

**STATE OF MAINE
PUBLIC UTILITIES COMMISSION**

Docket No. 2008-255

**MAINE PUBLIC UTILITIES COMMISSION
CMP and PSNH Request for Certification
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”)**

**BRIEF OF THE
PUBLIC ADVOCATE**

March 12, 2010

I. Introduction

On July 1, 2008, Central Maine Power Company (“CMP”) filed a Petition for approval to construct a major bulk power transmission upgrade on its system. It has named this the Maine Power Reliability Program, (“MPRP”). The MPRP includes about 350 miles of new 345 kV and 115 kV transmission lines, and upgrades to 20 substations, including several new 345/115 kV autotransformers. The initial estimated cost of the project was \$1.35 billion. *Petition, Volume I, page 52*. This was increased to \$1.55 billion in a subsequent filing. *September 26, 2008 project update, Probabilistic Estimate of Project Costs, page 1*. The MPRP was the result of a planning process that was led by the ISO-New England (“ISO-NE”) and included other utilities. *Petition, Volume I, page 2*. ISO-NE has approved \$1,375,904 of the project cost for socialization to the region. If approved by the Maine Commission CMP would build a new 345 kV path from Bangor Hydro-Electric’s substation at Orrington to Yarmouth and from a substation in South Gorham to Public Service of New Hampshire’s Three Rivers substation. The MPRP would include a new 115 kV line from the Lewiston area to Rumford known as the “western spur,” and another new 115 line from the Maxcys substation to Belfast known as the “midcoast spur.” It would also include a new 115Kv line – line 254 - from Orrington to Coopers Mills. Also

included would be several places where two circuits currently on one tower would be separated, and there are several 115 kV upgrades.

The Public Advocate proposes that most of the MPRP should receive a certificate, but that the need for one significant segment, the 345 kV line from South Gorham to Three Rivers,¹ and the 345/115 autotransformer proposed for installation at the Maguire Road substation has been overstated. Instead, we propose a less costly reinforcement scheme for this area. We also propose that the need in the midcoast area should be met with a solar pilot.

II. Statutory Standard and Burden of Proof

CMP filed this case under 35-A MRSA §3132 seeking a Certificate of Public Convenience and Necessity (CPCN). Pursuant to this statute, the Commission may grant a CPCN only upon a finding that a need for the transmission facilities exists. In Chapter 330(9)(B), need is defined in terms of a demonstrated benefit to consumers, based upon “an electrical need for the line, taking into account economics, safety and reliability.” Under 35-A MRSA §1314, the Company has the burden of demonstrating this need.

III. Argument

A. Introduction

This is a case about what is needed in order for customers of CMP to continue to receive reliable electric service via the bulk power system. CMP and ISO-NE conducted a needs assessment, employing a load flow study, in order to understand the need and to develop proposed reinforcements to meet that need. CMP and ISO-NE studied CMP’s entire high voltage

¹ In most places herein, capitalized place names refer to substations that connect to high voltage lines in the MRPR.

system under various required NERC and NPCC transmission planning standards and under certain key discretionary assumptions, and have proposed the MPRP as a result. These two factors – the size of the MPRP and the planning assumptions that determined that size – have dominated the processing of this docket. The size of the proposal has led to an enormous dedication of time and resources on behalf of many parties and the Commission Staff. The planning assumptions and the need they indicate have become the primary issue in the case and will be the subject of much of this brief.

B. The Planners Were Not Concerned With the Cost of the MPRP, but the Commission Should Be

ISO-NE is rightly concerned about the reliability of the bulk power grid. Transmission planners at ISO-NE are motivated by this ISO function when conducting needs assessments like the one at issue here. However, the cost of an upgrade is not a real concern. In the words of Mr. Oberlin, ISO-NE's transmission planner responsible for the MPRP, "we do not consider what the potential costs would be when we set up the conditions to be tested in a needs assessment." *Tr. February 2, 2010 at 17*. In other words, the dispatch scenarios and loading conditions are determined *without any regard* to the final cost of a transmission upgrade.²

We do not propose that ISO-NE should adopt a least cost alternative for every planning decision. There are factors that may influence whether a particular solution is reasonable even if

² ISO-NE's bonus policy, applicable to transmission planners, reinforces this approach. This policy states that "in the event of a major collapse of the bulk electric power systems managed by the company, no employee will receive an award for the calendar year in which the event occurred." *Tr. February 2, 2010 at 14*. There is no counterpart bonus language for solving reliability problems at a reasonable cost. *ODR 12-15*.

it is not a least cost solution. But ISO-NE, and the transmission utilities in the region, should seek to find the lowest reasonable cost solution.

That there is language in the ISO-NE tariff that requires that ISO-NE avoid the imposition of unreasonable costs. It states that the Regional System Plan (“RSP “)

shall be designed and implemented to . . . (iii) avoid the imposition of unreasonable costs upon any Transmission Owner, Transmission Customer or other user of a transmission facility.

ISO Tariff §II, Attachment K, section 3.4 (standards binder, tab 36). While the tariff requires that ISO-NE must avoid the imposition of unreasonable costs upon customers there is nothing built into the planning process to implement this directive and there is no incentive provided to have the planners focus on it. On the contrary planners are not even aware of the requirement and, based on Mr. Oberlin’s testimony quoted above, they did not take cost into account while developing the MPRP needs assessment.

