than its programmed limit. If the power system loses a large amount of Solar DER precisely when other generation has been lost, this makes a bad situation worse. This is an example of numerous cascading outage problems that plague the power grid.

Q.7. Can you provide more detail for the local distribution impacts from Solar DER in general and the Next Gen project in particular?

A.7. Yes. The GMP Fast Track Supplemental Review report in Section 3 specifies potential problems and solutions to various undesirable impacts on the distribution system from the proposed Next Gen Solar DER. The potential problems are addressed in subsections as follows:

3.3 Islanding

3.4 Voltage Analysis (Flicker and Steady-State)

3.5 Thermal Loading

3.6 Stability Analysis/Loss of Unit Synchronism

3.7 Reverse Flow

3.8 Circuit Protection and Coordination

Section 4 of the Fast Track report describes potential impacts of Next Gen on the distribution circuit protection system and power factor for Circuit WY81, to which Next Gen will be interconnected.

The Fast Track report states that the Next Gen project will not adversely impact the safety, reliability or power quality of the GMP WY81 circuit. The reasons stated in the report that there are no adverse impacts include that the inverter model meets applicable standards and other improvements have or will be made to the circuit and project. That the project is located close to the Weybridge substation (0.96 miles) and the distribution line from the substation to the project has a relatively high thermal rating and low impedance (three phase 477 ACSR) results is beneficial to meeting other requirements.

An example from the report that explains the reason for no adverse impact from Next Gen is in Section 4.1 – Integration with Area Electric Power System (EPS) Grounding:

"The Project's inverter meets the UL certification and GMP accepts the UL certification as adequate to meet this screening requirement, **unless specific operating issues have been recorded with the make and model of the proposed inverter**." [emphasis added]

Q.8. Do you have any critical comments regarding the Next Gen Fast Track report? If so, please provide your comments.

A.8. Yes. I have the following critical comments.

#1 The Next Gen Fast Track report has provided less detail than the system impact studies for the three other projects I mentioned above: 4 MW Bennington, 0.5 MW Soveren Westminster Business Park and 0.5 MW BED Solar. The three system impact studies were done by the consulting firm Control Point Technologies while the Next Gen Fast Track report was performed by GMP. The three system impact studies were much longer in length, in part due to appendices that included the interconnection application and invoices that provided quantification and verification that the project paid for system upgrades. But the three system impact studies also contained other valuable information such as results of analysis and additional analysis.

#2 The "…3,768 kW of distributed generation (including three synchronous generators), connected and in the queue, on the WY81 circuit" does not come close to the amount that I calculated from information obtained from publicly available data. I calculated that about 5,900 kW of generation will be connected to the WY81 circuit after the Next Gen project is installed. I obtained this data from the GMP maintained web site entitled Distribution Information System Map **, which shows type, location, kW rating and installation date for all DER projects on the GMP distribution system. I checked this data against a list of specific net metered DER projects that is maintained by the PSD and the list of standard offer projects maintained by VEPPI.

** Distribution Information System Map web address http://gmp.maps.arcgis.com/apps/OnePane/basicviewer/index.html?appid=dcf1de0fd1ff4cd29d81ca534d3b0318)

My calculations of the total generation that will be connected to the WY81 distribution circuit after the Next Gen project is installed are shown on Exhibit New Haven RA-01. The Exhibit also show total DER capacity as specified in the Fast Track Analysis for the SSE New Haven Solar II project, which is to be interconnected to WY80 circuit. The

WY80 minimum load is based on the ratio of minimum to peak for the WY81 circuit. Since there are only two distribution circuits sourced from the Weybridge substation, this exhibit shows the total of both circuits for total DER capacity and minimum load, to provide an estimate of total reverse power flow from DER at that substation, and for the contingency condition where both circuits are connected and served from a single distribution circuit from the substation.

