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ISO Cost Recovery Mechanism

Jurisdictional Scan

A report from FTI Consulting for IESO Nova Scotia

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Glossary

AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AESO	Alberta Electric System Operator
AUC	Alberta Utilities Commission
BSUoS	Balancing Services Use of System
CAISO	California Independent System Operator
DTS	Demand Transmission Service
FERC	Federal Energy Regulatory Commission
FTI	FTI Consulting LLP
FTI Business Case Report	Assessment of the Nova Scotia Value Framework and Business case conducted by FTI for IESO NS
GB	Great Britain
GMC	Grid Management Charge
GRA	General Rate Application
IESO NS	Nova Scotia Independent Energy System Operator
IESO Ontario	Ontario Independent Electricity System Operator
ISO	Independent System Operator
ISO-NE	ISO New England
LSE	Load Serving Entity
MSA	Market Services Agreement
MP	Market Participant
NE	New England
NEM	National Electricity Market (of Australia)
NEPOOL	New England Power Pool
NESO	National Energy System Operator
NSP	Nova Scotia Power
OATT	Open Access Transmission Tariff
OEB	Ontario Energy Board
Ofgem	Office of Gas and Electricity Markets
OPG	Ontario Power Generation

ROE	Return on Equity
RTO	Regional Transmission Organization
SC	Scheduling Coordinator
TNSP	Transmission Network Service Provider
TO	Transmission Owner
Tx-Connected	Transmission Connected
VIU	Vertically Integrated Utility

1. Introduction

IESO Nova Scotia

IESO Nova Scotia (“IESO NS”) was recently established as the independent system operator (“ISO”) of Nova Scotia, taking over the system planning and procurement functions of the incumbent vertically integrated utility (“VIU”), Nova Scotia Power (“NSP”).

The newly created IESO NS is an independent, non-profit organization currently trusted with responsibility for planning and procurement, and is soon expected to take over the system operation function from NSP. The transition from NSP is planned in two broad phases:

- **Phase 1** (already established): planning and management responsibilities, including the integrated resource plan process, which includes both energy resource and transmission planning activities, interconnection processes, and energy resource procurement, and
- **Phase 2** (planned for 2027): operation of the electricity transmission grid, and other roles with a day-to-day operational focus.

The rationale for establishing the IESO is to create a body with an enhanced focus on the electricity system’s requirements (separate from the interests of a VIU), which is expected to yield strategic benefits across planning, procurement and system operations.¹

ISO Costs

While there are important benefits from the IESO transition, it must be acknowledged that certain costs are inherent to running the IESO in Nova Scotia. These include:

- Capital, operating, maintenance and administrative costs (referred to collectively as “**Core Costs**”). These are internal costs related to ISO staff, control room operating and capital expenditures, load forecasting software and running procurement processes;
- Procurement costs, including fixed capacity payments and operational expenses of the procured resources, and ancillary services cost.

A significant portion of the ISO’s costs are not incremental for consumers as a result of having an ISO; rather, many of these costs arise from functions that would otherwise need to be performed by the VIU (e.g., the need for having a control centre and the staff operating it).

Currently, the IESO operates under a temporary mechanism to recover its costs. This mechanism recovers an approved monthly amount that is charged to NSP. However, IESO NS will need to develop an enduring mechanism for the recovery of its costs.

¹ Nova Scotia Clean Electricity Solutions Task Force, 31 January 2024, ([link](#)). IESO NS has engaged FTI Consulting LLP (“FTI”) to conduct an assessment of the Nova Scotia Value Framework and Business case (“FTI Business Case Report”).

In this context, IESO NS has engaged FTI to conduct an international benchmarking exercise on the approaches to cost recovery. The determination of charges to recover the cost to run an ISO varies by jurisdiction, but has similar, underlying fundamentals. In this report, we summarize the results of our jurisdictional scan of different ISO approaches to recovering **Core Costs**.

Benchmarking

While a primary, underlying purpose of an ISO is to independently operate the bulk electricity system as a non-profit entity, the roles and responsibilities of an ISO are not rigidly defined, and the range of functions an ISO typically executes varies (and can vary over time).

No existing ISO is entirely comparable with IESO NS in its current form; however, several ISOs share certain characteristics.² We cover the following ISOs in our jurisdictional scan, which were chosen to represent a variety of relevant peers:

- **Canadian ISOs:** Alberta Electric System Operator (“AESO”) and the Ontario Independent Electricity System Operator (“IESO Ontario”);
- **US ISOs:** ISO-New England (“ISO-NE”) and the California ISO (“CAISO”); and
- **ISOs outside of North America:** National Energy System Operator (“NESO”) in Great Britain (“GB”) and the Australian Energy Market Operator (“AEMO”).

As shown in Figure 1, we have considered four characteristics of IESO NS (utility structure, jurisdictional footprint, age and resource mix of the jurisdiction) and, for each characteristic, mapped a selection of ISOs that share it. These characteristics and the degree to which they are shared with other ISOs are described in more detail in Appendix 1.

Figure 1: Overview of the characteristics of IESO NS shared by other ISOs

CHARACTERISTIC	STRUCTURE	JURISDICTION	AGE	RESOURCE MIX
	Large Incumbent(s)	Single Province within a Nation	Newly Restructured	High Renewables
				
				
				

Source: FTI Analysis, logos from ISO websites.

² We describe the roles and responsibilities of a relevant range of existing ISOs in more detail and contrast them with IESO NS (as well as their costs) in the FTI Business Case Report.

The remainder of the report is structured as follows:

- In Section 2, we summarise our findings;
- In Section 3, we describe the process of how ISO costs are recovered by each benchmarked ISO in the jurisdictional scan;
- In Appendix 1, we provide additional information on ISO tariffs; and
- In Appendix 2, we provide an overview of the ISOs selected for benchmarking.

2. Summary of findings

Market Participants

The costs of running an ISO are recovered from market participants (“MPs”) who directly benefit from the ISO. The MPs applicable to our analysis can be split into four key categories:³

- **Load:** Load Serving Entities (“LSEs”)⁴ who serve ratepayers (e.g. NSP and municipalities) and large loads directly connected to the transmission system;⁵
- **Generation:** Generators or energy resources who produce electricity to supply to the grid (e.g. NSP and independent power producers);
- **Intertie traders:** Traders who use transmission lines to serve load outside of the ISO; and
- **Transmission owners (“TOs”):** Transmission asset owners who own transmission infrastructure.⁶

Generally, load (i.e., LSEs) pay the majority of ISO Core Costs. The costs of other MPs are ultimately recovered from load, so any fees levied on them will eventually end up in customer bills. For example, fees imposed on generators will be considered part of their operating costs, which generally will increase the cost of electricity supply that load pays. Similarly, fees imposed on TOs will be added to their regulated revenue requirement, which is also recovered from load.