Where ISO-NE has an overriding reliability-based motive in upgrading the transmission system, CMP has a financial motive to do so. If the entire MPRP is built, CMP stands to earn close to \$90 million in the first year following completion of the project. *Tr. February 3, 2010 at 186.* Of this amount, \$9 million is attributed solely to a 125 basis point “incentive adder” approved by FERC.³ *Id.* For each of the first few years, this amount would decrease by only \$4 or \$5 million. Obviously, this is a very strong financial incentive. CMP is also rightly concerned about the reliability of its transmission system, but CMP, through its role in concert

³ FERC approved a 125 basis point adder in conjunction with CMP’s base rate ROE for an ROE grant of 12.89%. *See, Central Maine Power Co. 125 FERC ¶61,079 (2008).* CMP’s President indicated the adder incentive was not needed, since CMP would have sought approval for the MPRP even in the absence of it. *Tr. November 12, 2008 at 129.*

with ISO-NE in conducting the needs assessment, has not demonstrated any concern about the reasonable cost of new transmission.⁴

Customers want reliability balanced against cost. The Commission's role is to do this balancing by focusing on what is needed, and it should determine what is needed in CMP's territory by examining the process that led to the MPRP and deciding whether that process was reasonably calculated to identify needs.

Transmission Cost Socialization. The ISO tariff specifies the cost allocation treatment of upgrades, modifications or additions to the New England transmission system. Specifically, reliability upgrades and market efficiency upgrades qualify as regional benefit upgrades and can receive recovery through regional rates from transmission customers taking service under the ISO-NE OATT. The cost of projects that qualify as reliability upgrades, and that are included in the Regional System Plan, such as the MPRP, are socialized throughout the region based upon each utility's portion of the peak load for the New England power pool customers. CMP points out that based on this formula, Maine ratepayers' share of the MPRP cost is just above 8.5%.⁵ All things being equal, this argument should make approval of the entire MPRP easy for the Commission given that the rate impact on CMP customers would be so small. However, all

⁴ Mr. Loehr, hired by CMP to offer his opinions about transmission planning from the point of view of NERC and the NPCC, stated that

we should really look at reliability standards as a base line, not something that you've determined that you try to balance with costs.

Tr. February 9, 2010 at 121. CMP's reliability expert then said, "Whose [sic] to say what's too expensive?" *Id. at 122.* He concluded by saying that any discussion about tradeoffs between cost and reliability is "best pursued over a glass of beer or something." *Id. at 124.* Mr. Loehr has not concerned himself with the cost of reliability upgrades since he worked for the NY Power Authority, a tenure that ended in 1972. *Id. at 127; Loehr February 23, 2009 Rebuttal at 23-24.*

⁵ Section 254, a 115 kV line that would run from Orrington to Coopers Mills, is likely to be considered for cost allocation by the ISO soon. *Tr. February 2 at 7-9.*

things are not equal. New England is host to a widespread transmission build-out, and many expensive projects are on the drawing board in other states. The rate impact of all these projects, including the MPRP, will have a significant impact on transmission rates in New England.

Between now and 2013, the RNS rate is on track to nearly double. *ODR 13-54; see also, ODR 13-20.* We urge the Commission to adopt the views of Mr. Poole:

I would urge the Commission not to abdicate its responsibility to evaluate need based on such considerations [Maine's small share of New England costs.] If the commissions in all six New England states adopted such an approach, the region would suffer significant transmission rate increases without receiving equivalent benefit in return. The disconnection between the CPCN review process from jurisdiction over the resulting rates is a flaw in the current transmission rate regime that should be corrected, not exploited.

Poole October 27, 2009 Testimony at 4.

C. Mr. Lanzalotta's Testimony Provides the OPA Solution to the Need

Mr. Lanzalotta was the hired by the Public Advocate to provide his engineering expertise in reviewing the MPRP. His task was to determine whether there was a need for increased reinforcement of CMP's transmission system, keeping in mind the cost to the customer. In other words, his approach was to think of what is in the overall best interests of CMP's 600,000 customers.

In his January 2009 testimony, he observed that the assumptions employed by the transmission planners about generator availability, interface loading and other system conditions were a "primary factor driving the system reinforcement proposals of the MPRP" and that they served to increase "the apparent need for electric transmission system reinforcement."

Lanzalotta January 28, 2009 Testimony at 4. He testified that it would not be "reasonable for the Commission to accept as a fait accompli all of these changes in planning procedures,

planning assumptions, and targeted reliability levels” and that as a result of using these unreasonable assumptions, CMP had failed to demonstrate a need for the MPRP. He concluded that he was unable to determine whether any need existed and that CMP should revise its criteria and reexamine the question of need. *Id.* at 5-6.

Mr. Lanzalotta submitted further direct testimony on October 23, 2009 in which he was able to draw somewhat more refined conclusions on the need as a result of the so-called “Staff Analysis.”⁶ He opined that some of the generation dispatch scenarios employed by ISO-NE and CMP in the load flow study were unreasonable and concluded that the more reasonable dispatch scenarios used in the Staff Analysis pointed to a group of transmission reinforcements that “provide a reasonable transmission solution to the bulk of the system problems identified in the Company’s analysis.” *Lanzalotta October 23, 2009 Testimony at 4.* At the time, these components included a 345 kV line from Orrington to Mason, through the Detroit, Albion and Maxcys substations, and a new 345 kV line connecting the Buxton and the South Gorham substations. The former solved the historic “Orrington south” 345 kV bottleneck. The latter would serve to reinforce the bulk system in the south at a much lower cost than that contained in the MPRP proposal (a 345 kV line from South Gorham to Three Rivers – the so-called “southern leg” or “S-1” solution).

