Conservation Behind the Meter Generation Potential Study

Potential Analysis Report

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June 30th, 2016

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Comprehensive Executive Summary

The IESO engaged Navigant Consulting, Ltd. (Navigant) to evaluate the potential for conservation behind the meter generation (BMG) to conserve electricity across Ontario. Key study objectives include:

- Understanding the potential to displace electric loads for Combined Heat and Power (CHP)[1] and Waste Energy Recovery (WER) installed in facilities connected:
  - To each of the local distribution systems
  - Directly to the transmission system
- Gaining insights, evidence, and documentation to make critical policy decisions about how, when, where, and to what extent to promote the installation and operation of BMG across Ontario.

Navigant documented each task under this assignment in separate task reports to the IESO. This Task 5 report includes a comprehensive executive summary.

The scope of this study is limited to:

- BMG nominal capacities of 100 kW to 10 MW (to 20 MW if the facility is connected directly to the electric transmission system)
- Facilities that have access to pipeline natural gas.

The key outputs of this study include:

- Technical Potential: Potential savings based on instantaneous installation of BMG in all technically suitable applications, regardless of economics
- Economic Potential: Portion of the technical potential that passes the Program Administrator Cost (PAC) test
- Market Potential:
  - Financial Market Potential: Portion of the economic potential that customers would eventually implement based on financial factors alone
  - Non-Financial Market Potential: Portion of the economic potential that customers would eventually implement accounting for both financial and non-financial factors

[1] CHP systems that qualify for incentives under either the IESO's Conservation First Framework LDC Tool Kit, or the IESO's Industrial Accelerator Program, are referred to as Conservation Combined Heat and Power (CCHP). We use the more general acronym "CHP" in this report.

- Cap & Trade Potential: Financial and non-financial market potentials adjusted for the impacts of the Climate Mitigation and Low-Carbon Economy Act
- Constrained Potential: Portion of the market potential achievable after accounting for electricity system constraints that may limit BMG installations

Each potential analysis includes:

- Results for CHP and WER
- Results by LDC (including transmission-connected facilities) and facility type
- Results for the years 2015, 2017, 2020, and 2025
- Nominal installed capacities (MW), annual electricity savings (GWh), and electric demand reductions (MW).

Results also include impacts on greenhouse gas emissions (metric tonnes CO2 equivalent) for market potentials.

The results of the BMG potential analysis show that:

- The 2025 province-wide market potential for multi-family, commercial, and institutional facilities is very low—only about 23 GWh out of the almost 10,000 GWh of technical potential for these facility types
- The 2025 province-wide market potential for industrial facilities is about 1,100 GWh, or about 7 percent, of the almost 16,000 GWh of technical potential for these facility types
- Scenarios 1 and 2 (40 percent versus 70 percent first-cost incentive) generally result in little or no difference in market potential. This occurs because other scenario constraints limit the incentive paid. For example, for both scenarios, the incentive cannot be higher than the annual electricity savings multiplied by $200 to $230/MWh.
- The Climate Mitigation and Low-Carbon Economy Act is projected to have almost no impact on WER and will decrease CHP potential by approximately 20%
- The constrained potential analysis shows modest reductions in market potential (about 6 percent reduction in CHP potential for scenario 1). However, available electricity network connection capacity, which must be determined on a project-by-project basis and which was not accounted for in this analysis, will reduce constrained potential further.

Table 1 summarizes the province-wide market potentials for CHP and WER for scenario 1 (current program incentives) based on modelled results.

Table 1: Summary of BMG Market Potentials Based on Modelled Results (for Scenario 1)[a]

Year	BMG Type	Installed Capacity (GW)	Electricity Savings (GWh)	Demand Savings (MW)
2015	CHP	13	95	11
2015	WER	~0	2	~0
2017	CHP	43	307	34
2017	WER	1	8	1
2017	CHP	89	639	71
2020	WER	2	16	2
2020	CHP	147	1040	116
2025	WER	4	26	3

a) Market potentials listed here are not adjusted to account for actual projects and project applications, connection constraints, or cap and trade legislation.

Analysis Scenarios

Table 2 summarizes the three analysis scenarios used in this study.

Table 2: Summary of Analysis Scenarios

Scenario	Description	Rationale
Scenario 1: Current Program Rules	First-Cost Incentive is lowest of: • 40% of eligible costs for CHP; 70% of eligible project costs for WER • Annual (single year) electricity savings multiplied by \$200/MWh or \$230/MWh [a] • Amount that would provide a Project Payback of one year for a Project.	• Current program rules
Scenario 2: Increase First-Cost Incentive Level	• Increase CHP incentive to 70% of first cost • Other requirements remain the same as in Scenario 1	• Straight-forward program change • Straight-forward comparisons to Scenario 1 for TRC and PAC • 70% provides a significant change relative to current programs, but still leaves the customer with first costs high enough to eliminate those who are not serious about operating BMG
Scenario 3: No First- Cost Incentive Level combined with Production Incentive	• Eliminate first-cost incentive • Include production incentive of \$0.02/kWh for the first 10 years of operation • Other requirements remain the same as in Scenario 1	• Precedents for use • Provides insights into the cost-effectiveness of production-based incentives compared to first-cost-based incentives • Will incent customers to operate BMG units effectively after installation

a) \$200/MWh for the Conservation First Framework; \$230/MWh for the Industrial Accelerator Program (for transmission-connected facilities)

BMG Technologies

Table 3 and Table 4 summarize cost and performance characteristics for the BMG technologies used in this study.

Table 3: Summary of CHP Cost and Performance Characteristics

Attribute	Internal-Combustion Engine [a]	Simple-Cycle Gas Turbine [a]	Steam Turbine (Rankine Cycle) [a]
Installed Cost (2015 $CAD/kW) [b]	$2200 - $4200	$2500 - $5800	$3300 - $5300
Variable O&M Cost (2015 $CAD/MWh) [b]	$14 - $36	$14 - $20	$6
Fixed O&M Cost (2015 $CAD/kW) [b]	$2 - $22	$14 - $43	Included under Variable O&M
Heat Rate (HHV) (Btu/kWh)	8000 – 12,000	11,000 – 17,000	37,000 – 55,000
Overall Efficiency (HHV) [c]	0.79	0.71	0.8

a) Ranges for CHP capacities of 100 kW to 5 MW for engines, 1 MW to 20 MW for gas turbines, and 500 kW to 20 MW for steam turbines. The analysis used performance and cost correlations that are a function of nominal CHP capacity.

b) Converted from USD to CAD (1.2767 CAD = 1 USD), and labour component adjusted from U.S. labour rates to Ontario labour rates.

c) Based on the unweighted sum of the electricity and recoverable thermal output of the CHP system while operating at full-load conditions.

Table 4: Summary of WER Cost and Performance Characteristics

Attribute	Steam Rankine Cycle [a]	Organic Rankine Cycle [a]
Installed Cost (2015 $CAD/kW) [b]	$1700 - $3800	$2900 - $5800
Fixed and Variable O&M Cost (2015 $CAD/MWh) [b]	$7 - $16	$13 - $23
Electrical Generation Efficiency (HHV) (% of Carnot) [c]	40%	40%

a) Ranges for WER capacities of 100 kW to 20 MW. The analysis used performance and cost correlations that are a function of nominal WER capacity.

b) Converted from USD to CAD (1.2767 CAD = 1 USD), and labour component adjusted from U.S. labour rates to Ontario labour rates.

c) Carnot efficiency is the theoretical maximum efficiency of a heat engine. It is a function of the absolute temperatures of the hot source and cold

Applicable Facilities

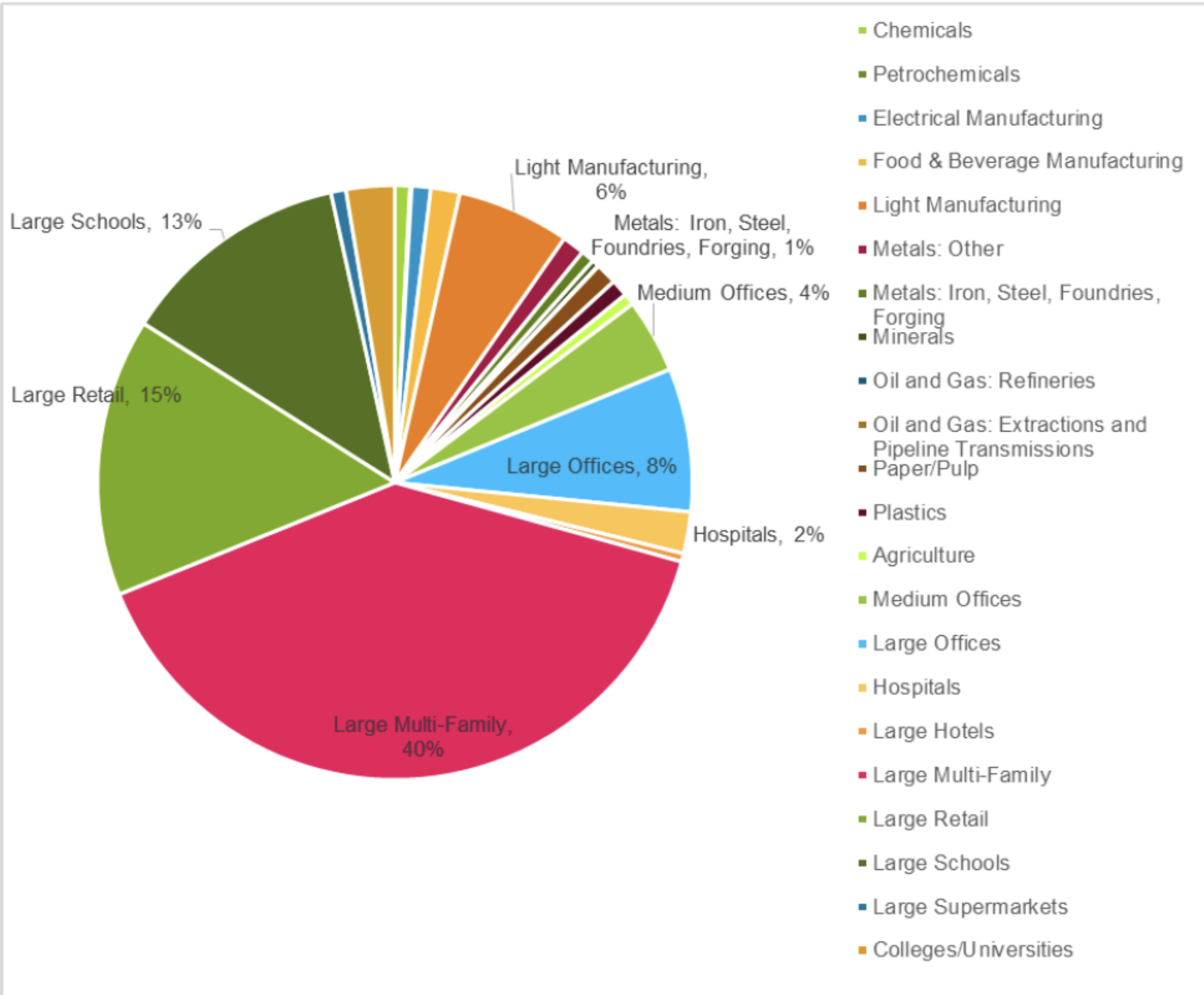
Table 5 lists the types of applicable facilities considered for this study. We selected facility types based on their potential to use BMG systems of 100 KW or larger, including multi-family, commercial/institutional, and industrial facilities that have significant thermal loads. At the request of the IESO, we also included greenhouses, which fall under the agricultural sector.

Table 5: Applicable Facilities Types

Commercial and Multi-Family Facility Types	Industrial Facility Types
Hospitals	Agriculture/Greenhouses
Large Hotels	Chemicals
Large Multi-Family	Electrical Manufacturing
Medium Offices	Food & Beverage Manufacturing
Large Offices	Light Manufacturing
Large Retail	Metals: Iron, Steel, Foundries, Forging
Large Schools	Metals: Other
Large Supermarkets	Minerals
Colleges/Universities	Oil & Gas: Refineries
-	Oil and Gas: Extractions and Pipeline Transmissions
-	Paper/Pulp
-	Petrochemicals
-	Plastics

Figure 1 shows the percent of floor space for each facility type considered in this study.

Figure 1: Applicable Facilities by Facility Type (Percent of Floor Space)



Source: IESO-supplied data, including MPAC commercial and multi-family data and D&B industrial data

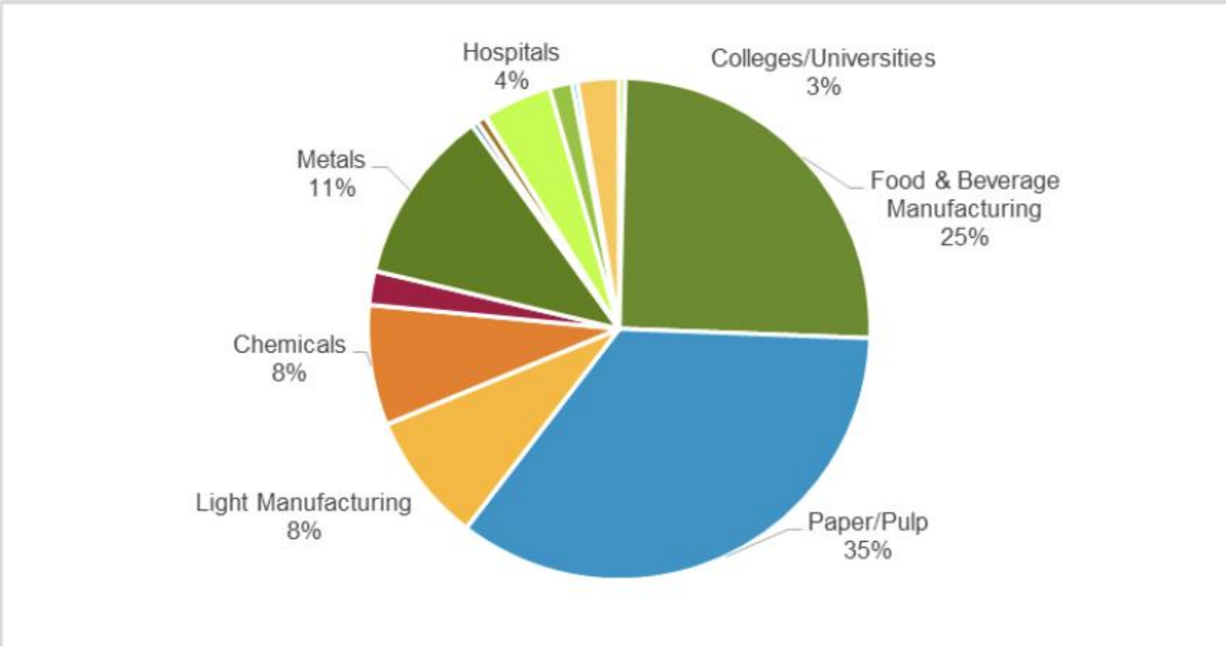
Existing Projects

We identified 107 CHP projects and 3 WER projects already in operation in Ontario facilities, representing about 1.1 GW of existing BMG projects (see Figure 2 and Figure 3).

Figure 2: Existing BMG Projects in Ontario

Sources: CIEEDAC CHP database; IESO-supplied data on previous BMG projects; inputs from Ontario LDCs

Figure 3: Existing BMG Projects in Ontario by Facility Type (Percent of Installed Capacity)



Energy Profiles

We modelled each facility type using annual hourly energy profiles (both thermal and electric). For commercial/institutional and multi-family facilities, we generated energy profiles using the U.S. Department of Energy's (DOE's) EnergyPlus building energy model, using inputs consistent with the DOE's Commercial Reference Buildings.[2] We used Typical Meteorological Year weather data for the largest city in each of Ontario's three climate zones (Windsor, Toronto, and Thunder Bay for ASHRAE climate zones 5, 6, and 7, respectively) to generate the profiles.

Table 6: DOE Reference Buildings used to Generate Commercial/Institutional and Multi-Family Energy Profiles

IESO Study Profile	DOE Profile	Reference Building Size (sq. ft.)
Colleges/Universities	Mix [a]	230,199
Hospitals	Hospital	241,351
Large Hotels	Large Hotel	122,120
Large Offices	Large Office	498,588
Medium Offices	Medium Office	53,628
Large Retail	Stand Alone Retail	24,962
Large Schools	Secondary School	210,887
Large Supermarkets	Supermarket	45,000
Large Multi-Family	Mid-Rise Apartment	33,740

a) Approximated using the following mix of available reference buildings: 52% large schools, 22% large offices, 25% large multi-family, and 1% hospitals

We obtained most industrial facility energy-use intensities (EUIs) from the Energy Information Administration, Manufacturing Energy Consumption Survey (MECS).[3] We calibrated these data using consumption data from Natural Resource Canada's (NRCan) Comprehensive Energy Use Database: Industrial Sector – Ontario.[4]

[2] Source: US Department of Energy. http://energy.gov/eere/buildings/commercial-reference-buildings
[3] Manufacturing Energy Consumption Survey, Energy Information Administration, 2010, https://www.eia.gov/consumption/manufacturing/
[4] Comprehensive Energy Use Database: Industrial Sector – Ontario, Natural Resource Canada, http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/comprehensive/trends_agg_on.cfm

For oil and gas extraction facilities, we determined EUIs by Ontario-specific facility floor spaces, Ontario-specific production, and industry-standard Energy Return on Investment (EROI) values both for conventional extraction and for oil sands extraction. We obtained greenhouse EUIs from a Cornell University study of greenhouse energy use.[5]

We used profiles representing Ontario-based industries to distribute consumption data over the 8760 hours in a year. We developed energy profiles by normalizing and combining metered and modelled energy profiles using energy profiles of industries in Ontario (provided by the IESO). Where we did not have adequate Ontario-specific data for a given industry, we supplemented IESO-provided energy profiles with profiles from CHP studies in areas outside of Ontario.

BMG Simulation Tool

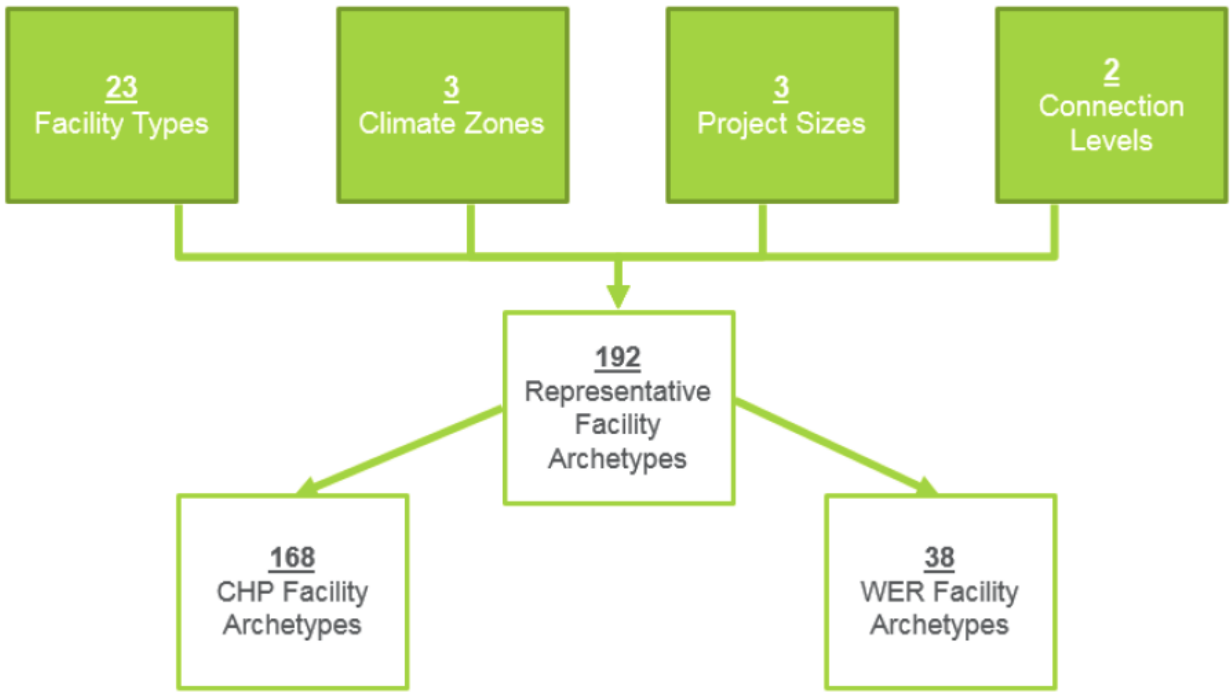
The rigor and complexity required to conduct this analysis led Navigant to develop a new BMG analysis tool. The key features of the new BMG tool are:

- Simulates BMG operation at the hourly level, accounting for:
    - Hourly variations in facility thermal and electric loads
    - Both volumetric-based and demand-based components of electric and gas rates
- Provides three options for CHP operational strategy:
    - “Smart” strategy (CHP operation responds to price signals)
    - Thermal-and-electric-load-following strategy (facility loads dictate operation, with no dumping of excess thermal energy)
    - Modified thermal-and-electric-load-following strategy (allows dumping of excess thermal energy during peak electric periods, subject to program constraints)
- Ensures compliance with IESO program constraints
- Provides high levels of granularity to show results by facility type, LDC, connection level (transmission or distribution), and analysis scenario.
- Accommodates multiple BMG capacity choices available to customers
- Developed in the Analytica platform to permit sophisticated operational algorithms, reduce coding errors, and reduce execution time compared to traditional spreadsheet-based models.

5 CUAES Greenhouses – Energy Consumption and Equivalents, Cornell University Agricultural Experiment Station, March 2014.
[5] CUAES Greenhouses – Energy Consumption and Equivalents, Cornell University Agricultural Experiment Station, March 2014.
https://cuaes.cals.cornell.edu/sites/cuaes.cals.cornell.edu/files/shared/documents/Greenhouse-energy-consumption-2014-03-21.pdf

For CHP, Navigant identified approximately 27,000 customers that met the minimum peak-demand requirements for BMG eligibility as per the IESO program rules for the Process and Systems and Industrial Accelerator programs in 2015. Navigant grouped these customers in 192 representative customer archetypes based on facility type, climate zone, facility size, and connection level (see Figure 4).

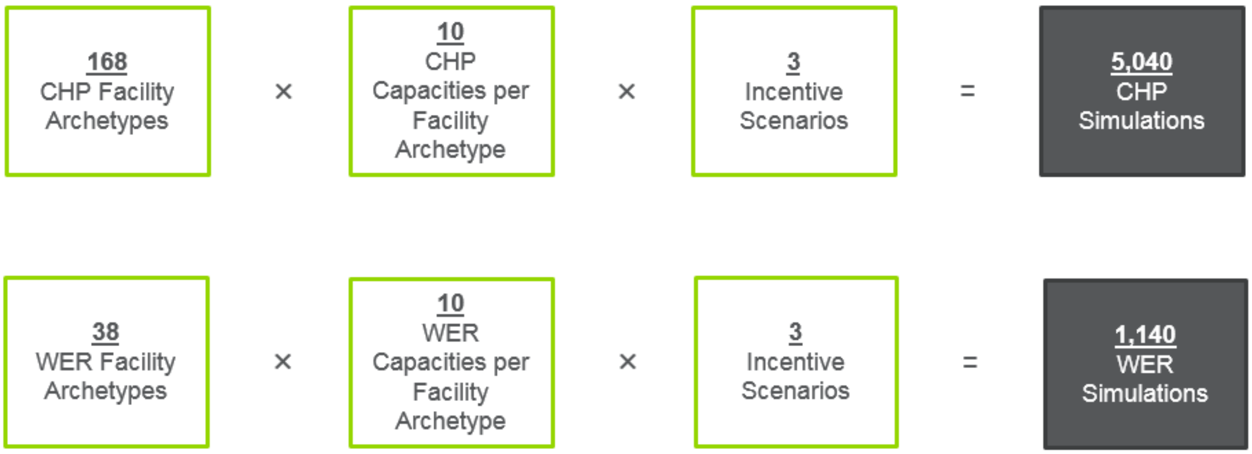
Figure 4: Representative Facility Archetypes [a]



a) The total representative facility archetypes add up to a number higher than 192 because the paper/pulp facility type (14 archetypes) is considered eligible for both CHP and for waste fuel-based WER.

As Figure 5 shows, we simulated 5040 CHP installations and 1140 WER installations to conduct this analysis.

Figure 5: CHP and WER Simulations



For technical and economic potentials, we assumed that BMG potentials increase in proportion to population growth. We used population growth projections for the major city in each climate zone (London, Toronto, and Thunder Bay for climate zones 5, 6, and 7, respectively).

While the BMG tool can simulate multiple CHP operational strategies, working with the IESO, we ultimately based the analysis on a modified load-following strategy:

- No electricity export to the grid
- No dumping of recoverable thermal energy, except during the 180 hours/year that, in our judgment, could impact Global Adjustment (GA). Thermal dumping is limited to ensure that the total system efficiency does not fall below 65% (HHV) for the year (per IESO program requirements).
- If either electric or thermal energy use falls below the minimum turn-down ratio of the CHP system, the CHP system does not run for that hour

WER can be driven by two different sources: waste heat (generally steam or hot air from industrial processes), or waste fuel (such as biomass from paper/pulp production). Navigant's BMG tool uses a straight-forward operational strategy for WER: if the hourly operational cost of running a WER unit is lower than the base-case hourly cost, the WER unit will operate at full capacity or up to the facility electric load, whichever is lower. Operation is also constrained by how much waste heat or waste fuel is available on an hourly basis.

Potential Analyses

We used three parameters to quantify potentials:

- **Electricity Savings:** The annual electricity generated by BMG at the customer site-level, which is equivalent to the amount of grid electricity saved (gigawatt-hours).
- **Demand Savings:** The average reduction in electric demand during summer peak hours achieved by BMG at the customer site (megawatts) (see Figure 6).

Figure 6: Summary Peak Demand Savings Periods

Season	Time	Months
Summer (Weekdays)	1 PM – 7 PM	June
		July
		August

Source: Ontario Power Authority[6]

- **Capacity:** The total nominal electric generation capacity of BMG units (gigawatts).

This summary reports only energy savings at the province-wide level—see the main body of the report for additional results.

Technical Potential

We based technical potential on the largest technically feasible BMG system beyond which there are no appreciable electricity savings.

CHP technical potential does not depend on incentive scenario because no price signals are taken into account during operation. WER results show differences by incentive scenarios due to the hourly cost minimization operational strategy.

Figure 7 summarizes the CHP technical potential for Ontario by year based on electricity savings. The province-wide CHP technical potential is about 22 TWh in 2015, increasing to about 24 TWh by 2025. This compares to about 53 TWh of baseline electricity consumption in 2015 for CHP applicable facilities, or about 42 percent reduction in electricity consumption. It also corresponds to about 16 percent of Ontario's total 2015 electricity consumption (about 137 TWh).[7]

[6] http://www.powerauthority.on.ca/sites/default/files/conservation/Conservation-First-EMandV-Protocols-and- Requirements-2015-2020-Apr29-2015.pdf
[7] Ontario Energy Reports—Demand for 2015 Q1, Q2, Q3, and Q4

Figure 7: CHP Technical Potential in Electricity Savings for System

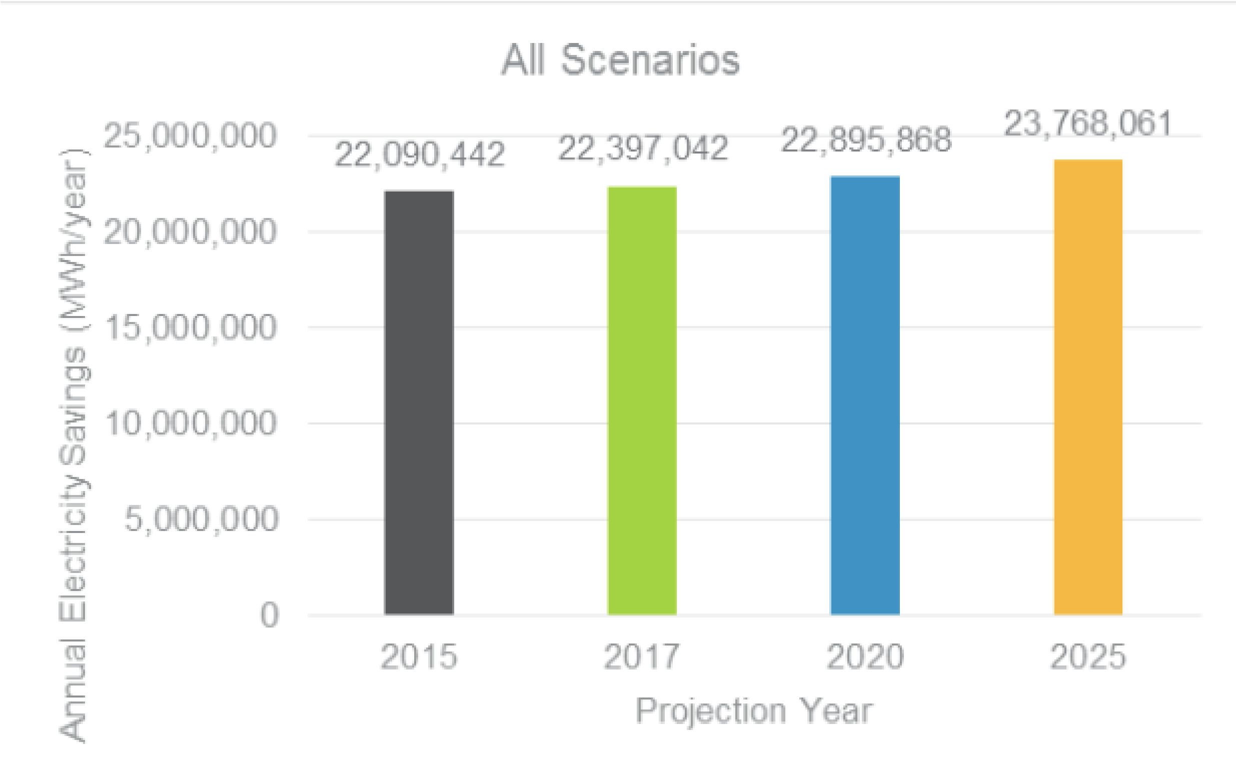
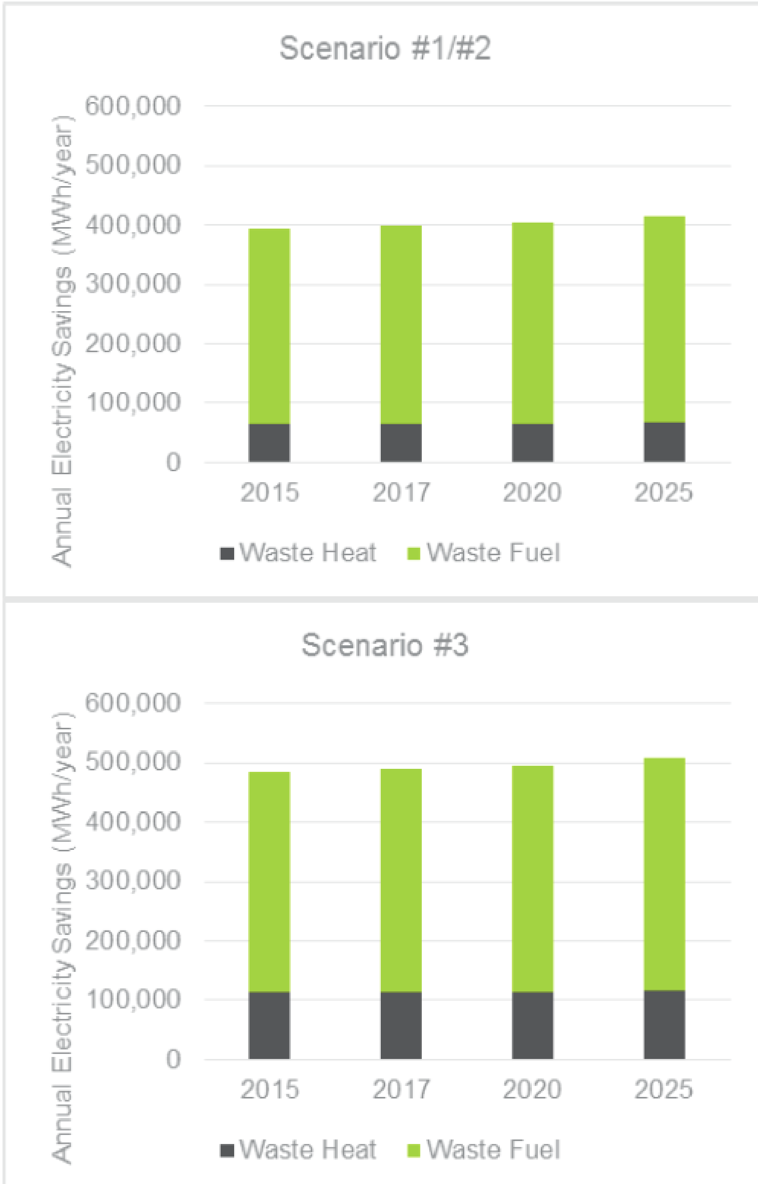


Figure 8shows the province-wide WER technical potential based on electricity savings for the three analysis scenarios. WER technical potentials are substantially lower compared to CHP technical potentials. WER technical potentials in 2015 range from about 0.4 to 0.5 TWh of baseline electricity consumption (depending on scenario), or about 2 percent of the 2015 CHP technical potential. It also corresponds to about 0.3 percent of Ontario's total 2015 electricity consumption (about 137 TWh). Waste fuel-based WER represents the bulk of WER technical potential (77 to 84 percent in 2015, depending on scenario).