Process

Figure 2: Summary of typical process for setting tariffs and recovering costs



The process for setting ISO tariffs to recover Core Costs typically involves four steps:

- 1) Determining the revenue requirement:** Typically, the revenue requirement is determined by the ISO and then approved by a third-party authority. However, in some jurisdictions (e.g. the AESO) it is ratified by the ISO board of the ISO itself.

³ This group could be greater expanded when considering the full benchmarking group, such as financial market participants - only the subset of MPs that are relevant for Nova Scotia are included here.

⁴ LSEs serve retail, or end-use customers. In some jurisdictions these are electric supply only entities (called retailers), while in others the distribution utility is the LSE. Some jurisdictions can have both (e.g. ISO-NE).

⁵ Some grids, such as ISO-NE, transmission-connected (“Tx-connected”) load is formally served by an LSE and therefore ISO core costs are recovered through the same retail rate process as used for distribution-level customers. This is not true in other jurisdictions where large customers directly connected to the transmission system are not served via an LSE, e.g., oil sands or mining in Alberta.

⁶ Only the AEMO charges TOs, see Note 3 of Table 1 for more information.

- 2) Allocating costs to MPs:** The revenue requirement is then allocated across MPs. Some ISOs charge MPs for specific services that create identifiable, incremental costs (e.g., market operation, system impact studies, non-standard information requests).
- **Number of relevant charges:** As shown in Table 1 (number of charges column), some ISOs recover Core Costs through multiple tariffs that split out more specific costs such as market operations from system operation.⁷
 - **Cost burden:** In practice, Core Costs are typically levied on load.
- 3) Setting ISO tariff rates:** For all benchmarked ISOs, the tariff methodology (which specifies the billing determinant⁸ by cost category and MP type) and tariff rates for each period are proposed by the ISO and subsequently approved by the regulator. The ISO forecasts the relevant volumes for each billing determinant. It then calculates the tariff by dividing the allocated cost by the forecast billing determinant.
- **Tariff calculation methodology:** The method used to calculate charges directly affects how costs flow to market participants within each class. Energy-based charges (per MWh) allocate costs proportionally to consumption or production, while demand-based charges (per MW) tie costs to peak usage, reserved capacity, or installed capacity. Some ISOs use transaction-based fees, connection charges, or hybrid approaches combining multiple metrics.
 - **ISO-only fee or integrated tariff:** Some ISOs calculate standalone ISO-only charges strictly to recover their Core Costs, while others roll their costs into a larger existing calculation for other costs such as recovery of transmission system assets.
 - **Updates:** Tariff rates are reviewed and updated periodically (generally annually, but some set rates for the coming 3 to 5 years).
- 4) Collecting tariffs with periodic true-ups:** Billing frequency ranges from daily to monthly settlement, with monthly being the most common.
- **True-up approaches:** Methods vary from quarterly adjustments (e.g., the AESO) to annual adjustments correcting for prior-year variances (ISO-NE, CAISO).⁹

Table 1 below summarizes the different charge structures used by the benchmarking ISOs to recover Core Costs.

⁷ Note that of all considered ISOs NESO is the only ISO (jointly with IESO NS) that does not operate a wholesale energy market. In GB the wholesale energy market is operated by power exchanges.

⁸ **Billing determinants** are the specific units of service consumption, such as megawatt-hours (MWh), megawatts (MW), or number of customers, used to calculate utility charges and determine how a revenue requirement is collected from customers. They are the denominators over which a revenue requirement is spread to determine rates, and later the multipliers applied to approved rates to calculate customers' bills.

⁹ **True-up** utility ratemaking is a regulatory mechanism that reconciles the difference between the estimated revenue requirements (projected costs) and the actually-billed revenues (actual costs) over a specific period, typically one year.

Table 1: Number of Core Cost charges by ISO and format by market participant

ISO	Number of charges ²	Load (LSE and Tx-connected load) ⁴	Generation	Intertie traders	Charge type
General	Varies	Energy consumption, sometimes includes fixed fees	Per unit or load obligation basis	Energy or capacity basis	ISO-only
ISO-NE	3	MW	Per-unit fee	MW	ISO-only
CAISO	2	MWh	MWh	MWh	ISO-only
IESO Ontario	2	MWh	N/A	MWh	ISO-only
AESO ¹	2 ⁵	MWh	MWh (market operation)	MWh/per-transaction	Integrated
NESO	2	MWh	N/A	N/A	Integrated
AEMO ³	3	MWh/per-unit fee	MWh/MW	N/A	ISO-only

Source: See Table 4.

Note: (1) The AESO also has specific service charges, charged on a per service basis and do not vary by market participant/TO; (2) The number of charges refers to the number of separate tariffs used to recover costs applicable to IESO Nova Scotia, as outlined in Table 4 (and is distinct from the recovery format used for each market participant); (3) The AEMO is unusual in that it charges TOs based on metered outflow (MWh); because no other grid charges TOs for Core Costs, TOs are not listed in this table;¹⁰ (4) In some grids, such as ISO-NE, transmission-connected (“Tx-connected”) load is formally served by an LSE and therefore ISO Core Costs are recovered through the same retail rate process as used for distribution-level customers; and (5) The AESO has additional rates that are similar to the transmission service rate discussed in this report, but are not counted in this table because they have similar derivation processes.

¹⁰ A 2022 determination by the Australian Energy Regulator (“AER”) concluded that “Transmission Network Service Providers (“TNSPs”) will be subject to incentive-based regulation over AEMO’s participant fees (excluding network transmission planner function fees), so TNSPs will have an incentive to assist AEMO to minimise AEMO’s costs that eventually flow through to consumers.” See Australian Energy Market Commission, Rule Determination ERC0335, 20 October 2022 ([link](#)).

3. Cost recovery approaches for benchmarked ISOs

This section consists of four subsections that (1) describe the four-step process that ISOs use to determine their Core Costs and recover these costs from MPs, (2) discuss the approaches by which these Core Costs are ultimately recovered from ratepayers across the benchmarked ISOs, (3) list the number of charges each of the benchmarked ISOs uses to recover its costs, and (4) consider how these findings could be relevant to Nova Scotia.

Overview of process

Most ISOs operate on a cost recovery basis rather than for profit, that is, they aim to recover their approved costs through regulated¹¹ tariffs and fees with no ability to earn a profit.¹² Figure 3 below illustrates the typical process for setting tariffs and recovering these costs. We discuss each step and how it can differ between ISOs further below.

