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August 12, 2015

Ms Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th floor
PO Box 2319
Toronto, ON
M4P 1E4

RE: EB-2015-0049 & 0029 GEC Interrogatory replies

Dear Ms Walli,

Please find enclosed 2 copies of the IR replies from Mr Chernick to APPrO, FRPO, Enbridge and Union Gas, in addition to those filed Monday. This completes interrogatory responses from the GEC witnesses. All will be uploaded to the RES system shortly and emailed to all parties.

Sincerely,

(Mr.) Kai Millyard
Case Manager
Green Energy Coalition

ec: All parties

GEC Response to APPRO Interrogatory #5

Question:

Reference: i) Evidence of Mr. Chernick page 24:

"The carbon emissions from the existing electric system would be almost entirely from gas-fired generation, which appears to be on the margin about 70% of the time.."

Preamble: APPrO would like to understand how Mr. Chernick arrived at his understanding of the amount of time that gas-fired generation is expected to be on the margin for the period 2016-2020.

a) Please explain in detail how Mr. Chernick arrived at the conclusion that gas-fired generation would be the marginal generation source 70% of the time for the period 2016-2020. Please provide all current, past and projected Independent Electricity System Operator (**IESO**) and Ontario Power Authority (**OPA**) data, including market clearing price data that was used to arrive at this conclusion.
b) Please provide the assumed system-wide emission factor that Mr. Chernick used for Ontario and all supporting sources of information.
c) Please provide the assumed Ontario gas-fired electricity generation fleet emission factor that Mr. Chernick used and all supporting sources of information.

Response:

a) The marginal emissions avoided by electric CDM in the 2016–20 period would be some combination of (1) gas-fired power plants in Ontario, when Ontario needs fossil generation to meet load or the US, (2) a mix of gas and coal-fired generation in the US, when Ontario is exporting, and (3) zero, when Ontario is spilling water. Mr. Chernick cited the analysis that he relied on, which is attached as Attachment 1. Mr. Chernick has not located any other forecasts of surplus baseload generation (SBG), spillage or marginal emission rates from IESO or OPG. From page 26 of Attachment 1, it appears that OPG was projecting that about 50% of hours in 2016 would experience SBG. Since page 27 shows SBG declining to near zero by 2020, Mr. Chernick estimated that the average marginal emissions on the Ontario system in 2016–2020 would be equivalent to 70% of typical gas emissions.
b) Mr. Chernick assumed an average 9 MMBtu/MWh marginal heat rate for a mix of marginal gas generation, and emissions of 53.1 kg/MMBtu of gas burned, or about 480 kg/MWh when gas is at the margin, or an average of about 335 kg/MWh including the 30% of the time that the marginal emissions are zero, since IESO is spilling water. The 9 MMBtu/MWh is in the middle of the range of about 7 MMBtu/MWh for the best combined-cycle units operating baseloaded, to 11 MMBtu/MWh for combustion turbines and steam plants with extensive cycling. The 53.1 kg/MMBtu value is from www.eia.gov/environment/emissions/co2_vol_mass.cfm.

Witness: Paul Chernick

c) See part (b). Mr. Chernick assumed that marginal fossil emissions from the Ontario generation system would be entirely from natural gas combustion.

Witness: Paul Chernick

Electricity Generation Optimization in a Period of Surplus Baseload Generation

Carnegie Mellon School of Business

April 24, 2013

Bruce Boland
SVP - Commercial Operations & Environment

ONTARIO POWER GENERATION

EB-2015-0029/0049 M.GEC.APPrO.5 Attachment 1

Outline

- Introduction to Ontario Power Generation
  and the Ontario power market
- Transformation to "Clean and Green"
- Coping with Surplus Baseload Generation
- Implied CO_2 cost of Renewables in Ontario
- Sizing the nuclear fleet for the Ontario System
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OPG Corporate Profile

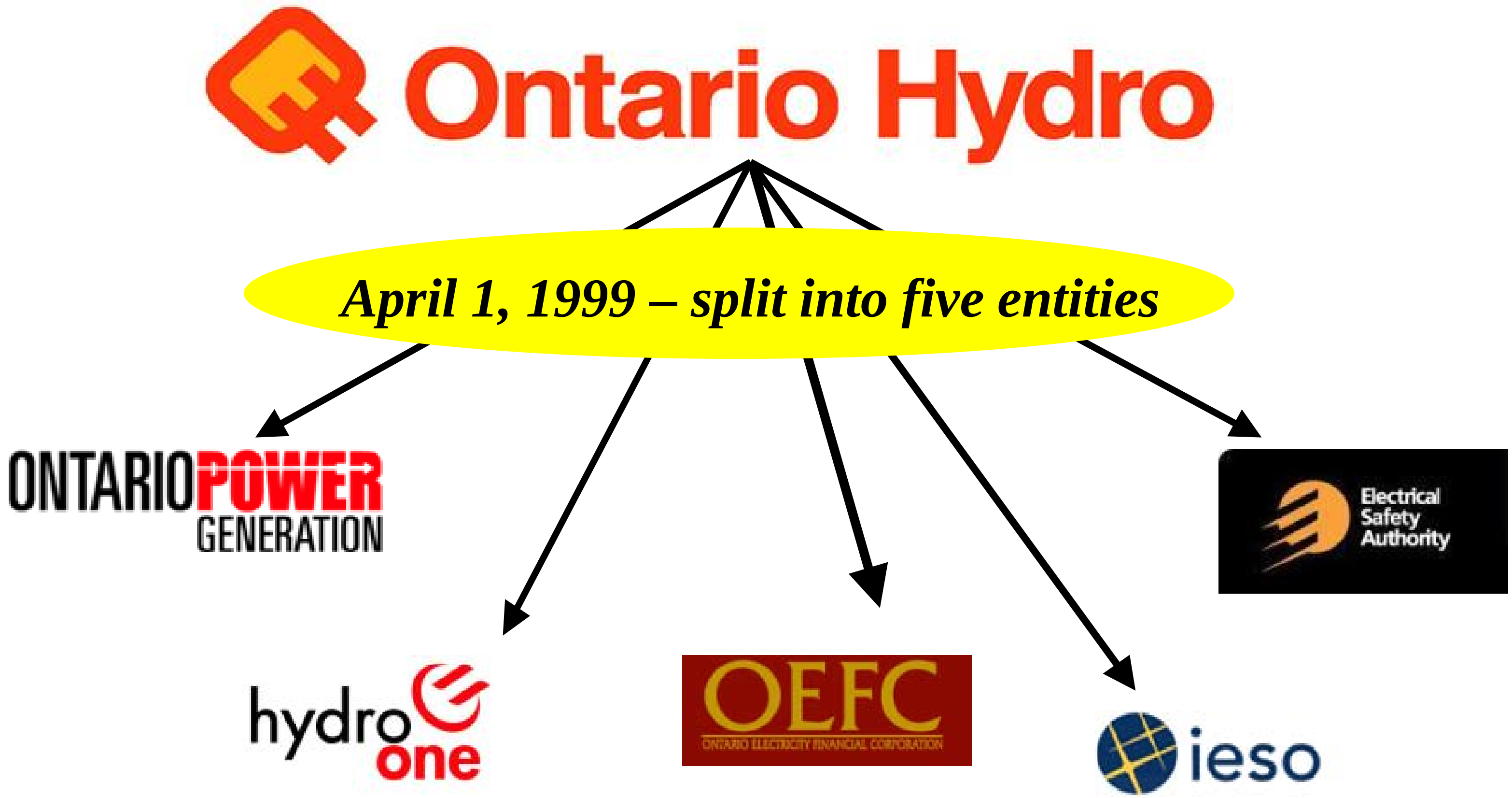
- Owned by the Province of Ontario
- Produces about 60% of Ontario's electricity
- 19,000 MW generating capacity
  - 2 nuclear 6600 MW
  - 65 hydro 7000 MW
  - 5 thermal 5400 MW
- Leases the 6300 MW Bruce Nuclear Plant to Bruce Power
- Over $32 billion in assets
- Over 10,000 employees
- 2012 revenue – $4.7 billion
- 2012 net income – $367 million

OPG’s Mandate

- Safe and reliable production of electricity
- Deliver value to Ontario as the low-cost generator of choice
- Provide support for Ontario’s Long-Term Energy Plan (LTEP):
  - Shut-down or convert coal-fired generation to biomass or gas by the end of 2014
  - Nuclear power about 50% of Ontario’s electricity supply; refurbish Darlington and operate Pickering to its end of life in 2020
  - Manage Hydroelectric, including Niagara Tunnel and Lower Mattagami Projects.
- Limited role in gas-fired generation.
  - Lennox 2000 MW gas/oil peaking plant
  - Partner in Portlands and Brighton Beach Combined Cycle Gas Turbines (CCGTs)
- OPG currently is not permitted to participate in wind and solar development.

Niagara Complex: Beck GS and Pumped Storage

Darlington Nuclear GS


Ontario Hydro
April 1, 1999 – split into five entities
ONTARIO POWER GENERATION
Electrical Safety Authority
hydro one
OEFC
ONTARIO ELECTRICITY FINANCIAL CORPORATION
ieso

A Quick History of the Ontario Electricity Market

- In May 2002, the Ontario electricity market was opened to competition, both wholesale and retail. It was designed as an energy only market. The Hourly Ontario Electricity Price (HOEP) is the average of the 12 five-minute market clearing prices.
- In the early years of the market, supply was tight and market prices were very high, but consumers were somewhat protected via various rebate mechanisms that limited OPG's earnings.
  - In 2002, in a run-up to provincial elections, the retail market was called off.
- Subsequently, OPG's nuclear and baseload hydro assets became regulated by the Ontario Energy Board (OEB). OPG's peaking hydro is still exposed to market price (HOEP).
- In 2003, Ontario government embarked on a path to shut down all coal-fired generation in the province. After several delays, this is now a reality; the use of coal will be almost eliminated by the end of 2013.
- In 2005, the Ontario Power Authority (OPA) was formed to contract for clean, efficient gas and renewable generation and manage conservation and demand management in the province.
- In 2010, the Provincial Government issued a Long-term Energy Plan which mandated that OPA contract for 10,700 MW of renewable generation, in addition to the 9000 MW of hydro now on the system or coming into service shortly.
- Since 2005, and especially after 2008, electricity demand in Ontario has declined rapidly, due to a sluggish economy and conservation and demand management.
- With 18 nuclear units still in service and the rapid rise of renewable generation, Ontario now finds itself in a surplus situation even with coal retirement.

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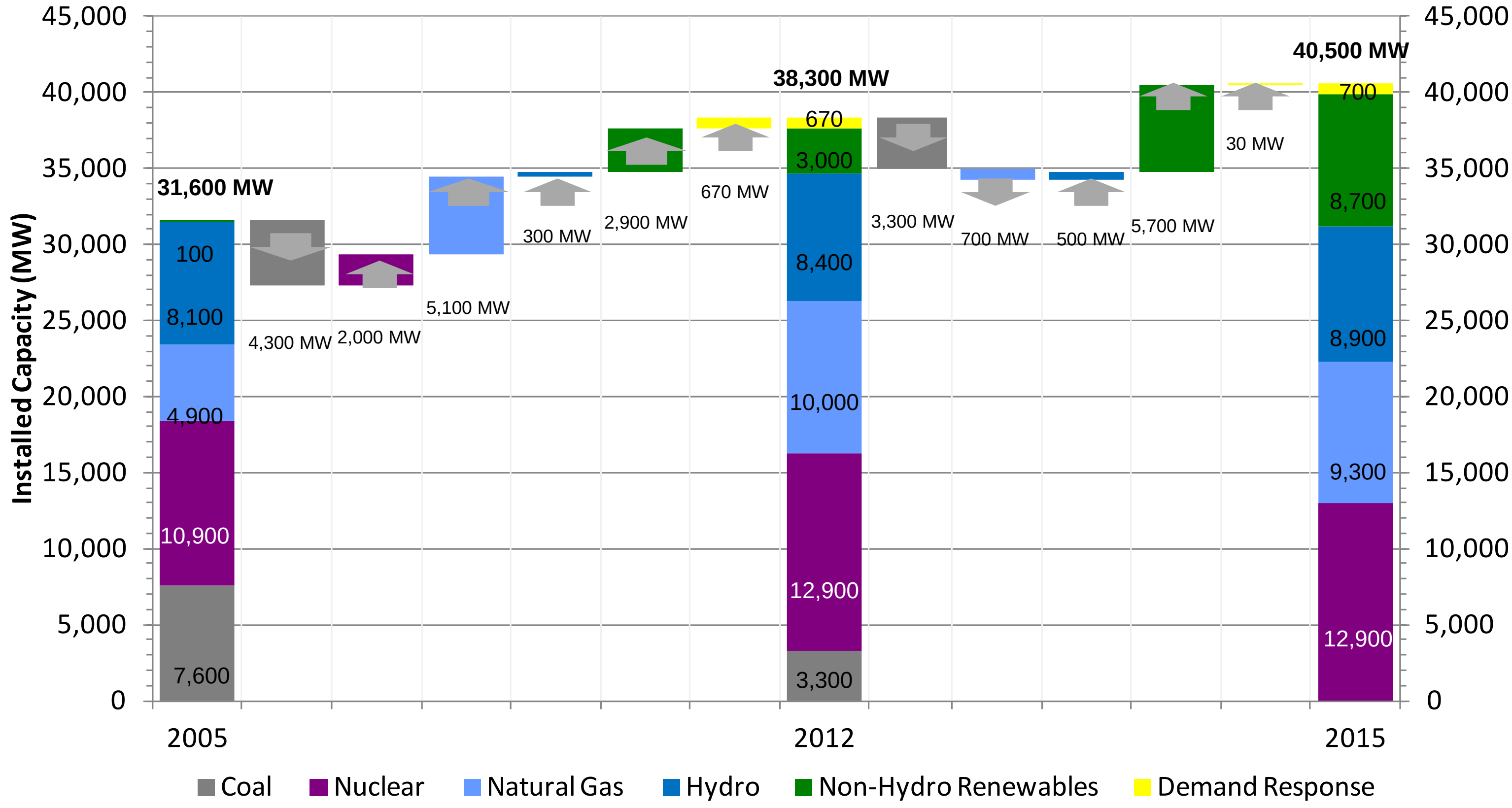
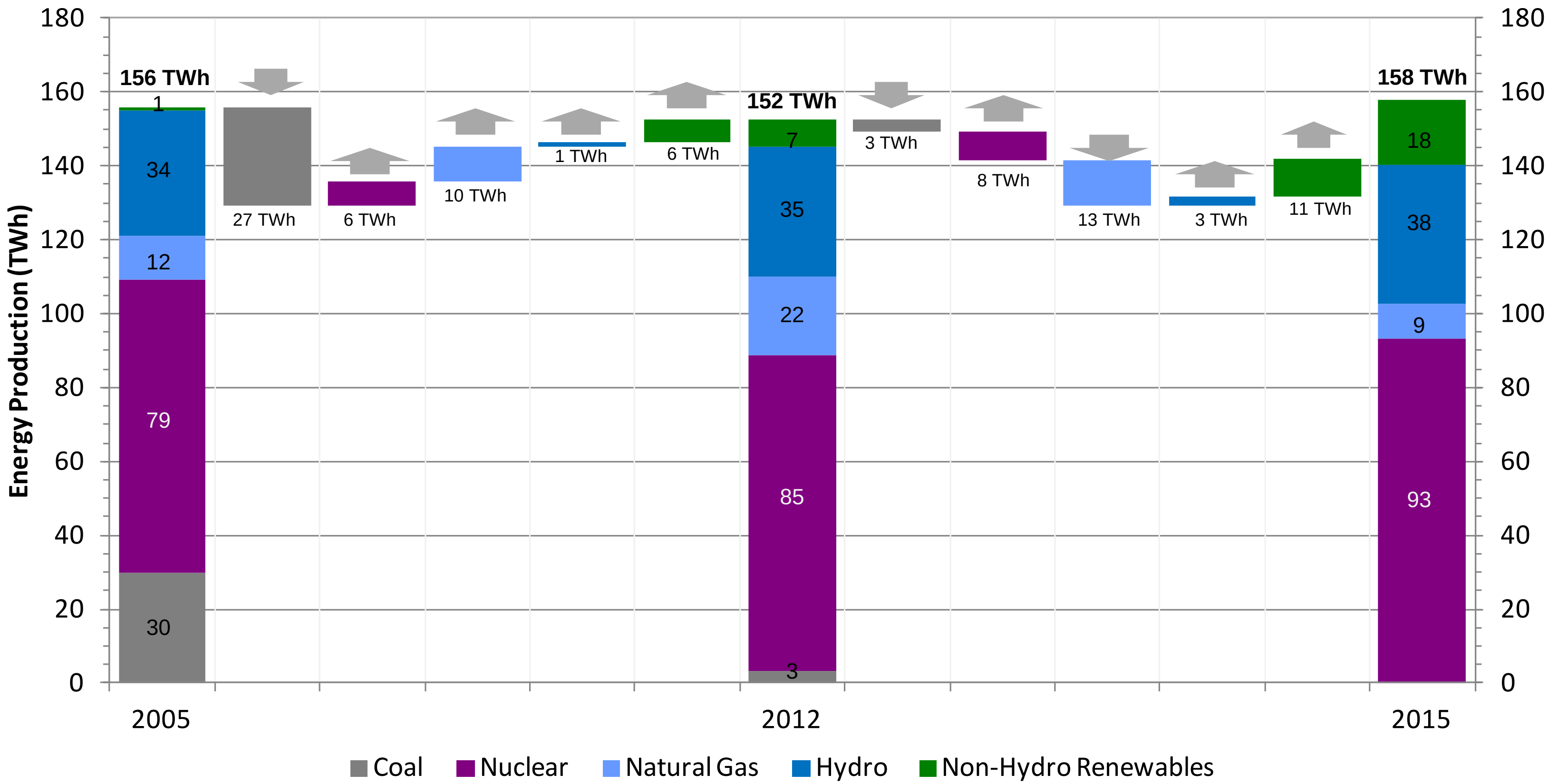
Capacity Transformation in Ontario, 2005-15

ONTARIO POWER GENERATION



APPrO 2012 – presented by Amir Shalaby – OPA

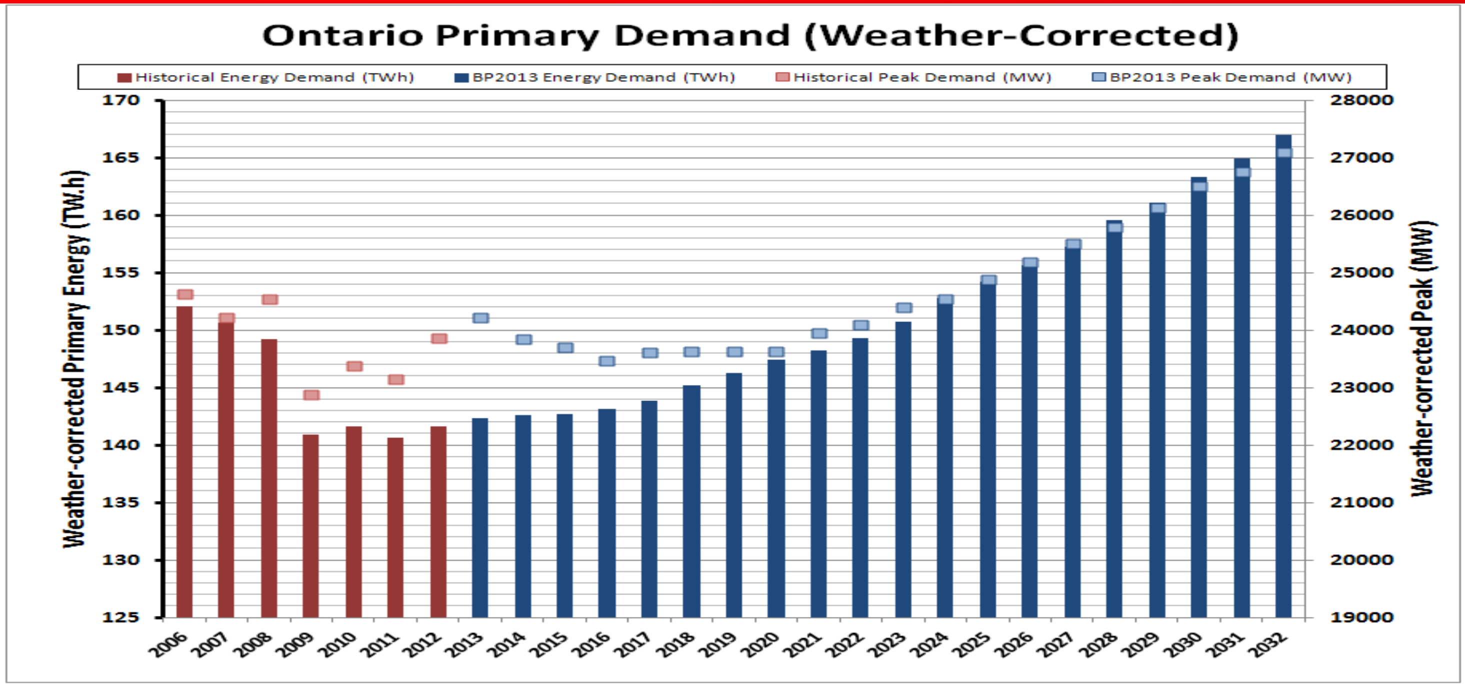
Energy transformation: coal is replaced by 2014; gas is replaced by non-emitting sources going forward.



