Guidehouse

Preface: Electricity Regulation 1 Year After the COVID-19 Pandemic
A Year of Disruption: Recommendations to Policymakers and Regulators

In 2019 and 2020, the Canadian Electricity Association (CEA) and Natural Resources Canada (NRCan) commissioned Guidehouse to research obstacles to electricity sector investment, innovation, modernization, and decarbonization, and to identify recommendations for overcoming these. This research was not publicly released due to the onset of the global COVID-19 pandemic. Now, a little more than a year into the pandemic, we are releasing this report at CEA's annual Regulatory Forum. This preface is intended to revisit the report after a period of profound disruption that, like for many other industries, also exerted tremendous pressure for change on the electricity sector. We classify these forces in terms of *Decarbonization, Decentralization, Digitalization* and *Democratization,* or *the "4Ds".* Our original report is available here, though the most relevant findings are below.

Preparing for Transformation

In terms of decarbonization, The Government of Canada signalled its intention to accelerate climate change action with the tabling of its 2021 budget and a COVID-19 recovery strategy focused on economic transition. The budget commits to increasing greenhouse gas (GHG) emissions reduction targets, offers tax-based incentives for zero emission vehicles to drastically cut transportation sector GHGs, establishes billions in funding for net-zero technology market acceleration, and increases public investment in the hydrogen market. The government's new climate plan will result in the need for multiples of clean power resources in Canada relative to today's production.[1]

At the same time, the 2020 election in the US led to increased support for a transformative policy setting that focuses on energy and climate. Global acceptance of renewable energy, distributed energy resources, and a transition within the energy landscape continues to dominate headlines, and there is strengthened enthusiasm for digital technologies.

It is clear that systemic renewal in the electricity sector will require a fundamental transformation, and that Canadian electric utilities face pressure to change across all fronts. 2020 will be remembered as an inflection point to conventional ways of thinking, while COVID-19 continues to remind us of the importance of being agile and flexible in anticipation of change, and the challenges and opportunities that continually run alongside the industry.

Electricity Policy, Regulation, and the 4Ds

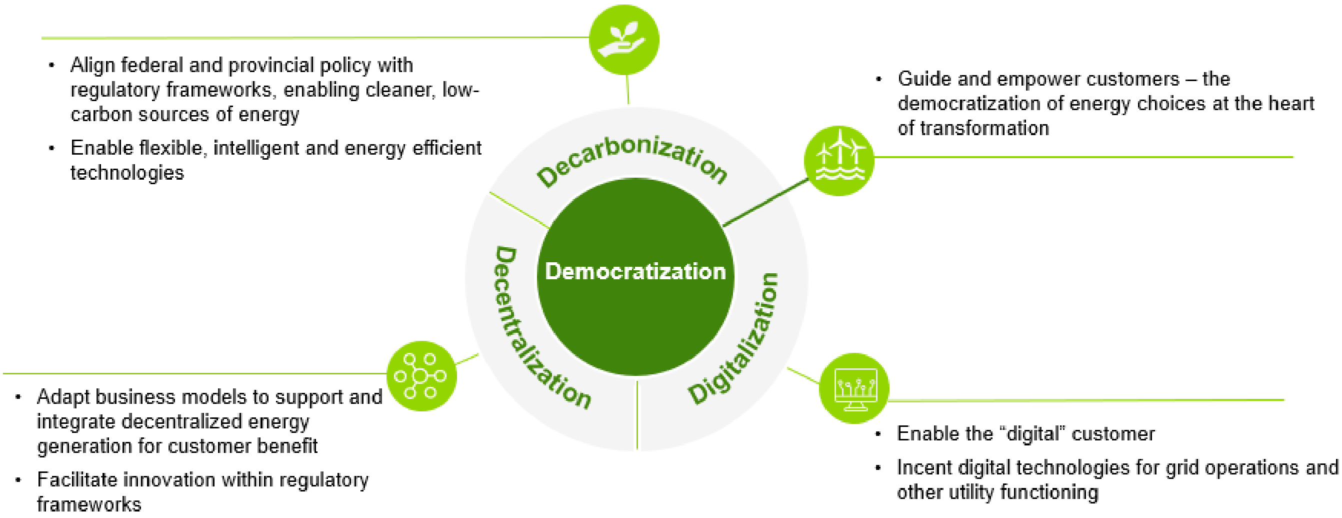
Although necessary to ensure cost effectiveness, safety, and reliability of the grid, regulatory regimes are not adapted to fully address the unprecedented transitional forces facing the electricity industry. Narrowly focused regulatory mandates do not allow for a long view of such transitions and therefore neglect many of the benefits, such as resiliency, sustainability, enhanced customer products, and competition. Many of today's policies focus on short-run economics and least-cost, minimum-viable product investment making, which does not address the profound forces that are taking hold in the sector; the 4Ds.

Each of the 4Ds intensified in terms of disruptive force in the past year. Regulators, policymakers, and industry must address these four key factors, which will be central to unlocking the sustainable

[1] State of the Canadian Electricity Industry – Renewal 2021, Canadian Electricity Association https://electricity.ca/library/state-of-the-canadian-electricity-industry-renewal-2021/

growth and development that is necessary for energy providers to optimize operations and provide the services and choices that customers demand. Included must be a consideration for companies pivoting to address these emerging issues within existing rate-regulated systems.

Figure 1: 4D Factors of Transformation



Using the 4Ds as guideposts, policymakers, regulators, and industry, can shift toward development of a regulatory ecosystem that continues to serve its traditional functions, while incentivizing innovative and sustainable products and services. Utilities must offer cost-effective development of infrastructure and platforms that unlock emerging and evolving technology value, system flexibility, and system resiliency.

Key Barriers

In 2019, Guidehouse advanced a stakeholder-informed research paper that identified the cumulative adverse impact of decades-old risk averse decision-making and current regulatory regimes in Canada. This paper identified key barriers to transformation based on research and engagement with distribution and transmission utilities, generators, and regulators from across

Canada. The report also provided examples of how other jurisdictions in the US and Europe have begun to address these barriers. The key barriers are summarized in *Figure 2*.

Calls to Action

Although many electricity companies have started to build innovative investments and business offerings through non-regulated subsidiaries, there is a compelling public imperative to allow these innovations to also occur efficiently within the rate-regulated systems as well. The failure to incentivize greater risk-taking and innovation by electricity companies in adaptation to changing market conditions hinders the industry's progress and modernization, and critically, its response to climate change.

If the policy context can be thought of as a platform and strategic direction for change, then regulation in the utility sector can be viewed as a catalyst, facilitating the implementation framework with which energy companies are motivated and incentivized to execute. With so much change occurring so rapidly in the technology, research, and development space, it is imperative that the policy and regulatory structures that underpin investment and operations for Canadian electric utilities also adapt and lead the transformation.

Figure 2: Key Regulatory Barriers

Barrier 1: Conflicts and inefficiencies in the consultation process
Nearly all market participants highlighted experiencing costly, inefficient, and adversarial regulatory proceedings, where stakeholders and intervenors are at odds with utilities.

Barrier 2: Insufficient regulation and guidance influencing investment in non-traditional assets
Governments should consider issuing timely policy directives to regulators, which go beyond traditional electricity-related statutes

Barrier 3: Undervalued and narrowly accepted benefit streams of non-traditional system assets
Regulators are perceived to lack the tools needed to consider the full value of non-traditional distribution investments in evaluations made for rate recovery. Investors may not be able to recover the full investment cost.

Barrier 4: Lack of innovative regulatory models that address the risk of stranded assets associated with new technologies
Regulators are hesitant to support research, development, and demonstration projects.

Barrier 5: Misaligned incentives between utility cost of service rate making and non-traditional assets
Utilities are traditionally allowed to profit from capital expenditures, but not operating expenditures where investment may be needed.

Barrier 6: Redundancy and overlap of Provincial and Federal regulatory oversight
Unclear jurisdiction and lack of coordination and communication between federal and provincial regulators can lead to utilities spending extra resources and time addressing redundant regulations with no clear benefit.

Recommendations

To accelerate the adoption of non-traditional assets, the federal government is well-suited via its convening and spending powers to facilitate collaboration with provinces on issues such as smart-grid investments, small modular reactors, battery storage, electrification, and hydrogen. Provincial and territorial directives, aided by federal spending power, would help electricity companies advance the policy objectives of their respective governments, while all levels of government should prioritize discussion on collaboration at intergovernmental initiatives such as the annual Energy and Mines Ministers' Conference (EMMC).

The following recommendations provide further guidance.

Recommendation 1: Regulators can take a broader view of conflicts within the context of regulatory deliberations and approvals. By considering more benefits and the role of the electricity industry in meeting national decarbonization goals, as well as allowing for innovative initiatives, regulators can enable environmental, social, and economic goals set out by federal and provincial policy platforms. Initially, establishing mechanisms for greater federal and provincial policy coordination will improve clarity of purpose for the electricity sector.

Recommendation 2: Simplify innovation-related funding in alignment with clear objectives to improve the policy signal. Instead of creating winners and losers through burdensome government funding application processes, regulators should consider allocating federal dollars through transformation-supportive framework criteria to be implemented through delivery agents such as electricity companies. Funding could be prioritized to support initiatives such as energy efficiency, energy storage, electrification, and hydrogen-based technologies.

Recommendation 3: Regulators can enhance and lead, offering guidance for treatment of non-traditional assets underpinned by robust analysis of benefits. Provincial regulators should consider providing utilities with specific rules regarding emerging technologies and related business models. For example, California passed several state bills that mandate energy storage procurement by a specific date.

Recommendation 4: Reimagine regulatory frameworks to adjust for lack of defined processes in gaining capital approval of non-traditional distribution investments. As a result, there may be less uncertainty about how to pursue these investments and whether they will be approved as prudent costs and rate-based. Non-traditional distribution investments are likely to be one of the most impactful in the electricity sector in coming years due the rise of environmental policy and the proliferation of new technologies digitizing operations and customer interfaces.

Recommendation 5: Shoulder the risks of innovation, testing and failure, in addition to the rewards. In the context of a regulated industry, both shareholders and customers must shoulder these risks. If the goal is to adapt to the changing landscape, innovate, and support government strategy, regulatory structures must provide a supportive platform to facilitate growth, enhancement, and value creation. Regulatory structures must change to find a balance for risk sharing.

Recommendation 6: Adapt current regulatory constructs to incentivize investments in digitization that is increasingly offered through cloud-based services (i.e., that are not brick and mortar). These investments are often not eligible for regulated rates of return and therefore not prioritized, despite such investments often offering far reaching long-run cost-savings and operational efficiency benefits. As economies digitize broadly, so must utility organizations. Digitization must deliver customer benefits and reduce costs, but also drive stronger shareholder returns.

The continually dynamic electricity industry is being disrupted. The best outcomes will result from a harnessing of transformative forces. Regulators and utilities must together forge a new system of policy, guidance, flexibility, and new models for success. The 4Ds offer useful signposts of a future energy context and there are number of key tactical next steps that must be taken to ensure the resiliency and effectiveness of utility assets for a robust, innovative, and growing economy in Canada.

