Ontario Capacity Auction: Assessment of Expected Benefits

September 18, 2014

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IESO-N-0027850

Contents

I. INTRODUCTION

Ontario is projected to face a capacity shortfall in the coming years driven in large part by nuclear retirements and nuclear refurbishments. Expiring contracts and rising demand, albeit at modest rates, add to Ontario's future capacity needs. The Ontario Power Authority's (OPA) projections illustrate the magnitude of the capacity shortfall that Ontario will be facing by the end of this decade and provide the starting point for recent IESO analysis. Beginning in 2019 a capacity shortfall appears and persists throughout the remainder of the planning period.

The rationale for introducing a capacity auction mechanism to Ontario has been provided in detail elsewhere.[1] To recap, Ontario currently benefits from a reliable, well-functioning electricity system that strives to ensure the efficient dispatch of resources to maintain a reliable supply of electricity to consumers. However, like many other electricity markets around the world, Ontario's wholesale energy market did not prove sufficient by itself to attract and support new entry and ensure a sufficient level of capacity to meet demand over the longer term. Instead, Ontario has relied on a combination of centralized procurement and contracting for resources through OPA and the Ontario Energy Board's regulation of Ontario Power Generation's assets to ensure long-term capacity needs are met.

In anticipation of the future capacity shortfall, the IESO's attention has turned to exploring what flexible, responsive mechanisms could be introduced to complement the existing market structure. A capacity auction is one approach that has been used in a number of North American markets and markets globally to meet the capacity needs of modern electricity systems cost effectively.

A capacity auction addresses many of the practical issues apparent in alternative mechanisms such as energy only markets and centralized long term contracting. In addition to moderating price volatility, providing an acceptable degree of revenue certainty and the flexibility to reflect

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[1] See IESO Backgrounder "Capacity Market for Ontario" (March 27. 2014) available at: http://www.ieso.ca/documents/consult/Capacity_Market-Backgrounder.pdf. See also presentation from IESO Information Session held on August 13, 2014, titled "Value of a Capacity Market in Ontario" at: http://www.ieso.ca/Documents/consult/CapacityMarket_InfoDay_Analysis.pdf

changing market conditions, capacity markets have a proven track record delivering cost effective reliability in a transparent, technology neutral way.

The remainder of this report provides a detailed description of the IESO analysis of potential benefits of introducing a made-in-Ontario capacity auction.

Also included is a third party review by NERA Economic Consultants that assessed the validity of key assumptions and the methodology used in the analysis.

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II. IESO QUANTITATIVE ANALYSIS

The IESO undertook a quantitative exercise to provide perspective on the magnitude of potential cost savings that a capacity auction could offer Ontario. This analysis was intended to be illustrative of what benefits could realistically be experienced in Ontario, acknowledging that by their very nature, market outcomes are not entirely predictable or guaranteed. There are many important factors that are subject to a great deal of uncertainty – in fact, the flexibility to adjust to uncertainty is one of the expected benefits of a market based solution when compared to a fully committed, planned approach based on long term contracts.

As with any forward looking analysis, a series of input assumptions are needed. Again, these assumptions are not supposed to be predictions of the future, but necessary to understand the mechanism. Therefore, the results of the analysis should be interpreted as the opportunity that a capacity auction could bring. As with any analysis based on future prices, the results presented could be higher or lower depending on prevailing market conditions.

While the exact quantity of future capacity need cannot be predicted with certainty, the best information about the future capacity needs resides in the outlook for supply and demand that was developed in Ontario's 2013 Long-Term Energy Plan.[2]

There are different ways that a capacity gap can be filled at potentially different costs. The LTEP uses a set of cost assumptions based on reference prices and recontracting costs. An alternative scenario using a capacity auction has been developed. The methodology and rationale for these assumptions are described next.

[2] Achieving Balance - Ontario's Long-Term Energy Plan (2013), pg. 18 available at: http://powerauthority.on.ca/sites/default/files/planning/LTEP_2013_English_WEB.pdf

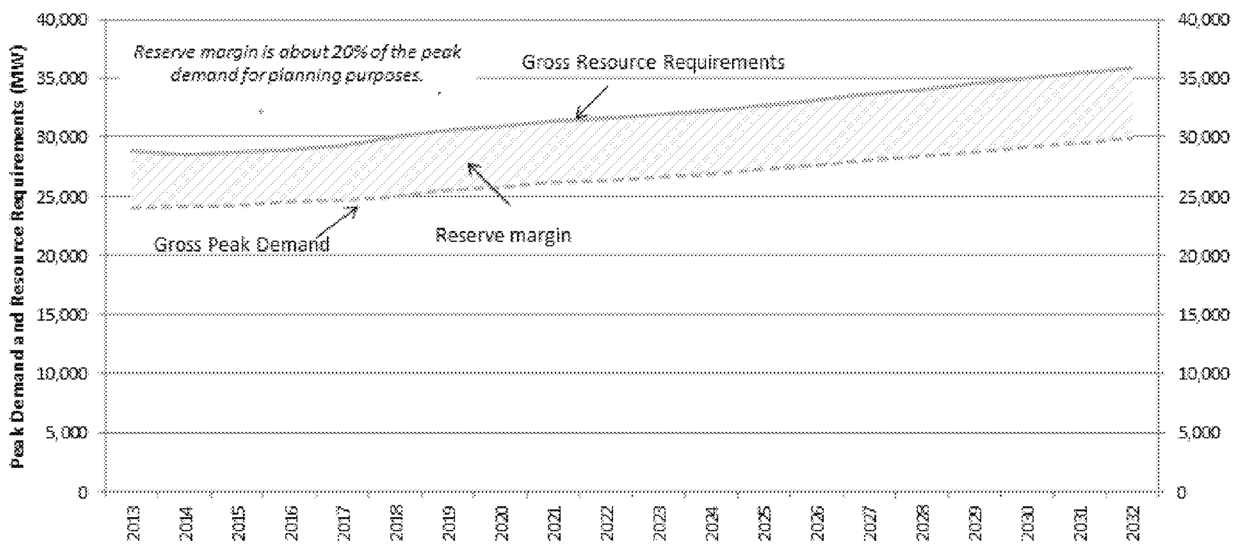
A. Ontario's Future Capacity Needs

The LTEP estimates Ontario's Net Resource Requirement annually out to 2032. The Net Resource Requirement is the amount of capacity required to meet peak demand less the impact from conservation plus the reliability reserve margin. In the LTEP the OPA forecasts annual peak electricity demand under a medium growth scenario.[3]

A.1 Gross Resource Requirement

Figure 1 presents Ontario's Gross Resource Requirement represented by Gross Peak Demand plus the Planning Reserve Margin up to 2032. Gross Peak Demand is projected to increase from approximately 24,000 MW to 30,000 MW by the end of the planning period, with the Gross Resource Requirement expected to exceed 35,000 MW. To meet future reliability requirements the OPA assumes a reliability reserve margin of 20 percent for planning purposes between 2018 and 2032.

Figure 1 – LTEP Gross Peak Demand and Reserve Margin[4]

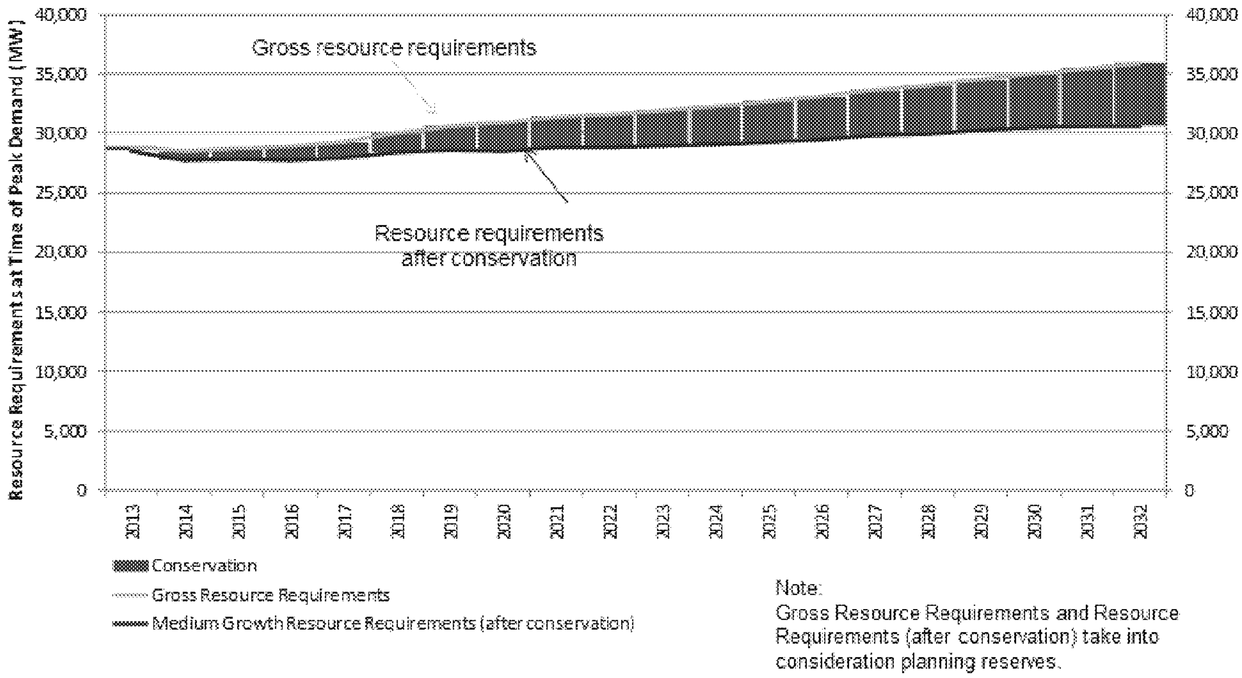


[3] http://powerauthority.on.ca/sites/default/files/planning/LTEP-2013-Summary-of-Assumptions.pdf (Slide 3)
[4] http://powerauthority.on.ca/sites/default/files/planning/LTEP-2013-Module-3-Supply-Demand-Balance.pptx (Slide 13)

A.2 Impact of Conservation on Resource Requirements

The Gross Resource Requirement does not consider the anticipated impact of conservation initiatives. The LTEP notes that the long-term conservation target of 30 TWh in 2032 represents a 16 percent reduction in forecast Gross Resource Requirement. Figure 2 below shows the impact of conservation on the Gross Resource Requirement resulting in the Net Resource Requirement. The Net Resource Requirement is anticipated to remain relatively flat over the next 20 years peaking at 30,633 MW by 2032, an increase of only 2,100 MW from 2013.[5]

