Ontario

MINISTRY OF
ENERGY

Enhancing Ontario’s Net Metering Program:

Policy Options & Analysis for Implementing Third-Party Ownership and Virtual Net Metering

Draft

04-20-2017

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1. Purpose and Context

Purpose:

- To present options and analysis for potential third-party ownership and virtual net metering policies under Ontario's Net Metering program.

Context:

- The 2013 LTEP committed to investigating the potential for the microFIT program to transition to a net metering program.
- As FIT and microFIT wind down in 2017, and in the context of evolving electricity distributor business models, climate change policies and decreasing cost of renewables, it is expected that net metering will present new opportunities to electricity consumers and the renewable energy sector.
- In December 2016, the Ministry of Energy initiated stakeholder engagement and analysis to inform considerations for potentially expanding Ontario's net metering program to include third-party ownership and virtual net metering.
- Ontario's electricity supply and demand outlook is a significant consideration for any updates to the Net Metering program, particularly for understanding the risks associated with uptake of new distributed renewable generation on the system.

2. Part 1 Net Metering Program Updates

2. Updating Ontario's Net Metering Program

- Between August 2015 and October 2015, the Ministry of Energy conducted stakeholder consultations on proposed Net Metering program updates.
- The following objectives were established for the updated net metering program:
  1) Reduce ratepayer costs associated with small-scale renewable generation, with the ultimate goal of achieving a self-sustaining program;
  2) Support Ontario's Conservation First policy by ensuring systems are right-sized and sited close to load;
  3) Reflect the costs and benefits of integrating net metered generation into the electricity system, and recover the costs efficiently and equitably; and
  4) Continue to offer consumers choice to offset their load using renewable energy, subject to system need and cost considerations.
- In July 2016, after analysis and consideration of stakeholder feedback, Ministry staff presented a phased approach to updating the net metering program:
  - Part 1 (Near-Term): Regulatory Updates Using Existing Legislative Authority.
  - Part 2 (Longer-Term): Regulatory Updates Requiring Legislative and Regulatory Amendments and Further Consultation/Study.

2. Part 1 Program Updates

- The Ministry of Energy's proposed "Part 1" amendments to the 2005 Net Metering Regulation (O. Reg. 541/05) were posted to e-laws February 8, 2017 and will be in force July 1, 2017.
- The amendments:
  - Clarify the description of the method used to calculate bill credits;
  - Clarify the carryover period for bill credits at a consecutive 12 month period;
  - Remove the 500 kilowatt (kW) project capacity size limit to allow for any sized renewable energy generation system
  - Allow for the use of energy storage and its recognition for the purposes of net metering; and
  - Allow participants with existing net metering agreements to choose to opt into the updated terms, or to maintain their existing agreements.

2. Part 1 Program Updates (cont'd)

- The Ministry of Energy also proposed the following non-regulatory actions in the August 2016 Environmental Registry posting:
  - Undertake a cost-benefit analysis to determine whether investments in Ontario's Meter Data Management and Repository should be made to enable time-of-use (TOU) billing;
  - Improve the availability of net metering program information; and
  - Undertake a cost-benefit evaluation of the program every three years.
- The Environmental Registry posting also indicated the OEB would be exploring the following steps to facilitate the updated program:
  - Develop a standardized net metering application and agreement, with consideration for streamlining processes;
  - Collect net metering information from electricity distributors at more frequent intervals to monitor implementation of the initiative; and
  - Improve the availability of net metering program information.
- *Third-party Ownership* (TPO) and *Virtual Net Metering* (VNM) emerged during stakeholder consultations as two areas of potential program enhancements that were of interest to the renewable energy sector, but would require legislative and regulatory amendments. The Ministry committed to further examination of TPO and VNM in the Part 1 EBR posting of August 19, 2016.

3. Part 2 Net Metering Program Updates and Analysis

3. Part 2 Net Metering Program Updates

- In December 2016, the Ministry initiated stakeholder and Indigenous engagement activities to examine potential implementation and impacts of third-party ownership (TPO) and virtual net metering (VNM). Outreach included meetings with an advisory working group, a public webinar, a questionnaire to collect written feedback, and targeted meetings with key stakeholder groups.
- The Ministry's analysis involved an assessment of impacts informed by stakeholder feedback and internal modelling of *business cases, program uptake* and *system impacts* based on the following net metering models: (See Appendix 1 for further details.)

Third-Party Ownership (TPO)	Single Entity Virtual Net Metering (SEVNM)	Multi-Entity Virtual Net Metering (MEVNM)
• Generation behind meter • Single load, single customer • Third party can own and operate • LDC credits customer bill for electricity sent to the grid • Restrictions could be imposed to regulate third parties	• Generation can be offsite • Multiple loads, single customer • Third party can own and operate • LDC credits customer bill(s) for electricity sent to the grid • Restrictions could be imposed on use of Dx, rate classes, etc.	• Generation can be offsite • Multiple loads, multiple customers • Third party can own and operate • LDC credits customer bills for portion of electricity • Restrictions could be imposed on use of Dx, rate classes, etc.

3. Scenario Analysis

- Based on stakeholder feedback and preliminary analysis, the Ministry has developed four policy scenarios representing potential project configurations under TPO and VNM frameworks:

Policy Scenario	Description
Scenario 1: **Baseline**	• Current net metering framework including Part 1 updates to come in force July 1, 2017.
Scenario 2: **Third-Party Ownership Only (TPO)**	• Flexibility for industry and LDC affiliates to own and operate metered generation under PPA agreements with electricity customers. • Assumes cost efficiencies gained from TPO ownership and operation of generation.
Scenario 3: **TPO + Single-Entity Virtual Net Metering (SEVNM)**	• SEVNM projects could include campus or municipal building load aggregation under a single renewable generation facility sized to meet the combined loads. • SEVNM projects could also include aggregation of multiple loads by residential or business customers. • A range of restrictions could apply to limit eligibility and restrict use of the distribution system. • Assumes current compensation regime for SEVNM projects (i.e. retail rates).
Scenario 4: **TPO + Multi-Entity Virtual Net Metering (MEVNM)**	• MEVNM projects could include condominiums, community net metering, business parks, co-ops and other ownership models for shared generation facilities. • A range of restrictions could apply to limit eligibility, use of the distribution system and administrative requirements. • Assumes current compensation regime (i.e. retail rates).

3. Scenario Analysis (cont'd)

- Ministry analysis considered stakeholder feedback and internal research and modelling to assess the potential impacts for the four scenarios. The impacts studied for the scenarios are highly dependent on the level of uptake, with impacts/risks increasing as uptake increases.
  - *Assessment of Market Potential:* Estimates of the total potential market size of customers that could participate in net metering determined by technical and economic constraints under different program designs.
  - *Business Cases:* Net metering business models and potential project configurations were modelled to compare project economics. Modelling inputs included solar PV electricity yields, project costs and customer demand profiles.
  - *Projected Uptake:* Analyzes how project economics under different business cases could stimulate different levels of net metering uptake. Uptake is modelled as a function of project returns on investment and was informed by secondary research of uptake in other jurisdictions.
  - *System Impacts Analysis:* Analyzes the potential impacts to future supply mix, cost of service, and rates. Modelling was performed at assumed levels of uptake to assess system level impacts over time. Distribution level impacts were informed by stakeholder feedback where costs could not be estimated.

3. System Impacts

- The IESO identified specific limitations and risks at the system level associated with implementation of TPO and VNM. Identified potential impacts are highly dependent on level of uptake:
  - Risk that pace of adoption would exceed IESO's ability to evolve operating capabilities.
  - Mechanisms do not exist for LDCs and IESO to maximize value of net metering capacity through regional planning tools and DER markets.
  - Underutilization of existing generation resources from high net metering uptake could increase system costs and rates.
  - Improperly located net metering capacity could increase congestion management payments to existing resources, increasing system costs and rates.
  - MDM/R is not currently configured to accept generation data or to receive data from demand customers (>50kW), which can lead to multiple bill settlement processes between IESO and LDCs.
  - Complexity of information management increases as the extent of aggregation increases (e.g. across LDCs, across rate classes, across billing cycles).
- The IESO also identified potential system level benefits and opportunities associated with implementation of TPO and VNM, dependent however, on the ability to direct new net metering capacity in response to system needs:
  - Potential to reduce generation and capacity costs through reduced load on the system.
  - Requiring net metering capacity to provide grid services would ensure system benefits and reduce need for additional contracted grid services from conventional generators.

3. Distribution-level Impacts

- LDCs identified specific limitations and risks at the distribution level associated with implementation of TPO and VNM. Identified potential impacts are highly dependent on level of uptake
  - Risk of increased customer management costs associated with TPO if adequate consumer protection and education measures are not in place.
  - Increased uptake would lead to additional administrative costs to handle applications, connections, etc.
  - Costs for upgrading billing systems and credit transfer procedures to accommodate varying complexities of net metering could have rate impacts on electricity distribution.
  - Complications between certain rate classes and net metering could result in risk of lost revenue or unintended “gaming”, particularly if large storage solutions become economic (e.g. ICI customers, storage and demand billed customers).
  - Current methods of recovering costs of net metering participation involves a small amount of cross-subsidization. Greater cost-shifting to non-net metered customers would result if uptake levels increase.
- LDCs also identified specific benefits and opportunities at the distribution level associated with implementation of TPO and VNM dependent on the ability for LDCs to have control over where and when net metering capacity is deployed, particularly for large net metering capacity and VNM models:
  - Potential for net metering capacity to provide distribution level grid service, such as frequency regulation or peak shaving.
  - Potential for net metering capacity to defer or offset infrastructure investment requirements where net metering resources can be aggregated and where storage allows for greater control.
  - LDCs are interested in reducing the risk of lost revenues from net metering by directing affiliates to provide net metering services to customers.

