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 Union

May 10, 2016

KLIPPENSTEINS
Barristers and Solicitors
160 John Street, Suite 300
Toronto, ON M5V 2E5

Murray Klippenstein, LSUC No. 26950G
Kent Elson, LSUC No. 57091I
Tel.: (416) 598-0288
Fax: (416) 598-9520

Lawyers for Environmental Defence

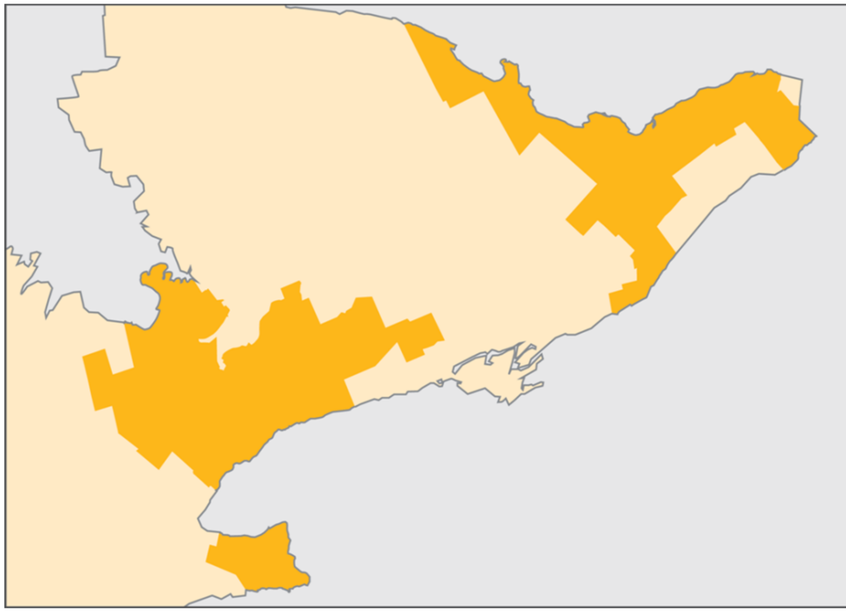
Index

Natural Gas & Ontario's Energy Mix

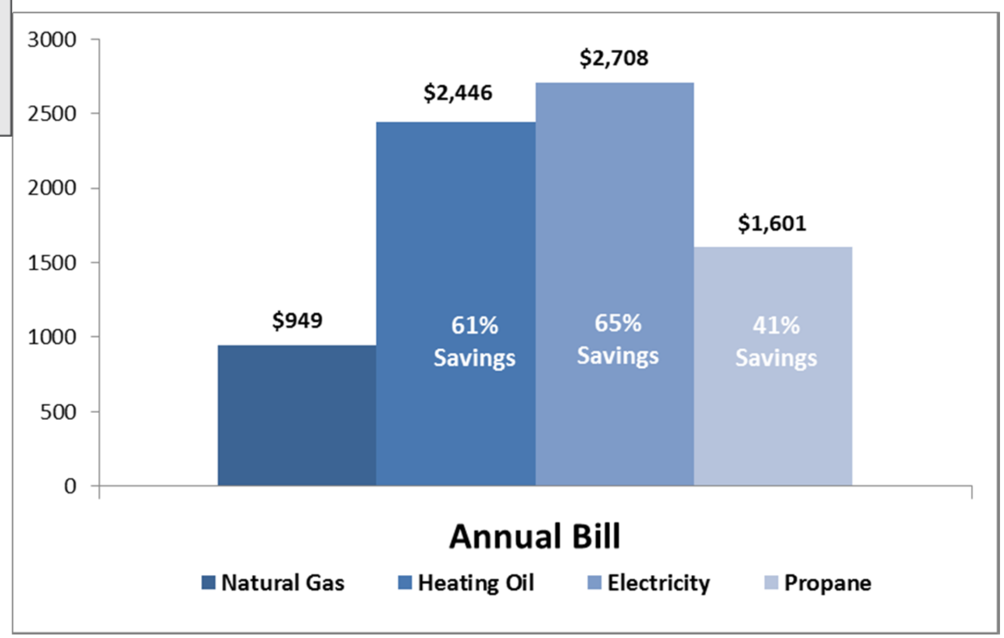
EB-2015-0237
Natural Gas Market Review, January 2016

Norm Ryckman

Enbridge Gas Distribution

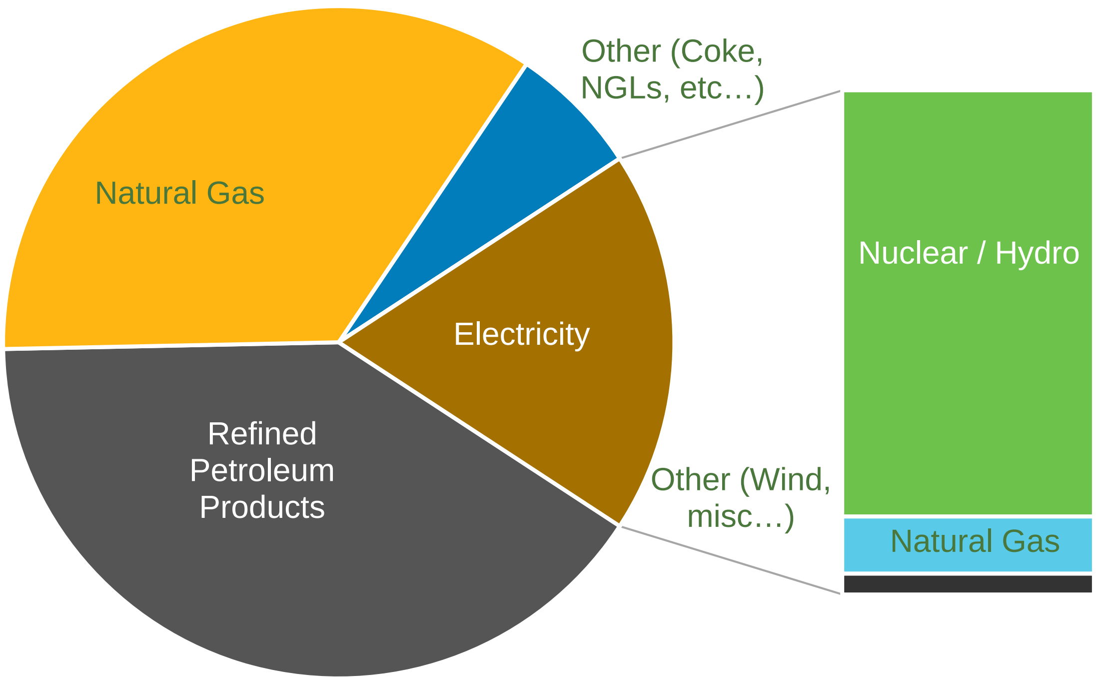


- EGD serves >2 million customers
- Adds ~35,000 customers/year



- 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.

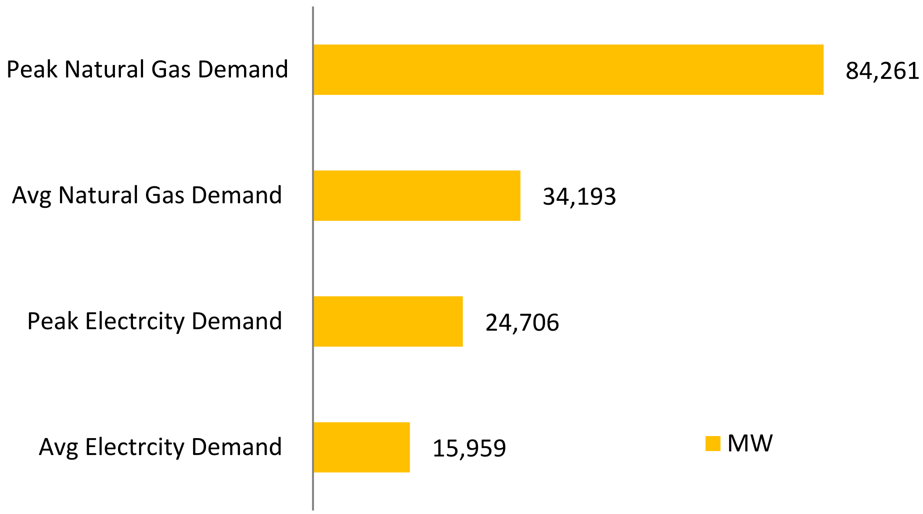
Electricity demand declined 2004 – 2014 due to CDM and loss of industry demand due to recession.

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)

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

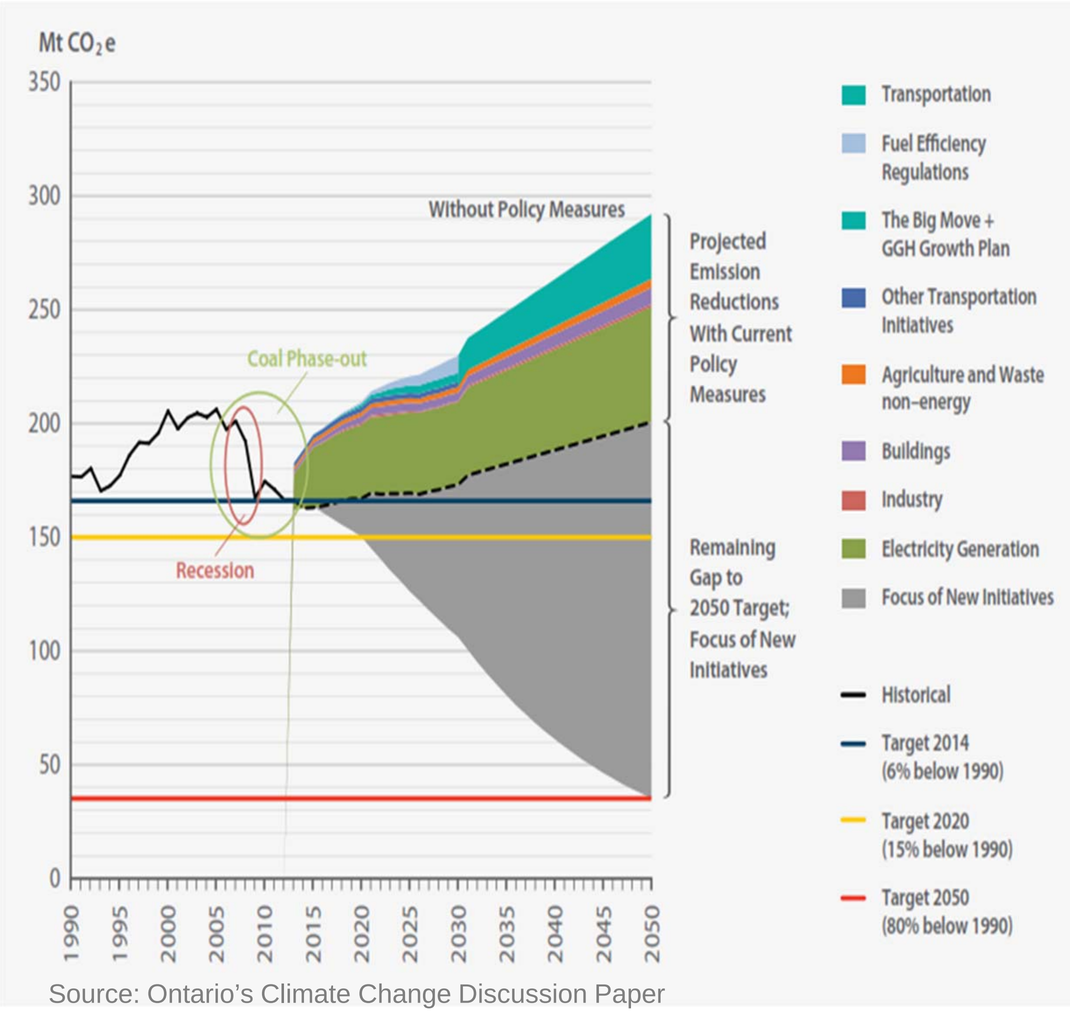
EB-2015-0237
Natural Gas Market Review, January 2016

