EB-2012-0064

Ontario Energy Board

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 **TORONTO HYDRO ELECTRIC SYSTEM LIMITED** for an order approving just and reasonable rates and other charges for electricity distribution to be effective June 1, 2012, May 1, 2013 and May 1, 2014.

ENERGY PROBE RESEARCH FOUNDATION
("ENERGY PROBE")
CROSS-EXAMINATION COMPENDIUM

PANEL 2A

Distribution Design Standards

Independent Survey and Review

Prepared for:

Toronto Hydro Electric System, Limited

Navigant Consulting, Inc.
333 Bay Street
Suite 1250
Toronto, ON M5H 2R2

www.navigantconsulting.com

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Overview

Background and Scope

Navigant ("NCI") was retained by Toronto Hydro Electric System, Limited ("THESL") to compare its design practices and equipment component standards for its electricity distribution system to those of other similar utilities, both within and outside the province of Ontario. Specifically, THESL seeks to determine:

- How its practices compare to other Ontario utilities and those in other provinces or in the United States
- Differences in design practices, standards, and materials, including potential costs and benefits of these differences
- Where differences exist, are they justified given the unique characteristics of Toronto and THESL

This summary report presents Navigant's independent assessment of THESL practices versus those of other utilities with similar service territories. Our findings reflect our judgment and experience gained from our knowledge of extensive reviews conducted in Ontario, other provinces, and the United States; supplemented by a formal survey completed by a select number of comparable utilities.

Work Plan and Approach

Navigant conducted the following tasks to assess THESL's distribution design practices and a selection of major components to other similar utilities.

1. ***Select THESL Overhead & Underground Design Standards for Review***

   Navigant met with THESL engineering and design staff to discuss and identify key overhead and underground design standards included in our review. Navigant's primary objective focused on identifying distribution design standards that have the greatest cost impact when implemented system wide. The following lists the key design standards Navigant investigated:

   - Overhead wire size and loading criteria
   - Pole class selection, maximum loading and replacement criteria
   - Maximum number of primary/secondary lines per pole

- Underground cable specifications, loading and duct bank design, including spare ducts
- Underground system design, including radial versus open loop configuration
- Distribution feeder ties, and capacity reservation for feeder/station back-up
- Overhead and padmount transformer selection and loading criteria
- Padmount switchgear selection and application
- Low voltage secondary grid and spot network design, application and protection
- Distribution protection practices, including smart grid applications
- Replacement/renewal criteria for underground cable, padmount/submersible devices, and rear lot conversions
- Overhead switch and protective devices, including communications systems
- Station switchgear design and replacement criterion

2. ***Prepare Survey***
   Navigant prepared a survey instrument and issued it to participating utilities with distribution system characteristics and load density similar to THESL. Navigant and THESL prepared the questions and identified a group of utilities deemed to be preferred candidates for the survey. The survey is included as Attachment A.

3. ***Interview Utility Participants***
   Navigant contacted five participating utilities with comparable service territory demographics, load density and distribution design standards to participate in the benchmark survey. Three of these utilities are located in Ontario; the other two in other provinces or states in the U.S.
   Navigant has worked with each of the participating electric utilities (and other similar utilities as well), both within Ontario and other provinces, and is very familiar with their distribution design practices. To encourage participation, Navigant agreed to share the results of the survey with the utilities, with the understanding that survey results and participants would be treated confidentially.

4. ***Summarize Results***
   Once the surveys and interviews were completed and results tallied, Navigant summarized its findings for each of the standards included in the review for this report. Findings were quantified, where applicable; all other results are presented qualitatively. Our report, presented herein, describes differences in design standards, including reasons why THESL's are justified due to unique characteristics of Toronto and THESL's system.

Distribution Design and Equipment Replacement Practices

The following describes NCI's assessment of THESL distribution design standards and criteria. The analysis examines equipment selection and design criterion that THESL applies for distribution capacity expansion, new connections, and to meet reliability and performance requirements.

THESL's Energy Delivery System

The City of Toronto is the fifth largest metropolitan area in terms of population in North America. Total load for the amalgamated system is approximately 5,000 MW, of which 2,000 MW was THESL peak load prior to amalgamation of surrounding systems. Most of the downtown load is served by 13.8kV and 4.16kV lines, while the remaining load is served mostly with 27.6kV distribution. Hydro One Networks, Inc. ("HONI") owns all of the transmission lines that supply transformer stations ("TS"). Hydro One also owns all equipment from the low side of the transformer switchgear up to and including all station equipment at 115kV or higher. THESL owns and operates the low-side switchgear and related equipment. THESL owns and operates one entire station, Cavanaugh, and will own most of the equipment at the proposed Bremner station in downtown Toronto, projected for commercialization in 2014.