Figure 8: WER Technical Potential in Electricity Savings for System



Economic Potential

Economic potential is the portion of technically feasible BMG that produces a net benefit from a program administrator perspective. Economic potential is determined by completing one cost-effectiveness screen on each BMG size and facility archetype that is at or below the capacity selected for calculating technical potential. The Program Administrator Cost (PAC) test evaluates the benefits to the program administrator (i.e., the IESO). Cost-effectiveness tests calculate the relevant benefit and cost components and the results can either be expressed as a dollar amount representing the net benefit (benefit minus costs) or as a ratio (benefits divided by costs). A project passes the PAC test if it results in a positive net benefit or if the benefit-cost ratio is greater than 1.0.

All facility types analyzed pass the PAC test and, therefore, BMG economic potentials are the same as the technical potentials summarized above.

Market Potential

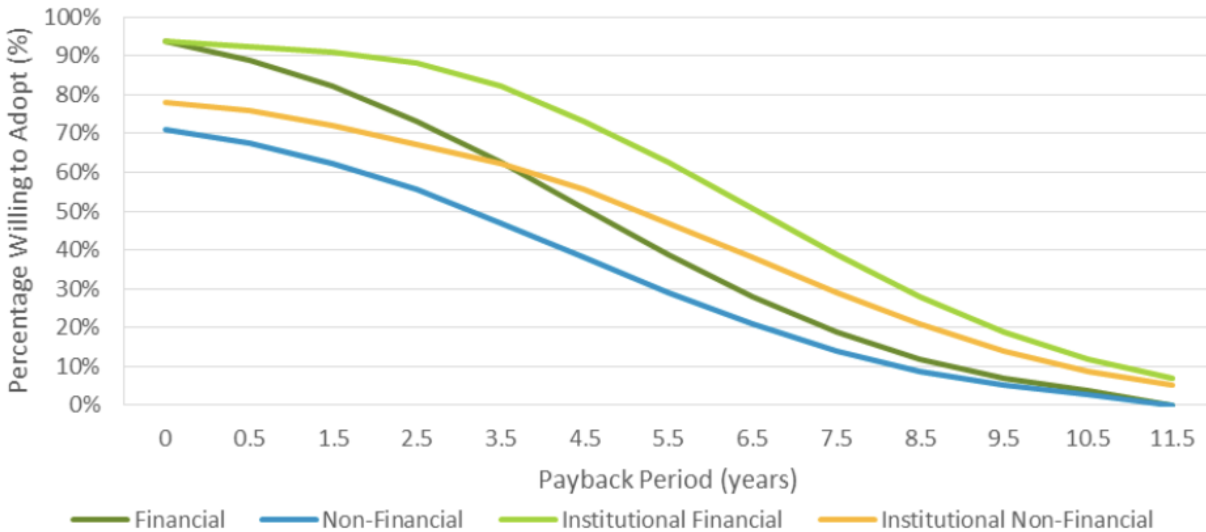
Market potential represents the portion of economic potential that is likely to be achieved over time. In contrast to technical and economic potentials, market potential considers the time required to raise awareness, generate market interest, conduct engineering analyses, and design, develop, and install BMG systems. Market potential is determined using three key steps and concepts:

1. Participant cost screen and optimal sizing
2. Financial and non-financial potential
3. Market diffusion.

The first step of the market potential considers all BMG sizes for a given facility that pass the PAC. These projects are run through a cost-effectiveness test that captures the customer perspective. The participant cost screen uses the Participant Cost (PC) test to evaluate the project from the customer’s perspective. The PC test calculates the benefit and cost components, and the results can either be expressed as a dollar amount representing the net benefit (benefit minus costs) or as a ratio (benefits divided by costs). A project passes the participant cost test if a positive net benefit results or if the ratio is greater than 1.0.

Payback acceptance curves define the relationship between the simple payback of a project and the percentage of the market that will proceed with a project. Both financial and non-financial factors impact a customer’s decision whether or not to move forward with a project, and different sectors generally have different payback thresholds. Navigant segmented the analysis of payback acceptance into four types: financial and non-financial (institutional facilities), and financial and non- financial (non-institutional). The financial payback acceptance curves were developed leveraging an in-depth analysis conducted by Navigant for an energy-efficiency potential study. The non-financial payback acceptance curves were developed using both quantitative and qualitative analyses to account for both financial and non-financial factors. Non-financial factors can include environmental permitting, technical constraints, site-specific concerns, customer security/reliability, and other factors. Figure 9 shows the resulting payback acceptance curves.

Figure 9: Payback Acceptance Curves



Market Diffusion characterizes the pace of project implementation taking into account factors such as marketing and outreach efficacy, project lead times, and equipment cost reductions over time.

Navigant used a Bass Diffusion model to represent the implementation of market potential over time. The model considers the influence from early adopters (innovators) and late adopters (imitators), which explains how uptake occurs at the onset of a new product, idea, or process. Figure 10 shows the market diffusion curve developed for this analysis.

Figure 10: BMG Bass Diffusion Curve

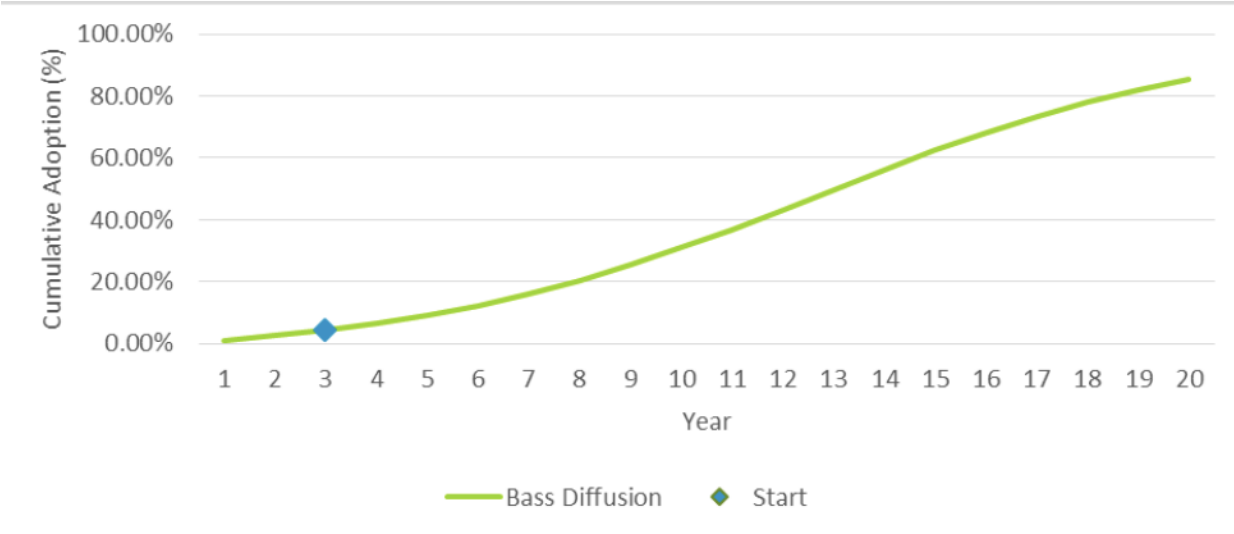


Figure 11 shows the province-wide CHP market potential based on electricity savings. The two charts in the figure, labeled “Non-Financial Payback Curve” and “Financial Payback Curve”, represent the overall market potential and the market potential considering only financial factors, respectively. The province-wide CHP market potential increases from about 60 to 130 GWh in 2015 (depending on scenario) to about 700 to 1400 GWh in 2025. The 2025 projections represent about 3 to 6 percent of the 2025 CHP technical potential (depending on scenario).

Figure 11: CHP Market Potential in Electricity Savings for System

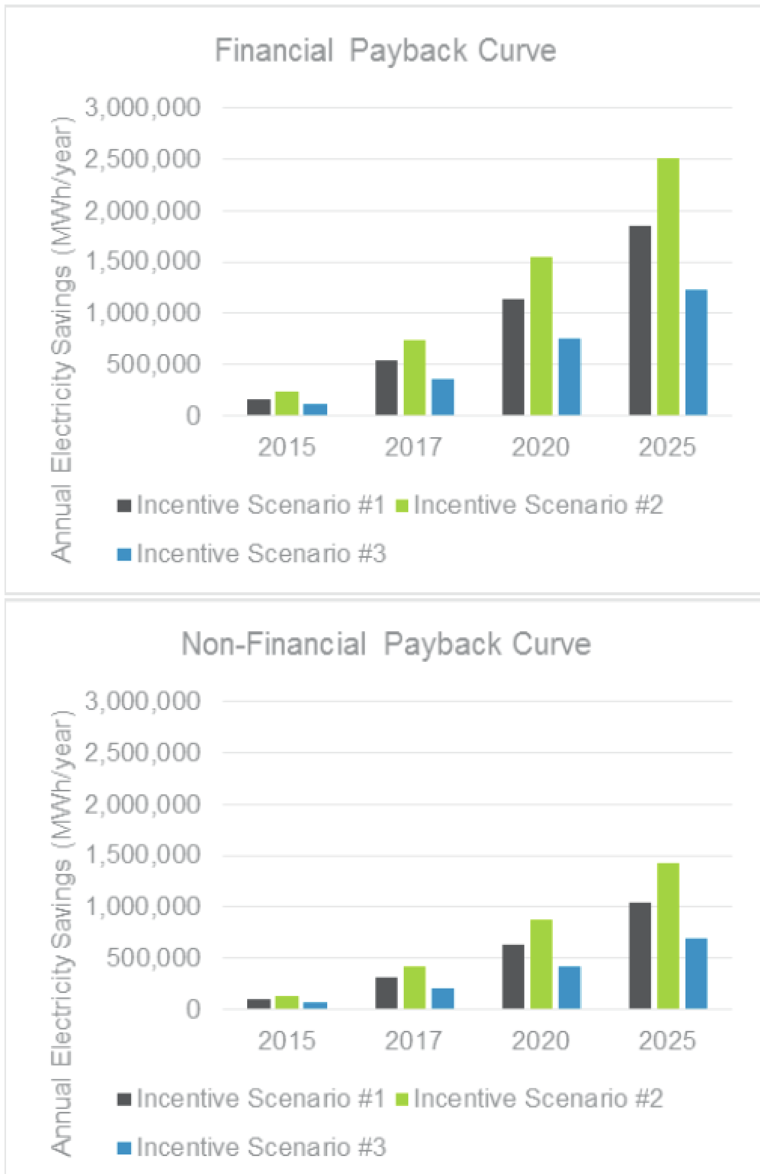
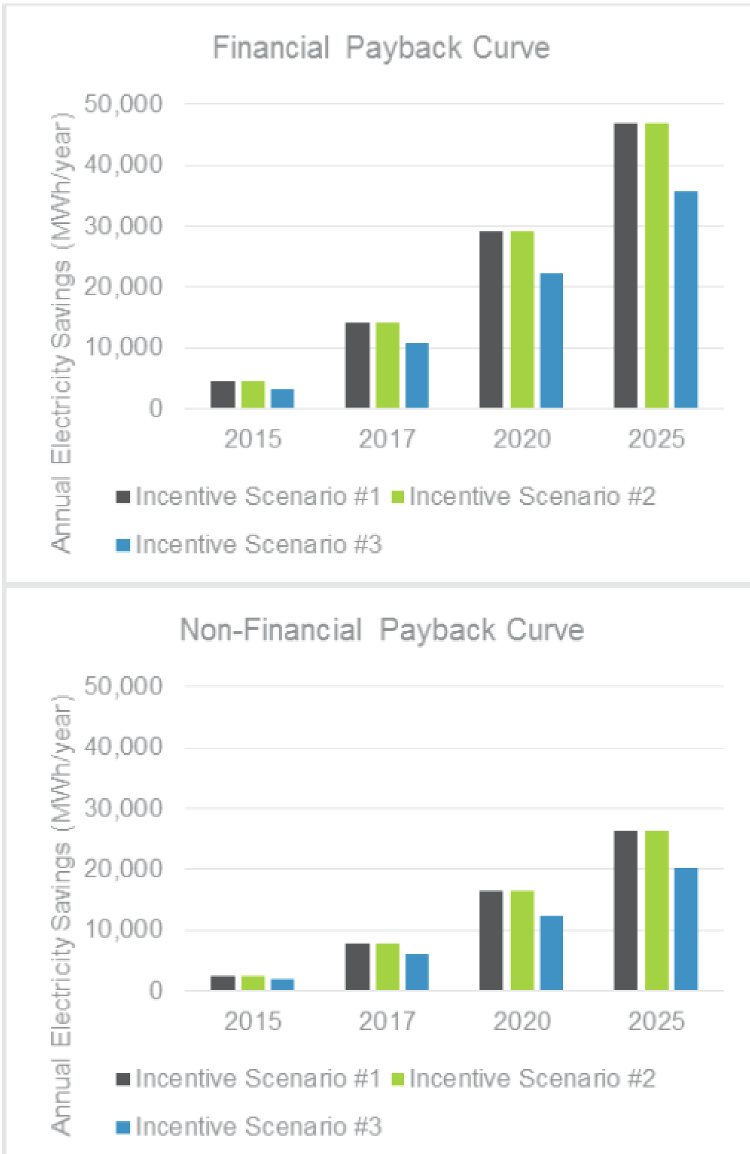


Figure 12 shows province-wide WER market potential based on electricity savings (both overall and financial-only market potentials). The province-wide WER market potential increases from about 1.9 to 2.4 GWh in 2015 (depending on scenario) to about 20 to 26 GWh in 2025 using non-financial payback curves. The 2025 market potential represents about 4 to 5 percent (depending on scenario) of the 2025 WER technical potential based on electricity savings.

Figure 12: WER Market Potential in Electricity Savings for System



Cap & Trade Potential

We evaluated the impact of recent cap and trade regulations to the potential for conservation behind the meter generation (BMG) to conserve electricity across Ontario.

The regulation creates a price for carbon which will directly affect natural gas prices and indirectly affect electricity prices. The changes in these prices may impact the potential for CHP across Ontario as costs and benefits are directly tied to both natural gas and electricity costs.

Navigant developed a Cap and Trade scenario to evaluate the impact of the new regulation relative to the base case (i.e., current program rules). Under the Cap and Trade scenario, Navigant leveraged electricity and gas forecasts provided by the IESO which account for the expected carbon prices.[8] We applied these forecasts at the Market Potential stage of the analysis to determine the impact of the proposed legislation on BMG potential.

The impact of the carbon cap-and-trade market shows a relatively minor increase in WER potential and a decrease of about 20% for CHP potential. The cap-and-trade pricing has a much larger impact on projected gas prices than electricity prices which results in a much larger impact for CHP than WER.

Figure 13 shows CHP market potential under carbon cap-and-trade based on electricity savings. Under scenario 1, in 2025, this market potential is about 81 percent of market potential without cap- and-trade (0.84 TWh vs. 1.04 TWh).

[8] Because the forecasts are not public, we do not describe them herein

Figure 13: CHP Market Potential with Carbon Market in Electricity Savings for System

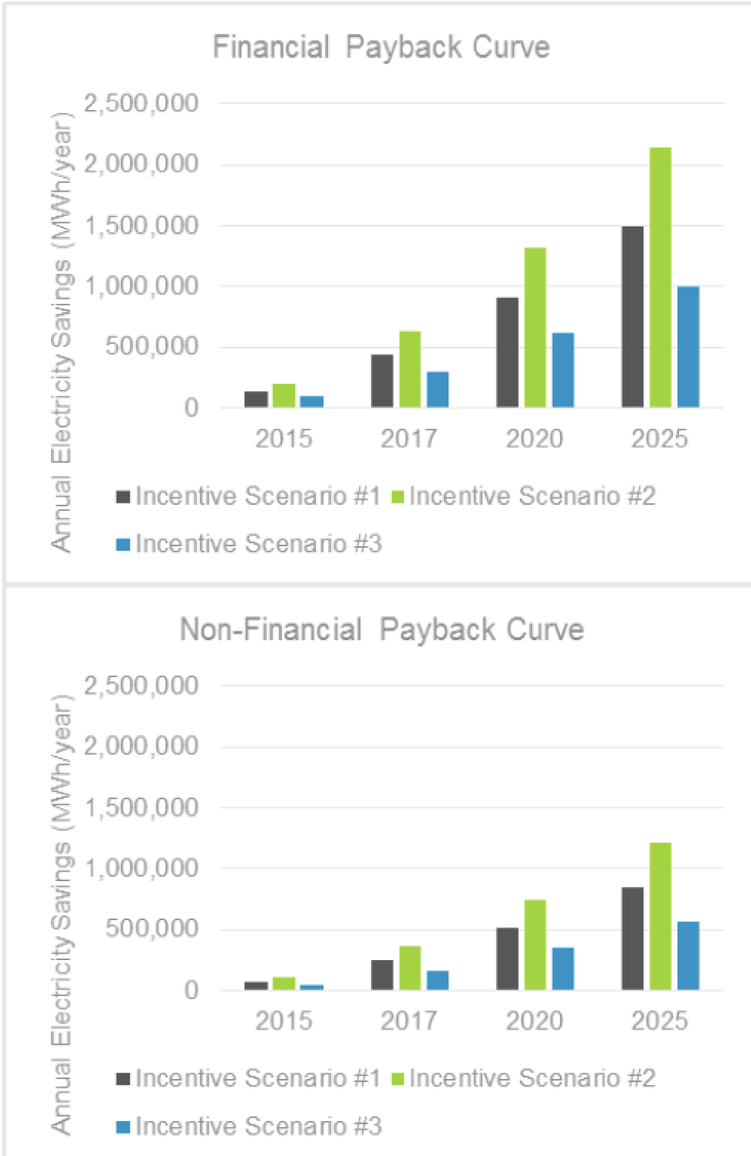
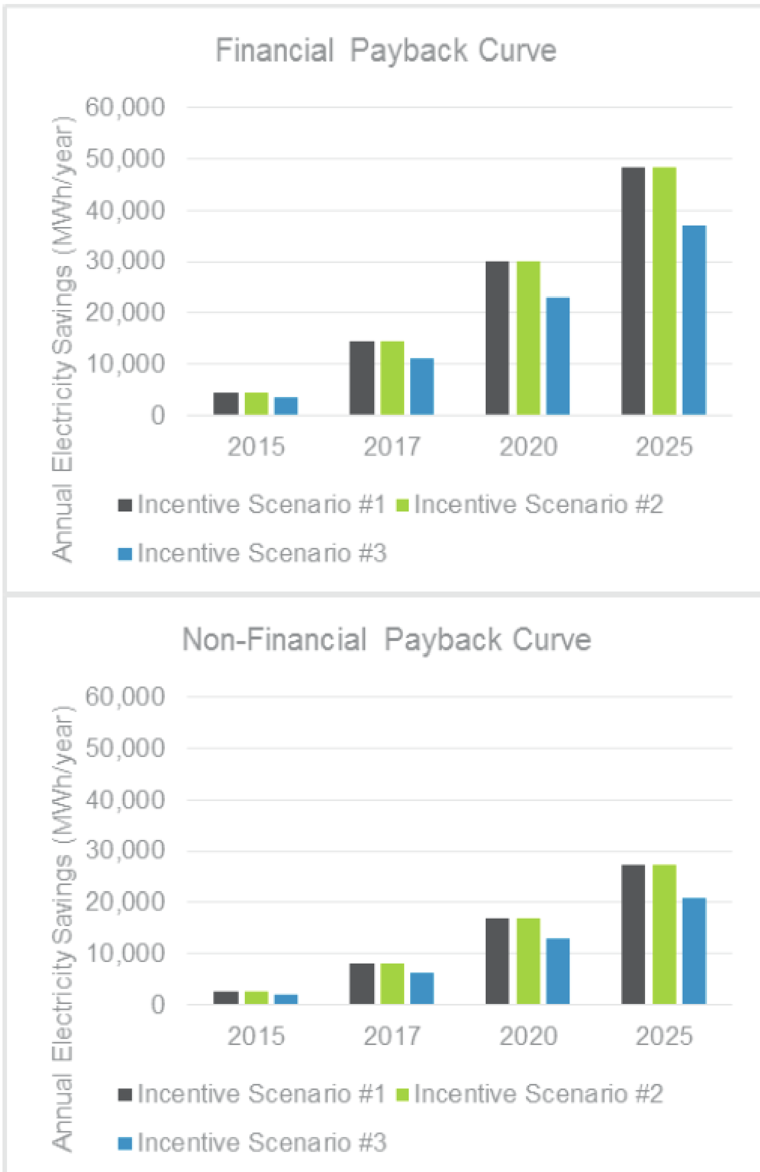


Figure 14 shows WER market potential under cap-and-trade based on electricity savings. For scenario 1, that potential is approximately 103% of potential without a carbon cap-and-trade market (27.2 GWh/year vs. 26.4 GWh/year).

Figure 14: WER Market Potential with Carbon Market in Electricity Savings for System



Constrained Potential

Constrained potential is the portion of the market potential achievable after accounting for electricity system constraints that may limit BMG installations. The IESO's planning department has determined that electricity network constraints must be determined at the transformer station, rather than LDC level, and that electricity network connection capacity will need to be assessed on a project-by-project basis when applications are received. Because this study estimates potential at the LDC level (not at the transformer-station level), it is not possible to apply constraints to quantify impacts on market potentials for all LDCs.

In cases where an LDC lies within an area that is fully area constrained, there is no potential for BMG projects larger than 500 kW. We excluded these LDCs from the constrained potential analysis.

Figure 15 shows that CHP constrained potential represents about 94 to 95 percent of 2025 market potential under incentive scenario #1 based on electricity savings.

Figure 15: Constrained Potential in Electricity Savings for System

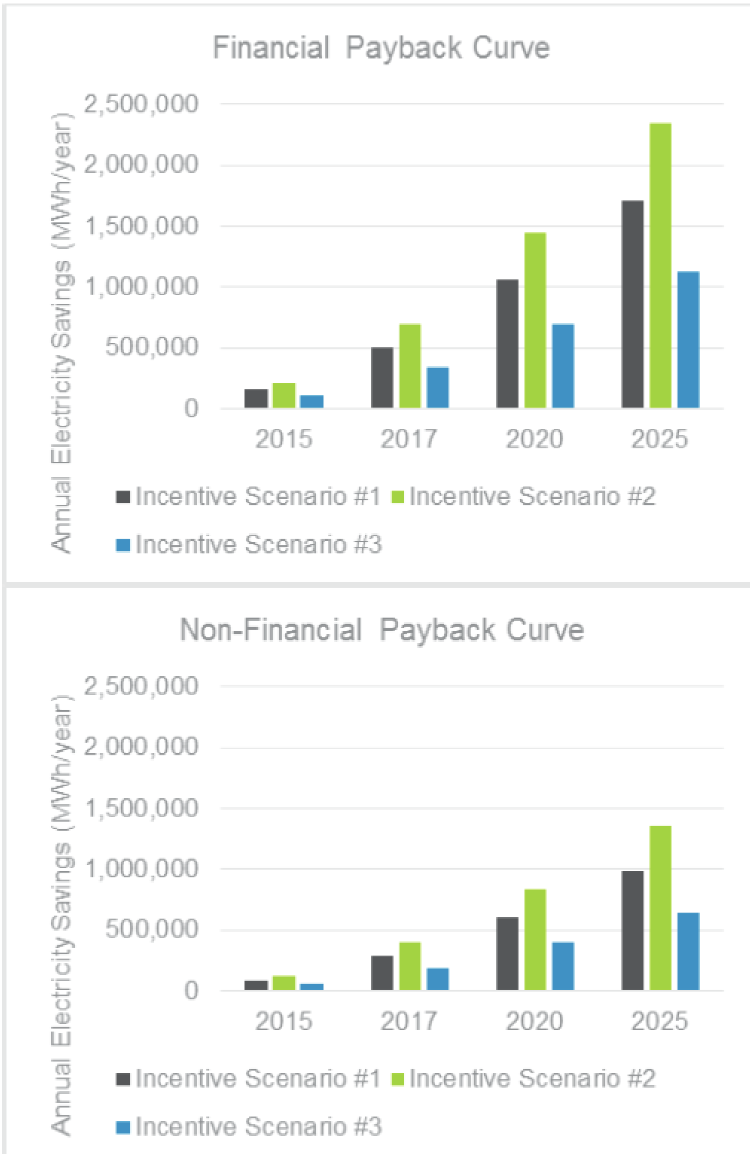
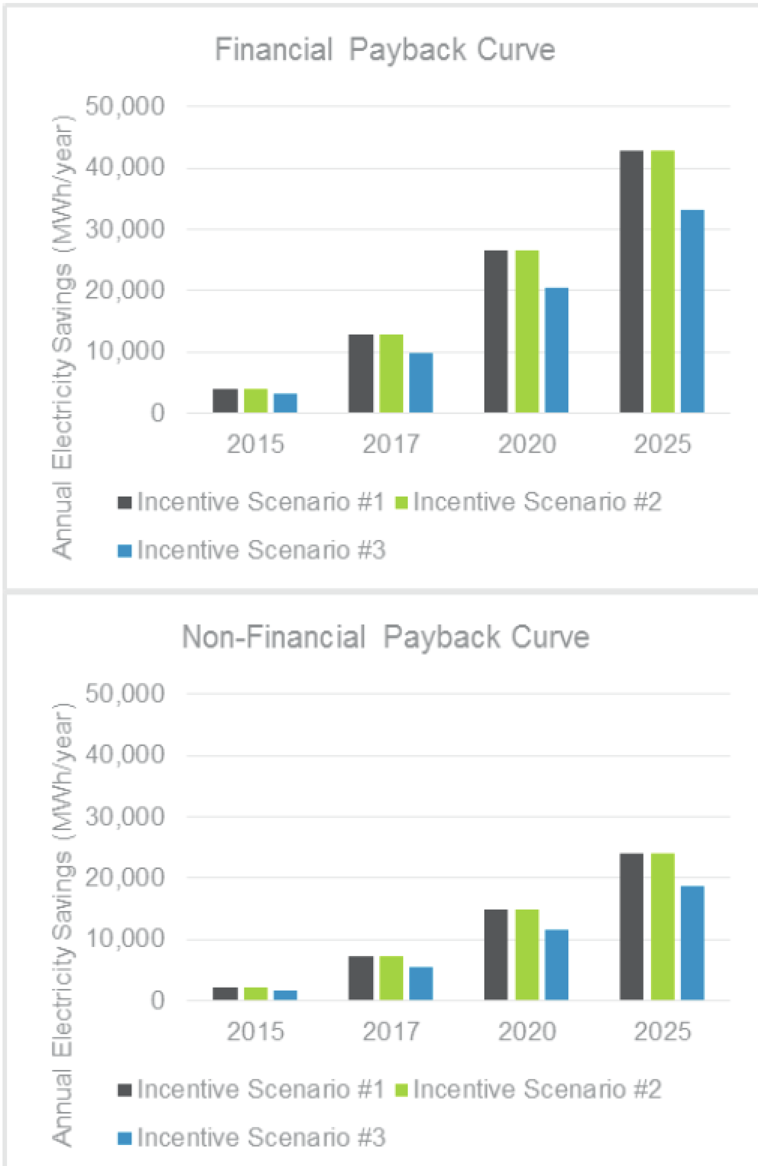


Figure 16 shows that 2025 WER constrained potential under scenario 1 represents about 91 percent of market potential by electricity savings.

Figure 16: WER Constrained Potential in Electricity Savings for System



Merged Results

The IESO has some existing BMG projects which went in-service through the program in 2015 and some applications which have already been received for BMG projects. These projects will contribute to the potential for the BMG program from 2015 to 2025. As a result, Navigant has also created merged results which present the combination of actual in-service projects and applications with the modelled potential. These merged results were created only for incentive scenario #1 (existing program rules) after applying constraints to the modelled results. Before merging results, Navigant assumed that some attrition will occur for projects for which applications were received but which are not yet in service. For these projects, Navigant assumed 75% of the application potential would result in achieved potential. Feedback from LDCs and previous BMG project contacts indicate that the average length from application to in-service is approximately 2 years. Navigant assumed that this application project potential will be realized by 2017. Navigant merged results at the facility type and LDC level. If the actual or application potential was greater than the modelled potential, than the modelled potential was overridden with actual and applications.

Merging the in-service and application projects with the modelled potential increases CHP electricity savings by 1.5 times and WER electricity savings by almost 5 times (see Figure 17 and Figure 18).

Figure 17: CHP Merged Model and Actual Constrained Potential in Electricity Savings for System

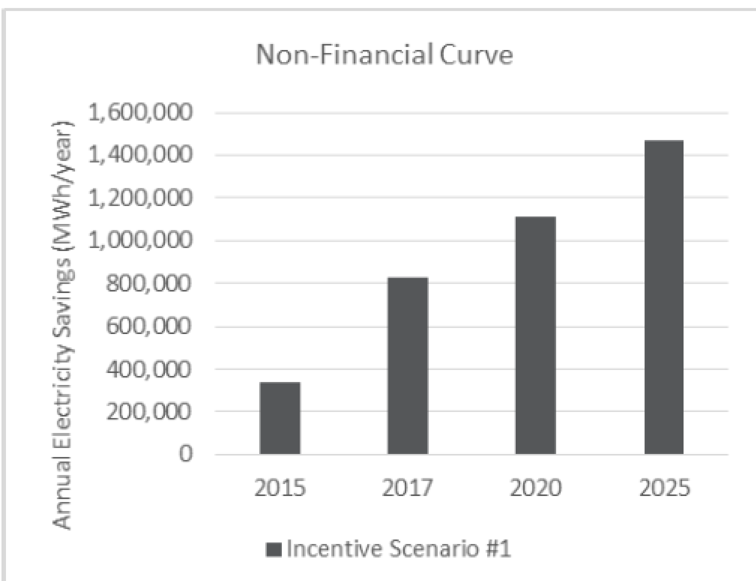
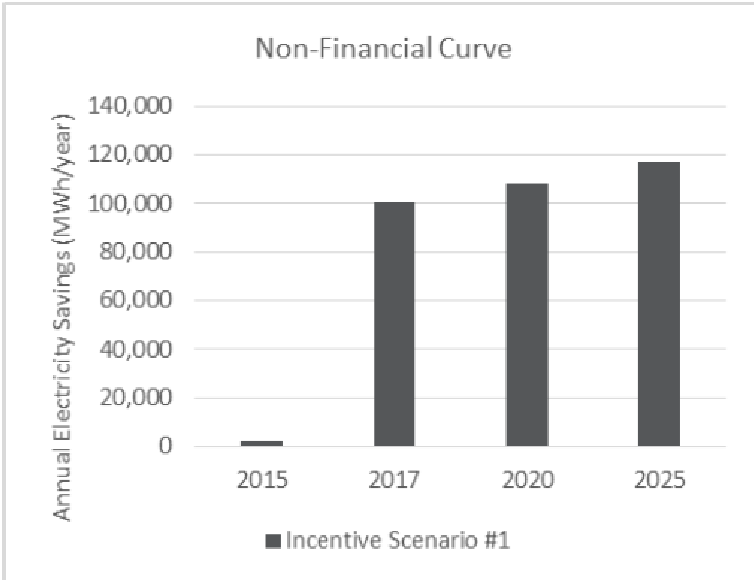


Figure 18: WER Merged Model and Actual Constrained Potential in Electricity Savings for System



1. Introduction

The IESO engaged Navigant Consulting, Ltd. (Navigant) to evaluate the potential for conservation behind the meter generation (BMG) to conserve electricity across Ontario. Key study objectives include:

- Understanding the potential to displace electric loads for Combined Heat and Power (CHP)[9] and Waste Energy Recovery (WER) installed in facilities connected:
  - To each of the local distribution systems
  - Directly to the transmission system
- Gaining insights, evidence, and documentation to make critical policy decisions about how, when, where, and to what extent to promote the installation and operation of BMG across Ontario.

Navigant produced a report for each key task. This report focuses on Task 5 (Potential Analysis). Under Task 5 of this study, Navigant, completed four subtasks (see Table 7) that are documented herein. Under a separate assignment, Navigant also evaluated the impacts of the Climate Mitigation and Low-Carbon Economy Act (Cap & Trade) on BMG potential, which is also documented in this report.

Table 7: Study Activities Documented in this Report

Subtask	Title	Description
5.1	"Technical" Potential	For each LDC (and for transmission-connected BMG—Tx level), select the largest technically feasible BMG system for each facility type, total the potential installed BMG capacity, annual electricity savings, and demand impacts by LDC (and Tx level) and facility type, and project potential for 2017, 2020, and 2025
5.2	"Economic" Potential	Assess BMG cost effectiveness from a Program Administrator Cost (PAC) perspective for a range of plausible BMG plant sizes. Identify all plant sizes and facility types that pass the PAC test. Determine economic potential based on the largest plant size for each facility type that passes the PAC test. [a]

[9] CHP systems that qualify for incentives under either the IESO's Conservation First Framework LDC Tool Kit, or the IESO's Industrial Accelerator Program, are referred to as Conservation Combined Heat and Power (CCHP). We use the more general acronym "CHP" in this report

Subtask	Title	Description
5.3	"Market" Potential	Determine both "Financial" and "Non-Financial" Potentials: Financial Potential: Portion of the economic potential that customers would eventually implement based on financial factors alone Non-Financial Potential: Portion of the economic potential that customers would eventually implement accounting for both financial and non-financial factors. In principle, non-financial potential could be either higher or lower than financial potential.
5.4	"Constrained" Potential	–Based on the limited information available about electricity network capacity and constraints, estimate the associated impacts on market potential
-	Cap & Trade Potential [b]	Develop modified financial and non-financial market potentials that reflect the impacts of the Climate Mitigation and Low-Carbon Economy Act

a) Description as modified by the IESO in a May 18, 2016 conference call. The IESO requested that we not include a Total Resource Cost constraint.

b) Add-on assignment to the original study authorized by the IESO on April 8, 2016.