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 7 of 30

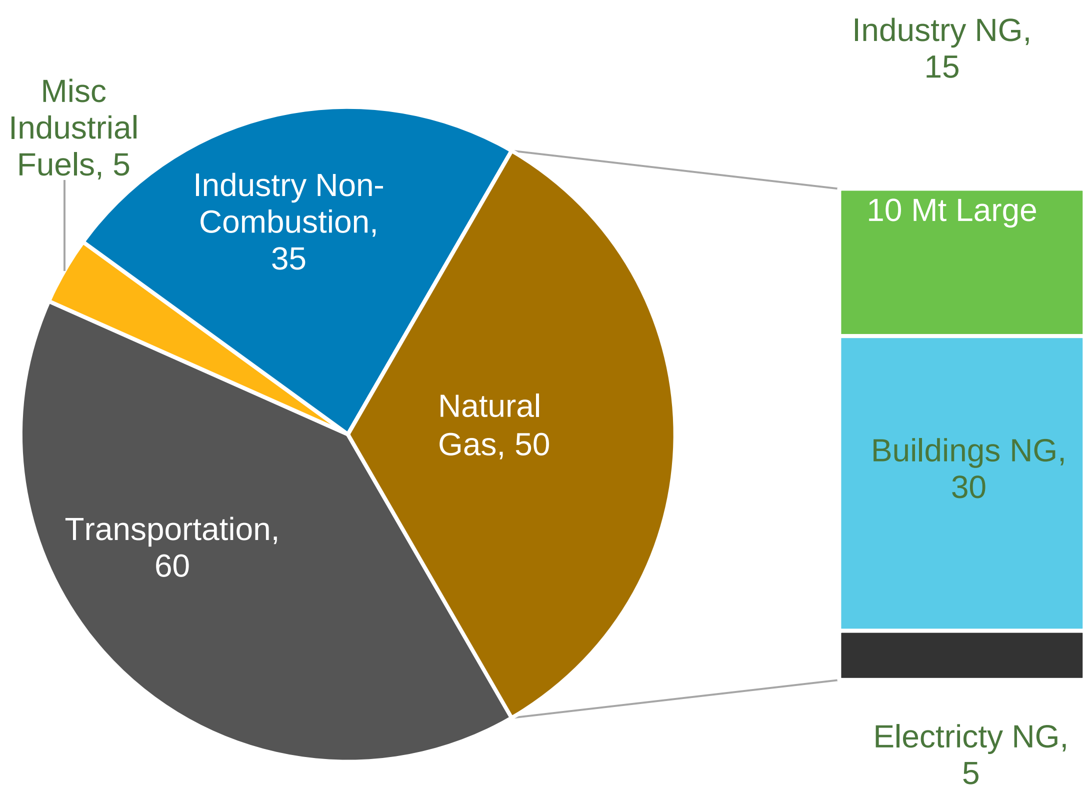
Ontario has defined 2020 and 2030 targets and a path to material de-carbonization by 2050



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 ($MtCO_2e$)

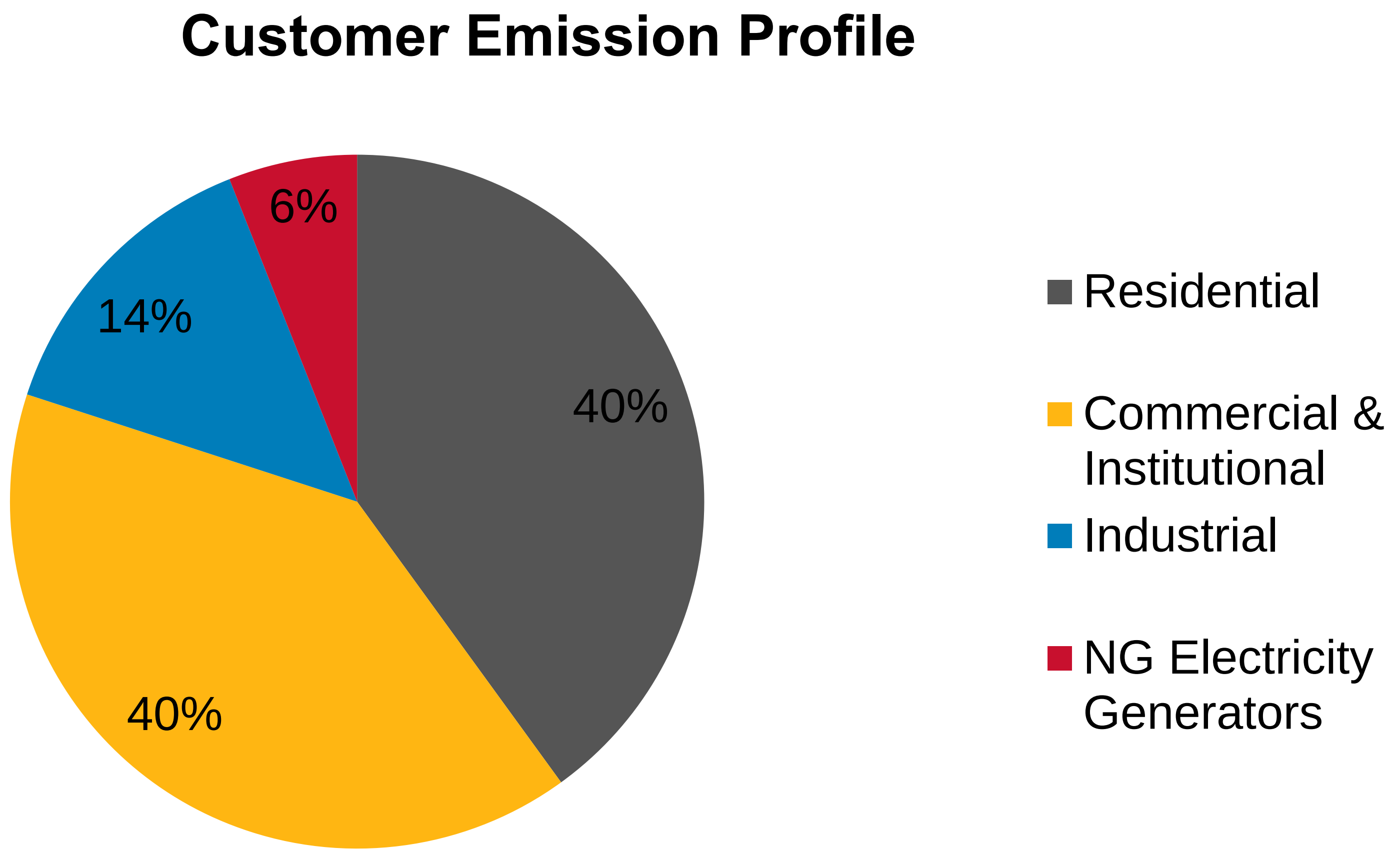
Ontario's 2017 GHG emissions profile for "Cap" covered sectors;

- 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

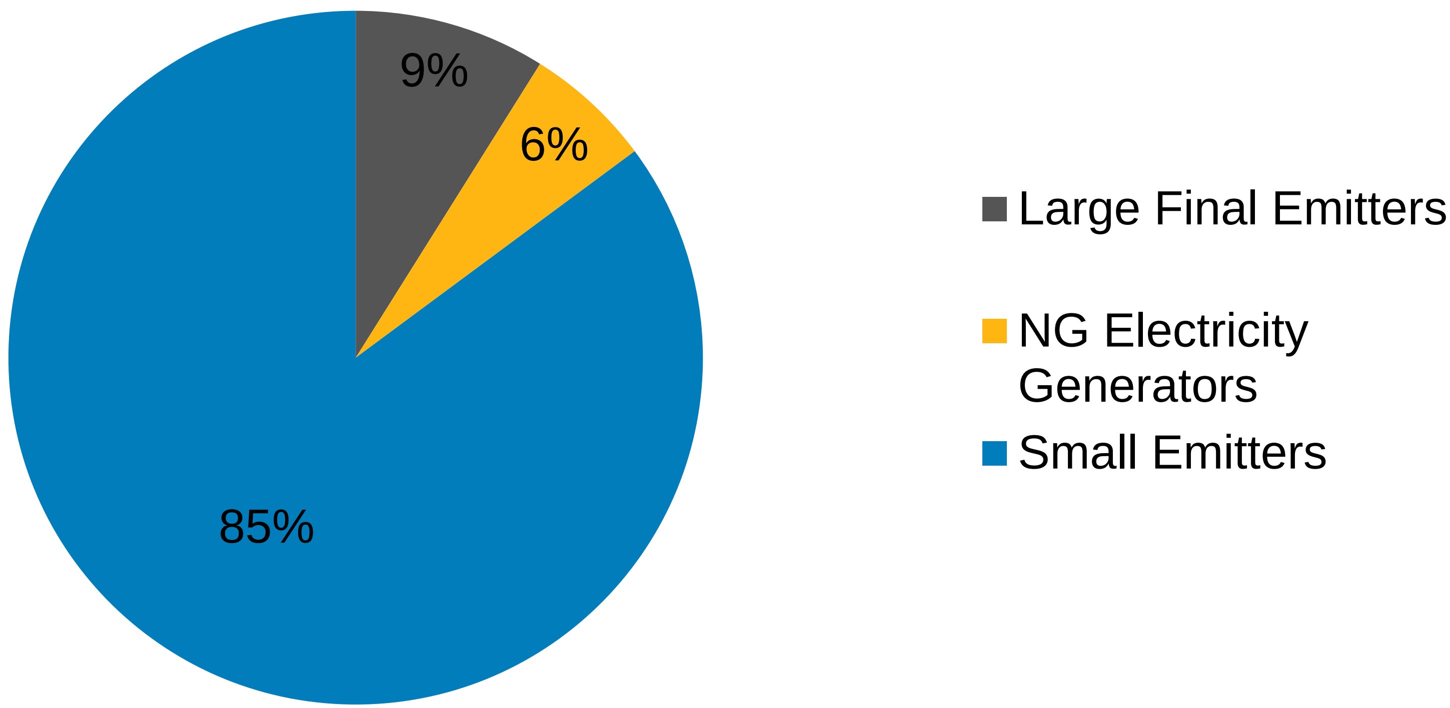


Ontario Energy Board Generic Community Expansion, Filed: 2016-04-22, EB-2016-0004, Exhibit S3.EGDI.ED.6, Attachment, Page 11 of 30