Regulatory Cumulative Impact Study

Canadian Electricity Regulations

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DISCLAIMER

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EXECUTIVE SUMMARY

Overview

Navigant was engaged by Canadian Electricity Association (CEA), with support from NRCan, to identify aspects within regulations and regulatory processes in the electricity sector that impede investment and innovation in the industry. Navigant carried out the following tasks through two phases of research to identify material pain points in current regulations and determine actionable recommendations for improvement:

- Phase 1 – Preliminary research through the following tasks:
  - High-level regulatory scan of Canadian electricity regulations to identify pain points among current processes
  - Workshop with key stakeholders to confirm and prioritize five focus areas among identified pain points for further research
- Phase 2 – In-depth research into the five focus areas through the following tasks:
  - In-depth regulatory research involving a deep dive into Canadian regulations, with a focus on completed and in-progress projects aligned with each of the five focus areas
  - Stakeholder interviews with relevant professionals representing utilities, power generators and regulators to validate our findings and recommend solutions
  - Jurisdictional scan of four regions to identify best-practices that can be used to solve many of the pain points identified in previous tasks

Findings

The findings of this engagement are summarized at a high level in the following three subsections. Detailed descriptions of the pain points, evidence from research and interviews and potential solutions from the jurisdictional scan can be found in Section 2 of the report.

Non-traditional Distribution

Investment in non-traditional distribution infrastructure is primarily slowed not by burdensome regulatory processes, but rather a regulatory void of guidance and assistance.

Navigant identified four pain points contributing to utilities' slow adoption of promising innovative technologies and ideas: insufficient regulation and guidance for investment in non-traditional distribution, undervaluation of non-traditional distribution technologies, risk of underperforming or stranded assets, and misaligned incentives between utility service optimization and business models.

Navigant reviewed regulations in California, New York, and Massachusetts to find inspiration for innovative policy solutions that may mitigate the aforementioned pain points. Though every jurisdiction has unique problems that demand unique solutions, parallels can be drawn to Canadian jurisdictions, and their innovative policies can provide inspiration for similar approaches in Canada.

Table 1. Distribution Pain Point 1

Distribution Pain Point 1 - Insufficient Regulation/Guidance for Investment in Non-traditional Distribution	
Evidence	Evidence summarized from Navigant's research and interviews: • In Alberta, due to lack of clear guidance, utilities each developed their own distinct pricing mechanisms, which are perceived as unfair to some distributed generation (DG) owners.[1] • In Ontario, while alternatives to traditional infrastructure are encouraged, there is no framework for applying for them. Utilities must develop their own structure for the proposal.
Potential Solution	Regulators should provide utilities with specific rules around which technologies and business models they are permitted to pursue and for which purposes. Examples from other jurisdictions are below: • California passed several state bills that mandate energy storage procurement, in which each utility is required to procure a specified amount of storage capacity by a specific date. • In a Massachusetts rate case, National Grid proposed a mechanism for a request for proposal (RFP) system for NWAs. • New York's Reforming the Energy Vision (REV) regulatory dockets encourage utilities to evolve into the role of Distribution System Platform providers. Actions like redesigning of price signals, compensation structures, and increasing access to data are aimed to allow utilities to embrace BTM technologies.

Table 2. Distribution Pain Point 2

Distribution Pain Point 2 – Undervaluation of Non-traditional Distribution Technologies	
Evidence	Evidence summarized from Navigant's research and interviews: • Ontario's Distribution System Code (DSC) dictates that distributors can only recover 6% of their investment in Renewable Enabling Improvements from ratepayers in their service territory. • A Canadian utility indicated that there is no standard framework for quantifying benefits of DERs. Utilities must provide their own assessment of benefits and do not know whether the regulator will agree with their methodology.
Potential Solution	Regulators should develop frameworks for quantifying benefits of DERs and provide utilities with them. Examples from other jurisdictions are below: • New York's regulator has developed benefit-cost analysis methodologies for NWAs to help utilities determine the true value of non-traditional projects • A California bill required utilities to determine optimal locations on their grids where DERs would provide the most value. • California has adopted the Distributed Energy Resources Avoided Cost Calculator developed by E3 to help determine the value DERs provide by deferring traditional poles and wires investments

[1] https://albertapowermarket.com/2017/06/27/unpacking-distributed-generation-the-alberta-utilities-commissions-challenge/

Table 3. Distribution Pain Point 3

Distribution Pain Point 3 – Risk of Underperforming or Stranded Assets	
Evidence	Evidence summarized from Navigant's research and interviews: • A Canadian utility noted that DERs are untested, so while there are known benefits to many of these technologies, regulators often require data to prove these benefits, of which there is little. • A Canadian utility expressed that some new technologies would require different business models that they do not know if they will be allowed to adopt.
Potential Solution	Regulators should make efforts to minimize risk associated with investing in DERs by taking action to understand their effects better. They should also shift the risk away from ratepayers by accepting increased responsibility and/or encouraging private sector involvement. Examples from other jurisdictions are below: • California's Demand Response Auction Mechanism creates a market in which sellers can bid flexible capacity into the California Independent System Operator's (CAISO) day-ahead market, providing more of a guarantee that investment in a DER project will be used/useful.[2] • New York utilities were required to provide frameworks for how they will reform the distribution grid in their service territories. This process produced a number of action items that will increase effective DER deployment. • New York REV's regulations encourage partnership between utilities and the private sector. This form of relationship can be used to offload some of the financial risk of investing in non-traditional distribution assets from ratepayers to private companies.

Table 4. Distribution Pain Point 4

Distribution Pain Point 4 – Misaligned Incentives Between Utility Service Optimization and Business Model	
Evidence	Evidence summarized from Navigant's research and interviews: • Cost of service ratemaking ties growth in electricity consumption and grid infrastructure to utility growth. Therefore, energy conservation directly hurts the utility financially. • Utilities are traditionally allowed to profit from capital expenditures but not operating expenditures. Many non-traditional distribution assets reduce a utility's capital expenses and increase operating expenses, decreasing profit. [3]

[2] https://www.pge.com/en_US/large-business/save-energy-and-money/energy-management-programs/demand-response-programs/2018-demand-response/2018-demand-response-auction-mechanism.page

[3] https://info.aee.net/hubfs/AEE%20Institute_Utility%20Earnings%20FINAL_Rpt_1.30.18.pdf

Distribution Pain Point 4 – Misaligned Incentives Between Utility Service Optimization and Business Model	
Potential Solution	Regulators should modify the ratemaking process to reward utilities for performance and customer satisfaction, instead of for building infrastructure. Examples from other jurisdictions are below: • New York is undergoing gradual ratemaking reform as part of REV. Some proposed modifications to the regulatory process include: allowing utilities to retain some of their capital budget if supplanted by DERs, monetized performance metrics, and more sophisticated rates with granular price signals and more precise demand charges.

Generation

Pain points and potential solutions related to the capital approval of thermal generation and the environmental approval of all generation types focused on the perceived excessive costs and regulatory burden imposed on thermal generators, as well as duplicative processes and excessive environmental regulatory burden imposed on all generation types.

The main source of pain points for thermal generation developers is Canada's proposed Clean Fuel Standard (CFS) and its incremental burden when stacked with the Output Based Pricing System (OBPS). These pain points include an increased cost to gas-fired electricity generation and unfair credit distribution for electrification of transport.

The pain points related to the environmental approval process include rework, lack of clarity, over production of regulatory documents, conflicts, and delays due to the input of many stakeholders. Bill C-69 was intended to alleviate burden on developers during the environmental approval process, however, Navigant has found that the decision-making process embedded in Bill C-69 may result in incremental burden placed on all generation developers.

To make recommendations for improvement, Navigant reviewed regulations and generation projects in California, Massachusetts and Norway.

Table 5. Generation Pain Point 1

Generation Pain Point 1 - Increased Cost to Gas-Fired Electricity Generation Due to the Stacking of CFS and OBPS	
Evidence	Evidence summarized from Navigant's research and interviews: • Canada's CFS is the first policy of its kind to include both stationary energy consumption and transportation energy consumption. All other similar policies Navigant reviewed only include transportation energy consumption.[4,5] • By 2023, the CFS would add an estimated 250% carbon cost on top of the OBPS for jurisdictions with natural gas power generation. Jurisdictions with substantial gas generation will be disproportionately impacted by CFS costs.

[4] Navius Research Inc., "Analysis of the Proposed Canadian Clean Fuel Standard", http://cleanenergycanada.org/wp-content/uploads/2017/11/CFS-technical-report.pdf

[5] Canada West Foundation, "WHAT NOW? | Lessons Learned?: Canada's new Clean Fuel Standard", https://cwf.ca/research/publications/what-now-lessons-learned-canadas-new-clean-fuel-standard/

Generation Pain Point 1 - Increased Cost to Gas-Fired Electricity Generation Due to the Stacking of CFS and OBPS	
Potential Solution	This pain point can be solved by excluding fuels used for power generation from Canada's CFS, as long as this fuel is used in high efficiency gas generators built to support intermittent renewable development. CFS' in the following jurisdictions exclude fuels used for power generation: • California • European Union

Table 6. Generation Pain Point 2

Generation Pain Point 2 - Credit Distribution for Electrification of Transport	
Evidence	Evidence summarized from Navigant's research and interviews: • Under Canada's CFS, credit creators for electric and hydrogen fuel cell vehicle charging include three entities; gas stations, office buildings, and residential homes. • Preparing the grid for EVs requires major investments from distribution utilities,[6,7] but it is not clear if utilities will be eligible to receive credits.
Potential Solution	This pain point can be solved by ensuring an equitable distribution of CFS credits, where credits are provided to those most financially impacted by CFS goals. California's CFS allows distribution utilities to earn credits when they supply electricity for EV deployment.[8]

[6] IEEE, "Impact of electric vehicles on power distribution networks", https://ieeexplore.ieee.org/document/5289760

[7] Tritium, "RESEARCH : PREPARING THE GRID FOR EV'S", https://www.tritium.com.au/news/newsitem?url=research-preparing-the-grid-for-ev-s

[8] Forbes, "How (Almost) Everyone Came To Love Low Carbon Fuels In California", https://www.forbes.com/sites/danielsperling/2018/10/17/how-almost-everyone-came-to-love-low-carbon-fuels-in-california/#59bb55e65e84

Table 7. Generation Pain Point 3

Generation Pain Point 3 - Environmental Assessment Rework, Lack of Clarity, and Over Production	
Evidence	Evidence summarized from Navigant's research and interviews: • During the environmental assessment of generation projects, the regulator often asks for additional information/requests from a proponent that were not included in initial guidelines. E.g., during the environmental assessment of the Whitla Wind Project in Alberta, the provincial regulator asked for additional environmental cumulative assessments which resulted in the proponent submitting four Noise Impact Assessments.[9] • During the environmental assessment of generation projects, the regulator can provide unclear guidance and vague statements regarding public and Indigenous consultation. For instance, during the assessment of the Site C Project in British Columbia, the regulator did not provide clear information to the proponent regarding consultation of Indigenous groups.[10]
Potential Solution	This pain point can be solved by deploying governmental agencies that study baseline environmental impact, take part in stakeholder engagement, and perform testing. One agency can collectively perform baseline assessments in areas that require the most rework. The following jurisdictions have deployed such governmental agencies: • California • Massachusetts