3. Summary of Analysis

Impacts	Scenario 1: Baseline	Scenario 2: TPO	Scenario 3: SEVNM	Scenario 4: MEVNM
Market Potential	Potential market: • 1064 MW over 10 yrs Achievable potential: • 429 MW over 10 yrs	Potential market: • 2,272 MW over 10 yrs Achievable potential: • 511 MW over 10 yrs	Potential market: • 3,168 MW over 10 yrs Achievable potential: • 546 MW over 10 yrs	Potential market: • 4,152 MW over 10 yrs Achievable potential: • 603 MW over 10 yrs
Business Cases	Payback for 2018 project (no incentive): 24-25 yrs. (residential) 19-20 yrs.(commercial) 19-20 yrs. (industrial)	Payback for 2018 project (no incentive): 20-21 yrs. (residential) 16-20 yrs. (commercial) 16-20 yrs. (industrial)	Payback for 2018 project (no incentive): 19-20 yrs. (residential) 15-17 yrs. (commercial) 15-20 yrs. (industrial)	Payback for 2018 project (no incentive): 15-16 yrs. (residential) 14-15 yrs. (commercial) 14-20 yrs. (industrial)
System Impacts (Rates)	Modelling of system impacts of a 50 MW per year update of new net metering solar PV capacity over the OPO forecast period showed a potential net impact on a typical non-net metered residential customer's bill rising to approximately $0.20 per month from 2022 and remaining relatively stable out to 2035.			
System Impacts (Transmission level)	• No significant issues for transmission or IESO operations at low uptake.	• No significant issues for transmission or IESO operations at low uptake.	• Potential for issues related to MDM/R depending on design.	• Issues related to utility-scale gen. and possible need for MDM/R upgrades.
System Impacts (Distribution level)	• Potential for issues with removal of 500kW cap and storage.	• Potential consumer protection and customer management issues.	• Billing settlement issues (need for Customer Information System upgrades).	• Billing settlement issues and customer management and administration issues.

3. Key Findings

- **<u>Market potential</u> is limited by available connection capacity:**
  - TPO and VNM can provide benefits to customers by addressing some of the economic and technical constraints of participation in net metering.
  - Given available connection capacity, VNM would expand access to customers, but would not expand overall market potential.

- **<u>Business cases</u> without incentives are marginal out to mid-2020s:**
  - TPO and VNM can provide benefits to customers by reducing costs of renewable generation and improve the business case for net metering.
  - Although MEVNM shows positive business case results, most business cases are negative to marginal without incentives.

- **<u>Uptake</u> will be driven by incentives at least until mid-2020s:**
  - TPO and VNM can influence business cases and level of uptake, but not enough to drive significant uptake in the near term; incentives will be required to drive uptake.
  - Impacts are highly dependent on level of uptake; managing uptake over time will minimize system risks and costs while facilitating opportunities to realize value from distributed resources under a net metering framework.

- **<u>System impacts</u> at the levels of uptake projected will have minimal overall effect on rates:**
  - Net metering uptake will have system benefits from deferred capacity requirements and commodity costs.
  - Rate impacts overall will be minimal, but depending on how cost recovery of net metering is addressed, cost-shifting will result in non-net metered customers seeing some bill increases.
  - Implementation costs for LDCs are minimal for TPO but could be significant for VNM projects. Further cost-benefit work of a program proposal would be required to quantify costs.

4. Policy Considerations

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Impact of Fair Hydro Plan

- Ministry analysis and stakeholder feedback indicate project economics under the net metering program are extremely challenging for small projects (GS<50kW) without incentives. The Ontario Fair Hydro Plan (OFHP) will further challenge the economics of residential and small commercial net-metered projects, specifically over the next four years.
- Under the Ontario Fair Hydro Plan the Global Adjustment for RPP consumers will be reduced until 2028, and subsequently, it will increase over and above what it would have been without the Fair Hydro Plan.
- Net Metering participants will see a decrease in the economics of the project attributable to the OFHP. For example, a single NM participant with a 4 kW solar PV installation in service in 2018 would see a reduced benefit of $928 under OFHP (over the 25 years of the project, expressed as the NPV $2016).
- As the price of electricity decreases over the first 10 years of the OFHP, the value of the self-consumption also decreases, in turn diminishing the value proposition for the participant.
- The magnitude of this decrease could be significant. For example, depending on assumptions, the decrease in profit could represent 15% of the original profit value.

Time-of-Use pricing

- CanSIA has indicated that transitioning to TOU pricing can improve solar PV NM economics. The Ministry estimates that TOU pricing could improve annual bill reductions by approximately 5% and is currently undertaking a cost benefit analysis of implementing TOU pricing.
- OEB decision pending on moving forward with five RPP pilots, to be in place by November 2017 and run for one year. Results of current pilot proposals would be expected in 2019 and could provide additional insight into TOU pricing for NM installations.

4. Policy Considerations (cont'd)

Removal of 500 kW size limit

- There is some uncertainty as to how Part 1 implications will affect market behaviour, and what issues may arise related to interactions between the removal of the 500 kW size limit and energy storage for specific demand customers.
- It is, however, evident that the change has been well received, with LDCs already hearing much interest from commercial and industrial customers.

Three-year cost-benefit evaluation

- As part of Part 1 NM updates, the Ministry committed to undertake a cost-benefit analysis of the program every three years, if required, coinciding with the LTEP cycle. This provides an opportunity to evaluate future NM opportunities as market conditions evolve.

Distributed generation projects

- Mechanisms do not exist for LDCs and IESO to realize value from Net Metering through regional planning and distributed energy resource markets.
- The Ministry is proposing that LTEP commit to investigating how renewable DG projects can provide value to the grid through funding deployment of strategic DG projects.

Net Metering Experience in Other Jurisdictions (see Appendix 3 for more details)

- Several U.S. states have experience with TPO and VNM. These markets have faced challenges in managing NM uptake and in designing appropriate regulatory frameworks (e.g. level of compensation, and connection processes).
- According to a report by the N.C. Clean Energy Technology Center, the two biggest sources of contention between the utilities and rooftop solar advocates have been 1) adequate compensation for rooftop solar customers and 2) whether or not to impose limits on the amount of electricity solar customers can sell back to the grid.
- A number of states have rolled back compensation levels as net metering uptake reaches capacity caps. For example, New York, Massachusetts, and California have all initiated processes to redesign net metering compensation rates in attempts to manage uptake and costs.

5. Policy Options

5. Overview of Policy Options

<u>Option 1:</u> Status Quo (Part 1 updates)

- Do not pursue changes to Ontario's Net Metering framework to allow Third-party Ownership or Virtual Net Metering at this time.
- Continue with implementation of Part 1 Net Metering updates.

<u>Option 2:</u> Third-Party Ownership Only *(RECOMMENDED)*

- Implement a framework for Third-party Ownership only.
- Do not enable Virtual Net Metering at this time.

<u>Option 3:</u> Third-Party Ownership + <u>Restricted</u> Virtual Net Metering

- Enable Third-party Ownership and implement a restrictive framework for Virtual Net Metering by regulating eligibility of single-entity VNM, and multi-entity VNM , for example, by customer type, rate class, price, location, or project size.

<u>Option 4:</u> Third-Party Ownership + <u>Unrestricted</u> Virtual Net Metering

- Enable Third-party Ownership and implement a permissive framework for Virtual Net Metering, with a market-based pricing mechanism and system-wide clearing of bill credits.

5. Option 1: Status Quo (Part 1 updates)

- Do not pursue further legislative and regulatory changes to the Net Metering framework to allow TPO and VNM at this time.
- Assess effects of Part 1 changes and other policy developments to inform future program updates.

Considerations:

- Part 1 updates already broadened net metering opportunities by removing 500 kW project cap and permitting generation matched with battery storage.
- Allows market to adjust to Part 1 program changes before considering additional changes.
- Minimal system impacts.
- Eases burden on small LDCs for developing administrative capacity for net metering.
- Provides opportunity to collect information on impacts of Part 1 updates and to proceed accordingly.
- Considers LDC feedback.
- Does not support an expansion of consumer choice.
- Risk level: Low

Stakeholder Reaction:

- Reflects LDC concerns about administrative burden and desire to maintain direct customer relationships.
- Loss of economic opportunities for the renewable energy industry.
- Limits immediate opportunities for industry and LDCs to create innovative distributed generation initiatives.

5. Option 2: Third-Party Ownership Only *(recommended)*

- Propose legislative and regulatory amendments that would enable third-party ownership (TPO) under Ontario's Net Metering Program.
    - Third-party providers would be able to own and operate net metered generation facilities and enter into service and/or financing agreements with customers under a number of business models (e.g. power purchase agreements, lease, rental, etc.).
- Do not enable virtual net metering at this time.
    - Consider supporting and/or enabling pilot projects that could provide empirical information about impacts/benefits of VNM projects to the system.

Considerations:

- Addresses the economic constraint for many potential renewable electricity customers of financing and maintaining a renewable energy system and expands consumer choice.
- Provides industry third-party participants with access to expanded potential market/customers and more options to market renewable energy to consumers.
- TPO was indicated to be the most important update to the majority of stakeholders to achieve flexibility for innovation and efficiency in the market.
- Establishes a foundation for future opportunities for electricity distributors to deploy innovative energy services and non-wires solutions to meet distribution system needs.
- Does not expand accessibility of net metering to many customers that cannot host net metering (e.g. Multi-Entity Residential Buildings, historic buildings, portion of homeowners and businesses).
- VNM projects that may present value to the system will not be able to proceed.

5. Option 2: Third-Party Ownership Only *(recommended)*

Considerations: (cont.)