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

Large Final Emitters versus Non-LFEs



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

ENBRIDGE

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)

ENBRIDGE

Initial Thoughts From ICF

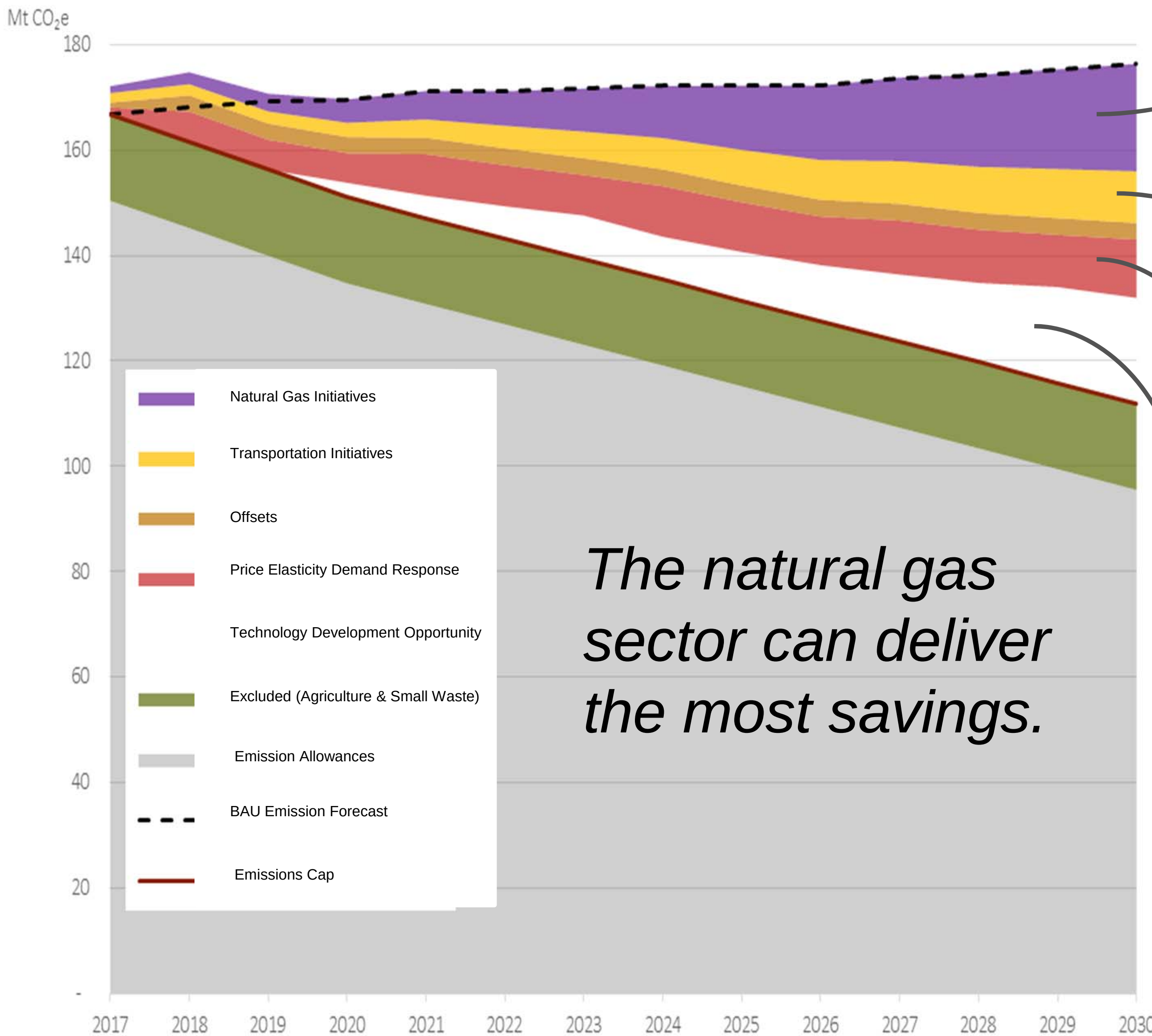
Potential Implications for Enbridge and Customers

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

ENBRIDGE

Natural Gas is Part of the Solution

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



Natural Gas Initiatives offer 20 Mt CO2e

Electrify light-duty cars and biofuels offer 10 Mt CO2e

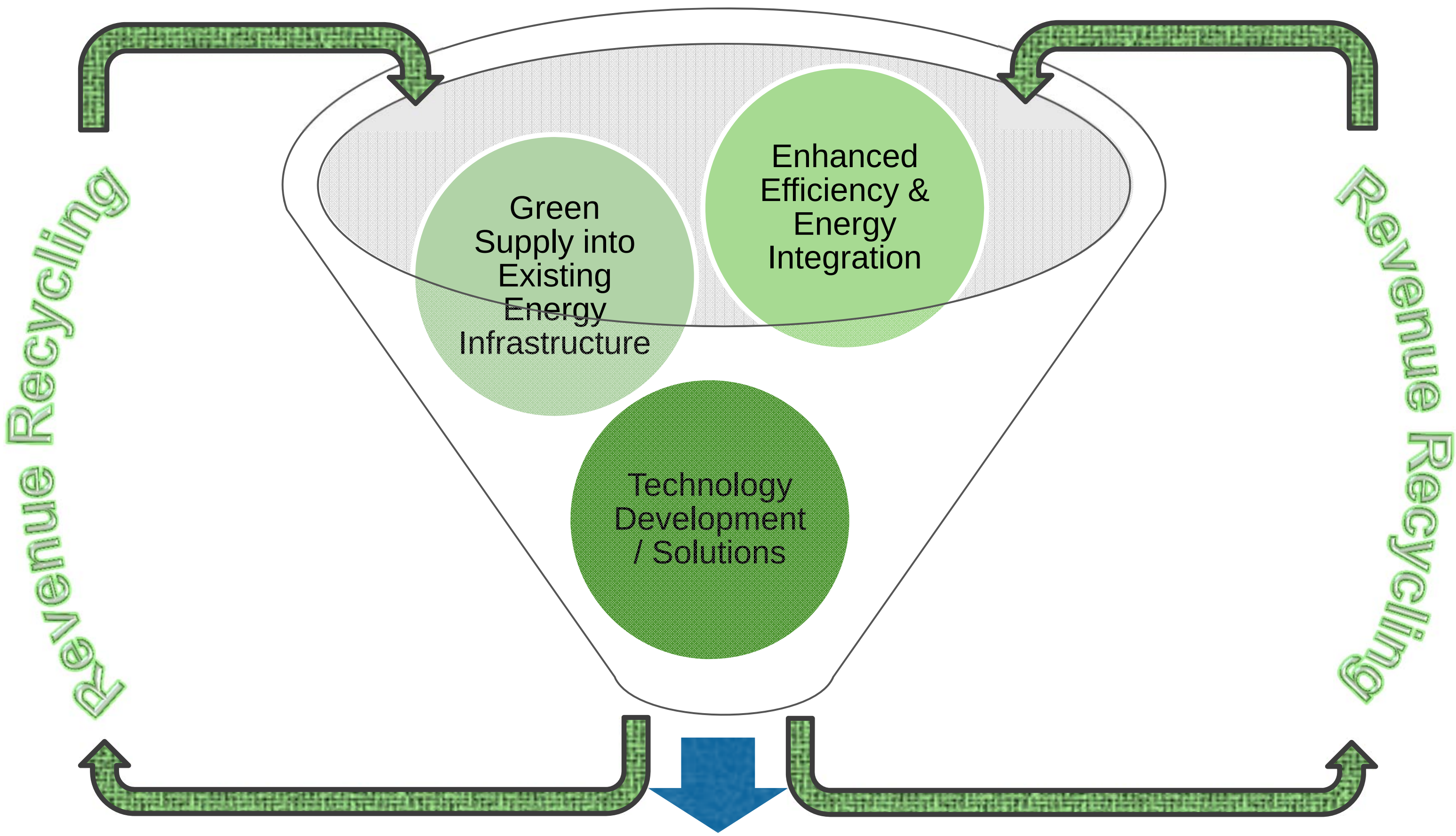
Price-related demand reductions 11 Mt CO2e

Technology Innovation can address 20 Mt CO2e

The natural gas sector can deliver the most savings.

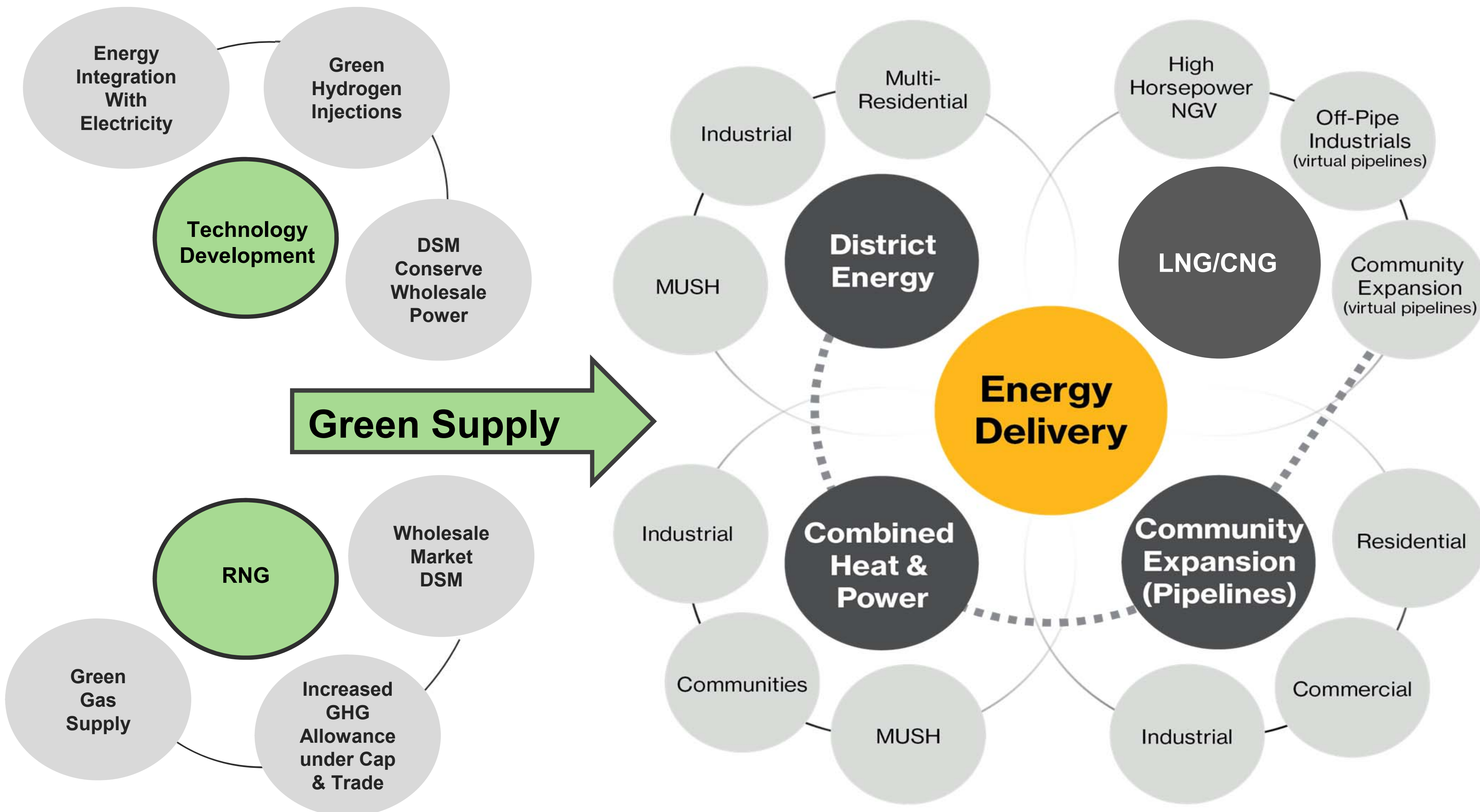
Source: ICF

Transforming the Natural Gas Energy Landscape



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

Transforming the Landscape



Energy Efficiency and Conservation (Demand Side Management)

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

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

Ontario Energy Board Generic Community Expansion
Filed: 2016-04-22
EB-2016-0004
Exhibit S3.EGDI.OGA.3
Attachment
Page 2 of 19

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.

