2024 Natural Gas Achievable Potential Study

Prepared for:

Ontario Energy Board

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List of Acronyms

AESC – Avoided Energy Supply Costs

BYD – Base Year Disaggregation

CFB – Canadian Federal Backstop (federal fuel charge)

CPUC – California Public Utilities Commission

EGI – Enbridge Gas Inc.

EPA – Environmental Protection Agency

IAC – Industrial Assessment Centre

IESO – Independent Electricity System Operator

KO – Kick-off

NYSDEC – New York State Department of Environmental Conservation

PIA – Prescriptive Input Assumption

RNG – Renewable Natural Gas

SCC – Social Cost of Carbon

TRM – Technical Reference Manual (or Technical Resource Manual)

Executive Summary

This document is the final reporting output of the Ontario Energy Board (OEB)'s 2024 Achievable Potential Study (the "2024 APS"). The OEB engaged Guidehouse in April of 2023 to estimate a set of potential natural gas reduction scenarios that might be used to inform the planning of future demand side management (DSM) programming. Guidehouse has previously developed the integrated (gas and electric) 2019 Conservation Achievable Potential Study[1] on behalf of both the OEB and the Independent Electricity System Operator (IESO).

The current study, the 2024 APS, addresses only measures intended to reduce natural gas consumption, and does not include electricity conservation measures, though impacts on provincial electric coincident peak demand (winter and summer) and energy consumption are tracked, given the significant emphasis of the study on questions of the potential for the electrification of Residential and Commercial end-uses.

Introduction

This study has been undertaken at the direction of the OEB in the Decision and Order for EB-2021-0002[2] (Enbridge Gas Inc.'s – EGI's – DSM plan). The critical text from that document that has informed the development of this study is this:

> "*The OEB expects that OEB staff will undertake a new conservation potential study to inform Enbridge Gas's next multi-year DSM Plan, with input provided by the SAG. To guide OEB staff, Enbridge Gas and the SAG, the OEB is interested in at least three scenarios being considered in the analysis: an annual reduction in total natural gas sales year-over-year of 0.5%, 1% and 1.5%. The study should focus on how these levels of annual natural gas reductions can be achieved through DSM programs in the most cost-effective manner while still providing opportunities for all customer segments to participate in DSM programs.*"

The process and methods used by this study are a direct reflection of this instruction.

In particular the implicit importance of close coordination with the Stakeholder Advisory Group (SAG) – of which more is mentioned below – and the development of Achievable potential scenarios that consistently deliver substantial reductions to the existing level of natural gas consumption across each year of the study horizon. It is this direction that drove the need to integrate the modeling of fuel switching (beneficial electrification) with energy efficiency measures, which in previous potential studies had been modeled separately, and to focus in much greater detail on the costs and benefits of electrification.

Based on the direction above, the objectives of this study were to:

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[1] Guidehouse (f/k/a Navigant), *2019 Integrated Ontario Electricity and Natural Gas Achievable Potential Study*, December 2019.
https://ieso.ca/2019-conservation-achievable-potential-study

[2] See Section 4.9, PDF 85 of 149 of
Ontario Energy Board, *Decision and Order: Application for Multi-Year Natural Gas Demand Side Management Plan (2022 to 2027),* Enbridge Gas Inc., EB-2021-0002, November 2022
https://www.oeb.ca/node/3869

- Develop a set of Achievable potential scenarios that deliver annual reductions to the current level of natural gas consumption of 0.5%, 1%, and 1.5%[3] ("…*an annual reduction in total natural gas sales year-over-year of 0.5%, 1% and 1.5%"*[4]

- Do so in close collaboration with the SAG, providing them opportunities to provide feedback on scenario definitions and sensitivities, input assumptions, and draft results (…*OEB staff will undertake a new conservation potential study … with input provided by the SAG)*.

- Develop from this work a set of insights into the most significant opportunities for natural gas reductions through DSM programming, and the uncertainties associated with those opportunities, identified through the modeling and SAG consultation process ("…*undertake a new conservation potential study to inform Enbridge Gas's next multi-year DSM Plan…"*

An Achievable potential study is a comprehensive, but high-level, assessment of sectoral market forces impacting the adoption of measures that reduce natural gas consumption. Its purpose, accordingly, is to identify the most significant opportunities for achieving natural gas reductions through program interventions. An Achievable potential study is not a program planning document.

Understanding this difference is essential context for interpreting the outputs of this study in comparison with the projections provided by DSM planning and assessing the differences between these two documents. These are different tools for different purposes: the potential study to identify the broad trends – to provide an initial "rough sort" of the most significant opportunities for natural gas reductions in the three sectors – and the DSM plan to provide a path for delivery of reductions by identifying the practical barriers to implementation and proposing the methods to breach them.

This interplay between these two efforts is an important reason for the close consultation of the SAG throughout the potential development process. This engagement ensured that SAG members were provided with insight into the development of the assumptions and opportunities to review the draft and final outputs of the study long before the completion of study reporting, and so to consider the insights offered by these results in the DSM plan.

The development of the 2024 APS proceeded approximately sequentially across six tasks:

1. **Base Year Disaggregation.** Specifies the granularity of the study and the distribution of base year consumption volumes across the sectoral end-uses and sub-sectors.

2. **Reference Forecast.** Applies the distributions estimated in the BYD to forecast volumes provided by EGI.

3. **Energy Efficiency and Fuel Switching Measures (Measure** Characterization)**.** Describes the approaches and sources used to define the savings, costs, applicability

[3] As noted in Section 7.1.2, OEB staff, in consultation with members of the SAG, determined that scenarios targeting the maximum Achievable potential ("Max Achievable" scenarios) would deliver greater informational value than the 1.5% targeted scenarios.

[4] Because the current Enbridge reference forecast (after removing DSM) projects growing, rather than flat consumption levels (see Section 3), achieving year-over-year reductions to current levels of consumption of (for example) 0.5% would require savings in each year of more than 0.5% relative to the reference forecast.

and other key measure characteristics that drive potential. This task was the most intricate and the one in which SAG members were most closely involved. The description of measure characterization in the body of this report is accompanied by an appendix (Appendix B) that provides a much deeper dive into the measure-level assumptions applied and the SAG feedback provided on these assumptions. In particular, this section documents some of the most important areas of measure-level uncertainty, and the most important areas of measure-level information where no consensus amongst the SAG could be achieved.

4. **Technical Potential.** Provides an estimate of technically feasible natural gas consumption reductions in each year of the projection period, unconstrained by restrictions of equipment turn-over, cost-effectiveness, or customer economics.

   The purpose of Technical potential is principally to act as a diagnostic tool for assessing the validity of measure savings and technical feasibility assumptions.

5. **Economic Potential.** Provides an estimate of technically feasible natural gas consumption reductions in each year of the projection period, including only measures that are cost-effective from a TRC-Plus perspective in each year of the projection period, unconstrained by restrictions of equipment turn-over, or customer economics. This Section also provides a description of the value streams used to assess system-level benefits and costs, value streams that drive cost-effectiveness.

   The purpose of Economic potential is principally to act as a diagnostic tool for assessing the validity of measure cost and system level cost and benefit assumptions.

6. **Achievable Potential.** Provides the estimated Achievable potential for the core and sensitivity scenarios. The relevant section of this report discusses and interprets the results, and provides a description of the key inputs used to estimate market adoption. Analysis of the estimated potential values by scenario drive this report’s key findings and recommendations.

Base Year Disaggregation and Reference Forecast

The base year used in this potential study is 2022. This was selected as the base year in consultation with SAG members and OEB staff. This year was the most recent available complete calendar year of consumption volume data available at the time the work was undertaken.

It should be noted that the “base year” in this document refers to the year for which observed or estimated consumption data were available to develop the granular sub-sector and end-use disaggregation applied to the reference forecast. This is different from the “starting year” used to define the targeted level of potential that some Achievable scenarios were calibrated to deliver. As noted in Section 7.1.1 the starting year used for setting Achievable scenario targets was 2023.

Within each sector, base year sectoral consumption volumes were disaggregated by sub-sector and end-use. These are all presented at the provincial level without further geographic disaggregation.[5]

[5] This does not mean that estimated potential does not account for geographic climate variation – some space-heating measures distinguish between installations in Northern and South/Central/Eastern Ontario for the purposes of modeling savings and measure uptake.

Three sectors are considered: Residential, Commercial, Industrial. The definitions of these in some cases differs from the 2019 APS. The base year (and the study itself) excludes all natural gas use in the following categories: power production, chemical production feedstock, wholesale not delivered by EGI, and the consumption of "extra-large" volume (ELV) Industrial customers.[6]

The objective of the Reference Forecast task is to extend the 10-year EGI natural gas volumes forecast to cover the 20-year period of analysis, and to disaggregate by sector, sub-sector and end-use. This disaggregation is required as sub-sector and end-use level consumption volumes are important inputs for the potential analysis, both for estimating potential energy efficiency and fuel switching savings, and for interpreting these estimates in the context of the projected baseline.

The reference forecast used directly in potential modeling is referred to as the "APS reference forecast". This is distinct from the EGI forecast of volumes. Although the APS reference forecast is derived from the EGI forecast, it applies several adjustments necessary for its use in this study (e.g., removal of DSM achievement, exclusion of ELV customers from the Industrial sector, etc.), and care should be taken to avoid confusing the two projections.

The 2024 Achievable Potential Study considers the 20-year period from 2024[7] through to the end of 2043. A projection of natural gas consumption volumes absent any programmatic DSM is an essential input to this analysis, providing a baseline against which estimated potential achievement can be compared, and from which estimates of savings may be derived.

Guidehouse's principal role in the Reference Forecast task was to apply the appropriate DSM adjustments (such that the forecast did not reflect the impacts of any future planned programmatic DSM) provided by EGI, and appropriately allocate forecast volumes (and customers, where relevant) by sector, sub-sector, and end-use, based on the BYD consumption shares. Guidehouse has not assumed any material structural changes to the BYD allocation across the forecast period.

Net-to-Gross in the APS

Because the reference forecast excludes the impacts of programmatic DSM, it implicitly accounts for all DSM achievement that would occur "naturally", without any programs.

This means that energy efficiency and fuel switching achievement by "free riders" *is already accounted for in the APS reference forecast.* Since the DSM achievement of free riders is embedded in the reference forecast, incremental achievable potential estimated by this study must necessarily have a net-to-gross value of 1 and be net of all free-ridership. This is consistent with the assumptions and interpretations of both the 2016 and the 2019 APS.

Accordingly, all the estimated program delivery costs (incentive and program administration) associated with the estimated potential are for the costs associated with the *net* achievement and do not account for any free ridership. In using the outputs of this study to develop program designs, planners should consider where to make adjustments to total estimated costs to account for the effects of free ridership, if any is expected.

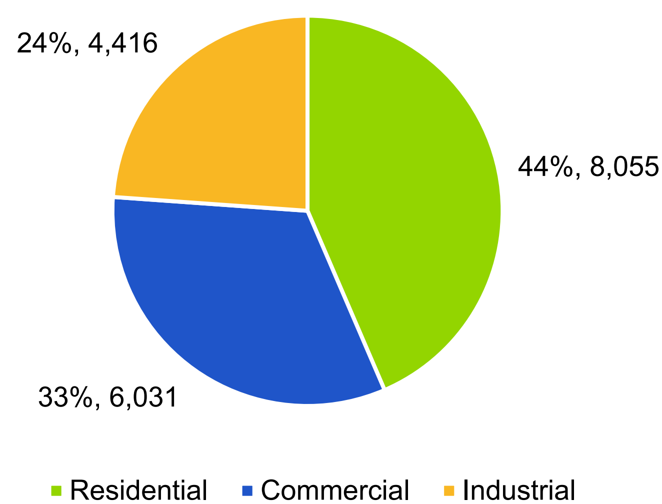
[6] Extra large volume (ELV) customers are those that consume 20 million or more cubic meters of natural gas each, per year (per the data provided to Guidehouse for the Base Year Disaggregation). A SAG member has indicated that this definition may not align with the EGI rate class definitions that the current large volume program is based on.

[7] It is the convention in Ontario to project potential over a period of analysis beginning in the year in which the study was completed or was intended to be completed. For example, e.g., the 2019 APS was published in December 2019 and covered a 20-year period of analysis from 2019 through 2038, and the 2016 APS (Gas) was published in June 2016 and covered a 16-year period from 2015 through 2030.

Base Year Disaggregation Results

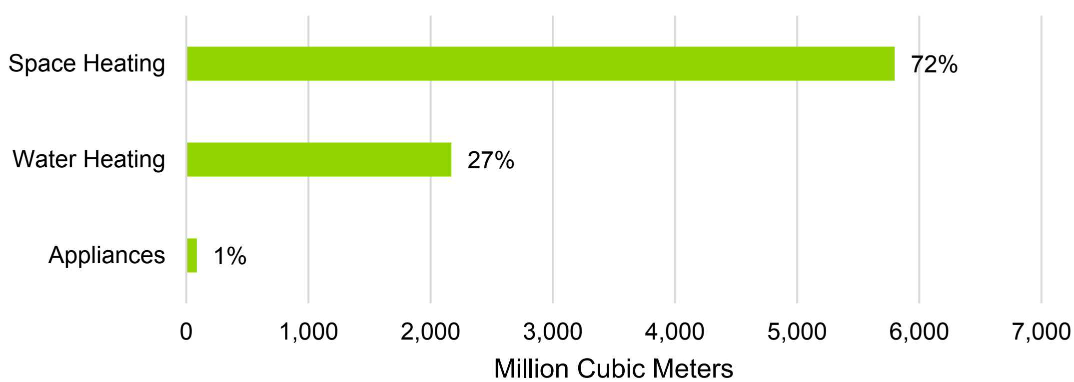
Total base year (2022) consumption across all sectors is approximately 18.5 billion m^3. The distribution by sector is shown in Figure 19 below. Note that the Industrial share below excludes the consumption of ELV customers which accounts for more than half the Industrial non-feedstock gas consumption in EGI's service territory. Multi-residential consumption is, consistent with EGI's tracking data, assigned to the Commercial, rather than the Residential sector.

Figure 1. Base Year Volumes by Sector (Millions of m^3)



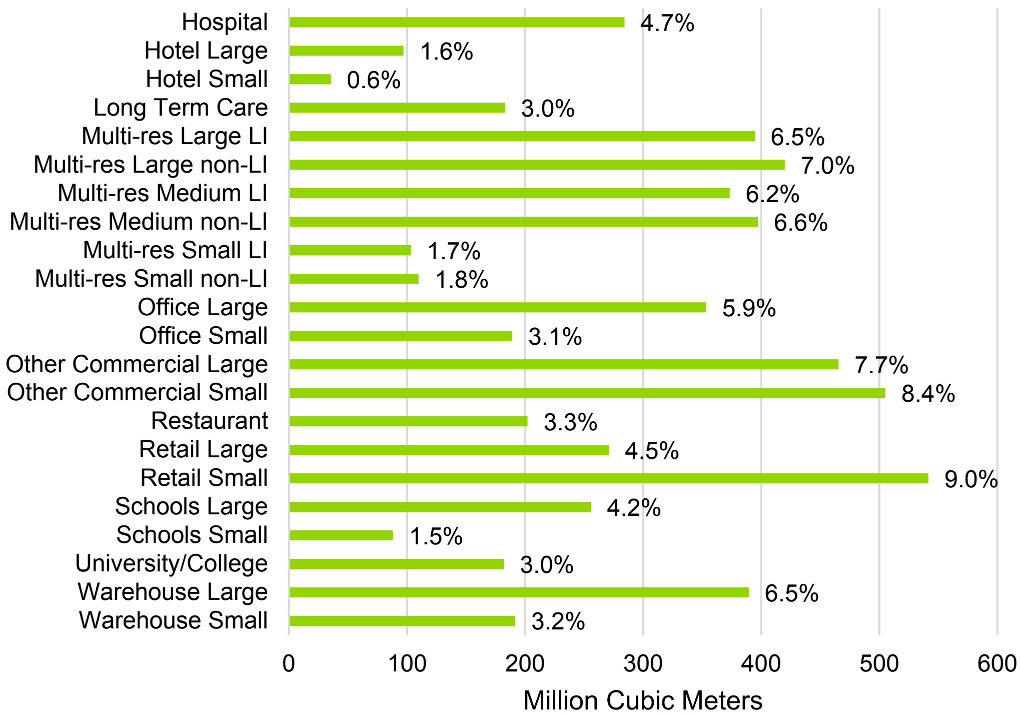
Total Residential consumption in the base year (2022) is approximately 8.1 billion m^3. Total base year consumption volumes (and sectoral share) by end-use are presented below. As would be expected, Space Heating is the dominant end-use.

Figure 2. Residential Base Year Consumption by End-use



Total commercial consumption in the base year (2022) is approximately 6 billion m^3. Total base year consumption volumes (and sectoral share) by sub-sector are presented below.

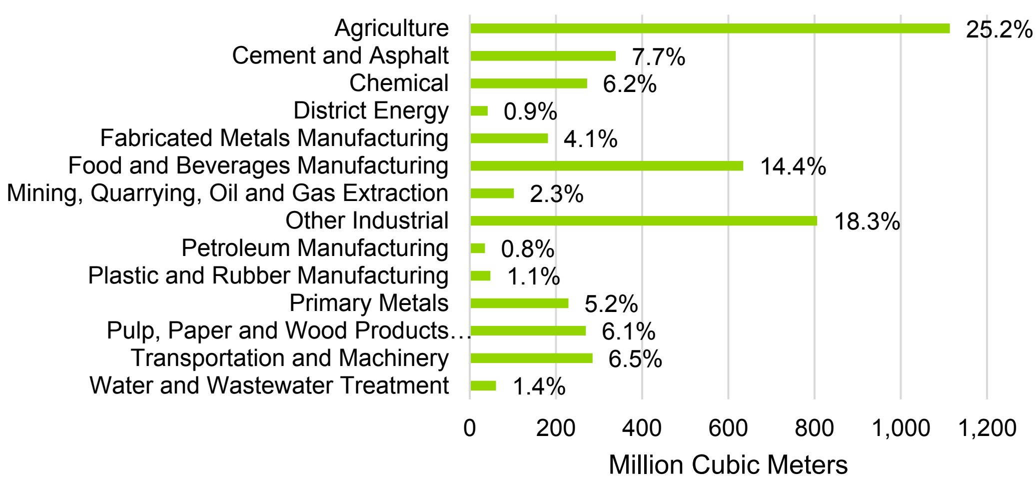
Figure 3. Commercial Base Year Consumption by Sub-Sector



Total industrial consumption in the base year (2022), with the consumption of the ELV customers removed, is approximately 4.4 billion m^3. ELV customers' consumed approximately 5 billion m^3 in the 2022 base year.

Total base year consumption volumes (and sectoral share) by sub-sector are presented below.

Figure 4. Industrial Base Year Consumption by Sub-Sector



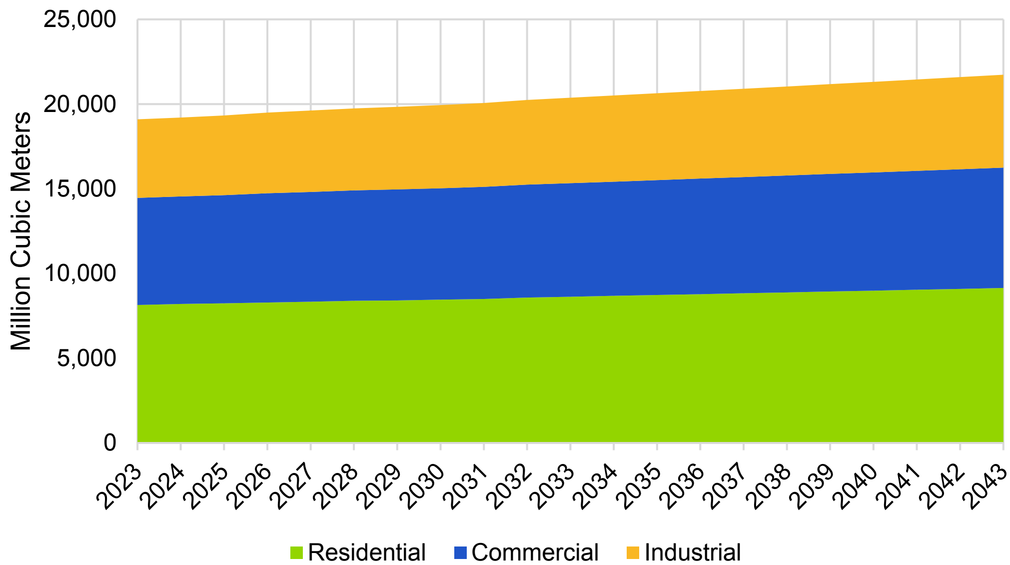
Reviewers must remember that the approximately 65 ELV customers that represent more than half of the non-feedstock gas consumption served by EGI are not included in the distribution above, and so it should *not* be regarded as representative of the province as a whole.

Reference Forecast Results

The underlying distribution of consumption by end-use and sub-sector are held constant using the BYD shares for the length of the period of analysis, so, for the sake of concision, this section does not present a breakdown of sectoral consumption by sub-sector or end-use.

The APS reference forecast for all three sectors is shown below. Total natural gas consumption across all three sectors (after the effects of DSM are removed) is projected to grow at approximately 0.65% per year over the projection period.

Figure 5. APS Reference Forecast by Sector



Measure Characterization

A measure is a technology, process, or project that is implemented to reduce a building's natural gas consumption. Measures may be either energy efficiency or fuel switching. Measures are the building blocks of the achievable potential study. Measure characterization is the process of developing a set of input assumptions to provide estimated values for the measure parameters that drive modeled potential.

The objective of the measure characterization task is to review and compile the necessary input assumptions required to estimate Technical, Economic, and Achievable potential, as described in subsequent chapters. This task is made up of three major components:

- **Measure List Development:** Guidehouse worked with members of the SAG to develop a list of energy efficiency and fuel switching measures for inclusion in the study. The final list of measures, reflecting all the various iterations (e.g., by building vintage, sub-sector, geography, etc.) input to Guidehouse's modeling software included 176, 1,086, and 436 line-items for, respectively, the Residential, Commercial, and Industrial sectors.[8]

- **Measure Characterization:** Guidehouse compiled measure input assumptions, deriving estimates for required measure parameters, including gas savings, electric savings and incremental consumption (fuel switching measures), winter and summer peak electricity demand savings (and increases), incremental measure costs, density, and saturation. Fuel switching measures were considered only for the Residential and Commercial sectors.[9]

- **Measure Review**: Measure inputs received extensive review by members of the SAG and were updated to reflect their feedback. Each sector's measures underwent two initial rounds of review by three sector-specific sub-committees. Measure inputs were subsequently reviewed, discussed, and updated based on feedback provided by SAG members as part of their review of the Technical, Economic, and Achievable potential estimates.

Guidehouse developed the list of measures included in this study based on a review of relevant provincial documentation, consultation with members of the SAG, and with a view to focus efforts on measures most likely to deliver sufficiently meaningful volumes of potential to justify the time required for Guidehouse to characterize them and the SAG to review them.

Key documents informing the development of the list include: the OEB Technical Reference Manuals (TRMs), Enbridge Gas's evaluation reports and filed plans, the 2019 Integrated Ontario Electricity and Natural Gas Achievable Potential Study, and other potential studies. Members of the SAG provided significant input into the selection of measures for inclusion on the list, for example on differentiating between building vintage (e.g., Air Sealing for pre-1974 homes, Air Sealing for homes built 1975 – 2006, etc.), bundling Industrial measures by end-use, excluding measures no longer included in EGI's programs (high-efficiency furnaces), etc.

In the Residential and Commercial sector, measures are all defined individually, and modeled as independent units (though subject to some off-setting interactions – e.g., some measures may compete against others for market share). For the Industrial sector, measures are bundled. Bundling of Industrial measures was supported by a consensus of the relevant SAG sub-committee (which included OEB staff), and SAG member contributed recommendations for the allocation of individual measures to bundles. Bundling was determined to be suitable for the Industrial sector due to granularity of the measure savings estimates, drawn from a database of estimated savings for measures recommended at specific Industrial sites by the Industrial Assessment Center (IAC).

The measure characterization effort consisted of estimating or defining values for more than 50 individual parameters for each measure included in this study. The most critical of these

[8] Only commercially available measures were included in the list. New technologies not yet available in the market were excluded on the basis that there would be insufficient data to characterize them accurately. Projected potential is derived only from measures included on the measure list.

[9] Please see Section 4.2.4.1 for a detailed discussion of the measure characteristics. For most, but not all, measures, the values of key parameters are held constant across the period of analysis. Significant exceptions are identified in Appendix B.

parameters are those that define the value of a measure, and those that define its available market for adoption.

Parameters that define measure value include: annual gas savings, peak winter electricity demand impact (for fuel switching measures), lifetime, and incremental cost. Parameters that define the available market for adoption include the measure's competition group, saturation, density, and technical suitability. Table 9 (Section 4.2.4.1), below defines a selection of the most important measure parameters.

Guidehouse and the SAG members that contributed measure characterization used many sources to develop the estimated measure parameters. Table 10, in Section 4.2.4 presents a summary of the most commonly used sources for measure characterization. Wherever possible, Guidehouse used savings and other parameter estimates published in the OEB's Technical Reference Manual (TRM), referenced below. Savings values for all fuel-switching measures were derived from Base Year Ontario gas consumption data provided by EGI, and closely reviewed by members of the SAG and OEB staff. Fuel switching measures were included only for the Residential and Commercial sectors. Fuel switching measures were not included for the Industrial sector due to constraints in the availability of Industrial fuel-switching measure data. Industrial measures were characterized primarily on the basis of the IAC data noted above. Some members of the SAG noted that reliance on this source for Industrial input data could mean that Industrial energy efficiency potential is understated (see Section 4.2.4.3 and Appendix B for more detail).

In selecting from the available sources, Guidehouse prioritized the use of the OEB TRM, and after this (because of its comprehensiveness, recency, and geographic similarity) the Illinois TRM, and then the other sources as required. SAG member-provided inputs and data were used in preference to other sources when these were uncontested by other SAG members, or where consensus existed. In cases where SAG members disagreed about the validity of an input provided by another SAG member, OEB staff provided direction to Guidehouse as to the input to apply.

Measure inputs received extensive review by members of the SAG and updates were made by Guidehouse to reflect SAG feedback where directed to do so by OEB staff. Each sector's measures underwent two initial rounds of review by one of three sector-specific sub-committees. Measure inputs were subsequently reviewed, discussed, and updated based on feedback provided by SAG members as part of their review of the Technical, Economic, and Achievable potential estimates.

The OEB TRM does not include any electrification measures. As such, the characterization of these measures was developed on the basis of the base year disaggregation (savings), the information in other TRMs or as available on the internet (costs), and the informed opinion of the members of the SAG (costs and applicability). In some cases, some non-electrification energy efficiency measures also required the development of input assumptions based in large part on the informed opinion of members of the SAG.

There is therefore considerable uncertainty attendant to certain aspects of these characterizations. Given that in some cases overall estimated potential can be quite sensitive to these assumptions, OEB staff have directed Guidehouse to document some of the measure assumptions that were subject to debate within the SAG.

A selection of these is presented in Appendix B.

Technical Potential

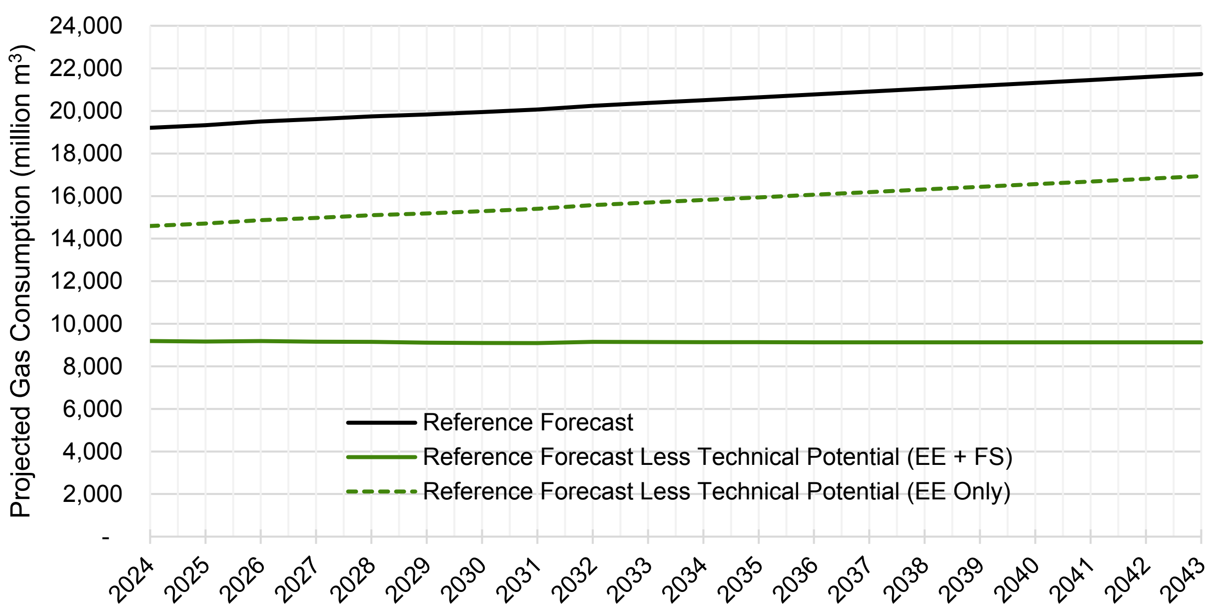
The goal of the Technical potential analysis is to estimate the combined maximum technically feasible reduction to natural gas consumption (given interactions, competition) that may be delivered by the measures characterised as part of the measure characterisation task.

The purpose of Technical potential is primarily diagnostic. Unconstrained Technical potential disregards all questions of cost-effectiveness, limitations on the timing of consumer adoption, or considerations of consumer payback. The most useful insights provided by Technical potential are at the measure-level, helping to identify measures the inputs of which may require review or revision. The importance of Technical potential as a quality control step was previously identified in the recommendations of the 2019 APS.

Technical potential estimates are "unconstrained" by considerations of equipment turnover, with each year treated as independent of the others. What this means is that (for example), the Technical potential in 2030 is an estimate of all savings that are technically feasible in 2030: all retrofit, all replace-on-burnout, and all new measures are replaced in a single year. Technical potential is the energy saving that can be achieved assuming that all baselines can immediately be replaced with their corresponding efficient measure/technology, wherever technically feasible, regardless of the cost, market acceptance, or whether a measure has failed and must be replaced.

The figure below provides a summary comparison of the aggregate estimated Technical potential and the reference forecast. The reference forecast is represented by the black line and the reference forecast less the estimated Technical potential is represented by the solid green line. The dashed green line represents the sensitivity scenario that considers the Technical potential only of energy efficiency measures and excludes fuel switching measures.

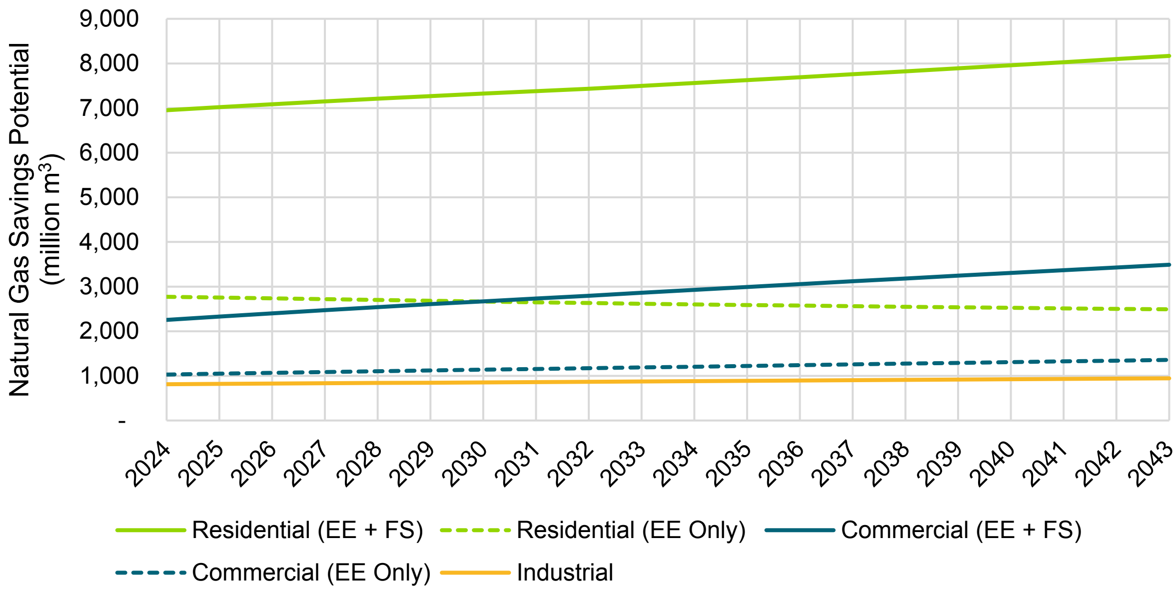
Figure 6. Reference Forecast and Technical Potential



This differs from the 2019 APS in which Technical potential was constrained by equipment turnover, so care should be exercised in comparing the Technical potential of the two studies.

The figure below shows the total estimated Technical potential when including fuel switching (solid lines) as well as under the sensitivity scenario, which considers only energy efficiency measures. No fuel switching measures were considered for the Industrial sector so only a single series is presented for this sector.

Figure 7. Technical Potential and EE-Only Sensitivity Technical Potential by Sector



Because Technical potential presents a snapshot in each year and is not constrained by considerations of equipment turnover, Technical potential begins the series very high. Growth over the period of analysis is a reflection of increasing stock, and thus an increasing number of opportunities of efficient measures.

Economic Potential

The goal of the Economic potential analysis is to estimate the combined maximum technically feasible reduction to natural gas consumption (given interactions, competition) that may be delivered in each year of the period of analysis by the measures that are cost-effective from the Total Resource Cost-Plus perspective adopted by the OEB.

The purpose of Economic potential is primarily diagnostic. Unconstrained Economic potential disregards limitations on the timing of consumer adoption and considerations of consumer payback. The outputs of the Economic potential, when compared to the Technical potential results, assist reviewers in assessing the accuracy and appropriateness of measure-level estimated costs, natural gas savings, and – for fuel-switching measures – the accuracy and appropriateness of incremental electric energy and coincident peak demand impact assumptions.

A key update to the value streams applied for estimating cost-effectiveness in the 2024 APS has been the inclusion of the Social Cost of Carbon (SCC) as the primary source to calculate the present-value cost impact of carbon emissions, instead of the federal fuel charge (sometimes referred to as the "*carbon price*" or "Canadian Federal Backstop" or CFB). Previously, for the 2019 APS, the CFB was used as a proxy to capture the present-value cost impacts of carbon emissions as required by the TRC-Plus perspective. This is discussed in greater detail in Section 6.2.2 of the report.

To better understand the implications of this update, and of the increased importance of fuel switching measures in the modeled measure mix, SAG members recommended that four versions of Economic potential be output. OEB staff directed Guidehouse output the following four versions of Economic potential.

- **EE + FS.** The primary version includes all measures, energy efficiency and fuel switching ("EE + FS") and uses the SCC for cost-effectiveness testing.
- **EE + FS - CFB.** A sensitivity version of Economic potential that includes all measures, but uses the CFB instead of the SCC for cost-effectiveness testing.
- **EE Only.** A sensitivity version of Economic potential that includes only energy efficiency measures and uses the SCC for cost-effectiveness testing.
- **EE Only – CFB**. A sensitivity version of Economic potential that includes only energy efficiency measures and uses the CFB instead of the SCC for cost-effectiveness testing.

A measure is considered cost-effective and included in the estimation of Economic potential where it has a TRC-plus ratio of one or more. The value streams included for cost-effectiveness testing were selected to be consistent with the direction provided by the OEB in its Decision and Order EB-2021-0002.[10]

In addition to measure-specific incremental costs, cost-effectiveness testing considered:

- **Natural Gas Avoided Costs:** The primary benefit stream. The values were provided by EGI.
- **Electric Energy Marginal Costs:** In most cases (i.e., for fuel switching measures) these are a cost. These were drawn from the IESO's 2022 APO.[11]
- **Cost of Peak Capacity:** The incremental cost assumed to be incurred by increases in provincial coincident electric peak demand. This value was drawn from the IESO's IRRP Guide to Assessing Non-Wires Alternatives.[12]

[10] See Section 4.9, PDF 85 of 149 of
Ontario Energy Board, *Decision and Order: Application for Multi-Year Natural Gas Demand Side Management Plan (2022 to 2027),* Enbridge Gas Inc., EB-2021-0002, November 2022
https://www.oeb.ca/node/3869

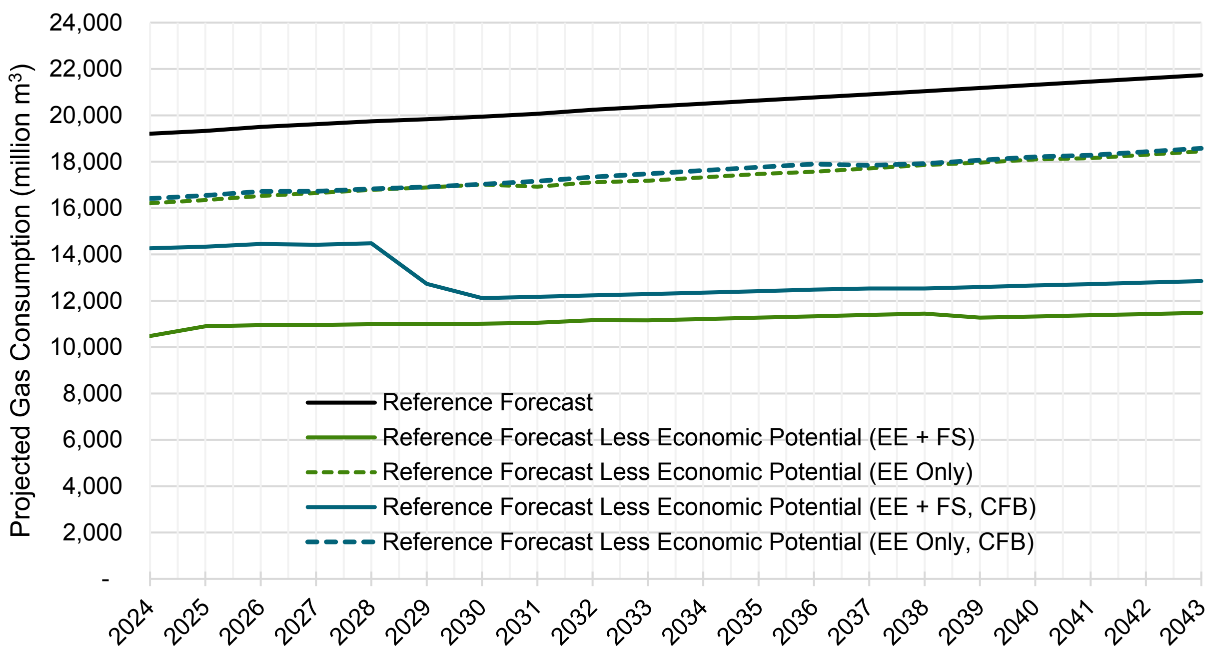
[11] See Figure 47 of
Independent Electricity System Operator, *Annual Planning Outlook Data Tables,* March 2024
https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook

[12] Independent Electricity System Operator, *Integrated Regional Resource Plans: Guide to Assessing Non-Wires Alternatives*, May 2023
Available at: **https://www.ieso.ca/Get-Involved/Regional-Planning/About-Regional-Planning/Planning-Information-and-Data**

- **Value of Carbon:** The social cost of carbon (SCC) was drawn from the Government of Canada[13] and the value of CFB was drawn from EGI.[14]

The figure below provides a summary comparison of the aggregate estimated Economic potential and the reference forecast. The reference forecast is represented by the black line and the reference forecast less the estimated Economic potential is represented by the solid green line. The dashed green line represents the sensitivity scenario that considers the Economic potential only of energy efficiency measures and excludes fuel switching measures. The blue lines represent the sensitivity scenarios that apply the CFB instead of the SCC for cost-effectiveness testing.

Figure 8. Reference Forecast and Economic Potential



The substantial increase in Economic potential (illustrated in the graph above as a reduction in forecast consumption) observed for the EE + FS CFB sensitivity scenario in the period from approximately 2029 through 2030 is due to Residential cold climate heat pumps with gas back up becoming cost-effective (see Section 6.3.3) due to increasing natural gas avoided costs (see Figure 43 in Section 6.2.2.1).

The close proximity of the two dashed lines (i.e., projected consumption less Economic potential from energy efficiency measures only) is an indication of the relatively bi-modal distribution of energy efficiency measure TRC ratios. While many fuel switching measures have TRC values close to one (and so are sensitive to changes in the value of carbon), most energy efficiency measures are either clearly cost-effective, or clearly not. When considering all measures,

[13] Government of Canada, *Social Cost of Greenhouse Gas Estimates – Interim Updated Guidance for the Government of Canada*, April 2023
https://www.canada.ca/en/environment-climate-change/services/climate-change/science-research-data/social-cost-ghg.html

[14] Enbridge Gas, Inc. *Federal Carbon Charge*, accessed February 2024
https://www.enbridgegas.com/ontario/my-account/rates/federal-carbon-charge

approximately one-third of Residential measures modeled are cost-effective with an SCC, whereas less than 20% are cost-effective with CFB. In contrast, 29% of Residential EE only measures are cost-effective under SCC, while 26% are cost-effective under CFB.

One of the most significant differences between the Technical and Economic potential outputs is that while full electrification of space heat dominated Technical potential, *hybrid* space heat electrification dominated Economic potential. This is a result of the impact of the incremental cost of peak electricity generation capacity on measure net system benefits.

Achievable Potential

The goal of the Achievable potential analysis is to estimate the volume of cost-effective and technically feasible natural gas reduction that could be achieved for a given level of spending by the program administrator to encourage measure adoption. The assumed level of program administrator spending (“incentives”) in any given Achievable scenario is defined by the goal of each scenario.

The purpose for estimating Achievable potential is to provide insight into the challenges to (and opportunities for) achieving the natural gas reductions that the OEB specified should be considered in this study, as part of its 2022 Decision and Order.[15] The targets specified in this document are aggressive and require that the study consider fuel switching and energy efficiency simultaneously within its scenarios.

Guidehouse calibrated potential estimation to meet these targeted reductions to absolute natural gas consumption levels, selecting as the starting point the reference forecast value for 2023, for each sector. The starting value of the reference forecast does not include EGI’s projected DSM achievement in that year – the starting value is forecast consumption in 2023[16], absent the forecast effects of any DSM programming.

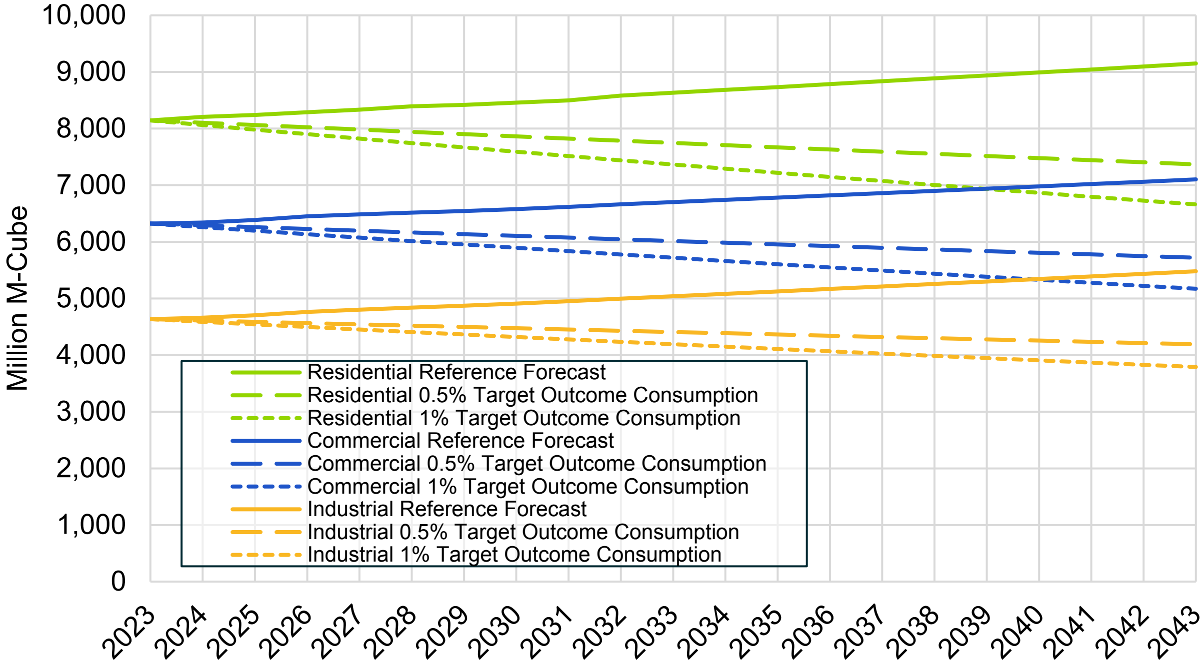
Targets were set independently for each sector, though it was evident from the measure lists (e.g., no Industrial fuel switching measures were included) that significantly more potential was likely to be estimated for some sectors than for others.

The reference forecast for each sector (solid lines) and the corresponding targeted consumption levels reflecting an annual decrease of 0.5% from the year prior (dashed line) and an annual decrease of 1% from the year prior (dotted line) are shown below.

[15] Ontario Energy Board, *Decision and Order: Application for Multi-Year Natural Gas Demand Side Management Plan (2022 to 2027),* Enbridge Gas Inc., EB-2021-0002, November 2022
https://www.oeb.ca/node/3869

[16] The selection of the starting year for establishing the target and the associated period of analysis (from 2024 through 2043) was the subject of discussion within the SAG. Additional detail about the selection of the base year and period of analysis may be found in Section E.1 of Appendix E.

Figure 9. Scenario Consumption Targets



The targeted potential used for model calibration is defined by the distance between the reference forecast (solid line) and the corresponding targeted consumption line (dashed or dotted) line in the plot above.

Achievable potential was estimated for six scenarios:

Table 1. Achievable Potential Scenarios

Scenario	Targeted Year-Over-Year Gas Reduction	Measures Included	Value of Carbon
A	0.5%	EE + FS	CFB
B	1%	EE + FS	SCC
C	Max Achievable	EE + FS	SCC
D	Max Achievable	EE + FS	CFB
E	Max Achievable	EE Only	CFB
F	1%	EE + FS	CFB

Achievable potential models the uptake of measures conditional on estimated payback acceptance curves when incentives are applied to all available measures in proportion to the provincial benefits they offer (see Section 7.2.2 for more details). In reality, DSM programs deliver savings not just through direct payment of incentives, but through rebates, mid-stream programs, and – particularly relevant for the Commercial and Industrial sectors – custom program offerings.

Achievable potential modeling does not, likewise, capture the effects of supply chain constraints for all measures (though these are modeled for some individual measures – see Appendix B), nor can it fully control for all the complexities associated with consumer choice. The Achievable potential modeling, for example, does not explicitly account for the fact that many businesses may be responsible for their natural gas costs, but that their landlords are responsible for procuring and maintaining building equipment. Nor does the modeling control for the partial market capture (and its distortionary impact on consumer decisions) of Ontario's water heater rental oligopoly in the Residential sector and the possible (though unknown) effects on equipment purchases.

Extensive and in-depth assessment of fuel-switching opportunities of the magnitude contemplated by the 2024 APS scenarios is very new in Ontario and has little precedent in the North American potential study literature. The value therefore in this analysis is principally defined by the insights it offers for the development of fuel switching programs and for the collection of additional data that may allow further refinements or expansions of the analysis.

In modeling potential, incentives are applied as a function of net system benefits in order to act as a corrective to the market failures noted above and deliver a more economically efficient provincial outcome. To achieve the targeted level of potential, the modeling team progressively increases the share of net benefits that are returned to consumers as incentives until the scenario target has been reached.

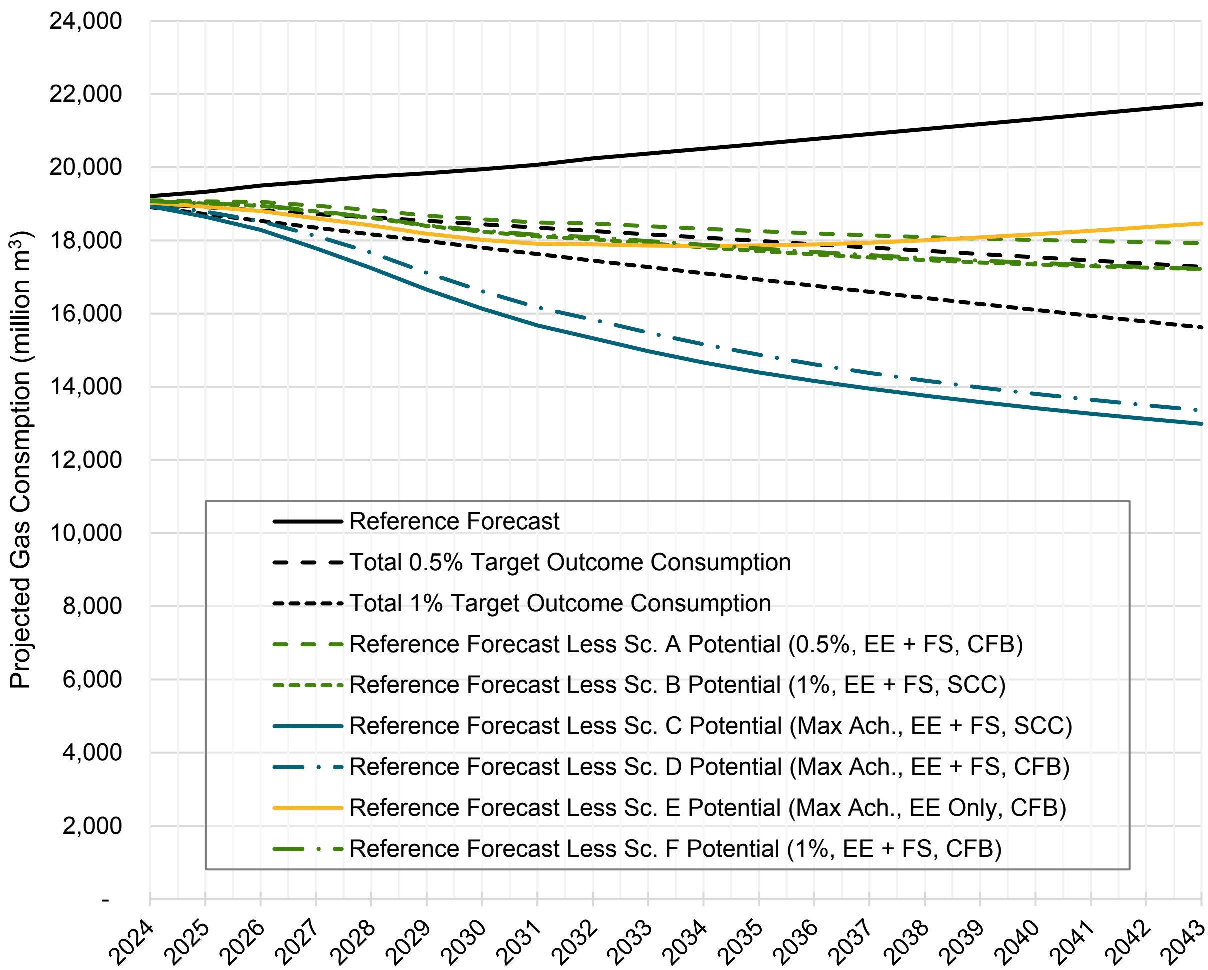
The incentive for a given measure cannot exceed its net system benefit (i.e., present value of lifetime avoided carbon and natural gas benefits, net of incremental electricity and peak capacity costs), nor can it exceed the incremental measure cost.

The figure below provides a summary comparison of the aggregate estimated Achievable potential by scenario, the reference forecast, and the two targeted levels of consumption targeted by Scenarios A, B, and F (i.e., a 0.5% and 1% year-over-year reduction in consumption, as illustrated in Figure 52).

- **Reference Forecast.** The reference forecast is represented by the black line.
- **Potential Targets.** The dashed and dotted black lines, represent (respectively) the targeted consumption related to a 0.5% year-over-year reduction in volumes and a 1% year-over-year reduction in volumes.
- **Reference Forecast Less Achievable Potential**
    - The three dark green lines represent the reference forecast less Achievable potential in one of the targeted reduction scenarios.
    - The dotted dark green line represents Scenario A, and
    - The dashed and dot-dashed green lines represent Scenarios B and F (these two are nearly the same and difficult to distinguish from one another in the graph).
    - The blue lines represent Max Achievable scenarios that include fuel switching, the solid blue line representing the Max Achievable estimated using the SCC value for carbon and the dot-dashed blue line representing the Max Achievable scenario estimated using the CFB value for carbon. The yellow line represents the estimated potential for the EE-only Max Achievable scenario.

In the figure below, as in subsequent figures, significant amounts of data are presented, and distinguishing individual series from one another may sometimes be challenging. All of the data underlying these charts are available within Appendix X2 and may be helpful to reviewers in interpreting the figures in this section of the report.

Figure 10. Reference Forecast, Targeted Consumption, and Achievable Potential



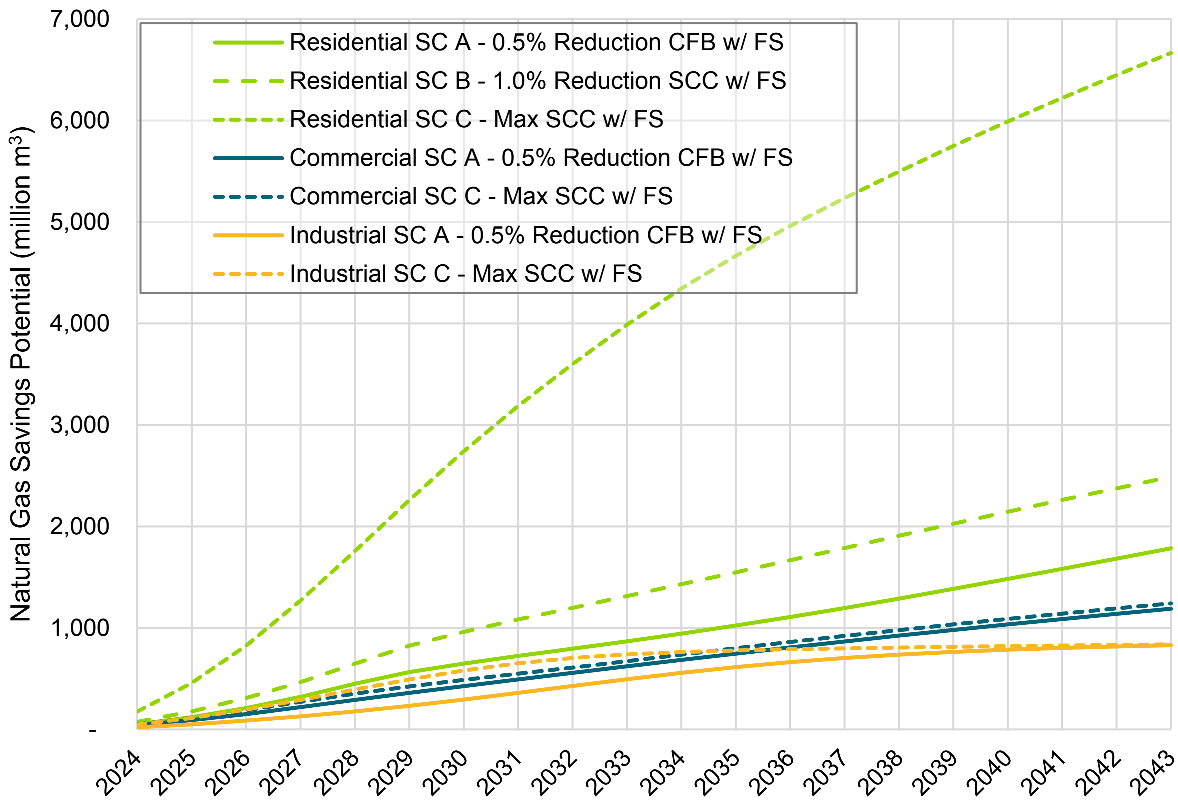
The gap between the Scenario B and F lines (dark green, dotted and dash-dotted respectively) and the dotted black target line for the 1% targeted consumption level is considerably greater in both absolute and relative terms than the gap between the Scenario A line and the 0.5% targeted consumption level (dashed black line). This is due to the Commercial Achievable potential in Scenarios B and F failing to reach the target, largely due to the very limited technical suitability of many Commercial fuel-switching measures. This result is described in greater detail in Section 7.3.1 below. Context for the technical suitability (and other questions of applicability) related to Commercial fuel switching measures is provided in Section B.3 of Appendix B.

The Max Achievable scenarios that include fuel switching (blue lines) do result in levels of consumption that are much lower than the more aggressive targeted level (i.e., the 1% year-over-year reduction illustrated by the dotted black line). This result is driven by the estimated

Max Achievable potential for the Residential sector, in which considerable potential exists beyond that achievable when targeting the 1% year-over-year reduction in total consumption.

The figure below compares a selection of Achievable potential scenarios across the three sectors.

Figure 11. Achievable Potential Scenarios by Sector



Within each sector some scenarios' output potential values that are very similar and so are not shown in this inter-sector comparison.

The key features of the outputs displayed above include:

1. **Residential Dominance.** Residential potential in the three most critical scenarios (A, B, and C) is higher than any other sector's potential regardless of scenario. The most significant contributor to the dominance of the Residential sector is the wide applicability of fuel switching measures in this sector.

2. **Clustering of Commercial Scenario Potential.** Scenario A (0.5% target) and Scenario C (Max Achievable) estimate potential series are very close to one another. The combined effects of very low technical suitability factors assumed for Commercial electrification measures (see Section B.3.10), exacerbated by the impacts on customer bills of peak demand charges means that there is virtually no adoption of full electrification of space heating in existing buildings. The fact that hybrid solutions are considered only for smaller-sized building sub-sectors also substantially limits the

modeled adoption of such measures. The proximity of these two scenarios outcomes indicates that incentives in Scenario A need to be set at or near their maximum values to attain the targeted potential.

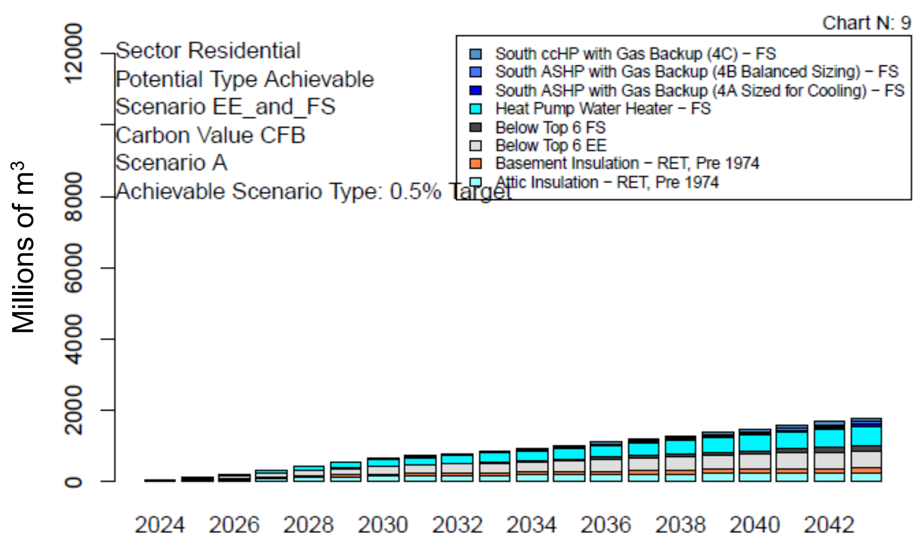
3. **Convergence of Industrial Potential Scenarios.** Scenario A (0.5% target) and Scenario C (Max Achievable) converge on approximately the same potential by the end of the period of analysis. This is a result of the measures included in the analysis, derived from the IAC database, which are very nearly all cost-effective, and which do not include any fuel-switching measures. Some members of the SAG have noted that this outcome, and the underlying methods used to develop the IAC database, may indicate that Industrial potential is understated (see Section 4.2.4.3 and Appendix B for more detail).

Reviewing measure-level potential can be challenging given the number of measures (and their various iterations) considered in the study.

To assist OEB staff and members of the SAG with their review of estimated potential, Guidehouse developed a series of diagnostic plots. These plots aggregate measure savings across sub-sectors and display only the savings for top six highest savings measures, on average, across the first ten years of the period of projection. The potential for all remaining measures is aggregated into two categories: “Below Top 6 EE” for energy efficiency measures, and “Below Top 6 FS” for fuel switching measures.

The figure below shows the measure-level potential diagnostic plot for the Residential sector for Scenario A. Recall that the “top six” measures for which potential are shown are the measures with the highest average potential across the first ten years of the period of analysis.

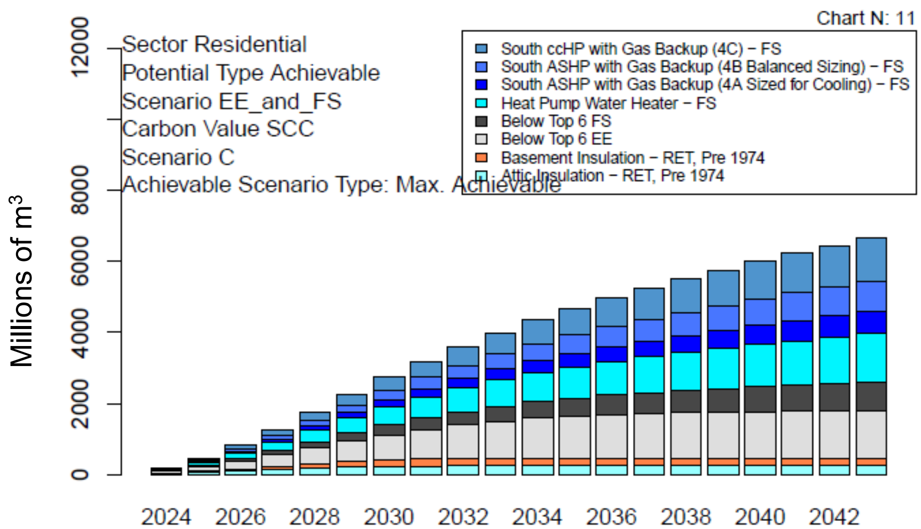
Figure 12. Residential Measure-Level Achievable Scenario A Potential (0.5% Target, EE + FS, CFB) – Top Six Measures (millions of m^3)



By far the single greatest contributor here is the heat pump water heater. This measure benefits from being technically suitable for a very high proportion of single-family homes, with a relatively modest incremental cost compared to the bill savings it offers, and – since it offers significant carbon and avoided gas benefits – considerable incentive “headroom”. This measure was the subject of considerable debate amongst SAG members, and a number of adjustments were applied to this measure based on that feedback, as documented in Section B.3.4 of Appendix B. Hybrid space-heat fuel-switching delivers much of the remaining fuel-switching potential.

The figure below shows the measure-level potential for the Max Achievable potentials scenario for the Residential sector estimated with the social cost of carbon.

Figure 13. Residential Measure-Level Achievable Scenario C Potential (Max Achievable, EE + FS, SCC) – Top Six Measures (millions of m³)



Maximizing incentives to equal 100% of measures' net system benefits results in a substantial increase in measure adoption, most notably for the hybrid fuel switching measures. Of these options 4C, the cold climate heat pump sized for heating with a gas back-up attains the most market share.

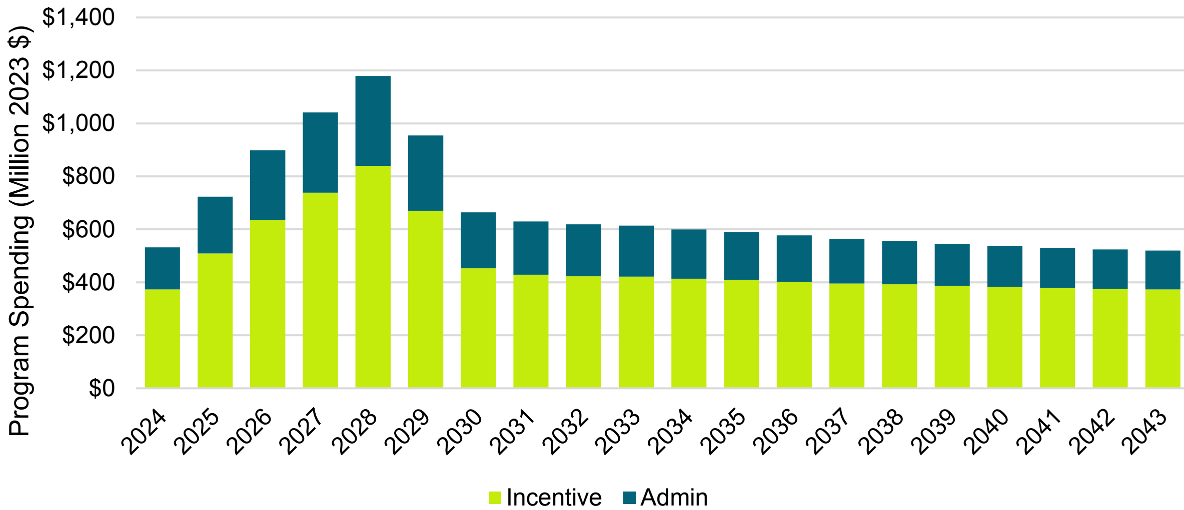
The costs of attaining the potential in the scenarios modeled in this study are considerable. The figure below shows the estimated annual incentive and program administration costs associated with the potential estimated for Scenario A. Total incentive costs across all sectors peak at $800 million in 2028, with total estimated program costs in that year reaching nearly $1.2 billion.

To help reviewers contextualize this cost, the OEB approved a budget of $167 million for EGI's 2023 DSM program[17], and the Ministry of Energy approved a budget of $1.034 billion over 4 years for the IESO's 2021-2024 electricity conservation programs.[18]

[17] Ontario Energy Board, *Decision and Order: Application for Multi-Year Natural Gas Demand Side Management Plan (2022 to 2027),* Enbridge Gas Inc., EB-2021-0002, November 2022
https://www.oeb.ca/node/3869

[18] Executive Council of Ontario, *Order in Council*, O.C. 1314/2022, approved 2022-09-29
Available at: **https://www.ieso.ca/en/Corporate-IESO/Ministerial-Directives** (September 29, 2022: "Expansion of the 2021 – 2024 Conservation and Demand Management Framework"

Figure 14. Scenario A Estimated Annual Program Costs



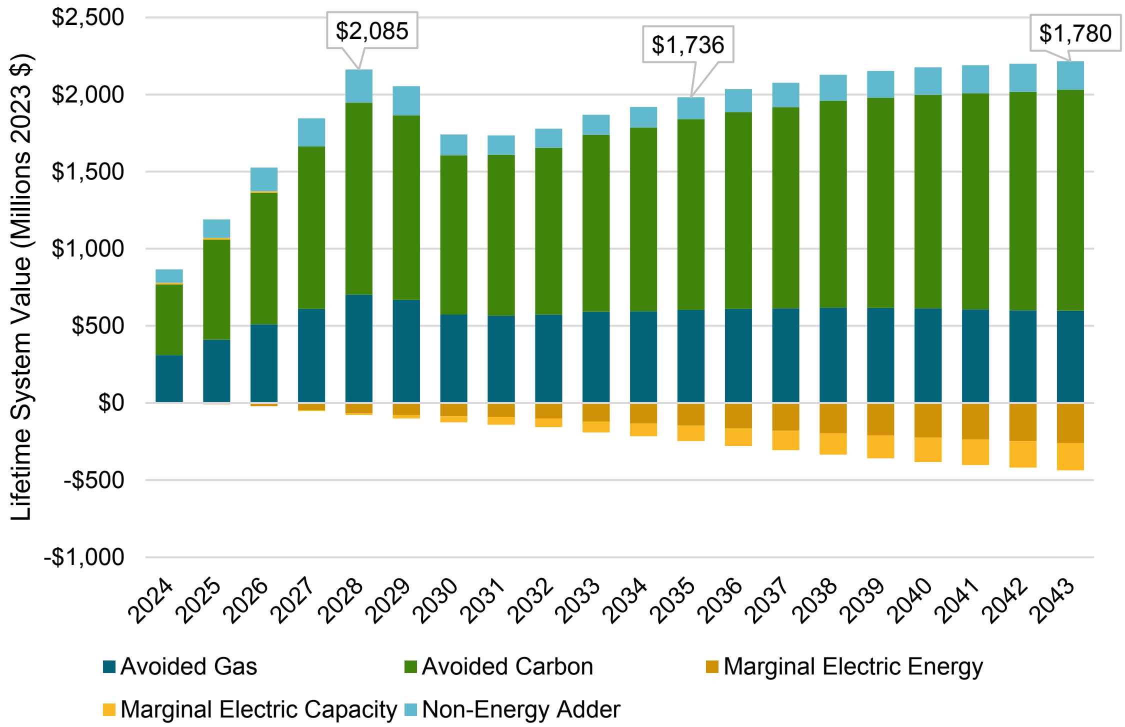
The shape of annual costs (increasing through 2028, then declining to a steady state) is related to the goal of adjusting incentives such that by the end of 2028 the targeted annual consumption values were being achieved. Potential also becomes less costly to acquire in later years as a variety of supply chain constraints loosen (see Appendix B) for those measures to which they were applied, and increasing market penetration by measures means a greater share of the equilibrium market share for each measure is attained.

Program administrator costs are significant. But so too are the benefits. The figure below shows the system-level value streams derived from Scenario A[19], across all three sectors. This includes both benefits, and costs. The net system benefits for the three example years are presented in the call-out boxes below.

The values shown in this graph represent the present-value lifetime value of the incremental measures adopted in the given year. In this way they correspond to – and can be directly compared with – the program administrator costs shown in Figure 68. Scenario A delivers present value program administrator benefits of nearly $2.1 billion in 2028, at a program administrator cost of approximately $1.2 billion.

[19] Scenario A targets a 0.5% year-over-year reduction in natural gas consumption, relative to 2023 volumes.

Figure 15. Scenario A Estimated Annual Net System Benefits



Findings

This study's key findings related to each of the key tasks of the study are presented below. This is not a comprehensive list of all outcomes and conclusions from the analysis but is rather a selection of the most important findings from this work, findings that have motivated the recommendations provided below.

1. **Base Year Disaggregation.** Because this study could not consider the energy efficiency or fuel switching potential of ELV customers responsible for nearly a quarter of Ontario's natural gas consumption in 2022, then, all else equal, the estimated potential values should be regarded as understated.

2. **Reference Forecast.** Achieving reductions to the absolute level of natural gas consumed in the province will require a significant expansion of the numbers and ambition of the programs designed to do so. The forecast annual growth rate of consumption of 0.6% (absent any DSM programs, and assuming continuing growth of new customers) means that to achieve absolute reductions to current levels of gas consumption (as specified in the OEB's guidance for this study), increasing – and substantial – volumes of gas consumption must be eliminated in each year.

3. **Measure Characterization.** The OEB Technical Resource Manual[20] does not include any fuel-switching measures. Completing measure characterization (in particular

[20] Ontario Energy Board, *Natural Gas Demand Side Management Technical Resource Manual*, Version 8.0, April 30, 2024
Available at: **https://engagewithus.oeb.ca/natural-gas-conservation-evaluation-advisory-committee**

estimating incremental costs and Technical Suitability factors) for such measures depended in large part on the qualitative judgements of members of the SAG. The final inputs used for potential estimation reflect available public or proprietary data, adjusted based on feedback provided by members of the SAG. These inputs are a major source of uncertainty for this study.

4. **Technical Potential**

   - *Fuel-Switching.* Technical potential with fuel-switching included is more than twice as high as Technical potential without fuel-switching considered.

   - *Industrial Potential.* Industrial potential is, as a share of the reference forecast, lowest of all sectors even when considering only energy efficiency. The Industrial sub-sectors are, even more so than the Commercial sub-sectors, highly idiosyncratic in their building, equipment, and energy-using process characteristics. This presents a major data collection challenge for bottom-up "widget-based" potential studies, particularly given the sometimes commercially sensitive nature of the information needed to identify energy efficiency and fuel switching opportunities, and likely results in potential that is understated for this sector.

5. **Economic Potential**

   - *Fuel-Switching Cost-Effectiveness Over Time.* Fuel switching measures tend to become more cost-effective over time. The pattern for measures that have winter peak electricity impacts is for cost-effectiveness to decrease steeply as the year in which Ontario transitions from summer to winter peaking (assumed to be 2036[21] for Economic potential) approaches, bottoming out in the transition year. After this, the gradually increasing value of the benefit streams (avoided natural gas and avoided carbon costs) substantially improves the cost-effectiveness of electrification measures that also deliver substantial efficiency improvements.

   - *Sensitivity of Potential to the Definition of Peak Demand.* In this study, peak electricity demand impacts have been valued at $144 per kW-year in constant 2023 dollars, and assumed to apply to incremental electric demand observed in the very small number of hours exhibiting characteristics (e.g., extreme temperatures) consistent with those used for projecting provincial peak demand for system planning. These assumptions were chosen in consultation with the IESO such that they should be consistent with direction provided by that agency in its IRRP Guide to Assessing Non-Wires Alternatives for the economic analysis. Definitions of peak demand that cover more hours (with lower value) could impact the cost-effectiveness of some partial and full electrification measures.

   - *Residential Water Heating.* With the assumptions in place in this study, Residential water heating fuel switching is only cost-effective when accounting for the efficiency gains provided by heat pumps; fuel switching to standard efficiency storage water heaters is not cost-effective..

[21] Assumption drawn from the IESO 2022 Annual Planning Outlook. The 2024 Annual Planning Outlook, published only after the completion of Economic potential, has revised the IESO's estimate, identifying that Ontario could begin to experience winter peaks as early as 2030.

- *Commercial Space Heating.* Cost-effective Commercial space-heating electrification opportunities are principally limited to smaller buildings, and more substantial for new construction than for existing buildings. The costs of Commercial space-heating electrification are, as documented in Appendix B, highly uncertain, and likely to vary considerably across the building types represented in different sub-sectors. Costs are, however, certainly lower for electrifying new construction than replacing gas-fired systems in existing buildings. This is reflected in the Economic potential which is higher for NEW measure types than it is for ROB measure types (as a share of the reference forecast), indicating that the most significant opportunity for cost-effective electrification of Commercial buildings lies in new construction.

