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Canadian Energy Research Institute

Comparative Life Cycle Assessment (LCA) of Base Load Electricity Generation in Ontario

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COMPARATIVE LIFE CYLE ASESSMENT (LCA)

OF BASE LOAD ELECTRICITY GENERATION IN ONTARIO

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EXECUTIVE SUMMARY

ES1.1 Background

The global revival in nuclear energy provides an opportunity to engage the public by providing a factual and objective assessment of nuclear energy as an electricity generation option. This will aid the development of a basis for rational decision-making towards this major energy source. The environmental performance of the electricity generating sector has gained added importance in many jurisdictions across Canada, making it timely to evaluate the environmental effects of various fuel pathways in electricity generating sector.

In this study, the Canadian Energy Research Institute (CERI) has set out to develop a rigorous analysis of the environmental and other attributes of the nuclear power generation option. To be informative, such an analysis must be comparative in nature and examine alternative power generation options on equal footing to allow evaluation of the relative shares of these options in meeting power generation needs. To that end, CERI has conducted a rigorous Life Cycle Analysis (LCA) of electricity generation from three alternative fuel sources: nuclear, coal and natural gas. CERI has also addressed a number of the major areas of concern relating to nuclear that are emphasized by opponents and sometimes exaggerated in public forums.

ES1.2 Purpose of the Study

The overall objective of this study is to identify and analyze current and potential life cycle environmental impacts (GHG emissions, other air pollutants, water pollution, and radiation) of electricity generation from nuclear, coal, and natural gas. All of these fuel sources are important contributors to Canadian electricity generation and have implications for the environment. It will also be useful to set out the power requirements in the economy and compare various sources of energy that might meet those requirements in an objective fashion.

ES1.3 Methodology

This study uses *process LCA*, an effective method for assessing the environmental aspects associated with generation of electricity from different sources over their life cycle. This type of analysis, in general, can assist with future electricity generation mix decisions, leading to improved environmental performance of the generation mix. For Ontario it might lead to the adoption of environmentally friendly technologies to maximize the value of renewable and nonrenewable sources by minimizing impacts on the environment. This enhances the sustainability of Ontario's natural resources operation and economy.

The study applies a 20-page standard developed by the International Organization for Standardization (ISO) 14040 as a guideline. This standard, in turn, requires the user to meet another standard ISO 14044 as well. The latter standard, which presents more detailed sub-standards and procedures, has also been adhered to where possible. Following these standards as guidelines ensures a measure of accuracy and therefore credibility to the final report. CERI has made every effort to ensure that the analysis is disciplined and complete.

ES1.4 The Process LCA

According to this approach, a system boundary is defined, and different processes are included in it. A process flowchart might be helpful for showing the system boundary, unit processes and their inter-relationships. The process model assessment typically consists of a detailed inventory of resource inputs and environmental outputs for the analysis period and processes considered. The outputs then can be evaluated for their environmental harm. Also, this approach requires material and energy balances for each of the processes.

Although this modeling approach is very data intensive and time consuming, it gives detailed information for a better product design and enables comparison between the environmental impacts of different processes along the production chain.

ES2 Power Generation in Canada

Canada generated 221,833 gigawatt hours of electricity, close to 4.23 percent of global output, in 1971. Through an average 3.17 per cent annual growth during 1972-2005, Canada's total electricity output (TEO) rose to 628,083 gigawatt hours, nearly 3.44 percent of global TEO, in 2005. Canada is now a major power generator on a global basis. It ranked 3rd after United States and Japan within the 30-strong OECD (Organization of Economic Development and Co-operation) group of countries and ranked 6th worldwide after United States, China, Japan, Russia and India in 2005. Canada's per capita power generation was 19,463 kilowatt hours in 2005; ranking 3rd within OECD and worldwide after Norway and Iceland.

In terms of electricity generation from coal (106,188 gigawatt hours), nuclear (92,040 gigawatt hours) and natural gas (36,324 gigawatt hours) - the focus of our LCA - Canada ranked 13, 7, and 22 respectively worldwide in 2005. On a per capita basis, Canada's coal, nuclear and natural gas electricity generation global rankings stood at 9, 10, and 38 respectively.

In 1971 the prime source was hydro electricity, amounted to 162.5 terawatt hours (TWh) close to 4 times that from the second source coal, from which 41.7 TWh was generated. Natural gas, other sources and nuclear followed with amounts several times smaller than that of coal. In 2005, while hydro and coal maintained their first and second position, their difference moderated. In the same year, nuclear, with 92 TWh, overtook natural gas and others to become the third source of electricity generation in Canada with minimal difference from coal from which 106.2 TWh of electricity was generated. It is also evident that nuclear has been the fastest growing electricity generation source.

Hydro, from which close to 60 percent of the Canadian electricity is generated, has a prime position. Hydro's share however, significantly dropped from 73.2 percent in 1971 to 57.9 percent in 2005, staying below its historical 64.1 percent average. Coal maintained a rather stable share close to 17 percent, while nuclear share grew substantially, from less than 2 percent in 1971 to 14.7 percent in 2005, well above its historical 12.0 percent average. Natural gas and others' shares also increased, with nuclear enjoying the highest share gain. One can therefore conclude that a more than a 15 percent drop in hydro's share was gradually redistributed mostly to nuclear, and a little to natural gas and other sources during 1971-2005.

Coal, nuclear and natural gas secured 16.9 percent, 14.7 percent and 5.8 percent in the Canadian electricity generation respectively in 2005. Long-term scenarios from the International Energy Agency assumes the following average global ranges of shares for coal, nuclear and natural gas in 2050: for coal from 16.5 to 47.1 per cent, for nuclear from 6.7 to 22 per cent, and for natural gas from 19.5 to 28.2 per cent. Canada's latest National Energy Board scenarios assume certain levels for 2030 electricity generation. The scenarios expect a significant drop in the share of coal from the 16.9 per cent in 2005, to 2.39 to 7.84 per cent, in 2030. The 2030 share of nuclear is expected to range from 13.77 to 15.70 per cent, close to the 14.7 per cent 2005 level. Natural gas share in 2030, however, is expected to vary between 8.30 to 9.35 per cent, significantly higher than the 5.8 percent in 2005.

Indexes of electricity generation and GDP, both taking their respective 1971 amounts equal to 100, grew to 285 in 2005. The gap between the two indexes grew wider from 1971 to 1987, stayed rather constant until 1996, then started shrinking, and turned negative from 2003. This means that the electricity generation growth was in general slightly higher up to 2002 but it turned slower than GDP growth from 2003 to 2005.

Indexes of total electricity generation (TEO) and population, both taking their respective 1971 amounts equal to 100, indicate that TEO was continuously growing at a higher speed than population with the gap between the 2 indexes growing wider throughout 1971-2005.

The Canadian population index grew at a relatively slow and smooth pace from 100 in 1971 to 147 in 2005; less than 50 percent growth, on average, during a 35-year period. The TEO index, however, experienced a much faster growth rising to 283 in 2005 thereby registering a more than 180 per cent growth, on the average, over the same period. The widening gap between the indexes is quite evident. This implies that TEO per capita was steadily rising in Canada during 1971-2005.

ES3 Nuclear industry in Canada

According to the World Nuclear Association (WNA), in 2004 Canada produced 13,676 tonnes of uranium oxide concentrate ($U_3O_{8)}$) accounting for approximately 30 per cent of total world production and valued at of $800 million. Canada's known uranium resources are 524,000 tonnes of U_3O_8, compared with Australia's reserves of 2.5 times that amount. Canada ranks third in the world for total uranium reserves and has the world's largest known high-grade deposit.

At this time, approximately 55 per cent of the total global nuclear power capacity is located in three industrialized countries: United States (26.6 percent), France (17.2 percent), and Japan

(12.9 percent). With its five nuclear facilities (Pickering, Darlington, Bruce, Gentilly and Point Lepreau), Canada is ranked eighth in the world.

According to the Canadian Nuclear Association (CNA), as of December 2007, there are 22 CANDU reactors in Canada, however only 18 are currently operating. The remaining reactors are shut down, being refurbished, or are being decommissioned. Two of the four out-of-service nuclear reactors (Bruce A1 & A2), each with a capacity of 750 MW, are expected to be refurbished and to restart operations in 2009 and 2010.

ES4.1 Life Cycle Methodology and Definitions

According to international standards of ISO 14040, the LCA process is a systematic approach that consists of four phases:

Goal Definition and Scope: The goal of the LCA is to compare all environmental impacts associated with the generation of one terawatt-hour (TWh: one billion kilowatt-hours) of electricity from power plants in the province of Ontario fuelled by nuclear, natural gas and coal. CERI compares the aforementioned electricity systems by tonnes of pollutants that are released for the generation of one TWh of electricity, on a life-cycle basis.

The scope of the LCA in this study is on a facility-by-facility basis; prototyping is avoided where possible. Hence this LCA method is characterized as process modeling. Following this method, a flow sheet or process tree with all the relevant processes is defined, and, all the relevant inflows and the outflows for each process are collected or estimated. For each of the processes of a system, energy/material inputs and outputs are analyzed. Finally, all pieces of information are summed up to give a comprehensive picture of the emissions associated with the use of each fuel to generate electricity.

The LCA takes a snapshot of electricity generation activities in 2005 and 2006, and it is specific to Ontario electricity generating sector together with its fuel supply. Only the operations of facilities within the system boundaries as described in the following paragraph are covered in the LCA. As such, processes like exploration, construction, decommissioning and waste management are not explicitly included but addressed in a more general way.

To determine which unit process should be included in a LCA study, the system boundary should be established and it must be consistent with the goal of the study. Based on the above mentioned criteria, the following stages are included in this process LCA: a) fuel preparation (extraction/production and processing), b) fuel transportation, and c) electricity generation operations within the power plant

It is important to mention that processes like construction, decommissioning, heavy water manufacture and waste management are addressed at various times through the report, but not included in the Life Cycle Inventory (LCI) analysis.

The following environmental impacts are of major interest in this study. The main pollutants are as follows: greenhouse gases (GHG), criteria air contaminants (CAC), other air pollutants, water pollutants, and radiation.

ES4.2 Electricity Generation in Ontario

The LCA covers electricity generation from nuclear, coal and natural gas. The system boundary for LCA study covers the operation of all active generating facilities in 2005-2006, with electricity output measured just before it enters the transmission system.

Nuclear: Currently, all uranium mining in Canada takes place in Saskatchewan. Once the uranium ore is at the surface, the uranium needs to be separated from the ore. This process is called milling. Uranium oxide concentrate or yellowcake (U_3O_8) is the product of milling. Key Lake, located 80 kilometers from McArthur River, has the largest uranium mill in the world.

Yellowcake is trucked from Saskatchewan milling operations to world's largest uranium refinery at Blind River, Ontario. There, it is refined to remove impurities and then converted into uranium trioxide (UO_3). From Blind River, most of the uranium trioxide goes to another Cameco facility at Port Hope, Ontario, where it is converted into uranium dioxide (UO_2) for use as natural uranium in existing CANDU reactors, or into uranium hexafluoride (UF_6) for enrichment and subsequent conversion to uranium dioxide for use in light water reactors

Uranium dioxide is next transported to fuel fabrication facilities where the fuel pellets for CANDU reactors are made. Finally the fuel bundles are transported to CANDU reactors and used for electricity generation. Generation of the electricity is the end of life-cycle in this study.

Coal: The coal production process, including mining, processing and cleaning, starts with mining of coal at open pit and underground mines. The Run of Mine coal (ROM) is subsequently hauled to the processing plants for screening, crashing and washing. Coal is then sent to a cleaning facility.

The cleaned coal is subsequently transported to the coal-fired power plants in Ontario. The long-distance transportation of coal is an important source of the emission in the complete cycle. Three types of coal are used by Ontario's coal-fired power plants: lignite, bituminous and sub-bituminous. It is assumed that the source of lignite is Saskatchewan's mines. CERI also assumes that all required bituminous and sub-bituminous coal is imported from US. Furthermore, as we evaluate the long-distance transportation emissions, three representative points of origin and two destinations are identified and selected: lignite is transported from Bienfait (Saskatchewan) to Thunder Bay (Ontario), sub-bituminous is transported from Gillette (Wyoming) to Nanticoke (Ontario) and bituminous is transported from Louisville (Kentucky) to Nanticoke (Ontario). The mode of transportation is rail and its fuel is diesel. Generation of electricity in power plants is the final process of the coal-fired electricity cycle.

Natural gas: The life cycle starts with field operations which refer to the production of natural gas (and oil) in Alberta and moving the gas by pipe to batteries.

Field operation starts with well drilling. Gas wells are connected to gathering systems that take the gas to processing plants for sweetening, dehydration, and removal of natural gas liquids. The final output of the gas processing plants is called "marketable gas" or "process gas" which meets the standard specification of pipeline requirements and using natural gas as burning fuel. In the next step natural gas is transported from Alberta to Ontario by pipeline.

Generation of the electricity from natural gas is the final process in the system boundary. Since the operation of power plants has a significant share in LCA of GHG emissions, CERI has compiled the average of 2005-2006 generation and GHG emissions of eighteen power plants in Ontario and illustrated their generation and associated emissions by gas turbine technology.

ES4.3 Life Cycle Inventory of Pollutants

Table ES.1 summarizes the LCA results for all three power generation options in Ontario.

Table ES.1
Life Cycle Pollutions from Power Generation in Ontario

Pollutants	Unit	Power Generation Options		
		Nuclear	Coal	Natural Gas
Total Criteria Air Contaminants (CAC)	t/TWh	12.42	6,712.78	1,452.63
Oxides of Nitrogen (NO_2)	t/TWh	2.45	1,676.58	720.12
Sulphur dioxide	t/TWh	8.54	3,907.36	363.32
Carbon Monoxide	t/TWh	0.00	418.11	274.47
Total Particulate Matter	t/TWh	0.61	685.68	20.91
Volatile Organic Compounds (VOC)	t/TWh	0.81	25.05	73.81
Other Air Pollutants				
Lead and its compounds	kg/TWh	0.09	22.21	0.61
Mercury and its compounds	kg/TWh	0.00	10.59	0.00
Arsenic and its compounds	kg/TWh	0.00	23.07	0.61
Radionuclides	TBq/TWh	39.85	0.06	0.92
Water Pollutants				
Lead and its compounds	kg/TWh	0.00	0.47	0.00
Mercury and its compounds	kg/TWh	0.00	0.13	0.00
Arsenic and its compounds	kg/TWh	0.19	1.56	0.00
Radionuclides	TBq/TWh	21.04	0.00	0.01
Greenhouse Gas (GHG) emissions (CO_2 equivalent)	t/TWh	1,836.74	1,051,215.33	540,391.16

Source: Table 4.4, Table 4.6 and Table 4.8 of Chapter 4

The figures in Table ES.1 indicate that GHG emissions and CACs from coal and natural gas power generation are several orders of magnitude higher than those from nuclear. However, nuclear's radionuclides are significantly higher than those of coal and natural gas. For easier comparison, Table ES.2 summarizes Table ES.1 based on pollutant values from nuclear power generation set equal to 100.

Table ES.2
Comparative Life Cycle Pollutions from Power Generation in Ontario
(Nuclear = 100)

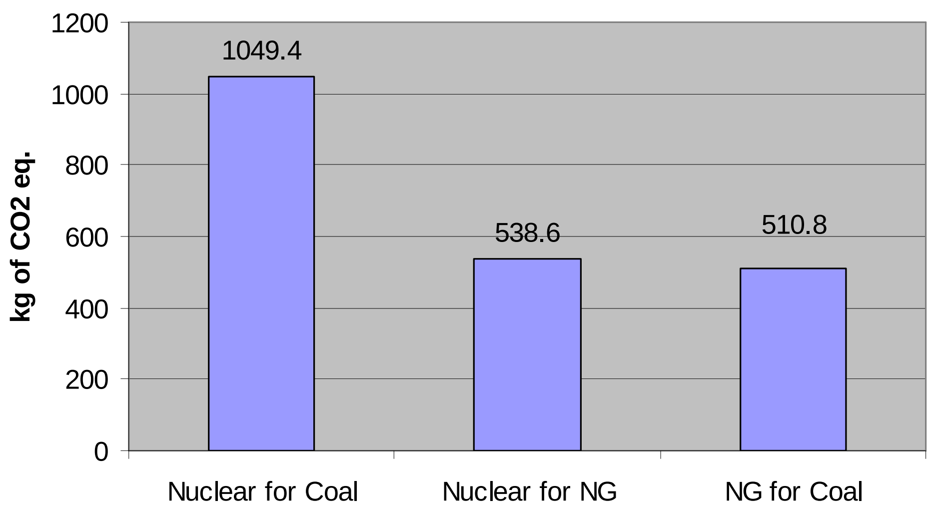
Pollutants	Power Generation Options		
	Nuclear	Coal	Natural Gas
Total Criteria Air Contaminants (CAC)	100	54,038	11,694
Radionuclides	100	0.092	1.530
Greenhouse Gas (GHG) emissions (CO_2 equivalent)	100	57,233	29,421

Source: Based on Table ES.1

Comparative results in Table ES.2 confirm that coal and natural gas power generation emit 540 and 117 times more CACs than nuclear respectively. With GHG emissions the difference is even more significant: coal and natural gas emit 572 and 294 times more GHG than nuclear. In comparison, radionuclides from coal are nearly negligible and those from natural gas are close to 1.5 percent of radionuclides from nuclear power generation.

Figure ES.1 shows the amount of GHG emissions that could be avoided by replacing one TWh of fossil fuel electricity with nuclear electricity. If one MW of coal-fired electricity capacity is replaced by one MW of nuclear or natural gas-fired electricity, Ontario could have avoided 1,049 kg or 497 kg of GHG emissions per hour of generation. This shows the potential for GHG abatement in the power generating sector of Ontario under current technologies.

Figure ES.1
Potential for GHG abatement by substituting one MWh of low carbon fuel for a higher carbon type of fuel.



SOURCE: Figure 4.11 of Chapter 4.

Also CERI estimates that a one per cent increase in the efficiency of all coal-fired power plants could have reduced the relevant GHG emission by about 267 kt in 2006 in Ontario. Furthermore, 1 percent improvement in the efficiency of natural gas-fired power plants could avoid approximately 43 kt GHG emissions in 2006 in Ontario.

As a result, it seems that influencing the level and pattern of electricity final demand, altering the mix of generating technologies, investing in measures that increase efficiency and changing the spatial location of pollution generating plants are the policy options, which can reduce the environmental impacts of power generating sector in Ontario.

ES5 Reliability, Safety and Security

In general, nuclear capacity factors have been rising in recent years. Our analysis concludes that a five-year period is a more appropriate time horizon than a single year as the basis for comparing the reliability of nuclear to generation from other fuels. On this basis nuclear has been found to be more reliable than generation from natural gas, although not by a wide margin.

This study has reviewed the safety and security issues in power generation starting at the initial stage of the production and transportation of fuel. It has also covered occupational hazards and environmental impacts, energy-related disasters by type, and terrorism threats. The study concludes that while all sources of energy have their own issues, on the whole, nuclear power generation is safer and more secure compared with the other two forms of electricity generation.

ES6 Conclusions

Canada's per capita power generation ranked 3rd within the OECD and worldwide. In terms of electricity generation from coal, nuclear and natural gas - the focus of our LCA - Canada placed 13th, 7th, and 22nd respectively in 2005 worldwide rankings. On a per capita basis, Canada's coal, nuclear and natural gas electricity generation global rankings stood at 9th, 10th, and 38th respectively. But how did Canada's global share of power generation match with its reserves and production shares? Table ES.3 presents some data on this.

Table ES.3
Canada's Global Shares of Reserves, Production and Electricity Generation from Coal, Natural Gas and Nuclear in 2005

Source	Reserves	Production	Power generation
Coal	0.72	1.15	1.44
Natural gas	0.94	6.75	1.01
Uranium	10.47	27.88	3.33

Source: Table 6.1 of Chapter 6

Table ES.3 indicates that although Canada held only 0.72% of world coal reserves it produced 1.15% of the world's coal, much higher than its reserves share. Canada's global share of power generation from coal was even higher at 1.44% although power generation had to compete with other industries and export markets to acquire its coal supplies. In fact, some of the coal used for electricity generation in Canada is imported from the United States.

Turning to natural gas, one can see that Canada's global production share was more than 6 times its reserves share, while its global power generation share was similar to its reserves share in 2005. This can be partly explained by the fact that Canada's natural gas reserves, unlike those of many other countries, are within economic reach of export markets and widespread domestic residential, commercial and industrial users; so electricity generation must compete with alternative uses for supplies of natural gas.

The figures relating to uranium present a somewhat different picture. While Canada held 10.47% of world uranium reserves, it was world's leading uranium producer with a share as high as 27.88% in 2005. Canada's share of world nuclear power generation, in contrast, was only 3.33%, less that one third of its reserves share and less than one eighth of its production share. Unlike coal and natural gas, uranium is almost entirely used for power generation. Although nuclear weapons were once an alternative market for uranium, today the dismantling of nuclear weapons produces a fuel supply for nuclear power in competition with freshly mined uranium. Most of Canada's uranium production is devoted to export markets, as illustrated in Table ES.4.

Table ES.4
Global Shares of Nuclear Electricity Generation, Uranium Reserves and Uranium Production, 2005

Country	Nuclear power generation	Uranium reserves	Uranium production
United States	29.29	10.37	2.79
France	16.31	0.00	0.01
Japan	11.01	0.20	0.00
Germany	5.89	0.09	0.22
Russia	5.40	4.00	7.83
Korea	5.30	0.00	0.00
Canada	3.33	10.47	27.72

Source: Table 6.2 of Chapter 6

In 2005, Canada was the 7th largest nuclear power generator with a 3.33 percent global share. The USA, ranking 1st, accounted for 29% of the global nuclear generation while its uranium reserves were similar to Canada's and its uranium production was much lower – slightly more than 10% of Canada's production. The number two nuclear power generator, France, possessed almost no recoverable uranium reserves and almost no uranium production, but it generated more than 16% of global nuclear electricity. The USA, France, Japan, Germany and Russia have their own indigenous nuclear power generation technologies. South Korea, however, relied on Canadian know-how, possessed no recoverable uranium reserves and produced no uranium in 2005, yet its nuclear power generation in that year was about 60% greater than Canada's.

Coal, nuclear and natural gas accounted for 16.9 percent, 14.7 percent and 5.8 percent of Canada's electricity generation respectively in 2005. Long-term scenarios from the International Energy Agency (IEA) anticipate the following average global ranges of shares for coal, nuclear and natural gas in 2050: a) coal (16.5 to 47.0%), b) nuclear (6.7 to 22.0%), and c) natural gas (19.5 to 28.2%). The latest National Energy Board (NEB) scenarios anticipate a significant drop in coal's share of Canada's electricity generation, from 16.9 percent in 2005 to a range of 2.39 - 7.84 percent, in 2030. Nuclear's 2030 share is expected to range from 13.77 to 15.70 percent, close to the 14.7 per cent 2005 level. Natural gas share in 2030, however, is expected to be between 8.30 to 9.35 per cent, significantly higher than its 5.8 per cent share in 2005. It may be that the numbers in Table ES.4 indicate the potential for the share of nuclear power generation in Canada to turn closer to the IEA's 22 per cent compared with NEB's 15.7 per cent in the future.

We now turn to the principal area of this study, LCA of electricity generation in Ontario. Yearly electricity generation from coal, nuclear and natural gas in Ontario during 2005-6 averaged 116.3 TWh. Nuclear was the clear leader with 68.49 percent followed by coal with 23.1 percent and natural gas with only 8.4 per cent. Table ES.5 summarizes environmental impacts of electricity supplied by coal, natural gas and nuclear means.

Table ES.5
Electricity generation from coal, natural gas and nuclear in Ontario; share in generation and life-cycle impacts 2005-6; percent

Source	Generation ratio	Life-cycle environmental impact ratios		
		GHG emissions	Criteria air contaminants (CAC)	Radionuclides
Coal	23.08	83.82	92.21	0.03
Natural Gas	8.43	15.74	7.29	0.19
Nuclear	68.49	0.43	0.51	99.78
Total	100.00	100.00	100.00	100.00

Source: Table 6.4 of Chapter 6

The figures in Table ES.5 indicate that while coal's share of power generation via these three fuels was about 23 per cent, it was responsible for more than 83 per cent of their greenhouse gas (GHG) emissions. GHG emissions from natural gas came to 16 per cent, almost double its generation share. Nuclear, while securing more than 68 per cent of the generation from these fuels, accounted for a mere 0.4 per cent of their GHG emissions. As for criteria air contaminants (CAC), 92 per cent of them came from coal-fired power generation and nuclear's share was just 0.5 percent. Nuclear's share of radionuclide emissions, at 99.8 per cent, was much more than proportional to its generation share, although United States evidence in terms of collective dose rather than emissions, described in Appendix F, portrays the nuclear life cycle as having a much lower population radiation dose than the coal life cycle.

For easier comparison, Table ES.6 presents environmental impact indexes derived from the information in Table ES.5.

Table ES.6
Indices of Environmental Emissions of Electricity Generation from Coal, Natural Gas and Nuclear in Ontario
Nuclear = 100

Source	GHG	CAC	Radionuclides
Coal	57,233	54,038	0.09
Natural Gas	29,421	11,694	1.53
Nuclear	100	100	100

Source: Calculated based on Table ES.5

The figures in Table ES.6 demonstrate that coal was 572 times as GHG-intensive as nuclear and natural gas was 294 times as GHG-intensive as nuclear over the 2005-6 period. Similarly, coal was 540 times as CAC-intensive as nuclear, while natural gas was 117 times as CAC-intensive as nuclear over this period. As for radionuclides, though, coal had an extremely lower emission rate than nuclear and natural gas had a 98% lower emission rate.

Having reviewed the findings of the previous Chapters of the report, one could say that nuclear power generation in Ontario had much less adverse environmental impacts compared with power generation from natural gas and coal, that it was more reliable than power generation from natural gas, and that it was safer and more secure. In addition to that, abundant recoverable uranium reserves, the availability of a dynamic indigenous nuclear power generation technology and Canada's leadership in developing new nuclear technologies would set the scene for a larger future share of nuclear in Canadian power generation than the 15.7 per cent anticipated by NEB. The 22 per cent upper end of IEA's scenarios seems both warranted and achievable.

CHAPTER 1
INTRODUCTION

1.1 Background

The global revival in nuclear energy provides an opportunity to engage the public in a positive way to provide a factual and objective assessment of nuclear energy as an electricity generation option, and to aid the process of developing an informational base for rational decision-making. The purpose of this study is to provide quantification for assessing the life cycle impacts of various energy sources contrasted to nuclear power.

In this study, the Canadian Energy Research Institute (CERI) has set out to develop a rigorous analysis of the environmental and other attributes of the nuclear power generation option that would be a valuable contribution to the debate about the future of the industry as a carbon constrained world looms on the horizon. To be informative, such an analysis must be comparative in nature and examine alternative power generation options on equal footing to facilitate evaluation of the relative shares of these options in meeting power generation needs. To that end, CERI will conduct a rigorous Life Cycle Analysis (LCA) of electricity generation from three alternative fuel sources: nuclear, coal and natural gas. CERI will also address a number of the major areas of concern occasionally expressed in public forums.

1.2 Purpose of the Study

The overall objective of this study is to identify and analyze current and potential life cycle environmental impacts (GHG emissions, other air pollutants, water pollution, and radiation) of electricity generation from nuclear, coal, and natural gas. All of these fuel sources are important contributors to Canadian electricity generation and have implications for the environment. It will also be useful to set out the power requirements in the economy and compare various sources of energy that might meet those requirements in an objective fashion. The detailed objectives of the study include the following:

- Conduct a comprehensive literature survey covering all aspects of the study.
- Analyze the past performance and the current status of the various fuels under examination with respect to trends in technology, reliability, efficiency, safety, security, and environmental (GHG emissions, other pollutants, water pollution, and radiation) impacts, related to baseload electricity generation in Canada.
- Develop an appropriate and applicable LCA methodology, and apply the said methodology to evaluate and analyze the environmental impacts of electricity generation from nuclear, coal and natural gas in Ontario.

- Evaluate other issues such as security, safety and reliability relating to nuclear, coal and natural gas.

1.3 Methodology

There are two broad categories of methods of conducting LCA, namely the "Process LCA" and Economic Input-Output LCA (EIO-LCA). The Process LCA examines the environmental impacts of an activity from inception to completion, or from cradle to grave. The activity is subdivided into smaller stages or processes, the environmental implications of each process are studied, and then environmental impacts are added to arrive at a number, giving total impact per unit of activity. An example is the amount of CO_2 per kilowatt-hour of electricity generated.

The EIO-LCA method, on the other hand, uses economic input/output tables, which enlist inter-sectoral economic exchanges, and a matrix relating economic activity to environmental impacts such as CO_2 emissions. Using the input/output table and the pollutions matrix, one could trace and calculate the overall environmental impacts per monetary unit of the activity in question.

This study applies a Process LCA method and uses a 20-page standard developed by the International Organization for Standardization (ISO) 14040 as a guideline. This standard, in turn, requires the user to meet another standard ISO 14044 as well. The latter standard, which presents more detailed sub-standards and procedures, has also been adhered to where possible. Following these standards, discussed in greater detail later in Section 1.4.2 in this Chapter, as guidelines ensure a measure of accuracy and therefore credibility to the final report. CERI has made every effort to ensure that the analysis is disciplined and complete.

Further details of the methodology will be presented in Chapter 4.

1.4 Literature Review

This section presents the results of the literature review conducted on various aspects of LCA. It is organized in five sections: background of LCA, ISO LCA standards, a review of LCA modeling approaches, sources and software for conducting an LCA and, finally, a brief literature review of various LCAs for electricity generation.

1.4.1 Background of LCA

In 1969 the first LCA was performed by Harry E. Teastley Jr. for Coca Cola Company, taking into account the whole environmental impacts of glass and plastic bottles for bottling the product. The energy crisis in 1970s had a major influence on environmental awareness. At that time, Life Cycle design opened a new era for integrating pollution prevention and resource conservation strategies. In particular, Life Cycle design looked at developing of more ecologically and economically sustainable product systems.

LCA was developed in parallel to the sustainable product design process and its focus was environment rather than economy. Interest in LCA has increased since 1980; the earlier research of EMPA (Europe) goes back to 1980s. An awkward situation occurred towards the end of 1980s, as different LCA studies for similar products often contained conflicting results. This was mainly due to using different terminology, database and modeling approach. It quickly became apparent that LCA reporting needed a standard. As a result, the Society of Environmental Toxicology and Chemistry (SETAC) became the main forum for the scientific discussion on LCA and the first works of SETAC on standardizing approaches initiated on 1991. SETAC developed a "Code of Practice" for LCA. Indeed, this code of practice was the base of the ISO guidelines.

Numerous other individuals and organizations have worked to develop and standardize LCA approaches. For instance, the Society for the Promotion of Life Cycle Development (SPOLD) was founded to accelerate the development of LCA. SPOLD also published and developed the data format to facilitate data exchange between different LCA databases. The organization mentioned that the scientific activities within SETAC have enhanced the quality of work in ISO standards.

As a result, the ISO, in line with others, set the ISO 14040 series to establish a uniform framework, approach and terminology for LCA.

1.4.2 ISO LCA Standards

The ISO LCA standards concern the technical as well as organizational aspects of LCA projects. The organizational aspects generally focus on the design of critical review processes, with special attention to the studies disclosed to the public. The following general standards are being produced in the ISO 14040 series:

- ISO 14040: A standard on principles and frameworks. 1st edition 1997
- ISO 14041: A standard on goal and scope definition as well as inventory analysis. 1st edition 1998
- ISO 14042: A standard on life-cycle impact assessment. 1st edition 2000
- ISO 14043: A standard on life-cycle interpretation. 1st edition 2000
- ISO 14044: A standard on requirements and guidelines. 1st edition 2006

The ISO standards are not easy to apply, which makes it difficult to see if an LCA has been performed according to the standard. It is almost impossible to get an official accreditation that states that an LCA or LCA methodology has been performed according to the ISO standard. For example, ISO 14042 does not allow weighting across impact categories for public comparisons between products. However, weighting is frequently used by many LCA studies and software.

1.4.3 Various LCA Modeling Approaches

This section defines various modeling approaches. This section discusses three, in particular: process, economic input/output and hybrid LCA methodologies.

1.4.3.1 Process Model

The LCA methodology that is described in ISO publications is called "Process LCA". According to this approach a system boundary is defined and different processes are included in it. A process flowchart might be helpful for showing the system boundary, unit processes and their inter-relationships. The process model assessment typically consists of a detailed inventory of resource inputs and environmental outputs for the analysis period and processes considered. The outputs then can be evaluated for their environmental harm. Carrying out a complete process LCA for complicated products is almost impossible and time consuming, as the number of processes and product components gets larger and data requirements becomes an issue. Also this approach requires material and energy balances for each of the processes.

SETAC and the US Environmental Protection Agency (EPA) use the process models for life-cycle assessments; therefore the modeling approach has been cited as SETAC-EPA LCA in some publications.

While conducting a complete process LCA is impracticable, selection of representative facilities and major components of the product is good approximation. Although this modeling approach is very data intensive and time consuming, it gives detailed information for a better product design and enables comparison between the environmental impacts of different processes along the production chain. As a result, the advantage of process LCA is that it can answer detailed questions, and its disadvantage is that it is time consuming and expensive to practice.

1.4.3.2 Economic Input-Output Model

The EIO-LCA takes a more aggregate view of the sectors producing all of the goods and services in an economy. The model uses two simplifications. First, a linear relationship simplification, any percentage increase in output from a factory requires the same percentage of extra inputs. Second, all production facilities can be aggregated into a limited number of sectors. To the economic input-output matrix an environmental discharge matrix is appended to create the EIO-LCA model.

The advantage of EIO-LCA model is that it does not need to define any boundary for the system as it covers the entire economy including all the material and energy input. Performing an LCA using this approach is also generally easier and quicker than the Process LCA discussed above. Its disadvantage is that it is at an aggregate level, such as "Electric Power Generation, Transmission and Distribution", rather than power generation from nuclear, natural gas or coal-fired facilities. It is often difficult to disaggregate data.

1.4.3.3 Hybrid LCA

Hybrid LCA is a combination of EIO-LCA and Process LCA. The model combines the scope of the economy wide EIO-LCA model with the detail of Process LCA. Hybrid LCA models have received considerable attention in the literature. Several approaches to hybrid LCA that have been suggested, the approaches vary in their theoretical basis and the ways in which the sub-models are combined. In one approach the EIO-LCA results can be used to estimate inputs and outputs of particular processes. In this case, the environmental aspects of intermediate commodities or energy, which is used in each process, are calculated by EIO-LCA and fed into a process model as inputs or outputs.

The other approaches are based on changes to the coefficients or the structure of EIO-LCA. In this case, the environmental impact matrix could be modified to represent changes in a particular industry. More generally, the coefficients of the input-output model itself may be modified too. One option is to disaggregate a particular sector into subsectors by using process estimates. Another approach would be to develop an alternative to the economic input-output table, for instance, an enterprise input-output model can be used instead. The enterprise input-output models can be developed for a particular facility.

1.4.4 Sources and Software for Conducting LCA

There are many useful periodical and non-periodical published sources for conducting LCA. CERI has investigated and searched the relevant documents from the following published sources:

- Periodicals
  - The International Journal of Life Cycle Assessment
  - Journal of Industrial Ecology
  - Renewable Energy
  - Energy Economics
- Books
  - Product Life Cycle Assessment to Reduce Health Risks and Environmental Impacts (1994)
  - The Computational Structure of Life Cycle Assessment (2002)
  - Handbook of Life Cycle Assessment (2002)
  - Introduction to Environmental Impact Assessment (2005)
  - Greening the Industrial Facility: Perspectives, Approaches, and Tools (2005)
  - Environmental Life Cycle Assessment of Goods and Services (2006)

In addition to the above sources, there are many reports or single studies regarding LCA for energy/electricity sectors. Some of these reports are listed in the next subsection; however the complete list is presented in the Bibliography.

Furthermore, there are a number of software packages - and their relevant databases - designed for conducting LCA. The software available is either based on Process Modeling or Input-Output approach. Some of the relevant LCA software is listed below:

- GHGenuis (for Canada, US, Mexico and India)
- GREET (for US)
- SimaPro (US and European database)
- EIO-LCA Economic Input-Output LCA at Carnegie Mellon University (US, Canada)
- TEAM (Databases for different countries including Canada)

1.4.5 LCA Studies for Electricity

CERI reviewed many international and Canadian documents. This section describes briefly the methodology, geographic location and findings of several studies that are relevant to our study of nuclear, natural gas and coal electricity fuel cycles.

CANDU Reactors and Greenhouse Gas Emissions

The first LCA study conducted for CANDU technology is Andseta et al. (1998). The authors investigate GHG emissions for nuclear electricity in Canada using a process Life Cycle Inventory (LCI), as the impact assessment had not been conducted. The study includes construction and decommissioning of the power plants. They produce the total GHG from CANDU per unit of electricity generated. They ultimately conclude that "over one hundred times as much CO_2 is avoided by deployment of the CANDU fuel cycle in place of coal plants in Canada than is released by CANDU construction, the fuel production process and decommissioning".

Life-Cycle Inventory Information of the United States Electricity System

Kim et al. (2005) performed an LCA and estimated the GHG emissions associated with the electrical system for the United States. Their method is process LCA and performed for the year 2000. They excluded the construction and decommissioning of the facilities and concluded that the main source of GHG emissions involved with the US electricity system is coal-fired electricity with 81 percent of the total. In addition, the natural gas-fired power plants contributed to 16 percent of the total.

Comparison of Energy Systems Using Life Cycle Assessment

In 2004, The World Energy Council (WEC) compared various LCA reports for different energy systems. The report concludes that the main environmental burden involved with generation of electricity originates at the fossil fuel power plants and the contribution of upstream stages are at most, 10 to 15 percent of the total fuel emissions for most of the fuel cycles. The report also identifies the production of one MWh of electricity from coal is involved with the release of more GHG pollutants than other fuels in the life cycle.

