EB-2016-0004

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act 1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF a generic proceeding on natural gas expansion in communities that are not served.

CROSS-EXAMINATION MATERIAL
Environmental Defence Cross-Examination of Enbridge

May 4, 2016

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Index

Tab	Contents	Pg

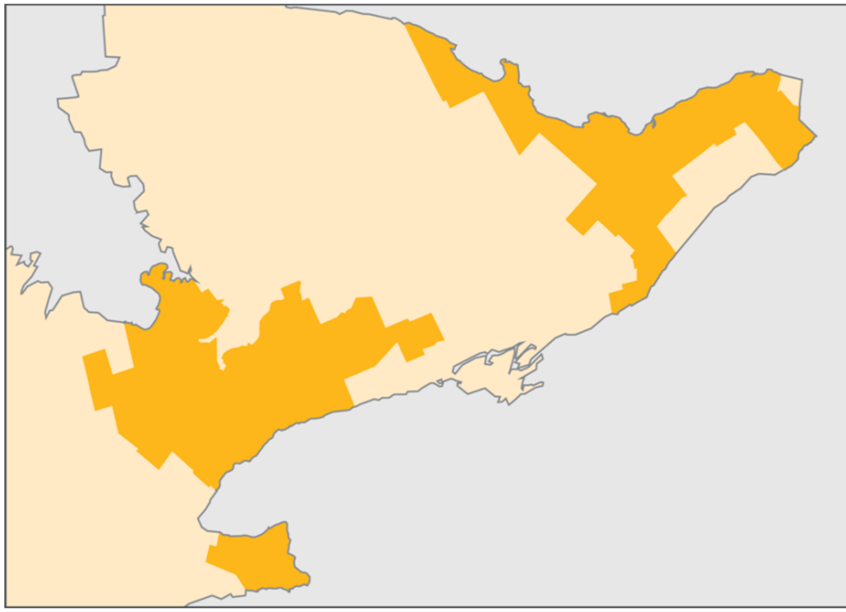
Natural Gas & Ontario's Energy Mix

EB-2015-0237
Natural Gas Market Review, January 2016

Norm Ryckman

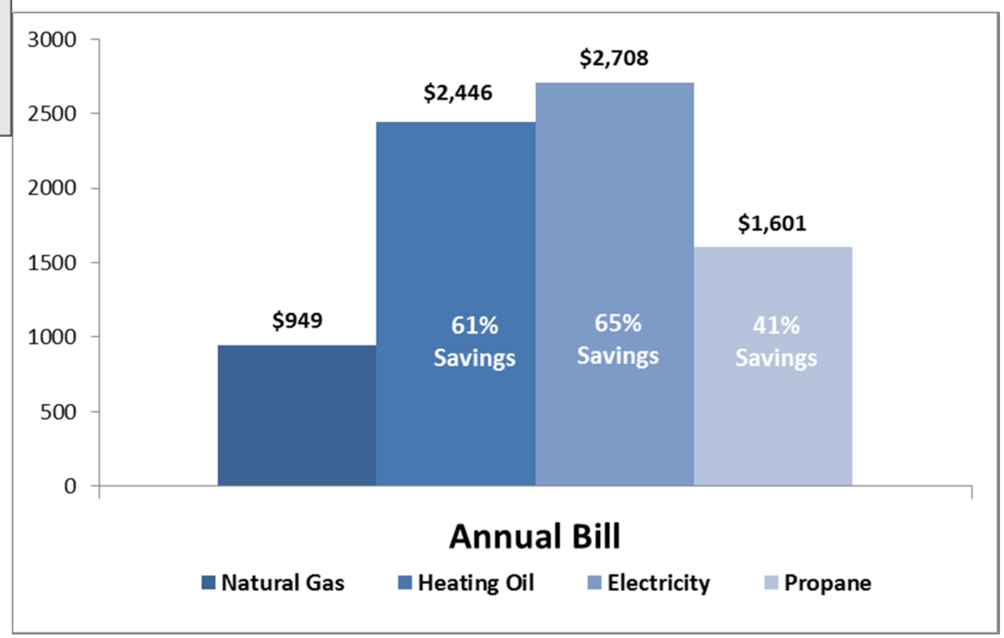
ENBRIDGE®

Enbridge Gas Distribution

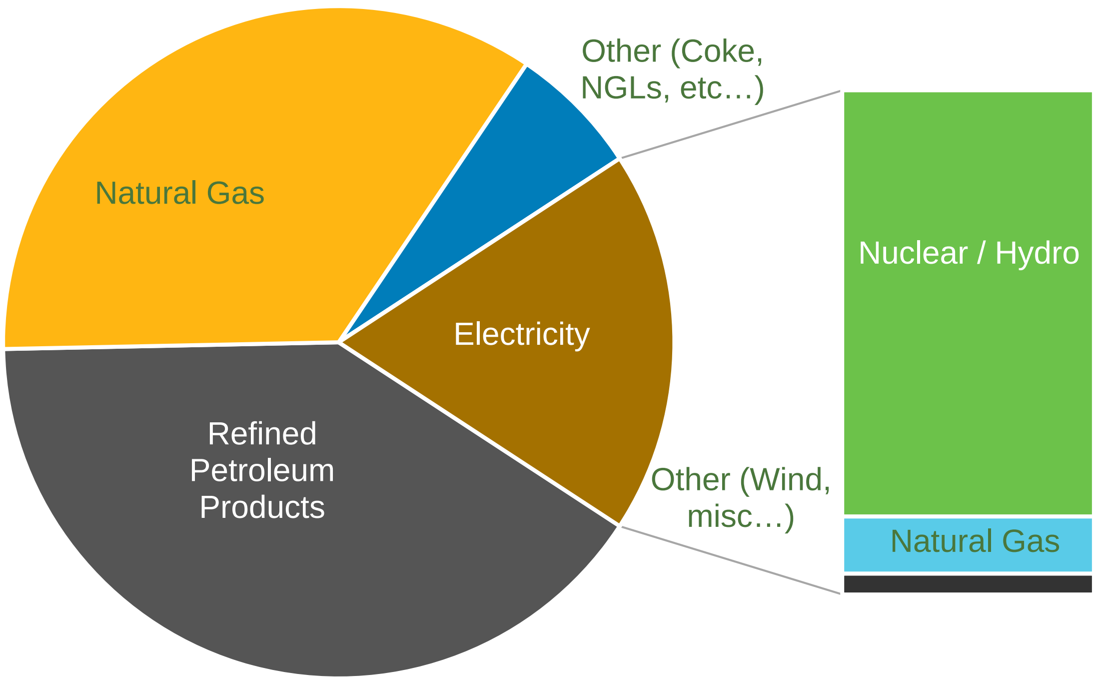


- EGD serves >2 million customers
- Adds ~35,000 customers/year

- Consumers recognize economic benefits of gas



Natural Gas is the largest energy source in Ontario and forecast to grow from 2014 to 2030



Source: ICF

Natural gas' share of Ontario's total energy final demand has grown to over 33% of the total (830,000TJ or 770 Bcf);

- New supply / demand paradigm in North America.
- Newly connected communities.
- Increasing usage in transport.
- Displacement of coal.
- Enabling renewables.

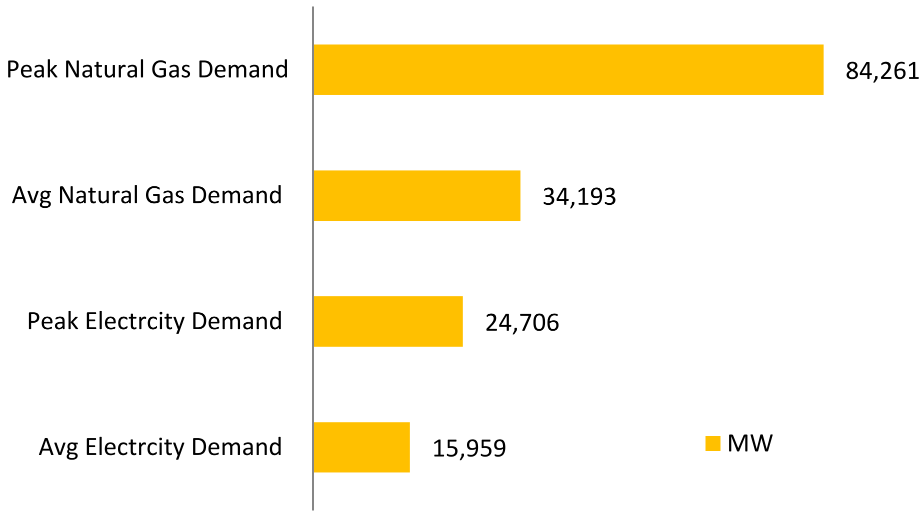
Electricity demand declined 2004 – 2014 due to CDM and loss of industry demand due to recession.

ENBRIDGE

Importance of Natural Gas Infrastructure

Peak Day and average day demand

Ontario Energy Delivery by Infrastructure Type



– Ontario's electricity grid must balance in real-time or use costly, short-term storage

– Ontario's existing natural gas network offers equivalent of 80 TWh of seasonal storage

– On peak heating days, storage reserves deliver energy equivalent of 90 nuclear reactors (then you would still need to get the power to where it is needed and equipment that can use it)

– Orderly transition to a low-carbon economy can leverage existing pipelines and storage with increasing quantities of green gas supply

Footnotes:
1. Ontario Peak natural gas demand is 6.9 bcf/day
2. Avg. natural gas demand includes refill of storage
3. Peak electricity demand recorded in Summer 2006 (IESO)

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Cap and Trade in Ontario and Impacts to Enbridge Natural Gas Customers

EB-2015-0237

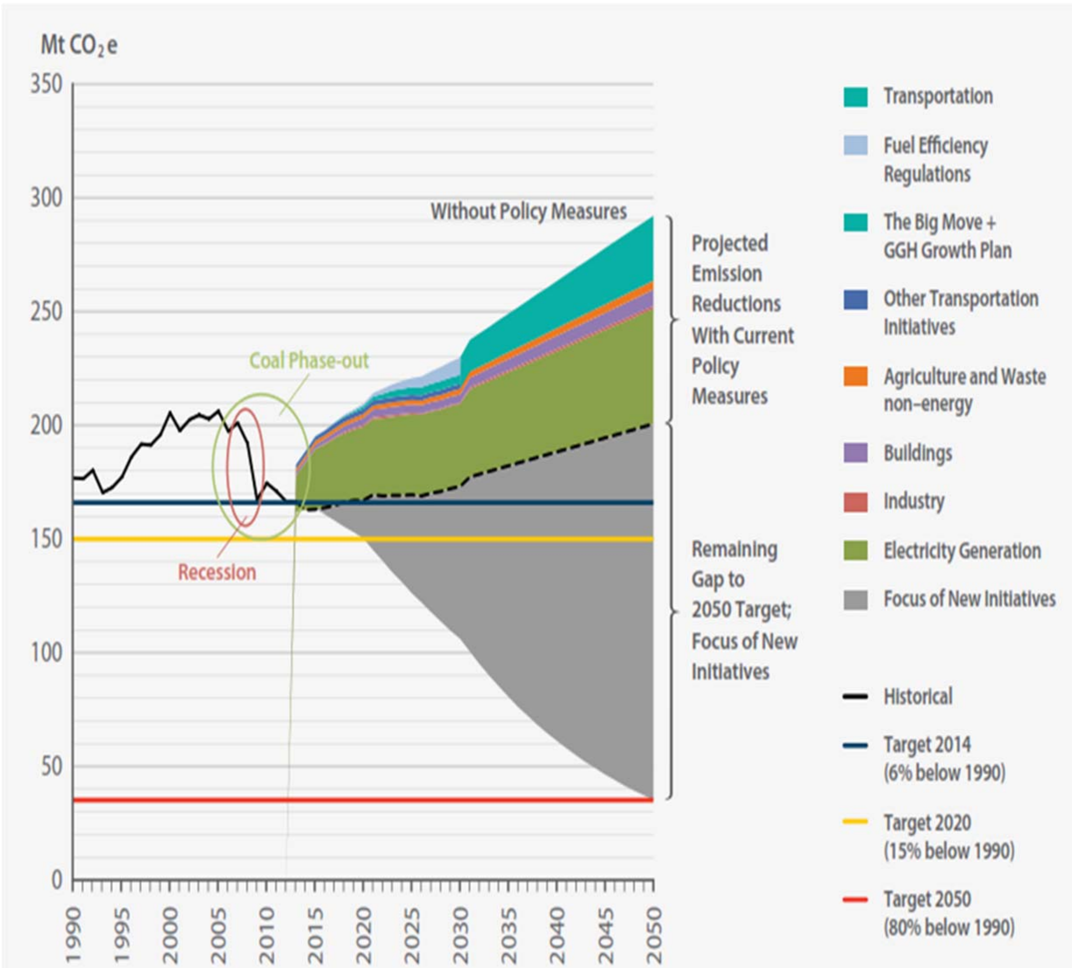
Natural Gas Market Review, January 2016

Norm Ryckman

Ontario Emissions and Cap and Trade Policy

Ontario Energy Board Generic Community Expansion, Filed: 2016-04-22, EB-2016-0004, Exhibit S3.EGDI.ED.6, Attachment, Page 8 of 30

