Exhibit No. PNG-12

Ontario Power
Authority Study

NATURAL GAS-FIRED GENERATION IN THE INTEGRATED POWER SYSTEM PLAN

Prepared for the
Ontario Power Authority

by:
North Side Energy, LLC
May 2008

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The Integrated Power System Plan (IPSP) includes a significant increase in natural gas-fired power generation capacity. This has raised questions about the ability of the natural gas market to supply the natural gas that will be needed, and the effects that additional gas-fired generation might have on other natural gas consumers in the province.

This report is organized in three sections:

Section I describes the natural gas delivery system that supplies Ontario, and its relationship to the larger North American market.

Section II describes the expected growth in natural gas use and the gas infrastructure required for electricity generation, based on information used in the IPSP.

Section III addresses the implications of additional gas use for electricity generation for other Ontario natural gas users.

I. The Ontario Natural Gas Market

Ontario is the largest market for natural gas in Canada, and is home to one of the principal gas storage and trading hubs in North America. While the principal source of natural gas for the province continues to be the gas producing areas in western Canada, increased pipeline capacity at Michigan border points has reduced Ontario's dependence on western Canadian production, and expanded the physical supply of natural gas coming into the province.

Nearly all Ontario natural gas consumers receive their gas from one of two large distribution utilities. In addition to their extensive gas distribution systems, Union Gas and Enbridge Gas Distribution operate underground gas storage reservoirs in Lambton County that tie into the Dawn Hub. Union Gas also operates the natural gas transmission pipelines that connect the Dawn Hub to the Toronto area.

Natural gas transported through Ontario supplies the Quebec market, and a significant portion of the gas consumed in the Northeast U.S. Table 1 describes the flows of natural gas entering and leaving Ontario in 2007. Of the 5,500 million cubic feet per day (MMcf/day) of natural gas that was delivered into Ontario, just over half exited the province to supply markets in Quebec (550 MMcf/day) and the Northeast U.S. (2,250 MMcf/day). The remaining amount (2,700 MMcf/day) was consumed within Ontario.

Table 1: Ontario Natural Gas Supply and Disposition, 2007

	(MMcf/day)
TCPL Northern Ontario Line	2,900
From Michigan	2,600
Total Supply	5,500
Ontario Market	2,700
Quebec Market	550
Exports to U.S.	2,250
Total Disposition	5,500

Source: TCPL

Ontario currently consumes approximately 1,000 billion cubic feet (Bcf) of natural gas per year, with most of this gas going to the residential and commercial sectors. About 10 percent of the natural gas consumed in Ontario is used to generate electricity.

Table 2: Ontario Natural Gas Consumption, 2001-2005

	(MMcf/day)				
	2001	2002	2003	2004	2005
Residential/Commercial	1,471	1,500	1,589	1,509	1,552
Industrial/Transport	783	895	878	950	959
Total End Use	2,254	2,395	2,467	2,459	2,511
Electric Generation/Other	318	329	346	312	330
Total Primary Energy	2,572	2,723	2,813	2,772	2,842

Source: National Energy Board

A. Natural Gas Transmission

Natural gas is delivered into Ontario through two routes. The TransCanada PipeLines (TCPL) mainline begins in Empress, Alberta and extends through northern Ontario to North Bay, where it divides into two branches. One branch (the Barrie line) runs south from North Bay to Toronto, then runs east to markets in Quebec and the U.S. (the Montreal line). The other branch (the North Bay shortcut) extends east past Ottawa and rejoins the Montreal Line near the Iroquois export point.

Natural gas also enters southern Ontario at several points along the Michigan border. The Great Lakes Gas Transmission (GLGT) system extends from the TCPL mainline at Emerson, Manitoba and reconnects with TCPL at St. Clair. TCPL then operates approximately 15 miles of pipeline to move gas from GLGT at St. Clair to Union Gas at the Dawn Hub. TCPL buys firm transportation service on GLGT, and uses this capacity both as an operational loop of its mainline system, and to deliver gas to the Sault Ste. Marie area.

Vector Pipeline delivers gas to Dawn from the Chicago Hub and from southeast Michigan gas storage facilities. Three other pipeline and storage operators connect with Union Gas: Panhandle Eastern Pipe Line, which ties into Union's Panhandle line in the Windsor area; Michigan Consolidated, the Michigan gas distribution subsidiary of DTE Energy, which connects to Union's St. Clair-Bickford line; and Bluewater Gas Storage, an independent gas storage operator, which connects to Union's Sarnia Industrial line. Finally, ANR Pipeline's Link pipeline connects to Enbridge's gas transmission lines at its Tecumseh gas storage facility near the Dawn Hub.

Union's Dawn-Trafalgar pipeline extends 230 km from the Dawn Hub to Parkway, where Union has connections with both TCPL and Enbridge. The Dawn-Trafalgar line has a total capacity of approximately 6,000 MMcf/day, and is currently being expanded. The pipeline is used both for Union's gas distribution operations and to provide third-party gas transportation services.

