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LDC ASSET RENEWAL SERIES

Part 4: Reliability

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1.0 Executive Summary

Keeping the lights on: it is at the heart of the electricity business. The other papers in this series consider the impact of institutional or external factors on the operation of distribution systems. In turn, we measure the successfulness of these systems by their reliability.

Reliability has both a power quality and consistency component. Its consistency is tracked by commonly used indexes such as SAIDI (average interruption length), SAIFI (average frequency of outages), CAIDI (time required to restore service), and MAIFI (frequency of momentary outages). Ontario's distributors, on average, appear to be less reliable than the Canadian average. Internationally, Ontario's reliability falls behind nations such as Singapore and Germany, both with advanced smart grids and highly undergrounded infrastructure. However, making such comparisons is a false analogy, particularly when comparing the dense, urban, city-state of Singapore to our large, cold, and diverse province. What is clear is that Ontario's distributors have been improving their reliability index scores over the last half-decade.

Ontarians appear to be satisfied with the degree of reliability their LDCs provide. They seem unwilling to pay more for increased reliability, nor willing to trade reduced rates for less reliable service. With electricity flowing to homes and consumers over 99% of the time, reliability arguably only becomes salient in the moments during and immediately after an interruption. Nevertheless, as we become more dependent on technology, the status quo may not be enough to satisfy customers.

Reliability is a function of the design of a distribution system and connected transmission system. Designers into the future will have to contend with a greater need to keep the power flowing along with increasing concerns about power quality. Voltage regulation and the self-healing grid offer engineers solutions to these increasing challenges.

The total costs of outages are difficult to quantify. Several decade-old studies in the United States predicted that the economic losses due to outages cost between $30 and $400 billion annually; a $150 billion loss is akin to adding 4 cents/kWh to the bill of each American consumer (Rouse and Kelly 4). Many of these costs are indirect costs are hidden to consumers, making it hard to justify higher rates for increased reliability for many.

The economic impact of an outage differs between location and customer. Thought should be given to designing the smart grid to place emphasis on those who need power the most. Using customer interruption costs along with existing metrics can provide a measure of economic loss from outages and provide the socioeconomic context to encourage good design. Government, the regulator, and LDCs alike will need to consider segregating customers based on the value each places on electricity.

1.1 Definitions

CAIDI – Customer Average Interruption Duration Index
DG – Distributed Generation
IEEE – Institute of Electrical and Electronics Engineers
LDC – Local Distribution Company
MAIFI – Momentary Average Interruption Frequency Index
OEB – Ontario Energy Board
PBR – Performance-based regulation
SAIDI – System Average Interruption Duration Index
SAIFI – System Average Interruption Frequency Index
SCADA – Supervisory Control and Data Acquisition
VBRP –Value-based reliability planning

2.0 Reliability: Definitions and Measures

For the purposes of our discussion, we define reliability as the consistency with which a utility delivers both the quality and quantity of electricity demanded. Reliability is affected by:

1. An outage or interruption, as defined by IEEE Standard 1366-2012 as "the total loss of electric power on one or more normally energized conductors to one or more customers connected to the distribution portion of the system" (2). In fewer words, an outage occurs when a customer or asset lacks voltage. The IEEE distinguishes three different types of outages events:
    a. A momentary interruption: The brief loss of power delivery to one or more customers caused by the opening and closing operation of an interrupting device;
    b. A sustained interruption: Any interruption not classified as a part of a momentary event. That is, any interruption that lasts more than five minutes; and,
    c. A major event interruption: Any interruption caused by an event that exceeds reasonable design and or operational limits of the electric power system (2-4).
2. Power quality disturbances that do not result in a complete loss of voltage or current. These include sags, swells, transients, noise, flicker, harmonic distortion, and frequency variations (IEEE 2). Large industrial customers are particularly sensitive to and can be a cause of these disruptions. Residential customers are increasingly guarding against power quality issues. For example, many appliances are connected to surge protectors.

Factors that influence reliability include, but are not limited to:

- Major events;
- Planned interruptions;
- Loss of supply;
- Weather conditions and climate;
- Interference by wildlife;
- Vegetation;
- Human interference;
- System design;
- Asset characteristics;
- Size of service territory;
- Restoration practices;
- Inconsistent renewable generation;
- DC loads;
- Air conditioners and system loads;
- Staff efficiency and competency;
- Vegetation and Utility setbacks;
- Population density; and,
- Industrial consumers

2.2 Measurement

The Institute of Electrical and Electronics Engineers defines most of the statistical tools to measure reliability[1] in *IEEE Standard 1366-2012: IEEE Guide for Electric Power Distribution Reliability Indices*. The four most common metrics used are:

1. SAIDI: System average interruption duration index
    - Sum of interruption durations in minutes or hours divided by customers served;
    - "The total duration of interruption for the average customer during a predefined period of time."

[1] Section 2.2 only relates to outages

2. SAIFI: System average interruption frequency index
    - Total interruptions divided by customers served;
    - "How often the average customer experiences a sustained interruption over a predefined period of time.[2]"
3. CAIDI: Customer average interruption duration index
    - The ratio of SAIDI to SAIFI;
    - "Average time required to restore service."
4. $MAIFI_X$: Momentary Average Interruption Frequency Index
    - Total interruptions *under x minutes* divided by customers served;
    - "...the average frequency of momentary interruption events."

These metrics address two components of reliability: maintaining a continuous flow of electricity and quick restoration of power after an interruption.

Other indexes measure interruptions and durations based on customers. Examples include:

- $CEMI_X$: Customers Experiencing Multiple (subscript x) Interruptions
    - "The ratio of individual customers experiencing *x* or more sustained interruptions to the total number of customers served."
- $CELID_X$: Customers Experiencing Long Interruption Durations
    - "The ratio of individual customers that experience interruptions with durations longer than or equal to *x.*"
- CI: Customers Interrupted
    - Total customers interrupted at some point over an interval.
- CHI: Customer Hours Interrupted
    - Total customers interrupted multiplied by the sum of the length of their outages over an interval.

Finally, ENS (Energy Not Supplied) is the estimated amount of energy that would have been delivered had it not been for an interruption. Thus, it depends on both the length of the interruption and the demand of the customer (Kaufmann et. al. 51).

These measures can be normalized for external factors, such as weather. There are two common normalization factors:

- The IEEE-1336 Standard major event day, where SAIDI exceeds a threshold calculated based on five years of historical data using the 2.5β methodology; and,
- A proportion of total customer base interrupted. For instance, Hydro One defines a *force majeure* as an event that interrupts 10 percent of its customers (OEB, *Staff Report - Phase 2* 11-12).

The criteria for what defines a major event varies considerably across jurisdictions (Kaufmann et. al. 42-51). The CEA has definitions for what constitutes a major event that closely relate to

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[2] Quotations indicate IEEE-1366 2012 definitions (4-9).

the 1336 standard (OEB, *Staff Report - Phase 2* 11-13), while much of Europe defines a *force majeure* event on a case-by-case basis (Kaufmann et. al. 52).

