Ontario

MINISTRY OF
ENERGY

Rate Mitigation Plan Options

Working Draft

February 1, 2017

CONFIDENTIAL DRAFT

Context

- Electricity costs are increasing as the necessary investments are made to decarbonize and modernize the province's electricity infrastructure (i.e., $35 billion+ investment in cleaner generation and $15.5 billion investment in Hydro One transmission and distribution systems).

- Ontario has taken a number of actions to lower electricity costs for all consumers by:
  - Deferring investments in generation (e.g., new build nuclear), improving market efficiency (e.g., wind dispatch) and decreasing the cost of renewable procurements (e.g., GEIA renegotiation, decreasing FIT prices).
  - Increasing cost effectiveness and improving efficiency by adopting new electricity market approaches (e.g., competitive LRP, no new NUG contracting).

- Following the 2016 Throne Speech, actions were announced to further reduce electricity costs by:
  - Providing an 8% rebate ($11/month savings), updating RRRP ($45/month savings), expanding ICI (up to one-third savings for participants) and suspending the LRP II and the EFWSOP (up to $3.8 billion in cost savings).

- On November 28, 2016, the Minister of Energy announced the need for changes in how electricity resources are procured, the need for wholesale market renewal and greater electricity consumer choice.

- The Ministry of Energy is currently updating its Long-Term Energy Plan (LTEP), which provides an opportunity to consider a range of policy changes to how the Ontario energy sector operates.

Options

- In recognition of the costs borne by ratepayers related to decarbonizing and modernizing the province's electricity sector, options for further rate mitigation include:

  1. Global Adjustment (GA) Smoothing – Provide significant and immediate rate relief through cost deferral of the GA.

  2. Electricity Support Programs to Help the Most Vulnerable – Provide a greater focus on vulnerable consumers by funding electricity support programs through the tax-base:
     - Delivery Charge Relief / Rural or Remote Electricity Rate Protection (RRRP) Enhancement;
     - Ontario Electricity Support Program (OESP) Expansion; and
     - Low-Income Conservation.

  3. Ontario Energy Board (OEB) – Identify opportunities for OEB red-tape reduction and future LDC efficiencies and rates.

  4. Ontario Power Generation (OPG) – Find further efficiencies in operations and pass on savings to ratepayers.

  5. Independent Electricity System Operator (IESO) – Modernize Ontario's electricity market through electricity Market Renewal initiatives

Proposed Initiatives – Potential Savings for Typical Residential / Industrial Electricity Consumers

Typical Residential Electricity Consumer

$/750kWh	2016	2017	2018	2019	2020	2021	2022	Timing of Benefit
1. Global Adjustment (GA) Smoothing (Moderate)	-	17.49	15.01	12.49	14.91	6.32	4.03	Immediate
2. Electricity Support Programs Funded Through the Tax-base to Help the Most Vulnerable								
a. Delivery Charge Relief / Rural or Remote Rate Protection (RRRP) Enhancement	-	TBC	TBC	TBC	TBC	TBC	TBC	Immediate
b. Ontario Electricity Support Program (OESP) Expansion*	-	0.83	0.83	0.83	0.83	0.83	0.83	Immediate
c. Low-Income Conservation	-	-	-	-	-	-	-	N/A
3. OEB – Red-Tape Reduction / LDC Efficiencies and Rates	-	TBD	TBD	TBD	TBD	TBD	TBD	Medium-Term
4. OPG – Operational Efficiencies	-	0.71	0.89	1.08	1.22	1.35	1.24	Immediate
5. IESO – Market Renewai Initiatives	-	-	-	-	-	1.00	1.03	Long-Term

Typical Industrial Electricity Consumer

$/MWh	2016	2017	2018	2019	2020	2021	2022	Timing of Benefit
1. Global Adjustment (GA) Financing (Moderate)	-	14.49	12.43	10.33	12.35	5.23	3.33	Immediate
2. Electricity Support Programs Funded Through the Tax-base to Help the Most Vulnerable								
a. Delivery Charge Relief / RRRP Enhancement	-	TBC	TBC	TBC	TBC	TBC	TBC	Immediate
b. OESP Expansion*	-	1.10	1.10	1.10	1.10	1.10	1.10	Immediate
c. Low-Income Conservation	-	-	-	-	-	-	-	N/A
3. OEB – Red-Tape Reduction / LDC Efficiencies and Rates	-	TBD	TBD	TBD	TBD	TBD	TBD	Medium-Term
4. OPG – Operational Efficiencies	-	0.59	0.74	0.89	1.01	1.12	1.03	Immediate
5. IESO – Market Renewal Initiatives	-	-	-	-	-	1.34	1.38	Long-Term

***Note:** Savings based on currently approved OESP rate set by OEB.
Note: The above initiatives will provide similar benefits for non-RPP Class B electricity consumers. Class B includes small-medium enterprises (SMEs).

Fiscal Impacts

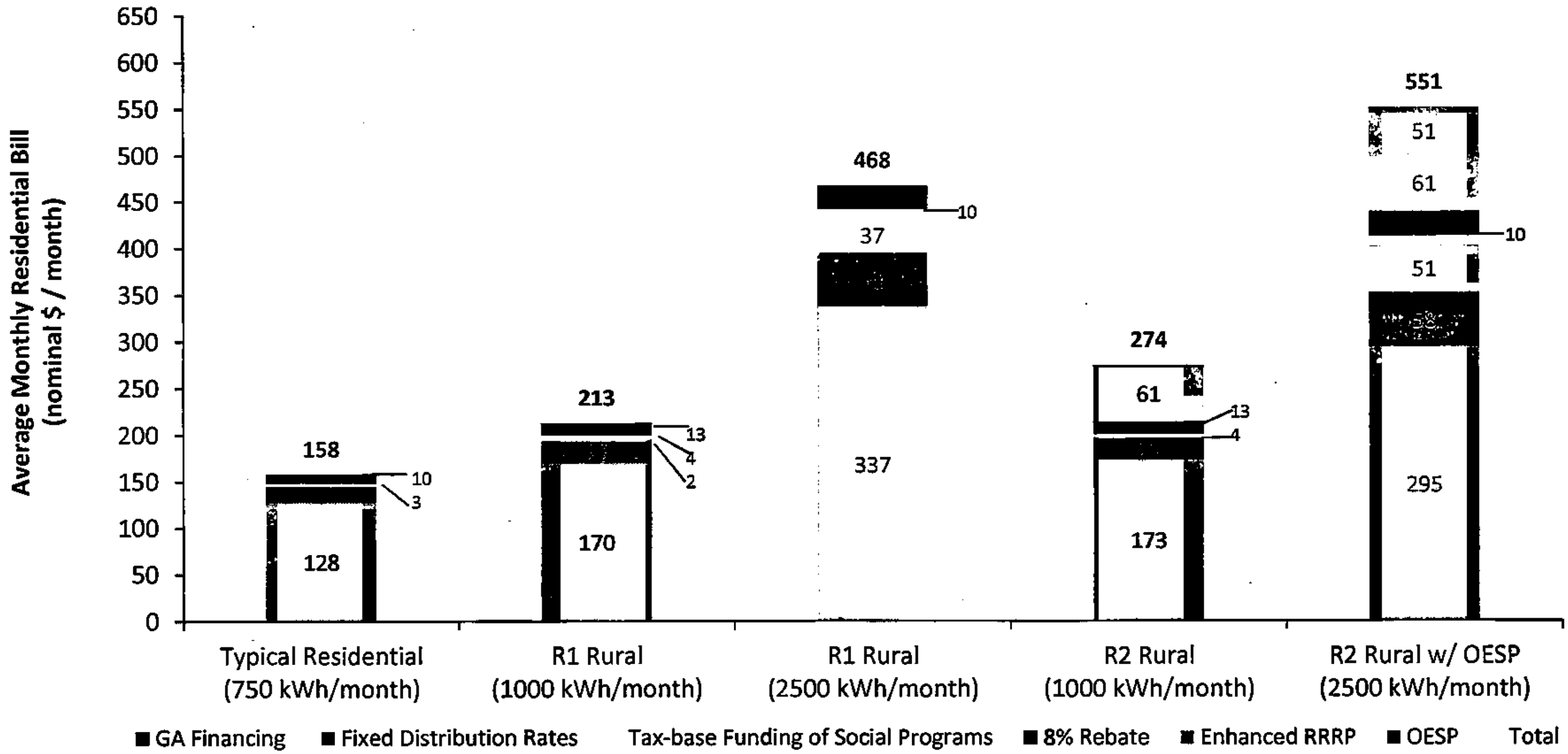
$M	2016-17	2017-18	2018-19	2019-20	2020-21
1. Global Adjustment (GA) Smoothing Financing (Moderate)	TBC	TBC	TBC	TBC	TBC
2. Electricity Support Programs Funded Through the Tax-base to Help the Most Vulnerable*					
a. Delivery Charge Relief RRRP Enhancement	-	64-90 306-332	52-72 300-320	38-54 293-309	26-36 287-297
b. OESP Expansion	-	178	239	290	334
c. Low-Income Conservation	-	30	30	30	30
3. OEB – OEB – Red-Tape Reduction / LDC Efficiencies and Rates	-	-	-	-	-
4. OPG – Operational Efficiencies**	-	-	-	-	-
5. IESO – Market Renewal Initiatives	-	-	-	-	-

***Note:** Includes costs of program expansion and various assumptions as detailed on relevant slides. Delivery charge relief and RRRP enhancement are calendar year costs, not fiscalized estiamtes.

** **Note:** Risk to fiscal plan of up to $240 million annually (foregone net income) if OPG is unable to reach more aggressive operational efficiency targets.

Source: Ministry of Finance, Energy

Illustrative Example of Rate Mitigation Impacts



Note: Based on Regulated Price Plan effective November 2016. Includes the 8% rebate pre-tax. Rural residential customers (R2) above are connected to Hydro One and includes the benefit of the enhanced Rural or Remote Rate Protection (RRRP). Assumes both standard RRRP growth at 2.6%/year, but also sees enhancement funding reduce over time as the move to fixed rates is completed. Assumes OESP enrollment of 100% by 2022 and includes costs with expanding benefits by 50%.

Illustrative Example of Rate Mitigation Impacts (cont'd)

		Actual 2016	2017*	2018	2019	2020
750 kWh	**Total Bill (pre-changes)**	**156**	**160**	**163**	**166**	**177**
	Impact of 8% Rebate	0	-11	-12	-12	-13
	Impact of GA Financing (moderate option)	0	-17	-15	-12	-15
	Impact of Tax-Basing Social Programs	-3	-3	-3	-3	-4
	Impact of Fixed Distribution Rate	0	0	0	0	0
	Revised Total Bill	**152**	**126**	**131**	**137**	**143**
750 kWh w/OESP	Impact of OESP		-51	-51	-51	-51
	Revised Total Bill	**152**	**75**	**80**	**86**	**92**

***Assumes July 1 Implementation of measures**

IESO - OPO Forecast

25% } over what period of time
30%

22% ~~with~~ + HST -$35 +
17% + HST —

Note: Based on forecast prices.. Rural residential customers (R2) above are connected to Hydro One and includes the benefit of the enhanced Rural or Remote Rate Protection (RRRP). Assumes both standard RRRP growth at 2.6%/year, but also sees enhancement funding reduce over time as the move to fixed rates is completed. Assumes OESP enrollment of 100% by 2022 and includes costs with expanding benefits by 50%.

Illustrative Example of Rate Mitigation Impacts (cont'd)

		Actual 2016	2017*	2018	2019	2020
1,000 kWh R1 Rural	**Total Bill (pre-changes)**	**TBC**	**TBC**	**TBC**	**TBC**	**TBC**
	Impact of 8% Rebate	TBC	TBC	TBC	TBC	TBC
	Impact of GA Financing	TBC	-23	-20	-17	-20
	Impact of RRRP	TBC	-61	-62	-64	-65
	Impact of Tax-Basing Social Programs	-4	-4	-4	-5	-5
	Impact of Fixed Distribution Rate	0	-1	-1	-1	0
	Revised Total Bill	**TBC**	**TBC**	**TBC**	**TBC**	**TBC**
1,000 kWh w/ OESP	Impact of OESP	0	-51	-51	-51	-51
	Revised Total Bill	**TBC**	**TBC**	**TBC**	**TBC**	**TBC**
2,500 kWh R1 Rural	**Total Bill (pre-changes)**	**TBC**	**TBC**	**TBC**	**TBC**	**TBC**
	Impact of 8% Rebate	TBC	TBC	TBC	TBC	TBC
	Impact of GA Financing	TBC	-58	-50	-42	-50
	Impact of RRRP	TBC	-61	-62	-64	-65
	Impact of Tax-Basing Social Programs	-10	-10	-11	-11	-12
	Impact of Fixed Distribution Rate	0	-36	-28	-21	-14
	Revised Total Bill	**TBC**	**TBC**	**TBC**	**TBC**	**TBC**
2,500 kWh w/ OESP	Impact of OESP	0	-51	-51	-51	-51
	Revised Total Bill	**TBC**	**TBC**	**TBC**	**TBC**	**TBC**

***Assumes fixed rate is accelerated and implemented beginning in 2017.**

Note: Based on forecast prices.. Rural residential customers (R2) above are connected to Hydro One and includes the benefit of the enhanced Rural or Remote Rate Protection (RRRP). Assumes both standard RRRP growth at 2.6%/year, but also sees enhancement funding reduce over time as the move to fixed rates is completed. Assumes OESP enrollment of 100% by 2022 and includes costs with expanding benefits by 50%.

Illustrative Example of Rate Mitigation Impacts (cont'd)

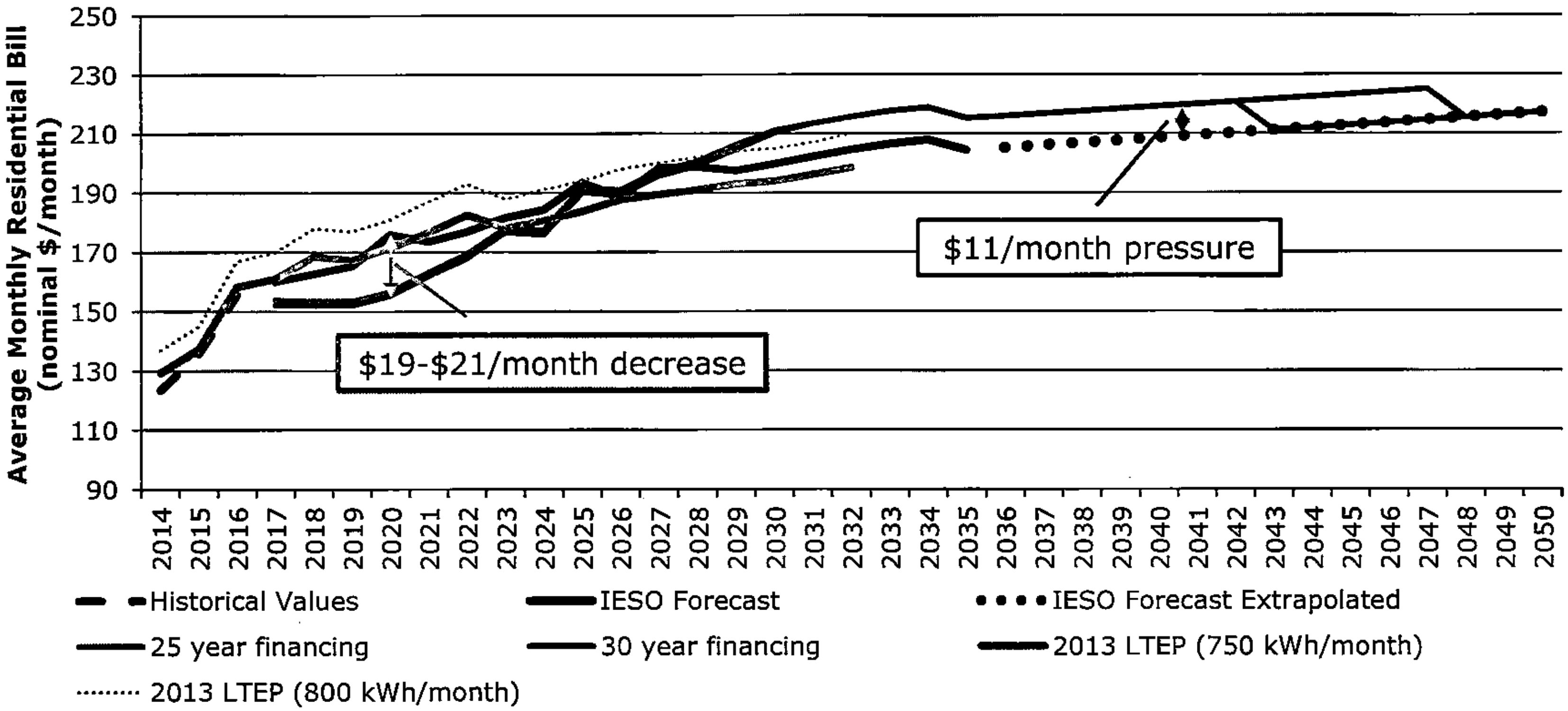
		Actual 2016	2017*	2018	2019	2020
1,000 kWh R2 Rural	**Total Bill (pre-changes)**	**TBC**	**TBC**	**TBC**	**TBC**	**TBC**
	Impact of 8% Rebate	TBC	TBC	TBC	TBC	TBC
	Impact of GA Financing	TBC	-23	-20	-17	-20
	Impact of RRRP	TBC	-61	-62	-64	-65
	Impact of Tax-Basing Social Programs	-4	-4	-4	-5	-5
	Impact of Fixed Distribution Rate	0	0	0	0	0
	Revised Total Bill	**TBC**	**TBC**	**TBC**	**TBC**	**TBC**
1,000 kWh w/ OESP	Impact of OESP	0	-51	-51	-51	-51
	Revised Total Bill	**TBC**	**TBC**	**TBC**	**TBC**	**TBC**
2,500 kWh R2 Rural	**Total Bill (pre-changes)**	**TBC**	**TBC**	**TBC**	**TBC**	**TBC**
	Impact of 8% Rebate	TBC	TBC	TBC	TBC	TBC
	Impact of GA Financing	TBC	-58	-50	-42	-50
	Impact of RRRP	TBC	-61	-62	-64	-65
	Impact of Tax-Basing Social Programs	-10	-10	-11	-11	-12
	Impact of Fixed Distribution Rate	0	-56	-39	-29	-22
	Revised Total Bill	**TBC**	**TBC**	**TBC**	**TBC**	**TBC**
2,500 kWh w/ OESP	Impact of OESP	0	-51	-51	-51	-51
	Revised Total Bill	**TBC**	**TBC**	**TBC**	**TBC**	**TBC**

***Assumes fixed rate is accelerated and implemented beginning in 2017.**

Note: Based on forecast prices.. Rural residential customers (R2) above are connected to Hydro One and includes the benefit of the enhanced Rural or Remote Rate Protection (RRRP). Assumes both standard RRRP growth at 2.6%/year, but also sees enhancement funding reduce over time as the move to fixed rates is completed. Assumes OESP enrollment of 100% by 2022 and includes costs with expanding benefits by 50%.

1. GA Smoothing with Delayed Increase in Payments – Impact on Residential Electricity Bills (Moderate)

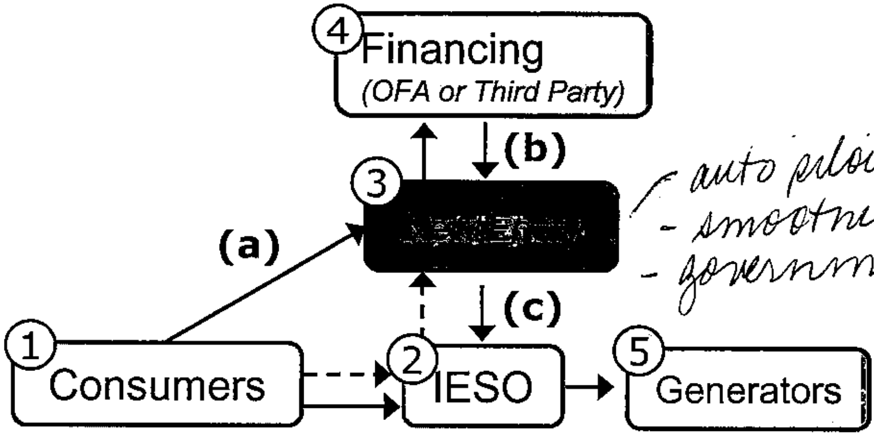
- In this option, the starting GA payment from all ratepayers in 2017 is lowered by $1.1 billion (green line) and $1.4 billion (red line), ratepayer payments *decrease* in the short term to keep residential bills relatively flat, then increases at 3% each year – up to a maximum of $2 billion above the true cost of GA – until the borrowed money is paid back over a 25 and 30 year financing period respectively.



- By **borrowing up to $19-$23 billion**, this scenario results in **a short-term residential electricity cost reduction of up to $19-$21/month** at the cost of **increased future electricity bills over 14-19 years of up to $11/month** above the true cost of electricity production.

1. GA Smoothing – Implementation Approach (New Entity)

- The diagram outlines a implementation approach that includes a new entity which would hold the debt and the receivable from ratepayers



auto pilot
- smoothing -
- government

will not have dominion

→ Early year fund flow

→ Future Repayment Mechanism

1. Electricity Consumers pay IESO a portion of the GA in early years. In the future, consumers would pay all in-year GA costs and repay the New Entity. Customers will not see a change in the structure of their bills (costs should diminish in early years).

2. The IESO pays generators (in early years), partially from consumers and partially financed by the New Entity. **(c)** The IESO would provide collection services to New Entity under a service contract.

3. The New Entity would fund part of the GA and **(a)** would have a legislative right to recover the principle, interest and administrative costs from customers (settled via service agreement with IESO).

4. The OFA or a 3rd party lender would fund the GA shortfall in early years and receive payments from the New Entity as debt is repaid **(b)** the debt would be subject to a contract between the New Entity and the lender.

5. Generators continue to receive payments from IESO according to existing contract / regulatory structures.

* If the OPA is the only potential borrower - how does this impact?

1. GA Smoothing – Considerations

Governance

- To achieve the desired accounting treatment, the entity would have to be structured as follows:
  - While the Province would choose the first board of directors or trustees, future directors or trustees would be selected in accordance with a mechanism created at the time the entity is created. The Province would have no ongoing role in appointments or in selection of key personnel, including the CEO.
  - The Province would not have a determining vote in the entity's business decisions. The entity could be structured so that the Province has no vote. ?
  - The Province would have no recourse to the entity's assets and would not be responsible for the debt. or any ongoing losses
  - Mechanisms would be required to prevent the Province from dissolving the entity and having access to its assets and obligations.
  - The Province would not be able to change the mission or mandate of the entity, once it is created.
  - The Province would have no right to approve business plans or budgets or to require amendments to them.
  - The Province would not be able to alter the terms of the entity's debt arrangements.
  - The Province would not be able to affect the debt by controlling the entity's financial and operating policies.
  - The Province would not have input into the operational and financial policies of the entity, including accounting, personnel, compensation, collective bargaining or deployment of resources. For example, legislation like the *Broader Public Sector Executive Compensation Act, 2014* and the *Broader Public Sector Accountability Act, 2010* would not apply.

Pull the NS16

- The implications of designing the entity to meet the accounting control, and creating an entity that the Province does not govern, means that: does the OE
  - Staff would not be OPS employees.
  - Oversight would not be provided by Offices of the Legislature (Auditor General, Financial Accountability Officer).
  - The *Freedom of Information and Protection of Privacy Act* would not apply.
- It may be possible to have the OEB provide some oversight through licensing or regulatory proceedings.