2. BMG SIMULATION TOOL

The rigor and complexity required to conduct this analysis led Navigant to develop a new BMG analysis tool. This section discusses the tool development.

2.1 Approach to BMG Tool Development

The key features of the new BMG tool are:

- Simulates BMG operation at the hourly level, accounting for:
    - Hourly variations in facility thermal and electric loads
    - Both volumetric-based and demand-based components of electric and gas rates
- Provides three options for CHP operational strategy:
    - “Smart” strategy (CHP operation responds to price signals)
    - Thermal-and-electric-load-following strategy (facility loads dictate operation, with no dumping of excess thermal energy)
    - Modified thermal-and-electric-load-following strategy (allows dumping of excess thermal energy during peak electric periods, subject to program constraints)
- Ensures compliance with IESO program requirements
- Provides high levels of granularity to show results by facility type, LDC, connection level (transmission or distribution), and analysis scenario.
- Accommodates multiple BMG capacity choices available to customers
- Developed in the Analytica platform to permit sophisticated operational algorithms, reduce coding errors, and reduce execution time compared to traditional spreadsheet-based models.

The BMG tool uses:

- BMG cost and performance characteristics that are documented in Navigant’s Task 3 report (April 12, 2016)
- Hourly facility energy profiles that are documented in Navigant’s Task 4 report (May 11, 2016).

2.2 Electric Rate Archetypes

Navigant developed detailed electric rate archetypes that closely capture the nuances of the relevant electric rates used in each of Ontario's LDCs. Table 8 summarizes the electric rate archetypes. The electric rate archetypes consist of three separate charges: demand charges, standby charges and fixed charges.

Table 8: Representative Electric Rate Archetypes

Charge Type	Units	General Service > 50 kW	Large Users > 5 MW	Tx-Connected Users
Demand Charge[10]	*$/kW-month*	$9.74	$7.67	$6.15[11]
Standby Charge[12]	*$/kW-month*	$2.73	$2.73	-
Fixed Charge	*$/month*	$628	$7,131	-

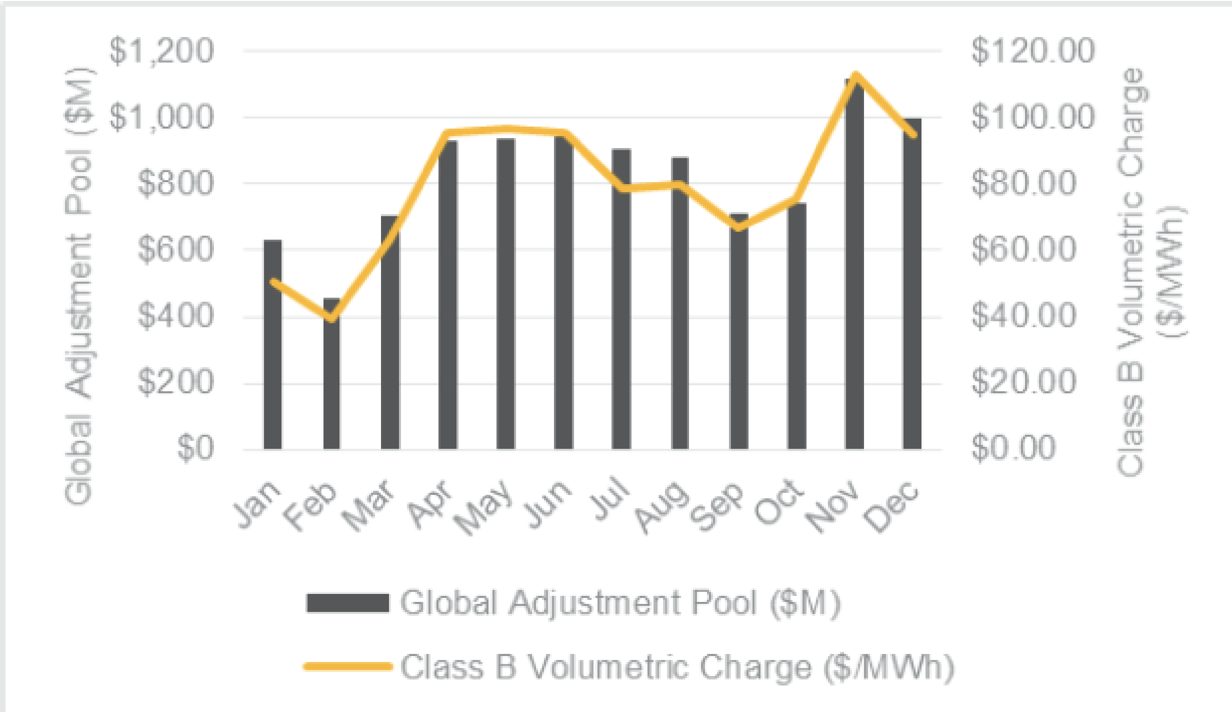
All electric rates are subject to IESO's Global Adjustment (GA) charge, which recovers out-of-market costs for generation capacity and conversation programs in Ontario. GA charges are split into two classes, whose eligibility and charges are calculated as follows:

- **Class A:** defined as customers with a maximum hourly demand in a month that exceeds an average of 5 MW during a specified base period. Customers between 3 MW and 5 MW with an eligible North American Industry Classification System (NAICS) code may also qualify.[13] Each customer's contribution to the system peak load during the five system peak hours of the year is calculated in a "Peak Demand Factor" (PDF). The PDF is then multiplied against a monthly cost pool to determine each customer's monthly GA charge.
- **Class B:** defined as customers that are not eligible to be Class A customers or are eligible to be Class A customers, but have opted out or have not opted in. Class B GA charges are calculated monthly on a volumetric basis.

Actual Class A and Class B GA charges for 2015 are shown in Figure 19.

[10] Demand charge denominator is based on the customer's maximum peak power drawn from the grid for that month
[11] There are three components of the demand charge for transmission customers: Network Service, Line Connection and Transformer Connection. The latter two are based on gross load, while the Network Service is based on net load
[12] Standby charges are calculated based on the difference between contracted maximum power drawn from the grid by the customer (which is contracted annually) and the monthly peak demand
[13] Ontario Regulation 429.04

Figure 19: 2015 IESO Global Adjustment Charges



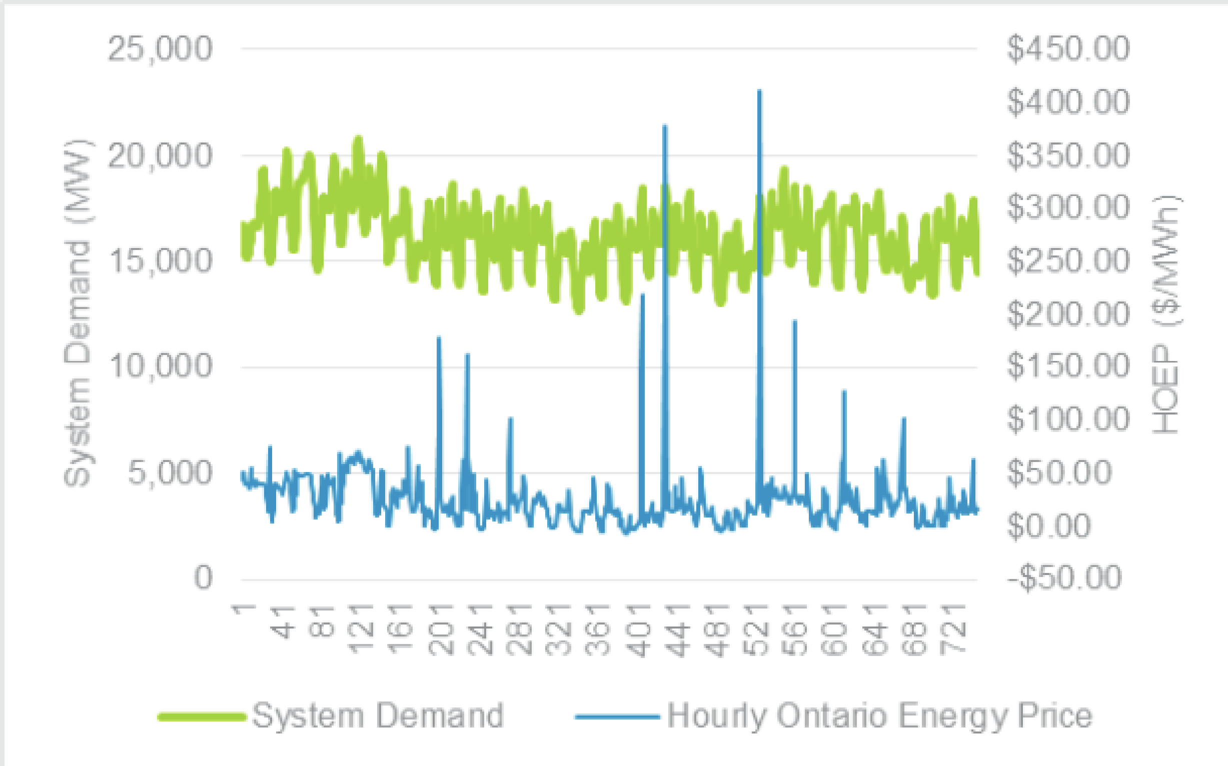
Source: IESO[14]

In addition, large customers are subject to the Hourly Ontario Electricity Price (HOEP). The HOEP is directly tied to the wholesale cost of electricity generation for each hour of the year. HOEP cost data relative to system demand for March 2015 are plotted in Figure 20.

In addition, large customers are subject to the Hourly Ontario Electricity Price (HOEP). The HOEP is directly tied to the wholesale cost of electricity generation for each hour of the year. HOEP cost data relative to system demand for March 2015 are plotted in Figure 20.

14 http://www.ieso.ca/Pages/Participate/Settlements/Global-Adjustment-for-Class-A.aspx; http://www.ieso.ca/Pages/Participate/Settlements/Global-Adjustment-for-Class-B.aspx

Figure 20: IESO Hourly Ontario Electricity Price - March 2015

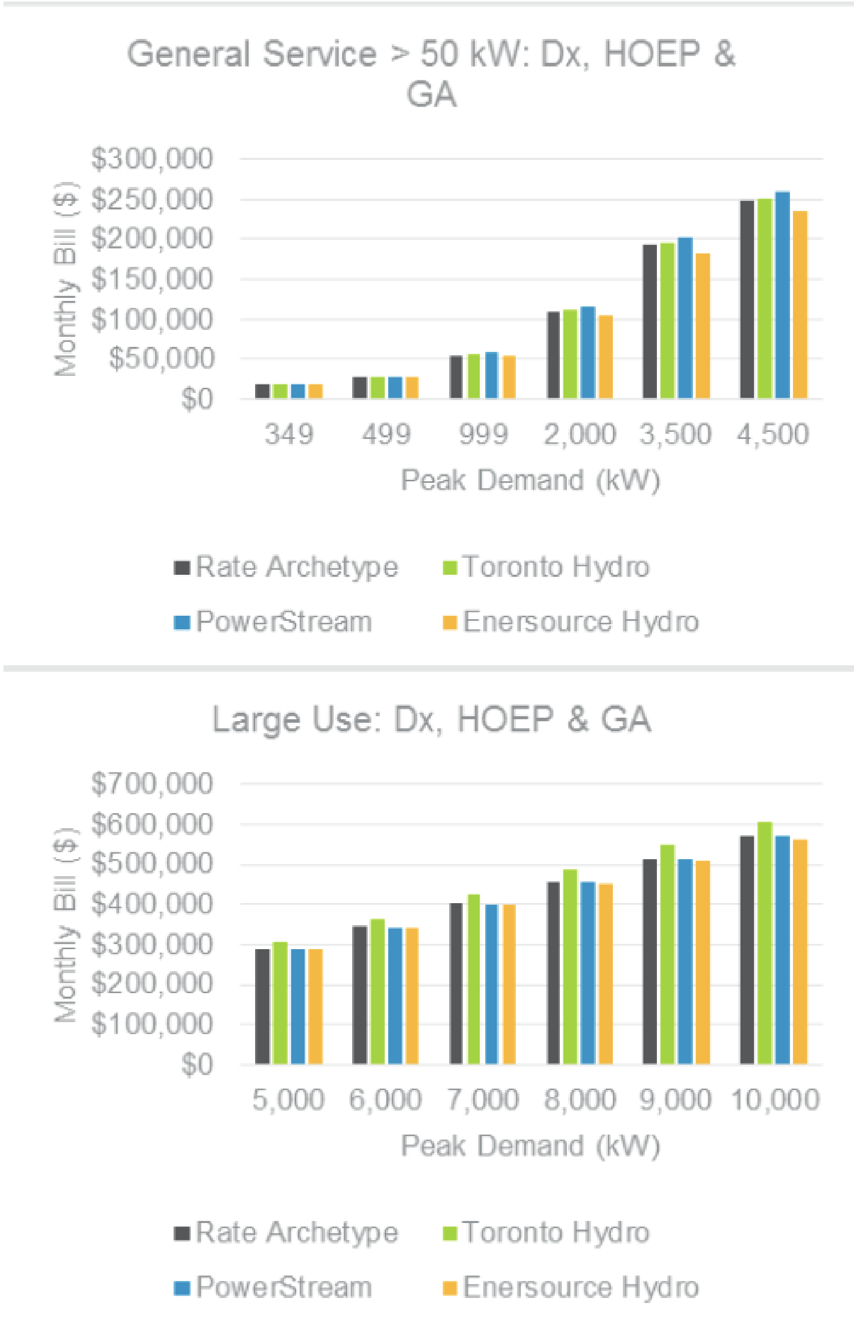


Source: IESO[15]

Navigant compared customer bills under these representative electric rate archetypes to what customer bills would look like for Toronto Hydro Electric System Limited (Toronto Hydro), PowerStream Inc. (PowerStream) and Enersource Hydro Mississauga Inc. (Enersource) in Figure 21. The close alignment of the rate archetypes with actual rates show that the rate archetypes accurately represent rate structures across Ontario.

[15] http://www.ieso.ca/Pages/Power-Data/Price.aspx

Figure 21: Navigant Rate Archetype Comparisons to LDC Rate Structures



Source: Navigant analysis and Toronto Hydro, PowerStream and Enersource Hydro rate structures:

http://www.ontarioenergyboard.ca/oeb/Industry/Regulatory%20Proceedings/Applications%20Before%20the%20Board/Electricity%20Distribution%20Rates

2.3 Natural Gas Rate Archetypes

For natural gas, Navigant developed six rate archetypes that were largely based on the rate structures for Union Gas Distribution and Enbridge Gas Distribution, the two largest natural gas utilities in Ontario.

Customers in each of the three climate zones have two possible rate structures, which are determined based on a combination of volumetric gas use and monthly contracted demand. The breakdown of each rate can be seen in Table 9: Representative Natural Gas Rate Archetypes, and their geographic mappings are color-coded to the regions in Figure 22. These rate archetypes estimate customer bills that are virtually identical to those calculated using actual rate structures.

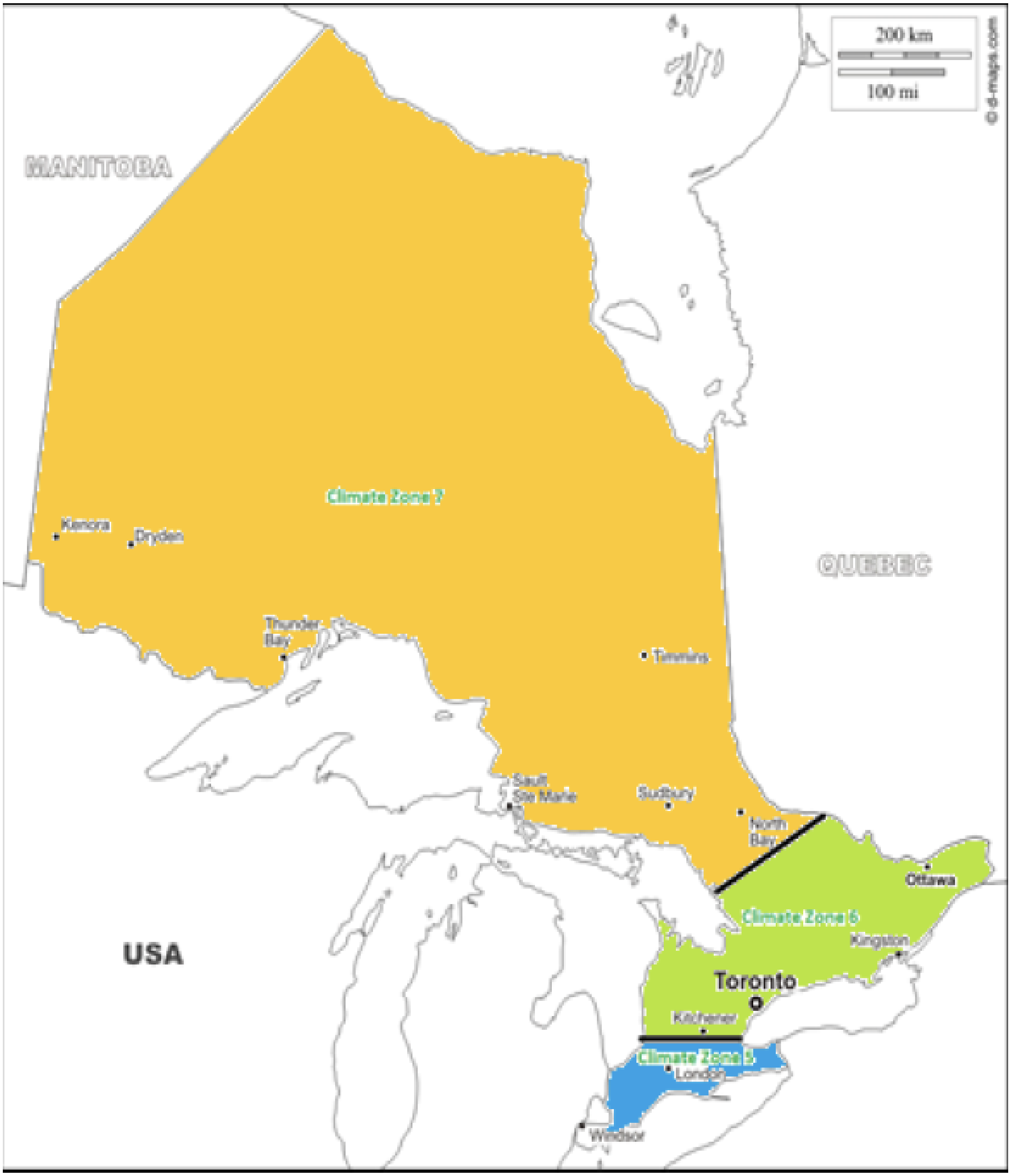
Table 9: Representative Natural Gas Rate Archetypes

Rate	Climate Zone	Blended Volumetric ($/m^3)	Contracted Demand ($/m^3-day)	Fixed Charge ($/month)
Union Northern/Eastern 10	7	$0.1869	-	$69
Union Northern/Eastern 20	7	$0.1401	$0.27 / $0.16 (tiered based on usage)	$915
Enbridge 100	6	$0.2182	$0.35	$120
Enbridge 110	6	$0.2099	$0.22	$576
Union M2	5	$0.1792	-	$69
Union M4	5	$0.1493	$0.48 / $0.21 / $0.18 (tiered based on usage)	$685

Source: Union Gas & Enbridge Gas rate structures[16]

[16] https://www.uniongas.com/business/account-services/unionline/contracts-rates ; https://www.enbridgegas.com/businesses/accounts-billing/understanding-your-bill/rate-calculator.aspx

Figure 22: Mapping of Rate Structures to Ontario Climate Zones

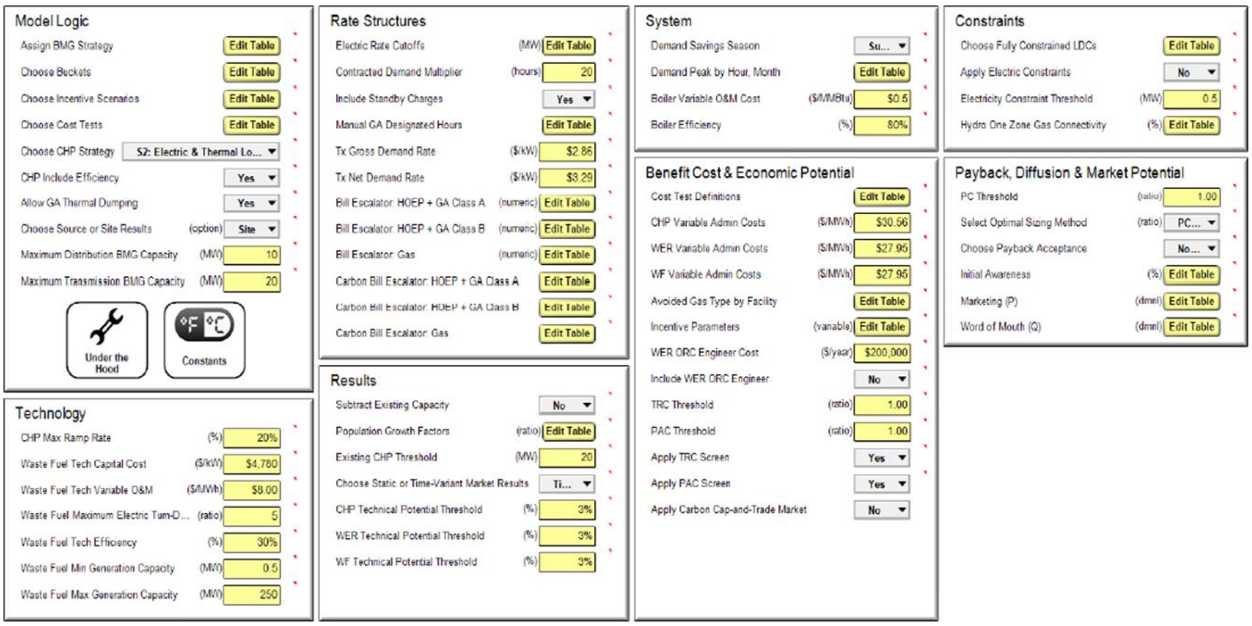


Source: Navigant analysis

2.4 Tool Functionality and Inputs

The BMG tool has the flexibility and robustness to handle numerous scenario analyses. Figure 23 shows a list of the various switches and functionalities available in the BMG tool.

Figure 23: Model Inputs & Functionality



Source: Navigant analysis

In addition, the tool imports an additional 20 sets of data (as seen in Figure 24) that include facility energy profiles, energy-use intensities, facility floor space, utility rates, BMG technology performance and cost characteristics, avoided costs, and more.

Figure 24: Imported Datasets for BMG Potential Study Model

3. Technical Potential

Technical potential captures the theoretical electric energy savings and demand reductions associated with instantaneous installation of an energy-saving technology in all technically suitable applications, without consideration of economic and market factors. Unlike most energy-efficiency measures, any given facility can select from a broad range of BMG capacities. Therefore, the traditional definition of technical potential was further refined. Navigant defines technical potential as the BMG capacity beyond which there are no appreciable energy savings.[17]

3.1 Analysis Matrix and Methodology

3.1.1 Summary of Analysis Scenarios

Table 10 summarizes the three incentive scenarios that Navigant modelled for BMG potential (as agreed to with the IESO).

Table 10: BMG Incentive Scenario Parameters

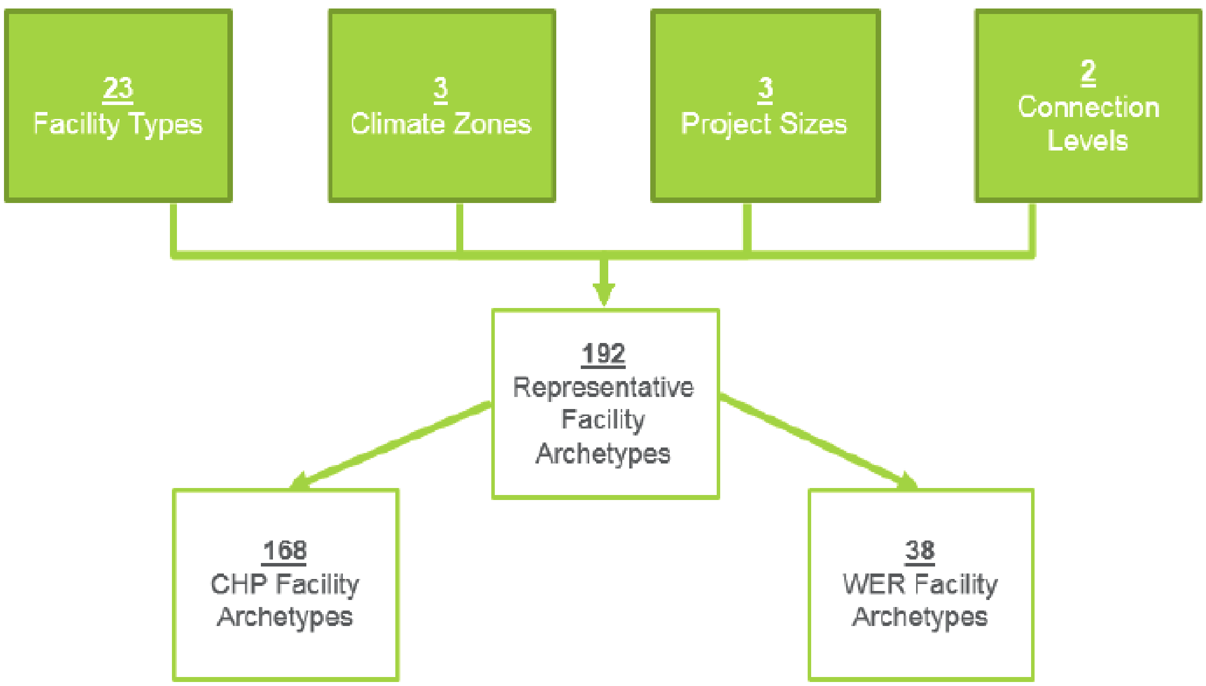
#	Scenario	Definition
#1	First cost incentive is the lowest of:	40% of initial capital cost $200/MWh (distribution) or $230/MWh (transmission) of annual electricity savings Incentive to create 1-year payback 70% of initial capital cost
#2	First cost incentive is the lowest of:	$200/MWh (distribution) or $230/MWh (transmission) of annual electricity savings Incentive to create 1-year payback
#3	$0.02/kWh production incentive for the first 10 years of operation No first-cost incentive	-

[17] Navigant analyzed 10 capacity increments ranging from 10 percent to 100 percent of the facility's annual peak electric demand, and based technical potential on the BMG capacity beyond which electricity savings increase by less than 3 percent of the facility annual electricity consumption

3.1.2 Analysis Matrix

For CHP, Navigant identified approximately 27,000 customers that met the minimum peak demand requirements for BMG eligibility as per the IESO program rules for the Process and Systems and Industrial Accelerator programs in 2015. Navigant grouped these customers in 192 representative customer archetypes based on facility type, climate zone, facility size, and connection level--see Figure 25.

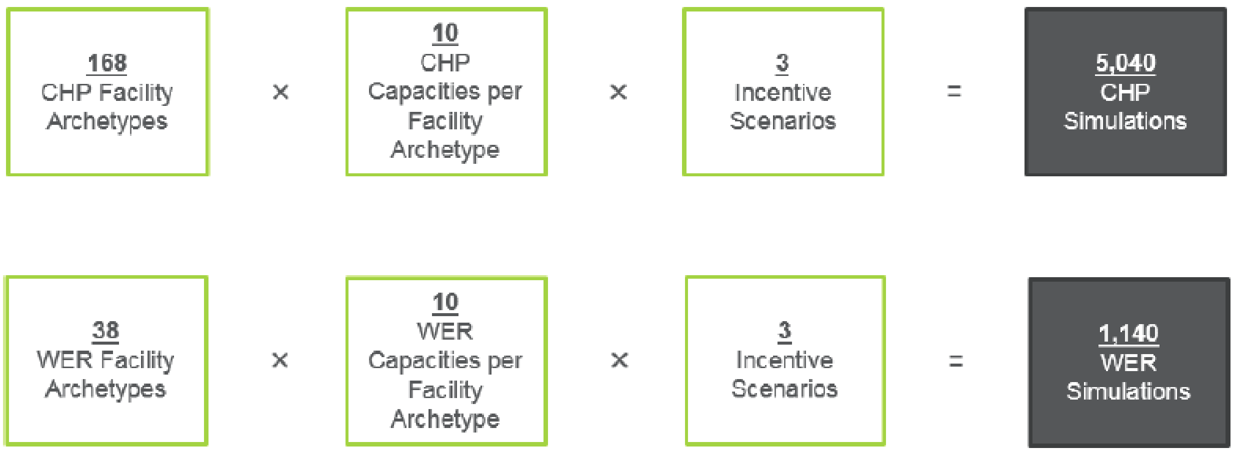
Figure 25: Representative Facility Archetypes[18]



[18] The total representative facility archetypes add up to a number higher than 192 because the paper/pulp facility type (14 archetypes) is considered eligible for both CHP and for waste fuel-based WER.

The result is a powerful, hourly simulation tool capable of multiple scenario analyses and thousands of 8,760-hour simulations--see Figure 26.

Figure 26: CHP and WER Simulations



3.1.3 Adjustments to Applicable Facilities for Access to Natural Gas

Navigant identified a pool of approximately 27,000 applicable facilities that would be eligible for BMG using the data and approaches identified in the Task 4 report. Some of these 27,000 facilities do not have access to natural gas.

The scope of this potential study is limited to facilities having access to natural gas. 108 facilities (0.4% of the original 27,000 applicable facilities) were removed as their associated LDC territories do not have access to natural gas. These LDCs are: Chapleau Public Utilities Corporation, Dubreuil Lumber, Sioux Lookout Hydro and Westario Power. In addition, we removed a portion of Hydro One facilities using the following approach:

- 24% of Hydro One customers are urban (UDd) versus rural (GSd)[19]
- Navigant estimates that about one-third of rural customers (defined as those between urban areas) have access to pipeline natural gas
- Based on the above, 52% of Hydro One customers (those over 50kW) have access to natural gas, and 48% do not.

3.1.4 Adjustments for Existing Projects

As documented in the Task 4 report, through the Canadian Industrial Energy End-Use Data and Analysis Center (CIEEDAC), existing project lists from the IESO and feedback from the LDCs,

[19] Based on Hydro One's customers and consumption by rate class, http://www.hydroone.com/RegulatoryAffairs/Documents/EB-2013-0416%20Dx%20Rates/Exhibit%20G/G2-01-02.pdf

Navigant developed lists of existing CHP and WER projects by capacity and their associated climate zones, facility types and LDCs. These lists include facilities served by existing, utility-scale CHP. Before completing the potential analyses, Navigant adjusted these lists of existing projects further:

- Include in existing projects only the utility-scale CHP systems under 20 MW (which is a small fraction of utility-scale CHP) because it was assumed that larger utility-scale CHP systems generally provide thermal energy to a small number of very large facilities that are not candidates for this study (i.e., these facilities are large enough that they would be unlikely to use CHP systems under 20 MW even if they did not already have an external source for thermal energy).
- At the request of the IESO, Navigant excluded from existing projects all 2015 projects (planned and actual) receiving incentives under IESO programs because these will be documented as part of the 2015 potential.

3.1.5 Population Growth Factors

Navigant developed escalation factors for technical and economic potential based on population growth data from the Ontario Ministry of Finance (see Table 11). These factors are used to project future technical and economic potentials (for 2017, 2020 and 2025) from 2015 estimates. We did not apply growth factors to multi-family facilities because (due to new requirements) new multi-family facilities will all be tenant-metered. Tenant-metered multi-family facilities are not conducive to CHP.

Table 11: Population Growth Factors for Technical and Economic Potential

Climate Zone	2015	2017	2020	2025
CZ5 (London)	1.0000	1.0055	1.0154	1.0333
CZ6 (Toronto)	1.0000	1.0213	1.0555	1.1152
CZ7 (Thunder Bay)	1.0000	0.9982	0.9973	0.9956

Source: Ontario Ministry of Finance (adjusted by Navigant for climate zones)[20]

[20] http://www.fin.gov.on.ca/en/economy/demographics/projections/

3.2 Operational Strategies

3.2.1 CHP

Based on IESO feedback, Navigant ultimately used CHP operational strategy #3 described in Table 12. This strategy operates the CHP system in response to electrical and thermal loads, but permits some dumping of thermal energy during hours of peak electric demand, to the extent permitted by the 65% minimum total system efficiency requirement imposed by the IESO's BMG programs.