- *The Value of Carbon Matters.* In the 2019 APS, the federal fuel charge (the carbon federal backstop, CFB) was used as a proxy for the value of avoided carbon. An enhancement to this study was the use of the social cost of carbon (SCC), aligning potential cost-effectiveness testing with practice in New England states, New York, New Jersey, and many others.[22] The SCC provides a more accurate estimate for the long-term costs of incremental emissions to Ontario, and, though it is higher than the CFB, the U.S. EPA has noted that it "*likely underestimate the marginal damages from GHG pollution*." (see Section D.2 of Appendix D for more details).

6. Achievable Potential

- *Aligning Incentives with Net System Benefits.* The 2024 APS has not excluded measures that are not individually cost-effective from Achievable potential. All measures are included, but incentives (i.e., program administrator potential acquisition costs) are scaled by measure to reflect the net system benefits these measures offer, rather than – as is sometimes the case – as some share of the measure's incremental cost. Despite not excluding non-cost-effective measures,[23] the estimated Achievable potential is, at the portfolio level, cost-effective. As described in Section 7.2.2, the net-benefits-derived incentive setting approach motivates economically efficient measure uptake in aggregate by aligning individual and provincial benefits. This avoids the necessity of arbitrarily constraining potential by not considering the benefits offered by measures that are – by themselves – not *on average* cost-effective but could be cost-effective for a sub-set of relevant customers.

- *Achieving the OEB's Targets.* The 1% reduction target scenario specified by the OEB for the potential study can be achieved *only* through substantial amounts of fuel-switching. The 0.5% reduction target scenario can be achieved without fuel switching through the late 2030s only when incentives and non-economic

[22] See for example:
Efficiency Vermont, *Analysis of State Approaches to Cost-Effectiveness Testing – Efficiency Vermont R&D Project: Cost-Effectiveness Screening Tests*, December 2021
https://www.efficiencyvermont.com/Media/Default/docs/white-papers/Analaysis_of_State_Approaches_to_Cost-Effectiveness_Testing.pdf

[23] Note that it is possible for a measure to not be cost-effective from a TRC-Plus perspective, but still offer significant net system benefits. Net system benefits are calculated using avoided carbon and natural gas costs (the benefits) and incremental electric energy and coincident peak capacity costs (the costs). In contrast, in the TRC-Plus calculation, these net system benefits are compared against a participant's (private) incremental equipment cost.

adoption factor assumptions are set to their maximum values (i.e., as in Scenario E).

- *Residential Space-Heating Electrification.* Residential hybrid space-heating electrification is a cost-effective way to substantially reduce gas consumption and carbon emissions.
- *Residential Water-Heating Electrification.* The heat pump water heater is the Residential measure with the largest Achievable potential. This is reflective of the relatively modest incremental cost of the measure, and the substantial net system benefits which flow through to incentives, both of which improve customer economics and projected uptake. Cost-effectiveness is, however, sensitive to assumptions about how much space-heating must be “cannibalized” to offset system waste cooling and the estimated magnitude of incremental peak demand. Guidehouse’s adoption modeling does not impose any assumptions about Ontario’s water heater rental oligopoly and how that could impact consumers’ equipment choices, another factor impacting uncertainty.
- *Residential Envelope Improvements.* Envelope improvements for older residential buildings offer substantial energy efficiency potential.
- *Commercial Electrification.* Considerable uncertainty exists around issues impacting the practicality and cost of the electrification of Commercial space-heating in particular. These issues were the subject of substantial SAG feedback, with one SAG member contending that even hybrid electrification (i.e., with gas back-up) of anything larger than very small businesses is a massive retrofit incurring substantial infrastructure costs and custom engineering. These concerns are reflected in both the estimated Technical Suitability of these measures and the incremental measure costs. The diversity of system configurations and combinations contribute substantially to uncertainties regarding the reasonable (and mean) for incremental equipment, installation, and labour costs in existing buildings. As noted above, such uncertainties are less of a factor for new construction (though still a non-trivial consideration).

Recommendations

Based on the extensive analysis carried out in this study, and that analysis’ findings, Guidehouse has developed three sets of recommendations:

1. Process Recommendations – Successes to Retain
2. Process Recommendations – Improvements to Consider.
3. Implementation Recommendations – Insight from the Study Findings

The first two sets of recommendations are related to the process of potential estimation itself. These identify the elements of the modeling and study development process that were clear successes in terms of improving the quality and usefulness of the study, as well as some of the lessons learned along the way for ways in which future studies could be improved.

The third set provides recommendations for implementing the actions necessary to acquire some of the potential estimated in this report. It is the provision of these insights that is intended, in the words of the OEB in its Decision and Order EB-2021-0002, "*to inform Enbridge Gas's next multi-year DSM Plan*" that is the core purpose of the potential study.

Process Recommendations – Successes to Retain

- *Stakeholder Consultation.* Close and frequent engagement with a set of SAG subcommittees unambiguously improved the quality of the study and the usefulness of the insights it provided. For future potential studies OEB staff should consider developing a formal time-bound process for resolving stakeholder disputes, and based on the lessons of this study, consider the most efficient way to communicate and resolve written feedback in a transparent and well-documented way.

- *Transparency of Inputs and Outputs to Stakeholders.* The full benefit of SAG stakeholder review is attainable only when measure-level model inputs (e.g., savings values, estimated costs, applicability factors) and estimated potential outputs (at all available levels of granularity) are available for review in a comprehensive and transparent manner. Providing full model input measure characterization transparency to the SAG was a significant logistical challenge.

  The volume of model inputs and outputs also proved to be a challenge for SAG members to review comprehensively, particularly those individual members of the SAG without extensive teams of support personnel. Guidehouse recommends that OEB staff consider, for future studies of this nature, whether it might be prudent to engage a small number of technical support personnel to assist the relevant SAG subcommittee members with their review of the many inputs and outputs that make up a potential study.

- *Coordination with the IESO.* The assistance of the IESO was essential for the 2024 APS. IESO staff provided Guidehouse and the OEB with essential input values related to the consumer cost of power (used to estimate customer economics and payback), provided direction regarding the use and definition of coincident peak demand impacts and the consideration of the carbon costs associated with incremental electricity generation.

  OEB staff should consider whether the IESO should be asked to play a larger role in future work by the OEB considering the cost-effectiveness of beneficial electrification. The inclusion in the SAG technical sub-committee of a representative of the IESO, particularly one that could use their internal network to identify the appropriate IESO experts to weigh in on issues related to electricity system costs, would likely improve the robustness and usefulness of the study outputs.

Process Recommendations – Improvements to Consider.

- *Update and Maintain the Technical Resource Manual*. Guidehouse strongly recommends that the OEB consider updating its TRM to include fuel switching measures. The Guidehouse team further recommends that OEB staff consider starting from the values developed for this study to take advantage of the work already completed in identifying and applying sources of data. These values should be reviewed by stakeholders and the OEB at regular intervals to ensure that they remain up to date and reflect the best available locally specific information.

- *Non-Residential Data Collection*. Guidehouse recommends that the OEB consider undertaking a prioritized baseline study of non-Residential sub-sectors to improve the quality of the data available to identify natural gas reduction opportunities in Ontario. Guidehouse recommends that in developing this effort, OEB staff explicitly recognize that such a study cannot be comprehensive, and instead to focus on a few end-uses and equipment types, or combinations of equipment types and sub-sectors, where improved information will be most impactful. Guidehouse recommends that OEB staff consider setting their information collection priorities to help support utility DSM planning considerations, and in consultation with program delivery staff and non-utility stakeholders with non-Residential DSM (energy efficiency and electrification) expertise.

- *Alternative Natural Gas Potential Estimation Approaches for the Industrial Sector*. The Guidehouse team has previously advocated for an alternative to the “bottom-up” or “widget-based” approach to potential estimation for the Industrial sector, including in its recommendations as part of the 2019 APS, as well as in its recommendations provided to the California Public Utilities Commission (CPUC) resulting from its top-down potential prototype analysis (see Section B.2 of Appendix B).[24] Guidehouse recommends that OEB staff review Guidehouse’s recommendations to the CPUC, in particular its recommendation for the development of sub-sector-specific potential estimates based on top-down techniques, using a combination of consumer meter data, on-site primary data collection, and the engagement of sub-sector specific expertise.[25]

Implementation Recommendations – Insight from the Study Findings

For all its measure detail and interactive mechanisms, the modeling applied to estimate Achievable potential is a vastly simplified representation of reality. Simplified representations of reality can, however, offer useful and actionable strategic insights to analysts tasked with reducing the consumption of natural gas and the emission of greenhouse gasses through energy efficiency and beneficial electrification.

Tactical considerations may mean that not all the strategic recommendations provided below may be suitable in all implementations.

- *Net-Benefit Focused Consumer Incentive Design.* The findings of this study, and a considerable corpus of economic literature, support the recommendation that measure incentives intended to encourage measure adoption should be defined as a function of net provincial benefits rather than – as is often the case – a function of a measure’s cost. Incentives set on the basis of net provincial benefits align the interests of individuals with those of the province as a whole, will incent more economically efficient decision-making, and are less likely to result in unintended or perverse outcomes than other methods of setting incentives. This study has demonstrated that providing incentives even for measures that are not – on average – cost-effective will result in cost-effective outcomes, and an overall larger net provincial benefit.

[24] The use of “bottom-up” methods for the 2023 APS was required to meet the study’s initially scoped timelines through the use of “off-the-shelf” models and databases.

[25] This is a critical point: if, for example, potential is being estimated for the Petroleum Manufacturing sub-sector using top-down techniques, then the team estimating that potential should ideally include at least one member with experience in that industry, ideally in a role that exposed them to questions of facility energy management.

- *Focus Electrification in New Construction*. Regardless of end-use or sector, the analysis in this report, and the feedback from SAG members indicate that the opportunities for electrification – in particular full electrification, but also hybrid electrification – are most cost-effective and technically feasible for new buildings. As such, Guidehouse would recommend that implementers consider focusing their efforts at electrification primarily (but not exclusively) on new construction. Electrification of new construction (again, either with hybrid or fully electric systems) does not require costly infrastructure retrofits required to adapt existing building systems (wiring, ducting, etc.) to electrified equipment. This is particularly true for Commercial buildings (see Appendix B).

- *Residential Water Heating Fuel Switching.* The findings of this study indicate that there exists a substantial opportunity for cost-effectively reducing water heating natural gas use and the associated greenhouse gas emissions by replacing natural gas storage water heaters at the end of their life with heat pump water heaters. Guidehouse would therefore recommend that implementers work with contractors and the two major water heater rental companies to encourage their customers to replace their natural gas water heaters with heat pump water heaters.

- *Residential Space Heating Fuel Switching.* Hybrid systems, where heat pumps meet a high proportion of a home's thermal requirements and gas furnaces the balance have, in this study, been demonstrated to be cost-effective for the province and for individuals in the most populated southern parts of the province. Some uncertainty exists regarding the costs of electrical upgrades that might be required in homes where the heat pump is sized for heating, and the cost-effectiveness of these measures is likely to be sensitive to how the coincident system peak electric demand is defined and valued.

  Data should be collected and further work done to resolve these uncertainties, but in the near term it seems clear that a focus on encouraging Residential consumers to replace their central air conditioning with a similarly-sized heat pump at end of life (i.e., the "4A" heat pump option) is a "no-regrets" policy. The incremental cost is relatively modest, and isolated to the equipment costs, and the measure is likely to deliver substantial winter and summer bill savings to consumers in addition to materially reducing summer coincident peak demand.

  Guidehouse recommends that implementers strongly consider building upon the recent successes in heat pump deployment, using the information and data from these efforts to support Residential consumers replacing their central air conditioning with heat pumps, and to better quantify the opportunities for heat pumps sized for home heating in Ontario.

- *Residential Space Heating Energy Efficiency.* Residential envelope improvements targeted at older homes deliver the largest volume of cost-effective energy efficiency Achievable potential of the measures considered. Envelope improvements deliver substantial provincial benefits, private bill savings and are likely to considerably improve the comfort and quality of life of consumers to which they are deployed (a benefit not directly valued in this study). Based on these findings, the Guidehouse team recommends that implementers consider what opportunities exist to expand the delivery of impactful envelope improvements to Residential consumers in older, leakier homes, particularly those located in colder, more northerly areas of the province.

- *Commercial Space Heating Fuel Switching.* The critical finding of this study with respect to Commercial sector space heat fuel switching is that considerable uncertainty exists regarding the costs and feasibility of electrification in existing Commercial buildings. This uncertainty substantially constrained the volume of Achievable potential estimated by this study, as documented in Appendix B. What locally specific data were available were drawn from research used to inform a hybrid Commercial space-heating electrification pilot that Guidehouse understands remains in-field at the time of publication of this study. Guidehouse recommends that the critical lessons learned from this pilot should be used to inform expansions of that pilot (to test alternative delivery and installation models) and to develop a more formal data collection strategy for informing future projections of Commercial space heating electrification potential.

1. Introduction

This document is the final reporting output of the Ontario Energy Board (OEB)'s 2024 Achievable Potential Study (the "2024 APS"). The OEB engaged Guidehouse in April of 2023 to estimate a set of potential natural gas reduction scenarios that might be used to inform the planning of future demand side management (DSM) programming. Guidehouse has previously developed the integrated (gas and electric) 2019 Conservation Achievable Potential Study[26] on behalf of both the OEB and the Independent Electricity System Operator (IESO).

The current study, the 2024 APS, addresses only measures intended to reduce natural gas consumption, and does not include electricity conservation measures, though impacts on provincial electric coincident peak demand (winter and summer) and energy consumption are tracked, given the significant emphasis of the study on questions of the potential for the electrification of Residential and Commercial end-uses.

The remainder of this section is divided into the following sub-sections:

1. **Background and Objectives.** Cites the OEB Decision that motivated the undertaking of this study, and highlights the objectives indicated for the study in that Decision.
2. **Potential Studies and DSM Planning.** Provides a brief summary distinguishing between the goals and purposes of potential studies and DSM plans, to provide reviewers with necessary context when reviewing both documents.
3. **The Stakeholder Advisory Group (SAG).** Identifies the role of the SAG in the development of this study, and the group's membership.
4. **Uncertainty and Precision.** Notes the role of uncertainty in the study and some of the key drivers of that uncertainty.
5. **Report Structure**. Summarizes the report's structure.

1.1 Background and Objectives

This study has been undertaken at the direction of the OEB in the Decision and Order for EB-2021-0002[27] (Enbridge Gas Inc.'s – EGI's – DSM plan). The critical text from that document that has informed the development of this study is this:

> "*The OEB expects that OEB staff will undertake a new conservation potential study to inform Enbridge Gas's next multi-year DSM Plan, with input provided by the SAG. To guide OEB staff, Enbridge Gas and the SAG, the OEB is interested in at least three scenarios being considered in the analysis: an annual reduction in total natural gas sales year-over-year of 0.5%, 1% and 1.5%. The study should focus on how these levels of*

[26] Guidehouse (f/k/a Navigant), *2019 Integrated Ontario Electricity and Natural Gas Achievable Potential Study*, December 2019.
https://ieso.ca/2019-conservation-achievable-potential-study

[27] See Section 4.9, PDF 85 of 149 of
Ontario Energy Board, *Decision and Order: Application for Multi-Year Natural Gas Demand Side Management Plan (2022 to 2027),* Enbridge Gas Inc., EB-2021-0002, November 2022
https://www.oeb.ca/node/3869

annual natural gas reductions can be achieved through DSM programs in the most cost-effective manner while still providing opportunities for all customer segments to participate in DSM programs."

The process and methods used by this study are a direct reflection of this instruction.

In particular the implicit importance of close coordination with the Stakeholder Advisory Group (SAG) – of which more is mentioned below – and the development of Achievable potential scenarios that consistently deliver substantial reductions to the existing level of natural gas consumption across each year of the study horizon. It is this direction that drove the need to integrate the modeling of fuel switching (beneficial electrification) with energy efficiency measures, which in previous potential studies had been modeled separately, and to focus in much greater detail on the costs and benefits of electrification.

Based on the direction above, the objectives of this study were to:

- Develop a set of Achievable potential scenarios that deliver annual reductions to the current level of natural gas consumption of 0.5%, 1%, and 1.5%[28] ("…*an annual reduction in total natural gas sales year-over-year of 0.5%, 1% and 1.5%"*[29])
- Do so in close collaboration with the SAG, providing them opportunities to provide feedback on scenario definitions and sensitivities, input assumptions, and draft results (…*OEB staff will undertake a new conservation potential study … with input provided by the SAG)*.
- Develop from this work a set of insights into the most significant opportunities for natural gas reductions through DSM programming, and the uncertainties associated with those opportunities, identified through the modeling and SAG consultation process ("…*undertake a new conservation potential study to inform Enbridge Gas's next multi-year DSM Plan…"*

1.2 Potential Studies and DSM Planning

An Achievable potential study is a comprehensive, but high-level, assessment of sectoral market forces impacting the adoption of measures that reduce natural gas consumption. Its purpose, accordingly, is to identify the most significant opportunities for achieving natural gas reductions through program interventions. An Achievable potential is not a program planning document.

A potential study can cover the breadth that it does only by deliberately abstracting away from the minutiae of program design and the thousands of decisions that drive program planning and the targeting of programs to specific sets of measures and groupings of consumers. As a consequence, DSM program planning projected outcomes will not necessarily match those of the potential study, nor should they be expected to.

[28] As noted in Section 7.1.2, OEB staff, in consultation with members of the SAG, determined that scenarios targeting the maximum Achievable potential ("Max Achievable" scenarios) would deliver greater informational value than the 1.5% targeted scenarios.

[29] Because the current Enbridge reference forecast (after removing DSM) projects growing, rather than flat consumption levels (see Section 3), achieving year-over-year reductions to current levels of consumption of (for example) 0.5% would require savings in each year of more than 0.5% relative to the reference forecast.

This distinction is explicitly recognized by the OEB in its Decision that provides the motivation for this study clearly differentiating the goals of the potential study:

> "*To guide OEB staff, Enbridge Gas and the SAG, the OEB is interested in at least three scenarios being considered in the analysis: an annual reduction in total natural gas sales year-over-year of 0.5%, 1% and 1.5%*"

from those of the DSM plan:

> "*the next DSM plan that strives for gradual increases in natural gas savings from DSM programs beginning with an initial target of net annual DSM savings that are the equivalent to 0.6% of annual sales in 2026, 0.8% of annual sales in 2027 and 1.0% of annual sales beginning in 2028 and continuing annually in 2029 and 2030*").

Understanding this difference is essential context for interpreting the outputs of this study in comparison with the projections provided by DSM planning and assessing the differences between these two documents. These are different tools for different purposes: the potential study to identify the broad trends – to provide an initial "rough sort" of the most significant opportunities for natural gas reductions in the three sectors – and the DSM plan to provide a path for delivery of reductions by identifying the practical barriers to implementation and proposing the methods to breach them.

This interplay between these two efforts is an important reason for the close consultation of the SAG throughout the potential development process. This engagement ensured that program planning staff were provided with insight into the development of the assumptions and opportunities to review the draft and final outputs of the study long before the completion of study reporting, and so to reflect the insights offered by these results in the DSM plan.

1.3 The Stakeholder Advisory Group (SAG)

A key feature of the 2024 APS is the level of stakeholder engagement. The SAG was included throughout the process, consulted at the outset and throughout each of the major sections laid out in the report below, and presented with draft and final results as they became available.

Members of the Guidehouse team met with members of the SAG on at least 34 occasions between the initiation of the engagement in late April of 2023 and December 19 of that year, and met with members of the SAG on at least 10 more occasions from the start of 2024 through the presentation of final outputs to that group in May of that year. Meetings with members of the SAG were facilitated by OEB staff. Members of the SAG provided extensive written feedback tracked by the Guidehouse team on a task-specific basis, and all responded to. As noted in Section 4.2.5, over 800 separate comments related only to measure characterization and draft potential estimates were tracked by the Guidehouse team, and email correspondence between Guidehouse and members of the SAG (facilitated by OEB staff) was frequent and extensive. In nearly every case in which a SAG member's feedback was unopposed by another SAG member OEB staff directed Guidehouse to adopt the recommendation. Where feedback was contested, Guidehouse and OEB staff facilitated further discussion with OEB staff ultimately determining the most appropriate compromise and directing Guidehouse to apply it.

This level of engagement, particularly by members of the SAG with technical expertise, has significantly benefited the study. Their input, particularly on questions of measure characterization (savings, costs, applicability) has been invaluable; the most meaningful assumptions underlying all of the measures delivering the most significant potential in this study have been developed based on feedback from (or inputs provided by) members of the SAG.

The SAG membership includes (in alphabetical order, by last name):

Table 2. List of Members of the Stakeholder Advisory Group

Member Name	Affiliation
Bullock, Deborah	Enbridge Gas, Inc.
Di Ilio, Alexander	OEB staff
Fernandes, Craig	Enbridge Gas, Inc.
Fernandez Perez, Maye	Enbridge Gas, Inc.
Ghiricociu, Octavian	Enbridge Gas, Inc.
Hicks, Scott	Enbridge Gas, Inc.
Johnson, Daniel	Enbridge Gas, Inc.
Kesik, Ted	Non-utility SAG member
Lontoc, Erika	Non-utility SAG member
Naden, Damir	Enbridge Gas, Inc.
Neme, Chris	Non-utility SAG member
Shepherd, Jay[30]	Non-utility SAG member
Tharmalingam, Pirapa	Enbridge Gas, Inc.
Wasylyk, Josh	OEB staff
Weaver, Ted[31]	Non-utility SAG member
Wirtshafter , Robert	Non-utility SAG member
Wyatt, Francis	Non-utility SAG member
Yu, Edith	Enbridge Gas, Inc.

In the course of the study smaller sub-committees were formed. In particular, three sector-specific measure sub-committees were formed to provide detailed review and commentary on measure characterizations, and a single sub-committee was formed toward the end of 2023 to review and comment on draft potential results.

This important sub-committee included, from the list above: Deborah Bullock, Craig Fernandes, Scott Hicks, Daniel Johnson, Chris Neme, Ted Weaver, Francis Wyatt, Edith Yu, Alexander Di Ilio, and Josh Wasylyk.

1.4 Uncertainty and Precision

Any projection into the future is inherently uncertain. It is possible in some cases to estimate the level of uncertainty around such projections and provide estimated error bands around results. The dimensionality of this study, however, is too great to allow for any reasonably robust quantitative estimate of the uncertainty bands surrounding the outputs. The study makes use of thousands of inputs from hundreds of sources, including, in some cases, the expert opinions of SAG member reviewers.

Recognizing this inherent uncertainty, Guidehouse has, as much as possible and practical, attempted to identify the most critical sources of uncertainty in this study and qualitatively

[30] Resigned from membership 2023-11-15

[31] Resigned from membership 2024-08-05

identify the sensitivity of results to changes in these inputs. Even uncertain projections may be useful when that uncertainty can be contextualized to allow reviewers to appropriately apply their own judgement in interpreting those results.

At the macro level, the most critical areas of uncertainty in this study are the projections of the system value related to incremental changes in energy use: the avoided costs of natural gas and carbon emissions, and the incremental costs imposed by increases in coincident peak electricity demand. At the measure level, the most critical areas of uncertainty typically relate to measure costs (particularly related to the behind-the-meter infrastructure costs related to electrification) and the applicability of certain fuel-switching measures (particularly in the Commercial sector).

1.5 Report Structure

This report is divided into eight primary sections:

7. **Introduction.** This section. Provides the context and goals of the study and the structure of the report.

8. **Base Year Disaggregation.** Specifies the granularity of the study and the distribution of base year consumption volumes across the sectoral end-uses and sub-sectors.

9. **Reference Forecast.** Applies the distributions estimated in the BYD to forecast volumes provided by EGI.

10. **Energy Efficiency and Fuel Switching Measures (Measure** Characterization)**.** Describes the approaches and sources used to define the savings, costs, applicability and other key measure characteristics that drive potential. The appendix to this section (Appendix B) includes considerable additional detail regarding the assumptions applied and the SAG feedback provided on these assumptions.

11. **Technical Potential.** Provides an estimate of technically feasible natural gas consumption reductions in each year of the projection period, unconstrained by restrictions of equipment turn-over, cost-effectiveness, or customer economics.

12. **Economic Potential.** Provides an estimate of technically feasible natural gas consumption reductions in each year of the projection period, including only measures that are cost-effective from a TRC-Plus perspective in each year of the projection period, unconstrained by restrictions of equipment turn-over, or customer economics. This Section also provides a description of the value streams used to assess system-level benefits and costs, value streams that drive cost-effectiveness.

13. **Achievable Potential.** Provides the estimated Achievable potential for the core and sensitivity scenarios, discusses and interprets the results, and provides a description of the key inputs used to estimate market adoption.

14. **Findings and Recommendations.** Summarizes the key insights delivered by the study, and the implications they have for future potential studies and the implementation of DSM program planning in Ontario.

The main body of this report is followed by a series of appendices that expand on the methods and results presented in the primary sections included in the report body, and noted above.

2. Base Year Disaggregation

The objective of the Base Year Disaggregation (BYD) task is to establish a detailed profile of natural gas consumption in Ontario across all sectors, sub-sectors[32], and end-uses for the 2022 base year. The disaggregated base year data is a key downstream input to the development of the reference forecast, along with EGI's forecast of natural gas volumes and premise counts .

This section of the potential study report is divided into three sub-sections:

1. **Scope:** Defines the granularity of this potential study, identifying the sectors, sub-sectors, and end-uses considered.
2. **Methodology:** Provides a description of Guidehouse's approach to disaggregating the base year (2022) natural gas consumption volume data provided by EGI into the required sub-sectors and end-uses.
3. **Results:** Includes a summary of consumption, building stock (number of premises), and energy intensities derived as part of this task.

Additional details regarding the scope, methods, and results of the BYD analysis can be found in Appendix A.

2.1 Scope

The base year used in this potential study is 2022. This was selected as the base year in consultation with EGI and OEB staff. This year was the most recent available complete calendar year of consumption volume data available at the time the work was undertaken.

Within each sector, base year sectoral consumption volumes were disaggregated by sub-sector and end-use. These are all presented at the provincial level without further geographic disaggregation. [33]

Three sectors are considered: Residential, Commercial, Industrial. The definitions of these in some cases differs from the 2019 APS. The base year (and the study itself) excludes all natural gas use in the following categories: power production, chemical production feedstock, wholesale not delivered by EGI, and the consumption of "extra-large" volume Industrial customers.[34]

2.1.1 Residential Sub-Sectors and End-Uses

Guidehouse has divided the residential sector into four sub-sectors. These are presented in Table 3, below.

[32] Sub-sectors were referred to in the previous study – the 2019 APS – as "segments". Sub-sectors, sometimes also referred to in potential studies as "building types", are a set of buildings within a sector defined either by physical characteristics of the building type (e.g., in the residential sector) or by the activities conducted there (e.g., in the commercial sector).

[33] This does not mean that estimated potential does not account for geographic climate variation – some space-heating measures distinguish between installations in Northern and South/Central/Eastern Ontario for the purposes of modeling savings and measure uptake.

[34] Extra large volume (ELV) customers are those that consume 20 million or more cubic meters of natural gas each, per year.

Table 3. Residential Sub-Sectors

Sub-Sectors
Detached House
Attached / Row House / Other
Low Income - Detached
Low Income - Attached / Row House / Other

Consistent with EGI's data tracking conventions, multi-family residential ("multi-residential" or "multi-res") buildings are included in the Commercial sector. Multi-res buildings were included in the Residential sector in the 2019 study. This re-classification was applied on the basis that most gas-related multi-residential building systems are more similar to those found in commercial buildings than to those found in single family homes, and to align with the way these consumers are classified in EGI's data.

Guidehouse has divided each Residential sub-sector's consumption volumes into three end-uses. These are presented in Table 4, below.

Table 4. Residential End-uses

End-Uses
Space Heating
Water Heating
Appliances

This list of end-uses is shorter than that considered for natural gas volumes in the 2019 APS.

The Appliances end-use combines the Washing/Drying Appliances, Cooking, and Miscellaneous Residential natural gas end-uses represented in the 2019 APS. This aggregation was applied based on the observation that nearly all consumption and efficiency potential in the 2019 APS were within the Space Heating and Water Heating end-uses.

Further differentiation of the consumption and savings volumes of the residual provided a level of precision that did not deliver any meaningful insight into future savings, and that might well be spurious, given the various uncertainties associated with the input data and the projection of current consumption shares into the future.

2.1.2 Commercial Sub-Sectors and End-Uses

Guidehouse has divided the Commercial sector into twenty-two sub-sectors. These are presented in Table 5, below. Most sub-sectors include multiple iterations (by volume of consumption) – for example "Hotel Large" and "Hotel Small". Sub-sectors without multiple size-based iterations (e.g., Long Term Care, Restaurant, etc.) are those where variation in annual consumption is, compared to other sub-sectors, sufficiently modest that SAG members and OEB staff were satisfied that greater granularity wasn't required.

Table 5. Commercial Sub-Sectors

#	Sub-Sectors	Size (annual consumption, m^3)
1	Hospital	All
2	Hotel Large	>= 50k
3	Hotel Small	< 50k
4	Long Term Care	All
5	Multi-res Large	>= 300k

#	Sub-Sectors	Size (annual consumption, m^3)
6	Multi-res Large – Low-Income	>= 300k
7	Multi-res Medium	50k – 300k
8	Multi-res Medium – Low-Income	50k – 300k
9	Multi-res Small	< 50k
10	Multi-res Small – Low-Income	< 50k
11	Office Large	>= 50k
12	Office Small	< 50k
13	Other Commercial Large	>= 50k
14	Other Commercial Small	< 50k
15	Restaurant	All
16	Retail Large	>= 50k
17	Retail Small	< 50k
18	Schools Large	>= 50k
19	Schools Small	< 50k
20	University/College	All
21	Warehousing Large	>= 50k
22	Warehousing Small	< 50k

The sub-sectors included in the 2024 APS have changed from the 2019 APS to more closely align with the commercial sub-sector classifications used by EGI. Multi-family residential buildings ("multi-res") have been re-classified as Commercial sub-sectors.

There are seven more Commercial sub-sectors in the 2024 APS than in the 2019 APS. This is result of splitting many sub-sectors based on annual gas consumption. In the 2019 APS, size subdivisions (large/other) were included only for hotel, office, and non-food retail sub-sectors. In the 2024 APS there are additional size/volume subdivisions for schools, warehouses, and multi-family residential buildings (which are split into small, medium, and large consumption customer types). The Guidehouse team included these additional consumption size divisions at the direction of OEB staff to better align with EGI's internal customer classification.

Guidehouse has divided each commercial sub-sector's consumption volume into three end-uses. These are presented in Table 6, below.

Table 6. Commercial End-uses

End-Uses
Space Heating
Water Heating
Other

The commercial end-use list has been condensed in comparison to the 2019 APS. In 2019, Cooking and Miscellaneous Commercial end-uses were also included.

2.1.3 Industrial Sub-Sectors and End-Uses

Guidehouse has divided the Industrial sector into fourteen sub-sectors. These are presented in Table 7, below.

Table 7. Industrial Sub-Sectors

#	Sub-Sectors
1	Agriculture
2	Cement And Asphalt
3	Chemical
4	District Energy
5	Fabricated Metals Manufacturing
6	Food And Beverages Manufacturing
7	Mining, Quarrying, Oil and Gas Extraction
8	Other Industrial
9	Petroleum Manufacturing
10	Plastic And Rubber Manufacturing
11	Primary Metals
12	Pulp, Paper, and Wood Products Manufacturing
13	Transportation And Machinery
14	Water And Wastewater Treatment

The sub-sectors included in the 2024 APS are consistent with the 2019 APS with two exceptions:

- District Energy has been added
- Cement And Asphalt has been added
- Nonmetallic Minerals (included in the 2019 APS) has been removed.

These changes have been made to more closely align with the industrial sub-sector classifications used by EGI. For the 2019 APS, District Energy gas consumption was allocated by EGI staff to individual sub-sectors and not included as a separate sub-sector.

Guidehouse has divided each industrial sub-sector's consumption volume into five end-uses. These are presented in Table 8, below.

Table 8. Industrial End-uses

End-Uses
Boiler
Process Heat
HVAC
CHP
Other

The Industrial end-use list is similar to the list included in the 2019 APS. That list included both "Process Heating (Direct)" and a "Process Heating (Water/Steam)" end-use. The Process Heating (Water/Steam) end-use from the 2019 APS has been replaced with Boiler, and the Other Process end-use has been replaced with Other. These changes have been made to align with the available industrial end-use consumption data from EGI.

As in the 2019 APS, no conservation measures applicable to combined heat and power (CHP) installations are included in this study. CHP was identified as a distinct end use in the base year to ensure the accuracy of the estimated magnitudes of the other base year end uses.

2.2 Methodology

This section summarizes the approaches used by Guidehouse to allocate shares of base year consumption volumes provided by EGI to each of the sub-sectors and end-uses.

Key data sources used by the Guidehouse team for the base year disaggregation included:

- Data provided by EGI, including:
    - Base year consumption volumes (at differing levels of granularity).
    - Industrial end-use shares by sub-sector
    - Base year consumption of Industrial "extra-large" customers, by sub-sector
    - Residential end-use survey data
    - Residential space-heating consumption share
- Other data sources used as inputs to the analysis include:
    - End-use energy consumption and GHG emissions drawn from NRCan's Comprehensive Energy Use Database.
    - The Residential share of Low-Income customers was drawn directly from the 2019 APS. [35]

A complete list of the most critical data sources can be found in Section A.2.1 of Appendix A.

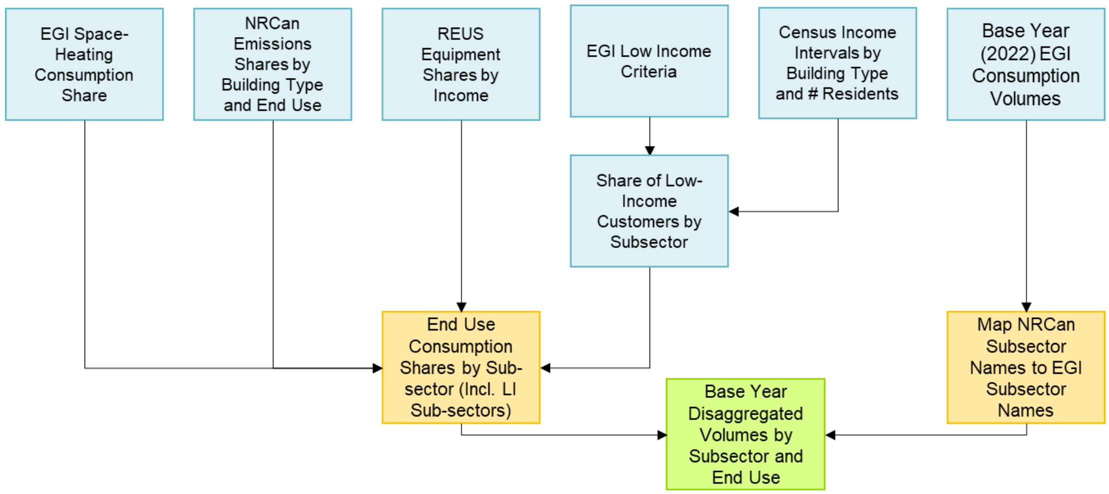
2.2.1 Residential Methodology

Figure 16 provides a visual summary of the way in which the Guidehouse team used the data identified in Section A.2.1 of Appendix A to develop an estimate of base year consumption volumes by sub-sector and end-use.

[35] EGI was unable to provide an estimated share of its customers that were low income, either in total or by sub-sector.

Guidehouse developed an initial estimate of the low income share by applying the eligibility criteria for EGI's Home Winterization Program (adjusted for inflation) to the same census cross-tabulation used to develop the 2019 low income share. This estimate, along with a second estimate, drawn from a cross-tabulation of income status and structural dwelling type from EGI's residential end-use survey (REUS) was reviewed by EGI, after which EGI recommended that Guidehouse use the 2019 APS values. OEB staff directed Guidehouse to follow this recommendation.

Figure 16. Summary of Residential Base Year Disaggregation Approach

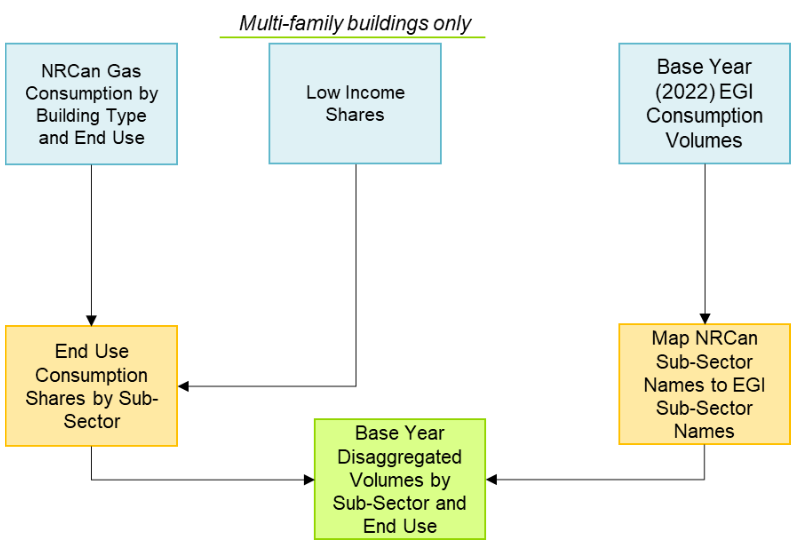


In summary, sub-sectoral splits (e.g., Detached, Semi-Detached, etc.) were drawn from EGI's data and mapped to the sub-sectors selected for this study (Table 3) and volumes and customer counts aggregated. End-use shares by sub-sector were drawn from two sources. The space-heating share of Residential gas consumption (72%) was provided by EGI. The residual was split between the remaining end-uses based on NRCan emissions shares data (as a proxy for gas use). Low Income end-use shares were adjusted based on the split of equipment for Low Income customers documented in EGI's Residential End-Use Survey (REUS – see Section A.2.1 of Appendix A), and the 2019 assumed share of Low Income customers.

2.2.2 Commercial Methodology

Figure 17 provides a visual summary of how the Guidehouse team applied the data identified in Data Sources to develop an estimate of Commercial base year consumption volumes by sub-sector and end-use.

Figure 17. Summary of Commercial Base Year Disaggregation Approach

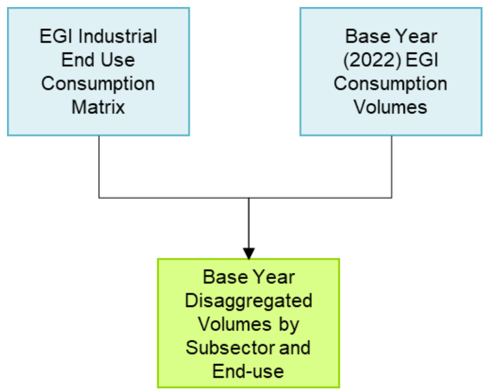


Multi-res end-use shares were derived using NRCan emissions data, the same approach used for assigning values to the non-Space Heating end-uses in the Residential sector. NRCan data for the Commercial sector includes energy use, separated by fuel (e.g., natural gas), building type, and end-use. As a result, it was possible to obtain end-use consumption shares directly, without using emission data as was necessary for the Residential sector (or for the Multi-res sub-sector within the Commercial sector).

2.2.3 Industrial Methodology

Figure 18 provides a visual summary of how the Guidehouse team applied the data identified in Data Sources to develop an estimate of Industrial base year consumption volumes by sub-sector and end-use.

Figure 18. Summary of Industrial Base Year Disaggregation Approach



EGI provided base year consumption volumes for the fourteen Industrial sub-sectors and an additional extra-large volume (ELV) sub-sector. EGI likewise provided the end-use shares for each sub-sector.

As noted at the beginning of Section 2.1, ELV customers were excluded from the analysis. This sub-sector includes fewer than 100 customers but accounts for more than 50% of the base year industrial consumption volume. The removal of this sub-sector was a consensus decision by the SAG. The principal reasons for the removal of this sub-sector were that DSM potential for these customers is likely to be facility-specific – properly accounting for potential savings would require an assessment of the processes, end-uses, and technologies in place at the specific facilities. Not only would such an assessment be impractical for the timelines and out of scope for this study, but the publication of the outcomes of such an assessment would be problematic for its potential to reveal commercially sensitive information.

This will necessarily mean that – by excluding the potential for these customers – DSM potential for the Industrial sector will be understated in absolute terms.

Some members of the SAG also noted that the economies of scale achievable by ELV customers are such that estimating DSM potential for this sector by simply applying the measures for the non-ELV customers to the ELV customers would understate ELV customer potential.

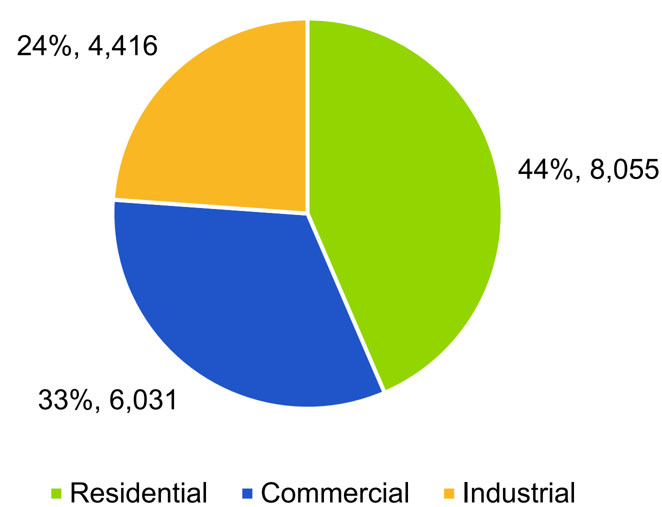
2.3 Results

This section provides a number of key summary statistics related to base year consumption volumes by sector, sub-sector, and end-use. The base year consumption volumes used in this analysis are derived from weather-normalized historical 2022 consumption values provided by EGI.

The base year shares of consumption volumes by end-use and sub sector and the number of premises by sub-sector are important, because it these shares that will be applied to projected consumption volumes and customer counts, respectively, to deliver the reference forecast.

Total base year (2022) consumption across all sectors is approximately 18.5 billion m^3. The distribution by sector is shown in Figure 19 below. Note that the Industrial share below excludes the consumption of ELV customers which accounts for more than half the Industrial non-feedstock gas consumption in EGI's service territory.

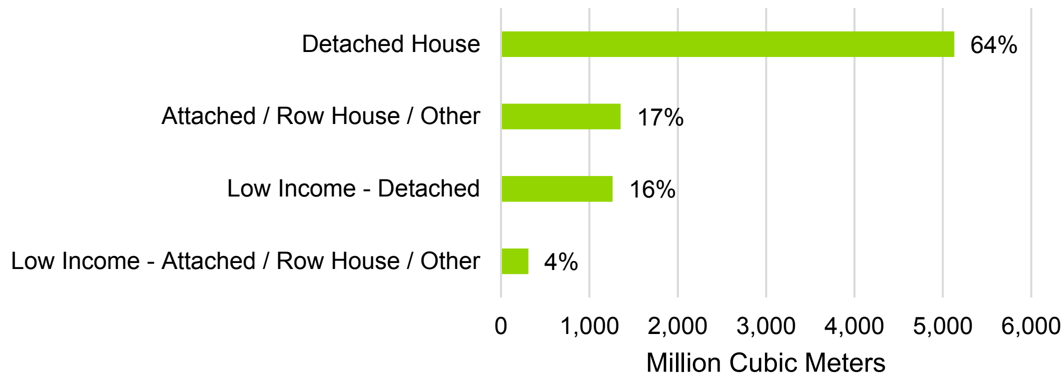
Figure 19. Base Year Volumes by Sector



1.1.1 Residential Results

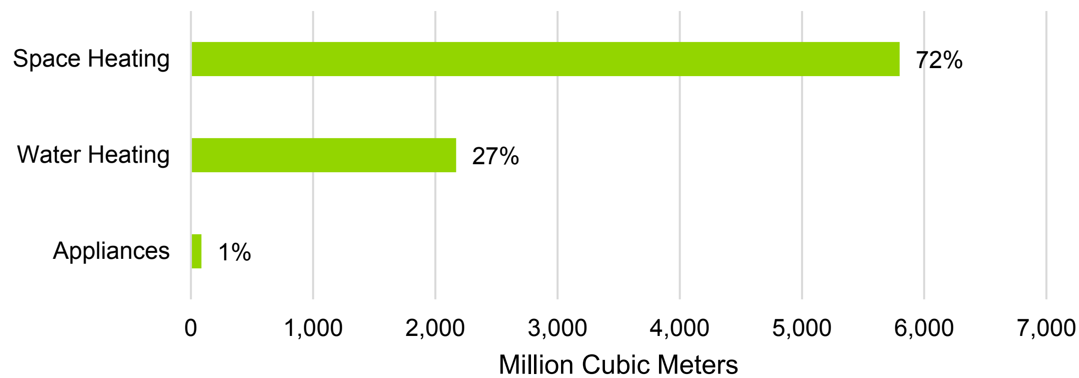
Total Residential consumption in the base year (2022) is approximately 8.1 billion m^3. Total base year consumption volumes (and sectoral share) by sub-sector are presented in Figure 20 below.

Figure 20. Residential Base Year Consumption by Sub-Sector



Total base year consumption volumes (and sectoral share) by end-use are presented in Figure 21 below. As would be expected, Space Heating is the dominant end-use.

Figure 21. Residential Base Year Consumption by End-use

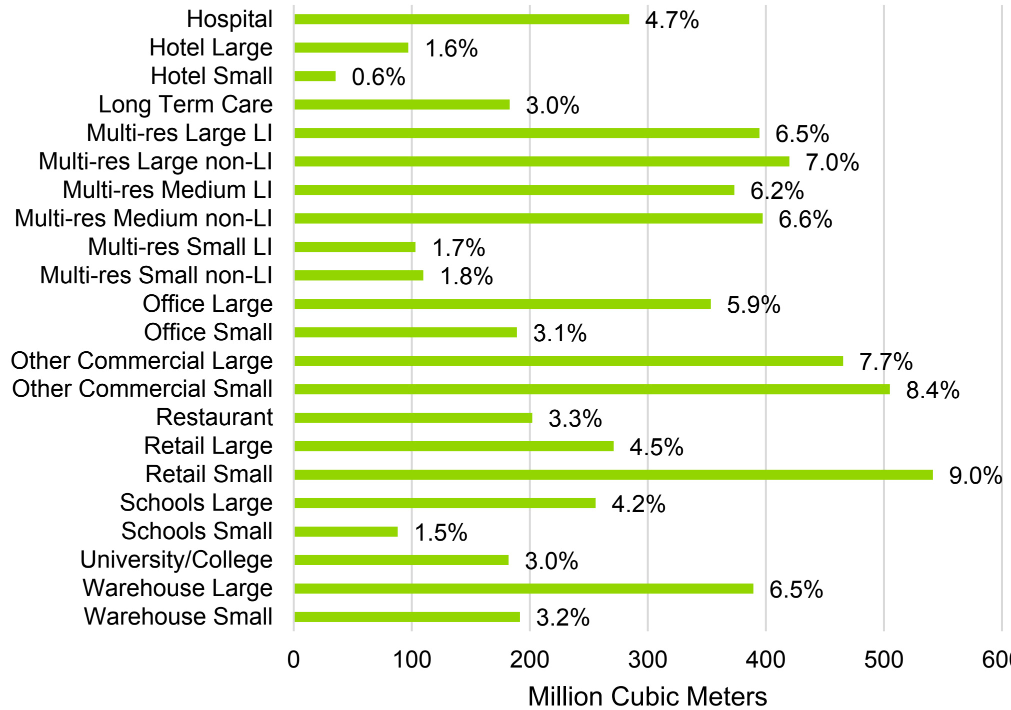


1.1.2 Commercial Results

Total commercial consumption in the base year (2022) is approximately 6 billion m^3.

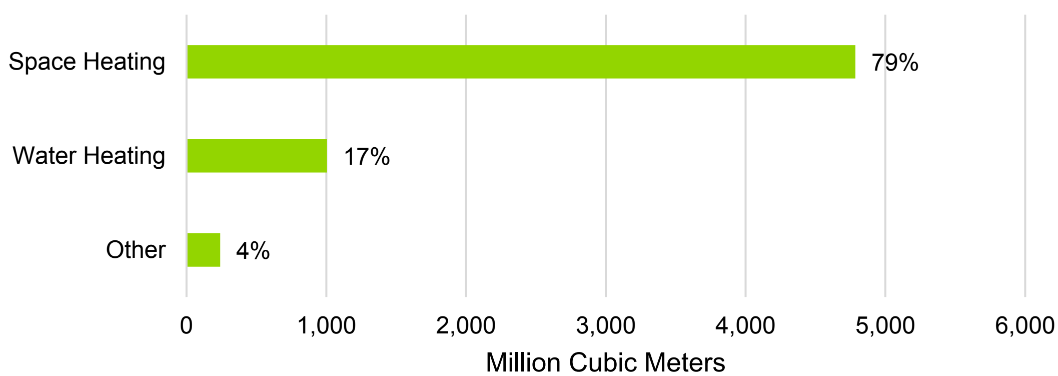
Total base year consumption volumes (and sectoral share) by sub-sector are presented in Figure 22 below.

Figure 22. Commercial Base Year Consumption by Sub-Sector



Total base year consumption volumes (and sectoral share) by end-use are presented in Figure 23 below. As would be expected, Space Heating is the dominant end-use.

Figure 23. Commercial Base Year Consumption by End-use



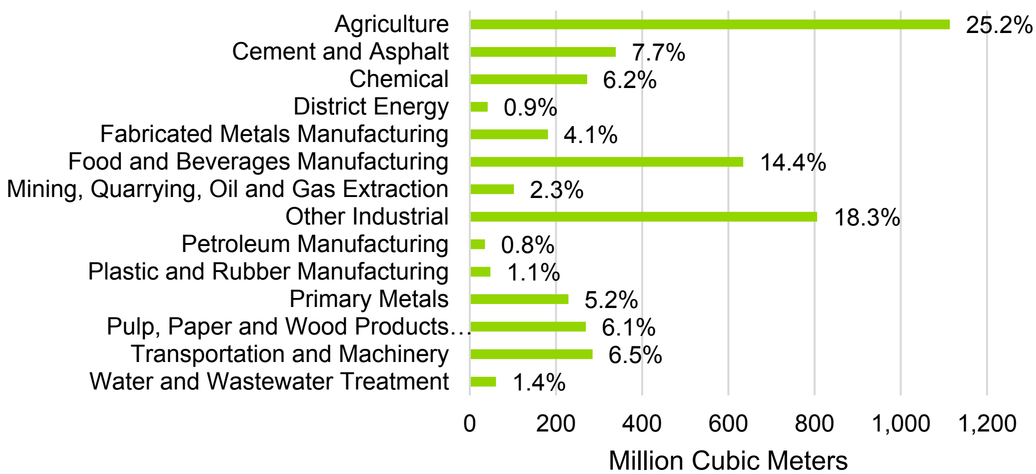
The end-use distribution for base year 2022 is very similar to the 2017 base year used for the 2019 APS. The principal difference is that in the 2019 APS Space Heating was estimated to account only for approximately 76% of gas use, with an estimated 3% and 5% of gas used by the Cooking and Miscellaneous Commercial end-uses (respectively).

1.1.3 Industrial Results

Total industrial consumption in the base year (2022), with the consumption of the ELV customers removed, is approximately 4.4 billion m^3. ELV customers' consumed approximately 5 billion m^3 in the 2022 base year.

Total base year consumption volumes (and sectoral share) by sub-sector are presented in Figure 24 below.

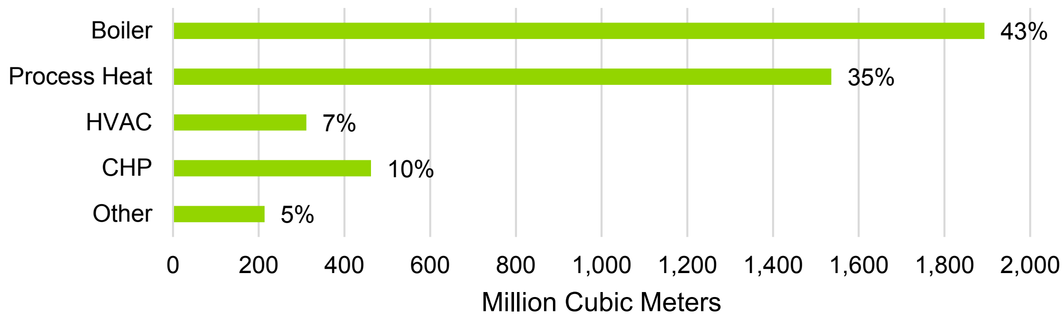
Figure 24. Industrial Base Year Consumption by Sub-Sector



Reviewers must remember that the approximately 65 ELV customers that represent more than half of the non-feedstock gas consumption served by EGI are not included in the distribution above, and so it should *not* be regarded as representative of the province as a whole. When ELV customers are included, for example, Primary Metals and Plastic and Rubber Manufacturing together make up approximately one third of all Industrial consumption, and Agriculture less than 12%

Total base year consumption volumes (and sectoral share) by end-use are presented in Figure 23 below. The distribution of consumption by end-use differs significantly from that presented in the 2019 APS due to the exclusion of ELV customers and the use of updated end-use categories available in EGI's data. Although CHP's share of base year consumption is presented below for completeness, no DSM measures addressing this end-use directly are included in this study.

Figure 25. Industrial Base Year Consumption by End-use



3. Reference Forecast

The objective of the Reference Forecast task is to extend the 10-year EGI natural gas volumes forecast to cover the 20-year period of analysis, and to disaggregate by sector, sub-sector and end-use. This disaggregation is required as sub-sector and end-use level consumption volumes are important inputs for the potential analysis, both for estimating potential energy efficiency and fuel switching savings, and for interpreting these estimates in the context of the projected baseline.

The reference forecast used directly in potential modeling is referred to as the “APS reference forecast”. This is distinct from the EGI forecast of volumes. Although the APS reference forecast is derived from the EGI forecast, it applies several adjustments necessary for its use in this study (e.g., removal of DSM achievement, exclusion of ELV customers from the Industrial sector, etc.), and care should be taken to avoid confusing the two projections.

3.1 Scope

The 2024 Achievable Potential Study considers the 20-year period from 2024[36] through to the end of 2043. A projection of natural gas consumption volumes absent any programmatic DSM is an essential input to this analysis, providing a baseline against which estimated potential achievement can be compared, and from which estimates of savings may be derived.

Guidehouse’s task in this case was not to develop this projection, but rather derive it from forecast values of consumption, planned DSM, and customer counts provided by EGI, and disaggregated using the sector, sub-sector and end-use shares developed as part of the BYD task.

The EGI forecast of weather-normalized consumption volumes and the associated projection of future DSM achievement are the core inputs to this task.

The EGI forecast distinguishes between general service consumption volumes and contract market volumes and uses different forecasting methods for these two categories.

General service consumption volumes include all Residential consumption, most Commercial consumption, and a small proportion of Industrial consumption. These are forecast using econometric methods;[37] using estimated historic relationships between observed consumption volumes and key input drivers (weather, macroeconomic and demographic drivers, etc.).

The general service forecast approach is reflective of industry standard practice and may effectively be understood to be a projection of natural gas consumption volumes under a business-as-usual scenario. Guidehouse understands that the EGI forecast does not reflect future changes in building codes, any impact of carbon pricing on gas volumes (beyond that

[36] It is the convention in Ontario to project potential over a period of analysis beginning in the year in which the study was completed or was intended to be completed. For example, e.g., the 2019 APS was published in December 2019 and covered a 20-year period of analysis from 2019 through 2038, and the 2016 APS (Gas) was published in June 2016 and covered a 16-year period from 2015 through 2030.

[37] For more details, please refer to EB-2022-0200, Exhibit 3, Tab 2, in particular Schedules 5-7.
https://www.rds.oeb.ca/CMWebDrawer/Record/759809/File/document

already embedded in existing trends of declining use), or any other potential (but uncertain) major changes in the structural drivers of demand for natural gas.

Contract market volumes are forecast using a “bottom-up” approach; existing customer-specific forecasts are developed by executive/account managers supplemented by input from the customer, and new customer forecasts are developed on the basis of connection requests.[38]

Despite significant uncertainties about future possible technology- or policy-driven changes to the demand for gas the Guidehouse team has assessed that the EGI forecast is the best available projection of natural gas consumption, based on the information available at the time it was developed.

Guidehouse’s principal role in the Reference Forecast task was to apply the appropriate DSM adjustments (such that the forecast did not reflect the impacts of any future planned programmatic DSM) provided by EGI, and appropriately allocate forecast volumes (and customers, where relevant) by sector, sub-sector, and end-use, based on the BYD consumption shares. Guidehouse has not assumed any material structural changes to the BYD allocation across the forecast period.

3.2 Methodology

This discussion of methodology is divided into four sections:

1. Forecast DSM Adjustment
2. Residential Methodology
3. Non-Residential Methodology (Commercial and Industrial)
4. Net-to-Gross Implication of DSM Adjustment

3.2.1 Forecast DSM Adjustment

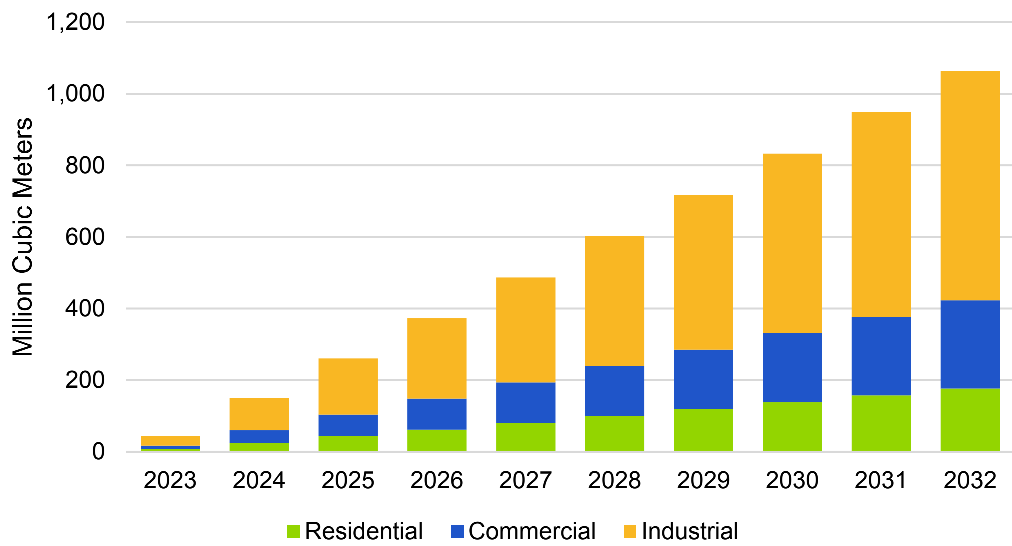
In this task, Guidehouse applied EGI’s projected DSM achievement (DSM savings estimated and provided by EGI) to adjust the forecast such that the forecast provides a projection of anticipated consumption volumes *absent any future programmatic DSM achievement*.

The DSM adjustment is essential and has important implications for the interpretation of results. The purpose of the 2024 APS is to develop an estimate of the potential achievement of programmatic DSM for energy efficiency and fuel switching. It is therefore essential that the baseline to which it is applied does not include the effects of any future programmatic DSM, the reason why the impacts of projected DSM achievement must be removed.

The projected volume of DSM achievement provided by EGI, by sector and year to be used in adjusting the provided forecast consumption, is provided in Figure 26, below.

[38] EB-2022-0200, Exhibit 3, Tab 2, Schedule 8.

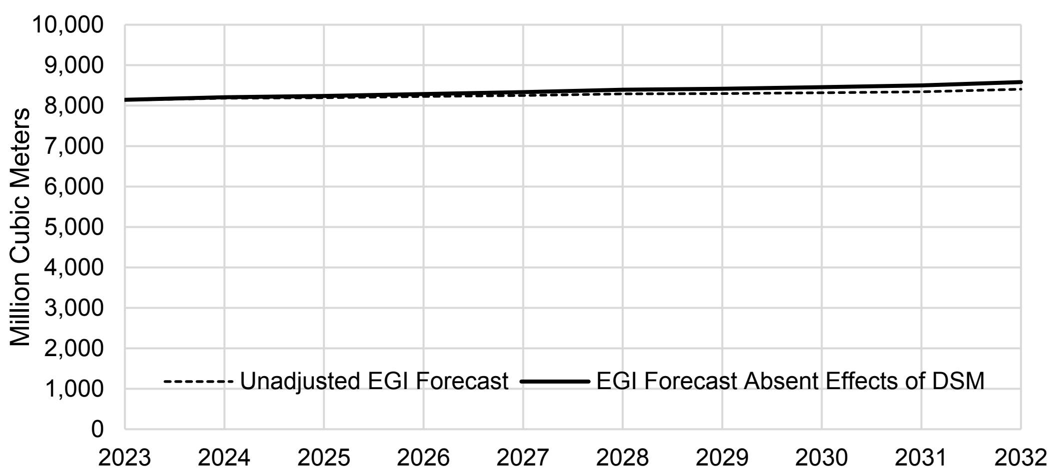
Figure 26. EGI DSM Achievement Projection



3.2.2 Residential Methodology

Figure 27 provides the EGI Residential volume forecast (solid black line) and the forecast when adjusted by Guidehouse to remove the projected effects of DSM.

Figure 27. EGI Residential Volume Forecast



The input EGI forecast covers only a 10-year period, from 2023 through 2032. To extend this to cover the entire period of analysis (through 2043), the Guidehouse team estimated the compound annual growth rate across the initial 10-year forecast period and extrapolated the sales and customer count forecast to 2043. Guidehouse extended both the input forecast (which includes the effects of DSM and the adjusted forecast (which provides a projection absent any programmatic DSM) for completeness, though only the adjusted forecast is used in the APS.

No other changes were required prior to the application of the consumption shares by sub-sector and end-use (to the consumption forecast) or the application of the premise shares by sub-sector (for the customer count forecast), as estimated in the BYD.

3.2.3 Non-Residential Methodology (Commercial and Industrial)

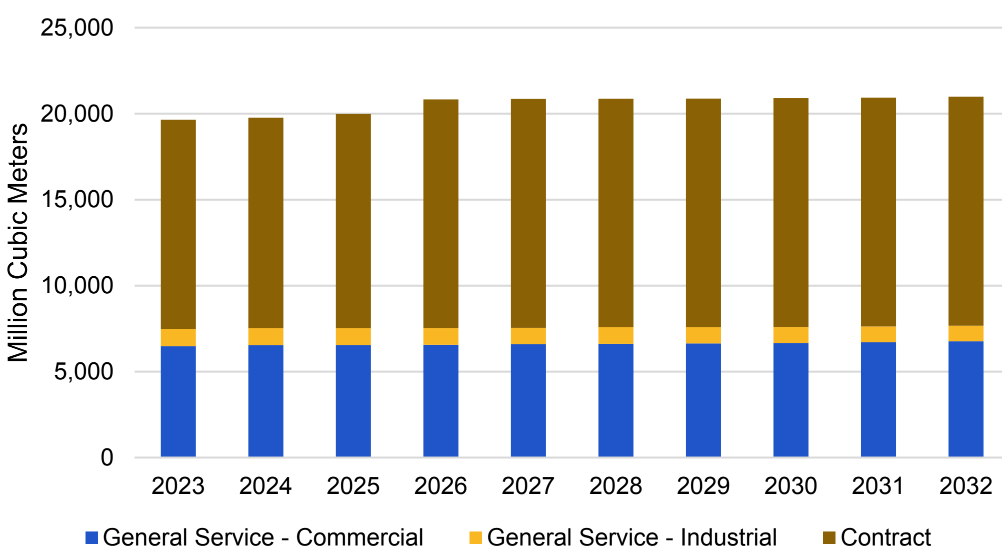
The process of deriving the APS reference forecast from the EGI forecast is considerably more complex for the two non-residential sectors than for the Residential sector because the classification process used by EGI for defining the sectors in the base year data (developed specifically to provide the base-year inputs requested by Guidehouse) differ from those used in the forecasting process.

Guidehouse understands that for the purposes of base-year disaggregation, the EGI team assigned the sector categories by account (including the “Feedstock” category to allow for its exclusion from the analysis), whereas the EGI forecast process derives its sectoral definitions from indicators in the CIS data. Accordingly at the recommendation of the EGI team, Guidehouse first removed volumes from the forecast requiring exclusion (e.g., ELV customers, wholesale volumes, power production volumes, etc.) and then allocated the remainder across the Commercial and Industrial sectors (and sub-sectors) according to the estimated BYD shares.

This process is described in more detail below.

Figure 28 provides the EGI non-residential forecast split into the three non-residential categories.

Figure 28. EGI Non-Residential Volume Forecast



The Contract category is itself divided into three categories: Power, Wholesale, and the remainder. Power (between approximately 2,100 and 2,400 million m^3 per year) and Wholesale (approximately 530 million m^3 per year) are removed from the total contract volume.[39]

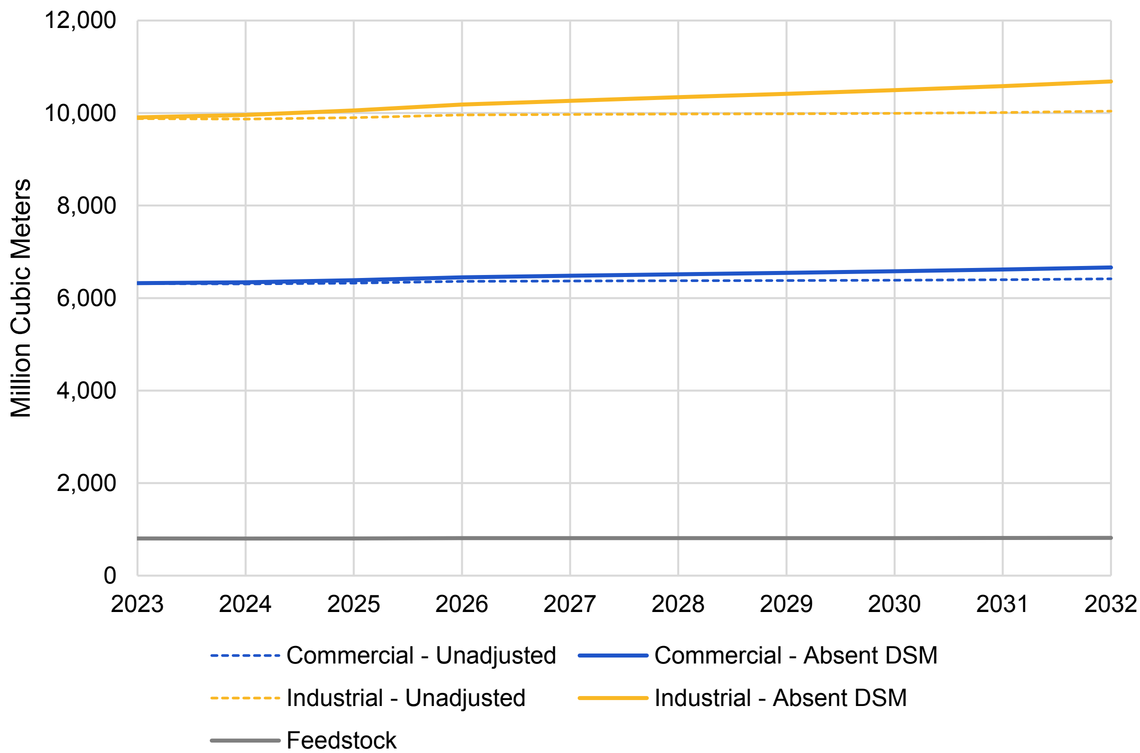
In reviewing the data, Guidehouse noted a substantial step-change in Contract consumption in 2026 in one specific EGI region, an increase in volumes by over 850 million m^3, a clear outlier compared year-over-year changes. Guidehouse assumed, based on the category (Contract),

[39] Power and Wholesale volumes are included in the plot shown in Figure 28.

and the magnitude of the change that this represented an addition of one or more ELV customers. Accordingly, Guidehouse estimated a trend for the 2023 through 2025 period for this region, compared this with the EGI forecast, took the difference, and applied this as an adjustment to the contract volumes (after Power and Wholesale had been removed) to remove the effect of what is assumed to be a new ELV customer (or customers) joining the system.

Following these two adjustments, the three series were aggregated into a single non-residential consumption volume. This was allocated to Commercial, Industrial, and Feedstock sectors on the basis of the BYD-estimated shares, after which projected DSM was added back in to provide a forecast of volume by sector absent the projected effects of programmatic DSM.[40]

Figure 29. Calibrated Forecast



For the Commercial APS reference forecast the only remaining step after this is the extrapolation of the projected volume consumption series to the end of the period of analysis, 2043, and the application of the sub-sector and end-use shares from the BYD task to deliver the final disaggregated Commercial forecast.

For the Industrial APS reference forecast, the ELV customer share (which accounts for more than half of Industrial volumes) is removed from the Industrial consumption after the extrapolation out to 2043 and the application of the sub-sector consumption shares from the BYD (in this case, the ELV customers are treated as a sub-sector).

[40] Feedstock volume was considered ineligible for energy efficiency measures. It is described in this section and included in Figure 29 to provide clarity on the forecast calibration adjustment methodology and to provide context for the alignment of base-year and calibrated forecast data.

3.2.4 Net-to-Gross Implication of DSM Adjustment

Because the reference forecast excludes the impacts of programmatic DSM, it implicitly accounts for all DSM achievement that would occur "naturally", without any programs.

This means that energy efficiency and fuel switching achievement by "free riders" *is already accounted for in the APS reference forecast.* Since the DSM achievement of free riders is embedded in the reference forecast, incremental achievable potential estimated by this study must necessarily have a net-to-gross value of 1 and be net of all free-ridership. This is consistent with the assumptions and interpretations of both the 2016 and the 2019 APS.

Accordingly, all the estimated program delivery costs (incentive and program administration) associated with the estimated potential are for the costs associated with the *net* achievement and do not account for any free ridership. In using the outputs of this study to develop program designs, planners should consider where to make adjustments to total estimated costs to account for the effects of free ridership, if any is expected.

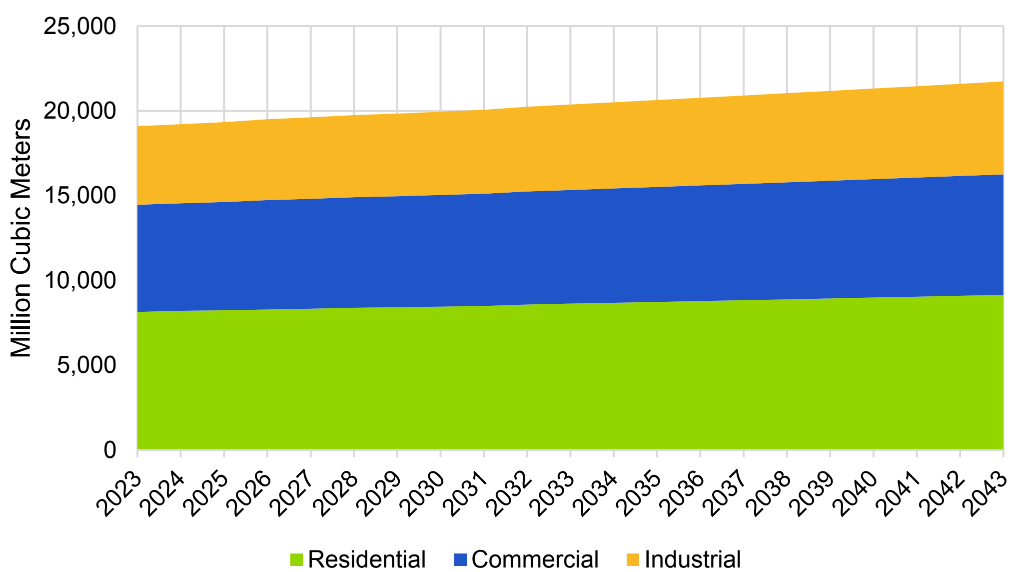
3.3 Results

This section provides a number of key summary statistics related to the APS reference forecast volumes.

The underlying distribution of consumption by end-use and sub-sector are held constant using the BYD shares for the length of the period of analysis, so, for the sake of concision, this section does not present a breakdown of sectoral consumption by sub-sector or end-use.

The APS reference forecast for all three sectors is shown in Figure 30 below. Total natural gas consumption across all three sectors (after the effects of DSM are removed) is projected to grow at approximately 0.65% per year over the projection period.

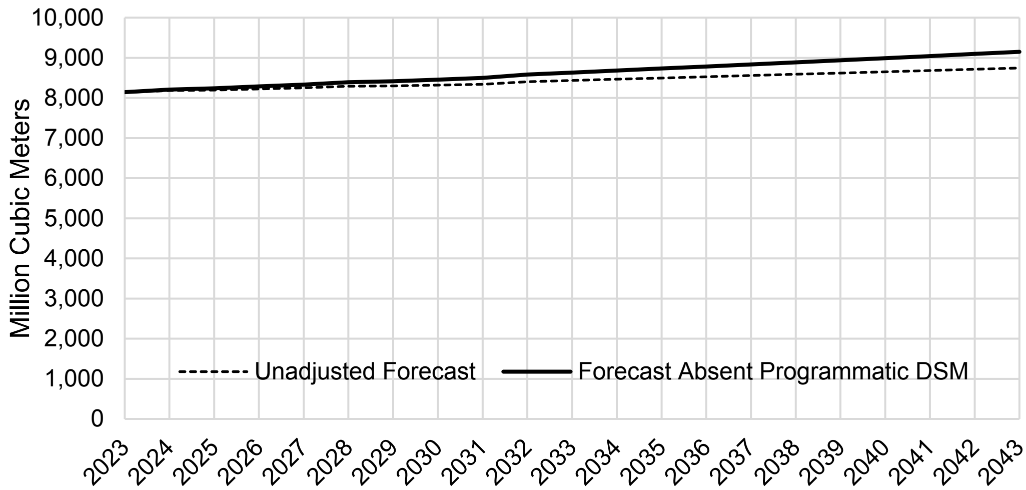
Figure 30. APS Reference Forecast by Sector



3.3.1 Residential Results

Figure 31 provides the Residential reference forecast across the period of observation. This includes both the forecast as prepared by EGI (the dashed line), and the forecast adjusted by Guidehouse to exclude all incremental programmatic DSM. The annual growth rate of the unadjusted forecast is approximately 0.4%, and the growth rate of the forecast assuming no further programmatic DSM is approximately 0.6%.

