Ontario

MINISTRY OF
ENERGY

Proposed Initiatives to Transform Ontario's Electricity Sector – Update

Working Draft

December 2016

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 cost 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), suspending the LRP II and the EFWSOP (up to $3.8 billion in cost savings) and recycling proceeds to industrial/ commercial consumers.

- 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.

Broad Policy Themes / Rationale

- Provide a greater focus on vulnerable consumers by funding electricity support programs, such as the Ontario Electricity Support Program (OESP) and the Rural or Remote Electricity Rate Protection, (RRRP) through the tax-base. In addition, provide greater support for lower income Ontarians by enhancing the OESP.

- Amortize electricity conservation and demand management (DM) programs over 15-years to provide lower costs for electricity consumers.
  - Alternatively, pay for conservation/DM programs through the tax-base and transition costs to the new "green bank entity" over time. Costs would be shifted in recognition of the burden borne by ratepayers in phasing out coal generation.

- Expand the scope of the "Trillium Trust" to make investments in energy infrastructure eligible for funding, such as remote electrification, large transmission projects, new or expanded interties and expansion of natural gas to rural areas, etc.

- Empower energy agencies to increase cost effectiveness and improve efficiency by having – IESO modernize Ontario's electricity market through electricity market renewal initiatives, the OEB identify opportunities for future LDC cost reductions/efficiencies and work with OPG to find further efficiencies in operations and pass on savings to ratepayers.

- Give consumers more choice by allowing households to "opt into" an alternative rate plan, based on a flat electricity rate, as an interim measure as the Ontario Energy Board (OEB) develops more pricing options over time.

- Help small business manage their electricity costs and provide relief for cap and trade until proceeds recycling is fully operational by ending the Debt Retirement Charge (DRC) early for commercial and small industrial Class B electricity consumers, a benefit of $7/MWh.

Proposed Initiatives – Potential Savings for Typical Residential Electricity Consumers

$/750kWh	2017	2018	2019	2020	2021	2022	Timing of Benefit
Recommended Initiatives							
1. Greater Focus on Vulnerable Electricity Consumers							
a. Fund Electricity Support Programs Through the Rate-Base (i.e., OESP, RRRP, First Nations rate)	2.16	2.31	2.41	2.49	2.54	2.58	Immediate
b. Enhance the OESP	-	-	-	-	-	-	n/a
2. 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
3. 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
4. Empower Energy Agencies to Increase Cost Effectiveness and Improve Efficiency							
a. IESO – Market Renewal	-	-	-	-	1.00	1.03	Long-Term
b. OEB – LDC Efficiencies/Rates*	TBD	TBD	TBD	TBD	TBD	TBD	Medium-Term
c. OPG – Operational Efficiencies	0.71	0.89	1.08	1.22	1.35	1.24	Immediate
5. Give Residential Consumers More Rate Choices	-	-	-	-	-	-	n/a
6. Help Small Business Manage Their Electricity Costs (i.e., End DRC early for Class B electricity consumers)**	-	-	-	-	-	-	n/a
7. Dedicate Departure Tax	1.39	1.39	1.39	1.39	1.39	1.39	Immediate
8. Extend Length of Existing Wind /Solar Contracts at Lower Prices	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Considered but not Recommended							
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

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).

Proposed Initiatives – Potential Savings for Average Industrial Electricity Consumers

$/MWh	2017	2018	2019	2020	2021	2022	Timing of Benefit
Recommended Initiatives							
1. Greater Focus on Vulnerable Electricity Consumers							
a. Fund Electricity Support Programs Through the Rate-Base (i.e., OESP, RRRP, First Nations rate)	2.88	3.08	3.21	3.33	3.39	3.44	Immediate
b. Enhance the OESP	-	-	-	-	-	-	n/a
2. 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
3. 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
4. Empower Energy Agencies to Increase Cost Effectiveness and Improve Efficiency							
a. IESO – Market Renewal	-	-	-	-	1.34	1.38	Long-Term
b. OEB – LDC Efficiencies / Rates*	TBD	TBD	TBD	TBD	TBD	TBD	Medium-Term
c. OPG – Operational Efficiencies	0.59	0.74	0.89	1.01	1.12	1.03	Immediate
5. Give Residential Consumers More Rate Choices	-	-	-	-	-	-	n/a
6. Help Small Business Manage Their Electricity Costs (i.e., End DRC early for Class B electricity consumers)**	-	-	-	-	-	-	n/a
7. Dedicate Departure Tax	1.86	1.86	1.86	1.86	1.86	1.86	Immediate
8. Extend Length of Existing Wind /Solar Contracts at Lower Prices	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Considered but not Recommended							
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

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).

