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November 6, 2017
Our File No. 67284

VIA COURIER & EMAIL TO:
boardsec@oeb.ca

Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto ON M4P 1E4

Attention: Ms. Kristen Walli, Board Secretary

Dear Ms. Walli:

Re: EB-2016-0003 - NOACC Coalition Letter of Comment

We are solicitors representing the Coalition of the Northwestern Ontario Associated Chamber of Commerce ("NOACC"), Common Voice Northwest ("CVNW") and the Northwestern Ontario Municipal Association ("NOMA") (hereinafter the "NOACC Coalition" or the "Coalition").

Coalition's Comments on the Proposed Amendments to the Transmission System Code and the Distribution System Code in File No. EB-2011-0043

The NOACC Coalition repeats its comments by letter dated June 17, 2013, and filed with the Ontario Energy Board with respect to its May 17, 2013 Notice of Proposal To Amend A Code, specifically the Transmission System Code ('TSC') and the Distribution System Code ('DSC') (the 'Notice'),[1] most notable being that from a policy perspective, the TSC and DSC proposed amendments do not require the system planner to consider the needs and circumstances of the actual end users. The "*Optimal Infrastructure Solution*" principle should include the context of the end users of that infrastructure. In other words "what is the ends user's Optimal Infrastructure Solution"?

[1] Weiler, Maloney, Nelson / NOACC Coalition. June 17, 2013. *Comment Letter in response to the May 17, 2013 Notice of Proposal to Amend a Code re EB-2011-0043.* Thunder Bay, Ontario

<u>Coalition's Comments to the Guiding Principles</u>

The NOACC Coalition submits the definition of "*Optimal Infrastructure Solution*" must include longer term planning where more robust infrastructure would be built in the first place. In the OEB's definition of "Optimal Infrastructure Solution", it equates "the lowest cost" solution as being the "most cost effective solution".

The "most cost effective solution" should be the goal in any reginal plan but any such solution must also take into account the concept of "risk". Any solution being considered has included with it some inherent risk that it may not be the best long term solution. A solution that reduces the "risk" that further, more costly, actions may be required in the foreseeable future may not necessarily be the "lowest cost" solution at any given time. It may however be the "most cost effective solution". Solution options that provide future flexibility are extremely beneficial to long term planning. The TSC needs to recognize that flexible solutions that reduce future risk are better solutions than those that are simply the immediate lowest cost option.

This may address current circumstances in the Northwest where large end users of electricity pay only for electricity infrastructure to meet their current portfolio needs, rather than their ultimate needs. Often this is done in isolation of any regional plan. It also reduces the chances of a competing enterprises being unable to set up close by because there is no additional electrical capacity.[2]

The NOACC Coalition submits the investment portion of such infrastructure cost should be socialized and paid for by all ratepayers. The increase in transmission costs that result [investment portion above the end users current portfolio needs] will ultimately affect all customers in the province, including initially through higher charges. Such increased cost will also provide, inter alia, the following benefits of a robust system:

> A. Increased Reliability and Security - As climate change increases the frequency and intensity of severe weather, a recent study in the United States found that building a more robust (or what they called "resilient") electrical grid makes good economic sense.[3] Northwest Ontario persistently incurs power outages, caused by various reasons most notable weather, that cause substantial losses to residents and businesses including lost output and wages, spoiled inventory, delayed production, inconvenience and damage to the equipment[4] [5]not to mention the damage to the electric grid itself. A robust system will mitigate these costs over time – saving the economy real dollars and reducing the

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[2] Corporation of the Municipality of Red Lake, The. 2011. *Red Lake and Upper Northwest Ontario's Electrical Power Situation.* Red Lake, Ontario.

[3] President's Council of Economic Advisers and the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability, with assistance from the White House Office of Science and Technology. August 2013. *Economic Benefits of Increasing Electric Grid Resilience to Weather Outages.* Executive Office of the President. The White House. Washington.

[4] Ontario Energy Board file EB-2007-0707. January 16, 2008. *Issues Proceeding 3.* Transcript, page 173. (Krassilowsky, Anne)

[5] City of Thunder Bay / NOMA. *37 Hour Power Outage at Goldcorp.* Thunder Bay, Ontario.

hardship experienced by Ontarians when extreme (or even not so extreme) weather strikes.

B. Participation in the Green Economy. All of Northwestern Ontario is and has been an orange zone for large renewable projects.[6] This is unfortunate in that the Northwest has the greatest potential for renewable energy development in the province.[7] If substantial investment in transmission and distribution does not occur, Northwestern Ontario specifically will not be able to fully participate and sustain a green economy. Regulatory oversight on this issue is important.[8]

C. Participation in the Global Economy - In the Northwest large private users of electricity are based primarily in the natural resource economy (forestry and mining). Business conditions are volatile and there are strong pressures on the unit costs of services. The slow and resource intensive nature of regulation make it difficult to respond to these pressures in a timely manner.[9] There by losing out on opportunities and investment in an ever increasing global economy.

In practice then, the most appropriate route is through the installation of robust infrastructure (which is more reliable) to meet the end users ultimate needs, such robust infrastructure does not constrain (but in fact promotes) other entrants or competitors, and upholds the objectives of regional plans. Such robust infrastructure also complies with the OEB objectives under section 1(1) of *Ontario Energy Board Act* to protect consumers, which include the ultimate end users, with respect to "adequacy" "reliability" and to "promote economic efficiency". Along with making common sense these submission also appropriately links with the next principle being "*Beneficiaries Pays*".

The ultimate end user(s) arise one beneficiary of the *Optimal Infrastructure Solution.* The customers of a transmitter and distributor may also be beneficiaries (i.e. by increased reliability and adequacy of electricity services). All rate payers may be further beneficiaries. All of the above are considered in the proposed amendments to the TSC and DSC, with the exception of governmental beneficiaries. Federal, provincial and municipal governments all stand to benefit significant tax dollars from those end users as a result of increased costs associated with the installation of robust infrastructure. For example, a University of Toronto 2014 study of the projected annual revenue of six (6) new gold mines in Northwestern Ontario for the Federal Government at $356,000,000; Provincial Government at $142,600,000; and local taxes at $2,600,000.[10] The prerequisite to taxing such amounts is infrastructure with most notable electricity services. But for electricity there is no mine.

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[6] Independent Electricity System Operator (IESO). Meeting Summary, Monday, June 27, 2016

[7] PCED Vol 16. Renewable energy in remote Aboriginal communities, page 87 ON. *Recent Developments in Renewable Energy in Remote Aboriginal Communities, Ontario, Canada* (Konstantinos Karanasios and Paul Parker)

[8] Carswell. Energy Law and Policy. Table 2: Ontario Feed-in Tariff Program Prices. (Gordon Kaiser and Bob Heggie, Editors)

[9] Carswell. Energy Law and Policy. Incentive Regulation for North American Electric Utilities. pages 276 and 277 (Gordon Kaiser and Bob Heggie, Editors)

[10] Dungan, Peter and Murphy, Steve. 2014. *An Au-Thentic Opportunity: The Economic Impacts of a New Gold Mine in Ontario.* Toronto, Ontario: Rotman School of Management, University of Toronto.

NOACC Coalition's submissions on the *Optimal Infrastructure Solution* and *Beneficiaries Pays* principle are consistent with being open, transparent and including all affected parties.

<u>Proposed Proportional Benefit Approach</u>

Not all ratepayers have the same access to electricity in Ontario. Northwestern Ontario, being west of Wawa to Kenora and north to Hudson's Bay, have less adequate and reliable electricity than the rest of the province. Geography and population density are factors.[11] [12] The NOACC Coalition submits the proposed Proportional Benefit Approach needs to account for such factors and deficiencies in access when determining what a fair and equitable apportionment is.

For example, the two major radial lines in the Northwest - serving (1) Ear Falls, Red Lake and Pickle Lake in the west, and (2) serving Greenstone in the east, we submit have failed to meet the Ontario Resource and Transmission Assessment Criteria (ORTAC) for well over a decade. Both lines have been subjected to unplanned outages lasting well over the standard of 8 hours in clear violation of ORTAC's 7.2 (7.2 Load Restoration Criteria). The IESO has established load restoration criteria for high voltage supply to a transmission customer. The load restoration criteria are established so that satisfying the restoration times will lead to an acceptable set of facilities consistent with the amount of load affected. The transmission system must be planned such that, following design criteria contingencies on the transmission system, affected loads can be restored within the restoration times listed - within approximately 8 hours. [13][14]

In order to verify the information provided in this submission as it relates to the quality of service to (1) Ear Falls, Red Lake and Pickle Lake and to (2) Greenstone, the OEB is encouraged to seek outage reports for the above noted two radial lines from Hydro One Networks for the past 20 years. These are not isolated incidents. The trend has been steeply negative and in Greenstone for example a breach has occurred each of the last four years (2013-2016). The OEB should require immediate action in cases where such a trend is evident.

The NOACC Coalition supports the OEB's belief that a specific customer should not be required to pay all of the costs associated with connection investments where the investment also addresses a broader network need (such as reliability or adequacy). The OEB, the NOACC Coalition submits, must expand its proportional benefit methodology to include a socialization factor that accounts for the deficiencies in the grid and the large geography and low population factors.

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[11] Ontario Energy Board file EB-2007-0707. January 16, 2008. *Issues Proceeding 3.* Transcript, pages 172-178. (Krassilowsky, Anne)

[12] Greenstone/Marathon Local Advisory Committee. *Appendix J: Local Advisory Committee Report on the Social-Economic Benefits of Electricity Options.*

[13] Common Voice Northwest Energy Task Force. October 29, 2013. *Electrical Demand and Supply for Northwestern Ontario.* page 6 Thunder Bay, Ontario.

[14] Common Voice Northwest Energy Task Force. October 28, 2013. *North of Dryden Draft Reference Integrated Regional Plan.* page 24 and 31 Thunder Bay, Ontario.

In practice, when demand for a system upgrade has been demonstrated for a number of years, the total cost of replacing or upgrading to meet current load should be paid for by all the ratepayers when those lines have not, or do not currently, meet the acceptable standard for transmission lines. Where the acceptable standard has been achieved and additional capacity is required, then the TSC formula steps in.

NOACC Coalition submits the formula should not be based on the distance of new wires to connect each customer. The length of line for a load increase is much greater in the Northwest than it would be in most all other parts of Ontario, as well as the percentage of the total new load from each new customer. These deficiencies and factors need to be considered in order to realistically determine what a fair and equitable apportionment is.

<u>Proposed TSC and DSC Amendments</u>

NOACC Coalition supports the OEB's proposal "to amend the TSC by adding sections 6.13A and 6.13B to allow costs associated with transmitter-owned connection investments to be apportioned between the customer(s) that caused the need for the connection investment and all ratepayers, based on the proportional benefit between the connection customer(s) and the overall system". This option of a case by case application approach may be useful in supporting NOACC Coalition's position for 230 kV line expansions north.

NOACC Coalition also supports the OEB's proposal to amend section 6.7.2 of the TSC to address the replacement of end-of-life transmission connection assets. The concept of a customer only having to pay the incremental cost of an upgrade to an end-of-life transmission facility (e.g. A4L) could be very beneficial for economic growth in Northern Ontario where many of the 115 kV transmission assets are very old. Included is the concept that the TSC would require the transmitter to consult with their customers when a transmission facility is reaching 75% of its rated capacity.

NOACC Coalition also supports the OEB's proposal for amending the TSC by adding a new section 6.3.19 requiring transmitters to accept the provision of the capital contribution by distributors in annual payments over a period of time up to five years rather than the current requirement of total contribution up front. NOACC suggests an amendment should be added to include large customers as well as distributors "provided the customers demonstrate acceptable financial capability". These above would alleviate the obstacles caused by "lumpy" transmission connection investments. The OEB uses the example of "a 115 kV line comes close but falls short of meeting a distributor's forecast needs, a 230 kV line would be required which would include much excess capacity under such circumstances".

The NOACC Coalition proposes the threshold for "large" load customers for both capital contribution (3.2.4) and by-pass compensation (3.5.1) be increased to demand that meets or exceeds 4 MW (as opposed to 3 MW). Upon review of the Northwest electrical load analysis one will note forestry loads of saw mills hover over 3 MW of demand but below 4 MW.[15] Slightly increasing this threshold by one MW may be vital assistance to a part of the beleaguered forestry industry that face cyclical markets.

The OEB touches briefly on the where there is "Community desire for more than 'optimal' solution in regional plan". The OEB recommends that such issues should be addressed on a case by case basis, in an adjudicative process, rather than changes to the Codes. NOACC Coalition supports further consideration be given to this being and include it in the Codes. Such an adjudicative process would likely be too costly to be practical for the small communities and industry in Northwestern Ontario.

Respectfully submitted,

Yours very truly,

WEILER, MALONEY, NELSON

Per:

NICK A. MELCHIORRE

NAM/hs
Enclosures

[15] Mason, John. Thunder Bay Economic Development Corporation. August 24, 2017. *Load Projection Comparison*. Thunder Bay, Ontario.

Weiler, Maloney, Nelson / NOACC Coalition. June 17, 2013. *Comment Letter in response to the May 17, 2013 Notice of Proposal to Amend a Code re EB-2011-0043.* Thunder Bay, Ontario

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June 17, 2013

File #57695

VIA MAIL AND EMAIL BoardSec@ontarioenergyboard.ca

Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4

Attention: Ms. Kirsten Walli, Board Secretary

Dear Ms. Walli:

Re: The City of Thunder Bay, Northwestern Ontario Associated Chambers of Commerce (NOACC) and the Northwestern Ontario Municipal Association (NOMA) Comment on the Proposed Amendments to the Transmission System Code and the Distribution System Code - File No. EB-2011-0043.

