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Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations

Statutory authority

Canadian Environmental Protection Act, 1999

Sponsoring departments

Department of the Environment and Department of Health

REGULATORY IMPACT ANALYSIS STATEMENT

(*This statement is not part of the Regulations*.)

Executive summary

Issue: Greenhouse gases (GHGs) are primary contributors to climate change. The most significant sources of GHG emissions are anthropogenic, mostly as a result of combustion of fossil fuels. The emissions of GHGs have been increasing significantly since the industrial revolution and this trend is likely to continue if no action is taken. In 2008, the latest year of emissions data available under Canada's National Inventory Report under the United Nations Framework Convention on Climate Change (UNFCCC), GHG emissions from the electricity generation sector contributed around 16% (or approximately 120 megatonnes [Mt]) to Canada's inventory of emissions. In the same year, coal-fired electricity generation was responsible for 93 Mt of GHG emissions in Canada, which represent 78% of total electricity sector emissions. Canadian historical data indicates that emissions in 2008 were about 19% above the 1990 levels.

In December 2009, the Government of Canada committed to a national greenhouse gas reduction target of 17% below 2005 levels by 2020, and inscribed this in the Copenhagen Accord. Our 2020 target is aligned with that of the United States (U.S.).

To achieve its target, the Government has established and is implementing a comprehensive plan to reduce greenhouse gas emissions in all major emitting sectors, on a sector by sector basis. On June 23, 2010, the Government announced it would take action to reduce carbon dioxide (CO_2) greenhouse gas emissions in the electricity sector by moving forward with regulations on coal-fired electricity generation.

Description: The proposed *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations* (the proposed Regulations) will set a stringent performance standard for new coal-fired units and those that have reached the end of their useful life. This will phase out high-emitting coal-fired generation and promote a transition towards lower- or non-emitting types of generation such as high-efficiency natural gas, renewable energy, or fossil fuel-fired power with carbon capture and storage.

The performance standard element of the proposed Regulations would come into effect on July 1, 2015. In addition, units would be required to begin reporting two years in advance of when they reach their end of useful life date or, in the case of

new units, in the first year of operation. Regulated entities would then be subject to enforcement and compliance requirements and penalties as specified under the *Canadian Environmental Protection Act, 1999* (CEPA 1999).

The Government's approach to addressing climate change is based on the principle of balancing environmental and economic considerations. The electricity industry is facing major capital stock turnover and regulatory uncertainty is impeding investments in new generation capacity.

Cost-benefit statement: The proposed Regulations are estimated to result in a reduction of approximately 175 Mt CO_2e of GHG emissions over the period 2015–2030. The present value of the costs of the proposed Regulations is estimated at $8.2 billion, largely due to the incremental natural gas costs ($4.8 billion), reduced net exports and new capital costs. The present value of the benefits are estimated at $9.7 billion, largely due to the avoided social cost of carbon (SCC) of $4.3 billion, avoided generation costs of $3.8 billion, and health benefits from reduced smog exposure of $1.4 billion. The net present value (NPV) of the proposed Regulations is estimated at $1.5 billion. A sensitivity analysis shows that this NPV could change somewhat depending on the value of key variables such as fuel prices and discount rate. The results of the analysis are expressed in $2010 and are discounted at 3%.

Business and consumer impacts: The estimated cost increase from the proposed Regulations would represent approximately 0.63% of the average total electricity bill over 16 years. It is expected that the cost increase would be passed onto consumers in proportion to their consumption. The estimated average cost increases over a 16-year period are expected to be small, ranging from $0.73/month in Saskatchewan on the lower end, to $2.14/month in Alberta.

The proposed Regulations are also expected to result in increases in electricity prices paid by industrial sectors. However, such impacts are expected to be a very small portion of total industry costs over the 16-year period analyzed.

Domestic and international coordination and cooperation: The proposed Regulations will help move Canada towards the Government's stated commitment to reduce GHG emissions to 17% below 2005 levels by 2020, which was inscribed in the Copenhagen Accord and is in alignment with the U.S. target. There are not expected to be any impacts on international trade agreements, and within the domestic market, the proposed Regulations reinforce the significant commitments that have already been made by provinces (e.g. Ontario) to reduce emissions from coal-fired electricity generation.

Performance measurement and evaluation plan: The Performance Measurement and Evaluation Plan (PMEP) describes the desired outcomes of the proposed Regulations such as GHG emissions reductions and reduced high-emitting coal-fired generation and establishes indicators to measure and evaluate the performance of the proposed Regulations in achieving these outcomes. The measurement and evaluation will be tracked on a yearly basis, with a five-year compilation assessment, and will be based on the information and data submitted in accordance with the reporting requirements and other readily available data and information sources.

Issue

Greenhouse gases (GHGs) are primary contributors to climate change. The most significant source of GHG emissions is anthropogenic, mostly as a result of combustion of fossil fuels. The emissions of GHGs have been increasing significantly since the industrial revolution and this trend is likely to continue if no action is taken.

Looking to the latest year of emissions data available under Canada's National Inventory Report under the UNFCCC, Canadian emissions in 2008 were about 19% above the 1990 levels. In 2008, GHG emissions from the electricity generation sector contributed around 16% (or approximately 120 Mt) to Canada's inventory of emissions. Coal-based electricity in Canada was responsible for 93 Mt of GHG emissions in Canada. These represent 78% of total electricity sector emissions.

In a hypothetical scenario that assumes Canadian governments (federal and provincial) have taken no steps to address climate change, Environment Canada estimates that the coming decade of economic growth in Canada would see annual GHG emissions reaching about 850 Mt by 2020 (with approximately 135 Mt coming from the electricity sector). This represents about a 16% increase relative to 2008 levels for total emissions and a 14% increase from the electricity sector.

Objectives

In 2005, Canada's total GHG emissions were 731 Mt, representing about 2% of global GHG emissions. The Government of Canada is committed to reducing Canada's total GHG emissions to 17% below its 2005 levels by 2020 (i.e. to 607 Mt) — a target that is inscribed in the Copenhagen Accord and aligned with that of the United States. Government policies to date and the impact of the proposed coal-fired electricity Regulations will reduce 2020 GHG emissions from 850 Mt down to 785 Mt, a difference of some 65 Mt or about one-quarter of the reductions required to meet Canada's target.

To secure the reductions in emissions from electricity generation in support of Canada's target, on June 23, 2010, the Government announced it would take action to reduce greenhouse gas emissions in the electricity sector by moving forward with regulations on coal-fired electricity generation.

The objective of the proposed Regulations is to ensure a transition away from high-emitting coal-fired electricity generation to low- or non-emitting generation such as renewable energy, high-efficiency natural gas, or thermal power with carbon capture and storage (CCS). The proposed Regulations would apply a performance standard to coal-fired electricity generation units. This standard would be set at the emissions intensity level with consideration of natural gas combined cycle (NGCC) technology — a high-efficiency type of natural gas generation — and be fixed at 375 tonnes of CO_2/GWh.

Description

1. Proposed Regulations

The Government's approach to addressing climate change is based on the principle of balancing environmental and economic considerations. The electricity industry is facing major capital stock turnover and major new investments are inevitable over the coming years. Regulatory certainty with respect to emissions requirements from electricity generation will facilitate investments in new, low- or non-emitting generation facilities at a low incremental cost, and at the same time ensure that investment decisions do not lead to stranded assets in the future (for example absent government regulations now, industry may build new standard coal-fired units to replace those due to retire in the coming years, and as a result would face much higher costs to reduce GHG emissions under potential, future regulations).

The proposed Regulations, made under the *Canadian Environmental Protection Act,1999* (CEPA 1999), would apply a performance standard to new coal-fired electricity generation units and to old units that have reached the end of their useful life. The performance standard element of the proposed Regulations would come into effect on July 1, 2015. In addition, units would be required to begin reporting two years in advance of when they would reach their end of useful life date or, in the case of new units, after their first year of operation. Regulated entities would then be subject to enforcement and compliance requirements and penalties as specified under CEPA 1999.

Under the proposed Regulations, the performance standard is set at the emissions intensity level with consideration of natural gas combined cycle technology — a high-efficiency type of natural gas generation — and will be fixed at 375 tonnes of CO_2/GWh. The standard would address emissions of CO_2 from the combustion of coal, coal derivatives (e.g. syngas) and petroleum coke (petcoke), and from all fuels burned in conjunction with coal, except for biomass.

The proposed Regulations address only CO_2 because GHG emissions from the electricity sector, including coal-fired electricity generation, are approximately 98% CO_2.

The performance standard will be applied to new and old coal-fired electricity generation units. New units are units that start producing electricity commercially on or after July 1, 2015. Old units are, in general, defined as units that have reached their end of useful life date, which is the later of 45 years from the units' commissioning dates or the end of their power purchase agreement (PPA). (see footnote 1) Existing units that were operating before July 1, 2015, but have not reached their end of useful life date are not directly subject to the performance standard.

Time-limited flexibilities would be made available to ensure the integrity of the electricity system all the while maintaining environmental objectives of emission reductions. These flexibilities are available through application and are subject to ministerial approval. In particular, these flexibilities include the following components:

- New and old units would be able to apply for a temporary deferral until January 1, 2025, from the application of the performance standard if they incorporate technology for CCS. Units that are granted this deferral must meet a number of regulated implementation/construction milestones and provide annual implementation reports on progress made with respect to these milestones.
- Existing units that employ CCS technology and that capture at least 30% of their CO_2 for 5 years before they are required to meet the performance standard would be able to transfer an 18-month deferral from the performance standard to old units in recognition for early action. These units will have to apply for deferral no later than September 1, 2021. The existing units also have to have equal or greater capacity than the end-of-life units, the units must have a common owner, and they must be in the same province.
- An existing unit that closes or meets the performance standard prior to when it would be required to do so could take on the performance standard obligation of an old unit that reaches its end of useful life date before 2020 for the remaining time before the existing unit reaches its own end of useful life date. The existing unit has to have equal or greater capacity than the end-of-life unit, both units have to have a common owner who has 50% ownership of both units, and they must be in the same province.
- A deferral to meeting the performance standard under emergency circumstances would be available where there is a disruption, or a significant risk of disruption, to the electricity supply. An emergency circumstance affecting the electricity supply is a circumstance that is either unforeseen or that arises when there is a formal declaration of emergency issued by the province or territory where the unit is located.

In their entirety, the proposed Regulations are designed to

- Require a stringent performance standard that units must meet, which also encourages investment in cleaner forms of electricity generation;
- Provide flexibility in not specifying a technology or fuel that must be used, thus allowing for innovation and technology development;
- Take advantage of existing anticipated capital stock turnover cycles in order to ensure that new investments do not strand existing capital;
- Provide predictability in that the early announcement of the proposed Regulations (five years in advance of its coming into force) respects the planning timelines needed for large capital investments; and
- Limit costs through a gradual application over time, in line with when each unit reaches its end of useful life and utilities have recovered their initial investment costs.

2. Electricity sector

The proposed Regulations are focused on coal-fired electricity generation in Canada. To assist in understanding the scope and impact of the proposed Regulations, the following analysis provides a profile of Canada's electricity generation sector and the place of coal-fired generation within it. It also examines some of the key features of the sector relating to generation capacity and fuel mix, interprovincial and international electricity flows, and electricity demand, all of which will have a bearing on the assessment of the impacts of the proposed Regulations.

2.1 Electricity generators

The Canadian electricity generation industry is composed of utility and non-utility generators that produce electricity by transforming the energy in water, coal, natural gas, refined petroleum products, miscellaneous other fuels, biomass, nuclear, wind and solar resources into energy. The process of supplying electricity to the public involves not only power generation at the plant, but also distribution through the electricity grid.

Overall, electricity generation in 2008 has grown to over 618 000 GWh, an increase of 0.2% from the previous high of 617 000 GWh observed in 2007. In 2008, hydroelectric power produced approximately 60% of Canada's total electricity, followed by nuclear (15%), coal (14%), natural gas (5%), refined petroleum products (RPP) and other fuels (5%), and the remainder coming from other sources such as wind and bioenergy (1%).

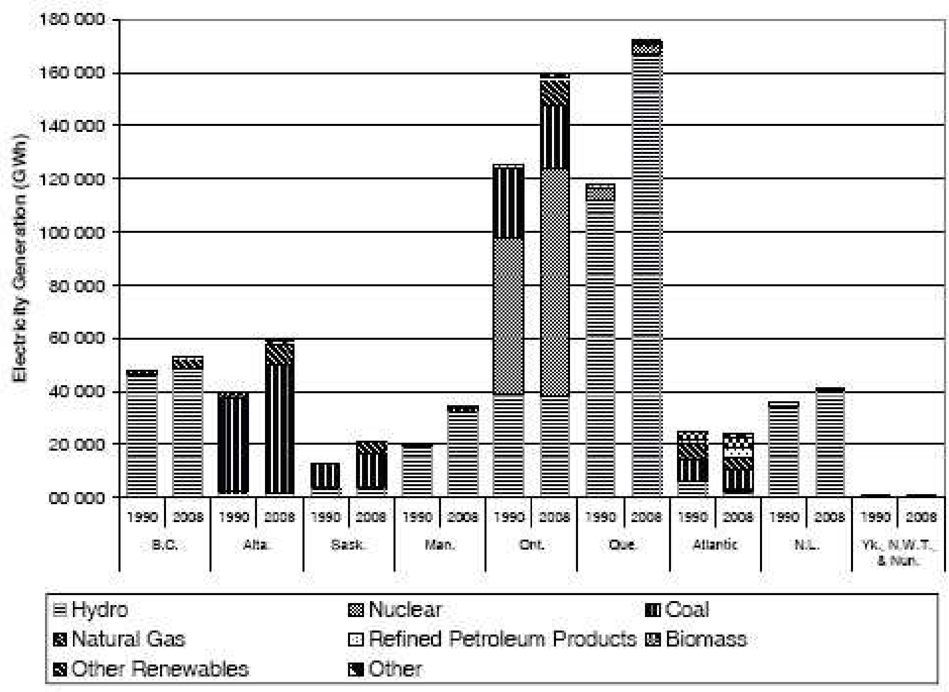
Economic factors such as fuel price can play a major role in fuel consumption decisions. For example, natural gas-fuelled generation increased by about 550% between 1990 and 2000 and remained constant between 2000 and 2005. Natural gas-based generation was lower between 2002 and 2004, due in part to higher natural gas prices, while generation in 2006 was lower due to softer demand. The rapid appreciation of the Canadian currency in 2004, however, had the effect of lowering natural gas costs, as these prices are based on international markets and foreign currency. Similar impacts can be inferred for coal, RPPs, and "other fuel" generation. With increasing oil costs, the usage of lower-priced and subsequently lower-grade fuels like coal and those included in the "other fuel" category has increased while RPP usage has decreased.

2.2 Regional trends — Generation and source

The trends reported below (see footnote 2) are based on utility generators, which represent about 92% of total generation (the remainder is non-utility, which does not directly serve the public — they generate electricity for their own end-use or for sale in wholesale markets). Coal-fired electricity generation currently does not represent any of the non-utility combustion-generation mix.

Figure 1 provides a breakdown of electricity generation by region and by source for the years 1990 and 2008. (see footnote 3) Coal-fired electricity sources predominate in Alberta and Saskatchewan, due in no small part to easy and reliable access to abundant coal resources. Hydro provides the majority of electricity generation in the provinces of Quebec, British Columbia, Manitoba, and Newfoundland and Labrador. In Ontario and the Atlantic region, the electricity generation mix is fairly diverse, with nuclear power providing the greatest percentage of the supply in Ontario. In terms of total generation, Quebec and Ontario have by far the highest generation totals — combined, they produced 332 000 GWh (58%) of Canada's electricity supply in 2008. They are followed by Alberta (about 58 900 GWh) and British Columbia (about 52 800 GWh), then by Newfoundland and Labrador (41 400 GWh).

Figure 1: Electricity Generation by Region and Source, 1990 and 2008



Overall generation has increased in all provinces. Since 1990, generation in Saskatchewan and Manitoba has grown by over 60%. In Manitoba, this growth was based on new hydro developments, while in Saskatchewan the increase was due to expanded use of coal and natural gas to meet demand. Generation in Alberta, Quebec and the Atlantic region grew between 46% and 49%. In Ontario, a 27% increase in generation was met with increased nuclear power over the period, plus a significant increase in the use of natural gas. In British Columbia and Newfoundland and Labrador, electricity generated from hydro increased by 10% and 14%, respectively.

2.3 Electricity trade flows

Although imports and exports of electricity together represent a very small fraction of total generation, the interconnectedness of the electricity grid with the United States combined with varying requirements in different regions of the country allow the easy import and export of cheap electricity in response to demand and pricing conditions on both sides of the Canada–U.S. border. As shown in Figure 2, electricity exports to the United States grew by 215% between 1990 and 2008, from 18 000 GWh to over 57 000 GWh, respectively. Imports from the United States have also increased, although at a much lower rate (43% between 1990 and 2008).

On balance, Canada is a net exporter of electricity to the United States mainly due to U.S. electricity demand, additional generation capacity, and the availability of low-cost hydro electric resources. Some regions in Canada, however, rely on imports to meet domestic load requirements during high demand periods (for example, during the winter months when electricity use is high in most provinces, and relatively low in many American states) or when water levels are low in hydropower based provinces.

Figure 2: Imports and Exports with the United States

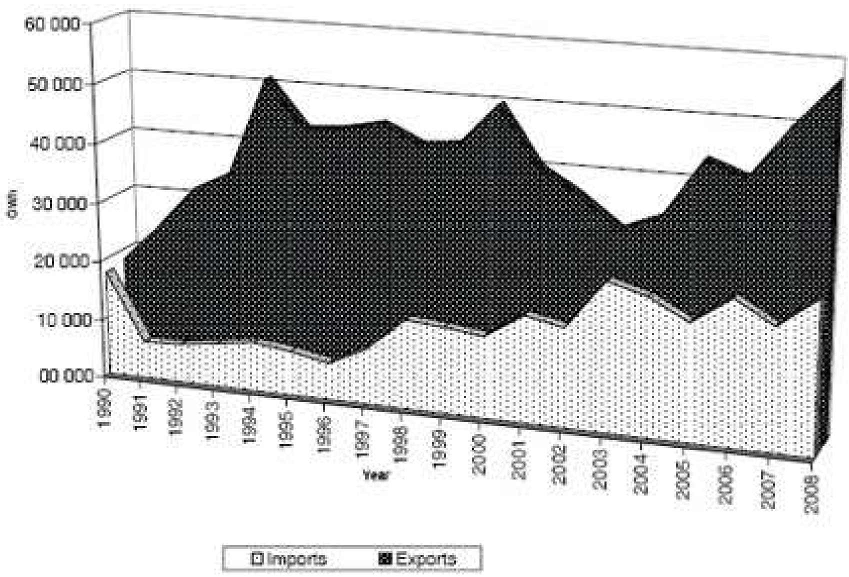
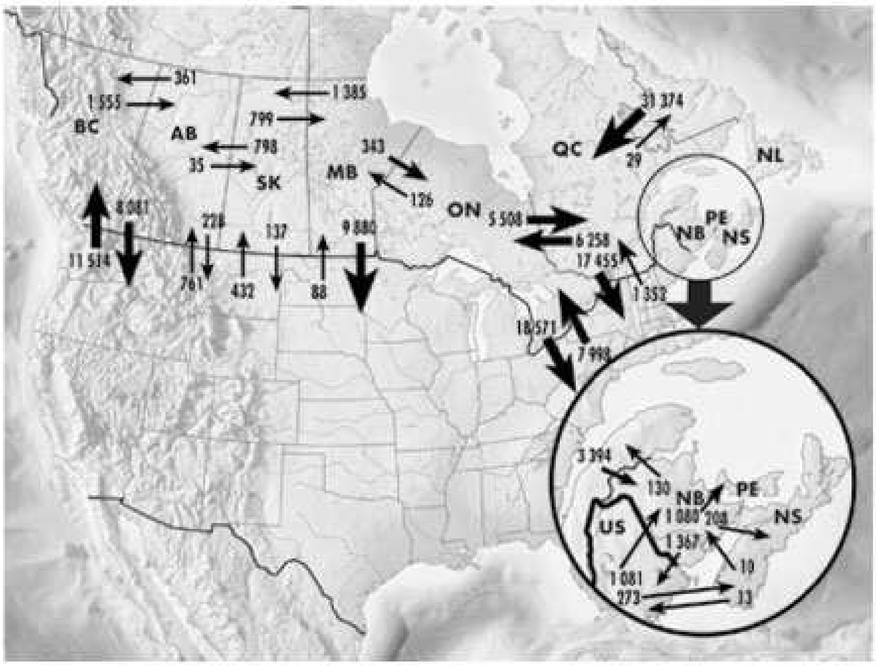


Figure 3 shows inter-provincial and international trade flows of electricity in 2008. Note that Ontario, Quebec and Manitoba exported the greatest volumes of electricity. The net importers of electricity include British Columbia, Alberta, Saskatchewan and Nova Scotia. Major Canadian electricity trade includes the transfer of hydro power from Newfoundland and Labrador into Quebec, interchanges between Ontario, Quebec and regions in the northeastern United States, and interchanges between British Columbia, Alberta and the U.S. Pacific Northwest.

In recent years, growth in Canadian electricity generation has lagged behind growth in domestic demand. As a result, the surplus available for export has been declining and some regions have increasingly relied on imports to meet domestic requirements during high-demand periods. Both Canada and the United States realize commercial benefits and improved electric reliability through trade, mainly due to complementary (off-set) demand peaking seasons.

Figure 3: Regional Trade Flows (see footnote 4)



Data for interprovincial transfers of electricity are from January 1, 2008, to December 31, 2008, and are compiled from Statistics Canada Electric Power Statistics monthly (megawatt-hour) table.

Data for United States imports and exports are for 2008 (excludes exchanges) and are compiled by the National Energy Board.

Arrows indicate import/export transactions and may not represent the actual electricity flow route from source to destination.

2.4 *Actual vs. potential generation*

Canada’s electricity-generating sector takes advantage of a full mix of hydro, nuclear, wind and other available generating sources. At the same time, actual generation from all these sources is less than potential generation. Potential generation can be determined by assuming capacity is fully operational for each hour, over the entire year. The difference between potential and actual generation can be due to numerous factors, including the availability (or lack thereof) of precipitation and wind as well as operational considerations such as required maintenance schedules.

Table 1 shows the actual generation, potential generation and capacity utilization level for major generation types in 2008. Nuclear generation had the highest capacity utilization level in 2008, with actual generation at over 77% of full capacity. This was followed by coal and hydro generation, while other sources such as gas, oil, and wind units had relatively high levels of available spare generation capacity. Typically, coal, gas, and oil units can operate at up to 85% of their potential generation capacity. However, the relatively higher price of gas and oil generation means that it is most often called upon only to meet peak demand, particularly in regions where coal or hydro generation is used to meet base load demand. Over any period of time, actual wind generation is typically much below its full theoretical capacity given the intermittent nature of sufficient wind energy.

Table 1: Actual vs. Potential Generation — 2008 (see footnote 5)

Type	Actual Generation (GWh)	Potential Generation (GWh)	Capacity Utilization (Actual/Potential)
Hydro	373 871	652 040	57%
Wind	3 807	20 873	18%
Nuclear	90 585	116 902	77%
Coal	104 580	139 631	75%
Oil	7 220	68 199	11%
Gas	31 363	81 702	38%
Total	**618 754**	**1 098 849**	**56%**

2.4.1 *Profile of coal plants/units*

Table 2 shows the installed capacity of coal plants/units, by province, as of 2010. The Canadian share of coal-fired electricity generation is the largest in Ontario (39%), followed by Alberta (38%), Saskatchewan (11%), Nova Scotia (8%), New Brunswick (3%) and Manitoba (1%). Approximately 95% of coal-fired electricity generating units reside in four provinces: Alberta, Ontario, Saskatchewan and Nova Scotia. In 2008, coal contributed to the electricity generation mix in six provinces: Alberta (74% of total generation), Nova Scotia (73%), Saskatchewan (60%), New Brunswick (31%), Ontario (17%) and Manitoba (1%).

Table 2: Coal Generation Capacity — Year 2010 (see footnote 6)

Region	Number of Coal Plants	Number of Coal Units	Coal-Generating Capacity (MW**)	Share of Total Coal-Generating Capacity for Canada
Ontario	4	15	6 459	39%
Alberta	7	18	6 397	38%
Saskatchewan	3	9	1 822	11%

Nova Scotia	4	8	1 308	8%
New Brunswick*	2	2	537	3%
Manitoba	1	1	98	1%
Total	**21**	**53**	**16 621**	**100%**

*One of the two coal units in New Brunswick in 2010 is now closed. Excludes petroleum coke (one unit).

**MW = megawatt.

Most of Canada's coal-fired generation capacity is old and nearing the end of its useful life. As a result, the coal-fired generation sub-sector is expected to undergo a major transition over the next several decades, with almost 85% of total coal-fired capacity reaching the end of its useful life by 2030. The following is a list representing the years at which units will reach the end of their useful life:

— Between 2010 and 2025, 35 units (66% of total);

— By 2030, an additional 9 units (83% cumulative);

— By 2035, an additional 3 units (89% cumulative);

— By 2040, an additional 5 units (98% cumulative); and

— By 2050, 1 additional unit (100% cumulative).

Alberta

Alberta's coal-fired electricity generation fleet is relatively old, with 13 of 18 units reaching their end of useful life by 2030. Alberta has regulatory requirements for all of the province's coal units; under the province's *Specified Gas Emitters Regulation*, the emissions intensity of existing coal units must be reduced to 12% below the 2003–2005 baseline emissions intensity of the facilities starting in 2007.

Ontario

The Government of Ontario has enacted regulations requiring that by December 31, 2014, coal would no longer be used in their currently operating coal units. Based on these regulations, the remaining generation stations at Atikokan (one unit), Lambton (four units), Nanticoke (eight units) and Thunder Bay (two units) would be closed by 2015. The closure of these coal units would be part of Ontario's commitment to fight climate change.

Saskatchewan

Saskatchewan's coal-fired capacity is aging, with five out of nine units at, or beyond, their end of useful life by 2020, and all but one reaching that point by 2030. Some of the units have recently been upgraded which could permit their use beyond their original useful life. Through recent consultations, SaskPower has indicated an intention to close two of its coal units in the near term (Boundary Dam units 1 and 2) and has announced that it will rebuild Boundary Dam unit 3 and integrate it with a CCS system.

Nova Scotia

Nova Scotia has two out of eight units reaching their end of useful life by 2020, and all but two reaching that point by 2030. Nova Scotia's 2009 Climate Change Action Plan and 2009 Energy Strategy commit the province to undertake orderly transition from dirty coal to cleaner and more sustainable energy sources. Subsequent to these, Nova Scotia's 2010 Renewable

Electricity Plan details the requirement for obtaining 25% of electricity from renewables by 2015, proposes to increase this to 40% by 2020, and caps the electricity sector at 12 000 GWh per year. This will result in reduced use of fossil fuels (primarily coal and petroleum coke [i.e. petcoke]).

New Brunswick

New Brunswick currently has only one coal-fired electricity generating unit, which will reach its end of useful life by 2038. One of the two coal units shown in Table 2 closed during 2010.

Manitoba

Manitoba has only one coal-fired electricity generating unit, which will reach its end of useful life by 2015. According to Manitoba's *Climate Change and Emissions Reduction Act*, after December 31, 2009, Manitoba Hydro must not use coal to generate power, except to support emergency operations.