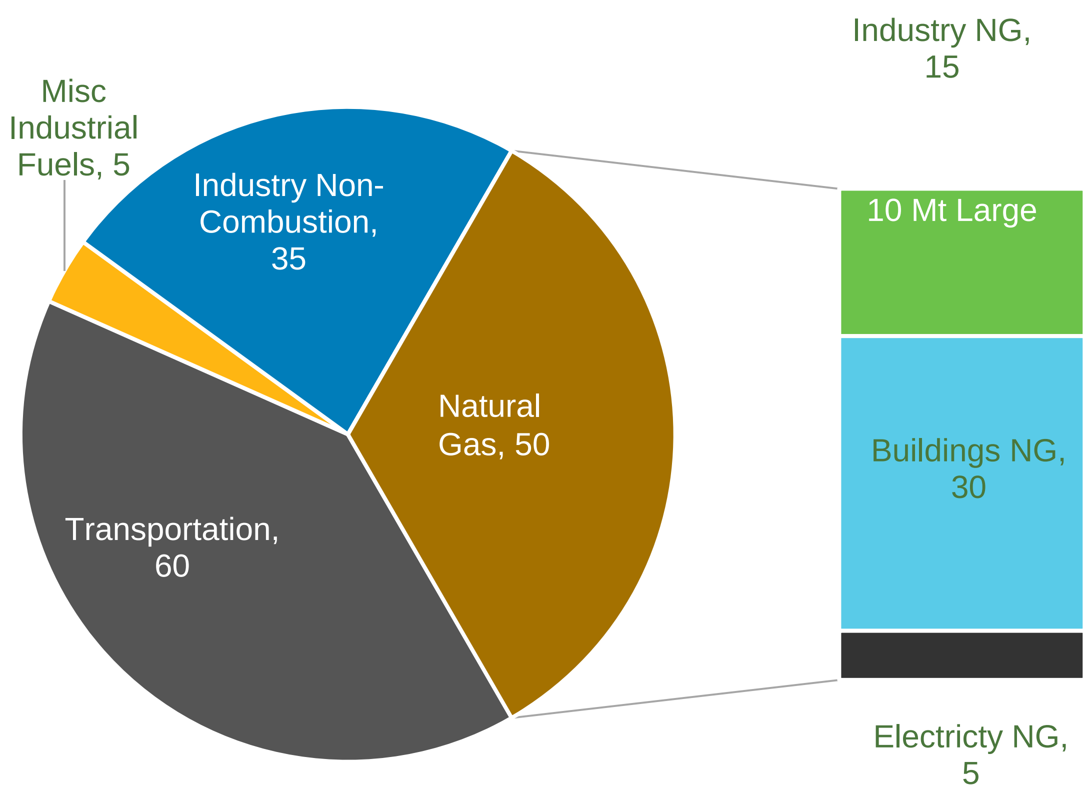
Ontario has defined 2020 and 2030 targets and a path to material de-carbonization by 2050



Source: Ontario's Climate Change Discussion Paper 2015, Ministry of the Environment and Climate Change

- Historic emission reductions from coal shut-downs and decline of industrial sector energy consumption.
- Ontario electricity emissions intensity = 0.05 t/MWh.
- Reductions associated with urban public transportation projects and energy efficiency are factored into the projection.
- Future reductions will need to come from energy efficiency and re-fueling current transport fuel and natural gas consumers.
- Ontario's emissions need to fall to 110 Mt by 2030 and 35Mt CO_2 by 2050.

Based on Ontario's emissions profile reductions must come from reduction in natural gas / transport fuel use



Source: ICF

Ontario Forecast 2017 GHG emissions for sectors /sources covered under proposed cap and trade ($MtCO_2e$)

Ontario's 2017 GHG emissions profile for "Cap" covered sectors;

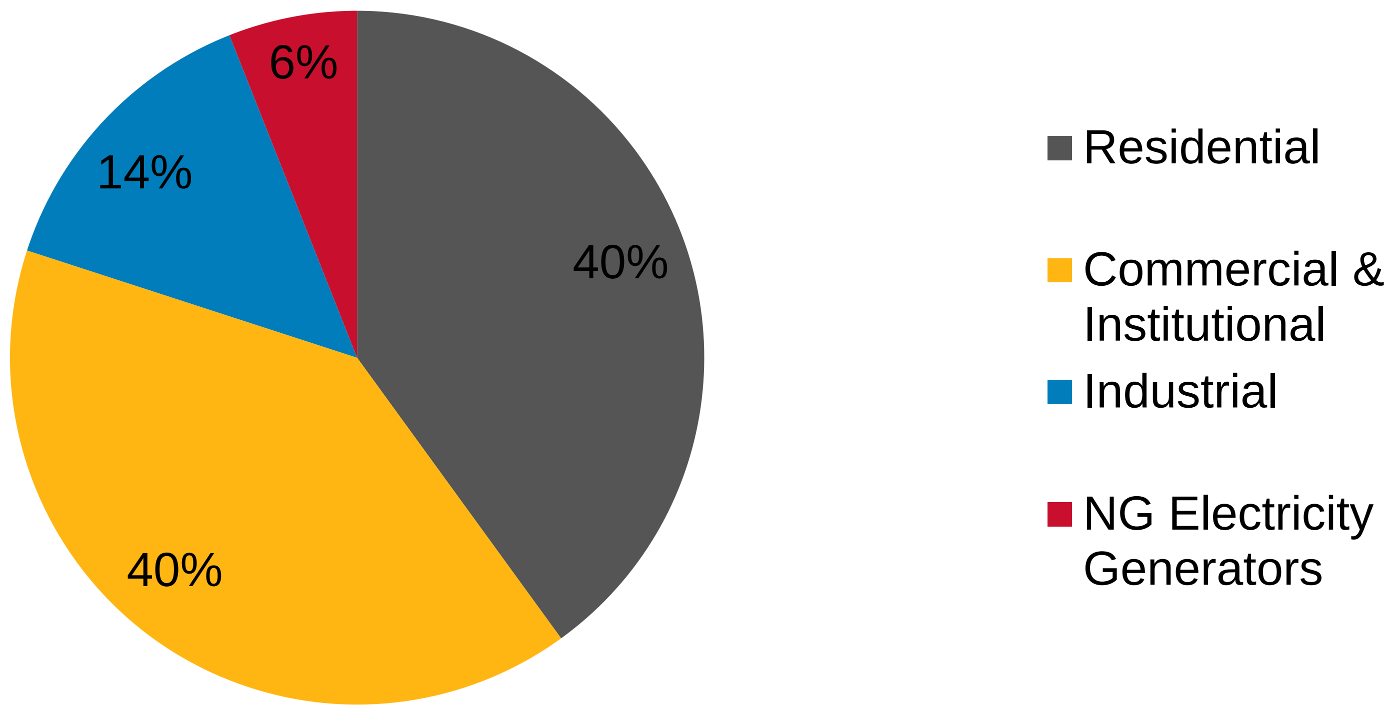
- 60 Mt CO_2e from transport fuel usage
- 50 Mt CO_2e from NG usage (950 Bcf)
  - 15 Mt industry
  - 30 Mt commercial and residential
  - 5 Mt electricity
- 5 Mt CO_2e from miscellaneous fuels
- 35Mt CO_2e from non-combustion / fixed process emissions

Customer Impacts

Emissions by Enbridge's Customer Type

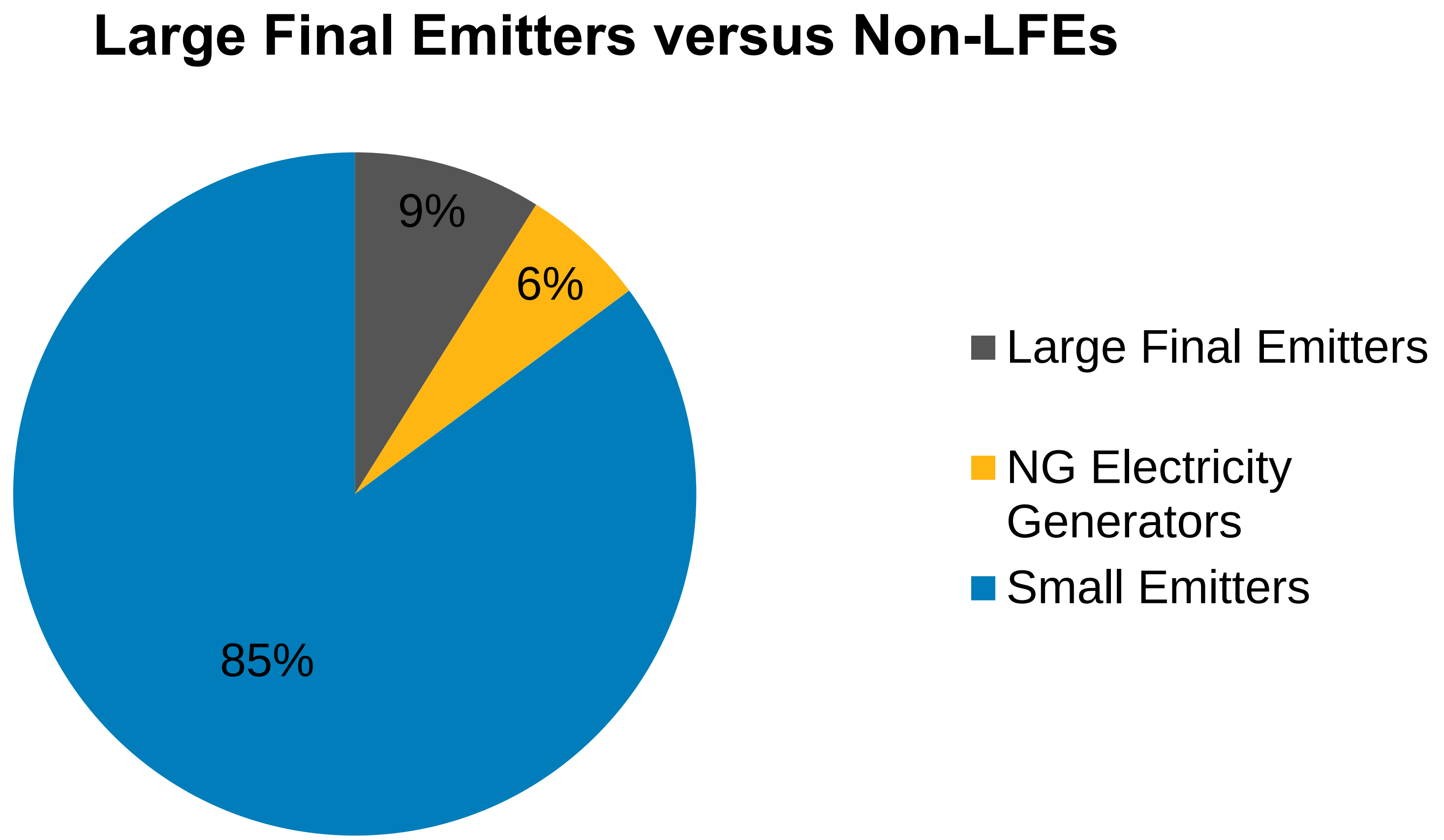
This graph shows where emissions are derived from our customer base due to combustion of NG