Some of these measures can be scaled. For instance, SAIDI and SAIFI can be measured on particular feeders, appropriately named FAIDI and FAIFI. FAIDI and FAIFI can help utilities identify Worst Performing Feeders (WPF) or circuits. Most American regulators require reporting on utilities' worst circuits (Kaufmann et. al. 54-57). Toronto Hydro uses "Feeders Experiencing Sustained Interruptions" (FESI) as a reliability measure. FESI is a frequency index that identifies feeders that exceed a certain number of sustained interruptions during a 12-month rolling period. For example, a FESI-7 feeder is one that has experienced seven outages within a year (Toronto Hydro D1.7.5.2-3).

Since 2000, LDCs must report SAIDI, SAIFI, and CAIDI to the OEB on a monthly basis. The regulator added MAIFI in 2010, but distributors that do not have the capability to measure momentary interruptions are exempt from reporting. LDCs' reports of these appear in the *Yearbook of Distributors* in gross form and net interruptions of supply form (OEB, *Staff Report* 4-5). The new Scorecard will use SAIDI and SAIFI as measures of system reliability and operational effectiveness (OEB, *Report of the Board* 22)

3.0 Ontario and the World: Reliability Standards and Measurement

3.1 International Practices

In a monopoly, the regulator stands in place of an efficient market, seeking to balance dependability with cost. Electricity regulators have three options to regulate system reliability:

1. Reporting: requiring utility report on their metrics; intervention occurs on an *ad hoc* basis;
2. Targets: Goals are set. Action plans are implemented if targets are missed; and,
3. Incentives/performance based regulation (PBR): penalizing and/or rewarding utilities on performance. Incentives can be symmetric (penalties and rewards) or asymmetric (penalties only). Incentives can affect regulated return-on-investment, or one-time payouts/fees (Hesmondhalgh, Zarakas & Brown 9; Kaufmann et. al. 30-32).

Worldwide, monitoring and incentives are more common than targeting. In the United States, 16 states use PBR, 11 set targets, 12 require reports only, while 12 states have no reporting requirements. Regulators evaluate utilities against a measure of their past performance controlled for variability, such as five-year averages for SAIFI and SAIDI. Industry-based benchmarks are rare worldwide; regulators recognize the different environments in which utilities operate (Kaufmann and Rebane 8; Kaufmann et. al. 37-38, 60).

3.2 Ontario: Current Standards and the OEB Group

In their report to the OEB, Pacific Economics observed:

> “Electricity distributors in Ontario currently report two system-wide reliability indices to the Board: the system average interruption frequency index (“SAIFI”) and the system average interruption duration index (“SAIDI”)... However, the targets for acceptable SAIFI and SAIDI performance have not been clearly defined. Distributors are expected to maintain a three-year moving average of their system reliability performance within historical levels, but reported performance is not compared against explicit SAIFI or SAIDI benchmarks” (Kaufmann and Rebane 1).

The Ontario practice can be characterized as reporting-based. In 2008, the Ontario Energy Board issued a notice of proposal to move to a reliability standard regime. In March 2011, staff recommended:

- Establishing a reliability standards regime “once issues relating to the quality and consistency of system reliability data have been resolved”;
- The use of IEEE Standard 1366 to exclude major event days;
- Excluding outages within distributor control from measures;
- Exploring customer centric measures, such as CEMI and CELDI; and,
- Considering worst performing circuit measures (OEB, *Staff Report* 12, 14-16).

The recommendation on establishing a reliability standard was contrary to the beliefs of the majority of stakeholders (OEB, *Staff Report* 12). In making the recommendation, staff noted:

> “… Staff does not agree that system reliability performance should be the exclusive purview of rates proceedings. Staff notes, in this regard, that the manner in which a distributor manages its system reliability performance has been a topic of review in rates proceedings, especially in terms of the review of asset management plans and capital budgets, and staff expects this to continue to be the case. Staff also expects that the establishment of a formal reliability regime, with consistent and comparable performance data from year to year, will assist the Board in making judgments as to whether a distributor’s capital expenditure for reliability purposes is reasonable and justifiable.”
>
> “The codification of system reliability standards will ensure that distributors maintain an appropriate focus on service quality and on areas where capital investment and improved asset management are most needed. It would also address stakeholder concerns over what they in some cases perceive to be diminishing reliability. In addition, mandatory system reliability standards could alleviate the concern of some stakeholders that incentive regulation provides opportunities to maximize profit at the expense of customer service” (OEB, *Staff Report* 12-13).

A few months later, the board invited parties to comment and join the Reliability Data Working Group. In the second phase of the process, the OEB explored issues surrounding the data used to form future standards. Accordingly, a second 2013 OEB staff report proposed to:

- Amend the definitions of SAIDI, SAIFI and CAIDI and "interruption" to match the wording used by the CEA and IEEE Standard 1366.
- Retain the definition of the "start" of an outage as when the LDC determines an outage has occurred, either through a customer call or AMI;
- Adopt an IEEE-like definition of "customer:" an active account with metered service;
- Continue to require MAIFI statistics from LDCs that have the ability to report them;
- Formalize normalization thresholds. Three criteria would qualify for normalization:
    - Loss of supply and outages related to equipment controlled by a third party;
    - Events out of a distributor's control:
        - Extreme weather as indicated by an Environment Canada Watch or Warning;
        - Foreign interference; (e.g. tampering, vandalism)
    - Planned or scheduled outages where the customer has been notified in advance;
- That the causes of outages become a reporting requirement;
- Introduce a measure that would focus on the worst performing *segment* of a *circuit* between switches/isolators. LDCs would report SAIDI metrics for the worst five percent of segments each year, and how often that circuit was within the worst five percent over five years (OEB, *Staff Report - Phase 2* 8, 15-16, 19, 25).

On September 18, 2013, the OEB announced it was reconvening the Working Group to finalize performance standards for SAIDI and SAIFI, and develop customer-centric measures (e.g. CEMI), and momentary outage metrics (e.g. MAIFI).

4.0 Ontario's Reliability Performance

4.1 Ontario's versus Canada's Performance[3]

The next series of charts follow the performance by Ontario's LDCs versus the CEA distribution average[4]. Although Ontario is improving, it lags behind the rest of Canada on both SAIDI and SAIFI measures.