Manitoba's Beyond Kyoto Plan also outlines the introduction of taxes on emissions from coal and provides capital support for coal-reliant industries to convert to cleaner energy and to develop biomass as a coal alternative.

2.5 *Electricity consumers*

Major consumers of electricity are shown in Table 3. The largest consuming sectors are industrial (see footnote 7) (40%), followed by residential (29%) and commercial (see footnote 8) (28%). Only a small proportion of electricity is consumed by the agriculture and transportation sectors (2% and 1% respectively).

Table 3: Electricity Consumption in Canada, 1990–2008 (TWh*) (see footnote 9)

Sector	**Sub-Sector**	**1990**	**1995**	**2000**	**2005**	**2007**	**2008**
Industrial	Iron and Steel	8.3	8.8	10.3	10.7	9.2	10.7
	Chemicals	18.2	19.3	19.2	19.5	18.3	17.2
	Petroleum Refining	5.7	4.9	5.4	6.6	7.8	7.9
	Aluminum and non-Ferrous	37	47.5	50.9	59.7	56.6	58
	Mining and Oil and Gas Extraction	28.8	31.6	33.5	37.5	33.6	33.4
	Other Manufacturing	36.1	37.2	44.3	43.1	44.8	42.9
	Pulp, Paper and Print	48.8	55.9	61.6	61.7	53.1	48.3
	Total	**182.9**	**205.2**	**225.2**	**238.8**	**223.5**	**218.4**
Residential		129.8	131.6	138.2	151	152.8	160.7
Commercial (including institutional and public administration)		108.4	117	125.8	135	143.6	155.8

*TWh = terawatt-hours

2.5.1 *Industrial sector*

The largest industrial consumers are aluminum and non-ferrous metals, pulp and paper, mining and oil and gas, chemicals, iron and steel and petroleum refining. Other manufacturing is significant but represents a combination of industries.

Since 1990, electricity consumption has increased in five of seven industrial sub-sectors. Among other developments, the shift from a resource-based economy, the rise of the automotive and electronics sector, and the growth of the service/IT industry have all had impacts on industrial electricity consumption. More recently, four of the seven industrial sub-sectors showed a decrease in electrical consumption relative to 2005 levels, likely being a response to economic factors. During this time period, the pulp, paper and print sub-sector showed the largest decrease in electricity consumption while the "other manufacturing" sub-sector (including transportation, equipment, electronics, and light consumer goods) showed the largest increase.

2.5.2 *Residential sector*

The residential sector is a major consumer of electricity, with demand that increased by 24% between 1990 and 2008 (Table 3). This is largely driven by population growth and rising consumer wealth and living standards. The number of homes in Canada increased by 31% between 1990 and 2007 (the last year for which data are available) and 10% between 2001 and 2007 alone. Growth in residential electricity demand was low to moderate during the recession that appeared in the early 1990s, but consumption increased significantly with greater economic growth after 1999. Fluctuations in seasonal temperatures are an important factor but decidedly a secondary driver of overall residential electricity demand. For example, electricity consumption increased by 5% between 2007 and 2008 while heating degree-days increased by about 1% over the same period.

2.5.3 *Commercial sector*

From 1990 to 2008, electricity consumption by the commercial sector grew by 44% (Table 3), in part due to growth in the service and IT sectors through structural changes in Canada's economy. This sector has also experienced an increase in the number of commercial buildings and floor space, which has meant larger areas to heat and cool, while computers, printers and other electrical appliances have become commonplace. Growth in electricity demand was particularly strong in more recent years in the commercial sector. For example, it increased its electricity consumption by 8% (from 144 TWh to 156 TWh) between 2007 and 2008, although the recent recession will likely have dampened growth for the last two years or so.

Regulatory and non-regulatory options considered

The Government of Canada is committed to reducing Canada's total greenhouse gas emissions by 17% from 2005 levels by 2020. To meet this target, Canada has stated that it will proceed with strong domestic, continental and international action, including the introduction of new regulations on coal-fired electricity generation.

The proposed Regulations to address CO_2 emissions from coal-fired electricity generation are considered the most effective instrument as they provide the necessary certainty and efficiency in achieving the objective of reducing GHG emissions from the electricity generation sector.

Voluntary approaches would not be able to provide assurance of emission reductions from this sector and the level of certainty needed to support industry investment.

Within the existing regulatory framework, two options were considered: cap-and-trade system and performance standard.

Regulatory option 1: Cap-and-trade system for the thermal electricity sector under CEPA 1999

Cap-and-trade is a policy instrument that places a mandatory cap on emissions through the distribution of emissions permits up to a pre-determined level, while providing regulated facilities flexibility in how they will operate within the limited number of emissions permits available to them. Regulated facilities could reduce their emissions through, for example, installation of abatement technologies, changing production processes or by buying permits from sources that can abate emissions at a lower cost. Under appropriate conditions, cap-and-trade can provide high certainty in reaching an environmental objective cost-effectively, while promoting new avenues for economic growth and innovation.

However, certain fundamental conditions are necessary for cap-and-trade to work effectively. First, the marginal costs of abatement across facilities must be different so that there is gain from trade and surplus permits are generated. Second, there must be a significant number of facilities to ensure the functioning of an efficient and liquid trading market. For example, the European Union Emissions Trading System (EU ETS) — the world's first international cap-and-trade system for CO_2 emissions — currently covers about 11 000 heavy energy consuming installations in power generation and manufacturing across 30 countries.

In the Canadian electricity generation sector, neither of these conditions exist to the degree that cap-and-trade exclusively for coal-fired electricity would appear to be a viable option. The Canadian electricity system is already among the lowest-emitting in the world, with coal-fired generation representing just 14% or so of the total electricity produced. This means that a cap-and-trade for electricity would be targeting only 53 units of coal-fired generating units across the whole country (as of 2010), and an even smaller number of operating entities/corporations. At the same time, there are relatively small variations in marginal costs across these units, making it unlikely that many of them could generate surplus emissions permits.

These factors would lead to significant constraints on trading opportunities which in turn lead to low levels of market liquidity and create a risk of large fluctuations in the price of carbon permits. This would make it difficult for companies to control costs and plan appropriately, and create great price uncertainty for electricity consumers. It would also limit their ability to align the construction of new facilities with normal capital investment / useful life cycles in order to achieve a smooth transition to lower-emitting fuels and/or technologies. A constrained carbon market for coal-fired generators would also be vulnerable to manipulation by one or two large facilities, a situation that is magnified in Canada by the preponderance of provincially owned utilities in the sector.

<u>Regulatory option 2: Performance standard regulations for coal-fired electricity generating units under CEPA 1999</u>

The proposed Regulations for the coal-fired electricity sector will set a stringent performance standard for new coal-fired units and those that have reached the end of their useful life. The performance standard will phase out high-emitting coal-fired generation units once their useful life is exhausted, and promote a corresponding transition towards lower- or non-emitting types of generation such as high-efficiency natural gas, renewable energy, or fossil fuel-fired power with carbon capture and storage.

The performance standard approach is administratively simpler and more efficient to implement compared to a cap-and-trade system, as it does not require the creation of a complex trading system to address emissions from a relatively narrow sector of the overall economy.

In doing so, the proposed Regulations provide regulatory certainty for the coal-fired electricity sector at a time when the sector is facing major capital stock turnover. This regulatory certainty allows utilities to factor GHG emissions considerations into their plans for replacement of end of useful life units, to align those investments with capital stock turnover cycles, and to avoid the risk of stranded assets.

Given the above considerations, a regulated performance standard was determined to be the preferred approach to address GHG emissions from the coal-fired electricity generation sector. Through consultations, industry and provincial stakeholders have expressed general support of the proposed regulated performance standard approach with consideration of specific issues.

Taking action now to regulate coal-fired electricity generation would achieve multiple economic and environmental objectives by providing investors, utilities, and electricity consumers with a regulatory environment that leads to both efficient and more certain reductions in CO_2 emissions from this sector as well as reductions in a wide range of air pollutants that negatively affect human health and the environment.

Benefits and costs

The proposed Regulations are estimated to result in a reduction of approximately 175 Mt of carbon dioxide equivalent (CO_2e) in GHG emissions over the period 2015–2030.

The present value of the costs of the proposed Regulations are estimated at $8.2 billion, largely due to the incremental costs of natural gas generation ($4.8 billion), reduced net exports and new capital costs. The total benefits are estimated at $9.7 billion, largely due to the avoided social cost of carbon (SCC) [$4.3 billion, at $25/tonne in 2010], avoided generation costs ($3.8 billion), and health benefits from reduced smog exposure ($1.4 billion). Over the 2015 to 2030 period, the net present value of the proposed Regulations is estimated at $1.5 billion. With an SCC of $100/tonne, the NPV would increase to $14.5 billion.

3. Analytical framework

The approach to cost-benefit analysis identifies, quantifies and monetizes, to the extent possible, the incremental costs and benefits of the proposed Regulations. The cost-benefit analysis framework applied to this study incorporates the following elements:

- Incremental impact: Impacts are analyzed in terms of incremental changes to emissions, costs and benefits to stakeholders and the economy. The incremental impacts were determined by comparing two scenarios: the business-as-usual (BAU) scenario and the regulatory scenario. Generally, the BAU scenario establishes what the electricity sector would look like in the future without the proposed Regulations. This scenario would include any pre-existing federal (see footnote 10) or provincial policies (see footnote 11) including the Ontario coal phase out. The regulatory scenario establishes what the electricity sector would look like with the implementation of the proposed Regulations. The two scenarios are presented in detail below (sections 6 and 7).
- Timeframe for analysis: The time horizon used for evaluating the economic impacts is 16 years (2015–2030). The first year of the analysis is 2015, when the proposed Regulations are expected to come into force. This study period was considered adequate for two reasons: (1) approximately two-thirds of coal-fired electricity units targeted by the proposed Regulations would be affected by that time; (see footnote 12) and (2) significant uncertainty exists for any post-2030 projections.
- Costs and benefits have been estimated in monetary terms to the extent possible and are expressed in 2010 Canadian dollars. Whenever this was not possible, due either to lack of appropriate data or difficulties in valuing certain components, incremental impacts were evaluated in qualitative terms. Table 4 summarizes the benefits and costs which were evaluated over a 16-year period.
- Discount rate: A social discount rate of 3% is used in the analysis for estimating the present value of the costs and benefits under the central analysis. This level is within the range prescribed by the Treasury Board Secretariat's cost-benefit analysis (CBA) guidelines. The discount rate is consistent with the discount rates that have been used for GHG related measures in Canada, as well as those being used by the United States and the European Commission. Costs and benefits were discounted to 2015, the first year of the analysis. A sensitivity analysis of discount rates and other key variables to test the associated variability of cost estimates was also conducted.

Table 4: Benefits and Costs of the Proposed Regulations

Benefits	Costs
• Avoided generation costs • Environmental benefits ○ GHG reductions ○ CAC* reductions ▪ Agriculture ▪ Visibility ▪ Soiling damage ▪ Timber, recreation ○ Mercury reductions • Health benefits ○ CAC reductions ▪ Mortality ▪ Hospitalizations, etc. ○ Mercury reductions	• Increase in generation costs ○ New capital ○ Fuel ○ Variable unit (O&M**) ○ Fixed unit (O&M) • Decommissioning of old coal-fired electricity units • Increase in imports • Decrease in export sales • Government costs

○ Lead reductions	

*Criteria air contaminant

**Operations and maintenance

4. Data and information sources

This analysis uses various sources of data.

Capacity, generation, emissions

This analysis is based on the modelling results that stem from the modelling work done by Environment Canada (EC) using its Environment, Energy, and Economy Model of Canada (E3MC). Specifically, data on capacity, demand, generation, GHG (CO_2e), criteria air contaminant (CAC) and mercury emissions for both BAU and regulatory scenarios were populated from E3MC.

E3MC has a dynamic view of the electricity system. When one unit closes, generation will be replaced with the least expensive option. As such, coal-fired units that close will not always be replaced with a new plant if there are other less expensive options available. For example, in some cases, the most economically attractive option may be to compensate for lost generation from end of useful life coal-fired generation with additional generation from existing units with additional capacity that have not yet reached their end of useful life.

It is important to note that while E3MC's results are generally robust, the projections only represent a plausible scenario of the future pathway of generation and emissions. The projections reflect a wide range of assumptions that are based on expert-driven knowledge and data availability as of September 2010. As with any projection, these assumptions could ultimately differ from reality. For example, some coal-fired units assumed to close in the BAU scenario may not close in reality (and vice versa). Changes to these assumptions (e.g. macroeconomic outlook, currently publicized utility plans, or development in commercially available technologies) would lead to a different outcome.

Fuel prices

The natural gas and coal price projections used in this analysis are from Natural Resources Canada (NRCan) [fall 2010] and are shown for key provinces in Figures 4 and 5, respectively. The figures also show the most recent forecasts of gas price for the United States, published by the Energy Information Administration (EIA), which suggest that the natural gas prices used in this analysis may be somewhat higher than the most recent forecasts, while the coal prices used may be somewhat lower. (see footnote 13) NRCan is currently in the process of revising its forecast and, on a preliminary basis, has indicated that the prices for natural gas could go down by as much as 20%, which would be in line with the most recent forecasts of EIA. To account for this eventuality, this analysis includes sensitivity analysis on natural gas prices of approximately 20%.

The analysis assumes no change in these projected prices due to any changes in demand resulting from the proposed Regulations. For natural gas, independent research (see footnote 14) commissioned by Environment Canada has concluded that the increased demand associated with the proposed Regulations would account for less than a 1% change in the overall North American market, which would not be significant enough to have a material effect on natural gas prices.

Figure 4: Natural Gas Prices — NRCan vs. EIA (2015–2030)

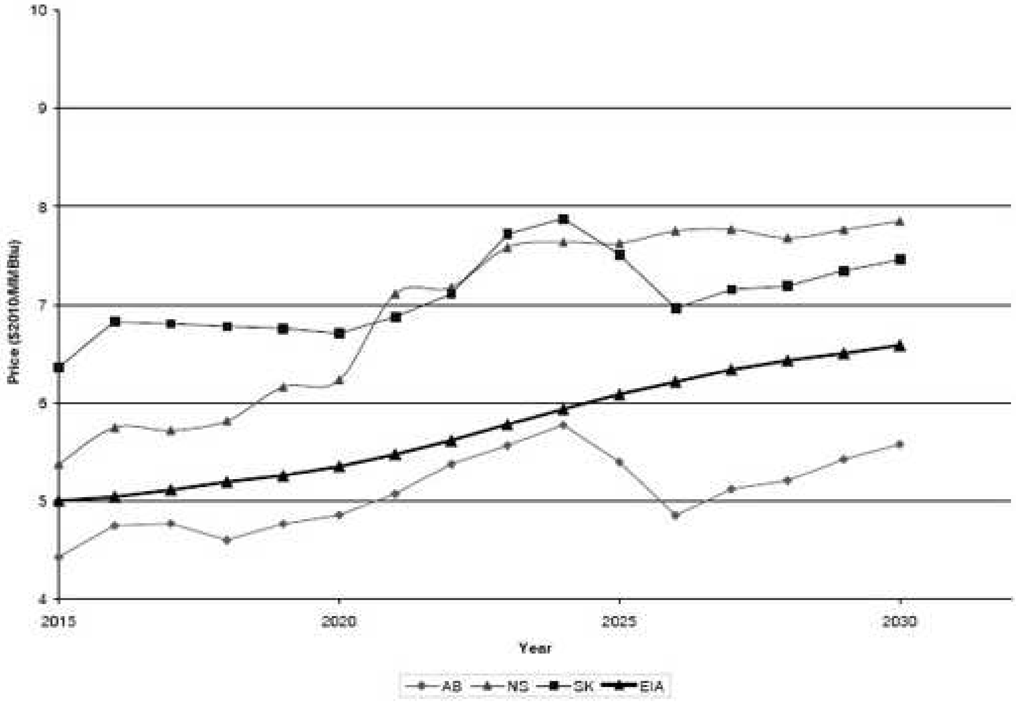
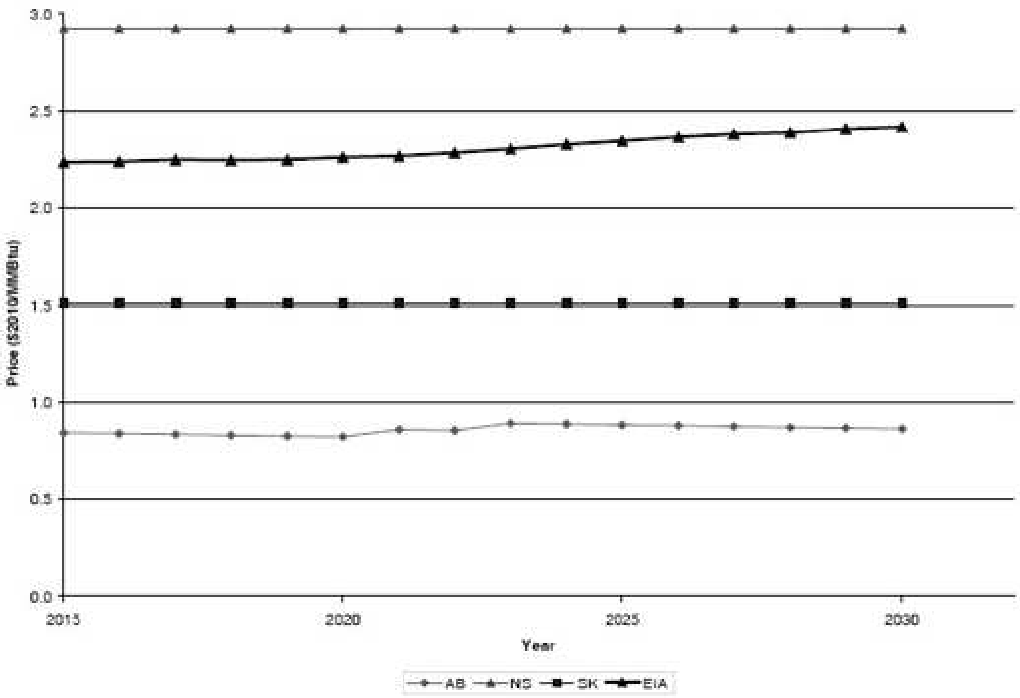


Figure 5: Coal Prices — NRCan vs. EIA (2015–2030)



Import and export prices of electricity

Import and export prices of electricity were obtained from the National Energy Board (NEB) and forecasted based on the latest EIA electricity price growth rate.

Air quality modelling

To estimate how these emission reductions would impact human health and the environment, Environment Canada first used A Unified Regional Air-quality Modelling System (AURAMS) to predict how the emission changes would affect local air quality. (see footnote 15) This is a fully three-dimensional state-of-the-art numerical model described in peer-reviewed scientific literature. (see footnote 16) AURAMS combined the information on predicted emission changes, with information on wind speed, temperatures, humidity levels, and existing pollution levels, in order to predict how these emissions changes would impact local air quality. (see footnote 17)

The CAC emissions (and resulting changes) are determined using emissions coefficients based on the 2007 National Pollutant Release Inventory (NPRI). The coefficients are determined by dividing a specific emission for 2007 by an economic driver for 2007 (e.g. volume of fuel used or volume of output). The results are then inputted into AURAMS.

Health and environmental benefits resulting from CAC reductions

The reductions in CAC emissions, hence the resulting improved air quality, would result in health and environmental benefits. Environmental benefits are estimated using Environment Canada's Air Quality Valuation Model (AQVM2). Health risks and impacts are estimated by Health Canada using the Air Quality Benefits Assessment Tool (AQBAT). (see footnote 18)

5. Key assumptions

- Under the BAU scenario, unless there is a firm or official provincial government or utility commitment, operating units do not automatically retire at the end of their useful life, but are assumed to be refurbished and to continue generating electricity as the lowest cost option to meet continuing or growing demand.
- Under the proposed Regulations, coal units are retired (closed) at the end of their useful life, subject to exceptions under compliance flexibility provisions noted above.
- Capital, average fixed O&M, and average variable O&M costs are assumed as follows:

	Capital costs for new unit ($/kW*)	Average fixed O&M costs ($/kW/Year)	Average variable O&M costs (excluding fuel) ($/MWh**)
Coal	1,502	11.26	5.01
NGCC	1,348	12.90	1.39

* kW=kilowatt; ** MWh=megawatt-hour

- Under the BAU scenario, all coal units that operate beyond their useful life (45 years) would require refurbishment at an assumed cost of $395/kW (see footnote 19) (26% of the costs for a new facility), extending life by 25 years.
- Decommission costs of $109/kW (see footnote 20) are assumed for coal units closed due to the proposed Regulations.

6. Business-as-usual scenario

Note that the analysis below, as well as for the regulatory scenario, builds on cases using the E3MC model. Although the results are robust overall, they are subject to significant uncertainty regarding specific projections, e.g. regarding specific new plants or retirements.

6.1 Coal-fired electricity generation unit retirements

Table 5 shows the coal unit retirements (closures) under the BAU scenario. All retirements occur by year 2015. Overall, 7 248 MW of capacity and 21 units are retired, largely driven by the Ontario coal phase out which accounts for 6 459 MW and 15 units of 21 units retiring under the BAU scenario. Total retirements account for 44% of total coal capacity as of 2010.

Table 5: Coal-fired Unit Retirements in the BAU Scenario

			Coal Capacity	Coal	Retired /

Region	Units	Retirement Year*	Retired (MW)	Capacity in 2010 (MW)	2010 Capacity (%)
Alberta	2	2011 2014	450	6 397	7%
Ontario	15	2011 2013 2015	6 459	6 459	100%
Saskatchewan	3	2014	282	1 822	15%
Nova Scotia				1 308	0%
New Brunswick	1	2010	57	537	11%
Manitoba				98	0%
Total	**21**	**-**	**7 248**	**16 621**	**44%**

* Coal-fired units do not operate in the retirement year.

All other units are assumed to continue to operate beyond the end of their useful life.

As noted above, the projections reflect a wide range of assumptions that are based on expert-driven knowledge and data and information availability as of September 2010. These assumptions could ultimately differ from reality. For example, some specific coal units assumed to close in the BAU scenario may not do so if there is a change in currently known provincial utility plans.

6.2 New or rebuilt coal-fired electricity generating units

Overall, 1 359 MW of new coal capacity would be added or rebuilt — three new units in Alberta (1 244 MW) (see footnote 21) and one rebuilt unit in Saskatchewan (115 MW). (see footnote 22) All new coal units come online or are rebuilt by year 2015 and therefore would not have to meet the proposed regulated performance standard until the end of their useful life. Two of the new units (i.e. Keephills 3 and Boundary Dam 3) are modeled to employ CCS technology.

6.3 New gas units

Overall, 3 213 MW (see footnote 23) of additional gas capacity would be added under the BAU scenario in the four provinces with coal units reaching their end of useful life by 2030. The additions are primarily in Alberta (1 813 MW) and Saskatchewan (1 100 MW), while Nova Scotia and Manitoba each only add 150 MW of capacity. (see footnote 24)

7. Regulatory scenario

7.1 Coal-fired unit retirements and compliance flexibility options

Although this analysis captures the potential impacts of the proposed Regulations on coal plant retirements, it does so under the fixed set of assumptions with respect to, among others, generation costs and economic growth, as previously noted for the BAU scenario.

Other factors, such as unforeseeable changes in provincial government policies or the relative prices of currently known technology options, may lead to different outcomes under the proposed Regulations.

Under the modelled regulatory scenario, coal units retire (close) at the end of their useful life or continue operating if they employ CCS. Although compliance flexibility options are available to all units that meet the criteria, for the purposes of modelling and based on expected responses to the proposed Regulations, they were accounted for in the analysis as follows:

- Standby status: This flexibility was modelled to affect Manitoba. Brandon was considered a stand-by unit and therefore does not need to meet the standard.
- Swapping: This flexibility was modelled to affect Nova Scotia. Lingan 1 and Lingan 2 switch retirement dates with Point Tupper and Trenton 5.
- Recognition for early deployment of CCS: This flexibility was modelled to affect Alberta. Sundance 1 was given one extra year of operation since Keephills 3 captures before 2025.
- CCS Deferral: The flexibility was modelled to affect Boundary Dam 3 in Saskatchewan where this unit would not be required to meet the performance standard until 2025.

Although the analysis captures the potential impacts of compliance flexibility, it does not perfectly mirror the flexibilities and outcomes that may materialize as a result of the proposed Regulations.

Table 6 shows the coal units that would retire by 2030 as a result of the proposed Regulations. Note that Manitoba does not have any closures since Brandon is considered a standby unit under compliance flexibility. Overall, 6 003 MW of capacity and 22 units are retired, predominately in Alberta (3 816 MW) and Saskatchewan (1 235 MW), which collectively represent 84% of retired capacity.

Table 6: Coal-fired Unit Retirements Due to the Proposed Regulations — By 2030

Region	Units	Coal Generation Capacity Retired (MW)	Retirement Year
Alberta	**11**	**3 816**	2016
			2017
			2019
			2021
			2022
			2023
			2024
			2026
			2027
			2029
			2029
Saskatchewan	**5**	**1 235**	2016
			2019
			2024
			2026
			2029
Nova Scotia	**6**	**952**	2016
			2019
			2025
			2026
			2029
			2030
Total	**22**	**6 003**	**-**

7.2 New coal and gas electricity generation units

The new coal and gas capacity added under the BAU scenario (section 6) would also be added under the regulatory scenario. The additional capacity required in the regulatory scenario (over and above BAU) is defined in section 8.2.

8. Impacts in the electricity sector

8.1 Demand

As stated above, the demand for electricity used in this analysis is obtained from Environment Canada's E3MC model. Under the BAU scenario, the total demand for electricity would increase from 585 TWh in 2015 to 678 TWh by 2030 (Table 7). This represents, on average, a growth of 1.0% per year. At the sector level, annual growth would be largest for commercial (1.4%), followed by industrial (1.2%), and lastly, residential (0.2%).

Under the regulatory scenario, relative to the BAU scenario, the demand for electricity would only decline slightly by 2030, from 678 TWh to 677 TWh. This 1 TWh (0.2%) reduction would come primarily from the industrial sector in response to the limited price impacts of the proposed Regulations.

Table 7: Electricity Demand (TWh) by Sector — Canada

Sector	2015			2030		
	BAU	Reg	%Diff	BAU	Reg	%Diff
Residential	162	162	0.0%	167	167	-0.1%
Commercial	176	176	0.0%	216	216	-0.1%
Industrial	246	246	0.0%	295	294	-0.3%
Transportation	0.7	0.7	0.0%	0.6	0.6	-0.5%
Total	**585**	**585**	**0.0%**	**678**	**677**	**-0.2%**

8.2 Capacity

Although the proposed Regulations do not specify fuel requirements, the analysis indicates that natural gas-fired generation will be the least costly alternative to current coal-fired electricity generation.

Under the regulatory scenario, relative to the BAU scenario, coal-fired electricity generating capacity would be reduced by 6 060 MW by 2030 (Table 8). This is mainly due to the 22 coal units retired (Table 6). Overall, 3 300 MW of natural gas capacity would be added by 2030 with the largest additions in Alberta, followed by Saskatchewan, Nova Scotia, and Manitoba (see Table 8). Over 80% of the additional gas capacity would come online over 2026 to 2030 (the remainder would be over 2021 to 2025). Minor additions in renewable capacity would also occur. The net reduction in capacity (-2 692 MW) occurs because provinces would leverage existing capacity that is under-utilized while complying with the proposed Regulations. More specifically,

- under the BAU scenario, capacity utilization at coal-fired units in Canada would be at 75% by 2030 (while increasing to 82% under the regulatory scenario); and
- under the BAU scenario, capacity utilization at NGCC units in Canada would be at 41% by 2030 (while increasing to 51% under the regulatory scenario).

