ONTARIO ENERGY BOARD

EB-2016-0160

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

AND IN THE MATTER OF an application by Hydro One Networks Inc. (Hydro One) pursuant to section 78 of the *Ontario Energy Board Act*, 1998 for electricity transmission revenue requirement and related changes to the Uniform Transmission Rates beginning January 1, 2017 and January 1, 2018.

ENVIRONMENTAL DEFENCE COMPENDIUM FOR CROSS-EXAMINATION OF PANEL 5

KLIPPENSTEINS
Barristers & Solicitors
160 John Street, Suite 300
Toronto, Ontario M5V 2E5

Murray Klippenstein
Kent Elson
Tel: (416) 598-0288
Fax: (416) 598-9520

Lawyers for Environmental Defence

Index

Note: The documents in tabs 2-12 are excerpts of the relevant document.

---

[1] https://www.nyserda.ny.gov/-/media/Files/Publications/Research/Electic-Power-Delivery/epri-assessment-losses.pdf
[2] http://www.hme.ca/reports/CASA_Report_--_The_Efficiency_of_Alberta's_Electrical_Supply_System_EEEC-02-04.pdf
[3] www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=43615
[4] http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=36718.
[5] www.ercot.com/content/mktrules/protocols/current/13-010109.doc
[6] http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/TransmissionGrid.pdf

EB-2016-0160
ED Cross-Examination
Compendium
Filed: 2016-11-28

2015 Transmission Loss Volumes and Cost Estimates

Ln	Item	Value
1	2015 Average Transmission Losses (%)	2.5%
2	2015 Generator Output	153.7 TWh
3	Transmission Loss Volume (MWh)	3,842,500 MWh
4	2015 Wholesale Market Generation Cost (HOEP & GA)	$101.38/MWh
5	Estimated Total Cost	**$389,552,650**

Note: The above cost estimate uses the 2015 weighted price average and therefore does not account for the fact that losses are highest at the peak when generation is the most expensive. Therefore, the figure likely underestimates the true cost of losses.

Sources and Calculations:

1. 2015 Average Transmission Losses (%): IESO, *Conservation & Demand Management Energy Efficiency Cost Effectiveness Guide*, March 2015, Appendix A[1]
2. 2015 Generator Output: IESO News Release, January 12, 2016[2]
3. Losses (MWh): Generator output multiplied by average transmission losses
4. 2015 Wholesale Market Electricity Price: IESO, Monthly Market Report, December 2015, p. 22[3]
5. Estimated Total Cost: Losses (MWh) multiplied by wholesale market commodity price.

[1] http://www.ieso.ca/Documents/conservation/LDC-Toolkit/Guidelines-and-Tools/CDM-EE-Cost-Effectiveness-Test-Guide-v2-20150326.pdf.
[2] http://www.newswire.ca/news-releases/ieso-releases-2015-ontario-electricity-data-sector-wide-changes-continue-to-impact-supply-demand-price-564992261.html.
[3] http://www.ieso.ca/imoweb/pubs/marketReports/monthly/2015dec.pdf.

Conservation & Demand Management Energy Efficiency Cost Effectiveness Guide

Independent Electricity System Operator

March 2015

APPENDIX A

Use to convert real dollars to nominal dollars.

Inflation Rate	2.00 %

Use to calculate the NPV of costs and benefits.

Cost Effectiveness Metric	Discount Rates (Real)
Discount Rate	4.00 %

Use to calculate the NPV of costs and benefits.

Base year	2014

Use to calculate savings at the generator level.

Line Losses	Percentage
Average Distribution System Losses	4.20 %
Average Transmission System Losses	2.50 %

IESO Releases 2015 Ontario Electricity Data: Sector-Wide Changes Continue to Impact Supply, Demand, Price

TORONTO, Jan. 12, 2016 /CNW/ - The annual release of electricity data by the IESO points to increased output from renewable sources of supply and continued uptake in electricity conservation programs.

Supply
Production by Ontario's nuclear units remained high in 2015, comprising 60 percent of the transmission-connected power generated in Ontario. Consistent with the rapid growth in wind and solar resources, output from both types of supply increased significantly during the year.

The table below provides a summary of Ontario's generator output, broken down by fuel type, for the past three years.

	Nuclear	Hydro	Coal	Gas/Oil	Wind	Biofuel	Solar/Other
2015	92.3 TWh	36.3 TWh	n/a	15.4 TWh	9.0 TWh	0.45 TWh	0.25 TWh
2015 (% of total)	60%	24%	n/a	10%	6%	<1%	<1%
2014	94.9 TWh	37.1 TWh	0.1 TWh	14.8 TWh	6.8 TWh	0.3 TWh	0.0185 TWh
2014 (% of total)	62%	24%	<1%	10%	4%	<1%	<1%
2013	91.1 TWh	36.1 TWh	3.2 TWh	18.2 TWh	5.2 TWh	0.2 TWh	n/a
2013 (% of total)	59%	23%	2%	12%	3%	<1%	n/a

Due to rounding, percentages may not add to 100.

While the table above captures supply connected to the high-voltage transmission system, Ontario is also experiencing rapid growth of smaller scale distribution-connected, or embedded, generation. At the end of 2015, there were nearly 3,000 megawatts (MW) of IESO-contracted embedded generation helping to meet Ontario's electricity needs – an increase of approximately 20 percent from the 2,479 MW of embedded generation available at the end of 2014.

Demand
Electricity consumption in Ontario declined in 2015. Total energy withdrawn from the high-voltage transmission system in 2015 reached 137.0 terawatt-hours (TWh), down from 139.8 TWh in 2014 – a two-percent drop that can be attributed to conservation initiatives, increases in embedded generation, mild weather and broader economic shifts.

After 2014, when demand for electricity peaked at 22,774 MW on January 7 during a frigid winter, the province reverted to its normal status as a summer-peaking jurisdiction. Demand for electricity in 2015 reached 22,516 MW on July 28, though the summer was generally characterized by moderate temperatures. Contributing to this relatively low summer peak were increased output from solar units (at the distribution level, where it offsets demand for grid-connected supply) plus ongoing growth in demand management and energy-efficiency measures.

Price
The weighted wholesale price of electricity – the Hourly Ontario Energy Price (HOEP) – for 2015 came in at 2.36 cents/kilowatt-hour (kWh). The estimated 2015 Global Adjustment (GA) rate as at December 31, 2015 was 7.78 cents/kWh. The total cost of power for Class B consumers, representing the combined effect of the HOEP and the GA, was 10.14 cents/kWh.

MONTHLY MARKET REPORT

December 2015

Connecting Today.
Powering Tomorrow.

7. Summary of Wholesale Market Electricity Charges in Ontario's Competitive Marketplace

A summary of this month's market results that correspond with the charge items indicated in the chart below.

IESO WHOLESALE MARKET	Arithmetic Average		Weighted Average	
	Current Month	Year-to-Date	Current Month	Year-to-Date
Commodity Charge				
HOEP	$10.04	$21.66	$10.95	$23.58
Actual Global Adjustment Class B Rate	$94.71	$77.80	$94.71	$77.80
Total	$104.75/MWh or 10.48¢/kWh	$99.46/MWh or 9.95¢/kWh	$105.66/MWh or 10.57¢/kWh	$101.38/MWh or 10.14¢/kWh
Wholesale Market Service Charges				
Hourly Uplift - CMSC	$0.09	$0.48	$0.10	$0.52
Hourly Uplift - IOG	$0.01	$0.05	$0.01	$0.05
Hourly Uplift - Other	$0.60	$0.86	$0.63	$0.91
Daily Uplifts	$0.02	$0.12	$0.02	$0.12
Monthly Uplift	$0.40	-$0.61	$0.40	-$0.56
IESO Administration	$0.80	$0.80	$0.80	$0.80
OPA Administration	$0.44	$0.44	$0.44	$0.44
Rural/Remote Settlement	$1.30	$1.30	$1.30	$1.30
Monthly Class B Capacity-Based DR Recovery	$0.27	$0.36	$0.27	$0.36
Overall Total	$3.93/MWh or 0.39¢/kWh	$3.80/MWh or 0.38 ¢/kWh	$3.97/MWh or 0.40¢/kWh	$3.94/MWh or 0.39 ¢/kWh
Wholesale Transmission Charge	$9.49/MWh or 0.95 ¢/kWh	$10.22/MWh or 1.02 ¢/kWh	$9.91/MWh or 0.99 ¢/kWh	$10.21/MWh or 1.02¢/kWh
Debt Retirement Charge	$7.00/MWh or 0.70 ¢/kWh	$7.00/MWh or 0.70 ¢/kWh	$7.00 /MWh or 0.70 ¢/kWh	$7.00/MWh or 0.70 ¢/kWh
TOTALS	$125.17/MWh or 12.52¢/kWh	$120.48/MWh or 12.05¢/kWh	$126.54/MWh or 12.65¢/kWh	$122.53/MWh or 12.25¢/kWh

Note: Year-to-Date is since January 1, 2015

Conservation & Demand Management Energy Efficiency Cost Effectiveness Guide

Independent Electricity System Operator

March 2015

$$LLF = {}^{1}/_{(1-(Tx\ Losses\ +\ Dx\ Losses))}$$

Once a LLF is calculated savings at the customer or end-user level can be converted to the generator level using the equation below.

$$Savings_{generator} = Savings_{Customer} \times LLF$$

Savings at the generator are used for valuing avoided electricity supply-side resource costs (i.e., system benefits), and savings at the customer or end-user level are used for lost revenue and bill savings calculations. Each component is outlined in section 4.2 and each test is outlined in detail in section 5 and will specify whether it is appropriate to use savings at the generator level or the end-user/customer level (i.e., whether or not line losses are included).

4.2 Components

Each component outlined in the following section is used to calculate one or more cost effectiveness metrics. Many of the components outlined below may use one or more of the concepts discussed previously.

Concepts Required:

Effective Useful Life (4.1.1)
Real vs. Nominal (4.1.2)
Discount Rates (0)
Base Year (4.1.4)
Net Present Value (4.1.5)
Net-to-Gross Ratio (4.1.6)
Line Losses (4.1.7)

4.2.1 Avoided Electricity Supply-side Resource Costs

Description: Avoided electricity supply-side resource costs associated with the implementation of CDM consist of two main components:

- Avoided energy costs; and,
- Avoided capacity costs.

Avoided energy costs account for variable generation costs including the cost of fuel and variable O&M for power plants. Avoided capacity costs account for the reduction in coincident peak demand capacity including avoided generation capacity (i.e., capital and fixed O&M required to build new generation), transmission, and distribution capacity costs.

Use: The avoided supply-side resource costs are calculated using the annual energy savings and annual peak demand savings over the EUL of the measures associated with the implementation of CDM. Savings used in this calculation should account for the NTGR and line losses (i.e., net savings at the generator level) and should be converted to real dollars using a consistent base year.

Costing Period Definitions

Table 1: Seasonal Periods

Season	Months Included
Winter	December – March
Summer	June – September
Shoulder	April, May, October & November

Table 2: Time of Use Periods

	Winter	Summer	Shoulder
On-Peak	0700 – 1100 and 1700 – 2000 weekdays (602 Hours)	1100 – 1700 weekdays (522 hours)	None
Mid-Peak	1100 – 1700 and 2000 – 2200 weekdays (688 hours)	0700 – 1100 and 1700 – 2200 weekdays (783 hours)	0700 – 2200 weekdays (1,305 hours)
Off-Peak	0000 – 0700 and 2200 – 2400 weekdays; All hours weekends and holidays (1,614 hours)	0000 – 0700 and 2200 – 2400 weekdays; All hours weekends and holidays (1,623 hours)	0000 – 0700 and 2200 – 2400 weekdays; All hours weekends and holidays (1,623 hours)

Note: Numbers are the daily hours for the various periods

Avoided Supply Costs
The following avoided supply costs are an output based on the resource mix defined in Ontario's Long-Term Energy Plan[21]

Year	Avoided Cost of Energy Production 2014 $/MWh by TOU Period								Avoided Capacity Costs 2014 $/kW-yr		
	Winter			Summer			Shoulder		At System Peak		
	On-Peak	Mid-Peak	Off-Peak	On-Peak	Mid-Peak	Off-Peak	Mid-Peak	Off-Peak	Generation Capacity	Transmission	Distribution
2015	$46.53	$43.38	$37.76	$33.65	$38.83	$31.87	$47.55	$40.77	-	$3.83	$4.73
2016	$36.08	$31.88	$31.81	$31.39	$36.65	$29.55	$42.24	$35.94	-	$3.83	$4.73
2017	$40.97	$34.96	$28.72	$27.98	$38.38	$30.74	$38.39	$33.51	$162.15	$3.83	$4.73
2018	$41.97	$35.82	$32.69	$25.14	$36.66	$29.75	$31.77	$26.98	$162.15	$3.83	$4.73
2019	$40.71	$38.57	$34.37	$37.43	$43.06	$34.67	$36.72	$32.90	$162.15	$3.83	$4.73
2020	$39.88	$36.86	$34.93	$36.75	$41.06	$33.80	$33.89	$31.23	$162.15	$3.83	$4.73
2021	$47.28	$45.16	$44.50	$43.91	$48.41	$44.82	$40.19	$38.99	$162.15	$3.83	$4.73
2022	$48.33	$47.47	$45.76	$42.48	$46.39	$43.93	$40.97	$39.27	$162.15	$3.83	$4.73
2023	$42.94	$42.84	$42.41	$41.86	$46.18	$42.58	$35.85	$33.64	$162.15	$3.83	$4.73
2024	$43.28	$42.02	$40.73	$41.90	$46.17	$41.61	$34.45	$32.84	$162.15	$3.83	$4.73
2025	$44.37	$43.42	$42.15	$40.28	$43.89	$39.21	$36.29	$36.05	$162.15	$3.83	$4.73
2026	$41.26	$40.08	$39.69	$39.77	$44.01	$38.82	$34.52	$32.62	$162.15	$3.83	$4.73
2027	$44.01	$41.72	$41.89	$39.32	$42.89	$38.96	$41.17	$39.10	$162.15	$3.83	$4.73
2028	$43.82	$42.88	$40.20	$41.56	$45.57	$40.75	$36.94	$33.86	$162.15	$3.83	$4.73
2029	$45.32	$43.69	$41.06	$40.96	$44.43	$40.30	$39.97	$39.19	$162.15	$3.83	$4.73
2030	$44.18	$43.17	$41.25	$42.10	$45.83	$39.88	$36.33	$34.50	$162.15	$3.83	$4.73
2031	$43.53	$42.40	$40.04	$40.95	$43.95	$38.57	$38.45	$37.29	$162.15	$3.83	$4.73
2032	$41.96	$40.90	$39.24	$40.56	$43.38	$38.15	$36.42	$33.61	$162.15	$3.83	$4.73
2033	$41.96	$40.90	$39.24	$40.56	$43.38	$38.15	$36.42	$33.61	$162.15	$3.83	$4.73
2034	$41.96	$40.90	$39.24	$40.56	$43.38	$38.15	$36.42	$33.61	$162.15	$3.83	$4.73

[21] Achieving Balance - Ontario's Long-Term Energy Plan – December 2013 (http://www.energy.gov.on.ca/en/ltep)

ONTARIO ENERGY BOARD

IN THE MATTER OF

HYDRO ONE NETWORKS INC. (HONI)

TRANSMISSION COST OF SERVICE APPLICATION

PROCEEDING ID NO.: EB-2016-0160

EVIDENCE

OF TRAVIS LUSNEY

On behalf of

ENVIRONMENTAL DEFENCE (ED)

Q1. Please provide a summary of your evidence.