Life Cycle Inventories for the Nuclear and Natural Gas Energy Systems, and Examples of Uncertainty Analysis

Denos et al. (2004) performed a process LCI analysis for nuclear and natural gas electricity systems for several Western European countries. The authors covered only the operation of facilities, excluding construction or decommissioning of the facilities. While the study did not cover the CANDU technology, it concludes that nuclear electricity systems emit significantly less than natural gas power systems.

Life Cycle Energy Balance and Greenhouse Gas Emissions of Nuclear Energy in Australia

In 2005, The University of Sydney conducted an LCA for nuclear energy in Australia. Their research group also studied CANDU technology in the report. One of their major findings is to use less but enriched fuel in Light Water Reactors (LWR), versus more but natural fuel in Heavy Water or Gas-cooled Graphite Reactors. The research group uses and develops a hybrid LCA approach for their analysis.

Environmental Assessment of Selected Canadian Electric Power Generation Systems Using a Site-Dependent Life-Cycle Impact Assessment Approach

This project, prepared for the Canadian Electricity Association (CEA) in 2005, completes a site-dependent LCA for the environmental impacts of selected Canadian electric power generation systems. They compared five different pilot projects in Canada including a wind farm; a new coal powered generation; a run-of-river large hydropower station; a CANDU nuclear power plant; and a thermal unit burning primarily natural gas. The study concludes that the modernization decisions made by the Canadian electricity industry in line with Canadian government regulations have resulted (or will result) in overall reductions in environmental impacts per unit of power generated and delivered. They take a process modeling approach.

Methods to Assess the Impacts on the Natural Environment of Generation Options

A report from the Ontario Power Authority (OPA) that is prepared by a consultant (2005) has taken the Impact Ranking approach for LCA. The approach is process LCA up to the inventory phase of LCA; however, for impact analysis the study ranks the impacts of the pollutants rather than analyzing them. In addition, the study is based primarily on the estimates from other LCA reports. This report covers various fossil fuel technologies of electricity generation, as well as CANDU. The study ranks the coal-fired electricity with the highest impact on the environment. The natural gas and nuclear electricity fuel cycles are ranked the second and the third.

1.5 Data Requirements

The availability of detailed data is of critical importance to any LCA study. CERI explored all of the known sources and has collected a rich and valuable set of data on numerous processes involved in electricity generation from nuclear, coal, and natural gas in Ontario. The set includes data on fuel production, fuel transportation and power plant operations, etc.

There were, however, bottlenecks in obtaining some of the required data. Some of the necessary pollutions/emissions data are not reported at all. Some of the data are only available in aggregate form. There are some outdated and/or inconsistently reported data.

CERI attempted to obtain as much data as possible and where necessary, has compiled data from different sources and has compared them to come up with the most reliable. Where actual data on some processes has not been available, CERI has applied generic formulations to calculated, environmental impacts, for example, in natural gas transportation by pipelines.

Further details on data are presented in Chapter 4.

1.6 Report Structure

The rest of this report has been structured as follows. Chapter 2 and Appendix A examine past trends, current status and future outlook of electricity generation in Canada and worldwide. The Canadian nuclear power industry and technology are discussed in Chapter 3. Appendices B and C present further information on nuclear power in Canada and provide some basics of nuclear, natural gas-fired and coal-fired power generation technologies. Chapter 4 presents the methodology and details of the results of application of LCA to electricity generation from nuclear, coal and natural gas in Ontario. Appendices D, E and F include some calculation details, printouts of a number of Excel sheets from the LCA model developed by CERI and some information on radionuclides. Other important issues such as reliability, safety and security of electricity generation from nuclear, coal and natural gas are discussed in Chapter 5. Finally, Chapter 6 presents some concluding remarks on all aspects the LCA application. Bibliography and Glossary of technical terms wrap up the report.

CHAPTER 2
POWER GENERATION IN CANADA

This Chapter examines past trends and current status of total electricity generation in Canada. The associated Appendix A elaborates on Canadian electricity generation from nuclear, coal and natural gas. It also examines some future scenarios of global and Canadian power generation. Section 2.1 studies historical developments in the power sector in Canada, global as well as regional contexts during 1971-2005. It addresses Canada's world and regional electricity generation shares, compares Canadian electricity generation growth rates to the world, regional and national rates and depicts the trends in the shares of various electricity generation sources within total generation. It also compares Canada's power generation trends to population and GDP trends during 1971-2005. Section 2.2 presents some concluding remarks.

In Appendix A, sections A.1 through A.3 examines Canada's global and regional shares in nuclear, coal-fired and natural gas-fired electricity generation, compares generation growth rates and presents an account of the three above-mentioned sources in the Canadian generation mix. Sections A.4 and A.5 discusses future outlook of electricity generation in the world and Canada, respectively, based on the latest scenarios from the International Energy Agency (IEA) and the National Energy Board (NEB) of Canada. These sections provide various outlooks as to what potential generation mix may look like in the not too distant future.

2.1 Power Generation During 1971-2005

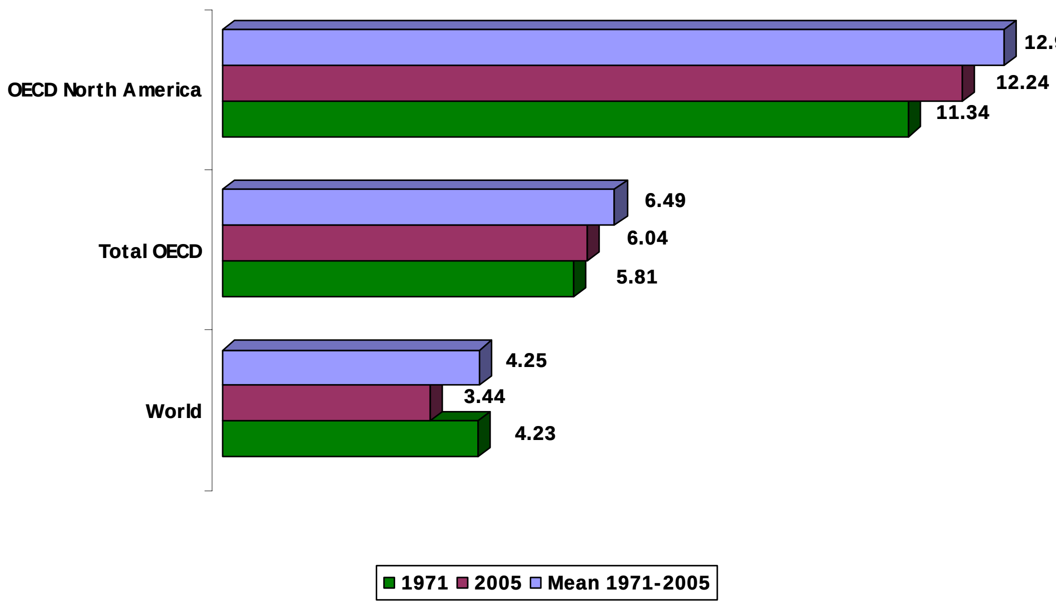
This section examines power generation in the world and Canada during 1971-2005. The following sections address Canada's world and regional electricity generation shares, compare its electricity generation growth rate to world, regional and country rates, and depict the trends in the shares of various electricity generation sources within total generation. This section also examines the trends in electricity generation from various sources, including coal, nuclear, natural gas and hydro. This section not only addresses their historical developments but also their current status in Canada, as well as growth rates and share in total electricity generation in Canada.

2.1.1 Power Generation: World and Regional Share

Canada generated 221,833 gigawatt hours of electricity, close to 4.23 percent of global output, in 1971. Through an average 3.17 percent annual growth during 1972-2005, Canada's Total Electricity Output (TEO) rose to 628,083 gigawatt hours, nearly 3.44 percent of global TEO, in 2005.[1] Figure 2.1 shows Canada's share of global and regional TEO.

[1] Calculated based on "IEA World Energy Statistics and Balances - Energy Balances of Non-OECD Member Countries - Energy Balances (ktoe) Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD*.

Figure 2.1
Share of Canada in World and Regional TEO; 1971, 2005 and Average Over 1971-2005
(per cent)



SOURCE: Calculated based on "IEA World Energy Statistics and Balances - Energy Balances of Non-OECD Member Countries - Energy Balances (ktoe) Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD*.

As seen in Figure 2.1, Canada's TEO lost share slightly during 1971-2005. The global share dropped from 4.23 per cent in 1971 to 3.44 percent in 2005 and the latter was below the historical 4.25 per cent share for the whole 1971-2005 period. The shares in OECD and in North America experienced the reverse pattern. Canada continued enjoying a high position in world and regional TEO because its population comprised only 0.54 per cent of the world population during 1971-2005, while its share of the global TEO was 4.25 per cent in the same period, close to eight times higher than the population share thanks in part to its electricity exports to the US and to its electricity intensive industries. Similarly, Canada's share of global TEO, 4.25 percent, was significantly higher than its share of global GDP, 1.95 per cent, and its share of global total primary energy production (TPEP), 3.25 per cent, during 1971-2005.[2] This is because Canada is a major producer and exporter of primary industry products.

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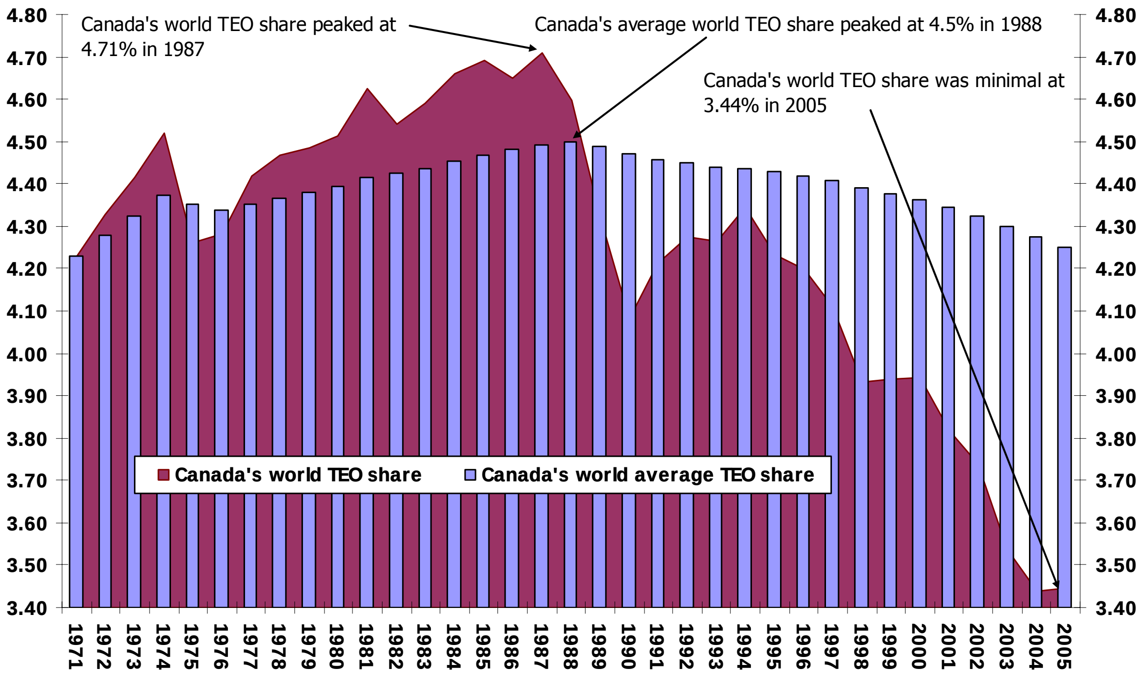
[2] Calculated based on "IEA World Energy Statistics and Balances - Energy Balances of OECD Countries - Energy Balances Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD* and "IEA World Energy Statistics and Balances – Energy Balances of Non-OECD Countries - Economic Indicators Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD*.

A similar strength in Canada's TEO is also evident on the regional level. While the average share of Canada's TEO within the OECD countries was as high as 6.49 per cent, its shares of population and GDP were relatively lower at 2.62 per cent and 3.14 per cent respectively during 1971-2005.

Figure 2.2 compares Canada's share in world TEO and its time average. Each average point represents the average share from 1971 to the year in question.

Figure 2.2
Canada's Share in World TEO and its Average; 1971-2005
(per cent)



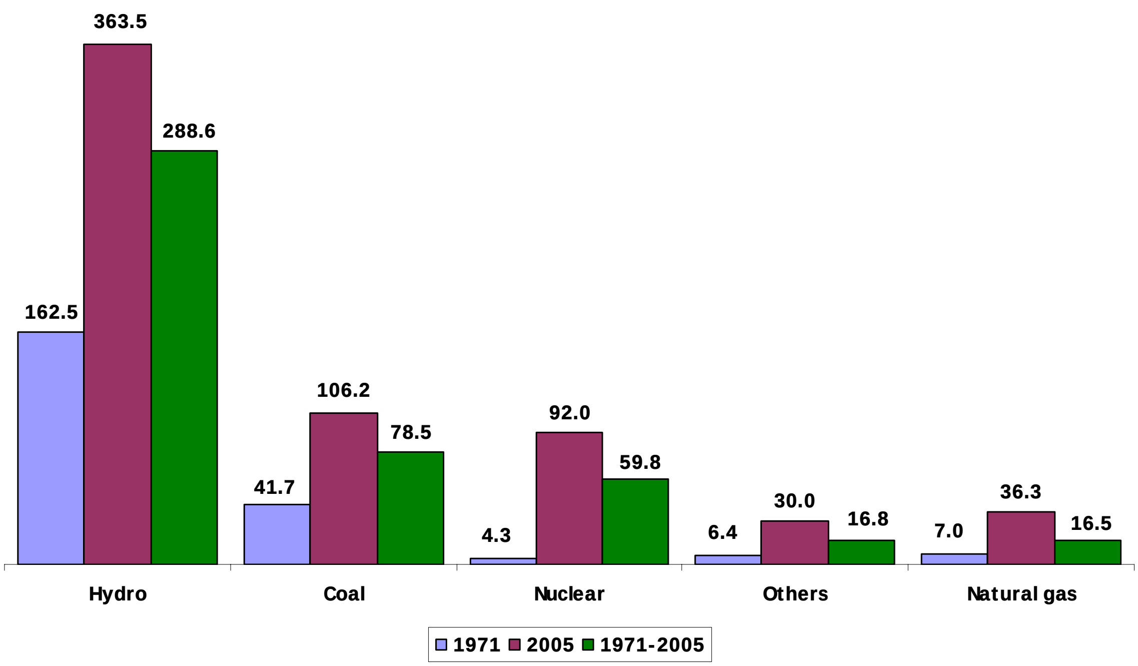
SOURCE: Calculated based on "IEA World Energy Statistics and Balances - Energy Balances of OECD Countries - Energy Balances Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD* and "IEA World Energy Statistics and Balances - Energy Balances of Non-OECD Member Countries - Energy Balances (ktoe) Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD*.

Figure 2.2 indicates that the share of Canada in world TEO maintained a more or less general uptrend pattern during 1971-1988. However, since 1989, Canada's TEO share has lagged behind its historical average. That is, on average other countries have maintained a more aggressive electricity generation growth compared to that in Canada during 1989-2005. The reason is that most of the non-OECD developing economies are generally more energy intensive during earlier stages of economic growth, and they need more electricity to run their development projects. Those economies were expanding their electricity generation industry faster than in OECD members such as Canada during 1989-2005.

2.1.2 Power Generation: Sources of Electricity Generation in Canada

This section classifies sources of electricity generation in Canada as hydro, coal, nuclear, natural gas and others (electricity generated from petroleum products and all renewable sources). Figure 2.3 shows the amounts of electricity generated from the said sources in 1971, 2005, and the average over 1971-2005 to indicate the trends in their relative positions.

Figure 2.3
Canadian Annual Electricity Generation by Source; 1971, 2005, and Average over 1971-2005 (TWh)

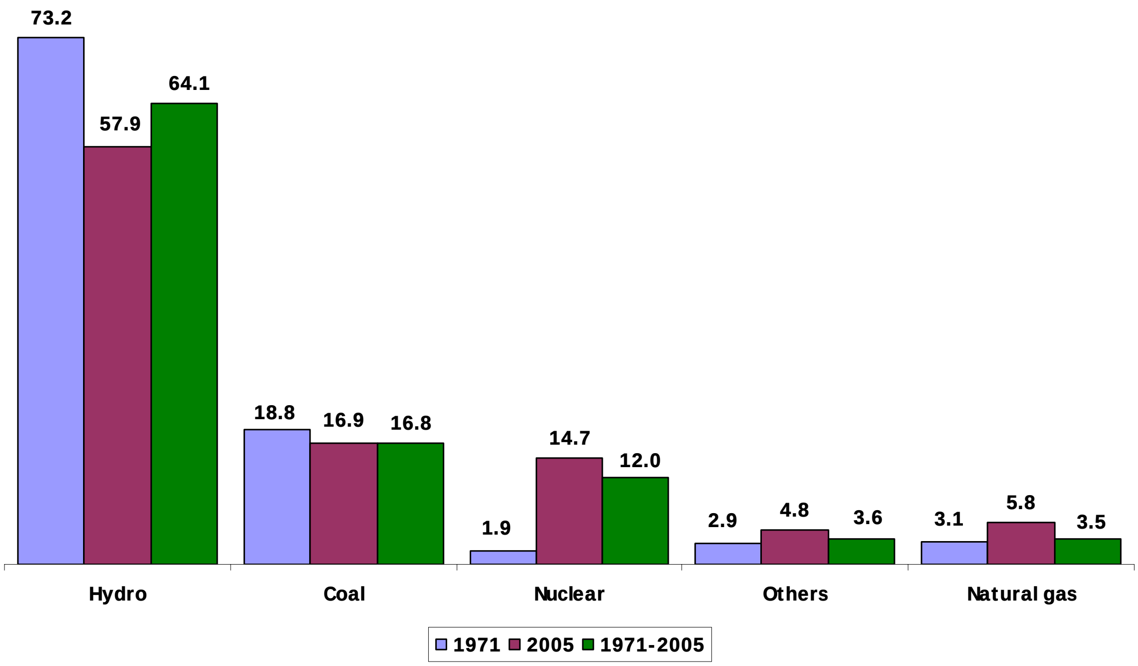


SOURCE: "IEA World Energy Statistics and Balances - Energy Balances of OECD Countries - Energy Balances Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD*. Averages calculated based on data from source.

Figure 2.3 indicates that in 1971 the prime source was hydro electricity, amounted to 162.5 terawatt hours (TWh) close to 4 times that from the second source coal, from which 41.7 TWh was generated. Natural gas, other sources and nuclear followed with amounts several times smaller than that of coal. In 2005, while hydro and coal maintained their first and second position, their difference moderated. In the same year, nuclear, with 92 TWh, overtook natural gas and others to become the third source of electricity generation in Canada with minimal difference from coal from which 106.2 TWh of electricity was generated. It is also evident that nuclear has been the fastest growing electricity generation source.

A similar comparison can be obtained by examining the shares of each source in total electricity generation. Figure 2.4 presents the shares in percentage terms.

Figure 2.4
Shares of Various Sources in Canadian Electricity Generation; 1971, 2005, and Average Over 1971-2005
(per cent)



SOURCE: Calculated based on "IEA World Energy Statistics and Balances - Energy Balances of OECD Countries - Energy Balances Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD*.

The numbers in Figure 2.4 clearly demonstrate the prime position of hydro from which close to 60 percent of the Canadian electricity is generated. Hydro's share however, significantly dropped from 73.2 per cent in 1971 to 57.9 per cent in 2005, staying below its historical 64.1 per cent average. Coal maintained a rather stable share close to 17 per cent, while nuclear share grew substantially, from less than 2 per cent in 1971 to 14.7 per cent in 2005, well above its historical 12.0 per cent average. Natural gas and others' shares also increased with nuclear enjoying the highest share gain. In the final analysis one can say that more than a 15 per cent drop in hydro's share was gradually redistributed mostly to nuclear, and a little to natural gas and other sources during 1971-2005.

2.1.3 Power Generation: TEO and Population Growth

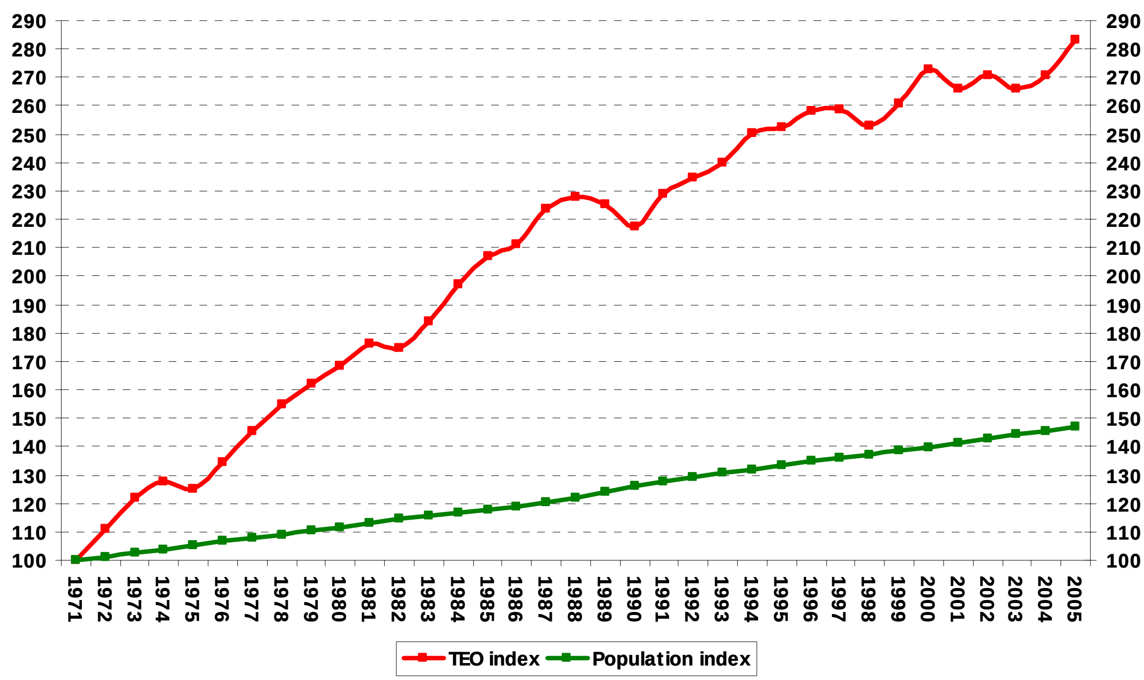
The Canadian economy grew at a greater rate than our population from 1971-2005. This can be partly attributed to increased manufacturing and raw materials, such as oil, exports both to the United States and the rest of the world. Domestically, we are consuming more electricity with the increasing availability of electronic products as well as changes to working conditions that now require more support from our heating and air conditioning.

The charts that follow illustrate the impact of our electricity consumption as it relates to our population growth and illustrates the ever expanding role of our exports on electricity requirements.

Indexes of electricity generation and population, both taking their respective 1971 amounts equal to 100, indicate that TEO was continuously growing at a higher speed than population with the gap between the 2 indexes growing wider throughout 1971-2005.

As Figure 2.5 indicates, the population index grew at a relatively slow and smooth pace from 100 in 1971 to 147 in 2005; less than 50 per cent growth, on average, during a 35-year period. The TEO index, however, experienced a much faster growth rising to 283 in 2005 thereby registering a more than 180 per cent growth, on the average, over the same period. The widening gap between the indexes is quite evident. This implies that TEO per capita was steadily rising in Canada during 1971-2005.

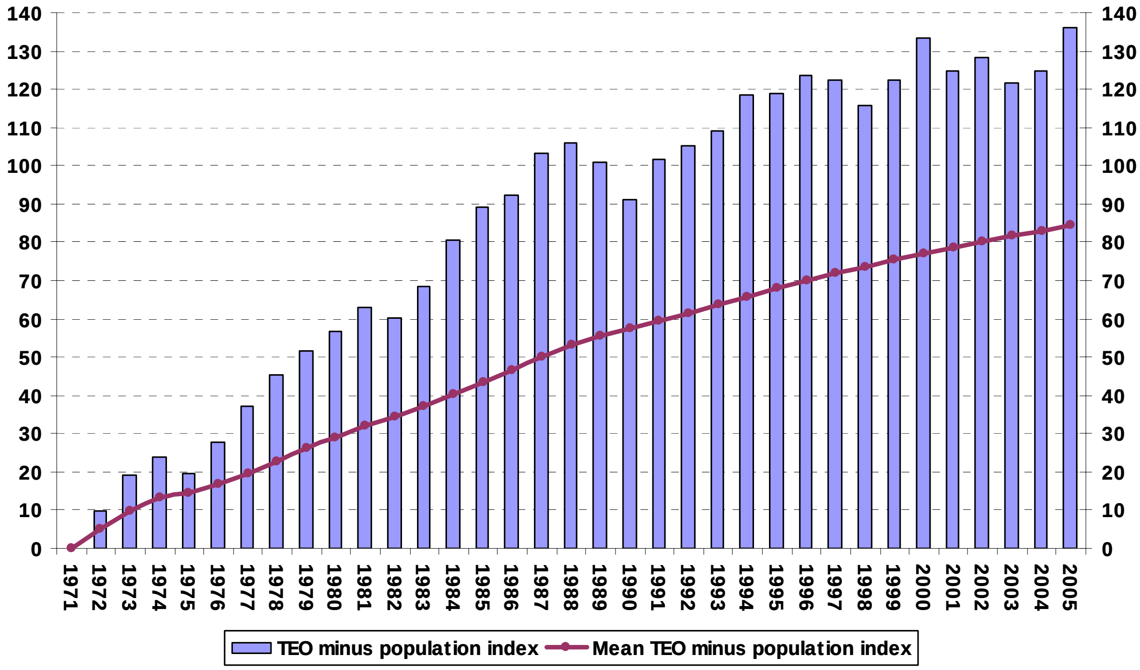
Figure 2.5
Canada TEO Index and Population Index; 1971-2005



SOURCE: Calculated based on "IEA World Energy Statistics and Balances - Energy Balances of OECD Countries - Energy Balances Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD* and "IEA World Energy Statistics and Balances – Energy Balances of OECD Countries - Economic Indicators Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD*.

A pictorial analysis of the movements in TEO and population indexes is presented in Figure 2.6 where the difference between TEO and population indexes has been graphed alongside its time average.

Figure 2.6
The Difference Between TEO and Population Indexes Alongside its Time Average; Canada; 1971-2005



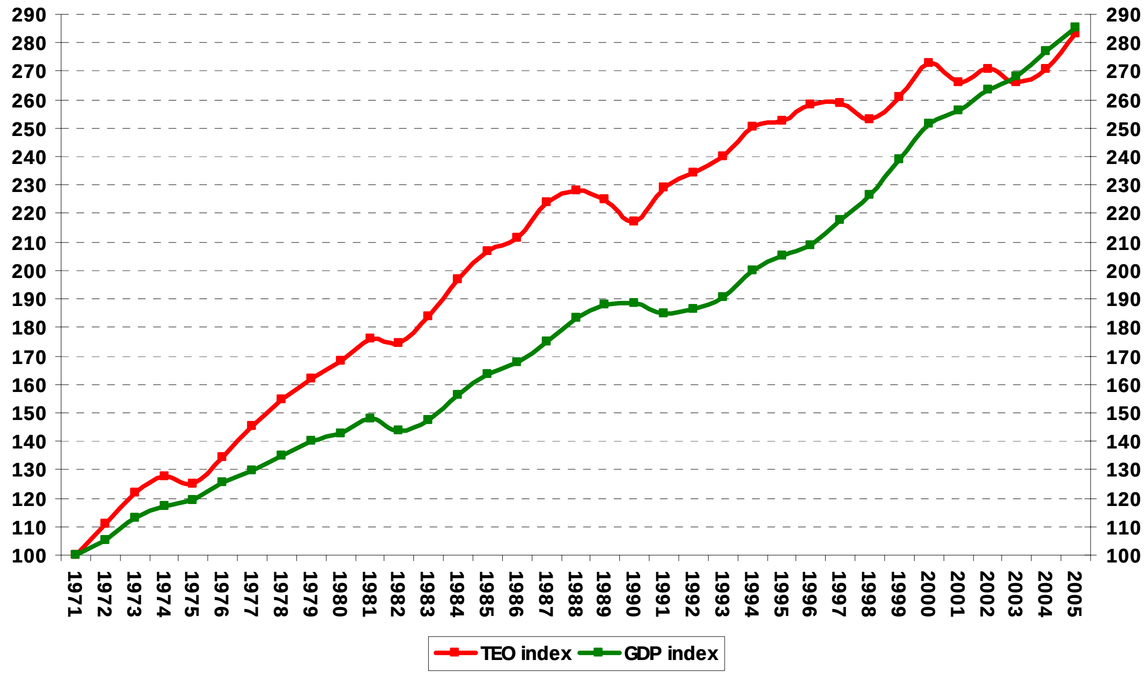
SOURCE: Calculated based on "IEA World Energy Statistics and Balances - Energy Balances of OECD Countries - Energy Balances Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD* and "IEA World Energy Statistics and Balances – Energy Balances of OECD Countries - Economic Indicators Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD*.

Figure 2.6 indicates that the gap between TEO and population indexes grew, rather monotonically, from 0 in 1971 to its historical high at 136.2 in 2005, that only in a few years during 1971-2005 did the gap register a decline and that on the average, the gap kept widening from 0 in 1971 to its maximum at 84.3 in 2005. This implies that the pace of electricity generation growth has persistently been faster and faster than that of population growth in Canada during 1971-2005. This could be partly explained by the substantial electricity exports during the said period.

2.1.4 Power Generation: TEO and GDP growth

Indexes of electricity generation and GDP, both taking their respective 1971 amounts equal to 100, indicate that both indexes were continuously increasing and that the gap between the 2 indexes grew wider from 1971 to 1987, stayed rather constant until 1996, then started shrinking, and turned negative from 2003. This means that the electricity generation growth was slower than GDP growth from 2003 to 2005. Figure 2.7 presents the details.

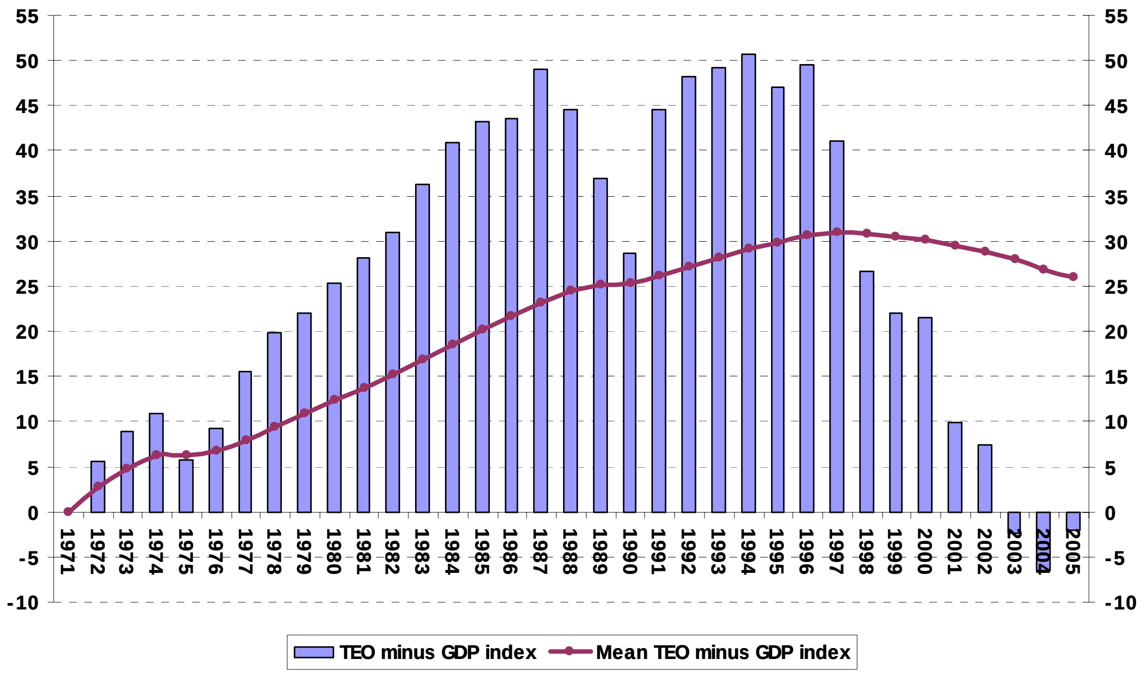
Figure 2.7
Canada TEO Index and GDP index; 1971-2005



SOURCE: Calculated based on "IEA World Energy Statistics and Balances - Energy Balances of OECD Countries - Energy Balances Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD* and "IEA World Energy Statistics and Balances – Energy Balances of OECD Countries - Economic Indicators Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD*.

To examine the trend in the relative movements in TEO and GDP indexes, we have graphed the difference between them and the time average of the difference, where every point is the average of the differences in the period from 1971 up to the year the point refers to. Figure 2.8 presents the graphs.

Figure 2.8
The Difference Between TEO and GDP Indexes Alongside its Time Average; Canada (1971-2005)



SOURCE: Calculated based on "IEA World Energy Statistics and Balances - Energy Balances of OECD Countries - Energy Balances Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD* and "IEA World Energy Statistics and Balances – Energy Balances of OECD Countries - Economic Indicators Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD*.

Figure 2.8 indicates that although the difference between TEO and GDP index registered a temporary fall from 1987, the average gap continued its ascent rather monotonically until 1997 when it amounted to its maximum at 31. However, the average gap was declining steadily from 30.8 in 1998 to 26.1 in 2005. This means that in Canada on the average, GDP grew at a relatively higher pace than electricity generation from 1998.

2.2 Concluding Remarks

This section presents concluding remarks on the topics examined in Chapter 2 and the associated Appendix A. The information presented throughout the Chapter and in the appendix confirms that Canada is a major power generator on a global basis. It generated 628,083 gigawatt hours of electricity in 2005; ranking 3rd after United States and Japan within the 30-strong OECD group of countries and ranking 6th worldwide after United States, China, Japan, Russia and India. Canada's per capita power generation was 19,463 kilowatt hours in 2005; ranking 3rd within OECD and worldwide after Norway and Iceland.

In terms of electricity generation from coal (106,188 gigawatt hours), nuclear (92,040 gigawatt hours) and natural gas (36,324 gigawatt hours) - the focus of our LCA - Canada ranked 13, 7, and 22 respectively worldwide in 2005. On a per capita basis, Canada's coal, nuclear and natural gas electricity generation global rankings stood at 9, 10, and 38 respectively.

Coal, nuclear and natural gas secured 16.9 per cent, 14.7 per cent and 5.8 per cent in the Canadian electricity generation respectively in 2005. Long-term scenarios from the International Energy Agency assumes the following average global ranges of shares for coal, nuclear and natural gas in 2050: for coal from 16.5 to 47.1 per cent, for nuclear from 6.7 to 22 per cent, and for natural gas from 19.5 to 28.2 per cent. Canada's latest National Energy Board scenarios assume certain levels for 2030 electricity generation. The scenarios expect a significant drop in the share of coal from the 16.9 per cent in 2005, to 2.39 to 7.84 per cent, in 2030. The 2030 share of nuclear is expected to range from 13.77 to 15.70 per cent, close to the 14.7 per cent 2005 level. Natural gas share in 2030, however, is expected to vary between 8.30 to 9.35 per cent, significantly higher than the 5.8 per cent in 2005.

CHAPTER 3
NUCLEAR POWER IN CANADA

This Chapter discusses nuclear power in Canada. It is divided into four sections. The first section reviews briefly, world nuclear power and uranium consumption. The second section discusses nuclear electricity generation in Canada. This section also reviews the status of Canada's five nuclear power plants (Pickering, Darlington, Bruce, Gentilly and Point Lepreau) and their nuclear reactors.

The third section considers briefly the various activities in Canada associated with the production of electricity from nuclear reactors. This section reviews the 'front end' of the fuel cycle such as mining, milling, enrichment for non-CANDU reactors, and fuel fabrication.

For additional information regarding nuclear power in Canada, refer to Appendices B and C. Appendix B examines research and development in Canada. However, in addition to examining the industries' important players, the appendix steps away from nuclear power generation to examine various significant nuclear products either being developed or used in Canada. Appendix C, on the other hand, provides a brief discussion of nuclear technology. This appendix discusses briefly the domestic Advanced CANDU Reactor (ACR) and Pressurized Water Reactor (PWR) from a technical perspective, as well as looks into future Canadian technology. This appendix also discusses natural gas and coal-fired technologies used for electricity generation.

3.1 World Nuclear Power and Uranium Consumption

In 2007, 439 nuclear power reactors were in service around the world in thirty-one countries with a combined generation capacity of 369,122 megawatts (MW). At present, nuclear power supplies about 16 percent of the world's electric energy.

Table 3.1 tabulates nuclear power capacity (MW) and generation (GWh) of all countries along with their GDP and population. Also presented in the table are the technologies employed for nuclear power generation in those countries. Approximately 55 percent of total global nuclear power capacity is located in three industrialized countries: United States (26.6 per cent), France (17.2 per cent), and Japan (12.9 per cent). With a total capacity of 12,599 MW, Canada is ranked eighth in the world.