The OPA Solution. On February 3, 2010, we filed the Surrebuttal testimony of Mr. Lanzalotta. This testimony took into account the Rebuttal Testimony of CMP and concluded that CMP had in fact established a need for reinforcement in all but one area proposed to be

⁶ From February through October of 2009, the Company performed several load flow studies using planning assumptions supplied principally by Commission Staff. The results of this process have been called the “Staff Analysis.” The Bench Analysis, beginning at page 31, contains a description.

covered by the MPRP. The one MPRP section that is not needed is the “southern leg”, specifically the 345 kV lines from South Gorham to Maguire and from Maguire to Three Rivers and the autotransformer at Maguire. While he determined that there is a need in all other areas, his testimony reveals that the need in the south is met by the Staff’s proposed southern alternative of a new 345 kV line from Buxton to South Gorham, along with the second autotransformer at South Gorham. Mr. Lanzalotta also indicates that four 115 kV lines in the south, sections 140, 163, 238 and 250, should be rebuilt in order to address further needs. Sections 238 and 250 are part of CMP’s proposed southern solution in the MPRP.

This package of reinforcements relies to a great degree on Staff Scenario 2, as described in the Bench Analysis, as well as the Company’s analyses of that scenario. *Lanzalotta Surrebuttal at 6*. These reinforcements do not rely on the D4 or the D5 dispatch scenarios, both of which Mr. Lanzalotta found to be unreasonable. We do not support the southern leg, because the need for these reinforcements is driven by generator dispatch scenario D4. *Id. at 21*. As addressed in Mr. Lanzalotta’s Surrebuttal Testimony on page 11, generator dispatch D4 assumes that six fossil generating units are unavailable, while dispatch D5 assumes nine generating units out of service. When these extreme generation dispatch scenarios are removed, the reliability violations, primarily the “did not solve” (DNS) load flow cases, that are the primary justification for the southern leg, are also removed⁷ and only a limited number of 115 kV line overloads remain on the Company’s system. *Id. at 6, and at 21-22*. These overloads would be addressed by the four 115 kV line rebuilds described above.

⁷ A DNS load flow case indicates an electric system that is not stable and that is in violation of NERC requirements.

We urge the Commission to deny a CPCN for the 345 kV lines that would run from South Gorham to Three Rivers through Maguire Road, and for the autotransformer and associated equipment at Maguire Road. The planning assumptions behind CMP's case for a need for the southern leg are unreasonable and do not support a conclusion that there is such a need. We do support a CPCN for a Buxton to South Gorham 345 kV line, as originally proposed in the Bench Analysis, and for upgrading sections 140, 163, 238 and 250 as recommended by Mr. Lanzalotta. While we also recognize a need in the so-called "midcoast" area, we do not support a transmission solution but rather recommend addressing the need through a solar generation pilot. See, Section III.G below. We support the remaining portions of the MPRP as described in Mr. Lanzalotta's Surrebuttal at page 5.⁸ We will hereafter refer to this proposal to solve CMP's bulk power reliability needs as the "OPA Solution".

D. Many of the Planning Assumptions Made by ISO-NE and CMP Planners are Unreasonable

The discretion for making planning assumptions about generator dispatch scenarios (along with other conditions) that form the base case (prior to contingencies) appears to originate with ISO's Planning Procedure 3 ("PP3"). In pertinent part, this states:

With due allowance for generator maintenance and forced outages, design studies will assume power flow conditions with applicable transfers, load and resource conditions that reasonably stress the system.

ISO PP3, section 3 (standards binder, tab 22, page 4). The phrase "reasonably stress" is informed by a definition in ISO PP5-3:

⁸ Mr. Oberlin testified that there are some sections of the MPRP that are no longer needed because of reduced load forecasts; these should not be included in any CPCN from this Commission. *Tr. February 2, 2010 at 78-79; see also, Tr. February 3, 2010 at 64.*

Reasonably stressed conditions are those severe load and generation system conditions which have a reasonable probability of actually occurring. Generally both import and export conditions should be addressed. The purpose of testing these conditions is to identify potential weaknesses in the system and not to test the worst imaginable extreme.⁹

*ISO PP5-3, section 5.2 (standards binder, tab 26, page 17); see also, Tr. February 2, 2010 at 11-12.*¹⁰

The D4 and D5 Dispatch Scenarios. CMP and ISO-NE devised a series of generation dispatch scenarios in the MPRP needs assessment. In these, the generators connected to the Maine and New Hampshire grid are modeled at various output levels, including zero output. *Petition, Exhibit I-1 page 33 of 573.* The purpose of these scenarios (and other non-generation stressed conditions) was “to examine the ability of the transmission system to reliably serve Maine customer peak demands under a wide range of system operating conditions at future load levels.” *Id. at p. 31 of 573.* Thus, the reasonableness of these scenarios, and the question of whether they “have a reasonable probability of actually occurring” must be measured on those days when there are peak loads, i.e. hot summer afternoons. There are two dispatch scenarios in the MPRP load flow modeling – D4 and D5 - that stand in sharp contrast to these ISO requirements and to CMP’s statement as applied to peak days. The D4 dispatch has 1463 MW of generation off, the bulk of it in the greater Portland area, including the entire Westbrook Energy Center (545 MW) (hereinafter “WEC”) and all four Wyman units in Yarmouth, a total of 870 MW. *See, e.g. Lanzalotta Surrebuttal at 11.* The D4 dispatch means that as a base case, only

⁹ The “worst imaginable extreme” is, ultimately, a meaningless phrase. One could imagine all kinds of extreme situations involving flood, earthquake, fire or terrorist acts.

