OECA - ONTARIO ENERGY COLLABORATIVE ASSOCIATION

12 OEB INITIATIVES

EXAMINING OPPORTUNITIES BETWEEN THEM

Regulatory Update, Completion Tracking & Risk Assessment

PURPOSE

Twelve OEB regulatory files are moving in parallel. This review identifies where cross-sector collaboration across their interfaces could support timely, efficient growth in Ontario.

KEY MESSAGES TO TAKE AWAY

1	PRUDENCE AND GROWTH MUST COEXIST
2	THE SEAMS ARE THE OPPORTUNITY
3	CONSULTATION MUST DRIVE DECISIONS

Collaborative Insights are OECA synthesis observations intended to identify cross-organizational interfaces and questions worth discussing. They are not OEB positions or formal OECA policy positions.

ENABLING BETTER DECISIONS FOR ONTARIO

Executive Summary

Ontario's electricity framework is moving through a significant transition. The twelve initiatives reviewed here address utility remuneration, connections, planning, DER valuation, spending, customer data, service rules, gas-electric coordination, and the evolving role of distributors. Together they point toward a more transparent, data-rich, and performance-focused system that can use distributed resources alongside conventional infrastructure.

We have an opportunity now to help these changes work together. Growth, electrification, and new customer loads increasingly connect decisions made by LDCs, the IESO, transmitters, municipalities, regulators, customers, and private investors. Timely information, aligned assumptions, and clear decisions across those interfaces can support faster, more coordinated implementation.

That expanded role has practical consequences. LDCs need sufficient capacity, incentives, and regulatory certainty to support growth while continuing to demonstrate prudent use of customer funds. Remuneration, benchmarking, connection policy, DER procurement, and non-wires solutions can therefore be considered together against a common objective: timely, efficient service in a rapidly changing system.

COLLABORATIVE INSIGHT - PRUDENCE AND GROWTH MUST COEXIST

LDCs must preserve reliability, affordability, and regulatory prudence while becoming active enablers of new load, electrification, DERs, and Ontario's economic development.

Material opportunities also sit between existing mandates. Early studies, capacity planning, enabling infrastructure, and project development may be required before responsibility can be assigned clearly to a customer, utility remuneration, or system investment. One question worth testing collaboratively is whether an independent growth-enablement fund could support justified early-stage work where the broader economic opportunity is clear and the conventional funding path remains uncertain.



Shared administrative and technical capacity offers another opportunity. Common data standards, model agreements, specialist procurement support, technical review resources, and repeatable processes could help smaller LDCs, and other participants move more quickly while maintaining consistency and prudence. Similar logic applies to rates and commercial rules: durable principles that accommodate storage, DERs, flexible loads, EVs and new customer models can reduce the need for repeated bespoke adjustments as technologies and business models evolve.

COLLABORATIVE INSIGHT- THE INTERFACES ARE THE OPPORTUNITY

Each organization has a defined mandate. Additional value can be created at the hand-offs between regulators, LDCs, transmitters, the IESO, municipalities, customers, and solution providers.

Commercial signals are part of those hand-offs. Customers and investors can respond when system needs are visible early enough and described clearly enough: location, timing, duration, capacity, and required performance. Better signals create room for storage, DERs, flexible demand, conventional infrastructure, and private capital to compete around the same identified need.

This also gives the OEB and IESO greater ability to concentrate on strategic system and regulatory priorities. Cross-sector implementation issues can be developed, tested, and clarified through broader collaborative forums before they require formal regulatory or system-planning action. Clearer interfaces can reduce administrative friction while preserving each organization's accountability and independence.

Ontario already has an extensive consultation culture. A further opportunity is more deliberate engagement around decisions and implementation. Policy papers, working groups, surveys, and written submissions remain valuable tools. Broader participation by municipalities, major customers, investors, technology providers, data users, consultants, and implementation specialists can add practical perspectives alongside LDCs and established sector participants.

One useful measure of consultation is what it enables: a clarified interface, a shared assumption, an investable signal, a repeatable process, or a decision that can move forward.

This creates a practical role for OECA. As an independent collaborative forum, OECA can bring together organizations that are responsible for different parts of the same issue, surface implementation barriers early, add customer and private-sector perspectives, test cross-organizational concepts, and maintain continuity between initiatives that otherwise progress on separate tracks.

OECA can also help distinguish the type of solution required. Some issues need regulatory action. Others may be addressed through better information, common standards, commercial mechanisms, shared technical capacity, or voluntary coordination. Identifying that distinction early can save time and focus formal processes where they add the greatest value.

The opportunity is additional connective capacity around Ontario's existing institutions: a place to strengthen interfaces, test practical solutions, and help connect strong individual initiatives into coordinated system outcomes.

Appendix A consolidates the Collaborative Insights arising from this review. Appendix B provides the detailed status and timing of the twelve OEB initiatives. The sections that follow focus on the material opportunities, interfaces, and implementation implications created by those initiatives together.

COLLABORATIVE INSIGHT- CONSULTATION ENABLES DECISIONS

Broader participation, clearer choices and accountable follow-through will convert regulatory direction into faster, coordinated implementation.



CORE OEB INITIATIVES REVIEW

1 Benefit-Cost Analysis Framework for Addressing Electricity System Needs - Phase Two

Docket: EB-2023-0125

The BCA Framework is the economic decision framework supporting comparison of non-wires solutions with conventional infrastructure. Phase One, finalized in May 2024, introduced the Distribution Service Test and an optional Energy System Test. Phase Two refines the broader Energy System Test and explores societal impacts.