Proposed Taxpayer Funded Electricity Price Mitigation

$M	2016-17[1]	2017-18[1]	2018-19[1]	2019-20[1]	2020-21[1]
Recommended Initiatives					
1. Greater Focus on Vulnerable Electricity Consumers					
a. Fund Electricity Support Programs Through the Rate-Base (i.e., OESP, RRRP, First Nations rate)		418	444	461	475
b. Enhance the OESP		471	507	529	546
2. Conservation Funding Options					
a. Amortize Conservation Program Costs (15-Year Amortization)	-	-	-	-	-
b. Fund Conservation Programs Through The Tax-Base	154	632	649	567	568
3. Expand the Scope of Trillium Trust to Make Investments in Energy Infrastructure (e.g., Transmission upgrade, etc.)	100	390	390	390	390
4. Empower Energy Agencies to Increase Cost Effectiveness and Improve Efficiency					
a. IESO – Market Renewal	-	-	-	-	-
b. OEB – LDC Efficiencies / Rates	-	-	-	-	-
c. OPG – Operational Efficiencies	-	-	-	-	-
5. Give Residential Consumers More Rate Choices	-	-	-	-	-
6. Help Small Business Manage Their Electricity Costs (i.e., End DRC early for Class B electricity consumers)**	110	450	-	-	-
7. Dedicate Departure Tax	260	260	260	260	260
8. Extend the Length of Existing Wind/Solar Contracts at Lower Prices	TBD	TBD	TBD	TBD	TBD
Considered but not Recommended					
Eliminate the Industrial Conservation Initiative (ICI)	-	-	-	-	-
Cancel LRP I	-	-	-	-	-

Source: Ministry of Finance, Energy

1a. Greater Focus on Vulnerable Electricity Consumers – Fund Electricity Support Programs Through the Tax-Base

- Provide a greater focus on vulnerable consumers by funding electricity support programs such as the Ontario Electricity Support Program (OESP) and the Rural or Remote Electricity Rate Protection (RRRP) through the tax-base instead of the regulatory charge line on consumers' electricity bills. **Note:** This could also apply to the proposed First Nation rate being explored by the OEB.

Considerations

Consumer Impacts and implementation

- By 2020, funding the OESP, RRRP and the First Nation rate reduction through a regulatory charge is estimated to cost approximately $2.50/month for a typical residential customer using 750 kWh per month. Transitioning that funding to the tax-base would reduce a typical residential customer bill by that same amount. As all programs provide strong social benefits, there is precedent for funding these programs through the tax-base. To address concerns from low income electricity consumers improvements to OESP could be implemented by increasing credits (could be up to double the current credits).

- To address concerns from low income electricity consumers improvements to OESP could be implemented by increasing credits (could be increased by 50% of the current credits)
  - Single low income consumer would see a change from $30 to $45/ month ($540/year):
  - Family of four with electric heat could see a change from $55 to $82.50/month ($990/year); and
  - Support for low income consumers that do not receive an electricity bill could also be explored, possibly through existing programs (e.g., Ontario Works or Ontario Disability and Support Program).

- RRRP and OESP are included in the "Regulatory" line on bills. If RRRP and OESP were eliminated from bills, the Regulatory line would decrease; however, as the Regulatory line is the smallest line item component of invoices, there is risk the decrease may not be perceived by customers.

- The non-rate mechanism to remove delivery charges from on-reserve First Nation customer monthly bills needs to be further explored.Funding RRRP and/or OESP with tax revenue would require amendments to existing legislation and regulations. Further legal analysis is required.

1b. Greater Focus on Vulnerable Electricity Consumers – OESP Enhancement

- As of December 9, 2017, just over 261,000 OESP applications that have been submitted to the OEB. A number of options could be explored to enhance the OESP to ensure that it reaches more people and / or provides greater benefits.

Considerations

Increase Uptake / Benefit Amounts of the Existing Program

- The OEB could work to Increase participation rates by:
  - Pursuing a more aggressive communication strategy;
  - 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).
- The OEB could also explore enhancing program benefits (see next slide for detail on a 50% increase).

Transfer the OESP to the Province

- The OESP was designed to ensure that it did not have a fiscal impact. If the OESP is to be funded by the tax-base, if could potentially become a program directly delivered by the province.
- Provincial delivery of the program may provide greater flexibility regarding the program enrollment process and timelines.
- The province would have to work closely with LDCs if the rebate was to appear on electricity bills rather than be delivered via the income tax system.

1. Greater Focus on Vulnerable Electricity Consumers – Fiscal Impacts

- Table below shows estimates of program costs up to 2020:

Year	OESP	OESP + 50%	RRRP	First Nations Delivery Rate	TOTAL	TOTAL OESP + 50%
2017	$101M	$151	$292M	$18M	**$411**	**$461**
2018	$122M	$183	$300M	$18M	**$440**	**$501**
2019	$133M	$200	$306M	$18M	**$457**	**$524**
2020	$140M	$211	$315M	$18M	**$473**	**$544**
2021	$140M	$211	$322M	$18M	**$480**	**$551**
2022	$140M	$211	$329M	$18M	**$487**	**$558**

1) Ontario Electricity Support Program (OESP)
   - After almost a year in market, close to 30% of potentially eligible customers are signed up.
   - The cost projections above assume the program grows to 50% of eligible consumers by 2020 and remains steady at this participation level in 2021 and 2022, with no increase in credit amounts. The second column has credits increase 50%.
     - Forecast assumes 10% administration costs

2) Rural and Remote Rate Protection (RRRP)
   - Provides benefits to R2 Hydro One consumers, Algoma, and remote communities.
   - Includes the expanded coverage that will begin on January 1, 2017.