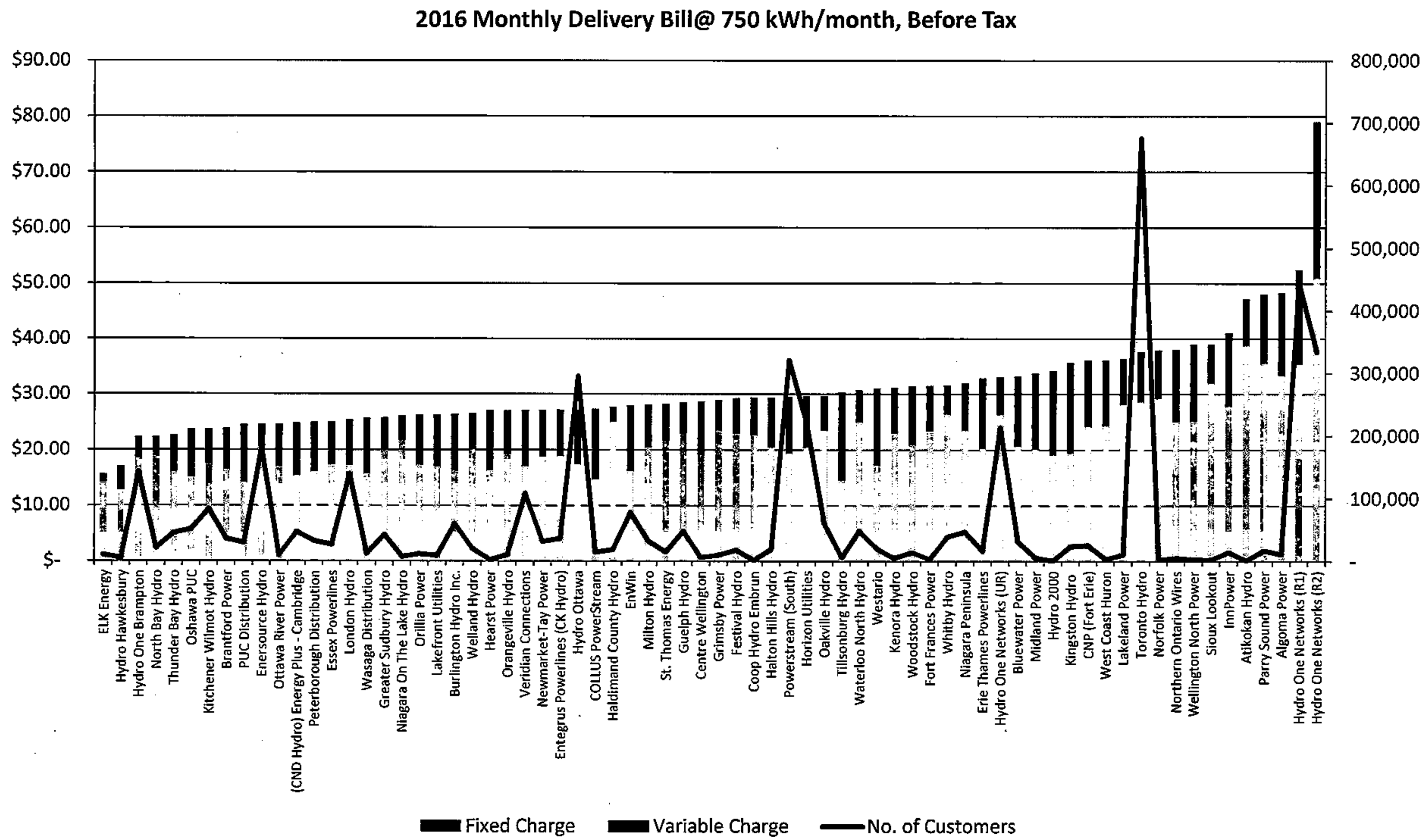
1. GA Smoothing – Other Considerations (cont'd)

- **Financing**
  - While 3rd party financing would help to meet accounting control tests, the cost may be high
    - The Province may need to internally test the market to determine potential cost of 3rd party financing / securitization.
  - Potential risks that 3rd parties will likely consider when determining cost of capital include:
    - Legislative framework (recovery mechanism);
    - Interest rate changes; and
    - Future electricity demand / customers.
- **Recovery Mechanism**
  - Province will need to explore different recovery/ administrative options.
  - DRC/RRP/Tax Rebate.
  - Consider whether a one-time, exit payment would be charged to ratepayers that are leaving the electricity system in order to recover foregone deferred charges.
- **Contractual / Legislative Agreements**
  - Either the New Entity or IESO would need a legislative right to recover the principle, interest and administrative costs from customers.
  - Form of an IESO collection services agreement would need to work within IESO's legislative framework, while providing sufficient comfort to the New Entity / 3rd party.
  - We need to consider whether the Province's ability to change legislation undermines the governance choices that we make to achieve the accounting control analysis

2a. Rural or Remote Rate Protection (RRRP) – Background

- The Rural or Remote Rate Protection (RRRP) program supports the most costly-to-serve distribution customers in Ontario. It is not income tested and most of the support goes to Hydro One's R2 (low density) rate class and remote communities.
  - Costs to these Hydro One customers are higher than average because of their relatively low density.
  - To mitigate these costs, the RRRP was recently enhanced to help lower the bills of Hydro One's R2 customers.
- RRRP is a fixed amount of credit that Hydro One R2 customer receive ($60.50/month) and focuses on ameliorating differences in distribution costs. This currently costs $242 million annually.
  - RRRP provides a standard benefit amount to customers within eligible rate classes.
  - Low volume consumers with relatively low delivery bills would receive the same amount of benefit as high volume consumers with relatively high bills.
- RRRP currently costs the average ratepayer $1.58/month in regulatory costs. This is expected to rise in line with the average annual distribution rate increase (estimated at 2.6%).
- There is potential in moving RRRP to the taxbase as it is a program aimed at addressing demographic differences. Some LDCs and ratepayers have expressed concern that RRRP unfairly requires them to subsidize other high cost ratepayers.
  - Currently ,$242 million is expended through the RRRP for Hydro One R2 customers. There is another ~$50 million collected through RRRP that supports operational costs for Algoma Power and Hydro One Remotes, and the fiscal and ratepayer impact numbers in this deck assumes this portion of the RRRP continue to be collected from ratepayers.

2a. Wide Variation in Delivery Rates Across the Province



* Hydro One customer numbers are for 2016 and divided by rate class. Hydro One R2 does not reflect RRRP enhancement.

2a. Overview of RRRP Enhancement – Options

See Appendix for additional information on options 2 & 3.	**Program Envelope for H1 ($M)***	**Monthly Rebate for R2:low density consumers (+/- from status quo)**	**Monthly Rebate for R1: medium-density customers**	**Monthly cost to ratepayers****
(Status Quo) RRRP program for R1 and R2 customers of Hydro One (as of January 2017)	$242M	$60.50/month	$0	$1.58/month
(1) Accelerates move to fixed distribution rates for those customers expected to see a reduction in costs.***	$306-$332M	Distribution costs capped at $64.64/month. Benefit begins at 1,200kWh/month	Distribution costs capped at $55.70. Benefit begins at 955kWh/month.	$2.07/month
(2) Increase total RRRP envelope to reduce R2 and R1 distribution costs at 1000kWh/month to Algoma Power costs at 1000kWh/month	$292M	$66.61/month (+$6.11/month)	$4.91/month	$1.90/month
(3) Change RRRP program to a volumetric-based tiered benefit program where rebate will be dependent on customer consumption levels				
(3a) • Assume total RRRP program envelope of $300M and distribute to R2 & R1 based on tiered-benefit levels. • Tiered-benefit levels: divide customer base into 3 equal buckets. Allocate $300M to each bucket in proportion to contribution of H1 distribution revenues. • Assume fixed current $60.50 rebate no longer applies equally to all R2 customers.	$300M	750kWh or less: $37.65 (-$22.85) 750 to 1,200 kWh: $44.74 (-$15.76) 1,200 kWh or more: $60.69 (+$0.49)	600Kwh or less: $16.05 600kwh to 1,000Kwh: $19.22 1,000kwh or more: $25.67	$1.90/month
(3b) • Expand RRRP program envelope and distribute to both R2 & R1 customers based on tiered-benefit levels. • Tiered-benefit levels determined in same manner as 3(a). • Assume fixed current $60.50 still applies to all R2 customers	$542M	750kWh or less: $81.66 (+$21.16) 750kwh to 1,200 kWh:$91.90 (+$31.40) 1,200 kWh or more: $114.95 (+$54.45)	600 kWh or less: $23.19 600kwh to 1,000 kWh: $27.76 1,000 kWh or more: $37.09	$3.20/month

*All option costs are inclusive of status quo RRRP, except 3(a) which assumes a phaseout of the program.
**Only if left on ratebase. Will increase based on yearly expansion.
***Based on Hydro One estimates. Consumer benefit is total costs subtract the cap amount.
Note: figures do not include ~$50M in RRRP costs currently supporting Algoma Power and Hydro One Remotes

2a. Potential RRRP Enhancement – Accelerating Fixed Rate Benefit (Background)

- Currently, LDCs recover their costs through a combination of a fixed monthly charge and a volumetric charge based on kilowatt hours used. As a result, customers of the same LDC will be charged different amounts for distribution based on their consumption level.
- However, the OEB has made a determination to establish fixed distribution rates for residential consumers, in recognition that the majority of distribution costs are irrespective of the volume of consumption. The OEB believes moving to fixed rates will:
  - Enable residential customers to leverage new technologies, manage costs through conservation, and better understand the value of distribution services.
  - Establish a fairer way to recover the costs of providing distribution service.
  - Provide greater revenue stability for distributors, which will position them for technological change in the sector, remove any disincentive to promote conservation, and help with their investment planning.
- Fixed rates will be set at the average consumption level for a rate class in order to recover the same amount of revenue as the mix of fixed and variable charges does today. As a result, below-average volume consumers will experience cost increases and above-average volume consumers will experience cost decreases.
- The OEB is gradually phasing-in the move to fixed rates in order to mitigate the impact of these increases to below-average volume consumers. Most LDCs will receive fully fixed rates in 2019. Hydro One will be transitioned over a longer timeframe (2022-2023).
  - Hydro One's density-based rate classes and recent re-allocation of costs between the classes results in significant impacts for Hydro One low volume consumers. Providing the longer timeframe allows for the impact of the change to be held at less than 10% for low volume customers at the 10th percentile of consumption.

2a. Potential RRRP Enhancement – Accelerating Fixed Rate Benefit (Impacts)

- Hydro One has estimated that if it accelerated the move to fixed rates effective 2017, the rates would be as follows:
  - R1: $55.70/month – the same cost as a customer who consumes 955kWh/month today.
  - R2: $64.64/month, when factoring in the $60.50 RRRP support – the same cost as a customer who consumes 1200kWh/month today.
- Using sample customer data provided by Hydro One, it is estimated that approximately 2/3rds of Hydro One R1 and R2 customers would experience cost increases if this was implemented:
  - R1: ~146k customers would see cost decreases, and ~298k customers would see cost increases.
  - R2: ~117k customers would see cost decreases, and ~217k customers would see cost increases.
- However, support from the fiscal plan can be used to accelerate the move to fixed rates for those high volume consumers who benefit – leaving low volume consumers to experience no change.
  - Hydro One estimates this would cost $64 million. If the move was expanded to include Hydro One Urban (UR rate class) and Seasonal customers, the cost would be ~$90 million.
  - When layering on the current RRRP support of $242 million, program costs are between $306-$332 million.
  - As the move to fixed rates was completed, fiscal plan support for these customers could be withdrawn.

Accelerated Fixed Rate Benefit Fiscal Impact						
	2017	**2018**	**2019**	**2020**	**2021**	**2022**
Fixed Rate Enhancement*	$64M-$90M	$52-$72M	$38M-$54M	$26M-$36M	$13M-$18M	$0
Total RRRP** (excluding Algoma Power & Hydro One Remotes)	$306-$332M	$300-$320M	$293-$309M	$287-$297M	$281M-$286M	$275M

**Range depends on just R1 & R2 or all rate classes. Cost decrease is estimated evenly, which could change based on Hydro One future rate impacts.*

*** Assumes 2.6% annual increase as estimate of average distribution rate increase*

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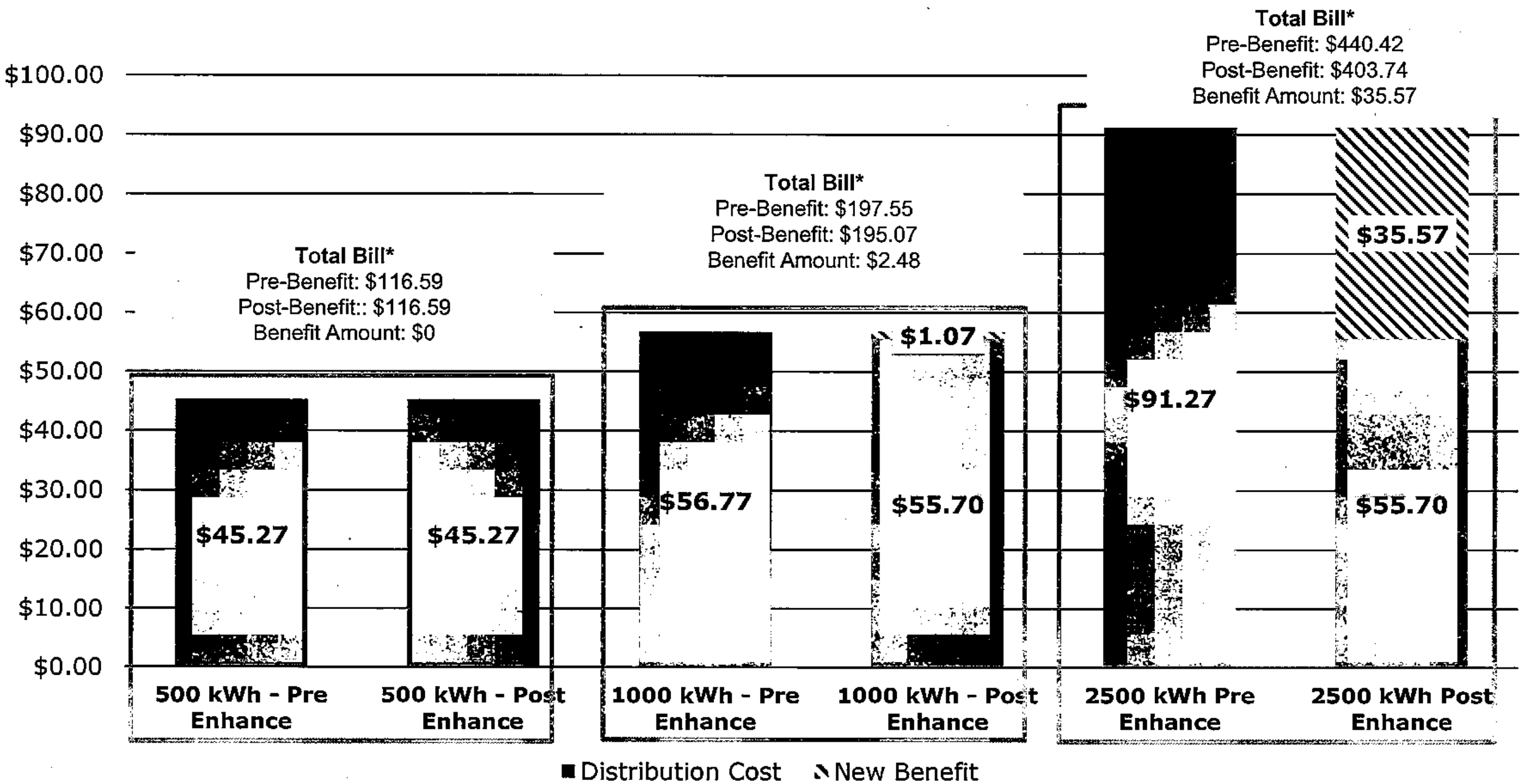
2a. RRRP Enhancement – Hydro One Mid-Density (R1) Ratepayer Impacts

- Under this option, R1 customers will not pay more than $55.70 for distribution service. Customers with costs below this threshold experience no change.

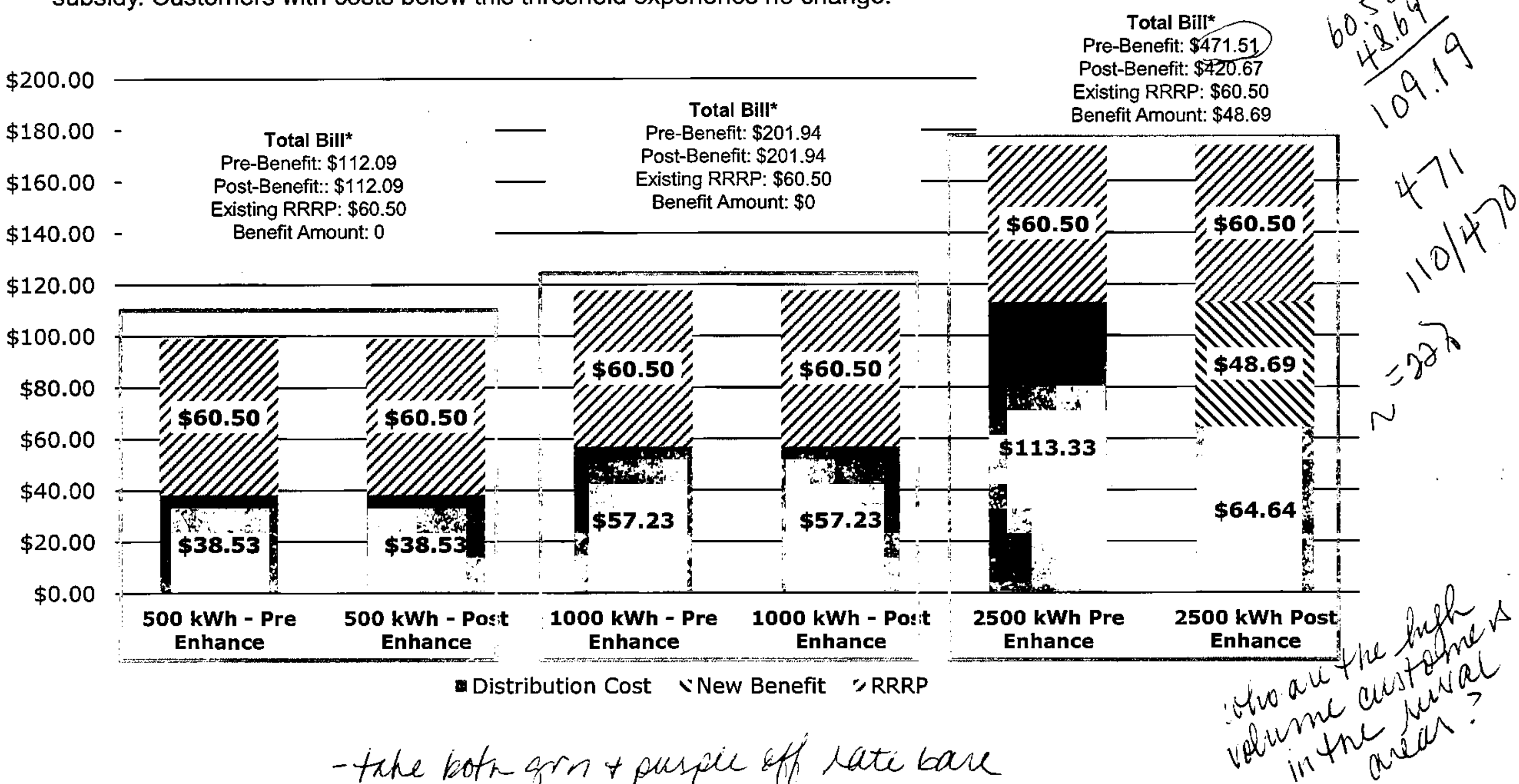


Note: Rates are for 2017

** Includes Electricity, Delivery, and Regulatory Charges. Excludes HST and 8% rebate.*

2a. RRRP Enhancement – Hydro One Low-Density (R2) Ratepayer Impacts

- Under this option, R2 customers will not pay more than $64.64, after accounting for the original $60.50 RRRP subsidy. Customers with costs below this threshold experience no change.



- take both grn + purple off rate base

Note: Rates are 2017

Note: R2 at 500Kwh has costs that align with those of other LDCs like Toronto Hydro

* Includes Electricity, Delivery, and Regulatory Charges. Excludes HST and 8% rebate.

2a. All RRRP Options – Fiscal Considerations

Ratepayer Impacts

- Some consumers with low consumption may still have proportional higher distribution rates. These customers will experience bill pressures both from the transition to fixed rates and from expected general rate increases (for which they are responsible for an increasing proportion).
- Hydro One distribution rates are expected to climb in coming years. The projected 2017 fixed rates of $64.64 (R2) and $55.70 (R1) will rise through the transition period. Therefore customers who receive a benefit will still experience bill increases.

Fiscal Impacts

- Having the original RRRP subsidy remain on the rate-base allows for program expansion from the fiscal plan while avoiding an additional $242M tax-base impact.
- Hydro One is expected to submit its cost of service application for 2018 and beyond (3-5 years) in spring 2017. The rate increases requested in this application could potentially increase the proposed fixed rate significantly, which would have significant impact on fiscal requirements and ratepayer impacts.
- Cost for Hydro One to implement and to upgrade customer billing systems is likely material. Those costs would ultimately be passed back to the customers of those LDCs.
- The Ministry will need to consider how consumption thresholds and/or benefit levels rise alongside the expected rise in distribution rates.
- There is a high risk of entrenching external subsidies, as there is no clear path to transition away from subsidies and toward a more sustainable, cost-based rate framework.

2a. All RRRP Options – Implementation Considerations

- LDCs would track credit variances in a variance account and settle amounts with the IESO, which receives taxpayer funding from ENERGY/MoF in the same manner as the 8% rebate happens today.
  - While this new program would build on exiting transfer payment protocols in use under the ORECA, it would be complex for Hydro On to implement, as CIS upgrades are likely needed.
  - Depending on the option chose, OEB estimates that the implementation would take at least 6 months or more, following finalized regulations, given need to change customer billing systems and determine settlement procedures.
- RRRP focuses on ameliorating differences in distribution costs, not the entire Delivery line of the residential bill which also includes transmission and line loss costs.
- Eligibility for RRRP is currently determined by LDC density levels. Hydro One R1 has similar density levels to some other LDCs (e.g., InnPower). Thus if the intention is to limit expansion to just Hydro One R1, a new eligibility criteria would have to be developed (legal and regulatory risks would need to be explored).
- New legislation would be required to establish this program. Legal and regulatory risks (particularly with regards to legal authority and to the Ontario Energy Board's role in setting rates and incenting efficiencies) require further analysis.
  - Some options may impact OEB rate-setting processes and create disincentives towards Hydro One productivity and performance improvements.
- Providing a tax-based subsidy outside of exiting rate setting mechanism reduces incentives for customers and distributors to engage on operating costs and capital planning.
- The development of an appropriate program can be initiated through a letter to the Ontario Energy Board via s. 35 of the *Ontario Energy Board Act, 1998*.

2b. Ontario Electricity Support Program (OESP) Expansion

- The OESP is an income-tested, application based program that lowers the electricity costs of the most vulnerable consumers by providing a rebate directly on their electricity bills.
- The OESP provides basic benefits to most consumers and enhanced benefits to Indigenous customers and customers with electric heat and medical devices.
- OESP funding is collected from a charge levied on all electricity ratepayers. Based on current level of program up-take and funding collection, OESP program benefits could be increased across the board by 50%. This would mean:
  - Single low income consumers would see an increase from $30 to $45/ month ($540/year);
  - Families of four with electric heat could see an increase from $55 to $82.50/month ($990/year); and
  - Indigenous and Métis consumers would also see benefit increases at the same level as those with electric heat and medical devices. These benefits could range from $67 to $113/month.
    - The Ministry is also considering options to support a “Delivery” line credit for Indigenous consumers. This would cost ~$18 million/year and would save Indigenous consumers between $75 and $100/month.
- Greater focus and support can be placed on lower income Ontarians by funding OESP through the tax base. This would also reduce costs for all consumers as a result of eliminating the OESP charge.
  - Average residential customer savings: $0.83/month; and
  - Average industrial customer savings: $1.10/MWh.