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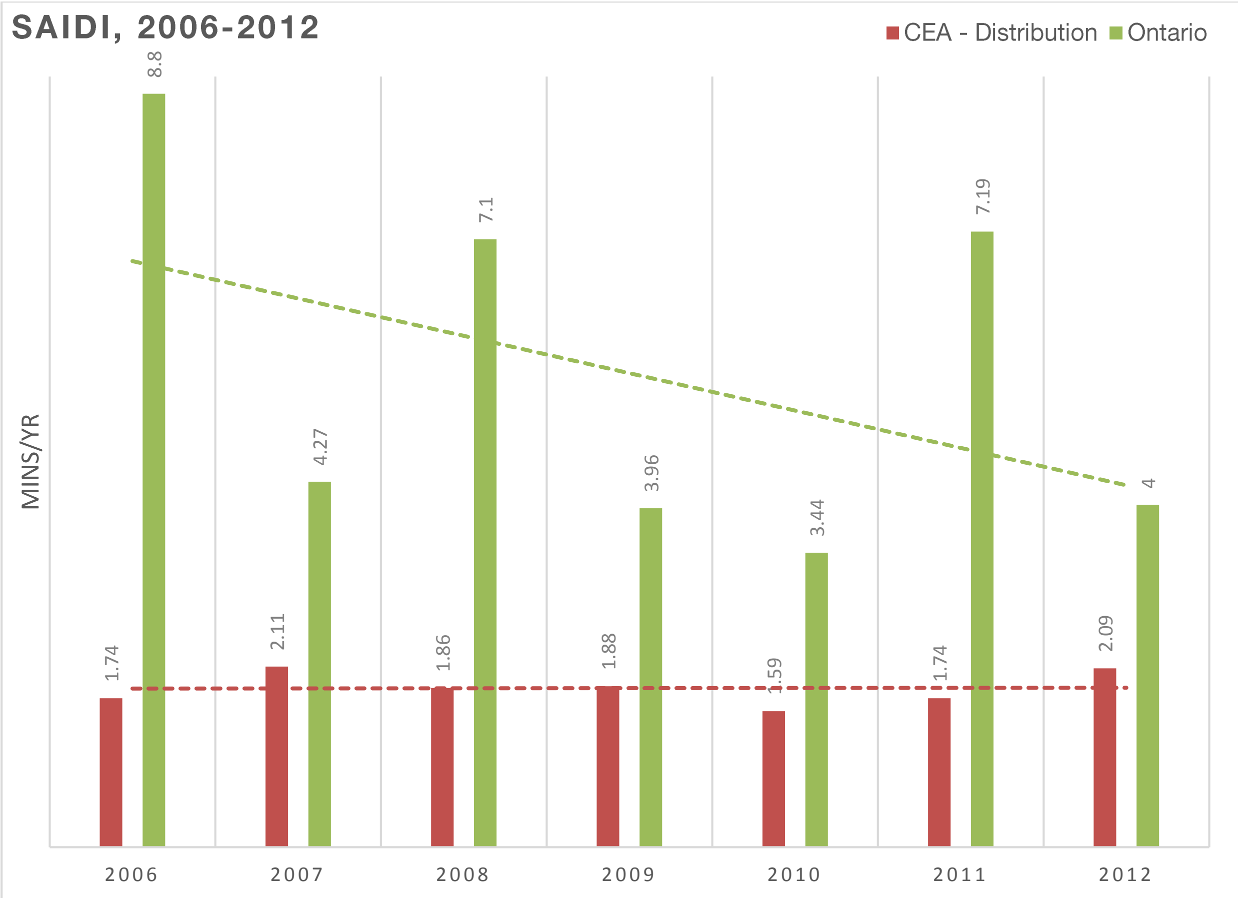
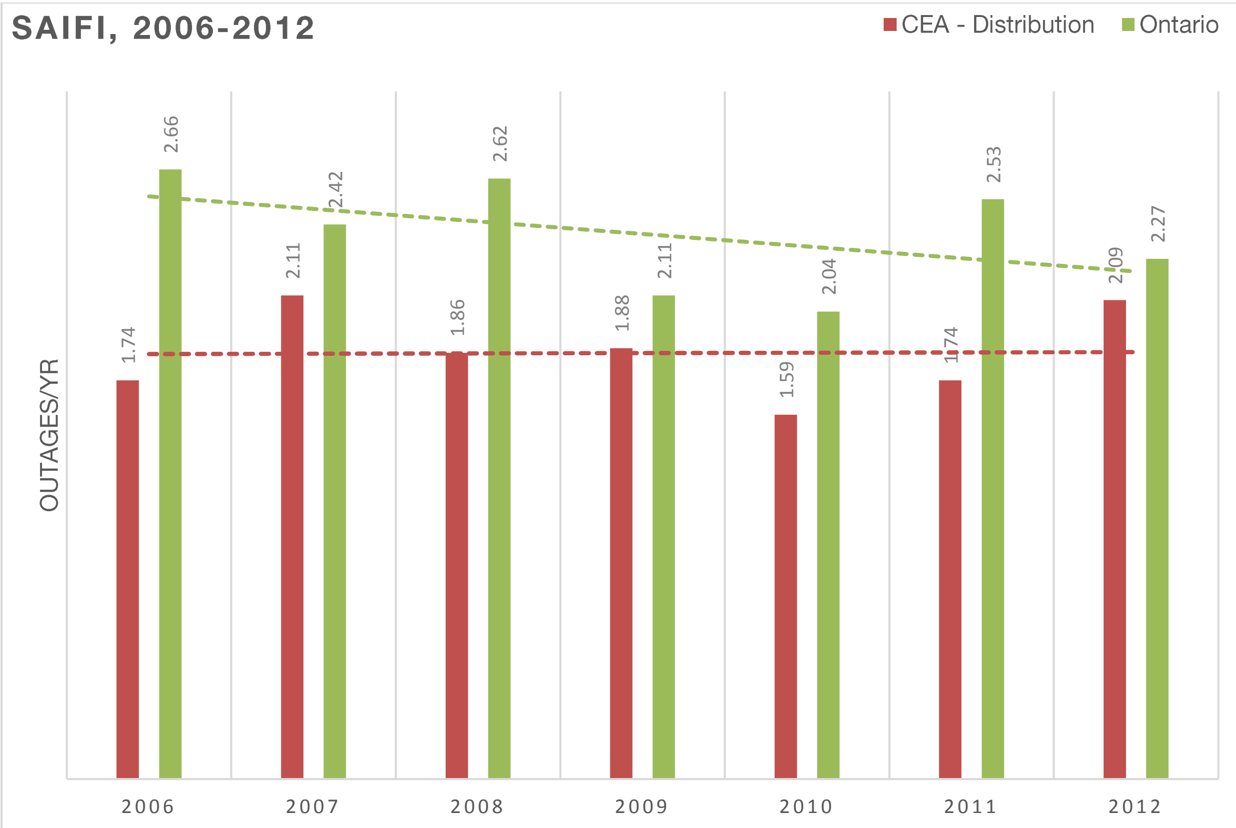
[3] We cannot stress enough that these comparisons do not imply causation or the "effectiveness" of a utility. Please see our roundtable discussion paper, where our participants conclude that these comparisons are a measure of continuous improvement *within* a utility.

[4] Ontario data from the Ontario Energy Board's *Yearbook of Electricity Distributors*, 2006-2012. Canada data from (BC Hydro, *F2013 Annual Reporting of Reliability Indices* 2).


SAIDI, 2006-2012
CEA - Distribution
Ontario
MINS/YR
8.8
1.74
4.27
2.11
7.1
1.86
3.96
1.88
3.44
1.59
7.19
1.74
4
2.09
2006
2007
2008
2009
2010
2011
2012


SAIFI, 2006-2012
CEA - Distribution
Ontario
OUTAGES/YR
1.74
2.66
2.11
2.42
1.86
2.62
1.88
2.11
1.59
2.04
1.74
2.53
2.09
2.27
2006
2007
2008
2009
2010
2011
2012


CAIDI, 2006-2012
CEA - Distribution
Ontario
MINS/YR
2.49
3.31
3.49
1.77
2.66
2.71
3.01
1.87
2.28
1.69
2.67
2.84
2.68
1.76
2006
2007
2008
2009
2010
2011
2012

4.2 Ontario versus International Performance

Compared to selected international jurisdictions, Ontario's reliability appears to be worse than most[5].