Efficiency in a transmission system can provide benefits to rate-payers and support Ontario's Conservation First framework. There are many options available to reduce transmission losses ranging from relatively inexpensive operational measures (e.g., increasing operating voltage within the standard above the nominal level) to large-scale capital investments (e.g., reconductoring transmission lines). These options need to be carefully assessed to determine cost-effectiveness and potential impacts on other considerations such as reliability and safety.

There are also several approaches for regulating and managing transmission losses. Recommended best practices include:

- Measuring, verifying and reporting consistently on the amount of transmission losses;
- Benchmarking of transmission losses to relevant jurisdictions with similar physical characteristics (e.g., size and geography) or policy characteristics (e.g., emphasis on conservation);
- Integrating transmission losses into operational and capital investment planning processes; and
- Considering encouraging loss reductions through explicit incentives.

For example, National Grid Electricity Transmission has integrated losses into planning processes by considering the benefits of transmission loss reductions while assessing options for asset replacement, equipment specification, procurement, operation, and new system developments including the impact of new technologies. It also has a robust monitoring and reporting program. Examples of incentive regulation to encourage loss reductions include rewarding transmission loss reductions through overall productivity targets (e.g. Norway), providing a revenue disincentive relating to transmission losses above a pre-determined rate (e.g. Austria), and assigning a value to transmission losses and rewarding or charging a transmitter if the cost of transmission losses are lower or higher than the reference value (e.g. Germany).

Overall, understanding the amount of losses within a transmission system is an important first step to determine if transmission loss reduction is a beneficial investment for rate-payers.

Q2. Please state your name, business address, and the nature of your business.

A. My name is Travis Lusney. I am a Director at Power Advisory LLC (Power Advisory). My business address is 55 University Ave – Suite 605, Toronto, Ontario.

Power Advisory is a management consulting firm focusing on the electricity sector and specializing in electricity market analysis and strategy, power procurement, energy policy development, litigation and regulatory support, and electricity project feasibility assessment.

Power Advisory's clients include power planning and procurement agencies, regulatory agencies, generation project developers, transmission companies, consumer advocates, non-governmental organizations and electric utilities.

Q3. Please describe, at a high level, where transmission system energy losses come from and the operational measures and capital investments that can be undertaken to reduce transmission system energy losses. Please provide a focused response containing only the background information that is necessary to understand your answers to the remaining questions.

A. Transmission losses occur from the transfer of energy production at generation sites to electricity demand centers through transmission infrastructure such as power transformers, transmission circuits (i.e., overhead transmission lines) or transmission cables (i.e., underground transmission lines) and switching assets (e.g., switchgear). Losses can be categorized into two general areas:

- Fixed losses that occur when infrastructure is energized. Fixed losses are independent of amount of load on the transmission assets. In other words, fixed losses do not depend on the amount of energy flowing through the equipment. An example of fixed losses is core losses from energization of power transformers.

- Variable losses occur from loading of the transmission equipment and are determined based on the current passing through the equipment. An example of variable losses are the heat losses that occur on transmission circuits or cables. The amount of losses is proportional to the square of the current loading on the transmission lines (i.e., I^2R).

There are many causes for losses within a transmission system. Options for reducing transmission losses often require a balance between reducing losses in one part of the transmission system while attempting to minimize increases in losses in other parts. In addition, reduction of transmission losses must be cost-effective (i.e., the dollars invested in loss reduction should be less than the cumulative future value of losses) and maintain transmission system reliability and stability. Implementation of one or more options to reduce transmission losses should consider the variety of impacts on the transmission system along with the option's cost-effectiveness.

Below I have presented a summary of transmission loss reduction options through operational measures and capital investments.

Operational Measures for Loss Reduction.

Operational measures to reduce transmission losses are based on adjustments to the planning and operation of the power system balanced against other operational considerations such as reliability, safety, cost, environmental impacts, etc. The following provides a summary of operational measures for reducing transmission losses

- Transmission system modeling is an excellent tool to assess loss reduction strategies and determine the optimal configuration of the power system. Modeling can provide a baseline understanding of the existing system configuration before alternative configurations, operational practices or investments are assessed. Modeling can also assist to maintain accurate records of installed infrastructure and system configuration, allowing transmission system operators to analyze the benefits and costs of loss reduction actions or programs across the entire system. Inclusion of transmission system modeling of transmission losses can be used on a daily basis to optimize the configuration of the transmission system.

- Increasing the voltage of the transmission system can decrease transmission losses by reducing the current for a given power transfer amount. The smaller current resulting from the higher operating voltage reduces the transmission losses. From an operational measure perspective, voltage increases can be accomplished by raising the operating voltage on an existing transmission system within the acceptable standard bound from a nominal voltage level. The Independent Electricity System Operator's (IESO's) Market Rules Appendix 4.1 stipulates that operating voltage can be over 10% from the nominal voltage for some voltage classes.[1]

- Another operational change for loss reduction is through the inclusion of the value of loss reduction in the planning process. By including the calculation and value assessment of losses as part of asset management or transmission system expansion planning, a transmitter is able to determine when loss reduction is cost-effective as part of the broader planning process objectives. Since utilities typically invest in long-life assets (i.e., 40+ year life expectation), it is important to consider loss reduction options in the decision making process for the procurement and arrangement of new or replacement equipment.

- Benchmarking the level of transmission losses in a transmission system to other jurisdictions can be helpful in determining if loss reduction strategies should be considered. Determining a benchmark requires the calculation of losses within a system and can establish a precedent regarding the validity of inputs and the approach to calculation of losses within a system. Benchmarking over multiple periods can provide a historic reference to

[1] The maximum continuous voltage is 550 kV for a nominal voltage of 500 kV, 250 kV for nominal voltage of 230 kV, and 127 kV for nominal voltage of 115 kV. IESO – Market Rules – Chapter 4 Grid Connection Requirements – Appendices.

understand how a system's losses naturally evolve over time and when action may be required. In other words, establishing a process to regularly assess transmission losses (e.g., annually) can be beneficial in understanding how a transmission system's losses compare against other similar systems and how losses change due to external forces.

Capital Investments for Loss Reduction.

Transmission conductor losses occur due to heating loss in the transmission line. The loss is a combination of the current the line is carrying and the resistance of the transmission line. The properties of the transmission circuit or cable (i.e., conductors), such as size, distance, temperature, or material, determine its resistance. The heating loss is determined by the square of the carrying current and the resistance (i.e., I^2R).

- One option for reducing transmission line losses is to reconductor the line to reduce the resistance. A common approach to reduce the resistance through reconductoring is to increase the size of the transmission conductor using the same material as the previous conductor. The larger size reduces the per unit resistance of the conductor and increases the thermal capacity transfer capability. Limits to reconductoring are primarily due to integration with existing transmission infrastructure such as the supporting capability of transmission towers and insulators. If the new transmission conductor is too large for the existing infrastructure, then additional investments are required that can reduce the cost-effectiveness of the reconductoring approach.

- A second option to reduce transmission conductor losses is to replace the conductor with materials that have extremely low resistance, sometimes referred to as superconductors. Superconductors achieve low resistance by cooling the material below a specific threshold temperature, while achieving substantially higher power transfer capability at the same voltage level and size as conventional materials[2]. The need to cool the

[2] U.S. Department of Energy, Office of Electricity, Superconductivity for Electric Systems Annual Peer Review Meeting, presentations available online: http://www.superpower-inc.com/content/technical-documents, July 2008, Arlington, VA.

superconductor means that the use is primarily restricted to underground applications where cooling capabilities are easier to apply compared to overhead transmission lines. The superconductor materials are expensive compared to conventional conductor materials[3] limiting the application to specific circumstances.

- A third option for reducing transmission conductor losses is to reduce the flow of reactive power on the transmission conductor. Reactive power is the result of current and voltage not being in phase and leads to total current on a line being greater than what is required to deliver the required power to a load. Reactive power compensation can be used to remove reactive power and reduce the additional transmission system losses. Reactive power compensation can be provided by a Flexible Alternating Current Transmission System (FACTS). FACTS is defined by the IEEE as "a power electronic based system and other static equipment that provide control of one or more AC transmission system parameters to enhance controllability and increase power transfer capability"[4]. FACTS can provide Shunt Compensation or Series Compensation.

    - Shunt compensation
        - Devices connected in parallel with the transmission line. Shunt-connected reactors are used to reduce the line over-voltages by consuming reactive power.
    - Series compensation

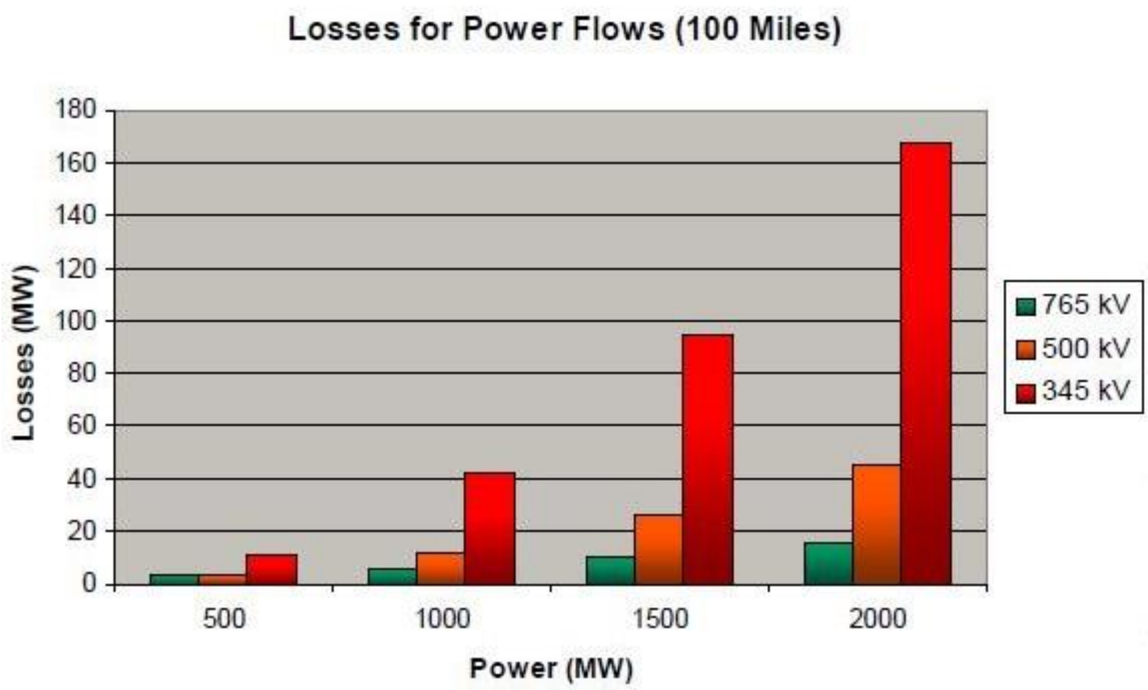
        Device connected in series with the transmission line and modifies the line impedance.

- Operational changes to increase voltage levels above the nominal amount to acceptable higher levels has been discussed under operational measures. Larger voltage increases to higher voltage levels (e.g., 230 kV to 500 kV) require investment in transmission infrastructure to ensure the transmission system can reliability operate at the higher voltage level. The

[3] *The Economist* 2001. "At last! The first practical superconducting power cables are now being installed." http://www.economist.com/node/691254 .

[4] *Proposed terms and definitions for flexible AC transmission system(FACTS)*, IEEE Transactions on Power Delivery, Volume 12, Issue 4, October 1997, pp. 1848–1853

impact on losses of higher voltages and the resulting loss reduction for equivalent power flows are shown in the figure below.



Source: Evan Wilcox, "765 kV Transmission System Facts For the Southwest Power Pool (SPP) Cost Allocation Working Group," May 28, 2008, page 17.

There are generally two types of transformer losses. The first is loading losses and depends on the amount of power the transformer is transferring. Loading losses are primarily created by the heating losses in the windings of the transformer, similar to the transmission conductor losses. The second type of transformer losses are core losses. Core losses are also referred to as no-load losses because the losses occur regardless of the power transfer in the transformer. As such, the losses occur at all times that the transformer is connected to the transmission system.

Design of transformers are consistently improving to increase efficiency and reduce loading losses and core losses. Replacement of transformers, primarily older transformers, can realize the benefits of new transformer design and materials to reduce transformer losses.

In summary, there are many options available to reduce transmission losses through operational measures or capital investment. Loss reduction options should be assessed to determine the cost-effectiveness and the impact on other considerations such as reliability and safety. Most operational measures involve identifying and understanding the level of transmission losses within a transmission system. The knowledge gained from understanding transmission losses can be leveraged when considering capital investments to reduce transmission losses.

Q4. Please discuss, at a high level, whether transmission companies such as Hydro One should actively monitor and manage transmission system energy losses.

A. The reduction of transmission losses increases the efficiency of the transmission network. Lowering transmission losses decreases the need for replacement energy production to meet Ontario's electricity demand which lowers costs for rate-payers. The Ontario government has emphasized energy efficiency through the Conservation First framework. The framework prioritizes conservation first, before new generation, where cost-effective[5]. The importance of electricity conservation was enshrined in the objectives of the Board by the Ontario government in 2009.

- "To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances".[6]

Cost-effective reduction of transmission losses can be an important component of Ontario's conservation efforts and can support meeting the Board's conservation objectives.