2b. OESP Expansion – Fiscal Impacts

- Table below shows estimate of program costs up to 2022:

Year	OESP Status Quo ($M)	+50% ($M)	TOTAL ($M)
2017	$108	$54	**$162**
2018	$150	$75	**$225**
2019	$186	$93	**$279**
2020	$215	$108	**$323**
2021	$243	$122	**$365**
2022	$272	$136	**$408**

- 2017 program costs are based at current program sign-up rate – 30% of eligible consumers. Cost projections assume the program grows to 100% of eligible consumers by 2022 and remains at that level.
- At the time of program design, it was estimated that 40-50% participation would be high for an application-based program delivered through electricity bills. However OESP can be enhanced by working to ensure the program uptake is as close as possible to 100%:
  - Streamlining the application process to make it easier and quicker to get through;
  - Putting in place a more aggressive communications strategy to make sure people are aware of the program;
  - Increasing funding for key partner agencies to work directly with individuals who are applying; and
  - Exploring automatic OESP qualification for those who receive provincial programs (e.g., ODSP).
- OEB is currently exploring options for simplifying the OESP process, including exploring options with MCSS on auto-enrollment options, discussing options to eliminate wet signature consent forms with the federal government, and working with partners to do open houses to better reach vulnerable consumers.

2b. OESP Expansion – Considerations

Considerations

- **Framework:** New legislation would be required to establish and define the parameters of a tax-based OESP. This may reveal additional considerations, including possible assessment as a tax credit.
- **Implementation:** Financial flow-through mechanisms would need to be considered in consultation with IESO and LDCs. Likely to be modeled after processes used for the Ontario Rebate for Electricity Consumers (OREC).
- **Alternative Delivery:** If the OESP was funded by the tax-base, it could also be explored whether the OESP could be better delivered as a provincial program via the tax system. This may help ensure that the program's participation rate is as high as possible, and could expand coverage to the ~142,000 low-income households that do not receive an electricity bill.
- **Transition to Social Assistance:** Moving OESP to the taxbase can be a transitional step in folding this program into a reform of social and disability assistance programs and enhancement of MCSS' Social Assistance Management System moving forward.
- **Additional Enhancements:** The enhanced credit could be expanded to include additional eligibility categories of customers. For example, a new "Low Density Consumer" category could be introduced that provides Hydro One R2 and/or R1 customers (highest distribution rates) who are already OESP eligible with the enhanced credit.
- **Variance Account:** The OEB has been collecting program funding in excess of program costs and has accrued a positive balance. This balance must be addressed when moving to the tax base.

2c. Low-Income Conservation Benefit Program

- Existing low-income programs delivered by LDCs and IESO help qualified residential customers and social and/or assisted housing providers improve their energy efficiency.
  - Programs include the Home Assistance Program and the Retrofit Program (Social Housing stream).
  - $500 million is planned under the Climate Change Action Plan (CCAP) to retrofit social housing.
- ENERGY is currently working with IESO to explore options to enhance and/or expand existing conservation programs for residential customers:
  - Participants could receive incentives for improved weatherization measures and appliances (e.g., new or upgraded furnace and central AC; windows/doors; washer/dryers, heat pumps (for electrically-heated residential customers). The new program would be delivered through LDCs and/or IESO.
  - Targeted education and awareness initiatives.
- The budget estimate below is illustrative and reflects a doubling of the 2015 spending for the Home Assistance Program, which was $20 million.

	2017	2018	2019	2020	2021*	2022*
Current Budget ($Million)	10	10	10	10	-	-
Proposed New Budget ($ Million)	40	40	40	40	-	-

- The incremental funds would enable deeper measures and reach additional customers.
- ENERGY is also exploring a potential new Affordability Fund to help customers who may not be eligible for low-income programs and who cannot upgrade their homes without financial assistance. This fund could potentially target customers who are in arrears and could help save on disconnection costs.

***Note:** The Conservation First Framework extends to 2020.

3. OEB – Red-Tape Reductions / LDC Efficiencies and Rates

Leveraging the OEB

- The Ontario Energy Board (OEB) has a mandate to regulate the electricity distribution sector in the public interest, ensuring the financial viability of the sector while promoting reliable service to customers at just and reasonable rates.
- The OEB, through the Renewed Regulatory Framework for Energy (RRFE), has since 2012 attempted to move the distribution sector towards a performance/outcomes-based regulatory framework.
  - While new reporting requirements such as the LDC performance scorecard are positive developments, RRFE does not tie these system performance expectations to LDC financial performance.
- Performance-based options have the potential to indirectly incent consolidation (in a manner that returns benefits to consumers), improve customer experience, and potentially reduce Return On Equity (ROE) in an equitable manner in the event performance expectations are not met.
- Encouraging shared partnerships on services between utilities will help reduce costs in the back end and encourage further innovation for small to medium sized utilities.

Opportunities

- ENERGY could help promote or accelerate these efforts by asking the OEB to look at opportunities to further drive LDC efficiencies and productivity.
- In parallel, the OEB could be instructed to review business cases behind its own regulatory requirements to reduce "red tape" and eliminate costs that LDCs indicate are creating pressures on operating expenses.
- This could be done through the Minister's letter, the LTEP Implementation Directive, s. 35 of the *Ontario Energy Board Act, 1998*, and/or the 2017 Mandate Letter and other agency business planning processes.

3. OEB – LDC Efficiencies and Rates (Performance Incentives) (cont'd)

Considerations

Sector:

- Exact bill reduction levels are unknown, but real OM&A and some capital cost avoidance can reasonably be expected.
- Could indirectly incent consolidation if LDCs feel they are unable to adequately manage their assets in light of tightening requirements.
- Any initiatives that have a direct impact on LDC profitability could affect the value of Hydro One.
- There is a tension between requiring productivity enhancements and creating firm performance standards. LDCs have to invest to maintain system levels, but also finding cost efficiencies, which is an incentive for innovation. The Ministry and the OEB may have to also explore reducing regulatory burden/barriers on LDCs so they have the tools available to satisfy new performance expectations.

Regulatory:

- The OEB is the electricity distribution sector's independent regulator and as such is responsible for establishing rate-setting mechanisms in line with its statutory objectives.
  - The Ministry would engage with OEB to align on approach, and provide only high-level direction so as to respect OEB's role in determining implementation specifics.
  - The OEB would likely need to conduct policy hearings and stakeholder consultations on these initiatives, though Ministry could request new rules be in place for next major LDC rate cycle.
- LDCs are resistant to peer comparison for a variety of historical and service territory issues. OEB econometric analysis has generally supported limiting peer comparisons. As comparisons would be an important component of benchmarking performance standards, the Ministry may experience sector pushback.
- Updating rate-setting mechanisms and regulatory processes could create regulatory uncertainty and limit LDC activity The OEB has revised its processes multiple times over the past 15 years.

4. OPG – Operational Efficiencies

- Provide expectation that OPG meet more aggressive cost targets, improving efficiency by ~$3/Megawatt hour (MWh).

Considerations

- OPG recently submitted its 2017-19 business plan to the Province for concurrence. That plan includes the following:
  - Enterprise total generating cost increasing from $48/MWh in 2016 to an average of $55/MWh over the plan period.
  - An average residential monthly bill increases of $1.05/month annually from 2017-2021.
- Much of this increase is due to the Darlington refurbishment project, which increases costs and reduces OPG's generation over the planning period.
- OPG has also shared its stretch targets for total cost of generation, which average $52/MWh over the 2017-19 plan, a ~$3/MWh reduction (5-6%) relative to its $55/MWh business plan targets.
- The Province could provide instructions to OPG to focus on its stretch target as part of the Minister's Concurrence letter. This is a public document that OEB would likely review and incorporate as part of OPG's current rate application.
- Consistent with regulations under the *Ontario Energy Board Act*, OPG is seeking smoothed rates for nuclear as part of its 2017-2021 rate application.
  - As a result, the benefit to ratepayers of reducing generation costs is uncertain.
  - Given that the application extends beyond the business plan period, and to ensure OPG does not delay costs beyond the planning horizon, the Province may want to provide additional direction for out year expenditures.
- If OPG is unable to meet more aggressive cost targets, this could impact net income, and the Province's fiscal plan.
  - The total cost of $3/MWh based on OPG's forecast production of 74 TWh/yr is about $240 million per year.
- The Province could work with OPG to craft language in the concurrence letter in order to avoid setting unintended precedents for future rate application processes.

5. IESO – Market Renewal

- Continue to move forward with Independent Electricity System Operator's (IESO) Market Renewal initiatives:
  - Market Renewal encompasses projects such as a single-schedule system (from the current two-schedule system), more frequent intertie scheduling to better align with other jurisdictions and a day-ahead market. There will be up front capital costs to enable the initiative. IESO is currently assessing these costs.
  - Moving to "technology-agnostic" procurements will provide new opportunities for innovation and modernization and ensure ratepayers receive the best prices possible.

Considerations

- Changes related to IESO's Market Renewal initiatives, reflected in HOEP and uplifts, are estimated to save up to $300 million per year, starting in 2021, leading to a reduction of:
  - About $1/month or less than 1% at current retail prices for a typical residential bill; and
  - About $1.30/MWh at current all-in prices for industrial and SME electricity consumers.
- The IESO's Market Renewal is a broad initiative that will impact all aspects of Ontario's electricity market. Ontario has had a uniform price since market opening.
- Adopting a technology-agnostic stance will lower the overall cost of providing electricity service by selecting the most cost-effective resources to fulfill various system needs.
- The IESO estimates that the total implementation cost – including a 15% contingency and net of avoided costs – will be $150 million. The bulk of the costs (capital) would only be recovered once the project has been implemented and as the benefits are being realized.

Communications (Place Holder)

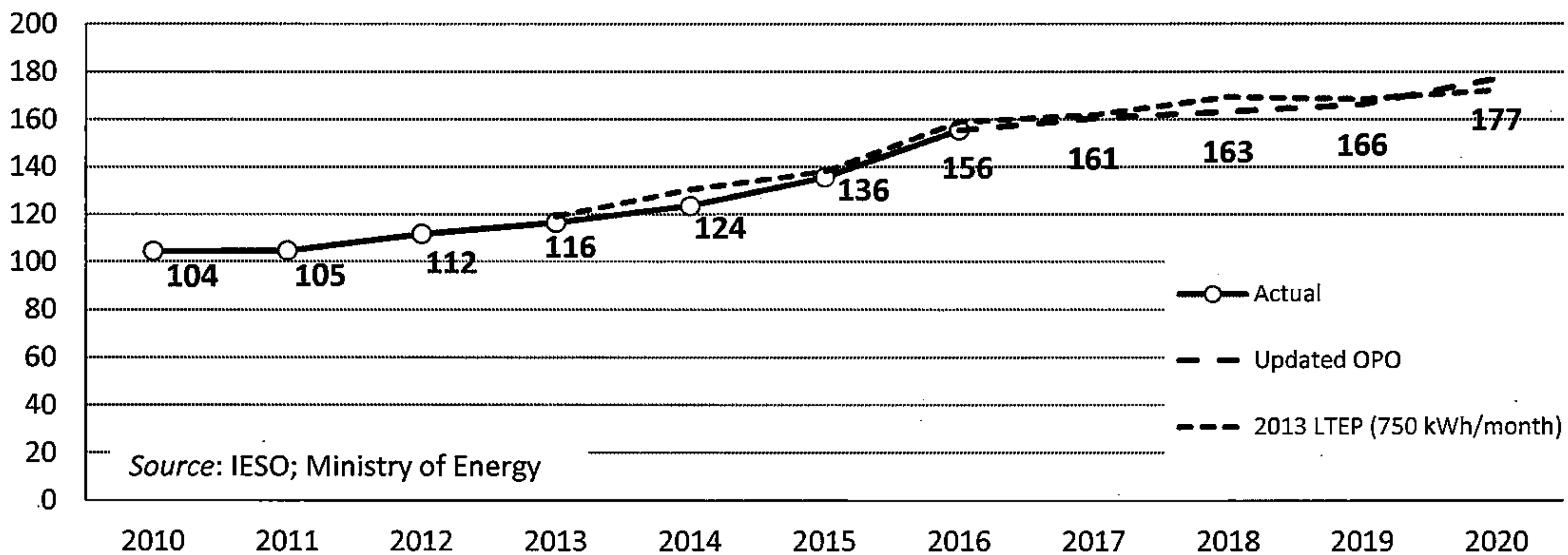
- Timing of announcement – Mid-February (TBD)
- Technical Briefing (TBD)
- Key messages will focus such topics as:
  - $XX off a month (including HST and RRRP);
  - Electricity savings for an average family; and
  - Electricity saving for an average "rural" family.

Appendix

Residential Electricity Prices

- Residential consumers electricity prices continue to be a concern for many Ontarians, particularly those that rely on electric heat.
  - **Note:** The typical residential bill is currently below the 2013 Long-Term Energy Plan (2013 **LTEP**) forecast.

Typical Residential Electricity Bills
Historical and Forecast in $/month



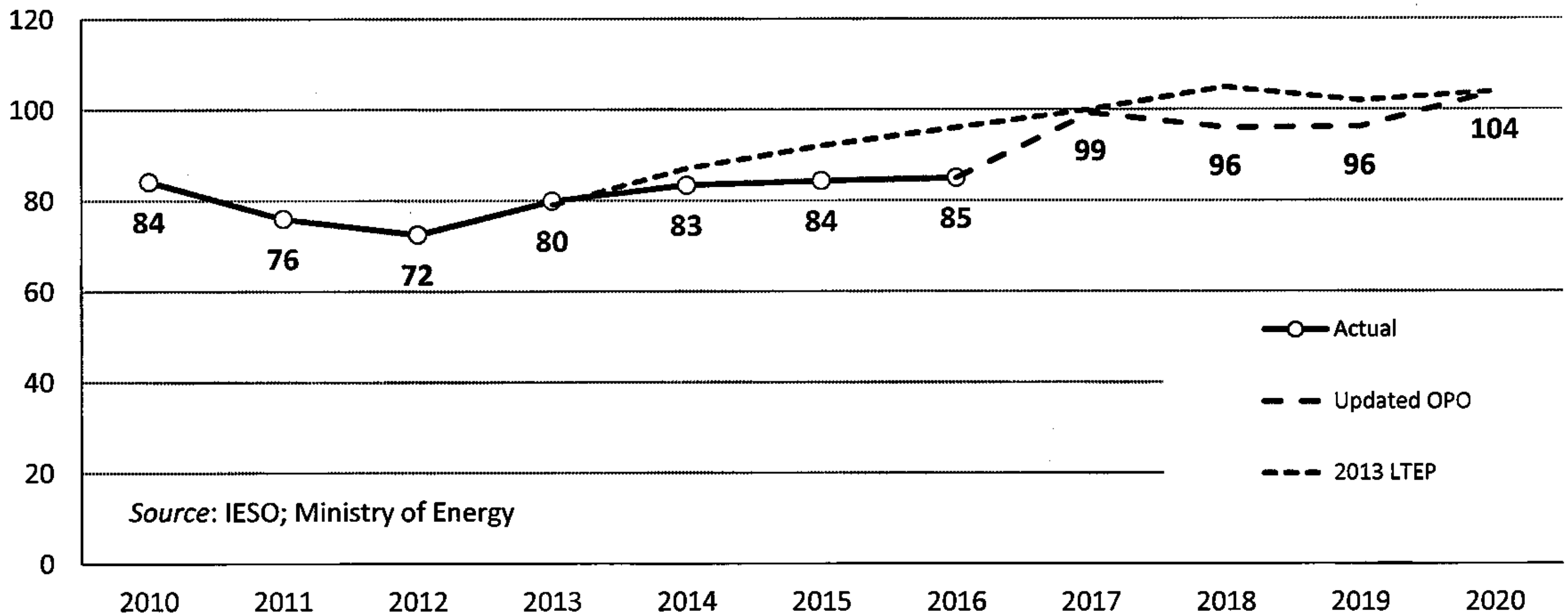
Source: IESO; Ministry of Energy

Note: The 2013 LTEP forecast for residential bills was based on 800 kWh/month without RRRP or electric heating; the above has been rebased to 750 kWh/month for comparison purposes. Typical residential are based on Toronto Hydro. The updated OPO forecast above includes the 8% rebate to offset the provincial portion of HST, ICI expansion and RRRP expansion.

Large Industrial Electricity Prices

- Industrial electricity prices continue to be a concern for many businesses.
  - **Note:** The typical industrial electricity price is currently below the 2013 LTEP forecast.

Typical Class A Electricity Prices
Historical and Forecast in $/MWh



Note: The 2013 LTEP forecast for industrial reflects a transmission connected Class A electricity consumer. The updated OPO forecast above includes ICI expansion and RRRP expansion.

Global Adjustment Smoothing

Global Adjustment (GA) Smoothing

- The global adjustment (GA) is comprised of costs for regulated and contracted generation, as well as conservation.

- Some contracted generation assets are expected to have a useful life that extends beyond the term of their current financial contracts (typically 20-years).

- Similarly, conservation costs are recovered through the GA on an annual basis while conservation initiatives provide benefits to the electricity system over the course of many years.

- Since the GA only includes costs related to the contractual life of these assets, there may be an opportunity to recognize the longer-term benefit of these assets to the electricity system and "bring forward" that benefit for ratepayers today, while deferring some of the current costs.

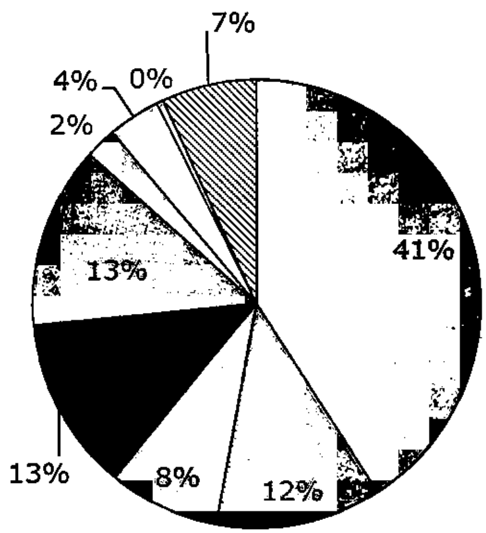
- An indicative GA financing proposal is presented that lowers ratepayers costs over the short term by borrowing money but increases costs over the long term when GA costs are forecast to be lower.

- **Note:** Not all generating assets will continue operations at the end of their contract term. Regulatory constraints (i.e., nuclear licences) or low demand conditions (i.e., as experienced with current expiring NUGs) would mean that some generators will shutdown at the expiry of their contract. Future ratepayers would be paying for these assets that are no longer producing power.

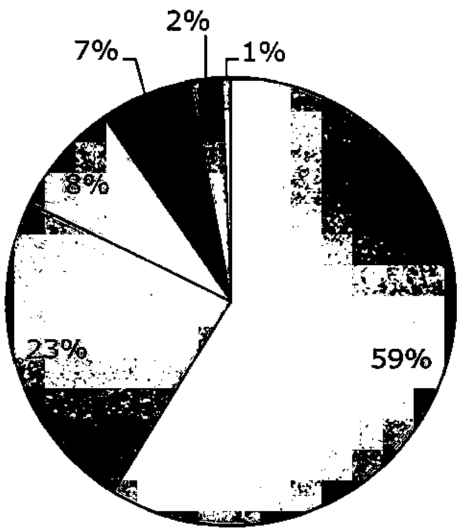
GA Smoothing – Cost Breakout

- The allocation of GA costs in 2016 is compared to the proportion of generation in the graph below.
- This cost breakdown will evolve over time as 2,181 MW of contracted generation comes online in the coming years.

2016 GA Cost: $12.3 billion



2016 Generation: 155 TWh

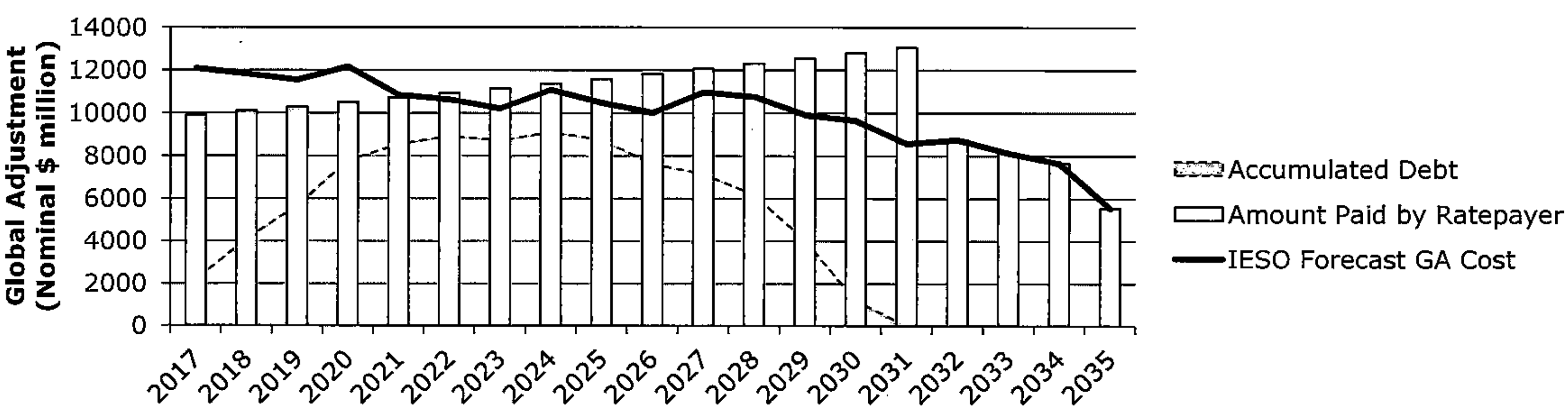


	GA ($M)	Gen. (TWh)
Nuclear	5,053	91
Hydro	1,473	36
Natural Gas	985	13
Wind	1,552	10
Solar	1,630	3
Biomass, Landfill and Byproduct	278	1
Conservation	467	
IEI Program	60	
OEFC*	842	

*OEFC indicates the cost of generator contracts managed by the OEFC which include contracts for natural gas, hydro and biomass generators.
** Conservation measures, not quantified here, serve to reduce Ontario energy demand. Actual electricity generation would be larger than 155 TWh in the absence of conservation programs.

GA Smoothing

- It is proposed that the amount of global adjustment (GA) paid by ratepayers in each year over the forecast period is set at a fixed amount and money is borrowed to make up the remainder of the GA cost in each year.
- Starting on January 1, 2017, the amount of GA paid by ratepayers is set at a value lower than the true cost of GA in 2017 and is increased according to a pre-defined schedule until the debt has been paid off.
- GA costs will be "smoothed" over time by lowering costs in the short term and increasing costs in the long term.
- In some scenarios, the amount of GA paid by ratepayers *above* the expected actual cost of GA is capped so as to limit large increases in the cost of electricity in any given year.
- All analysis is based on forecasts from Independent Electricity System Operator (IESO), assumes a 5% annual borrowing interest rate and an inflation rate of 2% per year.



Sample financing: Ratepayers pay less than the cost of GA in early years, borrowing up to $9 billion that is fully paid off in 2031 by charging ratepayers more than the cost of GA in later years.

GA Smoothing – Options

[redacted]

1. <u>Moderate / GA Financing with Delayed Increase (Moderate)</u>

   - The starting GA payment from all ratepayers in 2017 is lowered by $1.1 billion, ratepayer payments *decrease* in the short term to keep residential bills relatively flat, then increases at 3% each year – up to a maximum of $2 billion above the true cost of GA – until the borrowed money is paid back over a 25 and 30 year financing period respectively.