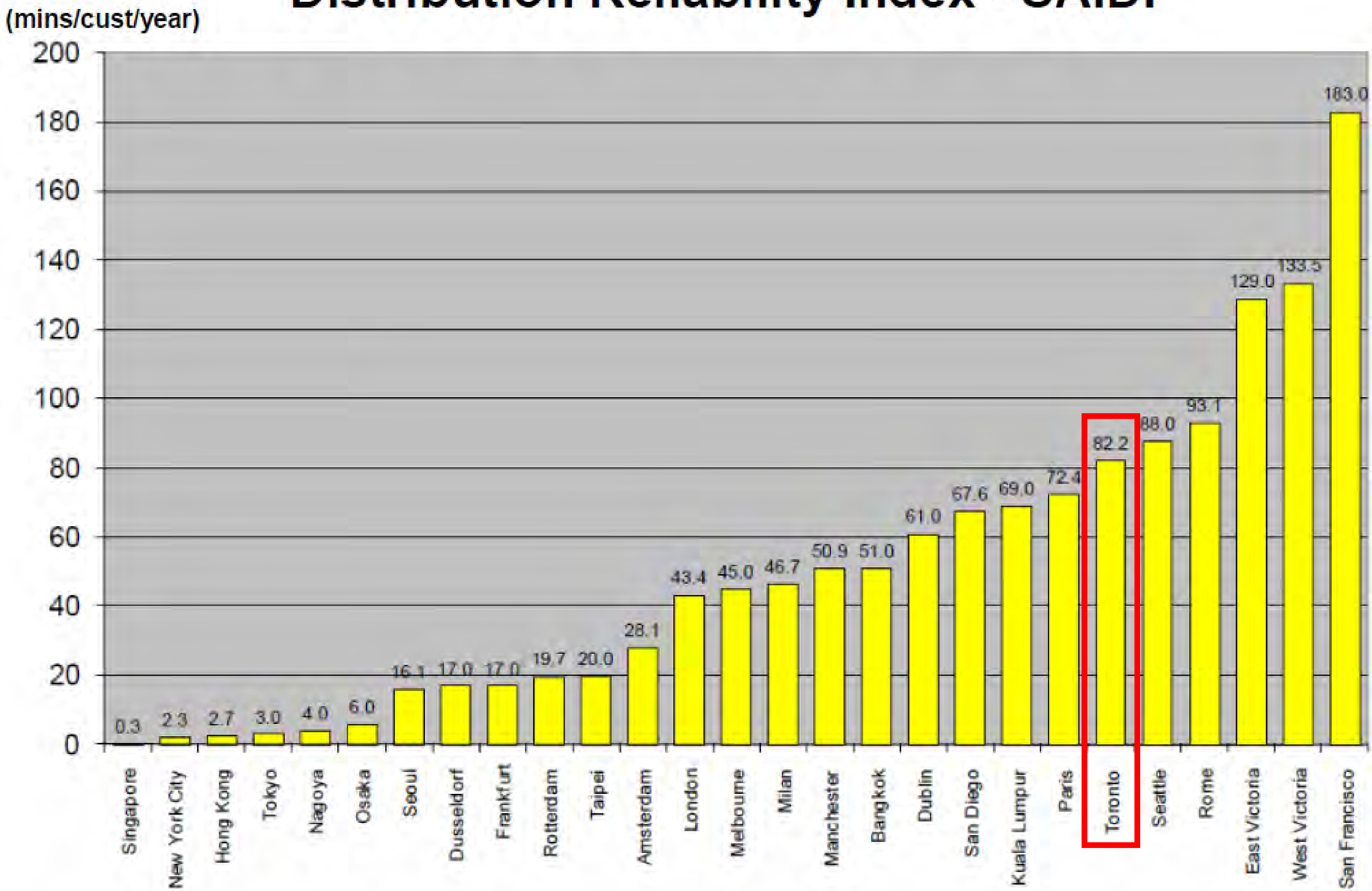
Unplanned SAIDI, inclusive, LV Networks (mins)								
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**Average**
New York State			270	129.6	321	574.8	1362	**531.48**
Ontario	528	256.2	426	237.6	206.4	431.4	240	**332.23**
Canada	259.8	441	296.4	339	217.8	279	335.4	**309.77**
California (Pacific Gas and Electric)	280.5	159.9	416.4	208.2	246.3	275.7	138.9	**246.56**
Portugal	243.19	136	162.67	280.03	276.04	131.43	94.15	**189.07**
Sweden	100	321.9	110.8	73.3	92.3	186.46	89.01	**139.11**
Hungary	127.7	141	111	125	132.59	85.12	76.89	**114.19**
Italy	60.55	57.89	89.64	78.67	88.84	107.96	132.73	**88.04**
France	86.3	61.6	74.1	173.8	95.1	53.9	62.9	**86.81**
UK	69.16	100.1	81.94	75.69	81.42	70.02	68.05	**78.05**
Netherlands	35.6	33.1	22.1	26.5	33.7	23.4	27	**28.77**
Germany	23.25	35.67	16.96	15.29	20.01	17.25	17.37	**20.83**

Unplanned SAIFI inclusive, LV Networks (mins)								
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**Average**
Portugal	3.81	2.62	2.8	3.63	4.32	2.41	1.88	**3.07**
Ontario	2.66	2.42	2.62	2.11	2.04	2.53	2.27	**2.38**
Italy	2.29	2.16	2.38	2.36	2.27	2.08	2.33	**2.27**
Canada	1.74	2.11	1.86	1.88	1.59	1.74	2.09	**1.86**
Hungary	1.79	1.92	1.62	1.69	1.63	1.26	1.17	**1.58**
Sweden	1.28	1.7	1.38	1.32	2.052	1.63	1.33	**1.53**
California (Pacific Gas and Electric)	1.73	1.25	1.56	1.31	1.38	1.26	1.12	**1.37**
France	1.33	0.98	1.18	1.1	0.98	0.92	0.9	**1.06**
New York			0.94	0.67	0.84	1.1	1.03	**0.92**
UK	0.74	0.88	0.77	0.73	0.72	0.69	0.65	**0.74**
Netherlands	0.45	0.33	0.31	0.33	0.38	0.34	0.32	**0.35**
Germany	0.46	0.43	0.33	0.28	0.32	0.34	0.29	**0.35**

Cities are economic drivers. Accordingly, there is value in looking at Toronto's comparative performance. In 2010, Singapore compiled a city-to-city comparison of SAIDI and SAIFI values, included in the next two pages. Toronto's performance is worse than most cities included in the study.