Transmission loss reduction options require changes to operational practices or investments in transmission system infrastructure. As the owner and operator of the transmission system, HONI should be a primary participant in assessing the

[5] Ontario Conservation First: Part I - http://www.energy.gov.on.ca/en/conservation-first/#introduction

[6] Ontario Energy Board Act, 1998 Board Objectives, electricity 1 (1) 3 - https://www.ontario.ca/laws/statute/98o15

cost-effectiveness of transmission loss reduction strategies. The impact of operational changes and the cost of new transmission infrastructure will require HONI's input, cost estimates and analysis to determine the potential outcome and benefit (or drawback). While the IESO has responsibility for power system planning in Ontario, the IESO must rely on HONI to provide input on the impact of power system planning assessments and decisions[7].

Q5. Please discuss and analyze potential actions that Hydro One could be required to take to monitor and manage transmission losses, such as:

- **a) Developing a transmission loss reduction plan including, among other things, the identification of cost-effective operational measures to reduce losses;**
- **b) Accounting for the benefits of loss reductions in investment planning; and**
- **c) Adopting a policy to undertake operational or capital projects to reduce transmission losses whenever the overall benefits to consumers outweigh the costs.**

There are several approaches for regulation of transmission losses. In Europe, a directive of the European Parliament and the Council on Energy Efficiency set a legislative framework that required national energy regulators to take into account energy efficiency in their decisions for transmission and distribution system operation and investment.[8] National regulators across Europe have adopted incentive regulation with three main components or considerations for transmission efficiency (i.e., loss reduction) regulation.[9]

The first component of transmission efficiency regulation is allocation of responsibility for procurement of losses. In some countries (e.g., Norway), the transmitter/network operator is responsible for procurement of energy to replace

---

[7] Bill 135, Energy Statute Law Amendment Act, 2016 - Royal Assent received Chapter Number: S.O. 2016 C.10 - http://www.ontla.on.ca/web/bills/bills_detail.do?locale=en&BillID=3539

[8] Article 15 – Directive 2012/27/EU - http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2012:315:0001:0056:en:PDF

[9] Grid Regulation Incentives for Network Loss Reduction – The ICER Chronicle Edition 1 – December 20, 2013 - http://www.icer-regulators.net/portal/page/portal/ICER_HOME/publications_press/ICER_Chronicle/Art_9

losses and those transmission loss costs are included in allowed revenue. Where the transmitter/network operator is responsible for procuring transmission losses, the energy is typically secured through real-time energy markets, bi-lateral agreements or through auctions/tenders for generation of firm energy. In other countries (e.g., Spain), the network operators are not responsible for procurement of losses and instead generators/suppliers are obliged to cover losses. This is sometimes accomplished through the calculation of transmission loss factors, similar to the approach used in Alberta.[10] The generators or suppliers are expected to supply energy to compensate for anticipated losses.

The second component of transmission efficiency regulation is how transmission loss costs are distinguished. If the loss costs are considered non-controllable, then the costs are passed through to rate-payers and are not the responsibility of transmitter. If the costs are considered controllable, then the costs would be part of the incentive-based regulation formula which influences the revenues a transmitter can receive and supports action by the network operator where prudent.

The third component of transmission efficiency regulation includes an explicit loss reduction incentive scheme as part of an overall incentive based regulation approach. There are many different incentive arrangements utilized by regulators.[11]

- In Norway, incentives for network losses are bundled with incentives for any other costs through their incentive-based regulatory model. Increased productively, which could include reduced transmission losses, beyond a specific target is rewarded.

- Another incentive arrangement is for the regulator to establish an acceptable rate of losses that are included in the transmission tariff. This approach encourages transmitters to maintain transmission losses below the pre-determined rate or else the cost of losses have a negative impact

[10] AESO – Loss Factors - https://www.aeso.ca/grid/loss-factors/

[11] EU Practices in treatment of technical losses in the high voltage electricity cost – Ad hoc Expert Facility under the INOGATE project "Support to Energy Market Integration and Sustainable Energy in The NIS"

on the overall revenue of the transmitter. This approach is sometimes used by jurisdictions where the transmitter is not responsible for procurement and therefore is typically passing the cost of losses through to customers (e.g. Austria).

- An incentive mechanism can assign a value to transmission losses and reward or charge a transmitter if the cost of transmission losses is lower or higher than the reference value (e.g., Germany)

Example of Transmission Loss Regulation

An example of transmission loss regulation is the transmission license of National Grid Electricity Transmission (NGET), a transmission company located in the United Kingdom (UK), which requires a report on transmission losses within its transmission system.[12] NGET is required to publish an annual transmission losses report and to publish a strategy on how NGET will address the level of transmission losses on its transmission system.[13]

> *Licence Condition: 2K.3.(a):* A description of the methodology used by the licensee to take Transmission Losses into account when planning load related reinforcements to the licensee's Transmission System.
> *Licence Condition: 2K.3.(b):* A description of the licensee's methodology to take Transmission Losses into account when the licensee is planning

Transmission Losses Report

The annual transmission losses report submitted by NGET includes three sections. The first section is a summary of the transmission losses in the transmission system since the previously published transmission losses report. The losses report provides a breakdown of transmission losses by major areas of the NGET service territory. The second section of the transmission losses report is a

[12] Ofgem – National Grid Electricity Transmission Plc – Special Conditions. https://epr.ofgem.gov.uk//Content/Documents/National%20Grid%20Electricity%20Transmission%20Plc%20-%20Special%20Conditions%20-%20Current%20Version.pdf

[13] National Grid Electricity Transmission, Transmission Losses Incentive, http://www2.nationalgrid.com/UK/Industry-information/Electricity-system-operator-incentives/transmission-losses/

progress report on the implementation of the previous NGET transmission losses strategy report. The progress report includes an estimate of the reduced transmission losses from the strategy plan. The final section of the annual transmission losses report provides an overview of any proposed changes to the transmission losses strategy. In addition, there is a high-level summary of the transmission losses strategy document. The annual transmission losses report also includes a description of any calculations used to estimate transmission losses in the transmission system.

For reference, National Grid's transmission system is composed of almost 8,000 km of transmission lines (i.e., overhead and underground).[14] HONI's transmission system is roughly three and half times larger at 29,000 km.[15]

Current National Grid Strategy for Transmission Losses

NGET's approach to the management of transmission losses has been relatively unchanged since the December 2013 strategy was published. The strategy employed by NGET can be summarized in five parts

1. Consideration of transmission losses through investment planning.
    - NGET uses a Whole Life Value (WLV) framework to make consistent investment decisions as it relates to alternative investment and policy options. The WLV includes consideration for transmission losses to ensure that investment planning accounts for the losses in comparison to other investment priorities.
2. Accounting for transmission losses in equipment specifications and procurement processes.
    - NGET assesses the benefit of reduced transmission losses versus the potential higher equipment costs. The transmission losses are determined by the specifications, procurement and operation of new equipment.
3. Impact on transmission losses from key load related developments.

[14] http://www2.nationalgrid.com/Contact-us/UK-Transmission/

[15] http://www.hydroone.com/ourcompany/pages/quickfacts.aspx

   - Estimating the impact of transmission losses from transmission system expansion or reinforcement to supply new electricity demand.
4. Impact on transmission losses from transmission asset replacement
   - Estimating the impact of transmission losses from replacement of transmission assets.
5. Consideration of the impact of new technologies on transmission losses
   - Assessing the potential impacts on transmission losses of new technology options available to NGET (e.g., adoption of HVDC).

In summary, NGET has integrated transmission losses assessment into their annual investment planning process through the WLV framework. NGET considers the benefits of transmission loss reduction while assessing options for asset replacement, equipment specification, procurement, operation, and new system developments including the impact of new technologies. On an annual basis, NGET reports transmission losses for their transmission system and provides an update on the implementation plan for cost-effective transmission losses.

Recommendations for the Board

Reductions in transmission losses improve the efficiency of the transmission system, reducing costs for rate-payers and assisting the Board in achieving its objective of promoting conservation. HONI, as the owner and operator of the majority of Ontario's transmission system, is an important component of any transmission loss reduction strategy. Given the potential benefits of transmission loss reduction, Power Advisory makes the following recommendations for the Board to consider for transmission loss management in the HONI transmission system. The recommendations are intended to be initial actions to assist the Board in determining whether further regulation, analysis or action is prudent.

1. Annual Measurement, Verification and Reporting of Transmission Losses

   Annual assessment of transmission losses for HONI can provide two primary benefits. The first benefit is that the annual assessment of transmission losses, including the measurement, verification and reporting, would assist in establishing a standard method for calculating transmission losses. Since

HONI has indicated that they do not maintain information on transmission losses, the annual reporting of transmission losses will likely lead to a discussion on how to accurately estimate transmission losses and what, if any, part of those losses should be addressed by HONI's operational procedures or capital investments. The annual transmission loss calculation will also increase the awareness of the impact of transmission losses on supply resource needs and alignment with the Conservation First framework adopted by the Government of Ontario. Without adequate data on transmission losses, it is difficult to determine if loss reduction options are cost-effective or not.

The second benefit is that a history of transmission loss changes can be established to determine if losses are increasing or decreasing. Data on historical transmission losses can provide the ability for HONI, the Board or intervenors to determine if possible actions are required to address changes in transmission losses or if further information is required to determine the nature of changing transmission loss values. The measured, verified and reported transmission losses can be a valuable input into any future benchmarking or consideration for incentives to reduce transmission losses.

2. Benchmarking HONI's Transmission Losses against Other Relevant Jurisdictions.

The HONI response to Environmental Defense on October 21, 2016, stated "Hydro One does not maintain information on energy losses, let alone use this type of information in its own transmission investment planning process."[16] An initial recommendation would be for HONI to benchmark transmission losses within their transmission system against other relevant jurisdictions. Benchmarking involves estimating transmission losses for HONI's system and comparing the transmission loss amount to transmission losses in other jurisdictions, preferably transmission systems with similar physical characteristics (i.e., size, generation supply mix, geography, climate, etc.) and policy characteristics (e.g., emphasis on efficiency and conservation measures). Any differences between transmission loss values should be assessed to determine if there are practical options to reduce the difference (e.g., capital

[16] Submissions by Hydro One Networks Inc. in Response to Environmental Defence – EB-2016-0160 – pg 2 of 7

investments or operational measures) or if there are prudent reasons that support the difference (e.g., transmission system size, generation supply mix, etc.). Benchmarking to other jurisdictions can provide an adequate foundation for determining if further actions are required by HONI on transmission loss reductions.

3. Integrate Transmission Losses Assessment in HONI's Planning Process

   Consideration for the reduction of transmission losses, either existing or in the future, should be integrated into the HONI planning process. Transmission losses are one of many factors that determine the cost and reliable operation of HONI's transmission system. Similar to other cost-benefit assessments, HONI should consider higher capital investment or operational costs in exchange for lower transmission losses. By including transmission loss assessment in their planning process, HONI may be able to identify alternatives that are cost-effective at reducing transmission losses without impacting other system planning priorities. In addition, HONI would be able to consider the impact of transmission losses in other planning process such as the regional planning process and possibly LDC distribution planning, both of which HONI is involved in as a transmitter.

4. Consider Incentives for Transmission Loss Reduction

   As discussed, many jurisdictions include incentive regulation to reduce transmission losses where the reductions are cost-effective. The transmission loss reduction regulation could include the Board establishing a cap on the acceptable transmission losses in the system, incentivizing HONI to maintain losses below a specific threshold, similar to how Austria's national regulator sets an "allowed rate of losses". Alternatively, the Board could consider including a value threshold for transmission losses and reward or penalize HONI for losses below or above the value threshold (i.e. similar to Germany). Another option is for the amount of transmission losses to be included as part of a broad set of incentives should future regulation focus on incentive based regulation for HONI. Including transmission losses would allow HONI to determine if reduction of transmission losses is a cost-effective approach versus other productivity improvements.

Overall, the recommendations by Power Advisory require a clear understanding of the current level of transmission losses within the HONI transmission system. Without knowing the amount of transmission losses that are in the transmission system and the potential benefits of loss reduction strategies, it is difficult to determine if any action is required.

Q6. What is your professional and academic background? Have you appeared before the Ontario Energy Board (Board)?

A. I am an electricity market analyst and power system planner with over 10 years of experience in the electricity sector. I specialize in energy market analysis, electricity policy analysis and development, power procurement and contracting, generation and transmission project evaluation, power system planning and strategy development. I am experienced in the evaluation and analysis of electricity markets and the competitiveness and operation of various generation technologies and transmission projects within these markets.

I joined Power Advisory after a position as the Senior Business Analyst of Generation Procurement at the Ontario Power Authority, where I was responsible for management and development of the Feed-In Tariff program. Prior to joining Generation Procurement, I worked as a Transmission Planner in Power System Planning at the Ontario Power Authority where I was actively involved in regional transmission planning, bulk system analysis and supporting system expansion procurements and regulatory procedures. I also worked for Hydro Ottawa Limited as a Distribution Engineer responsible for reliability analysis, capital budget planning, power system planning, and project management.

I have testified on behalf of the Alberta Utilities Commission as part of the Alberta Electric System Operator's 2014 General Tariff Application (Proceeding 2718), Proposed Approach for Designating Transmission Projects (February 2014).

I have a Master's of Science in Electrical Engineering and a Bachelor of Science in Electrical Engineering, both from Queen's University.

My resume is attached in Appendix A.

Assessment of Transmission and Distribution Losses in New York State

Final Report

Prepared for

THE NEW YORK STATE
ENERGY RESEARCH AND DEVELOPMENT AUTHORITY
Albany, NY

Michael Razanousky
Project Manager

Prepared by

EPRI

Tom Short

SAIC

Trishia Swayne

Contract #
15464

November, 2012

CITATIONS

This report was prepared by

SAIC Energy, Environment and Infrastructure, LLC
131 Saundersville Rd., Suite 300
Hendersonville, TN 37075

Principal Investigator

T. Swayne
K. Fagen
D. Andrus
P. Mullen

This report describes research sponsored by the Electric Power Research Institute (EPRI).

This publication is a corporate document that should be cited in the literature in the following manner:

Assessment of Transmission and Distribution Losses in New York. EPRI, Palo Alto, CA: 2012. PID071178 (NYSERDA 15464).

NOTICE

ACKNOWLEDGMENTS

EPRI wishes to express their heartfelt appreciation to the leadership team who provided thoughtful guidance as well as countless project details:

Mike Razanousky, NYSERDA

Central Hudson Gas & Electric Corp.

Consolidated Edison Co. of New York, Inc.

New York State Electric & Gas Corporation

Rochester Gas & Electric Corporation

Orange and Rockland Utilities, Inc.

Long Island Power Authority

New York Independent System Operator

New York Power Authority

Niagara Mohawk Power Corporation (National Grid)

We wish to acknowledge all members of Project PID071178 for their support and participation.