WHERE THE FILE STANDS

- Draft Phase Two revisions were released February 6, 2026; comments closed March 6 and the consultation is now concluded.
- The framework determines which benefits and costs count, who receives them, and how non-wires solutions compete with conventional infrastructure.
- It directly interacts with Stream 2 eDSM, DER valuation, regional planning, and DSO development.
- On July 7, 2026, the OEB revised its Non-Wires Solutions Guidelines to include Stream 2 distributor-led local eDSM. LDCs can develop proposals and request funding, including through 2027 rate applications.
- Stream 2 requires OEB approval, IESO endorsement, BCA support, verified peak savings, annual reporting and an eDSM Variance Account. Programs below a 1.0 BCA ratio for two consecutive years require mitigation.
- On September 3, 2026, the OEB established a generic Non-Wires Solutions Variance Account, supporting more routine treatment of NWS costs.

RISK IMPLICATIONS FOR LDCS AND OTHER PARTICIPANTS

Assumption risk. Load growth, avoided capital, persistence, discount rates, and timing can materially change BCA results.

Boundary risk. Whether benefits are counted at the distribution, transmission, generation, or societal level can determine project viability.

Comparability risk. Different assumptions can produce materially different results for similar projects.

Performance and measurement risk. eDSM and DER solutions depend on verified customer performance at the required location and time.

Double-expenditure risk. If demand grows faster than forecast or eDSM underperforms, program costs may be incurred, and conventional infrastructure may still be required.

Innovation risk. Tests that are too narrow can reject useful solutions; tests that are too broad can justify benefits that are difficult to verify or allocate.

Source: OEB BCA Framework - Engage With Us

RISK IMPLICATIONS

Performance risk. Unlike a transformer or feeder, an eDSM program depends on customers and/or DERs delivering the expected reduction at the right location and time.

Double-expenditure risk. If demand grows faster than forecast or eDSM underperforms, an LDC may incur program costs and still need the conventional asset later.

Measurement risk. Verified peak savings become economically consequential; baselines, attribution, and persistence can affect incentives, cost recovery, and confidence in planning.

Program-delivery risk. Local programs require geographically targeted customer participation, which can be harder than achieving province-wide conservation savings.

Source: OEB Non-Wires Solutions Guidelines



2 Distribution System Operator Capabilities

Docket: EB-2025-0060

The OEB's September 1, 2026, DSO Roadmap positions electricity distributors as central to the development and implementation of DSO capabilities, while leaving room for roles to evolve. It proposes a staged, evidence-based approach rather than imposing a single DSO model immediately.

COLLABORATIVE INSIGHT GROWTH

DSO policy also implies changes in technology, capabilities, and operating models. LDCs are being asked to remain prudent, regulated utilities while becoming more active enablers of load growth, flexibility, and economic development. Operating, cultural, and financing may need to evolve with that role.

WHERE THE FILE STANDS

- Workstream 1 will define the full scope of DSO capabilities and the conditions under which they should develop, helping distributors determine when grid modernization is justified.
- Workstream 2 will standardize "flexibility services" — the services DERs provide to distribution systems — and the rules governing delivery.
- Workstream 3 will establish mechanisms requiring distributors to proactively assess and plan for DSO capabilities and DER integration.
- Workstream 4 will provide longer-term regulatory clarity on required versus permitted DSO activities, sector roles, and organizational/business-structure questions.
- The OEB expects pilots and demonstrations to continue in parallel and to inform the enduring framework. The Roadmap explicitly seeks to reduce inconsistent approaches, stranded investment, and missed DER-integration opportunities.

RISK IMPLICATIONS FOR LDCS AND OTHER PARTICIPANTS

Stranded-technology risk. Premature investment in DER management systems, communications, or control platforms can become obsolete if standards, roles, or market interfaces change.

Cyber and operational risk. More active control of two-way power flows and DER dispatch expands cyber-security, communications, and operational dependencies.

Role-boundary risk. Distributors, the IESO, transmitters, aggregators, and DER owners may have overlapping operational interests. Dispatch priority and accountability must be clear during normal and emergency conditions.

Uneven-capability risk. Ontario LDCs vary significantly in size, DER penetration, and technical maturity. A one-size-fits-all timetable could create unnecessary cost; too much optionality could create fragmentation.

Market-neutrality risk. Where an LDC operates a platform, procures DER services, or owns assets, governance must prevent conflicts and preserve fair access for third-party providers.

Cost-recovery risk. A clear LDC remuneration framework can provide distributors with confidence to make justified enabling investments while protecting customers from premature or unnecessary spending.

Source: OEB DSO Capabilities / Roadmap

3 Spending Pattern Analysis

Docket: EB-2025-0108

The Spending Pattern Analysis examines how multi-year rate-setting under the Renewed Regulatory Framework for Electricity affects utility spending patterns and capitalization. Pacific Economics Group prepared the report, and stakeholder feedback was requested by February 13, 2026. The results now feed the Next Generation Rate Framework.

WHERE THE FILE STANDS

- The report examined Ontario and international utility spending, incentive structures, operational timelines, and capitalization practices.
- The OEB is using the findings as one input to a broader redesign of electricity distributor remuneration rather than treating spending behaviour as a stand-alone issue.
- The analytical question is important: multi-year rate frameworks can influence when utilities spend, what they capitalize, and how spending changes around rebasing cycles.

RISK IMPLICATIONS FOR LDCS AND OTHER PARTICIPANTS

Interpretation risk. Observed spending waves may reflect asset cycles, project timing, workforce constraints, or legitimate catch-up work, not strategic behaviour. Poor causal interpretation could produce inappropriate regulatory remedies.

Capitalization-policy risk. Changes in capitalization expectations can alter earnings, rate base growth, and intergenerational allocation of costs.

Investment-adequacy risk. Pressure to smooth or reduce spending could inadvertently defer necessary maintenance or capacity investment.