Table 8: Change in Generation Capacity (MW) by 2030

Region	Coal	Natural Gas	Others*	Total
Alberta	-3 873	2 050	51	-1 772
Saskatchewan	-1 235	750	10	-474
Nova Scotia	-952	350	2	-600
Manitoba	0	150	3	154
Total	**-6 060**	**3 300**	**68**	**-2 692**

Note: totals may not add up due to rounding.

*Others include biomass, wind, hydro, solar, and waste.

8.3 Generation and trade flows

Under the BAU scenario, coal-fired electricity generation would increase from 58 TWh in 2015 to 65 TWh by 2025, reaching 68 TWh by 2030 (Table 9). Over the same period, natural gas generation would increase from 48 TWh to 63 TWh, reaching 64 TWh by 2030. This represents, on average, a higher growth for gas (1.9%) compared to coal (1.1%).

Under the regulatory scenario, coal-fired generation would decrease to 50 TWh by 2025, reaching 30 TWh by 2030 (55% decrease from the BAU scenario). Moreover, natural gas generation would increase to 72 TWh by 2025, reaching 93 TWh by 2030 (46% increase from the BAU scenario). There would be a negligible impact on non-emitting generation.

Under the regulatory scenario, coal-fired generation would decrease to 50 TWh by 2025, reaching 30 TWh by 2030 (55% decrease from the BAU scenario). Moreover, natural gas generation would increase to 72 TWh by 2025, reaching 93 TWh by 2030 (46% increase from the BAU scenario). There would be a negligible impact on non-emitting generation.

Table 9: Electricity Generation by Fuel Type — Canada (TWh)

Type	2015			2025			2030		
	BAU	Reg	%Diff	BAU	Reg	%Diff	BAU	Reg	%Diff
Coal	58	58	0%	65	50	-24%	68	30	-55%
Natural gas	48	48	0%	63	72	14%	64	93	46%
Oil	7	7	0%	6	5	-7%	6	6	-1%
Non-emitting*	545	545	0%	605	605	0%	613	613	0%
Total	**657**	**657**	**0%**	**740**	**732**	**-1%**	**751**	**743**	**-1%**

*Non-emitting = Biomass + Geothermal + Hydro + Landfill Gases/Waste + Nuclear + Solar + Wave + Wind

Over 2015 to 2030, relative to the BAU scenario, there would be a total reduction in coal-fired generation of 218 TWh (Table 10) from provinces affected by the proposed Regulations (Alberta — 134, Saskatchewan — 54, Nova Scotia — 30). This displacement of generation from coal-fired units would be mostly offset by a 145 TWh increase in natural gas generation (Alberta — 90, Nova Scotia — 27, Saskatchewan — 23, Manitoba — 5). This yields a reduction in generation of 74 TWh. This remainder would be primarily met through increased imports, reduced exports, and reduced demand which resulted from price impacts.

Table 10: Change in Electricity Generation and Flows by Region, 2015–2030 (TWh)

Region	Generation					Net Imports**	
	Coal	Natural Gas	Oil	Non-Emit.*	Total	From Provinces	From United States
Alberta	-134	90	0	0.3	-44	31	0
Saskatchewan	-54	23	0	0.2	-30	18	10
British Columbia	0	0	0	0	0	-31	30
Manitoba	0	5	0	0	5	-17	12
Nova Scotia	-30	27	-2	0.2	-5	5	0
Canada	**-218**	**145**	**-2**	**0.3**	**-74**	**0**	**57**

*Non-emitting = Biomass + Geothermal + Hydro + Landfill Gases/Waste + Nuclear + Solar

** Net imports = imports – exports. Increase in net imports means increase in imports and/or decrease in exports.

8.3.1 Foreign imports and exports of electricity

Under the BAU scenario, imports would increase from 25 TWh in 2015 to 30 TWh by 2025, reaching 35 TWh by 2030 (Table 11). Over the same period, exports would increase from 52 TWh in 2015 to 74 TWh in 2025, and then decline to 55 TWh by 2030. This represents, on average, a growth of 2.3% per year for exports and 0.3% for imports. The sharp decline in exports post-2025 is projected to occur, because over time, under the BAU scenario, the excess capacity previously being exported is being relied upon to meet the domestic market (e.g. new capacity is not built to support the export market).

Under the regulatory scenario, imports would increase to 32 TWh by 2025, reaching 37 TWh by 2030 (4% increase from the BAU scenario). Moreover, exports would increase to 70 TWh by 2025, and then decline to 51 TWh by 2030 (7% decrease from the BAU scenario). As a result of the proposed Regulations, Canada would rely somewhat more on imports, while reducing its exports since a more significant portion of its capacity would now be required to accommodate the demand from the domestic market. As imports increase and exports decrease, net imports increase, although it should be noted that imports will still represent a small share of overall electricity demand in Canada under the proposed Regulation (about 5% of total domestic demand, up from 4% or so under the BAU scenario).

Table 11: Exports and Imports — Canada (TWh)

Type	**2015**			**2025**			**2030**		
	BAU	**Reg**	**%Diff**	**BAU**	**Reg**	**%Diff**	**BAU**	**Reg**	**%Diff**
Imports	25	25	0%	30	32	4%	35	37	4%
Exports	52	52	0%	74	70	-6%	55	51	-7%
Net imports	**-27**	**-27**	**0%**	**-44**	**-38**	**-12%**	**-20**	**-14**	**-26%**

8.3.2 Inter-provincial trade flows

As a result of the proposed Regulations, there would be some key shifts in inter-provincial electricity trade flows. These would be required to support the displaced coal-fired generation from affected provinces. More specifically, this is what is expected relative to the BAU scenario, over 2015 to 2030:

- Alberta exports less to British Columbia (14 TWh) and Saskatchewan (1 TWh) and imports more from British Columbia (17 TWh) and less from Saskatchewan (1 TWh);
- Saskatchewan exports less to Alberta (1 TWh) and Manitoba (0.1 TWh) and imports more from Manitoba (17 TWh) and less from Alberta (1 TWh);
- Nova Scotia exports less to New Brunswick (3 TWh) and imports more from New Brunswick (1 TWh);
- British Columbia exports more to Alberta (17 TWh) and imports less from Alberta (14 TWh); and
- Manitoba exports more to Saskatchewan (17 TWh) and imports more from Ontario (0.2 TWh) and less from Saskatchewan (0.1 TWh).

8.4 Costs and avoided costs to the electricity sector

Table 12 shows the present value of various major costs and avoided costs under the proposed Regulations. Over 2015 to 2030, new capital costs would increase by $1,277 million, fuel (natural gas) costs would increase by $4,753 million, and decommissioning costs would increase by $506 million. Together, they yield an incremental generation cost of $6,535 million over the 2015 to 2030 period.

As coal-fired electricity generation is being displaced by natural gas, the cost of purchasing coal, some fixed and variable costs of O&M for coal-fired units and the cost of refurbishment of end of life coal-fired units would be avoided. The avoided cost of purchasing coal is estimated to be $2,144 million, avoided fixed and variable O&M costs are estimated to be $958 million, and avoided refurbishment cost is estimated to be $731 million. In total, these avoided costs equal

$3,834 million from 2015 to 2030.

Table 12: Change in Generation Costs — Canada (Present Value Millions of 2010 dollars)

Cost category	2015	2020	2025	2030	Cumulative — 2015 to 2030
Capital	**830**	**-5**	**3**	**-1,330**	**545**
Net new capital	*830*	*-5*	*49*	*-2,390*	*1,277*
New capital	830	-5	49	459	4,126
Residual value				-2,850	-2,850
Net refurbishment	*0*	*0*	*-46*	*1,060*	*-731*
Refurbishment of EOL coal units	0	0	-46	-39	-1,831
Residual value				1,100	1,100
Fuel costs	**2**	**8**	**202**	**517**	**2,609**
Natural gas	2	89	358	824	4,753
Coal	1	-82	-156	-308	-2,144
Fixed O&M	**0**	**-14**	**-15**	**-6**	**-163**
Variable O&M	**-12**	**-34**	**-61**	**-92**	**-795**
Decommissions	**0**	**0**	**13**	**11**	**506**

Table 13 shows the present value of the change in generation costs for key provinces. Over 2015 to 2030, the largest increase would be for Alberta ($2.2 billion), followed by Manitoba ($253 million), Nova Scotia ($161 million) and Saskatchewan ($105 million). Note that the higher costs in Alberta are due to the combination of the following key factors:

- Alberta would use significantly more natural gas.
- On average, over 2015 to 2030, natural gas prices are 6.2 times greater than coal in Alberta, compared to 4.7 in Saskatchewan and 2.4 in Nova Scotia.
- Alberta would decommission more coal-fired units and capacity.

Also note that although Saskatchewan would add an incremental 750 MW of natural gas capacity by 2030, more than both Nova Scotia (350 MW) and Manitoba (150 MW), its capital costs are lower. This is because the majority of new capacity would be added in Saskatchewan during 2026 to 2030 — the last couple of years of the analysis. As such, the residual value of this new capacity is quite high, making its capital costs low compared to those of Nova Scotia and Manitoba. In contrast, Nova Scotia and Manitoba, who require less new capital, would have a proportionally lower residual value in 2030 since the new natural gas capacity would be added earlier (e.g. over 2021–2025). The avoided net refurbishment costs also apply in Saskatchewan, which reduces the capital costs for that province.

Table 13: Change in Generation Costs, by Region (Present Value Millions of $2010)

Region	Capital	Fuel	Operation and Maintenance	Decomm.	Total
Alberta	420	1,955	−524	322	2,173
Manitoba	80	182	−9	0	253
Nova Scotia	43	206	−169	81	161
Saskatchewan	2	254	−255	104	105
Total for Above Regions	**545**	**2,597**	**−957**	**506**	**2,691**

8.5 Foreign import and export costs

Over 2015 to 2030, relative to the BAU scenario, U.S. imports would increase by 13 TWh and exports decline by 44 TWh (Table 14). The reduction in coal generation would cause provinces to reduce their supply to the United States since this capacity would now be required to serve the domestic market. The increase in imports would occur in Saskatchewan and British Columbia, while reduced exports would occur predominately in British Columbia and Manitoba, with smaller reductions in Saskatchewan, Quebec and New Brunswick.

The value of foreign imports was determined by multiplying the change in imports by price. The price is the average price paid for U.S. electricity in the respective province for 2010 (from NEB (see footnote 25)), adjusted to future years by using the projected change in U.S. electricity prices (from EIA (see footnote 26)). Over 2015 to 2030, the total present value cost of increased imports would be $300 million, with the largest increases in Saskatchewan ($154 million) and British Columbia ($141 million). Similarly, the value of reduced foreign exports was determined by multiplying the change in exports by price. The price is the average price received from the United States in the respective province for 2010 (from NEB), adjusted to future years by using projected change in U.S. electricity prices (from EIA). This amount represents the foregone revenues. Over 2015 to 2030, the total value of reduced exports would be $1.3 billion, with the largest losses in British Columbia ($730 million) and Manitoba ($312 million).

Table 14: Change in Foreign Imports and Exports by Region (Present Value Millions of $ 2010)

Region	Change in U.S. Imports (TWh)	PV of Increased Foreign Imports ($M 2010)	Change in U.S. Exports (TWh)	PV of Reduced Foreign Exports ($M 2010)
Ontario	0	1	0.1	4
Quebec	0	0	−3	−87
Saskatchewan	7	154	−4	−129
British Columbia	6	141	−24	−730
Manitoba	0	0	−12	−312
New Brunswick	0	4	−2	−84
Canada	**13**	**300**	**−44**	**−1,338**

9.Government costs

The federal government would incur incremental costs related to training, inspections, investigations, and measures to deal with any alleged violations, and compliance and promotion activities.

With respect to enforcement costs, a one-time amount of $142,000 will be required for the training of enforcement officers and $50,000 to meet information management requirements.

The annual enforcement costs are estimated to be about $337,000 broken down as follows: roughly $298,000 for inspections (which includes operations and maintenance costs, transportation and sampling costs), $16,000 for investigations, $2,000 for measures to deal with alleged violations (including warnings, environmental protection compliance orders and injunctions) and about $21,000 for prosecutions.

With respect to compliance promotion, it is estimated that compliance promotion activities would cost roughly $170,000 during the first two years of implementation of the proposed Regulations and $20,000 for all the subsequent years. Compliance promotion activities could include training of compliance promotion officers, information management, mailing out of the final regulations, developing and distributing promotional materials (i.e. a fact sheet, Web material), responding to inquiries, attending trade association conferences, sending reminder letters, etc.

In addition to enforcement and compliance activities, the costs are estimated to be about $795,000 during the first year of the implementation of the Regulations. This includes the development of an electronic data entry system to support the reporting requirements. In subsequent years, the costs are estimated to be about $575,000 per year to administer the Regulations.

Over 2015 to 2030, the present value of government costs would be about $13 million.

10. Benefits to Canadians

10.1 Criteria air contaminant reductions from electricity sector

CAC refer to a group of air pollutants that include sulphur oxide (SO_x), nitrogen oxides (NO_x), particulate matter (PM), volatile organic compounds (VOC), carbon monoxide (CO) and ammonia (NH_3), ground-level ozone (O_3) and secondary particulate matter (PM). These air pollutants cause smog, acid rain, and other health hazards.

As a result of the proposed Regulations, the following are the most significant cumulative changes to generation in Canada over 2015 to 2030:

- Coal-fired electricity generation would decline by 218 TWh (net of a 37 TWh increase in CCS generation).
- Natural gas generation would increase by 145 TWh.

Since the CAC emissions from generating electricity using natural gas and coal with CCS are significantly lower than those from coal, this would result in fewer CAC emissions. The CAC emissions (and resulting changes) are determined using emissions coefficients based on the 2007 National Pollutant Release Inventory (NPRI). The coefficients are determined by dividing a specific emission for 2007 by an economic driver for 2007 (e.g. volume of fuel used or volume of output). The coefficient is then multiplied by future output (volume of fuel used or volume of output) to determine the projected emission levels and resulting changes. (see footnote 27)

Nationally, the proposed Regulations would lead to a reduction in CACs from the electricity sector, with the exception of VOCs which would increase marginally. Table 15 shows the cumulative changes over 2015 to 2030 (in absolute terms), which correspond to the following changes over time (in percentage terms):

- By 2020, SO_x (-6%), NO_x (-5%), PM_{10} (-4%), total particulate matter (TPM) [-4%], $PM_{2.5}$ (-2%), and CO and NH_3 (both -1%).
- By 2030, SO_x (-37%), NO_x (-24%), PM_{10} (-17%), TPM (-15%), CO and $PM_{2.5}$ (both -8%) and lastly, NH_3 (-5%).
- VOC increase by 0.3% by 2020, increasing to 4% by 2030.

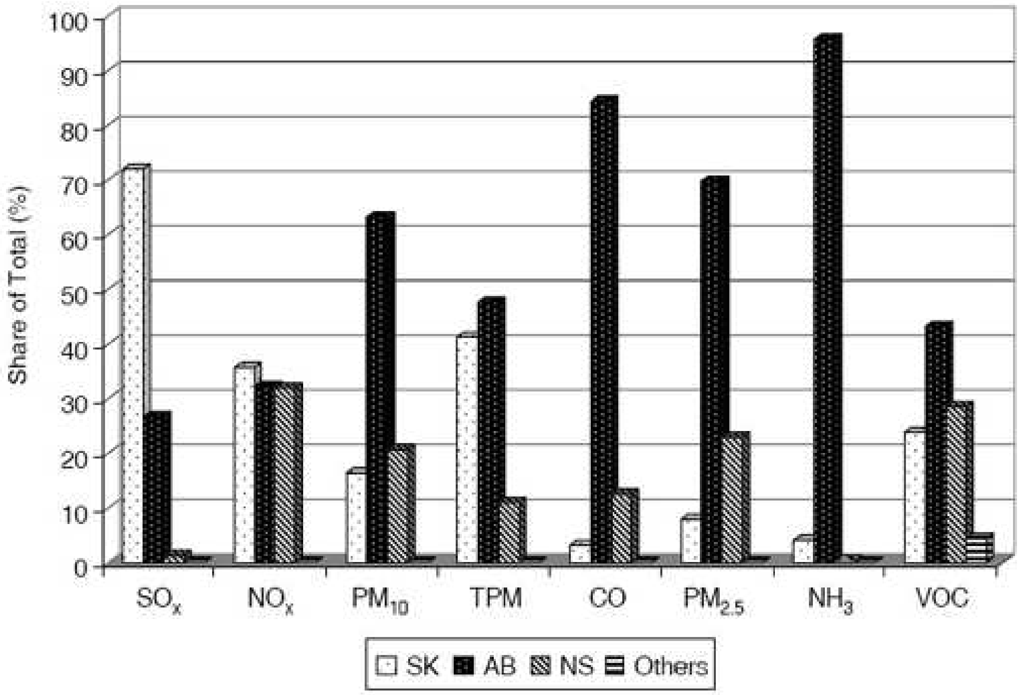
Table 15: Cumulative Changes in CAC Emissions

Criteria air contaminant	2015–2030 (kilotonnes)
Sulphur oxides (SO_x)	-742
Nitrogen oxides (NO_x)	-426
Total particulate matter (TPM)	-34
Particulate matter < 10 microns (PM_{10})	-19
Carbon monoxide (CO)	-16

Particulate matter < 2.5 microns ($PM_{2.5}$)	-6
Ammonia (NH_3)	-0.1
Volatile organic compounds (VOC)	2

The geographic distribution of the cumulative changes is shown in Figure 6. The proportional differences between provinces are largely determined by the amount of coal-fired generation displaced, the type of coal that would have been burned, and the type of replacement generation. In general, by far the biggest decline in harmful CACs would occur in Alberta, with the exception of SO_x, where Saskatchewan would experience the greatest drop in emissions.

Figure 6: Distribution of Cumulative Changes in CAC Emissions



10.2 Air quality modelling

To estimate how these emission reductions would impact human health and the environment, Environment Canada first used the AURAMS model to predict how the emission changes would affect local air quality. This is a fully three-dimensional state-of-the-art numerical model described in peer-reviewed scientific literature. AURAMS combined the information on predicted emission changes with information on wind speed, temperatures, humidity levels, and existing pollution levels, in order to predict how these emissions changes would impact local air quality.

The AURAMS air quality modelling system was run for an entire year for four scenarios of anthropogenic emissions representing two different projection years over the time horizon: two scenarios (one for the BAU scenario and the other for the regulatory scenario) were run for the year 2020, and the other two scenarios were run for the year 2030. The meteorological data used for these four scenarios is for the year 2006 and was generated by Environment Canada's weather forecast model.

The air quality model runs provided ambient air concentrations of pollutants in 2020 and 2030. However, the results for all the years between 2015 and 2030 were needed to complete this analysis. The selected method to obtain data for those years was to use the available model results for years 2020 and 2030 and to interpolate linearly the air quality metrics to obtain the metrics for 2021 up to 2029. The procedure was slightly different for the years 2015 to 2020 since it involved extrapolation. The BAU scenario was extrapolated linearly from 2020 to 2015 using the 2020 and 2030 model results. (see footnote 28) Once the values for the BAU scenario from 2015 to 2019 were obtained, the regulatory scenario was interpolated between the 2020 value and the 2015 value for the BAU scenario. As a result of this procedure, the regulatory scenario in 2015 would have metrics identical to the BAU scenario.

10.3 Coal mining and natural gas sectors

The change in electricity generation would also impact the emissions from the coal mining and natural gas (distribution and pipeline) sectors. However, the changes in these emissions are significantly smaller than those from the electricity sector. An analysis by Environment Canada indicated that these potential emission changes represent less than 1% of the total emissions from the electricity power sector. In addition, since the emission impacts occur in opposite directions (e.g. reductions in emissions from coal mining, increases from natural gas extraction and transportation), the net effect would be even smaller. As a result, these impacts were excluded from the analysis.

10.4 Point and area sources

The emissions in the air quality model were established in terms of point and area sources. Point sources are represented by specific spatial locations (latitude, longitude), and area sources have unknown spatial locations. All coal-fired electricity units were point sources (since the locations were known), but in cases where new gas capacity was projected to come online due to the proposed Regulations, the spatial location was unknown, and hence these emissions were modelled as though they were area sources. For area sources, the “Utility” data from Statistics Canada (see footnote 29)was used to spatially allocate the emissions, which relies on employment data.

One of the results from data preparation for air quality modelling work and the spatial distribution was that for Nova Scotia: there is an increase in SO_x emissions. This is not consistent with E3MC modelling results, which show a reduction in SO_x emissions (see Table 15 and Figure 6). Due to this inconsistency, the air quality modelling results for Nova Scotia were omitted. This omission would likely cause an underestimation of benefits due to the proposed Regulations.

10.5 Environmental benefits

10.5.1 GHG reductions from electricity sector

Since the GHG emissions from generating both from natural gas and coal CCS are significantly lower than coal, this would result in fewer GHG emissions. The coal emission factors differ by province due to the fact that different types of coal are available in different parts of the country. These emission factors are assumed constant over the projection period. Natural gas emission factors do not vary across provinces or over the projection period.

Over 2015 to 2030, there would be cumulative reductions in GHGs from the electricity sector as a whole, relative to the BAU scenario, of approximately 175 Mt (Table 16). The largest reductions would be in Alberta (65% of total), followed by Saskatchewan (23%) and Nova Scotia (13%). By 2020, this would represent a 6% reduction from the total electricity sector, which increases to 29% by 2030. These reductions are above and beyond existing and assumed federal and provincial actions. Figure 7 shows the GHG emissions in the electricity sector assuming no government actions, provincial actions only, and the combined provincial and federal actions (to illustrate the incremental outcome of the proposed Regulations on their own).

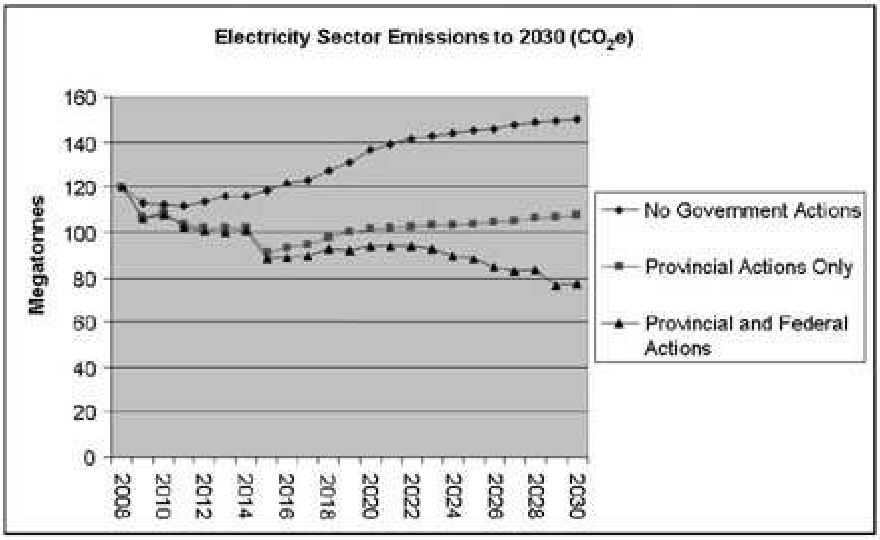
Table 16: GHG Emission Reductions

Region	**Cumulative, 2015–2030 (Mt, CO_2e)**	**Present Value of GHG Reductions ($M)**
Alberta	112	2,813
Saskatchewan	41	1,016

Nova Scotia	22	558
Canada	**175**	**4,338**

The value of GHG reductions is critically dependent on the climate change damages avoided at the global level. These damages are usually referred to as the social cost of carbon (SCC). Estimates of the SCC vary widely. For example, experts such as Tol, Nordhaus and Hope have reported mean SCC values in the range of $10 to $25 per tonne of CO_2e, whereas Stern has reported a value closer to $100. In large part this variability relates to uncertainties around key parameter choices in the estimation of the SCC, for example the appropriate discount rate to use in the calculation. It is generally acknowledged that estimates, even from the same model, vary widely depending on the chosen levels of key variables. While research by Environment Canada to determine the appropriate SCC for use in cost-benefit analysis is continuing, an estimated value of $25 per tonne of CO_2e has been adopted for this analysis, increasing at 2% per year. This value is consistent with the expected U.S. price of carbon and the trading value of permits in the European Climate Exchange. It is also generally consistent with the values presently being used by the U.S. government as well as by the European Commission. Based on this estimate, the present value of incremental GHG emission reductions under the proposed Regulations is estimated to be $4.3 billion (Table 16).

Figure 7: GHG Emission Profile



10.5.2 CAC reductions from electricity sector

The reductions in CAC emissions would result in environmental benefits. These have been estimated using Environment Canada's Air Quality Valuation Model (AQVM2), and supplemented with other environmental estimates in an attempt to incorporate those not addressed by AQVM2.

10.5.2.1 Estimates for soiling, visibility and agriculture

The benefit estimates resulting from the AQVM2 model are shown in Table 17 and discussed below. Over 2015 to 2030, the total present value of benefits for Canada is estimated at $81.9 million.

Table 17: Environmental Benefit Estimates for Canada (2015–2030) Present Value, $2010*

Region	*Soiling on households*	*Visibility on households*	*Ozone on crops*	**Total AQVM2**	**Other benefits****

Newfoundland and Labrador	49,000	651,000	27,000	**727,000**	
Prince Edward Island	9,000	60,000	197,000	**266,000**	
Nova Scotia	-	-	-	**-**	
New Brunswick	0	-142,000	86,000	**-56,000**	
Quebec	185,000	1,165,000	693,000	**2,043,000**	
Ontario	692,000	3,173,000	1,271,000	**5,136,000**	
Manitoba	843,000	4,899,000	3,929,000	**9,671,000**	
Saskatchewan	1,109,000	6,744,000	17,915,000	**25,768,000**	
Alberta	2,127,000	8,568,000	27,183,000	**37,878,000**	
British Columbia	-84,000	-206,000	738,000	**448,000**	
Yukon	0	0	N/A	**0**	
Northwest Territories	1,000	5,000	N/A	**6,000**	
Nunavut	0	3,000	N/A	**3,000**	
Canada	**4,931,000**	**24,920,000**	**52,039,000**	**81,890,000**	**8,873,000**

* Reliable estimates of provincial air quality improvements for Nova Scotia are not currently available due to data limitations that prevented the estimation of robust impacts for the province.

** Timber harvest, recreational use of forests and material maintenance costs.

Reduced soiling

Soiling from changes in ambient PM will result in cleaning expenditures. The SCSIE (Soiling Cleaning Savings Impacts Estimator) model estimates the avoided cleaning costs for Canadian households associated with different levels of PM_{10}. Over 2015 to 2030, the proposed Regulations are expected to reduce the present value of households cleaning costs by $4.9 million. This estimate may be regarded as conservative since it is limited to the residential sector and does not account for cleaning expenditures in the commercial and institutional sectors. As expected, the two provinces with the highest reductions in coal-fired electricity generation, Alberta and Saskatchewan, also exhibit the largest gains from reduced soiling.