EXECUTIVE SUMMARY

This report presents industry practices for loss calculations; examines industry trends on loss mitigation, including emerging trends; and explores techniques to determine the cost effectiveness of loss reduction measures.

In 2008, the State of New York Public Service Commission (PSC) established an Energy Efficiency Portfolio Standard for the state and adopted the goal of reducing New York's electricity usage by 15 percent by 2015 (15 x 15).[1] The PSC required the utilities to submit reports within six months of the order "identifying measures to reduce system losses and/or optimize system operations."[2]

The New York State Energy Research and Development Authority (NYSERDA); Electric Power Research Institute, Inc. (EPRI); and SAIC Energy, Environment & Infrastructure, LLC (SAIC) worked together with eight participating New York utilities and the New York Independent System Operator (NYISO) to identify practices and methodologies for performing evaluations of losses in electric systems and reduction studies. This report reviewed:

- Industry practices and methods used by the New York utilities to calculate losses in electric transmission and distribution (T&D) systems
- Measures to reduce system losses
- The effect of reactive power tariffs on electric losses

Results and Findings

Losses in electric transmission and distribution systems in the service territories of the participating New York utilities ranged from 1.5 to 5.8 percent for transmission losses and from 1.9 to 4.6 percent for distribution losses based on utility loss studies presented to the PSC in 2008 and 2009. These are comparable to other reported electric utility losses in the United States as reported by EPRI's Transmission Efficiency Initiative Study[3] and EPRI's Green Circuits Study[4].

Analysis confirms that New York utilities are using normal industry practices in calculating system losses and that there is not a single best practice that can be followed by every utility.

[1] PSC, Case 07-M-0548, "Proceedings on Motion of the Commission Regarding an Energy Efficiency Portfolio Standard," Order dated June 23, 2008.
[2] PSC, Case 08-E-0751, "Proceedings on Motion of the Commission to Identify the Sources of Electric System Losses and the Means of Reducing Them," Order dated July 17, 2008.
[3] *Transmission Efficiency Initiative*, EPRI, Palo Alto, CA. 2009. 1017894.
[4] *Green Circuits: Distribution Efficiency Case Studies*, EPRI, Palo Alto, CA. 2011. 1023518.

Table ES-1 presents options for calculating losses that might benefit utilities in performing future loss studies, gaining precision in calculations, and evaluating losses across the state cohesively.

Table ES-1
Noteworthy Industry Practices

Approach	Benefit	Requirements and Costs
Separate losses into technical and non-technical categories, and identify the cause and type of losses.	Target specific areas of loss contribution; develop appropriate strategies to mitigate losses; Document energy savings (in more specific areas) so that they can be properly credited for energy efficiency claims.	Adjustment in reporting of categories. Additional calculation methods, data, and/or metering may be required.
Install metering down to the distribution feeder level that captures kW, kVAR, kWh, kVARh.	Provide the necessary information to validate models and assumptions and help identify target areas for loss improvements. Gain precision in loss calculations by using actual metered data over assumptions and in calculating load and loss factors.	Adjustments in calculation methods in eliminating some assumptions and using actual metered data. Additional metering and/or updates to current metering technologies in use.
Move towards hourly transmission load flows or evaluate multiple load levels for various time periods (typically seasonal) in calculating transmission losses.	This type of modeling can provide a better representation of operating conditions that occur at different load levels and times of year. Gain precision in loss calculations.	May require updates to software, additional modeling of system components, additional metering.
Obtain more detailed system information (such as using a GIS/mapping system for identifying primary and/or secondary facilities).	Aides in reducing assumptions for loss calculations and in developing more detailed engineering models. Aides in identifying specific areas that will benefit from loss reduction where sampling methodology cannot accomplish this. Gain precision in loss calculations.	May require updates to software; additional effort in collecting system facility information if not already recorded. Additional expenses for collecting and maintaining system data.

Based on the work performed by the New York utilities, EPRI, and SAIC, as well as reviews of other industry studies, electric losses can be reduced by system improvements both on the transmission and distribution systems. Generic or case-specific cost/benefit analysis is required to justify required expenditure for these system improvements.

For transmission systems:

1. Optimization of existing controls for transformer taps, generator voltages, and switched shunt capacitor banks reduces current flow and minimizes losses.
2. Addition of shunt capacitor banks, fixed and switched, at points on the system closest to the reactive load source reduces current flow and minimizes losses.

For distribution systems:

3. Phase balancing reduces line and neutral conductor losses.
4. Distribution capacitor banks on the feeders to improve the feeder power factor reduces line losses.

5. Capacitor banks at or near the substation improve the station power factor caused by the substation power transformer VAR requirement, measured at the high side of the power transformer and reduce load losses in the substation transformer.
6. Use of life-cycle evaluation for equipment sizing (initial installation of distribution transformers and conductors) reduces transformer core and coil losses.

Not traditionally considered part of methods to reduce transmission and distribution losses, conservation voltage reduction (CVR) has shown in recent studies that reducing voltage can reduce demand and energy consumption without impact to customers. Voltage optimization (VO), which is a technique that first "tunes" the distribution system by implementing system improvements and then applies voltage reduction, increases the amount that the voltage can be reduced for most feeders, thereby reducing energy consumption, and can reduce losses by two to four times as compared to just lowering the voltage. The loss reduction comes from the no-load losses in the distribution transformers and from implementing system improvements to tune the distribution system, in addition to the minor reduction in line losses from reducing the energy consumption of end-use loads. Voltage optimization is not strictly T&D efficiency, but many of the same approaches to analyzing losses and T&D efficiency apply to voltage optimization. It has the potential for much larger energy savings than loss reduction.

Utilities can identify areas of the electric system that might have a higher potential for loss reduction and can perform specific analysis for these systems to determine whether system improvements can be cost-effective in reducing losses. Approaches to calculating the cost of losses and performing an economic evaluation of efficiency improvements are reviewed in this report.

From the review of reactive power tariffs, the participating New York utilities are incorporating provisions for reactive demand similar to other utilities across the country. Documentation and feedback on the impact of reactive power charges to utility customers are sparse and inconsistent in the industry. Some challenges identified in the industry and for the New York utilities include:

- Rates in place at several utilities in the industry are not applied consistently or are made so transparent that it is difficult to be able to determine whether the rate structure design is actually motivating customers to perform corrective actions.
- Choosing a requirement for an optimal reactive demand level can be challenging. There are other unique challenges in dealing with real-time control of reactive power resources such that having a single requirement would not produce optimal solutions at every point in the system.
- The penalties at several utilities in the industry may not be steep enough to motivate the applicable customers to take action.

Industry research demonstrates that the efficiency of the power-delivery system can be improved. If the main criterion for economic justification is the marginal cost of energy, the research tends to show that many initiatives to reduce losses cannot be cost-justified. If ancillary benefits such as carbon credits or power quality impacts are considered, project economics may change. For targeted areas, loss reduction can often be economically justified by implementing changes in the way that the system is operated—such as voltage set points, capacitor settings, and switching—and cost-justified capital investment that can reduce losses in the electric grid.

A Study on the Efficiency of

Alberta's Electrical Supply System

Project # CASA-EEEC-02-04

For Clean Air Strategic Alliance (CASA)

October 2004

Prepared by

jem energy

Acknowledgements

The authors wish to acknowledge Donna Tingley, Executive Director of CASA and the following members of the CASA Electrical Efficiency and Conservation Team for their valuable input and direction for this project:
Denise Chang-Yen, EPCOR
Jennifer Cummings, Direct Energy
Franz Diepstraten, Direct Energy
Shannon Flint, Alberta Environment
Gordon Howell, Howell-Mayhew Engineering
Rick Hyndman, CAPP
Simon Knight, Climate Change Central
Phyllis Kobasiuk, AAMDC
Bevan Laing, Alberta Energy
Glenn MacIntyre, Direct Energy
Brian Mitchell, Mewassin Community Action/ CO2RE
Jesse Row, Pembina Institute
Kim Sanderson, CASA Secretariat
Nashina Shariff, Toxics Watch
Brian Waddell, Alberta Environment

Respectfully submitted,
Project Team
Dave Miller and Marcel Chorel
JEM Energy & Associates
831 – 7th Ave. SW
Calgary, AB T2P 1A2
Tel: 403-860-6361
Fax: 403-508-2858

Table of Contents

V. Transmission and Distribution

The transmission system (grid) is an interconnected network of wires (transmission lines) that facilitate the transfer of electricity from points of supply (generators) to points of delivery (distributors or loads). Losses occur in exactly the same manner on the transmission and distribution systems and in various pieces of equipment, such as transformers, used in the delivery of electricity to customers.

Electricity is pushed through the grid by the voltage and flows along the grid in the form of current. This current experiences resistance in the transmission lines. The magnitude of the current is a function of how much load is flowing along the transmission line and the operating voltage of the transmission line. For a given fixed load, the current along the transmission line will vary in direct proportion to the operating voltage of the transmission line.

Once a transmission line has been designed and built, the operating voltage and the conductor size are fixed. The only variable left is the amount of current flowing in the line. The higher the power flow, the higher are the losses. The only possibility for a reduction in losses is a decrease in load. Electric load on a transmission line tends to increase over time due to increasing customer demands driven by economic forces. Transmission losses increase as well. There is a load-carrying limit for a transmission line, which is established by system stability and voltage drop considerations.

JEM Energy's project team attempted to answer two main questions:

1. What are the components of conductor line losses? For example, are these losses due to the conductor size and/or number of conductors per phase or by the distance of generation to load centers?
2. Could greater efficiencies be achieved with modern equipment? If we separate transformers' significant losses from conductor losses and apply data on the improved transformer design efficiency over time, can we provide estimated improvements?

Through the AEUB, AESO and other sources, the project team examined the total annual system losses, as determined by the metered energy entering the transmission system less the metered energy leaving the system. Unaccounted for energy (UFE) was also addressed, since the delivery of electricity over an electricity transmission and distribution system results in a portion of the electricity being consumed or lost before it reaches the customer. However, unaccounted for energy is not a consideration in transmission. This is an issue more prominent in the distribution system.

What is Alberta's current situation?

On the Alberta transmission system, power flows have increased significantly over the past decade. The load on the system has continued to grow due to increasing economic activity while very little new transmission has been built. This is particularly true in the main transmission corridor between Edmonton and Calgary.

Over the past few years, the transmission administrator (AESO) has managed the transmission flows in this heavily loaded corridor through the introduction of locational-based pricing incentives for generators located around Calgary. Although the main driver for these generators was to solve voltage collapse problems in the Calgary area, a resulting benefit has been reduced line losses on this corridor.

Six 240 kV transmission lines connect Edmonton to Calgary regions. (See Figure 2). These transmission lines average about 300 km in length. They represent about 10% of the total transmission lines in Alberta but account for approximately 25% of the transmission line losses This occurs for two reasons: the Calgary load, which represents one of the two major load centres in Alberta, and the 500 kV tie line to B.C. In 2001, exports to B.C. increased significantly. The load in Calgary has grown faster than the rest of the province.

While there are many similarities in the networks of different transmission and distribution companies there are also important and significant differences, including:

- geographical size of the area where the network is located
- number of customers connected to the network
- quantity of electricity distributed
- degree of dispersion of customers across the network
- proportion of different types of customers connected to the network, and
- amount of underground cables compared to overhead lines.

In addition to these differences, individual companies have historically adopted different designs, operating and investment principles, all of which have led to very different network configurations.

In Alberta, all transmission efficiency related data required for this study resides with the Alberta Electricity System Operator (AESO). The transmission owners are strictly operators and maintainers of their respective systems.

All transmission line owners, transmission capacity (total km of lines) and system voltages are listed in Table 14.

In 2003, total annual system losses were 2,765 GWh, or 4.45% of total energy transmitted – 62,089 GWh. This was determined by the metered energy entering the system plus scheduled imports (point of supply/POS) less the sum of the metered energy leaving the system plus the scheduled exports (point of delivery/POD). These losses reflect both conductor and transformer losses on the grid. AESO does not delineate between conductor and transformer losses.

Table 14.Total Circuit Kilometres of Alberta Transmission and Distribution Lines

Utility	Transmission Lines (>60 kV)	Distribution Lines (60 kv or less)	Total lines (in kilometers)
ATCO Electric	8,911	58,240	67,151
ENMAX	279	6,185	6,464
EPCOR	188	4,315	4,503
ALTALINK	11,246	10	11,256
FORTIS	0	94,231	94,231
CITY OF LETHBRIDGE	35	700	735
CITY OF MEDICINE HAT	54	606	660
CITY OF RED DEER	0	672	672
OTHER TOWNS	0	376	376
TOTALS	20,714	165,334	186,048

Ref: EUB 2002 Annual Electricity Statistics

What's happening in other jurisdictions?
The ECR report indicated an overall efficiency of 96.01% in 2002 for transmission in Canada. This compares very closely to the 95.55% efficiency experienced by the Alberta system. These efficiencies are the ratio of kilowatt-hours out to kilowatt-hours in. JEM Energy initiated research by contacting individual contributing ECR members. Their responses are illustrated in Table 15. The Department of Energy, Utilities and Sustainability in New South Wales, Australia also responded to a similar request and their response is included in Table 15.

Distribution
Total distribution system losses were collected from reliable sources such as the Alberta Energy Utilities Board (EUB) and distribution companies. A comparison of distribution losses similar to the comparisons done for transmission was conducted.

Utilities estimate distribution wire losses based on distribution voltage levels and conductor sizes and are determined by the total metered energy entering the distribution system less the total metered energy consumed by the customers.

Electricity losses occur in the operation of the following components of an electrical distribution system:

- distribution feeder conductors
- distribution service transformers, and
- secondary wires to individual customers.

Alberta distribution system losses shown in Table 15 were obtained from:

- Fortis distribution loss study to EUB, March 24, 2003
- EPCOR distribution loss study to EUB, September 30, 2003
- ENMAX distribution losses to EUB, October 10, 2003
- ATCO Electric distribution losses to EUB, 2004
- City of Red Deer, direct response to research team.

It is only recently that the EUB has been collecting losses studies and calculations as part of distribution tariff applications. Some companies indicated to JEM Energy that there is no standard protocol for the conduct of distribution losses studies so it is premature to draw conclusions by direct comparison of one study result to another.

Unaccounted for energy (UFE) or non-technical losses are those losses that cannot be determined analytically. These losses include a large list of items and are determined by subtracting the energy delivered from the energy accepted. They include physical losses from the distribution system such as contact with vegetation, contact with the ground resulting from vehicular or storm damage, lightning and corona. These non-technical losses also include administrative losses such as non-billed service, error in the estimation of un-metered delivery and meter/meter data management error. Non-technical losses also include losses that result from fraud and theft. Only one distribution utility addressed UFE as a percentage of total losses. It indicated UFE represented 0.46% of total losses, of which theft and fraud accounted for 0.32%.

