Toronto Integrated Regional Resource Plan Addendum: Richview x Manby 230 kV Circuit Upgrades

November 2021

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1 Executive Summary

This Toronto Integrated Regional Resource Plan (IRRP) addendum is recommending that Hydro One proceed with the reinforcement of the Richview TS to Manby TS (Richview x Manby) transmission corridor, targeting an in-service date of 2025, which the working group understands is the earliest possible in-service date given the project lead-time. The reinforcement includes replacing the idle 115 kV double circuit line with a new double circuit 230 kV line and the associated connection work at each end. This reinforcement was found to be the most feasible and cost-effective means of addressing an immediate supply capacity need in the Richview South area, and is consistent with the recommendation made in the 2019 Toronto IRRP.

Since the publication of the 2019 Toronto IRRP, there have been changes in planning assumptions that have necessitated re-studying a key recommendation in the 2019 IRRP to reinforce the Richview x Manby transmission corridor to meet a near-term supply capacity need. These changes include an updated Conservation and Demand Management (CDM) Achievable Potential Study, the launch of the 2021-2024 CDM Framework, and updates to the demand forecast in the area. These changes are relevant as they impact both the characteristics of the supply capacity need and the options available to meet this need.

The Addendum Study was initiated specifically to study the electricity reliability needs in the area served by the Richview x Manby transmission corridor (the "Richview South" area) given the updated demand forecast and other system assumptions, and the options to address this need given the updated information with respect to CDM and other non-wires alternatives as applicable. One such system assumption that has a significant impact on the evaluation of alternatives relates to changes in operating policy which require Dufferin TS to be transferred from Leaside TS supply to Manby TS supply during certain system conditions. This transfer has the effect of increasing the magnitude of the supply capacity need and therefore feasible alternatives should have the capability to supply this additional load when these transfers occur.

The reassessment of the need confirmed that there is a supply capacity need along the Richview x Manby transmission corridor starting in 2021; however, the magnitude of this need has increased compared to that in the 2019 IRRP. This increase is attributable to an increase in the demand forecast for the area, as a result of increased customer connections, and is further increased when considering the operating policy and Dufferin TS transfers to Manby TS. Following a review of options, including consideration of non-wires alternatives such as incremental cost-effective CDM, storage and demand response, as well as flexible AC transmission system (FACTS) devices, the recommendation for a transmission upgrade to address the Richview x Manby need has been reaffirmed. The transmission upgrade remains the most cost-effective option that alleviates the supply capacity need and maintains system reliability.

Given that the need is present day, and the transmission upgrade is not expected to come into service until 2025 given its lead-time, it is recommended that short-term measures, such as incremental cost-effective CDM and demand response (such as THESL's Local Demand Response program), be pursued where feasible and cost-effective to assist in reducing customer reliability risk until the transmission upgrade can come into service. While the Local Initiatives Program as part of the 2021-2024 CDM Framework will acquire a portion of the incremental cost-effective CDM, a new implementation mechanism would need to be developed to acquire the remaining portion.

2 Background

The Toronto IRRP, published August 9, 2019, identified a key near-term need associated with electricity supply capacity to the Richview South area. This area is defined electrically as being served by the Richview x Manby transmission corridor, and roughly comprises the western half of central and downtown Toronto, from the financial district in the east, Lawrence avenue to the north, and Etobicoke to the west, and portions of southern Mississauga and Oakville.

To address this need, the IRRP recommended that Hydro One reinforce the Richview TS to Manby TS transmission corridor. This corridor currently consists of two active 230 kV double circuit lines, and an idle 115kV double circuit line. The reinforcement would replace the idle 115 kV double circuit line with a new double circuit 230 kV line, in addition to associated connection work at each end. Following the 2019 IRRP, the regional planning Technical Working Group (consisting of IESO, Hydro One and Toronto Hydro) continued to recommend the Richview TS to Manby TS reinforcement in the Regional Infrastructure Plan published by Hydro One in March 2020.

As part of its ongoing planning efforts, the Technical Working Group continues to monitor developments in the region, even after plan completion, to identify signposts of change that should be considered in terms of their impact on the plan recommendations. In the case of the 2019 Toronto IRRP, there have been a number of changes including: the release of the 2021-2024 Conservation and Demand Management (CDM) Framework, additional information on the cost-effective CDM potential in the region through the Achievable Potential Study, and updates to the demand forecast. These changes should be considered as they impact both the characteristics of the supply capacity need and the options available to address this need.

As a result of these changes, and their potential impact on the Toronto IRRP recommendations, the IESO has undertaken an addendum study focused specifically on the area served by the Richview x Manby transmission corridor (i.e., the Richview South Area) so as to explore these changes and update or confirm the plan recommendations as appropriate.

3 Updated Assumptions

This section summarizes updates to the planning assumptions considered in the revised assessment of needs undertaken as part of this Addendum Study. Study assumptions not described in this Section are consistent with those in the 2019 IRRP.