APPrO 2012 – presented by Amir Shalaby – OPA

Source: IESO/OPA. Figures have been rounded.

Primary Demand returns to previous peak around 2025



- Collapse of heavy industry resulted in more energy decline than peak. Peak demand sustained by growth in air-conditioning load in residential/commercial buildings.
  - Energy down 8% from 2006 to 2012, peak down 3% in the same period.
- Ontario energy demand remains almost flat through 2015 with annual growth rate less than 0.3% through 2016 then grows 0.5% to 1.0% per year thereafter.
  - Demand depressed as customer cost increasing about 40% over the next 10 years.
  - In OPG forecast, time-of-use rates, real-time pricing, 5 CP program, demand response and conservation programs tend to push peak down proportionately more than energy going forward.
  - OPA shows a decline in annual energy to 2017 and nearly catches up to OPG forecast by 2031; peak higher than OPG after 2016.

OPG's Hydro System

ONTARIO POWER GENERATION

- At the end of 2012, OPG had 7000 MW of installed hydro capacity with an effective capacity at the time of summer peak of 5500 MW.
  - The long-term average annual output of the existing hydro fleet is 34 TWh or about a quarter of Ontario's current demand.

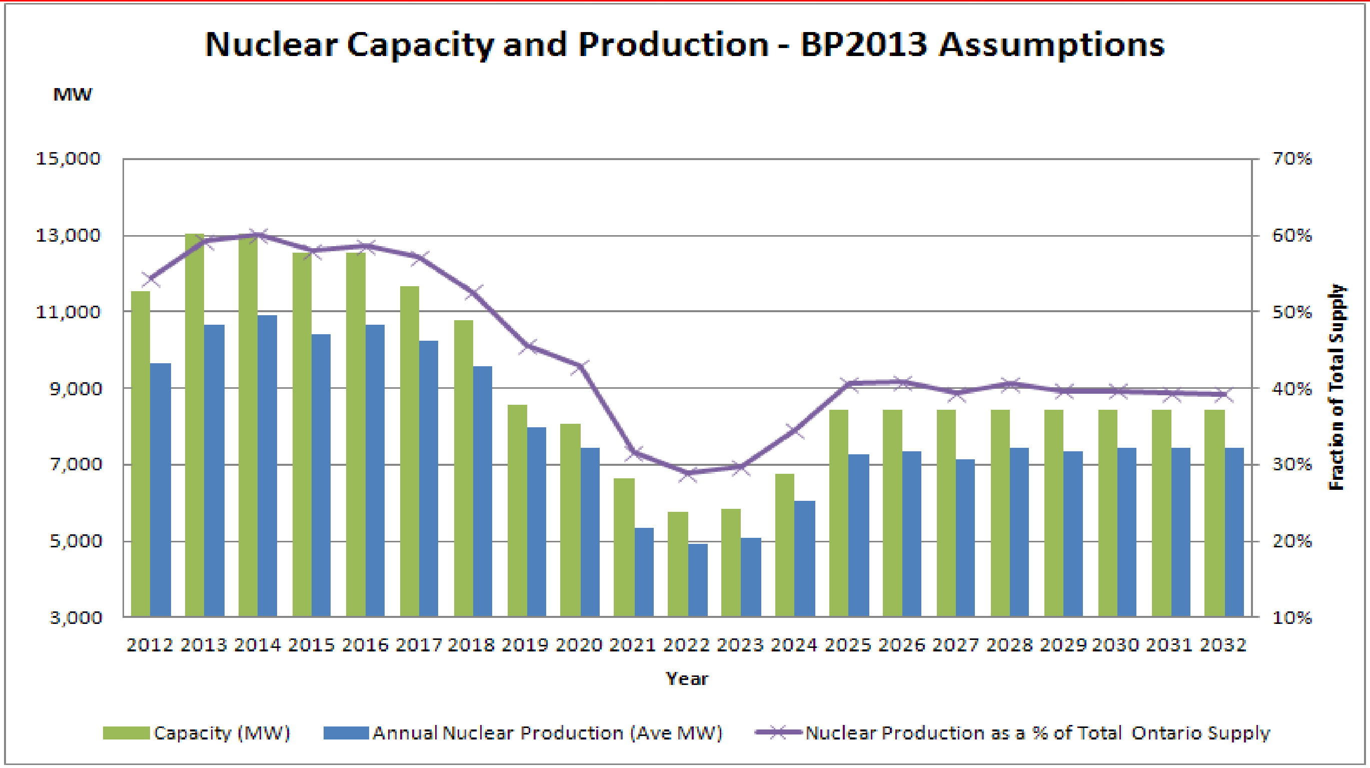
- OPG's baseload hydroelectric generation on the Great Lakes receives rates that are regulated by the Ontario Energy Board:
  - Beck Complex at Niagara Falls: 2000 MW
  - Saunders GS on the St. Lawrence River near Cornwall: 1000 MW

- With the exception of a few small newer units, OPG's remaining hydro resources are fully exposed to the market clearing price.
  - Most of these generating units have some storage capability, ranging from a few hours to a few weeks.
  - Ontario's hydro does not have large reservoirs like Quebec, British Columbia and Manitoba that can offer seasonal or multi-year storage.

- Several new hydro projects will add 500 MW and 2.5 TWh to the grid between 2013 and 2015. There are no further active plans for hydro development at this time.

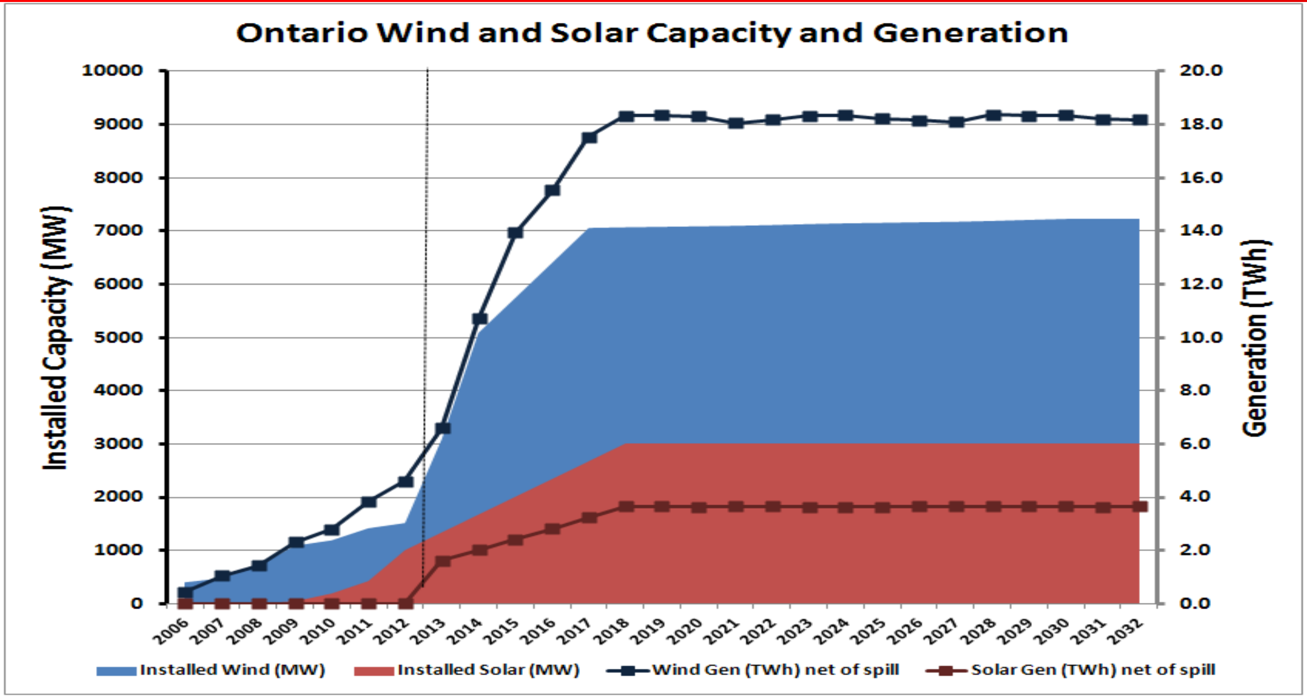
- Hydroelectric generation in Ontario pays a water rental fee for all water that is passed through a turbine to produce electricity. This can be considered the 'fuel' cost of hydroelectric generation. The water rental fee varies by the size of the station.

Nuclear Capacity will be need to be refurbished later this decade…..



- 6 Pickering Nuclear Units are expected to be retired by 2020 (3000 MW).
- Two (1500 MW) of the 4 Bruce A units have already been refurbished. OPG's BP2013 assumes that the 4 Bruce B units (3400 MW) will be refurbished starting in 2018.
  - The plans for the Bruce nuclear units are uncertain at this time.
- There is reasonable consensus that the 4 Darlington units (3800MW) will be refurbished between 2016-2024.

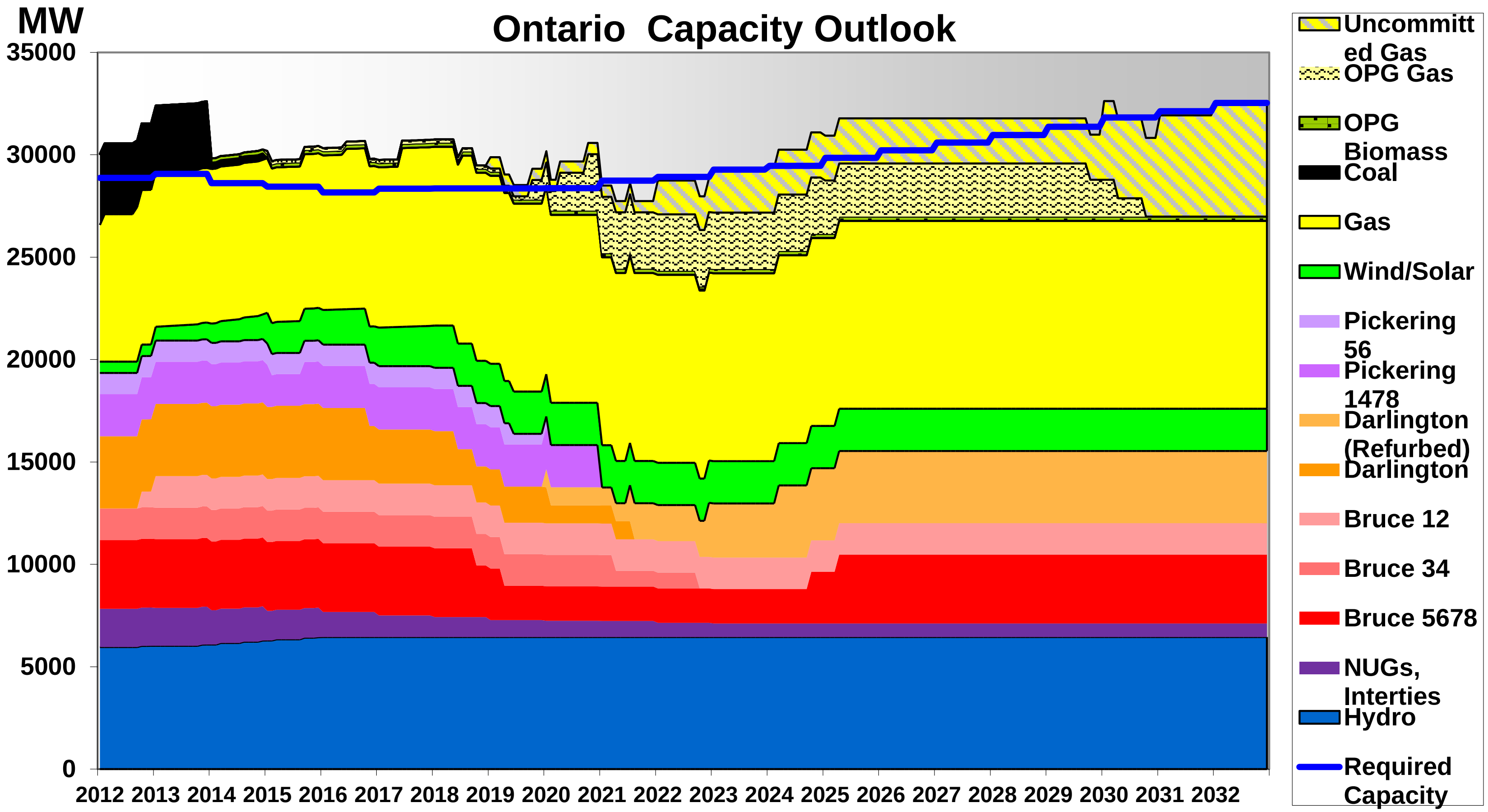
Wind + Solar grows to 10,000 MW and 22 TWh by 2018



- High proportion of 2018 targets effectively committed.
- Effective summer peak capacity contribution from 10,000 installed MWs is about 2,000 MW.
- Greatest renewable energy growth step occurs from 2013 to 2014.
- FIT Wind modeled as dispatchable, and hence curtailable for SBG, as per MR-381 with 90% offered at -$10MWh, 10% offered at -$25/MWh.

Ontario Effective Capacity Outlook

ONTARIO POWER GENERATION



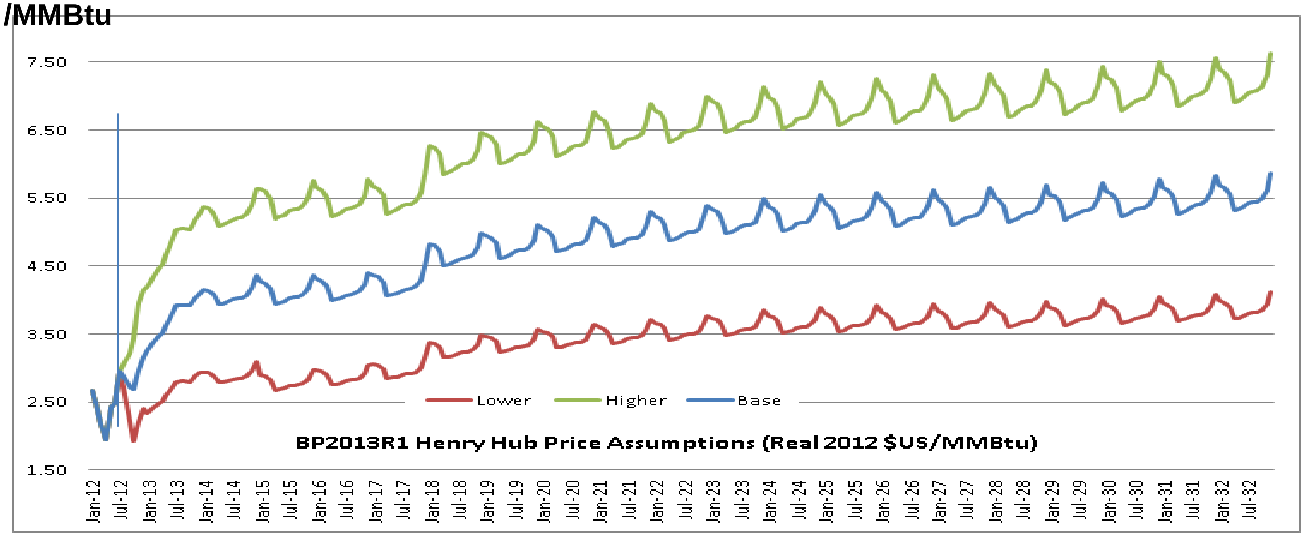
- The effective capacity at the time of the seasonal weather normal summer peak is shown vs. the required capacity (including a 20% reserve margin). The solid colors indicate installed/committed capacity. The shortfall will have to be made up by converting OPG's coal units to gas and/or building new Combustion Turbines (CT's).

Natural Gas prices expected to recover to over $4/MMBtu by 2014, about $5 by 2020 and $5.50 long-term.

ONTARIO POWER GENERATION

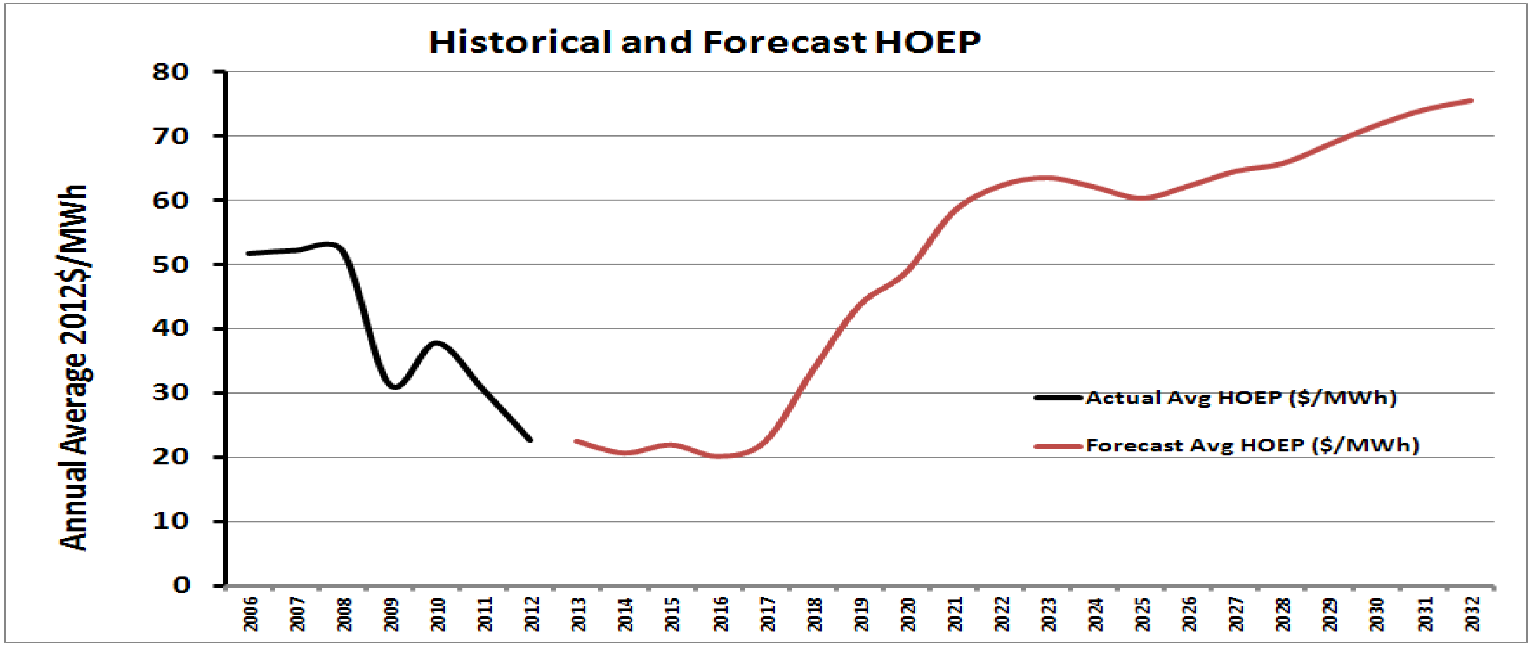
$2012 /MMBtu

BP2013 Gas Price Scenarios



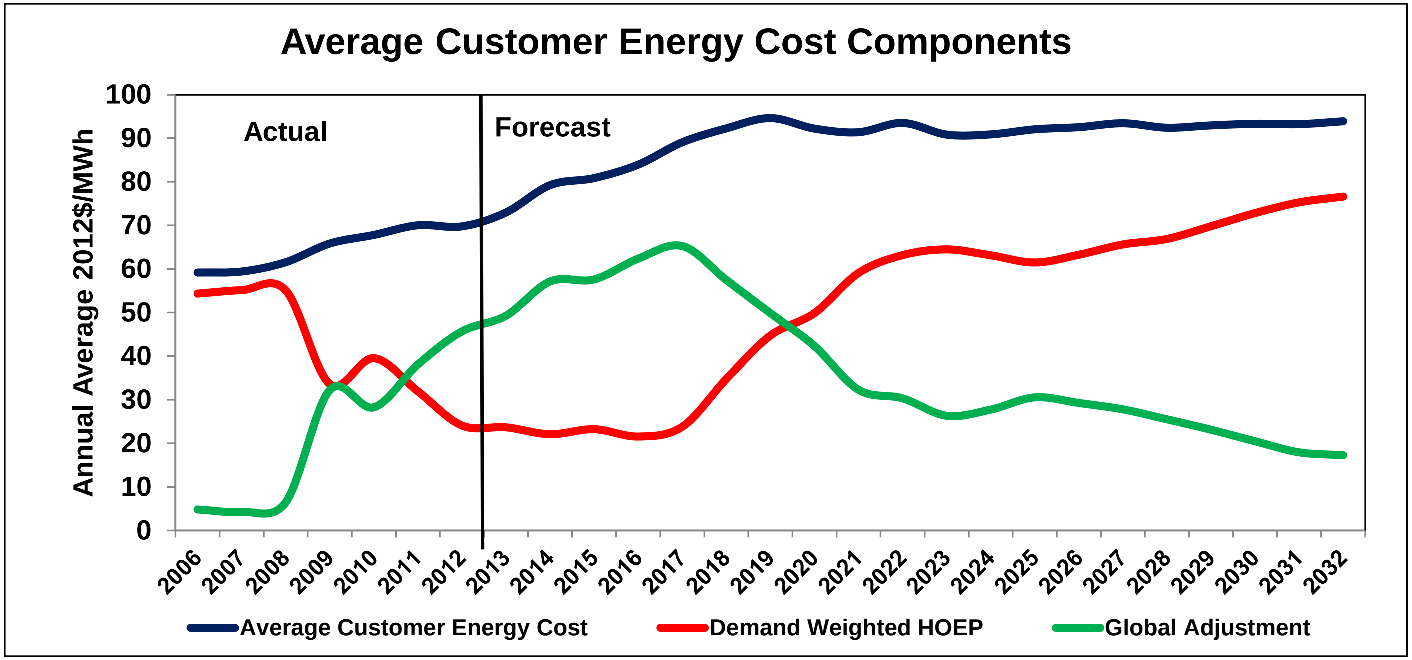
- Ontario has traditionally had a reliable supply of gas delivered through the TransCanada pipeline from Western Canada. A strong hub has evolved at Dawn near Sarnia with good storage capability for the Ontario market.
- With the development of shale gas in the US Northeast, new transmission is being built to connect these reserves into and through Ontario to enable ongoing stable supplies.
- Increasing interest in exporting Liquefied Natural Gas (LNG) from North America to Asia will slowly push Henry Hub prices towards world levels if shale gas production evolves as generally predicted.
- BP2013 includes carbon adders starting in 2018 at $15/tonne and increasing at $3/tonne/year.
  - By 2030, the carbon adder is $50/tonne, which adds about $25/MWh to gas-fired generation at a blended CCGT/CT heat rate.