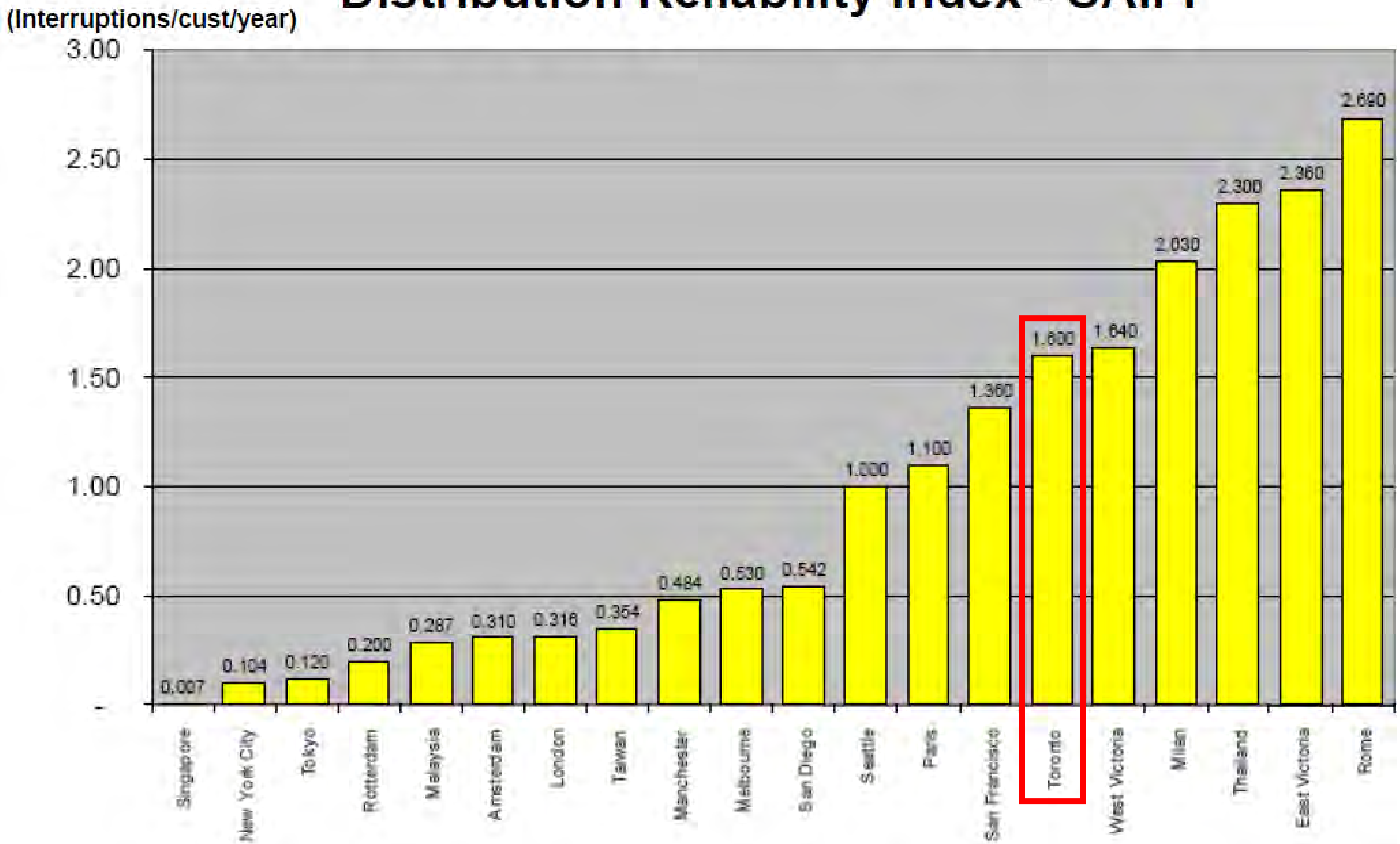
[5] European data from (CEER *5.1* 17-22). New York State Data from (New York State 36-39). PG&E data from (Pacific Gas and Electric Company 1).

Distribution Reliability Index - SAIDI



Source: Singapore Power, 11

Distribution Reliability Index - SAIFI



Source: Singapore Power, 13

The data demonstrates that nations such as Germany, the Netherlands, Japan, and Singapore have very reliable distribution networks in selected cities. Singapore's grid is worth noting for its vast improvement: SAIDI in that city-state fell from 33.1 in 1991/1992 to 0.3 in 2009/2010. These improvements are attributable to the implementation of SCADA, a closed-ring network, condition monitoring, and condition-based maintenance (Singapore Power 10, 35).

It is important to note that these charts were created for commercial promotion and measure the city against a non-random selection of cities. Some cities appearing in one chart do not appear in the other. Comparisons between Toronto and other jurisdictions do not account for different densities and territory sizes in other areas. Indeed, Rouse and Kelly suggest that these indices should reflect an area with similar levels of density; that urban, suburban, and rural customers have "customer expectations, customer densities and threats" and should be considered uniquely (23).

Common to all four case studies are high rates of undergrounding, at or above 70% of their distribution networks. Singapore's distribution system is approximately 99% buried. Both reliability and undergrounding are highly correlated to density (CEER *5.0* 34, 37-39). Singapore and Tokyo are amongst the most highly urbanized areas in the world, while Germany and the Netherlands are among the most densely populated nations in Europe. None of these case studies represent a jurisdiction with significant rural territory or low density areas like Ontario.

The four states in question face different geographical and climatological challenges. Japan and Singapore invest heavily in utility tunnels and cable vaults since both are island nations, while Japan is prone to earthquakes. The Netherlands is almost completely below sea level and is susceptible to mass flooding. Finally, most of Germany's electrical infrastructure was destroyed by 1945, while Ontario has been building continuously since the early 20th century.

4.3 Ontario Customers' Perception of Reliability

Sundaram et. al. conclude that averages such as SAIDI and SAIFI are not normally distributed, and as such, the median level of reliability – what half of customers perceive – is not well represented by these mean-centric measures (2-7). In any event, LDCs require a deeper understanding of the customer's perception of reliability to make informed investments and to predict consumer decisions in the future.

A survey performed for the OEB in 2010 found that and 92% of businesses and just less than nine out of ten residential customers were satisfied with their level of reliability. Electricity costs were the highest priority of 30% of residential and 40% of commercial customers, while less than 10% in both categories were most concerned with the dependability of their distributor. When outages did occur, homeowners and businesses alike were less satisfied with their customer service experience than the time it took to restore power. Over half of residential customers and 84% of businesses are unwilling to pay more for increased reliability. Further, over half of both groups would not pay less for decreased reliability (Pollara *Business Component* 6, 11, 16-17, 19; Pollara *Consumer Component* 6, 11, 15, 21-22). In short, the Pollara findings suggest that Ontarians desire to maintain their current level of reliability.