Table 12: CHP Operational Strategy Iterations

#	Strategy	Description
1	Cost Minimization + Electric Load Following	1. CHP units operate at full capacity during designated GA operational hours.[21] 2. For non-GA operational hours, CHP is operated at full capacity if baseline hourly cost is higher than the hourly cost while running a CHP unit. 3. For the remaining hours, CHP is not operated if the volumetric rate of electricity is below $0/MWh. 4. For remaining hours after that, CHP is operated to reduce facility demand by 20%, 40%, 60%, 80% or 100%. The optimal "demand reduction" strategy is chosen based on the lowest resulting monthly cost.
2	Electric + Thermal Load Following (Strict)	CHP units operate at a level where no electricity is exported and no thermal energy is dumped for each hour of the year. If this level falls below the minimum turn-down ratio allowed by the assigned CHP technology, the CHP unit does not run for that hour.

[21] GA "operational" hours are determined based on 20 peak hours of the year (not occurring on the same day) that customers suspect will be subject to Global Adjustment Class A charge calculations. CHP customers would operate their generator to meet as much of their demand as possible for those 20 hours along with the four hours before and after those suspected peak hours for a total of 180 hours of the year.

#	Strategy	Description
3	Electric + Thermal Load Following (Partial Thermal Dumping Allowed)	Similar to strategy #2, but CHP units are allowed dump thermal energy during the 180 designated GA operational hours until the 65% overall system efficiency floor is met.

Table 13 compares key characteristics of the three CHP operational strategies.

Table 13: CHP Operational Strategy Comparison

Strategy	Cost Optimization & Electric Load Following	Electric & Thermal Load Following	Electric & Thermal Load Following w/ Partial Thermal Dumping
Exports Electricity	X	X	X
Dumps Thermal Energy	✓	X	✓
Responds to Price Signals	✓	X	X
Responds to Possible GA Hours	✓	X	✓

3.2.2 WER

Waste energy recovery can be driven by two different sources: waste heat (generally steam or hot air from industrial processes) or waste fuel (such as biomass from paper/pulp production). Navigant's BMG tool uses a straight-forward operational strategy for WER: if the hourly operational cost of running a WER unit is lower than the base-case hourly cost, the WER unit will operate at full capacity or up to the facility electric load, whichever is lower. Operation is also constrained by how much waste heat or waste fuel is available on an hourly basis.

Hourly costs are ultimately determined by volumetric electricity costs, generator O&M costs and production incentives (for incentive scenario #3). This strategy is strongly influenced by the Hourly Ontario Energy Price (HOEP). In 2015, HOEP was zero or negative in 1,142 hours of the year.[22] During those hours, the WER is not operated.

[22] http://www.ieso.ca/Pages/Power-Data/2014-Electricity-Production-Consumption-and-Price-Data.aspx

3.3 Results—Technical Potential

As noted above, Navigant based technical potential on the largest technically feasible BMG system beyond which there are no appreciable electricity savings.

CHP technical potential does not depend on incentive scenario because no price signals are taken into account during operation. WER results show differences by incentive scenarios due to the hourly cost minimization operational strategy.

We use three parameters to quantify potential:

- **Electricity Savings:** The annual electricity generated by BMG at the customer site-level, which is equivalent to the amount of grid electricity saved (gigawatt-hours).
- Demand Savings: The average reduction in electric demand during summer peak hours achieved by BMG at the customer site (megawatts) (see Figure 27).

Figure 27: Summer Peak Demand Savings Periods: Summer Peak Demand Savings Periods

Season	Time	Months
Summer (Weekdays)	1 PM – 7 PM	June
		July
		August

Source: Ontario Power Authority[23]

- **Capacity:** The total nominal electric generation capacity of BMG units (gigawatts).

3.3.1 CHP

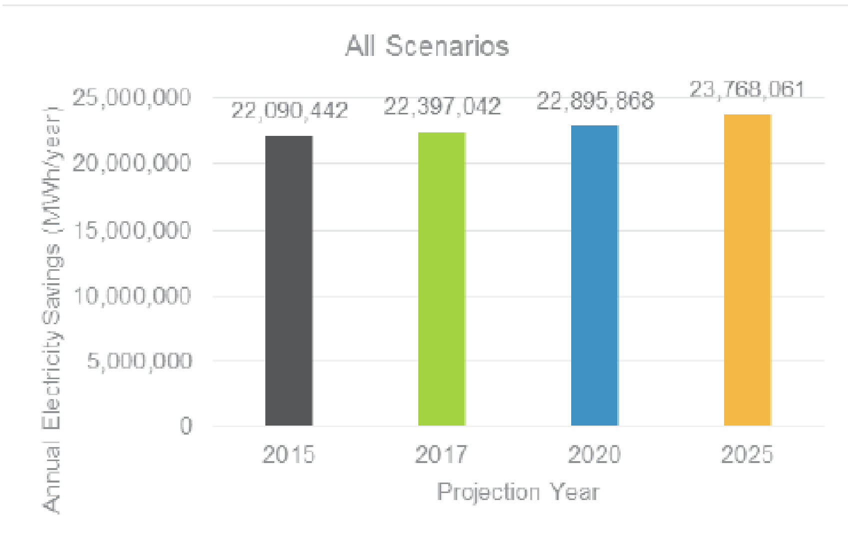
The sections below show CHP technical potential for Ontario. As noted above, CHP technical potential does not vary by scenario, so these results apply to all three analysis scenarios. Appendix A includes detailed technical potential results by LDC.

[23] http://www.powerauthority.on.ca/sites/default/files/conservation/Conservation-First-EMandV-Protocols-and-Requirements-2015-2020-Apr29-2015.pdf

3.3.1.1 Energy Savings

Figure 28 summarizes the CHP technical potential for Ontario by year based on electricity savings. The province-wide CHP technical potential is about 22 TWh in 2015, increasing to about 24 TWh by 2025. This compares to about 53 TWh of baseline electricity consumption in 2015 for CHP applicable facilities, or about 42 percent reduction in electricity consumption. It also corresponds to about 16 percent of Ontario's total 2015 electricity consumption (about 137 TWh).[24]

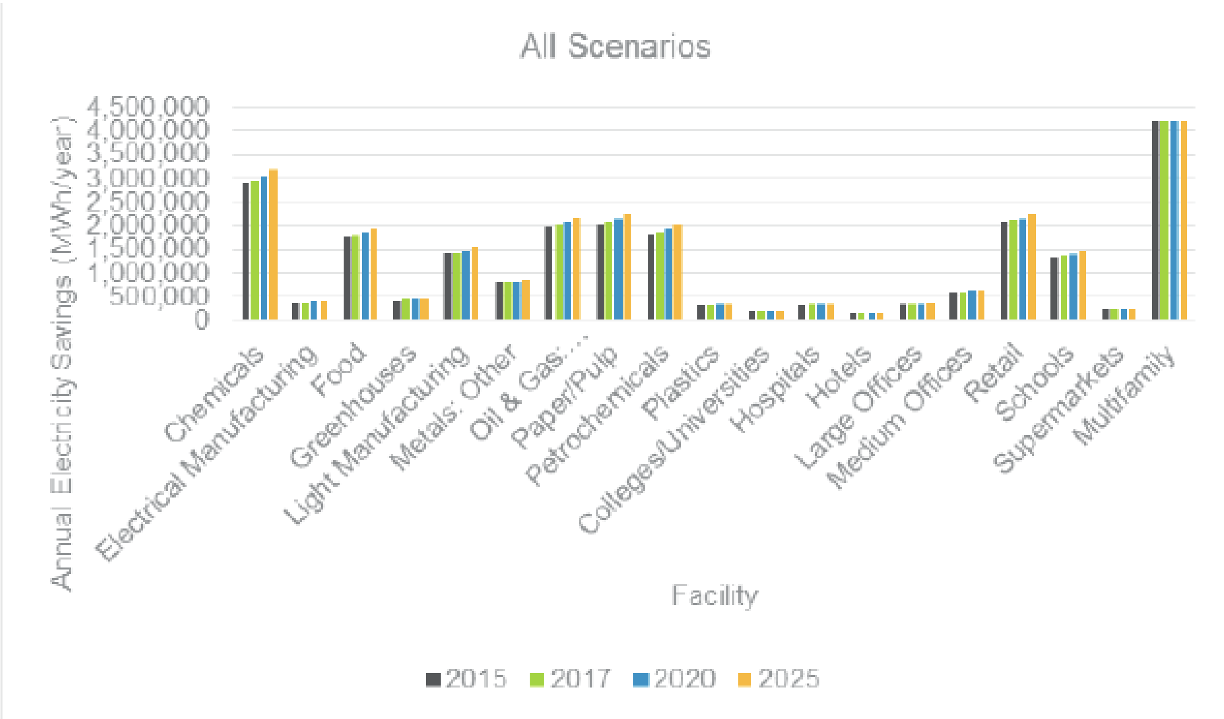
Figure 28: CHP Technical Potential in Electricity Savings for System



[24] Ontario Energy Reports—Demand for 2015 Q1, Q2, Q3, and Q4

Figure 29 shows the distribution by major facility type of province-wide CHP technical potential based on electricity savings. Not surprisingly, industrial facilities generally present the largest technical potential, but retail and multi-family facilities also present substantial technical potential. Industrial facilities represent 61 percent of the CHP technical potential.

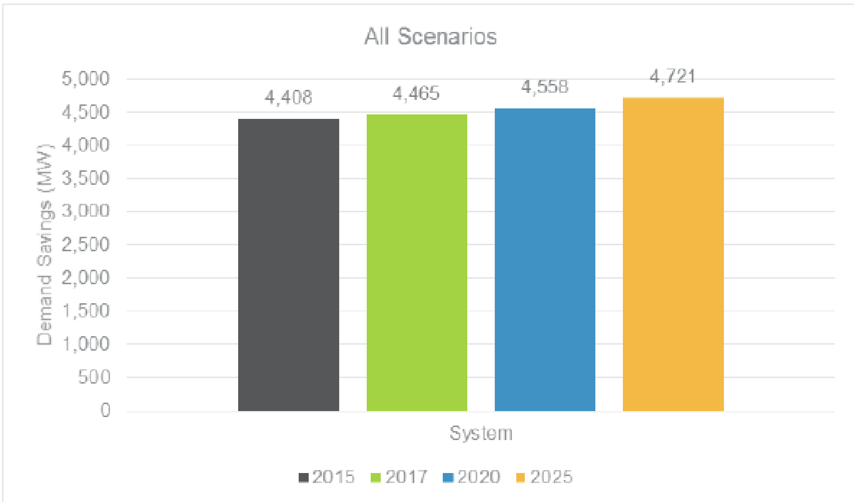
Figure 29: CHP Technical Potential in Electricity Savings by Facility Type



3.3.1.2 Demand Savings

Figure 30shows the province-wide CHP technical potential based on summer electric demand reduction (see demand definition in section 3.3 above). 2015 CHP technical potential for demand reduction (about 4.4 GW) is about 20 percent of Ontario's total summer peak demand (about 22.5 GW).[25]

Figure 30: CHP Technical Potential in Demand Savings for System

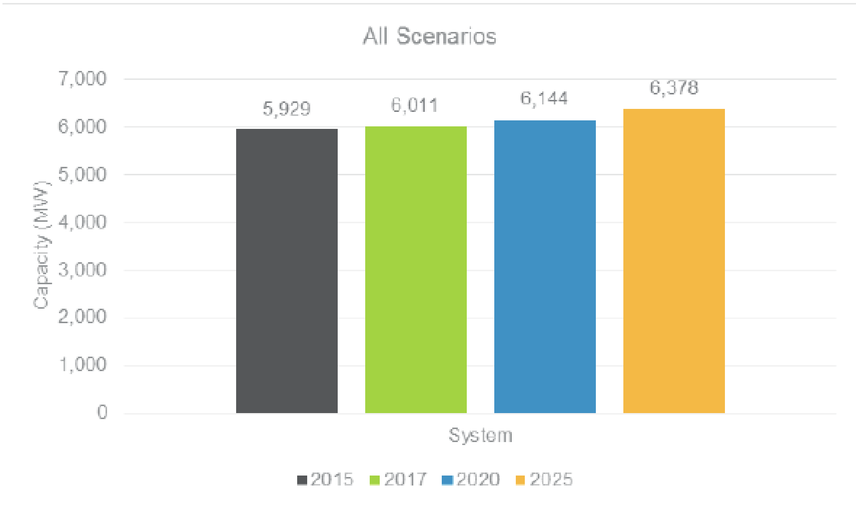


[25] http://www.ontarioenergyreport.ca/

3.3.1.3 Installed Capacity

Figure 31 shows the province-wide CHP technical potential based on nominal installed capacity, indicating that the CHP technical potential increases from about 5.9 GW in 2015 to about 6.4 GW in 2025.

Figure 31: CHP Technical Potential in Capacity for System



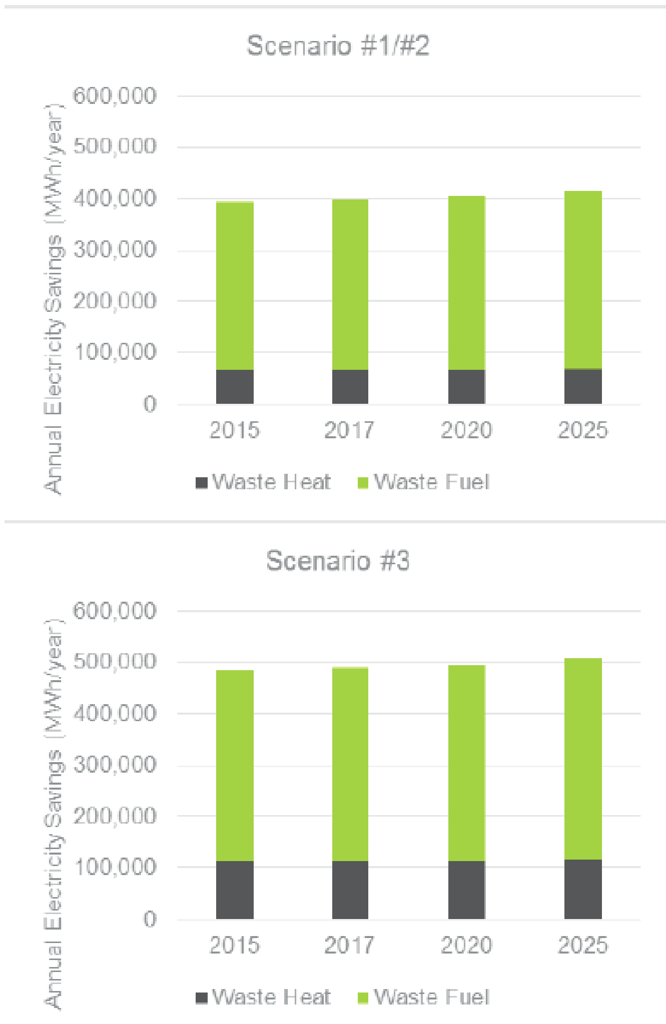
3.3.2 WER

The sections below show WER technical potential for Ontario. See also 8.Appendix B for additional technical potential results.

3.3.2.1 Energy Savings

Figure 32 shows the province-wide WER technical potential based on electricity savings for the three analysis scenarios. WER technical potentials are substantially lower compared to CHP technical potentials. WER technical potentials in 2015 range from about 0.4 to 0.5 TWh of annual electricity savings (depending on scenario), or about 2 percent of the 2015 CHP technical potential. It also corresponds to about 0.3 percent of Ontario's total 2015 electricity consumption (about 137 TWh). Waste fuel-based WER represents the bulk of WER technical potential (77 to 84 percent in 2015, depending on scenario).

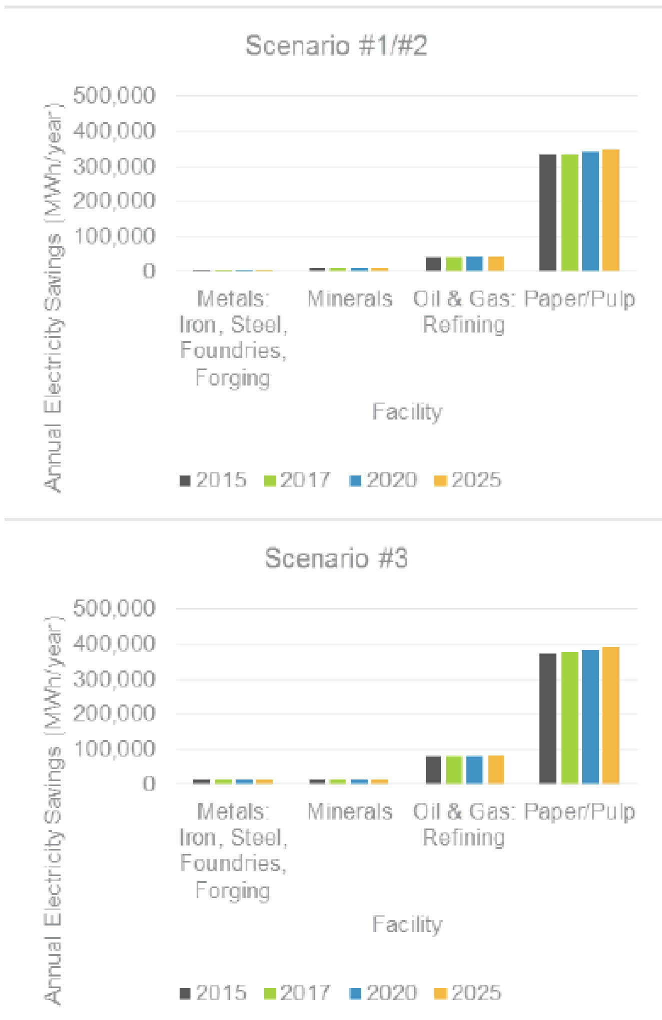
Figure 32: WER Technical Potential in Electricity Savings for System



3.3.2.2 Demand Savings

Figure 33 shows province-wide WER technical potential based on summer electric demand reductions (as defined in section 3.3 above). In 2015, WER technical-potential demand reduction (about 0.05 to 0.06 GW, depending on scenario) represent about 0.2 to 0.3 percent of the province's demand (22.5 GW). Scenario 3, which includes a production incentive, does not significantly change technical-potential demand reductions because the production incentive primarily increases WER hours of operation, rather than increasing generation capacity during any given hour.

Figure 33: WER Technical Potential in Electricity Savings by Facility Type



3.3.2.2 Demand Savings

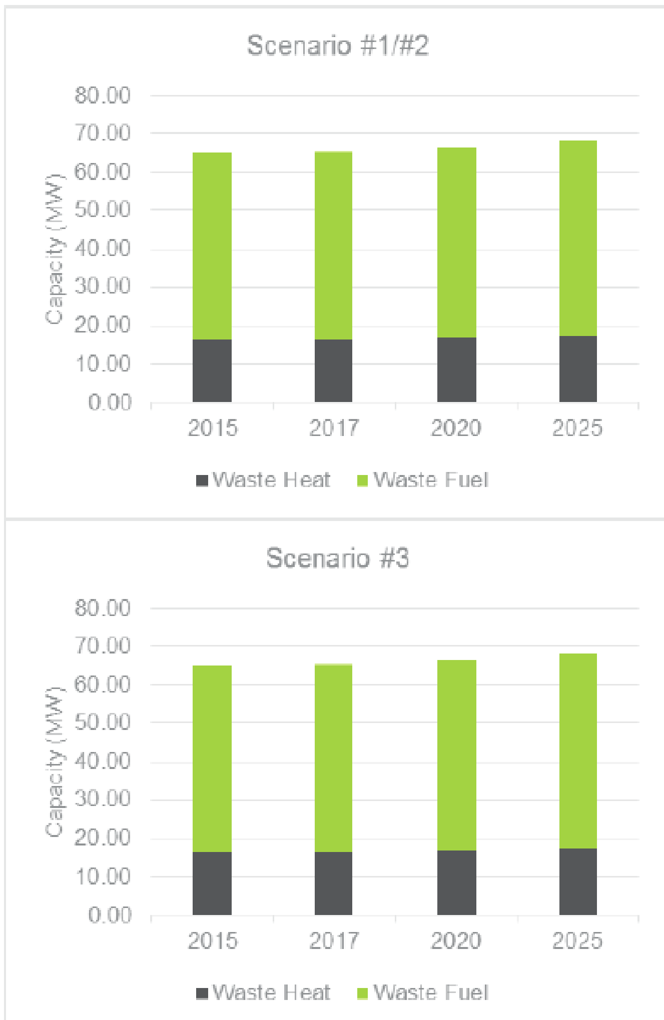
Figure 34 shows province-wide WER technical potential based on summer electric demand reductions (as defined in section 3.3 above). In 2015, WER technical-potential demand reduction (about 0.05 to 0.06 GW, depending on scenario) represent about 0.2 to 0.3 percent of the province's demand (22.5 GW). Scenario 3, which includes a production incentive, does not significantly change technical-potential demand reductions because the production incentive primarily increases WER hours of operation, rather than increasing generation capacity during any given hour.

Figure 34: WER Technical Potential in Demand Savings for System

3.3.2.3 Installed Capacity

Figure 35 shows province-wide WER technical potential based on nominal installed capacity, indicating that WER technical potential increases from about 0.065 GW in 2015 to about 0.068 GW in 2025. Similar to the observations noted in section 3.3.2.2 above, the production incentive under Scenario 3 has almost no impact on the WER nominal capacity selected for a particular facility.

Figure 35: WER Technical Potential in Capacity for System



4. Economic Potential

Economic potential is the portion of technically feasible BMG that produces a net benefit from a program administrator perspective. Economic potential will be expressed in terms of capacity (MW), peak demand savings (MW), and annual energy savings (GWh).

4.1 Methodology & Approach

Economic potential is determined by completing one cost-effectiveness screen on each BMG size and facility archetype that is at or below the capacity selected for calculating technical potential. The Program Administrator Cost (PAC) test evaluates the benefits to the program administrator (i.e., the IESO). Cost- effectiveness tests calculate the relevant benefit and cost components and the results can either be expressed as a dollar amount representing the net benefit (benefit minus costs) or as a ratio (benefits divided by costs). A project passes the PAC test if it results in a positive net benefit or if the benefit-cost ratio is greater than 1.0.

Economic potential assessments typically include the Total Resource Cost (TRC) test which considers a societal perspective. The IESO opted not to include the TRC assessment in the economic potential stage to reflect that both LDCs and customers are not driven to install BMG projects solely from a societal perspective. Under the Energy Conservation Agreement between LDCs and the IESO, LDCs are assessed from a PAC perspective. The TRC test components are outlined below. The TRC test is calculated for informational purposes, but the metric is not used as part of the economic screen.

Table 14 outlines the relevant cost-effectiveness components (i.e., benefits and costs) used in the TRC and PAC tests. A description of each component is described below.

Table 14: TRC and PAC Cost-Effectiveness Test Components

Cost Test Component		TRC	PAC
Benefits	Avoided Electricity Cost	✓	✓
	Avoided Capacity Cost	✓	✓
	Non-Energy Benefits Adder	✓	
Costs	Incremental Equipment Costs (or participant costs)	✓	
	Incremental O&M Costs	✓	
	Program Administration Costs	✓	✓
	Incentive Costs		✓

Source: IESO

Avoided Electricity Cost

The avoided electricity cost captures the value of grid electricity offset by the implementation of the BMG project. To determine the avoided electricity cost, the annual energy savings (GWh) are determined for each size and archetype and broken down into the eight season-and-time-of-use (STOU) buckets based on the facility load profile and hours of use. The savings by STOU are multiplied by the corresponding value of electricity in each STOU bucket according to the IESO's avoided cost table[26]. This calculation is performed for the effective useful life of the BMG project (assumed to be 20 years) and the stream of avoided electricity costs are converted to net-present-value using the IESO's assumed discount rate[27].

Avoided Capacity Cost

The avoided capacity cost captures the value of electricity system capacity (generation, distribution, and transmission) no longer required as a result of the implementation of the BMG project. To determine the avoided capacity cost, the peak demand savings (MW) are determined for each size and archetype in accordance with the IESO EM&V Protocols and Requirements[28] supported by the facility load profile and hours of use. The peak demand savings are multiplied by the corresponding annual value according to the IESO's avoided cost table. This calculation is performed for the effective useful life of the BMG project (assumed to be 20 years) and the stream of avoided capacity costs are converted to net-present-value using the IESO's assumed discount rate[29].

Non-Energy Benefits Adder

The non-energy benefits adder is required as per the October 23rd, 2014 Direction to the (former) Ontario Power Authority.[30]As per the Direction, the adder increases the TRC benefits (i.e., avoided electricity costs and avoided capacity costs) by 15 percent. It is important to note that, as per the Direction, the 15 percent adder is intended to account for the non-energy benefits such as environmental, economic, and social benefits. It is possible that some environmental benefits would be offset by an increase in emissions due to increased natural gas use, however, such an analysis was not within the scope of this study.

Incremental Equipment Costs (or Participant Costs)

The incremental equipment costs or participant costs capture the capital cost to the customer to implement the BMG project. Dissimilar to many energy efficiency projects, the participant costs

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[26] http://www.ieso.ca/Documents/conservation/LDC-Toolkit/Guidelines-and-Tools/CDM-EE-Cost-Effectiveness-Test- Guide-v2-20150326.pdf
[27] Ibid. 4 percent.
[28] http://www.powerauthority.on.ca/sites/default/files/conservation/Conservation-First-EMandV-Protocols-and- Requirements-2015-2020-Apr29-2015.pdf
[29] Ibid. 4 percent.
[30] Amending March 31, 2014 Direction Regarding 2015-2020 Conservation First Framework. October 23, 2014. http://www.powerauthority.on.ca/sites/default/files/news/MC-2014-2415.pdf

capture the full capital cost of the BMG project. The participant costs also capture the cost of the Preliminary Engineering Study (PES) and Detailed Engineering Study (DES) required to move forward with a capital incentive project in the Process & Systems or Industrial Accelerator programs.

Incremental O&M Costs

Incremental operations and maintenance (O&M) costs are intended to capture the net increase or decrease in facility O&M costs as a result of implementing a BMG project. When considering a BMG project there are two main components to Incremental O&M costs: facility O&M costs and increased natural gas costs. The facility O&M costs are determined based on the methodology specified within the task 3 report. Increased natural gas costs are determined using the rate archetypes described in section 2.3. Incremental O&M costs must be considered over the effective useful life of the BMG project (assumed to be 20 years). Facility O&M costs were assumed to escalate with inflation (2 percent) and natural gas prices were assumed to escalate as per the Sproule natural gas price forecast for the Dawn hub (i.e., the same source as the 2013 LTEP, but a newer forecast vintage). The stream increased or decreased O&M costs are converted to net-present-value using the IESO's assumed discount rate[31].

Program Administration Costs

Program administration costs capture the additional costs required to support the program from an administrative perspective. These costs could include, for example, marketing materials, contract review, customer outreach, or IT support. Program administration costs for BMG projects were determined using a $/MWh rate developed by CLEAResult for application review purposes using the IESO's original budget and savings forecasts for the Process and Systems Upgrades Incentive and Industrial Accelerator programs. This value was developed on the basis of the original program forecast (energy savings and budget) and is intended to capture both fixed and variable (or per project) program costs. The value was confirmed by IESO as a reasonable and accurate value.

Incentive Costs

Incentive costs capture the monetary or in-kind compensation provided directly to customers to encourage the installation of a BMG project. Incentives include the costs of the PES and DES which are covered by the IESO for the Process and Systems Upgrades Program up to $10,000 and $50,000, respectively, and for the Industrial Accelerator program $20,000 and up, and the capital incentive provided to customers. As per direction from the IESO, three incentive scenarios were calculated for the purposes of this study: (1) 40 percent of capital costs; (2) 70 percent of capital costs; and (3) $0.02/kWh production incentive.

[31] Ibid. 4 percent

Other Assumptions

There are several other assumptions required to calculate the components of the cost-effectiveness tests in alignment with the IESO Cost Effectiveness Guide[32]. For example, all electricity and peak demand savings are increased by a provincial average distribution and/or transmission system losses according to the connection point of the BMG project.

[32] Independent Electricity System Operator; Conservation & Demand Management Energy Efficiency Cost Effectiveness Guide; March 2015; http://www.ieso.ca/Documents/conservation/LDC-Toolkit/Guidelines-and- Tools/CDM-EE-Cost-Effectiveness-Test-Guide-v2-20150326.pdf

4.2 Benefit-Cost Results

Figure 36 and Table 15 show the benefit-cost results for selected representative customers.

Figure 36: Benefit-Cost Streams for Selected Customer Archetypes

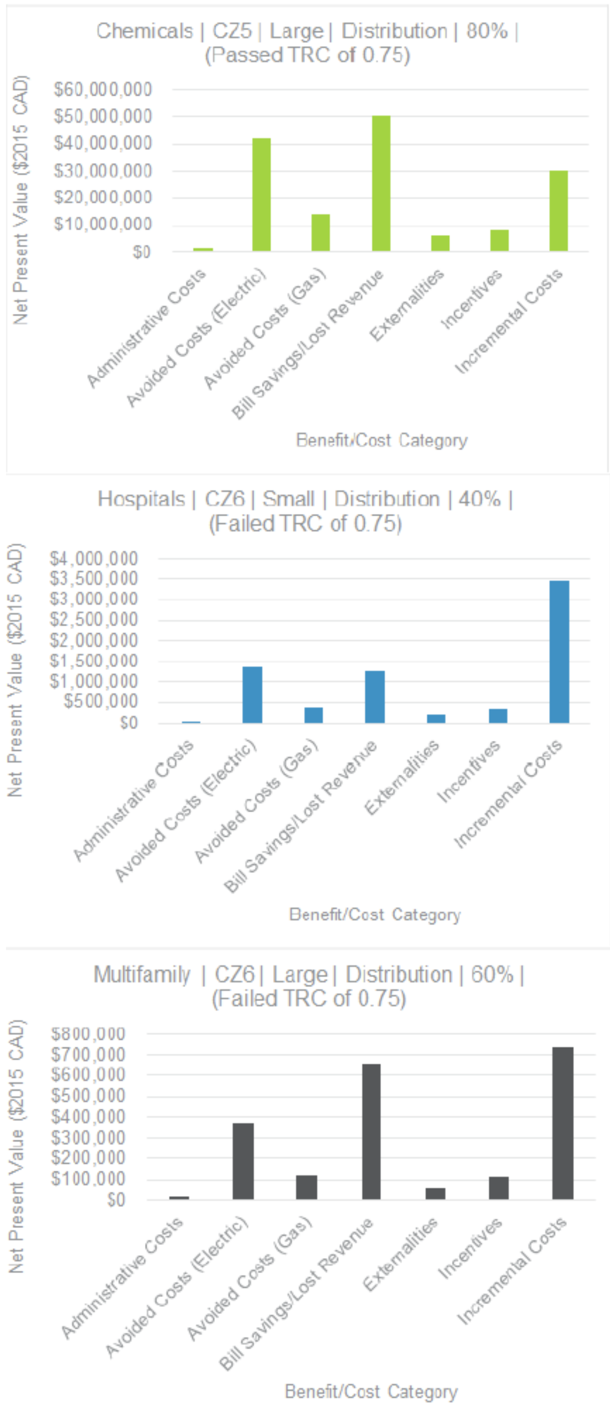


Table 15: Benefit-Cost Test Results for Selected Customer Archetypes

Representative Customer	Chemicals	Hospital	Multifamily
Capacity (MW)	7.1	0.52	0.17
TRC	1.06	0.51	0.44
PAC	4.34	3.18	2.86
PC	1.92	0.80	0.89

4.3 Results—Economic Potential

This section communicates the results of the economic potential analysis. As discussed in section 3 above, different facility sizes are considered for each archetype. Economic potential results are selected based on the largest BMG capacity (in megawatts) that passes the PAC screen. Due to the modified load-following operational strategy for CHP, which does not depend on price signals, results do not differ among the three scenarios. Incentives impact the PAC cost-effectiveness test, but PAC ratios are highly in favour of CHP (as utilities do not incur the high capital cost of CHP). As a result, all facility types modelled pass the PAC test.

Because the economic potential screens only based on PAC, and all facility types modelled pass the PAC test, CHP economic potentials match technical potentials.

Appendix A includes detailed results by LDC.

4.3.1 CHP

In addition to reporting economic potential results based on a PAC screen only, for informational purposes, we report CHP economic potential results using minimum TRC of 0.75.

4.3.1.1 Energy Savings

Figure 37 shows the province-wide CHP economic potential based on electricity savings. Removing the 0.75 TRC screen approximately doubles economic potentials.