Customer Emission Profile



Emissions for Enbridge's Large Final Emitters vs. Non-LFEs

This graph shows the percentage of emissions from those under and over the 25,000 tCO2e threshold for LFE



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Enbridge's Cap & Trade Information

Cap & Trade anticipated for January 1st 2017

– Under Ontario's Cap & Trade, EGD expected to purchase Greenhouse Gas (GHG) Allowances on behalf of customers under 25,000 t CO_2e
  - Large Final Emitters > 25,000 tCO_2e will purchase their own allowances
  - Customers between 10,000 and 25,000 tCO_2e required to report their emissions, but EGD will purchase allowances
  - Purchases of Allowances for natural gas power gen customers to be clarified.

– Calculation of allowances based on "custody transfer station" calculation, which would also include EGD's own emissions as unaccounted for gas (calculated as if gas is combusted)

– EGD anticipates recovering costs of purchasing allowances through a separate volumetric charge on customer bills to ensure Company & ratepayers are kept whole

– EGD anticipates maintaining a variance account for allowance purchases

– The volumetric charge likely to be updated quarterly to reflect changes in the price of emission allowances, minimizing volatility in the charge

– Anticipate filing of a GHG application with the OEB in fall 2016

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Potential Bill Impact

Rate Class	Cap and Trade Unit Rate	Annual Volume ("Typical Customer")	Current Annual Bill	Annual Cap and Trade Charge	Annual Bill with Cap and Trade	Bill Impact
Rate 1	\$0.03/m^3	2,400m^3	\$819.63	\$77.52	\$897.15	9.5%
Rate 6	\$0.03/m^3	22,606m^3	\$5,982.40	\$730.17	\$6,712.57	12.2%
Rate 110	\$0.03/m^3	9,976,120m3	\$1,747,941	\$322,229	\$2,070,169	18.4%
Rate 115	\$0.03/m^3	69,832,850m^3	\$11,745,005	\$2,255,601	\$14,000,606	19.2%
Rate 135	\$0.03/m^3	598,567m^3	\$98,394	\$19,334	\$117,683	19.7%
Rate 145	\$0.03/m^3	598,567m^3	\$108,159	\$19,334	\$127,493	17.9%
Rate 170	\$0.03/m^3	69,832,850m^3	\$10,517,949	\$2,255,601	\$12,773,550	21.4%

Footnotes: Assumes ~\$17 per tCO2e. Customer bills based on 2016 Q1 Total Annual Bill excluding Riders.
Rate 100 not included given small sample size (n=2)

Initial Thoughts From ICF

Potential Implications for Enbridge and Customers

1. Energy Efficiency / Demand Side Management
   - Rate of energy efficiency needs increase dramatically with GHG reductions as the key objective

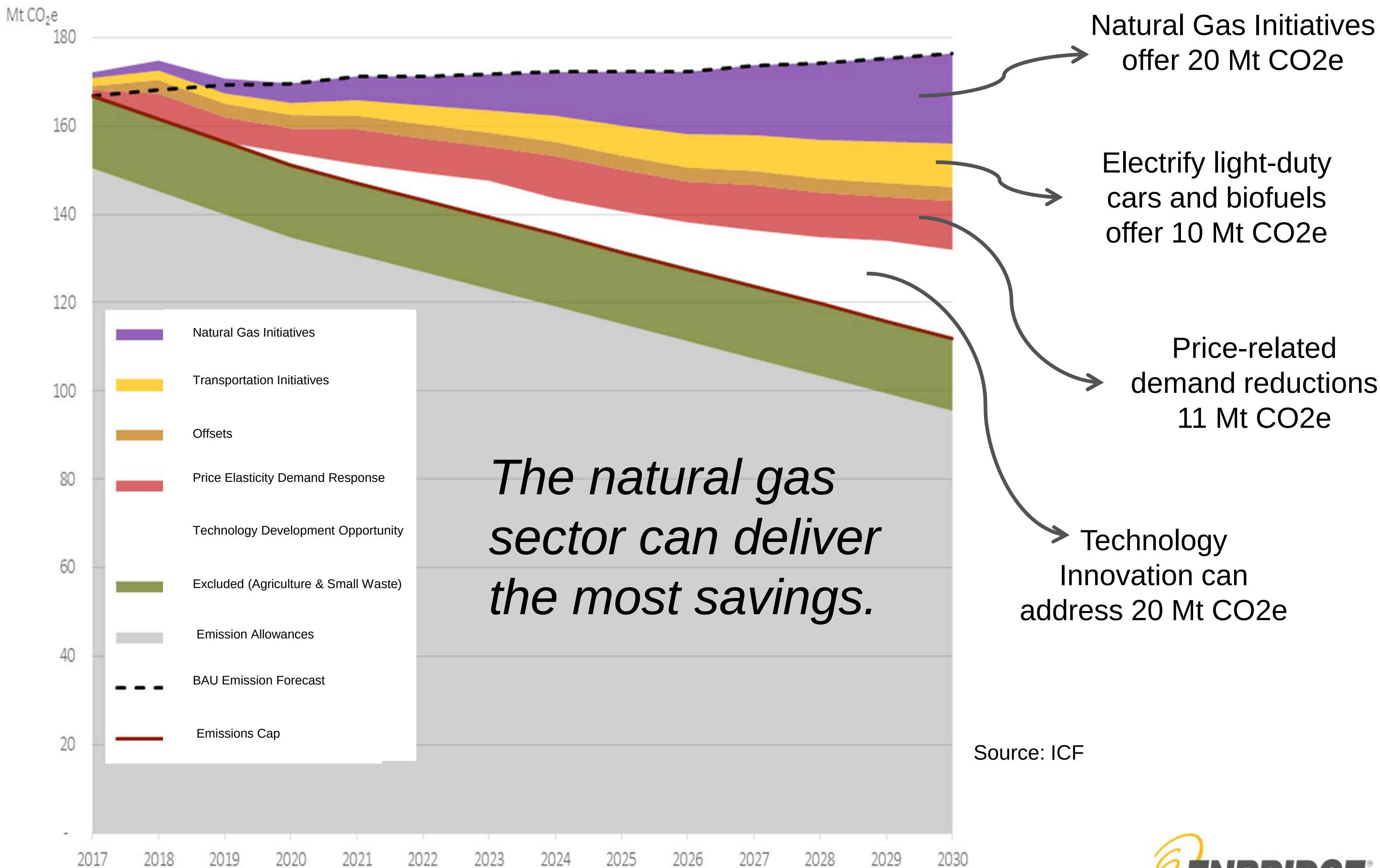
2. EGD will need to acquire \$300M–\$500M of allowance per year
   - Current settlement price of \$17/t results requires roughly \$350M of allowance (depending on inclusion of unbundled customers)

3. EGD will need to build allowance acquisition infrastructure
   - Accounting, finance, trading, analytics, offset/allowance sourcing, brokerage, MM&V, billing, customer relations, DSM, IT, etc.

4. EGD will need to re-imagine infrastructure and business model
   - Residential, commercial, institutional NG consumption could need to decline by ~40% by 2030
   - Even if protection afforded industrial emitters consumption will need to decline by 20 – 30%
   - No net increase in NG consumption for electricity generation
   - Electrification of transport and buildings

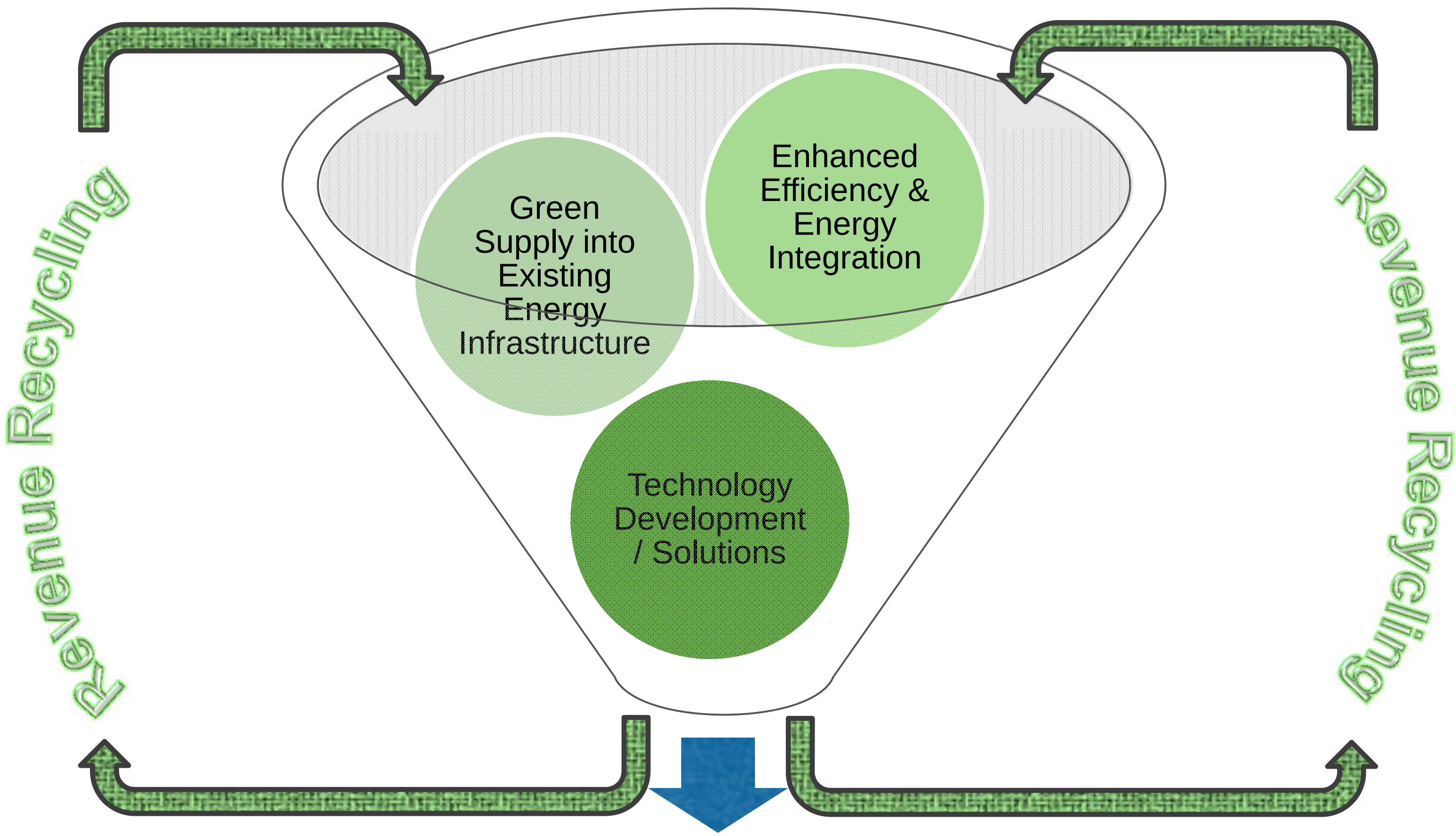
Natural Gas is Part of the Solution

Part Of The Solution - Ontario's Emission Reduction Forecast (2017- 2030)