The total DER capacity on a distribution circuit, combined with the circuit minimum load is probably the most important input to a system impact study. These two values determine whether or not there will be reverse power flow. If total DER capacity is greater than minimum load for a circuit, then power can flow at times of maximum generation and low load in the reverse direction, from the distribution circuit to the substation, and perhaps even into the subtransmission system. The total DER capacity also is an important determining factor in calculating other undesirable DER impacts such as unacceptable voltage level and flicker and thermal overloads.

The PSD net metering list contains two 148 kW projects that would be connected to the WY81 circuit that have received Certificate of Public Approval but are not built. One project received its CPG on 12/31/2014 and could still be built under conditions of the CPG. The other project received its CPG in early 2014 and could not be built unless it applied for an extension to its CPG condition. Such extensions are filed for and are received, so it’s possible that both projects will be built soon. I have not included them in my total DER capacity value above and have not investigated their current status.

#3 The three system impact studies all contained a section that addressed the issue of Temporary Over-Voltages on the Transmission Supply. The Next Gen report did not include any information on this issue or related analysis. The three system impact studies all contained a section that began as follows:

“The possibility of Temporary Over-Voltages on the Transmission Supply is of concern when there is a reverse of power onto the Supply that cannot be dampened during line to ground faults.”

As stated in the system impact studies, temporary over-voltages on the transmission supply may occur if there is reverse power flow. In the case of the Bennington Project, there was no possibility of reverse power flow because the minimum load on the transmission (46 kV subtransmission) breaker in question was greater than the maximum total Solar DER output. The BED project report stated that no upgrades were needed for this concern. For the Soveren Westminster project the subtransmission source was National Grid. National Grid standards required that the DER project must pay for upgrades at the Westminster substation to address potential problems due to temporary over-voltages on the transmission supply.

The Next Gen project has the potential for reverse power flow at the subtransmission level. The Next Gen project is connected to the Weybridge substation, which not only has considerable existing and planned DER, but also has GMP hydro generation. The

Weybridge substation is connected to other substations, such as Middlebury, on a radial 46 kV subtransmission line. The GMP hydro generation, while not installed on a distribution circuit, will contribute to potential reverse power flow on the 46 kV line serving Weybridge and Middlebury. The Middlebury substation also has connected hydro generation and the substation serves Middlebury load that has considerable existing Solar DER capacity. Thus, one would expect that GMP would have done the necessary analysis to determine if reverse power flow can occur, which can lead to temporary over-voltages on the subtransmission system.

#4 The Bennington project system impact study included results of more detailed analysis of contingency cases that occur under outage or maintenance conditions that result in one distribution circuit backing up another. Utilities commonly install switching devices that allow one distribution circuit to be temporarily connected to another. The purpose is to increase reliability, to allow continual operation if one or more components of the electric system are out of service either intentionally for routine maintenance or unexpectedly due to storms or equipment failures. The Bennington report stated that there were unacceptable distribution circuit conditions when a one of the backup cases occurred, i.e. when one distribution circuit was connected to another.

The Next Gen report did not consider the contingency of both circuits WY80 and 81 being connected together. That report does recognize that there is a circuit tie between the WY81 and WY80 distribution circuits in Section 2.2.8. This switch is normally open, that is, under normal conditions these two circuits are not connected. One reason for closing this switch is if there were problems with the substation recloser or voltage regulators on either circuit. My calculations show that if this switch were to close there would be sufficient reverse power flow to overload the remaining voltage regulators. The reclosers may also be overloaded but there is uncertainty concerning the recloser thermal rating.

Circuit WY80 has higher DER capacity and lower minimum load relative to that of WY81. That results in WY80 having greater magnitude of reverse power flow than WY81. There are only two distribution circuits sourced by the Weybridge substation. Thus, when one distribution circuit at the substation is required to temporarily carry the load of both circuits the amount of reverse power flow is more than double that of WY81, which normally is connected to the Next Gen project. The maximum reverse power flow possible is considerably higher than the thermal rating of the voltage regulators. An amount of reverse power flow that overloads the equipment would occur under even when DER output is not at maximum at times of low load, because the maximum reverse power flow is quite high.