Figure 37: CHP Economic Potential in Electricity Savings for System

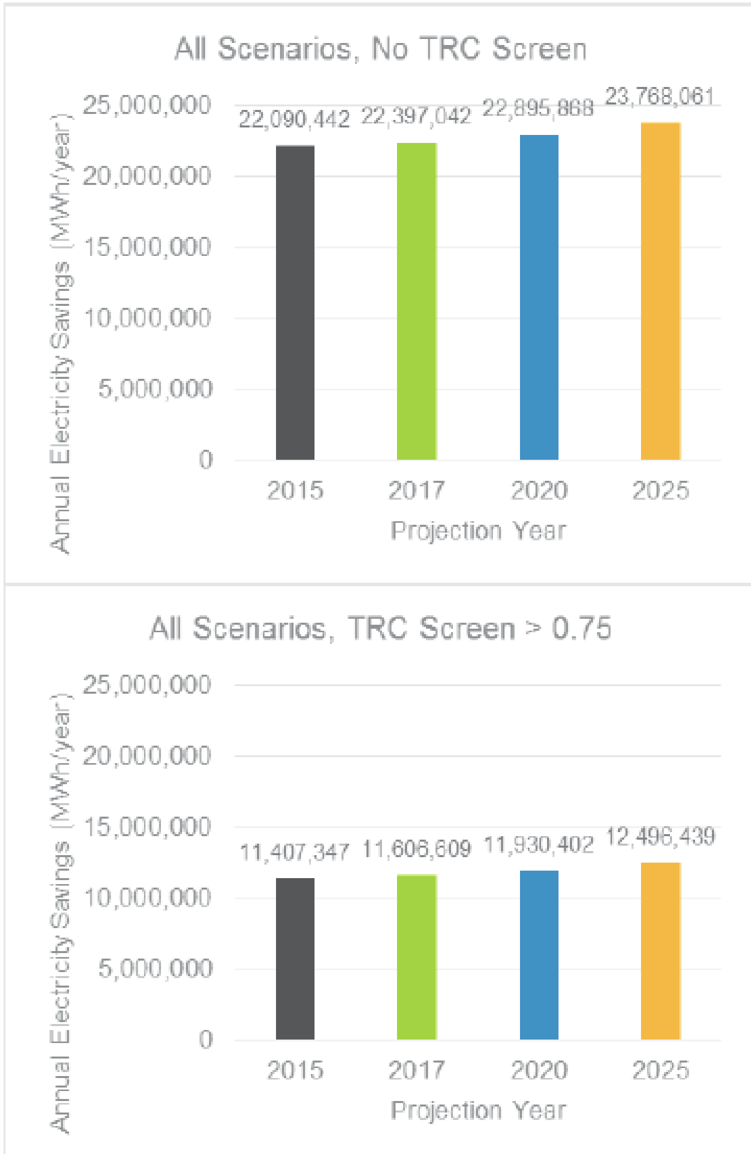


Figure 38 and Figure 39 show the distribution by major facility type for province-wide CHP economic potential. The figures show that removing the 0.75 TRC screen has a modest impact on economic potential for most industrial facilities, but substantially increases economic potential for multi-family and commercial//institutional facilities.

Figure 38: CHP Economic Potential in Electricity Savings by Facility, No TRC Screen

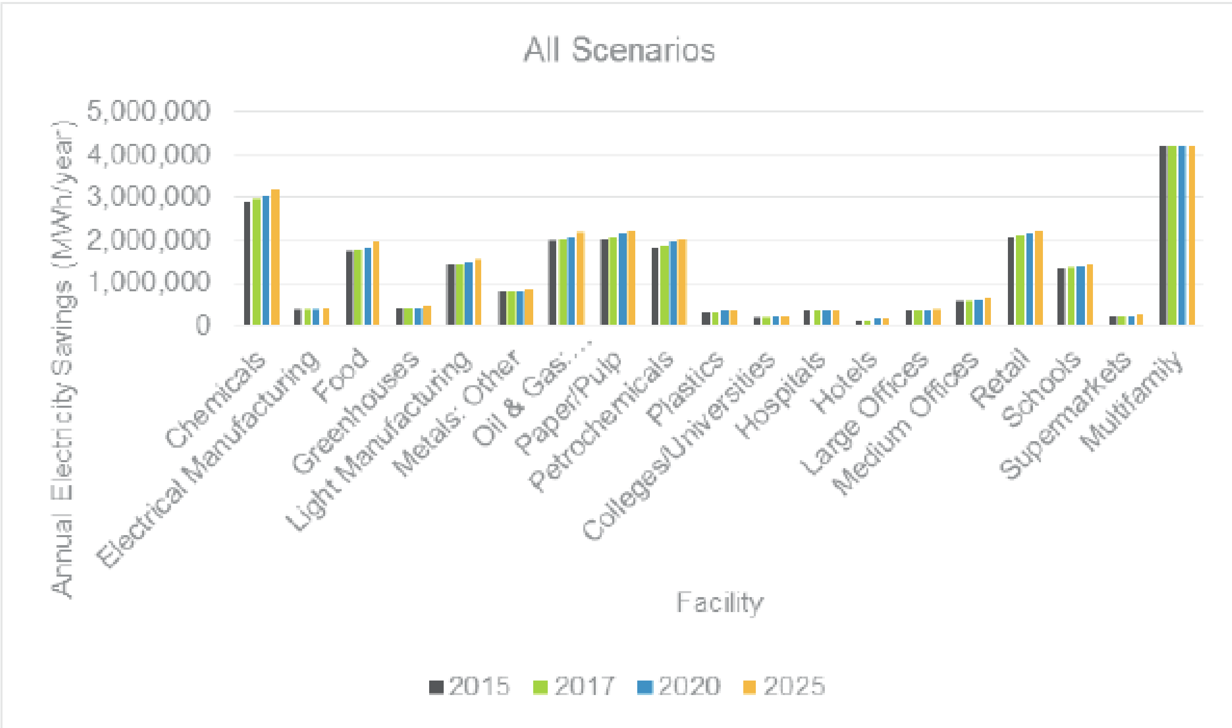


Figure 39: CHP Economic Potential in Electricity Savings by Facility, >0.75 TRC Screen

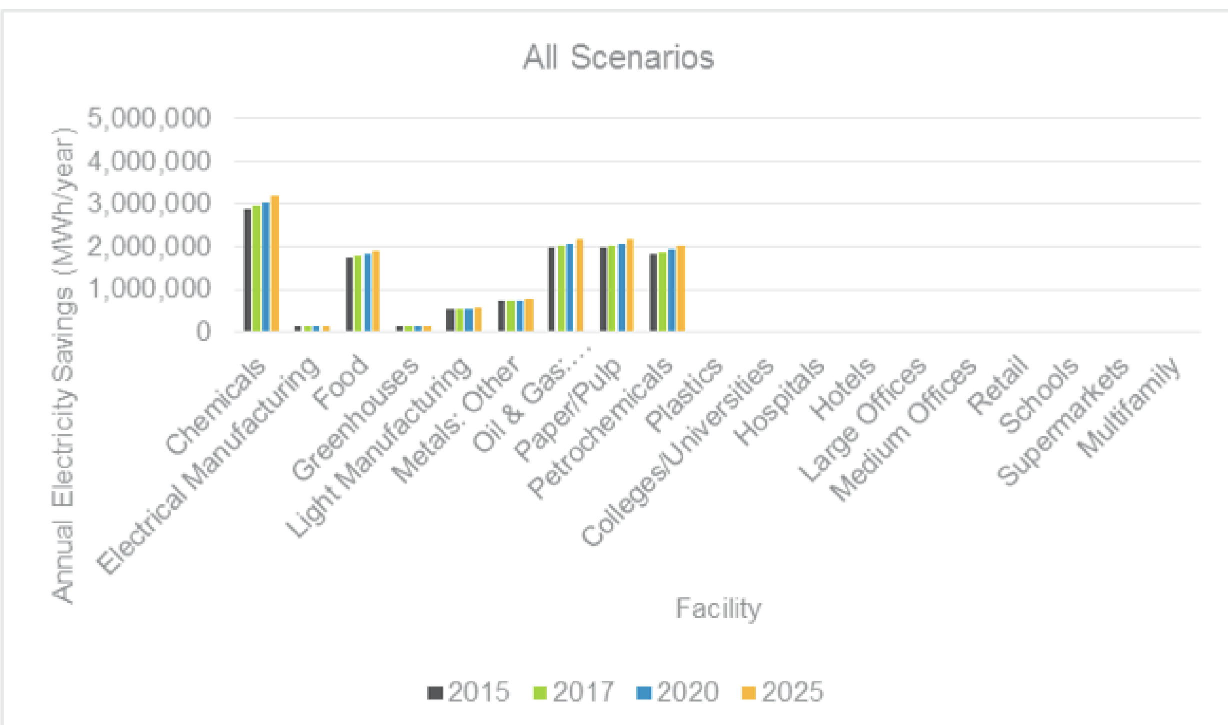
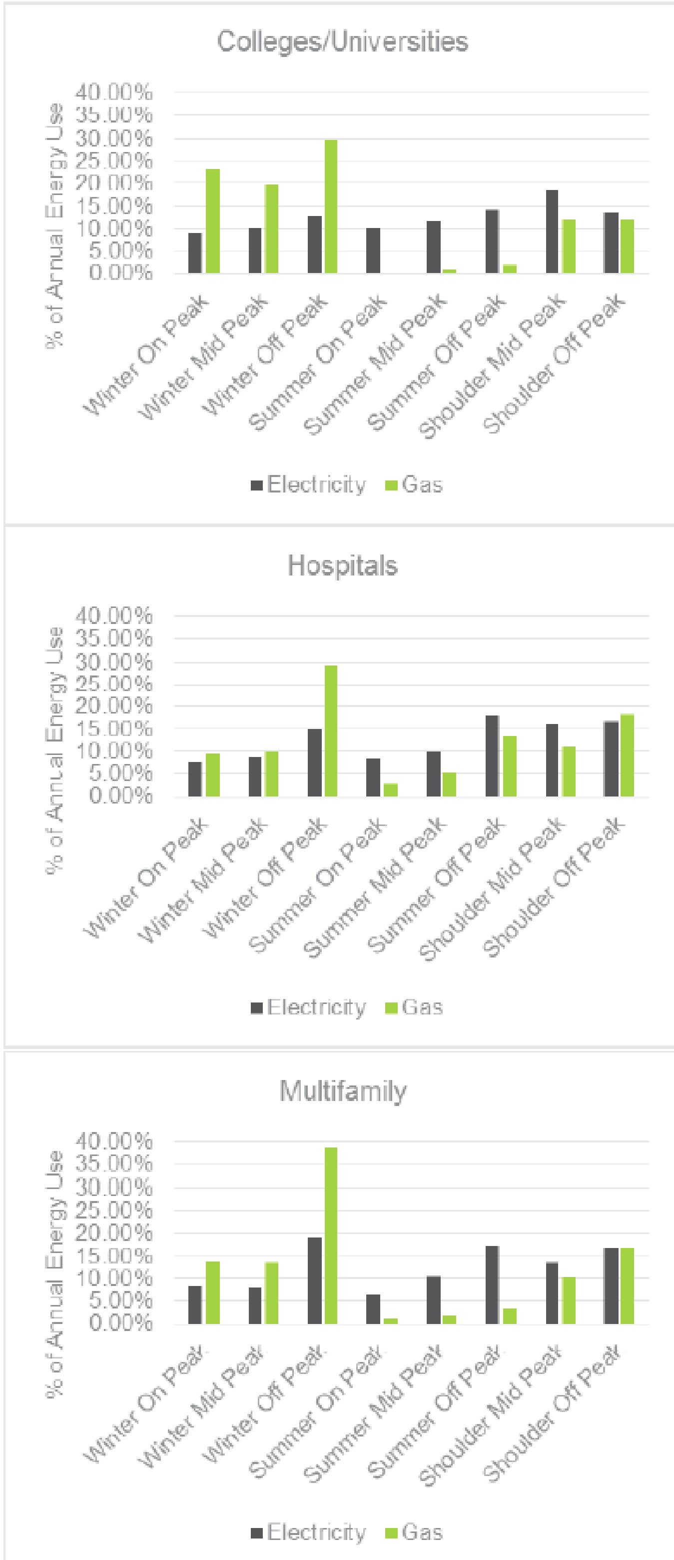


Figure 40 shows selected comparisons of the relative seasonal distributions of facility electric and thermal loads for several multi-family/commercial/institutional facility types. For these facility types, thermal loads tend to drop off in summer months, which can limit the hours that the CHP system can operate, despite the allowance in the operational strategy for limited thermal dumping. Figure 41 shows selected comparisons of the relative seasonal distributions of facility electric and thermal loads for two industrial facility types. In these industrial examples, while thermal loads vary somewhat throughout the year, they remain well aligned with the distribution of electrical loads, allowing the CHP system to operate more consistently throughout the year compared to the multi-family/commercial/industrial facility types.

Figure 40: Selected Commercial Load Profiles by Peak Status



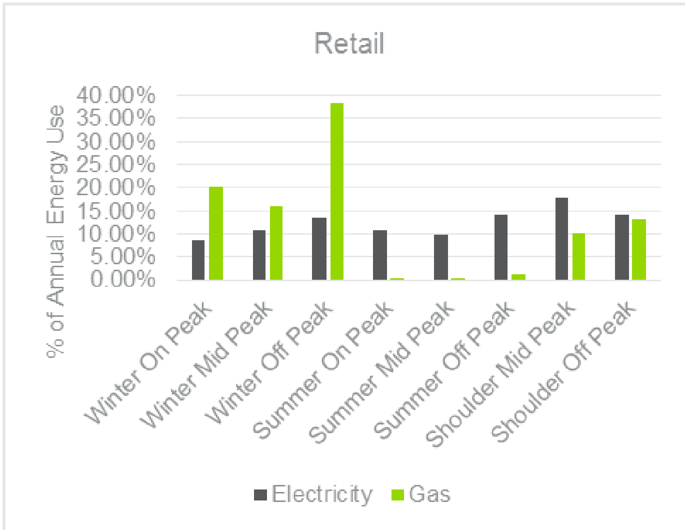
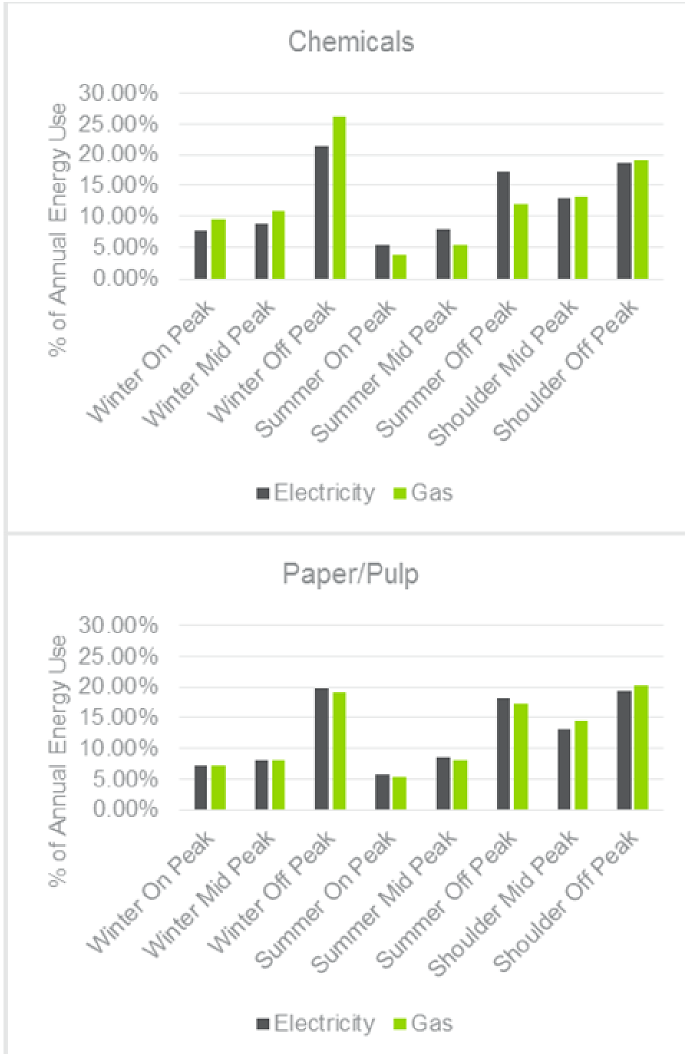

Retail
% of Annual Energy Use
40.00%
35.00%
30.00%
25.00%
20.00%
15.00%
10.00%
5.00%
0.00%
Winter On Peak
Winter Mid Peak
Winter Off Peak
Summer On Peak
Summer Mid Peak
Summer Off Peak
Shoulder Mid Peak
Shoulder Off Peak
Electricity
Gas

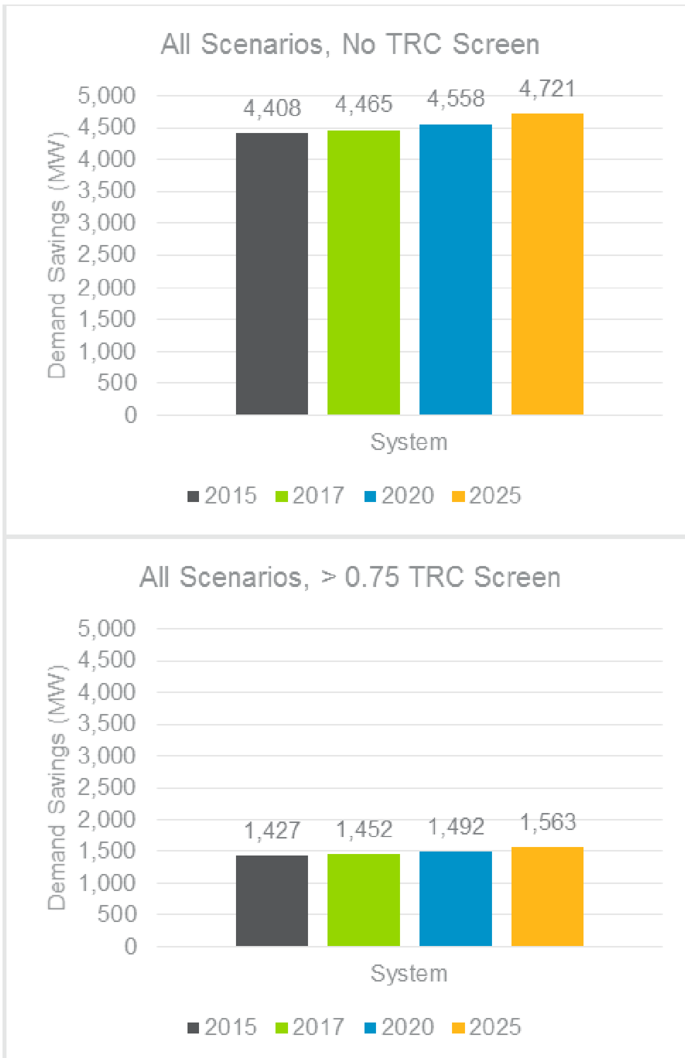
Figure 41: Select Industrial Load Profiles by Peak Status



4.3.1.2 Demand Savings

Figure 42shows the province-wide CHP economic potential based on summer electric demand reduction. Removing the 0.75 TRC screen increased economic potential demand savings by about a factor of three.

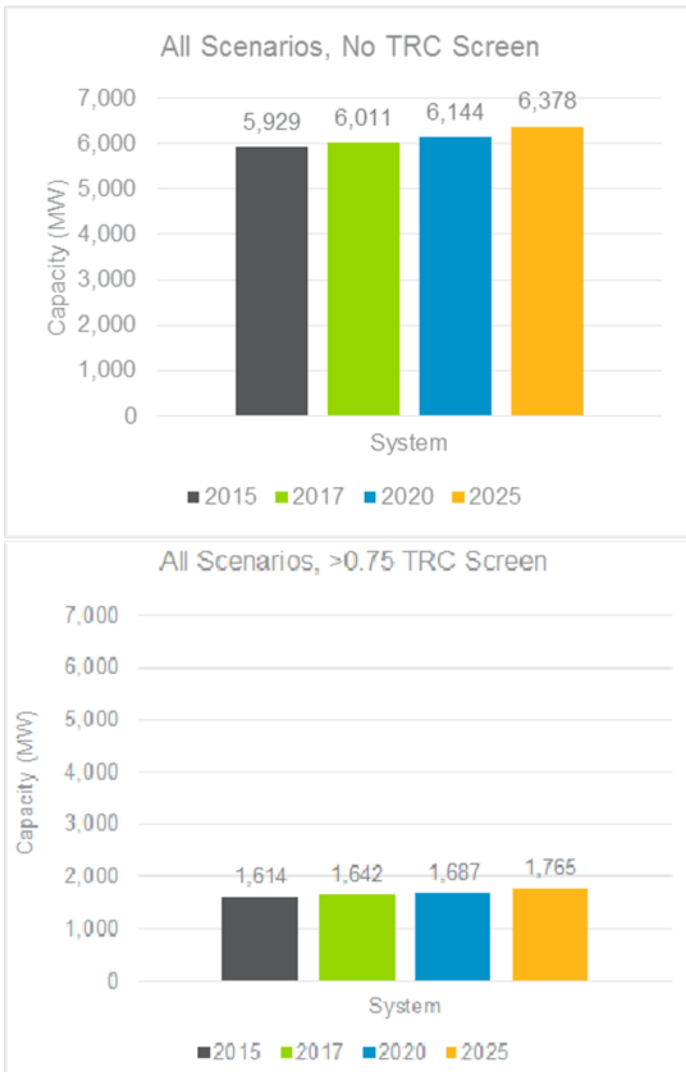
Figure 42: CHP Economic Potential in Demand Savings for System



4.3.1.3 Capacity

Figure 43 shows the province-wide CHP economic potential based on nominal installed capacity. Removing the 0.75 TRC screen increases CHP economic potential capacity by almost a factor of four.

Figure 43: CHP Economic Potential in Capacity for System



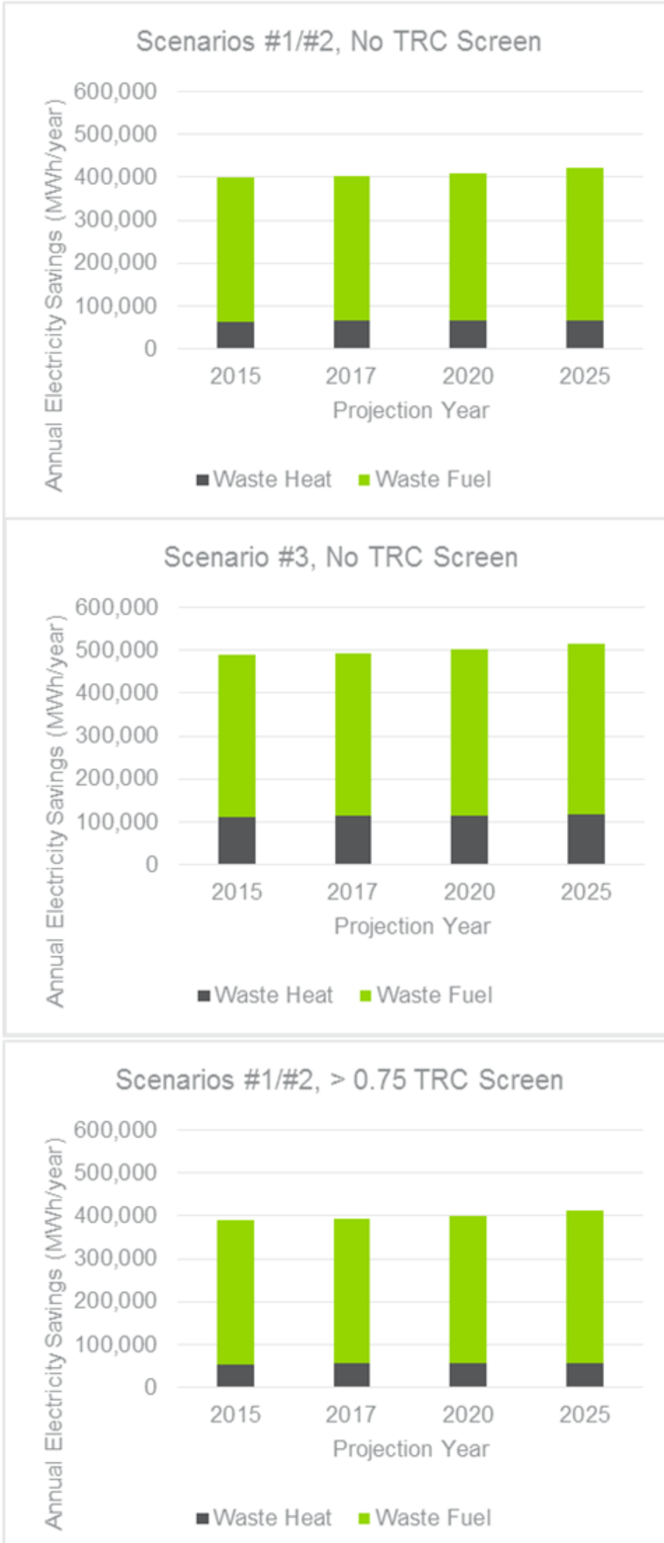
4.3.2 WER

For WER economic potential, results for incentive scenarios #1 and #2 differ from those for scenario #3 due to the hourly cost minimization employed in the WER operational strategy.

4.3.2.1 Energy Savings

Figure 44 shows the province-wide WER economic potential based on electricity savings. As discussed above, the economic potential matches the technical potential when no TRC screen is used.

Figure 44: WER Economic Potential in Electricity Savings for System



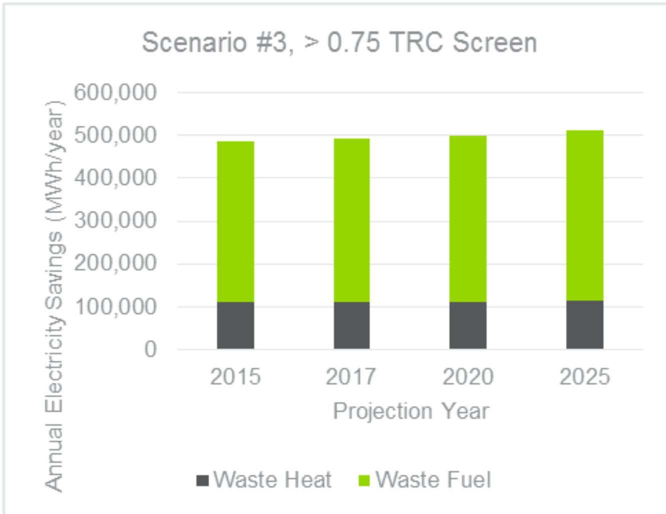
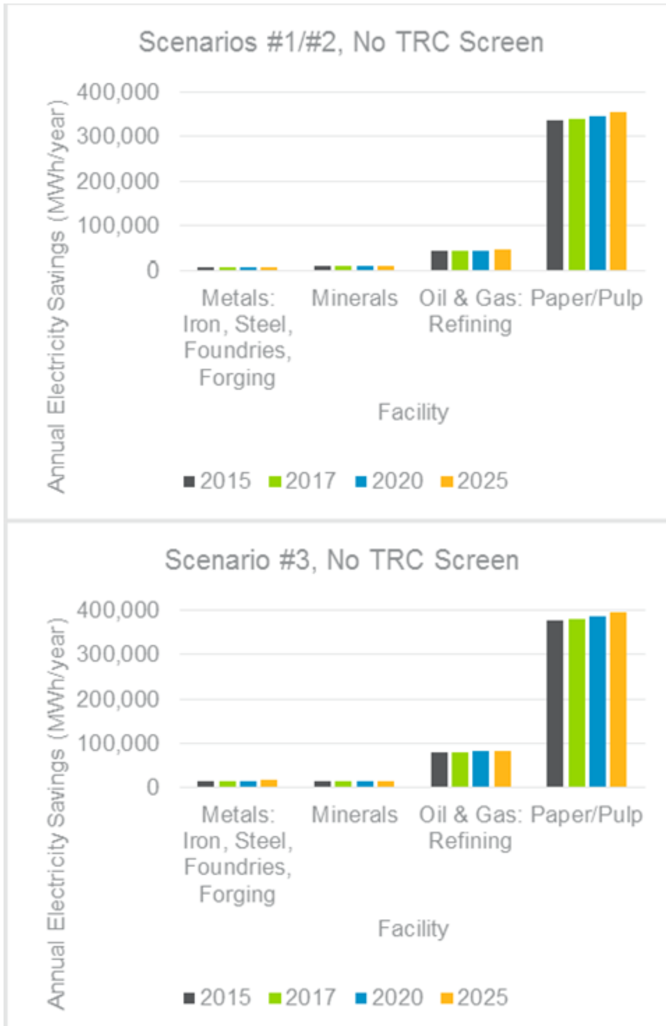

Scenario #3, > 0.75 TRC Screen
600,000
500,000
400,000
300,000
200,000
100,000
0
Annual Electricity Savings (MWh/year)
2015
2017
2020
2025
Projection Year
Waste Heat
Waste Fuel

Figure 45 shows the distribution by facility type of WER economic potential based on electricity savings.

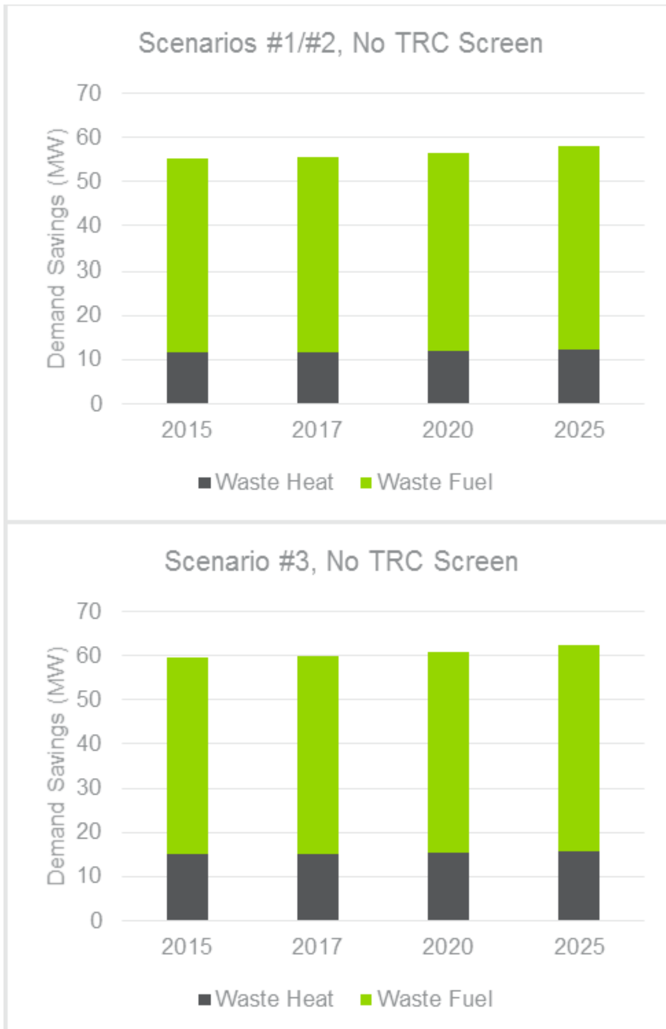
Figure 45: WER Economic Potential in Electricity Savings by Facility Type



4.3.2.2 Demand Savings

Figure 46 shows the province-wide WER economic potential based on summer electric demand reductions.

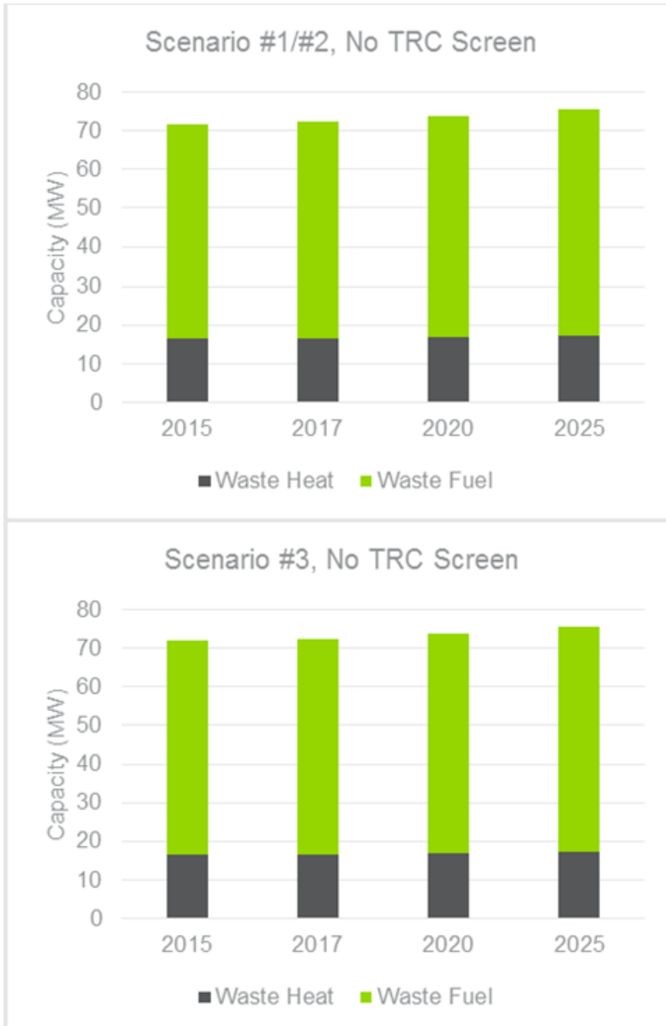
Figure 46: WER Economic Potential in Demand Savings for System



4.3.2.3 Capacity

Figure 47 shows province-wide WER economic potential based on nominal installed capacity.

Figure 47: WER Economic Potential in Capacity for System



5. Market Potential

Market potential represents the portion of economic potential that is likely to be achieved over time. Market potential is expressed in terms of capacity (MW), peak demand savings (MW), and annual energy savings (GWh). Both the technical and economic potential do not include a time component beyond adjustment for population changes (i.e., potential is calculated as if it is realized immediately). In contrast, market potential considers the time required to raise awareness, generate market interest, conduct engineering analyses, and design, develop, and install BMG systems.

