FORTIS INC. COMMENTS ON DRAFT CLEAN ELECTRICITY REGULATIONS

Fortis Inc. (**Fortis, we, our**) welcomes the opportunity to comment on the draft Clean Electricity Regulations (**CERs** or **regulation(s)**) published on August 19, 2023. We also concur with the comments submitted by Electricity Canada and the Canadian Gas Association.

We appreciate the time and effort that Environment and Climate Change Canada (**ECCC**) has put into its consultation processes around the CERs, and its openness to receiving input from industry. This is a complex issue, involving a range of priorities and perspectives, so it is important to have open dialogue and weigh all considerations to achieve workable and effective policy solutions.

Fortis has been in the electric public utility business for over a century. We operate 11 electric and gas utility companies across five Canadian provinces – British Columbia, Alberta, Ontario, Prince Edward Island, and Newfoundland and Labrador – as well as 10 U.S. states and three Caribbean countries. Our utility operations provide us with a broad perspective on the unique regional needs across Canada.

Our purpose is to deliver a cleaner energy future while continuing to provide our customers with safe, reliable, and affordable energy, delivered over resilient grid infrastructure. These core commitments are fundamental to our mission as a public utility, and our customers, communities, and regulators expect us to deliver on them. Our principal concern is that the CERs will negatively and disproportionately affect certain parts of the country, particularly as regards reliability and affordability. Accordingly, we submit that the design of the CERs must incorporate regional flexibility. Details of our perspective on this issue, and our other comments on the CERs, are set out below.

ELECTRICITY SECTOR EMISSIONS WITHIN THE NATIONAL CONTEXT

Canada has historically benefited from one of the lowest emitting electric grids in the world. Despite already low emissions, Canada's electricity sector has still achieved large emission reductions since 2005, far outpacing all other sectors. Between 2005 and 2021, the electricity sector achieved greater emissions reductions than did the entire economy on a consolidated basis. The investment tax credits (**ITCs**) announced in the 2023 federal budget are poised to drive further decarbonization within the electricity sector. There should be no doubt regarding the sector's commitment to help achieve Canada's emissions reduction targets.

The electricity sector faces the significant dual challenge of expanding electricity supply while also continuing to reduce emissions. The magnitude of this task is unprecedented, and if this transition does not occur at a gradual and orderly pace, significant disruption will likely ensue.

Whereas the industry has been built over the past century around slow and steady incremental growth and careful cost management, expectations are that total electricity demand will more than double between now and 2050. What's more, standard proven technologies that the industry has always relied upon to ensure reliable energy are now challenged from continuing to play a significant role, meaning that planning must proceed with greater risk and uncertainty than in the past.

Electrification of transportation, space and water heating, and other activities will increase electricity demand. These new requirements exceed what the grid was originally designed for and stress the system to maintain reliability, resiliency, and affordability. In 2019, refined petroleum products were the main source of energy consumed in Canada (38.7%), followed by natural gas (35.7%) and electricity (22.3%).[1] This provides a good reference point for the relative energy load historically carried by the country's electricity sector, and the magnitude of the challenge to now expand that grid to meet this growing new demand. Government must be pragmatic about the degree and rate at which new energy demand can be placed on the grid without over-extending the electricity system.

The industry must find a balance between both rapid and significant expansion of the power supply and lowering emissions at the same time and cannot focus too much on one of those goals at the expense of the other. We must not underestimate the scope of this challenge and simply proceed as if this will be business as usual for the electricity sector.

The design of the CERs should not impose significant financial and operational stresses on the utilities and power producers who have been leaders in reducing emissions and whose future success is critical to Canada's ability to further decarbonize its economy. Canada's emissions reduction goals rely heavily on our sector supporting the electrification of more carbon intensive parts of the economy. In the future, the reliability and affordability of the electric grid will be more important than ever. Accordingly, the design of the CERs must not threaten our ability to assist other sectors to decarbonize, and the ultimate goal of a net-zero economy by 2050. We believe the CERs must seek to balance emission reductions within our sector while reducing potential disruption to the industry and negative impacts on the public.

ECCC'S MODELING AND MAIN AREAS OF CONCERN

Our April 2022 comments on the initial clean electricity standard consultation emphasized accommodating regional differences in terms of feasible clean energy alternatives, and maintaining reliability and affordability for customers. As currently drafted, the CERs do not reflect the feedback and modeling recommendations we provided, and are more stringent, and more inflexible, than the original 2022 discussion paper proposed.