Table 3: Natural Gas Pipelines Entering Ontario

Upstream Pipeline	Downstream Pipeline	Entry Point	Capacity (MMcf/day)
TCPL Northern Ontario Line	TCPL	Manitoba	4,200
Great Lakes Gas Transmission	TCPL	St. Clair	2,100[1]
Vector Pipeline	Union Gas	Dawn	1,500
Panhandle Eastern Pipe Line	Union Gas	Ojibway	200
ANR Pipeline	Enbridge	Corunna	150
Michigan Consolidated	Union Gas	St. Clair	200
Bluewater Gas Storage	Union Gas	Sarnia	250
Capacity from Michigan			4,400
Total			8,600

Sources: National Energy Board and Federal Energy Regulatory Commission filings, and company websites.

Seven natural gas export points in Ontario and Quebec have combined capacity of approximately 2,750 MMcf/day.

Table 4: Natural Gas Export Points in Eastern Canada

Upstream Pipeline	Downstream Pipeline	Export Point	2007 Capacity (MMcf/day)
TCPL	Tennessee, National Fuel, Dominion	Niagara	675
TCPL	Empire	Chippawa	500
TCPL	Iroquois	Iroquois	1,200
TCPL	St. Lawrence Gas	Cornwall	50
TCPL	North Country	Napierville	60
TCPL	Vermont Gas	Philipsburg	55
TCPL (via TQM)	Portland Natural	East Hereford	210
Total			2,750

Source: TCPL

In recent years utilities and marketers supplying the Ontario and Quebec markets have reduced their long haul transportation services from Alberta and increased their use of short haul transportation from the Dawn Hub. This trend accelerated with the completion of Vector Pipeline in 2000. As a result of these developments, TCPL has excess firm capacity on its North Ontario pipeline, while firm transportation services on the Union Dawn-Trafalgar system and TCPL Montreal line are fully subscribed.

B. Pipeline and Storage Development

There has been substantial investment in the natural gas pipeline and storage facilities supplying the Ontario market within the last two years, and additional projects are either in construction or in advanced development. Much of this activity is directly related to the growth of gas-fired power generation in the province.

<u>Dawn-Trafalgar Transmission Capacity</u>

Union Gas is completing a three-phase expansion of its Dawn-Trafalgar system. These projects will increase take-away capacity from the Dawn Hub by 24 percent, from 5,200 MMcf/day in 2005 to 6,200 MMcf/day in 2009. According to information filed with the Ontario Energy Board (OEB), two gas-fired generators contracted for capacity in the Phase 2 expansion: the Greater Toronto Airports Authority (7.3 MMcf/day) and the Goreway project (116 MMcf/day). Ontario power generators are also expected to contract for a substantial portion of the 320 MMcf/day of firm transportation capacity created by the Phase 3 expansion.

Table 5: Union Gas Dawn-Trafalgar System Expansions

	Additional Capacity	Estimated Cost	In-Service Date
Phase 1	360 MMcf/day	$150 Million	November 2006
Phase 2	475 MMcf/day	$100 Million	November 2007
Phase 3	320 MMcf/day	$50 Million	November 2008
Total	1,155 MMcf/day	$200 Million	

Source: Union Gas filings with the Ontario Energy Board.

Natural Gas Storage

Natural gas storage facilities are used to meet high winter gas requirements and manage short term variations in supply and consumption throughout the year. The usable "working" capacity of an underground gas storage reservoir is the difference between the total capacity and base or "cushion" gas that stays in the reservoir to maintain pressure. The total working capacity of the existing underground storage facilities in Ontario is approximately 250 Bcf, or about one-fourth of the annual gas consumption in the province. During the winter peak, these storage facilities can deliver at least 4,000 MMcf/day into gas transmission pipelines at the Dawn Hub.

Natural gas storage expansion projects scheduled for completion by the end of 2008 will expand the daily deliverability from Ontario gas storage facilities by nearly 20 percent. Additional Ontario projects have been announced that could come on line as early as 2009. The Ontario market also has access to gas storage services from Michigan, which has over 600 Bcf of storage capacity.

Table 6: Ontario Underground Natural Gas Storage

	Working Capacity (Bcf)	Withdrawal Deliverability (MMcf/day)
Union	155.0	2,200
Enbridge	98.0	1,800
Capacity & Deliverability at 12/31/06	**253.0**	**4,000**
2007 Projects:		
MHP Canada St. Clair Field	1.1	15
Capacity & Deliverability at 12/31/07	**254.1**	**4,015**
2008 Projects:		
Union Dawn Deliverability Project	0.0	490
Union Dawn Capacity Uprate Project	2.0	0
Tipperary Gas	3.2	40
Enbridge Storage Enhancement	2.7	200
Capacity & Deliverability at 12/31/08	**262.0**	**4,745**

Source: Facilities applications and other filings with the Ontario Energy Board.