5.1 Methodology and Approach

Market potential is determined using three key steps and concepts that are described in more detail below:

1. Participant cost screen and optimal sizing
2. Financial and non-financial potential
3. Market diffusion.

5.1.1 Participant Cost Test Screen and Optimal Sizing

As discussed above, the BMG tool was used to analyze several BMG sizing options for each facility type, and the economic potential stage screened all projects from a PAC perspective and the largest BMG that passed was selected. The first step of the market potential considers all BMG sizes for a given facility that pass the PAC. These projects are run through a cost-effectiveness test that captures the customer perspective. The participant cost screen uses the Participant Cost (PC) test to evaluate the project from

the customer's perspective (see Table 16). The PC test calculates the benefit and cost components, and the results can either be expressed as a dollar amount representing the net benefit (benefit minus costs) or as a ratio (benefits divided by costs). A project passes the participant cost test if a positive net benefit results or if the ratio is greater than 1.0. A description of the component not already described in section 4.1 follows.

Table 16: PC Cost-Effectiveness Test Components

Cost Test Component		PC
Benefits	Bill Savings	✓
	Incentive Costs	✓
Costs	Incremental Equipment Costs (or participant costs)	✓
	Incremental O&M Costs	✓

Bill Savings

The bill savings component is intended to capture how much the customer saves on their electricity bill as a result of implementing a BMG project. To determine the value of this component, all components of the electricity bill are simulated for the customer prior to implementing the BMG project and after implementing the BMG project. The difference determines the value for this component. Bill savings must be considered over the effective useful life of the BMG project (assumed to be 20 years). To determine the bill savings over time, an index was developed to capture the increase rates over the life of the project. IESO's 2013 Long Term Energy Plan (LTEP) Hourly Ontario Energy Price (HOEP) and Global Adjustment (GA) forecasts for class A and class B customers were used. The stream of bill savings are converted to net-present-value using the IESO's assumed discount rate.[33]

The optimal sizing option for each facility type that passed the PC test continued to the next step in the market potential analysis.

5.1.2 Payback Acceptance

Payback acceptance curves define the relationship between the simple payback of a project and the percentage of the market that will proceed with a project. Both financial and non-financial factors impact a customer's decision whether or not to move forward with a project, and different sectors generally have different payback thresholds. Navigant segmented the analysis of payback acceptance into two types: financial and non-financial.

Financial Potential

The financial payback acceptance curves were developed leveraging an in-depth analysis conducted by Navigant for an energy-efficiency potential study. The study assessed telephone interviews with 400 commercial customers and 150 industrial customers. The survey inquired about the company's payback requirements or guidelines for the purchase of energy-efficient technologies. If a direct response was not provided, a series of questions were asked to deduce the payback range. The resulting data was used to develop a parametric estimation of payback functions. Navigant specified and estimated a functional form for the payback period that includes both payback time and other variables expected to affect payback times, and tested whether these other variables had statistically significant effects on payback. After a review of histograms of the payback times reported in the survey data, a normal-distributed specification was developed for the commercial and industrial versions of the curves.

[33] Ibid. 4 percent.

Non-Financial Potential

The non-financial payback acceptance curves were developed using both quantitative and qualitative analyses, described in more detail below. In addition to accounting for financial factors, the non-financial payback acceptance curves account for factors such as environmental permitting, technical constraints, site-specific concerns, and customer security/reliability.

The quantitative analysis leveraged the United States Department of Energy (US DOE) Industrial Assessment Centers (IAC) database. IAC provides no-cost energy assessments to small- and medium- sized US manufacturers with recommended actions to reduce electricity use, fuel consumption, and waste. The IAC program has conducted over 17,282 assessments using a consistent, documented methodology resulting in more than 131,031 associated recommendations. The database includes publicly available information on assessments including facility details (e.g., North American Industry Classification System or NAICS code, size, energy use, etc.) and recommendation details (e.g., type of recommendation, payback, energy and dollars saved, implemented or not, etc.). Cogeneration recommendations and electricity only energy efficiency (EE) projects were pulled from the database, including the payback period and whether or not the recommendation was enacted. Two regression analyses were conducted on the data. The first regression analysis resulted in a simplified payback acceptance curve for cogeneration projects and the second regression analysis resulted in a simplified payback acceptance curve for energy efficiency (electricity only) projects. The goal of this analysis was to determine to what extent non-financial factors influence the decision whether or not to proceed with a BMG project. Purely financial factors influence any project whether it is an EE project, a BMG project, or any other project. BMG project decisions, however, are also influenced by several non-financial factors that tend to have less impact on EE projects. Therefore, we deduced that the difference between the EE curve and the BMG curve represents reasonably well the non-financial factors attributable to BMG projects.

The qualitative analysis leveraged interviews conducted with eight LDC staff working directly with customers and five customers that initiated BMG applications, but abandoned their applications. Based on the interviews, customers are driven by the key benefits outlined in Table 17. During the interviews, customers highlighted that they rarely implement a BMG project for purely financial reasons. There is typically another reason that drives initial interest and in turn leads to the investigation of BMG.

Table 17: Benefits of BMG Implementation

Benefit	Description
Cost reduction	A key benefit of BMG is reducing electricity costs by generating onsite. There is also an opportunity for larger customers (>3MW) to reduce their global adjustment cost by reducing their demand.
Reliability/resilience	Customers cited the loss of electricity to be a significant cost to their business and the need for back-up power to be particularly important to them.
Predictability	Electricity bills can vary substantially on a month to month basis. By using more natural gas rather than electricity, there are additional opportunities to hedge the cost, and the bills are more consistent.
Expansion Costs	When businesses expand, in some cases an additional connection is required or the utility requires the customer to incur additional costs to serve the increase in load. Installing BMG can reduce these costs.
GHG reductions	Organizational policies to lower climate impacts can motivate customers to install BMG.[34]

Based on the interviews, customers are influenced by the key barriers outlined in Table 18. These barriers do not necessarily prevent project implementation, however, they can slow the implementation process. The customers interviewed that did not continue with their BMG application primarily noted technical constraints and financial constraints as the key reason(s) not to move forward.

Table 18: Barriers to BMG Implementation

Benefit	Description
Policy uncertainty	LDCs noticed a slow-down in application progress and program interest following the announcement of the Ontario cap and trade program.[35] In addition, LDCs expressed uncertainty related to standby rates and the treatment of GA charges.

[34] Some interviewees also cited this as a barrier because BMG can sometimes increase GHG emissions
[35] Interviews were conducted when the Climate Mitigation and Low-Carbon Economy Act was pending

Benefit	Description
Technical constraints	Some customers interviewed either did not have the thermal load to support a BMG project or encountered system constraints such as fault current, short circuit, and other equipment issues.
Internal constraints	Customers that are part of a company with multiple facilities face internal competition for capital and are often subject to capital spending cycles.
Gas connection	Some BMG technologies require a minimum natural-gas pressure. Natural-gas supplies in some locations are below this pressure requirement, which would necessitate an auxiliary gas compressor.
Environmental permitting	Customers must undergo an environmental permitting process prior to their in-service date. The timelines for environmental permitting are highly variable and one project experienced a 12 month process.
Paperwork/process	Though not a major barrier to implementation given the size of incentive, customers expressed frustration with the paperwork required. In some cases the contract required legal review and some customers expressed concern with allowing auditors in their facility at any time (for M&V and EM&V purposes).
Exchange rate	The recently unfavourable Canadian-dollar exchange rate has made some equipment more expensive and some customers are intending to wait until conditions improve.
Community impact	Some facilities are in more residential areas, and customers considered both the potential community impacts and community reaction to the BMG project.

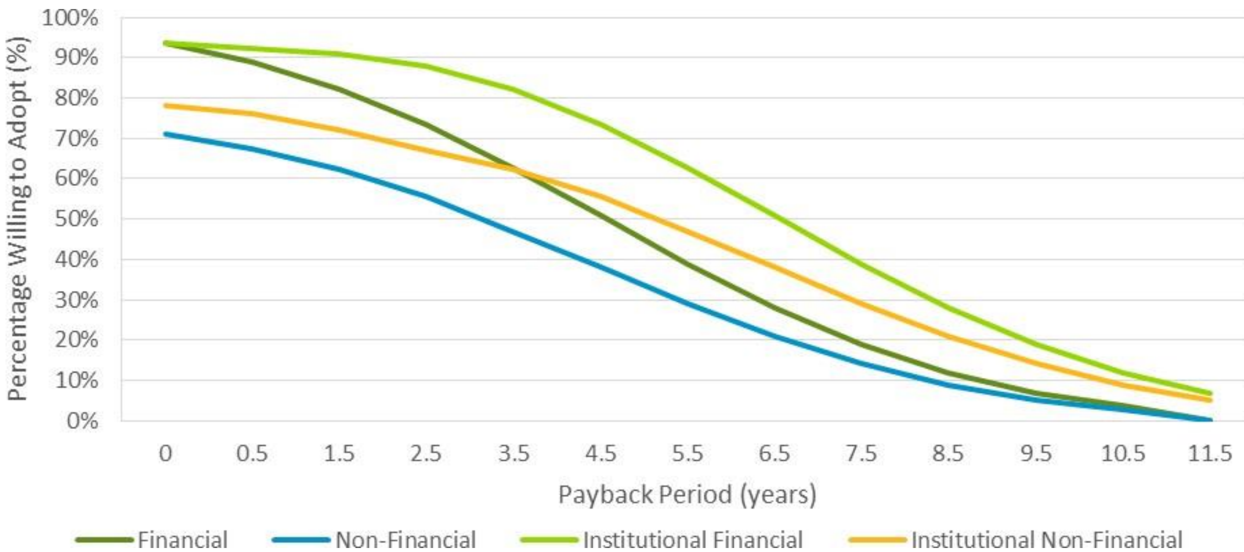
The key findings from the interviews are:

- Financial payback is a critical metric impacting a customer's decision
- Reliability of supply and predictability of costs are secondary factors, but also important in the decision whether or not to implement
- Uncertainty in rates and policy are major barriers (cap and trade in particular).

The interviews also identified special circumstances impacting the Multi Unit Residential Building (MURB) sector. Recently, additional environmental regulations and code changes were enacted preventing MURBs from storing diesel onsite for back-up generation purposes. MURBs are investigating BMG as an alternative to comply with regulations while realizing additional benefits. The non-financial payback curves were adjusted to reflect the qualitative findings noted above.

The resulting financial and non-financial payback acceptance curves are illustrated in Figure 48. Some types of industrial facilities will accept longer payback periods than some types of commercial facilities, and vice versa, making it difficult to differentiate payback acceptance based on sector. For example, within the industrial sector a lower payback is required for a pulp and paper facility which may have less confidence in its longevity, but a chemical facility would be willing to accept a slightly longer payback to realize the benefits. Therefore, we use a common payback acceptance curve for both the commercial and industrial sectors. However, decision-making considerations vary for institutional facilities which include hospitals, universities and schools as compared to other facility types. The curves reflect the fact that institutional facilities generally accept longer payback periods compared to most other facilities. A primary contributing factor is that institutional facilities generally have higher certainty that operations will continue for the foreseeable future.

Figure 48: Payback Acceptance Curves



Navigant used the payback period for the optimal sizing by facility type that passed the initial PC screen to determine the percentage of projects that would be willing to adopt from a financial and then non- financial perspective.

5.1.3 Market Diffusion

Market Diffusion characterizes the pace of project implementation taking into account factors such as marketing and outreach efficacy, project lead times, and equipment cost reductions over time. Navigant used a Bass Diffusion model to represent the implementation of market potential over time. The model considers the influence from early adopters (innovators) and late adopters (imitators), which explains how uptake occurs at the onset of a new product, idea, or process. Coefficients were developed to reflect the level of innovation (impacted by marketing, sales, and outreach) and imitation (impacted by word-of- mouth, social connections, and associations) based on the interviews discussion in the prior section.

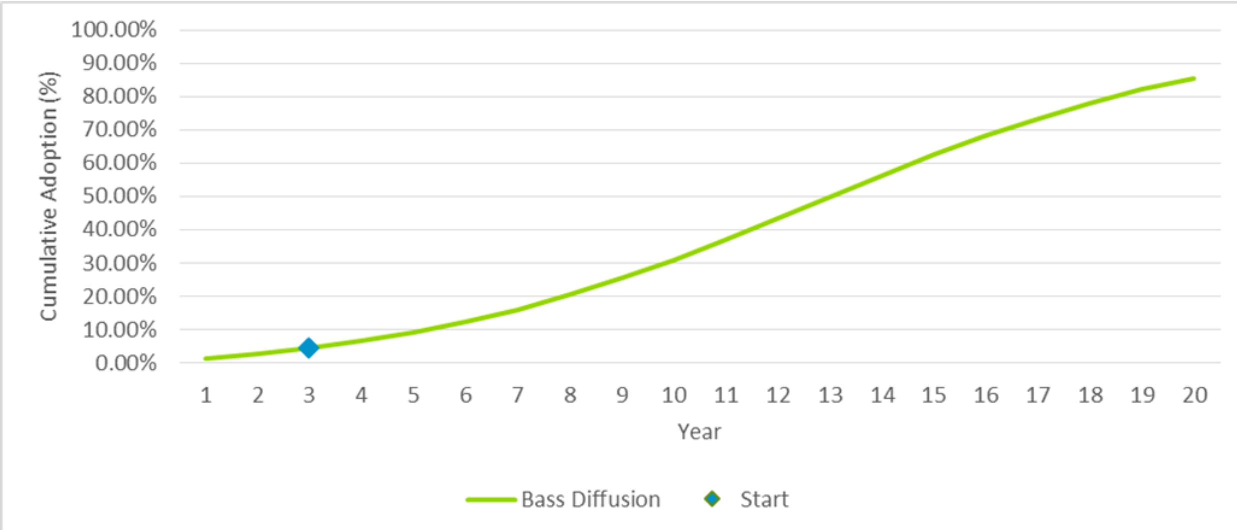
The interviews conducted provided insight into the pace of adoption, barriers that impact one sector over another, and enablers that can speed up the pace of adoption. Key influencers are:

- Industrial customers tend to have more knowledge of BMG and what the business case is, some industrial customers are actively seeking BMG incentives and opportunities. One customer revisits the financial payback of a BMG facility every 2 years.
- The market (consultants and LDCs) are actively contacting MURB customers with incentive options (PSUI) and offering build/own/operate services.
- The sales cycle (from first contact to project in-service) is highly variable and dependent on the sector:
    - Average ranges from 12 to 18 months for small and from 1 to 2.5 years for larger facilities
    - One environmental assessment was reported to take 1 year, with an average of around 6 months
    - Consultants targeting MURBs state 6 months to in-service (to be tested)
- Environmental permitting can be a time consuming step, taking up to 12 months
- All sectors can be influenced by capital spending cycles.

The Bass Diffusion model also requires an initial saturation assumption and a final market saturation assumption. The IESO programs offering BMG incentives have been in-market since 2012. To capture this market timing, year 3 of the Bass Diffusion Curve represents 2015. The final market saturation is assumed to be approximately 85 percent over 20 years. This indicates that 15 percent of the market potential will not be realized within 20 years.

The final curve (see Figure 49) was developed based on the information and methodologies discussed above. Navigant assumed that year three of this diffusion curve was representative of adoption in 2015.

Figure 49: BMG Bass Diffusion Curve



The total financial and non-financial potential determined from the payback acceptance step was modelled using the BMG Bass Diffusion curve to determine the demand savings (MW) and electricity savings (GWh) from 2015 to 2025.

5.1.4 Emissions

Navigant assessed the avoided CO2 emissions associated with the BMG potential. The IESO provided a representative hourly profile of the CO2 emissions associated with grid-supplied electricity use.[36] The CO2 emissions associated with natural gas use is 53.18 kg CO2/MMBtu.[37] For each facility, the electricity and natural gas use were modelled prior to the installation of BMG and after the installation of BMG.

[36] The emissions profile was based on the assumed 2017 generation mix
[37] From EIA: https://www.eia.gov/tools/faqs/faq.cfm?id=73&t=11.

5.2 Results—Market Potential

The sections below summarize the results of the BMG market potential analysis. Appendix A includes detailed results by LDC. Appendix B provides simple payback periods associated with the market potential analysis.

5.2.1 CHP

5.2.1.1 Energy Savings

Figure 50 shows the province-wide CHP market potential based on electricity savings. The two charts in the figure, labeled "Financial Payback Curve" and "Non-Financial Payback Curve", represent the market potential considering only financial factors and the overall market potential, respectively. The province- wide CHP market potential increases from about 60 to 130 GWh in 2015 (depending on scenario) to about 700 to 1,400 GWh in 2025. The 2025 projections represent about 3 to 6 percent of the 2025 CHP technical potential (depending on scenario).

Figure 50: CHP Market Potential in Electricity Savings for System

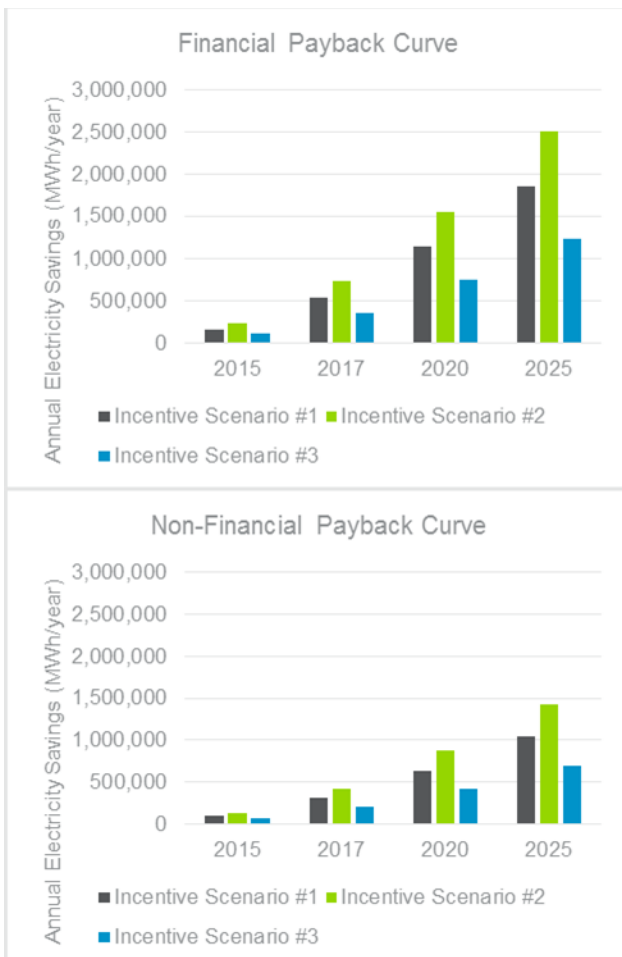
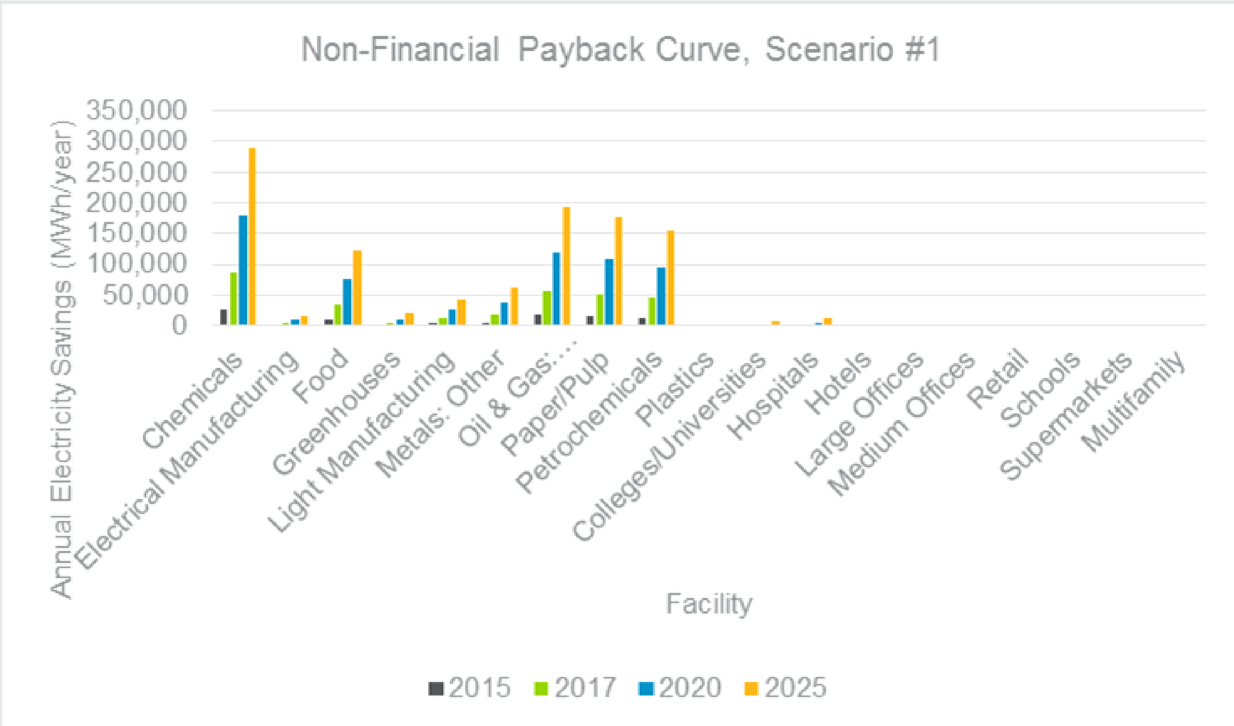


Figure 51 shows the distribution by major facility type of province-wide CHP market potential based on electricity savings. Large industrial facilities dominate the CHP market potential.

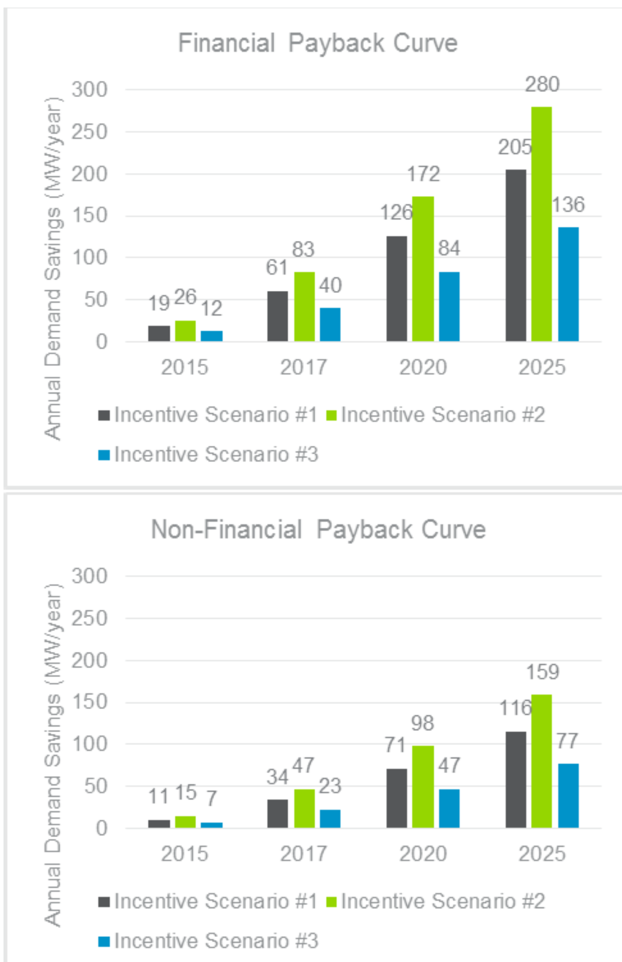
Figure 51: CHP Market Potential in Electricity Savings by Facility Type



5.2.1.2 Demand Savings

Figure 52 shows the province-wide CHP market potential based on summer electric demand reduction Again, the figure shows separate charts for market potential based only on financial factors (Financial Payback Curve). And the overall market potential (Non-Financial Payback Curve). The province-wide CHP market potential increases from about 7 to 15 MW in 2015 (depending on scenario) to about 77 to 159 MW in 2025 using a non-financial payback curve. The 2025 market potential represents about 2 to 3 percent of the 2025 CHP technical potential based on demand reductions.

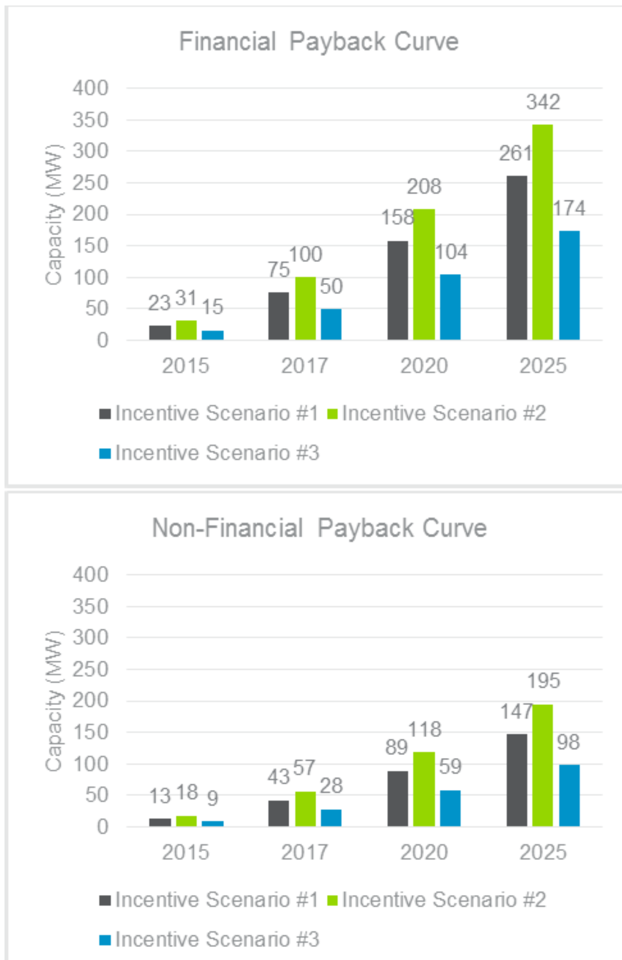
Figure 52: CHP Market Potential in Demand Savings for System



5.2.1.3 Capacity

Figure 53 shows the province-wide CHP market potential based on nominal installed capacity (both financial-only and overall market potentials). The province-wide CHP market potential increases from about 9 to 13 MW in 2015 (depending on scenario) to about 98 to 195 MW in 2025 using a non-financial payback curve. The 2025 market potential represents about 2 to 3 percent of the 2025 CHP technical potential based on installed capacity.

Figure 53: CHP Market Potential in Capacity for System



Based on information that the IESO provided, 83.9 MW of CHP capacity is expected to come online during or after 2015 through the PSUI and IAP programs. This is substantially higher than our 2015 market potential estimate (9 MW, under current program rules).

5.2.2 WER

5.2.2.1 Energy Savings

Figure 54 shows province-wide WER market potential based on electricity savings (both financial-only and overall market potentials). The province-wide WER market potential increases from about 1.9 to 2.4 GWh in 2015 (depending on scenario) to about 20 to 26 GWh in 2025 using non-financial payback curves. The 2025 market potential represents about 4 to 5 percent (depending on scenario) of the 2025 WER technical potential based on electricity savings.

Figure 54: WER Market Potential in Electricity Savings for System

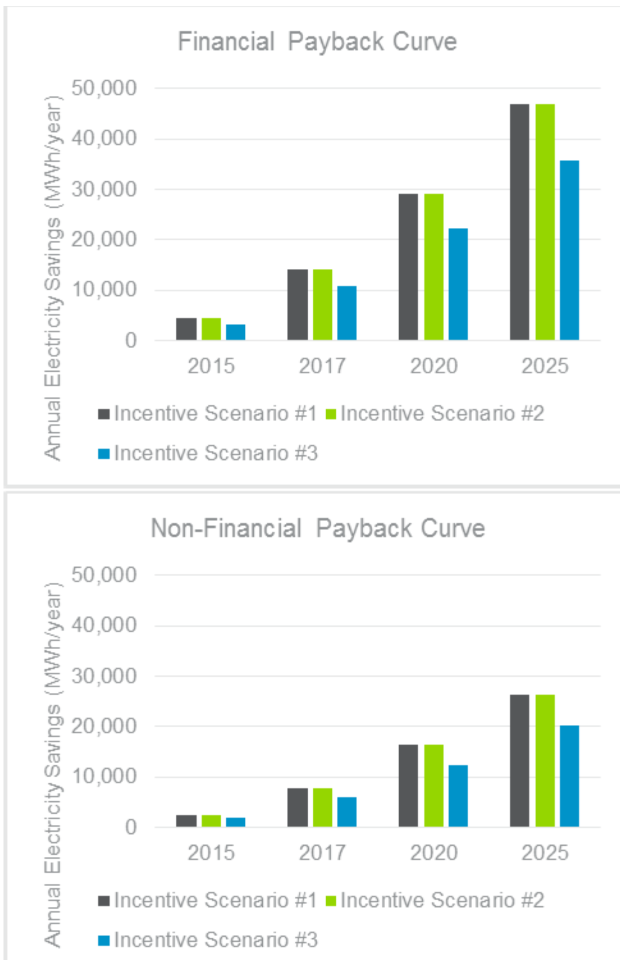
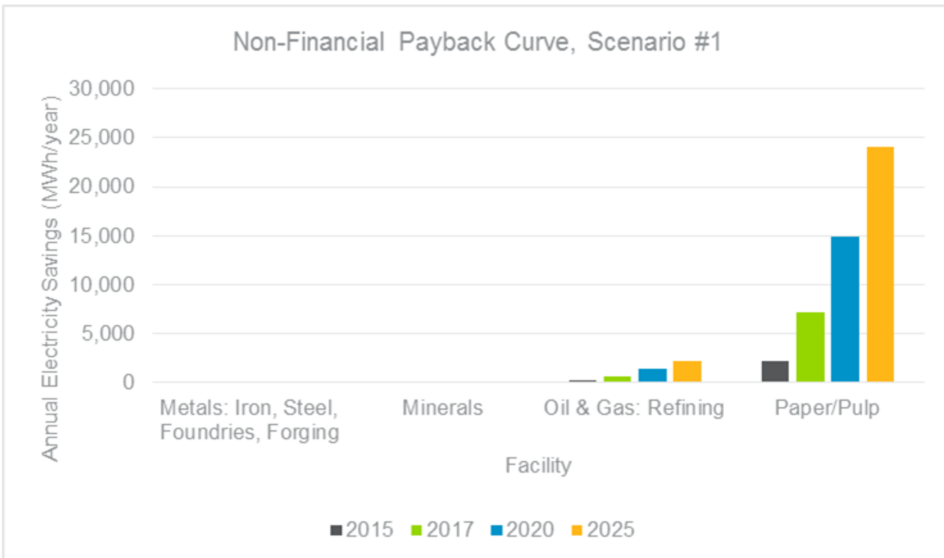


Figure 55 shows the distribution by major facility type of the province-wide WER market potential based on electricity savings (scenario 1 only). Paper/pulp dominates the WER market potential (over 90 percent of the market potential).

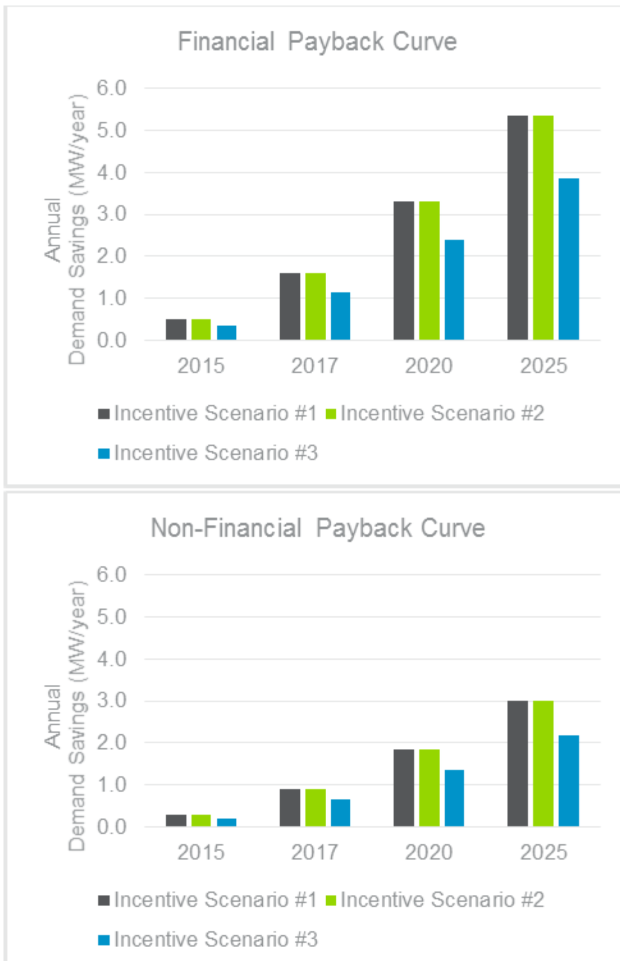
Figure 55: WER Market Potential in Electricity Savings by Facility Type



5.2.2.2 Demand Savings

Figure 56 shows province-wide WER market potential based on summer electric demand reductions (both financial-only and overall market potentials). The province-wide WER market potential increases from about 0.2 to 0.3 MW in 2015 (depending on scenario) to about 2.2 to 3.0 MW in 2025. The 2025 market potential represents about 4 to 5 percent (depending on scenario) of the 2025 WER technical potential based on demand reduction.