Table 8. Generation Pain Point 4

Generation Pain Point 4 - Environmental Assessment Conflicts, Waiting, and Delays due to Public Consultation	
Evidence	Evidence summarized from Navigant's research and interviews: • During the assessment of Kent Hills Wind Project in New Brunswick, the proponent was unaware that Aboriginal Affairs Secretariat would consult Indigenous people on behalf of the Crown due to a law change in November 2011. The proponent could have submitted the proposal without delays caused by this incremental Indigenous consultation.[11] • During the assessment of Tazi Twé Hydroelectric Project in Saskatchewan, there was a significant timeline mismatch between the federal and provincial regulators in providing Environmental Impact Statement (EIS) guidelines and approvals.[12,13]

[9] AUC 23049-A001 and 23049-A002
[10] Environmental Impact Statement Site C Clean Energy, https://www.ceaa-acee.gc.ca/050/evaluations/document/85328?culture=en-CA
[11] EIA file number 4561-3-1128 and 4561-3-1238.
[12] http://publications.saskatchewan.ca/#/categories/46
[13] https://www.ceaa.gc.ca/050/evaluations/document/exploration/80031?type=1&culture=en-CA

Generation Pain Point 4 - Environmental Assessment Conflicts, Waiting, and Delays due to Public Consultation	
Potential Solution	This pain point can be solved by introducing a memorandum of understanding (MOU) between ministries, provincial, and federal organizations. A demonstration of this solution can be seen in California where solar thermal projects (above 50 MW) require approvals from both the Bureau of Land Management (BLM) and the Energy Commission prior to construction. To provide a more efficient joint review, The BLM and Energy Commission have signed an MOU.[14]

Table 9. Generation Pain Point 5

Generation Pain Point 5 - Bill C-69 May Place Incremental Burden on Generation Developers	
Evidence	Evidence summarized from Navigant's research and interviews: • The decision-making process to approve generation projects embedded in Bill C-69[15] may be more burdensome for developers compared to the current environmental approval process, it may deter them from investing. • The opportunity to litigate a project has substantially increased under Bill C-69 than under previous environmental approval process. The combination of added discretionary power to the Minister and litigations from opponents can significantly delay projects. • This bill provides the government with the powers to undertake strategic assessments and regional assessments, possibly leading to lengthy discussions on public policy issues including sustainability and climate change. • The current proposed strategic assessment on climate change adds critical burdens to the developer. This includes required calculations on upstream greenhouse gas (GHG) emission generation and impact on carbon sinks. These considerations are not always feasible to calculate or discuss.
Potential Solution	In Norway, stakeholders are specifically mapped to power generation projects to ensure that only those affected by projects are involved in consultations. This reduces the opportunity to litigate or delay projects. Additionally, the environmental assessment process favours efficiency, placing a high priority on minimizing waste of resources during regulatory review.[16] If a similar framework were implemented in Canada, it may minimize the amount of undue delays developers may face.

Transmission

Navigant researched pain points and potential solutions related to environmental approval and land use planning of inter-country transmission projects. The four pain points that Navigant highlighted are as

[14] https://ww2.energy.ca.gov/sitingcases/solar/index_cms.html
[15] https://www.parl.ca/DocumentViewer/en/42-1/bill/C-69/royal-assent#ID0EKPLO
[16] Advisian – International Review of Environmental Assessment Processes (December 2016)

follows: redundancy and overlap of provincial and federal regulations, conflicts and waiting due to inefficiencies in the consultation process, bottlenecks as a result of unclear guidelines and defects and rework of environmental and land use planning assessments.

These pain points were pulled from in-depth research, as well as the stakeholder interviews. Navigant completed a jurisdictional scan and found best practices in California and France. These were then used as potential solutions to address the Canadian pain points.

Table 5. Transmission Pain Point 1

Transmission Pain Point 1 - Redundancy and Overlap of Provincial and Federal Regulations	
Evidence	Evidence summarized from Navigant's research and interviews: • The large scale of the Manitoba-Minnesota project led to unclear definitions of what was "within the province" and what was not. This led to the utility spending extra time and resources for both federal and provincial environmental assessments, resulting in a situation where multiple parties reviewed similar assessments for no clear benefit.[17] • Navigant interviewed a representative from Manitoba Hydro, developer of the Manitoba-Minnesota project, who made it clear that there was a lack of communication between federal and provincial regulators. The representative indicated that this was one of the largest pain points experienced during the regulatory process
Potential Solution	This pain point can be solved by initiating an MOU or a similar contractual obligation ensuring communication between jurisdictions. Two examples of similar contractual obligations are summarized below: • In the U.S., the Department of Energy (DOE) and eight other Federal agencies signed an MOU to improve coordination among project applicants, federal agencies, states and tribes involved in the siting and permitting process for electric transmission facilities on Federal land.[18] • The European Council has similar policies which underline the importance of streamlining and improving permit granting processes while respecting national competences.[19]

Table 4. Transmission Pain Point 2

Transmission Pain Point 2 - Conflicts and Waiting due to Inefficiencies in the Consultation Process	
Evidence	Evidence summarized from Navigant's research and interviews: • Multiple inter-country transmission projects displayed significant delays caused by undue consultations with stakeholders. For example, during the ITC Lake Erie Connector project, a party that

[17] Canadian Energy Regulator, Reasons for Decision: Manitoba Hydro, https://apps.neb-one.gc.ca/REGDOCS/Item/Filing/A95736)
[18] DOE, Coordination of Federal Transmission Permitting on Federal Lands, https://www.energy.gov/oe/services/electricity-policy-coordination-and-implementation/transmission-planning/coordination
[19] European Union, Official Journal, https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32013R0347&from=en

	published letters publicly about the project did not participate in the public hearing when offered the opportunity. [62] • Navigant interviewed a representative from the Canadian Energy Regulator (CER, formerly NEB) who stated that its common to have information requests from third parties which delays the approval of applications.
Potential Solution	This pain point can be solved by initiating a well-planned consultation process. • In Europe there is a 10-year network development plan (TYNDP) which provides a concise layout of what the consultation process should be for stakeholders. Stakeholders play a significant constructive role throughout the process. This solution can be applied in Canada to improve the conflict/waiting pain point as Navigant's research shows that there is currently no organization which outlines a significantly detailed process for consultations with stakeholders.[63]

Table 5. Transmission Pain Point 3

Transmission Pain Point 3 - Bottlenecks as a Result of Unclear Guidelines	
Evidence	Evidence summarized from Navigant's research and interviews: • Stakeholders indicated that section 58.11 and section 35 of the NEB Act caused significant issues due to the confusion over selecting a permit versus a certificate for an inter-country transmission project.[20] • Navigant interviewed a transmission developer who confirmed that there was confusion related to following the permit vs. certificate process. The developer initially selected the permit process, but later was required to follow the certificate process so the NEB could hold a public hearing. This caused significant delays and rework.
Potential Solution	This pain point can be solved by treating all transmission projects equally. • In Europe the 10-year network development plan (TYNDP) treats all projects of European relevance the same regardless of whether it is within one country or crossing one or more borders. This streamlines the intercountry transmission project approval process because these projects are treated the same as a project within the country, so no additional documents/processes are required[63]

Table 6. Transmission Pain Point 5

Transmission Pain Point 5 - Defects and Rework of Environmental and Land Use Planning Assessments	
Evidence	Evidence summarized from Navigant's research and interviews:

[20] Canadian Energy Regulator, Reasons for Decision: Manitoba Hydro, https://apps.neb-one.gc.ca/REGDOCS/Item/Filing/A95736)

	• Research showed that the developers for the Manitoba-Minnesota project were required to update their Construction Environmental Protection Plan (CEPP) to reflect Indigenous knowledge and field survey results. The developer was asked to complete this partway into the regulatory process, so they were required to rework/refile the same analysis.[21] • Navigant interviewed a representative from CER who noted that this is somewhat common and noted that if the same requests/issues are raised multiple times over many projects, then the initial guidelines / filing requirements are updated
Potential Solution	This pain point can be resolved by developing a process for updating application/filing requirements regularly. • In California, the California Independent System Operator (CAISO) has a transmission plan which is used to conduct regular and comprehensive updates for transmission projects. The process is biennial, and the interregional transmission coordination is achieved through key inputs from state agencies. The same principle can be applied in Canada with provincial and federal agencies coordinating to regularly update filing requirements, [66]

[21] Canadian Energy Regulator, Reasons for Decision: Manitoba Hydro, https://apps.neb-one.gc.ca/REGDOCS/Item/Filing/A95736)

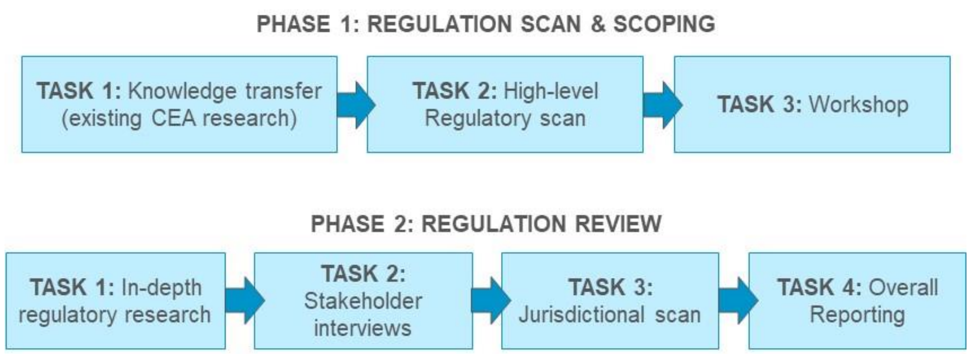
OVERVIEW

Navigant was engaged by CEA, with support from NRCan, to identify aspects within regulations and regulatory processes that impede investment and innovation in the electricity sector by:

- Tabulating relevant federal and provincial regulations that impact investment in a range of electricity sector asset classes;
- Identifying challenges faced by utility companies in gaining project approvals and making investments based on utility expenditure adjudication and broad-based project impact assessment; and
- Identifying and understanding potential conflicts, redundancies, and inefficiencies across federal and provincial regulations that impede investment and/or innovation in the electricity sector

The project has been carried out in two phases, consisting of multiple tasks:

Figure 1. Regulatory Cumulative Burden Activities



1. PHASE 1

1.1 Phase 1 – Regulatory Scan

Navigant carried out a preliminary regulatory scan into major asset classes and use cases, as outlined in Table 1-1. This effort was informed by reports and research provided by CEA, as well as direct research into regulations, legislation, and other publicly available documents.

Table 1-1. Phase 1 Asset Classes and Use Cases

Asset Class	Use Case
Distribution	• Grid Upgrades (Intelligence / Monitoring, Protection & Control, Distribution & Automation, Resiliency & Reliability) • Electrification related distribution investments • Consumer, AMI, cyber security investments • Distributed energy resources (DERs) including Non-wires alternatives (NWAs)
Transmission	• Interprovincial • Intraprovincial • Inter-country
Generation	• Megaprojects • Refurbishment / Relicensing (Hydroelectric, Fuel Conversion) • New Generation (Hydroelectric, Solar, Wind, Natural Gas, Storage)

Navigant's research focused on identifying areas of regulatory burden and procedural inefficiencies within the five regulation categories defined in Table 1-2.