Improved visibility

As ambient concentrations of particulate matter increase, visibility decreases *ceteris paribus*. Based on willingness to pay for improved visual range, the VIEW R2 (Visibility Impacts Estimator of Welfare for Residents) model estimates the monetary change in welfare for different levels of deciviews. (see footnote 30) The present value of welfare gains from improved visibility in the residential sector is expected to be $24.9 million, with Alberta and Saskatchewan combining for 61% of total benefits.

Increased agriculture productivity

The proposed Regulations would result in decreased ambient concentrations of tropospheric ozone. Based on exposure-response functions for 20 different crops, the VOICCE (Value of Ozone Impacts on Canadian Crops Estimator) model provides the change in production (tonnes) and total sales revenue per Census Agricultural Region (CAR) due to changes in levels of ozone. National benefits from increased agricultural productivity, expressed in the present value of sales revenue, are expected to be $52 million. (see footnote 31) The contributions from Alberta are about one-half of the national benefits, while Saskatchewan contributes one-third. The largest share of benefits is expected to occur in the wheat sector (30%), followed by peas, beans and lentils (24%), and canola (17%). (see footnote 32)

10.5.2.2 Estimates for timber harvest, recreational use of forests and material maintenance costs

To address additional environmental benefits that are not considered in AQVM2, a benefit transfer approach is developed to assess the economic impacts of NOx on timber harvests and recreational use of forest ecosystems, and of SO_2 on material maintenance costs. Applying the mean estimates from Muller and Mendelsohn (see footnote 33) to the reductions in NOx and SOx results in an additional $8.9 million of benefits (in present value terms).

10.5.2.3 Non-quantified benefits

The expected national benefits for the assessed environmental impacts approximate $90.8 million. However, the overall benefits may be regarded as conservative since many environmental benefits remain non-quantified due to data or methodological limitations. Among these impacts are the effects of improved visibility on tourism revenues, reduced acid deposition on forests, crops and ecosystems, reduced mercury deposition on recreational fishing, and the benefits of reduced $PM_{2.5}$ and ozone on livestock and wildlife mortality.

10.6 Health benefits

10.6.1 CAC reductions from electricity sector

From a human health perspective the key air pollution emissions from the electricity sector include emissions of NOx, SOx, and $PM_{2.5}$.

Nationally, the proposed Regulations are expected to reduce NOx, SOx, and $PM_{2.5}$ emissions from the electricity sector by about 5%, 6% and 2% respectively by 2020, relative to the BAU scenario. By 2030, emissions of NOx, SOx, and $PM_{2.5}$ from electrical power generation are estimated to decrease by 24%, 37% and 8% respectively, relative to the BAU scenario.

While these emission reductions are significant, they will not be uniformly distributed across the country. The changes in regional ambient air quality levels will be one of the key determinants of the human health impacts of the proposed Regulations.

From a human health perspective, the most important air quality improvements are the reductions in ambient $PM_{2.5}$ and ozone levels. The $PM_{2.5}$ reductions are particularly significant, accounting for more than 63% of the health benefits from the proposed Regulations in 2030, while ozone improvements account for 35% of the health benefits. Note that the reductions in ambient PM levels are due in large part to the reduction in precursor pollutants, such as NOx and SOx. Both NOx and SOx interact with the atmosphere in order to create PM. So while the primary PM emissions from the electrical sector are important, it is the secondary PM formation, that results from NOx and SOx emissions, that has the greatest human health impact.

10.6.1.1 Average ambient air quality improvements

The largest improvements in air quality are expected to occur in Alberta, Saskatchewan and Manitoba. This is true for both particulate matter and ozone. In fact, for PM, the 40 Canadian census divisions expected to experience the largest PM reductions (in both absolute and percentage terms) are all located in these three provinces. For ozone, the air quality improvements are somewhat more spread out, but the Prairies still tend to dominate.

By 2030, ambient $PM_{2.5}$ in some regions of Saskatchewan is expected to decrease by as much 8.8%, while reductions of 2% to 5% are found across much of Alberta, Saskatchewan and Manitoba. Ozone levels do not decrease as much as PM, but ozone levels are expected to go down as much as 1.6% in southern Saskatchewan, and by 0.2% to 0.6% across much of the Prairies by 2030.

While some areas will certainly experience greater air quality improvements than others, at a provincial level, air quality is expected to improve across almost all provinces. Air quality improvements experienced by typical residents in each province for 2030 are shown in Table 18. "Average" air quality for the province means air quality weighted based on the population of census regions.

Table 18: Estimated Average Provincial Air Quality Improvements in 2030*

Region	Projected Population	PM2.5 Levels (Population Weighted)		
		BAU (ug/ m^3)	Policy (ug/ m^3)	Percent Reduction
Newfoundland and Labrador	519 330	2.385	2.378	0.30%
Prince Edward Island	154 655	4.641	4.632	0.19%
Nova Scotia	-	-	-	-
New Brunswick	777 980	2.563	2.561	0.06%
Quebec	8 755 900	7.211	7.208	0.04%
Ontario	16 643 455	7.711	7.705	0.08%
Manitoba	1 398 290	3.747	3.686	1.62%
Saskatchewan	1 001 015	2.959	2.847	3.77%
Alberta	4 359 995	4.828	4.768	1.24%
British Columbia	5 649 820	6.958	6.959	-0.01%
Yukon	35 790	0.509	0.509	0.02%
Northwest Territories	53 570	0.950	0.948	0.18%
Nunavut	36 620	1.895	1.894	0.07%
Canada	**40 389 730**	**6.621**	**6.607**	**0.21%**

Region	Annual Ozone Levels (Population Weighted)		
	BAU (ppm)	Policy (ppm)	Percent Reduction
Newfoundland and Labrador	32.025	31.888	0.43%
Prince Edward Island	32.280	32.138	0.44%
Nova Scotia	-	-	-
New Brunswick	32.092	32.044	0.15%
Quebec	32.360	32.348	0.04%
Ontario	36.632	36.625	0.02%
Manitoba	30.895	30.817	0.25%
Saskatchewan	33.387	33.218	0.51%
Alberta	37.253	37.112	0.38%
British Columbia	39.376	39.377	0.00%
Yukon	35.059	35.058	0.00%
Northwest Territories	30.904	30.900	0.01%
Nunavut	30.435	30.434	0.01%
Canada	**35.612**	**35.578**	**0.09%**

* Reliable estimates of provincial air quality improvements for Nova Scotia are not currently available due to data limitations that prevented the estimation of robust impacts for the province.

10.6.1.2 Improved health outcomes

The human health impacts and resulting socio-economic benefits are highly dependent on population proximity to the source of coal-fired electricity emissions. It is the population exposure to changes in air quality, and not simply the absolute changes in PM and ozone levels themselves that determine the health benefits of the proposed Regulations. For this reason, the areas that experience the largest health benefits and the areas that experience the largest air quality improvements are not necessarily the same.

Health Canada used the Air Quality Benefits Assessment Tool (AQBAT) to estimate the change in health risks and impacts.

The health benefits covered by the analysis include a wide range of health outcomes linked with air pollution. These range from health outcomes such as asthma episodes, and minor breathing difficulties, to much more serious impacts such as visits to the emergency room and hospitalization for respiratory or cardiovascular problems. Air pollution even increases the average per capita risk of death. And while the change in individual risk levels are small, these individual risk reduction have a large social benefit, in terms of the estimated reductions in annual mortality levels, and the large social benefit associated with reduced mortality risk.

Table 19 shows some of the estimated changes in cumulative health outcomes for 2030 as a result of the proposed Regulations. The table also shows the estimated total present value of the improvement in social welfare, expressed in economic (dollar) terms, for all health impacts over 2015–2030. (see footnote 34) The total health benefits are estimated at $1.4 billion, with the largest benefits in Alberta (42% of total), followed by Saskatchewan (22%) and Manitoba (15%).

Table 19: Cumulative Avoided Health Impacts, 2015 to 2030, Selected Health Outcomes*

Region	Premature Mortality	Emergency Room Visits and Hospitalization	Asthma Episodes	Days of Breathing Difficulty and Reduced Activity	Present Value of Total Avoided Health Outcomes (2010 $M)
Newfoundland and Labrador	10	15	3 254	36 590	$49
Prince Edward Island	2	4	757	8 146	$10
Nova Scotia	-	-	-	-	-
New Brunswick	3	7	1 241	11 374	$15
Quebec	13	22	3 811	60 442	$66
Ontario	32	37	4 743	163 932	$167
Manitoba	39	49	6 572	183 834	$207
Saskatchewan	58	76	9 425	236 138	$306
Alberta	113	147	28 038	580 307	$587
British Columbia	-4	-4	-578	-17 284	-$23
Yukon Territory	0	0	0	7	< $1
Northwest Territories	0	0	8	180	< $1
Nunavut	0	37	2	77	< $1
Canada	**265**	**321**	**57 276**	**1 263 741**	**$1 385**

* Reliable estimates of provincial air quality improvements for Nova Scotia are not currently available due to data limitations that prevented the estimation of robust impacts for the province.

10.6.2 Mercury reductions from electricity sector

Mercury is a heavy metal that can be released into the environment as a result of human activity (e.g. primary anthropogenic), including through the combustion of coal. The largest anthropogenic source of mercury emissions in Canada is from electric power generation plants, which represented approximately 30% of emissions in 2007.

Once in the environment, mercury can be converted to various forms. For example, mercury can be transformed into a highly toxic compound called methyl mercury, which can accumulate in living organisms and biomagnify (i.e. increase in concentration) as it moves up the food chain. This is the form of mercury to which humans are most often exposed, primarily through consumption of fish and other seafood.

Studies have examined the link between exposure to mercury and intellectual quotient (IQ) effects. Neurological damage resulting in impaired prenatal brain development can lead to reduced IQ points, with associated costs for society stemming from direct and indirect loss of earnings and education, and well-being.

The proposed Regulations are estimated to result in a cumulative reduction of 3 982 kg of mercury released to the environment compared to the BAU scenario by 2030 (Table 20). The majority of these reductions are forecast to occur in Saskatchewan (54% of total) followed by Alberta (36%) and Nova Scotia (10%). Although the reduction in coal-fired electricity generation is larger in Alberta than Saskatchewan over 2015 to 2030, the reduction in mercury emissions is lower. This is because the emission intensity of mercury in coal is significantly greater in Saskatchewan than in Alberta.

Table 20: Mercury Reductions (Present Value in Millions of $2010)

Region	**Cumulative, 2015–2030 (kg)**	**Present Value of Mercury Reductions ($M)**
Saskatchewan	2 143	9
Alberta	1 433	6
Nova Scotia	406	2
Canada	**3 982**	**17**

Several studies in the economic literature have estimated and monetized the socio-economic value of mercury-related health impacts. In 2005, Rice and Hammit estimated the value of health benefits from proposed caps on mercury emissions from U.S. power plants. In 2008, Spadaro and Rabl estimated the total global impacts of reduced IQ due to global mercury emissions. In the absence of primary Canadian research, estimates of the value of mercury impacts in the United States will be adopted to Canada for use in this analysis. (see footnote 35)

For the impacts of mercury on brain development, Rice and Hammit (2005) estimated that IQ impacts had a value of $10,000 to $11,000 per kilogram of emissions, assuming that there is no lower threshold for impacts from exposure. If a non-zero threshold of impacts is assumed, then Rice and Hammit estimate the value of impacts to be lower at $3,900 to $4,500 per kilogram (in 2000 U.S. dollars). (see footnote 36)

The low value of $3,900 per kilogram of emissions will be used for the analysis. Adjusting the value of $3,900 in 2000 U.S. dollars gives a value of $5,780 in 2010 Canadian dollars. Applying this value to measure the benefits of the 3 982 kg of mercury expected to be reduced under the proposed Regulations gives a present value of $17 million (Table 20). (see footnote 37)

10.6.3 Lead reductions from electricity sector

In terms of health impacts, the developmental neurotoxicity endpoint that has been most studied and for which there is the greatest weight of evidence of a causal relationship is the adverse consequence of early-life lead exposure (children under the age of six) on psychometric tests of intelligence (IQ) among school-aged children.

When lead exposure affects IQ, it translates into foregone future earnings/productivity as affected individuals cannot work to their full potential at their usual employment when they reach adulthood.

Studies have shown that some effects of chronic lead exposure may also occur in adulthood. Coronary heart disease (CHD), hypertension and strokes are among the main adult human health endpoints that have been quantified in previous economic analyses.

Based on coal-fired units reported to the 2005 NPRI, the proposed Regulations are estimated to reduce the annual emissions of lead by 418 kg by 2030. (see footnote 38) This only represents 0.15% of the total lead releases reported to the 2005 NPRI (excluding open and natural sources). Although some health benefits are expected, the impacts have not been quantified since the reduction would only represent a very small proportion of total lead releases.

11. Summary

The results of the cost-benefit analysis are summarized in Table 21 for various reference years over the study period. The values have been discounted at 3% and are categorized into terms of quantified costs (generation, increased imports, reduced exports, government) and quantified benefits (avoided generation costs, environmental benefits and health benefits). The values shown for new capital and refurbishment are both net of residual value (RV), since adjustments were made to account for the remaining useful value of assets at the end of the study period. The NPV measures the net benefits (benefits minus costs) for the reference year indicated.

Overall, over 2015 to 2030, the NPV of the proposed Regulations is estimated at $1.5 billion. This assumes a SCC of $25/tonne (alternatively, at a SCC of $100/tonne, the NPV would increase to $14.5 billion). The total benefits are estimated at $9.7 billion, largely due to the avoided SCC of carbon ($4.3 billion), avoided generation costs ($3.8 billion), and health benefits from reduced smog exposure ($1.4 billion). The total costs are estimated at $8.2 billion, largely due to incremental purchase of natural gas fuel ($4.8 billion), reduced exports and new capital (both at $1.3 billion).

Table 21: Incremental Cost-Benefit Statement (2015–2030) [Millions of $2010]

Category	Base Year: 2015	2020	2025	2030	Total 16 Year (2015–30)	Average Annual
A. Quantified costs						
New capital (net of RV)	830	−5	49	−2,390	1,277	80
Natural gas fuel costs	2	89	358	824	4,753	297
Decommissioning of coal units	0	0	13	11	506	32
Sub-total: Generation						

costs	***832***	***84***	***419***	***−1,555***	***6,535***	***408***
Increased imports	0	21	28	27	300	19
Reduced exports	0	82	121	104	1,338	84
Government costs	1	1	1	1	13	1
TOTAL COSTS	**833**	**188**	**569**	**−1,424**	**8,185**	**512**
B. Quantified benefits						
B1. Avoided generation costs						
Refurbishment of coal units (net of RV)	0	0	46	−1,060	731	46
Fixed O&M	0	14	15	6	163	10
Variable O&M	12	34	61	92	795	50
Coal fuel costs	−1	82	156	308	2,144	134
Total	***11***	***129***	***278***	***−654***	***3,834***	***240***
B2. Environmental benefits						
Avoided social costs of carbon (SCC at $25/tonne)	25	138	319	648	4,338	271
Soiling, visibility, agriculture, timber and recreation	0	2	8	13	91	6
Total	***25***	***140***	***327***	***661***	***4,429***	***277***
B3. Health benefits						
Benefits of reduced levels of smog	0	33	123	195	1,385	87
Mercury	0	1	1	2	17	1
Total	**0**	**34**	**124**	**197**	**1,402**	**88**
TOTAL BENEFITS	**37**	**304**	**730**	**204**	**9,665**	**604**
E. NET PRESENT VALUE	**−796**	**116**	**160**	**1,628**	**1,479**	**92**
E1. Net present value — Avoided SCC at $100/tonne	−720	530	1,118	3,572	14,493	906

The table below reports some corresponding key summary metrics for the cost-benefit analysis. The socio-economic cost per tonne of GHG emissions is approximately $18/tonne. The socio-economic cost per tonne permits a comparison with other GHG measures such as regulations and programs. Costs are estimated to represent 85% of the benefit. The cost-benefit ratio allows a comparison with other regulations.

Table 22: Summary Metrics (2015–2030)

Category	Base Year: 2015	2020	2025	2030	Total 16 Year (2015–30)	Average Annual
Reduction in						

GHG emissions ($Mt\ CO_2e$)	0.9	5.3	12.7	27.2	174.7	11
Cost to benefit ratio					0.85	
Socio-economic cost per tonne of GHG ($/T) (see footnote 39)					18.20	

12. Sensitivity analysis

A sensitivity analysis was conducted for key variables to test the variability of impacts. This requires changing one variable at a time (while holding all other variables/impacts constant). Table 23 shows the results of the sensitivity analysis which are discussed below. Note that although the NPV is highly sensitive to some of the variables, it remains positive under all cases but one.

Table 23: Results of Sensitivity Analysis (Millions of $2010)

Sensitivity variables	Net present value		
	Lower	**Central**	**Upper**
1. Discount rate: 7%, 0%	763	1,479	2,363
2. Sensitivity to natural gas price assumption: +20%, −20%	529	1,479	2,430
3. Sensitivity to coal price assumption: −20%, +20%	1,050	1,479	1,908
4. Refurbishment of end of useful life coal-fired units — 50%	1,114	1,479	n/a
5. Social cost of carbon ($/tonne) — $10, $25, $100	−1,124	1,479	14,493

12.1 Discount rate

Using a higher discount rate (7%) would lower the NPV to $763 million. Conversely, applying zero discount rate (0%) would increase the NPV to $2.4 billion.

12.2 Natural gas price

Natural gas price is a key variable since the costs from incremental natural gas represent almost 60% of total costs. NRCan is currently revising its forecast and, on preliminary basis, has suggested it could go down by as much as 20% from the prices underlying this analysis. As such, for sensitivity analysis, a range of ± 20% was applied to NRCan's 2010 natural gas price forecast. This range was assessed by comparing the forecast to the 2011 Reference Case of the Annual Energy Outlook (AEO), published by the U.S. Energy Information Administration (EIA). On an average annual basis, over 2015 to 2030, the EIA national forecasts ranged from -19% to +13% of NRCan's prices for key provinces.

Using the lower gas prices would increase the NPV to $2.4 billion. Conversely, using the higher gas prices would reduce the NPV to $529 million. This corresponds to a "break-even" value of 31% (i.e. the NPV remains positive as long as the natural gas prices do not rise by 31% or more, relative to forecast). This highlights the extreme importance of the positive externalities resulting from the proposed Regulations.

12.3 Coal price

Coal price is a key variable since the avoided costs from coal represent over 20% of total benefits. For sensitivity analysis, a range of ±20% was also used on NRCan's coal prices.

Using the higher coal prices would increase the NPV to $1.9 billion. Conversely, using the lower coal prices would decrease the NPV to $1.1 billion. The sensitivity of results to coal prices are less than they are to gas prices, as shown by the higher "break-even" value of -69% (i.e. the NPV remains positive as long as the coal prices do not fall by 69% or more, relative to forecast).

12.4 Coal-fired electricity generating units requiring refurbishment

Under the BAU scenario, all coal units that operate beyond their useful life (45 years) were assumed to require refurbishment. A sensitivity analysis was performed assuming that only 50% of coal-fired units would need to be refurbished. This would reduce the NPV by 25% to almost $1.1 billion, but remaining positive by a significant margin.

12.5 Social cost of carbon

As noted in section 10.5.1, the SCC estimates vary widely depending on the assumptions used. Although the central estimate used an SCC of $25/tonne, the result was quite sensitive to the SCC. For example, if an SCC of $100/tonne is used, the NPV would increase from $1.5 billion to $14.5 billion.

13. Distributional analysis

Coal and natural gas industries

Coal sector

In 2008, Canada produced approximately 68 Mt of coal. (see footnote 40) Almost 50% of total production in Canada is high-value metallurgical coal and thermal (steam) coal exports which will not be affected by the proposed Regulations. Canadian thermal (steam) coal exports currently represent about 8% of production and has been rising in recent years.

Electricity generation makes up about 90% of total coal consumption in Canada. By 2030, the total coal used to generate electricity would decline by 21.6 Mt. The demand reduction comes from Alberta (13.5 Mt), followed by Saskatchewan (6.1 Mt) and Nova Scotia (2 Mt). In 2008, Alberta produced approximately 32 Mt of coal and exported 6 Mt, while Saskatchewan produced 10 Mt and exported a negligible amount (0.001 Mt). (see footnote 41)

Data from Statistics Canada (see footnote 42) indicates that coal used by the electricity sector in both Alberta and Saskatchewan is fully supplied by the regional coal producers. In Alberta, almost all coal used in utilities is sub-bituminous and, as of 2008, there were five sub-bituminous mines with a total capacity of 28 Mt/year. (see footnote 43) In Saskatchewan, all coal is lignite and, as of 2008, there were three lignite mines with a total capacity of 13 Mt/year. In contrast, Nova Scotia relies on imports for almost 85% of its total electricity generation, so the domestic production of coal would be less affected.

Natural gas sector

The North American gas market is a highly competitive market, in which natural gas can be bought from many supply sources and delivered to any market centre through an extensive North American pipeline grid. Gas price is set by market fundamentals such as increased industrial demand, increased production levels of gas, and high levels of natural gas in storage. Given it is a highly competitive market, the price of gas in one region differs from the price in another region only by the cost of transportation.

Over 2015–2030, the total natural gas used to generate electricity would increase by 1 165 PJ. The demand increase comes primarily from Alberta (762 PJ), Nova Scotia (192 PJ) and Saskatchewan (176 PJ). This translates into an increase of 16% for the electricity sector.

Environment Canada commissioned a report from Ziff Energy on the expected impacts of the proposed Regulations on the natural gas markets and prices. The report confirmed that the increased gas demand due to the proposed Regulations would not have a material impact on the functioning of the North American gas markets. More specifically,

- the increased demand would account for less than 1% of the overall North American market; and
- the average yearly price impact would be less than $0.01/MMBtu over the period considered.

Consumers

It is expected that the cost increase from the proposed Regulations would be passed onto consumers in proportion to their consumption.

From 2015 to 2030, the cumulative (undiscounted) electricity generation costs for Canada would increase by $3.5 billion as follows for key provinces: Alberta ($2.8 billion), Manitoba ($306 million), Nova Scotia ($216 million) and Saskatchewan ($179 million). This estimated cost increase would represent approximately 0.63% of the average total electricity bill over 16 years.

Allocating these costs to the 2007 residential customer based on the share of residential revenues to total revenues, and then onto a per-customer basis using average consumption, gives the following estimated cost increases in each of the provinces over a 16-year period:

- Alberta — $2.14/month (based on 5 814 kWh/year);
- Manitoba — $1.58/month (based on 16 488 kWh/year);
- Nova Scotia — $1.20/month (based on 10 382 kWh/year); and
- Saskatchewan — $0.73/month (based on 9 848 kWh/year).

The estimated cost increases reflect average consumption and the number of customers. Therefore, although the costs to Alberta ($2.8 billion) are significantly greater than Manitoba, Nova Scotia and Saskatchewan, the province would be allocating costs across a customer base that is about four times as large, which reduces its relative cost increase per customer.

Households who consume more (or less) than the average consumption would pay proportionately more (or less) of the total costs. Note that these costs exclude the impact of imports, exports and government costs since these would be difficult to allocate to consumers of a specific province.

Employment

The proposed Regulations would affect jobs in terms of the closure of coal-fired electricity generating facilities, as well as possibly coal mining if there are dedicated mines to that plant. However, these impacts are expected to be low for various reasons. First, the electricity sector is highly capital-intensive and would be somewhat offset in Alberta and Saskatchewan by the incremental western gas production activity that would be stimulated by the proposed Regulations. Second, employment impacts are considered to be transitional impacts and the unemployed will eventually find new jobs within the economy. As such, national and regional employment impacts are expected to be negligible under the proposed Regulations.

Competitiveness impacts

Electricity

The proposed Regulations are expected to result in increases in electricity prices paid by industrial sectors. However, such impacts are expected to be small. For example, it is estimated that for pulp and paper and chemicals sectors the cost increases over a 16-year period would be about one-tenth of one percent of total industry costs. In general, the competitiveness impacts would be mitigated by the ability to pass some of these costs onto consumers.

Natural gas prices

One of the concerns identified by stakeholders relate to the impact of the proposed Regulations on the price of natural gas and more specifically on natural gas intensive sectors. The sectors most sensitive to changes in gas prices include

- fertilizer manufacturers (approximately 85% of input cost is natural gas);
- the chemicals sector that uses gas as both a feedstock and process fuel, which is significant in terms of overall costs; and
- the pulp and paper sector — Industry Canada estimates energy accounts for 15% of overall pulp and paper costs. Additionally EIA estimates that 50% of this sector's energy requirements are self-generated by utilizing wood residues and by-products (black liquor).

As noted above, the study by Ziff Energy indicated that the impact of the proposed Regulations on gas prices would not be material, with an average yearly price impact of less than $0.01/MMBtu over the period considered.

Rationale

The Government of Canada is committed to reducing Canada's total GHG emissions to 17% below its 2005 levels by 2020 — a target that is inscribed in the Copenhagen Accord and aligned with the United States. In 2008, GHG emissions from the electricity generation sector contributed around 16% to Canada's inventory of emissions. These were mainly from coal-fired electricity generation, which represent 78% of total electricity sector emissions.

The Government of Canada's approach to addressing climate change is based on the principle of balancing environmental and economic considerations. The proposed regulated performance standard approach provides necessary regulatory certainty for the electricity sector at a time when the sector is facing major capital stock turnover, is administratively simpler and more efficient compared to a cap-and-trade system and provides more certain economic signals to decision makers considering new or re-placement power generation plants. In addition, through consultations, industry and provincial stakeholders have expressed widespread support of the proposed regulated performance standard approach.

As a consequence, a cost-benefit analysis was conducted for the selected regulatory instrument, which indicated that it would result in a reduction of approximately 175 Mt CO_2e of GHG emissions over a period of 16 years. The incremental cost of achieving these reductions is estimated to be $8.2 billion over the same period with associated benefits of $9.7 billion or a net benefit of approximately $1.5 billion. Depending on the province affected, the additional generation costs are estimated to be small, ranging from $0.73/month to $2.14/month for a typical average household over the 16-year period. On a national basis, the socio-economic cost per tonne of GHGs reduced under the proposed Regulations is estimated to be $18/tonne.

As a consequence of the above, the proposed Regulations are considered to be an effective and efficient way of fulfilling the Government of Canada's commitment of reducing Canada's total GHG emissions.

Consultation

Over the past year, the Government of Canada held consultations with the coal-fired electricity sector and with representatives from the governments of Alberta, Saskatchewan, Manitoba, Ontario, Nova Scotia, and New Brunswick—the provinces most reliant on coal-fired generation. Discussions centered on the Government's intention to develop regulations to reduce GHG emissions from coal-fired electricity generation. The Government of Canada met with stakeholders again in a series of face-to-face meetings over the summer and fall 2010 to obtain additional information that helped inform the drafting of the proposed Regulations. Targeted consultations were held with the provincial governments, industry, NGOs, and groups such as the Federal, Provincial and Territorial Working Group on Domestic Climate Change, the Canadian Council of Chief Executives, and the Canadian Electricity Association.

Overall, industry and provincial stakeholders have expressed support of the proposed regulated performance standard approach, but did have questions regarding how the proposed

Regulations would affect specific units or align with existing provincial regulatory programs. Among the non-governmental organizations consulted, some had questions regarding the exclusion of biomass, CO_2 emissions and a need to ensure that CCS provisions are not abused. In terms of consulted user groups, questions were raised about the secondary impact on natural gas production and electricity prices. The following summarizes key issues raised by stakeholders throughout consultations and sets out the current thinking on approaches for addressing them.