HOEP expected to average less $20/MWh until nuclear refurbishment starts



- Annual Ontario HOEP expected to be in the $20/MWh range through to 2017 as the impact of increasing natural gas prices is more than offset by increasing volumes of renewable energy.
- Nuclear refurb outages drive Ontario HOEP to levels set by the high heat rate gas units (Lennox, converted coal units).
- After the nuclear refurbishment, increasing gas prices and projected CO2 costs will keep increasing HOEP.

Components of Energy Cost



- In Ontario, the Global Adjustment (GA) mechanism is a charge to customers that recovers the difference between the market price and revenues owed to regulated and contracted generators. Conservation and demand management expenditures are also recovered through GA.
  - Currently, GA is allocated to the wholesale cost of power equally across all hours.
- Before nuclear refurbishment starts in Ontario, the GA is much higher than the market price of electricity.
- After the nuclear recovery, and with higher gas prices, the market price rises, the GA diminishes and the average customer cost of energy stabilizes.

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ONTARIO POWER GENERATION

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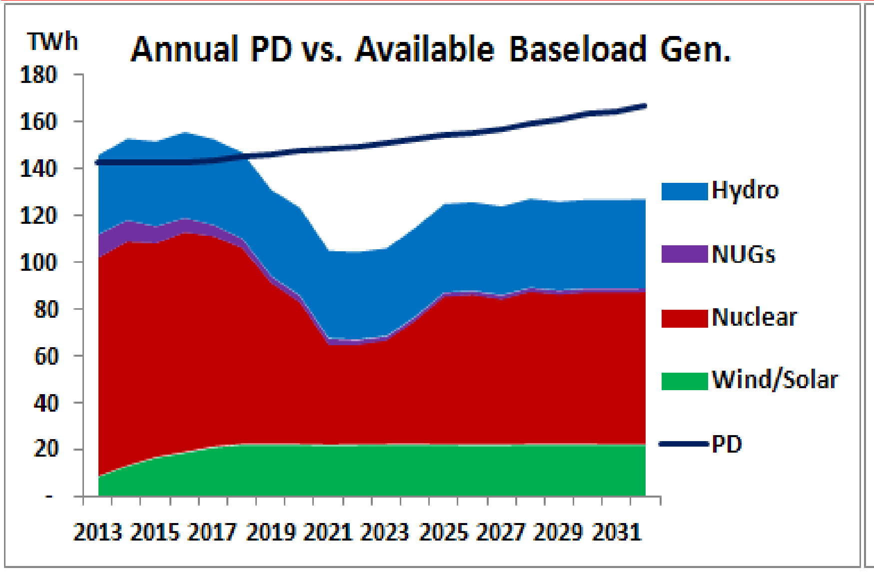
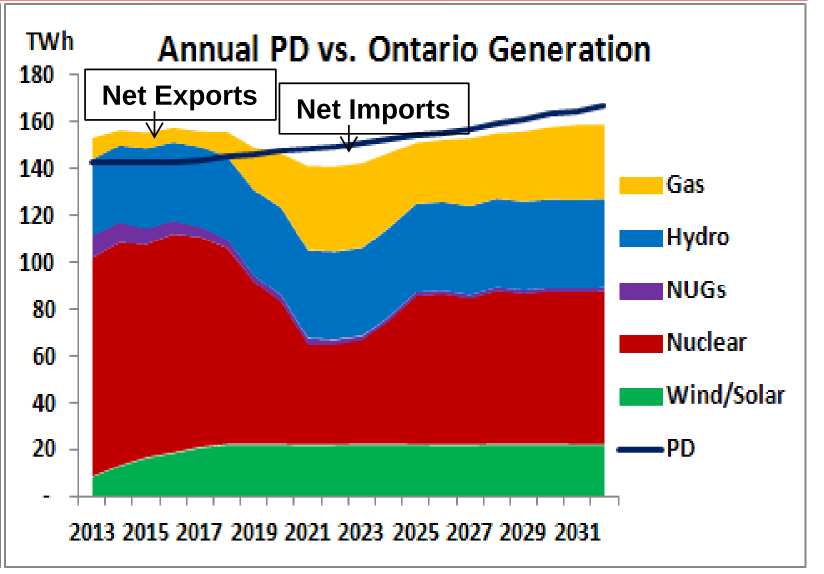
Annual Demand vs. Ontario Generation

ONTARIO POWER GENERATION

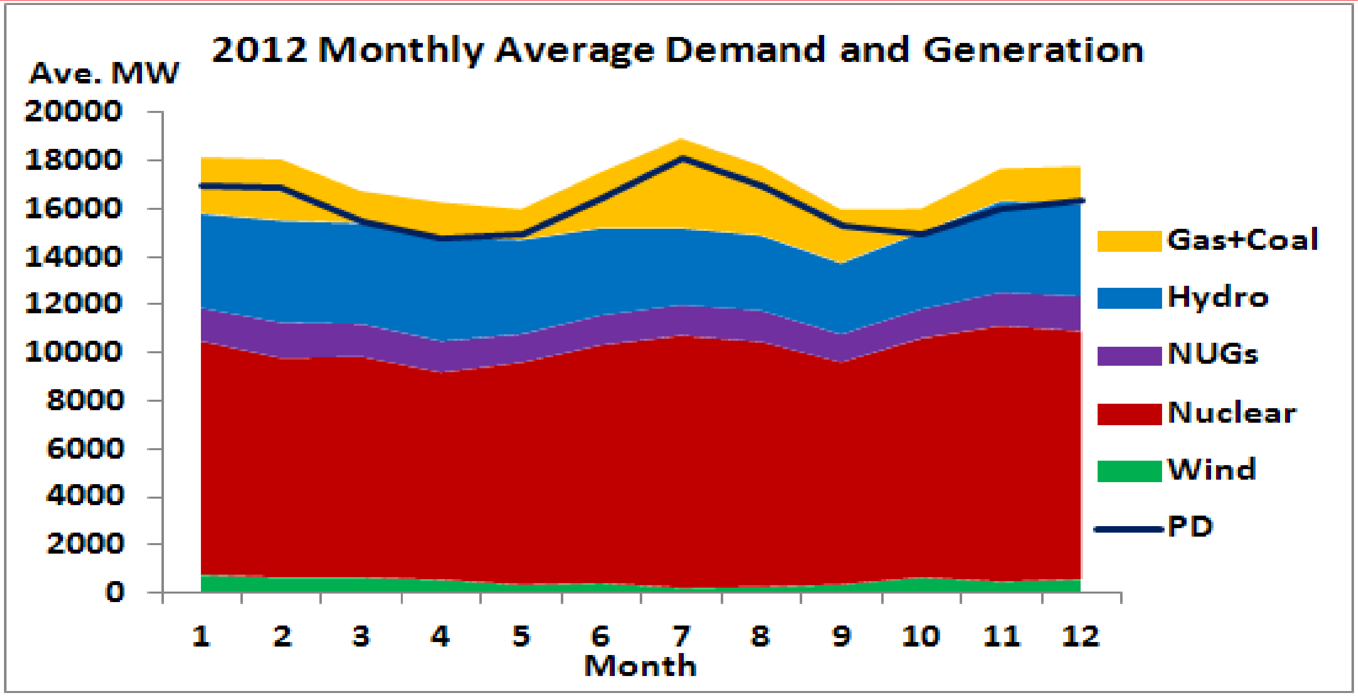




- Baseload generation is defined as:
  - Low marginal cost and no CO2 emitting generation such as nuclear, hydro or wind/solar
  - NUGs who have a contract ensuring that they can run
- In the 2013 to 2018 period the sum of this generation is more than the Ontario Primary Demand (PD), therefore some of this generation is surplus to the needs of the Ontario Electricity Consumer.
- Gas is dispatched when baseload generation is not available to meet demand.

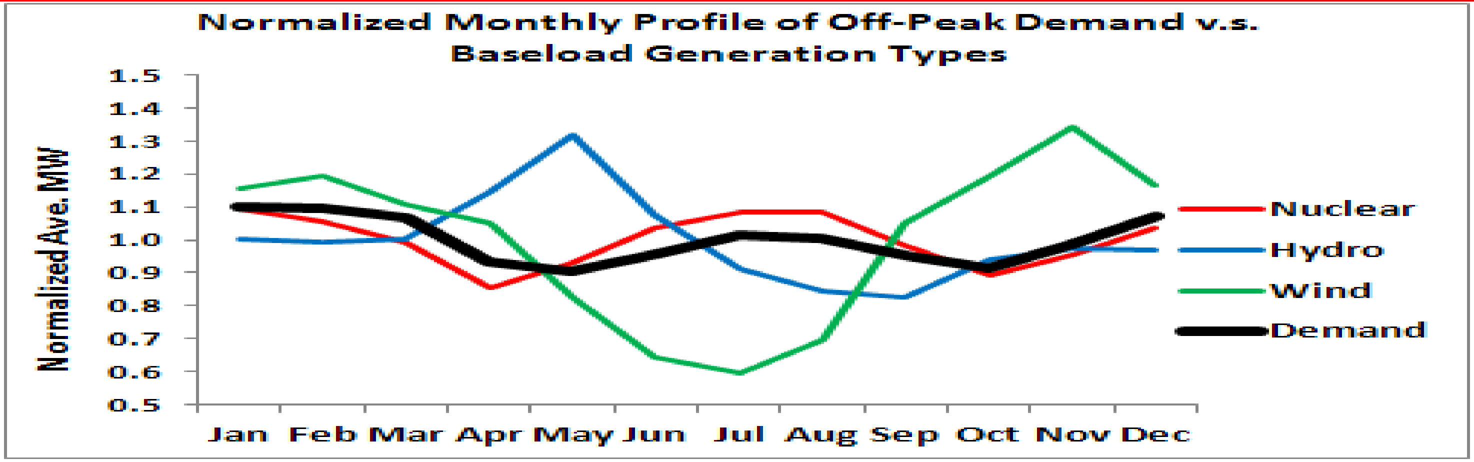
2012 Monthly Average Demand and Generation Profiles

ONTARIO POWER GENERATION



- The monthly average demand profiles shows that the Ontario system is clearly summer peaking.
- The Ontario system has been net exporting on average every month.
- However, in 2012, it does not yet have more baseload generation on average than demand. That starts in 2013.
- There was a small amount of SBG in 2012, due to the timing mismatch between demand and baseload generation.

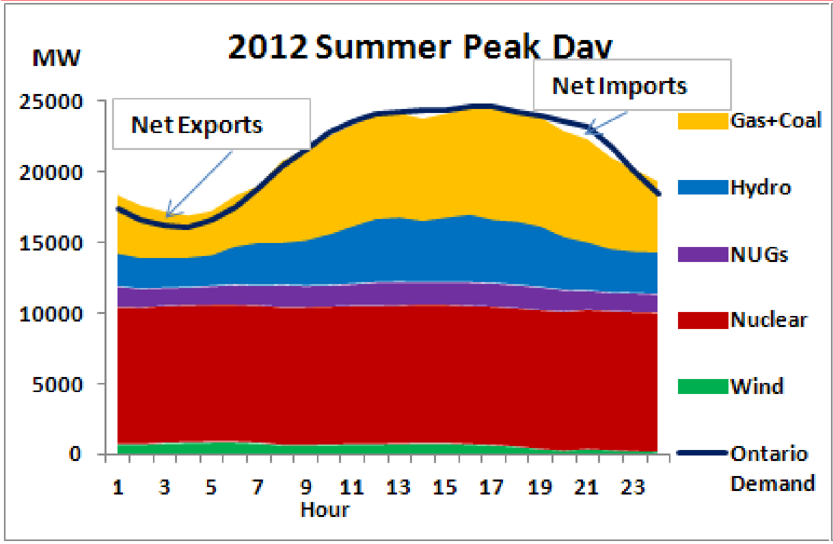
Monthly Profiles of Off-peak Renewable Generation

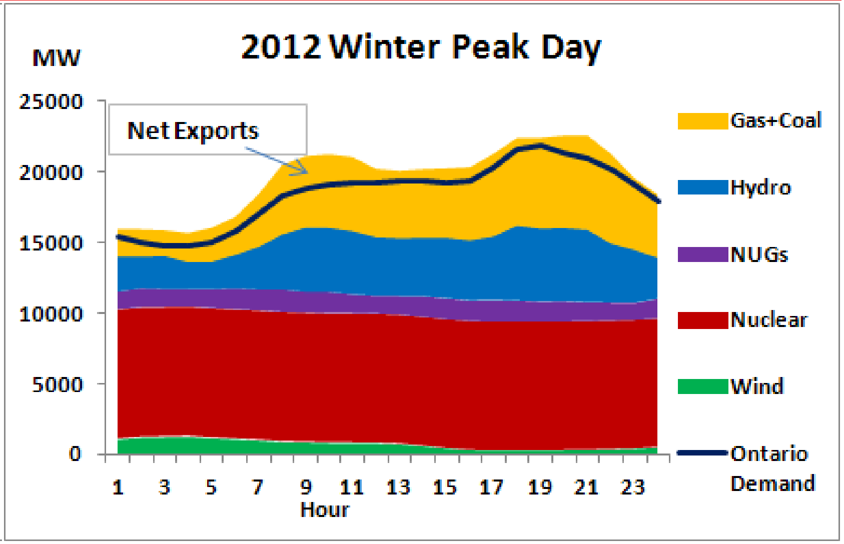


- Off-Peak energy demand is lowest in the spring and fall. When combined with spring hydro freshet and relatively strong winds in the shoulder seasons, April-June have the greatest surplus energy.

- The nuclear planned outage schedule contributes significantly to reducing spring and fall surplus.
  - Conversely, because nuclear planned outages are not typically scheduled for the summer, the amount of surplus energy in the summer can be higher than the winter.
  - Higher off-peak demand in winter than in summer also contributes.

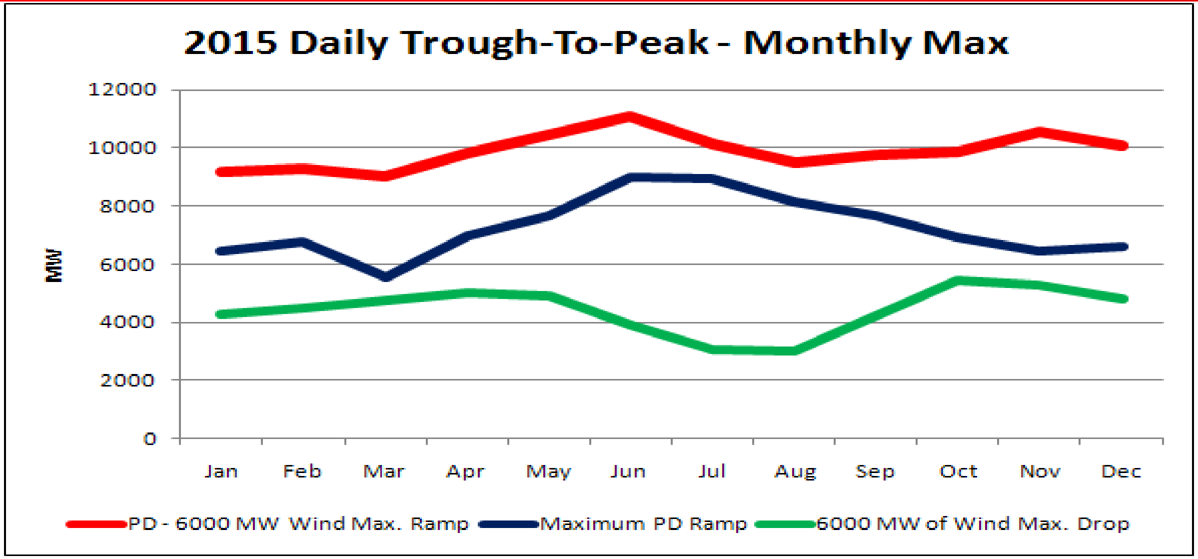
Summer and Winter Demand Profiles





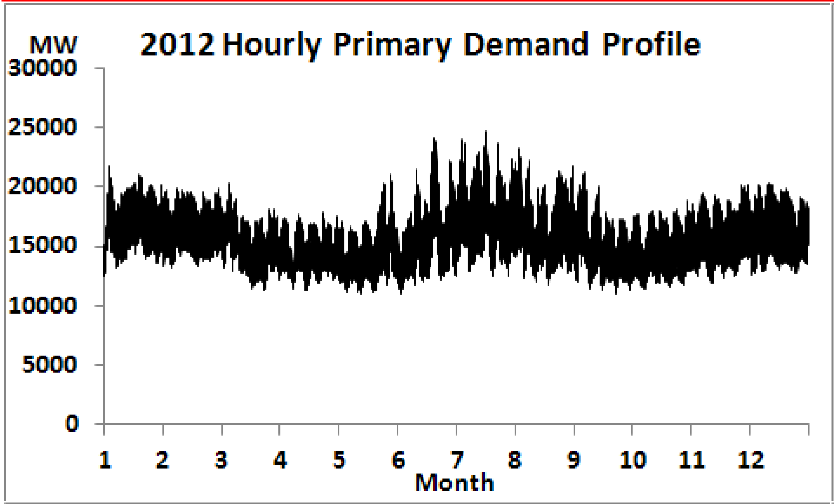
- In summer, demand in Ontario peaks in the early afternoon, due to air conditioning load.
  - This gives rise to the largest intra-day ramp requirement.
- In winter, there are two peaks, one early in the morning and the other around 6 pm.
  - The daily maximum ramp requirement is less than in the summer, but the daily energy requirement is higher.
- The flexibility of the peaking hydroelectric is used to follow demand net of wind. The remainder of the supply balancing is by gas and coal.
- Because there are some days when night time load has no A/C and the next day may be very hot, Ontario requires about 10,000 MW of ramping capability.