The following comments are made on behalf of the NOACC Coalition, comprised of Northwestern Ontario Associated Chambers of Commerce (NOACC), Northwestern Ontario Municipal Association (NOMA), the Township of Atikokan, and the City of Thunder Bay. The comments are in response to the May 17, 2013 Notice of Proposal To Amend A Code, specifically the Transmission System Code ('TSC') and the Distribution System Code ('DSC') (the 'Notice').

Regional Planning Concepts Capture by the Proposed Amendments

The NOACC Coalition applauds the formalization of a regional planning process intended in the proposed amendments to the TSC and the DSC.

Deficiencies in the Proposed Amendments

The NOACC Coalition notes, however, that there are significant deficiencies in the elements of regional planning represented in the proposed amendments. Those deficiencies are yet to be addressed. One of the outcomes of a commitment to regional planning must be an assessment of regional needs. If needs turn out to be materially different in a particular region it is axiomatic that the one size fits all form of system planning cannot be assumed to be applicable everywhere in the province.

Needs Assessment Not Required

It is essential to recognize that the successors to what once was Ontario Hydro remains a natural monopoly. A corollary to that fact is that a natural monopoly always runs the risk of confusing an internal exchange of information and requirements with serving the needs of its end use customers. The proposed amendments, which go a long way to formalizing power system planning on a regional basis, remain almost entirely a dialogue internal to the natural monopoly itself. There is no requirement in the proposed amendments that any part of the monopoly actually be required to turn to the end-use customer and ask the pivotal needs-based planning questions. What are your electricity needs? Are those needs being met? Is what the electricity system is doing now actually meeting your needs?

The proposed amendments to the TSC and the DSC do nothing to require that system planners advert in any concrete way to the fact that the only reason the electricity monopoly exists at all is to serve the end-user of the electricity. This results in, for example, a mislabelling the planning model set out in the proposed amendments as a "needs" based model. In actuality it is requirements-based planning model. It is not that requirements-based planning is wrong. On the contrary, it is essential that requirements planning take place where appropriate. The model for regional planning set out in the proposed amendments is certainly an improvement in system planning on a regional

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level. The point is that it is entirely a requirements-based model, not needs-based planning model.

Part of the confusion in trying to distinguish needs-based planning from requirements-based planning arises from the fact that the definitions[1] of the two words imply that on one level the words can be considered interchangeable. The word "require" is, in part, defined as "need". The word "need" is, in part, defined as "require". The distinction arises more clearly, in the part of the definition of "need" that identifies "circumstances requiring some course of action". It is in that part of the definition of the word that needs-based planning becomes intelligible. What are the "circumstances" of the end-user of electricity? It is only after there has been an investigation as to the "circumstances" that the end-user actually faces that there can be any assessment as to what "course of action" is needed. Hence, needs-based planning.

The NOACC Coalition notes the absence in the proposed amendments to the TSC and the DSC of any requirement for actual needs-based planning; that is, planning that begins with an inquiry into the "circumstances" of end-users, and would-be end-users of grid-based electricity supply in the Northwest Region. While the customers of a transmitter are largely going to be distributors, the customers of the distributors are largely going to be the end-users of the electricity. The regional planning that will result from the proposed amendments indicates only that the distributors are to be asked whether their requirements (misstated as needs) are being met. There is no indication that distributors are to be required to investigate the needs of end-users, or would-be end-users.

This anomaly, namely that the needs of the end-user are nowhere required to be investigated, is reflected in:

1. the fuzzy, if not absent, criteria that would prompt the development of an "Integrated Regional Resource Plan" ("IRRP") as distinct from a "Regional Infrastructure Plan" ("RIP"); and
2. the unquestioned assumption that planning models that may well address end-user needs in a densely populated region are transferable to meet the end-user needs in a vast, thinly populated area such as the Northwest Region.

[1] The Little Oxford Dictionary of Current English

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If Needs Assessment Were Required

If there were to be an inquiry into the needs of the end-users, and would-be end-users, of the grid-based power system in the Northwest Region NOACC can identify several issues that likely would arise.

1. While it may at first seem appropriate to develop a definition of network assets for purposes of consistency throughout the province, does that not beg the question as to planning that is truly regional in nature? Would an investigation of the needs of end-users and would-be end-users in the Northwest Region find those needs more appropriately served, for example, if the definition of network assets extended to all transmission lines (along with auto transformers & associated switch gear) in the Northwest Region?

2. While it may seem appropriate in a dense grid serving a highly populated region to let the lead transmitter represent whether an IRRP is required, there is no reason to assume that the end-users and would-be end-users in the Northwest Region would consider anything less than an IRRP to be acceptable. The assessment as to whether or not an IRRP should be developed is not appropriate in the hands of a transmitter. That assessment should, in the Northwest Region in particular, arise from a more transparent process in the hands of a proponent without the conflict of interest that a transmitter necessarily has. At very least the determination as to whether an IRRP is called for should be made on the basis of an assessment of the needs of the end-users and would-be end-users in the Northwest Region.

3. While it may seem appropriate in a dense grid serving a highly populated region to maintain the user-pay requirement, albeit in more reasonable form of subsequent additional-user contribution, that planning concept may well not be appropriate in a vast, thinly populated area such as the Northwest Region. Why would it be thought the end-user should bear the cost of constructing a power line over dozens of kilometres of Crown Land? Capping the cost to an end-user so that the end user does not pay the portion of the cost of the line constructed on Crown land could arguably be an offset to the burden of paying a cost of power many times greater than the production cost in the Northwest Region.

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4. While it may seem appropriate in a dense grid serving a highly populated region to remove the concept of "otherwise planned" from the TSC, that is not appropriate in a vast, thinly populated area such as the Northwest Region. Power system planning in a densely populated region, as indicated in the Notice, must address load growth. By its nature load growth makes the "needs" obvious. As a result planning to address load growth will quite properly be requirements-based. There is no reason, however, to assume that the criteria, analytical concepts, standards and planning models of requirements-based planning for load growth are going to be all that will be appropriate in system planning in a vast, thinly populated area such as the Northwest Region where load development and diesel replacement are of equal importance to load growth.

Conclusion

The NOACC Coalition is very appreciative of the movement towards a system of regional planning; however, in order to be effective regional planning must be based on an investigation as to the needs of the end users in the region itself. It must not be assumed that the needs of the end-users in the Northwest Region will be exactly the same as the needs of the end-users in regions with large populations and, correspondingly, dense electricity systems.

Yours very truly,

WEILER, MALONEY, NELSON

Per:

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Corporation of the Municipality of Red Lake, The. 2011. *Red Lake and Upper Northwest Ontario's Electrical Power Situation.* Red Lake, Ontario.

Provided to OPA in 2011

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Red Lake and Upper Northwest Ontario's Electrical Power Situation

Summary
Red lake has a long tradition of gold mining and continues to move forward with new discoveries occurring at an explosive pace. New mining developments have projected electrical demands exceeding 100 megawatts by 2013. This has put an undue strain on the 115 KV transmission corridor between Ear Falls and Red Lake referred to as the E2R.

Current Red Lake Regional Situation (100 megawatt requirement next 2011-2016, 120 megawatt requirement 2016-2031)
Goldcorp currently has an application before the OEB to install a new 115 KV tap about 5 miles south of Red Lake TS. It has been determined through System Impact Assessments and Connection Impact Assessments that this "tap" would have little or no impact on the transmission customers downstream of the "tap". However this has not been done without requirement for system upgrades at Ear Falls (capacitor bank and regulatory equipment at customer cost). Goldcorp has a large demand load requirement they will experience by 2013 including: 10 megawatts for their u/g tram; 10 megawatts for the new Cochenour Willans headframe; and up to 30 megawatts for the new processing mill they are considering constructing. Goldcorp has forecasted an 80 megawatt shortfall within the next 5 years.

Rubicon Minerals Inc. has applied to connect to the 44 KV M6 Feeder originating at Red Lake TS. Although they have been granted 5 megawatts, their operation requires an additional 5 megawatts. Rubicon is exploring diesel generation to generate their 5 megawatt shortfall.

Claude Resources is in the late stages of its mine rehabilitation program and advanced u/g exploration program. They have spoken to me about upgrading all their hoist motors to 25 KV from 13.8 KV and would require about 10 megawatts of electrical power once they reach production in 2015.

With all the junior exploration firms and drilling companies active in the area (Skyharbor Resources, Hytech Drilling, Chibogamou Drilling, MegaPrecious Metals, Premier Gold, etc.) we expect that there will be new "trends" resulting in a new mine every 4 years. Each new mine requires 10-15 megawatts once it reaches the production phase. By the year 2031 there will be 5 new mines in the Red Lake gold mining "camp" resulting in an additional 40 to 60 megawatt load.

Not to mention renewed current interest in a neighboring iron ore mine just south of Red Lake referred as Griffith Mine continues to grow. If Griffith restarts there will be a significant requirement for power precipitated by the enormous need for electricity during the iron ore processing phase (40 to 60 megawatts)

From the current load growth scenarios it should become quite apparent that the Dryden to Ear Falls and Ear Falls to Red Lake 115 KV corridors require extensive upgrades. These 115 KV transmission lines have minimum load capacities left and are in jeopardy of being seriously overloaded within 5 years! There are 2 options for upgrading these corridors:

1/ Twinning the 115 KV transmission lines from Dryden to Ear Falls and from Ear Falls to Red Lake
2/ Installing a 230 KV transmission line from Dryden to Red Lake

One might argue that the 115 KV twinning option makes the most sense (using compatible transformers (for example115/44 KV – 42 MVA transformers installed at Red Lake TS). That is until you examine the lack of robustness of such a system (radial) and the much more viable potential for looping. If a 230 KV line is being advocated from Dryden to Pickle Lake then a strong argument presents itself to loop the 230 KV system via Pickle Lake to Red Lake to Dryden. Although 230/115 KV and subsequent connection of the 115/44 KV – 42 MVA transformation maybe considered expensive, the robustness/reliability of such a system cannot be underestimated.

Load Growth Scenario – Upper Northwestern Ontario (185 Megawatts by 2011-2031)
Fast forward to 20 years from now. The Road North now reaches from Red Lake to Bearskin. Besides the Red Lake gold mining camp which now has increased its operated mines by 4 (60-80 megawatts additional load) there have been an additional 4 new gold mine start ups in the First Nation communities resulting in another 60 – 80 megawatts of electrical load. Additionally there has been a diamond mine opening up just north of Bearskin requiring an additional 40 megawatts. And just a reminder, by 2012 the Whitefeather Forest will receive their EA to open 650,000 hectares of harvestable timber. There have been serious discussions indicating 10 value-added forestry mills will open to process this wood supply. These mills will require another 50 megawatts of electrical power. Total Northwestern First Nation community load will be 15 megawatts (15 communities at an average of 1 megawatt per community).

Conclusion (305 megawatt power requirement for Red Lake and Upper Northwestern Ontario)
The total projected load by 2031 could reach 305 megawatts. The safe electrical demand load for a 230 KV line is 300 to 500 megawatts. The point is that once a 230 KV line is built to Red Lake, 115 KV transmission corridors can be installed from the 230 KV Red Lake TS to service the First Nations needs. Simply twinning the 115 KV does not address the gross requirement for electrical power that this region will encounter over the next 20 years, and we would still have a 115 KV radial line (albeit twinned) which does not have the reliability or robustness of a 230 KV looped system. Note the Grid Reinforcement bullet point from the recent Hydro One Announcement below:

Recent Announcement from Hydro One Website:

Hydro One is pleased to announce that it has initiated the first of these projects - the Northwest Transmission Expansion Project (the "Project") - a new single circuit 230,000 volt (230 kV) transmission line in northwestern Ontario. The proposed line would travel approximately 430 kilometres from the Nipigon area to the Pickle Lake area on a new 40-metre wide transmission corridor. New stations would also be required in the Nipigon and Pickle Lake areas for electrical transformation and switching.

This Project is contingent upon receiving a number of approvals, including Leave-to-Construct (Section 92) approval from the Ontario Energy Board and Environmental Assessment approval before construction can begin.

Hydro One is committed to working with First Nations, Métis, residents, businesses and the communities we serve in an open, fair and transparent manner, providing consultation opportunities throughout the process.

Benefits of Expanding the Northwestern Transmission System

- **Reliability** – The existing 115 kV transmission line between Ear Falls and Pickle Lake (E1C) is aging and has a poor performance record. The new line would provide an alternate source of supply resulting in improved reliability.
- **Capacity** – Electricity growth is expected to increase beyond the capacity of E1C, and the new line would provide the opportunity for existing customers to grow and for future customers to be connected to the provincial electricity system.
- **Renewables** – The northwest has renewable generation potential including approximately 100 MW at OPG's proposed Little Jackfish Hydroelectric Development as well as up to 280 MW of wind potential on the eastern side of Lake Nipigon. This line would provide the transmission capacity to develop this renewable generation.
- **Remote Communities** – The proposed line offers the opportunity for First Nations and other communities to connect to the grid in the future, reducing their dependency on diesel generation.
- ***Grid Reinforcement – Building the line would lay the groundwork for a future 230 kV connection between Dryden Transformer Station and the new station in the Pickle Lake area, creating a 230 kV ring and strengthening the grid's capacity in the northwest.***
- **Economic Development** – The project has the potential to create direct and indirect construction jobs, green jobs and related economic benefits for northwestern Ontario communities and businesses.

Bill Greenway
Economic Development Officer
Municipality of Red Lake

President's Council of Economic Advisers and the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability, with assistance from the White House Office of Science and Technology. August 2013. *Economic Benefits of Increasing Electric Grid Resilience to Weather Outages*. Executive Office of the President. The White House. Washington.