Table 7: Planned Gas Storage Expansion Projects

	Working Capacity (Bcf)	Withdrawal Deliverability (MMcf/day)	Planned In-Service Date
MHP Canada Sarnia Airport Pool	5.26	65	2009
Union Gas Heritage Pool	1.0	15	2009
Union Dawn Deliverability Project	0	220	2010
Enbridge Phase II Expansion	5.0	500	2011

Source: Filings with the Ontario Energy Board and company announcements.

Vector Pipeline

Vector Pipeline completed a major expansion project in 2007, and has applied to the Federal Energy Regulatory Commission to construct additional facilities in 2009. These two projects will expand Vector's year-around capability to deliver gas into Ontario from 906 MMcf/day in 2006 to 1,250 MMcf/day in 2010, an increase of just under 40 percent. Vector's firm capacity increases to 1,500 MMcf/day during the winter, and the pipeline can deliver nearly 2,300 MMcf/day into Ontario with the right operating conditions. Vector Pipeline recently constructed a new delivery meter at Courtright to deliver gas directly into Union's Sarnia Industrial line.

Table 8: Vector Pipeline Border Capacity

	Annual Capacity	Winter Capacity
Capacity at 12/31/06	906 MMcf/day	906 MMcf/day
Capacity at 12/31/07	1,147 MMcf/day	1,500 MMcf/day
Capacity at 12/31/09	1,249 MMcf/day	1,529 MMcf/day

Source: Vector Pipeline certificate applications filed with the Federal Energy Regulatory Commission.

TransCanada PipeLines

TCPL recently modified its pipeline facilities in Ontario and Quebec to increase its capacity to receive gas at Parkway for redelivery to markets in the U.S., Quebec and eastern Ontario. TCPL's most recent expansion, the 2007 Eastern Mainline Expansion Project, added gas compression capacity on both the Niagara and Montreal lines.

In late 2007 TCPL conducted a coordinated non-binding open season with ANR Storage and GLGT for Michigan storage service and associated transportation. This additional storage and delivery capacity would be available beginning in 2010. The final results of this offering have not been announced.

II. Natural Gas-Fired Generation Capacity

A. Existing Generating Plants

Natural gas-fired generation makes up about 16 percent of the province's total installed generation capacity of 31,000 MW. In 2007 these gas-fired plants generated 13.5 TWh, or about 9 percent of the total electricity produced in Ontario.

The largest gas-fired generating facility is the Ontario Power Generation's Lennox plant, located near Kingston. Lennox was constructed as an oil-fired facility in 1976, and was converted to burn either heavy fuel oil or natural gas in the 1990s. Lennox operates under a Reliability Must-Run contract with the IESO, and is used as a peaking resource and for operating reserve. Lennox's dual-fuel capability means that the plant does not need to consume natural gas during periods of peak gas demand.

Ontario Electricity Finance Corporation has long term contracts with 16 gas-fired plants with a combined capacity of 1,517 MW. These plants originally sold electricity to Ontario Hydro as non-utility generators (NUGs), and include combined heat and power (CHP) and smaller combined cycle facilities. These plants are self-dispatched, and currently operate at relatively high capacity factors. The majority of the NUG contracts expire between 2013 and 2018.

Table 9: Natural Gas-Fired Generating Capacity and Production

	Installed Capacity (MW)	2007 Production (TWh)
Lennox	2,100	0.888
NUG	1,517	8.129
CHP	322	0.946
Combined Cycle	1,090	3.529
Total	5,029	13.492

Most of the non-NUG CHP and combined-cycle capacity currently in operation entered service within the last five years. These plants include the Greater Toronto Airports Authority cogeneration plant (117 MW), the Brighton Beach combined cycle plant in Windsor (580 MW), and the TransAlta Sarnia cogeneration facility (510 MW).

The existing gas-fired generating plants are capable of consuming just over 1,000 MMcf/day. However, since Lennox can operate on oil during periods of high natural gas demand, the maximum natural gas requirement for power generation during periods of peak gas demand is only about half this amount.

Based on IESO production data, it is estimated that 284 MMcf/day of natural gas was used for electricity generation in 2007.[2] NUGs, which make up 30 percent of the installed capacity for gas-fired plants, accounted for over 60 percent of the natural gas used for power generation. Lennox, which is over 40 percent of the gas-fired capacity, accounted for less than 10 percent.

Table 10: Natural Gas Use for Electricity Generation, 2007

	Maximum Gas Use (MMcf/day)	Peak Gas Requirement (MMcf/day)	Estimated Consumption (MMcf/day)
Lennox	499	0	24
NUG	286	286	174
CHP	53	53	18
Combined Cycle	183	183	68
Total	1,021	522	284

The existing NUG and CHP plants run at a high capacity factor throughout the year. In 2007 the combined cycle plants and Lennox operated more during the peak summer months and less during the spring months.

