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December 8, 2009

VIA RESS, COURIER AND EMAIL

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4

Attention: Ms. K. Walli, Board Secretary

Dear Ms. Walli:

Re: Canadian Niagara Power Inc. - Application for Leave to Construct and Reinforce Transmission Facilities in the Fort Erie / Niagara Falls Area - Submissions-in-Chief (Board File No. EB-2009-0283)

We are counsel to Canadian Niagara Power Inc. (the "Applicant"). Enclosed are two copies of the Applicant's Supplemented and Restated Submissions-in-Chief, which have been filed electronically on RESS.

Yours truly,

for Charles Keizer

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ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Sched. B);

AND IN THE MATTER OF an application by Canadian Niagara Power Inc. for an Order or Orders pursuant to section 92 of the *Ontario Energy Board Act, 1998* (as amended) granting leave to construct and reinforce transmission facilities in and around Fort Erie, Ontario.

APPLICANT'S SUPPLEMENTED AND RESTATED SUBMISSIONS-IN-CHIEF

December 8, 2009

APPLICANT'S SUPPLEMENTED AND RESTATED SUBMISSIONS-IN-CHIEF

1. Introduction

These are the supplemented and restated submissions of Canadian Niagara Power Inc. ("CNP") in the matter of its application for leave to construct and reinforce transmission facilities in the Fort Erie and Niagara areas (EB-2009-0283). The Applicant's Submissions dated November 6, 2009 are subsumed and restated, in part, in these submissions and these submissions should be taken as the complete submissions-in-chief of the Applicant. Below, CNP will set out its case in brief. Each of the key elements of its position will be expanded upon to establish that, pursuant to section 96(2) of the *Ontario Energy Board Act*, 1998 (as amended), the Project is in the public interest with respect to prices and the reliability and quality of electricity service, as well as consistent with the policies of the Government of Ontario with respect to the use of renewable energy sources.

CNP has proposed a project that will develop a synchronous connection between the CNP transmission system, the IESO-controlled grid and the NYISO-controlled grid to provide the ability for instantaneous restoration of service on the CNP transmission system upon the loss of a single element (the "Project"). The Project has two purposes: (i) improving reliability on the CNP transmission system in accordance with Good Utility Practice; and (ii) providing intertie benefits to Ontario.

2. Case in Brief

From a reliability perspective, the current configuration of CNP's transmission system is deficient in a fundamental way. The system only has one normal source of supply. CNP's transmission system is exposed to the risk of its entire system "going dark" for extended periods if any one of several circumstances occur (Exhibit B, Tab 3, Schedule 1, p. 3). Because of the current configuration, these *system-wide* outages affect over 15,000 end-users (IR Response 1.0(iv)), including residential, commercial, institutional and industrial end-users and approximately 30,000 Ontario residents (Exhibit B, Tab 1, Schedule 1). It is also a disincentive for future growth.

Based on benchmarking, CNP's transmission system's reliability performance exceeds the average outage frequency and duration benchmarks established by the Canadian Electricity Association and Hydro One Networks Inc. ("Hydro One") (Exhibit B, Tab 3, Schedule 1 at p. 11-12). Historically, CNP's performance under the Independent Electricity System Operator's ("IESO") Local Area Performance benchmark have been inconsistent ranging from "Red", below threshold, to "Green", which is the threshold (Exhibit B, Tab 3, Schedule 1, p. 10). Given the configuration of the system and the natural risks associated with it, recent "near misses" could have easily, and once again, driven CNP's performance below the Local Area benchmark (Response to Interrogatory 1.0(x)). Recent good fortune leading to better performance is no guarantee that the trend will continue because the underlying reliability problem has not been remedied.

Good planning dictates that a transmitter should learn from the past and implement solutions to resolve reliability concerns in the present so as to avoid a future with the same consequences for end-users. Focusing only on good performance over a very short term period (such as 3 years) is "selective planning" and unreasonably ignores the problems that gave rise to the true indicators of performance over a longer timeframe.

The implications of reliability are real for end-users, as evidenced by letters from customers (see CNP response to Board Staff SI-3 and Appendix "B" thereto). In addition, CNP provided evidence in Section 2 of Exhibit B, Tab 4, Schedule 1, of the impact on end-users showing costs of $11.5 million. This cost validated CNP's calculation of value of lost load ("VoLL") in the range of $16.1 million. Furthermore, as described in CNP's response to Board Staff SI-1, the reliability of the CNP transmission system also has significant issues for prospective renewable energy generators seeking to connect projects developed under the OPA's Feed-in Tariff Program.

There has been some discussion in the proceeding as to the standard to apply with respect to CNP's obligations under the Transmission System Code ("TSC"). Notwithstanding that CNP has acknowledged that the NERC standard does not apply (General Response to Supplemental Interrogatories SI-1, -2 and -3), CNP has presented evidence and has consistently maintained that, based on the facts unique to CNP, the Project is needed as part of Good Utility Practice and that there are sufficient quantitative and qualitative benefits to justify the Project in the public interest. As noted in Section 4 below, the TSC's definition of Good Utility Practice permits its application to specific facts and actions.

CNP submits that the Project, which enables the system to withstand the loss of a single element, is the only solution to the reliability concerns. CNP considered a number of project variations and alternatives and each was either not viable or of questionable viability (Exhibit B, Tab 6, Schedule 1). Standing still is not an option as the emergency tie currently in place between CNP's transmission system and U.S. National Grid's ("USNG") transmission system in New York has limited capacity relative to CNP's peak load (Exhibit B, Tab 3, Schedule 1, p. 8) and takes significant time to bring into service (Response to Supplemental Interrogatory SI-4). The Project provides the only solution.