Table 3.1
2006 Economic and World Nuclear Power Indicators

Country	GDP Billion $US	Population Million	Nuclear Gen Capacity MW	Nuclear Generation TWh	Technology*
US	12,980	298.4	98,145	788.53	PWR/BWR/LMFBR/HTGR
France	1,871	62.8	63,363	425.83	GCR/PWR/GCHWR/LMFBR
Japan	4,220	127.5	47,593	271.58	BWR/HWLWR/PWR/GCR
Russia	1,723	142.9	21,743	137.47	PWR/LGR/LMFBR/BWR
Germany	2,585	82.4	20,339	158.97	PWR/BWR/LMFBR/PHWR/ GCHWR/HTGR
Korea Rep	1,180	48.8	16,810	124.18	PWR/PHWR
Ukraine	356	46.7	13,107	82.69	LGR/PWR
Canada	1,165	33.1	12,599	85.87	PHWR
UK	1,903	60.6	11,852	73.68	GCR/AGR/PWR/LMFBR/ HWLWR
Sweden	285	9.0	8,910	73.43	PWR/BWR
China	10,000	1,314	7,572	47.95	PWR/BWR
Spain	1,070	40.4	7,446	60.43	PWR/BWR/GCR
Belgium	330	10.4	5,824	45.80	PWR
Taiwan	668	23.0	4,904	37.94	PWR
Czech RP	221	10.2	3,368	25.01	PWR
Switzerland	253	7.5	3,220	25.61	PWR/BWR/GCHWR
India	4,042	1,095	3,040	15.04	PHWR/BWR
Bulgaria	77	7.4	2,722	15.60	PWR
Finland	172	5.2	2,676	21.55	PWR/BWR
Slovakia	96	5.4	2,442	16.18	PWR/GCHWR
Brazil	1,616	188.1	1,901	11.60	PWR
South Africa	576	44.2	1,800	14.28	PWR
Hungary	173	10.0	1,755	11.32	PWR
Mexico	1,134	107.4	1,310	8.73	BWR
Lithuania	54	3.6	1,185	14.35	LGR
Argentina	599	39.9	935	7.31	PHWR
Slovenia	46	2.0	656	5.21	BWR
Romania	197	22.3	655	5.27	PHWR
Netherlands	512	16.5	449	3.63	BWR
Pakistan	427	165.8	425	1.93	PHWR/PWR
Armenia	16	3.0	376	2.21	PWR
Total	**50,549**	**4,034**	**369,122**	**2,619**	

Source: CIA Fact Book (2006 GDP and POP) Nuclear Power – Global Status and Trends by Y. Sokolov & A. MacDonald (2006 Capacity) International Nuclear Safety center (2004 Generation and Technology)

*Notes: PWR - Pressurized Light Water Moderated and Cooled Reactor; BWR - Boiling Light Water Cooled and Moderated Reactor; PHWR - Pressurized Heavy Water Moderated and Cooled Reactor; HWLWR - Heavy Water Moderated, Boiling Light Water Cooled Reactor; LGR - Light Water Cooled, Graphite Moderated Reactor; LMFBR - Liquid Metal Fast Breeder Reactor; GCR - Gas Cooled, Graphite Moderated Reactor; GCHWR - Gas Cooled, Heavy water Moderated Reactor; HTGR - High Temperature Gas Cooled Reactor; AGR - Advanced Gas Cooled, Graphite Moderated Reactor

According to the World Nuclear Association (WNA), sixteen countries depend on nuclear power for at least a quarter of their electricity. Belgium, Bulgaria, Hungary, Slovakia, South Korea, Sweden, Switzerland, Slovenia and Ukraine get one third or more while France and Lithuania get around three quarters of their power from nuclear energy. The United States gets almost one fifth of their power from nuclear energy. China and India, the two most populous countries in the world, hold only 3 percent of global nuclear capacity.

In 2006, about 2,619 terawatt hours (TWh or billions of kWh) of electricity was generated around the world. As previously mentioned nuclear represents about 16 percent of the world electricity generation and is expected to increase. Not surprisingly, the three top producers of nuclear electricity generation were the United States (30 percent), France (16 percent) and Japan (10 percent). Canada generated 85 TWh (3.28 percent) and ranked seventh in world electricity generation.

With an additional 34 new reactors under construction in 12 countries with a combined capacity of 27,798 MW, the nuclear industry is experiencing something of a "nuclear renaissance".[3] In fact, the International Atomic Energy Agency (IAEA) anticipates that nearly 60 reactors may be built in the next 15 years.[4] It is also interesting to note how the nuclear power industry has been growing around the world.

Nuclear capacity, nuclear generation and percentage of world nuclear power are presented in Table 3.2, which is derived from Table 3.1. The last two columns of this table relate each country's nuclear capacity and generation to the world total.

The top five nuclear power producing countries by generation per $1000 GDP are Lithuania, Ukraine, Sweden, France and Bulgaria. The top five per capita nuclear power producing countries are Sweden, France, Belgium, Finland and Lithuania. Canada ranks ninth in the world, just behind the United States.

The WNA estimates that in 2007, approximately 66,529 tonnes of uranium will be used for nuclear power generation (as shown in Figure 3.1).[5] This can be translated to 78,500 tonnes of uranium oxide from mines (yellow cake). Nuclear fuels are either produced directly from mined uranium or supplied from secondary sources. The secondary sources include civil stockpiles, re-enriched depleted uranium tails, recycled uranium and plutonium from spent fuel, and uranium from dismantled military weapons.

[3] http://www.world-nuclear.org/info/inf17.html
[4] http://www.world-nuclear.org/info/inf17.html
[5] http://www.world-nuclear.org/info/reactors.htm

Table 3.2
2006 World Nuclear Power Capacity and Generation
Per Unit GDP and Per Person

	Nuclear Capacity		Nuclear Generation		% World Nuclear Power	
Country	KW per Billion $ GDP	KW per 1000 Person	KWh per 1000 $ GDP	KWh per Person	Capacity Share	Generation Share
Argentina	1,561	23.4	12.2	183.1	0.25	0.28
Armenia	23,515	126.3	137.9	740.8	0.10	0.08
Belgium	17,627	561.1	138.6	4,412.7	1.58	1.75
Brazil	1,176	10.1	7.2	61.7	0.52	0.44
Bulgaria	35,291	368.6	202.2	2,112.0	0.74	0.60
Canada	10,815	380.6	73.7	2,594.4	3.41	3.28
China	757	5.8	4.8	36.5	2.05	1.83
Czech Rep.	15,212	329.1	113.0	2,443.9	0.91	0.96
Finland	15,585	511.5	125.5	4,118.6	0.72	0.82
France	33,866	1,009.7	227.6	6,785.9	17.17	16.26
Germany	7,868	246.8	61.5	1,928.8	5.51	6.07
Hungary	10,162	175.8	65.6	1,134.5	0.48	0.43
India	752	2.8	3.7	13.7	0.82	0.57
Japan	11,278	373.4	64.4	2,130.6	12.89	10.37
Korea Rep	14,246	344.1	105.2	2,542.3	4.55	4.74
Lithuania	21,932	330.5	265.5	4,000.9	0.32	0.55
Mexico	1,155	12.2	7.7	81.3	0.35	0.33
Netherlands	877	27.2	7.1	220.1	0.12	0.14
Pakistan	995	2.6	4.5	11.6	0.12	0.07
Romania	3,320	29.4	26.7	236.3	0.18	0.20
Russia	12,619	152.2	79.8	962.0	5.89	5.25
Slovakia	25,345	448.9	167.9	2,974.4	0.66	0.62
Slovenia	14,236	326.3	113.1	2,592.6	0.18	0.20
S. Africa	3,123	40.7	24.8	323.2	0.49	0.55
Spain	6,959	184.3	56.5	1,495.9	2.02	2.31
Sweden	31,252	988.2	257.5	8,143.4	2.41	2.80
Switzerland	12,732	428.0	101.3	3,404.1	0.87	0.98
Taiwan	7,338	213.2	56.8	1,649.5	1.33	1.45
UK	6,228	195.5	38.7	1,215.7	3.21	2.81
US	7,561	328.9	60.7	2,642.1	26.59	30.11
Ukraine	36,838	280.6	232.4	1,770.3	3.55	3.16

Re-enriched uranium tails are derived from depleted uranium, which is a by-product of the enriching of natural uranium for use in light water nuclear reactors. When most of the fissile radioactive isotopes of uranium are removed from natural uranium, the residue is called depleted uranium. It is estimated that 1 Kg of enriched uranium requires 11.8 Kg of natural uranium,[6] and leaves about 10.8 Kg of depleted uranium with only 0.3 percent uranium 235. In 2002, the world's depleted uranium stock was estimated to be 1.2 million tonnes.

Weapons-grade uranium is enriched to much higher levels than required for power plants. Low-enriched uranium (LEU) for power plants can be derived from high-enriched uranium (HEU) in nuclear weapons stockpiles. HEU has been available to the nuclear power industry since 2000 as a result of disarmament treaties signed by the US and nations of the former Soviet Union. As of September 2007, the uranium from these stockpiles is displacing 10,600 tonnes of U_3O_8 from

[6] http://en.wikipedia.org/wiki/Depleted_uranium

mines every year, meeting approximately 13 per cent of the world's nuclear reactor requirements.[7]

3.2 Nuclear Electricity in Canada

As suggested in Chapter 2, nuclear energy is a significant component of Canada's energy mix. In 2005**,** total electricity generation capacity in Canada was 121,481 MW, of which nuclear power accounted for 13,345 MW.

Table 3.3 summarizes the electricity generation capacity mix by type of generation for each province in the year 2005. As the table illustrates, the province of Ontario dominates Canada's nuclear industry, with a ninety percent share. New Brunswick and Quebec each have a five per cent share of the total. Nuclear power is Ontario's principal, or primary, source of electricity. In 2006, according to Ontario's Independent Electricity System Operator (IESO), nuclear accounted for 54 per cent of Ontario's supply. Hydro and coal accounted for 22 per cent and 16 per cent, respectively.

Table 3.3
2005 Canada Electricity Generation Capacities by Province (MW)

Provinces	Hydro	Oil	Gas	Coal	Nuclear	Other	Total
NF	6,777	674	43				7,494
NS	404	554	98	1,097		299	2,452
PE		145				16	171
NB	930	1,546	350	541	680	447	4,494
QC	35,982	1,594	31		675	508	38,790
ON	8,473	2,126	2,822	6,337	11,990	509	32,257
MB	5,024	10	372	98		42	5,545
SK	855	0	1,054	1,790		175	3,873
AB	879	18	3,729	6,152		573	11,351
BC	12,545	48	1,553			602	14,748
YT, NT,NU	109	170	27			1	307
Total	**71,978**	**6,896**	**10,079**	**16,014**	**13,345**	**3,169**	**121,481**

SOURCE: Statistics Canada, Electric Power Generation, Transmission, and Distribution (Catalogue No. 57-202-XIE), 2005 (Table 1).

According to the CNA, as of December 2007, there are 22 CANDU reactors in Canada, however only 18 are currently operating.[8] The remaining reactors are shut down, being refurbished, or are decommissioned.[9] Two of the four out-of-service nuclear reactors (Bruce A1 & A2), each with a capacity of 750 MW, are expected to be refurbished and to restart operations in 2009 and 2010.

[7] http://www.uic.com.au/nip04.htm
[8] CNA, "Nuclear Energy Technology in Canada: Nuclear at a Glance", June 2008.
[9] Most of the information in this section is collected by either the CNA or COG and is available on their respective websites.

The status of Canada's five nuclear power plants (Pickering, Darlington, Bruce, Gentilly and Point Lepreau) and their nuclear reactors in 2008 are listed in Table 3.4.

Table 3.4
2006 Canadian Nuclear Power Capacity by Province (MW)

Provinces	Unit	Net Capacity (MW)	In-service Year	Status
Ontario	Darlington 1	878	1992	Operational
	Darlington 2	878	1990	Operational
	Darlington 3	878	1993	Operational
	Darlington 4	878	1993	Operational
	Total	**3,512**		
	Pickering A - Unit 1	515	1971	Operational
	Pickering A - Unit 2	515	1971	Laid-up
	Pickering A - Unit 3	515	1972	Laid-up
	Pickering A - Unit 4	515	1973	Operational
	Pickering B - Unit 5	516	1983	Operational
	Pickering B - Unit 6	516	1984	Operational
	Pickering B - Unit 7	516	1985	Operational
	Pickering B - Unit 8	516	1986	Operational
	Total	**4,124**		
	Bruce A - Unit 1	750	1977	Ref-start 2009*
	Bruce A - Unit 2	750	1977	Ref-start 2010*
	Bruce A - Unit 3	750	1978	Operational
	Bruce A - Unit 4	750	1979	Operational
	Bruce B - Unit 5	795	1985	Operational
	Bruce B - Unit 6	822	1984	Operational
	Bruce B - Unit 7	822	1986	Operational
	Bruce B - Unit 8	795	1987	Operational
	Total	**6,234**		
Quebec	Gentilly 2	635	1983	Operational
New Brunswick	Point Lepreau	635	1983	Operational
Total		**15,154**		

SOURCE: CANDU Owners Groups Inc.

Note: *Ref = undergoing refurbishment

With the exception of Bruce, which is leased to Bruce Power Inc, Ontario's reactors are owned and operated by Ontario Power Generation Inc. (OPG, formerly Ontario Hydro). Recall, the Nuclear Power Demonstration (NPD) and Douglas Point power plants have been retired from service, along with the Gentilly 1 reactor in Quebec.

Darlington has four large operating CANDU nuclear reactors with a capacity of 878 MW each, for a total net capacity of 3,512 MW. According to OPG, the Darlington Nuclear Generating Station alone is capable of providing about 20 percent of Ontario's electricity needs. The units are located on the north shore of Lake Ontario and were completed in 1993. Technology is similar to the Pickering Stations A & B. The OPG is currently planning to expand the Darlington nuclear site.

There are 8 reactors at Pickering station, 6 operating and 2 laid-up. Pickering is operated as two separate facilities: Pickering A includes Units 1, 2, 3 and 4 and Pickering B includes Units 5, 6, 7 and 8. Pickering A has 2 operating reactors (Units 1 and 4) and 2 which are shutdown (Units 2 and 3) while Pickering B has 4 operating reactors. Pickering A is the older of the two, going into operation between 1971 and 1973. Pickering B went into service between 1983 and 1986. All of the reactors use CANDU technology. The four reactors at Pickering A operated until 1997 when they were placed in voluntary lay-up under Ontario Hydro's nuclear improvement plan. While Units 2 and 3 remain shut down (or put into safe storage), Units 1 and 4 began commercial operation successfully in November 2005 and September 2003, respectively.[10] According to the OPG, they are currently considering a refurbishment plan to extend the life of Pickering B reactors to 2050-2060. Pickering A reactors have a net installed capacity of 515 MW each or 2,060 MW total. Current operating capacity is only 1,030 MW due to the safe storage of two units. Pickering B station reactors have a net installed and operating capacity of 516 MW each or approximately 2,064 MW total.

Ontario Hydro, the predecessor of OPG, constructed Bruce on the eastern shore of Lake Huron in stages between 1970 and 1987. The Bruce station is the largest nuclear facility in Canada in terms of output. The station consists of 8 CANDU nuclear reactors and has a total net installed capacity of 6,234 MW. Bruce A consists of Units 1, 2, 3 and 4 and Bruce B consists of Units 5, 6, 7 and 8. The Bruce A units were laid-up in 1995 and 1998, but Units 3 and 4 have been returned safely to service, and work is underway to restore the others. According to Bruce Power Inc., Unit 1 is scheduled for restart in 2009 and Unit 2 is scheduled for restart in 2010. There are plans to replace the steam generators in Units 3 and 4 by 2013. Bruce A Units have a net installed capacity of 750 MW each while Bruce B Units are between 795 and 822 MW each. Current output with 6 of the 8 reactors on line is 4,640 MW. In May 2001, Ontario Power Generation leased the two stations at the Bruce site to Bruce Power Inc., until 2018 with an option to extend the lease for a further 25 years. Bruce Power Inc. is also considering building two new reactors in the near future, and is also active into the potential of bringing nuclear energy to Alberta and, possibly Saskatchewan (Saskatchewan 2020 Update released on August 6, 2008).

There are two operating power reactors in Canada outside of Ontario. One is owned and operated by Hydro Québec at Gentilly, while the other is owned and operated by the New Brunswick Power Corporation at Point Lepreau, near St. John. Both are CANDU 6 reactors constructed during the early 1980s with a capacity of 635 MW.[11] Gentilly 1, which is no longer in service, was a 250 MW generating unit that employed boiling water technology. The experimental unit was unlike the CANDUs currently in service that use pressurized heavy water. Hydro Québec is considering refurbishment of their reactor. Point Lepreau supplies approximately 30 percent of total electricity generation in the province. At one point, it was thought that New Brunswick Power would have decommissioned Point Lepreau by this year.

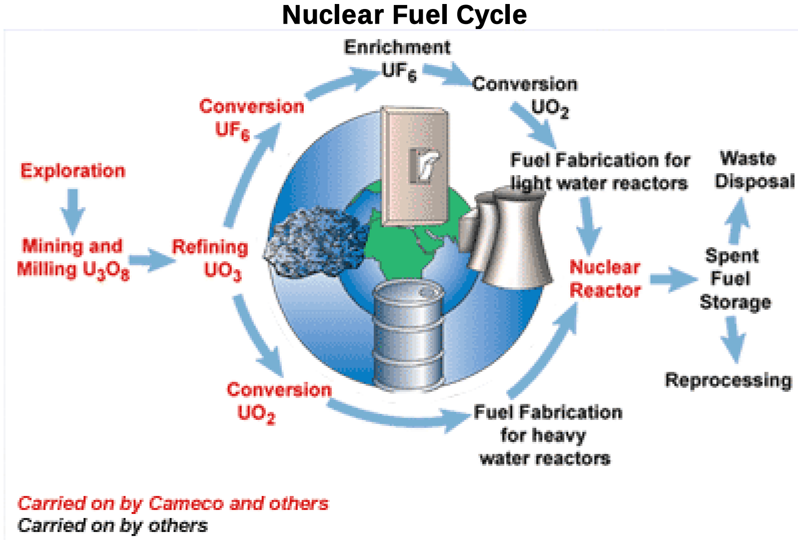
[10] www.opg.com/power/nuclear/pickering/unit1_details.asp
[11] http://www.candu.org/hydroquebec.html

However, New Brunswick Power[12] began an 18-month refurbishment in Spring 2008 to extend the station's life to 2032.[13]

3.3 "Front End" Nuclear Activities in Canada

This section discusses briefly the various activities in Canada associated with the production of electricity from nuclear reactions. While the nuclear fuel cycle ranges from mining of uranium ore to the disposal of nuclear waste, as presented in Figure 3.1, this section reviews only the 'front end' of the fuel cycle.

Figure 3.1
Nuclear Fuel Cycle



SOURCE: Cameco Corporation

Once a uranium deposit is discovered, the mined uranium undergoes a series of steps (mining, milling, enrichment for non-CANDU reactors, and fuel fabrication) at the 'front end' of the nuclear fuel cycle to prepare it for use in a nuclear reactor. After being used in a reactor to produce electricity, the 'spent fuel' may undergo a further series of steps including temporary storage, reprocessing, and recycling before eventual disposal as waste. Collectively these steps are known as the 'back end' of the fuel cycle.

The following section reviews the uranium mining industry, uranium refining, conversion and fuel fabrication in Canada.

3.3.1 The Uranium Mining Industry in Canada

With the advent of utilizing nuclear reactions to generate electricity, uranium became a coveted and controversial commodity. Uranium is the fuel used in most types of nuclear reactors. Naturally occurring uranium is made of 99.3 per cent Uranium-238 (U-238) and 0.7 per cent

[12] New Brunswick Power Nuclear Corporation is a subsidiary of New Brunswick Power Corporation, the largest electric utility in Atlantic Canada. It operates the Point Lepreau Generating Station.
[13] http://www.candu.org/nbpower.html

Uranium-235 (U-235), and it is the latter that is quite remarkable. When hit by a neutron, the atom is split in two and in the process releases large amounts of energy and more neutrons. The fissioning of one U-235 nucleus releases 50 million times more energy than the combustion of a single carbon atom.

Uranium is one of the most common heavy elements in nature; traces of it occur almost everywhere. It is about 500 times more abundant than gold and roughly as common as tin. Extraction, however, is only economically viable from richer deposits. The largest uranium deposits are found in Australia, Kazakhstan and Canada, which account for over half of the world's production. While Canada is the world's largest producer of uranium – providing over one quarter of total world production – it is the only nation that possesses high-grade ore. Canadian uranium holds U200,000 ppm (20 per cent), compared to low-grade ore body which contains U1,000 ppm (0.1 per cent).

Table 3.5 illustrates the uranium production from the top ten producers in the world. Canada remains the largest producer but Australia is rapidly closing the gap; three of the top five largest mines in 2006 are operating in Australia. Ranger, Rossing, and Olympic Dam are the second, third and fifth largest producing uranium mines in 2006, respectively. The largest is Canada's McArthur River mine, operated by Cameco Corporation.

Table 3.5
Uranium Production
(tonnes U)

Country	2002	2003	2004	2005	2006
Canada	11,604	10,457	11,597	11,628	9,862
Australia	6,854	7,572	8,982	9,516	7,593
Kazakhstan	2,800	3,300	3,719	4,357	5,279
Niger	3,075	3,143	3,282	3,093	3,434
Russia (est.)	2,900	3,150	3,200	3,431	3,262
Namibia	2,333	2,036	3,038	3,147	3,067
Uzbekistan	1,860	1,598	2,016	2,300	2,260
US	919	779	878	1,039	1,672
Ukraine (est.)	800	800	800	800	800
China (est.)	730	750	750	750	750

SOURCE: Australian Uranium Association (http://www.uic.com.au/nip41.htm).

According to the WNA, in 2004 Canada produced 13,676 tonnes of uranium oxide concentrate (U_3O_8)) accounting for approximately 30 per cent of total world production and valued at of $800 million. Canada's known uranium resources are 524,000 tonnes of U_3O_8, compared with Australia's reserves of 2.5 times that. Canada ranks third in the world for total uranium reserves and has the world's largest known high-grade deposit. Other countries with more than 10 per cent of the world total are Australia, Kazakhstan, and South Africa.

The major uranium mining companies in Canada are Cameco Corporation, COGEMA Resources Inc. and AREVA Resources Canada. Currently, all uranium mining in Canada takes place at three mines in Saskatchewan: McArthur River, Rabbit Lake, and McClean Lake. Table 3.6 illustrates the reserves and production of uranium and ores in Canada.

Cameco Corporation operates the McArthur River Key Lake mill, the Rabbit Lake mine/mill and mine, while the McLean Lake mine is operated by AREVA Resources Canada Inc. The McArthur River Mine was also the largest producing in the world in 2006, producing 18.2 percent of the world's total output.[14] Rabbit Lake and McLean Lake are the world's sixth and twelfth largest producing mines, respectively.

Table 3.6
Reserves and Production of Uranium and Ores in Canada

Mine	2006 Reserves (as End of 2006)			2006 production			
	U_3O_8 (Tonnes)	Grade of Uranium	Total Ore (Tonnes)	U_3O_8 (Tonnes)	Est. Grade Uranium	Est. Ore (Tonnes)	Reserve / Production U_3O_8
McClean Lake	12,800	1.6%	800,000	690	1.6%	43,000	18.6
Rabbit Lake	8,700	1.2%	725,000	1,962	1.2%	164,000	4.4
McArthur River/Key Lake	166,500	20.6%	808,000	7,193	20.6%	35,000	23.1
Subtotal	**188,000**	**8.1%**	**2,333,000**	**9,845**	**4.1%**	**242,000**	**19.1**
Cigar Lake (under construction)	102,600	20.7%	496,000	0		0	
Midwest (before regulator)	15,000	4.8%	312,000	0		0	

SOURCE: Saskatchewan Mining Association for 2006 U_3O_8 production (www.saskmining.ca); Areva Resources website www.arevaresources.com ("Reserves" under Publications - Uranium in Saskatchewan) for end-2005 reserves and associated grades; CERI estimate of 2006 total ore production based on reserves grades applied to 2006 production of U_3O_8.

Canada's uranium production peaked at a record level in 2002, with the start-up of the McArthur River mine in 2000. Production has been relatively steady since, decreasing only slightly. Over 80 percent of Canada's uranium is exported, mostly to the US and France.

Cigar Lake and Midwest, located in northern Saskatchewan, have estimated reserves of 102,600 tonnes and 15,000 tonnes, respectively. The two mines will be operated by joint ventures operated by Cameco Corporation, in the case of Cigar Lake to begin production by 2011 by the earliest, and AREVA Resources Canada Ltd. in the case of Midwest.[15] Regulatory processes, however, were completed in 2004.

[14] http://www.world-nuclear.org/info/inf23.html

[15] Cigar Lake is owned by Cameco (50 percent), Areva (37 percent), Idemitsu (8 percent), and Tepco (5 percent). Midwest is owned by Areva (69.16 percent), Denison (25.17 percent) and OURD Canada (5.67 percent).

While open-pit and underground mining are more common, an increasing proportion of uranium is mined using in situ techniques, such as circulating oxygenated groundwater through the porous ore body to dissolve the uranium. Open-pit mining is suitable for shallow deposits. McArthur River and Rabbit Lake are both underground, while McClean Lake is an open pit mine.[16]

The McArthur River Mine in Saskatchewan has the highest grade of uranium of any mine on Earth: 24.3 percent in U_3O_8 equivalent.[17] The other extreme is represented by Australia's Olympic Dam mine, the largest in the world in terms of reserves, with the world's lowest grade of just 0.07 percent. This grade would be considered uneconomic under normal circumstances, if gold and silver were not by-products of copper output. When the Cigar Lake Mine, also in Saskatchewan, comes on stream (currently slated for 2011) it will be the world's second best in terms of ore grade. Earlier estimations of reserves at Rabbit Lake indicated that reserves at the mine would be exhausted by the end of 2007. However, Cameco Corporation, which mines Rabbit Lake, has stated recently that incremental reserves have been found that should extend the life of the mine to at least 2011.[18] Prospects have also been identified for additional uranium in the vicinity of Rabbit Lake, and the drilling to identify additions to reserves is ongoing.

The uranium reserves at Canada's existing mines averaged over 8 per cent U_3O_8 at the end of 2006, as shown in Table 3.8, while the average grade of mined ore in 2006 was over 4 per cent. The distribution of processed ore is different from that of mined ore as shown in Table 3.8 because McArthur River ore is mixed with material from (mined-out), Key Lake stockpiles to reduce the uranium content to 4 per cent U_3O_8 equivalent before processing. The highest ore grade among Australia's three producing uranium mines is 0.21 per cent U_3O_8 equivalent at the Beverley mine.

Once the uranium ore is at the surface, the uranium needs to be separated from the ore. This process is called milling and it usually takes place near the mine. Using a strong alkaline solution or an acid, the uranium ore is extracted and precipitated. Uranium oxide concentrate is created through the process. Key Lake, located 80 kilometres from McArthur River, has the largest uranium mill in the world. Key Lake is now processing high-grade uranium ore from the McArthur River mine and from stockpile on site. The mill has an annual production capacity of 18 million pounds of U_3O_8. Key Lake mine was shut down in 2001.

Uranium ores were first produced in the early 1930s when the Eldorado Gold Mining Company began operations at Port Radium, Northwest Territories. By the late 1950s, 23 mines with 19 treatment plants were in operation in five districts, with the main production centre around Elliot Lake in Ontario.

The first uranium discovery in Saskatchewan occurred in 1950 at Beaverlodge. In 1968 the Rabbit Lake deposit was discovered in northern Saskatchewan, and was brought into production in 1975. Cluff Lake and Key Lake were discovered in the Athabasca Basin in 1972 and 1975

[16] http://www.uic.com.au/nip41.htm
[17] One tonne of pure uranium is equivalent to 1.17924 tonnes of U_3O_8.
[18] http://www.cameco.com/media_gateway/news_releases/2007/news_release.php?id=203

respectively; they started production in 1980 and 1983 respectively. Exploration expenditure in the region peaked at this time, resulting in the discoveries of Midwest, McClean Lake and Cigar Lake. Then in 1988 the newly formed Cameco Corporation discovered the massive McArthur River deposit. The uranium ore deposits discovered in Saskatchewan were a higher grade than the resources in Ontario, making it difficult for Ontario operations to compete. The Ontario mines were shut down in the early 1990s and have now been decommissioned. All of Canada's uranium production is now located in Saskatchewan.

3.3.2 Uranium Refining, Conversion and Enrichment

Additional processing is still needed for the uranium to be used as a fuel for a nuclear reactor. After removing impurities from the 'yellowcake' (U_3O_8), uranium trioxide (UO_3) is produced. The next phase of refining depends on what type of reactor will be used to generate electricity. For those types of reactors that do not require enriched uranium, such as the existing CANDU units, the yellowcake is brought to a conversion facility where it is converted to uranium dioxide ($U0_2$).

If the fuel is destined for light water reactors, as is the case for most uranium being exported to the US, the uranium undergoes several additional steps before it can be used as a fuel. First, the 'yellowcake' is converted to uranium hexafluoride (UF_6). Second, the uranium hexafluoride undergoes an enrichment process where the proportion of U-235 is increased by removing most of the U238. Most light water reactors require the uranium to have U-235 content of 3 percent to 5 percent. Separating gaseous uranium hexafluoride into two streams, one being enriched to the required level and known as low-enriched uranium, does this. There are two methods to enrich the uranium hexafluoride: gaseous diffusion and centrifuge. Finally, the enriched uranium hexafluoride is then converted back to enriched uranium oxide (UO_2).

Uranium in the form of yellowcake is trucked from Saskatchewan milling operations to world's largest uranium refinery at Blind River, Ontario, operated by Cameco. There, it is refined to remove impurities and then converted into uranium trioxide, in a multi-step chemical and physical process using solvent extraction. From Blind River, most of the uranium trioxide goes to another Cameco facility at Port Hope, Ontario, where it is converted into uranium dioxide for use as natural uranium in existing CANDU reactors, or into uranium hexafluoride for enrichment and subsequent conversion to uranium dioxide for use in light water reactors. About 80 per cent of the UO_3 from Blind River is converted to UF_6 to be shipped outside of Canada where it is enriched for use in light water reactors.

Natural uranium contains 0.7 per cent U-235, the uranium isotope of interest; enrichment increases U-235 content to the 3 per cent to 5 per cent range required for light water reactors. No enrichment facilities exist in Canada.

3.3.3 Fuel Fabrication

Fuel fabrication is the final stage of the 'front end' cycle. Fuel used for reactors is generally in the form of ceramic pellets. Fuel fabrication transforms the uranium oxide (UO_2) into ceramic pellets by pressing the uranium oxide into cylindrical shapes and baking them at a high temperature (over 1400 °C). The pellets are encased in metal tubes to form fuel rods. Rods grouped together are called a fuel bundle or a fuel assembly. Fuel fabrication depends on the different types of nuclear reactors. Pressurized Heavy Water Reactors (PHWR), CANDU technology, utilizes different fuel from most other nuclear technologies such as Boiling Water Reactors (BWR) and Pressurized Water Reactors (PWR). This will be discussed in greater detail in the following section when reviewing the different nuclear technologies.

Uranium dioxide, in either natural or enriched form, is pressed into cylindrical shapes, and hardened by baking at high temperatures. It is then fabricated into bundles, which are made into pellets. At Port Hope, bundles are fabricated and assembled by Zircatec Precision Industries (a recently-acquired subsidiary of Cameco). Fuel pellets are also fabricated in Toronto by General Electric Canada and then sent to GE Canada's Peterborough, Ontario facility for assembly. A fuel bundle for CANDU reactors contains either 28 or 37 rods of tubular zirconium alloy sheaths with uranium dioxide pellets inside, each rod being about 50 centimetres long. These fabrication facilities are largely devoted to the domestic market and to supplying CANDU reactors abroad, as the major uranium-importing countries have fabrication facilities of their own. Zircatec supplies the Bruce nuclear power plant, while GE Canada supplies Pickering and Darlington. In Cobourg, Ontario, Zircatec also manufactures zirconium tubing for fuel bundles, as well as certain CANDU reactor components and monitoring equipment.

All aforementioned facilities are licensed by the Canadian Nuclear Safety Commission (CNSC) to produce up to 1,800 megagrams (Mg) of uranium dioxide pellets contained in fuel bundles per year.

3.4 Concluding Remarks

This Chapter discusses nuclear power in Canada, and its current status within a global context. Currently, approximately 55 percent of the total global nuclear power capacity is located in three industrialized countries: United States (26.6 percent), France (17.2 percent), and Japan (12.9 percent). With its five nuclear facilities (Pickering, Darlington, Bruce, Gentilly and Point Lepreau), Canada is ranked eighth in the world.

According to the CNA, as of December 2007, there are 22 CANDU reactors in Canada, however only 18 are currently operating.[19] The remaining reactors are shut down, being refurbished, or are decommissioned.[20] Two of the four out-of-service nuclear reactors (Bruce A1 & A2), each with a capacity of 750 MW, are expected to be refurbished and to restart operations in 2009 and 2010.

While the nuclear fuel cycle ranges from mining of uranium ore to the disposal of nuclear waste, this section reviews the 'front end' of the fuel cycle. Canada has the world's largest known high-grade uranium deposits in the world. Other important 'front end' activities include milling,

[19] CNA, "Nuclear Energy Technology in Canada: Nuclear at a Glance", July 2006.

[20] Most of the information in this section is collected by either the CNA or COG and is available on their respective websites.

enrichment for non-CANDU reactors and fuel fabrication—all of which are important activities in the Canadian economy.

This Chapter reveals that Canada does indeed have a long, rich history in the nuclear science and Canada is an important player in nuclear power and will remain so in the near future.

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CHAPTER 4

ELECTRICITY GENERATION AND THE ENVIRONMENT

The environmental performance of the electricity generating sector has gained added importance in many jurisdictions across Canada, making it timely to evaluate the environmental effects of various fuel pathways in electricity generating sector.

The overall objective of this study is to identify and analyze current and potential environmental impacts from base-load electricity generation, which include greenhouse gas (GHG) emissions, other air pollutants, water pollution and radiation, on a life cycle basis. This study compares three fuel sources: nuclear, coal and natural gas. All of these sources of energy are important contributors to Canadian electricity generation and have implications for the environment.

One of the analytical tools used here is Life Cycle Assessment (LCA). As mentioned in literature review in Chapter 1, there are two broad categories of methods of conducting LCA: Process LCA and Economic Input/Output LCA (EIO-LCA). Process LCA examines the environmental impacts of an activity from inception to completion, or from cradle to grave. The activity is subdivided into smaller stages or processes, the environmental implications of each process are studied, and then environmental impacts are added to arrive at a number giving total impact per unit of activity. An example is the amount of CO_2 per kilowatt-hour of electricity generated.

This study uses Process LCA, an effective method for assessing the environmental aspects associated with generating electricity from different sources over their life cycle. This type of analysis, in general, can assist with future electricity generation mix decisions, leading to improved environmental performance of the generation mix. For Ontario it might lead to the adoption of environmentally friendly technologies to maximize the value of renewable and nonrenewable sources by minimizing impacts on the environment. This enhances the sustainability of Ontario's natural resources and economy.

This Chapter develops an appropriate and applicable LCA methodology, and uses it to evaluate and analyze the environmental impacts of electricity generation from nuclear, coal and natural gas. It is divided into three sections. The first discusses the chosen life-cycle methodology and defines the technical terms used in this report. This section is in turn divided into four parts: goal definition and scope, life-cycle inventory analysis, life-cycle impact assessment and life-cycle interpretation. The second section discusses the methodological framework for the Life Cycle Inventory. The third section describes the existing nuclear, coal-fired and gas-fired generating facilities in Ontario and their fuel supplies. It goes on to summarize the results of the LCI analysis. Finally, appendices D and E include some calculation details as well as printouts of a number of Excel sheets from the LCA model developed by CERI.

4.1 Life Cycle Methodology and Definitions

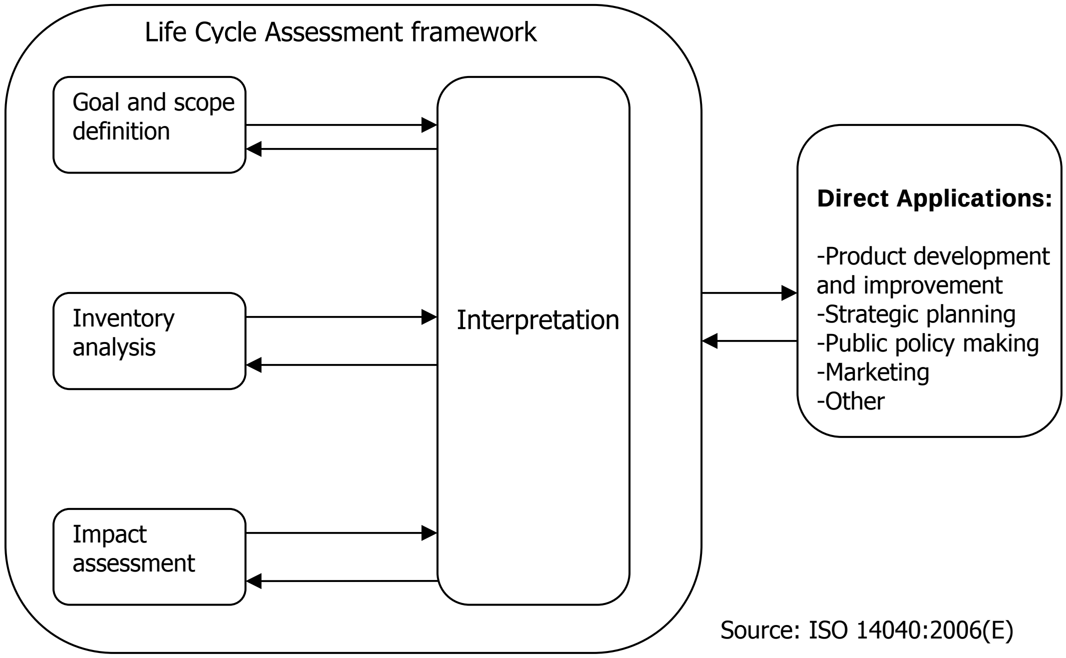
As previously mentioned, this study applies a Process LCA method and uses ISO 14040, the 20-page standard developed by the International Organization for Standardization as a guideline. This standard, in turn, requires the user to meet an additional standard, ISO 14044. The latter standard presents more detailed sub-standards and procedures that also are to be adhered to where possible. Following these standards as guidelines ensures a good measure of accuracy and therefore credibility to the analysis in that they have already been judged by others to be reasonable and broadly appropriate. CERI has made every effort to ensure that this analysis is disciplined and complete. However, a strict application of the said standards is not always adhered to in the interest of flexibility, practicability and feasibility. For example, one of the ISO's requirements is the critical review of the results by all affected parties before they are disclosed to the public; such external reviewing is beyond the scope of this project.

According to international standards of ISO 14040, the LCA process is a systematic approach that consists of four phases:

- Goal Definition and Scope
- Life Cycle Inventory Analysis (LCI)
- Life Cycle Impact Assessment (LCIA)
- Life Cycle Interpretation

As such this section is divided into four parts. Figure 4.1 illustrates the relationship between these phases and applications of the LCA.