Table 11: Natural Gas Use for Electricity Generation by Month, 2007

	(MMcf/day)											
	J	F	M	A	M	J	J	A	S	O	N	D
Lennox	15	36	13	1	4	36	20	77	27	25	11	25
NUG	200	197	191	160	155	150	151	161	158	158	194	193
CHP	18	19	19	16	13	18	18	20	17	17	19	20
Combined Cycle	59	83	73	46	52	58	57	89	77	75	69	76
Total	293	334	296	223	224	262	246	346	279	303	294	315

Source: Estimated from IESO electricity production data.

Location on the Natural Gas Network

For the purposes of this report, the natural gas pipeline and distribution network in Ontario is divided into five areas. The "West of Dawn" area includes the Union, Vector, TCPL, and Enbridge pipeline and distribution facilities that are located between Michigan border points and the Dawn Hub. "Union South" is the area between Dawn and Parkway that makes up the rest of Union's southern operations area. "Enbridge CDA" is the TCPL Enbridge Central Delivery Area, which includes the Greater Toronto Area and the Niagara area. "East" is defined as the TCPL Enbridge Eastern Delivery Area (EDA) and Union EDA. The "North/West" area covers the rest of the province.

Table 12 shows how the existing gas-fired generating capacity in Ontario is distributed across these five areas. The greatest amount of gas-fired capacity is in the East area, where Lennox is located. The next largest area is the West of Dawn area, which includes Windsor and Sarnia. Nearly half of the NUG capacity is in the North/West area.

Table 12: Gas-Fired Capacity and Maximum Gas Use by Area

	Installed Capacity (MW)					Maximum Gas Use (MMcf/day)
	Lennox	NUG	CHP	CCGT	Total	
West of Dawn	0	206	100	1,090	1,396	238
Union South	0	0	0	0	0	0
Enbridge CDA	0	194	117	0	311	56
East	2,100	446	0	0	2,546	583
North/West	0	671	105	0	776	144

B. Committed Gas-Fired Generation

The OPA has long term contracts with six large combined cycle projects and seven CHP projects that are committed to come on line between 2008 and 2010. These plants have a total capacity of 4,267 MW and represent an additional 715 MMcf/day of potential gas use. Most of the committed gas-fired generation capacity will be located in the West of Dawn area or the Enbridge CDA.

Table 13: Committed Gas-Fired Generation Capacity

	Capacity Additions (MW)	Maximum Gas Use (MMcf/day)
CHP	414	68
Combined Cycle	3,853	648
Total	4,267	716

Table 14: Committed Gas-Fired Capacity and Maximum Gas Use by Area

	Capacity Additions (MW)			Maximum Gas Use (MMcf/day)
	CHP	CCGT	Total	
West of Dawn	84	1,575	1,659	279
Union South	24	600	624	105
Enbridge CDA	243	1,678	1,921	322
East	0	0	0	0
North/West	63	0	63	10

Natural Gas Connection Facilities

Natural gas-fired generating plants typically require relatively large quantities of gas and high gas delivery pressures. To accomplish this, plants often locate close to major gas transmission lines and are supplied through dedicated pipeline laterals. Plants that are connected to the existing distribution network are often referred to as "embedded" plants. Embedded plants may require distribution system upgrades in addition to the plant-specific lateral and metering facilities.

Of the seven large "committed" gas-fired plants, four will have direct connections to major gas transmission lines. The other three are embedded plants that will utilize existing gas distribution facilities. The natural gas connections for the five plants for which facility construction applications have been filed with the OEB or National Energy Board (NEB) are described in Table 15.

Table 15: Location of Committed Gas-Fired Generating Plants

Power Plant	Location	Size (MW)	Gas Utility	Pipeline	Distance
Greenfield Energy	Courtright	1,005	Self build	Vector	2 km
Portlands Energy	Toronto	538	Enbridge	Embedded	
Goreway Station	Brampton	860	Enbridge	TCPL	6.5 km
St. Clair Energy	Corunna	570	Union	Embedded	
Greenfield South	Mississauga	280	Enbridge	Embedded	
Halton Hills	Halton Hills	600	Union	Union M12	4.6 km
Thorold Cogeneration	Thorold	236	Enbridge	TCPL	3.6 km

Source: Facilities applications filed with the Ontario Energy Board.