Table 1-2. Regulation Categories

Regulation Categories	Description
Capital approval	Approvals required/recommended to move forward with a particular investment. Often driven by political goals and/or longer-term utility planning (e.g., integrated resource plan, long term energy/resource plan).
Rates & recovery	Approvals required to obtain revenue from customer rates to fund the electricity investment. Could be in the form of a Power Purchase Agreement (e.g., for project developers) or electricity rates (e.g., for utilities). Often overseen by a regulator.
Land use planning	Site considerations, land access, water access and rights (where applicable), consultations, Indigenous engagement, often driven by both provincial and local regulations. Could also include building codes for distributed resources, rights of way, etc.
Environmental approval	Permitting, consultations, and requirements to build on a particular site. Often segmented by voltage and/or project size.
Interconnection	Siting and construction processes, approvals and permits required to connect generation/transmission, any additional transmission or distribution infrastructure required to support the project.

Research was carried out to ensure electricity regulations in each of the following industry structures were reviewed:

- Unbundled – Alberta
- Hybrid – Ontario

- Vertically integrated (non-regulator) – Saskatchewan and Nunavut[22]
- Vertically integrated (with regulator) – all other provinces and territories

During this research, Navigant assessed the level of potential regulatory burden inherent to targeted focus areas. A focus area is defined as a combination of an asset class and a regulation category with a high potential to have inefficient or burdensome regulations and processes that may impede investment. Capital approval of non-traditional distribution investments and environmental approval of renewable generation assets are two examples of focus areas.

Navigant used concepts from *lean manufacturing* to determine the presence of burden inherent to a focus area that may impede investment in the sector.

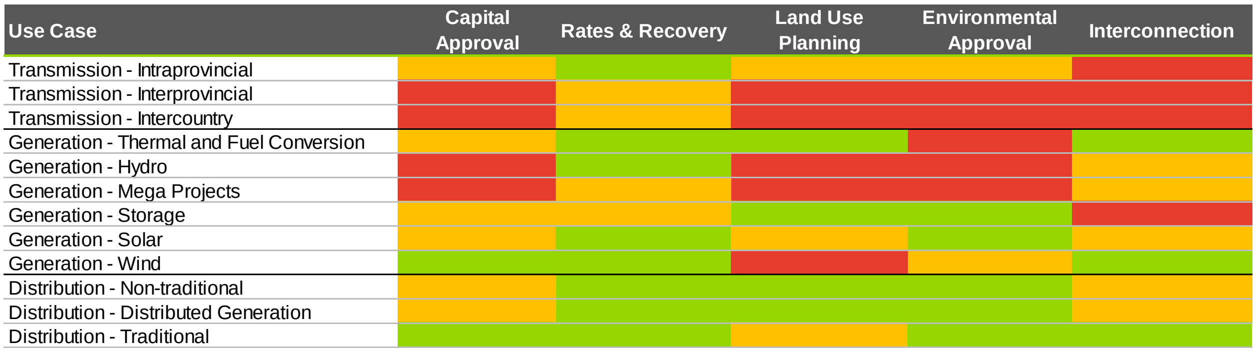
Table 1-3. Types of Burden

Types of burden	Description	Example of key questions related to this burden
Transportation	How documents are provided between entities and to stakeholders	How many entities are involved in the approval process?
Inventory	How long documents, information, etc. are waiting to be processed	Are requirements similar between entities (i.e., federal and provincial)?
Motion	How many entities are reviewing each component	Is there a legislative entity involved with scheduled sessions to tackle approvals?
Waiting	Delays caused by mismatched approvals, downtime, shortages	Do requirements seem similar across different stages of the approval process?
Over production	Requirements for more data or information than what is needed to approve/deny	Is the process clear for all use cases?
Over processing/analysis	More analysis, data, information is submitted/expected than what is required	Does the process appear to be designed for electricity investments?
Defects/rework	Requirements to complete the same analysis/consultations/etc. more than once	How many entities are involved in the approval process?

Figure 2 depicts Navigant's rankings of focus areas after the high-level regulatory scan. Areas that were given a 4 or 5 were deemed to have a medium to high probability of possessing processes that exhibit one or more of the areas of burden described above. In total, Navigant compiled 38 focus areas with a high probability of containing inefficient processes.

[22] Saskatchewan and Nunavut do have agencies that fill a regulatory role but lack a formal separate utilities commission or energy board.

Figure 2. Phase 1 Regulatory Scan Results[23]



Scale	# / 5
Low Potential for Burden	1 - 3
Medium Potential for Burden	4
High Potential for Burden	5

1.2 Phase 1 – Steering Group Workshop

Navigant presented its findings to CEA's Regulatory Cumulative Burden Steering group during a workshop held on July 10th, 2019. At this workshop, the 38 focus areas were presented to the group of experts in the following three exercises:

1. The entire group discussed high level findings and provided insight on the following questions:
    a. Which outcomes are most important for the country's electricity future?
    b. If you could eliminate/reduce the barriers to investment in specific use cases to achieve the outcomes above, where would you focus your efforts?
2. Navigant broke the group up into the following breakout sessions to discuss and prioritize focus areas with the most pain points within each asset class:
    a. Distribution
    b. Transmission
    c. Generation
3. The group reformed and each asset class breakout group presented their prioritized focus areas to the broader group. At the cumulation of these presentations, the full group voted on the "most painful" focus areas across each of the asset classes.

Based on insight gained during the workshop, Navigant made the following high-level changes to the approach:

[23] Non-traditional distribution investments can be broadly summarized as DERs and NWAs but can also include any investment that is not easily approved through a typical utility rate case

- Remove the Mega Projects use case – these are considered to mostly consist of hydroelectric projects, which already has its own use case, or nuclear, which is out of scope of this engagement

- Combine the renewable generation use cases – as the persisting pain point across all generation types is Environmental Approval. Thermal generation was kept separate, as it has specific pain points related to capital approval

- Combine distributed generation and non-traditional distribution investments – as they involve similar pain points

After completing the workshop, the Steering Group had prioritized the following five focus areas for further research in Phase 2 (see Table 1-4). These focus areas were chosen because the group felt they represented the most significant pain points impeding investment in the electricity sector.

Table 1-4. Prioritized Focus Areas

<table>
<tr><th>Focus Area</th><th>Summary</th><th>Impact</th></tr>
<tr><td>All Generation Types – Environment Approval</td><td>Generation projects require permits from multiple agencies before environmental approvals can be gained. The overlap between provincial and federal requirements leads to duplication of work. Bill C-69 was designed in part to avoid this duplication, but many perceive it to add significantly more requirements to gain environmental approval.</td><td>New generation will continue to be built to meet growing demand in many jurisdictions. As well, infrastructure renewal and reinvestment to meet environmental goals will challenge the generation sector. All generating types face the potential for regulatory burden during the environmental approval process. The current situation is especially impactful for refurbishment projects, which face almost the same level of regulatory scrutiny as new builds. The difficulty getting refurbishment approval results in many operators making the decision to run assets to end of life, resulting in a less efficient energy system.</td></tr>
<tr><td>Thermal Generation and Fuel Conversion – Capital Approval</td><td>When combined with existing regulatory requirements, the Clean Fuel Standard (CFS), Output-Based Pricing System (OBPS) and Bill C-69 pose a significant additional regulatory and financial burden on thermal projects.</td><td>Many jurisdictions that relied on coal for baseload generation have turned to fuel conversion and natural gas to meet coal-phase out requirements while maintain system baseload. The regulatory burden inherent with pursuing these projects will have a disproportionate impact on select provinces.</td></tr>
<tr><td>Non-Traditional Distribution – Rates and Recovery</td><td>Regulators are perceived to lack the tools needed to consider the full value of non-traditional distribution investments in evaluations made for rate recovery. As a result, investors may not be able to recover the full investment cost.</td><td rowspan="2">Steering group stakeholders voiced strong support of inclusion of this focus area with majority consensus. Non-traditional distribution investments are likely to be one of the most impactful in the electricity sector in coming years due the rise of environmental policy and proliferation of new technology.</td></tr>
<tr><td>Non-Traditional Distribution – Capital Approval</td><td>There is a lack of defined processes for gaining capital approval of non-traditional distribution investments. As a result, there is uncertainty about how to pursue these investments and whether they will be approved.</td></tr>
<tr><td>Inter-country Transmission – Environmental Approval and Land use Planning</td><td>There is a perceived a lack of coordination and communication between provincial and federal entities, and within federal entities. As a result, transmission developers face great uncertainty on timelines for regulatory processes and are often unable to get adequate responses from regulators.</td><td>Inter-country transmission projects are large, complex and involve many entities, resulting in great opportunities for pain points. There are currently eight intercountry lines at various stages of development, and such projects are estimated to grow in importance as power markets both north and south of the border are influenced by policy.</td></tr>
</table>

2. PHASE 2

2.1 Overview

Navigant carried out Phase 2 in three distinct tasks:

- In-depth Regulatory Research – reviewing Canadian electricity regulations for each focus area, looking at specific projects that have been developed or are in development
- Stakeholder Interviews – with relevant individuals to understand pain points directly from those involved. Navigant interviewed stakeholders from across Canada representing the following groups:
    - Distribution utilities
    - Transmission utilities
    - Power generators
    - Federal regulators
    - Provincial regulators
- Jurisdictional Scan – to identify regions where these pain points have been addressed or are non-existent. The findings from this scan are used to justify potential solutions to the collected pain points. Navigant has included findings from the following jurisdictions in this study:
    - California
    - Massachusetts
    - New York
    - France
    - Norway

The results of Navigant's Phase 2 research are summarized in the following subsections. Findings are categorized by asset class (non-traditional distribution, generation and transmission) and organized into tables for each pain point. Tables include the following information:

- Description of the pain point
- Evidence of the pain point – from in-depth regulatory research and stakeholder interviews
- Potential solution for the pain point – from the jurisdictional scan

2.2 Non-traditional Distribution

Navigant researched pain points and potential solutions related to non-traditional distribution capital approval and rates and recovery through an in-depth scan of regulations, rate cases and interviews with Canadian utilities. In general, pain points were related to the lack of established regulatory processes and lack of performance data for these types of investments. The pain points identified include:

- Insufficient Regulation/Guidance
- Undervaluation of assets
- Risk of investing
- Misaligned Incentives

Navigant reviewed regulations in California, New York and Massachusetts, as all three (especially New York and California) have adopted innovative policies. Each jurisdiction's approach to regulation is optimized to solve regional issues, which do not always apply to Canadian provinces but can be used as case studies to help address pain points inherent to Canadian electricity regulations.

Alternative terms for non-traditional distribution infrastructure used in this analysis include distributed energy resources (DERs) which are devices with a controllable load that are connected directly to the distribution system, and non-wires alternatives (NWAs) which are DERs that are implemented by a utility with the intention of deferring investment in traditional distribution infrastructure.