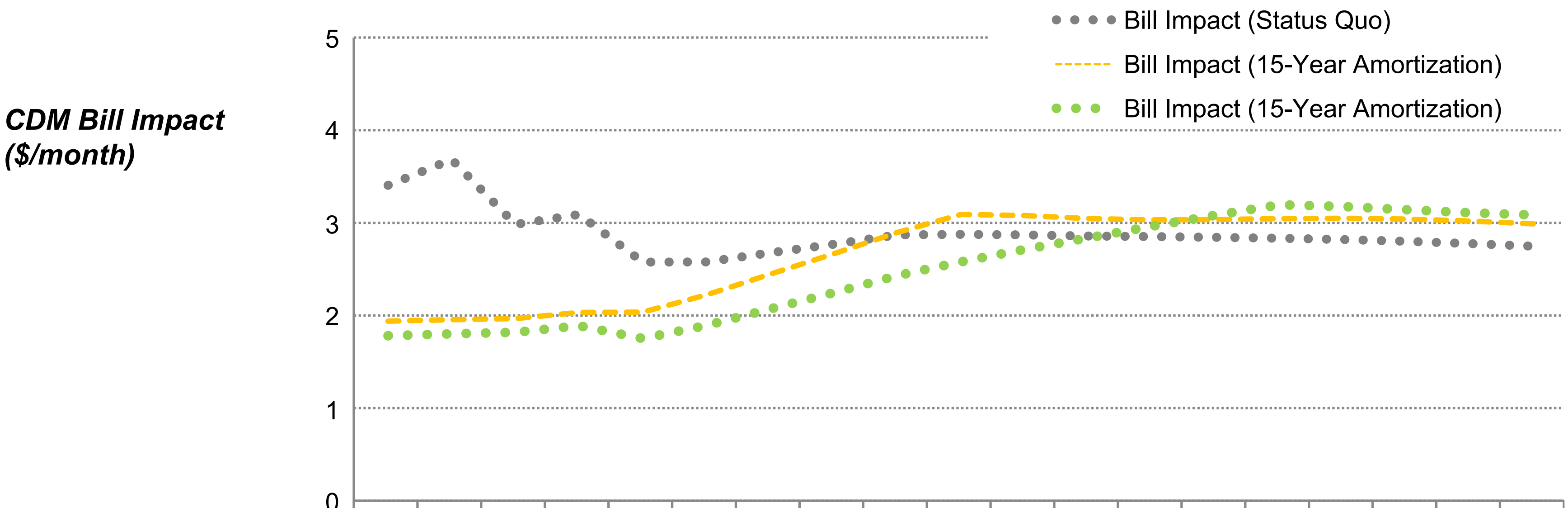
3) First Nation rate reduction (currently under development)
   - On November 14, 2016, OEB presented options to the Ministry on reducing costs for on-reserve First Nation customers.
   - OEB's recommended option to provide 100% delivery rate credit, which is estimated at $18.4 million per year.
     - Other options includes a seasonal fixed credit to account for demand changes over the year ($13 million) or a 50% total bill reduction ($23 million).

2a. Amortize Conservation Program Costs

- ~$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.
  - The time period over which costs could be amortized would be over the lifetime of funded CDM measures.
  - ENERGY is working 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, as interest charges begin to grow (a 3% interest rate is assumed; increases in interest rates could result in higher overall interest charges). Estimated interest charges are as follows:
  - $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).
- An alternative that could be explored would be to pay for CDM costs, or for a portion of these, from taxes.

2a. 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 (15-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%.

2a. 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 tangible benefit to the government or to Ontario.

- CDM costs, on their own, do not meet the criteria of a tangible capital asset because customers would have ownership and control of installed CDM measures, not the Province or IESO.

- **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 currently permitted only on an interim basis, so its future is unclear at present.

2a. Amortize Conservation Program Costs (cont'd)

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 staff have developed a note to seek an opinion from IESO's external auditor and from the Ontario Provincial Controller (OPC) to determine whether CDM costs could be amortized according to rate-regulated accounting standards.
- ENERGY to seek opinion on the proposal from IESO's external auditor.
- ENERGY will then send the IESO external auditor's opinion along with ENERGY's explanatory note to the Ontario Provincial Controller (OPC) to seek a formal opinion on whether CDM costs could be amortized according to rate-regulated accounting standards.
- Further legal analysis would also be required to confirm legal viability and possible approaches to implementation.

2a. Amortize Conservation Program Costs (cont'd)

Considerations (Rate Smoothing)

- A "rate smoothing" approach could be considered as a way to amortize IESO's annual conservation costs. In effect, a regulatory amendment could allow IESO to defer its recovery through the Global Adjustment (GA) of a portion of annual conservation costs and establish a "deferral account" with interest to reflect additional IESO financing. The deferral account would then be recovered over a longer time period (e.g., 10 or 15-years), thereby amortizing the recovery of conservation costs to better match the long-term benefits of conservation to the electricity system.