If the Project is brought into service, CNP's transmission system will be able to withstand the loss of its primary source of supply and to deliver uninterrupted supply to its end-users in such circumstances. If this is the case, the concerns expressed by end-users will be eliminated, the VoLL will be an avoided cost and renewable generation resources will be facilitated.

The Project will develop a synchronous connection between the CNP transmission system, the IESO-controlled grid and the NYISO-controlled grid, thereby providing significant system-wide benefits to Ontario due to the resulting increase in intertie capacity. The Project is rated to provide 150 MW of intertie capacity in both directions at the Niagara/New York interface, with an additional 100 MW in certain circumstances. As indicated in the response to Interrogatory 1.0(v), the IESO confirms that the Project would enhance the overall Ontario import/export capability and, therefore, provide:

- increased market activity and efficiency;

- flexibility to address situations of surplus baseload and/or renewable generation; and
- flexibility to import during periods of supply shortages (Board Staff Interrogatory 1.0(v)).

CNP quantified the intertie benefits at $39.9 million, being the total of the present value of $36.6 million arising from avoided generation capacity costs and $3.4 million arising from relieving constraints during generation maintenance outages (Exhibit B, Tab 4, Schedule 1, p. 10). The OPA confirmed that, subject to an adjustment, CNP's calculation of $36.6 million of intertie benefits is reasonable (See Appendix "D" of Supplemental Interrogatory Responses). In particular, in its correspondence, the OPA stated that "the use of avoided costs for demand response for this case is not entirely accurate because the value of demand response takes into account the value of reduced reserve margin requirements and losses. The value of demand reduction is expected to be about 20% higher than the value of additional supply" (See Appendix "D" of Supplemental Interrogatory Responses). Accordingly, CNP recalculated the avoided generation capacity benefit associated with the Project so as to take into account this variable. This recalculation determined the value of the avoided generation capacity benefit to be nearly $30.5 million (See response to Board Staff SI-7).

According to its pre-filed evidence, CNP's calculation of the Project's net present value ("NPV") is $10.4 million, being net of costs and the present value of both local benefits and Ontario system-wide benefits (Exhibit B, Tab 5, Schedule 1, Figure 5.2). Even when factoring into the NPV calculation the above-noted recalculation of intertie capacity benefits, the NPV remains positive at $4.27 million (Response to Supplemental Interrogatory SI-7). Furthermore, it is important to note that this NPV calculation does not include the significant qualitative benefits described further in Section 5(a) below and set out in Exhibit B, Tab 4, Schedule 1 at pp. 15-21. Clearly, based on the foregoing, the Project is in the public interest and satisfies the requirements of Section 96(2) of the OEB Act.

In the submissions that follow, the following is addressed:

- Reliability concerns, including:
  - Problems with the configuration of CNP's transmission system,
  - Reliability benchmarks,
  - Resolution of the reliability threat, and
  - the IESO's Ontario Resource and Assessment Criteria;
- Good Utility Practice and the Project as the Only Viable Solution;
- System-Wide Benefits for Ontario
- Qualitative Local and System-Wide Benefits
- Positive Net Present Value and Cost Recovery

3. Reliability Concerns

(a) The Current Configuration Does Not Work

The current configuration of the CNP transmission system does not allow for the system to provide uninterrupted supply upon the loss of its primary source. As explained in Exhibit B, Tab 2, Schedule 1, loss of the primary supply may result from:

- a fault on the Hydro One transmission system,
- a fault on line A37 between Hydro One's Murray TS and CNP's Station #11,
- a failure at Station #11, which is the sole supply point to line L2, or
- a fault on line L2, between Station #11 and Station #18.

An interruption to CNP's primary supply results in the entire CNP transmission system going dark.

While the CNP transmission system has some limited backup capability from USNG through the use of the Emergency Tie Line[1], this backup capability is deficient. As described in Exhibit B, Tab 3, Schedule 1 at p. 8, the Emergency Tie Line is no longer capable of meeting average monthly peak load levels on the CNP system. Moreover, as described in Exhibit B, Tab 3, Schedule 1 at pp. 5-8, the Emergency Tie Line cannot be engaged without there first being a significant interruption to supply. This is because it takes a minimum of 4 hours to complete the co-ordination and switching over to this alternate supply source, in a manner that does not cause adverse impacts on systems in New York and in Ontario, in the event of a forced outage.[2] As explained in CNP's response to Board Staff SI-4, this timeframe is needed:

- To allow for CNP to carry out its initial response, which involves identifying the problem and its location, assessing the damage, determining the approximate

[1] The Emergency Tie Line is described at Exhibit B, Tab 1, Schedule 1.

[2] For a planned outage, such as for purposes of carrying out maintenance on the CNP system, CNP can undertake some of the co-ordination activities in advance but the process of switching over to the Emergency Tie Line still requires an outage of approximately 30 minutes in duration. During such a planned outage, with few exceptions, the entire CNP system necessarily goes dark and all end-users are affected. Moreover, in order to switch back from the Emergency Tie Line to the primary supply source following either a planned or forced outage, CNP's system experiences an additional 30 minute outage during which the entire system goes dark and all end-users are once again affected.

repair time and making a decision on whether or not the outage warrants the use of the Emergency Tie Line. Where the outage is on HONI's system that supplies CNP, CNP must await the outcome of HONI's initial response before a decision can be made;

- To allow CNP's System Operator to communicate the relevant information to the IESO, HONI and USNG;
- To allow USNG, upon receiving the communication from CNP's System Operator, to initiate and complete its own process of preparing its system to supply the Fort Erie load, including ensuring sufficient generation capacity is available; and
- Upon USNG notifying CNP that it is ready and able to provide emergency supply, CNP must then follow a 31-step switching procedure to effect the transfer of its load to USNG through the Emergency Tie Line.