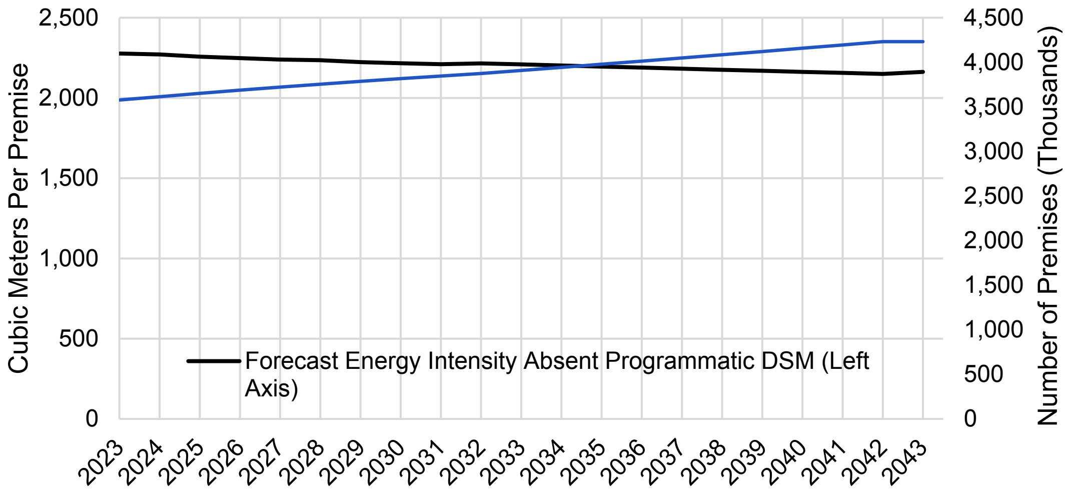
Figure 31. Residential Reference Forecast



Based on the estimated DSM achievement provided by EGI to Guidehouse, EGI estimates to achieve DSM savings of approximately 0.1% of baseline in 2023, rising to approximately 2% in 2032 (values beyond 2032 are Guidehouse's extrapolations, as described above).

Figure 32 shows forecast energy intensity assuming no incremental programmatic DSM (black line, left axis) and forecast customer counts (right axis). Customer numbers are projected to grow at a rate of approximately 0.8% per year. This is in line with the current Ontario Ministry of Finance long-term projected growth rate[41] of 1.14%.

Figure 32. Forecast Residential Customer Count and Energy Intensity



The projected decline in energy intensity for the adjusted forecast is approximately 0.3% per year, however the unadjusted forecast annual decline in intensity is approximately 0.5% per year. The unadjusted decline in intensity is aligned with the average annual change in normalized average use per customer reported for the Residential sector between 2012 (2,422 m^3 per customer per year) and 2022 (2,291 m^3 per customer per year) reported by EGI in its 2022 rate filing.[42]

Forecast shares by sub-sector and end-use are, by construction, the same as shown above for the base year disaggregation.

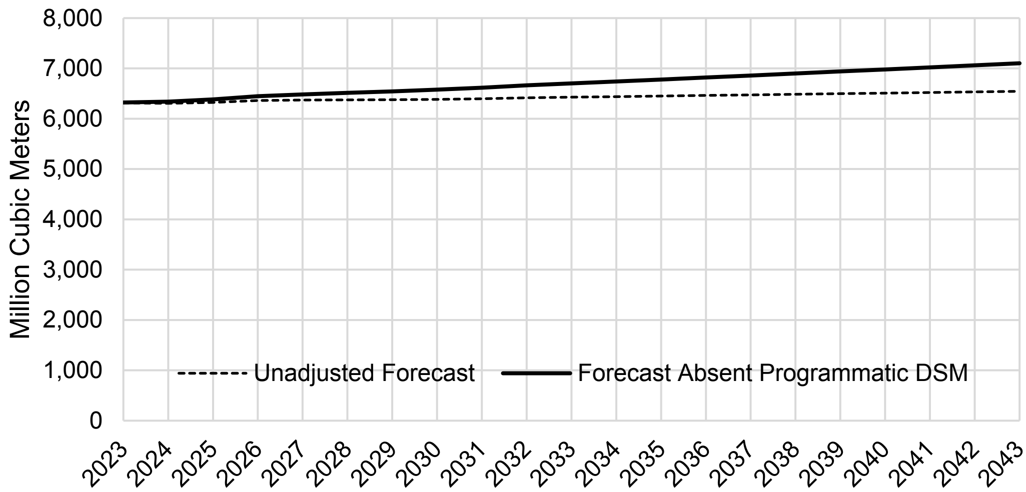
3.3.2 Commercial Results

Figure 33 provides the Commercial reference forecast across the period of observation. This includes both the unadjusted forecast (the dashed line, which implicitly reflects the impact of future programmatic DSM), and the forecast adjusted by Guidehouse to exclude all incremental programmatic DSM (solid line).

[41] Ontario Ministry of Finance, Ontario's Long-Term Report on the Economy – Chapter 1: Demographic Trends and Projections, June 2020 **https://www.ontario.ca/document/ontarios-long-term-report-economy/chapter-1-demographic-trends-and-projections#:~:text=Under%20all%20three%20scenarios%2C%20Ontario's,million%20on%20July%201%2C%202046**.

[42] EB-2022-0200, Exhibit 3, Tab 2, Schedule 5, Attachment 7, Page 2 of 2 (PDF page 172 of 377) **https://www.rds.oeb.ca/CMWebDrawer/Record/759809/File/document**

Figure 33. Commercial Reference Forecast

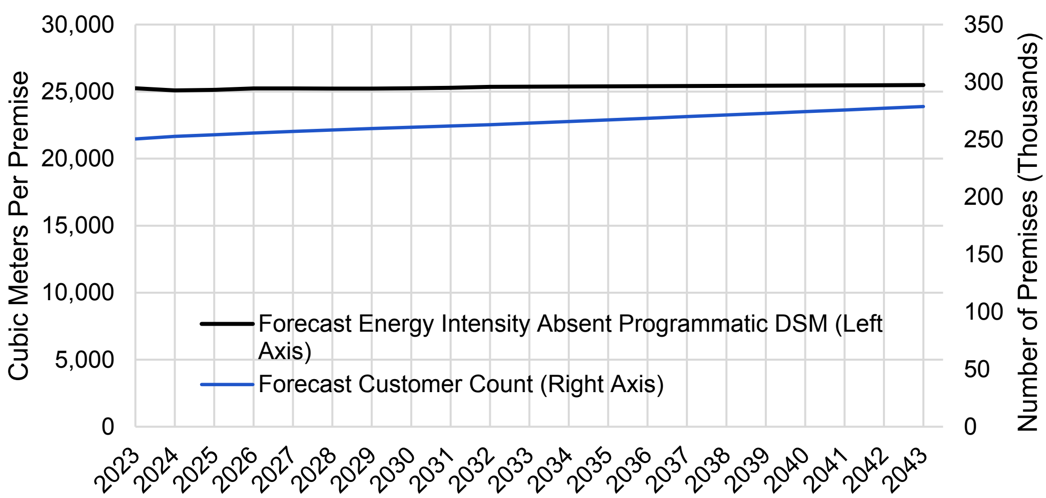


The annual growth rate of the unadjusted forecast is approximately 0.2% and the growth rate of the forecast assuming no further programmatic DSM is approximately 0.6%.

Under current plans, EGI estimates to achieve DSM savings of approximately 0.2% of baseline in 2023, rising to approximately 3.7% in 2032 (values beyond 2032 are Guidehouse's extrapolations, as described above).

Figure 32 shows forecast energy intensity assuming no incremental programmatic DSM (black line, left axis) and forecast customer counts (right axis). Customer numbers are projected to grow at a rate of approximately 0.5% per year.

Figure 34. Forecast Commercial Customer Count and Energy Intensity



The projected increase in energy intensity for the adjusted forecast is approximately 0.2% per year (in contrast, for the unadjusted forecast there is a projected decline of 0.2% per year).

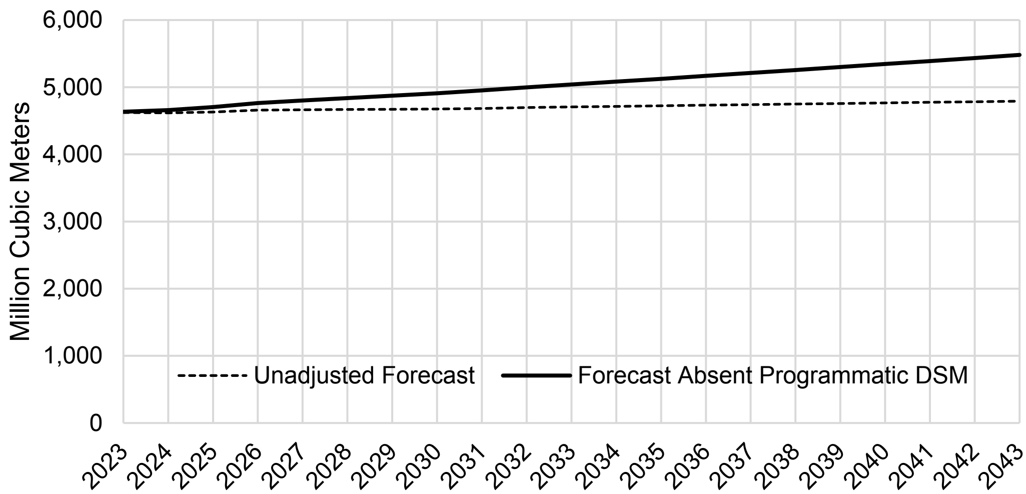
Forecast shares by sub-sector and end-use are, by construction, the same as shown above for the base year disaggregation.

3.3.3 Industrial Results

Figure 35 depicts the industrial reference forecast across the study period.

This includes both the unadjusted forecast (the dashed line, which implicitly reflects the impact of future programmatic DSM), and the forecast adjusted by Guidehouse to exclude all incremental programmatic DSM (solid line).

Figure 35. Industrial Reference Forecast

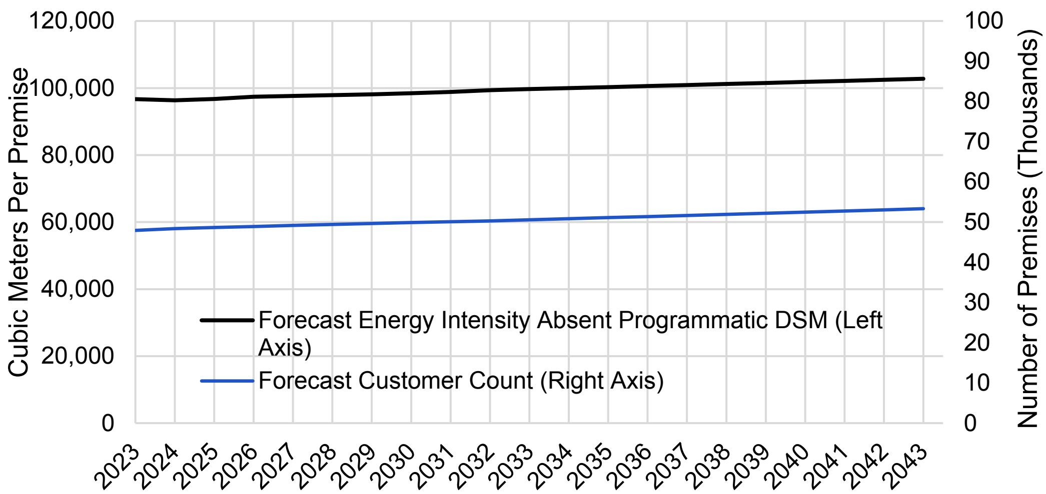


The annual growth rate of the unadjusted forecast is approximately 0.2% and the growth rate of the forecast assuming no further programmatic DSM is approximately 0.8%.

Under current plans, EGI estimates to achieve DSM savings of approximately 0.3% of baseline in 2023, rising to approximately 6% in 2032 (values beyond 2032 are Guidehouse’s extrapolations, as described above).

Figure 36 shows forecast energy intensity assuming no incremental programmatic DSM (black line, left axis) and forecast customer counts (right axis). Customer numbers are projected to grow at a rate of approximately 0.5% per year.

Figure 36. Forecast Industrial Customer Count and Energy Intensity



The projected increase in energy intensity for the adjusted forecast is approximately 0.5% per year (in contrast, for the unadjusted forecast there is a projected decline of 0.2% per year).

Forecast shares by sub-sector and end-use are, by construction, the same as shown above for the base year disaggregation.

4. Energy Efficiency and Fuel Switching Measures (Measure Characterization)

A measure is a technology, process, or project that is implemented to reduce a building's natural gas consumption. Measures may be either energy efficiency or fuel switching. Measures are the building blocks of the achievable potential study. Measure characterization is the process of developing a set of input assumptions to provide estimated values for the measure parameters that drive modeled potential.

This section of the potential study report is divided into three sub-sections:

1. **Scope:** Defines the sets of activities undertaken to complete this task.
2. **Methodology:** Provides a description of measure list development, measure characterization and the measure review process.
3. **Results:** Describes the outcomes of this task.

Additional details about the process and outcomes of measure characterization may be found in Appendix B.

4.1 Scope

The objective of the measure characterization task is to review and compile the necessary input assumptions required to estimate Technical, Economic, and Achievable potential, as described in subsequent chapters. This task is made up of three major components:

- **Measure List Development:** Guidehouse worked with members of the SAG to develop a list of energy efficiency and fuel switching measures for inclusion in the study. The final list of measures, reflecting all the various iterations (e.g., by building vintage, sub-sector, geography, etc.) input to Guidehouse's modeling software included 176, 1,086, and 436 line-items for, respectively, the Residential, Commercial, and Industrial sectors.

- **Measure Characterization:** Guidehouse compiled measure input assumptions, deriving estimates for required measure parameters, including gas savings, electric savings and incremental consumption (fuel switching measures), winter and summer peak electricity demand savings (and increases), incremental measure costs, density, and saturation. Fuel switching measures were considered only for the Residential and Commercial sectors.

- **Measure Review**: Measure inputs received extensive review by members of the SAG and were updated to reflect their feedback. Each sector's measures underwent two initial rounds of review by three sector-specific sub-committees. Measure inputs were subsequently reviewed, discussed, and updated based on feedback provided by SAG members as part of their review of the Technical, Economic, and Achievable potential estimates.

The magnitude of the measure characterization task – the number of measures that must be characterized and the number of parameters for each measure that must be estimated – means that it is an inherently meta-analytic activity. Measure characterization inputs all derive from secondary sources. The scope of this task does not include primary data collection by Guidehouse. Measure inputs are typically derived from data published in Technical Reference

Manuals (TRMs) or similar documents, evaluation reports, or are provided directly to the Guidehouse team by SAG member experts.

This means that the list of measures considered by this study is limited to those for which the input data (or the data necessary to derive the inputs) are available to the measure characterization team.

4.2 Methodology

The methodology section is structured into measure list development, measure characterization, and measure review.

4.2.1 Measure List Development

Guidehouse developed the list of measures included in this study based on a review of relevant provincial documentation, consultation with members of the SAG, and with a view to focus efforts on measures most likely to deliver sufficiently meaningful volumes of potential to justify the time required for Guidehouse to characterize them and the SAG to review them.

Key documents informing the development of the list include: the OEB Technical Reference Manuals (TRMs), Enbridge Gas's evaluation reports and filed plans, the 2019 Integrated Ontario Electricity and Natural Gas Achievable Potential Study, and other potential studies. Members of the SAG provided significant input into the selection of measures for inclusion on the list, for example on differentiating between building vintage (e.g., Air Sealing for pre-1974 homes, Air Sealing for homes built 1975 – 2006, etc.), bundling Industrial measures by end-use, excluding measures no longer included in EGI's programs (high-efficiency furnaces), etc.

Only commercially available measures were included in the list. New technologies not yet available in the market were excluded on the basis that there would be insufficient data to characterize them accurately. Measures related to gas use for power production were out of scope for this study.

A complete list of the measures included in this study may be found in Appendix X1, an Excel workbook that accompanies this report. A summary list of Commercial and Residential measures (and the underlying data sources used for characterization) can be found in Section B.1 of.

The lists in Appendix B identify all Residential and Commercial measures included in the study, but do not capture the granularity of the characterization. Measures are characterized separately by sub-sector, and may also be characterized by building vintage, location in the province (particularly for space-heating measures), efficiency level or other category. Once these additional dimensions are applied, there are 176, 1,086, and 436 measure line-items for, respectively, the Residential, Commercial, and Industrial sectors included in the study.

4.2.2 Measure Granularity and Representativeness

Measures included on the measure list should be each be understood as averages, reflecting a range of more specific individual installations.

The measure list used for this study represents a series of compromises. Creating a truly comprehensive list of measures is impossible; as each iteration of a measure becomes more specific, some exception to the proposed definition can be found and an additional iteration proposed. A truly comprehensive measure list, however, will provide spurious precision; if no market data exist, for example, to identify the share of detached homes by attic insulation R-value in increments of 1, then there is no value in defining a separate measure for each increment of 1.

Measures and their parameters (savings, costs, etc.) should therefore be understood as being representative of an underlying diverse distribution of installations, behaviours and equipment.

Any downstream analysis that is intended to target specific sub-sets of the applicable population should therefore consider what adjustments are appropriate to the definition (and estimated parameters) of the measure in question.

4.2.3 Measure Bundles

In the Residential and Commercial sector, measures are all defined individually, and modeled as independent units (though subject to some off-setting interactions – e.g., some measures may compete against others for market share). In the initial stages of measure list development a more bundled approach was considered. Measure bundling is a standard practice in DSM program design and may assist program administrators in realizing economies of scope and of scale.[43]

For the APS, however, it was determined in discussion with the SAG and OEB staff that where individual measure modeling was supported by available input data (i.e., in the Residential and Commercial sectors) it should be undertaken. This approach allows for greater transparency of inputs to the SAG members, and therefore a more effective review process. This approach also allows for a more granular assessment of the trade-offs offered by various measures when evaluating their performance contributing toward the estimated the Achievable potential.

The unbundled modeling of measures means that any downstream analyses related to future DSM achievement should apply the outputs of this study with care. In many cases it may be inappropriate to use APS outputs modeling individual measures for deterministic prediction of bundled program achievement. The (unbundled) measure-level APS outputs are intended for the directional diagnosis of the dynamic interaction of fuel switching and energy efficiency measures with customer and system economics, and not to predict DSM program achievement.

For the Industrial sector, measures are bundled. Bundling of Industrial measures was supported by a consensus of the relevant SAG sub-committee (which included OEB staff), and SAG member contributed recommendations for the allocation of individual measures to bundles. Bundling was determined to be suitable for the Industrial sector due to granularity of the measure savings estimates, drawn from a database of estimated savings for measures recommended at specific Industrial sites by the Industrial Assessment Center (IAC).[44]

Because savings are derived from averages (by measure) estimated across a distribution of sites, the percentage estimated savings were assumed (lacking any Ontario-specific data sources) to be approximately representative of the underlying distribution of Ontario Industrial

[43] For example, approximately 77% of Commercial and Industrial DSM savings (~49.3 million cubic meters, 22.5 for Enbridge and ~26.8 from Union) identified the 2021 Natural Gas DSM verification report are attributable to the C&I Custom program.

[44] Office of Manufacturing and Energy Supply Chains, *Industrial Assessment Centers (IACs),* **https://www.energy.gov/mesc/industrial-assessment-centers-iacs**

sites. IAC savings are adapted to the Ontario market by applying them as percentages of end-use consumption, allowing for measures to be bundled without obscuring any important underlying assumptions driving those savings.

4.2.4 Measure Characterization

Measure characterization is the process of developing estimated values for the key parameters required to model the adoption of each measure included in the study. This description of Guidehouse's approach to characterizing measures for the study is divided in to five sub-sections:

- Energy Efficiency Measure Characterization Key Parameters
- Measure Characterization Sources
- Energy Savings and Incremental Costs
- Peak Electricity Demand Impacts
- Applicability Factors

4.2.4.1 Energy Efficiency Measure Characterization Key Parameters

The measure characterization effort consisted of estimating or defining values for more than 50 individual parameters for each measure included in this study. The most critical of these parameters are those that define the value of a measure, and those that define its available market for adoption.

Parameters that define measure value include: annual gas savings, peak winter electricity demand impact (for fuel switching measures), lifetime, and incremental cost. Parameters that define the available market for adoption include the measure's competition group, saturation, density, and technical suitability. Table 9, below defines a selection of the most important measure parameters.

For most, but not all, measures, the values of key parameters are held constant across the period of analysis. Significant exceptions are identified in Appendix B.

Table 9. Measure Characterization Key Parameters

Parameter Name	Definition	Example
Measure Name	The efficient measure name	North Air Source Heat Pump with Gas Backup (*unless otherwise noted, examples provided below relate to this measure)*
Baseline Assumption	A description of the base equipment or process and an indication of its assumed efficiency. The average assumed efficiency of the baseline assumption may be a function of the measure replacement type.	Code 95% Furnace + SEER 13 AC
Efficient Assumption	A description of the efficient equipment or process and an indication of its assumed efficiency.	North ASHP (4.0 COP) + Gas Furnace Backup (95%), sized for cooling

Parameter Name	Definition	Example
Measure Lifetime	The expected useful life of the efficient measure. For measures classified as "replace on burnout" (ROB) base equipment lifetime is assumed to be the same as that of the efficient equipment and is used to characterize the available market in each year (via device turnover).	Measure Lifetime: 16 years
Base Measure Cost ($/unit basis) Efficient Measure Cost ($/unit basis)	The installed equipment cost of the base and efficient measures. The difference between these two values is the incremental measure installed cost, but may not include incremental labour cost (tracked as a separate parameter). Base Measure Cost may be equal to zero in retrofit (RET) cases where the baseline is the "do-nothing" case or may be equal to zero in cases where the input costing source included only an estimate of the incremental measure cost.	Base Measure Cost: $3461 Efficient Measure Cost: $10317
Replacement Type	Identifies when in the technology or building's life an efficiency measure is introduced. There are three replacement types: replace-on-burnout (ROB), retrofit (RET), and new construction (NEW). ROB and RET often distinguish between different types of measures (e.g., heating equipment vs insulation). NEW measures are often the same as ROB measures but with certain inputs (e.g., cost, savings) adjusted to reflect the fact that they are installed at or near the time of construction.	Residential ASHP with Gas Back-Up is **ROB** – the consumer decision is whether to replace the end-of-life gas furnace with a code-required 95% furnace or with an ASHP sized for cooling. Wall insulation is **RET** – the consumer decision is whether to continue to live with R10 insulation or, in a given year, upgrade to R24. These two examples demonstrate how the measure replacement type can determine the baseline efficiency: an ROB or NEW measure's baseline efficiency is typically the code-required minimum efficiency level equipment, whereas a RET measure's baseline efficiency condition is simply the absence of the measure.
Gas Savings [m^3/ year/ unit basis] Electric Energy Savings [kWh/ year/ unit basis] Electric Coincident Winter Peak Demand Savings [kW/ unit basis] Electric Coincident Summer Peak Demand Savings [kW/ unit basis]	Estimated annual gas and electric energy savings, and any corresponding coincident peak demand savings in summer or winter. Increased electricity consumption or peak demand for fuel switching measures is represented by a negative value.	Gas Savings: 957 m^3/year Electric Energy Savings: -2985 kWh/year Electric Coincident Winter Peak Demand Savings: 0 (*gas back-up is assumed to be running at time of winter peak)* Electric Coincident Summer Peak Demand Savings: 0.15 kW (*derived from the replacement of the less efficient central A/C)*
Unit Basis	The normalising unit for energy, demand, cost, and density estimates.	The Residential unit basis is per household, the Commercial unit basis is per building, and the Industrial unit basis is per cubic meter of gas saved
Measure Density	One of the parameters used to define the available market. The density provides an estimate of the average number of baseline conditions per unit basis.	The density used for the North ASHP with Gas Backup measure (Detached Houses) is 0.18. This calculated as the product of the share of Residential customers allocated to the northern climate zone, and the share of Residential customers with forced-air systems.

Parameter Name	Definition	Example
Efficient Measure Initial Saturation	The fraction of the Residential housing stock or Commercial building stock that has the efficiency measure installed in a given year. For the Industrial sector, saturations are based on energy consumption.	Approximately 3% of applicable Detached houses are assumed to be equipped with the efficient measure in the initial year of the projection period.
Technical Suitability	The percentage of the baseline technology that can reasonably and practically be replaced with the efficiency measure, for the applicable market.	It is assumed to be technically feasible to install an ASHP in approximately 95% of applicable Detached houses (i.e., those in the northern climate zone equipped with forced air systems).
Competition Group	Identifies measures competing to replace the same baseline density in order to avoid double counting of savings.	The three versions of the North ASHP with Gas Backup measure (each displacing a different share of gas consumption) compete with each other, and with the Cold Climate Air Source Heat Pump and Ground Source Heat Pump (in the "North SH Engine" competition group) for market share.

4.2.4.2 Measure Characterization Sources

Guidehouse and the SAG members that contributed measure characterization used many sources to develop the estimated measure parameters. Table 10, below presents a summary of the most commonly used sources for measure characterization, presented in alphabetical order, by source organization. Wherever possible, Guidehouse used savings and other parameter estimates published in the OEB's Technical Reference Manual (TRM), referenced below. Savings values for all fuel-switching measures were derived from Base Year Ontario gas consumption data provided by EGI, and closely reviewed by members of the SAG.

Table 10. Selection of Sources for Measure Characterization

Citation	Link (where relevant)
Enbridge Gas Inc., *2022 Residential Single Family Natural Gas End Use Survey*, and, *2022 Residential New Housing Natural Gas End Use Survey,* February 2023	Unpublished
Guidehouse, Presented to the Energy Information Administration, *EIA – Technology Forecast Updates – Residential and Commercial Building Technologies – Reference Case*, March 2023	**https://www.eia.gov/analysis/studies/buildings/equipcosts/pdf/appendix-a.pdf**
Guidehouse prepared for Enbridge Gas, Inc. , Comparison of Heat Pump Configurations and Performance in Ontario Homes, May 2023	Unpublished
Illinois Energy Efficiency Stakeholder Advisory Group, *Il Statewide Technical Reference Manual Version 11.0*, [45] accessed February 2024 *2023 Illinois Statewide Technical Reference Manual for Energy Efficiency Version 11 – Volume 2: Commercial and Industrial Measures*, September 2022	**https://www.ilsag.info/technical-reference-manual/il-statewide-technical-reference-manual-version-11-0/**

[45] Version 12 of the IL TRM was published in September of 2023 at which point initial measure characterization of most measures had been completed. It was subsequently consulted periodically as measures were reviewed and discussed by the SAG, but information drawn from this TRM is primarily drawn from version 11. Where the two versions were compared, Guidehouse staff found that in most cases inputs did not materially differ across versions.

Citation	Link (where relevant)
2023 Illinois Statewide Technical Reference Manual for Energy Efficiency Version 11 – Volume 3: Residential Measures, September 2022	
Iowa Utilities Board, *Energy Efficiency Programs – Technical Reference Manuals,* accessed February 2024 *Iowa Energy Efficiency Statewide Technical Reference Manual Version 7.0 Volume 2: Residential Measures,* July 2022 *Iowa Energy Efficiency Statewide Technical Reference Manual Version 8.0 Volume 2: Nonresidential Measures,* July 2023	**https://iub.iowa.gov/regulated-industries/energy-efficiency-programs**
Mass Save, *Technical Reference Manual*, Accessed February 2024 *Massachusetts Technical Reference Manual for Estimating Savings from Energy Efficiency Measures*, January 2023	**https://www.masssavedata.com/Public/TechnicalReferenceLibrary**
Michigan Public Service Commission, *Michigan Energy Measures Database*, Accessed November 2023	**https://www.michigan.gov/mpsc/regulatory/ewr/michigan-energy-measures-database**
Michigan Public Service Commission, *Michigan Behaviour Resource Manual*, Version 5.0	**https://www.michigan.gov/mpsc/regulatory/ewr/michigan-behavior-resource-manual**
New York State Department of Public Service, *Technical Resource Manual*, accessed February 2024 New York State Joint Utilities, *New York Standard Approach for Estimating Energy Savings from Energy Efficiency Programs – Residential, Multi-Family, and Commercial/Industrial Measures*, Version 10, December 2022	**https://dps.ny.gov/technical-resource-manual-trm**
Pennsylvania Public Utilities Commission, *SWE Team Incremental Measure Cost Database*, accessed February 2024	**https://www.puc.pa.gov/media/1316/act129_incremental_cost_database_v4-0.xlsx**
Ontario Energy Board, *Natural Gas Demand Side Management Technical Resource Manual Version 7.0*, November 2022	**https://engagewithus.oeb.ca/natural-gas-conservation-evaluation-advisory-committee/news_feed/2022-technical-resource-manual-update**
SAG-provided inputs, based on third-party sources (some included in this table), internal program data and analysis, and expert opinion.	
U.S. Department of Energy, Industrial Assessment Centre, *IAC Download Data*, Accessed July 2023	**https://iac.university/download**

In selecting from the available sources, Guidehouse prioritized the use of the OEB TRM, and after this (because of its comprehensiveness, recency, and geographic similarity) the Illinois TRM, and then the other sources as required. SAG member-provided inputs and data were used in preference to other sources when these were uncontested by other SAG members, or where consensus existed. In cases where SAG members disagreed about the validity of an input provided by another SAG member, OEB staff provided direction to Guidehouse as to the input to apply.

Measure-specific citations for inputs are provided in Appendix B.

4.2.4.3 Energy Savings and Incremental Costs

Residential and Commercial measure gas savings and incremental costs were developed through the application of the OEB TRM (preferred) or other TRMs or publicly available sources, as available. Savings calculations and cost estimates drawn from publicly available sources were in some cases adjusted or replaced based on recommendations or data provided by members of the SAG.

Fuel switching measures were considered only for the Residential and Commercial sectors. This was a limitation of the data available to Guidehouse and to the SAG. Savings for fuel-switching measures were developed specifically for this study, with savings for total end-use fuel-switching (e.g., the Residential cold climate air source heat pump, or ccHP) derived based on the per household or per building base-year end-use consumption derived in the Base Year Disaggregation task. Differences between savings in northern and southern parts of the province were addressed through the measure characterization on the basis of the average annual heating loads in Thunder Bay (north) and Toronto (south) reported in EGI heat pump study identified in Table 10.

Savings for partial electrification measures (e.g., air source heat pump with gas back up) were estimated as a function of the base-year end-use per household (or per building, for Commercial) end-use consumption. In these cases some share of space-heating was assumed to be displaced by the heat pump with the remainder of the heat load (in the coldest periods) addressed by the gas-fired component of the system.

Industrial measures were treated as custom, or bundled sets of, measures. Guidehouse defined Industrial measure savings as a percentage reduction of sub-sector and end-use consumption. The primary sources for Industrial measure savings and costs was the Industrial Assessment Center (IAC) database (see above). Guidehouse used the savings *opportunities* identified by IAC auditors (but not necessarily implemented/adopted) to quantify the segment-level remaining Technical potential.

Some SAG members noted in their review of Guidehouse’s Industrial measure data that IAC auditor recommendations are generally for measures demonstrated to be highly cost-effective across a wide range of installations, and that such audits – because of their relatively generic nature – tend not to identify emerging measures or specialized measures intended to address industry-specific gas-intensive end-uses. The implication of this observation is that there are significant energy savings opportunities not identified in the IAC audits and therefore not considered in the 2024 APS, suggesting that the Industrial measures considered for the 2024 APS may understate likely potential.

Section B.2 of Appendix B provides more detail on the process followed by the IAC to determine remaining measure-level potential.

4.2.4.4 Peak Electricity Demand Impacts

All references to “peak demand” in this report should be understood, unless otherwise explicitly noted, to refer to Ontario coincident electricity system peak demand.[46] The timing of coincident system peak demand for the purposes of this study is assumed to be consistent with the

[46] The impacts of the adoption of energy efficiency and fuel switching measures will also impact the coincident *gas* system peak demand. This can have important implications for natural gas supply and infrastructure costs; however assessing gas system peak demand impacts was outside the scope of this study

assumptions employed by the IESO for the value of system capacity (the cost of a marginal new resource) provided in its IRRP Guidelines[47], and with the seasonal timing of peak under projected design conditions in the 2022 APO.[48]

The 2024 APS differs from previous Ontario potential studies in that fuel-switching is treated not as a separate scenario and set of measures but is integrated in the modeling with the potential estimation for energy efficiency measures. This reflects the understanding of Guidehouse and OEB staff that for the potential study to deliver on the 0.5% and 1% year-over-year natural gas consumption reductions that the OEB directed the study to examine[footnote], fuel switching must be considered as a core resource, and not as an alternative hypothetical scenario.

Consequently, the impact of electrification on system peak (and the implications this has for the benefits of electrification) are a major concern for this study. As noted in Section 6, Guidehouse has accounted for the potential impact of electrification to accelerate Ontario's switch to becoming a winter-peaking jurisdiction, and has accounted for the marginal costs of incremental winter peak demand following that switch in its consideration of individual measure cost-effectiveness and net system benefit. More details on this can be found in Section D.1 of Appendix D.

For every electrification measure, therefore Guidehouse tracks both a summer and a winter peak demand impact. For water heating measures these are similar and are derived from estimated coincident peak demand factors drawn from the same sources as have provided the savings.

For space-heating measures demand impacts differ significantly by season.

Heat pump measures replacing less-efficient central air-conditioning units may (for example) deliver modest summer peak electricity demand savings, but where there is full electrification (as opposed to partial electrification using hybrid heat pumps with gas back-up) they will also result in significant increases in winter peak demand. So, for example, the peak (electricity) demand impact for a Residential cold climate heat pump without auxiliary gas heat is assumed to reflect that equipment operating with a coefficient of performance (COP) of 1.25 at times of system (winter) peak. This is in contrast to the assumed rated COP for this equipment of 4.3.

Hybrid (gas back-up) space-heating electrification measures were assumed to be installed by contractors operating under DSM program guidelines such that thermostats would be set to call for gas, instead of electric, heat at pre-set outdoor temperatures appropriate to sizing of the heat pump.[49] As such, these measures are assumed not to impact winter peak demand as it is defined for the purposes of estimating marginal capacity costs in this study. Should a more expansive view of coincident electric peak demand be adopted (e.g., the definition laid out in the

[47] Independent Electricity System Operator, *Integrated Regional Resource Plans: Guide to Assessing Non-Wires Alternatives*, May 2023

Available at: **https://www.ieso.ca/Get-Involved/Regional-Planning/About-Regional-Planning/Planning-Information-and-Data**

[48] Although the 2024 APO appeared prior to the completion of the 2023 APS, this study was sufficiently advanced by that time that a thorough update of the input values drawn from the 2022 APO was not practical.

[49] Through discussions with the SAG, Guidehouse understands anecdotally that it is current practice for installers of hybrid systems under the Greener Homes Grant to apply such defaults and has assumed an effective program design that formalizes this practice, with thresholds determined based on an updated analysis of the most current estimates of net system and customer benefits.

IESO's EM&V protocols[50]), peak demand for these measures would need to be re-assessed (though so too would the marginal system cost of that incremental demand).[51]

Peak demand impacts for most fuel-switching measures were developed on a custom, measure-by-measure basis, in consultation with the SAG, which reviewed and provided multiple rounds feedback throughout the study period.

4.2.4.5 Applicability Factors

The available market to which efficient measures may feasibly be deployed in the 2024 APS is defined by three applicability factors: density, saturation, and technical suitability.

- **Density** is, in this study, an estimate of the average number of baseline and efficient measure units per unit basis (per building in the Residential and Commercial sectors, and per m3 of gas use in Industrial sector). For example: there are approximately 0.86 gas-fired water heaters per detached house served by EGI. The density for water heater replacement measures (e.g., a heat pump water heater) is 0.86.

- **Saturation** although this may refer either to baseline or efficient initial saturation, the term most commonly identifies efficient initial saturation. Efficient initial saturation is the estimated share of the density that has already been captured by efficient measure. For example, 15% of detached homes built between 1975 and 2006 are assumed to already have roof insulation with an R-value of between 15.5 and 27. The saturation for this iteration of the roof insulation is 0.15.

- **Technical suitability** is the share of remaining potential opportunities for the measure (i.e., the share of the product of the density and one minus efficient saturation) at which the application of the measure is technically feasible. For example, residential heat pump water heaters have been estimated to be technically feasible at approximately 85% of Residential detached houses.

Applicability factors were drawn from EGI's Residential End-Use Survey, data developed as part of the Base Year Disaggregation (customer counts and gas use), Natural Resources Canada's Comprehensive Energy Use Database, the 2019 APS, and the informed professional opinions of SAG members and Guidehouse staff. A detailed list of all sources by measure for the applicability factors is provided in Section B.1 of Appendix B.

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[50] The IESO EM&V Protocol defines winter peak demand as being average demand between 6pm and 8pm on non-holiday weekdays, December through February.

See Table 6-1 of: Independent Electricity System Operator, *Evaluation, Measurement and Verification Protocol V4.0*, February 2021

Available at: **https://www.ieso.ca/en/Sector-Participants/Energy-Efficiency/Evaluation-Measurement-and-Verification**

[51] The IESO CDM Cost-Effectiveness Tool does not currently assign any value to winter capacity. Summer peak capacity is valued at – on average between 2024 and 2043 - $82 per kW-year (2021 dollars), considerably less than the value of $144 per kW-year used in this study.

See tab "Avoided Cost Table" of the CDM Tool ("IESO-CDM-CE-Tool-V9-2-Feb-17-2023.xlsb")

Available at: **https://www.ieso.ca/en/Sector-Participants/Energy-Efficiency/Evaluation-Measurement-and-Verification**

4.2.5 Measure Review Process

Measure inputs received extensive review by members of the SAG and updates were made by Guidehouse to reflect SAG feedback where directed to do so by OEB staff. Each sector's measures underwent two initial rounds of review by one of three sector-specific sub-committees. Measure inputs were subsequently reviewed, discussed, and updated based on feedback provided by SAG members as part of their review of the Technical, Economic, and Achievable potential estimates.

The Phase 1 round of measure review focused on measure savings and cost inputs. The Phase 2 round of measure review focused on the applicability factors.

Prior to the start of the Phase 1 review process, the Guidehouse team presented each sectoral sub-committee with a sector-specific tutorial articulating the underlying structure of Guidehouse's approach to estimating savings accompanied by some contextual information regarding how those savings were processed through its model. Prior to the start of the Phase 2 review process, the Guidehouse team presented to each sectoral sub-committee a tutorial specific to the calculation of applicability factors, including defining the various applicability factors and describing their interactions.

Following this two-phased review process, members of the SAG and the Guidehouse team continued to review, refine, and adjust measure definitions and inputs throughout the potential development process. Substantial revisions were made to measure inputs for the Residential and Commercial sectors following the SAG's review of the Technical, Economic, and Achievable potential draft results.

Guidehouse tracked 274, 389, and 45 sets of initial measure review comments for the Residential, Commercial and Industrial sector measures, respectively, as part of the initial two-phased review process. In many cases a single tracked line item would include multiple items, and frequently several iterations of review, response and discussion were required prior to a measure input being finalized.

The items noted above are only those tracked directly to the measure characterization task. An additional 59 and 74 line items (sets of comments) respectively were tracked for SAG feedback regarding the Technical/Economic and Achievable draft potential outputs, most of which related to measure-level assumptions driving savings.

4.3 Results

The measure parameter values are available in Appendix X1, an Excel workbook that accompanies this report.

5. Technical Potential

This section describes Guidehouse's approach to estimating Technical potential and presents the results for Ontario.

The objective of the Technical potential task is to estimate the technically feasible energy efficiency and fuel switching potential across the 20-year period of analysis, from 2024 through 2043. The Technical potential provides an upper bound to the projected achievement of future conservation efforts and is unconstrained by considerations of cost-effectiveness (captured by the Economic potential) or questions of consumer adoption (captured by the various Achievable potential scenarios). The Technical potential is driven by inputs provided by the reference forecast and measure characterisation tasks.

This chapter of the report is divided into three sections:

1. **Scope:** Outlines the primary and sensitivity outputs for Technical potential, identifies some of the most critical modeling mechanics, and defines the key outputs generated as part of the Technical potential analysis.
2. **Methodology:** Provides a high-level description of the key assumptions and analytic approaches used to estimate the Technical potential. Additional detail on select methods are found in Appendix C.
3. **Results:** Provides a summary of the results of the Technical potential.

5.1 Scope

The goal of the Technical potential analysis is to estimate the combined maximum technically feasible reduction to natural gas consumption (given interactions, competition) that may be delivered by the measures characterised as part of the measure characterisation task.

The purpose of Technical potential is primarily diagnostic. Unconstrained Technical potential disregards all questions of cost-effectiveness, limitations on the timing of consumer adoption, or considerations of consumer payback. The most useful insights provided by Technical potential are at the measure-level, helping to identify measures the inputs of which may require review or revision. The importance of Technical potential as a quality control step was previously identified in the recommendations of the 2019 APS.

5.1.1 Core and Sensitivity Scenarios

Accordingly, and given the increased emphasis in the 2024 APS on fuel switching measures, two versions of Technical potential were estimated at the request of the SAG:

- **EE + FS.** The primary version includes all measures, energy efficiency and fuel switching ("EE + FS").
- **EE Only.** A sensitivity version of Technical potential was also estimated, one in which only energy efficiency measures were included ("EE only").

5.1.2 Key Considerations in Technical Potential Estimation

Technical potential estimates are “unconstrained” by considerations of equipment turnover, with each year treated as independent of the others. What this means is that (for example), the Technical potential in 2030 is an estimate of all savings that are technically feasible in 2030: all retrofit, all replace-on-burnout, and all new measures are replaced in a single year.

This differs from the 2019 APS in which Technical potential was constrained by equipment turnover, so care should be exercised in comparing the Technical potential of the two studies.

Guidehouse has chosen to adopt the unconstrained approach for the 2024 APS for two reasons. Firstly, accounting for equipment turnover (as in constrained potential) adds an effect that confounds the assessment of total Technical potential in any given year and therefore impedes the primary purpose of the Technical potential; to provide measure-level quality checks. Secondly, it aligns the 2024 APS to Guidehouse’s standard practice for potential estimation in other jurisdictions, as well as to that of other firms in the potential estimation space. More details on this subject may be found in Section C.1 of Appendix C.

The estimation of Technical potential addresses the following considerations:

- **Measure Replacement Types:** Measures may be installed at the time of building construction (NEW), after construction but before the end of the measure’s useful life (retrofit - RET) or at the end of a measure’s useful life (replace-on-burnout - ROB).
- **Competing Measures and Competition Groups:** Cases in which two or more mutually exclusive measures exist (e.g., an ASHP with gas back-up or an ASHP with electric resistance auxiliary heat).
- **Measure stacking:** When two measures that share the same end use are installed at the same time, the total savings of the two combined may be less than the sum of their individual savings. For example, adding insulation to a home and replacing the furnace will deliver an aggregate savings that is less than the savings of these two measures on their own.

These are discussed in Section 5.2, below.

5.1.3 Potential Study Outputs

The primary outputs of the Technical potential analysis that are provided in this report are:

- **Natural Gas Technical Potential (millions of m^3)** from energy efficiency and fuel switching measures.
- **Winter Coincident Peak Demand Impacts (MW).** For the purposes of this study, winter peak demand is defined to be consistent with (though not identical to) the definition used by the IESO for calculating the peak demand factor (PDF) used in the allocation of the GA[52], except on a seasonal basis. So coincident winter peak demand is the demand assumed to be imposed on the system in the peak hour of the five highest demand days in the winter, on a forward-looking weather-normal basis.

[52] Independent Electricity System Operator, *Global Adjustment and Peak Demand Factor*, accessed March 2024 **https://www.ieso.ca/en/Sector-Participants/Settlements/Global-Adjustment-and-Peak-Demand-Factor**

- **GHG Emissions Reductions (Mt CO2e)** associated with the Technical potential natural gas savings[53], net of the incremental emissions required to supply the incremental electric energy required by fuel switching.[54]

Secondary outputs of the Technical potential analysis that have been estimated and tracked by Guidehouse, but have not, for concision, been included in this report, but are available in the accompanying Appendix X2 workbook, are:

- **Annual Electric Energy Impacts (GWh)** resulting from fuel switching measures.
- **Summer Coincident Peak Demand Impacts (MW).** Summer peak demand impacts associated with electrification, defined in a manner consistent with winter peak demand impacts. While winter peak demand impacts are in aggregate *increases* to peak demand associated with the electrification of space- and water-heating technologies, summer peak demand impacts are in aggregate *decreases* to peak demand associated with the replacement of standard efficiency A/C units with higher efficiency heat pumps.
- **Measure-Level Impacts (After Competition Groups).** Measure-level estimated Technical potential impacts for gas, electric energy, and winter and summer peak demand, after the competition group adjustment, but before the measure-stacking adjustment.

5.2 Methodology

Technical potential is defined as the energy savings that can be achieved assuming that all baselines can immediately be replaced with their corresponding efficient measure/technology, wherever technically feasible, regardless of the cost, market acceptance, or whether a measure has failed and must be replaced.

The calculation of Technical potential varies depending on the assumed measure replacement type, since Technical potential is calculated on a per-measure basis and includes estimates of savings per unit, measure density (e.g., quantity of measures per home), and total building stock.

The DSMSim™ model accounts for three replacement types, where Technical potential from **retrofit** and **replace-on-burnout** measures are calculated differently from Technical potential for **new construction** measures.

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[53] GHG emissions savings resulting from natural gas consumption reductions are calculated using the emissions factor developed by Enbridge Gas for its online emissions calculator

Enbridge Gas Inc., *Greenhouse gas emissions calculator*, accessed July 2023

https://www.enbridgegas.com/ontario/business-industrial/incentives-conservation/energy-calculators/Greenhouse-Gas-Emissions

[54] Incremental generation emissions are estimated by applying the projected average emissions factor derived from data in the IESO's 2022 Annual Planning Outlook, see Figures 43 and 48 of

Independent Electricity System Operator, *Annual Planning Outlook Data Tables,* December 2022

Available at: **https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook**

The average emissions factor, rather than the marginal emissions factor, was selected for use in this study on the logic that while modest increases in electricity consumption would be on the margin and served by marginal generation, a major structural change (i.e., aggressive electrification of space heating) would be considered by system planners as part of their planning. In this case in the medium term planners would not simply rely on the marginal resource (gas peakers) to meet the need, but procure a more diverse set of supply options. Thus it was determined to be appropriate to use the average emission factor in each forecast year (implicitly assuming that the entire generation mix would scale up) rather than the marginal emissions factor (implicitly assuming all projected load growth is met with simple cycle gas generation). It should be noted that the average emissions factor does climb over time, reflecting the 2022 APO's projected generation mix.

5.2.1 Measure Replacement Type

This study considers three measure types:

- **Replace-on-Burnout (ROB).** Are replacements of existing equipment that are at the end of their expected useful life (EUL) and must be replaced, or existing processes that must be renewed. A capital investment by the consumer is required whether for the efficiency measure or the baseline technology. This means the cost of implementing ROB measures is always incremental to the cost of a baseline (and less efficient) measure. This also means that savings are incremental to the consumption of the baseline replacement technology, not to the consumption of the technology at end-of-life being replaced.

  In Achievable potential estimation, the applicable market for ROB measures is constrained to the share of existing technologies reaching the end of their EUL in each year. Technical and Economic potential estimation relaxes this constraint and considers potential in each year as a snapshot of all available ROB potential, unconstrained by considerations of equipment turnover.

  An example ROB measure type is a water heater. When a standard gas storage water heater fails or reaches the end of its EUL it can be replaced either by another code compliant gas storage water heater (baseline technology), or one of: a high-efficiency gas storage water heater, an electric resistance storage water heater, or a heat pump water heater (one of three competing efficiency measures).

- **Retrofit (RET).** This measure type is the replacement of existing equipment before the equipment fails or for the installation of efficient processes or equipment not currently in place. RET measures incur the full cost of implementation rather than incremental costs to some other baseline technology or process because the customer could choose not to replace the measure and would, therefore, incur no costs.

  Examples of RET measures include most building envelope measures[55] (e.g., insulation, air curtains, etc.), demand recovery ventilation and adaptive thermostats.

- **New Construction (NEW).** New construction Technical potential is driven by equipment installations in new building stock rather than by equipment in existing building stock. New building stock is added to keep up with forecasted growth in total building stock and to replace existing stock that is demolished each year. Demolished stock is calculated as a percentage of existing stock in each year. New building stock (the sum of growth in building stock and replacement of demolished stock) determines the annual incremental additions to Technical potential, which is then added to totals from previous years to calculate the total potential in any given year.

  In many cases NEW measure incremental costs and savings are the same as for ROB measures. Examples where this is not the case include many Residential envelope measures (where incremental costs for NEW are much lower).

More detail regarding differences in Technical potential estimation by measure type may be found in Section C.2 of Appendix C.

[55] Notably, for the 2023 APS Residential windows are considered ROB, rather than RET measures, as pre a recommendation by members of the SAG – see Section B.3.8 of Appendix B

5.2.2 Competing Measures and Competition Groups

The study defines competition as efficient measures competing for the same installation as opposed to competing for the same savings (e.g., window A/C vs. split-system A/C) or for the same budget (e.g., space heating vs. water heating). For instance, a consumer may install a heat pump water heater or a high-efficiency gas-fired water heater. Both of belong to the same competition group, as only one of these would be installed. General characteristics of competing technologies used to define the competition groups included in are:

- Competing efficient technologies share the same baseline technology characteristics, including baseline technology densities, costs, and consumption.
- The total (baseline saturation plus efficient saturation) maximum densities of competing efficient technologies are the same.
- Installation of competing technologies is mutually exclusive (i.e., installing one precludes installation of the others for that application).
- Competing technologies share the same replacement type (RET, ROB, or NEW).

To avoid double-counting savings in the Technical potential, a single measure in each year is selected as the “winner” of the competition group. Only this measure’s Technical potential is included in the sub-sector and sectoral aggregations of potential. The “winner” of the competition group for Technical potential is selected by estimating the Technical potential for all the measures within the competition group. The measure with the largest aggregate first-year savings is the winner, and only that measure’s Technical potential is carried forward for aggregation to the sub-sector and sector level.

This application of the competition logic means that if two measures with have the same gas savings, but the Technical Suitability of one is lower than the other, the one with the higher Technical Suitability – the higher aggregate potential – will “win” the competition group. This is the case of electric resistance storage water heaters in the Residential sector, which displace heat pump water heaters in the Technical Potential because of the lower Technical Suitability of the latter. Although it is theoretically possible for a measure with higher savings to “lose” the competition group to a lower savings measure that has a much higher Technical Suitability, no examples of this outcome have been noted in the 2024 APS.

The logic applied to control for the effects of competing measures differs for Economic potential (which screens for cost-effectiveness) and Achievable potential (which allows for the adoption of a mix of competing measures).

5.2.3 Measure Stacking

The 2019 APS, at the request of stakeholders participating in that study’s Advisory Group, included measure stacking logic to control for the interactions of “engine” and “envelope” measures.[56] This post-processing step was applied to Technical, Economic, and Achievable potential and controlled for the fact that – for example – the sum of savings for an efficient

[56] For a complete description of this approach, please see Section D.1.1 of

Navigant (n/k/a Guidehouse) prepared for the Independent Electricity System Operator and the Ontario Energy Board, *2019 Integrated Ontario Electricity and Natural Gas Achievable Potential Study*, December 2019

Available at: **https://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Engagements/2019-Conservation-Achievable-Potential-Study** heating system (the “engine”) and improved insulation (“envelope”) will overstate the combined savings of both installed together.

This post-processing step was cumbersome and reduced the transparency of the Achievable potential by making it impossible – outside the proprietary DSMSim model – to match the sum of measure-level potential to aggregate sub-sector or sector-level potential. The 2019 report concluded that: “*The net effect of measure stacking for achievable potential in this study was trivial.*“ and recommended that, absent additional research into the frequency of stacking, this not be applied in future studies. The 2024 APS has, accordingly, not carried this post-processing logic forward.

Some form of measure stacking adjustment is, however, required for Technical and Economic potential by the inclusion of fuel switching and energy efficiency measures within the same scenario. Failure to apply post-processing to adjust gas savings from energy efficiency measures to reflect the displacement of gas-fired heating equipment by electric heating equipment in Technical potential (where adoption is not constrained by annual turnover assumptions) could result in estimated potential exceeding the reference forecast.

Accordingly, measure stacking logic is applied after the estimation of measure-level savings as these are being aggregated up to each unique combination of end-use and sub-sector. This logic applies an adjustment to the gas savings impact of envelope measures by assuming that the stock available for such measures is removed from the market by the penetration of equipment electrification measures.

This impacts only the aggregated (i.e., sub-sector/end-use) level potential, not measure-level potential. This means it is possible that the sum of Technical potential across measures (e.g., that discussed in Section 5.3.3) can exceed the reference forecast, even though the aggregated potential (which reflects the stacking logic) does not.

This post-processing is not necessary for the Achievable potential, where potential is constrained in each year by equipment turnover. For Achievable potential, the stock of buildings to which envelope measures can be applied is adjusted in each year on the basis of the stock that adopted electrification in the prior year.

5.3 Results

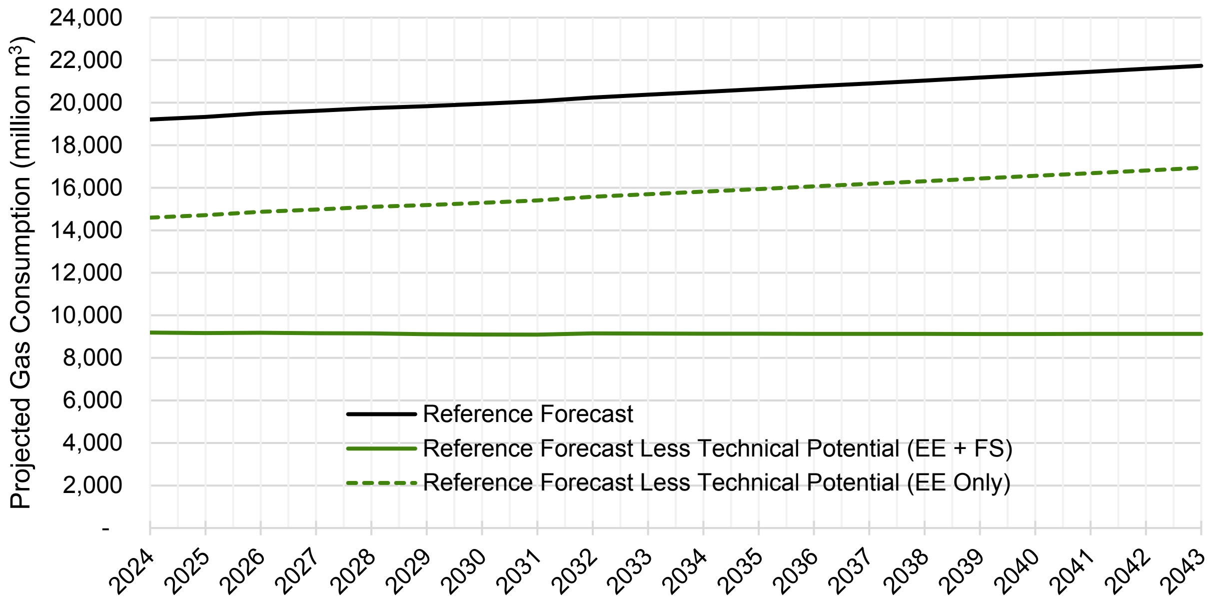
This section provides a summary of the Technical potential (EE + FS) and the sensitivity Technical potential (EE only) scenarios results from the following perspectives:

1. Natural Gas Technical Potential by Sector
2. Technical Potential Winter Peak Demand Impacts by Sector
3. Measure-Level Natural Gas Technical Potential by Sector

The GHG impacts of the Technical potential by sector, and a summary of the sub-sector-level Technical potential natural gas savings are presented in Appendix C.

Figure 37, below, provides a summary comparison of the aggregate estimated Technical potential and the reference forecast. The reference forecast is represented by the black line and the reference forecast less the estimated Technical potential is represented by the solid green line. The dashed green line represents the sensitivity scenario that considers the Technical potential only of energy efficiency measures and excludes fuel switching measures.

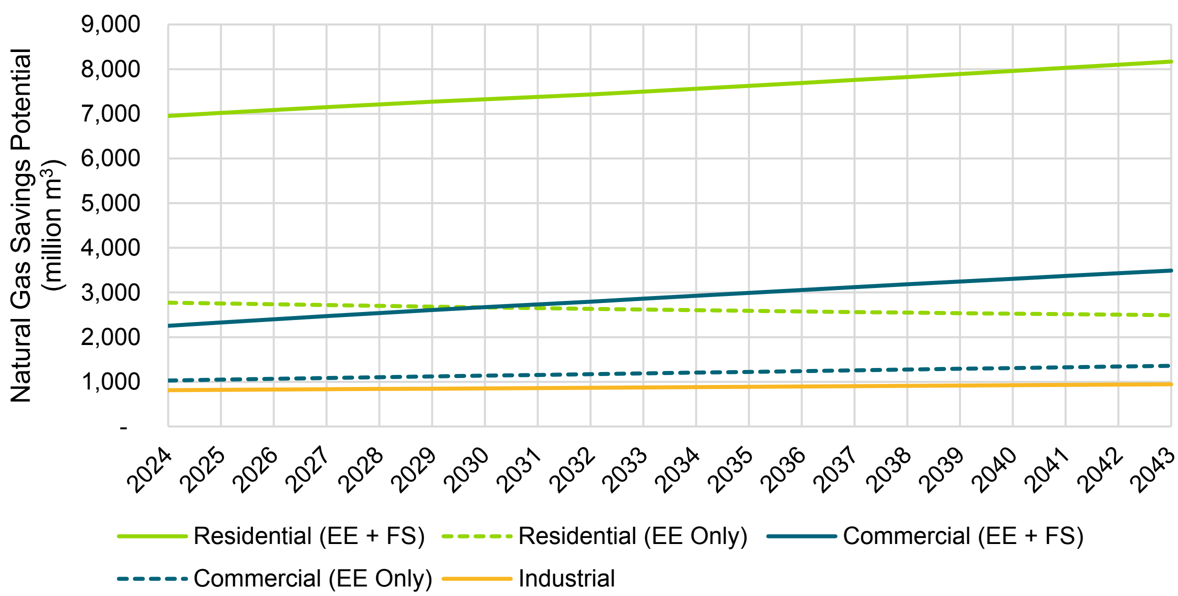
Figure 37. Reference Forecast and Technical Potential



5.3.1 Natural Gas Technical Potential by Sector

Figure 38, below, shows the total estimated Technical potential when including fuel switching (solid lines) as well as under the sensitivity scenario, which considers only energy efficiency measures. No fuel switching measures were considered for the Industrial sector so only a single series is presented for this sector.

Figure 38. Technical Potential and EE-Only Sensitivity Technical Potential by Sector



Because Technical potential presents a snapshot in each year and is not constrained by considerations of equipment turnover, Technical potential begins the series very high. Growth over the period of analysis is a reflection of increasing stock, and thus an increasing number of opportunities of efficient measures. The declining slope of the EE-only potential is a reflection of two factors:

- **NEW vs RET Savings.** The energy efficiency measures in the Residential sector are dominated by envelope improvements. The savings of such measures for NEW installations tend to be lower than for ROB installations because of the increasing code baseline efficiency level of homes.
- **Demolitions and RET savings.** Housing replacement over time erodes the market for higher-savings RET measures. This reduces potential. This effect is partially offset by the application of incremental measures to NEW construction, but the higher starting baseline efficiency cannot wholly offset this effect.

Table 11, below, shows the Technical potential as a share of the reference forecast for each sector. Industrial Technical potential is the lowest. This is for two reasons. Firstly, as noted in Section B.2 of Appendix B, the source for measure savings includes measures recommended for implementation through audits and so may not include higher-savings measures that are highly custom or industry specific, as well as measures that may deliver high levels of savings but with longer paybacks. The Industrial measure list likewise does not include any fuel-switching measures, measures which account for most of the savings.

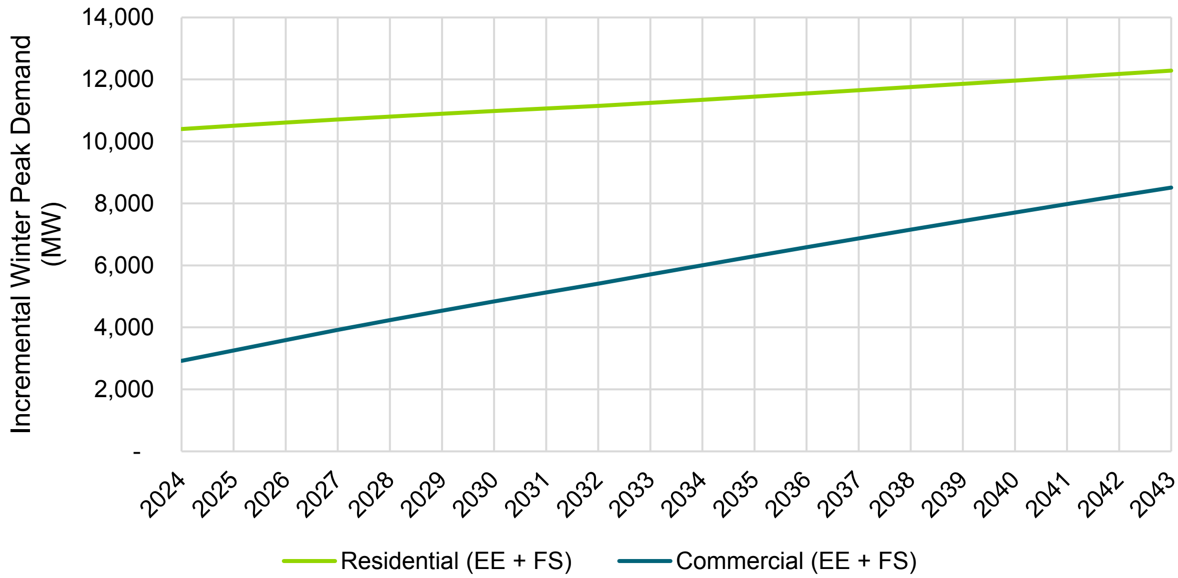
Table 11. Technical Potential As Percent of Corresponding Sector Reference Forecast

Scenario	Year	Residential	Commercial	Industrial	Total
Technical, EE + FS	2028	86%	39%	17%	**54%**
	2035	87%	44%	17%	**56%**
	2043	89%	49%	17%	**58%**
Technical, EE Only	2028	32%	17%	17%	**24%**
	2035	30%	18%	17%	**23%**
	2043	27%	19%	17%	**22%**

5.3.2 Technical Potential Winter Peak Demand Impacts by Sector

Figure 39 shows the estimated winter peak demand impact of the measures included in the Technical potential for the Residential and Commercial sectors. No winter peak demand impact is estimated for the Industrial sector as no fuel switching measures were included for that sector. In this graph, a positive value indicates an *increase* in peak demand.

Figure 39. Winter Peak Electricity Demand Impacts Associated with Technical Potential



The differential between the sectors' winter peak demand impact is consistent with the differential in natural gas Technical potential and the underlying measure mixes modeled for the two sectors. The scale of these estimated impacts is most apparent when comparing these estimated values to the IESO's forecast of winter peak demand under its 2024 Annual Planning Outlook scenario.[57] This work projects Ontario winter peak demand to increase from approximately 23 GW in 2025 to approximately 33 GW in 2043.

5.3.3 Measure-Level Natural Gas Technical Potential by Sector

Reviewing measure-level potential can be challenging given the number of measures (and their various iterations) considered in the study.

To assist OEB staff and members of the SAG with their review of estimated potential, Guidehouse developed a series of diagnostic plots. These plots aggregate measure savings across sub-sectors and display only the savings for top six highest savings measures, on average, across the first ten years of the period of projection. The potential for all remaining measures is aggregated into two categories: "Below Top 6 EE" for energy efficiency measures, and "Below Top 6 FS" for fuel switching measures.

Care should be taken in reviewing plots that include fuel switching measures to recall that due to measure stacking (which controls for the fact that fuel switching measures displace consumption that could yield savings from energy efficiency measures), the sum of potential across measures will be more than the aggregate sector-level potential shown above.

Figure 40 shows the measure-level potential diagnostic plot for the Residential sector.

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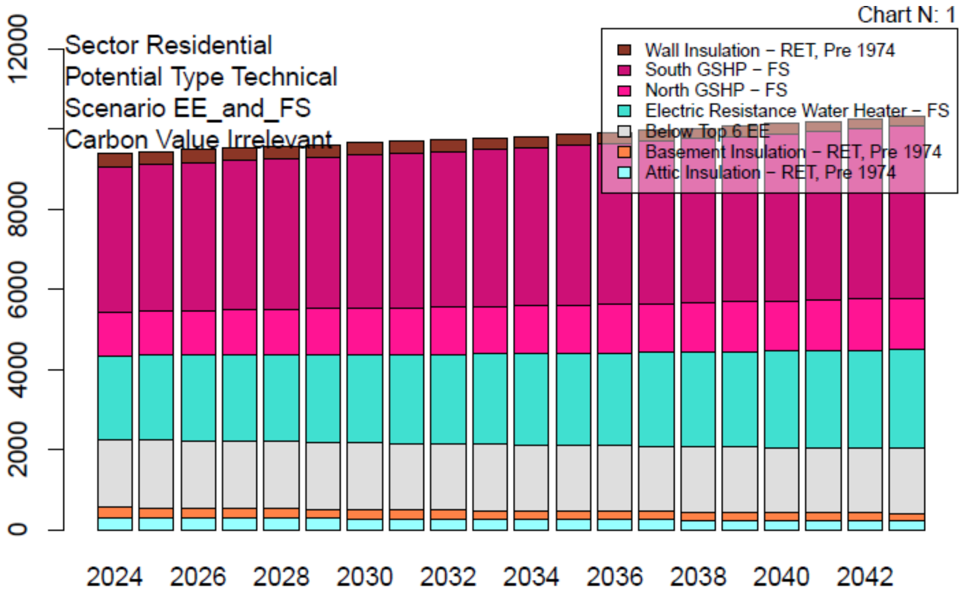
[57] See Figure 3 of
Independent Electricity System Operator, *Annual Planning Outlook Data Tables,* March 2024
https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook

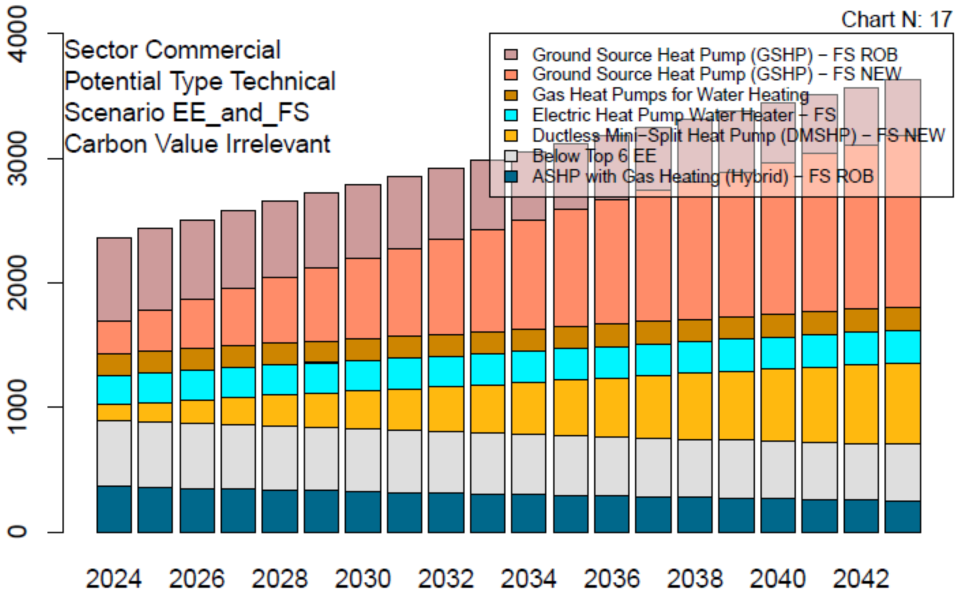
Figure 40. Residential Measure-Level Technical Potential – Top Six Measures (millions of m^3)



In the Residential sector, the ground source heat pump wins the Technical potential competition group. The GSHP delivers more savings than the hybrid electrification measures. The GSHP measure also results in a lower electric energy impact and considerably lower winter peak demand impact than the full electrification ASHP measure. Water heating electrification, represented by an Energy Star (EF=0.92) electric resistance water heater, captures nearly all consumption in that end-use. This measure wins, rather than the heat pump water heater fuel switching measure, because of its higher Technical Suitability (see Section B.3.4).

Figure 41 shows the measure-level potential diagnostic plot for the Commercial sector.

Figure 41. Commercial Measure-Level Technical Potential – Top Six Measures (millions of m³)

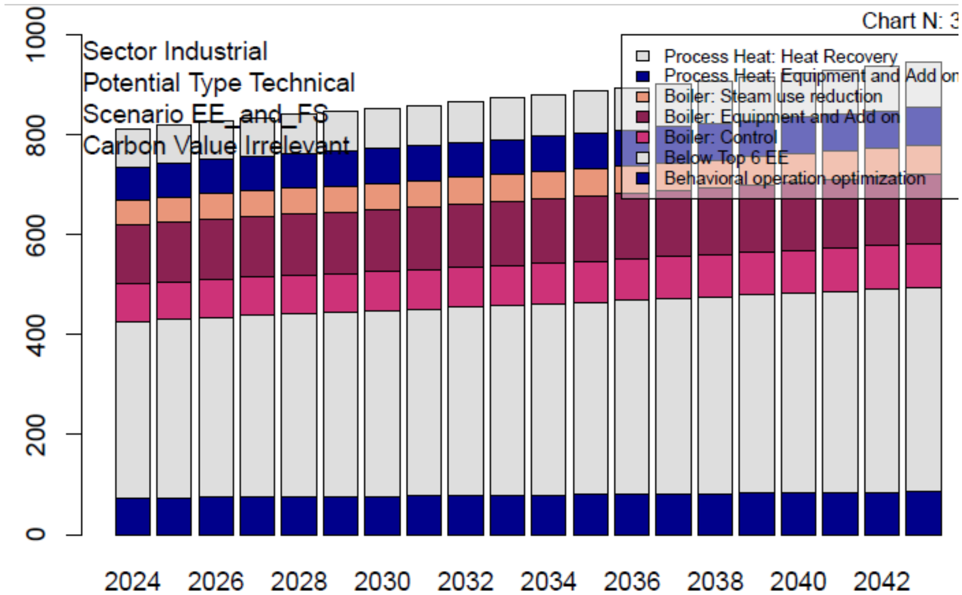


The most significant feature of the Commercial Technical potential, compared to the Residential, is the diversity of water and space-heating measures. This is an indication of the diversity in Technical Suitability of the different measures across the sub-sectors. As per a recommendation provided by a member of the SAG and endorsed by OEB staff, gas heat pump water heaters have zero Technical Suitability for sub-sectors of smaller buildings, and fuel switching heat pump water heaters have zero Technical Suitability for sub-sectors of larger buildings.

For space heating measures, the differentiation is more nuanced, with Technical Suitability of full and partial electrification measures driven by measure replacement type (i.e., NEW vs. ROB) as well as by sub-sector, but the underlying reason for the diversity is the same: the winning measure within a competition group is sub-sector specific, and the underlying equipment and processes differ considerably across Commercial sub-sectors.

Figure 42 shows the measure-level potential diagnostic plot for the Industrial sector.

Figure 42. Industrial Measure-Level Technical Potential – Top Six Measures (millions of m^3)



The most significant feature of this diagnostic for the Industrial sector is the dominance of the "Below Top 6 EE" measure category. For the Residential and Commercial sectors, this group of measures contributed only a relatively small proportion of potential. For the Industrial sector it contributes nearly half. This is a reflection of the highly diverse and sub-sector-specific nature of the measures; rather than three (Residential) or six (Commercial) measures dominating Technical potential, the driver of aggregate potential in the Industrial sector is the large set of measures that – because of the specialized nature – make relatively modest individual contributions, but together a significant aggregate contribution to sector potential.

6. Economic Potential

This section describes Guidehouse's approach to estimating Economic potential and presents the results for Ontario.

The objective of the Economic potential task is to estimate the technically feasible *and cost-effective* energy efficiency and fuel switching potential across the 20-year period of analysis, from 2024 through 2043. The Economic potential is estimated in the same way as the Technical potential but considers only measures with a cost-effectiveness ratio above one. The Economic potential does not consider questions of consumer adoption (captured by the various Achievable potential scenarios) and, like Technical potential, is unconstrained by considerations of equipment turnover. The Economic potential is driven by inputs provided by the reference forecast and measure characterisation tasks, and the provincial value streams used to evaluate cost-effectiveness from the Total Resource Cost-Plus perspective.

This chapter of the report is divided into three sections:

1. **Scope:** Outlines the primary and sensitivity outputs for Economic potential, identifies the value streams considered in cost-effectiveness testing.
2. **Methodology:** Provides a description of the cost-effectiveness testing applied to measures and the value streams used in assessing cost-effectiveness. Additional detail on the value streams used for cost-effectiveness testing may be found in Appendix D.
3. **Results:** Provides a summary of the results of the Economic potential.

6.1 Scope

The goal of the Economic potential analysis is to estimate the combined maximum technically feasible reduction to natural gas consumption (given interactions, competition) that may be delivered in each year of the period of analysis by the measures that are cost-effective from the Total Resource Cost-Plus perspective adopted by the OEB.

The purpose of Economic potential is primarily diagnostic. Unconstrained Economic potential disregards limitations on the timing of consumer adoption and considerations of consumer payback. The outputs of the Economic potential, when compared to the Technical potential results, assist reviewers in assessing the accuracy and appropriateness of measure-level estimated costs, natural gas savings, and – for fuel-switching measures – the accuracy and appropriateness of incremental electric energy and coincident peak demand impact assumptions.

6.1.1 Core and Sensitivity Scenarios

A key update to the value streams applied for estimating cost-effectiveness in the 2024 APS has been the inclusion of the Social Cost of Carbon (SCC) as the primary source to calculate the present-value cost impact of carbon emissions, instead of the federal fuel charge (sometimes referred to as the "*carbon price*" or "Canadian Federal Backstop" or CFB). Previously, for the 2019 APS, the CFB was used as a proxy to capture the present-value cost impacts of carbon emissions as required by the TRC-Plus perspective. This is discussed in greater detail in Section 6.2.2, below.

To better understand the implications of this update, and of the increased importance of fuel switching measures in the modeled measure mix, SAG members recommended that four versions of Economic potential be output. OEB staff directed Guidehouse output the following four versions of Economic potential.