The load density and type of load served suggest continuity of service to downtown electric load is critical, as it includes Toronto's financial district, large office complexes, numerous high rises, and major tourist destinations. Accordingly, approximately 350 MW of this load is served by highly reliable, complex electrical distribution supply systems configured in a network or grid arrangement. Total electric demand in the downtown core of Toronto is approximately 1,000 MW, of which 350 MW is served by secondary networks.

Design Standards and Expansion Criteria

The following describes the criterion THESL employs in the design of its electric power delivery system. Design criterion is presented separately for stations and distribution feeders, with a separate discussion of network facilities serving downtown Toronto.

Stations

Generally, THESL does not own or operate network transmission lines and stations, and therefore is not responsible for the establishment of planning, loading and reliability criteria for the high voltage system. Network transmission assets serving THESL stations are owned and operated by HONI. Most stations located outside downtown Toronto are served by overhead 230kV lines, whereas most downtown stations are served by a combination of overhead and underground 115kV lines.

Although THESL is not responsible for the transmission planning and design criteria, it works closely with HONI, the Ontario Power Authority ("OPA"), the Independent Electricity System Operator ("IESO"), and participates in joint planning sessions to coordinate and plan for the continuity of supply to THESL stations. THESL has also opined on transmission reliability in prior investigations conducted by the IESO.[1] Most important, THESL designs its municipal stations ("MS") (mostly 4.16kV and 13.8kV and 27.6kV) with consideration given to the design and contingency criterion applied to the transmission system. For example, if a loss of key transmission lines or transformers were to cause the entire or partial loss of station capacity, then THESL would need to design its system in a manner to ensure back-up feeders and station capacity were available.

THESL planning criteria specifies that all downtown stations must be able to serve projected load for a single contingency; that is, for loss of a single station transformer, incoming supply line or switchgear bus section, will not cause loss of load (also referred to as n-1 criteria). THESL employs a Dual Element Spot Network Design ("DESN") standard for downtown stations, with each bus supplied by two transformers. Stations typically include four 100 MVa 115/13.8kV transformers (owned by HONI). A maximum of 10 to 15 feeders are allowed per switchgear bus. Under this design, the 13.8kV station bus rating is typically the limiting element from a capacity standpoint. Net firm station capacity is derated to 95 percent of the projected future peak to account for unanticipated loads or weather anomalies. For the loss of a single transformer, THESL temporarily increases the utilization of the remaining transformers in service above nameplate ratings to an acceptable level.[2] These practices and criteria are consistent with survey participant practices and industry practices in general.[3]

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[1] For example, THESL offered its comments to the IESO *Stakeholders Engagement Plan SE-50 for Supply to Large Urban Centres* in a letter dated February 28, 2008.

[2] IEEE/ANSI has issued guidelines for oil-immersed transformers below 100 MVa that indicate the acceptable level of increasing loading without loss of life based on transformer preloading, temperature and duration of increasing loading. THESL practices are consistent with IEEE/ANSI guidelines.

[3] Some North American urban utilities serving critical, high density loads have adopted second contingency (n-2) station planning criterion.

THESL's planning criteria allow for the loss of any single major station element, at peak, without full or partial loss of load. An Emergency Preparedness exercise conducted in May 2006 suggested that THESL's planning criteria should include a requirement that outages caused by a partial or full loss of a station should be restored within 24 hours. However, without adjacent transformer station switchgear ties in downtown Toronto, this objective cannot be met for a major outage at several stations. Other utilities design their systems to provide feeder ties on most or all overhead and underground distribution lines. However, the construction of the proposed Bremner station and proposed feeder ties to Strachan and Esplanade and other proposed upgrades associated with externally driven upgrades along the waterfront will address this issue.

As noted earlier, THESL also owns many MS' that step down higher primary distribution voltages to lower voltage; mostly 27kV to 4.16kV and 13.8kV to 4.16kV. (Two utilities in the survey own most 230/27/12.47kV TS' as well.) These unit stations typically are equipped with one or more station class power transformers, building enclosures for relaying and controls, enclosed switchgear, and SCADA access. This practice is consistent with each of the utilities surveyed. Later in this report, programs that utilities have implemented to convert distribution lines to operate at higher voltages will be described. Generally, utilities have pursued this approach as means to either eliminate some, or all of the unit stations on their distribution system over time.

Distribution Feeder Design

Outside of the former downtown Toronto system, most THESL's feeders are rated 27.6kV and designed in a radial "open loop" configuration. The open loops include several transfer switches and normally open feeder ties that are suitable for inter-station load transfers. In the event of a contingency loss of station transformation capacity, these ties can be utilized to transfer load to other nearby stations where sufficient transformation capacity exists to carry the load. Many of the 27.6kV feeders and transfer switches are located overhead. This practice is consistent with other utilities participating in the survey group.