3.1 Updated Demand Forecast

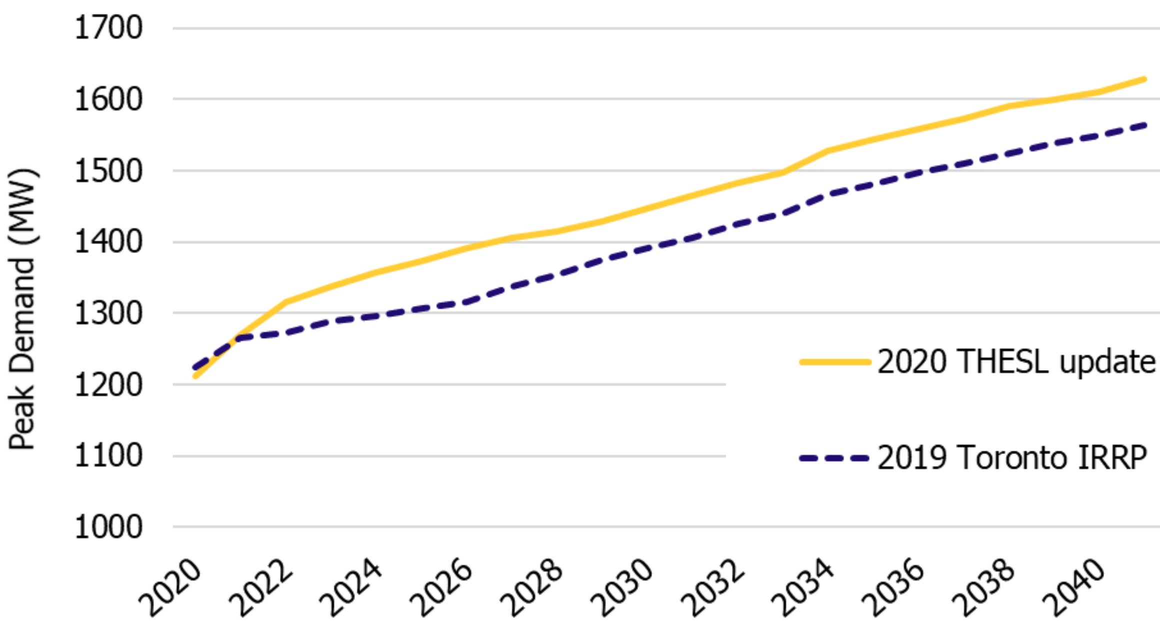
Toronto Hydro (THESL) provided an updated coincident demand forecast which reflects the most recent information with respect to customer connections. Due to the narrowed area of focus of the Addendum Study, updated forecasts were only provided for stations within the Richview South Area[1]. Demand forecasts for the applicable stations in southern Mississauga and Oakville were aligned with those used in the 2021 GTA West IRRP[2].

The graph below in Figure 1 compares the 2019 IRRP forecast with the updated forecast provided by THESL, for the area covered by this addendum. Note that in both cases, the impact of past conservation programs (i.e., those as part of the Conservation First Framework and Interim Framework) is included. The impact of CDM is described in Section 3.2.

[1] A forecast was also provided for Dufferin TS, which is normally supplied by Leaside TS but transferred to Manby TS under certain system conditions.

[2] GTA West Regional Planning, https://www.ieso.ca/en/Get-Involved/Regional-Planning/GTA-and-Central-Ontario/GTA-West

Figure 1| Summer Coincident Peak Demand – 2020 THESL update vs 2019 Toronto IRRP[3]



The updated forecast shows higher demand growth rate over the first three to five years of the forecast period compared to the 2019 IRRP forecast, followed by a rate of growth consistent with the 2019 IRRP forecast thereafter. After the first five years of the forecast, the demand from the THESL stations is approximately 60 MW higher (on average, per year) than the 2019 IRRP forecast for the remainder of the forecast period. THESL has indicated that a key driver of the changes in the 2020 demand forecast is new connection requests for primarily residential and commercial development.

Interest in electrification initiatives to reduce reliance on fossil fuels, and thereby greenhouse gas emissions, has been increasing in recent years and is a central theme in the City of Toronto's Transform TO Net Zero Strategy (which is under development and expected to be submitted to City Council at the end of 2021). While uncommitted initiatives as part of this draft strategy have not been accounted for in the demand forecast, these initiatives have the potential to further increase peak demand electricity use depending on the type of end use which is targeted. For example, electrification of transit, either public or private, can have a significant impact on electrical demand during late afternoons during summer, which coincides with when the transmission system is typically most constrained. Fuel switching for space heating, on the other hand, tends to have a larger impact during winter months, which are not typically as constraining for the transmission system in the GTA.

[3] These forecasts include Dufferin TS. Only THESL loads are included in this graph.