What's happening in other jurisdictions?

The ECR report indicates an overall efficiency of 95.8% for Canadian distribution systems. The report also documents distribution transformer efficiencies at 98.91% for single phase up to 25 KVA to 99.5% for those in the range of 3-phase 1000 KVA to 3000 KVA. Table 15 also illustrates Alberta's distribution system efficiencies with those in other jurisdictions.

Table 15. Transmission & Distribution System Efficiencies

Utility or Jurisdiction	Transmission System Efficiencies	Distribution System Efficiencies	Distribution Transformer Efficiencies (at 50% load)
Alberta	95.55%	ATCO 95.0%	99.2% (2003 purchases only)
		ENMAX 97.0%	99.3% (lg. 3 Ø) to 98.8% (sm.1Ø)
		EPCOR 97.6%	98.99% (500 kVa/10% to 100% load range) to 98.3% (<150 kVA)
		FORTIS 96.2%	99.44%
Sask Power	95.8%	95.3%	98.8%
Hydro One/Ontario	97.2%	92.7%	99.3% (11,158 Transformers)
Maritime Electric/PEI	96.3%	94.9%	99.2%
NS Power	97.1%	94.7%	98.8%
Manitoba Hydro	93.4%	95.6%	N/a
New South Wales/Australia	96.9%	93.8%	98.0%
Canadian Average (CEA/ECR)	96.0%	95.8%	98.9% (1Ø) to 99.5% (3Ø)

1Ø to 3Ø= single phase to three phase

Table 16 lists transmission and distribution losses by percentage for electricity supply systems for Western Europe, Australia and New Zealand compared to North America.

Table 16. Transmission and Distribution Losses (by percentage of total system) Europe, Australia, New Zealand and North America 1980 to 2000

Country	% losses 1980	% losses 1990	% losses 1999	% losses 2000
Finland	6.2	4.8	3.6	3.7
Netherlands	4.7	4.2	4.2	4.2
Belgium	6.5	6.0	5.5	4.8
Germany	5.3	5.2	5.0	5.1
Italy	10.4	7.5	7.1	7.0
Denmark	9.3	8.8	5.9	7.1
United States	10.5	10.5	7.1	7.1
Switzerland	9.1	7.0	7.5	7.4
France	6.9	9.0	8.0	7.8
Austria	7.9	6.9	7.9	7.8
Alberta	**N/a**	**N/a**	**N/a**	**8.0***
Sweden	9.8	7.6	8.4	9.1
Australia	11.6	8.4	9.2	9.1
United Kingdom	9.2	8.9	9.2	9.4
Portugal	13.3	9.8	10.0	9.4
Norway	9.5	7.1	8.2	9.8
Ireland	12.8	10.9	9.6	9.9
Canada	**10.6**	**8.2**	**9.2**	**9.9**
Spain	11.1	11.1	11.2	10.6
New Zealand	14.4	13.3	13.1	11.5
European Union	7.9	7.3	7.3	7.3
Average	**9.4**	**8.1**	**7.9**	**7.9**

(Ref: International Energy Agency through U.K. Office of Gas & Electricity Markets)

* Distribution component is average of 4 utilities from table 15

Can improvements be made to Alberta's transmission and distribution?

Transmission

Table 15 illustrates that transmission system efficiencies are relatively consistent in most Canadian jurisdictions. Alberta's system is very close to the national average of 96%.

However, there could be some efficiencies attainable. One of the areas for potential improvement is reducing the load on the transmission system by building generation closer to the markets they serve. This model was tried in the past with locational-based pricing incentives, such as the Invitation to Bid on Credits (IBOC), which incented new generators starting in 2001 and resulted in 281 megawatts of generation. The second was the Locational Based Credit Standing Offer (LBCSO), which resulted in 215 megawatts.

Two major initiatives are currently being studied to supply additional transmission capacity in Alberta and could provide opportunities to incorporate efficiencies:

- AESO application for 500 kV north/south line
- DC line Fort McMurray to the U.S. with major Alberta points of access (Northern Lights project)

In the U.S., the Oak Ridge National Transmission Technology Research Centre in Oak Ridge, Tennessee is conducting research into next-generation power lines that are lighter and can transmit far more electricity than the materials used in conventional lines. Though in a very preliminary stage, the claim is that "3M's new conductors can increase current-carrying capacity by three fold for the same size cable at minimal cost and environmental impact."[4]

There may also be scope for improvements in transmission transformer efficiencies. For example, AltaLink has a total of 445 transformers on the Alberta system, of which 292 are operating at 138 kilovolts (kV), and up to 83 MVA. The balance operates at 500 kV, 245 kV, 69 kV, 34.5 kV, 25 kV or 13.8 kV and range from 10 MVA to 400 MVA. The cost of these large transformers prohibits any economical replacements. However, Energy Star rated transformers would provide improved efficiencies, when replacements are required due to failures or upgrades.

Distribution

Compared to other jurisdictions, Alberta's distribution systems have lower losses and all but one is less than the Canadian average of 4.2%, as was illustrated in Table 15. One contributing factor is the age of the system. Distribution systems, including transformers are relatively newer in Alberta compared to other systems in Canada.

The CEA's ECR report shows the national average for transmission and distribution combined losses were 8.2% in 2002. Overall, transmission and distribution losses in Alberta averaged 7.68% during that same period.

Table 16 reports Canada's transmission and distribution losses at 9.9% for 2000. The most efficient is Finland with 3.7%, which represents a 40% reduction in losses since 1980. Non-technical reasons for the variances in losses can also be attributed to a country's geography, customer density, urban versus rural ratios, or loss calculation protocols. One reason Canada has higher transmission and distribution losses than other countries is due to the long distances of the transmission and distribution systems. However, the losses trend increased for Canada in 1999 and 2000 compared to a flat or downward trend in many other countries. There are also other variances, which could be further explored. For example why is Finland's loss rate is at 3.7% and New Zealand's at 11.5%, or what caused the U.S. to go from 10.5% for 10 years to 7.1% in 1999 and 2000? It is possible that some of these significant loss reductions may be attributed to increases in costs associated with losses in recent years. Therefore, greater attention and time is now paid to the accuracy of loss calculations. The source document for Table 16 does not

[4] Stovall, ORNL Engineering Science & Technology Division, 2002

indicate the protocols used by the various jurisdictions for the determination of their system losses. Further study into the protocols used would provide for better comparisons between Alberta and other jurisdictions.

In Alberta, the losses vary by distribution wires companies, due in part to rural vs. urban systems. Urban utilities such as ENMAX and EPCOR experience lower losses (up to 3%) due to shorter distances between substations and loads, and a higher concentration of customers, compared to ATCO Electric and Fortis with their many kilometers of rural distribution lines. Table 17 below illustrates the comparisons of Alberta's distribution system losses and customers per kilometer with those in Saskatchewan, Nova Scotia and PEI.[5] Although customers/km is a factor in distribution losses, utilities faced with low customers/km ratios have addressed this issue to a large degree with technological solutions, such as voltage regulators and capacitor banks.

Table 17. Customers/ KM to Distribution Losses Comparisons

Utility	KM of Distribution Lines	# of Distribution Customers	Cust/KM	Distribution Losses %age
ENMAX	6,185	359,942	58.2	3.0
EPCOR	4,315	287,732	66.7	2.4
Fortis	94,231	359,917	3.8	3.8
ATCO Electric	58,240	162,133	2.8	5.0
SaskPower	139,460	425,209	3.0	4.7
NS Power/Halifax Metro	2,677	165,217	61.7	5.3
NS Power/non-urban	22,047	284,265	12.9	
Maritime Electric	4,500	69,480	15.4	5.1

Variations may also be attributed to different protocols for calculating losses. Consequently, consistent protocols should be in place to accurately compare distribution system losses.

Unaccounted for energy is a prominent issue in the distribution system. Although included as losses, they are outside the scope of an efficiency study because they are non-technical losses and need to be addressed by specialists in those areas.

Transformers are an integral component of the transmission and distribution systems and have been considered a relatively high efficiency component. However, recent advances in technology have produced improvements and high efficiency Energy Star transformers are now available. The U.S. Energy Star transformer program is a voluntary program that recognizes utilities that make a commitment to purchase high efficiency distribution transformers. Partners agree to perform an economic analysis of total transformer-owning costs and to buy transformers that meet Energy Star guidelines only when they are cost

[5] EUB Electric Industry Annual Statistics 2002; SaskPower 2003 Annual Report; NS Power/J.Fraser email response Sept/04; Maritime Electric/N.Warren email response Sept/04

effective. Five Canadian firms are members of this initiative. Canada has not developed an Energy Star transformer program as yet. The U.S. Energy Star's website includes a transformer efficiency calculator that allows engineers and building personnel to evaluate options by comparing efficiencies and operating costs of Energy Star transformers with other models. The link to this site is listed in Appendix 2 of this report.

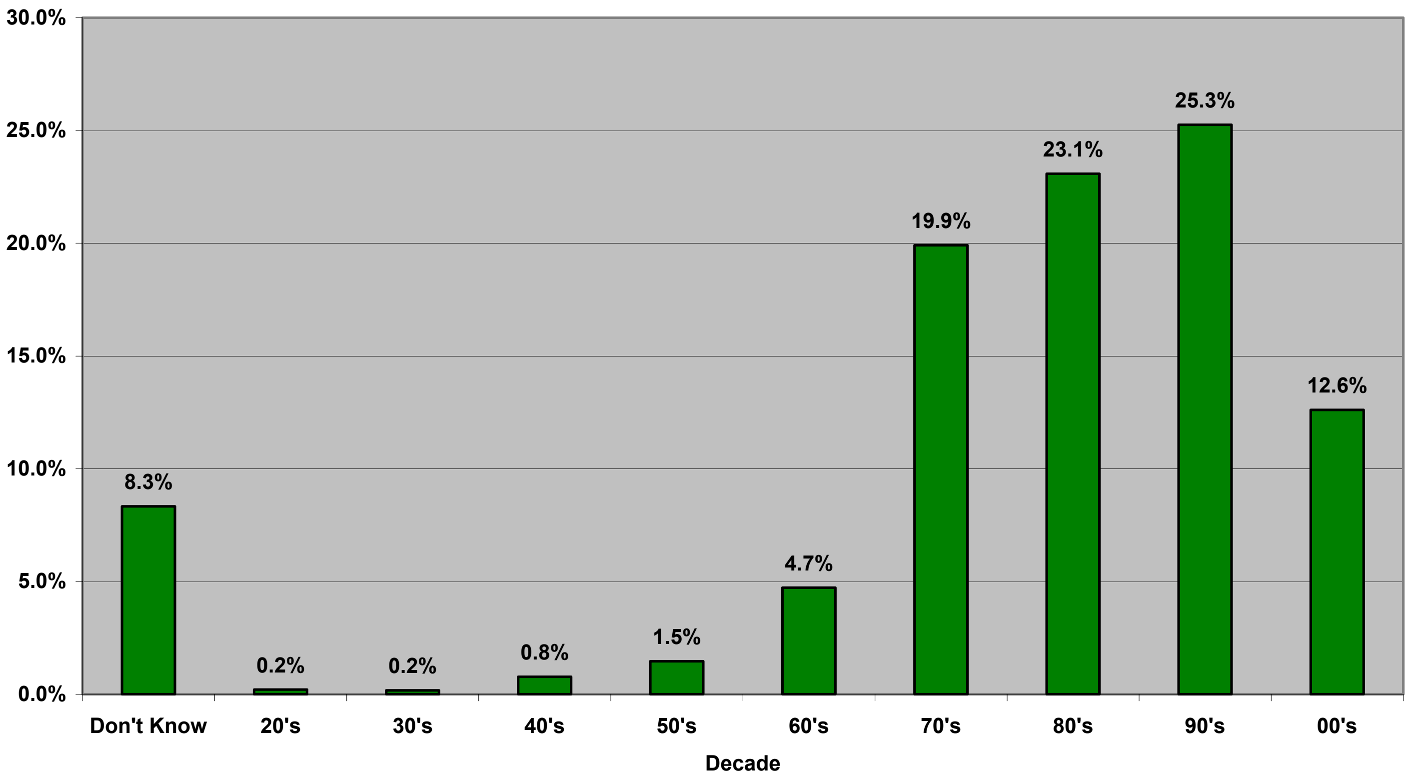
A U. S. Environmental Protection Agency (EPA) study on high efficiency distribution transformers estimated potential savings to be just under 100 kWh per transformer per year. (At 25% average load and expected life of 30 years, savings would be 2.9 billion kWh equating to 1,780,000 MT of CO_2 emission reductions). This is based on an average efficiency improvement of $1/10^{th}$ of 1 percent for all transformers sold to U.S. utilities in one year.[6] A link to the complete study is in Appendix 2. Other studies have indicated even greater savings, depending on loading assumptions and current transformer inventories.

It is estimated there are 340,000 in-service distribution transformers in Alberta. This is based on Fortis' in-service inventory of 179,902 [147,420 Fortis owned, balance customer owned], Enmax in-service inventory of 43,316, plus EPCOR's design criteria of 12 distribution transformers per customer. ATCO Electric was assumed to have same transformer per customer ratio as Fortis; Red Deer, Lethbridge, Medicine Hat & other towns assumed to have same transformer per customer ratio as EPCOR.[7]
Assuming a saving of 100-kWh/ transformer/year for all transformers currently in use in Alberta, estimated savings of 1,020 million kWh would result over an expected life of 30 years.

Future work could investigate barriers and financial challenges, such as mechanisms that provide balanced incentives between cost-effective investments in high-efficiency transformers and other resource options, or the potential for a Canadian Energy Star Transformer Program. Further study is required in this area to determine the potential savings, emission reductions, costs and economics. Figure 14 illustrates the Fortis in-service transformers age range by decade. This inventory represents just over half of the total in-service transformers in Alberta and of these over 25% are at least 25 years old. This data could form the basis for further study into the savings potential for an Energy Star initiative for Alberta.

