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London Economics International LLC

Approaches to Utility Remuneration and Incentives

Prepared for:

The Ontario Energy Board

www.londoneconomics.com

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To provide context for potential approaches to utility remuneration in Ontario, LEI will review experiences in other jurisdictions

- Exploration of changes to utility remuneration is driven by the desire to encourage continuous improvement and greater economic efficiency while creating a foundation for innovation which benefits customers

- Prior to considering changes to utility remuneration, it is important to understand what we are changing from

- As such, we will begin with an overview of Ontario's current remuneration policies and rate-setting options

- We will then look to other jurisdictions (the United Kingdom, New York, and California) to gain insight into various examples and lessons learned with regards to utility remuneration

- Overall, these case studies offer relevant takeaways on the challenges encountered, and the nature of solutions developed in their respective contexts

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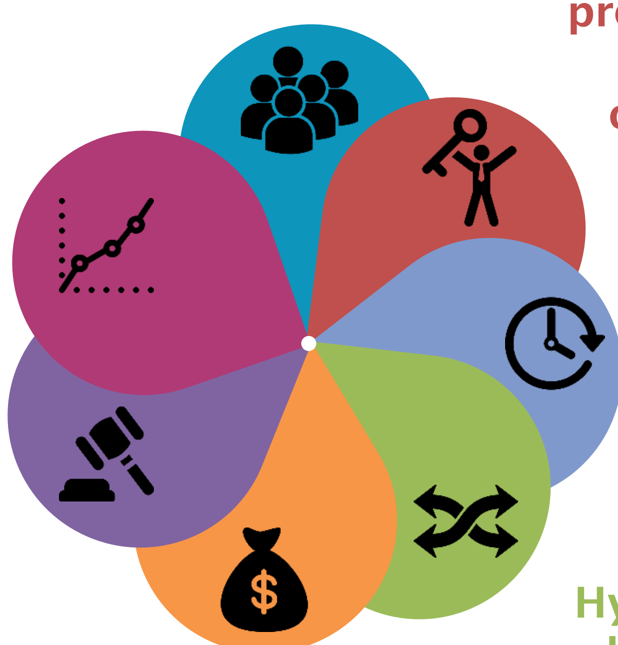
Ontario has one of the more sophisticated regulatory frameworks in the world, which can be characterized by numerous defining features

ONTARIO'S DEFINING ASPECTS

Relatively large number of distributors

Significant provincial and municipal ownership

No supply function for distributors



Approximately 20 years of regulatory experience in the power sector

Deployment of performance-based regulation ("PBR")

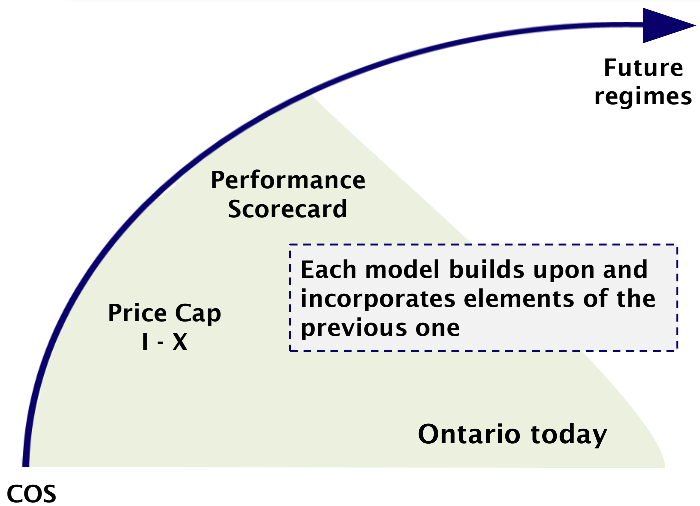
Hybrid of planned and market approach to generation development and dispatch

Use of Global Adjustment to fund capacity and policy objectives

Ontario's current regulatory framework has evolved from COS, to IRM focused on productivity, to a broader scorecard-based incentive structure

- **The current regime:**
  - allows utilities to choose from a menu of incentive options
  - uses a scorecard to monitor outcomes
  - deploys benchmarking to drive efficiencies
- **Under the Renewed Regulatory Framework ("RRF"), distributors have 3 options for setting rates: Price Cap IR, Custom IR, or an Annual IR Index**
  - RRF calls for distributors to focus on **customer preferences** and demonstrate that investment plans support **cost-effective planning and operation**

Progression of remuneration models



Electricity distributor scorecard metrics

Customer focus	Operational effectiveness	Public policy responsiveness	Financial performance
Service quality, customer satisfaction	Safety, system reliability, asset management, cost control	Conservation and demand management, connection of renewable generation	Financial ratios for liquidity, leverage, and profitability

Source: OEB. *2017 Sector-Wide Consolidated Scorecards of Electricity Distributors.* October 2018.