ECONOMIC BENEFITS OF INCREASING ELECTRIC GRID RESILIENCE TO WEATHER OUTAGES

Executive Office of the President

August 2013

THE WHITE HOUSE
WASHINGTON

This report was prepared by the President's Council of Economic Advisers and the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability, with assistance from the White House Office of Science and Technology

Executive Summary

Severe weather is the leading cause of power outages in the United States. Between 2003 and 2012, an estimated 679 widespread power outages occurred due to severe weather. Power outages close schools, shut down businesses and impede emergency services, costing the economy billions of dollars and disrupting the lives of millions of Americans. The resilience of the U.S. electric grid is a key part of the nation's defense against severe weather and remains an important focus of President Obama's administration.

In June 2011, President Obama released *A Policy Framework for the 21^{st} Century Grid* which set out a four-pillared strategy for modernizing the electric grid. The initiative directed billions of dollars toward investments in 21^{st} century smart grid technologies focused at increasing the grid's efficiency, reliability, and resilience, and making it less vulnerable to weather-related outages and reducing the time it takes to restore power after an outage occurs.

Grid resilience is increasingly important as climate change increases the frequency and intensity of severe weather. Greenhouse gas emissions are elevating air and water temperatures around the world. Scientific research predicts more severe hurricanes, winter storms, heat waves, floods and other extreme weather events being among the changes in climate induced by anthropogenic emissions of greenhouse gasses.

This report estimates the annual cost of power outages caused by severe weather between 2003 and 2012 and describes various strategies for modernizing the grid and increasing grid resilience. Over this period, weather-related outages are estimated to have cost the U.S. economy an inflation-adjusted annual average of \$18 billion to \$33 billion. Annual costs fluctuate significantly and are greatest in the years of major storms such as Hurricane Ike in 2008, a year in which cost estimates range from \$40 billion to \$75 billion, and Superstorm Sandy in 2012, a year in which cost estimates range from \$27 billion to \$52 billion. A recent Congressional Research Service study estimates the inflation-adjusted cost of weather-related outages at \$25 to \$70 billion annually (Campbell 2012). The variation in estimates reflects different assumptions and data used in the estimation process. The costs of outages take various forms including lost output and wages, spoiled inventory, delayed production, inconvenience and damage to the electric grid. Continued investment in grid modernization and resilience will mitigate these costs over time – saving the economy billions of dollars and reducing the hardship experienced by millions of Americans when extreme weather strikes.

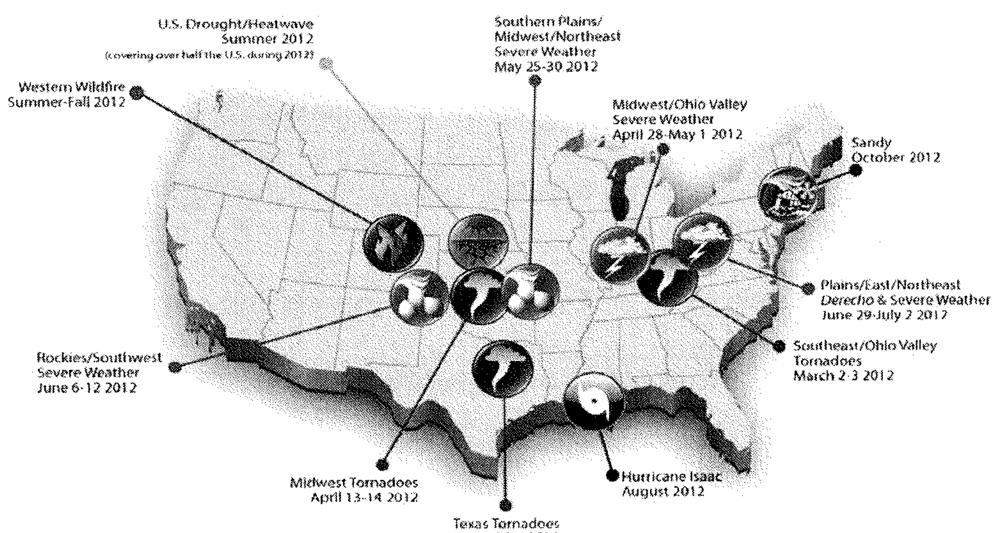
I. Introduction

The U.S. electric grid ("the grid") constitutes a vital component of the nation's critical infrastructure and serves as an essential foundation for the American way of life. The grid generates, transmits, and distributes electric power to millions of Americans in homes, schools, offices, and factories across the United States. Investment in a 21st century modernized electric grid has been an important focus of President Obama's administration. A modern electric grid will be more reliable, efficient, secure, and resilient to the external and internal cause of power outages – improving service for the millions of Americans who rely on the grid for reliable power.

Severe weather is the number one cause of power outages in the United States and costs the economy billions of dollars a year in lost output and wages, spoiled inventory, delayed production, inconvenience and damage to grid infrastructure. Moreover, the aging nature of the grid – much of which was constructed over a period of more than one hundred years – has made Americans more susceptible to outages caused by severe weather. Between 2003 and 2012, roughly 679 power outages, each affecting at least 50,000 customers, occurred due to weather events (U.S. Department of Energy).

The number of outages caused by severe weather is expected to rise as climate change increases the frequency and intensity of hurricanes, blizzards, floods and other extreme weather events. In 2012, the United States suffered eleven billion-dollar weather disasters – the second-most for any year on record, behind only 2011. The U.S. energy sector in general, and the grid in particular, is vulnerable to the increasingly severe weather expected as the climate changes (DOE 2013).

U.S. 2012 Billion-dollar Weather and Climate Disasters



Source: National Oceanic and Atmospheric Administration

The American Recovery and Reinvestment Act of 2009 ("Recovery Act") allocated $4.5 billion to the U.S. Department of Energy (DOE) for investments in modern grid technology which have begun to increase the resilience and reliability of the grid in the face of severe weather (Executive Office of the President 2013). A more resilient grid is one that is better able to sustain and recover from adverse events like severe weather – a more reliable grid is one with fewer and shorter power interruptions. Methods for improving the resilience and reliability of the grid include both high and low-tech solutions.

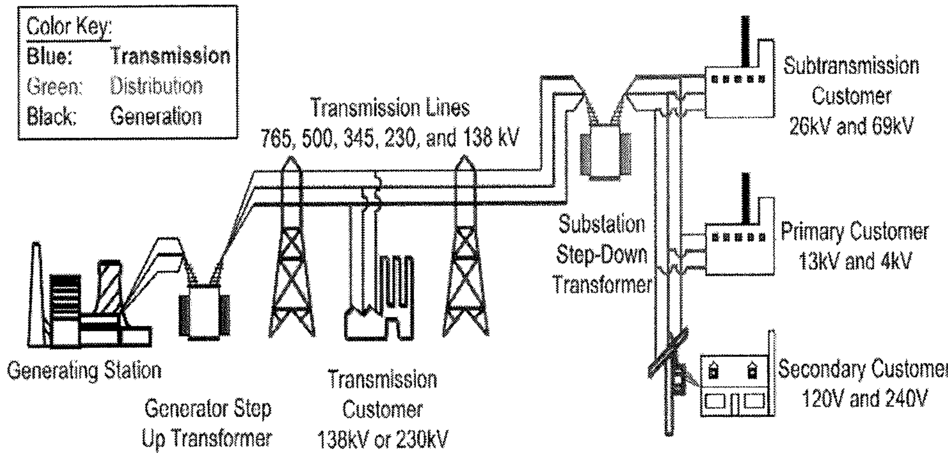
This report begins by describing the current state of the U.S. electric grid, the impact of widespread power outages caused by severe weather, and the increasing intensity and frequency of severe weather due to climate change. The report then documents numerous strategies for increasing the grid resilience and reliability. Lastly, an economic model is presented and used to estimate the annual cost of power outages caused by severe weather in the United States. The benefits of increased grid resilience include the avoided cost of these outages.

II. Status and Outlook of the Electric Grid

The grid delivers electricity to more than 144 million end-use customers in the United States (U.S. Energy Information Administration 2013). The grid consists of high-voltage transmission lines, local distribution systems, and power management and control systems.[1] Electricity is produced at generation facilities and transported to population centers by high-voltage transmission lines. After arriving at population centers, electricity enters local distribution systems where it travels through a series of low-voltage lines in a process called "stepping down" before reaching homes, offices and other locations for consumption. The grid connects Americans with 5,800 major power plants and includes over 450,000 miles of high voltage transmission lines (American Society of Civil Engineers 2012).

[1] Although the grid also includes generation facilities, this report focuses on the status and outlook of the grid's transmission, distribution and management/control systems.

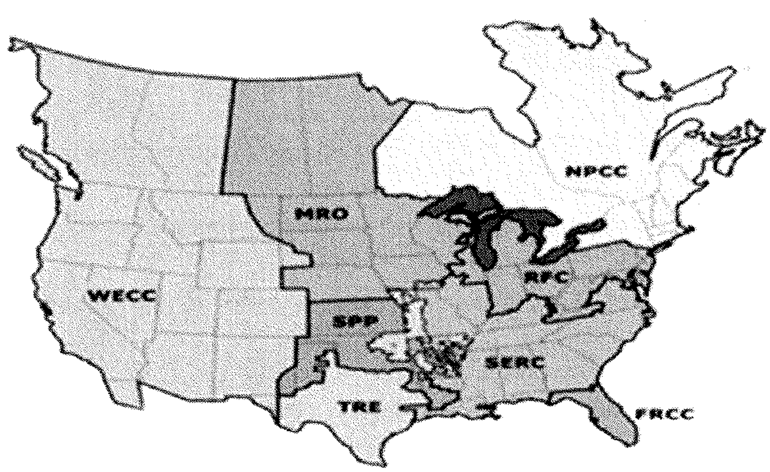
Basic Structure of the U.S. Electric Grid



Source: U.S. Canada Power System Outage Task Force

The transmission grid consists of eight regions and is overseen by the North American Electric Reliability Corporation (NERC), a non-profit entity responsible for the reliability of the bulk power system in North America (including the United States and Canada), subject to the oversight of the Federal Energy Regulatory Commission (FERC). The U.S. electric system is primarily comprised of three interconnections (Eastern, Western and Texas interconnection). The three interconnections are linked by direct current (DC) transmission lines which limit and control the amount of electricity transferred between them. Within each interconnection, electricity travels through a network of alternating current (AC) transmission lines.

North American Reliability Corporation, Grid Regions

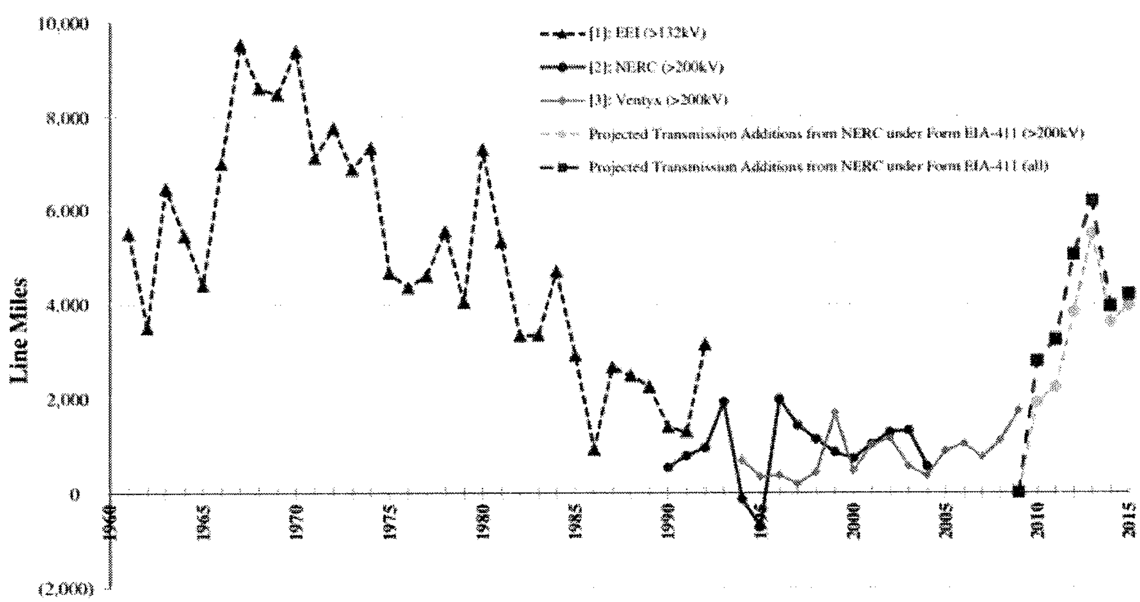


Source: North American Reliability Corporation

Most of the grid is privately owned by for-profit utility companies. Since public utilities are natural monopolies, government agencies regulate electric rates and operating practices. State agencies regulate the rates charged by local utilities while both federal and state governments oversee the operation of generating facilities and transmission systems (ASCE 2012). Electric utilities are defined as any entity generating, transmitting or distributing electricity. Utilities can be either publicly-owned, investor-owned or cooperatives. As of 2010, roughly 62 percent of utilities were publicly-owned; however, investor-owned utilities serve the majority of customers (68 percent) (American Public Power Association 2012).

Construction of the grid began in the late 1880s and continues today – albeit at a significantly slower pace. In the mid-2000s, transmission lines across all eight NERC regions were built at a rate of roughly 1,000 circuit miles per year. This rate more than doubled to 2,300 circuit miles in the five years leading up to a NERC reliability assessment published in 2012. Despite the increase, projected construction of transmission lines remains well below the rates experienced between 1960 and 1990 (Pfeifenberger 2012). Seventy percent of the grid's transmission lines and power transformers are now over 25 years old and the average age of power plants is over 30 years (Campbell 2012).