It is important to note that the Fast Track Analysis report for SSE New Haven Solar II project will be connected to circuit WY80. That report states that the project fails Criterion #3, which states that the aggregate DER capacity will not exceed 15% of the distribution circuit annual peak load. The addition of the SSE New Haven Solar II project resulted in a value of 521% for this parameter and thus failed by a huge margin. The New Haven GLC Solar also failed this test.

#5 The three system impact studies all included an anti-islanding screening analysis based on various data inputs, the inputs and results for which were included in the system impact study on a single page. The Next Gen report did not include such a screening analysis.

#6 The Next Gen report did not suggest or mandate that the Next Gen project install an event recorder on the utility side of the recloser at the point of interconnection. The Bennington System Impact Study stated that:

"To verify that the Project does not generate over-voltage conditions the PCC recloser may be equipped with an event recorder capable of capturing A, B, and C phase voltages…with a resolution of 1 ms [1/1000 of a second] and capable of capturing ¼ cycle [1/240 of a second] events."

The reason for this statement is that while inverters are designed to prevent over-voltages during certain conditions, the inverters may sometimes fail, like any piece of equipment. Having an event recorder with such a short time period resolution would allow GMP to verify that customers are not experiencing over-voltages caused by the Next Gen project. An over-voltage, commonly called a "voltage surge", can damage customer appliances and equipment even if it occurs during a very short period.

#7 The three system impact studies all specified that a required condition of the project owner was "…successful completion of the Company approved witness testing per IEEE 1547 Section 5." Such testing would be witnessed by the Company's (GMP's) representatives. The Next Gen Fast Track report did not mention anything about witness testing.

Q.9. Is the Next Gen project unique among other Solar DER projects regarding uncertainties in the total DER capacity per distribution circuit?

A.9. No. It is difficult to determine the appropriate value for total DER capacity on each circuit. New DER projects, particular Solar projects, continue to be developed. Also, the PSD, PSB and GMP do not do an adequate job maintaining lists of such projects. There are many projects to monitor and from which to periodically receive data. Developers can delay or cancel projects.

The Next Gen project is subject to the fundamental flaw that affects all DER projects in Vermont. The data for existing projects is inadequate. There are a very large number of new proposed projects that changes regularly. There are deadlines imposed on utilities and regulators to evaluate and approve such projects in short time periods. Utilities must perform system impact studies under such time pressures with data problems.

Finally, there is the problem that can be considered as "the straw that broke the camel's back". Any one or small group of DER projects may not cause any power quality or reliability problems. But collectively, after the last project is installed, there is too much DER capacity for certain distribution circuits and/or the Vermont or New England bulk power system. DER projects are placed in commercial operation after various time periods after regulatory approval. Some are built soon after approval, others much later. There are system upgrades that may be required for certain projects, based on expected completion schedules. But there may be much higher DER capacity levels installed than were originally expected. It may be difficult to compel the owner of the last DER project installed on a circuit to pay for upgrades caused by projects that were installed earlier. Unfortunately, the utility customer would end up paying for such improvements.

Q.10. Does the Next Gen project, either by itself or as part of the large aggregate of Solar DER projects in Vermont reduce system reliability? If so, please describe.

A.10. Yes. There are two other sets of reliability problems caused by all Solar DER projects in Vermont. I will first describe the first one set of problems is related to the use of inverters which are required for each Solar project.

Note that the Next Gen Fast Track report includes the following caveat as mentioned above regarding inverter preventing potential grounding problems: "…**unless specific operating issues have been recorded with the make and model of the proposed inverter"** [emphasis added].

There are many different inverter models used for Solar DER projects. Given that many models exist and there are thousands of Solar DER projects operating in Vermont, where many larger projects have multiple inverters, there is a greater chance of having specific operating issues. That the caveat was placed in the Next Gen Fast Track report, most likely as boilerplate language, indicates there is a concern that operating issues can occur.