Figure 2 –Resource Requirement after Conservation[6]



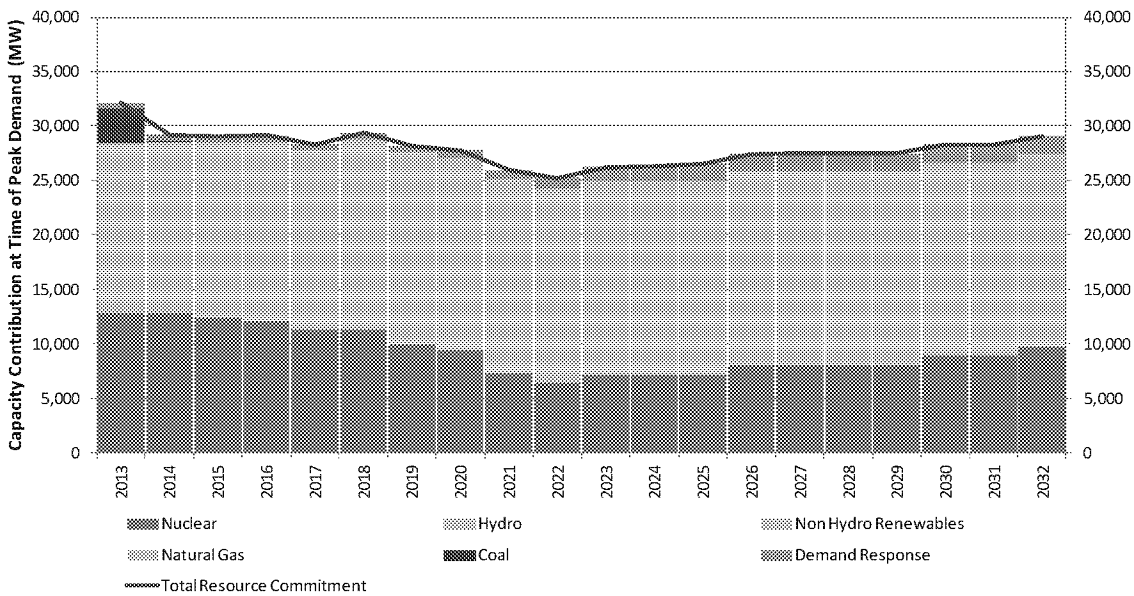
[5] Annual Net Peak Demand and Required Reserve available from detailed LTEP information: Module 3: Generation and Conservation Tabulations and the Supply /Demand Balance at: http://powerauthority.on.ca/sites/default/files/planning/Data-Tables-Module-3-Supply-Demand-Balance.xlsx

[6] http://powerauthority.on.ca/sites/default/files/planning/LTEP-2013-Module-3-Supply-Demand-Balance.pptx (Slide 14)

A.3 Committed Resource Commitment to Meet Peak

The OPA estimates the amount of effective capacity that will be available to meet each annual peak demand in Figure 3. This effective capacity is based on the resources that currently exist, are committed to come on-line, or are directed to be developed during the planning period (referred to as the Total Resource Commitment). An increase in new installed generating capacity from non-hydro renewables by 2020 offsets the initial decline in existing capability. The decline is due to coal shut down and nuclear units retiring or undergoing refurbishment.

Figure 3 –Contribution of Resources at Time of Peak Demand [7]



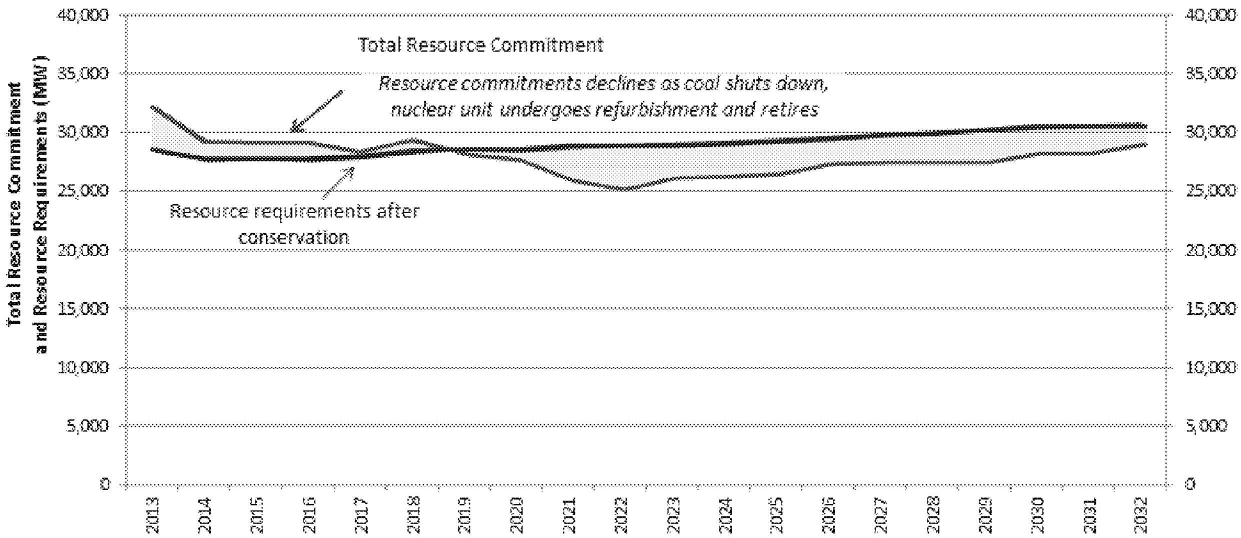
A.4 Ontario Resource Requirement and Committed Resources

The OPA's projection of the Total Resource Commitment is compared to the resource requirements less conservation in Figure 4 below. In comparing the total reserve commitment to the projected resource requirements, the OPA identifies some quantity of "Planned Flexibility" capacity will be needed. Planned flexibility includes a suite of potential options including new

[7] http://powerauthority.on.ca/sites/default/files/planning/LTEP-2013-Module-3-Supply-Demand-Balance.pptx (Slide 11)

generation, repowering, clean imports, renegotiating expiring NUG contracts, additional demand response or additional conservation.

Figure 4 – Ontario Resource Requirement and Committed Resources[8]



In its LTEP presentation materials, the OPA acknowledge the Total Resource Commitment will be higher or lower under different scenarios.

A.5 Directed Demand Response

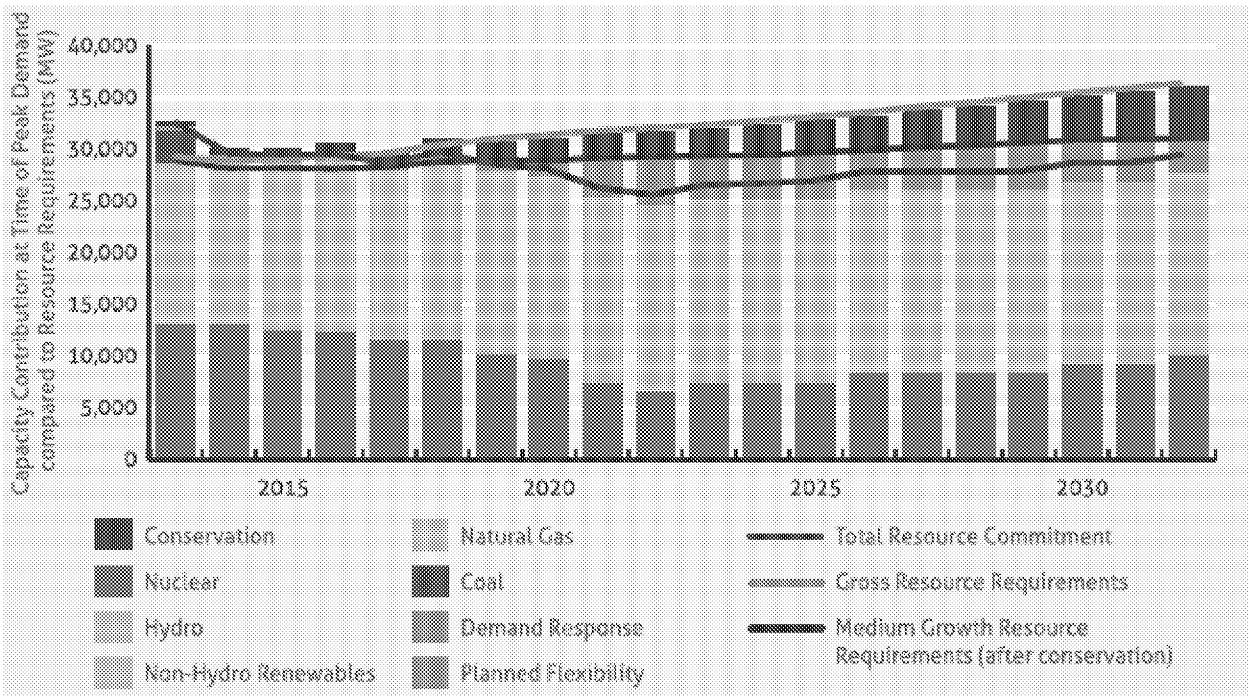
The LTEP included directed dispatchable Demand Response as part of the portfolio Total Resource Commitment. This directed Demand Response was projected to be procured starting in 2020 and quickly growing to contributing as much as 1,000 MW to the Total Resource Commitment by the end of the planning period.[9]

[8] http://powerauthority.on.ca/sites/default/files/planning/LTEP-2013-Module-3-Supply-Demand-Balance.pptx (Slide 17)
[9] http://powerauthority.on.ca/sites/default/files/planning/LTEP-2013-Module-2-Conservation.pptx (Slide 21)

The LTEP also noted that responsibility for administering new and existing Demand Response initiatives will be transferred from the OPA to the IESO.[10] The IESO is in the process of transitioning existing Demand Response programs and introducing new Demand Response initiatives with the aim of expanding the use of Demand Response to meet 10 percent of peak demand by 2025, or approximately 2,400 MW.

In the context of a capacity auction, the IESO believes that Demand Response is one resource that could compete to meet resource adequacy needs. The amount of new Demand Response that clears a capacity auction is not limited to the amount of directed Demand Response assumed in the LTEP, but is determined based on the cleared quantity that is cost effective relative to other capacity resources. To reflect this approach, the 1,000 MW of directed dispatchable Demand Response is included as part of the capacity shortfall secured through a capacity auction.