U.S. Historical Transmission Construction



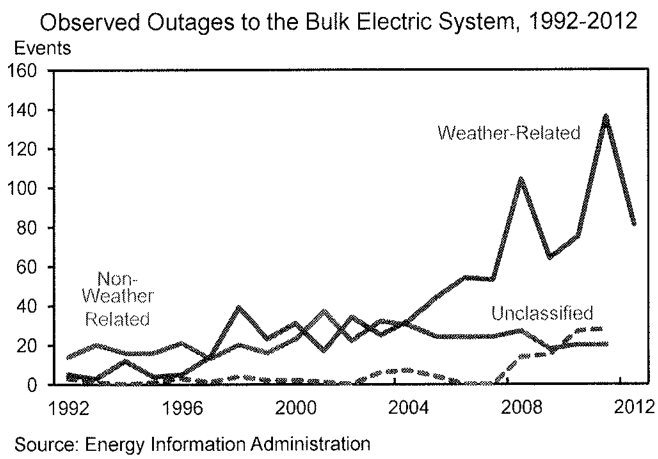
Source: The Brattle Group, 2012

The age of the grid's components has contributed to an increased incidence of weather-related power outages. For example, the response time of grid operators to mechanical failures is constrained by a lack of automated sensors. Older transmission lines dissipate more energy than new ones, constraining supply during periods of high energy demand (ABB Inc. 2007). And, grid deterioration increases the system's vulnerability to severe weather given that the majority of the grid exists above ground.

In response to the growing need for grid modernization, the federal government has allocated billions of dollars to replace, expand and refine grid infrastructure. The American Recovery and Reinvestment Act of 2009 ("Recovery Act") allocated $4.5 billion for investments in modern grid technology (EOP 2013). Smart grid technology utilizes remote control and automation to better monitor and operate the grid. Between June 2011 and February 2013, Recovery Act funds have been used to deploy 343 advanced grid sensors, upgrade 3,000 distribution circuits with digital technology, install 6.2 million smart meters and invest in 16 energy storage projects (EOP 2013). These investments have contributed to significant increases in grid resilience, efficiency and reliability.

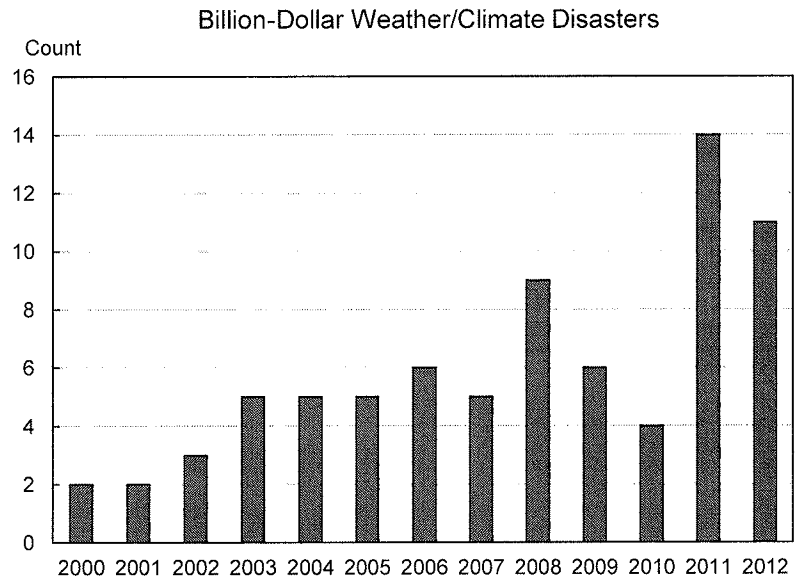
III. Impact of Severe Weather on the U.S. Electric Grid

Severe weather is the single leading cause of power outages in the United States. Outages caused by severe weather such as thunderstorms, hurricanes and blizzards account for 58 percent of outages observed since 2002 and 87 percent of outages affecting 50,000 or more customers (U.S. DOE, Form OE-417). In all, 679 widespread outages occurred between 2003 and 2012 due to severe weather. [2] Furthermore, the incidence of both major power outages and severe weather is increasing. Data from the U.S. Energy Information Administration show that weather-related outages have increased significantly since 1992.



[2] Other causes of power outages include: operational failures, equipment malfunctions, circuit overloads, vehicle accidents, fuel supply deficiencies and load shedding – which occurs when the grid is intentionally shut down to contain the spread of an ongoing power outage (U.S. DOE, Form OE-417).

Since 1980, the United States has sustained 144 weather disasters whose damage cost reached or exceeded $1 billion. The total cost of these 144 events exceeds $1 trillion (U.S. Department of Commerce 2013). Moreover, seven of the ten costliest storms in U.S. history occurred between 2004 and 2012 (U.S. DOC 2012). These "billion dollar storms" have rendered a devastating toll on the U.S. economy and the lives of millions of Americans.



Source: National Oceanic and Atmospheric Administration (NOAA)

According to the National Climate Assessment, the incidence and severity of extreme weather will continue to increase due to climate change. The 2009 assessment of the U.S. Global Change Research Program (USGCRP) on behalf of the National Science and Technology Council found that anthropogenic emissions of greenhouse gases are causing various forms of climate change including higher national and global temperatures, warmer oceans, increased sea levels, and more extreme weather events (USGCRP 2009). The increased incidence of severe weather represents one of the most significant threats posed by climate change (USGCRP 2013).

Climate change is expected to alter patterns of precipitation. Northern areas of the United States are projected to become wetter, especially in the winter and spring, while southern areas are projected to become drier. In addition, heavy precipitation events will become more frequent. Depending on location, severe downpours currently occurring once every 20 years are projected to occur every 4 to 15 years by 2100 (USGCRP 2009).

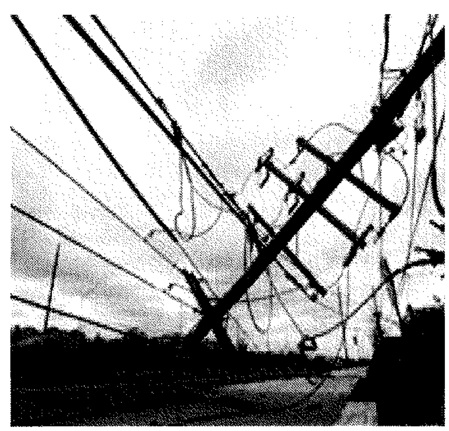
In addition to higher temperatures and changing patterns of precipitation, scientists expect warmer ocean temperatures to increase hurricane intensity. Hurricanes draw energy from the temperature difference between ocean surfaces and the mid-level atmosphere. Over the past three decades, the North Atlantic has already experienced the trend of increasing hurricane intensity (Kossin et al. 2007). Moreover, several studies project a substantial increase in hurricane-related costs due to climate change (Mendelsohn et al. 2012; Nordhaus 2010; Narita et al. 2009). Similarly, winter storms will also become stronger, more frequent, and costly (USGCRP 2009). Investment in modern infrastructure will be required to maintain grid reliability as these weather changes occur.

Case Study: Superstorm Sandy

Superstorm Sandy made landfall near Atlantic City, New Jersey as a post-tropical cyclone on October 29, 2012 and then continued northwest over New Jersey, Delaware and Pennsylvania. The heaviest damage was due to record floods in New York and New Jersey. A storm surge of 12.65 feet hit New York City causing flooding of 4 to 11 feet in Lower Manhattan. New Jersey experienced a storm surge of 8.57 feet which caused flooding of 2 to 9 feet in ten counties across the state. In all, the storm damaged 650,000 homes and knocked out power for 8.5 million customers.

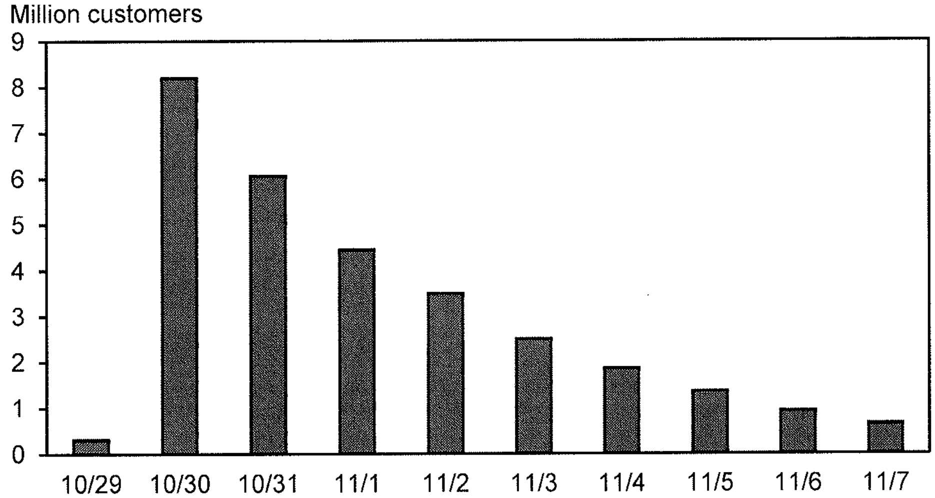
Sandy directly caused the deaths of 72 people in the United States and an estimated $65 billion in damages – the second-costliest cyclone to hit the U.S. since 1900. Sandy indirectly caused the death of another 87 people, 50 of which were attributed to power outages. Numerous senior citizens without heat died from hypothermia while other victims died of carbon monoxide poisoning due to improperly vented generators (U.S. DOC 2013; Blake 2013).

Smart grid investments made by the U.S. Department of Energy's Smart Grid Investment Grant (SGIG) in some of the states hit by Sandy lessened the impact for thousands of electric customers. For example, In Philadelphia, roughly 186,000 smart meters were up and running by the time Sandy hit. The Philadelphia Electric Company (PECO) estimated that about 50,000 customers experienced shorter outages due to its new smart grid systems, which also included upgrades to its Outage Management System (OMS). PECO observed more than 4,000 instances where smart meters were able to remotely determine when power was restored, saving PECO and its customers time and money.



In the Washington D.C. metropolitan area, the Potomac Electric Power Company (PEPCO) said it was able to restore power to 130,000 homes in just two days after Sandy thanks to advanced meter infrastructure (AMI) deployed under its SGIG projects. With smart meters and AMI connecting roughly 425,000 homes, PEPCO received "no power" signals that allowed them to quickly pinpoint outage locations. The signals arrived at PEPCO's central monitoring center, allowing the company to respond to customers quickly and effectively. After power was restored, PEPCO continually "pinged" the meters to verify service restoration, thus avoiding the need to send repair crews.

Hurricane Sandy Power Outages

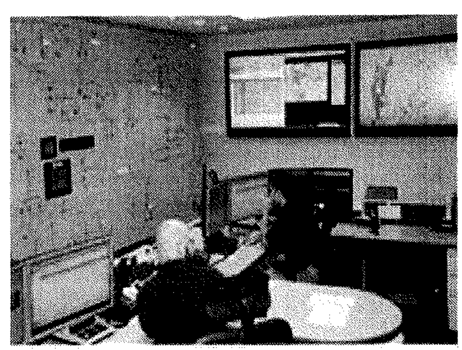


Source: Department of Energy

Case Study: Hurricane Irene

Hurricane Irene made landfall near Cape Lookout, North Carolina on August 27, 2011 as a category one hurricane and then continued north-eastward making a second landfall near Atlantic City, New Jersey. Irene's most significant impact was on the mid-Atlantic states through New England with the heaviest damage occurring in New Jersey, Massachusetts and Vermont due to inland flooding (Avila and Cangialosi 2011). In all, 2.3 million people were mandatorily evacuated in advance of Irene's devastation (U.S. DOC, 2011).

More than 6.5 million people in the United States lost power during Hurricane Irene, which includes over 30 percent of the people living in Rhode Island, Connecticut and Maryland (U.S. DOE 2011). Irene caused the death of 41 people in the United States and resulted in $15.8 billion in total damages (Avila and Cangialosi 2011) - the seventh costliest hurricane in U.S. history (U.S. DOC 2012a).



Smart grid investments made before Irene's landing lessened the storm's impact for thousands of electric customers. Investments in advanced metering infrastructure (AMI) improved outage notification and response time, greatly reducing the duration of outages. In Pennsylvania, the Pennsylvania Power & Light's (PPL) smart grid investments in distribution automation technologies made a difference for 388,000 customers who lost power.

IV. Strategies for Achieving Grid Resilience

Grid resilience, a core requirement for climate adaptation, includes hardening, advanced capabilities, and recovery/reconstitution. Although most attention is placed on best practices for hardening, resilience strategies must also consider options to improve grid flexibility and control. Resilience includes reconstitution and general readiness such as pole maintenance, vegetation management, use of mobile transformers and substations, and participation in mutual assistance groups. This section summarizes several key ways to improve grid resilience. Additional details are provided in the U.S. Department of Energy report (DOE 2010a).

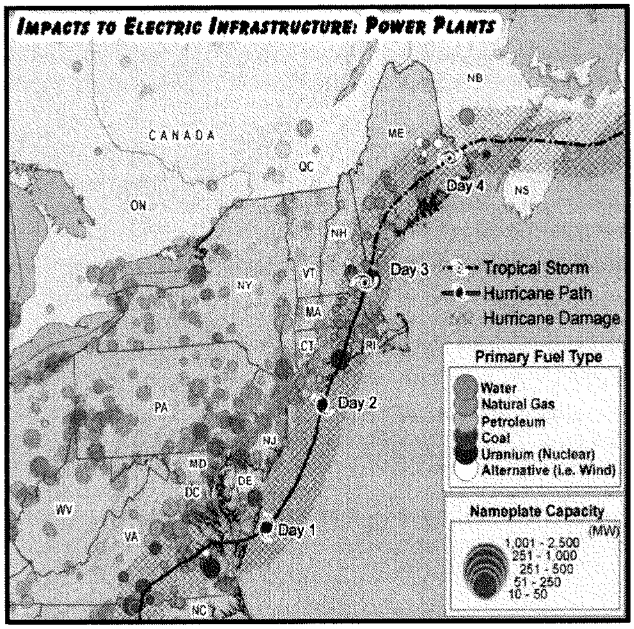
Grid resilience strategies require a partnership across all levels of government and the private sector to promote a regional and cross-jurisdictional approach. Because the electric grid cannot be 100 percent secure, the strategy must identify the greatest risks to the system and determine the cost and impact to mitigation/hardening strategies to advance the capability of the grid. Furthermore, the 2003 Northeast Blackout and the 2011 Southwest Blackout raised several reliability issues and technology limitations that add complexity to grid resilience. Although this report focuses on the economic benefit of avoiding outages related to severe weather, grid resilience encompasses an all-hazard approach.