- Reduces risk of unanticipated levels of uptake and associated system impacts.
- Avoids immediate need for LDCs to incur large billing and customer service system upgrades.
- Provides opportunity for sector and government to gather information and experience to better understand potential impacts and consider implementation of VNM at time of three-year Net Metering review. Pilot projects could create opportunities for innovation and learning in near term.
- Allows for appropriate consumer protection and education measures and best practices for third-party companies to be in place before allowing increased "retailing" activity.
- Risk level: Measured, iterative approach

Stakeholder Reaction:

- The Solar PV sector strongly supports TPO, citing it as critical to continued activity in Ontario's renewables sector.
  - The business models, target markets and project configurations the sector is contemplating would largely be enabled by third party participation in the current net metering program (i.e. including Part 1 updates, effective July 2017).
  - Feedback was supportive of VNM, though it was indicated as non essential.
- LDCs, and in particular LDC affiliates, support TPO, subject to appropriate consumer protection measures and clearly defined relationships between LDCs, customers and TPOs.
- May not be seen as going far enough by some stakeholders.

5. Option 3: Third-Party Ownership + Restricted VNM

- Implement TPO and a restrictive framework for VNM through regulation of eligible single-entity and multi-entity virtual net metering project types based on customer type, rate class, price, location, project size, or technology.
  - A highly prescriptive regulatory framework could target municipalities, First Nations, universities and other public buildings, for example.
  - Could also scope to VNM projects in prescribed scenarios to allow for niche participation (i.e. adjacent buildings)

Considerations:

- Enables VNM projects that may provide value to customers and may present value to the system while providing a mechanism to manage project uptake and system impact.
- Provides increased consumer choice for some participants.
- Builds experience and a chance to gather information to inform future updates for a more permissive VNM framework.
- A highly prescriptive regulatory framework for VNM would (depending on program design and restrictions imposed) arbitrarily exclude potential participants and create technical barriers for some projects.
  - For example, a focus on MUSH sector would exclude businesses; or restricting to single LDC territories would impose barriers to customers in small embedded LDCs.
- Sets precedent for compensation of VNM projects at retail rates, which may not reflect true value for the system.
- VNM at retail rates may also create challenges for bill settlements and credit transfers across LDCs and rate classes.

5. Option 3: Third-Party Ownership + Restricted VNM

Considerations: (cont.)

- LDC impacts:
  - Depending on scoping and eligibility restrictions, greater risk for small LDCs where larger targeted VNM projects have significant local impacts (e.g. revenue base, stranded assets, etc.).
  - Limiting eligibility to a select group of potential participants may have similar cost impacts to LDCs associated with billing and administrative requirements as a permissive VNM framework (e.g. significant investment for a smaller number of projects).
  - Precedes the planned TOU assessment for NM, which would require additional LDC system updates if implemented.
- Requires legislative amendment, and creation of a prescriptive regulatory framework that may require further amendments if/as modifications are needed.
- Less prescriptive regulatory amendments that would enable pilot projects with funding to make LDCs “whole” could accomplish similar objectives to a restricted VNM approach.
- Risk level: Moderate

Stakeholder Reaction:

- Supported by industry and project proponents (e.g. municipalities, universities, etc.)
- Industry may claim this does not go far enough to support renewables industry.
- LDCs: depends on scoping and implementation (e.g. preference to not settle across different LDCs) and what investments they are being asked to incur when in terms of system updates

5. Option 4: Third-Party Ownership + Unrestricted VNM

- Implement TPO and a permissive framework for VNM with market-based pricing mechanism and system-wide clearing of bill credits.

Considerations:

- Significant consumer choice to participate in a wide range of project configurations.
- Unrestricted opportunities for industry to develop and operate projects where technically possible.
- Compensation mechanism (i.e. HOEP+GAM, or others) provides a mechanism to control level of uptake and manage impacts to LDCs and system.
- Potential for generation to be sited where there is no load. Large projects likely to overwhelm connection queues and take up available local connection capacity.
- Introducing a permissive VNM framework at this time has significant risks for ratepayers:
    - In Ontario's current supply situation, there are few opportunities for net metering capacity to provide value to the system, and mechanisms do not currently exist to provide IESO and LDCs with tools to identify system needs, and direct distributed energy resources through net metering to meet system needs.
    - Without appropriate mechanisms in place to limit uptake of net metering or direct when and where it is deployed, there is a risk that participation rates could overwhelm technical and administrative capacities of IESO and LDCs and have significant rate impacts and cross-subsidization effects.
    - Retail rate compensation is not appropriate for the types of generation projects that would likely occur under a permissive VNM framework (e.g. utility-scale renewables). IESO would be in a position to procure new renewable capacity at much lower cost through competitive procurement.

5. Option 4: Third-Party Ownership + Unrestricted VNM

Considerations: (cont.)

- LDC impacts:
  - Includes magnified risks associated with Option #3.
  - Also precedes TOU assessment for NM, which would require additional LDC system updates if implemented.
- Would require legislative amendment to provide authority to create a detailed regulatory framework.
- Unlikely to be implemented by 2018 and could delay less substantive changes that broaden NM participation, such as third-party ownership.
- Risk-level: High

Stakeholder Reaction:

- Supported by a segment of the renewable sector and project proponents.
- Potentially significant cost impacts on LDCs to implement (operations, administration, billing system upgrades)
- Opens up opportunities for LDC affiliates (e.g. to provide net metering services to customers and reduce lost revenue risks)

6. Implementation and Ongoing Activities

6. Near Term Next Steps

- Seek DM/MO direction on recommendation and implementation
- Brief Minister (early May)
- Seek Cabinet approval concurrently with LTEP Submission and directives (end of May)
- Leverage LTEP publication to communicate policy intent and include content in directives to IESO and OEB (June 2017)

6. Legislative and Regulatory Amendments

- ENERGY would take the following actions to implement Third Party Ownership by July 2018:
  - Beginning in June 2017, ENERGY to develop proposed legislative amendments to the OEB Act to provide the requisite regulation making authority to define eligible Third-party Ownership under the Net Metering Regulation.
  - ENERGY to seek LRC/Cabinet approval of proposed legislative amendments (late summer 2017)
  - Proposed legislative amendments to be introduced in Fall 2017 (legislative vehicle TBD)
  - ENERGY to post proposed legislative amendments and a draft regulatory proposal to the Environmental and Regulatory Registries for a 45-day public comment in fall 2017.
  - ENERGY to finalize proposed regulatory amendments following the EBR comment period and seek LRC approval upon passage of the legislative amendments (early 2018), with regulatory amendments to take effect July 1, 2018.

6. Legislative and Regulatory Approvals

Q2 2017

Late May 2017
Seek Cabinet Approval along with LTEP

Q3 2017

July – Aug. 2017
Seek LRC Approval on Proposed Draft Leg. Amendments

Q4 2017

Sept. – Dec. 2017
Introduce Proposed Draft Leg. Amendments in the House

Sept. – Dec. 2017
EBR Posting of Proposed Draft Reg. Amendments

Q1 2018

Jan. – Feb. 2018
Seek LRC Approval on Proposed Draft Reg. Amendments

Mar. 2018
File Final Reg. Amendments

Mar. 2018
Post Decision Notice for Reg. and Leg. Amendments

Q3 2018

July 2018
Updated NM Leg. and Reg. come into affect

LEGEND

- NM Legislative Process
- NM Regulatory Process
- NM Leg. & Reg. Process
- LTEP Process

6. Consumer Protection Measures and Project Siting

- Assessment of consumer protection provisions and project siting considerations under net metering are addressed in a separate briefing.
- Key highlights include:
  - Net metering projects pursued by individual homeowners are generally covered by existing consumer protection regulations.
  - Enhanced consumer education will help ensure prospective net metering participants are aware of their rights, and assist with making informed decisions when considering working with third-party companies.
  - ENERGY is working with partner Ministries to examine options to help ensure appropriate project siting measures for net metered projects.

6. Further Examination of VNM

- ENERGY will take the following actions to support further examination of implementing VNM in the Ontario context, ensure value to the system and to improve delivery of net metering across LDCs:
  - **Through LTEP Implementation Directive, direct IESO to study impacts of increased net metering capacity and associated technical and economic constraints** and to include the following specific items:
    - Alternative pricing mechanisms for VNM projects, such as HOEP + GAM.
    - Regional planning mechanisms and limitations of processes to allow LDCs and IESO to evaluate and direct NM resources as well as opportunities for industry to participate.
    - Treatment of crossover of NM and participation in ancillary services (e.g. DER provided by NM aggregators).
  - **Through LTEP Implementation Directive, direct OEB to explore cost recovery of LDC and IESO net metering costs** including**:**
    - Deferral accounts for large NM costs such as TOU or MDM/R investments.
    - Standardization of connection and administrative fees for net-metered customers.
    - Treatment of costs with both LDC and IESO system benefits.
  - **Explore potential for funding programs to support pilot projects in the near term.** Scope of examination for funding programs to include:
    - Innovative DG projects reliant on NM to be deployed such as Ministry's proposed LTEP DG support program.
    - VNM projects for specific customer types with LDC partners to explore technical and administrative challenges. These could include projects currently under development with specific interest in VNM models (e.g. municipalities, net zero communities).
    - Funding can cover administrative costs of LDCs and incentive for economic business cases for proponents.