- **EE + FS.** The primary version includes all measures, energy efficiency and fuel switching ("EE + FS") and uses the SCC for cost-effectiveness testing.
- **EE + FS - CFB.** A sensitivity version of Economic potential that includes all measures, but uses the CFB instead of the SCC for cost-effectiveness testing.
- **EE Only.** A sensitivity version of Economic potential that includes only energy efficiency measures and uses the SCC for cost-effectiveness testing.
- **EE Only –** CFB. A sensitivity version of Economic potential that includes only energy efficiency measures and uses the CFB instead of the SCC for cost-effectiveness testing.

Like Technical potential, Economic potential estimates are "unconstrained" by considerations of equipment turnover. Each year is treated as independent of the others.

6.1.2 Value Streams Considered

A measure is considered cost-effective and included in the estimation of Economic potential where it has a TRC-plus ratio of one or more. The value streams included for cost-effectiveness testing were selected to be consistent with the direction provided by the OEB in it's Decision and Order EB-2021-0002.[58]

In addition to measure-specific incremental costs, cost-effectiveness testing considered:

- **Natural Gas Avoided Costs:** The primary benefit stream. The values were provided by EGI.
- **Electric Energy Marginal Costs:** In most cases (i.e., for fuel switching measures) these are a cost. These were drawn from the IESO's 2022 APO.[59]
- **Cost of Peak Capacity:** the incremental cost assumed to be incurred by increases in provincial coincident peak demand. This value was drawn from the IESO's IRRP Guide to Assessing Non-Wires Alternatives.[60]

[58] See Section 4.9, PDF 85 of 149 of
Ontario Energy Board, *Decision and Order: Application for Multi-Year Natural Gas Demand Side Management Plan (2022 to 2027),* Enbridge Gas Inc., EB-2021-0002, November 2022
https://www.oeb.ca/node/3869

[59] See Figure 47 of
Independent Electricity System Operator, *Annual Planning Outlook Data Tables,* March 2024
https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook

[60] Independent Electricity System Operator, *Integrated Regional Resource Plans: Guide to Assessing Non-Wires Alternatives*, May 2023
Available at: **https://www.ieso.ca/Get-Involved/Regional-Planning/About-Regional-Planning/Planning-Information-and-Data**

- **Value of Carbon:** the social cost of carbon (SCC) was drawn from the Government of Canada[61] and the value of CFB was drawn from EGI.[62]

Greater detail is provided on the derivation of these series in Section 6.2.2.

6.1.3 Potential Study Outputs

The primary outputs of the Economic potential analysis that are provided in this report are the same as for Technical potential:

- **Natural Gas Economic Potential (millions of m^3)**.
- **Winter Coincident Peak Demand Impacts (MW).**
- **GHG Emissions Reductions (Mt CO2e)**

Secondary outputs of the Economic potential analysis that have been estimated and tracked by Guidehouse, but have not, for concision, been include all those identified for Technical potential as well as:

- **Annual Electric Energy Impacts (GWh)**.
- **Summer Coincident Peak Demand Impacts (MW).**
- **Measure-Level Impacts (After Competition Groups).**

6.2 Methodology

Economic potential is defined as the energy savings that can be achieved assuming that all baselines can immediately be replaced with their corresponding efficient measure/technology, wherever technically feasible, regardless of market acceptance, or whether a measure has failed and must be replaced. Only measures that are cost-effective in any given year (i.e., have TRC-Plus test ratio of 1 or more) are considered for inclusion in Economic potential.

Like Technical potential, Economic potential is unconstrained by considerations of technology annual replacement rates.

This section is divided into three sub-sections:

1. **Cost Effectiveness** describes the cost-effectiveness testing approach applied in estimating Economic potential.
2. **Provincial Benefit and Cost Streams** describes each of the four value-streams – in addition to the measure-specific incremental costs – considered in cost-effectiveness testing.

[61] Government of Canada, *Social Cost of Greenhouse Gas Estimates – Interim Updated Guidance for the Government of Canada*, April 2023
https://www.canada.ca/en/environment-climate-change/services/climate-change/science-research-data/social-cost-ghg.html

[62] Enbridge Gas, Inc. *Federal Carbon Charge*, accessed February 2024
https://www.enbridgegas.com/ontario/my-account/rates/federal-carbon-charge

3. **Competing Measures & Measure Stacking** briefly describes how the competition group and measure stacking logic used in the Technical potential differ for the estimation of Economic potential.

6.2.1 Cost Effectiveness

Measure cost-effectiveness is determined on the basis of the benefit/cost ratio calculated using the TRC-Plus test, as defined in the OEB's Decision approving EGI's multi-year DSM plan.[63]

Measure cost-effectiveness is calculated by dividing the present value of measure benefits by the present value of measure costs (i.e,, streams of benefits and costs are tracked over the lifetime of the measure and converted to a present value for the year the measure is adopted). In years where this fraction is greater or equal to one, the measure is cost-effective. In years where this fraction is less than one, the measure is not cost-effective.

Consistent with the OEB's direction in EB-2021-0002[64], the present value of benefit streams is calculated using a 4% social discount rate. This is applied to streams of benefits and costs tracked in 2023 constant dollars.

If a measure's present value of electric energy savings and peak demand reductions is positive (i.e., it saves electricity) this is counted in the numerator as a benefit. If a measure's present value of electric energy savings and peak demand reductions is negative (i.e., it is a fuel switching measure) this is counted in the denominator as a cost.

As per the requirements of the TRC-Plus test, a 15% non-energy benefits adder is applied to avoided resource costs (benefits) other than carbon costs.

6.2.2 Provincial Benefit and Cost Streams

Cost-effectiveness testing considers the incremental measure cost, which is specific to each measure, as well as four other series of value streams. These are:

- **Natural Gas Avoided Costs**.
- **Electric Energy Marginal Costs.**
- **Cost of Peak Capacity**
- **Value of Carbon**

As part of its development of global model inputs, Guidehouse obtained input series for all the sets of value noted above, converted them (as required) to constant 2023 dollars, extended them through 2073 (to account for the calculation of present value of longer-lived measures

[63] See Section 4.9, PDF 85 of 149 of
Ontario Energy Board, *Decision and Order: Application for Multi-Year Natural Gas Demand Side Management Plan (2022 to 2027),* Enbridge Gas Inc., EB-2021-0002, November 2022
https://www.oeb.ca/node/3869

[64] See Section 11.2 of
Ontario Energy Board, *Decision and Order: Application for Multi-Year Natural Gas Demand Side Management Plan (2022 to 2027),* Enbridge Gas Inc., EB-2021-0002, November 2022
https://www.oeb.ca/node/3869

adopted later in the period of analysis), and made other transformations as described in the sub-sections below.

This extrapolation noted above is required to provide a complete series of future values to assess the cost-effectiveness of long-lived measures adopted in the final years of the period of analysis. So, for example, extrapolated cost or benefit values in 2063 would affect the cost-effectiveness of measures with a 25-year EUL adopted in 2039.

Without access to the underlying predictive models, Guidehouse's options for extending available forecasts are limited to an extension of trends, or flat-line extension. Guidehouse has elected to consistently extend estimated trends in forecast data across all forward-looking series, recognizing the shortcomings of this approach, but noting that absent other information this is the most appropriate convention to apply.

6.2.2.1 Natural Gas Avoided Costs

The natural gas avoided costs provide an estimate of the benefits of the natural gas energy savings measures. EGI provided four series of values to Guidehouse, Baseload and Weather Sensitive avoided costs for the Union and EGD rate zones, all in constant 2023 dollars.

Guidehouse understands that EGI's avoided costs reflect natural gas commodity costs, upstream transportation and third-party services costs, seasonal storage requirements costs, unaccounted for fuel losses and downstream infrastructure costs, but do not include the 15% non-energy benefit adder required by the TRC-Plus cost test, or the cost of carbon.

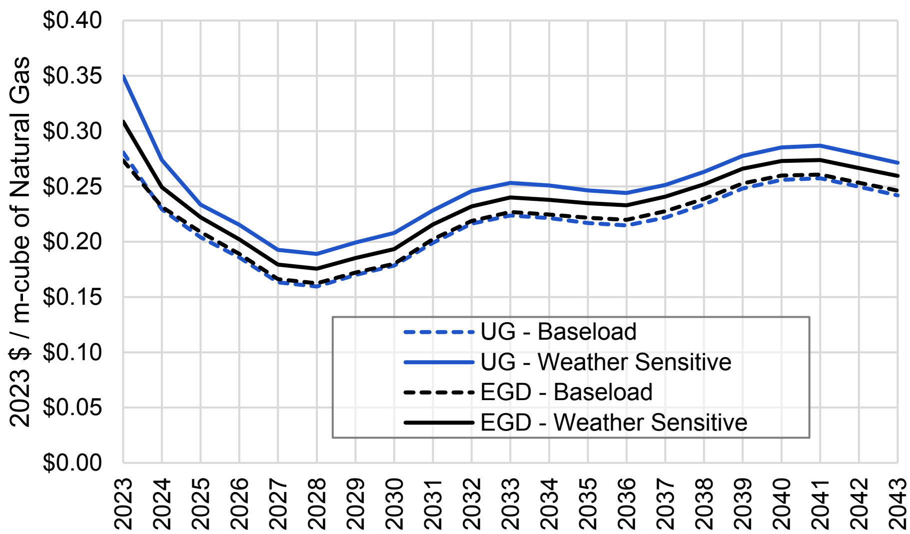
The first and final year natural gas avoided cost values provided by EGI, by rate zone and load type are provided in Table 12

Table 12. Summary Gas Avoided Costs Provided by EGI ($2023 per m3)

Year	Union Rate Zone		Enbridge Rate Zone	
	Baseload	Weather Sensitive	Baseload	Weather Sensitive
2023	$0.28	$0.35	$0.27	$0.31
2052	$0.28	$0.31	$0.28	$0.29

The series provided by EGI extend only through 2052. As noted above, Guidehouse requires a series of avoided costs extending to 2073. The four series were extended to 2073 by estimating the 5-year compound annual growth rate (CAGR) in the last five years of the available data and applying this to extend the series out to 2073. Annual values of the avoided costs across the study's period of analysis are shown in Figure 43, below.

Figure 43. Gas Avoided Costs (constant $2023 per m3)



Since for the 2024 APS, potential is being modeled on a provincial, rather than a regional basis, the UG and EGD rate zone values had to be combined to create an Ontario-wide set of avoided costs. Sector-specific rate zone weights were drawn from those provided to Guidehouse as part of the development of the 2019 APS.

The weights used to combine these values are presented in Table 13 below.

Table 13. Share Weights to Combine Region Avoided Costs

Sector	UG	EGD
Residential	40%	60%
Commercial	28%	72%
Industrial	76%	24%

6.2.2.2 Electric Energy Marginal Costs

For internal consistency, Guidehouse has used the same series of annual marginal value of energy for evaluating the costs imposed by incremental electricity use (e.g., via fuel switching) as well as the benefits yielded by electricity savings (e.g., from insulation measures that impact electric space cooling as well as gas space-heating).

Guidehouse and OEB staff engaged with IESO staff to identify the most appropriate series for valuing incremental electricity consumption (or savings). The IESO recommended against using the electric energy avoided costs included in the online CDM cost-effectiveness tool[65] on the basis that these had been developed based on the IESO's energy efficiency portfolio of programs and would be inappropriate to apply for the valuing the costs of the electrification of space-heating.

[65] Available at:

Independent Electricity System Operator, *Evaluation, Measurement and Verification*, accessed August 2023 **https://www.ieso.ca/en/Sector-Participants/Energy-Efficiency/Evaluation-Measurement-and-Verification**

The IESO team recommended that the best available proxy for the incremental system energy costs imposed by electrification would be the marginal cost projection from the 2022 APO.[66] The IESO team made it clear that where the system impact of electrification is significant this could change the resource mix and thus the marginal cost of electric energy. All the Achievable potential scenarios that include fuel switching measures deliver system impacts that could be considered significant, meaning that – though based on the best information available at the time the study was completed – the value of the projected electric energy impacts must be regarded as highly uncertain.

Accordingly, Guidehouse used the annual weighted average marginal costs forecast (running through 2043) published as Figure 47 of the 2022 APO[67] (data tables for this report are available at the link cited above). OEB staff, in correspondence with the IESO, confirmed that these marginal costs reflect the IESO's assumptions about line losses and are therefore the marginal cost of incremental energy "at the meter".

To convert the values reported by the APO into values that could be used in the analysis Guidehouse applied the following steps:

1. **Extrapolate.** Extend the cost series to 2073.
2. **Convert Dollar Year.** The dollar values in the APO are 2022 dollars, for the 2024 APS, all values must be in 2023 dollars for comparability.

Marginal costs (and other APO values needed to develop the marginal cost series – see below) were extrapolated out to 2073 on the basis of the CAGR estimated for the final five years of the available series. To convert APO marginal costs from 2022 dollars to 2023 dollars, Guidehouse assumed an inflation rate of 2%, drawn from the cost-effectiveness parameters specified by the IESO in its CDM cost-effectiveness tool.[68]

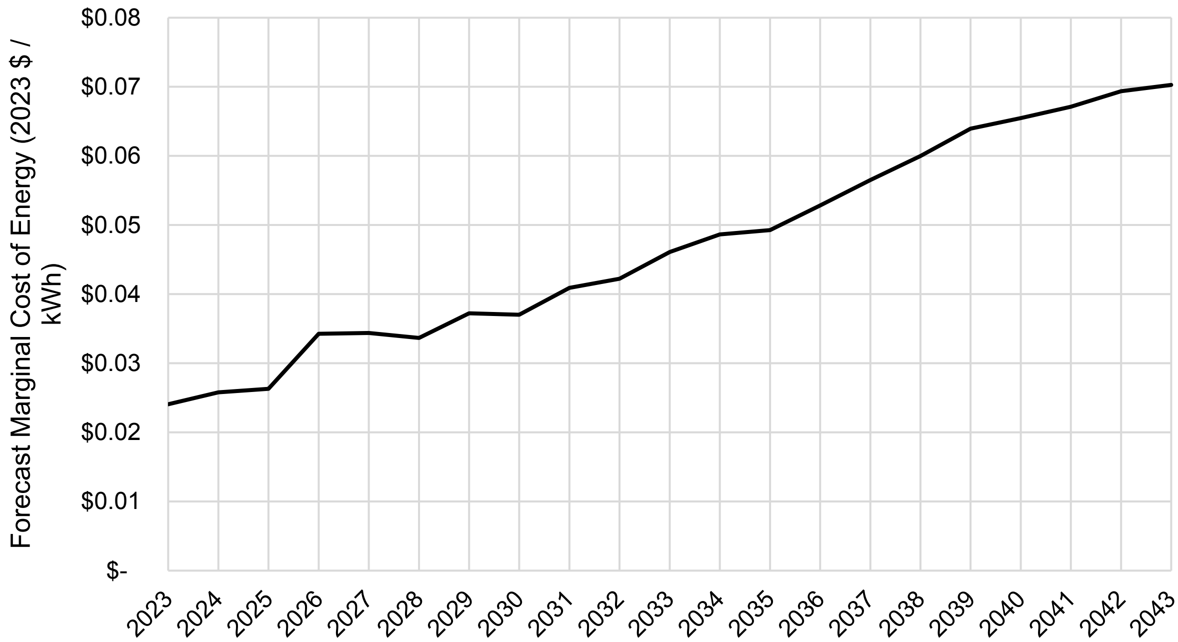
The output series of electric energy marginal costs used for cost-effectiveness testing as part of the 2024 APS are provided in Figure 44, below.

[66] Although the 2024 APO appeared prior to the completion of the 2023 APS, this study was sufficiently advanced by that time that a thorough update of the input values drawn from the 2022 APO was not practical.

[67] Independent Electricity System Operator, *Annual Planning Outlook Data Tables,* March 2024
https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook

[68] See the "CE Parameters" tab of the tool, filename: "IESO-CDM-CE-Tool-V9-2-Feb-17-2023.xlsb"
Available at:
Independent Electricity System Operator, *Evaluation, Measurement and Verification*, accessed August 2023
https://www.ieso.ca/en/Sector-Participants/Energy-Efficiency/Evaluation-Measurement-and-Verification

Figure 44. Electric Energy Marginal Costs



6.2.2.3 Cost of Peak Capacity

To estimate the marginal capacity cost of incremental peak demand due to fuel switching, Guidehouse is using the system capacity value of $144,000 per MW-year ($144 per kW-year) recommended by the IESO for valuing the benefits of non-wires alternatives.[69] This value is held constant in real (2023) dollars across the entire study period.

Additional details on how this value was selected, and how it is applied in the Economic and Achievable potential analysis may be found in Section D.1 of Appendix D.

6.2.2.4 Value of Carbon

In Ontario, DSM[70] (for natural gas) and CDM[71] (for electricity) potential assessments and evaluations have for many years now used the Total Resource Cost-Plus ("TRC-Plus") test for cost-effectiveness testing. This test includes considerations not just of resource impacts (e.g.,

[69] Section 6 of

Independent Electricity System Operator, Integrated Regional Resource Plans: Guide to Assessing Non-Wires Alternatives, May 26, 2023

Available at:

https://www.ieso.ca/en/Get-Involved/Regional-Planning/About-Regional-Planning/Planning-Information-and-Data

[70] See, for example

Ontario Energy Board, *Decision and Order: Application for Multi-Year Natural Gas Demand Side Management Plan (2022 to 2027),* Enbridge Gas Inc., EB-2021-0002, November 2022

https://www.oeb.ca/node/3869

[71] Navigant (n/k/a Guidehouse) prepared for the Independent Electricity System Operator, and the Ontario Energy Board, *2019 Integrated Ontario Electricity and Natural Gas Achievable Potential Study*, December 2019

https://www.ieso.ca/2019-conservation-achievable-potential-study

the costs avoided by reducing natural gas consumption), but also societal benefits of DSM and CDM, including non-energy benefits and the cost to society of incremental carbon emissions.

In the 2019 APS, the federal carbon backstop price was used as a proxy for the cost of carbon to consumers.[72] For the 2024 APS Guidehouse recommended the use of the Social Cost of Carbon (SCC) to replace this proxy as a more accurate estimate of the present-value cost of incremental emissions to Ontario. After assessing alternative estimates of the SCC available, and presenting these to the SAG and OEB staff, OEB staff directed Guidehouse to use the Government of Canada's[73] estimates of the SCC (at an assumed 2% social discount rate[74]) in its cost-effectiveness testing.

After consultation with members of the SAG, OEB staff directed Guidehouse to also model sensitivity Economic and Achievable potential scenarios that used the federal fuel charge (referred to in this report as the Canadian Federal Backstop, or CFB). Forecast values of the CFB are available only until 2030. In the 2019 APS carbon values for subsequent years were held constant at 2030 values for the remainder of the period of analysis. For this 2024 APS, OEB staff, at the request of a SAG member, directed Guidehouse to assume that the CFB continued to grow in real terms (constant dollars) in the post-2030 period, according to the linear trend exhibited leading up to 2030.

The two series of carbon values used for cost-effectiveness testing in the 2024 APS are shown in Figure 45, below.

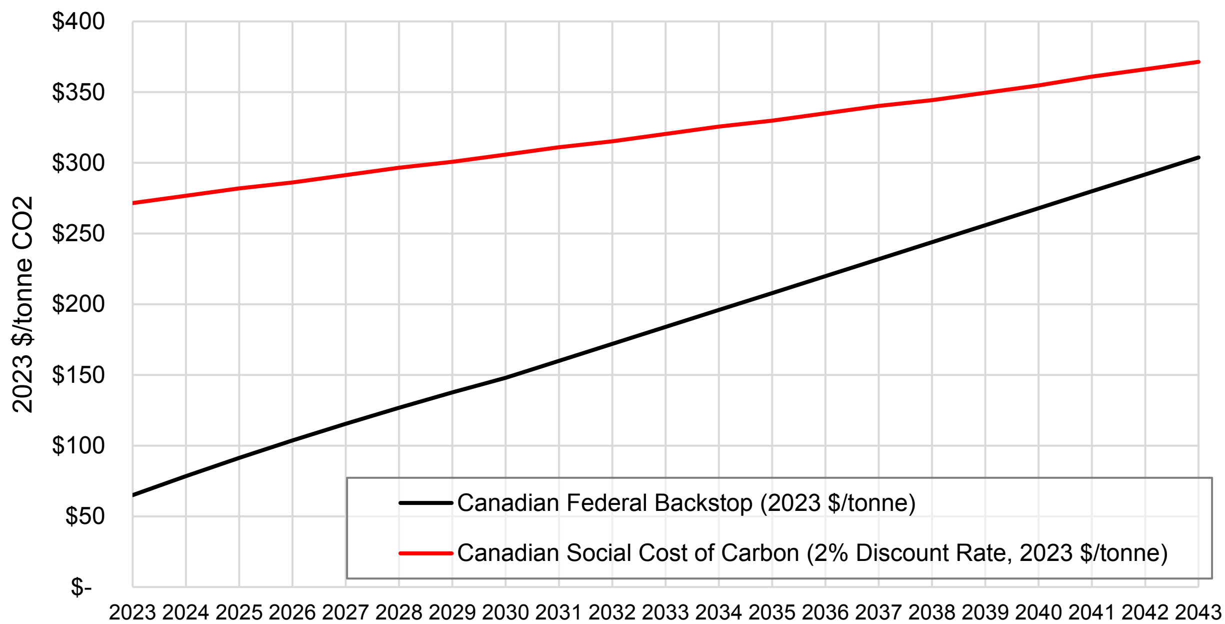
.

[72] Because the carbon price is an intra-provincial transfer – funds collected in Ontario are returned as rebates to Ontarians – it is not on its own appropriate for inclusion in provincial-perspective cost-effectiveness testing (any more than measure incentives or provincial sales taxes would be). In 2018, however, it was determined to be a reasonable, locally-specific and publicly available proxy for the costs imposed on Ontario by incremental carbon emissions, for the purposes of cost-effectiveness screening.

[73] Government of Canada, *Social Cost of Greenhouse Gas Estimates – Interim Updated Guidance for the Government of Canada*, updated April 2023, accessed August 2023 **https://www.canada.ca/en/environment-climate-change/services/climate-change/science-research-data/social-cost-ghg.html#toc0**

[74] Estimates of SCC are often presented at different social discount rates. The higher the social discount rate, the lower the present value of the future damage costs or future mitigation costs from each incremental unit of greenhouse gas emissions.

Figure 45. Carbon Values used for 2024 APS



Additional detail regarding the different sets of carbon values considered for the APS may be found in Section D.2 of Appendix D.

6.2.3 Competing Measures & Measure Stacking

Competition groups and measure stacking logic continue to apply in Economic potential in the same way they do in Technical potential, with the notable difference that only those measures in any given year that pass the cost-effectiveness screen are considered.

6.3 Results

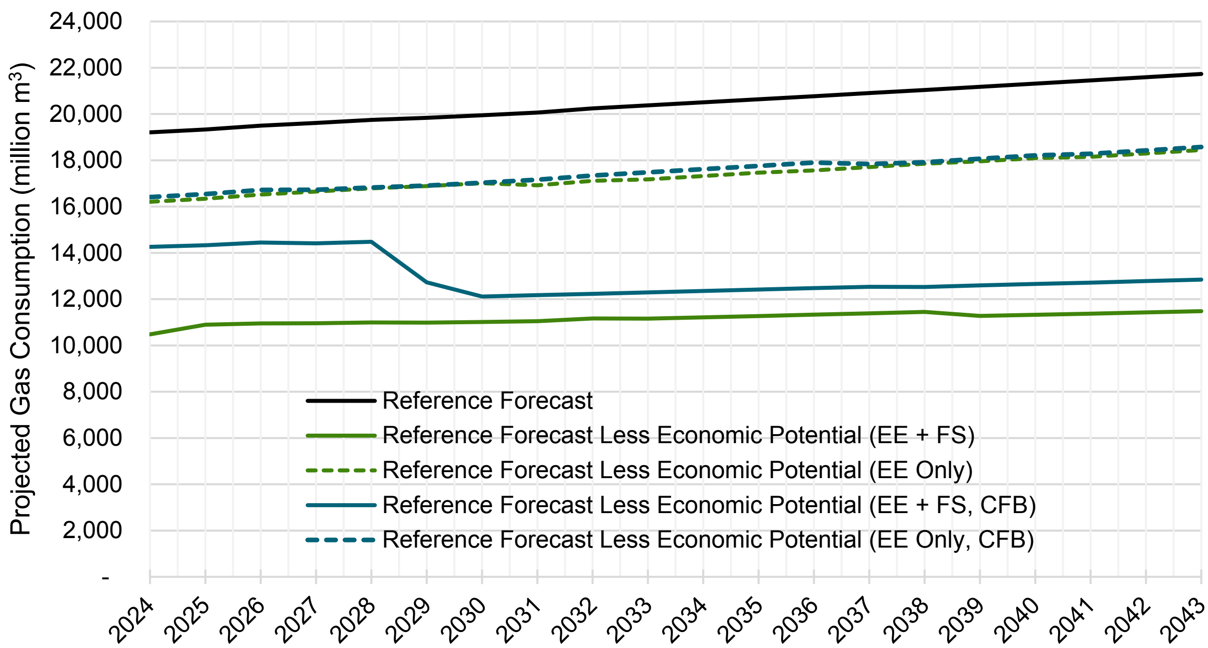
This section provides a summary of the Economic potential (EE + FS) and the sensitivity Economic potential scenarios (EE Only, EE + FS – CFB, EE Only – CFB) results from the following perspectives:

1. Natural Gas Economic Potential by Sector
2. Economic Potential Winter Peak Demand Impacts
3. Measure-Level Natural Gas Economic Potential

The GHG impacts of the Economic potential by sector, and a summary of the sub-sector-level Economic potential natural gas savings are presented in Appendix D.

Figure 46, below, provides a summary comparison of the aggregate estimated Economic potential and the reference forecast. The reference forecast is represented by the black line and the reference forecast less the estimated Economic potential is represented by the solid green line. The dashed green line represents the sensitivity scenario that considers the Economic potential only of energy efficiency measures and excludes fuel switching measures. The blue lines represent the sensitivity scenarios that apply the CFB instead of the SCC for cost-effectiveness testing.

Figure 46. Reference Forecast and Economic Potential



The substantial increase in Economic potential (illustrated in the graph above as a reduction in forecast consumption) observed for the EE + FS CFB sensitivity scenario in the period from approximately 2029 through 2030 is due to Residential cold climate heat pumps with gas back up becoming cost-effective (see Section 6.3.3) due to increasing natural gas avoided costs (see Figure 43 in Section 6.2.2.1).

The close proximity of the two dashed lines (i.e., projected consumption less Economic potential from energy efficiency measures only) is an indication of the relatively bi-modal distribution of energy efficiency measure TRC ratios. While many fuel switching measures have TRC values close to one (and so are sensitive to changes in the value of carbon), most energy efficiency measures are either clearly cost-effective, or clearly not. When considering all measures, approximately one-third of Residential measures modeled are cost-effective with an SCC, whereas less than 20% are cost-effective with CFB. In contrast, 29% of Residential EE only measures are cost-effective under SCC, while 26% are cost-effective under CFB.

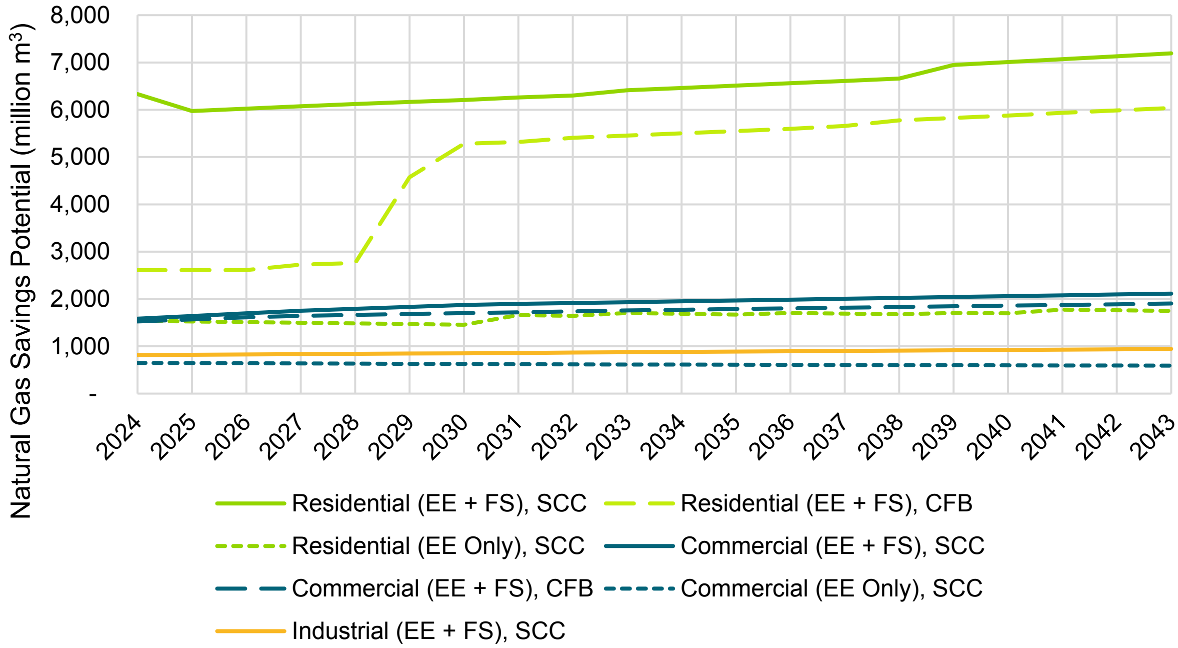
6.3.1 Natural Gas Economic Potential by Sector

Figure 72, below, shows the total estimated Economic potential when:

- including fuel switching and using the SCC (solid lines)
- including fuel switching and using the CFB (long dashed lines)
- including energy efficiency measures only and using the SCC (dotted lines)

No fuel switching measures were considered for the Industrial sector, and nearly all Industrial measures are cost-effective regardless of the carbon value, so only a single series is presented for this sector.

Figure 47. Economic Potential and Sensitivity Economic Potential Scenarios by Sector



The shapes of the lines over time provide important insight into the impact that the change in avoided costs over time has on measure cost-effectiveness. Note from Section 6.2.2.4 that the difference between SCC and CFB values is consistently declining over time – both series grow approximately linearly over time. In contrast, the natural gas avoided costs (see Figure 43) declines steeply in the initial years of the projection period, and then begins growing again in 2029.

As is shown in 6.3.3 this change in avoided costs results in the hybrid ASHP with gas back-up becoming cost-effective in approximately the same period, resulting in the substantial growth in Economic potential in 2029 and 2030. Recall that Economic potential is unconstrained by considerations of equipment turnover, so a change in the cost-effectiveness of an important measure can result in dramatic changes to potential from one year to the next.

Table 11, below, shows the Economic potential as a share of the reference forecast for each sector. As noted previously, Industrial measures are nearly all cost-effective by a substantial measure, making Economic potential for this sector nearly the same as the estimated Technical potential and also insensitive to changes in the carbon value applied.

Both graph and table demonstrate (as would be expected) that sectoral potential is significantly greater when fuel switching is considered, and that Residential Economic potential is particularly sensitive to avoided costs. Commercial Economic potential, like Technical potential, is substantially constrained by assumptions about Technical Suitability that are driven by the challenges of the heterogenous Commercial sub-sectors.

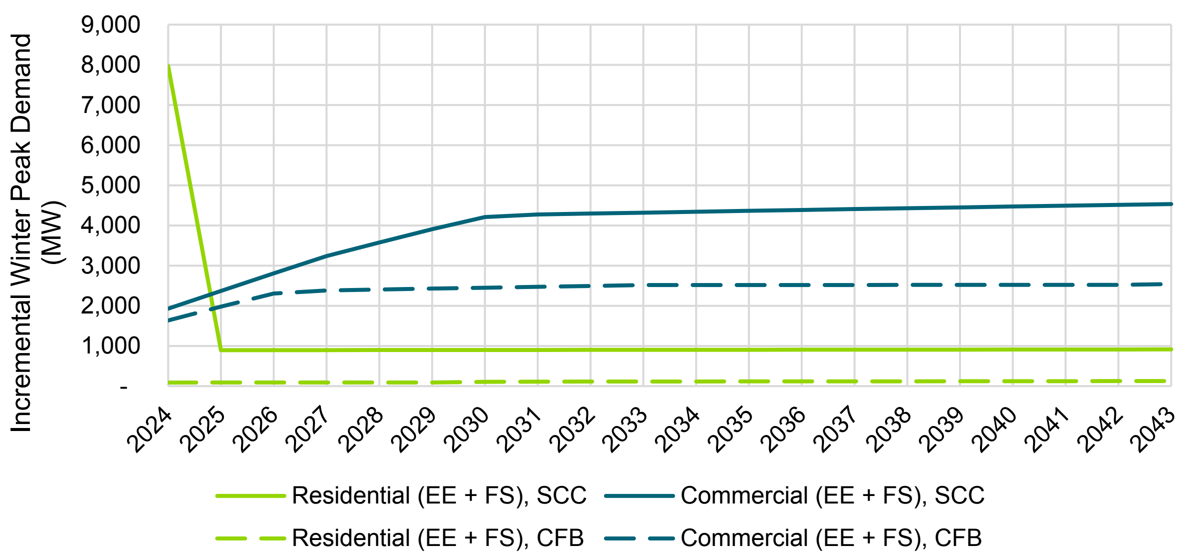
Table 14. Economic Potential As Percent of Corresponding Sector Reference Forecast

Scenario	Year	Residential	Commercial	Industrial	Total
Economic, EE + FS, SCC	2028	73%	28%	17%	**44%**
	2035	75%	29%	17%	**45%**
	2043	79%	30%	17%	**47%**
Economic, EE + FS, CFB	2028	33%	26%	17%	**27%**
	2035	64%	26%	17%	**40%**
	2043	66%	27%	17%	**41%**
Economic, EE Only, SCC	2028	18%	10%	17%	**15%**
	2035	19%	9%	17%	**15%**
	2043	19%	8%	17%	**15%**
Economic, EE Only, CFB	2028	18%	9%	17%	**15%**
	2035	16%	9%	17%	**14%**
	2043	18%	8%	17%	**15%**

6.3.2 Economic Potential Winter Peak Demand Impacts

Figure 73 shows the estimated winter peak demand impact of the measures included in the Economic potential for the Residential and Commercial sectors. No winter peak demand impact is estimated for the Industrial sector as no fuel switching measures were included for that sector. In this graph, a positive value indicates an *increase* in peak demand.

Figure 48. Winter Peak Electricity Demand Impacts Associated with Economic Potential



The defining feature of this plot is the sharp drop in incremental winter peak demand that occurs in 2024 for the EE + FS SCC Residential potential. Demand impacts for Residential potential remain flat over the remainder of the period of analysis for the EE + FS SCC scenario, but still substantially (~1,000 MW) above the Residential EE + FS CFB scenario.

The initial very high peak demand impact in 2024 for the Residential EE + FS SCC potential is driven primarily by fully electric ASHP measures in the North region. This measure (and the electric resistance water heater) is cost-effective only in the first year of the analysis. In the second year of the analysis, the present value calculation of system peak demand costs includes more of the period beginning in 2036 when Ontario is assumed to switch to winter peaking. This substantially increases the present value of system costs, meaning that the full electrification measures – even under the SCC – cease to be cost-effective.

Recall that although the year in which Ontario is assumed to switch to winter-peaking is dynamic to estimated Achievable potential, for the Economic potential it is held static at the year identified in the 2022 APO: 2036. The IESO's update, the 2024 APO (published too late to allow its data to be included in this analysis) projects the province to switch to winter peaking in 2030. In this circumstance, none of the full electrification measures in the Residential sector would be cost-effective, even in the first year.

The constant peak demand impact observed for the Residential EE + FS SCC scenario is a result of new construction (NEW) measure type replacement by the full electrification measures. In the unconstrained approach, each year is a snapshot in time (i.e., turnover rates are not controlled for), but one that tracks the timing of new stock additions. That is, Residential full electrification measures are not cost-effective for NEW stock in 2025, but they were in 2024, so the potential in 2025 must account for the NEW stock added in 2024 and cost-effective options available at the time that stock was added.[75]

As with the ROB electrification measures, had this scenario been modeled with the more recently available assumption that Ontario becomes winter peaking by 2030, there would likely much less Economic potential in the Residential sector flowing from the full electrification measures, and thus a winter peak demand impact more comparable to the Residential EE + FS CFB scenario.

Winter peak demand in subsequent years is relatively low compared to what might be expected given the volume of gas consumption replaced by electric space heat. This outcome is driven by the assumption that the hybrid space-heating systems in the Residential sector are set to call for gas heat (instead of electric heat) on the basis of outdoor temperature information provided to the thermostat via the internet. In this configuration the 4C system would use the gas back-up only at the very low temperatures to be expected under system design conditions.

This assumption is a reasonable one given the highly focused definition of system peak defined by the way peak demand is valued (see Sections 4.2.4.4 and 6.1.2). An alternative, more expansive, definition of peak could require a re-assessment of that assumption, though any

[75] One of the sometimes-confusing complexities of modeling unconstrained potential is the treatment of NEW measures. For both ROB and NEW, potential is unconstrained by turnover – all measures that could be adopted in a given year (regardless of equipment turnover rates) are adopted. NEW measure potential in each year, however has to track *when* the new construction took place since the year in which that occurred affects the overall potential. So, for example if an ROB measure is cost-effective in Year 1, Economic potential for that measure will be an estimate of potential if every instance of the base measure is replaced in that year. If in Year 2 that measure ceases to be cost-effective, its Economic potential will be zero.

In contrast if a NEW measure is cost-effective in Year 1, Economic potential for that measure will be an estimate of potential if every instance of the base measure in the buildings constructed in Year 1 is replaced in that year. If in year 2 that measure ceases to be cost-effective, its Economic potential will be the Year 1 incremental Economic potential (since the new construction measure *was* cost-effective in that year) but without any additional potential to account for Year 2 new construction since the measure is no longer cost effective in Year 2.

Section C.1 of Appendix C provides an illustrated example of the modeling mechanics described above.

such adjustment to the definition of peak electric demand would also need to appropriately adjust the assumed cost of capacity, making it challenging to assess the impact of such a change without additional modeling.

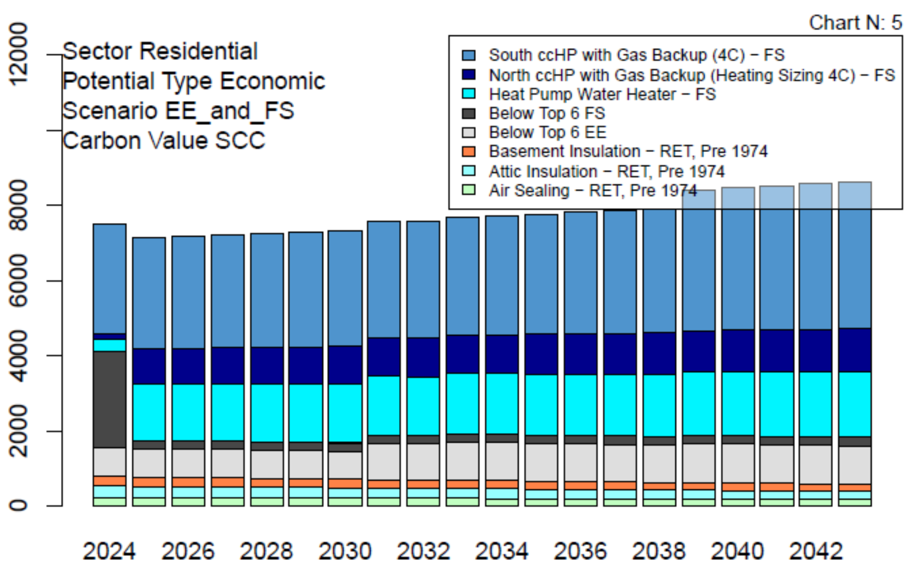
The Commercial sector demand impacts are driven primarily by cold climate heat pumps (full electrification) for *new construction only*, and heat pump water heaters (see 6.3.3, below). Both measures remain cost-effective across most sub-sectors for most of the period of analysis. For replace-on-burnout measures, the hybrid ASHP (with gas backup, and so no contribution to peak demand) "wins" the competition group due its much higher Technical Suitability factor.

6.3.3 Measure-Level Natural Gas Economic Potential

Care should be taken in reviewing plots that include fuel switching measures to recall that due to measure stacking (which controls for the fact that fuel switching measures displace consumption that could yield savings from energy efficiency measures), the sum of potential across measures will be more than the aggregate sector-level potential shown above.

Figure 74 shows the measure-level potential diagnostic plot for the Residential sector. Recall that the "top six" measures for which potential are shown are the measures with the highest average potential across the first ten years of the period of analysis.

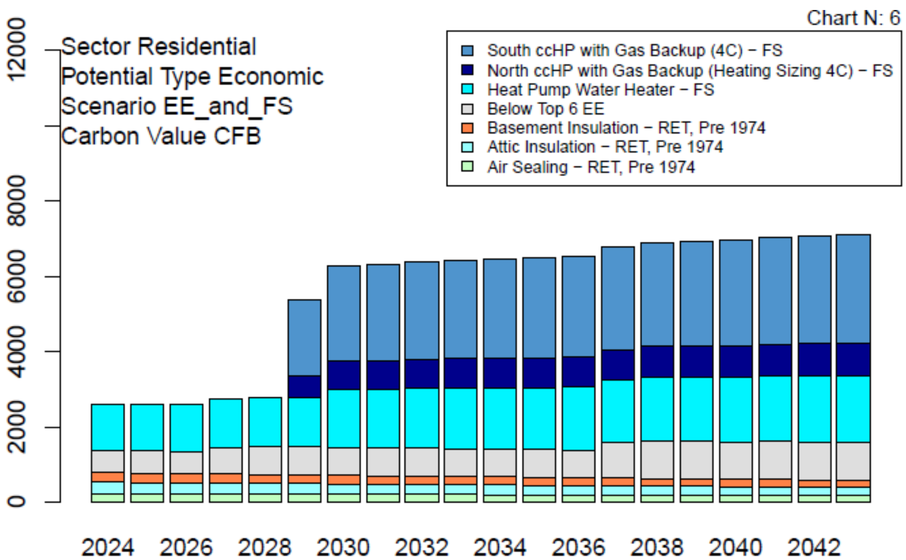
Figure 49. Residential Measure-Level Economic Potential (EE + FS, SCC) – Top Six Measures (millions of m^3)



The defining feature of this chart is the discontinuity in the first year (2024) in which heat pump water heater and North region heat pump with gas back-up potential is displaced by "Below Top 6 FS" (fuel switching) measures. This category includes the North region full electrification (4D) cold climate heat pump option as well as the electric resistance water heater option, both of which cease to be cost-effective in 2025.

The small wedge of dark grey ("Below Top 6 FS") that persists in subsequent years are those two full electrification measures applied to NEW construction. In each year of the projection period these measures are applied to the NEW stock added in 2024 since they were cost effective in that year. This wedge is not visible in the CFB sensitivity scenario shown in Figure 50 (immediately below) since with this alternative, lower, carbon value the NEW full electrification measures are never cost-effective.

Figure 50. Residential Measure-Level Economic Potential (EE + FS, CFB) – Top Six Measures (millions of m^3)

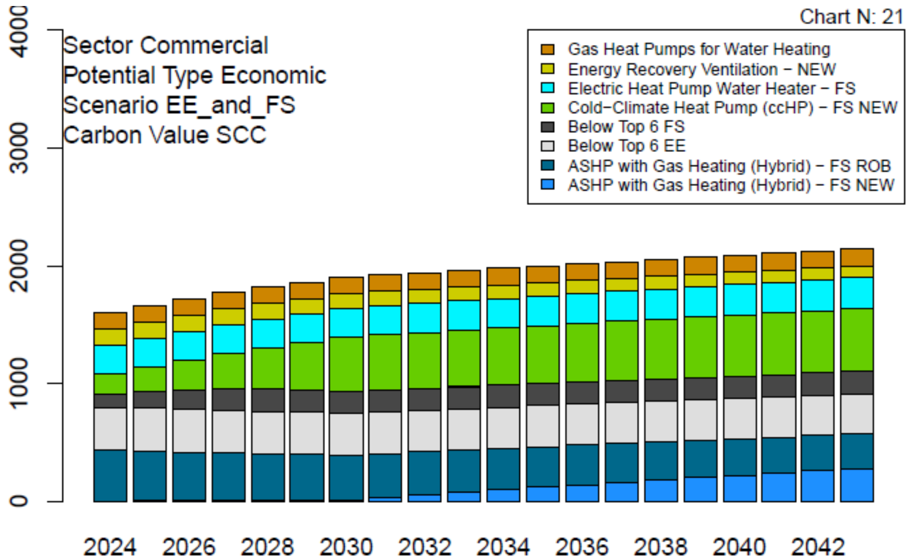


Notable in this figure is the absence of the two hybrid heat pump measures in the early years of the projection period. These become cost-effective as a result of the gradual increase in the CFB (Figure 45) and the change in direction of the trend in gas avoided costs at approximately the same time, which begin to increase (Figure 43).

Figure 51 shows the Commercial measure-level Economic potential for the EE + FS, SCC scenario. As noted previously this scenario is very similar to the EE + FS, CFB scenario in both level of potential and distribution across measures. The most noteworthy feature of this plot is, like for Technical potential, the diversity of measures.

Particularly noteworthy is the capture of NEW construction by the full electrification heat pump measure (where Technical Suitability is relatively high) in contrast with the hybrid measure, which captures ROB installations (existing buildings), where the hybrid measure is closer to a like for like replacement than the full electrification measure and thus the Technical Suitability much higher. Growth in the NEW full electrification measure slows in the period approaching the year in which Ontario is assumed to transition to a winter peaking jurisdiction as its peak demand impacts become more costly, and potential is captured by the NEW version of the hybrid measure – a competing measure.

Figure 51. Commercial Measure-Level Economic Potential (EE + FS, SCC) – Top Six Measures (millions of m^3)



The Commercial EE + FS CFB potential is very similar to that of the SCC scenario, and Industrial Economic potential is very close to the Technical potential for the same sector, and so neither is presented here.

7. Achievable Potential

This section describes Guidehouse's approach to estimating Achievable potential and presents the results for Ontario.

The objective of the Achievable potential task is to estimate the cost-effective energy efficiency and fuel switching potential natural gas reductions (and commensurate electric demand increases) that might be achieved through the application of incentives to the set of measures characterized for the study. Unlike either Technical or Economic potential, Achievable potential explicitly considers, and controls for, considerations of equipment turnover, as well as some of the economic and non-economic factors that drive measure adoption.

In the 2024 APS, Achievable potential is estimated for six different scenarios.

This chapter of the report is divided into three sections:

1. **Scope:** Describes the goal of Achievable potential estimation, noting some of the most important global assumptions and limitations that must be considered in interpreting the result. This section also identifies the scenarios considered, the motivation for their selection, and the outputs they provide.
2. **Methodology:** Provides a description of the critical model input, assumptions, and analytic approaches used to estimate Achievable potential. Additional detail on some of the methods may be found in Appendix E.
3. **Results:** Provides a summary of the results of the Achievable potential.

7.1 Scope

The goal of the Achievable potential analysis is to estimate the volume of cost-effective and technically feasible natural gas reduction that could be achieved for a given level of spending by the program administrator to encourage measure adoption. The assumed level of program administrator spending ("incentives") in any given Achievable scenario is defined by the goal of each scenario.

The purpose for estimating Achievable potential a is to provide insight into the challenges to (and opportunities for) achieving the natural gas reductions that the OEB specified should be considered in this study, as part of its 2022 Decision and Order.[76] The targets specified in this document are aggressive and require that the study consider fuel switching and energy efficiency simultaneously within its scenarios.

The sections below provide a summary of the scope of the analysis undertaken and are essential context for interpreting the results described in the subsequent sections. The first identifies the motivation for the selection of the targeted consumption reductions that were used to calibrate estimated potential in some scenarios. The second defines the six scenarios for which Achievable potential was estimated. The third section identifies some of the key global assumptions of the analysis, and the implications for how reviewers should interpret outputs.

[76] Ontario Energy Board, *Decision and Order: Application for Multi-Year Natural Gas Demand Side Management Plan (2022 to 2027),* Enbridge Gas Inc., EB-2021-0002, November 2022
https://www.oeb.ca/node/3869

The final selection provides, as in the corresponding Technical and Economic potential sections, a list of the key outputs of the Achievable potential analysis.

7.1.1 Scenario Targets

In its 2022 Decision and Order[77], the Ontario Energy Board explicitly defined its expectations for the analysis to be undertaken in the 2024 APS. The relevant section[78] of that decision is reproduced below, with emphasis added to identify the most critical direction.

> "*The OEB expects that OEB staff will undertake a new conservation potential study to inform Enbridge Gas's next multi-year DSM Plan, with input provided by the SAG. To guide OEB staff, Enbridge Gas and the SAG, the OEB is interested in at least three scenarios being considered in the analysis: an annual reduction in total natural gas sales year-over-year of 0.5%, 1% and 1.5%. The study should focus on how these levels of annual natural gas reductions can be achieved through DSM programs in the most cost-effective manner while still providing opportunities for all customer segments to participate in DSM programs.*"

The OEB directed that the potential study consider scenarios which could deliver a decrease of 0.5% (1%, 1.5%) in total gas consumption in each year of the period of projection, relative to the consumption in the year prior. This is equivalent to applying a compound annual growth rate of negative 0.5% (negative 1%, negative 1.5%) to some starting year value of natural gas consumption.

Guidehouse set targets for calibrating its potential estimation accordingly, selecting as the starting point the reference forecast value for 2023, for each sector. The starting value of the reference forecast does not include EGI's projected DSM achievement in that year – the starting value is forecast consumption in 2023[79], absent the forecast effects of any DSM programming.

Targets were set independently for each sector, though it was evident from the measure lists (e.g., no Industrial fuel switching measures were included) that significantly more potential was likely to be estimated for some sectors than for others.

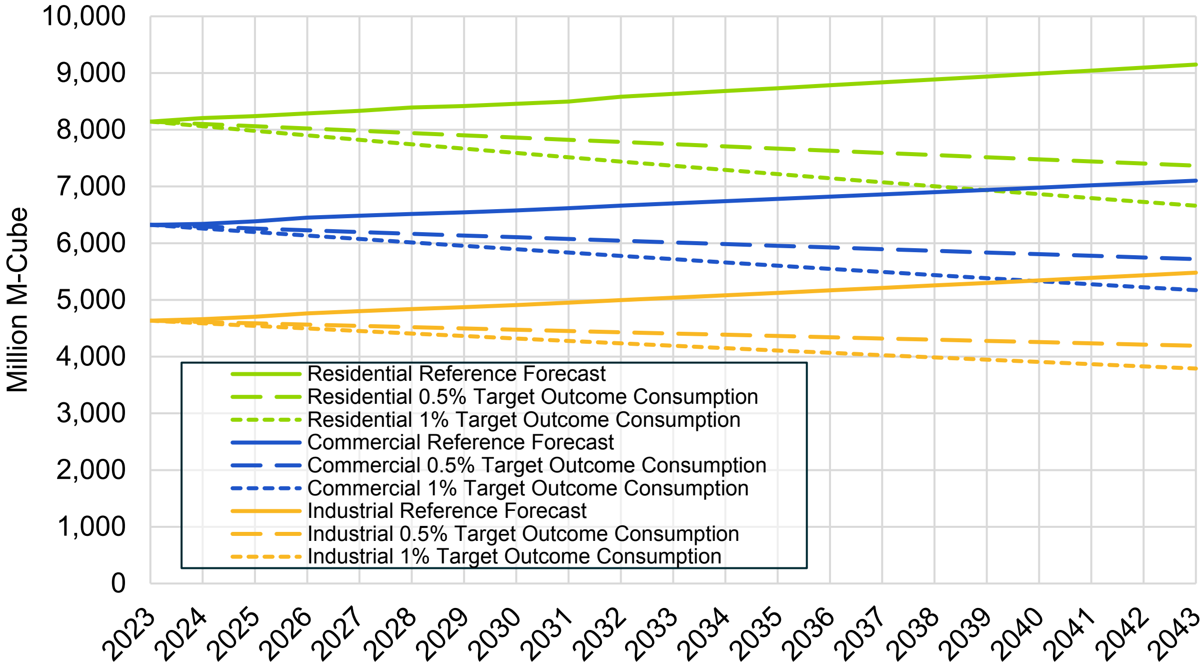
The reference forecast for each sector (solid lines) and the corresponding targeted consumption levels reflecting an annual decrease of 0.5% from the year prior (dashed line) and an annual decrease of 1% from the year prior (dotted line) are shown below in Figure 52.

[77] Ontario Energy Board, *Decision and Order: Application for Multi-Year Natural Gas Demand Side Management Plan (2022 to 2027),* Enbridge Gas Inc., EB-2021-0002, November 2022
https://www.oeb.ca/node/3869

[78] "Findings", page 66, or PDF page 68/149

[79] The selection of the starting year for establishing the target and the associated period of analysis (from 2024 through 2043) was the subject of discussion within the SAG. Additional detail about the selection of the base year and period of analysis may be found in Section E.1 of Appendix E.

Figure 52. Scenario Consumption Targets



The targeted potential used for model calibration is defined by the distance between the reference forecast (solid line) and the corresponding targeted consumption line (dashed or dotted) line in the plot above.

7.1.2 Scenario Definitions

Guidehouse worked with OEB staff and the SAG to define six Achievable potential scenarios. Each scenario is defined by:

- **The targeted potential outcome** – either one of the targets specified by the OEB in its 2022 Decision, or a maximum achievable potential.
- **The measures included** – most scenarios included both energy efficiency and fuel switching measures, but, as a sensitivity, one scenario was estimated that included only EE measures.
- **The value of carbon** – in addition to the SCC, sensitivity scenarios were, at the request of some SAG members, estimated using the linear extrapolation of the federal fuel charge (referred to here as the Canadian Federal Backstop, or CFB).

Table 15. Achievable Potential Scenarios

Scenario	Targeted Year-Over-Year Gas Reduction	Measures Included	Value of Carbon
A	0.5%	EE + FS	CFB
B	1%	EE + FS	SCC
C	Max Achievable	EE + FS	SCC

Scenario	Targeted Year-Over-Year Gas Reduction	Measures Included	Value of Carbon
D	Max Achievable	EE + FS	CFB
E	Max Achievable	EE Only	CFB
F	1%	EE + FS	CFB

For scenarios with a specific gas reduction target (i.e., scenarios A, B, and F), the Guidehouse modeling team progressively adjusted the incentives applied to measures with the goal of ensuring that potential met the target in 2028, and again in 2043. More details regarding the manner in which incentives are applied may be found in Section 7.2.2.

In some cases, the target could not be met, even when maximizing incentives. This is addressed in Section 7.3.

For scenarios described as “Max Achievable”, incentives were set to the maximum permissible for each measure (see Section 7.2.2 for more details) as were two of the non-economic factors that drive adoption, marketing and word-of-mouth assumptions. Marketing and word-of-mouth parameter values are derived as part of the model calibration process described in Section E.2.3 of Appendix E.

The six scenarios were chosen to meet the requirements laid out by the OEB in its 2022 Decision and to address the needs expressed by SAG members to better understand the sensitivity of the different potential scenarios to the carbon value used, and the exclusion of fuel switching measures. No scenario targeting the 1.5% year-over-year in annual sales specified by the OEB was estimated. OEB staff, in consultation with the SAG, determined that running the set of alternative Max Achievable scenarios (varying carbon value and measure types as shown above) would deliver greater informational value, and directed Guidehouse to estimate the scenarios above.

7.1.3 Interpreting Results: Understanding Model Assumptions and Deriving Insights

Guidehouse’s estimates of Achievable potential do not constitute a predictive forecast of natural gas reductions, but rather an estimate of what *could* be achieved, conditional on the simplifying assumptions required to model incredibly complex market dynamics across three very different sectors. The results of the study deliver the greatest value when they are interpreted based on an understanding of some of the most important of these assumptions, both those described immediately below, and elsewhere in this report.

Achievable potential models the uptake of measures conditional on estimated payback acceptance curves when incentives are applied to all available measures in proportion to the provincial benefits they offer (see Section 7.2.2 for more details). In reality, DSM programs deliver savings not just through direct payment of incentives at point of sale, but through rebates, mid-stream programs, and – particularly relevant for the Commercial and Industrial sectors – custom program offerings.

Achievable potential modeling does not, likewise, capture the effects of supply chain constraints for all measures (though these are modeled for some individual measures – see Appendix B), nor can it fully control for all the complexities associated with consumer choice. The Achievable potential modeling, for example, does not explicitly account for the fact that many businesses may be responsible for their natural gas costs, but that their landlords are responsible for procuring and maintaining building equipment. Nor does the modeling control for the partial market capture (and its distortionary impact on consumer decisions) of Ontario's water heater rental oligopoly in the Residential sector and the possible (though unknown) effects on equipment purchases.

Extensive and in-depth assessment of fuel-switching opportunities of the magnitude contemplated by the 2024 APS scenarios is very new in Ontario and has little precedent in the North American potential study literature. The value therefore in this analysis is principally defined by the insights it offers for the development of fuel switching programs and for the collection of additional data that may allow further refinements or expansions of the analysis.

Estimating Achievable potential for natural gas reductions from energy efficiency and fuel switching measures abstracted from some of the practical (but complex) barriers to adoption does not diminish the value of the estimates, but rather highlights the potential benefits to the province of overcoming these barriers with effective DSM program design.

7.1.4 Potential is Net of Free Riders

The reference forecast used in this study explicitly excludes the impacts of future programmatic DSM. This means that the reference forecast accounts for any savings achieved by consumers acquiring energy efficiency or fuel switching measure absent any program. This group of consumers – those that adopt measures irrespective of DSM program offerings – are referred to in the DSM literature as "free riders", and any savings they deliver cannot be attributed to programmatic DSM.

Since all estimated Achievable potential is incremental to the reference forecast, and since the reference forecast already accounts for consumer actions absent a DSM program, all potential is, definitionally net of free riders. The assumed net-to-gross ratio of estimated Achievable potential is one.

Likewise, the estimated incentive costs of the Achievable potential account only for the incentive costs attributable to net new participants. It is reasonable to expect, however, that programs offered to consumers will have free-riders (whose actions are implicitly embedded in the potential study's reference forecast). Program planners or those assessing program plans should, in their use of the estimated Achievable potential to inform their analysis, carefully consider how free-ridership may impact estimated incentive costs, and make adjustments appropriate to the sector and measure, and consistent with the implications of the reference forecast.

7.1.5 Potential Study Outputs

The primary outputs of the Achievable potential analysis expand on those provided for Technical and Achievable potential, and include:

- Natural Gas Achievable Potential (millions of m^3).
- Winter Coincident Peak Demand Impacts (MW).
- GHG Emissions Reductions (Mt CO2e)
- Program Benefits and Costs (Millions of 2023 $)

- Levelized Measure Incentive Costs (Cost Curve) (2023 $ per million m3[80])

Secondary outputs of the Achievable potential analysis that have been estimated and tracked by Guidehouse, but have not, for concision, been included in this report include:

- Annual Electric Energy Impacts (GWh).
- Summer Coincident Peak Demand Impacts (MW).
- Measure-Level Impacts (After Competition Groups).

7.2 Methodology

Achievable potential is an estimate of the impacts (natural gas savings, peak demand impacts, etc.) from the potential adoption of the energy efficiency and fuel switching measures, conditional on annual equipment turnover considerations, customer payback (itself a function of assumed incentives), word-of-mouth and marketing effects, and technical suitability.

The critical outputs – Achievable potential savings, incentive and administrative costs, etc. are then calculated from the estimated Achievable measure uptake.

This section is divided into four sub-sections:

1. **Measure Adoption.** This section describes the mechanics of the modelling of measure adoption.
2. **Incentives and Incentive-Setting.** This section describes how incentives were set for the six Achievable potential scenarios estimated.
3. **Administration Costs.** This section describes how program administration cost estimates were developed.
4. **Ontario's First Winter Peak Year.** This section describes the assumptions applied regarding Ontario's transition from summer-peaking to winter-peaking province.

7.2.1 Measure Adoption

For the 2024 APS, Achievable potential in each scenario has been estimated principally through the adjustment of the assumed level of incentives provided to consumers to improve measure payback, either to their highest possible level (Scenarios C, D, E), or to target a specific level of Achievement (Scenarios A, B, F).

In each year of the projection period:

- The long-term equilibrium market share for each measure is estimated.
- Adjustments are applied to account for measures in competition with one another.
- The incremental adoption of the measure is estimated, moving the measure's market share closer to the projected long-term equilibrium level.

Equilibrium market share is determined as a function of measure incremental costs, bill savings, and the incentives applied by the modeler in the given year and scenario. Incentives are applied as a function of system benefits and incremental measure cost – this function is constant across measures, though the value of the incentive is not.

80

7.2.1.1 Equilibrium Market Share

The long-run equilibrium market share for each measure is estimated in each year of the period of analysis by calculating the simple measure payback, comparing this to the relevant payback acceptance curve, and making the appropriate adjustments to competing measures' market shares to avoid double-counting.

Payback

Measure payback is calculated by dividing the incremental measure cost faced by consumers by the first year net bill savings that measure provides to the customer. For

- Energy efficiency measures, first-year net bill savings are the product of natural gas savings and forecast retail rates in the given year.
- Residential fuel switching measures, first-year net bill savings are the product of natural gas savings and forecast retail rates in the given year *less* the product of incremental electricity consumption and the forecast average consumer electricity price (see Section E.3 of Appendix E for more details on customer-facing energy prices used in this study).
- Commercial fuel switching measures, first-year net bill savings are the product of natural gas savings and forecast retail rates in the given year
    - *less* the product of incremental electricity consumption and the forecast average consumer electricity price and
    - *less* the product of the incremental monthly billed peak demand and the distribution demand charge.

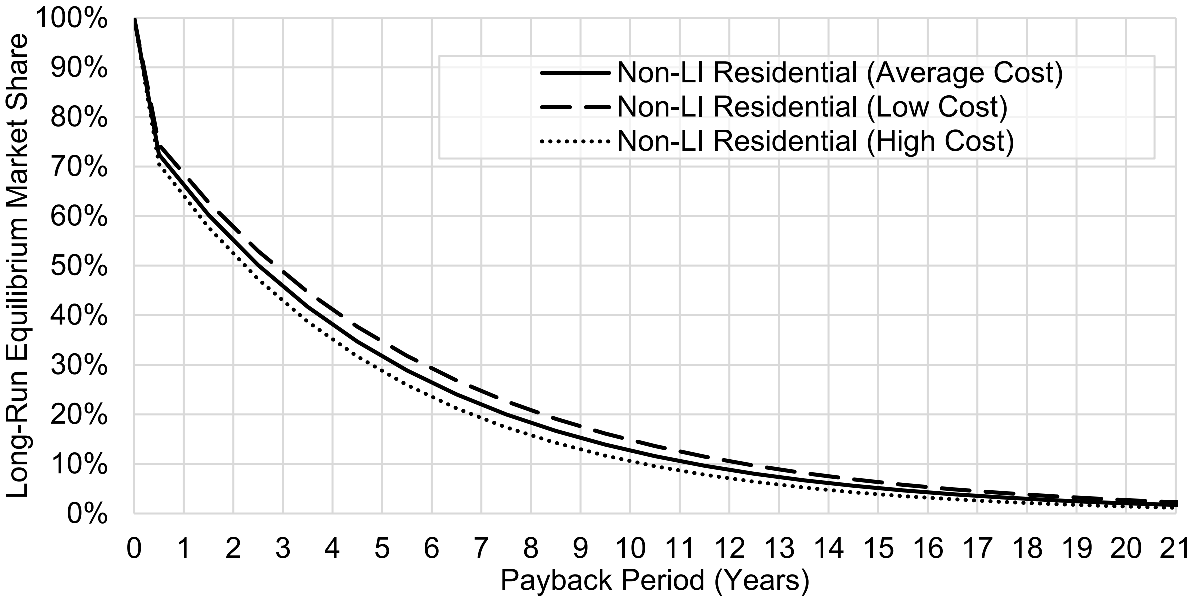
Payback (the number of years before the measure savings cover the cost of the measure) is then applied to the relevant payback acceptance curve (see below).

Reviewers are reminded that the energy retail rates used to estimate measure payback are *not* the same as the system avoided and marginal costs (described in 6.2.2 and Appendix D) used for the estimation of measure cost-effectiveness.

Payback Acceptance

The long-run equilibrium market share (i.e., how quickly a technology reaches final market saturation) is calculated by comparing a measure's payback period to a customer payback acceptance curve. Figure 53, below provides a set of example payback acceptance curves for the non low-income Residential customer grouping, for average cost measures (solid line), low cost measures (dashed line) and high cost measures (dotted line).

Figure 53. Non Low-Income Residential Payback Acceptance Curves



Guidehouse uses 12 distinct payback acceptance curves across the three sectors. These were derived through a primary data collection process and Delphi panel deployed as part of the 2019 APS data collection work. The Delphi panel included two individuals that that were contributing members of the current SAG. A third contributor to the current APS was a member of the 2019 APS Advisory Group consulted regarding the deployment and outcome of the Delphi process.

Additional details regarding the derivation of these curves (and the curves themselves) may be found in Section E.2.1 of Appendix E of this report, and Appendix F of the 2019 APS.

Competition Groups

The measure list considered includes many competing, mutually exclusive, measures. For example: in the Residential sector there are four iterations of the space-heating air-source heat pump measure, three hybrid (natural gas auxiliary heat) and one full electrification version. These measures compete for the long-term market share.

In the Technical and Economic potential, competition groups are resolved in a winner-takes-all fashion, with a single competing measure capturing all adoption. Achievable potential allows for diversity in adoption; customer economics are used to allocate the long-run equilibrium market share captured by efficient measures to the various competing measures such that savings are not double-counted.

For each measure, in each year, and in each sub-sector, the participant cost test ratio is calculated. This is the ratio of measure incremental cost (numerator) to participant net benefits (denominator); gas bill savings net of electric energy and demand (Commercial only) charges, plus any applicable scenario incentives.

These ratios are applied to a logit discrete choice model[81] to allocate market share across the competing measures based on their relative customer economics. The output of this calculation is then used to allocate the highest equilibrium market share attained by any of the competing measures across all the competing measures.

7.2.1.2 Awareness and Incremental Adoption

Two approaches are used for calculating the approach to equilibrium market share (i.e., how quickly a technology reaches final market saturation). One approach is used for measures installed in new buildings (replacement type: NEW) or those modelled as retrofit measures (replacement type: RET). Another approach is used for those measures replaced at the end of their life where the available market is constrained by assumed equipment turnover (replacement type: ROB – replace-on-burnout).

Both approaches rely on Bass diffusion[82,83] to simulate the S-shaped growth toward equilibrium commonly seen in the adoption of new technologies. The Bass Diffusion model describes the process of the adoption of products as an interaction between users and potential users. In the model, achievable potential adopters "flow" to adopters by two primary mechanisms – adoption from external influences, such as marketing and advertising, and adoption from internal influences, such as word-of-mouth or peer-effects. Both effects together increase the awareness of the availability of the measure and so increase the percentage of those that would be willing to adopt the measure (the long-term equilibrium market share) that actually do so.

For RET and NEW measure replacement types movement along the diffusion curve is motivated by prior-year efficient measure saturation (word-of-mouth effects), and a marketing parameter calibrated to historical data (see below). For ROB measures, the diffusion of awareness in the market interacts with stock turnover, limiting the share of possible measure adoption to: the fraction of the long-run equilibrium market share that is (as simulated by Bass diffusion) "aware" of the measure, and also making a purchase decision in the given year due to existing equipment coming to the end of its expected useful life.

The marketing and word of mouth factors are calibrated in the model by back-casting projections of potential using historically deployed incentive values and comparing model outputs to evaluated program outcomes. This is described in greater detail in Appendix E.

Like Technical potential, Economic potential is unconstrained by considerations of technology annual replacement rates.

7.2.2 Incentives and Incentive-Setting

The primary user input manipulated by the modeling team to achieve targeted levels of Achieved potential in each of the scenarios is the magnitude of the incentives applied to measures.

[81] A logit formulation is based on documented consumer decision theory that accounts for consumer preferences in competing choices based on the relative and absolute differences between the choices.

Daniel McFadden and Kenneth Train, "Mixed MNL Models for Discrete Response," *Journal of Applied Econometrics,* Vol. 15, No. 5, 447-470, 2000; and Kenneth Train, *Discrete Choice Methods with Simulation*, (Massachusetts: Cambridge University Press, 2003).

[82] Bass, Frank (1969). "A new product growth model for consumer durables." *Management Science* 15 (5): p215–227.

[83] See Sterman, John D. Business Dynamics: Systems Thinking and Modeling for a Complex World. Irwin McGraw-Hill. 2000. p. 332.

Incentive Source

In each year of the analysis, the model estimates the present value (PV) of the lifetime net system benefits delivered by each measure. This is the PV of natural gas avoided costs and avoided carbon costs net of the marginal costs of electric energy and coincident peak generating capacity required by the measure. This value, the lifetime net system benefit, is the benefit to the province of measure adoption.

Incentives are applied as a share (a percentage) of this net system benefit.

This is a form of Pigouvian subsidy.[84] This is intended to correct for the inefficient market outcome that results from:

- **External Carbon Costs.** There is a misalignment between consumer prices for energy and the cost the consumption of this energy imposes on the province. The full cost of incremental GHG emissions imposed on the province of Ontario (per the SCC) is not captured in the price consumers pay for natural gas. This is a negative externality that motivates economically inefficient decision-making.

- **External Energy Benefits.** Individual consumers bear the entire incremental cost of measure adoption. Because energy prices are not fully cost-reflective,[85] consumers may not realize the full benefit that their adoption of energy efficient and fuel switching measures deliver to the province. This is a positive externality, and likewise may motivate economically inefficient decision-making.

In modeling potential, incentives are applied as a function of net system benefits in order to act as a corrective to the market failures noted above and deliver a more economically efficient provincial outcome.

Many potential studies apply incentives as a function of measure cost. The 2019 APS, for example applied incentives as a share of the customer's levelized unit energy cost (LUEC).[86] Applying incentives as a function of LUEC is an appropriate approach when – as in that study – the scenarios are calibrated to a targeted overall cost. The 2024 APS, however, is calibrated to target a specific level of achievement, and must consider two fuels, making the 2019 less appropriate in this case than the approach noted above.

To achieve the targeted level of potential, the modeling team progressively increases the share of net benefits that are returned to consumers as incentives until the scenario target has been reached.

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[84] See for example:

Baumol, W.J. (1972), "On Taxation and the Control of Externalities", American Economic Review, 62 (3): 307–322 **https://www.jstor.org/stable/1803378**

And

Turvey, Ralph (1963). "On Divergences between Social Cost and Private Cost". Economica. 30 (119): 309–313. **https://www.jstor.org/stable/2601550**

[85] Residential electricity prices, for example, use variable revenue collection mechanisms to offset many costs that are effectively fixed in the short-run, but that may undervalue costs in the long-run.

[86] See Section 7.2.2.1 of the 2019 APS

Incentive Constraints

Two constraints are imposed on incentives in the potential study modeling to help ensure that incentives deliver economically efficient outcomes, equitably.

- **Economic Efficiency.** Incentives can never be set to be higher than the net system benefit the measure delivers to the province. Doing so would result in economically inefficient outcomes and aggregate potential that was not cost-effective.

- **Equity.** Incentives likewise cannot be set to be higher than measure incremental cost. This second condition was specified for inclusion following consultation with members of the SAG out of consideration for the potential perception of cross-subsidization.

Given these constraints, it is appropriate to include in the Achievable potential *all* measures, not just those that test as cost-effective. Measures that are (on average) not cost-effective (i.e., where net system benefits are lower than incremental measure costs) will receive relatively modest incentives, moderating their adoption.

This approach is an explicit attempt to address modeling concerns periodically raised in discussions of potential studies. Specifically, that individual measures will be more cost-effective for some consumers than others, and that many DSM programs include measures that are not on their own cost-effective (on average), but that contribute to an overall cost-effective portfolio outcome.

The incentive application approach, and its constraints, accommodate both issues; modest incentives that result in improved (but still long) average payback time for measures will result in adoption by some consumers (for whom it is personally cost-effective to do so). The constraints on incentives, however, mean that overall sectoral potential benefits will always exceed incremental costs.[87]

7.2.3 Administration Costs

Program administration costs tend to vary widely depending on the nature of the program design. This factor cannot be controlled for within the potential study, as this study remains agnostic on questions of program design.

For this reason, Guidehouse typically estimates program administration costs as a simple function of incentive costs. For this study, Guidehouse has applied the following ratios to incentive costs to deliver overall program administration costs.

[87] Scenarios D (EE + FS, CFB, Max Achievable) and E (EE only, CFB, Max Achievable) attain TRC-plus ratios of between 0.9 and 1 in some years for the Residential sector. This however, is a result of the program administration adder, and ratios exceed one when this adder is removed. Even with the program administration adder, all targeted scenarios (0.5% and 1%, Scenarios A, B, and F) test as cost-effective at the sectoral level.

Table 16. Program Administrative Cost Ratios

Sector / Sector Category	Program Administration Costs as a % of Incentive Costs
Low Income	58%
Residential	26%
Commercial	60.5%
Industrial	50.8%

The values above should be considered as illustrative. Program administration costs are a function of a program's design, and a potential study is not a DSM program design. Program administration costs are likewise unlikely to be linear in incentives, and so caution should be used in interpreting estimates of program costs for the potential scenarios, especially the Max Achievable scenarios which maximize incentive (and therefore program administrative) spending.

The ratios above for the Commercial and Industrial sector were provided (at Guidehouse's request) by EGI and used based on direction provided by OEB staff.. EGI has indicated that these ratios reflect EGI's 2023 program costs. The ratios for the Residential sector (Low-Income and non-Low-Income) were developed by OEB staff on the basis of ratios provided to them by EGI. EGI did not provide input as to how the program administrative costs percentages above should be applied in an increased budget scenario.

Reviewers of this report should take care not to interpret these ratios as anything more than a simplified output developed to allow for transparent – but illustrative only – estimation of the program administration costs associated with the estimate potential.