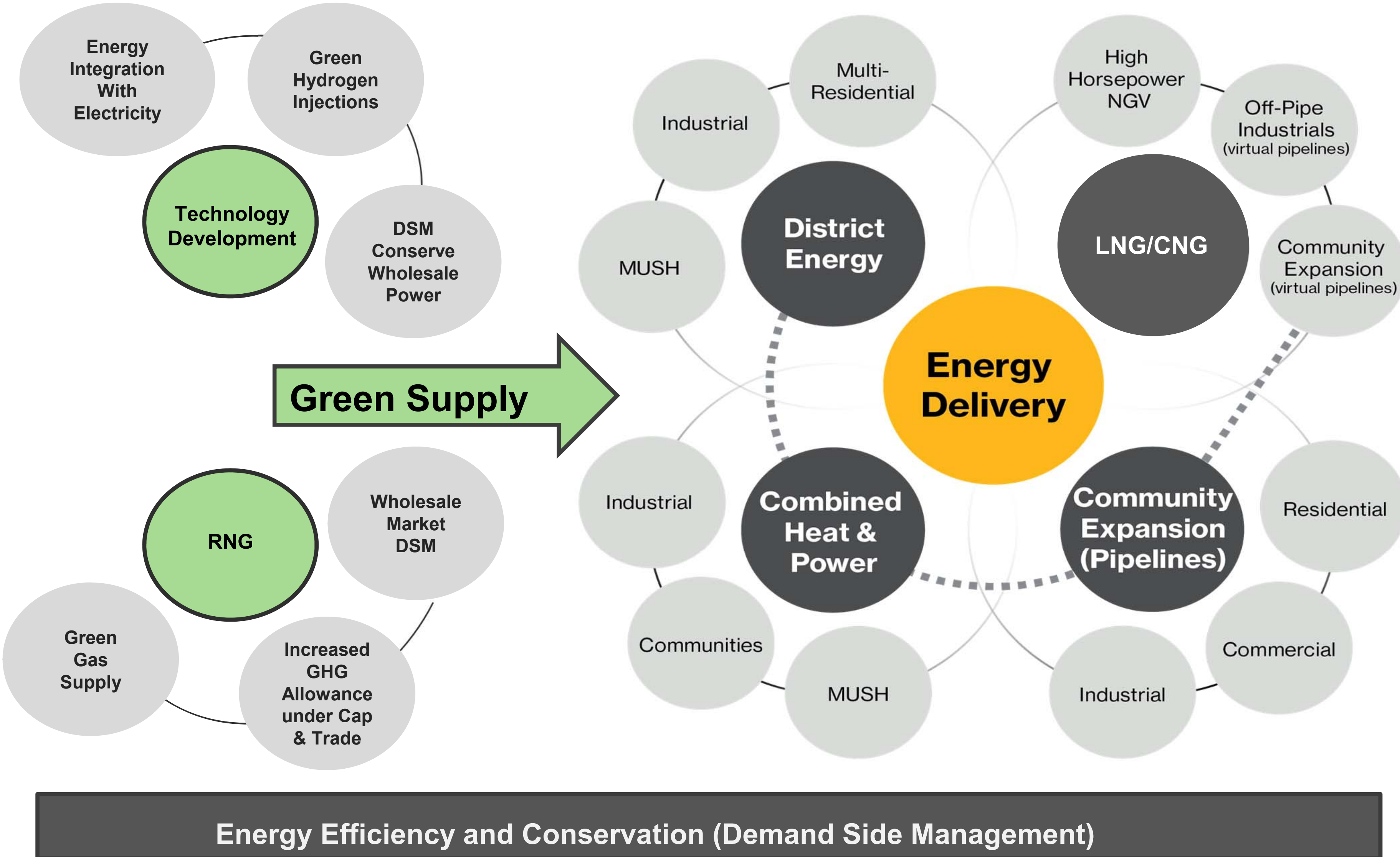
Source: ICF

Transforming the Natural Gas Energy Landscape



Optimized Infrastructure = Material Progress Towards Emission Goals While Maintaining Economic Competitiveness

Transforming the Landscape



Summary

- In partnership with our customers, Enbridge believes we can help government and customers achieve more cost-effective GHG reductions going forward
- Pipelines can offer more cost-effective renewable energy supplies (green or renewable natural gas) - to date, this market remains untapped in Ontario
- Government policies should be tailored to our energy intensive and export-based economy, and must enable us to remain competitive while making meaningful reductions in GHG emissions
- Technology development and commercialization is critical to the creation of a lower carbon economy in Ontario; seek opportunities to support existing industry with new revenue sources (e.g. technology adoption for conversion of CO_2 in high-value commodities such as chemicals, fuels, etc.)
- Compliance options should focus on promoting both near-term reductions and the advancement of technology for larger future reductions over time
- Regulatory considerations need to be given on carbon allowance purchasing strategy and operational needs to implement cap and trade policy, including timelines and additional resources

ICF INTERNATIONAL

ENBRIDGE

uniongas
A Spectra Energy Company

Enbridge Gas Distribution and Union Gas

Results from Aligned Cap & Trade Natural Gas Initiatives Analysis

November 2015

Outline

- Review of key assumptions defining Ontario Cap-and-Trade Scenarios
- Aligned Natural Gas Initiatives Assumptions
  - Renewable Natural Gas (RNG)
  - Combined Heat and Power (CHP)
  - Compressed/Liquefied Natural Gas (CNG/LNG)
  - Cap and Trade Energy Conservation (CTEC)
- Emissions Reduction Forecast and Initiatives Results
- Price Elasticity Demand Response
- Summary
- Appendix (separate file): Company-Specific Change in Natural Gas Demand

Assumptions: Cap-and-Trade Policy

- Ontario’s cap-and-trade program begins: **January 1, 2017**
- Link with Quebec and California: **January 1, 2018** (linkage not modeled)
- **Free allocation Scenario**: EITE industry and natural gas distributors
- **No free allocation Scenario**: transportation fuel distributors, electricity generators, and natural gas distributors
- **Cap**: -3.2% / year from 2017 to 2020 and -2.3% from 2020 to 2030
- **Offsets**: capped at 8%
- **Price floor**: aligned with Quebec and California (starting at $13 in 2017)
- **Reserve bank**: 3 tiers fixed at $50/$55/$60 in 2017 and increasing annually

Ontario Energy Board Generic Community Expansion
Filed: 2016-04-22
EB-2016-0004
Exhibit S3.EGDI.OGA.3
Attachment
Page 3 of 19

Assumptions: Activity Data

Business as usual

- Ontario’s provincial forecast of GHG emissions
- Electricity sector aligned with Ontario’s Long Term Energy Plan
- UG/EGD forecast of NG demand by customer segment out to 2030
- Beyond current DSM Plans no uptake of NG emission reducing opportunities

Cap-and-Trade Scenarios

- NG: RNG, CHP, CNG/LNG, CTEC
- Non-NG Transport: reduced activity, LCFS, and electrification

Model is populated with UG and EGD activity data and assumptions.

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EB-2016-0004
Exhibit S3.EGDI.OGA.3
Attachment
Page 4 of 19

Renewable Natural Gas

- Both UG and EGD provided annual forecast volume of RNG based on the Alberta Innovates (May 2011) Study.
- RNG production estimates derived from: anaerobic digestion (AD) and gasification.
- Introduction of RNG from various methods for AD and gasification sources as they relate to the availability of RNG supplies, the related technology maturity, scale and costs.

*Actual market transformation will significantly depend on evolving policy and technology development support.

- Assumption is Ontario's cap-and-trade regulations permit the sourcing of RNG supplies from outside of provincial boundaries.

RNG Volume and Emissions Reductions Forecast	2017	2018	2019	2020	2021	2022	2023
Ontario Total Volume (million m^3/yr)	19	34	151	267	396	503	947
Ontario Emissions Reductions (Mt CO_2e/yr)	0.04	0.06	0.28	0.50	0.75	0.95	1.79

RNG Volume and Emissions Reductions Forecast	2024	2025	2026	2027	2028	2029	2030
Ontario Total Volume (million m^3/yr)	1,355	1,997	2,546	3,052	3,444	3,837	4,265
Ontario Emissions Reductions (Mt CO_2e/yr)	2.56	3.77	4.81	5.77	6.51	7.25	8.06

Notes: 1) RNG volume and emissions reduction estimates represent cumulative values.
2) Emissions reductions do not include offset volumes associated with RNG, please refer to Assumptions Book for offset potential associated with RNG.

- CHP growth will total 1000 MW by 2030. Of this total, assume 40% is behind-the-meter CHP and 60% is grid-connected CHP delivering power into the wholesale electricity market.
- Assume a 50:50 market share for UG-EGD franchise areas for both behind-the-meter CHP and grid-connected CHP.

Provincial CHP Cumulative Capacity (Additional to Current Installed Capacity) and Emissions Reductions	2017	2018	2019	2020	2021	2022	2023
Ontario CHP (MW)	42	110	198	344	391	461	508
Ontario Emissions Reductions (Mt CO_2e/yr)	0.05	0.13	0.23	0.39	0.45	0.53	0.58

Provincial CHP Cumulative Capacity (Additional to Current Installed Capacity) and Emissions Reductions	2024	2025	2026	2027	2028	2029	2030
Ontario CHP (MW)	547	641	691	757	857	931	1,000
Ontario Emissions Reductions (Mt CO_2e/yr)	0.62	0.73	0.79	0.86	0.98	1.06	1.14

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EB-2016-0004
Exhibit S3.EGDI.OGA.3
Attachment
Page 6 of 19

Combined Heat and Power (continued)

- Calculation methodology from a CHP calculator developed by EGD, based on the principle of coincidence of load, was used.
  - Assumes operating hours of CHP (in both categories) are 100% coincident with the hours of grid-connected gas generation, and additional CHP operating hours are assumed to be coincident with zero-carbon grid generation
  - e.g. CHP operating for 7,500 hours per year displaces gas-fired generation for 7,000 hours in the year, and zero carbon emitting generation (i.e. nuclear, hydro) for 500 hours in the year (i.e. CHP wears full GHG emissions for hours it displaces non-emitting electricity)

Parameter	
Average Efficiency of Gas-fired Grid-connected Power Plants (HHV)	45%
Line Transmission and Distribution Losses	5%
Average Annual Grid-connected Gas Plant Operating Hours	7,000
Boiler Thermal Efficiency (HHV)	78%

Parameter	Behind-the-meter CHP[1]	Grid-connected CHP[2]
Electrical Efficiency	37.5%	48.1%
Heat-to-Power Ratio	1.2	0.8
Average Annual Operating Hours	7,500	4,200
Resulting Total System Efficiency (total power + thermal energy output/fuel consumed)	83%	87%

[1] Efficiency and heat-to-power ratio based on assumption that behind-the-meter CHP is likely to be a mix of small reciprocating engines (e.g. institutional buildings) and gas turbines (e.g. industrial sites with a requirement for steam). Operating hours based on assumption that CHP will run to meet thermal demands of process load or operation of a facility.