The mostly underground 13.8kV system in downtown Toronto predates the overhead 27.6kV open loop design located in the amalgamated distribution systems. Unlike the 27.6kV system, downtown stations and radial 13.8kV distribution feeders rely on the 115kV voltage transmission system to maintain reliability to downtown customers. The current downtown 13.8kV design criterion excludes reservation of feeder capacity to back-up load from other stations. This design configuration has no inter-station feeder ties, which limits load transfer among downtown stations.[4] Thus, the loss of a downtown station would result in significant

[4] The absence of feeder ties and reliance on incoming supply to maintain reliability does not address the complete loss of a station, which is usually deemed as a very low probability, but high impact event. However, the near full

and extended loss of load until repairs are completed and the station returned to service.[5] Notably, lack of space in downtown area for underground feeder tie switches and the absence of spare conduit or underground duct bank systems is a major deterrent to creating feeder ties where none currently exist. In contrast, most other utilities surveyed provided inter-station tie capability for underground distribution located in urban areas.

About 350 MW of high density load in downtown Toronto is served by low voltage secondary grid networks. These networks operate in a looped arrangement such that a loss of any single element will not cause overloads or loss of load. A substantial portion of secondary network load in downtown Toronto is served from a few stations, with some busses dedicated to serving network load. THESL secondary grid networks, both from a design and planning criterion perspective, is similar to other utilities surveyed.[6] However, Toronto is one of the largest cities in Canada, and therefore has significantly more and larger networks than most of the other utilities surveyed.[7] Some utilities also have installed enhanced communications and protection systems, described in greater detail in subsequent sections.

Conformance with Industry Design Criteria

As noted, planning guidelines for stations in Ontario (and adopted by THESL) are based on a single contingency (n-1) planning criterion. Station bus design includes transfer busses with full feeder back-up capability reserved for maintenance or when outages occur. Many downtown loads are served by secondary grid (lower load density) or spot (highest load density such as high rise buildings) networks. Each of these design practices is consistent with common utility practices for urban areas, with the primary exception being the absence of inter-station feeder ties in downtown Toronto.

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utilization of station bus capacity and deterioration of equipment has increased outage exposure and the probability of station outages.

[5] Three prior events highlight the exposure caused by the loss of downtown stations. In January 2009, one of the coldest days of the year, the Dufferin station was shut down due to flooding caused by the operation of HONI's transformer fire protection system. Over 34,000 customers were interrupted, some for up to 24 hours. A similar flooding event occurred at the Terauley station in January 2005, causing an interruption of service to over 3,500 downtown customers for up to 10 hours. Lastly, a TS transformer failure at Windsor on October 14, 2010 caused an interruption of service to several downtown high rise buildings and retail centers during daytime business hours.

[6] Some utilities report that some network primaries may be used to serve radial load, sometimes with auto-transfer switches (as opposed to spot networks).

[7] The single contingency criterion that THESL applies to station transformers is less conservative than other large utilities serving critical, high density loads. For example, the City of Manhattan (Consolidated Edison Company of New York) applies a second contingency (n-2) criterion for lines and stations serving the Island of Manhattan. Similar criterion has been adopted for critical government and commercial load centers in Washington, D.C. by the Potomac Electric Power Company, Houston, and other large cities worldwide, such as downtown Tokyo.

Overhead Distribution Design and Component Selection

The following presents survey results for overhead systems, including a comparison of THESL practices to survey participants. Where differences exist, Navigant describes the circumstances causing these differences, such as constraints associated with the design and operation of a major urban distribution system.

Overhead Conductors

Most utilities with 15kV class distribution (e.g., 12.47kV, 13.8kV and 14.4kV) now use 477 or 556 AAC conductor or equivalent on most three-phase main line sections. Maximum normal loadings are between 400 to 500 amperes (8 to 10 MW). Actual ampere ratings of overhead main lines are 600 to 700 amps, but the limiting element typically is underground exit cables, where capacity limits are lower. For most utilities, including THESL, overhead distribution system capacity is constrained by underground exit feeders which are the limiting elements due to localized duct bank heating.

Related findings include:

- Lateral taps for most utilities is 1/O conductor or equivalent, although older lines sometimes are #2 or smaller. Most utilities, including THESL, have formal programs or measures in place to upgrade older and deteriorated lateral tap lines built with smaller conductors such as #6 copper. Some of these programs are incorporated into worst performing feeder and other reliability programs.

- Each of the utilities surveyed also use distribution rated 25kV or higher. Utilities load these lines up to 15 to 20 MVa, or higher during emergencies, although average loadings typically are lower. All utilities also use lower voltage distribution such as 4.16kV, typically in downtown areas that are fully built out. Similar to THESL, many of these utilities are converting some of these lines to operate at higher voltages.

- Most utility overhead distribution lines contain two to three tie points to enable full transfer between stations. This practice is consistent with THESL's 27.6kV system, but in contrast, THESL's practices on it downtown 13.8kV system differs, where many feeders do not have open ties with feeders served from other nearby 13.8kV stations.