- In 2015, the Ministry amended a regulation that requires the Ontario Energy Board (OEB) to set "smoothed" nuclear rates for OPG's Darlington and Pickering nuclear stations over a 20-year period.
  - The regulation allows OPG to defer recovery in rates of a portion of its nuclear revenue during the Darlington refurbishment (expected to be complete in 2026) and recover these deferred costs over the remaining ten years (i.e., to 2036). The effect is a less volatile path of nuclear rate increases and decreases for Ontario ratepayers over the 20-year period.
  - OPG will establish a "deferral account" to record the deferred amounts each year up to 2026 plus accumulated interest on the balance to reflect OPG's financing costs as a result of rate smoothing. The deferral account is then drawn down on a straight-line basis between 2026 and 2036.

- **Note**: Further discussion is needed to determine the relevant regulation or legislation, to be amended for IESO (e.g., OEB regulation of IESO costs and fees, GA regulation for how IESO recovers its conservation costs from ratepayers).

2b. Conservation Funding – Fund Conservation Programs Through the Tax-Base

- Propose to fund 2017-2020 electricity conservation and demand management program costs* using tax dollars instead of ratepayer dollars.
  - Funds received through the Hydro One Departure Tax could potentially be repurposed towards this.
- Total remaining 2017-2020 electricity conservation program costs are expected to be ~$2.1 billion.

<u>Considerations</u>

- Electricity conservation programs provide a number of benefits to society, however, Ontario's ratepayers have been covering these costs:
  - Avoiding/deferring future energy infrastructure investments, reducing disruption in communities (e.g., avoiding the need to build new natural gas generation);
  - Environmental benefits (e.g., reduced natural gas peaking generation and GHG emissions); and
  - Social and economic benefits (e.g., job creation and assistance managing electricity bills).
- There is precedence for using tax dollars to fund conservation programs.
  - Between 2007 and 2011, Ontario funded the Home Energy Savings retrofit program using tax dollars.
- Funding conservation programs though the tax-base is expected to result in a benefit of $3.40/month for residential electricity consumers in 2017. This could provide immediate short term relief to consumers while other rate mitigation initiatives are developed (e.g., market renewal, LDC efficiencies).

* **Note:** This includes costs towards the Conservation First Framework, Industrial Accelerator Program, Demand Response and the Conservation Fund)

3. Expand the Scope of Trillium Trust to Make Investments in Energy Infrastructure

- Fund investments in specific transmission projects through the tax-base. **Note:** This could include the provincial portion of funding for the Remote First Nation Connection Project and a fund to support projects that improve adequacy and reliability in areas where new transmission would unlock economic growth.

Considerations

- Tax-base funding would allow for transmission infrastructure to be built without impacting electricity rates.

Remote Connection Project

- Ontario ratepayers currently support costs of remote electricity service through RRRP on the order of $28 million/year
- Connecting 21 remote communities to the Ontario grid is supported by a positive business case due to diesel cost savings over time. If RRRP is funded through the tax base as proposed above, this project represents an opportunity to reduce impacts from RRRP.
- Direct investment in Ontario's portion of the capital costs of the project through a provincial fund (e.g., Trillium Trust) could also be considered along with mechanisms for cost recovery through transmission rates to refresh the fund as industry benefits from the transmission investment.
- The amount of investment and long-term savings depend on a federal contribution to the project and ENERGY is currently in discussions with Canada with the goal of concluding a cost-sharing agreement by spring 2017.
- A move to tax-based funding may have implications for cost oversight, since the OEB's mandate is to have oversight of ratepayer impacts. Alternative methods to review cost prudence of tax-based funding may be needed.

Transmission Projects to Enhance Economic Growth

- A tax-based fund could target investments in projects that have been identified in IESO regional plans and that would stimulate economic growth but are not proceeding due to cost barriers under the OEB's beneficiary pays principle. Investments could also target areas where the existing system poses challenges for delivering reliable service such as in parts of Northern Ontario with long single circuits.
- Potential opportunities for investment could include a transmission reinforcement in the **Greenstone area**, upgrades south of **Red Lake** and others TBD based on program design.
- This approach would allow a potion of project costs to be socialized to advance key projects without impacting rates or OEB's principles of cost allocation. Scope and scale of fund would be refined through program design.

4a. Empower Energy Agencies – IESO / Market Renewal

- Continue to move forward with IESO's 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.

- 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.

4b. Empower Energy Agencies – OEB / LDC Efficiencies and Rates

- Reducing costs and having LDCs become more efficient could result in a reduction of Distribution costs on a consumer's electricity bills.
  - Currently, LDCs recover their costs through the Delivery line of the electricity bill. The Delivery line on the bill is broken into Distribution and Transmission costs. LDCs are responsible for the Distribution costs of the electricity bill which account which account for about 20% of the total bill.
  - Distribution costs vary across the province as LDCs have different service territories and needs (e.g, geography, number of customers, density of customers, life/health of capital assets, etc). See next slide
    - For example, comparing 2016 with 2006, distribution rates have increased by about 24.5% (or about 2.2% per year, compounded annually) across the Province, with significant variation between regions and LDCs (-17% to 148%). Overall consumer price inflation in Ontario for the same period increased by about 19% or 1.8% per year.