3.2 Updated Conservation and Demand Management Assumptions

For the purposes of regional planning, conservation assumptions, including impacts of Codes and Standards, and CDM programs, are typically accounted for in two different ways. Firstly, the anticipated impacts of existing programs and the impacts of future committed programs which have been approved and funded are subtracted from the demand forecast to produce a net forecast which is used in the technical analysis of system performance. This ensures that identified system needs account for the anticipated impacts of committed conservation programs. Secondly, incremental cost-effective CDM potential, beyond committed programs as part of existing frameworks and policy is considered as part of the identification and evaluation of potential options to address needs This section describes the way in which CDM has been built into the forecast; consideration of incremental cost-effective CDM as part of the identification and evaluation of options is discussed further in Section 4.1[4].

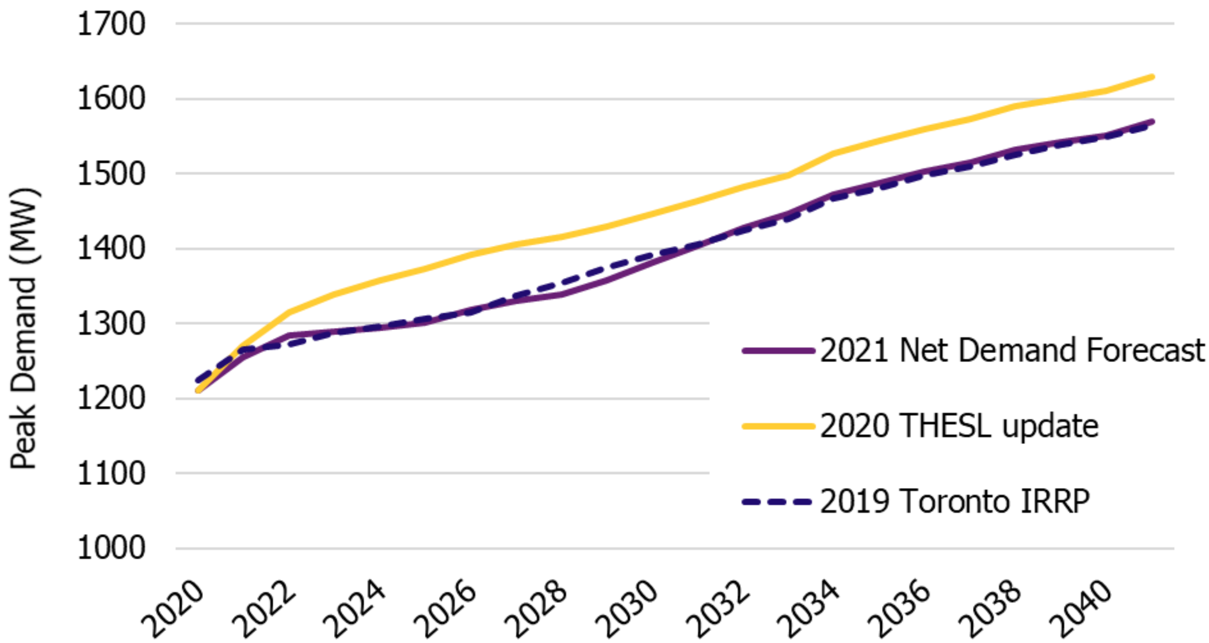
In the 2019 IRRP, no adjustments were made to the demand forecast to account for future initiatives (e.g., CDM programs) because, at the time of IRRP development, conservation programs were being developed according to the Conservation First Framework, which was set to expire in 2020. As a result, information about future conservation initiatives, including targets and funding, was limited, and therefore future conservation assumptions were not accounted for.

Since publication of the 2019 IRRP, Ontario has released the 2021-2024 CDM Framework. For the purposes of this addendum, this framework has been the primary source of information to assist in developing assumptions about the future impact of provincially driven conservation savings. Anticipated impacts of conservation were developed on a station by station basis, and subtracted from the THESL forecast update to produce the final 2021 addendum forecast. The methodology used to develop these CDM assumptions is described in Appendix A.

The graph below in Figure 2 shows the original 2019 IRRP forecast, the updated forecast provided by THESL in 2020, and the final net 2021 addendum forecast used in the technical assessment of needs.

[4] Note that impacts of previous programs (e.g., Conservation First Framework, Interim Framework) are inherently included in the forecast provided by THESL.

Figure 2| Summer Coincident Peak Demand - 2021 Net Forecast



Note that the impact of the 2021-2024 CDM Framework largely offsets the additional demand growth observed in the first three to five years of the forecast. The end result is a final net demand forecast for the 2021 addendum that is similar to the 2019 IRRP demand forecast; the key difference is that the updated net demand forecast includes the impact of the 2021-2024 CDM Framework, whereas the forecast in the 2019 IRRP does not. There is also minimal impact on the forecast resulting from existing distributed generation.