Figure 4.1
Phases of a LCA



Source: ISO 14040:2006(E)

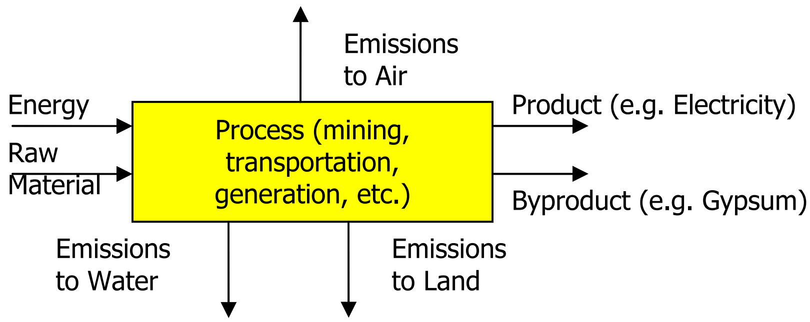
Since the objective of this report is to compare the environmental aspects of different electricity generation methods in Ontario, the Life Cycle Impact Assessment (LCIA) phase is beyond the scope of this project. In other words, as the magnitude of the emissions is different among various sources of electricity, the magnitude of the impact on environment will be different. Furthermore this study excludes the translation of emissions into impacts because a large amount of resources are required to carry out a full assessment of the complicated and far-reaching impacts associated with a given combination of emissions. Therefore this report will cover all stages of LCA except for the impact assessment.

4.1.1 Goal Definition and Scope

The **goal** of the LCA is to compare all environmental impacts associated with the generation of a terawatt-hour (TWh: one billion kilowatt hours) of electricity from power plants in the province of Ontario fuelled by nuclear, natural gas and coal. CERI compares the aforementioned electricity systems by tonnes of pollutants that are released for the generation of one TWh of electricity, on a life-cycle basis.

The **scope** of the LCA in this study is on a facility-by-facility basis; prototyping is avoided where possible. Therefore the LCA method that is proposed is characterized as process modeling. This method is well documented in ISO guidelines 14040 and 14044. Following this method, a flow sheet or process tree with all the relevant processes is defined, and, all the relevant inflows and the outflows for each process are collected or estimated. For each of the processes of a system, energy/material inputs and outputs are analyzed. Finally, all pieces of information are summed up to give a comprehensive picture of the emissions associated with the use of each fuel to generate electricity. Figure 4.2 illustrates the unit process concept.

Figure 4.2
Sample of a Unit Process



CERI has attempted to obtain as much data as possible for all processes and where necessary has compiled data from different sources and has compared them to come up with the most suitable source. Where facility-specific data on some processes has been unavailable or insufficient, generic performance of some of the processes is considered. For similar or identical processes, such as gas-fired power plants with identical technologies, values calculated for one unit are aggregated to cover the whole group. Furthermore, when it is appropriate, generic formulations are employed to calculate the environmental impacts.

CERI has explored all of the known sources and has collected a rich and valuable set of data on numerous processes involved in electricity generation from nuclear, coal, and natural gas.

The LCA takes a snapshot of electricity generation activities in 2005 and 2006 and is specific to Ontario electricity generating sector together with its fuel supply. Only the operations of facilities within the system boundaries as described in the following paragraph are covered in the LCI. As such, processes like exploration, construction, decommissioning and waste management are not explicitly included but addressed in a more general way.

To determine which unit process should be included in a LCA study, the **system boundary** should be established and it must be consistent with the goal of the study. Based on the above mentioned criteria, the following stages are included in this process LCA.

- Fuel preparation (extraction/production and processing)
- Fuel transportation
- Electricity generation operations within the power plant

While the specific system boundaries of the various fuel cycles will be discussed later in this Chapter, it is important to mention that processes like construction, decommissioning, heavy water manufacture and waste management are addressed at various times through the report, but not included in the Life Cycle Inventory (LCI) analysis. However, exploration is beyond the scope of this study.

As plant construction affects all three modes of electricity generation, it is discussed in the following several paragraphs. CERI has undertaken research into life-cycle emissions produced during all phases of electricity generation from nuclear, coal and natural gas and has decided not to include emissions produced during the plant construction phase. The following discusses the two reasons for this decision.

First, the construction CO_2 emissions for nuclear on per terawatt-hour (TWh) basis are similar to the emissions produced during the natural gas and coal-fired power plant construction. Therefore, no matter which of the three forms of electricity generation is utilized, the construction-phase emissions do not change significantly. This is illustrated in Table 4.1.

Table 4.1
Construction Emissions of Various Electricity Generation Technologies[21]

Power generation technology	Kilo tonnes of CO_2 per TWh	Ratio of construction CO_2 to operations CO_2 (%)
IGCC (coal)	1.10	0.14
SUPC (coal)	1.49	0.18
CCGT (gas)	0.95	0.22
SXC (nuclear)	2.22	6.89

Notes: CCGT: Combined Cycle Gas Turbine, IGCC: Integrated Gasification Combined Cycle, SUPC: Supercritical Coal, SXC: Sizewell C (PWR)

Table 4.2 below is useful to supplement Table 4.1, in that CO_2 emissions in the construction phase is roughly proportional to the quantity of materials utilized[22]. Table 4.2 illustrates the various quantities of materials for various electricity generation technologies.

[21] Estimating life cycle from Table 2 of: S. Andeseta et al., "CANDU Reactors and Greenhouse Gas Emissions" http://www.computare.org/Support%20documents/Publications/Life%20Cycle.htm, retrieved October 20, 2008.

[22] S. Andeseta et al., "CANDU Reactors and Greenhouse Gas Emissions" http://www.computare.org/Support%20documents/Publications/Life%20Cycle.htm, retrieved October 20, 2008.

Table 4.2
Material Quantities for Construction of Various Electricity Generation Technologies, circa 1983 [23]
(Thousands of tonnes per EJ/year)

Generation Technology	Steel	Concrete	Other Metals
Coal - Electric	1500	5500	30
Coal - Synfuel	600	*	30
CANDU 900Mwe (1995)	1600	14000	*
LWR	2500	15000	125
CANDU 600Mwe (1995)	1400	18000	*
Hydro	3500	60000	200
Wind	8000	35000	1000
Biomass	4500	12000	*

Notes: * Indicates data not available; - Indicates value is negligible; LWR, Light Water Reactor

Second, the third column in Table 4.1 shows the ratio of construction to operation emissions and confirms that construction-related emissions are negligible when compared to those related to operations of coal and natural gas power plants. In fact, those emissions are less than one third of 1 percent of operations emissions and can well be ignored. According to the ISO Standard 14044, *Environmental Management – Life cycle assessment – Requirements and guidelines*, "deletion of life-cycle stages, processes, inputs or outputs is only permitted if it does not significantly change the overall conclusions of the study" (8). Although the ratio of construction emissions in nuclear is significantly larger than those for coal and natural gas, one should remember that the actual nuclear construction emissions of 2.22 kilo tonnes per TWh is not, in absolute terms, significantly higher than the 0.95-1.49 range related to coal and natural gas.

For the aforementioned reasons, it can be concluded that the inclusion or exclusion of construction-related CO_2 emissions does not significantly affect the outcome of the ongoing study which compares total life-cycle emissions.

In addition, the following environmental impacts are of major interest in this study. The main pollutants are as follows:

- **Greenhouse Gases (GHG):**
  - Carbon dioxide (CO_2)
  - Methane (CH_4)
  - Nitrous oxide (N_2O)
- **Criteria Air Contaminants (CAC):**
  - Sulfur dioxide
  - Carbon monoxide

[23] Estimating life cycle from Table 2 of: S. Andeseta et al., "CANDU Reactors and Greenhouse Gas Emissions" http://www.computare.org/Support%20documents/Publications/Life%20Cycle.htm, retrieved October 20, 2008.

- Oxides of Nitrogen
- VOCs (Volatile organic compounds)
- Particulate Matters

- **Other Air Pollutants:**
  - Lead
  - Mercury
  - Arsenic
  - Uranium

- **Water Pollutants:**
  - Lead
  - Mercury
  - Arsenic
  - Uranium

- **Radiation:**
  - Tritium
  - Other

4.1.2 Life Cycle Inventory Analysis (LCI)

This phase of LCA involves data collection and calculations to quantify the environmental impacts of different processes. Conducting of the LCI analysis is very data intensive and is an iterative process. After collecting or estimating the environmental impacts of all processes in a system (like nuclear power), the identical emissions are aggregated and then converted into tonnes of emissions per TWh of generated electricity. Finally CERI is able to compare different electric generation and will be able to identify the most environmentally-friendly. The detailed LCIs for different sources of electric generation will be discussed under their allocated subsections in this report.

4.1.3 Life Cycle Impact Assessment (LCIA)

This phase of LCA is aimed at evaluating the significance of potential environmental hazards using the LCI results. As stated previously, this phase of LCA will not be covered in this project. In other words, as the magnitudes of the emissions are different among various sources of electricity, the magnitude of the impact on environment will be different. Furthermore this study excludes the impact assessment because a large amount of resources are required to carry out a full assessment of the complicated and far-reaching impacts induced by electricity generation chain of activities. Therefore this report will cover all stages of LCA, except the impact assessment.

4.1.4 Life Cycle Interpretation

At this stage findings of the LCI are studied and interpreted. This part will discuss the limitations and findings of the LCI and compares different electricity generating systems.

4.2 Methodological Framework for Life Cycle Inventory

After defining the goal and scope of the project, several spreadsheets are designed by the aid of Microsoft Excel to collect and/or estimate emission data for each of the processes, at the inventory phase of the LCA. Samples of the designed spreadsheets are presented in Tables D.1 through D.3 of Appendix D. The emissions from different processes are aggregated and reported as the life-cycle emissions involved with the generation of electricity from nuclear, coal and natural gas. At the inventory phase of LCA, sources of the data are identified and in some cases validity of the information is cross checked with other sources. As previously mentioned, where actual data is not available various estimations or calculations are applied.

To estimate the pollutions involved with each process (like mining & milling of uranium) in a system (like nuclear electricity) CERI make use of material and energy balance information for applicable facilities. Various emission and efficiency factors for specific processes are required to quantify the emissions associated with specified energy and material inputs. Where material or energy balance information was not available, emissions have been estimated by the aid of GHGenius software of Natural Resources Canada. GHGenius has been frequently used and cited by many LCA studies for biofuels in Canada. In addition, the model has several built-in LCIs for various electricity generation systems in Canada. The software also has the option to select Ontario's electric system as the underlying electric system for LCA. Since GHGenius is based on many linked Excel spreadsheets, it can be modified or updated to get the best possible results for CERI's case studies.

The results of the three LCIs are then compared and discussed. In the Section 4.3, LCA analyses are performed and discussed in turn for electricity obtained from nuclear, coal and natural gas in Ontario. The LCI results for the three fuels are compared and conclusions are drawn.

4.3 Application of LCA to Alternate Sources of Electricity in Ontario

In this section LCA analyses for nuclear, coal-fired and natural gas-fired electricity generation in Ontario are performed.

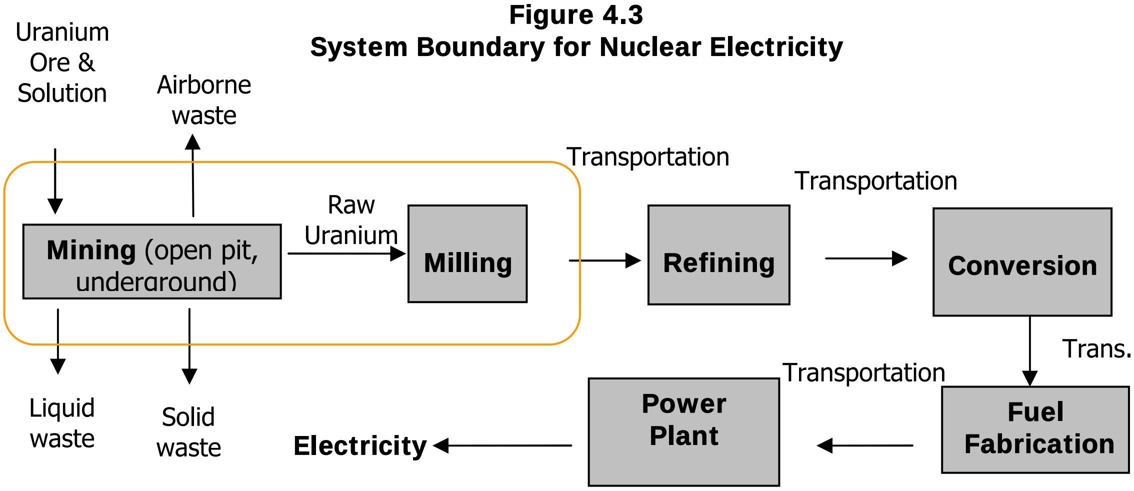
4.3.1 Generation of Nuclear Electricity in Ontario

Based on the assumptions and details provided in section 4.1, the following **system boundary for nuclear electricity** of Ontario has been identified. The system boundary for this LCA study covers the operation of all active generating facilities in 2005-2006, with electricity output measured just before it enters the transmission system. Figure 4.3 establishes the system boundary for nuclear electricity in Ontario. As previously mentioned in Chapter 3, the chain of activities starts with the mining of uranium ore from open pit and underground mines. Currently, all uranium mining in Canada takes place in Saskatchewan. Once the uranium ore is at the surface, the uranium needs to be separated from the ore. This process is called milling and usually takes place near the mine. Using a strong alkaline solution or an acid, the uranium ore is extracted and precipitated. Uranium oxide concentrate or yellowcake (U_3O_8) is the product of milling. Key Lake, located 80 kilometers from McArthur River, has the largest uranium mill in the world. Since mining and milling are related activities and usually are operated in one facility, we consider mining and milling as one process.

Uranium in the form of yellowcake is trucked from Saskatchewan milling operations to world's largest uranium refinery at Blind River, Ontario. There, it is refined to remove impurities and then converted into uranium trioxide (UO_3), in a multi-step chemical and physical process using solvent extraction. From Blind River, most of the uranium trioxide goes to another Cameco facility at Port Hope, Ontario, where it is converted into uranium dioxide (UO_2) for use as natural uranium in existing CANDU reactors, or into uranium hexafluoride (UF_6) for enrichment and subsequent conversion to uranium dioxide for use in light water reactors

Uranium dioxide is next transported to fuel fabrication facilities where the fuel pellets for CANDU reactors are made. Finally the fuel bundles are transported to CANDU reactors and used for electricity generation. Generation of the electricity is the end of life-cycle in this report.

Figure 4.3
System Boundary for Nuclear Electricity



As previously mentioned, processes like exploration, construction, decommissioning[24], heavy water manufacture[25] and waste management[26] are addressed, but not included in the Life Cycle

[24] Since there has never been a nuclear power station decommissioned anywhere in North America (or the world) it would be inappropriate to include decommissioning for other sources. As such, it has been excluded from this analysis. We therefore do not feel that excluding this will make a substantial difference. As additional information becomes available it would be worth reconsidering this assumption.

[25] No heavy water is currently manufactured in Canada; existing inventories are drawn down to supply domestic heavy water requirements. Other countries produce heavy water. The Bruce heavy water plant produced about 16,000 tonnes of heavy water over its lifetime, whereas approximately 48 tonnes of heavy

Inventory (LCI) analysis. Each of the above boxes is considered to be a single process with its own inputs, outputs and emissions as displayed in Figure 4.2.

The following is a summary of the facilities that have been identified and will be included in the inventory analysis of LCA.

- Mining & milling: Key Lake, McArthur River, Rabbit Lake and McClean Lake
- Refining: Blind River
- Conversion: Port Hope
- Fuel fabrication: Zircatec Port Hope, GEC Toronto and GEC Peterborough
- Power plants: Pickering (A & B), Bruce (A & B) and Darlington

4.3.1.1 Data

The following section discusses data issues and sources. It is divided into the same manner of the system boundary: mining and milling, refining and conversion, fuel fabrication and power generation. Wherever the actual consumption of energy or GHG emissions is not available, GHGenius software is used to estimate the fuel consumption and emissions involved with the relevant process.

Mining and Milling

Cameco Corporation operates the McArthur River mine and associated Key Lake mill along with the Rabbit Lake mine/mill, while the McLean Lake mine and mill are operated by AREVA Resources Canada Inc, although they are partly owned by Denison Mines and OURD Canada Ltd. Production data for mining and milling (for 2005 and 2006) were obtained from the Cameco Corporation website[27], as most of the uranium mining and milling operations in Saskatchewan are owned by the company. Specifically, the material inputs/outputs of McArthur River mine, Rabbit Lake mine and mill, and Key Lake mill are reported on the Cameco website both quarterly and annually. Quantity of ore extracted from McClean Lake was obtained from Denison Mines Corp. Its Annual Information Form is posted on the SEDAR website[28]. Output of yellowcake from the milling process, is tabulated in an annual publication by the Saskatchewan uranium industry entitled "Uranium in Saskatchewan"[29].

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water are needed to make up the annual losses of Ontario's operating CANDU reactors. The emissions associated with producing one tonne of heavy water at the Bruce plant or in a new plant using more modern technology are not currently available for use in this life cycle analysis. The Bruce plant used the Girdler Sulphide Process, and must have had significant sulphur emissions.

[26] Please see discussion in Chapter 5 – Section 5.1.2.3 regarding Canadian regulations and spent fuel management in Canada

[27] http://www.cameco.com/operations/uranium/mcarthur_river/annual_production.php

[28] http://www.sedar.com/homepage_en.htm

[29] http://www.cameco.com/uranium_101/uranium_sask/

As for emissions, all pollutant data were gathered from Environment Canada's National Pollutant Release Inventory (NPRI) and Metal Mining Effluent Regulations (MMER) Inventory. GHG emissions from diesel consumption used by machinery to extract uranium in this case were estimated by GHGenius, as no report was available with this data.

Refining and Conversion

The Blind River uranium refinery and the Port Hope fuel conversion facility in Ontario are solely owned by Cameco Corporation. Thus UO_3 production from Blind River refinery was obtained from the Cameco website. The data on UO_3 sent to the Port Hope facility, to be converted to UO_2 or $UF_{6,}$ were also gathered from the company's website.

Similarly, criteria air contaminants (CAC) and other pollutant data were collected from the NPRI and GHGenius as above was used to estimate GHG emissions.

Fuel Fabrication

There are three fuel fabrication facilities in Ontario that convert UO_2 or UF_6 to synthetic fuel to be used in nuclear power plants around the world. Data for these facilities were not available at all for 2005. In February, 2006, Cameco acquired the Zircatec plant and so information on synthetic fuel production from February to December of 2006 was available and recorded on Cameco's website. However, the other two conversion plants operated by General Electric Canada did not record any information on their production.

No emissions were listed under these plants either, presumably because they were below reporting threshold rates. Thus estimations were made.

Power Plants

Ontario Power Generation (OPG), a Crown Corporation, owns and operates Darlington and Pickering (Pickering A & B) nuclear power stations. Their annual production for years 2005 and 2006 are posted on the OPG's website[30]. The third power plant, Bruce (A & B), on the other hand is privately operated by Bruce Power (although OPG still owns it and is leasing it to Bruce Power on a long-term contract). Its annual production information can be found in Bruce Power's annual reports[31].

Emission data such as air and water pollutants are found in the NPRI for all three power plants. Radiological data were also recorded for years 2005 and 2006 from annual publications found in the respective websites (OPG and Bruce Power).

Transportation

[30] http://www.ontla.on.ca/library/repository/ser/223468/2006q4-yearend.pdf
[31] http://www.brucepower.com/uc/GetDocument.aspx?docid=2429

The GHG emissions from transporting uranium from Saskatchewan mines to Ontario's upgrading facilities and on to nuclear plants were derived from NRCan's Office of Energy Efficiency website. CERI's assumptions of the transportation routes were as follows:

Table 4.3
Nuclear Road-Based Haul Distances (From Mining & Preparation to Power Plants)

Miles	Kilometers	Substance	Route Segment
50	80	uranium ore	McArthur River to Key Lake
137	220	yellowcake	Key Lake to Pinehouse
155	250	yellowcake	Pinehouse to Prince Albert
134	215	yellowcake	Prince Albert to Dafoe
110	177	yellowcake	Dafoe to Yorkton
100	161	yellowcake	Yorkton to Dauphin
38	61	yellowcake	Dauphin to Junction
85	137	yellowcake	Junction to Minnedosa
28	45	yellowcake	Minnedosa to Brandon
552	888	yellowcake	Brandon to Thunder Bay
438	705	yellowcake	Thunder Bay to Sault Ste Marie
86	138	yellowcake	Sault Ste Marie to Blind River
1863	**2997**	**yellowcake**	**Key Lake to Blind River (subtotal)**
337	543	UO_3	Blind River to Toronto (=Port Hope)
31	50	UO_2	Port Hope to Peterborough
81	130	semi-fabr fuel	Peterborough to Toronto
16	25	fabricated fuel	Toronto to Darlington power plant

Map distances are compiled from a combination of sources, including the internet, a Rand McNally road atlas and a MapArt Publishing road map of Saskatchewan and Alberta.

NRCan's Office of Energy Efficiency reports that in 2005, 226 billion tonne-kilometres of freight moved by heavy truck, with 36.96 megatonnes of associated greenhouse gas emissions, or 164 tonnes of CO_2 equivalent per million t km. Statistics Canada reports that uranium consumption in Ontario power plants was 1429.5 tonnes in 2005. The corresponding freight haulage is an estimated 6.94 million t km, so imputed GHG emissions are 164 x 6.94 = 1,139 tonnes of CO_2 equivalent. Statistics Canada also reports that in 2005 Ontario's nuclear electricity generation amounted to 77.9 TWh. The transportation GHG emission factor for nuclear can therefore be estimated as 1,139 t/77.9 TWh = 14.6 tonnes of CO_{2eq} per TWh.

4.3.1.2 Life Cycle Inventory (LCI)

This section presents the results from the LCI analysis for nuclear electricity in Ontario. LCI is performed by inserting the collected data in the designed spreadsheet for each of the processes (See sample spreadsheets; Figures D.1 through D.7 in Appendix D). After converting data to similar units, they are aggregated and emissions calculated per TWh of generated electricity. Upstream transportation is included in all processes and for simplicity they are based on representative distances between several origin and destination points. The transportation mode is assumed to be road, and the total representative distance is 3,825 km.[32] CERI also assumed that diesel is the only fuel that is used by trucks. Table 4.4 presents the estimation and aggregation results for nuclear generation of all processes within the system boundary defined in Figure 4.3.

Table 4.4
Life Cycle Assessment Results for one TWh of Nuclear Electricity Generated in Ontario

Emission (2005-2006 average)	Unit	Mining & Milling	Refining & Conversion	Fuel Fabrication	Power Plant	Life Cycle Emission
Total CAC	t/TWh	1.53	0.11	0.00	10.78	12.42
Oxides of Nitrogen (N02)	t/TWh	0.23	0.11	0.00	2.11	2.45
Sulphur dioxide	t/TWh	0.46	0.00	0.00	8.08	8.54
Carbon Monoxide	t/TWh	0.00	0.00	0.00	0.00	0.00
Total Particulate Matter	t/TWh	0.02	0.00	0.00	0.58	0.61
Volatile Organic Compounds (VOC)	t/TWh	0.81	0.00	0.00	0.00	0.81
Other Air Pollutants						
Lead (and its compounds)	kg/TWh	0.00	0.03	0.00	0.06	0.09
Mercury (and its compounds)	kg/TWh	0.00	0.00	0.00	0.00	0.00
Arsenic	kg/TWh	0.00	0.00	0.00	0.00	0.00
Radionuclides	TBq/TWh	7.02	0.00	0.00	32.83	39.85
Water Pollutants						
Arsenic	kg/TWh	0.19	0.00	0.00	0.00	0.19
Radionuclides	TBq/TWh	0.00	0.00	0.00	21.04	21.04
GHG emission CO2 eq.	t/TWh	1609.22	103.23	124.18	0.11	1836.74

Note: Zero figures have either negligible values or are not reported.

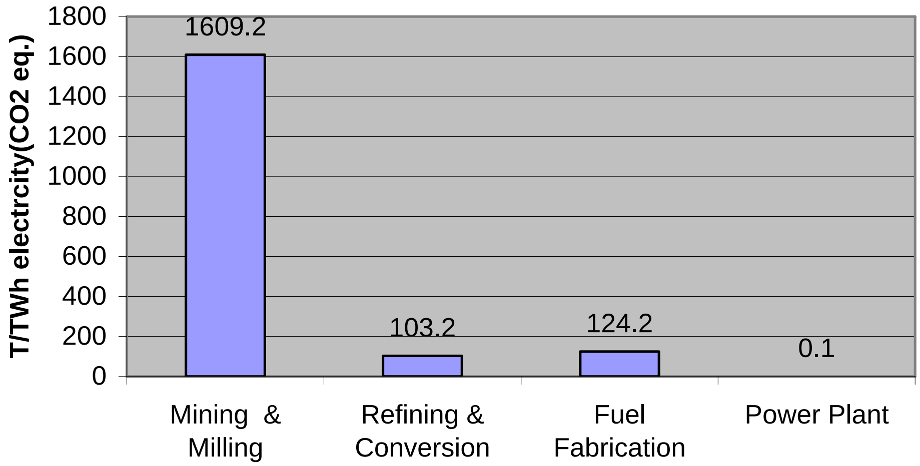
Most of the life-cycle emissions of radionuclides from the nuclear fuel cycle, as illustrated in Table 4.4, are released at the power plant, with relatively modest mine-site emissions.

The LCA results indicate that the Mining and Milling process is the main source of GHG emissions. However, we were unable to estimate the GHG emissions associated with emergency fossil fuel generators in nuclear power plants, but these are likely insignificant.

Figure 4.4 summarized the results for nuclear generation.

32- This is the distance from McArthur River → Key Lake → Blind River → Port Hope → Peterborough → Toronto → Darlington

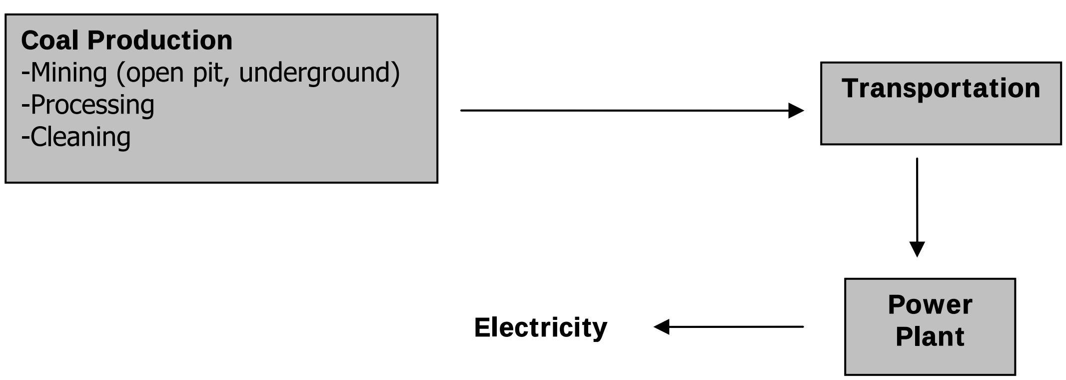
Figure 4.4
GHG Life Cycle Emissions from Generation of Nuclear Electricity in Ontario



4.3.2 Coal-Fired Electricity Generation in Ontario

Based on the assumptions and details provided in Section 4.1, the following **system boundary for coal-fired electricity** in Ontario has been identified. The system boundary for this LCA study covers the applicable portion of the operation of all active facilities in 2005-2006 upstream from transmission. Figure 4.5 illustrates the chain of activities for coal-fired electricity.

Figure 4.5
System Boundary for Coal-Fired Electricity



Each of the above boxes is considered as a process and has its own inputs, outputs and emissions as displayed in Figure 4.2. Since mining, processing and cleaning are related activities and usually are performed in one facility, we label them as Coal Production in one process. The process starts with mining of coal at open pit and underground mines. The Run of Mine coal (ROM) is subsequently hauled to the processing plants for screening, crashing and washing. Coal is then sent to a cleaning facility. Before coal arrives at the power plant one way of cleaning the coal is by simply crushing it into small chunks and washing it in the coal preparation plants. The coal floats to the surface while high-sulphur impurities and other heavy impurities sink. Unfortunately, not all of coal's sulphur can be removed by washing because some of the sulphur in coal is chemically connected to coal's carbon molecules (organic sulphur). Most modern power plants are required to have special devices installed that clean the organic sulphur from the coal's combustion gases before the gases go up the smokestack. The technical devices are called flue gas desulphurization (FGD) units or scrubbers that scrub the sulphur out of the smoke released by coal combustion[33].

The cleaned coal is subsequently transported to the coal-fired power plants in Ontario. Since the long-distance transportation of coal is an important source of the emission in the complete cycle, it is considered as a separate process. Three types of coal are used by Ontario's coal-fired power plants: lignite, bituminous and sub-bituminous. For simplicity, it is assumed that the source of lignite is Saskatchewan's mines. CERI also assumes that all required bituminous and sub-bituminous is imported from US. Furthermore, to avoid complexities involved with locating the mines and power plants, as we evaluate the long-distance transportation emissions, three representative points of origin and two destinations are identified and selected. CERI assumes that lignite is transported from Bienfait (Saskatchewan) to Thunder Bay (Ontario), sub-bituminous is transported from Gillette (Wyoming) to Nanticoke (Ontario) and bituminous is transported from Louisville (Kentucky) to Nanticoke (Ontario). The mode of transportation is rail and its fuel is diesel.

Generation of electricity in power plants is the final process of the coal-fired electricity cycle. Pulverized coal combustion (PCC) is the most commonly used method in coal-fired power plants[34]. The pulverized coal power plant design is based on the utilization of pulverized coal feeding a conventional steam boiler and steam turbine.

The following is a summary of the facilities that have been identified and will be included in the inventory analysis of coal-fired electricity.

- Coal production: Saskatchewan (lignite) and US (bituminous/sub-bituminous)
- Transportation: from Saskatchewan and US to Ontario
- Power plants: Atikokan (lignite), Lambton (bituminous, subbituminous), Nanticoke (bituminous, subbituminous) and Thunder Bay (lignite, sub-bituminous)

[33] There is also a family of new technologies that work like "scrubbers" by cleaning NOx from the flue gases (NOx Scrubbers). Some of these devices use special chemicals called "catalysts" that break apart the NOx into non-polluting gases. Although these devices are more expensive than "low-NOx burners," they can remove up to 90 percent of NOx pollutants.

[34] The PCC refers to any combustion process that use very finely ground (pulverized) coal in the process.

4.3.2.1 Data

The following section discusses data issues and sources. It is divided into the same manner of the system boundary: production (mining, processing and cleaning), transportation and power plants. When the actual Consumption of energy or GHG emissions was not available, GHGenius software was used in order to estimate the fuel consumption and emissions involved with the relevant processes.

Production

As previously mentioned, lignite, bituminous, and sub-bituminous are types of coal that are used by the Ontario power plants. Lignite is imported into Ontario from the Beinfait Mine in Saskatchewan, while we assume that most bituminous and sub-bituminous coal is imported from Louisville, KY and Gillette, WY, respectively. Beinfait mine production data was collected from annual reports published by Royal Utilities Income Fund (RUIF). RUIF directly holds all of the shares of Prairie Mines & Royalty Ltd, which is the largest thermal coal producer in Canada. Emissions for the Beinfait mine were obtained from the Government of Canada GHG Reporting Site (GHG Inventory).

On the other hand, the actual emissions related to coal production was unavailable. CERI employed the GHGenius software to generate estimates.

Transportation

GHG emissions were estimated through NRCan's Office of Energy Efficiency website which lists tables of GHG emissions by means of transportation. CERI assumes that the mode of transportation between origins and destination is diesel-fueled rail. Transportation data was gathered and recorded as follows:

Table 4.5
Coal Rail-Based Haul Distances (From Mining & Preparation to Power Plants)[35]

Miles	Kilometers	Route
Bituminous Coal		
618	994	Louisville KY to Nanticoke ON
Sub-bituminous Coal		
1,944	3,128	Gillette WY to Nanticoke ON
Lignite		
704	1,133	Bienfait SK to Thunder Bay ON

Source: Canadian Pacific Railway estimates, private communication.

NRCan's Office of Energy Efficiency reports that in 2005 there were 356 billion tonne-kilometres of rail freight moved, with 6.16 megatonnes of associated greenhouse gas emissions, or 17.2 tonnes per million t km. A total of 26.9 TWh of electricity was produced in Ontario from coal (average in 2005 and 2006), with coal haulage to Ontario coal-fired power plants amounting to an estimated 26.5 billion t km.

Power Plants

The four power plants in Ontario are Atikokan (lignite), Lambton (bituminous, subbituminous), Nanticoke (bituminous, subbituminous) and Thunder Bay (lignite, sub-bituminous). OPG Inc operates all the coal power plants in Ontario, listing their production in TWh, for the years 2005 and 2006, on their website[36]. All pollutants/GHG emissions data are all available in Environment Canada's NPRI and GHG inventories.

4.3.2.2 Life Cycle Inventory (LCI)

This section reveals the results from the LCI analysis for coal electricity in Ontario. LCI is performed by inserting the collected data in the designed spreadsheet for each of the processes See sample spreadsheets; Figures D.8 to D.11 in Appendix D). After converting data to similar units, they are aggregated and emissions calculated per TWh of generated electricity. Table 4.6 presents the estimation and aggregation results for coal generation of all processes within the system boundary defined in Figure 4.5.

[35] In fact coal from Kentucky goes by rail in the United States to Lake Erie (presumably Cleveland or Toledo), and then crosses to Nanticoke by boat. Although this reduces the travel distance, it is not clear what the net impact would be on transportation emissions. According to the ORNL/Department of Energy Transportation Energy Data Book (Tables 9.5 and 9.9), the energy intensity of domestic waterborne commerce in 2005 was 515 Btu/ton-mile compared to 337 Btu/ton-mile for Class I freight railroads. Both rail and marine transportation of coal use diesel. No emission rates or energy intensity figures for marine freight have been published by Natural Resources Canada's Office of Energy Efficiency.

[36] http://www.opg.com/investor/pdf/2006factsheet.pdf

Table 4.6
Life Cycle Assessment Results for one TWh of Coal-Fired Electricity Generated in Ontario

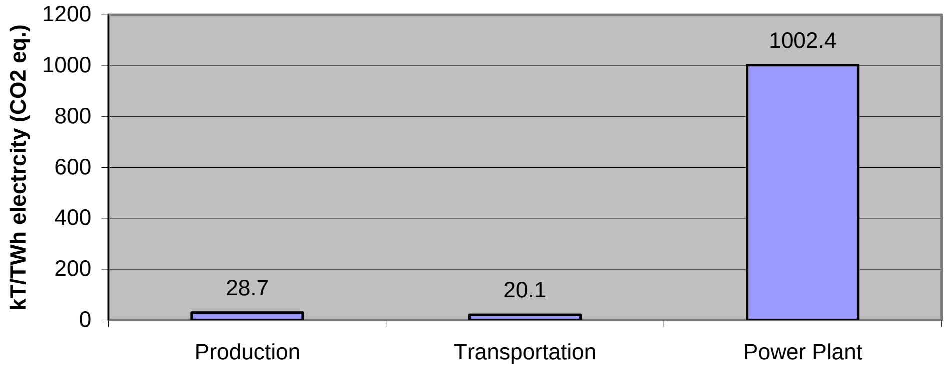
Emission	Unit	Production	Transportation	Power Plant	Life Cycle Emission
Total CAC	t/TWh	654.18	437.11	5621.49	6712.78
Oxides of Nitrogen (N02)	t/TWh	78.76	338.65	1259.17	1676.58
Sulphur dioxide	t/TWh	242.34	28.16	3636.86	3907.36
Carbon Monoxide	t/TWh	0.00	47.35	370.76	418.11
Total Particulate Matter	t/TWh	333.08	12.29	340.31	685.68
Volatile Organic Compounds (VOC)	t/TWh	0.00	10.65	14.40	25.05
Other Air Pollutants					
Lead (and its compounds)	Kg/TWh	0.00	0.00	22.21	22.21
Mercury (and its compounds)	Kg/TWh	0.00	0.00	10.59	10.59
Arsenic (and its compounds)	Kg/TWh	0.00	0.00	23.07	23.07
Radionuclides	TBq/TWh	0.003 to 0.092	0.00	0.01	0.012 to 0.100
Water Pollutants					
Lead (and its compounds)	Kg/TWh	0.00	0.00	0.47	0.47
Mercury (and its compounds)	Kg/TWh	0.00	0.00	0.13	0.13
Arsenic (and its compounds)	Kg/TWh	0.00	0.00	1.56	1.56
GHG emission CO2 eq.	t/TWh	28748	20070	1002397	1051215

Note: Zero figures have either negligible values or are not reported in NPRI database (negligible).

Emission of radionuclides in the coal-fired electricity's life cycle occurs at both the mine and the power plant, as illustrated in Table 4.6. The figures for the mine are based on the 1988 report of the United Nations Scientific Committee on the Effects of Atomic Radiation (UNSCEAR) to the General Assembly that noted the absence of any "measured data on the emission of radon from coal mines." In lieu of such data, UNSCEAR used two crude approaches that estimated worldwide radon releases from coal mines as 300 and 800 TBq per year, respectively. This gave rise to the huge range for radionuclide emission rates from coal mines shown in Table 4.6.

The LCA results indicate that the Power Plant Process is the main source of GHG emissions when coal is used. Unfortunately, we were not able to locate a source of information for other types of emissions in the Transportation Process. Figure 4.6 summarized the results for coal generation.

