TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT1.1

EVIDENCE REFERENCE:

2-SEC-42(A)

UNDERTAKING(S):

To provide the full list of potential projects that the 2025 Copperleaf optimization process used.

RESPONSE(S):

The final, approved 2025 project list, derived through the Copperleaf Portfolio Optimization Process, was previously submitted in Attachment 2-SEC-42(A) - Copperleaf Key Outputs as part of the Interrogatory response 2-SEC-42.

In this undertaking, Attachment JT1.1(A) - 2025 Copperleaf Project List is submitted. This contains the comprehensive list of all potential projects considered and subjected to the 2025 optimization process. Within this project list, each project is identified as either having been optimized for inclusion in the final 2025 approved list or deferred.

As stipulated in Section 5.3.2 of Schedule 2-5-4 - Asset Management Process, two core lists are generated: a preliminary list and a final approved list. Attachment JT1.1(A) - 2025 Copperleaf Project List represents the initial project pool, based on high-level estimates, that was optimized to create and support the preliminary project list. This preliminary project list is subject to subsequent refinement, a second round of optimization, and finalization to produce the approved list.

It is important to note that the project scoring and cost values documented in Attachment JT1.1(A) - 2025 Copperleaf Project List may differ from those in the final figures presented in Attachment 2-SEC-42(A). These differences result from the changes and refinements made to the project scope and associated cost estimates during the subsequent cost estimate refinement process.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT1.2

EVIDENCE REFERENCE:

2-Staff-59

UNDERTAKING(S):

Under Staff 59 the intervention value or the net value, at 254, page 73, at the asset level and also then at the program level for each of the three alternatives, being cost containment, short-term risk mitigation, and long-term risk mitigation, and if it is possible in each of those to break it down by those various value scores at the aggregate level for each of the asset categories, so we can see what the change in reliability risk is, financial risk, safety risk, environmental risk, and the replacement costs.

RESPONSE(S):

Hydro Ottawa would like to clarify that the undertaking was to provide the asset risk values used relative to the replacement costs at the asset and program level for the three system renewal alternatives used in the intervention value calculation referenced in Hydro Ottawa's response to the interrogatory 2-Staff-59, part c.

Please refer to Attachment JT1.2(A) - Asset Intervention Values for the risk values and intervention value at the asset type and program level for the three alternatives considered for system renewal investments: cost containment, short-term risk mitigation, and long-term risk mitigation. Hydro Ottawa employs a strategic, forward-looking approach to System Renewal investment planning, utilizing levelized spending to mitigate the long-term effects of asset degradation or failure. These investments are scaled to reduce the corresponding risk values obtained from Copperleaf Predictive Analytics (PA), as shown in Attachment JT1.2(A) - Asset Intervention Values, to maintain overall system reliability.

Attachment JT1.2(A) shows the 2024 risk values (used as a baseline) and the residual risk values by 2030 as a result of intervention, based on the three investment scenarios considered for system renewal planning. These values are categorized by asset class and asset system. Copperleaf PA uses these risk values to determine the intervention value of replacing a specific asset within the system, as well as the recommended intervention date, by comparing them against the replacement costs. Key risk measures tied to reliability impact, safety implications, environmental considerations, financial aspect, and compliance have been considered in determining individual asset risk profiles. While all risk measures have been weighted equally in the PA model, reliability risk was found to be the major contributor, given its wide applicability across all asset types and data availability around asset failure modes and the related customer impact. The information generated by Copperleaf PA will grow and be refined over time as there are improvements to asset risk information. Hydro Ottawa's asset renewal strategy focuses on mitigating and managing asset risks, considering long-term impacts, through the strategic replacement of deteriorating infrastructure, rather than the outright replacement of all aged or deteriorated assets.

Replacement programs for all asset types (Stations, Overhead, Underground, and Metering) are evaluated at the asset class level. This assessment is conducted through the System Renewal Material Investment Plan, as outlined in Schedule 2-5-7 - System Renewal Investments. System renewal investment planning primarily considers three investment alternatives: cost containment, short-term risk mitigation, and long-term risk mitigation. These alternatives are further detailed in Section 5.2.1.1 Program Planning Approach of Schedule 2-5-4 - Asset Management Process. The alternatives were developed with the objective of balancing long term-cost impacts with equipment lead-time, resourcing limitations and risk mitigation associated with assets in degraded condition. The aforementioned alternatives are evaluated against the corresponding evaluation criteria considered (such as safety, reliability, financial, system observability, resilience, etc.), to finalize an optimal investment alternative for a given asset type.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT1.3

EVIDENCE REFERENCE:

2-SEC-39(A)

UNDERTAKING(S):

To provide a revised asset condition assessment results by asset type that removes service age as a condition.

RESPONSE(S):

This undertaking requested Hydro Ottawa to provide a revised condition assessment of its assets (such as transformers and distribution lines) by excluding age as an underlying condition parameter in the Health Index (HI) assessments.

After reviewing with subject matter experts, Hydro Ottawa maintains that it cannot provide a valid condition assessment without incorporating age, as it is a vital condition parameter. Excluding age from the condition assessment framework would render the results invalid for planning purposes. Age is essential because it serves as a reliable indicator of an asset's expected physical degradation over its in-service life, which is critical for predicting its remaining useful life.

To advance the HI framework, Hydro Ottawa has already reduced its reliance on age as the sole determinant of condition. This change was reviewed and approved by an independent third-party expert (Hatch) and detailed in Section 5.1.2.1 - Asset Condition Assessment under Schedule 2-5-4 -

Asset Management Process. To ensure the reliability of the HI value, a validity measure was implemented, which mandates that at least 70% of the condition information must be available for a Health Index score to be defined.

For assets with a known age but insufficient inspection data to meet the 70% threshold, age is now translated to an equivalent condition value. This is achieved using a piecewise linear relationship established during the failure curve development exercise with Hatch. This process is used to provide the Copperleaf Predictive Analytics (PA) system with a necessary condition value for assets that otherwise lack a valid HI score. These updates, including the third-party validation by Hatch, are documented in Section 5.1.2.1 - Asset Condition Assessment under Schedule 2-5-4 - Asset Management Process.

A key enhancement to Hydro Ottawa's asset management since the last rate application has been the incorporation of predictive analysis via the Copperleaf PA module. This allows for proactive forecasting of system renewal needs and optimization of replacement timelines. A valid HI value is a crucial input for this system, enabling the forecast of degradation and the determination of risk-based intervention dates.

Removing age as a condition parameter will compromise the validity of HI values for most station and distribution assets, as it will cause them to fail the 70% condition information requirement. Consequently, asset interventions will revert to being driven by age-based estimates (the age-to-condition translation defined by the Hatch curve) rather than actual, observed asset condition. This dependence on the age-to-condition translation, as opposed to a validated HI score, will significantly impact the accuracy and optimization of Hydro Ottawa's system renewal investment plans, as shown in Table A, based on the resulting proportion of invalids.

Table A: Condition Assessment Summary by Excluding Age as a Condition Parameter

Asset System	Asset Class	Condition Assessment					
		Very Poor	Poor	Fair	Good	Very Good	Invalids
Stations	Station Transformer	0%	1%	32%	48%	11%	**8%**
	Station Breakers - Air	0%	0%	20%	14%	29%	**36%**
	Station Breakers - SF6	0%	0%	0%	5%	25%	**70%**
	Station Breakers - Oil	0%	0%	32%	10%	16%	**43%**
	Station Breakers - Vacuum	0%	0%	1%	14%	16%	**69%**
Overhead (OH)	Poles	2%	17%	18%	23%	22%	**18%**
	OH Switches	0%	0%	0%	0%	3%	**97%**
Underground (UG)	UG Cables	-	-	-	-	-	**100%**
	Vault Transformers	-	-	-	-	-	**100%**
	Vault Switchgear	-	-	-	-	-	**100%**
	UG Switchgear	0%	0%	7%	7%	65%	**21%**
	Cable Chambers	0%	1%	8%	24%	47%	**20%**

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT1.4

EVIDENCE REFERENCE:

Attachment 2-Staff-57(A)

UNDERTAKING(S):

To provide what is available with respect to the grid modernization KPIs.

RESPONSE(S):

As listed as "2024 - Grid Modernization Key Performance Indicatory (KPI) Development", in response to interrogatory 2-SEC-39 part b, Hydro Ottawa engaged Hatch in 2024 to identify and refine a set of KPIs to monitor the progress of Hydro Ottawa's Grid Modernization Roadmap (Attachment 2-Staff-57(A) - Hydro Ottawa Grid Modernization Strategy 2025).

As an output of the engagement, Hatch provided the following eight KPIs for evaluation. The final report from the engagement with Hatch is included in Attachment JT3.15(D) - Grid Modernization Key Performance Indicator (KPI) Development.

1. **System Observability:** To measure the capability to monitor the grid for situational awareness, enable better system planning, operation control, and optimize investment decision-making.
   - Scope: Feeder Observability and Station Observability
   - Objectives: Situational awareness for system planning and operation control

- Outcomes Measured: number of devices installed, performance of devices, intended benefit materialization

2. **System Controllability:** To measure the capability to remotely control the grid for security, safety and reliability performance.
   - Scope: Feeder level
   - Objectives: higher automation level enables more flexible control for better security, safety and reliability
   - Outcomes Measured: number of switches to be automated for remote control, intended performance, intended benefit

3. **Improved Grid Model Accuracy:** To measure the clean up process of the grid network model and the simulation progress of feeder-level hosting capacity.
   - Scope: feeder-level errors and simulations
   - Objectives: an accurate grid model will help improve simulations, ADMS implementation, etc.
   - Outcomes Measured: low priority warnings in CYME, high priority warnings in CYME, Errors in CYME, Feeders with hosting capacity simulated

4. **Feeder Loading:** To measure loading at the feeder level for optimal grid operation and planning.
   - Scope: all feeders
   - Objectives: Improve visibility on system loading, avoiding system overloading and bottleneck, and aid in system planning.
   - Outcomes Measured: System-wide Feeder Load Index distribution

5. **Station Loading:** To measure loading at the Station and Bus level for optimal grid operation and planning.
   - Scope: Station and bus loading

- Objectives: Improve visibility on system loading, avoiding system overloading and bottleneck, and aid system planning.
- Outcomes Measured: System-wide Station Load Index distribution

6. **Load Constraint Management:** To measure conductors, cables, and distribution transformers loading for optimal grid operation and planning.
   - Scope: Primary conductors, primary cables, and distribution transformers
   - Objectives: Improve visibility on system loading, avoid system overloading and bottleneck, and aid system planning.
   - Outcome Measured: System-wide Load Index distribution

7. **DER Visibility & Management:** To measure HOL's monitoring capability of DERs connected to the grid.
   - Scope: All types of Distributed Generators (including synchronous generators, induction generators, and inverter-based).
   - Objectives: Track HOL's monitoring capabilities of DERs larger than 10 kW
   - Outcomes Measured: For DERs larger than 10 kW (non-microgeneration), the monitoring capability of DERs, including:
     i. Monitoring & Control Box (MCB) Classic
     ii. MCB Lite - monitoring only
     iii. MCB Lite - with control
     iv. Transfer trip panel

8. **DER Hosting Capacity:** To measure HOL's capability to host additional DERs.
   - Scope: Feeders
   - Objectives: current scopes uses HOL's existing restricted feeder list. Once hosting capacity for each feeder is simulated, the simulated hosting capacity should be referred to identify restricted feeders.
   - Outcome Measured: Number of feeders that are restricted from connecting new DERs due to limited hosting capacity

As a result of current data availability Hydro Ottawa is assessing the value of seven grid modernization KPIs, listed below, including any updates to the scope or outcomes measured in comparison to those outlined above. Note that Load Constraint Management (KPI number 6 above) is currently not being assessed due to limited data availability.

1. **System Observability**
    - Outcomes Measured: excludes performance of devices
2. **System Contrablability**
    - Outcomes Measured: excludes intended performance
3. **Improved Grid Model Accuracy**
4. **Feeder Loading Index**
5. **Station Loading Index**
6. **DER Visibility & Management**
    - Outcomes Measured: updated to track DERs larger than 50 kW to align with HOL current threshold for MCB requirements
7. **DER Hosting Capacity**
    - Objectives: current scopes use HOL's existing restricted feeder list.

Refer to Attachment JT1.4(A) - Hydro Ottawa Grid Modernization KPI Calculations for the calculations.

1. System Observability

Definition: To measure the capability to monitor the grid for situational awareness, enable better system planning, operation control, and optimize investment decision-making.

Inputs (Feeder):

FCI condition, quantity, performance, targets, intended benefit level, weights

AMI 2.0 quantity, performance, targets, intended benefit level, weights

SCADAmate switch quantity, performance, targets, intended benefit level, weights

Inputs (Station):

Digital relays quantity, performance, targets, intended benefit level, weights

RTUs quantity, performance, targets, intended benefit level, weights

PQ meters quantity, performance, targets, intended benefit level, weights

Outcome measured

A. Number of devices installed
B. Performance of devices (temporarily turned off due to data availability)
C. Intended benefit materialization

Performance metric Calculation

$$KPI(i,j) = \sum_{j=1}^{target} \sum_{i=1}^{target} (A_i * B_i * C_i) w_i W_j$$

where $\boldsymbol{i}$ represents the individual feeder (e.g., feeder 1), $\boldsymbol{j}$ represents the individual program (e.g., FCI, AMI 2.0 meters), $\boldsymbol{w}$ is the weight for each feeder, and $\boldsymbol{W}$ is the weight for each program.

Intended Benefit Level	Benefit
1	Data used for asset condition and grid operation monitoring
2	Data used for maintenance planning
3	Data used for capital planning
4	Data used for control and operation
5	Data used for investment and strategic decision making

Outputs (Feeder):

Overall % Observability

FCI % Observability

AMI 2.0 % Observability

SCADAmate Switch % Observability

Outputs (Station):

Overall % Observability

Digital Relay % Observability

RTU % Observability

PQ Meter % Observability

2. System Controllability

Definition: To measure the capability to remotely control the grid for security, safety and reliability performance.

Input:

Tie Switches Quantity

Sectionalizer Quantity

Criteria 1: Each feeder shall have at least 2.5 switches

Criteria 2: Criteria 1 fulfilled AND every 650 customers should have 1 switch

Outcome Measured

A. Number of switches to be automated for remote control

B. Intended performance (*for this calculation all switches were considered 100% working*)

C. Intended benefit

Performance metric Calculation for feeder controllability

$$KPI(i) = \sum_{i=1}^{target}(A_i * B_i)$$

where i represents the individual feeder (e.g., Feeder 1)

Outputs:

Criteria 1 and 2 Pass Count/Pass %

3. Improved Grid Model Accuracy

Definition: To measure the clean up process of the grid network model and the simulation progress of feeder-level hosting capacity.

Inputs:

# of Low Priority Warnings

# of High Priority Warnings

# of Errors

Hosting Capacity Simulated

Target # of warnings, errors and hosting capacity simulated

Outcome Measured

A. Low priority warnings in CYME
B. High priority warnings in CYME
C. Errors in CYME
D. Feeders with hosting capacity simulated

Performance metric calculation for feeders

This KPI will track the progress of warnings and errors in CYME that are treated/resolved each year based on target defined for each category/year, as well as the number of feeders with hosting capacity simulated. Calculations are based on:

- **Actual Number**: Difference between previous year and current year
- **Target Number**: Difference between previous year and target improvement

Outputs:

Avg. % of warnings and errors over target warnings and errors

% Hosting Capacity Simulated (relative to target)

4. Loading Index - Feeder

Definition: To measure loading at the feeder level for optimal grid operation and planning.

Inputs:

Design Ampacity

Planned Ampacity

Revised Load (Average Amps)

Outcome Measured
System-wide Feeder Load Index Distribution

Performance Metric calculation for feeders

$$Percentage\ Loading = \frac{Average\ Amps}{Design\ or\ Planning\ Ampacity} \times 100\%$$

Load Index	Criteria
5	x > 70% of Design Rating
4	x ≥ 100% of Planning Rating
3	85% of Planning Rating ≤ x < 100% of Planning Rating
2	40% of Planning Rating ≤ x < 85% of Planning Rating
1	x < 40% of Planning Rating

Outputs:

# of feeders with load index between 1-5

5. Loading Index - Station

Definition: To measure loading at the Station and Bus level for optimal grid operation and planning.

Inputs:

Station Design Rating (MVA)

SUM of Loading (MVA)

# of existing connected breakers

Target # of breakers

Outcome Measured
System-wide Station Load Index distribution

Performance Metric calculation for stations

$$Percentage\ Loading = \frac{Sum\ of\ Loading\ MVA}{Station\ Design\ Rating\ or\ Planning\ MVA} \times 100\%$$

Load Index	Criteria
5	x > 70% of Design Rating
4	x ≥ 100% of Planning Rating
3	70% of Planning Rating ≤ x < 100% of Planning Rating
2	40% of Planning Rating ≤ x < 70% of Planning Rating
1	x < 40% of Planning Rating

Outputs:

# of stations with load index between 1-5

6. DER Visibility and Management

Definition: To measure HOL's monitoring capability of DERs connected to the grid.

Inputs (Visibility):

Total # of DERs Interconnected

Total kW Interconnected

# of Microgenerations

# of DERs with monitoring capability by HOL

Target DER Visibility

Inputs (Management):

Total # of DERs Interconnected

Total kW Interconnected

# of Microgenerations

# of DERs with MCB Lite Control

# of DERs with Transfer Trip Control

Target DER Management

Outcome measured

A. For DERs larger than 50 kW(Non-Microgeneration), the monitoring capability of DERs, including:
1. MCB CLASSIC
2. MCB LITE - MONITORING ONLY
3. MCB LITE - WITH CONTROL
4. TRANSFER TRIP PANEL

Performance metric calculation for feeders

$$DER\ Visibility = \frac{\#\ of\ Non-Microgeneration\ with\ monitoring}{Total\ \#\ of\ Non-Microgeneration\ DERs\ connected} \times 100\%$$

Outcome measured

A. For DERs larger than 200 kW(Non-Microgeneration), the control capability of DERs, including:
1. MCB LITE - WITH CONTROL
2. TRANSFER TRIP PANEL

Performance metric calculation for feeders

$$DER\ Management = \frac{\#\ of\ Non-Microgeneration\ with\ control}{Total\ \#\ of\ Non-Microgeneration\ DERs\ connected} \times 100\%$$

Outputs:

% Overall DER Visibility

% Overall DER Management (MCB Lite Control)

% Target achieved

7. DER Hosting Capacity

Definition: To measure HOL's capability to host additional DERs.

Inputs:

Hosting Capacity [kW]

Is feeder restricted by hosting capacity? (Y/N)

→

Outcome measured

A. Number of feeders that are restricted from connecting new DERs due to limited hosting capacity

→

Outputs:

# of restricted feeders

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT1.14-VECC-1.0

EVIDENCE REFERENCE:

Exhibit 1, Tab 3, Schedule 1, page 26
Exhibit 8, Tab 4, Schedule 1, page 8
Exhibit 8, Tab 4, Schedule 3, page 1
6-Staff 189
8-VECC 68

UNDERTAKING(S):

Exhibit 1-3-1 states:
"Hydro Ottawa "proposes to set both rates and revenue related to Other Revenue for 5 years. Where rates are proposed to be adjusted in years two to five, for simplicity, an annual inflation rate of 2.1% is proposed to avoid annual adjustments to the rates throughout the rate term."

With respect to the wireline pole attachment rate, Exhibit 8-4- 1 states:
"For the purpose of calculating revenue requirement, Hydro Ottawa has used the OEB-approved 2025 rate for 2026- 2030 estimate. This approach was taken to mitigate any decrease in the number of pole attachments due to the increased desire for third parties to move assets underground."

Exhibit 8-4-3 states: "Table 1 below provides illustrative RSCs for 2026-2030. The 2026 charges are consistent with 2025 approved rates in the OEB Decision and Order for retailer service charges. As a placeholder for the generic RSCs the 2027-2030 period, charges have been held flat for illustrative purposes. Hydro Ottawa proposes to update RSCs in accordance with applicable OEB Decisions and Orders during the 2026-2030 period."

VECC 68 states: "Hydro Ottawa is proposing to update the Wireline Pole Attachment charge annually based on the OEB approved rate."

With respect to USOA 4082 and 4084, Staff 189 states: "The assumption used to forecast Retail Services Revenue amounts is based on the number of applicable retailer customers multiplied by the OEB generic rates."

1.1 It is understood that the current 2026 forecast for revenues from Retail Service Charges (USOA 4082 and 4084) is based on the approved 2025 rates (Exhibit 8-4-3, page 1). Is Hydro Ottawa proposing to update this forecast now that the OEB has approved (Decision and Order EB-2025-0199) the rates for 2026?

1.2 For purposes of determining Other Revenues for 2027-2030, is Hydro Ottawa proposing that the revenues from Retail Service Charges be: i) held constant at the forecast level for 2026 (per Exhibit 6-3-4, Table 2), ii) escalated using the 2.1% per annum inflation factor (per Exhibit 1-3-1) or iii) escalated based on the approved generic rate for the year (per Staff 189)?

1.3 It is understood that the current forecast revenues from 3rd party wireline pole attachments are based on the approved 2025 rates (Exhibit 8-4-1, page 8). Is Hydro Ottawa proposing to update this forecast now that the OEB has approved (Decision and Order EB2025-0200) the rate for 2026?

RESPONSE(S):

1.1 The proposed 2026 forecast for revenues from Retail Service Charges (USOA 4082 and 4084) was based on the approved 2025 rate and 2023 retailer transaction count for each charge. Hydro Ottawa does not propose to update this forecast to reflect the OEB's 2026 inflation rate, as the number of retailer transactions continued to decline in 2024 and the total retailer service revenue was less than 2023 Actuals.

1.2 For purposes of determining Other Revenues for 2027-2030, Hydro Ottawa proposed that the revenues from Retail Service Charges be held constant at the forecast level for 2026 (per Exhibit 6-3-4, Table 2). Hydro Ottawa also proposes to update the actual rate for 2026-2030 by using the OEB generic rates for the purpose of billing retailers. Hydro Ottawa has held the count associated with retailer service charges constant despite experiencing a decline in count for many years, as such Hydro Ottawa anticipates less revenue will be collected over the rate period than built into proposed revenue as Hydro Ottawa expects the transaction count to decline.

1.3 For purposes of determining Other Revenues for 2026-2030, Hydro Ottawa used the 2025 OEB Approved wireline pole attachment rate. Hydro Ottawa is not proposing to update the Other Revenue forecast for 2026-2030 based on the 2026 Approved rate in alignment with holding total Other Revenue amounts for 2026-2030 to the original amounts submitted. Hydro Ottawa also proposes to update the actual wireline carrier rate for this period by applying the OEB's generic rates for the purpose of billing the charge.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT1.14-VECC-2.0

EVIDENCE REFERENCE:

6-Staff 189
Exhibit 8, Tab 3, Schedule 2, page 2

UNDERTAKING(S):

With respect to the SSS Administration Charge, Staff 189 states:
"The assumption used to forecast Standard Supply Admin Charge amounts is based on the number of applicable retailer customers multiplied by the prescribed OEB generic rates in 2021-2025, 2026 was determined through a costbased approach and 2027-2030 were based on the proposed inflation factor, pending OEB approval".

Exhibit 8-3-2 states:
"To remain consistent with OEB province wide charges, such as the pole attachment and retailer service charges, Hydro Ottawa proposes to inflate the 2026 rate by the OEB approved inflationary factor for the 2027-2030 period."

2.1 For purposes of determining Other Revenues for 2027-2030, is Hydro Ottawa proposing that the revenues from SSS Administration Charges 2026 be escalated using: i) the 2.1% per annum inflation factor or ii) the OEB approved inflation factor for each of the years?

2.2 For purposes of determining Other Revenues for 2027-2030, is Hydro Ottawa proposing that the revenues from SSS Administration Charges 2026 also be escalated based on the forecasted (per the Load Forecast) number of customers to whom the rate will be applicable (and not the number of retailer customers per Staff 189)?

RESPONSE(S):

2.1 For purposes of determining Other Revenues for 2027-2030, Hydro Ottawa applied the 2.10% inflationary factor to the proposed SSS charge, in alignment with the inflationary factor used throughout the Application. In setting rates annually, Hydro Ottawa is not proposing to update Other Revenue as part of Revenue Requirement and use the estimated Other Revenue as proposed. Hydro Ottawa has proposed this approach for regulatory efficiency in the update and review of its annual application. The OEB Inflation factor would be used to set the SSS charge annually.

2.2 For purposes of determining Other Revenues for 2027-2030, Hydro Ottawa proposes that the revenues from SSS Administration Charges be based on the proposed SSS customers outlined in Schedule 3-1-1 - Revenue Load and Customer Forecast, with the inclusion of Streetlight, Unmetered Load, FIT and MicroFIT number of accounts (and not the number of retailer customers per interrogatory 6-Staff-189). For clarity, in setting the other revenue for 2027-2030 Hydro Ottawa has adjusted the revenue using the Load forecast count for SSS customers.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT1.14-VECC-3.0

EVIDENCE REFERENCE:

6-Staff 189
6-Staff 186 d)

UNDERTAKING(S):

With respect to USOA 4090 – Electric Services Incidental to Energy Sales, Staff 189 states: "As per Section 4 of Schedule 6-3-4 Other Operating Revenue. The assumption used to forecast Fixed Distribution Charge amounts is based on the number of applicable retailer customers multiplied by the OEB generic rates."

3.1 Please confirm that: i) Section 4 of Schedule 6-3-4 deals with charges applicable to generators and not retailers and ii) with the exception of MicroFIT, there no OEB generic rates for generators.

3.1.1 Please revise the response to Staff 189 accordingly.

3.2 Section 4 of 6-3-4 includes a discussion regarding the proposed MicroFIT charges However Staff 186 d) states that MicroFIT revenues are included in USOA 4235. Please confirm which account includes MicroFIT revenues - 4090 or 4235.

3.3 In terms of the actual generator service charges for 2027-2030 (including MicroFIT) is Hydro Ottawa proposing that: i) they be approved as part of this application and set using the 2.1%

annual inflation factor or ii) they be adjusted throughout the 2027-2030 term based on the OEB approved inflation factors for each of those years?

3.4 In terms of the forecast revenues from generator charges to be included as Other Revenue for 2027 to 2030, is Hydro Ottawa proposing that they are to be set as part of this Application assuming a 2.1% annual increase in the related service charges?

3.5 Do the forecast 2027-2030 revenues from generator charges assume any increase in the number of generators over the 2026- 2030 period?

3.5.1 If yes, what at the forecast billing units for each charge for 2027-2030?

RESPONSE(S):

3.1.i) Confirmed, Section 4 of Schedule 6-3-4 - Other Operating Revenue deals with charges applicable to generators and not retailers.

ii) Confirmed, with the exception of MicroFIT, there are no OEB generic rates for generators. Therefore, for distributors who have not established a rate for larger generators, similar to the OEB MicroFIT generic rate, the additional costs related to non MicroFIT generators are socialized to load customers.

3.1.1 The response to 6-Staff-189 has been updated and provided as an attachment to this undertaking as Attachment JT1.14-VECC-3.0(A) - 6-Staff-189.

3.2. MicroFIT revenues are included in USofA 4090 as the MicroFit Generator rate is not listed under specific service charges in Hydro Ottawa's tariff of rates and charges. The MicroFit generic rate was established as a service classification per EB-2009-0326. Hydro Ottawa has a utility specific approved rate.

The response to 6-Staff-186 has been updated and provided as an attachment to this undertaking as Attachment JT1.14-VECC-3.0(B) - 6-Staff-186.

3.3 Hydro Ottawa is proposing that the actual generator service charges for 2027-2030 (including MicroFIT and other generations <10 kW) be approved as part of this application. The FIT monthly and HCI, RESOP, Other month service charges have been set using the 2.1% annual inflation factor for each of those years. For greater clarity, should the monthly generator service charge for 2026 be approved as proposed, the actual generator rates for 2027-2030 would be the rates outlined in Table 1 of Schedule 8-4-2 - Generation Charges.

3.4 Hydro Ottawa is proposing to set the forecast revenue from generator charges for the years 2027 to 2030 as part of this application and as outlined as "Generator Services" in Table 2 of Schedule 6-3-4 - Other Operating Revenue.

3.5 The forecast 2027-2030 revenues from generator charges do not assume any increase in the number of generators over the 2026-2030 period. Hydro Ottawa has experienced relatively flat volumes, with the occasional Microfit or Fit customer disconnecting, and an occasional new larger generator being added. This can be illustratively seen in the historical revenue as provided in Table 1 in Schedule 6-3-4 - Other Operating Revenue.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

6-Staff-189

EVIDENCE REFERENCE:

Other Revenue
Ref. 1: Exhibit 6 / HOL_Attachment 6-3-1(A)_OEB Appendix 2-H - Other Revenue_20250415
Ref. 2: Exhibit 1 / Tab 3 / Schedule 1 / p. 26 (pdf Exhibit 1 part 1, p. 240)
Ref. 3: Exhibit 8 / Tab 3 / Schedule 2 / p. 2 (pdf p. 120)

Preamble:
Hydro Ottawa states in reference 2 that it "proposes to set both rates and revenue related to Other Revenue for 5 years. Where rates are proposed to be adjusted in years two to five, for simplicity, an annual inflation rate of 2.1% is proposed to avoid annual adjustments to the rates throughout the rate term."

In reference 1, OEB staff notes that only Account 4225 Late Payment Charges shows an increase of 2.1% per year from 2027-2030 while Other Revenue accounts show different rates of growth or decline for this period.

In reference 3, Hydro Ottawa states that "To remain consistent with OEB province wide charges, such as the pole attachment and retailer service charges, Hydro Ottawa proposes to inflate the 2026 rate by the OEB approved inflationary factor for the 2027-2030 period. As a placeholder for the OEB approved inflationary factors, the 2027-2030 rates have been escalated by 2.10% annually."

QUESTION(S):

a) Please explain Hydro Ottawa's assumptions used to forecast other revenue amounts for each account in reference 1 for the 2026 Test Year and for the 2027 to 2030 period.

b) For other revenues in reference 1 that will be adjusted based on the annual rate of inflation for the 2027 to 2030 period, please confirm whether Hydro Ottawa will update these revenues using the OEB's approved inflation factor when the information is available.

c) Please confirm whether Hydro Ottawa will update the pole attachment revenue (recorded in Account 4210 Rent from Electric Property) based on the OEB's approved pole attachment charge for the 2026-2030 period when the information is available.

RESPONSE(S):

a) Please see Table A below for each USofA account listed in Appendix 2H with the description of the forecast assumptions. Hydro Ottawa's assumptions used to forecast other revenue amounts for each account in reference 1 for the 2026 Test Year and for the 2027 to 2030 period, are detailed across the following schedules: Schedule 6-3-2 - Specific Service Charge Revenue, Schedule 6-3-3 - Late Payment Charge Revenue, Schedule 6-3-4 - Other Operating Revenue, and Schedule 6-3-5 - Other Income & Deductions

Table A - USofA Account Forecast Assumptions

USofA	USof Account Description	Description of Forecast Assumptions
4082	Retail Services Revenues	As per Section 3 of Schedule 6-3-4 Other Operating Revenue. The assumption used to forecast Retail Services Revenue amounts is based on the number of applicable retailer customers multiplied by the OEB generic rates.
4084	Service Trans Requests Revenue	As per Section 3 of Schedule 6-3-4 Other Operating Revenue. The assumption used to forecast Retailer Specified Meter Read Fees amounts is based on the number of applicable retailer customers multiplied by the OEB generic rates.
4086	SSS Administration Revenue	As outlined in Section 2 and 3 of Schedule 8-3-2 Standard Supply Service Charge. The assumption used to forecast Standard Supply Admin Charge amounts is based on the number of applicable retailer customers multiplied by the prescribed OEB generic rates in 2021-2025, 2026 was determined through a cost-based approach and 2027-2030 were based on the proposed inflation factor, pending OEB

USofA	USof Account Description	Description of Forecast Assumptions
		approval.
4090	Electric Services Incidental to Energy Sales	As per Section 4 of Schedule 6-3-4 Other Operating Revenue. The assumption used to forecast Fixed Distribution Charge amounts is based on the number of applicable generators ~~retailer customers~~ multiplied by the ~~OEB generic~~ Hydro Ottawa utility specific rates.
4210	Rent from Electric Property	The assumption used to forecast Wireline Pole Attachments revenue amounts is based on the number of pole attachments multiplied by the 2024 generic provincial rate. Wireless Pole Attachment revenue was inflated per rate increases from customer agreements; assumption for duct rental was based on access agreements with third party; assumption for property rental was based on the amount of leases.
4225	Late Payment Charges	As per Schedule 6-3-3 Late Payment Charge Revenue. Hydro Ottawa anticipates an increase in Late Payment Charge (LPC) revenue for 2026, reflecting historical trends observed between 2021 and 2023. For the period from 2027 to 2030, LPC revenues are expected to continue rising at a more moderate and consistent pace
4235	Miscellaneous Service Revenues	As outlined in Schedule 6-3-2 Specific Service Charge Revenue and Schedule 8-4-1 Specific Service Charges. The assumption used to forecast Miscellaneous Services Revenue is based on the rate factored by the estimated volume.
4325	Revenues from Merchandise (Services to Third Parties)	As per Section 2 of Schedule 6-3-5 Other Income & Deductions. Forecast assumption was based on current trends, anticipated volume and the nature of customer requests.
4330	Costs and Exp of Merchandising (Services to Third Parties Costs)	As per Section 2 of Schedule 6-3-5 Other Income & Deductions, forecast assumption was based on current trends, anticipated volume and the nature of customer requests, and the addition of a new Non-Wires Customer Solutions Program, along with a new non-billable activity: Residential Electrical Isolations/Re-energizations.
4362	Loss Retire of Util & Oth Prop	As per Section 3 of Schedule 6-3-5 Other Income & Deductions, the forecast for Gains and Losses on Disposal of Utility Property is based on anticipated planned and unplanned asset retirements, including those from storm damage and new initiatives like the 2026 Metering Upgrades Program, all informed by normalized historical expenditures.

USofA	USof Account Description	Description of Forecast Assumptions
4375	SLA Services to Hydro Ottawa Affiliates	As per Section 4 of Schedule 6-3-5 Other Income & Deductions and Section 2 of Schedule 4-2-1 Shared Services and Corporate Cost Allocation, forecast assumption was based on transfer prices determined according to the Affiliate Relationships Code for Electricity Distributors and Transmitters (ARC).
4380	SLA Costs from Hydro Ottawa Affiliates	As per Section 4 of Schedule 6-3-5 Other Income & Deductions and Section 2 of Schedule 4-2-1 Shared Services and Corporate Cost Allocation, forecast assumption was based on transfer prices determined according to the Affiliate Relationships Code for Electricity Distributors and Transmitters (ARC).
4405	Interest and Dividend Income	As per Section 5 of Schedule 6-3-5 Other Income & Deductions shows that the assumption used to forecast Interest and Dividend Income is based on historical trend of the account

b) As noted in Schedule 1-3-1 - Rate Setting Framework, the Proposed 2026-2030 Custom Rate Framework for Other revenue is to set both rates and revenue for 5 years. Where rates are proposed to be adjusted in years 2 to 5 based on inflation, the rate is set at 2.1% for all four years (no adjustment based on the OEB approved inflation factor).

c) Hydro Ottawa confirms it will not be updating the Pole Attachment revenue based on OEB's inflationary factor for 2026-2030. The revenue amount included in Table 2 of Schedule 6-3-2 - Specific Service Charge Revenue and Appendix 2-H is proposed to be set for all years as described in Table A above, without any annual updates.

INTERROGATORY RESPONSES TO ONTARIO ENERGY BOARD STAFF

6-Staff-186

EVIDENCE REFERENCE:

Ref. 1: Exhibit 6 / HOL_Attachment 6-3-1(A)_OEB Appendix 2-H - Other Revenue_20250415
Ref. 2: Exhibit 6 / Tab 3 / Schedule 5 / p.7 (pdf p. 221)

QUESTION(S):

a) Account 4362 – Loss Retire of Utility and Other Property has a sub-category of "Net Book Value and Proceeds". What is included in this sub-category?
b) Please confirm that Account 4405 does not contain interest amounts related to DVAs. If not confirmed, please revise Appendix 2-H to remove any interest amounts associated with DVAs.
c) Reference 2 states that material cash balances are not anticipated for Interest and Dividend Income between 2024 and 2030. Please explain why there are no projected cash balances between 2024 and 2030, while cash balances were present from 2021 to 2023.
d) Please confirm that Hydro Ottawa records MicroFit-related revenues under Account 4235. If not, please update Appendix 2-H.

RESPONSE(S):

a) Account 4362 is for costs associated with the disposal of fixed assets. This includes assets that are retired early or are damaged, such as by a storm. When these assets are sold, Hydro Ottawa might receive proceeds from the sale of the scrap materials, and the assets may also still have a net book value at the time they are disposed of.

b) Confirmed, Account 4405 does not contain interest amounts related to DVAs.

c) As clarification, cash balances are anticipated for 2024 - 2030, however, they are not expected to be material, which is the driver of the amounts captured in USoA account 4405. The historical data referenced in 2021-2023 supports this statement given the immaterial annual amounts noted.

d) Confirmed, Hydro Ottawa records miscellaneous service revenue to MicroFit customers under Account 4090~~4235~~.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT1.14-VECC-4.0

EVIDENCE REFERENCE:

6-Staff 189
8-VECC 68
8-SEC 85
Exhibit 6, Tab 3, Schedule 2, pages 1 & 4

UNDERTAKING(S):

With respect to USOA 4235 (Miscellaneous Revenues), VECC 68 sets out how each of the specific service charges will be determined for the years 2026-2030. With respect to USOA 4235, Staff 189 states: “As outlined in Schedule 6-3-2 Specific Service Charge Revenue and Schedule 8-4-1 Specific Service Charges. The assumption used to forecast Miscellaneous Services Revenue is based on the rate factored by the estimated volume.”

SEC 85 sets out the historical 2021-2024 and forecast 2025- 2026 billing units for each of the Specific Service Charges.

4.1 For each of the Specific Service , please provide the forecast 2027- 2030 billing units used to establish the forecast Other Revenue from USOA 4235 (per Exhibit 6-3-2, Table 2).

RESPONSE(S):

Please see Table A below for the forecast 2027- 2030 billing units in Table 2 of Schedule 6-3-2 - Specific Service Charge Revenue.

Table A - 2027-2030 Specific Services Charges Forecasted Billing Units

	Test Years			
	2027	2028	2029	2030
Customer Administration				
Easement Certificate for Unregistered Easements	232	232	232	232
Duplicate invoices for previous billing	416	416	416	416
Special Billing Service, per hour	141	141	141	141
Credit Reference/Credit Check (+ credit agency costs)	35	35	35	35
Unprocessed Payment Charge	3,096	3,096	3,096	3,096
Account Set Up Charge / Change of Occupancy Charge	59,415	59,415	59,415	59,415
Interval Meter - Field Reading	-	-	-	-
High Bill Investigation - If Billing is Correct	6	6	6	6
Non-Payment of Account				
Reconnect at Meter - Regular Hours	1,794	1,794	1,794	1,794
Reconnect at Meter - After Regular Hours	236	236	236	236
Reconnect at Pole - Regular Hours	4	4	4	4
Reconnect at Pole - After Regular Hours	1	1	1	1
Other				
Temporary Service - Install and Remove ("TS-I&R") - Overhead - no transformer	29	29	29	29
TS-I&R - Underground - no transformer	28	28	28	28
TS-I&R Overhead - with transformer	1	1	1	1
Specific Charge to Access Power Poles - Wireline	70,555	70,555	70,555	70,555
Energy Resource Facilities Administration Charge	1	1	1	1

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT1.14-VECC-5.0

EVIDENCE REFERENCE:

3-SEC-62 a) and b)
Attachment 3-SEC-62(B) – Updated Revenue Load Forecast A

UNDERTAKING(S):

SEC 62 a) provides updated actual customer numbers and load for November and December 2024 and up to June 2025.

SEC 62 b) and the accompanying attachment provide the resulting forecast customer numbers and load for 2026-2030 using the updated data.

5.1 Please provide versions of the following files (submitted as part of the initial application) that support the forecast provided in SEC 62 b)

- HOL_Attachment 3-1-1(C) - 1.Load Forecast Data – Customers
- HOL_Attachment 3-1-1(C) - 2.Load Forecast Data – kWh
- HOL_Attachment 3-1-1(C) - 3.Load Forecast Data – kW

5.2 In preparing the update load forecast, did Hydro Ottawa's assumptions change regarding the Savings from DSM programs in 2024-2030? 5.2.1 If so, update Exhibit 3, Attachment 3-1-1(B) – Table 3-2 and explain the changes.

5.3 In preparing the update load forecast, did Hydro Ottawa's assumptions change regarding the Customer Reclassification and LU class disaggregation?

5.3.1 If so, indicate what the changes were in terms of both customer counts and kWh by class by year.

5.4 In preparing the update load forecast, did Hydro Ottawa's assumptions change regarding Electrification and Large Loads?

5.4.1 If so, please provide revised versions of Exhibit 3-1-1, Table 7 and Exhibit 3, Attachment 3-1-1(B) Tables 3-3 and 3-4.

5.5 In Attachment 3-SEC 62(B) the customer count, kWh and billing kW results are not broken down as between the GS 50-1499 and GS1500-4999 classes. Please provide revised schedules with this breakdown.

RESPONSE(S):

5.1 Upon final review of the requested files some information was missing. Hydro Ottawa will update this undertaking response as soon as the information is available.

5.2 No, Hydro Ottawa's assumptions regarding the Savings from eDSM programs in 2024-2030 did not change.

5.3 No, Hydro Ottawa's assumptions regarding Customer Reclassification and Large User customer disaggregation did not change.

5.3.1 Please see response to 5.3

5.4 No, Hydro Ottawa's assumptions regarding Electrification and Large Loads did not change.

5.4.1 Please see response to 5.4

5.5 Table A, B and C below further break down the kWh, billing kW, and monthly average customer count provided in response to interrogatory Attachment 3-SEC-62(B) - OEB Appendix 2-IB - Load Forecast Analysis.