- Where ties exist, most utilities reserve up to one-third of feeder capacity for back-up. Most utilities include emergency ratings when establishing feeder tie capacity limits; whereas one utility does not apply emergency ratings in its planning criteria. This practice is comparable to the design criterion THESL applies to its 13.8kV and 27.6kV distribution system.

- For most utilities, use of open wire construction is dominant. However, utilities increasingly are using bundled conductor (e.g., spacer cable) such as Hendrix or tree wire on primary three-phase lines most susceptible to tree-related interruptions. THESL's design standards specify use of tree wire in areas susceptible to tree-related interruptions. Both tree wire and bundled conductor are viewed as a cost-effective reliability improvement measures, designed to improve reliability performance metrics.[8]

- For secondaries, utilities use triples or quadruplex wire as a standard, although several have large amounts of legacy open wire secondaries. Open wire secondaries are typically replaced in conjunction with conversion or other primary line upgrades or relocations. THESL does not have an active conversion program for open wire secondaries.

The design and loading practices employed by the utility survey group outlined above are generally consistent with those currently employed by THESL. The primary exception is the number of feeders installed on overhead distribution and absence of back-up on downtown 13.8kV feeders. For the former, THESL tends to limit the number of feeders in congested areas to two; whereas some utilities allow up to three or four per pole, particularly on taller poles. One utility reported that three to four feeders are allowed only where lines of different voltages are installed on the pole, where there is less risk of the loss of multiple feeders from the same station. However, THESL pole height and number of feeders often is limited to two in congested areas or where obstructions exist; THESL allows a greater number of feeders to be installed in less congested areas, particularly on 27.6kV lines.

Poles and Structures

Pole routing practices varied among the survey group. Most utilities prefer to install poles near travelled roadways. However, some utilities have significant amounts of back lot legacy

[8] Several U.S. utilities use bundled conductors extensively, sometimes as a design standard. It is often installed on line sections where heavy tree growth, coupled with limited horizontal clearances makes bundled conductors a cost-effective choice.

construction, especially on single-phase lateral tap lines. Some of these utilities have implemented programs and policies to move these lines roadside, but often are forced to relocate overhead as underground due to difficulty in obtaining permits for new pole lines. Where overhead distribution is located in urban areas, these lines often are located in alleyways.

Pole Selection Practices

Most utilities, including THESL, use class 2 or 3 wood poles, 40 to 50 feet in height for three-phase primary overhead lines. The use of stronger class 2 poles typically is used in areas where large devices are installed, on lines with multiple circuits, corner structures, or in areas highly susceptible to vehicular accidents. Most lateral, single and two-phase lines are equipped with Class 4 poles, typically 40 feet in height. Taller poles are used for both three-phase lines and laterals where underbuild primary is installed or where additional clearance is needed for devices, highway crossings or where other obstructions exist. One utility reports extensive use of concrete poles (relative to other utility practices), and is developing policies to determine when concrete should be used versus wood; for example, concrete poles should be located on main traveled roadways where guying rights are more difficult to obtain. THESL also generally uses concrete poles on its distribution system for similar reasons.

Most existing three-phase construction is cross arm (including alley-arm) while most single phase lines use pole-top insulators. Several utilities, including THESL report that current design standards specify armless construction with stand-off insulators - cross arms are replaced on feeders where legacy design was cross arm construction, or in areas where tight clearances require use of alley arm construction. Utilities with poles located in densely populated areas often use higher poles to maintain vertical or horizontal clearances. Each of these practices is generally consistent with those currently employed by THESL.

Some utilities own and operate lower voltage transmission (e.g., subtransmission) rated 34.5kV or 69kV installed on wood poles, often along roadways with distribution underbuild. This practice is not applicable to THESL's system, as all TS' that supply THESL are rated 138kV or 230kV. Utilities with 34.5kV or 69kVtransmission lines often include one or more 13.8kv or 25kV lines below the transmission conductor. This practice does not apply to THESL, as it does not own lines rated 34.5kV and higher.

Cross Arms and Insulators

All utilities surveyed use standard 8 foot cross arm construction, although THESL's and several other utilities current standard for 15kV class distribution specify armless construction; cross arms are used for legacy applications or where additional clearances are required. Use of stand-off insulators is more prevalent on utilities with 25kV (or higher) distribution. A common practice among utilities is to install insulators rated for higher voltage distribution; for example, utilities often will install insulators with 25kV Basic Impulse Level ("BIL") ratings on 15kV class lines and insulators with BIL ratings of 35kV for 25kV lines. The use of higher insulators with higher BIL is intended to improve reliability at relatively low cost or where future voltage conversions are expected or likely to occur. One utility reports it is proposing to examine fiberglass crossarms on a pilot basis.

Two of the reporting utilities indicated the institution of formal insulator replacement programs, mostly to facilitate the change-out of porcelain insulators with fiberglass. Typically, these are detected or identified through scheduled inspections. Some utilities, including THESL, also change out defective porcelain insulators on gang-operated switches. Defective porcelain is identified either during routine tests where the devices are operated to assess integrity or previously identified as defective by equipment suppliers.