Table 16: Gas Facilities Projects for Committed Generating Plants

Power Plant	Natural Gas Requirement	Required Gas Facilities	Estimated Cost
Greenfield Energy	193 MMcf/d	2 km of 16-in pipeline	$4.9 M
Portlands Energy	98 MMcf/d	6.5 km of pipeline loop; 2.9 km of pipe to plant	$48.5 M
Goreway Station	153 MMcf/d	6.5 km of 24-in lateral to TCPL	$22.4 M
		TCPL meter	$2.6 M
St. Clair Power	96 MMcf/d	4.5 km of pipeline loop; 2.9 km of pipe to plant	$12.1 M
Halton Hills	100 MMcf/d	4.6 km of 20-in pipeline	$23.2 M

Source: Facilities applications filed with the Ontario Energy Board and National Energy Board.

C. Planned Gas-Fired Generation

The IPSP provides for 2,786 MW of planned gas-fired generation that is scheduled to go into service between 2011 and 2014. This includes 2,220 MW of combined cycle and simple cycle capacity, and an additional 586 MW of CHP. These plants will be capable of consuming approximately 530 MMcf of natural gas per day. The combined cycle and simple cycle plants will be located in the Enbridge CDA and Union South areas. CHP development is not restricted to specific areas. The type and location of the new gas-fired generation in the IPSP is based on the use of natural gas for peaking and for other high value uses, including local area reliability and operating reserve.

Table 17: Planned Gas-Fired Generation Capacity

	Capacity Additions (MW)	Maximum Gas Use (MMcf/day)
CHP	586	96
Combined Cycle	850	143
Simple Cycle	1,350	290
Total	2,786	529

Table 18: Planned Gas-Fired Capacity and Maximum Gas Use by Area

	Capacity Additions (MW)				Maximum Gas Use
	CHP	CCGT	SCGT	Total	(MMcf/day)
West of Dawn	0	0	0	0	0
Union South	0	0	450	450	97
Enbridge CDA	0	850	900	1,750	336
East	0	0	0	0	0
North/West	0	0	0	0	0
Undefined	586	0	0	586	96

D. Natural Gas Requirements for Committed and Planned Capacity

Under the IPSP, natural-gas fired generation capacity in Ontario grows by 140 percent, from 5,029 MW in 2007 to 12,082 MW in 2015. The potential peak requirement for natural gas for power generation increases by about 1,250 MMcf/day, from 522 MMcf/day in 2007 to 1,767 MMcf/day in 2015.

Gas-fired generators that enter into contracts with the OPA are expected to acquire natural gas at the Dawn Hub. Buying gas at Dawn reduces exposure to firm gas transportation charges, provides access to natural gas storage and balancing services, and aligns the generator's gas supply costs with the financial settlement terms in the OPA contracts, which are based on the Dawn daily gas price index.

The natural gas facilities needed to fuel these plants will depend on the plants' peak daily gas use and location. In particular, new gas-fired plants located in the West of Dawn area will require less in the way of new gas infrastructure than plants located in the Enbridge CDA or Union South areas. This is because there is surplus pipeline capacity to deliver gas into Dawn from the west, but Union's capacity to transport gas to markets downstream of Dawn is often fully utilized, especially on peak winter days. Plants located in the North/West area will have access to available gas transmission capacity on the TCPL mainline, which reduces their gas infrastructure requirements.

Table 19: Gas-Fired Generation Capacity by Area, 2015

	Installed Capacity (MW)					
	Lennox	NUG	CHP	CCGT	SCGT	Total
West of Dawn	0	206	184	2,665	0	3,055
Union South	0	0	24	600	450	1,074
Enbridge CDA	0	194	360	2,528	900	3,982
East	2,100	446	0	0	0	2,546
North/West	0	671	168	0	0	839
Unspecified	0	0	586	0	0	586
Total	2,100	1,517	1,322	5,793	1,350	12,082

Table 20: Gas-Fired Capacity and Potential Gas Use, 2015

	Installed Capacity (MW)	Natural Gas Use (MMcf/day)	
		Maximum	Peak
Lennox	2,100	499	0
NUG	1,517	286	286
CHP	1,322	217	217
Combined Cycle	5,793	974	974
Simple Cycle	1,350	290	290
Total	12,082	2,266	1,767

Table 21: Change in Potential Gas Use by Area

	(MMcf/day)				
	2007 (A)	Committed (B)	Planned (C)	2015 (A) + (B) + (C)	Change (B) + (C)
West of Dawn	238	279	0	517	279
Union South	0	105	97	202	202
Enbridge CDA	56	322	336	714	658
East	583	0		583	0
North/West	144	10	0	154	10
Unspecified	0	0	96	96	96
Maximum Gas Use	1,021	716	529	2,266	1,245
Lennox (Oil Backup)	(499)	0	0	(499)	
Peak Requirement	522	716	529	1,767	1,245

E. Natural Gas-Fired Generation Capacity and Gas Use Through 2027

Installed Capacity

The IPSP includes the option for further natural gas-fired capacity additions after the last of the planned capacity enters service in 2014. "Unspecified" or "proxy" capacity is modeled in the IPSP as either simple cycle or combined cycle gas-fired generation, and the amount, type, and timing of unspecified capacity differ by planning scenario. However, there is no commitment that the additional resource requirements shown in the plan will be met using natural gas-fired generation.