2. <u>GA Financing (Moderate)</u>

   - The amount of GA paid by ratepayers in 2017 is lowered by $3.2 and $3.4 billion below the true cost of GA and increases at 2% in each subsequent year until the total amount of money borrowed is paid off in 25 and 30 years respectively.
   - Future GA over-payments above the true cost of GA are capped at $2 billion to limit electricity cost increases in any given year.

3. <u>GA Financing (Low)</u>

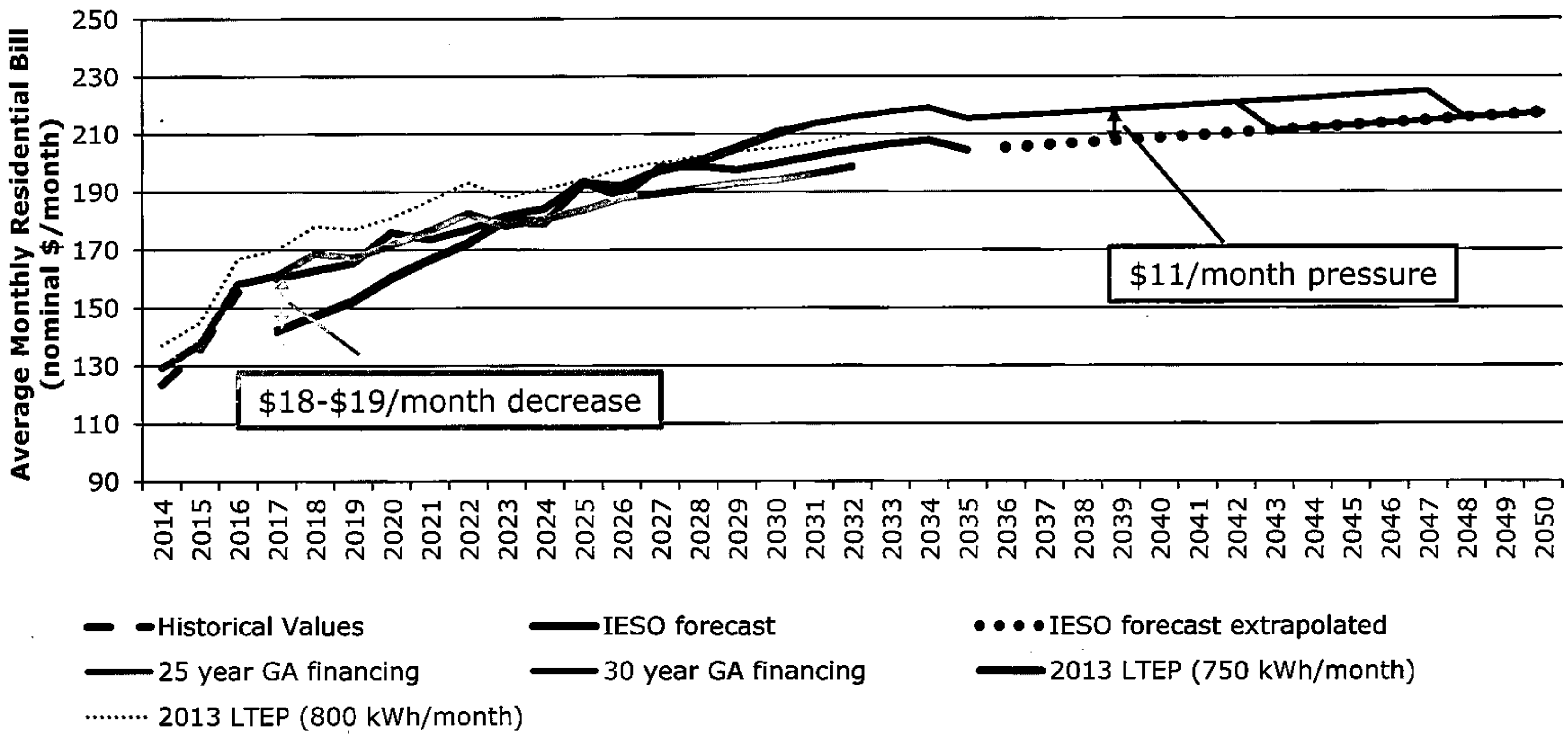
   - The amount of GA paid by ratepayers in 2017 is lowered by $2.5 billion below the true cost of GA and increases in each subsequent year until the total amount of money borrowed is paid off.
   - Future GA over-payments above the true cost of GA are capped at $2 billion to limit electricity cost increases in any given year.

4. <u>High / GA Financing (High)</u>

   - The amount of GA paid by ratepayers in 2017 is lowered by $4.4 and $5 billion below the true cost of GA and increases at 2% in each subsequent year until the total amount of money borrowed is paid off in 25 and 30 years respectively.
   - No limit is placed on the amount charged to ratepayers above the true cost of GA.

GA Smoothing – Impact on Residential Electricity Bills (Moderate)

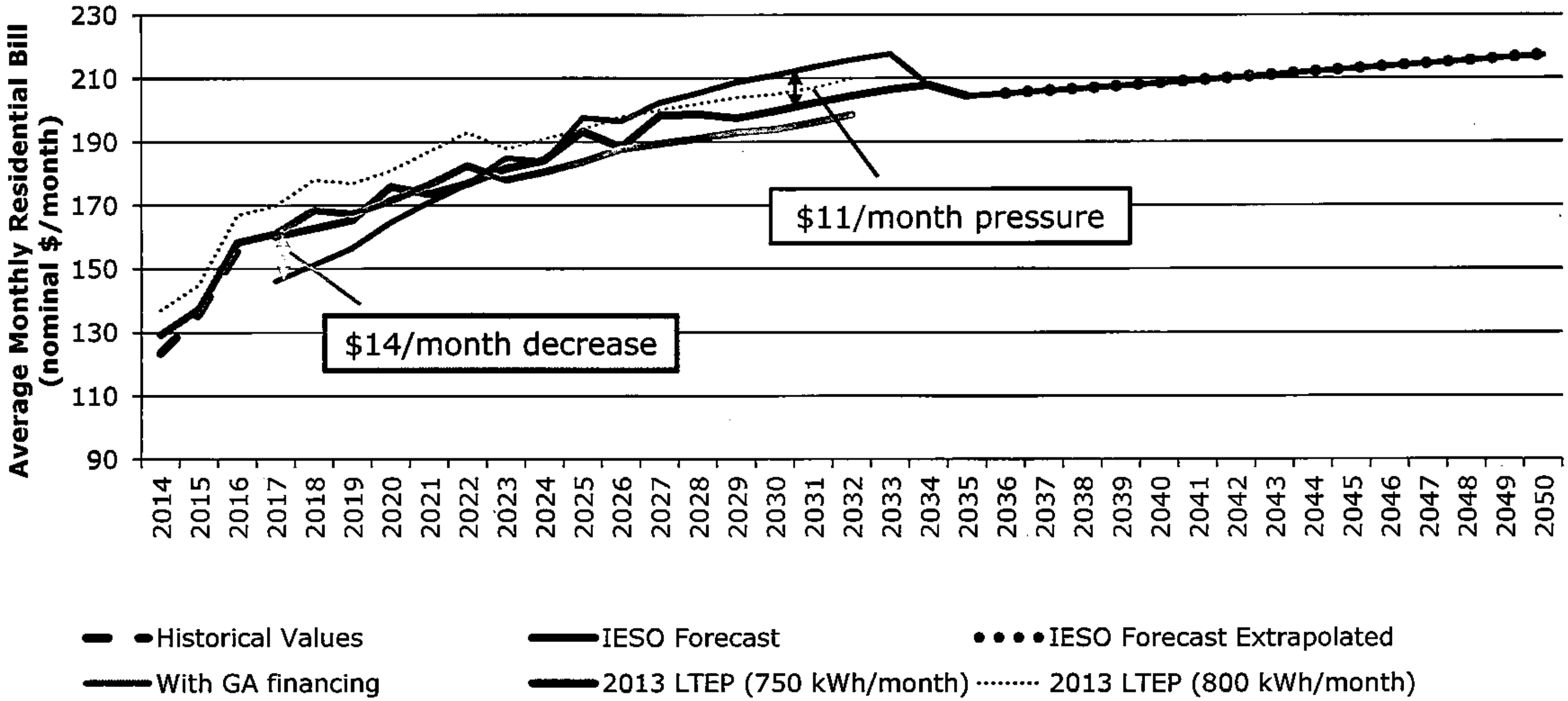
- In this scenario, the starting GA payment from all ratepayers in 2017 is lowered by $3.1 billion (green line) and $3.3 billion (red line) and increases at 2% each year – up to a cap of no more than $2 billion more than the true cost of GA in any year – until the borrowed money is paid back in 25 and 30 years respectively.



- By **borrowing up to $19-$23 billion**, this scenario results in a **short-term residential electricity cost reduction of up to $17-$19/month** at the cost of **increased future electricity bills over 14-19 years of up to $11/month** above the true cost of electricity production.

GA Smoothing – Impact on Residential Electricity Bills (Low)

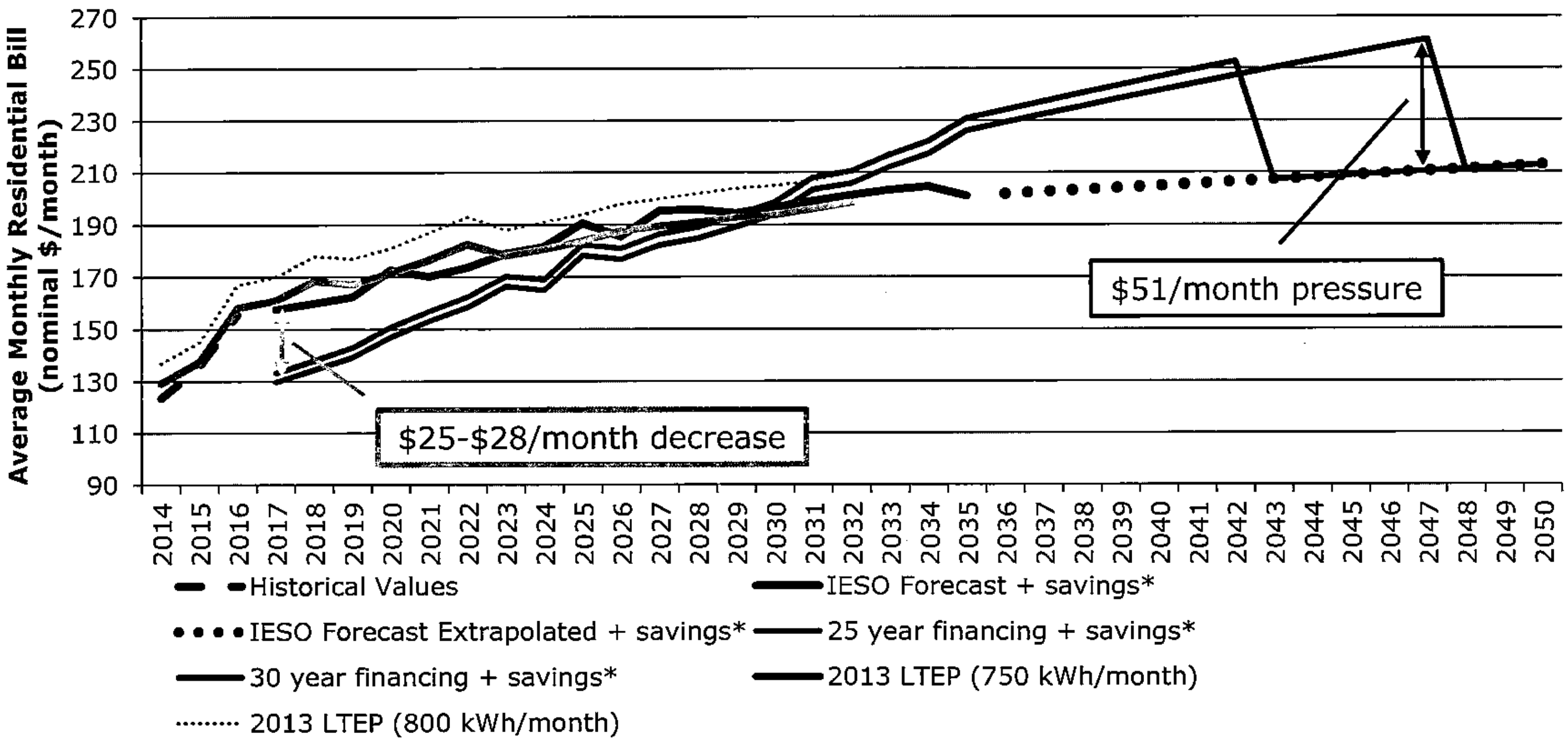
- In this option, the starting GA payment from all ratepayers in 2017 is lowered by $2.5 billion and increases at 2% each year – up to a cap of no more than $2 billion more than the true cost of GA in any year – until the borrowed money is paid back in 2032.



- By **borrowing up to $9.3 billion**, this scenario results in **a short-term residential electricity cost reduction of up to $14/month** at the cost of **increased future electricity bills over 10 years of up to $11/month** above the true cost of electricity production.

GA Smoothing – Impact on Residential Electricity Bills (High)

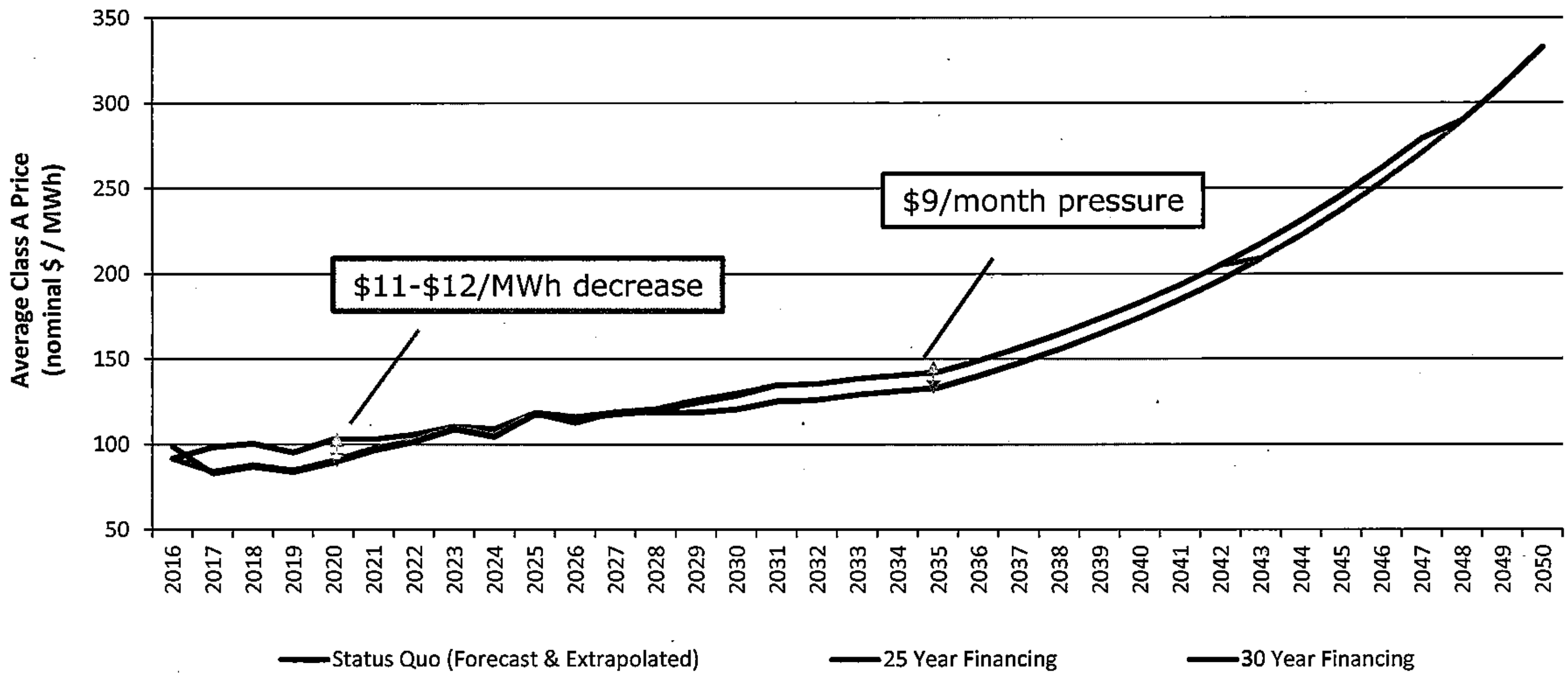
- In this option, the starting GA payment from all ratepayers in 2017 is lowered by $4.4 and $5 billion and increases at 2% each year until the borrowed money is paid back over a 25 and 30 year financing period respectively.



- By **borrowing up to $65 billion**, this scenario results in **a short-term residential electricity cost reduction of up to $25-$28/month** at the cost of **increased future electricity bills over 12-17 years of up to $46-$51/month** above the true cost of electricity production.

GA Smoothing – Impact on Large Industrial Electricity Consumers (Moderate)

- In this option, the starting GA payment from all ratepayers in 2017 is lowered by $1.1 billion (green line) and $1.4 billion (red line), decreasing the average Class A electricity price in the short term.

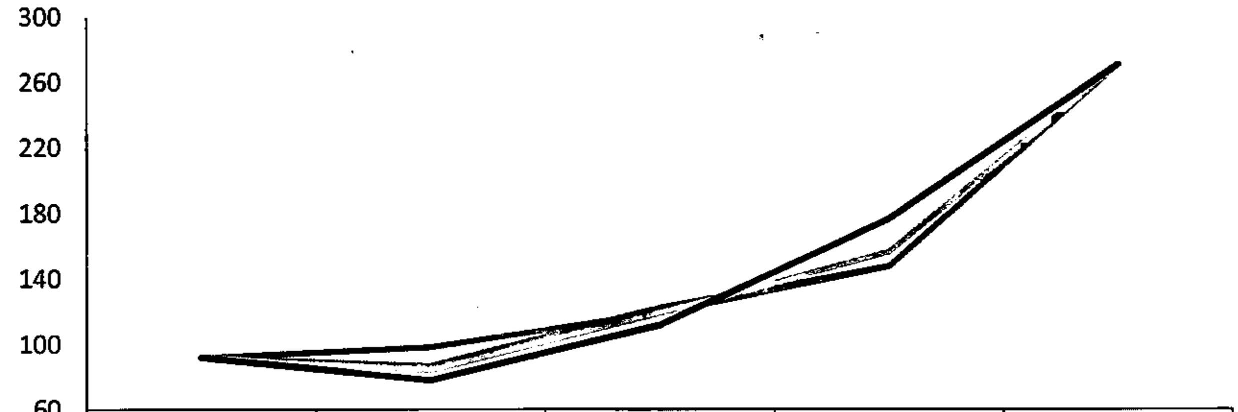


- By borrowing up to $19-$23 billion, this scenario results in a reduction between 2017 and 2024, however, the cost increases above the true cost of electricity production by 2026.

GA Smoothing – Impact of the Level of Financing on Large Industrial Electricity Consumers

- Below graph illustrates the estimated impact of the level of GA financing for an average Class A electricity consumer over a 25 year amortization period.

Estimated All-In Electricity Price
for Average Class A in $/MWh



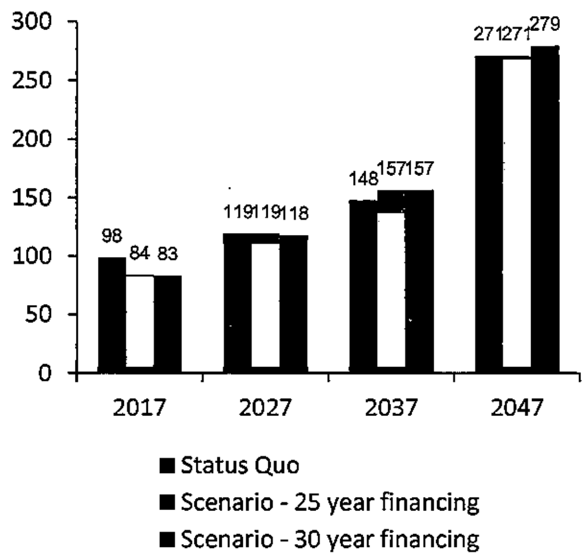
	2016	2017	2027	2037	2047
Status Quo	92	98	119	148	271
Low Financing		87	122	148	271
Moderate Financing	-	84	119	157	271
High Financing		78	112	177	271

Note: Assumes that demand by industrial sector continues at average 2011-2015 levels. Please see the Appendix or more information on the estimated impact on large industrial electricity consumers.

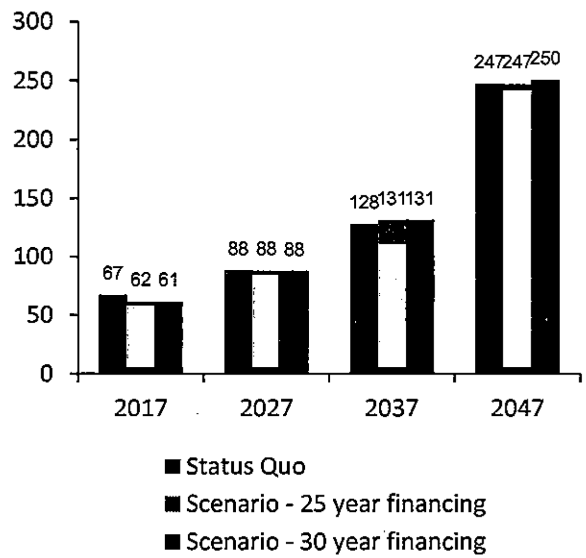
GA Smoothing – Illustrative Impact for Large Industrial Electricity Consumers

- Below graphs illustrate the estimated impact under the moderate GA financing scenario for an average Class A electricity consumer, a consumer that pays low GA (i.e., pulp and paper) and high GA (i.e., refining and chemical manufacturing).

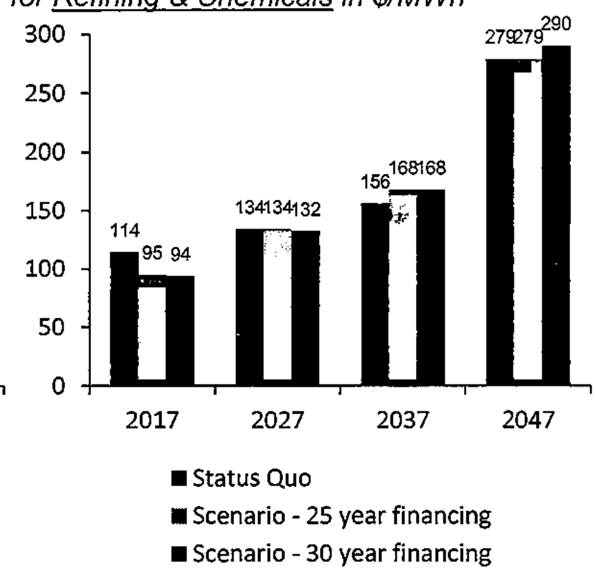
Estimated All-In Electricity Price
for Average Class A in $/MWh



Estimated All-In Electricity Price
for Pulp & Paper in $/MWh



Estimated All-In Electricity Price
for Refining & Chemicals in $/MWh



Note: Assumes that demand by industrial sector continues at average 2011-2015 levels.

GA Smoothing – Considerations (*Accounting Treatment: Does Province Control Entity?)*

Defining the Government Reporting Entity

- The government reporting entity should comprise government components and those organizations that are controlled by the government.

Determining Whether Control Exists

- Control is the power to govern the financial and operating policies of another organization with expected benefits or the risk of loss to the government from the other organization's activities.
- Whether a government controls an organization is a question of fact that must be determined by reference to the definition of control described in the prior paragraph and the particular circumstances of each case.
- Requires the application of professional judgment based on the definition of control and the substance of the relationship.
- It is the preponderance of evidence that would be considered in assessing whether a government controls an organization.