For the duration of this process, the entire CNP transmission system remains dark and all end-users are affected.

(b) Outages to the CNP Transmission System are System-Wide Outages

With the exception of only a few minor circumstances,[3] the CNP system's configuration results in outages that are *system-wide* outages and which affect over 15,000 end-users in the service territory, which has a population of approximately 30,000 people. The CNP service territory is primarily urban and includes a diverse group of end-users. These include residential, commercial, institutional and industrial end-users who depend on a reliable source of supply (Exhibit B, Tab 4, Schedule 1, pp 6-7). As explained in Exhibit B, Tab 3, Schedule 1 on p. 14, in addition to unplanned or forced outages, due to the system's configuration some planned maintenance activities on CNP's transmission system require outages to the entire system. Two

[3] The minor exceptions are those instances where planned outages are needed for maintenance purposes on certain parts of the system where isolation of that outage is possible.

such outages have taken place in recent years. Outages adversely impact individuals, businesses and institutions, as well as the economic well-being of the region served by CNP's transmission system. CNP filed as evidence, in its response to Board Staff SI-3, letters from end-users expressing concerns relating to the need for reliability. This series of correspondence from end-users stresses the importance and need for improved reliability on the CNP transmission system. Examples of comments from the letters include the following:

- Aero-Safe Processing Inc., which operates an anodizing, electroplating and metal finishing facility that supplies the military and aerospace industries, explains that "*a large power interruption would impact our customers ability to assemble completed product and meet the very stringent time lines dictated by their prime customers resulting in loss of revenue and large financial penalties . . . Improving the reliability of electrical power to this facility would enhance our ability to meet our customer's timelines, maintain our environmental obligations and employee safety requirements.*"

- AmericanColor, which operates a large printing facility for newspaper and mail inserts and which serves major retailers and large food chains in Canada and the United States, explains that "*a major power interruption would have a large impact on (client) sales, as their flyers would not be printed and distributed in the allowed timeframe. The key impact to the food chains would be the loss of perishable goods that would not be advertised and therefore not sold.*"

- The Town of Fort Erie, through the Office of the Mayor, explains that "*Fort Erie has had its share of power interruptions . . . CNP has proposed an elegant solution . . . This will establish a level of reliability of supply for the Town of Fort Erie that other communities are receiving, a very important economic development benefit . . . As Mayor I wish to offer my support for this CNP project as part of the overall pool of transmission resources and bring the same level of reliability to our border community as other towns and cities across Ontario now enjoy.*"

- Buffalo and Fort Erie Public Bridge Authority explains that "*the Peace Bridge is . . . the busiest border crossing for cars and the third busiest truck crossing (between Canada and the United States) . . . Many sectors of the local, regional, provincial and national economy rely on a free-flowing border with no interruptions. Many factories rely on just-in-time inventory control which would be disrupted if the border is closed. Tourist operators, particularly in the Niagara Region rely heavily on cross border traffic. A long term power outage would have a significant negative impact on border traffic movements* *and the overall economy. It is imperative that the reliability of the power supply be enhanced to ensure that the border continues to operate uninterrupted. It is crucial that an alternative or a redundant power supply be achieved as quickly as possible.*"

Among the end-users is the Buffalo and Fort Erie Public Bridge Authority, which operates the Peace Bridge – one of the busiest and most economically significant border crossings between Canada and the United States (Exhibit B, Tab 4, Schedule 1, p. 15). This is a critical infrastructure link and among the busiest border crossings between Canada and the United States. The Peace Bridge is important for trade and houses vital security and immigration-related facilities. Power outages result in significant delays, most notably to truck traffic. The economic impacts of such delays cannot be measured precisely, but it is estimated that on average trade across the Peace Bridge is valued at US$3.4 million *per hour*. In addition, there are impacts on truck drivers, transport companies and on all of the parties who rely upon the timely delivery of goods (See Exhibit B, Tab 4, Schedule 1 at pp. 15-17). A letter from the Buffalo and Fort Erie Public Bridge Authority is included in Appendix "B" of the Supplemental Interrogatory Responses.

As noted in section 2, above, and as described in Exhibit B, Tab 4, Schedule 1 at pages 2-9, CNP has provided evidence of the local economic implications of CNP's reliability problems on its system end-users. In particular, CNP considered the value of lost load ("VoLL") as the basis for quantifying the benefit, from the Project, of avoiding outages. This approach, conservatively applied, determined that the value of avoiding outages has a net present value of $16.1 million. The validity of this finding was supported in the evidence through the use of "bottom-up" calculations using data on a narrow range of local costs associated with service interruptions.

This approach identified $11.5 million of avoided costs, which validates the finding through the VoLL approach. CNP therefore concluded that the net present value of avoiding outages would be $16.1 million.