Small-utility structural risk. Smaller distributors often have lumpy projects and limited ability to smooth work programs. A framework designed around large-utility patterns may create unintended consequences.

Behavioural response risk. Utilities adapt to incentives. New controls intended to reduce one undesirable pattern can create another if the full incentive system is not considered together.

Source: OEB Spending Pattern Analysis

4 Implementation of the OEB's 10-point Action Plan

Docket: EB-2025-0098

The 10-point Action Plan is intended to improve adjudicative excellence, reduce regulatory burden, and lower costs. It changes how intervenors participate, how costs are managed and reported, and how the OEB manages proceedings.

WHERE THE FILE STANDS

- The ten actions cover intervenor scope, budgets, categorization and collaboration, interrogatory duplication, alternate engagement for individuals, utility-cost reporting, annual reporting, active adjudication, streamlined processes for small utilities, and predictable cost awards.
- As of August 2026, the OEB had made several items operational: a $20,000 soft cap for intervenors in certain small-distributor cost-of-service applications; continued intervenor-categorization pilots; revised procedural expectations to reduce duplication; updated AI disclosure requirements for filings; a streamlined Small Distributor Process; and a revised cost award schedule.
- On August 21, 2026, the OEB published a new cost reporting dashboard covering applicants, intervenor, and OEB adjudicative costs for electricity distribution cost-of-service and transmission revenue-requirement applications.

RISK IMPLICATIONS FOR LDCS AND OTHER PARTICIPANTS

Participation-quality risk. Efficiency initiatives can reduce duplication, but overly restrictive budgets or scope limits can also reduce useful testing of evidence and diversity of perspective.

Collaboration-governance risk. Requiring similarly interested intervenors to collaborate can lower cost but raises practical questions about who coordinates, how differences are preserved, and how contribution is recognized.

Utility-cost transparency risk. Public cost dashboards create useful benchmarking pressure but can invite simplistic comparisons between proceedings with materially different complexity.

Process-compliance risk. New filing, AI-disclosure, procedural and collaboration expectations create additional compliance requirements for utilities and intervenors.

Small utility opportunity and risk. Streamlined processes can reduce regulatory burden, but acceptance criteria and abbreviated procedures must still allow legitimate local complexity to be understood.

Source: OEB 10-point Action Plan



5 Distribution Customer Connections Review and Streamlining Transmission Connections

Docket: EB-2025-0204 / EB-2025-0216

Phase II is implementing the OEB's connection-process reforms for load customers. The policy objective is to create greater clarity, predictability, and transparency, and to improve coordination among distributors, transmitters, and the IESO. The OEB's June 2026 report identified delays, inconsistent procedures, insufficient communication, and limited accountability as recurring concerns.

COLLABORATIVE INSIGHT CONNECTIONS

Connection performance increasingly affects economic-development outcomes. Faster internal processes may have limited effect if coordination and information-sharing among customers, LDCs, transmitters, the IESO, and municipalities remain fragmented. Large-load connections also offer lessons that may apply more broadly as demand grows.

WHERE THE FILE STANDS

- For distribution connections, the OEB is developing a Load Customer Connection Procedures (LCCP) document, a coordinated transmitter-distributor process where transmission work is required, stronger information-sharing requirements, and record-keeping/reporting/performance measurement.
- For transmission connections, the OEB is formalizing a comprehensive connection process and developing performance standards with public reporting for transmitters.
- The DCC Phase II Advisory Group began in July 2026. A 15-organization working group has been established and includes the Ontario Energy Collaborative Association.
- The work is expected to lead to detailed procedures, code amendments, and technical requirements. The connection framework therefore is moving from principles toward enforceable and measurable processes.

RISK IMPLICATIONS FOR LDCS AND OTHER PARTICIPANTS

Accountability-allocation risk. LDCs are responsible for connecting and serving distribution customers, but connection performance can depend on transmitters, the IESO, municipal approvals, equipment suppliers, developers, and customers. Performance standards should distinguish delays within an LDC's control from those arising elsewhere in the connection process.

Information-quality risk. Connection forecasts and designs often evolve. Standard procedures improve clarity but increase the importance of version control, assumptions, documentation, and timely disclosure when customer load, schedule, or project configuration changes.

Economic-development risk. Connection delays can affect factories, housing, data centres, EV infrastructure, and commercial growth. Electricity connection performance is therefore increasingly an economic-development issue, not merely a utility-service issue.

Smaller LDC capability risk. Standardized processes, customer communication, and reporting can impose a proportionately larger administrative burden on smaller distributors with limited specialist staff.

Metric-design risk. Public performance measures can create useful discipline, but poorly designed metrics may reward speed at the expense of engineering diligence, prudent sequencing, or cost effectiveness.

Source: OEB Distribution Customer Connections Review



6 Accounting Procedures Handbook Update

Docket: EB-2025-0214

The OEB is updating an Accounting Procedures Handbook that dates from 2011. The update is intended to reflect current IFRS requirements, emerging accounting for regulatory assets and liabilities, and OEB policies issued since the existing handbook was published.

WHERE THE FILE STANDS

- A seven-organization working group has been established, including electricity distributors, Hydro One, and consumer representatives.
- The OEB website shows a working-group meeting scheduled for October 16, 2026.
- The update could affect account definitions, deferral and variance account practices, capitalization, reporting consistency, and treatment of new types of costs arising from DERs, grid modernization, and market changes.

RISK IMPLICATIONS FOR LDCS AND OTHER PARTICIPANTS

Implementation-system risk. Accounting changes may require modifications to ERP systems, charts of accounts, controls, audit procedures, and staff training.

Transition and comparability risk. Changes in account treatment can make year-over-year comparisons difficult and create reconciliation work during transition.