3.3 Dufferin TS Supply

Dufferin TS is a step down transformer station located in central Toronto which typically peaks at approximately 125 MW. It has the ability to be served from either the Leaside sub-system, or the Manby sub-system (via the Richview x Manby corridor). While under normal operating conditions Dufferin TS is supplied via Leaside, operators have the ability to transfer Dufferin to Manby supply as an interim measure to manage periods of high demand on the Leaside sub-system, or as a result of system or resource outages which are impactful to the Leaside sub-system. Table 1 shows the historical use of this operational measure and increased use in recent years.

Table 1| Table showing Percentage of Time Leaside loads are transferred to Manby and Manby Loads transferred to Leaside

	Leaside loads transferred to Manby		Manby loads transferred to Leaside	
	Percentage of year	**Percentage of summer**	**Percentage of year**	**Percentage of summer**
2018	2%	4%	2%	0%
2019	16%	0%	0%	0%
2020	31%	52%	2%	0%

One of the factors which has increased the frequency with which this measure is deployed is the removal of a bulk contingency exception on the Leaside TS x Cherrywood TS corridor in summer 2020, due to the broader bulk electricity system impacts from contingencies involving these facilities. Before the exemption was removed, operators did not need to respect the sudden loss of two circuits along this corridor[5], as this event was not expected to impact the bulk power system outside of the Toronto area. Recent technical assessments have shown that this type of contingency can have a cascading impact on the broader bulk electricity system, including systems outside Ontario, under certain import conditions. As a result, operators must now ensure that at any time a sudden loss of two circuits will not cause this adverse impact. This becomes more likely as the load served by the Leaside sub-system increases, and particularly when Portlands GS or transmission assets are out of service pre-contingency. Transferring Dufferin TS to Manby supply lowers the amount of load served by the Leaside sub-system, and is therefore one way that operators can manage this condition.

Because transfer of Dufferin TS to Manby TS is not a standard operating condition, it has not been included as a basecase assumption in this addendum for the purposes of establishing system need. At the same time, given the frequency with which this action is taken, and the likelihood that it will remain a valuable tool for operators to maintain reliability in the future, it is strongly recommended that any solution to address the Richview x Manby supply capacity need be sized to ensure the continued viability of this action. Of particular interest, Hydro One has indicated that the use of this operating measure is expected to increase throughout the 2020s in order to accommodate outages required in the vicinity of Leaside TS to enable work on the Ontario Line transit project.

In other words, a solution that addresses the Richview x Manby capacity need must also be able to withstand the added load of supply to Dufferin TS. Otherwise, any solution would address one sub-system need (Manby), while introducing constraints to operator actions on a different sub-system (Leaside). In practical terms, this means that establishing the need

[5] Regional Reliability Reference Directory #1: Design and Operation of the Bulk Power System, NPCC

date associated with Richview x Manby will be done assuming Dufferin supply via Leaside. However, when evaluating potential solutions to address this need, the required capacity will be considered under a Dufferin supply via Manby scenario.

3.4 Updated Contingencies Considered

A study to determine the load meeting capability (LMC) of the existing Richview by Manby corridor was conducted using the updated demand forecast and system topology assumptions. Additional technical details can be found in Appendix C.

The planning criteria applied in this study are in accordance with planning events and performance as detailed by:

- North American Electric Reliability Corporation ("NERC") TPL-001 "Transmission System Planning Performance Requirements" ("TPL-001"),
- Northeast Power Coordinating Council ("NPCC") Regional Reliability Reference Directory #1 "Design and Operation of the Bulk Power System ("Directory #1"), and
- IESO Ontario Resource and Transmission Assessment Criteria ("ORTAC").

Under these standards and requirements, and in this particular part of the system, load rejection/curtailment of up to 150 MW is permissible following the loss of two transmission elements. ORTAC does not specify a limit to the amount of load rejection/curtailment allowed following the loss of three or more elements so long as the load rejection/curtailment does not impact other areas outside the IESO controlled grid. For clarity, no load rejection/curtailment is allowed following the loss of one transmission element in this part of the system.

The following summarizes the critical single and double contingencies studied, consistent with NERC and NPCC planning events, for scenarios with all elements in-service and with one element initially out-of-service. In addition, this study considered the most limiting contingency of the existing system as identified by the Richview to Manby Reinforcement SIA (2018-637); namely the R24C + K23C double contingency following an R15K outage. This extra contingency was compared to the studied contingencies below to determine the LMC of the system.

The studied N-1 contingencies are:

- R1K
- R2K
- R13K
- R15K
- R24C

The studied N-2 contingencies are:

- R1K + R2K
- R13K + R15K

4 Updated Richview x Manby Needs Assessment

After accounting for updated system models and assumptions as described in Section 3, a needs assessment was carried out for the Richview x Manby corridor to produce a revised need statement. The limiting phenomenon observed continues to be loading on the R2K circuit following the loss of R15K and occurs in 2021. This contingency was limiting under the basecase scenario (an N-1 contingency), and the Dufferin supply from Manby scenario. Additional technical details can be found in Appendix C.