7.2.4 Ontario's First Winter Peak Year

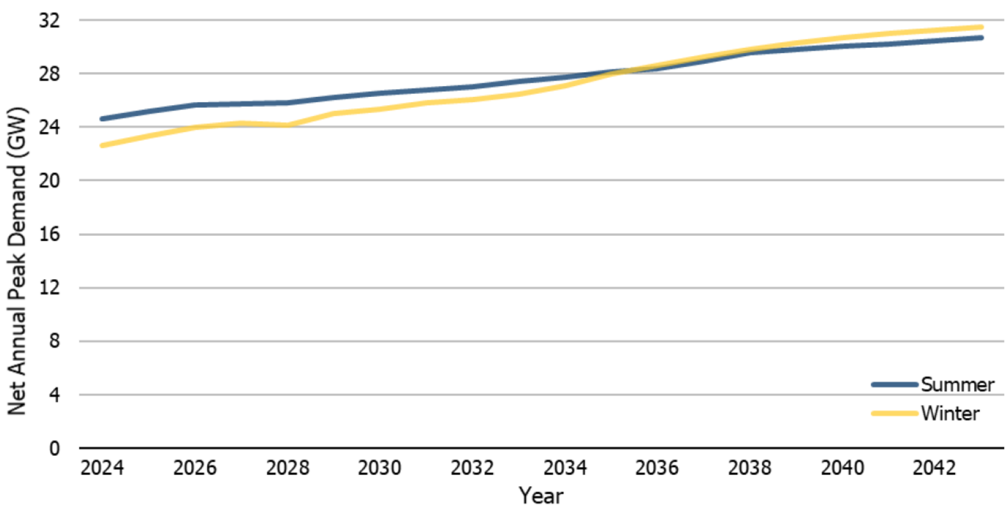
For the purposes of cost-effectiveness testing, Guidehouse has applied the value of capacity ($144 kW-year) prescribed by the IESO[88] for valuing non-wires alternatives. Guidehouse has applied this cost of incremental peak demand to fuel-switching measures only in those years in which Ontario is projected to be a winter-peaking utility.

No system cost is applied to incremental peak demand in winter months when Ontario is assumed to be summer-peaking and no system benefit is applied to peak demand savings in summer months when Ontario is assumed to be winter peaking. This approach is consistent with how peak capacity benefits from conservation and demand management (CDM) have been treated by the IESO for cost-effectiveness testing (i.e., that winter peak demand reductions have no value so long as Ontario is summer peaking).

[88] Independent Electricity System Operator, *Integrated Regional Resource Plans: Guide to Assessing Non-Wires Alternatives*, May 2023
Available at: **https://www.ieso.ca/Get-Involved/Regional-Planning/About-Regional-Planning/Planning-Information-and-Data**

At the time modeling was undertaken, the most recently available projection of Ontario winter and summer peak demands were included in the IESO's 2022 APO.[89] This document projected that Ontario would become winter peaking by 2036, but provided projections indicating the proximity winter and summer peak demands in the years prior – see Figure 54 below, reproduced from the APO.

Figure 54. IESO's 2022 APO Seasonal Peak Demand Projections (Figure 2 in Original Document)



Anticipating that Achievable potential scenarios would include sufficient adoption of space-heating fuel switching – in particular the adoption of ASHPs in the Residential sector which could both increase winter peak demand and reduce summer peak demand (replacing less efficient central A/C units) – the Guidehouse modeling team tracked peak demand impacts to determine whether adoption might accelerate Ontario's transition to winter peaking. When net increases in peak demand were found to result in the province transitioning to a winter peak sooner, the transition year was updated by the modeling team.[90]

An earlier transition impacts the economics of fuel-switching measures by increasing the number of years within the measure's lifetime in which incremental coincident peak demand costs are incurred.

The first year in the province becomes winter-peaking as a result of the estimated measure adoption, by scenario, is provided in Table 17, below.

[89] Independent Electricity System Operator, *Annual Planning Outlook Data Tables,* March 2024 **https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook**

[90] The change of transition year is not a dynamic part of the model, but a manual adjustment. The transition years shown below were determined in the penultimate estimation run of the model and then applied for the final model run that delivered the estimated results presented in the this report.

Table 17. Achievable Potential Scenarios

Scenario	Targeted Year-Over-Year Gas Reduction	Measures Included	Value of Carbon	Year in Which Ontario Becomes Winter-Peaking
A	0.5%	EE + FS	CFB	2035
B	1%	EE + FS	SCC	2035
C	Max Achievable	EE + FS	SCC	2033
D	Max Achievable	EE + FS	CFB	2034
E	Max Achievable	EE Only	CFB	2036
F	1%	EE + FS	CFB	2035

As would be expected, the greatest acceleration to Ontario's transition to a winter-peaking utility is provoked by the Max Achievable scenarios that include fuel switching.

The process of tracking potential and adjusting the transition year is applied only for the Achievable potential estimation. Economic potential is estimated holding the transition year fixed at 2036, as identified in the IESO's 2022 APO.

As Guidehouse was in the process of finalizing measure and modeling inputs in consultation with the SAG, the IESO published its 2024 APO. This document noted the IESO's revised estimate that Ontario could become winter-peaking by as soon as 2030. Guidehouse and OEB staff assessed that updating the 2024 APS to reflect all the updated values included in the 2024 APO would be time-consuming, would require significant additional consultation with the SAG, and would result in an unacceptable delay to the delivery of this report.

As such, OEB staff directed Guidehouse to proceed with the values already included in the model, those derived from the 2022 APO.

An earlier transition year (e.g., 2030 instead of 2033 or 2034) will primarily impact full electrification space heating measures. More specifically, the sooner the province becomes winter-peaking, the less cost-effective full electrification measures in the early part of the period of analysis will become. Hybrid space-heating measures (which use natural gas at the time of system peak) are unaffected. Water heating fuel switching measures would be somewhat less cost-effective in the earlier years of the period of projection which would (via the incentive-capping mechanism) also reduce projected adoption in the case of an earlier assumed winter-peaking transition year.

7.3 Results

This section provides a summary of the Achievable potential scenario results from the following perspectives:

1. Natural Gas Achievable Potential by Sector
2. Achievable Potential Winter Peak Demand Impacts
3. Measure-Level Natural Gas Achievable Potential
4. Achievable Potential Cost-Effectiveness

5. Achievable Potential Program Administrator Annual Costs and Benefits

The GHG impacts of the Achievable potential by sector, and a summary of the sub-sector-level Achievable potential natural gas savings are presented in Appendix E.

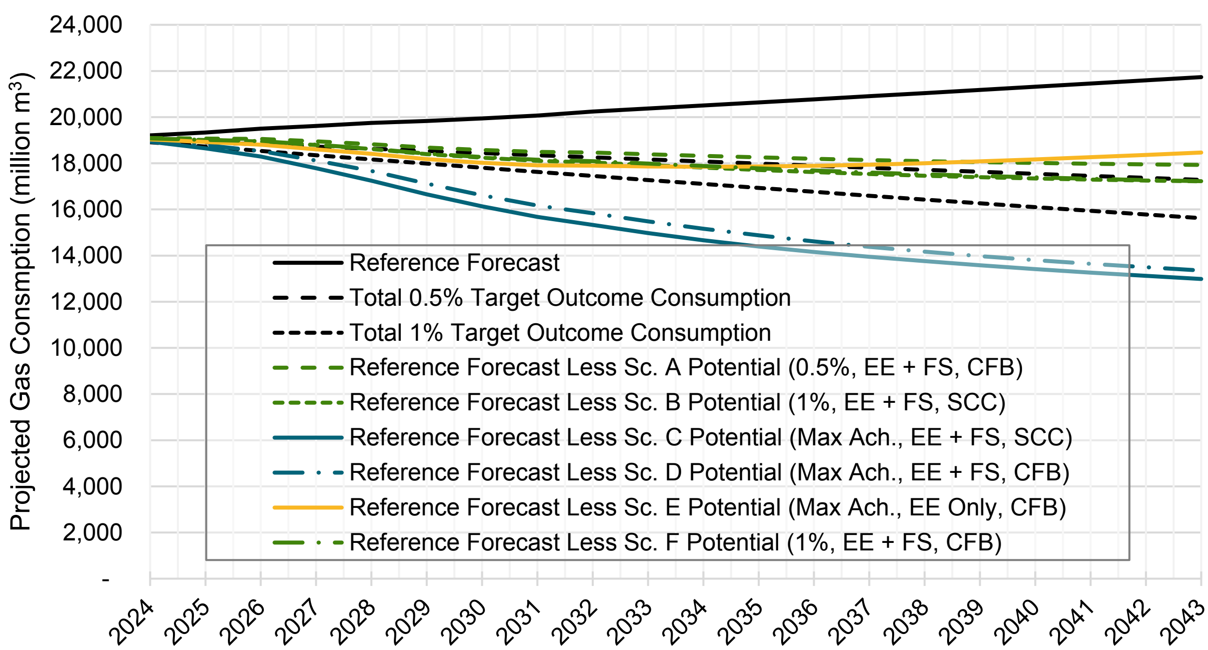
Figure 71, below, provides a summary comparison of the aggregate estimated Achievable potential by scenario, the reference forecast, and the two targeted levels of consumption targeted by Scenarios A, B, and F (i.e., a 0.5% and 1% year-over-year reduction in consumption, as previously illustrated in Figure 52).

The reference forecast is represented by the black line. The dashed and dotted black lines, represent (respectively) the targeted consumption related to a 0.5% year-over-year reduction in volumes and a 1% year-over-year reduction in volumes. The three dark green lines represent the reference forecast less Achievable potential in one of the targeted reduction scenarios. The dotted dark green line represents Scenario A, and the dashed and dot-dashed green lines represent Scenarios B and F (these two are nearly the same and difficult to distinguish from one another in the graph).

The blue lines represent Max Achievable scenarios that include fuel switching, the solid blue line representing the Max Achievable estimated using the SCC value for carbon and the dot-dashed blue line representing the Max Achievable scenario estimated using the CFB value for carbon. The yellow line represents the estimated potential for the EE-only Max Achievable scenario.

In the figure below, as in subsequent figures, significant amounts of data are presented, and distinguishing individual series from one another may sometimes be challenging. All of the data underlying these charts are available within Appendix X2 and may be helpful to reviewers in interpreting the figures in this section of the report.

Figure 55. Reference Forecast, Targeted Consumption, and Achievable Potential



The clustering of results can make a detailed review of this chart challenging, but there are several noteworthy features. First, Scenario A (0.5%, the dark green dashed line) does *not* attain the 0.5% targeted level of consumption (dashed black line). This is an expected outcome; no fuel switching measures were modeled for the Industrial sub-sector, and since each sector's incentives were calibrated to the targeted potential in each scenario, the aggregate (cross-sector) potential can attain the target only if the target is attained in all three sectors.

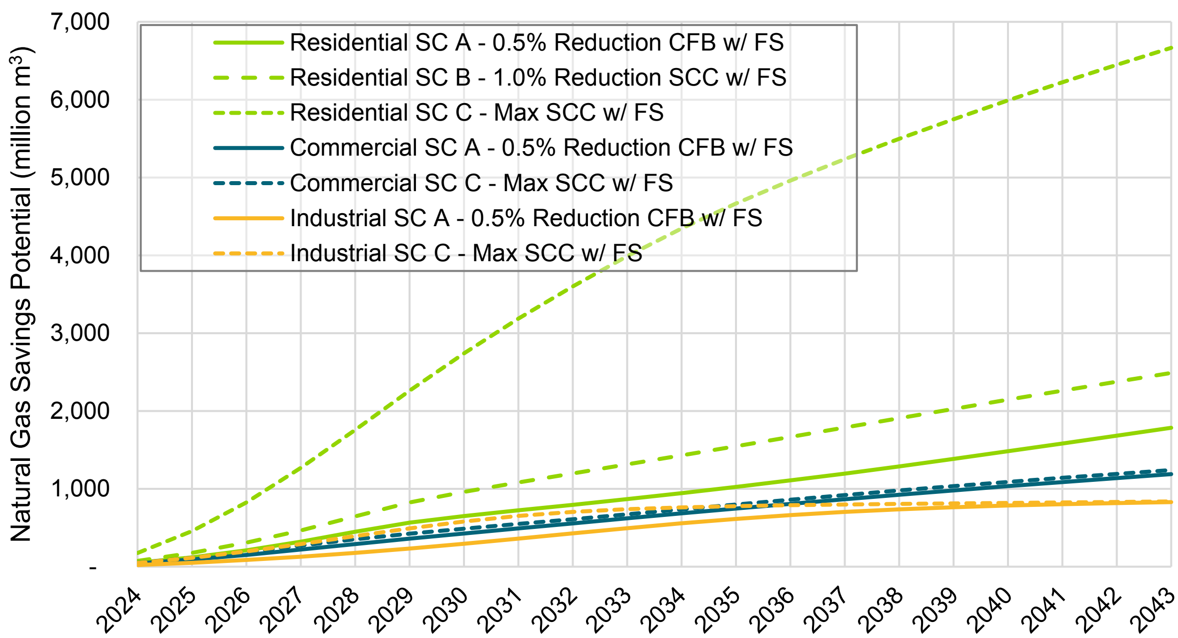
The gap between the Scenario B and F lines (dark green, dotted and dash-dotted respectively) and the dotted black target line for the 1% targeted consumption level is considerably greater in both absolute and relative terms than the gap between the Scenario A line and the 0.5% targeted consumption level (dashed black line). This is due to the Commercial Achievable potential in Scenarios B and F failing to reach the target, largely due to the very limited technical suitability of many Commercial fuel-switching measures. This result is described in greater detail in Section 7.3.1 below. Context for the technical suitability (and other questions of applicability) related to Commercial fuel switching measures is provided in Section B.3 of Appendix B.

The Max Achievable scenarios that include fuel switching (blue lines) do result in levels of consumption that are much lower than the more aggressive targeted level (i.e., the 1% year-over-year reduction illustrated by the dotted black line). This result is driven by the estimated Max Achievable potential for the Residential sector, in which considerable potential exists beyond that achievable when targeting the 1% year-over-year reduction in total consumption.

7.3.1 Natural Gas Achievable Potential by Sector

Figure 72, below, compares a selection of Achievable potential scenarios across the three sectors (scenarios are comprehensively compared to each other and the targets, by sector below).

Figure 56. Achievable Potential Scenarios by Sector



Within each sector some scenarios' output potential values that are very similar and so are not shown in this inter-sector comparison.

The key features of the outputs displayed above include:

- **Residential Dominance.** Residential potential in the three most critical scenarios (A, B, and C) is higher than any other sector's potential regardless of scenario. Part of this is due to the fact that the Residential sector also has the largest volume of consumption in the reference forecast[91], though an examination of Table 18 below shows that even when expressed as a percentage of the reference forecast the Max Achievable and Scenario B potentials are much higher for Residential than other sectors. The most significant contributor to the dominance of the Residential sector is the wide applicability of fuel switching measures in this sector.

- **Clustering of Commercial Scenario Potential.** Scenario A (0.5% target) and Scenario C (Max Achievable) estimate potential series are very close to one another. The combined effects of very low technical suitability, exacerbated by the impacts on customer bills of peak demand charges means that there is virtually no adoption of full electrification of space heating in existing buildings. The fact that hybrid solutions are considered only for smaller-sized building sub-sectors also substantially limits the potential adoption of such measures. The proximity of these two scenarios outcomes indicates that incentives in Scenario A need to be set at or near their maximum values to attain the targeted potential.

- **Convergence of Industrial Potential Scenarios.** Scenario A (0.5% target) and Scenario C (Max Achievable) converge on approximately the same potential by the end of the period of analysis. This is a result of the measures included in the analysis, derived from the IAC database, which are very nearly all cost-effective, and which do not include any fuel-switching measures.

Table 18, below, shows the Achievable potential as a share of the reference forecast for each sector, by scenario.

Table 18. Achievable Potential As Percent of Corresponding Sector Reference Forecast

Scenario	Year	Residential	Commercial	Industrial	**Total**
SC A - 0.5% Reduction CFB w/ FS	2028	5%	4%	4%	**5%**
	2035	12%	11%	12%	**12%**
	2043	20%	17%	15%	**18%**
SC B - 1.0% Reduction SCC w/ FS	2028	8%	4%	4%	**6%**
	2035	18%	11%	12%	**14%**
	2043	27%	17%	15%	**21%**
SC C - Max SCC w/ FS	2028	21%	5%	8%	**13%**
	2035	53%	12%	15%	**30%**
	2043	73%	17%	15%	**40%**
	2028	16%	5%	8%	**11%**

[91] Reviewers should note that this is only the case because of the exclusion of the Extra Large Volume customers from the reference forecast, as described in Section 2. When ELV customers are included, the Industrial sector is the largest natural gas-consuming sector in the province.

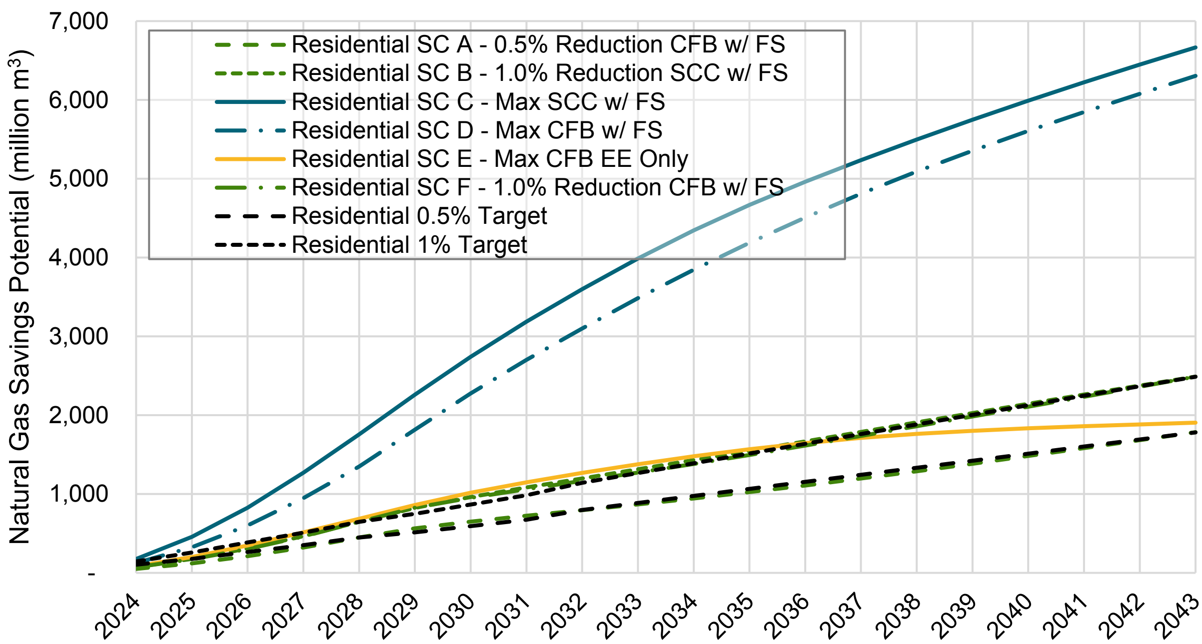
Scenario	Year	Residential	Commercial	Industrial	Total
SC D - Max CFB w/ FS	2035	48%	12%	15%	**28%**
	2043	69%	17%	15%	**39%**
SC E - Max CFB EE Only	2028	8%	4%	8%	**7%**
	2035	18%	6%	15%	**13%**
	2043	21%	7%	15%	**15%**
SC F - 1.0% Reduction CFB w/ FS	2028	8%	4%	4%	**6%**
	2035	17%	11%	12%	**14%**
	2043	27%	17%	15%	**21%**

The number of scenarios (and targets) preclude including all series for each sector on a single plot – the result would be too cluttered to be useful. Figure 56, above, compares a selection of the most relevant scenarios across the sectors to allow for an inter-sectoral comparison.

The figures below provide an intra-sectoral comparison of the scenarios, showing the estimated Achievable potential for all six scenarios for each sector as a single plot, and superimposing the targets identified in Section 7.1.1 above. The colour and line-type formatting of these plots follows the convention established at the aggregate level in Figure 55, where forecast consumption net of the effects of potential is compared across scenarios.

Figure 57 shows the estimated Residential Achievable potential for each scenario, as well as the targeted level of Achievement.

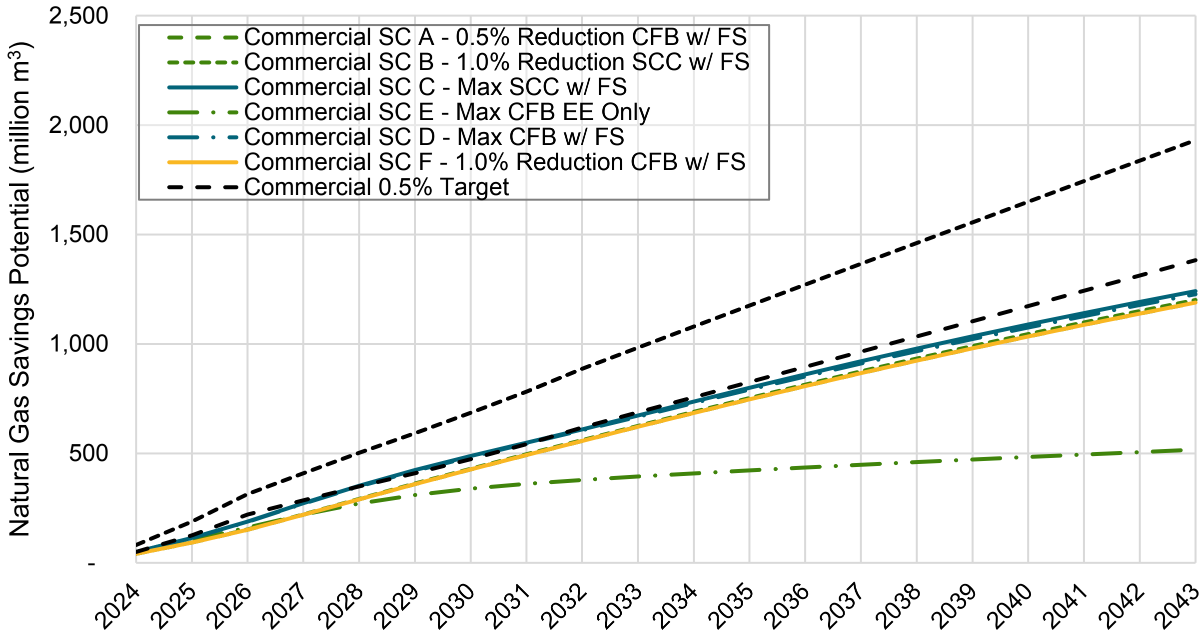
Figure 57. Residential Achievable Potential Scenarios and Targets



Scenario A, B, and F potential series lines are obscured by the target lines in most years because scenario potential achieves the specified target in most years. The Max Achievable potential when considering only EE measures is, for many years of the period of analysis, very similar to the Scenario B and F potential results. The magnitude of the difference between the Scenario E yellow line and the blue Scenario C and D lines illustrates the incremental potential available at maximum possible incentives when fuel switching measures as well as energy efficiency measures are considered.

Figure 58 shows the estimated Commercial Achievable potential for each scenario, as well the targeted level of Achievement.

Figure 58. Commercial Achievable Potential Scenarios and Targets

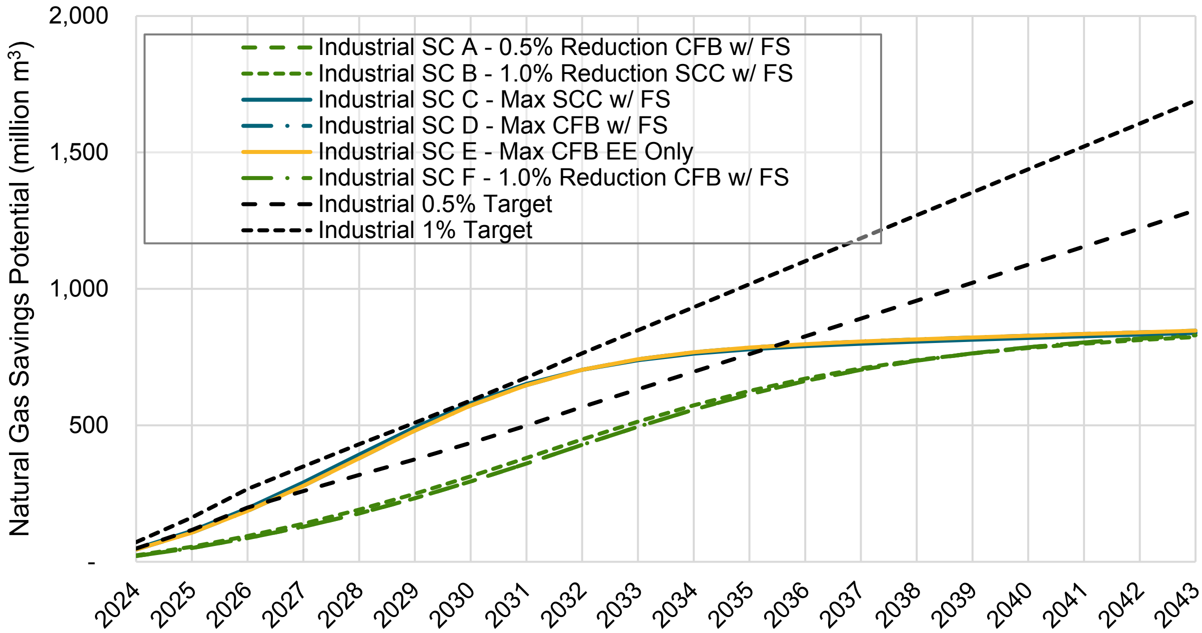


Most notable is that even by maximizing incentives, Scenario A's potential comes close to, but does not quite achieve, its target. Given that Scenario A has maximized incentives, there is very little incremental incentive that can be applied in Scenario B or F. Only the Max Achievable scenarios that consider fuel switching are able to attain the 0.5% target.

The reason Scenario C and D (Max Achievable) attain the Scenario A target in the early years when Scenario A itself cannot is that in addition to maximizing incentive assumptions, the Max Achievable scenarios also maximize the assumed effects of marketing and word-of-mouth, effects that are calibrated to historical achievement for the targeted scenarios (see Section E.2.3 of Appendix E for more details). These effects increase the share of equilibrium market share that is achieved in each year, but do not affect the equilibrium market share itself (which will be quite high given the scenario incentives) or,, most importantly, the Technical Suitability which caps potential (see Section B.3.10 of Appendix B for more details).

Figure 59 shows the estimated Industrial Achievable potential for each scenario, as well the targeted level of Achievement.

Figure 59. Industrial Achievable Potential Scenarios and Targets



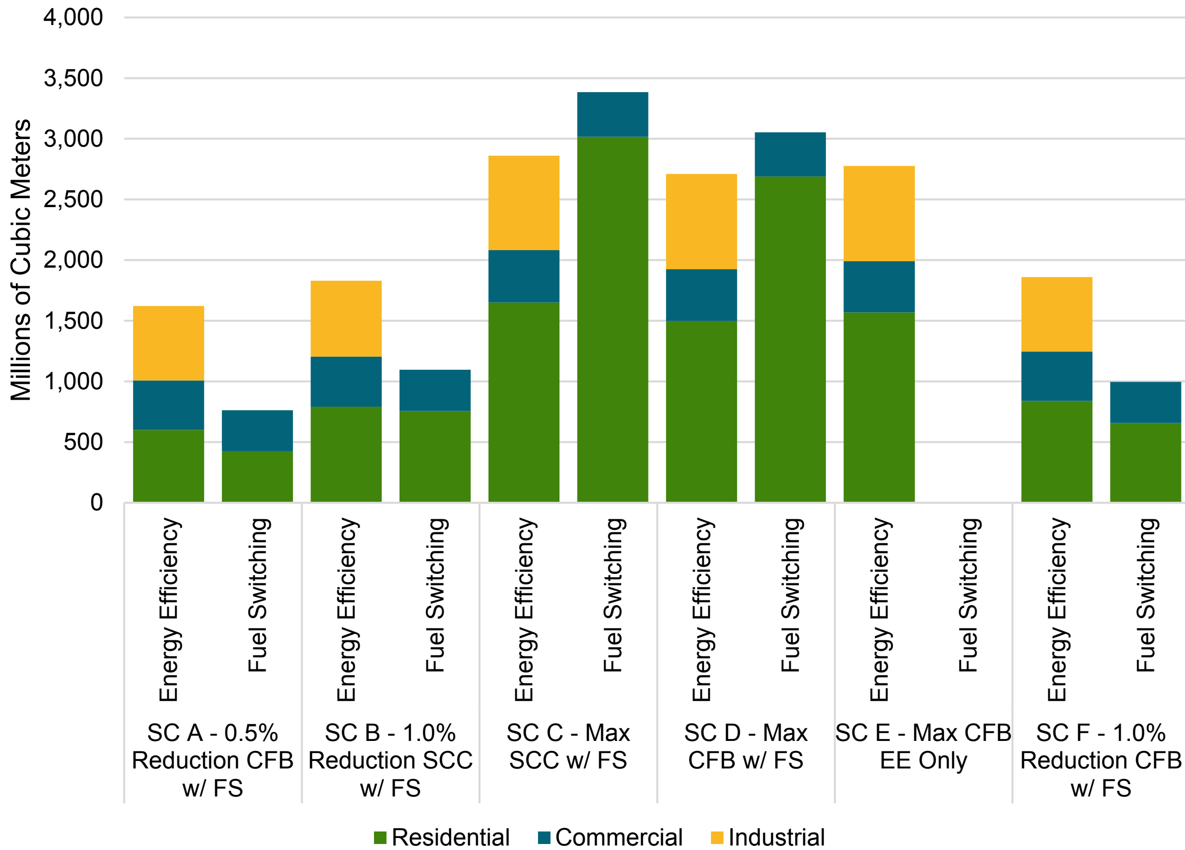
For Industrial Achievable potential, the scenarios follow clear patterns. All Max Potential Achievable scenarios rise quickly and attain the 1% target in approximately 2029, 2030, and 2031. The targeted scenarios don't rise as quickly but eventually, by the terminal year of the period of analysis, converge on the same level of potential as the Max Achievable scenarios. Although the non-incentive inputs to the Max Achievable accelerate adoption, they do not alter the long-term equilibrium market share, which is why in those scenarios the potential grows faster, but eventually converges toward the same point as the targeted scenarios.

The incentives in the targeted scenarios are set to their maximum values, but still fail to achieve either the 0.5% or the 1% target. This is largely due to the measure list, which does not include any fuel switching measures.

Figure 60 illustrates the importance of Residential fuel-switching for driving variation in potential across the scenarios. This figure presents Achievable potential in 2035, by scenario and sector, split between fuel switching and energy efficiency potential. Commercial and Industrial contributions remain relatively static across all scenarios, principally due to the issue identified above: because the fuel switching measures are excluded (Industrial) or defined very narrowly and so technically suitable only for a small share of buildings (Commercial) incentives have to be maximized to approach the 0.5% target, leaving no room for increases across the more aggressive scenarios.

In contrast, fuel switching in the Residential sector delivers potential on par with energy efficiency measures (in Scenarios A, B, and F) and nearly 1.5 times energy efficiency potential in the Max Achievable scenarios that include fuel switching.

Figure 60. Achievable Potential in 2035 by Scenario and Measure Type

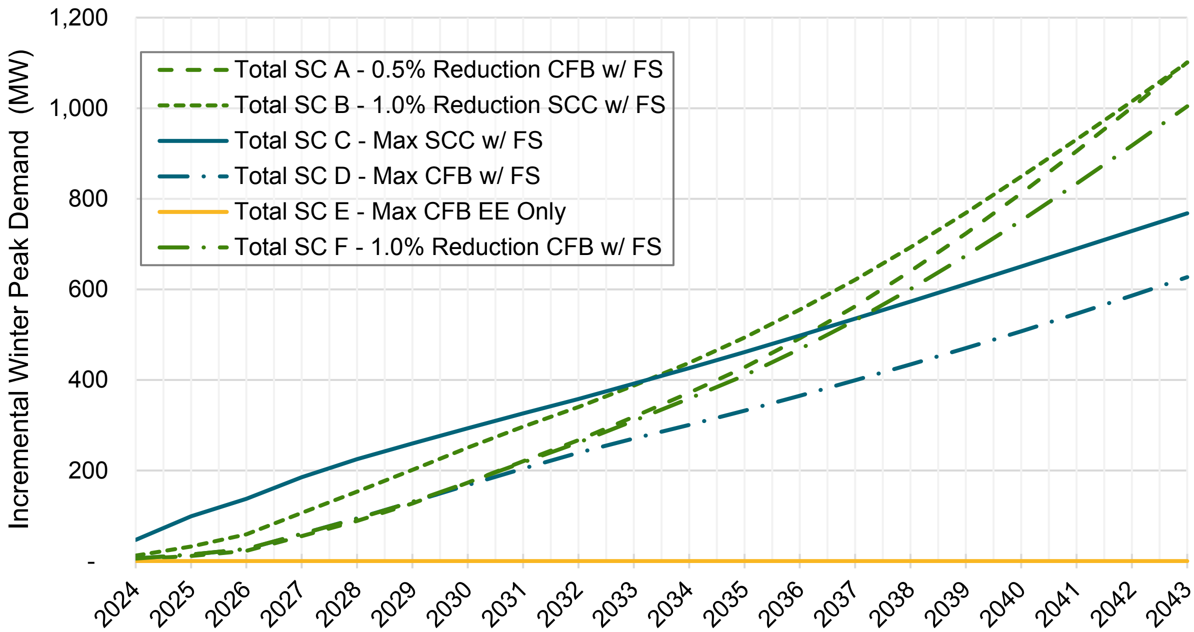


7.3.2 Achievable Potential Winter Peak Demand Impacts

Figure 61 shows the estimated winter peak demand impact of the measures included in the Achievable potential for the Residential and Commercial sectors in each of the six scenarios. Note that the impact for Scenario D (EE Only) is zero. In this graph, a positive value indicates an *increase* in peak demand.

This plot provides a counter-intuitive outcome in the final years of the period of analysis. Although in the early years, the peak demand impact is highest (as would be expected) for the Max Achievable scenario that uses the SCC (Scenario C), in the closing years of the period of analysis, the three targeted scenarios (Scenarios A, B, and F) all of which yield considerably less potential overall (see Figure 55) actually result in *higher* peak demand impacts than the Max Achievable scenario. What drives this unexpected outcome?

Figure 61. Winter Peak Electricity Demand Impacts Associated with Achievable Potential



- This unexpected outcome is entirely driven by the Residential sector. In the Commercial sector, winter peak demand increases are very closely correlated with the Achievable potential. This outcome in the Residential sector is the result of: the timing of adoption and capture of market share and the interplay between the changing values of winter capacity, carbon value, and retail rates over time.

- **Timing of Adoption.**
    - The Max Achievable potential scenarios maximize available incentives from the first year of the period of analysis.
    - This means that a much higher share of the market adopts fuel switching measures early in the period of analysis compared to the targeted scenarios.
- **Incentive Value and System Benefit.**
    - The impact on net system value of winter peak demand growth is greatest in the year that Ontario is modeled to transition to winter peaking.
    - It is in this year that the PV of lifetime capacity costs (which is a constant value in real terms - $144 per kW-year) is highest relative to the PV of lifetime carbon and avoided gas costs (which increase in real terms over time).
    - Because measure net system benefits are calculated based on the present value of lifetime costs, measure net system benefit is substantially impacted by these capacity costs in the early years of the period of analysis.
    - This is exacerbated when some adoption of full electrification measures pulls the transition year forward (as is the case for the Max Achievable scenarios).
    - Because of the way incentives are assigned – as a function of net system benefit – this means that the incentive for full electrification space heating is, relative to the incentive for hybrid systems, lowest in these early years.
- **Retail Rates.**

- Although the natural gas retail rates used in this analysis are substantially lower than electricity retail rates when compared in common energy units (see Section E.3 of Appendix E), the distance between them narrows over time.
- This effect compounds with the incentive effect noted above to improve the customer economics of the full electrification measures over time.
- Note that Residential consumers, unlike Commercial customers, are not subject to a demand charge – the only disincentive for increasing system demand to which they are exposed is the impact of demand on modeled incentives.

- **Measure Competition**
  - When overall incentive levels are lower (i.e., in the targeted scenarios), the impact on customer economics of the changing retail rates is more important, and significantly improves the payback of full electrification in relative (not absolute terms) when compared to the payback of the hybrid measure.
  - When measure competition is considered this results in a greater share of the market going to fully electric space-heating compared to the scenarios where higher incentives – incentives set to correct for inefficient market outcomes – are offered.

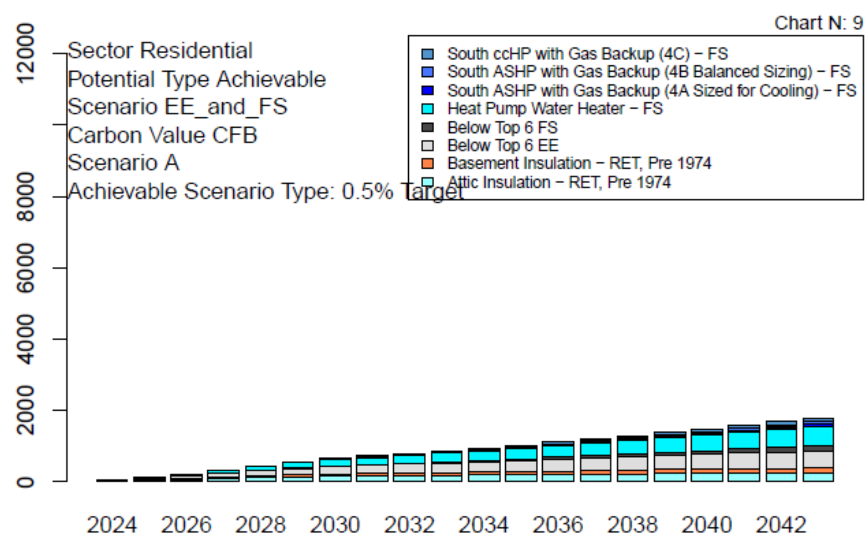
The critical insight this outcome offers is this: improving the alignment between consumer incentives and provincial costs delivers greater provincial value. The disconnect between the provincial cost of peak demand and the price Residential customers pay for increasing that demand (nothing) results in a less economically efficient outcome for the province than when incentives are applied to better align an individual's economic decision-making with the economic interests of the province.

7.3.3 Measure-Level Natural Gas Achievable Potential

Figure 62 shows the measure-level potential diagnostic plot for the Residential sector for Scenario A. Recall that the "top six" measures for which potential are shown are the measures with the highest average potential across the first ten years of the period of analysis.

Figure 62. Residential Measure-Level Achievable Scenario A Potential

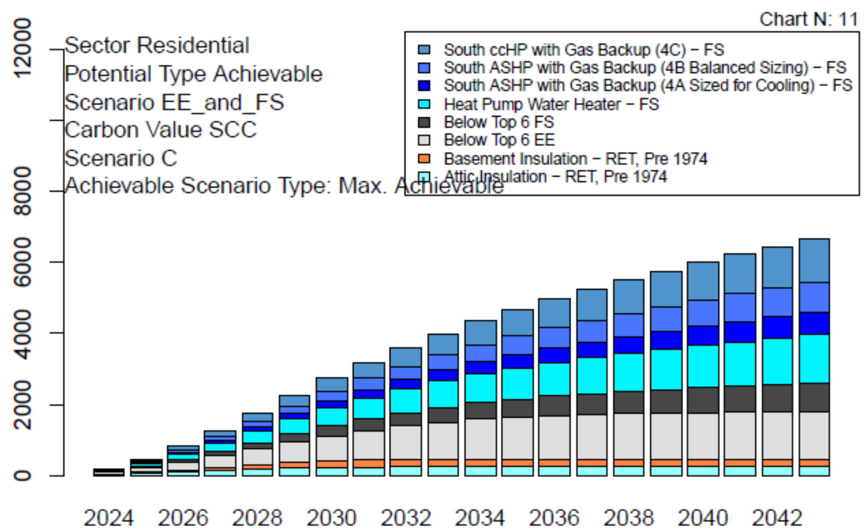
(0.5% Target, EE + FS, CFB) – Top Six Measures (millions of m^3)



By far the single greatest contributor here is the heat pump water heater. This measure benefits from being technically suitable for a very high proportion of single family homes, with a relatively modest incremental cost compared to the bill savings it offers, and – since it offers significant carbon and avoided gas benefits – considerable incentive "headroom". This measure was the subject of considerable debate amongst SAG members, and a number of adjustments were applied to this measure based on that feedback, as documented in Section B.3.4 of Appendix B. Hybrid space-heat fuel-switching delivers much of the remaining fuel-switching potential, though a non-trivial amount of potential (and commensurate winter electricity peak demand increases) in later years is delivered by full electrification heat pumps. This potential is embedded in the black "Below Top 6 FS" section of the graph above.

Figure 63 shows the measure-level potential for the Max Achievable potentials scenario estimated with the social cost of carbon.

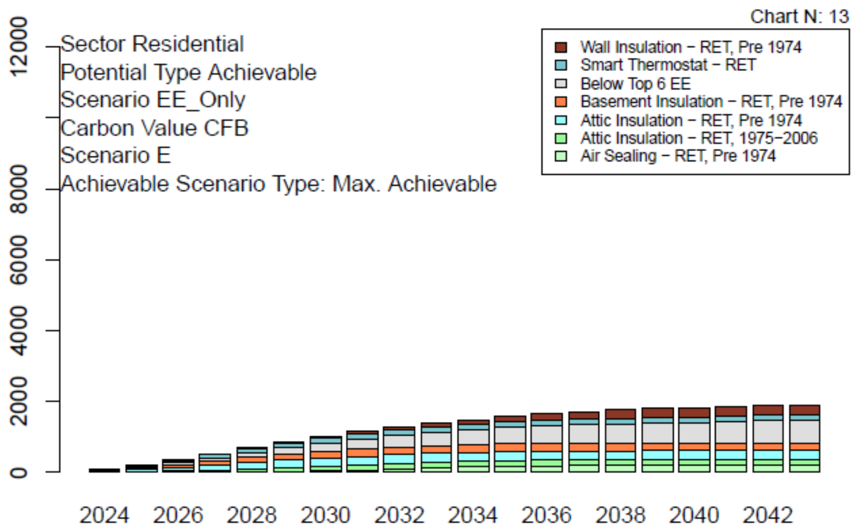
Figure 63. Residential Measure-Level Achievable Scenario C Potential (Max Achievable, EE + FS, SCC) – Top Six Measures (millions of m^3)



Maximizing incentives to equal 100% of measures' net system benefits results in a substantial increase in measure adoption, most notably for the hybrid fuel switching measures. Of these options 4C, the cold climate heat pump sized for heating with a gas back-up attains the most market share.

When considering the EE only scenario (Scenario E), in Figure 64 it is clear that the most significant contributors to estimated potential are envelope measures; insulation and air sealing, in particular.

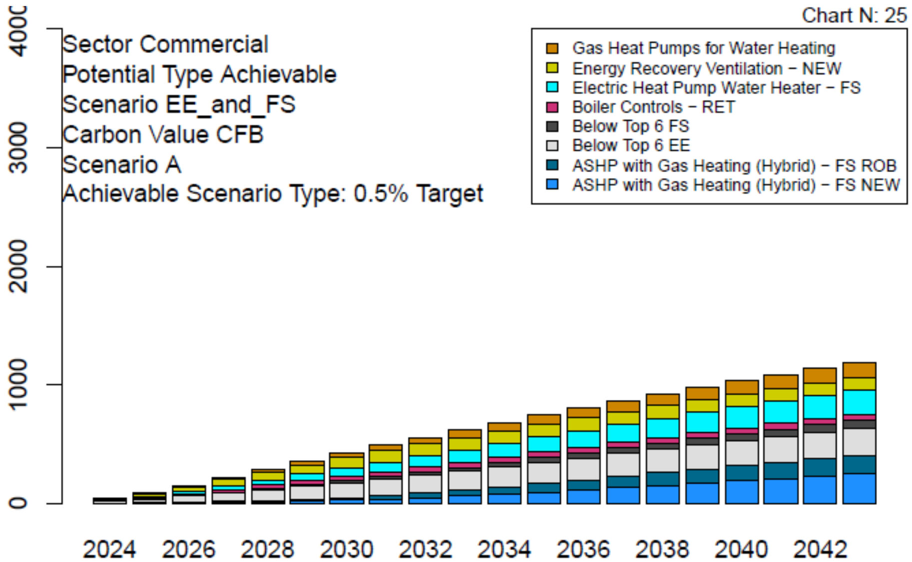
Figure 64. Residential Measure-Level Achievable Scenario E Potential (Max Achievable, EE Only, CFB) – Top Six Measures (millions of m^3)



Measure-level potential for Scenario A for the Commercial sector is presented in Figure 65, below. As noted previously, the limited applicability of some fuel switching measures limits the potential for these measures, as modeled, in the potential estimation (see Section B.3.10 of Appendix B for more details). In the Commercial sector, delivery demand charges also significantly reduce the attractiveness of full electrification (particularly of space heating) to Commercial consumers. As in the Residential sector, water heating electrification potential is significant.

Adoption of hybrid heat pumps is much greater for the new construction (NEW) than for replace-on-burnout (ROB) replacement type, reflecting the logistical challenges identified by a member of the SAG for the conversion of Commercial heating systems to hybrid systems reflected in the assumed Technical Suitability of the ROB version of this measure.

Figure 65. Commercial Measure-Level Achievable Scenario A Potential (0.5% Target, EE + FS, CFB) – Top Six Measures (millions of m³)



Measure-level potential for Scenario E (energy efficiency measures only) for the Commercial sector is presented in Figure 66 below. Unlike the Residential sector, where energy efficiency potential was concentrated in building envelope measures like insulation and air sealing, the Commercial highest-potential measures reflect a greater diversity of use cases, as would be expected given the heterogenous nature of the different sub-sectors.

Figure 66. Commercial Measure-Level Achievable Scenario E Potential (Max Achievable, EE Only, CFB) – Top Six Measures (millions of m³)

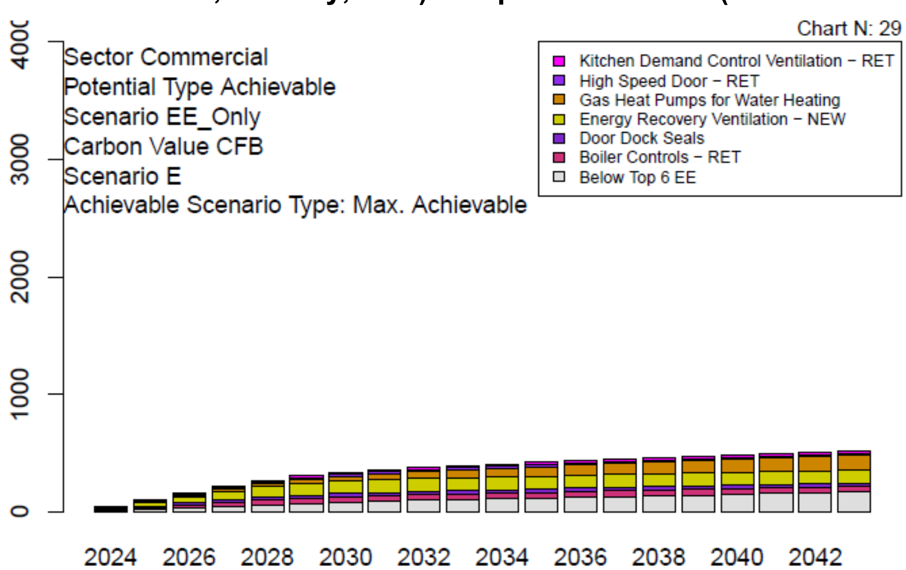
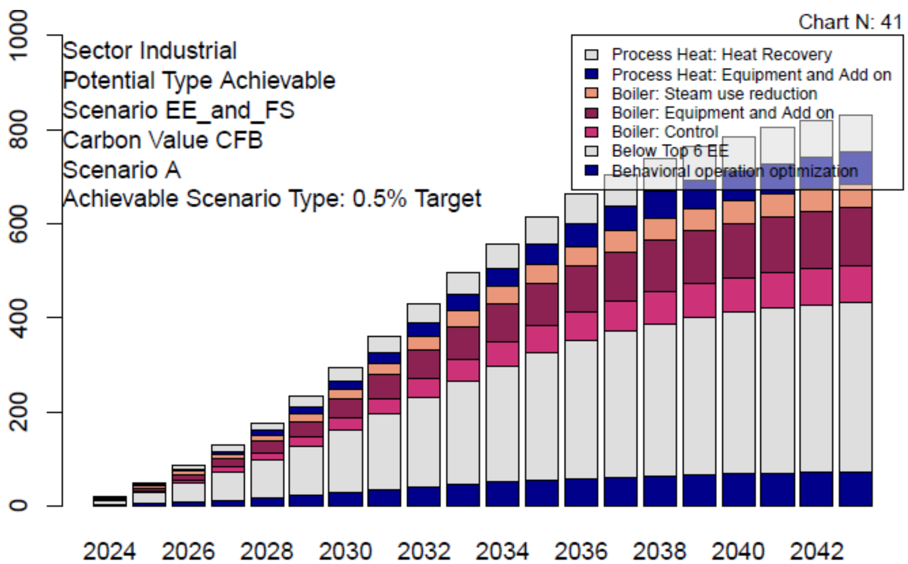


Figure 67 shows the measure-level potential for the top six measures in the Industrial sector. As with Economic and Technical potential, the top six measures account for a much smaller share of overall potential than in the Residential or Commercial sectors. This is a reflection of the underlying heterogeneity of the market and the niche nature of many measures which may be highly specific to a given sub-sector. As noted previously in Sections 2.2.3, and 4.2.4.3, the nature of the IAC database (which reflects measures that are overwhelmingly cost-effective from a consumer perspective as well as from a total resource perspective) is such that these estimates understate the Industrial sector's potential gas reductions.

Figure 67. Commercial Measure-Level Achievable Scenario A Potential (0.5% Target[92], CFB) – Top Six Measures (millions of m^3)



7.3.4 Achievable Potential Cost-Effectiveness

The 2024 APS does not exclude measures that are not cost-effective on an individual basis from inclusion in the Achievable potential. This is consistent with real-world DSM programs, which may include measures that are not on average cost-effective, and ignores the reality that a measure may not be cost-effective for all consumers installations (i.e., not cost-effective on average) but may be cost-effective in a large minority.

To avoid situations in which sector-level Achievable potential fails to be cost-effective, Guidehouse assigned incentives on the basis of net system benefits. This Pigouvian subsidy corrects for misalignments between consumer incentives and system benefits and approximately maximizes overall total resource benefits. Despite the inclusion of all measures (not just those that are individually cost-effective), sectoral TRC, exclusive of estimated program administration costs, is materially above one for all sectors and scenarios, as shown in Table 19.

Table 19. Sectoral TRC-Plus Ratios – No Program Admin

Scenario	Year	Residential	Commercial	Industrial
	2028	1.65	2.51	6.33
	2035	1.54	2.55	7.99

[92] No fuel switching measures were included for the Industrial sector.

Scenario	Year	Residential	Commercial	Industrial
SC A - 0.5% Reduction CFB w/ FS	2043	1.47	2.48	6.85
SC B - 1.0% Reduction SCC w/ FS	2028	1.90	3.21	9.39
	2035	1.73	2.73	9.61
	2043	1.43	2.55	7.05
SC C - Max SCC w/ FS	2028	1.44	3.14	9.54
	2035	1.34	2.73	7.42
	2043	1.27	2.54	5.20
SC D - Max CFB w/ FS	2028	1.26	2.48	6.51
	2035	1.19	2.55	6.31
	2043	1.22	2.47	4.83
SC E - Max CFB EE Only	2028	1.50	2.79	6.51
	2035	1.32	2.54	6.31
	2043	1.23	2.57	4.83
SC F - 1.0% Reduction CFB w/ FS	2028	1.51	2.51	6.33
	2035	1.56	2.55	7.99
	2043	1.39	2.48	6.85

Program administration costs are not included in the calculation of measure net system benefits that drives incentives. This means that implicit approximate benefit maximization motivated by the incentive design means that for the Residential sectors the sector-level TRC-plus falls slightly below 1 in some years, as shown below in Table 20.

Table 20. Sectoral TRC-Plus Ratios – With Program Admin

Scenario	Year	Residential	Commercial	Industrial
SC A - 0.5% Reduction CFB w/ FS	2028	1.33	1.72	2.89
	2035	1.39	2.06	3.68
	2043	1.35	2.13	3.85
SC B - 1.0% Reduction SCC w/ FS	2028	1.52	2.22	4.27
	2035	1.50	2.24	4.44
	2043	1.29	2.19	4.02
SC C - Max SCC w/ FS	2028	1.14	2.15	4.22
	2035	1.09	2.29	3.91
	2043	1.06	2.18	3.43
SC D - Max CFB w/ FS	2028	1.00	1.68	2.88
	2035	**0.96**	2.10	3.29
	2043	1.03	2.12	3.19
SC E - Max CFB EE Only	2028	1.14	1.64	2.88
	2035	1.00	1.62	3.29
	2043	**0.95**	1.68	3.19
SC F - 1.0% Reduction CFB w/ FS	2028	1.20	1.72	2.89
	2035	1.35	2.06	3.68
	2043	1.24	2.13	3.85

As noted in Section 7.2.3, however, program administration cost estimates are highly uncertain and, based as they are on a simple ratio, unlikely to accurately capture the types of economies of scale that would be expected in a real-world program implementation designed to capture the potential identified in the Max Achievable scenarios.

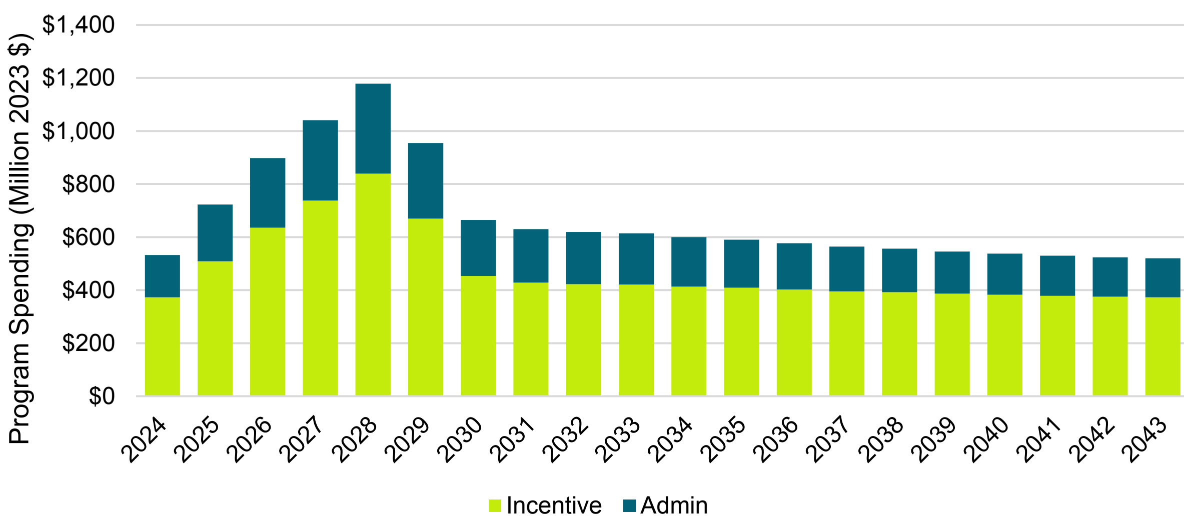
7.3.5 Achievable Potential Program Administrator Annual Costs and Benefits

This section provides summaries of program administrator costs and benefits for estimated Achievable potential. For concision, only Scenario A costs and benefits are shown in this report, but all scenario values are available in Appendix X2.

The costs of attaining the potential in the scenarios modeled in this study are considerable. Figure 68 shows the estimated annual incentive and program administration costs associated with the potential estimated for Scenario A. Total incentive costs across all sectors peak at $800 million in 2028, with total estimated program costs in that year reaching nearly $1.2 billion.

To help reviewers contextualize this cost, the OEB approved a budget of $167 million for EGI's 2023 DSM program[93], and the Ministry of Energy approved a budget of $1.034 billion over 4 years for the IESO's 2021-2024 electricity conservation programs.[94]

Figure 68. Scenario A Estimated Annual Program Costs



The shape of annual costs (increasing through 2028, then declining to a steady state) is related to the goal of adjusting incentives such that by the end of 2028 the targeted annual consumption values were being achieved. Potential also becomes less costly to acquire in later years as a variety of supply chain constraints loosen (see Appendix B) for those measures to which they

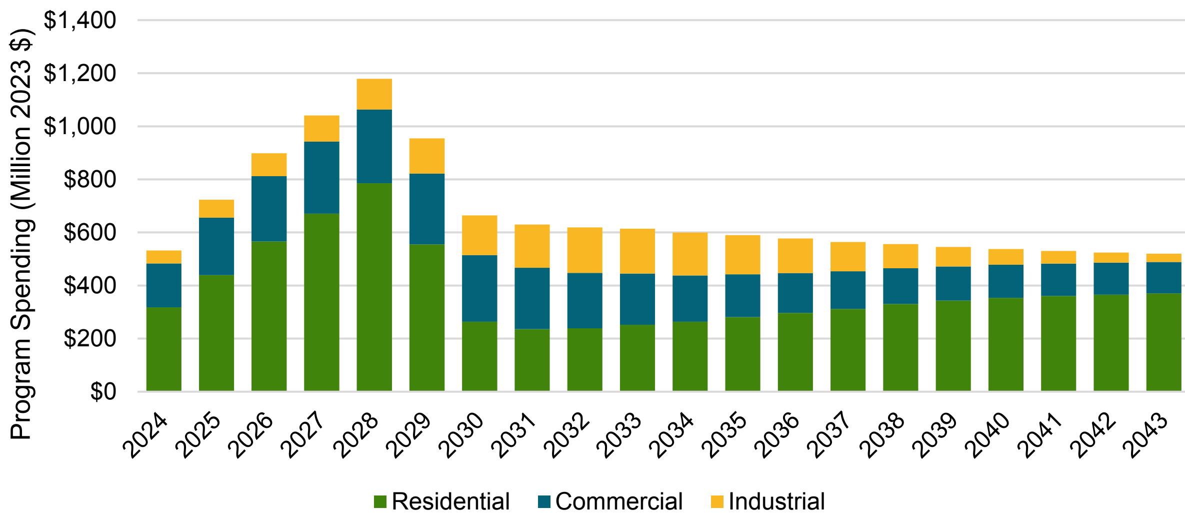
[93] Ontario Energy Board, *Decision and Order: Application for Multi-Year Natural Gas Demand Side Management Plan (2022 to 2027),* Enbridge Gas Inc., EB-2021-0002, November 2022
https://www.oeb.ca/node/3869

[94] Executive Council of Ontario, *Order in Council*, O.C. 1314/2022, approved 2022-09-29
Available at: **https://www.ieso.ca/en/Corporate-IESO/Ministerial-Directives** (September 29, 2022: "Expansion of the 2021 – 2024 Conservation and Demand Management Framework"

were applied, and increasing market penetration by measures means a greater share of the equilibrium market share for each measure is attained.

As would be expected, most of these costs are attributable to the Residential sector, where the majority of the estimated potential has been identified, this is visible in Figure 69 which plots total costs (admin and incentive) by sector and year.

Figure 69. Scenario A Estimated Annual Program Costs – by Sector

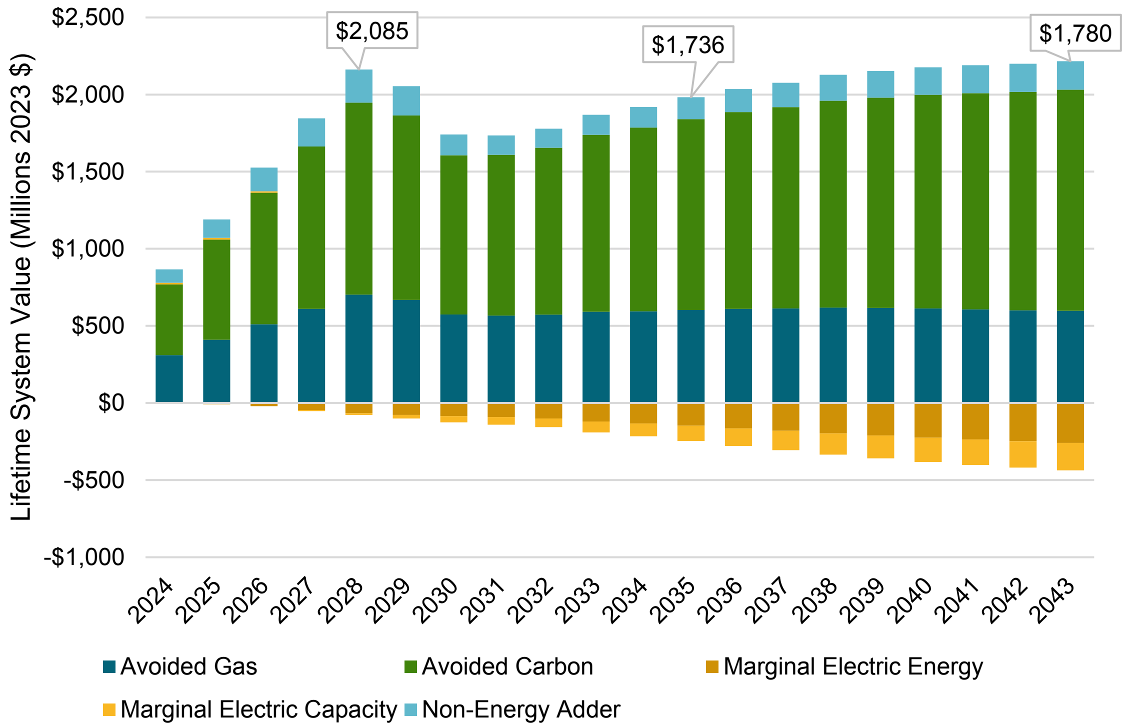


Program administrator costs are significant. But so too are the benefits. Figure 70 shows the system-level value streams derived from Scenario A, across all three sectors. This includes both benefits, and costs. The net system benefits for the three example years are presented in the call-out boxes below.

The values shown in this graph represent the present-value lifetime value of the incremental measures adopted in the given year. In this way they correspond to – and can be directly compared with – the program administrator costs shown in Figure 68. So, while the lifetime costs of delivering the Scenario A potential are significant – nearly $1.2 billion in 2028 – so too are the benefits.

The present value of the benefits delivered by the $1.2 billion in 2028 amount over $2 billion in the same year.

Figure 70. Scenario A Estimated Annual Net System Benefits



8. Findings and Recommendations

This section summarizes some of the key findings of the 2024 Achievable Potential Study and presents a series of recommendations.

8.1 Findings

This study's key findings related to each of the key tasks of the study are presented below. This is not a comprehensive list of all outcomes and conclusions from the analysis but is rather a selection of the most important findings from this work, findings that have motivated the recommendations provided in Section 8.2.

8.1.1 Base Year Disaggregation

<u>Because a high proportion of Industrial natural gas volumes could not be included in this study, the estimated potential for this sector will be understated.</u>

The base year (2022) consumption of the Industrial sector addressed by this study is approximately 4.4 billion cubic meters (see Section 2.3). This is the smallest of the three sectors, but only because the volumes of the Extra Large Volume (ELV) customers that consume more than 20 million cubic meters of natural gas per year are excluded.

In 2022, ELV customers at 65 premises (sites) accounted for over 5 billion cubic meters of gas consumption. When these are included in the Industrial sector consumption, this sector becomes the largest consumer of gas in the province, with nearly 20% more gas consumed than the Residential sector. The idiosyncratic and site-specific nature of the processes employed by this very small group of customers, and concerns about the publication of commercially sensitive data have meant that these customers could not be included in this study.

This is a significant, though unavoidable under the circumstances, omission. Because this study could not consider the energy efficiency or fuel switching potential of ELV customers responsible for nearly a quarter of Ontario's natural gas consumption in 2022, then, all else equal, the estimated potential values should be regarded as understated.

8.1.2 Reference Forecast

<u>Achieving reductions to the absolute level of natural gas consumed in the province will require a significant expansion of the numbers and ambition of the programs designed to do so.</u>

The forecast annual growth rate of consumption of 0.6% (absent any DSM programs,[95] and assuming continuing growth of new customers) means that to achieve absolute reductions to current levels of gas consumption (as specified in the OEB's guidance for this study), increasing – and substantial – volumes of gas consumption must be eliminated in each year.

[95] Accounting for the projected effect of DSM programs, the total volumes of consumers included in this study is estimated to grow at approximately 0.3% per year.

The OEB's guidance for this study was to estimate potential scenarios that deliver "*an annual reduction in total natural gas sales year-over-year of 0.5%, 1% and 1.5%*". That is, to estimate potential that delivers an annual growth rate of natural gas volumes of -0.5%, -1%, and -1.5%.

Given the difference between the base case forecast growth rates without considering projected DSM (0.6%) and with DSM (0.3%) the implication is that program achievement must more than triple to deliver the reductions of the least aggressive scenario specified by the OEB for this study. Naturally, the required amount of DSM to meet the targets noted is conditional on the reference forecast – a flat or declining reference forecast would require a less aggressive DSM intervention to meet the targets, compared to the current, increasing, forecast.

8.1.3 Measure Characterization

Very little reliable data is available to characterize the opportunities and costs of electrification, particularly in the non-residential sectors.

The OEB Technical Resource Manual[96] does not include any fuel-switching measures. Completing measure characterization (in particular estimating incremental costs and Technical Suitability factors) for such measures depended in large part on the qualitative judgements of members of the SAG. The final inputs used for potential estimation reflect available public or proprietary data, adjusted based on feedback provided by members of the SAG. These inputs are a major source of uncertainty for this study.

For the Residential sector, for example, assumptions about the average cost of electrical upgrades required for hybrid as well as full electrification space-heating measures are qualitative estimates provided by (and heavily debated amongst) SAG members. Concerns about the range of possible cost estimates (and the robustness of any sub-sector-specific estimated average value) resulted in the use of constrained measure definitions and estimates of Technical Suitability. So little reliable information about sub-sector-specific Industrial electrification opportunities was available that Guidehouse determined that it would be imprudent to model fuel-switching for that sector.

A summary of SAG discussions and outcomes on these matters may be found in Appendix B.

The lack of available data from robust empirical sources to support characterization of some aspects of some measures is a significant source of uncertainty in this study.

8.1.4 Technical Potential

Technical potential with fuel-switching included is more than twice as high as Technical potential without fuel-switching considered.

[96] Ontario Energy Board, *Natural Gas Demand Side Management Technical Resource Manual*, Version 8.0, April 30, 2024
Available at: **https://engagewithus.oeb.ca/natural-gas-conservation-evaluation-advisory-committee**

- Residential Technical potential when fuel switching is included is, by 2043, more than 3.25 times greater than EE-only Technical potential, and accounts for nearly 90% of the reference forecast.

- Commercial sector Technical potential when fuel switching is included is, by 2043, more than 2.5 times greater than EE-only Technical potential, and accounts for nearly 50% of reference forecast. Technical potential is lower than for the Residential sector because of the assumed Technical Suitability for full and hybrid space-heating electrification in existing buildings is relatively low. Technical Suitability values for new construction are much higher (see Section B.3.10 of Appendix B for more information).

- Industrial Technical potential includes no fuel-switching measures and accounts for only approximately 17% of the reference forecast.

Technical potential when fuel-switching is included would be even higher were it not for the constrained Technical Suitability assumptions for some Commercial fuel-switching measures, and the fact that no fuel-switching measures were modeled for Industrial at all,

The constrained Technical Suitability for Commercial fuel-switching and the lack of any fuel-switching potential estimated for the Industrial sector are largely driven by a dearth of sub-sector-specific data about building baseline conditions referenced above, and thus the fuel-switching and energy efficiency opportunities specific to these sub-sectors.

<u>Estimated Industrial Technical potential likely understates available opportunities for natural gas consumption reductions in that sector.</u>

Industrial potential is, as a share of the reference forecast, lowest of all sectors even when only energy efficiency opportunities are considered, and fuel-switching is excluded. The Industrial sub-sectors are, even more so than the Commercial sub-sectors, highly idiosyncratic in their building, equipment, and energy-using process characteristics. This presents a major data collection challenge for bottom-up “widget-based” potential studies, particularly given the sometimes commercially sensitive nature of the information needed to identify energy efficiency and fuel switching opportunities.

Guidehouse’s use of the IAC database of audit-recommended measures addresses this challenge by including a wide range of actually-identified sub-sector-specific opportunities. This database is, however, limited in that it: does not comprehensively address fuel-switching and tends to address only measures likely to be very attractive to customers (i.e., with very high payback).

8.1.5 Economic Potential

<u>Fuel switching measures tend to become more cost-effective over time.</u>

The dynamics of cost-effectiveness from a TRC-Plus perspective are, for fuel switching measures complex. Cost-effectiveness is a function of four time series of values whose trends fluctuate over time: avoided natural gas costs, avoided carbon costs, incremental electric energy costs, and incremental electric system capacity costs.

The pattern for measures that have winter peak electricity impacts is for cost-effectiveness to decrease steeply as the year in which Ontario transitions from summer to winter peaking (assumed to be 2036 for Economic potential) approaches, bottoming out in the transition year. After this, the gradually increasing value of the benefit streams (avoided natural gas and avoided carbon costs) substantially improves the cost-effectiveness of electrification measures that also deliver substantial efficiency improvements.

This overall trend does not reflect any assumed change in the cost of electrification measures over time (except for some Commercial measures, as noted in Appendix B). This trend is also likely to be sensitive to assumptions about the costs of any electrical upgrades required in buildings to accommodate electrification, as well as to changes in projected value streams (avoided gas, avoided carbon, and winter peak capacity).

Economic potential is sensitive to how peak electric demand is defined and valued.

In this study, peak electricity demand impacts have been valued at $144 per kW-year in constant 2023 dollars, and assumed to apply to incremental electric demand observed in hours exhibiting characteristics (e.g., extreme temperatures) consistent with those used for projecting provincial peak demand for the purposes of system planning. These assumptions were chosen in consultation with the IESO such that they should be consistent with direction provided by that agency in its IRRP Guide to Assessing Non-Wires Alternatives for the economic analysis.

This definition makes the Residential heat pump 4C option (sized for heating, with gas back-up used only in extreme conditions) considerably more cost-effective than the 4D option (full electrification), all else equal. A more expansive definition of peak demand (e.g., the highest-demand 100 hours in a weather-normal year) would likely reduce the cost-effectiveness of the 4C option (since there would likely be some non-zero peak demand impact), but could improve the cost-effectiveness of the 4D option (since the cost per kW-year applied over more hours would necessarily need to be lower).

Residential water heating fuel switching is only cost-effective when accounting for the efficiency gains provided by heat pumps.

Figure 49 demonstrates that although more opportunities exist to replace natural gas storage water heaters with electric resistance heaters, the peak demand impacts of this type of equipment means it ceases to be cost-effective as the year that Ontario transitions to winter peaking approaches. The efficiency gains offered by heat pump water heaters, however, mean that even when these measures impose incremental capacity costs, their net energy savings ensure that they remain cost-effective.

Cost-effective Commercial space-heating electrification opportunities are principally limited to smaller buildings, and more substantial for new construction than for existing buildings.

The costs of Commercial space-heating electrification are, as documented in Appendix B, highly uncertain, and likely to vary considerably across the building types represented in different sub-sectors. Costs are, however, certainly lower for electrifying new construction than replacing gas-fired systems in existing buildings. This is reflected in the Economic potential which is higher for NEW measure types than it is for ROB measure types (as a share of the reference forecast), indicating that the most significant opportunity for cost-effective electrification of Commercial buildings lies in new construction.

Almost all Industrial Technical potential is also cost-effective Economic potential.

This is an expected outcome given the source of the data – the IAC database of recommended Industrial efficiency measure implementation based on facility audits. As noted in Appendix B, the measures included in the database are likely to be predominantly those measures with very short paybacks that are most likely to be adopted by Industrial customers. This means that most Technical potential is also Economic and could also mean that Industrial potential (by possibly failing to consider measures that are cost-effective from a total resource cost perspective, but having longer paybacks) might be understated.

The value of carbon used for estimating cost-effectiveness is important.

In the 2019 APS, the federal fuel charge (the carbon federal backstop, CFB) was used as a proxy for the value of avoided carbon. An enhancement to this study was the use of the social cost of carbon (SCC), aligning potential cost-effectiveness testing with practice in New England states, New York, New Jersey, and many others.[97]. The SCC provides a more accurate estimate for the long-term costs of incremental emissions to Ontario, and, though it is higher than the CFB, the U.S. EPA has noted that it "*likely underestimate the marginal damages from GHG pollution*." (see Section D.2 of Appendix D for more details).

The importance of the value of carbon for the cost-effectiveness of many fuel-switching measures is evident from a review of Figure 46 and Figure 47, which compare Economic potential estimated using the SCC instead of the CFB, and Figure 49 and Figure 50, which compare measure-level Economic Residential potential with the two different values. Residential Economic potential estimated using the SCC is, for example, more than twice Residential Economic potential using the CFB in 2028. Likewise, hybrid Residential heat pump measures are cost-effective in every year of the period of analysis when using the SCC, but only become so in 2029 when using the CFB.

8.1.6 Achievable Potential

Good incentive design can deliver cost-effective portfolios without excluding measures that are individually not cost-effective.

The 2019 APS excluded measures not found to be cost-effective from inclusion in the estimation of Achievable potential. This approach understates the volume of aggregate potential that can be cost-effectively achieved by excluding from consideration measures that may not be cost-effective on average, but which may prove so for some individual consumers.

The 2024 APS has not excluded measures that are not individually cost-effective from Achievable potential. All measures are included, but incentives (i.e., program administrator potential acquisition costs) are scaled by measure to reflect the net system benefits these measures offer, rather than – as is sometimes the case – as some share of the measure's incremental cost.

[97] See for example:
Efficiency Vermont, *Analysis of State Approaches to Cost-Effectiveness Testing – Efficiency Vermont R&D Project: Cost-Effectiveness Screening Tests*, December 2021
https://www.efficiencyvermont.com/Media/Default/docs/white-papers/Analysis_of_State_Approaches_to_Cost-Effectiveness_Testing.pdf

As noted in Section 7.3.4, despite not excluding non-cost-effective measures, the estimated Achievable potential is, at the portfolio level, cost-effective. As described in 7.2.2, the net-benefits-derived incentive setting approach motivates economically efficient measure uptake in aggregate by aligning individual and provincial benefits. This avoids the necessity of arbitrarily constraining potential by not considering the benefits offered by measures that are – by themselves – not *on average* cost-effective.

<u>The 1% reduction target scenarios specified by the OEB for the potential study can be achieved only through substantial amounts of fuel-switching.</u>

The 0.5% reduction target scenario can be achieved without fuel switching through the late 2030s only when incentives and non-economic adoption factor assumptions are set to their maximum values (i.e., as in Scenario E). Achieving natural gas consumption reductions of 0.5% year-over-year from a start year of 2023 can be achieved and maintained over the entire period of analysis only if fuel-switching measures are included, as may be seen in Figure 55.