Ontario distributors have three rate-setting options, choosing the method that best meets their requirements and circumstances

Key elements of the three rate-setting options

Setting of Rates		Price Cap IR	Custom IR	Annual IR Index
"Going-in" Rates		Determined in a single forward test-year COS review	Determined in a multiyear application review	No COS review, existing rates adjusted by the Annual Adjustment Mechanism
Form		Price Cap Index	Custom Index	Price Cap Index
Coverage		Comprehensive (i.e. Capital and OM&A)		
Annual Adjustment Mechanism	**Inflation**	Composite Index	Distributor-specific rate trend for the plan term to be determined by the Board, based on: (1) the distributor's forecast (revenue and costs, inflation, productivity); (2) the inflation and productivity analyses; and (3) benchmarking to assess the reasonableness of the distributor's forecasts	Composite Index
	Productivity	Peer Group X-factors comprised of industry TFP growth potential and a stretch factor		Based on Price Cap IR-X-factors
Role of Benchmarking		To assess reasonableness of distributor cost forecasts and to assign stretch factors		N/A
Sharing of Benefits		Productivity factor		
		Stretch factor	Case-by-case	Highest Price Cap IR stretch factor
Term		5 years (rebasing plus 4 years)	Minimum term of 5 years	No fixed term
Z factors		Same as in the 3rd generation incentive regulation		
Performance Reporting & Monitoring		A regulatory review may be initiated if a distributor's annual reports show performance outside of the +/- 300 basis point earnings dead band or if performance erodes to unacceptable levels		
Appropriate for		Distributors that anticipate some incremental investment needs will arise during the plan term	Distributors with significantly large multi-year or highly variable investment commitments with relatively certain timing and level of associated expenditures	Distributors with relatively steady state investment needs

Source: OEB. *Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach.* October 2012. p.13.

The underlying key issues prompting consideration of change in utility remuneration are wide ranging

01 Rapid pace of evolution

Motivation for evaluating changes to utility remuneration is driven by **declining technology costs** and potential for increased customer choice

02 Aligning capex and opex incentives

Alignment requires a margin that encourages utilities to treat capex and opex interchangeably, and leads to **ownership and capital neutral decisions**

03 Managing uncertainty and allocating risk

Requires advanced **scenario planning** tools and **due diligence** on the part of utilities

04 Providing greater customer choice

Will require consideration of **what** sorts of choices are valuable to consumers, **how much** it costs to make that choice available, and how choice can be allowed without creating **intraclass subsidies**

05 Funding public policy mandates

The prospect of **grid defection** limits policymakers' ability to use the distribution bill to accomplish a range of social objectives

06 Reassessing the regulatory compact

Involves refining the understanding of the **obligation to serve** and what constitutes **just and reasonable rates**

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The jurisdictional case studies selected for review provide initiatives and lessons for Ontario

▶ Jurisdictions reviewed include the UK, New York, and California

- These jurisdictions share a common history with Ontario of unbundling from vertically integrated utilities to **disaggregated generation, transmission and distribution** (except for California, which is partially unbundled)
- Akin to Ontario's IESO, many of these jurisdictions have an **independent system operator** which administers a wholesale energy market
- All jurisdictions have moved away from traditional COS regulation

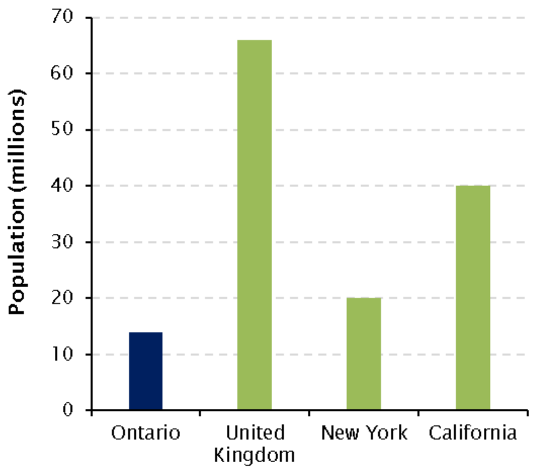
Rationale for selecting case study jurisdictions