ECCC has built the CER model around three main pillars: (1) lowering emissions, (2) maintaining reliability, and (3) preserving affordability. However, the CERs are premised on the adoption of a single set of national standards, essentially a one-size-fits-all model. This fails to acknowledge that the compliance burden to be borne by ratepayers will vary greatly by province, even while all provinces are already being challenged to meet the significant electricity supply demands being driven by electrification. This will translate into higher reliability risk and significant rate increases in those regions that require greater transformation of their electrical grids.

In developing the CERs, ECCC has placed significant reliance on its NextGrid model. However, it is merely that, a model, and cannot foretell actual future events. Several industry participants, and Electricity

[1] Statistics Canada, Energy supply and demand, 2019, https://www150.statcan.gc.ca/n1/daily-quotidien/210121/dq210121d-eng.htm

Canada, have expressed reservations whether the NextGrid modelling accurately represents future reliability and affordability under the CERs.

We are concerned that the cost of compliance may not be fully accounted for under the model, particularly for those regions with the greatest compliance challenge, and that customers in these regions will face significant rate increases. These cost pressures may in turn negatively affect investments in the electricity system that could have further reliability implications. Even those regions with an abundance of firm, non-emitting generation resources, such as Quebec, Manitoba, and British Columbia, will face significant challenges as they seek to expand to serve growing needs for clean and firm supplies of energy.

The cost of CER compliance will be incurred when the sector is already dealing with growing demand due to the electrification of other sectors, including growth in electric vehicle adoption and the deployment of heat pumps for space heating in place of oil or gas furnaces. These changes in the industry will drive significant investment beyond generation, including major upgrades to distribution networks and deployment of smart grid technology, which will also impact customer rates.

We are concerned that the NextGrid model assumes a best-case scenario in relation to certain key unknown future circumstances, while power utilities must plan contingencies for worst case scenarios, with wide margins of error. We are concerned that reliance on the NextGrid modelling could lead to sub-optimal policy choices, and therefore urge further independent work to assess the model to reduce the probability of missteps. We support Electricity Canada's recommendation for a comprehensive and transparent analysis of all economic modeling conducted by the federal government as it relates to forecasts of average electricity prices; volatility of electricity prices; provincial electricity prices; and transmission and distribution costs. It is also critical to understand how the CERs may impact winter peak electricity generation and transmission constraints. Such analysis should recognize the needs of regions that will depend on fossil fuel-based power generation for the foreseeable future to meet acceptable reliability and safety standards.

REGIONAL IMPACTS

Atlantic Canada

We have concerns about how the CERs would affect Atlantic Canada. Coal generation in Nova Scotia and New Brunswick must be decommissioned by 2030, leaving a significant gap in the generation capacity to be filled by zero- or low-emitting resources. The magnitude of this challenge means that the CERs will disproportionately impact ratepayers in the Maritime provinces from a cost perspective.

The North American Electric Reliability Corporation (NERC) has noted that the Maritimes (i.e., New Brunswick, Nova Scotia, and Prince Edward Island) are under heightened reliability risk due to capacity constraints. This was highlighted earlier this year when each of Hydro Quebec, Nova Scotia Power, NB Power, and Maritime Electric experienced record peak loads during extreme cold, and reserve margins fell dangerously low.

The Maritimes are expected to experience growing demand for electricity, driven in part by population growth, but also economy-wide decarbonization efforts such as the electrification of transportation.

New generation capacity is needed to meet this growth in demand, beyond what will be required before 2030 to simply replace retiring coal plants.

While fossil fuel fired plants produce power when needed, output from most renewable generation is intermittent. Nova Scotia has recently announced its intention to develop 1,000 MW of onshore wind by 2030, which would then generate approximately 50 percent of the province's electricity. To help address intermittency the province plans to build three new battery storage sites. Therefore, while renewables and short- to mid-term battery storage can and should constitute a significant portion of the Atlantic region's energy in the future, there must still be dispatchable generation, or long-term energy storage (e.g., hydro), for when that intermittent power is not available for longer time periods. Absent new technologies, such as small modular reactors (**SMRs**) which are currently unproven, and in any event may not be feasible for many utilities, this will require fossil fuel baseload and/or back-up generation.

The CERs performance standard is based on combined cycle natural gas generation with carbon capture, utilization, and storage (**CCUS**). While Nova Scotia and New Brunswick have limited natural gas distribution, there is no natural gas infrastructure in Prince Edward Island or Newfoundland and Labrador. If these provincial grids lose primary baseload from nuclear or hydro power, options for dispatchable generation are effectively limited to fossil fuel fired generation, such as diesel. However, the use of diesel generation will be much more constrained under the CERs performance standard than natural gas generation, which is generally ubiquitous outside Atlantic Canada.