In addition, electricity generators require reliable transmission both as a source of supply for their generation facilities and as a means for delivering their generation output. This includes renewable energy generators proposing to connect either directly to the transmission system or to the distribution system that is served by CNP's transmission system. CNP, through its distribution system that serves Fort Erie, has received several queries and expressions of interest from prospective renewable energy generators. Reliability history has been an important part of these queries. As discussed in CNP's response to Board Staff SI-1, prospective renewable energy generators may be reluctant to connect to the existing CNP transmission system or the distribution system that it serves for reasons that include the following:

- Given the 20-year timeframe of a contract under the OPA's Feed-in Tariff Program, a renewable generator would be interested in longer-term reliability performance, which, based on data since 2002, would show that CNP has, on average, experienced lower than average reliability;
- There is not much more that CNP can do to improve the reliability of its transmission system unless it undertakes the Project, because the Project is the only means of resolving the fundamental reliability problem associated with the CNP system;
- Despite CNP's improved reliability performance over the last three years, the number of near-miss events, the nature of the reliability problem associated with the system, and the fact that there were no material changes made to the system or its manner of operation which caused the improved reliability performance during this timeframe, indicates that the system remains highly vulnerable to frequent outages of significant scope and duration; and

- Under the FIT Contract for renewable energy generators, such a generator would be at risk of not receiving payments for electricity in any period in which it is able to generate but for an outage on the transmission system to which it is directly or indirectly connected.

(c) **Reliability Benchmarks**

Typical measures of reliability include frequency, duration, loss of load probability, energy unsupplied and customer impacts. With respect to the frequency and duration of outages under the current configuration, CNP considered its historical performance against the findings of the Canadian Electricity Association's *Study on Forced Outages of Transmission System Equipment, 115-149 kV* (Exhibit B, Tab 3, Schedule 1, p. 11). This analysis generally indicates that the performance of the CNP transmission system has been below average. For the period 2002-2006 (being the period of the CEA report), the outage frequency on the CNP transmission system is 8.75 outages per 100 km-year, far greater (730% higher) than the CEA average frequency of 1.0534 outages per 100 km-year.

With respect to the comparison against the Hydro One Customer Delivery Point Performance Standards, CNP's transmission system performance from 2002 to 2008 fell below both the minimum and average performance standards for both frequency and duration of outages. Specifically, as set out in Exhibit B, Tab 3, Schedule 1 at p. 12, this comparison shows that the average of the three-year rolling averages for the frequency of interruptions on the CNP Transmission System has been 2.9 outages per year, with a maximum of 4.3 outages per year. This is compared to Hydro One's average benchmark of 1.1 outages per year and its minimum standard of performance of 3.5 outages per year (See Figure 3.3(b)). With respect to outage duration over the same period, the analysis indicates that the CNP Transmission System experienced an average of 184 minutes of outages per year based on the average of three-year rolling averages, as indicated by Figure 3.3(a), which is far greater than the average standard of 22 minutes of outages per year under Hydro One's CDPPS and greater than the minimum standard of performance of 140 minutes per year.

In contingency planning, it is pertinent to consider the potential exposure of the system to risk. Of particular note for CNP are the significant portions of the transmission system which consist of lines strung on wooden poles located along road allowances where there is a risk that vehicular accidents can cause service disruptions. These wooden poles are also subject to the possibility of burning due to insulator tracking. In addition to the vehicle accidents and burning pole incidents described in Exhibit B, Tab 3, Schedule 1, Figure 3.2 of the pre-filed evidence, which lists events that resulted in actual system outages, in recent years there have also been a number of similar events on these portions of the system that gave rise to significant risks of lengthy, forced outages, but which did not actually result in service disruption. As described in CNP's response to Interrogatory 1.0(x):

1) A vehicle accident occurred in 2005 that resulted in a broken transmission pole;
2) A transmission pole burned in 2006 due to insulator tracking;
3) A vehicle accident occurred in 2009 that resulted in a broken transmission pole; and
4) A transmission pole burned in 2009 due to insulator failure on a 34.5 kV underbuild circuit.

While each of these incidents could very well have given rise to lengthy outages to CNP's entire transmission system, CNP and the end-users of the system were very fortunate that none of the above-noted incidents actually caused forced outages. Nevertheless, these incidents demonstrate the types of risks faced by CNP, any one of which poses a significant risk of causing a forced outage.

In 2007 and 2008, favourable weather conditions were experienced and there were no vehicular accidents affecting CNP's transmission system (Interrogatory Response 1.0(xi)). As part of its ongoing maintenance programs, CNP carried out activities that included the removal of trees that posed potential risks to transmission lines and the replacement of some older insulators. Prior to 2007, CNP also implemented more systematic line inspection and vegetation management programs. While these activities may have reduced some risk, there is no way to quantify their relative contributions, if any, to CNP's reliability performance in 2007 and 2008 (Interrogatory Response 1.0(xi)).

Under the IESO's Local Area Performance benchmarks, the performance of a transmission system is rated as "Red", "Yellow" or "Green" based on system performance in relation to performance in recent years. Red indicates poorer performance than threshold and Green indicates threshold performance. Since 2002, the rating of the CNP Transmission System has gone from Yellow (2002) to Red (2003 and 2004) to yellow (2005 and 2006) to Green (2007 and 2008). The inconsistency in the performance record for the CNP Transmission System is indicative of the fact that in some years CNP is fortunate that no major equipment failures or supply outages occur but in other years, despite its good management, CNP is exposed to potentially serious reliability concerns (Exhibit B, Tab 3, Schedule 1, p. 10).