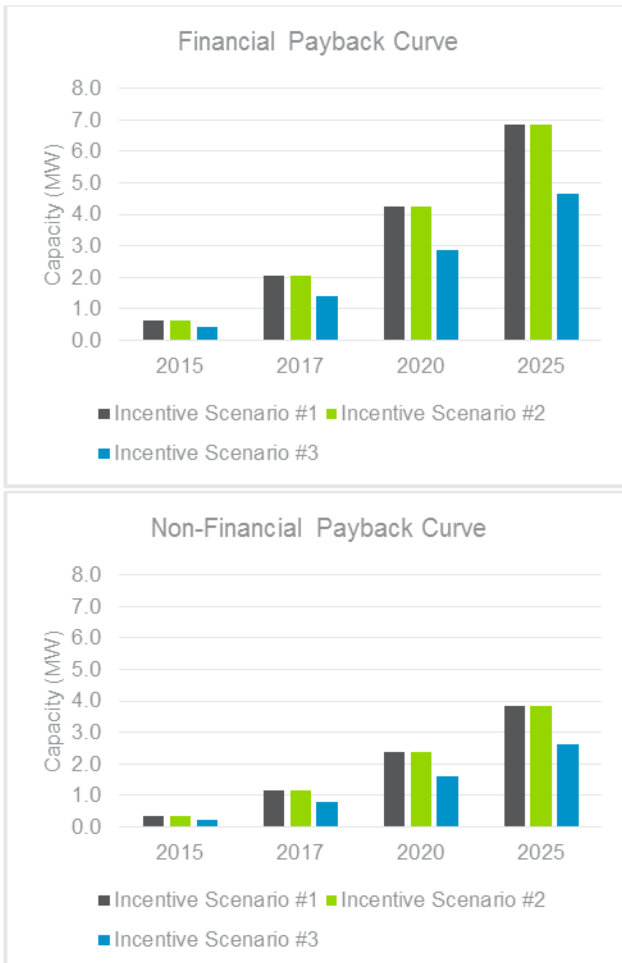
Figure 56: WER Market Potential in Demand Savings for System



5.2.2.3 Installed Capacity

Figure 57 shows province-wide WER market potential based on nominal installed capacity (both financial- only and overall market potentials). The province-wide WER market potential increases from about 0.2 to 0.4 MW in 2015 (depending on scenario) to about 2.6 to 3.9 MW in 2025. The 2025 market potential represents about 4 to 6 percent (depending on scenario) of the 2025 WER technical potential based on installed capacity.

Figure 57: WER Market Potential in Capacity for System



5.2.3 Payback Periods

Table 19 and Table 20 summarize the ranges of CHP and WER payback periods by major facility type, respectively. Payback periods vary within a major facility type depending on climate zone, size (small, medium, or large), whether the facility is transmission-level or distribution-level, and scenario. As can be seen in Appendix B, payback periods do not vary significantly between scenario 1 and scenario 2 despite the substantial difference in first-cost incentive (40 percent versus 70 percent of first cost). This occurs because other incentive constraints limit the incentive paid. For example, for both scenarios, the incentive cannot be higher than the annual electricity savings multiplied by $200 to $230/MWh.[38] First-cost incentives also may not exceed the amount necessary to reduce the simple payback period of a project to one year. The combination of these other constraints means that the 70% first cost incentive is rarely in effect for a BMG project.

Table 19: Summary of CHP Payback Periods [a]

Industrial Facility Type	Simple Payback Periods (Years)	Commercial Facility Type	Simple Payback Periods (Years)
Chemical	2 – 9	College/University	6 – 11
Electrical Manufacturing	3 – 7	Hospital	6 – 14
Food	2 – 9	Hotel	5 – 9
Greenhouse	3 – 11	Large Office	No Potential
Light Manufacturing	2 – 11	Medium Office	No Potential
Metals: Other	3 – 9	Multi-Family Residential	10 – 11
Oil & Gas Extraction	1.5 – 5	Retail	No Potential
Paper/Pulp	2 – 9	School	12 – 13
Petrochemicals	1 – 6	Supermarket	10 – 11
Plastics	4 – 9		

[38] $200/MWh if connected at the distribution level; $230/MWh if connected at the transmission level.

a) Excludes facilities that show no market potential because they do not pass the Participant Cost Test. See Appendix B for further breakdown of payback periods by facility type.

Table 20: Summary of WER Payback Periods [a]

Industrial Facility Type	Simple Payback Periods (Years)
Metals, Iron, Steel, Foundries, Forging	7 – 10
Minerals	7 – 12
Oil- & Gas: Refining	5 – 6
Paper/Pulp	4 – 7

a) Excludes facilities that show no market potential because they do not pass the Participant Cost Test. See Appendix B for further breakdown of payback periods by facility type

5.2.4 *Emissions*

Figure 58 shows market potential in annual CO2 savings at the system level for CHP (both financial and non-financial potentials). In the case of CHP, CO2 emissions increase due to switching from a relatively low-carbon electric grid to higher-carbon natural gas. For non-financial potential, increases in province- wide CO2 emissions range from about 7,500 to 16,100 metric tons/year in 2015 and increase to 82,400 to 175,700 metric tons/year in 2025.

Figure 58: CHP Market Potential in CO_2 Savings for System

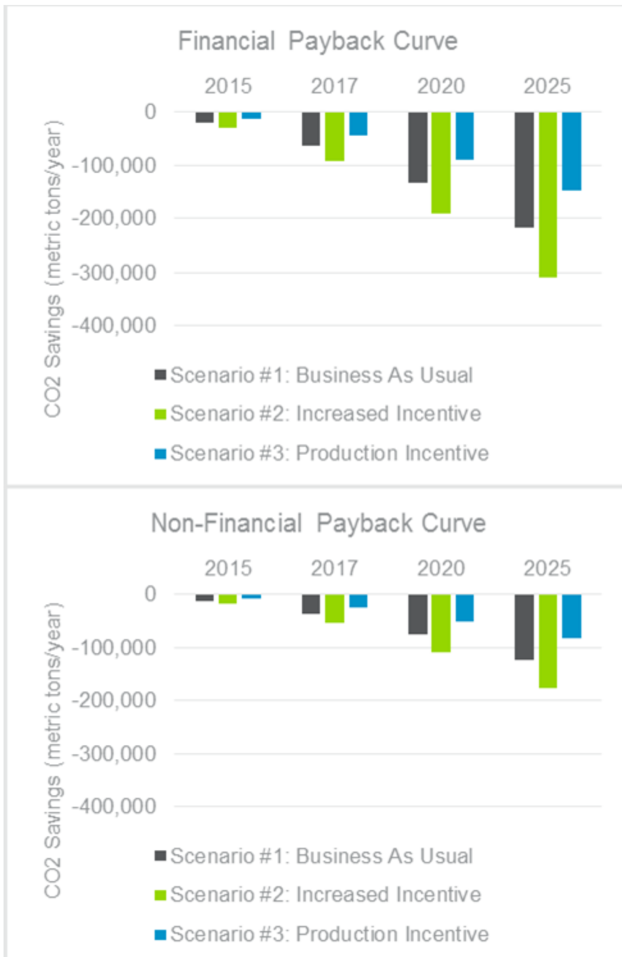
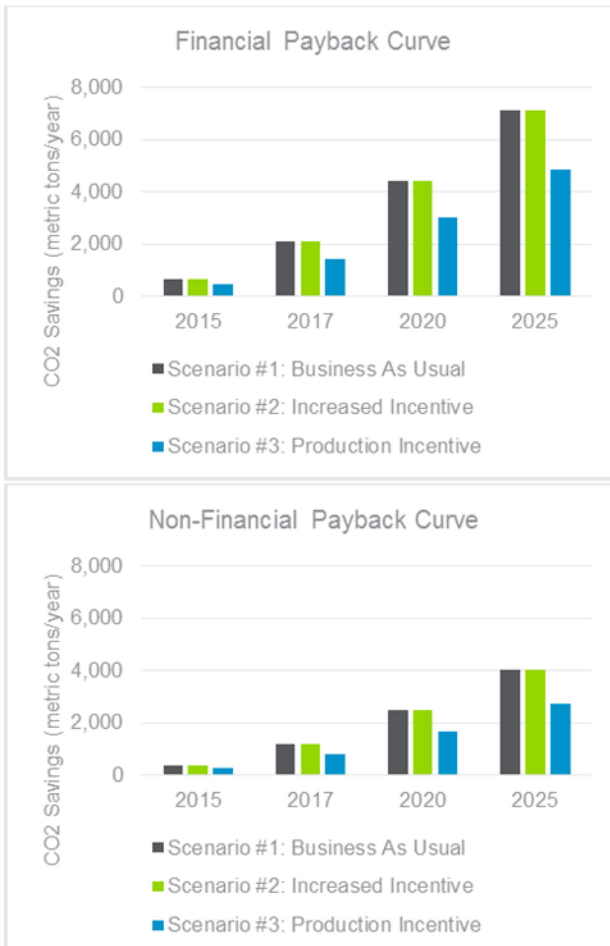


Figure 59 shows market potential in annual CO2 savings at the system level for waste energy recovery (both non-financial and financial potentials). In the case of WER, CO2 emissions decrease because little or no additional natural gas is used to generate electricity.[39] For non-financial potential, province-wide CO2 savings range from about 250 to 370 metric tons/year in 2015 and increase to 2,740 to 4,010 metric tons/year in 2025.

Figure 59: WER Market Potential in CO_2 Savings for System



[39] For WER, the program rules permit up to 10% co-firing with natural gas. Therefore, some natural gas is used, but we neglect the impacts

6. Cap & Trade Potential

6.1 Methodology and Approach

The IESO requested an evaluation of the impact of recent cap and trade regulations on the potential for conservation behind the meter generation (BMG) to conserve electricity across Ontario.

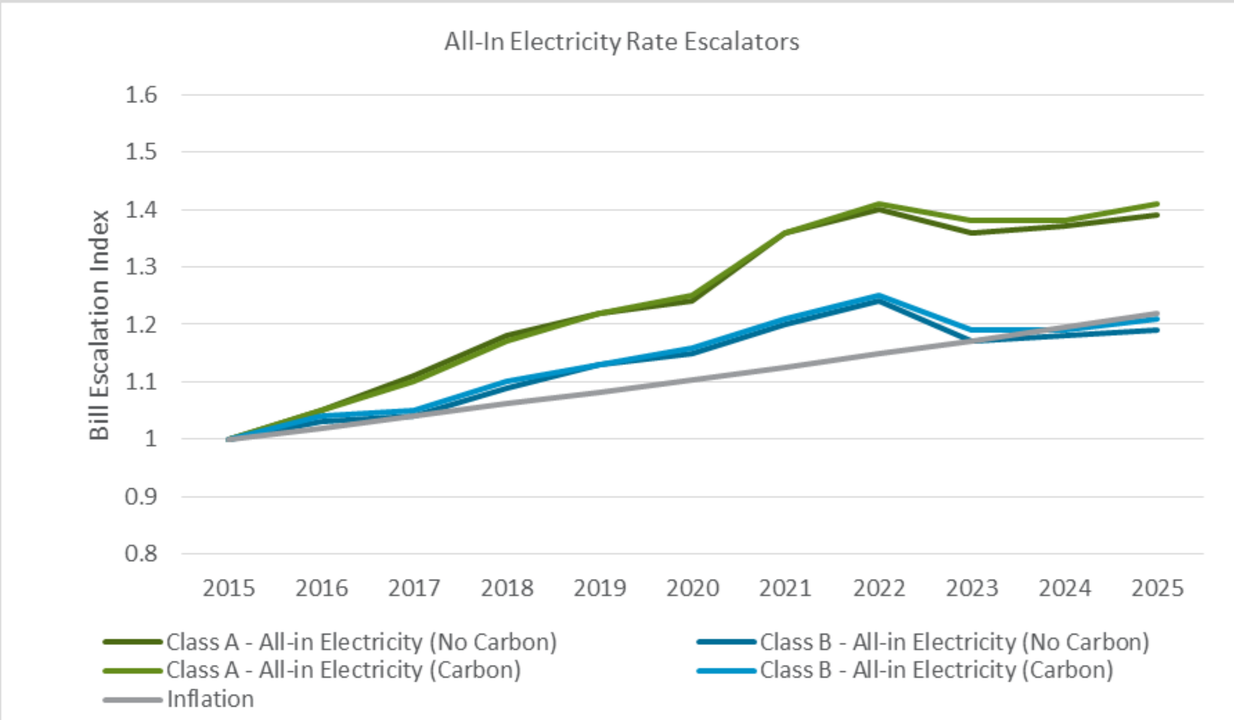
The regulation creates a price for carbon which will directly affect natural gas prices and indirectly affect electricity prices. The changes in these prices may impact the potential for CHP across Ontario as costs and benefits are directly tied to both natural gas and electricity costs.

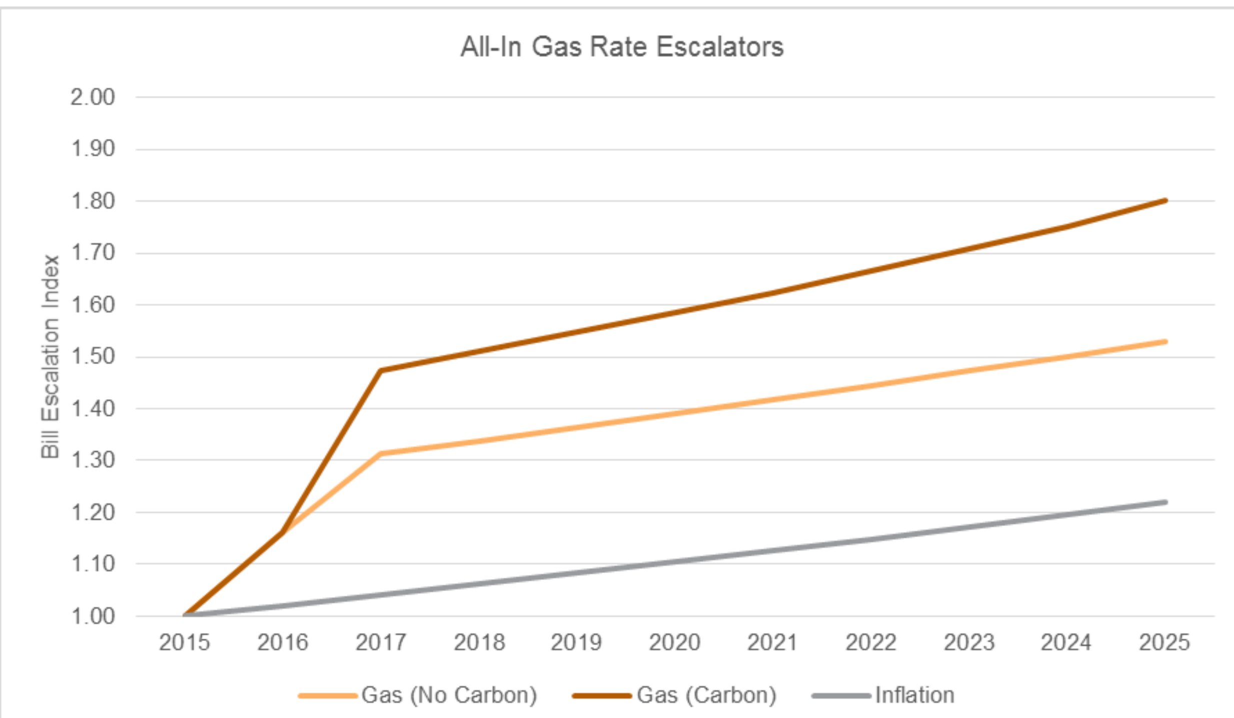
Navigant developed a Cap and Trade scenario to evaluate the impact of the new regulation relative to the base case (i.e., current program rules). Under the Cap and Trade scenario, Navigant leveraged electricity and gas forecasts provided by the IESO which account for the expected carbon prices.[40] We applied these forecasts at the Market Potential stage of the analysis to determine the impact of the proposed legislation on BMG potential.

The rate of change for these indices can be seen in Figure 60. Note that the "Change Index" represents the ratio of change from the component's starting point in 2015. Natural gas prices increase faster than electricity prices both without and with a carbon market but gas prices are also far lower than electricity prices to start with on an equivalent-energy unit comparison.

[40] Because the forecasts are not public, we do not describe them herein

Figure 60: Customer Bill Escalation Indices





6.2 Results

The impact of the carbon cap-and-trade market is a relatively minor increase (approximately 3%) in WER potential and a decrease of about 20% in CHP potential. The cap-and-trade pricing has a much larger impact on projected gas prices than electricity prices which results in a much larger impact for CHP than for WER.

Potential for some facilities drops more significantly under cap and trade than for others. This is the result of a number of factors which are used to determine the payback period for each project. As noted earlier, BMG projects at some facility types have longer payback periods than others. Under the cap and trade scenario these facility types have more projects which move to a payback period above what is generally acceptable based on the payback curves, meaning that a larger portion of the projects will not move forward.

Appendix A includes detailed results by LDC and facility type.

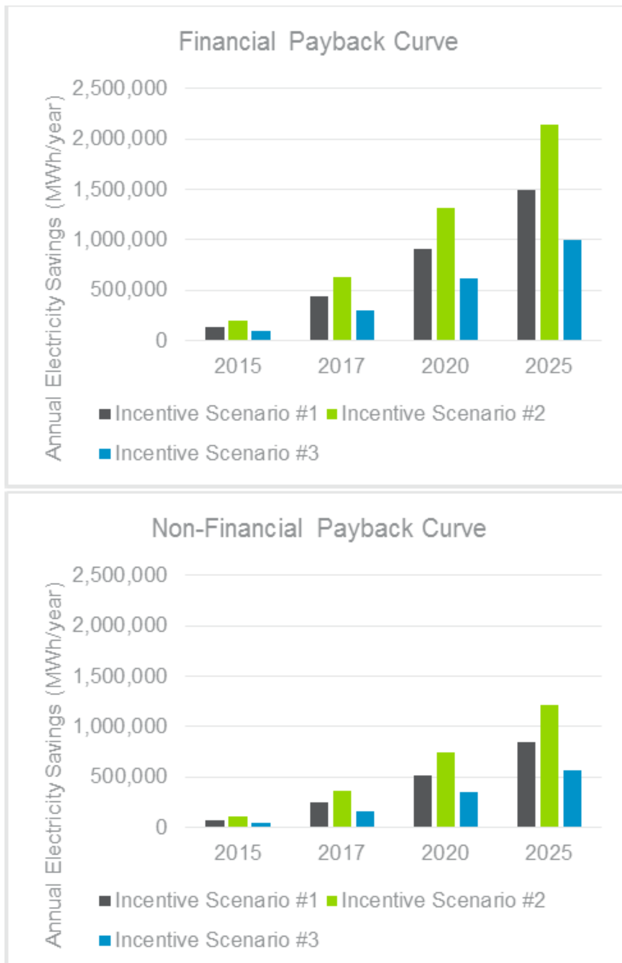
6.2.1 CHP

The following sections compare CHP market potential results under a cap-and-trade market to the market potential results reported in section 5.2.1 above.

6.2.1.1 Energy Savings

Figure 61 shows CHP market potential under carbon cap-and-trade based on electricity savings. Under scenario 1, in 2025, this market potential is about 81 percent of market potential without cap-and-trade (0.84 TWh vs. 1.04 TWh).

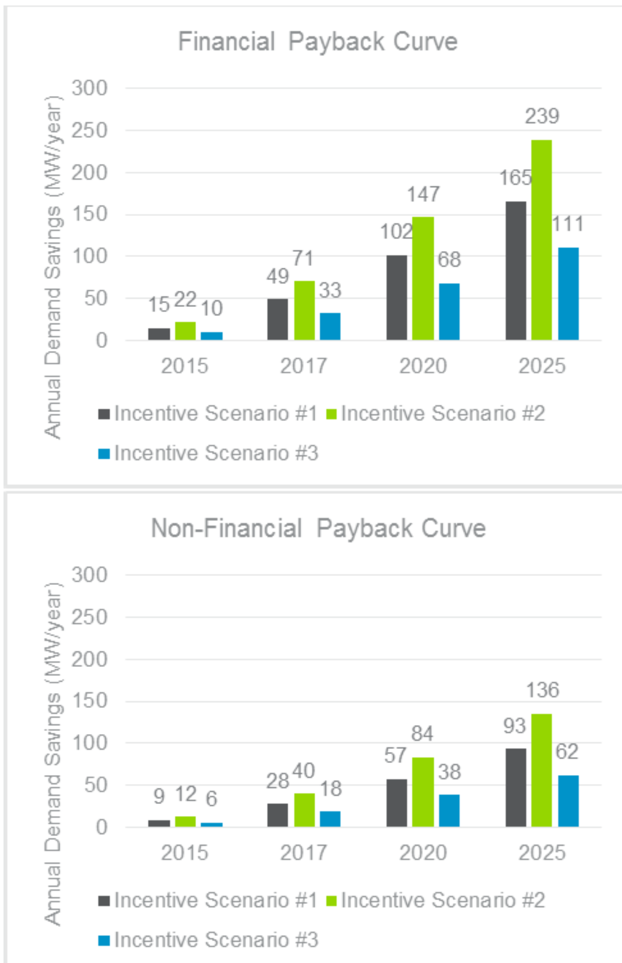
Figure 61: CHP Market Potential with Carbon Market in Electricity Savings for System



6.2.1.2 Demand Savings

Figure 62 shows CHP market potential under carbon cap-and-trade based on summer electric demand reduction. Under scenario 1, in 2025, this is about 80% of market potential without cap-and-trade (93 vs. 116 MW).

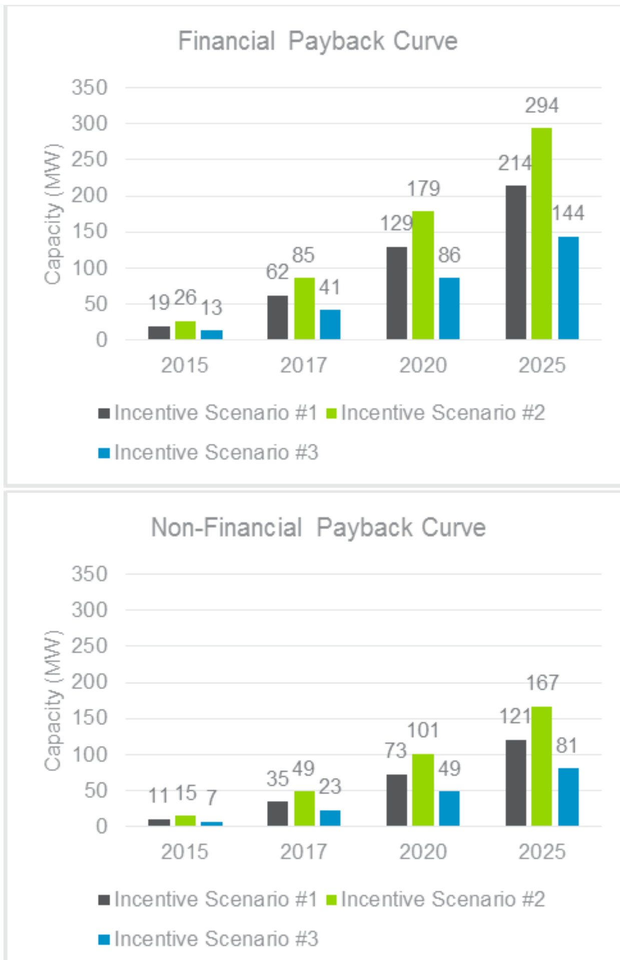
Figure 62: CHP Market Potential with Carbon Market in Demand Savings for System



6.2.1.3 Installed Capacity

Figure 63 shows CHP market potential under cap-and-trade based on installed capacity. Installed capacity shows a similar trend compared to demand savings. In 2025, under scenario 1, capacity-based market potential under carbon cap-and-trade is about 82% of capacity-based potential without cap-and- trade (121 MW vs. 147 MW).

Figure 63: CHP Market Potential with Carbon Market in Capacity for System



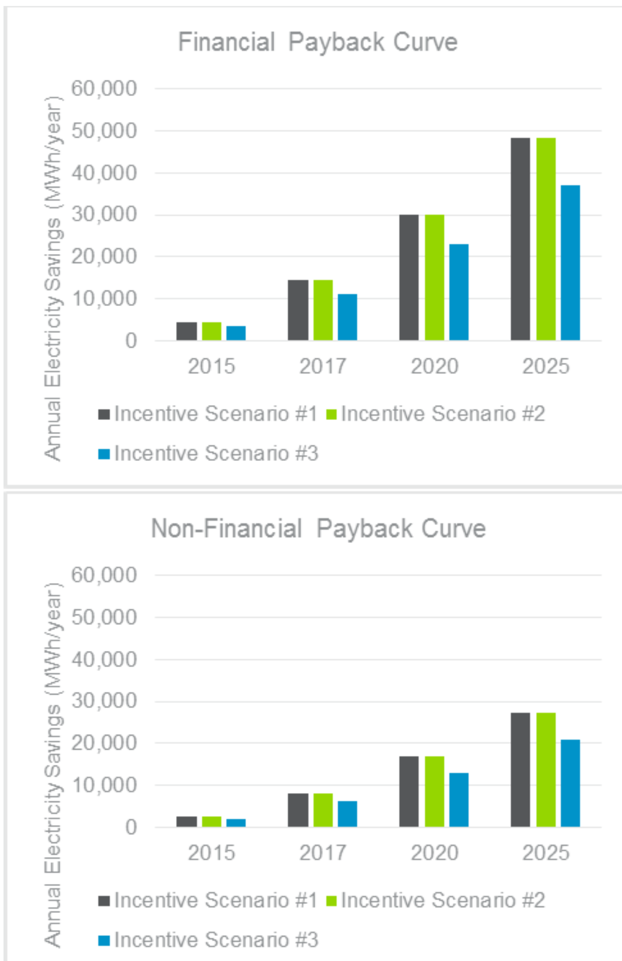
6.2.2 WER

Our analysis found that WER potential increases slightly under cap-and-trade. This results from the slight impact that cap-and-trade has on electricity prices.

6.2.2.1 Energy Savings

Figure 64 shows WER market potential under cap-and-trade based on electricity savings. For scenario 1, the market potential is approximately 103% of the potential without a carbon cap-and-trade market (27.2 GWh/year vs. 26.4 GWh/year).

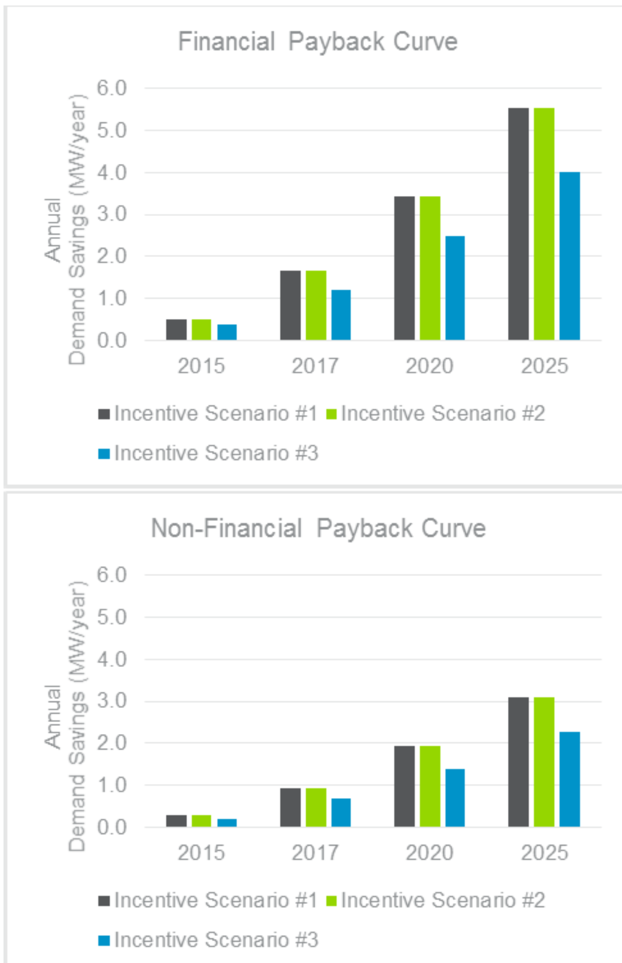
Figure 64: WER Market Potential with Carbon Market in Electricity Savings for System



6.2.2.2 Demand Savings

Figure 65 shows WER market potential under cap-and-trade based on summer electric demand reduction. For scenario 1, the market potential is approximately 103% of the potential without a carbon cap-and-trade market (3.1 MW vs. 3 MW).

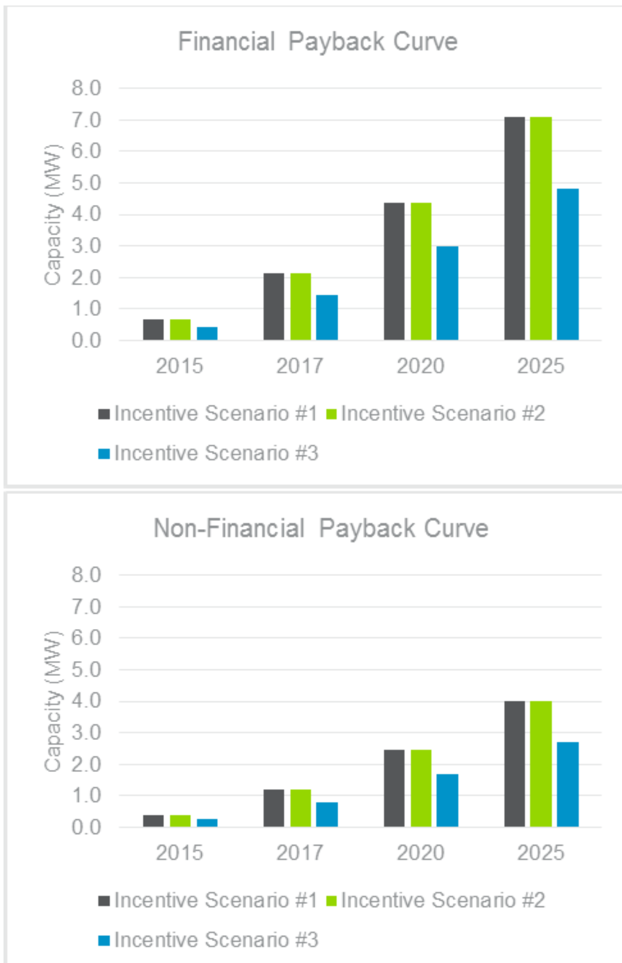
Figure 65: WER Market Potential with Carbon Market in Demand Savings for System



6.2.2.3 Installed Capacity

Figure 66 shows WER market potential under cap-and-trade based on installed capacity. For scenario 1, the market potential is approximately 103% of the potential without a carbon cap-and-trade market (4.0 MW vs. 3.9 MW).

Figure 66: WER Market Potential with Carbon Market in Capacity for System



6.2.3 *Emissions*

Figure 67shows market potential in annual CO2 savings at the system level for CHP (both non-financial and financial potentials) for the cap-and-trade scenario. Province-wide increases in CO_2 range from about 6,000 to 13,500 metric tons/year in 2015 and increase to 66,000 to 148,000 metric tons/year in 2025 for a non-financial potential.

Figure 67: CHP Market Potential with Carbon Market in CO_2 Savings for System

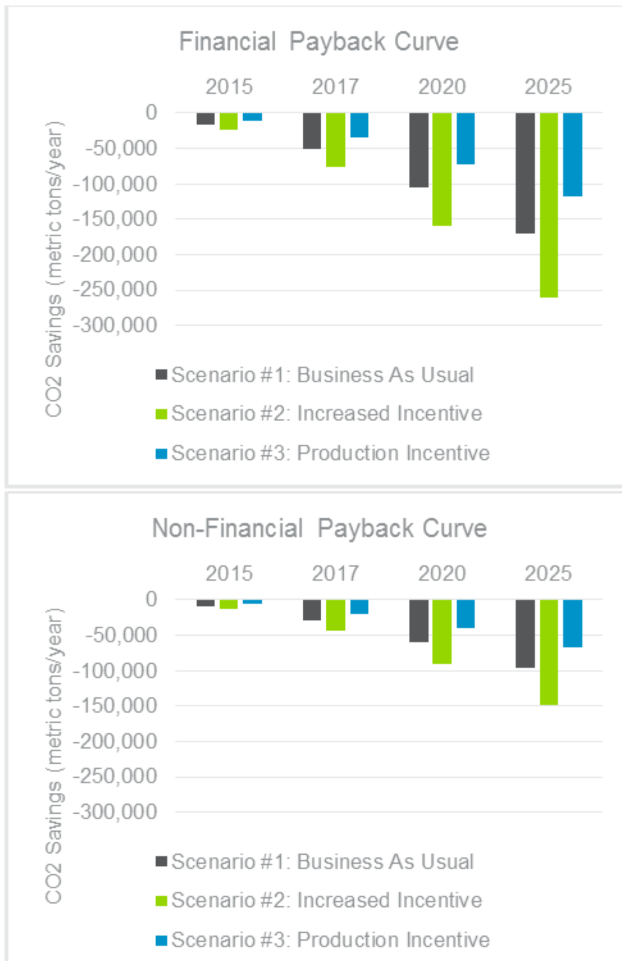
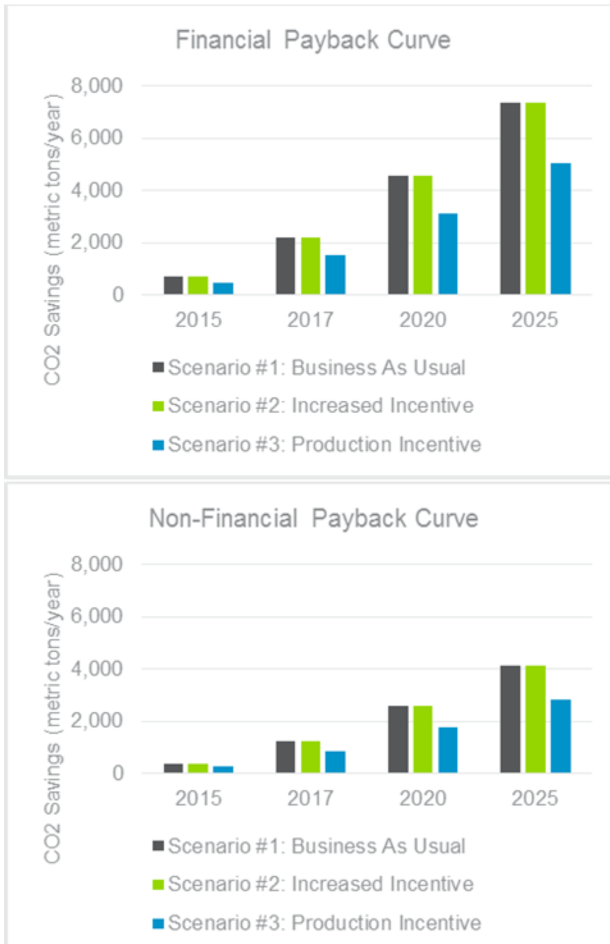


Figure 68shows market potential in annual CO2 savings at the system level for waste energy recovery (both non-financial and financial potentials). In the case of WER, CO2 emissions decrease because little or no additional natural gas is used to generate electricity. Province-wide CO_2 savings range from about 260 to 380 metric tons/year in 2015 and increase to 2,840 to 4,150 metric tons/year in 2025 for non- financial potential.