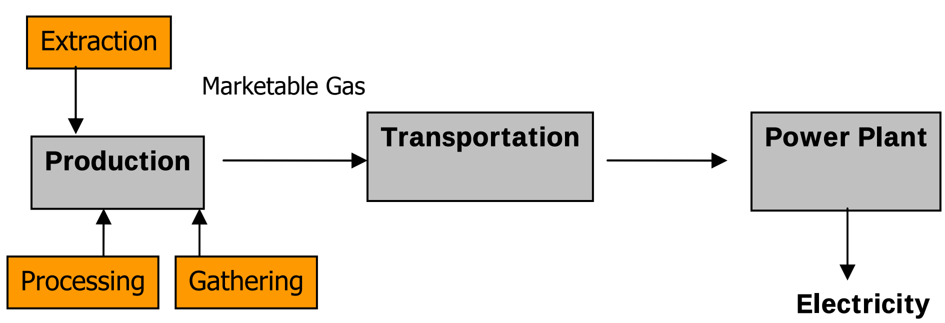
Figure 4.6
GHG Life Cycle Emissions from Generation of Coal-Fired Electricity in Ontario



4.3.3 Natural Gas-Fired Electricity Generation in Ontario

Based on the assumptions and details provided in Section 4.1, the following **system boundary for natural gas-fired electricity** of Ontario has been identified. The system boundary for this LCA study covers the operation of all active natural gas facilities, which are connected to the grid, in 2005-2006 before transmission. Figure 4.7 illustrates the chain of activities for gas-fired electricity.

Figure 4.7
System Boundary for Natural Gas-fired Electricity



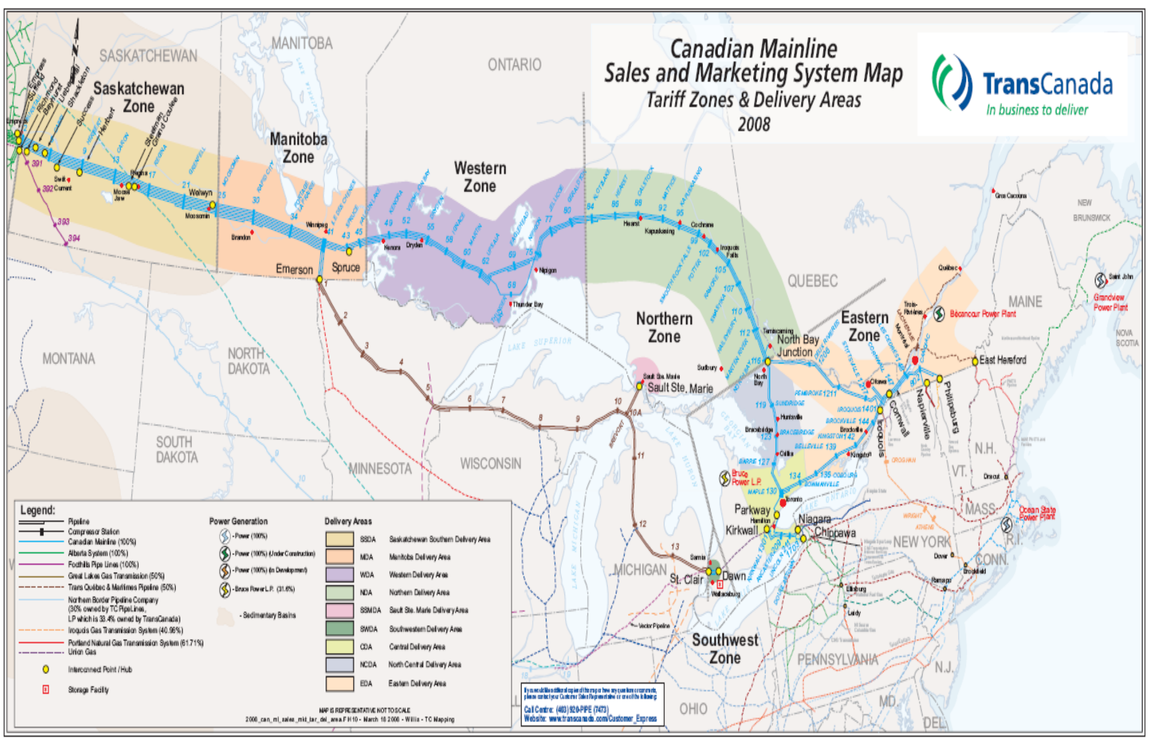
The process starts with field operations, which predominately take place in Alberta. Field operations refer to the production of natural gas (and oil) through field facilities (compressors, boilers, motors and turbines) and moving them by pipe to batteries (a system of tanks and equipment receiving well effluent).

In field operations, well activity includes well drilling (boring a hole from the surface to a gas reservoir), drill-stem test (production potential of the zone), flow test (deliverability of a well), pumping (bringing the oil and gas to the surface), and well servicing and repair. In the field, non-associated wet and dry gas is produced from gas wells and associated gas from oil well. A crude oil battery is a unit where the production from a crude oil wells is separated into its constituent of natural gas (associated gas), crude oil, and water. The associated or solution gas are vented, flared, re-injected, or compressed into a nearby natural gas gathering system. If the associated gas is beyond the economic reach their surplus is usually vented or flared or injected to maintain reservoir pressure.

Gas wells are connected to gathering systems that take the gas to processing plants for sweetening (processing sour gas to sweet gas), dehydration (removal or reduction of water content of gas), and removal of natural gas liquids (propane, ethane, etc). The final output of the gas processing plants is called "marketable gas" or "process gas" which meets the standard specification of pipeline requirements and using natural gas as burning fuel.

In the next step, natural gas is transported from Alberta to Ontario by pipeline. Figure 4.8 illustrates TransCanada's mainline sales and marketing system.

Figure 4.8
Canadian Mainline Sales and Marketing System Map



Source: http://www.transcanada.com/Mainline/info_postings/tariff/maps/MLmap.pdf

In 2005, Alberta produced 131.7 billion cubic meters (bcm) of marketable natural gas, of which 22.8 bcm was used domestically and the rest of 108.9 bcm were removed from Alberta[37]. In the

[37] ERCB-ST3, Alberta Energy Resource Industries Monthly Production

same year, TransCanada Pipeline (TCPL) moved 56.3 bcm of gas eastward from Alberta[38]. Before natural gas reached Ontario, part of the gas entering the TCPL main line was consumed in Manitoba (Saskatchewan being essentially self-sufficient in natural gas) and part went southward from near Winnipeg (Ile des Chenes) into the United States at Emerson, Manitoba. Statistics Canada shows that in 2005, approximately 74% of the gas (43.2 bcm) entering TCPL crossed from Manitoba directly into northern Ontario.

Generation of the electricity from natural gas is the final process in the system boundary. Since the operation of power plants has a significant share in LCA of GHG emissions, CERI has compiled the average of 2005-2006 generation and GHG emissions of eighteen power plants in Ontario and illustrated their generation and associated emissions by gas turbine technology. The following power plants which supply to the Ontario electricity grid are considered:

Combined Cycle Facilities (7): Nipigon (EPCOR), North Bay (EPCOR), Kapuskasing (EPCOR), Calstock (EPCOR), Tunis (EPCOR), West Windsor, Brighton Beach Power

Cogeneration Facilities (11): Ottawa (TransAlta), Mississauga (TransAlta), Windsor (TransAlta), Iroquois Falls, Kingston Cogeneration LTD., Cardinal Power facility, Sarnia Regional Cogeneration Plant (TransAlta), Lake Superior Power Facility, Fort Frances - Abitibi-Consolidated, Whitby LP, GTAA

Each of the above (Figure 4.7) boxes is considered as a process and has their own inputs, outputs and emissions. Since the extraction, processing and gathering of natural gas are known as upstream activities they are considered as one process and labeled as Production, however, the environmental impacts of all sub-processes are accounted. In this report we have assumed that all natural gas requirements of Ontario power plants are met by Alberta. In other words, CERI has used Alberta's natural gas specification and distance from Ontario. It is also assumed that natural gas is the only fuel, which is used to meet the energy requirements of all activities in the Figure 4.7. For instance, all pipeline compressors are natural gas-fired and all processing plants use natural gas for their energy needs. Also eighteen power plants in Ontario which are connected to the electricity grid are considered. Eleven of these power plants are cogeneration facilities, the remaining are combined cycle natural gas power plants.

The following is a summary of the facilities that have been identified and included in the inventory analysis of gas-fired electricity.

- Production: Alberta
- Transportation: from Alberta to Ontario
- Power plants:

    a) Combined Cycle Facilities (7): Nipigon (EPCOR), North Bay (EPCOR), Kapuskasing (EPCOR), Calstock (EPCOR), Tunis (EPCOR), West Windsor, Brighton Beach Power

[38] Statistics Canada-catalogue no. 57-003-x, Report of Energy Supply – Demand in Canada – 2005.

b) Cogeneration Facilities (11): Ottawa (TransAlta), Mississauga (TransAlta), Windsor (TransAlta), Iroquois Falls, Kingston Cogeneration LTD., Cardinal Power facility, Sarnia Regional Cogeneration Plant (TransAlta), Lake Superior Power Facility, Fort Frances - Abitibi-Consolidated, Whitby LP, GTAA.

4.3.3.1 Data

The following section discusses data issues and sources. It is divided in the same manner as the system boundary: field operation, pipeline operation and power plants. When the actual consumption of energy or GHG emissions was not available, GHGenius software was used to estimate the fuel consumption and emissions involved with the relevant processes.

Production

Field operation (natural gas production) contribute to emissions from:

- Combustion fuels that are consumed by boilers, engines, pump jacks, gas gathering system and gas processing plants. All oil fields are equipped with pump jacks, and almost all pump jacks use electricity for their operation, whereas gas fields rely on the pressure of natural gas in reservoirs to cause it to flow and thus are not equipped with pump jacks.

- Flaring solution gas which is not within economic reach of an existing pipeline or those solution gases that must flare due to emergencies or operational problems.

- Venting natural gas (fugitive emissions) because of injecting gas, and leaking equipment components.

The average fuel intensity in field operation is estimated by gas consumption to process gas production. The same methodology is used for estimating gas flaring and gas venting[39].

In the field that equipped with gas processing plants for every cubic meter of natural gas production approximately:

- 0.07939 m^3 of raw gas and 0.02894 m^3 of process gas use as fuel.

- 0.00464 m^3 of raw gas and 0.00003 m^3 of process gas are flared.

- 0.00287 m^3 of raw gas is vented to the atmosphere.

[39] ERCB, ST3 2003-2005.

CAC emissions are estimated by investigating a sample of 52 facilities from different categories of activities in Alberta. The Energy Resources Conservation Board (ERCB) annually publishes volumetric data for gas plant and gas gathering system activities such as receipts, dispositions, and processes. There are many active natural gas facilities in Alberta owned by private and public entities. The facilities that are included in the ERCB's database can be divided into the following eight sub-categories as below:

- Sweet gas plants
- Acid gas flaring plants < 1Ton/day sulphur
- Acid gas flaring plants > 1Ton/day sulphur
- Acid gas injection plants
- Sulphur recovery plants
- Mainline straddle plants
- Fractionation plants
- Gas gathering system

We have carefully reviewed the 52 facilities from different categories and searched the National Pollutant Release Inventory (NPRI) for their respective Criteria Air Contaminant (CAC) for years 2005 and 2006. Using the facilities' annual production and collected CAC data and generalizing the estimates for whole natural gas field operation industry we are able to estimate CAC emissions for the production process.

Transportation

After removing impurities and meeting the pipeline specifications, the gathering systems collects process gas from producing areas (processing plants) and moves the gas to distribution systems (e.g. residential and industrial customers), and transmission systems serving markets in other Canada provinces and the United States.

Gas flows through the pipeline system by compressor stations, and turbines that are placed at regular intervals along the pipeline to increase the line pressure. Therefore pipelines not only require fuel but they release fugitive emissions.

CERI assumes that per cubic meter of natural gas moving from Alberta to Ontario (gas export pipeline) use approximately 0.05 m^3 of gas as fuel. CERI also estimates fugitive emissions of gas pipeline through the pipe fittings and their rotating equipment leaks.

For this purpose, CERI specified 36 stations and 136 compressors between Alberta boarder (Empress) and the Maple Station number 130 in Ontario. It is assume that the transmission line uses 1 valve per 32 Km where each valve is attached with 2 flanges. Furthermore, each compressor is assumed to have 6 flanges, 4 compressor seals, and 2 pressure control valves (vented to the atmosphere).

On this basis, every cubic meter of natural gas moving from Alberta to Ontario releases approximately 0.00008 m^3 of gas (methane) to the atmosphere (See Table E.1 in Appendix E). The rate of methane release per fitting is taken from the Canadian Association of Petroleum producers[40].

The same methodology is used for Alberta gathering systems that move gas within Alberta and to the provincial boundary of Empress. CERI specified 20 stations and 60 compressors between the Zama and Empress. On this basis for every cubic meter of natural gas approximately 0.000037 cubic meter of methane is vented to the atmosphere (See Table E.2 in Appendix E).

The amount of gas use as fuel and flaring at Alberta gas gathering system is taken from AEUB statistical reports[41] and Statistics Canada[42] respectively: for every cubic meter of natural gas production approximately 0.02 m^3 of gas use as fuel and 0.00031 m^3 are flared.

The details estimation of GHG emissions from natural gas use for electricity generation in Ontario is illustrated in Appendix E, Table E.3.

The National Pollutant Release Inventory (NPRI) reports the air contaminant emissions associated with moving natural gas by pipelines for each Canadian province[43].

For estimation of air contaminant emissions (tonnes per cubic meter) of natural gas moving from Alberta to southern Ontario (northern leg of the TransCanada (TCPL) main line specifically to Maple Station #130) CERI identifies the amount of gas removal by TCPL-east and ascribe that percentage to total air contaminant emissions of each province as follows.

Statistics Canada[44] reports the inter-regional transfers of natural gas for each Canadian province and shows that approximately 43.2 billion cubic meters (74 percent) of that gas entering the TCPL main line at Empress crossed from Manitoba into to the northern leg of the TCPL. Thus 74 percent the emissions from compressor stations west of Winnipeg were ascribed to those movements.

Air contaminant emissions must be also estimated for natural gas moved from Alberta receipt points to the TCPL mainline at Empress, for subsequent delivery to Manitoba-Ontario border

[40] Canadian Association of Petroleum Producers - Calculating Greenhouse Gas Emissions
[41] AEUB, ST3-2004 and ST60B-2005
[42] Statistics Canada-catalogue no. 57-003-x, year2005
[43] http://www.ec.gc.ca/pdb/querysite/query_e.cfm
NAICS Code: Pipeline transportation of natural gas (4862)
[44] Statistics Canada, Catalogue number 57-003-X

(Northern leg). For such estimates, average distances of 240 km and 620 km are assumed for internally consumed gas and crossing provincial boundary[45], respectively.

The above assumptions indicates that approximately 37 percent[46] of Alberta transmission pipeline air contaminant emissions were attributable to moving 43.2 billion cubic meters of natural gas from Alberta to Ontario. Table E.4 in Appendix E shows the details estimation of CAC emissions from moving natural gas from Alberta to Ontario.

<u>Power plants</u>

Statistics Canada[47] reported that in 2005, Ontario electric utilities produced 120.7 TWh of electricity where approximately 10 percent of that was generated from natural gas. The same report indicates that in 2005 on average, the Ontario electric utilities used approximately 238 * 10^6 m^3 of gas for per TWh of electricity generation. The above information used for estimation of GHG emissions (See Table E.3 in Appendix E).

Natural gas power plants in Ontario are owned mostly by the private sector. This made data collection quite challenging since only 13 out of 33 power plants reported full information on their annual generation and GHG emissions, as several of these natural gas-fired plants are used internally by steel mills, paper & pulp mills, etc. to generate their own electricity. Thus, two sources are used for electricity generation data: annual reports of every power plant operator and the Independent Electricity System Operator's (IESO) website. The IESO displays monthly generation data for each gas-fired power plant connected to the Ontario electricity grid.

As for CACs and other pollutants (including GHGs), they were derived from the NPRI and GHG inventory. Any power plant that has either missing GHG emissions or annual generation data are exempted and not considered as part of the study.

4.3.3.2 Life Cycle Inventory (LCI)

This section reveals the results from the LCI analysis for natural gas electricity in Ontario. LCI is performed by inserting the collected data in the designed spreadsheet for each of the processes (See sample spreadsheets; Figures E.1 through E.5 in the Appendix E). After converting data to similar units, they are aggregated and emissions calculated per TWh of generated electricity. According to Statistics Canada, electricity generation from natural gas in Ontario averaged 9.8 TWh during 2005-6. Table 4.7 presents the estimation and aggregation results of all processes within the system boundary defined in Figure 4.7.

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45 240 km represents the average distance from Edson to Calgary and to Edmonton, and 620 Km from Edson to Empress.

[46] (621* 43.2)/{(240 * 22.8) + (621 * 108.9)} = 0.37

[47] Statistics Canada – Catalogue no. 57-202

Table 4.7
Emissions Involved With the Generation of one TWh of Electricity from Different Technologies in Ontario

Emission	Unit	Cogeneration	Combined Cycle	All Power Plants
Total CAC	t/TWh	860.82	533.16	758.54
Oxides of Nitrogen (N02)	t/TWh	585.75	366.98	517.46
Sulphur dioxide	t/TWh	6.80	0.00	4.67
Carbon Monoxide	t/TWh	210.81	121.15	182.82
Total Particulate Matter	t/TWh	28.04	2.12	19.95
Volatile Organic Compounds (VOC)	t/TWh	29.43	42.90	33.63
Other Air Pollutants				
Lead (and its compounds)	kg/TWh	0.88	0.00	0.61
Mercury (and its compounds)	kg/TWh	0.00	0.00	0.00
Arsenic (and its compounds)	kg/TWh	0.08	0.00	0.61
Radionuclides	TBq/TWh			0.78
Water Pollutants: Radionuclides	TBq/TWh	0.00	0.00	0.00
GHG emission CO2 eq.	t/TWh	559980	402045	445208

Note: Zero figures have either negligible values or are not reported.

Since cogeneration facilities produce electricity and steam, the collected actual emission data corresponds to both products. To study the emissions involved with the generation of electricity, we should be able to separate the emissions involved with the steam production. Only three cogeneration facilities reported their steam production in 2005-2006. Therefore the average fraction of electricity to total energy output (electricity and heat) is calculated and applied to the other cogeneration facilities. The average ratio of electricity to energy output for three power plants (Kingston Cogeneration LTD., Cardinal Power facility and Iroquois Falls) is 86 percent.

The LCA results indicate that the chief source of greenhouse gases in the natural gas life cycle is the power plant itself. Surprisingly, perhaps, the cogeneration facilities were found to have higher emission rates for greenhouse gases and most of the other pollutants than gas-fired combined cycle power plants. One might have thought that being able to make effective use of exhaust steam through cogeneration would lead to a more efficient process and therefore lower emission rates throughout. But according to Canadian Industrial Energy End-Use Data and Analysis Center, "this is not always the case, particularly in the systems with high heat to power ratios and moderate system efficiencies or systems that operate at part load for significant portions of time"[48]. This means that cogeneration facilities are not as environmentally friendly as they are thought to be. "Furthermore when we compare standalone combined cycle generators with cogeneration facilities we note that many of the investigated facilities are single cycle cogeneration facilities rather than combined cycle cogeneration facilities"[49].

The seemingly non-intuitive results arise from the fact that some cogeneration facilities employ single-cycle generation technology and are less efficient in generating electricity than combined-

[48] CIEEDAC (2004, page 5)
[49] Ibid

cycle plants that produce only electricity as a useful output. Hence, a weighted average of electric efficiencies for a combination of single and combined cycle generators should be lower than electric efficiency of standalone combined cycles[50]. Therefore on average the cogeneration facilities consume more energy than standalone facilities to generate one MWh of electricity in Ontario. As a result, the existing combination of studied cogeneration facilities in Ontario is not environmentally friendlier than the standalone combined cycle facilities.

The LCA estimation results for all processes are reported in Table 4.8. The LCA estimates are based on weighted average performance of two types of power plant technologies in Ontario.

Table 4.8
Life Cycle Assessment Results for one TWh of Natural Gas-Fired Electricity Generated in Ontario

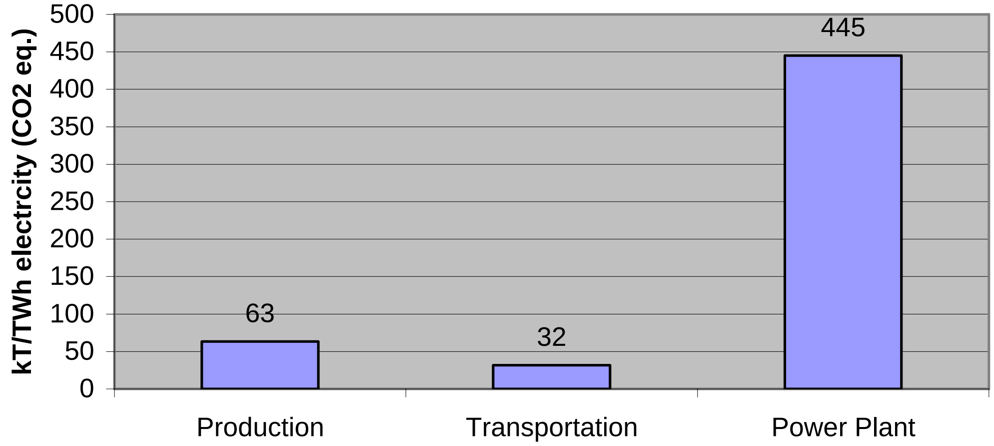
Emission	Unit	Production	Transportation	Power Plant	Industry Life Cycle Emission
Total CAC	t/TWh	619.88	74.21	758.54	1452.63
Oxides of Nitrogen (N02)	t/TWh	145.19	57.47	517.46	720.12
Sulphur dioxide	t/TWh	358.65		4.67	363.32
Carbon Monoxide	t/TWh	75.92	15.73	182.82	274.47
Total Particulate Matter	t/TWh	0.00	0.959	19.95	20.91
Volatile Organic Compounds (VOC)	t/TWh	40.13	0.047	33.63	73.81
Other Air Pollutants					
Lead (and its compounds)	t/TWh	0.00	0.00	0.61	0.61
Mercury (and its compounds)	t/TWh	0.00	0.00	0.00	0.00
Arsenic (and its compounds)	t/TWh	0.00	0.00	0.61	0.61
Radionuclides	TBq/TWh	0.10	0.04	0.78	0.92
Water Pollutants: Radionuclides	TBq/TWh	0.01	0.00	0.00	0.01
GHG emission CO2 eq.	t/TWh	63,329	31,854	445208	540391

Note: Zero figures have either negligible values or are not reported.

The LCA results indicate that Power Plant process is the main source of GHG emission among the others. Figure 4.9 better explains our findings. The findings also support the fact the combined cycle power plants are more efficient than cogeneration facilities and thereby they emit less GHG.

[50] While the overall energy efficiency of cogeneration facilities are between 70-85%, the electric efficiency of them are 34-55% for combined cycle and 24-42% for single cycle (gas turbine)(source CIEEDAC (2004)).

Figure 4.9
GHG Life Cycle Emissions from Generation of Natural Gas-Fired Electricity in Ontario



4.4 Conclusion

Among the three investigated power generation technologies in Ontario, GHG emissions involved with the generation of one TWh of nuclear electricity are so small that, as illustrated in Table 4.8 below, they are not comparable in magnitude to the emissions involved with the generation of one TWh of electricity from natural gas and coal on a life-cycle basis. The asterisks in Table 4.9 indicates a value less than 5 kt per TWH, which can be inferred from the fact that none of the facilities in the nuclear life cycle, mine, refinery, conversion facility or power plants, exceeded Environment Canada's reporting threshold of 10,000 tonnes of CO_2 equivalent in 2005 or 2006. As noted below, CERI estimates the nuclear GHG emission rate to be 1.8 kilo tones per TWh.

In comparing Tables 4.4 and 4.6, it is evident that the nuclear life cycle has much higher emissions of radionuclides than the coal-fired life cycle. Even so, for reasons elaborated in Appendix F, analyses of United States data conclude that the corresponding population impacts in terms of collective doses of radiation on a per TWh basis are much lower for the nuclear life cycle than for the coal-fired cycle. This is one circumstance where emissions turn out not to be a good proxy for impacts.

Table 4.9
Comparative Life-Cycle GHG Rates for Ontario Electricity Generation

Fuel	Emission Rate (Mt of CO_2 equivalent per TWh)
Coal	1.05
Gas	0.56
Nuclear	0.00*

* Indicates value less than 5 kt per TWh

The figures in Table 4.9 also indicate that while the production of one TWh of electricity from coal and natural gas would emit 1,047.5 kilo tonnes (kt) and 555.6 kt of GHG respectively on a life-cycle basis, the same amount of nuclear electricity would emit only 1.8 kt GHG. A comparison of coal-fired and gas-fired electricity generation reveals that the former emits GHG to the environment at almost twice the rate of the latter.

Figure 4.10 demonstrates that production and transportation of natural gas imposes more GHG emissions than coal, however, at the power plant stage coal emits more than natural gas. The Criteria Air Contaminants (CAC) is also significantly higher for coal-fired power plants in Ontario. While the GHG emissions of coal-fired power plants are almost two times those of natural gas power plants, the CAC emissions involved with one TWh of electricity from coal-fired power plants are more than 7 times those of natural gas-fired power plants. This is mainly due to the large amounts of ashes and sulphur dioxide that are produced by coal-fired power plants. Apparently coal is not desulphurized like natural gas at the production stage and produces more ash as it burns.

Figure 4.10
Comparison between GHG emissions involved with one TWh of electricity from natural gas and coal in Ontario (2005-2006 average)

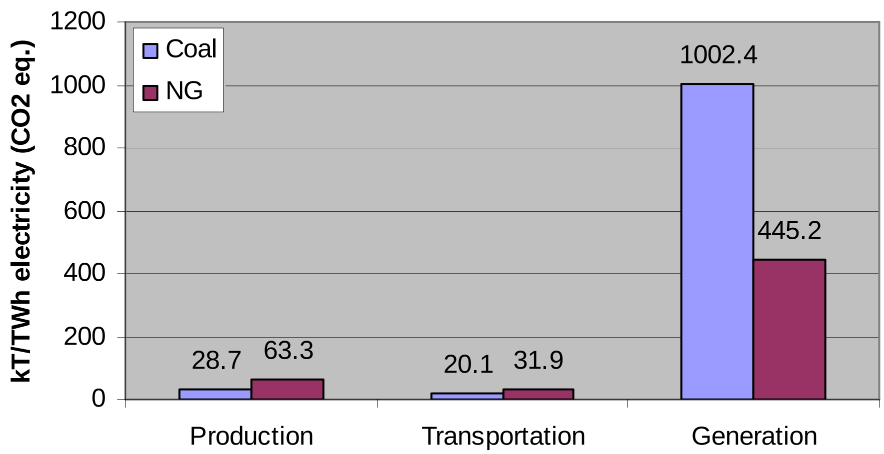
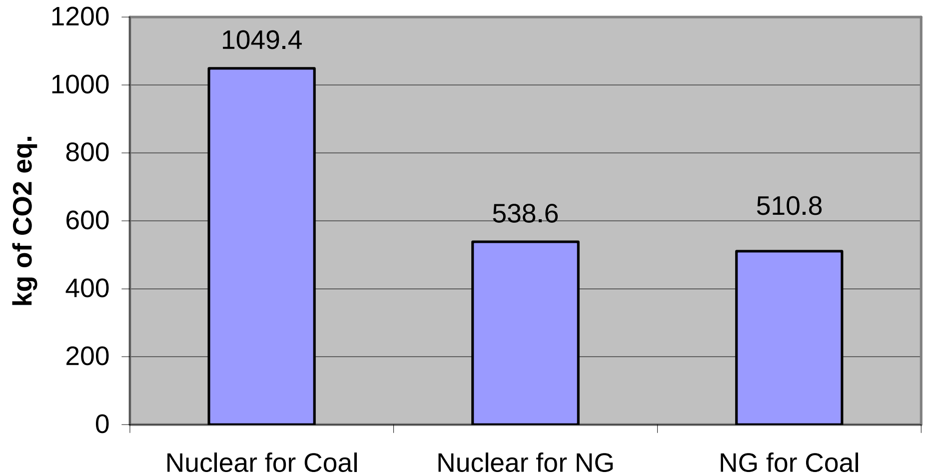


Figure 4.11 shows the amount of GHG emissions that could be avoided by replacing one TWh of fossil fuel electricity with nuclear electricity. If a MW of coal-fired electricity capacity is replaced by a MW of nuclear or natural gas-fired electricity, Ontario could have avoided 1049 kg or 497 kg of GHG emissions per hour of generation. This shows the potential for GHG abatement in the power generating sector of Ontario under current technologies.

Figure 4.11
Potential for GHG abatement by substituting one MWh of low carbon fuel for a higher carbon type of fuel.



Also CERI estimates that 1 per cent increase in the efficiency of all coal-fired power plants could have reduced the relevant GHG emission by about 267 kt in 2006 in Ontario. Furthermore, 1 percent improvement in the efficiency of natural gas-fired power plants could avoid approximately 43 kt GHG emissions in 2006 in Ontario.

As a result, it seems that influencing the level and pattern of electricity final demand, altering the mix of generating technologies, investing in measures that increase efficiency and changing the spatial location of pollution generating plants are the policy options, which can reduce the environmental impacts of power generating sector in Ontario.

CHAPTER 5
RELIABILITY, SAFETY AND SECURITY ISSUES IN ELECTRICITY GENERATION

This Chapter provides an examination of reliability, safety and security issues in electricity generation. It is divided into three parts. The first explores the reliability of nuclear, natural gas and coal electricity generation. The second discusses safety and security issues of nuclear, natural gas and coal. The third section provides concluding remarks.

5.1 Reliability

This section discusses the reliability of various types of electricity generation: nuclear, natural gas, and coal.

The Canadian Electricity Association (CEA) published reliability statistics for 2003 and for the five year average (1999-3003) in its publication *2003 Generating Equipment Status Annual Report.*

The statistics most relevant are Operating Factor (OP FACTOR), Available But Not Operating Factor (ABNOF), Forced Outage Rate (FOR), Derated Adjusted Unit Forced Outage Probability (DAUFOP) and Incapability Factor. The values of OP FACTOR and ABNOF reflect the degree of utilization of the units, whereas the values of FOR and DAUFOP are measures of reliability. The definition of OP FACTOR, ABNOF, FOR, and DAUFOP are as follows[51]:

- **OP FACTOR (%):** Total Operating Time (whether under normal operation, under forced derating or under scheduled derating) divided by Unit Hours, the total number of hours in a year [8,760 except in a leap year].

- **ABNOF (%):** Number of hours available for normal operation but not operating plus number of hours available but not operating under forced derating [typically due to a component failure] plus number of hours available but not operating during scheduled deratings), all divided by Unit Hours.

- **FOR (%):** It is the ratio of Total Forced Outage Time to Total Unit Hours times 100. Total Forced Outage Time is the sum of hours in a forced outage state, hours in a forced extension of a maintenance outage and hours in a forced extension of a planned outage.

- **Incapability Factor (%):** The Incapability Factor refers to the percentage of capacity that, on average, is unavailable throughout the year or throughout the five-year period.

- **DAUFOP (%):** It is the percentage of time that unscheduled outages would cause a unit to be unavailable throughout the year or throughout the five-year

[51] Canadian Electricity Association, 2003 Generation Equipment Status Annual Report.

average. In other words, the probability that a generating unit will not be available when required (derating included).

From the definitions provided, CERI has made several conclusions. If the OP FACTOR is high and ABNOF is low, then the unit was used for baseload. On the other hand, if the OP FACTOR is low and ABNOF is high, then the unit was used for peaking. A less extreme value for either of these factors would result from use in intermediate load. In addition, the closer the values FOR and DAUFOP are to zero, the more reliable the unit is.

The reliability statistics for coal, natural gas and coal are shown in Table 5.1.

Table 5.1
Operating Characteristics of Canadian Gas, Nuclear and Coal Units

	Period	OP FACTOR (%)	ABNOF (%)	FOR (%)	Incapability Factor (%)	DAUFOP (%)
Nuclear	2003	76.3	2.1	12.2	23.7	11.9
	1999-2003	81.9	0.7	5.7	19.4	7.5
Natural Gas	2003	13.0	71.5	18.2	16.5	10.5
	1999-2003	46.1	33.9	15.3	21.8	13.4
Coal	2003	80.4	5.2	5.9	18.0	9.1
	1999-2003	79.1	4.8	6.7	19.1	9.4

SOURCE: Canadian Electricity Association, 2003 Generation Equipment Status Annual Report, Tables 6.2.13 & 14 and Tables 6.3.1 & 2.

Recall, the values of OP FACTOR and ABNOF determine the availability of the operation. Over the five-year period 1999-2003 natural gas units in Canada were "available but not operating, ABNOF" 33.9 percent of the time, compared to 0.7 percent for nuclear and 4.8 percent for coal-fired units. Table 5.1 indicates that over the period 1999 to 2003, natural gas units were utilized largely for peaking, while nuclear and coal-fired units were utilized largely for baseload. This is evident by their respective OP FACTORS values.

The CEA also reports that over the same five-year period the probability that a unit would be unavailable if needed DAUFOP was 13.4 percent for natural gas units compared to 7.5 percent for nuclear units and 9.4 percent for coal-fired units.

Recall that the values of FOR and DAUFOP reflect the values are measures of reliability, or unreliability. Over the five-year period 1999-2003 the FOR of coal-fired units in Canada was 6.7 percent compared to 15.3 percent of natural gas units and 5.7 percent of nuclear units. Over the same period, the incapability factor for coal-fired units was 19.1 percent while nuclear units were 19.4 percent and 21.8 percent for natural gas units. It can be seen that by both criteria, natural gas was the least reliable fuel over the five-year period, while nuclear was the least reliable fuel in the single year 2003. The above analysis establishes that nuclear performance has been improving, and therefore the five-year basis is appropriate.

The statistics in Table 5.2 are for Canada and the United States over a period when no nuclear capacity was commissioned in either country. It is important to note that both countries utilize different technologies, Canada using the CANDU reactor and the United States using either the BWR or the PWR. It is still, however, useful to observe trends in output from nuclear generation.

The trend in both countries is to get more and more nuclear energy out of an existing fleet of nuclear generating units. United States capacity factors exclude from the denominator the sole laid-up unit Brown's Ferry #1, using the convention employed in the Canadian Nuclear Association's calculation of capacity factors. This exclusion makes very little difference to the calculated capacity factor in this case, as there are 104 operating units in the US. Recently, Brown's Ferry #1's has received regulatory approval for return to service.

Table 5.2
Trends in Output from Nuclear Generation, Canada and the United States

Year	Canadian Nuclear Output (TWh)	US Nuclear Output (TWh)	US Nuclear Capacity Factor (%)
1999	69.3	728.3	85.3
2000	68.7	753.9	88.1
2001	72.4	768.8	89.4
2002	71.3	780.1	90.3
2003	70.7	763.7	87.9
2004	85.3	788.5	90.1
2005	86.8	780.5	89.4

Sources: Statistics Canada, Catalogue No. 57 601, Table 8.2; United States Energy Information Administration, Annual Energy Review 2005, Table 9.2.

In summary, nuclear capacity factors have been rising. A five-year average is therefore a more appropriate time horizon than a single year as the basis for comparing the reliability of nuclear to generation from other fuels. On this basis nuclear, as shown in Table 5.1, has been found to be more reliable than generation from natural gas, although not by a wide margin.

The following analysis considers all CANDU reactors built in Canada and other jurisdictions. A number of CANDU units have been built in other jurisdictions, in circumstances where the vendor had more control over the ultimate design and construction. This analysis does not, however, include PHWRs built in India.

Table 5.3 illustrates CANDU's nuclear reactor performance in 2007. It is taken from the Canadian Nuclear Association's website and includes eight nuclear power reactors built outside of Canada; four in South Korea, two in China, one in Argentina and two in Romania.

Table 5.3
CANDU Nuclear Reactor Performance

December 2007 Reactor	In service	Capacity (MW)	Performance in 2007 (%)	Lifetime Performance (%)
Point Lepreau	1983	680	74.9	82.1
Gentilly-2	1983	675	78.4	79.5
Wolsong 1	1983	622	89.8	85.7
Wolsong 2	1997	730	90.9	94.0
Wolsong 3	1998	729	94.3	95.4
Wolsong 4	1999	730	93.2	97.2
Embalse	1984	648	76.2	84.9
Cernavoda 1	1996	706	97.6	88.4
Cernavoda 2	2007	705	93.2	93.2
Qinshan 1	2002	700	88.3	87.5
Qinshan 2	2003	700	99.9	89.2
Pickering 1	1971	542	38.8	63.1
Pickering 4	1973	542	43.7	66.1
Pickering 5	1983	540	57.6	73.4
Pickering 6	1984	540	71.5	77.1
Pickering 7	1985	540	81.9	79.4
Pickering 8	1986	540	86.9	76.1
Bruce 3	1978	805	75.3	62.8
Bruce 4	1979	805	80.1	61.5
Bruce 5	1985	845	96.6	83.4
Bruce 6	1984	872	71.6	79.9
Bruce 7	1986	872	97.2	83.7
Bruce 8	1987	845	93.2	81.6
Darlington 1	1992	934	96.7	84.1
Darlington 2	1990	934	83.0	75.7
Darlington 3	1993	934	94.2	85.2
Darlington 4	1993	934	81.0	85.1
Total/Average		19,655	82.4	81.3

Source: http://www.cna.ca/english/pdf/NuclearFacts/2007/Candu_Nuclear_Performance_07.pdf

The list does not include the laid-up units Bruce 1 & 2 and Pickering 2 & 3, both from the table and from the computation of totals and averages. While some opponents of nuclear may be unhappy regarding the omissions, proponents of nuclear generation would argue that various units that have been laid-up for some years could have been refurbished long ago were OPG not starved for capital. It is also important to note that the continuing laid-up status is not due to technical limitations. Now that it has been decided to restart Bruce 1 & 2 and to put Pickering 2 & 3 into safe storage, perhaps a middle position of including the two Bruce units and excluding the two Pickering units would be acceptable to all, even if the decision to place Pickering 2 & 3 into safe storage may have been influenced by OPG's prescribed rate cap and limitations on rate of return. In any case, no such controversy exists with respect to CANDU units outside Ontario because none of them has ever been laid-up. Their lifetime capacity factors range from 61.5 percent to 97.2 per cent.