¹⁰ For its part, CMP has stated:

The MPRP, because it is a planning study for the purpose of ensuring system reliability at all times and not just under average conditions, need to evaluate system performance under more extreme (but still plausible) scenarios.

Petition, Exhibit B-2 page 9 of 53 (emphasis supplied).

62% of the total generation studied in Maine and New Hampshire was treated as online. *ODR 12-4*. The D5 dispatch scenario provided even more stress, turning off 1743 MW of generation, more than 53% of the maximum amount of generation in the modeling. *Lanzalotta Surrebuttal at 11*. CMP and ISO-NE decided not to use the D5 dispatch for N-1-1 testing, but only a screening tool because it was too severe.¹¹ *Tr. February 3, 2010 at 169-170; December 16, 2009 at 27*.

It is difficult to imagine that during the peak summer hours, when generators make their most money in the ISO-NE administered wholesale energy market, all of these generating units would be offline. It is unimaginable that these units¹² would be off for routine maintenance, and the likelihood that all of them would be experiencing a forced outage at the same time simply does not “have a reasonable probability of actually occurring.” Mr. Lanzalotta has variously described this scenario as “beyond . . . what is reasonable,” “an overly severe test for the transmission system,” and “extreme”. *Lanzalotta January 28, 2009 Testimony at 16; Lanzalotta October 23, 2009 Testimony at 7; Lanzalotta Surrebuttal at 10, 14, respectively*. He further stated that extreme dispatch scenarios like D4 “have a place in system planning studies in evaluating overall system strength, but [it is] not a reasonable basis alone on which to base the need for additional transmission facilities.” *Id. at 14*. The Bench Analysis judiciously referred to it as arbitrary (*Bench Analysis at 20*) but also stated that “the MPRP dispatches do not model system conditions which have a reasonable probability of actually occurring.” *Id. at 23*. Mr. Dunn, on behalf of the Yarmouth Intervenors, stated that D4 is not realistic, and is unusual. *Dunn Direct at 9*.

¹¹ Mr. Conant stated that the D5 scenario probably fit the “worst imaginable extreme”. *Tr. December 16, 2009 at 13*. The transcript lists Dr. Silkman as the speaker. We believe this is an error and that, from context, the speaker was Mr. Conant (or perhaps Mr. Conroy).

¹² The Bench Analysis states, at 20: “there is no scheduled [generator] maintenance over the summer peak period.”

The ISO itself defines the loss of the “entire capability of a generating station” as an extreme contingency. *ISO PP3, section 5 (standards binder, tab 22, page 7); Lanzalotta Surrebuttal at 13.* This being so, it cannot be any less extreme when assumed as part of the base conditions during peak hours rather than as a contingency.

Mr. Lanzalotta pointed out that the 1463 MW offline in the D4 scenario represents almost the entirety of CMP’s unadjusted 2009 summer peak load of 1565. *Lanzalotta October 23, 2009 Testimony at 7.* In his Surrebuttal, he further pointed out that the D4 scenario is very unlikely to actually occur. The ISO’s 2007 and 2008 Annual Markets Reports each contain a description of generator unit availability throughout New England. Table 9-7 in the 2007 report shows that the system average availability that year was 90%. *Lanzalotta Surrebuttal at 14, link provided in footnote 13.* Figure 9-9 in the 2007 report demonstrates that for all of New England during the peak-demand days, between 1300 and 1800MW of generation was unavailable. This alone demonstrates how extreme the D4 scenario, with 1463 MW offline in Maine alone, really is.

For all Maine generation in the last three years, there have been only 37 instances where the ISO had scheduled a generator to run and it failed to do so, or was delayed. *ODR 13-1; ODR 12-11.* There are only nine times when this occurred during June, July or August.¹³ It is unclear whether these failures were during peak hours. The point is that of all the generation available in Maine, this is a very small number.

Perhaps most telling, there has been no time in the last three years when WEC and the Wyman units were all unavailable – i.e. scheduled to run but did not run - at the same time.

¹³ Unfortunately, ISO confidentiality protocol prevents us from knowing which generators these were.

ODR 12-6. This is important because it shows that when scheduled for actual dispatch, WEC and Wyman have not been simultaneously unavailable at any time in the last three years, let alone during peak hours. *See also, ODR 12-29.*

ISO-NE personnel have, at various times in this proceeding, attempted to justify their use of these dispatch scenarios, or the turning off of a specific generator.¹⁴ None of these explanations comply with PP3 and PP5-3.

During the very first technical conference, Mr. Oberlin was asked to explain why all three units in the WEC were treated as off. He indicated that the WEC's Maine-issued air permit required this treatment. This was wrong, and he was forced to back off. *OPA 10-1 (this response affirms that ISO made this assertion; the transcript from October 8, 2008 is corrupted and unreadable.); ODR 8-3.* In OPA 10-1, CMP indicated the possibility of a disruption in the gas pipeline that feeds the plant. WEC is located in Westbrook, very near to the confluence of the Maritimes & Northeast Pipeline and the Portland Natural Gas Transmission System pipeline. It is safe to assume that the line to the plant from these pipelines is relatively short. It is also no older than WEC itself which was built in the late 90s. The likelihood of the gas spur to the plant suffering a disruption is extremely small. In ODR 8-3, Mr. Oberlin cited "fuel supply concerns" as an example of why the entire generating station might be unavailable. This could refer to the same gas spur referred to in OPA 10-1. Or, it might refer to disruptions on the interstate pipelines. If this is the case, however, one would assume that one of the ISO's dispatch scenarios would have all of the gas plants modeled off, which is not the case.