Table 2 shows the amount of peak demand forecast in excess of the load meeting capability of the corridor based on the limiting phenomenon. Also included is the original 2019 peak capacity need by year, for comparison:

Table 2| Table showing the Richview x Manby Peak Demand Need in the 2019 IRRP vs. 2021 Addendum

Peak Demand (MW)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
2019 IRRP Original Need										
2019 Supply Requirement	-	11	29	38	49	59	79	97	117	133
2021 Addendum Revised Need										
2021 Supply Requirement (Basecase)	1	24	35	48	58	77	90	102	119	142

Under basecase assumptions, needs have increased slightly compared to the original 2019 IRRP, largely as a result of higher than anticipated near term growth rates, as well as updates to the operational configuration of the system (operating Claireville and Richview buses as split). It is worth noting again that the revised needs include the impact of the 2021-2024 CDM Framework, while the 2019 IRRP did not have any CDM impacts included.

5 Updated Options Analysis

This section explores potential options that may assist in meeting the Richview x Manby corridor needs. These potential options include non-wires alternatives (NWAs), such as incremental CDM programs and other DER technologies, FACTS devices and the Richview x Manby transmission reinforcement. While this Addendum Study has considered non-wires alternatives, the primary focus is on incremental CDM programs in light of the updated information available with respect to this option through the Achievable Potential Study and the 2021-2024 CDM Framework. The feasibility of employing DERs and FACTS devices to meet the Richview x Manby corridor needs were not explicitly explored in the first cycle of regional planning for Toronto. In this addendum, DERs and FACTS devices are explored as part of the options analysis.

Given the importance of maintaining the capability to supply Dufferin TS from the Manby sub-system, as described in Section 3.3, the potential options have been evaluated against their capability to provide the required capacity including Dufferin TS.

5.1 Incremental CDM

In addition to the expected impact of conservation programs and savings embedded into the demand forecast (described in Section 3.1 above), the addendum also considered the potential for additional incremental CDM savings to target the Richview x Manby transmission corridor need. The potential for new CDM in the study area was developed by taking the 2019 Achievable Potential Study (APS)[6], and scaling the results for the study area based on customer composition and peak demand. These values were further reduced to account for the savings already accounted for through the provincial 2021-2024 framework, which was not accounted for when the 2019 APS was developed. This produced an estimated incremental achievable cost effective potential for the area of 27 MW in 2025, and 121 MW in 2030. Table 3 shows the expected cumulative CDM potential, by year. Note that these savings forecasts are estimates and can be further refined as programs are developed to target local CDM opportunities.

[6] 2019 Conservation Achievable Potential Study (https://www.ieso.ca/2019-conservation-achievable-potential-study)

Table 3| Incremental Cost Effective Achievable CDM Potential

	2022	2023	2024	2025	2026	2027	2028	2029	2030
Incremental Cost Effective Achievable CDM Potential (MW)[7]	3	7	14	27	44	61	78	100	121
Local Incentive Program Target (MW)	2.8	5.4	8	8	8	-	-	-	-

Although the anticipated amount of incremental achievable cost effective CDM in the study area is insufficient to fully meet the supply capacity need under either the basecase and Dufferin TS supply from Manby scenarios (refer to Table 2), this option can still be leveraged in two ways:

- Incremental cost effective achievable CDM may be considered with other options which may, together, fully meet the need, and;
- Incremental cost effective achievable CDM will help lower customer exposure to reliability risk by reducing the number of hours and/or magnitude of need when peak demand is expected to exceed planning ratings. This could be particularly useful in mitigating risk before other solutions can come into service given their lead time.

One program that has recently been developed to target some of this potential in the Richview south area is the Local Initiative Program, or LIP. As part of the 2021-2024 Conservation and Demand Management CDM Framework, the LIP will develop local initiatives to deliver CDM savings in targeted areas of the province with identified system needs. Under this program, up to 8 MW (out of a total 44 MW in Table 3 above) is expected to be achieved in the study area by 2026. Additional information on this program is available on the IESO website[8]. It should be noted that alternate mechanisms would be needed to acquire remaining portion of incremental cost effective achievable CDM beyond the LIP.

This section does not include a cost evaluation of the CDM measures (whether it be from 2021-2024 CDM Framework or the LIP) as they are considered to be committed by way of Ministerial directive, and, as such, already passed a system cost-effectiveness test. While the remaining portion of the incremental cost effective achievable CDM is not committed, it has been determined to be cost effective from a system perspective.

[7] Note that this potential includes the funded Local Initiative Program and as of yet unfunded CDM potential

[8] Save on Energy, Local Initiatives https://saveonenergy.ca/en/For-Business-and-Industry/Programs-and-incentives/Local-Initiatives

5.2 Distributed Energy Resources

Distributed Energy Resources, or DERs, are a range of technologies which work by meeting system capacity needs locally. They include numerous technologies including, but not limited to, solar PV, energy storage, behind-the-meter generation, and demand response. They provide an alternate source of electricity, thereby reducing the electricity demanded from the grid and alleviating the strain on the electricity system. The Addendum Study has reviewed DER options in this context, to ensure there are no significant changes that would change the ability of DERs to defer the needs.