My personal experience with electronic equipment used by utilities is that failures do occur, and the problems caused by such failures are roughly proportional to the number of electronic controls and the newness of the technology. Also, unforeseen problems sometimes surface a few years after installation. For example, the smart meter on my home was replaced relatively soon after installation, due to a batch of such meters having faulty circuit boards. Obviously, this problem was discovered only after the installation of the batch of meters. Also, there were major unforeseen software problems caused by the massive increase in data caused by the smart meters. There are currently about 6200 Solar DER projects in Vermont. As explained above, the number of inverters is greater than that number, since many larger projects use multiple inverters.

Inverters have been used for decades for specific uses and for solar generation on a large scale starting over 10 years ago. However, the use of Solar DER projects on a large scale has only occurred in relatively few places on the planet. In the USA, Hawaii probably has the highest Solar DER penetration. Some distribution circuits in California, Arizona, Vermont and other states may be close to or slightly exceeding the Hawaii levels. Germany has probably the highest country wide Solar DER penetration.

These high Solar DER penetration levels are relatively new. While utilities have known about the power quality and reliability impacts of Solar DER for many years, the operating experience with distribution circuits and subsystems is not sufficiently long to discover all problems that were originally unexpected. The electric power system is designed to provide reliable service over a wide range of weather and the wide range of customer usage patterns. There is a huge set of possible conditions that occur, during and after which the power system is expected to continue operating. It is quite possible that some problems have not occurred yet, because the high Solar DER levels were only recently installed.

For example, transient over-voltage occurs when generation on a distribution circuit exceeds load and protective equipment (circuit breakers or reclosers) or switching procedures isolate that circuit. Since isolation events may not occur often, and those events have to occur at the same time that Solar DER is sufficiently high, such conditions that may cause over-voltages are rare. Thus it is likely that there have not been such over-voltage problems because the simultaneous events have not yet occurred. As time goes by and more Solar DER is installed, the likelihood of such problems increases.

The second part of the potential reliability problems due to inverters that more complicated and difficult to quantify at this time. That problem is related to the features designed into each inverter because of the UL and IEEE standards. These standards require that the inverter shut off all solar generation very quickly after the inverter detects either voltage or frequency that is outside of programmed values. For example, if the distribution circuit experiences low voltage, which could occur during outages, the inverter effectively shuts down the solar project. Shutting down generation prevents energizing part of the circuit, which is a safety problem.

There are studies recently completed that show that the functionality mandated for all inverters by the UL and IEEE standards should be changed. As described in A.6. above, there is a problem if the power system loses a large amount of Solar DER precisely when other generation has been lost. As Solar DER penetration reaches a certain point, loss of DER output makes a bad situation worse. If a major outage causes frequency to drop, and that frequency drop causes inverters to simultaneously shut off Solar DER output, a cascading outage condition occurs. The same phenomenon can occur with low voltage, in a condition called voltage collapse.

The new studies suggest benefits to changing the simple programming that causes the inverter to shut off solar generation if voltage or frequency is over or under set values. Instead, utilities prefer that inverters “ride through” low or high voltage and frequency, based on such values over time. For example, the inverter shut down if frequency was 59.5 Hz for X seconds, but would allow much longer operation before shut down if the frequency was higher at 59.8 Hz.

The problem is that UL and IEEE standards are only changed on intervals of several years. The next revision to the IEEE 1547 standard will occur in 2016 at earliest. Ironically, the added cost for such functionality is negligible, if one compares the cost of an inverter with the functionality to one that doesn't. However, there is a risk that a large set of inverters may need to be replaced or retrofit, at a considerable cost. There is an expectation that the new IEEE 1547 will include the new functionality described above. The new inverters are referred to as "smart inverters".

Germany is requiring replacement or retrofitting of over 15,000 solar PV projects sized 10 Kw or higher, at a cost of $70 to 180 Million Euros, due to such voltage and frequency issues, over a period of three to four years. The new German inverters will have the greater functionality that prevents shut offs as described above. Granted, Germany has a much higher amount of Solar DER than Vermont and New England. Germany also has a higher relative amount of intermittent wind generation than New England. However, that Germany is requiring wholesale replacement of solar inverters is a reliability concern for two reasons. First, it provides a good example of unanticipated problems caused by high penetration of Solar DER. Second, it raises the question that Vermont may be at or close to a point where there is a reliability problem on a regional basis, given that all Solar DER capacity installed through at least 2016 will be controlled by older vintage inverters that can decrease regional grid reliability.