<u>Considerations</u>

- 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.
- Since 2012, the OEB has taken action – through the Renewed Regulatory Framework for Energy – to more closely link rate regulation with performance measures and outcomes.
- There maybe opportunities to promote further cost reductions and performance improvements within the distribution sector as there is continued evolution of the regulatory framework in Ontario.
  - Tightening LDC requirements may also indirectly incent other desired policy outcomes, such as LDC consolidation and grid modernization to realize further cost reductions.
  - To further help address the costs associated with the Delivery line of the electricity bill, program such as the RRRP (previous slide) could be expanded to include other customers that may face higher costs.
- ENERGY could help promote or accelerate these efforts by asking the OEB through the LTEP Implementation Directive, s. 35 of the *Ontario Energy Board Act, 1998*, and the 2017 Mandate Letter and other agency business planning processes.
- In addition, further changes to the departure and transfer tax regimes could be considered to provide a further incentive for LDC mergers and acquisitions.

4b. Empower Energy Agencies – OEB / LDC Efficiencies and Rates (cont'd)

Considerations

- Distribution rates vary across the province as a result of different LDC service area needs.
- However, if a simple average was taken for the monthly distribution cost before tax, across all rate zones, it would average to $30.86 per month, for a residential customer consuming 750 kWh per month.*
  - This is based on preliminary estimates and the amount will fluctuate on monthly consumption from customers; and
  - LDCs have different customer base with different consumption types.
- If there was a desire to bring all customers' delivery rates down to this average through the use of taxpayer funding, preliminary analysis suggests that:
  - If it is assumed that all consumers use 750 kWh per month, it would cost approximately $385 million per year.
    - ~$315 million of this cost is for Hydro One. Hydro One R1 and R2 customers typically consume more than 750kWh/month.
  - The cost increases to ~$445 million per year if assumed that H1 R2 consume 1200 kWh and H1 R1 customers consume 1,000 kWh.
  - The program cost would vary from year-to-year, and LDCs would move in and out of the program as they change relative to the average distribution costs.

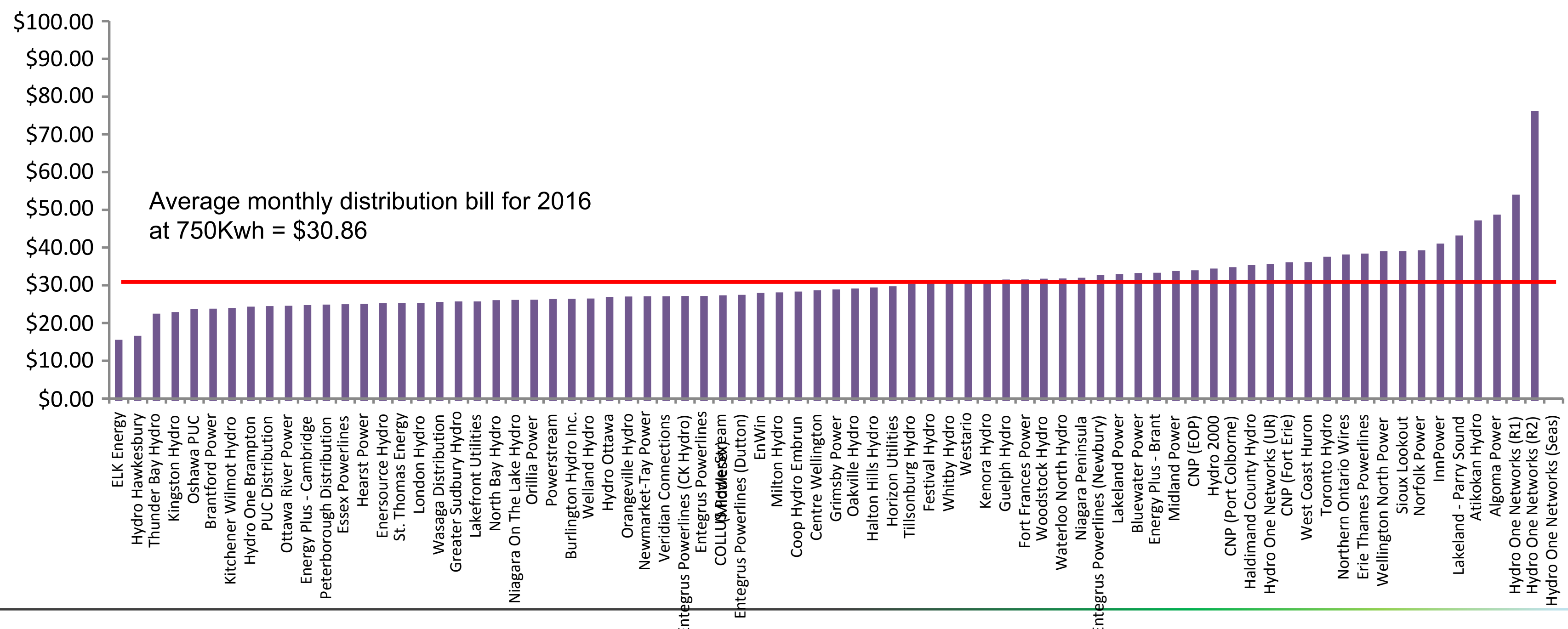
*** Note:** Excludes Seasonal, Remotes, James Bay LDCs, and LDCs not rate regulated by OEB (Cornwall, Cat Lake, Dubreilville). Based on 2016 rates, including 2016 RRRP subsidy. Certain LDCs (Chapleau, Espanola, Renfrew, Rideau St. Lawrence, are using 2015 rates as interim).