GA Smoothing Considerations (*Accounting Treatment: Does Province Control Entity?)* (cont'd)

Indicators of Control

- There are certain indicators that provide more persuasive evidence of control:
  - Government has the power to unilaterally appoint or remove a majority of the members of the governing body of the organization;
  - Government has ongoing access to the assets of the organization, has the ability to direct the ongoing use of those assets, or has ongoing responsibility for losses;
  - Government holds the majority of the voting shares or a "golden share" 1(1) that confers the power to govern the financial and operating policies of the organization; and
  - Government has the unilateral power to dissolve the organization and thereby access its assets and become responsible for its obligations.

- Other indicators that may provide evidence of control exist when the government has the power to:
  - Provide significant input into the appointment of members of the governing body of the organization;
  - Appoint or remove the CEO or other key personnel;
  - Establish or amend the mission or mandate of the organization;
  - Approve the business plans or budgets for the organization and require amendments;
  - Establish borrowing or investment limits or restrict the organization's investments;
  - Restrict the revenue-generating capacity of the organization, notably the sources of revenue; and
  - Establish or amend the policies that the organization uses to manage, such as those relating to accounting, personnel, compensation, collective bargaining or deployment of resources.

GA Smoothing – Schedule of Borrowing and Re-Payments

- The table below shows an illustrative schedule of borrowing and re-payments under financing of the GA. Schedule assumes a 5% interest rate compounded annually.

Debt Borrowing/Payment Schedule for GA Financing

$ millions	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Amount by which debt account changes in present year, not including interest	-1,142	-1,667	-2,115	-3,409	-1,819	-1,337	-635	-1,215	-325	451	-187	350	1,531	2,000
Amount by which debt account changes in present year, including interest	-1,142	-1,725	-2,258	-3,665	-2,259	-1,889	-1,282	-1,926	-1,132	-413	-1,072	-588	563	1,061

$ millions	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Amount by which debt account changes in present year, not including interest	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	0	0
Amount by which debt account changes in present year, including interest	1,114	1,169	1,228	1,289	1,354	1,421	1,492	1,567	1,645	1,728	1,814	1,905	0	0

– does this

GA Smoothing – Auction Proceeds Recycling

- Initially, GA smoothing provides, for the majority of electricity consumers, a price reduction that is greater than what would be provided as a result of "all hours" proceeds recycling proposal.
- As shown in tables, only an electricity consumer operating a day-shift and paying an extremely low GA would be worse off under GA financing over the short term.
- Over the longer term, proceeds recycling provides a greater benefit for all consumers.

Table 1 – Benefit of GA Financing Net of Cap and Trade

$/MWh	2017	2018	2019	2020
Class A	-13.24	-10.89	-8.68	-10.21
Low GA (e.g., Pulp & Paper)	-3.35	-2.00	-0.97	-0.83
High GA (e.g., Chemical)	-18.26	-15.38	-12.57	-14.93
Extreme Low GA Day-Shift	0.68	2.02	2.82	3.93
Class B	-23.21	-19.92	-16.58	-19.85

Table 2 – Benefit of "All Hours" Proceeds Recycling Net of Cap and Trade

$/MWh	2017	2018	2019	2020
Class A	-2.10	-2.48	-2.65	-3.26
Low GA (e.g., Pulp & Paper)	-1.16	-1.27	-1.32	-1.50
High GA (e.g., Chemical)	-2.55	-3.05	-3.27	-4.09
Extreme Low GA Day-Shift	0.24	0.49	0.59	1.01
Class B	-2.67	-2.67	-2.67	-2.68

GA Smoothing – Auction Proceeds Recycling (cont'd)

- Estimates of the monthly impact as based on a 5 MW facility consuming 2,340 MWh per month are shown below.

Illustrative Benefit of GA Financing Including the Cost of Cap and Trade				
$/month, 5 MW Facility	**2017**	**2018**	**2019**	**2020**
Class A	-30,984	-25,482	-20,317	-23,885
Low GA	-7,832	-4,682	-2,278	-1,932
High GA	-42,723	-35,994	-29,407	-34,934
Extreme Low GA Day-Shift	1,585	4,722	6,592	9,199
Class B	-54,312	-46,623	-38,793	-46,445

Illustrative Benefit of "All Hours" Volumetric Proceeds Recycling Including the Cost of Cap and Trade				
$/month, 5 MW Facility	**2017**	**2018**	**2019**	**2020**
Class A	-4,914	-5,803	-6,201	-7,628
Low GA	-2,714	-2,972	-3,089	-3,510
High GA	-5,967	-7,137	-7,652	-9,571
Extreme Low GA Day-Shift	562	1,147	1,381	2,363
Class B	-6,248	-6,248	-6,248	-6,271

Note: For illustrative purposes, the estimates above for a 5 MW load assume a 65% load factor.

Electricity Support Programs to Help the Most Vulnerable

Delivery Charge Relief – Background

- The **Delivery** line on a typical consumer bill accounts for roughly 25-35% of the total bill before taxes.

- Delivery covers the costs of getting electricity from generating stations across the province to homes and businesses and combines three cost components of the electricity sector into one line item charge:

  - **Transmission:** The costs of moving electricity across high voltage lines from generating stations to the distribution system. This cost is recovered through a variable charge that is approved by the OEB.

  - **Distribution:** The costs of moving electricity from the transmission system to homes and businesses. Depending on the LDC, distribution costs makes up about 60% to 80% of the Delivery line.

    - This cost is currently recovered through both a variable charge and fixed charge, approved by the OEB. Distribution rates are moving to a fully-fixed charge over next 5 years.

  - **Line Loss:** The costs to recover electricity that is lost as heat when its delivered over a power line, as well as power theft. Each LDC is assigned by the OEB a specific line-loss adjustment factor to reflect their loses particular to their assets. This factor is multiplied against the monthly electricity cost to determine the monthly cost.

- To help mitigate delivery costs, the Province has expanded the Rural or Remote Protection Program (RRRP) to further reduce distribution costs for rural customers across the province.

  - Starting on January 1 2017, 330,000 Hydro One low density (R2 class) customers will receive $60.50 per month in RRRP to bring their total Delivery line costs to roughly $81 for 1,000 kWh/month (2016 rates).

SAMPLE MONTHLY BILL STATEMENT

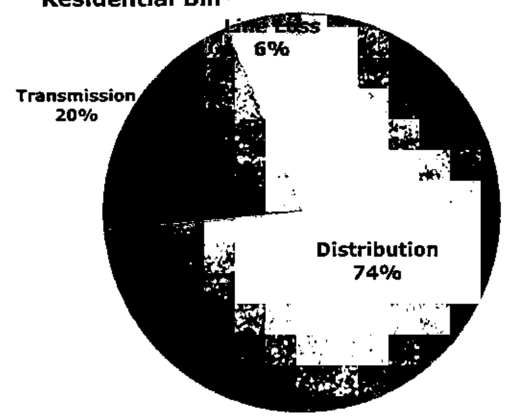
Anytown Hydro-Electric Limited

Account Number: 000 000 000 000 0000

Meter Number: 00000000

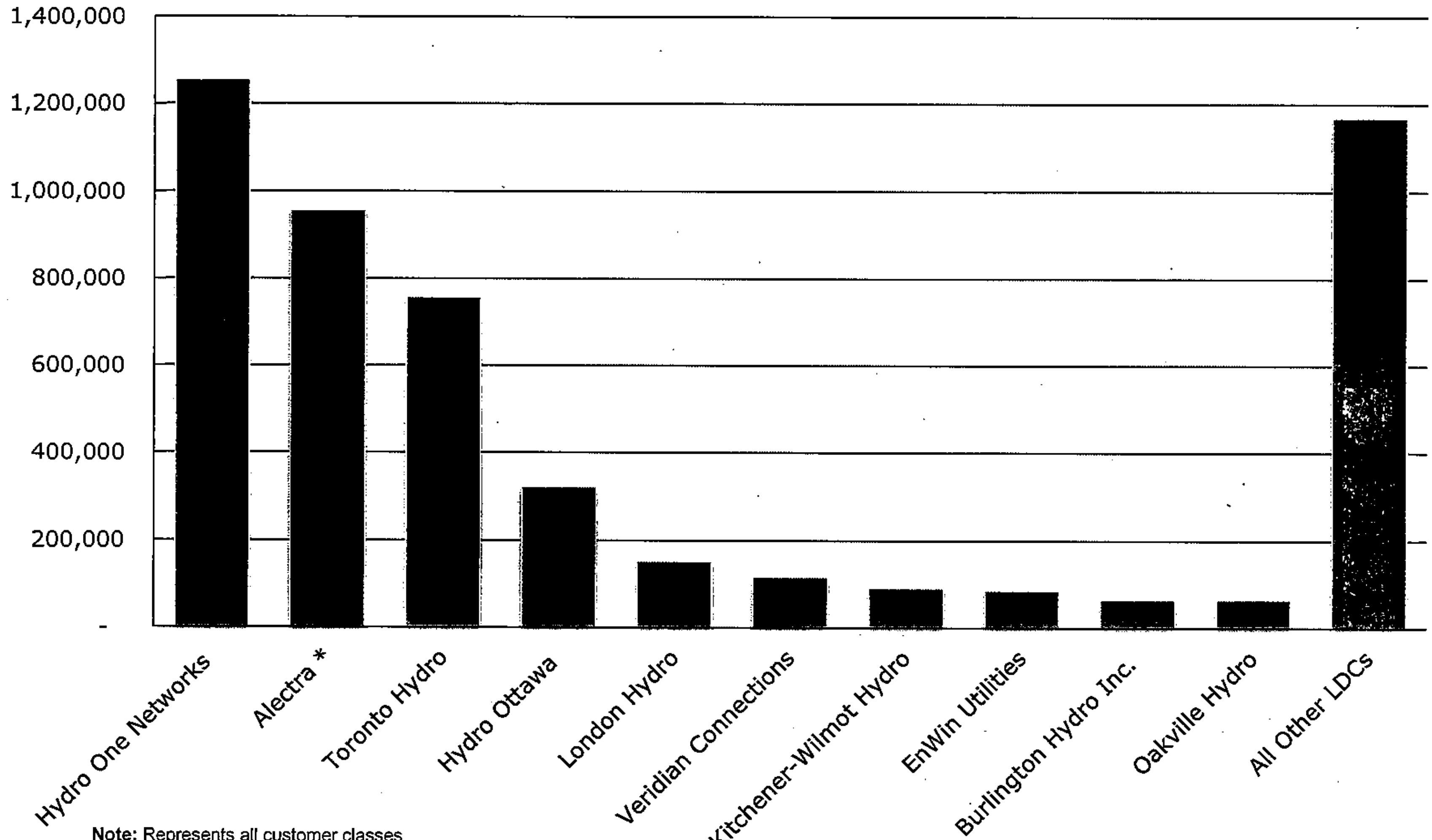
Your Electricity Charges	
Electricity	
Off-Peak @ 8.700 ¢/kWh	41.20
Mid-Peak @ 13.200 ¢/kWh	16.35
On-Peak @ 18.00 ¢/kWh	23.60
Delivery	53.07
Regulatory Charges	4.79
Debt Retirement Charge	0.00
Total Electricity Charges	**$139.00**
HST	18.07
8% Provincial Rebate	(11.12)
Total Amount	**$145.95**

Cost breakdown of Delivery Line for an Average Residential Bill*



* Toronto Hydro Bill @ 750Kwhs

Largest LDCs by Customer Base



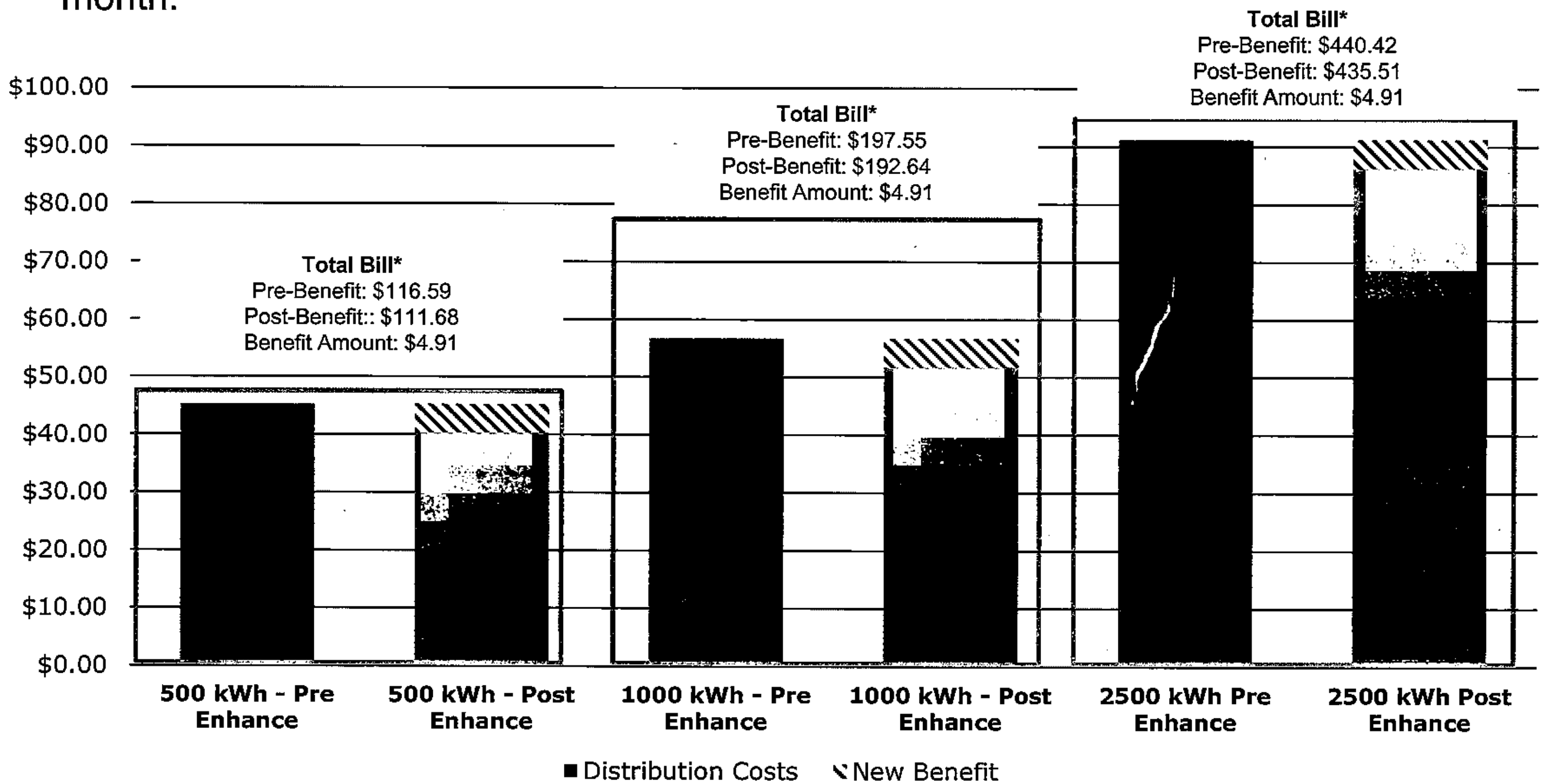
Note: Represents all customer classes
Source: OEB Yearbook 2015
*Recently approved merger of Powerstream, Enersource, Horizon, and Hydro One Brampton

RRRP Enhancement Options

- There are a number of options for changing the eligibility criteria and structure of the RRRP program to enhance its benefits, including:
  - Accelerate the move to fixed rates for high-volume R2 and R1 customers.
    - Would immediately transition relatively high-volume R2 and R1 consumers to fixed rates to provide an immediate benefit; and
    - Relatively lower-volume consumers would transition to fixed rates over the OEB-mandates period.
  - Use existing RRRP program with enhanced eligibility and benefits:
    - Expand the program to include Hydro One R1 customers in addition to R2 customers; and
    - Raise the benefit to bring both R2 and R1 distribution charges down to the level of Algoma Power.
  - Turn the RRRP into a volumetric credit with enhanced eligibility and benefits:
    - Change the program eligibility and benefits as above (include R1 customers and bring R2 and R1 customers down to the level of Algoma Power);
    - Create consumption "buckets" (e.g. e.g., <750kWh, 750-1200kWh, >1200kWh per month) and provide a larger RRRP credit for each bucket rather than a fixed credit regardless of consumption; and
      - ▶ A strictly volumetric credit would mean some R2 customers would receive a smaller benefit than the existing $60.50 a month. A revised program could ensure that all R2 customers will receive at least $60.50 a month, which would increase the program envelope.
    - Could be an interim step to turning the RRRP into a fully volumetric credit, which would avoids having different consumption bucket levels for each customer type.

RRRP Option 2 – Hydro One Mid-Density (R1) Ratepayer Impacts

- To equalize distribution cost to Algoma at 1000 kWh, R1 customers receive $4.91 per month.

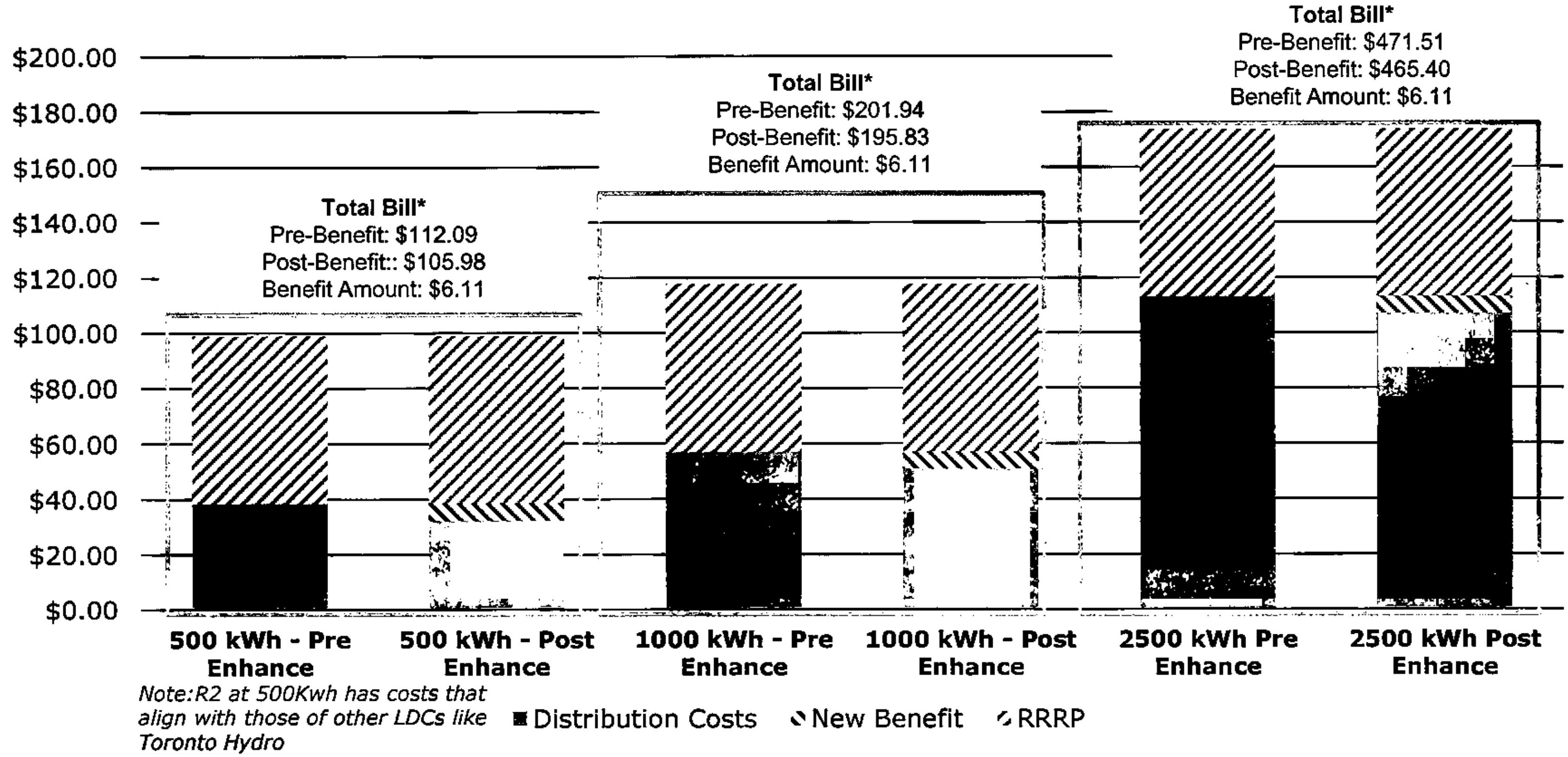


Note: R1, R2 and Algoma rates are 2017.

** Includes Electricity, Delivery, and Regulatory Charges. Excludes HST and 8% rebate.*

RRRP Option 2 – Hydro One Low-Density (R2) Ratepayer Impacts

- To equalize distribution cost to Algoma at 1000 kWh, R2 customers receive an additional $6.11 per month (for a total RRRP subsidy of $66.61).



Note: R1, R2 and Algoma rates are 2017.

* Includes Electricity, Delivery, and Regulatory Charges. Excludes HST and 8% rebate

RRRP Option 3(a) – $300 Million Benefit Allocation

- To determine benefit levels, each rate class can be assigned a portion of the $300 million in proportion to how they contribute to H1 revenues.* These amounts can then be sub-divided in a similar fashion into three buckets of equal customers for each rate class.
- Under this scenario, and not counting amounts currently received through RRRP, R2 is allocated ~$191 million (64%) and R1 is allocated ~$109 million (36%).
- These amounts are sub-divided into the customer buckets per the tables below.