Table 2-1. Distribution Pain Point 1

Distribution Pain Point 1 - Insufficient Regulation/Guidance for Investment in Non-traditional Distribution	
Description	Regulators are perceived to not provide enough guidance on how utilities are expected to apply for non-traditional distribution pilots and projects. Utilities are also unsure of which assets they are allowed to invest in and the likelihood of successful capital approval. The uncertainty makes utilities hesitant to act.
Evidence 1: In-depth Regulatory Research	In Alberta, the Alberta Utilities Commission (AUC) has provided minimal guidance on how to price distributed generation (DG). As a result, utilities each developed their own distinct pricing mechanisms, which are perceived as unfair to some DG owners.[24]
Evidence 2: Stakeholder Interviews	In a Canadian province, utilities have stated that they do not know what products and services they are allowed to invest in, and how they are allowed to recover costs. Private companies are beginning to invest in the space and utilities feel like they are unable to compete.
	In Ontario, while alternatives to traditional infrastructure are encouraged, there is no framework for applying for them. Utilities must develop their own structure for the proposal, and do not know how the Ontario Energy Board (OEB) will receive it.
	A Canadian regulator expressed that they have no preference for what kinds of technologies utilities use, they expect utilities to make the best decision. They feel it is inappropriate to dictate which technologies utilities are allowed to invest in or how to use them. They are open utilities submitting any kind of proposal and are merely responsible for assessing the reasonableness of those proposals.

[24] https://albertapowermarket.com/2017/06/27/unpacking-distributed-generation-the-alberta-utilities-commissions-challenge/

<table>
<tr><th colspan="2">Distribution Pain Point 1 - Insufficient Regulation/Guidance for Investment in Non-traditional Distribution</th></tr>
<tr><td></td><td>A Canadian regulator brought up that it may be able to help utilities find out about alternatives to traditional distribution infrastructure. They may investigate ordering that this information be made available to all utilities in their jurisdiction.</td></tr>
<tr><td rowspan="4">Potential Solution: Jurisdictional Scan</td><td>Regulators should provide utilities with specific rules around which technologies and business models they are permitted to pursue and for which purposes. Development of frameworks or templates for rate applications can minimize confusion and streamline the development and processing of applications. To encourage DER deployment, regulators should identify where the various DERs can provide the most benefit and encourage utilities to develop these in those areas.</td></tr>
<tr><td>California passed several state bills that mandate energy storage procurement, in which each utility is required to procure a specified amount of storage capacity by a specific date.

• One bill prompted the California Public Utilities Commission (CPUC) to create a program that required 1.325 gigawatts (GW) of storage procurement across California by 2024[25]
• A later bill requires the three investor-owned utilities to procure an additional 500 megawatts (MW) of behind-the-meter (BTM) storage between them[26]
• A third bill directed utilities to determine the cost effectiveness of deploying 100 MW of energy storage[27]

Whether or not Canadian regulators decide to require specific quantities of non-traditional distribution resources, directives of this nature can focus utilities' attention on the issues best suited for non-traditional solutions and minimize doubt about the regulator's receptiveness to the proposal.</td></tr>
<tr><td>In a Massachusetts rate case, National Grid proposed a mechanism for a request for proposal (RFP) system for NWAs. The three criteria that must be met are:

• The cost of traditional infrastructure to meet the need is greater than $1 Million
• The load being addressed is less than 20% than the total area load
• The need is at least 3 years out[28]

Rules and decision-making mechanisms like these simplify the task of evaluating traditional infrastructure against non-traditional solutions by narrowing the scope to situations in which NWAs are the most likely to be attractive.</td></tr>
<tr><td>New York's Reforming the Energy Vision (REV) regulatory dockets encourage utilities to evolve into the role of Distribution System Platform providers. Actions like redesigning of price signals, compensation structures, and increasing access to data are aimed to allow utilities to embrace BTM technologies and reduce spending on infrastructure. Like the case in California, this sends a clear message to utilities that non-traditional solutions are not only an option, but an expectation.</td></tr>
</table>

[25] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200920100AB2514
[26] https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201520160AB2868
[27] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB801
[28] https://www.greentechmedia.com/articles/read/top-10-utility-regulation-trends-of-2018#gs.6e0l07

Distribution Pain Point 1 - Insufficient Regulation/Guidance for Investment in Non-traditional Distribution	
	These examples show that instructions from regulatory bodies on how and when they would like utilities to implement non-traditional distribution infrastructure could spur DER investment on the part of Canadian utilities by simplifying the decision-making process and inspiring confidence that rate applications will be well-received. The federal government's current involvement in the electricity sector mostly pertains to generation and transmission projects. They provide funding for smart grid projects; however, they may also be able to assist utilities by providing data on what technology options are available to distributors and how they can most effectively use them. If emphasis is placed on finding the best opportunities for innovation, funding may become less important in making projects economical as stronger projects are proposed.

Table 2-2. Distribution Pain Point 2

Distribution Pain Point 2 – Undervaluation of Non-Traditional Distribution Technologies	
Description	Outdated or early-stage regulatory models do not properly account for all the benefits of DERs. This makes it difficult for utilities to receive approval, as traditional infrastructure appears more economical.
Evidence 1: In-depth Regulatory Research	Ontario's Distribution System Code (DSC) dictates that distributors can only recover 6% of their investment in Renewable Enabling Improvements (i.e. DERs) through rates, effectively minimizing the benefit distributors can receive from these non-traditional distribution investments.[29]
	According to Independent Electricity System Operator (IESO) Storage Rules, a single energy storage unit is not allowed to provide operating reserve and frequency regulation at the same time. Seeing as many energy storage technologies are capable of this, the rule applies an unnecessary restriction on the operation of energy storage assets and may make them less economically viable.[30]
Evidence 2: Stakeholder Interviews	An Ontario distribution utility told Navigant that the Ontario DSC 6% rule is an artifact that does not reflect the value stack of energy storage systems. There is a gap between the value proposition of DERs and how they are valued by the OEB.
	An Ontario distribution utility feels that regulators can evaluate economics from a mathematical perspective, but there is no process for valuing less-tangible benefits of NWAs such as deferred capital investment, customer choice and satisfaction, and reduced environmental impact.
	A Canadian utility indicated that there is no framework for quantifying benefits of DERs in their province, and utilities need to come up with one themselves. Therefore, they are subject to the regulator disagreeing with their valuation methodology and rejecting their proposals.

[29] https://www.torontohydro.com/documents/20143/63725/CIR2020-Consolidated-Application.pdf/a19245b5-bb5c-15fe-e9ec-599d5644915c?t=1558718500465

[30] https://www.ontarioenergyreport.ca/pdfs/The%20Study%20of%20Energy%20Storage%20in%20Ontario%20Distribution%20Systems%20-FINAL.pdf

Distribution Pain Point 2 – Undervaluation of Non-Traditional Distribution Technologies	
	A Canadian regulator told Navigant that, as an economic regulator, they are not mandated to quantify intangible benefits to DERs, however they consider them. The regulator acknowledged that there are benefits to standardizing a cost-benefit methodology and suspect they may do that in the future as it comes up in the course of policy.
Potential Solution: Jurisdictional Scan	In order to prevent undervaluation, frameworks should be developed to quantify or account for intangible benefits of DERs. Location can have a significant effect on how well a DER performs, so locational factors should be considered when valuating DERs.
	The New York Public Service Commission (NYPSC) has developed benefit-cost analysis methodologies for NWAs to help utilities determine the true value of non-traditional projects. Some evaluation elements were adopted from Consolidated Edison's Brooklyn-Queens Demand Management program (BQDM).
	NY REV aims to create robust retail energy markets that account for both environmental and economic benefits of load management.
	A California bill required utilities to determine optimal locations on their grids where DERs would provide the most value. [31] Data collection activities such as these are crucial to ensuring the right investments are made.
	California has adopted the Distributed Energy Resources Avoided Cost Calculator developed by E3 to help determine the value DERs provide by deferring traditional poles and wires investments.[32]
	As these findings show, there are tools, processes and regulatory actions that have been effectively implemented elsewhere to better capture the value of DERs through deferral of investment in poles and wires and social and environmental impacts. Similar actions can be taken across Canada to improve the business case for non-traditional distribution assets. Federal action may be useful in collecting and providing data on benefits of DERs, and how and where to implement various non-traditional distribution technologies to maximize these benefits. This would help utilities make a better business case for projects.

Table 2-3: Distribution Pain Point 3

Distribution Pain Point 3 - Risk of Underperforming or Stranded Assets	
Description	With limited data on DER performance and an industry undergoing rapid change, utilities are cautious about investment in non-traditional assets due to regulators' perceptions of underperformance, stranding of assets and inability to empirically demonstrate societal economic benefits. Conventional regulatory methods concentrate risk on utilities, discouraging innovation.

[31] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB327

[32] https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Divisions/Policy_and_Planning/Thought_Leaders_Events/Tierney%20White%20Paper%20-%20Value%20of%20DER%20to%20D%20-%203-30-2016%20FINAL.pdf

Distribution Pain Point 3 - Risk of Underperforming or Stranded Assets	
Evidence: Stakeholder Interviews	A Canadian utility noted that DERs are untested, so while there are known benefits to many of these technologies, regulators often require data to prove these benefits, of which there is little.
	Utilities in multiple provinces are concerned at the prospect of stranded assets if the technology does not perform as expected or is replaced by newer, better technology before end of economic life. Utility financial success, reputation, and affordable power for ratepayers are threatened by this prospect, because regulators are perceived to accept minimal responsibility for DER integration and planning.
	A Canadian utility expressed that some new technologies would require different business models that they do not know if they will be allowed to adopt.
	An Ontario distribution utility pointed out that utilities are risk-averse organizations. They want a guarantee that their investments will earn returns and many DERs cannot provided guaranteed returns due to the regulator's limited experience with them.
	A Canadian regulator indicated that it does not see any burden intrinsic to the regulatory process, but rather a cultural barrier due to utilities' preference to propose tried and true methods and hesitance to be on the "bleeding edge". They acknowledge however that there may be a role for the regulator to play in structuring how to think about risk.
Potential Solution: Jurisdictional Scan	This pain point can be addressed in two main ways: minimize the risk of investing in non-traditional distribution assets or shift the risk away from ratepayers. Risk can be minimized by creating markets, ensuring supply is deployed in accordance with demand, and through thorough research on DER performance. Risk can be shifted away from the utility through top-down deployment directives from the regulator, which make the regulator responsible for determining how and where to use these technologies, or by allowing partnerships with private companies, who have greater risk tolerance and do not typically spend ratepayer money.
	California's Demand Response Auction Mechanism creates a market in which sellers can bid flexible capacity into the California Independent System Operator's (CAISO) day-ahead market. The utility gains access to the capacity but no revenue that accrues as a result. This provides more of a guarantee that investment in a DER project will be used/useful, and more certainty of how much of a return can be expected.[33]

[33] https://www.pge.com/en_US/large-business/save-energy-and-money/energy-management-programs/demand-response-programs/2018-demand-response/2018-demand-response-auction-mechanism.page

Distribution Pain Point 3 - Risk of Underperforming or Stranded Assets	
	All New York utilities were required to submit individual Distribution Service Implementation Plans (DSIPs) by June 30, 2016 followed by a joint Supplemental DSIP that served as frameworks for how they were going to reform the distribution grid in their territory and evolve into Distribution System Platform providers. As a result, NY utilities have added DER Forecasting, Hosting Capacity Analysis, and Non-Wires Suitability Criteria to their Distribution System Planning process, developed monitoring and control standards for DERs, increased coordination between each other, and identified enhancements to the NWA procurement procedure, including provision of common types of system data, establishing bidder pre-qualification, and forming a basis of performance requirements. Over 35 opportunities for NWAs have been identified between the NY utilities.[34] Canadian regulators and utilities should carry out similar coordinated long-term planning processes to identify the specific steps required to elevate DERs to their full potential and establish timelines. They can look to New York for examples of changes that may need to be made.
	New York REV's regulations encourage partnership between utilities and the private sector. This form of relationship can be used to offload some of the financial risk of investing in non-traditional distribution assets from ratepayers to private companies.
	Pacific Gas & Electric (PG&E) has developed a new Distribution Resource Plan that is designed to help integrate DERs. It is built around: • Building sufficient feeder capacity to accommodate DER growth • Quantifying locational value, benefits, and costs that impact rates • Assessing DER growth scenarios and their impacts to the distribution grid • Demonstrating DER integration into planning, operations, and investment[35] This aims to minimize the risk of making the wrong investments by increasing understanding of how DERs impact the grid and focusing on building a grid that can support them.
	As shown above, there are several ways of making NWAs less risky for utilities to invest in. Whether it's through creating robust markets, carefully coordinated long-term planning, or redesign of the regulatory approval process, minimizing ratepayers' risk is crucial to kickstarting widespread adoption of DERs in Canada.