[2] Efficiency and heat-to-power ratio from manufacturer specifications for an illustrative large (8.5 MW) reciprocating engine, based on assumption that grid-connected CHP will be designed to maximize electrical power output. Operating hours based on typical operating hours for district energy-connected CHP with seasonal heat load, and the assumption that wholesale CHP runs only when the grid needs the electricity and can be approximated by the same annual operating hours as district energy-connected CHP.

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Exhibit S3.EGDI.OGA.3
Attachment
Page 7 of 19

CNG/LNG for Transportation

- EGD and UG provided volume of natural gas consumption based on current fuel consumption per target sector (does not include light-duty vehicles) and NG market capture estimates
  - UG/EGD provincial total assumed to be 50:50 market share
- Analysis uses a 22% emissions reduction factor for displacement of any BAU fuel (diesel, gasoline, fuel oil) with NG

Provincial NG Consumption for Transportation and Emissions Reductions	2017	2018	2019	2020	2021	2022	2023
Marine (million m³/yr)	-	-	17	35	52	70	87
Rail (million m³/yr)	-	-	33	65	98	130	163
On-Road Diesel (million m³/yr)	20	86	216	388	560	862	1,422
On-Road Gasoline (million m³/yr)	-	31	77	139	201	310	511
Ontario Total Volume (million m³/yr)	**20**	**117**	**343**	**627**	**912**	**1,372**	**2,184**
Ontario Emissions Reductions (Mt CO_2e/yr)	0.01	0.06	0.18	0.33	0.49	0.73	1.16

Provincial NG Consumption for Transportation and Emissions Reductions	2024	2025	2026	2027	2028	2029	2030
Marine (million m³/yr)	105	122	140	157	175	192	210
Rail (million m³/yr)	195	228	260	293	325	342	342
On-Road Diesel (million m³/yr)	2,241	3,233	3,664	3,879	4,009	4,052	4,095
On-Road Gasoline (million m³/yr)	806	1,162	1,317	1,395	1,441	1,457	1,472
Ontario Total Volume (million m³/yr)	**3,347**	**4,745**	**5,381**	**5,724**	**5,950**	**6,042**	**6,118**
Ontario Emissions Reductions (Mt CO_2e/yr)	1.78	2.53	2.87	3.05	3.17	3.22	3.26

Ontario Energy Board Generic Community Expansion
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EB-2016-0004
Exhibit S3.EGDI.OGA.3
Attachment
Page 8 of 19

LNG for Stationary Combustion (Load Displacement)

- Analysis based on estimate of annual natural gas consumption volume forecasts from 2017 to 2030 agreed on by the EGD/UG working group
  - Forecast corresponds to an approximately 46% market capture by 2030 of 'current' Ontario consumption of relevant stationary fuel types
- Assume that 38% of the total volume displaces propane fuel use, and the remainder displaces diesel and oil use
- Assume that the stationary NG volumes are split 50:50 between Enbridge and Union
- Analysis uses a 22% emissions reduction factor for displacement of stationary diesel and fuel oil with LNG; or 16% emission reduction factor for displacement of propane with LNG

Provincial Stationary LNG Consumption and Emissions Reductions	2017	2018	2019	2020	2021	2022	2023
Ontario Total (million m^3/yr)	64	135	193	250	309	366	421
Ontario Emissions Reductions (Mt CO_2e/yr)	0.04	0.08	0.12	0.15	0.19	0.22	0.26

Provincial Stationary LNG Consumption and Emissions Reductions	2024	2025	2026	2027	2028	2029	2030
Ontario Total (million m^3/yr)	476	532	587	642	697	752	807
Ontario Emissions Reductions (Mt CO_2e/yr)	0.29	0.32	0.36	0.39	0.43	0.46	0.49

Cap and Trade Energy Conservation

- Cap and trade energy conservation (CTEC) quantification based on aggressive scenarios run by EGD in Navigant DSM model, and translated to UG's franchise by assuming the same proportional increase in budget and savings over the current OEB-approved DSM plan
- UG provided an estimate of additional 'large volumes' savings
- Initiative divided into two 'slices'
  - 'Slice 1' is a medium/constrained scenario corresponding to the highest modelled scenario that would be considered to have a 'reasonable yield' as a traditional DSM program
  - 'Slice 2' is the additional savings obtained in a high scenario, which is a modelled scenario where DSM incentives are set at 100% of capital costs for all currently economic measures. Traditional DSM may not be an effective policy tool to access these savings due to the high cost per m^3 savings.

Provincial CTEC Cumulative Savings and Emissions Reductions	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Medium/Constrained Scenario (Slice 1) (million m^3/yr)	263	513	756	989	1,215	1,432	1,637	1,835	2,033	2,232	2,430	2,628	2,826	3,025
Ontario Emissions Reductions (Mt CO_2e/yr)	0.50	0.97	1.43	1.87	2.30	2.71	3.09	3.47	3.84	4.22	4.59	4.97	5.34	5.72
High Scenario (Slice 1 + Slice 2) (million m^3/yr)	364	714	1,053	1,376	1,688	1,985	2,264	2,533	2,801	3,070	3,338	3,607	3,875	4,144
Ontario Emissions Reductions (Mt CO_2e/yr)	0.69	1.35	1.99	2.60	3.19	3.75	4.28	4.79	5.29	5.80	6.31	6.82	7.32	7.83

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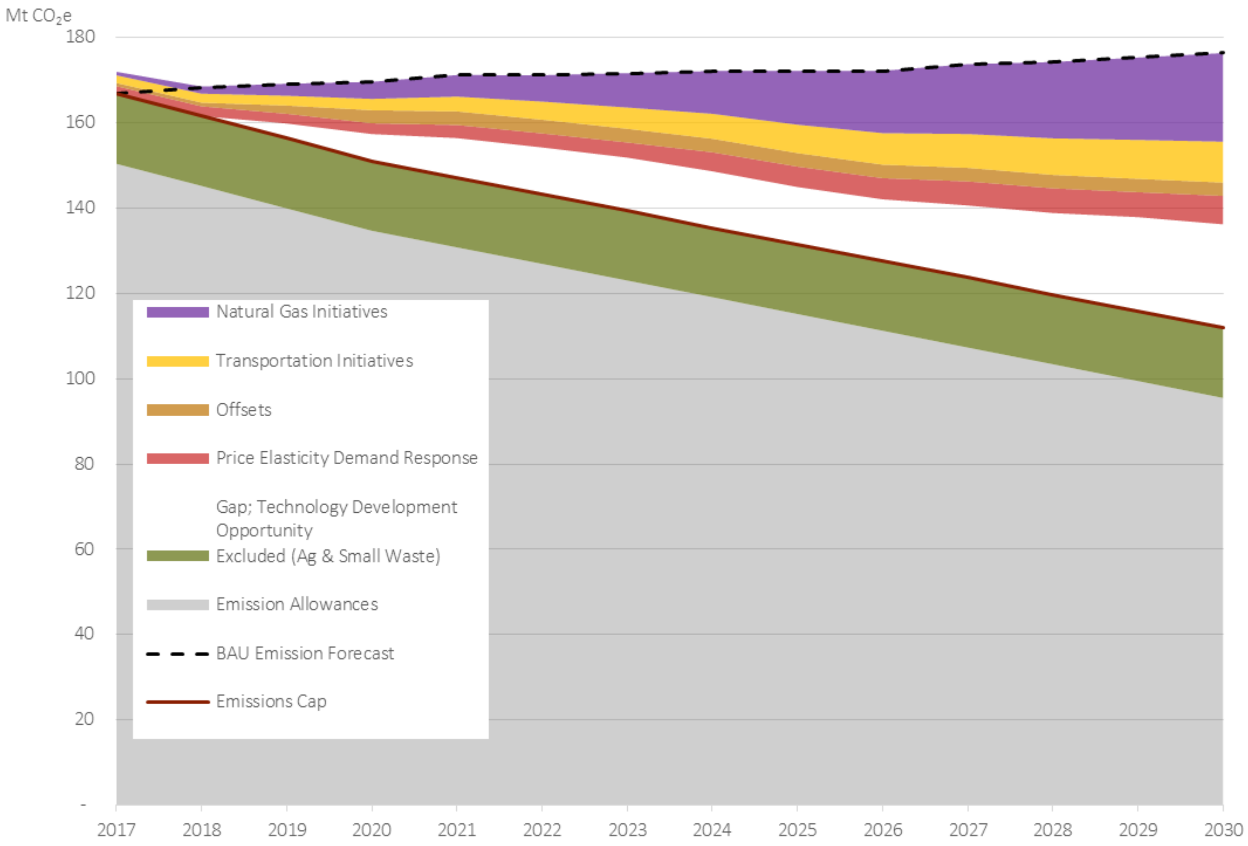
Filed: 2016-04-22
EB-2016-0004
Exhibit S3.EGDI.OGA.3
Attachment
Page 10 of 19

Assumptions: Non-NG Transportation Initiatives

- Electrification of light-duty vehicles
  - 1.5 million electric vehicles (EVs) by 2030
  - Assumed rapid penetration of EVs as a result of government incentive
  - 4.1 MWh/year required per EV for annual travel of 20,000 km
  - Non-emitting electricity generation used to power EVs
- Zero Emission Vehicle mandate modelled on the California ZEV mandate, beginning in 2017
- Reduce Vehicle Kilometres travelled, considers potential impact of transit programs incremental to the Big Move
- Low Carbon Fuel Standard modelled on the California LCFS, beginning in 2017 and following the same schedule for increased stringency
  - Accounts for existing renewable fuel mandates in Ontario

Ontario Emissions Reduction Forecast: With Free Allocation to Natural Gas Distributors