Figure 5 – Ontario Planned Supply Mix[11]



[10] Ontario's LTEP (2013), pg. 23 available at: http://powerauthority.on.ca/sites/default/files/planning/LTEP_2013_English_WEB.pdf

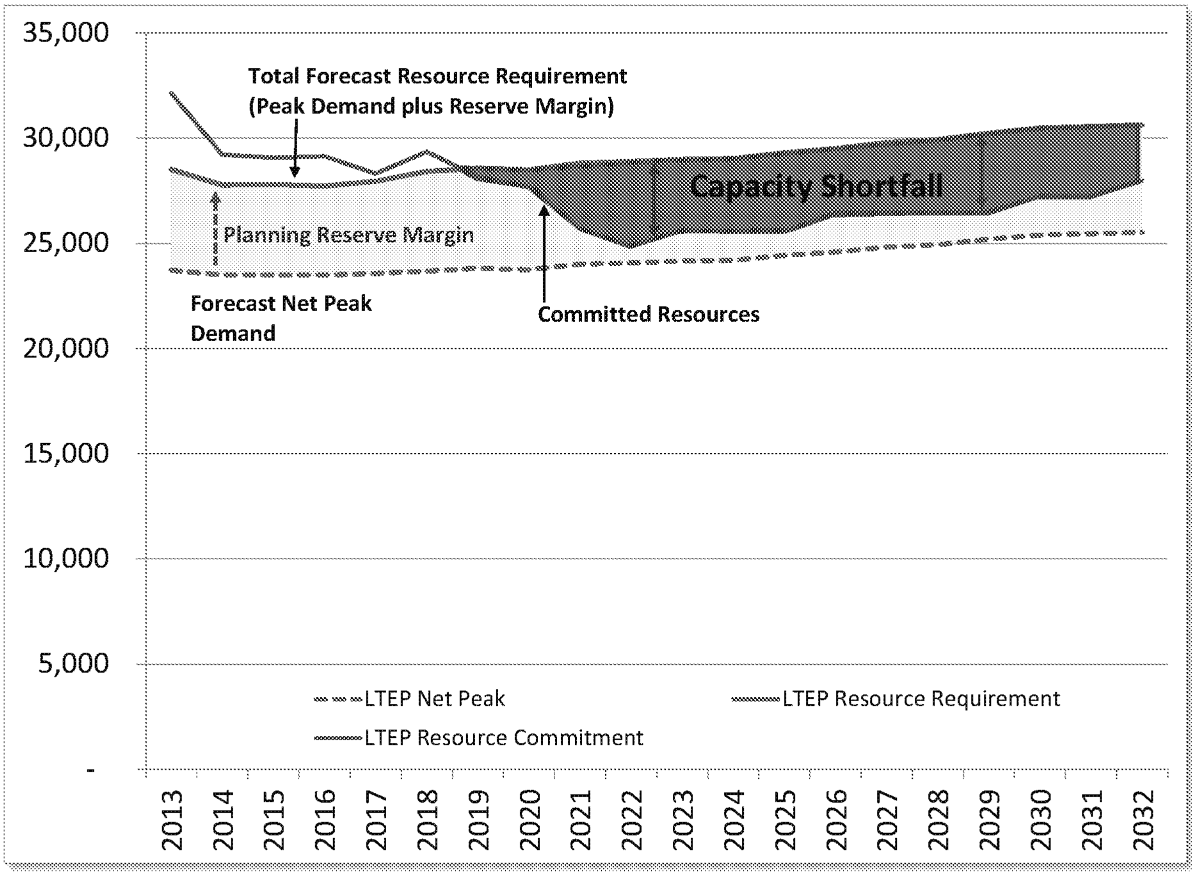
[11] http://www.energy.gov.on.ca/docs/LTEP_2013_English_WEB.pdf (Figure 18)

A.6 Calculating the Capacity Shortfall

Figure 6 plots annual Committed Resources compared to the Forecast Resource Requirement after adjusting for the directed Demand Response.

Beginning in 2019 a capacity shortfall appears and persists throughout the remainder of the planning period and reaches a maximum of 4,042 MW in 2022. The shortfall increases quickly early next decade as a result of scheduled refurbishment to nuclear units at the Bruce and Darlington facilities.

Figure 6 – Ontario Resource Requirement and Committed Resources



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A.7 Expiring Contracts

In addition to the capacity shortfall, current OPA contracts with existing natural gas facilities will begin to expire in 2023 with a significant amount of expiring contracts beginning in 2029. These are shown in Figure 7.

Figure 7 – OPA Natural Gas and Biomass Contracts as of March 31, 2014[12]

Contract Facility	Cogeneration Facility	Contract Capacity (MW)	Commercial Operation/Term Commencement Date	Contract Expiry Date
Birchmount Energy Centre	✓	2.6	23-Dec-13	Q4 2033
Bur Oak Energy Centre	✓	3.3	20-Feb-14	Q1 2034
Brighton Beach Power Station		541.3	01-Jan-06	Q3 2024
Durham College District Energy Project	✓	2.3	11-Mar-08	Q1 2028
East Windsor Cogeneration	✓	84	06-Nov-09	Q4 2029
Essar Cogeneration Facility*	✓	63	13-Jun-09	Q2 2029
Great Northern Tri-Gen Facility	✓	11.3	31-Oct-08	Q4 2028
Goreway Station		839.1	04-Jun-09	Q2 2029
Greenfield Energy Centre		1,005	16-Oct-08	Q4 2028
GTAA Cogeneration Plant	✓	90	01-Feb-06	Q1 2026
Halton Hills Generating Station		641.5	01-Sep-10	Q3 2030
Lennox Generating Station		2,000	01-Jan-13	Q3 2022
London Cogeneration Facility	✓	12	31-Dec-08	Q4 2028
Ottawa Health Sciences Centre		73.7	1-Jan-14	Q1 2034
Portlands Energy Centre		550	22-Apr-09	Q2 2029
Sarnia Regional Cogeneration Plant	✓	444	01-Jan-06	Q4 2025
St. Clair Energy Centre		577	30-Mar-09	Q1 2029
Sudbury District Energy Cogeneration Plant	✓	5	01-Jan-06	Q4 2024
Sudbury District Energy, Hospital Cogeneration	✓	6.7	01-Jan-06	Q4 2024
Thorold Cogen	✓	236.4	28-Mar-10	Q1 2030
Trent Valley Cogeneration Plant	✓	6.7	01-Jan-06	Q4 2015
Warden Energy Centre	✓	5	04-Jun-08	Q2 2028
Villa Colombo Vaughan	✓	0.2	14-Nov-13	Q3 2030
York Energy Centre		393	09-May-12	Q2 2032
	Subtotal	7,593		

[12] http://powerauthority.on.ca/sites/default/files/news/OPA-Q1-2014-Electricity-Supply-Report.pdf (Table 13)

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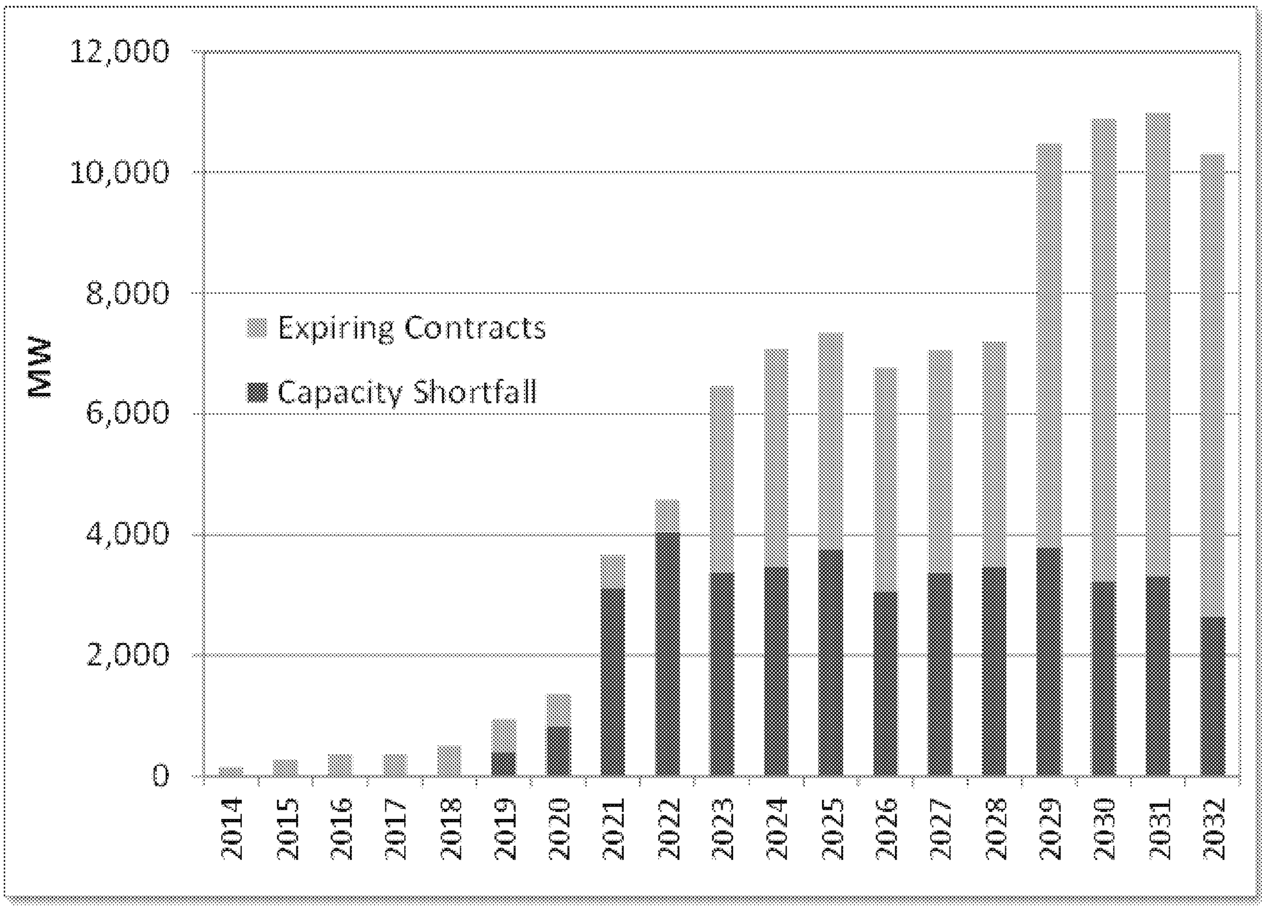
With the introduction of a capacity auction and after contract expiry these facilities could compete with other resources to satisfy Ontario's resource adequacy needs. In addition, OPA Demand Response 3 contracts will gradually expire over the next couple years adding to the potential pool of resources that could participate.