As discussed in CNP's response to Board Staff SI-1, while CNP's local area performance based on the IESO's process and criteria for assessment has been categorized as "Green" in 2007 and 2008, achieving this "Green" classification has been largely a function of the classification methodology, which compares unsupplied energy levels in recent years against a 10-year average level of unsupplied energy. For the "Green" years of 2007 and 2008, CNP performance was measured against the 10-year average level of unsupplied energy on the CNP transmission system between 1993 and 2002. Based on this, just a 30 minute outage in a period of average load in one of those years would have caused CNP's classification to fall to "Yellow" and if an outage of such duration were to have occurred in consecutive years, CNP's classification would have fallen to "Red". However, the threshold for achieving the "Green" classification has been reset for 2009 to 2014 based on the 10-year average level of unsupplied energy between 1999 and 2008. As such, for the next 5 years it will take an outage of approximately 150 minutes or more for CNP's classification to fall to "Yellow" and two consecutive years with an outage of such duration for CNP's classification to fall to "Red". Putting this measure into context, declining performance over time lowers this threshold and better performance raises the threshold. The underlying assumption is that a transmitter strives to improve. However, as in CNP's case, when all improvements have been made, the change in the benchmark to signify "Green" merely represents the shifts in CNP's good fortune and the inherent uncertainties associated with the reliability of the system.

Despite this moving target, any one of the near-miss events noted in CNP's response to Board Staff Interrogatory 1.0(x) would be expected to have given rise to an outage of approximately 4 hours. As such, CNP's classification under the IESO's process and criteria for assessing local area performance can change at any time, as a result of just a single event. There is no certainty that CNP will stay "Green" and there is nothing inherent in CNP's system that would enable CNP to avoid falling to "Yellow" or "Red" under this performance indicator. Consequently, CNP cannot provide assurance to end-users or prospective generators that it can consistently stay within the "Green" classification. For these reasons, there should be little weight given to CNP's recent classifications under this performance indicator.

(d) **Resolution of Reliability Threat**

Notwithstanding CNP's good management, a change in CNP's good fortune could return CNP to "Yellow" or "Red" status and result in even poorer performance relative to the CEA or CDPPS standards. If the Project is implemented, none of the incidents from 2002-2006 or the near-misses in the past 3 years would have caused a transmission line outage resulting in system-wide outages to end-users (Exhibit B, Tab 4, Schedule 1, p. 2).

Implementation of the Project will enable CNP to consistently achieve and improve with respect to benchmarks. The threat to CNP's reliability, particularly by way of the total loss of supply due to the loss of a single element, would be eliminated and the impact on and costs to end-users would be avoided.

(e) Resource and Transmission Assessment Criteria

In response to Board Staff interrogatory SI-16, the IESO referenced the *Ontario Resource and Transmission Assessment Criteria* (the "RTAC") relating to load security and restoration.[4] In its response in SI-16, the IESO states that transmission systems such as CNP's must be planned such that all loads must be restored with approximately 8 hours.

CNP submits that the IESO has not fully stated what the criterion is or how it should be applied, and has not adequately set out the context in which it should be applied. It is not a bright line test that establishes a benchmark for reliability from an operator's perspective.

As such, the Board should not give full weight to the IESO's statement as it is written in the IESO's response to SI-16 and should take into account the following:

- The RTAC is to be used to evaluate long-term system adequacy and connection assessments, not for identifying "operating" criteria (RTAC, p.1). CNP seeks to implement the Project from an operational perspective to improve system reliability and to implement a technical remedy to avoid the threat to reliability that impacts all of the end-users in the CNP system. The approval of the Project is about operation and the real life impacts associated with operation and not about operating the system to a generally applied design standard of approximately 8 hours.

- The study parameters must be applied on the basis of good utility practice and judgment, taking into account the particular circumstances and characteristics of the part of the IESO-controlled grid that is being studied (RTAC, p.3). As stated in these submissions and in the general response to Board Staff SI-1, -2 and -3, CNP has maintained that good utility practice should be applied based on the circumstances on a case by case basis. It is reasonable to state that no utility in Ontario would believe that it is good utility practice for a utility to take up to 8

[4] The RTAC is available on the IESO's website at:
http://www.ieso.ca/imoweb/pubs/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

hours to restore power to 56 MW of load. Moreover, this load represents the total demand of the CNP system and represents an urban area with diverse end-users and an important international border crossing. Consideration should be given to the fact that the contingency impacts 100% of the CNP load and that the Project would help in improving the supply reliability. This is consistent with the IESO's *Supply Deliverability Guidelines*,[5] which state the following at page 3:

> *The planned deliverability to be provided to a load should take into account contingencies, past performance, probability of failure, the size of the load involved, the cost of interruptions to the customers, and the cost of remedial measures.*

- The 8 hour restoration time is part of a transmission system planning design criteria that affected loads be restored within the following times.

    a. All loads within approximately 8 hours;

    b. Loads in excess of 150 MW within approximately 4 hours; and

    c. Loads in excess of 250 MW within 30 minutes (RTAC, p.30).

    Each case can be considered separately, taking into account the probability of the contingency, frequency of occurrence, length of repair time, the extent of hardship caused and cost (RTAC. p. 30).

    Higher or lower levels of reliability may be applied for technical, economic, safety and environmental reasons (RTAC, p.30). The criteria set out above are planning parameters. One can only view these as basic minimums and not standards to assess reliability from an operational sense. These criteria are not determinative of good utility practice which is factually driven.