14. Level of performance standard

The Government introduced that it was considering a performance standard to be set within the range of 360 tonnes of CO_2/GWh to 420 tonnes of CO_2/GWh. The lower end of the range (360 tonnes of CO_2/GWh) reflects the emissions performance of a natural gas combined cycle (NGCC) unit operating under optimum conditions; that is, a new, large, high-efficiency unit achieving a high rate of fuel conversion efficiency, operating at a high-capacity factor, and located at sea level.

It was articulated that the majority of NGCC units operating in Canada do not meet these conditions and cannot achieve emission rates of 360 tonnes of CO_2/GWh, and, as such, the majority of industry stakeholders are supportive of a performance standard of 420 tonnes of CO_2/GWh. When faced with any level of standard within the range identified, the response options for the coal-fired electricity generation units do not change as they will have to either close or make significant investments. However, for units that continue or begin operation, a lower standard will ensure even lower yearly CO_2 emissions (e.g. CCS units would need to capture more CO_2 emissions to meet a lower standard). In addition, the level used will become a consideration in any potential future discussions regarding a performance standard for natural gas units. As a result, the Government is proposing to move forward with a performance standard of 375 tonnes of CO_2/GWh.

15. Definition of old or end of useful life unit

Some industry members have raised concerns regarding elements of the proposed end of useful life definition. In particular, concerns were raised with respect to how the proposed Regulations will address existing power purchase agreements and whether they will accommodate the date when units start burning coal instead of the date that the unit began operating (for example, with another fuel).

15.1 Power purchase agreements

With respect to power purchase agreements (PPAs), they claim that upon entering the PPA, they were expecting to be able to operate the unit in a competitive market for some years after the expiry of the PPA and generate additional profits; the proposed Regulations would limit or take away that ability.

It is the understanding of the Government that PPAs, as part of their establishment, included consideration of asset amortization (i.e. investment cost recovery). With an interest to primarily limit stranding investment assets and economic impacts, the proposed end of useful life definition allows for the later of 45 years from their date of commercial operation or the end of the power purchase agreement. This provision would be limited to PPAs expiring by 2020. However, for circumstances where PPAs end early, a transitional provision will be included whereby an old unit that is subject to a PPA would receive a deferral of the performance standard for up to three years beyond the expiry date of the PPA, up until December 31, 2016.

15.2 Rebase the useful life of units

Specific stakeholders expressed concern about having a unit that started operation as an oil-fired unit, but then was re-commissioned to burn coal. Accordingly, they contend that the end of 45 years of useful life date should commence when the unit began burning coal instead of the date when the unit initially began operation.

The Government appreciates their concern to rebase the start date of the unit, but also recognizes that the unit began generating revenue and recovering its capital costs at the time it began operation, not just at the time it began burning coal. As a result, the proposed Regulations will allow for an 18-month life extension for units that converted from oil to coal prior to June 23, 2010.

16. Carbon capture and storage (CCS) issues

16.1 Requirements for deferral for new units

The approach presented in June 2010 proposed an exemption until 2025 for new units that incorporate technology for CCS. In consultations with stakeholders, there was broad support for this provision.

Providing a deferral until 2025 is considered reasonable as it is expected that CCS technology will be commercially viable by that time.

It is recognized that the risk of a new unit closing after receiving this exemption is considered low, but construction milestones will still be required within the proposed Regulations. In summary, for new units to be granted a time-limited deferral from the performance standard, the applicant would have to submit documentation and demonstrate commitment and ability to meet regulated construction milestones. In order to maintain the deferral, these units need to comply with each regulated milestone including, among others, the completion of studies by January 1, 2020, the capture of CO_2 by January 1, 2024, and the compliance with the performance standard on or before January 1, 2025.

16.2 Requirements for deferral for old units

A number of companies have advocated that the deferral should also be available for old units. Unlike new units, the potential for taking advantage of the system is greater for old units as the capital investment in these units has already been recovered, and an old unit could simply treat this provision as an opportunity to defer closure until 2025. Therefore, the criteria for deferral for old life units will be more stringent than for new units, where regulated construction milestones are to be completed within six years of their end of useful life date. At that time, they will be required to capture at 30% until January 1, 2025, and then meet the performance standard thereafter.

16.3 Additional CCS issues

16.3.1 Incentive for CCS projects

Some industry and provincial members claim that their CCS projects will not be economical under the proposed regulatory approach because they were relying on an offset trading market to render their projects economically viable. Furthermore, some units will begin operating long before July 1, 2015, and consequently will be able to operate for a significant number of years until the end of their 45 years of useful life is reached, leaving no incentive in the proposed Regulations to proceed with CCS.

As a result, if an existing unit employs CCS technology and captures at 30% for 5 years before they are required to meet the performance standard, they can apply to transfer to an old unit an 18-month deferral from the performance standard in recognition of their early action. These units must be of similar sizes, have a common owner and be in the same province. CO_2 emissions that are released from the old unit for operating an additional 18 months are balanced by the requirement for the existing unit to capture at 30% for 5 years.

Other stakeholders have requested flexibility in the proposed Regulations to allow them to incorporate lessons learned from retrofitting their units with CCS into their decision making for retrofitting additional units in the future. The provision previously discussed that would allow old units to be eligible for a deferral if they incorporate technology for CCS would accommodate such requests.

16.3.2 Abuse of CCS provisions

The possibility of the CCS deferral provision being used as a way to avoid the performance standard was raised as an issue during consultations.

The Government shares this concern and has developed within the proposed Regulations stringent and regulated milestones to ensure that units that receive a CCS deferral are taking real steps to implement CCS and meet the performance standard.

Further, the proposed Regulations explicitly recognize the risk of abuse is greater for old units that receive a CCS deferral. As a result, these units will have to meet the same regulated milestones, but must do so sooner than new units.

17. Substitution of units

Certain stakeholders have inquired about the possibility of a "substitution" provision that would allow them to choose which unit they close down. Their rationale is that, for system efficiency reasons, they would prefer to shut down a newer unit, which is not yet subject to the proposed Regulations, instead of one of their older units.

The proposed Regulations include a provision whereby an existing unit can assume the performance standard obligation of an old unit so long as the units being substituted are of similar sizes (thus reducing emissions by an equivalent amount), have a common owner and are located in the same province. The exemption of the old unit will last until the date by which the existing unit would reach its own end of 45 years of useful life.

18. Petroleum coke (petcoke)

The proposal announced in June 2010 covers only units that burn coal. However, stakeholders have raised the issue that petcoke produces more GHG emissions and more sulphur dioxide emissions than does coal and switching from coal to petcoke could be used to circumvent the proposed Regulations.

The Government is of the perspective that allowing such a fuel switch would be accommodating a circumvention of the proposed Regulations, so it explicitly includes petcoke as a covered fuel within the proposed Regulations.

19. Standby units

Certain stakeholders argued that specific units are intended to operate as "standby" units in order to respond to exceptional circumstances where the supply of electricity may be compromised. To be available for that purpose, the units must run constantly at a low level.

Standby units will need to maintain operation at or below 7% of their capacity. The performance standard will come into force for standby units on January 1, 2020.

20. Other issues raised

20.1 Equivalency agreements

Some provinces have expressed their desire for equivalency agreements. Their rationale is that some provincial regulations will provide greater GHG reductions at lesser cost than the federal regulations.

Equivalency agreements with provinces, under which the federal regulations would stand down and the provincial regime would apply, could be established under CEPA 1999 if there is an enforceable provincial regime that would deliver an equivalent environmental outcome. This may be considered once the proposed Regulations are in force.

20.2 Development of a standard for natural gas electricity generating units

There has been virtual consensus among stakeholders that it would be desirable for the federal government to provide clarity regarding the regulatory requirements for new natural gas-fired units. Their argument is that the proposed coal-fired Regulations will likely spur the construction of new natural gas-fired units, adding to the effect of other drivers such as low natural gas prices; it would therefore be better to know sooner rather than later what expectations are regarding the performance of such units.

In response, the Government has indicated that the current focus of efforts is to develop the performance standard for coal-fired units.

20.3 Exclusion of CO_2 emissions from biomass

The exclusion of CO_2 emissions from biomass from the performance standard was raised as an issue during consultations.

The greenhouse gases accounting methodology for the national report inventory is based on the Intergovernmental Panel on Climate Change (IPCC) 2006 guidelines. Within these guidelines, CO_2 emissions from biomass combustion are not accounted for because they are assumed to be reabsorbed by vegetation during the next growing season. The proposed Regulations are consistent with the IPCC treatment of biomass combustion.

20.4 Impacts on natural gas and electricity prices

The proposed Regulations intend to result in increased electricity supply from low- and non-emitting generating sources, including additional generation from natural gas. In addition, as regulatees respond to the proposed Regulations, they may transfer costs to consumers in the form of higher electricity prices. Both of these issues were raised during consultations with user-group stakeholders.

With respect to natural gas, the proposed Regulations are expected to increase its demand in the electricity sector by 16%, which would account for less than 1% of the overall North American market.

The Government of Canada met with representatives from the chemicals, fertilizer and steel sectors to discuss the proposed Regulations. The key issues and concerns raised at these meetings and the Government’s response are summarized below.

20.4.1 Chemicals

- A significant portion of costs for inorganic chemical products companies is electricity, so higher electricity prices will have an impact.
- Natural gas is the number one feedstock for polyethanol, so there is a concern about the impact on natural gas prices.
- The change in the price of natural gas would impact the demand for natural gas (and where the supply is sold), which in turn could impact the opportunity to capture liquids.
- Co-generation is important to the petrochemical sector which needs processed steam. As generation switches to natural gas, coal is no longer an option for steam generation. The petrochemical sector needs co-generation or else it will switch to bunker fuels.

20.4.2 Fertilizers

- The use of natural gas is an important input for fertilizer manufacturing and it represents a large portion of costs on a cost-production basis.

- Any resulting increase in natural gas prices will be passed on to the fertilizer industry, which may not be able to pass it on to customers.
- The absolute natural gas prices are not what is important — the price in North America relative to those of other competitive areas of the world (Trinidad, South America, Russia, etc.) is.

In response to the issues raised by chemicals and fertilizers stakeholders and as previously mentioned, the study by Ziff Energy indicated that the impact of the proposed Regulations on natural gas prices would not be material, with an average yearly price impact of less than $0.01/MMBtu over the period considered. Therefore, the proposed Regulations are not expected to have a material impact on the competitiveness of these sectors.

20.4.3 Steel

The steel industry expressed some concerns regarding the impact of higher electricity prices on steel production, particularly the impact on the production of steel using arc furnaces.

The steel industry, like other large industrial users of electricity, tends to pay lower rates. In examining this issue, the Department apportioned the incremental costs from the proposed Regulations in proportion to a sector's share of total electricity costs. The degree to which they are affected also depends on their costs of electricity relative to other inputs. In the case of the steel industry, the cost increase was estimated to be 0.07% of total costs. This is a lower percentage than average, although the Department recognizes that it may still be an issue for certain steel producers.

21. Overall

Provisions developed within the proposed Regulations respond to concerns raised through the consultations, but are limited in availability and duration in order to emphasize their use as transitional measures, all the while maintaining environmental objectives and the stringency of the proposed Regulations.

These provisions

- maintain consistency of a national regulatory approach and the focus on emission reductions;
- treat regions and regulatees equitably;
- minimize stranded capital investments; and
- avoid setting an undesirable precedent for other sectors.

Implementation, enforcement and service standards

22. Implementation

The regulated community is small and well known and has already been extensively consulted in the development of the proposed Regulations, as well as in previous efforts to regulate greenhouse gases from this sector. As a result, there is a heightened awareness and interest in the forthcoming regulations on the part of the regulatees.

To meet the objectives of the proposed Regulations, compliance promotion activities targeting owners and operators of coal-fired electricity generators will be delivered to ensure a high level of compliance as early as possible during the regulatory implementation process.

Compliance promotion activities, before publication in the *Canada Gazette*, Part II, would include the mandatory 60-day comment period following the publication of the proposed Regulations in the *Canada Gazette*, Part I. This comment period and the time afterwards provide an opportunity for further clarification on regulatory structure and implementation.

In addition, the earliest some regulatees will be required to report under the proposed Regulations will be in 2013, where the requirement to comply with the performance standard will come into effect January 1, 2015. Compliance promotion activities will also be conducted before the coming into effect of these two requirements and as units become subject to the regulatory requirements based on their respective end of useful life date.

Regulatees will be required to submit a performance report with specified required information through an electronic reporting system. Environment Canada will monitor the GHG emission performance of electricity-generating units and compliance with the proposed Regulations. Early reporting provides an opportunity for targeted compliance promotion activities for regulatees who may not be submitting data as required, all of which is conducted before the compliance with the performance standard is required. Early reporting also assists Environment Canada in addressing any reporting or quantification concerns that may become apparent.

It should also be considered that the number of regulatees needing to comply with the performance standard and reporting requirements increases over time as these requirements are relative to the electricity-generating unit's age. This phasing in of regulatees also facilitates easier implementation of compliance promotion activities and monitoring of compliance.

In the situation where a unit is found to exceed applicable standards, the normal course of events would be to perform an engineering audit as part of an enforcement inspection to determine if a compliance order should be issued to the owners/operators of the unit.

23. Enforcement

The proposed Regulations are made under CEPA 1999. Therefore, enforcement officers will, when verifying compliance with the proposed Regulations, apply the Compliance and Enforcement Policy for CEPA 1999. (see footnote 44) This Policy sets out the range of possible responses to alleged violations, including warnings, directions, environmental protection compliance orders, ticketing, ministerial orders, injunctions, prosecution and environmental protection alternative measures (which are an alternative to a court prosecution after the laying of charges for a CEPA 1999 violation). In addition, the Policy explains when Environment Canada will resort to civil suits by the Crown for cost recovery.

To verify compliance, enforcement officers may carry out an inspection. An inspection may identify an alleged violation, and alleged violations may also be identified by Environment Canada's technical personnel, through information transmitted to the Department by the Canada Border Services Agency or through complaints received from the public. Whenever a possible violation of the proposed Regulations is identified, enforcement officers may carry out investigations.

When, following an inspection or an investigation, an enforcement officer discovers an alleged violation, the officer will choose the appropriate enforcement action based on the following factors:

- Nature of the alleged violation: This includes consideration of the damage, the intent of the alleged violator, whether it is a repeat violation, and whether an attempt has been made to conceal information or otherwise subvert the objectives and requirements of the Act;
- Effectiveness in achieving the desired result with the alleged violator: The desired result is compliance within the shortest possible time and with no further repetition of the violation. Factors to be considered include the violator's history of compliance with the Act, willingness to cooperate with enforcement officers, and evidence of corrective action already taken; and
- Consistency: Enforcement officers will consider how similar situations have been handled in determining the measures to be taken to enforce the Act.

23.1 Penalties

Under CEPA 1999, every person who commits an offence is liable (*a*) on conviction on indictment, to a fine of not more than $1,000,000 or to imprisonment for a term of not more than three years, or to both; and (*b*) on summary conviction, to a fine of not more than $300,000 or to imprisonment for a term of not more than six months, or to both.

Where an offence under CEPA 1999 is committed or continued on more than one day, the person who committed the offence is liable to be convicted for a separate offence for each day on which it is committed or continued.

24. Service standards

Service standards are being proposed with respect to the implementation of various compliance flexibility provisions. In particular, for regulatees using temporary compliance flexibility provisions (i.e. exceptional circumstances, stand-by status, swapping, temporary exemption for incorporating CCS or recognition for early deployment of CCS) there would be specific application and approval requirements, as well as additional reporting requirements with associated timelines.

The proposed Regulations will require annual reporting of energy and emissions but will not directly require any licensing, permitting or certification by the federal government. The use of certified measuring devices will be required but certification of such measuring devices lies outside of the proposed Regulations. In this context there will be no service standards issues.

Performance measurement and evaluation

The Performance Measurement and Evaluation Plan (PMEP) describes the desired outcomes of the proposed Regulations and establishes indicators to assess the performance of the proposed Regulations in achieving these outcomes. The PMEP package comprises three documents:

- the PMEP, which details the regulatory evaluation process;
- the logic model, which provides a simplified visual walkthrough of the regulatory evaluation process; and
- the table of indicators, which lists clear performance indicators and associated targets, where applicable, in order to track the progress of each outcome of the proposed Regulations.

The three documents complement each other and allow the reader to gain a clear understanding of the outcomes of the proposed Regulations, the performance indicators, as well as the evaluation process.

1. Outcomes

The PMEP details the suite of outcomes for each unit as they comply with the proposed Regulations. These outcomes include the following:

- Upon publication of the proposed Regulations, the regulated community will become aware of the proposed Regulations and meet the reporting requirements, when applicable (immediate outcome).
- Then, as the performance standard enters into force for a unit of a given vintage, the owner/operator of this unit will meet the performance standard, make use of time-limited flexibility mechanisms, invest in CCS technology, or retire the unit (intermediate outcome).
- In all cases, these cumulative actions will progressively contribute to the final outcomes and intended objective of the proposed Regulations: reducing GHG emissions from coal-fired generation, and decreasing the proportion of electricity generated by high-emitting coal-fired sources (final outcome).

As a key feature of the proposed Regulations, units will become subject to the performance standard requirements as well as to compliance and promotion activities gradually, depending on when they reach their respective end of useful life date. As a result, the outcomes, such as anticipated reductions in GHG emissions, will take place progressively and accumulate over time.

2. Performance indicators and evaluation

Clear, quantitative indicators and targets, where applicable, were defined for each outcome — immediate, intermediate, and final — and will be tracked on a yearly basis. In addition, a compilation assessment will be conducted every five years starting in 2020 to gauge the performance of every indicator against the identified targets. This regular review process will allow the Department to clearly detail the impact of the proposed Regulations on the coal-fired electricity generation sector as more and more units become subject to the regulatory requirements, and to evaluate the performance of the proposed Regulations in reaching the intended targets. The five-year compilation review also respects the expected capital stock turnover timelines for this industry.

These performance indicators are available in the table of indicators, and make direct references to the outcomes listed in the logic model.

Contacts

Caroline Blais
Director
Electricity and Combustion Division
Environment Canada
351 Saint-Joseph Boulevard
Gatineau, Quebec
K1A 0H3
Telephone: 819-994-6272
Fax: 819-994-9938
Email: caroline.blais@ec.gc.ca

Luis Leigh
Director
Regulatory Analysis and Valuation Division
Environment Canada
10 Wellington Street
Gatineau, Quebec
K1A 0H3
Telephone: 819-953-1170
Fax: 819-997-2769
Email: luis.leigh@ec.gc.ca

PROPOSED REGULATORY TEXT

Notice is hereby given, pursuant to subsection 332(1) (see footnote a) of the *Canadian Environmental Protection Act, 1999* (see footnote b), that the Governor in Council, pursuant to subsections 93(1) and 330(3.2) (see footnote c) of that Act, proposes to make the annexed *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations*.

Any person may, within 60 days after the date of publication of this notice, file with the Minister of the Environment comments with respect to the proposed Regulations or a notice of objection requesting that a board of review be established under section 333 of that Act and stating the reasons for the objection. All comments and notices must cite the *Canada Gazette*, Part I, and the date of publication of this notice, and be sent by mail to Caroline Blais, Director, Electricity and Combustion Division, Environmental Stewardship Branch, Department of the Environment, Gatineau, Quebec K1A 0H3, by fax to 819-994-9938 or by email to ecd-dec@ec.gc.ca.

Any person who provides information to the Minister of the Environment may submit with the information a request for confidentiality under section 313 of that Act.

Ottawa, June 23, 2011

JURICA ČAPKUN
Assistant Clerk of the Privy Council

TABLE OF CONTENTS

(This table is not part of the Regulations.)

REDUCTION OF CARBON DIOXIDE EMISSIONS FROM COAL-FIRED GENERATION OF ELECTRICITY REGULATIONS

SCHEDULE 2

SCHEDULE 3

SCHEDULE 4

SCHEDULE 5

PART 1

SOLID FUELS

PART 2

LIQUID FUELS

PART 3

GASEOUS FUELS

PART 4

LIST OF FUELS FOR THE PURPOSE OF SUBSECTION 23(2)

SCHEDULE 6

REDUCTION OF CARBON DIOXIDE EMISSIONS FROM COAL-FIRED GENERATION OF ELECTRICITY REGULATIONS

OVERVIEW

Purpose

1. (1) These Regulations establish a regime for the reduction of carbon dioxide (CO_2) emissions that result from the production of electricity by means of thermal energy using coal as a fuel, whether in conjunction with other fuels or not.

Contents

(2) These Regulations are divided into four Parts:

(*a*) Part 1 sets out a performance standard for the intensity of emissions of CO_2 from regulated units and provides for exceptions based on the substitution of units and for temporary exemptions in relation to emergencies and units integrated with carbon capture and storage systems;

(*b*) Part 2 sets out requirements for the reporting, sending and recording of information;

(*c*) Part 3 sets out quantification rules for determining the intensity of emissions of CO_2 from regulated units; and

(*d*) Part 4 provides dates for the coming into force of these Regulations and, in particular, provides for the delayed coming into force of the performance standard in respect of standby units until January 1, 2020.

INTERPRETATION

Definitions

2. (1) The following definitions apply in these Regulations.

“Act”
« *Loi* »

“Act” means the *Canadian Environmental Protection Act, 1999*.

“ASTM”
« *ASTM* »

“ASTM” means ASTM International, formerly known as the American Society for Testing and Materials.

“auditor”
« *vérificateur* »

“auditor” means a person who

(*a*) is independent of the responsible person who is to be audited;

(*b*) is certified as an auditor by a certification body accredited by the Standards Council of Canada; and

(*c*) has a good knowledge of continuous emission monitoring systems.

“authorized official”
« *agent autorisé* »

“authorized official” means

(*a*) in respect of a responsible person that is a corporation, an officer of the corporation who is authorized to act on its behalf;

(*b*) in respect of a responsible person who is an individual, that person or a person authorized to act on their behalf; and

(*c*) in respect of a responsible person that is another entity, a person authorized to act on its behalf.

“biomass”
« *biomasse* »

“biomass” means a fuel that consists only of plants or parts of plants, waste of animal origin, or any product made of either of those, and includes wood and wood products, agricultural residues and wastes, biologically derived organic matter found in municipal and industrial wastes, landfill gas, bio-alcohols, spent pulping liquor, sludge gas and animal- or plant-derived oils.

“calendar year”
« *année civile* »

“calendar year” means

(*a*) for 2015, the period of six consecutive months that begins on July 1, 2015; and

(*b*) in any other case, the period of twelve consecutive months that begins on January 1.

"capacity factor"
« *facteur de capacité* »

"capacity factor", in respect of a unit in a calendar year, means the ratio of the quantity of electricity referred to in section 18 that is produced by the unit to the quantity of electricity that would be produced by the unit in the calendar year if it were to operate at its production capacity at all times during the calendar year.

"coal"
« *charbon* »

"coal" includes petroleum coke and synthetic gas that is derived from coal or petroleum coke.

"commissioning date"
« *date de mise en service* »

"commissioning date" means

(*a*) for an electricity generator that began producing electricity by means of thermal energy using a fuel other than coal, and not in conjunction with coal, but, before June 23, 2010, was converted into a unit, the day that is 18 months after the day on which that generator began to produce electricity for sale using fuel other than coal, and not in conjunction with coal; and

(*b*) in any other case, the day on which a unit begins to produce electricity for sale.

"existing unit"
« *groupe existant* »

"existing unit" means a unit that is neither an old unit nor a new unit.

"facility"
« *centrale* »

"facility" means all units, buildings and other structures, and stationary equipment — including equipment for the separation and initial pressurization of CO_2 of the capture element of a carbon capture and storage system — either on a single site or on adjacent sites that function as a single, integrated site to enable the production of electricity.

"fossil fuel"
« *combustible fossile* »

"fossil fuel" means a fuel other than biomass.

"front end engineering design study"
« *étude d'ingénierie d'avant projet détaillé* »

"front end engineering design study" means a collection of studies that provide the necessary details to support the carrying out of a construction project for the capture element of a carbon capture and storage system, including

(*a*) technical drawings and documents that describe the capture element of the system in sufficient detail to permit the tendering of a contract for its construction;

(*b*) an estimation of the capital cost of that capture element with a margin of error of ± 20%;

(*c*) a safety review of that capture element;

(*d*) a risk assessment of the carbon capture and storage system, namely an assessment of the risks that may delay or prevent the completion of the construction of the system, including technical, economic, environmental, legal and labour-related risks;

(*e*) a strategy to mitigate those risks; and

(*f*) a detailed plan to carry out the construction of the carbon capture and storage system, including a schedule for the completion of its major steps.

"gasification system"
« *système de gazéification* »

"gasification system" includes a gasification system that is in part located underground.

"GPA"
« *GPA* »

"GPA" means the Gas Processors Association of the United States.

"operator"
« *exploitant* »

"operator" means the person that operates or has the charge, management or control of a unit.

"new unit"
« *groupe nouveau* »

"new unit" means a unit, other than an old unit, whose commissioning date is on or after July 1, 2015.

"major equipment"
« *équipement majeur* »

"major equipment" means a boiler, gasifier, shift reactor, turbine, air pollution control device, air separation unit, compressor, CO_2 separation system or any other equipment that

(*a*) is manufactured in accordance with specifications in its purchase order and takes more than 12 months after the date of the purchase order to be manufactured and delivered; or

(*b*) costs $10,000,000 or more.

"old unit"
« *groupe en fin de vie utile* »

"old unit" means a unit that has reached the end of its useful life but continues to produce electricity.

"power purchase agreement"
« *accord d'achat d'électricité* »

"power purchase agreement" means an agreement between the responsible person for a unit and a distributor of electricity in respect of the sale of the electricity produced by that unit to that distributor.

"production capacity"
« *capacité de production* »

"production capacity", in relation to a unit, means

(*a*) the maximum continuous rating, expressed in MW, as reported in a given calendar year to a competent provincial authority or an electric system operator in accordance with the laws of the province where the unit is located; or

(*b*) if no report has been made, the most electricity that was produced for sale, expressed in MW, during two continuous hours in that calendar year.

"Reference Method"
« *Méthode de référence* »

"Reference Method" means the document entitled *Reference Method for Source Testing: Quantification of Carbon Dioxide Releases by Continuous Emission Monitoring Systems from Thermal Power Generation* published in June 2011 by Her Majesty in right of Canada, as represented by the Minister of the Environment.

"responsible person"
« *personne responsable* »

"responsible person" means an owner or operator of a unit.

"standard cubic metre" or "standard m^3"
« *mètre cube normalisé* » *ou* « *m^3 normalisé* »

"standard cubic metre" or "standard m^3" has the meaning assigned to a cubic metre at standard pressure and standard temperature by the definition "standard volume" in subsection 2(1) of the *Electricity and Gas Inspection Regulations*.

"standby unit"
« *groupe de réserve* »

"standby unit" means an old unit that, for a given calendar year, operates at a capacity factor of 7% or less.

"unit"
« *groupe* »

"unit" means a unit comprised of equipment — including boilers and other combustion devices, generators, turbines and air pollution control devices — for the production of electricity by means of thermal energy using coal as a fuel, whether in conjunction with other fuels or not.