Western Canada

Western Canada will also see significant challenges in complying with the draft CERs.

Unlike British Columbia, Manitoba, Quebec, and Newfoundland and Labrador, the province of Alberta lacks significant hydro power, and has instead leveraged its abundant hydrocarbon natural resources as a fuel source for its electricity generation fleet. Also unlike other Canadian provinces, Alberta has a competitive wholesale electricity market.

In 2015, the government of Alberta announced that it would eliminate emissions from coal power generation by 2030. Alberta is expected to be fully transitioned from coal-powered electricity by the end of 2023. Approximately 60 percent of Alberta's power currently comes from natural gas generation, which replaced coal as the province's largest power source while significantly lowering the sector's overall emissions. The province has led the country in wind development, which currently comprises approximately 20% of Alberta's generation. Objectively, Alberta's electricity sector has made significant strides in lowering its overall emissions.

Over this period, the province has seen significant increases in transmission costs as a percentage of customers' overall bills, partially attributable to buildouts to connect new generation assets. These costs will likely increase as more transmission is required to connect new generation sources to the grid.

The provincial government has raised concerns over how the CERs will affect reliability and has indicated that the costs to the province to decarbonize its grid by 2035 are prohibitive and will cause large increases in Albertans' power bills. This challenge is amplified by the fact that the Alberta grid must at the same time service the country's fastest growing economy.

The Alberta Electric System Operator (**AESO**) has also warned of negative consequences of adopting a net-zero electricity grid by 2035, urging a slower-paced approach to understand which developing technologies are best positioned to help decarbonize Alberta's grid. Alberta has significant potential to further reduce emissions if new technologies prove feasible, including CCUS, but also new energy sources such as geothermal. However, proving these technologies will take time. The AESO has warned of relying on new unproven technologies with a limited track record to replace reliability attributes provided by the gas fleet, all within a 12-year time span, noting that it would be very challenging and costly. Participants in Alberta's competitive wholesale electricity market will bear much of the risk associated with the CERs. Some participants may decide to exit the market if further investment cannot be economically justified due to the risk and uncertainty that the CERs add to the business case for building new generation. This too could negatively affect reliability and energy costs in the province.

In many ways, Saskatchewan is very similar to Alberta in that it has limited undeveloped hydro potential and is highly dependent on fired generation, including coal and natural gas power plants, for its energy supply. Saskatchewan is also caught in the same difficult position of not knowing what new technologies, if any, will enable current gas generation to come within the CERs' performance standard by 2035. Given these uncertainties, planning to comply with the 2035 net-zero target will likely create significant challenges and reliability risks, and drive significant cost increases for Saskatchewan ratepayers.

While British Columbia's grid is primarily supported by hydro generation, if demand grows as expected, the province will be stretched in finding additional renewable generation potential. The Site C project, which is behind schedule and over budget, is seen as the most viable undeveloped hydro site in the province. There are limited large scale "prime" hydro sites left to develop in British Columbia. That means future hydro developments will involve greater cost for lower output. While untapped wind and solar resources exist, these are technologies that may not be optimal for the province, which has historically had a significant winter peak energy load. British Columbia's large population and vibrant economy will require significant additional generation as it targets a net-zero economy, though at this time there is no clear and easy path to that goal.

Western provinces have their own unique challenges with the standards contained in the draft CERs. The recurring themes that are echoed in the east and west are reliability and affordability. We urge greater flexibility in the CERs, through regionally adjusted performance standards and extended compliance timelines, to mitigate the potentially disruptive reliability and affordability impacts of the new regulations in those most challenged regions. We expect that ECCC's regulatory impact analysis underestimates the CERs' impact on rates, particularly in Atlantic Canada, Alberta, and Saskatchewan.

THE RISK OF UNPROVEN ASSUMPTIONS

Technology

Certain unproven assumptions built into the CER model increase compliance risk for utilities should they prove incorrect. What's more, some of these assumptions are foundational to the entire CER design and will make the model unworkable if wrong. For example, it is not yet proven that CCUS will be a feasible option to bring emissions from combined cycle natural gas generation within the performance standard. Further, deployment of CCUS technology will also depend on the timely design and implementation of provincial regulatory regimes to effectively govern CCUS, which is yet to occur in most provinces. The CERs make accommodation to allow additional time for development of CCUS technology to enable achievement of the performance standard, but such an outcome is not assured.