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.

Ontario Energy Board Generic Community Expansion
Filed: 2016-04-22
EB-2016-0004
Exhibit S3.EGDI.OGA.3
Attachment
Page 5 of 19

Combined Heat and Power

- 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

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.

Ontario Energy Board Generic Community Expansion
Filed: 2016-04-22
EB-2016-0004
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

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

Ontario Energy Board Generic Community Expansion
Filed: 2016-04-22
EB-2016-0004
Exhibit S3.EGDI.OGA.3
Attachment
Page 9 of 19

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

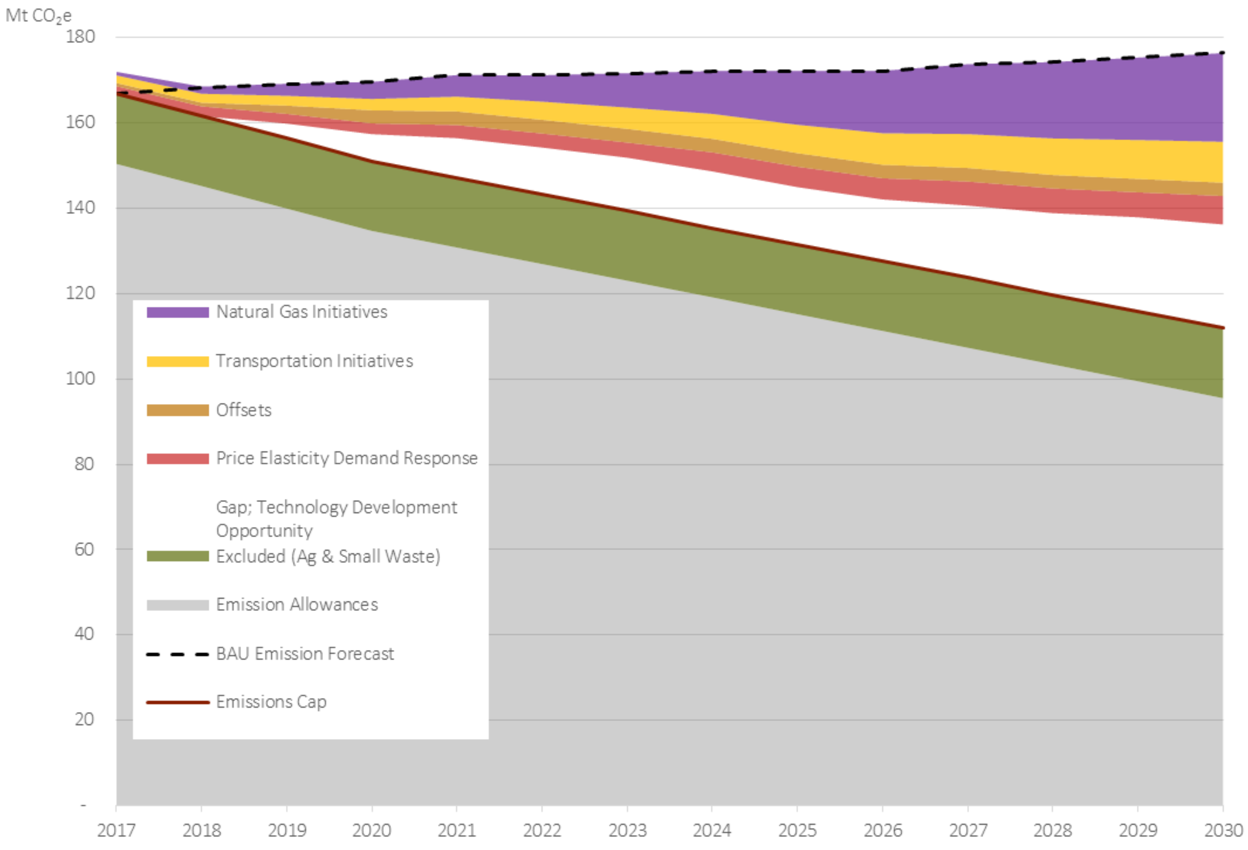
Ontario Energy Board Generic Community Expansion
Filed: 2016-04-22
EB-2016-0004
Exhibit S3.EGDI.OGA.3
Attachment
Page 10 of 19

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 Energy Board Generic Community Expansion
Filed: 2016-04-22
EB-2016-0004
Exhibit S3.EGDI.OGA.3
Attachment
Page 11 of 19

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



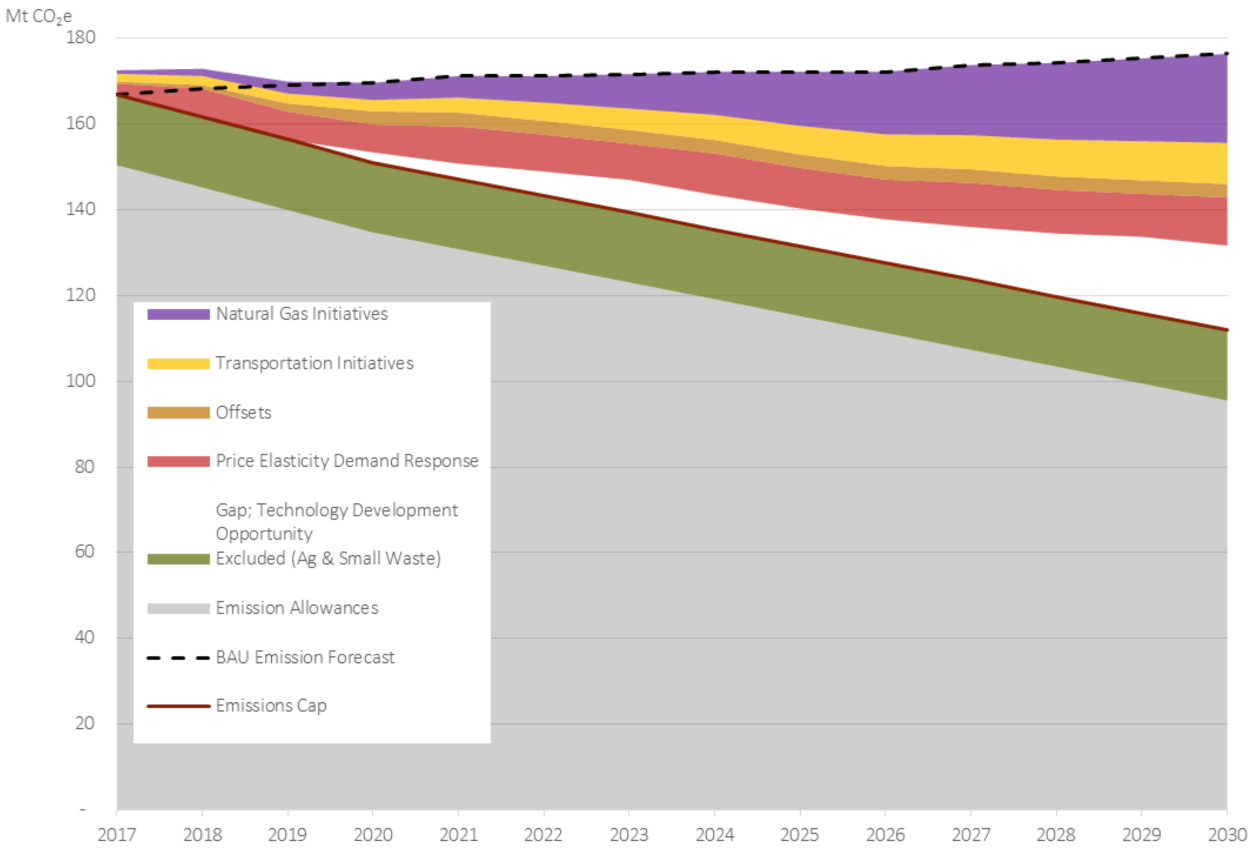
C&T scenario with free allocation informed by UG/EGD activity data and assumptions.

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**

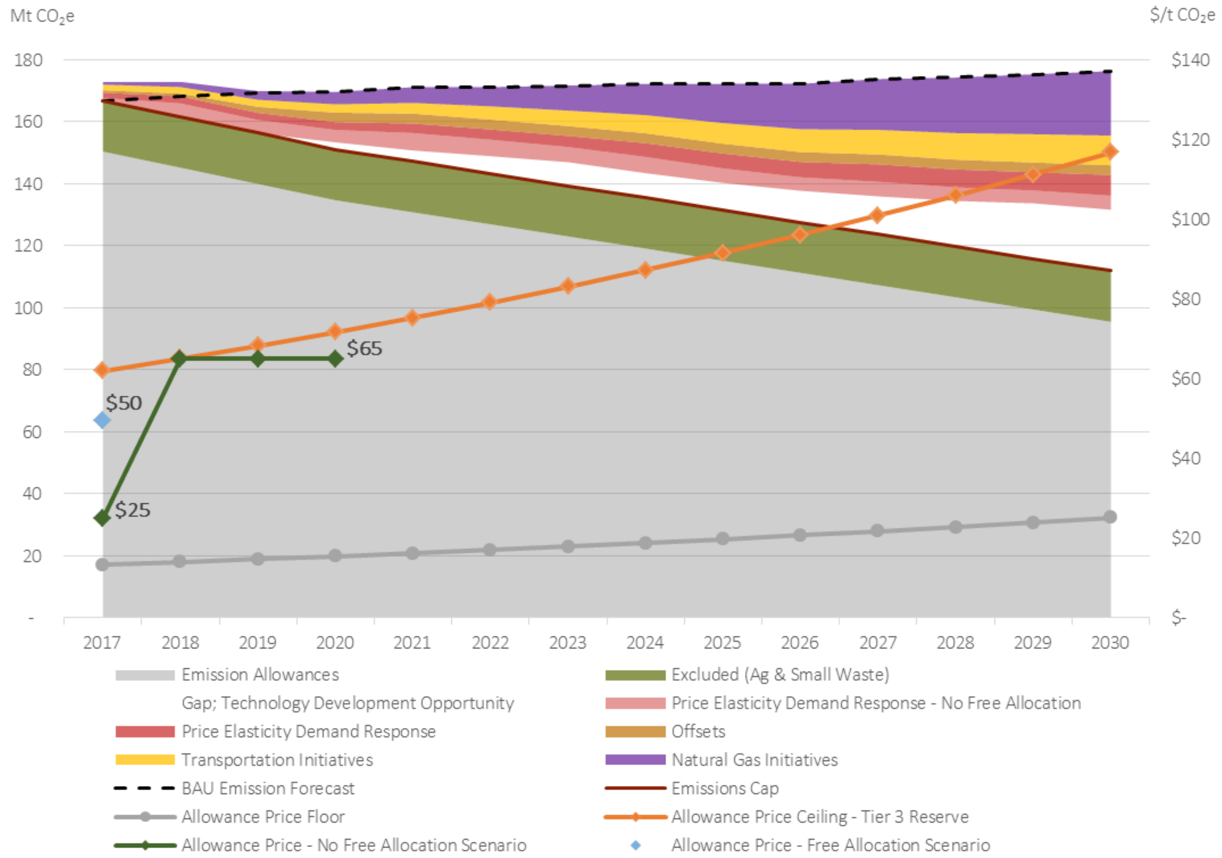
Cumulative allowance shortage of **100 Mt CO_2e** from 2017-2030.