- It is important for the Board to understand the origins of the 8 hour time frame. The 8 hour time frame evolved from the IESO's *Supply Deliverability Guidelines*, which in turn were based on Ontario Hydro's "Guide to Planning Regional Supply Facilities" (also known as the "E2" Guide). The IESO modified the E2 Guide as part of the *Supply Deliverability Guidelines*. Both provide for the restoration of loads less than 75 MW within 8 hours. However it is important to note the following:

[5] The Supply Deliverability Guidelines are available on the IESO website at: http://www.ieso.ca/imoweb/pubs/marketAdmin/IMO_GDL_0021_IMOSupplyAvailabilityGuidelines.pdf

> *(The) E2 guide tried to capture the cost of interruptions by relating transmission facilities to load size. However, the guide did not directly specify the level of reliability to be provided in terms of typical measures such as frequency, duration, loss of load probability, energy unsupplied ... or customer impacts . . . Ontario Hydro made decisions on new facilities or enhancements on a case-by-case basis. They were not made solely on the provision of the E2 Guide. For example, higher levels of customer reliability may have been provided for technical, economic, safety and environmental reasons* (IESO Supply Deliverability Guidelines, p.1).

As such, the 8 hour time frame is not a bright line test, but only a planning parameter that is not reflective of true operating conditions that must be taken into account as part of good utility practice.

4. Good Utility Practice and the Only Viable Solution

CNP is relying on that part of the definition of "good utility practice" set out in section 2.0.33 of the Transmission System Code which provides that "good utility practice" means:

> *any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition.*

While this aspect of the definition is worded so as to be applied with hindsight to projects that have already been carried out, if CNP could have carried out this project without leave and then sought recovery for costs at a later date, then this would be the applicable measure of whether it was good utility practice to do the Project. As such, there is no reason why this portion of the definition does not apply to a leave to construct proceeding. There are not two standards, i.e. one for actions taken with leave and one for actions taken without leave. Using this portion of the definition is therefore appropriate to employ on a case by case basis.

For the CNP transmission system, providing the ability to withstand the loss of a single contingency is the only viable solution to providing improved reliability that, in the circumstance, is consistent with fundamental principles of good utility practice. For a system of the size and nature of CNP's transmission system, serving end-users with the diversity and economic significance of those served by CNP's system, good utility practice requires CNP to strive to improve reliability and to lessen the threat to reliability. The only solution that achieves this is the Project, which permits the system to have the ability to withstand the loss of one element. CNP would have a readily available secondary supply available to provide uninterrupted service in the event of the unplanned loss of the system's primary supply. In addition, good utility practice suggests that CNP should have the ability to carry out planned outages for purposes of carrying out maintenance activities without incurring lengthy system-wide outages in the course of switching to and from an emergency supply source (See Exhibit B, Tab 3, Schedule 1, p. 14).

While CNP carries out a wide range of activities and is always considering improvements that may enhance system performance, no such activities or improvements would address the basic reliability problem of the system not being able to withstand the loss of its primary supply source. As indicated in CNP's responses to Board Staff interrogatories:

- With respect to the two circuits on the limiting Queen St. Tower to High Tower section, where only one of the circuits is currently energized, even if the second circuit was upgraded to 60-cycle, re-insulated and energized, the basic reliability problem of not having N-1 contingency would not be mitigated (See responses to 1.0(vi) and 2.0(ii)(b));

- An upgrade to the limiting transmission line section between Queen St. Tower and High Tower would improve line capacity by a small margin and would therefore increase the capacity of the Emergency Tie Line by a small margin, but the Emergency Tie Line would still provide inadequate emergency backup supply and would still take at least 4 hours to engage. Such an upgrade would not address the basic reliability problem of not being able to withstand the loss of a single element (See response to 2.0(ii)(a));

- The minimum 4-hour long procedure for engaging the Emergency Tie Line in the event of a forced outage, along with the similar process for switching back to the primary supply cannot be condensed or shortened. As discussed above in 3(a) above, this amount of time is needed in order for CNP to carry out its initial response activities (or await the completion of HONI's initial response for an outage on HONI's system), as well as for necessary communications and coordination, for USNG to perform the necessary operations to prepare its system to supply Fort Erie load, and for CNP to complete its 31-step switching procedure. These processes are needed to ensure the safe and effective connection with the USNG system, as well as to prevent adverse consequences to the USNG system that would otherwise result from use of the Emergency Tie Line. In any event, even if the process could be shortened, this would not address the basic reliability problem of not being able to withstand the loss of a single element (See response to 2.0(ii)(c); and

- CNP has in recent years carried out work for purposes of enhancing system performance and minimizing risk, including the removal of trees posing risks to the transmission lines, the replacement of some older insulators, as well as the implementation of more systematic line inspection and vegetation management programs. CNP also has a range of planned system improvements of a normal or ongoing nature, such as procedural improvements and capital and maintenance expenditures to enhance system robustness. While these activities may reduce some risk and improve system performance, none of this work addresses the basic reliability problem of not having N-1 contingency (see responses to 1.0(xi) and 2.0(ii)(d)).

As indicated, the only solution to the fundamental reliability problem of the system not being able to withstand the loss of its primary supply is to equip the system with this ability to provide uninterrupted supply in the event of such loss. Furthermore, the Project is the only viable means of doing so. To arrive at this conclusion, CNP considered two alternative projects as well as three different variations of the Project. These are discussed in Exhibit B, Tab 6, Schedule 1.

As explained in Section 3 of Exhibit B, Tab 6, Schedule 1, each of the two options considered would have involved development of a new transmission line along existing rights-of-way in order to connect the CNP system to the IESO-controlled grid at a second location. One option would have been to connect at Station #11 in Niagara (the "Niagara Project Alternative") and the other option would have been to connect at Crowland TS in Port Colborne (the "Port Colborne Project Alternative"). Each of these alternatives would be expected to provide the same local reliability benefits as would be expected from the Project.