In interpreting these results, the Pacific Group warns:

> "…it is often found that respondents react most strongly to recent events that have affected their perception of utility performance. For example, a recent storm that resulted in a significant number of outages will typically have a negative impact on the reliability score. Similarly, a recent rate increase will negatively impact the price score. These movements tend to be temporary, unless reinforced by an ongoing series of events" (Kaufmann et. al. 18)

5.0 Looking Forward

Increases in the number or duration of interruptions enlarge the economic losses for those affected, LDCs included. A perceived lack of reliability may drive customers to seek contingencies, like homeowners purchasing uninterrupted power supply devices for their computers. Poor reliability may expedite the growth of distributed generation (DG). This would cause decreasing delivery revenue for LDCs that already face declining intensity. Since the majority of interruptions occur within the distribution network, and since LDCs are the point of contact for the customers, they bear the majority of the blame when the power does go out. Unreliable electricity supply could contribute to manufacturing facilities relocating elsewhere and dissuade new businesses from choosing to establish operations in Ontario. Accordingly, a reliable system is of great importance to the wellbeing of Ontario's LDCs.

5.1 Distribution Assets

International practice demonstrates a strong correlation between dependability and the degree of undergrounding. Yet, underground networks are far more costly than overhead wires, and outages in undergrounded grids can be much more difficult and take longer to resolve. Undergrounding is also much more common in densely populated locations.

The assets between the wires also matter. LDCs incorporate devices such as automatic reclosers, fuses, circuit breakers, and switches to prevent damage to their assets and minimize the scope of interruptions by sectionalizing. System reliability to a degree is a function of the number of and location of sectionalizers.

When automatic sectionalizers are combined with SCADA data, LDCs can provide a fault location, isolation, and service restoration service (FLISR). FLISR systems are able to reroute power and isolate outages to minimize those customers affected to only a few. Broad implementation of FLISR is colloquially known as the "self-healing grid." Centralized switching and instant telemetry to the control room will allow operators to quickly and effectively isolate outages to fewer and fewer customers, and pinpoint outage causes for repair crews. Burlington Hydro realized a 40% increase in reliability with the introduction of a self-healing grid in their downtown core. EPB of Chattanooga, Tennessee added an additional 200 smart switches to the already 1200 on their system, realizing a reliability increase of 60% and saving the community up to $60 million in losses (14).

As distributed generation and renewables continue to be connected, power quality and load will become much more variable. As such, using SCADA systems to provide a dynamic rating regime for LDC assets may prove to increase efficiency and reliability. With the introduction of telemetry, an understanding of the geography around the asset, plus ambient temperature feedback, control room operators will soon be able to adjust the rating of a particular asset based on prevailing conditions. A case study in New Zealand demonstrated that transformers could be operated to at least 150% of their rating, thus maximizing the capacity and using the full potential value of the asset (Jalal, Rashid, & van Vliet 3). Dynamic rating also provides operators another tool to route electricity though the safest and most reliable routes during periods of system stress.

Distributed generation is already challenging the traditional asset paradigm of wires and boxes. Several studies confirm that distributors are having success with installing DG on part of their systems that are near capacity or towards the end of long feeders (Gil & Joos 1599). This allows for deferred replacement of wires and transformers. As DG becomes more portable with microgeneration and batteries – and more cost-effective at all sizes – investment in storage and load management might be the most appropriate way to maintain or seek greater reliability. We have discussed a scenario where DG is incorporated *en masse*, micro-grid networks become commonplace, and LDCs are relegated to a backup role. In this case, LDCs may decide only to invest in wires that connect these islands together for redundancy and limited infrastructure to provide backup connection to the transmission network.

5.2 Distribution Planning

The design of the distribution network is the primary determinant of the extent of outages when they occur. Most networks are radial, where customers consume electricity from a feeder, coming from one source of electricity. A loop can have one or multiple sources of electricity and allows flow in either direction. Utilities can isolate a failure along a loop system by feeding customers from different directions or sources. Finally, a network or grid structure is a series of interconnected loops. With multiple supply connections, outages affect fewer customers, as most can rely on different "paths" for their electricity. A hybrid design is possible: for instance, radials running from a main loop, or like downtown Toronto, a radial system backed up by a grid-like secondary network. To improve reliability, LDCs can move from radial towards network design (Settembrini, Fisher, & Hudak N.E 704-708).

Reliability is a basic design criterion in distribution system planning for LDCs. Historically, utilities have focused on minimizing the probability of outages and the time required to restore power after balancing economic constraints, design structure, and procurement options. They did so indirectly through contingency-coverage planning, which is engineered in such a way that the system can operate after a set number of failures (EPRI 6-1). This planning is much more common in the transmission sector, commonly known as N-X planning.

Beyond contingency planning, a reliability-index approach dictates a benchmark – such as a SAIDI and SAIFI – as a planning constraint. System design is conducted to meet those targets. As such, it inherently considers the customer by explicitly incorporating reliability into their consideration. The number of contingencies built into the system is dictated by the desired robustness of the system, not vice versa (EPRI 6-1).

Much like time-based maintenance informing preventative-based maintenance, utilities use historical reliability data on assets and feeders to inform predictive analysis. Predictive analysis uses this data as inputs into a simulation. Planners run numerous simulations, adjusting external factors such as ambient temperature and loading to predict the weak points within a system. LDCs then determine the impact of each failure event on a distribution component and the frequency at which such an event is likely to occur, using the results from numerous simulations. The results can help LDCs rank investment priorities as part of their asset management process. Predictive analysis is a new planning discipline that is increasingly adopted by utilities (EPRI (6-)2-3, (9-)1-3, 5-14).

Predictive analysis will become more difficult in the future. Although utilities have some lead time when a new subdivision or condo is constructed, they have little time to react to consumer decisions. It is very hard to predict, for instance, when and where consumers will purchase electric cars and chargers, which can add the equivalent to the load of a house on a feeder. Solar PV is another consumer decision that is difficult to gauge in the long-term.

Grid design can be further optimized by considering the socioeconomic context of the grid and the costs associated with reliability within an area using value-based reliability planning (VBRP). The optimal level of reliability is reached when network design minimizes the sum of both the costs to the utility for infrastructure and the costs of unreliable service to the customer at that level (Sullivan and Schellenberg 7-9).

For instance, it is likely that an outage in the downtown core of Toronto is more costly to society than an outage in suburban North York. Such a design would optimize the value of the grid at the macro level. It does, however, present some challenges:

1. It requires economic study to determine customer interruption costs. Is it the case that an outage in downtown Toronto is more costly to society than an outage in North York?
2. It requires a understanding and ability to predict the indirect costs of a failure;
3. It requires, to an extent, arbitrary boundaries around which locales require greater reliability. Where does the financial district stop?

5.3 Customer Interruption Costs

The most recent academic calculation of customer interruption costs is found in Sullivan, Mercurio, and Schellenberg 2009. The following reproduced chart provides the results of their econometric model in determining customer interruption costs during summer peak (xxi):

Table ES- 1. Estimated Average Electric Customer Interruption Costs US 2008$ by Customer Type and Duration (Summer Weekday Afternoon)					
Interruption Cost	Momentary	½ hour	1 hour	4 hours	8 hours
Medium and Large C&I					
Cost Per Event	$11,756	$15,709	$20,360	$59,188	$93,890
Cost Per Average kW	$14.40	$19.30	$25.00	$72.60	$115.20
Cost Per Un-served kWh	$173.10	$38.50	$25.00	$18.20	$14.40
Cost Per Annual kWh	$0.002	$0.002	$0.003	$0.008	$0.013
Small C&I					
Cost Per Event	$439	$610	$818	$2,696	$4,768
Cost Per Average kW	$200.10	$278.10	$373.10	$1,229.20	$2,173.80
Cost Per Un-served kWh	$2,401.00	$556.30	$373.10	$307.30	$271.70
Cost Per Annual kWh	$0.023	$0.032	$0.043	$0.140	$0.248
Residential					
Cost Per Event	$2.70	$3.30	$3.90	$7.80	$10.70
Cost Per Average kW	$1.80	$2.20	$2.60	$5.10	$7.10
Cost Per Un-served kWh	$21.60	$4.40	$2.60	$1.30	$0.90
Cost Per Annual kWh	$0.0002	$0.0002	$0.0003	$0.0006	$0.0008

This data is dated, particularly considering the increasing use of both the Internet and the home as an office. Thus, the costs for residential customers appear to be understated.