Regulatory-asset risk. The treatment of deferral/variance accounts and regulatory assets can materially affect timing of cost recovery, earnings, and customer bills.

Policy-integration risk. The handbook must remain aligned with fast-moving policy files. If accounting rules lag rate design or DER programs, utilities can face uncertainty over how to record and recover costs.

Smaller-LDC burden. System changes and specialist accounting requirements can impose high fixed costs on smaller utilities.

Source: OEB Accounting Procedures Handbook Update

7 Regional and Bulk Electricity System Planning Process Review

Docket: EB-2025-0248

The OEB released its report on September 10, 2026. It concludes that Ontario needs regional and bulk planning that is more responsive to rapidly changing demand, clearer about roles, and better prepared before formal planning cycles begin.

WHERE THE FILE STANDS

- The OEB will establish terms of reference for regional Technical Working Groups, create a forecast standard, streamline regional planning, strengthen monitoring of IRRP recommendations, and create an opportunity for written stakeholder comments between active planning cycles.
- The OEB plans to evolve the existing Forecast Guideline into a mandatory forecast standard supported by proposed Transmission System Code and Distribution System Code amendments.
- The report expects distributors to maintain continuous forecast readiness and regular coordination with municipalities and Indigenous communities.
- The OEB supports eliminating the stand-alone Scoping Assessment and folding key activities into IRRP work, potentially saving about three months. Hydro One also expects two months of time savings in Regional Infrastructure Planning starting in 2027 in suitable cases.
- For bulk planning, the OEB recommends that the IESO develop a formal bulk-planning process document, publish and maintain a dashboard, and provide quarterly status/schedule updates.

RISK IMPLICATIONS FOR LDCS AND OTHER PARTICIPANTS

Forecast-readiness risk. The OEB is moving from episodic forecasting toward continuous capability. LDCs that do not maintain current forecasts, assumptions, and municipal/developer intelligence may face both planning and compliance risk.

Scenario-management risk. Multiple demand scenarios improve resilience but increase workload and can create inconsistent decisions if triggers for moving between scenarios are unclear.

Implementation-accountability risk. IRRP recommendations increasingly need named owners, milestones, and monitoring. This makes post-plan execution more visible and exposes slippage sooner.

Municipal information risk. Regional electricity forecasts depend on growth plans, housing, economic development, and climate strategies, but project-level data may sit with developers or customers rather than municipalities.

Solution-provider access risk. The OEB recognized limited opportunities for wire and non-wire solution providers to introduce alternatives. Better access can improve innovation but requires a process that preserves fairness and planning discipline.

Source: OEB Regional and Bulk Planning Report



8 Review of the Valuation of Distributed Energy Resources

Docket: EB-2025-0268

The OEB's March 2026 report, released September 2, 2026, addresses several commercially significant DER policy questions. It distinguishes DER compensation from DER delivery rates and recommends changes intended to align compensation more closely with system value.

The broader significance is commercial. The report begins to establish the conditions under which customers, aggregators, solution providers, and investors can respond to electricity system needs with private capital. Time, location, service value, connection treatment, procurement, and the ability to combine legitimate revenue streams all become increasingly important investment signals.

COLLABORATIVE INSIGHT MARKET SIGNALS

DER policy can support growth by making needs and opportunities clear to customers and solution providers. Clear compensation, data access, connection rules, and operating rights support sound investment decisions.

WHERE THE FILE STANDS

- The OEB recommends moving from conventional net metering toward net billing with time and location-based compensation for injected electricity, subject to government action.
- It recommends removing regulatory restrictions on community net metering and net billing and increasing the mandatory distributor acceptance threshold from 1% to 2% of annual peak load.
- It identifies dynamic pricing for certain Class B customers, study of ICI connected DERs, transmission value compensation pathways, and greater value stacking as areas for action.
- The OEB says distributors can already lead DER procurements for distribution and certain transmission needs and expects those opportunities to expand as compensation pathways improve.
- For delivery rates, the OEB will prioritize certain Retail Transmission Service Rate exemptions for eligible distribution connected storage and consider broader base rate issues, connection cost responsibility and behind the meter rate consistency.
- These changes create potential commercial pathways for storage, distributed generation, flexible demand, EVs, building controls, aggregators, and customer owned resources to provide measurable system services.

COLLABORATIVE INSIGHT PRIVATE CAPITAL

Ontario can unlock significantly more private investment if customers can see the need, understand its value, and rely on a credible pathway to compensation. The strongest DER framework is one that allows private capital to improve customer resilience while also supporting grid reliability and growth.

- Greater recognition of time and location creates an opportunity to direct investment toward actual system needs rather than compensating all DER output in the same manner.
- Clearer procurement and compensation mechanisms could allow more electricity system requirements to be addressed using customer and third-party capital.

RISK IMPLICATIONS FOR LDCS AND OTHER PARTICIPANTS

Revenue erosion / cost-shift risk. DER delivery rate exemptions or net billing changes can reduce distributor revenue and shift costs to nonparticipating customers unless beneficiary pays principles and recovery mechanisms are carefully designed.

Locational value complexity. Time and location-based compensation require granular data, transparent methodologies, and sufficient certainty for customers and investors to act on the signal.



Value stacking coordination risk. A DER may serve distribution, transmission, and wholesale market needs. Contract terms, dispatch rights and measurement rules must prevent double counting while allowing legitimate multiple value streams.

Technology neutrality risk. Different historical treatment of renewable generation, storage, and behind the meter resources can distort investment decisions. More consistent treatment is important as participation expands.

Procurement capability risk. LDC led DER procurement requires commercial, operational, measurement, and contract management capabilities that distributors have not historically required.