	Rationale	Approach	Innovative features
 UK	RIIO (Revenue = Incentives + Innovation + Outputs) performance-based regulatory model underpinned by a focus on total expenditure	PBR underpinned by a focus on totex	• Financial incentives tied to distributor performance outcomes • Sharing of totex savings between customers and the utility
 NY	Ongoing REV and VDER initiatives tackle the evolving role of the distribution utility and the monetization of DERs for utilities and third parties	Hybrid of PBR and DSPP	• Utility demonstration projects under REV to explore new products and services
 CA	Lessons from regulator-led DER Action Plan as well as an incentive pilot mechanism to encourage utility investment in DERs	Three-year rate plans (COS hybrid)	• Ownership-neutral DER incentive pilot mechanism • DER wholesale market participation initiative under development

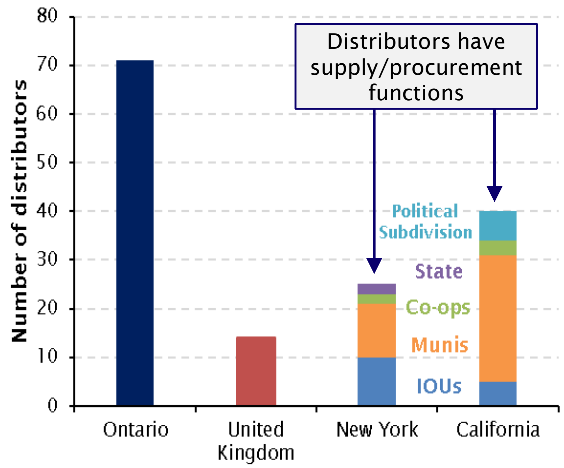
Acronyms: Reforming the Energy Vision ("REV"); Value of Distributed Energy Resources ("VDER"); Distributed System Platform Provider ("DSPP")

Of the jurisdictions selected, Ontario is most comparable to New York in terms of installed capacity and annual load