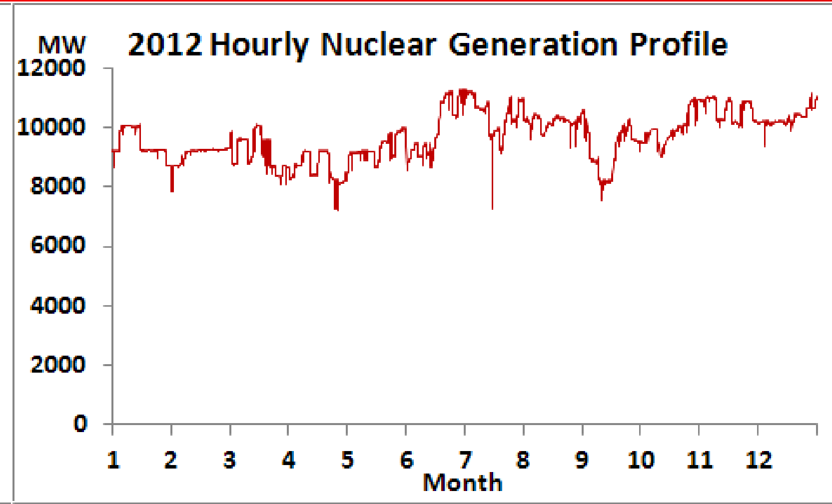
Monthly Pattern in Daily Maximum Ramp Requirement

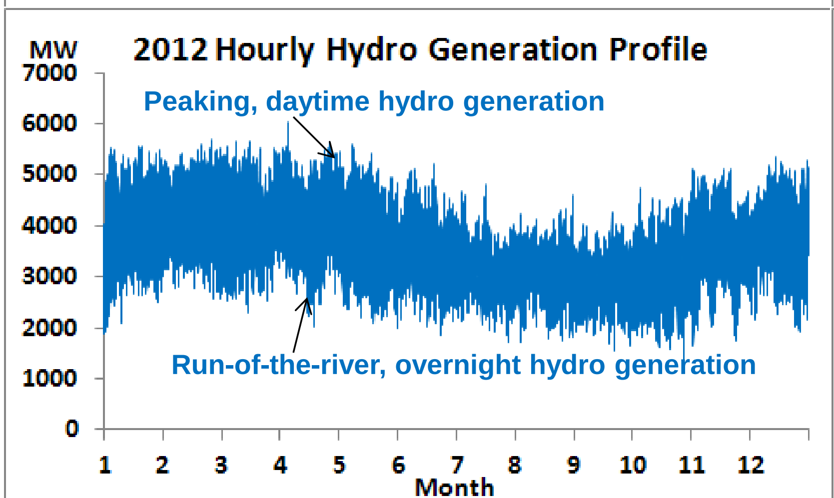


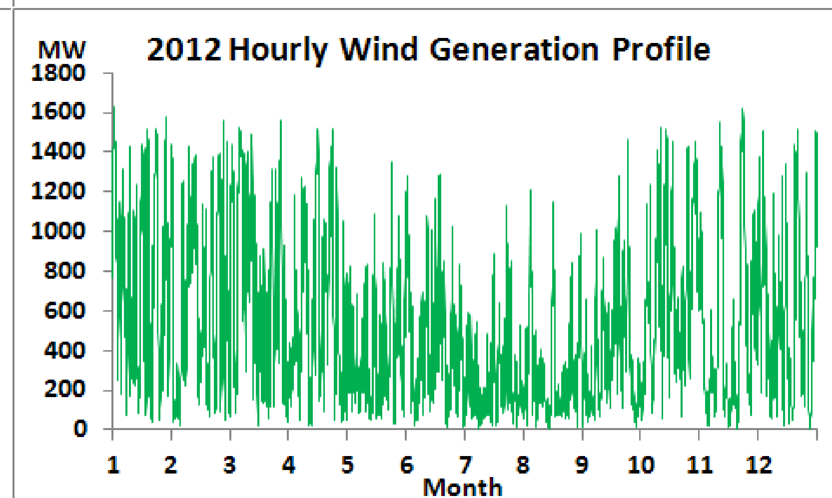
- The maximum daily ramp of the demand profile occurs in early summer, when there is not a lot of air conditioning at night, but it gets really hot during the day.
- The worst wind drop on a daily basis occurs in the spring and fall; the least in the summer.
- The combined effect of rising demand and decreasing wind generation increases the daily ramp requirement in winter drastically. It also adds moderate additional ramp requirement in the summer.
- With the addition of wind capacity, the maximum ramp requirement to be met by hydro and thermal system could occur almost any time of the year. As well, the daily peak requirement on the dispatchable system could occur at any hour of the day.

Hourly Profiles of Demand and Baseload Generation

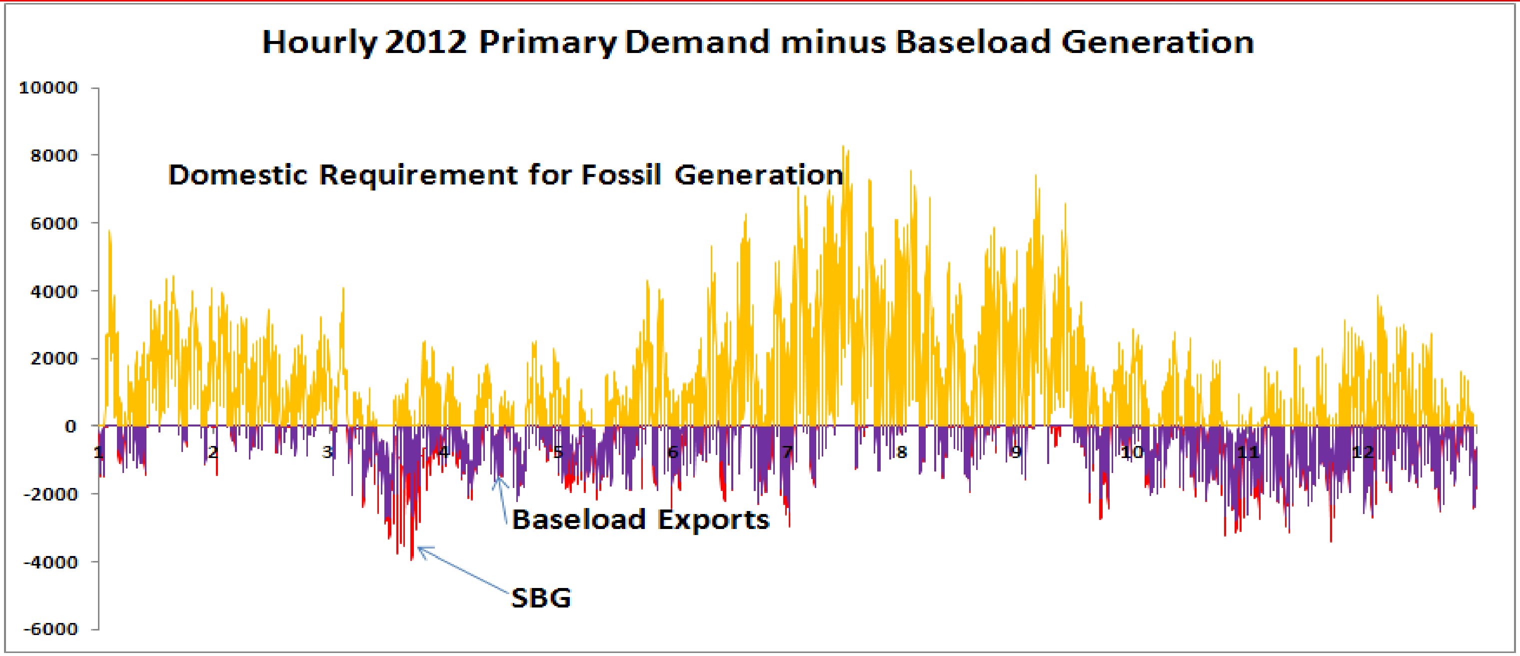








Actual 2012 Hourly PD-Baseload Generation



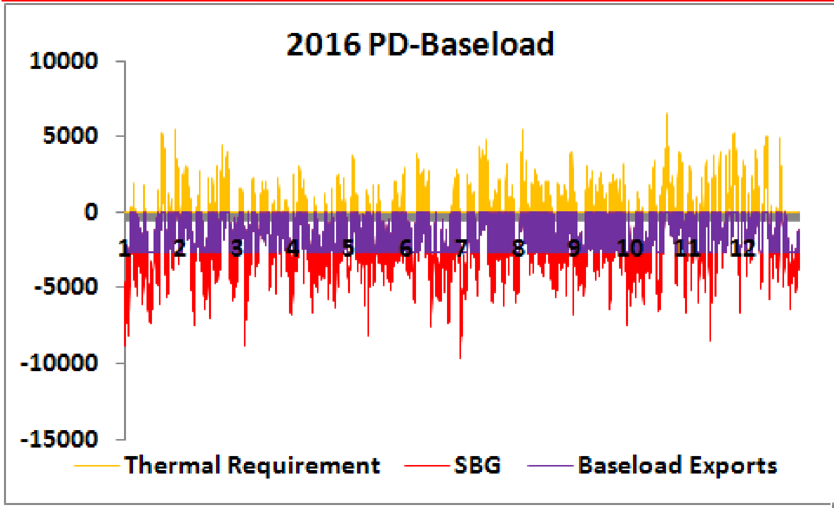
- When the Hourly PD-Baseload Generation (PD-Nuclear-Hydro-Wind-Solar-NUGs) is positive, domestic demand must be met with fossil generation (coal or natural gas) or imports.

- When the Hourly PD-Baseload Generation is negative, this potential surplus energy can be exported (at a loss to Ontario customers) or it becomes SBG (spill).

- In 2012, SBG was a relatively rare occurrence, amounting to less than 0.5 TWh. It was managed by spilling water and occasionally maneuvering nuclear units.

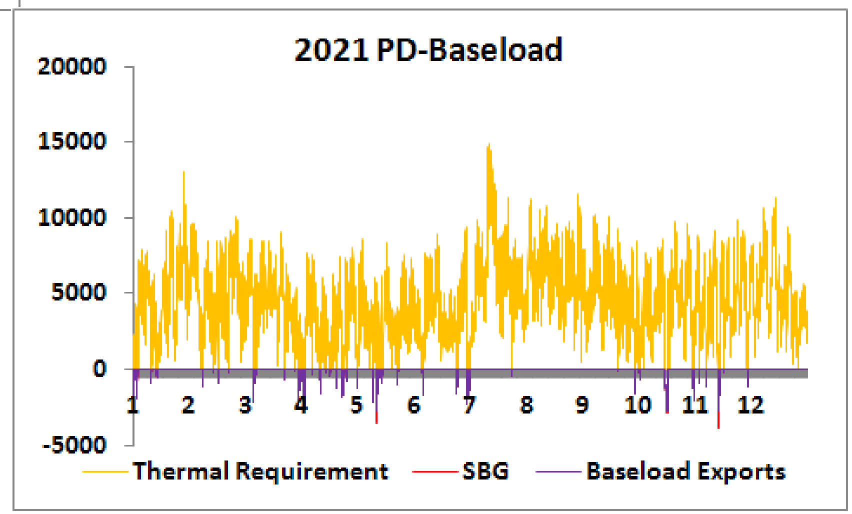
2016-Worst SBG, 2021-No SBG

ONTARIO POWER GENERATION

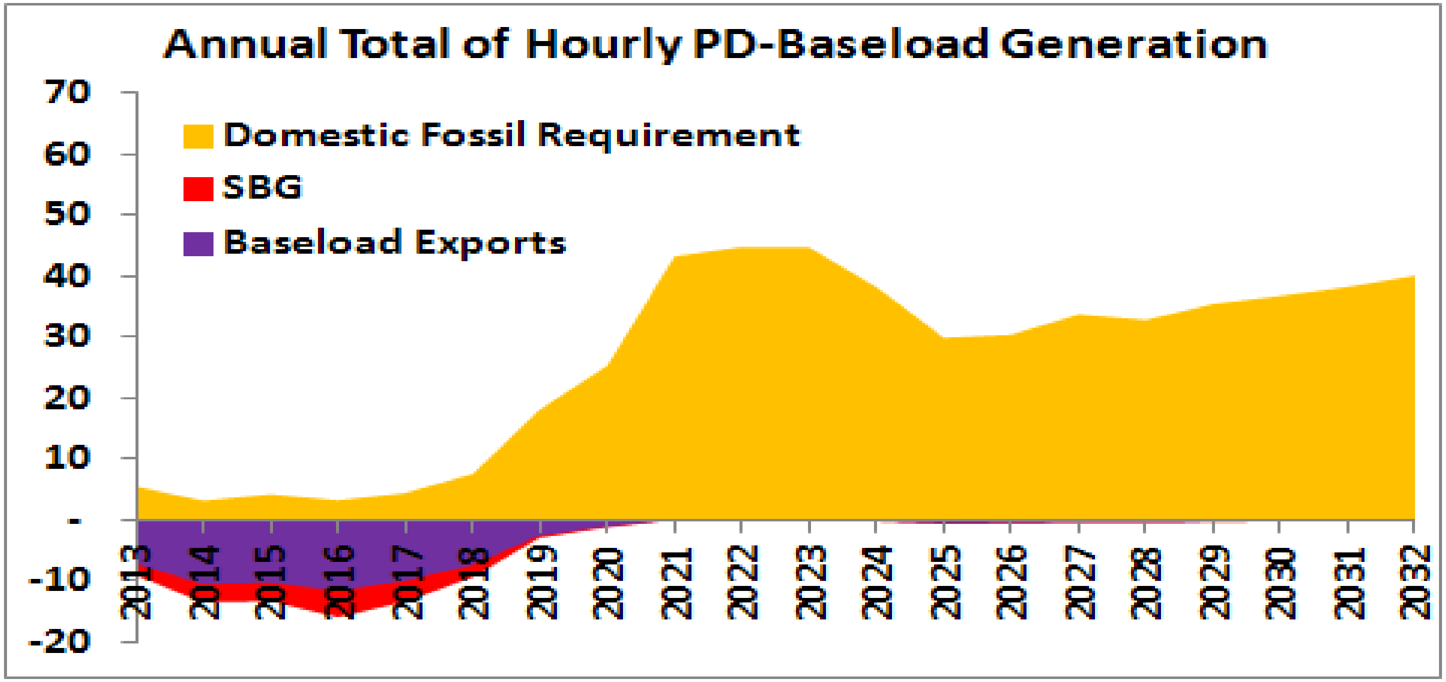


- With wind and solar being added rapidly in the next few years with sluggish demand growth net of conservation and demand management, baseload exports and SBG are forecast reach their peak in 2016.
- Prices are expected to clear at baseload/spill prices sometimes all day.

- In 2021, with 6 nuclear units at Pickering retired and some Bruce Power and Darlington Nuclear units under refurbishment, the surplus problem will disappear.
- The market will clear at gas prices, either CT or CCGT.

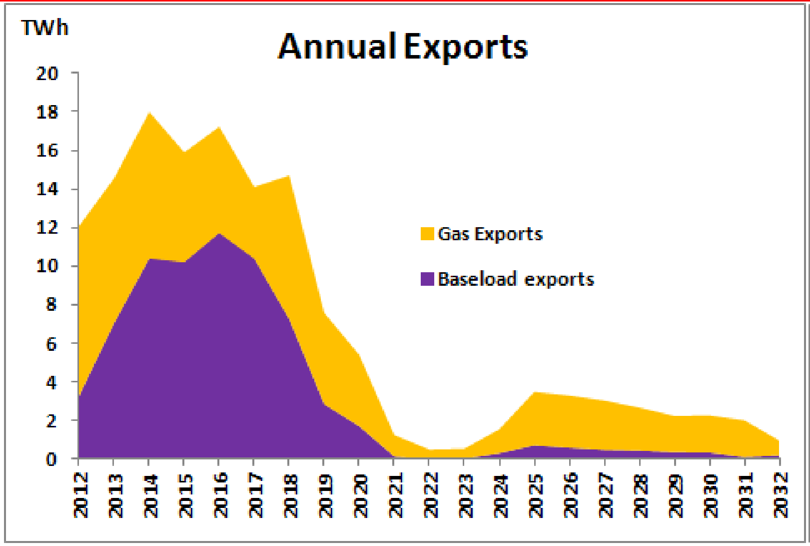


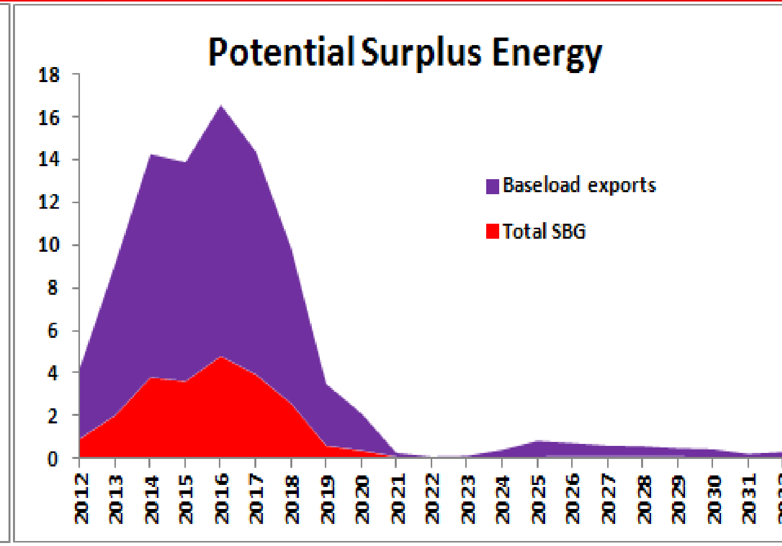
Annual Summary of PD-Baseload Generation



- The current surplus period is forecast to last until nuclear refurbishment starts.
- Due to the timing mismatch between renewable generation and electricity demand, even in the worst surplus years, there is some demand for fossil generation.
- After the refurbished nuclear units return to service, with the presently forecasted level of nuclear capacity, potential surplus energy and SBG will be negligible.
- During the nuclear refurbishment period, the domestic demand for gas/imports will be up to 55 TWh per year.

High net exports will continue until 2018

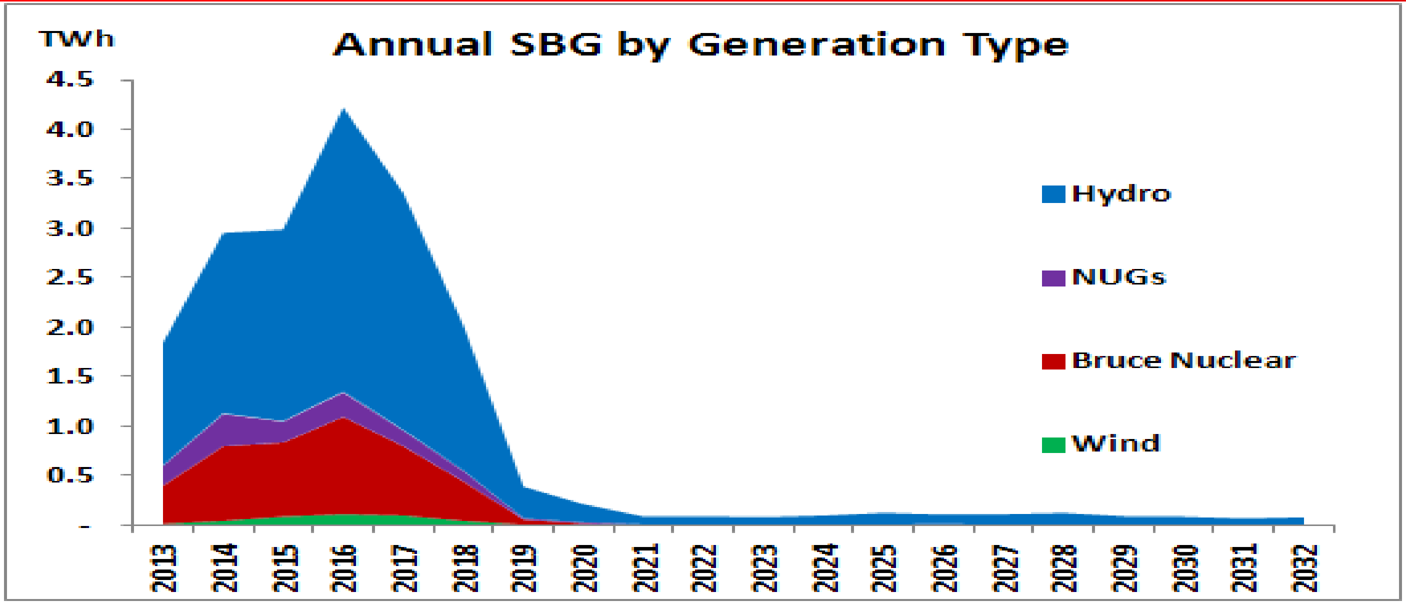




- The province's net exports average about 15TWh per year from 2013 through to 2018.
- Ontario exports gas-fired generation at market prices, but up to 12 TWh per year of excess baseload generation is expected to be sold at well below cost in the export market.
  - When exporting fossil generation, Ontario usually recovers the marginal cost, except if the units were offered at unit commitment prices and are required to stay on for the minimum up-time at their minimum laminations.
- In addition to baseload generation exported at a loss, surplus energy includes SBG in Ontario of about 4 TWh per year. Total potential surplus energy of up to 16 TWh a year is projected from 2013 to 2018.