As noted above, the CER performance standard is premised on combined cycle natural gas generation with CCUS. If CCUS proves ineffective in enabling such generators to achieve the performance standard, practically, this only leaves the option of substituting conventional natural gas with either renewable natural gas (**RNG**) or hydrogen. Scaling RNG to meet such demand would require significantly accelerated expansion of current RNG supply. Surprisingly however, the federal government's clean energy ITCs as currently proposed do not incentivize investment in RNG. We believe the ITCs must incent RNG investment, especially given the potential in Canada for RNG from agriculture, waste water treatment, forestry, and landfills.[2]

The use of blue or green hydrogen as fuel for natural gas generators also has its challenges. Hydrogen fuels have not yet been proven to be economically feasible solutions at scale. These hydrogen fuel sources must be located close to the generation source, otherwise transporting the fuel will significantly increase the cost of power production. The feasibility of using blue hydrogen to fire natural gas generators is also dependent upon the effectiveness of CCUS, which as noted above, is at this time a developing technology.

Similarly, SMRs are a new and unproven technology. While Ontario Power Generation is working on testing this technology, the outcome is currently unknown, and it may be imprudent to assume this will be a viable option for planning purposes. Further, the operation of nuclear power plants is a highly specialized field, with complex operational, safety, and regulatory requirements, and may not be a realistic option for most utilities with no experience with this technology. It is also unclear whether there is social license for nuclear power outside Ontario and New Brunswick.

Wind generation is assumed to become a larger portion of total energy supply, including in Nova Scotia. However, due to intermittency and limits on the duration of battery storage, its prohibitive cost, and uncertainty around future supply of critical minerals and other components, significant investment in dispatchable generation will still be required. Also of note, NERC has identified reliability concerns affecting inverter-based resources (**IBRs**), such as wind, solar and battery resources, and has been directed to develop new IBR reliability standards. While such new standards may address the currently identified IBR reliability concerns, it is uncertain whether these resources will have the same long-term reliability characteristics as traditional thermal baseload generation.

Cost

We are also concerned with the cost assumptions in ECCC's regulatory impact assessment cost benefit analysis. When comparing the baseline and regulatory scenarios, the analysis indicated the incremental

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[2] See the Final Report in the BC Renewable and Low-Carbon Gas Supply Potential Study undertaken by the BC Bioenergy Network, FortisBC and the Province of British Columbia, January 28, 2022, https://www.cdn.fortisbc.com/libraries/docs/default-source/news-events/bc-renewable-and-low-carbon-gas-supply-potential-study-2022-03-11.pdf

cost of new transmission to be approximately $6 billion. Based upon our experience developing transmission and distribution infrastructure, it is our view that this cost is underestimated.

Clean generation is often not located close to where the electricity is consumed and therefore requires transmission infrastructure to connect to the grid and ultimately customers. Today, most transmission lines are intra-provincial, connecting generation to customer load in urban centres. While inter-provincial transmission will be important for connecting jurisdictions with more abundant clean electricity to jurisdictions with less, intra-provincial transmission is likely where most investment is needed.

Both transmission *and distribution* infrastructure will require significant investments to maintain system reliability for our customers during the clean energy transition. This is illustrated by a preliminary analysis that FortisBC conducted of the energy infrastructure needed in the City of Kelowna, a region with approximately 76,000 electricity customers and 44,000 natural gas customers, over the next 20 years. This analysis demonstrates what could happen if the current energy demand served by the natural gas system is fully shifted to the electric system. FortisBC found that rapidly increasing electricity use will drive significant transmission and distribution investment.

As both a gas and electricity provider, FortisBC is uniquely positioned to observe and understand the interplay between both energy delivery systems. The Kelowna study found that building an electric grid large enough to fully replace the current gas system with an electric-only approach would create significant costs for customers. The results also highlight the importance and prudence of using the existing gas system to deliver greater quantities of renewable and low carbon gases, especially to serve peak winter heating loads, rather than replacing the system with electric infrastructure.

Using software modelling based on real energy use data, FortisBC found that fully replacing the energy supplied to Kelowna by the gas system would more than double the demand for electricity during periods of high winter use. This would require an expansion of the region's electric system, at a preliminary estimated cost in the range of $3.0 - $3.4 billion, resulting in significant rate increases for electric customers. Intra-provincial transmission and distribution were the key cost drivers in this analysis; the cost of additional generation would be over and above the costs highlighted in the analysis. The cost projection in the Kelowna analysis, dealing with one small part of British Columbia, leads us to seriously question the overall cost projections under the NextGrid model.