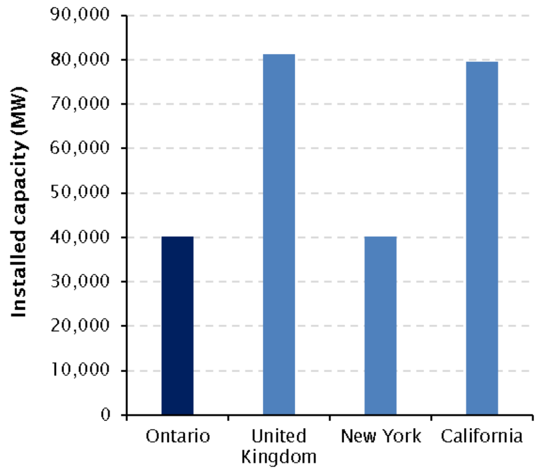
Population



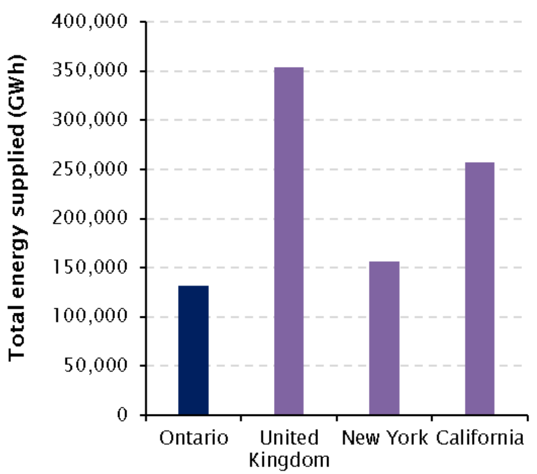
Number of distributors



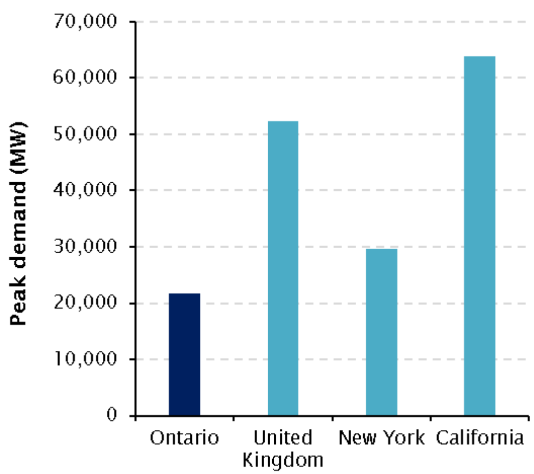
Installed capacity



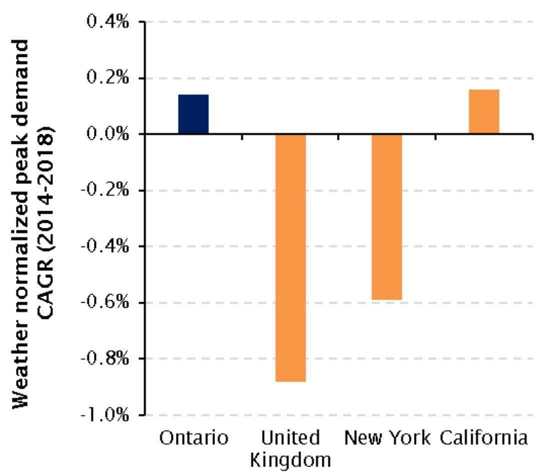
Total energy supplied



Peak demand



Load growth



Sources: OEB; IESO; Digest of UK Energy Statistics; Ofgem; New York State Comptroller; NYISO; California Energy Commission; Energy Information Association; United States Census Bureau; US Bureau of Economic Analysis.

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The RIIO framework provides a model of how a totex approach can be implemented

Revenue = **Incentives** + **Innovation** + **Outputs**

- **RIIO is a performance-based regulatory ("PBR") model underpinned by a focus on total expenditure ("totex")**
  - RIIO-ED1 is the RIIO model applied to the electricity distribution sector – it sets the outputs that distributors need to deliver and the revenues they are allowed to collect for an eight-year period (April 1, 2015 to March 31, 2023)
- **The totex approach combines a portion of utility capital expenditures ("capex") and operating expenditure ("opex") solutions into one regulatory asset that allows a rate of return on both**
- **The UK's PBR model employs a building blocks approach that calibrates the indexing formula based on forward-looking revenue requirements of each regulated utility over the term of the price controls**
  - Revenue requirements are set based on estimates of the likely capital and operating costs and return of and return on an efficient asset base

RIIO Objectives

Focusing on stakeholders in their decision-making processes	Investing efficiently to ensure continued safe and reliable services at a low cost
Innovating to lower network costs for consumers	Supporting the government's environmental objectives of development of a low carbon economy

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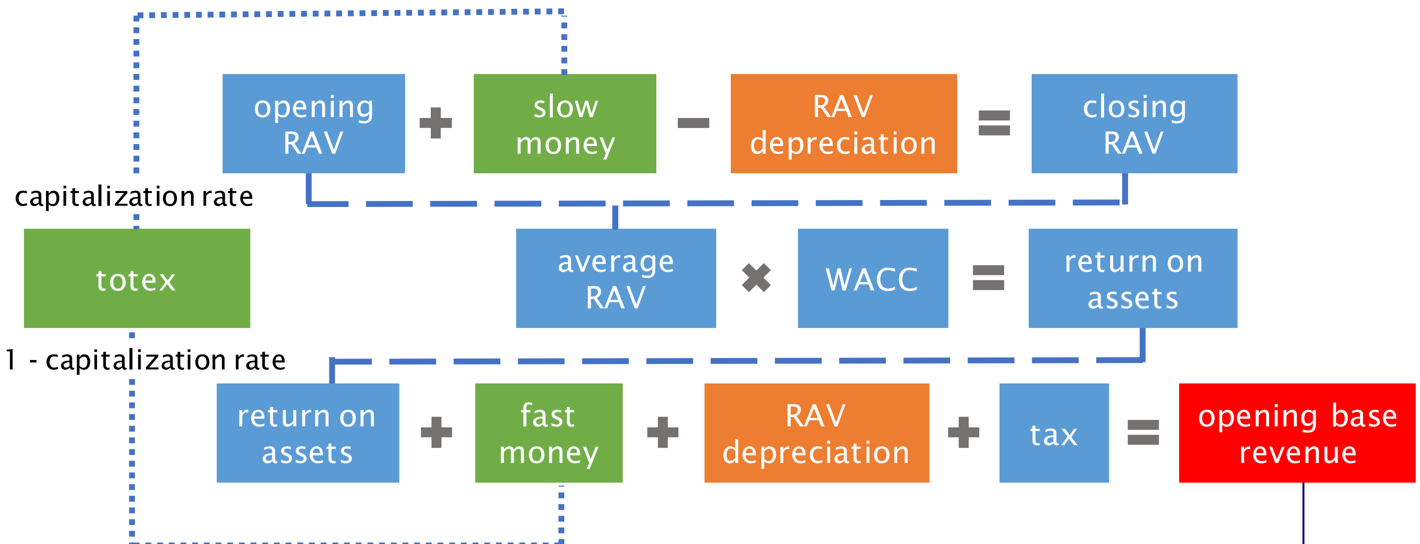
Totex adds a predetermined amount of a utility's annual expenditure to its rate base