4b. Empower Energy Agencies – OEB / LDC Efficiencies and Rates (cont'd)

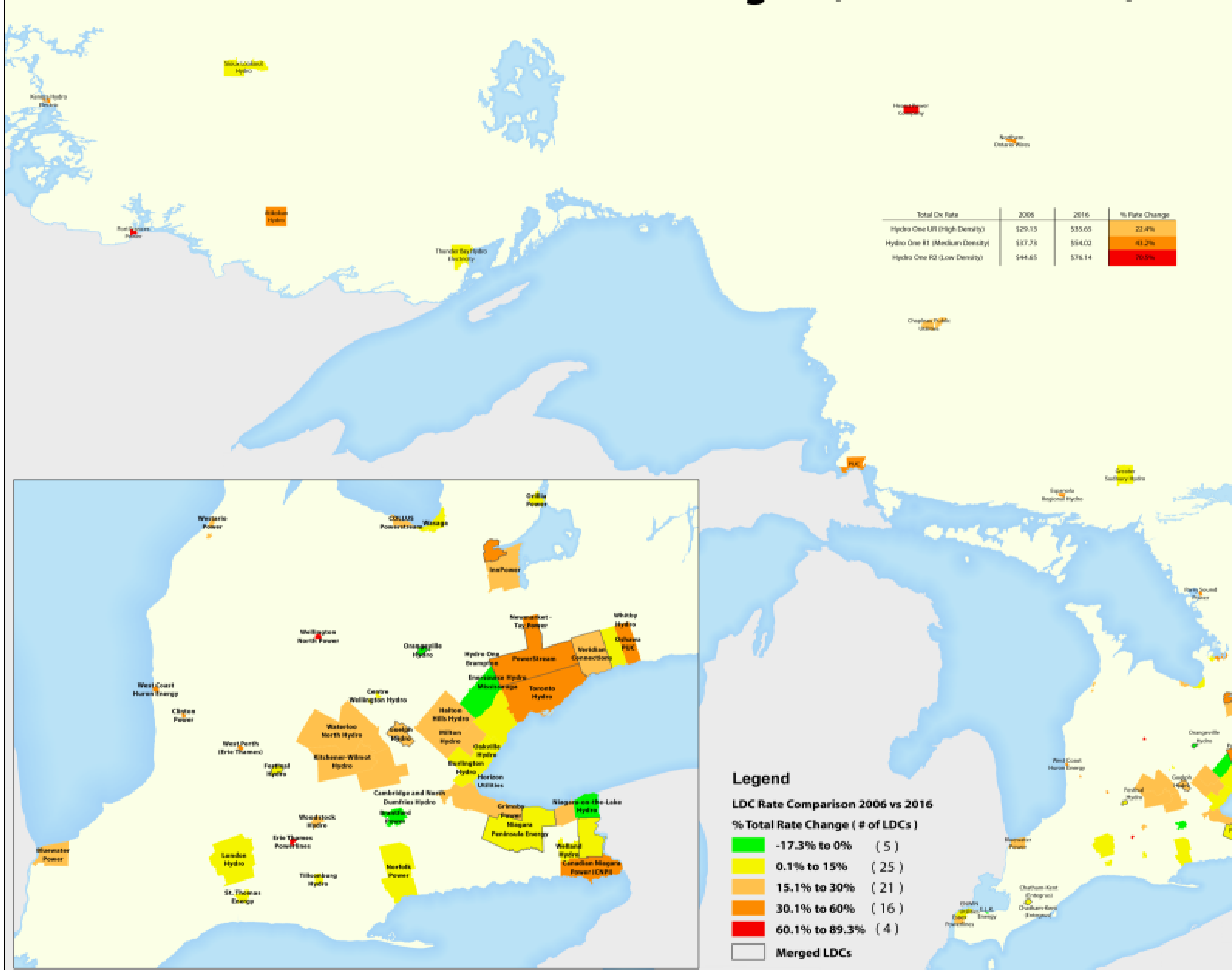
- As shown in the chart below:
  - Majority of the funding would go Hydro One and Toronto Hydro customers;
  - LDCs below the provincial average may argue that their customers are not being helped by this initiative; and
  - Mechanism to ensure that LDCs continue to be motivated to achieve efficiencies would need to be designed.