<u>Residential hybrid space-heating electrification is a cost-effective way to substantially reduce gas consumption and carbon emissions.</u>

Hybrid space-heating electrification delivers substantially more Achievable potential than full electrification in existing buildings where infrastructure costs impact cost-effectiveness and customer economics. Since incentives are set as a function of provincial net benefits, the more cost-effective hybrid options generally receive more incentives (and so have a better payback) than the full electrification option. The question of which iteration (4A, B, or C) of hybrid electrification is optimal is likely to be highly sensitive to assumptions regarding the timing and length of system peak as noted above.

<u>Residential water-heating appears to offer the most significant opportunity for Achievable natural gas reductions.</u>

The heat pump water heater is the Residential measure with the largest Achievable potential. This is reflective of the relatively modest incremental cost of the measure, and the substantial net system benefits which flow through to incentives, both of which improve customer economics and projected uptake when included in program with advertising and awareness support.

Benefits (and therefore uptake) are driven by estimated efficiency improvements offset only by a relatively modest peak electric demand impact. Cost-effectiveness (and so incentives and adoption) is likely sensitive to assumptions about how much space-heating must be “cannibalized” to offset system waste cooling and the estimated magnitude of incremental peak demand. Guidehouse’s adoption modeling does not necessarily reflect reality of Ontario’s water heater rental oligopoly and how that could impact consumers’ equipment choices.

<u>Envelope improvements for older residential buildings offer substantial energy efficiency potential.</u>

Insulation and air sealing for older (pre-1974) homes are consistent winners in economic and achievable potential. These measures offer significant system benefits in terms of gas and carbon reductions, while also improving customer comfort and reducing consumer bills. These are the most material contributors to EE savings. Professional air sealing, however, has been assumed to have limited capacity in Ontario in the near-term (see Section B.3.6), and so does not begin delivering substantial Achievable potential impacts until after 2029.

Commercial electrification poses significant challenges related to measure applicability and estimated incremental costs.

Considerable uncertainty exists around issues impacting the practicality and cost of the electrification of Commercial space-heating in particular. These issues were the subject of substantial SAG feedback, with one SAG member contending that even hybrid electrification (i.e., with gas back-up) of anything larger than very small businesses is a massive retrofit incurring substantial infrastructure costs and custom engineering. These concerns are reflected in both the estimated Technical Suitability of these measures and the incremental measure costs. The diversity of system configurations and combinations contribute substantially to uncertainties regarding the reasonable (and mean) for incremental equipment, installation, and labour costs in existing buildings. As noted above, such uncertainties are less of a factor for new construction (though still a non-trivial consideration).

In addition to these challenges, reviewers considering questions of applicability should also bear in mind that in many cases the entities responsible for purchasing equipment (landlords) are not the businesses using them or paying the utility bill (tenants). Insufficient data were available to robustly model this dynamic in the 2024 APS and reviewers should consider the implications of this important potential barrier to adoption when evaluating estimated potential.

Commercial electrification poses significant challenges related to customer economics.

The impact of electrification on coincident peak demand impacts Residential customer economics only through the incentive: as coincident system peak demand increases, a measure's net system benefits fall, and so the value of incenting these measures falls. Because of the infrequent nature of coincident peak demand (as defined in this study) this challenge can be addressed by focusing on supporting the adoption of hybrid space-heat electrification measures, or through (for example) combining support for the adoption of full electrification measures with some form of load flexibility or demand response program.[98]

Commercial customer economics are, however, more challenging. Most commercial customers with average monthly peak demands in excess of 50 kW are, in Ontario, subject to a volumetric distribution demand ($/kW) charge on a monthly basis. Electrification of space-heating can therefore have a substantial impact on customer bills that can affect adoption. In this study, for example, full electrification space-heating measures are adopted in any kind of meaningful volume only within the small warehousing segment, where that sub-sector's relatively high thermal load factor (i.e., proximity of average and peak thermal loads) means that gas energy bill savings are less acutely offset by increases in distribution demand charges.

Non-coincident monthly peak demand charges present a potentially significant barrier to the adoption of hybrid and full electrification fuel switching measures in the Commercial sector.

[98] For example, National Grid UK's Equinox program for managing electrified heat pump loads. **https://www.nationalgrid.co.uk/projects/equinox-equitable-novel-flexibility-exchange**

8.2 Recommendations

This sub-section of Section 8 provides a set of recommendations for consideration by OEB staff, members of the SAG, as well as other sector stakeholders and policy makers.

The first two parts of this section provide recommendations related to the process of potential estimation itself. These identify the elements of the modeling and study development process that were clear successes in terms of improving the quality and usefulness of the study, as well as some of the lessons learned along the way for ways in which future studies could be improved. The process-related recommendations reflect the Guidehouse team's experience with the 2024 APS specifically, but also some of the critical differences between the processes employed for the 2024 APS and those employed for the 2019 APS.[99]

The recommendations in these first two parts of this sub-section will be of interest to OEB staff, to the members of the SAG subcommittees most closely involved in the development of this study, and in particular to any other analysts who may wish, in the future, to project the potential for energy efficiency and beneficial electrification in Ontario or elsewhere.

The third part of this section provides a set of recommendations for implementing the actions necessary to acquire some of the potential estimated in this report. It is the provision of these insights that is intended, in the words of the OEB in its Decision and Order EB-2021-0002, "*to inform Enbridge Gas's next multi-year DSM Plan*" that is the core purpose of the potential study.

8.2.1 Process Recommendations – Successes to Retain

The Guidehouse team has identified the following key successes upon which future potential studies in Ontario should continue to build:

- *Stakeholder Consultation.*
- *Single Geographic Region.*
- *Transparency of Inputs and Outputs to Stakeholders.*
- *Unconstrained Potential.*
- *Coordination with IESO*

8.2.1.1 Stakeholder Consultation.

Close and frequent engagement with a set of SAG subcommittees unambiguously improved the quality of the study and the usefulness of the insights it provided.

OEB staff coordinated dozens of meetings between all parties – OEB staff, SAG members, and Guidehouse team members – both large and small across the approximately 16-month period of study development. As noted in Section 4.2.5, over 800 separate comments related only to measure characterization and draft potential estimates were tracked by the Guidehouse team. Likewise, the SAG stakeholder review process of Achievable potential estimates generated seven formal rounds of comment responses (provided via email), each of which provoked considerable subsequent correspondence and meetings between members of the sub-committee.

[99] The 2023 APS Guidehouse team included the same technical Director and project manager as the 2019 APS.

This level of scrutiny and review, accompanied by informed debate on items of particular interest by experts with decades of industry experience has unquestionably improved the quality of the study and the usefulness of its outputs. Technical insight from such experts (in particular) as well as the provision of additional data (both publicly available and not) allowed for more sophisticated measure characterization and for modeling workflows to more accurately reflect some real-world dynamics impacting the adoption of DSM measures (e.g., changes in price over time, supply chain constraints, etc.).

For future potential studies OEB staff should consider the following possible improvements to the stakeholder consultation process:

- **Dispute Resolution and Logging.** OEB staff strived to forge consensus – or at least mutually acceptable compromise – amongst SAG members, but this was not (and will not) always possible. The process of attempting to resolve some disagreements (e.g., residential electrification panel costs) took, in some cases, many months. This had a considerable impact on the project timeline.

  Going forward, OEB staff may wish to consider establishing some more formal time-bound process or framework for resolving disagreements amongst stakeholders, particularly in instances for which there are very limited data available and where OEB staff must rely upon the intuition and educated guesses of industry expert stakeholders. This framework should explicitly include provisions for documenting the process and resolution of disagreements, in some manner analogous to what Guidehouse has attempted in Section B.3 of Appendix B. Guidehouse expects that the creation of a more formal process will better enable OEB staff and its contractor to plan and schedule any future potential studies.

- **Evolved Approach for Addressing Written Feedback.** Guidehouse began by tracking and responding to SAG feedback using a SAG Response Matrix developed in MS Excel. In this format each SAG member's comment was noted in one column, Guidehouse's response in the next, the SAG member's reply in the subsequent column, etc.

  For simple and uncontroversial comments this system worked well (e.g., when a SAG member recommended an alternative source or input for a measure characterization). As the study progressed and comments became lengthier and more sophisticated, the format became unwieldy. Additionally, Guidehouse noted that some SAG members sometimes missed comments made by other SAG members (and the responses to them), forcing re-litigation of some feedback after it had been believed resolved.

  Guidehouse addressed this by moving to an email-based format; comments were submitted by SAG members in MS Word documents or emails and were responded to by the Guidehouse team in summary emails sent to all members of the SAG sub-committee. This allowed for contextual formatting and longer, more detailed responses. This also ensured visibility to all SAG members. OEB staff noted to Guidehouse, however, that some members of the SAG were dissatisfied with this format. Guidehouse would therefore recommend that in subsequent engagements of this nature OEB staff consider establishing (or having their contractor establish) some type of SharePoint-based comment tracker in an MS Word document. This would allow for text formatting of comments and responses and the inclusion of graphs and illustrations but would also allow for simplified tracking of resolved comments.

Finally, Guidehouse recommends that planning for potential studies explicitly consider the time required to obtain and respond to stakeholder feedback. As originally scoped this study was due to be completed in approximately 9 months. Approximately halfway through the original schedule, in the summer of 2023, this schedule had to be entirely adjusted when it became clear that the schedule, as originally planned, was not compatible with level of stakeholder engagement in that process. Guidehouse recommends that for future planning, OEB staff assume that a potential study similar in scale to the 2024 APS (with a similar level of stakeholder engagement) will require approximately 18 months from start to finish.

8.2.1.2 Single Geographic Region.

The 2019 APS modeled adoption across different regions of the province; ten different transmission zones (for electricity) and five different natural gas utility regions. In contrast, for the 2024 APS results were modeled provincially with geographic differences in measures modeled only where such differences mattered or could be reasonably well quantified. For example, in 2023 the space-heating electrification measures were characterized separately for North and South Ontario to capture important differences in net system benefits and customer economics.

This coarser approach proved a significant improvement. While in theory the much finer-grained approach of the 2019 study should have improved the study's precision, the reality is that the vast majority of inputs are simply not available at the corresponding level of geographic granularity. This means that up-front geographic disaggregation will in many cases simply add dimensionality without purpose, make input development, modeling, and output management correspondingly more cumbersome and results much more challenging for stakeholders and analysts to review.

Modeling only a single geographic area significantly increased the useability of the outputs by stakeholders and other analysts, and Guidehouse would recommend that future studies continue to use this approach, addressing regional differences only for those measures where such differences make a significant difference to savings values, and where data are available to support a regionally differentiated measure characterization.

8.2.1.3 Transparency of Inputs and Outputs to Stakeholders.

The full benefit of stakeholder review is attainable only when measure-level model inputs (e.g., savings values, estimated costs, applicability factors) and estimated potential outputs (at all available levels of granularity) are available for review in a comprehensive and transparent manner.

Providing full model input measure characterization transparency to SAG members was a significant logistical challenge. This required the creation of a user-friendly set of input workbooks to enable SAG review, and required that these be synced in near-real time with model input updates to ensure that SAG members could review updated outputs (i.e., estimated potential) against the inputs that delivered them.

Contractors engaged to develop potential studies in the future should expect these requirements and plan for them, so as to minimize any lags between the provision of feedback by stakeholders and the reflection of the outcome of that feedback in the measure input documents. The sharing of updated input and output workbooks through a stakeholder accessible SharePoint site was found to work well for this process and provides a useful template for consideration in future work of this nature.

The volume of model inputs and outputs also proved to be a challenge for SAG members to review comprehensively, particularly those individual members of the SAG without extensive teams of support personnel. Guidehouse recommends that OEB staff consider, for future studies of this nature, whether it might be prudent to engage not just individual experts as members of the SAG, but also (for those SAG members not already equipped with a team) a small number of technical support personnel to assist the relevant SAG subcommittee members with their review of the many inputs and outputs that make up a potential study.

8.2.1.4 Unconstrained Potential.

The 2024 APS is the first natural gas potential study in Ontario to present Technical and Economic potential unconstrained by considerations of annual equipment stock roll-over. Put another way, the Technical potential for a replace-on-burnout measure in any given year, is the Technical potential available if all base case instances were replaced at once, and replacements were not just limited to those instances where (in the given year) the existing equipment reached the end of its life.

The 2019 APS was constrained (i.e., Technical and Economic potential was estimated only for those ROB measures at the end of their life in a given year) for consistency with previous studies. This constraint was removed for the 2024 APS to bring the Ontario study in line with other jurisdictions (see Section C.1 of Appendix C), and to reduce the number of confounding factors to be considered when assessing the implications of Technical and Economic potential.

Using unconstrained potential, for example, makes it much clearer to see in Figure 49 and Figure 50 the impact that using the SCC instead of the CFB carbon value has on the cost-effectiveness of hybrid space-heating technology. Removing the confounding factor that comes from constraining potential based on equipment turn over means that the Technical and Economic potential can provide a much clearer understanding of the underlying measure-level dynamics and do a better job of fulfilling their purpose as diagnostic outputs.

The Guidehouse team recommends that future studies continue to present unconstrained, rather than constrained Technical and Economic potential.

8.2.1.5 Coordination with IESO

The 2019 APS was an integrated study, one that considered both electric and natural gas conservation. The 2024 APS did not consider electric energy efficiency measures or distributed energy resources, focusing only on measures that reduce the consumption of natural gas. Given the targeted reductions that the OEB prescribed for modeling in its Decision and Order, fuel switching – electrification of space and water heating end-uses, was a major component of the study, and in fact may be the defining feature of the 2024 APS.

The assistance of the IESO was therefore essential. IESO staff provided Guidehouse and the OEB with essential input values related to the consumer cost of power (used to estimate customer economics and payback), provided direction regarding the use and definition of coincident peak demand impacts and the consideration of the carbon costs associated with incremental electricity generation.

OEB staff should consider whether – in future potential studies, or in any work related to assessing the way in which fuel switching cost-effectiveness is assessed (both from the provincial and the individual – customer economics – perspectives) the IESO should be asked to play a larger role. The inclusion in the SAG technical sub-committee of a representative of the IESO, particularly one that could use their internal network to identify the appropriate IESO experts to weigh in on issues related to electricity system costs, would likely improve the robustness and usefulness of the study outputs.

8.2.2 Process Recommendations – Improvements to Consider.

The Guidehouse team has identified the following potential areas for improvement which future potential studies in Ontario should consider in their planning:

- *Update and Maintain the Technical Resource Manual*
- *Non-Residential Data Collection*
- *Alternative Natural Gas Potential Estimation Approaches for the Industrial Sector*
- *Technical and Economic Potential to Guide Measure Input Review*
- *Sector-Specific Potential Estimation*

8.2.2.1 Update and Maintain the Technical Resource Manual

The majority of SAG feedback, and the majority of the most challenging debates amongst members of the SAG related to measure characterization; that process of estimating the individual measure savings, costs, and applicability factors. One reason for this was that although the OEB publishes a Technical Resource Manual (TRM) it does not include any fuel-switching measures. The inclusion of such measures in the TRM would not eliminate debate, but might potentially allow such debate to be mostly concluded prior to any future study, and so reduce the time required by stakeholders, OEB staff, and the potential study vendor to align on a set of values deemed acceptable for inclusion in the study.

Guidehouse therefore strongly recommends that the OEB consider updating its TRM to include fuel switching measures. The Guidehouse team further recommends that OEB staff consider starting from the values developed for this study to take advantage of the work already completed in identifying and applying sources of data. These values should be reviewed by stakeholders and the OEB at regular intervals to ensure that they remain up to date and reflect the best available locally-specific information.

8.2.2.2 Non-Residential Data Collection

The lack of availability of robust and detailed data sets to enable market and measure characterization in the non-residential sectors remains a challenge for potential estimation. The collection of such data is an immense challenge compared to the residential sub-sectors. In contrast the non-residential sub-sectors have many fewer individual consumers, and the individual characteristics (in terms of size, process and equipment types, operating hours, etc.) are all much more heterogenous than for the Residential sector.

As such, approaches for data collection for the Residential sector (e.g. comprehensive surveys by telephone and email) may not be appropriate for non-Residential sub-sectors, as it will be challenging to obtain sufficient responses in sufficient detail to obtain robust estimates of key metrics of interest.

Guidehouse recommends that the OEB consider undertaking a prioritized baseline study of non-Residential sub-sectors to improve the quality of the data available to identify natural gas reduction opportunities in Ontario. Guidehouse recommends that in developing this effort, OEB staff explicitly recognize that such a study cannot be comprehensive, and instead to focus on a few end-uses and equipment types, or combinations of equipment types and sub-sectors, where improved information will be most impactful.

Guidehouse recommends that OEB staff consider setting their information collection priorities to help support utility DSM planning considerations, and in consultation with program delivery staff and non-utility stakeholders with non-Residential DSM (energy efficiency and electrification) expertise.

8.2.2.3 Alternative Natural Gas Potential Estimation Approaches for the Industrial Sector

The Guidehouse team has previously advocated for an alternative to the “bottom-up” or “widget-based” approach to potential estimation for the Industrial sector, including in its recommendations as part of the 2019 APS, as well as in its recommendations provided to the California Public Utilities Commission (CPUC) resulting from its top-down potential prototype analysis (see Section B.2 of Appendix B).

The Guidehouse team did not propose such an approach for this study, the 2024 APS, based on the length of the originally planned timeline. Though the bottom-up approach based on the IAC database that Guidehouse used for this study is imperfect and likely to understate potential, it is relatively mature, and, given the source of the data, is as robust an approach as can be developed without extensive primary data collection activities.

Guidehouse recommends that OEB staff review Guidehouse’s recommendations to the CPUC, in particular its recommendation for the development of sub-sector-specific potential estimates based on top-down techniques, using a combination of consumer meter data, on-site primary data collection, and the engagement of sub-sector specific expertise.[100]

Given the challenges posed by the collection of customer data that may be commercially sensitive (in particular from ELV customers whose potential has not been estimated in this study), the OEB may wish to consider whether there might be some value in combining the functions of custom DSM program delivery with the development of sub-sector-specific potential estimation. Making the provision of data for use in potential estimation a condition of accessing custom program incentives and support might allow for the development of a more robust estimate of Industrial energy efficiency and fuel switching potential. Any such combination of potential estimation and program delivery activities should be subject to stakeholder review to mitigate against any potential moral hazard.

[100] This is a critical point: if, for example, potential is being estimated for the Petroleum Manufacturing sub-sector using top-down techniques, then the team estimating that potential should ideally include at least one member with experience in that industry, ideally in a role that exposed them to questions of facility energy management.

8.2.2.4 Technical and Economic Potential to Guide Measure Input Review

Measure input review by external stakeholders delivers the most value when it is informed by current potential estimates.

Guidehouse previously recommended in its 2019 APS that measure inputs not be reviewed until the initial estimate of Technical potential is available. This would help direct reviewers' attention to those measures where reviewers' time and input would be most consequential for study outcomes. Guidehouse would recommend that in any future studies, measure savings, technical suitability and baseline saturations should be the primary focus of review once Technical potential is available, and that measure costs become the primary focus of review once Economic potential is available.

In such an instance (where measures are reviewed only once potential is available), the potential study vendor would need to assume the provision of at least three draft versions of Technical and Economic potential to reviewers: the first at the same time as measure input workbooks, a second in response to changes made based on reviewer feedback, and a final (or quasi-final) based on a second set of feedback provided by reviewers.

Guidehouse recommends that OEB staff consider this approach for future studies as a way of making more efficient use of stakeholder expertise and maximizing the value they can provide for study outcomes. Scheduling of any future study would need to carefully (and realistically) consider the length of time required for these review and revision cycles.

8.2.2.5 Sector-Specific Potential Estimation

A key challenge of robust potential estimation and its review by stakeholders is the breadth covered by the analysis. The expertise and modeling approaches most suitable to estimate Residential potential are not the same as those most suitable for Commercial or Industrial sector potential estimation. Guidehouse recommends that the OEB consider whether there might be value in the future in staggering the development of potential studies to focus on one sector at a time.

This could simplify the process of stakeholder engagement by allowing OEB staff to engage stakeholders with specific sector expertise in a more concentrated manner, and allowing stakeholders, OEB staff and vendor, to focus on the idiosyncratic challenges of each sector separately.

8.2.3 Implementation Recommendations – Insight from the Study Findings

For all its measure detail and interactive mechanisms, the modeling applied to estimate Achievable potential is a vastly simplified representation of reality. Simplified representations of reality can, however, offer useful and actionable strategic insights to analysts tasked with reducing the consumption of natural gas and the emission of greenhouse gasses through energy efficiency and beneficial electrification.

Tactical considerations may mean that not all the strategic recommendations provided below may be suitable in all implementations. The evidence of the work undertaken in this study by Guidehouse, the members of the SAG, and OEB staff, however, supports these recommendations on a strategic basis, and suggests that their consideration could deliver substantial long-term value to Ontario's energy consumers.

The Guidehouse team has developed the following recommendations that should be considered:

- *Net-Benefit Focused Consumer Incentive* Design
- *Focus Electrification in New Construction*
- *Residential Water Heating Fuel Switching*
- *Residential Space Heating Fuel Switching*
- *Commercial Space Heating Fuel Switching*

8.2.3.1 Net-Benefit Focused Consumer Incentive Design

The findings of this study, and a considerable corpus of economic literature, support the recommendation that measure incentives intended to encourage measure adoption should be defined as a function of net provincial benefits rather than – as is often the case – a function of a measure's cost.

Incentives set on the basis of net provincial benefits align the interests of individuals with those of the province as a whole, will incent more economically efficient decision-making, and are less likely to result in unintended or perverse outcomes than other methods of setting incentives. This study has demonstrated that providing incentives even for measures that are not – on average – cost-effective will result in cost-effective outcomes, and an overall larger net provincial benefit.

A measure that is not TRC-Plus cost-effective on average may be so for a substantial minority of consumers. Setting an incentive commensurate with the average net system benefits[101] will encourage adoption amongst these consumers and yield benefits inaccessible when such measures are entirely screened out.

Guidehouse would recommend that implementers consider setting their budgets for acquiring consumption reductions from certain measures or bundles of measures to be commensurate with the net provincial TRC-Plus benefits (including avoided gas and emissions costs) of such reductions.

[101] A measure may not be cost-effective from a TRC-Plus perspective, but still offer significant net system benefits. Net system benefits are calculated using avoided carbon and natural gas costs (the benefits) and incremental electric energy and coincident peak capacity costs (the costs). In contrast, in the TRC-Plus calculation, these net system benefits are compared against a participant's (private) incremental equipment cost.

A measure that offers net system benefits, but is not TRC-Plus cost-effective is a measure where the incremental cost is, for the average consumer, greater than the net system benefits and any non-energy benefits consumers on average derive from that measure.

By offering an incentive that is reflective of some share of net system benefits to all consumers, consumers who happen to have below-average incremental measure costs, or derive above average non-energy benefits from the measure will still have the opportunity to access an incentive and deliver incremental system benefits, despite the measure not being – on average – cost-effective from a TRC-Plus perspective.

8.2.3.2 Focus Electrification in New Construction

Regardless of end-use or sector, the analysis in this report, and the feedback from SAG members indicate that the opportunities for electrification – in particular full electrification, but also hybrid electrification – are most cost-effective and technically feasible for new buildings.

As such, Guidehouse would recommend that implementers consider focusing their efforts at electrification primarily (but not exclusively) on new construction. Electrification of new construction (again, either with hybrid or fully electric systems) does not require costly infrastructure retrofits required to adapt existing building systems (wiring, ducting, etc.) to electrified equipment. This is particularly true for Commercial buildings (see Appendix B).

New construction also allows for a more focused implementation – focusing on developments, rather than individual buildings one at a time – and so can potentially offer important scale advantages, including simplifying the process of coordination with third parties (such as the local distribution company or the IESO) that may be able to help mitigate electricity system cost impacts.

Demand flexibility equipment for electrified loads and the distributed energy resource management systems (DERMS) for buildings are likely to be considerably more economic if procured as part of building design phases. These may in turn be able to offset some of the (very substantial) incremental capacity costs associated with electrification.

Implementers should therefore consider carefully the benefits of prioritizing the electrification of loads in Residential and Commercial new build.

8.2.3.3 Residential Water Heating Fuel Switching

The findings of this study indicate that there exists a substantial opportunity for cost-effectively reducing water heating natural gas use and the associated greenhouse gas emissions by replacing natural gas storage water heaters at the end of their life with heat pump water heaters. Guidehouse would therefore recommend that implementers work with contractors and the two major water heater rental companies to encourage their customers to replace their natural gas water heaters with heat pump water heaters.

Substantial barriers exist for such an implementation; the focus of water heater fuel switching was, only a decade ago, on moving customers *away* from electric water heaters for reasons of cost. No program of fuel-switching is likely to achieve adoption without adequately informing consumers and trade allies of the benefits of electrification, particularly in terms of the bill savings provided by the substantial increase in efficiency offered by heat pump water heaters.

Implementation of any such program should leverage the network advantages offered by Ontario's water heater rental oligopoly for deploying equipment, incentives, and measures to mitigate the impacts of coincident peak demand. Engaging with these firms and with the IESO offer significant opportunities for optimizing benefits..

A key finding of the 2024 APS has been to identify a substantial, cost-effective and achievable opportunity for residential water heating fuel switching, an opportunity that the Guidehouse team would recommend implementers consider pursuing in collaboration with the IESO.

8.2.3.4 Residential Space Heating Fuel Switching

Absent the application of demand response technologies or programs, the full electrification of Residential space-heating equipment imposes significant costs on Ontario consumers due to substantial generation capacity required to serve space-heating load under peak load winter design conditions. Full electrification of space heating in existing homes could likewise impose significant incremental costs on individual consumers through the need to upgrade electrical panels or undertake other electrical work. Significant uncertainty exists regarding readiness of Ontario homes currently served by natural gas to fully electrify their space-heating equipment, but it is clear that, in aggregate, the costs of required upgrades would be significant.

Hybrid systems, where heat pumps meet a high proportion of a home's thermal requirements and gas furnaces the balance, have, in this study, been demonstrated to be cost-effective for the province and for individuals in the most populated southern parts of the province. Some uncertainty exists regarding the costs of electrical upgrades that might be required in homes where the heat pump is sized for heating, and the cost-effectiveness of these measures is likely to be sensitive to how the coincident system peak electric demand is defined and valued.

Data should be collected and further work done to resolve these uncertainties, but in the near term it seems clear that a focus on encouraging Residential consumers to replace their central air conditioning with a similarly-sized heat pump at end of life (i.e., the "4A" heat pump option) is a "no-regrets" policy. The incremental cost is relatively modest, and isolated to the equipment costs, and the measure is likely to deliver substantial winter and summer bill savings to consumers in addition to materially reducing summer coincident peak demand.

Guidehouse understands that contractors servicing the Residential market have recently successfully delivered substantial amounts of hybrid electrification to consumers via the federal Greener Homes Grant. Ongoing work to migrate Residential central cooling systems to heat pumps capable of servicing thermal loads in the winter should take advantage of the lessons learned from this work; the publication of formal process and impact evaluations of the delivery would provide invaluable information for future work in assessing electrification potential and in supporting the achievement of further gas savings via the opportunistic replacement of central A/C units by heat pumps.

Guidehouse therefore recommends that implementers strongly consider building upon the recent successes in heat pump deployment, using the information and data from these efforts to support Residential consumers replacing their central air conditioning with heat pumps, and to better quantify the opportunities for heat pumps sized for home heating in Ontario.

8.2.3.5 Residential Space Heating Energy Efficiency

Residential envelope improvements targeted at older homes deliver the largest volume of cost-effective energy efficiency Achievable potential of the measures considered. Envelope improvements deliver substantial provincial benefits, private bill savings and are likely to considerably improve the comfort and quality of life of consumers to which they are deployed (a benefit not directly valued in this study).

Based on these findings, the Guidehouse team recommends that implementers consider what opportunities exist to expand the delivery of impactful envelope improvements to Residential consumers in older, leakier homes, particularly those located in colder, more northerly areas of the province.

8.2.3.6 Commercial Space Heating Fuel Switching

The critical finding of this study with respect to Commercial sector space heat fuel switching is that considerable uncertainty exists rerding the costs and feasibility of electrification in existing Commercial buildings. This uncertainty substantially constrained the volume of Achievable potential estimated by this study, as documented in Appendix B. What locally specific data were available were drawn from research used to inform a hybrid Commercial space-heating electrification pilot that Guidehouse understands remains in-field at the time of publication of this study.

Guidehouse recommends that the critical lessons learned from this pilot should be used to inform expansions of that pilot (to test alternative delivery and installation models) and to develop a more formal data collection strategy for informing future projections of Commercial space heating electrification potential.

Appendix A. Base Year Disaggregation

This Appendix provides expanded detail regarding the scope, methods, and results of the BYD task. To ensure the additional detail (not shown in the main report body) is put in its appropriate context, some content of this Appendix may be duplicative of that of Section 2.

A.1 Scope

The base year used in this potential study is 2022. This was selected as the base year in consultation with SAG members, as the most recent available complete calendar year of consumption volume data available at the time the work was undertaken.

For the purposes of base year disaggregation and the reference forecast, Guidehouse has applied no geographic disaggregation. This differs from the 2019 APS, where the province of Ontario was divided into 10 zones (for electric energy efficiency potential) and 5 natural gas regions. The driver of the decision to treat the 2024 APS as a *provincial* study rather than a regional one was the availability of data to distinguish market, premise, and measure characteristics at a geographically granular level.

In most cases sub-provincial data sources demonstrate insufficiently precise variations between regional characteristics to justify the incremental schedule costs required to characterize and model potential in such a geographically granular fashion.[102] The decision to work at a purely provincial level, noting the importance of reflecting some savings variation in space-heating measures depending on climate zone, was presented to the Stakeholder Advisory Group (SAG) early in the study development process and received its support.[103]

As in the 2019 APS, potential is broken out into three sectors: Residential, Commercial, and Industrial. Natural gas volumes for some groups of consumers provided by EGI have been excluded from the analysis:

- **Power Production and Feedstock** (e.g., for use in chemical production) gas volumes in are excluded from the base year data and the potential study as a whole as they are understood to be an inappropriate target for programmatic DSM achievement.
- **Wholesale Volumes** (e.g., gas sold to other Ontario distribution utilities, like EPCOR) have also been excluded; and,
- **Extra-Large Volume Customers.** The SAG, at its 2023-09-14 meeting with Guidehouse and OEB staff, recommended that the study exclude these customers from the base year and the analysis. The SAG agreed that although significant opportunities for DSM exist within this group of customers, these opportunities are specific to individual customers and distinct from the typical opportunities for other customers in the same sub-sector. The extra-large volume customers could not be treated individually by the study as doing so could result in publication of competitively sensitive data and would require customer-specific opportunity assessment outside the scope of this study. This left two options: combine the extra-large customer volumes with those of the more

[102] This does not mean that estimated potential does not account for geographic climate variation – some space-heating measures distinguish between installations in Northern and South/Central/Eastern Ontario for the purposes of modeling savings and measure uptake.

[103] Ontario Energy Board, Natural Gas Demand Side Management Stakeholder Advisory Group (EB-2022-0295) Meeting #2, April 28,2023

https://engagewithus.oeb.ca/dsm-sag

modestly sized customers and treat the sub-sector uniformly (as was done in the 2019 study), or exclude them from consideration. The SAG recommended these customers be excluded from the study entirely, and OEB staff directed Guidehouse to implement this recommendation.

The key criteria used to select the sub-sectors and end-uses into which consumption volumes should be disaggregated were:

1. **Availability.** Do the data exist to support a disaggregation of consumption to the given sub-sector and end-use? Further, are reliable data accessible to allow for a meaningful differentiation of the potential DSM opportunity at a given level of granularity?
2. **Materiality.** Does the sub-sector or end-use consumption volume contribute a meaningful proportion of the overall sector's volume?
3. **Singularity.** Is the given sub-sector or end-use meaningfully different (in terms of end-use intensities and technology densities) from all the others into which it might otherwise be aggregated?
4. **Stakeholder Feedback.** In some cases specific sub-sectors were requested by members of the SAG, and OEB staff directed Guidehouse to include these sub-sectors.

A.2 Methodology

This section describes the approaches used by Guidehouse to combine the input data to estimate the shares of base year consumption volumes by sub-sector and end-use within each sector. This section begins with a description of the data sources used, followed by three sector-specific sections that identify the details of how those data sources were used.

A.2.1 Data Sources

Table 21 provides a comprehensive summary of the data sources used by Guidehouse for the base year disaggregation.

Table 21. Data Sources

Data Type	Data Source	Description	Citation
Base Year (2022) EGI Consumption Volumes - Residential	EGI	Weather-normalized natural gas consumption and premise count in 2022 divided by EGI Region (North, South), EGI housing category (e.g., Detached, Semi-Attached, etc.), construction vintage, and consumption quartile.	File: "APS_ResidentialFile_sent.xlsx" provided by OEB to Guidehouse 2023-06-08
NRCan Energy use by Building Type and End-use	Natural Resources Canada	Annual energy use (PJ) and/or GHG emissions (Mt of CO2e) separately, by end-use, residential building type or commercial segment, and energy source for the year 2020 (the last available year of data at the time of this analysis). These data are used in some cases to allocate end-use shares.	Natural Resources Canada, *Comprehensive Energy Use Database* **https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/comprehensive_tables/list.cfm**

Data Type	Data Source	Description	Citation
Industrial End Use Consumption Matrix	EGI	Share of gas consumption, by end-use per sub-sector.	File: "EGI_OEB PS Industrial Sub-sector- End Use Matrix_2023-08-11 RevDN2.xlsx" provided by email on 2023-08-17 by the OEB
Extra Large Volume (ELV) Consumption Breakdown by Sub-Sector	EGI	Volume of gas consumption by ELV customers, allocated to the industrial sub-sectors	File: "Extra Large volume_sector allocated_sent.xlsx" provided by email on 2023-07-31 by the OEB
REUS Equipment Shares by Income Level	Residential End-use Survey	Share of equipment by energy source (electric, gas, etc.), separately, by building type and income status.	File: "REUS-APS.xlsx" provided 2023-07-28 by OEB
Low Income Shares	2019 APS	A SAG member requested that Guidehouse use the low-income shares estimated for the 2019 APS and reported in Appendix A of that document. OEB staff directed Guidehouse to use the share requested.	Email correspondence from OEB staff, 2023-08-24

In addition to the sources above, Guidehouse has, in its analysis (where it is reasonable to do so), compared the estimated 2023 base year disaggregated volumes to the base year disaggregated volumes from the 2019 APS.[104]

A.2.2 Residential Methodology – Additional Detail

Low Income shares were drawn from the 2019 APS (see Appendix A of that document).

For that study, Low Income shares were provided by IESO zone. Guidehouse took an average of these values by dwelling category (single family and multi-family), weighted using the 2019 APS count of customers by dwelling category and IESO zone.[105] This share of Low Income premises by structural building type was then applied to REUS data identifying equipment shares by sub-sector and income status to provide an adjustment factor that could be applied to provincial average end-use energy shares by sub-sector, derived from NRCan's emissions (by sub-sector and end-use) data.

[104] Navigant (n/k/a Guidehouse) prepared for the Independent Electricity System Operator, and the Ontario Energy Board, *2019 Integrated Ontario Electricity and Natural Gas Achievable Potential Study*, December 2019 **https://www.ieso.ca/2019-conservation-achievable-potential-study**

[105] EGI was unable to provide an estimated share of its customers that were low income, either in total or by sub-sector. Guidehouse developed an initial estimate of the low income share by applying the eligibility criteria for EGI's Home Winterization Program (adjusted for inflation) to the same census cross-tabulation used to develop the 2019 low income share. This estimate, along with a second estimate, drawn from a cross-tabulation of income status and structural dwelling type from EGI's residential end-use survey (REUS) was reviewed by EGI, which recommended the use of the 2019 study Low Income shares. OEB staff directed Guidehouse to adopt this recommendation.

NRCan emissions data were initially used for the allocation of volumes across end-uses rather than energy data because the NRCan energy data do not provide a fully granular cross-tabulation of energy use by energy source (gas or electricity), sub-sector, and end-use. Emissions values are provided by sub-sector and end-use and are explicitly noted to exclude emissions related to electricity production, making them a reasonable proxy for natural gas energy shares.[106]

EGI staff, reviewing these values recommended that Guidehouse instead use a value of 72% for the share of space-heating Residential gas consumption, providing a workbook deriving this value that was forwarded to Guidehouse by OEB staff on 2024-09-21. The EGI team recommended that Guidehouse split the remaining share of gas use (classified as water heating use in the provided data) between appliances and water heating. OEB staff directed Guidehouse to implement this recommendation, taking the space heating share as given and splitting the remaining share of gas use between appliances and water heating on the basis of the NRCan emissions data.

These shares of end-use consumption by sub-sector were combined with the Low Income adjustment to create a full set of energy shares by (NRCan) sub-sector and end-use. NRCan's sub-sectors were mapped to the sub-sectors defined by EGI in its base-year data, the end-use shares applied, and then aggregated across the sub-sectors to be used in the study, as noted above, in Table 3.

In this process, Guidehouse applied substantial aggregation to the base-year category splits included in the consumption volume data by EGI, which is divided into categories by additional variables including construction vintage and volume of consumption. Aggregation was applied for the reasons noted above: differentiation and data availability. Only consumption data (provided by EGI) was available to Guidehouse at this level of granularity. End-use shares, equipment densities, and other variables important to potential estimation were not. Modeling this sector at the maximum level of granularity provided in the consumption data would therefore at best make no difference to the output potential estimates, and at worst bias results due to the spurious precision of the inputs.

Should additional precision regarding equipment densities, measure savings, end-use consumption shares, etc. at some point become available at a level of granularity that matches the precision of EGI's data, there may be value in modeling potential for the most impactful measures at this level of granularity. It may also, alternatively, be that such additional detail is useful for DSM program planning, but does not add to the value of potential study estimation focused on the provincial potential outcomes of dozens of different measure types.

A.2.3 Commercial Methodology – Additional Detail

The Multi-Res sub-sector was disaggregated with an approach similar to that used in the Residential sector. End-use survey data distinguishing equipment shares for Low Income versus non-Low Income households in Multi-Res buildings was not available. The Residential end-use survey data did not include an applicable building segment for multi-unit buildings. As a result, the Guidehouse team could not differentiate the end-use intensity for low-income versus non-low-income segments within the multi-unit residential building sub-sectors; intensities for low-income and non-low-income segments are therefore the same.

[106] Guidehouse confirmed that natural gas consumption by end-use in the aggregate residential sector was sufficiently close to emissions by end-use, making emissions a reasonable proxy for the more granular cross-tabulation. For example, 2020 Space Heating GHG emissions account for approximately 75% of emissions (Table 2, CEUD) and approximately 72% of energy use (Table 5, CEUD).

The Guidehouse team applied the segment mapping contained in Table 22 to map NRCan commercial building segment definitions to the 2024 APS sub-sectors.

Table 22. Commercial Sub-sector to NRCan Segment Mapping

Sub-Sector Group	NRCan Building Segment
Hospital	Health Care and Social Assistance
Hotel	Accommodation and Food Services
Long Term Care	Health Care and Social Assistance
Multi-Res	Apartment
Office	Offices
Other Commercial	Other Services
Restaurant	Accommodation and Food Services
Retail	Retail Trade
Schools	Educational Services
University/College	Educational Services
Warehousing	Transportation and Warehousing

A.3 Results – Additional Detail

Where possible, Guidehouse has endeavoured to compare base year consumption values shown below with the appropriate comparable values from the 2019 APS to help provide additional context. In some cases such comparisons would be confounded by changes in approach (e.g., changes in the end-use allocation approach) or changes in the underlying data available to Guidehouse (e.g., the use of premises instead of floorspace for estimating commercial intensities).

Total base year (2022) consumption across all sectors is approximately 18.5 billion m^3.

This is significantly lower than the approximately 23.2 billion m^3 of base year consumption reported in the 2019 APS (for a 2017) base year, principally as the result of the exclusion of the approximately 5 billion m^3 attributable to ELV customers. Canada's Energy Regulator (CER)'s estimate for provincial gas consumption also aligns approximately with base year values, after correcting for the removal of the ELV; that agency estimates total Ontario gas consumption in 2022 as being approximately 23.2 billion m^3.[107]

A.3.1 Results – Residential Additional Detail

Total residential consumption in the base year (2022) is approximately 8.1 billion m^3.

This is somewhat higher than the approximately 7.9 billion m^3 of base year gas use for non-Multi-Res sub-sectors in the 2019 APS.[108] This growth in consumption is somewhat slower than

[107] Canada Energy Regulator, *Canada's Energy Future 2023: Data Appendices*, accessed August, 2023 **https://apps.cer-rec.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA**

[108] The 2019 APS used a 2017 base year and (unlike the 2023 APS) included Multi-Res (apartments) in the Residential sector rather than in the Commercial sector, as in this 2023 APS. Both the 2017 base year data (for the 2019 APS) and the 2022 base year data (for the 2023 APS) were provided by EGI and weather normalized

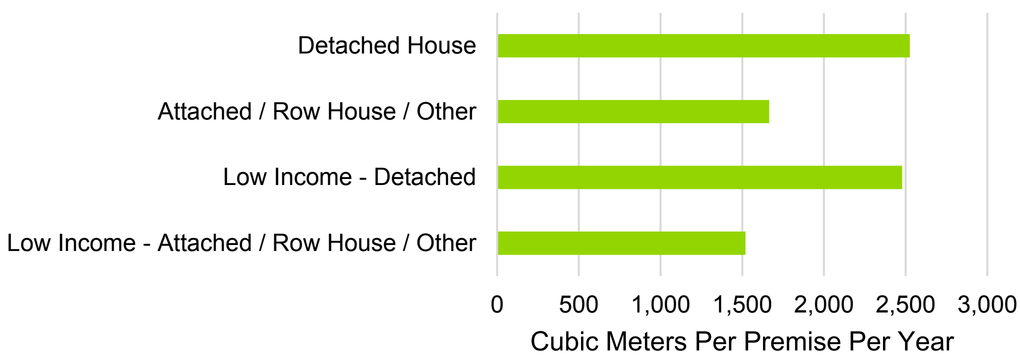
growth in customer counts reported in EGI's 2022 rate filing,[109] with total residential customers growing from 3.3 million in 2017 to an estimated 3.5 million in 2022.

The CER, in contrast, estimates that provincial Residential gas consumption has declined from approximately 9.1 billion m^3 (341 PJ) in 2017 to approximately 8.6 billion m^3 (320 PJ) in 2022, though comparisons between CER's estimates and those in this study must be made with caution as it is unclear whether the CER allocates Multi-Res to the Residential or Commercial sector.

As implied by the above, average Residential energy intensity (use per customer) appears to be declining. Base year energy intensities by sub-sector are provided in Figure 71, below. The current estimated 2022 energy intensity for the Residential sector as a whole is approximately 2,264 m^3 per year, in contrast to an energy intensity of approximately 2,360 m3 per year derived from the 2017 values included in EGI's rate filing.

EGI's 2022 rate filing has also noted the downward trend in Residential use per customer. That document notes[110] that "*Over the past fifteen years, Enbridge Gas has exhibited an approximate 6.8% decrease in residential average use, which corresponds to an average annual decline of approximately 0.5%".*

Figure 71. Residential Base Year Intensity by Sub-Sector

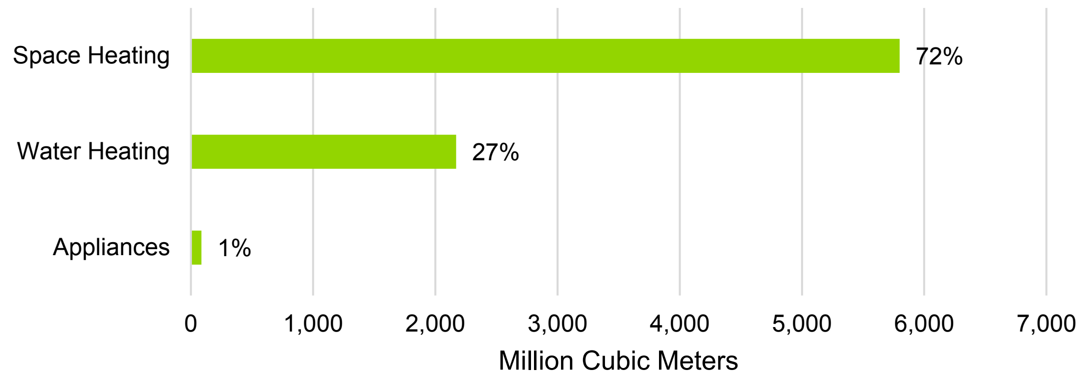


The intensities of the Low Income sub-sectors are in both cases lower than the corresponding non-Low Income. This is a result of adjustments made (as described above) based on the REUS data.

[109] Ontario Energy Board, *Enbridge Gas Inc. – 2024 – 2028 Natural Gas Distribution Rates – Phase One*- EB-2022-0200, Exhibit 3, Tab 2, Schedule 7.
https://www.oeb.ca/applications/applications-oeb/current-major-applications/eb-2022-0200

[110] EB-2022-0200, Exhibit 3, Tab 2, Schedule 5, Page 7 of 28 (PDF page 115 of 377
https://www.rds.oeb.ca/CMWebDrawer/Record/759809/File/document

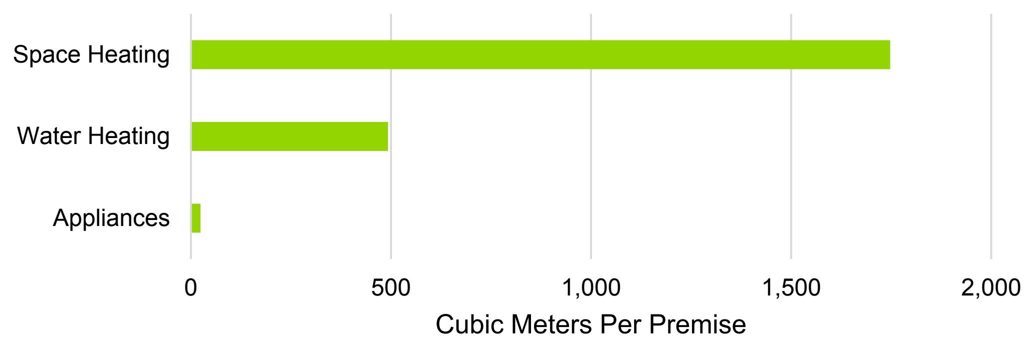
Figure 72. Residential Base Year Consumption by End-use



The proportion of natural gas consumption by non-Multi-Res premises that can be attributed to space-heating is lower than that included in the base year data for the 2019 APS (76%). The proportion of gas use attributable to water heating, however, is considerably higher than the 13% estimated for non-Multi-Res premises in the 2019 APS. Most of this difference is attributable to the "Miscellaneous Residential" end-use used in the 2019 APS, which accounted for 8% of base year consumption for non-Multi-Res premises[111], and four-point reduction in the space-heating share of gas use, which must be recovered from other end-uses.

Base year energy intensities by end-use are provided in, below.

Figure 73. Residential Base Year Intensity by End-use



Changes in the approach to allocating end-use shares confounds[112] comparisons of end-use intensities besides that of space heating, which shows an annual decline in intensity of approximately 3.1%, in line (as would be expected given its share of total consumption) with the overall decline in residential natural gas energy intensity.

A.3.2 Results – Commercial Additional Detail

[111] The driver of this difference is the source of the end-use shares used. The 2019 APS used end-use intensities drawn from the 2016 APS and calibrated to REUS equipment shares and (then-current) consumption volumes. The 2023 APS draws end-use shares from EGI (for space-heating) and from the most recently available end-use data published by NRCan in the CEUD (for water heating and appliances).

[112] End-use allocations in the 2019 APS were based on end-use intensities 2016 APS, calibrated to the 2019 APS' base year values. End-use allocations in the 2023 APS are a combination of the space-heating share provided by EGI, and derivations based on end-use emissions shares obtained from NRCan's CEUD.

Total commercial consumption in the base year (2022) is approximately 6 billion m^3.

This is lower than the approximately 6.4 billion m^3 of base year gas use for the combined volumes of all commercial and Multi-Res sub-sectors in the 2019 APS[113], reflecting an implied annual decline of approximately 1.1%.[114]

Caution should be used in interpreting this apparent decline; though Guidehouse has endeavoured to account for the shift of multi-family residential customers from the Residential sector (2019 APS) to the Commercial sector (2024 APS), the large number of Commercial sub-sectors and the potentially differing underlying definitions used to summarize consumption by sub-sector are likely to confound the comparison.[115]

For context, in EGI's 2022 rate filing[116] reports that General Service Commercial customers consumed approximately 6.2 billion m3 in 2017, growing to 6.4 billion m3 in 2022. This strongly suggests that the apparent decline in consumption when comparing the two Achievable Potential Studies is principally an artefact of the differing sectoral definitions applied in the two studies.

No simple comparison in sectoral energy intensities between the 2019 APS and the 2024 APS is possible, unfortunately, as the 2019 APS normalized commercial consumption on the basis of floorspace, whereas the 2024 APS (lacking sub-sector-level floorspace data) only has premise counts with which to normalize consumption to an intensity value.

[113] The 2019 APS used a 2017 base year and (unlike the 2023 APS) included Multi-Res (apartments) in the Residential sector rather than in the Commercial sector, as in this 2023 APS. For the purposes of comparisons with the 2023 APS base year values in this report, Guidehouse has shifted 2019 APS Multi-Res consumption from the Residential to the Commercial sector.

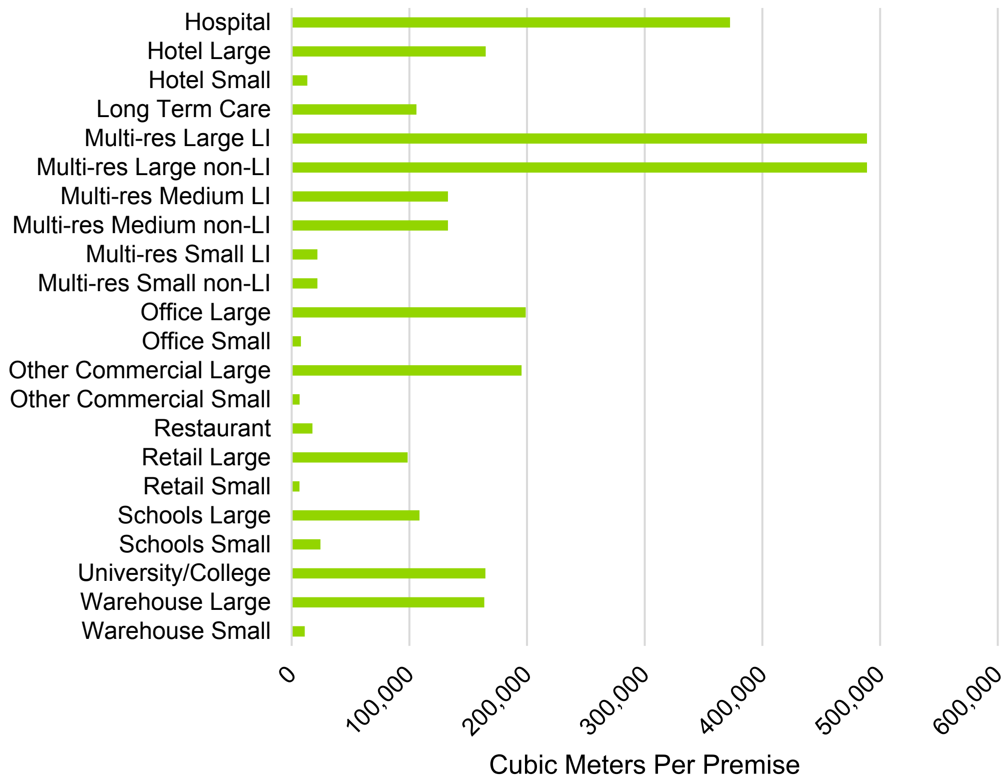
[114] Both the 2017 base year data (for the 2019 APS) and the 2022 base year data (for the 2023 APS) were provided by EGI and weather normalized.

[115] For the 2019 APS, sub-sector ("segment" in that report) definitions were driven by the IESO on the basis of their available database of sub-sector-specific commercial floorspace. In contrast, for the 2023 APS sub-sector definitions are based on sub-sector tracking by EGI.

[116] Ontario Energy Board, *Enbridge Gas Inc. – 2024 – 2028 Natural Gas Distribution Rates – Phase One*- EB-2022-0200, Exhibit 3, Tab 2, Schedule 7.

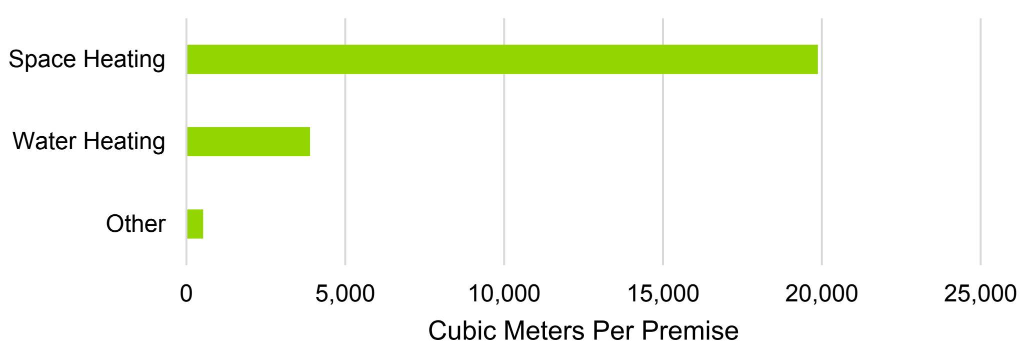
https://www.oeb.ca/applications/applications-oeb/current-major-applications/eb-2022-0200

Figure 74 Commercial Base Year Intensity by Sub-Sector



Commercial end-use intensities (annual consumption per customer) are presented in Figure 75 below.

Figure 75. Commercial Base Year Intensity by End-use



A.3.3 Results – Industrial Additional Detail

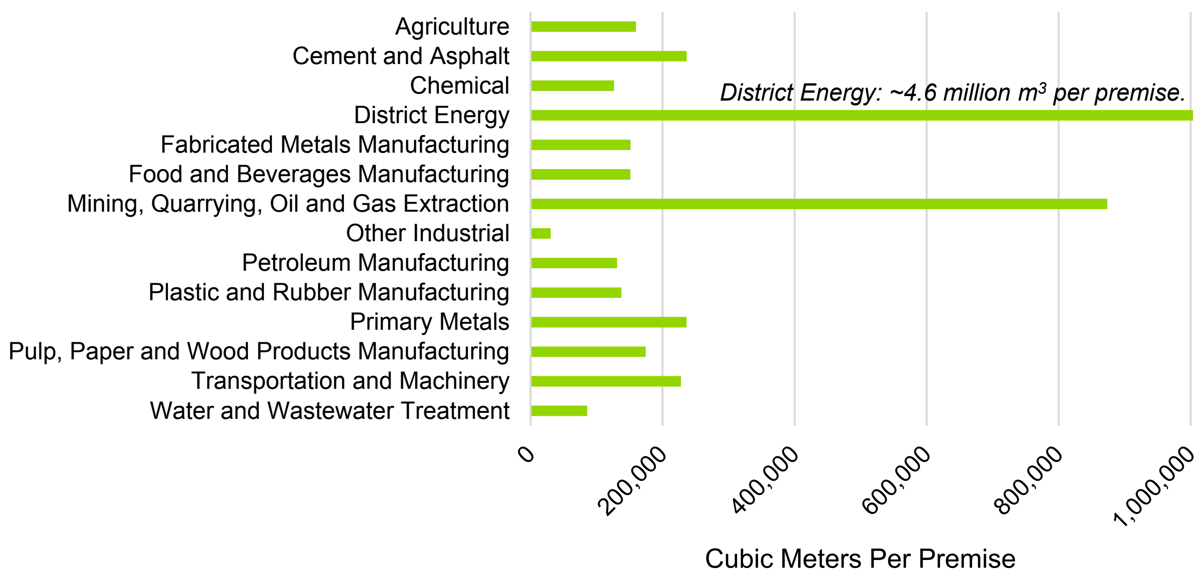
Total industrial consumption in the base year (2022), with the consumption of the ELV customers removed, is approximately 4.4 billion m^3. ELV customers' consumed approximately 5 billion m^3 in the 2022 base year. In total EGI's Industrial consumption is approximately 9.4 billion m^3.

This is higher than the approximately 9 billion m^3 of base year gas use for the combined volumes of all industrial sub-sectors in the 2019 APS. As with the commercial sector, caution must be used in interpreting this apparent growth; EGI's data principally distinguish between "Residential" and "Non-Residential" sectors. Further subdivision into industrial and commercial sectors is based on queries performed by Enbridge Gas Distribution and Union Gas staff (in 2019) and EGI staff (in 2023).

Total non-residential consumption (the sum of commercial and industrial) in base year 2023 is (inclusive of the ELV customer volumes for which no potential is estimated in this study) approximately 15.5 billion m^3, slightly higher than total non-residential consumption in base year 2017 (used for the 2019 APS) of 15.35 billion m^3. This aggregate annual increase in consumption of approximately 0.16% is consistent with historical values of Ontario non-residential gas volumes reported over the same period by Canada's Energy Regulator[117] which suggest an annual increase of approximately 0.12%.

Figure 76, below, provides the estimated average energy intensity (m^3 per premise) by sub-sector. Because of the heterogenous nature and size of industrial facilities (and potential idiosyncrasies in the underlying data in the relationship between premises, buildings, and customers), these results should be interpreted with caution. No values for Industrial energy intensity were presented as part of the 2019 APS.

Figure 76 Industrial Base Year Intensity by Sub-Sector



The end-use distribution for base year 2022 has changed considerably from the 2017 base year data used for the 2019 APS due largely to changes in the categories included and to the exclusion, for the 2024 APS, of the ELV customers.

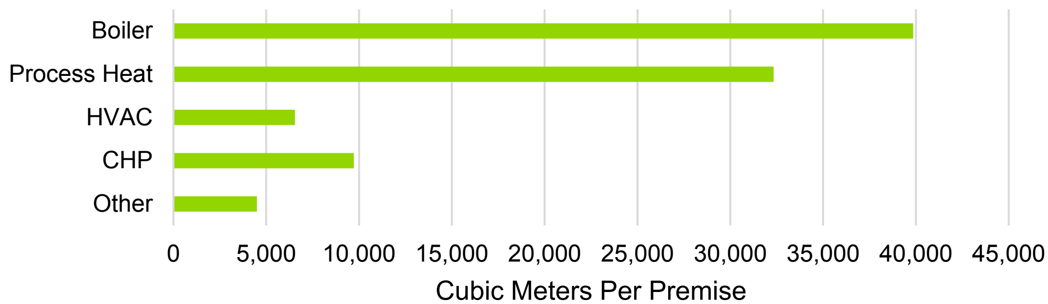
The boiler and the process heat end-uses are consistent across both the 2019 APS and the 2024 APS. In the 2024 APS these together account for approximately 72% of consumption. In

[117] Canada Energy Regulator, *Canada's Energy Future 2023: Data Appendices*, accessed August, 2023 **https://apps.cer-rec.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA**

the 2017 base year used in the 2019 APS, the sum of the Process Heating (Direct) and Process Heating (Water/Steam) accounted for approximately 74% of industrial consumption.

As in the commercial sector, industrial premises are highly heterogenous, so aggregate end-use intensities are of limited value. For completeness, however, these are presented below.

Figure 77. Industrial Base Year Intensity by End-use



Appendix B. Measure Characterization

This Appendix provides additional detail regarding the characterization of the measures included in this study. It is divided into three sections:

1. **Residential and Commercial Measure Sources.** This section provides a table for each sector identifying the source for critical inputs for each set of measures.

2. **Industrial Measure Source.** This section provides additional detail regarding the IAC database, the primary source for measure-level information for the Industrial sector.

3. **Important Measure-Level Considerations.** This section flags issues related to specific measures that should be considered in interpreting the results of this study and when considering the appropriate characterization of measures going forward for updating the OEB TRM or developing additional measure substantiation documents.

B.1 Residential and Commercial Measure Sources

Table 23 identifies the source used for each measure's estimated savings, incremental cost, and to derive the appropriate applicability for Residential measures. For each measure included below there exist multiple iterations included in the modeling. Measure iterations typically capture differences by sub-sector and, in the Residential sector, differences by vintage of building construction.

The selection of building vintage categories was determined by the vintage categories of consumption data provided by EGI. Different iterations by vintage were included at the request of SAG members on the basis that the cost-effectiveness of Residential envelope measures can vary significantly depending on a building's vintage, and the inclusion of multiple iterations can improve study precision.

Table 23. Sources for Savings, Cost and Applicability Factors for Residential Measures

Measure Name	Savings Source(s)	Cost Source(s)	Applicability Factors Source(s)
North ASHP with Gas Backup (Sized for Cooling 4A)	Guidehouse/Enbridge Heat Pump Study, Illinois TRM V12 5.3.1, Canmet sizing guide, Base Year Disaggregation data	Illinois TRM V12 5.3.1, 5.3.7, and 5.3.3, SAG input.	Base Year Disaggregation for climate split, Technical Suitability for forced air systems provided by a SAG member.
North ASHP with Gas Backup (Balanced Sizing 4B)			
North CCHP with Gas Backup (Heating Sizing 4C)			
North CCHP with Electric Backup (Heating Sizing 4D)			
South ASHP with Gas Backup (4A Sized for Cooling)			
South ASHP with Gas Backup (4B Balanced Sizing)			
South CCHP with Gas Backup (4C)			
South CCHP with Electric Backup (4D)			
North GSHP	Illinois TRM V12 - 5.3.1 and 5.3.8, Base Year Disaggregation data	Xcel Energy Colorado TRM – 18.2 Residential Ground Source Heat Pump	Base Year Disaggregation for climate split, Technical Suitability for forced air systems provided by a SAG member.
South GSHP			

Measure Name	Savings Source(s)	Cost Source(s)	Applicability Factors Source(s)
Air Sealing	Illinois TRM V11 - 5.6.1	SAG member.	Base Year Disaggregation for building vintage split, saturation provided by a SAG member.
Attic Insulation	Illinois TRM V11 - 5.6.5, SAG members	SAG member, based on program data	Enbridge Residential Natural Gas End Use Study 2022 Annual Results, Base Year Disaggregation for building vintage split, saturation provided by a SAG member.
Roof Insulation	Illinois TRM V11 - 5.6.5	SAG member, based on program data	Enbridge Residential Natural Gas End Use Study 2022 Annual Results, Base Year Disaggregation for building vintage split, saturation provided by a SAG member.
Basement Insulation	Iowa TRM V7 - 2.6.7, SAG members	SAG member, based on program data	Enbridge Residential Natural Gas End Use Study 2022 Annual Results, Base Year Disaggregation for building vintage split, saturation provided by a SAG member.
Wall Insulation	Illinois TRM V11 - 5.6.4, SAG members	SAG member, based on program data	Enbridge Residential Natural Gas End Use Study 2022 Annual Results, Base Year Disaggregation for building vintage split, saturation provided by a SAG member.
Windows - Tier 1 and Tier 2	SAG input, OEB TRM V7, NY TRM	OEB TRM V7, NY TRM. SAG member	ENERGY STAR Certified Homes, Version 3 (Rev. 09) – Cost & Savings Estimates and assumptions. Saturation provided by SAG member.
Doors	SAG input, OEB TRM V7, NY TRM	ENERGY STAR Certified Homes, Version 3 (Rev. 09) – Cost & Savings Estimates.	ENERGY STAR Certified Homes, Version 3 (Rev. 09) – Cost & Savings Estimates and assumptions. Saturation provided by SAG member.
Smart Thermostat	OEB TRM V7	OEB TRM V7	Density assumed. Saturation from Enbridge Residential Natural Gas End Use Study 2022 Annual Results.
Heat Recovery Ventilator	Massachusetts TRM 2016-2018 p.109	OEB TRM V7 (for com HRV, NC/R)	Density reflecting homes with mechanical ventilation from SAG members; Saturation reflecting homes built prior to 2016 building code HRV requirement from SAG member; Technical Suitability for forced air systems provided by a SAG member.
Heat Pump Water Heater	Illinois TRM V11 - 5.4.3, PA TRM – 2.3.1, Base Year Disaggregation data	Illinois TRM V11 - 5.4.3 and 5.4.2	Enbridge Residential Natural Gas End Use Study 2022 Annual Results; Tech suitability provided by SAG.
Electric Resistance Water Heater	Illinois TRM V11 - 5.4.3, Base Year Disaggregation data	Illinois TRM V11 - 5.4.3 and 5.4.2	Enbridge Residential Natural Gas End Use Study 2022 Annual Results; Tech suitability provided by SAG.
Tankless Water Heater (Non-Condensing)	OEB TRM V7	OEB TRM V7	Enbridge Residential Natural Gas End Use Study 2022 Annual Results.
Tankless Water Heater (Condensing)			
Gas Storage Water Heater			
Home Energy Report	Michigan Behavior Resource Manual	Michigan Behavior Resource Manual	Assumed applicable to all gas customers.

Table 24 identifies the source used for each measure's estimated savings, incremental cost, and to derive the appropriate applicability for Commercial measures.

Table 24. Sources for Savings, Cost and Applicability Factors for Commercial Measures

Measure Name	Savings Source(s)	Cost Source(s)	Applicability Factors Source(s)
Cold-Climate Heat Pump (ccHP)	Illinois TRM V11 - 4.4.9, Base Year Disaggregation data	SAG inputs, IL TRM, EIA Technology Forecast Updates – Residential and Commercial Building Technologies, ACEEE Electrifying Space Heating in Existing Commercial Buildings: Opportunities and Challenges	Technical suitability provided by a SAG member.
ASHP with Gas Heating (Hybrid)	Illinois TRM V11 - 4.4.9, Base Year Disaggregation data	SAG inputs, IL TRM, EIA Technology Forecast Updates – Residential and Commercial Building Technologies, California eTRM	Technical suitability provided by a SAG member.
Ground Source Heat Pump (GSHP)	Illinois TRM V11 - 4.4.44, Base Year Disaggregation data	Illinois TRM V11 - 4.4.44	Guidehouse assumptions.
Ductless Mini-Split Heat Pump (DMSHP)	Illinois TRM V11 - 4.4.59, Base Year Disaggregation data	Illinois TRM V11 - 4.4.59, 4.4.11	Technical suitability provided by a SAG member.
Gas Heat Pumps for Space Heating	Illinois TRM V11 - 4.4.55	Illinois TRM V11 - 4.4.55	Technical suitability provided by a SAG member.
Unit Heater	OEB TRM V7, Condensing Unit Heater	OEB TRM V7, Condensing Unit Heater	2019 Integrated Electricity and Gas Achievable Potential Study, Xcel Energy Potential Study
Wall Insulation	Illinois TRM V11 – 4.8.30	SAG member input	2019 Integrated Electricity and Gas Achievable Potential Study, PA TRM 2016, CO TRM 2015, SAG member input.
Duct Insulation	Iowa TRM V8 – 3.3.15	Illinois TRM V11 – 4.4.56	2019 Integrated Electricity and Gas Achievable Potential Study, Fortis BC/BC Hydro End Use Report
Roof Insulation	Illinois TRM V11 - 4.8.2	Illinois TRM V11 - 4.8.2	2019 Integrated Electricity and Gas Achievable Potential Study
Duct Sealing	Michigan MEMD 2023	Michigan MEMD 2023	Building assumptions, 2019 Integrated Electricity and Gas Achievable Potential Study
Air Sealing	New York TRM V10 – C&I Air Leakage Sealing	Michigan MEMD 2023	Residential measure (Enbridge Residential Natural Gas End Use Study 2022 Annual Results), Building assumptions
Air Curtain	OEB TRM V7, SAG member input	OEB TRM V7, SAG member input.	2019 Integrated Electricity and Gas Achievable Potential Study
Windows	New York TRM V10 - Window	Iowa TRM V5 – 3.7.5	2019 Integrated Electricity and Gas Achievable Potential Study, ENERGY STAR V7 Analysis Report, MI MEMD
High Speed Door	SAG member data	Illinois TRM V11 - 4.8.2	Guidehouse assumptions
Door Dock Seals	OEB TRM V7	OEB TRM V7	2019 Integrated Electricity and Gas Achievable Potential Study; Technical suitability provided by a SAG member
Smart Thermostat (Small Commercial)	Illinois TRM V11 - 4.4.48	Illinois TRM V11 - 4.8.48	2019 Integrated Electricity and Gas Achievable Potential Study (SaskPower PS)

Measure Name	Savings Source(s)	Cost Source(s)	Applicability Factors Source(s)
Kitchen Demand Control Ventilation	OEB TRM V7	OEB TRM V7	2019 Integrated Electricity and Gas Achievable Potential Study, CBSA, SDG&E 2012 Workpaper
Demand Control Ventilation	OEB TRM V7, SAG member	OEB TRM V7	SAG member inputs
Energy Recovery Ventilation	OEB TRM V7	OEB TRM V7	2019 Integrated Electricity and Gas Achievable Potential Study, Xcel Potential Study; Saturation from SAG member input
Destratification Fans	OEB TRM V7	OEB TRM V7	2019 Integrated Electricity and Gas Achievable Potential Study, SAG inputs
Condensing Make-Up Air Unit (MUA)	OEB TRM V7	OEB TRM V7	2019 Integrated Electricity and Gas Achievable Potential Study, Xcel PS, Union gas end use survey
Boiler Controls	Illinois TRM V11 - 4.4.4, 4.4.20-23	Illinois TRM V11 - 4.4.4, 4.4.20-23	2019 Integrated Electricity and Gas Achievable Potential Study, CBECS, BC Hydro PS
Steam Trap	Illinois TRM V11 - 4.4.16	Illinois TRM V11 - 4.4.16	Michigan Potential Study 2021; Technical suitability provided by a SAG member.
Electric Heat Pump Water Heater	Illinois TRM V11 - 4.3.1	Illinois TRM V11 - 4.3.1	2019 Integrated Electricity and Gas Achievable Potential Study; GH SME-based assumptions; Technical suitability provided by a SAG member.
Condensing Storage Water Heater	OEB TRM V7	OEB TRM V7	
Tankless Water Heater	OEB TRM V7	OEB TRM V7	
Gas Heat Pumps for Water Heating	Illinois TRM V11 - 4.4.55	Illinois TRM V11 - 4.4.55	2019 Integrated Electricity and Gas Achievable Potential Study, GH SME-based assumptions
Water Heating Controls	New York TRM V10 - DHW Control & Illinois TRM V11 4.3.8	Illinois TRM V11 - 4.3.8	CPUC Potential Study, California RASS, SAG member input
Drain Water Heat Recovery	New York TRM V10 – Drain Water Heat Recovery	U.S. Department of Energy (https://www.energy.gov/energysaver/drain-water-heat-recovery)	SAG and Guidehouse SME-based assumptions, 2019 Integrated Electricity and Gas Achievable Potential Study
Dishwasher	OEB TRM V7	OEB TRM V7	2019 Integrated Electricity and Gas Achievable Potential Study, National Grid Potential Study; SAG member input
Commercial Ozone Laundry Treatment	OEB TRM V7, SAG input	OEB TRM V7, SAG input	2019 Integrated Electricity and Gas Achievable Potential Study, IL TRM, SAG member input
Steam Cooker	OEB TRM V7	OEB TRM V7	2019 Integrated Electricity and Gas Achievable Potential Study, Xcel Energy PS
Fryer	OEB TRM V7	OEB TRM V7	2019 Integrated Electricity and Gas Achievable Potential Study, Xcel Energy PS
Combination Oven	OEB TRM V7	OEB TRM V7	2019 Integrated Electricity and Gas Achievable Potential Study, Arkansas TRM
Broiler	OEB TRM V7	OEB TRM V7	2019 Integrated Electricity and Gas Achievable Potential Study, Union Gas End Use Surveys

Measure Name	Savings Source(s)	Cost Source(s)	Applicability Factors Source(s)
Griddle	OEB TRM V7	OEB TRM V7	2019 Integrated Electricity and Gas Achievable Potential Study, Union Gas End Use Surveys
Strategic Energy Management	California Public Utilities Commission (CPUC) Potential Study	California Public Utilities Commission (CPUC) Potential Study	SAG and Guidehouse SME-based assumptions
Retrocommissioning	California Public Utilities Commission (CPUC) Potential Study	California Public Utilities Commission (CPUC) Potential Study	SAG and Guidehouse SME-based assumptions

B.2 Industrial Measure Source

The primary source for Industrial measure inputs is the IAC database. The contents of this database are recommendations provided by IAC auditors following the audits of industrial facilities. This database forms the underlying raw input for the Industrial measure characterizations, which have been developed by Guidehouse's Industrial team through judicious applications of bundling based on a careful review and assessment of database records.

IAC follows a standard process for auditing industrial sites and collecting all the relevant information about their equipment inventory. During a 1- or 2-day audit, the IAC team identifies potential energy efficiency measures that could be implemented at the site. The measures are identified based on IAC member expertise, and a detailed audit of the site equipment. The measures identified vary from site to site based on the individual site operation, opportunities and equipment present at the site. The IAC team members identify a list of measures and decide what measures should be investigated further. At this point, measures may be removed from the list only due to lack of applicability and actual installation concerns (i.e., technically infeasible recommendations are dropped). Once the measures have been finalised, the IAC team members then collect data related to these measures during the audit to further investigate savings potential and cost for these measures.

Some SAG members have presented the view that relying on the IAC database for savings estimates will understate potential. These SAG members have noted that the length of the audit constrains auditors to identifying relatively generic measures and that a more rigorous audit by more specialized auditors would likely identify significantly greater opportunities more specific to the individual sites.

These SAG members also noted that auditor recommendations will be biased toward measures with very short payback periods and so more likely to be adopted by the auditee, and may in many cases (given the available time) not identify additional measures that may be cost-effective from a total resource perspective, but with a longer payback and so less likely to be adopted.

The Guidehouse team has in the past noted the importance of primary data-collection efforts, and the use of industry-specific experts in developing measure input assumptions that can be leveraged in potential studies. This was a recommendation by members of the Guidehouse team in the 2019 APS (see Section 10.2.2.1 of that document) and work conducted previously for the California Public Utilities Commission.[118] Such primary research could not be accommodated within the timeline of this study, but should be considered by OEB staff and stakeholders to inform energy efficiency and fuel switching potential estimation for the Industrial sector in the future.

B.3 Important Measure-Level Considerations

The OEB TRM does not include any electrification measures. As such, the characterization of these measures was developed on the basis of the base year disaggregation (savings), the information in other TRMs or as available on the internet (costs), and the informed opinion of the members of the SAG (costs and applicability). In some cases some non-electrification energy efficiency measures also required the development of input assumptions based in large part on the informed opinion of members of the SAG.