Transformers and Devices

The design standards that THESL uses for overhead transformers are comparable to the utility group; although one utility continues to install three-phase overhead devices whereas THESL uses three single-phase units for three-phase loads. One company reports it is actively replacing submersibles with pad mount devices. However, THESL continues to install many submersible transformers to comply with City requirements; whereas other utilities are seeking to minimize or eliminate their use due to maintenance and harsh operating environments. Most utilities utilize line reclosers to isolate faults and reduce customer interruptions; some utilities are more aggressive in terms of the number of devices installed. THESL previously considered, but has not adopted use of line reclosers due to the shorter primary line sections, longer laterals and fault current levels that typically are above standard recloser ratings. One utility has pursued distribution automation aggressively, including installation of auto-loop schemes that use reclosers or motor-operated switches to isolate faults and transfer load to unfaulted lines sections from feeders supplied by nearby stations.

Some utilities, including THESL, are considering or actively replacing completely self-protected (“CSP”) transformers, but Navigant did not identify any with an active program to proactively replace them on an accelerated basis. Some are replaced and retired as part of a renewal project triggered for reasons other than CSP transformer replacement.

All utilities report that transformers are viewed as “run-to-failure” devices. Obviously damaged or worn transformers detected during scheduled 3-year inspections sometimes are replaced or upgraded. One utility reports it has begun to replace one-of-a-kind type devices (or those with limited installed quantities) to reduce inventories needed for spares. THESL has begun to remove legacy equipment and one-of-a-kind devices that are no longer consistent with current design and procurement practices in order to have standardized equipment and to reduce the dependence on one-of-a-kind devices, which may be hard to procure.

Rear to Front Lot Conversions

Few companies are actively relocating overhead lines to front or roadside locations, as lines along property frontage or roadways usually need to be relocated underground at significant cost. Some companies are relocating overhead lines to underground, but only when needed for reliability or lack of access. Virtually all primary and secondary relocations include use of conduit, either concrete-encased duct banks for primary three-phase lines and directional boring and flexible conduit for single-phase laterals. Direct buried cable, while discouraged, is sometimes used for replacement of secondary cable due to cost or when replacing small segments of line.

Specific findings include:

- The preferred method for single-phase lines is to use directional boring in combination with the installation of flexible conduit. THESL practice is to install concrete-encased conduit for single- and three-phase cable.
- Those relocating lines underground have formalized policies that also mandate the use of padmounted transformers (as opposed to submersibles); this has caused some difficulties in obtaining easements as property owners are reluctant to grant easements when installation of underground cables is conditioned upon the installation of padmount transformers.
- One company has established a policy to only install pad mount transformers when submersible devices fail or need to be replaced due to deterioration.
- Where relocations are single-phase only, directional boring with flexible conduit is most often used. However, where three-phase main line primary distribution is relocated, concrete-encased duct bank is installed in trenches dug by backhoes. The use of conduit also includes single phase lines that may later be upgraded to three-phase.
- One utility reports that it pays for electric panel replacements if the utility has chosen to relocate the line.

- One utility reports that it does not replace service cable for underground residential distribution ("URD")[9] due to cost, unless the cable is obviously deteriorated.
- Where secondaries and services are replaced, these are usually in duct as directional boring is applied where possible.
- Utilities report that concrete-encased duct bank systems are installed for three-phase primary trunk lines or where street crossings exist. This is consistent with THESL practices.

Where concrete encased duct banks are installed to accommodate three-phase primary cable, these typically are 1x4 ducts, configured horizontally. If additional feeders are in the planning horizon, 2x4 duct bank systems may be installed. For major street crossings with three-phase lines, typically 4x4 duct banks (or larger) are installed.

One utility reports that it is installing spare conduits at road crossings when other utilities (e.g., communications utilities) are installing new lines or replacing existing communications cable. THESL has adopted a similar practice, as the impact on electric infrastructure is reviewed and coordinated with City departments, provincial agencies or other utilities when new construction is proposed or where new lines are to be installed.

[9] Often referred to as underground rural distribution by some utilities.

Underground Distribution Design

The following presents survey results for underground distribution, including a comparison of THESL practices to survey participants. Where differences exist, Navigant describes the circumstances causing these differences, such as constraints associated with the design and operation of a major urban distribution system.

Most utilities surveyed use extensive amounts of cable, both for three-phase main lines serving urban or commercial load, and URD for residential areas. Due to legacy systems, the type of cable and infrastructure that currently exists varies widely among utilities. However, all utilities, including THESL, report that cable replacement and underground infrastructure renewal are critical areas due to the presence of older, first or second generation cable with known defects and performance concerns. All report that replacements are carefully prioritized to ensure only the worst performing cables and sections are replaced first.