Table A - 3.0-SEC-62 Revenue Load Forecast kWh by Rate Class

	2025	2026	2027	2028	2029	2030
Residential	2,593,073,317	2,598,486,536	2,614,803,988	2,649,631,949	2,672,170,678	2,706,639,658
General Service < 50 kW	745,695,849	738,002,620	734,190,566	736,041,210	734,753,617	733,977,760
General Service 50-1000 kW	2,427,661,397	2,382,325,770	2,365,404,281	2,362,520,550	2,350,966,038	2,341,224,881
General Service 1000-1500 kW	401,177,820	397,411,315	387,061,877	378,492,856	376,655,830	374,989,554
General Service 1500-5000 kW	731,812,726	717,373,164	707,328,036	701,156,164	692,820,640	684,794,186
Large User	513,647,022	534,832,421	557,500,644	604,226,353	657,514,517	691,680,394
Unmetered Scattered Load	14,236,301	14,308,959	14,363,366	14,417,773	14,472,180	14,526,587
Sentinel Lighting	41,366	40,631	39,896	39,161	38,427	37,692
Street Lighting	21,589,898	21,659,543	21,659,543	21,659,543	21,659,543	21,659,543
TOTAL	**7,448,935,696**	**7,404,440,960**	**7,402,352,197**	**7,468,185,559**	**7,521,051,471**	**7,569,530,256**

Table B - 3.0-SEC-62 Revenue Load Forecast kW by Rate Class

	2025	2026	2027	2028	2029	2030
General Service 50-1000 kW	5,979,361	5,840,081	5,797,878	5,790,686	5,761,869	5,737,575
General Service 1000-1500 kW	921,870	896,805	876,820	861,552	857,684	854,175
General Service 1500-5000 kW	1,597,798	1,597,038	1,576,014	1,563,097	1,545,652	1,528,854
Large User	974,070	1,022,952	1,089,883	1,222,323	1,393,895	1,503,860
Sentinel Lighting Connections	120	120	114	108	108	108
Street Lighting Connections	60,239	60,354	60,354	60,354	60,354	60,354
TOTAL	**9,533,458**	**9,417,350**	**9,401,063**	**9,498,120**	**9,619,562**	**9,684,926**

1 **Table C - 3.0-SEC-62 Revenue Load Forecast Monthly Average Customer and Connection Count by Class**

	2025	2026	2027	2028	2029	2030
Residential	344,451	346,478	348,504	352,008	356,364	360,320
General Service < 50 kW	25,821	25,969	26,039	26,162	26,314	26,452
General Service 50-1000 kW	3,015	2,952	2,952	2,952	2,952	2,952
General Service 1000-1500 kW	89	90	91	90	90	91
General Service 1500-5000 kW	79	80	79	79	79	79
Large User	10	11	12	13	14	14
Unmetered Scattered Load Connections	4,140	4,243	4,358	4,472	4,587	4,702
Sentinel Lighting Connections	48	47	46	45	44	43
Street Lighting Connections	64,822	65,686	66,596	67,505	68,415	69,324
TOTAL	**442,475**	**445,556**	**448,677**	**453,326**	**458,859**	**463,977**

2

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT1.14-VECC-7.0

EVIDENCE REFERENCE:

3-VECC 21, 22, 23, 24 and 27

UNDERTAKING(S):

7.1 The attachments provided in VECC 21, 22, 23, 24 and 27 set out the impact of the reclassification on the forecast volumes for the GS<50, GS50-999, GS1000-1499, GS1500-4999 and LU classes respectively and the values net to zero as expected. The attachments provided in VECC 21, 22, 23 and 24 also set out the impact of the LU customer disaggregation on the forecast volumes for the GS<50, GS50-999, GS1000-1499 and GS1500-4999 classes respectively. However the attachment to VECC 27 does not include the impact on the LU class volumes of the LU customer disaggregation. Please explain where the impact of the LU customer disaggregation is captured in the attachment to VECC 27 and provide a revised file that explicitly sets out the impact of the LU disaggregation as part of the response.

RESPONSE(S):

The impact of the Large User disaggregation was captured by removing the historical kWh and KW prior to modeling. As result, the 2025-2030 model output forecast is devoid of the single large user customer. The Large Use MWh amounts in Attachment 3.0-VECC-27(A)- LU Sales Forecast (with eDSM and Reclass Adjustment) tab i) already incorporates the impact of the Large User being removed from the forecast, therefore no further isolated adjustment is required on top of the model output.

Conversely, in the GS<50, GS50-999, GS1000-1499 the impact of the disaggregation is not captured in the historical kWh and KW amounts, requiring adjustments to be completed on top of the model output to reflect the impact.

Hydro Ottawa provided detailed monthly billing data for the historical Large User and resulting accounts in the GS classes for 2024 to allow Itron to complete the forecast adjustments.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT1.14-VECC-8.0

EVIDENCE REFERENCE:

3-VECC 29 a)

UNDERTAKING(S):

8.1 VECC 29 a) requested the MW from Figure 1 (Exhibit 1-3-1, page 2) that were included in the load forecast. The response provided a chart and indicated that it represents the MWs included in the planning forecast. Does the chart also represent the MWs included in the load forecast per Exhibit 3-1-1?

8.1.1 If not, what is the difference and why?

RESPONSE(S):

8.1. No, Figure 1 in Schedule 1-3-1 - Rate Setting Framework that was reproduced in Interrogatory response 3.0-VECC-29 as Figure A does not represent the additional load in the revenue Load Forecast. The figure represents the large load customer peak (MW) requests that Hydro Ottawa received as of January 1, 2025 and contemplated as part of the revenue load forecast. The statement included in the response to 3.0-VECC-29 a), that Hydro Ottawa considered certain projects in the revenue load forecast that had a Signed Offer to Connect and/or a Submitted Load Summary Form was intended to draw the connection between the two forecasts and the data both relied on.

8.1.1 The differences are outlined in the response to undertaking JT4.14.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT1.14-VECC-9.0

EVIDENCE REFERENCE:

3-VECC 19 a) – f)
3-VECC 21 c) – h)
3-VECC 22 b) – g)
3-VECC 23 c) – h)
3-VECC 24 b) – g)

UNDERTAKING(S):

9.1 The referenced interrogatories requested details regarding the determination of the actual 2013-2024 values as well as the forecast 2025-2030 values for the XHeat, XCool and XOther variables used in the various load forecast models. In each case the response stated: "Itron is unable to execute within the timelines for responding to interrogatories. With Itron's support, Hydro Ottawa will be prepared to provide the requested information by way of undertaking at the Technical Conference." Please provide the responses to cited interrogatories.

9.2 Do the forecast 2025-2030 XHeat, XCool and XOther variables used in the various models assumed further efficiency improvements after 2024?

9.2.1 If so, how is overlap avoided between these assumptions and the eDSM values subsequently used to subsequently adjust the customer class load forecasts?

9.2.2 If so, please separate out the impact of the additional efficiency improvements built into the various models for 2026-2030 and provide revised forecasts assuming these improvements are not made?

RESPONSE(S):

9.1 Hydro Ottawa has provided responses to the cited interrogatory questions as the following attachments:

- 3-VECC-19 a) – f) - Attachment JT1.14-VECC-9.0 (A) - Res XHeat, XCool, and XOther
- 3-VECC-21 c) – h) - Attachment JT1.14-VECC-9.0 (B) - GS50 XHeat, XCool, and XOther
- 3-VECC-22 b) – g) - Attachment JT1.14-VECC-9.0 (C) - GS1000 XHeat, XCool, and XOther
- 3-VECC-23 c) – h) - Attachment JT1.14-VECC-9.0 (D) - GS1500 XHeat, XCool, and XOther
- 3-VECC-24 b) –g) - Attachment JT1.14-VECC-9.0 (E) - GS5000 XHeat, XCool, and XOther

9.2 Yes, the forecasted XOther variable used in the Statistically Adjusted End-Use (SAE) modeling framework reflect continued efficiency improvements after 2024. These improvements are due to both market-driven changes and Federal codes and standards.

9.2.1 The eDSM variable represents additional efficiency not included in the XOther variable. The eDSM variable is capturing savings above and beyond the naturally market driven efficiency savings.

9.2.2 Hydro Ottawa will update this undertaking response as soon as the information is available.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT1.14-VECC-10.0

EVIDENCE REFERENCE:

3-VECC 21 a)

UNDERTAKING(S):

10.1 VECC 21 a) asked if the GS<50 forecast model was tested with a COVID variable also included. The response indicates that it was and the attachment referenced in the response provides the monthly forecast values based on a model which includes a COVID variable. Please provide the full model results – similar what was provided for the GS<50 model in Attachment 3-1-1(C) - 2. Load Forecast Data – kWh filed with the original application.

RESPONSE(S):

The full model results for the GS <50 forecast tested with a COVID variable have been provided as Attachment JT1.14-VECC-10(A) - GS <50 Load Forecast Data - Baseline kWh with COVID variable.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT1.14-VECC-11.0

EVIDENCE REFERENCE:

3-VECC 24 h)

UNDERTAKING(S):

11.1 VECC 24 h) provides the results for version of the GS 1500-5000 model that included a CDM variable. Did the version of the model that was tested with a CDM variable also include a Trend variable?

11.1.1 If yes, please provide the results (i.e., model, model statistics and resulting forecast) for a model that includes a CDM variable but no Trend variable?

RESPONSE(S):

11.1 The version of the GS5000 sales model tested with a CDM variable did not also include a separate Trend variable. The model's development initially included a CDM variable, similar to the GS50 and GS1000 models, but this variable was subsequently removed and replaced by a Trend variable in the final adopted model, meaning the model did not combine both simultaneously.

As described in the interrogatory response 3.0-VECC-24 part h), the CDM variable was removed because its estimated coefficient (−1.5) was inconsistent with expected results and historical trends, leading to an unreliable forecast and was replaced by a statistically significant linear Trend variable (t-statistic of −3.5) to properly capture the underlying sales trend. (Note: The previously reported coefficient of -2.5 in response 3.0-VECC−24 part h) was a data reporting error; the correct value is −1.5.)

Attachment JT1.14-VECC-11.0(A) - GS5000 Consumption Model (w/ CDM and w/o Trend) reports this corrected coefficient value and utilizes the original population and GDP figures for the model's development, rather than the most recently updated figures.

11.1.1 Please refer to the following attachments that contain results for the model that includes a CDM variable but no Trend variable:

- Attachment JT1.14-VECC-11.0(A) - GS5000 Consumption Model (w/ CDM and w/o Trend)
- Attachment JT1.14-VECC-11.0(B) - GS5000 Demand Model (w/ CDM and w/o Trend)

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT1.14-VECC-12.0

EVIDENCE REFERENCE:

Exhibit 3-1-1, Table 11 (page 18)
3-DRC-10
3-VECC 28 c)

UNDERTAKING(S):

12.1 Exhibit 3-1-1, Table 11 sets out the total number of EVs for each year from 2023 to 2030 (as confirmed in VECC 28 c). DRC 10 provides the number of new EVs in each year. However, the values in DCR 10 do not reconcile with the changes in the year over year values shown in Table 11. As an example DRC 10 shows that the number of new EVs in 2030 is 8,000. However, in Table 11 the change in number of total EVs from 2029 to 2030 is 5,690. Please explain why the annual increases in DRC 10 don't align with the changes in the annual totals in Table 11 and revise the evidence as necessary?

RESPONSE(S):

12.1. The difference in Table 11 of Schedule 3-1-1: Revenue Load and Customer Forecast and Table B of interrogatory response 3-DRC-10 is due to the inclusion of a vehicle retirement factor assumption in the total EV vehicles in service. The vehicle retirement factor assumption is based on the estimated 2018-2022 average percentage of vehicles retired in Ontario derived using new and total vehicle registrations data from StatsCan.

The value of 8,000 new EVs in 2030 (Table B) is the gross number of new EVs, whereas the change in total EV's from 2029 to 2030 (Table 11) is the net change in number of EVs after accounting for the estimated number removed from service. This explanation applies to all years noted in both documents.

The revenue load forecast includes a forecast of incremental annual LDEV kWh from new LDEVs as presented in Table B.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT1.14-VECC-14.0

EVIDENCE REFERENCE:

3-VECC 30 e)
Exhibit 3, Attachment 3-1-1(B), Table 3-2
Exhibit 3, Attachment 3-1-1(C) – 2. Load Forecast Data – kWh
3-Staff 11

UNDERTAKING(S):

VECC 30 e) states: “The CDM savings as reported in Table 3-2 from Attachment 3-1-1(B) - Hydro Ottawa Long-Term Electric Energy and Demand Forecast were used to determine the CDM variable for the revenue load forecast.”

Attachment 3-1-1(C) – 2 Load Forecast Data – kWh provides the monthly historic CDM data used in the Residential, GS<50 and GS1000 models.

14.1 For both the GS<50 and GS 1000 classes, the sum of the monthly CDM values for any of the years 2018-2023 (per Attachment 3-1- 1(C) - 2) does not equal annual values set out in Table 3-2. Please explain why.

14.2 Similarly, for the Residential class, for each of the years 2018-2030 multiplying the monthly average CDM per customer by the number of customers in the month and summing over the year does not equal the annual values as set out in Table 3-2. Please explain why.

14.3 For purposes of using the models to forecast sales after October 2024, it is understood that the CDM variables used in the models are based on savings from programs implemented up to October 2024 and that savings from the programs after October 2024 are meant to be captured by the eDSM adjustment. In Attachment 3-1- 1(C) – 2. Load Forecast Data – kWh the post October 2024 values used for the CDM variables are all held constant at the October 2024 value for the relevant customer class. However, for CDM programs implemented in 2018-2023, Staff 11 shows that the savings in the years after 2024 decline. Why wasn't this decline reflected in the values used for purposes of the load forecast models?

RESPONSE(S):

14.1 The observed discrepancy is due to the methodology used to transform the static annual CDM values from Attachment 3-1-1(B) - Hydro Ottawa Long-Term Electric Energy and Demand Forecast Table 3-2 into the dynamic monthly variables required for the load forecasting model. The model does not assume full savings are realized starting in January; rather, savings are treated as accumulating throughout the year, with full realization often lagging until the subsequent year. Furthermore, the calculated monthly variable is subject to a 12-month moving average. Due to this built-in lag and averaging technique, the summation of the monthly CDM variables for any given year will, by design, be less than the corresponding annual value set out in Table 3-2.

14.2 For the Residential class, the monthly CDM per customer variable is calculated by first converting the total annual saving to a monthly basis while factoring in the half-year savings and lag (savings accumulate over time and are not fully realized until the next year), and then dividing this adjusted total by the number of customers. An additional significant factor is a constraint imposed on the calculated variable, which prevents the per-customer value from declining (even if customer counts are increasing faster than the total CDM savings, which occurs starting in 2022). Consequently, both the timing lag in savings realization and the applied constraint on the per-customer variable introduce a necessary divergence, meaning the monthly summation will not equal the annual value in Table 3-2.

14.3 Attachment 3-1-1(C) - Load Forecast Data illustrates the growing historical impact of energy efficiency savings from 2013 through October 2024. The variable CDM tracks these accumulated savings from programs implemented up to that date. Since the CDM program is closed, no new savings are being added from it. The CDM variable's value after October 2024 represents the persistence of the savings already achieved.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT1.14-VECC-15.0

EVIDENCE REFERENCE:

Exhibit 3, Attachment 3-1-1(B), Table 3-2
Exhibit 3-1-1, Table 13
3-VECC 30 e)

UNDERTAKING(S):

Exhibit 3-1-1, Table 13 sets out the further adjustment made to the load forecast for each customer class to account for DSM savings implemented after October 2024.

VECC 30 e) states that the savings from DSM savings implemented after October 2024 are included in Table 3-2 of Exhibit 3, Attachment 3-1-1(B) and that they were determined by subtracting the cumulative savings as of October 2024 from the forecast value for 2024 through 2030?

15.1 The totals in Table 13 for each of the years 2025 to 2030 are less than the difference between the value for that year in Table 3-2 and the value for 2024 from Table 3-2. If anything one would have expected the values in Table 13 to be greater since Table 13 is meant to also capture the last two months of 2024. Please reconcile this discrepancy and provide schedules for each class that demonstrates how the values in Table 13 were derived from those in Table 3-2.

RESPONSE(S):

For the reconciliation of the two referenced tables, please refer to Attachment JT1.14-VECC-15.0(A) - eDSM Savings Reconciliation for further details. The difference between the tables reflect the half year savings factor used to forecast the revenue load forecast.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT1.14-VECC-17.0

EVIDENCE REFERENCE:

7-VECC 52

UNDERTAKING(S):

VECC 52 requested “the calculations supporting the proposed Billing and Collecting weighting factors for 2026”. The response notes that Hydro Ottawa has identified six distinct patterns of customer utilization for the 18 major vendors providing Bill and Collect services and identifies the allocation factors for each. However, the response does not provide the calculation of the proposed 2026 Billing and Collecting weighting factors.

17.1 Please provide a schedule that sets out:

- The total 2026 forecast expenses associated with each of the six customer utilization patterns,
- The allocation of each the six pattern category’s total expense to customer classes based on the category’s allocation factors and the forecast 2026 customers by class,
- The total Billing and Collecting costs allocated to each class, and
- The resulting weighting factors (with Residential having a weight of 1.0).

RESPONSE(S):

Please see Table A below which details the derivation of 2026 Bill and Collect weighting factors as presented on Tab I5.2 Weighting Factors of Attachment 1-Staff-1(H) - 2026 Cost Allocation

Model.xlsm. Internal staff costs are already included in each 'Vendor Pattern' line item by applying overhead costs to capital expenditures, as outlined in Schedule 2-6-2 - Capitalization of Overhead.

Table A - Derivation of 2026 Bill and Collect Weighting Factors ($)[1]

	Residential	GS <50	GS 50-1,499		GS 1500-4999	Large Use	Street Light	Standby	USL	Sentinel	Total
			GS 50-999	GS 1000-1499							
Vendor Pattern 1	$ 921,600	$ 62,062	$ 21,313	$ 556	$ 488	$ 76	$ 48	$ 11	-	-	$ 1,006,153
Vendor Pattern 2	$ 9,550	$ 643	-	-	-	-	-	-	-	-	$ 10,193
Vendor Pattern 3	-	$ 3,010	$ 1,034	$ 26	$ 23	$ 4	-	-	-	-	$ 4,097
Vendor Pattern 4	$ 2,469,496	$ 333,973	$ 11,988	$ 1,497	$ 275	$ 40	$ 104	$ 115	$ 3,179	-	$ 2,820,667
Vendor Pattern 5	$ 4,762,226	$ 320,695	$ 110,142	$ 2,869	$ 2,524	$ 395	$ 242	$ 51	$ 1,398	$ 676	$ 5,201,219
Vendor Pattern 6	-	-	$ 481,926	$ 12,564	$ 11,053	$ 1,730	$ 1,059	$ 223	-	-	$ 508,555
Total	**$ 8,162,872**	**$ 720,384**	**$ 626,403**	**$ 17,511**	**$ 14,362**	**$ 2,247**	**$ 1,453**	**$ 399**	**$ 4,577**	**$ 676**	**$ 9,550,884**
Customers per Class	$ 348,287	$ 26,016	$ 3,053	$ 84	$ 70	$ 11	$ 7	$ 6	$ 129	$ 39	
Cost per Customer	$ 23.437	$ 27.690	$ 205.176	$ 208.468	$ 205.176	$ 204.251	$ 207.569	$ 66.523	$ 35.478	$ 17.327	
Weighting Factor			8.75429	8.89473							
	1.00000	1.18146	8.82451		8.75428	8.71481	8.85640	2.83837	1.51376	0.73930	

[1] 2026 Bill and Collect Expense (USoA 5315, 5320)

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT1.14-VECC-18.0

EVIDENCE REFERENCE:

8-VECC 65 b)
Exhibit 8-2-1, page 5

UNDERTAKING(S):

18.1 VECC 65 b) states: "Hydro Ottawa proposes the 2027-2030 LV rates will be set annually based on the proposed RTSRs and RTSR model inputs for the corresponding year." For the years 2027-2030 is Hydro Ottawa proposing that: i) the LV expense used in the RTSR model will the set as part of this application where the current values are set out in Exhibit 8-2-1, page 5 or ii) that the LV expense will be forecasted at the time the rates are set for each of those years and then the LV rates determined using the RTSR model for the rate year?

RESPONSE(S):

Hydro Ottawa is proposing for the years 2027-2030 that the LV expense used in the RTSR model will be set as part of this application where the proposed values are set out in Schedule 8-2-1 - Retail Transmission and Low Voltage Service Rate page 5, table 3.

These amounts align with the 2026-2030 Low Voltage expense included in the power supply expenses for working capital, which are also proposed to be set for the Custom IR term.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT1.14-VECC-19.0

EVIDENCE REFERENCE:

7.0-VECC 60 a)
7-Staff 196 a)

UNDERTAKING(S):

The response to VECC 60 a) sets out what the 2026 Standby Rates would be based on Hydro Ottawa's current rate design methodology.

Staff 196 a) provides the Standby bill for 2026 using the current/status quo rate design for three scenarios detailed in Schedule 7-1-3. The service charge used is $186.89 while the volumetric charge used is $4.0144/kW in Example 1 ($3211.52/800kW) and Example 3 ($2207.92/550).

19.1 Please explain why the 2026 status quo service charge and volumetric rate used in Staff 196 a) don't match those in VECC 60 a)

RESPONSE(S):

Hydro Ottawa believes this undertaking referencing the Standby rates provided is in relation to interrogatory response 7.0-VECC-60 b) and has responded based on this understanding.

The example in 7-Staff-196 a) provides the Standby bill impact using the current standby structure at 2025 approved rates (status quo) and 2026 proposed rates.

The rates provided in 7.0-VECC-60 were calculated based on the 2025 approved rate design (status quo) while updating based on 2026 revenue requirement and updated cost allocation results.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT1.14-VECC-20.0

EVIDENCE REFERENCE:

7-VECC 61 i)
Exhibit 7-1-3, page 5

UNDERTAKING(S):

Exhibit 7-1-3 sets out the formula for calculating the Standby billing demand when Generation is ON and OFF during certain periods as:
Contract Demand – (Metered Peak generator OFF kW – Metered Peak generator ON of kW) – (the lower of Metered Peak generator ON or 500 kW).

VECC 61 I) provides Standby bills for a number of scenarios. Deconstructing the Standby bills yields the following Standby billing demands for the 4th, 5th, 6th, 7th and 8th scenarios using the proposed Standby service charge of $186.89 and a volumetric rate of $4.0144/kW:
Scenario #4: {($2,194.42-$186.89)/$4.0144} = 500 kW
Scenario #5: {($1,391.41-$186.89)/$4.0144} = 300 kW
Scenario #6: {($588.33-$186.89)/$4.0144} = 100 kW
Scenario #7: {($1,792.91-$186.89)/$4.0144} = 400 kW
Scenario #8: {($989.90-$186.89)/$4.0144} = 200 kW

20.1 Based on the scenario descriptions provided in the interrogatory (both question and response), it is understood that scenarios are as follows:

- If the peak Gross Load of 1,000 kW occurs when the Generation is ON then the Metered Peak generator ON is 200 kW and the Metered Peak Generator OFF is 450 kW.

- If the peak Gross Load of 1,000 kW occurs when the Generation is OFF then the Metered Peak generator ON is 200 kW and the Metered Peak Generator OFF is 1,000 kW

Based on the above understanding of the scenarios and the contract values attributed to each scenario the formula for determining the Standby billing demand does not appear to yield the billing demand values set out in the Preamble for Scenarios 4-8. Please reconcile and explain whether the issue is with the billing demand formula as described or with the interpretation of the scenarios. Also, as necessary, please re-calculate the Standby billing demand for each of the five scenarios.

RESPONSE(S):

20.1 The issue is with the interpretation of the scenarios detailed in interrogatory response 7.0-VECC-61 i).

In Scenarios #4 - #8 described in the preamble, the backup overrun adjustment applies to the calculation of the Standby charge. For clarity, in Table A Hydro Ottawa has provided the Generation ON kW and Generation OFF kW assumptions used to calculate the illustrative bill impacts provided in interrogatory response 7.0-VECC-61 i).

1

Table A - Generation ON kW and Generation OFF kW

	Example 1 - GEN ON ENTIRE PERIOD	Example 2 - GEN OFF ENTIRE PERIOD	Example 3 - 800 kW Contract	Example 3 - 0kW Contract Demand	Example 3 - 100 kW Contract	Example 3 - 800 kW Contract	Example 3 - 0kW Contract Demand	Example 3 - 100 kW Contract
			Gross load Peak GEN ON	Gross load Peak GEN ON	Gross load Peak GEN ON	Gross load Peak GEN OFF	Gross load Peak GEN OFF	Gross load Peak GEN OFF
Peak Generation ON - kW	200	0	200	200	200	800	800	800
Peak Generation OFF - kW	0	1,000	450	450	450	1,000	1,000	1,000
Preamble Scenario Reference	***1***	***2***	***3***	***4***	***5***	***6***	***7***	***8***

2

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT1.5

EVIDENCE REFERENCE:

2-SEC-43

UNDERTAKING(S):

To provide the annual budget for each of those years, 2020 to 2025, for each of those programs.

RESPONSE(S):

Hydro Ottawa's annual board approved budget can be found in Attachment JT1.5(A) - Hydro Ottawa Annual Budget.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT1.6

EVIDENCE REFERENCE:

2-SEC-44(B)

UNDERTAKING(S):

To provide an updated version of the table at 2-SEC-44, Appendix B, showing the other two alternatives.

RESPONSE(S):

Please refer to "Attachment JT1.6_Revised SEC-44(B) - 2030 Asset Condition Count and Percentage by Alternatives" which is the updated version of the table from 2-SEC-44, Appendix B. The original version only included the 2030 asset condition and percentages for the preferred alternative. During the technical conference, a request was made to update the attachment to include the 2030 asset condition for the two additional investment alternatives considered.

Hydro Ottawa notes that in Attachment 2-SEC-44(B), line 18 presented the total underground asset count based on a no-investment scenario by 2030. This has now been updated to reflect the total unit count pertinent to the three preferred alternatives for system renewal investment planning, and can be found in Attachment JT1.6(A) - Updated 2-SEC-44(B) - 2030 Asset Condition Count and Percentage by Alternatives.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT1.7

EVIDENCE REFERENCE:

2-5-4 Figure 71

UNDERTAKING(S):

To have in tabular format and in graphical format by planning region the 2030 and 2035 forecast, the latest actuals, as well as the planned capacity at the end of 2030, as well as the current capacity within the system as demonstrated in Figure 71.

RESPONSE(S):

Table A and Figures 1 and 2 provide revisions to Figure 71 of Schedule 2-5-4 - Asset Management Process. It should be noted that in the original Figure 71 the Limited Time Rating (LTR) planning capacity values represented the Winter LTR, aligning to the mid-to-long-term IRRP forecast assumption of shift to a winter peak. As the capacity planning assumptions for the 2026-2030 period continued to use summer peak, all capacity evidence was assuming summer LTRs for planning capacity. As such, and for ease of comparison, Table 1 and Figures 1 and 2 assume summer ratings and contain the following data, for every planning region, all represented in MW:

- **2024 Actuals:** 2024 weather normalized actual peak load from the hour of system coincident peak
- **2024 LTR:** 2024 planning rating (summer Limited Time Rating, or LTR). This includes Piperville MTS (120 MVA / 108 MW in the South-East 28kV region) and Hydro Road TS (120 MVA / 108 MW in the 44kV region).

- **2030 LTR:** Planning rating (summer LTR) by 2030 with all proposed investments
- **2030 Forecast**: 2030 IRRP Forecast peak demand
- **2035 Forecast:** 2035 IRRP Forecast peak demand

As defined within Section 8.4.1 of Schedule 2-5-4 - Asset Management Process, the planning rating is "the sum of either the transformers' 10-day LTR or the allowable top load rating if no LTR is published, following the loss of the largest element in the station (N-1 contingency). For stations with a single supply and transformer, feeder ties from adjacent stations provide contingency backup and the planning capacity is based on the single unit's rated capacity (10-day LTR or top load rating if LTR is not available)".

It should be noted that the summation of LTRs for all transformers in a planning region is not indicative of overall system capacity as it assumes that all transformers are operating under emergency overload conditions simultaneously and that all other system components are capable of handling that combined, short-term load. This is rarely the case, as other components have their own continuous and emergency ratings that must be respected to maintain system stability and reliability. For effective planning, Hydro Ottawa does not simply assess a region's health by comparing its 2024 Actual load to its 2024 LTR. Instead, the company compares the 2024 Actual to the system's Continuous Rating (N-0) to ensure normal operations are within limits. More importantly, Hydro Ottawa compares the 2030 and 2035 Forecasts to the 2030 LTR to ensure the system can safely meet the forecasted peak demand even with an N-1 contingency and maintain its reliability obligation.

For example, in the East 28kV region, the 2024 LTR is 160 MW, while the 2024 Actual is 93 MW. This large difference (67 MW) does not represent 67 MW of unused normal capacity; rather, it represents the required capacity cushion to ensure that if the largest transformer fails on the peak day, the remaining equipment can immediately and safely carry the 93 MW load for the limited time required for restoration.

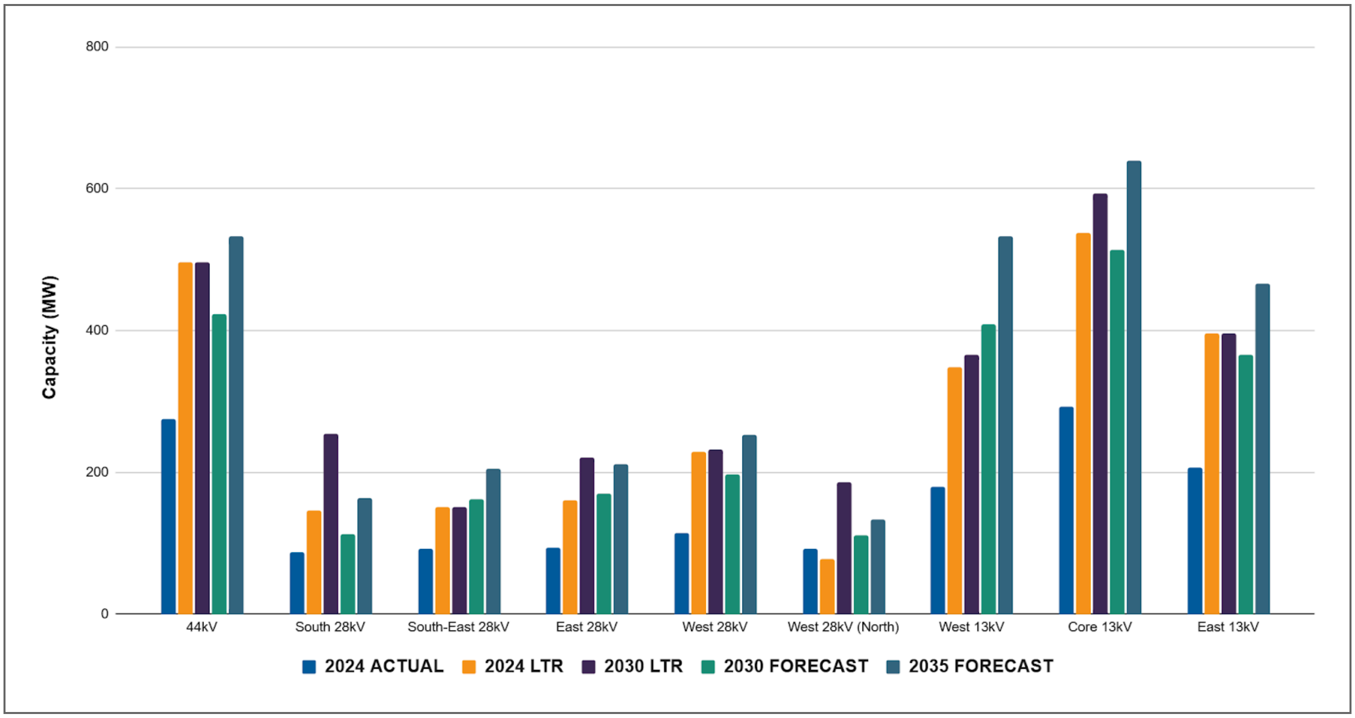
1 **Table A - LTRs, Actuals, and IRRP Forecast (MW)**

Planning Region	2024 Actual	2024 LTR	2030 LTR	2030 Forecast	2035 Forecast
44kV	274	497	497	423	533
South 28kV	88	147	255	114	163
South-East 28kV	92	151	151	162	205
East 28kV	93	160	221	170	212
West 28kV	115	229	232	198	253
West 28kV (North)	93	78	186	111	134
West 13kV	179	348	366	408	533
Core 13kV	292	538	594	514	640
East 13kV	207	396	396	367	466
West 12kV	7	14	14	14	17
Nepean 8kV	88	112	112	120	158
Bells Corner/ Bayshore 8kV	36	49	56	54	73
Barrhaven 8kV	22	26	26	29	40
West 8kV	13	27	27	17	23
Casselman 8kV	7	11	16	12	16
East 8kV	33	41	41	46	62
Central 4kV	104	212	212	214	298
East 4kV	82	165	165	148	206

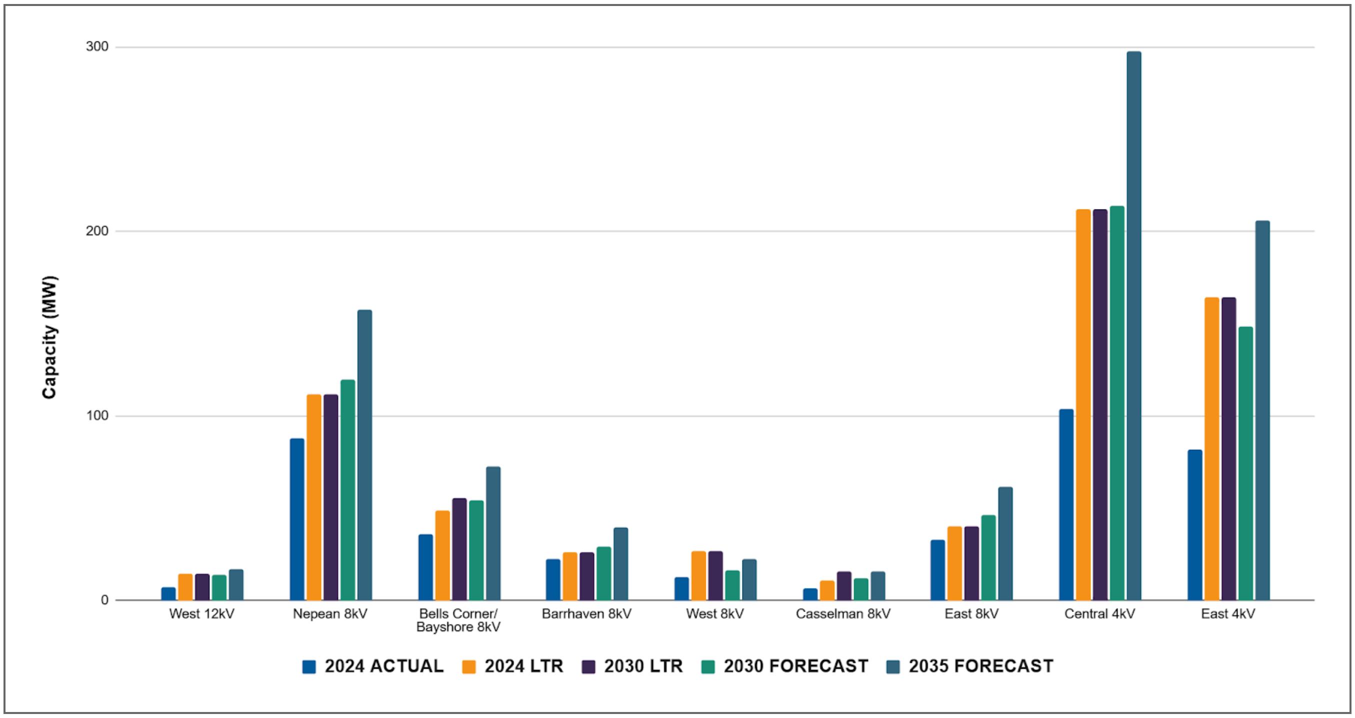
2

Accordingly, Figure 1 below graphically represents Table 1 for the 44kV, 28kV and 13kV systems and Figure 2 below represents the 12kV, 8kV and 4kV systems.

Figure 1 - Graphical form of Table 1 (44kV, 28kV, 13kV)



1 **Figure 2 - Graphical form of Table 1 (12kV, 8kV, 4kV)**



2

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT1.8

EVIDENCE REFERENCE:

2-Staff-72

UNDERTAKING(S):

To provide the figure a from 2-Staff-72 in the tabular format, and to clarify whether the actuals and weather-corrected information actually provided in MVA instead of megawatts; and if not, is there a power conversion that was used.

RESPONSE(S):

Figure A in the interrogatory response 2-Staff-72 was initially given with actuals and weather corrected values in MVA, whereas the forecasts were given in MW. Tables A and B below provide actuals and weather corrected values in MW, using a standard power factor of 0.9, along with the decarbonization scenario forecasts in MW. Note that the system peak provided within Tables A and B for the decarbonization scenarios is the higher value of either the summer or winter peak.

Table A - 2002-2016 Actuals, weather corrected, and forecast(s) in MW

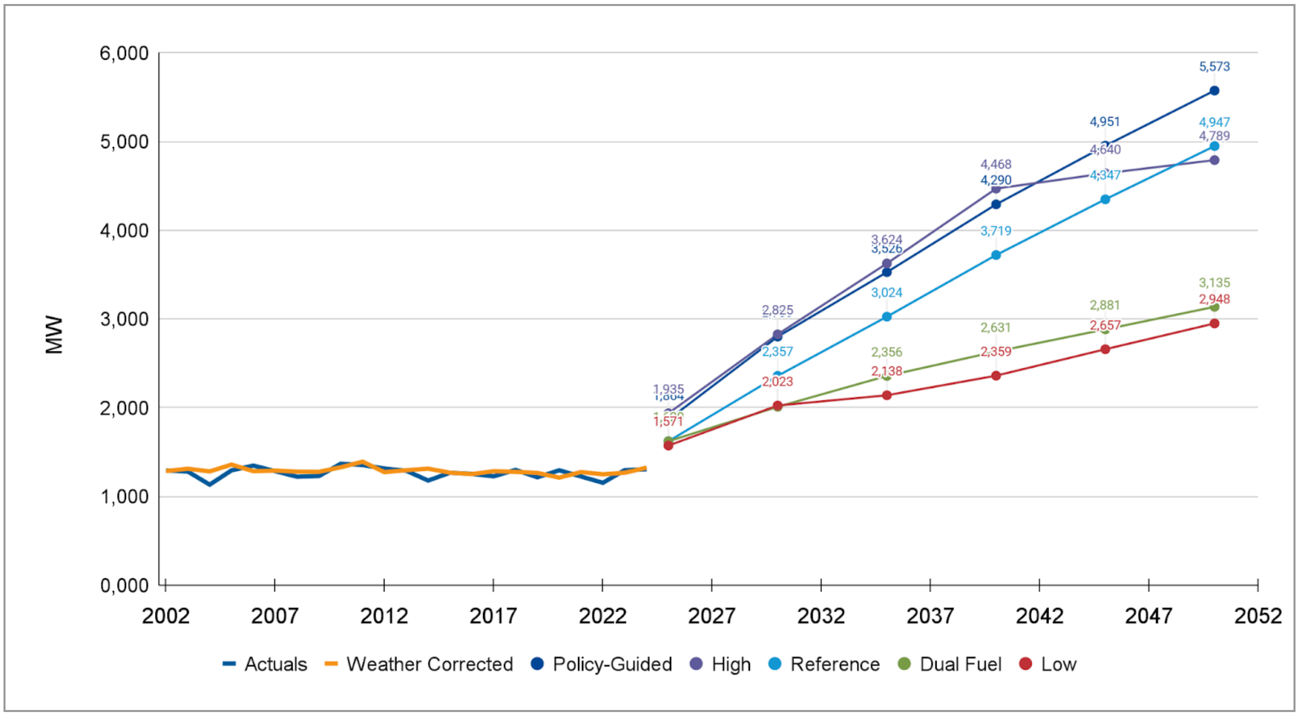
Year	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Actuals	1,290	1,278	1,131	1,292	1,346	1,283	1,220	1,227	1,366	1,352	1,313	1,287	1,177	1,265	1,252
Weather Corrected	1,284	1,310	1,280	1,357	1,283	1,289	1,277	1,275	1,327	1,389	1,272	1,294	1,311	1,265	1,250
Policy-Guided															
High															
Reference															
Dual Fuel															
Low															

Table B - 2017-2050 Actuals, weather corrected, and forecast(s) in MW

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	2040	2045	2050
Actuals	1,224	1,297	1,213	1,292	1,222	1,152	1,295	1,304						
Weather Corrected	1,282	1,275	1,263	1,210	1,273	1,247	1,265	1,322						
Policy-Guided									1,864	2,799	3,526	4,290	4,951	5,573
High									1,935	2,825	3,624	4,468	4,640	4,789
Reference									1,620	2,357	3,024	3,719	4,347	4,947
Dual Fuel									1,620	2,008	2,356	2,631	2,881	3,135
Low									1,571	2,023	2,138	2,359	2,657	2,948

Figure 1, provides an update to the reference Figure A from response to interrogatory 2-Staff-72 including 2024 actuals and all values in MW.

Figure 1 - Updated Figure A in MW



TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT1.9

EVIDENCE REFERENCE:

1-SEC-3

UNDERTAKING(S):

To provide evidence that Hatch had undertaken an analysis or review of the predictive analytics inputs process.

RESPONSE(S):

Please refer to Attachment JT1.9(A) - HOL PA Distribution Model Review in response to the request to provide the report or evidence of Hatch's analysis and review of Hydro Ottawa's predictive analytics input process, listed as "2024 - Review of Copperleaf Predictive Analytics (PA) Value Framework" in response to interrogatory 2-SEC-39 part b).

As part of Hydro Ottawa's PA implementation review initiative, Hydro Ottawa worked with Hatch to update the percentages of incipient, degraded, and catastrophic failure modes for each asset type.

The updated failure mode percentages were then utilized within the risk likelihood calculations in Copperleaf Predictive Analytics to define the probability of emergency, critical or expected asset failures as discussed in Section 5.1.4 - Asset Risk Assessment in Schedule 2-5-4 - Asset Management Process.

Project Memo

H370894

23-03-2023

To: Pranav Pattabi
From: Jakub Gara

cc: Margaret Flores
Cheng Lin

Hydro Ottawa Limited
Copperleaf Predictive Analytics Support

Distribution Asset Model Review

1. Introduction

Hatch Ltd. ("Hatch") has been tasked by Hydro Ottawa Limited ("HOL") to provide a review of the Distribution Asset Model used for the Copperleaf Predictive Analytics tool. Materials provided by HOL included:

- *Asset Specific Assumptions*
- *Asset Type and System Field Assumptions*
- *Hydro Ottawa Distribution Asset Model*
- *PA Model Timeline*

The model and assumptions have been reviewed for accuracy and general alignment with industry asset investment planning ("AIP") methodologies and practices, including: Common Network Asset Indices Methodology (CNAIM), Hatch's value framework and AIP project experience, failure mode classification, distribution asset failure consequence quantification, reliability metrics definition, and other risk and value model bast practices.

Findings of the distribution asset model review are provided in section 2 with applicable references to the *Hydro Ottawa Distribution Asset Model* document or *Assumptions* spreadsheets.

2. Assumptions

It is assumed that values provided in the *Assumptions* spreadsheets have been determined by HOL team and have been based on the historical values. Hatch has not reviewed the calculations nor the source information as those are not available at this time. It is also assumed that some of the assumptions have been provided based on CNAIM methodology or Copperleaf internal libraries.

3. Model review findings

The review evaluated the distribution asset model's alignment with industry AIP methodologies and practices. The results presented here focus on the major findings.

Re: 2.1 Model Inputs

Table 1

OutageDurationInHours **–** Hatch understands that this value will be assigned by HOL internally for each asset. Currently there is no selection present for feeder configuration (i.e., *3 hours (loop) and 8 hours (radial)*).

Table 2

PercentageOfFailuresCatastrophic, PercentageOfFailuresIncipient, PercentageOfFailuresDegraded – these inputs represent relative probabilities of failure for each asset type. While the nomenclature is aligned with the CNAIM methodology, it is unclear if the definition of the relative probabilities is the same. Values for each relative probability differ significantly from CNAIM values captured in Table 1.

Table 1: Wood pole relative failure probabilities comparison

	Catastrophic	Degraded	Incipient
HOL values	2.1	10.6	87.3
CNAIM values	10.0	70.0	20.0

PercentageOfFailuresCatastrophic – based on the current model this failure mode is the sole contributor to the Reliability Risk value measure. With the relative probability contribution to the general probability of failure (POF) ranging from 0.1% to 3% the impacts to the reliability value measures will be minimal. As such, in the case of distribution cables where the PercentageOfFailuresCatastrophic is 2%, only 2 out of 100 failures would have caused an outage to the customer. HOL may want to establish a firm definition of failure modes and their respective model function such that reliability (outage-related) events have a higher representation.