Figure 68: WER Market Potential with Carbon Market in CO_2 Savings for System



7. Constrained Potential

7.1 Methodology and Approach

Navigant was tasked with determining the constrained potential given the electricity network connection capacity by LDC. The IESO's planning department determined that electricity network constraints must be determined at the transformer station, rather than LDC level, and that electricity network connection capacity will need to be assessed on a project-by-project basis when applications are received. Because this study estimates potential at the LDC level (not at the transformer-station level), it is not possible to apply constraints to quantify impacts on market potentials for all LDCs.

The IESO provided some information about area constraints. In cases where and LDC lies within an area that is fully area constrained, there is no potential for BMG projects larger than 500 kW.

Figure 69 lists the LDCs that are within a fully constrained area and potential for projects over 500 kW, and that have been removed at the constrained potential step.

Figure 69: LDCs Within Fully Constrained Area

LDC
Niagara-on-the-Lake Hydro Inc.
Welland Hydro-Electric System Corp
Canadian Niagara Power
EnWin Utilities Ltd.
E.L.K. Energy Inc.
Essex Powerlines Corp.
PUC Distribution Inc.
Thunder Bay Hydro Electricity Distribution Inc.
Algoma Power Inc.
Kenora Hydro Electric Corporation Ltd.
Greater Sudbury Hydro Inc.
Sioux Lookout Hydro Inc.
Fort Frances Power Corporation
North Bay Hydro Distribution Limited
Midland Power Utility Corporation

LDC
Fort Albany Power Corporation
Chapleau Public Utilities Corporation
Northern Ontario Wires Inc.
Hearst Power Distribution Company Limited
Atikokan Hydro Inc.
Espanola Regional Hydro Distribution Corporation
Dubreuil Lumber Inc.
Attawapiskat Power Corporation
Kashechewan Power Corporation

7.2 Results

Because only area constraints have been applied where LDCs are within fully constrained areas, the constrained potentials presented below are expected to be higher than what can be achieved. Available electricity network connection capacity, which must be determined on a project-by-project basis, will reduce constrained potentials relative to the projections below. Appendix A includes detailed results by LDC.

Constrained potential results below are compared to the market potential results in sections 5.2.1 and 5.2.2.

7.2.1 CHP

Figure 70, Figure 71, and Figure 72 show that CHP constrained potential represents about 94-95 percent of 2025 market potential under incentive scenario #1 based on electricity savings, demand savings and installed capacity.

Figure 70: CHP Constrained Potential in Electricity Savings for System

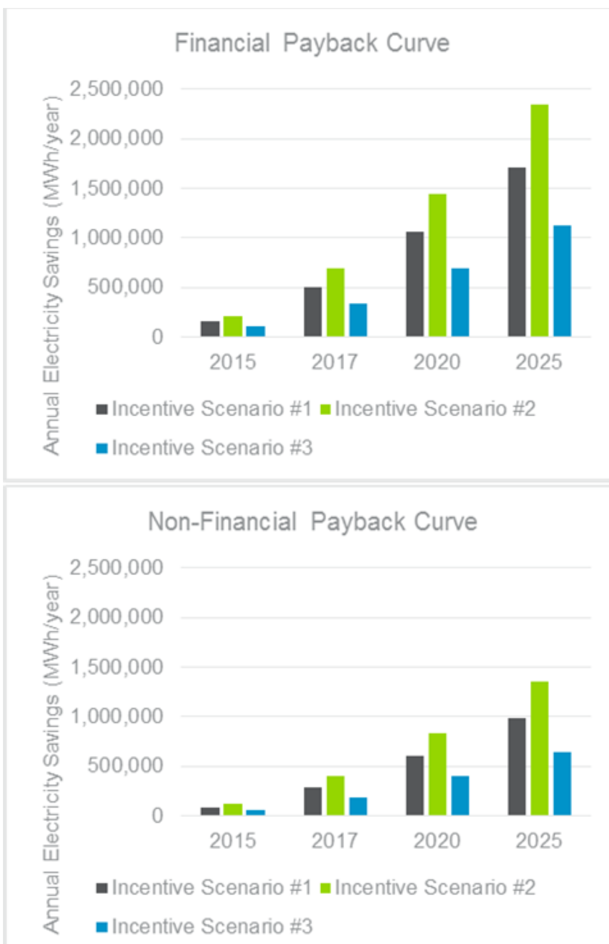


Figure 71: CHP Constrained Potential in Demand Savings for System

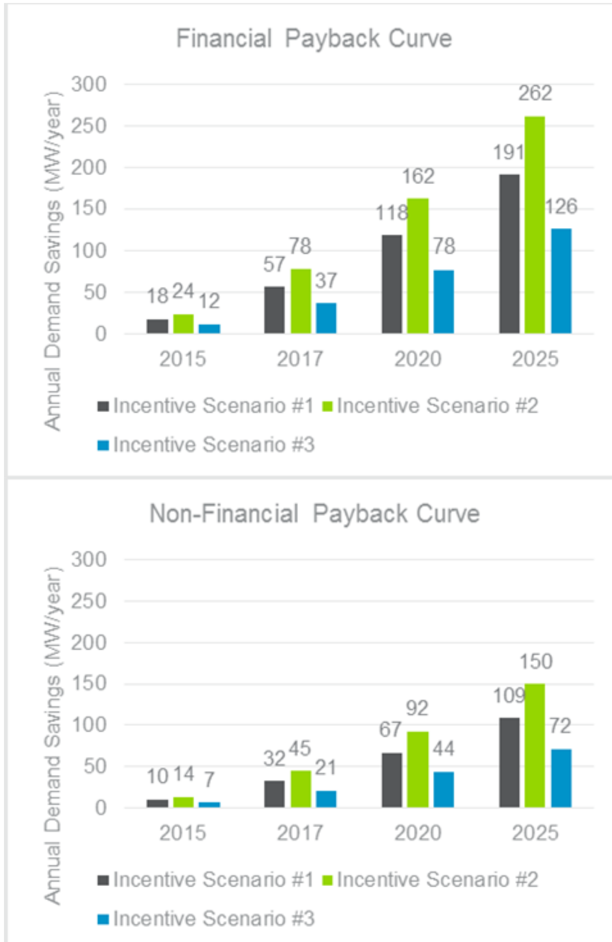
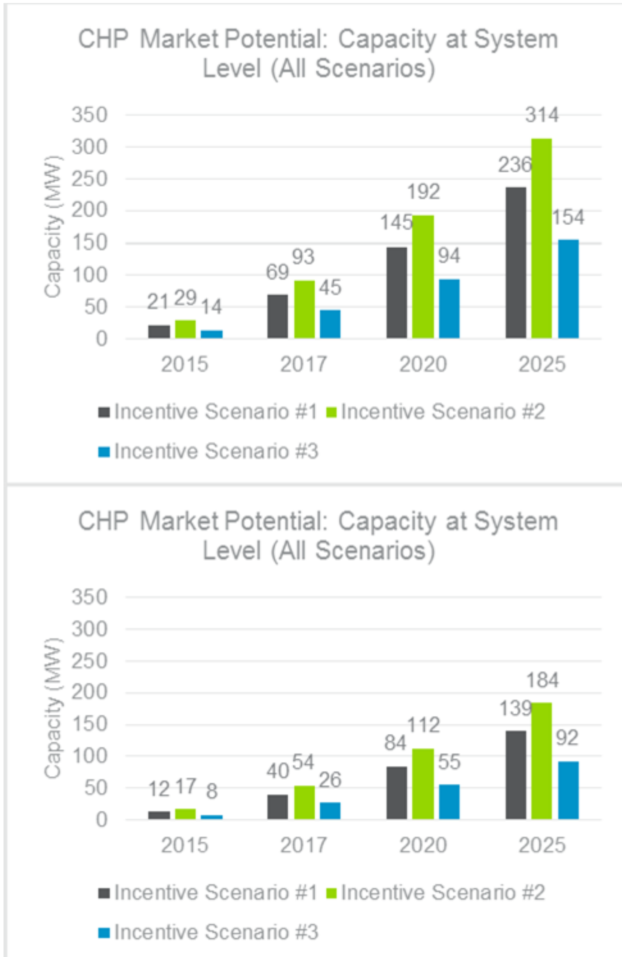


Figure 72: CHP Constrained Potential in Capacity for System



7.2.2 WER

Figure 73, Figure 74, and Figure 75show that 2025 WER constrained potential under scenario 1 represents about 91 percent, 93 percent, and 90 percent of market potential by electricity savings, demand savings and capacity, respectively.

Figure 73: WER Constrained Potential in Electricity Savings for System

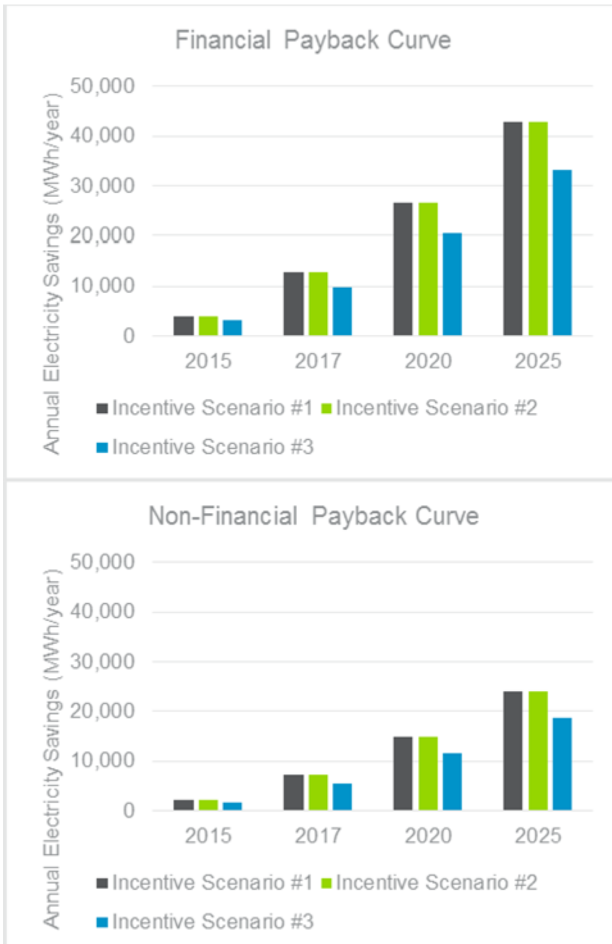


Figure 74: WER Constrained Potential in Demand Savings for System

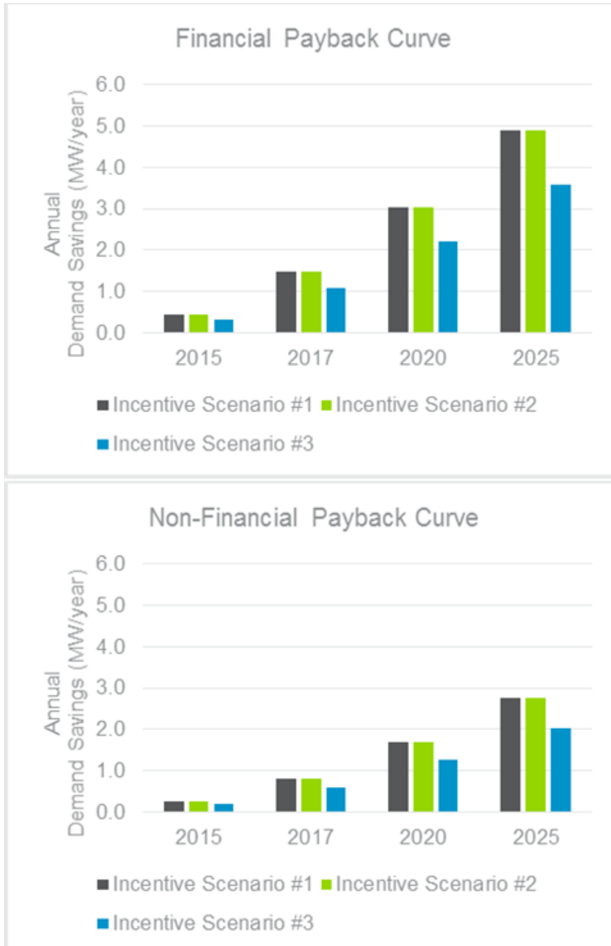
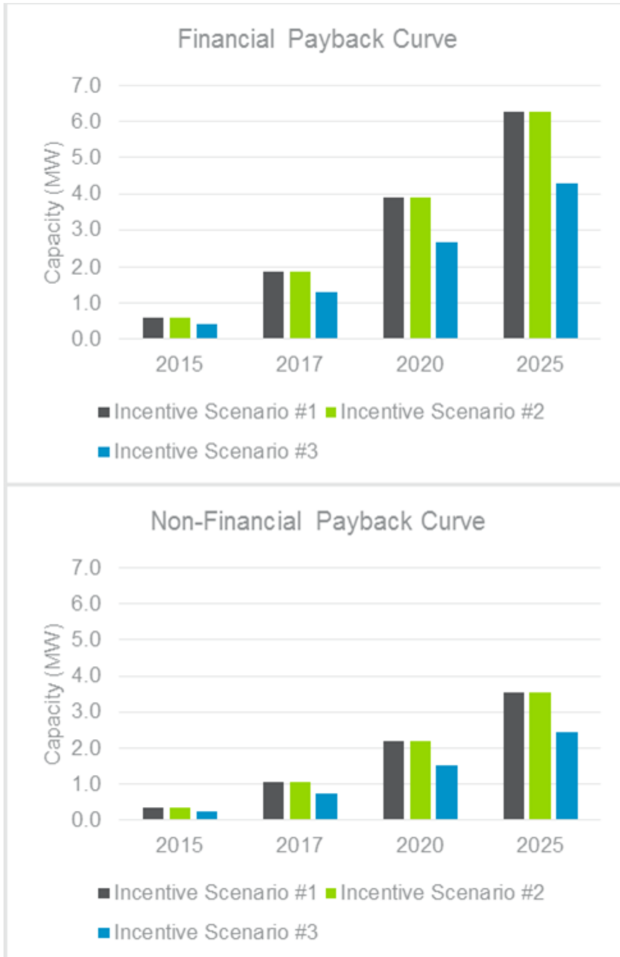


Figure 75: WER Constrained Potential in Capacity for System



7.2.3 Emissions

Figure 76 shows the constrained potential in annual CO2 savings at the system level for CHP (both non- financial and financial potentials). Province-wide increases in CO2 emissions range from about 7,100 to 15,300 metric tons/year in 2015 and increase to 77,600 to 167,000 metric tons/year in 2025 for non- financial potential.

Figure 76: CHP Constrained Potential with Carbon Market in CO_2 Savings for System

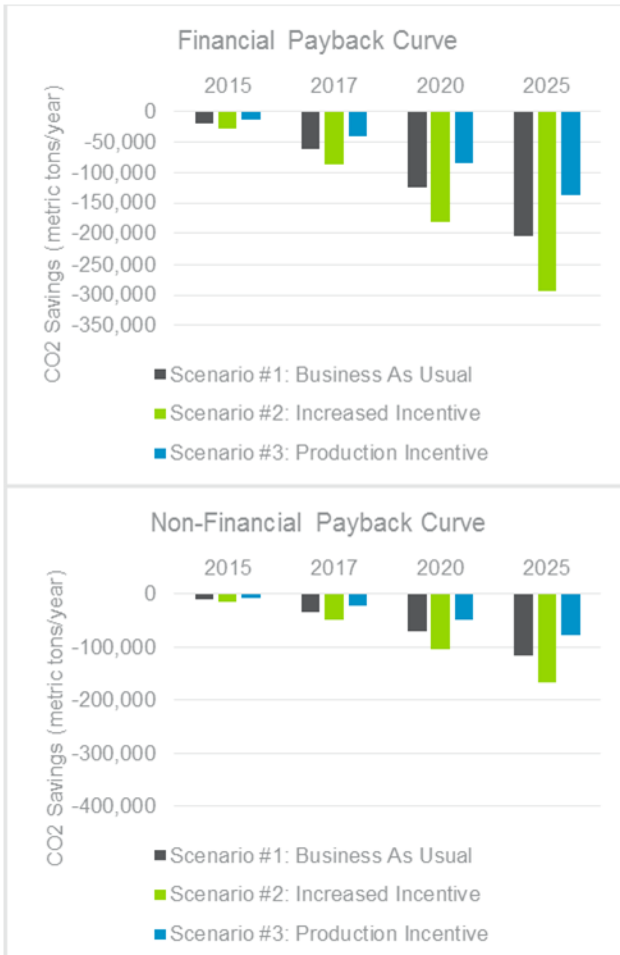
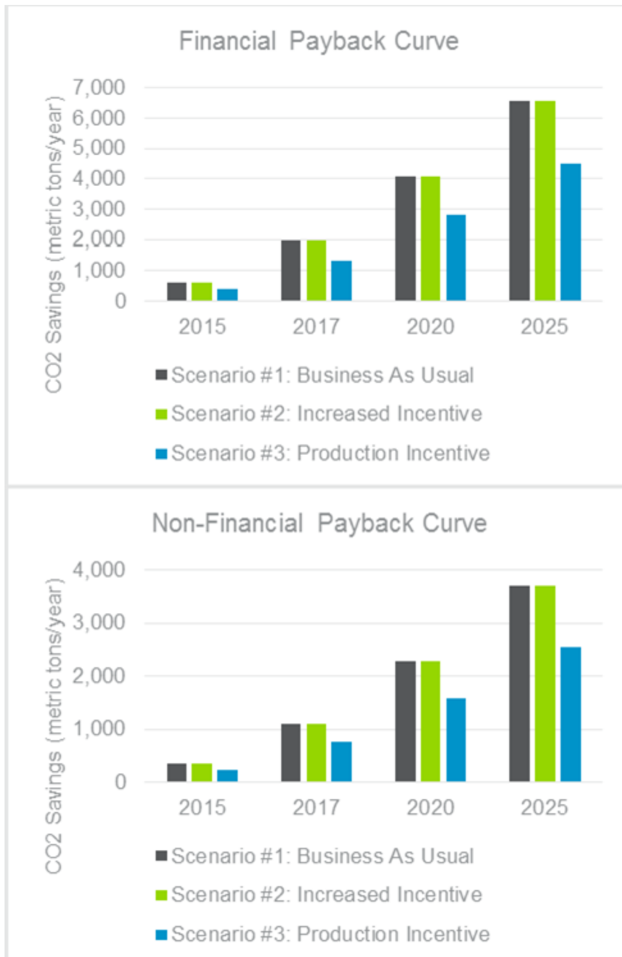


Figure 77 shows constrained potential in annual CO2 savings at the system level for WER (both non- financial and financial potentials). Province-wide CO2 savings range from about 230 to 340 metric tons/year in 2015 and increase to 2,500 to 3,700 metric tons/year in 2025 for non-financial potential.

Figure 77: WER Market Potential with Carbon Market in CO_2 Savings for System



7.2.4 Merged Results

The IESO has some existing BMG projects which went in-service through the program in 2015 and some applications which have already been received for BMG projects. These projects will contribute to the potential for the BMG program from 2015 to 2025. Navigant created merged results which combine actual in-service projects and applications with the modelled potential. These merged results were created only for incentive scenario #1 (existing program rules) after applying constraints to the modelled results.

Before merging results, Navigant assumed that some attrition will occur in projects for which applications were received but which are not yet in service. For these projects, Navigant assumed 75% of the application potential would result in achieved potential. Feedback from LDCs and previous BMG project contacts indicate that the average length from application to in-service is approximately 2 years.

Navigant has assumed that this application project potential will be realized by 2017. Navigant merged results at the facility type and LDC levels. If the actual or application potential was greater than the modelled potential, then the modelled potential was overridden with actuals.

Merging the in-service and application projects with the modelled potential increases CHP electricity savings by 1.5 times and WER electricity savings by almost 5 times (see Figure 78 and Figure 79) by 2025. Figure 80 illustrates the merged potential results for all BMG (CHP and WER) split between distribution and transmission connected customers.

Figure 78: Merged Model and Actual Constrained Potential in Electricity Savings for System

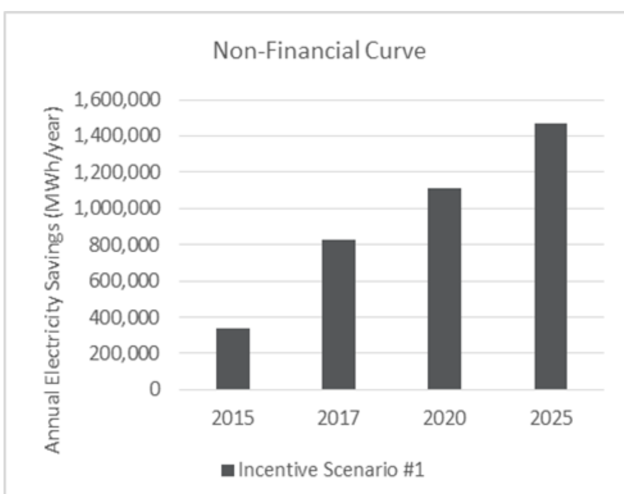


Figure 79: WER Merged Model and Actual Constrained Potential in Electricity Savings for System

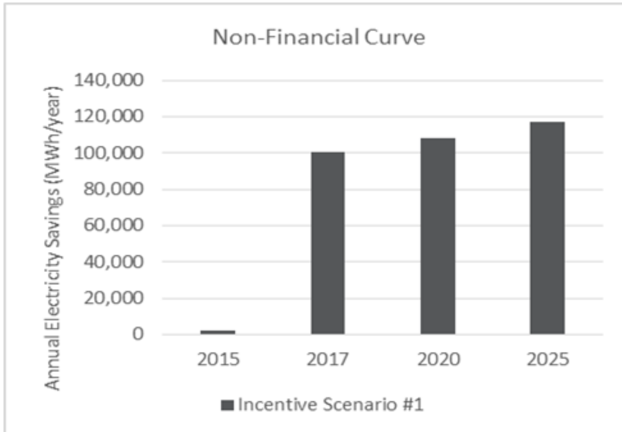
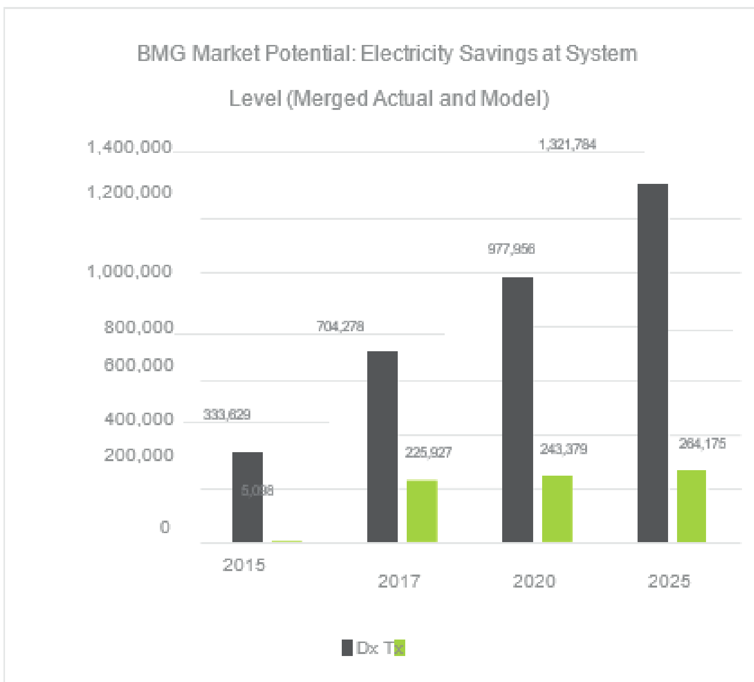


Figure 80: BMG Merged Model and Actual Constrained Potential in Electricity Savings for System



8. Observations

The results of the BMG potential analysis show that:

- The 2025 province-wide market potential for multi-family, commercial, and institutional facilities is very low—only about 23 GWh of the almost 10,000 GWh technical potential for these facility types
- The 2025 province-wide market potential for industrial facilities is about 1,100 GWh, or about 7 percent, of the almost 16,000 GWh technical potential for these facility types
- Scenarios 1 and 2 (40 percent versus 70 percent first-cost incentive) generally result in little or no difference in market potential. This occurs because other scenario constraints limit the incentive paid. For example, for both scenarios, the incentive cannot be higher than the annual electricity savings multiplied by $200 to $230/MWh.
- The Climate Mitigation and Low-Carbon Economy Act is projected to have almost no impact on WER and will decrease CHP potential by approximately 20% in the long term
- The constrained potential analysis shows modest reductions in market potential (about 6 percent reduction for scenario 1). However, available electricity network connection capacity, which must be determined on a project-by-project basis and which were not accounted for in this analysis, will reduce constrained potentials further.
- Merged results reveal an achievable potential of 978 GWh of annual distribution-level electricity savings by 2020.

Table 21 summarizes the province-wide market potentials for CHP and WER for scenario 1 (current program incentives).

Table 21: Summary of Ontario BMG Market Potentials (for Scenario 1)

Year	BMG Type	Installed Capacity (GW)	Electricity Savings (GWh)	Demand Savings (MW)
2015	CHP	13	95	11
2015	WER	~0	2	~0
2017	CHP	43	307	34
2017	WER	1	8	1
2020	CHP	89	639	71
2020	WER	2	16	2
2025	CHP	147	1040	116
2025	WER	4	26	3

Appendix A. Detailed Results

While conducting this analysis, Navigant developed numerous sets of results based on varying combinations of model parameters. These parameters include:

- Without or with a TRC screen of 0.75 (section 4.1 – economic potential only)
- Financial vs. non-financial payback acceptance curves (section 5.1.2, market potential only)
- Without or with a carbon cap-and-trade market (section 6.1, market potential only)
- Without or with electric system constraints (section 7.1, constrained potential only)

Each of these results are presented where applicable by:

- Technical, economic and market potential
- LDC, facility type, connection level and system
- Electricity savings, demand savings and capacity

These detailed results can be found in the zip file attachment "**Appendix A – IESO BMG Potential Study Model Detailed Results 6 21 2016.zip**".

Appendix B. Payback Periods

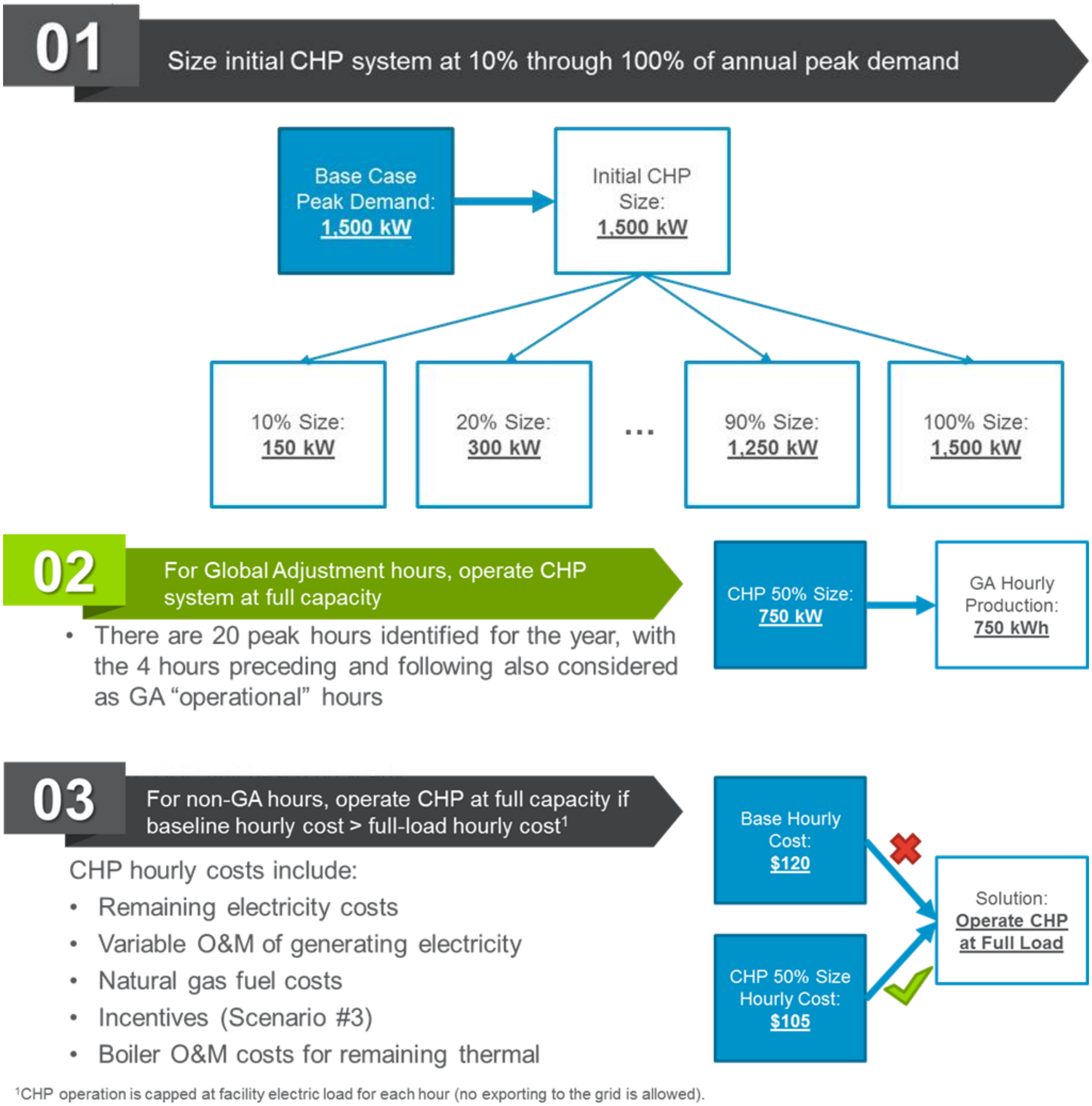
The IESO requested results regarding simple payback periods calculated through Navigant's BMG model. Appendix B is contained within a separate attachment with simple payback periods for all representative customer archetypes (both CHP and WER) under a no-carbon market scenario.

The file title is **"Appendix B – IESO BMG Potential Study Model Simple Payback Periods.xlsx".**

Appendix C. Description of a "Smart" Operational Strategy

The infographic presented in Figure 81 shows the "smart" CHP operational strategy.

Figure 81: Smart Operational Strategic Infographic



04 For remaining hours, do not operate CHP if the effective electric volumetric rate is below $0/MWh.

- The Hourly Ontario Energy Price has zero or negative prices for 1,142 instances in 2015.
- These instances usually occur due to high baseload grid production (nuclear, hydro) during low demand hours.

05 For all remaining hours, operate CHP unit to reduce facility demand by 20%, 40%, 60%, 80% and 100%.[1]

CHP 50% Size: **750 kW**

Baseline Demand for Hour: **500 kW**

Demand Reduction	20%	40%	60%	80%	100%
Demand Target	400 kW	300 kW	200 kW	100 kW	0 kW
CHP Production	-	-	300 kW	400 kW	500 kW

Turndown ratio too high (load factor drops too far)

[1]In the case where facility demand for the hour is larger than the CHP unit, CHP operation is reduced by 20%, 40%, 60%, 80% and 100%.

06 Calculate hourly and monthly costs under each demand reduction scenario

	Hourly	Monthly
Electric	• HOEP Charge • GA Charge (Class B) • CHP O&M Cost • Production Incentive (Scenario #3)	• LDC Demand Charge • GA Charge (Class A) • Standby Charge • LDC Fixed Charge
Gas	• CHP Gas Costs • Remaining Thermal Gas Costs • Remaining Boiler O&M Costs	• Contracted Demand Charge

07 Choose demand reduction scenario that results in the lowest total monthly cost for each month of the simulation.

- Checks are then applied to ensure CHP unit meets minimum efficiency and savings targets