6. Part 1 Implementation and non-regulatory commitments

- The Ministry continues to work to implement Part 1 non-regulatory commitments:
  - The TOU cost-benefit analysis is in progress. The LDC survey can be initiated in Spring 2017 with the project potentially completed by end of 2017.
  - The Ministry is in the process of updating its website to improve the availability of net metering program information; and
  - The three-year cost-benefit evaluation of the net metering program will coincide with the next LTEP (2020).
- The Environmental Registry posting also indicated the OEB would be exploring the following steps to facilitate the updated program. The OEB is currently undertaking the following steps:
  - Near term initiatives (necessary updates to meet July 1, 2017 in-force date):
    - DSC Code Amendments to update regulation numbering and language in the DSC appendices related to net metering projects over 500 kW requiring a generator license.
  - Longer-term initiatives:
    - Standard application and agreement, reporting frequency, improving availability of information are targeted for completion by end of 2017.

Appendices

Appendix 1: Additional Analysis
Appendix 2: Stakeholder Engagement
Appendix 3: Experience in Other Jurisdictions

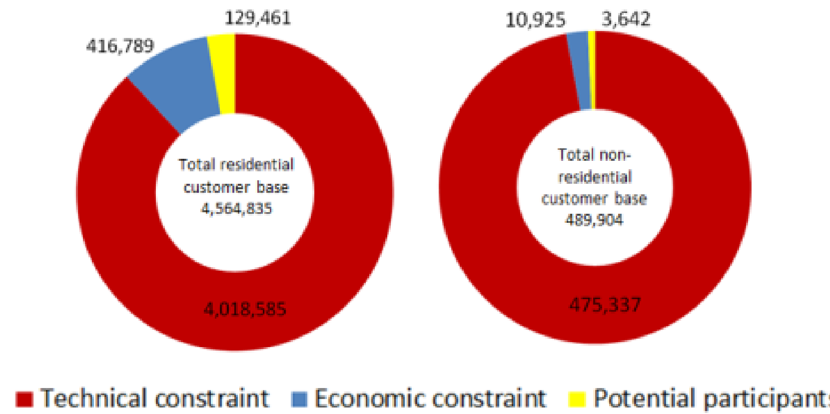
Appendix 1: Additional Analysis

Market Potential

- An estimate of market potential, representing the potential number of customers that could participate in net metering, was estimated by applying constraints on the total electricity customer base as follows:
  - *Technical constraints* – includes physical limitations to host generation facilities and available connection capacity.

  (Note: NREL estimates that 49% of U.S households and 48% of businesses are unable to host a PV system.)
  - *Economic constraints* – includes ability for households or businesses to afford or finance generation facilities.
- Program design influences the market potential by addressing certain constraints.
  - For example, TPO may relieve economic constraints by addressing the need for participants to have upfront capital to invest; VNM could relieve the technical constraint for participants to have access to a suitable roof space to host solar PV.
- Estimated market potential is used to determine an estimate for achievable potential (i.e. those who would participate in net metering – see next slide), which determines the upper bound for projecting net metering uptake.

Estimated potential net metering participants as a portion of total electricity customers



Assumptions

- Connection capacity (red bar), which is estimated at approx. 4200 MW currently, based on thermal limits and upstream circuit capacity, is the overriding technical constraint limiting potential net metering customers.
- Estimate assumes half of the available connection capacity is set aside for residential and half for non-residential.
- Economic constraints (blue bar) further limit potential net metering customers to those who can afford to purchase renewable generations systems. Estimate assumes only 25% of customers able to connect would have means to invest in net metering capacity.
- Source data: Ontario Energy Board. 2015 Yearbook of Electricity Distributors; August 3, 2016. http://www.ontarioenergyboard.ca/oeb/_Documents/RRR/2015_Yearbook_of_Electricity_Distributors.pdf

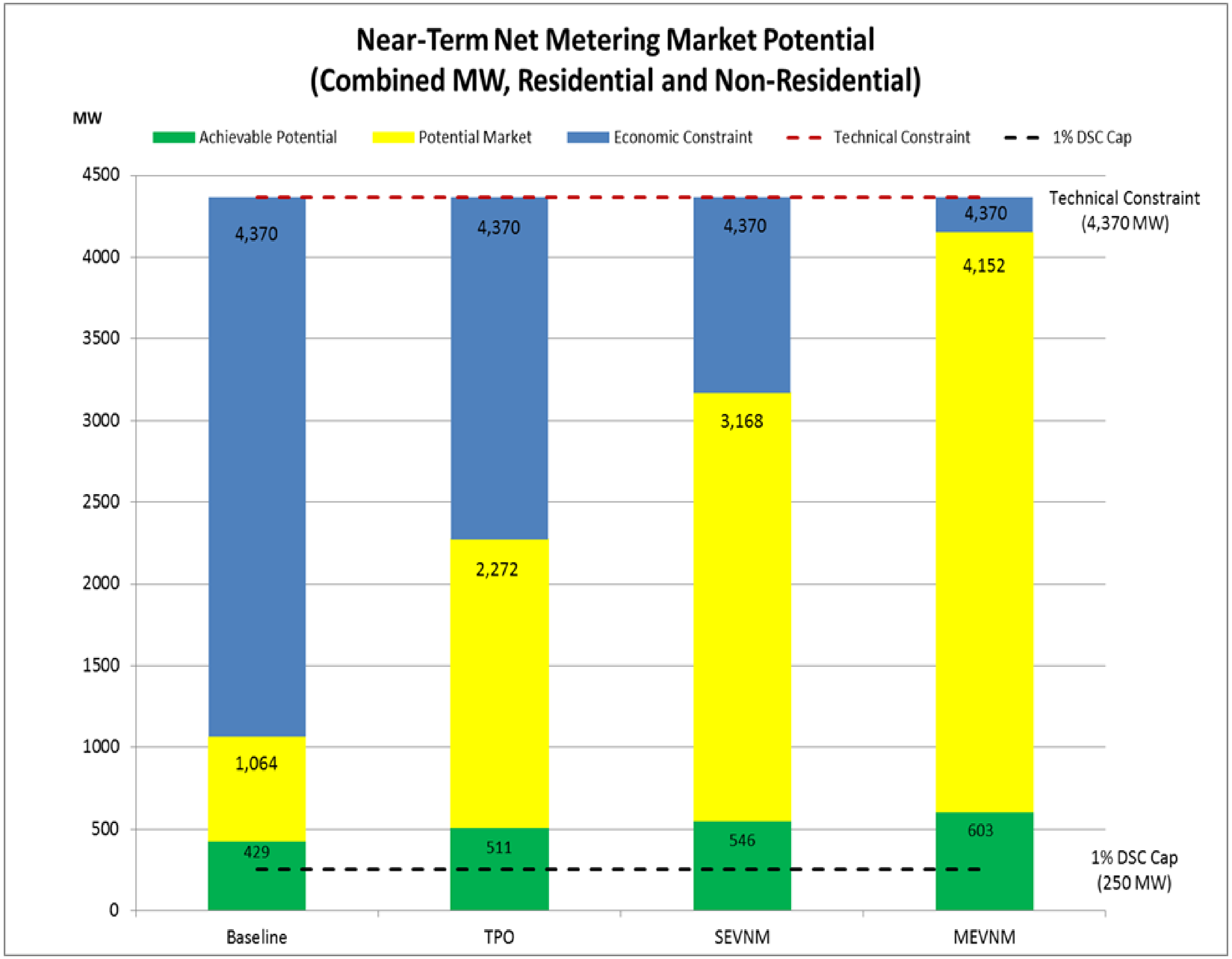
Market Potential (cont'd)

Results

- Achievable potential (green bar) illustrates the estimated maximum MW capacity that could be reached under each scenario.
- TPO and VNM scenarios result in improved market potential by addressing economic constraints.
- Available connection capacity limits the benefit of TPO and VNM scenarios.

Assumptions

- MW capacity is based on a 4 kW size for solar PV system for residential customers and a 150 kW for non-residential.
- The 1% DSC Cap (250MW) is estimated based on LDC peak load. It represents a limit for LDC requirement to provide net metering.



Impact of Incentives on Residential Business Case

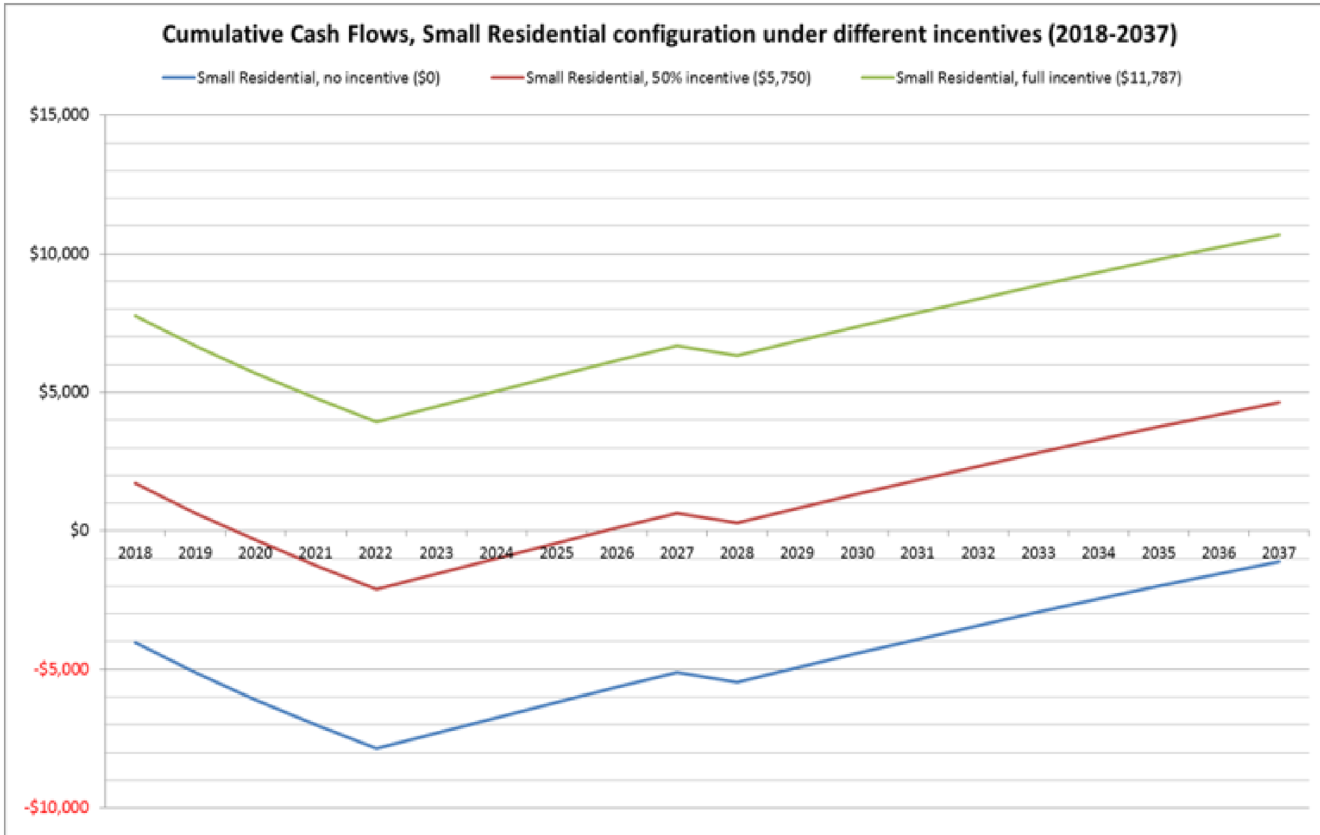
- Net metering business cases were modelled to determine the financial case from a customer perspective. Financial benefits are derived in the form of savings on electricity bills of net-metered customers, while costs are derived from upfront capital costs of solar PV systems. The example below compares cashflows over the life of a residential project with and without incentives.