Three IPSP scenarios were examined for this report: Base Case (Scenario 1); High Demand (Scenario 2); and No Northern Renewables (Scenario 4). Each scenario has two cases, depending on whether Pickering B is refurbished during the planning period.

The capacity additions included in the IPSP for the years after 2014 vary considerably from case to case. Table 22 shows the installed gas-fired generation capacity and potential gas use for Case 1B (Base Case, Pickering Not Refurbished), the case with the most gas-fired capacity additions and the highest potential peak gas requirement. Installed gas-fired generation capacity and the maximum gas requirement both peak in 2019. An additional 700 MW of unspecified capacity added between 2014 and 2019 is modeled as a mix of simple cycle and combined cycle generating capacity. The potential peak gas requirement for electricity generation continues to increase after 2019 as 125 MW of new combined cycle generation replaces the dual-fired Lennox plant.

Table 22: Gas-Fired Generation Capacity and Potential Gas Use (Case 1B)

	Installed Capacity (MW)			
	2015	2019	2023	2027
Lennox	2,100	2,100	0	0
NUG	1,517	1,517	1,386	1,517
CHP	1,322	1,322	1,322	1,322
Combined Cycle	5,793	5,918	5,918	6,043
Simple Cycle	1,350	1,925	1,925	1,925
Total	12,082	12,782	10,551	10,807
Maximum Gas Use (MMcf/day)	2,266	2,410	1,887	1,932
Peak Requirement (MMcf/day)	1,767	1,911	1,887	1,932

Natural Gas Consumption

Table 23 shows the average daily gas use for electricity generation for each of the six cases and the estimated change in gas use from 2007. The growth in natural gas consumption is similar across all six cases through 2015, but diverges thereafter. Natural gas use peaks in the 2016-2020 time period, then declines as other generating resources become available. Under the assumptions of Case 2B (High Demand, Pickering Not Refurbished), gas use for power generation doubles between 2007 and the 2016-2020 period. The increase over the same period in Case 1A (Base Case, Pickering Refurbished) is 55 percent. In all cases the growth in natural gas consumption is smaller than the increase in natural gas-fired generation capacity. Under the two of the three scenarios, gas use for power generation is lower in the 2021-2027 period than in the 2008-2010 period.

Table 23: Estimated Gas Use for Electricity Generation

	(MMcf/day)			
	2008-2010	2011-2015	2016-2020	2021 - 2027
Case 1A	**348**	**385**	**439**	**319**
Case 1B	348	385	505	324
Case 2A	350	398	518	434
Case 2B	**350**	**397**	**577**	**429**
Case 4A	348	386	432	329
Case 4B	348	385	498	335
Change from 2007:				
Case 1A	**64 (23%)**	**101 (36%)**	**155 (55%)**	**35 (12%)**
Case 1B	64 (23%)	101 (36%)	221 (78%)	40 (14%)
Case 2A	66 (23%)	114 (40%)	234 (82%)	150 (53%)
Case 2B	**66 (23%)**	**113 (40%)**	**293 (103%)**	**145 (51%)**
Case 4A	64 (23%)	102 (36%)	148 (52%)	45 (16%)
Case 4B	64 (23%)	101 (36%)	214 (75%)	51 (18%)

Table 24 shows the estimated natural gas use by month for the peak year (2019) under the highest IPSP case (Case 2B). The seasonal variation in gas consumption for electricity generation increases relative to the 2007 numbers shown in Table 11.

Table 24: Natural Gas Use for Electricity Generation by Month, 2019 (Case 2B)

	(MMcf/day)											
	J	F	M	A	M	J	J	A	S	O	N	D
Lennox	0	0	0	0	0	2	13	15	5	0	0	0
NUG	64	63	59	56	53	51	52	52	35	58	58	53
CHP	70	70	70	70	70	70	70	70	70	70	70	70
Combined Cycle	628	556	303	156	187	508	648	653	337	215	340	503
Simple Cycle	155	37	27	0	0	150	258	256	94	0	7	87
Total	916	726	458	282	309	781	1040	1045	559	342	475	712

F. Summary of Findings

- Natural gas use for electricity generation grows from 10 percent of Ontario consumption in 2007 to about 20 percent of Ontario consumption in the High Demand scenario. In all cases, natural gas use for power generation peaks during the 2016-2020 period and is lower in later years of the 20-year planning period.