Priority 1: Manage Risk

Risk management is a process that examines and evaluates policies, plans, and actions for reducing the impact of a hazard or hazards on people, property and the environment. Managing expectations is an important aspect of risk management because risk to the grid cannot be completely eliminated even with the most appropriate and successful strategies. (The National Academies Press 2012).

An important part of assessing risk is the ability to conduct exercises to identify and mitigate the potential impacts of identified hazards. In 2011, the Department of Energy conducted four major regional exercises across the country. One of the scenarios for the Northeast Exercise simulated a hurricane. The simulated hurricane closely resembled Hurricane Irene and produced an estimate of 6.4 million customers without power.

Individual utilities also engage in storm preparation, response planning, and readiness exercises. These activities are important, as is communication and coordination among utilities and participation in mutual aid programs.



Priority 2: Consider Cost-Effective Strengthening

Electricity is a critical element of the highly interdependent energy supply and distribution system. A refinery or pipeline pumping station, even if undamaged by a hurricane, will not be able to operate without access to electricity. Most utilities have active plans in place to harden their infrastructure against wind and flood damage. In fact, since 2005, multiple state public utility commissions have issued rulemakings and/or regulatory activities related to electricity infrastructure hardening.

Hurricane-force winds are the primary cause of damage to electric utility transmission and distribution (T&D) infrastructure. Upgrading poles and structures with stronger materials constitutes a primary hardening strategy. For distribution systems, this usually involves upgrading wooden poles to concrete, steel, or a composite material, and installing support wires and other structural supports. For transmission systems, this usually involves upgrading aluminum structures to galvanized steel lattice or concrete. In addition, adequate vegetation management programs can help prevent damage to T&D infrastructure. Although transmission system outages do occur, roughly 90 percent of all outages occur along distribution systems (Edison Electric Institute).

Placing utility lines underground eliminates the distribution system's susceptibility to wind damage, lightning, and vegetation contact. However, underground utility lines present significant challenges, including additional repair time and much higher installation and repair costs. Burying overhead wires costs between $500,000 and $2 million per mile, plus expenses for coolants and pumping stations. Perhaps the most important issue for coastal regions is that underground wires are more vulnerable to damage from storm surge flooding than overhead wires.

Common hardening activities to protect against flood damage include elevating substations and relocating facilities to areas less prone to flooding. Unlike petroleum facilities, distributed utility T&D assets are not usually protected by berms or levees. Replacing a T&D facility is far less expensive than building and maintaining flood protection. Other common hardening activities include strengthening existing buildings that contain vulnerable equipment, and moving equipment to upper floors where it will not be damaged in the event of a flood.

Case Study: Florida Power & Light Company

Florida Power & Light Company (FPL) expects to invest approximately half a billion dollars between 2013 and 2015 to improve electric system resilience for its customers. The plan builds on the company's storm hardening initiative by incorporating additional lessons learned from Superstorm Sandy, such as those related to flooding, as well as from Florida storm activity in 2012. These recent experiences show that strengthened electric infrastructure reduces storm-related outages and reduces restoration times when outages occur. Specifically, FPL's 2013-2015 investment plans include: 1) hardening for critical facilities and other essential community needs, 2) accelerated deployment of wind-resilient transmission structures and equipment, and 3) strengthened equipment in areas most vulnerable to storm surges. (Florida Power & Light Company 2013, DOE 2012a)

Priority 3: Increase System Flexibility and Robustness

Additional transmission lines increase power flow capacity and provide greater control over energy flows. This can increase system flexibility by providing greater ability to bypass damaged lines and reduce the risk of cascading failures. Power electronic-based controllers can provide the flexibility and speed in controlling the flow of power over transmission and distribution lines.

Energy storage can also help level loads and improve system stability. Electricity storage devices can reduce the amount of generating capacity required to supply customers at times of high energy demand – known as peak load periods. Another application of energy storage is the ability to balance microgrids to achieve a good match between generation and load. Storage devices can provide frequency regulation to maintain the balance between the network's load and power generated. Power electronics and energy storage technologies also support the utilization of renewable energy, whose power output cannot be controlled by grid operators.

A key feature of a microgrid is its ability during a utility grid disturbance to separate and isolate itself from the utility seamlessly with little or no disruption to the loads within the microgrid. Then, when the utility grid returns to normal, the microgrid automatically resynchronizes and reconnects itself to the grid in an equally seamless fashion. Technologies include advanced communication and controls, building controls, and distributed generation, including combined heat and power which demonstrated its potential by keeping on light and heat at several institutions following Superstorm Sandy.[3]

Priority 4: Increase Visualization and Situational Awareness

Until recently, most utilities became aware that customers had lost power when the customers called to report the outage. Thus utilities have had incomplete information about outage locations, resulting in delayed and inefficient responses. Smart meters have outage notification capabilities which make it possible for utilities to know when customers lose power and to pinpoint outage locations more precisely. Smart meters also indicate when power has been restored. When the outage notification capability enabled by smart meters is coupled with automated feeder switching, the result is a significant improvement in field restoration efforts since field crews can be deployed more efficiently, saving time and money. The Recovery Act investment has added greater visibility and intelligence across the electric system through advanced outage management systems, distribution management tools as well as transmission visibility.

Another example, synchrophasor technology, derived from phasor measurement units (PMUs), is used within the transmission system to provide high-fidelity, time-synchronized visibility of the grid. PMUs enable operators to identify reliability concerns, mitigate disturbances, enhance the efficiency/capacity of transmission system, and help manage islanding during emergency situations.

[3] Stony Brook University, "In the Aftermath of Superstom Sandy: A Message from President Stanley," http://www.stonybrook.edu/sb/sandy/index.shtml; ICF International, "Combined Heat and Power: Enabling Resilient Energy Infrastructure for Critical Facilities," 03/2013, http://www1.eere.energy.gov/manufacturing/distributedenergy/pdfs/chp_critical_facilities.pdf.

Case Study: Entergy Corporation
During Hurricane Gustav in 2008, Entergy, an energy company responsible for delivering power to customers in Arkansas, Louisiana, Mississippi and Texas, had 14 transmissions trip-out-of-service in the Baton Rouge to New Orleans area which created a Baton Rouge-New Orleans electrical island for 33 hours, meaning interconnection to the grid was lost. During this period, Entergy was able to control the island's frequency, balance three large generating units, and maintain electric service to customers because of the 21 PMUs the company had installed across a four-state area. PMUs identified and warned of islanding conditions during emergencies and provided Entergy with insight into how to manage islands and where else in the territory additional PMUs were needed. Entergy's success with PMUs during Gustav demonstrated that these devices had moved from being optional equipment to vital components of a modern electric grid (Galvan et al. 2008).

Priority 5: Deploy Advanced Control Capabilities

Many of the recipients of Recovery Act funds are deploying automated feeder switches that open or close in response to a fault condition identified locally or to a control signal sent from another location. When a fault occurs, automated feeder switching immediately reroutes power among distribution circuits isolating only the portion of a circuit where the fault has occurred. The result is a significant reduction in the number of customers affected by an outage and the avoidance of costs typically borne by customers when outages occur.

One recent example involves EPB of Chattanooga who estimated that power outages resulted in an annual cost of $100 million to the community and installed automated fault isolation and service restoration technology. During a July 2012 wind storm, automated switching in the distribution system instantly reduced the number of sustained outages by 50 percent to 40,000 customers. When coupled with information on customer outage provided by meters, the utility was able to avoid 500 truck rolls and reduce total restoration time by 1.5 days, representing almost $1.5 million in operational savings and significant avoidance of costs to customers.

The reports for both the 2011 Arizona-Southern California and 2003 Northeast blackouts illustrate that real-time monitoring tools were inadequate to alert operators to rapidly changing system conditions and contingencies (FERC/NERC 2012). Providing operators with new tools that enhance visibility and control of transmission and generation facilities could help them manage the range of uncertainty caused by variable clean electricity generation and smart load, thus enhancing the understanding of grid operations.

Priority 6: Availability of Critical Components and Software Systems

Installing equipment health sensors can reveal possibilities for premature failures. Typically, these devices are applied on substations and other equipment whose failure would result in significant consequences for utilities and customers. When coupled with data analysis tools, equipment health sensors can provide grid operators and maintenance crews with alerts and actionable information. Actions may include taking equipment offline, transferring load to alleviate stress on critical components, or repairing equipment. Understanding equipment condition allows utilities to undertake predictive and targeted maintenance. As a result, utilities can employ asset management strategies that lead to greater availability of critical components.

Large power transformers are custom-designed equipment that entail significant capital expenditures and long lead times due to an intricate procurement and manufacturing process. These transformers can cost millions of dollars and weigh between approximately 100 and 400 tons. The domestic production capacity for large power transformers in the United States is improving. In addition to EFACEC's first U.S. transformer plant that began operation in Rincon, Georgia in April 2010, at least three new or expanded facilities will produce extra high voltage large power transformers (U.S. DOE 2012b).

V. The Economic Benefit of Modernization and Increased Grid Resilience

The significant impact of severe weather on the U.S. electric grid showcases the importance of investment in grid modernization. A modern electric grid will be more resilient to severe weather, meaning outages will affect fewer customers for shorter periods of time. This report estimates the annual cost of outages caused by severe weather.

The Cost of Power Outages

Several studies have estimated the total cost of power outages in the United States, including those caused by weather and those caused by non-weather related events. These studies are based on estimates of utility customers' value of service reliability, which is in turn estimated either by surveys of willingness to pay for avoided outages or by survey estimates of the direct costs of outages (Sullivan et al. 2009).

Previous Estimates of Annual Cost of Power Outages

Source	Estimate (2012 dollars)	Year published
All outages		
Swaminathan and Sen	$59 billion	1998
PRIMEN	$132 to $209 billion	2001
LaCommare & Eto	$28 to $169 billion	2005
Weather-related outages		
Campbell (CRS)	$25 to $70 billion	2012

An early estimate of the total cost of power outages was developed by Swaminathan and Sen in 1998. The estimate uses data from a 1992 Duke Power survey on the cost of outages to the U.S. industrial sector. The study focuses solely on industrial customers and excludes the commercial and residential sectors. The study extrapolates survey data from industrial firms in the southeastern region of the United States to estimate the cost of outages to industrial firms across the country. Evidence suggests, however, that the cost of outages to industrial customers varies significantly by geographic region (Lawton et al. 2003).

In 2001, Primen Inc., a consulting firm now a part of the Electric Power Research Institute, estimated the total cost of power outages using survey data from 985 industrial and digital economy (DE) firms. Unlike Swaminathan and Sen, Primen's survey was representative of firms in all geographic regions of the United States. Industrial and DE firms were chosen due to their sensitivity to power outages and important contribution to U.S. GDP. Each firm was asked to estimate the cost of hypothetical outages varying in duration, time of day and whether or not the outage was expected.[4] The results of the surveys were extrapolated across all business sectors to determine the total annual cost of outages. Like Swaminathan and Sen, Primen's inflation-adjusted cost estimate of $132 billion to $209 billion does not account for the cost of outages to residential customers.

In 2005, LaCommare and Eto estimated the total cost of power outages using national statistics reported by utility firms on outage frequency and duration. The cost of each outage was determined using a cost function calculated in Lawton et al. 2003. Lawton based the function on survey data gathered from various customer groups on the cost of outages. Using Lawton's cost function, LaCommare and Eto found that two-thirds of the annual cost of outages was caused by those lasting less than five minutes ("momentary outages"). According to LaCommare and Eto, this is due to the high frequency of momentary outages relative to sustained outages.

It appears that the only prior estimate of the cost of outages caused specifically by weather was published by the Congressional Research Service in 2012 (Campbell 2012). Campbell estimated the inflation-adjusted annual cost of weather-related outages in the United States to be between $25 billion and $70 billion. Campbell's calculations draw on prior estimates of the total cost of outages, outage duration and the fraction of outages due to weather.[5,6]

[4] This valuation method is known as direct cost estimation (or "direct costing") and is widely used by utilities to assess the value of power reliability (PRIMEN 2001).

[5] Campbell's estimate of the cost of outages caused by weather-events was derived in two steps. First, Campbell calculated the cost of outages lasting longer than five minutes ("sustained outages"). The cost of sustained outages was calculated by multiplying Primen's 2001 estimate of the total cost of outages ($132 to $209 billion) by the

New Estimate of the Cost of Weather-Related Outages

This report provides new estimates of the annual cost of power outages caused by weather. The estimates are based on value-of-service (VOS) data compiled by Sullivan et al. (2009), originally collected by major electric companies using customer surveys. A range of costs is calculated for each year between 2003 and 2012. These annual estimates are then used to calculate a range of the inflation-adjusted average annual cost.

The estimate in this report uses data from the U.S. Department of Energy on power outages occurring between 2003 and 2012 and composite VOS estimates by customer type (residential, commercial and industrial).