Underground Cable

Most utilities, including THESL, with 15kV class distribution (e.g., 12.47kV and 13.8kV) typically use 500 MCM copper or 750/1000 MCM Aluminum conductor or equivalent on three-phase main line sections. THESL design standards specify that copper should be used for most 13.8kV lines in the downtown area; copper or aluminum is used on 27.6kV distribution. Maximum normal loadings are between 8 to 10 MW, or 400 to 500 amps. For primary cable, use of tree-retardant, cross linked polyethylene ("TR-XLPE") is common; typically equipped with jacketed concentric neutrals or copper shield. For main line sections, use of 1000 MCM aluminum is common, with 500 MCM copper installed in areas where smaller existing duct banks require smaller cable.

Some utilities limit maximum feeder loadings to about 350 amps due to heating limits in exit feeders, where multiple feeders cause localized heating and resulting capacity derating. Actual conductor ampere ratings on most primary overhead sections are 600 to 700 amps, but the limiting element typically is underground exit cables, where ampere ratings are lower. Most utilities, including THESL, design the overhead distribution system with underground exit feeders that are the limiting element on overhead feeder capacity.

Lateral taps and URD construction for most utilities, including THESL, is 1/O aluminum or equivalent, although older lines sometimes are equipped with #2 copper.

Each of the utilities surveyed also install primary distribution cable rated 25kV or higher. All utilities load these lines up to 20 MVa, although average loadings typically are lower due to exit feeder constraints. All utilities also use lower voltage distribution such as 4.16kV, typically in downtown areas that are fully built out. Many of these utilities are also converting some of these lines to operate at higher voltages.

Most utility underground distribution lines contain two to three tie points to enable full transfer between stations. This contrasts THESL's practices on it downtown 13.8kV system, where many feeders are not equipped with ties to feeders served from other stations.

All utilities have significant amounts of URD, some direct buried, and others in conduit. Most utilities now require duct bank, open loop systems, although some lines are still direct buried. Directional boring is often used where obstructions limit the utility's ability to dig trenches. All utilities have replaced older deteriorated URD cable (mostly installed in the late 1960's and 1970's), with much of it being cross-linked polyethylene ("XLP") with unjacketed neutrals, or with corroded sheathing.

Civil Infrastructure

All utilities have implemented an underground civil infrastructure upgrade or replacement program, as most have facilities that are up to 60 to 80 years old or longer. However, the level of investment compared to the amount of infrastructure in service appears to be modest, as the cost of major infrastructure upgrades of replacements can be exceedingly expensive. For example, the cost to replace an underground vault typically can be $1 million or higher. Similarly, duct banks are increasingly a concern, including clay tile ducts (terra cotta) or other older materials that have become brittle or begun to collapse. Navigant found that very few of these ducts are actually being replaced on a widespread basis. In some cases, new concrete-encased duct bank systems are being installed in conjunction with distribution upgrades associated with new construction or downtown load growth.

Because THESL vaults and duct banks are located in areas with high traffic density, multiple circuits and minimal greenways (for accessing or locating duct banks), replacement of civil infrastructure is a greater challenge for THESL; a key difference to other utilities that have better access and less restrictive rules on when work can be performed. The latter point refers to municipal rules that limit work along travelled roadways to off-peak hours, thereby increasing the difficulty in coordinating the work as well as higher cost. Further, THESL typically allows up to four cables per duct bank, with a larger number of cables allowed in congested areas. The design and loading practices employed by the utility group, outlined above, are generally consistent with THESL, as each utility surveyed has space or routing constraints that require exceptions to the company's preferred design and material selection practices.

Paper Insulated Lead Cable

All but one utility uses Paper Insulated Lead Cable ("PILC") on main line underground sections. Some report very favorable performance, but are limiting or eliminating installation of new PILC. Those with PILC have implemented replacement programs, due to degraded reliability and the relatively few suppliers of PILC cable. Some of these programs are in their infancy, with proposed replacements, prioritized based on condition assessment and reliability exposure. Notably, at least two utilities plans to continue to support use of PILC, with one utility reportedly stockpiling the cable as a hedge to future cost increases or lack of supply. Similar to some of the utilities surveyed, THESL continue to use PILC on its 13.8kV system for maintenance or replacement, although TR-XLPE is installed on new underground lines.

Cable Replacement

Many utilities report that they have or are planning to implement primary cable replacements programs. However, many appear to in their infancy, as prior replacements have been very modest as a percent of total cable known to be potentially at risk of failure. Most utilities reported large amounts of cable that may be near the end of its service life, with costs for replacement potentially higher than amounts in current replacement plans. At least one utility reports that it is focusing on cable failures caused by inadequate or improperly installed vault racks as cable failure records indicate failures are often in vaults where racking is inadequate. Vaults are inspected for cable droop, damaged racks, missing racks, and are consequently replaced or repaired (instead of replacing cable) if deemed inadequate.