- **The base revenue requirement is estimated in the same way as the standard RPI-X building blocks approach with a return on the regulated asset value ("RAV"), depreciation allowance, an operating cost allowance, and tax**
- **However, the key difference under the RIIO model is the use of a portion of the totex (or the slow money), and not the actual capex, to the additions to the asset base**

Components of opening base revenue



Simplified process for calculating allowed revenue

Allowed revenue = [Opening base revenue + Totex performance] × Inflation + Incentive payments + Innovation funding + Other

Sources: Ofgem. *Guide to the RIIO-ED1 Electricity Distribution Price Control.* January 18, 2017. p.15; Ofgem. *RIIO-ED1 Annual Report 2017-18.* March 8, 2019. p.14.

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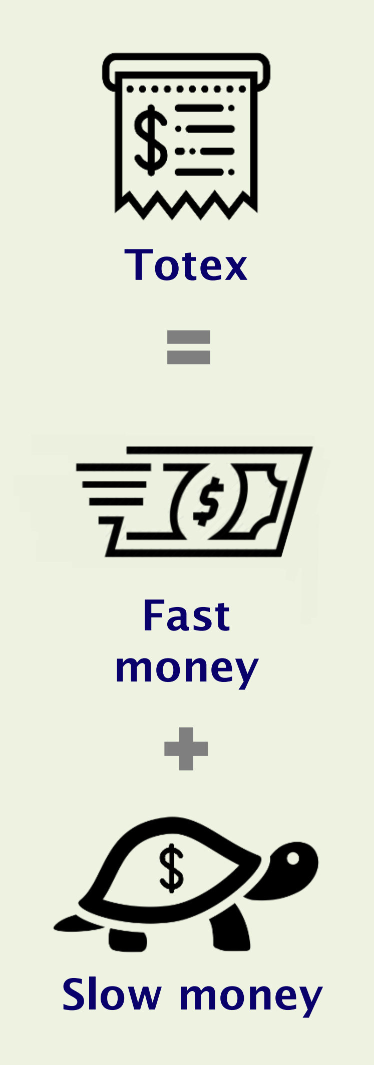
The totex concept is used in RIIO to ensure capex and opex are treated interchangeably

- **Under the totex approach, utilities are incentivized to consider whole life costs, rather than being driven to choose between opex and capex, and are thus encouraged to choose the most overall cost-effective solution**
- **Totex is comprised of "fast" money and "slow" money**
  - **Fast money** represents the money funded in the year incurred, and is equivalent to the opex
  - **Slow money** represents the money added to the regulatory asset value ("RAV") that is funded over time through allowances for depreciation and return on capital, and is equivalent to the capex

Totex includes "*all economical and efficiently incurred expenditure relating to a [utility's] regulated [distribution] business*," including non-operational capex and business support costs, and excluding pension deficit repair payments, statutory/regulatory depreciation and amortization, etc.

(Ofgem, 2013)



Source: Ofgem.

The RIIO model provides framework for rewards and penalties to drive desired outcomes for utility performance

▶ The totex capitalization rate is the expected future opex-capex split and determines the proportion of totex added to the RAV (i.e. slow money)

- Signifies proportion of the utility's expenditure that is funded over the long-term
- According to Ofgem, the "*[capitalization] rate refers to the speed that company expenditure is paid for by consumers*" and so, "*a higher [capitalization] rate means a larger proportion of total spend is paid for by consumers in the future, rather than now*"
- Set at the outset, generally based on the historical and forecast split of capex and opex relative to the totex, and differs for each utility

Relevant achieved results (2015 to end of fiscal year 2017/18)

Reliability and availability outcomes: the number of customer interruptions fell by 11% and the duration of interruptions decreased by 9% on average

Environmental outcomes: distributors were on track to meet their carbon footprint reduction targets, but fell short of their Sulphur hexafluoride emissions and oil leakage targets

Financial performance: in terms of totex budgets, distributors spent £10.2 billion ($18.9 billion CAD) out of the £10.9 billion ($20.2 billion CAD) of approved expenditures, amounting to savings of 6% or £684 million ($1.2 billion CAD)

- Customers will receive 47.5% of these savings, the remaining 52.5% will be retained by distributors

Source: Ofgem. *RIIO-ED1 Annual Report 2017-18.* March 8, 2019.