The above information was obtained from a document posted on the ISO-NE public web site as part of the Distributed Generation Forecast Working Group. The home web page states that this working group "…is a regional forum for interested parties, including state policymakers, distributed generation (DG) program administrators, and distribution companies, to provide input on ISO New England's long-term DG forecast. Its role includes gathering information on planned DG projects (including technology type, size, and interconnection requirements), and examining challenges and solutions associated with large-scale DG integration in New England."

http://www.iso-ne.com/committees/comm_wkgrps/othr/distributed_generation_frcst/2014mtrls/jul112014/epri_derintreqs_rev1.pdf

Q.11. What is the second set of problems from the large aggregate of Solar DER projects in Vermont?

A.11. VELCO has requested that Vermont utilities provide more "visibility" regarding actual hourly generation output of Solar DER. Visibility means having up to the minute data on actual generation output from the numerous Solar DER projects. Since the Next Gen project is a standard offer project, it will provide a continuous stream of generation data to VELCO and thus will have some visibility. However, all Solar DER projects in Vermont, including standard offer projects, do not submit hourly generation to ISO-NE. Thus, VELCO does not receive up to the minute generation data that other generation units over 5 MW are required to do. Standard Offer projects are not required to submit hourly data to ISO-NE on a daily basis, as generation units up to 5 MW are required.

The lack of timely data to VELCO for the large aggregate of Solar DER projects in Vermont tends to reduce reliability on a regional basis. VELCO and ISO-NE need this accurate load information to match generation to load. However, the load that is metered and reported to ISO-NE is called the reported load. Reported load is the actual load consumption of Vermont's utility customers, minus generation from all Solar DER projects. To the extent that ISO-NE has a lower estimate of Vermont load due to lower solar generation due to unexpected greater cloud cover, ISO-NE will have less generation available to supply load. Reliability problems are more likely whenever load exceeds available generation.

I understand that VELCO and Vermont utilities are working on correcting this problem

Exhibit New Haven RA-02 is a graph that illustrates the significant impact of the aggregate Solar DER on Vermont load. This is a graph of Vermont hourly electrical load for March 30 and 31 of 2015. The graph shows load as a percent of the daily peak on March 30, which was slightly higher than that of the following day. The two days are both weekdays and weather conditions affecting actual load are about the same on both days. Thus, one would expect that the actual load curve would appear to be nearly the same for both days.

It is important to repeat the difference between "actual load" and "reported load." The reported load is the actual load less aggregate Solar DER. By chance the cloud cover was much greater on the first day, so hourly reported load during daylight hours was much higher than that of the second day. Weekday hourly actual load in "shoulder" months, where ambient temperatures are moderate, is generally flat as shown in the black lines. I obtained hourly solar generation from a sample of five standard offer projects in various parts of Vermont. Using that data, I plotted the solar generation as a per cent of solar nameplate rating. Also, I estimated what the actual load curves would be. The red line is estimated actual load.

As shown the solar generation was much higher on the second day than the first. The MW values of the solar generation cannot be directly compared graphically to the load values. The highest load for the two days is about 750 MW, and the total Solar DER capacity is about 100 MW. Note that the maximum solar generation is 16 %, or 16 MW on the first day, and 83% or 83 MW on the second. Thus the solar maximum output on the second day is about 67 MW higher, which results in a much lower reported load curve. Also the reported load on the second day is "V" shaped due to the high solar generation, in comparison to the nearly flat reported load curve on the first day. This example shows that aggregate Solar DER capacity is such that variations in solar output day to day are approaching 10% of load. With a Vermont annual peak of about 1,000 MW and a current aggregate Solar DER of over 100 MW, the Solar impact is already significant and is expected to increase.