- The potential maximum natural gas requirement for electricity generation increases from 1,021 MMcf/day in 2007 to 2,266 MMcf/day in 2015. However, the modeling done for the IPSP indicates that actual peak gas use will be considerably lower. Under the High Demand scenario (Case 2B), the highest daily gas use occurs in 2019, with a summer peak of 1,710 MMcf/day and a winter peak of 1,468 MMcf/day. The estimated peak in daily gas consumption is less than the potential maximum because gas-fired plants used for peaking and operating reserve do not run simultaneously, and on the days when these plants do operate, they are dispatched for only a limited number of hours per day.

- The seasonality of natural gas use for electricity generation will increase, with the highest gas use in the summer and a slightly lower peak in the winter.

- Most of the natural gas transmission, storage, and distribution facilities needed for the 4,300 MW of committed gas-fired capacity included in the IPSP are currently available or in construction. This includes the expansion of the Union Dawn-Trafalgar system to supply plants in the Enbridge CDA, and the additional gas storage deliverability needed to provide the flexible gas balancing services required by intermediate and peaking generation facilities.

- An additional 400 MMcf/day of additional firm transportation capacity on the Union Dawn-Trafalgar system could be needed by 2014 to supply the 2,200 MW of simple cycle and combined cycle generation planned for the Enbridge CDA and Union South areas. This capacity requirement is comparable in size to the expansion facilities Union is already building for the committed plants located in the same areas, and only about one-third as large as the total increase in capacity from Union's recent three-phase expansion project.

III. POTENTIAL IMPACT ON NATURAL GAS USERS

The planned expansion of natural gas-fired electric generation capacity has raised concerns about the potential impact of increased natural gas use on other gas consumers. These concerns include:

1. Declining natural gas production in western Canada will reduce the availability of natural gas in the Ontario market.

2. Increased gas use for electricity generation will cause natural gas prices to be higher and more volatile.

3. Supplying fuel to new gas-fired generating plants will require costly expansions of pipeline, distribution and storage facilities, and other gas consumers will need to pay higher rates to fund these investments.

4. Increased gas use for electricity generation will reduce the availability of interruptible gas distribution services used by industrial gas users.

Will natural gas supplies be available?

There are concerns that a reduction in natural gas supplies from western Canada will affect the availability of natural gas in the Ontario market. While western Canada is still the primary source of natural gas delivered to Ontario, the fact that the Ontario market is now connected, directly or indirectly, to multiple sources of natural gas in Canada and the U.S. means that developments in western Canada are less important than they might have been in the past. In the near term, reductions in Alberta supplies are expected to be largely offset by increased Rocky Mountain and offshore Gulf Coast production, and supplies from new liquefied natural gas (LNG) import terminals (see Table 25). Over the longer term, production from known gas reserves in the Mackenzie Delta, Newfoundland, and Alaska are expected to reach the market to supplement existing sources of supply. Based on these developments, long term forecasts from sources such as the National Energy Board and the U.S. Energy Information Administration indicate that natural gas supplies will be adequate to meet existing requirements and support growth in Canadian and U.S. markets without large increases in natural gas prices.

Table 25: Canadian and U.S. Gas Supplies through 2030

	(MMcf/day)					
	2007	2010	2015	2020	2025	2030
Western Canada	16,035	15,343	14,291	11,824	9,305	7,455
Mackenzie	0	0	800	1,200	1,900	1,900
Eastern Canada	533	548	228	125	125	125
Newfoundland	0	0	0	500	1,000	1,000
Canadian Production	16,568	15,891	15,319	13,649	12,330	10,480
LNG Imports	0	500	1,400	2,050	2,050	2,850
Canadian Supply	16,568	16,391	16,719	15,699	14,380	13,330
U.S. Onshore	42,356	41,973	40,740	38,959	37,808	38,384
U.S. Offshore	8,658	9,890	11,836	11,808	10,575	9,507
Alaska	1,205	1,151	1,041	3,260	5,479	5,507
U.S. Production	52,219	53,014	53,617	54,027	53,862	53,398
LNG Imports	2,027	3,288	5,808	6,493	6,192	7,781
U.S. Supply	54,246	56,302	59,425	60,520	60,054	61,179
Canada & U.S. Supply	70,814	72,693	76,144	76,219	74,434	74,509
Henry Hub Price (2006 USD)	$6.78	$6.90	$5.87	$5.95	$6.39	$7.22

Sources: NEB "Canada's Energy Future: Reference Case and Scenarios to 2030" November 2007, and Energy Information Administration "Annual Energy Outlook 2008" (revised early release) March 2008.

Will greater use of natural gas for electricity generation cause natural gas prices to increase?