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.

Model Output Allowance Price *NOT an allowance price forecast

2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
CP1	CP2			CP3			CP4			CP5			CP6



Model Assumptions:

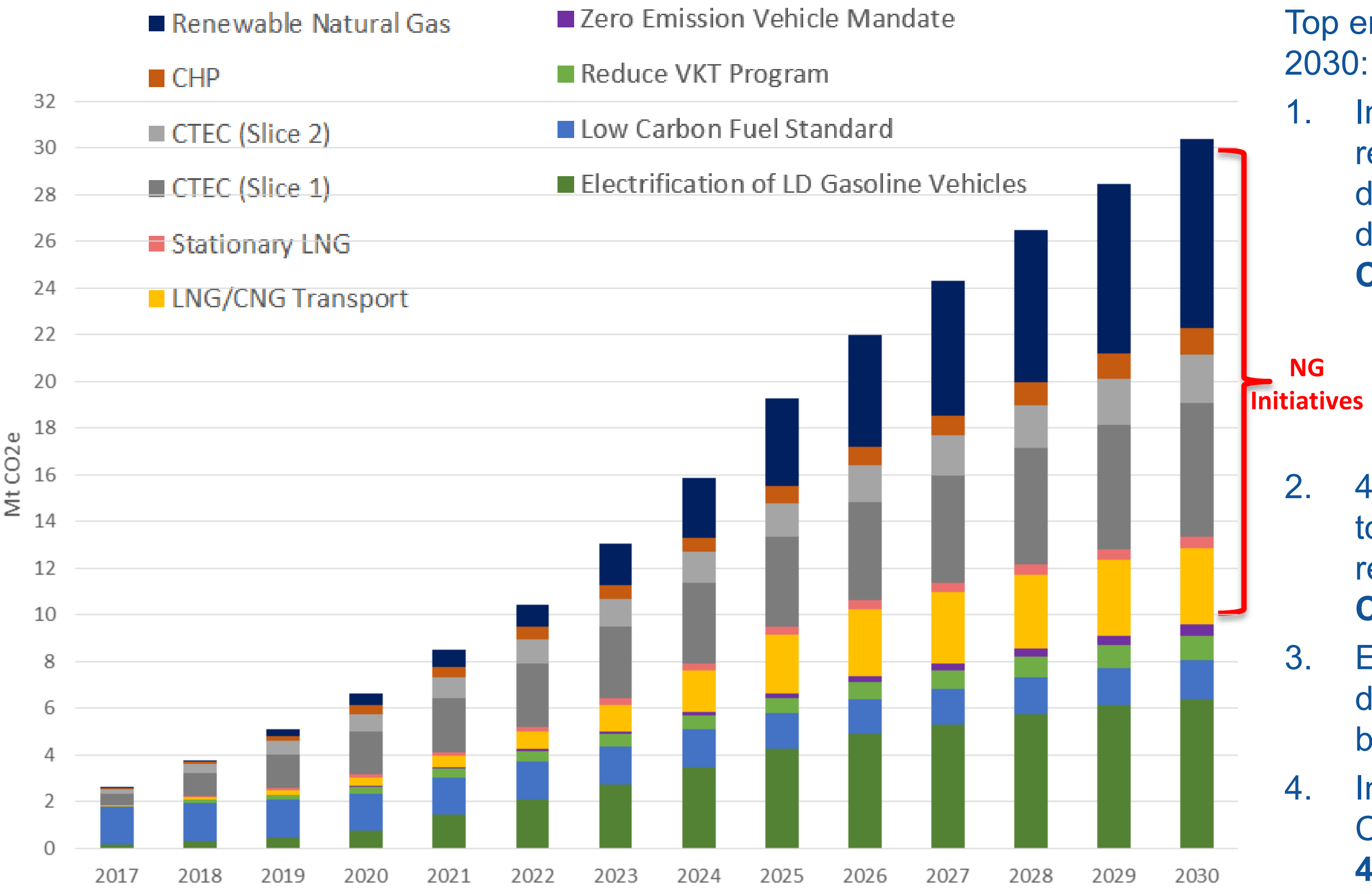
- Ontario in a vacuum
  - No link to QC/CA allowance markets
- Price is solved per WCI compliance period (CP)
- Price is constrained between the WCI floor and ceiling
  - Assume the top tier reserve price is a hard ceiling price for modelling purposes
- If price exceeds ceiling, model stops solving

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

Ontario Energy Board Generic Community Expansion
Filed: 2016-04-22
EB-2016-0004
Exhibit S3.EGDI.OGA.3
Attachment
Page 15 of 19

Summary of Aligned Initiatives Results

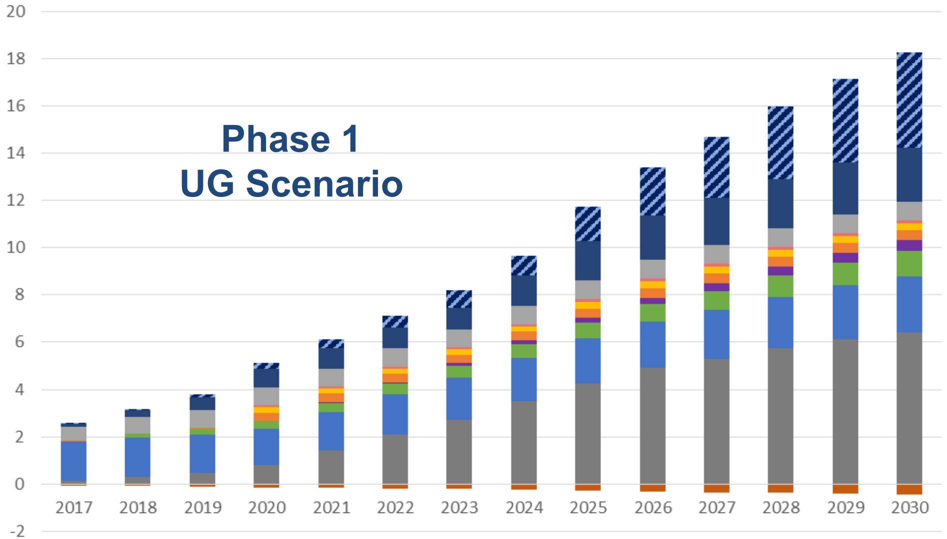


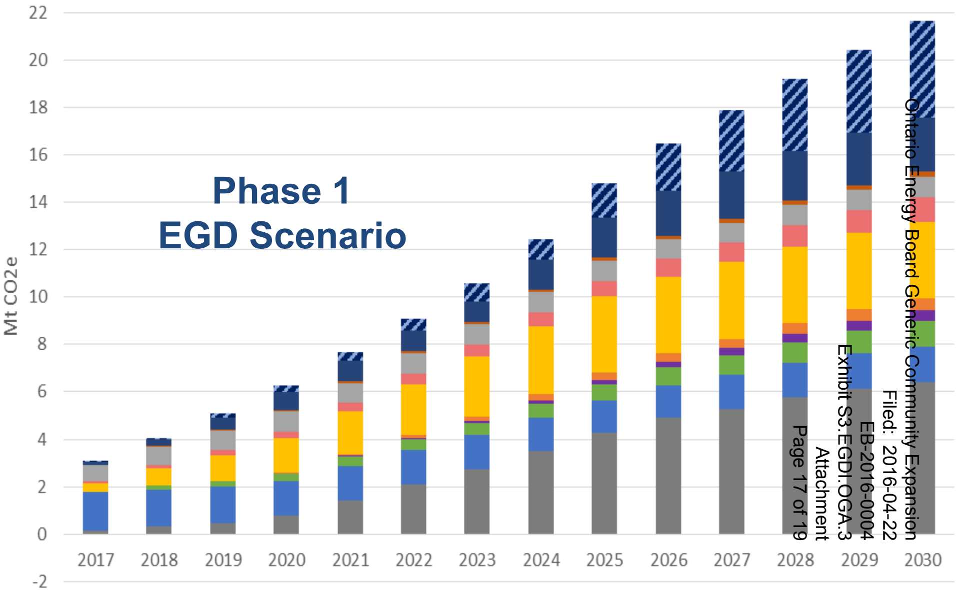
Top emission reduction initiatives in 2030:

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

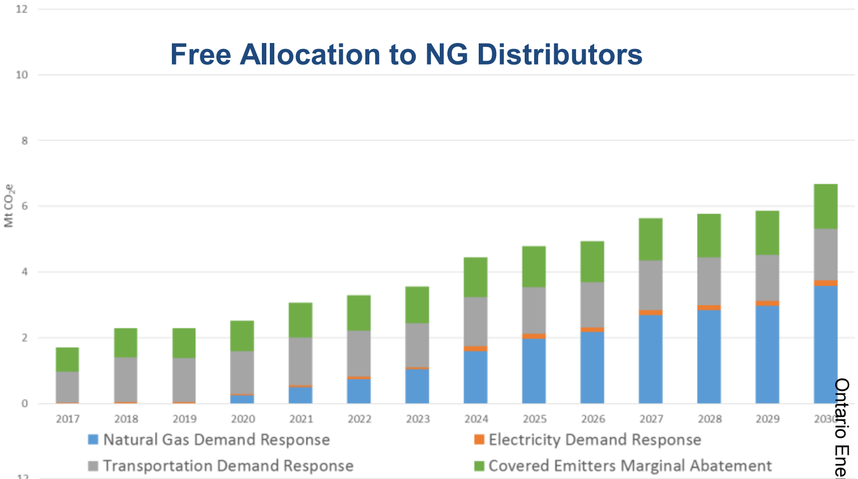
Provincial Totals Year 2030	Phase 1 UG Scenario	Phase 1 EGD Scenario	Phase 2 UG/EGD Aligned Scenario
	Mt (CO_2e)		
RNG	6	6	8
CTEC	1	1	8
LNG/CNG	1	5	4
CHP	-0.5	0.2	1

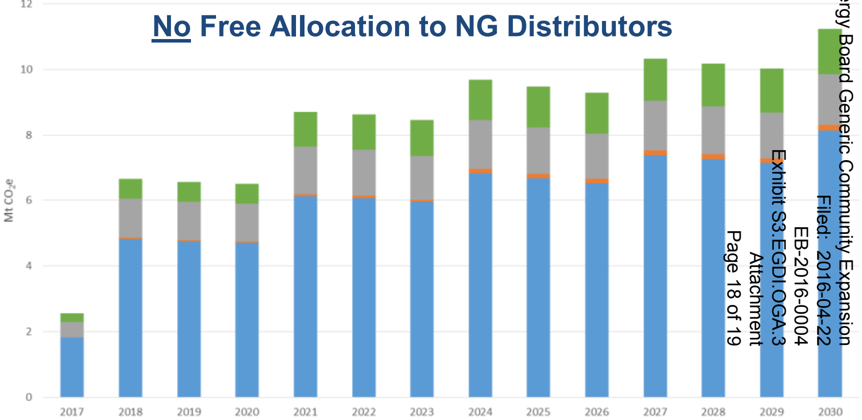




End users respond to high price of allowance / energy by reducing usage

- 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.