PercentageOfFailuresDegraded – in the current model this failure mode has relatively insignificant overall contribution to POF (2%-23%). In contrast, this failure mode in CNAIM methodology accounts for the majority of failures for most distribution asset classes (~25%-70%). HOL may also want to explore the applicability of some of the degradation patterns within this failure mode to contribute to the reliability risk value measure (currently not present). More details are provided in 3.5.1 Consequence Formulas below.

PercentageOfFailuresIncipient – in the current model this failure mode has a relatively large overall contribution to POF (75%-95%). In contrast this failure mode in CNAIM methodology accounts for smaller portion of failures for most distribution asset classes (~15%-45%).

ConditionToCatastrophicFailureCurve, ConditionToIncipientFailureCurve, ConditionToIncipientFailureCurve – the methodology for the failure curve calibration to account for Health Index (HI) used in the model is unknown at this time. It is Hatch's understanding that currently the generic methodology of “effective age” is used internally at HOL to account for condition in the failure curve calibration. However, for the purpose of integration in the distribution model the approach must be aligned with the general definition of each of failure modes. In order to use CNAIM values for ConditionToCatastrophicFailureCurve, ConditionToIncipientFailureCurve, ConditionToIncipientFailureCurve HOL may want to consider aligning the general failure mode definition with CNAIM in the interim before the comprehensive relative failure probability study is completed.

EnvironmentalCatastrophicLikelihoodFactor, EnvironmentalIncipientLikelihoodFactor, EnvironmentalDegradedLikelihoodFactor – no method or source of information is available at this time that provides insights into these factors. It’s understood that the scores in this category have been assigned based on arbitrary assumptions in the interim.

ConditionToMaintenanceCurve – no method or source of information is available at this time. Hatch understands that the maintenance costs in this category have been assigned based on general assumptions in the interim for all asset types equally. HOL may want to explore the maintenance cost vs health index relationship variance for each asset class independently to better reflect the historical performance.

Re: 3.1 Reliability Component

3.1.1 Consequence Formulas

The formula for ReliabilityRiskConsequence is calculated based on maximum (max) of CMICost, DurationCost and FrequencyCost. Based on the provided formulas these variables represent:

- CMICost - outage duration related cost, based on HOL asset outage duration and Copperleaf interruption cost.
- DurationCost - outage duration related cost, based on HOL asset outage duration, HOL peak load, and Copperleaf DurationCostPerKwh.
- FrequencyCost – outage frequency related cost, based on HOL peak load and Copperleaf FrequencyCostPerKw.

As reliability in the electric distribution utility industry is typically expressed through both duration and frequency metrics, HOL may want to consider using other functions (e.g., sum) to associate the ReliabilityRiskConsequence with a combination of both, rather then focusing on the more impactful one (unless the CMICost, DurationCost and FrquencyCost are defined such that each of them accounts for both costs associated with outage duration and number of customer interrupted, this build-up is currently not available for review)

FeederPerformance.WorstPerformer – the element *(1 + FeederPerformance.WorstPerformer * OptimizerPercentage / 100)* can generate either 1 or 1.25 value. This would increase the ReliabilityRiskConsequence Value Measure by 25% if the asset is on the WPF. This approach prioritises replacements on WPFs which have been historically underperforming due to various factors. The WPF typically serves as a metric and becomes the effect of poor reliability rather than the driver behind it. Also, HOL may want to explore the logic behind the defined 25% escalation.

ElectricalCIConsequence – Calculated as a simple sum of all the customers in each customer type. HOL may want to consider assigning weights to normalize the numbers in the context of the reliability value calculation if the normalization is not addressed in any other part of the calculation.

CatastrophicFailuresConsequence, IncipientFailuresConsequence, and DegradedFailuresConsequence = 1 – Unsure what is the function and logic behind this assignment.

3.1.2 Likelihood Formulas

Based on the description of three (3) likelihoods and their relation to eight (8) reliability value measures, only the CatastrophicFailureLikelihood is directly related to the value of the asset replacement through ReliabilityRiskConsequence (*Not all the value measures calculated by the Distribution Asset Model will contribute to the overall value of the asset replacement*). HOL may want to consider expanding ReliabilityRiskConsequence to include the DegradedFailuresConsequence, clearly define the failure modes and further calibrate relative probabilities.

Re: 3.2 Safety Component

This section, largely based on CNAIM methodology can be further updated with HOL-specific numbers (i.e. *LostTimeAccident*) once the definition of failure modes and further calibration of relative probabilities is completed.

Re: 3.3 Compliance Component

Hatch understands that the compliance in this section relates to potential PCB release, currently not applicable for HOL’s assets. HOL may want to consider including future obsolescence risk in this component.

Re: 3.4 Environmental Component

3.4.1 Consequence Formulas

CostPerKilogramOfSF6 – HOL may want to use current (2023) Canadian Unit Carbon Prices

OilLeakedConsequence – HOL may want to use Canadian values

Re: 3.5 Financial Component

3.5.1 Consequence Formulas

FinancialRiskConsequence – based on the assumptions provided in the spreadsheets:

FinancialRiskEmergencyReplacementConsequence – 2 * Planned renewal replacement cost
FinancialRiskCriticalReplacementConsequence – 1.5 * Planned renewal replacement cost
FinancialRiskCollateralDamageConsequence – 0 (except SXFRM and SXFRMTC)

and the related likelihoods, it is understood that the degraded failure accounts for unplanned replacement. Therefore degraded failure can also contribute to the reliability risk value measure alongside the catastrophic failure as both cause customer outages (please see Re: 2.1 Model Inputs, Table 2)

3.5.2 Likelihood Formulas

FinancialRiskLikelihood – denominator in the formula should have FinancialRiskCollateralDamageConsequence vs FinancialRiskCollateralDamageLikelihood:

…/ (FinancialRiskEmergencyReplacementConsequence + FinancialRiskCriticalReplacementConsequence + ~~FinancialRiskCollateralDamageLikelihood~~ FinancialRiskCollateralDamageConsequence + FinancialRiskMaintenanceCostConsequence)

4. Conclusions

Hatch reviewed the distribution model to asses it's alignment with industry AIP methodologies and practices. The general mechanics of the Distribution Asset Model and fundamental assumptions behind the values captured in Assumptions spreadsheets are aligned with industry practices and should serve the purpose of planning distribution asset replacements.

However, HOL may want to explore some areas where further refinement or clarification will benefit the model, planning process, and ultimately increase regulatory support likelihood.

1. Failure modes definition – Incipient, Degraded and Catastrophic failures can be clearly defined (ideally for each asset class) to further support the assignment of relative probabilities to reflect the general CNAIM methodology or a custom approach with clear boundaries. Ultimately, the allocation of relative failure probabilities feed into each value measure (i.e., financial risk, reliability risk, environmental risk, safety risk) and therefore the definition should be consistent between the probability and consequence sides.
2. Information granularity – the current version of the model has the ability to accommodate refined assumptions in the future. However, at this time a large number of asset, asset type, and system assumptions are provided at a high level. The higher granularity would benefit the effectiveness of the planning process while providing increased transparency for the regulatory process support.
3. Reliability inputs – the current distribution asset model contemplates the outage duration considerations at the asset type level while at the same time focusing only on major driver behind reliability impact (duration or frequency). To improve the soundness of the methodology some adjustments to the model may be required today to only focus on improving the level of granularity in the future. Based on Hatch's experience on similar projects, in some regulatory jurisdictions the CNAIM values and methodology are tested against utility-specific data or industry values. To support the development of future regulatory evidence HOL can explore the ways to increase the level of dependability on its own system and environment values through a pilot project targeting the most critical asset classes.

JG:jg

Attachment(s)/Enclosure: none

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT1.10

EVIDENCE REFERENCE:

Attachment 2-Staff-67(A) - Appendix A - NWCSP BCA Summary Report

UNDERTAKING(S):

For the BCA analysis in 2-Staff-67, Attachment A, to provide the supporting calculations.

RESPONSE(S):

Table A details the cost categories that contribute to the average distribution capacity cost. This breakdown is provided in response to the request for supporting calculations for the $78.6M average distribution capacity cost cited in the "Program Assumptions" tab of Attachment 2-Staff-67(A) - Appendix A - NWCSP BCA Summary Report.

Table A - Cost Breakdown ($’000 000s)

Cost Category	Cost
Distribution station cost	$42.3
Primary distribution cost	$26.3
Connection Cost Recovery Agreement with Transmission Provider	$10.0
TOTAL	**$78.6**

Annual Marginal Distribution Cost (avoidance benefit) was estimated using an average distribution capacity cost per 100 MVA using historical actuals. Three components required to unlock 100 MVA of capacity are the distribution station cost, primary distribution cost and Connection Cost Recovery Agreement (CCRA) costs. More details on each of these components and cost calculations are as follows:

Distribution Station Cost ($42.3M)

- This represents the cost to build a representative 230kV/28kV, 100MVA station with two station transformers and provision for eight feeder breakers.
- Cost Calculation: The $42.3M was derived using the average preliminary cost estimates of three comparable 100 MVA 28kV stations currently underway within the Capacity Upgrades Capital Program (Piperville MTS - $38.1M, Mer Bleue MTS - $45.3M, and Kanata North MTS - $43.6).

Primary Distribution Cost ($26.3M)

- This cost encompasses extending egress for feeders out of a station, upgrading pole lines and underground cabling, and integrating SCADA-enabled switches as required.
- Cost Calculation: The $26.3M was derived using the cost estimates for the distribution upgrades for the 2026-2030 period in the Kanata region, $20.7M (page 51 of Schedule 2-5-8 - System Service Investments) plus the costs incurred in that region during the 2021-2025 period ($5.6M) that contribute to the overall feeder integration plan.

Connection Cost Recovery Agreement (CCRA) Costs ($10M)

- CCRA costs refer to Hydro Ottawa's share of transmission infrastructure upgrades, determined through system capacity assessments. These upgrades include connections for new/upgraded stations and addressing equipment limitations at Hydro One owned stations, which supports grid reliability and growth.
- Cost Calculation: The $10M cost was an estimate assumed based on past project experience, and the scope of work anticipated for the new Kanata North MTS as the full CCRA assessment has not yet been completed by Hydro One. As stated in Section 7.5.1 of Schedule 2-5-9 - General Plant Investments "The requirement for the Cyrville MTS, New Kanata North Station,

and Greenbank Station transmission line upgrades have been determined through the Integrated Resource Planning Process (IRRP). However, the cost and cost-sharing arrangements for these upgrades have not yet been determined and are therefore not included in the current forecast." Hydro Ottawa's prior project experience set the transmission line upgrade cost at $5M, which was combined with $5M for the station connection to yield $10M. However, current project scoping with Hydro One has established a shift: relatively small transmission extensions (approximately 3 km) for projects now move past $5M, with costs frequently reaching or exceeding $10M.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT1.11

EVIDENCE REFERENCE:

4-SEC-72 and Staff-134

UNDERTAKING(S):

To quantify the decrease

RESPONSE(S):

As noted in Hydro Ottawa' letter regarding transcript revisions submitted on September 2025, Hydro Ottawa understands this undertaking request to be "to consider whether it is possible to quantify the decrease in proactive maintenance".

Hydro Ottawa is addressing a two-part request as part of this undertaking. First, to reconcile the 2025-2026 maintenance program variance between interrogatory responses 4-SEC-72 and 4-Staff-134. Second, Hydro Ottawa was asked to consider whether it is possible to quantify the potential decrease in maintenance from 2026-2030 due to the proposed increase in system renewal capital spending.

a) The discrepancy between the cost breakdown for the Testing, Inspection, and Maintenance (TIM) program in the interrogatory response 4-Staff-134 (Table A) and the 4-SEC-72 cost driver table can be reconciled by clarifying how the costs are categorized. Both documents agree on the total increase for the TIM program in 2026 as $6.1 million. The difference lies in the sub-categorization of this $6.1 million. Table A below helps align the categories between the two documents.

Table A: Comparison of TIM Program Breakdown between 4-Staff-134 and 4-SEC-72

<table>
<tr><th rowspan="2">Category</th><th colspan="2">4-Staff-134</th><th colspan="2">4-SEC-72</th></tr>
<tr><th>Cost</th><th>Purpose</th><th>Cost</th><th>Purpose</th></tr>
<tr><td rowspan="2">Existing TIM Programs</td><td>$1.0M</td><td>Enhancements of existing TIM Programs (as detailed in Table A 4-Staff-134)</td><td rowspan="2">$1.4M</td><td rowspan="2">(Shown as “Other” in 4-SEC-72)</td></tr>
<tr><td>$0.4M</td><td>Increase related to projected contractor pricing increases and reactive maintenance spending, not specific program enhancements</td></tr>
<tr><td>Overall Distribution</td><td>$1.8M</td><td>Proposed funding to introduce improvements to maintenance programs/practices based on changing/evolving needs. Exploring opportunities include automating/improving the capture of inspection information, enhanced condition assessment based on artificial intelligence, etc.</td><td rowspan="2">$4.6M</td><td rowspan="2">(Shown as “Proactive Distribution Maintenance in 4-SEC-72)</td></tr>
<tr><td>Third Party Non-Wire Alternative</td><td>$2.8M</td><td>Third party operating and maintenance of non-wire alternative solutions</td></tr>
<tr><td>Overall Inflation</td><td>$0.1M</td><td>General inflation</td><td>$0.1M</td><td>(Inflation based on the OEB inflation parameters and OEB approved program costs as shown in 4-SEC-72)</td></tr>
<tr><td>Sub-Total (Program Enhancements)</td><td>$5.6M (as shown in Table A of 4-Staff-134)</td><td></td><td>N/A</td><td></td></tr>
<tr><td>TOTAL</td><td>$5.6M + $0.4M+ $0.1M = $6.1M</td><td></td><td>$6.1M</td><td></td></tr>
</table>

Key Clarifications:

- Program Enhancement Costs ($5.6M): 4-Staff-134 explicitly reports $5.6M for all TIM program enhancements.
- Total TIM Increase ($6.1M): The total variance in 2026 for the TIM program in both documents is $6.1M.
- New Proactive Programs: The $4.6M classified as "Proactive Distribution Maintenance" in 4-SEC-72 represents the incremental costs for new proactive distribution maintenance programs. This amount is broken down in the response to interrogatory 4-Staff-134 as Third Party Non-Wire Alternative Solutions ($2.8M) and Overall Distribution ($1.8M).
- Existing Program Enhancements and Other Costs: The remaining $1.4M in 4-SEC-72 under the "Other" cost driver includes:
  - The $1.0M in 4-Staff-134 for enhancements to existing TIM programs.
  - The $0.4M increase attributed in 4-Staff-134 to projected contractor pricing increases, reactive maintenance spending, and general inflation (beyond the OEB-approved calculation).
- Inflation: $0.1M is consistently attributed to the inflation calculated based on the OEB parameters on OEB approved program costs in both analyses

b) Hydro Ottawa does not forecast any reduction in maintenance spending during the 2026-2030 period as a result of the proposed asset renewal investment, excluding inflationary factors and proposed program enhancements.

Hydro Ottawa must adhere to the OEB's time-based inspection cycle requirements (Appendix C: Minimum Inspection Requirements[1]), necessitating ongoing proactive maintenance of all assets, regardless of age or installation period. Hydro Ottawa's TIM programs for station and distribution assets are discussed in detail in Section 8.3 - Testing, Inspection & Maintenance Programs in Schedule 2-5-4 - Asset Management Process.

[1] Ontario Energy Board, "Appendix C, Minimum Inspection Requirements", https://www.oeb.ca/documents/dscappc.pdf

Hydro Ottawa's proposed System Renewal program will result in an increase in the overall percentage of degraded assets. By 2030, an estimated 8% of the overall assets will be in degraded condition, representing a 2% increase compared to 2024. The corresponding age and condition profiles of various asset types are discussed in Schedule 2-5-7 - System Renewal Investments (in the Alternatives Considered sections of Section 2.6 - Stations and Buildings Infrastructure Renewal, Section 3.6 - OH Distribution Assets Renewal, and Section 4.6 - UG Distribution Assets Renewal), indicating an increasing backlog of assets requiring intervention in 2030. Therefore, the overall asset demographics confirm the continued, high-volume need for testing, inspection, and maintenance activities to manage the operational risk of the large volume of aging assets that will not be replaced.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT1.12

EVIDENCE REFERENCE:

4-SEC-71 b)

UNDERTAKING(S):

To provide supporting documentation for the $1.8 million for incremental enhancements in 4-SEC-71 part b.

RESPONSE(S)

As a part of the proposed incremental maintenance enhancements between 2026-2030, Hydro Ottawa is exploring automation and artificial intelligence to refine condition assessments and improve overall asset management. The activities covered under the $1.8M proposed in 4-Staff-134 (Table A) are listed in 4-SEC-71 b) as follows:

- **Image Recognition for Anomaly Detection:** Utilize image recognition, based on images captured during inspections and patrols, to identify anomalies and establish asset degradation mechanisms.
- **Machine Learning for Regional Analysis:** Utilize K-Means Clustering and other Machine Learning techniques for geographical analysis. This involves grouping areas based on shared characteristics (e.g., inspection data, asset names, installation types) to pinpoint distinct regional patterns and understand their underlying drivers.

- **Automated Station Inspections:** Automate station inspection forms using image-based recognition capabilities to identify nameplate information and asset deficiencies.
- **Real-time Asset Condition Assessment:** Develop intelligent models (e.g., Duval's Pentagon) for dynamic, real-time condition assessment of critical assets like station transformers, leveraging online monitoring data.

The estimated annual cost breakdown for the aforementioned initiatives is shown in Table A.

Table A - Estimated Yearly Maintenance Enhancement Costs ('$000)

Initiative	Activity	Cost
Image Recognition and Machine Learning for Anomaly Detection and Failure Trend Analysis	Core Algorithms & Processing	$890
	Infrastructure & Data Management	$195
	Support Activities	$25
	Initiative Total	**$1,110**
Automated Station Inspections	Inspection Execution & Scope	$370
	Reporting & Support	$35
	Initiative Total	**$405**
Real-Time Condition Assessment	Data Prep & Core Algorithm	$225
	Result Validation, Reporting & Support	$60
	Initiative Total	**$285**
Grand Total		**$1,800**

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT1.14

EVIDENCE REFERENCE:

KT1.1

UNDERTAKING(S):

To provide responses to exhibit KT1.1.

RESPONSE(S):

Please see responses included as JT1.14-VECC-1.0 through JT1.14-VECC-21.0.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT1.16

EVIDENCE REFERENCE:

2-CO-21

UNDERTAKING(S):

To provide totals for each category.

RESPONSE(S):

As part of the interrogatory response 2-CO-21, Table A summarized the cumulative demand in MVA of large load requests. As part of this undertaking, Table A categorizes large loads into signed offers to connect, and submitted load summaries. It also breaks down the incremental cumulative demand in MVA by whether the customer is new or existing.

Table B provides the customer count for large load customers, again categorized into signed offers to connect, and submitted load summaries and also provides a breakdown of new and existing customers. Data is provided until 2026 in Table B because there are no new customers added to these categories beyond 2026.

Table A - Breakdown of New/Existing Customers (Cumulative MVA)

Stage	New Customer?	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Signed Offer to Connect	No	0	13	14	48	76	113	113	113	113	113	113	121	131	131	131	133	133	133
Submitted Load Summary Form	No	4	5	7	11	14	44	44	51	64	92	92	100	100	100	100	137	137	148
Submitted Load Summary Form	Yes	0	0	0	14	15	17	18	21	22	24	25	27	28	28	28	28	28	28

Table B - Breakdown of New/Existing Customers (Cumulative Count)

Stage	New Customer?	2023	2024	2025	2026
Signed Offer to Connect	No	4	4	4	4
Submitted Load Summary Form	No	4	4	4	4
Submitted Load Summary Form	Yes				2

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO COMMUNITY ACTION FOR ENVIRONMENTAL SUSTAINABILITY

JT1.17

EVIDENCE REFERENCE:

2-CO-13

UNDERTAKING(S):

To file the referenced document.

RESPONSE(S):

Please refer to Attachment JT1.17(A) - Outage Classification Guideline GRG0001 in response to the request to provide Hydro Ottawa's process for reporting outages based on Ontario Energy Board Reporting and Record keeping Requirements (RRR).

Hydro Ottawa records all power interruptions in accordance with the OEB's definitions for primary causes outlined in the OEB's RRRs, as shown in Section 4.5: Performance by Cause Code under Schedule 2-5-3: Performance Measurement for Continuous Improvement. The methodology and background on Major Event Days is also outlined in Section 4.4: Major Event Days under Schedule 2-5-3 - Performance Measurement for Continuous Improvement.

HydroOttawa	TITLE: **Guideline**	
RECOMMENDED: **A. Kumar EIT** **P. Pattabi P.Eng**	NO: **GRG0001**	REV: **2**
APPROVED: **M. Flores P.Eng**		
REV. DATE: **2023-12-15**		

Interruption Classification Guideline

See Hydro Ottawa's Intranet site for the latest revisions

REVISION SHEET

Revision	Description of Change	Date	Initial
0	Initial Document	2017-11-23	mm/jg
1	Primary Cause Updates	2023-03-22	av/pp/mf
2	Secondary Cause Updates	2023-12-15	av/pp/mf

TABLE OF CONTENTS

1 Introduction

Hydro Ottawa is required to report interruption statistics to the Ontario Energy Board (OEB) and voluntarily shares information about system interruptions with other members of the Canadian Electric Association (CEA).

This document is to be used to define how interruptions are classified in order to meet the reporting requirements to the OEB and CEA. This document will also provide guidance and interpretation of the definitions for classification.

2 References

OEB - Electricity Reporting and Record Keeping Requirements Bulletin - March 3, 2023
OEB – Electricity Reporting and Record Keeping Requirements Bulletin – November 21, 2022
OEB – Electricity Reporting and Record Keeping Requirements – May 3, 2016
CEA – Service Continuity User Manual – October 2016

3 OEB Definitions

Outage - It is defined as the loss of ability of a component to deliver power. An outage may or may not cause an interruption of service to customers, depending on system configuration.

Interruption - It means the loss of electrical power, being a complete loss of voltage, to one or more customers, including planned interruptions scheduled by the distributor but excluding: part power situations, interruptions scheduled by a customer, interruptions by order of emergency services, disconnections for non-payment or power quality issues such as sags, swells, impulses or harmonics.

Sustained interruption - It means an interruption with a duration of one minute or more.
Note: This excludes interruptions to a section of the feeder when the distributor is required to isolate the feeder section as a result of an order by emergency services.

Momentary interruption - It means an interruption with a duration of less than one minute. Note: These interruptions are generally restored by automatic reclosure facilities and are of a very short duration (on the order of a few seconds). If the reclosure operates multiple times within five minutes, and remains closed after that, it would be considered one momentary interruption. If the recloser operates multiple times and remains open after the operations, it would be considered a sustained interruption.

4 Primary Cause Codes

There are 10 primary cause codes Hydro Ottawa reports to the OEB and CEA to classify and maintain records of all customer interruptions. The following table of definitions has been taken from the OEB's Electricity Reporting and Record Keeping Requirements (November 21 2022)

Table 1 - OEB Cause Codes

Code	Cause Code	Definition
0	Unknown/Other	Customer interruptions with no apparent cause that contributed to the interruption.
1	Scheduled Interruption	Customer interruptions due to the disconnection at a selected time for the purpose of construction or preventive maintenance.
2	Loss of Supply	Customer interruptions due to problems associated with the distribution system owned and/or operated by another distributor, and/or in the transmission system.
3	Tree Contacts	Customer interruptions caused by faults resulting from tree contact with energized circuits under normal environment and weather conditions
4	Lightning	Customer interruptions due to lightning striking the distribution system, resulting in an insulation breakdown and/or flash-overs.
5	Equipment Failure (Formally known as Defective Equipment)	Customer interruptions resulting from distributor equipment failures due to deterioration from age, incorrect maintenance, or defective equipment/material.
6	Adverse Weather	Customer interruptions resulting from rain, ice storms, snow, winds, extreme temperatures, freezing rain, frost, or other extreme weather conditions (exclusive of Code 4 event).
7	Adverse Environment	Customer interruptions due to distributor equipment being subject to abnormal environments, such as salt spray, industrial contamination, humidity, corrosion, vibration, fire, or flooding.
8	Human Element	Customer interruptions due to the interface of distributor staff with the distribution system.
9	Foreign Interference	Customer interruptions beyond the control of the distributor, such as those caused by customer owned equipment, animals, vehicles, dig-ins, vandalism, sabotage, and foreign objects.

5 Secondary Sub-Cause Codes

Secondary Sub-cause codes are used to further differentiate interruption causes. They are used to quickly and easily differentiate underlying contributors to customer interruptions. This granularity is priceless when responding to internal data requests, public complaints, as well as, in the development of asset management plans.

OEB has taken the direction that breaking down the primary cause codes further into sub-cause codes will offer greater insights into distributors' reliability performance. This will assist distributors in making informed investment decisions based on the root cause of the interruptions. Consequently, OEB amended its file EB-2021-0307 dated March 2, 2023, by adding sub-cause codes to reliability reporting. As a part of this exercise, OEB has adopted the need for high-level sub-cause codes. Upon reviewing the OEB recommendations, it was observed that they weren't providing sufficient granularity to benchmark and compare our system performance against other utilities in Canada and the world. As a result, HOL has adopted the cause codes from both the CEA Service Continuity Committee (of which HOL is a member) and the latest OEB RRR bulletin, as detailed in Appendix A.

The following subsections provide a brief description of all secondary sub-cause codes for each primary cause code.

5.1 Unknown/Other

Customer interruptions with no apparent cause or reason which could have contributed to the interruption.

These are interruptions where there has been no adverse weather or lightning reported in the area. Patrolling the affected lines found no signs of foreign interference or tree contacts.

There are no secondary sub-cause codes associated with Unknown/Other.

5.2 Scheduled Interruption

Customer interruptions due to the disconnection at a selected time for the purpose of construction or preventive maintenance.

These are planned interruptions for safety when working in close proximity to energized equipment. Also for make safe situations from external requestors.

This also includes scheduled interruptions to repair / replace deteriorated equipment.

Table 2 - Scheduled Interruption Secondary Sub-Codes

Code	Sub-cause Code	Description	Example
101	Customer Requested	Interruption requested by a customer.	A building owner is performing renovations to a specific area on the building and they would prefer power to be out for several hours. A building has requested

			an interruption to perform preventative maintenance.
102	Construction	Interruption required to safely perform construction activity.	A scheduled interruption is required for new builds or upgrade activities (e.g. replacing a pole mounted transformer, removing equipment).
103	Maintenance	Interruption required to safely maintain the plant. The device has not yet failed, maintenance is performed to improve performance or prolong the life of the asset.	Routine maintenance is required on a piece of equipment (i.e., rust removal, installation of new insulators, etc.).
104	Vegetation Management	Interruption required to safely trim or remove trees & vegetation.	Contractors or utility employees must perform tree trimming duties on right-of-way and a temporary interruption is required for safety.
105	Forced Switching	A secondary interruption which must be taken in order to repair &/or restore a previous interruption.	A switching point must be opened to isolate a work area to replace a failed device. The interruption caused by a failed device is Equipment Failure, while the interruption caused by opening the switching point is considered a Scheduled Interruption.
106	Sectionalizing	Interruptions taken to allow for staged restoration.	A network section is temporarily forced out to restore other portions of the network first.
107	Building/ High Load Move	Interruptions required to allow for movement of very large items, like buildings and bridge trusses, etc.	Temporary interruption requested to perform a house move.
108	Emergency Services Request	Interruption requested by emergency services such as Fire Department or Police	Fire department requests isolation to safely extinguish a house fire.

5.3 Loss of Supply

Customer interruptions due to problems associated with the distribution system owned and/or operated by another distributor, and/or in the transmission system.

These are planned and inadvertent interruptions from transmitter owned equipment that results in the loss of supply to Hydro Ottawa owned assets and customers.

Table 3 - Loss of Supply Secondary Sub-Codes

Code	Sub-cause Code	Description	Example
201	Transmission Planned	Any planned transmission level interruption where 4 hours or more notice is provided to the LDC, otherwise code as transmission inadvertent or generation inadvertent.	Transmission crews notify you 24 hours in advance to perform maintenance work that results in temporary loss of supply.
202	Transmission Inadvertent	Any inadvertent transmission level interruption, where less than 4 hours of notice is provided to the LDC.	Transmission system unexpectedly stops supplying electricity.
203	Generation Inadvertent	Any interruption caused by generation issues, including U/O Frequency, winding faults, etc.	Generation units are forced out, and supply no electricity to your network system.
204	Loss of Supply Distribution	Problems associated with the distribution system owned and/or operated by another distributor. Distribution supply points are listed in Appendix D	A tree branch fell on an overhead distribution line owned by a host distributor and caused an interruption to the downstream distributor.

5.4 Tree Contact

Customer interruptions caused by faults resulting from tree contact with energized circuits under normal environment and weather conditions.

These interruptions are when there is evidence that vegetation has come into contact with Hydro Ottawa's energized system resulting in an interruption.

Table 4 - Tree Contact Secondary Sub-Codes

Code	Sub-cause Code	Description	Example
301	Fallen Tree On Right-of-Way	Entire or major trunk of tree situated on a right-of-way falls on energized line or equipment.	An entire tree falls on lines or equipment damaging them and resulting in an interruption. Tree is on the Right-of-Way.
302	Broken Branch	Branch separates from a tree.	Branch breaks from a tree and strikes lines or equipment resulting in an interruption.
303	Tree Growth/ Untrimmed Tree	Tree grows into a line.	Tree growth causes damage to lines or equipment resulting in an interruption.
304	Fallen Tree Off Right-of-Way	Entire or major trunk of trees situated off a right-of-way falls on energized lines or equipment.	Tree fell from off right-of-way falls on line or distribution equipment.
305	Other Vegetation	Any other vegetation related to interruptions (i.e., ivy, moss, etc.)	Ivy grows into equipment and causes an interruption.

5.5 Lightning

Customer interruptions due to lightning striking the Distribution System, resulting in an insulation breakdown and/or flashovers.

These interruptions are when there is reasonable evidence that lightning in the area was the probable cause of the interruption.

There are no secondary sub-codes associated with Lightning.

5.6 Equipment Failure (formally known as Defective Equipment)

Customer interruptions resulting from equipment failures due to deterioration from age, incorrect maintenance, or defective equipment/material.

These do not include interruptions where equipment failed but the root cause was another primary cause. E.g. lightning caused a transformer to fail or a motor vehicle accident.

Table 5 - Equipment Failure Secondary Sub-Codes

Code	Sub-cause Code	Description	Example
501	Electrical Failure	Any failure of equipment resulting in a flash-over or insulation breakdown.	An insulator burns out.
502	Mechanical Failure	Any failure involving the physical breakage of plant.	A crossarm brace bolt breaks.
503	Defective Equipment/ Material	Material was flawed in some way at the time of installation which resulted in its failure substantially before expected end of life.	A manufacturer assembly defect causes the device to fail after 500 hours in usage. Design of equipment results in early failure (e.g. recloser failures due to poor design.)
504	Corrosion	Build-up of rust on metallic components results in bad connection or oil leaks.	Corrosion causes a transformer oil leak resulting in an interruption.
505	Moisture Ingress	Ingress of water into live parts resulting in breakdown of insulation.	Moisture in a breaker causes a flashover.
506	Distributed Energy Resources (DER) Failure	Any failure of a distributor owned DER facility.	An interruption due to a distributor-owned energy storage unit that failed to mitigate a power quality issue on the feeder as designed.

5.7 Adverse Weather

Customer interruptions resulting from rain, ice storms, snow, winds (approximately equal to 90 km/hr), extreme ambient temperatures, freezing fog, or frost and other extreme conditions.

These are interruptions caused by weather events that stress Hydro Ottawa’s system beyond design standards and capabilities.

These do not include interruptions caused by lightning but include interruptions caused by tree contacts and equipment breakage during adverse weather conditions.

Table 6 - Adverse Weather Secondary Sub-Codes

Code	Sub-cause Code	Description	Example
601	Tree Contact Weather	Fallen tree or tree branches due to adverse weather conditions	Severe windstorm caused tree branches to touch overhead lines causing the protection to lockout.
602	Equipment Breakage	Equipment breakage or temporary malfunction due to adverse weather conditions that do not fall under 601	Ice formed on distribution lines during freezing rainfalls, and the weight forced the conductors to collapse, resulting in an interruption.
603	Other Adverse Weather	Interruption caused by adverse weather but did not involve tree contact or equipment breakage	Extreme wind caused overhead conductors to slap together

5.8 Adverse Environment

Customer interruptions due to equipment being subjected to abnormal environments such as salt spray, industrial contamination, humidity, corrosion, vibration, fire or flooding.

These interruptions are due to adverse conditions where the assets are installed.

Interruptions taken to prevent damages to equipment due to adverse environment conditions should be classified as such.

Table 7 - Adverse Environment Secondary Sub-Codes

Code	Sub-cause Code	Description	Example
701	Contamination (Salt)	Salt deposits on bushings and insulators cause them to flash over.	Salt spray from road de-icing corrodes the connections causing an interruption.
702	Contamination (Dirt, pollution, other external particles)	Non-salt deposits (dirt, industrial pollution) on bushings and insulators causing them to flash over.	Pollution build-up causes an interruption.
703	Fire	House / Forest fire causes power to be interrupted.	A house fire causes damage to nearby distribution equipment resulting in an interruption to other households. Not the same as when Emergency Services Requests an interruption.
704	Flood	Only to be used when the flood directly affects the plant. Not to be used when flood limits mobility.	When flood waters create a path between live and grounded parts causing a flashover, or when flood waters physically disrupt plant to cause an interruption.

705	Unstable Earth	Disruption to the Earth's surface results in destruction of plant. Landslide, sinkhole, earthquake.	Sinkhole damages several poles breaking the lines to a neighbourhood, and causes a forced interruption until power is restored to the customers. An earthquake causes equipment damages or protective devices to operate.

5.9 Human Element

Customer interruptions due to the interface of the utility staff with the system such as incorrect records, incorrect use of equipment, incorrect construction or installation, incorrect protection settings, switching errors, commissioning errors, deliberate damage or sabotage by employees/contractors.

These are preventable interruptions that can be linked to human error.

Table 8 - Human Element Sub-Codes

Code	Sub-cause Code	Description	Example
801	Switching Error	Use when a switching operation creates an unexpected interruption.	A technician opens the wrong switching device and causes an interruption to occur.
802	Protection Setting	Use when an interruption results from the miscoordination or incorrect settings of protective devices.	Miscoordination of protection equipment causes station bus protection to trip instead of feeder breaker.
803	Improper Design	Use when sub-standard design causes errors that leads to an interruption event.	Incorrect design schema used for mounting a pole transformer, eventually resulting in an interruption.
804	Improper Construction/installation	Use when substandard construction materials or poor installation leads to an interruption event.	During construction an electrical cable gets cut and results in an interruption.
805	Improper Equipment/Tool/ Maintenance	Use when improper tools or equipment are used, or when improper maintenance procedures are performed.	The line technician uses the wrong tool and interruption ensues.
806	Commissioning Error	Commissioning activities errors cause unplanned interruption.	Commissioning activities cause an unplanned interruption.
807	Incorrect Records/ labelling	Use when incorrect or outdated records or information is used in the field which then results in an error.	Field workers perform maintenance according to incorrect records or labels resulting in an interruption.
808	Distributed Energy Resources (DER)	Interruption caused by improper connection and/or improper	A distributor owned DER's protection device didn't operate as designed to isolate the DER

		operation of DERs by the distributor.	facility and interrupted other customers supplied on the same feeder/feeder section.

5.10 Foreign Interference

Customer interruptions beyond the control of the utility such as birds, animals, vehicles, dig-ins, vandalism/sabotage and other foreign objects.

These are interruptions due to external forces interfering with Hydro Ottawa's system.

This also includes interruptions caused by assets owned by a third party.

Table 9 - Foreign Interference Sub-Codes

Code	Sub-cause Code	Description	Example
901	Wildlife (Bird/Animal)	Crows, seagulls, woodpeckers, squirrels, raccoons, cats, rats, bears, etc.	A squirrel makes contact with transformer bushings.
902	Vehicle	Motor vehicle accidents, which make contact with poles, guys, etc.	A vehicle strikes a pole and takes down an overhead line.
903	Crane	Crane or Boom-truck makes contact with plant.	A construction crane strikes and removes several distribution lines and/or poles.
904	Agricultural Equipment	Tractors, combines, graders, etc.	Tractor or Combine pulls on a guy wire causing an interruption.
905	Dig-In	Excavator, backhoe, augers or other equipment digs into underground cables.	A customer uses an auger and digs down which results in the cutting of a cable causing an interruption.
907	Foreign Objects	Use when strange objects hit the line, like balloons, kites, sneakers, etc.	Someone sets off fireworks on their street and they strike some insulators and/or pole mounted transformer bank causing an interruption to several homes.
908	Customer-Cut Trees	Non-utility/ non-contractor person drops a tree on line.	A homeowner cuts tree in their yard and it falls on lines creating an interruption.
909	Vandalism/Sabotage	Use when deliberate acts cause an interruption. (sabotage, terrorism, gunplay)	Vandals break into a pad-mounted transformer and damage it.
910	Other Utilities	Use when the interruption is caused by a neighbouring utility operating on your system in error without permission.	Another utility inadvertently shuts down your power flow to several of your customers.
911	Customer Owned Equipment	Interruption caused by assets owned and/or operated by third party	Customer owned equipment causes LDC owned feeder breaker to open

912	Distributed Energy Resources (DER)	Failure or improper operation of DER facilities not owned / operated by distributors.	A customer-owned DER's protection didn't operate as designed to isolate a fault in the DER facility and interrupted other customers supplied on the same feeder/feeder section.

6 Interruptions with Multiple Causes

Interruptions that originate from an initial cause but result in additional customer interruptions due to subsequent causes should be separated where appropriate.

For the interruption to be separated, the subsequent interruption needs to be one (1) minute or greater and affect a different population of customers than the original interruption.

Note that care should be taken not to double count affected customers when separating interruptions to identify multiple causes.

The following are examples where interruptions should be separated:

1. Fuse or recloser operates downstream on a distribution feeder and in order to safely make repairs or work around energized equipment, the entire feeder is isolated at the station breaker. The subsequent interruption would be Scheduled Interruption – Forced Switching.
2. Motor vehicle accident causes station breaker protection to operate. Due to error in protection coordination, the entire bus or station is tripped off resulting in a larger interruption. The initial interruption where the breaker would isolate the interruption would be classified as Foreign Interference – Vehicle. The subsequent interruption, to the rest of the circuits on the affected bus, would be classified as Human Element – Protection Settings.

7 Equipment Failure Types

Where interruptions are the result of equipment failures it is expected that the type of equipment which has failed is identified as part of the interruption record. The intent is that by tracking the specific types of equipment that negatively impact system reliability, future system investments can be better planned, targeted and justified. It is therefore required to identify the equipment that has failed (root cause) and not the equipment which has operated.

Table 10 - Equipment Failure Types

Primary Apparatus Failed	Secondary Apparatus Failed
Civil Structures	Duct
	Manhole
	Unknown \ Other
Customer Owned	Customer-Owned
O/H Conductor	Hot-Line Clamp
	O/H Conductor
	Pigtail
	Stirrup
	Sleeve
	Ampact
	Unknown \ Other
O/H Switchgear	Fused Cutout
	Inline Switch
	Load Break Gang
	Non-Load Break Gang
	Recloser (1ph)
	Recloser (3ph)
	Simple Solid Blade Switch
	Vega Switch
	Unknown \ Other
O/H Transformer	O/H Transformer (1ph)
	O/H Transformer (3ph)
	Step Transformer (Rabbit)
	Voltage Regulator
	Unknown \ Other
Pole	Crossarm
	Insulation Failure (Pole Fire)
	Pole
	Unknown \ Other
Pole Attachment	Arrester
	Ground
	Insulator
	Unknown \ Other
Secondary \ Service	Meter
	Mole
	O/H Service
	Secondary Pedestal
	U/G Service
	Unknown \ Other

Primary Apparatus Failed	Secondary Apparatus Failed
Station Equipment	Arrester
	Primary Cable Termination
	Primary Switchgear
	Relay
	Secondary Cable Termination
	Secondary Switchgear
	Transformer
	Unknown \ Other
U/G Cable	PILC
	PILC Splice
	Transition Splice
	XLPE
	XLPE Splice
	Unknown \ Other
U/G Cable Attachment	Arrester
	Elbow \ Insert
	Pothead
	Termination \ Stress Cone
	Unknown \ Other
U/G Switchgear	Gas-Insulated Dead Front
	Live-Front
	Primary Pedestal
	Unknown \ Other
U/G Transformer	Kiosk (1ph)
	Kiosk (3ph)
	Oil Filled - Submersible
	Padmount (1ph)
	Padmount (3ph)
	SIDT - Submersible (Turtle)
	Unknown \ Other
Vault Equipment	Breaker \ Relay
	Cable
	Connector
	Switch
	Transformer
	Unknown \ Other
Unknown \ Other	Unknown \ Other
None	None

Appendix A - Sub-Cause Code Comparison Sheet

OEB Cause Codes				HOL Cause Codes - GRG0001			
Code	**Cause Code Name**	**Sub-Cause Code Name**	**Description**	**Code**	**Cause Code Name**	**Sub-Cause Code Name**	**Description**
0	**Unknown**		Customer interruptions with no apparent cause that contributed to the interruption.	**0**	**Unknown**	Unknown	Customer interruptions with no apparent cause that contributed to the outage.
1	**Scheduled Outage**		Interruption due to disconnection at a selected time for the purpose of construction or maintenance.	**1**	**Scheduled Outage**		Customer interruptions due to the disconnection at a selected time for the purpose of construction or preventive maintenance.
101		Non distributor activities	Interruption required to safely perform activity that is unrelated to the distributor's distribution system	101		Customer Requested	Customer Requested Outage requested by a customer
				107		Building/ High Load Move	Outages required to allow for movement of very large items, like buildings and bridge trusses, etc.
				108		Emergency Services Request	Outage requested by emergency services such as Fire Department or Police
				102		Construction	Outage required to safely perform construction activity.

102		Distributor activities	Interruption required to allow the distributor to safely perform construction or maintenance activity.	103		Maintenance Management	Outage required to safely not yet failed, maintenance is performed to improve performance or prolong the life of the asset.
				104		Vegetation	Outage required to safely trim or remove trees & vegetation.
				105		Forced Switching	A secondary outage which must be taken in order to repair &/or restore a previous outage.
				106		Sectionalizing	Outages taken to allow for staged restoration.
2	**Loss of Supply**		Interruption due to problems associated with the distribution system owned and/or operated by another distributor, and/or in the transmission system	**2**	**Loss of Supply**		Customer interruptions due to problems associated with assets owned and/or operated **by another party**, and/or in the bulk electricity supply system. For this purpose, the bulk electricity supply system is distinguished from the distributor's system based on ownership demarcation.
201		Loss of Supply Transmission	Problems in the transmission system or assets owned and maintained by the transmitter.	201		Transmission Planned	Any planned transmission level outage where 4 hours or more notice is provided to the LDC, otherwise code as transmission inadvertent or generation inadvertent.
				202		Transmission Inadvertent	Any inadvertent transmission level outage, where less than 4 hours of notice is provided to the LDC.
				203		Generation Inadvertent	Any outage caused by generation issues, including U/O Frequency, winding faults, etc.