There is therefore considerable uncertainty attendant to certain aspects of these characterizations. Given that in some cases overall estimated potential can be quite sensitive to these assumptions, OEB staff have directed Guidehouse to document some of the measure assumptions that were subject to debate within the SAG.

A selection of these is presented below. This is not a comprehensive list; as noted above, the SAG contributed hundreds of comments and engaged in many hours of discussion and debate. The list below has been limited to those assumptions to which OEB staff believe Achievable potential is likely to be most sensitive, which are likely to be of additional interest to reviewers of the 2024 APS, or which SAG members specifically requested be noted in Guidehouse's reporting. This list is also primarily reflective of measure-level debates that transpired during the period in which the SAG was reviewing draft outputs of Technical, Economic, and Achievable potential.

The focus on issues identified in this period is a reflection of the reality that with the results available to them, members of the SAG were better able to assess the materiality of any adjustment to measure inputs on the final outcome. It is Guidehouse's expectation that this resulted in SAG members prioritizing their review and feedback of those measures which they believed to be most important to the outcome of the study, measure updates which therefore merit a more detailed description in the sub-sections that follow below.

The sub-sections below address:

- **Residential Measures**
    - Residential Space-Heating Electrification Measure Versions
    - Residential Air Source Heat Pump Equipment Costs
    - Residential Space Heating Electrification Panel Costs (Service Upgrades)

[118] See slide 14 of 35 of
Guidehouse, prepared for the CPUC, *Potential and Goals Studies: Top-Down Stakeholder Presentation 2*, April 2022
https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/energy-efficiency/2021-potential-goals-study/top-down-stakeholder-presentation-part-2-report-20220331.pdf
And Section 2.2.1 of
Guidehouse, prepared for the CPUC, *2021 Energy Efficiency Top-Down Potential Prototype Analysis. Part 2: Addendum – Pathways to Applications of Top-Down Analysis*, March 2022
https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/energy-efficiency/2021-potential-goals-study/cpuc-top-down-part-2-final.pdf

  - Residential Heat Pump Water Heaters
  - Residential Ancillary Air Sealing Benefits from Insulation Measures
  - Residential Professional Air Sealing
  - Residential Attic Insulation Framing Factor
  - Residential Windows
- **Commercial Measures**
  - Commercial Space-Heat Measure Definitions
  - Commercial Hybrid Space-Heating Electrification Technical Suitability
  - Commercial Space-Heating Electrification Incremental Cost Estimates

B.3.1 Residential Space-Heating Electrification Measure Versions

Four alternative versions of the air source heat pump measure were considered in the 2024 APS, consistent with the guidelines provided by Canmet in its ASHP sizing and selection guide.[119] Naming of these versions of the measure follow the Canmet convention of measures 4A, 4B, 4C, and 4D.

Some of the key features of each version of the measure are summarized in Table 25 below.

Table 25. Residential ASHP Groupings

	4A	4B	4C	4D
Auxiliary Heat Source	Gas	Gas	Gas	Electric Resistance
Heat Capacity Sizing	Sized for 100% of design cooling load.	Sized for 125% of design cooling load.	Sized for design heating load	Sized for design heating load
Heat Pump Type	Standard air source heat pump.	Standard air source heat pump.	Cold-climate air source heat pump	Cold-climate air source heat pump
Winter Peak Demand Assumption	No impact, gas auxiliary heating in use. Installers following program guidelines set system to call for gas heat when outdoor temperatures fall below a pre-specified value. Gas is used frequently in the heating season.	No impact, gas auxiliary heating in use. Installers following program guidelines set system to call for gas heat when outdoor temperatures fall below a pre-specified value that is lower than the 4A case value. Gas is used moderately in the heating season.	No impact, gas auxiliary heating in use. Installers following program guidelines set system to call for gas heat when outdoor temperatures fall below the design temperature assumed by electricity system planners when projecting winter peak demand. Gas is used very infrequently – only in extreme conditions.	Assume effective COP of 1.25 at time of system peak (per SAG recommendation), and a winter peak coincident demand factor of 1.

A separate iteration of each version was characterized, by sub-sector (Detached, Detached Low Income, Attached/Other, Attached/Other – Low Income) and climate zone (North, South).

[119] Natural Resources Canada, CanmetENERGY, *Air-Source Heat Pump Sizing and Selection Guide*, Version 1.0, December 2020 **https://natural-resources.canada.ca/sites/nrcan/files/canmetenergy/pdf/ASHP%20Sizing%20and%20Selection%20Guide%20(EN).pdf**

Differences in savings by climate zone were based on geographically distinct savings estimated in the EGI heat pump study (see Table 23, above) for the different types of equipment. The "north" and "south" versions of the measures were based on the average heating loads of heat pumps located in Thunder Bay, and Toronto, respectively, in the EGI heat pump study.

The timing of coincident system peak demand for the purposes of this study is assumed to be consistent with the assumptions employed by the IESO for the value of system capacity (the cost of a marginal new resource) provided in its IRRP Guidelines[120], and with the seasonal timing of peak under projected design conditions in the 2022 APO.[121]The assumption that the hybrid measures (i.e., with gas auxiliary heat) are supplying heat entirely using the non-electric auxiliary heating source depends in part on the assumption that system peak conditions (i.e., the temperatures aligned with forecast peak demand values that drive system planning decisions and therefore incur system costs for new marginal resources) occur very infrequently.

Should, in the future, valuation of system winter peak demand change to include more hours, Guidehouse recommends that the winter peak demand impact assumptions of the measure characterization be re-assessed..

No iteration of the 4D version of the measure as it is currently defined is cost-effective after 2025 in any of the Achievable potential scenarios – principally as a result of the peak demand impact. The 4D version of this measure would, additionally not be cost-effective in *any* year if the analysis were updated to use the most current IESO assumption[122] (2030) for the first year in which Ontario will once more be winter-peaking.[123]

A more expansive definition of peak demand (e.g., the definition of winter peak demand identified in the IESO's EM&V protocols as average demand between 6pm and 8pm on non-holiday weekdays in December through February – approximately 120 hours) would reduce the peak demand value of the 4D measure since average temperatures in many of those hours would be much higher than the system design temperature for peak demand forecasting, but would conversely *increase* the peak demand value of the 4C measure since no gas back-up would be running in many of those hours. Cost-effectiveness for space-heating measures, and thus natural gas achievable potential, is likely to be sensitive to assumptions about the value of peak capacity and the timing of the demand that requires incremental peak capacity.

B.3.2 Residential Air Source Heat Pump Equipment Costs

There was some debate within the SAG as to whether the estimated equipment costs were comprehensive for the 4D version of the Residential ASHP measure.

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[120] Independent Electricity System Operator, *Integrated Regional Resource Plans: Guide to Assessing Non-Wires Alternatives*, May 2023

Available at: **https://www.ieso.ca/Get-Involved/Regional-Planning/About-Regional-Planning/Planning-Information-and-Data**

[121] Although the 2024 APO appeared prior to the completion of the 2023 APS, this study was sufficiently advanced by that time that a thorough update of the input values drawn from the 2022 APO was not practical.

[122] See, Independent Electricity System Operator, *Six Graphs and a Map: 2024 Annual Planning Outlook and Emissions Update*, March 2024

https://www.ieso.ca/Powering-Tomorrow/2024/Six-Graphs-and-a-Map-2024-Annual-Planning-Outlook-and-Emissions-Update

[123] Because of the publication date of the IESO's 2024 APO update, the updated assumptions that this provided could not be accommodated into the 2023 APS, which reflects the assumption of the 2022 APO that Ontario will become winter peaking in 2036.

The primary source for efficient equipment costs was the IL TRM V11 (Section 5.3.1). This source characterizes the fixed and variable (USD$ per ton) cost of ASHPs by SEER level.[124] Measures 4A and 4B were assumed to be represented by the IL TRM costs for the SEER 16 version, and 4C and 4D were assumed to be represented by the IL TRM costs for the SEER 18 version. OEB staff directed Guidehouse to use the base equipment cost estimates drawn from Ontario retailer advertised prices recommended by the SAG to compare to the efficient equipment prices noted above to derive an incremental cost for this measure.

One member of the SAG expressed a concern about the estimated equipment costs for the 4D case, based on the above source. This SAG member indicated that they did not believe that the IL TRM costs included the cost of an air handler and fan coil, and that these costs should be added to the estimated efficient equipment costs for the 4D case. Other SAG members disagreed and OEB staff directed Guidehouse to assume that the efficient equipment costs included all required equipment.

B.3.3 Residential Space Heating Electrification Panel Costs (Service Upgrades)

The non-equipment incremental costs related to the four Residential air source heat pump measures (4A through 4D) were the subject of significant debate by the SAG.

All members of the SAG agreed that for full electrification (the 4D) case some incremental cost should be included to account for the cost of electrical panel service upgrades that some customers would require in order to accommodate the demand associated with full electrification. No consensus could be reached, however, on the appropriate value to use for each of the heat pump versions.

Although ranges of estimates are available from a variety of sources (some of which are identified below), these ranges tend to be very wide and are unaccompanied by sufficient information to allow reviewers to determine whether these are appropriate for the Ontario context. Likewise, there is no information available to indicate the share of Ontario households by service level (e.g., 200 amp, 60 amp, 30 amp, etc.) This means that it is unclear what adjustment to apply to estimated incremental average panel upgrade costs to account for the fact that some existing share of Ontario households would not require the upgrade at all..

In the initial stages of review of the Technical and Economic potential, the SAG agreed to assume an incremental $1,000 cost for the 4D version of the Residential cold climate ASHP measure to capture the costs of electrical upgrades. This initial value was assumed to reflect both distributional and attributional assumptions.

The “distributional” assumption being that some share of Residential customers already have 200 amp service, and the “attributional” assumptions to reflect the fact that (for the purposes of cost-effectiveness testing) the panel upgrade might be undertaken anyway to allow for the installation of a Level 2 electric vehicle supply equipment (EVSE – a charger), and that the life of the panel upgrade would extend well past the life of the efficient equipment (the cold climate heat pump).

Further discussion by the SAG highlighted the fact that the attributional effects may impact cost-effectiveness but would be unlikely to impact customer economics and the decision to adopt the

[124] Version 12 of the IL TRM has updated the range categories to use SEER2 rather than SEER, but the estimated costs remain the same once the conversion from SEER2 to SEER is applied.

measure. Given that it is impractical, in Guidehouse's model, to model a single measure with two sets of costs (one for cost-effectiveness and one for customer economics) it was determined that the attributional assumptions about cost should be excluded. Including attributional assumptions (e.g., that some of the panel upgrade cost should be attributed to EV-enabling upgrades, that some of the panel upgrade cost should be attributed to subsequent equipment installations due to the very long life of the panel upgrade compared to the efficient equipment, etc.) improves measure cost-effectiveness because it reduces the amount of the panel upgrade cost that is attributed to the individual measure being assessed.

Some of the estimates of panel upgrade costs included:

- **IL TRM** This source recommends (in section 5.3.1 of Version 11), that an additional $2,000 (USD) be assumed for full displacement fuel installations

- **CPUC Potential and Goals Study.**[125] This study states that: "*The electric panel upgrade costs for single-family homes vary considerably, ranging from $1,900 to $8,188, with a rough average cost of about $4,600.*"

- **Electricity Canada.**[126] This article[127], cited in the EGI Heat Pump study to illustrate the potential cost of a panel upgrade references a "*soft quote… was anywhere between $3,000 - $5,000*"

One SAG member proposed that an incremental $1,000 be assumed for versions 4A, 4B, and 4C, and an incremental $3,000 be assumed for version 4D. The underlying assumption for the $1,000 increment for the hybrid installations was formalized by OEB staff as capturing incremental costs of upgrades required to individual breakers and cabling required to facilitate the additional load from the new equipment. The incremental $3,000 for the 4D version is intended to capture the more comprehensive upgrades required for complete electrification. In both cases these average incremental infrastructure costs assume that some share of the population will not require them, already having sufficient capacity to allow for partial or full electrification.

As a result of objections from other SAG members that it was inappropriate to assume incremental electrical upgrade costs for the version of the measure sized to the cooling load (4A), the final assumed incremental costs for electrical upgrades for each version of the Residential air source heat pump measure that OEB staff directed Guidehouse to use are shown in Table 26below.

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[125] See Appendix C, on PDF page 140 of 253 of:
Guidehouse, prepared for the California Public Utilities Commission, *2023 Energy Efficiency Potential and Goals Study*, June 2023
https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/energy-efficiency/2023-potential-goals-study/final-2023-group-e-pg-study-report.pdf

[126] Formerly the Canadian Electricity Association.

[127] Electricity Canada*, We are So Close to Affording Zero Carbon Electric Home Heating*, May 2022
https://www.electricity.ca/knowledge-centre/journal/we-are-so-close-to-affording-zero-carbon-electric-home-heating/

Table 26. Incremental Electrical Upgrade Costs

Measure Version	Incremental Cost of Electrical Upgrades
4A Sized for 100% of Cooling (Gas Backup)	0
4B Sized for 125% of Cooling (Gas Backup)	$1,000
4C Sized for Heating (Gas Backup)	$1,000
4D Sized for Heating (Electric Resistance Backup)	$3,000

Each of these estimated values is an average and so intended to implicitly capture the fact that some (unknown) share of customers installing the measure will not require a service upgrade.

Given the volume of hybrid systems installed in Ontario through the federal Greener Homes Grant (administered by EGI as the Home Efficiency Rebate Plus program) there should now be sufficient data available to validate or to adjust the assumptions above, either directly from reporting submitted by contractors, or through a formal process evaluation (trade ally surveys and interviews, etc.)

Unfortunately, neither the data nor the analysis such data would require to deliver a more robust estimate of incremental electrical upgrade costs for hybrid electrification was available to the OEB at the time these assumptions were developed by the SAG. Future development of TRM entries for this measure should support estimated incremental infrastructure cost assumptions with an analysis of the outcomes of hybrid installations to date in Ontario.

B.3.4 Residential Heat Pump Water Heaters

One SAG member proposed a technical suitability of 95% for heat pump water heaters. Another SAG member objected, and instead recommended using a value of 50%, citing an article by the U.S. Department of Energy[128] which states: "*Heat pump water heaters require installation in locations that remain in the 40º–90ºF (4.4º–32.2ºC) range year-round and provide at least 1,000 cubic feet (28.3 cubic meters) of air space around the water heater. Air passing over the evaporator can be exhausted to the room or outdoors.*"

Other SAG members dissented, citing anecdotal evidence that most Ontario water heaters are located in fully or semi-conditioned utility rooms or basements that are likely to meet these criteria (e.g., a 12-foot square room with a 7-foot ceiling). Following this discussion, OEB staff directed Guidehouse to assume a technical suitability of 85% for this measure.

A SAG member also noted a concern regarding the incremental cost of electrical work required to enable the installation of a heat pump water heater, replacing a gas storage water heater. Based on some SAG member feedback, Guidehouse proposed that a $500 incremental cost be

[128] U.S. Department of Energy, Energy Saver, *Heat Pump Water Heaters,* accessed February 2024 **https://www.energy.gov/energysaver/heat-pump-water-heaters#:~:text=Heat%20pump%20water%20heaters%20require,to%20the%20room%20or%20outdoors**

assumed. No SAG objection to this assumption was recorded, and OEB staff directed Guidehouse to assume $500 in incremental electrical upgrade costs for this measure.

A third SAG member concern with this measure related to the waste cooling it produces. Given that the heat pump water heater (HPWH) heats water by drawing from the warm air that surrounds it in its utility room, this will increase the premise thermal load. The v11 IL TRM (on which the measure characterization is based) provides for a correction factor for this, recommending that savings be scaled down by 5%. One SAG member recommended that this be replaced by a factor of 60.4%, or the share of hours in a year in which space heating is, on average required (5,293 hours per year).

Following objections from another SAG member that this adjustment was inappropriately large, and subsequent to discussion amongst the SAG that concluded that the 5% recommended by the IL TRM appeared inappropriately small, members of the Guidehouse team met with a member of the team responsible for the development of the Illinois TRM, who provided the Guidehouse team with a workbook for review. Following this review, the Guidehouse team concluded it would be most prudent, in the Ontario context, to derive an estimate of the interactive effect from another source.

The impact of this effect was estimated by adapting the algorithm provided by the PA TRM for estimating interactive effects.[129] This adjustment is applied as an energy adjustment, rather than as a percentage erosion of savings, but when converted to such for a comparison results in a value equivalent to approximately 23%, significantly higher than the 5% value recommended by the IL TRM, but lower than the 60.4% recommended by the first SAG member.

B.3.5 Residential Ancillary Air Sealing Benefits from Insulation Measures

In reviewing an initial draft of estimated Achievable potential, one SAG member recommended that the various insulation measures be updated to include savings resulting from air sealing outcomes that are achieved when insulation is installed. This SAG member identified that the IL TRM algorithm (and the underlying data upon which it was based) should be adjusted for the incremental air sealing impacts it offers.

This SAG member used data obtained from EGI's 2020 home retrofit program reporting to demonstrate that 96%, 81%, and 85% of the 14,000 participants that installed attic, basement, or wall insulation (respectively) achieved a more than 10% air leakage reduction. Based on this and some additional analysis circulated to the SAG and OEB staff via email, this SAG member recommended that:

- Attic insulation is assumed to deliver a 10% reduction in air leakage
- Wall insulation is assumed to deliver a 10% reduction in air leakage
- Basement insulation is assumed to deliver a 10% reduction in air leakage

[129] See section 2.3.1 of

State of Pennsylvania, Act 129 Energy Efficiency and Conservation Program & Act 213 Alternative Energy Portfolio Standards, *Technical Reference Manual Volume 2: Residential Measures*, Issued August 2019, revised February 2021

Available at: **https://www.puc.pa.gov/filing-resources/issues-laws-regulations/act-129/technical-reference-manual/**

Another SAG member disagreed objecting that these estimated reductions in air leakage were too high and that the first SAG member’s analysis failed to control for the fact that participants may have also installed mechanical equipment upgrades noting that such upgrades can deliver air sealing benefits. This SAG member recommended instead that values of 5%, 5%, and 3% be used.

The first SAG member repeated the analysis with sites with mechanical upgrades removed and found the conclusions did not change. OEB staff directed Guidehouse to apply the air leakage savings derived by the first SAG member to the appropriate insulation measures.

B.3.6 Residential Professional Air Sealing

Following a review of draft potential, one SAG member expressed concern about the estimated penetration of the Residential professional air sealing measure, indicating that there is no material capacity within the province of Ontario to deliver this service to the parameter specified in the measure characterization. In subsequent discussion between SAG members, there was a general consensus that some ramp-up in provincial delivery capacity was required, but disagreement between SAG members regarding the initially available capacity, and the speed at which it could grow.

In subsequent correspondence, the Guidehouse team proposed limiting the available market to 10% of the applicable market in year 1 of the period of analysis, and subsequently growing the available capacity on an annual basis. Though some SAG members indicated that this adjustment was acceptable, the first SAG member indicated that they estimated that this adjustment would only limit the available market to 25,000 homes in year 1. This SAG member proposed that an available market of 5,000 professional air sealing installations in the first year of the period of analysis be considered, noting that they believed even this to be an aggressive estimate.

OEB staff directed Guidehouse to impose a ceiling of 5,000 installations in the first year of the projected period of analysis (2024), and then allow the ceiling to grow for the subsequent four years, through to the end of 2028, to simulate the growth of market capacity to deliver the measure. Following 2028, the Guidehouse team was directed to remove this constraint and allow adoption to flow according to the standard model dynamics.

The Guidehouse DSMSim model does not include a capability to directly cap adoption for specific measures, so Guidehouse implemented the constraint through the application of a payback adder, calibrated so as to achieve the desired outcome (adoption not to exceed 5,000 in 2024). A concave decay function was applied to the adder, reducing the adder at an increasing rate until 2029 at which point it becomes zero. For context, in Scenario A of the Achievable potential this resulted in measure adoption by approximately 24,000 Residential sites in 2028 (the last year in which the constraint was applied).

B.3.7 Residential Attic Insulation Framing Factor

One SAG member noted that the IL TRM measure algorithm applies a 7% “framing factor” and recommended that Guidehouse consider adjusting this value. The framing factor is intended to control for the fact that ceiling joists occupy some attic space and limit the available volume of the attic that can be insulated.

This SAG member noted that the 2024 APS assumed R-value would likely require the addition of insulation above the joists, covering them and significantly diminishing the thermal bridge and recommended that the framing factor for the added insulation should be different to that of the existing insulation.

Lacking a specific value to apply, to make such an adjustment, OEB staff directed Guidehouse not to apply such an adjustment, but to note this concern in its reporting such that it could be addressed in any subsequent development of an attic insulation substantiation document or entry in the OEB's TRM.

B.3.8 Residential Windows

No SAG consensus could be reached on the appropriate replacement type for windows. One SAG member argued that although windows are not mechanical equipment and subject to the expectation of failure and the need for periodic replacement, in most homes windows possess a natural lifecycle and are periodically replaced by homeowners as part of other renovations.

Another SAG member objected, indicating that these measures should be treated (as they had been in the 2019 APS) as a retrofit (RET) and not a replace-on-burnout (ROB).

The difference in categorization impacts the way in which the applicable market in each year is defined, and the customer economics that drive the adoption decision. When a measure is a retrofit (RET) (as windows were treated in the 2019 APS), each year all households in the applicable market (i.e., with windows that align with the base technology assumption) make the choice whether or not to replace their windows.

Customer economics are driven by the full cost of the new windows. Since the baseline condition is doing nothing, the incremental cost is the full cost of the measure. The applicable market in each year is large, but the economics will be (relative to the alternative below) poor, so the share that adopts will be smaller.

When a measure is a replace-on-burnout (ROB) measure, the applicable market in each year making the decision to replace their windows is defined as one divided by the lifetime of the measure (in this case assumed to be 25 years). So in year the applicable market is much smaller than under the RET assumption. The incremental cost is, however, much lower. Since the modeling assumption is that houses have their windows replaced on average every 25 years, the cost of the efficiency measure is not incremental to the “do nothing” alternative, but incremental to the baseline replacement. This substantially reduces the incremental cost, and improves customer economics relative to the RET case.

The first SAG member's recommendation (that windows be treated as an ROB measure) was made on the basis that this SAG member believed this better reflects the reality of the decision-making process for this measure. The second SAG member expressed a practical concern that treating it as an ROB measure will substantially reduce the estimated incremental cost of the measure and might impact the DSM program administrator's ability to offer sufficiently meaningful incentives to motivate adoption.

OEB staff directed Guidehouse to treat the measure as ROB with a 25-year lifetime. Commercial sector windows are, consistent with the 2019 APS, still treated as RET measures.

B.3.9 Commercial Space-Heat Measure Definitions

This section of the appendix provides a description of how the Commercial space-heat electrification measures definitions were developed by Guidehouse in collaboration with the SAG.

The definition of these measures (and the process by which it was arrived at) is essential context for understanding the development of the estimated Technical Suitability applicability factor, and the estimated measure costs (described in greater detail in the two sections immediately below).

The 2024 APS measure list includes four measures for the electrification of Commercial space-heating:

- Cold-Climate Heat Pump (ccHP) – full electrification.
- ASHP with Gas Heating (Hybrid) – partial electrification.
- Ductless Mini-Split Heat Pump – full electrification.
- Ground Source Heat Pump – full electrification.

Draft estimates of Achievable potential showed very little potential from the full electrification measures.[130] The hybrid ASHP measure, however, showed significant potential and was the subject of the most active debate by members of the SAG.

A significant impediment to the SAG, OEB staff and Guidehouse aligning on the appropriate costs and savings assumptions was the breadth of the measure definition, which had deliberately been specified only at a relatively high level such that the measure could be applied to a high proportion of Commercial buildings.

Early in the measure characterization process it was generally agreed that the share of larger commercial buildings for which space heating electrification is technically feasible is much smaller than for smaller commercial buildings. It was initially assumed, however, that *some* share of larger buildings could be electrified (partially or fully) with the hybrid and cold climate ASHP measures.

Retaining the assumption that some share of larger buildings could be electrified led to significant challenges in developing cost and savings estimates for the commercial heat pump measures (more details on cost estimation in Section B.3.11 below). Guidehouse's understanding[131], based on the information provided by a first SAG member, is that the range of costs and savings is likely to vary considerably across Commercial installations (in particular larger buildings) for two reasons:

- Electrification of space-heating with heat pumps outside of the use of packaged roof-top units (RTUs) or mini-split systems is a highly building-specific (customized) solution. Such customized solutions may require on-site engineering, the cost of which is impossible to reliably estimate with the data available to Guidehouse and the SAG.
- Where RTUs are used for larger buildings, they must be understood less as individual pieces of equipment that can be replaced ad-hoc by electric alternatives as they reach end of life, but rather as components of a system – elements of an array.

[130] This was a result principally of the incremental winter peak demand imposed by these measures which reduces the measures' cost-effectiveness (and thus available incentives), and significantly impacts customer utility bills (via the customer distribution peak demand charge).

[131] The stakeholder providing this context has many years of professional technical expertise with natural gas DSM and DSM measures, and no objections were made by other stakeholders, but the Guidehouse team did not undertake any market research to validate these claims, as doing so would be beyond the scope of this study.

- In buildings where RTUs are deployed as an array it is unfeasible (due to electrical upgrades and complexities related to the HVAC control systems) to replace only a single gas-fired RTU with a fully electric RTU.
- In buildings with arrays of RTUs there is often overlap in the zones heated by individual RTUs. This means that (for example) replacing a single conventional gas-fired RTU with a hybrid (gas auxiliary heat) ASHP would not deliver the measure-level estimated savings because the higher grade heat from the conventional units would displace that from the heat pump.

This SAG member recommended that, for these reasons, electrification measures in existing buildings should be considered as retrofit (RET) rather than replace-on-burnout (ROB) measures.

In response to this feedback, Guidehouse developed a more targeted definition of hybrid ASHP and the commercial ccASHP measures applied in a replace-on-burnout scenario. For the purposes of this study, therefore, hybrid ASHP and ccASHP (ROB) measures are defined to apply:

- Only to smaller buildings equipped with individual RTUs or with small arrays (e.g., four or fewer) of RTUs
- Only to buildings where all the RTUs are approximately the same age (e.g., installed together at time of construction or renovation) and therefore on a similar replacement cycle.

The measure definition further assumes that DSM program support will include some encouragement for facility managers to consider proactive replacement[132] of arrays with equipment sufficiently near the end of the EUL that the depreciated value of the unit is so low that dual baseline considerations are unnecessary. That is, the assumption is of a DSM program design focused on the simultaneous replacement of all RTUs in a given building.

Finally, the hybrid ASHP measure was assumed to be sized for the building cooling load, such that measure incremental costs do not need to account for costs related to a panel upgrade.

This more constrained measure definition was recognized to exclude many potential opportunities for electrification in larger buildings. OEB staff directed Guidehouse to adopt this definition, developed in response to SAG feedback and intended to enable members of the SAG and Guidehouse staff – given the data available – to align on estimated savings and costs within the timeframe required for study completion.[133]

Future efforts to quantify the potential for the electrification (partial or complete) of space heating in commercial buildings must address the uncertainties identified by members of the SAG in this study and should include primary data collection and analysis. Such analysis would most productively support future electrification potential projections managed by OEB staff if the planning, collection, and analysis of primary data was subject to oversight by members of the

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[132] The U.S. Department of Energy has, for example, produced documentation to assist program administrators and facility managers develop a business case for RTUs that are past their economically useful life, but still within their operational life, see:

U.S. Department of Energy, Better Buildings, *Business Case for Proactive Rooftop Unit (RTU) Replacement*, November 2015

https://betterbuildingssolutioncenter.energy.gov/sites/default/files/attachments/ARC_Business_Case.pdf

[133] The stakeholder that had provided the feedback summarized above requested that the record note that they believed this assumed definition was "*not reflective of reality and therefore does not provide actionable findings to inform forecasts for potential/budgets.*"

same technical SAG subcommittee that participated in the discussions on this subject for the 2024 APS.

B.3.10 Commercial Hybrid Space-Heating Electrification Technical Suitability

An important driver of the estimated Achievable potential of the hybrid ASHP Commercial measure is the value applied as its Technical Suitability. This applicability factor constrains the size of the available market, and so the potential of the measure. This sub-section of this appendix is intended to describe the process by which these values were arrived at.

During the initial measure review process, one SAG member noted that a potential study in another jurisdiction had excluded large building boiler systems from consideration as candidates for replacement by air- and ground-source heat pumps. This SAG member recommended that Guidehouse update its applicability factors to exclude larger building sub-sectors. OEB staff directed Guidehouse to apply this recommendation to the study.

Other SAG members noted that boiler systems are not universal in large buildings and opportunities – though fewer than in smaller buildings – may still be present. Accordingly, the first SAG member recommended an updated set of Technical Suitability factors for the ccASHP measure. The Technical Suitability factors for the ccASHP and hybrid ASHP (gas backup) were defined (for ROB measures), at this stage of the study as noted in Table 27 below.

Table 27. Electrification Measure Technical Suitability – Revision 1

Sub-Sector	ccASHP (ROB and NEW)	Hybrid ASHP (ROB and NEW)
Hospital	5%	5%
Hotel – Large	5%	5%
Hotel – Small	100%	100%
Long Term Care	20%	20%
Multi-residential – Large	5%	5%
Multi-residential – Large – Low-Income	5%	5%
Multi-residential – Medium	75%	75%
Multi-residential – Medium – Low Income	75%	75%
Multi-residential – Small	100%	100%
Multi-residential – Small – Low-Income	100%	100%
Office – Large	5%	5%
Office – Small	100%	100%
Other Commercial – Large	20%	20%
Other Commercial – Small	100%	100%
Restaurant	100%	100%
Retail – Large	50%	50%
Retail – Small	100%	100%
Schools – Large	50%	50%
Schools – Small	100%	100%

Sub-Sector	ccASHP (ROB and NEW)	Hybrid ASHP (ROB and NEW)
University/College	5%	5%
Warehousing – Large	20%	20%
Warehousing - Small	100%	100%

SAG feedback related to the first draft of Commercial Achievable potential focused on the various heat pump measures. In follow-up correspondence to that meeting the SAG member that had provided recommended Technical Suitability updates for the ccASHP measure previously provided a set of updated recommended applicability factors.

This update provided a Technical Suitability estimate for each heat pump measure and sub-sector, as well a novel applicability factor created by this SAG member, a Market Applicability factor. This factor was intended to capture market barriers to adoption. This SAG member identified supply chain issues as a major driver and noted that its recommendations considered consultations with customers, contractors, distributors, and subject matter experts from other jurisdictions as well as a review of DSM plans from other jurisdictions. The SAG member also noted that its analysis reflected its view that heat pumps – because of supply chain challenges in the market – should not be categorized as replace-on-burnout measures.

This SAG member provided these updated estimated Technical Suitability and Market Applicability factors for the ccASHP (ROB and NEW), hybrid ASHP (ROB only), Gas heat pump (ROB only), ductless mini-split heat pump (DMSHP) (ROB only), and ground source heat pump (GSHP) (ROB and NEW).[134] For concision, only the proposed Technical Suitability and Market Applicability factors for the ccASHP (ROB) and hybrid ASHP (ROB) are presented below.

Table 28. ccASHP Technical Suitability (Replace-on-Burnout) – Revision 2

Sub-Sector	Proposed Technical Suitability	Proposed Market Applicability	Overall Applicability Factor
Hospital	25%	0.50%	0.13%
Hotel – Large	25%	0.50%	0.13%
Hotel – Small	35%	0.50%	0.18%
Long Term Care	38%	0.50%	0.19%
Multi-residential – Large	38%	0.50%	0.19%
Multi-residential – Large – Low-Income	38%	0.50%	0.19%
Multi-residential – Medium	35%	0.50%	0.18%
Multi-residential – Medium – Low Income	35%	0.50%	0.18%
Multi-residential – Small	35%	0.50%	0.18%

[134] These estimates are presented below solely to provide sufficient context for reviewers of this report to understand the evolution of the Technical Suitability for these important measures. These values were developed under a very constrained timeline (five calendar days) with the implicit understanding that they were intended as a “working” estimate, potentially subject to further adjustment based on the informed opinions of other stakeholders. Guidehouse expects that in a more formal setting and with more time available for research and analysis these values might differ.

Sub-Sector	Proposed Technical Suitability	Proposed Market Applicability	Overall Applicability Factor
Multi-residential – Small – Low-Income	35%	0.50%	0.18%
Office – Large	38%	0.50%	0.19%
Office – Small	35%	0.50%	0.18%
Other Commercial – Large	38%	0.50%	0.19%
Other Commercial – Small	35%	0.50%	0.18%
Restaurant	35%	0.50%	0.18%
Retail – Large	38%	0.50%	0.19%
Retail – Small	35%	0.50%	0.18%
Schools – Large	50%	0.50%	0.25%
Schools – Small	50%	0.50%	0.25%
University/College	25%	0.50%	0.13%
Warehousing – Large	25%	0.50%	0.13%
Warehousing - Small	45%	0.50%	0.23%

The appropriate interpretation of the values above is each year approximately 6.25% of existing heating installations in each sub-sector is eligible for end-of-life replacement (based on an estimated useful life of 16 years). In (for example) the Hotel – Small sub-sector, it might be possible to incentivize the installation of ccASHPs in 0.18% of these – i.e., ccASHPs might be installed in approximately 0.01125% of existing small hotels in each year[135] of the period of projection.

- **Technical Suitability** estimates for the ccASHP measure above were noted by the SAG member to have been informed by their expectations related to service line upgrades, grid constraints, and/or timing issues to allow for capacity upgrades required to facilitate the replacement of gas-fired with fully electric equipment.
- **Market Applicability** estimates were noted by the SAG member to have been informed by their expectation that larger buildings would require more custom solutions, that a single A/C unit failure will not lead to an entire HVAC system overhaul, and because of supply chain issues.

Table 29. Hybrid ASHP (Gas Backup) Technical Suitability (Replace-on-Burnout) – Revision 2

Sub-Sector	Proposed Technical Suitability	Proposed Market Applicability	Overall Applicability Factor
Hospital	50%	1%	0.50%
Hotel – Large	50%	1%	0.50%
Hotel – Small	70%	10%	7.00%
Long Term Care	75%	1%	0.75%
Multi-residential – Large	75%	1%	0.75%

[135] Given the number of small hotel consumers in the base year data, this is equivalent to an upper limit of approximately 0.3 measure installations per year, or one installation every three years.

Sub-Sector	Proposed Technical Suitability	Proposed Market Applicability	Overall Applicability Factor
Multi-residential – Large – Low-Income	75%	1%	0.75%
Multi-residential – Medium	70%	10%	7.00%
Multi-residential – Medium – Low Income	70%	10%	7.00%
Multi-residential – Small	70%	10%	7.00%
Multi-residential – Small – Low-Income	70%	10%	7.00%
Office – Large	75%	1%	0.75%
Office – Small	70%	10%	7.00%
Other Commercial – Large	75%	1%	0.75%
Other Commercial – Small	70%	10%	7.00%
Restaurant	70%	10%	7.00%
Retail – Large	75%	1%	0.75%
Retail – Small	70%	10%	7.00%
Schools – Large	25%	1%	0.25%
Schools – Small	25%	1%	0.25%
University/College	50%	1%	0.50%
Warehousing – Large	50%	10%	5.00%
Warehousing - Small	90%	10%	9.00%

The hybrid ASHP measure is assumed to have been sized for the building's design cooling load to avoid issues related to electrical service upgrades. Resolving with the SAG to the compromise noted in Section B.3.3 for Residential infrastructure upgrade costs was time-consuming, contentious, and unsatisfactory for all participating SAG members (in different ways). Resolving these questions for the more complex, idiosyncratic, and opaque Commercial sector was determined by OEB staff to be improbably unlikely within the time available to complete the study, hence the sizing assumption.

- **Technical Suitability** estimates for the ccASHP measure above were noted by the SAG member to have been informed by their expectations few schools are currently equipped with cooling, and that for some sub-sectors (e.g., Hotel – Small) require a mini-split solution.

- **Market Applicability** estimates were noted by the SAG member to have been informed by their expectation that larger buildings would require more custom solutions, that a single A/C unit failure will not lead to an entire HVAC system overhaul, and because of supply chain issues.

Other SAG members and OEB staff acknowledged the importance of considering the supply chain issues, but noted that such issues tend to be transitory, that market transformation is a generally accepted goal of DSM program design, and that it was therefore not appropriate to "lock in" the assumption that bottlenecks in supply are permanent.

In parallel to the discussion of Technical Suitability, estimated measure costs and savings were subjects of active discussion amongst the SAG. As noted in Section B.3.9, above, issues related to the range of possible installation types made alignment on cost and savings assumptions challenging, and it was proposed by the Guidehouse team that the ccASHP and hybrid ASHP measures be defined more specifically as being replacements specifically for RTUs and to be considered only for the smaller sub-sectors.

The SAG member that had proposed the updated applicability factors agreed that these elements of the measure redefinition were reasonable under the circumstances and agreed to revise their proposed Technical Suitability values accordingly (though, as noted above in Section B.3.9, this SAG member did object to some of the other assumptions included in the updated definition).

An additional factor considered in this SAG member's re-estimation of Technical Suitability was the removal from their analysis of the Market Applicability factor. Guidehouse's model included no corresponding parameter for this, and, as noted above, the remaining SAG members and OEB staff agreed that it was inappropriate to set a permanent decrement to Technical Suitability based on restrictions to market supply.

Guidehouse therefore proposed implementing a cap on adoption in the first year of the period of projection. This cap would be gradually relaxed over time and then removed altogether under the assumption that production and distribution would eventually "catch up" to demand.

Primary research related to assessing the persistence of supply constraints was not part of the scope of this study. Guidehouse therefore developed a strawman proposal for SAG consideration – a vector describing a ceiling on adoption by the applicable market that increases over time until it disappears entirely at the end of 2029.[136] This proposal was based on the assumption that after the year in which the program was introduced, five more years of concerted program activity designed to address questions of market transformation and stimulate consumer demand would be sufficient incentive for profit maximizing vendors to adapt their process and eliminate the supply constraint.

Guidehouse's proposed cap to adoption was 5% of the applicable market in 2024, escalating to 22% of the applicable market by the end of 2029, after which it would not apply.[137] This was developed as a strawman, with the intention of developing a more accurate estimate via a consensus of expert opinion. The first SAG member expressed concerns about this estimate, noting significant uncertainty regarding manufacturing and installer capacity and its expectation that lead times following orders for this equipment is 20 or more weeks.

Neither this SAG member nor any others offered any alternative estimates, and so OEB staff directed Guidehouse to apply the proposed cap vector on adoption to the hybrid ASHP measure.

[136] In correspondence between SAG members, OEB staff, and the Guidehouse team there was some ambiguity as to the final year in which the cap was applied. The final year in which the cap on adoption was applied for the final model run was 2029.

[137] The mechanism within the DSMsim model through which this was applied is the "Awareness" factor. This is a factor that limits adoption in the model as a function of prior year adoption, and of assumed levels of marketing. Rather than allowing this factor to evolve over time according to the standard model dynamics the vector of annual caps on adoption were applied over the period noted above.

Subsequent to the specification of the cap in the first year, though prior to the communication to SAG members of the proposed change in that cap over time, the first SAG member provided, at the request of OEB staff and the Guidehouse team, a third revision[138] of Technical Suitability, one reflecting the revised definition of the measure, and the assumption that an additional factor to account for supply constraints would be applied in potential estimation for the hybrid ASHP. Updated estimates of Technical Suitability for gas heat pumps (same values as hybrid ASHP), and ductless mini-split heat pumps (full electrification) (same values as ccASHP) were also provided. OEB staff reviewed these proposed values and directed Guidehouse to use them to estimate the potential values presented in this report.

Table 30. Hybrid ASHP (ROB) and ccASHP (ROB and NEW) Technical Suitability – Revision 3

Sub-Sector	Hybrid ASHP (ROB)	ccASHP (ROB)	ccASHP (NEW)
Hospital	0%	0%	50%
Hotel – Large	0%	0%	50%
Hotel – Small	70%	1%	50%
Long Term Care	20%	0%	50%
Multi-residential – Large	0%	0%	50%
Multi-residential – Large – Low-Income	0%	0%	50%
Multi-residential – Medium	0%	0%	50%
Multi-residential – Medium – Low Income	0%	0%	50%
Multi-residential – Small	70%	1%	50%
Multi-residential – Small – Low-Income	70%	1%	50%
Office – Large	0%	0%	50%
Office – Small	70%	1%	50%
Other Commercial – Large	0%	0%	50%
Other Commercial – Small	70%	1%	50%
Restaurant	70%	1%	50%
Retail – Large	0%	0%	50%
Retail – Small	70%	1%	50%
Schools – Large	0%	0%	50%
Schools – Small	0%	0%	50%
University/College	0%	0%	50%
Warehousing – Large	25%	0%	50%
Warehousing - Small	25%	1%	50%

[138] As noted above, the context in which these estimates was developed is important when assessing them, in particular in comparing them to any future values derived from market characterization analysis. The stakeholder developed and provided these values in six calendar days at the request of OEB staff in order that the final round of estimated potential could be estimated under the revised timeline with the implicit understanding of all involved that these values are highly uncertain, and that additional work will be required in the future to develop a more refined estimate for a potentially altered definition of the measures in question.

B.3.11 Commercial Space-Heating Electrification Incremental Cost Estimates

Costs are another major driver of the potential adoption estimated in the Achievable potential scenarios. Of all the space-heating electrification measures, the costs of the hybrid ASHP are most relevant. This is because, as noted before, the peak demand impacts of the full electrification measures substantially reduce net system benefits (and so limit available incentives) as well as impact customer utility bills (and so reduce payback). The impact of these factors on potential adoption substantially reduces the sensitivity of these measures' potential to changes in incremental cost. Because the hybrid ASHP is assumed to use its auxiliary gas system on the coldest winter days, this measure does not have any winter peak demand impact and changes to this set of measures' incremental cost is more impactful on overall potential than for the full electrification measure.

Costs for the hybrid ASHP measure underwent several revisions over the course of the study. Initially, the same measure incremental cost, derived from the Illinois TRM, was applied to all sub-sectors. A SAG member noted that in larger buildings requiring boilers, the boiler would still be required to provide back-up heat and that the appropriate cost value to apply was the *total* measure cost and not the incremental measure cost. Guidehouse implemented this change at the direction of OEB staff, though continued to use the Illinois TRM incremental costs for installations in sub-sectors where the base equipment was assumed to be a furnace (i.e., smaller building sub-sectors).

Initial draft estimates of Commercial Achievable potential presented to the SAG were very high, in all scenarios, largely due to the very low assumed incremental costs of the hybrid ASHP measure. The reason for the low incremental cost was principally the assumption that hybrid ASHP measures were replacing a central A/C and commercial furnace measure, and so the increment in cost was driven primarily by the difference in cost between the ASHP and the A/C unit.

The Guidehouse team identified for the SAG its concern that incremental costs were understated because they failed to account for the likelihood that though a ASHP on its own was only slightly more costly than a comparable air-conditioning unit, a combined ASHP and furnace RTU would likely, due to its relative novelty, be considerably more costly than a combined A/C and furnace RTU. Guidehouse accordingly requested the assistance of the SAG in identifying appropriate costs.

In the course of subsequent research, OEB staff identified a recently deployed Ontario hybrid ASHP RTU pilot[139] and worked with SAG members to identify what data could be drawn from this source. One SAG member noted that supply chain constraints had delayed installations and so no data were yet available from the pilot. The team was, however, able to share some cost quotes for hybrid RTUs it had obtained in the course of its research.

The Guidehouse team used this source to derive an estimate of the fixed ($2,605) and variable ($148 per ton) incremental cost for a hybrid ASHP RTU. Applied to the simple average of the

[139] Heating Plumbing Air Conditioning Magazine advertisement: "Earn incentives on every hybrid rooftop unit" **https://www.hpacmag.com/eBlast/get-hybrid-rtu-incentives-from-enbridge-gas/**

system sizes included in the data provided by a SAG member, this yielded a blended average incremental cost of approximately $977 per ton.[140]

The estimated base case fixed cost ($6,100) and variable cost ($1,810 per ton) when applied to the simple average of system sizes included in the data this yields a blended average base case cost of $2,898 per ton. This means that the incremental cost of the hybrid ASHP unit was approximately 34% of the cost of the baseline unit. This share is quite high compared to some approximately comparable U.S. DOE-published information on costs for ASHPs and rooftop A/C units.

The U.S. DOE has published estimates of the installed costs of rooftop A/C and ASHP units as part of the EIA's Technology Forecast Updates.[141] In this document, the installed cost of an ASHP RTU (2023, "New Standard"[142]) is $165 USD per kBtu/hr and the estimated installed cost of the rooftop AC (2023, "New Standard" [143]) is $151 USD per kBtu/hr. The incremental cost is $USD 14 per kBtu/hr, or approximately 9% of baseline equipment costs, in contrast to the 34% estimated for the hybrid ASHP (see above).

Acknowledging that this comparison is imperfect, Guidehouse nonetheless concluded based on this finding and the observable trend in pricing for emerging DSM technologies, that a major driver of the higher incremental cost could be the niche nature of this equipment. Accordingly Guidehouse concluded that it would be reasonable to assume that this cost would decline over time as installations of hybrid ASHP became more widespread.

The Guidehouse team therefore proposed to the SAG that costs for the hybrid ASHP should be assumed to decline over time, such that by 2029 the incremental cost of the measure had fallen from 34% of baseline equipment costs to 15% of baseline equipment costs.

Two members of the SAG supported this proposal without changes, noting the assumptions were reasonable given the information available. A third member of the SAG did not support this proposal, noting that they saw "*no evidence that commercial heat pump costs will decline at a material rate in the near term (5+ years)*".

OEB staff directed Guidehouse to apply the assumed decline in cost over time in its potential estimation.

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[140] The total cost (applied to the new construction – NEW – sub-sectors assumed to have a boiler as the base case heating equipment) had a fixed component of $8,705 (fixed) and $1,958 per ton (variable).

[141] U.S. Energy Information Administration prepared by Guidehouse, *EIA – Technology Forecast Updates – Residential and Commercial Building Technologies – Reference Case*, March 2023 **https://www.eia.gov/analysis/studies/buildings/equipcosts/pdf/appendix-a.pdf**

[142] See PDF page 140 of 263

[143] See PDF page 136 of 263

Appendix C. Technical Potential

This appendix presents additional detail regarding the development and outputs of the Technical Potential analysis. It is divided into three subsections:

1. Unconstrained Potential. Provides additional context for understanding what it means when Technical (and Economic) potential are presented, unconstrained by considerations of equipment turnover.

2. Measure Types. Provides an expanded description of the different measure replacement types and the differences in how Technical potential is estimated for each one.

3. Expanded Results. Provides additional results, including GHG impacts of Technical potential, and sub-sector-level splits of Technical potential.

C.1 Unconstrained Potential

Technical potential estimates are “unconstrained” by considerations of equipment turnover. Each year treated as independent of the others. What this means is that (for example), the Technical potential in 2030 is an estimate of all savings that are technically feasible in 2030: all retrofit (RET), and all replace-on-burnout (ROB) measures are replaced in a single year. All technically feasible new construction opportunities through they year in question are also filled by the most efficient measure immediately, though the treatment of new construction opportunities is subtly different from existing opportunities in order to fully account for the impact new construction has on building stock (more on this below in the discussion of Economic potential).

This differs from the 2019 APS in which Technical potential was constrained by equipment turnover, so care should be exercised in comparing the Technical potential of the two studies.

Guidehouse has chosen to adopt the unconstrained approach for the 2024 APS for two reasons.

- Firstly, accounting for equipment turnover (as in constrained potential) adds an effect that confounds the assessment of total Technical potential in any given year and therefore impedes the primary purpose of the Technical potential; to provide measure-level quality checks.
- Secondly, it aligns the 2024 APS to Guidehouse’s standard practice for potential estimation in other jurisdictions, as well as to that of other firms in the potential estimation space.

The presentation of unconstrained Technical and Economic potential is Guidehouse standard practice, and has been used in many previous studies and accepted by regulators, stakeholders and utilities. Previous studies developed by Guidehouse using unconstrained Technical and Economic potential include: Michigan (2021), Nova Scotia (2019, and 2024), Massachusetts (2024), National Grid (2020 and 2024), Xcel Energy (2022), CPUC (2020, 2022, 2024), Inter-Mountain Gas Company (2023).

Potential studies developed by other firms for a set of Florida utilities[144] and for Dominion Energy[145] also take this approach. This approach has *no* impact on Achievable potential and is employed to improve the diagnostic effectiveness of Technical and Economic potential by removing confounding effects of equipment turnover which are irrelevant when considering a theoretic (but not practically possible) upper limit of available potential.

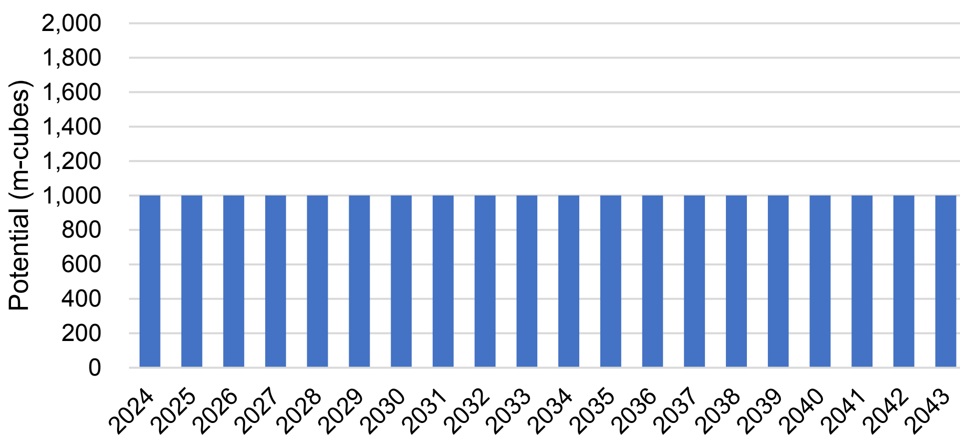
The stylized example below was developed to assist stakeholders in better understanding unconstrained Technical and Economic potential.

Consider the following simplified example:

- 10 existing customers in the entire province (10 in 2024, 10 in 2025, etc.)
- Only one measure in the entire province
  - Replace on burnout (ROB) type equipment measure
  - Useful life of 10 years
  - Technical suitability of 100% (i.e., all 10 customers could adopt this measure).
  - Saves 100 m-cubes per year.

In this case Technical potential would be 10 customers x 100 m-cubes = 1,000 m-cubes per year in every year of the period of analysis. That is, Technical potential would be flat over the entire period of the analysis as shown in Figure 78 below.

Figure 78. Stylized Example of Technical Potential – ROB Measures



Consider a second simplified example, this time for NEW construction. Assume:

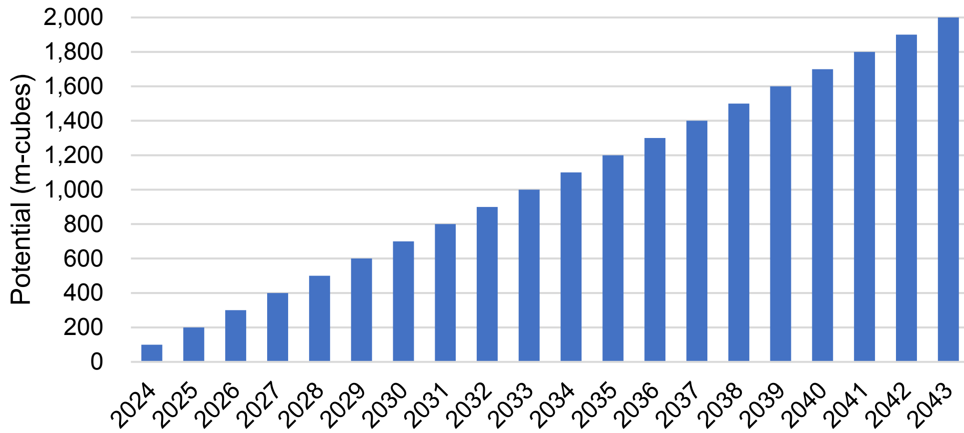
- There is one new building (customer) in 2024, and one new building in each year thereafter (so a total of 20 new buildings by the end of 2043
- All other assumptions as above.

In this example, Technical potential would grow at 100 m-cubes per year, bounded in each year by the growth in new construction in previous years, as illustrated in

[144] See Exhibits JH-2, JH-3, etc. a series of potential studies developed by Nexant for Dockets 20190015-EG to 20190021-EG filed Before the Florida Public Service Commission, April 12, 2019
Available: **https://www.psc.state.fl.us/library/filings/2019/03679-2019/03679-2019.pdf**

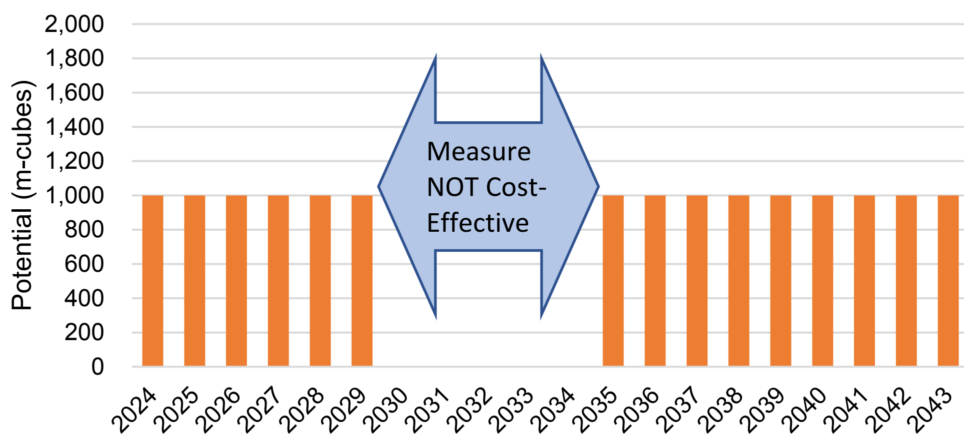
[145] DNV prepared for Dominion Energy, *Dominion Energy Efficiency Potential Study: 2020 to 2029*, September 2021
https://www.dominionenergy.com/-/media/pdfs/virginia/save-energy/potential-study-final-report-august-2021.pdf?la=en&rev=0a762e9a58784aba8dde0ef3dfd355cf&hash=78B1D55649FC2B91AE627A27A750C94E

Figure 79. Stylized Example of Technical Potential – NEW Measures



Now, consider that in this example both the ROB and NEW measures cease to be cost-effective in 2030, but becomes cost-effective again in 2035. In this case, Economic potential for ROB measures would appear as illustrated in the figure below.

Figure 80. Stylized Example of Economic Potential – ROB Measure

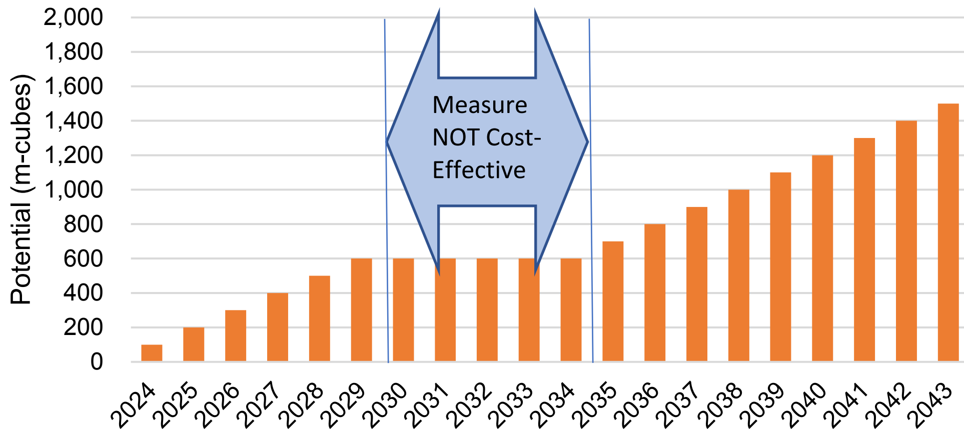


It is for this very reason that Guidehouse uses this unconstrained and annually independent approach; it highlights the impact of significant changes to input values in a way which makes them straightforward to identify temporally.

For NEW measures, the outcome looks different and at first appears very similar to what reviewers with experience in other potential studies might mistake for the potential associated with cumulative adoption of a standard ROB measure – see Figure 81, below.

In this example, as in that for the ROB measure, the measure is not cost-effective in the period from 2030 through 2034. However, in each year, the model assesses the cost effectiveness of all buildings new since the start of the period of analysis *according to the year in which they were built*. This means that even though the measure is not cost-effective in 2030, it was in 2024, so Economic potential includes the potential – for the NEW version of the measure – associated with new construction completed in 2024.

Figure 81 Stylized Example of Economic Potential – NEW Measure



To reviewers used to the cumulative approach of Achievable potential this can sometimes be confusing.

As noted above, the unconstrained approach disregards questions of equipment turnover because these confound the analysis of the outputs unproductively. Technical and Economic potential values are diagnostic tools, not intended to be a realistic representation of adoption. Constraining adoption to turnover obscures year-specific effects and diminishes the usefulness of the potential as a diagnostic tool

C.2 Measure Types

Measures are assigned one of three replacement types: ROB, RET, and NEW, as described in Section 5.2.1.

Replacement Type: RET and ROB

Retrofit (RET) measures are either early replacement measures (e.g., early water heater replacement) or measures for which the baseline is simply the absence of a measure (e.g., additional insulation, etc.). RET measures can also be efficient processes not currently in place and not required for operational purposes.

In contrast, replace-on-burnout (ROB) measures, sometimes referred to as lost opportunity measures, are replacements of existing equipment that has reached the end of its expected useful life (EUL) must be replaced or are existing processes that must be renewed. In Achievable potential estimation, the applicable market for ROB measures is constrained to the share of existing technologies reaching the end of their EUL in each year. Technical and Economic potential estimation relaxes this constraint and considers potential in each year as a snapshot of all available ROB potential, unconstrained by considerations of equipment turnover.

In any given year, for the Residential and Commercial sectors, DSMSim uses the existing building stock to estimate Technical potential. For the Industrial sector savings are scaled on the basis of reference forecast consumption. Existing building stock is reduced each year by the quantity of demolished building stock in that year and does not include new building stock that is added throughout the simulation. For RET and ROB measures, annual potential is equal to total potential, thus offering an instantaneous view of Technical potential.

Technical potential, per measure, for RET and ROB measures is estimated as described in Equation 8-1.

Equation 8-1. Retrofit and Replace-on-Burnout Measures, Technical Potential

$$Total\ Potential = Existing\ Stock\ x\ Measure\ Density\ x\ Savings\ x\ Technical\ Suitability$$

Where:

- *Total Potential:* Cubic meters of Technical potential gas savings (m^3) attributable to the given measure in the given year
- *Existing Stock:* Count of existing buildings in each year, or customer segment consumption per year for the given sub-sector.
- *Measure Density:* Measure installations per unit of stock, as defined in Section4.2.4.1, for the given measure.
- *Savings:* Annual m^3 estimated savings per year, per measure, for the given measure.
- *Technical Suitability:* Ratio between 0 and 1 to represent the percentage of situations the measure is technically suitable for the application.

Replacement Type: NEW

The cost to implement new construction (NEW) measures is incremental to the cost of a baseline (and less efficient) measure. However, NEW technical potential is driven by equipment installations in new building stock rather than by new equipment in existing building stock. New building stock is added to keep up with forecast growth in total building stock and to replace existing stock that is demolished each year. Demolished (sometimes called replacement) stock is calculated as a percentage of existing stock in each year.

The annual demolition rate applied in the 2024 APS is drawn from the 2019 APS and is provided by sector in Table 31.

Table 31. Demolition Rates by Sector

Sector	Annual Demolition Rate
Residential	1.58%
Commercial	2.01%
Industrial	0%

New building stock (the sum of growth in building stock and replacement of demolished stock) determines the annual incremental addition to Technical potential (AITP), which is then added to totals from previous years to calculate the total potential in any given year. Technical potential, per measure, for NEW measures is estimated as described in Equation 8-2.

Equation 8-2. New Measures Technical Potential

$$AITP = New\ Stock\ x\ Measure\ Density\ x\ Savings\ x\ Technical\ Suitability$$

Where:

- *Annual Incremental NEW Technical Potential (AITP):* Cubic meters of Technical potential gas savings (m^3) attributable to the given measure in the given year
- *New Stock*: Count of incremental new buildings in the given year, or customer sub-sector consumption per year for the given sub-sector

And the remaining variables are as defined above for RET and ROB.

The total Technical potential in any given year for NEW measures is the sum of the incremental potential in prior years and the current year.

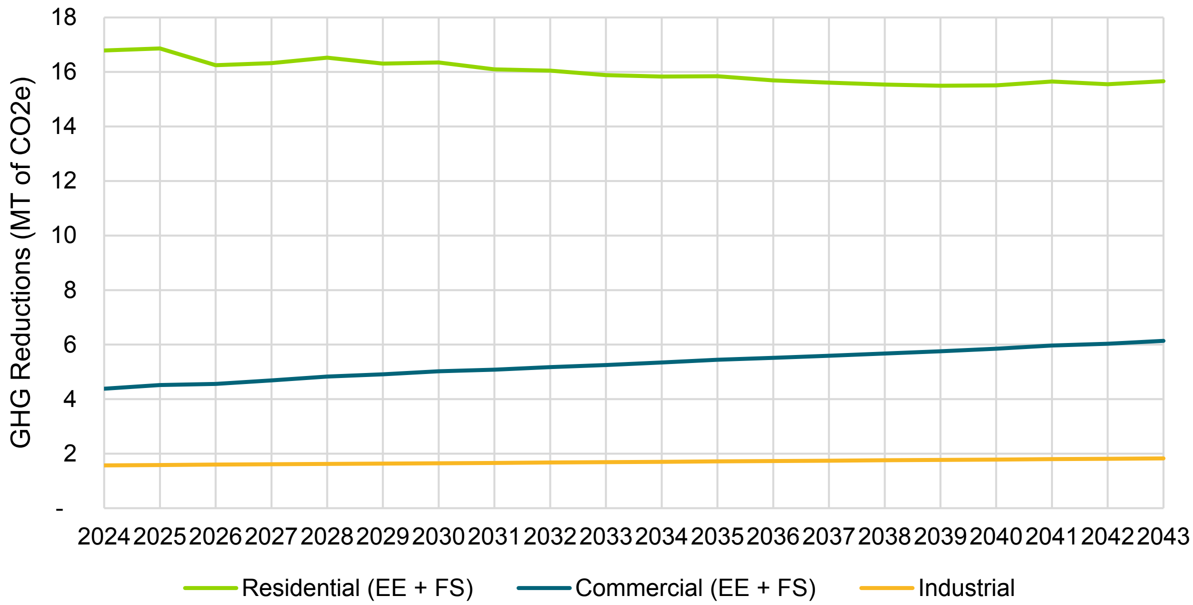
C.3 Expanded Results

This section of Appendix C includes additional Technical potential impacts that Guidehouse and the OEB team have identified as likely to be of interest to reviewers: the GHG emissions impacts associated with the Technical potential, and the more granular presentation of Technical potential by non-Residential sub-sector. The corresponding impacts of the Technical potential sensitivity scenario and of other, less relevant impacts (electric energy, summer peak demand) may be found in the study outputs data but are not included in this report.

C.3.1 GHG Emissions Impacts by Sector

Figure 82 shows the impact of the Technical potential on provincial GHG emissions. GHG impacts are calculated as the GHG reductions resulting from reduced natural gas consumption, net of the incremental emissions from the power generation required to support electrification. GHG emissions reductions in each year reflect the Technical potential in each year; that is, they reflect potential in the given year as a snapshot, unconstrained by typical considerations of equipment turnover.

Figure 82. GHG Emissions Reductions Associated with Technical Potential



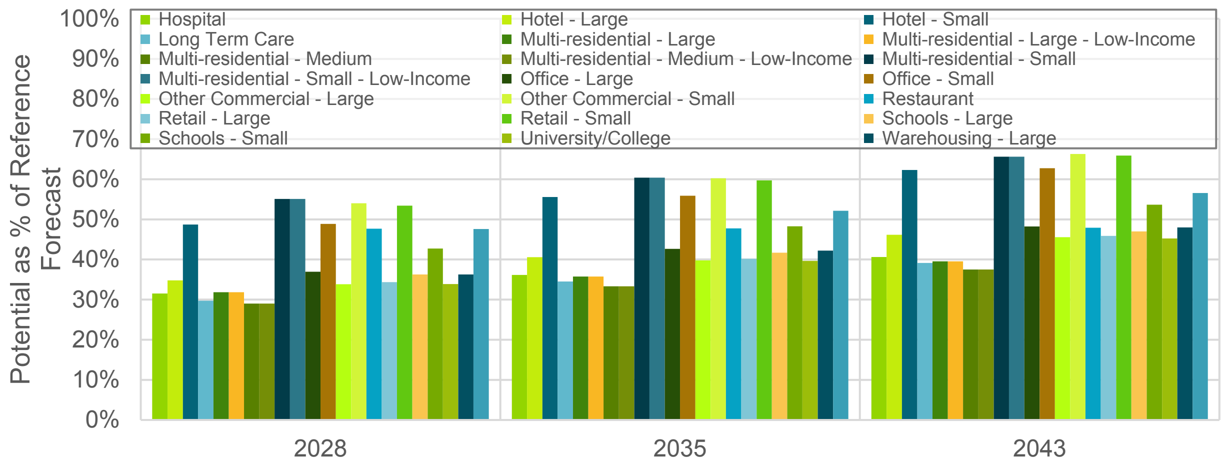
Estimated GHG reductions are, as would be expected, consistent with the magnitude of Technical potential. The slightly declining slope of the Residential GHG emissions is driven by the projected increase in the power generation emissions factor over time. The Commercial GHG emissions impact does not exhibit this effect because a high proportion of Commercial fuel switching potential in later years of the potential projection is driven by the NEW replacement type (because of the more favourable Technical Suitability). This means the growth of fuel switching potential partially offsets the netting effects of the increasing carbon intensity of power generation.

As noted in Section 5.1.3 GHG impacts are derived from emissions factors drawn from EGI's website (natural gas GHG impacts) and from the IESO's 2022 APO data (power generation GHG impacts).

C.3.2 Natural Gas Technical Potential by Sub-Sector

Residential Technical potential as a percentage of reference forecast does not vary by sub-sector, and so is not shown here (though these values are available in the accompanying data outputs). Figure 83 shows the Technical potential by Commercial sub-sector as a percentage of the reference forecast.

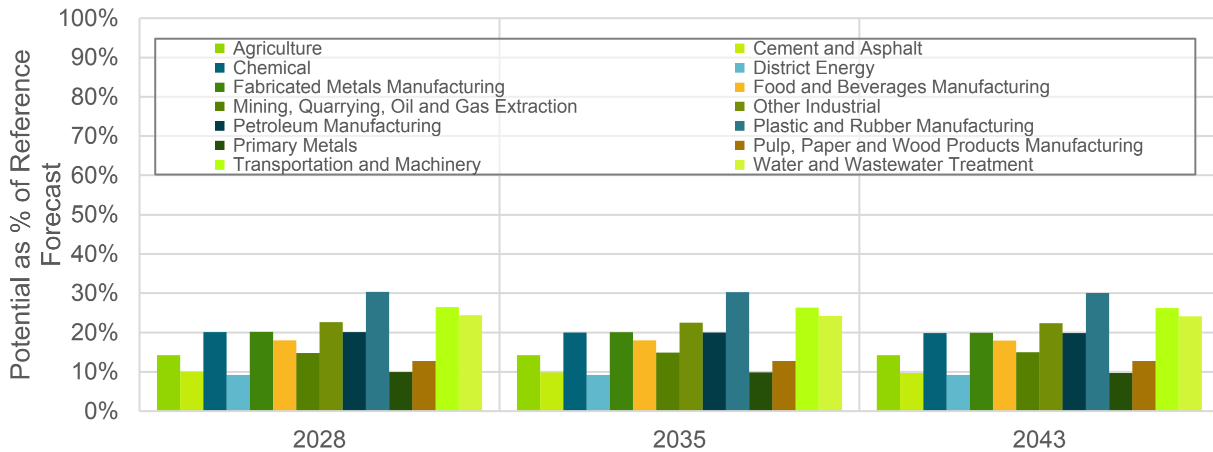
Figure 83. Commercial Technical Potential by Sub-Sector as Percent of the Corresponding Sub-Sector Reference Forecast



Unlike Residential Technical potential, substantial differences in Technical potential exist across the sub-sectors. The primary driver of this is the estimated Technical Suitability values for fuel switching measures, which are generally much lower (or in zero in some cases) for sub-sectors characterized by larger buildings. A discussion of the derivation of these factors may be found in Section B.3.10 of Appendix B.

Figure 84 shows the Technical potential by Industrial sub-sector as a percentage of the reference forecast. This displays even greater variation than the Commercial sector, where the variation in relative potential is driven largely by questions of building size. In the Industrial sector, opportunities for energy efficiency, as catalogued by the IAC, are largely driven by the Industrial processes specific to each sub-sector (or in some cases for larger consumers, to each site).

Figure 84. Industrial Technical Potential by Sub-Sector as Percent of the Corresponding Sub-Sector Reference Forecast



Also noteworthy is how much lower potential across many sub-sectors is compared even to the larger-building Commercial sub-sectors where SAG members have identified for Guidehouse that fuel switching opportunities are very limited.

The very low estimated Technical potential for some sub-sectors is a reflection of the very limited data available for this sector. Opportunities for energy efficiency and fuel switching will tend to be sub-sector or site-specific, and the smaller number of consumers can mean that collecting data or market intelligence identifying these opportunities can be very challenging due to consumer concerns about the commercially sensitive nature of such information. Addressing these challenges and collecting additional sub-sector specific information will likely yield higher estimates of Technical potential for Industrial sub-sectors.

Appendix D. Economic Potential

This appendix presents additional detail regarding the development and outputs of the Economic Potential analysis. It is divided into three subsections:

1. **Cost of Peak Capacity.** Describes how winter peak capacity costs were estimated, and how the effect of fuel-switching on the timing of Ontario becoming winter peaking is accounted for in the assessment of cost-effectiveness.

2. **The Value of Carbon.** Lays out the sourcing of the carbon value assumptions used in this analysis.

3. **Expanded Results.** Provides additional results, including GHG impacts of Economic potential, and sub-sector-level splits of Economic potential.

D.1 Cost of Peak Capacity

To estimate the marginal capacity cost of incremental peak demand due to fuel switching, Guidehouse is using the system capacity value of $144,000 per MW-year ($144 per kW-year) recommended by the IESO for valuing the benefits of non-wires alternatives.[146] This value is held constant in real (2023) dollars across the entire study period.

Incremental electricity demand imposes the estimated cost of capacity only in those highest demand hours that drive system planning decisions and the potential construction of additional peak generation capacity. For simplicity, and for the purposes of developing the peak demand impact estimates for individual fuel switching measures, Guidehouse has assumed that the definition of “peak” demand is approximately consistent with the way in which the IESO determines the Class A and Class B peak demand factor.[147]

The peak demand period as defined is infrequent and covers only a very small number of hours per year. This is a significantly more targeted definition than that typically used for measure cost-effectiveness testing in the IESO’s CDM tool.[148] That tool defines “peak demand” over a much broader set of hours and values peak demand commensurately less than the value and definition selected for the 2024 APS.

The more targeted value was selected for the 2024 APS to better reflect the nonlinear demand from heat pump electrification. Heat pump electric demand will tend to be relatively low

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[146] Section 6 of

Independent Electricity System Operator, Integrated Regional Resource Plans: Guide to Assessing Non-Wires Alternatives, May 26, 2023

Available at:

https://www.ieso.ca/en/Get-Involved/Regional-Planning/About-Regional-Planning/Planning-Information-and-Data

[147] Independent Electricity System Operator, *Global Adjustment and Peak Demand Factor*, Accessed February 2024

https://www.ieso.ca/en/Sector-Participants/Settlements/Global-Adjustment-and-Peak-Demand-Factor

[148] The CDM tool uses the same definition of peak demand impacts as those prescribed in the IESO’s EM&V Protocol: the average demand impact between 1pm and 7pm on non-holiday weekdays, June through August (Summer) and between 6pm and 8pm on non-holiday weekdays, December through February (Winter).

See Table 6-1 of: Independent Electricity System Operator, *Evaluation, Measurement and Verification Protocol V4.0*, February 2021

Available at: **https://ieso.ca/en/Sector-Participants/Energy-Efficiency/Evaluation-Measurement-and-Verification** (compared to the thermal load being met) in most hours of the heating season, but can climb very steeply when very cold outdoor temperatures require the activation of heat pumps' auxiliary resistance heat strips.

Capacity costs are applied only to a measure's peak demand for the season in which Ontario is assumed to peak. This means (for example) that a fuel switching measure will not incur any peak capacity costs in years in which Ontario is assumed to still be summer-peaking.

For Economic potential, Guidehouse has assumed, consistent with the IESO's 2022 APO[149], that Ontario becomes winter-peaking in 2036. For Achievable potential, the year of the switch from summer to winter-peaking is determined dynamically; estimated summer and winter peak demand impacts are applied to the 2022 APO's forecast summer and winter peak demand values to determine the year of the switch.

For the Achievable potential scenarios, the assumed year in which Ontario becomes winter peaking is provided in Table 32 below.

Table 32. Achievable Potential Seasonal Peak Switch Year

Scenario	Potential Target	Measures Included	Carbon Value	Year Ontario Becomes Winter Peaking
A	0.5%	EE + FS	CFB	2035
B	1%	EE + FS	SCC	2035
C	Max	EE + FS	SCC	2033
D	Max	EE + FS	CFB	2034
E	Max	EE Only	CFB	2036
F	1%	EE + FS	CFB	2035

Because a measure's cost-effectiveness is defined by the present value of benefits divided by the present value of its costs, the costs of winter peak capacity can have a significant impact on a measure's cost-effectiveness even in years that are not winter-peaking.

For example, in Economic potential (switch year: 2036), when considering a measure in 2035, even though it incurs no capacity cost for 2035, the measure's cost effectiveness does include the present value of the capacity costs it imposes in 2036, 2037, and so on, across the measure's EUL.

D.2 The Value of Carbon

The cost of carbon is an essential input in assessing the cost-effectiveness of DSM and fuel-switching measures. Natural gas avoided costs capture only the benefits of gas savings related to the procurement and distribution costs of gas. The cost of carbon addresses the external costs imposed on the province of Ontario of natural gas consumption and its attendant greenhouse gas emissions.