- All figures are illustrative as assumptions about consumption may not reflect actual consumption levels. In addition, rates are influence by temporary rate rider and other unforeseen impacts.

2016 Monthly Residential Distribution Bill, @ 750 kWh, Before Tax



LDC Distribution Rate Changes (2006 vs 2016)



Total Dx Rate	2006	2016	% Rate Change
Hydro One UR (High Density)	$29.15	$35.65	22.4%
Hydro One R1 (Medium Density)	$37.75	$54.02	43.2%
Hydro One R2 (Low Density)	$44.65	$76.14	70.5%

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

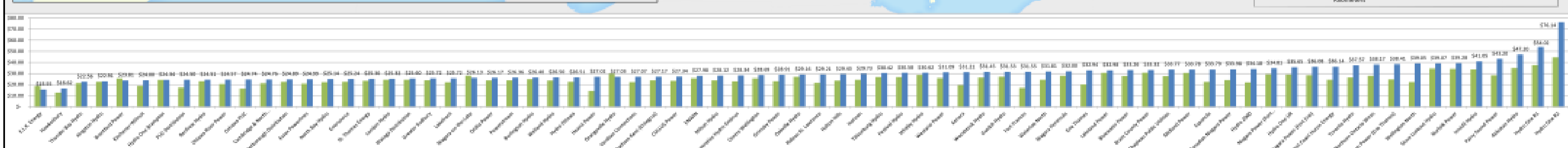
- **Rate Calculation:** Monthly residential distribution bill rates, before taxes, are based on consumption of 750 kWh. Distribution charges account for approximately 23% of the average 2016 residential bill. All figures calculated by ENERGY staff without input from OEB.
- **Colours:** Colour coding 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.

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

Published December 2016



4c. Empower Energy Agencies – 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. Give Consumers More Rate Choices

- OEB continues to move forward with its Regulated Price Plan (RPP) Roadmap:
  - The OEB is undertaking a comprehensive review of the RPP, including exploring the introduction of offering different pricing plan options for customers following the completion of pilot programs in 2018. The plan is expected to be implemented over a 3-5 year period.
- Until new pricing plans are available, the OEB could provide an “opt-in flat rate RPP” structure that could be made available to residential, farm and small business consumers on an interim basis (2-3 years) until a wider range of price plans are available, providing customers with pricing choice.
- Time-of-Use (TOU) pricing could also be introduced for non-RPP Class B consumers to reduce Global Adjustment (GA) volatility and reduce system costs.

Current TOU	New Flat Rate
On: 18.0 ¢/kWh	11.1 ¢/kWh
Mid: 13.2 ¢/kWh	
Off: 8.7 ¢/kWh	

Considerations

- Would provide consumers with electricity pricing choice.
- The OEB has indicated that the option would lead to no overall change in system costs. Consumers with higher peak and mid-peak usage patterns would see a decrease in their electricity bills, while those with higher off-peak usage patterns would see an increase.
  - While the current strong supply conditions may allow for such an RPP structure (i.e., peak demand requirements can be easily met), administrative costs could be high (distributors would need to design/implement an opt-in process and associated billing system on an interim basis).

	Current TOU	New Flat Rate
1) Monthly electricity bill- higher peak and mid-peak usage patterns	$172	$163
2) Monthly electricity bill- higher off-peak usage patterns	$152	$163

***Note:** 1) assumes a consumer consumption pattern of 45%:30%:25% (Off -peak: Mid-peak: On-peak), while 2) assumes consumer consumption pattern of 80%:10%:10% (Off-peak: Mid-peak: On-peak). Estimates are based on OEB’s online electricity bill calculator (for Toronto Hydro- November 2016 rates)

5. Give Consumers More Rate Choices (cont'd)

Considerations

- The decision to undertake smart meter investments was partly justified on the basis of TOU pricing. If TOU pricing were to be made optional, some stakeholders could question the rationale for smart meter investments.
  - Rationale for offering a flat rate option could focus on providing customers with choice until new pricing plans are rolled out under the RPP roadmap.
- If a flat rate design is introduced, there could be significant consumer opposition to any return to a mandatory TOU.
- After the interim flat rate period, the OEB could offer a wider range of pricing plans to consumers.
  - As part of its RPP review, the OEB will be running pilots with LDCs to assess customer response to alternative time periods and pricing structures.
  - Learnings from these pilots will help inform potential changes to the RPP. Pilots are expected to be in market May 2017 and run for one year.
- Non-RPP Class B electricity consumers currently pay Global Adjustment (GA) on a volumetric basis. Moving them to TOU would provide an incentive to shift consumption to off-peak periods.
  - Consumers, including manufacturers, who are unwilling to shift would face higher costs and likely not be supportive of the changes.
  - The decision to pursue TOU pricing for non-RPP class B consumers will impact proceeds recycling as there is interplay between the two initiatives.