202		Loss of Supply Distribution	Problems associated with the distribution system owned and/or operated by another distributor.	204		Loss of Supply Distribution	Problems associated with the distribution system owned and/or operated by another distributor.
3	**Tree Contacts**		Interruption caused by faults resulting from tree contact with energized circuits	**3**	**Tree Contacts**		Customer interruptions caused by faults resulting from tree contact with energized circuits
301		Fallen tree on right-of-way	Entire or major portion of, or major trunk of a tree, where the base of the tree is situated on distribution right-of-way or public right-of-way, that falls on an energized line or other distribution system equipment.	301		Fallen tree on right-of-way	Entire or major portion of, or major trunk of a tree, where the base of the tree situated on distribution right-of-way or public right-of-way, that falls on an energized line or other distribution system equipment.
302		Broken branch/tree growth/untrim med tree	Branch breaks from tree and strikes lines or equipment, or tree growth causes damage to lines or equipment.	302		Broken Branch	Branch separates from the tree.
				303		Tree Growth/ Untrimmed Tree	Tree growth causes damage to lines or equipment resulting in an outage.
				305		Other Vegetation	Any other vegetation related to outages (i.e., ivy, moss, etc.)
303		Fallen tree off right-of-way	Entire or major portion of, or major trunk of a tree, where the base of the tree is situated off distribution right-of-way or public right-of-way, that falls on an energized line or other distribution system equipment.	304		Fallen tree off right-of-way	Entire or major portion of, or major trunk of a tree, where the base of the tree situated off distribution right-of-way or public right-of-way, that falls on an energized line or other distribution system equipment.
4	**Lightning**		The lightning category includes all interruptions caused by lightning.	**4**	**Lightning**	Lightning	Customer interruptions due to lightning striking the distribution system, resulting in an insulation breakdown and/or flash-overs.

5	**Equipment Failure**		Customer interruptions resulting from the failure of distributor owned equipment failures due to deterioration from age, incorrect maintenance, or defective equipment/material. Note: Customer interruptions caused by DER equipment failure shall be reported under code 5.3 if the DER is owned by the distributor. Note 2: Scheduled outages to repair/replace deteriorated equipment should be reported under 1.3	**5**	**Equipment Failure**		Customer interruptions resulting from distributor equipment failures due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance.
501		Equipment Failure	Any failure of distribution equipment resulting from deterioration or improper maintenance of the distribution equipment.	501		Electrical Failure	Any failure of equipment resulting in a flash-over or insulation breakdown.
				502		Mechanical Failure	Any failure involving the physical breakage of a plant.
				504		Corrosion	Build-up of rust on metallic components results in bad connection or oil leaks.
				505		Moisture Ingress	Ingress of water in to live parts resulting in breakdown of insulation
502		Distributed Energy Resources (DER) Failure	Any failure of a distributor-owned DER facility.	506		Distributed Energy Resources (DER) Failure	Any failure of a distributor-owned DER facility.

503		Defective equipment / material	Equipment/material was flawed in some way at the time of installation, which resulted in its failure	503		Defective Equipment/ Material	Material was flawed in some way at the time of installation which resulted in its failure substantially before expected end of life.
6	**Adverse Weather**		Interruption resulting from severe rain, ice storms, heavy snow, severe windstorm (~90 kilometers an hour or greater), extreme temperatures, freezing rain, frost, hail or other extreme weather conditions (exclusive of cause code 4). Adverse weather includes but is not limited to the following conditions:	**6**	**Adverse Weather**		Interruption resulting from severe rain, ice storms, heavy snow, severe windstorm (~90 kilometers an hour or greater), extreme temperatures, freezing rain, frost, hail or other extreme weather conditions (exclusive of cause code 4). Adverse weather includes but is not limited to the following conditions:
601		Tree contact weather	Fallen tree or tree branches due to adverse weather conditions.	601		Tree contact weather	Fallen tree or tree branches due to adverse weather conditions.
602		Equipment breakage	Equipment breakage or temporary malfunction due to adverse weather conditions that do not fall under cause code 6.1.	602		Equipment breakage	Equipment breakage or temporary malfunction due to adverse weather conditions that do not fall under cause code 601.
603		Other adverse weather	Interruption caused by adverse weather but did not involve tree contact or equipment breakage.	603		Other adverse weather	Interruption caused by adverse weather but did not involve tree contact or equipment breakage.
7	**Adverse Environment**		Interruption due to distributor equipment being subject to abnormal environments, such as salt spray, industrial contamination, humidity, corrosion, vibration, fire or flooding.	**7**	**Adverse Environment**		Customer interruptions due to distributor equipment being subject to abnormal environments, such as salt spray, industrial contamination, humidity, corrosion, vibration, fire, or flowing.
				701		Contamination (Salt)	Salt deposits on bushings and insulators cause them to flash over.

				702		Contamination (Dirt, Pollution, other external particles)	Non-salt deposits (dirt, industrial pollution) on bushings and insulators causing them to flash over.
				703		Fire	House / Forest fire causes power to be interrupted.
				704		Flood	Only to be used when the flood directly affects the plant. Not to be used when flood limits mobility.
				705		Unstable Earth	Disruption to the Earth's surface results in destruction of plant. Landslide, sinkhole, earthquake.
8	**Human Element**		Interruption due to the interface of distributor staff with the distribution system.	**8**	**Human Element**		Customer interruptions due to the interface of distributor staff with the distribution system.
801		Distributed Energy Resources (DER)	Interruption caused by improper connection and/or improper operation of DERs by the distributor.	808		Distributed Energy Resources (DER)	Interruption caused by improper connection and/or improper operation of DERs by the distributor.
				801		Switching Error	Use when a switching operation creates an unexpected interruption
				802		Protection Setting	Use when an interruption results from the miscoordination or incorrect settings of protective devices.
				803		Improper Design	Use when sub-standard design causes errors that leads to an interruption event.

802		Other Human Element	Any other interruptions caused by distributor staff or contractors acting on the distributor's behalf.	804		Improper Construction/installation	Use when substandard construction materials or poor installation leads to an interruption event.
				805		Improper Equipment/Tool/ Maintenance	Use when improper tools or equipment are used, or when improper maintenance procedures are performed.
				806		Commissioning Error	Commissioning activities errors cause unplanned interruption
				807		Incorrect Records/ labelling	Use when incorrect or outdated records or information is used in the field which then results in an error.
9	**Foreign Interference**		Interruption caused by external factors, such as those caused by customer equipment, DERs not owned by distributors, animals, vehicles, dig-ins, vandalism, sabotage, foreign objects and cybersecurity events.	**9**	**Foreign Interference**		Customer interruptions beyond the control of the distributor, such as those caused by animals, vehicles, dig-ins, vandalism, sabotage, and foreign objects.
901		Wildlife	Interruption caused by contact with any form of wildlife.	901		Wildlife (Bird/Animal)	Interruption caused by contact with any form of wildlife.
902		Vehicle	Motor vehicle accidents, which make contact with poles, guys, etc.	902		Vehicle	Motor vehicle accidents, which make contact with poles, guys, etc.
903		Dig-in	Excavator, backhoe, augers or other equipment digs into underground cables.	905		Dig-In	Excavator, backhoe, augers or other equipment digs into underground cables.

904		Customer Owned equipment	Failure or improper operation of electrical equipment not owned by distributors (excluding DER equipment) that caused interruption to one or more customers.	911		Customer Owned equipment	Failure or improper operation of electrical equipment not owned by distributors (excluding DER equipment) that caused interruption to one or more customers.
905		Distributed Energy Resource (DER)	Failure or improper operation of DER facilities not owned/operated by distributors.	912		Distributed Energy Resource (DER)	Failure or improper operation of DER facilities not owned/operated by distributors.
906		Other (non-distributor staff)	Customer interruptions caused by the act of person other than distributor staff. Including interruptions caused by agricultural or construction equipment, sabotage, terrorism, balloon, kites, sneakers, etc.	903		Crane	Crane or Boom-truck makes contact with plant
				904		Agricultural Equipment	Tractors, combines, graders, etc.
				907		Foreign Objects	Use when strange objects hit the line, like balloons, kites, sneakers, etc.
				908		Customer-Cut Trees	Non-utility/ non-contractor person drops a tree on the HOL line.
				909		Vandalism/Sabotage	Use when deliberate acts cause an interruption. (sabotage, terrorism, gunplay
				910		Other Utilities	Use when the interruption is caused by a neighboring utility operating on your system in error without permission.

Appendix B – Classification Table

Code	Cause Code	Sub-cause Code	Description	Example
0	**Unknown / Other**		**Customer interruptions with no apparent cause that contributed to the interruption.**	It truly is unknown, investigation occurred and no cause was determined.
1	**Scheduled Interruption**		**Customer interruptions due to the disconnection at a selected time for the purpose of construction or preventive maintenance.**	
101		Customer Requested	Interruption requested by a customer.	A building owner is performing renovations to a specific area on the building and they would prefer power to be out for several hours. A building has requested an interruption to perform preventative maintenance.
102		Construction	Interruption required to safely perform construction activity.	A scheduled interruption is required for new builds or upgrade activities (e.g. replacing a pole mounted transformer, removing equipment).
103		Maintenance	Interruption required to safely maintain the plant. The device has not yet failed, maintenance is performed to improve performance or prolong the life of the asset.	Routine maintenance is required on a piece of equipment (i.e., rust removal, installation of new insulators, etc.).
104		Vegetation Management	Interruption required to safely trim or remove trees & vegetation.	Contractors or utility employees must perform tree trimming duties on right-of-way and a temporary interruption is required for safety.
105		Forced Switching	A secondary interruption which must be taken in order to repair &/or restore a previous interruption.	A switching point must be opened to isolate a work area to replace a failed device. The interruption caused by a failed device is Equipment Failure, while the interruption caused by opening the switching point is considered a Scheduled Interruption.
106		Sectionalizing	Interruptions taken to allow for staged restoration.	A network section is temporarily forced out to restore other portions of the network first.
107		Building/ High Load Move	Interruptions required to allow for movement of very large items, like buildings and bridge trusses, etc.	Temporary interruption requested to perform a house move.
108		Emergency Services Request	Interruption requested by emergency services such as Fire Department or Police	Fire department requests isolation to safely extinguish a house fire.
2	**Loss of Supply**		**Customer interruptions due to problems associated with the distribution system owned**	

			and/or operated by another distributor, and/or in the transmission system.	
201		Transmission Planned	Any planned transmission level interruption where 4 hours or more notice is provided to the LDC, otherwise code as transmission inadvertent or generation inadvertent.	Transmission crews notify you 24 hours in advance to perform maintenance work that results in temporary loss of supply.
202		Transmission Inadvertent	Any inadvertent transmission level interruption, where less than 4 hours of notice is provided to the LDC.	Transmission system unexpectedly stops supplying electricity.
203		Generation Inadvertent	Any interruption caused by generation issues, including U/O Frequency, winding faults, etc.	Generation units are forced out, and supply no electricity to your network system.
204		Loss of Supply Distribution	Problems associated with the distribution system owned and/or operated by another distributor. Distribution supply points are listed in Appendix D.	A tree branch fell on an overhead distribution line owned by a host distributor and caused an interruption to the downstream distributor.
3	**Tree Contacts**		**Customer interruptions caused by faults resulting from tree contact with energized circuits under normal environment and weather conditions.**	
301		Fallen Tree On Right-of-Way	Entire or major trunk of tree situated on a right-of-way falls on energized line or equipment.	An entire tree falls on lines or equipment damaging them and resulting in an interruption. Tree is on the Right-of-Way.
302		Broken Branch	Branch separates from a tree.	Branch breaks from a tree and strikes lines or equipment resulting in an interruption.
303		Tree Growth/ Untrimmed Tree	Tree grows into a line.	Tree growth causes damage to lines or equipment resulting in an interruption.
304		Fallen Tree Off Right-of-Way	Entire or major trunk of trees situated off a right-of-way falls on energized lines or equipment.	Tree fell from off right-of-way falls on line or distribution equipment.
305		Other Vegetation	Any other vegetation related to interruptions (i.e., ivy, moss, etc.)	Ivy grows into equipment and interruption causes an interruption.
4	**Lightning**		**Customer interruptions due to lightning striking the distribution system, resulting in an insulation breakdown and/or flash-overs.**	Sufficient evidence is available to conclude lightning caused the interruption.
5	**Equipment Failure (formally known as Defective Equipment)**		**Customer interruptions resulting from distributor equipment failures due to deterioration from age, incorrect maintenance, or defective equipment/material.**	
501		Electrical Failure	Any failure of equipment resulting in a flash-over or insulation breakdown.	An insulator burns out.

502		Mechanical Failure	Any failure involving the physical breakage of plant.	A crossarm brace bolt breaks.
503		Defective Equipment/ Material	Material was flawed in some way at the time of installation which resulted in its failure substantially before expected end of life.	A manufacturer assembly defect causes the device to fail after 500 hours in usage. Design of equipment results in early failure (e.g. recloser failures due to poor design.)
504		Corrosion	Build-up of rust on metallic components results in bad connection or oil leaks.	Corrosion causes a transformer oil leak resulting in an interruption.
505		Moisture Ingress	Ingress of water into live parts resulting in breakdown of insulation.	Moisture in a breaker causes a flashover.
506		Distributed Energy Resources (DER) Failure	Any failure of a distributor owned DER facility.	An interruption due to distributor- owned energy storage that failed to mitigate a power quality issue on the feeder as designed.
6	**Adverse Weather**		**Customer interruptions resulting from rain, ice storms, snow, winds (approximately equal to 90km/hr), extreme temperatures, freezing rain, frost, or other extreme weather conditions (exclusive of Code 4 event).**	
601		Tree Contact Weather	Fallen tree or tree branches due to adverse weather conditions.	Severe windstorm caused tree branches to touch overhead lines causing protection to lockout.
602		Equipment Breakage	Equipment breakage or temporary malfunction due to adverse weather conditions that do not fall under 601.	Ice formed on distribution lines during freezing rainfalls, and the weight forced the conductors to collapse, resulting in an interruption.
603		Other Adverse Weather	Interruption caused by adverse weather but did not involve tree contact or equipment breakage.	Extreme wind caused an overhead conductors to slap together.
7	**Adverse Environment**		**Customer interruptions due to distributor equipment being subject to abnormal environments, such as salt spray, industrial contamination, humidity, corrosion, vibration, fire, or flowing.**	
701		Contamination (Salt)	Salt deposits on bushings and insulators cause them to flash over.	Salt spray from road de-icing corrodes the connections causing an interruption.
702		Contamination (Dirt, pollution, other external particles)	Non-salt deposits (dirt, industrial pollution) on bushings and insulators causing them to flash over.	Pollution build-up causes an interruption.
703		Fire	House / Forest fire causes power to be interrupted.	A house fire causes damage to nearby distribution equipment resulting in an interruption to other households. Not the same as when Emergency Services Requests an interruption.

704		Flood	Only to be used when the flood directly affects the plant. Not to be used when flood limits mobility.	When flood waters create a path between live and grounded parts causing a flashover, or when flood waters physically disrupt plant to cause an interruption.
705		Unstable Earth	Disruption to the Earth's surface results in destruction of plant. Landslide, sinkhole, earthquake.	Sinkhole damages several poles breaking the lines to a neighbourhood, and causes a forced interruption until power is restored to the customers. An earthquake causes equipment damages or protective devices to operate.
8	**Human Element**		**Customer interruptions due to the interface of distributor staff with the distribution system.**	
801		Switching Error	Use when a switching operation creates an unexpected interruption.	A technician opens the wrong switching device and causes an interruption to occur.
802		Protection Setting	Use when an interruption results from the miscoordination or incorrect settings of protective devices.	Miscoordination of protection equipment causes station bus protection to trip instead of feeder breaker.
803		Improper Design	Use when sub-standard design causes errors that leads to an interruption event.	Incorrect design schema used for mounting a pole transformer, eventually resulting in an interruption.
804		Improper Construction/installation	Use when substandard construction materials or poor installation leads to an interruption event.	During construction an electrical cable gets cut and results in an interruption.
805		Improper Equipment/Tool/ Maintenance	Use when improper tools or equipment are used, or when improper maintenance procedures are performed.	The line technician uses the wrong tool and interruption ensues.
806		Commissioning Error	Commissioning activities errors cause unplanned interruption.	Commissioning activities cause an unplanned interruption.
807		Incorrect Records/ labelling	Use when incorrect or outdated records or information is used in the field which then results in an error.	Field workers perform maintenance according to incorrect records or labels resulting in an interruption.
808		Distributed Energy Resources (DER)	Interruption caused by improper connection and/or improper operation of DERs by the distributor.	A distributor owned DER's protection device didn't operate as designed to isolate the DER facility and interrupted other customers supplied on the same feeder/feeder section.
9	**Foreign Interference**		**Customer interruptions beyond the control of the distributor, such as those caused by customer owned equipment, animals, vehicles, dig-ins, vandalism, sabotage, and foreign objects.**	

901	Wildlife (Bird/Animal)	Crows, seagulls, woodpeckers, squirrels, raccoons, cats, rats, bears, etc.	A squirrel makes contact with transformer bushings.
902	Vehicle	Motor vehicle accidents, which make contact with poles, guys, etc.	A vehicle strikes a pole and takes down an overhead line.
903	Crane	Crane or Boom-truck makes contact with plant.	A construction crane strikes and removes several distribution lines and/or poles.
904	Agricultural Equipment	Tractors, combines, graders, etc.	Tractor or Combine pulls on a guy wire causing an interruption.
905	Dig-In	Excavator, backhoe, augers or other equipment digs into underground cables.	A customer uses an auger and digs down which results in the cutting of a cable causing an interruption.
907	Foreign Objects	Use when strange objects hit the line, like balloons, kites, sneakers, etc.	Someone sets off fireworks on their street and they strike some insulators and/or pole mounted transformer bank causing an interruption to several homes.
908	Customer-Cut Trees	Non-utility/ non-contractor person drops a tree on line.	A homeowner cuts a tree in their yard and it falls on lines creating an interruption.
909	Vandalism/Sabotage	Use when deliberate acts cause an interruption. (sabotage, terrorism, gunplay)	Vandals break into a pad-mounted transformer and damage it.
910	Other Utilities	Use when the interruption is caused by a neighbouring utility operating on your system in error without permission.	Another utility inadvertently shuts down your power flow to several of your customers.
911	Customer Owned Equipment	Interruption caused by assets owned and/or operated by third party	Customer owned equipment causes LDC owned feeder breaker to open
912	Distributed Energy Resources (DER)	Failure or improper operation of DER facilities not owned / operated by distributors.	A distributor owned DER's protection didn't operate as designed to isolate a fault in the DER facility and interrupted other customers supplied on the same feeder/feeder section.

Appendix C – Classification FAQ

Q1: How do I classify a planned interruption to replace equipment that has not yet caused an interruption?
A1: If the equipment is deemed to be of imminent failure (such as a leaking transformer), or if the equipment is being replaced because of a service upgrade, then in both cases it should be classified as a “Scheduled Interruption” with secondary sub-cause code “Construction”.

Q2: If there is a weather event and trees or lightning are causing interruptions, how should the interruptions be classified?
A2: “Lightning” supersedes “Adverse Weather” classifications. If during an adverse weather event, interruptions can be reasonably identified as being caused by lightning should be classified as such. All other interruptions during an adverse weather event that cannot be classified by other cause codes should be classified as “Adverse Weather”.

Q3: How do I classify an interruption due to soil remediation around a transformer?
A3: Soil remediation without the replacement of a transformer should be classified as “Scheduled Interruption” with secondary sub cause code as “Maintenance” whereas; soil remediation in conjunction with a transformer replacement should be classified as “Scheduled Interruption” with secondary sub cause code as “Construction”.

Q4: How do I classify an interruption due to a house fire?
A4: If the fire department has requested an interruption to extinguish the fire, then it should be classified as “Scheduled Interruption” with a secondary sub-code “Emergency Services Requested”.

If the house fire causes damages to Hydro Ottawa owned equipment and results in an interruption then it should be classified as “Adverse Environment” with secondary sub-code “Fire”.

Appendix D – List of Distribution Supply Points

Station	Feeder	Voltage (kV)	HOL Switch	Type
Bilberry TS	77M3	27.6	597, 1506, W86, 1305, 2730, 183, 217-S, 217, 276.	Back-up Supply
Bilberry TS	77M4	27.6	433, 1235, 1258	Back-up Supply
South March TS	A9M3	44	A9M3-74, A9M3-ILS, A9M3-MSO	Nominal Supply
South March TS	A9M5	44	A9M5-74, A9M5-ILS, A9M5-LC, SM5-M6, A9M5-84,	Nominal Supply
St. Isodore TS	62M2	44	V11-LC	Nominal Supply to Casselman - 62M2
Beckwidth DS	BECKF2	16	S22783, S27640, SW651	Nominal Supply
Casselman DS	36F1	8.32	1590	Back-up Supply
Casselman DS	36F2	8.32	1589	Back-up Supply
Manotick DS	81F5	8.32	S22163	Back-up Supply
South Gloucester DS	56F3	8.32	W910	Nominal Supply
South Gloucester DS	56F2	8.32	W1301, W1246	Nominal Supply
Alexander DS	ALEXF1	27.6	SW746, SW551, 676, 789	Back-up Supply
Alexander DS	ALEXF2	27.6	678	Back-up Supply

Appendix E – System Office Cheat Sheet

Interruption Type	Primary Cause	Secondary Cause	Primary Fail	Secondary Fail
Equipment Replacement/upgrades/installations	Scheduled Interruption	Construction	None	None
Vault Maintenance (If requested by the customer)	Scheduled Interruption	Customer Requested	None	None
Service Upgrade (If requested by the customer)	Scheduled Interruption	Customer Requested	None	None
Request by Emergency Services (e.g. isolation for a house fire)	Scheduled Interruption	Emergency Services Request	None	None
Transformer interruption for secondary maintenance requested by customer	Scheduled Interruption	Customer Requested	None	None
Interruption to transfer plant to new pole	Scheduled Interruption	Construction	None	None
Interruption required to maintain a piece of equipment (not replace)	Scheduled Interruption	Maintenance	None	None
Circuit isolation required to repair the failed device causing an interruption	Scheduled Interruption	Forced Switching	None	None
Interruption due to the host distributor	Loss of Supply	Loss of Supply Distribution	None	None
Caused by customer equipment (e.g. customer owned line fault trips breaker, vault overtripping, etc.)	Foreign Interference	Customer Owned Equipment	None	None
Pole fire when salt is likely a factor (Winter, Spring) unless otherwise proven	Adverse Environment	Contamination (Salt)	None	None
Pole fire when salt is not likely a factor (Summer, Fall) unless otherwise proven	Equipment Failure	Electrical	Pole	Insulation Failure (Pole Fire)
An interruption due to ice formed on OH distribution lines that results in the collapse of the conductor due to weight, under freezing rain	Adverse Weather	Equipment Damage	None	None
Storm where there is sufficient evidence that lightning was in the area during the interruption and no other cause was found (No trees, etc.)	Lightning	Lightning	None	None
An interruption during a storm where there is sufficient evidence that high wind was in the area during the	Adverse Weather	Other Adverse Weather	None	None

interruption and no other cause was found (No trees, lightning, etc.)				
Any third party Contact (Crane, vehicle, animal, dig-in, etc.)	Foreign Interference	Pick appropriate cause	None	None
Cable Fault (Initial Report, unless otherwise proven)	Equipment Failure	Electrical Failure	UG Cable	Unknown
Unknown cause (Initial report – Follow up will be required to ensure absolutely unknown)	Unknown	Unknown	Unknown	Unknown
Equipment Failure	Equipment Failure	Pick appropriate cause	Pick Appropriate	Pick Appropriate
Leaking Transformer replacement	Scheduled Interruption	Construction	Pick Appropriate	Pick Appropriate
Planned interruption to replace/maintain defective equipment	Scheduled Interruption	Maintenance / Construction	Pick Appropriate	Pick Appropriate
Soil Remediation due to leaking transformer (Transformer has already been replaced)	Scheduled Interruption	Maintenance	None	None
A storm caused tree branches to touch the overhead line and cause an interruption	Adverse Weather	Tree Contact Weather	None	None
Switching Error	Human Element	Switching Error	None	None
Cause by incorrect nomenclature/mapping or labeling	Human Element	Incorrect Records/Labelling	None	None
Overtripping of HOL equipment (The interruption caused by the overtripping should be reported separately with the initial reported under appropriate interruption and cause code)	Human Element	Protection Setting	None	None
Planned Forestry Interruption for Clearance Only	Scheduled Interruption	Vegetation Management	None	None
Interruption caused by tree contact under normal environment and weather condition or emergency trimming (Planned or unplanned)	Tree Contact	Pick appropriate cause	None	None

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO COMMUNITY ACTION FOR ENVIRONMENTAL SUSTAINABILITY

JT1.18

EVIDENCE REFERENCE:

N/A

UNDERTAKING(S):

To file the referenced UR.

RESPONSE(S):

As noted in the Day 1 Transcript of the Technical Conference, page 125, line 15, this undertaking was answered during the proceeding via reference to interrogatory 2-ED-17 Section c), however the undertaking was not removed.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO COMMUNITY ACTION FOR ENVIRONMENTAL SUSTAINABILITY

JT1.19

EVIDENCE REFERENCE:

2-CO-13

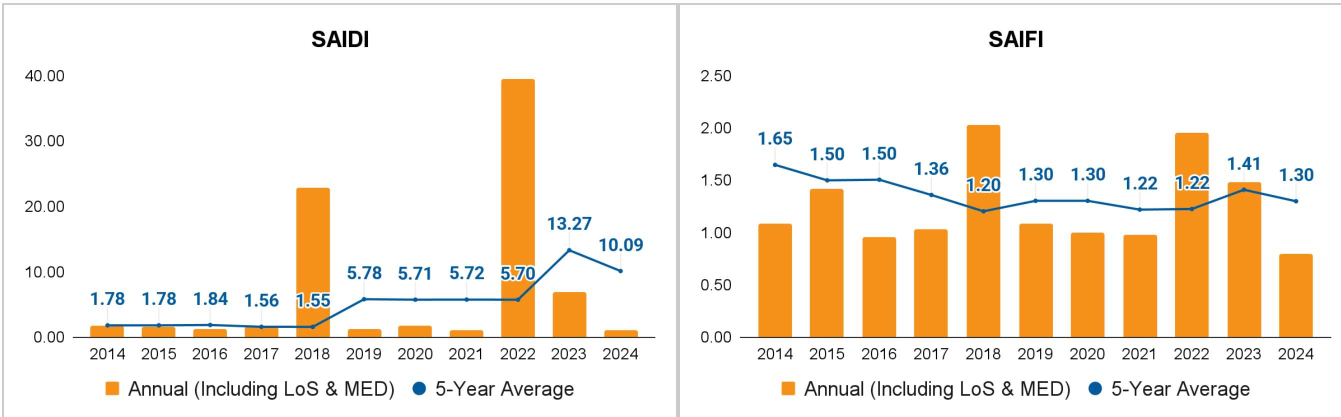
UNDERTAKING(S):

(a) To provide Figure B in the same format as figure a for CO-13;
(b) Provide the apples-to-apples Figure B excluding 2018 and 2022, which appear to be the outlier events, so it would be providing Figure B, in the same format as Figure A, and then providing Figure B in the same format as figure a with 2018 and 2022 data removed.

RESPONSE(S):

a) Hydro Ottawa was requested to provide Figure B in the same format as Figure A (showing 5-year averages) specifically for interrogatory 2-CO-13. Please refer to Figure B1 below, which has been formatted identically to Figure A and includes the 5-year average data.

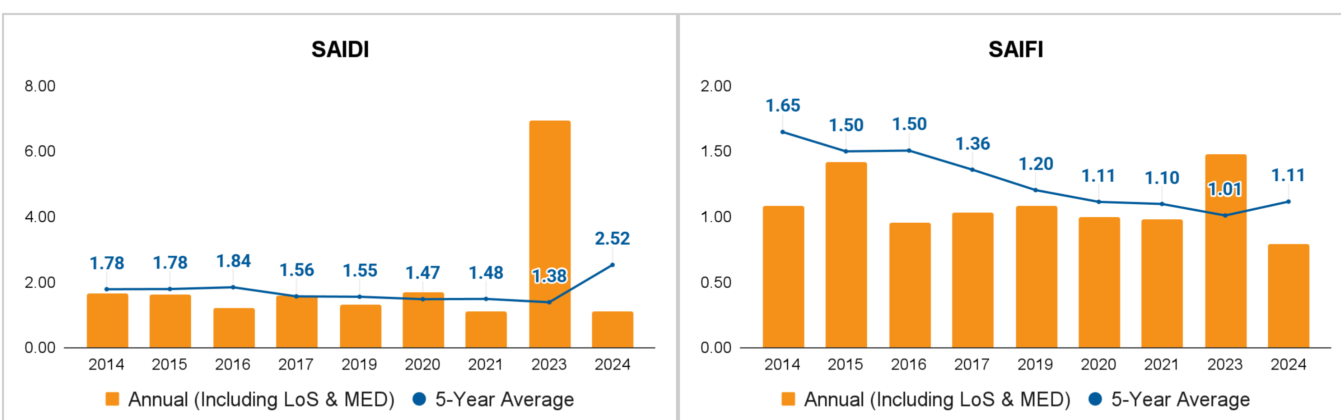
Figure B1 - SAIDI & SAIFI - Annual (Including Loss of Supply and Major Event Days)



Please see below Figure B 2018 and 2022 as outliers in the same format as Figure A including 5 Year Average data.

b) Hydro Ottawa was asked to provide Figure B in the same format as Figure A (showing 5-year averages), specific to interrogatory 2-CO-13, by removing the outliers observed in 2018 and 2022. Figure B2 below has been formatted identically to Figure A, includes the 5-year average data, and excludes the outlier years 2018 and 2022.

Figure B2 - SAIDI & SAIFI - Annual (Including Loss of Supply and Major Event Days, Excluding 2018 and 2022 as Outliers)



TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CONSUMERS COUNCIL OF CANADA

JT1.20

EVIDENCE REFERENCE:

2-Staff-104a

UNDERTAKING(S):

To provide any analysis that Hydro Ottawa completed with respect to its views of the lack of success of the cable injection program that it ran previously.

RESPONSE(S):

Hydro Ottawa implemented a cable injection program from 2013 to 2019 as part of its asset management strategy for underground cables as a cable rejuvenation strategy. The objective of cable injection is to address water treeing within the cable insulation which can lead to failure. Hydro Ottawa continuously monitored the results and impact of the rejuvenation in context of the overall underground cable asset management strategy. It was noted that the program's effectiveness showed signs of decline, notably in 2015 when the proportion of injectable cables dropped to 40%. This decline was attributed to two primary issues, based on Hydro Ottawa's specific demographics of underground cables:

1. **Strand-Blocked Cables:** A high percentage of the cables identified for injection, mainly from the mid-1980s, contained strand-block compound used by manufacturers, which prevented the injection fluid from being applied, meaning that this type of cable is not a candidate for injection.
2. **Uninjectable Splices:** Many splices in nearly all targeted areas proved uninjectable, even with

a low-pressure method. Numerous flow test failures rendered these cables uninjectable, leading to them being marked as splice-blocked.

To overcome the limitations mentioned above, Hydro Ottawa refined its scoping for cable injection post 2015, to remove cables with uninjectable splices and strand-blocked cables from the program scope. However, even with this refined approach, Hydro Ottawa identified further risks with the intervention strategy in 2017 after injecting 11 km of cables in the 77M6 circuit. Post-injection, the feeder continued to experience cable faults, with 9 immediate failures in 2018 and an additional 5 faults between 2019-2020 within the sections that had been injected. These failures prompted the need for cable replacement in the region for 2021-2025. This experience led Hydro Ottawa to further investigate the application of cable injection and it was noted that the continued failures were attributed to degradation modes not remediated by cable injection. As stated, cable injection primarily addresses water treeing, but fails to mitigate other degradation modes such as partial discharge and concentric neutral corrosion - primary modes of failure identified through analysis of cable failures.

Hydro Ottawa reconfirmed these additional degradation modes in 2024 through advancements in the scope of the cable testing program, as detailed in Section 4.4.2 under Schedule 2-5-4 - Asset Management Process, supporting the assessment that there was limited to no value of cable injection for Hydro Ottawa’s underground cable demographics, due to the types and failure modes.

Based on the learnings outlined above, Hydro Ottawa's cable management strategy for 2026-2030 focuses on identifying regional degradation mechanisms through an improved cable testing program to enable the identification of appropriate intervention strategies based on the severity of degradation, including targeted cable replacement (under planned or critical renewal programs), cost-effective replacement of cable accessories (primarily elbows), and ongoing monitoring and management based on condition data captured through yearly cable testing. Section 4 of Schedule 2-5-7 - System Renewal Investments outlines Hydro Ottawa’s capital Cable Renewal strategy for 2026-2030.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CONSUMERS COUNCIL OF CANADA

JT1.21

EVIDENCE REFERENCE:

2-Staff-104

UNDERTAKING(S):

To provide a high-level estimate of the cost differential between cable replacements and cable injection.

RESPONSE(S):

To provide a high-level cost estimate comparing cable injection and cable replacement, Hydro Ottawa has analyzed data from 2016-2018 for a representative 11.2 km cable segment. While 11.2 km of cable was injected during this period, 78.1 km of cable was proactively replaced through planned work at a program cost of $19.8M. Table A normalizes this cost comparison by equivalent lengths.

The 11.2 km of injected cable proved to be a false economy, subsequently necessitating 1.32 km of emergency replacement between 2018 and 2020. This failure directly resulted in 9 unplanned customer outages.

It's also important to note that the costs for planned cable replacement encompass associated padmount transformer replacements, which naturally elevate the total program cost beyond a simple like-for-like cable comparison.

For a comprehensive understanding of Hydro Ottawa's findings and the strategic decision to discontinue cable injection as an intervention, please consult our response to JT1.20. Specifically, Hydro Ottawa’s observations of recurrent cable failures post-injection, leading to emergency replacements and unacceptable unplanned customer outages, underscored the unreliability and ultimate ineffectiveness of this practice.

Table A - Comparison between Cable Injection and Cable Replacement Costs

Cost Category	Unit Rate	Total Cost
Cable Injection (11.2 km, 2016-2018)	$63/m	$0.7M
Emergency Cable Replacement Resulting from Injection(1.32 km, 2018-2020)	$290/m	$0.38M
Unplanned Customer Outages Resulting from Injection	9	
Total Cost Related to Cable Injecting Program		**$1.08M**
Cable Replacement (11.2 km, 2016-2018)	$254/m	$2.8M
Unplanned Customer Outages	0	
Total Cost Related to Cable Replacement Program		**$2.8M**

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CONSUMERS COUNCIL OF CANADA

JT1.22

EVIDENCE REFERENCE:

2-CCC-18

UNDERTAKING(S):

To provide a detailed analysis that compares the original cost estimate and the actual cost for the Piperville MTS, and with respect to any material cost variances, please provide detailed rationale.

RESPONSE(S):

Interrogatory 2-CCC-18 part c) describes the Piperville MTS project's initial budget of $24.6M as projected in 2018 and included in the 2021-2025 Rate Application. The project has since been updated with a budget of $38.7M for the 2021-2025 rate period and an expected energization date in 2026, for a total cost of $42.3M spanning 2021-2026. This information is listed in Schedule 2-5-8 - System Service Investments under the Capacity Upgrades section on page 50. Please see Table A which further shows the comparison of the original cost estimate of Piperville MTS from the 2021-2025 Rate Application Submission (OEB Approved) to the presently forecasted total cost (Updated Forecast), inclusive of spending from 2021-2025 period and out to the energization in 2026. The cost increases are associated with a change in station capacity (60 MVA vs 100 MVA), unanticipated subsurface conditions, and major equipment and construction cost escalation.

The increase in station capacity from 60 MVA to 100 MVA was primarily due to an increase in growth forecast in the region, in combination with consideration for long term impacts relative to decarbonization goals. Given a station is built for 50 years, this increase in capacity allows for efficient capital deployment and optimized asset utilization. This change directly impacted both the cost of engineering, as well as the cost of the power transformers.

Unanticipated subsurface conditions of very soft and severely corrosive clay soils, requiring 50 m deep foundations and specialty corrosion mitigation design and technology, further increased engineering and construction costs.

As experienced globally throughout the high voltage equipment market, the project experienced significant cost increases in much of the major equipment procurement, most notably affecting transformers and high voltage breakers.

The project energization schedule was updated from an anticipated 2025 completion, to 2026, causing an additional year of escalation, at rates higher than initially estimated.

Table A – Piperville Original vs Updated Cost Estimate ($'000 000s)

Category	OEB Approved	Updated Forecast	Variance	Rationale
Engineering	$ 1.3	$ 2.3	$ 1.0	As a result of increasing the station size from 60 MVA to 100 MVA, and unanticipated subsurface conditions, engineering costs increase, engineering costs increased by $1.0M. As a further breakdown: $0.4M was required for the environmental assessment, $0.1M corrosion design added to project scope, and approximately ~$0.5M in general design service efforts as a result of the scope changes.
Procurement				
Land purchase	$ 1.0	$ 1.5	$ 0.5	Actual land purchase costs approximately $0.5M higher than estimate
Major Equipment	$ 9.5	$ 18.3	$ 8.8	Transformers estimated at $3.4M were purchased at $11M, and HV breakers estimated at $0.4M were purchased at $1.4M, both as a result of supply chain constraints and cost escalations within the industry.
Minor Materials	$ 1.4	$ 1.0	$ (0.4)	Some materials moved into construction contracts (below)

Category	OEB Approved	Updated Forecast	Variance	Rationale
Construction				
Civil Construction	$ 9.7	$ 18.4	$ 8.6	Approximately $3M in cost increases associated with subsurface conditions, and approximately $4.5M as a result of general cost escalations from the timing of budget development to Purchase Order. $0.8M recategorized from Electrical Construction.
Electrical Construction	$ 1.7	$ 0.9	$ (0.8)	$0.8M recategorized to Civil Construction
TOTAL	**$ 24.6**	**$ 42.3**	**$ 17.7**	

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TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CONSUMERS COUNCIL OF CANADA

JT1.23

EVIDENCE REFERENCE:

2-CCC-20 part e

UNDERTAKING(S):

To provide the detailed calculation used to forecast the budget for the residential subdivision capital program in Excel format.

RESPONSE(S):

Attachment JT1.23(A) - 2026-2030 Residential Subdivision - Supporting Data provides the details and calculations for the forecasted 2026-2030 Residential Subdivision Capital Budget generally described in interrogatory 2-CCC-20 part (e). The Ottawa Growth Projections support can also be found in Attachment JT1.23(B) - Ottawa Growth Projections for reference to Housing Growth increases for 2026-2030.

As requested, the tables start with the historical average and include every assumption used to calculate the forecasted 2026-2030 budgets. Upon completing this undertaking, it was noticed that a formula capturing the 2021-2023 average also included the 2018-2023 average in the starting assumption. This additional cell capture equates to costs being understated by ($1.1M) over the five year period, which is approximately (0.28%) of the total $369M gross costs requested through System Access from 2026-2030. When compared to JT1.24, this is a net impact of $3.4M between the three affected programs.

DOCUMENT 1

Growth Projections for the New Official Plan:
Methods and Assumptions for Population, Housing and Employment
2018 to 2046

November 2019

Research and Forecasting Unit
Planning, Infrastructure and Economic Development Department

Table of Contents

Executive Summary

Projections of long-term change in population and associated housing and employment are fundamental to a community's ability to plan for land use, housing needs, land requirements, transportation and infrastructure, financing, recreational and social needs, and other basic services.

The new Official Plan provides a strategy and policy framework to guide development and growth over a 28 year period from July 2018 to July 2046. New projections are required to estimate the growth that will occur over this period. The projections begin with population growth, being the driver for household growth and employment growth.

The purpose of this report is to:

a) explain the methodology and assumptions in the growth projections;

b) present the results of the scenarios developed, including the recommended Medium Population Projection as the basis for growth projections in the new Official Plan;

c) develop the projected housing demand from 2018 to 2046; and,

d) develop the projected employment from 2018 to 2046.

Population

The projections of population use a cohort-survival model, the widely-accepted best methodology and the same technique used in previous projections. Cohort-survival separates population change into its basic components; births are added to the population, deaths are subtracted, net migration is incorporated and the existing population is aged to arrive at future population totals.

The new projections are based on the most recent detailed Statistics Canada data for the City of Ottawa. A base year of 2018 on July 1 is used; the latest year for which detailed data are available. The end year is 2046 providing a projection period of 28 years. The City of Ottawa population projections benchmarks various growth components to Ontario projections by Statistics Canada and the Ontario Ministry of Finance. Similar to other major Canadian cities, the most significant component of population growth will be from international immigration.

Three scenarios were developed, summarized below.

Low Projection: assumes a continuation of declining birth rates, a life expectancy increase of about 2 years, lower rates of in-migration and higher rates of out-migration. The above assumptions result in a 2046 population of 1,271,848, an increase of 264,000 (26%) from 2018.

Medium Projection: Assumes an increase in the birth rate, a life expectancy increase of about 4 years, increasing in-migration based on the federal immigration targets and moderate rates of out-migration. Under this scenario the result is a 2046 population of almost 1,410,000, an increase of 402,000 (40%) from 2018.

High Projection: Assumes a larger increase in birth rates, a life expectancy increase of about 5 years, in-migration rates exceeding the mid-point of the federal immigration targets and minimal out-migration. These result in a 2046 population of 1,587,000, an increase of 579,000 (57%) from 2018.

The medium projection is the recommended scenario as the basis for the new Official Plan growth projections. This projection is higher than the previous projection developed in 2016. Using 2031 for comparison, the medium projection is 66,000 persons or 5.7% higher at 1,219,200 than the previous 2031 projection of 1,153,500 persons.

Households and Housing

Projected housing requirements for this population projection is estimated to be 194,800 new private households, including a vacancy factor, over the 28-year period, an increase of 48% from 2018. These new dwelling units are projected to be comprised of 34% single-detached, 3% semi-detached, 36% rowhouse, and 27% apartments.

Employment

The projected employment includes the work force that lives in Ottawa from the population projection along with commuters from outlying communities and persons with more than one job. The projected employment by 2046 is 827,000 jobs, an increase of 30% from 2018.

Basis of the Growth Projections for the New Official Plan, 2018-2046

Growth projections begin with the population growth as the foundation for future housing and employment needs. Housing needs are analyzed by the types of housing or dwellings that the future population will occupy. Employment needs are analyzed by the amount of jobs stemming from the future population and commuting flows between Ottawa and outlying communities. This report provides methods and assumptions used for the projections and the selected scenario that is the basis of the growth projections recommended for the City of Ottawa's new Official Plan from 2018-2046.

This report is divided into three parts:

Part I: Population Projections

Part II: Households and Housing Projections

Part III: Employment Projections

Appendices are provided as a reference and for further information in relation to each of the projections.

Part I. Population Projections

Methodology

The projections use a cohort-survival model, the widely-accepted best methodology for projections by age and gender. The same technique has been used in all previous City of Ottawa and, prior to 2001, Region of Ottawa-Carleton projections since the 1980s. Cohort survival separates population change into its basic components; births are added, deaths are subtracted, and net migration (in and out migration from various sources) is added. These components are summarized in Figure 1 with further details in subsequent sections of the report.

Figure 1: Cohort-Survival Components of Growth

Population Gain	Births		International Immigrants		Returning Emigrants		Positive Net non-permanent residents	Positive Net Interprovincial migration	Positive Net Intraprovincial migration
Population Loss		Deaths		Emigrants		Net Temporary Emigration	Negative Net non-permanent residents	Negative Net Interprovincial migration	Negative Net Intraprovincial migration

Base Year

Statistics Canada conducts a Census every five years with the last being 2016. After each Census they also produce post-censal population estimates for non-Census years by each of the population components of births, deaths, and the various sources of in- and out-migration at the city of Ottawa level. The most recent estimate was on July 1 2018, with a population of 1,007,501[1]. This population estimate is used as the base for the current set of projections rather than city staff's own population estimate to keep data sources consistent throughout the model.

Projections Benchmarks

Statistics Canada produces population projections for Canada, Provinces and Territories[2]. The Ontario Ministry of Finance also produces population projections for Ontario and the counties within[3]. Both projections also use a cohort-survival model and provide specific population growth estimates by component.