A.8 Total Capacity Shortfall and Expiring Contracts

Figure 8 shows the magnitude of the total MW that could be targeted to be procured through the annual capacity auctions, including both the anticipated capacity shortfall and expiring contracts.

Figure 8 – Capacity Shortfall and Expiring Contracts



In the near term the bulk of the MW total is comprised of resources required to maintain an adequate capacity for reliability purposes during the nuclear refurbishment process. By the end of the planning period, in excess of 10,000 MW could be cleared through the capacity auction with a greater share being comprised of resources whose current contracts will have expired.

A.9 Future Uncertainty

Changes that impact the magnitude of the Resource Requirement and the Committed Resources could impact the amount of capacity that is procured in future auctions. Although there is certainty around the timing of expiring contracts, the magnitude of the capacity shortfall could be higher or lower than projected depending on future demand. There is more uncertainty associated with the later years of the planning period. For example, the forecast of Net Peak Demand will differ from actual Net Peak Demand due to changes in the underlying economic conditions in Ontario. Secondly, there may be differences in the deliverability of resource targets.

There could also be uncertainty around the effective capacity that will be available to meet peak demand such as potential unexpected delays in the refurbishment of ten nuclear units at Bruce and Darlington scheduled to occur between 2016 and 2031. The capacity shortfall is calculated based on this refurbishment schedule presented in the LTEP as shown in Figure 9 below. Changes to the schedule could increase the size of the capacity shortfall, which would increase the potential cost savings from implementing a flexible capacity auction mechanism.

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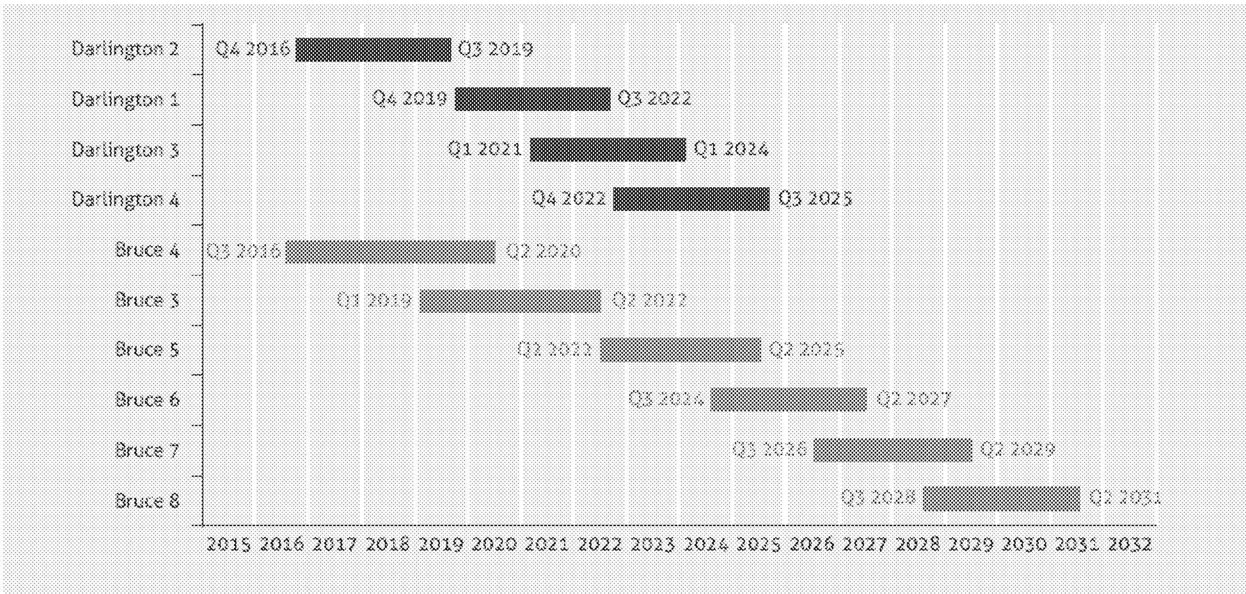
Figure 9 - Nuclear Refurbishment Sequence (LTEP 2013)[13]



[13] LTEP 2013, pg 30: http://www.energy.gov.on.ca/docs/LTEP_2013_English_WEB.pdf

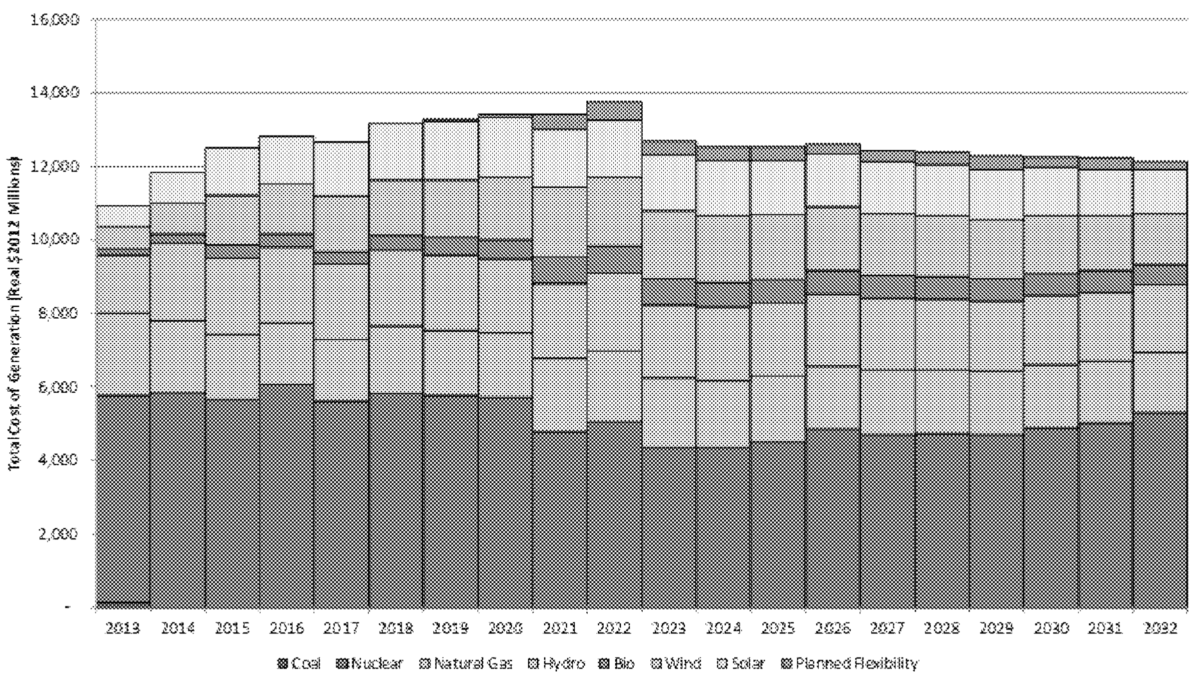
B. Cost of Capacity Under LTEP

B.1 Cost of Planned Flexibility in the LTEP

In the LTEP, the OPA identifies the Capacity Shortfall would be met by "Planned Flexibility" resources. Planned Flexibility is identified in the LTEP to include a mix of potential resources that could meet Ontario's peaking capacity needs, which could include a combination of hypothetical Single-Cycle Gas Turbine (SCGT) units, re-contracted Non-Utility Generators (NUGs), imports and demand response.[14] For LTEP modelling purposes the OPA assumes the cost of Planned Flexibility to be equivalent to the cost of a new SCGT at approximately $130,000/MW-year.[15,16]

The projected costs associated with the "Planned Flexibility" are noted in the Detailed LTEP Information Breakdown provided by the OPA.

Figure 10 - LTEP Assumed Generation Cost by Resource



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[14] http://powerauthority.on.ca/sites/default/files/planning/LTEP-2013-Module-3-Supply-Demand-Balance.pptx (Slide 16)

[15] http://powerauthority.on.ca/sites/default/files/planning/LTEP-2013-Module-4-Cost.ppt (Slide 8)

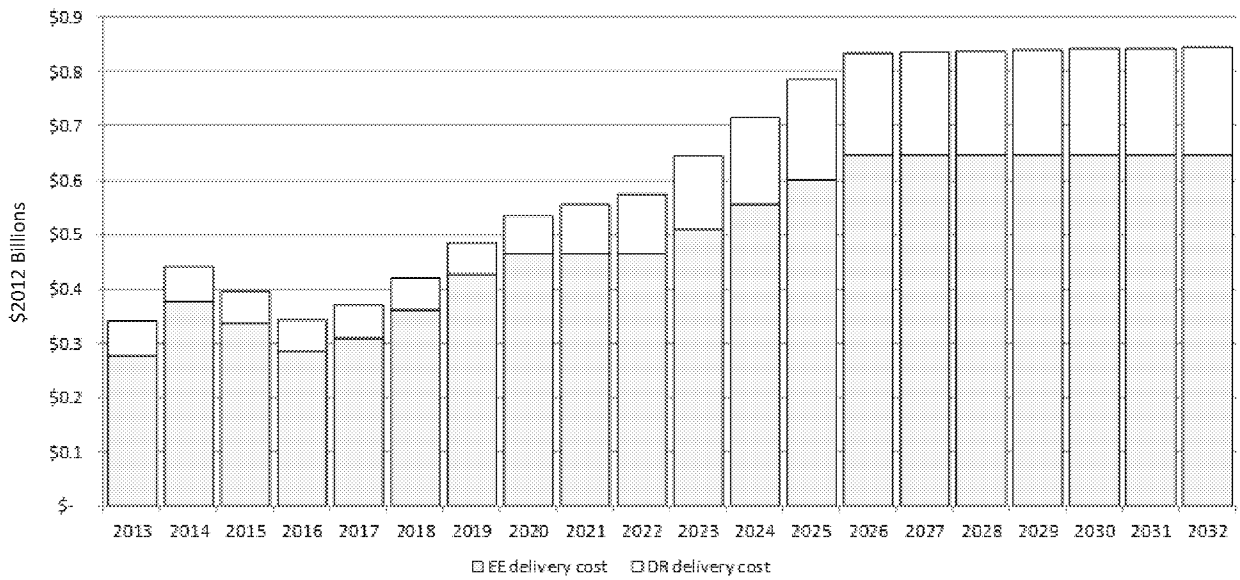
[16] http://powerauthority.on.ca/sites/default/files/planning/LTEP-2013-Module-2-Conservation.pdf (Slide 20)

B.2 Cost of Demand Response in LTEP

In the LTEP, existing demand response resource costs are based on current program experience. As mentioned in Section A.5, the OPA assumed that new directed Demand Response resources will be developed as the capacity shortfall arises at the end of the decade at a cost similar to a hypothetical SCGT ($130,000 MW/year).[17]

These demand response resources would be anticipated to competitively participate in a capacity auction. Therefore, costs associated with demand response (Figure 11) are included in addition to the planned flexibility costs when determining the cost of meeting the capacity shortfall under LTEP.