Figure 3: Summary of typical process for setting tariffs and recovering costs



Step 1: Determination of revenue requirement

The process begins with the ISO forecasting its revenue requirement for its Core Costs over the period of assessment, which is the revenue that it must recover through its tariffs and charges to fund the approved expenditure. This is typically approved by a third-party authority. For example, in Ontario the IESO prepares a 3-year business plan which includes forecasted costs that are then approved by the Ontario Energy Board (the regulator). The exception is Alberta where the revenue requirement to cover Core Costs is approved internally by the AESO Board of Directors.¹³

Step 2: Allocation of revenue requirement

The revenue requirement is then allocated across the relevant services to determine the MPs that bear these costs. As we discuss in more detail below, these are typically LSEs and large loads connected to the transmission network, generation and intertie traders, which ultimately tend to flow through ISO costs to end-user bills. For example, in GB NESO levies Balancing Services Use of System (“BSUoS”) on LSEs, who then recover those costs from ratepayers through retail tariffs.¹⁴

¹¹ This differs from regulated utilities which include an approved regulated Return on Equity (“ROE”) when setting tariff rates.

¹² All ISOs covered in our analysis are non-profit organisations, except NESO which is a state-owned entity.

¹³ AESO, 2026 Budget Development Process, ([link](#)).

¹⁴ NESO, BSUoS charges, ([link](#)), Ofgem, Decision on reflecting changes to BSUoS charges in the price cap, 17 February 2023, ([link](#)).

More specific costs can also be charged directly to the relevant user or beneficiary (the quantum of which is expected to be low relative to other costs). For example, ISO-NE directly charges the relevant party for certain system impact and facilities studies, significant and non-routine information requests, non-standard contract provisions and non-standard billing arrangements.¹⁵

Step 3: Set ISO tariff rates

Tariff rates are generally not set by the ISO directly. For all the ISOs benchmarked, the tariff methodology and the tariff rates for each period are calculated and proposed by the ISO, but require approval from the regulator (see Table 2 below).

Table 2: Entities that propose and approve tariffs

ISO	Proposed by	Approved by	Assessment frequency	Charge type
General	ISO	Federal or provincial regulator	Generally annual	Varies
ISO-NE	ISO-NE	FERC, reviewed and commented on by six NE states, NEPOOL and other interested parties ¹⁶	Annual	ISO-only charge ¹⁷
CAISO	CAISO	FERC, budget is approved by the CAISO Board of Governors ¹⁸	Annual	ISO-only charge ¹⁹
IESO Ontario	IESO Ontario	OEB ²⁰	Tariffs set for 3 years, with different rates applied in each year	ISO-only charge
AESO	AESO	AUC ²¹	Annual	Integrated into Rate DTS charge ²²
NESO	NESO	Ofgem ²³	Two seasonal fixed tariff rates each year, assessed annually ²⁴	Integrated into BSUoS charge
AEMO²⁵	AEMO	AER	Framework agreed for 5-year period, with tariff rates updated annually	ISO-only charge

Note: FERC = Federal Energy Regulatory Commission; NE = New England; NEPOOL = New England Power Pool; OEB= Ontario Energy Board, AUC = Alberta Utilities Commission; DTS = Demand Transmission Service;

¹⁵ Docket No. ER25-134 – see Section IV.A on Recovery of ISO Administrative Expenses, 17 October 2024, ([link](#)).

¹⁶ ISO-NE, The ISO's Funding and Budgeting Process, ([link](#)).

¹⁷ ISO-NE, Transmission, Markets and Services Tariff, ([link](#)), ISO-NE, Tariff rates, ([link](#)).

¹⁸ CAISO, Tariff, 2026, ([link](#)), Senate Energy, Utilities and Communications Committee, 12 March 2025, ([link](#)).

¹⁹ CAISO, Tariff, 2026, ([link](#))

²⁰ IESO, IESO Business Update – 2023-2025 Revenue Requirement Submissions, 10 May 2023, ([link](#)).

²¹ AESO, Tariff, ([link](#)).

²² AESO, Rate Demand Transmission Service, 1 January 2026, ([link](#)).

²³ NESO, BSUoS Fixed Tariff 6 October 2025–March 2026, December 2024, page 5, ([link](#)).

²⁴ NESO, BSUoS Final 2026/27 Tariffs, 15 January 2026, ([link](#)), Ofgem, 30 October 2024, ([link](#)).

²⁵ AEMO, FY27 Draft Budget and Fees, 2026, ([link](#)).

and AER= Australian Energy Regulator, Ofgem = Office of Gas and Electricity Markets, BSUoS = Balancing Services Use of System.

The tariff calculation methodology will specify the billing determinants used to recover costs, which can differ by cost allocation category and market participant type. For example, in Australia's National Electricity Market ("NEM") operated by AEMO, the billing determinants for LSEs and large load are a variable MWh consumption charge and a fixed fee, whereas generators pay based on their metered energy generation and registered capacity. In contrast, NESO's Core Costs are recovered through BSUoS payments which are exclusively charged to load on a per-MWh basis. We provide more detail on the types of charges paid by MPs for the benchmarked jurisdictions further below (see Table 4).

The ISO then forecasts the relevant billing determinant volumes and sets tariff rates by dividing the allocated cost by the forecasted billing determinant. These rates are then submitted to the regulator for final approval.