However, as neither of the alternatives would provide additional intertie capacity, they would not provide any of the associated system-wide benefits that are expected from the Project (Exhibit B, Tab 6, Schedule 1, p. 8). Because of this, the project alternatives were both found to have negative net present values (See Exhibit B, Tab 6, Schedule 1, pp. 16-17). Moreover, as these alternatives would require the construction of lengthy, new lines through a region that includes highly populated areas in some places, along with numerous areas that are recognized as being environmentally sensitive, the permitting and stakeholdering risks would be significant (See Exhibit B, Tab 6, Schedule 1, pp. 13-16). The viability of the Niagara Project Alternative and the Port Colborne Project Alternative was therefore found to be highly uncertain. By contrast, as explained in Exhibit B, Tab 4, Schedule 1 at page 20, the Project maximizes the use of existing infrastructure. In particular, it is not expected that the Project will require any new transmission poles or towers or any additional lands. In addition to avoiding land acquisition costs through the use of existing infrastructure, impacts on the community are minimized. This results in advantages from a regulatory and permitting perspective for the Project.

CNP also considered several different variations of the Project. These variations, discussed in Section 2 of Exhibit B, Tab 6, Schedule 1, involved the development of a synchronous connection with USNG using phase shifters at different sizes - 60 MVA, 80 MVA and 150 MVA. The conclusion of this analysis demonstrated that, due to the need to overcome system limitations for each alternative, the incremental cost of using a 150 MVA phase shifter is minimal. As such, the use of a 150 MVA phase shifter was found to be, by far, the most prudent approach to developing a synchronous connection with New York. Generally, to make full use of the smaller sized phase shifters, most of the system upgrades needed for the Project would still be required. Therefore, for a very small incremental cost associated with the higher capacity phase shifter, significant incremental benefits would be realized (See Exhibit B, Tab 6, Schedule 1, pp. 2-7). The Project, therefore, was found to be the only viable option.

5. The Project Offers Significant System-Wide Benefits to Ontario

CNP has demonstrated three broad classes of benefits that will be derived from the Project: (1) local reliability benefits that have been quantified (see section 4, above), (2) intertie capacity benefits to Ontario that have been quantified, and (3) qualitative local and system-wide benefits. It should be noted that, in all aspects of the analysis, CNP has taken a highly conservative approach to quantifying the reliability and intertie capacity benefits anticipated from the Project.

With respect to intertie capacity benefits, CNP identified two types of benefits that were able to be quantified: (a) reduced capacity requirements for Ontario, and (b) insurance against generation maintenance outages. These are discussed in Exhibit B, Tab 4, Schedule 1 starting at p. 10.

To quantify the value of the Project in reducing capacity requirements for Ontario, CNP considered the cost of building equivalent new generating capacity. To support this methodology, CNP used the Board's *Guidelines for Electricity Distributor Conservation and Demand Management*, which provide a forecast of avoided costs for generation capacity to the year 2025. Based on the Guidelines, the net present value of the avoided generation cost for 150 MW of generation capacity over the life of the Project was determined to be approximately $365 million. Consistent with CNP's highly conservative approach to quantifying the benefits of the Project, this amount was reduced by a factor of 90% to arrive at an estimate of $36.5 million for the net present value of the avoided generation cost provided by the Project (See Exhibit B, Tab 4, Schedule 1 at pp. 12-13). An additional $3.4 million in benefits was identified in respect of the fact that the Project would help relieve constraints during shoulder seasons when generation may not be available due to maintenance activities (See Exhibit B, Tab 4, Schedule 1 at p. 14). Together, CNP has therefore quantified $39.9 million in benefits associated with the increased intertie capacity provided by the Project.

As noted in its correspondence of December 3, 2009, which is provided in Appendix "D" of CNP's responses to the Supplemental Interrogatories, the OPA has endorsed CNP's approach to quantifying the present value of avoided generation costs as being reasonable, with one adjustment. In particular, the OPA stated that "the use of avoided costs for demand response for this case is not entirely accurate because the value of demand response takes into account the value of reduced reserve margin requirements and losses. The value of demand reduction is expected to be about 20% higher than the value of additional supply." Accordingly, CNP recalculated the avoided generation capacity benefit associated with the Project so as to take into account this variable. This recalculation determined the value of the avoided generation capacity benefit to be nearly $30.5 million (See response to Board Staff SI-7).

According to its pre-filed evidence at Figure 5.2 of Exhibit B, Tab 5, Schedule 1, CNP's calculation of the Project's net present value ("NPV") is $10.4 million, being net of costs and the present value of both local benefits and Ontario system-wide benefits. When factoring into the NPV calculation the above-noted recalculation of intertie capacity benefits, the NPV remains positive at $4.27 million (Supplemental Interrogatory Response SI-7). Furthermore, this NPV calculation does not include the significant qualitative benefits described below. Based on the foregoing, the Project is in the public interest and satisfies the requirements of Section 96(2) of the OEB Act.

(a) Qualitative Local and System-Wide Benefits

CNP has identified numerous qualitative benefits that can be expected from the Project. These are described in Section 4 of Exhibit B, Tab 4, Schedule 1. As indicated in 5.3.2 of the Board's Filing Requirements, qualitative benefits are an important consideration in evaluating the Project and alternatives to the Project.

These qualitative benefits include significant benefits to the Fort Erie Public Bridge Authority which operates the Peace Bridge connecting Fort Erie, Ontario with Buffalo, New York (Exhibit B, Tab 4, Schedule 1, p. 15).