R1 Monthly Benefit Allocation			
Customer Buckets	**% of R1 Revenue**	**Total Benefit Allocation**	**Per Customer Subsidy**
600kWh or less	26%	~$29M	**$16.05/month**
600kWh – 1000kWh	32%	~34M	**$19.22/month**
1000kWh or more	42%	~46M	**$25.67/month**

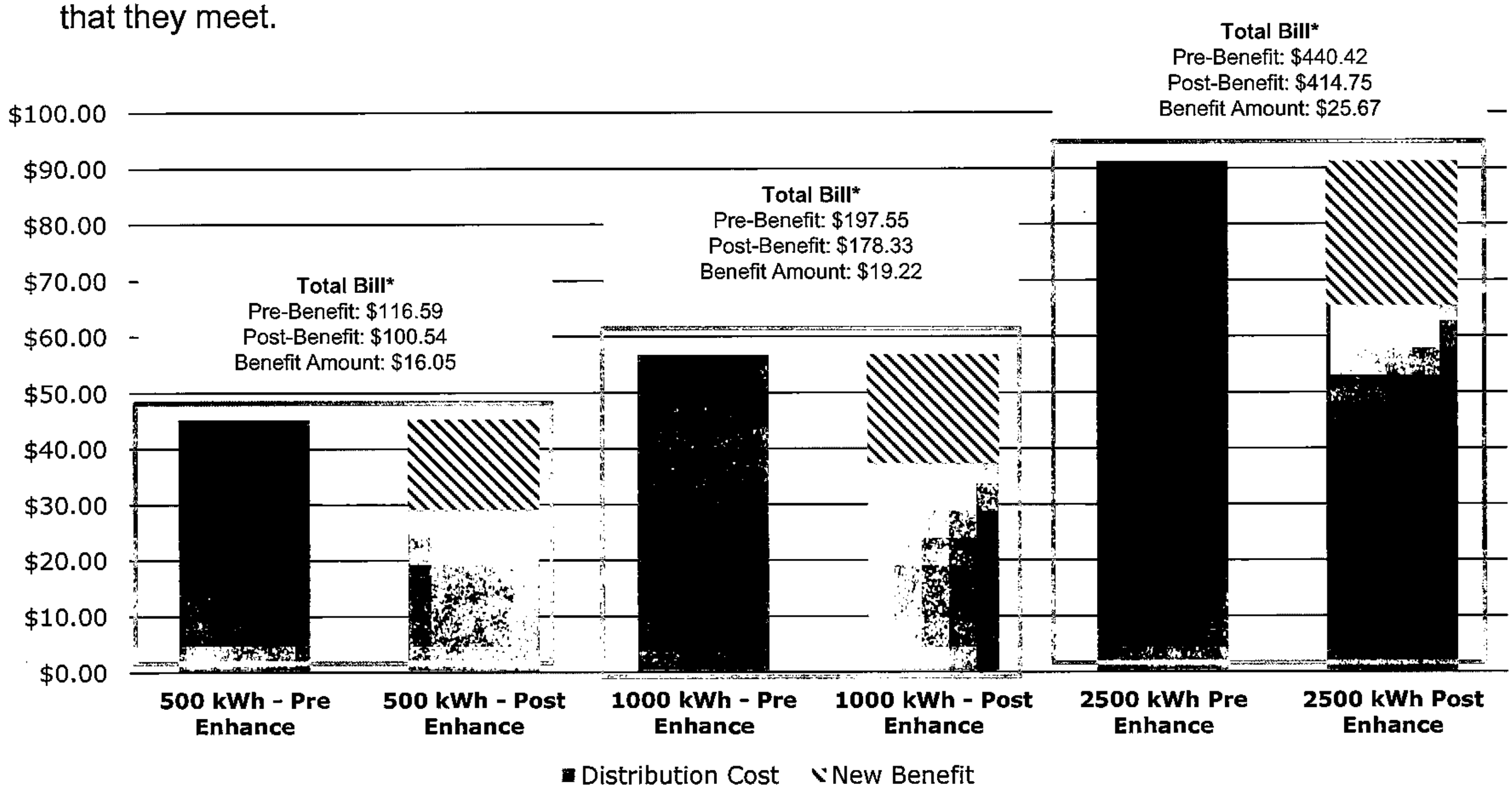
R2 Monthly Benefit Allocation			
Customer Buckets	**% of R2 Revenue**	**Total Benefit Allocation**	**Per Customer Subsidy**
750kWh or less	26%	~$50M	**$37.65/month**
750kWh – 1200kWh	31%	~$60M	**$44.74/month**
1200kWh or more	43%	~$81M	**$60.69/month**

**This methodology can be used to calculate benefit levels at any desired funding envelope.*

***This division developed using 2016 customer data provided by Hydro One, representing ~85% of affected customers*

RRRP Option 3(a) – Hydro One Mid-Density (R1) Ratepayer Impacts

- Under this option, R1 customers receive a monthly benefit dependent on the consumption threshold that they meet.

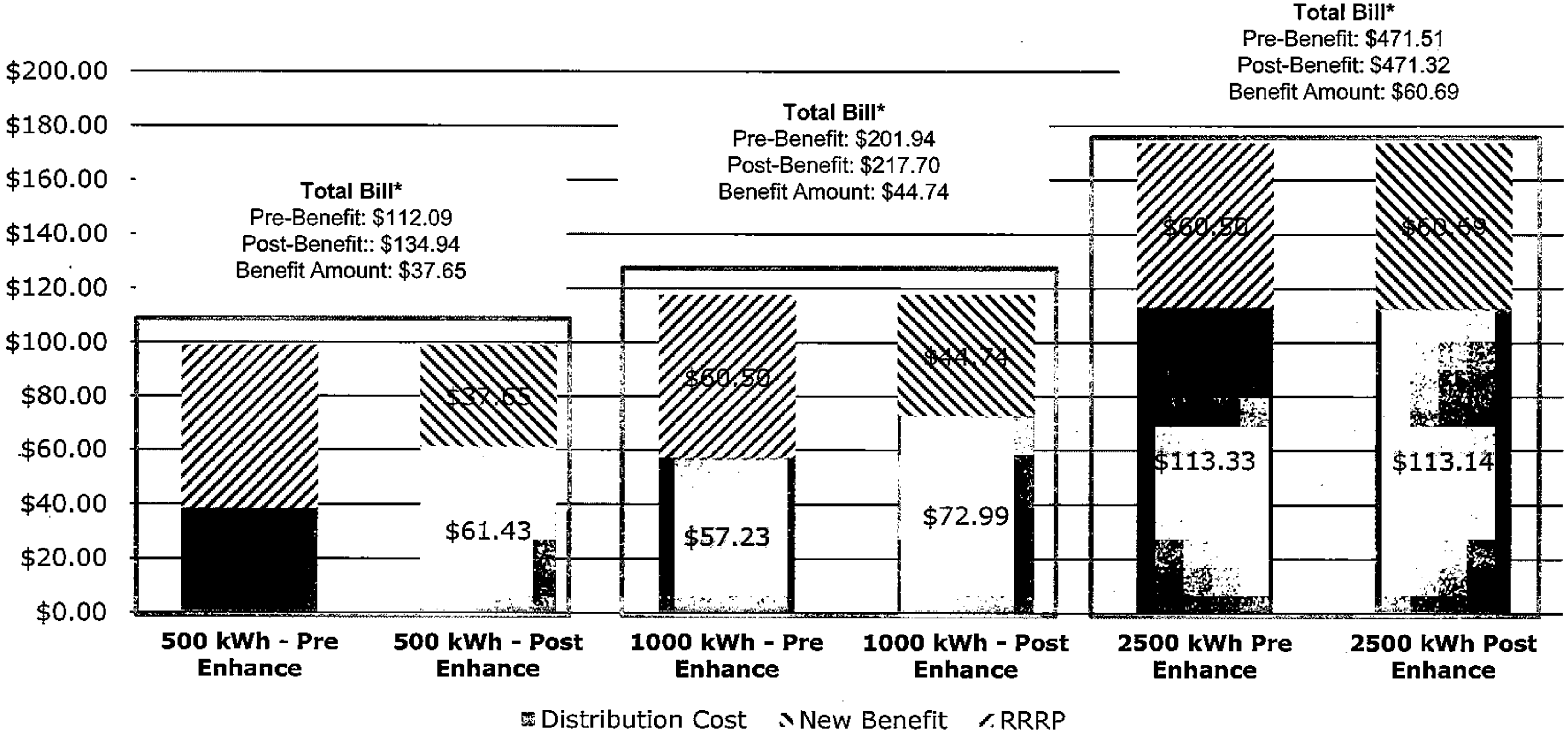


Note: Rates are for 2017

** Includes Electricity, Delivery, and Regulatory Charges. Excludes HST and 8% rebate.*

RRRP Option 3(a) – Hydro One Low-Density (R2) Ratepayer Impacts

- As a result of eliminating the $60.50 benefit and re-allocating funding proportionally across rate classes, most R2 customers see less benefit under this option.



Note: Rates are 2017

Note:R2 at 500Kwh has costs that align with those of other LDCs like Toronto Hydro

** Includes Electricity, Delivery, and Regulatory Charges. Excludes HST and 8% rebate.*

RRRP Option 3(b) – $300 Million Benefit Allocation + Status Quo RRRP

- To ensure no R2 customer receives less benefit than the status quo, the $60.50/month subsidy can be maintained.
- To determine benefit levels, each rate class can be assigned a portion of the $300 million in proportion to how they contribute to remaining H1 revenues.* These amounts can then be sub-divided in a similar fashion into three buckets of equal customers for each rate class.
- Under this scenario, R2 is allocated ~$143 million (47%) and R1 is allocated ~$157 million (53%). These amounts are sub-divided into the customer buckets per the tables below.**

R1 Monthly Benefit Allocation			
Customer Buckets	**% of R1 Revenue**	**Total Benefit Allocation**	**Per Customer Subsidy**
600kWh or less	26%	~$41M	**$23.19/month**
600kWh – 1000kWh	32%	~50M	**$27.76/month**
1000kWh or more	42%	~66M	**$37.09/month**

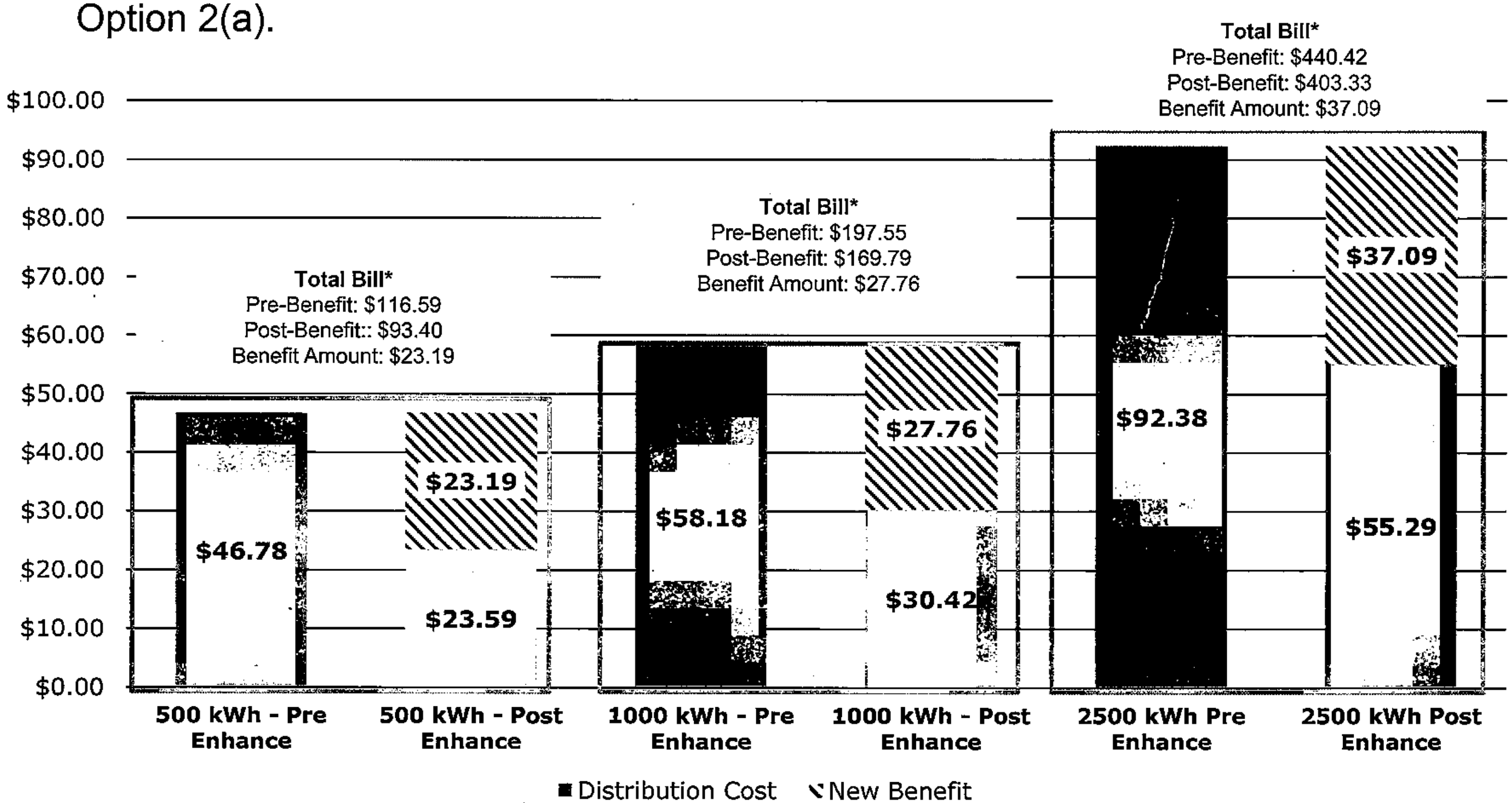
R2 Monthly Benefit Allocation			
Customer Buckets	**% of R2 Revenue**	**Total Benefit Allocation**	**Per Customer Subsidy (+$60.50 RRRP)**
750kWh or less	20%	~$28M	**$21.16/month**
750kWh – 1200kWh	29%	~$42M	**$31.40/month**
1200kWh or more	51%	~$73M	**$54.45/month**

**This methodology can be used to calculate benefit levels at any desired funding envelope.*

***This division developed using 2016 customer data provided by Hydro One, representing ~85% of affected customers*

RRRP Option 3(b) – Hydro One Mid-Density (R1) Ratepayer Impacts

- Under this option, R1 customers receive a higher monthly benefit than they did under Option 2(a).

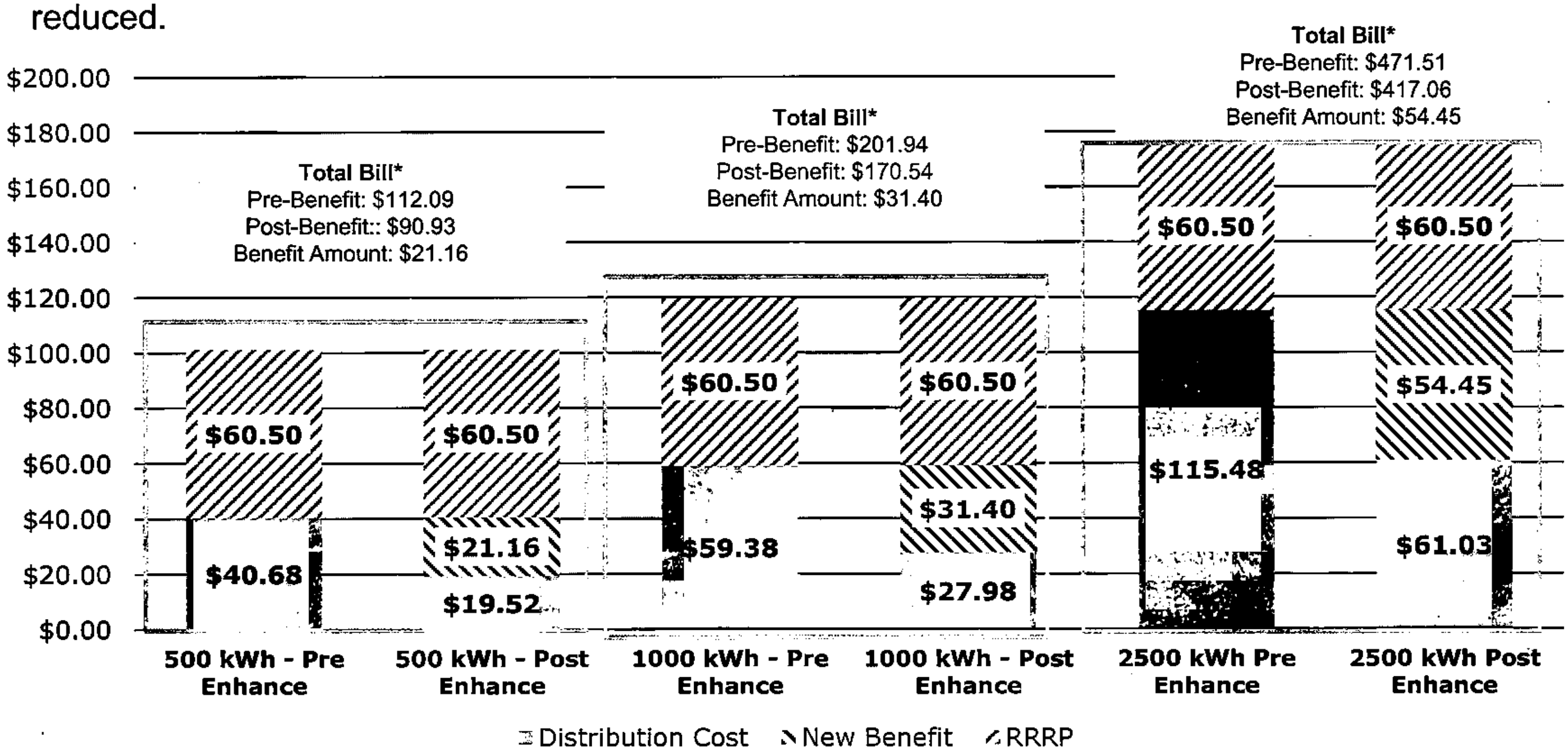


Note: Rates are for 2017

* Includes Electricity, Delivery, and Regulatory Charges. Excludes HST and 8% rebate.

RRRP Option 3(b) – Hydro One Low-Density (R2) Ratepayer Impacts

- Under this option, R2 customers receive a lower new benefit than they did under option 2(a). However as a result of retaining the original $60.50 RRRP subsidy, their total distribution costs are reduced.



Analysis Data & Assumptions

Customers

- Hydro One provided sample data representing ~85% of customers:
  - R1: 394,155
  - R2: 303,840
- These figures were used to determine the portion of the $300M to allocate between the rate classes. However, when determining the individual customer amounts, actual customer figures from the 2017 distribution rate application were used:
  - R1: 445,243
  - R2: 334,551

Rates

- All rate impacts calculated using 2017 rates as approved by the OEB, not including rate riders.
  - R1: Fixed - $33.77; Volumetric - $0.023/kWh
  - R2: Fixed - $80.33/month (-$60.50 RRRP); Volumetric - $0.0374/kWh

Revenues

- The customer sample provided by Hydro One projected (using 2017 rates) the following revenues:
  - R2: $259,265,061
  - R1: $236,793,283
- These numbers were used to assume the ratio of revenues between the rate classes to help determine how to allocate the $300 million. For option 2(a), where it was assumed the RRRP subsidy would be removed, RRRP funding was added to the R2 revenue figures.

Alternative Proposal – $55 Delivery Cap

- To provide further relief for customers across the province, the province could create a 'customer-specific' program that would cap the delivery line cost.
- The proposed program would limit the amount an LDC can bill consumers for Delivery at a to-be-determined reasonable cost. Delivery costs that exceed the cap would be covered by support from the fiscal plan.
- The proposed program would target customers within the LDC territory based on their Delivery cost.
  - Delivery costs vary month to month and LDCs will need to keep track of the customers who will receive the receive the additional support.
- Eligibility for increased protection would be based solely on delivery charges above the established threshold and therefore would not be specific to any one LDC. All LDCs must be prepared to offer the program to some of their customers
  - A delivery line item cap of $55 would align with what a Toronto Hydro customer consuming 750kWhs would pay in delivery costs (2016 rates).

$55 Delivery Cap – Total Fiscal Impact

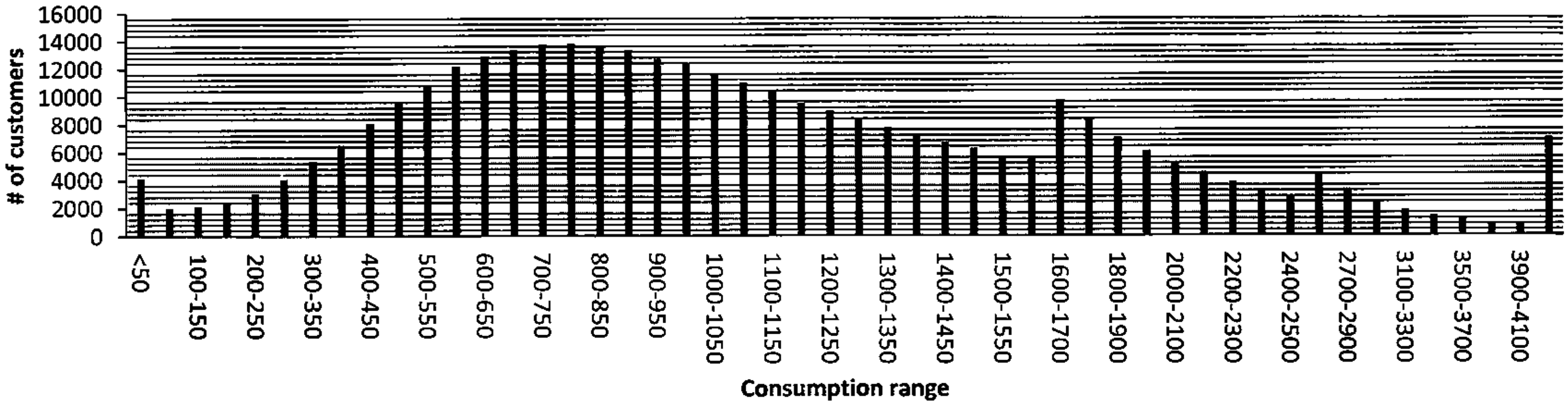
- Considering all caveats on the next slides and risks regarding quality of available data, seasonality changes in benefit, future weather risk, and the impacts of high volume outliers, the table below presents best estimate for the fiscal impact of capping the Delivery line at $55 for residential consumers.

LDC	Total Customers	# Customers Receiving Rebate	% Customers Receiving Rebate (# Customers Served by the LDCS)	Estimated Total Annual Cost ($M)
Hydro One Low-Density (R2)	335,000	279,000	83%	$175-$195
Hydro One Mid-Density (R1)	445,000	415,000	93%	$135-$155
Hydro One Urban (UR)	214,000	58,000	27%	$8-$15
H1 total (slide 19-20)		***$318M - $365M***		
Toronto Hydro (slide 21)	676,000	233,000	35%	$35-$50
Veridian Connections (slide 22)	108,000	7,800	7%	$1-$2
Other LDCs Between 100k-700k Customers (slides 22-23) (6 in Total)	1,200,000	TBD	TBD	$35-$50
LDCs 20-100k Customers (slides 24-25) (25 in Total)	1,026,000	218,000	21%	$15-20
LDCs Under 20k Customers (slides 26-27) (37 LDCs)	310,000	70,000	23%	$5-10
15% Risk Buffer				**$60-$75**
TOTAL	**~4,300,000**	**TBD**	**TBD**	**$470-$575M**

- This fiscal projection includes only full-time residential consumers who receive a bill from an LDC. It excludes costs for Hydro One seasonal, customers who do not receive a bill from an LDC (ex: condos served by unit sub-metering providers), or any type of commercial customer.
- A portion of this cost would be offset in the fiscal plan by a reduction in the amount required to fund the 8% rebate as a result of lowering the pre-8% rebate total bill.