Results

- A typical residential NM system without incentives has long paybacks of about 20 years.
- Incentives improve the business case significantly.

Assumptions

- Cost of solar PV: uses CanSIA cost curves, Res (hi-low) and C/I (hi-low).
- Residential case shown here uses a projected 2018 cost of $2.44/W.
- Electricity prices: uses LTEP 2013 price index.
- High and low incentives based on 50% and 100% of PWC report: See legend.



Business Cases

Assumptions

- A range of potential business cases that could occur under TPO and VNM were modelled.
- Business cases take into account customer type, rate class and representative load profile, as well as expected solar PV size and cost.
- TPO scenario business cases under conventional net metering projects assume a lower cost of solar PV systems as a result of efficiency gains from third-party ownership and operation.
- SEVNM scenario business cases assume a range of potential load aggregation by a single customer, and therefore larger sized solar PV systems.
- MEVNM cases assume a range of potential combined ownership and load aggregation of customers, and therefore larger sized systems and cost reductions from TPO financing.

Business Cases (cont'd)

Results

- Results shown in three measures:
- Compound Annual Growth Rate (CAGR): 1% CAGR is roughly equivalent to 2.5% ROI
- Payback: Number of years for initial investment to be recovered.
- Net Benefit: Net present value of all benefits over life of project.
- Net Benefits shown to the right for a given year in which a project is started show how the business case changes over time as electricity rates and cost of solar PV systems change.
- The overall trend shown here is that business cases improve over time as cost of solar decreases relative to electricity rates.
- Residential business cases worsen over time as a result of modelling assumptions using decreasing LTEP 2013 price indexing relative to other inputs.

Residential Business Cases

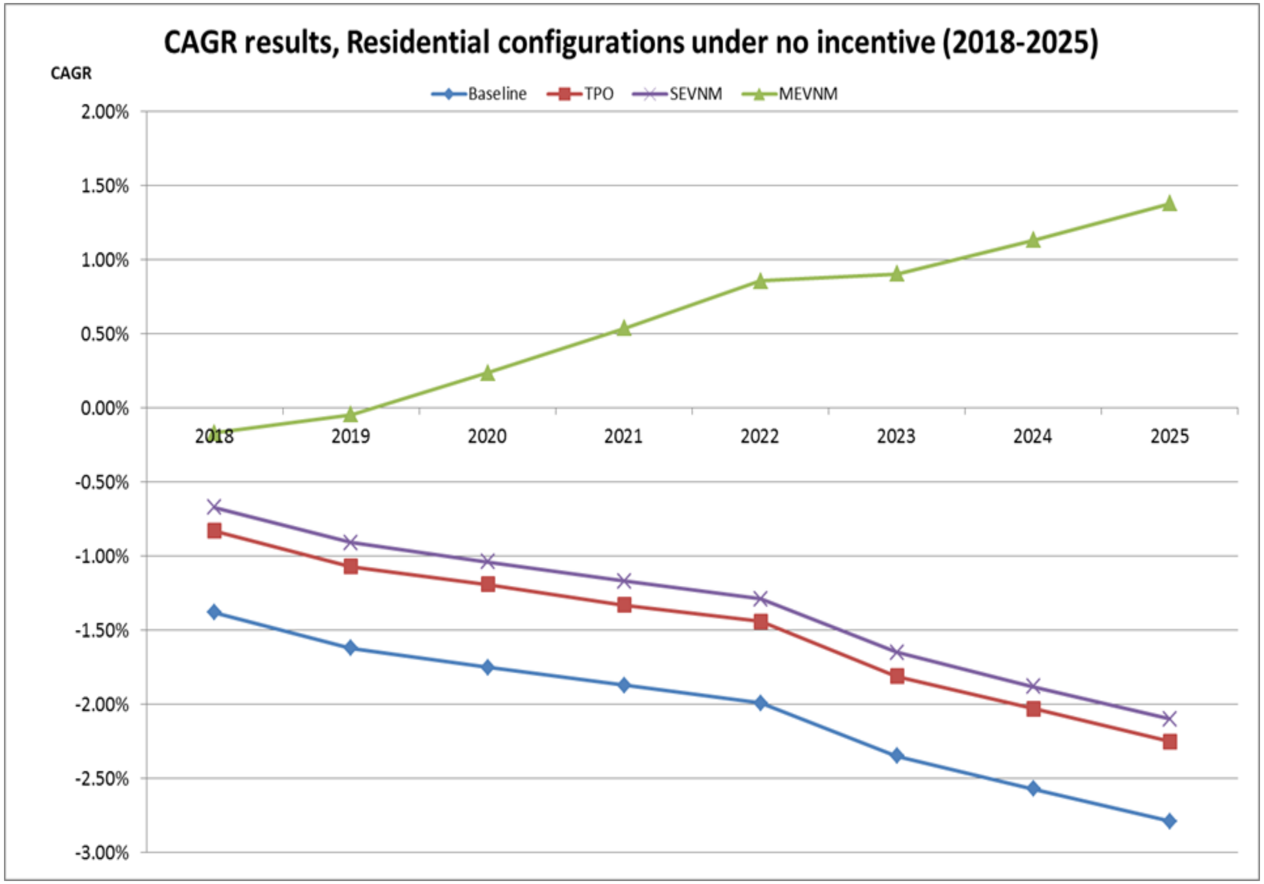
- The following graph shows residential business cases for the scenarios under consideration over time, starting in 2025. The projects modelled include a conventional NM installation, a TPO project, participation in a community NM project and a homeowner with multiple residences under a SEVNM project.

Results

- Conventional and TPO residential NM shows a decrease in the business case over time as a result of scale and decreasing real electricity prices in LTEP 2013 index.
- MEVNM residential cases improve over time.

Assumptions

- Baseline: 12 kW system; $2.85/W (2018) decreasing to $1.99/W (2025).
- TPO case: 12 kW system; $2.44/W (2018) decreasing to $1.71/W (2025).
- SEVNM case: 20 kW system; $2.44/W (2018) decreasing to $1.71(2025).
- MEVNM case: 1 MW system (community NM); $1.66/W (2018) decreasing to $1.16/W (2025).