Investment certainty risk. A theoretical value stream does not necessarily create a financeable project. Investors need reasonable certainty regarding compensation, duration, measurement, operating obligations, and the conditions under which rules may change.

Participation complexity risk. If connection, contracting, settlement, and operating requirements remain complex, DER participation may remain concentrated among sophisticated market participants rather than expanding more broadly.

Source: OEB DER Valuation Report

COLLABORATIVE INSIGHT FROM EXCEPTION TO NORMAL PARTICIPATION

DERs can progressively become a routine part of Ontario's electricity system. Homes, businesses, and institutions can contribute through generation, storage, EVs, flexible loads and intelligent controls, allowing customers to participate as system resources as well as consumers.

RELATED DEVELOPMENT - Market Surveillance Panel - Locational Pricing in the Renewed Markets

On August 7, 2026, the Market Surveillance Panel published its initial observations on the first twelve months of real-time locational marginal prices in Ontario's renewed electricity markets (May 2025 to April 2026).

The MSP found that locational pricing improves transparency into congestion and price divergence. Congestion was highly localized, including recurring structural constraints in Northwestern Ontario and less frequent but high-impact events in Ottawa.

The MSP cautioned that persistent LMP spreads can signal a need for further analysis but are not, by themselves, sufficient justification for capital investment; a comprehensive cost-benefit analysis remains necessary.

RISK IMPLICATIONS

Investment-signal risk. A price spread identifies scarcity or constraint cost, but not necessarily the optimal remedy. Congestion can be temporary, operational, or better addressed by non-wires options.

Regional-development risk. Persistent constraints become more visible to industrial customers, generators, storage developers, and municipalities, potentially influencing where economic activity locates.

Interpretation risk. Transparent prices support better decisions when users understand what is driving them, how persistent the signals may be, and how wholesale prices relate to local distribution constraints.

Source: OEB Market Surveillance Panel reports

COLLABORATIVE INSIGHT COMMERCIALIZATION

The opportunity is to make system needs visible before prescribing the solution. Clear information about location, timing, capacity, duration, and performance can allow customers, aggregators, and investors to compete to provide value.



9 Gas-Electric Co-ordination and Information Sharing

Docket: EB-2025-0227

This consultation responds to Ontario's Integrated Energy Plan direction for an ongoing gas-electric coordination and information-sharing forum. The objective is to improve energy planning by ensuring that electricity and natural-gas participants exchange relevant planning information such as demand, fuel use, generation, and electrification patterns change.

COLLABORATIVE INSIGHT COORDINATE BEFORE SYSTEM STRESS PEAKS

Electricity and natural-gas planning are increasingly interdependent. During periods of concurrent system stress, natural gas may be needed for both customer heating and electricity generation. Early discussion of priorities, operating assumptions, contingencies, and decision rights can help participants prepare before both systems are constrained. Information sharing is valuable when it supports clear, coordinated decisions that protect reliability across both systems.

WHERE THE FILE STANDS

- The OEB launched the file in December 2025 and posted a second questionnaire on April 27, 2026, to refine the types of information that should be shared.
- The initiative is increasingly connected to regional planning: the OEB's September 2026 regional/bulk report says that information expected at annual regional Technical Working Group meetings will be identified in coordination with the Gas-Electric Coordination Information Sharing Forum.
- The file matters because electricity and gas forecasts can no longer be developed as if the two systems evolve independently.

RISK IMPLICATIONS FOR LDCS AND OTHER PARTICIPANTS

Cross-sector forecast risk. Electrification can reduce gas loads while gas-fired generation and other uses can increase gas-system dependencies. Errors in one sector can therefore propagate into the other.

Confidentiality and data-governance risk. Useful planning data may include commercially sensitive customers, projects, or infrastructure information. The forum will need workable rules for sharing enough information without undermining confidentiality or security.

Timing risk. Information that arrives after a planning decision is effectively unavailable. The value of the forum will depend on cadence, triggers, and update obligations, not only on what data fields are identified.

Assumption mismatch risk. Gas and electricity entities may use different economic, weather, customer-adoption, and policy assumptions. Coordination must address assumptions as well as raw data.

Source: OEB Gas-Electric Co-ordination and Information Sharing



10 Next Generation Rate Framework

Docket: EB-2026-0002

The Next Generation Rate Framework brings four previously separate files into one integrated review of electricity distributor remuneration: performance-based regulation, Spending Pattern Analysis, total cost benchmarking, and the Incremental Capital Module policy. The OEB confirmed the framework is intended to remain fit for purpose while distributors build for electrification and economic growth.

WHAT HAS CHANGED / WHERE THE FILE STANDS

- The OEB has explicitly chosen a holistic approach after stakeholder feedback that remuneration, benchmarking, spending behaviour, and capital mechanisms should not be designed independently.
- The Spending Pattern Analysis report and stakeholder feedback are inputs into this consultation.
- The framework could influence how utilities are rewarded for efficiency, service outcomes, capital deployment, innovation, and non-wires alternatives over a multi-year rate term.

COLLABORATIVE INSIGHT NEXT GENERATION RATE FRAMEWORK

The remuneration framework can be assessed against the role Ontario now expects LDCs to play. Prudence and affordability remain fundamental, but LDCs are increasingly being asked to enable growth, electrification, new load, DERs, and more active customer participation. The framework can be designed to reward efficient outcomes and timely capacity enablement, without creating an inherent bias toward capital, operating expenditure, utility ownership, or third-party solutions

RISK IMPLICATIONS FOR LDCS AND OTHER PARTICIPANTS

Revenue-model risk. Changes in performance-based regulation can alter the relationship between investment, operating cost, productivity expectations, and shareholder return.