Secondary Networks

All of the utilities surveyed, except one, operate one or more secondary networks, including grid and spot networks. Some of the spot networks operate in a mini-grid configuration. One utility is in the final phases of converting its only network to operate radially. The latter is due to several factors, including the need to upgrade degrading network equipment and cables, the loss of key skills for operating and maintaining the networks, and the limited number of suppliers of network equipment. One utility is expanding its network, while another is expanding its network only by adding service lines within the existing network. THESL expects to expand secondary grids mostly within existing networks.

Several owners of network systems have or plan to enhance network reliability and reduce major outage exposure by adding fast-acting current limiting fuses ("CLF") at station breaker locations, heat detection equipment, and through real-time access to load data and remote switching of breakers or network devices within vaults. Several have also begun to replace underground infrastructure, including cable chambers, vault walls/roofs, cable racks, and supporting devices. Utilities expanding their networks are also adding new vaults and associated primary cable and network equipment. Despite concerns with regard to duct bank condition, only a limited amount of underground duct banks are being replaced.

Stations

Most of the discussion that follows focuses on distribution class equipment and design practices, as most transformer stations and equipment is owned and operated by HONI. Similar to THESL, most utilities own and operate MS' that convert higher distribution voltages to lower operating voltages. Many of these stations include enclosed structures, transformation equipment, switchgear and protective devices that functionally, are comparable to those used in TS'.

A key difference in design practices employed by THESL is the use of station equipment with higher fault level ratings (e.g., breakers with rating higher than standard 20kA ratings) due to high fault current levels associated with the highly interconnected HONI bulk power system and strong generation sources. Notably, the cost of the higher rated equipment is considerably higher than devices with standard ratings.

Municipal Stations and Voltage Conversions

All utilities have or plan to convert portions its distribution system, mostly 4.16kv to 12.47/13.8kV; or in some case to 25kV or higher. All utilities report that these conversions are performed due to the need for higher capacity or for renewal due to deteriorated equipment. Most utilities plan to continue to own, operate and maintain unit stations, mostly 12.47/13.8 to 4.16kV although at least one utility proposes to convert all lines fed from unit stations to operate at higher voltages – all stations would be retired within the next 30 to 40 year, with all distribution feeders served from HONI (or in some cases, company owned stations). Other reasons cited for the conversion includes increasing obsolete or deteriorating station equipment, higher Operations, Maintenance and Administration ("OM&A"), larger inventories and spares, and costly capital upgrades. One utility indicated it strictly wanted to be in the 'wires' business, with a focus on distribution line assets as opposed to station equipment. This would also allow them to eliminate station equipment from their equipment inventory, and phase out crew training for station class equipment. THESL practices are comparable to utilities surveyed, including the planned retirement of some MS' in conjunction with distribution line conversions.

Another key reason for conversion is the ability to retire older unit stations equipped with obsolete switchgear or deteriorated transformers. Some utilities have implemented programs to partially convert some lower voltage lines, and install padmount step down transformers and switchgear, with SCADA communications, at much lower cost than fully-equipped stations.[10]

Although conversion programs are underway at these utilities, many expect several unit stations to be in service for the next 10 to 20 years or longer. Utilities that expect to keep unit stations in service for an extended time frame continue to invest in upgrades needed to ensure the lower voltage systems are reliable. These upgrades include replacing or adding new transformation capacity, switchgear and protection systems; particularly where obsolete or susceptible to catastrophic failures, such as non-arc resistant switchgear.

To reduce cost, some utilities install overhead or pad mount step down transformers to retain portions of the lower voltage distribution, particularly in areas that are not expected to grow over time. This may include use of several smaller step down banks or individual transformers. In contrast, one utility reports that once a feeder (or set of feeders) is selected for conversion in conjunction with the retirement of a unit station, it will convert all line sections to operate at a higher voltage – single phase step down transformers for single-phase lateral is strongly discouraged. All utilities report that all construction in lower voltages areas – typically 4.16kV – is built to the current higher voltage design standard. The most common example is installation of 15kV class (or higher) insulators on existing 4.16kV lines during upgrades or replacement.

Replacement Criteria

Some utilities proposed to replace some unit stations, but continue to operate unit stations that cannot be replaced on a cost-effective basis. Utilities that expect to keep unit stations in service indefinitely or at least for an extended number of years will typically invest in the following to ensure these stations continue to operate reliably and safely.

- Switchgear – typically for the replacement of non-arc resistant components
- Power Transformers – either new purchases or re-use of devices removed from other stations that have been retired
- SCADA/RTU's – often in conjunction with communications systems upgrades
- Protection Equipment – programmable devices often installed in conjunction with switchgear replacement

[10] A variation of this option is to install overhead step down transformers – for example, three 500kVA devices on a single pole – along with an overhead line recloser or in-line fuses.

All utilities report that non-arc resistant switchgear is being replaced in many unit and TS'. However, some report that existing switchgear will remain in service if it will be in service for 10 to 20 years or less.