The excellent performance of the PHWR units was not limited to CANDU. The average of all the PHWR units, whether Canadian or Indian, for the 2003 period was 83.3 per cent. In the same year, Nuclear Power Corporation of India Limited's Kakrapar Atomic Power Station Unit 1 (KAPS) was declared the best performing PHWR operating across the world, with a Gross Capacity Factor (GCF) of 98.4 per cent during the preceding 12 months.

5.2 Safety and Security Issues Regarding Nuclear, Natural Gas, and Coal

This section discusses safety and security issues of nuclear, natural gas and coal. As such this section is divided into three parts: nuclear, natural gas, and coal.

The section regarding the safety and security of nuclear power provides a review of occupational hazards and environmental impacts of uranium mining, a comparative safety analysis and nuclear and other types of energy, analyzes energy-related disasters by type, examines Canadian regulations and spent fuel management and, finally, examines terrorism threats to nuclear power.

The section regarding the safety and security of natural gas discusses occupational hazards regarding natural gas, discusses public safety issues and environmental issues and reviews the safety and security issues of liquefied natural gas (LNG). It is important to remember that natural gas is no longer exclusively a continental market. According to both government and private sources, increased imports of natural gas will be required to meet future shortfalls in major consuming regions, such as North America. There are abundant reserves of "stranded gas" found in locations around the world that are beyond the reach of pipelines. Some include Australia, Russia, Venezuela, Malaysia and Nigeria.

The section regarding the safety and security of coal discusses occupational hazards of coal mining, reviews environmental threats of coal mining and examines public safety and environmental impacts of coal combustion. From the coal industry's earliest days, there have always been dangers associated with mining and usage. In Europe and North America, where the industry is mature and safety issues have been of great concern for over a century, many of these hazards have been reduced significantly. In the world's largest coal producing country, China, where the industry has only recently begun its rapid growth, the perils are great and increasing.

5.2.1 Nuclear

This section regarding the safety and security of nuclear power is subdivided into four parts. The first part provides a review of occupational hazards and environmental impacts of uranium mining. The second part discusses a comparative safety analysis and nuclear and other types of energy. This section analyzes energy-related disasters by type. The third part examines Canadian regulations and spent fuel management, while the last examines terrorism threats to nuclear power.

5.2.1.1 Uranium Mining: Occupational Hazards and Environmental Impacts

This section discusses occupational hazards in uranium mining and milling industry. Recall that, as discussed in Chapter 3 of this report, Canada is the world's largest producer of uranium, providing over one third of total world production. Canada ranks third in the world for total uranium deposits and has the world's largest known high-grade deposit. The major uranium mining companies in Canada are Cameco Corporation, AREVA Resources Canada Inc. and COGEMA Resources Inc. There are currently three producing mines in Saskatchewan: McClean Lake, Rabbit Lake, and McArthur River. Key Lake is still being operated as a mill for ore from McArthur River. With Ontario's mines shutting down and decommissioned in the early 1990s, all of Canada's uranium production are located in Saskatchewan.

Uranium mining has long been regarded a hazardous occupation dating back to the fifteenth century in present day Germany and Czech Republic. Many workers died from a 'mysterious illness', often diagnosed as lung cancer in the 1800s. It was not until the early 1920s that radon was thought to be the cause. Uranium miners experienced higher emissions of alpha particles from radon between 1949 and 1959. Accumulated doses were in excess of recommended limits. That being said, much has changed in the past forty years.

Canada's uranium mining and milling industry's radiation safety regulations are among the most comprehensive and stringent in the world. It is important to note that Canada has a long history of mining uranium and much has been learnt since uranium ores were first produced in the early 1930s when the Eldorado Gold Mining Company began operations at Port Radium, Northwest Territories. By the late 1950s, 23 mines with 19 treatment plants were in operation in five districts, with the main production centre around Elliot Lake in Ontario.

More importantly, radiation levels are well within regulated norms. The Canadian Nuclear Safety Commission (CNSC) regulations apply; they have stringent regulations that deal with health standards for gamma radiation and radon gas exposure, as well as for ingestion and inhalation of radioactive materials. All uranium mines and mills in Canada are regulated and licensed by the CNSC for the protection of Canadians and the environment.

Table 5.4 indicates uranium mines in Canada, and the various license types. The list does not include fourteen inactive uranium mines and mills in Ontario, Saskatchewan and Northwest Territories.

Table 5.4
Uranium Mines in Canada

Facility	Location	Licensee	License Type	Status
Cigar Lake Project	Saskatchewan	Cameco Corporation	Construction	Under construction
Cluff Lake	Saskatchewan	AREVA Resources Canada Inc.	Decommissioning	Carrying out decommissioning activities
Key Lake Operation	Saskatchewan	Cameco Corporation	Operation	Licensed to produce up to 7,200,000 kg of uranium per year; licensed to receive ore slurry from McArthur mine
McArthur River Project	Saskatchewan	Cameco Corporation	Operation	Licensed to mine up to 7,200,000 kg of uranium per year
McClean Lake Project	Saskatchewan	AREVA Resources Canada Inc.	Operation	Licensed to produce up to 3,629,300 kg of uranium per year
Midwest Joint Venture	Saskatchewan	AREVA Resources Canada Inc.	Site Preparation	Site activities suspended indefinitely pending environmental assessment
Rabbit Lake Operation	Saskatchewan	Cameco Corporation	Operation	Licensed to produce up to 6,500,000 kg of uranium per year

Source: Canadian Nuclear Safety Commission.

The following precautions are undertaken in Canadian and Australian uranium mines, two of the largest players in the global arena:[52]

- To minimize inhalation of gamma- or alpha-emitting minerals, dust is controlled. Dust is the main source of radiation exposure in an open cut uranium mine and in the mill area and was most often to blame for illness in the early years of mining;
- Radiation exposure of workers in the mine, plant and tailings areas are limited. In practice radiation levels from the ore and tailings are usually very low;
- Radon daughter exposure is minimal in an open cut mine because there is sufficient natural ventilation to remove the radon gas. In an underground mine, a good forced-ventilation system is required to achieve the same result. Canadian doses (in mines with high-grade ore) average about 3 mSv/yr (millisieverts/year), while at Olympic Dam in Australia radiation doses in the mine from radon daughters less than about 1mSv/yr; and
- Strict hygiene standards are imposed on workers handling the uranium oxide concentrate (U_3O_8). If it is ingested it has a chemical toxicity similar to that of lead oxide (Both lead and

[52] http://www.world-nuclear.org/info/inf24.html

uranium are toxic and affect the kidneys. The body progressively eliminates most Pb or U, via urination).

Radiation doses in Canadian mines are well within accepted limits, as procedures are among the most comprehensive in the world. This is attested to by the Athabasca Working Group (AWG).[53] The AWG has been conducting an environmental monitoring program at Wollaston Lake in northern Saskatchewan, sending samples to the Saskatchewan Research Council's (SRC's) Saskatoon laboratory for chemical analysis. Water samples from a reference site at Fidler Bay have been compared to those of effects sites at Welcome Bay, Hidden Bay and Collins Bay. It is important to note that treated effluent from the Rabbit Lake mine is released into Hidden Bay. The group found in 2005 that "as in previous years, the levels of parameters measured in the 2005 water samples were all *well below* provincial guidelines for the protection of aquatic life and drinking water quality...In fact, the levels of the majority of the key parameters were too low for the laboratory to measure throughout the 2000 to 2005 sampling years." Compared to a drinking water quality guideline level of 20 micrograms per litre for uranium in water, all four sites had less than one microgram per litre throughout the period, with the sole exception in 2002 when Hidden Bay's uranium level slightly exceeded 2 micrograms per litre. Arsenic levels in 2003 amounted to less than one-half of a microgram per litre compared to a drinking water quality guideline level of 25 micrograms per litre. The highest arsenic levels were recorded in 2002, when both Fidler Bay and Hidden Bay were close to, but below, 3 micrograms per litre.

P.A. Thomas attempted to disentangle the effects of uranium mining and milling from those attributable to the existence of radioactive minerals.[54] Thomas concludes in her 2000 paper that the problem with fugitive tailings dusts relates to past mining, not to future mining, and is therefore not a reason to forego future mining:

> Soils, vegetation, small mammals, and birds were measured for uranium series radionuclides at three sites near the operating Key Lake uranium mill in northern Saskatchewan. Sites, impacted by windblown tailings and mill dust, had significantly higher concentrations of uranium, 226Ra, 210Pb, and 210Po in soils, litter, vegetation, tree needles and twigs, small mammals, and birds, compared to a control site . . .
>
> The high uranium concentrations and U/226Ra ratios in old black spruce twigs vs. all other Key Lake vegetation was in agreement with previous work by Dunn . . . Dunn had suggested that the deep root system in black spruce extracts dissolved uranium from groundwater, particularly in mineralized regions. He found that black spruce twigs could be used to map potential areas of uranium deposits in northeastern Saskatchewan.

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[53] "Wollaston Lake: Athabasca Working Group Environmental Monitoring program 2000 to 2005," accessed at www.cri.ca/common/pdfs/awg/Wollaston_Lake.pdf

[54] P. A. Thomas, "Radionuclides in the Terrestrial Ecosystem near a Canadian Uranium Mill – Part I: Distribution and Doses," Health Physics, Volume 78(6), June 2000 pp. 614-24, accessed at http://gateway.ut.ovid.com.ezproxy.lib.ucalgary.ca/gw1/ovidweb.cgi; Thomas et al., "Radionuclides and Trace Metals in Canadian Moose near Uranium Mines: Comparison of Radiation Doses and Food Chain Transfer with Cattle and Caribou," Health Physics, Volume 88(5), May 2005 pp. 423-38, accessed at http://gateway.ut.ovid.com.ezproxy.lib.ucalgary.ca/gw1/ovidweb.cgi

> The soil and vegetation levels measured in this study were elevated beyond the existing baseline and monitoring data for uranium, 226Ra and 210Pb, previously measured at Key Lake . . .
>
> If one accepts the position that deterministic effects on reproduction and mortality are the only radiation effects of concern in animal populations, then the potential effects of the high 226Ra doses in Key Lake small mammals and birds can be roughly compared to some general dose limits. The no observed effect level (NOEL) for reproductive effects in mice is 1 mGy d^{-1} (365 mGy y^{-1}) with the NOEL for mortality effects 10 times higher . . . If one applies a radiation weighting factor of 20 for alpha radiations, then the Key Lake animals are near the NOEL for reproductive effects. If one does not accept a quality factor of 20, then the highest absorbed doses at Key Lake (12 mGy y^{-1}) are an order of magnitude below the 365 mGy y^{-1} limit for reproductive effects . . .
>
> The tailings [at Key Lake, resulting from processing McArthur River ore] will be placed subaqueously in one of the previously mined out Key Lake pits, thus preventing any further problem with fugitive tailings dusts . . .

Perhaps more to the point are the human health findings of Thomas's 2005 paper on radionuclides in large animals. Thomas calculated doses of 2.4 mSv y^{-1} for caribou intake, and a dose from moose intake of just 0.3 percent of the figure for caribou, noting that "these doses can be compared to the public dose limit of 1 mSv y^{-1} from human activities...and average background dose to US residents of 3.6 mSv y^{-1} including inhalation of radon and medical exposures." She concludes that the risk of human cancer on an annual basis from consumption of Wollaston caribou would be 1.2×10^{-4} and, subsequently, notes that "natural soil types and diet may exert as much effect as uranium mining".

To put things into perspective, Table 5.5 illustrates various radiation doses and their effects.

Table 5.5
Radiation Doses and Impacts

2 mSv/year	Typical background radiation experienced by everyone (average 1.5 mSv in Australia, 3 mSv in North America).
1.5 to 2.0 mSv/year	Average dose to Australian uranium miners, above background and medical.
2.4 mSv/year	Average dose to US nuclear industry employees.
up to 5 mSv/year	Typical incremental dose for aircrew in middle latitudes.
9 mSv/year	Exposure by airline crew flying the New York - Tokyo polar route.
10 mSv/year	Maximum actual dose to Australian uranium miners.
20 mSv/year	Current limit (averaged) for nuclear industry employees and uranium miners.
50 mSv/year	Former routine limit for nuclear industry employees. It is also the dose rate which arises from natural background levels in several places in Iran, India and Europe.
100 mSv/year	Lowest level at which any increase in cancer is clearly evident. Above this, the probability of cancer occurrence (rather than the severity) increases with dose.
350 mSv/lifetime	Criterion for relocating people after Chernobyl accident.
1,000 mSv/cumulative	Would probably cause a fatal cancer many years later in 5 of every 100 persons exposed to it (i.e., if the normal incidences of fatal cancer were 25 percent, this dose would increase it to 30 percent).
1,000 mSv/single dose	Causes (temporary) radiation sickness such as nausea and decreased white blood cell count, but not death. Above this, severity of illness increases with dose.
5,000 mSv/single dose	Would kill about half those receiving it within a month. 10,000 mSv/single dose Fatal within a few weeks.

Source: World Nuclear Association: Radiation and Nuclear Energy (August 2007).

The following information is from the National Dose Registry, which is maintained by Health Canada.[55] The NDR showed that the average radiation dose to underground uranium miners in 1999 was 1.41 millisieverts (mSv), while the average dose to surface uranium miner was 0.15 mSv. The average doses to nuclear fuel processors were 2.40 mSv in 1999. These radiation doses are well within regulatory occupational limits - 100 mSv over a 5-year period with a maximum of 50 mSv in any one year and the annual limit of 1 mSv for the general public.

It seems that examining the Northern Saskatchewan Health Indicators Report 2004[56] for possible evidence of high cancer rates in northern Saskatchewan reveal nothing out of ordinary. Over the period 1993-1999, cause-of-death statistics placed cancer at 21 percent of deaths in northern Saskatchewan compared to 26 percent for the province as a whole. In principle, this may indicate a lower death rate for cancer or a higher death rate for other causes. In any case, no impact on human health is stated by the North Saskatchewan report.

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[55] http://www.hc-sc.gc.ca/ewh-semt/pubs/eval/handbook-guide/vol_4/mining-miniere-2_e.html
[56] Accessed at www.mcrrha.sk.ca/Dounloads/files/2004%20Health%20Indicators%20Report%20Revision1.pdf

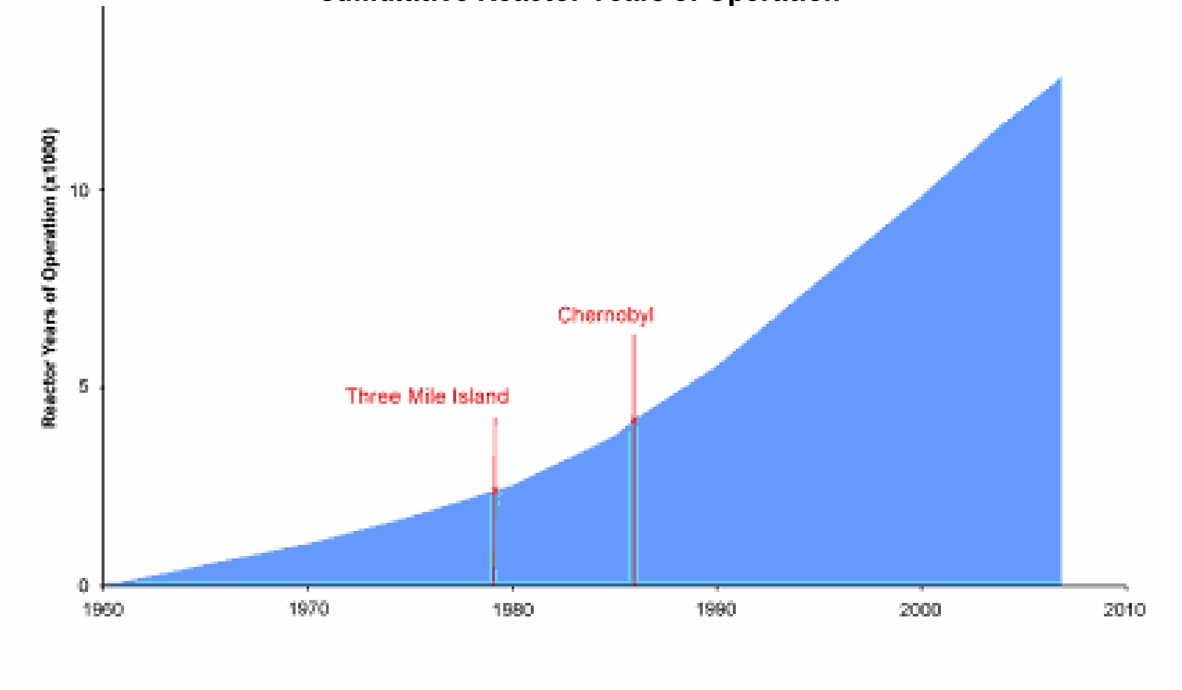
The evidence does not suggest a significant health problem associated with either uranium mining and milling or the presence of radioactive ores. Saskatchewan's Green Strategy: 2007 states, "Abandoned uranium mining operations in northern Saskatchewan have been inventoried and assessed…the sites do not pose an immediate threat to human life and their impact on the environment is very localized."

5.2.1.2 Comparative Safety Analysis

The most significant nuclear incident related to commercial nuclear activities in North America happened at the Twin Unit Three-Mile Island Nuclear Generating Station (TMI). TMI-2, the second unit, suffered an incident in 1979 that resulted in severe damage to the core of the facility. There were no fatalities from TMI-2, and the practice of reactor containment was effective in preventing the release of harmful radiation beyond the containment facility. All melted fuel was contained within the pressure vessel. This differed from the 1986 accident at the Chernobyl plant in the Ukraine, a reactor which had no upper containment facilities. There existed lower containment in the event of fuel melting, but the plant was incapable of containing a steam explosion, which is precisely what happened.

It is important to note that all modern reactors have containment facilities that are designed to prevent releases of radioactivity from the reactor core. Chernobyl is not representative of the nuclear industry's approach to safety, either structurally or operationally. As Figure 5.1 indicates, many years of cumulative reactor years of operation have occurred since both Chernobyl and Three Mile Island.

Figure 5.1
Cumulative Reactor Years of Operation



Source: http://www.world-nuclear.org/info/inf06.html

In terms of the immediate loss of life, the world's twelve largest energy-related disasters since 1977 are identified in Table 5.6. By way of comparison, the corresponding number of immediate fatalities in the wake of Chernobyl was 32, although its eventual death toll included 47 staff and firefighters.

Table 5.6
Energy-related Disaster by Type: Largest Number of Facilities

Type of Disaster	Location	Number Killed	Year
Hydro-electric dam failure	Machhu II, India	2,500	1979
Hydro-electric dam failure	Hirakud, India	1,000	1980
LPG pipeline leak and fire	Asha-ufa, Siberia	600	1989
Fuel depot hit by lightning	Durunkha, Egypt	580	1994
Oil fire	Cubatao, Brazil	508	1984
Oil pipeline leak and fire	Warri, Nigeria	500+	1998
Oil fire	Seoul, South Korea	500	1994
LPG explosion	Mexico City, Mexico	498	1984
LPG explosion	Nile River, Egypt	317	1983
Coal mine (methane explosion)	Kozlu, Turkey	272	1992
Gas well blowout with H_2S	Gaoqiao, China	234	2003
Coal mine (methane explosion)	Sunjiawan, Liaoning, China	215	2005

SOURCE: Condensed from a table on the World Nuclear Association's website (www.world-nuclear.org).

North America has been relatively free of major energy-related disasters, yet fatalities continue. A total of three operators died at an experimental military reactor in the United States in 1961. In comparison, almost 400 Americans die each year in accidents associated with transportation of coal, nearly all of them members of the general public. The most recent coal mining disaster in Canada was at the Westray Mine, where methane gas and coal dust exploded killing 26 miners in 1992. Although the Canadian oil and gas industry is proud of the fact that no member of the general public has perished due to oil and gas activities, its own workers have succumbed from time to time. According to the Calgary Herald on May 2, 2007, "the Alberta oil patch has claimed 41 lives from January 2000 to date, not including on-the-job accidents that killed 163 oil patch workers between 1994 and 2005."

An appropriate way of comparing the mortality track record of different energy sources is to relate them to the amount of electricity generated. This is the approach taken in Table 5.7, which expresses the mortalities on a terawatt year basis. One terawatt year is the equivalent of the yearly output of twenty nuclear power plants the size of one CANDU or PWR plant contemplated in this analysis. At a 93 percent capacity factor, the yearly output of such a CANDU or PWR nuclear power plant considered herein would be slightly more than 18 terawatt hours.

Table 5.7
Comparison of Accident Statistics in Primary Energy Production

Fuel	Immediate Fatalities 1970-92	Who?	Deaths per TWa* of electricity
Coal	6400	Workers	342
Natural Gas	1200	Workers & Public	85
Hydro	4000	Public	883
Nuclear	31	Workers	8

SOURCE: World Nuclear Association, compiled from Ball, Roberts & Simpson, Research Report #20, Centre for Environmental & Risk Management, University of East Anglia, 1994; Hirschberg et al, Paul Scherrer Institute, 1996; in: IAEA, Sustainable Development and Nuclear Power, 1997; Severe Accidents in the Energy Sector, Paul Scherrer Institute, 2001.
Note: TWa is an abbreviation for terawatt year (a = annum).

Consider not just the fatalities at facilities but accidents and fatalities associated with the transportation of energy. The dangers of coal mining, to be discussed in detail later in this Chapter, have been widely documented and reported. Table 5.7 indicates that coal facilities throughout the world undeniably still suffer safety issues. What has not been so well-publicized is the danger involved in transporting coal, a danger that some argue exceeds the perils of mining.

For example, in the United States in 2006 there were 26 coal mining fatalities, presumably none of which involved the general public. In contrast, there were 680 fatalities involving U.S. freight trains in that year, with coal accounting for over 30 percent of freight tonnage and over 40 percent of total rail freight Ton-miles; moreover, a majority of such deaths involved members of the general public rather than railroad employees. Coal supplied to Ontario's coal-fired power plants is shipped largely by rail in the United States, where the rail freight mortality rate was 422 deaths per trillion Ton-miles or 289 deaths per trillion tonne-kilometres.

In 2005 there were 577 fatalities in Canadian collisions involving commercial vehicles of all types (including buses) according to Transport Canada, a year in which a total of 267,261 million tonne-kilometres of freight was moved by road. This implies a mortality rate of 2,159 deaths per trillion tonne-kilometres. Canadian statistics are employed because road transportation of uranium ore, yellowcake and nuclear fuel for Ontario nuclear power plants takes place largely or entirely in Canada.

On this basis, the freight-related mortality rate for trucking is 7.5 times as high as for rail. Nevertheless, the superior energy density of nuclear vastly outweighs this disadvantage, because a TWh of nuclear electricity in Ontario required an estimated 92,000 t-km of fuel transportation compared to 1,074,500,000 t-km of fuel transportation for a TWh of coal-fired generation. On a per-TWh basis, the probability of a death-related fuel transportation incident for nuclear power is estimated as 2,159 * 92,000 / 1,000,000,000,000 or 0.00020 deaths. For coal, the probability of a transportation-related death on a per-TWh basis is estimated as 289 * 1,074,500,000 / 1,000,000,000,000 or 0.31. In other words, for comparable amounts of electricity output, the estimated transportation mortality rate for coal is about 1,550 times as high as for nuclear.

As for pipelines, the NEB reports that there have been no fatalities associated with pipelines under its jurisdiction since 1997, when two people died in a construction accident.

There is not a single recorded transportation fatality in Canada attributable to fuelling nuclear power plants.

5.2.1.3 Canadian Regulations on Power Plants and Spent Fuel Management

The Federal Government, under the direction of the Canadian Nuclear Safety Commission (CNSC), regulates nuclear activities in Canada. The CNSC describes itself as the "nuclear energy and material watchdog in Canada",[57] and is responsible for the regulation of nuclear power reactors, uranium mines and mills, fuel fabrication and processing facilities and waste management facilities.

Any new reactors would follow the regulatory guidelines detailed in the February 2006 document, "*Licensing Process for New Nuclear Power Plants in Canada, INFO-0576*". The process requires a proponent to apply for a license for site preparation, construction and operation of a nuclear reactor. In addition, a positive decision on an Environmental Assessment (EA) under the *Canadian Environmental Assessment Act* is required in order for a new nuclear reactor to be built in Canada. This process, as outlined in the 2006 document, is anticipated to take anywhere from 18 to 36 months from start to finish, depending on a number of factors involved. The licenses can be applied for in a parallel process, while the EA is being carried out.

[57] http://www.nuclearsafety.gc.ca/eng/about_us/, February 7, 2007

Spent nuclear fuel can be defined as irradiated fuel bundles that are discharged from operating nuclear reactors in Canada. These reactors are all CANDU designs, as described in the previous section. Spent fuel is also discharged from research reactors. In terms of regulations on spent fuel and waste in Canada, it is generally separated into two generic categories: High and Low level waste. High-level waste consists primarily of spent nuclear fuel, or nuclear fuel waste. Low-level waste consists of all other radioactive waste streams that are not associated with spent fuel. The focus of this section will be on spent nuclear fuel.

Currently in Canada, spent fuel is being kept on licensed facilities at reactor sites located in Ontario, Quebec, New Brunswick and Manitoba. Currently, spent nuclear fuel is removed from reactors and then stored in wet storage for 7-10 years to reduce heat and radioactivity. It is then transferred into concrete dry storage containers that have the life span of 50 years. In December 2004, there was a total of 1.4 million fuel bundles in wet storage and 0.3 million bundles in dry storage facilities in Canada.[58] It is possible to reprocess spent nuclear fuel to generate additional energy. For security of supply reasons, reprocessing is taking place in France, UK, Belgium, Japan, and Russia.

Due to the high public interest and concern for long-term spent nuclear fuel management, the Canadian Government formed the *Nuclear Fuel Waste Act* in November 2002. Following the Act's implementation, the Federal Government formed the *Nuclear Waste Management Organisation* (NWMO). The mandate of the NWMO is to recommend an approach for Canada's long-term management of spent nuclear fuel.[59]

The NWMO completed a comprehensive study in early 2007 on the potential options for spent fuel management in Canada.[60] The study was sent to the Canadian Government for consideration as part of Canada's long-term plan for spent fuel management. The study concludes that a process called *Adaptive Phase Management* be used for the long-term management of spent fuel in Canada. Adaptive phased management consists of both a technical method and a management system. In June 2007, the Nuclear Waste Management Organization (NWMO) was given responsibility for implementing Adaptive Phased Management (APM), Canada's plan for the long-term management of used nuclear fuel.

The APM approach can be broken down into three phases. Phase 1 is preparing for the central used fuel management, using public awareness programs over a 30 year period. Phase 2 is the central storage and technology demonstration. This phase would take 30 years and would require technology plans to be finalized, and construction to be under way. Phase 3 is long-term containment. Isolation and monitoring would last for at least 60 years. Long-term containment is a process by which spent nuclear fuel is moved to a central repository for Deep Geological Storage. Storage would involve placing spent nuclear fuel underground in the Canadian Shield

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[58] "Ontario's Integrated Power Systems Plan, Discussion Paper 4: Supply Resources", Page 21, OPA November 9, 2006 Report.

[59] NWMO Mandate, http://www.nwmo.ca/default.aspx?DN=18,1,Documents&l=English, February 7, 2007.

[60] NWM http://www.nwmo.ca/default.aspx?DN=20,1,Documents&l=English, February 7, 2007.

and would rely on natural and engineered barriers to isolate the spent fuel from humans and the surface environment over its hazardous lifetime. The central site could be designed to allow removal of spent nuclear fuel for reprocessing. Currently, the location of a central site is being determined.

5.2.1.4 Terrorism Threats to Nuclear Power

The events of September 11, 2001, have raised concerns about the vulnerability of nuclear power plants to attack by large commercial aircraft. International and domestic regulations, as governed by the International Atomic Energy Agency and the CNSC, respectively, are being continuously improved to address issues related to domestic and international terrorism. Canadian nuclear plants were designed to withstand such extreme events as earthquakes, tornadoes and hurricanes, but as terrorism manifests itself in increasingly destructive ways, it becomes important to evaluate nuclear plant defenses against potent, intentional attacks.

In December 2004, the Canadian Government commissioned Dr. John Gittus to provide an assessment of the appropriate premiums for the reinsurance coverage for third party nuclear damage arising from acts of terrorism.[61] In this comprehensive analysis, this expert in nuclear insurance and risk concludes that the risk of a terrorist incident damaging a reactor and resulting in the release of radioactivity is still deemed to be sufficiently low such that the insurance industry is willing to provide commercial insurance.

The risk of a commercial airliner being crashed into a nuclear facility has increased since 2001 but has not increased sufficiently to result in the defueling and decommissioning of the world's nuclear power stations. This scenario is very unlikely to occur, for a couple of reasons. First, nuclear containment's weakest point is at the centre top. As one could imagine, it is exceedingly difficult for commercial jet aircraft to make a vertical dive. Secondly, the most significant impact by an aircraft is the engine blocks. Hence, fighter jets are more serious threats to nuclear facilities than commercial jet aircraft. This scenario has already been tested at Scandia National Laboratories in the 1988 "rocket-sled" test.[62]

The availability of commercial insurance, excellent safety record and a renewed global commitment to nuclear energy is helping drive a global "nuclear renaissance".

A 1994 report entitled *Terror 2000: The Future Face of Terrorism* anticipated "every major aspect of the 9/11 attacks and was carried out as part of the Fourth Annual Defense World-wide Combating Terrorism Conference", according to one of the report's co-authors Marvin Cetron.[63]

[61] Professor John H. Gittus, "Review of the Premium for Government Reinsurance of Terrorist Coverage under the Canadian Nuclear Liability Act, (NLA)", December 16, 2004. Information pertaining to the contents of the document and its context have been derived through conversations with Dr. Gittus and other experts in the field of nuclear energy in Canada.

[62] Footage of this test is available at the Sandia National Laboratories website, http://www.sandia.gov/news/resources/video-gallery/index.html, August 21, 2007.

[63] M. J. Cetron, "Defeating Terrorism: Is It Possible?" *The Futurist*, Volume 41, No. 3 (May-June 2007), pp. 18-25.

The report was a scenario analysis that considered eight "high-probability threats" and seven "high-impact threats". Prospective attacks on any nuclear or coal facility were not found on either threat list. Interestingly, among the "high-impact threats" was to a scenario to "detonate a tanker full of liquefied natural gas at a terminal in Boston Harbour." This is the location of the Everett LNG facility.

Subsequent to the 9/11 attacks the Electric Power Research Institute[64] conducted "computer analyses of models representative of all US nuclear power plant containment types". The following quotations and remarks are taken from EPRI's peer-reviewed report:

The wing span of the Boeing 767-400 (170 feet) – the aircraft used in the analyses – is slightly longer than the diameter of a typical containment building (140 feet). The aircraft engines are physically separated by approximately 50 feet. This makes it impossible for both an engine and the fuselage to strike the centerline of the containment building. As a result, two analyses were performed. One analysis evaluated the "local" impact of an engine on the structure. The second analysis evaluated the "global" impact from the entire mass of the aircraft on the structure. In both cases, the analysis conservatively assumed that the engine and the fuselage would strike perpendicular to the centerline of the structure. This results in the maximum force upon impact to the structure for each case.

The analyses indicated that no parts of the engine, the fuselage or the wings – or the jet fuel – entered the containment buildings. The robust containment structure was not breached, although there was some crushing and spalling (chipping of material at the impact point) of the concrete.

[For similar reasons] two analyses were performed for both a pressurized water reactor pool and a boiling water reactor pool. The stainless steel pool liner ensures that, although the evaluations of the representative used fuel pools determined that there was localized crushing and cracking of the concrete wall, there was no loss of pool cooling water. Because the used fuel pools were not breached, the used fuel is protected and there would be no release of radionuclides to the environment.

The analyses show [that a used fuel transportation container] body withstands the impact from the direct engine strike without breaching...Because the fuel transport container is not breached, there would be no release of radionuclides to the environment…

The study determined that the structures that house reactor fuel are robust and protect the fuel from impacts of large commercial aircraft.

[64] "Deterring Terrorism: Aircraft Crash Impact Analyses Demonstrate Nuclear Power Plant's Structural Strength", December 2002, accessed at www.nei.org/documents/eprinuclearplantstructuralstudy200212.pdf.

5.2.2 Natural Gas

This section regarding the safety and security of natural gas is subdivided into three parts. Section 5.2.2.1 discusses occupation hazards regarding natural gas. Section 5.2.2.2 discusses public safety issues and environmental issues. Section 5.2.2.3 discusses the safety and security issues of LNG. It is important to remember that natural gas is no longer exclusively a continental market. Increased imports of natural gas will be required to meet future shortfalls in major consuming regions, such as North America. There are abundant reserves of "stranded gas" found in locations around the world that are beyond the reach of pipelines. Some include Australia, Russia, Venezuela, Malaysia and Nigeria. Many of the locations with stranded gas operate facilities to produce and export LNG today.

5.2.2.1 Production: Occupational Hazards and Public Safety Issues

This section explores occupational hazards and public safety issues on the production-side of the natural gas industry. While the natural gas industry prides itself on its safety record, accidents do occur. The Canadian industry has, however, taken precautions.

On the federal level, the National Energy Board (NEB) regulates parts of Canada's energy industry. The NEB is an independent federal agency that regulates oil, gas and electric utilities. In general, its purpose is to promote safety and security, environmental protection, and efficient energy infrastructure and markets in the Canadian public interest. Safety has been part of the Board's mandate since 1959, and in April 2005, the NEB Act was amended to include "Security" within the Board's mandate. The Act provides the Board with the clear statutory basis to regulate security of the energy infrastructure under its jurisdiction. The NEB's Security Management Program is intended to provide appropriate regulatory oversight during a project lifecycle to ensure that regulated companies and operations are safeguarded against security related threats according to risk-based security requirements and continuous security risk management.

On the provincial level, the most important governing body was the Alberta Energy and Utilities Board (EUB). The EUB was the governing body of the energy industry in the province of Alberta, the largest producer of oil and gas in Canada. On 1 January 2008 the EUB was divided into two separate regulatory bodies:

- The Energy Resources Conservation Board (ERCB), which regulates the oil and gas industry, and
- The Alberta Utilities Commission (AUC), which regulates the utilities industry. Provincial authorities regulate environmental and safety aspects of local natural gas distribution companies.

The ERCB is an independent, quasi-judicial agency of the Government of Alberta. The organization regulates the safe, responsible, and efficient development of Alberta's energy resources: oil, natural gas, oil sands, coal, and pipelines. Environmental concerns, such as air emissions, water protection and land reclamation, are under the jurisdiction of the ERCB and the provincial government (Alberta Environment). Other provincial and territorial regulators often use the ERCB's standards.

The Canada-Newfoundland Offshore Petroleum Board and the Canada-Nova Scotia Offshore Petroleum Board regulate offshore exploration and development. The National Energy Board (NEB) regulates exploration and production in Yukon, Nunavut, and the Northwest Territories.

Industry associations such as the Canadian Association of Petroleum Producers (CAPP) and the Canadian Petroleum Products Institute (CPPI) have also adopted environmental and safety codes of practice and operating guidelines for their member companies. These standards are often incorporated into regulations. Petroleum Services Association of Canada (PSAC) also puts more effort into raising awareness for safety and training to avoid and reduce on-the-job risks.

According to Alberta Employment, Immigration and Industry (EII), the upstream oil and gas industries fared well in lost-time claim rate and disability injury rate against other major industries in Alberta in 2005 and 2006. The former represents the probability of an injury or disease to a worker during a one-year period of work. The disabling injury rate, on the other hand, represents the probability or risk of a disabling injury or disease to a worker during a one-year period of work. It covers a broader range of injuries than the lost-time claim rate. Table 5.8 shows that the lost-claim rate in 2006 for the Upstream Oil and Gas Industries was 1.16 per 100 person-years. This is much lower than all other major industries, except for Mining and Petroleum Development. The disabling injury rate for the Upstream Oil and Gas Industries was 3.93 per 100 person-years, lower than the provincial rate of 4.14. At 2.05, Business, Personal and Professional Services, unsurprisingly, had the lowest disabling injury rate in 2006. Upstream industries include exploration, seismic exploration, surveys, and oil and gas drilling.

Table 5.8
Lost-time Claim and Disabling Injury Rates by Major Industry – Alberta

Major Industry Sector	2005		2006	
	Lost-Time Claim Rate	Disabling Injury Rate	Lost-Time Claim Rate	Disabling Injury Rate
Agriculture and Forestry	3.3	3.87	3.24	4.1
Business, Personal and Professional Services	1.64	2.12	1.54	2.05
Construction and Construction Trade Services	2.58	5.18	2.5	5.22
Manufacturing, Processing and Packaging	3.43	7.35	3.11	7.01
Mining and Petroleum Development	1.01	3.8	0.87	3.64
Public Administration, Education and Health Services	2.6	3.12	2.66	3.41
Transportation, Communication and Utilities	3.06	4.35	3.17	4.81
Wholesale and Retail	2.35	3.35	2.43	3.67
Upstream Oil and Gas Industries	1.29	4.14	1.16	3.93
Alberta	2.41	4.02	2.35	4.14

Source: 2006 WCB Data (prepared by Data Development and Evaluation).

Workers Compensation Board (WCB) suggests that by sub-sector, the Upstream Oil and Gas Industries have some of the lowest claim rates among all sub-sectors. Table 5.9 illustrates lost-time claim rate by sub-sector for Upstream Oil and Gas Industries, while Table 5.10 shows occupational fatalities by sub-sector for Upstream Oil and Gas Industries. Claim rates for all sub-sectors has decreased between 2002 and 2006. Oilfield Trucking Services sub-sector had the highest amount of claims while the Tar Sands industry had the lowest.