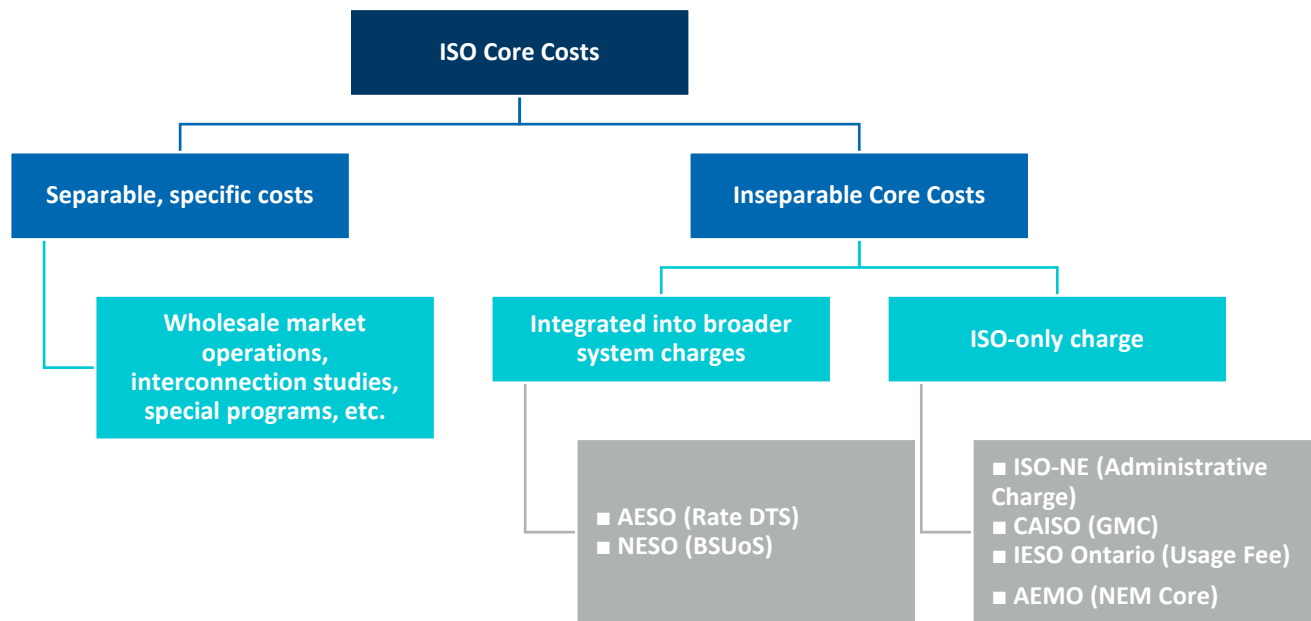
Tariff rates are also reviewed and updated periodically. The assessment frequency varies by jurisdiction – some ISOs reassess their tariffs annually (e.g. ISO-NE and CAISO), whereas others set tariffs over a 3- to 5-year period (e.g. in Ontario tariffs are for 3 years, albeit the rates change each year).

The type of charge that ultimately gets put on MPs (mostly load, i.e., LSEs and directly transmission-connected load), generally falls into two types:

- **ISO-only charge:** a fee that covers ISO Core Costs, which is billed to the load and other MPs (if relevant). Additional charges to recover the direct costs of administering certain services are collected separately. For example, ISO-NE's Scheduling, System Control and Dispatch Service charge recovers the ISO's Core Costs, and ISO-NE also has two additional charges for other internal ISO costs outside the scope of IESO Nova Scotia's Core Costs to directly recover the costs of administering energy markets (Energy Administration Service) and capacity markets (Reliability Administration Service).
- **Integrated into broader system charges:** the ISO Core Costs are incorporated into another tariff process that recovers costs external to ISO roles. The ISO costs are included as a line item in a more comprehensive charge that could include other services such as network assets and energy costs to balance the system, among others, which are typically an order of magnitude larger than the ISOs' costs.

As shown in Figure 4 below (and in Table 1 illustrated by number of charges), most ISOs in the benchmarking group use a charge that recovers solely ISO fees, while the AESO and NESO have their costs integrated into broader charges. The figure additionally illustrates the flow of recovery for costs that are separable from other ISO costs and are being directly recovered from benefitting parties, such as interconnection study requests recovered from the requesting party.

Figure 4: Cost recovery (tariff) structure



Note: GMC = Grid Management Charge.

Step 4: Collection and true-up

Billing frequency varies by jurisdiction and may be daily, weekly or monthly.

Since both costs and billing volumes are forecasts, most ISO tariff frameworks include true-up mechanisms to reconcile over- or under-recovery in subsequent periods and correct for differences between forecast and actual costs or billing volumes. Table 3 below presents true-up processes and the assessment and billing frequency for each comparator.

Table 3: Summary of true-up process, assessment frequency and billing frequency by ISO

ISO	Billing Frequency	True-up process
General	Daily, weekly or monthly	Most ISO tariff frameworks include true-up mechanisms
ISO-NE	Monthly in arrears	In Year X, ISO sets tariffs for Year X+1 to true-up revenue requirement from Year X-1 ²⁶
CAISO	Weekly in arrears ²⁷	In Year X, ISO sets tariffs for Year X+1 to true-up revenue requirement from Year X-1 ²⁸
IESO Ontario	Monthly ²⁹	Adjustment mechanism enables IESO to reapply to regulator to update tariffs in later years of period ³⁰
AESO	Monthly ³¹	Quarterly tariff adjustments for account reconciliation (Rider C) ³²
NESO	Settled on a daily basis ³³	Over/under recovery adjustment (K factors) applied to subsequent tariff rates.
AEMO³⁴	Monthly	In Year X, ISO sets tariffs for Year X+1 to true-up revenue requirement from Year X-1

Ratepayer recovery

For LSEs there is a final step consisting of how they recover the ISO costs that they are charged. Each LSE will have its own unique ratemaking process, to determine how its share of the ISO's revenue requirement is recovered from end users, often as part of their existing rate case (e.g. General Rate Application or "GRA") process. Several reasons why the ratemaking process differs between LSEs are:

- Some ISO charges levied on the LSEs (such as capacity-based) cannot be linearly passed through to end users. For example, if in New England a 250 MW-month LSE is charged a total of \$75,000 at a rate of \$300/MW-month, the LSE cannot charge end users in the same way. This is because, due to non-simultaneity of peak usage, charging each end user from the LSE \$300/MW-month adds up to a much larger number than \$75,000. The LSE therefore has to internalise the ISO costs in its rates charged to end users in a way that the LSE recovered from their ratepayers the

²⁶ ISO-NE, Recovery of ISO Administrative Expenses, 1 January 2026, pages 4-6, ([link](#)).

²⁷ CAISO, CAISO Payments Calendar, 1 January 2026 through 31 December 2026, ([link](#)).

²⁸ CAISO, Budget and Grid Management Charge – 2026, 21 May 2025, ([link](#)), 2026 Final Grid Management Charge Revenue Requirement, Project Budget, and Rates, 18 December 2025, pages 63-64, ([link](#)).

²⁹ IESO, Settlement Process, ([link](#)).

³⁰ Energy Regulation Quarterly, IESO Application to the Ontario Energy Board for 2024 and 2025 Incremental Revenue Requirement, Expenditures, and Usage Fees, December 2024, ([link](#)).

³¹ AESO, Settlement and Credit, ([link](#)).

³² AESO, Deferral Accounts - Rider C & DAR, ([link](#)).

³³ NESO, BSUoS Payment Calendar 26-27, ([link](#)).

³⁴ AEMO, FY27 Draft Budget and Fees, 2026, ([link](#)).

same ISO costs that it is charged for. In the example above, an LSE with a monthly consumption of 75,000 MWh could charge its ratepayers \$1/MWh to recover the ISO costs it is charged.