The Ottawa population projections rely on benchmarks to the best data available at the time of development. The Statistics Canada projections are preferred on the basis that the development of assumptions incorporates both quantitative and qualitative analysis through a survey of experts on future demographic trends. Assumptions are provided for each of the growth components, which is particularly important for international migration being the most significant contributor to population growth for Ottawa and all other major Canadian cities. Projections are provided nationally and each of the provinces and territories.

In addition to geographic breakdown, Statistics Canada also provide projections through low, medium and high growth scenarios. The Ottawa projections are benchmarked to each of the Ontario scenarios to provide a local estimate of low, medium and high growth scenarios.

However, the Statistics Canada projections are less useful for Ottawa assumptions on domestic migration. Their interprovincial migration projection sees Ontario as the origin and destination source,

[1] Statistics Canada, Population Estimates July 1, by Census Division. Table 17-10-0139-01

[2] Statistics Canada, 2019. *Population Projections for Canada (2018 to 2068), Provinces and Territories (2018 to 2043): Technical Report on Methodology and Assumptions.* Publication 91-620-X. https://www150.statcan.gc.ca/n1/pub/91-620-x/91-620-x2019001-eng.htm

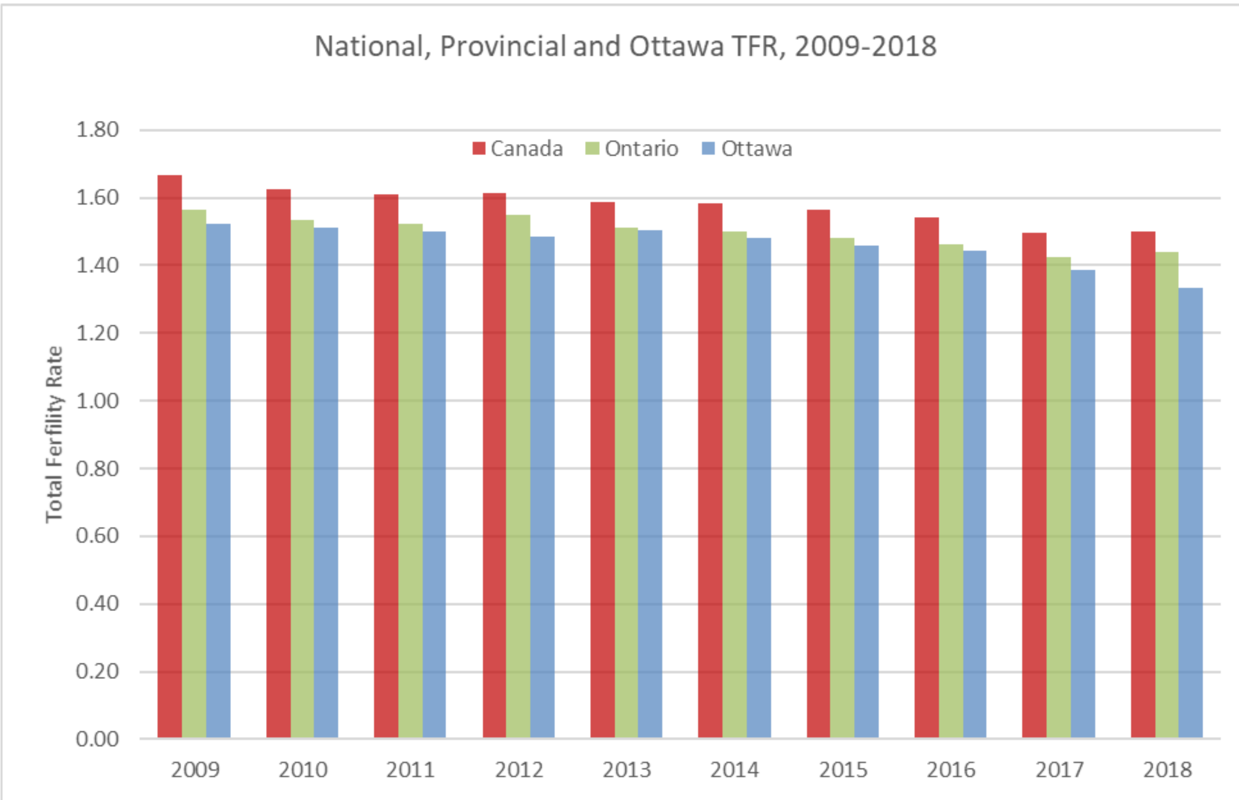
[3] Ministry of Finance, 2019. *Ontario Population Projections, 2018-2046.* https://www.fin.gov.on.ca/en/economy/demographics/projections/

rather than Ottawa. In addition, as domestic projections are only provided at the Provincial and Territory level, no estimates are provided for intraprovincial migration, being movement within Ontario. The Ontario Ministry of Finance projections however provide projections at the county level, with the city of Ottawa being one of the counties. The Ministry then is able to provide Ottawa specific growth estimates for both the interprovincial and intraprovincial migration components.

Births and Fertility

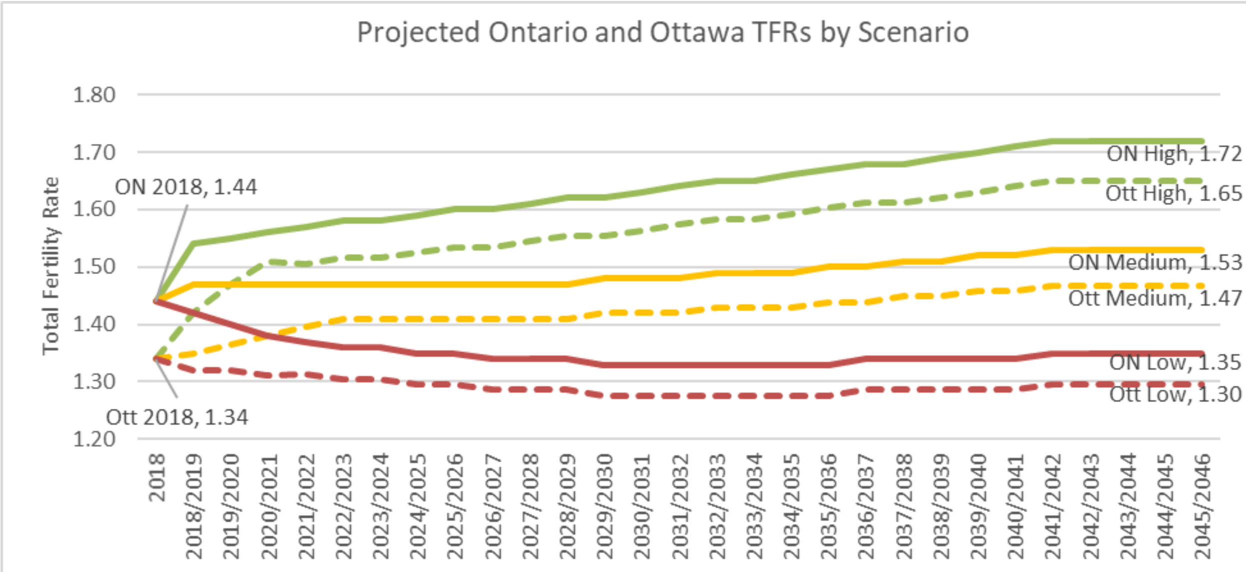
The best predictor of future births is the Total Fertility Rate (TFR), the average number of children per woman throughout child-bearing years. Rates in Ottawa have historically been lower than the national and provincial averages and continue to be lower according to the most recent data. Over the past decade Ottawa rates were steady in the first half and then declined slightly in the second half. Generally Ottawa rates have declined in a similar trend to national and provincial rates, with the exception of the two most recent years when Ottawa rates declined in contrast to the increases seen at the other levels as shown in Figure 2.

Figure 2: National, Provincial and Ottawa Total Fertility Rates (TFR)



The Statistics Canada Ontario TFR projections assume a change from a TFR of 1.49 in 2018 to a decrease to 1.35 in the low scenario, a small increase to 1.53 in the medium scenario and a larger increase to 1.72 in the high scenario. The historical relationship of the past 10 years between Ontario and Ottawa TFRs is assumed to be maintained throughout the projection period, with a transition in the short-term to account for the recent lower Ottawa ratios to the provincial rate. Applying this ratio to the Statistics Canada TFR projections for Ontario results in Ottawa TFRs that change in 2018 from 1.34 to 1.30 in the low scenario, 1.47 in the medium scenario and 1.65 in the high scenario. The Ontario and Ottawa TFR projections by 2046 for these scenarios are shown in Figure 3.

Figure 3: Projected Ontario and Ottawa Total Fertility Rates (TFR) by Scenario

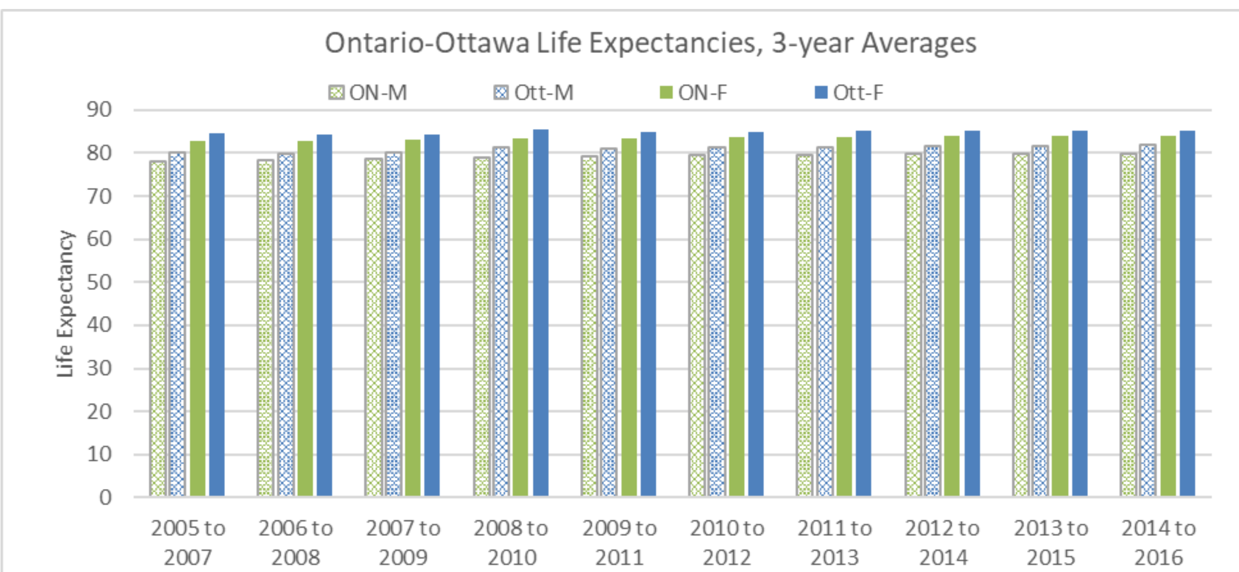


Deaths: Life Expectancy and Mortality Probabilities

Ottawa-specific life tables were developed to estimate future deaths. Life tables determine annual probabilities for survival for each age and gender over the projection period. Mortality probabilities by age and gender were derived from the Statistics Canada death projections for Ontario.

The associated life expectancies at birth were determined based on the historical relationship in the past 10 years of life expectancies between Ontario and Ottawa. Ottawa residents typically exhibit a longer life expectancy than the provincial average as shown in the three-year averages in Figure 4.

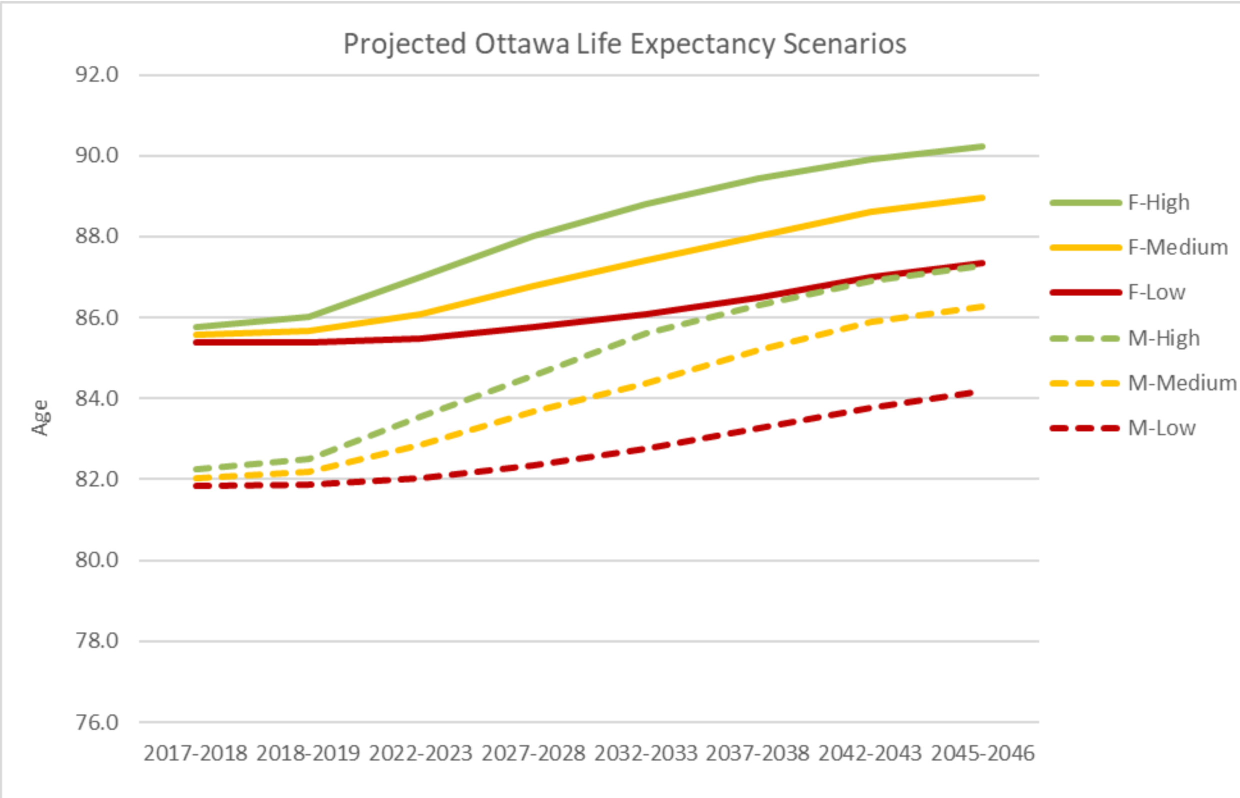
Figure 4: Ontario-Ottawa Life Expectancies



F = Female; M = Male

This historical relationship is applied to the Statistics Canada life expectancy projections for Ontario in their low, medium and high scenarios to develop projected Ottawa life expectancy scenarios by gender as shown in Figure 5.

Figure 5: Projected Ottawa Life Expectancy Scenarios



F = Female; M = Male

Net International Migration

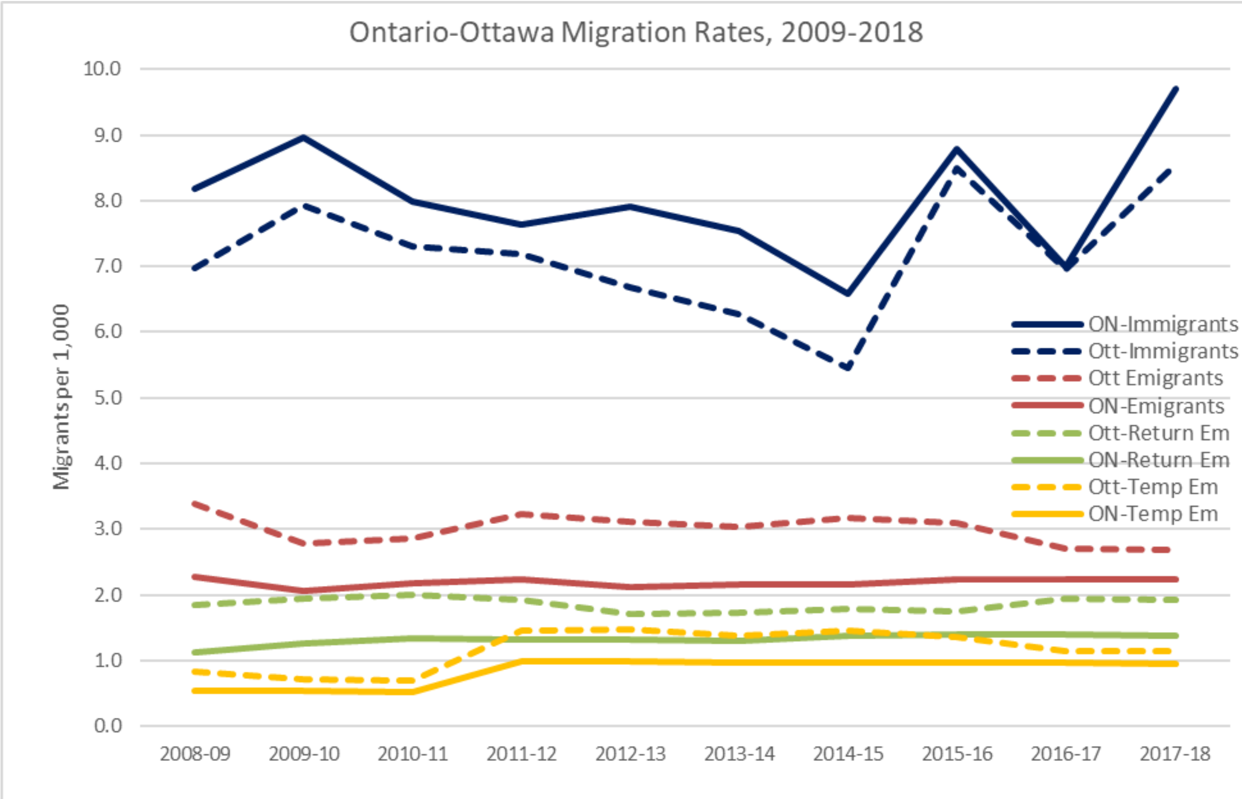
Migration is, and has been for many decades, the most important factor affecting changes in Ottawa's population. Net migration, the number of people moving to Ottawa minus the number moving out, is the result of many processes. For the purposes of the projections, these are categorized into three primary migration streams; international, interprovincial, and intraprovincial migration.

International migration is the movement of people between Ottawa and all countries outside of Canada. International migration is further subdivided into permanent resident immigrants (those that move to Ottawa), emigrants (those that leave Ottawa on a permanent basis), returning emigrants (those that move back to Ottawa from another country), temporary emigrants (those that leave Ottawa on a temporarily for another country), and net non-permanent residents (the difference between those that move to Ottawa on a temporary basis and those that leave Ottawa after a temporary stay or able to change their status to a permanent residency). Non-permanent residents (NPRs), are persons who have work, student or temporary resident permits, or persons claiming refugee status.

With the exception of the net non-permanent residents, the migration streams can be measured as a rate of migrants per 1,000 persons. Net NPRs are measured in absolute number of persons.

Immigration rates were in decline for both Ontario and Ottawa since 2009/2010 but have picked up starting in 2014/2015. In contrast, emigration rates have been relatively steady in both Ontario and Ottawa over the past 10-years as shown in Figure 6.

Figure 6: Historical Ontario-Ottawa Migration Rates

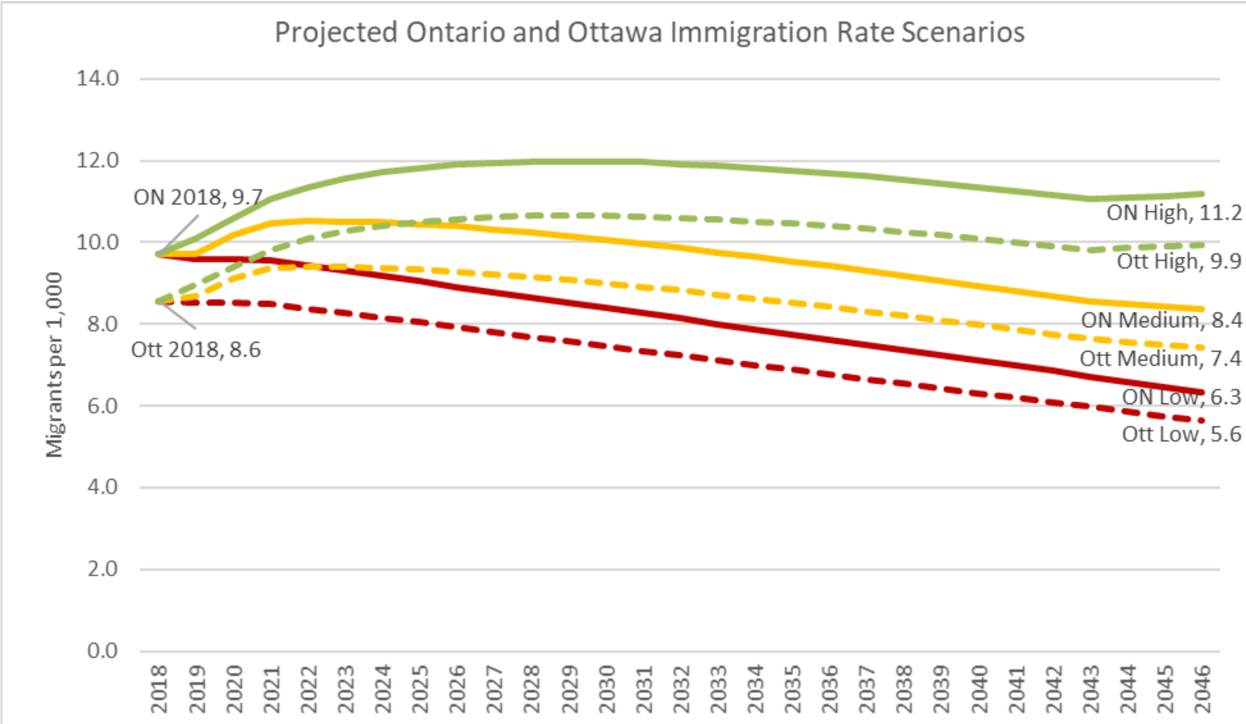


The Statistics Canada projections for Ontario are used as benchmarks to project population changes in each of five sub-categories of international migration. All Ontario immigration scenarios assume a peak rate during the projection period and then decline and differ not only in the level of immigration but also when the peak is reached. The 2018 Ontario immigration rate of 9.7 per 1,000 declines to 8.4 by 2046 in the low scenario; increases to 10.5 in 2022 then declining to 8.4 by 2046 in the medium scenario; and, increases to 12.0 by 2029 then declining to 11.1 by 2046 in the high scenario. These scenarios are a result of the short-term assumptions based on federal immigration targets established to 2021 and the results of the Statistics Canada survey of experts on future demographic trends regarding their views on the future evolution of immigration in Canada for the long term.

Each of the emigration components however are assumed to have a constant rate throughout the projection period, with the medium scenario being similar to the current 10-year historical rates, the low scenario about 75% of the medium scenario and the high scenario about 33% higher than the medium scenario.

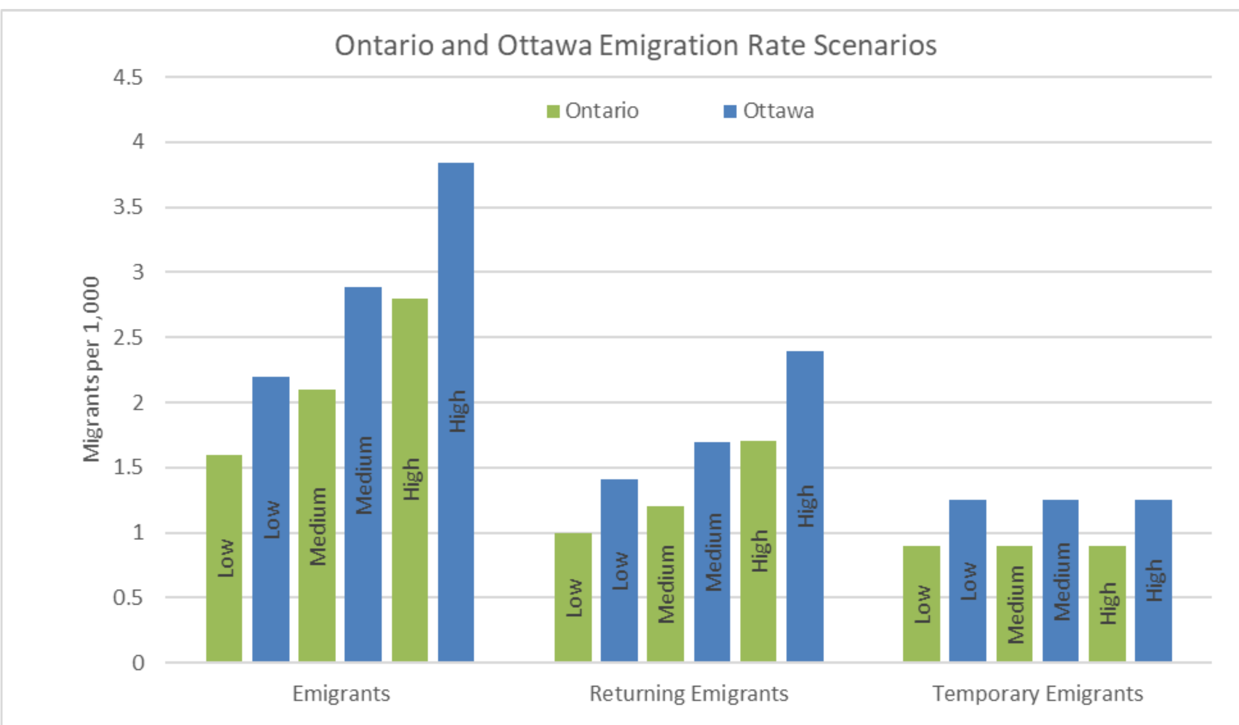
The historical relationship between Ontario and Ottawa in the past 10-years are applied to each of the projected Ontario immigration and emigration components for each of the low, medium and high growth scenarios to derive the projected Ottawa immigration and migration components. The projected immigration rates for by 2046 Ontario and Ottawa are shown in Figure 7.

Figure 7: Projected Ontario and Ottawa Immigration Rate Scenarios



The projected Ottawa emigration components are held constant throughout the projection period as per the Statistics Canada projections for Ontario. The constant ratios between Ontario and Ottawa for these components by scenario are shown in Figure 8.

Figure 8: Ontario and Ottawa Emigration Rate Scenarios



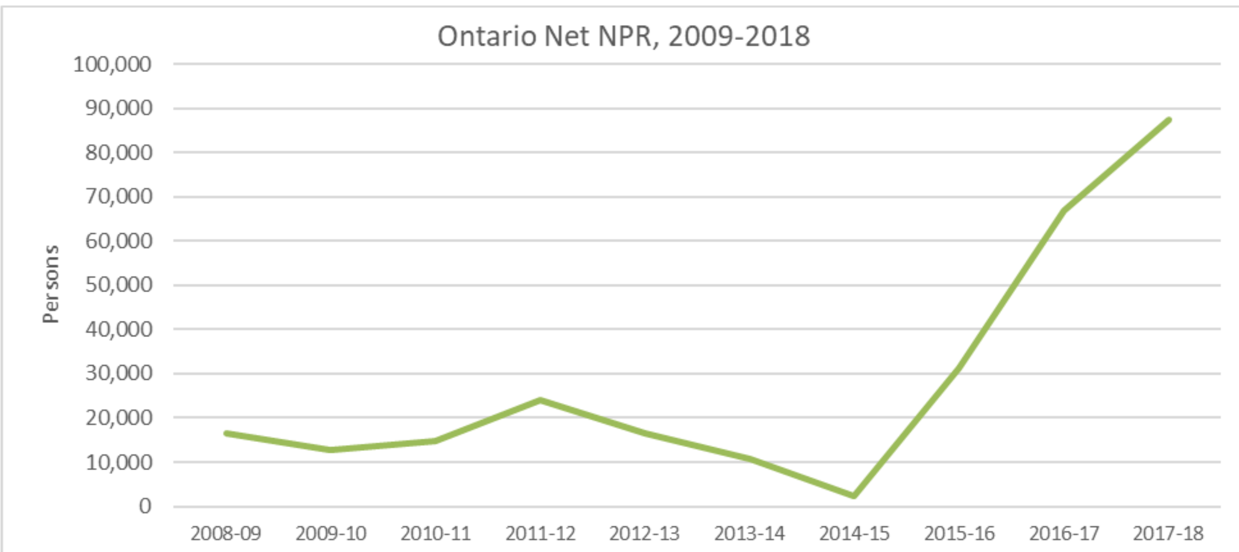
The difference between the projected immigrants, emigrants, returning emigrants, and temporary emigrants provides the net international migration projections.

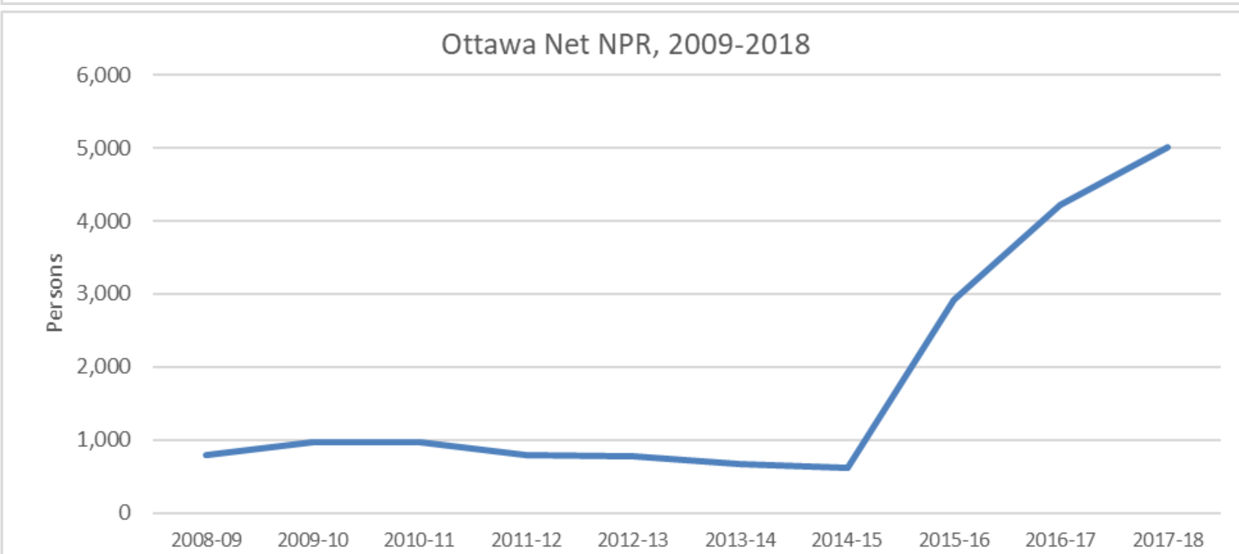
Net Non-Permanent Residents

Non-Permanent residents are persons who have been legally granted the right to live in Canada on a termporary basis through a student permit, work permit, visitor permit or refugee claimants. This group is not subject to the same risks and probabilities of dying or emigrating during the projection period and is not affected by immigration since immigrants are permanent residents. Since children born in Canada are automatically Canadian citizens regardless of the parents' status as permanent residents or visitors, the fertility of female non-permanent residents only affects the projected population of permanent residents. Hence, the non-permanent population depends only on absolute counts rather than rates.

Over the past 10-years the number of net non-permanent residents in Ontario and Ottawa have followed a similar pattern, holding relatively steady with a sharp increase from 2015 to 2018 as shown in Figure 9. The sharp increase in recent years is mostly the result of an increase in foreign students and to a lesser extent refugee claimants.

Figure 9: Ontario and Ottawa Net Non-Permanent Residents (NPR), 2009 to 2018



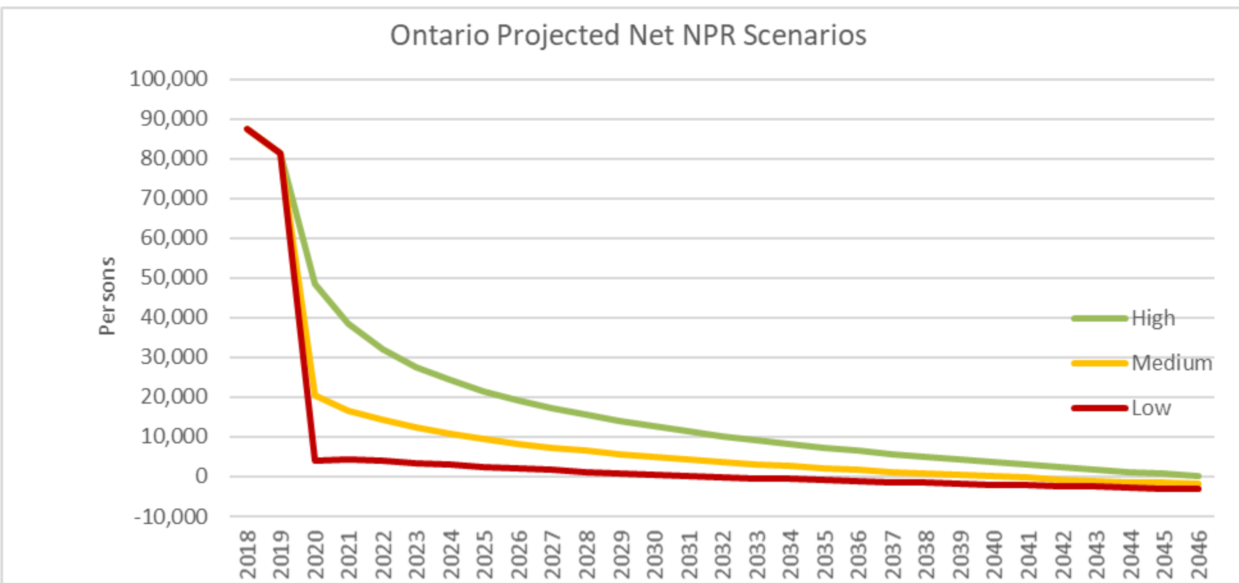


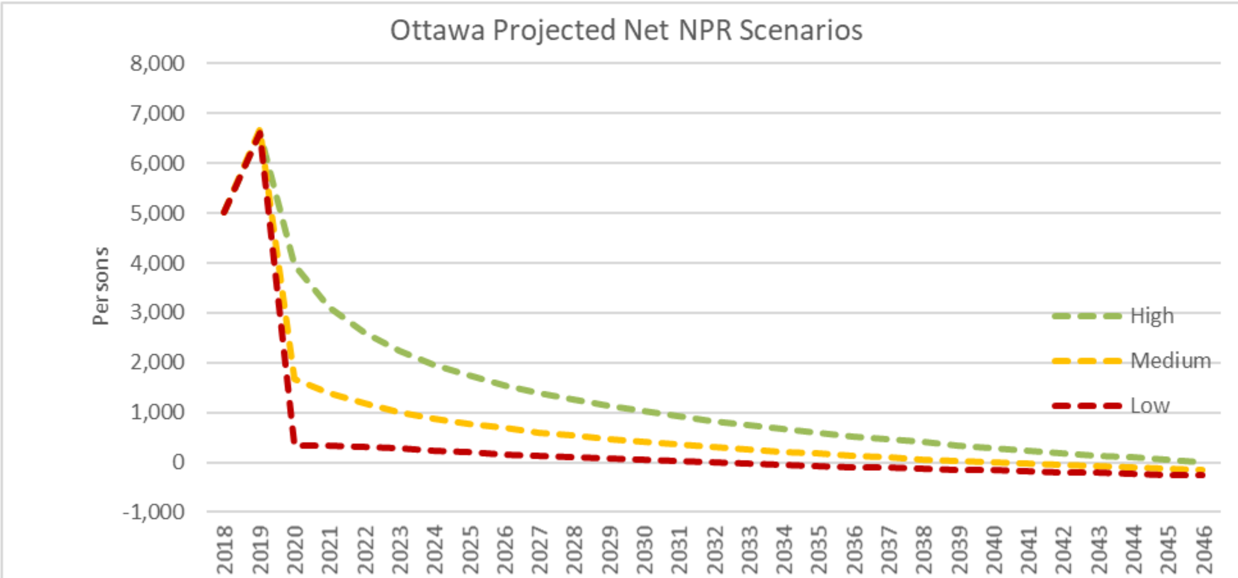
Unlike other components of migration, the Statistics Canada projections of NPRs are based on the number of non-permanent residents in Canada each year. The net change in NPRs is then derived by comparing one year with the previous year.

Similar to the immigration projections, the Statistics Canada projections of NPRs combine a short-term outlook influenced by recent historical data and a long-term outlook based on the results from the survey of experts on future demographic trends. The total number of NPRs in Canada generally increases gradually to a future year such as 2043 then are constant afterwards. For projections purposes a number for net change is required, being the annual inflow minus outflow of temporary residents. Because this category is only temporary, a person entering the country as a NPR has to eventually leave the country or move to another category with a permanent residency status, which is also considered as an outflow. When the number of NPRs in Canada decreases on an annual basis this means the outflow was higher than the inflow and the net change in the number of NPRs is negative.

The historical relationship over the past 10-years for net non-permanent residents between Ontario and Ottawa has been applied to the Statistics Canada net non-permanent resident projections for Ontario. The projections assume a sharp decline in the short-term for all scenarios and gradually decreasing over the projection period as shown in Figure 10. As indicated earlier, in recent years there was a sharp increase in the inflow of NPRs to Ottawa coupled with a relatively low outflow of NPRs from Ottawa, resulting in a net change that was historically high. The assumption for the future is that the inflows and outflows will be more in balance resulting in a low net change and even a negative change in the long term.

Figure 10: Ontario and Ottawa Projected Net Non-Permanent Residents (NPR) Scenarios



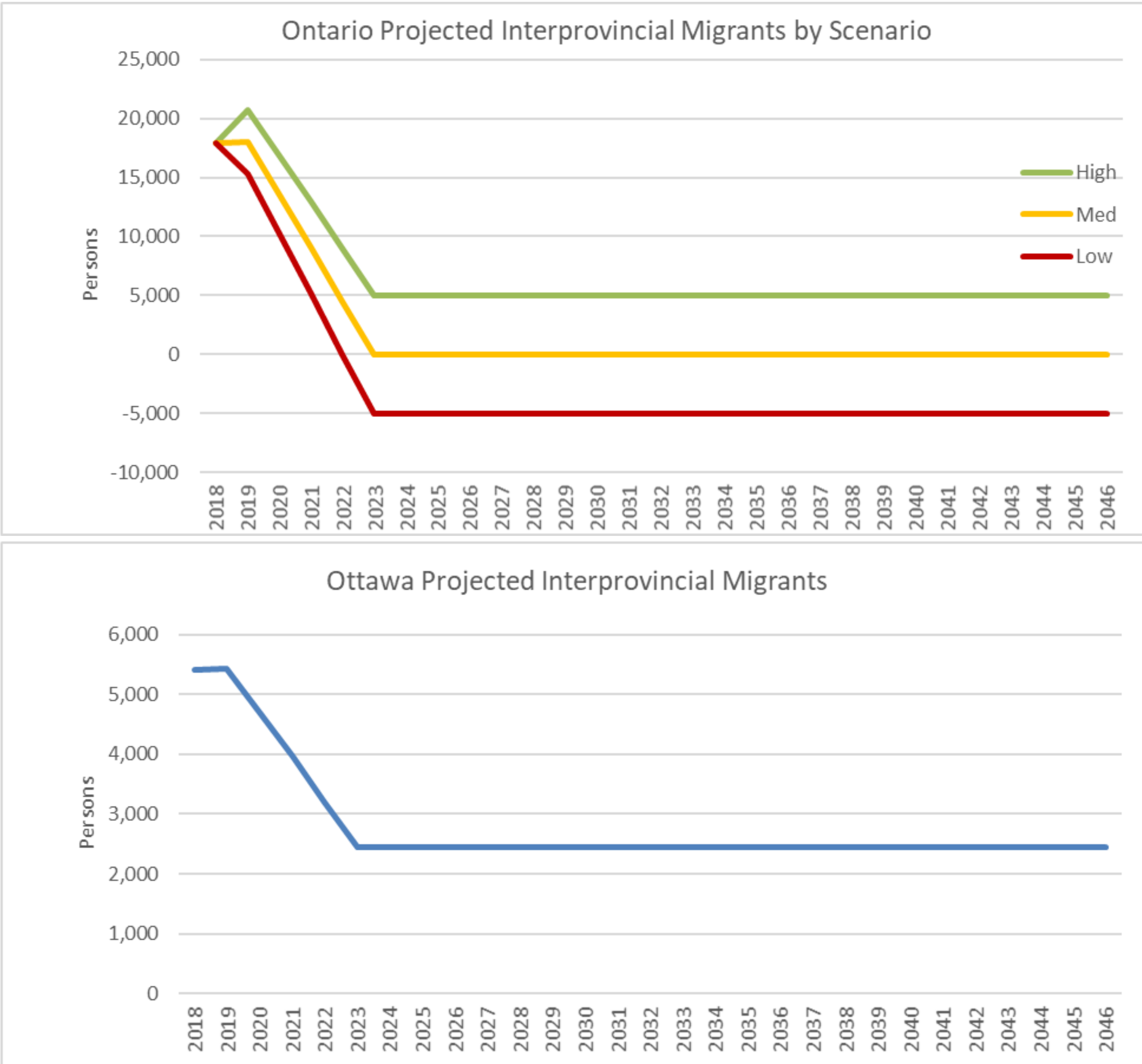


Net Domestic Migration

Interprovincial migration is movement between provinces outside of Ontario to Ottawa. Net interprovincial migration is the difference between those that move out of Ottawa to non-Ontario provinces and those that move to Ottawa from non-Ontario provinces. Although Statistics Canada provides net interprovincial migration they treat Ontario as the source and destination for migration flows. This is a subtle but significant distinction for Ottawa as flows to Ontario but outside of Ottawa should not count as flows to Ottawa.

The Ontario Ministry of Finance has recently developed new projections to the year 2046 for Ontario and its 49 counties or census divisions, including the city of Ottawa. For interprovincial migration, the projection assumes a sharp decrease in the short-term and then holds constant over the long-term for all scenarios and only differ on the amount of decrease and the level that is held constant. Each census division's share of Ontario inflow and outflow of interprovincial migrants over the last five years is applied to projected flows at the provincial level and then held constant throughout the projection period. However, Low and High scenarios were not were not conducted for census divisions. Figure 11 shows the projected three net interprovincial migration scenarios for Ontario and the single scenario for Ottawa.