"useful life"
« *vie utile* »

"useful life", in respect of a unit, means the period that begins on the commissioning date and ends on the latest of

(*a*) December 31 of the calendar year that is 45 years after the commissioning date,

(*b*) subject to paragraph (*c*), if a power purchase agreement in relation to the unit was in force on June 23, 2010, the earlier of

(i) December 31, 2020, and

(ii) December 31 of the calendar year in which the power purchase agreement expires, and

(*c*) if the later of the dates described by paragraphs (*a*) and (*b*) is the date referred to in subparagraph (*b*)(ii) and that power purchase agreement expires on or before December 31, 2016, the earlier of

(i) December 31, 2016, and

(ii) December 31 of the calendar year that is three years after the calendar year in which that power purchase agreement expires.

Interpretation of incorporated documents

(2) For the purposes of interpreting documents incorporated by reference into these Regulations, "should" must be read to mean "must" and any recommendation or suggestion must be read as an obligation.

Standards incorporated by reference

(3) Any standard of the ASTM, GPA or International Standards Organization that is incorporated by reference into these Regulations is incorporated as amended from time to time.

PART 1

REGULATED UNITS AND EMISSION LIMIT

EMISSION-INTENSITY LIMIT

375t/GWh

3. (1) A responsible person for a new unit or an old unit must not, on average, emit with an intensity of more than 375 tonnes CO_2 emissions from the combustion of fossil fuels in the unit for each GWh of electricity produced by the unit during a calendar year.

Quantification of electricity and emissions

(2) The quantity of

(*a*) electricity referred to in subsection (1) is to be determined in accordance with section 18; and

(*b*) emissions referred to in subsection (1) is to be determined in accordance with the applicable provisions of sections 19 to 23.

CO_2 released from sorbent

(3) The CO_2 emissions released from the use of sorbent to control the emission of sulphur dioxide from a unit are to be included as CO_2 emissions from the combustion of fossil fuels in that unit for the purpose of subsection (1).

Coal gasification systems

(4) Emissions from a gasification system that produces synthetic gas derived from coal or petroleum coke that is used as a fuel to produce electricity from a unit referred to in subsection (1) are to be included as emissions from that unit for the purpose of subsection (1), if that coal gasification system has at least one responsible person in common with that unit.

CCS excluded

(5) The CO_2 emissions from a unit referred to in subsection (1) do not include emissions that

are captured in accordance with the laws of Canada or a province that regulate that capture and are transported and stored in accordance with the laws of Canada or a province, or the United States or one of its states, that regulate, as the case may be, that transportation or storage.

Partial year exemption

(6) For greater certainty, if a responsible person is exempted under subsection 6(4), 7(3) or 13(4) from the application of subsection (1) for a period during a calendar year, the average emission-intensity limit set out in that subsection applies for the remainder of that calendar year.

REGISTRATION

Registration

4. (1) A responsible person for a unit must register the unit by sending to the Minister a registration report that contains the information set out in Schedule 1

(*a*) for an existing unit and old unit, on or before February 1, 2013; and

(*b*) for a new unit, on or before 30 days after its commissioning date.

Registration number

(2) On receipt of the registration report, the Minister must assign a registration number to the unit and inform the responsible person of that registration number.

Change of information

(3) If the information provided in the registration report changes, the responsible person must send a notice to the Minister that provides the updated information not later than 30 days after the change.

SUBSTITUTION OF UNITS

Application of subsection 3(1)

5. (1) For the purpose of subsection 3(1), a responsible person for a unit that reaches the end of its useful life during a calendar year before 2020 may apply to the Minister to have another unit (referred to in this section as the “substituted unit”) substituted for the original unit if

(*a*) the substituted unit is an existing unit;

(*b*) the original unit and the substituted unit have a common owner who has an ownership interest of 50% or more in each of those two units;

(*c*) those two units are located in the same province; and

(*d*) the production capacity, during the calendar year before the calendar year in which the application is made, of the substituted unit was equal to or greater than the production capacity, during that calendar year, of the original unit.

Period of application

(2) The application must be made

(*a*) if the original unit is an old unit that has reached the end of its useful life in a calendar year before 2015, in the period of 2014 before June 1; and (*b*) if the original unit is an existing unit that will reach the end of its useful life during a calendar year before 2020, in the period of that calendar year before 2020 before June 1.

Content of application

(3) The application must include the registration number of the original unit and the substituted unit and information, with supporting documentation, to demonstrate that paragraphs (1)(*b*) to (*d*) are satisfied.

Granting of application

(4) The Minister must, within 30 days after receiving the application, grant the application if

(*a*) the substituted unit is not involved in an exemption granted under subsection 13 (4); and

(*b*) the Minister is satisfied that paragraphs (1)(*a*) to (*d*) are satisfied.

Effect

(5) The effect of the granting of the application is that subsection 3(1) applies in respect of the substituted unit rather than the original unit as of the later of

(*a*) the beginning of the calendar year after an application is made, and

(*b*) July 1, 2015.

Cessation of effect

(6) The substitution referred to in subsection (5) ceases to have effect, and subsection 3(1) applies in respect of the original unit, as of the earliest of

(*a*) the calendar year that begins after the day on which the responsible person for that unit and the substituted unit notifies the Minister that they wish that the granting of the application no longer have any effect,

(*b*) the calendar year that begins after the day on which paragraph (1)(*b*) is no longer satisfied,

(*c*) the calendar year that begins after a calendar year during which the production capacity of the original unit was more than the production capacity of the substituted unit referred to in paragraph (1)(*d*),

(*d*) the calendar year that begins after the end of the useful life of the substituted unit, and

(*e*) a calendar year during which the electricity produced by the substituted unit by means of thermal energy used fossil fuels without any use of coal as a fuel.

EMERGENCY CIRCUMSTANCES

Conditions for application

6. (1) A responsible person for a unit may, under emergency circumstances referred to in subsection (2), apply to the Minister for an exemption from the application of subsection 3(1) in respect of the unit, if

(*a*) as a result of the emergency circumstances, there is a disruption, or a significant risk of disruption, to the electricity supply in the province where the unit is located; and

(*b*) the operation of the unit will end, decrease the risk of, or mitigate the consequences of, the disruption.

Definition of emergency circumstances

(2) An emergency circumstance is a circumstance

(*a*) that arises due to an extraordinary, unforeseen and irresistible event; or

(*b*) under which one or more of the measures referred to in paragraph 1(*a*) of the *Regulations Prescribing Circumstances for Granting Waivers Pursuant to Section 147 of the Act* has been made or issued in the province where the unit is located.

Application

(3) The responsible person must, within 15 days after the emergency circumstance arises, provide the Minister with their application. The application must include the registration number of the unit and information, with supporting documentation, to demonstrate that paragraphs (1)(*a*) and (*b*) are satisfied.

Granting of exemption

(4) The Minister must, within 30 days of receipt of the application, grant the exemption if the Minister is satisfied that paragraphs (1)(*a*) and (*b*) are satisfied.

Period of exemption

(5) The exemption has effect as of the day on which the emergency circumstance began and ceases to have effect on the earliest of

(*a*) the day that is 90 days after that day,

(*b*) the day specified by the Minister, and

(*c*) the earlier of

(i) the day on which the event referred to in paragraph (2)(*a*) ceases to cause a disruption, or a significant risk of disruption, to the electricity supply in the province where the unit is located, and

(ii) the day on which the measure, if any, referred to in paragraph (2)(*b*) ceases to be in effect.

Extension

7. (1) If paragraphs 6(1)(*a*) and (*b*) will continue to apply on and after the day on which an exemption granted under subsection 6(4) is to cease to have effect, the responsible person may, before that day, apply to the Minister for an extension of the exemption.

Application

(2) The application must include the registration number of the unit and information, with supporting documentation, to demonstrate that

(*a*) paragraphs 6(1)(*a*) and (*b*) will continue to apply after the day on which the exemption is to cease to have effect; and (*b*) steps — other than the operation of the unit during the period of the exemption — have been, and are being, taken to end, decrease the risk of, or mitigate the consequences of, the disruption.

Granting of extension

(3) The Minister must, within 15 days after receiving the application, grant the extension if Minister is satisfied that paragraphs (2)(*a*) and (*b*).

Duration

(4) The extension ceases to have effect on the earliest of

(*a*) the day that is 90 days after the day on which the application for the extension was made,

(*b*) the day specified by the Minister, and

(*c*) the day referred to in paragraph 6(5)(*c*).

CARBON CAPTURE AND STORAGE

Temporary Exemption — System to be Constructed

Application

8. (1) A responsible person for a new unit or an old unit may apply to the Minister for a temporary exemption from the application of subsection 3(1) in respect of the unit if

(*a*) for a new unit, the unit is designed to permit its integration with a carbon capture and storage system; and

(*b*) for an old unit, the unit may be retrofitted to permit its integration with a carbon capture and storage system.

Granting and content of application

(2) The application must indicate the registration number of the unit and include the following supporting documents and information:

(*a*) a copy of the resolution of the board of directors of the owner of the new unit or old unit in question that approved of the construction of a carbon capture and storage system for the unit;

(*b*) a declaration that includes the following statements:

(i) that, based on the economic feasibility study referred to in paragraph (*c*), the unit, when operating with an integrated carbon capture and storage system is, to the best of the responsible person's knowledge and belief, economically viable, and

(ii) that, based on the technical feasibility study referred to in paragraph (*d*) and the implementation plan referred to in paragraph (*f*), the responsible person expects to satisfy the requirements referred to in section 9 and, as a result, to be in compliance with subsection 3(1) by January 1, 2025;

(*c*) an economic feasibility study that demonstrates the economic viability of the unit when it operates with an integrated carbon capture and storage system and that

(i) provides project cost estimates, with their margin of error, for the construction of the integrated carbon capture and storage system, and

(ii) identifies the source of financing for that construction;

(*d*) a technical feasibility study that establishes — based on information referred to in Schedule 2 related to the capture element, transportation element and storage element of the carbon capture and storage system — that there are no insurmountable technical barriers to carrying out the following activities:

(i) capturing a sufficient volume of CO_2 emissions from the combustion of fossil fuels in the unit to enable the responsible person to comply with subsection 3(1),

(ii) transporting the captured CO_2 emissions to suitable geological sites for storage, and

(iii) storing the captured CO_2 emissions in those suitable geological sites;

(*e*) a description of any work that has been done to satisfy the requirements referred to in section 9, along with the information referred to in Schedule 3 with respect to that work; and

(*f*) an implementation plan that provides a description of the work to be done, with a schedule for the steps necessary, to achieve the following objectives:

(i) satisfaction of the requirements referred to in section 9, and

(ii) compliance of the responsible person with subsection 3(1) by January 1, 2025 when the unit is operating with an integrated carbon capture and storage system that captures CO_2 emissions from the combustion of fossil fuels in the unit in accordance with the laws of Canada or a province that regulate that capture and transports and stores those emissions in accordance with the laws of Canada or a province, or the United States or one of its states, that regulate, as the case may be, that transportation or storage.

Granting of application

(3) The Minister must, within 120 days after receiving the application, grant the temporary exemption if

(*a*) the resolution referred to in paragraph (2)(*a*) unconditionally approves of the construction of a carbon capture and storage system for the unit;

(*b*) the application includes the documents referred to in subsection (2); and

(*c*) the information contained in those documents can reasonably be regarded as establishing that

(i) the operation of the unit, when integrated with the carbon capture and storage system, will be economically viable,

(ii) the capture, transportation and storage elements of the carbon capture and storage system will be technically feasible,

(iii) if applicable, a requirement referred to in section 9 has been satisfied by work done before the application was made, and

(iv) the responsible person will satisfy the requirements of section 9 and, as a result, will be in compliance with subsection 3(1) by January 1, 2025 when the unit is operating with an integrated carbon capture and storage system.

Duration

(4) A temporary exemption, unless revoked under section 12, remains in effect until December 31, 2024.

Requirements

9. A responsible person who has been granted a temporary exemption in respect of a unit under subsection 8(3) must satisfy the following requirements:

(*a*) carry out a front end engineering design study by

(i) in the case of a new unit, January 1, 2020, and

(ii) in the case of an old unit,

(A) July 1, 2016, if the end of its useful life occurred before July 1, 2015, and

(B) in any other case, the earlier of

(I) one year after the end of its useful life, and

(II) January 1, 2020;

(*b*) purchase any major equipment that is necessary for the capture element by

(i) in the case of a new unit, January 1, 2021, and

(ii) in the case of an old unit,

(A) July 1, 2017, if the end of its useful life occurred before July 1, 2015; and

(B) in any other case, the earlier of

(I) two years after the end of its useful life, and

(II) January 1, 2021;

(*c*) enter into any contract required for the transportation and storage of CO_2 emissions from the unit by

(i) in the case of a new unit, January 1, 2022, and

(ii) in the case of an old unit,

(A) July 1, 2018, if the end of its useful life occurred before July 1, 2015, and

(B) in any other case, the earlier of

(I) three years after the end of its useful life, and

(II) January 1, 2022;

(*d*) take all necessary steps to obtain all permits or approvals required in relation to the construction of the capture element by

(i) in the case of a new unit, January 1, 2022, and

(ii) in the case of an old unit,

(A) July 1, 2018, if the end of its useful life occurred before July 1, 2015, and

(B) in any other case, the earlier of

(I) three years after the end of its useful life, and

(II) January 1, 2022;

(*e*) in the case of an old unit, take all necessary steps to secure delivery of the major equipment referred to in paragraph (*b*) by

(i) July 1, 2019, if the end of its useful life occurred before July 1, 2015, and

(ii) in any other case, the earlier of

(A) four years after the end of its useful life, and

(B) January 1, 2023;

(*f*) ensure that the unit, when operating with an integrated carbon capture and storage system, captures CO_2 emissions from the combustion of fossil fuels in the unit in accordance with the laws of Canada or a province that regulate that capture and transports and stores those emissions in accordance with the laws of Canada or a province, or the United States or one of its states, that regulate, as the case may be, that transportation or storage by

(i) in the case of a new unit, January 1, 2024, and

(ii) in the case of an old unit,

(A) July 1, 2020, if the end of its useful life occurred before July 1, 2015, and

(B) in any other case, the earlier of

(I) five years after the end of its useful life, and

(II) January 1, 2024;

(*g*) in the case of an old unit that is operating with an integrated carbon capture and storage system, ensure that, during a calendar year, at least 30% of the CO_2 emissions from the combustion of fossil fuels in the unit are captured in accordance with the laws of Canada or a province that regulate that capture and are transported and stored accordance with the laws of Canada or a province, or the United States or one of its states, that regulate, as the case may be, that transportation or storage by

(i) July 1, 2021, if the end of its useful life occurred before July 1, 2015, and

(ii) in any other case, the earlier of

(A) six years after the end of its useful life, and

(B) January 1, 2024.

Implementation report

10. (1) A responsible person who has been granted a temporary exemption in respect of a unit must, for each calendar year following the granting of the temporary exemption, provide the Minister with an implementation report that indicates the unit’s registration number and includes supporting documents that contain the following information:

(*a*) the steps taken during that year to construct the capture, transportation and storage elements of the carbon capture and storage system and to integrate those elements with the unit;

(*b*) any requirement referred to in section 9 that was satisfied during that year, along with the information or documents referred to in Schedule 3;

(*c*) a description of the manner in which those steps were carried out or those requirements were satisfied;

(*d*) any changes, with respect to the most recently provided information to the Minister, to the proposed engineering design for the capture element, to the preferred transportation methods or routes or to the preferred storage sites, for the carbon capture and storage system; and

(*e*) a description of any steps necessary, with a schedule for those steps, to achieve the following objectives:

(i) the satisfaction of any requirements referred to in section 9 that remain to be satisfied, and

(ii) the compliance of the responsible person with subsection 3(1) by January 1, 2025 when the unit is operating with an integrated carbon capture and storage system that captures CO_2 emissions from the combustion of fossil fuels in the unit in accordance with laws of Canada or a province that regulate that capture and transports and stores those emissions in accordance with laws of Canada or a province, or the United States or one of its states, that regulate, as the case may be, that transportation or storage.

Due date

(2) The implementation report must be provided by March 31 of the calendar year that follows the calendar year in question.

Updated information

11. If any event occurs or any circumstance arises that may prejudice the ability of the responsible person to achieve an objective referred to in paragraph 10(1)(*e*), the responsible person must send a notice, without delay, to the Minister that indicates the unit's registration number and contains the following information:

(*a*) a description of the event or circumstance and the nature of the prejudice;

(*b*) an explanation of how the prejudice is to be overcome in order to ensure that the objective will be achieved; and

(*c*) in relation to that explanation, an update to any information previously provided to the Minister under paragraphs 10(1)(*c*) to (*e*), together with any necessary supporting documents.

Revocation — non-satisfaction or misleading

12. (1) The Minister must revoke a temporary exemption granted under subsection 8(3) if

(*a*) the responsible person does not satisfy a requirement referred to in section 9; or

(*b*) any information indicated or contained in the application for the temporary exemption, an implementation report referred to in section 10 or a notice referred to in section 11 is false or misleading.

Revocation — implementation report or reasonable grounds

(2) The Minister may revoke the temporary exemption if

(*a*) the responsible person has not provided an implementation report in accordance with section 10;

(*b*) there are reasonable grounds for the Minister to believe that the carbon capture and storage system will not operate so as to capture, transport and store CO_2 emissions as described in paragraph 9(*f*) by the date referred to in that paragraph; or

(*c*) there are reasonable grounds for the Minister to believe that the responsible person will not emit CO_2 from the combustion of fossil fuels in the unit in accordance with subsection 3(1) by January 1, 2025.

Reasons and representations

(3) The Minister must not revoke the temporary exemption under subsection (1) or (2) unless the Minister has provided the responsible person with

(*a*) written reasons for the proposed revocation; and

(*b*) an opportunity to be heard, by written representation, in respect of the proposed revocation.

Eighteen-month Exemption — Existing Unit with System

Exemption

13. (1) A responsible person for an old unit may, on application made to the Minister before September 1, 2021, be exempted from the application of subsection 3(1) in respect of the old unit for a period of 18 consecutive months that begins on January 1 of the calendar year subsequent to the calendar year in which the application is made if

(*a*) an existing unit and the old unit have a common owner who has a ownership interest of 50% or more in each of those two units;

(*b*) the production capacity of the existing unit, during the calendar year before the calendar year in which the application is made, was equal to or greater than the production capacity of the old unit during that calendar year;

(*c*) the existing unit and the old unit are located in the same province;

(*d*) the CO_2 emissions from the combustion of fossil fuels in the existing unit are captured in accordance with the laws of Canada or a province that regulate that capture and are transported and stored in accordance with the laws of Canada or a province, or the United States or one of its states, that regulate, as the case may be, that transportation or storage;

(*e*) at least 30% of those CO_2 emissions are captured, transported and stored in accordance with paragraph (*d*) for a period of five consecutive calendar years; and

(*f*) the existing unit does not reach the end of its useful life during that period.

Application

(2) A responsible person for an old unit must apply for the exemption before September 1 of the calendar year immediately before the calendar year for which the exemption is sought.

Contents

(3) The application must indicate the registration number of the old unit and of the existing unit and include supporting documents that contain information to demonstrate that

(*a*) paragraphs (1)(*a*) to (*d*) and (*f*) are satisfied; and

(*b*) for a period of six consecutive months that ends before the day on which the application is made, at least 30% of the CO_2 emissions from the combustion of fossil fuels in the existing unit were captured, transported and stored in accordance with paragraph (1)(*d*).

Grant

(4) The Minister must, within 30 days after receiving the application, grant the exemption if

(*a*) no exemption referred to in subsection (1) has been previously granted in respect of the old unit;

(*b*) no exemption referred to in subsection (1) that involved the existing unit has been previously granted;

(*c*) the existing unit referred to in subsection (1) is not a substituted unit referred to in subsection 5(5); and

(*d*) the Minister is satisfied that subsection (3) is satisfied.

Obligation to capture 30% of CO_2 emissions

(5) A responsible person who has been exempted under subsection (4) in respect of an existing unit must ensure that paragraphs (1)(*d*) and (*e*) are satisfied for the remaining portion of the period of five consecutive calendar years that begins on or before January 1 of the calendar year in which the application was made.

PART 2

REPORTING, SENDING AND RECORDING OF INFORMATION

Annual report

14. (1) For each calendar year, a responsible person for each of the following units must, on or before June 1 following the end of that calendar year, send an annual report to the Minister that contains the information set out in Schedule 4:

(*a*) a new unit;

(*b*) an old unit;

(*c*) a substituted unit referred to in subsection 5(1); and

(*d*) an existing unit referred to in subsection 13(1), if that calendar year is a calendar year included in the remaining portion of the five consecutive calendar years referred to in subsection 13(5).

Existing units

(2) The responsible person for an existing unit must send a report in accordance with subsection (1) for the calendar year in which its useful life is to end and for the preceding calendar year.

Electronic report, notice and application

15. (1) A report or notice that is required, or an application made, under these Regulations must be sent electronically in the form and format specified by the Minister and must bear the electronic signature of an authorized official of the responsible person.

Paper report or notice

(2) If the Minister has not specified an electronic form and format or if it is impractical to send the report, notice or application electronically in accordance with subsection (1) because of circumstances beyond the person's control, the report, notice or application must be sent on paper, signed by an authorized official of the responsible person, and in the form and format specified by the Minister. However, if no form and format have been so specified, it may be in any form and format.

Record-making

16. (1) A responsible person for a unit must make a record

(*a*) of any application referred to in subsections 5(3), 6(3), 7(2), 8(2) or 13(3), including the information referred to in those subsections, along with a copy of the supporting documents;

(*b*) of any notice referred to in section 11 that was sent to the Minister, along with a copy of the information that was contained in it and any supporting documents;

(*c*) for each calendar year during which a responsible person used a continuous emission monitoring system referred to in paragraph 19(1)(*a*), of any document, record or information referred to in section 8 of the Reference Method;

(*d*) of the results of the analysis of every sample collected in accordance with section 26;

(*e*) of every measurement and calculation used to determine a value of an element of a formula set out in section 18 and sections 20 to 23;

(*f*) that demonstrates that the installation, maintenance and calibration of measuring instruments referred to in subsection 24(1) was in accordance with that subsection and subsection 24(3) and of every calibration referred to in subsection 24(2); and

(*g*) that demonstrates that any meter referred to in section 18 complies with the requirements of the *Electricity and Gas Inspection Act* and the *Electricity and Gas Inspection Regulations*, including a certificate of inspection or verification referred to in those regulations.

When records made

(2) Records referred to in paragraphs (1)(*c*) to (*g*) must be made as soon as feasible but not later than 15 days after the information to be recorded becomes available.

Retention of records and reports

17. A responsible person who is required under these Regulations to make a record or send a report must keep the record or a copy of the report, as well as any supporting documents that relate to the information contained in that record or copy, for at least seven years after they make the record or send the report. The record or copy must be kept at the person's principal place of business in Canada or at any other place in Canada where it can be inspected. If the record or copy is kept at one of those other places, the person must provide the Minister with the civic address of that other place.

PART 3

QUANTIFICATION RULES

PRODUCTION OF ELECTRICITY

Electricity

18. (1) The quantity of electricity referred to in paragraph 3(2)(*a*) is to be determined in accordance with the following formula

$$G_{gross} - G_{aux}$$

where

G_{gross} is the gross quantity of electricity that is produced by the unit during the calendar year, expressed in GWh and measured at the electrical terminals of the generators of the unit using meters that comply with the requirements of the *Electricity and Gas Inspection Act* and the *Electricity and Gas Inspection Regulations*;

G_{aux} is the quantity of electricity — that is used by the facility in which the unit is located during the calendar year to operate infrastructure and equipment and that is related to the unit for electricity generation and for separation, but not pressurization, of CO_2 — expressed in GWh and determined under a method of attribution considered by the responsible person to be most appropriate, based on data collected using meters that comply with the requirements of the *Electricity and Gas Inspection Act* and the *Electricity and Gas Inspection Regulations*.

Same method of attribution in subsequent years

(2) Once the responsible person has, for a calendar year, decided on the method of attribution referred to in the description of G_{aux} that they consider to be most appropriate, they must use that method for every subsequent calendar year, unless

(*a*) during a subsequent calendar year, a unit located at the facility ceases to produce electricity or a new unit is added to those located at the facility; or

(*b*) during a subsequent calendar year, the operation of any unit located at the facility is integrated with a carbon capture and storage system.

Change of method of attribution

(3) If paragraph (2)(*a*) or (*b*) applies in a subsequent calendar year, the responsible person must — when making the determination referred to in the description of G_{aux} in subsection (1) for that subsequent calendar year — use the method that they consider most appropriate under the circumstances described in that paragraph. Subsection (2) applies in respect of that method of attribution and that subsequent calendar year as if they were, respectively, the method of attribution and the calendar year referred to in that subsection.

CO_2 EMISSIONS

Quantification Methods

CEMS or fuel-based methods

19. (1) For the purposes of sections 3 and 14, the quantity of CO_2 emissions from the combustion of fossil fuels in a unit for a calendar year is to be determined

(*a*) by using a continuous emission monitoring system (CEMS) in accordance with section 20; or

(*b*) by using a fuel-based method, based on the quantity of carbon in the fossil fuel fed for combustion, in accordance with section 21 and section 22 or 23.

Emissions from coal gasification systems

(2) If a coal gasification system referred to in subsection 3(4) is used to produce fuel for a unit, the quantity of emissions from the unit referred to in subsection (1) must be determined in accordance with paragraph (1)(*a*). To the extent that the emissions from the coal gasification system are not captured, transported and stored as described in subsection 3(5), that quantity must be determined for the purpose of subsection 3(1) by using a direct measure of the flow of, and concentration of CO_2 in, those emissions.

Continuous Emissions Monitoring System

Quantification

20. (1) If paragraph 19(1)(*a*) applies, the quantity of CO_2 emissions referred to in subsection 19(1) is to be determined in accordance with the following formula:

$$E_u - E_{bio} + E_{non\text{-}ccs}$$

where

E_u is the quantity of CO_2 emissions, expressed in tonnes, from the unit, "u", during the calendar year from the combustion of fuel, as measured by the CEMS in accordance with sections 7.1 to 7.7 of the Reference Method;

E_{bio} is the quantity of CO_2 emissions, expres sed in tonnes, from the combustion of biomass in the unit during the calendar year, determined

(*a*) by using a fuel-based method

(i) in accordance with paragraphs 23(1)(*a*) or (*b*), if the unit combusts solid biomass at an average daily rate of less than 3t/day during the given calendar year, and

(ii) in accordance with the applicable formula set out in paragraphs 22(*a*) to (*c*) for the type of biomass combusted, in any other case, or

(*b*) by using the method, based on data from the CEMS, described in subsection (2); and

$E_{non\text{-}ccs}$ is the quantity of CO_2 emissions, expressed in tonnes, from the combustion of fuel in the unit, including those emissions referred to in subsection 3(4), during the calendar year — other than the quantity of those emissions as measured by the CEMS and described by E_u — that is determined using a direct measurement of the flow of, and concentration of CO_2 in, the emissions from that combustion of fuel but that are not ultimately captured, transported and stored as described in subsection 3(5).