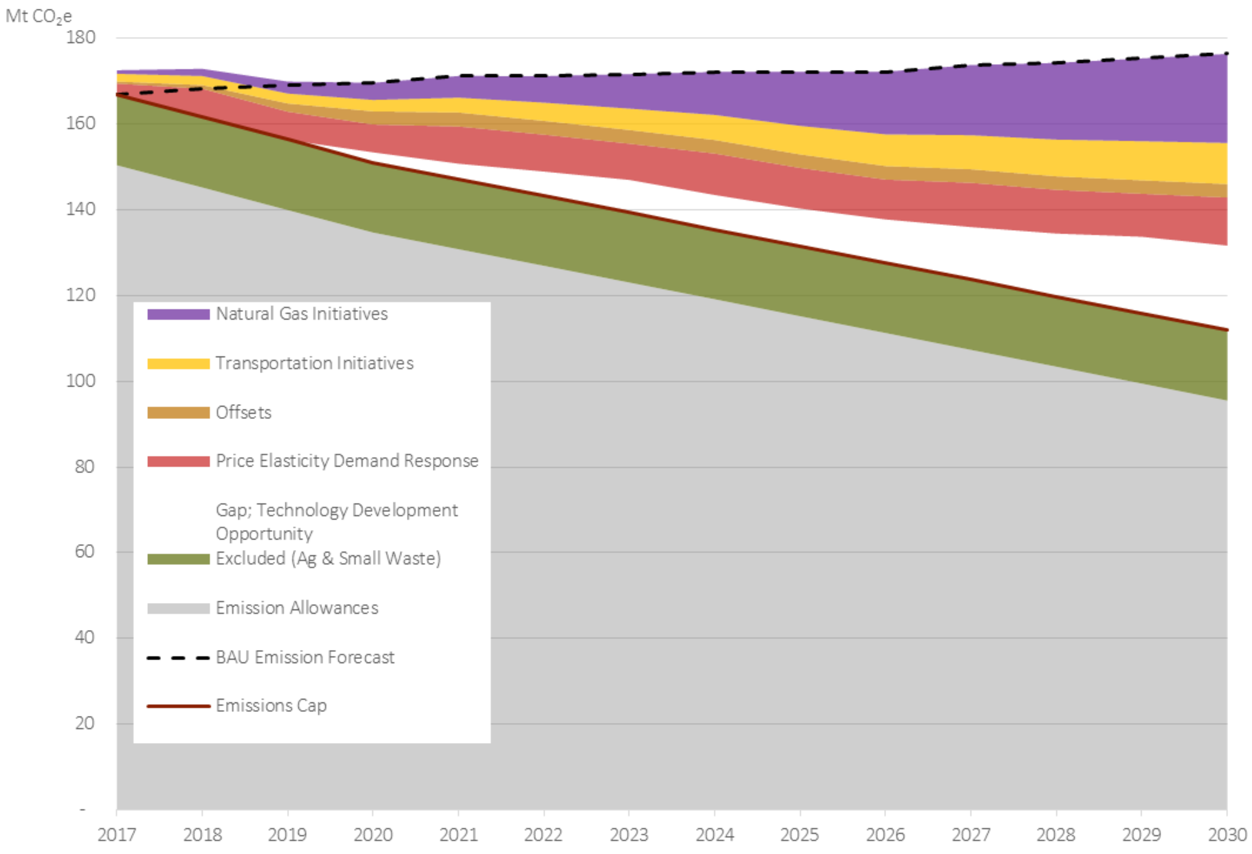
C&T scenario with free allocation informed by UG/EGD activity data and assumptions.

By 2030

- NG related initiatives **reduce emissions by 21 Mt CO_2e**, the largest GHG reduction potential in the study timeframe.
- Non-NG transport initiatives **reduce emissions by 10 Mt CO_2e**.
- Elasticity demand response to increasing fuel prices results in **reductions of 7 Mt CO_2e**.
- Gap; Technology Development Opportunity of **24 Mt CO_2e**

Cumulative allowance shortage of **161 Mt CO_2e** from 2017-2030.

Ontario Emissions Reduction Forecast: No Free Allocation to Natural Gas Distributors



C&T scenario assuming no free allocation informed by UG/EGD activity data and assumptions.

By 2030

- NG related initiatives **reduce emissions by 21 Mt CO_2e**, the largest GHG reduction potential in the study timeframe
- Non-NG transport initiatives **reduce emissions by 10 Mt CO_2e**.
- Elasticity demand response to increasing fuel prices results in **reductions of 11 Mt CO_2e**.
- Gap; Technology Development Opportunity of **20 Mt CO_2e**

Cumulative allowance shortage of **100 Mt CO_2e** from 2017-2030.

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Exhibit S3.EGDI.OGA.3
Attachment
Page 13 of 19

Ontario Emissions Reduction Forecast: Potential for Complementary Initiatives

- Based on modeled results, Ontario cannot meet its GHG reduction objectives solely from within its own domestic market – will need to purchase allowances from other WCI jurisdictions, or close the gap with complementary initiatives targeting technology developments/innovation that achieve deeper GHG reductions (e.g. natural gas heat pumps, etc.).
- Serious consideration should be given to the ensuring auction proceeds are reinvested to achieve maximum emissions reductions for the province.
- It is important to establish complementary initiatives (for example - a natural gas technology fund) early in the cap-and-trade program development process to ensure technology solutions are commercialized early enough to deliver the needed GHG reductions, or cumulative allowance shortages will grow.

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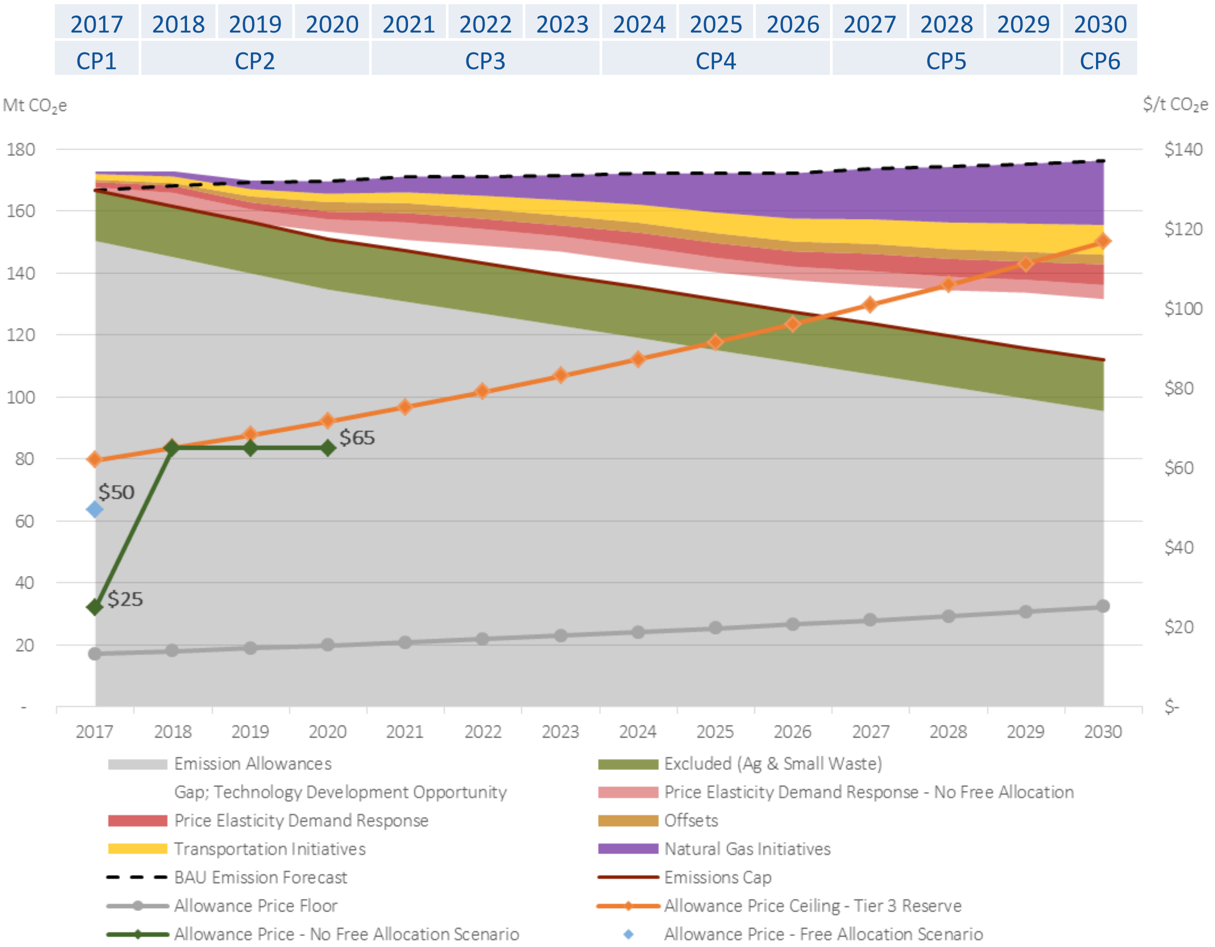
EB-2016-0004
Exhibit S3.EGDI.OGA.3
Attachment
Page 14 of 19

Model Output Allowance Price *NOT an allowance price forecast



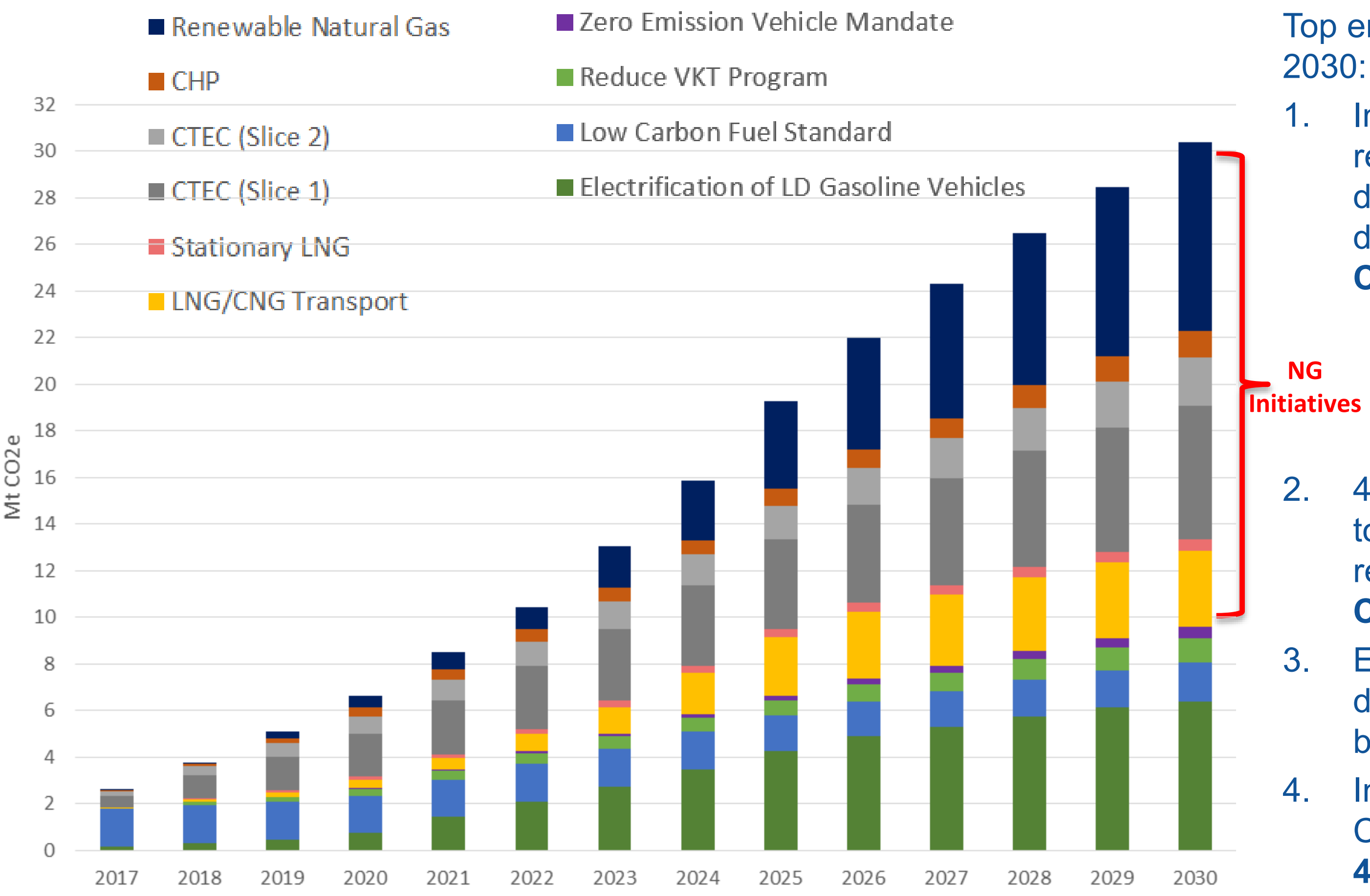
Model Assumptions:

- Ontario in a vacuum
  - No link to QC/CA allowance markets
- Price is solved per WCI compliance period (CP)
- Price is constrained between the WCI floor and ceiling
  - Assume the top tier reserve price is a hard ceiling price for modelling purposes
- If price exceeds ceiling, model stops solving

Model Results:

- ➢ The price exceeds ceiling after CP1 or CP2 for the free and no free allocation scenario, respectively
- ➢ There are insufficient emission reductions in Ontario to meet the reduction targets within these price constraints

Summary of Aligned Initiatives Results

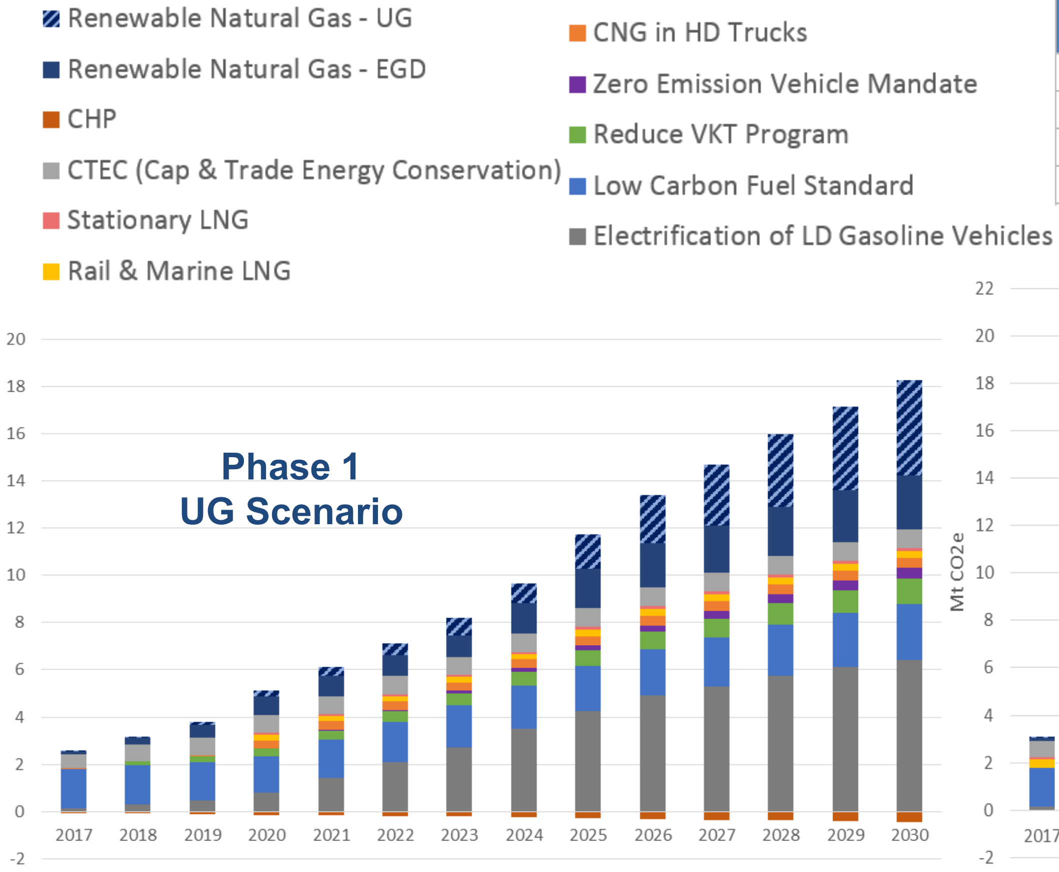


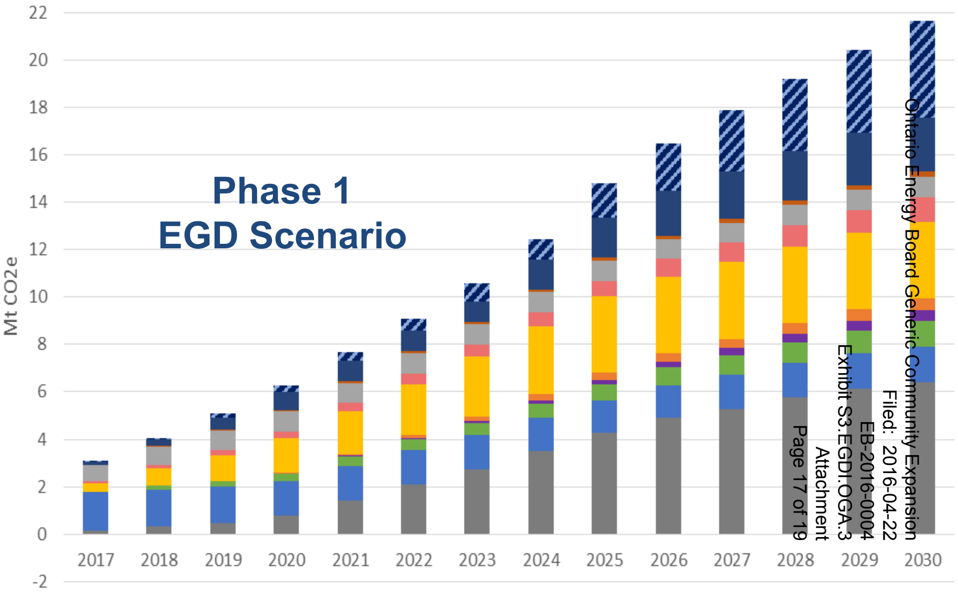
Top emission reduction initiatives in 2030:

1. In total, NG energy efficiency reduces emissions by **8 Mt CO_2e** due to 4.1 billion m^3 of CTEC demand destruction and **1 Mt CO_2e** due to 1,000 MW of CHP.
   – Highest modelled CTEC scenario with 'reasonable yield' as traditional DSM program (Slice 1) reduces emissions by 6 Mt CO_2e due to 3.0 billion m^3 demand destruction.
2. 4.3 billion m^3 of RNG (~15% of total provincial NG consumption) reduces emissions by **8 Mt CO_2e**.
3. Electrification of 1.5 million light-duty vehicles reduces emissions by **6 Mt CO_2e**.
4. In total, 6.9 billion m^3 of CNG/LNG reduces emissions by **4 Mt CO_2e**.

Previous Initiatives Results

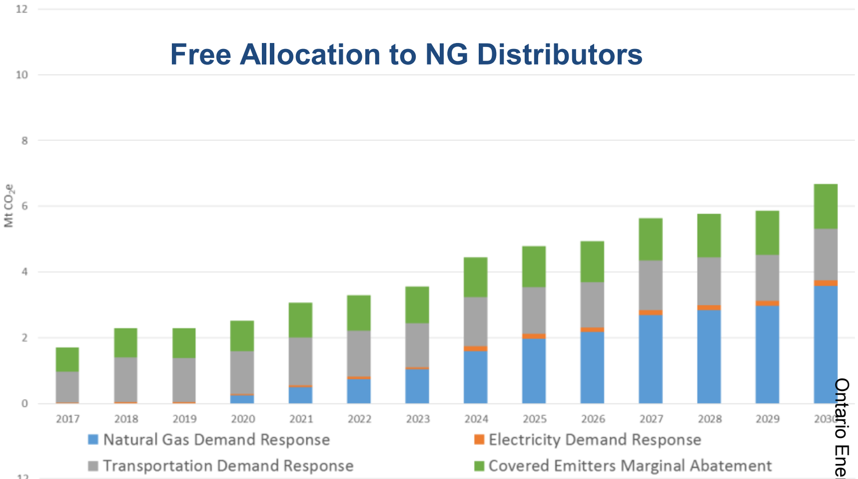
Provincial Totals Year 2030	Phase 1 UG Scenario	Phase 1 EGD Scenario	Phase 2 UG/EGD Aligned Scenario
	Mt (CO_2e)		
RNG	6	6	8
CTEC	1	1	8
LNG/CNG	1	5	4
CHP	-0.5	0.2	1

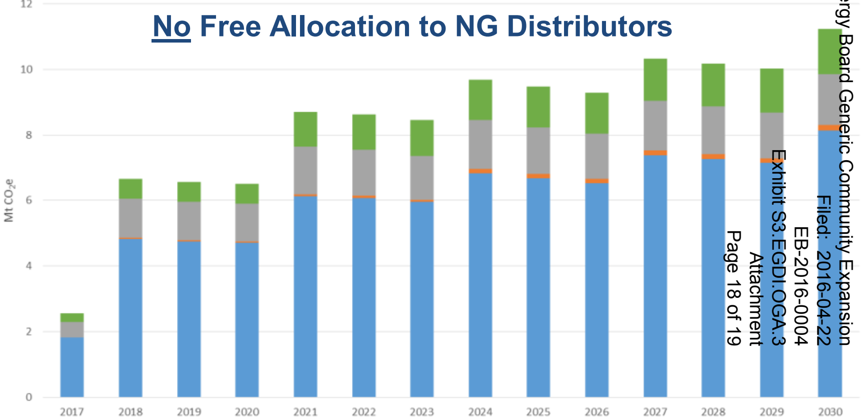




End users respond to high price of allowance / energy by reducing usage

- Price elasticity assumptions informed by **limited available research**.
  - Natural Gas: *The Likely Effect of Carbon Pricing on Energy Consumption in Canada*. Dr. D. Ryan & Noha Abdel Razek, University of Alberta, May 2012.
  - Transportation Fuels & Electricity: ICF expert opinion
- No physical constraint imposed in the model.
  - e.g. in reality, NG demand destruction would be limited by a minimum space heating requirement for Ontario's climate
- Price elasticity applied to prices consumers pay for:
  - Electricity
  - Transportation – light duty gasoline & diesel only
  - Natural Gas – residential, commercial & small industrial sub-sectors
- Industrial marginal abatement costs based on research for industry sector or sub-sector and ICF expert opinions.
  - Adjusted to avoid double counting EE abatement in complementary initiatives
- NG demand destruction would be reduced through free allocation to NG distributors (vs. no free allocation).





Aggressive 2030 targets and C&T policy will reduce demand for NG in Ontario

NG Initiatives (RNG, CNG/LNG, CTEC and CHP) have the potential to maximize Ontario's GHG reductions in the 2017-2030 timeframe, but policy and regulatory support will be key to achieving this potential. NG can contribute broad spectrum and cost-effectively as a foundational fuel to a low carbon economy:

- NG is critical for re-fueling heavy transport.
- RNG (decarbonized CH_4) is critical to leveraging existing energy infrastructure for GHG reductions and as a means of limiting consumer cost-pressures under cap-and-trade. Policy/regulatory support for some new infrastructure required for delivery, but this could be a modest investment compared to alternatives.
- Deeper energy efficiency and conservation understood as contributors to the solution - EGD/UG delivery of programs necessary for success.
- CHP efficiency benefits are well understood, and represent the most efficient use of NG for power generation in the near-term, and the use of RNG in the future.

However, there are caveats:

- NG for transport requires thinking through the role of NG Distributors in establishing the refueling infrastructure required to achieve early market adoption.
- RNG potential availability: EGD and UG are relying on preliminary market assessments. Policy/regulatory signals are needed to prioritize this before the understanding of market and technology potential can improve.
- Deeper energy efficiency and conservation must be considered beyond the lens of traditional DSM programs (complicated by OEB mandate).
- CHP may be the victim of unintended consequences in cap-and-trade design.

Short term (2017-2030):

- Opportunity for UG/EGD: price (vs. electricity) and infrastructure.
- Challenge for UG/EGD: regulator mandate, rate design considerations, money and time to deploy new infrastructure vs. 2030 target.
- NG demand destruction limited by minimum space heating needs and consumer resistance (cost) to electrifying building heating. Early start on NG technology innovation needed as an energy cost control measure, and as a means of preserving low-carbon electricity for electrification of light-duty transportation.