[6] The Economic & Environmental Benefits of High-Efficiency Distribution Transformers/US EPA
[7] email from J.Holmes/Fortis Aug. 2004; email from K.Hawrelko/Enmax Sept. 2004; EPCOR distribution loss study to EUB, September 30, 2003

Figure 14
Fortis In-Service Transformer's Age by Decade



National Grid Electricity Plc
Special Condition 2K.4 – Transmission Losses Report
Reporting Period 1 April 2014 to 31 March 2015

Introduction

National Grid Electricity Transmission (NGET) has a licence obligation that, “On or before 31 October 2014 and for each subsequent year, unless the Authority directs otherwise, the licensee must publish an annual Transmission Losses report for the previous Relevant Year prepared in accordance with the provisions of this condition to be published on, and be readily accessible from its website, and to include in reasonable detail:
(a) the level of Transmission Losses from the licensee’s Transmission System, measured as the difference between the units of electricity metered on entry to the licensee’s Transmission System and the units of electricity metered on leaving that system;
(b) a progress report on the implementation of the licensee’s strategy under paragraph 2K.2, including the licensee’s estimate of the contribution to minimise Transmission Losses on the licensee’s Transmission System that has occurred as a result; and
(c) any changes or revisions the licensee has made to the strategy in accordance with paragraph 2K.2 of this condition.
There is also the requirement, as part of SC2K.5 to include “a description of any calculations the licensee has used to estimate Transmission Losses on the licensee’s Transmissions System.”

2K.4 (a) Transmission Losses for this reporting period

Transmission Losses have been calculated for the 2014/15 financial year for the GB system as a whole and for each separate licencee system. The calculation is based on the latest applicable settlement metering currently available for generation, demand and French / Moyle Interconnector BMUs, together with operational metering for the boundaries between the Scottish Hydro Electric and Scottish Power systems and the Scottish Power and England and Wales systems.

Overall the losses arising from the GB transmission system are calculated by taking the difference between the sum of infeed to and the sum of the offtakes from the transmission system. This is carried out using data from the Elexon SAA-IO14 data feed. At a GB level the Total Generation (sum of positive metered active power) and Total Demand (sum of negative metered active power) values can be used.

Table 1 shows last year’s losses and the Table 2 shows historical losses for comparison purposes in order to see changes based on the losses strategy and changes to load and non-load related activities.

Table 1 – 2014/15 losses from the UK transmission system

Period – 1 Apr 2014 to 31 Mar 2015		
TRANSMISSION SYSTEM	Loss (TWh)	Loss %
England and Wales (NGET)	4.60	1.65
South Scotland (SPTL)	0.42	1.17
North Scotland (SHETL)	0.67	8.04
TOTAL NETWORK LOSSES	5.68	1.84

Table 2. Historical losses from the UK Transmission System

Losses (TWh)	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
E/W	5.15	4.92	5.36	4.22	5.23	4.93	4.45	4.60
South Scotland	0.74	0.67	0.49	0.53	0.55	0.44	0.49	0.42
North Scotland	0.29	0.37	0.29	0.24	0.36	0.27	0.38	0.67
GB	**6.18**	**5.96**	**6.14**	**4.99**	**6.14**	**5.64**	**5.32**	**5.68**
Losses (%)	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**
E/W	1.62	1.59	1.77	1.40	1.80	1.67	1.57	1.65
South Scotland	2.17	1.81	1.46	1.54	1.47	1.30	1.29	1.17
North Scotland	2.38	2.86	2.59	2.55	3.04	3.05	3.55	8.04
GB	**1.75**	**1.73**	**1.82**	**1.49**	**1.92**	**1.72**	**1.70**	**1.84**

It is not possible to quantify the exact causes for the small increase in losses from 2013-14 to 2014-15 (1.57% to 1.65%). It can be seen from data from previous years that losses will vary from year to year due to various factors, the effect of which cannot be easily quantified. Transmission losses can be affected by various factors including the volume of electricity transmitted and the amount of resistive equipment electricity travels through from generation to load point. This is affected by the location of generation and the distribution of demand across the system causing varying levels of flow on the network throughout the year. Operational measures are also taken to manage system compliance and security which may affect transmission losses.

Operational measures which affect transmission losses could, amongst others, include the use of Quad Boosters and Series Reactors to divert power away from overloaded lines under particular circumstances or use of Voltage Control Circuits (switching out of certain circuits) to manage high Volts on the system. For example, in 2014-15 National Grid experienced an increased need to undertake operational measures to mitigate voltage increases on the system (due to low levels of transmission on parts of the network) which can have the impact of increasing transmission losses.

Reactive compensation equipment (MSC, reactors, SVC) all have resistive losses associated. But because they will compensate for VAr travelling on the OHLs from far sources, they also have the effect of reducing losses by providing VAr locally. It is not certain whether the total effect will be positive or negative because this can vary depending on situations.

National Grid's approach for the management of transmission losses remains unchanged from that outlined in the December 2013 published strategy document (as required by Special Condition 2K paragraph 2 of the Transmission Licence) and the subsequent update in October 2014 (SpC 2K, paragraph 4).

In addition to ongoing network investment and to ensure effective and innovative future development of the network, National Grid is investigating new conductor types to install on the network which could provide benefits including increased capacity, reduced noise and reduced resistance. These conductors may be considered for use on the network in due course following R&D activities and Type Registration.

As more generation is connected at the periphery of the network, the losses are expected to increase. Load losses do not linearly change with circuit loading being proportional to the square of the current carried. A particularly heavily loaded circuit in one year contributing significantly to the total losses may be less loaded the next year and have a much smaller proportion of the total losses. Local reactive support for voltage management avoids the transmission of reactive power over distances that would otherwise increase system losses.

2K.4 (b) Progress on implementation of Transmission Losses Strategy for this reporting period

Information shown in this section is in the context of National Grid operating the full GB system but only owning and being responsible for the assets of the England and Wales transmission system.

National Grid's approach for the management of transmission losses remains unchanged from that outlined in the December 2013 published strategy document. Utilisation of National Grid's Whole Life Value framework assists the selection of economically justified investments based on a broad range of investment criteria, including consideration of transmission losses. Where the Whole Life Value framework identifies that the cost of transmission losses are material to the investment decision and that sufficient certainty of future year-round transmission flows make the analysis worthwhile, then further detailed transmission loss assessments will be undertaken that quantify year-round transmission losses.

National Grid has been considering transmission losses in equipment specifications and procurement processes in line with this strategy prior to its launch, so non-load related investments delivered can be attributed to this strategy.

Further like-for-like replacement schemes delivered in 2014/15 are reported via updates to section 5 of the strategy.

Transmission network developments that have passed or shall pass through the optioneering phase after National Grid's transmission losses strategy release in December 2013 present the greatest opportunity for the consideration of transmission losses to influence the chosen investment solution. All schemes where optioneering has taken place since December 2013 (load and non-load) have been assessed under National Grid's Whole Life Value framework. Of these investment decisions, optioneering has identified that losses could be material to the investment decision in some instances.

In alignment with the Whole Life Value assessment, transmission losses have been considered for different transmission solutions. Studies concluded that under peak system conditions, investment solutions that employed a new circuit would experience up to a 25% reduction in losses on local transmission circuits, justifying a clear losses benefit from investment for system peak conditions.

As a result of the 2014 Network Development Policy (the economic decision making process for undertaking load related investment on the Transmission Network) as published in the ETYS, the following schemes are being progressed by National Grid Transmission Owner which were identified as reducing losses on the system in the Transmission Strategy.

The reconductoring works completed between Harker, Hutton and Quernmore Tee have increased transfer capability across B7 boundary and also reduced transmission losses due to the less resistive conductor type used. The same is also true for the reconductoring works completed on the Trawsfynydd-Treuddyn circuit.

2K.4 (c) Proposed changes to Transmission Losses Strategy for future reporting periods

In this section the aim is to give an overview of the proposed changes or recommendations and the Strategy document itself will have the full details that list refers to. These are not changes to the overall strategy as that is unchanged, merely amendments to reflect the actual output from each year. These updates show the latest information available.

- An update of load related and non-load related investments will be provided in sections 4 and 5 of the Strategy assessing the impact on transmission losses of additional transmission developments (delivered and planned) since the Strategy's first publication in 2013 and last year's updates.
- Section 5 of the strategy outlines the treatment of non-load related investments that are deemed to have a material impact on transmission losses, namely; transformer, cable and overhead line replacement schemes. To assess the benefits in terms of indicative losses that replacement schemes can offer, this section will be modified to include all replacement schemes delivered in the year 2014/15
- For transformer replacements, section 5.1 will be updated to estimate losses for all like-for-like replacements in the previous Relevant Year, discounting replacements where transformer capacity has been increased or transformers are replaced for load-related investments. All transformers assessed under this methodology demonstrate a reduction in transformer losses as a result of each recent replacement scheme.
- Similarly, cable and overhead line sections of the strategy (5.2 and 5.3) will also be revised to account for further replacements for the 2014/15 year. No further cable replacement schemes were delivered for the previous Relevant Year, leaving the conclusion of cable assessments unchanged, i.e. they must be considered on a per replacement basis.
- We are continually refining our transmission losses assessment methodology for load related developments, and as a result the use of a modelling tool for assessment of losses will be replaced with a different system over the next two years.

2K.5 Calculations used to estimate Transmission Losses

The calculations outlined below show how we estimate the overall Transmission Losses, taking into consideration the collection of metered information detailing the power flow onto and off of the Electricity System

$$BoundaryLosses(TWh) = \frac{(\frac{ConstrainedFlow}{100})^2 \times kmWT \times R\%/km}{\frac{CCTWT}{CapWT}}$$

$$Annual\ MWh\,Losses = \frac{\left(\frac{(LoadLoss_{Old} - Load\ Loss_{New})}{\Delta} + (No\,LoadLoss_{Old} - No\,Load\ Loss_{New})\right) \times \frac{50}{52} \times 8760h}{1000}$$

$$\Delta = \frac{1}{(RMS\ average\ \ transformer\ loading)^2}$$

$$TotalLosses(TWh) = \left(\sum BoundaryLosses\,per\,boundary\right) + Load\,\mathrm{Re}lated\,Losses + Fixed\,Losses$$

nationalgrid

National Grid Strategy Paper

National Grid's Strategy Paper to address

Transmission Licence Special Condition 2K:

Electricity Transmission Losses

Reporting Period: 1 April 2013 to 31 March 2021

Published: November 2013

Revised: September 2014

Executive Summary

This paper presents National Grid Electricity Transmission's strategy for the consideration and mitigation of transmission losses over the RIIO-T1 Price Control period. This second edition (published October 2014) is prepared in accordance with Special Condition 2K of the electricity Transmission Licence, providing a review and update of the strategy to support the submission of the 2013/2014 transmission losses annual report (published separately).

Throughout the design and development of the transmission network, National Grid's Whole Life Value framework is utilised to support the selection of a preferred option to meet the investment need. This framework assists selection of the appropriate investment, backed by economically justified decisions based on a broad range of investment criteria that include transmission losses.

This updated strategy paper describes this approach, its employment in investment decision making, and updates transmission developments (and loss estimates) delivered in the 2013/14 financial year. Where the Whole Life Value framework identifies that the cost of transmission losses are material to an investment decision and that sufficient certainty of future year-round transmission flows make the analysis worthwhile, then further detailed transmission loss assessments will be undertaken that quantify year-round transmission losses.

Detailed year-round loss assessments are likely to impact investment decisions for, amongst others, incremental wider works and overhead line reconductoring schemes. For the former, detail of the key transmission reinforcements, the method of associated transmission loss estimation and results expected under the 2013 Electricity Ten Year Statement (ETYS) Gone Green base case are outlined. As an updated ETYS publication will not be provided until November 2014, wider works results are unchanged in this revision and will be reviewed via the 2014/15 strategy update (and subsequent transmission losses annual report). Proposals to revise the method of wider works loss calculation for future revisions of this strategy (i.e. 2015 onwards) are discussed. Transmission loss estimates for key enabling works developments are also defined. Where transmission losses increase for recommended investments, this demonstrates that transmission losses are one in a number of factors considered by National Grid when selecting the most economic and efficient transmission solutions.

Recent overhead line reconductoring, transmission cable replacement, and grid transformer replacement examples are provided as an indication of the likely impacts on transmission losses of similar replacements in the RIIO-T1 period. In the case of both overhead line and cable schemes, transmission losses are considered on a case-by-case basis, whereas material and manufacturing improvements indicate that a transmission loss reduction can be expected from replacing 'old' for 'new' transformers. Published data from National Grid indicates that future system-wide transmission losses are likely to increase as a result of developments that include the connection of more generation to the periphery of the network. As of this revision, this forecast will be compared to annual metered data via the National Grid's transmission losses annual report.

The methods by which National Grid account for transmission losses in equipment specifications and procurement processes are outlined for cables, overhead lines and transformers. For transformer tenders, associated losses are often a significant or deciding factor in the choice of a winning bid. National Grid has deployed extra high conductivity (EHC) alloy in all non – load related overhead line conductor replacements. All Aluminium Alloy Conductor (AAAC) has been utilised to counteract an increase in transmission losses. For load related replacements, overhead line conductors such as GAP, ACCC (Aluminium Conductor Carbon Core) and ACCR (Aluminium Conductor Composite Reinforced) have been developed to provide significant increases in transmission capacity. The increase in transmission loss (cost) resulting from increased transmission capacity must be considered alongside the capital saving of avoiding new lines build to meet system requirements.

The trade-off between capital investment and transmission loss costs are clear throughout this strategy paper. This will continue to be the case with future technology developments where the capital cost of increased capacity on existing (e.g. series compensation) or new (e.g. HVDC links) assets must be considered alongside their impacts on transmission losses.

ERCOT Protocols
Section 13: Transmission and Distribution Losses

January 1, 2009

13.2.5 Loss Monitoring

ERCOT shall monitor Transmission Losses annually and will investigate abnormal loss factors. ERCOT and Transmission Service Providers shall use the cost of losses as one criterion in evaluating the need for transmission additions.

13.3 Distribution Losses

By October 30th of each year for the next calendar year, or two (2) months prior to the posting of any update to the approved Distribution Loss Factor (DLF) codes and calculation each Distribution Service Provider (DSP), except NOIEs, shall calculate and provide ERCOT the Annual DLFs to be applied to distribution voltage level Loads in its area of certification. ERCOT shall review and approve the DLF calculation methodology used by each DSP prior to use of the loss factors for settlement purposes. If the DLF calculation methodology does not conform with ERCOT's interpretation of the Protocol criteria in this subsection, ERCOT will work with the DSP to correct the deficiency. Until deficiencies are resolved, the last approved DLF and the calculation methodology will be posted, and the last approved DLFs shall be used for settlement. A DSP may only submit a change to the DLF calculation methodology annually or when a change in a DSP service area warrants an update to the approved DLF based on the DSP internal evaluation.

The TDSP shall assign a DLF code to each ESI ID. A maximum of five (5) DLFs may be submitted for each DSP based upon ERCOT approved parameters, such as service voltages or number of transformations.