E_{bio} based on CEMS data

(2) For the purpose of determining the value of E_{bio}, the method, based on data from the CEMS, consists of making the following sequence of determinations:

(*a*) determine the volume of CO_2 emitted from combustion of fuel in the unit for each hour of production of electricity during the calendar year in accordance with the following formula:

$$0.01 \times \%CO_{2w,h} \times Q_{w,h} \times t_h$$

where

$\%C0_{2w,h}$ is the average concentration of CO_2 in relation to all gases in the stack emitted from the combustion of fuel in the unit during a given hour, "h", during which the unit produced electricity in the calendar year — or, if applicable, a calculation made in accordance with section 7.4 of the Reference Method of that average concentration of CO_2 based on a measurement of the concentration of oxygen (O_2) in relation to all those gases — expressed as a percentage on a wet basis,

$Q_{w,h}$ is the average volumetric flow during that hour, measured on a wet basis by the stack gas volumetric flow monitor, expressed in standard m^3,

t_h is the period during which the unit produced electricity, expressed in hours to two decimal places, the digit at the second decimal place being increased by one if the digit at the third decimal place is 5 or more;

(*b*) determine the volume of CO_2 emitted from combustion of fossil fuel in the unit during the calendar year, expressed in standard m^3 and referred to in this subsection as V_{ff}, in accordance with the following formula:

$$\sum_{i=1}^{n} Q_i \times F_{c,i} \times HHV_{d,i}$$

where

Q_i is the quantity of fossil fuel type "i" combusted in the unit during the calendar year, determined

(*a*) for solid fuels, in the same manner as used in the determination of M_f in the formula set out in paragraph 22(1)(*a*) and expressed in tonnes,

(*b*) for liquid fuels, in the same manner as used in the determination of V_f in the formula set out in paragraph 22(1)(*b*) and expressed in kL, and

(*c*) for gaseous fuels, in the same manner as used in the determination of V_f in the formula set out in paragraph 22(1)(*c*) and expressed in standard m^3;

i is the i^{th} fossil fuel type combusted in the unit during the calendar year, with "i" going from the number 1 to n, where n is the number of fossil fuels so combusted,

$F_{c,i}$ is the fuel-specific carbon based F-factor for each fossil fuel type "i" — as the case may be, the default value as set out in column 3 of the Table to subsection (3) for each fuel type set out in column 2 of that Table or as determined for that fuel type in accordance with Appendix A of the Reference Method — expressed in standard m^3 of CO_2/GJ,

$HHV_{d,i}$ — expressed in GJ/tonne, for a solid fuel, in GJ/kL, for a liquid fuel, and in GJ/standard m^3, for a gaseous fuel — is (*a*) the default higher heating value listed in column 2 of Schedule 5 for the fossil fuel type "i" listed in column 1 of that Schedule, and

(*b*) in the absence of that default higher heating value, a default higher heating value for that fossil fuel type "i" established by a body that is internationally recognized as competent to establish default higher heating values for fuels;

(*c*) determine the volume of CO_2 emitted from the combustion of biomass in the unit during the calendar year, expressed in standard m^3 and referred to in this subsection as V_{bio}, in accordance with the following formula:

$$V_T - V_{ff}$$

where

V_T is the sum of the volumes of CO_2 emitted from combustion of fuel in the unit during each hour of production of electricity during the calendar year, as determined under paragraph (*a*), and

V_{ff} is the element determined in accordance with the formula set out in paragraph (*b*); and

(*d*) determine the quantity of the CO_2 emissions from the combustion of biomass in the unit during the calendar year, namely the element E_{bio} described in the formula set out in subsection (1), by making the following two determinations:

(i) determine the fraction of the volume of CO_2 emissions from all fuel combusted in the unit attributable to the combustion of biomass in the unit during the calendar year, referred to in this section as Bio_{fr}, in accordance with the following formula:

$$\frac{V_{bio}}{V_T}$$

where

V_{bio} is the volume of CO_2 emitted from the combustion of biomass in the unit during the calendar year determined in accordance with the formula set out in paragraph (*c*),

V_T is the value of V_T determined in ac-cordance with the formula set out in paragraph (*c*), and

(ii) determine the quantity of CO_2 emissions namely E_{bio} in accordance with the following formula:

$$(Bio_{fr} \times E_u) - E_s$$

where

Bio_{fr} is the fraction of the volume of CO_2 emissions from all fuel combusted in the unit attributable to the combustion of biomass in the unit during the calendar year determined in accordance with the formula set out in subparagraph (i),

E_u is the value for E_u determined in accordance with the formula set out in subsection (1), and

E_s is the quantity of CO_2 emissions, expressed in tonnes, measured by the CEMS that is released from the use of sorbent to control the emission of sulphur dioxide from the unit during the calendar year, determined in accordance with the following formula:

$$S \times R \times \frac{44}{MW_s}$$

where

S is the quantity of calcium carbonate ($CaCO_3$) or other sorbent material so used, expressed in tonnes,

R is the stoichiometric ratio, on a mole fraction basis, of CO_2 released on usage of one mole of sorbent material, where R=1 if the sorbent material is $CaCO_3$, and

MW_s is the molecular weight of the sorbent material, expressed in grams, where MW_s = 100 g if the sorbent material is $CaCO_3$.

Default F-factor

(3) The default value for the fuel-specific carbon based F-factor for certain types of fossil fuel is set out in column 3 of the following table:

TABLE

	Column 1	Column 2	Column 3
Item	Fossil fuel	Type	F-factor (standard m^3/GJ)
1.	Coal	Anthracite	54.2
		Bituminous	49.2
		Sub-bituminous	49.2
		Lignite	53.0
2.	Oil	Crude, residual or distillate	39.3
3.	Gas	Natural	28.4
		Propane	32.5

Disaggregation

(4) Despite subsection (1), if there is one or more other units at a facility where a unit is located and a CEMS measures emissions from that unit and some of those other units at a common stack rather than at the exhaust duct of that unit and of each of those other units that brings those emissions to the common stack, then the quantity of emissions attributable to that unit for the purpose of subsection (1) is determined based on the ratio of the heat input of that unit to the heat input of that unit and all of those other units sharing the common stack in accordance with the following formula:

$$\left[\frac{\sum_{j=1}^{n} Q_{uj} \times HHV_{uj}}{\sum_{i=1}^{n} \sum_{j=1}^{n} Q_{ij} \times HHV_{ij}} \right] \times E$$

where

Q_{uj} is the quantity of fuel type "j" combusted in that unit "u" during the calendar year, determined

(*a*) for a solid fuel, in the same manner used in the determination of M_f in the formula set out in paragraph 22(1)(*a*) and expressed in tonnes,

(*b*) for a liquid fuel, in the same manner used in the determination of V_f in the formula set out in paragraph 22(1)(*b*) and expressed in kL, and

(*c*) for a gaseous fuel, in the same manner used in the determination of V_f in the formula set out in paragraph 22(1)(*c*) and expressed in standard m^3;

HHV_{uj} is the higher heating value, determined in accordance with section 23 and expressed in the applicable unit of measure referred to in that section of fuel type "j" combusted during the calendar year in that unit "u";

i is the i^{th} unit located at the facility with "i" going from the number 1 to n, where n is the number of units that share a common stack;

j is the j^{th} fuel type, including types of biomass, combusted during the calendar year in a unit located at the facility with "j" going from the number 1 to m, where m is the number of those fuel types;

Q_{ij} is the quantity of fuel type "j" combusted in each unit "i" during the calendar year, determined for a solid fuel, a liquid fuel and a gaseous fuel, respectively, in the manner described in Q_{uj};

HHV_{ij} is the higher heating value, determined in accordance with section 23 and expressed in the applicable unit of measure referred to in that section, of fuel type "j" combusted during the calendar year in unit "i"; and

E is the quantity of CO_2 emissions, expressed in tonnes, from the combustion of fuels in all the units during the calendar year, measured by a CEMS at the common stack in accordance with subsection 20(1).

Fuel-based Methods

Determination

21. If paragraph 19(1)(*b*) applies, the quantity of CO_2 emissions referred to subsection 19(1) is to be determined by the following formula:

$$\sum_{i=1}^{n} E_i \times E_s - E_{ccs}$$

where

E_i is the quantity of CO_2 emissions attributable to the combustion of fossil fuel "i" in the unit during the calendar year, expressed in tonnes, determined in accordance with section 22 or 23;

i is the i^{th} type of fossil fuel combusted in the unit during the calendar year, with "i" going from the number 1 to n, where n is the number of types of fossil fuel so combusted;

E_s is E_s in the formula set out in subparagraph 20(2)(*d*)(ii); and

E_{ccs} is the quantity of CO_2 in those emissions, expressed in tonnes, from the combustion of fuel in the unit, during the calendar year, that are captured in accordance with the laws of Canada or a province that regulate that capture and are transported and stored in accordance with the laws of Canada or a province, or the United States or one of its states, that regulate, as the case may be, that transportation or storage, which quantity is determined using a direct measurement of the flow of, and concentration of CO_2 in, those emissions.

Measured carbon content

22. (1) Subject to section 23, the quantity of CO_2 emissions attributable to the combustion of a fuel in a unit during a calendar year, expressed in tonnes, is determined in accordance with the applicable formula, as follows:

(*a*) for a solid fuel

$$M_f \times CC_A \times 3.664$$

where

M_f is the mass of the fuel combusted during the calendar year as determined, as the case may be, on a wet or dry basis, expressed in tonnes and measured by a measuring device, and

CC_A is the weighted average, expressed in kg of carbon per kg of the fuel, of the carbon content of the fuel determined in accordance with subsection (2) on the same wet or dry basis as used in the determination of M_f;

(*b*) for a liquid fuel

$$V_f \times CC_A \times 3.664$$

where

V_f is the volume of the fuel combusted during the calendar year, expressed in kL, determined by using flow meters, and

CC_A is the weighted average, expressed in tonnes of carbon per kL of the fuel, of the carbon content of the fuel determined in accordance with subsection (2) at the same temperature as used in the determination of V_f; and

(*c*) for a gaseous fuel

$$V_f \times CC_A \times \frac{MM_A}{MV_{cf}} \times 3.664 \times 0.001$$

where

V_f is the volume of the fuel combusted during the calendar year, expressed in standard m^3, determined by using flow meters,

CC_A is the weighted average, expressed in kg of carbon per kg of the fuel, of the carbon content of the fuel determined in accordance with subsection (2),

MM_A is the average molecular mass of the fuel, expressed in kg per kg-mole of the fuel, determined based on fuel samples collected in accordance with section 26, and

MV_{cf} is the molar volume conversion factor, namely 23.645 standard m^3 per kg-mole of the fuel at standard conditions of 15°C and 101.325 kPa.

Weighted average

(2) The weighted average, CC_A referred to in paragraphs (1)(*a*) to (*c*) is, based on fuel samples collected in accordance with section 26, determined in accordance with the following formula:

$$\frac{\sum_{i=1}^{n} CC_i \times Q_i}{\sum_{i=1}^{n} Q_i}$$

where

CC_i is the carbon content of, as the case may be, the composite sample, or the sample, of the fuel for the i^{th} sampling period expressed for solid fuels, liquid fuels and gaseous fuels, respectively, in the same unit of measure as set out in CC_A, as provided to the responsible person by the supplier of the fuel or determined by the responsible person, and measured

(*a*) for a solid fuel that is

(i) coal, biomass or derived from waste, in accordance with ASTM D5373-08, entitled *Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal*, and

(ii) any other solid fuel, in accordance with an applicable ASTM standard for the measurement of the carbon content of the fuel;

(*b*) for a liquid fuel, in accordance with any of the following ASTM standards that applies for the measurement of the carbon content of the fuel:

(i) ASTM D3238-95 (2005), entitled *Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method* and along with either of the following applicable ASTM standards:

(A) ASTM D2503-92 (2007), entitled *Standard Test Method for Relative Molecular Mass (Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure*, and

(B) ASTM D2502-04 (2009), entitled *Standard Test Method for Estimation of Molecular Weight (Relative Molecular Mass) of Petroleum Oils From Viscosity Measurements*, and

(ii) ASTM D5291-10, entitled *Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants*; and (*c*) for a gaseous fuel, in accordance with

(i) either of the following ASTM standards that applies for the measurement of the carbon content of the fuel:

(A) ASTM D1945-03 (2010), entitled *Standard Test Method for Analysis of Natural Gas by Gas Chromatography*, and

(B) ASTM D1946-90 (2006), entitled *Standard Practice for Analysis of Reformed Gas by Gas Chromatography*, or

(ii) by means of a direct measuring device that determines the carbon content of the fuel;

i is the i^{th} sampling period referred to in section 26, with "i" going from the number 1 to n, where n is the number of those sampling periods; and

Q_i is the mass or volume, as the case may be, of the fuel combusted during the i^{th} sampling period expressed

(*a*) for a solid fuel, in tonnes,

(*b*) for a liquid fuel, in kL, and

(*c*) for a gaseous fuel, in standard m^3.

Quantification based on HHV

23. (1) For an eligible fuel referred to in subsection (2), the quantity of CO_2 emissions attributable to the combustion of the fuel in a unit during a calendar year, expressed in tonnes, may be determined in accordance with subsection (4) based on the following higher heating value of the fuel:

(*a*) the higher heating value of the fuel that is measured in accordance with subsection (6) as provided by the supplier of the fuel to the responsible person and, if not so provided, as so measured by the responsible person; and

(*b*) in the absence of a measured higher heating value referred to in paragraph (*a*), the default higher heating value, listed in column 2 of Schedule 5, of the fuel, as listed in column 1 and, in the absence of that default higher heating value, a default higher heating value for that fuel established by a body that is internationally recognized as competent to establish default higher heating values for fuels.

Eligible fuel

(2) Eligible fuels are

(*a*) a fuel combusted in a unit in respect of which an exemption from the application of subsection 3(1) has been granted under subsection 6(4);

(*b*) a fuel referred to in section 22 that is combusted during the calendar year at less than any of the average daily rates referred to in subsection (3);

(*c*) a fuel listed in Part 4 of Schedule 5; and

(*d*) a fuel combusted in a standby unit.

Average daily rates

(3) The average daily rates are

(*a*) for a solid fuel, 3 t/day;

(*b*) for a liquid fuel, 1900 L/day; and

(*c*) for a gaseous fuel, 500 standard m^3/day.

Quantity of emissions

(4) The quantity of emissions is to be determined in accordance with the following formula:

$$Q \times HHV \times EF \times 0.001$$

where

Q is the quantity of the fuel combusted in the unit during the calendar year determined

(*a*) for a solid fuel, in the same manner as used in the determination of M_f in the formula set out in paragraph 22(1)(*a*) and expressed in tonnes,

(*b*) for a liquid fuel, in the same manner as used in the determination of V_f in the formula set out in paragraph 22(1)(*b*) and expressed in kL, and

(*c*) for a gaseous fuel, in the same manner as used in the determination of the element V_f in the formula set out in paragraph 22(1)(*c*) and expressed in standard m^3;

HHV — expressed in GJ/tonne, for a solid fuel, in GJ/kL, for a liquid fuel, and in GJ/standard m^3, for a gaseous fuel — is

(*a*) if paragraph (1)(*a*) applies, the weighted average of the higher heating value of the fuel, determined in accordance with subsection (5), based on fuel samples collected in accordance with section 26, and

(*b*) if paragraph (1)(*b*) applies, the default higher heating value set out in column 2 of Schedule 5 for the fuel, as listed in column 1 and, in the absence of that default higher heating value, a default higher heating value for that fuel established by a body that is internationally recognized as competent to establish default higher heating values for fuels;

EF is the default emission factor, set out in column 3 of Schedule 5, for that fuel listed in column 1 and, in the absence of that default emission factor, a default emission factor for that fuel established by a body that is internationally recognized as competent to establish default emission factors for fuels.

Weighted average

(5) The weighted average higher heating value of the fuel is determined in accordance with the following formula:

$$\frac{\sum_{i=1}^{n} HHV_i \times Q_i}{\sum_{i=1}^{n} Q_i}$$

where

HHV_i is the higher heating value of, as the case may be, each composite sample, or sample, of the fuel for the i^{th} sampling period measured in accordance with subsection (6) as provided by the supplier of the fuel to the responsible person and, if not so provided, as so measured by the responsible person;

i is the i^{th} sampling period referred to in section 26, with "i" going from the number 1 to "n", where n is the number of those sampling periods; and

Q_i is the mass or volume, as the case may be, of the fuel combusted during the i^{th} sampling period, expressed

(*a*) for a solid fuel, in the same manner as used in the determination of M_f in the formula set out in paragraph 22(1)(*a*) and expressed in tonnes,

(*b*) for a liquid fuel, in the same manner as used in the determination of V_f in the formula set out in paragraph 22(1)(*b*) and expressed in kL, and

(*c*) for a gaseous fuel, in the same manner as used in the determination of V_f in the formula set out in paragraph 22(1)(*c*) and expressed in standard m^3.

Measurement of HHV

(6) The higher heating value of a fuel is to be measured

(*a*) for a solid fuel that is

(i) coal or biomass, in accordance with ASTM D5865-10a, entitled *Standard Test Method for Gross Calorific Value of Coal and Coke*,

(ii) derived from waste, in accordance with either ASTM D5865-10a or ASTM D5468-02 (2007), entitled *Standard Test Method for Gross Calorific and Ash Value of Waste Materials*, and

(iii) any other solid fuel, an applicable ASTM standard for the measurement of the higher heating value of the fuel;

(*b*) for a liquid fuel that is

(i) a middle distillate, an oil or a liquid fuel derived from waste, in accordance with

(A) ASTM D240-09, entitled *Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter*, or

(B) ASTM D4809-09a, entitled *Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method)*, and

(ii) any other liquid fuel, an applicable ASTM standard for the measurement of the higher heating value of the fuel; and

(*c*) for a gaseous fuel,

(i) in accordance with any of the following applicable ASTM or GPA standards:

(A) ASTM D1826-94 (2010), entitled *Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by*

Continuous Recording Calorimeter,

(B) ASTM D3588-98 (2003), entitled *Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels*,

(C) ASTM D4891-89 (2006), entitled *Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion*,

(D) GPA Standard 2172-09, entitled *Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer*, and

(E) GPA standard 2261-00, entitled *Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography*, or

(ii) by means of a direct measuring device that determines the higher heating value of the fuel, but if the measuring device provides only lower heating values, those lower heating values must be converted to the corresponding higher heating values.

ACCURACY OF DATA

Measuring devices other than CEMS

24. (1) A responsible person for a unit must install, maintain and calibrate any measuring instrument, other than a CEMS referred to in paragraph 19(1)(*a*), used for the purpose of section 3 or 14 in accordance with the manufacturer's instructions or any applicable generally recognised national or international industry standard.

Frequency of calibration

(2) The responsible person must calibrate every measuring device referred to in subsection (1) at the greater of the following two frequencies:

(*a*) at least once in every calendar year but at least five months after a previous calibration, and

(*b*) the frequency recommended by the manufacturer.

Accuracy of measurements

(3) Any measuring device referred to in subsection (1) must enable measurements to be made with a margin of error of ± 5%.

CEMS

25. (1) A CEMS referred to in paragraph 19(1)(*a*) that is used by a responsible person for the purpose of section 3 or 14 must comply with the Reference Method.

Certification

(2) Before a CEMS referred to in paragraph 19(1)(*a*) is used for the purpose of that paragraph, it must be certified by the responsible person in accordance with section 5 of the Reference Method.

Annual audit

(3) For each calendar year during which a responsible person uses a CEMS referred to in paragraph 19(1)(*a*), the auditor must

(*a*) assess, based on the review referred to in section 6.5.2 of the Reference Method, whether, in the auditor's opinion, the responsible person's use of the CEMS complied with the Quality Assurance/Quality Control manual referred to in section 6 of the Reference Method;

(*b*) ensure that the Quality Assurance/Quality Control manual has been updated in accordance with section 6.5.2 of the Reference Method; and

(*c*) assess whether, in the auditor's opinion, the CEMS has met the specifications set out in the Reference Method, in particular, in its sections 3 and 4.

Auditor's report

(4) The responsible person must obtain a report, signed by the auditor, in respect of the audit that contains the information set out in Schedule 6. They must send the auditor's report to the Minister with their annual report referred to in subsection 14(1).

FUEL SAMPLING AND TESTING REQUIREMENTS

Fuel sampling

26. (1) The determination of the value for the elements related to carbon content and higher heating values referred to in sections 20 to 23 must be based on fuel samples taken in accordance with this section.

Frequency

(2) Each fuel sample must be taken at a time and location in the fuel handling system that provides the following representative sample of the fuel combusted at the following minimum frequency:

(*a*) for coal other than synthetic gas derived from coal or derived from petroleum coke, one composite sample during each week that the unit produces electricity prepared in accordance with ASTM D2013 / D2013M-09, entitled *Standard Practice for Preparing Coal Samples for Analysis*, that consists of sub-samples taken at least twice from coal that was fed for combustion during that week and at least 48 hours apart, in accordance with

(i) ASTM D2234/D2234M-10, entitled *Standard Practice for Collection of a Gross Sample of Coal*, or

(ii) ASTM D7430-10b, entitled *Standard Practice for Mechanical Sampling of Coal*;

(*b*) for a type of solid fuel other than coal, one composite sample per month that consists of sub-samples of the fuel of that type, each of which has the same mass, that were taken — from fuel that was fed for combustion during each week that begins in that month and during which the unit produces electricity — at least 48 hours after any previous sub-sample and after all fuel treatment operations have been carried out but before any mixing of the fuel from which the sub-sample is taken with other fuels;

(*c*) for a type of liquid fuel and of a gaseous fuel other than natural gas, one sample per quarter with each sample of fuel of that type taken at least one month after any previous sample was taken; and

(*d*) for natural gas, two samples per calendar year with each sample taken at least four months after any previous sample was taken.

Additional samples

(3) For greater certainty, the responsible person who takes, for the purpose of these Regulations, more samples than the minimum required under subsection (2) must make the determination referred to in subsection (1) based on each sample — and, in the case of composite samples, each sub-sample — taken, including those additional samples.

Missing Data

27. (1) If, for any reason out of the control of a responsible person, the emission-intensity referred to in subsection 3(1) cannot be determined in accordance with the formulae set out in section 18 or any of sections 20 to 23 because data required to determine an element of one of those formulae was not obtained for a given period within the calendar year, replacement data for that given period must be used in accordance with this section to determine that emission-intensity.

Replacement data — CEMS

(2) If a CEMS referred to in paragraph 19(1)(*a*) is used for the determination of an element of a formula set out on in section 20 for which data was not obtained, replacement data is to be obtained in accordance with section 3.5.2 of the Reference Method.

Replacement data — Fuel-based methods

(3) If a fuel-based method referred to in paragraph 19(1)(*b*) is used for the determination of an element of a formula set out in any of sections 20 to 23 that is related to the higher heating value, carbon content or molecular weight of a fuel and for which data was not obtained for a given period of 28 days or less, replacement data is to be the average of the determinations for that element using the fuel-based method in question during the equivalent period immediately before and if applicable, the equivalent period immediately after that given period. However, if that determination is not available during the equivalent period immediately before the given period, the replacement data is to be the determination for that element using the fuel-based method in question during the equivalent period immediately after the given period.

Maximum use of replacement data

(4) During a calendar year, there may be up to six given periods referred to in subsection (3), but the number of days for which data was not obtained during all of those periods combined is not to exceed 28.

PART 4

COMING INTO FORCE

January 1, 2013

28. (1) Subject to subsections (2) and (3), these Regulations come into force on January 1, 2013.

July 1, 2015

(2) Section 3 in respect of new units and old units other than standby units, subsections 5(1) and (6) and sections 6 to 13 come into force on July 1, 2015.

January 1, 2020

(3) Section 3 in respect of standby units comes into force on January 1, 2020.

SCHEDULE 1

(Subsection 4(1))

REGISTRATION REPORT — INFORMATION REQUIRED

1. Information respecting the responsible person:

(*a*) whether they are the owner or operator of the unit and their name and civic address;

(*b*) the name, title, civic and postal addresses, telephone number and, if any, email address and fax number, of their authorized official; and

(*c*) the name, title, civic and postal addresses, telephone number and, if any, email address and fax number, of a contact person, if different from the authorized official.

2. Information respecting the unit:

(*a*) for each responsible person for the unit, other than the one mentioned in item 1(*a*), if any

(i) their name and civic address,

(ii) whether they are an owner or operator, and

(iii) in the case of an owner, their percentage of ownership interest;

(*b*) its name and civic address, if any;

(*c*) if applicable, its National Pollutant Release Inventory identification number assigned by the Minister for the purpose of section 48 of the Act;

(*d*) for an existing or old unit

(i) the calendar year in which the unit reaches, or reached, the end of its useful life, and

(ii) whether it will cease to produce electricity for sale before July 1, 2015 and, if known, the date by which it will cease production;

(*e*) its commissioning date; and

(*f*) the date of expiry of any power purchase agreement in relation to the unit that was in force on June 23, 2010.

SCHEDULE 2
(Paragraph 8(2)(d))

TECHNICAL FEASIBILITY STUDY — INFORMATION REQUIRED

1. Information respecting the capture element of the carbon capture and storage system:

(*a*) a description of how the emissions are to be captured, including a preliminary engineering design and a description of the preferred technology and processes to be used;

(*b*) a description of any changes to the unit that are needed for its integration with the capture element;

(*c*) an identification of any major equipment to be installed and of any other significant equipment to be modified or replaced;

(*d*) process flow diagrams and mass and energy balances, including external energy inputs;

(*e*) a summary of auxiliary energy loads;

(*f*) an estimate of the unit's production capacity when it is operating with an integrated capture element;

(*g*) an estimate of the unit's gross quantity of electricity produced for a calendar year — as described in G_{gross} in the formula set out in subsection 18(1) of these Regulations — when it is operating with an integrated capture element;

(*h*) an estimate of the rate of capture of CO_2 emissions and of the volume of CO_2 emissions to be captured for a calendar year and for the operating life of the unit;

(*i*) a preliminary resource analysis for the unit when it is operating with an integrated capture element, including water consumption, heat and power consumption, raw material consumption and fuel consumption;

(*j*) documents establishing that adequate space has been set aside at the facility in which the unit is located and that adequate access is to be provided for the purpose of installing the required equipment, including site plans that show

(i) the outline and location of all significant electricity generating equipment, carbon capture equipment and compression equipment, as well as any ancillary equipment necessary, sized to capture the sufficient volume of CO_2 referred to in subparagraph 8(2)(*d*)(i) of these Regulations,

(ii) the area, or areas, to be used to stage construction activities, and

(iii) the point of exit of the pipeline to transport the captured CO_2 from the facility to the storage site, if the captured CO_2 is not stored at the facility;

(*k*) an identification of the potential risks and obstacles, based on the preferred capture technology, to the construction and operation of the capture element integrated with the unit;

(*l*) a list of each environmental, safety and other approval or permit required for the construction and operation of the unit integrated with the capture element; and

(*m*) a list of potential suppliers of equipment, materials or services that are needed for the construction and operation of the unit integrated with the capture element.

2. Information respecting the transportation element of the carbon capture and storage system:

(*a*) an identification of, and justification for, one or more preferred transport methods and routes to an appropriate geological storage site referred to in paragraph 3(*b*), supported by a routing map and a geographic information system (GIS) file for each method and route;

(*b*) the expected location and size of pumping stations and receipt and delivery points and any interconnects on the pipeline for each preferred route;

(*c*) an estimation of the diameter of the pipeline for each preferred route that is required to transport the sufficient volume of CO_2 referred to in subparagraph 8(2)(*d*)(i) of these Regulations;

(*d*) if applicable, a detailed description of how any tankers that are to be used to transport the captured CO_2 emissions are to be obtained and, if required, commissioned and a plan detailing how any required port infrastructure for shipping the captured CO_2 emissions on those tankers is to be developed;

(*e*) an identification of the potential risks and obstacles, for each preferred route, to the construction and operation of the pipeline or shipping network along that route, including any surface or subsurface land use that may conflict with that construction or operation, along with an explanation of how those risks and obstacles are to be overcome in order to permit that construction or operation;

(*f*) a list of each environmental, safety and other approval or permit that is required for the construction or operation of the transportation element; and

(*g*) a list of potential suppliers of equipment, materials or services that are needed for construction and operation of the transportation element.