SBG Management

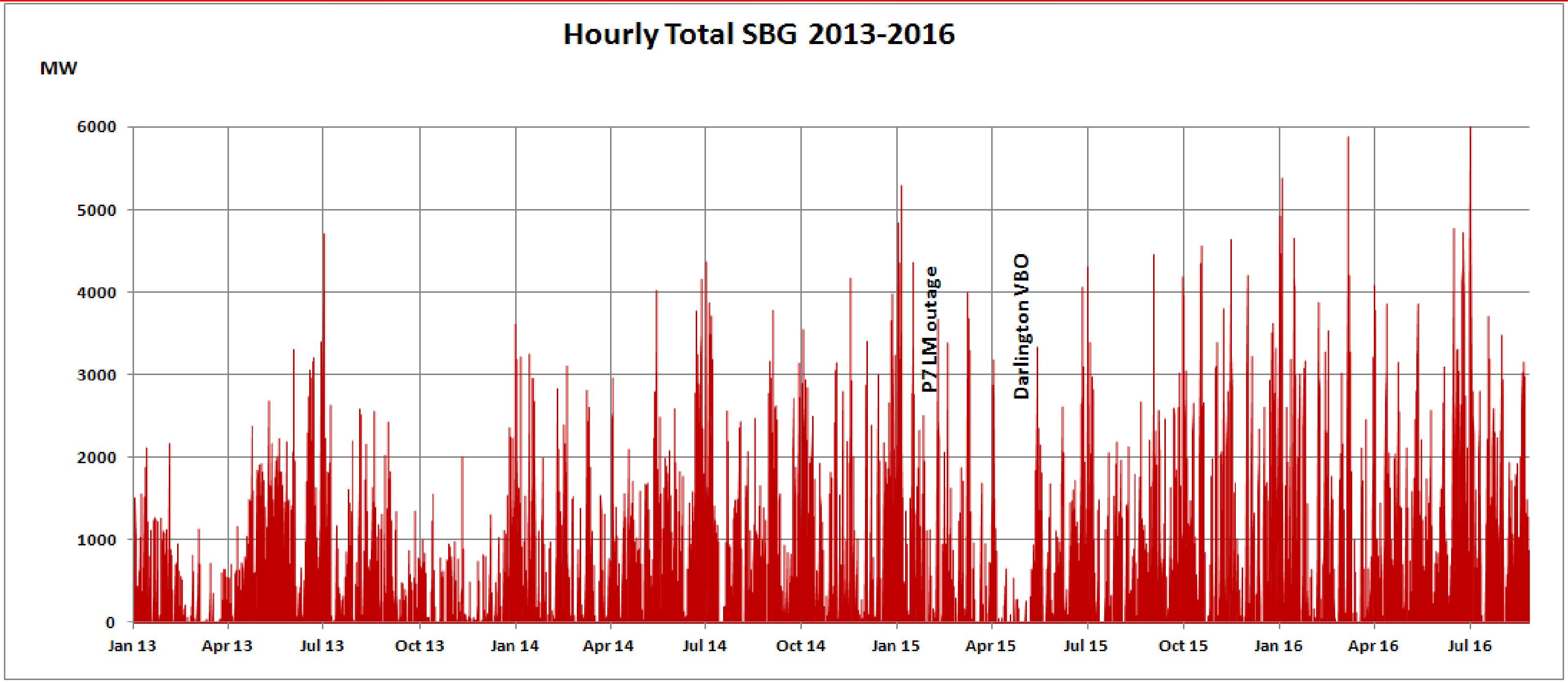
ONTARIO POWER GENERATION



- BP2013 assumed that a new set of market rules designed to facilitate the integration of Renewable Energy (MR-381) would come into effect.
- Under this regime, hydro generation spills first, followed by 2400 MW Bruce Power units manoeuvring and the residual SBG will be handled by spilling wind.
  - This is achieved by introducing a floor of -5$/MWh for Bruce manoeuvring and -$10 to -$25/MWh for wind.
  - In practice, the IESO says it will use wind dispatchability to micro-manage small changes in SBG and Bruce manoeuvres will be committed in 300 MW blocks.
- Between 2012 and 2015, Ontario's Local Distributing Companies (LDC's) have been allocated $350 million per year to deliver conservation programs.
- Without renewables, SBG in the pre-nuclear refurbishment period would be reduced by 80%.

Simulated Hourly Total SBG (2013-2016)

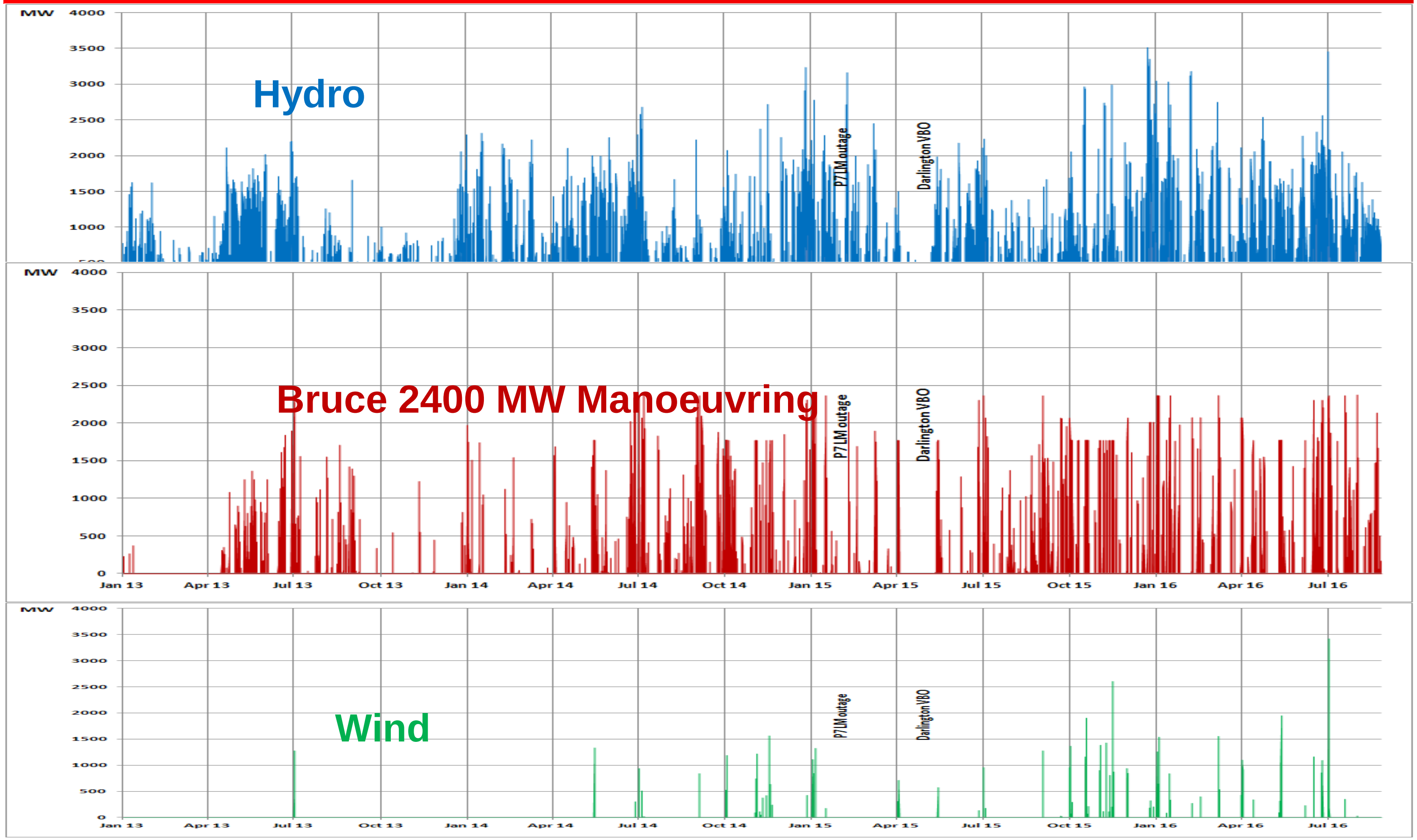
ONTARIO POWER GENERATION



- In the 2013-2016 period, SBG occurs in 45%(!) of hours, requiring OPG's hydro to be spilled for about 3500 hours/per year.
- Approximately, 8% of hours, or 700 hours/year, will require nuclear manoeuvring after all spillable hydro has been spilled.
- The residual SBG will be handled by wind. Wind will be called on to be dispatched down about 0.8% of the time or about 70 hours per year.

Hourly SBG by Generation Type (2013-2016)

ONTARIO POWER GENERATION



The Economics of Hydro Spill

- OPG's non-regulated hydro resources are offered into the market in a manner which is designed to at least recover their marginal running cost, recognizing the water rental fee.

- It is in OPG's financial interest not to generate when the cost of production (including water rental fee) exceeds the revenue earned from the market, as any production would be at a loss in net revenue.
  - Much of the time, water can be stored in the forebay to avoid generating
  - However during and following periods of high runoff, storage capability can be limited or exhausted. All water must then be utilized to generate to the extent feasible, or be passed through sluice gates as spill.
  - With some foresight, hydroelectric spill can be initiated earlier in an effort to mitigate negative revenue impacts. These pre-emptive hydroelectric spill tactics are known as 'pre-spill' for short.

- There are many operational considerations that may limit the ability to spill or pre-spill. However, for most scenarios where excessive surplus generation is expected in many hours over a longer duration of at least 5 days, the economics of pre-emptive hydroelectric spill are usually favourable and, as good utility practice, it is the right thing to do.

- It is ironic that over the next few years, these spilling tactics may be precipitated to accommodate an excess supply of wind offering with a negative floor price.

Outline

- Introduction to Ontario Power Generation and the Ontario power market
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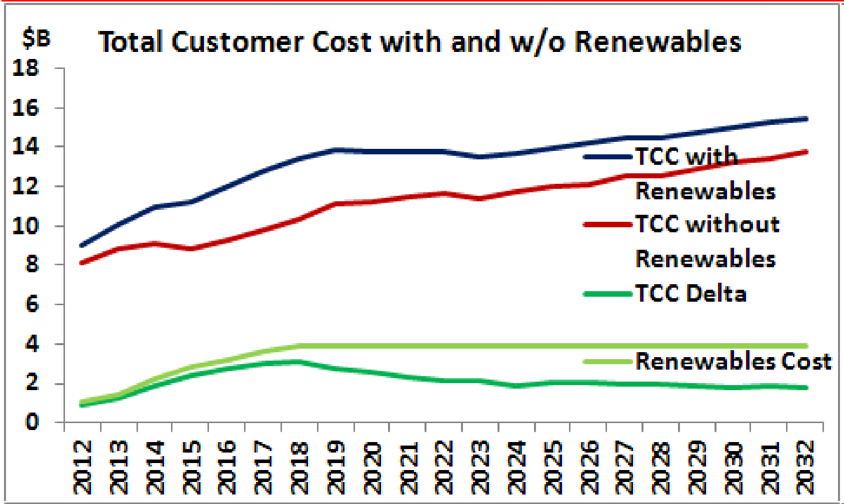
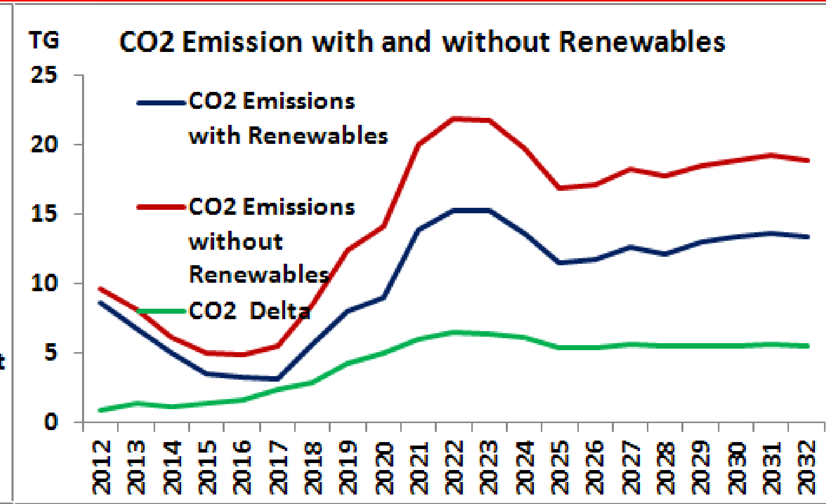
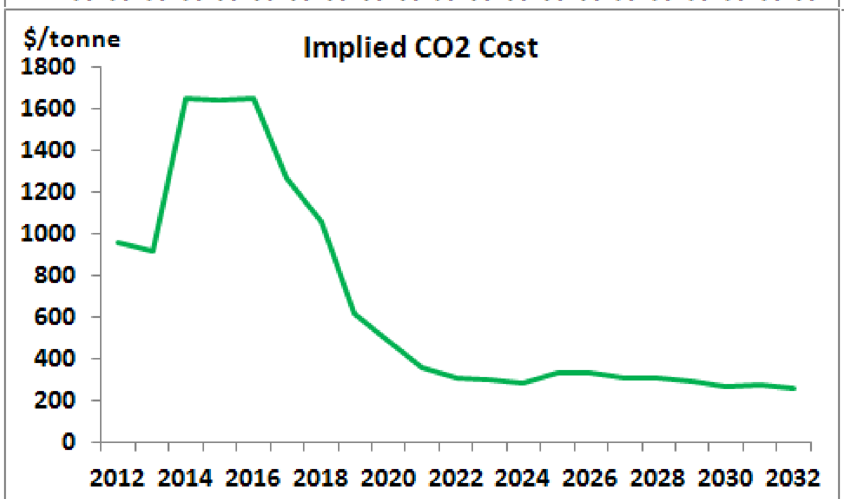
Implied CO_2 Cost with and without Renewables - a measure of system optimality

ONTARIO POWER GENERATION







- The cost of renewables rises from $1B/year now, to $4B/year by 2018.
- The incremental (delta) Total Customer Cost due to renewables rises from $1B/year now to $3B by 2018 and then settles at $2B after the nuclear recovery.
- The avoided CO_2 emissions rise from 1 TG/year now to 5 TG/year.
- The implied CO_2 cost in Ontario's renewable investment is $1000/tonne now, but will rise to over $1600/tonne in the worst SBG years, and then settle at around $300/tonne.

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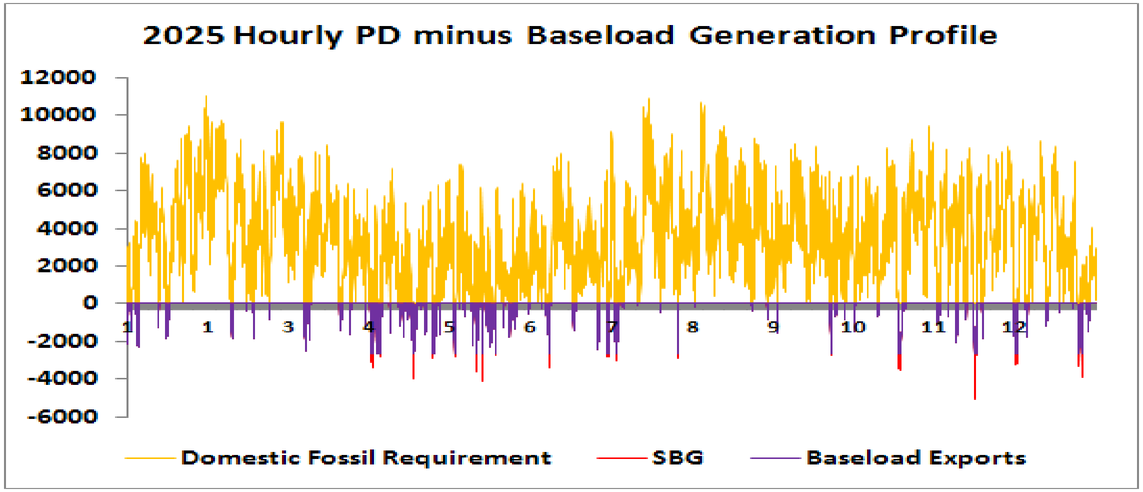
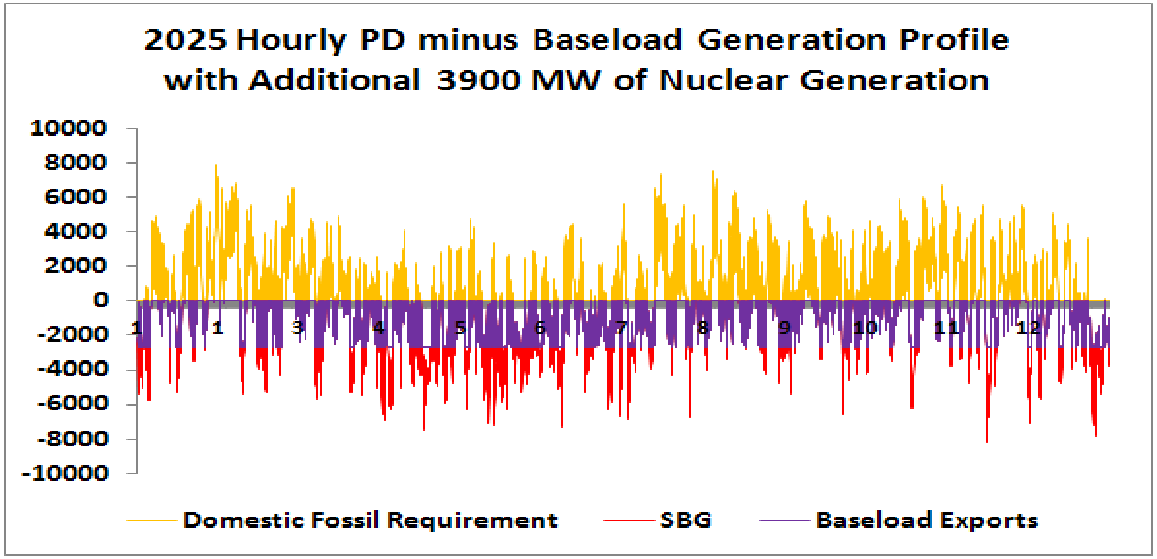
How much Nuclear in the mid-2020's?

- Ontario's Long-Term Energy Plan places significant, but not clearly specified, premiums on carbon-free and renewable energy, reduced dependence on imported fuels and less exposure to fuel or carbon price risk going forward. In this context, how much nuclear should be on the Ontario system given installation of the targeted 7000 MW of wind?

- As the plot below shows, with 10 nuclear units in-service in 2025, the Ontario power system has about the right amount of nuclear generation so that the 7000 MW of wind is displacing gas-fired generation or imports, rather than nuclear and hydro, as in the present decade.



How much Nuclear in the mid-2020's?



- For instance, if nuclear supply in 2025 increased by refurbishing two more Bruce units (1500 MW) and adding two new nuclear units (2400 MW), it would recreate the 2017 SBG conditions.

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Pumped Storage at Niagara

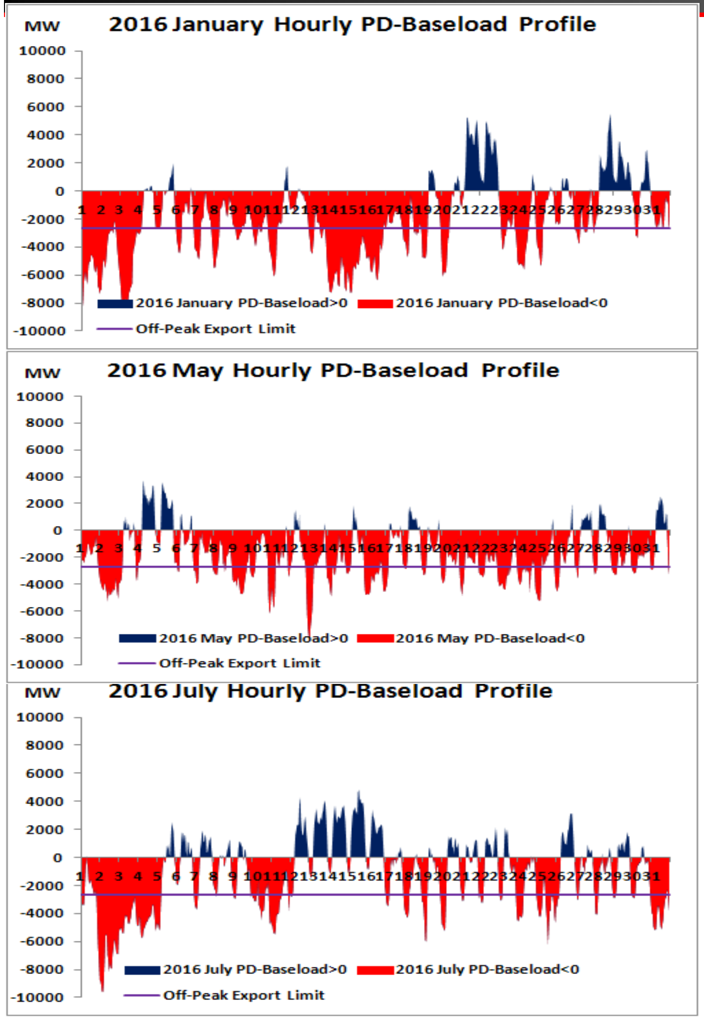
ONTARIO POWER GENERATION

- Ontario has a Pumped Generating Station (PGS) at Beck as part of the Niagara Falls Complex.
  - It consists of 6 units, an average head of 20 m, generating about 100 MW at efficiency.
  - With each cubic metre per second (cms) of water that goes through the PGS in generation mode, we get about 0.18 MW.
- Beck has 24 units with an average head of 90 m, generating about 1800 MW at efficiency.
  - The same cms of water used by the PGS generates 0.80 MW at Beck.
- The Beck-PGS has about 10 hours of storage.
- **While the PGS itself is only about 70% efficient, the combined efficiency of the Beck and PGS is above 90%.**

The Beck PGS and SBG

- The Beck PGS can help manage SBG and is the most efficient pumped storage facility in Ontario. It is expected to be able to time-shift about 0.5 TWh of energy per year.
- During SBG periods, the PGS can pump away surplus power at night and generate the next day, if there is room in the Beck generators.
- Because of the high combined efficiency of the PGS/Beck Complex, it can also pump if the marginal unit at night is CCGT gas, and generate if the marginal unit is CT gas the next day.
- Other pumped generating stations of 60-70% efficiency have difficulty playing the CCGT/CT arbitrage, which is also around 70%.