Table 5.9
Lost-Time Claim Rate by Upstream Oil and Gas Sub-sector – Alberta

Sub-Sector	2002	2003	2004	2005	2006
Downhole and Other Oilfield Services	2.04	2.09	1.50	1.76	1.48
Petroleum Producers/Exploration	0.32	0.43	0.30	0.03	0.30
Drilling Oil and Gas Wells	2.38	3.84	2.84	2.31	1.84
Oilfield Trucking Services	4.65	5.97	5.38	4.35	4.06
Well Servicing with Service Rigs	2.43	2.83	2.08	1.83	1.59
Tar Sands	0.30	0.53	0.53	0.22	0.16
Oilfield Maintenance and Construction	2.64	2.44	2.00	2.04	2.44
Upstream Oil and Gas	1.28	1.59	1.26	1.29	1.16

Source: 2006 WCB Data (prepared by Data Development and Evaluation).

According to the WCB, the Upstream Oil and Gas Industries accounted for 17 of all 124 fatalities (13.7 percent) in Alberta in 2006. Of the 17 fatalities, 10 were classified as Motor Vehicle

Incidents. Three were classified as Workplace Incidents and four were Occupational Disease. This is shown in Table 5.10.

Table 5.10
Upstream Oil and Gas Occupational Fatalities by the Sub-Sector – Alberta

Sub-Sector	2002	2003	2004	2005	2006	Total	%
Downhole and Other Oilfield Services	9	3	6	6	8	32	38.6
Petroleum Producers/Exploration	3	6	3	1	2	15	18.1
Drilling Oil and Gas Wells	2	6	2	1	1	12	14.5
Oilfield Trucking Services	1	4	1	2	4	12	14.6
Well Servicing with Service Rigs	2	2	3	2	0	9	11.0
Tar Sands	1	0	0	0	1	2	2.4
Oilfield Maintenance and Const.	0	0	0	0	1	1	1.2
Upstream Oil and Gas Industries	18	21	15	12	17	83	100.0

Source: 2006 WCB Data (prepared by Data Development and Evaluation).

While the upstream oil and gas industry is quite safe, there are several issues that need to be handled carefully. One of the health, safety and security issues is the proper handling of sour gas, or gas that contains hydrogen sulphide (H_2S). In Canada, nearly 30 percent of total natural gas produced is characterized as sour gas -- most of it is found in Alberta and north-eastern British Columbia. For this reason Canadian oil and gas companies are world leaders in the safe and efficient operation of sour gas facilities. Companies require emergency response planning, public consultation, safety equipment, and worker training for critical sour gas operations. As this untreated gas is toxic to humans and animals, additional precautions include breathing apparatuses for rig personnel and notifying people living nearby. Amine gas treating is often used to remove hydrogen sulphide from natural gas.

In June 2007, the EUB (now the ERCB) completed a seven-year initiative dealing with how sour gas is regulated and developed in Alberta. Emerging from the EUB's Public Safety and Sour Gas (PSSG) independent committee were 87 recommendations. The objective is to change the way sour gas is regulated in the province, to reduce the impacts of sour gas on public safety and environment.

Besides sour gas affecting air quality, other impacts from upstream oil and gas activity may be venting, sulphur dioxide, and odours. In fact, according to the Centre for Energy, the leading public complaint from upstream gas activities is air quality -- more specifically, odours. Other issues regarding public safety and environment from upstream oil and gas industry include land use, waste management, and surface and groundwater quality. Extraction of natural gas may lead to a decrease in pressure in a reservoir. This in turn may lead to subsidence at ground level. Subsidence may affect ecosystems, waterways, sewer and water supply systems, foundations, etc. The industry, however, has stringent regulations it must follow. In addition, according to Statistics Canada, the upstream oil and gas industry spent just over $1 billion on environmental protection in 2002.

5.2.2.2 Transmission Lines: Safety and Security Issues

An important element of the natural gas industry is the transportation of natural gas. According to the NEB, there are 540,000 kilometres of pipelines in Canada. This large and complex network transports approximately 95 percent of the country's crude oil and natural gas from producing areas, such as Alberta, British Columbia and Saskatchewan, to distribution systems all over North America.

The NEB regulates all interprovincial and export pipelines, while pipelines that do not cross provincial or national boundaries fall under the provincial jurisdictions. In the case of Alberta, provincial pipelines and infrastructure fall under the ERCB.

Protecting pipeline infrastructure is dangerous and costly in some parts of the world. Pipelines in Nigeria, for example, are very difficult to secure. It is quite common for individuals to compromise the pipe to siphon fuel and sell it on the black market. In other cases, pipelines are easy targets for organizations trying to send a political message. Pipeline sabotage has become the weapon of choice in some parts of the world. For example, there have been over 200 attacks on the pipeline running from Kirkuk to the Ceyhan, a Turkish Mediterranean terminal.[65] The Colombian-based Revolutionary Armed Forces of Colombia (FARC) is another example of a terrorist organization that employs pipeline sabotage, very frequently compromising pipelines in Columbia and northern Ecuador. While terrorism is not a primary issue in Canada, protecting pipelines from accidental compromises is. Satellites currently monitor much of Canada's extensive pipeline network.

In 2006 the NEB released a Proposed Regulatory Change (PRC) 2006-01 outlining the proposed changes to the Onshore Pipeline Regulations, 1999 (OPR 99) and the Processing Plant Regulations (PPR) to address pipeline security management. The PRC 2006-01 outlines the Board's expectation that companies follow the Pipeline Security Management Program. The program is to provide systematic, comprehensive, and proactive management of security risks to pipelines.

5.2.2.3 Distribution: Occupation Hazards and Public Safety Issues

Natural gas is a colourless and odourless gas. While not toxic, it is highly flammable. Following the New London School, Texas, disaster in 1937, in which nearly three hundred students perished, the United States began adding odorant to natural gas. Adding odorants such as t-butyl mercaptan or thiophane gives gas that rotten-egg smell. The odorants in minute doses are non-toxic.

[65] http://www.iags.org/n0328051.htm

Explosions caused by natural gas leaks occur a few times a year. Individual homes and small businesses are most frequently affected. The dangers of natural gas leaks were exemplified on April 18, 2008 in Nipawin, Saskatchewan. An explosion and fire destroyed three buildings in the downtown area, killing two people and injuring several others. According to SaskPower, nearly 2,000 people lost electricity in the northern Saskatchewan town, located 140 kilometres east of Prince Albert. A construction crew rupturing a gas line caused the massive explosion. Gas usually dissipates outdoors but when it collects in large quantities it is quite dangerous.

While accidents occur they are relatively few, compared to the tens of millions of structures that use natural gas. The individual risk of using natural gas is very low, that may be attributed, in large part, to education. The general populace is well-educated about the use of natural gas in their homes and businesses. Utilities such as Union Gas, Enbridge and Terasen Gas provide excellent information regarding general natural gas safety tips. That being said, accidents with construction crews and homeowners puncturing gas lines are a problem. Many utilities have run "call before you dig" campaigns.

Some of the dangers of natural gas include back drafting, gas leaks and odour, gas meter safety, carbon monoxide poisoning, and chimney and vent inspection. Back drafting and chimney and vent inspections are important, especially if combustion appliances are used, such as wood burning and natural gas fireplaces, natural gas furnaces, and water heaters. These types of appliances need a source of air to operate safely. If there is not sufficient ventilation within the structure, carbon monoxide poisoning becomes a danger.

Carbon monoxide is a colourless, odourless gas that is very toxic. According to the US Consumer Product Safety Commission, natural gas heating systems are a leading cause of carbon monoxide deaths in the US. Detectors are available that warn of carbon monoxide and/or explosive gas (methane, propane, etc.). Carbon monoxide symptoms range from shortage of breath and slight headache to unconsciousness, brain damage, and death.

Provincial authorities regulate environmental and safety aspects of local natural gas distribution companies. The AUC regulates investor-owned natural gas, electric, and water utilities and certain municipally-owned electric utilities to ensure that customers receive safe and reliable service at just and reasonable rates. While the AUC regulates the utilities industry in Alberta, other provincial counterparts include the British Columbia Utilities Commission (BCUC) and the Ontario Energy Board (OEB), which regulates natural gas and electricity utilities.

<u>Liquefied Natural Gas</u>

LNG has received considerable attention in recent years. This is especially the case in North America, where the combination of record high natural gas prices and growing consumption of natural gas is leading analysts and investors to consider LNG as a potential major source of US natural gas supply. Another factor that has spurred interest in LNG imports is the belief that in spite of a sharp increase in new wells drilled, North American natural gas resources have likely reached a plateau. This combined with rapid technological advances, which have impacted the costs of liquefaction, shipping, re-gasification, and storing of LNG, has made LNG an economically viable option. At any given time, there are between 40 – 50 LNG projects being proposed for Canada, Mexico, and the United States. North America is not alone in the development of LNG re-gasification terminals; new facilities in China, India, and Europe have also been proposed. The problem beginning to arise is this: the quantity of LNG supply from liquefaction facilities falls short of the supply requirements for the proposed North American re-gasification terminals.

Table 5.11 the eight existing LNG terminals in the US and their respective capacities. Sabine and Freeport received their first commercial shipments in April 2008. There is also an existing import terminal in Penuelas, Puerto Rico, but as it does not serve or affect the US market, it is not included by the Federal Energy Regulatory Commission (FERC).

Table 5.11
Existing US LNG Import Terminals

Existing Facilities	Capacity (mmcf/d)	
Everett, Massachusetts	1,035	SUEZ LNG - DOMAC
Cove Point, Maryland	1,000	Dominion – Cove Point LNG
Elba Island, Georgia	1,200	El Paso – Southern LNG
Lake Charles, Louisiana	2,100	Southern Union – Trunkline LNG
Gulf Of Mexico	500	Gulf Gateway Energy Bridge – Excelerate Energy
Offshore Boston	800	Gulf Gateway–Excelerate Energy
Freeport, Texas	1,500	Cheniere/Freeport LNG
Sabine, Louisiana	2,600	Sabine Pass Cheniere LNG
TOTAL	**10,735**	

Source: FERC http://www.ferc.gov/industries/lng/indus-act/terminals/exist-prop-lng.pdf (04/08)

In spite of a long history and an excellent safety record, LNG has had a somewhat muddled and controversial past. The objective of this section is to provide a brief background on LNG and discuss various issues regarding safety and security of LNG terminals and ships.

Background

LNG is natural gas that has been cooled to the point where it condenses into its liquid state. The four main components of the LNG supply cost chain are, exploration and production, liquefaction, shipping, and re-gasification (including onshore storage).

Exploration and Production

While supply of natural gas is becoming a problem in North America, this is not the case globally. The problem is that gas reserves are often located a long way from market. LNG, however, provides a means of moving natural gas long distances when pipeline transportation is not feasible.

With the rapid growth in demand for natural gas worldwide, it is expected that nations with large "stranded" natural gas reserves, such as Saudi Arabia, Egypt and Iran, will become bigger players in the near future. Currently, the largest exporters of LNG are Indonesia, Algeria, Malaysia, and Qatar. However, many other countries, such as Australia, Nigeria, and Trinidad & Tobago, play smaller but significant and growing roles as natural gas producers and LNG exporters.

Liquefaction

LNG is natural gas that has been cooled to the point when it condenses into its liquid state. This occurs at -256° Fahrenheit and at atmospheric pressure. In its liquid state, natural gas occupies only one six-hundredth of its gaseous volume. This makes it economical to transport between continents and over long distances in specially designed LNG tankers.

In addition, LNG becomes a clear, colourless, odourless liquid that weighs slightly less than half as much as water, so it floats on fresh or salt water. It is the same natural gas that many North Americans use in their homes, except in liquid form.

Feed gas to the liquefaction plant comes from the production field. The contaminants found in produced natural gas are removed to avoid freezing up and damaging equipment when the gas is cooled to LNG temperature. Current suppliers deliver gas with heat content in the range of 980-1,080 btu/cf, which meets North American pipeline specifications. However, future suppliers may deliver "hot" gas with a heat content in excess of 1,080 btu/cf. LNG with Btu values in excess of 1,080 btu/cf. This would exceed North American pipeline specifications because this gas contains almost no inert gases, such as CO_2 and N_2 and more non-methane hydrocarbons, such as ethane, propane and butanes, than historical US supplies.

Shipping

LNG tankers are double-hulled ships specially designed and insulated to prevent leakage or rupture in an accident. The LNG is stored in a special containment system within the inner hull where it is kept at atmospheric pressure and -256ºF. Three types of cargo containment systems have evolved as modern standards. These are: the spherical (Moss) design, the membrane design and the structural prismatic design. Currently most LNG ships use spherical (Moss) tanks, and they are easily identifiable as LNG ships because the top half of the tanks are visible above the deck.

Modern day ships are 300 meters long and 50 meters wide and constructed with double hulls. This construction method not only increases the integrity of the hull system but also provides additional protection for the cargo tanks in the event of an accidental collision.

The typical LNG carrier can transport between 125,000 to 138,000 cubic meters of LNG, which will provide between 2.6 to 2.8 billion standard cubic feet of natural gas. This ship size is similar to that of an aircraft carrier but significantly smaller than that of the Very Large Crude oil Carrier (VLCC). LNG tankers are generally less polluting than other shipping vessels because they burn natural gas in addition to fuel oil as a fuel source for propulsion.

Shipping represents a substantial cost component of the LNG chain and holds a number of opportunities for optimization and improvement. Historically, the industry has been very conservative in terms of increasing the size of ships, primarily as a result of port and terminal constraints. However, the technology exists today to build larger ships and capture similar economies of scale to those of larger LNG trains. Other improvements are occurring in new cargo containment as well as new propulsion systems.

Storage and Re-gasification

To return LNG to a gaseous state, it is fed into a re-gasification plant. On arrival at the receiving terminal in its liquid state, LNG is pumped first to a double-walled storage tank, similar to those used in the liquefaction plant, at atmospheric pressure, then pumped at high pressure through various terminal components where it is warmed in a controlled environment.

LNG can also be pumped directly from the LNG ship to the pipelines without a storage tank. Then LNG is warmed by passing it through pipes heated by direct-fired heaters, seawater, or through pipes that are in heated water.[66] The vaporized gas is then compressed up to line pressure and enters the pipeline system as natural gas. Finally, residential and commercial consumers receive natural gas for daily use from local gas utilities or in the form of electricity.

Security and Safety Issues

The LNG industry boasts an exemplary safety record, but maintaining it requires ongoing research and development. In the post-September 11 world, security risks to LNG facilities are perceived as greater and are garnering more public attention in the United States and elsewhere. Responding to public concerns and designing expanded safety and security measures would benefit from increased understanding of LNG containment infrastructure (tankers and storage tanks).

As such, NIMBY-ism (NIMBY = Not In My Back Yard) is a large problem. Local opposition does not want a major LNG terminal near their industrial facilities, fishery locations, and certainly not near residential areas. There are legitimate and ill-informed perceptions about the risks involved with LNG. For example, in March 2004, voters in Harpswell, Maine, rejected plans to build a new $350 million LNG terminal on a former Navy fuel depot site because it was considered too close to a residential area. The project was cancelled soon thereafter. Residents argued that an LNG terminal would harm the nearby fisheries in terms of trap loss from vessel traffic and displacement of fishing activity as a result of security exclusion zones around the terminal berths. The outcomes do not appear so dramatic for other proposed terminals, but, nevertheless, local opposition can be strong enough to delay or even cancel LNG projects.

[66] Federal Energy Regulatory Commission (FERC) views seawater racks as potentially harmful to the sea life. Terminals planning on using this technology have been put on hold pending an environmental assessment.

The increasing demand for natural gas will significantly increase the number and frequency of LNG tanker deliveries to ports in North America. Because of the increasing number of shipments, concerns about the potential for an accidental spill or release of LNG have increased. Safety has always been a leading public perception problem, in spite of the fact that the most recent accident – an explosion at Skikda, a major Algerian LNG terminal, in 2004 – is one of only 4 major accidents that have happened since the early 1940s. In addition, since the incidents surrounding September 11, 2001, concerns have increased over the impact that an attack on hazardous or flammable cargoes, such as those carried by LNG ships, could have on public safety and property.

The risks and hazards from an LNG spill will vary depending on the size of the spill, environmental conditions, and the site at which the spill occurs. Hazards can include cryogenic burns to the ship's crew and people nearby or potential damage to the LNG ship from contact with the cryogenic LNG. Vaporization of the liquid LNG can occur once a spill occurs and subsequent ignition of the vapour cloud could cause fires and overpressures that could injure people or cause damage to the tanker's structure, other LNG tanks, or nearby structures.

Ship Safety

The safety record of LNG ships far exceeds any other sector of the shipping industry with more than 40,000 secure deliveries. Over the past 40 years, there have been no collisions, fires, explosions, or hull failures resulting in a loss of containment for LNG ships in port or at sea. However, the introduction of large LNG ships poses new technical challenges for the industry. One of the challenges in moving to larger ships is the potential to have higher cargo sloshing loads with larger ship tanks.

All LNG vessels that enter the US must meet both domestic regulations and international requirements. Domestic regulations for LNG vessels were developed in the 1970's under the authority of the various vessel inspection statutes now codified under Title 46 of the United States Code, which specifies requirements for a vessel's design, construction, equipment, and operation. These regulations closely parallel international LNG requirements; but are more stringent in the following areas: the requirements for enhanced grades of steel for crack-arresting purposes in certain areas of the hull, specification of higher allowable stress factors for certain independent type tanks, and prohibition of cargo venting as a means of regulating cargo temperature or pressure. In Canada, there are a number of operational certificates that an LNG tanker requires to operate in Canadian waters. These certificates are issued upon positive inspection of the subject vessel under various inspection regimes, (Port State Control, Canada Shipping Act, Canada Labour Code, etc).

Because of the safety and security challenges posed by transporting millions of cubic feet of LNG, vessels typically undergo a more frequent and rigorous examination process than conventional crude oil or product tankers. LNG vessels are boarded by marine safety personnel prior to US port entry to verify the proper operation of key navigation, safety, fire fighting, and cargo control systems.

LNG vessels are subject to additional security measures. Many of the security precautions for LNG vessels are derived from analysis of "conventional" navigation safety risks, such as groundings, collisions, propulsion, and steering system failures. These precautions pre-date the events of September 11, 2001, and include such items as traffic control measures for special vessels that are implemented when an LNG vessel is transiting or approaching a port, and security zones around the vessel to prevent other vessels from approaching it. Also included are escorts by Coast Guard patrol craft and, as local conditions warrant, coordination with other Federal, State and local transportation, law enforcement and/or emergency management agencies to reduce the risks to, or reduce the interference from, other port area infrastructure or activities. All such measures are conducted under the authority of existing port safety and security statutes, such as the Magnuson Act (50 U.S.C. 191 et. seq.) and the Ports and Waterways Safety Act.

One of the most important post-9/11 maritime security developments has been the passage of the Maritime Transportation Security Act of 2002 (MTSA). Under the authority of the MTSA, the Coast Guard has developed new security measures applicable to vessels, marine facilities, and maritime personnel. The domestic maritime security regime is closely aligned with the International Ship and Port Facility Security (ISPS) Code. Under the ISPS Code, vessels in international service, including LNG vessels, must have an International Ship Security Certificate (ISSC). To be issued an ISSC, the vessel must develop and implement a threat scalable security plan that establishes access control measures, security measures for cargo handling and delivery of ships stores, surveillance and monitoring, security communications, security incident procedures, and training and drill requirements. The plan must also identify a Ship Security Officer who is responsible for ensuring compliance with the ship's security plan.

Terminal Safety

Permitting can be a drawn-out process, because North America has little experience with these facilities. For an LNG terminal, regulations developed under the authority of the Ports and Waterways Safety Act assign to the Coast Guard the responsibility for safety issues within the "marine transfer area" of LNG terminals. The "marine transfer area" is defined as that part of a waterfront facility between the vessel, or where the vessel moors, and the first shutoff valve on the pipeline immediately before the receiving tanks. Safety issues within the marine transfer area include electrical power systems, lighting, communications, transfer hoses and piping systems, gas detection systems and alarms, firefighting equipment, and operations such as approval of the terminal's Operations and Emergency Manuals, and personnel training.

Recently developed maritime security regulations require the LNG terminal operator to conduct a facility security assessment and develop a threat-scalable security plan that addresses the risks identified in the assessment. Much like the requirements prescribed for vessels, the facility security plan establishes access control measures, security measures for cargo handling and delivery of supplies, surveillance and monitoring, security communications, security incident procedures, and training and drill requirements.

In Canada, Marine Transportation Security Regulations (MTSR) requires that the facility, port, and ship have a security plan approved by Transport Canada Marine Security. All LNG imported into Canada will require an import license pursuant to Part VI of the National Energy Board Act (NEB Act) or an order pursuant to the National Energy Board Act Part VI (Oil and Gas) Regulations. Proponents may seek Certificates of Public Convenience and Necessity pursuant to section 52 of the NEB Act or an exemption order pursuant to section. 58 of the NEB Act to construct and operate an LNG Import Facility and/or interconnecting pipeline facility if it crosses provincial or international boundary or is built by a company regulated by the NEB. The facilities in question would also trigger an Environmental Assessment under CEAA.

LNG terminals are designed to include spill containment systems, fire protection systems, multiple gas, flame, smoke and low- and high-temperature detectors and alarms, and automatic and manual shut-down systems. Each LNG tank/process area must have a thermal exclusion zone and a vapour dispersion exclusion zone within the owner's control as per FERC regulations. Annually, US Department of Transportation (DOT) staff inspects LNG terminals to monitor conformance with all requirements. Every two years, FERC staff inspects LNG facilities to monitor the condition of the physical plant and inspects changes from the originally approved facility design or operations. Canadian requirements are similar in nature and fall under Transport Canada, Marine Security department.

Risks from accidental LNG spills, such as collisions and groundings, are small and manageable with current safety policies and practices. Risks from intentional events, such as terrorist acts, can be significantly reduced with appropriate security, planning, prevention, and mitigation.

Management approaches to reduce risks to public safety and property from LNG spills include operation and safety management, improved modeling and analysis, improvements in ship and security system inspections, establishment and maintenance of safety zones, and advances in future LNG off-loading technologies. If effectively implemented, these elements could significantly reduce the potential risks from an LNG spill.

Large, unignited LNG vapour releases are unlikely. If they do not ignite, vapour clouds could spread over distances greater than 1,600 m from a spill. For accidental spills, the resulting hazard ranges could extend up to 1,700 m. For an intentional spill, the hazard range could extend to 2,500 m. The actual hazard distances will depend on breach and spill size, site-specific conditions, and environmental conditions.

If and when an LNG spill occurs, then in general, the most significant impacts to public safety and property exist within approximately 500 meters (1,640 feet) of a spill, with much lower impacts at distances beyond 1,600 m (5,250 feet), even for very large spills.[67] Under certain conditions, it is possible that multiple LNG cargo tanks could be breached as a result of the

[67] "Guidance on Risk Analysis and Safety Implications of a Large Liquefied Natural Gas (LNG) Spill Over Water", *Sandia Report*, Sandia National Laboratories, SAND2004-6258, December 2004.

breaching event itself, as a consequence of LNG-induced cryogenic damage to nearby tanks, or from fire-induced structural damage to the vessel.

Proposed LNG terminals in Canada are subject to stringent requirements and approvals by a number of federal and provincial organizations such as Fisheries and Oceans Canada, Environment Canada, Public Works and Transport Canada, Provincial Utility Boards, among others. All LNG facilities will have to satisfy the Canadian Environmental Assessment Act. The Minister of the Environment will have to make a decision on the environmental assessment prior to the responsible authority being able to issue a permit, a license or other type of decision (land or money). Any new or altered works in, on or over navigable water require approval from the Regional Superintendent of Navigable Waters Protection. Approval comes after, among other things, a positive environmental assessment (EA) from Transport Canada Environmental Affairs.

5.2.3 Coal

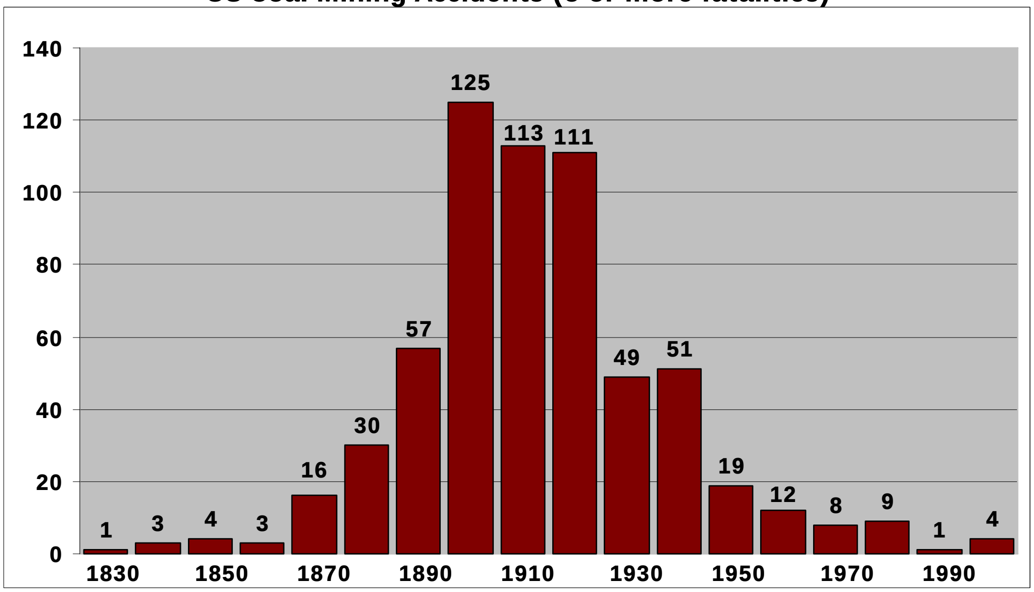
This section regarding the safety and security of coal is also subdivided into three parts. Section 5.2.3.1 discusses occupational hazards of coal mining. Section 5.2.3.2 discusses environmental threats of coal mining. Section 5.2.3.3 reviews public safety and environmental impacts of coal combustion. From the coal industry's earliest days, there have always been dangers associated with mining and usage. In Europe and North America, where the industry is mature and safety issues have been of great concern for over a century, many of these hazards have been reduced significantly. In the world's largest coal producing country, China, where the industry has only recently begun its rapid growth, the perils are great and increasing.

5.2.3.1 Coal Mining: Occupational Hazards

Records exist confirming that coal mining has always been a hazardous profession. In the United Kingdom, over 100,000 people have died in the mines and hundreds of thousands more have sustained injury since mass production of coal began during the Industrial Revolution.[68] In the United States, where Kentucky, West Virginia, and Pennsylvania coal seams were first exploited in the 19th century, fatalities in mines also jumped as production increased (Figure 5.2).

[68] "Coal Mine Safety in China: Can the Accident Rate be Reduced?" Roundtable before the Congressional-Executive Commission on China. 108th Congress, 2nd session. Washington DC. December 10, 2004, page 4.

Figure 5.2
US Coal Mining Accidents (5 or more fatalities)



Source: NIOSH. http://www.cdc.gov/niosh/mining/statistics/disall.htm

However, with safety measures being developed over the years, the number of serious accidents in the US has fallen dramatically.

The most significant occupational hazard that has affected the industry throughout its history has been gas explosions. Odourless, highly combustible methane gas (CH_4) is present to varying degrees in all coal seams, and in the industry's early days when safety standards were rudimentary, open flames were used to cast light in underground mines, causing countless explosions; even sparks created by metal contacting stone were enough to set off an explosion in a poorly-ventilated shaft. Technological advancements and a better understanding of the risks involved in mining have reduced the danger of underground explosions, but they are still an ever-present concern. Of the 616 recorded accidents at US mines that have suffered 5 or more fatalities, 540 (87.5 percent) were caused by explosions or fires.

The invention of the safety lamp, which covered the naked flame and reduced the possibility of gas coming into contact with fire, was the first great safety innovation in the coal mining industry. When the safety lamp came into widespread use at the turn of the 20^{th} century, serious accidents had reached a peak, but started to fall soon thereafter (Figure 5.2). This was not a foolproof safety method, though, because glass could break and the flames could spread. The lamp-caused ignition problem was solved by mid-century when sealed, battery-powered lamps came into widespread use. The latest technology utilized today is the white LED lamp, which provides a long, safe operating life and a readily visible, dense light over a wide angle of vision.[69] When such lamps break, they do not emit electrical sparks and therefore pose no fire or explosion risk.

Fire and explosion risk has also been reduced by other measures such as enhanced methane drainage methods, advances in ventilation technology and know-how, better underground mine design, improved blasting procedures, and adding rock dust to the mines to render inert the highly flammable coal dust.[70] Because explosion risk will never be completely eliminated in underground mines, injury and fatality mitigation strategies have been developed for the immediate post-explosion period. These include the erection of passive and active barriers as well as miner refuge stations within the mine. A passive barrier is a large container holding a fire-extinguishing stone dust or water; wind triggered by an explosion causes the container to tip and douse the flames. Active barriers also known as trigger barriers, are equipped with sensors that detect explosions precisely and engage a fire suppressant. Theoretically, the active barriers provide a more timely response than the passive barriers, neither early nor late. But to operate they require either an external power source or a battery and are therefore not foolproof mechanisms.[71]

Refuge stations are small zones where miners may move to in the event of an explosion or roof collapse. These areas provide temporary shelter until escape or rescues are possible. Stations can usually be sealed off from the rest of the mine and often have a borehole to the surface, which enables fresh air to penetrate the station and food and water to be sent down.[72] Though the goal in any emergency situation is to evacuate miners as quickly and safely as possible, at times when personnel are trapped in remote reaches of the mine, retreat to a refuge station may be the only viable survival option.

There are many other occupational hazards that underground coal miners face such as collapsing shafts, flooding, rock falls, and falls within mines. Longer term problems include exposure to diesel fumes from mine machinery, hearing loss resulting from working in confined spaces with heavy machinery (this is often the case in longwall mining which relies on machines to carve out and extract the coal), muskoskeletal disorders like osteoarthritis, and pneumoconiosis–-an incurable ailment more commonly known as "black lung disease."

Black lung disease has been largely controlled in jurisdictions where new coal-dust-reducing technologies have been implemented. These technologies, such as ventilating air and water sprays, have succeeded in reducing the incidence of black lung disease in the US from 28.2 per

[69] "Visual Performance for Incandescent and Solid-State Cap Lamps in an Underground Mining Environment" Sammarco, John J., and Timothy Lutz. Conference Record of the 2007 IEEE Industry Applications Conference: Forty-second IAS Annual Meeting, September 23-27, 2007, New Orleans, Louisiana. Piscataway, NJ: Institute of Electrical and Electronics Engineers, 2007; 4:1-6.

[70] "Coal Mine Safety Achievements in the US and the Contribution of NIOSH Research". Esterhuizen, G. and R. Gurtunca.

[71] "Passive and Triggered Explosion Barriers in Underground Coal Mines - A literature review of recent research". Zou, D. and S. Panawalage. A report to NRCan-CANMET, Natural Resources Canada. Ottawa. September, 2001.

[72] "Refuge Stations/Bays & Safe Havens in Underground Coal Mining". A report to The Underground Coal Mining Safety Research Collaboration by DJF Consulting. May 2004.

cent of all miners in 1973 to only 3.3 per cent by 1999.[73] However, as US coal production has increased in recent years, incidents of black lung disease have also started to rise.

Occupational hazards similar to those in other advanced coal mining nations exist in the Canadian coal mining industry and, historically, deaths and injuries occurred in major mining centres such as Drumheller, Alberta (though methane levels in the Drumheller mines were very low and caused only one explosion there) and Cape Breton Island. The Nova Scotia industry was essentially closed down in the wake of the Westray Mine methane explosion in 1992 that killed 26 workers. Today there are only two underground Canadian coal mines, one at Grande Cache, Alberta and another at Quinsam, British Columbia, and both are highly-mechanized room-and-pillar operations; therefore, the number of underground mine workers in Canada today are a fraction of those in other highly-developed mining countries like the UK and the US – and the occupational hazards, though still present, are not of the same scale.

In China, the coal industry has a short history, since that nation was fundamentally an agrarian society prior to the communist revolution. Much of China's economic growth today is fuelled by coal, which is plentiful there. The state-owned underground mines are monitored for safety, and the Chinese government has been involved with organizations such as the Chemical Energy and Mining Federation and the International Labor Organization in order to improve safety standards within those mines. By far, most safety problems occur in China's smaller, privately-owned underground mines, which are not monitored strictly. The death rate in these operations has been compared to that of British collieries during the Industrial Revolution, another place and time of small, privately-owned, unsafely-run mines.[74] Though it may be claimed legitimately that safety policies were poorly observed in the early days of the British coal mining industry, it is also true that safety regulations and equipment of that era did not approach today's standards and technologies. In China, however, modern standards are understood but not observed; advanced technologies are available but not utilized. The result is that China now produces 35 per cent of the world's coal and suffers 80 per cent of the world's coal mining-related deaths and injuries.

5.2.3.2 Coal Mining: Environmental Impacts

Surface mining impacts the environment in a highly visible way. With heavy equipment digging at overburden to access the coal, and with some of these mines being many square miles in size, the effect on the landscape can be striking. Rehabilitation efforts can help the landscape to recover to a degree with land filled back in and vegetation re-established.

However, a major problem with the mines while they are in operation and even after they are rehabilitated, is leaching or acid mine drainage (AMD). This occurs when rain and oxygen reach sulphides, creating sulphuric acid which can then transport heavy metals into the water table or

[73] "Dust Control Practices for Underground Mining". Colinet, Jay F. and Edward D. Thimons. Proceedings of the 32nd International Conference of Safety in Mines Research Institutes, 28-29 September 2007, Beijing: National Center for International Exchange & Cooperation on Work Safety (SAWS), 2007. 332-338.

[74] Official Government of China statistics state that more than 250,000 coal miners have perished in mining accidents since the People's Republic was established in 1949

nearby streams and lakes. At its worst, AMD can sterilize waters, and though there are many means of dealing with this problem, they are generally expensive in terms of operational and capital costs. For example, AMD can be actively neutralized with chemicals such as calcium carbonate, hydrated lime, and caustic soda, creating sludge, but this sludge is still an environmental issue that produces additional disposal costs. It is also possible to lay down a layer of clay to minimize leaching when rehabilitating mined-out areas, but the long-term efficacy of this technique has yet to be determined. In recent years, so-called "passive" solutions, including development of wetlands, have been employed at lower cost and with a degree of success. Contaminated water that flows into wetlands is effectively cleansed (heavy metals bind and ph levels rise), though this does not occur immediately but over a period of years.[75]

Subsurface mining does not leave highly visible scars upon the landscape, but it affects the environment in other ways. Methane constantly escapes from the shafts as mining is conducted, and though the methane usually escapes in very small quantities, at 21 times the global warming potential (over the next 100 years) of Carbon Dioxide, any release of methane is cause for concern.[76] One way of dealing with methane is to capture it from seams before mining commences; this lessens the risk of methane explosions once mining begins, and it provides a source of energy. Coal methane capture projects are becoming more common as climate change issues grow in prominence; China and the US plan to build 15 large-scale, coal-methane-capture and utilization projects in China between 2007 and 2012.[77]

5.2.3.3 Coal Combustion: Public Safety & Environmental Impact

The history of coal as an industrial power source can be traced back to the steam engines of the 18th century. Coal combustion is therefore the earliest source of industrial-level man-made emissions, and to this day it continues – the burning of coal releases more particulates and gases into the atmosphere than any other human activity. And coal burning will increase as long as oil and gas prices remain high – it is the cheapest alternative to those fuels that is available today.

Some of these ever-increasing coal combustion emissions have been linked to respiratory and other physical ailments; others have been connected to acid rain and climate change. Technologies that deal with coal combustion emissions have been developed over the years to improve public safety and lessen environmental impact.

Particulates are one of the most obvious problems caused by coal combustion because they are present in the ash and haze sent out through smokestacks. Evidence links particulates with respiratory ailments like asthma, and long-term exposure to fine particulates (less than 10μ in

[75] Sheoran, A.S. and V. Sheoran."Heavy metal removal mechanism of acid mine drainage in wetlands: A critical review." Minerals Engineering 19 (2006) 105–116. Pages 105-06.

[76] Forster, P. et al. "Changes in Atmospheric Constituents and in Radiative Forcing". *In: Climate Change 2007:The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change.* Cambridge University Press, Cambridge, United Kingdom and New York, NY, US. (2007) 129-234. Page 212

[77] http://www.epa.gov/cmop/docs/cmm_us_china_flyer.pdf

diameter) has been proven to increase risk of cancer and heart disease.[78] Modern coal plants throughout the world are equipped with electrostatic precipitators (ESP) and fabric filters, which can remove 99.5 per cent of all particulates. However, particulates are still a grave problem in places like the interior provinces of China where a high proportion of coal plants are not fitted with the latest particulate-removal technology.

Oxides of sulphur and nitrogen, commonly referred to as SO_x and NO_x, emitted by the burning of coal, contributed significantly to the acid rain problem that began to afflict many parts of the world in the second half of the 20th century. When low ph precipitation (the lower the ph level, the higher the acidity) falls to the ground, it affects not only streams and lakes, but soil, trees, and even buildings; fish kills, infertile soil, dying trees, and decaying stone structures all worsen as ph levels in precipitation drop. Human health is affected, too, as particulates are formed from SO_x and NO_x, and as noted previously, cause an increase in heart and respiratory ailments. The problem of acid rain has been addressed to varying degrees of success in the developed world. Smoke stacks were raised in many coal-burning plants in order spread the oxides over a greater area; this lessened the problem near the plants but then caused increased acid rain elsewhere. More successful was the introduction of the flue gas desulphurization (FGD) process to the stacks to neutralize sulfur emissions.

The strong connection between acid rain and coal combustion is being underlined today in China, where coal is responsible for 69 per cent of total energy production (as of 2003) and much of the southwest of the country, where there is less neutralizing alkaline dust from the northern deserts, is subject to acid rain. Though the central government has recognized the problem and has implemented an acid-rain control policy, the technological, societal, and environmental costs are high and rising.[79]

CO_2 is the major coal combustion emission and an important greenhouse gas. Coal is the most carbon-intense of all fossil fuels, and because it is used for a large proportion of electricity generation in the world's most industrialized nations, burning coal contributes a high percentage of overall CO_2 emissions.[80] In the United States, the problem of CO_2 emissions from coal-fired generation has been addressed by the Supreme Court, which classified CO_2 as a pollutant in 2007. This, in turn, set the stage later that year for the Kansas state government to turn down a coal-fired electricity plant proposal on the grounds that the CO_2 emissions pose a threat to public health and the environment.[81] There has not been a wholesale rejection of coal-fired generation

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[78] Pope, C. Arden III et al. "Lung Cancer, Cardiopulmonary Mortality, and Long-term Exposure to Fine Particulate Air Pollution" *The Journal of the American Medical Association*. Vol 287, No. 9 March 6, 2002. 1132-41. Page 1132.