Business Cases for Residential, Commercial and Industrial net metering projects

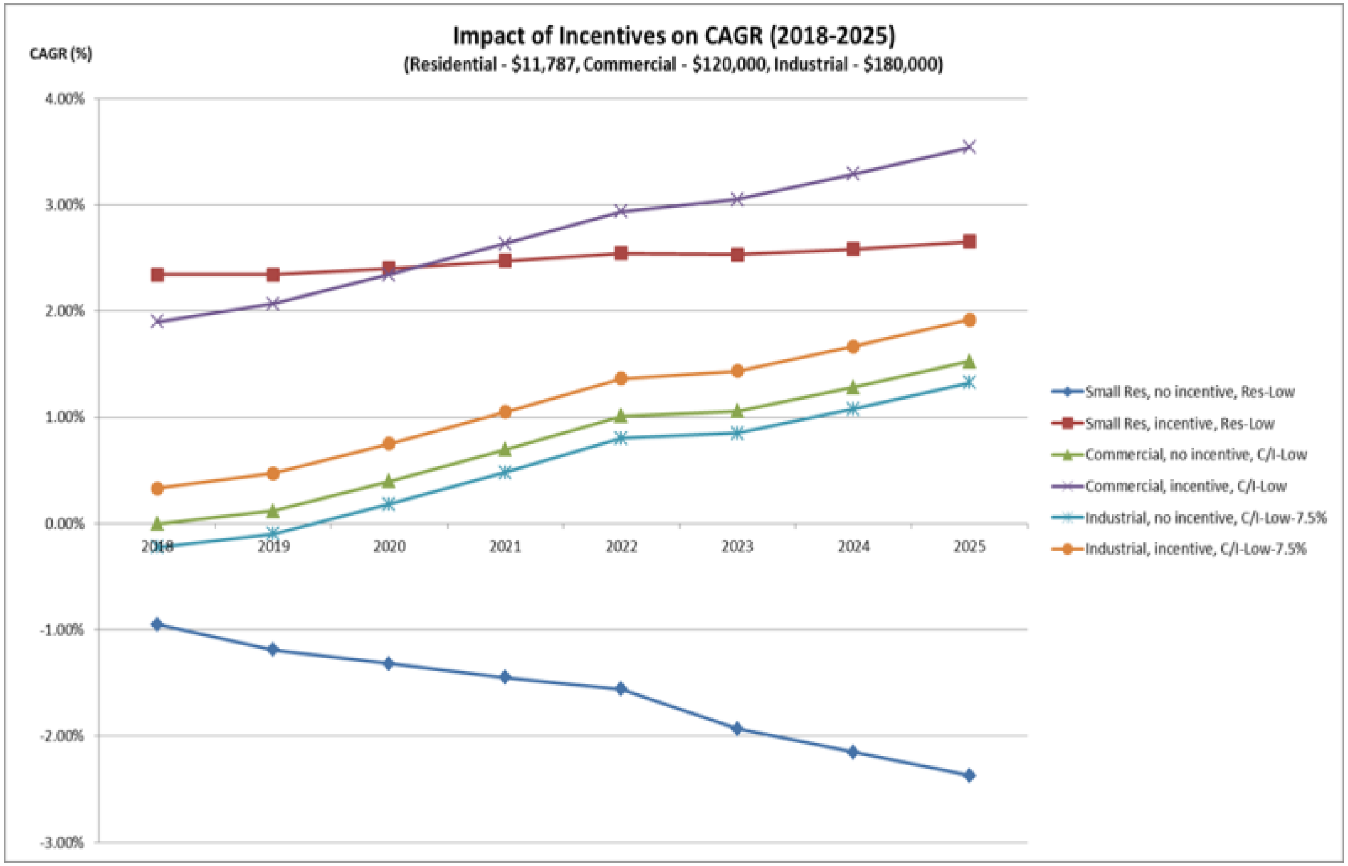
- Representative business cases for residential, commercial and industrial net metering projects were modelled with an added incentive based on recent recommendations from the PWC *Program Analysis & Recommendations* report.

Results

- Incentives yield positive business cases that would drive uptake.
- Residential net metering projects are the most challenged and are projected to require incentives over the longest period.

Assumptions

- Shows the CAGR for a given project type started in a given year from 2018 to 2025.
- Incentive level of $11,787 for residential, $120,000 for commercial and $180,000 for industrial.
- Incentives would be provided each year up to 2025.



Projected Uptake

- Net metering uptake is a key determinant of impacts to the system, such as LDC costs, impacts on cost of service, rate impacts, technical and administrative challenges, etc.
- Unlike with FIT, uptake cannot be determined through targets; it is a function of market dynamics (i.e. business case for customers) and program design. LDCs are required by regulation to offer net metering upon request within technical limitations (i.e. capacity to connect determine by thermal and circuit limits at feeders).
- The model has the following assumptions and limitations:
  - Uptake projections are a function of the business cases; positive business cases will drive uptake.
  - Participants will be financially motivated to invest in renewable generation for net metering, if the net benefits are equal or greater to the opportunity cost of market returns.
  - The model does not account for non-financially motivated individuals/entities that would invest at lower than market returns.
  - Different customer types have different investment thresholds. For example, municipalities, LDCs or affiliates, or businesses with corporate greening strategies may be satisfied with long paybacks or even negative returns.
  - The upper limits of projected uptake are determined by the achievable potential taking into consideration the technical and economic constraints for participation in net metering.
- Without incentives added to the business cases for net metering, the model projects no measurable uptake over time. Although, it can be assumed that a minimal level of uptake would occur in the absence of incentives, for purposes of projecting potential uptake and comparing policy options for TPO and VNM, incentives have been assumed based on the PWS report recommendations.

Projected Uptake (cont'd)

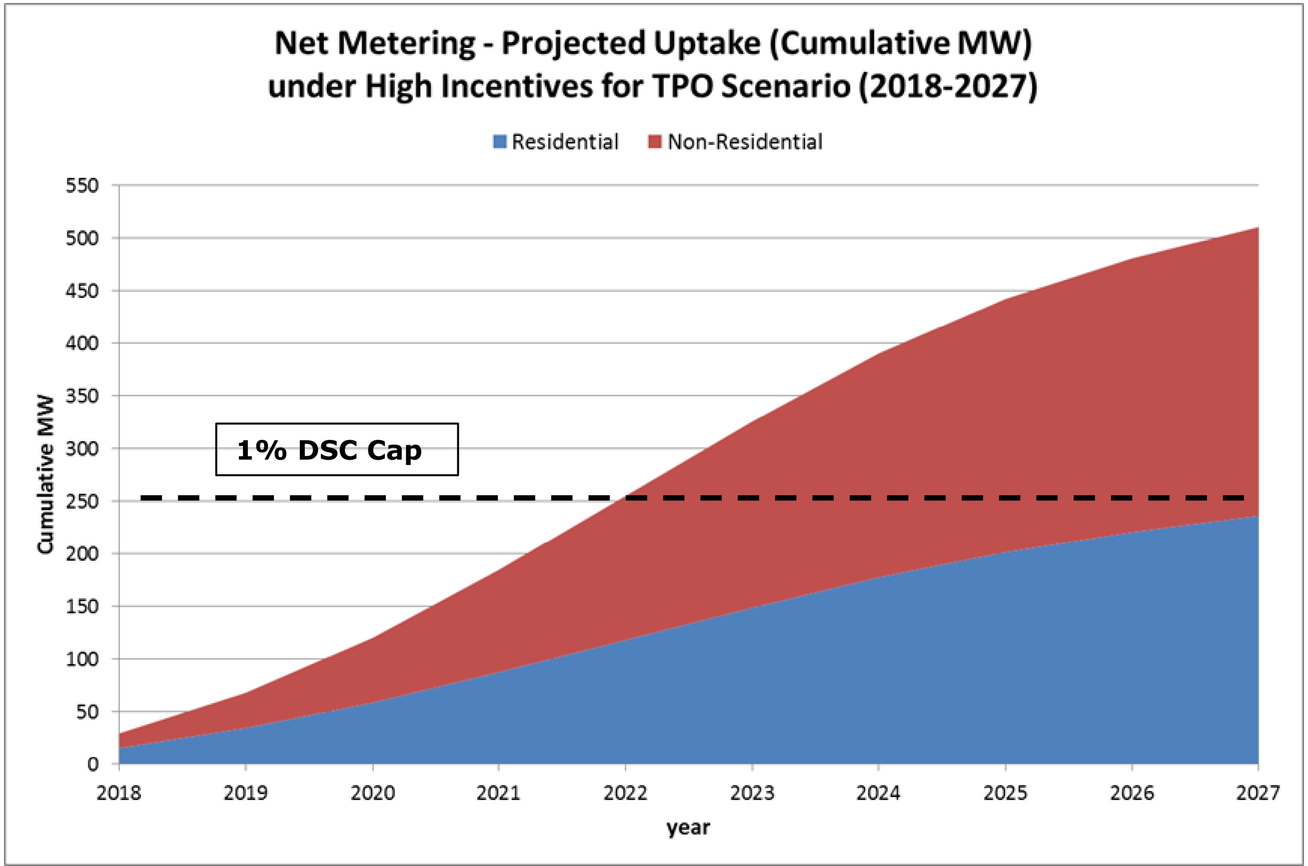
- Projected net metering uptake for residential and non-residential customers with incentives over 10 years under the TPO only scenario yields approximately 500 MW of installed capacity by 2027.

Results

- Assessing the 1% DSC Cap by 2022 will be imperative for certainty of continued uptake.
- TPO scenario assumes a steady growth of uptake; MEVNM scenario could involve a much quicker uptake rate, depending on connection process.

Assumptions

- Project uptake assumes a high incentive level and TPO scenario.
- LDCs would continue to offer net metering over the 1% cap or cap would be lifted.
- LTEP 2013 rate index applied to all business cases (does not include OFHP impacts).