Figure 11: Ontario and Ottawa Projected Net Interprovincial Migration

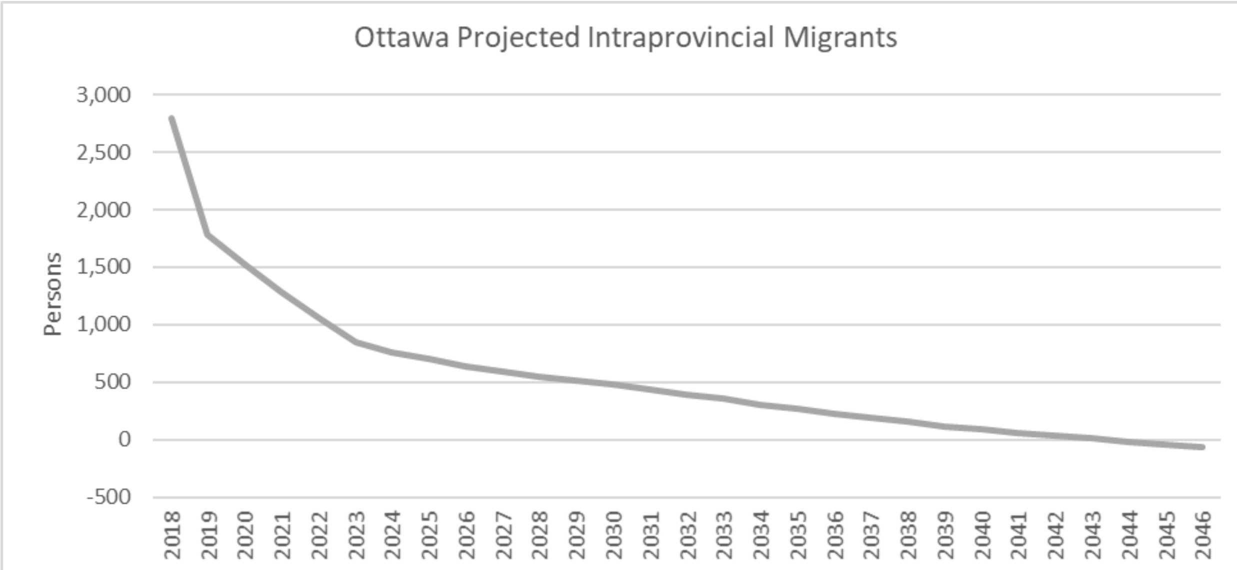


The Ontario Ministry of Finance projections assume that overall net interprovincial migration for Ottawa will decline in the short-term and then assumed to maintain it's share of positive net interprovincial migration of about 2,500 persons annually.

Intraprovincial migration is movement within Ontario to Ottawa. Net intraprovincial migration is the difference between those that move out of Ottawa to other areas within Ontario and those that move to Ottawa from other areas within Ontario. Statistics Canada projections do not include movement within provinces hence no estimates for intraprovincial migration within Ontario are available.

The Ontario Ministry of Finance models intraprovincial migration using origin-destination migration rates by age for each census division over the past five years. This approach takes into account annual changes in age structures within census divisions as migration rates and origin-destinations differ by age group. The assumptions are the same throughout all the scenarios. As with interprovincial migration for census divisions, Low and High scenarios were not conducted for intraprovincial migration. Figure 12 shows the projected net intraprovincial migration for the city of Ottawa.

Figure 12: Ottawa Projected Intraprovincial Migration



The Ontario Ministry of Finance projections assume that net intraprovincial migration for Ottawa will decline rapidly in the short-term and then gradually decline to slightly negative, meaning more people will be moving-out than moving-in over the long-term.

Summary of Ottawa Population Projection Component Assumptions by Scenario

The population projections for the city of Ottawa from 2018 to 2046 are benchmarked to the Statistics Canada population projections for Ontario for the births, deaths and international migration components and the Ontario Ministry of Finance for the domestic migration components. This approach results in three Ottawa scenarios representing low, medium and high growth. A summary of the assumptions for the Ottawa growth components by scenario are shown in Figure 13.

Figure 13: Summary of Ottawa Population Projection Component Assumptions by Scenario

Component	Scenario 1 Low	Scenario 2 Medium	Scenario 3 High
Natural Increase			
Total Fertility Rate (TFR)	1.38 to 1.29	1.38 to 1.42	1.38 to 1.65
Male Life Expectancy	82 to 84.2 years	82 to 86.3 years	82 to 87.3 years
Female Life Expectancy	85.6 to 87.4 years	85.6 to 89 years	85.6 to 90.2 years
Rates/1,000 population			
International immigrants	8.6 to 5.6	8.6 to 10.5 to 7.4	8.6 to 12.0 to 9.9
Emigrants	2.6 to 3.8	2.6 to 2.9	2.6 to 2.2
Returning emigrants	1.9 to 2.4	1.9 to 1.7	1.9 to 1.4
Net temporary emigration	1.1 to 1.2	1.1 to 1.2	1.1 to 1.2
Annual numbers			
Net non-permanent residents	5,006 to -256	5,006 to -159	5,006 to 10
Net interprovincial migration	5,417 to 2,438	5,417 to 2,438	5,417 to 2,438
Net intraprovincial migration	2,791 to -62	2,791 to -62	2,791 to -62

Projection Results

Results for the three scenarios are summarized in Figure 14 with further details provided in Appendix 1. Relative to the current Official Plan projection to 2031, the medium projection is higher by 65,700 persons or 5.7 percent.

Figure 14: Population Projections by Scenario

				Growth				
Scenario	**2018**	**2031**	**2046**	**Annual**	**2018-31**		**2018-46**	
Low	1,007,501	1,172,813	1,271,848	9,441	165,312	16.4%	264,347	26.2%
Medium	1,007,501	1,219,232	1,409,649	14,362	211,731	21.0%	402,148	39.9%
High	1,007,501	1,276,126	1,586,515	20,679	268,625	26.7%	579,014	57.5%

Compared to Ottawa's historical population growth, the medium scenario is within 4% of the annual population growth in the past 10-years, which saw more growth in the second half (2013-2018) than the first half (2008-2013) as shown in Figure 15. Compared to the 2013-2018 period, on an annual basis the medium scenario is 8% lower. However, population growth over the past 10-years has been on an upward trend, whereas the growth projections in all scenarios do not necessarily sustain annual increases over the projection period.

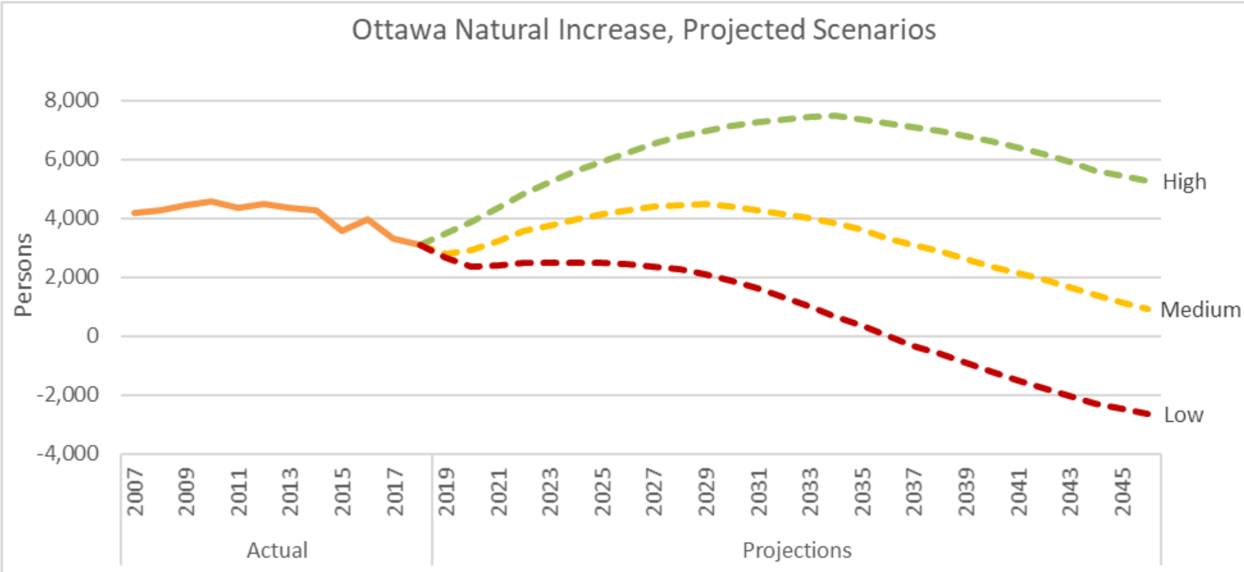
Figure 15: 10-year Historical Ottawa Annual Population Growth and by Period

				Annual, first 5-yr period	**Annual, second 5-yr period**	**Annual, 10-yr period**
Post-censal	2008	2013	2018	2008-13	2013-18	2008-18
estimates	869,038	930,748	1,007,501	12,342	15,531	13,846

Annual Population Growth by Scenario

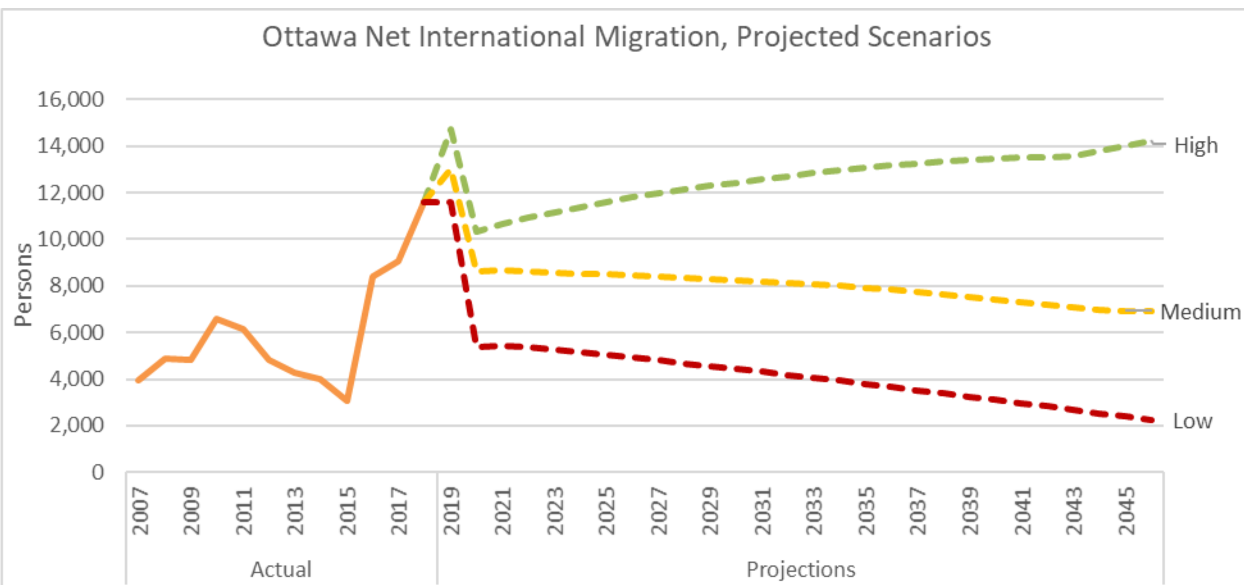
As shown in Figure 1 earlier, population growth is the sum of components that contribute to population gain less those that are subject to population loss. The addition of births and the subtraction of deaths is referred to as natural increase. The addition of those moving to Ottawa and subtraction of those moving out of Ottawa are referred to as net migration and the migration components can be categorized between net international migration and net domestic migration. Reviewing how growth will occur throughout the projection period by natural increase (Figure 16), net international migration (Figure 17) and net domestic migration (Figure 18) provides context on whether population growth is expected to continue growing annually or eventually decline.

Figure 16: Ottawa Natural Increase by Projected Scenarios



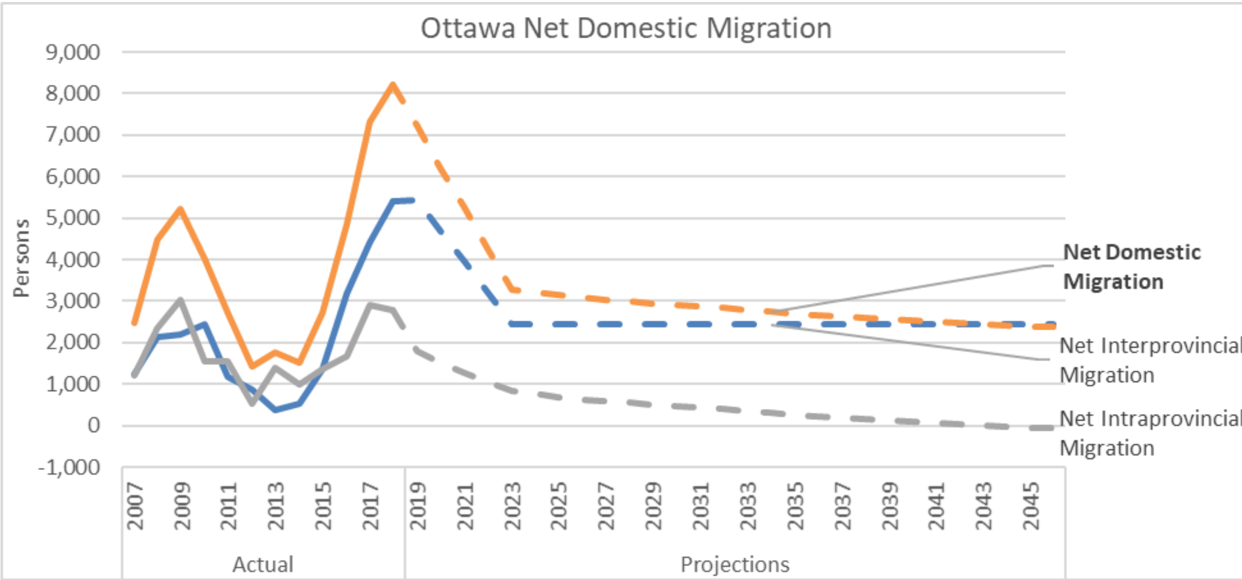
All scenarios regarding natural increase show an eventual decline due to an increase in the number of deaths related to the aging population, with a relatively small difference in absolute persons between the medium and high scenarios. Regardless of the scenario, natural increase is expected to make up a smaller component of population growth in the long-term.

Figure 17: Ottawa Net International Migration by Projected Scenarios



The projected net international migration scenarios show a decline in the short-term, mainly influenced by the drop for net non-permanent residents shown in Figure 10 earlier, after which the rates for immigration and returning emigrants offset declines in the out-migration streams. However only the high scenario projects a continued net increase with the other scenarios projecting net growth declining slightly.

Figure 18: Ottawa Net Domestic Migration



Net domestic migration is benchmarked to net interprovincial and intraprovincial projections for the city of Ottawa from the Ontario Ministry of Finance. However, low and high scenarios were not developed for these migration streams at the municipal level. Domestic net migration is projected to decline sharply over the short-term and then gradually decline over the long-term.

Most of the growth components in the scenarios project that population growth will eventually decline on an annual basis mainly due to declines in natural increase and declines in the relatively high levels of recent actual net international, in particular NPRs, and domestic migration. The annual growth by component for each scenario are provided in Appendix 2.

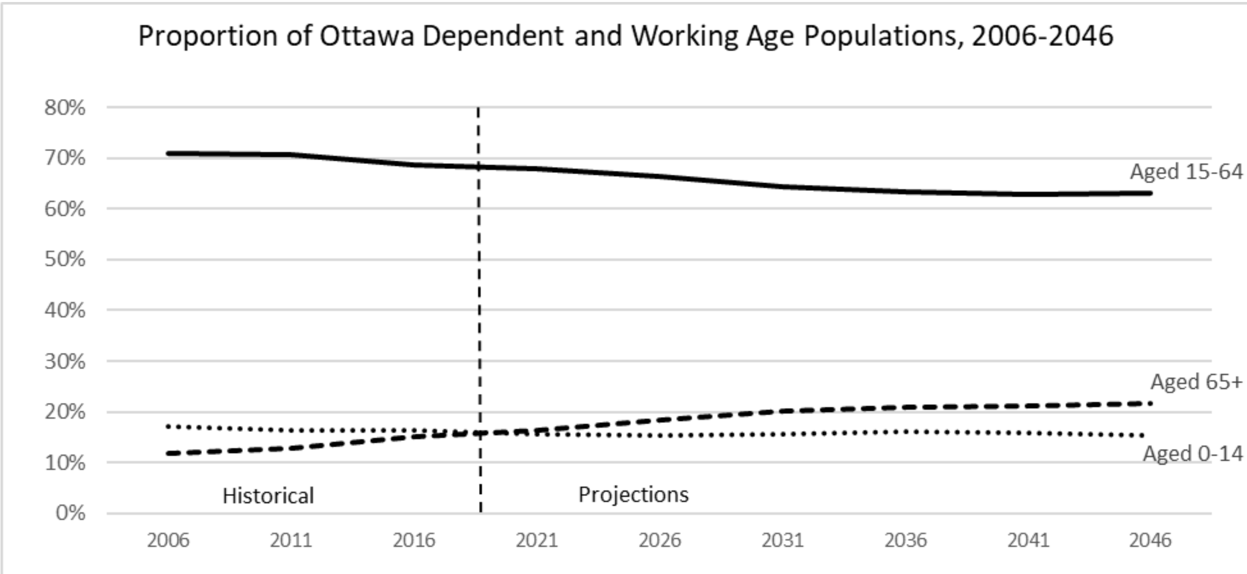
The federal immigration target levels have been set to increase annually to 2021 and there is no indication of a reversal or decline of annual target levels[4] post-2021. When compared with recent historical post-censal population estimates, their annual growth and components of growth, the medium growth scenario would be the most likely scenario for population growth from 2018 to 2046.

Dependency Ratio

The Dependency Ratio measures the ratio between the “dependent” population, being the combined population aged 14 and under and over 65 to the population aged 15 to 64, traditionally the “working age” population. Under the medium scenario, the ratio for Ottawa is projected to increase from 46.2 in 2018 to 58.6 in 2046. Over 70 percent of the increase is due to growth in the older population. The medium scenario has the working-age population continuing to increase to 2046, with their proportion of the total growth being about the same as the dependent population (49.6% and 50.4% respectively over 2018-46); however, the proportion of the working age population will gradually decrease while the dependent population will gradually increase as shown in Figure 19.

[4] Federal immigration targets are numbers of persons rather than a rate per 1,000 population used in the population projections.

Figure 19: Proportion of Ottawa Dependent and Working Age Populations



Conclusion

By 2046, the medium scenario projects a population of 1,409,649 for the city of Ottawa. This scenario should be selected as the reference scenario for the Official Plan growth projections because it incorporates the most reasonable set of assumptions when considering all the information available and on an annual basis tracks relatively close to population growth over the past 10-years. By 2046, Ottawa's population will be older with more than 1 in 5 persons being aged 65 or older (compared to roughly 1 in 6 in 2018). This age group will double in size and those 80 or older will almost triple in size.

Part II. Households and Housing Projections

Housing is the single largest consumer of urban land and consequently a vital component in planning for future land requirements. The projected population forms the basis for the projected number of new households and the number of new housing types they will live in.

Methodology

The methodology to determine future housing demand is determined as follows:

1. Households are determined by applying a headship rate, the portion of the population in each five-year age group that represents a single household, to the projected population by age group.
2. Housing units by dwelling type are projected by applying the "propensity" for each household age group to choose a single-detached, semi-detached, row house or apartment. Rates for both household headship and housing propensities are based on historical census data.
3. A factor is added to allow for a vacancy rate in rental and ownership units and to replace demolished units of the same type.

Private Households

Residents of collective establishments, which include hospitals, certain retirement homes[5], shelters, prisons, etc, are separate from the "population in private households" (PIPH). The PIPH with age distribution from the 2016 Census is available from Statistics Canada. However, the 2016 Census does not include persons missed on Census day, also known as the undercount. Statistics Canada provides post-censal estimates to determine how many individuals were missed and adjusts the Census population accordingly. For this reason, post-censal estimates are preferred over the Census results when feasible. Further details on the PIPH and the post-censal estimates used as the starting point for the household projections are provided in Appendix 3.

Number of Households

The number of households is determined by applying a headship rate to the projected population by age groups. The headship rate is the percentage of the population that is classified as the "primary household maintainer" in a Census by Statistics Canada, being the person that pays the rent, mortgage, taxes and other related property bills for the dwelling. The headship rate for an age group is the percentage of the population within that age group that is classified as the primary household maintainer. The headship rates for 2016 are held constant throughout the projection period as previous testing of projected headship rates yields relatively little change to the overall results. An adjustment is made to estimate the private households missed in the undercount by applying the PIPH to the post-censal population estimates and the headship rate. Further details on the 2016 headship rates and the adjusted estimate for total private households are provided in Appendix 4.

Applying the 2016 headship rates to the projected population in private households by age determines the number of private households per age group. Private households were estimated to be 404,400 in 2018 and projected to be 590,600 in 2046, being a growth of almost 186,200 or 46% private households over the projection period.

Households by Dwelling Type

The growth of approximately 186,200 private households need to be divided between dwelling types in order to adequately plan how much land is required for accommodation as different dwelling types develop at different densities and require different amounts of land. The propensity of the population in private households to occupy a dwelling type derives the division into dwelling types. The Census provides the percentage of household maintainers occupying one of four general dwelling types for the

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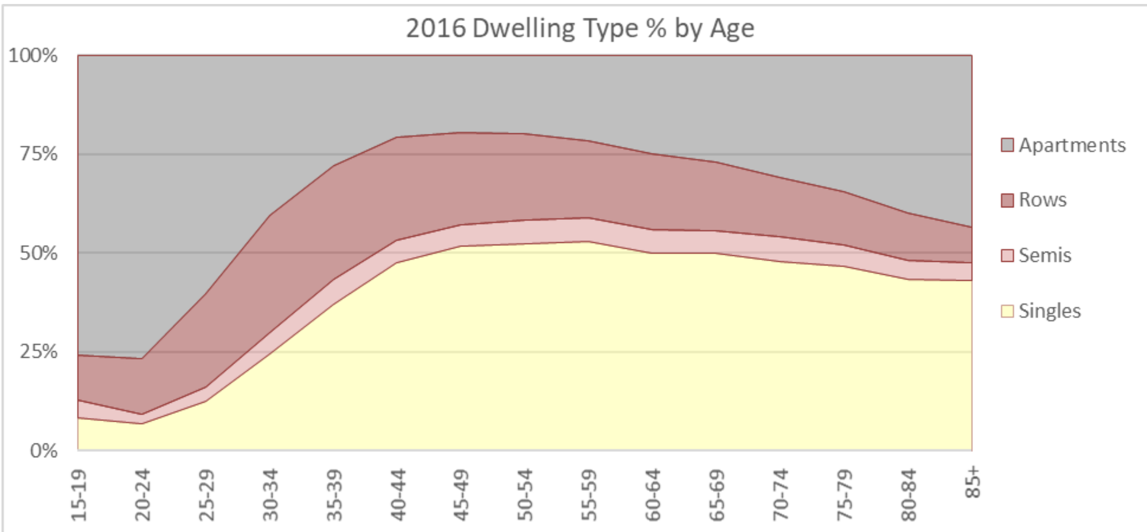
[5] Some retirement homes are classified as collective dwellings, while others are counted as private dwellings. The differentiating criterion is based on the level of care provided on a unit basis within each building.

projections model: single-detached, semi-detached, rowhouse, and apartment. Further details on the dwelling type definitions are provided in Appendix 5.

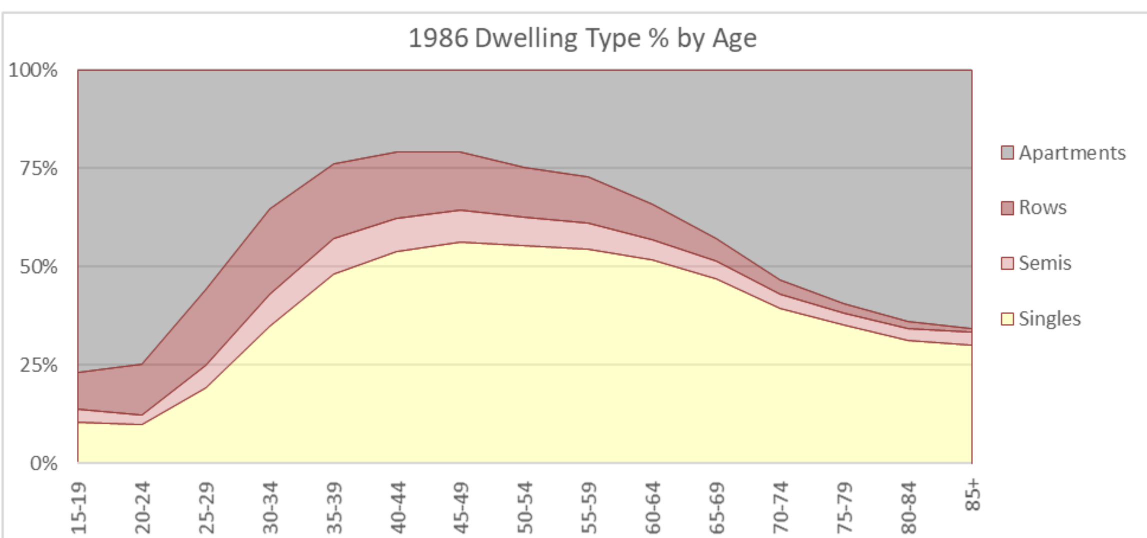
For example, Figure 19a shows the percentage of dwelling types that were occupied by the age of the household maintainer from the 2016 Census, where younger households occupied apartments, then as they became older, they tended to occupy rowhouses and single-detached. But then after their mid-fifties their share of apartment occupancies increased.

Figure 19a: Percentage of Dwelling Types by Age of Household Maintainer, Ottawa 2016



Data on housing propensities were available for each census beginning in 1986. The same information for 1986 shows a difference in dwelling type occupancy by age. While younger households still occupied mostly apartments, their preferences for rowhouses and single-detached increased faster and were higher to their mid-fifties in 1986 than in 2016. But after their mid-fifties the decline in single-detached was steeper, with a smaller share of rowhouses and a larger share of apartments compared to 2016.

Figure 19b: Percentage of Dwelling Types by Age of Household Maintainer, Ottawa 1986



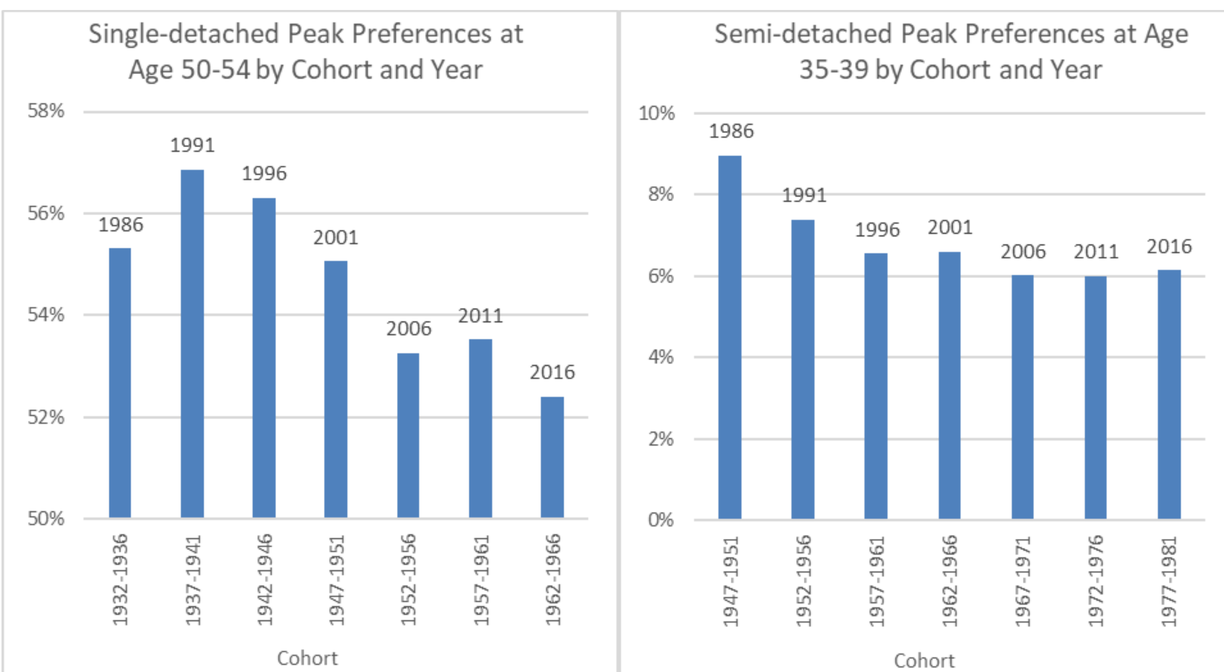
Looking to the Past: Emerging Patterns in Dwelling Type Propensities

The examination of dwelling type propensities by age of household maintainer begins by reviewing each Census from 1986 to 2016, a period of 30 years, for the city of Ottawa[6]. A form of longitudinal analysis was used where the occupancies for each cohort was observed as they aged every 5 years throughout this 30-year period. A cohort in this analysis is a group of people born within a period of five years. For example, those born between 1947 to 1951 were aged 35 to 39 years in 1986. In 1991 they were aged 40 to 44 years and so on to 2016 when they were aged 65 to 69 years. The occupancy shares of the four general dwelling types were observed in this manner from the oldest cohorts being born between 1912 to 1916 to the youngest cohorts born between 1997 to 2001, totalling 18 cohorts across age groups as young as 15 to 19 years to over 85 years.

Between 1986 to 2016 three patterns become evident in the preference and occupancy of dwelling types. First, single-detached, semi-detached and rowhouse appear to have a peak preference at certain ages. For single-detached, the highest preference across most cohorts was at age 50 to 54. The only exception is the cohort born between 1942 to 1946 where their peak preference for single-detached was at 45 to 49 years. For semi-detached, the highest preference for most cohorts was at age 35 to 39. For rowhouses the highest preference for most cohorts was either age 30 to 34 or 35 to 39. Apartments show the opposite with the lowest preference at age 50 to 54 across most cohorts.

Second, the peak propensity at these age groups for the single-detached and semi-detached dwelling types decrease for younger cohorts. As shown in Figure 20, the preference of the cohort born between 1932 to 1936 for single-detached was 55.3% at age 50 to 54 in 1986. Although the next cohort to reach age 50 to 54 in 1991 increases their single-detached preference to 56.9%, the remainder of the cohorts decrease their single-detached preference to 52.4% in 2016 by those born between 1962 to 1966. Semi-detached follows a similar pattern with those born between 1947 to 1951 having a semi-detached preference of 9.0% at age 35 to 39 in 1986. Future cohorts at the same age then decrease their semi-detached propensities, with those born between 1977 to 1981 having a preference of 6.1% in 2016.

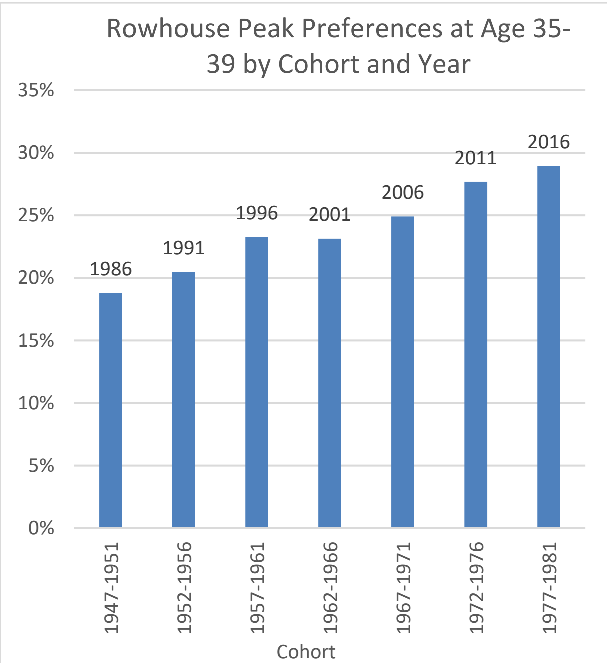
Figure 20: Declining Peak Preferences by Cohort for Single-Detached and Semi-Detached

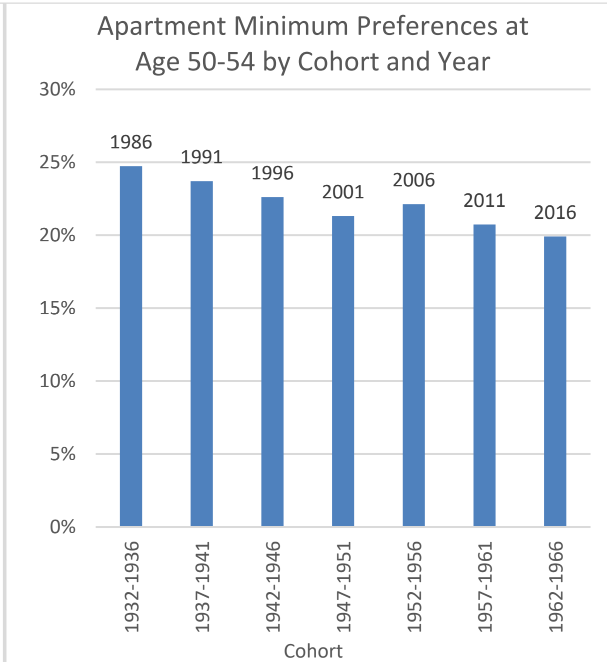


6 Statistics Canada defines the current city of Ottawa geographic area as the Ottawa Census Division or Subdivision. The Census Division was used to maintain the same geographic boundaries pre- and post-amalgamation in 2001.

Rowhouse peak preference occurs in the opposite direction with the propensities increasing for younger cohorts. As shown in Figure 21, in 1986, those born between 1947 to 1951 were 35 to 39 years old and had a rowhouse preference of 18.8%. In 2016, those born between 1977 and 1981 were also 35 to 39 years old and had a rowhouse preference of 28.9%. The peak age group for rowhouse does seem to shift between the two age groups of 30 to 34 and 35 to 39. For the projections model, an assumption was made that future cohorts would peak in the older age group of 35 to 39 to coincide with the assumption that the delayed life stage milestones associated with this generation would continue due to the pursuit of post-secondary education, increased debt and rising housing costs[7, 8, 9].

Figure 21: Increasing Rowhouse Peak Preferences and Declining Apartment Minimum Preferences





The minimum apartment preferences at age 50 to 54 decreased with younger cohorts as shown in Figure 21. In 1986 those born between 1932 to 1936 had an apartment minimum preference of 24.7% at age 50 to 54. In 2016, those born between 1962 to 1966 had an apartment minimum preference of 19.9% at age 50 to 54.

Figure 22 shows the changing percentage that each of the four dwelling types of single-detached, semi-detached, rowhouse, apartment by cohort as they age from 1986 to 2016. Generally, bars on the far left side of a cohort represent preferences in 1986 and bars on the far right side of a cohort represent preferences in 2016, showing a cohort's dwelling type preference as they age, with older ages represented by darker shading. The 35 to 39 and 50 to 54 age groups shown in Figures 20 and 21 are highlighted in Figure 22, showing the peak (for single- and semi-detached and rowhouse) and minimum (for apartment) dwelling propensities relative to the other age groups.

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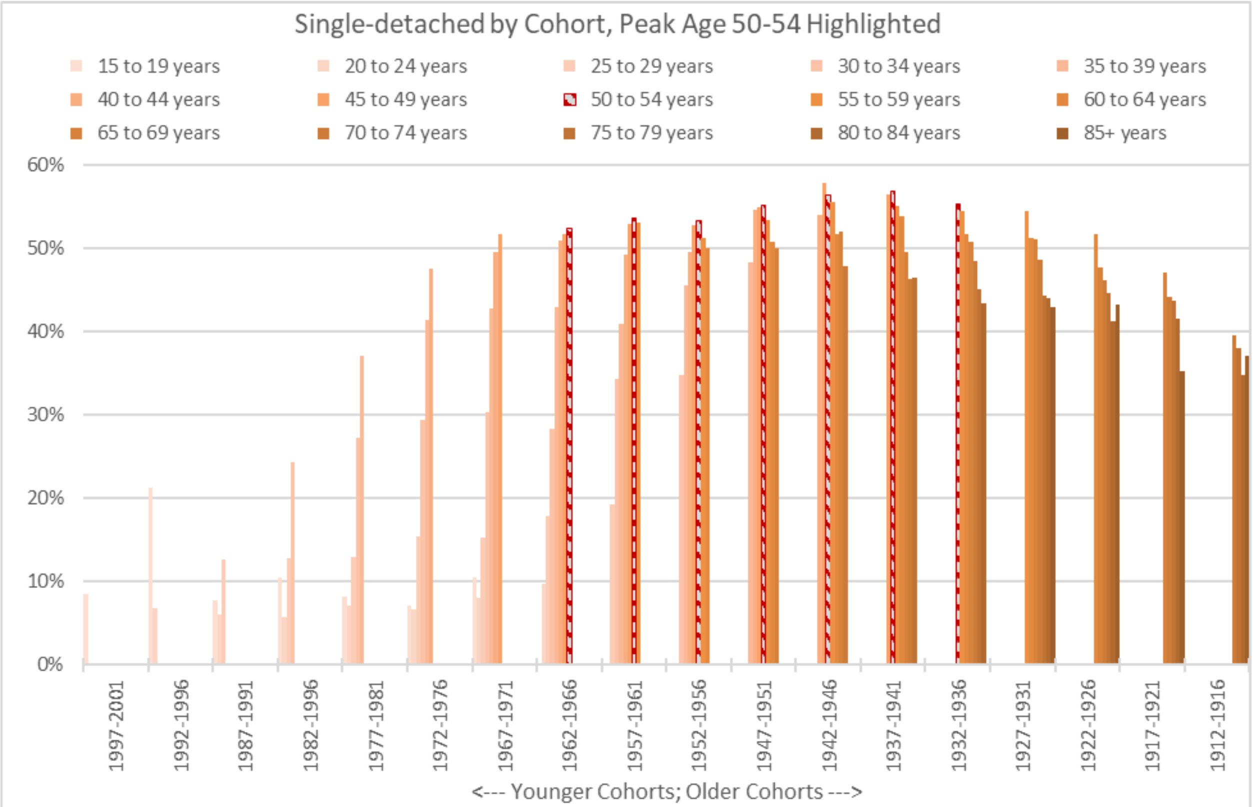
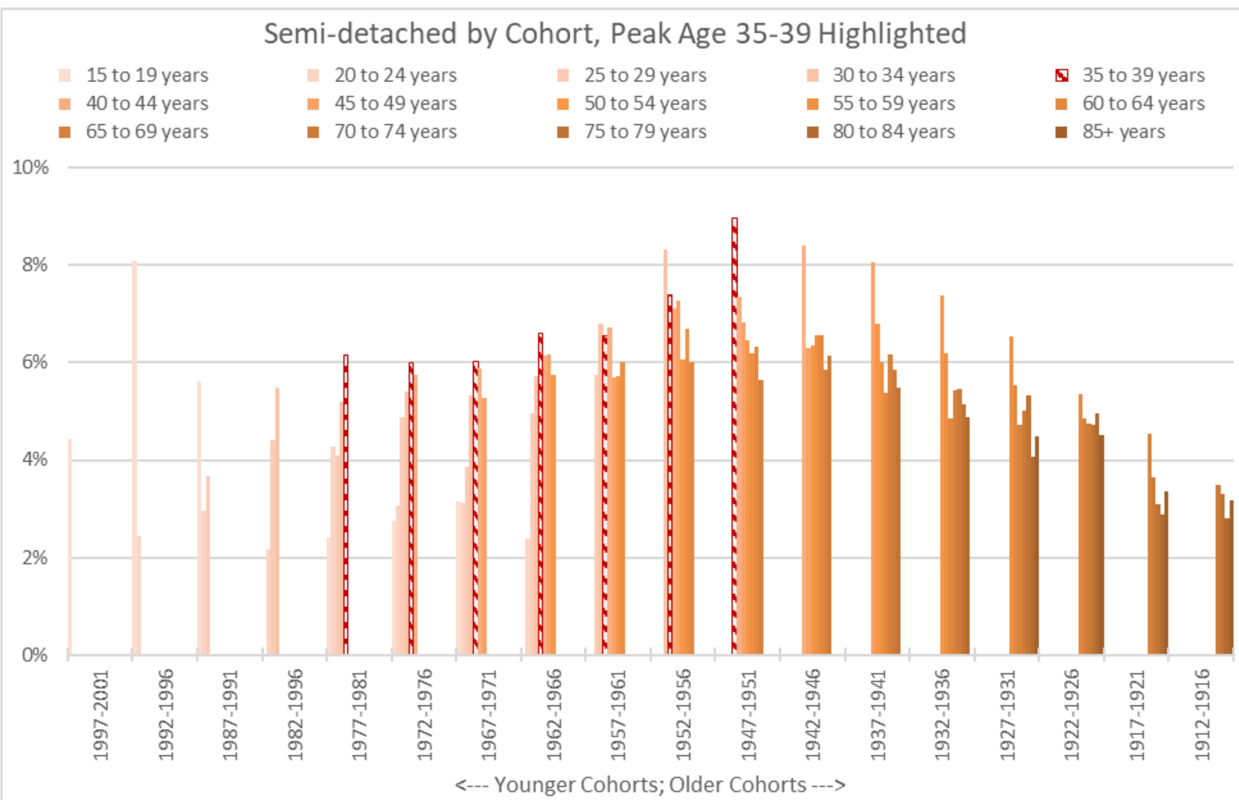
[7] Statistics Canada, 2019. *Economic Well-being Across Generations of Young Canadians: Are Millennials Better or Worse Off?* Publication 11-626-X No.092. https://www150.statcan.gc.ca/n1/pub/11-626-x/11-626-x2019006-eng.htm

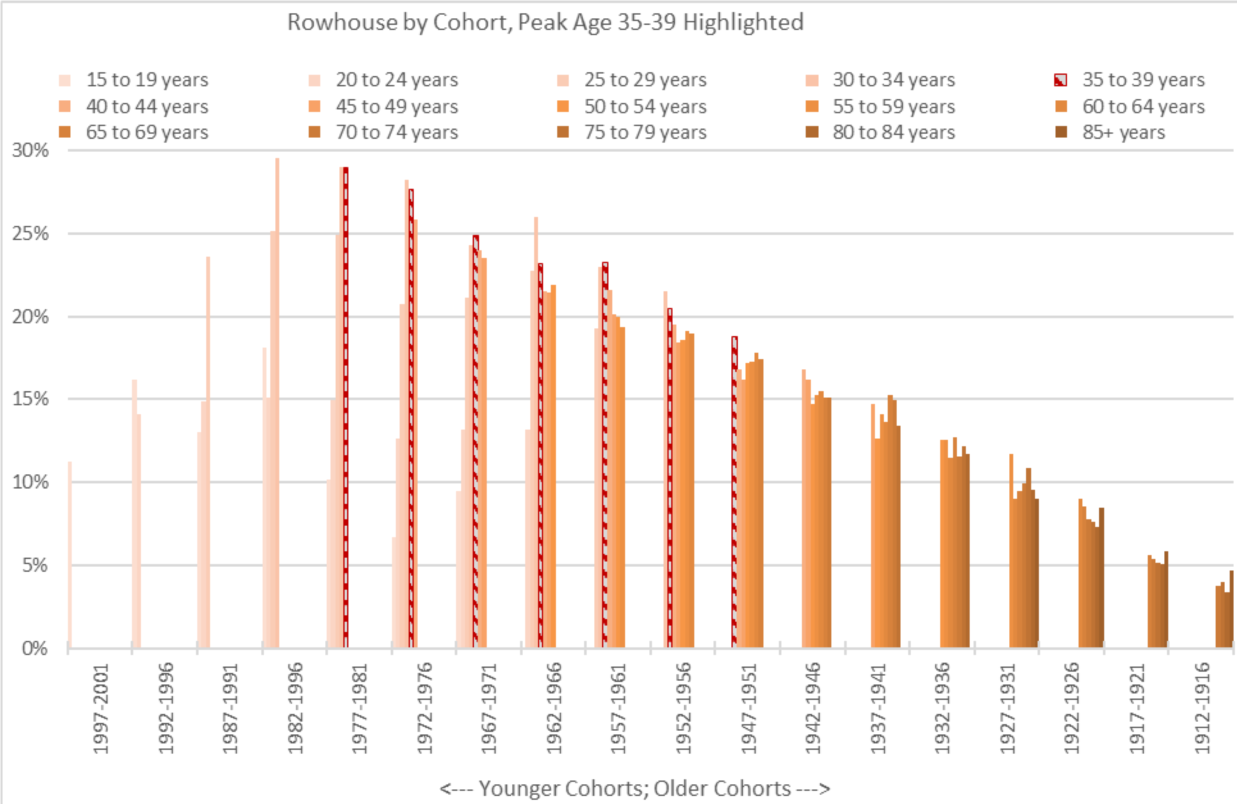
[8] US Census Bureau, 2017. *The Changing Economics and Demographics of Young Adulthood: 1975-2016*. Publication P20-579.