The increase in Ontario natural gas consumption associated with the IPSP is estimated to be relatively small and of short duration, suggesting that any effects on natural gas prices would be both minor and temporary. Even at its peak, the estimated increase in annual natural gas use for electricity generation in Ontario represents less than one-half of one percent of the total North American market. While an increase in gas use of this magnitude should not have a measurable effect on the natural gas prices throughout North America, a rapid increase in gas use within Ontario could cause the local gas price to rise relative to the overall market. This would show up as an increase in the Dawn Hub price relative to other natural gas reference prices, such as the Henry Hub index.[3]

Any increase in the natural gas price at Dawn compared to other markets would be mitigated, however, by the ability of gas market participants to shift gas supplies within the larger Northeast market area. This would increase the available supply of gas in Ontario—either by delivering more gas into the province, or by substituting natural gas from other lower-priced areas for natural gas that is currently flowing through Ontario to downstream markets. New pipeline projects, such as the construction of the Rockies Express pipeline into the Northeast U.S. market area, and new East Coast LNG terminals, will increase the opportunities for this type of substitution. Finally, because gas use for electricity generation is projected to decline in the later years of the IPSP planning period, any increase local Ontario price would be short-lived.

Table 26: Increase in Natural Gas Use Relative to the Market

Change in Ontario gas use for electricity (300 MMcf/day) as a percentage of:	
Ontario natural gas consumption (2,700 MMcf/day)	11%
Gas entering Ontario (5,500 MMcf/day)	5.5%
Eastern Canada and Northeast U.S. market (10,000 MMcf/day)	3%
Canada/U.S. gas market (70,000 MMcf/day)	< 0.5%

Will the use of natural gas for electricity generation affect price volatility?

Natural gas-fired power generators are expected to buy natural gas in the daily Dawn market to meet their expected fuel requirements. To the extent that generators' fuel requirements are tied to factors, such as weather, that are variable or difficult to predict, these purchases could affect the daily natural gas spot price. However, the liquidity of the gas commodity market at Dawn, supported by large physical storage injection and withdrawal capacity, should reduce the impact of electricity markets on natural gas price volatility.

Will the construction of new gas infrastructure for electricity generators increase distribution and storage rates for other customers?

The natural gas facilities that Union and Enbridge construct for new electric generating plants will not increase the distribution rates paid by other gas customers. In fact, to the extent that the additional revenues from new electric generators exceed the distributor's cost of providing service, distribution rates should actually decline. Before approving any new gas facilities, the OEB conducts an economic evaluation of the proposed projects, and considers any impact on the reliability and flexibility of the gas distribution system that could affect other gas users. The economic standard used by the OEB is that the revenue the gas utility obtains under a long term contract with the customer receiving the service must, at a minimum, cover the costs of the project. Requiring projects to have a positive net present value ensures that they are not subsidized by other gas customers. Also, because the economic evaluation uses only firm charges, and omits any payments tied to throughput, the OEB ensures that there will be no cross-subsidies if gas deliveries are lower than expected. If the net present value is negative, the customer must make up the difference in the form of an up-front contribution in aid to construction. If actual costs exceed the estimate, the OEB requires the utility to adjust the contribution in aid of construction to cover the extra costs.

OEB policy also prevents the costs of natural storage facilities developed to provide new storage services to gas-fired electricity generators from increasing the rates paid by other in-franchise customers. Any investments to acquire or expand natural storage facilities to provide new market-priced storage services will be borne by the utility's shareholders, not its ratepayers.

With respect to gas transmission facilities, both the OEB and NEB generally allow the costs of new facilities to be rolled into existing rates. This means that a transmission facilities expansion that includes capacity for gas-fired electricity generators could either increase or reduce the rates paid by existing customers, depending on the costs of the expansion. However, given the large size of the gas transmission systems supplying the Ontario market, any rate impacts should not be significant.[4]

Will the use of natural gas for electricity generation affect the availability of interruptible distribution services?

Large gas-fired generation facilities that connect directly to major gas transmission lines will not affect the local distribution systems that supply industrial gas users. Embedded generators are expected to contract for firm gas distribution services, which will fund any distribution system expansions that are necessary to meet the generators' peak daily gas requirements. Since new gas-fired electricity generators are not expected to compete with industrial customers for interruptible delivery capacity, there should not be a direct connection between growth in gas-fired generation and the availability of interruptible gas distribution services.

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[1] GLGT's website lists the peak capacity at St. Clair as 2,886.7 MMcf/day.

[2] Natural gas use is estimated using the following heat rates:

Lennox	10,100 MMBtu/KWh
NUG	8,011 MMBtu/KWh
CHP	7,000 MMBtu/KWh
Combined cycle	7,150 MMBtu/KWh
Simple cycle	9,141 MMBtu/Kwh.

The gas use quantities are converted from MMBtu to MMcf based on 1,021 Btu per cubic foot.

[3] The Henry Hub, located in southern Louisiana, is the pricing point for natural gas futures trading on the New York Mercantile Exchange.

[4] Evidence submitted by Union Gas in a recent Dawn-Trafalgar expansion proceeding indicated that the project would result in a slight reduction in the rates paid by existing shippers (Decision and Order, Case EB-2005-0550, June 12, 2006, p. 6).