Projected Level of Uptake in Capacity and Installations

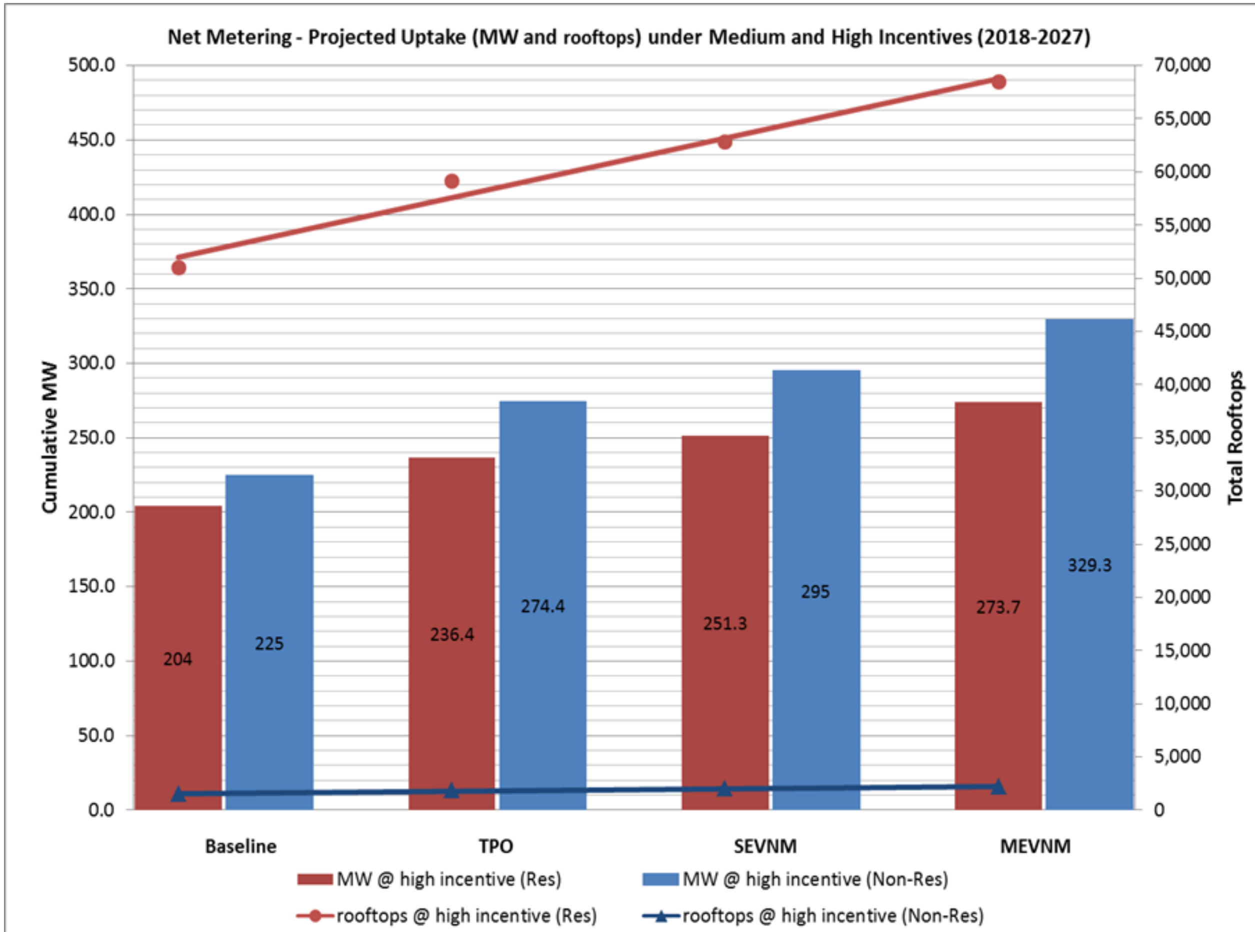
- Business cases inform the modelling of projected uptake. The graph below shows projected levels of uptake in both MW of installed capacity and number of rooftops/installations for the four policy scenarios in 2028 (cumulative 10-yr period) with the inclusion of incentives.

Results

- Projected levels of uptake range from approximately 430 MW to 600 MW over a 10-year period.
- TPO and VNM scenarios improve uptake over baseline scenario.
- Level of incentive has significant impact on uptake.
- Differences in TPO and VNM scenarios have much smaller impact than level of incentives.

Assumptions

- High incentives are $11,787 (PWC) for residential and $120,000 (PWC average of commercial and industrial) for non-residential.
- Half of available connection capacity is set aside for residential and half for commercial/industrial.

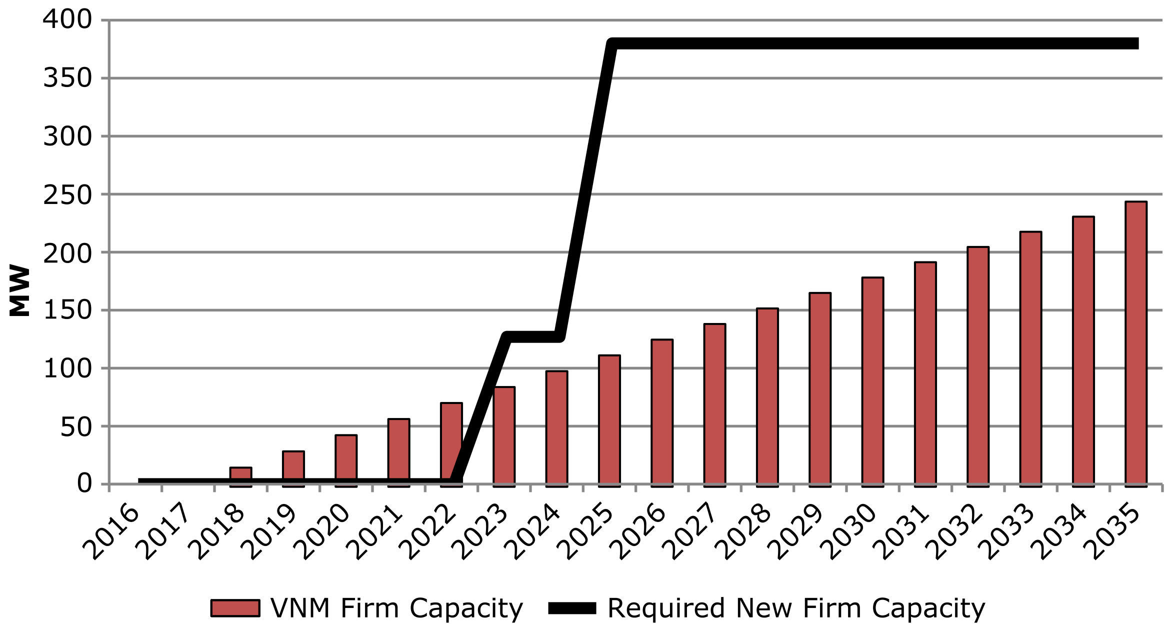


System-level Impacts

- The Ministry examined the potential for system impacts based on an assumed level of average uptake per year of 50 MW of new distributed generation (solar PV) capacity per year from 2018 to 2035. The modelling results showed potential for impacts on the system in the following ways:
  - System benefits:
    - Avoided electricity costs: the decrease in cost of service due to fuel savings and other costs of generation displaced by new DG capacity.
    - Avoided/deferred capacity investments: the decrease in cost of service due to new DG capacity displacing the need for investment in new capacity (natural gas) requirements under the OPO.
    - Decrease in emissions – relative to the baseline OPO scenario, there would be a decrease in emissions and associated costs.
  - System costs:
    - Costs from lower overall demand – fixed system costs (portions of the global adjustment and transmission charges) would be spread over less overall demand, shifting a higher cost burden to the rest of customers, if cost recovery of NM is not addressed.
    - Potential increase in electricity bills/rates - in the absence of rate restructuring to avoid cross-subsidization, there would be an increase in the electricity bills of non-net metered customers, while net-metered customers would see decreases in their overall bill payments in most cases.
    - Less opportunity for lower-cost energy and capacity options – although NM does lead to system benefits as described above, this analysis does not take into account the fact that the same benefits could be realized by lower-cost options (e.g. a capacity auction would likely procure capacity that is lower cost than NM capacity).

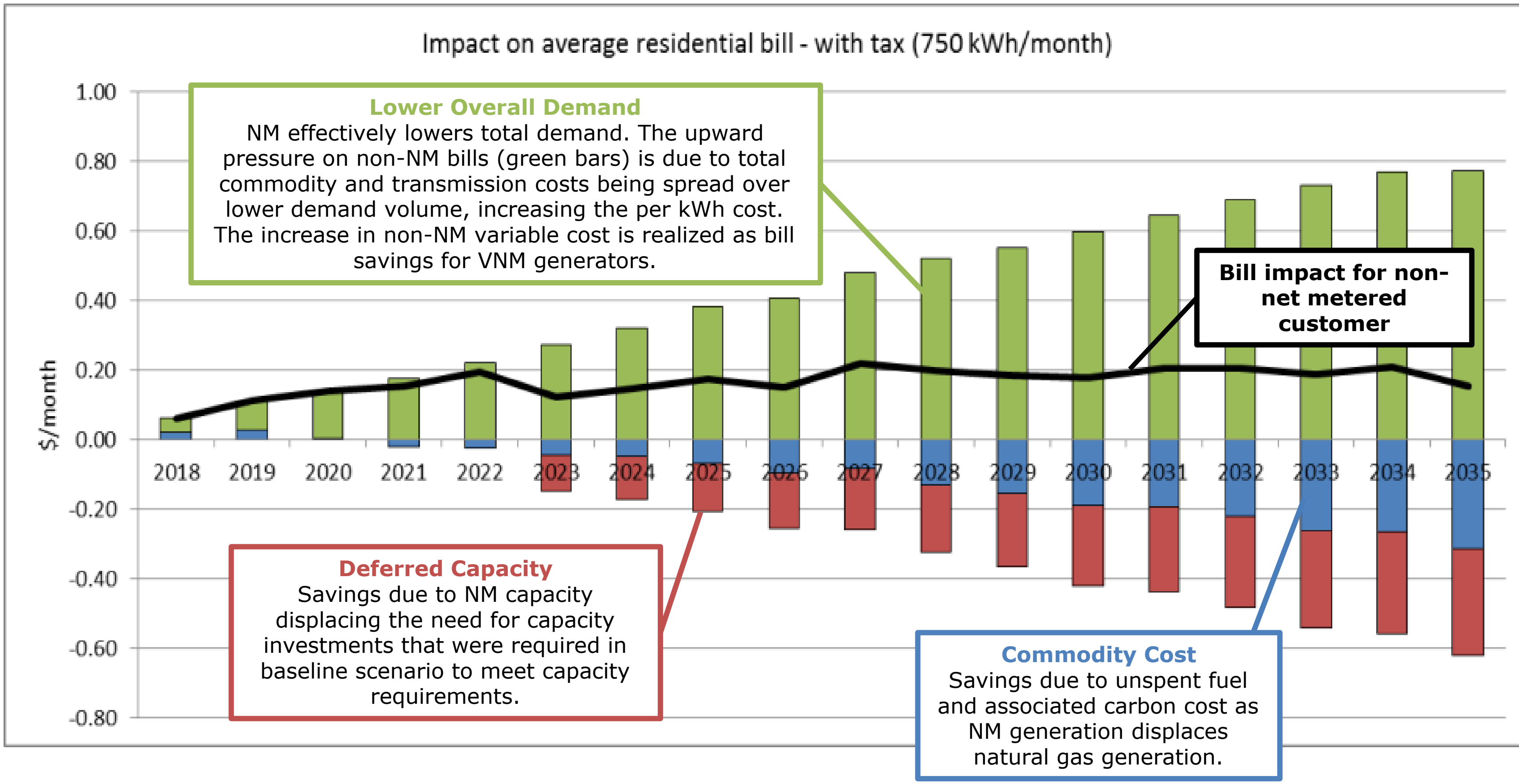
System Impacts (cont'd)

- The graph below shows the build out of firm photovoltaic capacity in each year that is assumed in the illustrative NM scenario (red bars).
- The black line indicates the *new* capacity that is calculated to be required based on the 2016 Ontario Planning Outlook which assumed new gas facilities in order to achieve the required new firm capacity.
- Firm capacity factor – the fraction of installed capacity that is expected to be available at the time of peak demand – is assumed to be 30% for solar photovoltaic generation and 89% for gas generation.
- The illustrative build out of NM capacity displaces the need for some additional new capacity investments.