Capital-versus-operating incentive risk. If incentives are not neutral, utilities may be encouraged toward capital-intensive or operating-expense solutions even when another option produces better customer value.

Benchmarking risk. Comparisons can improve accountability but may penalize distributors with legitimately different customer density, geography, asset condition, growth, or resilience needs unless models control those factors adequately.

Transition risk. LDC planning horizons are long. A new remuneration framework introduced while utilities are making major electrification, and capacity investments can create uncertainty about future recovery and incentives.

Innovation risk. If returns on new capabilities such as DER orchestration, digital systems, flexibility procurement, and customer-facing programs are unclear, LDCs may rationally defer innovation.

Source: OEB Next Generation Rate Framework

11 Customer Service Rules Review

Docket: EB-2026-0109

Launched August 25, 2026, this consultation reviews selected customer-service rules for electricity distributors, rate-regulated natural-gas distributors, and unit sub-meter providers. It responds to the December 2025 Ministerial Letter of Direction and consumer/stakeholder feedback. For LDCs, it adds another layer of performance and consumer-protection expectations while connection, rate-framework, and data obligations are changing.

COLLABORATIVE INSIGHT - SERVICE SUPPORTS ECONOMIC ACTIVITY

In a growing electricity system, customer service supports both consumer protection and economic activity. The speed and clarity with which an LDC can support a new home, business, industrial expansion, or electrification project can affect investment and economic development.

WHERE THE FILE STANDS

- The OEB lists the file as Active and has not published an overall completion date on the project page.
- The review is relevant to LDC operating processes, customer communications, compliance systems, and potentially performance measures.

RISK IMPLICATIONS FOR LDCS AND OTHER PARTICIPANTS

Compliance-change risk. Rule changes can require modifications to billing, collections, customer communications, training, systems, and audit controls.

Customer-expectation risk. More explicit service requirements can improve customer protection but also make process failures more visible and measurable.

Implementation-capacity risk. Smaller LDCs may face disproportionate system and staffing costs when several regulatory changes arrive concurrently.

Source: OEB Customer Service Rules Review

12 Green Button Data Collection - Distributor Survey

Docket: EB-2026-0230

Launched September 3, 2026, this is a new OEB policy initiative to assess how Green Button services are being delivered and used across Ontario. It builds on the earlier Green Button Implementation consultation and responds to the December 2025 Letter of Direction. The OEB plans targeted engagement in fall 2026, a draft survey for broad comment in early 2027, and a final survey after comments.

WHERE THE FILE STANDS

- The initiative is a one-time distributor survey, but its findings are intended to inform future OEB consideration of Green Button adoption, performance, and operational practices.
- The older Green Button Implementation file (EB-2021-0183) remains listed as Active by the OEB, so the new survey should be viewed as a second-stage performance/usage assessment rather than a brand-new policy area.

COLLABORATIVE INSIGHT - DATA ENABLES PARTICIPATION

Green Button can provide value beyond compliance when it functions as usable digital infrastructure. Reliable access to energy information can help customers manage demand, adopt DERs, optimize buildings, charge EVs intelligently, and participate in an increasingly flexible electricity system.

RISK IMPLICATIONS FOR LDCS AND OTHER PARTICIPANTS

Data-quality risk. If utilities collect or report Green Button performance differently, province-wide comparisons may be misleading.

Technology and vendor risk. Green Button depends on secure, interoperable digital systems, and third-party/vendor performance outside the traditional wires business.

Privacy/cyber risk. Greater customer-authorized data sharing increases the importance of identity, consent, security, and incident-management controls.

Value-realization risk. Implementation compliance does not guarantee customer adoption or useful third-party services; the survey may expose a gap between availability and actual value.

Source: OEB Green Button Data Collection - Distributor Survey

OECA ASSISTANCE IN COLLABORATIVE ENGAGEMENT

The policy direction is increasingly clear that Ontario's electricity transition cannot be delivered by regulation alone. The harder work now sits between organizations: where forecasts are exchanged, connections are coordinated, DERs are valued, municipal growth plans meet grid constraints, and accountability passes from one party to another. Those interfaces are where delay, duplication, and missed opportunity accumulate.

As an independent, not-for-profit organization, OECA is positioned to help address those interfaces. Its role is to bring the organizations responsible for distinct parts of the system into the same room, connect issues that are being addressed in separate regulatory files, and turn cross-sector discussion into practical implementation insight.

OECA can help by:

- convening regulators, system agencies, LDCs, transmitters, municipalities, customers, Indigenous communities, and solution providers around shared implementation issues.
- testing where hand-offs in data, timing, accountability, and decision-making are breaking down.
- connecting lessons across regulatory files before inconsistencies become embedded.
- giving smaller organizations and non-traditional participants a practical route into system-level conversations; and
- carrying recurring implementation issues back into regulatory, planning and industry forums in a constructive, non-advocacy way.

This is not a substitute for the OEB, IESO, utilities, or industry associations. OECA provides the connective function between the full range of Ontario energy stakeholders.

Ontario is asking the electricity system to support economic growth, electrification, major new loads, DER participation, and more active customers at the same time. That requires more than technically sound policy. It requires sustained collaboration across organizations that were not designed to plan and execute as one system.

That is where OECA can be part of the solution.



COLLABORATIVE ENGAGEMENT





Appendix A - Collaborative Insights

These call-outs are collected here for rapid review and future wording adjustments. They are synthesis observations intended to assess interfaces across the regulatory and operating model; they are not OEB positions.