There are a number of tools available for utilities that seek to understand their customer interruption costs. In their study of VBRP, Schellenberg and Sullivan put forth several methodologies to quantify these costs, including:

- Macroeconomic indicators;
- Customer surveys;
- Case studies;
- Market-based methods; and,
- Rule-of-thumb methods using previous studies (12-13).

They advocate “generally accepted survey practices” in Sullivan and Keane’s 1995 Guidebook, a seven-step process to best understand the costs to an LDC’s customer base (4.1).

A function for interruption costs (C) is[6]:

$$C_i = DC(L) + IC_i(L)$$

[6] Our calculations and functions is based in part on (BC Hydro, *Power Quality Customer Financial Impact/Risk Assessment Tool*, 5-7).

Where cost to customer *i* is a function of the length *L* of an outage, and a customer's cost profile, *f* (C_i(L)), and their share of societal indirect costs, IC_i(L), that are both functions of length. The cost profile varies from customer to customer. For instance, the cost of an outage of any given length is likely different between a commuter, a factory, and a person who runs a business from home. Indirect costs are harder to capture. For instance, a traffic light outage may not have a direct cost to a consumer but has indirect costs, such as the opportunity cost of time stuck in traffic. Costs borne by others may also add to the cost borne by the individual. For instance, outages may encourage public demand for greater reliability, which in turn may raise an individual's rates.

The average cost to a customer over a time period can be found by using existing benchmarks that can be refined to the LDC, community, even feeder level. This average cost of downtime over a given time period for customer *i*:

$$\overline{C_i} = (SAIFI_i) \times f[DC_i(SAIDI_i)] + IC_i(SAIDI_i)$$

To find the true economic impact of the average outage time per year, we need to determine the average number of outages and the direct and indirect cost profiles at their average length. General cost profiles can be determined for customer classes, allowing the regulator to set different targets for large to small electricity consumers.

5.4 Power Quality

New technology is creating new challenges and opportunities for LDCs. DG will provide more sources of electricity, while batteries will provide power contingency and regulation. Yet, DG, incorporation of renewables, and increasing DC loads will likely create more concerns about power quality. If the EV is widely adopted, increased imbalances can be expected. Even many of the electronics used by the smart grid for monitoring are sensitive to power quality issues.

Voltage management technology is beginning to enter the distribution system beyond its traditional presence only at the substation level. These devices can help improve power quality across the network. They also open the door to voltage conservation that can be scaled down to the meter level. By operating parts of the system at lower voltages when feasible, voltage management can make networks more efficient and reliable. Utilities have used Volt/Var optimization for years for power factor correction in large, industrial users; implementation at the distributor can help power quality while reducing load losses by two to five percent (NEMA 1). That said, LDCs must be careful in implementing this technology: a lower starting voltage can leave an area susceptible to damaging voltages from a contingency, while it also will impede the IESO's ability to implement wide area voltage reduction during an emergency.

LDCs are required by the system code to "…maintain a voltage variance standard in accordance with the standards of the Canadian Standards Association CAN3-235. A distributor shall practice reasonable diligence in maintaining voltage levels, but is not responsible for variations in voltage from external forces, such as operating contingencies, exceptionally high loads and low voltage supply from the transmitter or host distributor" (OEB, *Distribution System Code* 71). In controlling harmonics, they are to "use appropriate industry standards and good utility practice as guidelines" (OEB, *Distribution System Code* 71). Ultimately, it is the source of any power quality problem that is responsible for rectifying the situation. Further, those connecting to the grid must meet additional standards at the point of interconnection. Nevertheless, LDCs concerned with liability and reliability install redundant power quality regulation devices, even though owners of DG may have sufficient measures in place. Consideration should be given to efficiently allocating the onus of ensuring power quality as non-conventional loads continue to connect.

As more customers become sensitive to power quality, LDCs could expand the practice to allow customers to pay for greater reliability and power quality. In both the United States and Europe, firms can sign contracts to ensure a high level of power quality to their facilities. Rouse and Kelly found that "this arrangement was found to be an efficient way to increase power quality without adding costs on the general tariffs (24)."

5.5 Regulation and Governance

There are a number of indexes available to measure reliability. Any use of comparators should reflect the nature of our province: it is large, experiences varying weather, and contains significant urban centres as well as millions of kilometres of rural territory. Simply, comparing SAIFI between Hydro One and Ottawa Hydro is not appropriate. The OEB recognizes this, stating "…the Board is of the view that the reliability data reported to the Board does not provide a true representation of a distributor's performance" (OEB *Staff Report* 5).

Pacific Economics suggested that the OEB use "…distributor-specific benchmarks for SAIFI and SAIDI based on the distributor's historical average values for the respective indicators;" in recognition of the different environments in which our LDCs operate (Kaufmann & Rebane 2). As standards are set, the OEB could choose a continuous-improvement model: that LDCs must meet or beat their historical SAIFI and SAIDI levels. That said, history may not be a good indicator of the reliability that will be needed in the future. Another option is to set a target, a SAIDI and SAIFI level that an LDC should meet to reach the desired level of reliability into the future. This would require significant study to determine what levels of reliability each LDC should reach. Either approach can lead to sub-optimal investment if the target or benchmark does not reflect the level of reliability required and/or desired by Ontarians.

The introduction of performance based regulation would fit well into the Board's performance-based approach. Distributors could be allocated targets and financial repercussions according to their size and operating environment. If penalties affected return on investment, utility owners may be convinced to invest more into their LDCs to maintain reliability, and thus their returns. Designing such a system would be difficult: although it would arguably infuse greater private sector discipline into natural monopolies, the regime would have to be constructed in such a way to ensure that costs are not borne by the consumer.

Digitalization and use of computers means that even momentary power interruptions can lead to significant economic losses. In 2004, LaCommare and Eto found that two-thirds of the total cost of interruptions in the United States are attributable to momentary outages (27). The OEB should continue to require MAIFI or another measure that tracks momentary outages, and emphasis on this measure should be increased (Rouse and Kelly 22). As Ontario continues to implement the smart grid, the OEB may consider setting a mandatory date for LDCs to have the capability to measure momentary outages. Advances in SCADA and monitoring technologies will increase the frequency of normally unreported outages – like MAIFI events – within the first years of implementation. After a few years, however, Ontarians should have a perspective on the rate of momentary outages in their service territory.