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

UNION GAS LIMITED

Answer to Interrogatory from
Environmental Defence

Reference: Exhibit A, Tab 1, pp. 5-22

Does Union 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:

Union does not agree that existing gas consumers should only be required to subsidize expansions if all of the three criteria above are met. Although Union agrees that the impact of GHG emissions is one of the factors that should be considered in the evaluation of a project, emissions are not the only factor that should be considered. The overall public benefits of proceeding should be the most significant factor.

With respect to conditions (a) and (b) above, considering emission impacts only would not take into account consumer choice. Union has made its proposals as a means of addressing requests from consumers and from municipalities, and their needs should not be ignored in weighing the costs and the benefits of an expansion project. The most urgent need expressed by these parties is the cost savings that would result from converting from other fuels to natural gas. Examples of this are provided at Exhibit S15.Union.Staff.8. Energy efficiency efforts will not result in comparable savings for these consumers, and renewable energy investments are more costly than converting.

With respect to condition (c), Union agrees that subsidies from existing customers should not be utilized if there is not a clear public benefit. The degree of required subsidization from existing customers should be also considered in weighing the costs and benefits of proceeding with a project. As stated at Exhibit S15.Union.BOMA.52 and Exhibit S15.Union.IGUA.6, Union's proposals result in an estimated bill impact of $2.91 per year (an average of $0.24 per month) for a typical existing residential customer with annual consumption of 2,200 m^3. This is a manageable level of subsidization in view of the benefits that would result.

UNION GAS LIMITED

Answer to Interrogatory from
Environmental Defence

Reference: Exhibit A, Tab 1, pp. 5-22 & EB-2015-0179, Exhibit A, Tab 1, p. 37

a) Has Union 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 Union 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-b) Union has not made these comparisons. Such comparisons would be onerous and not relevant to a generic proceeding. Union’s proposal is in response to the Governments desire to support the expansion of natural gas to additional communities and in response to customer requests.

Ministry of Energy

Office of the Minister

4th Floor, Hearst Block
900 Bay Street
Toronto ON M7A 2E1
Tel.: 416-327-6758
Fax: 416-327-6754

Ministère de l'Énergie

Bureau du ministre

4e étage, édifice Hearst
900, rue Bay
Toronto ON M7A 2E1
Tél. : 416 327-6758
Téléc. : 416 327-6754

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

Ontario
Executive Council
Conseil exécutif

Order in Council
Décret

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.

Economic and Emissions Benefits of Expanding Natural Gas Distribution Pipelines to Canadian Consumers

November 2015

Submitted by:
ICF International
300-222 Somerset Street West
Ottawa, Ontario K2P 2G3

Canadian Gas Association
Association canadienne du gaz

Submitted to:
Canadian Gas Association

ICF Contact
Harry Vidas
703-218-2745

Other ICF Contributors
Peter Narbaitz
Bansari Saha
Katie Segal

CO2 Emission Price Sensitivity

It is important to understand how the customer impacts calculated in this study would be affected by existing or future CO2 emission prices. The NEB fuel price forecasts used in this study do not include any CO2 emission prices,[24] and results before this section have not accounted for any CO2 emission prices. To establish the sensitivity of results to GHG prices, emission factors were used to calculate the net changes to GHG emissions from the natural gas conversions, and two CO2 emission price scenarios were considered.

- The low CO2 emission price scenario is reflective of existing or anticipated CO2 emission prices in various provinces.
- The high price scenario highlights potential impacts from CO2 emission prices significantly higher than what is currently planned.

Along with the net changes to annual (2025) GHG emissions, presented below in Exhibit 21 and Exhibit 22, subsequent exhibits in this section highlight the impact of CO2 emission prices on the new natural gas customers considered in this study.

Overall, the conversions considered in this study would result in a decrease in annual GHG emissions equivalent to over 75,000 tonnes of CO2 per year. This information shows that CO2 emission price impacts are strongly dependent on the fuel-mix being displaced by natural gas.

The business case for replacing heating oil, propane, and heavy oil with natural gas is improved by CO2 emission prices, as these fuels are more carbon-intensive than natural gas. However, the merit for converting electric and biomass heating is reduced by the increased costs of CO2 emission prices.

Exhibit 21 Net Annual GHG Emission Reductions, by Province

Province	Net Annual GHG Emission Reductions by Province (tCO2e), 2025			
	Residential	Commercial / Institutional	Industrial	Total
Ontario	24,703	10,267	4,857	**39,827**
BC	7,257	905	591	**8,753**
Quebec	3,179	5,379	9,251	**17,809**
Manitoba	5,464	4,958	259	**10,680**
Canada	**40,602**	**21,509**	**14,958**	**77,069**

[24] The NEB Energy Futures study accounts for CO2 emission prices at large industrial sites in Quebec when estimating impacts on consumption growth in the province, but no CO2 emission prices are included in the fuel price forecasts referenced here.

Exhibit 22 Net Annual GHG Emission Reductions, by Fuel Type

Previous Heating Fuel	Net Annual GHG Emission Reductions by Previous Fuel Type (tCO2e), 2025			
	Residential	Commercial / Institutional	Industrial	Total
Heating Oil	48,451	31,922	14,449	**94,822**
Propane	16,153	15,431	12,714	**44,297**
Electricity	(23,671)	(24,451)	(9,708)	**(57,830)**
Biomass	(331)	(1,393)	(2,685)	**(4,408)**
Heavy Oil	-	-	188	**188**
Total	**40,602**	**21,509**	**14,958**	**77,069**

The low CO2 emission price scenario considers a price frozen at $15 per tonne of CO2 equivalent emissions throughout the entire study period (2016-2040), for Quebec, Ontario, and Manitoba.[25] For British Columbia, this scenario initially considers $30 / tCO2e, and rises to $40 / tCO2e in 2020. The high price scenario considers a price of $100 / tCO2e for all provinces, through-out the entire study period.

Exhibit 23 and Exhibit 24 demonstrate how the inclusion of low and high CO2 emission prices would impact the average annual fuel cost savings of new natural gas customers, respectively. Along with the cost savings under each scenario, the percent increase to the net cost savings from the inclusion of CO2 emission prices is included. These exhibits show that, on average, residential customer net fuel cost savings would increase by 1.3% and 6.5% under the low and high CO2 emission price scenarios, respectively, compared to not accounting for any GHG price. It is important to keep in mind that CO2 emission prices will cause natural gas fuel costs to rise substantially, in absolute terms, and customers will be paying larger heating bills under these scenarios. However, the increased net fuel cost savings under these scenarios highlights that average customer costs would have increased even more if they were still using their previous fuels. The equivalent annual cost savings without consideration of a CO2 emission price were presented earlier, in Exhibit 13.

Exhibit 23 Low CO2 Emission Price - Average Annual Fuel Cost Savings, by Province (2016-2040)

Province	Average Annual Fuel Cost Savings, per Customer ($2015)					
	Residential		Commercial/Institutional		Industrial	
	Net Cost Savings ($)	CO2 Change (%) [26]	Net Cost Savings ($)	CO2 Change (%) [26]	Net Cost Savings ($)	CO2 Change (%) [26]
Ontario	1,790	1.0%	22,194	0.4%	178,501	0.8%
BC	1,555	1.9%	11,348	0.8%	114,837	11.4%
Quebec	991	1.5%	61,060	1.3%	529,997	1.7%
Manitoba	1,572	1.4%	8,510	1.2%	152,758	1.3%
Canada	**1,640**	**1.3%**	**18,871**	**0.6%**	**253,112**	**1.4%**

[25] The study authors are not aware of plans for a CO2 emission price in Manitoba, but the province is included here to highlight potential impacts.
[26] Percent change from case with no CO2 emission price.

Exhibit 24 High CO2 Emission Price - Average Annual Fuel Cost Savings, by Province (2016-2040)

Province	Average Annual Fuel Cost Savings, per Customer ($2015)					
	Residential		Commercial/Institutional		Industrial	
	Net Cost Savings ($)	CO2 Change (%) [27]	Net Cost Savings ($)	CO2 Change (%) [27]	Net Cost Savings ($)	CO2 Change (%) [27]
Ontario	1,886	6.4%	22,640	2.4%	186,600	5.4%
BC	1,602	5.0%	11,489	2.0%	133,180	29.2%
Quebec	1,074	10.1%	65,507	8.7%	581,090	11.5%
Manitoba	1,698	9.6%	9,065	7.8%	164,060	8.8%
Canada	**1,725**	**6.5%**	**19,431**	**3.6%**	**271,005**	**8.5%**

As with the overall changes to GHG emission levels, the exhibits above show significant differences between provinces, driven by the differences in the fuel-mixes expected to be converted to natural gas.

To better understand the impact of provincial fuel-mixes, Exhibit 25 and Exhibit 26 present the annual fuel cost savings under the two CO2 emission price scenarios, separated by fuel type. While the average increase to residential customer fuel cost savings are the same, at 1.3% and 6.5%, the changes between fuel types are significant. Once again, it is important to keep in mind that CO2 emission prices will cause natural gas fuel costs to rise substantially, in absolute terms, and customers will be paying larger heating bills under these scenarios. However, the changes to net fuel cost savings under these scenarios highlight which previous fuel types would have smaller cost increases from a CO2 emission price. For example, residential customers converting from heating oil to natural gas will see their annual cost savings increase by 14.5% under the high CO2 emission price scenario, while on average customers converting from electric heating will see their savings decreased by 20.1% from the same GHG prices. The equivalent annual cost savings by fuel type, without consideration of a GHG price, were presented earlier, in Exhibit 15.

Exhibit 25 Low CO2 Emission Price - Average Annual Fuel Cost Savings, by Fuel Type (2016-2040)

Previous Fuel Type	Average Annual Fuel Cost Savings, per Customer ($2015)					
	Residential		Commercial/Institutional		Industrial	
	Net Cost Savings ($)	CO2 Change (%) [27]	Net Cost Savings ($)	CO2 Change (%) [27]	Net Cost Savings ($)	CO2 Change (%) [27]
Heating Oil	1,821	3.6%	19,910	2.5%	146,494	6.3%
Propane	1,561	1.1%	12,204	2.0%	349,703	2.2%
Electricity	1,373	-5.5%	24,613	-1.7%	306,079	-2.8%
Biomass	338	-25.6%	15,868	-19.6%	271,416	-15.6%
Heavy Oil	-	-	-	-	21,310	13.4%
Average	**1,640**	**1.3%**	**18,871**	**0.6%**	**253,112**	**1.4%**

[27] Percent change from case with no CO2 emission price.