Table 2-4: Distribution Pain Point 4

Distribution Pain Point 4 – Misaligned Incentives Between Regulatory Structure and Utility Business Model	
Description	Outdated ratemaking methods and compensation structures disincentivize investment into DERs.

[34] https://jointutilitiesofny.org/wp-content/uploads/2016/10/3A80BFC9-CBD4-4DFD-AE62-831271013816.pdf

[35] https://www.pge.com/en_US/for-our-business-partners/energy-supply/electric-rfo/wholesale-electric-power-procurement/2017-distribution-resource-plan-and-request-for-offers.page

Distribution Pain Point 4 – Misaligned Incentives Between Regulatory Structure and Utility Business Model	
Evidence: In-depth Regulatory Research	Cost of service ratemaking ties growth in electricity consumption and grid infrastructure to utility growth. Therefore, energy conservation directly hurts the utility financially.
	Traditionally, utilities are granted a rate of return when recovering capital expenditures (CAPEX). However, utilities typically are not allowed to profit when recovering operating expenditures (OPEX). Programs and projects that reduce demand (energy efficiency, demand response, etc.) reduce CAPEX and increase OPEX, decreasing a utility's revenue and return potential.[36]
Evidence: Stakeholder Interviews	A Canadian regulator pointed out that they are evaluating how utilities are remunerated within their province and aim to ensure that the right incentives are in place.
Potential Solution: Jurisdictional Scan	Performance-based ratemaking (PBR) is the primary solution to misaligned incentives. Numerous compensation schemes have been conceptualized, and some have been implemented, which compensate utilities for the provision of reliable and affordable service to customers rather than simply for the construction of poles and wires. This way, utilities do not have to choose between their own bottom line and the most efficient way to meet demand.
	As part of REV, New York is undergoing ratemaking reforms designed to align utility incentives with customer incentives. This is designed to be a gradual process to minimize disruption. Provisions will be introduced as they become relevant. Proposed modifications to be introduced include: • Market based earnings: REV will encourage alternative sources of revenue, such as service fees for platform participation • Regulators propose to modify "claw back" provisions so that some of the capital budget can be retained if DERs supplant the need for the project • Regulators also propose Earning Impact Mechanisms (EIMs), monetized performance metrics to move ratemaking away from cost of service and towards performance-based ratemaking • Demand charges are encouraged as they are the most accurate measure of system costs, and properly incentivize deployment of resources to minimize peak demand • Utilities are encouraged to increase participation in time-of-use (TOU) rates as advanced metering infrastructure (AMI) becomes more widespread • More sophisticated rates such as "smart home rates" that include granular price signals that better reflect costs, will become possible as technology improves • Improvements to C&I rates could include more precise demand charges that reflect the time of day the cost was incurred

[36] https://info.aee.net/hubfs/AEE%20Institute_Utility%20Earnings%20FINAL_Rpt_1.30.18.pdf

Distribution Pain Point 4 – Misaligned Incentives Between Regulatory Structure and Utility Business Model	
	In summary, modifications to the ratemaking process that reward Canadian utilities for providing excellent service to their customers, and not for building the most infrastructure, will ensure that utilities are invested in leveraging DERs to create a resilient and efficient distribution grid. Performance-based ratemaking has been adopted and is evolving in Ontario, Alberta, Quebec, and BC, however the rest of the country still uses cost of service ratemaking. A federal mandate for provinces to shift to performance-based ratemaking may be useful in spurring innovation in provinces that are reluctant to change their regulatory model.

2.3 Generation

Navigant researched pain points and potential solutions related to the capital approval of thermal generation and the environmental approval of all generation types. In general, pain points were related to the excessive costs and regulatory burden imposed on thermal generators, as well as duplicative processes and excessive environmental regulatory burden imposed on all generation types.

The pain points related to the capital approval of thermal generation include:

- Increased cost to gas-fired electricity generation
- Credit distribution under the Clean Fuel Standard

The pain points related to the environmental approval process include:

- Rework, lack of clarity, and over production of regulatory documents
- Conflicts, waiting, and delays due to the input of many stakeholders

Navigant reviewed many Canadian generation projects to collect pain points. The primary projects among these are:

- Site C, British Columbia
- Whitla Wind Project, Alberta
- Keephills, Alberta
- Solar Sol-Luce Kingston Project, Ontario
- Kent Hills Wind Project, New Brunswick

The main source of pain points for thermal generation developers is Canada's proposed CFS and its incremental burden when stacked with OBPS. Bill C-69 was intended to alleviate burden on developers during the environmental approval process, however, Navigant has found that the decision-making process embedded in Bill C-69 may result in incremental burden placed on all generation developers. To make recommendations for improvement, Navigant reviewed regulations and generation projects in California, Massachusetts and Norway.

Table 2-5: Generation Pain Point 1

Generation Pain Point 1 - Increased Cost to Gas-Fired Electricity Generation Due to the Stacking of CFS and OBPS	
Description	Canada's CFS and the OBPS will result in a stacking of carbon costs imposed on thermal power generators. This stacking may be particularly burdensome for gas-fired generators.
Evidence 1: In-depth Regulatory Research	Canada's CFS is the first policy to include both stationary energy consumption and transportation energy consumption. All other similar policies Navigant reviewed only include transportation energy consumption.[37,38] As a result, CFS imposes a cost on generators, as they must use expensive low carbon intensive fuel (e.g. renewable natural gas), or purchase credits to remain compliant. The Canadian Chamber of Commerce notes that natural gas supply and delivery may be regulated thrice through OBPS, CFS and the explicit carbon price.[39]
Evidence 2: Stakeholder Interviews	Navigant interviewed a Canadian power generator who indicated that by 2023, CFS would add an estimated 250% carbon cost on top of the OBPS for jurisdictions with natural gas. Jurisdictions with substantial gas generation will be disproportionally impacted by CFS costs. The interviewee stated that Alberta will pay approximately 60% of all electricity sector CFS costs.
Potential Solution: Jurisdictional Scan	This pain point can be solved by excluding fuels used for power generation from Canada's CFS, as long as this fuel is used in high efficiency gas generators built to support intermittent renewable development.
	California adopted the Low Carbon Fuel Standard (LCFS) in 2009 which does not include stationary energy consumption.[40,41] • The LCFS is a state-wide policy designed to reduce the lifecycle carbon intensity (CI) of transportation fuels • The average carbon intensity of fuels sold in California has declined almost 5% from 2010 to 2017 The original LCFS called for a 10% CI reduction from 2010 levels by 2020. Despite not meeting the target yet, in September 2018, California Air Resources Board (CARB) adopted regulatory amendments to extend the LCFS for an additional ten years with a target of 20% CI reduction from 2010 levels by 2030.[42]

[37] Navius Research Inc., "Analysis of the Proposed Canadian Clean Fuel Standard", http://cleanenergycanada.org/wp-content/uploads/2017/11/CFS-technical-report.pdf

[38] Canada West Foundation, "WHAT NOW? | Lessons Learned?: Canada's new Clean Fuel Standard", https://cwf.ca/research/publications/what-now-lessons-learned-canadas-new-clean-fuel-standard/

[39] Canadian Chamber of Commerce, "The Unsavory Pancaking of Canada's Climate Regulations"

[40] California Air Resources Board, "Low Carbon Fuel Standard", https://ww3.arb.ca.gov/fuels/lcfs/fro_oal_approved_clean_unofficial_010919.pdf

[41] Forbes, "How (Almost) Everyone Came To Love Low Carbon Fuels In California", https://www.forbes.com/sites/danielsperling/2018/10/17/how-almost-everyone-came-to-love-low-carbon-fuels-in-california/#59bb55e65e84

[42] University of California, Davis, "Status Review of California's LCFS", https://its.ucdavis.edu/research/californias-low-carbon-fuel-standard/

Generation Pain Point 1 - Increased Cost to Gas-Fired Electricity Generation Due to the Stacking of CFS and OBPS	
	Similar CFS programs such as Oregon's CFS[43], the European Union Fuel Quality Directive[44], and British Columbia's Renewable and Low-Carbon Fuel Regulation[45] only include transportation fuels. By excluding fuel used for power generation from the CFS, highly efficient generators will not be disproportionately impacted by CFS costs and can continue to support the development of renewables in Canada.

Table 2-6: Generation Pain Point 2

Generation Pain Point 2 - Credit Distribution for Electrification of Transport	
Description	Canada's CFS provides credits for electrification of transport. However, distribution utilities are not one of the recipients of the credits despite bearing huge costs.
Evidence 1: Stakeholder Interviews	Navigant interviewed a Canadian generator who identified the following issues: Under Canada's CFS, credit creators for electric and hydrogen fuel cell vehicle charging include public and private electric vehicle (EV) charging (EV charging network operators for public charging and site hosts for private/commercial charging) and residential charging. This means that three entities can receive credits for electrification of transport; gas stations, office buildings, and residential homes. Preparing the grid for EVs requires major investments from distribution utilities,[46,47] but it is not clear if distribution utilities will be eligible to receive credits. One argument is that any funds gained from EV adoption should be used to maintain the grid. This is so that other electricity rate payers, who do not use EVs, are less burdened by the incremental cost of incorporating EVs.
Potential Solution: Jurisdictional Scan	This pain point can be solved by ensuring an equitable distribution of CFS credits, where credits are provided to those most financially impacted by CFS goals.