Value-of service data. Customer value-of-service was calculated as a function of outage duration using a model from Sullivan et al. (2009). Sullivan et al. provides original VOS estimates for various customer groups using data from 28 consumer surveys conducted by 10 major electric companies between 1989 and 2005. These surveys assessed the cost of power outages to residential customers and commercial/industrial customers of varying size. Commercial and industrial customers were surveyed using the direct cost method. Each firm was asked to estimate the cost of hypothetical power interruptions varying in duration, time of day and whether or not the outage was expected. Residential customers were asked to report their willingness to pay to avoid similar outages. The willingness to pay (WTP) method is a form of contingent valuation – a method used in economics to value goods and services not bought or sold in a marketplace. The willingness to pay method was used to estimate the cost to residential customers because – unlike firms – a substantial fraction of foregone consumer welfare (i.e. being without heat) does not translate into direct costs borne by residents.[7]

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percentage of outages lasting longer than five minutes (43 percent). Campbell excluded momentary outages since they are rarely caused by weather events. Second, Campbell calculated the cost of outages caused by weather by multiplying the cost of sustained outages by the percentage of outages due to weather-events. Campbell used two different estimates for the percentage of outages due to weather – one from the University of Vermont (44 percent) and one from the Lawrence Berkeley Laboratory (78 percent) (Hines 2008; Mills 2012). The two estimates were used to calculate a range of the inflation-adjusted cost of outages caused by weather: $25 billion to $70 billion.

[7] The contingent valuation method (CV) – which includes willingness to pay measures – has been the subject of academic debate. In 1993, the National Oceanic and Atmospheric Administration (NOAA) convened a panel chaired by two Nobel Laureate economists to assess the validity of CV measures. The panel concluded that, if correctly implemented, the CV method provides reliable value estimates. The panel then established a set of universal guidelines for effective CV surveys. Subsequent literature has further advanced the understanding and

The utility surveys compiled by Sullivan et al. (2009) are not necessarily random samples of all utility customers. Two different weighting schemes were therefore used to adjust the estimates to reflect the current distribution of residential, commercial, and industrial customers as reported by the U.S. Bureau of Economic Analysis. These two different weighting schemes yield two different estimates of the average VOS for an outage of a given duration.

Outage distribution data. The U.S. Department of Energy tracks the cause, duration and number of customers affected for each power outage reported in a given year.[8] Outages are reported to DOE by electric utilities under a mandatory reporting requirement. This mandatory reporting dataset is henceforth referred to as the DOE MRDS. For major storms like Superstorm Sandy and Hurricane Irene, DOE also tracks the power restoration process. The number of customers without power in major storms is published in Emergency Situation Reports twice a day during the storm and with decreasing frequency in the days that follow.[9]

The next figure shows the distributions of customer power outages for fifteen major storms occurring between 2004 and 2012[10]. In the plot, the peak number of customers affected is normalized to one for comparability. The distribution shows the fraction of customers without power, as a percentage of the peak number of customers without power, at any given time during the outage event.

All of the fourteen storm-outage-profiles resemble one another, even though they range in duration from 3 to 20 days. The number of customers affected rises sharply in the first few hours of the event and peaks 15 to 25 percent into the total duration. Power is restored to a majority of customers relatively quickly, however a substantial number of customers remain without power long after the event begins. The fourteen storm profiles were used to construct a representative profile shown in black on the chart below. This representative profile was then applied to all power outages caused by weather reported in the DOE MRDS.[11]

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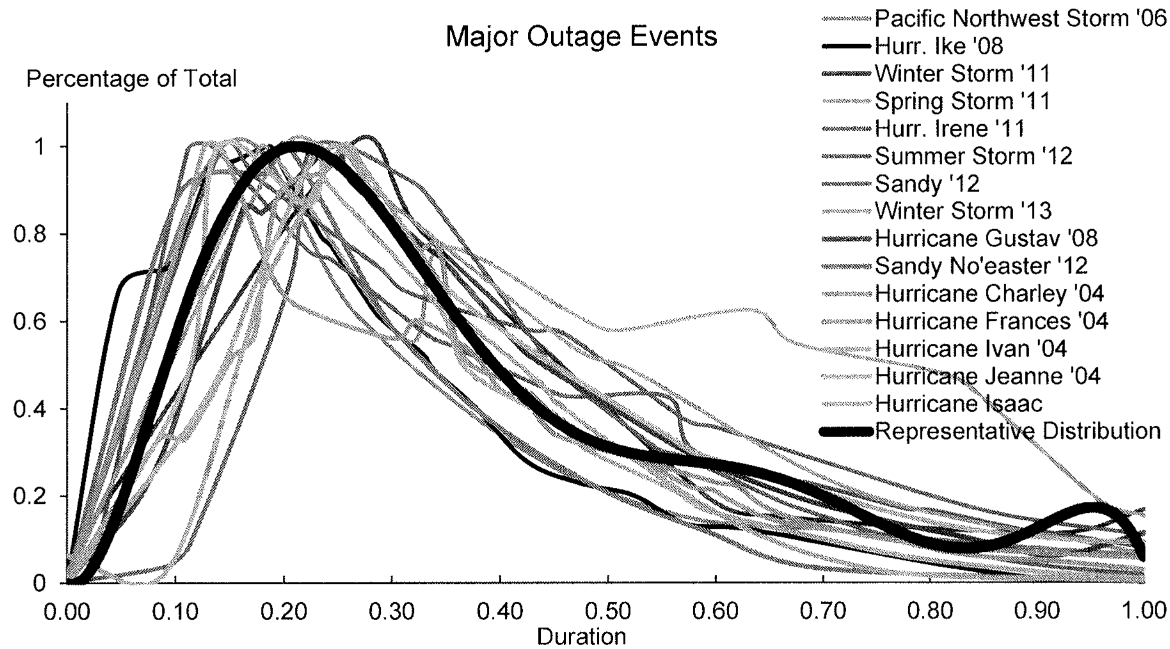
validity of the method – see Carson et al. 1996; Carson 1997; Foreit and Foreit 2002; and Johnston and Joglekar 2005.

[8] The data are compiled in Electric Emergency Incident and Disturbance Reports available at http://www.oe.netl.doe.gov/oe417.aspx.

[9] See http://www.oe.netl.doe.gov/emergency_sit_rpt.aspx.

[10] The chosen storms are all non-overlapping storm events reported in the Emergency Situation Reports with at least seven published outage reports, thereby providing enough distinct outage and time observations to compute a useful empirical customer outage profile.

[11] In instances in which a storm has Emergency Situation Reports and can be identified in the DOE MRDS, data from the reports are used in place of the mandatory reporting data.



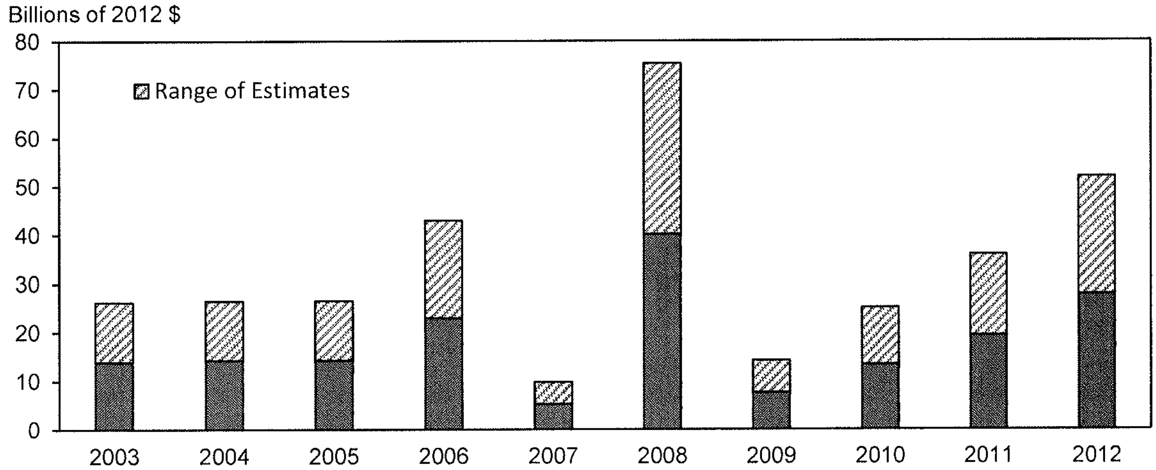
Source: Department of Energy, Office of Electrcity Delivery and Energy Reliability

Estimate of the cost of weather-related outages. Outage cost was calculated using the two sets of VOS estimates derived using Sullivan et al. (2009). The cost of an outage was calculated twice since each set of VOS estimates results in a different outage cost estimate. Using each set of VOS estimates, a weighted cost was calculated for outages of different durations. The weighted cost function was derived by assigning weights to Sullivan et al.'s customer groups based on each group's share of the total pool of electricity customers.

After calculating a weighted cost for each outage duration, an average cost function was determined for U.S. electric customers. The total cost of each outage in the DOE MRDS was estimated using the average per-customer cost function aggregated by the number of customers affected and the outage duration distribution. Finally, outage costs were aggregated by year and adjusted for inflation. Because the calculations were performed using each set of VOS estimates, two estimates of the annual cost of outages are provided for each year. Across all ten years, the average annual cost of outages caused by weather ranges from $18 to $33 billion.

The estimated costs by year are provided in the following figure and table. There is considerable variation in costs by year, ranging from $5 to $10 billion in 2007 to $40 to $75 billion in 2008. Large storms dominate these cost estimates. Outage costs due to Hurricane Ike in 2008 are estimated to be $24 to $45 billion while outage costs due to Superstorm Sandy in 2012 are estimated to be $14 to $26 billion.

Estimated Costs of Weather-Related Power Outages



Source: CEA estimates using data from Census Bureau, Department of Energy , Energy I nformation Administration, Sullivan et al 2009.

Year	Estimated Cost of Weather Related Outages (Billions 2012 $)
2012	$27 – $52
2011	$19 – $36
2010	$13 – $25
2009	$8 – $14
2008	$40 – $75
2007	$5 – $10
2006	$23 – $43
2005	$14 – $27
2004	$14 – $27
2003	$14 – $26

These estimates account for numerous costs associated with power outages including: lost output and wages, spoiled inventory, inconvenience and the cost of restarting industrial operations. The value of lost output can be calculated separately using the DOE MRDS and additional aggregate wage and output data. When calculated, the calculations show that between 20 and 25 percent of the annual cost of weather-related power outages are due to lost output.

Discussion

The methodology here is subject to a number of caveats. The (scaled) distribution of outages was estimated based on data from large storms and then applied to smaller storms. Although the analysis here suggests that the shape of the distribution does not depend on storm size, the shape could be different for small and large storms. Additionally, to the extent that businesses are prioritized for power restoration, the estimate in this report may overstate the actual cost of outages. On the other hand, because these estimates only account for storms with widespread outages, and because the majority of costs may come from the more-frequent momentary outages lasting less than 5 minutes (LaCommare and Eto 2005), the small storms neglected here could substantially add to the cost estimates.

Like the estimates discussed in the literature, the estimates in this report are based on private costs borne by customers who lose power. In addition to private costs, outages also produce externalities – both pecuniary and nonpecuniary. For example, outages that limit air transport produce negative network externalities throughout the country. Generally speaking, the costs of major outages are borne not only by those without power, but also by the millions of people inconvenienced in other ways.

The estimate in this report also differs from the effect of weather-related outages on GDP. Some of the lost GDP arising from storms is made up later by overtime hours, additional hiring, and additional consumption. For example, when the electrical grid goes down, the money spent on line crews to repair and replace grid components enters into GDP. Similarly, GDP is increased when a homeowner replace spoiled food. These additional expenditures counteract the negative effect of the storm on GDP, but they do not increase welfare. Essentially, GDP is higher after a homeowner restocks the refrigerator – but the homeowner is worse off for having to do so.

Additional Benefits of Resilience

A more resilient electric grid brings a host of benefits beyond reduced vulnerability to severe weather. Investments in smart grid technology designed to increase resilience can improve the overall effectiveness of grid operations leading to greater efficiencies in energy use with accompanying reductions in carbon emissions, as well as providing greater assurances to businesses upon which our economy depends (U.S. DOE 2010b; 2011b). These technologies can also enhance national security by bolstering the nation's defense against cyber-attacks given that 99 percent of all U.S. Department of Defense installations located within the United States rely on the commercial electric grid for power (Samaras and Willis 2013).

Increased grid resilience may also reduce expenditures not directly captured in this paper's cost estimates: expenditures by firms and individuals on back-up generators, second utility feeds, power conditioning equipment and other items purchased to mitigate the effects of power outages.

Many of these additional benefits of grid resilience constitute positive externalities – societal benefits beyond the direct costs avoided by electric customers. For example, power outages can hinder public safety since police, firefighters and emergency medical personnel struggle to provide assistance during outages (Sullivan et al. 2009). Manufacturing businesses far removed from an outage may face economic costs if their supply chains are disturbed. Online businesses engaged in long-distance transactions may also be negatively affected by reduced internet traffic. These externalities are arguably large in dollar terms, but quantifying them goes beyond the scope of this report.

VI. Conclusion

The U.S. electric grid is highly vulnerable to severe weather. This report estimates the average annual cost of power outages caused by severe weather to be between $18 billion and $33 billion per year. In a year with record-breaking storms, the cost can be much higher. For example, weather-related outages cost the economy between $40 billion and $75 billion in 2008, the year of Hurricane Ike. These costs are expected to rise as climate change increases the frequency and intensity of hurricanes, tornadoes, blizzards and other extreme weather events.

Preparing for the challenges posed by climate change requires investment in 21st century technology that will increase the resilience and reliability of the grid. The Recovery Act allocated $4.5 billion for investments in smart grid technologies.