For TS', utilities collectively report that obsolete protection and older electro-mechanical devices are systematically being replaced with programmable devices, particularly in locations where distributed generation is present or is expected to be installed on local distribution lines.

1 Introduction and Summary

Toronto Hydro-Electric System Limited ("THESL") retained Power System Engineering, Inc. ("PSE") to review ten business cases that THESL prepared for its 2012 Incremental Capital Module ("ICM") filing. These business cases ("BCs") primarily deal with proposed capital improvements that are rooted in reliability concerns. Other causes, such as safety, operational concerns, or regulatory requirements, can also be factors. PSE performed a high-level review on these business cases, focusing on overall methodologies and strategies. This report (the "PSE Report") describes PSE's overall viewpoints regarding these ten business cases.

Electric distribution utilities have important responsibilities when it comes to providing reliable power in a safe manner at a cost that is fair to both existing and future customers. One of the most demanding responsibilities is to install, operate, and maintain, a capital-intensive infrastructure, which is necessary in delivering electric power to better the lives of families, business, and the community. From the inception of the power industry, the challenge of managing these assets has become more and more demanding as the average age of plant continues to grow. This challenge has grown not only due to the aging of the infrastructure, but to the increased demands of end-use customers for an extremely reliable power delivery system.

Electric distributors endeavor to recognize in their planning process the full costs of their decisions. The full costs are an amalgamation of the direct utility costs and the externalized costs to customers. This is especially true for projects that are primarily reliability-driven in nature (e.g. feeder automation projects). The long-term planning objective is to minimize the overall costs, irrespective of the stakeholder incurring that cost.[1]

Overall Costs = Utility Costs + Customer Interruption Costs

THESL's approach to asset management is a groundbreaking one. The company's method aims to optimize capital spending projects from the perspective of all stakeholders. The approach recognizes the impact of its decisions on customers and explicitly incorporates this broad view into the planning process. Distribution utilities are beginning to recognize the reliability, safety, and operational consequences of their aging infrastructures. There is a need for a culture change in making asset choices that incorporates a full view of the cost impacts of their decisions. THESL's methodology is innovative and, in PSE's opinion, on the right track.

Chapter 2 ("Infrastructure Asset Planning and Management") discusses THESL's approach to managing aging assets, with an eye on some specific business cases. Chapter 3 of the PSE Report ("Business Cases—Methodology") evaluates THESL's general approach to selecting and prioritizing reliability-driven projects. PSE concludes that THESL's general approach provides an important tool in evaluating the economic merits of projects from the ratepayer perspective.

[1] The planner should also keep in mind other factors that should play into this decision. An example of this could be employee and public safety improvements, which are unquestionably important but not given a monetized value in the cost/benefit analysis.

amount of spending and then determine the prioritization of the projects within the spending limits.

The business cases exemplify THESL's solid approach to their planning process. The proposed solutions incorporate measuring anticipated failures in order to be proactive in asset replacement, distinguishing between frequency and duration of outages, assigning a risk-cost based on failure estimates and the consequences of those failures. THESL typically presents a preferred solution along with alternatives and determines which solution strikes the right balance of cost and reliability for both customer and utility.

2. <u>THESL's evaluation of the proposed ICM projects applies industry leading techniques that aim to economically justify projects from the standpoint of all stakeholders, including customers.</u>

   The economic evaluation of the projects examined by THESL incorporates the risks to customers of failure due to aging equipment and other risk factors. This process enables the inclusion of the risks faced by customers of asset failure. The economic merits of each project and its alternatives can be more accurately and fairly evaluated through this risk-cost assessment. This is a groundbreaking approach to asset management for reliability-driven projects and represents a key data point in making sound financial decisions on spending capital wisely and in the best interests of ratepayers. It is PSE's belief that as infrastructure continues to age across the industry, these tools will become popular and necessary in decision-making processes.

   An advantage of the process engaged by THESL is the ability to provide internal and external decision-makers with an objective analytical tool to assist them in the evaluation of diverse capital projects. While this tool should be supplemented with system knowledge and other analysis, it can illuminate the benefits of projects and these can be weighed against anticipated investment costs. This process can help to identify projects that may have previously been looked over or help eliminate projects that may not be in the public's interest. Prioritization of projects and giving urgency to projects that offer high benefit to cost ratios to ratepayers is a valuable use of THESL's Feeder Investment Model ("FIM").[2]

3. <u>Deferral or abandonment of the proposed THESL ICM projects will likely increase the probability of lower reliability to customers served by the corresponding facilities and present potential safety hazard exposures to the public and utility workers.</u>

   The THESL approach truly shows advancement in distribution planning. Their approach balances two conflicting demands of electricity customers: low rates and reliable service. At the same time their approach balances utility expenses and economic consequences to customers. Where appropriate, THESL also considers safety factors for both the public and utility personnel in its analysis.

[2] For a description of the FIM, please refer to THESL's Managers Summary, Appendix 4.