3. Information respecting the storage element of the carbon capture and storage system:

(*a*) an estimation of the volume of CO_2 emissions to be captured and stored during each calendar year and over the anticipated operating life of the unit;

(*b*) an identification of one or more feasible storage sites that are expected to be used to store the captured CO_2 emissions, supported by a delineation of the geographical extent of each storage site and at least one study showing that the required capacity to store the sufficient volume referred to in subparagraph 8(2)(*d*)(i) of these Regulations is available based on generally accepted national or international protocols for storage capacity estimation;

(*c*) an identification of any requirement under federal or provincial laws for the purity of captured CO_2 emissions, along with an explanation of how that requirement is to be met;

(*d*) a preliminary assessment of the integrity of the storage element in preserving an impervious barrier to leakage of stored CO_2 emissions and of any risk to breaching that integrity at each feasible storage site referred to paragraph (*b*), along with a preliminary strategy to mitigate the risk;

(*e*) a preliminary plan for measuring and verifying the volume of stored CO_2 emissions and for monitoring any leak of the stored CO_2 emissions from the storage element;

(*f*) an identification of any surface or subsurface land use that may conflict with the operation of the storage element at each feasible storage site referred to in paragraph (*b*), along with an explanation of how the conflict is to be resolved in order to ensure access to each of those sites;

(*g*) a list of each environmental, safety and other approval or permit that is required for the construction or operation of the storage element; and

(*h*) a list of potential suppliers of equipment, materials or services that are needed for the construction and operation of the storage element for each feasible site referred to in paragraph (*b*).

SCHEDULE 3
(Paragraphs 8(2)(e) and 10(1)(b))

INFORMATION ON SECTION 9 REQUIREMENTS

1. If a front end engineering design study referred to in paragraph 9(*a*) of these Regulations has been carried out, the following information to summarize that study:

(*a*) an overall description of the construction project for the carbon capture and storage system, including technical drawings and documents that describe

(i) the configuration and layout of the facility in which the unit is located when it is operating with an integrated capture element of the system,

(ii) the transportation element of the system, and

(iii) the site of the storage element of the system;

(*b*) an estimate of its capital cost, including a summary of the analysis that led to that estimate and a justification for the margin of error of that estimate;

(*c*) a summary of the safety review of the capture element of the carbon capture and storage system;

(*d*) a summary of the risk assessment of the carbon capture and storage system;

(*e*) a summary of the strategy to mitigate those risks;

(*f*) a summary of the plan to carry out the construction of the carbon capture and storage system, including a schedule for the completion of its major steps;

(*g*) the identification of potential persons with whom to enter into agreements to carry out the construction of the carbon capture and storage system;

(*h*) the name and business address of the persons responsible for the development of the front end engineering design study and a description of their contribution to its development;

(*i*) a description of the capture technology selected in the front end engineering design study for the capture element of the carbon capture and storage system and of its integration with the unit;

(*j*) an identification of any major equipment required to be purchased for the construction of the capture element of the carbon capture and storage system;

(*k*) an estimate of the performance of the unit when it is operating with an integrated carbon capture and storage system, supported by process flow diagrams and mass and energy balances, including an estimate of

(i) the rate of capture of CO_2 emissions and the volume of CO_2 emissions to be captured for a calendar year and for the operating life of the unit,

(ii) the production capacity of the unit,

(iii) the unit's gross quantity of electricity produced for a calendar year — as described by G_{gross} in the formula set out in subsection 18(1) of these Regulations — when it is operating with an integrated capture element,

(iv) a summary of auxiliary energy loads,

(v) the period during a calendar year that a unit is expected to be available for producing electricity, and

(vi) for a calendar year, the quantity of CO_2 emissions from the combustion of fossil fuels in the unit referred to in subsection 3(1) of these Regulations and of nitrogen oxides, sulphur oxides, particulate matter, mercury and, if applicable, ammonia emissions from the unit; and

(*l*) a summary of the resource analysis for the unit when it is operating with an integrated capture element of the carbon capture and storage system, including water consumption, heat and power consumption, raw material consumption and fuel consumption.

2. If any major equipment that is necessary for the capture element referred to in paragraph 9(*b*) of these Regulations has been purchased, a copy of the purchase orders and receipts respecting the purchase of that equipment.

3. A declaration, signed by all contracting parties to any contract referred to in paragraph 9(*c*) of these Regulations that indicates that it has been entered into and the date on which it was entered into.

4. A copy of any permit or approval referred to in paragraph 9(*d*) that has been obtained.

5. A copy of a receipt that demonstrates that final payment has been made in respect of any major piece of equipment referred to in paragraph 9(*e*) of these Regulations that has been delivered and that indicates the date of delivery.

6. A declaration — signed by the responsible person and, if applicable, any party contracting with the responsible person for the capture element, transportation element or storage element of the carbon capture and storage system — that indicates the date on which CO_2 emissions from the combustion of fossil fuels in the unit have been captured in accordance with the laws of Canada or a province that regulate that capture and have been transported and stored in accordance with the laws of Canada or a province, or the United States or one of its states, that regulate, as the case may be, that transportation or storage.

7. A declaration, signed by the responsible person for an old unit, that indicates the date on which 30% of the CO_2 emissions from the combustion of fossil fuels in that unit have been captured by that unit in accordance with the laws of Canada or a province that regulate that capture and have been transported and stored in accordance with the laws of Canada or a province, or the United States or one of its states, that regulate, as the case may be, that transportation or storage.

SCHEDULE 4
(Subsection 14(1))

ANNUAL REPORT — INFORMATION REQUIRED

1. Information respecting the responsible person:

(*a*) whether they are the owner or operator of the unit and their name and civic address;

(*b*) the name, title, civic and postal addresses, telephone number and, if any, email address and fax number, of their authorized official; and

(*c*) the name, title, civic and postal addresses, telephone number and, if any, email address and fax number, of a contact person, if different from the authorized official.

2. Information respecting the unit:

(*a*) for each responsible person for the unit, other than the one mentioned in paragraph 1(*a*), if any

(i) their name and civic address,

(ii) whether they are an owner or operator, and

(iii) in the case of an owner, their percentage of ownership interest;

(*b*) its name and civic address, if any;

(*c*) its registration number and, if applicable, its National Pollutant Release Inventory identification number assigned by the Minister for the purpose of section 48 of the Act;

(*d*) if applicable, the number of other units located at facility in which the unit is located and, for each of those other units, the information referred to in (*a*); and

(*e*) if applicable, a statement that indicates that the unit shares a common stack with any of those other units and, if so, a statement that identifies each of those units.

3. Information respecting the emission-intensity referred to in subsection 3(1) of these Regulations from the combustion of fuel in the unit — other than a unit referred to in 4(*d*) — during the calendar year:

(*a*) the emission-intensity for the unit, namely the ratio of the quantity of CO_2 emissions referred to in paragraph (*c*) to the quantity of electricity referred to in subparagraph (*b*)(i), expressed in tonnes per GWh;

(*b*) in respect of the quantity of electricity produced by the unit

(i) that quantity determined in accordance with section 18 of these Regulations, expressed in GWh,

(ii) the value determined for G_{gross} and G_{aux} in the formula set out in subsection 18(1) of these Regulations,

(iii) the gross electricity produced by units located at the facility for the calendar year, namely the sum of the value determined for G_{gross} referred to in subparagraph (ii) and of the gross electricity produced by all other units located at the facility determined in accordance with that description of G_{gross},

(iv) the quantity of electricity, expressed in GWh, that is used by the facility in which the unit is located during the calendar year to operate infrastructure and equipment for electricity generation and for separation, but not pressurization, of CO_2, based on data collected using meters that comply with the requirements of the *Electricity and Gas Inspection Act* and the regulations made under it,

(v) if that calendar year is the calendar year referred to in subsection 18(2) of these Regulations for which a method of attribution was considered to be most appropriate, a detailed description of that method of attribution and an explanation of why they considered it to be most appropriate, and

(vi) if that calendar year is a subsequent calendar year referred to in subsection 18(3) of these Regulations, a detailed description of the method of attribution referred to in that subsection used for that subsequent calendar year and an explanation of why they considered it to be most appropriate;

(*c*) in respect of the quantity of CO_2 emissions from the combustion of fuels in the unit,

(i) if paragraph 19(1)(*a*) of these Regulations applies for the determination of that quantity

(A) that quantity, expressed in tonnes, determined in accordance with section 20 of these Regulations,

(B) the values, expressed in tonnes, determined for E_u, E_{bio} and $E_{non\text{-}ccs}$ in the formula set out in subsection 20(1) of these Regulations,

(C) a statement that indicates whether paragraph (*a*) or (*b*) of the description of that E_{bio} was used to determine the value of that element, and

(D) the value, expressed in tonnes, determined for E_s in the formula set out in subparagraph 20(2)(*d*)(ii) of these Regulations, and

(ii) if paragraph 19(1)(*b*) of these Regulations applies for the determination of that quantity

(A) that quantity, expressed in tonnes, determined in accordance with sections 21 and, as the case may be, 22 or 23 of these Regulations,

(B) the values, expressed in tonnes, determined for E_i for each fuel combusted, and for $E_{ccs,}$ in the formula set out in section 21 of these Regulations,

(C) the value, expressed in tonnes, determined for E_s in the formula set out in subparagraph 20(2)(*d*)(ii) of these Regulations,

(D) a statement for each fuel combusted that indicates whether the quantity referred to in clause (A) was determined in accordance with section 22 or 23 of these Regulations,

(E) if that quantity was determined in accordance with section 22 of these Regulations,

(I) the value of CC_A in the formula set out in paragraph 22 (1)(*a*), (*b*) or (*c*) of these Regulations, as the case may be, for each fuel combusted, and

(II) a statement that indicates which ASTM standards referred to in that description of CC_i were used to determine that value of CC_A referred to in subclause (I) or, for a sample of gaseous fuel, that indicates that a direct measuring device was used to determine that value,

(F) if that quantity was determined in accordance with section 23 of these Regulations,

(I) for each fuel combusted,

1. its type,
2. a statement that indicates which of paragraph 23(2) (*a*),(*b*) or (*c*) of these Regulations describes the fuel, and
3. for a fuel described by paragraph 23(2)(*c*) of these Regulations, the average daily rate at which the fuel was combusted,

(II) if paragraph 23(1)(a) of these Regulations applies

1. the measured value of HHV, as described in paragraph (*a*) of that element, in the formula set out in subsection 23(4) of these Regulations for each fuel combusted,

2. the default CO_2 emission factor, set out in column 3 of the applicable table to Schedule 5, for that fuel if that fuel is listed in column 1 of that table and, if that fuel is not so listed, the default CO_2 emission factor for that fuel established by a body that is internationally recognized as competent to establish default emission factors for fuels and a statement that indicates the name of the body, and

3. a statement that indicates which ASTM or GPA standard, as the case may be, referred to in subsection 23(6) of these Regulations was used to determine the measured value of HHV referred to in subsubclause 1 or, for a gaseous fuel, that indicates that a direct measuring device was used to determine that measured value,

(III) if paragraph 23(1)(b) of these Regulations applies

1. the default value of HHV, as described in paragraph (*b*) of that element, in the formula set out in subsection 23(4) of these Regulations for each fuel combusted,

2. a statement that explains the absence of a measured higher heating value and that indicates, if that default higher heating value is established by a body that is internationally recognized as competent to establish default higher heating values for fuels, the name of the body, and

3. the default CO_2 emission factor, set out in column 3 of the applicable table to Schedule 5, for that fuel if that fuel is listed in column 1 of that table and, if that fuel is not so listed, the default CO_2 emission factor for that fuel established by a body that is internationally recognized as competent to establish default emission factors for fuels and a statement that indicates the name of the body;

(*d*) if applicable, documents that establish that the captured CO_2 emissions were captured, transported and stored as described in subsection 3(5) of these Regulations; and

(*e*) for each type of fuel combusted,

(i) the type and, if that type is biomass, an explanation of why that type meets the criteria set out in the defintion “biomass” in section 2 of these Regulations, and

(ii) the quantity of fuel combusted.

4. Information for the calendar year respecting

(*a*) the number of hours during which the unit produced electricity;

(*b*) if a substituted unit referred to in subsection 5(1) of these Regulations has been substituted for the unit, the production capacity of that unit;

(*c*) for a standby unit, the capacity factor for the standby unit;

(*d*) for a unit referred to in subsection 6(4) of these Regulations

(i) the emergency period for the calendar year, namely, the first day in the calendar year on which the emergency existed and the last day in the calendar year on which it existed,

(ii) the number of hours in the emergency period during which the unit operated, and

(iii) the information referred to in 3 for each of the emergency period and any other period of the calendar year; and

(*e*) for an existing unit referred to in subsection 13(4) of these Regulations, the rate of capture of CO_2 emissions from the unit.

5. A copy of the auditor's report referred to in subsection 25(4) of these Regulations.

6. If replacement data referred to in section 27 of these Regulations was used for any period during the calendar year

(*a*) the reason for which data required to determine an element of a formula set out in section 18 or any of sections 20 to 23 of these Regulations was not obtained and an explanation as to why that reason was out of the control of the responsible person;

(*b*) the element of the formula for which, and the given period referred to in subsection 27(1) of these Regulations during which, data was not obtained, including the hour or day, as the case may be, on which that given period begins and ends; and

(*c*) the value determined for that element using replacement data, along with details of that determination, including

(i) the data used to make that determination for each period referred to in subsection 27(2) or (3) of these Regulations,

(ii) the method used to obtain that data, and

(iii) a justification of the period or periods used as the basis of that determination.

SCHEDULE 5
(Subsections 20(2) and (4), 23(1), (3) and (6) and 26(2))

LIST OF FUELS

PART 1

SOLID FUELS

TABLE

Item	Column 1 Type of fuel	Column 2 Default higher heating value (GJ/tonne)	Column 3 Default CO_2 emission factor (kg CO_2/GJ)
1.	Bituminous Canadian coal – Western	25.6	86.1
2.	Bituminous Canadian coal – Eastern	27.9	82.1

3.	Bituminous non-Canadian coal – U.S.	25.7	95.6
4.	Bituminous non-Canadian coal – Other Countries	29.9	85.2
5.	Sub-bituminous Canadian coal – Western	19.2	89.9
6.	Sub-bituminous non-Canadian coal – U.S.	19.2	95.0
7.	Coal – lignite	15.0	92.7
8.	Coal – anthracite	27.7	86.3
9.	Coal coke and metallurgical coke	28.8	86.0
10.	Petroleum coke from refineries	46.4	82.3
11.	Petroleum coke from upgraders	40.6	86.1
12.	Municipal solid waste	11.5	86.0
13.	Tires	31.2	81.5
14.	Wood and wood waste[1]	19.0	88.0
15.	Agricultural byproducts[1]	17.0	112.0
16.	Peat	9.3	106.0

[1] The default higher heat values for wood and agricultural byproducts are on a totally dry basis.

PART 2

LIQUID FUELS

TABLE

Item	Column 1 Type of fuel	Column 2 Default higher heating value (GJ/kL)	Column 3 Default CO_2 emission factor (kg CO_2/GJ)
1.	Diesel	38.3	69.5
2.	Light fuel oil	38.8	70.2
3.	Heavy fuel oil	42.5	73.5
4.	Ethanol	21.0	64.9

PART 3

GASEOUS FUELS

TABLE

Item	Column 1 Type of fuel	Column 2 Default higher heating value (GJ/standard m^3)	Column 3 Default CO_2 emission factor (kg CO_2/GJ)
1.	Biogas (captured methane)	0.0281	49.4

PART 4

LIST OF FUELS FOR THE PURPOSE OF SUBSECTION 23(2)

TABLE

Item	Column 1 Type of fuel	Column 2 Default higher heating value (GJ/kL)	Column 3 Default CO_2 emission factor (kg CO_2/GJ)
1.	Distillate fuel oil No.1	38.78	69.37
2.	Distillate fuel oil No. 2	38.50	70.05
3.	Distillate fuel oil No. 4	40.73	71.07
4.	Kerosene	37.68	67.25
5.	Liquefied petroleum gases (LPG)	25.66	59.65
6.	Propane (pure, not mixtures of LPGs)[1]	25.31	59.66
7.	Propylene	25.39	62.46
8.	Ethane	17.22	56.68
9.	Ethylene	27.90	63.86
10.	Isobutane	27.06	61.48
11.	Isobutylene	28.73	64.16
12.	Butane	28.44	60.83
13.	Butylene	28.73	64.15
14.	Natural gasoline	30.69	63.29
15.	Motor gasoline	34.87	65.40
16.	Aviation gasoline	33.52	69.87
17.	Kerosene-type aviation	37.66	68.40
		(GJ/standard m3)	(kg CO_2/GJ)
18.	Pipeline quality natural gas	0.03826	47.57

[1] The defaults factors for propane are only for pure gas propane. The product commercially sold as propane is to be considered LPG for the purpose of these Regulations.

SCHEDULE 6
(Subsection 25(4))

AUDITOR’S REPORT — INFORMATION REQUIRED

1. The name, civic address and telephone number of the responsible person.

2. The name, civic address, telephone number and qualifications of the auditor and, if any, the auditor’s fax number and email address.

3. The procedures followed by the auditor to assess whether

(*a*) the responsible person’s use of the CEMS complied with the Quality Assurance/Quality Control manual referred to in section 6 of the Reference Method; and

(*b*) the CEMSs meets the specifications set out in the Reference Method, in particular, in its sections 3 and 4.

4. A declaration of the auditor's opinion as to whether

(*a*) the responsible person's use of the CEMS complied with the Quality Assurance/Quality Control Manual referred to in section 6 of the Reference Method; and

(*b*) the CEMS met the specifications set out in the Reference Method, in particular, in its sections 3 and 4.

5. A statement of the auditor's opinion as to whether the responsible person ensured that the Quality Assurance/Quality Control manual was updated in accordance with section 6.5.2 of the Reference Method.

[35-1-o]

Footnote 1
An agreement between the responsible person for a unit that produced electricity and a distributor of that electricity in respect of the sale of the electricity produced by the unit to the distributor.

Footnote 2
Source: National Inventory Report 1990–2008: Greenhouse Gas Sources and Sinks in Canada, Part 3, 2010, Environment Canada.

Footnote 3
Owing to their relatively small contribution to Canadian supply, the Atlantic Provinces have been grouped together, as have the territories.

Footnote 4
Source : Office national de l'énergie

Footnote 5
Source: Actual generation from Electric Power Generation, Transmission and Distribution (2008), Report on Energy Supply and Demand in Canada (2008). Potential generation from Electric Power Generating Stations (2008), Statistics Canada. Potential generation (GWh) for 2008 = Capacity (GW) for 2008 × 365 days × 24 hours per day.

Footnote 6
Source: Environment, Energy, and Economy Model of Canada (E3MC) — Environment Canada; other published sources.

Footnote 7
Manufacturing industries, including mining and oil and gas extraction.

Footnote 8
Including institutional and public administration.

Footnote 9
Data source: *Energy Statistics Handbook*, 4th Quarter, 2009, Statistics Canada, Catalogue No. 57-601-X.

Footnote 10
Federal policies include strengthened energy efficiency standards, the *Renewable Fuels Regulations*, ecoAction programs; and the *Passenger Automobile and Light Truck Greenhouse Gas Emission Regulations*.

Footnote 11
Provincial policies include energy efficiency standards, building code regulations, incentives/rebates, the Quebec fuel tax, the B.C. carbon tax, Alberta's industrial regulations, Nova Scotia's cap on electricity sector GHG emissions, Nova Scotia's renewable energy

standard, the Ontario coal phase out, and the Ontario feed-in-tariff.

Footnote 12
As measured by both units and capacity.

Footnote 13
Annual Energy Outlook (AEO) — 2011 Reference case, adjusted to 2010 dollars.

Footnote 14
Impact of a Performance Standard for Coal Fired Generation, Ziff Energy Group (March 2011).

Footnote 15
AURAMS was developed and is continually updated by Environment Canada scientists of the Science and Technology Banch. AURAMS is currently used by Environment Canada for various applications related to air pollution in North America. The model is intended to describe the formation of tropospheric ozone, particulate matter, and acid deposition in North America in support of policy and decision making.

Footnote 16
See Gong et al., 2006; McKeen et al., 2007; Samaali et al., 2009; and Smyth et al., 2009.

Footnote 17
The relationship between air pollution emissions and ambient air quality is extremely complicated and non-linear. This is particularly true for the formation of ground-level ozone, through the interaction of nitrogen oxides and volatile organic compounds.

Footnote 18
The AQBAT model contains functions representing the relationship between air pollution exposure and per capita health risks. The model also contains estimates of the social welfare benefit (or socio-economic value) of reducing the risks of different health outcomes. Using the estimated changes in ambient air quality under the proposed Regulations, AQBAT estimated how the per capita risk of health problems would be reduced. Changes in per capita health risks are then multiplied by the appropriate socio-economic value to estimate the benefit of the per capita risk reductions. Both the reduction in per capita risks and the estimated per capita welfare benefits are then multiplied by the exposed population to determine the estimated number of avoided health events and the total economic value of the health benefits, for each census division in Canada. These are then aggregated by census division to calculate provincial and national health impacts and benefits.

Footnote 19
Based on estimates from recently refurbished coal units.

Footnote 20
Based on estimates from recently decommissioned coal units.

Footnote 21
Keephills (CCS) — 419 MW (2011), H. R. Milner — 450 MW (2014) and Swan Hills — 375 MW (2015).

Footnote 22
Boundary Dam (CCS) — 115 MW (2014).

Footnote 23
2 249 MW from Oil/Gas Combined Cycle, 619 MW from Oil/Gas Combined Turbine and 345 MW from Oil/Gas Steam.

Footnote 24
Additions in Alberta come from announced plants and come online over 2010 to 2013. The additions in Saskatchewan are based on E3MC results and come online over 2020 to 2029. The additions in Nova Scotia come from an announced plant that comes online in 2010 and additions

in Manitoba are based on E3MC results and come online over 2019 to 2021.

Footnote 25
Electricity Exports and Imports, Monthly Statistics for December 2010, National Energy Board.

Footnote 26
Annual Energy Outlook (AEO) — 2011 Reference Case.

Footnote 27
The emission factors are based on NPRI 2007, and hence often differ at the unit level. Projected increases in new generation are calibrated to historical national inventory levels.

Footnote 28
If the extrapolation led to any negative values for metric, then that metric was reset to zero for those years.

Footnote 29
See Profile of Labour Market Activity, Industry, Occupation, Education, Language of Work, Place of Work and Mode of Transportation for Canada, Provinces, Territories, Census Divisions and Census Subdivisions, 2006 Census, Statistics Canada, Catalogue No. 94-579-X2006001.

Footnote 30
The deciview is a visual index designed to be linear with respect to perceived visual air quality changes over its entire range. The deciview scale is zero for pristine conditions and increases as visibility degrades. A change in deciview represents a perceptible change in visual air quality.

Footnote 31
It seems relevant to mention that the CAR dataset does not cover northern Saskatchewan, Yukon, Nunavut, and the Northwest Territories. Even though little agricultural activity is expected to occur in the three latter regions, the exclusion of northern Saskatchewan may lead to an underestimation of the national benefits, as this province already has about one-third of the total benefits for agriculture. Current agricultural data doesn't allow an assessment of the magnitude of the underestimation.

Footnote 32
"Wheat" includes spring wheat, durum, and winter wheat; "Corn" includes grain and silage; "Peas, Beans and Lentils" includes dry field peas, chick peas, lentils, dry white beans, and other dry beans; "Others" includes potato, tobacco, sugar beet, tomato, lettuce, and onion.

Footnote 33
Mean marginal damage ($2010/tonne) are as follows: NOx (timber): $4.78, NOx (recreation): $2.87, SO2: $12.14 (materials).

Footnote 34
Note that the health outcomes shown in Table 19 are statistical estimates, based in adding up changes in per-capita risks. For example, the AQBAT model predicts that in 2030 these Regulations would reduce mortality risks in Manitoba, resulting in an estimated five fewer premature deaths per year in the province. However, this does not mean that there will be five specific, identifiable individuals who will be "saved" in Manitoba in 2030. Rather, in 2030, it is estimated that the per-capita risk of death will be reduced by about 0.00036% for the average person. Given the estimated population of 1.4 million in Manitoba for 2030, a per-capita risk reduction of 0.00036% can be expected to reduce the total number of deaths province-wide by about five per year. But the "health benefits" of the proposed Regulations are not the number of lives "saved" per se, but rather the reduction in the average per-capita risk. Similarly, the values in the economic benefit column do not measure the benefit of the individual lives saved, or hospitalizations prevented. Rather, this is the aggregated benefit of the reduction in individual risk levels across the province.

Footnote 35
It is understood that there are critical differences in population distribution and mercury exposure between Canada and the United States and, as a result, U.S. values should be taken

as rough approximations of Canadian benefits only.

Footnote 36
More recently, Spadaro and Rabl (2008) estimated the global impacts of global mercury emissions on brain development. Because of their global focus, Spadaro and Rabl estimated a much lower value of health impacts per kilogram of mercury emissions. However, when they took the same methodology they used in their study, and applied it to U.S. data, they came up with a result that was nearly identical to the results of Rice and Hammit. Given the similar results in both of these studies, the results from Rice and Hammit will be adopted for use in this analysis.

Footnote 37
Note that the discussion and the values estimated above apply only to the neurological impacts of mercury exposure and the resulting impacts on IQ. There is emerging scientific evidence that mercury is also a factor in heart disease and the risk of premature death. The inclusion of a potential heart disease and mortality link to mercury would result in a significant increase in the estimated benefits of the mercury reductions. For example, when Rice and Hammit (2005) include heart disease and mortality risks in their analysis, they find the value of health benefits from mercury reductions increases nearly 50 times, to over $180,000 per kilogram. Due to uncertainty in the quantification of these impacts, they have not been included in this analysis. However, given the omission of these potentially significant impacts, the benefit estimate should be seen as a low-end estimate of the value of potential health impacts from mercury.

Footnote 38
Lead impacts from coal unit closures only. Excludes coal units not reported to NPRI and any lead releases from replacement generation.

Footnote 39
The socio-economic cost per tonne is calculated by subtracting the sum of all of the non-GHG benefits from the total costs of the proposed Regulations and then dividing by the tonnes of GHGs reduced by the measure.

Footnote 40
Energy Statistics Handbook, 3rd Quarter 2010, Statistics Canada.

Footnote 41
Data for Nova Scotia was not available.

Footnote 42
Electric Power Generation, Transmission and Distribution, Statistics Canada (2007).

Footnote 43
Overview of Canada's Coal Sector, Natural Resources Canada (2008).

Footnote 44
Environment Canada's Compliance and Enforcement Policy is available at www.ec.gc.ca/alef-ewe/default.asp?lang=en&n=AF0C5063-1.

Footnote a
S.C. 2004, c. 15, s. 31

Footnote b
S.C. 1999, c. 33

Footnote c
S.C. 2008, c. 31, s. 5

NOTICE:
The format of the electronic version of this issue of the *Canada Gazette* was modified in order to be compatible with extensible hypertext markup language (XHTML 1.0 Strict).

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