A multi-dimensional strategy will prepare the United States for climate change and the increasing incidence of severe weather. Developing a smarter, more resilient electric grid is one step that can be taken now to ensure the welfare of the millions of current and future Americans who depend on the grid for reliable power.

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Ontario

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2007-0707**	
VOLUME:	**Issues Proceeding 3**	
DATE:	**January 16, 2008**	
BEFORE:	**Pamela Nowina**	**Presiding Member**
	Ken Quesnelle	**Member**
	David Balsillie	**Member**

EB-2007-0707

THE ONTARIO ENERGY BOARD

IN THE MATTER OF Sections 25.30 and 25.31 of the Electricity Act, 1998;

AND IN THE MATTER OF an Application by the Ontario Power Authority for review and approval of the Integrated Power System Plan and proposed procurement processes.

Hearing held at the Metro Toronto Convention Centre
South Building, Room 714, Toronto, Ontario
on Wednesday, January 16, 2008,
commencing at 9:03 a.m.

ISSUES PROCEEDING 3

B E F O R E:

PAMELA NOWINA	PRESIDING MEMBER
KEN QUESNELLE	MEMBER
DAVID BALSILLIE	MEMBER

That's located about 250 miles northeast of my community, the City of Dryden, and we all are approximately 11 to 1,200 miles from where we sit at this table today. It is at the end of one of the radial lines that John spoke of earlier in these submissions.

Pickle Lake is fed by a 115-kilovolt power line that comes across, as you saw on the map, from Ear Falls. Pickle Lake's current capacity is 15 MW. This line was built way back in the 1940s. It's old and it's antiquated. It is 156 miles long and has 2,275 structures, each of those structures with three cross arms.

You can only imagine what wind or lightning storm, the havoc that that can cause, to say nothing of the ice storms and the massive blow-down areas that we have throughout Ontario, and especially in northwestern Ontario.

The Musselwhite Mine, which is 90 miles north of Pickle Lake, draws upon Pickle Lake's electricity supply. Musselwhite is a 4,000 tonne per day gold producer.

Further, the nearby Ozznaburg reserve also draws upon Pickle Lake's electricity supply, plus there are 22 First Nation reserves north of Pickle Lake, each with an average population of a thousand people, and all use Pickle Lake as their transportation and commercial hub.

These 22 reserves use diesel generators as their only source of electricity. Most of that diesel goes in by the ice roads and the winter roads in the north, and only in the wintertime.

Right now, currently there is virtually no additional

City of Thunder Bay / NOMA. 37 *Hour Power Outage at Goldcorp*. Thunder Bay, Ontario.

37 Hour Power Outage at Goldcorp

68.5 (oz/hr) x 37 (hrs) x $1,798.10 (per oz)	$4,557,284.45
68.5 (oz/hr) x 12 (hrs. x 50%) x $1,798.10 (per oz)	739,019.10
Total loss to Goldcorp	**$5,296,303.55**

The loss of wages for three
12 hr shifts x 300 workers per shift x $60 hr = $648,000
wages and no productivity.

This brings the total cost of the power outage to

$5,944,303.55.

Northwestern Ontario Municipal Association

Independent Electricity System Operator (IESO). Meeting Summary, Monday, June 27, 2016

ieso
Connecting Today.
Powering Tomorrow.

Meeting Summary	
Date:	Monday, June 27, 2016
Location:	Thunder Bay, ON
Subject:	Thunder Bay Local Advisory Committee Meeting #3
Attendees:	**Committee Members in Attendance** Hugh Briggs Ralph Bullough Cameron Burgess Larry Hebert Ellen Mortfield Patricia Obie Ray Quinn Erik Ross Duff Stewart **Hydro One Transmission** Hamid Hamadanizadeh **Hydro One Distribution** Rich Baggerman (via webinar) **IESO** Stephanie Aldersley Bob Chow Luisa Da Rocha Megan Lund Salvatore Provvidenza Alex Merrick Terry Young **Thunder Bay Hydro** Rob Mace Tim Wilson Karla Bailey
LAC Meeting Materials:	**http://www.ieso.ca/Pages/Participate/Regional-Planning/Northwest-Ontario/Thunder-Bay.aspx**

Key Topics	Follow-up Actions
Opening Remarks and Roundtable Introductions • Ms. Da Rocha welcomed everyone and reviewed the meeting agenda • Roundtable introductions were made • Hugh Briggs from Lakehead University delivered opening remarks and noted that Lakehead University is celebrating their 51st anniversary this year as well as the 10th anniversary of the Orillia campus. Mr. Briggs highlighted several initiatives on campus including the $22 million retrofit of the power house and campus 10 years ago that reduced gas consumption by 45% and electricity by 18-22% and these savings have been maintained. The university is building on this by actively looking at a co-generation facility on campus and other energy initiatives. Lakehead University is also exploring next steps in the renovation of the science and research centre, and the development of a building for Indigenous programs.	

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Powering Tomorrow.

Review of LAC Meeting #2 Summary and Follow-Up Actions • The summary from LAC meeting #2 was reviewed with the committee and was deemed final with no changes to be made.	☐ Meeting summary to be posted on Thunder Bay LAC webpage

Discussion of LAC Inquiries Received Since the Last Meeting
 	
Presentation Summary: In response to a LAC member inquiry regarding why renewable energy was not being considered for northern Ontario, a written answer was shared with the Committee. It was noted that the IESO announced 16 contracts in March for the first round of the Large Renewable Procurement. A key aspect of these proposals was connection availability and the northwest area of the province was identified as having no availability to connect projects of this size, although some availability exists for smaller renewable energy projects (up to 500 kilowatts). It was also noted that the regional planning process is designed to ensure the reliability and adequacy of a region's electricity system to supply demand while meeting accepted reliability criteria and planning standards. In the northwest, there are adequate resources to supply today's demand. The regional planning process is not intended to enable the connection of renewable generation where no new generation is required.
 	
Questions and feedback from LAC members:
• There is no mention of the East-West Tie? Are you looking at this?
  o This bulk transmission project's planned in service date is 2020. It is expected that there will be a significant amount of growth in the mining and pipeline sectors, and the East-West Tie will serve this growth in the northwest as a whole.
• There was mention that there might not be enough nuclear power to send out to the northwest?
  o At the moment, there is sufficient capacity and very clean power will be available to supply the northwest; this is not an issue over the next while. Northern Ontario is winter peaking while the south is summer peaking, and this diversity helps with the availability of energy.
  o The provincial government is embarking on the development of their next Long-Term Energy Plan and they will be holding engagements across the province. The IESO will circulate information to the LAC once available.	

Recap of Electricity Needs in the Thunder Bay Planning Area *Presentation Summary: Since the last LAC meeting, a new demand forecast has been developed for the area that reflects a base year of 2015 (updated from 2013), incorporates new demand forecasts provided by Thunder Bay Hydro and Hydro One Distribution, and reflects updates to some of the industrial assumptions in the Greenstone - Marathon area which impact on the ability to meet demand in the Thunder Bay area. The updated demand forecast has resulted in an updated needs assessment. As part of the regional planning process, this needs assessment was developed based on the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC).*	

Today, the Load Meeting Capability (LMC) in the area is adequate and there is 150MW of margin which allows quite a bit of room for growth. Based on the updated forecasts, a need for additional capacity may arise in the late 2020's once the margin has been diminished. This would be a peaking need, it would occur during the winter months probably for a few hours a year when the hydro generators are dry and the load is high. Decisions do not have to be made today on new infrastructure as there is room for growth and the amount of margin will be monitored. If the margin diminishes in the future, there is time to evaluate the options and determine the best option.

Some minor needs were also identified in the area including the potential need for step down transformer capacity at Port Arthur Transformer Station (TS) which may occur around 2030. This is a good opportunity to look at a variety of options such as conservation or demand response to try and defer this need as far as possible. Another minor need is a line uprating needed on the R2LB line which Hydro One is addressing by increasing the clearance of a section of the line.

Questions and feedback from LAC members:

- What is ORTAC?
  - The "Ontario Resource and Transmission Assessment Criteria" is the IESO's criteria used when developing regional plans.
- Where do biomass generators fit into the bulk/regional system and how can long range planning promote the use of them?
  - The three levels of electricity planning are interconnected and decisions at one level can affect decisions at other levels. For example, if there is a need in a region and the best way to address the need is through generation, then that generation (including biomass) can also provide value to the bulk or distribution systems. Depending on the type of plant and where it is located, it is possible to provide supply to the regional network which would then tie in to the northwest bulk system.
- The Greenstone mine is currently going through an environmental assessment process and they are discussing using gas generation. Is there any infrastructure or plans to service that area?
  - The development of the Greenstone-Marathon IRRP began in early 2015 and Local Advisory Committees were established for the area. Early on, the IESO was advised that the need in the area is urgent and that a plan was required as soon as possible. To address this, the IESO developed an Interim IRRP (released June 2015) that provided recommendations on how to connect the mining, pumping stations and saw mill projects in the near term. The IESO has spoken with the mining and gas company representatives and they are looking at installing generation instead of pursuing the transmission option. Ultimately, it is up to the proponents to decide which option they will pursue. The final Greenstone-Marathon IRRP is being released at the end of June 2016. As it relates to the Thunder Bay IRRP, the studies have assumed the Greenstone loads will be connected via transmission along line A4L served primarily by the Lakehead TS.
- Is the unit running at the Thunder Bay Generating Station (GS) part of the 475WM of supply available in the area (slide 6)? Doesn't the contract end in 2019 and wouldn't you lose 150MW of supply in 2019?

- The graph represents the capabilities of all generators in the area as well as the transformation capabilities of Lakehead TS. The Thunder Bay GS current contract only allows a certain amount of fuel and it doesn't have enough fuel to provide a reliable source of capacity for the area, so it does not contribute to the LMC. Therefore, Thunder Bay GS has an installed capacity of 150MW and it is part of the supply, but the value attributed to it is zero since due to its short supply of fuel, it is unable to run reliably when it is needed.

- On March 10 there was a 15 hour power outage in Greenstone during cool temperatures because of the unreliability of that line.
- How are the pipeline loads being divided between the west of Thunder Bay, Thunder Bay and Greenstone planning areas?
  - The plan for the pumping stations is to connect as many as possible to the electricity system. Where the stations are near transmission lines, it is easy to determine which region it will be in. For example, if the station is near a line west of Mackenzie TS it will be considered in the West of Thunder Bay plan, if it is around Lakehead TS to the Greenstone area then it will be included in the Thunder Bay plan, and if it is along the A4L, it will be included in the Greenstone plan. There are also pumping stations that are not near a transmission line where new circuits may need to be built and the station wouldn't fall into any one particular planning region. In this case, it may depend on which way electricity is flowing at the time that it is pumping.
- How much of the Greenstone growth is from the pipeline (slide 6)?
  - One station is part of the Greenstone area growth. The top part of the graph (marked as pipeline conversion) represents the stations in the Thunder Bay area. There are several pumping stations that potentially could be converted in the Greenstone area. The most economic option for electricity supply to the pumping stations would include a new 230kV line to the Greenstone area. This would result in a lower demand as seen by the Thunder Bay 115kV subsystem, which supplies the existing 115kV line to the Greenstone area.
- What is an auto-transformer?
  - An auto-transformer converts power from the bulk system voltage (230kV) to the regional transmission voltage (115kV) at which point it can be delivered to customers and Local Distribution Companies in the area.
- Where is the R2LB line?
  - Hydro One: R2LB is a three terminal line that comes down from Pine Portage TS to Lakehead TS to Birch TS. There are two lines in parallel, one with a higher rating than the other because of some clearances (due to feeders underneath), but that will be fixed.

Approaches to Meet Area Needs and/or Maintain LMC Margin

Presentation Summary: As context for the options discussion, a diagram (slide 9) was presented to the LAC members to illustrate the transmission and generation options to meet capacity needs in the Thunder Bay area. The existing East-West Tie takes electricity from the rest of the system (which has a projected surplus forecasted to the mid-2020s) and brings it into the northwest. With the expansion of the East-West Tie scheduled to be completed in 2020, there is sufficient capacity to meet the needs in the northwest. Once the electricity moves through the East-West Tie, some of the electricity supplies other loads and some supplies the Thunder Bay area through the Lakehead TS.

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<u>Transmission Options:</u> *While there are currently no capacity limitations in the area, if load should grow under the high growth scenario, supply would be limited by the number of autotransformers at the Lakehead TS. This is because the amount of electricity that can be supplied by the existing two autotransformers isn't enough to meet the forecast need that may arise in the mid-2020s. The two transmission options, both of which permit utilization of grid resources via the expanded East-West Tie, are:* • *Install a third auto-transformer at Lakehead TS ($30M)* • *Install a new auto-transformer at Birch TS with a new 230kV line ($100M) – provides another supply point that could potentially enable further growth* *<u>Thunder Bay Generation Option:</u>* *While most of the capacity and energy needs can be met through the existing Lakehead TS, there are a few hours during the year where it may not be enough. In these situations, local supply could meet that need. If future need is met through local generation, it would need to be operating in advance in order to ramp between 0-40MW to meet the capacity shortage. Description of the Thunder Bay GS as an option:* • *Thunder Bay GS currently operates one 150MW unit on advance biomass that is shipped from Norway. The contract is set to expire in 2019.* • *Any further consideration of this asset on biomass will require a more certain and a more cost effective method of procuring fuel.* • *The facility has a minimum load point of approximately 25% of installed capacity, approximately 40MW, matching the size of the projected need. As this is the minimum capacity, there is no room to ramp between 0-40MW.* • *When compared to other peaking systems, the facility's ramp rate is slower. Any local generation solution would need to run in advance of the need so that it's ready to produce power when needed.* *A comparison was provided (slide 12) between the transmission and generation options taking in to consideration cost, operability and flexibility.* *<u>Other Supply Options:</u>* • *The Nipigon contract is approximately 40MW and is set to expire at the end of 2022; further operation is uncertain at this time.* • *Hydroelectric – based on current information, local hydro is not suitable to meet the potential need since Thunder Bay has peaking, not energy needs.* • *New Build – Whether powered by natural gas or biomass, a new facility would be fairly expensive; there is uncertainty surrounding fuel costs and availability.* *<u>Distributed Generation (DG) Options:</u>* *Over the past 10 years, FIT, microFIT, RESOP and HCI programs have resulted in over 27MW of installed DG in the Thunder Bay area and going forward, DG will continue to be developed through the FIT and microFIT programs. Any new generation contracted before the LMC is met will help defer the need; however, there are currently short circuit limitations at some of the transmission stations that would impose limits on the generation that can be installed on the distribution system. A lot of the generation procured from the FIT and microFIT programs is solar which is not effective in meeting peak loads in the area (night time in the winter). Water and bioenergy DG might be better fits for meeting needs, but it would depend on the type of generation.*	

<u>*Conservation and Demand Management (CDM) Options:*</u>
CDM plays a key role in maximizing existing assets and offsetting demand growth which could allow for the deferment of infrastructure needs. Conservation is best suited to a need where load growth is slow and the need is far in the future, thereby allowing the additional time needed to get conservation results. The load forecast already includes the conservation targets set out in the provincial Long-Term Energy Plan (LTEP) and the LDC's Conservation Plan to meet their conservation targets for 2020. Given these factors, additional CDM may delay, but it will not eliminate area needs.