The next iteration of RIIO (RIIO-2) addresses some of the shortcomings Ofgem has identified about RIIO-1

- **Adopted in July 2018, RIIO-2 is the next iteration of RIIO price controls**
  - The new framework will begin in April 2021 for gas distributors and gas and electricity transmitters, and **April 2023 for electricity distributors**

Issues identified in RIIO-1 and relevant solutions in RIIO-2

Shortcomings of RIIO-1	Improvements in RIIO-2
Eight-year rate plan with limited regulatory flexibility in a rapidly changing industry	Default price controls reduced to **five-year terms** (with the option to extend if there are demonstrated **significant net benefits to consumers**)
Limited **stakeholder engagement** in the target-setting process	Setting up **internal customer engagement groups** (within distribution companies) and user groups (transmission sector) to ensure business plans align with customer needs; creation of a **central, independently-chaired RIIO-2 Challenge Group** which will challenge business plans; introducing **public hearings**
Limited effectiveness in **incentivizing innovation**	Retaining an **innovation stimulus package**, limited to innovation projects that might not otherwise be delivered under the core RIIO-2 framework
Price controls seen as overly **complex and burdensome**	Simplified price controls through establishing **automatic refunds** to customers and using **indexation** to minimize forecasting error where feasible

Source: Ofgem. *RIIO-2 Framework Decision.* July 30, 2018; Ofgem. *RIIO-2 Enhanced Stakeholder Engagement Guidance – Version 1.* April 9, 2018.

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Since the initiation of REV, the Public Service Commission issued an order setting forth a new model framework for ratemaking and utility revenue

- **NY utilizes multi-year rate plans – which is a PBR approach to ratemaking**
- **The ratemaking order delineates boundaries of a modern ratemaking model that augments conventional cost-of-service ratemaking by adding outcome-based incentives (earning adjustment mechanisms or "EAMs") and market-based platform earnings (platform service revenues or "PSRs")**
  - Utilities in New York submit a rate plan every three years
  - EAMs and PSRs are forms of earning opportunities that differentiate New York's ratemaking process from a traditional PBR process

Platform service revenues

PSRs are new forms of utility revenues associated with the **operation and facilitation of distribution-level markets** – utilities may generate revenues by replacing traditional infrastructure with "**non-wires alternatives**"

- PSRs are generally allocated at 80% to ratepayers and 20% to utility shareholders (although this is subject to change)

Earning adjustment mechanisms

EAMs **encourage innovation** across four categories: system efficiency, energy efficiency, customer engagement, and DER interconnection – utilities propose **metrics and targets** to be approved by the Public Service Commission ("PSC")

- EAMs are similar to Ontario's performance scorecard metrics, with added financial implications

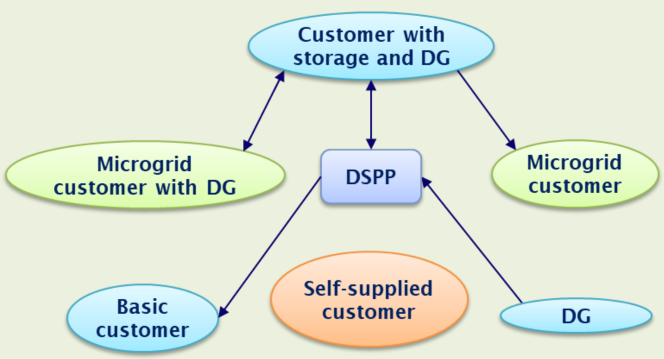
Source: NY PSC. *Order Adopting a Ratemaking and Utility Revenue Model Policy Framework. Case 14-M-0101.* May 19, 2016.