This section is divided into three sub-sections:

1. **The Cost of Carbon for Ontario.** This sub-section identifies the source for the 2024 APS assumed cost of carbon, and the reasoning for its selection.

[149] The 2024 APO significantly revised this estimate and projects that Ontario to become winter-peaking in 2030. Unfortunately the timing of the 2024 APO was such that its updates could not be included in the 2023 APS without compromising the 2023 APS' delivery schedule.

2. **Assessed Alternatives.** This sub-section summarizes the work undertaken by Guidehouse and considered by OEB staff in selecting what series of costs to use for the social cost of carbon in this study.
3. **Cost of Carbon for the 2024** APS**.** This sub-section relates the transformation of the selected series into 2023 constant dollars and provides (for illustrative purposes) a comparison of the cost of carbon and the federal backstop price of carbon in terms of the value offered per unit of gas consumption reduced ($/m³).

D.2.1 The Cost of Carbon for Ontario

In Ontario, DSM[150] (for natural gas) and CDM[151] (for electricity) potential assessments and evaluations have for many years now used the Total Resource Cost-Plus ("TRC-Plus") test for cost-effectiveness testing. This test includes considerations not just of resource impacts (e.g., the costs avoided by reducing natural gas consumption), but also societal benefits of DSM and CDM, including non-energy benefits and the cost to society of incremental carbon emissions.

In the 2019 APS, the federal carbon backstop price was used as a proxy for the cost of carbon to consumers.[152] For the 2024 APS Guidehouse recommended the use of the Social Cost of Carbon (SCC) to replace this proxy as a more accurate estimate of the present-value cost of incremental emissions to Ontario. After assessing alternative estimates of the SCC available, and presenting these to the SAG and OEB staff, OEB staff directed Guidehouse to use the Government of Canada's[153] estimates of the SCC (at an assumed 2% social discount rate[154]) in its cost-effectiveness testing.

These values are drawn by the Government of Canada from the U.S. Environmental Protection Agency's "*Report on the Social Cost of Greenhouse Gases*".[155]

This report notes that "*The modeling implemented in this report reflects conservative methodological choices… the resulting SC-GHG* [social cost of greenhouse gases] *estimates likely underestimate the marginal damages from GHG pollution*." Indeed, these values are considerably lower than those used for DSM cost-effectiveness testing across New England

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[150] Ontario Energy Board, *Decision and Order: Application for Multi-Year Natural Gas Demand Side Management Plan (2022 to 2027),* Enbridge Gas Inc., EB-2021-0002, November 2022
https://www.oeb.ca/node/3869

[151] Navigant (n/k/a Guidehouse) prepared for the Independent Electricity System Operator, and the Ontario Energy Board, *2019 Integrated Ontario Electricity and Natural Gas Achievable Potential Study*, December 2019
https://www.ieso.ca/2019-conservation-achievable-potential-study

[152] Because the carbon price is an intra-provincial transfer – funds collected in Ontario are returned as rebates to Ontarians – it is not on its own appropriate for inclusion in provincial-perspective cost-effectiveness testing (any more than measure incentives or provincial sales taxes would be). In 2018, however, it was determined to be a reasonable, locally-specific and publicly available proxy for the costs imposed on Ontario by incremental carbon emissions, for the purposes of cost-effectiveness screening.

[153] Government of Canada, *Social Cost of Greenhouse Gas Estimates – Interim Updated Guidance for the Government of Canada*, updated April 2023, accessed August 2023
https://www.canada.ca/en/environment-climate-change/services/climate-change/science-research-data/social-cost-ghg.html#toc0

[154] Estimates of SCC are often presented at different social discount rates. The higher the social discount rate, the lower the present value of the future damage costs or future mitigation costs from each incremental unit of greenhouse gas emissions.

[155] United States Environmental Protection Agency, Climate Change Division, Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances, September 2022
https://www.epa.gov/system/files/documents/2022-11/epa_scghg_report_draft_0.pdf

(i.e., in Massachusetts, Connecticut, Vermont, New Hampshire, Maine, and Rhode Island) and defined by the *Avoided Energy Supply Costs in New England* 2021 study and its updates (this series uses a 1% discount rate, which significantly increases costs).[156]

Likewise, a review of the historical estimates of the social cost of carbon show that these have (for the same forecast year) grown considerably over time, reflecting an improved understanding of the costs imposed by incremental carbon emissions. In constant dollars, the most current Canadian estimate of the cost of carbon per tonne in 2020 is more than five times higher than it was at the time of it was previously updated in 2016 and more than seven times higher (in constant dollars) than the 2020 cost estimated in 2010.[157]

Before determining to proceed with the 2% discount rate set of carbon costs currently recommended for use by the Government of Canada, Guidehouse considered a suite of carbon costs from a variety of sources, including a novel adaptation of a non-linear growth trend in costs applied to the present-day federally recommended 2% discount value. This set of alternatives considered for this study are summarized in the section below.

D.2.2 Assessed Alternatives

Despite the evidence noted above indicating that the current federally recommended carbon costs understate the true costs of carbon, OEB staff, in consultation with the SAG, directed Guidehouse to apply these costs to its economic screening. This sub-section serves to document the alternatives considered by Guidehouse and by OEB staff in the selection of the appropriate carbon costs to use and provide a foundation for future analysis.

The Guidehouse team reviewed the available professional and academic literature covering estimates of the cost of carbon emissions to make an informed recommendation. A summary of some the key cost series reviewed and that were initially recommended by Guidehouse is shown in Figure 85.

The Canadian federal carbon backstop price is provided for comparison purposes[158], though caution should be exercised in comparing these series: the carbon cost series are estimates made by various agencies and researchers of the costs that will be imposed on their respective jurisdictions by incremental carbon emissions. The federal Canadian fuel charge (carbon price)

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[156] See:

Synapse Energy Economics, *AESC 2021 Materials*, accessed August 2023

AESC 2021 Materials | Synapse Energy (synapse-energy.com)

And

Knight, Pat, prepared for AESC Supplemental Group AESC 2021 Supplemental Study: Update to Social Cost of Carbon Recommendation, October 2021

AESC_2021_Supplemental_Study-Update_to_Social Cost_of_Carbon_Recommendation.pdf (synapse-energy.com)

[157] See the introductory tables of

Government of Canada, Environment and Climate Change Canada, Technical Update to Environment and Climate Change Canada's Social Cost of Greenhouse Gas Estimates, 2016

https://publications.gc.ca/collections/collection_2016/eccc/En14-202-2016-eng.pdf

An important - but far from the only – driver of this change is the decision to use a discount rate of 2% for the more recent update, rather than 3% as used in the 2016 update.

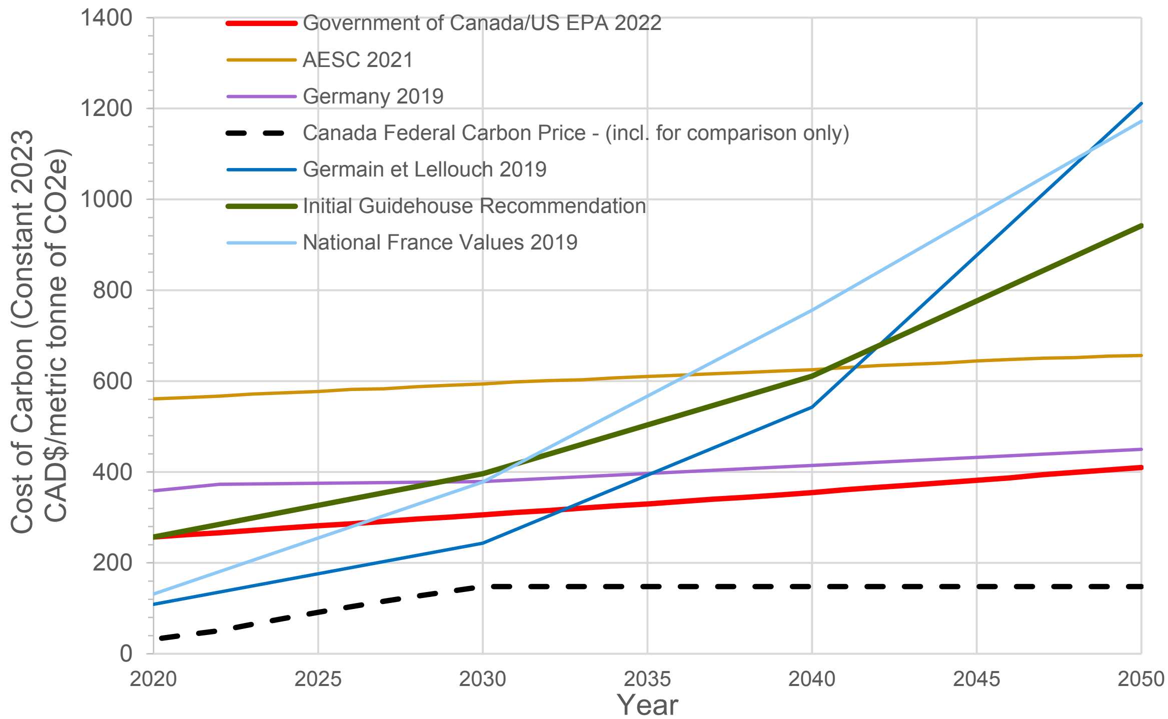
[158] Note that in this graph, in the years following 2030, the value of the CFB is held constant at 2030 values. This differs from the series used as a sensitivity in the study, which was, recommended by a stakeholder and endorsed by OEB staff, escalated in real terms consistent with pre-2030 trends. See Section 6.2.2.4.

is a policy-driven incentive developed by the government to encourage consumers and businesses to reduce their purchases of products and services subject to that charge.

The federal carbon price is determined by the political capital of the legislators that choose it; the carbon costs are estimated through the peer-reviewed research of scientists, engineers, and economists.

Citations for all series presented in Figure 85 are provided in Table 33, below Figure 85.

Figure 85. Cost of Carbon Estimates (2023 CAD$/metric tonne CO2e)



The thicker green line was Guidehouse's initial recommendation for the carbon price to be used for cost-effectiveness screening for this study, the 2024 APS.

This set of values was derived through an application of the growth rate function used to escalate carbon costs over time established by Germain and Lellouch to the 2020 2% discount rate cost of carbon estimate recommended by the Government of Canada (i.e., the red line – note the common starting point of both series).

This recommendation was made on the basis of the observations that:

a) the current estimated cost of carbon is acknowledged by the EPA as an underestimate,
b) updates over time to the federally recommended estimated cost of carbon have increased at an increasing rate, and
c) the severity and magnitude of climate change impacts projected by researchers continue to be revised upwards.[159]

[159] For example, the IPCC, in its sixth assessment report (AR6) revised its assessment of the risk of extreme weather events at 2.5 degrees Celsius warming from "High" (in the fifth assessment, AR5) to "Very High". See:

Following the presentation of this recommendation and detailed supporting materials to OEB staff and the SAG, it was determined in discussions that it would, at present, be more prudent to use the federally recommended values for the cost of carbon at the 2% discount rate (i.e., the red line in the chart above).

Going forward, Guidehouse has recommended that the OEB continue to revisit the literature estimating the costs imposed on Ontario of incremental carbon emissions and consider the possibility of using a series of carbon costs derived with a lower discount rate. The current federally recommended carbon costs use a 2% discount rate, down from the 3% value used in 2016[160] and the Government of Canada report providing these estimates does also include carbon costs estimated with a 1.5% discount rate.

This value would be in line with that commonly understood to have been used by the *Stern Review*[161] (1.4%)[162], a value selected based on the ethical considerations that arise when applying a social discount rate across generations. Additionally, an even lower social discount rate is recommended for use by the AESC: "*we recommend that the MA EE PAs* [the Massachusetts energy efficiency program administrators] *rely on the current Federal IWG estimate using a 1 percent discount rate.*"[163]

Citations for the carbon cost (and the Canadian federal carbon price) series shown in Figure 85 are provided in Table 33 below.

Table 33. Citations for Carbon Cost Series

Series Name	Citation
Government of Canada/ U.S. EPA 2022	Government of Canada, Social Cost of Greenhouse Gas Estimates – Interim Updated Guidance for the Government of Canada, updated April 2023, accessed August 2023 **https://www.canada.ca/en/environment-climate-change/services/climate-change/science-research-data/social-cost-ghg.html#toc0** And United States Environmental Protection Agency, Climate Change Division, Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances, September 2022

Intergovernmental Panel on Climate Change, Climate Change 2023 Synthesis Report – Summary for Policymakers, 2023

https://www.ipcc.ch/report/ar6/syr/downloads/report/IPCC_AR6_SYR_SPM.pdf

[160] Government of Canada, Environment and Climate Change Canada, Technical Update to Environment and Climate Change Canada's Social Cost of Greenhouse Gas Estimates, 2016

https://publications.gc.ca/collections/collection_2016/eccc/En14-202-2016-eng.pdf

[161] Stern, N., Stern Review: The Economics of Climate Change, October 2006

Available online:
http://mudancasclimaticas.cptec.inpe.br/~rmclima/pdfs/destaques/sternreview_report_complete.pdf

[162] The Stern Review does not provide its discount rate explicitly – subsequent researchers have, however, calculated the value used. For example in this paper, which also provides a useful review of differing approaches and perspectives to the selection of a social discount rate for valuing the impacts of climate change:

Lawrence H. Goulder and Roberton C. Williams III, *The Choice of Discount Rate for Climate Change Policy Evaluation*, Resources for the Future Discussion Paper, 2012

https://media.rff.org/documents/RFF-DP-12-43.pdf

[163] Section 2.3 of

Knight, Pat, prepared for AESC Supplemental Group AESC 2021 Supplemental Study: Update to Social Cost of Carbon Recommendation, October 2021

AESC_2021_Supplemental_Study-Update_to_Social Cost_of_Carbon_Recommendation.pdf (synapse-energy.com)

This source in addition has a nuanced discussion of discount rate selection which forms the basis for its recommendation.

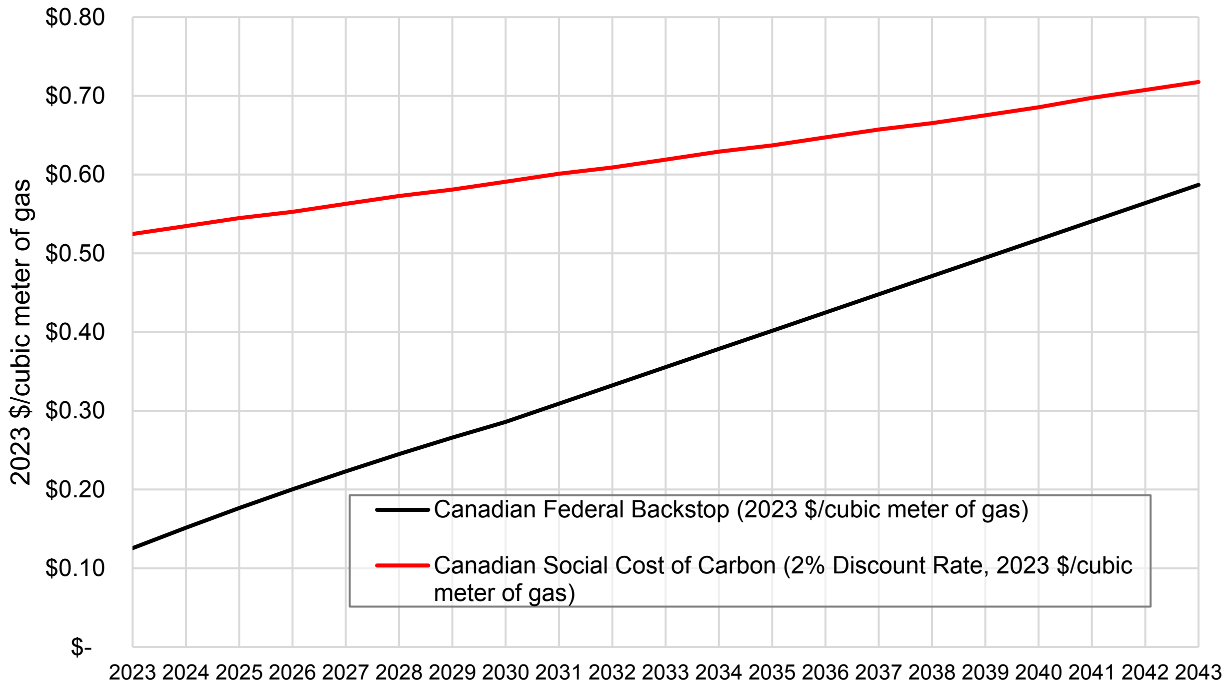
Series Name	Citation
	https://www.epa.gov/system/files/documents/2022-11/epa_scghg_report_draft_0.pdf
AESC 2021	Synapse Energy Economics, *AESC 2021 Materials*, accessed August 2023 **https://www.synapse-energy.com/aesc-2021-materials** And Knight, Pat, prepared for AESC Supplemental Group AESC 2021 Supplemental Study: Update to Social Cost of Carbon Recommendation, October 2021 **https://www.synapse-energy.com/sites/default/files/AESC_2021_Supplemental_Study-Update_to_Social%20Cost_of_Carbon_Recommendation.pdf**
Germany, 2019	(Translated) German Federal Environment Agency, *Societal costs of environmental pollution*, August 2023 (Original) Umwelt Bundesamt, *Gesellschaftliche Kosten von Umweltbelastungen* **https://www.umweltbundesamt.de/daten/umwelt-wirtschaft/gesellschaftliche-kosten-von-umweltbelastungen#gesamtwirtschaftliche-bedeutung-der-umweltkosten**
Canada Federal Carbon Price – (incl. for comparison only)	Enbridge Gas Inc, *Federal Carbon Pricing Program*, accessed August 2023 **https://www.enbridgegas.com/business-industrial/commercial-industrial/large-volume-services-rates/federal-carbon-pricing**
Germain et Lellouch, 2019	Jean-Marc Germian and Thomas Lellouch, L'Institut national de la statistique et des études économiques, *The Social Cost of Global Warming and Sustainability Indicators: Lessons from an Application to France*, 2020, Issue 517-518-5, pages 81 – 102 **https://ideas.repec.org/a/nse/ecosta/ecostat_2020_517t_6.html**
National France Values, 2019	France Stratégie, rapport de la commission présidée par Alain Quinet, *Une Valeur tutélaire du carbone pour évaluer les investissements et les politiques publiques*, February 2019 **https://www.strategie.gouv.fr/sites/strategie.gouv.fr/files/atoms/files/fs-2019-rapport-la-valeur-de-laction-pour-le-climat_0.pdf**

D.2.3 Cost of Carbon for the 2024 APS

The Government of Canada's recommended social cost of carbon is provided in constant 2021 Canadian dollars per tonne for the period from 2020 through 2080. To prepare this series for inclusion in the analysis for the purposes of cost-effectiveness testing, all that was required was to convert this to constant 2023 Canadian dollars, using the 2% inflation rate assumed for this project (consistent with the IESO's CDM cost-effectiveness assumptions).

For the purposes of cost-effectiveness screening, Guidehouse's model takes carbon costs as a dollar per tonne input, applying these to projected measure-specific estimated emissions. To illustrate the potential effect of these values on measure cost-effectiveness they have been converted to dollars per m^3 and plotted with the federal backstop price of carbon in Figure 86 below. The effect of including carbon value on cost-effectiveness may be assessed by comparing this series of values to the avoided costs of natural gas provided in Figure 43 of Section 6.2.2.4.

Figure 86. Carbon Cost and Carbon Price (2023 $/$m^3$)



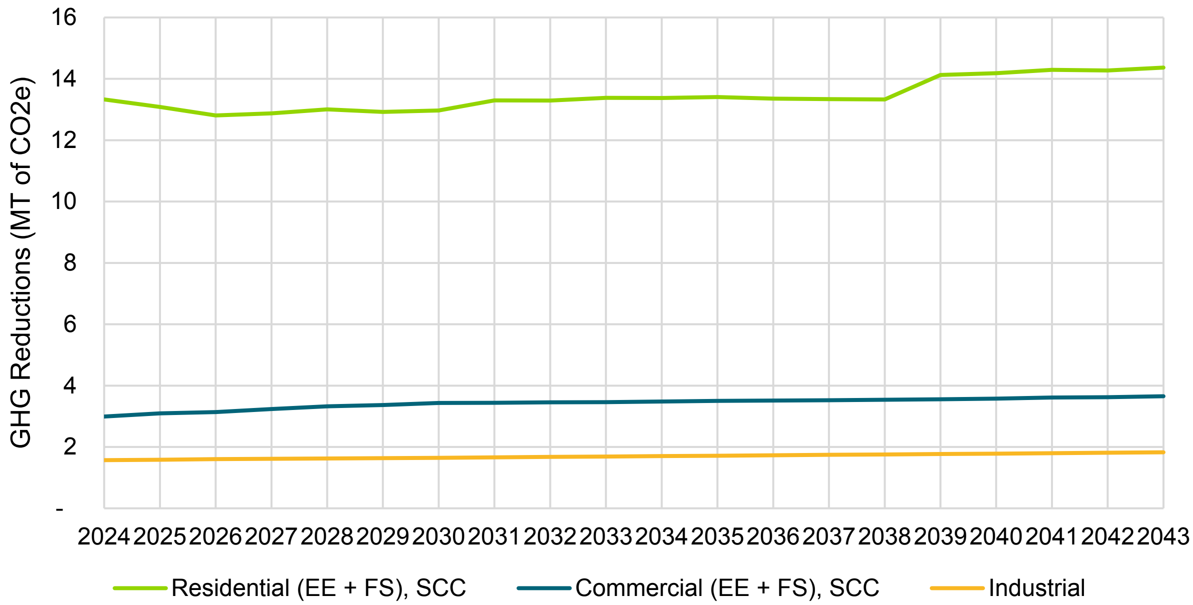
D.3 Expanded Results

This section of Appendix D includes additional Economic potential impacts that Guidehouse and the OEB team have identified as likely to be of interest to reviewers: the GHG emissions impacts associated with the Economic potential, and the more granular presentation of Economic potential by non-Residential sub-sector. The corresponding impacts of the Economic potential sensitivity scenarios and of other, less relevant impacts (electric energy, summer peak demand) may be found in the study outputs data but are not included in this report.

D.3.1 GHG Emissions Impacts by Sector

Figure 87 shows the impact of the Economic potential on provincial GHG emissions. GHG impacts are calculated as the GHG reductions resulting from reduced natural gas consumption, net of the incremental emissions from the power generation required to support electrification.

Figure 87. GHG Emissions Reductions Associated with Economic Potential



Estimated GHG reductions are, as would be expected, consistent with the magnitude of Economic potential.

As noted in in Section 5.1.3 GHG impacts are derived from emissions factors drawn from EGI's website (natural gas GHG impacts) and from the IESO's 2022 APO data (power generation GHG impacts).

D.3.2 Natural Gas Economic Potential by Sub-Sector

Figure 88 shows the Economic (EE + FS, SCC) potential by Residential sub-sector as a percentage of the reference forecast for that sub-sector. Technical potential as a percentage of reference forecast was very similar across the four sub-sectors, Economic potential differs significantly. Economic potential as a share of the sub-sector-specific reference forecast is much smaller for the Attached sub-sectors than for the Detached.

This is largely a function of greater thermal requirements assumed for the Detached sub-sector. While the incremental measure costs for the space heating fuel switching measures are lower for the Attached sub-sector than for the Detached sub-sector, the differential in costs is much smaller than the differential in savings. This means that for the South region, the ASHP (with gas back-up) measure does not become cost-effective as an ROB measure for the Attached sub-sector until approximately the last five years of the period of projection. In contrast, this measure is cost-effective (in the EE + FS, SCC scenario) across the entire period of projection for Detached sub-sector.

Figure 88. Residential Economic Potential by Sub-Sector as Percent of the Corresponding Sub-Sector Reference Forecast

The difference in the cost-effectiveness of space heating fuel switching across the sub-sectors is a noteworthy contrast to the cost-effectiveness of water heating, which is much more similar across the two sub-sectors, depending less on the building thermal requirements and more on the average number of inhabitants. The difference in Economic potential for these two end-uses across the sub-sectors is illustrated in Figure 89 below.

Figure 89. Residential Economic Potential by Sub-Sector for Space Heating and Water Heating as Percent of the Corresponding Sub-Sector/End-Use Reference Forecast

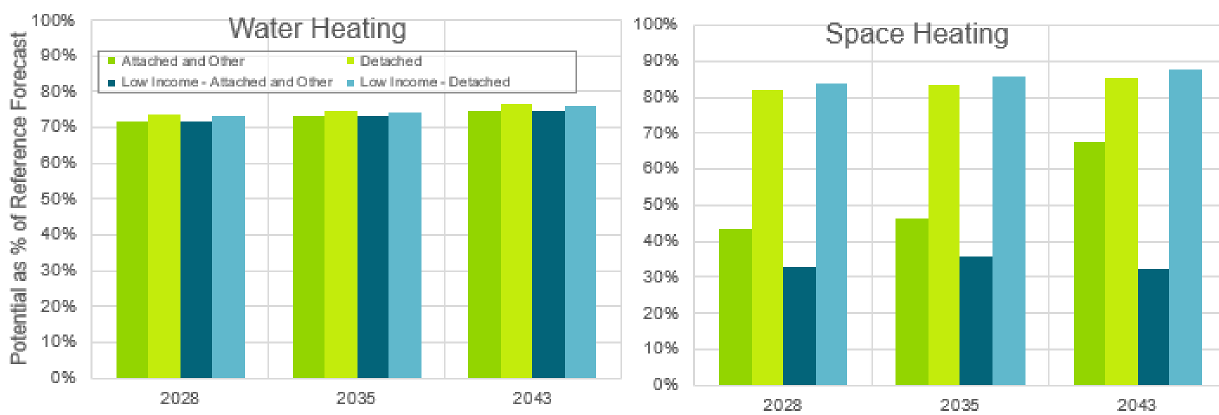
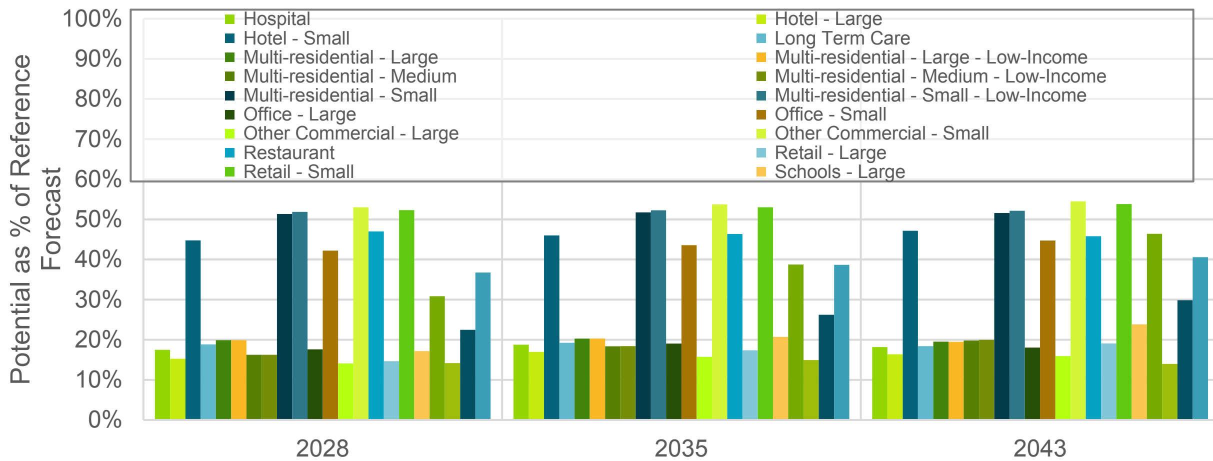


Figure 90 shows the Economic potential by Commercial sub-sector as a percentage of the reference forecast.

Figure 90. Commercial Economic Potential by Sub-Sector as Percent of the Corresponding Sub-Sector Reference Forecast



The most salient feature of the version of the plot above in the Technical potential Appendix (Section C.3.2) was distinct split between sub-sectors characterized by larger buildings (potential smaller in relative terms) and those characterized by smaller buildings (potential larger in relative terms). This was noted as being largely the outcome of the application of Technical Suitability factors which (as described in detail in Section B.3.10) substantially limit the fuel switching potential in Commercial sub-sectors characterized by larger buildings.

This split between larger and smaller buildings is even starker when Economic potential is considered. In the Technical potential, larger building sub-sectors delivered substantial volumes of fuel switching potential via ground source heat pumps. These measures are not cost-effective, resulting in a substantial decline in Economic, relative to Technical, potential for these sub-sectors.

As noted previously, Technical and Economic potential for the Industrial sectors are very similar – the sub-sector level Economic potential as a percentage of the reference forecast and so are not provided here for reasons of concision, though all these results are available in Appendix X2.

Appendix E. Achievable Potential

This appendix presents additional detail regarding the development and outputs of the Achievable Potential analysis. It is divided into three subsections:

1. **Period of Analysis.** Documents the reasoning for the selection of the period of analysis of this study, from 2024 through 2043.
2. **Achievable Potential Methodology - Additional Detail.** Provides additional detail on the modeling mechanics applied to estimate Achievable potential.
3. **Retail Energy Rates.** Provides the sources and assumptions for the retail rates used in the analysis for estimating customer payback.
4. **Expanded Results.** Provides additional results, including GHG impacts of Achievable potential, and sub-sector-level splits of Achievable potential.

E.1 Period of Analysis

The period of analysis for the 2024 APS covers the 20-year period from 2024 through 2043. The first year of this period of analysis, 2024, is consistent with convention for Achievable potential studies in general (and Ontario Achievable potential studies in particular[164]), i.e., that the first year in the period of analysis is either the year of publication of the study or the first year following the year of publication.[165].

The state of Michigan[166] follows a similar convention. Other jurisdictions sometimes begin projects in the first calendar year following study completion (e.g., California[167], Illinois[168]).

This projection range was discussed (in the context of the targets specified by the OEB for the study, see Section 7.1.1) at the SAG meeting 2023-06-08, and preliminary results across this range were presented to SAG members beginning in October of 2023. Technical and Economic potential updates were presented with the same range in November and December of 2023.

[164] The first year in the period of analysis for the 2019 potential study was 2019, the year in which it was published.

[165] The 2023 APS is so named because under the initial OEB staff plan it was due for publication in 2023. OEB staff determined in the summer of 2023 that this publication date would provide stakeholders insufficient time to provide the level of review and feedback desired, and the study publication date was pushed to its current date.

[166] Guidehouse, prepared for the Michigan Public Service Commission, *Michigan Energy Waste Reduction Statewide Potential Study (2021 – 2040)*, August 2021
https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/workgroups/ewr-study/mi_ewr_statewide_potential_study_final_draft_report.pdf

[167] Guidehouse, prepared for the California Public Utilities Commission, *2023 Energy Efficiency Potential Study*, June 2022
https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/energy-efficiency/2023-potential-goals-study/final-2023-group-e-pg-study-report.pdf

[168] Dunsky Energy Consulting, prepared for Commonwealth Edison, *Commonwealth Edison Energy Efficiency Potential Study: A Comprehensive Assessment of 2021 – 2030 Net Economic Opportunities. Volume 1: Results*, August 2020
https://www.ilsag.info/wp-content/uploads/ComEd-2021-2030-Potential-Study-Final-Report-rev1_Aug-2020.pdf

The first feedback provided to Guidehouse regarding the period of analysis was a request that it be extended further into the past: one SAG member's in-line feedback (provided 2024-02-16) to Guidehouse's Industrial Achievable potential summary memo (posted on the stakeholder SharePoint on 2024-01-19) asked why potential was not provided for 2023. In a comment subsequently provided by the same SAG member on 2024-03-18, that SAG member asserted that 2025 should be the study base year (and therefore 2026 the first year of the period of analysis and the first year for which potential should be presented), a view with which another member of the SAG agreed.

The reasoning for this assertion was that given that the potential study should inform EGI's DSM plan, it should start in the same year as that plan.

OEB staff directed Guidehouse to proceed with the period of analysis as specified: 2023 as the base year from which targets are developed, and 2024 as the first year in the period of projection. This direction was provided to Guidehouse because of

- **Timing Concerns.** As a practical matter the study, was too far advanced – nearly 11 months from start – when this feedback was provided. Making all the required updates would have delayed the delivery of outputs and reporting unacceptably.

- **Interpretation Concerns.** Deviating from convention and beginning the period of analysis coincident with the timing of the DSM Plan might imply that the potential study results should act as a blueprint to the plan. The study, as noted in Section 1.2, is intended only to inform the DSM Plan. The two pieces of work have different targets, make use of different inputs, and are intended for different purposes. The potential study highlights key emerging issues and concerns that inform the program design decisions that define the DSM Plan.

In the circumstances, OEB staff determined that it was more prudent to complete the study using the period of analysis (2024 through 2043) as originally defined, allowing for the possibility of a future study update using a 2026 start year if required.

E.2 Achievable Potential Methodology - Additional Detail

This section of Appendix E provides additional details about the modeling mechanics employed by DSMSim, the proprietary potential estimation model used by Guidehouse. It is divided into four sub-sections:

1. Payback Acceptance
2. Bass Diffusion, Awareness, and Incremental Adoption
3. Model Calibration
4. Re-Participation

E.2.1 Payback Acceptance

A fundamental component of Guidehouse's methodology in estimating customer adoption of energy efficient or electrification technologies is that customers make choices to adopt technologies based on the technology's simple payback. From the customer perspective, the economics of the efficient technology is driven by:

- the incremental cost of the measure,
- the savings in operating cost; and,
- the incentives offered by the utility.

These factors can be used to calculate the simple payback for a measure.

As the simple payback for the customer decreases, the total number of customers willing to adopt a measure increases. The percent of the market share willing to adopt a measure with a payback of zero years represents the maximum share of the market that is willing to adopt the measure.

By using the relationship between simple payback and the percentage of customers willing to adopt a measure (the payback acceptance curve), Guidehouse can estimate the equilibrium market share for all the included measures under a variety of scenarios and sensitivities. The changes in the customer payback in the OEB APS are driven by changes in incentives available to customers. By increasing incentives available to customers, the total pool of customers willing to adopt increases and in this way, incentives are increased until enough customers adopt technologies to reach a targeted reduction in gas sales.

The 2024 APS uses the same payback acceptance curves as the 2019 APS. These were developed for the 2019 study using the Delphi method, which included the deployment of surveys and a workshop consultation with panel of industry experts to inform the payback acceptance of the Residential, Commercial, and Industrial sectors (see Section 7.2.1 of the 2019 APS).[169]

The Delphi panel was validated by comparing its results to primary research conducted in Colorado in 2021. A comparison of the two datasets showed that the Delphi panel produced similar results to the primary research conducted in Colorado. In the Residential sector, The Delphi panel produced a higher estimate of customers willing to adopt a technology with a 0-year payback, though overall the payback acceptance curves were similar. The Delphi results for Commercial and Industrial sectors from the 2019 APS produced payback acceptance curves that estimated customers accepted longer paybacks than the primary research conducted in Colorado. The results were similar enough that the team concluded that the Ontario specific research from 2019 was the most appropriate dataset to use to describe payback acceptance for the current OEB APS.

Customer-accepted payback often differs by customer type, income, and project cost. For example, the typical payback accepted in the industrial sector is shorter than in the residential sector. This is expected because an industrial customer is likely more focused on the economics of the project compared to other investments they can make, where a residential customer may place higher value on comfort or aesthetics and thus be willing to accept a longer payback period. The payback curves used in the current APS are segmented into the categories shown below in Table 34. For residential measures, the cost category is determined by the cost to the customer after incentives. If the cost is $100 or less the measure is low cost, greater than $100 but less than $1,000 is average, and greater than or equal to $1,000 is high cost. In the commercial sector, payback curves are based on whether the subsector is a business or

[169] Navigant (n/k/a Guidehouse) prepared for the Independent Electricity System Operator and the Ontario Energy Board, *2019 Integrated Ontario Electricity and Natural Gas Achievable Potential Study*, December 2019
Available at: **https://www.ieso.ca/2019-conservation-achievable-potential-study**

institution, with offices getting the average of the two, as they are a mix of business and institutions. Similarly, Industrial payback curves are based on the subsector.

Table 34 Sector and Subsector Measure Cost Categories

Sector	Subsector	Measure Cost
Residential	Non-Low-Income	Low Cost
		High Cost
		Average
	Low-Income	Low Cost
		High Cost
		Average
Commercial	Businesses	N/A
	Institutions	
	Average	
Industrial	Resource Extraction, Refining, and Manufacturing	N/A
	Consumer Goods	
	Agriculture	

Each payback curve is shown below in Figure 91, Figure 92, Figure 93, Figure 94 for residential non-low-income, residential low-income, commercial, and industrial respectively.

Figure 91 Residential Non-Low-Income Payback Acceptance

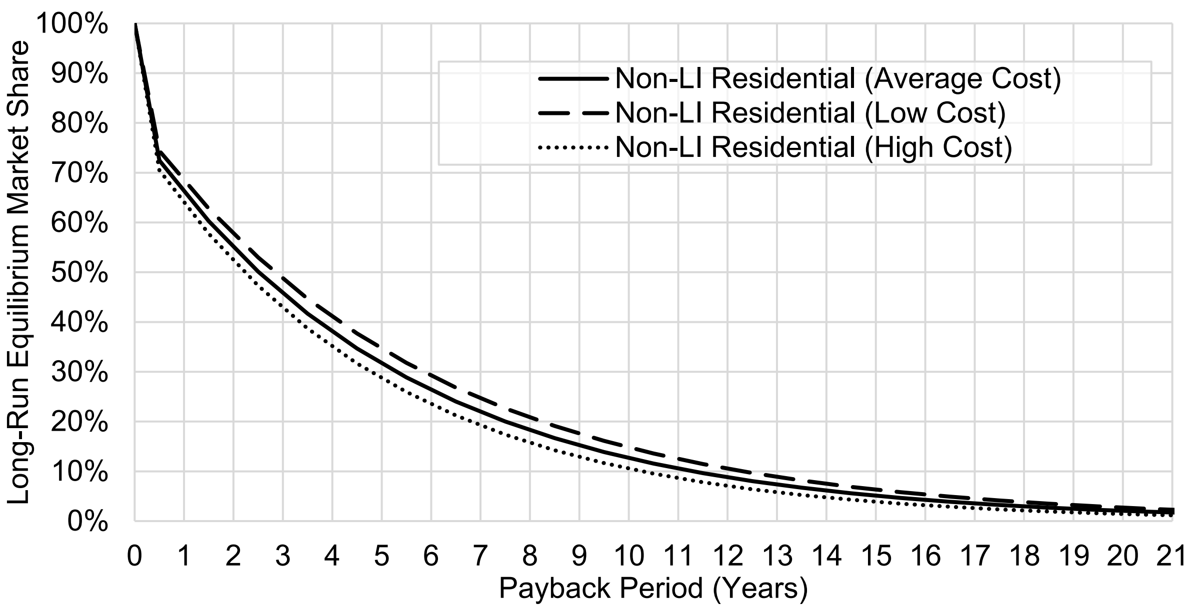


Figure 92 Residential Low-Income Payback Acceptance

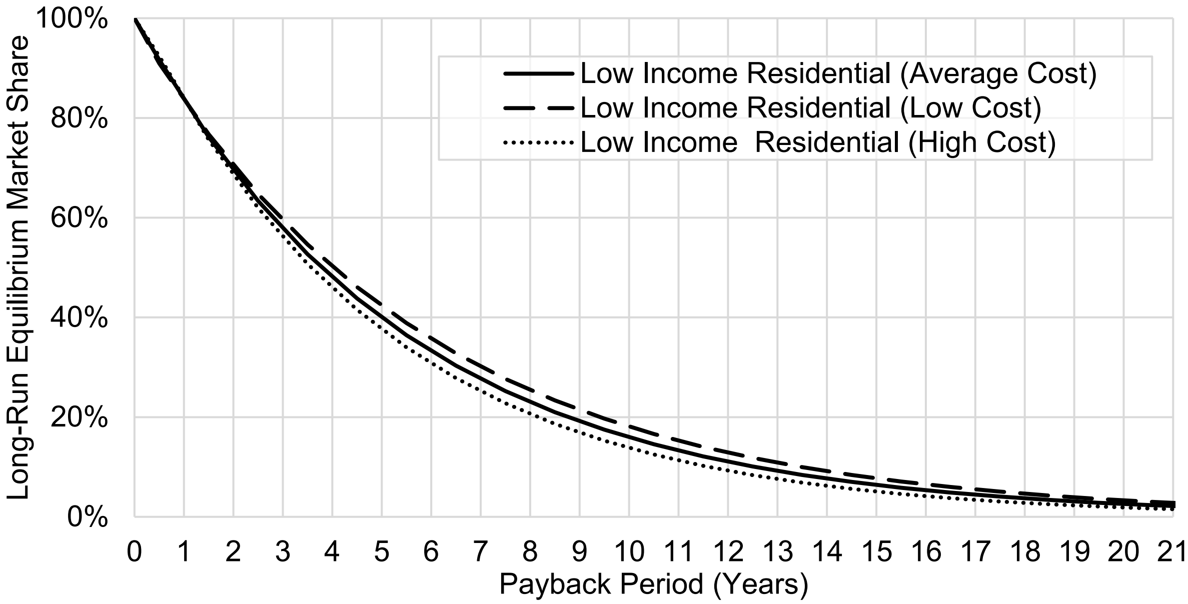


Figure 93 Commercial Payback Acceptance

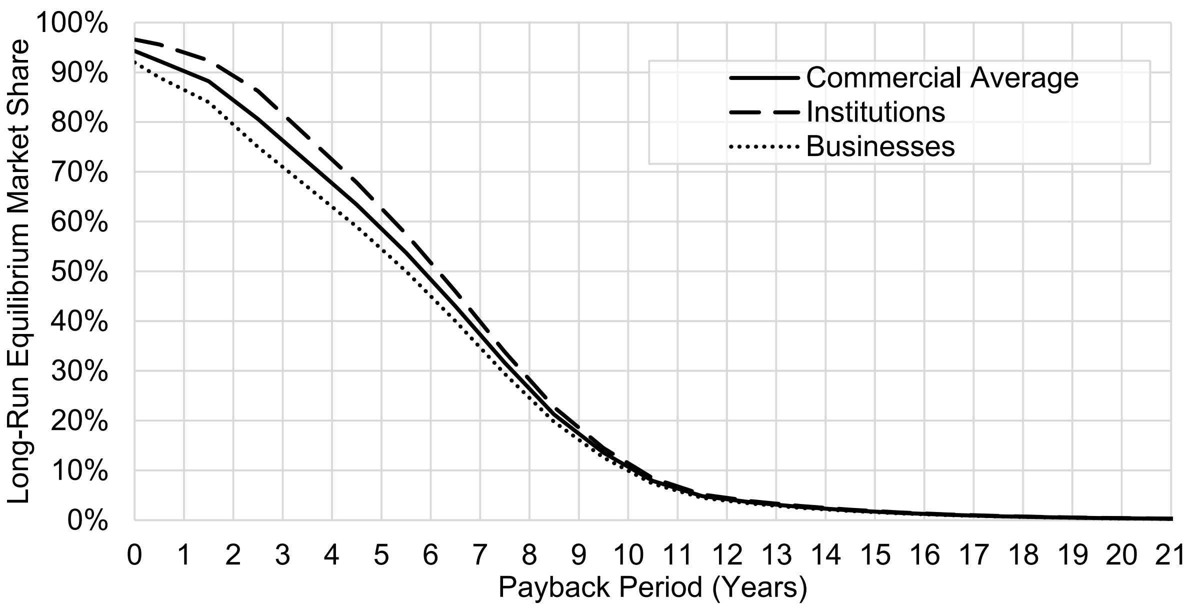
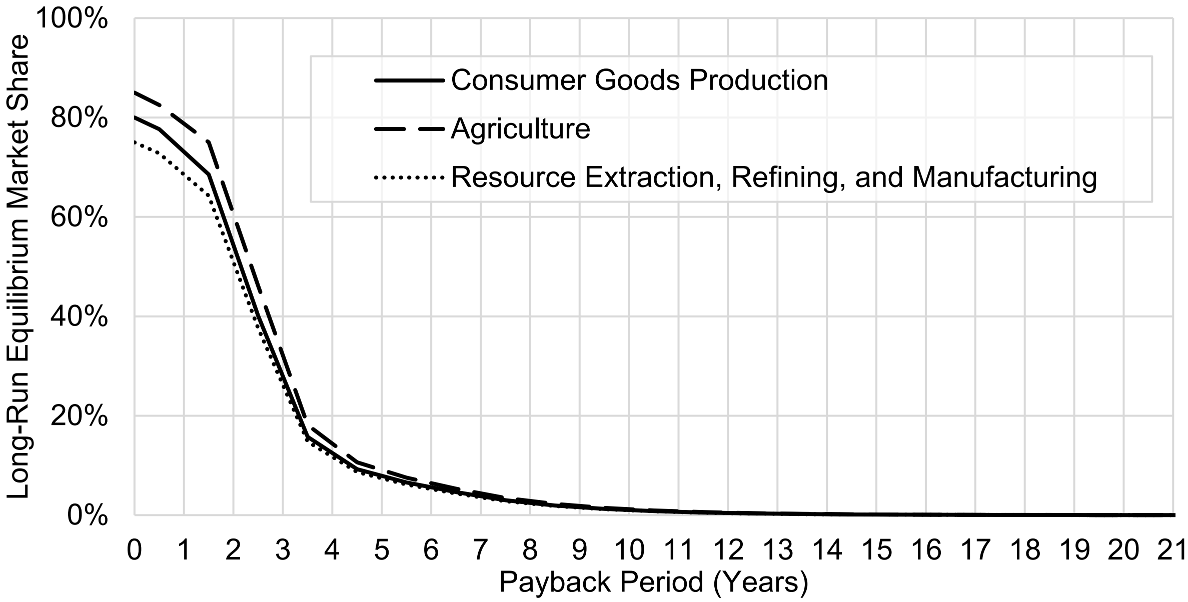


Figure 94 Industrial Payback Acceptance



E.2.2 Bass Diffusion, Awareness, and Incremental Adoption

Two approaches are used for calculating the approach to equilibrium market share (i.e., how quickly a technology reaches final market saturation). One approach is used for measures installed in new buildings (replacement type: NEW) or those modelled as retrofit measures (replacement type: RET). Another approach is used for those measures replaced at the end of their life where the available market is constrained by assumed equipment turnover (replacement type: ROB – replace-on-burnout).

Both approaches rely on Bass diffusion[170,171] to simulate the S-shaped growth toward equilibrium commonly seen in the adoption of new technologies.

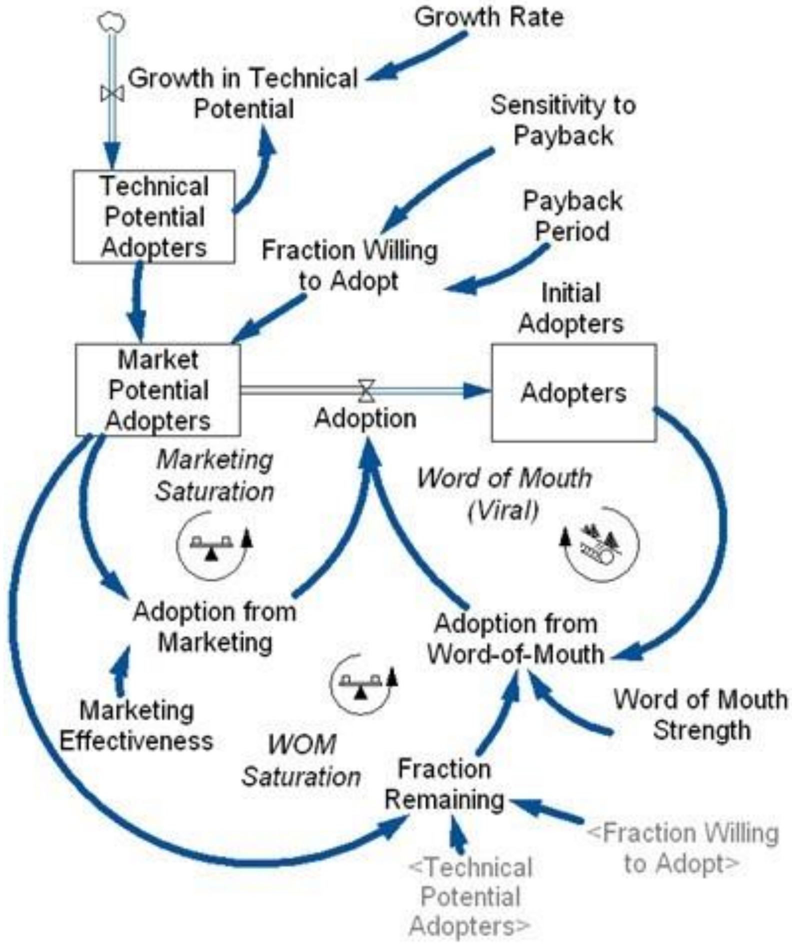
The adoption approach for RET and NEW replacement type measures uses an enhanced version of the classic Bass diffusion model to simulate the S-shaped approach to equilibrium that is commonly observed for technology adoption.

Figure 95 provides a stock/flow diagram illustrating the causal influences underlying the Bass model. In this model, achievable potential adopters flow to adopters by two primary mechanisms: adoption from external influences, such as program marketing/advertising, and adoption from internal influences, including word-of-mouth. The fraction of the population willing to adopt is estimated using the payback acceptance curves shown above.

[170] Bass, Frank (1969). "A new product growth model for consumer durables." *Management Science* 15 (5): p215–227.

[171] See Sterman, John D. Business Dynamics: Systems Thinking and Modeling for a Complex World. Irwin McGraw-Hill. 2000. p. 332.

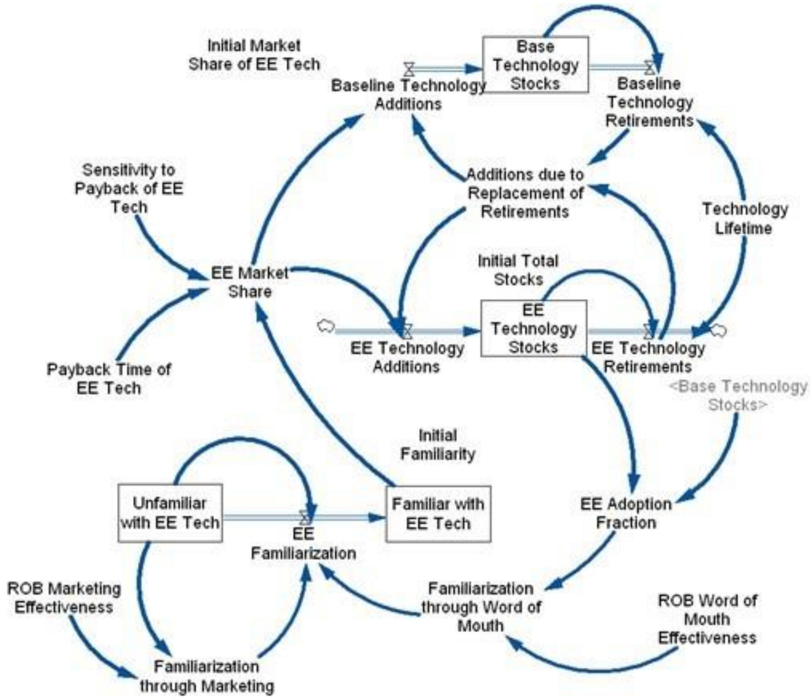
Figure 95. Stock/Flow Diagram of Diffusion Model for New Products and Retrofits



The marketing effectiveness and external influence parameters for this diffusion model are typically estimated upon the results of case studies where these parameters were estimated for dozens of technologies. Recognition of the positive, or self-reinforcing, feedback generated by the word-of-mouth mechanism is evidenced by increasing discussion of the concepts such as social marketing as well as the term viral, which has been popularized and strengthened most recently by social networking sites such as Facebook and YouTube. However, the underlying positive feedback associated with this mechanism has been ever present and a part of the Bass diffusion model of product adoption since its inception in 1969.

The dynamics of ROB technology adoption are more complicated than for NEW/RET measures. Adoption of ROB measures requires simulating the turnover of long-lived technology stocks. To account for this, the DSMSim™ model tracks the stock of all technologies and explicitly calculates technology retirements and additions consistent with the lifetime of the technologies. This approach considers the technology churn in the estimation of achievable potential, since only a fraction of the total stock of technologies are replaced each year, which affects how quickly technologies can be replaced. A model that endogenously generates growth in the familiarity of a technology, analogous to the Bass approach described above, is overlaid on the stock-tracking model to capture the dynamics associated with the diffusion of technology familiarity. A simplified version of the model employed in DSMSim™ is shown in Figure 6.

Figure 96. Stock/Flow Diagram of Diffusion Model for Replace-on-Burnout Measures



E.2.3 Model Calibration

Model calibration is a critical step in the potential estimation process. Calibration of the model's marketing effectiveness and word-of-mouth parameters at the sector level is done using historical program participation.[172]

Key inputs for the Achievable potential assessment are payback acceptance curves that represent the percentage of customers from different customer groupings willing to purchase a technology based on the time it takes the technology to pay back the upfront cost after incentives through annual cost savings.[173]

Calibration of a predictive model imposes unique challenges, as future data is not available to compare against model predictions. While engineering models, for example, can often be calibrated to a high degree of accuracy since simulated performance can be compared directly with performance of actual hardware, predictive models do not have this luxury. Demand-side management models, therefore, must rely on other techniques to provide the recipient of model results with a level of comfort that simulated results are reasonable. Guidehouse takes a number of steps to make sure that the initial, base year projected portfolio achievements used for the forecast model are reasonable and consider historic adoption, including:

[172] Ontario Energy Board, 2021 Natural Gas Demand-Side
Management Annual Verification, 1 November 2022,
Report, **https://www.oeb.ca/consultations-and-projects/policy-initiatives-and-consultations/natural-gas-demand-side-management**.
EGI also provided workbooks with the tracking data that supported the verification report.

[173] Payback is assessed by scaling first year bill savings across the life of the measure and comparing this to upfront costs.

- **Comparing historical forecast (backcast) values, by sector, against historic achieved savings** (e.g., from program savings for 2019-2021 and projected achievements in 2021 and 2022). Although some studies indicate that demand-side management potential models are calibrated to check first-year simulated savings precisely equal to prior-year reported savings, the Guidehouse team has found that forcing precise agreement can introduce errors into the modeling process by masking the explanation for differences—particularly when the measures included may vary significantly from those available historically. Thus, while the team endeavors to achieve agreement to a degree that is reasonable between past results and backcast results, the approach does not force the model to do so.
- **Identifying and ensuring an explanation existed for significant discrepancies** between forecast savings and prior-year savings, recognizing that some ramp-up is expected, especially for new measures or archetype programs.

E.2.4 Re-Participation

The model assumes that 100% of program participants re-adopt energy efficient measures after the end of the efficient measure's expected useful lifetimes. This implies that efficient measures generally do not revert to a minimum code or lower efficiency level. As such, the model's cost accounting incurs an incentive cost on the initial conversion of a minimum code or lower efficiency measure to an efficient measure, but it does not incur incentive costs when replacing incumbent equipment that was already updated to efficient equipment during the study horizon. Incremental savings are counted only for new program participants, and these savings are summed up year-over-year to represent cumulative potential.

Behavior measures, such as home energy reports, are an exception to this approach. When a behavior measure is re-adopted at the end of its expected useful lifetime, the incentives provided for those measures are added to total program administrator spending. The rationale is that similar savings opportunities provided by behavior measures are only available with ongoing support or administration from the program administrator. Because ongoing program administrator support is required to achieve behavior measure savings, the incentives provided to repeat adopters are incurred multiple times throughout the study horizon.

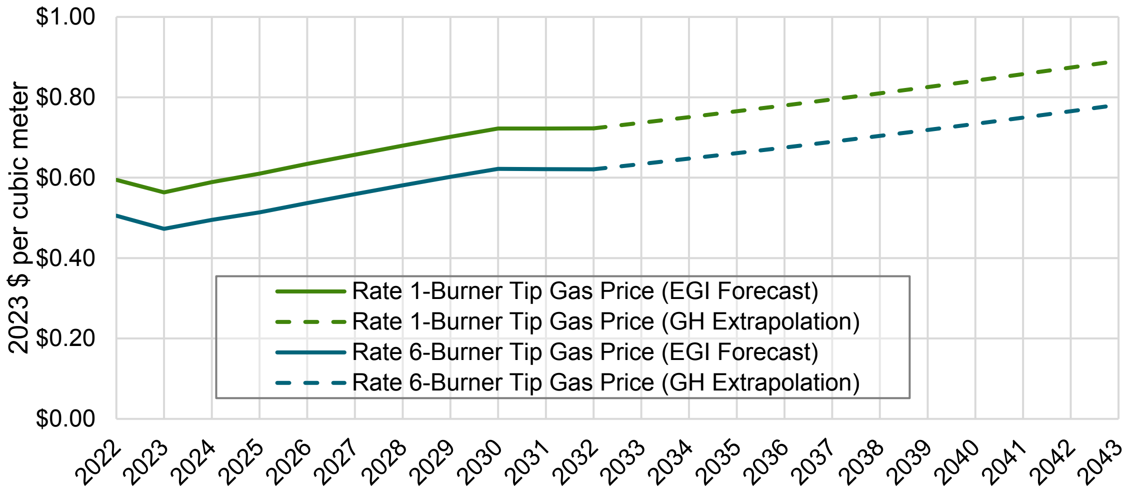
E.3 Retail Energy Rates

Assumed retail rates are a critical input to the adoption modeling discussed above. The retail rates of natural gas and electricity help to determine each measure's payback and thus its long-term equilibrium market share.

EGI provided OEB staff with a forecast of the annual Rate 1 and Rate 6 burner tip gas price, which OEB directed Guidehouse to use as proxies for the Residential and Commercial/Industrial gas prices, respectively, over the period of analysis. Notes provided by EGI indicate that these rates include the fuel charge (carbon price). Projected values were provided in nominal dollars out to 2032. Guidehouse converted these to constant 2023 dollars and extrapolated values beyond 2032 based on the compound annual growth rate (CAGR) estimated from the forecast as provided between the years 2027 and 2032.

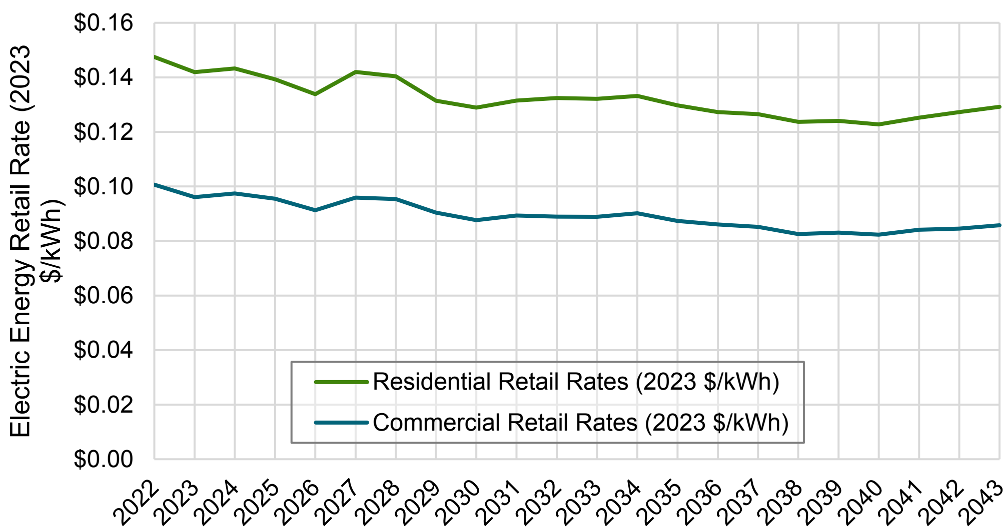
The two series of natural gas retail rates used for assessing customer payback is presented below.

Figure 97. Forecast Natural Gas Retail Rates



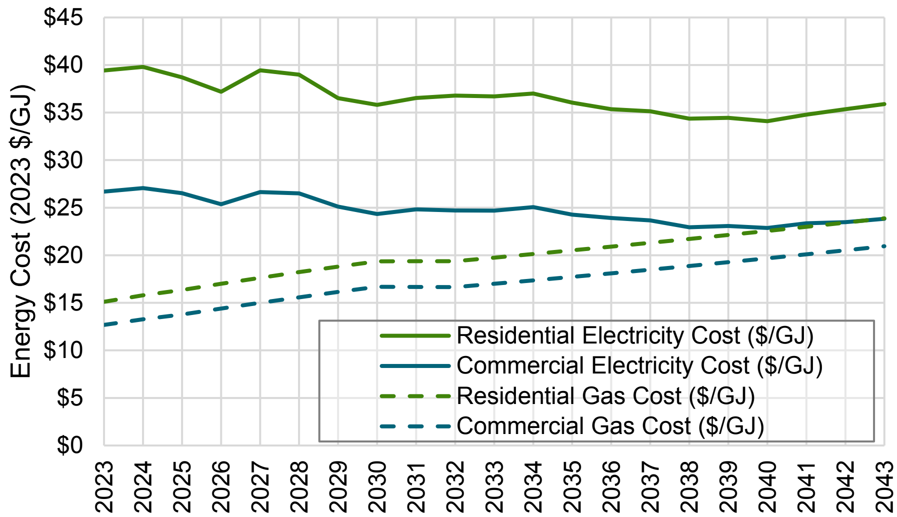
Electric energy retail rates for Residential and non-Residential Class B consumers (used for Commercial customers) were provided by the IESO through 2042. OEB staff directed Guidehouse to use the electric energy retail rates from the IESO. Guidehouse converted these into constant 2023 dollar values and extrapolated values beyond 2042 based on the average five-year CAGR across the different series in the final years of the IESO's forecast.

Figure 98. Forecast Electric Energy Retail Rates



To better understand the dynamics impacting consumer decision-making consider Figure 99, below which expresses both series in common units. Note that although natural gas remains much less costly than electricity through the period of projection, the difference between the two sets of costs narrows considerably. Compounded by improved efficiency of the modeled electrification technologies (which require fewer joules of input) and the rising cost of carbon over time (which flows through to incentives), this indicates that, all else equal, the customer economics of fuel switching should improve over time.

Figure 99. Forecast Natural Gas and Electricity Retail Rates in Common Units



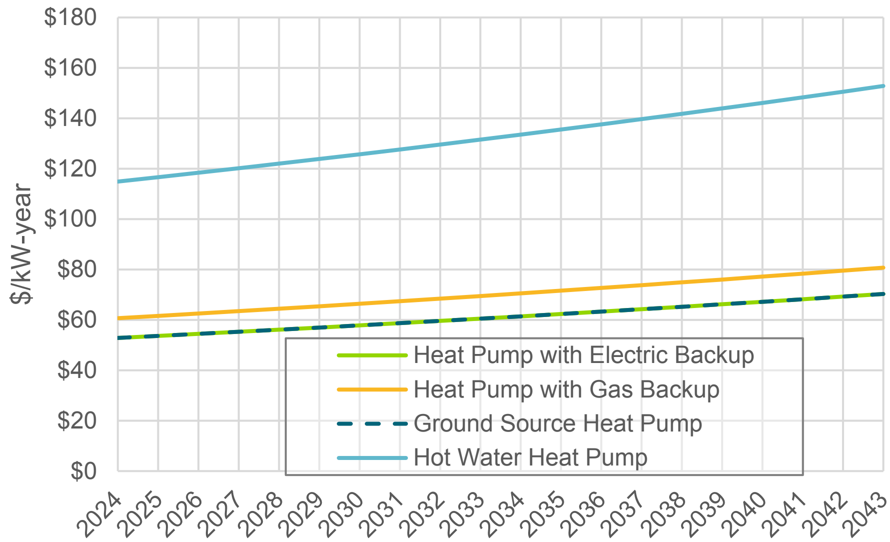
Finally, Guidehouse considered delivery demand charges ($/kW) to which larger non-residential consumers are subject. Excluding these from consideration when assessing the customer economics of fuel-switching would overstate the customer benefits of electrification.

To develop an annual cost to apply to fuel switching measures, Guidehouse began from published 2024 distribution and transmission volumetric charges published for customers of four electricity distributors: Alectra, Toronto Hydro, Hydro One, and London Hydro. Lacking a forecast of these rates, Guidehouse escalated them in real terms (i.e., in constant 2023 dollars) over the period of analysis using the same CAGR applied to Commercial energy retail rates to extrapolate that series.

These projected monthly charges were then applied to the estimated measure-specific monthly peak demands to deliver an annual delivery demand cost for non-Residential customers. Measure-specific monthly demand values for space heating measures were estimated as a function of: the difference between the space-heating balance point and the climate normal daily minimum temperature in each month, the maximum value that difference takes in the year (typically in January), and measure's winter peak demand estimated as part of the measure characterization task. Values were estimated using both Toronto and Ottawa climate normals, and averaged across the two regions.

This delivers a measure-specific load-shape-driven annual demand charge (2023 $/kW). By construction, this means that the flatter the load profile, the higher will be the annual $/kW charge, which may appear counter-intuitive, but when applied to measure peak demands (which are much higher for the peakier measures) yields expected results. For example, in Figure 100, below, the annual rate is highest for the heat pump water heater. This is because this measure's load is (on a monthly basis) relatively flat – the peak for this measure is approximately the same in winter months as in summer months. However, a water heater's winter peak demand is (compared to a fully electric heat pump) relatively low – despite the higher rate, the peak demand cost to the customer is lower for the HPWH than for the fully electric ccASHP.

Figure 100. Annual Peak Demand Charge by Commercial Measure



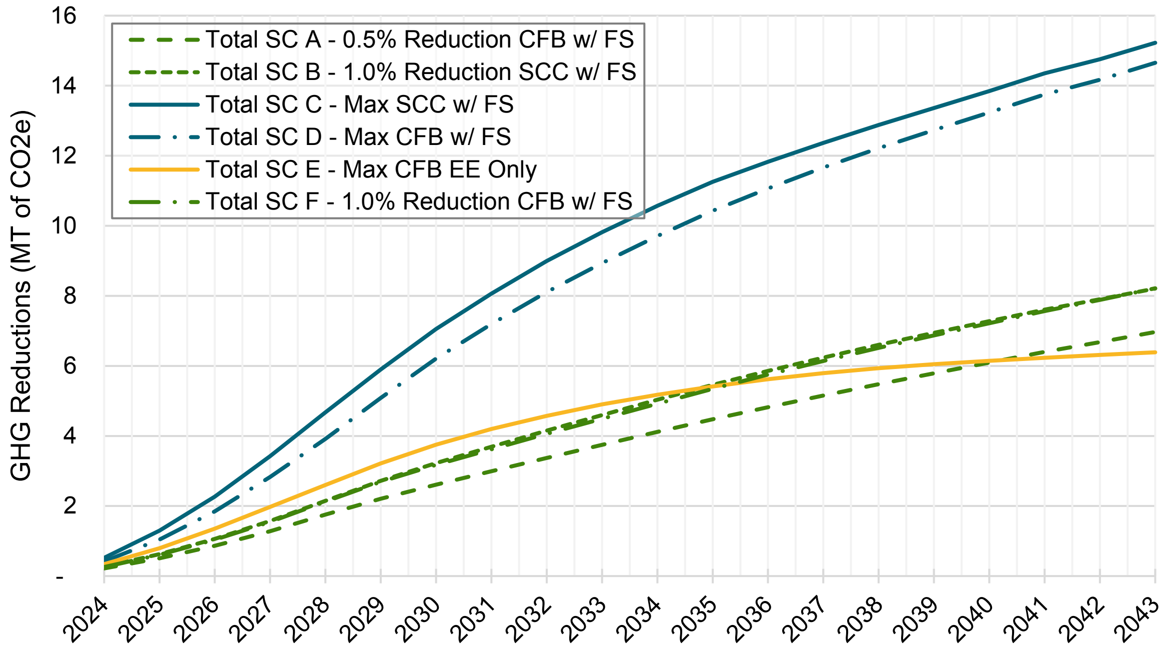
E.4 Expanded Results

This section of Appendix E includes additional Achievable potential impacts that Guidehouse and the OEB team have identified as likely to be of interest to reviewers: the GHG emissions impacts associated with the Achievable potential, and the more granular presentation of Achievable potential by sub-sector. The corresponding impacts of the Achievable potential sensitivity scenarios and of other, less relevant impacts (electric energy, summer peak demand) may be found in the study outputs data but are not included in this report.

E.4.1 GHG Emissions Impacts by Sector

Figure 101 shows the impact of the Achievable potential on provincial GHG emissions, by scenario. GHG impacts are calculated as the GHG reductions resulting from reduced natural gas consumption, net of the incremental emissions from the power generation required to support electrification.

Figure 101. GHG Emissions Reductions Associated with Economic Potential



Estimated GHG reductions are, as would be expected, consistent with the magnitude of Achievable potential.

As noted in Section 5.1.3, GHG impacts are derived from emissions factors drawn from EGI's website[174] (natural gas GHG impacts) and from the IESO's 2022 APO data[175] (power generation GHG impacts).

E.4.2 Natural Gas Achievable Potential by Sub-Sector

Figure 102 shows the Scenario A Achievable potential by Residential sub-sector as a percentage of the reference forecast for that sub-sector. The pattern shown is very similar to that presented in Appendix D for Economic potential. The principal feature of interest is the fact that Low-Income potential as a share of reference forecast is greater than for non-low-income sub-sectors. This is primarily the result of the differing payback acceptance curves for these sub-sectors; the Low-Income curve (Figure 92) is consistent with the assumption that economic considerations are more important to Low-Income households considering the purchase of efficient equipment than non-Low-Income households.

[174] GHG emissions savings resulting from natural gas consumption reductions are calculated using the emissions factor developed by Enbridge Gas for its online emissions calculator

Enbridge Gas Inc., *Greenhouse gas emissions calculator*, accessed July 2023

https://www.enbridgegas.com/ontario/business-industrial/incentives-conservation/energy-calculators/Greenhouse-Gas-Emissions

[175] Incremental generation emissions are estimated by applying the projected average emissions factor derived from data in the IESO's 2022 Annual Planning Outlook, see Figures 43 and 48 of

Independent Electricity System Operator, *Annual Planning Outlook Data Tables,* December 2022

Available at: **https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook**

Figure 102. Residential Achievable Potential by Sub-Sector as Percent of the Corresponding Sub-Sector Reference Forecast

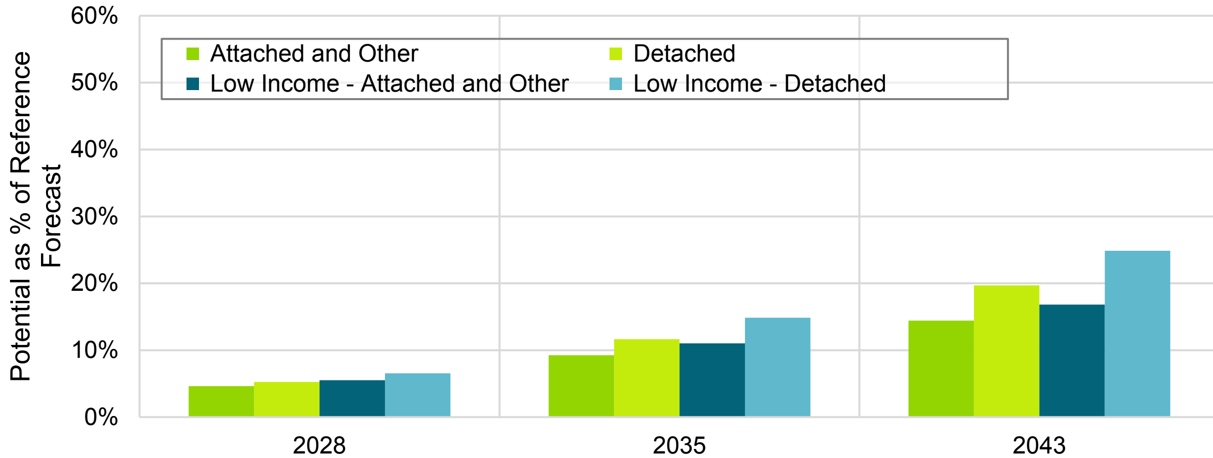
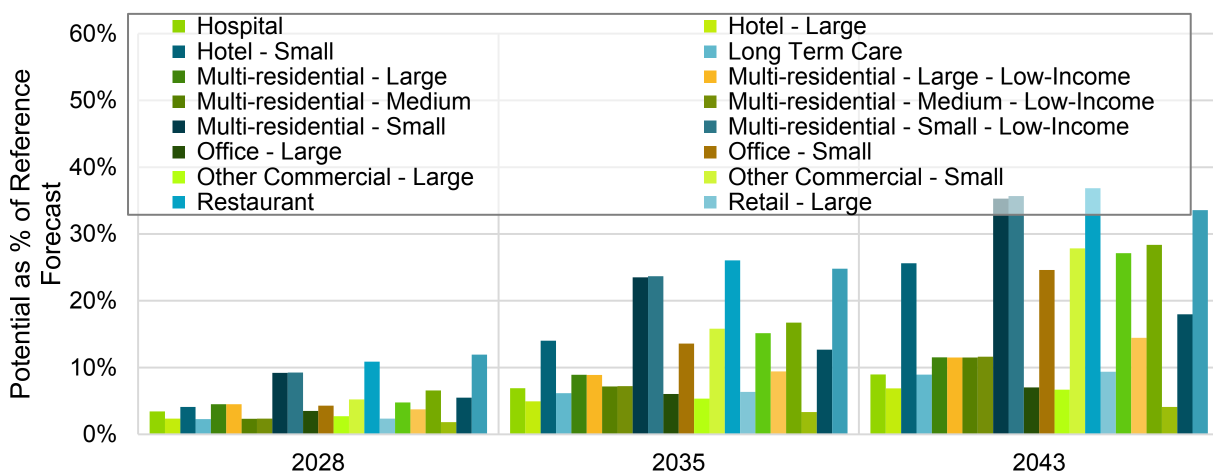


Figure 103 shows the Achievable potential by Commercial sub-sector as a percentage of the reference forecast.

Figure 103. Commercial Achievable Potential by Sub-Sector as Percent of the Corresponding Sub-Sector Reference Forecast



The most salient feature of the version of the plot above in the Technical and Economic potential Appendices was distinct split between sub-sectors characterized by larger buildings (potential smaller in relative terms) and those characterized by smaller buildings (potential larger in relative terms). This was noted as being largely the outcome of the application of Technical Suitability factors which (as described in detail in Section B.3.10) substantially limit the fuel switching potential in Commercial sub-sectors characterized by larger buildings. Sub-sector potential reflects the same underlying drivers and outcomes as Economic potential: assumed values for Technical Suitability of fuel switching substantially limit the Achievable potential for the sector.