The study team considered the amount of DER required to defer the Richview x Manby transmission reinforcements (the status quo recommendation from the 2019 IRRP) from its anticipated in-service date of 2025 to 2030. This assumption balances the lead-time of the transmission reinforcement with the capacity of DER required in the specific Richview South area. No DER costs are included between 2021 and 2024 as they will impact all options equally (given the anticipated in-service dates of the other options) and are thus not required for comparison of the options.

The maximum annual capacity required by DER solutions to fully address the system capacity need was informed by the net peak demand forecast used in this addendum and assumes that all incremental cost effective achievable CDM is acquired first. Additionally, a sample load duration profiles was developed in order to estimate the number of cumulative hours and total energy required for each event when the net peak load exceeds the LMC of the Richview x Manby transmission corridor. Details on how these load profiles were developed are provided in Appendix B. Taken together, the annual capacity, duration and energy requirements help to identify which DER technologies are technically capable of meeting the need.

Because the need identified in the Richview South area occurs during summer peak conditions, only DERs which are able to dispatch when required during late summer afternoons are considered technically feasible. Consideration was given to the following resource types:

- Resources that have cost and operating characteristics equivalent to a Simple Cycle Gas Turbine (SCGT); any other mention of SCGT in the report is meant in this context.
- Battery Storage - This technology works by charging during periods when electricity is less costly and the system is not constrained (such as overnight), and discharging during peak conditions when the need occurs.
- Demand Response (DR)- This technology relies on customers within the target area reducing their net demand (through load shifting, curtailment, or behind-the-meter generation) when a signal is received.

As shown in the table above, the amount of DERs required, in addition to all incremental cost effective achievable CDM, is significant, particularly to accommodate Dufferin TS transfers. The technical working group ruled out further consideration of DERs on this basis as further described below.

- An SCGT of this magnitude is unlikely to be feasible to site in the specific Richview South area and would cost orders of magnitude more than other solutions.
- Battery energy storage is also unlikely to be feasible when considering the characteristics of the need and current battery technology and costs.
- Demand response is not considered a feasible means of meeting the need, particularly considering Dufferin TS transfers, given that peak demand offsets would be equivalent to around 15% of total peak load being curtailed in the specific Richview South study area. In addition, based on the results from the 2020 Capacity Auction the total additional potential for DR in the Toronto Zone (i.e., wider Greater Toronto Area) is approximately 186 MW. In order to meet the supply capacity need, approximately 170 MW (assuming also that all incremental cost effective achievable CDM is acquired) of this potential would need to be achieved annually in the specific Richview South area.

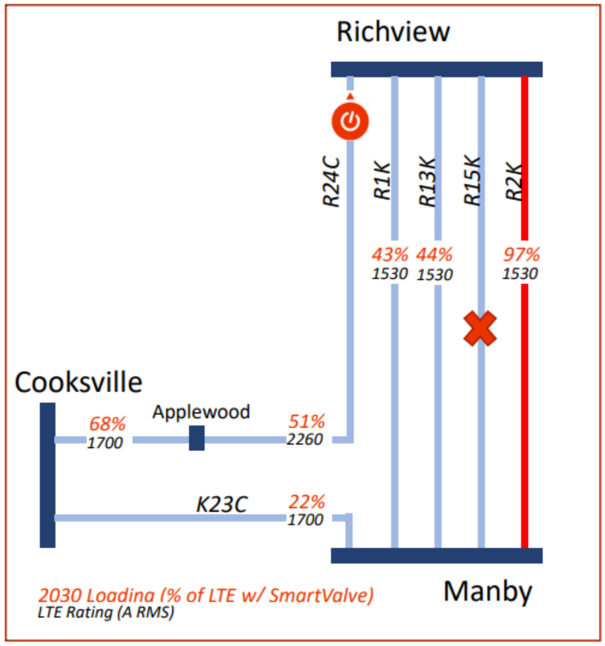
5.3 FACTS Devices

Flexible AC Transmission System (or FACTS devices) are a broad category of electrical equipment which can be used to dynamically control voltages within the system, and influence how power flow is distributed across multiple circuits. In the case of Richview South, system needs are driven by flow along the limiting Richview x Manby corridor. A separate circuit in the area, i.e., Richview x Cooksville (R24C), is not as heavily loaded during typical summer peak conditions and presents an opportunity to offload the Richview x Manby corridor if power could be diverted to this circuit. One particular type of FACTS device, Static Synchronous Series Capacitors (SSSCs), has been evaluated for technical feasibility and cost considerations for this application. SSSCs work by injecting a voltage in series with the line, which introduces an inductive or capacitive reactance and influences the share of power which will flow through that circuit, compared to other parallel routes.

This analysis was undertaken by Smart Wires Inc., a technology company with experience in building and installing SSSCs devices.