Figure 11 – LTEP Assumed Cost of Demand Response and Energy Efficiency[18]



B.3 Cost of Expiring Contracts in the LTEP

The OPA provided the IESO assumed costs built into the LTEP for re-contracting the facilities with expiring contracts over the planning period. These modelled costs are a function of the current contractual terms paid to individual facilities adjusted for depreciation and capital

[17] http://powerauthority.on.ca/sites/default/files/planning/LTEP-2013-Module-2-Conservation.pptx (Slide 20)
[18] http://powerauthority.on.ca/sites/default/files/planning/LTEP-2013-Module-4-Cost.ppt (Slide 14)

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requirements. Due to the confidential nature of the contract terms, the modelled costs for expiring capacity are not published.

C. Capacity Costs in Jurisdictions with Centralized Capacity Markets

The projected cost of satisfying Ontario's resource needs to 2032 is identified in the LTEP. To determine the potential savings that may be achieved under a capacity auction requires an estimate of a reference price based on what other jurisdictions with centralized capacity markets pay for capacity. Capacity clearing prices in U.S. jurisdictions are factual records of what was paid to providers of capacity by the system operators. This information was reviewed to determine what capacity auction prices could be if similar capacity prices observed in US were realized in Ontario. The reference price was determined based on auction price outcomes in NY and PJM over last five years (2009-2013 auctions) for reasons outlined in Section C.1. below.

C.1 Capacity Auction Clearing Prices in Other Jurisdictions

In the U.S. there are three jurisdictions that currently operate centralized capacity markets; PJM, New York ISO, and ISO New England. These markets have been established for a number of years subsequently reaching a state of maturity. Early results led to the development of market design best practices such as a downward sloping demand curve, leading to much improved price stability. Given the degree of change in U.S. capacity market designs experienced in the early years of implementation, auction clearing prices for the last five years were reviewed.

Auction price outcomes in New England were not included in the analysis. New England's Forward Capacity Auction (FCA) was implemented in 2008 and, since that date, it has operated with a vertical demand curve. This resulted in the auction clearing at administratively set floor prices for the first seven auctions,[19] until the eighth auction (February 2014) concluded with a slight shortfall in capacity and administratively set scarcity prices. In April 2014, ISO-NE submitted to FERC a proposal to implement a sloped demand curve with the rationale to "*reduce price volatility over time, yielding smaller swings in capacity prices when the market moves from conditions of excess supply to periods when new capacity resources are needed*"[20]. In June 2014,

[19] With the exception of one zone in FCA#7

[20] http://isonewswire.com/updates/2014/4/1/iso-ne-and-nepool-submit-proposal-to-establish-sloped-demand.html

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FERC accepted the proposal [21] and the sloped demand curve will be utilized in the next FCA to be held in February 2015.

If these results had been included they would have reduced the reference price for capacity auctions. However, because of the skewed auction results and the recent change to the market design, the ISO-NE capacity prices have not been included in the analysis.

MISO also runs a voluntary annual capacity auction that allows its Market Participants to meet resource adequacy objectives through a market-based design. Recent changes to its market design have created an enhanced resource adequacy construct. Two auctions have been held under this new design, the first in April 2013 and the second in 2014. The first auction cleared at a very low system wide clearing price of 1.05 per megawatt day[22]. The most recent auction cleared at prices ranging from $3.29 to $16.75 depending on the zone[23].

Again, if these prices had been included they would have reduced the reference price for capacity auctions. However, because of the unique, voluntary nature of the auction (integrated with utilities planning reserve margin requirements) and the nascent state of its development, the results from these auctions have not been included in the analysis.

To determine a single reference price to be used in the analysis, for both New York and PJM over the last five years, an average price was calculated weighted by the relative size of each of the capacity markets.

This information is taken from auction results by zone that are published by the ISOs following each auction. Using the cleared prices and quantities for each zone in each auction an average annual weighted average capacity cost can be calculated.

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[21] http://isonewswire.com/updates/2014/6/3/spi-news-ferc-accepts-iso-ne-and-nepool-proposal-to-institut.html

[22] https://www.misoenergy.org/AboutUs/MediaCenter/PressReleases/Pages/AnnualCapacityAuctionProvidesCertainty.aspx

[23] https://www.misoenergy.org/AboutUs/MediaCenter/PressReleases/Pages/MISOClearsSecondAnnualCapacityAuction.aspx

It is important to note that ISOs publish capacity auction prices in slightly different units. PJM and MISO publish prices in $/MW day, while ISO-NE and NYISO publish prices in $/ kw month.

Figure 12 – PJM Auction Results (Example 2016/17 Base Residual Auction) [24]

Auction Results	RTO	MAAC	SWMAAC	PEPCO	EMAAC	DPL-SOUTH	PSEG	PS-NORTH	ATSI	ATSI-CLEVELAND
Offered MW (UCAP)	184,380.0	71,607.5	12,386.0	6,126.1	34,139.9	1,764.4	6,784.3	4,181.6	12,791.3	2,874.3
Cleared MW (UCAP)	169,159.7	65,546.4	12,030.0	6,093.1	31,521.7	1,746.0	6,293.6	3,702.1	8,672.2	2,350.0
System Marginal Price	$59.37	$59.37	$59.37	$59.37	$59.37	$59.37	$59.37	$59.37	$59.37	$59.37
Locational Price Adder*	$0.00	$59.76	$0.00	$0.00	$0.00	$0.00	$99.87	$0.00	$35.08	$0.00
Extended Summer Price Adder**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$19.78	$19.78
Annual Price Adder	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Resource Clearing Price for Limited Resources	$59.37	$119.13	$119.13	$119.13	$119.13	$119.13	$219.00	$219.00	$94.45	$94.45
Resource Clearing Price for Extended Summer Resources	$59.37	$119.13	$119.13	$119.13	$119.13	$119.13	$219.00	$219.00	$114.23	$114.23
Resource Clearing Price for Annual Resources	$59.37	$119.13	$119.13	$119.13	$119.13	$119.13	$219.00	$219.00	$114.23	$114.23

*Locational Price Adder is with respect to the immediate parent LDA

**Annual Resources and Extended Summer DR receive the Extended Summer Price Adder

Figure 13 – NYISO Auction Results (Example May 2013 Auction) [25]

Post Data

Posted Date	Posted By
04-May-2013 03:08 PM	Pete Morrison

Locational Calculations

Location	Forecasted Peak Load MW	Requirement %	Derating Factor %	ICAP MW Requirement	UCAP MW Requirement	UCAP Effective %
LI	5,514.5	105.00%	6.84%	5,790.3	5,394.3	97.82%
NYC	11,485.0	86.00%	5.59%	9,877.1	9,325.0	81.19%
NYCA	33,278.6	117.00%	8.91%	38,936.0	35,466.8	106.58%

24 http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2016-2017-base-residual-auction-report.ashx (slide 15)
25 http://icap.nyiso.com/ucap/public/ldf_view_icap_calc_detail.do
http://icap.nyiso.com/ucap/public/auc_view_spot_detail.do

Summer 2013 Capability Period 05/2013 Spot Market Auction Results - UCAP Posted Date: 05/04/2013 17:35 PM	05/2013
LI	
Awarded Deficiency (MW)	1.7
Awarded Excess (MW)	340.300
% Excess Above Requirement	5.31
Price ($/kW-M)	$7.20
NYC	
Awarded Deficiency (MW)	3,687.1
Awarded Excess (MW)	378.800
% Excess Above Requirement	4.05
Price ($/kW-M)	$16.29
NYCA	
Awarded Deficiency (MW)	6,295.7
Awarded Excess (MW)	1,817.200
% Excess Above Requirement	5.12
Price ($/kW-M)	$5.76
HQ	
Awarded as part of NYCA Def./Exc. (MW)	304.900
Price ($/kW-M)	$5.76
IESO	
Awarded as part of NYCA Def./Exc. (MW)	0.000
Price ($/kW-M)	$0.00
NE	
Awarded as part of NYCA Def./Exc. (MW)	0.000
Price ($/kW-M)	$0.00
PJM	
Awarded as part of NYCA Def./Exc. (MW)	0.000
Price ($/kW-M)	$0.00
Total Awarded Deficiency (MW)	9,984.500
Total Awarded (MW)	11,801.700
*ROS Price Paid By LSE's (Weighted Avg.)	$5.760

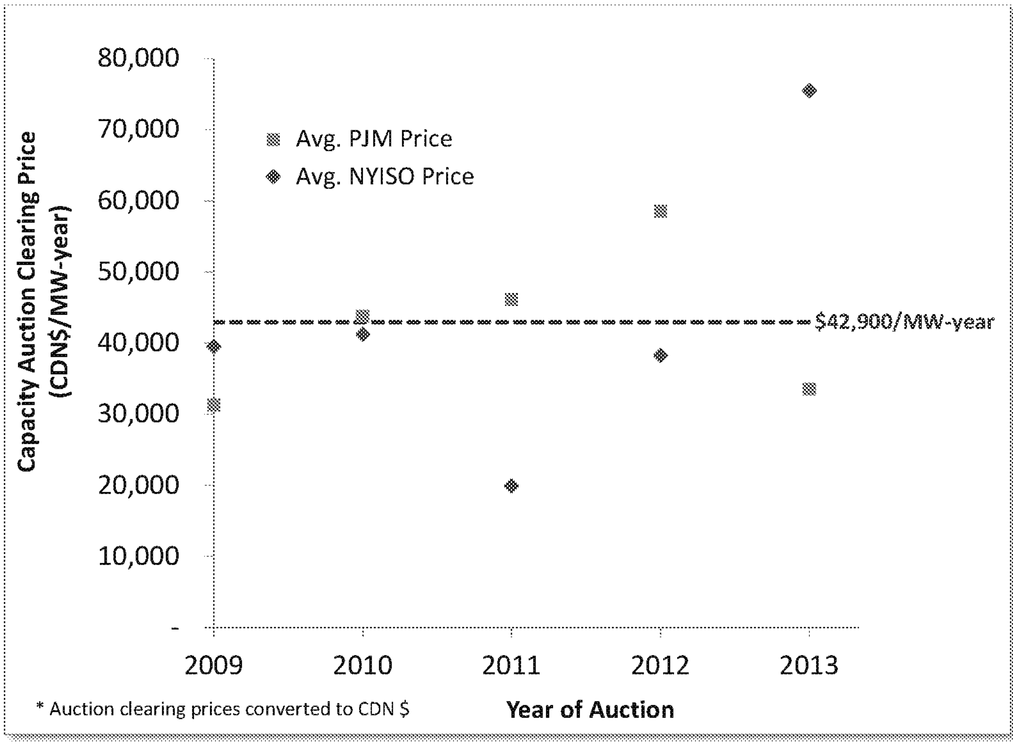
Footnotes:

External CA MW are included in the NYCA MW Totals
*External awards sink in ROS

Spot Auction Clearing Prices posted each month and for each of the capacity zones.