Exhibit 26 High CO2 Emission Price - Average Annual Fuel Cost Savings, by Fuel Type (2016-2040)

Previous Fuel Type	Average Annual Fuel Cost Savings, per Customer ($2015)					
	Residential		Commercial/Institutional		Industrial	
	Net Cost Savings ($)	CO2 Change (%) [28]	Net Cost Savings ($)	CO2 Change (%) [28]	Net Cost Savings ($)	CO2 Change (%) [28]
Heating Oil	2,013	14.5%	22,106	13.8%	192,859	39.9%
Propane	1,658	7.4%	13,420	12.1%	391,798	14.5%
Electricity	1,160	-20.1%	22,749	-9.2%	256,476	-18.5%
Biomass	158	-65.3%	(6,053)	-130.7%	(13,823)	-104.3%
Heavy Oil	-	-	-	-	26,389	40.4%
Average	**1,725**	**6.5%**	**19,431**	**3.6%**	**271,005**	**8.5%**

It is notable from the exhibits above that in the low CO2 emission price scenario, even though cost savings are reduced for customers converting from some fuel types, all customers can still achieve cost savings through natural gas conversions. Only in the high CO2 emission price scenario do some conversions no longer achieve cost savings for customers, more specifically biomass conversions.

Exhibit 27 and Exhibit 28 present the NPV of the fuel conversions from the customer's perspective, for the low and high CO2 emission price scenarios, respectively. Overall, CO2 emission prices do not cause large changes to the Canada-wide customer NPV, from the $1.44 billion calculated without a GHG price. For example, the overall customer NPV in the high price scenario is 7.1% higher. Again, CO2 emission prices will cause natural gas fuel costs to rise substantially; however, the increased NPV highlights that the average customer would see a smaller cost increase than if they were still reliant on their previous fuels. The equivalent NPVs without consideration of a GHG price were presented earlier, in Exhibit 16. It is important to keep in mind that since this present value is taken from the customer perspective, it does not directly include the distributor's full costs for pipeline expansion infrastructure; as noted earlier, the present value of this shortfall was estimated to be $486 million.

Exhibit 27 Low CO2 Emission Price - NPV of Fuel Conversion from New Customer Perspective

Province	Net Present Value from New Customer Perspective by Customer Type ($2015)				
	Residential	Commercial / Institutional	Industrial	Total	CO2 Change (%) [28]
Ontario	361,634,294	405,175,381	108,171,510	**874,981,185**	**0.9%**
BC	179,559,865	50,881,874	2,642,222	**233,083,962**	**2.1%**
Quebec	36,889,217	74,251,196	101,794,558	**212,934,971**	**1.6%**
Manitoba	63,949,986	66,823,199	3,507,837	**134,281,022**	**1.5%**
Canada	**642,033,362**	**597,131,650**	**216,116,127**	**1,455,281,139**	**1.3%**

[28] Percent change from case with no CO2 emission price.

Exhibit 28 High CO2 Emission Price - NPV of Fuel Conversion from New Customer Perspective

Province	Net Present Value from New Customer Perspective by Customer Type ($2015)				
	Residential	Commercial / Institutional	Industrial	Total	CO2 Change (%) [29]
Ontario	390,027,828	416,025,691	113,405,042	**919,458,560**	**6.0%**
BC	186,377,989	51,685,389	3,081,911	**241,145,289**	**5.6%**
Quebec	40,734,584	79,961,971	111,776,981	**232,473,537**	**11.0%**
Manitoba	69,992,786	71,820,549	3,780,141	**145,593,477**	**10.1%**
Canada	**687,133,187**	**619,493,601**	**232,044,075**	**1,538,670,863**	**7.1%**

[29] Percent change from case with no CO2 emission price.

E.B.O. 188

IN THE MATTER OF the Ontario Energy Board Act, R.S.O. 1990, c. O.13;

AND IN THE MATTER OF a hearing to inquire into, hear and determine certain matters relating to natural gas system expansion for The Consumers' Gas Company Ltd., Union Gas Limited and Centra Gas Ontario Inc.

BEFORE: G.A. Dominy
Presiding Member

R.M.R. Higgin
Member

J.B. Simon
Member

FINAL REPORT OF THE BOARD

January 30, 1998

economic inefficiency of proceeding with financially unfeasible projects outweighs the public interest in using the portfolio approach.

2.2 POSITIONS OF THE PARTIES

2.2.1 The ADR Agreement proposed that each utility group all proposed new distribution customers and new facilities to serve them, for a particular test year into one portfolio (the "Investment Portfolio"). The Investment Portfolio would be designed to achieve a NPV of zero or greater (including normalized reinforcement costs).

2.2.2 The ADR Agreement proposed that each utility also maintain a rolling 12 month distribution expansion portfolio (the "Rolling Project Portfolio"). The cumulative result of project-specific discounted cash flow ("DCF") analyses from the past 12 months would be calculated monthly. The costs and revenues associated with serving customers on existing mains would not be included. The Rolling Project Portfolio would be used as a management tool by the utilities to decide on appropriate distribution capital expenditures.

2.2.3 The Dissent Document listed three concerns with the Investment Portfolio proposed in the ADR Agreement:

i. service lines off existing mains are included;
ii. security of supply projects are not included; and
iii. reinforcement costs have been normalized rather than using forecast actual costs.

2.3 BOARD'S COMMENTS AND FINDINGS

Investment Portfolio

2.3.1 The Board accepts the ADR Agreement proposal that each utility would group into one portfolio, the Investment Portfolio, all proposed new distribution customer attachments and facilities for a particular test year. The Investment Portfolio would be designed to achieve a positive NPV (greater than zero) in the test year (including normalized reinforcement costs).

2.3.2 The Board considers that a primary purpose of the Investment Portfolio analysis is to provide the Board with sufficient evidence to decide whether a utility's test year system expansion plan will result in undue rate impacts.

2.3.3 The Board understands that the ADR Agreement's proposed Investment Portfolio contains the capital costs of facilities for all new customers added during a test year. The analysis of system expansion financial feasibility includes revenues and operation and maintenance ("O&M") costs associated with these new customers over horizons as proposed up to 40 years. The utilities propose to include an allowance for reinforcement costs to supply the new projects on a normalized basis.

2.3.4 Since the Investment Portfolio analysis is intended to predict the financial and rate impacts of test year incremental system expansion capital expenditures and associated revenues and expenses, it is inappropriate to include historic capital expenditures or revenues from attachments in prior periods.

2.3.5 The Board accepts the difficulty in isolating test year customers attaching to new mains only (versus those attaching to mains built in prior years). However, as specified in the Guidelines attached as Appendix B, an estimate of the NPV without attachments to prior expansions will be required. This will enable the Board to better monitor the overall economic feasibility of such projects.

2.3.6 The Board's interpretation of the Investment Portfolio analysis and its associated rate impacts was assisted by reference to Consumers Gas' interrogatory response [Exhibit I, Tab 7, Schedule 8] in the E.B.R.O. 495 Consumers Gas 1998 rates case. The Board directs the utilities to file future impact analyses in a similar form (see paragraph 6.3.4).

2.3.7 The Board sought further explanation for the proposed treatment of reinforcement costs in the Investment Portfolio in its letter of July 4, 1997 to the utilities. The utilities responded that "normalized" reinforcement costs were categorized into "special" reinforcement and "normal" reinforcement. The costs of the former are those associated with specific major reinforcements of the system and are amortized over a period of 10-20 years. The normal reinforcement costs are the residual of the total identified reinforcement costs after the special reinforcement costs are deducted. The historical average for the special and normal reinforcement costs will then be used as the normalized amount to be included in the portfolio analysis as a percentage of the total capital expenditure in the year.

2.3.8 The Board finds the proposed treatment of reinforcement costs to be included in the Investment Portfolio as proposed in the ADR Agreement appropriate for overall portfolio analysis purposes. Union currently includes an allowance related to the carrying costs for advancement of reinforcement expenditures resulting from a new project and the Board finds this approach to be appropriate.

2.3.9 The Board does not agree that a design target of zero NPV and a P.I. of 1.0 is appropriate given the forecast risks inherent in the Investment Portfolio analysis. As the Investment Portfolio NPV approaches zero the marginal projects will be those with long cash flow break-even periods. Such projects require subsidy for long periods and hence increase short term rate impacts disproportionately.

2.3.10 In addition, the Board notes that the Investment Portfolio includes the costs and revenues associated with attaching customers to existing mains (i.e. mains constructed prior to any given test year). These projects by their nature will be more profitable for the utilities, since the costs of the mains are not included in the Investment Portfolio calculation. The Board concludes that the Investment Portfolio should be designed to achieve a positive NPV including a safety margin (for example, corresponding to a P.I. of 1.10). The Board believes that a portfolio designed in this way will minimize the forecast risks and hence more likely achieve the desired results of no undue rate impacts.

Rolling Project Portfolio

2.3.11 The Board also accepts the ADR Agreement proposal to maintain a Rolling Project Portfolio. The Rolling Project Portfolio provides an ongoing method of determining the financial feasibility and rate impact of expansion projects over a previous 12 month period. The Rolling Project Portfolio excludes the costs and revenues associated with new customers attaching to mains built prior to the last 12 month period. The Rolling Project Portfolio also provides a basis to compare a utility's Investment Portfolio with actual system expansion. Union has used a Rolling Project Portfolio approach for some time and has filed rate impacts from significant individual projects in its rates cases (e.g. E.B.R.O. 493/494 Exhibit B1, Tab 4, Appendices C and D).

2.3.12 As noted above the Board finds the proposed treatment for reinforcement costs to be included in the Rolling Project Portfolio to be appropriate.

2.3.13 The Board finds the Rolling Project Portfolio as proposed by the utilities to be a useful management tool. This Portfolio provides a mechanism for facilitating review of the financial status of overall distribution system expansion at the time that individual major projects are before the Board for either franchise and certificate approval, or for approval of leave to construct and also for monitoring purposes.

2.3.14 The Board has previously expressed its position that inclusion in the Investment Portfolio, of revenues and costs for infill customers connecting to existing mains may provide a mismatch between periodic costs and revenue. The Board notes that the Rolling Project Portfolio, which is the utilities' primary management tool, does not include such infill customers. Therefore, the Board finds that the Rolling Project Portfolio does provide appropriate matching and that an NPV of zero (or greater) is appropriate.