Other qualitative benefits, discussed in Exhibit B, Tab 4, Schedule 1 at pp. 17-21, include the following:

- Short-term Supply Shortage — as a result of the increased intertie capacity provided by the Project, the Project will offer some protection against short-term supply shortages which can result from unexpected reductions in Ontario-based supply due to growing dependence on intermittent sources;
- Surplus Baseload — as a result of the increased intertie capacity provided by the Project, during periods of low Ontario demand, the Project would provide the IESO with greater flexibility by allowing for greater exports of surplus baseload generation to New York;
- Increased Opportunities for Trade — as a result of the increased intertie capacity provided by the Project, in normal operating circumstances the intertie would provide benefits associated with the possibility of increased trade with New York;
- Use of Existing Infrastructure — the Project offers the practical, economically efficient and social benefit of maximizing the use of existing infrastructure and not requiring the use of additional lands; and
- Fewer Regulatory Risks — related to the above-noted benefit regarding the use of existing infrastructure and the need for no additional lands, the Project presents few regulatory risks as compared to the alternatives considered and the Project offers significant benefits without adversely affecting people, communities or the natural environment.

As indicated in the response to Board Staff interrogatory 1.0(v), the IESO confirms and emphasizes several of the above-noted benefits, particularly those related to the increased intertie capacity that would result from the Project. Specifically, the IESO confirmed and emphasizes the potential for the Project to enhance the overall Ontario import/export capability and, therefore, to provide:

- increased market activity and efficiency,
- flexibility to address situations of surplus baseload and/or renewable generation, and
- flexibility to import during periods of supply shortages.

Moreover, in the IESO's response to Supplemental Interrogatory SI-13, it is stated that "in the IESO's view, should CNP choose to meet the N-1 planning criteria, it will enable itself to maintain a higher degree of load security, especially given the noted diversity and economic significance of its customer base."

6. Net Present Value and Cost Recovery

The Project carries an estimated cost of $30.9 million (See Figure 5.1 of Exhibit B, Tab 5, Schedule 1). As indicated in CNP's response to Board Staff interrogatory 3.0(i), when an allowance for funds used during construction (AFUDC) is included, the cost estimate rises to $33.2 million. As indicated in Exhibit B, Tab 5, Schedule 1, the Project has a positive net present value of over $10 million. This calculation takes into account the project cost including AFUDC. When also factoring into the calculation the adjustment identified in the December 3, 2009 correspondence from the OPA, the Project is found to have a positive Net Present Value of $4.27 million (Supplemental Interrogatory Response SI-7), as well as the many important qualitative benefits described above.

CNP proposes that the Project costs, which include the capital contribution that CNP will have to make to USNG to cover the costs of work to be carried out on the USNG system in support of the Project, be added to CNP's rate base upon the Project coming into service. These costs would then be recovered through the Uniform Transmission Rates. This is appropriate for the following reasons:

- the Project is required in accordance with good utility practice which, as indicated, in the present circumstances requires CNP to provide a reliability solution;
- the Project is part of good system planning and provides significant local benefits;
- the Project will, as discussed, provide a wide range of significant, system-wide benefits to Ontario, such benefits having been confirmed and emphasized by the IESO; and
- the Project will provide the level of reliability that is needed to support economic growth in the Niagara and Fort Erie region, as well as to support the potential future connection of new generation, including renewable energy generation facilities, to the CNP transmission system and/or the distribution system that it serves, all in support of provincial government policy objectives.

As described in Exhibit B, Tab 5, Schedule 1, it is expected that rates would increase by an average of 1.2 cents per kilowatt, per month, over the life of the Project. On this basis, the expected impact of the Project on a typical residential customer would be 2.7 cents per month or an increase of 0.024%.

7. Conclusions

For all of the foregoing reasons, we hereby submit that leave should be granted in accordance with CNP's Application, pursuant to Section 92 of the *Ontario Energy Board Act*, for an order or orders granting:

(a) leave to reinforce 2.0 km of line (being CNP's lines A36 and A37) to accommodate the maximum capability of an upgraded interconnection between CNP's transmission system in Fort Erie, Ontario and US National Grid's ("USNG") transmission system in Buffalo, New York;

(b) leave to construct and reinforce 0.5 km of Conductor from the Bertie Hill Tower to Queen Street Tower in Fort Erie with 795 MCM conductor to provide capacity of at least 150 MW; and

(c) leave to construct and reinforce 0.66 km of Conductor from the Queen Street Tower in Fort Erie, Ontario, across the Niagara River, to the High Tower forming part of the USNG transmission system in Buffalo, New York.

And including the following, which are fundamental and integral to the completion of the forgoing:

(a) installation of an additional 115 kV breaker adjacent to the Murray taps on A36N and A37N;

(b) installation of two additional breakers at Station #17 in Stevensville for enhanced sectionalizing and zone control;

(c) installation of a 150 MVA phase shifting transformer and voltage regulator at Station #18 in Fort Erie;

(d) construction of a 115 kV three-breaker ring station located at switch SW 998 in Buffalo, New York, that will tie L46, L47 and USNG's Canada Bus; and

(e) removal and replacement of approximately 10 km of conductor from the Huntley Station to a new 115 kV Paradise Station being planned by USNG in Buffalo, with a new 115 kV three-phase transmission circuit.

All of which is respectfully submitted by:

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Charles Keizer, Counsel for the Applicant

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Jonathan Myers, Counsel for the Applicant