To enable useful comparison, PJM and NYISO prices have been converted from $/MW-day and $/kw-month respectively to $/ MW-year in Figure 14, which plots the annual weighted average prices for each jurisdiction over the last five years. These weighted average prices are then converted to Canadian dollars using the average annual Bank of Canada exchange rate. Capacity prices have cleared higher and lower than the average reflecting changing supply and demand conditions from year to year. Capacity clearing prices over the auctions held between 2009 and 2013 have cleared, on average, at a price of $42,900/MW-year.

Figure 14 – Capacity Clearing Prices in U.S. Jurisdictions



C.2 Additional Net Revenues Available to Capacity Providers in the U.S. Markets

Capacity payments represent one source of revenue that resources can earn in the wholesale market. Other sources of market payments include energy and ancillary services (E&AS) revenues. To the extent that net revenues (revenues less variable costs) are earned from each of these sources, they will help contribute to a resource's fixed capital costs. In turn this will reduce the amount of revenue that resources need to recover from the capacity auction (affecting their offers into the auction).

The PJM Market Monitor estimates historical net E&AS revenues for different types of resources in the PJM market.[26] This information was used to calculate what the equivalent types of resources considered in the LTEP to meet the capacity shortfall (ie: planned flexibility and

[26] Annual PJM Net Energy and Ancillary Services Revenues available in the Monitoring Analytics SOM Report 2013: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2013/2013-som-pjm-volume2-sec7.pdf

directed demand response) would have earned over the last five years in the U.S. markets. That is, what were the net E&AS revenues earned by a combination of imports, demand response, uprates to existing units, and new simple-cycle gas turbines over the last five years. When dispatched to produce energy or supply ancillary services these resource types are often infra-marginal in the PJM market. This is because many older, less efficient gas, coal or oil-fired facilities can be displaced in the PJM offer stack.

The relative proportion of cleared capacity by resource type information is taken from the annual RPM Base Residual Auction Results reports.[27] Figure 15 below presents the proportion of MW that cleared in PJM by resource type and the associated net E&AS revenues.

Figure 15 - Net E&AS Revenues and Percent of New Entry by Peak Resource Type in PJM (2009-2013)

Resource Type	Net Energy+ AS Revenues ($CDN/MW-year)	% of New Entry by Peak Resource Type
CT - Gas	27,000	10%
Imports	0	22%
DR	0	55%
Uprates	41,000	13%
	Weighted Avg.	**$8,000**

Net E&AS revenues for uprates were determined by taking a weighted average of the Net E&AS revenues found in the PJM Market Monitoring report weighted by the resource type of the uprated unit.[28]

Overall, Net E&AS revenues were calculated to be $8,000/MW-year based on PJM's historical mix of equivalent resources identified in the LTEP to meet planned flexibility. The equivalent information is not calculated by NYISO's market monitor. For the purpose of the analysis, these revenues are assumed to be similar to those earned in PJM.

[27] The 2016/2017 results available at: http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2016-2017-base-residual-auction-report.ashx

[28] Uprates by fuel type available in PJM's 2016/2017 BRA Results Report (Table 8): http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2016-2017-base-residual-auction-report.ashx

Therefore, the cost for capacity in the U.S for equivalent capacity is $42,900/MW-year (capacity price) plus $8,000/MW-year (Net E&AS revenues) totalling $50,900/MW-year.

C.3 Additional Revenues

In the LTEP it was assumed that the planned flexibility resources would require $130,000/MW-year. Annual energy output for the planned flexibility resources is forecast to be very low over the planning period.[29] In the infrequent instances where they have been forecast to run, these resources are anticipated to be the marginal price setting resource. As a result they are expected to make little to no net revenues above what is required to cover variable costs – they would break even when producing. Comparatively speaking, Ontario's current natural gas fleet is relatively new and efficient, meaning new peaking resources are unlikely to displace older resources in the stack. Thus, no adjustment for net E&AS revenues was required. In comparison, similar units in capacity auctions were paid $42,900/MW-year plus $8,000/MW-year earned in the E&AS markets.

[29] http://powerauthority.on.ca/sites/default/files/planning/LTEP-2013-Module-3-Supply-Demand-Balance.pptx (Slide 39)

D. Potential for Cost Savings in meeting Ontario's Capacity Shortfall

By combining the analysis performed under Parts A, B and C a comparison can be made of between the cost of meeting the projected capacity shortfall under LTEP and what the cost could be if capacity market prices observed in U.S. markets were attained through a capacity auction in Ontario.

This is not a projection of what Ontario capacity auction prices will be. This should not suggest that prices in Ontario over the next two decades will be exactly the same as those seen elsewhere over the past five years. Auction prices will depend on many factors including future peak demand growth, success of conservation initiatives, nuclear refurbishment, development of the demand response sector, technological innovation, capacity situations in other jurisdictions, energy market prices, cost of financing, etc. Instead, this comparison allows for an illustration of what the cost for meeting the capacity shortfall could realistically be in Ontario with a capacity auction mechanism.

Other jurisdictions have been able to secure resource adequacy at prices well below the cost of new entry by incentivizing the development of alternative sources of capacity. These alternative sources of capacity have historically included demand-side resources, imports, and uprates to existing facilities. The Net Cost of New Entry (Net CONE) is an important input into the positioning of the demand curve in a capacity auction. Net CONE represents an estimate of the revenues a new generator will need to earn to enter the market and recover capital investment and annual fixed costs after considering net revenues earned in the energy and ancillary services markets.

Over the last five years, Net CONE in both PJM and New York has, on average, exceeded $100,000/MW-year (in Canadian dollars) although it can be as much as 30 percent higher than the average in specific zones within these jurisdictions. The estimates do not appear out of line from Net CONE estimates in Ontario as LTEP implicitly assumes a cost of $130,000/MW-year for the planned flexibility resources representing the net cost of new entry.

Figure 16 – Cost of New Entry and Average Capacity Clearing Price

$CDN/MW year	PJM	NYSIO
Avg Net Cost of New Entry	$100,000	$122,000
Avg Capacity Clearing Price	42,900	42,700
% of Net CONE	17-55%	29-54%

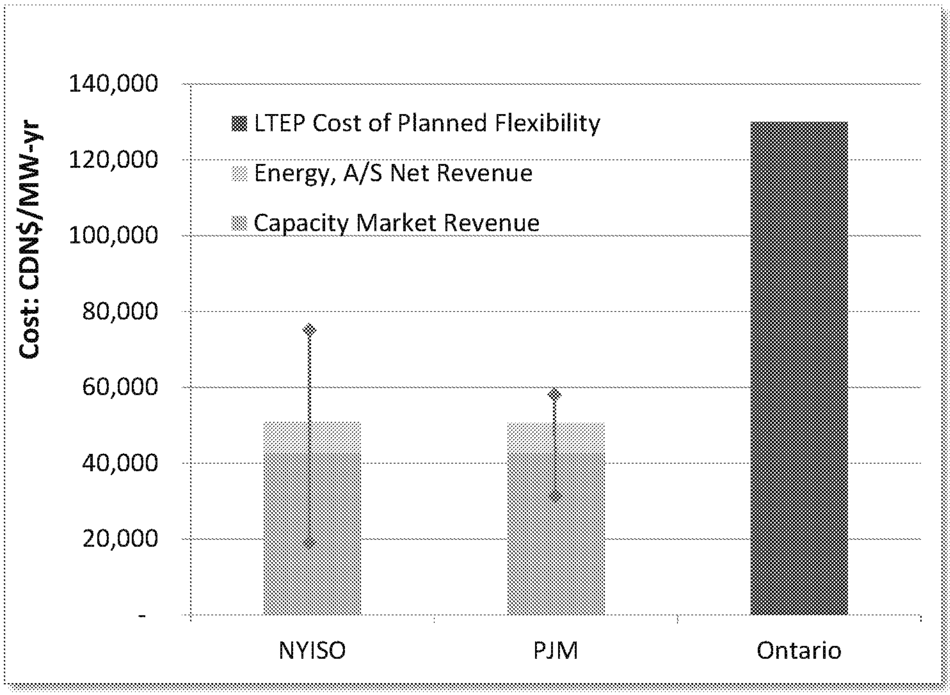
Note: U.S costs based on average since 2009

Average capacity prices in PJM and New York have cleared at substantially less than Net CONE. These types of outcomes may be achieved if Ontario were to experience penetration rates from low-cost non-traditional resources similar to what has cleared in other jurisdictions such as demand response, imports, or uprates on existing gas and hydroelectric assets. Markets have proven to be effective in eliciting responses from new resources not necessarily predictable ahead of time through a planning process.

D.1 Comparing the Per MW Year Cost

Figure 17 presents the average cost of capacity relative to the estimated cost of peaking capacity in Ontario. The vertical lines in the figure represent the range of capacity auction prices in each of the jurisdictions. Capacity prices have shown some volatility as conditions have changed, prices have typically cleared well below the cost of new entry.