¹⁴ ISO conducts no probability analysis of generator availability. *Tr. February 2, 2010 at 176.*

The ISO's inability to pinpoint its reasons for constructing the D4 dispatch under questioning highlights the arbitrariness of that scenario and supports the conclusion that it represents an unreasonable extreme. The ISO did not appear to consider whether WEC and the Wyman units all being off at the same time had a "reasonable probability of actually occurring" until asked in this docket. Otherwise, one would assume that they would have a coherent answer.

CMP also averred, in OPA 10-1 that ISO had reached the conclusion that WEC "may not be able to physically operate in simple cycle mode." *Id.* Mr. Oberlin confirmed this. *ODR 8-3.*

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The stress on the system in the load flow studies caused by the D4 dispatch is exacerbated by other factors in the modeling, leading to the apparent need for more reinforcement. These other factors include the 90/10 load forecast and the modeling of CMP's large customers that have behind-the-meter generation.

The Modeled Load Levels. The 90/10 load forecast employed in the load flow modeling is an extreme stress condition, which, when combined with the D4 scenario and other discretionary planning assumptions, leads to the apparent need for more reinforcement than

necessary. The use of this forecast, rather than the 50/50 forecast, is not prescribed and is therefore discretionary. *Lanzalotta January 28, 2009 Testimony at 12*. In brief, a 90/10 forecast is one that has a 10% probability of being exceeded due to weather conditions while a 50/50 forecast has 50% probability of being exceeded due to weather conditions. *Bench Analysis at 13*. Mr. Rourke indicated that the 90/10 forecast would be considered “extreme weather conditions.” *Tr. December 16, 2009 at 177-178*. The difference between these two forecasts represents about 160 MW of peak load. *EX 9-2 Supplemental; see also Lanzalotta Surrebuttal at 7 (The 90/10 forecast “adds from 140 to 185 MW in various years to the forecast peak loads for the state.”)* Higher load levels mean more stress on the transmission system. *Id. at 9*.

Mr. Lanzalotta indicated that a 90/10 forecast has its place, but that the additional margins of system capability caused by the 90/10 forecast “should be kept in mind when other system planning assumptions are developed.” *Lanzalotta Surrebuttal at 7*.

In addition to employing the 90/10 forecast, the load levels used in CMP’s needs assessment fail to incorporate *any* amount of demand response resource in Maine, as confirmed by CMP. *OPA 03-02(c), OPA 03-05, OPA 13-1(e)*. The load forecast itself incorporates only a portion of the peak load reduction associated with the Maximum Achievable Cost Effective energy efficiency, as confirmed by Mr. Davulis. *Tr. February 4, 2010 at 133*. CMP assessed the impact of demand response only in its NTA analysis, and that analysis did not consider the full amount of demand resource availability, as Mr. Fagan indicated in his Direct (pp 38-45) and in his Surrebuttal (pp 9-19). In making this assertion, Mr. Fagan relied on a variety of sources, including ISO-NE FCM auction results, CMP data responses and a FERC Staff-sponsored report

on demand response potential. In his Direct, Mr. Fagan pointed out that almost 200 MW of demand response that did not clear in the second ISO-NE FCM auction was also not considered as a potential resource in the NTA analysis. *Fagan Direct at 40-41.*

In addition, the results of the third ISO NE FCM auction indicated a total of 367 MW of “Demand” type resources cleared and available in Maine in 2012 (including 280 MW of demand response, 54 MW of energy efficiency and 33 MW of real time emergency generation treated as a demand response resource). *ODR 12-2, ISO NE Forward Capacity Market Auction Results Filing, October 30, 2009, pages 14-134 “Attachment A Capacity Supply Obligations”.* This level - which when adjusted for the energy efficiency component (which is included in CMP’s load forecast) equals 313 MW – is achieved for the *early* year of 2012. It is significantly larger than the grossed-up, entire-state, NTA-employed demand response value of 211 MW for 2012, as reflected in ODR 01-41; and it is also greater than the demand response resource amount considered in the NTA for even the furthest *future* year – e.g., 289 MW in 2017. *ODR 01- 41, page 2.*

CMP confirmed that it did not include *any* level of demand response in its transmission needs assessment. *OPA 3-5 and OPA 13-1(e).* This was in spite of clear indications **** **Begin CONFIDENTIAL******

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February 9, 2010 at 188-189. Obviously, since CMP failed to follow up on this potential source of load reduction, Mr. Fagan was unable to assign it a MW number.

The June 2009 FERC Staff Report, jointly prepared by Freeman, Sullivan & Co, Global Energy Partners, LLC and The Brattle Group, showed that the demand response potential, as a percentage of peak load in Maine under a “business as usual” scenario (i.e. “if current and planned demand response stays constant”), was between 16% and 17% over the next nine years. *Fagan Surrebuttal at 13.* CMP ignored this potential when it determined the load levels at which to test the MPRP needs assessment.¹⁵

Mr. Fagan concludes:

DR resources have the potential to significantly impact the need for MPRP elements because the effect of these resources, if utilized appropriately, would be to lower transmission system peak load levels by hundreds of MW below what CMP currently uses then conducting its needs analyses with power flow modeling.

Id. at 21.