<u>*Demand Response (DR) Options:*</u>
DR plays a role in reducing load at peak by triggering customers who have flexibility in their load to decrease load at times of system need. Currently the DR program is for meeting provincial needs, but if DR is to be an option for regional needs, then a different type of trigger mechanism is needed. The IESO is currently undertaking pilot programs for another regional plan looking at a regional or local DR program. At the moment, Thunder Bay peak does not match the provincial peak; therefore the current DR program design does not help address capacity needs in the Thunder Bay area.

<u>*Summary of Options:*</u>
Transmission is the most suitable option to meet the potential need due to its relatively low cost and the nature of the need. The short lead time of 3 years will allow the IESO to monitor load growth and commit resources when needed. Concurrent with this, development of transmission west of Thunder Bay will be monitored for opportunities to coordinate activities between the two plans as this could have additional benefits to the Thunder Bay system. Generation options are less suitable given their costs and performance capabilities in relation to the future needs. CDM has been incorporated into the load forecast and economic demand management activities like DR will continue to be explored in the Thunder Bay area, to help defer infrastructure investments.

Questions and Feedback from LAC members on the transmission options:

- With respect to the East-West Tie, would it be better to put in a higher voltage line instead of a new line? There are lots of lines coming into Thunder Bay.
  - The new East-West Tie line is based on the existing line which is a double circuit 230kV line and it will add about 450MW of additional capacity. A higher voltage line (e.g. 500 kV) would not provide further benefit since it would become the largest contingency (i.e. after the loss of the 500 kV line, you're left with a 230 kV line). There may be value to twinning the line. The current load in the northwest is about 750MW and the line supplies almost half the load, with an additional 600MW from hydro. The Tie serves two purposes – it provides capacity for the northwest and it allows excessive power to flow toward the northeast without restriction. Currently, there is still a bottleneck from the northeast to Toronto, but once that is resolved there will be a free running "highway" all the way from the northwest down to Toronto.
- The (transmission) solution seems to be based on more centralized generation in southern Ontario as opposed to a distributed generation system, so we are going to be relying more and more on a generator that is a thousand miles away to meet our needs. This seems different from what I have heard about generation and seems like a very short-term thought pattern.
  - The vast majority of demand in the northwest is currently served by hydro generation. To meet future needs, we are looking at the few hours of the year

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when demand spikes and the rivers are running dry. In these situations, the bulk transmission system can assist in meeting this need in a cost-effective way. In Ontario, there is no incremental generation being built in the south to serve the northwest – we have built enough to meet system adequacy in the south and this can help meet needs without building more resources.

- Does the new auto transformer at Birch TS only help the City of Thunder Bay or does it help the Thunder Bay region?
  - It helps the entire region. While the costs of installing an autotransformer at Birch TS are higher, the option was added to explore possible synergies with the west of Thunder Bay bulk reinforcement project. While that route is not yet known, we may be able to take advantage of that line to create a second supply point at Birch TS. This is looking at the longer term.
- Who plays the role of the coordinator between Hydro One and the private developer for the East-West Tie? IESO? OEB?
  - The IESO looks after provincial and regional planning. However, broader system planning is part of the government's Long-Term Energy Plan. It sets the general policy direction on electricity matters including items such as resources and conservation. The next version of the LTEP will be developed at the end of this year and the government will be consulting across the province. The IESO is providing input into the development of the plan and will be asked to prepare an implementation plan based on the LTEP.
- Since we last met a very devastating thing happened in Fort McMurray. One of my concerns is the proximity of the existing East-West Tie to the new line. Is fire damage a possibility?
  - On the resource side, the northwest has over 600MW of hydro, and 200MW of interconnection with Minnesota and Manitoba that can be drawn upon in an emergency. There have been cases that single circuits on wood poles were knocked down by a forest fire, but that would not be a problem on the East-West Tie as they are steel lattice towers. In 2011 there was an ice storm that knocked down 14 towers and Hydro One quickly built a bypass on wood poles to keep the connection between the northwest and the northeast.
- I believe the East-West Tie averaged 12 outages per year from 2009 to 2014. During one outage, the line near Schreiber was down for 16 days. They might have bypassed it but that didn't happen overnight.
  - The bypass was built quickly. Generally, outages of the East-West Tie are not causing customer outages. Local generation, the connections to Manitoba and Minnesota all prevent blackouts and customer outages due to the East-West Tie going down. Now with double circuits, the likelihood of both circuits going down is very low.

Questions and Feedback from LAC members on the generation options:

- Is gas generation off the table with the recently proposed Ontario Climate Change Action Plan? Will electricity generation from natural gas be restricted? Since Thunder Bay GS is a provincial asset, I suspect that the government is not going to allow that it be changed to natural gas.
  - Gas-fired generation is less advantageous than previously. We still don't have a plan that says there is no gas. For the purposes of today's discussion, references to Thunder Bay GS are biomass plant.
- What is the "slow relative ramp" for Thunder Bay GS?
  - It is not slow in absolute terms but slower in terms of newer systems because

of the nature of the technology. Thunder Bay GS is a ranking system where there is a boiler to heat up water and create steam that is then pushed through a steam turbine, versus having a gas turbine or an engine that runs off diesel. It is slow versus other dispatchable systems.

- Was Thunder Bay GS brought up as an option for comparisons sake?
  - This option is presented because of the level of interest. A number of options eliminate themselves based on operability characteristics, relative capital costs, the nature of the need etc. The costs in relation to other options make them uneconomic or not feasible.
- Forecasting is what the IESO does - forecasting loads and predicting needs. Based on this, you should be able to determine when a facility like Thunder Bay GS is going to be needed in enough time to allow them to be up and running when they are needed. Why is this a negative?
  - There are different types of generators that will ramp up faster than others. When you look at loads throughout the day you can see how quickly things can change and we are seeing that more so today then a number of years ago. When you are looking at generating capability then ramp rate is one of the things that is considered. Compared to other options that may be available, the ramp rate might not be as good. Ramp rates, start-up costs, minimum run time – these are all operating characteristics that help make a decision.
- For the generation option, is it the IESO's standpoint that you're looking for one source, multiple sources, or does this matter?
  - There are several options. It could be a single facility with multiple generators in it or a single large generator. The timing of the need around late 2020's, allows enough time to get the most out of conservation, to see how the localized DR pilots are doing and try to defer the need as much as possible. The decision does not need to be made right away.
- Slide 12 is negative towards Thunder Bay GS. The worst case scenario is presented and that's not really fair. You're saying slow ramp rate, slow start up and that is only when the unit is cold. If the unit is hot, then it's a quick start and it's a quick ramp rate. Your data is correct for one set of circumstances and I think it might be set up purposely to be bias for the transmission. It's not a true representation.
  - These are the characteristics under a certain set of circumstances but these are the circumstances we are forecasting. With respect to the load forecast scenario, the 40MW is a very optimistic need.
- When the East-West Tie went down for 16 days in Schreiber, the generating station was operating 24/7 full load for that period of time. This represents a need for a rapid capability unit in the northwest.
  - With existing load levels and connections to Manitoba and Minnesota, you will not need generation to run 24 hrs/day in that situation.
- Thunder Bay GS provides security that is needed. Should something happen, you can mobilize an alternative source of power that is here and available. It is a matter of what you want to pay to have that insurance policy for the future. Fort McMurray has taught us that anything can happen. There are tornados in the north, and if one took out the line, we might need to able to provide power in the local area or even out to the broader regions. We need to keep looking at it – you have the asset and it's not something you need to throw away.
- Are there any other plants in North America that are being developed with advanced biomass? I know that one of the issues is the supply of the fuel, so what's the forecast for that?

- Ontario Power Generation (OPG) has indicated that within North America they are leading the way and lots of people are visiting their biomass facility to look at what they have been doing especially since the United States is looking at the retirement of some of their coal plants.
- There is a proposal in the Armstrong area for a biomass generator that will take over for the diesel generators, approximately 3MW. That is the perfect application for a local load centre generation. Is the IESO looking for more of those types of low generation biomass units that are quick operating assets and can be placed close to a load centre? Does this impact the orange zone? It prevents having to build or upgrade long transmission lines.
  - Whitesand First Nations had a proposal for a biomass generator as well as a pellet plant. Because of the government's policy to reduce diesel generation in remote First Nations communities, they sent a directive to the IESO to arrange a power purchase agreement with Whitesand First Nations but they will remain off grid and not influence the orange zone.
  - For the foreseeable future, there is abundant clean and low cost generation. We have procured a lot of renewable generation over the past few years and now the idea of generating on top of that with local biomass is not the most economic at this time because there is enough on the system. We are not building that much transmission with some exceptions in the northwest such as the line to Pickle Lake.

Questions and Feedback from LAC members on Distributed Generation, Conservation and Demand Response:

- How can FIT be an option for the future if the northwest is an orange zone?
  - Projects under the 500kW in size can still connect.
- Do Time-of-Use rates contribute to making a false peak? This could probably be better managed by looking at the rates to push different peak times.
  - It is perhaps not the TOU that is affecting peak as much as the different programs in place to incent industrial customers to consume power at non-peak times. Through the DR pilot program, we hope to learn more about the triggers and characteristics of the load that would be ideal for this. This would only be for a few hours during the year.
- On slide 14, all but three projects are solar. This seems to go against what was said about solar not being effective in Thunder Bay since peak loads occur in the evenings. Why is the IESO encouraging ineffective generation?
  - Although these projects are likely not contributing to reduce the demand locally since the peak occurs overnight in winter, these projects contribute to reducing the provincial demand as the peak occurs in the summer during the hottest days of the year and typically that's when the water dries up in the northwest. Also, the FIT and microFIT are provincial procurement programs.

General Questions and Feedback from the LAC members:

- There is a local company looking at making glass for solar panels – 68 MW load per line (eventually 4 lines). Can the company work with OPG on this? This may eliminate the need to bring supply from Norway.
  - IESO needs to contract on behalf of the rate payers of Ontario and needs to consider whether other resources can be used to supply the load. From the perspective of the IESO, there is enough capacity on the system to supply any load in the area. If there is a desire to have generation contracted, it is up to

the external parties. For large loads, it is important to contact the IESO to start the connection process.
• If the northwest is contributing supply to southern Ontario which is summer peaking, then the northwest should never be an orange zone or maybe just a winter orange zone.
  ○ The orange zone refers to the Large Renewable Procurement whereas the distributed generation slide refers to FIT which is projects less than 500kW. An issue arises if you procure a large project in the north (i.e. 100MW wind farm) where the generated power can either be consumed by a customer or it can be transferred out of the region through the East-West Tie. If there are not enough customers at the time and the East-West Tie is congested, the new wind turbine needs to be turned off because there is nowhere for the power to go, even though the turbines were procured with ratepayer money. With smaller projects like FIT (under 500 kW) and microFIT (under 10kW) this is generally not an issue. These are typically solar projects which generate the most power in the summer when the rivers aren't running as strongly and therefore not as much power is flowing along the East-West Tie.
• If the line is truly congested then it's not getting to where it supposed to go, regardless of the size of project.
  ○ If the lines are congested and generation is higher than demand, then something has to be curtailed. For each large renewable procurement, a new set of transmission and distribution availability tables is prepared that shows the availability for each line across the province.
• Right now the whole north, not just the northwest is an orange zone for LRP.
  ○ The northwest has been at zero capacity for a number of years and the capacity in the northeast became zero on the last Large Renewable Procurement and will stay zero unless something happens. The IESO will endeavour to update the tables more often.
• When does a decision need to be made on the solution for Thunder Bay?
  ○ Not for a while. Typically it takes three years to install a new auto transformer and some solutions can be done quicker. There is time to explore the potential for a more localized DR program which isn't available yet, but could be a good approach in the future. With regards to the timing of the regional plans, they are renewed every five years or sooner. This Thunder Bay regional plan will be released towards the end of 2016 which means that the next regional plan will come out towards the end of 2021 at the latest. The IESO will be monitoring the developments in the area during that time and the next regional plan can be triggered earlier if needed.	

Public Questions or Feedback: • There were no public questions or feedback.	
Next Steps: • Another meeting of the Thunder Bay LAC will be scheduled to discuss the draft plan recommendations prior to publication of the Thunder Bay IRRP.	