Figure 17 – Capacity Costs Comparison

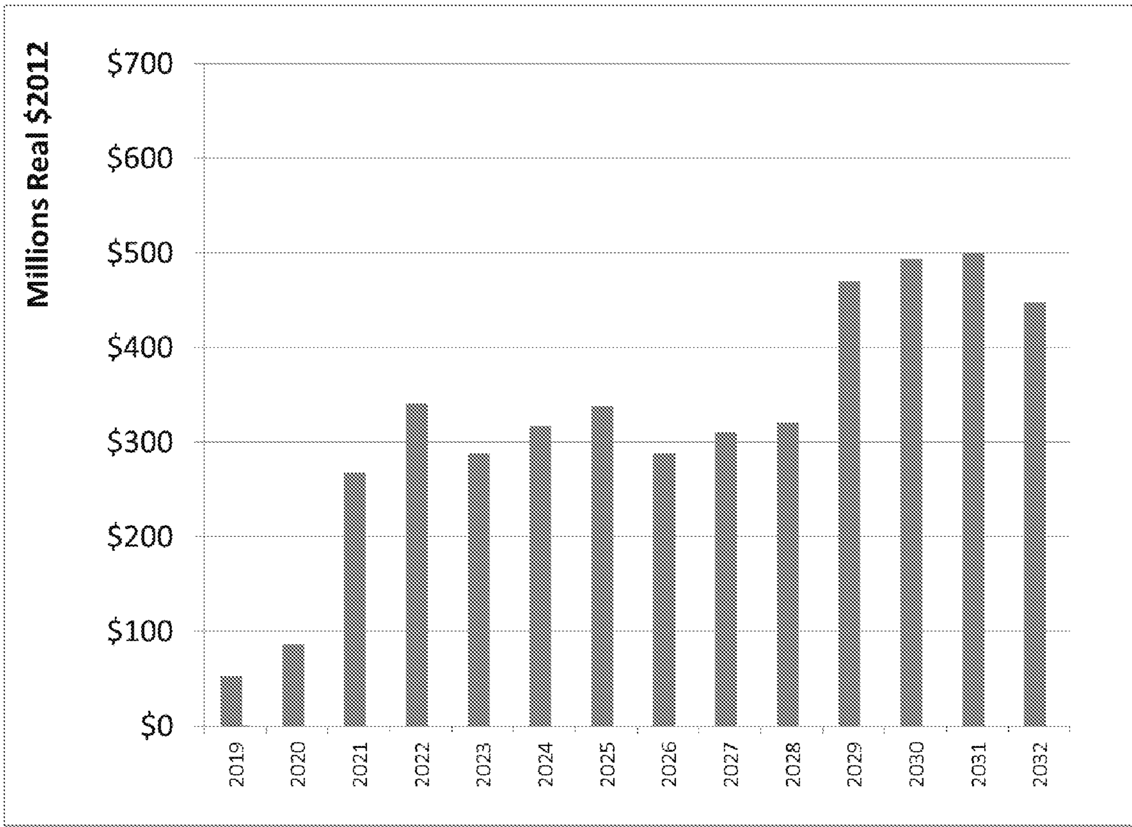


D.2 Applying the per MW year costs to the Projected Shortfall

The potential benefits over the planning period are determined by comparing the all-in cost of capacity in the U.S. jurisdictions ($51,900 MW-year) with the LTEP's assumed costs of meeting both the capacity shortfall (cost of $130,000/MW-year) and the assumed cost of re-contracting resources. Figure 18 presents the cost savings from solving the projected capacity shortfall and expiring contracts through a capacity auction relative to the costs assumed in the LTEP.

In the early part of the 2020 decade, meeting the capacity shortfall through a capacity auction mechanism could provide an annual savings in the $250 to $350 million range. Annual savings are larger towards the end of the planning period, between $450 and $500 million, as contracts begin to expire.

Figure 18 – Potential Cost Savings from a Capacity Auction



D.3 Uncertainty

The later years of the planning period are subject to greater uncertainty. Along with uncertainty associated with peak demand projections and the amount of resources available to meet peak demand, there is also uncertainty around the types of resources that will most likely come online. The types of resources that enter the market are in part determined by the needs of the province reflected through energy, ancillary services, and capacity clearing prices. For example, high energy market prices would be indicative of a need for resources that provide energy such as new combined-cycle units. Low to moderate energy market clearing prices may reflect a need for peaking resources to meet capacity needs (peaking generation or demand-side resources). The amount of additional revenue required to meet a resource's fixed capital costs differ significantly across different resource types, therefore capacity clearing prices can be influenced by the types of resources that offer in and clear the capacity auction.

The potential benefits from a capacity auction could be higher under a scenario where there are unexpected delays in the return to service for refurbished Bruce or Darlington nuclear units. Delays could change both the timing and magnitude of future capacity shortfalls increasing the potential benefits from implementing a capacity auction. The LTEP cost assumptions are based on a resource requirement using a projection of peak demand under a "medium growth" scenario. The potential benefits will be higher if the actual resource requirements are higher, than the LTEP. This could occur as a result of higher than expected economic growth in the province or less than expected penetration from conservation resources.

In order to understand the range of prices that might be realised and understand the potential risk from price volatility in the marketplace the analysis reviewed the highest priced clearing prices in PJM and New York. In the unlikely scenario that little penetration was experienced from non-traditional resources, auction clearing prices could be higher than the average. However, even in the highest priced regions within the jurisdictions with centralized capacity markets, clearing prices have cleared below Net CONE and significantly below the OPA estimated cost of planned flexibility. Over the last five years, the highest price capacity zones have been the PSEG-North zone in PJM and the New York City Zone in New York. On average, these two zones have cleared at $88,100/MW-year[30] and including the energy and ancillary services adder results in an all-in cost of $96,200/MW-year. Even under a higher priced scenario reflecting the all-in costs associated with very import constrained zones, there remains a significant potential benefit relative to the status quo. Overall, the risk of costs resulting from a capacity auction exceeding those assumed in the LTEP over the full period can be considered extremely small.

Due to system needs capacity auction prices will exhibit variation year-to-year, sometimes exceeding the average and sometimes clearing lower than the average. Over time, it can be expected that prices would clear at sufficient levels to maintain a reliable resource mix that reflects incremental system needs. Based on the experience of New York and PJM, that price is

[30] NYC Zone capacity clearing prices available at: http://icap.nyiso.com/ucap/public/auc_view_spot_detail.do and PJM zonal prices available at: : http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2016-2017-base-residual-auction-report.ashx

substantially lower than the cost of new entry represented by Net CONE, or the LTEP cost assumptions.

D.4 Additional Benefits of a Capacity Auction

The above analysis demonstrates the potential cost savings that a capacity auction could offer in Ontario. There are additional benefits that a capacity auction can provide that have not been quantified that would increase the benefits of implementing a capacity auction. These benefits include:

- Flexibility – Capacity auctions provide a mechanism to reduce the risk of overbuilding if supply and demand conditions do not transpire as forecast while maintaining reliability. A combination of a forward base auction and supplemental rebalancing auctions better ensures that the appropriate amount of capacity is procured for a delivery year.

- Resource Diversity through Innovation – A capacity market promotes participation from all resource types and allows non-traditional resources an opportunity to compete against traditional resources. These resources will clear the capacity auction when cost effective relative to building a new peaking resource. U.S. jurisdictions with centralized capacity markets have seen an increase in non-traditional low cost resources clearing the capacity auctions. For example, in PJM, over 10 percent of the capacity that has cleared recent base auctions have come from uprates to existing units, imports, Demand Response and Energy Efficiency resources.[31]

- Improved Risk Sharing – Long-term contracts place a significant amount of investment risk on consumers. A capacity auction will shift some of this risk to participants that are in the best position to manage it.

- Transparency – Capacity auction prices provide a clear signal for capacity for all resources to help in planning purposes. For example, in the U.S. markets analyzed, auction clearing prices are published by zone shortly after each base and rebalancing

[31] See PJM's 2017/2018 RPM Base Residual Auction Results at: http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2017-2018-base-residual-auction-report.ashx

auction and are important to both consumers that pay for the capacity and existing and potentially new capacity resources to help make efficient investment decisions.

- Efficient Entry and Exit – Capacity auctions provide clear price signals that allow new resources to determine whether they are competitive relative to other types of capacity. For example, capacity auctions in PJM have proven effective in ensuring reliability even as environmental regulations affecting significant coal fired generation capacity have come into force. Capacity auctions also provide a mechanism for existing resources to make efficient retirement decisions.

D.5 Conclusion

The quantification of potential benefits illustrates the significant potential for cost savings to Ontario consumers from introducing a competitive capacity auction to address future capacity shortfall requirements. Even if only a portion of the total benefits can be realised, Ontario electricity consumers can expect to significantly benefit from the introduction of a capacity auction. Suppliers can also expect to benefit as well; a regular auction provides an enduring mechanism for existing providers as well as an opportunity for new players and new technologies to compete.

By focusing on incremental capacity needs, a capacity auction can be considered a low risk option on a number of levels. First, the auction would focus on a specific reliability need not served by existing contracted or committed resources. Second, there is time to get the design right. Third, an auction would operate alongside existing market structures. Fourth, even under high priced scenarios (high clearing prices persisting for extended periods) costs can be expected to be lower than those currently projected in the LTEP. Fifth, Ontario has the opportunity to learn from other markets. Finally, implementation costs are expected to be small in relation to the expected benefits.

III. THIRD PARTY REVIEW

The IESO engaged NERA Economic Consulting to provide a third party validation of key assumptions and the methodology taken. NERA's assessment is provided in the following pages.

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NERA Note on IESO Analysis

We have been asked by IESO staff to review an analysis and underlying documentation they have prepared regarding net benefits from the implementation of a capacity market in Ontario. Our conclusions are:

- The basic structure of the analysis is sound, and the calculations are straightforward.

- The analysis presented gives only one part of the potential benefits. Even so, benefits outweigh costs by a substantial margin, fully justifying further exploration of the creation of an Ontario capacity market.

- The benefit estimate is critically dependent on the Ontario Power Authority's (OPA) Long Term Energy Plan (LTEP)[1]. In particular, the LTEP estimates that the consumer cost for new entry in Ontario will be approximately $130/kW-year in 2012 CND. Since this value is considerably higher than is observed for capacity procured in similar regions (in particular, PJM and the New York ISO) the difference represents an economic cost savings to Ontario consumers. That said, both sides of this comparison are subject to substantial uncertainty, as is any such economic forecast. The bulk of this paper will discuss the uncertainties on both sides. Our central conclusion in that the differences in capacity costs are in fact largely attributable to markets. Well-designed markets often deliver surprising results which provide value to consumers and we believe they have done so in PJM and NYISO.

- The remaining calculations, with one exception require a careful parceling out of these benefits over time to the particular rate classes. These calculations all appear to be done correctly with a minimum of assumptions which might provoke controversy.

- The exception comes from discounting. The analysis shows estimates as the simple sum of benefits over time. While easy to describe and for ease of direct comparison, these estimates are correctly calculated, a proper measure of benefits should discount the benefits over time at a social discount rate for Ontario to arrive at accurate present-valued results. That said, the effects of doing so will not come close to reversing the result of benefits substantially exceeding costs.