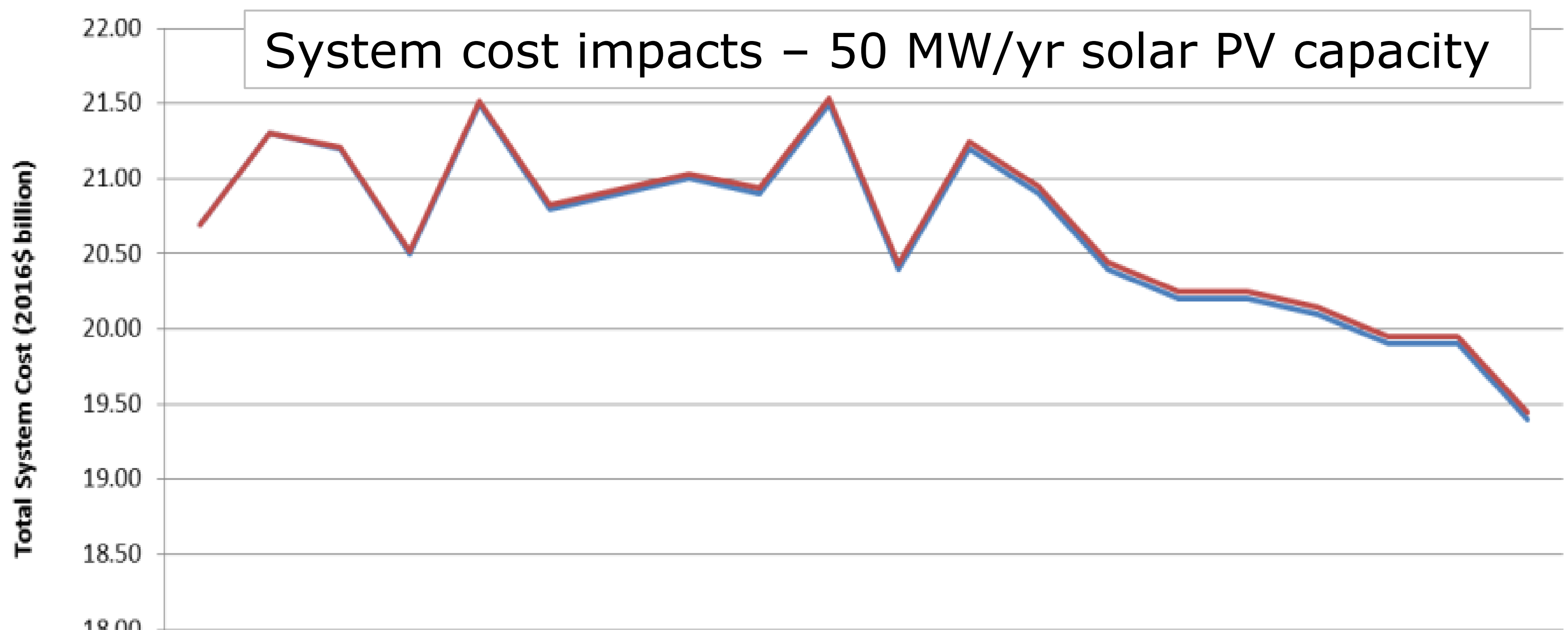
Potential Impacts on Non-Net Metered Customers

- The graph below shows potential rate impacts for an assumed 50 MW per year of net metering capacity on **non-net metered customers only** over time. Deferred capacity (red) and commodity costs (blue) are savings to the cost of service, whereas lower overall demand (green) represents cost-shifting that could occur, if issues of cost recover and cross-subsidization effects are not addressed.



Impact on Total System Costs

- Net costs for the projected level of net metering uptake are minimal in relation to total system costs. The graph below shows the expected cost difference between the baseline case (red) and projected 50 MW per year of net metering solar PV capacity (blue).



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
IESO Baseline	20.70	21.30	21.20	20.50	21.50	20.80	20.90	21.00	20.90	21.50	20.40	21.20	20.90	20.40	20.20	20.20	20.10	19.90	19.90	19.40
With net metering	20.70	21.30	21.21	20.52	21.52	20.82	20.93	21.03	20.93	21.54	20.44	21.25	20.94	20.44	20.24	20.25	20.15	19.95	19.95	19.45

Appendix 2: Stakeholder Engagement

Stakeholder Engagement

Engagement	Summary of Stakeholder and Indigenous Engagement Activities
Webinar	• Hosted by Ministry on January 12, 2017 to introduce the key concepts to be explored in Part 2 and drive feedback through questionnaire. • Approximately 450 registered for the webinar, including individuals from industry (270), LDCs (63), municipalities (18), government (26), Indigenous groups (6), co-ops (7).
Questionnaire	• Key vehicle to capture written feedback. • 54 submissions were received from LDCs, municipalities, industry associations and renewable energy companies by the February 8, 2007 submission deadline.
Advisory Working Group (AWG)	• Composed of representatives from Toronto Hydro, Hydro One, Alectra, Oshawa PUC, Niagara Peninsula Energy, CanSIA, RESCO Energy, Potentia Solar, IESO, OEB and the Ministry of Energy. • Met four times between December and March 2017 to discuss: engagement plans; policy objectives and program design principles; program design considerations and business models; and a cost benefit framework for evaluating program design options.
Targeted Meetings	• Engaged key stakeholders on specific topics. • Meetings held with: Oxford County, Multi-unit residential building managers, CanSIA and group of solar developers, Canadian Biogas Association, Ontario Waterpower Association, Bullfrog Power, Large LDCs, Electricity Distributors Association and member LDCs, LDC Affiliates, IESO, and OEB.
Indigenous	• A targeted meeting was held with Lac des Mille Lacs First Nation, Wikwemikong Unceded Indian Reserve, Jazz Solar; and a meeting was held with Hydro One Remote Communities. • Direct outreach to the Métis Nation of Ontario and the Chiefs of Ontario, which included the offer of one-on-one meetings to discuss any feedback or concerns. • Ministry to continue to inform Indigenous communities on potential updates to the net metering program as opportunities arise, including a planned meeting with the IESO Indigenous Working Group in May 2017.

Appendix 3: Experience in Other Jurisdictions

Net Metering in Other Jurisdictions

- The following examples of net metering programs in New York, California and Hawaii illustrate some of the challenges regulators are facing in jurisdictions with high net metering interest and uptake:

  - **New York State** has enabled a TPO/VNM model that is open to all participants, with a project cap of 2 MW and a statewide monetary incentive available to approximately 2 GW of projects.
    - Projects must be located in the same service territory as their customers. Applications to site projects have been disproportionately located in low-density population service territories, leading to a supply-demand mismatch across the state (e.g. strong customer demand in New York City, with very few proposed projects).
    - Very few projects have come online, despite over 1,600 applications being submitted over the last year. With no commercial operation date requirements in the first-come, first-serve application process, projects with either no customers or load are stuck in the approvals process, leading to a glut of incentive entitled capacity with no phasing or location strategy.

  - **California's** net metering program has been successful at driving strong program uptake under a TPO framework that has offered Time of Use rates and subsidies, but concerns have arisen from utilities that compensation is too high.
    - This year, California's big three utilities will be filing general rate cases that shift the hourly schedule of on-peak and off-peak hours – and the widely varying retail prices per kWh that go with them, into much later in the day.
    - Solar industry experts expect these changes will significantly lower the value of future net -metered, on-site projects from 15% to 20% for residential systems, and from 20% to 40% for schools or public agencies.

Net Metering in Other Jurisdictions *(cont'd)*

- **Hawaii** *(sourced from Hawaiian Electric website)*
  - Since 2001, over 60,000 customers installed systems under the Hawaiian Electric net metering program, mostly driven by the high cost of electricity in Hawaii (average 33¢/kWh).
  - As of October 2015, Hawaiian Electric stopped accepting net metering applications due to overwhelming participation and developed of a new Distributed Energy Resource Program, which includes the Customer Self-Supply (CSS) and Customer Grid-Supply (CGS) programs.
  - CSS provides retail rate credits and is intended for customers who intend to only self-consume. Electricity exported to the grid does not receive a credit and a standardized $25/month connection charge is applied to the account.
  - CGS customers receive a credit for exported electricity (up to 100kW capacity) that is less than the retail rate (15.07-27.88¢/kWh). Regional credit rates and capacities limits are set based on local system needs.