- Even for LSEs that are levied a usage-based charge (per MWh, which could theoretically be linearly passed through to customers), because no LSE charges the same rates to all customers, it is improbable an LSE would charge its customers the same per-MWh charge to recover ISO fees that the LSE itself is charged. Once the ISO charge is levied on the LSE, it is added to the LSE's own revenue requirement used in its own ratemaking process (similar to NSP's GRA process). Each LSE's ratemaking process is complex and results in differing ratepayer tariff charges for often 10+ customer classes (residential, low income, small and large commercial, street lighting, house of worship, etc.). Each customer class could have their own allocation methodology that could be a mixture of fixed (per-bill), usage-based (per MWh) and capacity (per MW) charges. Hence by doing so, different customer classes might contribute more or less than other customer classes per MWh consumed to the ISO costs (charged via the LSE).
- In some of the benchmarking ISOs, such as ISO-NE, a single ISO may have dozens of LSEs including distribution utilities (similar to NSP), retailers³⁵ in deregulated jurisdictions, and large load users directly connected to the transmission system, among others. This likely increases the discrepancy in the way end users are charged for ISO costs (indirectly via the relevant intermediary, e.g., an LSE).

Types of ISO charges to recover Core Costs

Each ISO in our benchmarking group adopts a different approach to recovering its internal costs, as set out in Table 4 below. These typically account for which MPs benefit from system operations, which impose costs, and how to balance administrative simplicity with cost causation principles.

For Ontario IESO and NESO all shared ISO costs are recovered from a single charge (excluding direct-assigned costs such as interconnection studies) with the difference that in the case of NESO, costs for payments to generators for ancillary services and associated balancing costs³⁶ are recovered from the same charge (i.e., what we refer to as an 'integrated' charge) while the charge in Ontario only covers the ISO costs (i.e., what we refer to as an 'ISO-only' charge). The other ISOs each have multiple charges, which typically include one main charge to recover Core Costs, with additional charges to recover the direct costs of administering certain services.

³⁵ **Retailers** are LSEs that serve customers, often through competitive (not cost-based or rate-regulated) rates, and do not generally own distribution or transmission assets. Alternatively called "retail suppliers" these entities buy electricity from wholesale markets or through bilateral contracts.

³⁶ The costs to the ISO of directing and managing ancillary services, and for overseeing balancing the system are still considered Core Costs

It should be noted that the ISOs in the benchmarking group have more roles and responsibilities than IESO NS, meaning they have internal costs outside the scope of Nova Scotia IESO NS's Core Costs. These other internal costs are listed in Table 4 below.

Charges to recover costs of administering markets (internal costs outside the scope of IESO NS's Core Costs) are typically recovered on a per transaction basis, with the format of other charges varying by market participant:

- **Load:** typically pays on a consumption-basis, sometimes including fixed fees.
- **Generation:** basis of payment is more varied, and can be charged based on volume of trades.
- **Intertie traders:** typically pay on a volume-basis, but sometimes capacity-basis.
- **TOs:** pay on the basis of metered energy flowing away from the transmission connection point (AEMO only).

Note that while not all costs are directly passed through to load (directly or indirectly via LSEs or retailers), those that are levied on generation, intertie traders and TOs will eventually recover the relevant costs from load (e.g., the additional incurred costs will be internalised in the procurement contract or offer of a generator).

AEMO sets the proportions of each charge to be recovered from each stakeholder group for a 5-year period and then sets the specific rates to achieve this. AEMO's NEM Core charge is recovered 55% from load, 26% from generation and 19% from TOs.^{37,38} In contrast, NESO's charges are solely borne by load as the load is the only MP to which BSUoS are charged.³⁹

³⁷ In AEMO, TNSPs own and operate the transmission assets, while AEMO provides broader system balancing and market operation services. There are five TNSPs each serving one of the five states in the NEM (interconnectors link the grid at state borders to allow electricity to flow between states). TNSPs link generators to the 13 major distribution networks that supply electricity to end-use customers. See AEMO, Transmission: who does what?, 11 April 2013, ([link](#)).

³⁸ AEMO, AEMO's NEM Participant Fee Structure Review, 2026, page 3, ([link](#)).

³⁹ Prior to April 2023, cost recovery charges were split broadly evenly between load and generation. Ofgem, the GB regulator, decided to apply charges only to load to remove distortions between groups that were treated differently (large generators were charged, while small generators and intertie traders were not). Ofgem also stated that it was not efficient for cost recovery charges to be levied on generation because *"the costs are passed through into wholesale costs, which includes unnecessary risk premium and transaction costs."* (See Ofgem, CMP308 – Decision and final impact assessment, 25 April 2022, ([link](#))).

Table 4: Types of charges to recover internal costs (→ denotes Core Costs relevant to Nova Scotia, which are counted in Table 1)

Types of Charges - Charges that also recover non-Core Costs are marked (*)	Load	Generation	Intertie traders	Transmission owner
ISO-NE⁴⁰				
ISO Administrative Expenses* : Not a separate charge, but category that recovers the ISO's internal costs. This is reflected in three separate charges below.				
→ Scheduling, System Control and Dispatch Service (charge under Administrative Charge above) : Charge to recover costs associated with scheduling the movement of power through, within or into the New England control area, including ancillary services.	Capacity (per kW-month)	N/A	Capacity-based (if through or out of NE) for peak reserved capacity, each hour of service (per kW)	N/A
→ Energy Administration Service : Charge to recover costs associated with administering the Energy Markets.	Per transaction	Per transaction	N/A	N/A
Reliability Administration Service : Charge to recover costs associated with administering capacity markets.	Peak load (per kW)	N/A	Per transaction (if through or out of NE) and per MWh exported	N/A
→ Various one-off fees : recover costs of interconnection studies, non-standard information requests, etc.	Varies	Varies	Varies	N/A
CAISO⁴¹				
→ Grid management charges* : Charge to recover ISO internal costs. The charge has four components, each with their own distinct rate: (1) market services, (2) system operations and dispatch (Core Cost, relevant to IESO NS) , (3) balancing services charge (Core Cost, relevant to IESO NS) , and (4) congestion revenue rights. ⁴²	Consumption (per MWh)	Generation (per MWh)	Imports/exports (per MWh)	N/A

⁴⁰ ISO-NE, Recovery of ISO Administrative Expenses, 1 January 2026, pages 10-16, ([link](#)). See also ISO-NE, Billable Line-Item Descriptions, ([link](#)).