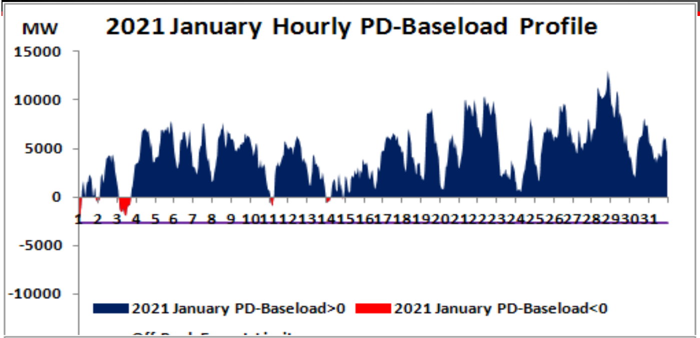
Assessing the Benefits of New Storage
2016: High SBG Conditions Year-Round

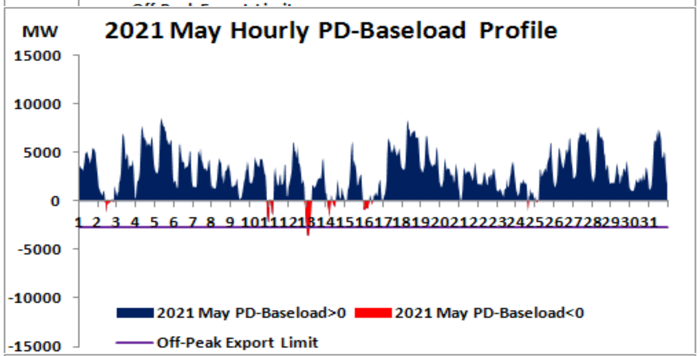


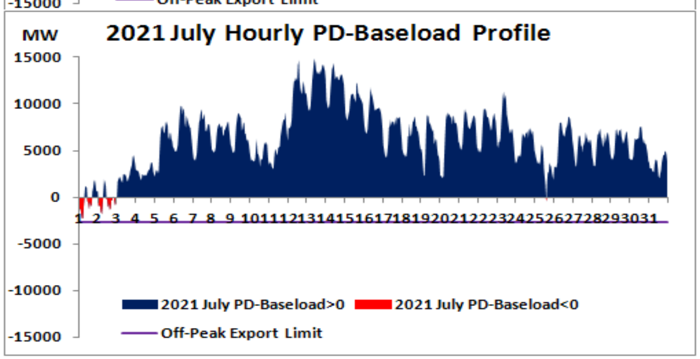
- These plots show expected weather-normal, *hourly* Primary Demand minus Baseload for a typical winter, spring and summer month in 2016.
- Negative values in red indicate that a baseload resource is at the margin.
- Positive values in blue indicate that gas-fired generation is at the margin.
- Ideal conditions for a short-term storage facility would show red periods alternating with blue periods.
- In summer, a reasonable proportion of the days do show conditions conducive to use of storage. In the other seasons, the number of opportunities is limited.

Assessing the Benefits of New Storage
2021: Minimum Nuclear Supply

ONTARIO POWER GENERATION







- With Pickering reaching End of Life, and 2 units each at Darlington and Bruce B assumed to be off line for refurbishment (BP2013), only about 4000 MW of nuclear is operating in 2021. The picture looks similar from 2018 to 2023.

- The charts indicate that that there are very few hours when baseload (red) is at the margin. This implies there is little cheap energy for pumping off-peak available.

- Most hours gas, or imports that displace gas, are at the margin. The expected maximum price differential under these conditions is about 30%. This is about the same as the efficiency loss through storage, leaving little margin to recover fixed costs.

- There were many years in Ontario where coal was on the margin both on and off peak – this is not a new situation.

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Key Messages

- Ontario has chosen a path towards a “clean and green” energy future:
  - Stop the use of coal for generation by the end of 2014.
  - Purchase 10,700 MW of renewable generation via feed-in-tariffs.
  - Refurbish nuclear generation later this decade.
- The consequence is surplus energy in the short-term and a steep increase in the customer cost of energy in the longer-term.
- In the next few years, the combination of high nuclear and wind generation in a system which already had a significant hydro capability results in periods of wasted energy (spilled or exported at a loss). The seasonal timing mismatches between electricity demand, hydro and wind generation exacerbate the problem.
- The management of SBG in Ontario will mean spilling hydroelectric generation (often requiring pre-spill), maneuvering nuclear units and shutting down wind generators. It is the cumulative effect of the FIT contracts and the prevailing economic incentives that are creating this order of SBG management.
- After nuclear refurbishment around 2025, adding additional nuclear generation, given the current level of committed wind, would reintroduce the surplus problem, and raise customer cost, based on the currently expected gas/carbon prices for that period.
- New storage technologies need to become more efficient and lower capital cost to become economic against combustion turbines and to contribute economically to accommodating more nuclear supply.
- The implied CO_2 cost is a useful measure to compare investments in different technologies that replace CO_2 emitting generation.

Thank you & Discussion

GEC Response to APPRO Interrogatory #6

Question:

Reference: i) Evidence of Mr. Chernick page 9 and Table 1.
ii) Evidence of Mr. Chernick page 15.

Preamble: The evidence indicates that:

> "*Most of these analyses estimated that a 1% reduction in US gas consumption would reduce gas prices by about 1%-3%. For the current forward Henry Hub supply prices for 2016-2020, a price reduction of 1%-3% would be about US \$0.034-\$0.10/MMBtu or about \$0.001-\$0.004/m3 (in U.S. dollars).*"

a) Please provide any and all forward price curves for gas at Henry Hub that Mr. Chernick considered or relied upon for this statement.
b) Please provide any and all updated forward price curves for gas at Henry Hub following the recent release of the U.S. Environmental Protection Agency's final Clean Power Plan (**CPP**).
c) Please provide any and all assessments of the impact of the CPP on U.S. gas demand.
d) Please provide data for Table 1 to reflect the period and estimates in years from 2005 to 2015.
e) Please comment on how load reductions and decontracting affected the costs of gas transportation in Canada along the TransCanada Pipeline (**TCPL**) mainline routes with specific reference to the regulated tolls resulting from the National Energy Board RH-003-2011 and RH-001-2014.

Response:

a) Mr. Chernick did not record the specific forwards he consulted before making this statement. See Excel Attachment 1 Tab 1 for a table of Henry Hub prices for July 1, July 15 and July 31.
b) See Excel Attachment 1 Tab 2 for the forwards for settlements on August 3 (the date the final CPP was released) through August 7.
c) Mr. Chernick has not attempted to assemble all such assessments. The following table is reproduced from the Regulatory Impact Analysis for the Clean Power Plan Final Rule, Table 3-18, Projected Average Henry Hub (spot) and Delivered Natural Gas Prices.

	Henry Hub (2011$/MMBtu)		
	2020	2025	2030
Base-Case	$5.20	$5.12	$6.01
Rate-based	$5.48	$4.73	$6.21
Mass-based	$5.40	$4.97	$5.92
Change from Base Case			
Rate-based	5.4%	-7.5%	3.3%
Mass-based	3.9%	-3.0%	-1.4%

Witness: Paul Chernick

d) See p. 8-302 of "Putting Downward Pressure on Natural Gas Prices: The Impact of Renewable Energy and Energy Efficiency," Wiser, R., et al, 2004 ACEEE Summer Study on Energy Efficiency in Buildings, pp. 8-294 to 8-308, attached as Attachment 2. That Attachment also provides complete cites to the studies, if APPrO wishes to investigate further.
e) Load reductions reduce the cost of transportation on the TCPL mainline (or any other pipeline). Under some circumstances, reductions in throughput result in higher rates (as largely fixed costs are spread over lower sales), but the total cost to customers will stay the same or decline.

Putting Downward Pressure on Natural Gas Prices: The Impact of Renewable Energy and Energy Efficiency

Ryan Wiser, Mark Bolinger, and Matthew St. Clair, Lawrence Berkeley National Laboratory[1]

ABSTRACT

Increased deployment of renewable energy (RE) and energy efficiency (EE) is expected to reduce natural gas demand and in turn place downward pressure on gas prices. A number of recent modeling studies include an evaluation of this effect. Based on data compiled from those studies summarized in this paper, each 1% reduction in national natural gas demand appears likely to lead to a long-term average wellhead gas price reduction of 0.75% to 2.5%, with some studies predicting even more sizable reductions. Reductions in wellhead prices will reduce wholesale and retail electricity rates, and will also reduce residential, commercial, and industrial gas bills. We further find that many of these studies appear to represent the potential impact of RE and EE on natural gas prices within the bounds of current knowledge, but that current knowledge of how to estimate this effect is extremely limited. While more research is therefore needed, existing studies suggest that it is not unreasonable to expect that any increase in consumer electricity costs attributable to RE and/or EE deployment may be substantially offset by the corresponding reduction in delivered natural gas prices. This effect represents a wealth transfer (from natural gas producers to consumers) rather than a net gain in social welfare, and is therefore not a standard motivation for policy intervention on economic grounds. Reducing gas prices and thereby redistributing wealth may still be of importance in policy circles, however, and may be viewed in those circles as a positive ancillary effect of RE and EE deployment.

Introduction

Renewable energy (RE) and energy efficiency (EE) have historically been supported due to perceived economic, environmental, economic development, and national security benefits. More recently, price volatility in wholesale electricity and natural gas markets has increasingly led to discussions about the potential risk mitigation value of these resources. Deepening concerns about the ability of conventional North American gas production to keep up with demand have also resulted in a growing number of voices calling for resource diversification.

RE and EE offer a direct hedge against volatile and escalating gas prices by reducing the need to purchase variable-price natural gas-fired electricity generation, replacing that generation with fixed-price RE or EE resources. In addition to this *direct* contribution to price stability, by displacing marginal gas-fired generation, RE and EE can reduce demand for natural gas and *indirectly* place downward pressure on gas prices.[2] Many recent modeling studies of increased RE and EE deployment have demonstrated that this “secondary” effect on natural gas prices

[1] This work was funded by the Office of Energy Efficiency and Renewable Energy of the U.S. Department of Energy (DOE) under Contract No. DE-ACO3-76SF00098. We particularly appreciate the support and encouragement of the DOE’s Office of Planning, Budget Formulation, & Analysis (especially Sam Baldwin and Mary Beth Zimmerman), and the Wind & Hydropower Technologies Program (especially Jack Cadogan).

[2] Improvements in natural gas conversion efficiency, and end-use natural gas efficiency measures, would also directly reduce gas demand, as would increases in coal or nuclear generation.

could be significant, with the consumer benefits from reduced gas prices in many cases more than offsetting any increase in electricity costs caused by RE/EE deployment.[3] As a result, this effect is increasingly cited as justification for policies promoting EE and RE. Yet to date, little work has focused on reviewing the reasonableness of this effect as portrayed in various studies, and benchmarking that output against economic theory. This paper begins to fill that void.

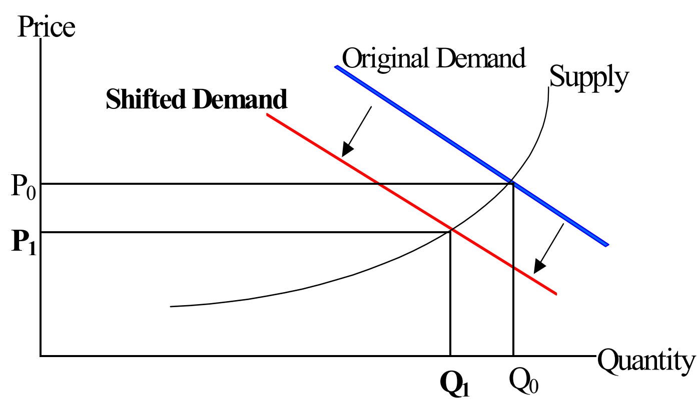
We first review economic theory to better understand the economics underlying the price suppression effect. We then review many of the modeling studies conducted over the past five years that have measured this effect, illustrating the potential impacts of RE and EE deployment on consumer electricity and gas bills, and calculating the inverse price elasticity of gas supply implied by the modeling output. We compare the resulting range of inverse price elasticities with each other (to test for model consistency across time and across models), as well as to empirical estimates from the economics literature (to test for model consistency with the real world). We end the paper with a summary or our findings.

Natural Gas Supply and Demand: A Review of Economic Theory

Supply and Demand Curves

Whether today's inflated natural gas prices represent merely a short-term imbalance between supply and demand, or instead a longer-term effect that reflects the true long-term marginal cost of production, is unclear (see, e.g., EMF 2003; Henning, Sloan & de Leon 2003; NPC 2003). In either case, economic theory predicts that a reduction in natural gas demand, whether caused by enhanced electric or natural gas efficiency, or by increased deployment of RE, will generally lead to a subsequent reduction in the price of gas relative to the price that would have been expected under higher demand conditions. As shown in Figure 1, this price reduction ($P_0 \rightarrow P_1$) results from an inward shift in the aggregate demand curve for natural gas ($Q_0 \rightarrow Q_1$). Because gas consumers are "price takers" in a market whose price is determined by national supply and demand conditions (with some regional differentiation), the price reduction benefits consumers by reducing gas prices for electricity generators (assumed to be passed through, in part, in the form of lower electricity prices), and by reducing gas prices for direct use in the residential, commercial, industrial, and transportation sectors.

Figure 1. The Effects of a Shift in Demand for Natural Gas



The magnitude of the price reduction will clearly depend on the amount of demand reduction: greater amounts of gas displacement will lead to greater drops in the price of the

[3] Note that any increase in costs associated with renewable energy or energy efficiency could be due to technology-forcing standards (e.g., a renewables portfolio standard or appliance energy efficiency standards), or to the imposition of a system-benefits charge used to support these clean energy technologies.

commodity.[4] As long as gas prices remain within reasonable bounds, RE and EE are expected to largely displace gas generation; the higher gas price forecasts of recent years, however, suggest that RE and EE may increasingly displace coal over time, muting the impact on gas prices. As importantly, the shape of the gas supply curve – the relationship between the level of natural gas production and the price of supply – will also have a sizable impact on the magnitude of the price reduction. The shape of the supply curve for natural gas will, in turn, depend on whether one considers short-term or long-term effects. Economists generally assume upward, steeply sloping supply curves in the short term when supply constraints exist in the form of fixed inputs like labor, machinery, and well capacity. In this instance, gas producers are unable or unlikely to quickly and dramatically increase (decrease) supply in response to higher (or lower) gas prices.

In the long term, however, the supply curve will flatten because supply will have time to adjust to lower demand expectations, for example, by reducing exploration and drilling expenditures. Because natural gas is a non-renewable commodity, the long-term supply curve must eventually slope upward as exhaustion of the least expensive resources occurs. If the pace of technological innovation in exploration and extraction is rapid, however, the transition to more expensive reserves may be delayed and the long-term supply curve may remain relatively flat. The shape of the long-term supply curve is an empirical question, and is subject to great uncertainty and debate. Nonetheless, economists generally agree that, while both the short- and long-term supply curves are upward sloping, the long-term supply curve will generally be flatter than the short-term supply curve. This implies that the impact of increased RE and EE deployment on natural gas prices will be greater in the short term than in the long term. We return to these issues later, when reviewing modeling output.

In this paper, we emphasize the long-term impacts of RE and EE investments, and hence focus our attention on the shape of the long-term supply curve. We do this for two principal reasons. First, RE and EE investments are typically long-term in nature, so the most enduring effects of these investments are likely to occur in the long term. Second, the model results presented in this paper often do not clearly distinguish between short-term and long-term effects, and most models appear better suited to long-term analysis. We also focus on the *national* impacts of increased RE and EE deployment; future work will review the impacts of *regionally* focused RE and EE investment.

Measuring the Inverse Price Elasticity of Supply

To measure the degree to which shifts in gas demand affect the price of natural gas, it is convenient to use elasticity measures. The *price elasticity of natural gas supply* is a measure of the responsiveness of natural gas supply to the price of the commodity, and is calculated by dividing the percentage change in quantity supplied by the percentage change in price:

$E = (\%\Delta Q)/(\% \Delta P)$, where Q and P denote quantity and price, respectively.

[4] One would not generally expect any particular threshold of demand reduction to be required to lower the price of gas. Instead, greater quantities of gas savings should simply result in higher levels of price reduction. The impact on prices, however, need not be linear over the full range of demand reductions, but will instead depend on the exact – yet unknown – shape of the supply curve in the region in which it intersects the demand curve.

In the case of induced shifts in the demand for natural gas, however, we are interested in understanding the change in price that will result from a given change in quantity, or the *inverse price elasticity of supply* ("inverse elasticity"):

$$E^{-1} = (\%\Delta P)/(\%\Delta Q)$$

Given greater supply responsiveness over the long term than in the short term, the long-term supply curve should experience *lower* inverse price elasticities of supply than will the short-term supply curve.

Social Benefits, Consumer Benefits, and Wealth Transfers

We have made the case that increased deployment of RE and EE can and should lower the price of natural gas relative to a business-as-usual trajectory. The magnitude of the expected price reduction is an empirical question that we address in later sections of this paper. Before proceeding, however, it is important to address the nature of the "benefit" that is obtained with the price reduction, because mischaracterizations of this benefit are common, and may lead to unrealistic expectations and policy prescriptions.

In particular, according to economic theory, lower natural gas prices that result from an inward shift in the demand curve do not lead to a gain in net economic welfare, but rather to a shift of resources (i.e., a transfer payment) from natural gas producers to natural gas consumers. While natural gas producers see their profit margins decline (a loss of producer surplus), natural gas consumers benefit through lower natural gas bills (a gain of consumer surplus). The net effect on aggregate social welfare (producer plus consumer surplus) is zero assuming a perfectly competitive and well-functioning aggregate economy.

This effect is shown graphically in Figures 2 and 3. Figure 2 shows consumer and

Figure 2. Consumer and Producer Surplus

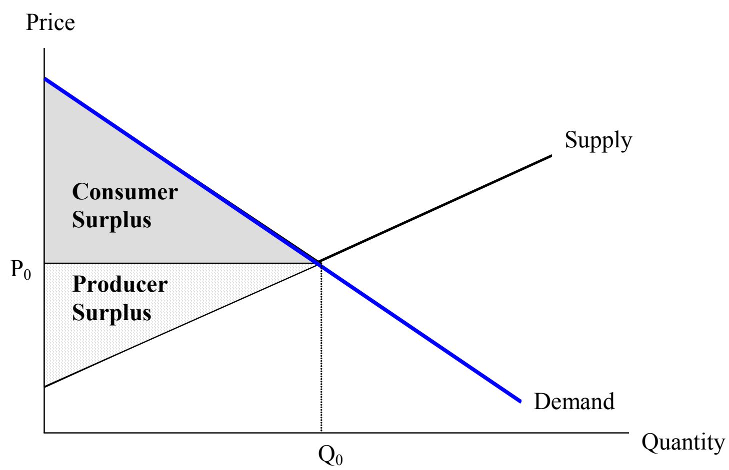
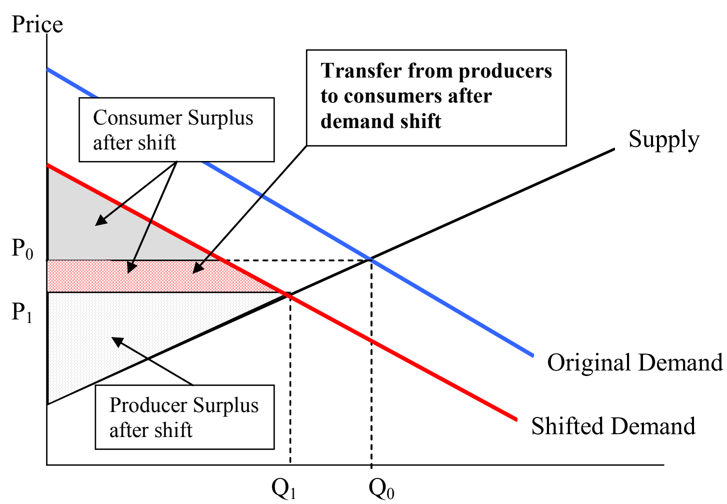


Figure 3. The Effect of a Demand Shift



producer surplus before the demand shift, while Figure 3 shows the impact of the demand shift on consumer and producer surplus. After the shift, the market price and quantity of natural gas fall to P_1 and Q_1, and consumer surplus now also includes the cross-hatch area in Figure 3 that was previously producer surplus. This area represents the price reduction benefit that consumers gain, and represents a redistribution of wealth from producers to consumers.