Was Appendix, preliminary page 2 247

APPENDIXB ONTARIO ENERGY BOARD GUIDELINES FOR ASSESSING AND REPORTING ON NATURAL GAS SYSTEM EXPANSION IN ONTARIO

1998 248

Was Appendix, preliminary page 3 249

CONTENTS

Was Appendix, page 1 258

I. OVERVIEW - PURPOSE AND OBJECTIVE OF THE GUIDELINES

The Ontario Energy Board ("OEB", "Board") Guidelines for Assessing and Reporting on Natural Gas System Expansion In Ontario ("The Guidelines") provide a common analysis and reporting framework to be applied by regulated Ontario Local Distribution Companies - Union Gas Limited and The Consumers' Gas Company Ltd. ("the utilities") to natural gas distribution system expansion. The principles upon which the Guidelines are based reflect the Board's conclusions in its Distribution System Expansion Reports under Board File No. E.B.O. 188. (Interim Report[12JM1-0:1] dated August 15, 1996; Final Report[1] dated January 30, 1998). 259

Portfolio Approach 260

The main change from prior policy and practice is the use of a portfolio approach, as opposed to a 261 project-by-project approach, to the planning, analysis, management and reporting of distribution system expansion projects. The intent of the portfolio approach is to provide the utilities a greater degree of flexibility in determining which projects to undertake, while the Board retains overall regulatory control to ensure no undue cross subsidy or rate impacts result from distribution system expansion.

Financial Feasibility Analyses 262

The Guidelines provide the utilities with direction with respect to the structure of their system 263 expansion portfolios and the methods for conducting financial feasibility analyses at both the individual project level and the portfolio level. The Guidelines standardize the elements to be used in the discounted cash flow ("DCF") analysis as well as establish the parameters for the costs and revenues that are the inputs to that analysis.

Reporting 264

The Guidelines establish a mechanism to evaluate the performance of each of the utilities' distri- 265 bution expansion activities on a portfolio basis and on an individual project basis. The Guidelines also outline reporting requirements for system expansion plans and post expansion impacts. The forecast rate impacts of a utility's expansion plans will be presented in rates case filings on a prospective test year basis.

These reporting requirements are intended to provide the Board and interested parties with suffi- 266 cient information to monitor the utilities' expansion activities and their associated rate impacts. The performance of the utilities related to implementation of these Guidelines will be evaluated as part of each utility's rates case.

Customer Connection Policies Was Appendix, page 2 267

Part of the utilities' management of distribution system expansion will be the provision of common 268 customer connection policies. These will include policies relating to service line fees, customer contributions to otherwise financially unfeasible projects and for projects dominated by one or more large volume customers.

Environmental Considerations 269

To ensure that the utilities plan and construct system expansion facilities in an environmentally 270 acceptable manner, the Guidelines also address the routing and environmental planning, documentation and reporting requirements for distribution expansion projects.

Was Appendix, page 3

1. SYSTEM EXPANSION PORTFOLIOS 271

1.1 Investment Portfolio 272

Each of the utilities will group into a portfolio (the "Investment Portfolio") the costs and revenues associated with all new distribution customers who are forecast to attach in a particular test year (including new customers attaching to existing mains). The Investment Portfolio is to include a forecast of normalized system reinforcement costs. 273

The Investment Portfolio will be designed to achieve a profitability index ("PI") *greater* than 1.0. 274

1.2 Rolling Project Portfolio 275

Each of the utilities will maintain a rolling 12 month distribution expansion portfolio (the "Rolling Project Portfolio") updated monthly, as an ongoing management tool for estimation of the future impacts of capital expenditures associated with distribution system expansion. The Rolling Project Portfolio will exclude those customers requiring only a service lateral from an existing main. 276

The utilities will calculate monthly the cumulative result of project-specific DCF analyses from the past twelve months for the Rolling Project Portfolio. It will include all future customer attachments, revenues and costs on the basis of the life cycle of each of the projects making up the Portfolio. 277

2. STANDARD TEST FOR FINANCIAL FEASIBILITY 278

The standard test for determining the financial feasibility at both the project and the portfolio level will be a DCF analysis, as set out below. 279

2.1 DCF Calculation and Common Elements 280

The DCF calculation for a Portfolio will be based on a set of common elements. For revenue forecasting, the common elements will be as follows: 281

(a) for the Rolling Project Portfolio, total forecasted customer attachments over the Customer Attachment Horizon for each project; 282

(b) for the Investment Portfolio, a forecast of all customers to be added in the Test Year; 283

(c) an estimate of average use per added customer which reflects the mix of customers to be added; 284

(d) a factor which reflects the timing of forecasted customer additions; and 285

Was Appendix, page 4

(e) rates derived from the existing rate schedules for the particular utility, net of the gas commodity component. 286

For capital costs, the common elements will be as follows: 287

(a) an estimate of all costs directly associated with the attachment of the forecast customer additions, including costs of distribution mains, services, customer stations, distribution stations, land and land rights; 288

(b) an estimate of incremental overheads applicable to distribution expansion at the portfolio level; and 289

(c) an estimate of the normalized system reinforcement costs. 290

For expense forecasting, the common elements will be as follows: 291

(a) gas costs as used in revenue forecasts (excluding commodity costs); 292

(b) incremental operating and maintenance costs; 293

(c) income and capital taxes based on tax rates underpinning the existing rate schedules; and 294

(d) municipal property taxes based on projected levels. 295

2.2 Specific Parameters 296

Specific parameters of the common elements include the following: 297

(a) a 10 year customer attachment horizon;. 298

(b) a customer revenue horizon of 40 years from the in service date of the initial mains (20 years for large volume customers); 299

(c) a discount rate equal to the incremental after-tax cost of capital based on the prospective capital mix, debt and preference share cost rates, and the latest approved rate of return on common equity; 300

(d) discounting reflecting the true timing of expenditures. Up-front capital expenditures will be discounted at the beginning of the project year and capital expended throughout the year will be mid-year discounted, as will revenue, gas costs, and operating and maintenance expenditures; and 301

(e) gas costs based on the weighted average cost of gas ("WACOG") excluding commodity costs. 302

Was Appendix, page 5

3. MONITORING PORTFOLIO PERFORMANCE AND SHORT-TERM RATE IMPACTS 303

3.1 Rates Case Filings 304

The following information will be filed in each rates case: 305

Test Year 306

(a) the Investment Portfolio, including NPV, the total capital in the portfolio and the portfolio PI; 307

(b) an estimate of the aggregate NPV of all new facilities requiring a new franchise and/or certificate of public convenience and necessity and of all "infills" (i.e. main extensions and service attachments in existing service areas excluding service lines to customers off existing mains) based on extrapolated historical data; 308

(c) an estimate of the Test Year rate impacts of the Investment Portfolio based on the: 309

(i) contribution to annual revenue requirement; 310

(ii) Rate Impact Measure presented as the ratio of added revenue to costs for each customer class; and 311

(iii) class-specific estimated percent rate and annual average bill increases. 312

(d) estimates of the NPV and the benefit-cost ratio for the Investment Portfolio using a Societal Cost Test ("SCT"), defined in the Report of the Board, E.B.O. 169 III, as an evaluation of the costs and/or benefits accruing to society as a whole, due to an activity. The SCT analysis should be consistent with that used for the utilities' DSM programs. The benefit-cost ratio shall be presented with and without monetized externalities. 313

Historic Year: 314

(a) the Historic Year Investment Portfolio, including the NPV, total capital in the portfolio, and the portfolio PI; 315

(b) the aggregate NPV, the total capital, and the portfolio PI for: 316

- (i) the Rolling Project Portfolio at the end of the historic year; 317
- (ii) all completed projects with negative NPVs; 318
- (iii) all completed projects with positive NPVs; 319

(c) upon the request of the Board, a list of the projected results of individual extensions included in the Rolling Project Portfolio; 320

(d) actual expenditures on reinforcement projects; and 321

(e) the rate impact of the Historic Year Investment Portfolio reflecting actual capital expenditures and customer related data. Was Appendix, page 6 322

3.2 Ongoing Monitoring Information 323

The utilities shall establish a process to allow the Board to monitor the performance of their distribution system expansion project portfolios including financial and environmental requirements. 324

A. Financial Monitoring 325

In consultation with Board Staff, the utilities shall select projects from their Rolling Project Portfolios on an annual basis and shall file the following with respect to the sample: 326

- (a) the cumulative number of customers attached at the end of the 3rd full year and the associated revenues and costs; and 327
- (b) the corresponding year 3 customer attachment forecasts and associated revenues and costs. 328

B. Environmental Monitoring 329

In consultation with Board Staff, the utilities shall select a set of completed projects and file data on those projects on an annual basis as described below. The projects chosen should be selected in a random, stratified manner, reflecting the range of environmental impacts encountered in the time period and the various levels of environmental planning, documentation and reporting required. The selection should be reviewed by an independent auditing group within the utility, which group shall include (a) trained environmental auditor(s). The utility shall file the following with respect to each sample: 330

1. a description of how the project complied with the Board-approved environmental screening, planning, documentation and reporting requirements; 331

2. a table of significant features, how they were avoided or mitigated, and resulting impacts; 332

3. a table displaying the concerns raised by affected parties including member ministries of the Ontario Pipeline Coordination Committee, how they were addressed, and reasons for any outstanding concerns; 333

4. issues of significance arising from any post-construction monitoring; 334

5. where alternatives were investigated, a display of alternatives (routes/sites) which show the various trade-offs between customer attachments, and environmental, social and financial costs and a discussion of how the preferred alternative was chosen; 335

6. evidence that all necessary approvals (permits, licences) were obtained; and Was Appendix, page 7 336

7. forecast versus actual costs of the environmental planning. 337

3.3 Risks of Non-performance 338

In the event that the actual results of the Investment Portfolio do not produce a positive NPV or a PI of at least 1.0, the following will occur: 339

(a) the utility will be required to provide a complete variance explanation in its rates case and the Board will determine whether or not an acceptable explanation has been provided; and 340

(b) the implications of a negative NPV or PI less than 1.0 will be determined by the Board on a case by case basis. 341

Final
Demand Side Management
2014 Annual Report

December 4, 2015

unionGas
A Spectra Energy Company

Executive Summary

2014 is the eighteenth year that Union Gas Limited (Union) has delivered natural gas savings to its customers through cost effective Demand Side Management (DSM) programs. Union's DSM programs support residential, low-income, commercial and industrial customers to realize energy savings and environmental benefits by providing energy efficiency education, awareness and incentives. To date, Union's commitment to DSM initiatives has translated to approximately 1.400 billion m^3 of annual natural gas savings, equivalent to more than $2.786 billion in net Total Resource Cost benefits. As the third year within the construct of EB-2011-0327, 2014 represented opportunities to drive deeper savings for customers.

Success in 2014 includes strong program performance within the Resource Acquisition, Low-Income and Market Transformation scorecards. Of particular note are an increase in participation in the Residential Home Reno Rebate program; a rebranding of the Low-Income Home Weatherization Program offering to target specific market segment needs; partnering with over 25 key associations to communicate the benefits of Commercial/Industrial energy conservation programs; and having over 25% of the top 50 home builders in Union's franchise area build a portion of their respective housing stock to efficiencies 20% higher than the current Ontario Building Code.

Key evaluation priorities at the Technical Evaluation Committee (TEC) included the development of the Technical Reference Manual as well as the launch of the custom net-to-gross impact evaluation study, which both contribute to the continual improvement of DSM technical and evaluation standards for natural gas utilities in Ontario.

The company is pleased to report that the 2014 DSM portfolio generated 1.889 billion m^3 of cumulative natural gas savings with a program spend that was $33.714 million, or 5.19% over the 2014 DSM budget of $32.049 million. This achievement earned Union a Utility Shareholder Incentive of $8.988 million.

Union celebrates the success of its 2014 DSM programs and the associated significant energy reductions that ratepayers have realized.