⁴¹ CAISO, 2026 Final Grid Management Charge Revenue Requirement, Project Budget, and Rates, 18 December 2025, page 47, ([link](#)), CAISO, ISO Charge Code Matrix, 13 February 2025, ([link](#)), CAISO, Grid Management Charge, slides 13-23, 2017, ([link](#)), CAISO, CAISO, Configuration Guide For 4567 GMC System Operations Real-time Dispatch Charge Code, ([link](#)), Configuration Guide For 4566 GMC System Operations Balancing Authority Area Services Charge Codey, ([link](#)), CAISO, Sample Invoice, ([link](#)).

⁴² Grid management charges are based on scheduled + RT instructed volumes for market services charges, but delivered volumes for system operations charges.

Types of Charges - Charges that also recover non-Core Costs are marked (*)	Load	Generation	Intertie traders	Transmission owner
The CAISO calculates an MP's Grid Management Charge ("GMC") charge based on its volumes and activity as relevant to the four components above, and then levies the GMC one line item on the bill.				
System Operations and Dispatch (component of GMC above): Recovers costs the ISO incurs for running the grid in real time.	Consumption (per MWh)	Generation (per MWh)	Imports/exports (per MWh)	N/A
Balancing Services Charge (component of GMC above): recovers costs the ISO incurs for transmission planning, summer coordination, and planning coordination costs.	Consumption (per MWh)	Generation (per MWh)	Imports/exports (per MWh)	N/A
Miscellaneous fixed fees: Charges to recover costs associated with operation of the wholesale market.	Per transaction / bid / nomination or per MWh	Per transaction / bid / nomination or per MWh	Per transaction / bid / nomination or per MWh	N/A
→ Supplemental services rates: Charge to recover costs associated with imbalance market services and operation.	Consumption (per MWh)	Consumption (per MWh)	Consumption (per MWh)	N/A
Ontario IESO⁴³				
→ Usage fee*: Charge to recover costs to operate the market and ensure reliability.	Consumption (per MWh)	N/A	Exported volumes (per MWh)	N/A
Wholesale market fee: Recover costs of the day-to-day electricity market operations, and system planning and administration.	Consumption (per MWh)	N/A	Consumption (per MWh)	N/A
→ Various one-off fees: recover costs of interconnection studies, etc.	Varies	Varies	Varies	N/A
AESO				
→ Demand Transmission Service ("DTS")*: Recovers general and administrative costs alongside costs of transmission network and ancillary services. ⁴⁴	Components based on monthly coincident demand (MW); energy	N/A	N/A	N/A

⁴³ IESO, IESO Business Update – 2023-2025 Revenue Requirement Submissions, 10 May 2023, ([link](#)).

⁴⁴ AESO, ISO Tariff, 1 January 2026, ([link](#)), AESO, Tariff Update Application, 7 November 2025, ([link](#)), AESO, ISO tariff rate calculations (approved), 7 November 2025, ([link](#)).

Types of Charges - Charges that also recover non-Core Costs are marked (*)	Load	Generation	Intertie traders	Transmission owner
	consumption (MWh); and a tiered, MW-based proportion of substation costs.			
Other Transmission Service Charges* : a small share of Core Costs are also allocated to other customer classes: Demand Opportunity Service (“DOS”) for non-firm local demand, Export Opportunity Service (“XOS”) for non-firm exports, and Export Opportunity Merchant Service (“XOM”) for other merchant interties. ⁴⁵	Consumption (per MWh)	N/A	MWh and fixed fee per transaction	N/A
Energy Market Trading Charge : Recovers AESO’s market operating costs as well as charges from the AUC and the Market Surveillance Administrator (“MSA”). ⁴⁶	Per MWh traded	Per MWh traded	Per MWh traded	N/A
→ Specific service charges : recovers the cost of specific services. ⁴⁷			Per service requested	
NESO				
→ BSUoS* : Recovers NESO’s planning and administrative costs alongside balancing costs, ancillary services and system operation. ⁴⁸	Actual MWh consumption	N/A	N/A	N/A
→ Application fee : Set to recover costs incurred by NESO associated with studies and other application costs for new connections. ⁴⁹	Fee dependent on size, type and location of connection		N/A	N/A

⁴⁵ Decision 30427-D01-2025 (2026 ISO Tariff Update), ([link](#)).

⁴⁶ AESO, Energy Market Trading Charge, ([link](#)).

⁴⁷ AESO, ISO Fees, ([link](#)), Section 103.6 - ISO Fees and Charges, ([link](#)).

⁴⁸ NESO, Final BSUoS Tariffs for 2026/27, December 2025, page 15, ([link](#)), Ofgem, NESO Financial Handbook, 31 March 2026, ([link](#)).

⁴⁹ NESO, Connection Charges, Summary Effective 1 April 2024, ([link](#)).

Types of Charges - Charges that also recover non-Core Costs are marked (*)	Load	Generation	Intertie traders	Transmission owner
AEMO ⁵⁰				
→ NEM Core: Covers costs of AEMO's core functions, metering, settlement, near-term planning and administrative costs, as well as costs of ensuring power system security and reliability.	50% consumption (per MWh) and 50% per connection fixed fee	50% metered energy (per MWh) and 50% capacity (per MW)	N/A	Metered energy flowing away from transmission connection point (per MWh) ⁵¹
Electricity retail markets: Covers costs of facilitating retail market competition in east coast and southern states of Australia.	Per connection point	N/A	N/A	N/A
IT upgrade & SMS/GS: Covers costs of implementing 5-minute settlement rule changes	50% consumption (per MWh) and 50% per connection fixed fee	50% metered energy (per MWh) and 50% capacity (per MW)	N/A	N/A
→ NEM Reform: Covers costs of implementing NEM Reform Programme including AEMO foundation and strategic initiatives.	50% consumption (per MWh) and 50% per connection fixed fee	50% metered energy (per MWh) and 50% capacity (per MW)	N/A	N/A
Cyber security & Resilience: Covers costs of fulfilling AEMO's current cyber-security roles and future reforms.	50% consumption (per MWh) and 50% per connection fixed fee	50% metered energy (per MWh) and 50% capacity (per MW)	N/A	Metered energy flowing away from transmission connection point (per MWh) ⁵²
→ Miscellaneous: There are multiple other charges directly paid by those incurring costs (e.g. registrations, connections, additional services charge, National Transmission Planner).	Varies (but typically either fixed or in line with Core NEM charging)	Varies (but typically either fixed or in line with Core NEM charging)	N/A	Varies (but typically either fixed or in line with Core NEM charging)

⁵⁰ AEMO, NEM Participant Fee Structures, pages 4-6, February 2026, ([link](#)), AEMO, AEMO's NEM Participant Fee Structure Review, 2026, ([link](#)).