We note that the regulatory impact assessment conducted by ECCC also assumed construction of the Atlantic Loop interconnecting the four Atlantic provinces and Quebec. Both Nova Scotia and New Brunswick have since indicated that they will not participate in the project as originally envisioned, largely due to the excessive cost of this transmission project. The difficulty experienced in advancing this project illustrates the significant challenges in executing such a process, especially where multiple provinces and utilities are involved, and the weakness of certain key assumptions included in the ECCC model.

If foundational assumptions underpinning the CER model, such as the efficacy of CCUS, prove incorrect, the practical workability of the model will be undermined. To this extent, the CERs represent a serious gamble, where the odds of succeeding are unknown, but the cost of failing could be devastating to the country and our economy. The Kelowna study highlights the significant costs of expanding transmission and distribution infrastructure to meet increasing demand for electricity and the need for more granular modeling to understand the impacts of electrification and how they might be addressed. For an industry that must incorporate large margins of error in its planning, and requires many years to plan major capital projects, such uncertainty is unsettling. Again, this suggests that a more gradual approach to transitioning away from fired generation and greater flexibility should be built into the regulations.

END OF PRESCRIBED LIFE

We recommend that the end of prescribed life (**EOPL**) for existing generation should be longer than 20-years. Even if practical and proven substitutes for the current fossil fuel generation fleet existed in all parts of Canada today, and were known to be reliable and affordable, the 20-year EOPL would still create significant challenges from a planning, reliability, and affordability perspective.

Under the 20-year EOPL, most emitting generation built before 2015 would have to be decommissioned by 2035, or in 12 years, which from a utility planning perspective is a very short timeframe. Most wind and solar generation will require construction of new transmission to serve distant load centres. Utility planning and permitting processes for such projects have extremely long timelines and are not controlled by utilities. Provincial regulators apply a prudency standard to evaluate proposed capital investments, and approvals cannot be assumed, particularly where rates will be significantly impacted. Including permitting processes, the timelines for completion of major projects can take well over a decade.

The rapid build-out of new generation will also cause the accumulation of significant cost related to retiring generation assets that has not been fully amortized. This will drive rate increases as more generation must be maintained, not just to meet growing demand, but also to ensure dispatchable capacity is preserved.

We urge ECCC to consider extending the 20-year EOPL to enable a more gradual transition of the generation fleet and mitigate the potentially disruptive impacts to supply, reliability, and affordability. It may be appropriate to consider using a range of different EOPL's based on the region where a unit is located, its emissions intensity, and the viability of alternate non-emitting generation options.

OTHER COMPLIANCE FLEXIBILITIES

Other compliance flexibilities would improve the workability of the CER model, including:

- The use of carbon offsets in calculating "net" emissions,
- The pooling/averaging of units for emissions calculations,
- The use of multi-year averaging for calculating emissions to allow for annual variability, and
- The use of a reasonable capacity factor for peaker units instead of the proposed annual 450-hour operating limit

Greater flexibility in these areas would assist utilities in better managing their generating resources while still achieving reasonable overall emissions reduction objectives and maintaining affordability.

It is also important to note that most provinces are subject to mandatory NERC reliability standards, which define the reliability requirements for planning and operating the North American bulk power system. These mandatory reliability standards address a range of issues, including the provision of primary frequency response; operating reserve; reactive support and voltage control; and load following and ramping. Thermal generation sources are particularly well suited to providing these vital services and maintaining power quality and grid stability. NERC has cautioned that the rapid deployment of renewables and retirement of dispatchable thermal generation could in certain markets negatively affect reliability, and therefore should be undertaken through careful system planning. Canadian utilities that are subject to NERC standards play an important role in protecting the integrity of the interconnected North American grid. The CERs must be flexible enough to accommodate compliance with current and future NERC reliability standards.

EMERGENCY PROVISIONS

We see significant confusion arising when trying to apply the emergency provisions to real life situations. We are also concerned that these provisions will undermine utilities' ability to effectively manage their generation assets to avoid power outages.

The definition of an "emergency circumstance " is vague and the "extraordinary, unforeseen and irresistible" standard is difficult to understand from a practical perspective. For example, it has been suggested that the loss of the transmission feed from the Muskrat Falls hydro facility in Labrador to the island of Newfoundland is foreseeable. Such an occurrence could create serious supply issues, but it is not clear whether it would it be disqualified as an "emergency circumstance" because it was foreseeable. Meaningful guidance is required to enable the sector to incorporate these considerations in planning activities.