#	Location	Collaborative Insight
1	**Executive Summary**	EXECUTION Ontario's next constraint may be coordination capacity. The policies are moving; the opportunity is to make the information hand-offs between organizations work as deliberately as the policies themselves. OECA can help create that connective tissue.
2	**Distribution System Operator Capabilities**	GROWTH DSO policy involves technology, capabilities, and operating models. LDCs are being asked to remain prudent, regulated utilities while becoming more active enablers of load growth, flexibility, and economic development. Operating, cultural and financial models may need to evolve with that role.
3	**Distribution Customer Connections**	CONNECTIONS Connection performance increasingly affects economic-development outcomes. Faster internal processes may have limited effect if customer, LDC, transmitter, IESO and municipal information hand-offs remain fragmented. Large-load connections offer lessons that may apply more broadly as demand grows.
4	**DER Operational Valuation**	MARKET SIGNALS DER policy can support growth when customers and solution providers can understand and act on the signals. Clear compensation, data access, connection rules, and operating rights can support credible investment decisions.
5	**DER Capital Valuation**	PRIVATE CAPITAL Clear system needs, understandable value, and credible compensation pathways can improve conditions for private investment. A well-designed DER framework can allow private capital to support customer resilience, grid reliability, and growth.
6	**DER Valuation / Locational Pricing**	COMMERCIALIZATION Identification of system needs can enable better solutions before actions are prescribed. Clear information about location, timing, capacity, duration, and performance can allow customers, aggregators, and investors to compete to provide value.
7	**DER Valuation / Customer Participation**	FROM EXCEPTION TO NORMAL PARTICIPATION DERs are increasingly capable of becoming a routine part of Ontario's electricity system. Homes, businesses, and institutions can contribute through generation, storage, EVs, flexible loads, and intelligent controls, participating as system resources as well as consumers.
8	**Gas-Electric Co-ordination & Information Sharing**	COLLABORATION BEFORE SYSTEM STRESS Electricity and natural-gas planning are increasingly interdependent. Information sharing is most valuable when it helps participants clarify priorities, assumptions, contingencies, and decision rights before both systems are constrained.
9	**Next Generation Rate Framework**	ALIGN INCENTIVES WITH THE ROLE Prudence and affordability remain fundamental, while LDCs are increasingly expected to enable growth, electrification, new load, DERs, and active customer participation. A key design question is how regulation can support efficient outcomes and timely capacity.
10	**Customer Service Rules Review**	SERVICE SUPPORTS ECONOMIC ACTIVITY In a growing electricity system customer service supports both consumer protection and economic activity. The speed and clarity with which an LDC can support a new home, business, industrial expansion, or electrification project can directly affect investment and economic development.
11	**Green Button Data Collection**	DATA ENABLES PARTICIPATION Green Button can provide value beyond compliance when it functions as usable digital infrastructure. Reliable access to energy information can help customers and their partners manage demand, adopt DERs, optimize buildings, charge EVs intelligently, and participate in a more flexible electricity system.
12	**Initiative Interaction**	SYSTEM-WIDE COORDINATION AND COLLABATION Individual initiatives can perform well within their mandates while cross-initiative results still depend on effective coordination and collaboration. Data, timing, accountability, and incentives deserve the same attention as the individual policies.



Appendix B - Broader OEB Consultation / Working-Group Monitoring Inventory

The OEB's active-policy index contains additional electricity-related files beyond the twelve core initiatives. Some are predecessor files, standing programs or long-running reviews rather than new 2026 strategic consultations. They remain relevant to LDC monitoring. A separate current policy-consultation process - the reconvened Uniform Transmission Rates Phase 2 Working Group (EB-2026-0166) - was also identified through the OEB's consultation calendar and RDS materials.

Docket	Initiative	Launch / start	Completion Date / activity note
EB-2026-0166	Uniform Transmission Rates Phase 2 Working Group	May 27, 2026, reconvened	No completion date identified; meetings continue Sep. 17, 2026. Active working-group process.
EB-2025-0149	Electricity Transmission Rates Filing Requirements Review	Jun. 5, 2025	No overall completion date identified; OEB active index still lists Active.
EB-2025-0142	AI in OEB filing preparation — Rules amendments	Apr. 11, 2025	No overall completion date identified; active index still lists Active.
EB-2024-0236	Review/Evaluation of Incremental Capital Module Policy	Aug. 28, 2024	No separate completion date; now one of the four files integrated into Next Generation Rate Framework.
EB-2024-0199	Vulnerability Assessment and System Hardening (VASH)	Jun. 27, 2024	No overall completion date identified; active index still lists Active.
EB-2024-0092	System Expansion for Housing Developments	Mar. 13, 2024	No overall completion date identified; active index still lists Active.
EB-2023-0229	Regulatory Efficiency for Very Small Utilities	Aug. 31, 2023	No overall completion date identified; active index still lists Active.
EB-2023-0135	LEAP Emergency Financial Assistance Review	Jul. 19, 2023	No overall completion date identified; active index still lists Active.
—	Electricity Utility Cyber Security	Feb. 7, 2023	Standing/ongoing work; no overall completion date identified.
EB-2022-0267	Reporting and Record-keeping Requirements Consultation	Oct. 24, 2022	No overall completion date identified; active index still lists Active.
EB-2023-0071	Electric Vehicle Integration	Sep. 19, 2022	No overall completion date identified; active index still lists Active.
—	Energy Transition	Sep. 19, 2022	Umbrella/ongoing initiative; no overall completion date identified.
EB-2022-0096	Distribution Cost of Service Filing Requirements Update	Feb. 22, 2022	No overall completion date identified; active index still lists Active.
—	Green Button Industry-led Working Group	Dec. 2, 2021	Two-year implementation-period forum was originally contemplated; OEB active index still lists Active. This is a legacy-status anomaly worth monitoring.
EB-2021-0307	Reliability and Power Quality Review	Nov. 30, 2021	No overall completion date identified; active index still lists Active.
EB-2021-0183	Green Button Implementation	Jul. 5, 2021	Original concept contemplated a two-year phase-in; OEB still lists file Active in 2026. New EB-2026-0230 survey indicates continuing policy work.
EB-2022-0011	Intervenor Processes and Cost Awards	May 10, 2021	No current completion date identified; subsequent 10-point Action Plan now carries major efficiency implementation work.
EB-2020-0176	Regional Planning Process Review	Dec. 10, 2020	Legacy file still listed Active; newer EB-2025-0248 review has produced a 2026 report.
EB-2019-0207 / EB-2021-0117	DER Connections Review	Aug. 13, 2019	Long-running file still listed Active; related DER/DSO initiatives now overlap materially.
EB-2018-0278	Activity and Program-based Benchmarking	Oct. 10, 2018	Long-running active listing; remuneration/benchmarking work now also sits within NGRF.