Reforming the Energy Vision ("REV") conceptualizes the DSPP model for the distribution utility as incremental to their current role

- **REV is a multi-pronged strategy to develop a clean, resilient, and affordable energy system, initiated by the New York PSC**
  - Prioritizes energy efficiency and clean, locally produced power
  - Encourages deeper DER penetration
  - Provides guidance on the supporting tariff design structures required

Expanding the traditional distribution utility model

Utilities act as distributed system platform providers ("DSPPs") – which incentivizes them to consider DER solutions as an alternative to traditional grid investments



Sample demonstration projects

The PSC directed the six large IOUs in NY to develop and file demonstration projects to test new approaches to distributed resource adoption:

- **Battery storage systems for Con Edison's customers**, which will increase energy storage technologies' ability to export power to Con Edison's primary and secondary distribution systems
- **Battery storage innovation for New York City**, which allows large commercial batteries to feed the electric grid and enables utilities to study the impact on existing Dynamic Load Management programs
- **Virtual net metering of solar power for street lighting**, which allows municipalities to use remote solar farms to offset their street lighting costs, while compensating the city for the value of solar power produced

Source: NYPSC. *Annual Report Stat Fiscal Year 2017-2018.* August 7, 2018.

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Value of Distributed Energy Resources (“VDER”) provides guidance on the tariff framework necessary to support third party owned DERs

- **The ongoing VDER initiative tackles the evolving role of the distribution utility and the monetization of DERs for utilities and third parties**
- **The Value Stack compensation methodology represents a step to replace Net Energy Metering with a more accurate valuation and compensation of DERs**
  - VDER factors include energy price, avoided carbon emissions, cost savings to customers and utilities, as well as other savings from avoiding expensive capital investments
- **Since its implementation in 2017, NY PSC Staff filed two white papers with recommendations for improving the VDER tariff, specifically relating to VDER compensation for avoided costs and VDER capacity value compensation**
- **In April 2019, the NY PSC released an updated Value Stack Order, which adopts recommendations from the white papers with modifications**

Goals and components of the Value Stack Order

Goals

- Improve the **predictability, transparency, and accuracy** of compensation
- Encourage robust **community distributed generation** development

Achieved through

Components

✓ Calculation of the **Demand Reduction Value, Locational System Relief Value**, and **Capacity Value**

✓ A new **Community Credit**

Sources: NY PSC. *Order on Phase One Value of Distributed Energy Resources Implementation Proposals, Cost Mitigation Issues, and Related Matters. Case 15-E-0751.* September 14, 2017; NY PSC. *Order Regarding Value Stack Compensation. Case 15-E-0751.* April 18, 2019.

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California's ratemaking framework involves three-year rate plans set through traditional rate proceedings

- **The California Public Utilities Commission ("CPUC") regulates the three largest IOUs operating in California: Pacific Gas and Electric ("PG&E"), Southern California Edison ("SCE"), and San Diego Gas and Electric ("SDG&E")**
  - The CPUC also has regulatory authority over Electric Service Providers and Community Choice Aggregators that supply power in California
- **The CPUC sets electric rates in thee-year plans through traditional General Rate Case ("GRC") proceedings**
  - The CPUC is also responsible for monitoring and enforcing safety standards in the industry, and allocating the capital needed to maintain and develop California's electric infrastructure
  - It also undertakes environmental assessments of proposed transmission lines, power plants, and other major electric facilities

CPUC's GRC proceeding steps

GRC Phase I	Determine the total amount of revenue the utility is authorized to collect
GRC Phase II	Determine the share of the cost each customer class is responsible for, as well as the rate schedules for each class
CPUC review	CPUC approves the budget for the first year of the GRC cycle (test year) and prescribes inflation adjustments and other factors that may affect costs for years 2-3 (post-test years)

Source: CPUC. "What is a General Rate Case ("GRC")?" Web. March 26, 2019.

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California's DER Action Plan seeks to align legislative and policy measures into three broad categories

- **In November 2016, the CPUC released the DER Action Plan to align the separate proceedings on DER and related issues**
  - The Action Plan aims to guide the development and implementation of DER policy and establish a forum for considering innovative rate design

- **The Action Plan divides DER policy activity into three groups:**

1. Rates and Tariffs

- A continuum of rate options available for customers
- Rates reflect time-varying marginal cost
- Processes for adopting innovative rates are flexible and timely
- Rates remain affordable for non-DER customers

2. Distribution Planning, Infrastructure, Interconnection, and Procurement

- DERs meet grid needs through a seamless planning and sourcing process
- IOUs are motivated to accelerate deployment of DERs regardless of the impact on distribution capacity investment opportunities
- DER sourcing is technology-neutral and competitively procured
- Full value of DERs is reflected including grid services, renewables integration and GHG value

3. Wholesale DER Market Integration and Interconnection

- DERs participate as grid resources through higher visibility and dispatchability
- DERs are enabled to earn multiple revenue streams by delivering multiple services to the wholesale market
- Non-discriminatory market rules including for mobile electric transportation resources

Note: The Action Plan was updated in May 2017, with non-substantive changes made to improve clarity.
Source: CPUC. *California's Distributed Energy Resources Action Plan: Aligning Vision and Action.* 2016.