The following coding standards will be used to identify the DLF applicable to each ESI ID:

- T = Transmission connected Customers (no Distribution Loss Factor applied)
- A through E = TDSP defined Customer segment(s)

The DSPs, except NOIEs, are obligated to provide DLFs to ERCOT. ERCOT will post the DLF and calculation methodology, including any equations and constants, for each DSP.

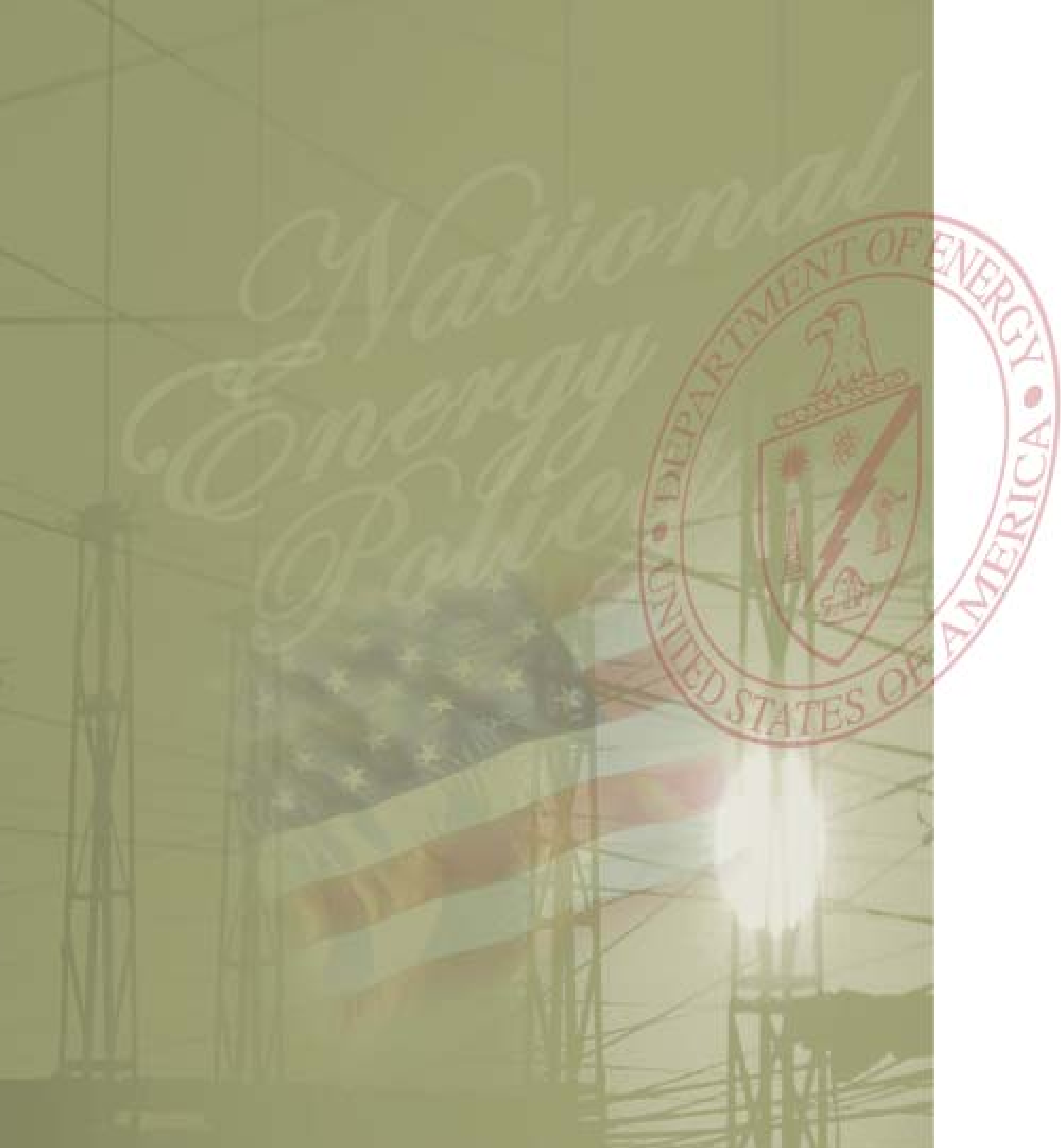
Loss factor variables submitted by the DSP shall include:

(1) The annual DLF coefficients (F_1, F_2, and F_3) for each DLF code; and

(2) The methodology upon which the calculation of the coefficients (F_1, F_2, and F_3) was made.

13.3.1 Loss Factor Calculation

ERCOT shall use the DLFs submitted by the DSP to calculate the Settlement Interval DLFs. DLFs will be calculated from the data provided by DSPs as follows using the following equation:



National Transmission Grid Study

The Honorable Spencer Abraham
Secretary of Energy

U.S. Department
of Energy

May 2002

4

Pricing Transmission Services to Reflect True Costs

The first step toward increasing the role of market forces in managing transmission system operations efficiently and fairly is increasing the role of price signals to direct the actions of market participants toward outcomes that improve operations. Improving operations by relying on accurate price signals may, by itself, alleviate the need for some construction of new transmission facilities. Moreover, when new construction is needed, price signals will help market participants identify opportunities and assess options to address bottlenecks.

Several aspects of transmission operations, including congestion and losses, could be effectively addressed by pricing based on the principle that if market participants see the true costs of transmission services reflected in prices, they will use or procure these services efficiently. For example, pricing principles should encourage location of new generation in congested areas as opposed to location in areas with no congestion. Thus, reliance on uplift charges, in which costs are recovered from all transmission users on an equivalent basis, should be minimized.[34] Here, we focus on examples where application of these principles may be especially important for addressing transmission bottlenecks.[35]

Although curtailing some transactions is essential to ensure reliability when transmission lines are in danger of being overloaded, the economic losses associated with these curtailments can be reduced by sending price signals that will allow market participants to choose which transactions to curtail in response to the relative value of the transactions. Congestion pricing, in which the party that creates congestion pays for the costs of relieving it, is a powerful example of using

[34]Uplift charges are charges paid by all users; these charges represent costs that are difficult to apportion to particular market participants or that regulators allocate evenly among all users in order to achieve other policy objectives. In cases where uplift charges must be used to recover costs, however, performance-based regulations (discussed in Section 3) that provide incentives to minimize these charges and improve operational efficiency should be considered.

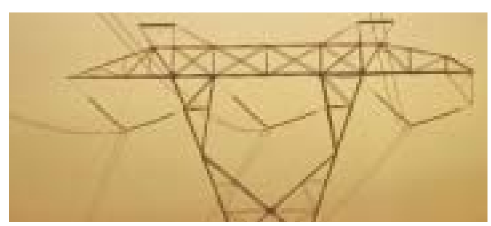
[35]For additional background on this discussion, see the Issue Paper, "Transmission System Operation and Interconnection," by F. Alvarado and S. Oren.

economic signals to relieve congestion efficiently. FERC's Order 2000 identifies reliance on market-based mechanisms to manage congestion as one of the eight functions of RTOs.

Transmission of electricity is not 100 percent efficient; losses, which result from the heating of lines and transformers, are inevitable, so delivering 100 MWs of electricity to an end point requires that more than 100 MWs be put into the transmission system. Losses depend on a variety of factors, including the physical properties of transmission facilities, the distance the electricity must travel, and the current use of transmission facilities by others. The costs of system losses are sometimes included in uplift charges borne equally by all transmission system users, which leads to inefficient use of the system. More accurate pricing and allocation of transmission losses will lead to more efficient markets because participants can see and respond to the true costs of using the transmission system.

Transmission pricing should recognize the inherent differences between intermittent, low-capacity-factor renewable energy sources that are often located far from loads (such as wind energy) and conventional generation, which is not intermittent. Pricing should not unduly disadvantage renewable power plants. For example, wind plants must pay for their own ancillary services. However, because of the inherent difficulty of precisely scheduling transmission needs for wind plants on a day-ahead basis, these plants should be allowed access to a real-time clearing market for differences, subject to non-punitive penalties based on cost, and/or allowed a wider clearing band for scheduling, as has been proposed by several states.

When we propose greater reliance on competitive economic forces to procure and apportion the costs of transmission services, we must recognize that markets for electricity and electricity services are still maturing. Approaches for organizing markets must minimize the risks of unintended design flaws that can be exploited by market participants. There is a need to develop methods for "testing" market rules in controlled laboratory-like settings to identify and correct design flaws prior to implementation. While we are gaining experience with markets, there must be safeguards—i.e., close oversight and rapid, deliberate response by FERC, including stringent penalties—to prevent market abuses. FERC has already initiated activities to increase its capability to monitor electricity markets more aggressively.



RECOMMENDATION

- DOE, working with FERC, will continue to research and test market-based approaches for transmission operations, including congestion management and pricing of transmission losses and other transmission services.

MDP_RUL_0002

MARKET RULES

for the Ontario Electricity Market

Appendix 4.1 – IESO-Controlled Grid Performance Standards

<table>
<tr><th>Ref</th><th>Item</th><th colspan="4">Requirement</th></tr>
<tr><td></td><td colspan="5">Transmission System</td></tr>
<tr><td>1</td><td>Frequency variations</td><td colspan="4">All equipment shall be capable of continuously operating in the range between 59.5 Hz and 60.5 Hz.</td></tr>
<tr><td rowspan="6">2</td><td rowspan="6">Voltage variations</td><td colspan="4">Under normal conditions voltages are maintained within the range below.</td></tr>
<tr><td></td><td colspan="3">Transmission Voltage</td></tr>
<tr><td>Nominal (kV)</td><td>500</td><td>230</td><td>115</td></tr>
<tr><td>Maximum Continuous (kV)</td><td>550</td><td>250*</td><td>127*</td></tr>
<tr><td>Minimum Continuous (kV)</td><td>490</td><td>220</td><td>113</td></tr>
<tr><td colspan="4">*In northern Ontario, the maximum continuous voltage for the 230 and 115 kV systems can be as high as 260 kV and 132 kV respectively</td></tr>
<tr><td>3</td><td>[Intentionally left blank]</td><td colspan="4"></td></tr>
<tr><td>4</td><td>[Intentionally left blank]</td><td colspan="4"></td></tr>
<tr><td>5</td><td>[Intentionally left blank]</td><td colspan="4"></td></tr>
<tr><td>6</td><td>[Intentionally left blank]</td><td colspan="4"></td></tr>
<tr><td>7</td><td>[Intentionally left blank]</td><td colspan="4"></td></tr>
<tr><td>8</td><td>[Intentionally left blank]</td><td colspan="4"></td></tr>
</table>

IN THE MATTER OF a cost of service application made by Hydro One Networks Inc. ("**Hydro One**") Transmission with the Ontario Energy Board (OEB) on May 31, 2016 under section 78 of the *Ontario Energy Board Act,* 1998, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to its transmission revenue requirement and to the Ontario Uniform Transmission Rates, to be effective January 1, 2017 and January 1, 2018 ("**Transmission Rate Application**");

AND IN THE MATTER OF the Ontario Energy Board's Decision on Motions for Full and Adequate Responses to Interrogatories and Technical Conference Questions issued in respect of proceeding EB-2016-0160 on November 1, 2016 (the "**Motions Decision**").

HYDRO ONE NETWORKS INC.

ADDITIONAL EVIDENCE

I. INTRODUCTION

Q.1 What is the purpose of this evidence?

A.1 This evidence complies with the directions set out in the Ontario Energy Board ("**OEB**" or "**Board**") Motions Decision dated November 1, 2016. Five matters are addressed:

- NATF Peer Review and Transmission Reliability Report Summaries;
- Business Plans;
- Asset Investment Economic Analysis;
- Internal Audit Reports; and
- Transmission Losses Discussion.

Additionally, in accordance with the Motions Decision, Hydro One will provide its 3rd quarter ROE information in a separate filing, as soon as reasonably practicable after the information becomes publicly available.

V. INTERNAL AUDIT REPORTS

Q.20 Please describe the internal audit reports that Hydro One has been required to file.

A.20 The two internal audit reports, entitled "Investment Planning" and "Transmission Lines Preventative Maintenance Optimization" have been filed with the Board under a separate cover letter given the interim confidential status of this information. The cover letter to this separate filing describes Hydro One's reasons for maintenance of the confidential status of these reports.

VI. TRANSMISSION LOSSES DISCUSSION

Q.21 Please summarize the Motion Decision regarding Transmission Losses.

A.21 The Motions Decision requires Hydro One to either provide estimates of transmission losses and their cost, using the approaches described in footnote 9 of Environmental Defence's ("**ED**") Reply Submission dated October 25, 2016,[25] or explain why these estimates cannot be provided or are otherwise inappropriate.

Q.22 Are the estimates of transmission losses and their costs as per ED's Motion Reply inappropriate?

A.22 Yes, for the following reasons. Transmission losses arise as part of the ongoing operation of the integrated power system. Losses associated with each transmission element carrying electrical current ("**Transmission Element**") are determined by the following equations:

$$\textit{Transmission Element Losses} = (\textit{Current})^2 \times \textit{Resistance}$$

The overwhelming majority of Transmission Elements are either: (1) line conductors; or (2) transformers. The summation of all Transmission Element losses equals total transmission system losses:

$$\textit{Transmission System Losses} = \sum \textit{Transmission Element Losses}$$

[25] Motions Decision, p 7; EB-2016-0160, Reply Submission filed by Environmental Defence (25 October 2016), p 3, footnote no. 9.

Q.23 What factors influence the "Current" variable?

A.23 "Current" is a function of many factors, including:

- demand level;
- distribution of that demand;
- dispatch of generation (i.e. source of current);
- grid operation, as directed by the Independent Electric System Operator ("**IESO**");
- scheduled transactions;
- loop flows; and
- customer requirements and restrictions.

Current flow may vary along each Transmission Element in each hour and throughout each year. Current, measured in Amperes (A), is the dominant factor in quantifying losses. Depending on system conditions, Current ranges from 100 A to more than 1000 A for each Transmission Element (typically, the range is around 200-500 A, although it is difficult to make such generalizations).

The dominance of the current variable stems from the square relationship in the equation. For example, a 30% change in Current (e.g. an increase of 30%, from 100 A to 130 A) results in a 69% overall increase in Transmission Element Losses ($130^2 / 100^2 \approx 169\%$).

Overall system demand significantly affects Current flow. The higher the demand, the greater the Current flowing through the system. Distribution of demand across the system also impacts Current flow. The loading profiles at each transmission load centre or transmission customer connection point are determined by the operation patterns and characteristics of load customers.

The location and output levels of generators supplying power to the system determines how much Current will flow across different parts of the transmission system to supply transmission load centres and customers. Transactions (such as exports) and loop flows also result in higher Current flows. Generators located further from load centres result in current flows across a greater number of Transmission Elements for the delivery of energy. Higher losses result when generators are located further away from load centres.