A technically-appropriate subset of Maine’s available demand response resources could be used to position, or posture, the system on a forecasted “extreme peak” or peak day (either of which occur infrequently) thereby allowing for a much-reduced peak load level to be used in the modeling of the system. CMP did not analyze the nature of this potential even though Maine is rich in demand response resources, and thus CMP did not develop a needs assessment scenario that directly accounted for the value of this resource. Demand response can be present in the

¹⁵ LaCapra (or at least Mr. Hahn of LaCapra), CMP’s consultant whose concern was non transmission alternatives, was, as of December 2009, was unaware of this June 2009 FERC report on demand response potential. *Tr. December 21, 2009 at 34.* Mr. Hahn failed to become aware of this recent FERC report in spite of his own references to a demand response potential study performed by EPRI and a 2006 FERC study. *LaCapra Rebuttal, December 4, 2009 Consultant Report at 32.*

modeled load in the N-1 study. *Tr. February 3, 2010 at 13*. In the MPRP needs analysis, this was done only for peak load savings already present in Efficiency Maine programs. *Petition, Exhibit B-2, pages 15-16 of 53*. In addition to using demand response resources to “posture” the system “pre-contingency” during infrequently-experienced “extreme” and normal peak periods, demand response resources could also be used in the thirty minutes following a first contingency in order to contribute (along with other operator actions) towards positioning the system to survive a possible second contingency. Thus, demand response could also be used in an N-1-1 study. *See, e.g., Tr. February 3, 2010 at 25-26; see also, Poole testimony, Tr. February 9, 2010 at 188-189*. The needs analysis apparently did not include this approach.

There is a cost to demand response – customers who have the capability to affect system peak for needs assessment purposes do not reduce demand for free. However, given that the needs assessment is a peak day/peak hour study, and there are very few such hours in a year, the cost should have been investigated. A relatively modest payment used to posture the system for N-1 or N-1-1 could obviate the need for tens of millions of dollars worth of transmission reinforcement.

Large Customer Modeling. In setting up the modeled loads for the needs assessment study, CMP assumed that its largest customers would be taking power off the grid at their “most probable maximum load consumption.” *Petition, Exhibit B-2, page 10 of 53*. For four of the largest customers,¹⁶ all of which have significant behind-the-meter generation, this maximum load consumption totaled around 312 MW. *Id.* Inclusion of these amounts in the assumed loads necessarily required the assumption that the behind-the-meter generators at these customers’

¹⁶ CONFIDENTIAL: REDACTED .

facilities were not running at usual output levels. The combined MW of the on-site, behind-the-meter generation capacity of these four customers is 320 MW. *OPA 3-3, Attachment 2.*

According to CMP, the effect of this assumption "...adds approximately 200 MW to the previously identified New England load and CMP load forecast." *Petition, Exhibit I-1, page 30 of 573.* As with the dispatch scenarios, or at least with respect to D4 and D5, this is an extreme stress that has no "reasonable probability of actually occurring". CMP has done no analysis of the probability of this occurring, (*Tr. October 9, 2008 at 271*) so it was, like the dispatch scenarios, an assumption made to stress the system.

In fact, it appears that the maximum contractual load is never on the system. Mr. Conant stated the following:

When you turn on some of these generators, they basically support all of the load from those mills. They turn into net contributors to the supply of the system, and when they are offline, they basically go down to a much lower load than their stated maximum contract capacity.

Tr. February 3, 2010 at 29-30. This obviously begs the question why the planners deemed some of the generators off and the load at the contractual maximum, when a more reasonable assumption could have been used based on CMP's own information concerning the large industrial customer's contribution to system peak load, as modeled in the Staff Analysis. *Bench Analysis, p. 33.*

The fact is that the average contribution to peak of these four customers, since 2002, is 64.26 MW, an amount smaller than all but one of the loads modeled. *ODR 13-19.* A comparison of the individual large customer contributions to peak in ODR 13-19 with the maximum measured peak in ODR 13-22 also reveals that the maximum peaks have not been

coincident with system peak. It would make sense that customers with generation would take steps to ensure that their generators were operating on the system peak days given that the cost of grid power is highest on peak days. One can assume both that the owners of these units would seek to profit on peak demand days by selling excess energy into the market, and, for those customers with power contracts with market-following rates, seek to avoid taking power off the grid in order to avoid those same high energy prices.

The stresses on the system from these discretionary planning assumptions affect the entire grid as studied, including in the southern part of the state, and thus contribute to the apparent need for the southern leg. Because the need for transmission between Maine and New Hampshire, i.e. the southern leg, is directly dependent on how much generation is available in Maine, by not modeling any demand response in the load levels, and by severely reducing the behind-the-meter generation in Maine in the load flow studies, CMP creates additional loading on the transmission lines to New Hampshire. This additional loading translates into reliability violations under certain generation dispatch scenarios and contingency conditions, thereby supporting the apparent need for the southern leg.

In sum, the MPRP needs assessment applied an unreasonable amount of stress. A 90/10 forecast, extreme dispatch scenarios, load levels that exclude significant demand response potential and effectively modeling large customers loads with much of their behind-the-meter generation off are conditions that cannot reasonably be assumed to occur simultaneously during the peak load hours of the year, and thus should not have been combined as base conditions in

the same load flow modeling study. Under reasonable planning assumptions, there is a need for reinforcement in the south, but there is no need for the southern leg as proposed by CMP.