6. End DRC Early for Commercial/Small Industrial Class B Electricity Consumers

- Propose to remove the $0.07/kWh Debt Retirement Charge (DRC) from the bills of commercial/small industrial Class B consumers beginning in 2017, instead of April 1, 2018.
  - **Note:** Class A consumers (e.g., large industrial) would continue to pay DRC until at least April 1, 2018.

Considerations

- For a Class B consumer currently paying about $152/MWh, removing the DRC would represent a savings of about 5%.
  - A 50% reduction in the DRC charge would represent a savings of about 2%.
- Alternatively, the reduction of the DRC could be to $0.035/kWh starting in 2017, to provide relief for cap and trade until proceeds recycling is fully operational.
- Residential consumers have had the DRC removed from bills since January 1, 2016. Taking DRC off commercial and small industrial bills would result in equal treatment for these groups of consumers.
- The savings for commercial and small industrial consumers associated with this proposal would drop to zero in April 2018, since this is the current planned date for removing the DRC from non-residential bills.
- Prior to moving forward with this proposal, additional analysis from Legal Services and the MOF would be needed.

7. Dedicate Departure Tax

- In connection with the IPO, as a result of leaving the PILs regime and entering the corporate tax regime, Hydro One was deemed to dispose of its assets for proceeds equal to its fair market value, triggering a PILs liability of $2.6 billion (Departure Tax).
- This was paid to the Ontario Electricity Financial Corporation (OEFC), to be dedicated towards repayment of electricity sector stranded debt.
- The Province could explore repurposing some of those funds to the benefit of ratepayers.
- This may reduce the risk that the Ontario Energy Board (OEB) assigns to ratepayers the benefit from an associated tax asset, resulting in lower earnings and decreased share value for Hydro One. This decision is currently before the OEB, as part of Hydro One's Transmission rate application.
- If the Province were to transfer $2.6 billion in economic benefits to the rate base over 10 years suggest the following impacts (assuming 140TWh per year):
  - Residential Ratepayer Impact (if spread over 10 years): up to $1.39 per month on a typicalbill; and
  - Industrial Ratepayer Impact (if spread over 10 years): up to $1.86 / MWh

Considerations

- Cost savings to ratepayers and associated fiscal impacts would depend on timing and which ratepayers (e.g., Hydro One customers, or all Ontario customers) will benefit from some or all of the $2.6 billion value.
- The departure tax was effectively a true-up for lower PILs payments from Hydro One in previous years – it was not a one-time windfall for the Province. In other words, it ensures that Hydro One paid all its tax obligations under the PILs regime before moving into the normal corporate tax regime.
- The related ~$2.4 billion fiscal benefit to the Province (from the deferred tax benefit) has already been credited to the Trillium Trust to be used to build infrastructure under Moving Ontario Forward.
- Repurposing funds paid to OEFC may have an impact on the defeasance of electricity stranded debt.
- While this is a shift from messaging that value from the broadening of ownership of Hydro One is being used pay down debt and fund transit and transportation, the Province could link to electricity infrastructure investments (e.g., as an offset to infrastructure investments already made in the sector, or to specific initiatives such as conservation).

8. 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 extend existing renewable energy contracts, for example, by 10 years, and renegotiating a lower price in the near term.

<u>Considerations</u>

- Projects in commercial operation offer potential for rate reduction whereas projects that have yet to reach commercial operation provide potential to mitigate future rate increases only.
- The attractiveness of this option would vary from project to project.
- Revised pricing would be subject to contract renegotiation, as such benefit would be difficult to forecast accurately.
- [placeholder] Extending contract terms for x MW of FIT 1 contracts could result in deferred costs of $X M (or reduced annual $ ratepayer costs)
- Since the Minister of Energy is not a party, 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 the IESO could guarantee the outcome.
- Further analysis is required of whether there is scope within the existing contracts for IESO to renegotiate their terms in this manner.
- Extending contract terms would reduce planned flexibility and associated costs in the medium term.

Key Outcomes / Next Steps

- The proposed initiatives provide the following opportunities to:
  - Re-set how electricity programs and energy infrastructure are funded by shifting costs to the tax-base from the rate-base) to:
    - Enhance existing and new programs that provide support to the most vulnerable consumers(i.e., OESP and RRRP)
    - Fund new infrastructure targeted at ensure system reliability and capacity are more equitable across the province have similar levels of reliability; and
    - Better harmonize delivery rates across the province.
  - Lower the cost of electricity for all consumers;
  - Provide electricity consumers with greater choices (i.e., alternative rate plan based on a flat electricity rate);
  - Provide system benefits (e.g., market renewal); and
  - Increase cost effectiveness and improve efficiency.

- The timing of the impact of these rate mitigation initiatives varies.
  - Immediate and near-term impacts can be achieved by shifting costs to the tax-base or changing how certain costs are recovered from consumers or eliminating certain programs.
  - Over the longer term, changes to the electricity supply mix and achieving efficiencies in the electricity market could yield system savings.

- Pursuing the initiatives would require legislative and/or regulatory amendments and working with the electricity sector agencies, LDCs and other stakeholders to implement the initiatives.