Long term (2030-2050):

- Demand destruction vs. BAU is inevitable. Technology innovation and green gas supplies needed for the economy to have access to cost-effective energy by pipeline.

ENBRIDGE GAS DISTRIBUTION INC. (ENBRIDGE)
RESPONSES TO INTERROGATORIES OF ED

INTERROGATORY #1

Reference: Page 6-8

Does Enbridge agree that existing gas consumers should be required to subsidize expansions of Ontario's natural gas distribution system only if all of the following criteria are met:

a) The expansion will lead to a net reduction in Ontario's greenhouse gas emissions [e.g., this could occur if the new customers' previous energy source (e.g., heating oil) had higher greenhouse gas emissions];
b) Expanding the gas system is the most cost-effective, feasible option to achieve the greenhouse gas emission reductions [i.e., do not expand the gas distribution system using existing customer subsidies if the emission reductions could be achieved at a lower cost by energy efficiency or renewable energy investments (e.g., home energy retrofits, heat pumps)]; and
c) The subsidy is necessary to make the project happen [e.g., do not require existing customers to subsidize an expansion of the gas system if the cost could be recovered from the new customers via a surcharge on their gas rates]?

If "no", please fully justify your response. Please specifically address each of the three criteria in your response. Note that the above three criteria would not be to the exclusion of other criteria required for community expansion.

RESPONSE

Enbridge does not agree that the criteria set out above are the determinative considerations.

a) Reduction of greenhouse gas emissions is not the only factor considered in the weighing of the costs and benefits of gas distribution system expansion project.

b) Due to the happenstance of timing and geography there could be situations and reasons where it is desirable and practical to take steps that may not result in the lowest GHG option. For example, electricity generation in Ontario includes natural gas generation. Natural gas generation provides significant societal benefits in terms of economics, reliability and operational flexibility. This component of the electricity generation fleet has also helped Ontario integrate more renewable energy sources into its generation portfolio. It is also important to consider site versus source (a more holistic view of energy use and consumption) in order to understand the net impact of potential changes from the point of generation to the point of end use.

c) Yes the Company agrees that subsidies from existing customers should not be utilized where they are not required. The Company also recognizes that intergenerational and geographical impacts appropriately exist within the design and application of postage stamp rates.

ENBRIDGE GAS DISTRIBUTION INC. (ENBRIDGE)
RESPONSES TO INTERROGATORIES OF ED

INTERROGATORY #11

Reference: Page 33

(a) Has Enbridge compared the stage 2 benefits that would flow from a dollar of spending on the community expansion projects it is considering and:
   a. The stage 2 benefits that would flow from a dollar of DSM spending; and
   b. The stage 2 benefits that would flow from a dollar of spending on renewable energy spending, such as investment in heat pumps?

   If yes, please provide the comparison.

(b) Has Enbridge compared the stage 3 benefits that would flow from a dollar of spending on the community expansion projects it is considering and:
   a. The stage 3 benefits that would flow from a dollar of DSM spending; and
   b. The stage 3 benefits that would flow from a dollar of spending on renewable energy spending, such as investment in heat pumps?

   If yes, please provide the comparison.

RESPONSE

(a) No.

(b) No.

Ministry of Energy

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Ontario

FEB 17 2015

Ms Rosemarie Leclair
Chair & Chief Executive Officer
Ontario Energy Board
PO Box 2319
2300 Yonge Street
Toronto ON M4P 1E4

Dear Ms Leclair:

As part of Ontario's Long-Term Energy Plan (LTEP), the government committed to work with gas distributors and municipalities to pursue options to expand natural gas infrastructure to service more communities in rural and northern Ontario.

In addition to our LTEP commitment, the government is working to develop a Natural Gas Access Loan and a Natural Gas Economic Development Grant. The Ministry of Economic Development, Employment and Infrastructure is the ministry responsible for establishing these programs, and is in the early stages of their design. The Ministry of Energy will provide support.

In my letter to you on June 26, 2014, with respect to the OEB's 2014-2017 Business Plan, I asked that the Board examine its oversight of the natural gas sector and to assess what options may exist to facilitate connecting more communities to natural gas.

I am writing to you today to encourage the Board to continue to move forward on a timely basis on its plans to examine opportunities to facilitate access to natural gas services to more communities, and to reiterate the government's commitment to that objective. I appreciate your continued support to ensure the rational expansion of the natural gas transmission and distribution system for all Ontarians.

Sincerely,

Bob Chiarelli
Minister

Order in Council
Décret

Ontario
Executive Council
Conseil exécutif

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and concurrence of the Executive Council, orders that:

Sur la recommandation de la personne soussignée, le lieutenant-gouverneur, sur l'avis et avec le consentement du Conseil exécutif, décrète ce qui suit :

WHEREAS the government adopted a policy of putting conservation first in its 2013 Long-Term Energy Plan, *Achieving Balance*.

AND WHEREAS it is desirable to achieve reductions in electricity consumption and natural gas consumption to assist consumers in managing their energy bills, mitigating upward pressure on energy rates and reducing air pollutants, including greenhouse gas emissions, and to establish an updated electricity conservation policy framework ("Conservation First Framework") and a natural gas conservation policy framework.

AND WHEREAS the Minister of Energy intends to issue a direction to the Ontario Power Authority to require that it undertake activities to support the Conservation First Framework, including the funding of electricity distributor conservation and demand management programs.

AND WHEREAS the Minister of Energy may, with the approval of the Lieutenant Governor in Council, issue directives under section 27.1 of the *Ontario Energy Board Act, 1998* in order to direct the Board to take steps to promote energy conservation, energy efficiency, load management or the use of cleaner energy sources, including alternative and renewable energy sources.

AND WHEREAS the Minister of Energy may, with the approval of the Lieutenant Governor in Council, issue directives under section 27.2 of the *Ontario Energy Board Act, 1998* in order to direct the Board to take steps to establish conservation and demand management targets to be met by electricity distributors and other licensees.

NOW THEREFORE the Directive attached hereto is approved and shall be and is effective as of the date hereof.

Recommended ______________________
Minister of Energy

Concurred ______________________
Chair of Cabinet

Approved and Ordered MAR 2 6 2014
Date

____
Lieutenant Governor

O.C./Décret 467/2014

MINISTER'S DIRECTIVE

TO: THE ONTARIO ENERGY BOARD

I, Bob Chiarelli, Minister of Energy, hereby direct the Ontario Energy Board (the "Board") pursuant to my authority under sections 27.1 and 27.2 of the *Ontario Energy Board Act, 1998* (the "Act") to take the following steps to promote electricity conservation and demand management ("CDM") and natural gas demand side management ("DSM"):

1. The Board shall, in accordance with the requirements of this Directive and without holding a hearing, amend the licence of each licensed electricity distributor ("Distributor") to establish the following as the CDM target to be met by the Distributor:

    i. add a condition that specifies that the Distributor shall, between January 1, 2015 and December 31, 2020, make CDM programs available to customers in its licensed service area and shall, as far as is appropriate and reasonable having regard to the composition of the Distributor's customer base, do so in relation to each customer segment in its service area ("CDM Requirement");

    ii. add a condition that specifies that such CDM programs shall be designed to achieve reductions in electricity consumption;

    iii. add a condition that specifies that the Distributor shall meet its CDM Requirement by:

        a) making Province-Wide Distributor CDM Programs, funded by the Ontario Power Authority (the "OPA"), available to customers in its licensed service area;

        b) making Local Distributor CDM Programs, funded by the OPA, available to customers in its licensed service area; or

        c) a combination of (a) and (b); and

    iv. add a condition that specifies the Distributor shall, as far as possible having regard to any confidentiality or privacy constraints, make the details and results of Local Distributor CDM Programs available to other Distributors upon request.

2. Despite paragraph 1, the Board shall not amend the licence of any Distributor that meets the conditions set out below:

    i. with the exception of embedded distributors, the Distributor is not connected to the Independent Electricity System Operator ("IESO") – controlled grid; or

    ii. the Distributor's rates are not regulated by the Board.

3. The Board shall establish CDM Requirement guidelines. In establishing such guidelines, the Board shall have regard to the following objectives of the government in addition to such other factors as the Board considers appropriate:

i. that the Board shall annually review and publish the verified results of each Distributor's Province-Wide Distributor CDM Programs and Local Distributor CDM Programs and report on the progress of Distributors in meeting their CDM Requirement;

ii. that CDM shall be considered to be inclusive of activities aimed at reducing electricity consumption and reducing the draw from the electricity grid, such as geothermal heating and cooling, solar heating and small scale (i.e., <10MW) behind the meter customer generation. However, CDM should be considered to exclude those activities and programs related to a Distributor's investment in new infrastructure or replacement of existing infrastructure, any measures a Distributor uses to maximize the efficiency of its new or existing infrastructure, activities promoted through a different program or initiative undertaken by the Government of Ontario or the OPA, such as the OPA Feed-in Tariff (FIT) Program and micro-FIT Program and activities related to the price of electricity or general economic activity; and

iii. that lost revenues that result from Province-Wide Distributor CDM Programs or Local Distributor CDM Programs should not act as a disincentive to Distributors in meeting their CDM Requirement.

4. The Board shall establish a DSM policy framework ("DSM Framework") for natural gas distributors whose rates are regulated by the Board ("Gas Distributors"). In establishing the DSM Framework, the Board shall have regard to the following objectives of the government in addition to such other factors as the Board considers appropriate:

   i. that the DSM Framework shall span a period of six years, commencing on January 1, 2015, and shall include a mid-term review to align with the mid-term review of the Conservation First Framework;

   ii. that the DSM Framework shall enable the achievement of all cost-effective DSM and more closely align DSM efforts with CDM efforts, as far as is appropriate and reasonable having regard to the respective characteristics of the natural gas and electricity sectors;

   iii. that Gas Distributors shall, where appropriate, coordinate and integrate DSM programs with Province-Wide Distributor CDM Programs and Local Distributor CDM Programs to achieve efficiencies and convenient integrated programs for electricity and natural gas customers;

   iv. that Gas Distributors shall, where appropriate, coordinate and integrate low-income DSM Programs with low-income Province-Wide Distributor CDM Programs or Local Distributor CDM Programs;

   v. that the Board shall annually review and publish the verified or audited results of each Gas Distributor's DSM programs;

   vi. that an achievable potential study for natural gas efficiency in Ontario should be conducted every three-years, with the first study completed by June 1 2016, to inform natural gas efficiency planning and programs. The achievable potential study should, as far as is appropriate and reasonable having regard to the respective characteristics of the natural gas and electricity sectors, be coordinated with the OPA with regard to the OPA's requirement to conduct an electricity efficiency achievable potential study every three-years;

vii. that DSM shall be considered to be inclusive of activities aimed at reducing natural gas consumption, including financial incentive programs and education programs; and

viii. that lost revenues resulting from DSM programs should not act as a disincentive to Gas Distributors in undertaking DSM activities.

5. By January 1, 2015, the Board shall have considered and taken such steps as considered appropriate by the Board towards implementing the government's policy of putting conservation first in Distributor and Gas Distributor infrastructure planning processes at the regional and local levels, where cost-effective and consistent with maintaining appropriate levels of reliability.

6. Nothing in this Directive shall be construed as directing the manner in which the Board determines, under the *Ontario Energy Board Act, 1998*, rates for Gas Distributors or for Distributors, including in relation to applications regarding regional or local electricity demand response initiatives or infrastructure deferral investments.