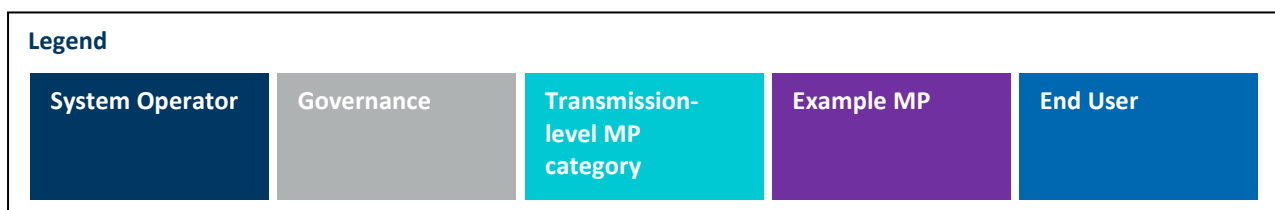
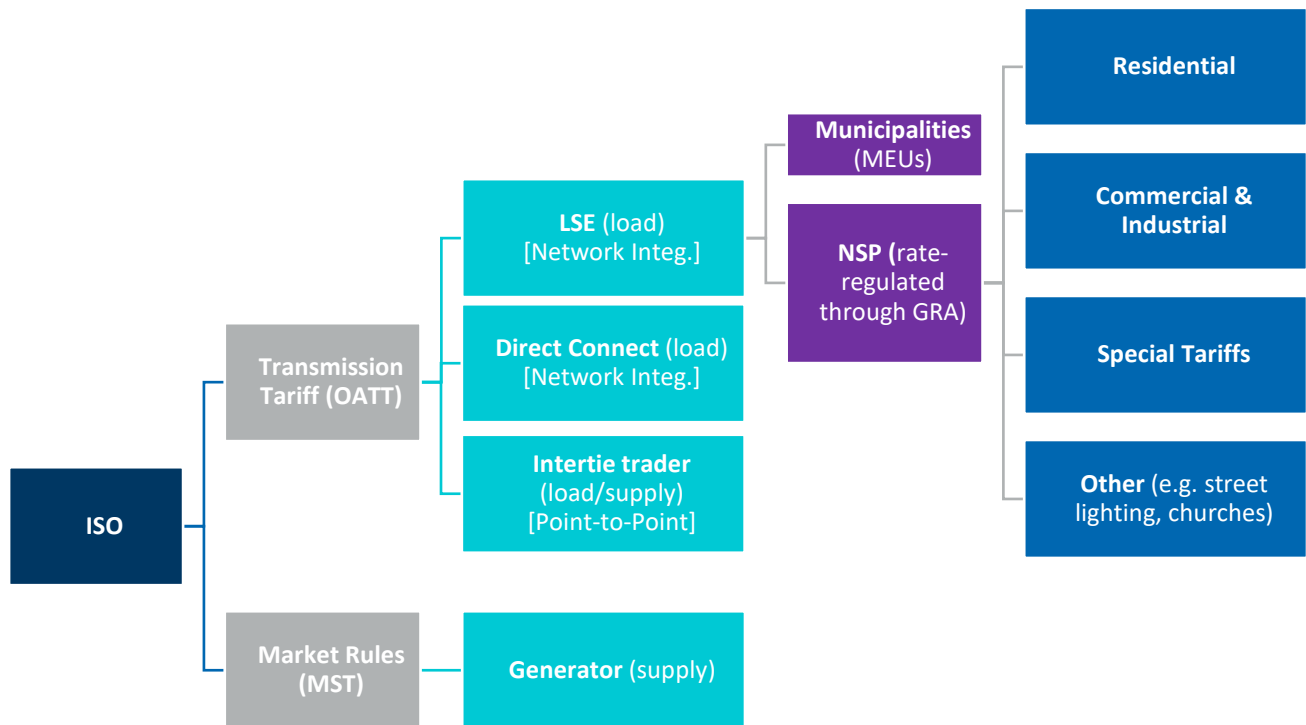
⁵¹ Charged based on Adjusted Consumed Energy, which is defined as the metered energy flowing away from the transmission network connection point to which the market connection point is assigned. See AEMO, 3.15.4(a)(2) of Chapter 3, NEM National Electricity Rules, ([link](#)).

⁵² Charged based on Adjusted Consumed Energy, which is defined as the metered energy flowing away from the transmission network connection point to which the market connection point is assigned. See AEMO, 3.15.4(a)(2) of Chapter 3, NEM National Electricity Rules, ([link](#)).

Relevance to Nova Scotia

The market participants in Figure 5 represent those applicable across the various benchmarking group ISOs described above. Because many of those grids run wholesale energy and other markets not present in Nova Scotia, only a subset of these MPs is relevant for consideration of applying the findings of the jurisdictional scan above to Nova Scotia. This figure will provide context for considering how the IESO in Nova Scotia may consider designing its own charging mechanism.

Figure 5: Potential IESO market participants



Appendix 1: Additional Information

Certain ISOs also levy a fixed membership fee on MPs, regardless of size or volume of market activity. This is summarized in Table 5 below.

Table 5: Participation fee per ISO

	ISO-NE	CAISO	IESO	AESO	NESO	AEMO
Frequency	Annual	Monthly	N/A	Annual	N/A	One time registration
MP	Transmission, generation, supplier	Scheduling coordinators	N/A	Pool participation fee	N/A	Participant dependent
Cost	\$5,000 USD	\$1,500 USD	N/A	\$150 CAD	N/A	Between \$2,850 and \$66,850 AUD

Note: A scheduling coordinator (“SC”) is an entity certified by CAISO to act on behalf of market participants. SCs submit energy schedules, manage bids, and settle energy transactions within the market.⁵³

Sources: ISO-NE membership FAQ, ([link](#)), 2026 Final Grid Management Charge Revenue Requirement, Project Budget, and Rates, page 47, ([link](#)), CAISO 2026 GMC Rates and Other Fees, ([link](#)), AESO Rules standards and tariff, ([link](#)), AEMO Budget and fees, pages 78-80, ([link](#)).

⁵³ Syso technologies, Scheduling coordinator, ([link](#)).

Appendix 2: Overview of ISOs selected for benchmarking

In this appendix, we provide an overview of the ISOs that were selected for benchmarking in this jurisdictional scan. The ISOs selected for benchmarking were chosen to represent a variety of applicable peers. IESO NS has several defining characteristics that influence our benchmarking group selection. We summarise those characteristics and the relevant ISOs in Figure 6 below.

Figure 6: Overview of the characteristics of IESO NS shared by other ISOs

CHARACTERISTIC	STRUCTURE	JURISDICTION	AGE	RESOURCE MIX
	Large Incumbent(s)	Single Province within a Nation	Newly Restructured	High Renewables
				
				
				

Source: FTI Analysis, logos from ISO websites.