[43] State of Oregon, "Oregon Clean Fuels Program", https://www.oregon.gov/deq/aq/programs/Pages/Clean-Fuels.aspx
[44] European Commission, "Fuel Quality", https://ec.europa.eu/clima/policies/transport/fuel_en
[45] Province of British Columbia, "Renewable & Low Carbon Fuel Requirements Regulation", https://www2.gov.bc.ca/gov/content/industry/electricity-alternative-energy/transportation-energies/renewable-low-carbon-fuels
[46] IEEE, "Impact of electric vehicles on power distribution networks", https://ieeexplore.ieee.org/document/5289760
[47] Tritium, "RESEARCH : PREPARING THE GRID FOR EV'S", https://www.tritium.com.au/news/newsitem?url=research-preparing-the-grid-for-ev-s

Generation Pain Point 2 - Credit Distribution for Electrification of Transport	
	In California, utilities gain LCFS credits by supporting EV deployment (i.e. providing electricity). Utilities sell the credits, mostly to oil companies, who need the credits to meet the LCFS target. Utilities use the revenue to provide point-of-sale rebates to EV buyers and support the construction of public high-speed charging stations. Utilities value this funding because it encourages the sale of EVs, which provides a new electricity market, as well as the potential to use EV charging to balance uneven demand and variable wind and solar power supply.[48] By allowing distribution utilities to earn credits under Canada's CFS, utilities can continue to play a role in incorporating EVs without applying undue financial burden to electricity rate payers.

Table 2-7: Generation Pain Point 3

Generation Pain Point 3 - Environmental Assessment Rework, Lack of Clarity, and Over Production	
Description	During the environmental assessment of generation projects, the regulator often asks for additional information/requests from a proponent that were not included in initial guidelines. Often the proponent must perform rework because of this unclear guidance from the regulator. Unclear guidance is especially burdensome when it includes vague statements regarding public and Indigenous consultation.
Evidence 1: In-depth Regulatory Research	During the environmental assessment of the Whitla Wind Project in Alberta, the provincial regulator asked for additional information (environmental cumulative assessments) from a proponent, which was not initially required in guidelines. Also, the proponent had to submit four updated Noise Impact Assessments in response to information requests and to address neighbouring proposed facilities.[49] During the assessment of the Site C Project in British Columbia, the combined (federal and provincial) regulator did not provide clear information to the proponent regarding consultation of Indigenous groups. It was unclear what potential measures to prevent, mitigate or otherwise address, and how to mitigate potential effects on Indigenous interests. The role of Indigenous people in the decision making is unclear.[50]
Evidence 2: Stakeholder Interviews	A generation utility in Canada told Navigant that it would be helpful if the regulator provided clearer requirements for environmental approval. Clearer requirements will help organizations develop an environmental assessment that is less likely to be challenged, leading to less rework and regulatory burden.

[48] Forbes, "How (Almost) Everyone Came To Love Low Carbon Fuels In California", https://www.forbes.com/sites/danielsperling/2018/10/17/how-almost-everyone-came-to-love-low-carbon-fuels-in-california/#59bb55e65e84

[49] AUC 23049-A001 and 23049-A002

[50] Environmental Impact Statement Site C Clean Energy, https://www.ceaa-acee.gc.ca/050/evaluations/document/85328?culture=en-CA

Generation Pain Point 3 - Environmental Assessment Rework, Lack of Clarity, and Over Production	
Potential Solution: Jurisdictional Scan	This pain point can be solved by deploying government agencies that study baseline environmental impact, take part in stakeholder engagement, and perform testing. One agency can collectively perform baseline assessments in areas that require the most rework.
	In California, governor Edmund G. Brown requested formation of a federal-state government task force to facilitate coordination, planning and permitting of state and federal activities related to offshore renewable energy. In response, Bureau of Ocean Energy Management (BOEM) established the BOEM California Intergovernmental Renewable Energy Task Force as a partnership of state, local, and federal agencies, and federally recognized tribal governments.[51] It also serves as a forum to discuss stakeholder issues and concerns; exchange data and information about biological and physical resources, ocean uses and priorities; and facilitate early and continual dialogue and collaboration opportunities. In the future, developers can use the data gathered, engagement results, and conflict analysis to avoid this pain point.
	In Massachusetts, Massachusetts Clean Energy Centre (MASSCEC) is a state economic development agency funded by ratepayers of investor-owned utilities and municipal electric departments.[52] • MASSCEC does environmental characterization. It works with U.S. BOEM and has sponsored multi-year studies (acoustic buoys and aerial surveys to assess whale, turtle, and avian activity) of marine wildlife to gather baseline data to inform the federal permitting process and accelerate the responsible siting of offshore wind projects. • MASSCEC performs stakeholder engagement. • MASSCEC's Wind Technology Testing Center (WTTC) offers a full suite of certification tests for turbine blades up to 90 meters in length. WTTC also offers the latest wind turbine blade testing and prototype development methodologies to help the wind industry deploy the next generation of land-based and offshore wind turbine technologies By deploying a government agency in Canada that takes part in stakeholder engagements, performs baseline environmental assessments and testing, it would help developers avoid rework and over production. This will reduce environmental approval costs for developers and promote investment in Canada.

[51] BOEM, "Outreach Summary Report California Offshore Wind Energy Planning", https://www.boem.gov/California-Outreach-Summary-Report/

[52] https://www.masscec.com/about-masscec

Table 2-8: Generation Pain Point 4

Generation Pain Point 4 - Environmental Assessment Conflicts, Waiting, and Delays due to Public Consultation	
Description	During the environmental assessment process of generation projects, the proponent can be required to get feedback and approvals from certain parties before submitting an environmental assessment application. The feedback may include stakeholder or public comments, which do not have stringent depth or time guidelines. This can result in significant waiting and delays.
Evidence 1: In-depth Regulatory Research	During the assessment of Kent Hills Wind Project in New Brunswick, the proponent was unaware that Aboriginal Affairs Secretariat would consult Indigenous people on behalf of the Crown due to a law change in November 2011. The proponent was not notified of this change and carried out the incremental Indigenous consultation. The proponent could have submitted proposal without delays caused by this incremental Indigenous consultation.[53]
	During the assessment of Tazi Twé Hydroelectric Project in Saskatchewan, the federal regulator provided Environmental Impact Statement (EIS) guidelines in April 2013, but the provincial regulator provided guidelines in August 2013. The developer required both sets of guidelines to begin work on the EIS. In addition, federal approval was received July 2015, but provincial approval was received February 2017.[54,55]
Evidence 2: Stakeholder Interviews	A utility with generation plants in Canada expressed the difficulty surrounding the uncertainty of what it means to be within compliance for environmental approval. The utility also noted that the ministries (fisheries, oceans, etc.) need to be coordinated and aligned on the content of environmental approval conditions, which increases the complexity of the process.
Potential Solution: Jurisdictional Scan	This pain point can be solved by introducing a memorandum of understanding (MOU) between ministries, provincial, and federal organizations.
	In California, solar thermal projects (above 50 MW) require approvals from both the Bureau of Land Management (BLM) and the Energy Commission prior to construction. Therefore, to provide a more efficient joint review under the National Environmental Protection Act (NEPA) and California Environmental Quality Act (CEQA), the BLM and Energy Commission have signed an MOU.[56] An MOU, or similar contractual obligation, helps ensure alignment across all parties involved in environmental approval (e.g. ministries, municipal agencies etc.) The MOU can include provisions for communication protocols and collaboration to ensure consistent application of regulations across the multiple agencies.

[53] EIA file number 4561-3-1128 and 4561-3-1238.
[54] http://publications.saskatchewan.ca/#/categories/46
[55] https://www.ceaa.gc.ca/050/evaluations/document/exploration/80031?type=1&culture=en-CA
[56] https://ww2.energy.ca.gov/sitingcases/solar/index_cms.html

Table 2-9: Generation Pain Point 5

Generation Pain Point 5 - Bill C-69	
Description	The decision-making process to approve generation projects embedded in Bill C-69 may result in an incremental burden placed on generation developers. Instead of making it easier for developers to get projects approved compared to the current environmental approval process, it may deter them from investing.
Evidence 1: In-depth Regulatory Research[57]	Bill C-69 gives the federal Environment Minister added discretionary power to approve a project, and to decide whether a project should be assessed or not. Additionally, the Minister and Governor in Council are given numerous opportunities to halt the review process.
	The decision framework for an environmental assessment has shifted to a determination of whether a project is in the "public interest" rather than whether it causes significant adverse environmental effects.
	The regulator has authority to delegate the carrying out of any part of an Impact Assessment (IA) and the preparation of the IA report to Indigenous stakeholders. This can give control to a party that may not be as objective as the regulator and increases the number of parties involved in the IA process.
Evidence 2: Stakeholder Interviews	The following insight represents feedback from Navigant's interview with a Canadian power generator: The opportunity to litigate or delay a project has substantially increased under Bill C-69 than under previous environmental approval process. Even an opponent can cause these delays. The bill creates a wide range of opportunities to challenge the completeness of the regulatory process.The factors listed under Section 22 "Factors to Be Considered" are ambiguous, increasing the potential for misinterpretation increasing the potential for regulatory burden. Project assessments have the potential to become a place to debate broader public policy issues, resulting in increased cost and regulatory uncertainty. This bill provides the government with the powers to undertake strategic assessments and regional assessments which can lead to lengthy discussions on public policy issues including sustainability and climate change. Instead of assessing a public policy objective against an applicable defined framework (strategic assessment, regional assessment, or policy guidance), the assessment is essentially without limit. Environment and Climate Change Canada (ECCC) is reviewing a draft of a strategic assessment on climate change. However, the current proposed framework adds critical burdens to the developer. This includes required calculations on upstream greenhouse gas (GHG) emission generation and impact on carbon sinks. These considerations are not always feasible to calculate or discuss. In some cases, upstream emissions may be unavoidable and not in control of the developer.

[57] https://www.parl.ca/DocumentViewer/en/42-1/bill/C-69/royal-assent#ID0EKPLO

Generation Pain Point 5 - Bill C-69	
Potential Solution: Jurisdictional Scan	In Norway, stakeholders are specifically mapped to power generation projects to ensure that only those affected by projects are involved in consultations. This reduces the opportunity to litigate or delay projects. Additionally, the environmental assessment process favours efficiency, placing a high priority on minimizing waste of resources during regulatory review.[58] If a similar framework were implemented in Canada, it may minimize the amount of undue delays developers may face.

2.4 Transmission

Navigant researched pain points and potential solutions related to environmental approval and land use planning of inter-country transmission projects. In general, pain points were related to the regulatory burden imposed on inter-country transmission projects due to the overlap of provincial and federal jurisdictions and the resulting lack of communication and duplication of efforts.

Navigant's highlighted pain points for transmission relate to processes that include the following areas of burden:

- Redundancy
- Conflicts/Waiting
- Bottlenecks
- Defects/Rework

These pain points were pulled from in-depth research, as well as the stakeholder interviews. Navigant assessed many inter-country transmission projects, but the primary projects used in this analysis are:

- The Manitoba-Minnesota Transmission Line
- The Lake Erie Connector
- The Woodstock-Houlton International Power Line
- The Quebec Northern Pass

The Manitoba-Minnesota Transmission Line project was analyzed to a great extent as it was the largest-scale inter-country transmission line project and was a significant source of regulatory pain points. From the in-depth regulatory research as well as the stakeholder interviews, it was evident that regulatory processes carried out during the project, and the other inter-country transmission projects, were not streamlined. Navigant researched best practices in California and France, which can be used to inform potential solutions to address these Canadian pain points.