Wealth transfers of this type are not generally considered justification for policy intervention on economic grounds. Reducing gas prices and thereby redistributing wealth may still be of importance in policy circles, however, and may be viewed in those circles as a positive ancillary effect of RE and EE deployment; energy programs are frequently assessed using consumer impacts as a key evaluation metric. Furthermore, this effect may in fact provide a welfare gain if economy-wide macroeconomic adjustment costs are expected to be severe in the case of gas price spikes and escalation, or if the demand reduction is significant enough to mitigate the potential for market power in the gas market. Additionally, if consumers are located within the U.S., and producers are located outside of the U.S., the wealth redistribution would serve to increase aggregate U.S. welfare, an increasingly likely situation as the country becomes more reliant on imports of natural gas (especially liquefied natural gas). Finally, lower gas prices may help preserve U.S. manufacturing jobs, lead to displacement of more polluting energy sources, and reduce the cost of environmental regulatory compliance. We leave it to others to further debate the merits of considering this effect in policy evaluation.

A Review of Previous Studies

Previous studies of RE and EE policies have estimated the impact of increased clean energy deployment on natural gas prices. Many of these studies have exclusively evaluated a *renewables portfolio standard* (RPS) – a policy that requires electricity suppliers to source an increasing percentage of their supply from RE over time – while others have also looked at EE and environmental policies. These studies have focused on national as well as state-level policies, and have most typically used the National Energy Modeling System (NEMS), a model that is revised annually, and that is developed and operated by the DOE's Energy Information Administration (EIA) to provide long-term (e.g., to 2020 or 2025) energy forecasts.

While the shape of the short-term natural gas supply curve is a transparent, exogenous input to NEMS, the model (as well as other energy models reviewed for this study) does not exogenously define a transparent long-term supply curve; instead, a variety of modeling assumptions are made which, when combined, implicitly define the supply curve. For this reason, in order to evaluate the long-term gas price effect of RE and EE by measuring the inverse price elasticity of supply, it is necessary to do so implicitly by reviewing modeling results.

For the purposes of this paper, we have sought to compile information on a subset of the relevant studies. These include: (1) five studies by the EIA focusing on national RPS policies, two of which model multiple RPS scenarios; (2) five studies of national RPS policies by the Union of Concerned Scientists (UCS), two of which model multiple RPS scenarios, and one of which also includes aggressive energy efficiency investments; (3) one study by the Tellus Institute that evaluates three different standards of a state-level RPS in Rhode Island (combined with the RPS policies in Massachusetts and Connecticut); and (4) an ACEEE study that explores the impact of national and regional RE and EE deployment on natural gas prices. The EIA, UCS, and Tellus studies were all conducted in NEMS (note that NEMS is revised annually, and that these studies were therefore conducted with different versions of NEMS), while the ACEEE study used a gas market model from Energy and Environmental Analysis (EEA).

Table 1 presents a summary of some of the results of these studies.[5] A majority of the studies predict that increased RE generation (and EE, if applicable) will modestly increase retail electricity prices on a national basis, though this is not always the case. Increased RE and EE also cause a reduction in gas consumption, ranging from less than 1% to nearly 30% depending on the study. Reduced gas consumption, in turn, suppresses gas prices, with price reductions ranging from virtually no change in the national average wellhead price to a 50% reduction in that price. As one might expect, the more significant reductions in gas consumption and prices are typically associated with those studies that evaluated aggressive RE/EE deployment.

Table 1. Summary of Results from Past RPS Studies

Author	RPS/EE	**Increase in US RE Generation** *Billion kWh*	**Reduction in US Gas Consumption** *Quads (%)*	**Gas Wellhead Price Reduction** *$/MMBtu (%)*	**Retail Electric Price Increase** *Cents/kWh (%)*
EIA (1998)	10%-2010 (US)	336	1.12 (3.4%)	0.34 (12.9%)	0.21 (3.6%)
EIA (1999)	7.5%-2020 (US)	186	0.41 (1.3%)	0.19 (6.6%)	0.10 (1.7%)
EIA (2001)	10%-2020 (US)	335	1.45 (4.0%)	0.27 (8.4%)	0.01 (0.2%)
EIA (2001)	20%-2020 (US)	800	3.89 (10.8%)	0.56 (17.4%)	0.27 (4.3%)
EIA (2002a)	10%-2020 (US)	256	0.72 (2.1%)	0.12 (3.7%)	0.09 (1.4%)
EIA (2002a)	20%-2020 (US)	372	1.32 (3.8%)	0.22 (6.7%)	0.19 (2.9%)
EIA (2003)	10%-2020 (US)	135	0.48 (1.4%)	0.00 (0.0%)	0.04 (0.6%)
UCS (2001)	20%-2020, & EE (US)	353	10.54 (29.7%)	1.58 (50.8%)	0.17 (2.8%)
UCS (2002a)	10%-2020 (US)	355	1.28 (3.6%)	0.32 (10.4%)	-0.18 (-2.9%)
UCS (2002a)	20%-2020 (US)	836	3.21 (9.0%)	0.55 (17.9%)	0.19 (3.0%)
UCS (2002b)	10%-2020 (US)	165	0.72 (2.1%)	0.05 (1.5%)	-0.07 (-1.1%)
UCS (2003)	10%-2020 (US)	185	0.10 (0.3%)	0.14 (3.2%)	-0.14 (-2.0%)
UCS (2004)	10%-2020 (US)	181	0.49 (1.6%)	0.12 (3.1%)	-0.12 (-1.8%)
UCS (2004)	20%-2020 (US)	653	1.80 (5.8%)	0.07 (1.87%)	0.09 (1.3%)
Tellus (2002)	10%-2020 (RI)	31	0.13 (0.4%)	0.00 (0.0%)	0.02 (0.1%)
Tellus (2002)	15%-2020 (RI)	89	0.23 (0.7%)	0.01 (0.4%)	-0.05 (-0.3%)
Tellus, (2002)	20%-2020 (RI)	98	0.28 (0.8%)	0.02 (0.8%)	-0.07 (-0.4%)
ACEEE (2003)	6.3%-2008, & EE (US)	NA	1.37 (5.4%)	0.74 (22.1%)	NA

Notes:

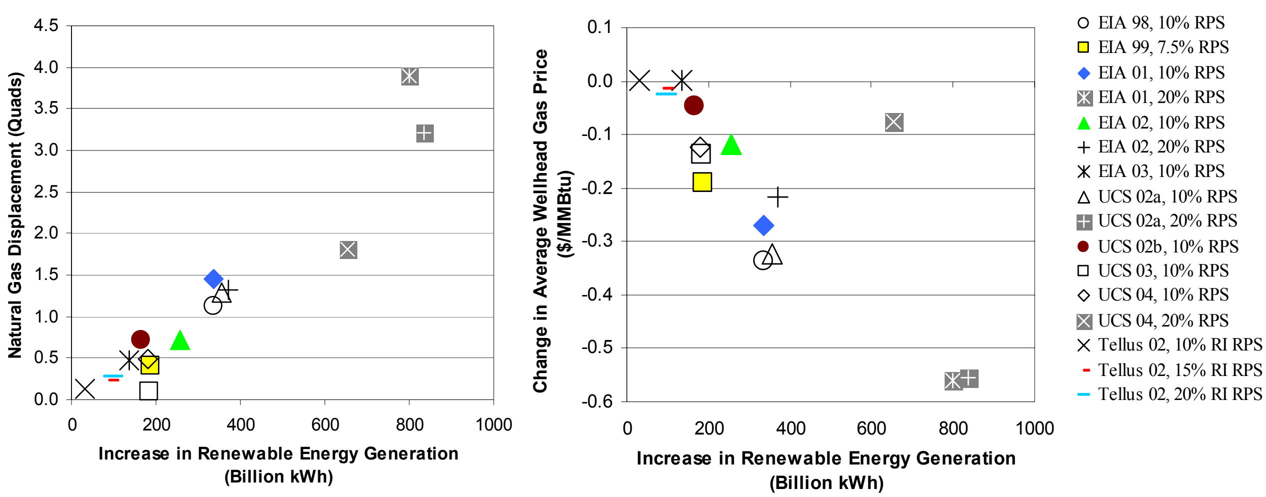
- The data for the ACEEE study are for 2008, the final year of the study's forecast. All other data are for 2020.
- All dollar figures are in constant 2000$.
- The reference case in most studies reflects the EIA AEO, with some studies making adjustments based on more recent gas prices or altered renewable technology assumptions. The one exception is UCS (2003), in which the reference case reflects a substantially higher gas price environment than the relevant AEO reference case.
- The Tellus study models an RPS for RI, also including the impacts of the MA and CT RPS policies. All the figures shown in this table are for the predicted *national* level impacts of these regional policies.

Wellhead price reductions translate into reduced bills for natural gas consumers, and also moderate the expected RE-induced increase in electricity prices predicted by many of the studies by reducing the price of gas delivered to the electricity sector. Though not shown in Table 1,

[5] Table 1 presents the projected impacts of increased RE and EE deployment in each study relative to some baseline. These baselines differ from study to study, which partially explains why, for example, a 10% RPS in two studies can lead to different impacts on renewable generation.

with some exceptions, the absolute reduction in electric and non-electric sector delivered natural gas prices largely mirrors the reduction in wellhead gas prices, suggesting that changes in wellhead prices largely flow through to delivered prices on an approximate one-for-one basis.

Focusing on just those studies that *exclude* EE deployment (i.e., all but ACEEE 2003, and UCS 2001),[6] Figure 4 presents the impact of increased RE generation on the displacement of national gas consumption in 2020. Figure 5, meanwhile, shows the impact of increased RE on the national average wellhead price of natural gas.



These figures, along with Table 1, show clearly that increased RE and EE are predicted to reduce natural gas consumption and prices, while retail electricity prices are predicted to rise in at least some instances. The net predicted effect on consumer energy bills can be positive or negative, depending on the relative magnitude of the electricity and natural gas bill effects.

Again taking a subset of the studies, Figure 6 presents these offsetting effects.[7] While variations exist across the different studies, the net present value of the cumulative (2003-2020) predicted increase in consumer electricity bills (if any) in the RPS cases compared to the reference case is often on the same order of magnitude as the net present value of the predicted decrease in consumer natural gas bills. From an aggregate *consumer* perspective, therefore, the net impact of these policies is typically predicted to be rather small, with nine of thirteen RPS analyses even showing net consumer savings (i.e., negative cumulative bill impacts).[8]

Though not shown explicitly in these tables and figures, also note that RE and EE are expected to lead to greater reductions in gas consumption in those studies that rely on lower gas price forecasts in the business-as-usual scenario. More recent studies that often rely on higher gas price forecasts (e.g., UCS 2003, 2004) generally find greater coal displacement (and less gas

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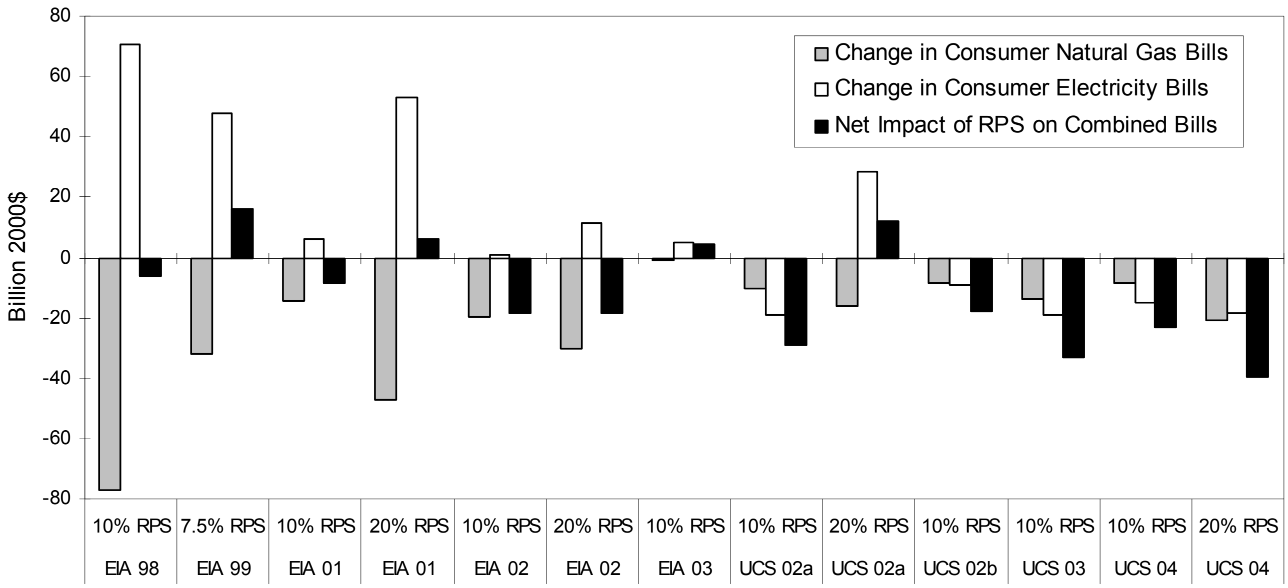
[6] We exclude the two studies that involve EE deployment here only to simplify the graphical results.

[7] Figure 6 shows the energy bill impacts only for the national RPS studies for which these data were available (i.e., it excludes the Tellus analysis as well as the two studies in which EE investments were also modeled).

[8] Note that in several of these studies, RPS cost caps are reached, ensuring that consumers pay a capped price for some number of *proxy* renewable energy credits (and leading to increased electricity prices) while not obtaining the benefits of increased RE generation on natural gas prices. Accordingly, if anything, Figure 6 underestimates the possible consumer benefits of a well-designed renewable energy program with less-binding cost caps.

displacement) over time as coal out-competes gas for new additions. In a high gas-price environment, this effect may mitigate the benefit of RE and EE in reducing those prices.



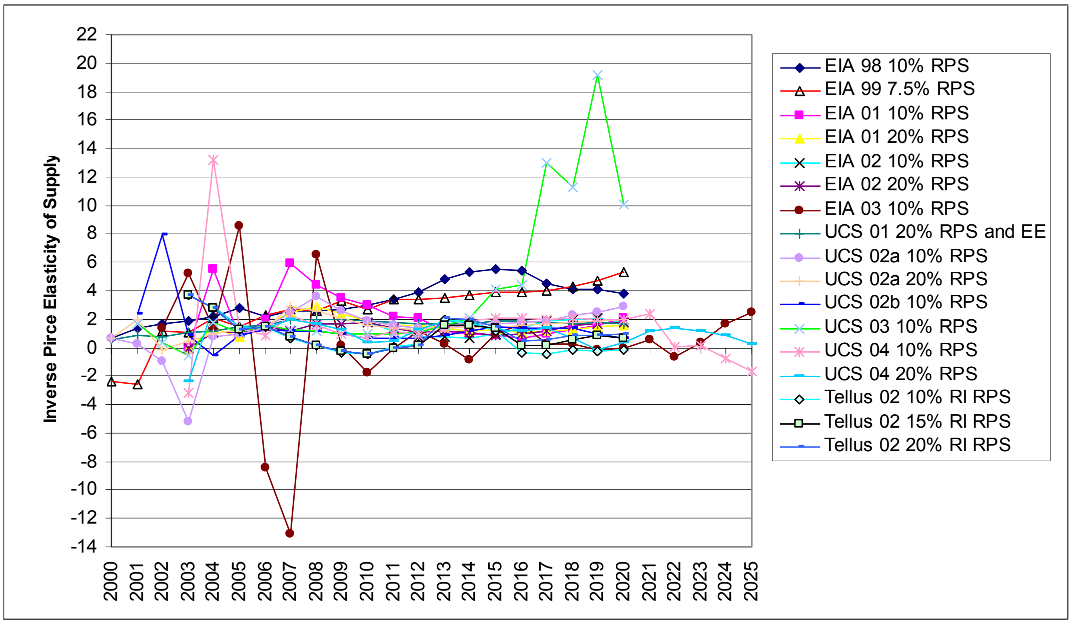
Summary of Implied Inverse Price Elasticities of Supply

Ignoring for now the different impacts of RE/EE on gas consumption across studies, to compare the natural gas price response to increased RE and EE deployment we can calculate the inverse price elasticity of supply implied by the results of each study. Doing so requires data on the predicted average national wellhead price of natural gas and total gas consumption in the United States, under both the business-as-usual baseline scenario as well as the policy scenario of increased RE and/or EE deployment.[9] With the possible exception of the ACEEE study, the resulting inverse elasticities can be considered long-term elasticities.[10]

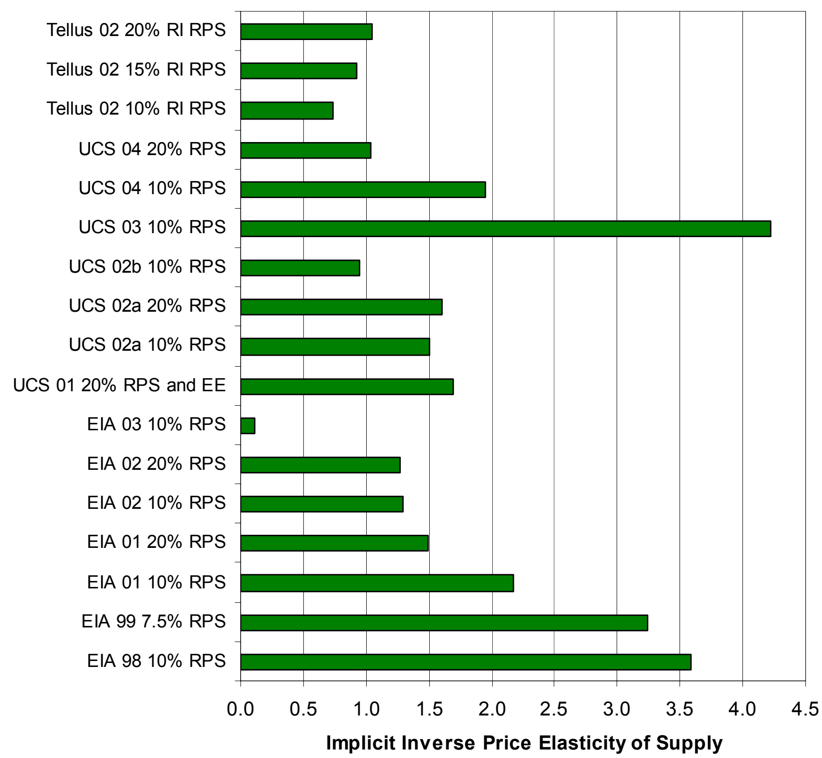
Figure 7 presents a comparative analysis of *long-term* implicit inverse elasticities across studies and years (excluding the ACEEE 2003 results, which are presented later). As shown, the implied inverse elasticity in each study exhibits a great deal of variation over the forecast period. Though some of the studies show a reasonable level of consistency in the inverse elasticity over time, others show large inter-annual swings. This is especially (though not always) true when the aggregate reduction in gas demand is small, leading to substantial "noise" in the results.

[9] The inverse elasticity calculations presented here use U.S. price and quantity data, under the assumption that at present the market for natural gas is more regional than worldwide in nature (Henning, Sloan & de Leon 2003). Of course, the market for natural gas consumed in the U.S. is arguably a North American market, including Canada and Mexico, with LNG expected to play an increasing role in the future. Trade with Mexico is relatively small, however, and Canadian demand for gas pales when compared to U.S. demand. LNG, meanwhile, remains a modest contributor to total U.S. consumption.

[10] It deserves note that our review of NEMS output in the national RPS studies shows that predicted natural gas prices in NEMS do not appear to be more sensitive to demand changes in the short-term than in the long-term. Because of this, one might question NEMS' treatment of long-term and short-term natural gas supply elasticities.