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[1] Available at http://www.powerauthority.on.ca/power-planning/long-term-energy-plan-2013

I. Benefits of Capacity Markets

The IESO analysis does not purport to all potential social benefits of capacity markets. Instead, it focuses on one set of benefits: reduced cost of capacity procurement. Thus, some benefits, like increased flexibility and risk shifting are not captured in the IESO analysis[2].

OPA in the 2013 LTEP has estimated that new capacity from a simple cycle gas turbine (SCGT) will cost Ontario $130/kW-year in $2012 CND. The LTEP does not detail the source of this calculation, but it is certainly not out of line with SCGT estimations with which we are familiar, including those which NERA has participated in. The plan shows additions of SCGTs, so they are presumably part of the least-cost mix of installed additions.

In equilibrium, all generation types have the same marginal cost of addition. If this were not true, we would simply add more of the least expensive unit type and less of the most expensive type. While at any given time one unit type might present a lower cost of addition than another, it is sensible in planning studies to adopt the global perspective that all technology types which are part of the long-term plan have the same costs at the margin. The LTEP explicitly does this for demand-side resources, for example, also assuming that they will cost about $130/kW-year at the margin. There may be other technology types which are selected even though they present *higher* costs because they provide other benefits which are not directly considered, *eg*, renewables for their environmental benefits or nuclear for its fuel diversity benefits. But treating all additions as if they cost $130/kW-year then properly eliminates any such subsidies from the cost-benefit criterion, as they will be presumably be achieved either under a capacity market or under direct OPA procurement.

The IESO analysis then makes a series of calculations to demonstrate that capacity market procurements in the PJM and IESO markets have substantially undercut the $130/kW-year figure. At that point, the rest of the benefit calculation follows in a fairly straightforward fashion. The difference in procurement cost is multiplied by the expected number of MW procured[3], and the resulting aggregate saving is then subtracted from the global adjustment and then allocated back out to loads according to the division of the global adjustment[4].

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2 There is an interpretation which might possibly be construed to at least partially include flexibility benefits. This will be discussed below in footnote 3.

3 We have made no inquiry into the LTEP projections of capacity required. One clear potential advantage of capacity market is their flexibility to more precisely calibrate purchases to needs (though a full exploration of this benefit will depend on, among other things, the shape of any particular demand curve used). One interpretation of the OPA $130/kW-year estimate is that it has been grossed up to reflect the inflexibility of traditional 20 year contracting. If so, the estimates here may include some component of flexibility benefits.

4 Actually, the gross cost of procurements is subtracted from the global adjustment and the cost of capacity market procurement is allocated back separately. This highlights the fact that the allocation back to loads of the savings is mostly arbitrary, since

Thus, to a large extent, the persuasiveness of the IESO analysis hinges on the persuasiveness with which the two alternative capacity market scenarios are derived. We turn to these now.

II. Calculating Indicative Procurement Costs by Analogy with US Markets

A. Introduction

First, we agree with the IESO authors that the capacity market values used in the cost-benefit analysis here are *not* forecasts of capacity prices. Further, there are substantial future unknowns which impact forecasts. Instead, this analysis should be considered relative to the OPA projection. It is reasonable to suppose that the many unknowns would affect the $130,000/MW-year OPA estimate in the same direction with even greater magnitude. When the contracting paradigm is long-term, unanticipated upward shocks become long-term cost items. The process is not symmetric, however; unanticipated downward shocks are far more difficult to capture in long-term contracts so long as monitoring costs leave control of the plants in the hands of plant operators with massive incentives to get the plant re-contracted when current prices are higher than contracted prices.

But this is not the main reason to give credence to the type of analysis done here. In all three eastern US capacity markets, capacity prices have consistently fallen short of engineering and economic estimates of the net Cost of New Entry (CONE). This has been a general source of surprise in these markets, but it is a consistent regularity. In this section we will first review the specific IESO methodology used here, but we then will explain why we think the results garnered are sensible.

B. IESO Methodology

First, the IESO uses only two of the three eastern US capacity markets, discarding the experience of the New England ISO. Had ISO-NE been included, the benefits of a capacity market would have been dramatically larger, as prices in New England have, until the most recent auction, consistently fallen and been constrained only by a statutory floor. This is not the place to discuss the reasons why this has happened, but as the New England market has had a substantial set of anomalies; its omission is therefore reasonable.

any savings could be allocated back to loads using some other methodology. Indeed, one of the potential social benefits of a capacity market scheme is the ability to send capacity signals back to loads in a more efficient way. In any case, this calculation used here simply allocates costs back to loads as if the capacity market is essentially part of the global settlement pool.

In PJM and the NYISO, the IESO analysis uses the last five years of observed capacity prices. This has several benefits: first, it ignores startup periods in these markets; second, it reflects the most recent experience and is therefore most comparable to the OPA procurement estimate, which is forward-looking.

In the base scenario, these last five years of prices are averaged across zones by ISO and then averaged over the five year period. The averaging processes squeeze out much temporary volatility which is immaterial for these purposes. Observed energy and ancillary service prices are then added to the capacity price observed[5] to get an all-in price of capacity[6]. These are then converted to CND to make directly comparable with the OPA estimate. The difference is stark: US capacity markets results are converted to a comparable figure of only $43,000/MW-year.

In the high-cost scenario, the same analysis is repeated with the highest-cost zone in each of the two ISOs: New York City for NYISO and PSEG-North for ISO-NE. In this scenario, US capacity costs rise to $88,000/MW-year, still only 2/3rds of the OPA procurement estimate.

C. Why Are US Markets So Inexpensive?

There are any number of reasons to explain the success of PJM and NYISO in procuring capacity. A complete explanation would require a much more substantial effort than we have been asked to perform here, which is simply to opine as to whether the results achieved in these markets are reasonable. We believe that they are. There are good reasons to believe that procurement in capacity markets can proceed at considerably less than administrative estimates of the cost of new entry.

First, substantial amounts of capacity may be available at far less than CONE. Capacity uprates at existing units, demand side resources and subsidized renewables may be available at prices far lower than the CONE of new units.

Second, the CONE of a hypothetical new unit may be higher than the CONE of new units which take advantage of special circumstances, *eg*, unusual proximity to the network, placement in a load pocket which raises energy revenues or any number of other special circumstances, including superior management acumen in constructing or operating the units. Administrative

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5 These are sourced from the PJM market monitor's report and applied to both PJM and NYISO values. More aggregated, but similar, results are also available in the market monitor's reports for NYSIO.

6 SCGTs are a preferred vehicle for estimating CONE because their energy and ancillary service profits are generally quite small; they are much closer to "pure" capacity. Consequently, even major adjustments for the particular structure of energy markets in NY, PJM and Ontario will have a relatively small effect – higher energy prices reduce capacity prices and lower energy prices raise capacity prices, though in the case of very low energy prices, only capital costs of an SCGT will matter.

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determinations will always estimate the *average* marginal unit, not the best marginal unit, which would require specific information unavailable to the calculation.

We believe these two reasons substantially underlie the observed result: competitive markets open the market to inframarginal competitors who can earn substantial payments above their own costs, and this then shifts the supply curve outward so that only those competitors who can beat the administratively-determined CONE have a chance of succeeding. This is the simply promise of markets in action: an ability to find the most inexpensive source of supply from consumers.

We are of course mindful that these are not the only possible reasons for these results. In particular, it has been alleged that capacity market bargains might stem from: (a) subsidies by governmental bodies[7]; (b) inappropriate selection of SCGTs as the reference price; (c) short run recession-based demand shortfalls which reduce the need for new capacity; (d) short-run exploitation of "low hanging fruit" which is not expected to persist; (e) bilateral contracting which bypasses the market; and (f) insufficient goad for exit reducing the need for new capacity. While any of these might have some force in some places at some times, we do not feel, as an indicative matter, that they overcome the central observation that capacity markets have delivered capacity at surprisingly inexpensive prices and in ways which were not anticipated.

These observations would have considerably more force if both markets did not actually see the addition of traditional generating units supported only by these capacity markets and prospective market prices. Both markets have in fact seen such additions, strongly suggesting that prices as high as the internal administrative estimates (which are reasonably close to the OPA $130,000/MW-year estimate) are not sustainable over the longer term.

To those who are not convinced by this line of argument, we suggest that they focus on the "high-cost" scenario, which essentially cabins the results to the very high cost New York City area, either New York City directly in the NYISO results or the New Jersey NYC suburbs in the PS-North region of PJM. We believe that this scenario demonstrates that the favorable benefit-cost ratio is unlikely to be overturned by more careful inquiry into the source of low capacity market prices in PJM and New York.

III. Costs of a Capacity Market

The IESO asked us to estimate a startup and ongoing cost for a capacity market in Ontario. We did so by contacting various sources at the current US ISOs and in conversations with IESO staff. We believe the estimates we have derived are reasonable, but since they are far below even this partial

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7 We do not believe that subsides are widespread or have had material influences on the NYISO and PJM capacity markets. Both markets have "buyer side mitigation" that is intended to eliminate subsidized uneconomic entry.

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estimate of net benefits derived, we find it extremely unlikely that any experienced costs could overturn the favorable benefit-cost ratio.

IV. Discounting

The IESO calculation demonstrates rate impacts on a year-by-year basis and then aggregates those year-by-year numbers into an aggregate number through simple addition. In our opinion, this is less useful than a calculation which presents a present discounted value. We understand that it is being done to be comparable with the methodology of the LTEP and makes sense on that limited basis, but it is an inappropriate way to perform aggregate benefit cost analysis that involves costs and benefits with different time patterns. While the analysis is all performed in real 2012 dollars, there is still a pure real social discount rate which must be applied to properly present results in present value. Imagine two projects which returned one 2012 dollar. One project returns that result 30 years from now while the other returns that result next year. From a benefit-cost perspective, the project which returns that result more quickly is to be preferred. There are two main reasons for this result. First, capital spent today displaces capital from other projects; faster return enables the capital to be redeployed more quickly, enabling higher social gains. Second, as the expected returns are pushed into the future, the risk that they will not eventuate rises, and a pure social discount rate takes that risk into account.

We have no real opinion of what the real discount rate ought to be. A reasonable real social discount rate will be sure to be relatively modest, certainly less than 5 percent per year. Thus, the basic result, that benefits far exceed costs, will not be reversed. Choice of a discount rate would require a separate process to calibrate to Ontario's needs.

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