[58] Advisian – International Review of Environmental Assessment Processes (December 2016)

Table 2-10. Transmission Pain Point 1

Transmission Pain Point 1 - Redundancy and Overlap of Provincial and Federal Regulations	
Description	During the approval process for an inter-country transmission project, there is often an overlap in documents and other procedures for similar tasks and processes required by the province and federal regulators. This is burdensome to the developer as they must exhaust more resources than is necessary to fulfill the same/similar assessments.
Evidence 1: In-depth Regulatory Research	Navigant's research showed that there was overlap in jurisdictional responsibility for the Manitoba-Minnesota Transmission Line project. The large scale of the project led to unclear definitions of what was "within the province" and what was not. This led to the utility spending extra time and resources for both federal and provincial environmental assessments, resulting in a situation where multiple parties reviewed similar assessments for no clear benefit.[59]
	The National Energy Board (NEB), now Canadian Energy Regulator (CER) imposed condition 23 on Manitoba Hydro, which required the developer to file post-construction monitoring reports with the NEB annually for at least 10 years. They also expect that, if there are any outstanding issues at the end of the 10 years, Manitoba Hydro will be required to apply adaptive management strategies, appropriately extend the monitoring period for those environmental indicators, and continue reporting monitoring results to the Board. This overlaps with provincial requirements for annual reporting and appears possibly redundant to an outside observer.
Evidence 2: Stakeholder Interviews	Navigant interviewed a representative from Manitoba Hydro, developer of the Manitoba-Minnesota project, who made it clear that there was a lack of communication between federal and provincial regulators. The representative indicated that this was one of the largest pain points experienced during the regulatory process and indicated that it would be highly beneficial if there was a form of contractual obligation requiring collaboration and communication protocols between federal and provincial regulators for future inter-country transmission lines.
	An interview with the federal regulator confirmed that that there is no requirement or expectation for the regulator to collaborate with the provinces. The regulator noted that their mandate was set in legislation by parliament, and they fulfil the mandate in the legislation, no more and no less.

[59] Canadian Energy Regulator, Reasons for Decision: Manitoba Hydro, https://apps.neb-one.gc.ca/REGDOCS/Item/Filing/A95736)

Transmission Pain Point 1 - Redundancy and Overlap of Provincial and Federal Regulations	
Potential Solution: Jurisdictional Scan	This pain point can be solved by initiating an MOU or a similar contractual obligation ensuring communication between jurisdictions. Below are two examples of how an MOU and better communication policies can help to mitigate this paint point: I) In the U.S., the Department of Energy (DOE) and eight other Federal agencies signed an MOU to improve coordination among project applicants, federal agencies, states and tribes involved in the siting and permitting process for electric transmission facilities on Federal land. The MOU improves uniformity, consistency, and transparency by describing each entity's role and responsibilities when project applicants wish to build electric transmission facilities. Additionally, the MOU designates a "Lead Agency" serving as the single point-of-contact for coordinating all federal environmental reviews necessary to site electric transmission facilities on federal lands. In most instances, the Departments of Agriculture or Interior will be the Lead Agency, since they have jurisdiction over most of the Federal lands and rights-of-way for proposed electric transmission facilities.[60]
	An MOU would help to mitigate the redundancy experienced by Canadian utilities due to a lack of collaboration/communication between federal and provincial authorities. I) The European Council has similar policies which allow for better communication between jurisdictions. The policies outline the following: Permit granting processes should neither lead to administrative burdens which are disproportionate to the size or complexity of a project, nor create barriers to the development of the trans-European networks and market access. The conclusions of the European Council as of 19 February 2009 highlighted the need to identify and remove barriers to investment, including by means of streamlining of planning and consultation procedures. Those conclusions were reinforced by the conclusions of the European Council on 4 February 2011 which once again underlined the importance of streamlining and improving permit granting processes while respecting national competences.[61] A policy like this that highlights the importance of streamlining processes while respecting national competencies would help to mitigate the issue of a lack of collaboration between provincial and federal jurisdictions in Canada.

[60] DOE, Coordination of Federal Transmission Permitting on Federal Lands, https://www.energy.gov/oe/services/electricity-policy-coordination-and-implementation/transmission-planning/coordination

[61] European Union, Official Journal, https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32013R0347&from=en

Table 2-11. Transmission Pain Point 2

Transmission Pain Point 2- Conflicts and Waiting due to Inefficiencies in the Consultation Process	
Description	Stakeholders indicated the importance of third-party input into environmental approval. However, the lack of defined processes may lead to *undue* interference from third parties. This can lead to waiting/delays due to inefficiencies in the consultation process and lack of resources, as well as conflicts between stakeholders.
Evidence 1: In-depth Regulatory Research	Research showed that multiple inter-country transmission projects experienced significant delays caused by undue consultations with stakeholders. Using the Lake Erie Connector project as an example, a third party published public letters about the project. As a result, the developer was required to hold a public hearing with the third party to allow them to voice their concerns about the project. The third party ultimately did not attend the hearing. This caused significant delays in the approval process for this project, as the third party did not provide valuable input while unnecessarily increasing the complexity of the process.[62]
Evidence 2: Stakeholder Interviews	In an interview, the CER stated that it is very common to have information requests when getting applications, which delays the approval of applications. This may be due to third party issues raised, clarification questions about the evidence filed, clarification about inconsistencies within the evidence or between evidence filed by various parties.
Potential Solution: Jurisdictional Scan	This pain point can be solved by initiating a well-planned consultation process. Below is an example of how in Europe a well-planned consultation process allows for smoother consultation and less conflicts/waiting: I) In Europe there is a 10-year network development plan (TYNDP) which provides a concise layout of what the consultation process should be for stakeholders. Stakeholders play a significant constructive role throughout the process through consultations on the different parts of the TYNDP, public workshops and the permanent Network Development Stakeholder Group which gathers European associations representing the industry, consumers and Non-Government Organizations (NGOs).[63] This solution can be applied in Canada to improve the conflict/waiting pain point as Navigant's research shows that there is currently no organization which outlines a significantly detailed process for consultations with stakeholders. The current CER guideline does not appear to be sufficient for stakeholder engagement. A process like this would be highly beneficial to developers if incorporated into current guidelines.

[62] Canadian Energy Regulator, Reasons for Decision: ITC Lake Erie, https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/energy/pdf/ITC_Crown%20Consultation%20and%20Accommodation%20Report_EN_accessible.pdf

[63] ENTSO, TYNDP, https://tyndp.entsoe.eu/

Table 2-12. Transmission Pain Point 3

Transmission Pain Point 3 - Bottlenecks as a Result of Unclear Guidelines	
Description	During the approval process for an inter-country transmission project there is often unclear guidelines on what is required from the proponent. These process inefficiencies cause misalignments in timing, result in multiple documents waiting to be processed and potentially halt the entire process.
Evidence 1: In-depth Regulatory Research	Stakeholders indicated that section 58.11 and section 35 of the NEB Act caused significant issues due to the confusion over selecting a permit versus a certificate for an inter-country transmission project. If the developer selects a permit, the application will be subject to provincial oversight. If the developer selects a certificate, the application will be subject to federal oversight.[64]**Error! Bookmark not defined.**
Evidence 2: Stakeholder Interviews	Navigant's interview with a transmission developer confirmed that there was confusion related to following the permit vs. certificate process. The developer initially selected the permit process, but later was required to follow the certificate process so the NEB could hold a public hearing. This caused significant delays and rework for the developer.
	Navigant learned from an interview with the CER that, in the past, the NEB could not hold a public hearing if the developer selected a permit. The CER is now able to hold hearings under the permit process.
Potential Solution: Jurisdictional Scan	This pain point can be solved by treating all transmission projects equally. For example, the approval process for an inter-country transmission project would remain the same as the approval process for a within-country transmission project. Below is an example of how this is implemented in Europe: I) The European Network of Transmission System Operators for Electricity (ENTSO-E)'s Ten-Year Network Development Plan process treats all projects of European relevance the same regardless of whether it is within one country or crossing one or more borders. This streamlines the intercountry transmission project approval process because these projects are treated the same as a project within the country, so no additional documents/processes are required.[63] This solution can be applied in Canada to potentially alleviate the bottlenecks experienced by developers. If all inter-country transmission projects are treated the same as within-country transmission projects, the burden related to the overlap in federal and provincial processes inherent to inter-country transmission projects will be minimized.

[64] Canadian Energy Regulator, Reasons for Decision: Manitoba Hydro, https://apps.neb-one.gc.ca/REGDOCS/Item/Filing/A95736)

Table 2-13. Transmission Pain Point 4

Transmission Pain Point 4 – Defects and Rework of Environmental and Land Use Planning Assessments	
Description	During the environmental assessment and land-use planning processes of transmission projects, the regulatory agency can ask for additional information from a proponent that was not included in the initial guidelines. This often results in rework for the proponent, as unclear guidance can lead to the same analysis being completed multiple times.
Evidence 1: In-depth Regulatory Research	The NEB stated partway into the regulatory process for the Manitoba-Minnesota project that the Construction Environmental Protection Plan (CEPP) submitted by Manitoba Hydro had not been updated to reflect Indigenous knowledge studies and field survey results. Therefore, condition 10 was imposed which required Manitoba Hydro to rework/refile the same analysis reflecting all changes and commitments.[65]
Evidence 2: Stakeholder Interviews	In Navigant's interview with the CER, it was noted that it is common to have information requests from third parties on inter-country transmission applications. These requests often result in incremental requirements for the developer. The regulator noted that if the same requests/issues are raised multiple times over many projects, then the initial guidelines / filing requirements are updated. Navigant believes this results in a reactionary process, as there are relatively few inter-country transmission line applications, thus initial guidelines do not get updated often. However, it is clear that applications are subject to multiple incremental requests when they are submitted.

[65] Canadian Energy Regulator, Reasons for Decision: Manitoba Hydro, https://apps.neb-one.gc.ca/REGDOCS/Item/Filing/A95736)

Transmission Pain Point 4 – Defects and Rework of Environmental and Land Use Planning Assessments	
Potential Solution: Jurisdictional Scan	This pain point can be solved by developing a process for updating application / filing requirements regularly. Below is an example of how California manages filing requirements effectively: I) The CAISO has a transmission plan which calls for a regular and comprehensive evaluation of the ISO transmission grid to address grid reliability requirements, identify upgrades needed to successfully meet California's policy goals and explore projects than can bring benefits to consumers. This plan relies heavily on key inputs from state agencies in translating legislative policy into actionable policy driven inputs. The ISO conducts its coordination with neighboring planning regions through the biennial interregional transmission coordination framework established in compliance with Federal Energy Regulatory Commission (FERC) Order No. 1000. [66] As a result, guidelines can be updated regularly based on this structured evaluation of requirements. The same philosophy can be applied in Canada with provincial and national agencies coordinating to regularly update filing requirements in order to mitigate this pain point.

[66] California ISO, Transmission Plan, http://www.caiso.com/Documents/RevisedDraft-2018-2019_Transmission_Plan.pdf