Delivery Charge Relief – Hydro One Fiscal Impact Estimate

- The Ministry received complete customer base consumption information on Hydro One from the OEB for 2013 – showing how many customers consume a certain level of kWhs. Example for Hydro One R2 customers:



- Using 2013 consumption data and adjusting for 2015 customer numbers and 2016 rates, the table below presents the annual cost estimate* for providing a $55 Delivery line cap to Hydro One customers:

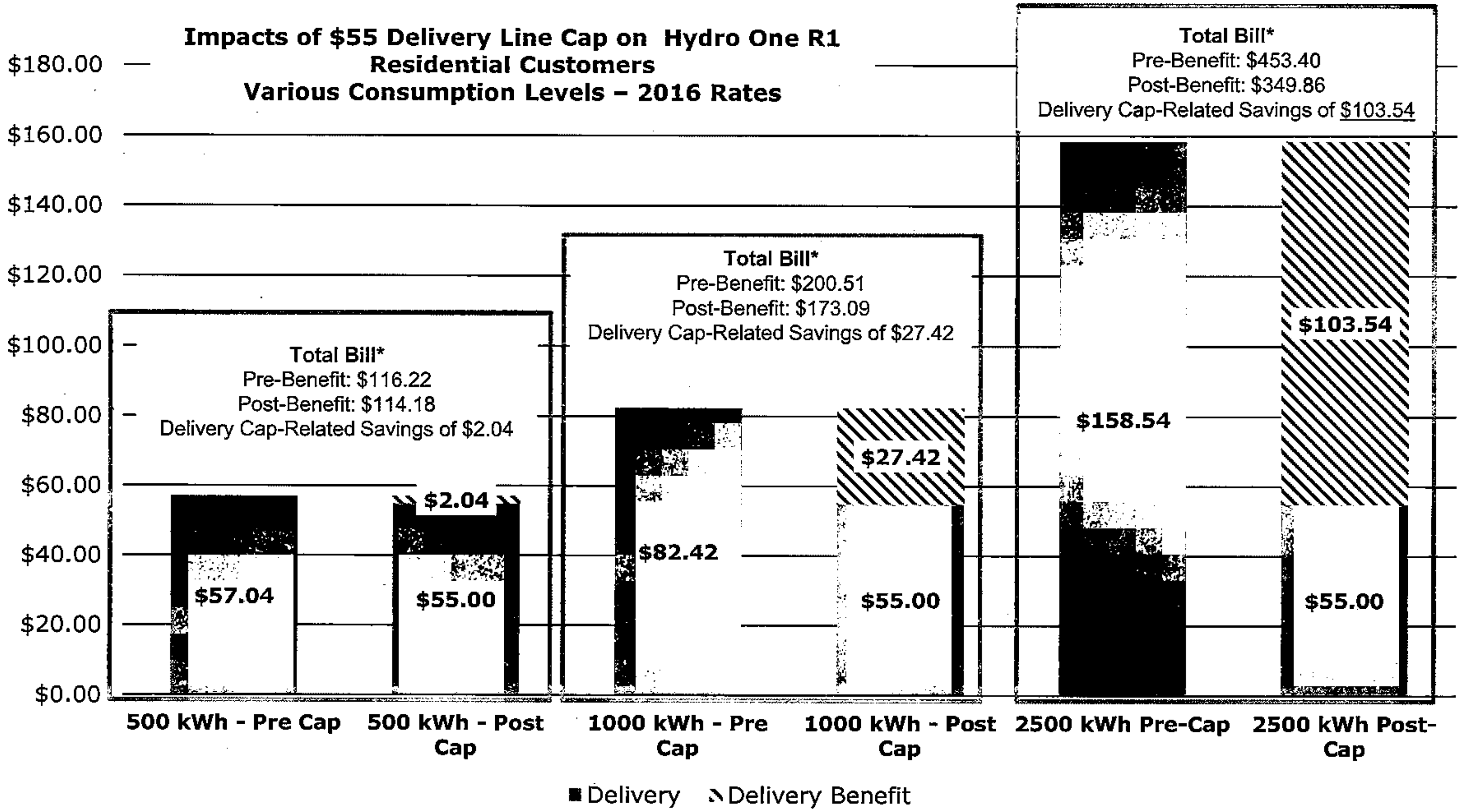
H1 Rate Class**	# Customers Receiving Rebate	% Customers Receiving Rebate (# Customers Served by the rate class)	Estimated Total Annual Cost ($M)
Hydro One Low-Density (R2)	279,000	83% (335,000 total)	$175-$195
Hydro One Mid-Density (R1)	415,000	93% (445,000 total)	$135-$155
Hydro One Urban (UR)	58,000	27% (214,000 total)	$8-$15
TOTAL	**752,000**	**76%**	**$318-$365**

**Future year weather (hot summer, cold winter) presents a fiscal risk and could push estimates beyond the band.*

*** Not including 150k H1 Seasonal customers. The OEB is considering moving these customers to other rate classes, which would increase the fiscal impact.*

Delivery Charge Relief – Hydro One Mid-Density (R1) Ratepayer Impacts

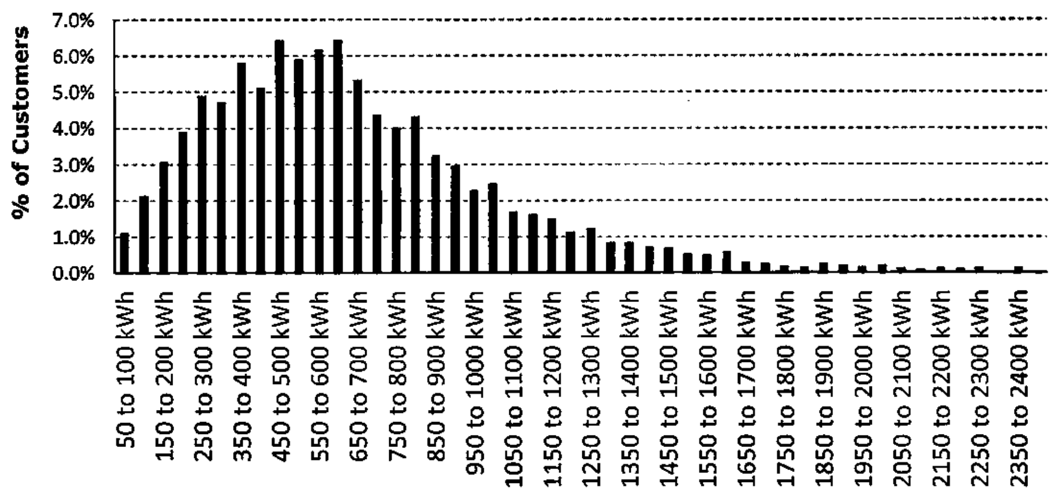
- Below is an example of a Hydro One R1 customer at different consumption levels and the level of subsidy they would receive.



** Includes Electricity, Delivery, and Regulatory Charges. Excludes HST and 8% rebate.*

Delivery Charge Relief – Toronto Hydro Fiscal Impact and Ratepayer Impact

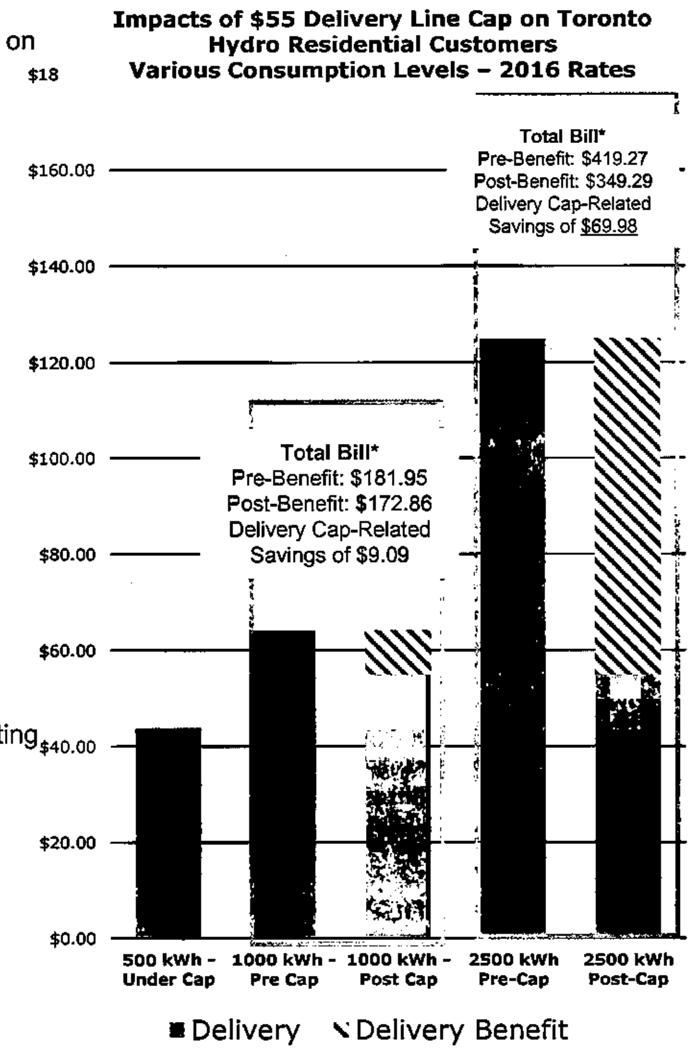
- The Ministry received a sample (~4,000) of customer base consumption information on Toronto Hydro from the OEB for 2013 – showing how many customers consume a certain level of kWhs. Spread of customers is as follows:



- Using this sample to project fiscal impacts has *significant fiscal risk* as it may not appropriately capture high volume outlier consumers.

- Noting this risk, using this sample – grossing for 2015 customer numbers and adjusting for 2016 rates – produces the following cost estimate*:

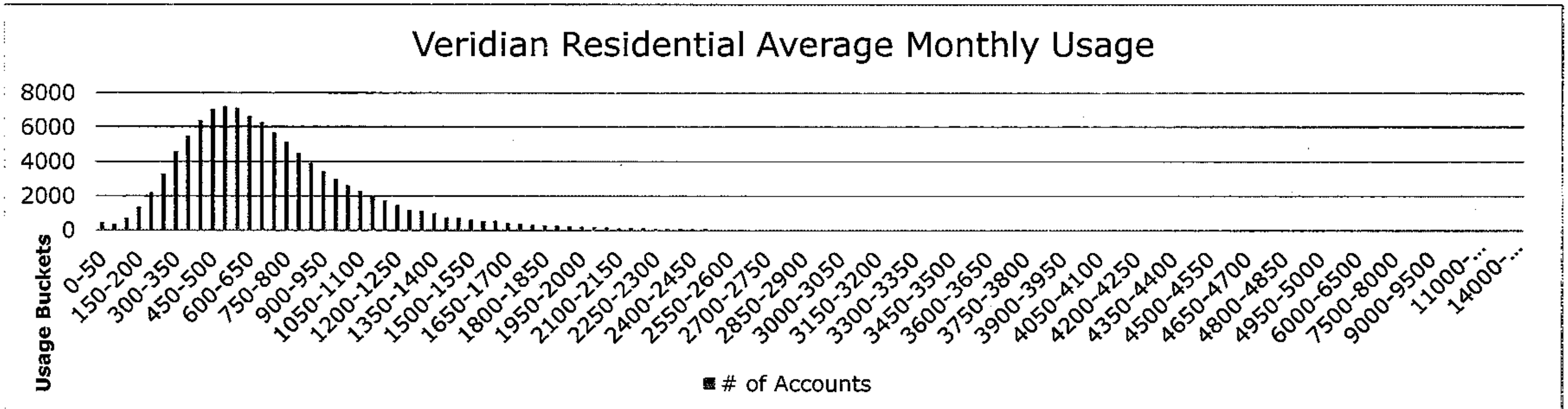
LDC	# Customers Receiving Rebate	% Customers Receiving Rebate (# Customers Served by Toronto Hydro)	Estimated Total Annual Cost ($M)
Toronto Hydro	233,000	35% (676,000 total)	$35-$50



**Future year weather (hot summer, cold winter) presents a fiscal risk and could push estimates beyond the band.*

Delivery Charge Relief – LDCs Between 100k-700k Fiscal Impact Estimate

- The Ministry received complete customer base consumption information (~108,000 customers) for Veridian Connections from the OEB for 2013 – showing how many customers consume a certain level of kWhs. Spread of customers is as follows:



- The Veridian Connections data set included a greater usage spread i.e. bucketed kWh usage from 0-50kWh up to greater than 15,000kWh when compared to the data sets provided for the smaller and medium sized LDCs

- Using this sample – grossing for 2015 customer numbers and adjusting for 2016 rates – produces the following cost estimate*:

LDC	# Customers Receiving Rebate	% Customers Receiving Rebate (Customer Base)	Estimated Total Annual Cost ($M)
Veridian Connections	**7,800**	**7%** (108,000 total)	$1.01

- It is difficult to project costs to the remaining 6 LDCs** in this range due to lack of data and the disparity in rates between them. These LDCs represent roughly twice as many customers as Toronto Hydro, though have lower rates. Thus to protect against fiscal risk, cost to serve these LDCs should be assumed at **$35-$50M** until data quality improves.

**Future year weather (hot summer, cold winter) presents a fiscal risk and could push estimates beyond the band.*

***Powerstream, Hydro Ottawa, Horizon, Enersource, London Hydro, Hydro One Brampton*

Delivery Charge Relief – LDCs Under Between 20k-100k Customers – Fiscal Impact Estimate

- The Ministry received a complete customer base consumption information for 2 LDCs serving between 20k-100k customers from the OEB for 2013 – showing how many customers consume a certain level of kWhs.
- Using 2013 consumption data and adjusting for 2015 customer numbers and 2016 rates, the table below presents the annual cost estimate* for providing a $55 Delivery line cap to these 2 LDCs.

LDC	# Customers Receiving Rebate	% Cust Receiving Rebate (LDC Customer Base)	Estimated Total Annual Cost ($M)
Entegrus Powerlines	6,000	16% (36,300 total)	$0.15
Whitby Hydro	10,200	26% (39,250 total)	$1.10

- Averaging these sample LDCs and scaling to the entire 20k-100k LDC population (25 LDCs in total) provides the following total cost estimate* for this LDC community:

LDC	# Customers Receiving Rebate	% Customers Receiving Rebate (# Customers Served by the 25 LDCS)	Estimated Total Annual Cost ($M)
LDCs 20-100k Customers (25 in Total)	218,000	21% (1,026,000 total)	$15-20M

- Using this sample to project fiscal impacts has *moderate fiscal risk* as medium LDCs have different penetrations of electric heat. Analysis may not accurately capture the impacts of high volume outlier customers. However given the scale compared to Hydro One and Toronto Hydro this risk has a moderate impact on the total fiscal projection

**Future year weather (hot summer, cold winter) presents a fiscal risk and could push estimates beyond the band.*

Delivery Charge Relief – LDCs Under 20k Customers – Fiscal Impact Estimate

- The Ministry received a complete customer base consumption information for 5 LDCs under 20,000 customers from the OEB for 2013 – showing how many customers consume a certain level of kWhs.

- Using 2013 consumption data and adjusting for 2015 customer numbers and 2016 rates (2015 rates used for Rideau St. Lawrence) the table below presents the annual cost estimate* for providing a $55 Delivery line cap to these 5 LDCs.

LDC	# Customers Receiving Rebate	% Cust Receiving Rebate (LDC Customer Base)	Estimated Total Annual Cost ($M)
Orillia Power Distribution	2,800	24% (11,900 total)	$0.11
Wasaga Distribution	1,750	14% (12,350 total)	$0.07
Rideau St. Lawrence	1,800	35% (5,000 total)	$0.42
Woodstock Hydro	3,000	21% (14,500 total)	$0.22
Midland Power Utility	1,150	19% (6,200 total)	$0.13

- Averaging these sample LDCs and scaling to the entire <20k LDC population (37 LDCs in total) provides the following total cost estimate* for the small LDC community:

LDC	# Customers Receiving Rebate	% Customers Receiving Rebate (# Customers Served by the 37 LDCS)	Estimated Total Annual Cost ($M)
LDCs <20k Customers (37 in Total)	70,000	23% (310,270 total)	$5-10M

- Using this sample to project fiscal impacts has *moderate fiscal risk* as small LDCs have different penetrations of electric heat. Analysis may not accurately capture the impacts of high volume outlier customers. However given the scale compared to Hydro One and Toronto Hydro this risk has a moderate impact on the total fiscal projection

**Future year weather (hot summer, cold winter) presents a fiscal risk and could push estimates beyond the band.*

Delivery Charge Relief – Options for Setting a Cap

- When implementing the program, setting the cap by linking with a specific LDC's delivery costs may be viewed as arbitrary.
- It could also create difficulties over time as the chosen LDC's rates (e.g., Toronto Hydro) may change in unpredictable ways due to cost pressures unique to that LDC.
- A more robust effort to set a cap would be to link it to a specific rate level, relative to the spread of other rates in the province. Option include:
  - Setting the cap at the average of approved delivery charges for 1000kWh: **$53.46;**
  - Setting the cap at a level where 75% of all approved delivery charges fall below for 1000kWh: **$58.17;** and
  - Setting the cap at a level equal to the lowest service territory currently receiving RRRP support for 750kWh: **$66.29.**
- Various options and methods can be designed using simple or weighted rate averages and consumption thresholds.
- Selecting a level similar to Toronto Hydro's rates could satisfy the near-term policy intent while providing a reliable measure for adjusting the cap moving forward.
  - The OEB could be given authority to adjust the cap year-over-year based on the desired marker.

Agencies

OEB – LDC Efficiencies and Rates (Performance Incentives)

Option	Description	Potential Cost Impacts*	Timeline**	Notes
Performance Standards with Rewards & Penalties	Strengthen LDC scorecard by connecting to LDC financial performance through earnings sharing or penalties paid to consumers. Ex: SAIDI/SAIFI; OM&A per customer	• 1-2% of revenue requirement could be recycled back to customers. • Performance penalties would be real, periodic on-bill $ reductions. • Cost reduction would only occur if standards are not met.	1 year	UK Regulator Ofgem requires utilities to pay consumers up to £50 if reliability standards are not met.
Enhanced Economic Regulation	Revise rate-setting to reflect tightening productivity requirements and capital cost avoidance.	• <1% reduction in rates annually, with additional capital investment avoidance. • Methods include stronger productivity factors, broader peer comparisons, and elimination of ICM.	1-3 years	Incents innovation by requiring LDCs to provide equal or better service on less inflation-adjusted revenue annually.
LDC Collaboration Incentives	Create regulatory incentives for LDCs to pursue efficiencies and service sharing agreements.	• Potential to avoid individual LDC capital investments of up to six figures, plus additional OM&A tightening. • Actual level of rate reduction dependent on specific LDC proposals.	1 year for new guidelines, savings to be realized through LDC planning process.	LDCs have already indicated an interest in pursuing such arrangements but have expressed concern on regulatory barriers and costs.
Line Loss Accountability	Create appropriate benefit-sharing mechanism so LDCs are incented to pursue line loss reductions.	• Potential for 1-3% reduction in commodity charges associated with losses. • Requirements dependent on business cases so costs don't outweigh benefits.	1-2 years	Potential linkages with related proposal for in-front of the meter conservation.

***Note:** Dependent on implementation specifics as determined by OEB

****Note:** Timelines begin from Ministry approval of OEB LTEP Implementation Plan

LDC Distribution Rate Changes (2006 vs 2016)

KEY FINDINGS

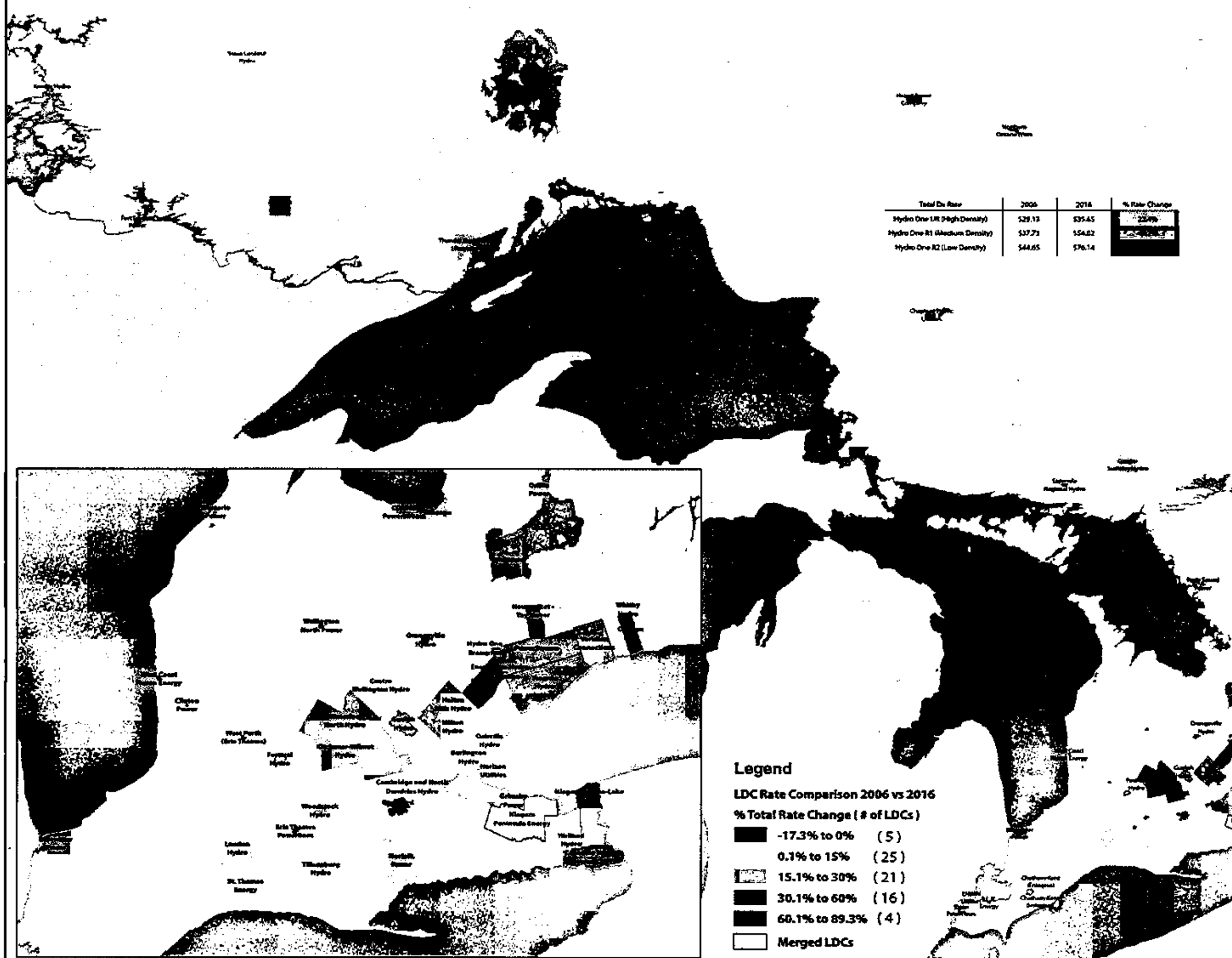
- In summary, distribution rates (including rate riders) have increased by about 24.5% across the Province, with significant variation between regions and LDCs (-17% to 148%).
- There is generally no correlation between LDC size or location and distribution rate increase in absolute or percentage terms.
- The current analysis shows no clear relationship between the percentage rate increase and the absolute rate level (that is, high rate increase LDCs may still have among the lowest rates, and low rate increases may have higher rates.
- No clear relationship between amalgamation and rates.
- The analysis does suggest that Hydro One has the highest rates, and some of their customers have seen higher than average rate increases.

NOTES

- **Rate Calculation:** Monthly residential distribution bill rates, before taxes, are based on consumption of 750 kWh. Distribution charges account for approximately 23% of the average 2016 residential bill. All figures calculated by ENERGY staff without input from OEB.
- **Colours:** Colour coding of the map only depicts the change in LDC rate amounts (i.e. LDCs in red don't necessarily have the highest total rates).
- **Mergers:** Rates for customers in merged LDCs have experienced different levels of change. For merged entities, the largest LDC in 2006 was used. An accompanying map focuses on merged entities.
- **Points in Time:** Current analysis compares 2016 and 2006 only. Rates could have had an uneven trajectory, especially considering regulatory decisions such as time limited charges/rebates with temporary impacts.

Only LDCs with distribution rates of 2006 and 2016 are shown. Only the largest distribution areas are shown and smaller satellite areas are not all shown.