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The integrated DER incentive pilot is an example of removing utility DER ownership bias and compensating utilities for new responsibilities

- **In December 2016, the CPUC adopted an Integrated Distributed Energy Resource ("IDER") incentive pilot mechanism to encourage the three largest IOUs (PG&E, SDG&E, and SCE) to invest in pilot DER projects**
- **Through the incentive mechanism, the CPUC aims to encourage the deployment of DERs as an alternative to additional capital expenditures on traditional distribution infrastructure**
  - The incentive is set at a 4% pre-tax basis applied to the annual payment for the DERs which are alternative to the traditional distribution investment
  - The incentive allows the utility to record the value of the incentive in a balancing account for later recovery

Summary of key steps involved in CPUC's incentive pilot mechanism

Project identification	Complete solicitation process	Recovery of incentive
Utilities have four months to identify at least one project for Incentive Pilot via a **Distribution Planning Advisory Group ("DPAG")**	Utilities have **14 months** to complete the solicitation process to contract DER projects	In the case of successful solicitations (i.e. deferral of the traditional distribution expenditure is achieved), utilities record the value of the incentive for recovery in an **Energy Resource Recovery Account** compliance application

Source: CPUC. *Decision Addressing Competitive Solicitation Framework*. 2016.

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California's largest IOUs provide examples of both successful and unsuccessful solicitations under the incentive pilot mechanism

Successful solicitations

PG&E

- On November 14, 2018, PG&E issued Request for Offers ("RFO") in response to the CPUC's incentive pilot mechanism
- Two DER contracts were approved by the CPUC on May 25, 2019 with a total capacity of 2.75 MW
- The pilot demonstration will be conducted at PG&E's Gonzales substation, an area expected to experience overload conditions due to peak demand
- The additional capacity from the DERs will be used to address thermal overloads in the area

SOUTHERN CALIFORNIA EDISON Energy for What's Ahead

- SCE began soliciting in January 2018 and selected the Eisenhower Project in Cathedral City and the Newbury Project in Thousand Oaks
- Following the completion of the solicitation in May 2018, SCE received the CPUC's approval for a total of 9.5 MW of in-front-of-the-meter energy storage contracts which will defer the substation upgrades by 9.5 years

Unsuccessful solicitations

SDGE

- SDG&E started its solicitation process for the pilot in January 2018
- SDG&E issued an RFO to solicit energy efficiency, demand response, renewable generation resources, energy storage, and/or distribution generation resource projects for installation in Circuits 303 and 783 near Carlsbad, California
- On July 2, 2018, SDG&E reported to the CPUC that its solicitation process did not receive any cost-effective bids, and that it would proceed with traditional wire solutions instead

Sources: PG&E. "2018 IDER RFO." Web. March 26, 2019; PG&E. *Advice Letter 5531-E.* June 5, 2019; CPUC. *California Smart Grid – Annual Report to the Governor and the Legislature.* February 2019; SDG&E. *Advice Letter 3245-E.* August 14, 2018.

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Case studies provide insight into types of initiatives which could be considered in Ontario

ENHANCED STATUS QUO

Builds upon **current IRM practices** with added features to address the **balance** between **customer choice** and **helping utilities mitigate risk** (e.g. optional shorter year terms/off-ramps, increased customer control of the level of service reliability, addition of DER connection time to scorecard metrics)

MARGIN TARGETING

Shifts the focus from capital in rate base to providing utilities a **margin** to provide services in a **technology and ownership neutral way** – DER host utilities are provided a minimum guaranteed margin in exchange for a requirement of ownership and technology neutral investments

TOTEX

Totex shifts the focus from capital in rate base by combining a portion of utility **capital expenditures and operating expenditures** into **one regulatory asset** that allows a rate of return on both

DSPP

The DSPP model whereby the utility performs the role of a **distribution system operator** capable of managing more bi-directional flows, engaging in ownership and technology neutral procurements, and compensating DERs in cases where they offset distribution utility costs