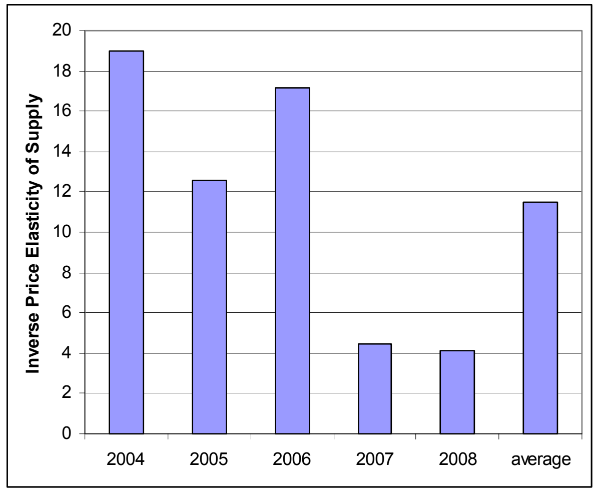
Because relying on the implied inverse elasticity for any single year could be misleading, Figure 8 summarizes the average value of the implied inverse elasticities over an extended forecast period (2003-2020). Despite substantial inter-annual and inter-study variations, there is some consistency in the *average* long-term inverse elasticities, with twelve of seventeen analyses (all of which use NEMS) having elasticities that fall within the range of 0.7 to 2.0.[11]



Though the implied inverse elasticities derived from NEMS appear to represent the long-term supply curve for natural gas,

[11] UCS (2003) has a substantially higher average inverse elasticity than most of the other studies. As noted earlier, UCS (2003) evaluated the potential impact of an RPS under a scenario of higher gas prices than in a typical AEO reference case, making this study not totally comparable to those covered in the body of this paper (the study includes a more constrained gas supply than most of the other analyses, especially in the later years).

this does not appear to be the case in the ACEEE study. The ACEEE study reports the impact of increased RE/EE over a shorter period (2004-2008), and uses a gas market model from EEA that reports impacts on a more disaggregated basis by region and by time interval. While the ACEEE study did analyze the potential impact of state and regional RE and EE deployment, Figure 9 reports the results of the national deployment scenario. As shown, early year inverse elasticites are high (at over ten). By 2008, the inverse elasticity drops to four, still over twice as large as the average long-term inverse elasticities implicit in the latest versions of NEMS.[12]



Because the other studies reviewed in this paper do not seek to present short-term impacts at the same level of disaggregation as ACEEE, it is difficult to benchmark the ACEEE results with those of other studies. The national short-term impacts forecast by ACEEE are aggressive (arguably open to critique for being too aggressive), however, and at the least should not be extrapolated into later years (but should instead be considered shorter-term impacts that are unlikely to persist for the long-term). By the same token, the ACEEE results demonstrate that the positive impacts of increased RE and EE may be more significant in the short-run than estimated by other modeling studies, whose approaches are arguably better able to address longer-term influences.

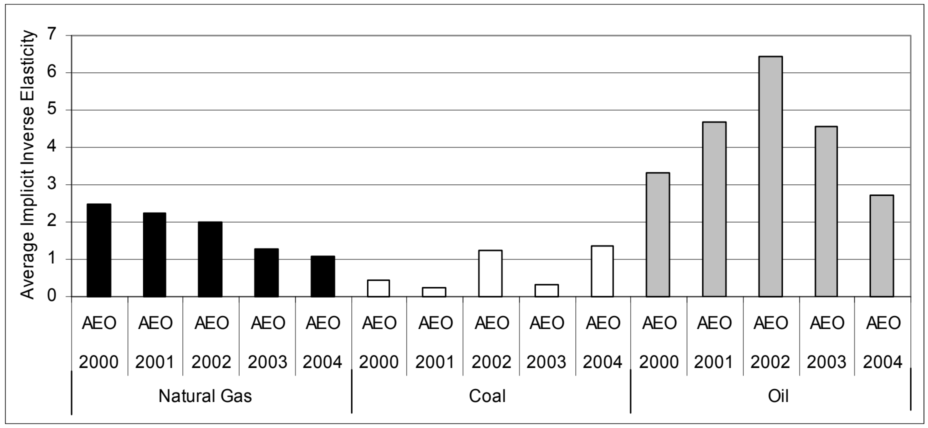
Benchmarking to Other Markets and Energy Models

In evaluating the results presented in the previous section, it is useful to compare these inverse elasticities to those calculated for natural gas and other fossil fuels in other EIA NEMS analyses, as well as other national energy models altogether.

In particular, the RE and EE studies reviewed above are only one example of an exogenous demand shock that triggers a natural gas price response. The low- and high-economic growth scenarios published as part of the EIA's Annual Energy Outlook (AEO) each year are another such example. Low economic growth, compared to the reference case, leads to less demand for fossil fuels, while high economic growth results in the opposite effect. Figure 10 shows the range of average (2003-2020) implied inverse elasticities for natural gas, coal, and oil from Annual Energy Outlook 2000-2004, focusing on the low economic growth case relative to the reference case forecast.[13]

[12] Note that the natural gas price data used to construct the inverse elasticities implicit in the ACEEE results are projected Henry Hub prices, while the previous studies relied upon wellhead price projections. Because Henry Hub prices are typically higher than wellhead prices, inverse elasticities calculated with Henry Hub data will be lower than if wellhead prices were used.

[13] Like natural gas, the coal market is assumed to be national, and the implicit inverse elasticity was calculated using forecasts of U.S. coal minemouth prices and total U.S. coal consumption. Oil, on the other hand, is assumed to be a world market, so the elasticity calculation used the world oil price and total world oil consumption from the AEOs.



The average implicit inverse elasticities for natural gas presented in Figure 10 are broadly consistent with – though perhaps somewhat higher than – the results of the NEMS-based EE and RE studies presented earlier – i.e., they range from 1.1 to 2.5. Figure 10 also shows that the implicit inverse elasticities for natural gas appear to have generally decreased with successive versions of NEMS, which the EIA updates each year, perhaps implying that EIA has tried to moderate its treatment of this effect in recent years. As might be expected given plentiful and relatively inexpensive domestic coal supplies, the implicit inverse elasticity for coal is lower than that for natural gas and oil. The inverse elasticity for oil, on the other hand, is *much* higher than those for coal and gas, reflecting an assumption of highly inelastic supply.

Finding a degree of consistency between the results of the RE and EE studies presented earlier and the AEO's economic growth cases presented here should perhaps come as little surprise: with the exception of the ACEEE study, each of these studies has used the same basic model, NEMS (though again, we note that NEMS is revised annually). We therefore also sought to compare the long-term inverse elasticites implicit in NEMS with those of other national energy models. Data from a recent study by Stanford's Energy Modeling Forum (EMF 2003) allows for this comparison. In particular, this study presents the potential impact of high gas demand on natural gas consumption and price in 2010 and 2020 using seven different energy models. Table 2 presents the results of this analysis.

Table 2. Implicit Inverse Elasticities in a Range of National Energy Models

Energy Model	Natural Gas Consumption Change		Natural Gas Price Change		Inverse Price Elasticity of Supply	
	2010	2020	2010	2020	2010	2020
NEMS	3.0%	4.5%	6.4%	0.5%	2.13	0.11
POEMS	4.0%	4.3%	7.1%	7.8%	1.75	1.81
CRA	8.7%	11.9%	20.3%	11.1%	2.33	0.93
NANGAS	1.2%	3.1%	7.8%	14.8%	6.67	4.76
E2020	4.0%	8.4%	4.2%	6.3%	1.03	0.76
MARKAL	3.2%	6.3%	6.5%	13.4%	2.04	2.13
NARG	-2.3%	-0.2%	8.4%	9.7%	-3.57	-50.00

As shown, inverse elasticity estimates among these major national energy models vary substantially. Five of the seven models (NEMS, POEMS, CRA, E2020, and MARKAL) report inverse elasticity estimates that are broadly consistent with those presented earlier, while two of the models (NANGAS and NARG) create anomalous results. It deserves note, however, that several of these models (e.g., POEMS and MARKAL) rely in part on modeling inputs to NEMS, making consistency among the models perhaps less useful than otherwise would be the case. Finally, the National Petroleum Council recently issued a national study relying on the EEA model, and whose sensitivity cases show an average implicit long-term inverse elasticity of approximately four (consistent with the 2008 ACEEE results presented earlier) (NPC 2003).

Benchmarking to Empirical Elasticity Estimates

With few exceptions, the energy modeling results reviewed previously present a consistent basic story: reducing the demand for natural gas, whether through the use of RE and/or EE or through other means, is expected to lead to lower natural gas prices than in a business-as-usual scenario. While the magnitude of the long-term implicit inverse price elasticity of supply varies substantially across model and years, the central tendency appears to be 0.75 to 2.5: a 1% reduction in national gas demand is expected to cause a corresponding wellhead price reduction of 0.75% to 2.5% in the long-term, with some models predicting even larger effects (up to a 4% reduction in long-term gas prices for each 1% drop in gas consumption).

These are merely modeling predictions, however, based on an estimated shape of a gas supply curve that is not known with any precision. It would also not be an overstatement to say that the historic ability of modelers to estimate future natural gas prices has been dismal, leading to obvious questions about the degree of confidence to place in these modeling results. It is therefore useful to benchmark these forecasts against empirical estimates of historical inverse elasticities. While empirically-derived estimates of historical inverse elasticities may not predict future elasticities accurately (the natural gas supply curve may have a different shape in 2010 than it did in 1990), and data and analysis difficulties plague such estimates, these estimates nonetheless offer a dose of empirical reality relative to the modeling results presented earlier.

Unfortunately, empirical research on energy elasticities has focused almost exclusively on the impact of supply shocks on energy *demand* (demand elasticity) rather than the impact of demand shocks on energy *supply* (supply elasticity). Our literature search uncovered only one recently published empirical estimate of the long-term supply elasticity for natural gas. Krichene (2002) estimates this long-term supply elasticity to be 0.8 (for the period 1973-1999), yielding an *inverse* elasticity of 1.25. Surprisingly, this is *larger* than Krichene's short-term inverse elasticity, estimated to be -10. Examining the 1918-1973 time period separately, Kirchene estimates inverse elasticities of 3.57 in the long-term and -1.36 in the short term. Krichene estimates these elasticities using U.S. wellhead prices and international natural gas production, however, making a direct comparison to the model results presented earlier impossible.

With only one published figure (of which we are aware) for long-term gas supply elasticity, it may be helpful to review published estimates for other non-renewable energy commodities, namely oil and coal. Unfortunately, few supply constraints exist for coal, and long-term inverse elasticities are therefore expected to be lower than for natural gas. Oil production, while clearly a worldwide rather than regional market, has more in common with gas, but OPEC inserts uncompetitive influences into oil supply behavior. The comparability of natural gas, oil, and coal elasticities is therefore questionable.

Hogan (1989) estimates short- and long-term inverse elasticities for oil in the United States of 11.1 and 1.7, respectively. Looking more broadly at the *world* oil market, Krichene (2002) calculates the long-term inverse elasticity for oil to be 0.91 from 1918-1973, and 10 from 1973-1999. Ramcharran (2002) finds evidence of an uncompetitive supply market for oil for the period 1973-1997, with a short-term inverse elasticity estimate of -5.9. For non-OPEC nations, meanwhile, he found a more competitive short-term inverse elasticity of 9.4.

The EIA (2002b) found only two studies that sought to estimate the supply elasticity for coal. The first, by Beck, Jolly & Loncar (1991), reportedly estimates an inverse elasticity for the Australian coal industry of 2.5 in the short term and 0.53 in the long term. The second study focuses on the Appalachia region of the United States (Harvey 1986), and estimates inverse elasticities of 7.1 in the short term and 3.1 in the long term.

In summary, there are few empirical estimates of supply elasticities, and data and analysis problems plague even those estimates provided above. Nonetheless, empirical estimates of historical long-term inverse elasticities for gas, coal, and oil are positive, and the modeling output presented earlier for natural gas and other non-renewable energy commodities is not wildly out of line with historical empirical estimates. Nonetheless, the range of implicit inverse elasticities of gas presented earlier is broad, and the empirical literature does not facilitate a narrowing of that range. Further, while not clearly supported by either the empirical literature or modeling output, there are some who believe that technological progress is likely to keep the long-term supply curve for natural gas relatively flat, implying a large overstatement of the magnitude of the natural gas price reduction effect in the modeling results presented earlier.

Conclusions

Concerns about the price and supply of natural gas have grown in recent years, and futures and options markets predict high prices and significant price volatility for the immediate future. Whether we are witnessing the beginning of a major long-term nationwide crisis, or a costly but shorter-term supply-demand adjustment, remains to be seen.

Results presented in this paper suggest that resource diversification, and in particular increased investments in RE and EE, have the potential to help alleviate the threat of high natural gas prices over the short and long term. Whether through gas efficiency measures, or by displacing gas-fired electricity generation, increased deployment of RE and EE is expected to reduce natural gas demand and consequently put downward pressure on gas prices. A review of the economics literature shows that this effect is to be expected, and can be measured with the inverse price elasticity of gas supply. Due to the respective shapes of long- and short-term supply curves, the long-term price impact is expected to be less significant than shorter-term impacts.

Importantly, the direct impact of this natural gas price reduction does not represent an increase in aggregate economic wealth, but is instead a benefit to consumers that comes at the expense of natural gas producers. Conventional economics does not support government intervention for the sole reason of shifting the demand curve for natural gas and thereby reducing gas prices. If policymakers are uniquely concerned about the impact of gas prices on consumers, however, then policies to reduce gas demand might be considered appropriate on wealth redistribution grounds; at a minimum, such policymakers might view reduced gas prices as a positive secondary effect of increased RE and EE deployment.

A large number of modeling studies have recently been conducted that implicitly include an evaluation of this effect. Though these studies show a relatively broad range of inverse price elasticities of natural gas supply, we also find that many of them exhibit some central tendencies. Benchmarking these results against other modeling output, as well as a limited empirical literature, we conclude that many of the studies of the impact of RE and EE on natural gas prices appear to have represented this effect within reason, given current knowledge.

Despite this, there are sometimes significant changes in the implicit inverse elasticities not only across models, but also between years within the same modeling run and between modeling runs using the same basic model. Inverse elasticities do not always remain within reasonable bounds. Combine this with the fact that the natural gas supply curve is unknown, and that the historic ability of energy modelers to predict future gas prices is dismal, and we do not believe that much weight should be placed on any *single* modeling result. More effort needs to be placed on accurately estimating the supply curve for natural gas, and in validating modeling treatment of that curve, before any single modeling result can reasonably be relied upon.

In the mean time, in estimating the impact of RE and EE on natural gas prices, it would be preferable to consider a range of natural gas elasticity estimates to bound this effect. Relying on the data summarized in this paper, we conclude that each 1% reduction in national gas demand could lead to a long-term average wellhead price reduction of 0.75% to 2.5%, with some of the models predicting even more aggressive price reductions. Reductions in the wellhead price will not only have the effect of reducing electricity rates, but will also reduce residential, commercial, and industrial gas bills. Based on the results presented in this paper, it is not unreasonable to expect that any increase in consumer electricity costs that are caused by RE and/or EE will be substantially offset by the expected reduction in delivered natural gas prices.

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GEC Response to APPRO Interrogatory #7

Question:

Reference: i) Evidence of Mr. Chernick pages 18-25.

Preamble: In the evidence, Mr. Chernick indicates that: (i) Ontario proposes to impose a charge on gas use; (ii) Ontario recently joined the Western Climate Initiative (**WCI**); and (iii) the forward price of carbon is in the range of $20 USD/tonne in 2014 rising linearly to $35 USD/tonne in 2030 and $61.50 USD/tonne in 2040.

a) Please confirm that Synapse is providing other paid evidence in this proceeding.
b) Please provide any and all information that Mr. Chernick relied upon indicating that the point of regulation for carbon pricing will be the gas user (i.e. end-use gas customer).
c) Please indicate when Ontario joined the WCI and its terms of entry.
d) Please provide the actual carbon allowance auction prices in California and Québec in accordance with the following table:

Auction Period		Auction Price		
2013	Q1	California	Québec	RGGI[1]*
	Q2			
	Q3			
	Q4			
2014	Q1			
	Q2			
	Q3			
	Q4**			
2015	Q1			
	Q2			

*while not technically linked, Québec provides for consideration of RGGI allowances in related export transactions for power.
**California/Québec linked auction.

e) Please provide any and all assumptions of carbon pricing in multi-state cooperation programs, such as RGGI and WCI both pre- and post-implementation of the U.S. CPP.
f) Please provide any and all factual/technical support for the 1.89 kg CO_2/m_3 emission factor used in the analysis.
g) Please provide any and all relevant currency exchange forecasts for the 2016-2020 period.
h) Please provide all carbon and related cost estimates set out in this section of the evidence on a metric tonne basis.
i) Please provide all assumptions and limitations implicit in the proposed social cost of carbon estimates.
j) Please confirm that Mr. Chernick assumed that the avoided cost of carbon emissions would be, in part, a function of the prevailing carbon price.
k) Please provide any and all data supporting the implied CO_2 costs in footnote 15.

Response:

a) Mr. Chernick understands that two Synapse staff (Tim Woolf and Kenji Takahashi) will be testifying in this proceeding. Their evidence was coauthored by Erin Malone, Alice

Napoleon, and Jenn Kallay. None of these individuals were authors of the Synapse 2015 carbon-price report.

b) Mr. Chernick did not make that assertion in his evidence. It is likely that some very large emitters of CO_2 will be included as regulated entities, based on previous proposals for carbon cap-and-trade, California practice, and the Greenhouse Gas Emissions Reductions Consultation on Cap and Trade presentation (M.GEC.IGUA.1 Attachment 1).
c) Ontario joined the WCI in 2008. Mr. Chernick does not have the "terms of entry."
d) See response to GEC.APPrO.4g.
e) Mr. Chernick has not reviewed the detail of the RGGI and WCI regulations to determine whether they may be affected by the CPP. APPRO is welcome to review the RGGI and WCI documents, many of which are available on line. The California GHG rules may need to be revised to harmonize with features of the CPP rules, such as the lack of offsets; alternatively, California could request a waiver of rules if it can convince the EPA that the proposed state rule would exceed the reductions required by EPA.
f) The value of 1.89/kg is consistent with Enbridge (B/T1/S2 fn 2) which cites *Guideline for Greenhouse Gas Emissions Reporting* (as set out under Ontario Regulation 452/09 under the Environmental Protection Act), Appendix 10; ON.20, General Stationary Combustion, Calculation Methodology 1, Ontario Ministry of the Environment, December 2009, PIBS# 7308e. The molecular composition of gas varies; it is mostly methane, with some heavier hydrocarbons and some inert gases (nitrogen, CO_2), all of which affect both the energy content and the CO_2 emissions per m^3. (See https://www.uniongas.com/about-us/about-natural-gas/Chemical-Composition-of-Natural-Gas for more detail.) The 1.89kg/m^3 value is also consistent with other sources, including:
   - the Greenhouse Gas Protocol spreadsheet at ghgprotocol.org/sites/default/files/ghgp/Stationary_combustion_tool_%28Version4-1%29.xlsx,
   - 53.1 kg/MMBtu (from www.eia.gov/environment/emissions/co2_vol_mass.cfm) and about 28 m^3/MMBtu,
   - 1879 g/m^3 for Ontario and 1918 g/m^3 for Alberta, from https://ec.gc.ca/ges-ghg/default.asp?lang=En&n=AC2B7641-1.

g) Mr. Chernick has not assembled all potentially "relevant currency exchange forecasts for the 2016-2020 period."
   - The most recent traded forward contracts are available at http://www.cmegroup.com/trading/fx/g10/canadian-dollar.html.
   - The CIBC foreign-exchange forecast is available at http://research.cibcwm.com/economic_public/download/fxmonthly.pdf
   - The Scotiabank forecast is available at http://www.gfx.gbm.scotiabank.com/Chart_Feed/fxout.pdf
   - The National Bank of Canada forecast is available at www.nbc.ca/content/dam/bnc/en/rates-and-analysis/economic-analysis/forex.pdf

- The Royal Bank of Canada forecast is available at http://www.rbc.com/economics/economic-reports/pdf/financial-markets/rates.pdf

h) Mr. Chernick believes that he has presented all the carbon prices and costs he mentions (in Table 3, Table 4, and page 22, lines 11–13) in terms of metric tonnes.
i) The available documentation of the social-cost analysis is at http://www.epa.gov/climatechange/EPAactivities/economics/scc.html.
j) Yes. Mr. Chernick assumed that the gas utilities and/or large users would need to buy allowances for additional emissions and would be able to sell allowances for emissions reductions, compared to a baseline.
k) Mr. Chernick does not have any information other than the Boland/OPG presentation cited in the footnote and provided as Attachment 1 to M.GEC.APPRO.5. APPRO may want to direct the question to IESO.