Q.12. From your experience working at GMP can you make any general qualitative statements about the statewide process of utility processing of Solar DER projects and the resultant potential impact on power quality and reliability? If so, please provide.

A.12. The informal, unwritten corporate policy at GMP, as I perceived from statements from the CEO and other management, was that speed of execution was much more important than rigorous analysis. Thus, employees were motivated to finish projects as quickly as possible and not spend extra time on detailed analysis or peer review. This was particularly true with the Rutland Solar City initiative where members of the Power Supply Department, in which I worked, were told that GMP management placed a very high value on fast development of the Rutland solar projects.

A compounding problem is that GMP staff levels before and after the merger are much lower than that I observed from my CVPS experience. GMP continues to reduce its lean staffing levels by not replacing employees that continue to leave the company for other jobs or upon retirement. Also, GMP downsized departments by reassigning employees from original departments to a shared non-technical labor pool. In this large labor pool, referred to as the Enterprise Resource Team, the reassigned employees were prevented from doing technical work to support their former departments. For example, experienced analysts and accountants were purposefully removed from their departments, rather than having the benefit of their valuable experience and capability in their original departments before retirement. Such transfers did not reduce costs since such employees were guaranteed their same salaries. I have heard this week that GMP has disbanded the shared labor pool, but I don't know any details about its impact on staffing.

GMP has incentives to have lean staffing. Labor costs are part of total Operating and Maintenance Costs, which are an input in the merger savings formulae. Also, GMP is experiencing loss of revenue from the large growth net metering DER capacity and from customer conservation. Labor savings help offset such revenue losses.

GMP employees also face deadlines and other requirements imposed by the PSB rules governing DER projects. Vermont's aggressive renewable energy goals also impose a sense of urgency. There are also deadlines due to expiration of financial incentives that cause additional constraints. The net metered solar credit of six cents per kilowatt-hour was reduced to lower values for projects installed after the end of 2014. Thus, there was a rush to install net metered Solar projects at the end of 2014. There may also be a similar rush to install DER projects at the end of 2016, if the 30% federal investment tax credit for Solar DER projects is not extended or is reduced.

A glaring example of the problems that occurred due to GMP management mandated time constraints is the loss of generation from the GMP Kingdom Community Wind Project. This was a major undertaking for GMP involving unique, complex problems of interconnecting a large amount of generation in a weak part of the statewide subtransmission system. The critical work was done by GMP in the design stage before the merger. In summary, GMP suffered costly wind generation curtailments in the first year of operation because it failed to install a synchronous condenser as required by ISO-NE standards. The synchronous condenser was finally installed and curtailments were greatly reduced. The official story from GMP management was that ISO-NE was at fault for the condenser's untimely installation. However, my review of the wind project system impact study, which was available well ahead of time, and discussions with VELCO and other engineers indicated that the problem clearly was caused by GMP management, not ISO-NE.

The huge volume of DER projects, combined with time and labor resource constraints and corporate policy, provide a situation in which shortcuts may be taken and mistakes may be made. Also, as described above, utilities are still learning about Solar DER impacts as Solar penetration levels escalate. I am not saying that GMP employees or management do not always work to maintain power quality, reliability and safety. GMP values power quality and reliability highly, and values safety the highest of all. I am saying that human fallibility is a factor to consider in the context of high work load relative to resources and complexity caused by Vermont's renewable energy policy and rules.

Q.13. Please summarize your opinion, findings and conclusion regarding the proposed project's impact on system reliability and stability, economics, and public safety.

A.13. There are numerous critical comments regarding the Next Gen Fast Track report, which indicate that the project will have a negative impact on power quality and reliability. There is an extremely large amount of DER capacity on both the distribution circuit WY81 to which the Next Gen project will be interconnected, and the other distribution circuit that is sourced by the Weybridge substation and provides backup for circuit WY81. The project will also increase the aggregate amount of Solar DER capacity in Vermont, which in aggregate has a negative impact on reliability. The excessive, undue pressure put on utility and regulatory employees to process a very large volume of DER projects under tight schedules also increases the chance for errors that may impact power quality and reliability.