The basecase model developed for the addendum was used to evaluate performance of the SSSC device following the same limiting contingencies observed for the loss of R15K, with and without the Dufferin TS supply scenario from the Manby system. A three phase installation of SSSCs were assumed to be installed along the less utilized R24C circuits, to carry additional power flows which would otherwise flow along, and exceed planning limits of, R2K. This is shown conceptually with sample flows and ratings in Figure 3.

Figure 3| Diagram showing most limiting contingency and element and proposed location of SSSC technology (Source: Smart Wires Inc.)



Based on the evaluation carried out, the SSSC device would defer the supply capacity need up to approximately 2028 with Dufferin TS supplied by Manby, after which, the Richview x Manby transmission reinforcements would be required. Although all relevant performance criteria would be met under this alternative up until 2028, this solution would require the use of Load Rejection (L/R) under certain contingencies, such as the loss of two circuits mentioned in Section 3.4. This is considered an acceptable practice under established planning criteria to recognize the relatively low probability of multi-order contingencies occurring at the same time as high system loading, however this has been cited as a concern by THESL which has expressed its preference for solutions that reduce the likelihood of implementing load rejection for dense urban areas.

The SSSC facilities could be deployed within one year of the equipment order, at a cost approximately $4-6 M, with ongoing annual maintenance costs of around $50,000-80,000. However, additional costs, time, and considerations are required to ensure a suitable location exists to accommodate this type of facility. Hydro One has indicated that given the maximum short circuit rating of the SSSC equipment (68 kA), it would have to be installed some distance from Richview TS (where equipment must accommodate short circuit ratings of 70 kA). This would mean finding a suitable location along the R24C corridor between Richview TS and Cooksville TS, and designing and constructing a fenced in facility with Environmental Assessment (EA) approvals, protections, control, and telemetry equipment.

Using the timeline and costs for building similar facilities within the GTA, Hydro One estimated that the necessary development costs would add approximately $6-8 M to the

SSSC equipment, and could be completed within approximately 30 months. The facility itself would also would take up significant space in the existing right of way, and could introduce a risk of community opposition as a result. Delays with the EA process could also potentially add a year or more to the project timeline, depending on the level of involvement and whether a full class EA is triggered.

Additional concerns have also been raised regarding timelines for detailed engineering evaluation and approval for the use of SSSC, given that this technology has not been used in Ontario before. Both Hydro One and the IESO would require a detailed review of this technology and its performance characteristics before it could be approved for connection to Hydro One facilities or the interconnected grid. These concerns include dynamic performance of the technology under fault conditions, and testing of equipment at low temperatures.

Hydro One has indicated that testing of new technology may add additional time to the approvals process before development can be undertaken. The total cost and timeline of the Smart Wires solution is estimated at least $10.5 M, with an earliest in-service date of 2025. The total NPV cost of this option, including the cost of the Richview x Manby transmission reinforcements which would be required by 2029, is approximately $32 M.

5.4 Richview x Manby Transmission Reinforcement

The transmission based solution studied in this addendum is the same solution initially recommended in the 2019 IRRP; that is rebuilding an idle 115 kV double circuit line as a 230 kV double circuit line. This is outlined in the proposed Richview TS by Manby TS upgrades as found in the System Impact Assessment (SIA) Report ID 2018-637.

According to the SIA Report, the RxK upgrades involves the following:

- The existing idle 115 kV line between Richview TS and Manby TS will be rebuilt as a new 230 kV double circuit line, with both circuits tied together to form one super-circuit. The new 230 kV super-circuit will take the breaker positions of the existing circuit R15K at both ends and be designated as circuit R15K.
- The existing circuit R15K will be re-connected at both ends, taking the breaker positions of the existing circuit R1K and renamed R1K.
- The existing R1K and R2K circuits will be bundled as one new super-circuit R2K, taking the breaker positions of the existing R2K at both ends.
- The Horner TS tap point on the existing R13K circuit will be moved onto the new circuit R15K.
- The existing last section of K21C of nine meters connected to Cooksville TS will be upgraded. The long-term thermal rating of the new line section will be at least 2000 Amps.

Based on the study results found in Appendix D, under the updated demand forecast, it is found that the most limiting contingency will not result in any violations of planning criteria. Load rejection up to 350 MW may be required under certain scenarios (i.e. when three elements are out of service on the Richview South area) which is still acceptable under applicable planning criteria. Therefore, it is expected that the proposed transmission solution can meet the demand as forecasted in the Toronto IRRP addendum up to the end of the study period in 2040. Based on current estimates from Hydro One, the upgrade would be complete by Q2 2025 and will cost approximately $23 M (NPV) assuming development work begins immediately.

6 Revised Planning Outcomes

After completing the revised needs statement, a review of technically feasible options was undertaken using updated assumptions, particularly related to incremental cost effective achievable CDM. A preferred solution was identified on the basis of technical feasibility, cost, and ability to fully meet system needs over the long term. The results of this assessment are included in Section 6.1 below.