Generation dispatch varies significantly throughout the year between peak, off-peak and shoulder periods. Ontario's IESO directs the day to day operations of the provincial grid. These activities include generation dispatch, transmitter operations, setting voltage levels across the transmission system, and providing ancillary services. Current flows across Transmission Elements, and thus the entire transmission system, are significantly influenced by the IESO's actions, which are essential to ensure the reliable operation of the transmission system as well as electricity market efficiency.

Q.24 Do transmitter operations decisions impact Current flow?

A.24 No. Transmitter operations decisions do not control or affect the level of Current flow in any meaningful way from a Transmission System Losses perspective. The Transmitter may require outages to perform maintenance and repairs, and outages may temporarily change the distribution of current flows. However, all transmission element outages are approved by and under the direction of the IESO. Transmitters' facilities do, however, affect the second variable, "Resistance".

Q.25 Please describe the Resistance variable used in the Transmission Element Losses equation.

A.25 Resistance is a concept analogous to friction. Resistance impedes the flow of Current through a Transmission Element causing some electric energy to be transformed into heat and resulting in losses.

Q.26 Is the quantity of Resistance of line conductors equal to the Resistance with transformers?

A.26 No. In Ontario, the losses that occur on line conductors are more than four times the losses that occur on transformers. Correspondingly, Resistance in aggregate on line conductors is significantly larger than Resistance on transformers.

Q.27 What are the key factors that affect the Resistance of a line conductor?

A.27 There are four such factors:

- Conductor size. The larger the conductor, the lower the Resistance.

- Conductor length. Resistance is directly proportional to the length. For example, (and holding all other variables constant) a typical conductor rating is 0.086 Ohms/km. If the line conductor was 100 km in length, then this Transmission Element would have a Resistance of 8.6 Ohms.

- Conductor temperature. Resistance increases with higher temperatures, which is linked to Current. Higher temperatures are a function of current. The higher the Current level, the higher the temperature (and thus the higher the Resistance).

- Conductor material. Different conductor materials have different Resistance characteristics. Aluminum, particularly aluminum conductor steel reinforced ("**ASCR**"), is the main standard used in North America.

Q.28 Can the inherent Resistance level for a line conductor change once it is placed in operation?

A.28 No. Once line conductors are installed, the Resistance characteristic of that conductor remains constant for the life of the asset, usually for a period ranging between 60 and 80 or more years. Historically, Hydro One has replaced less than 1% of its conductor fleet each year. Going forward, Hydro is projecting a need to replace 1.7% or approximately 500km annually. This means that the Resistance level of 98.3% of Hydro One's conductor fleet would remain unchanged from year to year.

Q.29 Can Resistance improvements occur through oversizing conductors that are replaced annually?

A.29 Annual conductor investments provide only marginal improvements to Resistance. Assuming existing lines and towers can accommodate a larger conductor, Resistance improvements due to a larger conductor typically yields a 10% to 20% reduction in Resistance. Overall cost of the larger conductor, including assessment of whether existing towers and lines could be used for a larger conductor would also require consideration.

Q.30 Please provide an example that illustrates the level of investment needed to materially reduce the Resistance of line conductors.

A.30 Assume Hydro One has a 440 circuit km proposed for conductor replacement in 2018, representing approximately 1.5% of its conductor fleet. Assume also that the overall economic impact of Total System Losses is, as suggested by ED, equal to $390 million given that losses are directly proportional to Resistance (note that this value is given for the purposes of illustration; it is not proven that this is the overall economic impact of Total System Losses).[26] For the purposes of simplicity, also assume that this amount is entirely due to line conductor losses in Ontario.

Under this scenario, the maximum opportunity to reduce losses from the conductor replacement would equal $6 million (i.e. 1.5% of $390 million). However, the maximum opportunity assumes that Resistance could be entirely eliminated, which is not the case. As stated, Resistance improvements range between 10% and 20%, and are due primarily to physical and technological constraints. Assuming a midpoint of 15%, the Resistance improvement opportunity would be valued at $1 million (i.e. 15% x $6 million).

Such incremental reductions in Resistance should be placed in context of the associated costs. A program to increase line conductor sizes would incur costs that far exceed the $1 million benefit level, given the magnitude, scope and length of the line conductors involved. For example, a 440 circuit km conductor replacement would be expected to cost in the range of $180 million.

Resistance improvement through increasing conductor size assumes that all existing towers and other lines components supporting the replaced conductor would have the design capacity to structurally support and allow for the operation of larger conductor.

[26] ED's estimate differs significantly from the Total Transmission System Loss-related amounts recovered by the IESO through the wholesale competitive electricity market in 2015 and 2016 to-date. According to the IESO, the Total Transmission System Loss-related amount recovered in 2015 was approximately $66.3 million. For the period January 1 to September 30, 2016, this amount was approximately $36.1 million. Hydro One was advised by the IESO that these amounts were recovered through Charge Code 150 (Net Energy Market Settlement Uplift), which covers differences between the amount paid to suppliers for the commodity and the amount paid by buyers in a given hour. The IESO administers Charge Code 150, not Hydro One.

This is unrealistic given the fact that tower sizes and lines are designed to support the existing in-service conductors, and the opportunities to replace them with a larger conductor are very limited. Overall costs in this illustration would increase dramatically if changes to towers and line design are necessary.

Q.31 Would this analysis change if it was assumed that greater conductor replacement occurred than historical levels?

A.31 Under this scenario, assume Hydro One decided to replace 3% of its conductor fleet. This would mean that 1.5% of that fleet would be replaced before reaching end of life. This outcome alone would impose significant costs that could have been avoided by allowing continued operation of the conductors now in service. The magnitude of those costs would further escalate by inclusion of the full cost of the larger conductor along with additional reinforcements that may be required. It also assumes that resources are available for double the level of conductor replacement work. For 440 circuit km, conductor replacement costs would be expected to be in the range of $180 million. Again, further significant costs would be incurred if changes to towers and lines were also necessary to support the operational design of the new larger conductor. On the benefits side, the Resistance improvement would only increase to approximately $2M (3% x 390M x 15%). The main conclusion from this scenario is that increased levels of conductor replacement for the sole purpose of improving Resistance would result in significant costs with very marginal economic benefits.

Q.32 The illustrations above address Transmission Element Losses. How does this analysis impact Total System Losses?

A.32 Recall the formula for Total System Losses is the summation of all Transmission Element Losses. The summation formula means that Resistance for 98.5% of Hydro One’s remaining Transmission Element Losses would remain unchanged. Any Resistance improvement from a Transmission Element is still muted by the fixed nature of Resistance on all remaining Transmission Element Losses. Again, the far more substantive change shown in this analysis is the significant costs that would be incurred to effectively “chase” a relatively small economic benefit.

Q.33 The illustrations above focus on conductor size. Do any of the other factors that contribute to Resistance provide opportunities for improvements?

A.33 As noted above, the other factors affecting Resistance are conductor length, conductor temperature and conductor material.

Hydro One has little or no opportunity to reduce the length of conductors. In the case of conductor replacements, the length is effectively predetermined by the location of existing rights of way and towers. When new lines are proposed, the shortest route is selected, subject to other physical, technical, environmental and existing land use constraints.

Conductor temperature is a function of Current flow; it is not a variable that Hydro One can manage independently.

With respect to conductor material, ASCR is widely recognized as having the best overall performance and cost balance for most transmission operations. ASCR is a standard that Hydro One uses for most of its line conductors, including annual line conductor replacement.

Q.34 Why does collecting information on Transmission System Losses not inform the identification of candidate transmission investments?

A.34 The Transmission System Losses is an aggregate value, and as explained above is the sum of the losses on all transmission elements. It is largely a reflection of the Current flow that is driven by the operation of market participants other than the Transmitter. Transmission line investments rely on locational and situational specifics and the associated information to assess need, identify solutions and determine the cost-benefit trade-offs. The level of Transmission System Losses as an aggregate value does not assist in determining locational and situational specifics. It does not identify what transmission elements to focus on, nor does it provide an indication that a specific investment is even required.

Q.35 What conclusions arise from this illustration?

A.35 There are two main conclusions:

1. Changes in Transmission System Losses are far more dependent upon Current than on Resistance. Factors that affect Current relate to the overall operation of the electricity market and the activities of other market participants in Ontario, and fall outside of Hydro One's responsibilities. As such, variations of losses on the transmission system would not inform a transmitter's performance, good or bad.

2. Transmission System Losses are not directly factored into Hydro One's investment planning process. This is because the opportunities to make a material reduction to Resistance are extremely limited. Due to the enormity of the costs required to reduce Resistance (and therefore to reduce losses), Transmission System Losses will never form the basis for identifying and selecting an investment candidate except in very special and limited circumstances.

VII. CONCLUSION

Q.36 Does this conclude Hydro One's additional evidence?

A.36 Yes.

IN THE MATTER OF a cost of service application made by Hydro One Networks Inc. Transmission with the Ontario Energy Board on May 31, 2016 under section 78 of the *Ontario Energy Board Act,* 1998, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to its transmission revenue requirement and to the Ontario Uniform Transmission Rates, to be effective January 1, 2017 and January 1, 2018.

AND IN THE MATTER OF the Notice of Motion filed with the Board on September 29, 2016 by Environmental Defence.

AND IN THE MATTER OF Hydro One Networks Inc. Submissions in response to the Notice of Motion filed by Environmental Defence, in accordance with Rule 8.03 of the Ontario Energy Board Rules of Practice and Procedure.

SUBMISSIONS OF HYDRO ONE NETWORKS INC.
IN RESPONSE TO ENVIRONMENTAL DEFENCE
October 21, 2016

A. INTRODUCTION

In accordance with Procedural Order No. 3 dated October 12, 2016, and Rule 8.03 of the *Rules of Practice and Procedure,* Hydro One Networks Inc. ("**Hydro One**") provides submissions in response to the Notice of Motion filed on September 29, 2016, by Environmental Defence (the "**ED Motion**") and to address submissions filed by Board Staff on October 18, 2016.

The ED Motion requests an order from the Board requiring Hydro One to provide further responses to specific interrogatories. Board Staff supports the ED Motion based on the belief that transmission losses are relevant to Hydro One's transmission planning exercise, and thus information respecting transmission losses is relevant to this rate proceeding. Board Staff submits that while some of the information may take considerable time to produce, Hydro One should use its best efforts to provide the requested information.

B. SUBMISSIONS

The ED Motion requests that Hydro One produce further and better responses to the following interrogatories:

Interrogatory	Additional Information Requested
• ED IR #1	The actual maximum capacity that can be imported to and

from Ontario's five adjoining jurisdictions (actual capacity after considering operational constraints, not installed capacity) ("**Maximum Import/Export Capacity**").

- ED IR #2 — Hydro One's annual transmission energy losses as a percent of its total annual transmission throughput volumes and transmission energy losses during annual peak demand hour as a percent of the total demand of its customers during the peak hour, for the last 10 years ("**Annual Transmission Losses**").
- ED IR #3(c) — Estimates of the average transmission energy losses for transmission companies in the United States and Canada ("**Average Third Party Transmission Losses**").
- ED IR #4(a)(c) — Detailed description of the various sources of Hydro One's transmission energy losses, including a percentage breakdown by geographic region and type, and a list of steps Hydro One could be taking to reduce transmission losses that it is currently not taking ("**Transmission Loss Sources**").
- ED IR #5 — Estimate of the annual cost of Hydro One transmission losses for the last ten years ("**Transmission Loss Costs**").

Hydro One opposes the ED Motion on the basis that it is not in possession and control of the information requested.

Theoretically, transmission investments to address system losses would be considered in Hydro One's transmission planning process if the IESO identified a specific system need and directed Hydro One to carry out a particular project intended to address this type of need. Overall system and regional planning are matters within the IESO's responsibilities. In the present circumstances, however, the IESO has not identified such needs, nor has it provided such direction to Hydro One. Under Ontario's market structure, the costs associated with energy losses are recovered as a component of the prevailing market price for electricity. The planning and recovery of costs associated with energy losses are within the purview of the IESO; therefore, Hydro One does not maintain information on energy losses, let alone use this type of information in its own transmission investment planning process.

As noted in ED's Motion, Hydro One and the IESO have advised ED of the level of information that each possesses in respect of energy losses on the transmission network. The IESO does not collect energy loss information specific to transmitters or other market participants, and as noted Hydro One does not maintain this information. These responses have not been considered sufficient for ED's purposes, and thus what ED seeks is for Hydro One and/or the IESO to take positive steps to obtain and produce information that Hydro One does not possess.

Hydro One objects to this request. The effort required for Hydro One to create and produce the type of information requested by ED would require assessing a variety of dynamic factors that apply to the market demand for electricity in each hour of the year and correlating this to each circuit comprising the Hydro One transmission system, as well as interconnecting transmission systems.

From its correspondence dated October 19, 2016, ED seeks to address transmission losses further in this proceeding by engaging an expert to address the topic of transmission losses and how losses are addressed in other jurisdictions. Hydro One does not see this step as in any way being relevant to or justifying the ED Motion at hand, namely, production of information that Hydro One does not possess. If the Board effectively determines that transmission losses are a topic germane to this proceeding by approving ED's request to have expert testimony prepared on the topic of how the treatment of transmission losses in jurisdictions outside of Ontario has bearing on Hydro One's investment planning process, then Hydro One will have Mr. Bing Young available to address, to the extent possible, questions ED has with respect to why Hydro One does not use energy losses information in the manner requested by ED in its transmission planning process.

1. Maximum Import/Export Capacity

Hydro One does not have information on the actual maximum import/export capacity associated with each of Ontario's five adjoining jurisdictions. Available information respecting Ontario's export and import capacity was provided by the IESO in its September 16, 2016 letter to ED ("**IESO Letter #1**").[1] IESO Letter #1 included a link to the Ontario Transmission System report dated June 21, 2016, which provides Ontario's theoretical coincident import/export capacity. While the report does not specifically provide import/export capacity, it does provide the transfer capability of Ontario's interconnections.[2] In IESO Letter #1, the IESO notes that the amount of

[1] IESO Letter #1 has been filed in the record of EB-2016-0160 on September 16, 2016; IESO Letter #1 is also referred to in Environmental Defence Motion For Full and Adequate Interrogatory Responses: EB-2016-0160 Motion Record, Tab 9, pp. 1-2.

[2] Ontario Transmission System, IESO, June 21, 2016, at p 16, as referenced in Environmental Defence Motion For Full and Adequate Interrogatory Responses: EB-2016-0160 Motion Record, Tab 9, p 2.