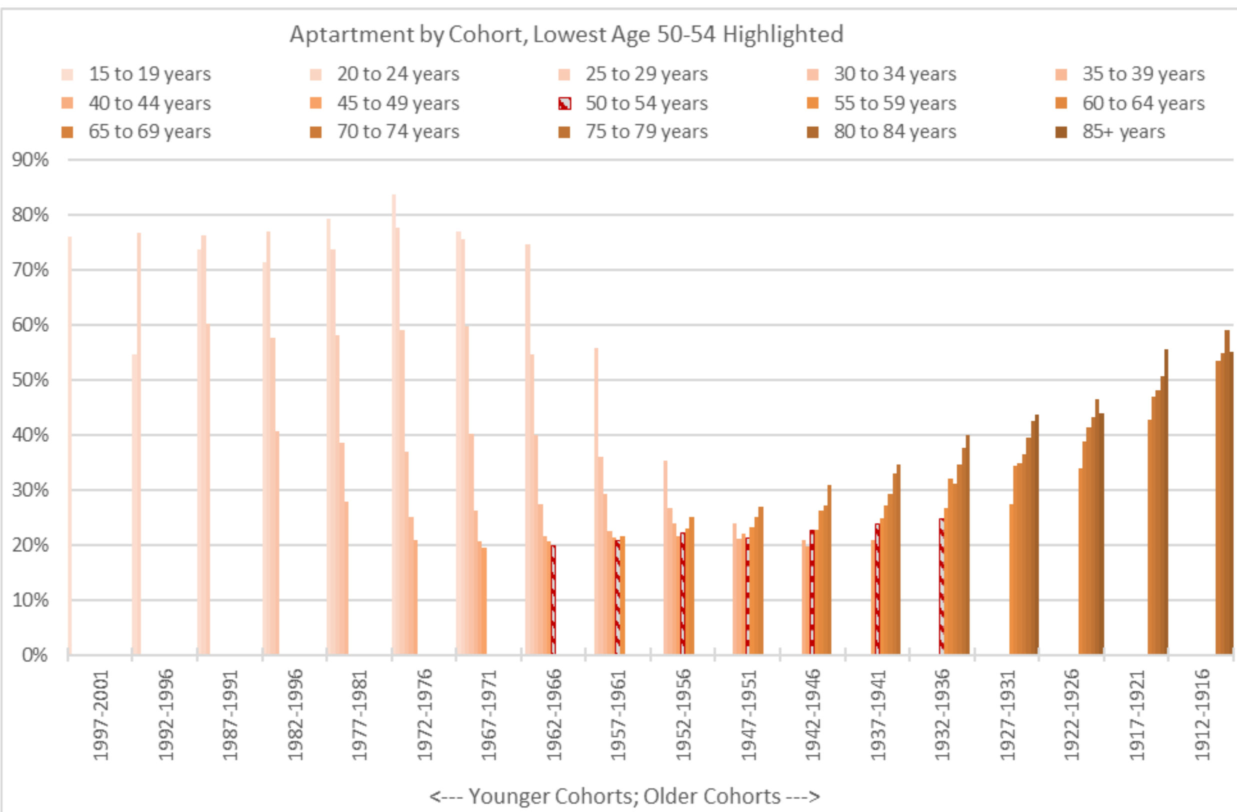
[9] Abacus Data, 2015. *Life, Work, and the Emerging Workforce: A study of the perceptions and attitudes of Canada's emerging Millennial generation.* https://abacusdata.ca/wp-content/uploads/2015/04/Abacus_CCCE_Report_FINAL.pdf

Figure 22: 1986-2016 Dwelling Type Preferences by Cohort.






Rowhouse by Cohort, Peak Age 35-39 Highlighted
15 to 19 years
20 to 24 years
25 to 29 years
30 to 34 years
35 to 39 years
40 to 44 years
45 to 49 years
50 to 54 years
55 to 59 years
60 to 64 years
65 to 69 years
70 to 74 years
75 to 79 years
80 to 84 years
85+ years
30%
25%
20%
15%
10%
5%
0%
1997-2001
1992-1996
1987-1991
1982-1996
1977-1981
1972-1976
1967-1971
1962-1966
1957-1961
1952-1956
1947-1951
1942-1946
1937-1941
1932-1936
1927-1931
1922-1926
1917-1921
1912-1916
<--- Younger Cohorts; Older Cohorts --->


Aptartment by Cohort, Lowest Age 50-54 Highlighted
15 to 19 years
20 to 24 years
25 to 29 years
30 to 34 years
35 to 39 years
40 to 44 years
45 to 49 years
50 to 54 years
55 to 59 years
60 to 64 years
65 to 69 years
70 to 74 years
75 to 79 years
80 to 84 years
85+ years
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
1997-2001
1992-1996
1987-1991
1982-1996
1977-1981
1972-1976
1967-1971
1962-1966
1957-1961
1952-1956
1947-1951
1942-1946
1937-1941
1932-1936
1927-1931
1922-1926
1917-1921
1912-1916
<--- Younger Cohorts; Older Cohorts --->

A third observed pattern is that all the cohorts increase their preference from age 20 to 24 years to their respective peak ages for the single-detached, semi-detached and rowhouse dwelling types. The cohorts then tend to decrease their preference from their respective peak ages as they get older. For example, in Figure 22, those that were born between 1962 to 1966 increase their preferences for single-detached from age 20-to-24 to 50-to-54. Those that were born between 1932 to 1936 decrease their preferences for single-detached dwellings from age 50-to-54 to 80-to-84.

For semi-detached in Figure 22, the cohort born between 1977 to 1981 increased their preferences for semi-detached from age 20-to-24 to 35-to-39. Those that were born between 1947 to 1951 decreased their preferences for semi-detached from age 35-to-39 to 65-to-69.

For rowhouse in Figure 22, the cohort born between 1977 to 1981 increased their preferences for rowhouses from age 20-to-24 to 35-to-39. Those that were born between 1947 to 1951 decreased their preferences for rowhouses from age 35-to-39 to 65-to-69.

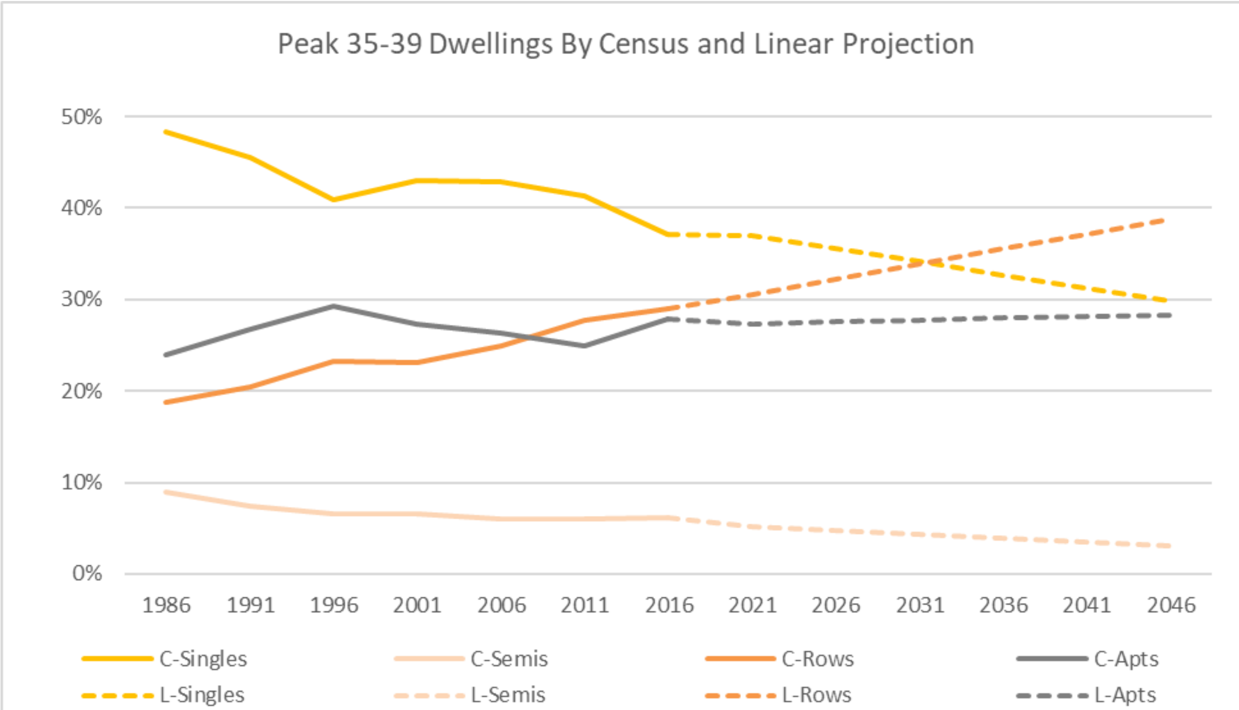
Apartments exhibit the opposite trend from the other dwelling types where apartment preference tends to peak at the younger ages, then declines to the lowest levels at age 50 to 54, then increases with age at a more gradual rate. For example, in Figure 22, those that were born between 1962 to 1966 decrease their preferences for apartments from age 20-to-24 to 50-to-54. Those that were born between 1932 to 1936 increase their preferences for apartments from age 50-to-54 to 80-to-84.

Dwelling Type Propensity Projections

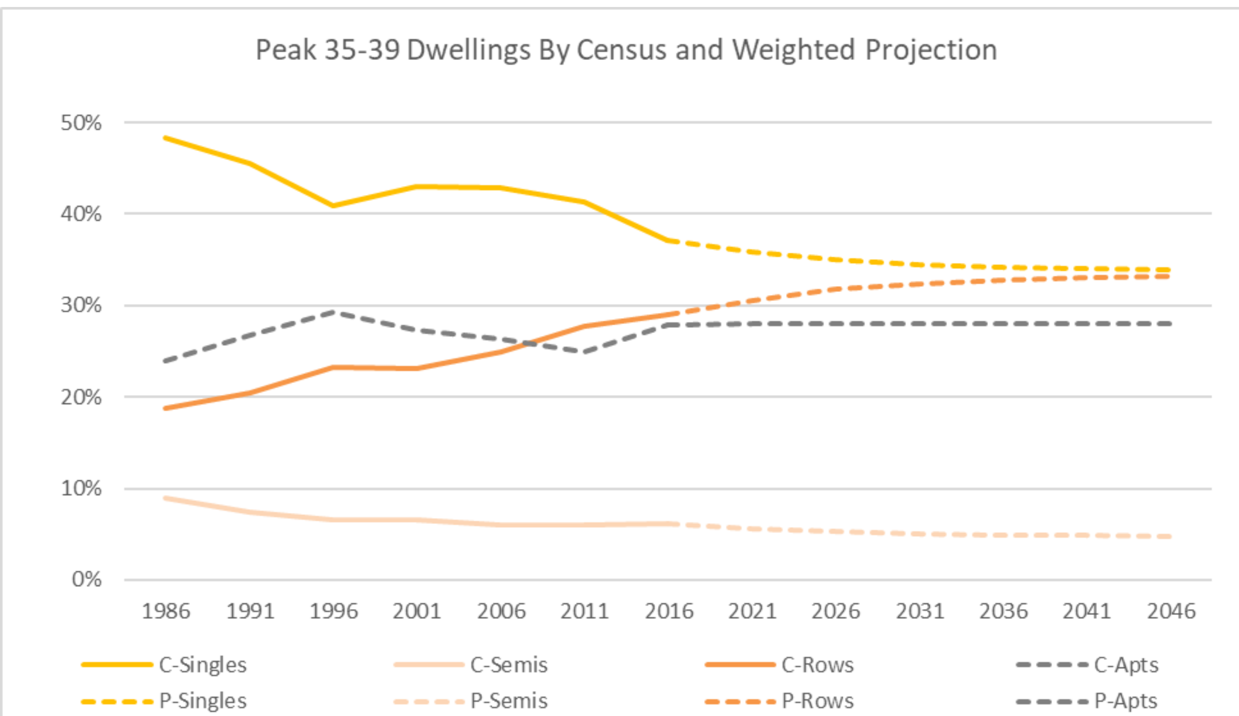
These observations of various cohort behaviours form the basis for the method to project what the future propensities for dwelling types will be for existing and future cohorts as they age. The method has three parts based on the observed trends. First, the peak propensity at ages 50 to 54 for single-detached, 35 to 39 for semi-detached and rowhouse, and the minimum propensity at age 50 to 54 for apartments are assumed to continue throughout the projection period. Second, the continued decline of the peak propensities at these ages for single-detached, semi-detached and apartments; and, the continued increase of peak propensity for rowhouses are assumed to continue. Third, the increase of propensities from age 20 to 24 to the respective peak age groups and then a decline as cohorts age for single-detached, semi-detached and rowhouse are assumed to continue. Apartments are assumed to decline from the 20 to 24 age group to the minimum propensities at age 50 to 54 and then increase gradually as cohorts become older.

A variety of trends were applied to the continuation of the peak propensity change for single-detached, semi-detached and rowhouses and minimum propensity change for apartments, but a limiting factor is that all the dwelling types are proportions of the total private occupied housing stock for an age group and need to be treated uniformly. A method was selected that continues the past observed changes in propensities for the 35 to 39 and 50 to 54 age groups in the short-term, with the influence or historical observations diminishing over the long-term. The method assumes that the linear trend of observed propensities from 1986 to 2016 continues to 2021, and then a logarithmic (log) weighting is applied to the linear trend after 2021 so that the rate of change slows to 2046. This method has the advantage of not over-exaggerating shifts in the longer term from one dwelling type to another thereby overestimating some dwellings and underestimating others. Figures 23 and 24 show the differences between the potential over exaggeration of linear projections and linear-log weighted projections for the 35 to 39 and 50 to 54 age groups over the long-term.

Figure 23: Age 35-39 Peak Dwelling Propensities, Linear Projection and Linear-Log Weighted Projection

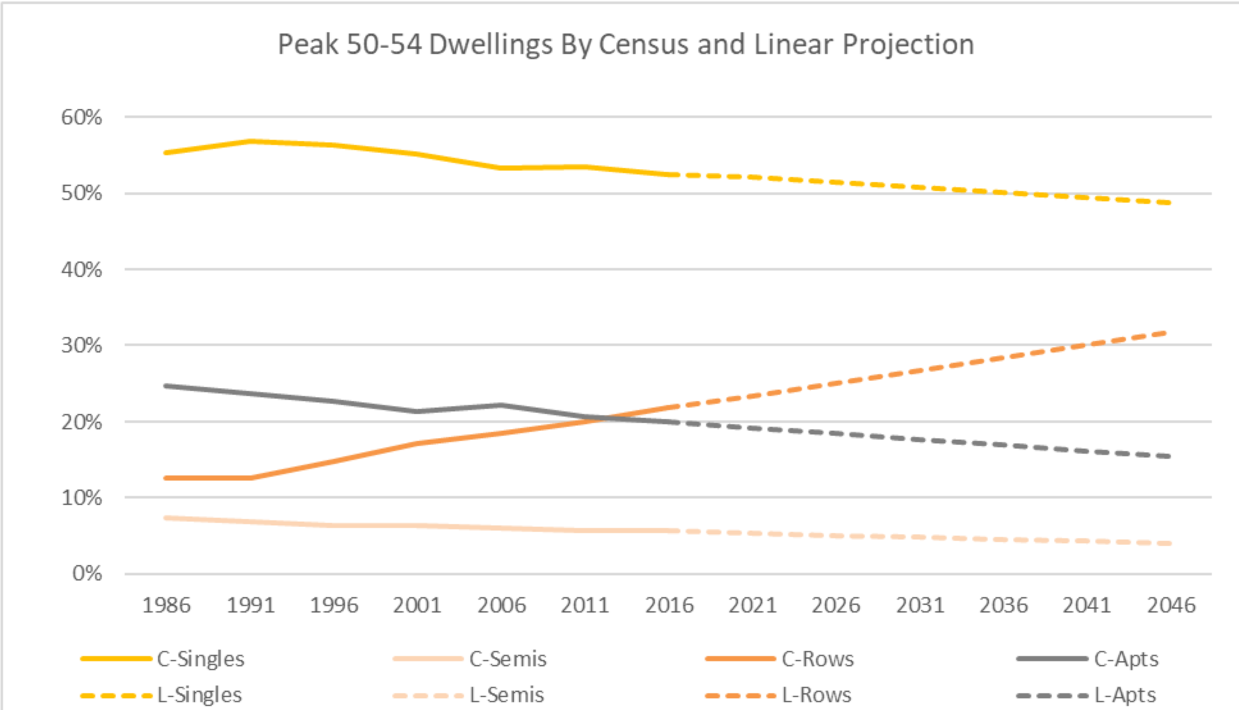


C = Census; L = Linear Projection

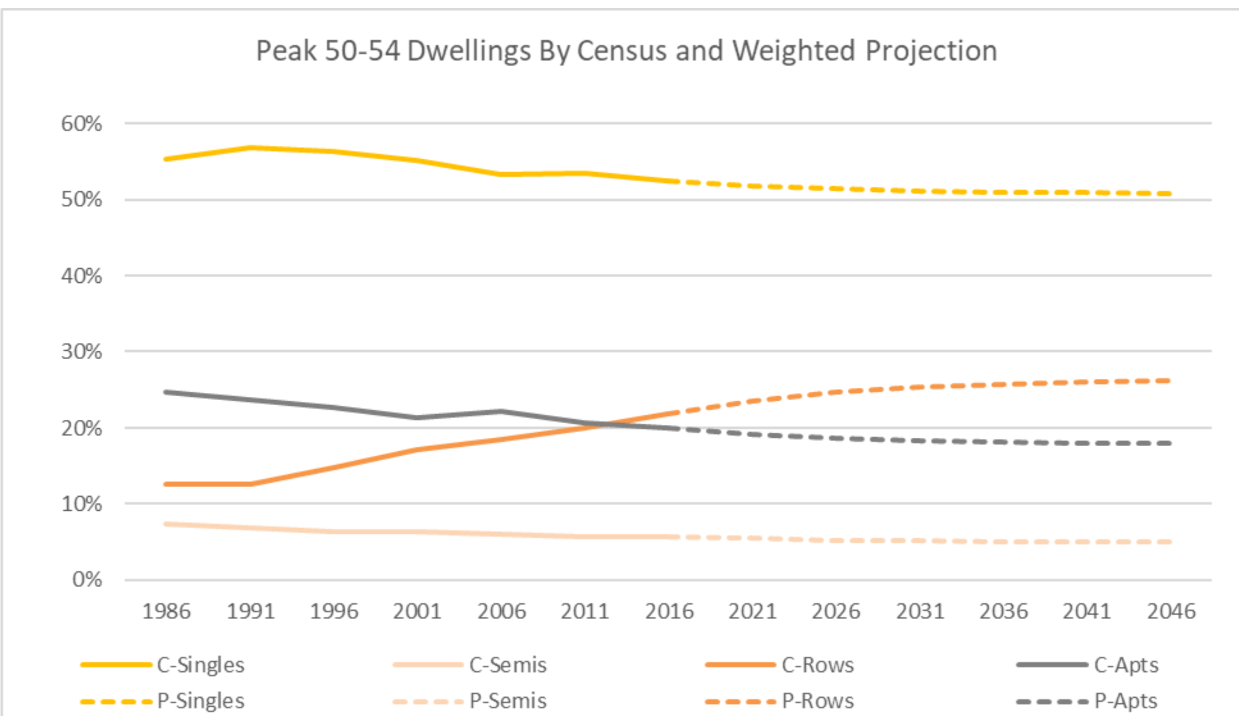


C = Census; P = Weighted Projection

Figure 24: Age 50-54 Peak Dwelling Propensities, Linear Projection and Linear-Log Weighted Projection



C = Census; L = Linear Projection



C = Census; P = Weighted Projection

The third component of the dwelling type projections is to determine the propensities of each cohort as they age to and from the 35 to 39 and 50 to 54 age groups. The future dwelling type propensity for each cohort relies on the average propensity change from the existing age group to the future target age group of the three previous cohorts that had already reached the target age group. As shown in Figure 25, the cohort that was born between 1972 to 1976 was age 40 to 44 years in 2016 and had a single-detached propensity of 47.5%. The previous three cohorts born between 1967 to 1971, 1962 to 1966, and 1957 to 1961 on average increased their preference for single-detached as they aged from 40-to-44 years to 45-to-49 years by 2.3%. Applying this average rate of increase to the cohort born between 1972 to 1976 as they aged to 45 to 49 years increases their preference for single-detached by 2.3% to 49.8% in 2021 from 47.5% in 2016. The previous three cohorts are used because their rate of change tends to be more stable than the previous cohorts, decreasing the amount of variance assumed to be applied as cohorts age and resulting in smoother propensity changes throughout the projection period.

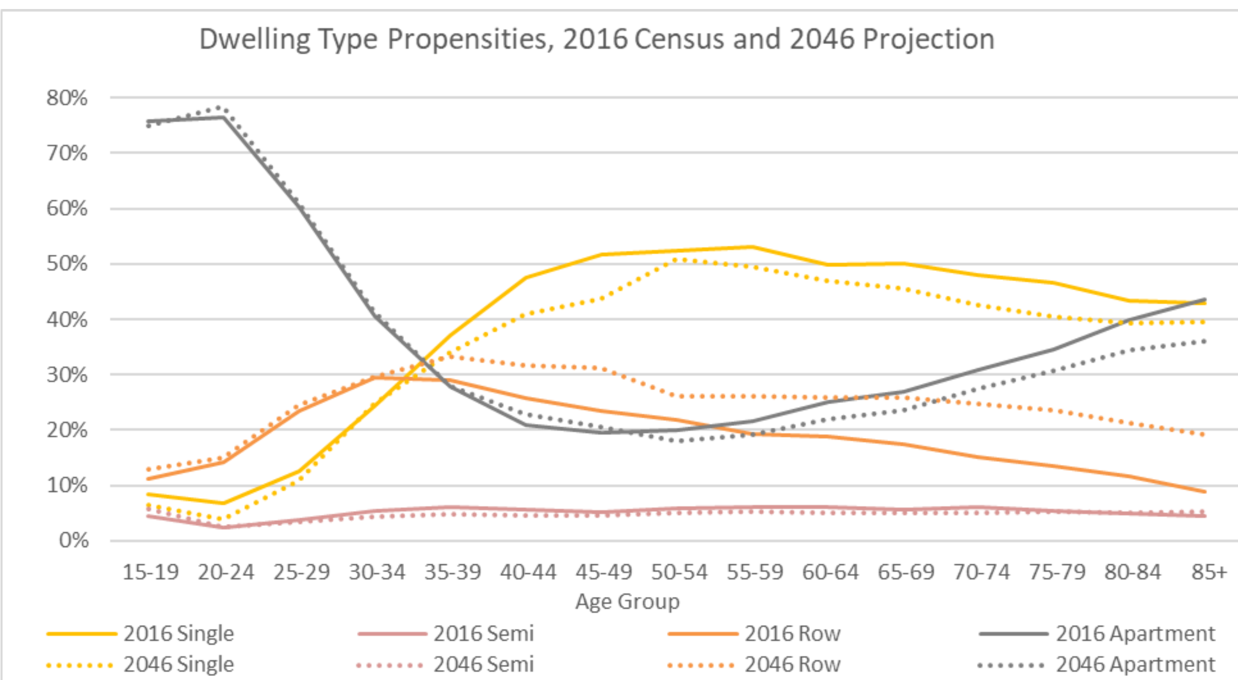
Figure 25: Example of applying cohort change to a future age from average of three previous cohorts

Cohort % in Single-detached	Year aged	40-44	Year aged	45-49	Change from 40-44 to 45-49	Average Cohort Change	40-44 in 2016	Average Cohort Change	45-49 in 2021
1972-1976	2016	47.5%	2021	?			47.5%	+2.3%	49.8%
1967-1971	2011	49.6%	2016	51.7%	2.1%				
1962-1966	2006	50.8%	2011	51.7%	0.9%	2.3%			
1957-1961	2001	49.2%	2006	53.0%	3.8%				

Dwelling Type Projections Results

The dwelling type projections show an increasing shift towards rowhouse type dwellings from the population in their mid-30s to their mid-50s than what has been observed in the past. As shown in Figure 26, from their mid-50s to their senior years, the population will see decreasing preferences for both single-detached and apartments, with some increasing preferences for rowhouses. Semi-detached will remain relatively stable throughout the projection period. Overall, single-detached will remain the most preferred dwelling type from age 35 to 39 and onward.

Figure 26 Dwelling Type Propensities, 2016 Census and 2046 Projection



Demolitions and Vacancies

In addition to 186,200 private household occupancies, additional dwelling units for demolition replacements and vacancies should be added to create a more fulsome picture of land demand. The concept of demolition replacements should be limited to the households that intend to remain within the city and occupy a new private household after the demolition of their principal residence. Demolitions however occur for a variety of reasons where the original occupants either move out of the city, or stay within the city but move to a collective dwelling, move to a rental unit, move to a resale unit, or move to a new housing unit, including a replacement unit on the same lot. For the purposes of projecting demand for new private housing units, only the last situation adds new dwelling units to the 186,200 private household occupancies stemming from net migration and natural increase. In practice however it is not possible to determine the rationale for a demolition or the type of housing the original occupants move to or follow where they move to and create a direct relationship with the net migration estimates in the population projection.

The City can track demolition permits and determine the dwelling type that was demolished and the dwelling type that the original unit was replaced with. Because the projections categorize new households by dwelling type, assumptions must be made about the specific dwelling types that are added to the dwelling type projections developed from the above propensities. The dwelling projections model assumes that for those demolished units that are replaced with the same units, half are assumed to be for those occupying the previous unit, with the exception of apartments where all of the former tenants are assumed to seek another apartment unit and remain within the city due to tenure and the different ownership structure associated with apartment units.

Housing demand was adjusted by allowing for the replacement of 260 demolished units annually being the annual average of demolition permits over the past ten years. The split of the same replacements by unit type was 22% single-detached, 1% semi-detached, 1% rowhouse and 76% apartments.

A further adjustment was made to allow for a vacancy rate in new units. Ownership units were assumed to have a 0.5% vacancy, similar to previous projection models. Rental units were assumed to have a 3.0% vacancy throughout the projection period, which is referred to as a balanced market. While there may be periods where vacancies are lower or higher the projection model assumes overall there will be a balanced market throughout the period.

Overall, demolition replacements and vacancy allowances are estimated to add 9,400 units to housing needs between 2018 and 2046 (Figure 27).

Figure 27 Demolition Replacements and Vacancies in New Units, 2018-2046

	Single-detached	**Semi-detached**	**Rowhouse**	**Apartment**	**Total**
Demolitions	1,568	84	28	5,544	7,224
Vacancies	329	32	525	1,297	2,183
Total	1,897	116	553	6,841	9,407

Conclusion

Over the 2018 to 2046 period there is a projected demand for 194,808 new housing units. Demand by unit type, including demolitions and vacancies, are shown in Figure 28. Further details on the projected number of households by age group and dwelling types can be found in Appendix 6.

Figure 28 Projected Housing Demand by Unit Type, 2018-2046

	Single-detached	**Semi-detached**	**Rowhouse**	**Apartment**	**Total**
2018-46	66,116	6,375	69,736	52,582	194,808
Shares	33.9%	3.3%	35.8%	27.0%	100.0%

Part III. Employment Projections

Ottawa's employment prospects will be influenced by the aging workforce, governmental budgets for the Federal service and macro-level factors that can impact the private sector. These drivers are taken into consideration in the assumptions for the components of the employment projection.

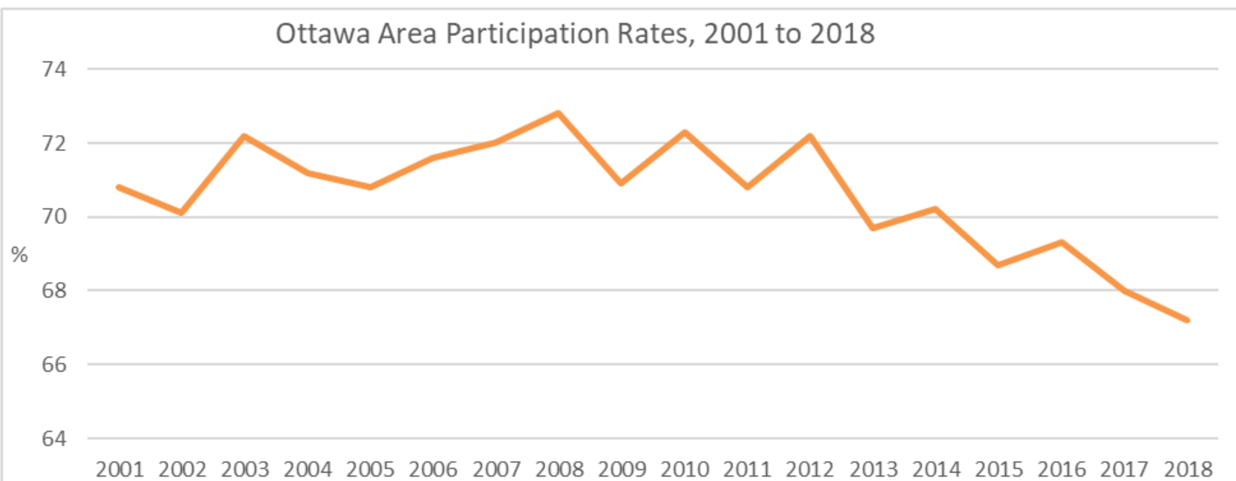
Methodology

Labour force participation rates by age and sex were applied to the age-sex structure of the projected population to produce an estimate of the resident labour force. This number is adjusted by assumed unemployment rates to produce the number of employed residents. The number of net in-commuters from adjacent municipalities, the difference between the number of Ottawa residents who hold jobs outside of the City and the number of people who reside outside of Ottawa but hold jobs in Ottawa, is added to the projected resident labour force to project the total number of jobs located in Ottawa. A multiple jobholder rate is then applied to account for people having more than one job.

Participation Rates

The labour force participation rate (LFPR) is the percentage of the population 15 and over that is in the labour force, either working or seeking work. Since 2011, the LFPR has been declining in the Ottawa area, mainly due to the aging population, with 2011 coinciding with the first cohort of the baby boom generation reaching 65 years of age. Figure 29 shows the LFPR for the Ontario portion of the Ottawa-Gatineau Census Metropolitan Area (CMA)[10], which declined from 70.8% in 2001 to 67.2% in 2018.

Figure 29: Ontario part of the Ottawa-Gatineau CMA Participation Rates, 2001-2018

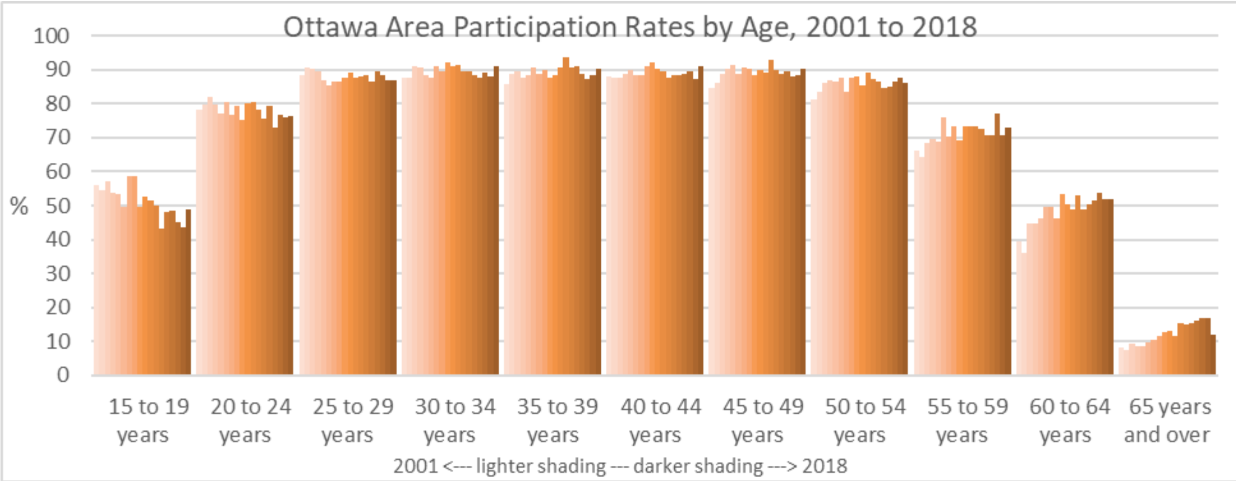


Two primary factors influence the total LFPR; the health of the overall economy and the demographic age/sex structure of the population. Higher economic growth attracts more people into the labour force, increasing the rate. The age structure of the labour force has strong influences on the effect of demographic change. Typically, rates among the younger segment of working age adults are lower due to the pursuit of education. The older segment of working age adults can also be lower due to retirements and health limitations. However, in recent years, there have been changes in the patterns observed for the older adults with increasing participation rates for both males and females. Figure 30 shows the LFPRs from 2001 to 2018 by age group. In general, the younger segments of the working population are participating less in the labour force since 2001, with some signs of increase over the most recent years, possibly due to lower than historical unemployment rates providing more job opportunities. The middle

[10] Statistics Canada, Custom Tabulation. Statistics Canada does not provide detailed labour force statistics for the city of Ottawa geography. The Ontario part of the Ottawa-Gatineau CMA includes the city of Ottawa, city of Clarence-Rockland, township of Russell, and the municipality of North Grenville and is the closest geography to the city of Ottawa for detailed labour force statistics.

age segment has seen relatively stable LFPRs, while the older population age groups have been increasing their participation rates.

Figure 30: Ontario part of the Ottawa-Gatineau CMA Participation Rates by Age, 2001-2018



While the recent LFPR increase for the younger age segments differs somewhat from earlier observations, there is not enough of a long-term trend to reasonably assume the increases for these age groups will continue over the projection period. However, stable rates among the mid-age segments and increases among older adults are expected to continue over the projection period as the local economy has a strong knowledge-based sector that coincides with a demographic that is showing interest in continuing to work past the traditional retirement age of 65. In general, people will have longer and healthier life-spans and projected increases in the older adult population will likely result in labour shortages and add pressure to pension systems, factors which can also contribute to the likelihood of increasing older age participation rates.

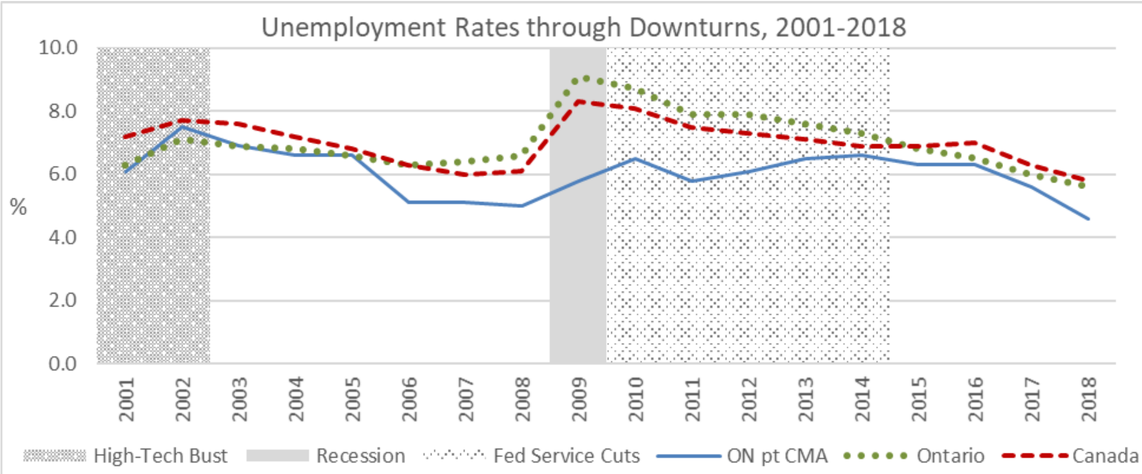
Statistics Canada has published a study on labour force projections to 2036 and concludes that the overall national participation rate will decrease mainly due to the aging of the population, from 66% in 2017 to 63% in 2036 but that the LFPR is expected to continue increasing in the older adult work force[11]. The study provides a benchmark for the participation rate by age group for the employment projections to 2046. The study projects that in 2036 the Ottawa-Gatineau CMA will have a participation rate of 64.3 in their reference scenario. The participation rate projections for the Ottawa employment projections to 2046 takes the Statistics Canada projection into account by adjusting for the city of Ottawa proportion of the CMA and the projected national participation rate by age group[12]. The result is a decline of participation rates for age groups under 50 and an increase of participation rates for age groups over 55. Despite the assumed increase in participation rates for the older segment of the population, it will not fully offset the effects of an aging labour force and overall LFPRs for the city of Ottawa are projected to decrease from 66.7% in 2018 to 62.5% by 2046.

Unemployment Rates

Relative to the national and provincial rates, Ottawa has typically had lower unemployment rates even during periods of downturn as shown in Figure 31. During the local "high-tech bust" in 2001-2002, Ottawa rates were still under national rates; in the 2008-2009 recession Ottawa rates were below national and provincial rates; and, while the Federal government austerity measures through 2010 to 2014 saw job cuts to the federal service, the Ottawa unemployment rate was still lower than national and provincial unemployment rates.

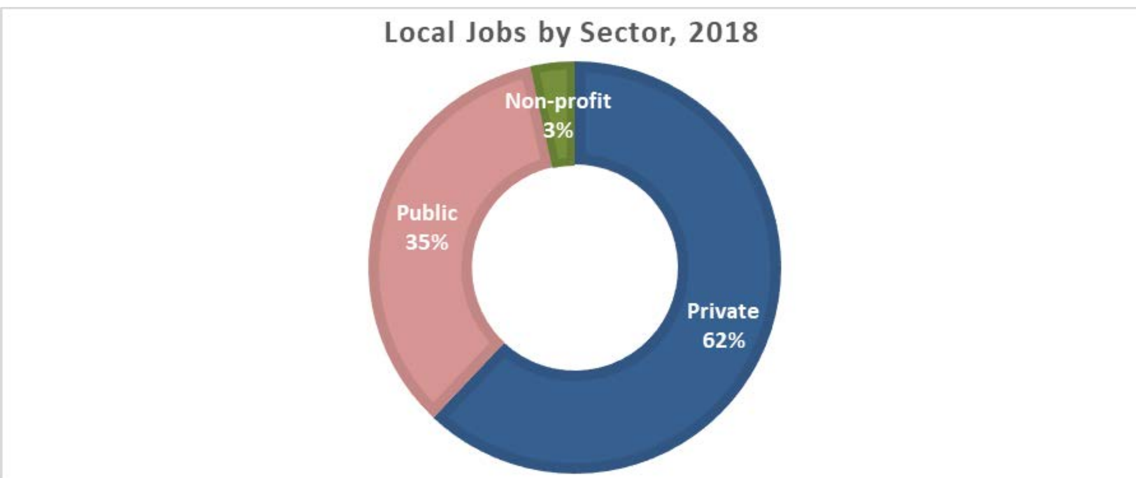
[11] Statistics Canada, 2019. *The labour force in Canada and its regions: Projections to 2036*. Publication 75-006-X. https://www150.statcan.gc.ca/n1/pub/75-006-x/2019001/article/00004-eng.htm
[12] *Ibid.* Chart 8, Trends from 1995 to 2017 Scenario.

Figure 31: Comparative unemployment rates through periods of downturn, 2001-2018



This shows that the local unemployment rate has remained relatively robust to disruptions to both macro and local economies and, public and private sectors. Much of this resiliency may be related to the make up of the local economy by sector, where the public sector accounts for 1 out of 3 jobs as shown in Figure 32[13]. The relatively large proportion of the public sector[14] provides some measure of insulation to the overall local economy when one sector is more affected by a downturn than the other.

Figure 32: Local Economy Composition by Sector, 2018



In addition to the context of the local economy, as with the LFPR, the unemployment rate is also expected to remain low over the long-term relative to rates observed in the past, as the older segment of the population ages out of the work force, creating more employment opportunities and reducing the ratio of those participating in the labour force seeking a job to the overall labour force. Throughout the projection period the unemployment rate is assumed to remain at lower levels based on the resiliency of the local economy to economic downturns and the demographic change that will put pressure on a lower unemployment rate. The local unemployment rate is forecast to increase slightly from 4.6% in 2018 to 4.8% in 2021 due to expected lower federal service growth that will be somewhat offset with committed and anticipated construction opportunities and a positive outlook for the high-tech sector[15]. As Stage 2 of

[13] Statistics Canada, Labour Force Survey, custom tabulation.
[14] *Ibid:* the Ottawa public sector is comprised of federal (55%), provincial (39%) and local (6%) governments, providing additional breadth in downturns from a single senior government's policies.
[15] Conference Board of Canada, 2019. *Metropolitan Outlook 1: Ottawa-Gatineau – Autumn 2019*.

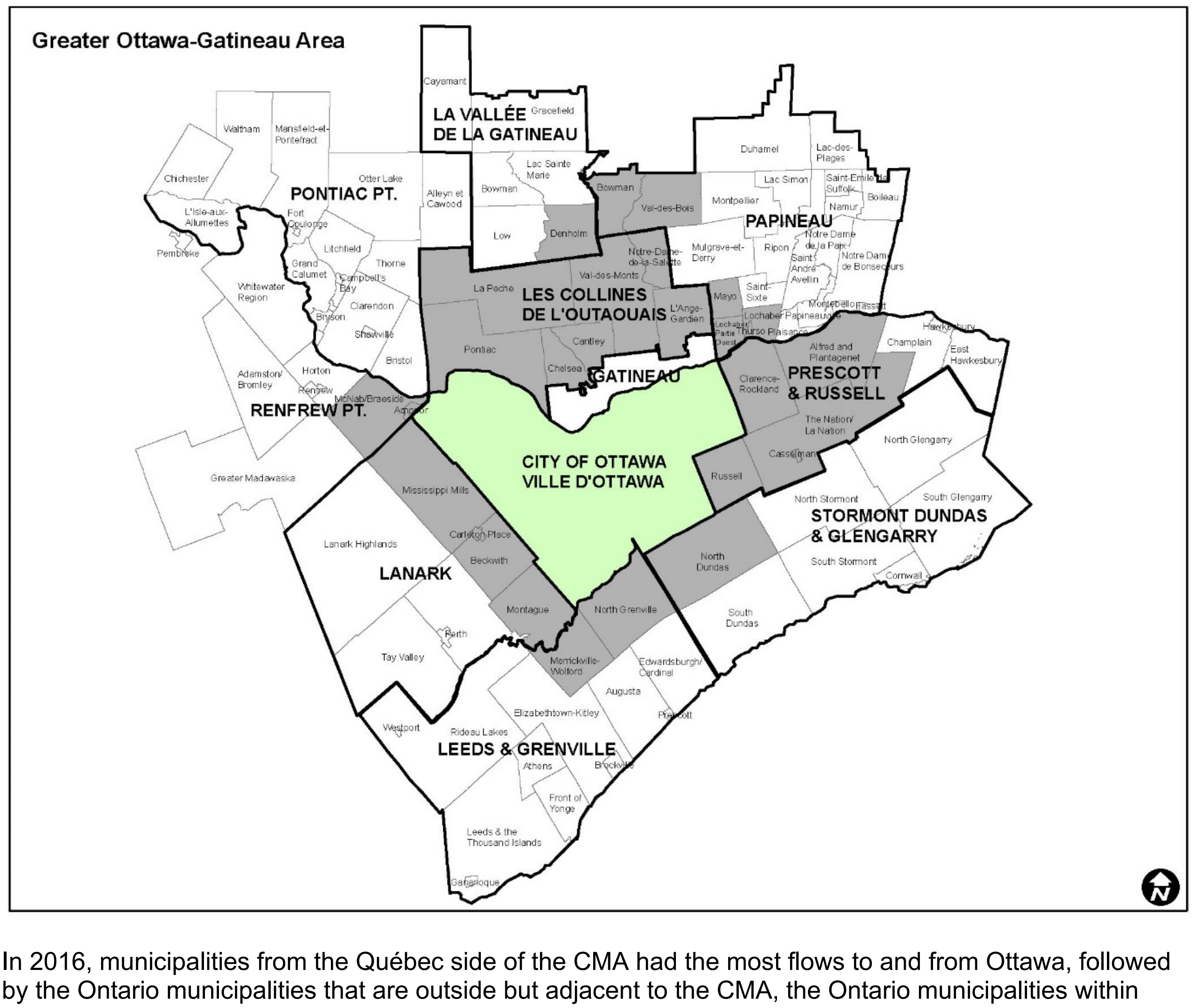
LRT wraps-up post-2021, the unemployment rate will gradually ease to 4.9% by 2026, reaching 5.0% by 2031 and holding constant to 2046.