- Utility structure:** As comparisons to Nova Scotia's power system being composed primarily (currently, almost entirely) of a VIU, we have included several grids with large incumbent structures. The CAISO and ISO-NE have large, privately-owned⁵⁴ VIUs that are part of the geographical area they operate.⁵⁵ In Ontario, Ontario Power Generation Inc. ("OPG") owns a significant share of the generation fleet in the grid operated by the IESO Ontario. OPG is fully owned by the province of Ontario and an important share of its current generation assets are legacy assets from the former VIU structure.⁵⁶

⁵⁴ In this context, privately owned refers to entities that are not government or state-owned; many vertically integrated utilities in the US are ultimately owned by publicly traded corporations.

⁵⁵ The VIUs (owning generation, transmission, distribution and retail) operate within an ISO and depending on the jurisdiction share transmission and resource planning tasks with the ISO and state public utilities commissions. Several New England states have passed some form of liberalisation laws that required some form of legal or functional separation of asset classes, or divestiture of generation assets. Transmission planning remains primarily with the utility.

⁵⁶ Most VIUs in Canada are government-owned, e.g., BC Hydro, Manitoba Hydro, SaskPower, New Brunswick Power and Hydro-Québec.

- 2) **Jurisdictional footprint:** Spanning one province, IESO NS is similar to the AESO and IESO Ontario, each of which can focus on the policy objectives of one provincial government with minimal federal involvement. In contrast, federal policies and regulations still play a large role in single-state ISOs such as CAISO in the US. Other ISOs span over more than one province or state, each of which may have differing energy policy objectives. The CAISO is an interesting case as it is undergoing a major market expansion process into a larger, multi-state region. Jurisdictional and governance concerns are key issues in the details of this process.⁵⁷
- 3) **Age:** IESO NS is very new relatively speaking – most ISOs were established 20+ years ago. The system operator in GB NEMO, however, was only unbundled in 2024 from National Grid, one of the three privately-owned TOs in GB, providing a key example of a system that recently underwent an unbundling process. The age of an ISO is also tied to their degree of independence from related sector parties, with more mature ISOs having more time to establish independence.
- 4) **Resource Mix:** IESO NS is in the midst of a planned transition away from coal and to increasing shares of renewables, including wind. This renewable-heavy mix is shared by IESO Ontario which has significant shares of hydro resources.⁵⁸ In-state utility-scale solar generation in CAISO is approximately 25% with another approximately 10% from rooftop solar.⁵⁹ AEMO is shifting from historical reliance on coal to a system with over 20% electricity from solar and 15% from wind.⁶⁰ CAISO and AEMO are also now managing systems with significant instantaneous shares of inverter-based resources like wind and solar which change the types and volumes of grid services required to keep the system within safe operating limits. This is increasingly challenging when the penetration is high across the wider synchronous grid, as is often the case for AEMO.

We provide a summary of each ISO's operating costs and the size characteristics of their respective power systems (which impact the level of their operating costs) in Table 6 below.

⁵⁷ Bonneville opts to join SPP's Markets+ day-ahead market over CAISO alternative, Utility Dive, 7 March 2025, ([link](#)).

⁵⁸ Ontario IESO, Ontario's electricity grid, ([link](#)).

⁵⁹ California Energy Commission, 2023 Total System Electric Generation, ([link](#)), California Energy Commission, Data Show Clean Power Increasing, Fossil Fuel Decreasing in California, 18 August 2023, ([link](#)).

⁶⁰ AEMO, AEMO Fact sheet, ([link](#)).

Table 6: Comparison of power system size characteristics and operating costs by ISO

	Unit	IESO NS	ISO-NE	CAISO	IESO	AESO	NESO	AEMO
Approximate people served	millions	1	15	32	15	5	67	23
Transmission	km	5,200	14,500	41,800	30,000	26,000	35,900	40,000
Installed Capacity (GW)	GW	3	31	89	38	23	72	73
Peak Load	GW	2	20	48	25	12	45	34
Total Energy Consumption	TWh	11	117	253	139	63	275	190
Ownership structure		Non-profit	Non-profit	Non-profit	Non-profit	Non-profit	State owned company	Non-profit
Operating costs	USD\$ million	\$10 Phase 1	\$252	\$222	\$206	\$113	\$476	\$224

Notes: Most recent available data shown; years vary.

Sources: CAISO 5-year summary ([link](#)), RIIIO-2 Regulatory Financial Reporting Pack Guidance ([link](#)), IESO 2023 Annual report ([link](#)), AEMO Annual Report 2025 ([link](#)), AESO Annual Report 2024 ([link](#)), NESO Annual Report 2025 ([link](#)), ISO New England Financial report 2024 ([link](#)), Capital IQ Data Accessed 10 December 2025, CAISO About, ([link](#)), ISO-NE Key Stats ([link](#)), AESO About ([link](#)), Export grid status: Market Renewal in Ontario ([link](#)), World Bank Group: Access to electricity (%) ([link](#)), ONS: Estimates to population for UK ([link](#)), AEMO Fact sheet ([link](#)), World Bank Group: Population ([link](#)), IESO NS Phase 2 ([link](#)), AESO About the grid ([link](#)), IESO Introduction ([link](#)), NEXT European TSOs list ([link](#)), NS Power 2025 10-Year System Outlook ([link](#)), CAISO Department of market monitoring update (Nov 23) ([link](#)), ISO-NE PR Winter Outlook 2025 ([link](#)), AESO Annual Market Statistics Report (January 2026) ([link](#)), IESO Transmission-Connected Generation ([link](#)), UK Gov DUKES 2025: Table 5.12 ([link](#)), AEMO Generation Information ([link](#)), CAISO 2024 statistics ([link](#)), AESO 2024 Annual Market Statistics ([link](#)), 360 Energy: Summer Heat Drives Record Electricity Demand in Ontario and the US Northeast ([link](#)), NESO: Britain's Electricity Explained: 2024 Review ([link](#)), NEM seasonal peak demand ([link](#)), EMA monthly peak system demand ([link](#)), IESO 2025 Year in Review ([link](#)), NEM Annual electricity consumption ([link](#)), EMA SES Chapter 3: Energy Consumption ([link](#)), CAISO Q3 2025 financial report ([link](#)), ISO-NE 2025 and 2026 Preliminary Operating and Capital Budgets ([link](#)), AESO LinkedIn ([link](#)), IESO Information ([link](#)), NESO About ([link](#)), CAISO Decision on 2025 budget ([link](#)).