E. Approving the OPA Proposal Would Not Unduly Delay Further ISO-NE Review and Ultimate TCA Approval

Based on reasonable interpretations of the planning standards and criteria, as discussed above, the Commission should approve the OPA Solution. The consequence of such a decision would be that ISO-NE would need to evaluate the change in the scope of the project in order to determine whether it was materially different from the original project and, if so, ISO-NE would need to assess its performance to determine if it continued to meet the region's reliability needs. *Tr. December 16, 2009, at 272.*

Changing the scope of a proposed project or eliminating a project that is contained in the Regional System Plan (RSP) is not unprecedented and indeed is provided for in the ISO-NE tariff. The tariff contemplates that there may be changes in circumstances that require projects to be re-evaluated. Pursuant to Attachment K of the ISO-NE tariff, the RSP project list may be updated by adding, removing or revising transmission solutions through the stakeholder process. *ISO Tariff §II, Attachment K section 3.6(c) (standards binder, tab 36).* The transmission planning process and the RSP are not static. The RSP is reviewed and changed as needed.¹⁷

A review of the OPA Solution would require the same process and include much of the same information used in the needs assessment for the entire project. As noted by ISO-NE it

¹⁷ There is precedent in New England for altering the scope of a transmission project. ISO-NE is currently studying two components of the NEEWS project in Connecticut to determine if they can be removed from the Regional System Plan. *Tr. Dec. 16, 2009 at 267.*

would be a “do-over.” However it could be done in an expedited manner. *Tr. Dec. 16, 2009 at 265.* This is because much of what would need to be studied for the OPA Solution has already been done. It is clear that the engineers who have worked on the MPRP project have completed many studies that they could build off of in examining and testing the reliability of the OPA Solution. *Tr. Dec. 16, 2009 at 273.*

For the northern portion of the OPA Solution, even using the assumptions employed in the needs analysis for the MPRP, there is no question that the elements of the MPRP supported by the OPA, meet the region's reliability needs. These elements increase the integrity of the Maine transmission system, effectively eliminating the segments of the transmission backbone of Maine where there were, previously, only single a 345 kV line. (Orrington to Maxcys and Maxcys to Maine Yankee).

With respect to the “southern” solution proposed by the OPA, this solution also meets the region’s reasonably-defined reliability needs. As addressed elsewhere in this brief, the generation dispatch scenarios D4 and D5 are not reasonable, and, therefore, the transmission system reinforcement needs defined by these two generation dispatch scenarios are not reasonable. However, the southern solution proposed by the OPA satisfies all of the reliability needs that were determined by the Company using the reasonable generation dispatch scenarios, D1, D2, and D3. It provides for two new 345 kV transmission lines into the Portland area, two new autotransformers in the area, and several 115 kV line reinforcements, and it meets all of the reasonable reliability needs of the area as forecasted over the next ten years.

The OPA Solution meets the reliability needs of the region.¹⁸ It is consistent with good utility practice and has a lower cost than the MPRP. Given these factors, it should be incumbent upon ISO-NE in examining the proposal, to include it in the RSP as a Reliability Transmission Upgrade and as such determine that it is eligible for pool supported PTF costs. If the MPRP qualified as PTF there is no defensible reason the OPA proposal should not also be eligible for cost socialization.

F. CMP's Non Transmission Alternatives Analysis is Flawed

With its Petition, CMP filed a study performed by LaCapra Associates that purported to study Non Transmission Alternatives (NTAs) to the MPRP. *Petition Exhibit I-3*. This study is, however, seriously flawed and does not provide the Commission with a meaningfully complete analysis of NTAs. First, the LaCapra study relies on needs identified by the MPRP transmission study (*Tr. February 4, 2010 at 18*), and we have demonstrated that some of those needs are inflated by the discretionary planning assumptions employed by ISO-NE. Second, the LaCapra study, with only minor exceptions, did not attempt to show what might happen if part of the MPRP were built and part of the need, however stated, were met with NTAs. *Fagan Direct at 17; Fagan Surrebuttal at 22; Tr. February 4, 2010 at 4*. In Mr. Fagan's words:

If you don't consider hybrid solutions, that implies ignoring an entire set of reliability options that might be lower cost than either a transmission-only or an NTA-only solution.

Fagan Surrebuttal at 22.

Given the opportunity to explain this lack of possible hybrid solutions, Msrs. Hahn and Peaco did not appear to understand what a meaningful hybrid study would be, stating that NTAs

¹⁸ In the words of Mr. Cannatta, "The Staff Scenario [upon which the OPA Solution is based] results in a reliable power system in accordance with ISO criteria versus the CMP MPRP system which overdesigns the system." *Tr. February 10, 2010, pp. 17-18*.

were compared to MPRP's entire northern solution separately from the entire southern solution. *LaCapra Associates Report, CMP Rebuttal, December 4, 2009 at 15.* There was no study of a hybrid northern solution (e.g., a 345 kV line from Orrington to Surowiec coupled with NTAs), a hybrid southern solution versus NTAs, or even a study of the effect of the inclusion of the second South Gorham autotransformer on possible NTAs. *Tr. February 4, 2010 at 4.*¹⁹

In this, and in prior transmission CPCN cases, both with CMP and other utilities, NTAs have fallen short. This need not be the case. Solving reliability needs is not the sole province of transmission utilities, and ratepayers can benefit from a rigorous examination of lowest reasonable cost solutions whether it is energy efficiency, demand response, generation, transmission or various combinations of these.