Net In-Commuting

As part of a larger regional economy, a portion of Ottawa's resident labour force commutes out of the city for work and residents from outlying areas commute into the city. The net change of in-commutes minus out-commutes are additional jobs to the resident labour force that works within the city. These outlying areas include not only the municipalities that form the Ottawa-Gatineau CMA, but also the smaller municipalities in both provinces that are adjacent to the CMA. There are also significant flows to and from other areas, with the most significant being Montréal, Toronto, Lanark, and Cornwall.

The main commuter area of Ottawa is the entire Ottawa-Gatineau Census Metropolitan Area (CMA) plus adjacent municipalities in Ontario and Québec that are not included in the CMA. Map 1 shows the City of Ottawa in relation to these outlying areas

Map 1: City of Ottawa and Adjacent Municipalities



In 2016, municipalities from the Québec side of the CMA had the most flows to and from Ottawa, followed by the Ontario municipalities that are outside but adjacent to the CMA, the Ontario municipalities within the CMA and then the Québec municipalities that are outside but adjacent to the CMA. These areas are shown on Map 1, where the Ontario municipalities within the CMA are the city of Clarence-Rockland, township of Russell, and the municipality of North Grenville. The shaded Ontario municipalities, with the exception of the previous three mentioned, are adjacent to Ottawa and the shaded Québec municipalities are those outside and adjacent to the CMA. In 2016 there were over 96,000 people commuting into Ottawa for work and over 27,000 persons commuting out of Ottawa for work, for a net difference of about 69,000 more people commuting into Ottawa[16], representing about 11% of total Ottawa jobs.

Destination-origin commuting flows for these areas were extrapolated from the 2006 and 2016 Census and the 2011 National Household Survey to the year 2021. After 2021 flow increases are assumed to diminish to 2046 as work force population growth in outlying areas will grow at lower rates than Ottawa. By 2046 net commuters will represent about 9% of total Ottawa jobs.

Place of Work

Statistics Canada separates employed residents by their place of work. For the purpose of this report, Ottawa's employed labour force includes all workers with usual place of work, no fixed place of work, and those who work at home. It is assumed that the majority of workers with no fixed place of work (such as landscape contractors and salespersons) conduct most of their business within Ottawa and therefore they are counted as part of the employed labour force.

Multiple Jobholders

In addition to jobs from commuters that live outside of Ottawa and those that live and work in Ottawa, there are persons that have more than one job and these jobs should also be included into the overall employment projection. A multiple jobholder rate is derived from the number of Ontario multiple jobholders[17] and is applied to the Ottawa employed labour force. A 5-year moving average of the growth rate based on recent historical data is applied throughout the projection period, starting at 5.6% in 2018, increasing to 6.1% by 2046.

Employment Projections Results

Figure 33 summarizes the employment projection results. The projected employed labour force will increase to 707,500 jobs by 2046, a growth of 168,800 or 31%. Net commuters are projected to increase to 76,400 by 2046 and multiple jobholders will increase to 43,200 by 2046. In total the number of jobs in the City of Ottawa is projected to grow to 827,000 in 2046, a growth of almost 190,000 jobs or 30%.

Figure 33: Employment Projections Summary, 2018-2046

	2018	2026	2036	2046
1. Employed Labour Force, Ottawa[18]	538,629	593,320	651,571	707,490
2. In-commutes from Québec CMA	51,710	54,532	58,205	60,681
3. Out-commutes to Québec CMA	-18,915	-20,354	-22,257	-23,576
4. In-commutes from Adjacent Québec	390	411	439	458
5. Out-commutes to Adjacent Québec	-	-	-	-
6. In-commutes from Ontario CMA	15,005	15,618	16,409	16,932
7. Out-commutes to Ontario CMA	-1,765	-1,948	-2,194	-2,371
8. In-commutes from Adjacent Ontario	19,275	20,063	21,078	21,750
9. Out-commutes to Adjacent Ontario	-2,665	-2,941	-3,313	-3,579
Number of jobs in Ottawa	607,414	664,573	725,956	783,883
Multiple Jobholders in Ottawa	30,163	33,819	38,443	43,157
Total number of jobs in Ottawa	**637,577**	**698,393**	**764,398**	**827,040**

[16] Statistics Canada. Custom tabulation.
[17] Statistics Canada. Table 14-10-0044-01 Multiple jobholders by industry, annual (x 1,000) https://doi.org/10.25318/1410004401-eng
[18] Ottawa's employed labour force includes employed Ottawa residents that work from home and residents with no fixed workplace address.

Conclusion

From 2018 to 2046, the total number of jobs in Ottawa is expected to increase by 30 percent to 827,000, slower than the population growth rate of 40 percent, mainly due to the aging population, the number of people reaching retirement and leaving the work force. Even with an anticipated increase in participation rates by the older adult population the increased proportion of seniors in the labour force will lead to lower employment growth rates than observed in the past. Additional details on the employed labour force, participation rates, unemployment rates, Ottawa jobs, and multiple jobholders over the projection period can be found in Appendix 6.

Appendix List

1. Population Projection Scenario Summaries
2. Components of Population Growth by Scenario
3. Population in Private Households
4. Census and Estimated Post-Censal Private Households
5. Descriptions of Dwelling Types
6. Households, Dwelling Types and Employment Details

Appendix 1 – Population Projection Scenarios

Low Scenario Population Projection								
City of Ottawa	**2018**	**2021**	**2026**	**2031**	**2036**	**2041**	**2046**	**Change 2018-2046**
Population (mid-year)	1,007,501	1,058,576	1,118,635	1,172,813	1,217,164	1,249,784	1,271,848	264,347
Average annual increase		10,215	12,012	10,836	8,870	6,524	4,413	9,441
Average Annual % Increase		1.0%	1.1%	1.0%	0.8%	0.5%	0.4%	0.9%
Population by Age Group								
0-4	51,018	51,572	55,031	58,460	58,460	56,554	54,712	3,694
5-9	54,870	55,432	54,741	57,954	61,178	60,952	58,802	3,932
10-14	55,696	58,605	58,791	57,918	60,973	64,009	63,572	7,876
15-19	60,083	62,123	63,237	62,819	61,477	64,100	66,727	6,644
20-24	77,393	78,184	69,030	68,678	67,115	64,763	66,534	-10,859
25-34	147,624	163,431	178,804	168,836	157,700	154,207	148,650	1,026
35-44	133,551	142,343	159,569	181,951	195,688	184,332	171,733	38,182
45-54	138,674	134,205	136,516	147,968	164,290	185,868	198,799	60,125
55-64	131,924	138,880	136,503	129,776	132,458	143,926	160,077	28,153
65-69	49,350	54,157	64,284	68,678	62,537	62,537	65,439	16,089
70-74	40,314	46,153	51,410	60,973	65,145	59,587	59,802	19,488
75-79	27,142	31,381	41,570	46,459	55,158	59,129	54,508	27,366
80+	39,862	42,110	49,150	62,343	74,986	89,818	102,492	62,630
0-19	22.0%	21.5%	20.7%	20.2%	19.9%	19.7%	19.2%	10.0%
20-34	22.3%	22.8%	22.2%	20.3%	18.5%	17.5%	16.9%	-4.4%
35-54	27.0%	26.1%	26.5%	28.1%	29.6%	29.6%	29.1%	36.1%
55-64	13.1%	13.1%	12.2%	11.1%	10.9%	11.5%	12.6%	21.3%
65-69	4.9%	5.1%	5.7%	5.9%	5.1%	5.0%	5.1%	32.6%
70-74	4.0%	4.4%	4.6%	5.2%	5.4%	4.8%	4.7%	48.3%
75-79	2.7%	3.0%	3.7%	4.0%	4.5%	4.7%	4.3%	100.8%
80+	4.0%	4.0%	4.4%	5.3%	6.2%	7.2%	8.1%	157.1%

Medium Scenario Population Projection								
City of Ottawa	**2018**	**2021**	**2026**	**2031**	**2036**	**2041**	**2046**	**Change 2018-2046**
Population (mid-year)	1,007,501	1,064,144	1,141,815	1,219,232	1,291,690	1,355,263	1,409,649	402,148
Average annual increase		11,329	15,534	15,483	14,492	12,714	10,877	14,362
Average Annual % Increase		1.1%	1.5%	1.4%	1.2%	1.0%	0.8%	1.4%
Population by Age Group								
0-4	51,018	52,281	59,778	66,327	68,987	69,087	68,446	17,428
5-9	54,870	55,729	56,257	63,632	70,079	72,584	72,505	17,635
10-14	55,696	58,830	59,727	60,231	67,566	73,909	76,277	20,581
15-19	60,083	64,036	65,188	65,169	65,068	71,883	77,770	17,687
20-24	77,393	79,365	73,887	72,740	71,231	69,898	75,719	-1,674
25-34	147,624	163,614	181,876	178,691	171,378	167,827	163,888	16,264
35-44	133,551	142,716	161,562	186,205	204,257	200,583	192,443	58,892
45-54	138,674	134,345	137,487	150,555	169,266	193,623	211,213	72,539
55-64	131,924	139,000	137,180	131,300	135,303	148,720	167,500	35,576
65-69	49,350	54,242	64,741	69,652	64,011	64,621	68,390	19,040
70-74	40,314	46,247	51,926	62,162	67,103	62,045	62,898	22,584
75-79	27,142	31,467	42,109	47,696	57,416	62,324	58,134	30,992
80+	39,862	42,273	50,095	64,871	80,024	98,157	114,465	74,603
0-19	22.0%	21.7%	21.1%	20.9%	21.0%	21.2%	20.9%	33.1%
20-34	22.3%	22.8%	22.4%	20.6%	18.8%	17.5%	17.0%	6.5%
35-54	27.0%	26.0%	26.2%	27.6%	28.9%	29.1%	28.6%	48.3%
55-64	13.1%	13.1%	12.0%	10.8%	10.5%	11.0%	11.9%	27.0%
65-69	4.9%	5.1%	5.7%	5.7%	5.0%	4.8%	4.9%	38.6%
70-74	4.0%	4.3%	4.5%	5.1%	5.2%	4.6%	4.5%	56.0%
75-79	2.7%	3.0%	3.7%	3.9%	4.4%	4.6%	4.1%	114.2%
80+	4.0%	4.0%	4.4%	5.3%	6.2%	7.2%	8.1%	187.2%

High Scenario Population Projection City of Ottawa	2018	2021	2026	2031	2036	2041	2046	Change 2018-2046
Population (mid-year)	1,007,501	1,072,306	1,171,228	1,276,126	1,383,776	1,487,871	1,586,515	579,014
Average annual increase		12,961	19,784	20,980	21,530	20,819	19,729	20,679
Average Annual % Increase		1.3%	1.8%	1.8%	1.7%	1.5%	1.3%	2.1%
Population by Age Group								
0-4	51,018	54,004	65,426	75,169	82,238	85,850	87,490	36,472
5-9	54,870	56,089	58,915	70,441	80,313	87,440	91,123	36,253
10-14	55,696	59,111	60,799	63,877	75,614	85,608	92,853	37,157
15-19	60,083	67,234	68,148	68,411	70,708	81,853	91,427	31,344
20-24	77,393	81,390	81,901	79,144	77,400	78,191	88,244	10,851
25-34	147,624	163,389	185,367	193,116	191,995	188,196	187,766	40,142
35-44	133,551	142,916	163,053	189,864	214,172	223,373	223,205	89,654
45-54	138,674	134,406	138,238	152,933	174,227	201,747	226,424	87,750
55-64	131,924	139,119	137,851	132,778	138,124	153,634	175,340	43,416
65-69	49,350	54,322	65,217	70,623	65,467	66,669	71,329	21,979
70-74	40,314	46,336	52,458	63,323	68,947	64,342	65,759	25,445
75-79	27,142	31,557	42,682	48,900	59,500	65,114	61,201	34,059
80+	39,862	42,432	51,174	67,549	85,071	105,854	124,354	84,492
0-19	22.0%	22.0%	21.6%	21.8%	22.3%	22.9%	22.9%	63.7%
20-34	22.3%	22.8%	22.8%	21.3%	19.5%	17.9%	17.4%	22.7%
35-54	27.0%	25.9%	25.7%	26.9%	28.1%	28.6%	28.3%	65.2%
55-64	13.1%	13.0%	11.8%	10.4%	10.0%	10.3%	11.1%	32.9%
65-69	4.9%	5.1%	5.6%	5.5%	4.7%	4.5%	4.5%	44.5%
70-74	4.0%	4.3%	4.5%	5.0%	5.0%	4.3%	4.1%	63.1%
75-79	2.7%	2.9%	3.6%	3.8%	4.3%	4.4%	3.9%	125.5%
80+	4.0%	4.0%	4.4%	5.3%	6.1%	7.1%	7.8%	212.0%

Appendix 2 – Components of Population Growth by Scenario

Low Scenario Population Projection							
Year*	**Start**	**Births**	**Deaths**	**Natural Increase**	**Net Migration**	**End**	**Year***
2018	1,007,501	9,553	7,205	2,348	19,883	1,029,731	2019
2019	1,029,731	9,893	7,631	2,262	12,634	1,044,627	2020
2020	1,044,627	10,003	7,795	2,207	11,742	1,058,576	2021
2021	1,058,576	10,250	7,963	2,286	10,696	1,071,559	2022
2022	1,071,559	10,496	8,138	2,358	9,645	1,083,562	2023
2023	1,083,562	10,685	8,318	2,367	9,470	1,095,400	2024
2024	1,095,400	10,870	8,477	2,393	9,301	1,107,094	2025
2025	1,107,094	11,047	8,647	2,400	9,141	1,118,635	2026
2026	1,118,635	11,184	8,827	2,357	8,998	1,129,990	2027
2027	1,129,990	11,310	9,018	2,293	8,848	1,141,131	2028
2028	1,141,131	11,412	9,220	2,193	8,703	1,152,027	2029
2029	1,152,027	11,476	9,452	2,024	8,564	1,162,615	2030
2030	1,162,615	11,483	9,695	1,788	8,410	1,172,813	2031
2031	1,172,813	11,469	9,946	1,523	8,257	1,182,594	2032
2032	1,182,594	11,432	10,205	1,227	8,099	1,191,919	2033
2033	1,191,919	11,415	10,470	944	7,931	1,200,795	2034
2034	1,200,795	11,362	10,702	660	7,772	1,209,227	2035
2035	1,209,227	11,263	10,936	326	7,611	1,217,164	2036
2036	1,217,164	11,160	11,171	-11	7,444	1,224,598	2037
2037	1,224,598	11,077	11,404	-326	7,283	1,231,555	2038
2038	1,231,555	11,030	11,632	-602	7,118	1,238,070	2039
2049	1,238,070	10,963	11,843	-880	6,960	1,244,151	2040
2040	1,244,151	10,888	12,047	-1,160	6,793	1,249,784	2041
2041	1,249,784	10,809	12,244	-1,435	6,638	1,254,987	2042
2042	1,254,987	10,747	12,431	-1,684	6,468	1,259,771	2043
2043	1,259,771	10,680	12,609	-1,928	6,300	1,264,143	2044
2044	1,264,143	10,605	12,721	-2,116	6,134	1,268,161	2045
2045	1,268,161	10,540	12,826	-2,286	5,973	1,271,848	2046

* Population figures are mid-year

Medium Scenario Population Projection							
Year*	Start	Births	Deaths	Natural Increase	Net Migration	End	Year*
2018	1,007,501	9,553	7,107	2,446	20,241	1,030,189	2019
2019	1,030,189	9,900	7,484	2,416	14,813	1,047,417	2020
2020	1,047,417	10,399	7,582	2,817	13,910	1,064,144	2021
2021	1,064,144	10,815	7,683	3,132	12,879	1,080,155	2022
2022	1,080,155	11,245	7,790	3,454	11,858	1,095,467	2023
2023	1,095,467	11,543	7,901	3,643	11,731	1,110,841	2024
2024	1,110,841	11,843	8,017	3,826	11,624	1,126,292	2025
2025	1,126,292	12,142	8,144	3,998	11,526	1,141,815	2026
2026	1,141,815	12,408	8,281	4,126	11,434	1,157,376	2027
2027	1,157,376	12,672	8,429	4,243	11,349	1,172,967	2028
2028	1,172,967	12,880	8,587	4,293	11,255	1,188,515	2029
2029	1,188,515	13,049	8,772	4,276	11,177	1,203,968	2030
2030	1,203,968	13,158	8,968	4,191	11,073	1,219,232	2031
2031	1,219,232	13,250	9,172	4,078	10,974	1,234,284	2032
2032	1,234,284	13,321	9,386	3,935	10,857	1,249,075	2033
2033	1,249,075	13,405	9,607	3,798	10,740	1,263,613	2034
2034	1,263,613	13,447	9,840	3,607	10,619	1,277,839	2035
2035	1,277,839	13,433	10,078	3,355	10,497	1,291,690	2036
2036	1,291,690	13,406	10,318	3,089	10,371	1,305,149	2037
2037	1,305,149	13,393	10,557	2,836	10,237	1,318,222	2038
2038	1,318,222	13,413	10,794	2,619	10,098	1,330,939	2039
2049	1,330,939	13,409	11,017	2,391	9,962	1,343,293	2040
2040	1,343,293	13,389	11,236	2,153	9,817	1,355,263	2041
2041	1,355,263	13,361	11,449	1,913	9,676	1,366,851	2042
2042	1,366,851	13,346	11,654	1,692	9,528	1,378,072	2043
2043	1,378,072	13,296	11,851	1,445	9,402	1,388,919	2044
2044	1,388,919	13,238	12,056	1,182	9,335	1,399,436	2045
2045	1,399,436	13,193	12,253	941	9,272	1,409,649	2046

* Population figures are mid-year

High Scenario Population Projection							
Year*	**Start**	**Births**	**Deaths**	**Natural Increase**	**Net Migration**	**End**	**Year***
2018	1,007,501	9,553	7,014	2,539	20,937	1,030,978	2019
2019	1,030,978	10,462	7,346	3,116	17,804	1,051,898	2020
2020	1,051,898	11,174	7,356	3,818	16,590	1,072,306	2021
2021	1,072,306	11,650	7,367	4,282	15,528	1,092,116	2022
2022	1,092,116	12,153	7,383	4,770	14,559	1,111,445	2023
2023	1,111,445	12,539	7,401	5,138	14,508	1,131,091	2024
2024	1,131,091	12,933	7,508	5,425	14,498	1,151,014	2025
2025	1,151,014	13,336	7,626	5,710	14,505	1,171,228	2026
2026	1,171,228	13,718	7,754	5,965	14,521	1,191,714	2027
2027	1,191,714	14,117	7,892	6,226	14,548	1,212,488	2028
2028	1,212,488	14,490	8,041	6,449	14,576	1,233,513	2029
2029	1,233,513	14,824	8,195	6,629	14,607	1,254,749	2030
2030	1,254,749	15,105	8,360	6,746	14,631	1,276,126	2031
2031	1,276,126	15,378	8,534	6,844	14,638	1,297,609	2032
2032	1,297,609	15,640	8,717	6,923	14,645	1,319,178	2033
2033	1,319,178	15,890	8,907	6,982	14,643	1,340,803	2034
2034	1,340,803	16,093	9,174	6,919	14,645	1,362,366	2035
2035	1,362,366	16,227	9,447	6,780	14,630	1,383,776	2036
2036	1,383,776	16,334	9,723	6,611	14,617	1,405,004	2037
2037	1,405,004	16,441	10,001	6,441	14,592	1,426,037	2038
2038	1,426,037	16,573	10,277	6,295	14,556	1,446,889	2039
2049	1,446,889	16,677	10,580	6,097	14,524	1,467,510	2040
2040	1,467,510	16,758	10,878	5,879	14,482	1,487,871	2041
2041	1,487,871	16,821	11,172	5,649	14,439	1,507,959	2042
2042	1,507,959	16,885	11,458	5,427	14,382	1,527,768	2043
2043	1,527,768	16,878	11,737	5,141	14,524	1,547,433	2044
2044	1,547,433	16,868	11,968	4,899	14,667	1,566,999	2045
2045	1,566,999	16,891	12,194	4,698	14,818	1,586,515	2046

* Population figures are mid-year

Appendix 3 – Population in Private Households

Age Group	2016 Census Total Population, Age 15+	2016 Census Population Age 15+ in Private Households	2016 Census % of Population Age 15+ in Private Households	2016 Post-Censal Total Population, Age 15+	2016 Post-Censal Estimated Population Age 15+ in Private Households
15-19	57,190	56,695	99.1%	59,133	58,621
20-24	68,645	68,155	99.3%	73,430	72,906
25-29	63,695	63,245	99.3%	68,873	68,386
30-34	61,670	61,275	99.4%	66,427	66,002
35-39	59,575	59,160	99.3%	63,113	62,673
40-44	62,710	62,225	99.2%	65,183	64,679
45-49	65,960	65,440	99.2%	67,582	67,049
50-54	73,210	72,530	99.1%	74,430	73,739
55-59	66,765	66,020	98.9%	67,968	67,210
60-64	54,990	54,315	98.8%	55,680	54,997
65-69	48,130	47,425	98.5%	48,235	47,528
70-74	33,875	33,110	97.7%	34,269	33,495
75-79	24,600	23,460	95.4%	24,656	23,513
80-84	17,950	15,855	88.3%	17,975	15,877
85+	19,580	12,510	63.9%	19,698	12,585
Total 15+	778,545	761,420	97.8%	806,652	789,261

Source: Statistics Canada, 2016 Census, 2016 Post-censal estimates, City of Ottawa calculations.

Appendix 4 – Census and Estimated Post-Censal Private Households

Age Group	2016 Census Population Age 15+ in Private Households	2016 Census Number of Household Maintainers	2016 Census Headship Rate	2016 Post-Censal Estimated Population Age 15+ in Private Households	2016 Post-Censal Estimated Private Households
15-19	56,695	1,470	2.6%	58,621	1,520
20-24	68,155	13,665	20.0%	72,906	14,618
25-29	63,245	25,290	40.0%	68,386	27,346
30-34	61,275	30,660	50.0%	66,002	33,025
35-39	59,160	31,645	53.5%	62,673	33,524
40-44	62,225	34,095	54.8%	64,679	35,440
45-49	65,440	37,950	58.0%	67,049	38,883
50-54	72,530	43,235	59.6%	73,739	43,955
55-59	66,020	39,290	59.5%	67,210	39,998
60-64	54,315	32,550	59.9%	54,997	32,958
65-69	47,425	28,920	61.0%	47,528	28,983
70-74	33,110	20,360	61.5%	33,495	20,597
75-79	23,460	14,670	62.5%	23,513	14,703
80-84	15,855	10,945	69.0%	15,877	10,960
85+	12,510	9,015	72.1%	12,585	9,069
Total 15+	761,420	373,760	49.1%	789,261	385,580

Source: Statistics Canada, 2016 Census, 2016 Post-censal estimates, City of Ottawa calculations.

Appendix 5 – Descriptions of Dwelling Types

Ottawa Projections	Census Definition	
 Single-detached	Single-detached house	A single dwelling not attached to any other dwelling or structure (except its own garage or shed). A single-detached house has open space on all sides, and has no dwellings either above it or below it. A mobile home fixed permanently to a foundation is also classified as a single-detached house.
	Other single-attached house	A single dwelling that is attached to another building and that does not fall into any of the other categories, such as a single dwelling attached to a non-residential structure (e.g., a store or a church) or occasionally to another residential structure (e.g., an apartment building).
 Semi-detached	Semi-detached house	One of two dwellings attached side by side (or back to back) to each other, but not attached to any other dwelling or structure (except its own garage or shed). A semi-detached dwelling has no dwellings either above it or below it, and the two units together have open space on all sides.
 Rowhouse	Row house	One of three or more dwellings joined side by side (or occasionally side to back), such as a townhouse or garden home, but not having any other dwellings either above or below. Townhouses attached to a high-rise building are also classified as row houses.
 Apartment	Apartment or flat in a duplex	One of two dwellings, located one above the other, may or may not be attached to other dwellings or buildings.
	Apartment in a building that has five or more storeys	A dwelling unit in a high-rise apartment building which has five or more storeys.
	Apartment in a building that has fewer than five storeys	A dwelling unit attached to other dwelling units, commercial units, or other non-residential space in a building that has fewer than five storeys.
	Mobile home	A single dwelling, designed and constructed to be transported on its own chassis and capable of being moved to a new location on short notice. It may be placed temporarily on a foundation pad and may be covered by a skirt.
	Other movable dwelling	A single dwelling, other than a mobile home, used as a place of residence, but capable of being moved on short notice, such as a tent, recreational vehicle, travel trailer, houseboat or floating home.

Source: Statistics Canada, Dictionary, Census of Population, 2016.
Dwelling images, Wood Buffalo Economic Development Corporation

Appendix 6 – Household, Dwelling and Employment Details, Medium Scenario

City of Ottawa	2018	2021	2026	2031	2036	2041	2046	Change 2018-2046
Total Households	**404,437**	**428,900**	**468,050**	**504,739**	**537,133**	**565,524**	**590,583**	**186,146**
Households by Age Group of Head								
<25 years	16,951	17,445	16,384	16,155	15,852	15,762	17,072	121
25-34 years	65,759	72,750	81,572	80,581	77,093	75,524	73,742	7,983
35-44 years	71,766	76,666	86,797	100,000	109,782	107,859	103,457	31,691
45-54 years	80,864	78,318	80,125	87,696	98,609	112,760	123,113	42,249
55-64 years	77,842	82,027	80,973	77,492	79,848	87,757	98,842	21,001
65+ years	91,255	101,694	122,199	142,815	155,949	165,862	174,356	83,101
Total Dwellings	**404,437**	**429,778**	**470,703**	**509,104**	**542,949**	**572,773**	**599,245**	**194,808**
Single-detached	167,934	174,873	187,083	199,923	212,195	223,634	234,050	66,116
Semi-detached	21,612	22,569	24,009	25,237	26,240	27,163	27,987	6,375
Rowhouse	88,169	96,757	111,457	125,736	138,280	148,995	157,904	69,736
Apartment	126,722	135,580	148,154	158,209	166,234	172,982	179,303	52,582
Average annual new dwelling units	-	8,447	8,185	7,680	6,769	5,965	5,294	6,957
Labour Force & Employment								
Population 15+	845,917	897,304	966,053	1,029,042	1,085,057	1,139,682	1,192,422	346,505
Participation Rate	66.7%	65.7%	64.6%	63.7%	63.2%	62.8%	62.5%	-
Labour Force	564,600	589,741	623,891	655,361	685,864	716,007	744,727	180,126
Unemployment Rate	4.6%	4.8%	4.9%	5.0%	5.0%	5.0%	5.0%	-
Unemployed Persons	25,972	28,466	30,571	32,768	34,293	35,800	37,236	11,265
Employed Residents	538,629	561,275	593,320	622,593	651,571	680,206	707,490	168,862
5-Year Absolute Change	-	22,646	32,045	29,273	28,978	28,636	27,284	-
Net In-Commuting	68,785	69,706	71,253	72,800	74,385	75,586	76,392	7,607
Employment in Ottawa	607,414	630,981	664,573	695,393	725,956	755,792	783,883	176,469
Multiple Jobholder Rate	5.6%	5.6%	5.7%	5.8%	5.9%	6.0%	6.1%	-
Multiple Jobholders	30,163	31,431	33,819	36,110	38,443	40,812	43,157	12,994
Total Employment in Ottawa	637,577	662,413	698,393	731,504	764,398	796,605	827,040	189,463

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CONSUMERS COUNCIL OF CANADA

JT1.24

EVIDENCE REFERENCE:

CCC-21 part e
CCC-22 part e
CCC-23 part d

UNDERTAKING(S):

To provide a tabular format of the description of the gross cost estimation approach for commercial, infill and system expansion.

RESPONSE(S):

Attachment JT1.24(A) - Commercial, Infill, and System Expansion - Supporting Data provides the details and description of calculations for the 2026-2030 Commercial Developments, Infill Services, and System Expansion Capital Budgets as described in 2-CCC-21 part (e), 2-CCC-22 part (e), and 2-CCC-23 part (e) respectively. The Ottawa Growth Projections can be found in Attachment JT1.23(B) - Growth Projections for reference to Housing and Employment Growth increases for 2026-2030.

As requested, the tables start with the historical average and include every assumption used to calculate the forecasted 2026-2030 budgets. Upon completing this undertaking it was noticed that a formula capturing the 2021-2023 average included the 2018-2023 average in the starting assumption for both the Infill Services and System Expansion budgets. Commercial Developments did not experience this instance. This additional cell capture equates to $4.5M over the 5 year period, which is approximately 1.21% of the total $369M gross costs requested through System Access from 2026-2030. When comparing to JT1.23, this is a net impact of $3.4M between the three affected programs.

With respect to the Commercial Developments program, discrete projects were summed for known and unknown projects (noted as discrete placeholder), and can be attributed to rows D and C respectively. The discrete placeholder was added based on recent trends in large discrete projects.

With respect to the Infill Program, there were no known or placeholder discrete projects added.

With respect to System Expansion, discrete projects were estimated using known projects and with placeholder projects based on historical trends. This is identified in Row F.

Please note that the discrete project mentioned in JT1.26 has been reclassified from Commercial Developments to System Expansion based on updated project information. This is shown in attachment JT1.24 (A) - Supporting Data as a reduction in the Discrete line under tab Commercial Developments Program and an increase in the Discrete line under tab System Expansion Program.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CONSUMERS COUNCIL OF CANADA

JT1.25

EVIDENCE REFERENCE:

2-CCC-23

UNDERTAKING(S):

Re: 2-CCC-23a, Table A, to provide an expanded version of this table that includes 2023 and 2024.

RESPONSE(S):

Please see updated Table A from interrogatory 2-CCC-23 part (a) expanded to include 2023 and 2024. As mentioned in 2-CCC-23, the 2018-2022 timeframe was chosen for contribution forecasting given the specific characteristics and data availability pertinent to the program. The System Expansion program operates with a smaller data set and requires additional years to ensure the forecast is representative of typical activity. The 2023 data set was deemed unrepresentative due to the limited size of available reference projects. Please also note the representative gross costs were determined using direct costs.

Hydro Ottawa's System Access forecast methodology does not use unit rates to determine baseline spending or contributions. Hydro Ottawa has found unit rate cost projections to be an unreliable measure for accurate financial forecasting due to the inherent variability and unpredictable timing of customer-driven projects. Individual System Access projects frequently have anomalies and inconsistent timelines that would lead to skewed results when forecasting with unit rates. Instead, Hydro Ottawa's forecasting methodology uses cost as a proxy for project volumes based on continuous feedback through project delivery and the tracking of associated risk.

UPDATED Table A – Historical System Expansion Direct Costs and Contributed Capital ($'000 000s)

	Historical Years							Average
	2018	2019	2020	2021	2022	2023	2024	2018-2022
System Expansion (Excluding Discrete Projects) - Gross	$ 4.3	$ 0.9	$ 0.9	$ 1.5	$ 0.7	$ 0.3	$ 0.9	
Contributed Capital (Excluding Discrete Projects)	$ (0.1)	$ (1.0)	$ (0.5)	$ (1.3)	$ (0.5)	$ 0.8*	$ (3.3)	
Contribution Rate	3%	108%	50%	83%	76%	(312)%	385%	64%

*Positive value due to accrual reversal from December 2022

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CONSUMERS COUNCIL OF CANADA

JT1.26

EVIDENCE REFERENCE:

2-CCC-23 Table B

UNDERTAKING(S):

Re: 2-CCC-23a, to provide all of the discrete projects for the forecast period and show both the gross capital and the capital contribution separately for those discrete projects.

RESPONSE(S):

Tables A and B below provide all of the System Expansion discrete projects for the forecast period shown by both gross capital and the capital contribution separately. Please note burdens are included in this response while only direct costs are included in the interrogatory response in 2-CCC-23. Based on historical discrete project trends, one discrete project was added in both 2028 and 2030 as a placeholder and is listed as "Discrete Placeholder." Note that information below that can be used to deduce specific customers' billing information has been redacted.

Table A – System Expansion Discrete Project Gross Capital ($'000 000s)

		Test Years				
Line No.	**Gross Capital**	**2026**	**2027**	**2028**	**2029**	**2030**
1	[redacted][1]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	Discrete Placeholder	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Discrete Subtotal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7	Other System Expansion	$ 2.2	$ 2.1	$ 3.7	$ 2.3	$ 4.7
	Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table B – System Expansion Discrete Project Capital Contribution ($'000 000s)

		Test Years				
Line No.	**Capital Contribution**	**2026**	**2027**	**2028**	**2029**	**2030**
1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	Discrete Placeholder	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Discrete Subtotal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7	Other System Expansion	$ (1.3)	$ (1.3)	$ (2.3)	$ (1.4)	$ (2.9)
	Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[1] [redacted] reclassified from Commercial Developments to System Expansion based on updated project information.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CONSUMERS COUNCIL OF CANADA

JT1.27

EVIDENCE REFERENCE:

2-CCC-23

UNDERTAKING(S):

To provide for the historical period all of the discrete system expansion projects broken out between gross capital and capital contributions.

RESPONSE(S):

Please see Table A and Table B that provide all of the System Expansion discrete projects for the Historical Years (2021-2024) and Bridge Year (2025) shown by both gross capital and the capital contribution separately. Please note burdens are included in this response while only direct costs are included in the interrogatory response in 2-CCC-23. Please also note that information below that can be used to deduce specific customers' billing information has been redacted.

Table A – System Expansion Discrete Project Gross Capital ($'000 000s)

		Historical Years				Bridge Year
Line No.	**Gross Capital**	**2021**	**2022**	**2023**	**2024**	**2025**
1	[redacted]	[redacted]				
2	[redacted]					
3	[redacted]					
4	[redacted]					
5	[redacted]					
	Discrete Subtotal					
6	Other System Expansion	$ 2.5	$ 2.8	$ 1.8	$ 3.3	$ 4.7
	Total	[redacted]				

Table B – System Expansion Discrete Project Capital Contribution ($'000 000s)

		Historical Years				Bridge Year
Line No.	**Capital Contribution**	**2021**	**2022**	**2023**	**2024**	**2025**
1	[redacted]	[redacted]				
2	[redacted]					
3	[redacted]					
4	[redacted]					
5	[redacted]					
	Discrete Subtotal					
6	Other System Expansion	$ (2.2)	$ (2.5)	$ (0.8)	$ (5.6)	$ (3.7)
	Total	[redacted]				

*Balances that show $0.0 or ($0.0) are less than $50K or ($50K)

[1] [redacted] reclassified from Commercial Developments to System Expansion based on updated project information.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CONSUMERS COUNCIL OF CANADA

JT1.28

EVIDENCE REFERENCE:

CCC-34 - Table A; Schedule 2-5-4 Figure 74

UNDERTAKING(S):

To provide the Hydro Ottawa planning forecast 2025 to 2030, in tabular format, in megawatts and in MVAs.

RESPONSE(S):

With regard to Table A of interrogatory response 3-CCC-34, Hydro Ottawa would like to provide a clarification that as noted in Footnote 2 of Table A, it is not the IRRP Forecast; rather, it is the Reference Scenario forecast from the Decarbonization Study. The IRRP Forecast is the Reference Scenario forecast as represented in Table A of interrogatory response 3-CCC-34 combined with committed large load requests identified after the Decarbonization Study reference scenario was finalized.

Hydro Ottawa's Planning forecast derived based on the methodology defined in Section 9.4.1 of Schedule 2-5-4 - Asset Management Process is provided in Table B along with a comparison with the IRRP Forecast and the Reference Scenario submitted in Table A of interrogatory response 3-CCC-34. The IRRP forecast for the years 2026 to 2029 and 2031 to 2034 was prorated since the Reference Scenario in the Decarbonization Study provided forecasts in 5-year intervals starting from 2025. Hydro Ottawa uses a standard power factor of 0.9 for conversion from MVA to MW.

Table B - Forecast Comparison (MW), 2025-2035

Year	Planning Forecast	IRRP Forecast	Reference Scenario Table A-3-CCC-34
2025	1,613	1,635	1,620
2026	1,753	1,732	
2027	1,844	1,899	
2028	1,951	2,143	
2029	2,028	2,300	
2030	2,102	2,463	2,357
2031	2,181	2,599	
2032	2,264	2,752	
2033	2,315	2,877	
2034	2,364	3,009	
2035	2,423	3,134	3,024

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CONSUMERS COUNCIL OF CANADA

JT1.29

EVIDENCE REFERENCE:

1-3-1 Table 8

UNDERTAKING(S):

To expand Table 8 with the historical system capacity from 2015 to 2024.

RESPONSE(S):

Please refer to Table A below.

Table A - System Capacity 2015-2030

Year	System Capacity (MVA)
2015	1,804
2016	1,804
2017	1,837
2018	1,837
2019	1,879
2020	1,879
2021	1,921
2022	2,054
2023	2,054
2024	2,128
2025	2,128
2026	2,228
2027	2,353
2028	2,632
2029	2,640
2030	2,723

Hydro Ottawa notes that the system capacity mentioned in Table 8 of Schedule 1-3-1 had assumed all utility-owned Battery Energy Storage Systems (BESS) would be energized in 2030. However, based on corrections provided in the interrogatory response 2-Staff-111, Table B, the planned energization for the BESS systems is scheduled between 2028 and 2030. The figures in Table A above incorporate this corrected BESS energization schedule. This has resulted in updated system capacity numbers in 2028 and 2029.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CONSUMERS COUNCIL OF CANADA

JT1.33

EVIDENCE REFERENCE:

2-CCC-29 part e

UNDERTAKING(S):

To provide a breakdown as to how the cost developed for the distribution capacity upgrade was informed for Greenbank MTS.

RESPONSE(S):

Interrogatory response 2-CCC-29 part (e) details the cost estimation methodology for distribution capacity upgrade projects. As a part of this undertaking, the cost breakdown and the cost basis for the distribution capacity upgrade project at Greenbank MTS is provided.

As referenced in Section 2.5.2 of Schedule 2-5-8 - System Service Investments, Page 52, Greenbank MTS distribution capacity upgrade was calculated to be $20.0M. This amount can be broken down into two main components; Greenbank MTS Feeder Integration and 8kV Voltage Conversion as detailed in Table A below.

Table A: Greenbank MTS Distribution Upgrade Cost Breakdown

Component	Total Cost	Includes
Greenbank Feeder Integration	$8,250,000	Station Egress, Feeder Line Extensions, Pole Line Upgrades
8kV Voltage Conversion	$11,750,000	Conversion of existing 8kV feeders in the Nepean 8kV Planning region to 28kV
TOTAL	**$20,000,000**	

Further breakdown of these two components is provided as follows:

- **Greenbank Feeder Integration: $8,250,000**
    - **Egress Work: $4,650,000**
        - **Duct Structures:** Two sixteen-duct structures, each approximately 500m long, are planned to extend north and south from the station. With a unit cost of $1500/meter, the total estimated cost for the duct work is $1,500,000.
        - **Underground Egresses:** Six underground egresses were included, three within each duct structure. Each egress was estimated at 500m in length, with a unit cost of $720/meter. For a total length of 3000 meters, the electrical work for these egresses is estimated at $2,160,000.
        - **Supporting Scope:** As outlined in the response to interrogatory 2-CCC-29 part (e), the supporting scope has an allocation of $990,000. This includes other essential components, namely sidewalk reinstatement, manholes, and riser poles. This sum can be further itemized as follows:
            - **Sidewalk Reinstatement:** Approximately 1000m (500m for each duct structure) of sidewalk is slated for reinstatement following duct construction. A unit cost estimate of $750 per meter was utilized, resulting in a total estimated cost of $750,000.
            - **Manholes:** Two manholes were considered (one for each duct structure) at a unit cost of $84,000, for a total cost of $168,000.
            - **Riser Poles:** Three riser poles were considered at a unit cost of $24,000, for a total cost of $72,000.

- **Underground Feeder Line Extension: $3,600,000**
  - A single underground feeder line, approximately 5000 meters long, was proposed to run south of the station. At a unit cost of $720/meter, the total cost for this feeder line extension is $3,600,000.

- **8 kV Voltage Conversion: $11,750,000**
  - The 8kV assets adjacent to Greenbank MTS are proposed for voltage conversion to 28kV, facilitating the integration of Greenbank MTS. A total of $11,750,000 has been allocated and is further itemized into the following components:
    - **Replacing existing poles:** These upgrades are necessary to prepare the existing overhead infrastructure for the future 28kV feeders. A total cost of $1,760,000 was estimated. This estimate was calculated while considering the number of poles that would need to be replaced or upgraded in order to prepare for the voltage conversion. A total number of 64 poles were considered, at a unit cost estimate of $27,500.
    - **Upgrading existing transformers (single phase and three phase):** These upgrades are necessary to facilitate the transfer of existing underground and overhead transformers from 8kV to 28kV systems. A total cost of $840,000 was estimated. This estimate was calculated considering the number of transformers that would need to be replaced in order to prepare for the voltage conversion. A total number of 8 three phase transformers and 64 single phase transformers were considered, at a unit cost estimate of $25,000 and $10,000 respectively.
    - **Upgrading existing cables (overhead and underground):** These upgrades are necessary for upgrading the existing overhead and underground cables. A total cost of $9,150,000 was estimated. This estimate was calculated considering the length of cables that would need to be replaced in order to prepare for the voltage conversion. A total length of 6.8km of underground conductor and 3.3km of overhead conductor were considered, at a unit cost estimate of $1,200 (per meter) and $15,000 (per 50m span) respectively.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION

JT1.34

EVIDENCE REFERENCE:

N/A

UNDERTAKING(S):

(a) To advice the peak load of each of those chargers, in kilowatts;
(b) To advise the peak load of a residential home without an EV recharger

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RESPONSE(S):

As noted in Hydro Ottawa's letter regarding transcript revisions submitted on September 29, 2025, it is Hydro Ottawa's understanding that the undertaking is to demonstrate the peak demand of a single residential home with and without a Level 2 electric vehicle charger. After reading the OEB EB-2024-0115 transcript for Day 1, the exchange between Mr. Landanyi and L. Heuff indicates that Mr. Landanyi is only interested in understanding the difference between the peak demand of a home with and without a Level 2 electric vehicle charger. Therefore, as noted in Hydro Ottawa's letter regarding transcript revisions submitted on September 29, 2025, this undertaking should read "To advise the peak load of a residential home with and without a Level 2 residential charger."

The average residential home of less than 2,000 square feet in Ottawa has a peak demand ranging from 4.5 kW to 11.25 kW. The average peak demand of a Level 2 electric vehicle charger is 3.6 kW. When considering the addition of a Level 2 electric vehicle charger, this results in a peak demand of between 8.1 kW to 14.85 kW.