It is also recognized that the urgency of this system need, coupled with the expected timeline to implement the preferred solution, will result in a multi-year period in which loads in the Richview South area may be at increased risk of experiencing lowered reliability. Optional measures to mitigate this risk, including activities already underway, are explored in Section 6.2.

6.1 Preferred Solution

Based on the updated review of system needs associated with the Richview x Manby transmission corridor and evaluation of options to address this need, the transmission upgrade option continues to be the preferred option to address system capacity needs in the Richview South area. A transmission upgrade, including rebuilding an idle 115 kV double circuit line to 230 kV, and associated connection work at Richview TS and Manby TS, with an expected in-service date of 2025 is the only solution which is able to meet needs associated with anticipated load growth over the medium and long term at the lowest cost to Ontario ratepayers. A summary of the economic assumptions and results can be found in Appendix E.

By providing a significant increase in both supply meeting capability and customer reliability, this solution is also the only alternative that will allow for the continued transfer of Dufferin TS to the Manby system beyond 2028 while still respecting standard planning criteria and ratings. Based on the updated load forecast, the need for this transmission upgrade is present day. Notably, the transfer of Dufferin TS during peak summer conditions have already caused the load meeting capability of the Richview x Manby corridor to be exceeded during summer peak in 2020, when considering planning criteria[9]. The frequency with which this event occurs is expected to increase throughout the 2020s as a result of continued forecast growth throughout Toronto, as well as increased operator transfers of Dufferin TS to Manby supply to accommodate outages associated with the construction of the Ontario Line.

[9] Note that the limiting contingency (loss of R15K) did not occur in 2020. It was a risk of the need materializing when considering planning ratings.

It is therefore recommended that Hydro One immediately proceed with work on this project targeting an in-service date of 2025. Note that the technical working group understands this is the earliest possible in-service date given the project lead time.

Use of SSSCs has the potential to meet the needs until approximately 2028 with Dufferin TS transferred to Manby. However, when compared to a transmission solution, this option will be more expensive and would expose customers to greater potential levels of load rejection under certain contingencies (though still within acceptable ranges under established criteria). Additionally, potential delays associated with study and approval of a technology untested in Ontario would add additional time and uncertainty to implement this solution, while costs associated with building a site suitable for accommodating this technology would add both costs and risk from a project planning perspective. For these reasons, an SSSC is not recommended as a solution in this application.

6.2 Potential Mitigation Measures Before Implementation of Preferred Solution

As discussed above, this addendum has validated the need for transmission upgrades of the Richview x Manby corridor to meet anticipated near term supply capacity needs in the Richview South area. However, due to the anticipated timelines associated with design, approvals, and construction of this project, it is unlikely to be in service until summer of 2025, even though need is present day. As a result, even if the recommended actions are pursued, customers in the Richview South area remain exposed to greater reliability risks than permitted under standard planning criteria for the next three to four years.

The periods of time where load may be at risk following a single element outage can emerge when load served by the Richview x Manby corridor exceeds its LMC. Any measure which is able to reduce customer demand during summer hours would lower the amount of load which could potentially be at risk of interruption by an equal amount. In other words, any decrease in load above the LMC would carry a reliability benefit, even if it is not able to keep loads below this threshold entirely.

However, quantifying the value of this reliability benefit is challenging, as there is no associated transmission deferral. Instead, it is recommended that NWA be considered within the context of broader provincial supply and demand needs, and be prioritized in the Richview South area and pursued where cost effective. Among the NWA considered in this addendum, both CDM and DR have the potential to lower exposure to customer reliability needs until the transmission upgrade can come into service, and may be cost effective from a system benefit perspective.

In the case of CDM, the Local Initiatives Program will identify and procure cost effective opportunities in the Richview South area. Targeting spending in areas with known reliability benefit or local deferral value is consistent with the objectives laid out in the 2021-2024

Conservation Framework. More information on this initiative is available on the IESO website.[10]

There is opportunity to leverage THESL's flagship Non-Wires Alternatives program, Local Demand Response (DR), which has been deployed successfully since 2018. Local DR is a big step forward in evolving conventional utility station planning to include the consideration of non-wires alternatives alongside traditional poles and wires investments. This program is designed to help address short-to-medium term capacity constraints at targeted transformer stations by identifying opportunities where behind-the-meter, customer-owned DERs, can be leveraged to support the broader distribution system cost-effectively. The 2020-2024 Local DR program will target three station areas, including Basin TS, Manby TS, and Horner TS, with the goal of competitively procuring up to 17 MW of DR capacity to be deployed in 2022. This program supports broad regional planning goals and provides the opportunity to realize benefits at both the distribution level and the transmission level in the Richview south area.

[10] Save on Energy, Local Initiatives https://saveonenergy.ca/en/For-Business-and-Industry/Programs-and-incentives/Local-Initiatives

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