The Commission has the authority to require utilities to conduct meaningful studies that would provide useful information on NTAs compared to full and partial transmission reinforcement options so that it can be in a better position to decide what best satisfies a need. In this case, the original NTA assessment did not fully account for demand response resource availability known at that time, and the December 2009 Rebuttal testimony did not update the availability of demand response resources based on the results of the ISO NE 3rd FCM auction, which were known in October 2009. This underestimation of the demand response resource availability led to a significant exaggeration of the level of supply-side resources that would be required under an NTA scenario, and an exaggeration of the financial effects when compared to an MPRP-only solution. Also, the NTA modeling did not consider, even as a sensitivity

¹⁹ At hearing, Mr. Peaco attempted to explain this by saying that inclusion of the South Gorham auto in the threshold load levels "wouldn't change that – that load level." *Id.* If this is true, one would have expected this assertion to have been made in Rebuttal.

analysis, the possibility that Maine capacity prices might be lower than the rest of New England, a scenario made more likely if MPRP was not built – which is exactly what the NTA analysis was supposed to be considering.

The Commission can require that information like this be developed with sufficient time for study and implementation. The Commission should update its chapter 330 to require meaningful NTA analysis along these lines.

G. The Commission Should Authorize Two Pilots to Test GridSolar’s Proposal

We urge the Commission to conduct a proceeding to investigate the implementation of the GridSolar model in two pilots.²⁰ We suggest that these pilots occur in two separate areas of CMP’s territory, Portland/South Portland and in the midcoast. The investigation would provide for an evaluation of the cost and feasibility of the GridSolar proposal as tailored to these two areas.

GridSolar has made a credible case for solar distributed generation, with fossil-fired back-up generation and demand response, as an alternative to transmission. *Fagan Surrebuttal*, pp. 51-56. In addition, GridSolar’s smart grid proposal to monitor, through metering and communication devices, the entire grid for the purposes of manipulating the loadings on the high voltage lines deserves to be tested in Maine. The concept is simple: monitor loads at low voltage substations, and dispatch distributed generation to satisfy demand before the demand appears on

²⁰ We believe it is appropriate to allow GridSolar participate in these two pilots. The MPRP docket has been open for many months, and was preceded by many meetings open to all stakeholders, such that notice of the MPPR has widespread. GridSolar is the only alternative provider that has come forward and offered a solution. In the event the Commission disagrees, it should nevertheless conduct an RFP process for these pilots targeted to the type of proposal that GridSolar has made.

the PTF system. CMP has indicated that this approach has the same reliability as the MPRP. *GridSolar October 27, 2009 Testimony, pp. 6-7, and Exhibit – Second Supplemental.* This smart grid proposal would have the added benefit of providing to the Commission and other stakeholders precise loading and load growth information on individual circuits and in discreet load pockets. Such information, coming from a third party whose interest is not in maximizing the amount of utility transmission plant could be extremely valuable in transmission planning, particularly for the non-PTF system where this Commission has primary authority.

Mr. Lanzalotta indicated that there is a need in the midcoast area and that instead of CMP's proposed "midcoast spur," a NTA could be deployed. *Lanzalotta Surrebuttal at 22-23.* Also, in its initial NTA report, LaCapra indicated that a developing need in the Portland/South Portland area could be addressed with NTAs. *CMP Petition Ex. I-3, LaCapra Report, page 6, and 122 et. seq.; Tr. February 4, 2010 at 84.* We believe that the Commission should consider GridSolar for a distributed solar generation pilot in each of these areas. To the extent possible, we also recommend that GridSolar's smart grid idea be a part of these pilots. We recommend that the Commission retain oversight of these pilots, with frequent reports on the progress and results. ISO-NE has stated that it factors state-approved contracts for reliability resources into planning in accordance with Attachment K. *Tr. February 2 at 88.*

In the event that one or both of the pilots proves to be a viable solution at a reasonable cost, and if there otherwise appears to be cause for continued use of a distributed solar generation model, the Commission should then consider deployment of distributed solar generation in other areas to forestall the need for other transmission upgrades.

IV. Observations on Electro-Magnetic Fields

Power lines emit electro-magnetic fields (EMFs). Under the laws of physics, EMFs are capable of rather precise measurement. They are the strongest when a line is fully loaded, electrically, since they are caused by the current in a line. They are also strongest the closer one gets to the line, and their effect falls off the further one goes from a line.

After years of study, the health effects of EMFs remain unclear. Nevertheless, the suggestion of childhood leukemia and other diseases is serious and warrants close attention. While it is possible to characterize the issue as one of a remote health risk versus yet higher electric rates, if the Commission finds that the presence of EMFs warrants measures designed to reduce these risks, we will support such efforts. And yet, since electricity is an essential service, the only meaningful alternatives are to locate lines where there are no people or to bury lines whenever they come near people. The first is either impossible or impossibly expensive, requiring the purchase of all homes that are or would become near a line and to build new lines in areas where there are no people which would surely involved the extensive use of eminent domain.²¹ The second option of burying lines is also potentially extremely expensive. Any Commission action must involve a clear understanding of the cost-setting precedent.

It is possible to design and engineer power lines to mitigate the magnetic field's reach. For example, there is a process involving double circuit lines called "reverse phasing" which is accomplished by connecting the lines at the substation to cause the magnetic fields to cancel out

²¹ In fact, because of the present proscription on the use of eminent domain to take property within 300 feet of a residence, a statutory change would be necessary. *See, 35-A MRS.A §3136(2)*.

to some extent along the route. CMP should be required to take reasonable steps to mitigate the reach of magnetic fields when it constructs electrical facilities in connection with this case.

V. Conclusion

The MPRP deserves approval except for the southern leg which is supported only by the unreasonable discretionary planning assumptions employed by ISO-NE and CMP planners. We recommend a less costly but fully reliable alternative transmission solution in the south. We also recommend that the Commission authorize two pilot projects to test the effectiveness of GridSolar's proposal.

Dated this 12th day of March, 2010

Respectfully Submitted,

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