We note that in the event of an emergency circumstance, a unit operator would have the ability to seek a waiver of compliance with the performance standard where "the operator of the electricity system in the province in which the unit is located or an official of that province responsible for ensuring and supervising the electricity supply orders the responsible person to produce electricity to avoid a threat to the supply or to restore that supply." Some jurisdictions do not have an independent system operator or government official responsible for electricity supply. For example, it is not clear that in Nova Scotia and Prince Edward Island, the vertically integrated utility would have authority to direct dispatch of an unabated unit. Similar uncertainty arises in the case of the Newfoundland and Labrador System Operator, which is affiliated with Newfoundland and Labrador Hydro, the main source of electricity supply in the province.

Under interconnection agreements, utilities may also have contractual responsibilities to provide energy to adjacent jurisdictions in cases of supply shortfalls. Such mutual aid arrangements are a long-standing practice in the utility industry for public safety and may require the firing of backup generation on short notice to avoid outages at a neighbouring utility or province.

This section requires practical guidance where there is no independent system operator or public official responsible for ensuring and supervising the electricity supply, where contractual mutual aid obligations require the firing of backup generation, or where actions required under mandatory NERC reliability standards conflict with the emergency provisions. For example, ECCC may consider a simple standard which allows the operation of an unabated unit where the unit operator reasonably believes that operation of the unit is necessary to avoid a threat to the supply or to restore that supply, or to comply with NERC reliability standards. These should be relatively infrequent events and would likely have a *de minimus* impact on overall emissions.

ECCC should also consider that the decision whether to dispatch an unabated unit may be required on an urgent basis, where delay to seek direction from a system operator or government official will result in a power outage. Practically, this may come down to a split-second decision required of an employee at a generating station or network operations centre. The CER's emergency provisions should align with the practical realities of how decisions are made to maintain service to the public during times of emergency, and if anything, err on the side of caution in ensuring service to the public.

CRIMINAL LIABILITY

We are of the view that imposing criminal liability for violations of the CERs is an unreasonable and inappropriate approach, given the context of transparent, regulated utilities providing a critical public service.

Maintaining service to customers and public safety is a public utility's highest priority, and utilities plan and operate in good faith to meet that service commitment. Utilities also face urgent decisions on how to maintain power for their customers during times of extreme weather or other challenging circumstances, without having the option or luxury of delaying to consider extraneous factors beyond simply trying to keep the power on for customers. Complicating these planning and decision-making processes with the specter of potential criminal liability, assessed in hindsight, is not appropriate or constructive. Utility employees should not face criminal liability for actions taken in good faith to fulfill their utility's responsibilities to the public under the regulatory compact. The draft regulations could have the unintended consequence where actions taken to avoid potential criminal liability could create real life-threatening situations.

ROLE OF THE PROVINCES

The CERs directly regulate electricity generation facilities, which are under provincial jurisdiction. Provincial utility regulator responsibilities include safeguarding grid reliability and the affordability of rates. Such regulators oversee utilities' capital expenditures and long-term resource planning, and utilities are generally only permitted to recover their prudent expenditures, as determined by these regulators. Provincial regulatory approval will be required before a utility can undertake any significant capital expenditures to comply with the CERs, including investments in new generation or transmission, or recovering the cost of assets that may become stranded before the end of their useful lives. Consequently, provincial regulatory approval will be a precondition to implementing many of the planning decisions dictated by the CERs.

It is especially important that the regulations be not only legally sound, but also balanced, fair, and workable from a practical perspective if they are to be supported by the provinces. The electricity sector must have long-term certainty given the long lead times and planning associated with building electrical infrastructure. As such, strong alignment is required between the federal and provincial governments to provide regulatory certainty to enable us to deploy capital on these long-term investments. To help achieve federal-provincial alignment, introducing compliance flexibility, extended compliance timelines, and regional adjustment mechanisms to support the most affected provinces would be recommended.

Finally, the accommodation of regional differences has been a foundational element in the governance of Canada and our success as a large and diverse nation. Similarly, success for Fortis has been predicated on ensuring that our utilities have the autonomy and flexibility to successfully navigate their distinct political, economic, and regulatory environments. We must not allow the CERs to become a negative and divisive issue. Meeting the challenge of climate change will require cooperation and support from all regions of our country, and we urge you to ensure this initiative is designed to address the legitimate concerns of all Canadians.

Thank you for the opportunity to provide input to this important policy process.

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