Important activity-status caution. Several older files remain labelled Active on the OEB website even where a newer initiative has overtaken part of the subject matter or the public page has not been updated recently. This review treats those as monitoring signals, not as proof of a formal pause. Only an explicit OEB statement would justify calling an initiative formally halted.



Consultation Effectiveness Questions

1. Are accountabilities clear where a customer outcome depends on several regulated and non-regulated parties?	**2.** Do performance metrics measure controllable performance rather than elapsed time caused by dependencies?
3. Are utilities maintaining continuously current forecasts rather than rebuilding them only when a formal planning cycle starts?	**4.** Are municipal, Indigenous community, developer, and large-customer plans reaching electricity planners early enough?
5. Are BCA assumptions standardized enough to allow comparable decisions while still reflecting local circumstances?	**6.** Does the remuneration framework create neutrality between capital, operating, third-party, and non-wires solutions?
7. Can DER providers stack legitimate value streams without double counting or conflicting dispatch obligations?	**8.** Are smaller LDCs being given scalable compliance and technology pathways?
9. Are technology investments being paced to evidence and interoperability standards so that stranded investment is minimized?	**10.** Are rate and compensation reforms protecting non-participating customers from unintended cost shifts?
11. Are regulatory initiatives being sequenced so one policy does not force spending before another establishes recovery or accounting treatment?	**12.** Is Ontario measuring collaboration outcomes - fewer handoff failures, faster issue resolution, better information quality - rather than simply increasing the number of meetings?

Appendix C - OEB Source Appendix & Research Note

Source	Link
OEB Policy initiatives and consultations index	https://www.oeb.ca/consultations-and-projects/policy-initiatives-and-consultations
Archived and complete policy initiatives	https://www.oeb.ca/consultations-and-projects/archived-and-complete-policy-initiatives-and-consultations
Benefit-Cost Analysis Framework	https://www.oeb.ca/consultations-and-projects/policy-initiatives-and-consultations/benefit-cost-analysis-framework
DSO Capabilities	https://www.oeb.ca/consultations-and-projects/policy-initiatives-and-consultations/dso-capabilities
Spending Pattern Analysis	https://www.oeb.ca/consultations-and-projects/policy-initiatives-and-consultations/spending-pattern-analysis
OEB 10-point Action Plan	https://www.oeb.ca/consultations-and-projects/policy-initiatives-and-consultations/implementation-oebs-10-point-action
Distribution Customer Connections Review	https://www.oeb.ca/consultations-and-projects/policy-initiatives-and-consultations/distribution-customer-connections
Streamlining Transmission Connections	https://www.oeb.ca/consultations-and-projects/policy-initiatives-and-consultations/streamlining-transmission
Accounting Procedures Handbook Update	https://www.oeb.ca/consultations-and-projects/policy-initiatives-and-consultations/accounting-procedures-handbook
Regional and Bulk Electricity System Planning Process Review	https://www.oeb.ca/consultations-and-projects/policy-initiatives-and-consultations/regional-and-bulk-electricity
Valuation of Distributed Energy Resources	https://www.oeb.ca/consultations-and-projects/policy-initiatives-and-consultations/review-valuation-distributed-energy
Gas-Electric Co-ordination and Information Sharing	https://www.oeb.ca/consultations-and-projects/policy-initiatives-and-consultations/gas-electric-co-ordination-and
Next Generation Rate Framework	https://www.oeb.ca/consultations-and-projects/policy-initiatives-and-consultations/next-generation-rate-framework
Customer Service Rules Review	https://www.oeb.ca/consultations-and-projects/policy-initiatives-and-consultations/customer-service-rules-review
Green Button Data Collection - Distributor Survey	https://www.oeb.ca/consultations-and-projects/policy-initiatives-and-consultations/green-button-data-collection
Green Button Implementation	https://www.oeb.ca/consultations-and-projects/policy-initiatives-and-consultations/green-button-implementation
Reports of the OEB	https://www.oeb.ca/regulatory-rules-and-documents/reports-oeb
Non-Wires Solutions Guidelines	https://www.oeb.ca/regulatory-rules-and-documents/rules-codes-and-requirements/nws-guidelines-electricity
Market Surveillance Panel Reports	https://www.oeb.ca/ontarios-energy-sector/market-surveillance-panel/msp-reports

Research note

This review uses the Ontario Energy Board's official Policy Initiatives and Consultations index, individual OEB project pages, Engage With Us materials, OEB reports, and current policy-consultation calendar entries reviewed until September 12, 2026. "Completion Date" records an OEB-stated original target where one was identified; where no overall completion date was published, the table says so. A later public posting date is not treated as proof that delivery to the Minister was late unless the public record establishes a missed deadline. The review also flags extended public-update gaps but does not label them a formal halt unless the OEB says the work was paused or stopped.