Further, as non-traditional loads continue to connect, OEB may consider encouraging the monitoring and implementation of power quality metrics, such as voltage swells or harmonics. In the event of widespread adoption of the micro-grid, the government and the OEB may extend service benchmarks to operators of those systems. Here, the LDC can play a role in measuring the reliability and quality of a micro-grid. Public benchmarking of micro-grids would allow consumers to compare performance across communities and provide more information about the value of a condominium or home.

Finally, efficient grid design addresses the socioeconomic context by ensuring greater reliability to those who require it more, value it more, or will cause the greatest economic impact during an outage. Moving towards such a model will require that the regulator and the government recognize that some customers are more valuable to the economy and society than others. Providing different levels of service to ratepayers would be difficult to justify, particularly if they pay the same rates.

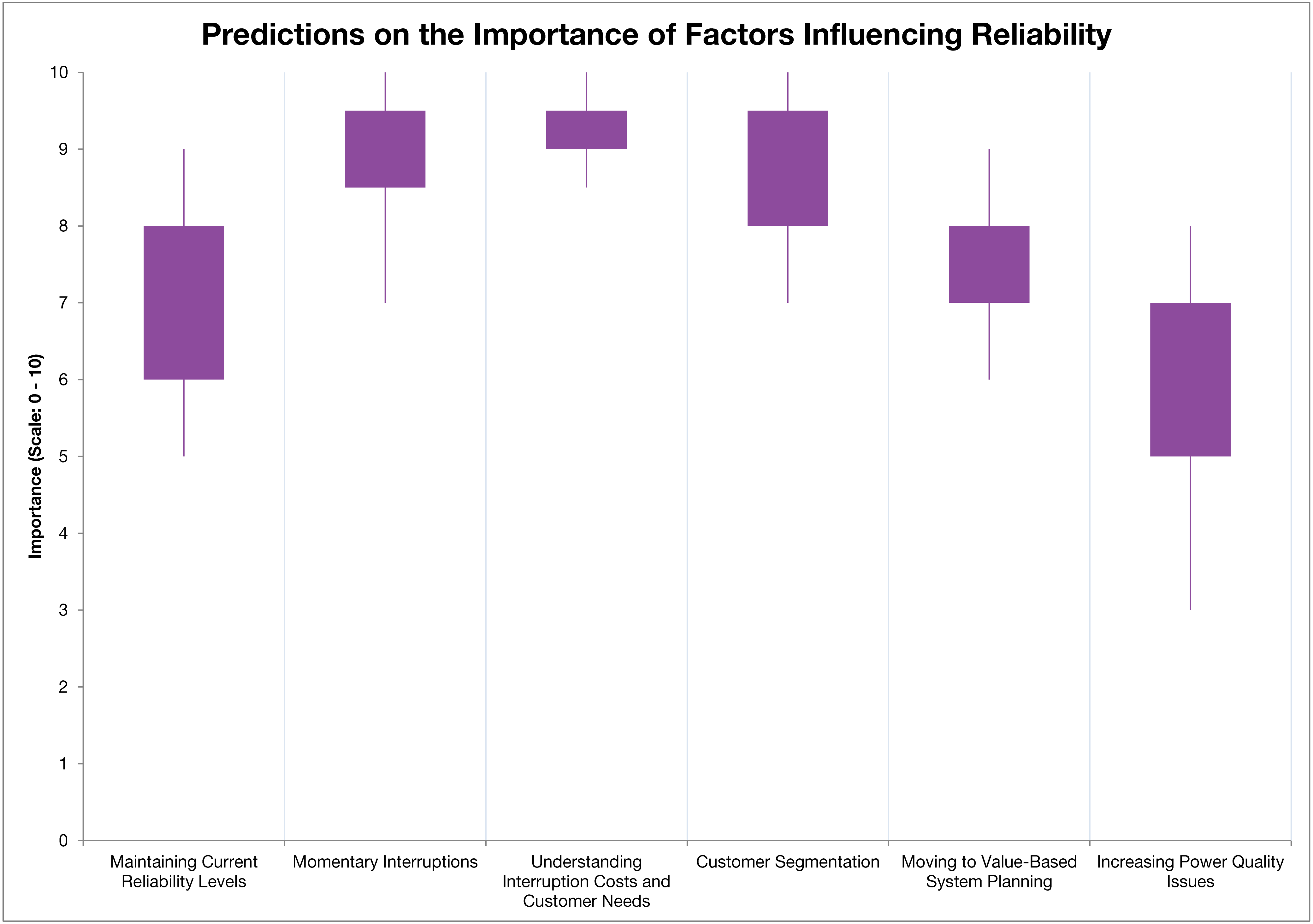
The Future of the Distribution Sector: Reliability

Visual:

An analysis of the relative importance of factors relating to the provision of reliability into the future. Projected importance is ranked from one to ten on the vertical axis. Each topic on the horizontal axis includes a “bar and line.” The line represents the possible range of the topic’s importance, while the bar represents our predicted importance.

Observations

- Many of the issues discussed in previous papers are threats to reliability, including weather, increasing urbanization, vegetation, and asset demographics;
- Asset renewal, smart grid, DG, and micro-grids will likely increase reliability;
- LDCs have a number of indices to accurately measure reliability, but:
  - These indices measure past performance, not current conditions; and,
  - Network-wide statistics can be misleading, particularly considering differing geography and density;
- Recording, reporting, and addressing momentary outages is becoming more important as they have a greater effect on customers. Currently, only those LDCs with the capabilities to report on momentary interruptions are obligated to do so;
- The OEB requires LDCs to only report on these statistics, although they are currently developing a reliability target regime.
- Distribution reliability indices are important as they provide a measure to gauge improvement at the LDC level. These are local measures. Comparing indices between jurisdictions will lead to invalid conclusions: factors such as climate, grid age, system design, rate base, population density, investment decisions, and geography are unique to every distribution network;
- Today, Ontarians are price sensitive, but generally satisfied with the level of their reliability;
- System planning is evolving from a redundancy basis to reliability-index planning, targeting a specific reliability metric;
- We expect more value-based reliability planning, where systems are designed with greater reliability in important socio-economic areas;
- To facilitate this new planning paradigm, LDCs need a greater understanding of the direct and indirect interruption costs to individual customers and to society more broadly;
- Value-based planning leads to the segmentation of the customer base: homes and businesses can pay different rates for different levels of reliability. Moving to rate segmentation would be difficult to communicate to customers;
- Increasing DC loads from electronics is degrading overall power quality on LDC networks; and,
- The private or “unregulated” power services sectors may provide the most efficient way to address the reliability needs of customers through protection devices, solar panels, small storage; There is no Canadian standard on power quality, nor do LDCs report on power quality.


Predictions on the Importance of Factors Influencing Reliability
Importance (Scale: 0 - 10)
10
9
8
7
6
5
4
3
2
1
0
Maintaining Current Reliability Levels
Momentary Interruptions
Understanding Interruption Costs and Customer Needs
Customer Segmentation
Moving to Value-Based System Planning
Increasing Power Quality Issues

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