Total Dx Rate	2006	2016	% Rate Change
Hydro One UR (High Density)	$29.13	$35.45	[illegible]
Hydro One R1 (Medium Density)	$37.73	$54.02	[illegible]
Hydro One R2 (Low Density)	$44.65	$76.14	[illegible]



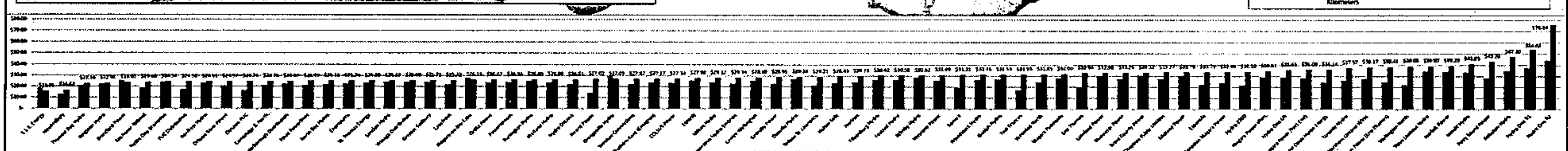
Below LDCs had either acquired or merged: (# of merged LDCs)

a. Powerstream Inc. (5)
b. Chatham-Kent Hydro Inc. (13)
c. Veridian Connections Inc. (4)
d. Guelph Hydro Electric Systems Inc. (2)
e. Festival Hydro Inc. (2)
f. Orangeville Hydro Limited (2)
g. Niagara Peninsula Energy Inc. (3)
h. Peterborough Distribution Incorporated (3)

Data source: Rate database, Rate orders and OEB yearbook
Produced by Strategic Policy and Analytics Branch,
Strategic Network and Agency Policy Division,
Ministry of Energy

0 30 60 120 180 240
Kilometers

Published December 2016



Other Options Considered

Other Options Considered – Typical Residential Electricity Consumer

$/750kWh	2017	2018	2019	2020	2021	2022	Timing of Benefit
Enhanced Tax-based RPP Rebate (5%)	7.04	7.17	7.31	7.77	7.61	7.83	Immediate
Contract Renegotiations							
a. Contract Extensions – Wind and Solar	TBD	TBD	TBD	TBD	TBD	TBD	TBD
b. Clean Energy Supply Contract	TBD	TBD	TBD	TBD	TBD	TBD	Immediate
Conservation Funding Options							
a. Amortize Conservation Program Costs (15-Year Amortization)	1.62	1.88	1.16	1.20	0.82	0.69	Immediate
b. Fund Conservation Programs Through The Tax-Base	3.47	3.83	3.17	3.35	2.84	2.90	Immediate
Eliminate the Industrial Conservation Initiative (ICI)	4.40	4.24	4.10	4.24	3.73	3.58	Immediate
Cancel LRP I	-	-	TBD	TBD	TBD	TBD	Medium-Term
Expand the Scope of Trillium Trust to Make Investments in Energy Infrastructure (e.g., Transmission upgrade, etc.)	-	-	-	2.16	2.16	2.17	Medium to Long-Term
Dedicate Departure Tax	1.39	1.39	1.39	1.39	1.39	1.39	Immediate
Give Residential Consumers More Rate Choices	-	-	-	-	-	-	n/a
Help Small Business Manage Their Electricity Costs (i.e., End DRC early for Class B electricity consumers)**	-	-	-	-	-	-	n/a

Note: The above initiatives will provide similar benefits for non-RPP Class B electricity consumers. Proposal 1 assumes OESP participation of 50% and 5-year maturity. *Assessing the range of ratepayer impacts will be done through the LTEP development and implementation process in conjunction with the OEB. **Class B includes small-medium enterprises (SMEs).

Other Options Considered – Average Industrial Electricity Consumers

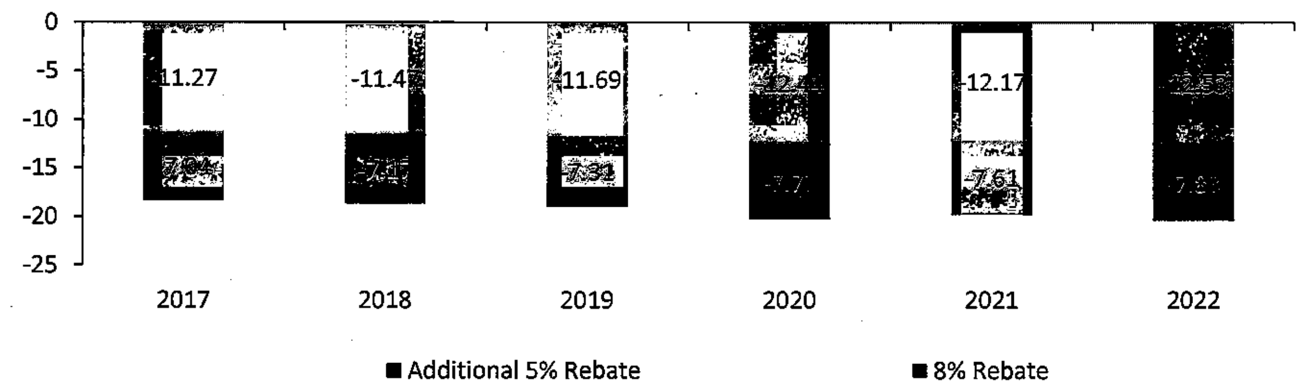
$/MWh	2017	2018	2019	2020	2021	2022	Timing of Benefit
Enhanced Tax-based RPP Rebate (5%)	-	-	-	-	-	-	N/A
Contract Renegotiations							
a. Contract Extensions – Wind and Solar	TBD	TBD	TBD	TBD	TBD	TBD	TBD
b. Clean Energy Supply Contract	TBD	TBD	TBD	TBD	TBD	TBD	Immediate
Conservation Funding Options							
a. Amortize Conservation Program Costs (15-Year Amortization)	1.12	1.30	0.80	0.83	0.57	0.47	Immediate
b. Fund Conservation Programs Through The Tax-Base	2.88	3.17	2.66	2.77	2.36	2.41	Immediate
Eliminate the Industrial Conservation Initiative (ICI)	(24.12)	(23.21)	(22.45)	(23.23)	(20.42)	(19.61)	Immediate
Cancel LRP I	-	-	TBD	TBD	TBD	TBD	Medium-Term
Expand the Scope of Trillium Trust to Make Investments in Energy Infrastructure (e.g., Transmission upgrade, etc.)	-	-	-	1.79	1.79	1.79	Medium to Long-Term
Dedicate Departure Tax	1.86	1.86	1.86	1.86	1.86	1.86	Immediate
Give Residential Consumers More Rate Choices	-	-	-	-	-	-	n/a
Help Small Business Manage Their Electricity Costs (i.e., End DRC early for Class B electricity consumers)**	-	-	-	-	-	-	n/a

Note: The above initiatives will provide similar benefits for non-RPP Class B electricity consumers. Proposal 1 assumes OESP participation of 50% and 5-year maturity. *Assessing the range of ratepayer impacts will be done through the LTEP development and implementation process in conjunction with the OEB. **Class B includes small-medium enterprises (SMEs).

Enhanced Tax-Base RPP Rebate (5%)

- Enhancing the rebate by a further 5% on the amount before tax provides an average savings of about $7 each month or $84 annually for a typical residential electricity consumer.
- As of January 1, 2017, electricity consumers eligible for the Regulated Price Plan (RPP) receive an 8% rebate equivalent to the provincial portion of HST on their pre-tax bill.
- The eligibility criteria for the 8% rebate is as follows:
  - Consumers with a demand of 50 kW or less;
  - Consumers with a demand of 250,000 kWh/year or less;
  - Farms;
  - Multi-unit residential buildings and other facilities used as residential rental units;
  - Dwellings;
  - Condominiums; and
  - Co-operatives with housing units.

Benefit for a Typical Residential RPP Consumer
in $/750-kWh month



Enhanced Tax-Base RPP Rebate (5%) (cont'd)

Considerations

- Amendments would be required related to the *Ontario Rebate for Electricity Consumers Act, 2016.*
- The Act authorizes the making of regulations to reimburse electricity vendors for amounts credited to consumers' accounts under the Act. The Act authorizes the making of other regulations to put in place mechanisms needed to implement the financial assistance.
- The rebate could be made retroactive to January 1, 2017. Similar to the current 8% rebate, electricity consumers would receive a retroactive payment once the local distributor begins issuing the rebates if the distributor needs more time to adjust its billing systems.

Fiscal Cost of an Enhanced Rebate
in $millions

Cost ($M)	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022
Cost of 8% Rebate	271	1,119	1,086	1,171	1,159	1,208
Cost of 13% Rebate	440	1,818	1,764	1,903	1,884	1,963
Cost of Incremental 5% Rebate	169	699	679	732	724	755

Extend Length of Existing Wind / Solar Contracts

- Wind and solar developments are typically contracted through standard offer procurements on 20 year fixed terms at fixed pricing.
- Many of these projects have already reached commercial operation.
- The province could explore options for IESO to negotiate extensions to existing renewable energy contracts, for example, by 10 years, in return for the contract holders agreeing to a lower price in the near term.
- Since extending the contracts would lock in an additional 10 years of GHG emissions free generation to support electrification of transportation and other sectors, consideration could be given to funding the contract extensions with future cap and trade proceeds.

Considerations

- Projects in commercial operation offer potential for near-term rate reduction whereas projects that have yet to reach commercial operation provide potential to mitigate future rate increases only.
- The attractiveness of this option to contract holders would vary from project to project and would depend on project economics.
- Revised pricing would be subject to negotiation, and associated ratepayer savings would be difficult to forecast accurately.
- The duration of contract renegotiation is difficult to forecast and would be challenging to achieve in the near term.
  - Proponents may have to renegotiate their project financing arrangements, ensure project investors are satisfied with any changes in ROI, and extend land leases.
- Project host communities and Indigenous communities whose traditional territory the projects are sited in may not be interested in these projects extending their operational period; discussions/consultation may be required in advance of this potential option moving forward.

Extend Length of Existing Wind / Solar Contracts (cont'd)

Considerations

- Should Ontario be successful in negotiating lower prices in the near term, it should be noted that contract holders will be in a strong bargaining position (given their existing fixed-priced contracts), and will likely extract additional value from the negotiations.
- The Province is not a party to the contracts and has never been involved in the negotiation of the contracts themselves. IESO would be required to renegotiate the contracts, which would likely involve a direction or directive to IESO.
- Further analysis is required as to how ENERGY could express its policy intent to have IESO renegotiate the contracts for a reduced rate at a longer term, however it is unlikely that IESO could guarantee the outcome.
- Further analysis is also required to ascertain whether there is scope within the existing contracts for IESO to renegotiate their terms in this manner.
- Extending contract terms may require investments in component replacement and additional operation and maintenance costs that developers would seek to recover under any renegotiated contract. Such assumptions are not reflected in Ministry cost estimates and their inclusion would further reduce potential cost savings.
- Extending contract terms would reduce planned flexibility and increase the risk of overpayment as this existing capacity would now be contracted into the 2040s and not the 2030s.

Extend Length of Existing Wind / Solar Contracts (cont'd)

Considerations

- Ontario has over 4,500 MW of wind in commercial operation, with the vast majority being large scale (>500kW) developments.
  - This includes over 2,700 MW of large FIT 1 and GEIA wind projects representing 47 contracts (average size ~58 MW) and over 1,000 MW of solar projects representing 103 contracts.
- Below are two potential approaches to reducing ratepayer costs in the near term by extending contract terms at reduced prices. An illustrative example of a typical large wind project is used.
- **Example:** 100 MW FIT 1 wind project achieving Commercial Operation in 2014 (i.e., 17 years remaining on initial 20 year contract), assuming a 10 year contract extension negotiated at the LRP I low weighted average wind price of $64.5/MWh
  - (17 years @ $135/MWh + 10 years @ $64.5/MWh)
- **Potential Approach 1:** Provide a single new contract price that is the average of the lower extension price and the FIT contract price over the new contract term. The new price would be lower over a longer term.
  - **Illustrative Example:** New contract for 27 years at $129/MWh.
  - New contract price set to allow 10% rate of return over 27 year contract per FIT pricing approach.
  - **Note:** Examples are illustrative. Actual prices and potential costs will vary depending on individual contract holders.

100 MW Wind Project	**Status Quo**	**27 Year Contract (remaining term extended for 10 additional years)**
Contract Cost (NPV 2017)	$550 Million	$582 Million
Average Monthly Ratepayer Impact Over First 5 Years	$0.03 savings	
Average Monthly Ratepayer Impact Over Remaining 22 Years	$0.02 increase	
Average Monthly Ratepayer Impact Over Entire 27 Year Contract	$0.01 increase	

Extend Length of Existing Wind / Solar Contracts (cont'd)

Considerations

- **Potential Approach 2:** Offer facilities a revised contract that extends terms and is structured to offer lower pricing in the initial contract years and higher pricing in the later years of the contract.
  - **Illustrative Example:** New contract for 27 years at $85.9/MWh over the first 5 years and $169/MWh over the remaining 22 years.
    - Price over first 5 years is LRP I weighted average wind price.
    - Price over remaining 22 years is set to allow 10% rate of return over entire 27 year contract per FIT pricing approach.
    - **Note:** Examples are illustrative. Actual prices and potential costs will vary depending on individual contract holders.

100 MW Wind Project	Status Quo	27 Year Contract	
		Initial 5 Years	Last 22 Years
Contract Cost (NPV 2017)	$550 Million	$632 Million	
Monthly Average Ratepayer Impact Over First 5 Years	$0.09 savings		
Monthly Average Ratepayer Impact Over Remaining 22 Years	$0.07 increase		
Monthly Average Ratepayer Impact Over Entire 27 Year Contract	$0.04 increase		

Extend Length of Existing Wind / Solar Contracts (cont'd)

- Below are illustrative estimates of potential savings if all contracts for large FIT and GEIA wind and solar projects in commercial operation are renegotiated according to the approaches illustrated above.
- Estimates are for large (10 MW or greater) FIT 1 and GEIA wind and solar projects in commercial operation, totalling about 2,700 MW of wind and about 900 MW of solar capacity. A 10 year contract extension is assumed at a price of:
  - **For Wind:** LRP I low weighted wind price of $64.5/MWh
  - **For Solar:** LRP I low weighted solar price of $141.5/MWh

Potential Approach 1:

[redacted]	**Current Contracts***	**New Extended Contracts**
Total Value (NPV 2017)	$23.3 Billion	$23.1 Billion
Average Annual Contract Value (First 5 Years)	$1.6 Billion	$1.4 Billion
*Figures assume projects remain operational after contract expiry at the LRP I low weighted price inflated to the year of contract expiry, as per OPO assumptions .		

Potential Approach 2:

	Current Contracts	**New Extended Contracts**
Total Value (NPV 2017)	$23.3 Billion	$25.6 Billion
Average Annual Contract Value (First 5 Years)	$ 1.6 Billion	$0.8 Billion

Source: Figures reflect IESO contract data current as of Sept 2016. Also includes two Phase III solar projects (100 MW combined) that came online in late 2016 not included in Sept 2016 IESO contract data.

Extend Length of Existing Wind / Solar Contracts (cont'd)

- Contract re-negotiations could be piloted with large wind and solar contract holders.
- For example, the top 5 contract holders by portfolio value (online projects 10 MW and larger) include:

Contract Holder	Technology	# of Contracts	Capacity (MW)	Estimated Value (NPV 2017)
Samsung*	Wind & Solar	7	899	$5.0 Billion
NextERA	Wind	6	534	$2.7 Billion
Northland Power	Wind & Solar	15	290	$1.8 ~~2~~ Billion
Pattern / Capital Power	Wind	1	270	$1.4 ~~5~~ Billion
ENGIE	Wind	4	265	$1.2 Billion
All Other	Wind & Solar	76	1398	$8.1 Billion
Total	**Wind & Solar**	**109**	**3654**	**$20.2 Billion**

Source: IESO contract data current as of Sept 2016.
*Includes two Phase III solar projects (100 MW combined) that came online in late 2016 not included in Sept 2016 IESO contract data.

Clean Energy Supply (CES) Contracts

- There are 13 natural gas facilities operating under Clean Energy Supply (CES) contracts. Given the current excess capacity, some of these facilities could be renegotiated to reduce output in the near term.

- In conjunction, OPG could seek to negotiate outright purchases of certain Ontario gas assets. Given the current excess capacity in electricity supply in Ontario, OPG can seek to negotiate outright purchases of certain Ontario gas assets and reposition them such that ratepayers would pay only for the "current need" component:
  - Contract terms would be renegotiated with the Province to temporarily idle the facilities;
  - Variable expenditures would be largely avoided with the facilities only incurring fixed costs; and
  - Plant life would be extended to a period post-2024 when additional power would be required.

- OPG has estimated monthly residential bill reductions of $2.37 to $4.00 from 2017 to 2019 if such an approach was taken for Ontario's gas portfolio.

- Natural targets would be assets that OPG either jointly owns (e.g., Portland, Brighton Beach) or operate on OPG's site with acquisition funding coming from Provincial borrowing.
  - Although OPG could also look beyond its facilities to the broader natural gas fleet in Ontario.

Considerations

- This proposal would reduce GHGs and provide some near-term cost benefits through lower staffing and maintenance costs:
  - Contract terms would be renegotiated with to temporarily idle the facilities;
  - Variable expenditures would be largely avoided with the facilities only incurring fixed costs; and
  - Plant life would be extended to a period post-2024 when additional power would be required.

- It will likely be challenging to find a willing seller and/or to negotiate a favourable price:
  - Sellers that are approached are in a strong position to extract value from OPG/the Province; and
  - Similarly, OPG's negotiating position would be weakened if this was viewed as part of the broader rate mitigation strategy.

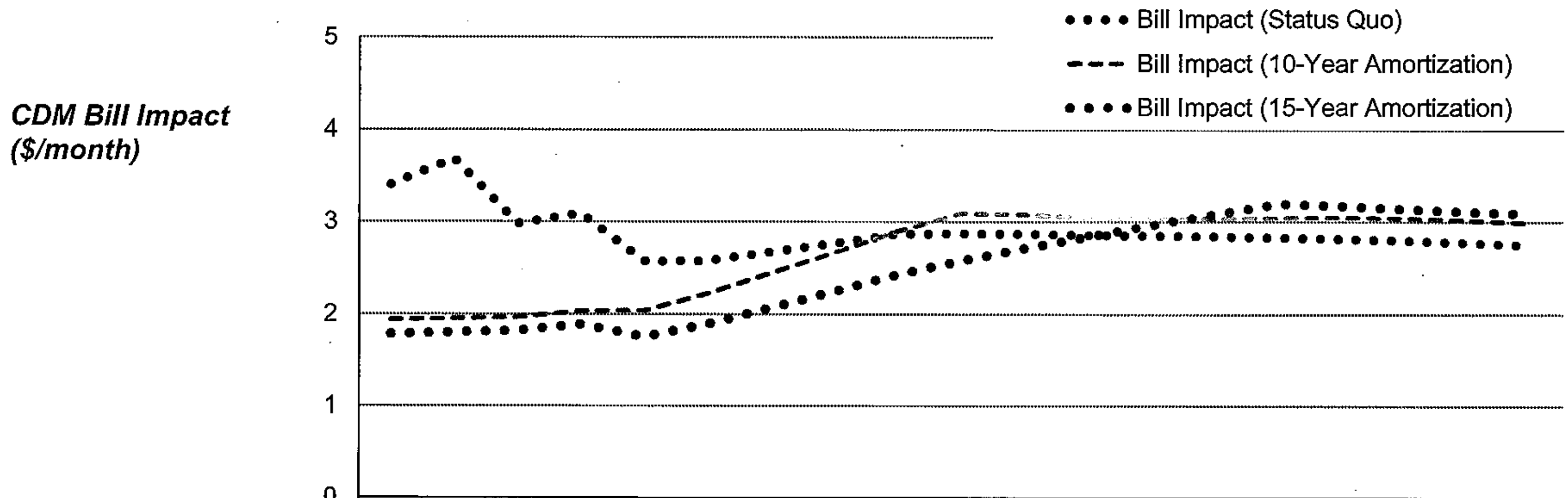
- In the past, OPG and IESO's contract renegotiations have been contentious and lengthy.

Amortize Conservation Program Costs

- This option would not be pursued if the Global Adjustment (GA) was financed (Option 1).
- ~$3 billion from the electricity ratepayer base will be spent on conservation programs delivered under the Conservation First Framework (CFF) and the Industrial Accelerator Program (IAP) between 2015 and 2020.
- Currently, Conservation and Demand Management (CDM) program costs are recovered from the Global Adjustment (GA) mechanism about one month after expenses are incurred.
- As a potential rate mitigation measure, certain CDM costs could be amortized. This would involve IESO borrowing funds from the Ontario Financing Authority (OFA) on an annual basis to fund program incentives (non-administrative costs).
  - The time period over which costs could be amortized would be over the lifetime of funded CDM measures.
  - ENERGY would work with IESO to determine the appropriate lifetime period – the graph on the next slide, which illustrates residential bill impacts, presents two cases: **10-year and 15-year measure lifetimes**.
- In both cases, amortizing a portion of conservation spending would produce a benefit for electricity ratepayers in excess of $1/month from 2017 to 2020. Over time the benefit would decrease and turn into a cost (higher electricity rates than would otherwise occur), as interest charges begin to grow. Estimated interest charges are as follows (a 3% interest rate is assumed; increases in interest rates could result in higher overall interest charges):
  - $712 million ($2016) – Amortizing eligible 2017-2035 CDM costs for 10-year period; and
  - $1.3 billion ($2016) – Amortizing eligible 2017-2035 CDM costs for 15-year period .
- Legislative changes would be needed to allow recovery of interest payments from ratepayers, or these costs could be recovered from the Consolidated Revenue Fund (CRF, or taxes).
- An alternative that could be explored would be to pay for CDM costs, or for a portion of these, from the tax-base.

Amortize Conservation Program Costs (cont'd)

Conservation Residential Bill Impact – Status Quo, 10-Year and 15-Year Amortization



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Bill Impact (Status Quo)	3.40	3.68	2.98	3.09	2.58	2.58	2.68	2.77	2.87	2.88	2.87	2.86	2.85	2.84	2.83	2.82	2.80	2.78	2.75
Bill Impact (10-Year Amortization)	1.94	1.95	1.97	2.03	2.04	2.22	2.45	2.67	2.90	3.09	3.08	3.05	3.03	3.04	3.04	3.05	3.04	3.02	2.99
Bill Impact (15-Year Amortization)	1.78	1.80	1.82	1.89	1.75	1.89	2.07	2.25	2.43	2.58	2.71	2.84	2.96	3.08	3.20	3.18	3.14	3.11	3.09

Source: IESO; Ministry of Energy

Note: Chart assumes that conservation incentive costs are available for amortization while administration cost are not. Although there is variable from year to year, incentives represent about two-thirds of conservation spending in Ontario. Chart assumes conservation spending continues at a similar rate beyond 2020. Chart assumes a 10 of 15-year borrowing rate of 3.0%.

Amortize Conservation Program Costs (cont'd)

Considerations

- Under **Public Sector Accounting Board (PSAB) accounting standards**, used by both the Province and IESO, only certain assets can be amortized: 1) pensions and 2) tangible capital assets. Under PSAB an asset must meet several criteria to be considered a capital asset, including:
  - A tangible capital asset must be tangible and substantive and the Ontario government must have title and operate the asset.
  - A tangible capital asset must bring a tangibie benefit to the government or to Ontario.

- **Rate-regulated accounting** was developed to recognize the unique nature of regulated entities (e.g., electricity generators, LDCs). Under rate-regulated accounting certain costs can be treated as amortizable assets that would not normally be considered assets under accounting principles.
  - Over the past several years, the Auditor General (AG) has expressed concerns about the appropriateness of recognizing rate-regulated assets in the Province's consolidated financial statements.
  - Rate-regulated accounting is currently under review by international accounting standard setting bodies and is currentiy permitted only on an interim basis, so its future is unclear at present.

Amortize Conservation Program Costs (cont'd)

[redacted]

Considerations

- If some of Ontario's CDM costs could be amortized, analysis shows that ratepayer impacts would be reduced in the short-term but interest charges on the loan would result in increased overall ratepayer costs in the longer-term.

- Legislative amendments would be needed to allow recovery of loan interest charges from GA.

- ENERGY has received an opinion on the proposal to amortize CDM costs from IESO's external auditor.
  - Ernst and Young indicated that an argument could be made to support the recognition of the costs as an asset as the costs meet essential asset characteristics, as prescribed by PSAB.

- ENERGY staff have developed a note to seek an opinion from the Ontario Provincial Controller (OPC) to determine whether CDM costs could be amortized according to rate-regulated accounting standards.

- If there is a desire to pursue this option, ENERGY would seek a formal opinion from the OPC on whether CDM costs could be amortized according to rate-regulated accounting standards, ENERGY would send its note along with IESO external auditor's opinion to OPC.
  - In 2013 when this option had been explored, staff at the OPC agreed with the view that amortized conservation costs can be considered as assets, but noted that the Auditor General may disagree with considering amortized conservation costs as assets.

- Further legal analysis would also be required to confirm legal viability and possible approaches to implementation.