[79] Larssen, Thorjorn et al. "Acid Rain in China". Environmental Science and Technology. 40:2, 2006. 418-425. Page 418-420.

[80] "Carbon Dioxide Emissions from the Generation of Electric Power in the United States". Department of Energy. Environmental Protection Agency. United States Government. Washington , DC. July 2000. Page 3.

[81] Mufson, Steven. "Power Plant Rejected Over Carbon Dioxide For First Time". Washington Post. October 19, 2007. Page A01

in the United States, but public concern over climate change is increasingly informing environmental policy and legislation.

Just as occupational hazards increase in Chinese coal mines as government control of the mines decreases, so do emissions increase in regional coal-fired electricity plants that operate beyond Beijing's grasp. China's environmental policy has decentralized over the years to the point where Beijing holds little effective legal control over newly-installed power generation technology in the poorer provinces. The wealthy coastal provinces, with Special Economic Zones and a greater central government presence, lately have been building cleaner-burning, technologically-advanced power plants, whereas other provinces have been constructing plants based on mid-20th century Soviet technology – in direct contravention of Beijing-mandated environmental regulation.[82] Recent studies examining Chinese provincial GHG emissions data find annual total emissions growth to be approximately 11 per cent. This is double the earlier estimates of the Intergovernmental Panel on Climate Change (IPCC) and attributable in large part to coal-fired electrical generation built within the country's interior.[83]

Similar to the United States, Europe, and other industrialized regions, there is increasing public concern within China over industrial pollution in general and CO_2 emissions in particular -- but to this point, economic growth has been valued over environmental concerns. And even if there were a sea change in Chinese government policy, emphasizing green means to drive the economy, it is increasingly apparent that the central government does not necessarily control the design, construction, and operation of all the coal-fired power plants in the country. Chinese CO_2 emissions from coal-fired generation are greater than those of any other country in the world in 2008 and with few effective restraints in place, are set to grow significantly well into the next decade.

5.3 Concluding Remarks

Chapter 5 analysed and compared reliability, safety and security of electricity generation from coal, natural gas and nuclear. From a reliability standpoint, this section asserts that nuclear has been found to be more reliable than generation from natural gas, although not by a wide margin.

This Chapter also reviews the safety and security issues in power generation starting at the initial stage of the production and transportation of fuel. The section regarding the safety and security of nuclear power provides a review of occupational hazards and environmental impacts of uranium mining, a comparative safety analysis and nuclear and other types of energy, analyzes energy-related disasters by type, examines Canadian regulations and spent fuel management and, finally, examines terrorism threats to nuclear power. The section regarding the safety and security of natural gas discusses occupational hazards regarding natural gas, discusses public

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[82] Reuters: March 13, 2008. "China's Emissions Rising Faster Than Thought – Report" March 13, 2008. www.alertnet.com; Auffhammer, M. and R.T. Carson, "Forecasting the path of China's CO_2 emissions using province-level information". Journal of Environmental Economic Management (2008), doi:10.1016/j.jeem.2007.10.002. Page 8.

[83] Auffhammer and Carson, Page 17.

safety issues and environmental issues and reviews the safety and security issues of LNG. It is important to remember that natural gas is no longer exclusively a continental market. The section regarding the safety and security of coal discusses occupational hazards of coal mining, reviews environmental threats of coal mining and examines public safety and environmental impacts of coal combustion.

This section concludes that while all sources of energy have their own issues, on the whole, nuclear power generation is safer and more secure compared with the other two forms of electricity generation.

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CHAPTER 6
CONCLUSIONS

This Chapter summarizes the results of the analysis presented in Chapters 2 through 5 and elaborates on the conclusions thereof.

A background discussion of power generation in Canada from 1971 to 2005 was presented in the first section of Chapter 2, followed by the views of the International Energy Agency (IEA) and Canada's National Energy Board (NEB) on the outlook for power generation up to 2050 and 2030 respectively. It was shown that Canada is a major power generator on a global basis; ranking 3rd after United States and Japan within OECD, and 6th worldwide. Canada's per capita power generation ranked 3rd within OECD and worldwide.

In terms of electricity generation from coal, nuclear and natural gas - the focus of our LCA - Canada placed 13th, 7th, and 22nd respectively in 2005 worldwide rankings. On a per capita basis, Canada's coal, nuclear and natural gas electricity generation global rankings stood at 9th, 10th, and 38th respectively. But how did Canada's global share of power generation match with its reserves and production shares? Table 6.1 presents some data on this.

Table 6.1
Canada's Global Shares of Reserves, Production and Electricity Generation from Coal, Natural Gas and Nuclear in 2005, per cent

Source	Reserves	Production	Power generation
Coal	0.72	1.15	1.44
Natural gas	0.94	6.75	1.01
Uranium	10.47	27.88	3.33

Sources: Reserves and production figures calculated based on data from "BP Statistical Review of World Energy 2008" and "BP Statistical Review of World Energy 2006" copyright British Petroleum Plc, UK, accessed online through www.bp.com; electricity generation shares calculated based on "IEA World Energy Statistics and Balances - Energy Balances of OECD Countries - Energy Balances Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD* and "IEA World Energy Statistics and Balances - Energy Balances of Non-OECD Member Countries - Energy Balances (ktoe) Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD*.

Table 6.1 indicates that although Canada held only 0.72 per cent of world coal reserves it produced 1.15 per cent of the world's coal, much higher than its reserves share. Canada's global share of power generation from coal was even higher at 1.44 per cent although power generation had to compete with other industries and export markets to acquire its coal supplies. In fact, some of the coal used for electricity generation in Canada is imported from the United States.

Turning to natural gas, one can see that Canada's global production share was more than six times its reserves share, while its global power generation share was similar to its reserves share in 2005. This can be partly explained by the fact that Canada's natural gas reserves, unlike those of many other countries, are within economic reach of export markets and widespread domestic residential, commercial and industrial users; so electricity generation must compete with alternative uses for supplies of natural gas.

The figures relating to uranium present a somewhat different picture. While Canada held 10.47 per cent of world uranium reserves, it was world's leading uranium producer with a share as high as 27.88 per cent in 2005. Canada's share of world nuclear power generation, in contrast, was only 3.33 per cent , less than one third of its reserves share and less than one eighth of its production share. Unlike coal and natural gas, uranium is almost entirely used for power generation. Although nuclear weapons were once an alternative market for uranium, today the dismantling of nuclear weapons produces a fuel supply for nuclear power in competition with freshly mined uranium. Most of Canada's uranium production is devoted to export markets, as illustrated in Table 6.2.

Table 6.2
Global Shares of Nuclear Electricity Generation, Uranium Reserves and Uranium Production, 2005, per cent

Country	Nuclear power generation	Uranium reserves	Uranium production
United States	29.29	10.37	2.79
France	16.31	0.00	0.01
Japan	11.01	0.20	0.00
Germany	5.89	0.09	0.22
Russia	5.40	4.00	7.83
Korea	5.30	0.00	0.00
Canada	3.33	10.47	27.72

Sources: Nuclear power generation shares calculated based on "IEA World Energy Statistics and Balances - Energy Balances of OECD Countries - Energy Balances Vol. 2007 release 01"; and "IEA World Energy Statistics and Balances - Energy Balances of Non-OECD Member Countries - Energy Balances (ktoe) Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD*. Uranium reserve shares calculated based on data from "Uranium 2005: Reserves, Production and Demand"; Table 2, page 15; copyright Organization for Economic Cooperation and Development (OECD) 2005, Paris, France. Uranium production shares calculated based on data from "Uranium 2007: Reserves, Production and Demand"; Table 19, page 39; copyright OECD 2007, Paris, France.

In 2005, Canada was the 7th largest nuclear power generator with a 3.33% global share. The USA, ranking 1st, accounted for 29 per cent of the global nuclear generation while its uranium reserves were similar to Canada's and its uranium production was much lower – slightly more than 10 per cent of Canada's production. The number two nuclear power generator, France, possessed almost no recoverable uranium reserves and almost no uranium production, but it generated more than 16 per cent of global nuclear electricity. The USA, France, Japan, Germany and Russia have their own indigenous nuclear power generation technologies. South Korea, however, relied on Canadian know-how, possessed no recoverable uranium reserves and produced no uranium in 2005, yet its nuclear power generation in that year was about 60% greater than Canada's.

Coal, nuclear and natural gas accounted for 16.9 per cent, 14.7 per cent and 5.8 per cent of Canada's electricity generation respectively in 2005. Long-term scenarios from the IEA anticipate the following average global ranges of shares for coal, nuclear and natural gas in 2050:

coal	16.5 to 47.0 per cent
nuclear	6.7 to 22.0 per cent
natural gas	19.5 to 28.2 percent.

The latest NEB scenarios anticipate a significant drop in the coal's share of Canada's electricity generation, from 16.9 per cent in 2005 to a range of 2.39 - 7.84 per cent, in 2030. Nuclear's 2030 share is expected to range from 13.77 to 15.70 per cent, close to the 14.7 per cent 2005 level. Natural gas share in 2030, however, is expected to be between 8.30 to 9.35 per cent, significantly higher than its 5.8 per cent share in 2005. Do the numbers in Table 6.2 indicate the potential for the share of nuclear power generation in Canada to turn closer to the IEA's 22 per cent compared with NEB's 15.7 percent in the future? Let's first review the conclusions of Chapters 3, 5 and 4.

Chapter 3 dealt with nuclear technology in Canada. It identified Canada as a leader in nuclear technology, research, and applications other than electricity generation. Canada is also a leading member of the Generation IV forum (GIF). Established in 2000, the GIF's mandate is to develop the next generation of nuclear energy systems. Member nations include the United States, Argentina, Brazil, Canada, France, Japan, South Korea, South Africa and Switzerland. The European Union, Russia and China joined the organization in 2006.

The GIF has decided to pursue six systems, including the Supercritical Water-Cooled Reactor (SCWR). The task force's objective is to develop these systems commercially by 2020 to 2030. While member nations specialize in the various technologies, Canada and Japan are taking a leadership role in developing the SCWR. Canada is the world's authority on SCWR technology, as this high-temperature, high-pressure, water–cooled reactor is a variation of the Advanced CANDU Reactor (ACR). The SCWR is often referred to as the CANDU X.

Chapter 5 discussed and compared the reliability, safety and security of electricity generation from coal, natural gas and nuclear. It asserted that nuclear has been found to be more reliable than generation from natural gas, although not by a wide margin. The chapter also reviews the safety and security issues in power generation starting at the initial stage of the production and transportation of fuel. It concludes that - in total - nuclear power generation is safer and more secure than the other two forms of electricity generation.

We now turn to Chapter 4, which covers the principal area of this study, LCA of electricity generation in Ontario. Table 6.3 first gives some data on power generation in Ontario during 2005 and 2006. The average for the two years has also been provided because on environmental impacts have been assessed based on the averages for 2005 and 2006.

Table 6.3
Electricity generation from coal, natural gas and nuclear in Ontario

Sources: Ontario Power Generation Inc.; "Fact Sheet 2005" and "Fact Sheet 2006"; accessed online in 2008 via http://www.ontla.on.ca/library/repository/ser/223468/2005q4-yearend.pdf and
http://www.ontla.on.ca/library/repository/ser/223468/2006q4-yearend.pdf;
Bruce Power; website accessed in 2008 via http://www.brucepower.com/uc/GetDocument.aspx?docid=2429; and
The Independent Electricity System Operator; website accessed in 2008 via
http://www.ieso.ca/imoweb/marketdata/genDisclosure.asp

Yearly electricity generation from coal, nuclear and natural gas in Ontario during 2005-6 averaged 116.3 TWh. Nuclear was the clear leader with 68.49 per cent followed by coal with 23.1 per cent and natural gas with only 8.4 per cent. Table 6.4 summarizes environmental impacts of electricity supplied by coal, natural gas and nuclear means, discussed in more detail in Chapter 4.

Table 6.4
Electricity generation from coal, natural gas and nuclear in Ontario; share in Generation and life-cycle impacts 2005-6; percent

Source	Generation ratio	Life-cycle environmental impact ratios		
		GHG emissions	Criteria air contaminants (CAC)	Radionuclides
Coal	23.08	83.82	92.21	0.03
Natural Gas	8.43	15.74	7.29	0.19
Nuclear	68.49	0.43	0.51	99.78
Total	**100.00**	**100.00**	**100.00**	**100.00**

Source: Calculated based on Table 6.3 above and Tables 4.4, 4.6 and 4.8 of Chapter 4

The figures in Table 6.4 indicate that while coal's share of power generation via these three fuels was about 23 per cent, it was responsible for more than 83 per cent of their greenhouse gas (GHG) emissions. The GHG emissions from natural gas came to 16 per cent, almost double its generation share. Nuclear, while securing more than 68 per cent of the generation from these fuels, accounted for a mere 0.4 per cent of their GHG emissions. As for criteria air contaminants (CAC), 92 per cent of them came from coal-fired power generation and nuclear's share was just 0.5 per cent. Nuclear's share of radionuclide emissions, at 99.8 per cent, was much more than proportional to its generation share. Nevertheless, comparative information from the United States as summarized in Appendix F leads to the conclusion that on a per TWh basis the collective radiation dose from the nuclear life cycle is much lower than the collective radiation dose from the coal-fired life cycle.

For easier comparison, Table 6.5 presents environmental impact indexes derived from the information in Table 6.4.

Table 6.5
Indices of Environmental Emissions of Electricity Generation from Coal, Natural Gas and Nuclear in Ontario
Nuclear = 100

Source	GHG	CAC	Radionuclides
Coal	57,233	54,038	0.09
Natural Gas	29,421	11,694	1.53
Nuclear	100	100	100

Source: Calculated based on the information in Table 6.4 above

The figures in Table 6.5 demonstrate that coal was 572 times as GHG-intensive as nuclear and natural gas was 302 times as GHG-intensive as nuclear over the 2005-6 period. Similarly, coal was 540 times as CAC-intensive as nuclear, while natural gas was 117 times as CAC-intensive as nuclear over this period. As for radionuclides, though, coal had an extremely lower emission rate than nuclear and natural gas had a 98 per cent lower emission rate.

Having reviewed the findings of the previous chapters of the report, one could say that nuclear power generation in Ontario had much less adverse environmental impacts compared with power generation from natural gas and coal, that it was more reliable than power generation from natural gas, and that it was safer and more secure. In addition to that, abundant recoverable uranium reserves, the availability of a dynamic indigenous nuclear power generation technology and Canada's leadership in developing new nuclear technologies would set the scene for a larger future share of nuclear in Canadian power generation than the 15.7 per cent anticipated by NEB. The 22 per cent upper end of IEA's scenarios seems both warranted and achievable.

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APPENDIX A
POWER GENERATION FROM NUCLEAR, COAL, NATURAL GAS AND FUTURE SCENARIOS

Appendix A is complementary to Chapter 2, Power Generation in Canada. It examines past trends, current status of electricity generation from nuclear, coal and natural gas in Canada; and future outlook of electricity generation in Canada and the world. Sections A.1 through A.3 examine Canada's global and regional shares in nuclear, coal-fired and natural gas-fired electricity generation, compare generation growth rates and present an account of the three above-mentioned sources in the Canadian generation mix. Sections A.4 and A.5 discusses future outlook of electricity generation in the world and Canada, respectively, based on the latest scenarios from the International Energy Agency (IEA) and the National Energy Board (NEB) of Canada.

A.1 Power Generation: Nuclear Electricity Output (NEO)

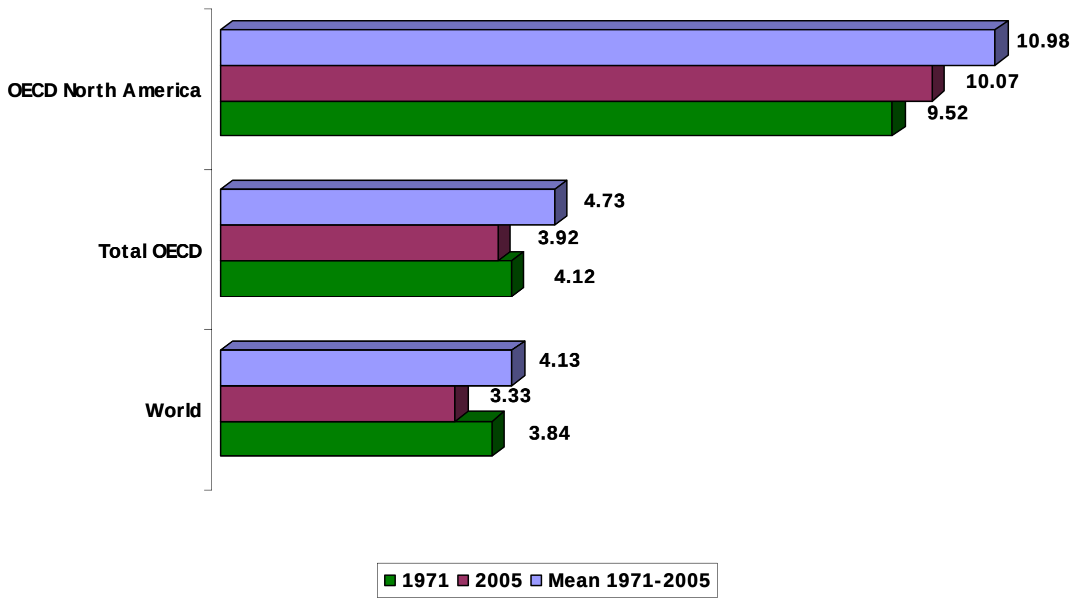
CERI's analysis now turns to the individual major sources of electricity generation, namely nuclear, coal, natural gas and hydro. The first source to be examined is nuclear. Canada has a special position in world nuclear electricity generation. The availability of large amounts of uranium and the existence of a domestic proprietary nuclear technology are major contributors to the said position. This is discussed in greater detail in Chapter 3 and Appendix B.

The following sections address Canada's world and regional nuclear electricity generation shares, and compare its nuclear electricity generation growth rate to world, regional and country rates.

A.1.1 Nuclear Electricity Output: World and Regional Share

Canada generated 4,267 gigawatt hours of nuclear electricity, equivalent to 3.84 per cent of the global total, in 1971. Through an average 11.62 percent annual growth, Canada's NEO rose to 92,040 gigawatt hours, equivalent to 3.33 per cent of global output, in 2005. Figure A.1 presents Canada's share in global and regional NEO.

Figure A.1
Share of Canada in world and Regional NEO; 1971, 2005 and Average Over 1971-2005 (per cent)

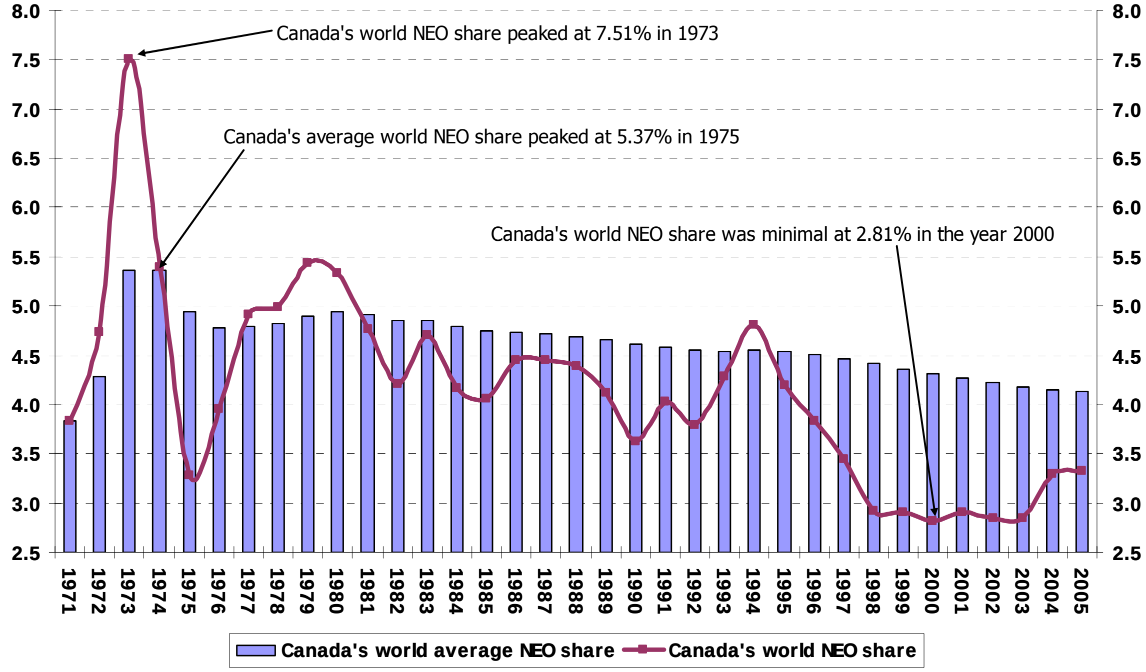


SOURCE: Calculated based on "IEA World Energy Statistics and Balances - Energy Balances of OECD Countries - Energy Balances Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD* and "IEA World Energy Statistics and Balances - Energy Balances of Non-OECD Member Countries - Energy Balances (ktoe) Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD*.

Figure A.1 indicates during 1971–2005, Canada's 4.13 percent average global share of NEO was close to eight times higher than its global population share (0.54 per cent), more than twice its world GDP share (1.95 per cent), about 0.88 per cent greater than its global total primary energy production share (3.25 per cent), but slightly (0.12 per cent) less than its world electricity generation share (4.25 per cent). The fact that the 1971 and 2005 shares were below average and that the 2005 share was less than than in 1971 imply that Canada's world share have been on the decline in recent years. Similar patterns can be observed with Canada's OECD and North American shares.

Figure A.2 compares Canada's share in world NEO and its time average. Each average point represents the average share from 1971 to the year in question.

Figure A.2
Canada's Share in World Total NEO and its Average, 1971-2005
(per cent)



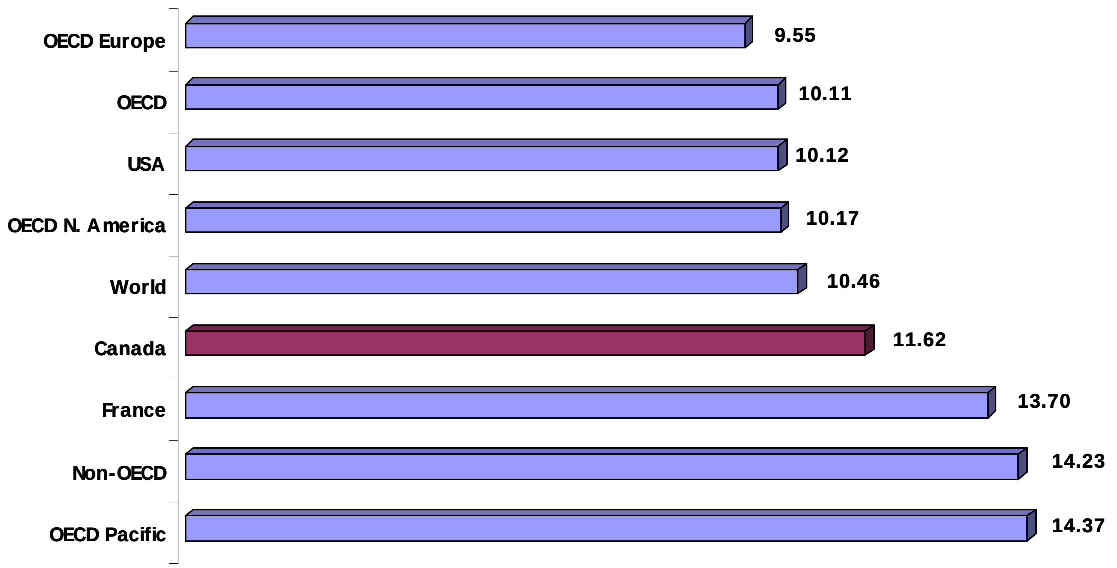
SOURCE: Calculated based on "IEA World Energy Statistics and Balances - Energy Balances of OECD Countries - Energy Balances Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD* and "IEA World Energy Statistics and Balances - Energy Balances of Non-OECD Member Countries - Energy Balances (ktoe) Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD*.

Figure A.2 indicates that, in spite of a temporary upward trend from 1990 to 1994, the general trend in Canada's NEO world share was downwards from 1980 to 2003. That is, other countries were expanding their nuclear power industry at relatively higher rates than in Canada. The highest share, 7.51 per cent, occurred in 1973; and the lowest, 2.81 per cent, was registered in the year 2000. It should be noted that Canada's world share was consistently below its historical average from 1995 to 2005, causing the average share to take a downward trend.

A.1.2 Nuclear Electricity Output: Comparison of Growth Rates

Figure A.3 presents average growth rates in NEO in Canada, other countries and regions for the 1972-2005 period.

Figure A.3
Average Annual NEO Growth Rate, 1972-2005
(per cent)



SOURCE: Calculated based on "IEA World Energy Statistics and Balances - Energy Balances of OECD Countries - Energy Balances Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD* and "IEA World Energy Statistics and Balances - Energy Balances of Non-OECD Member Countries - Energy Balances (ktoe) Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD*.

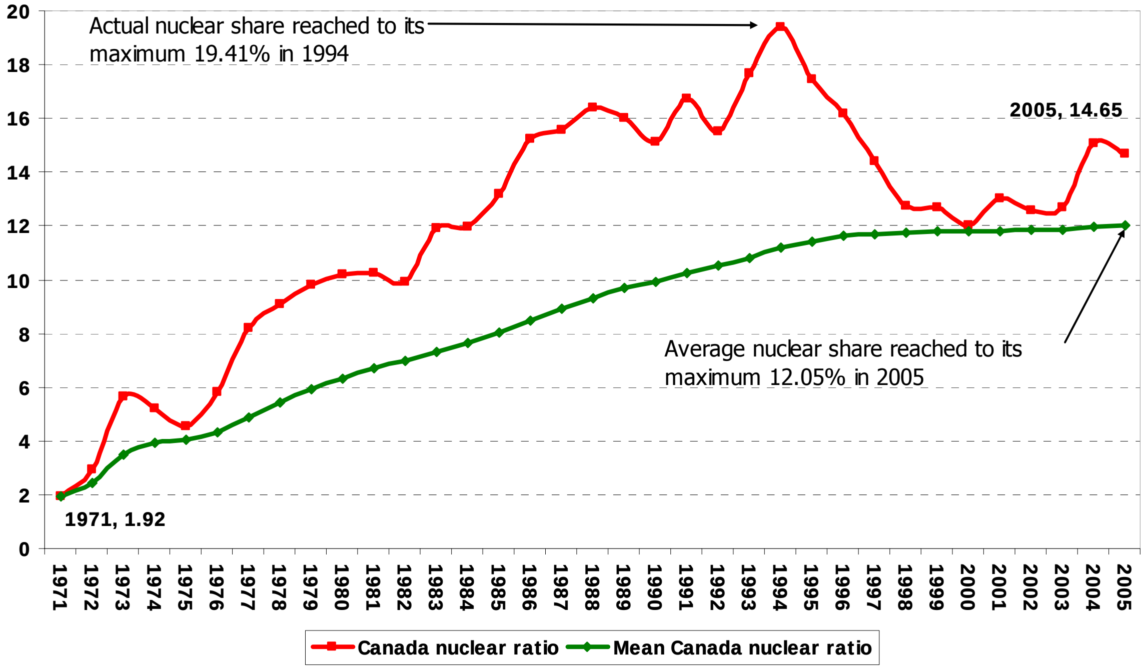
Figure A.3 indicates that Canada's nuclear electricity output grew, on the average, at 11.62 per cent, a higher rate than those of world, North America, US, and OECD. However, the growth rate was higher in non-OECD countries, OECD Pacific and France as an example in OECD Europe.

A.1.3 Nuclear Electricity Output: Share in Total Electricity Generation in Canada

Nuclear power's share in total electricity generation in Canada was as low as 1.92 per cent in 1971. Through a rather steady growth, the share climbed to 19.41 per cent in 1994. However, the share then underwent a steep fall to 12.02 per cent in the year 2000, but gradually improved afterwards to reach 14.65 per cent in 2005. It is noticeable that the share was always above its time average throughout 1971-2005 and that the average share steadily grew from 1.92 per cent in 1971 to 12.05 per cent in 2005, indicating that the general underlying nuclear share trend remained upward all the time.

Figure A.4 provides further details.

Figure A.4
Share of Nuclear in the Canadian Total Electricity Generation; 1971-2005
(per cent)



SOURCE: Calculated based on "IEA World Energy Statistics and Balances - Energy Balances of OECD Countries - Energy Balances Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD*.

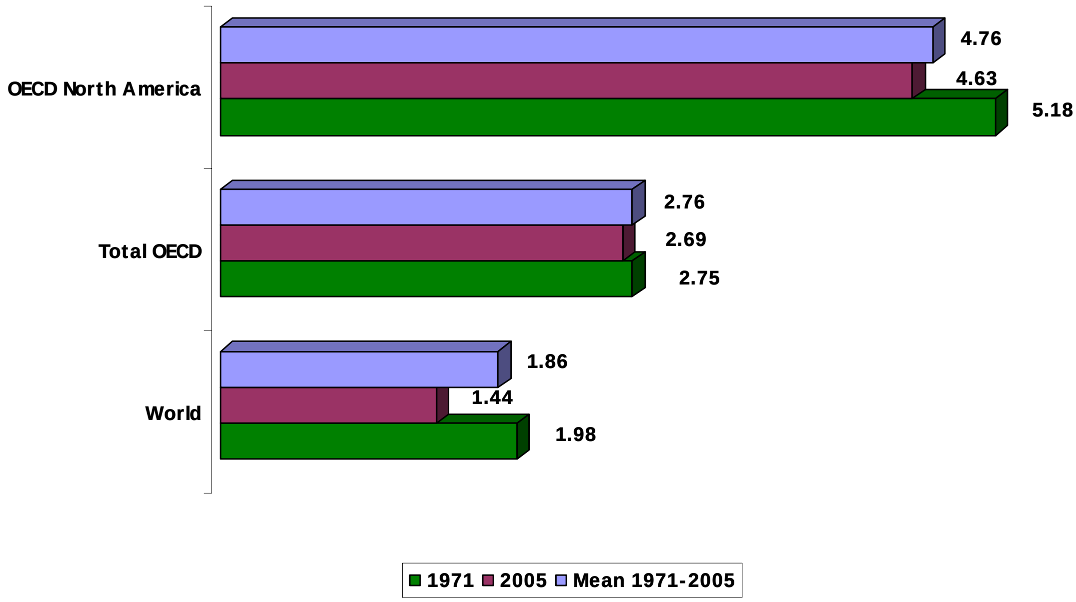
A.2 Power Generation: Coal Electricity Output (CEO)

The previous section analyzed Canada's nuclear electricity output. The following sections address Canada's world and regional coal electricity generation shares, and compare its coal electricity generation growth rate to world, regional and country rates.

A.2.1 Coal Electricity Output: World and Regional Share

Canada generated 41,707 gigawatt hours of electricity from coal, equivalent to 1.98 per cent of the global total, in 1971. Through an average 3.11 per cent annual growth, Canada's CEO rose to 106,188 gigawatt hours, equivalent to 1.44 per cent of global output in 2005. Figure A.5 presents Canada's share in global and regional CEO.

Figure A.5
Share of Canada in World and Regional CEO; 1971, 2005 and Average Over 1971-2005
(per cent)

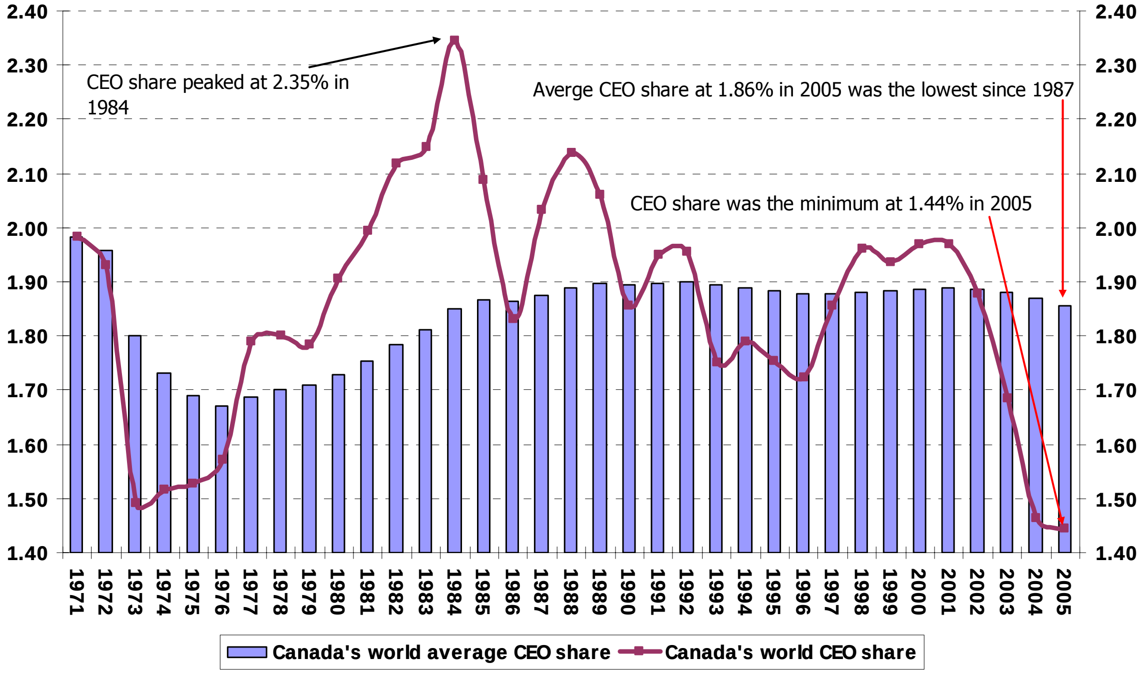


SOURCE: Calculated based on "IEA World Energy Statistics and Balances - Energy Balances of OECD Countries - Energy Balances Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD* and "IEA World Energy Statistics and Balances - Energy Balances of Non-OECD Member Countries - Energy Balances (ktoe) Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD*.

Figure A.5 indicates during 1971-2005, Canada's 1.86 per cent average global share of CEO was close to three and a half times higher than its global population share (0.54 per cent), slightly less than its world GDP share (1.95 per cent), much lower than its global total primary energy production share (3.25 per cent), and less than half of its world electricity generation share (4.25 per cent). The fact that the 2005 share was below average and less than in 1971 implies that Canada's world share has been on the decline in recent years. Similar patterns can be observed with Canada's OECD and North American shares.

Figure A.6 compares Canada's share in world CEO and its time average. Each average point represents the average share from 1971 to the year in question.

Figure A.6
Canada's Share in World Total CEO and its Average, 1971-2005
(per cent)



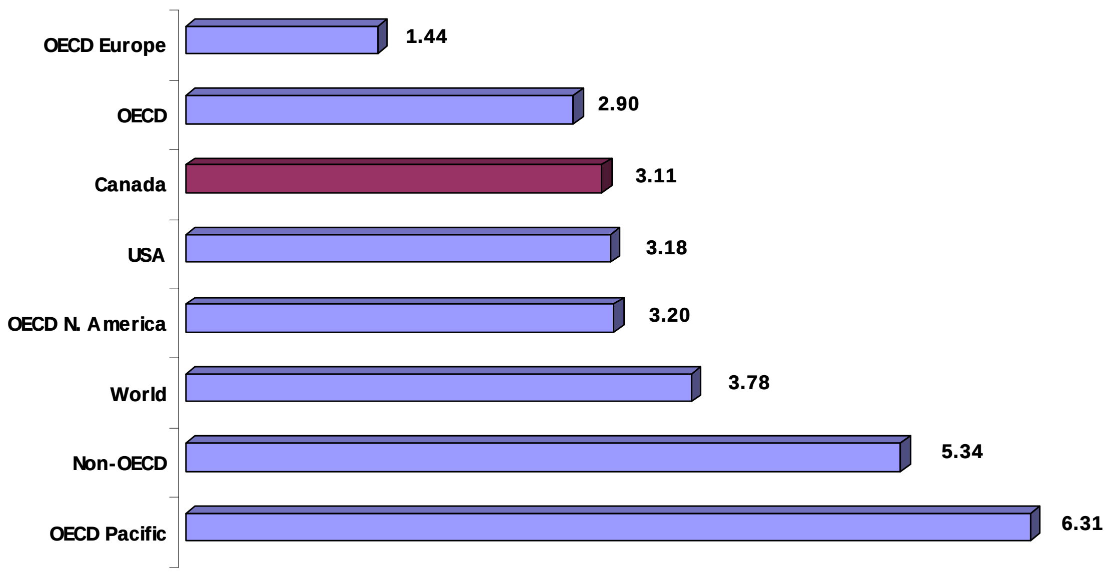
SOURCE: Calculated based on "IEA World Energy Statistics and Balances - Energy Balances of OECD Countries - Energy Balances Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD* and "IEA World Energy Statistics and Balances - Energy Balances of Non-OECD Member Countries - Energy Balances (ktoe) Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD*.

Figure A.6 indicates that, in spite of a temporary upward trend from 1973 to 1984, the general trend in Canada's CEO world share was downwards from 1985 to 2005. That is, other countries were expanding their coal industry at relatively higher rates than in Canada. The highest share (2.35 per cent), occurred in 1984; and the lowest (1.44 per cent), was registered in the year 2005. It should be noted that Canada's average, 1.86 per cent in 2005 was the lowest since 1987 implying an underlying downtrend in recent years.

A.2.2 Coal Electricity Output: Comparison of Growth Rates

Figure A.7 presents average growth rates in CEO in Canada and other countries and regions for the whole 1972-2005 period.

Figure A.7
Average Annual CEO Growth Rate, 1972-2005; per cent



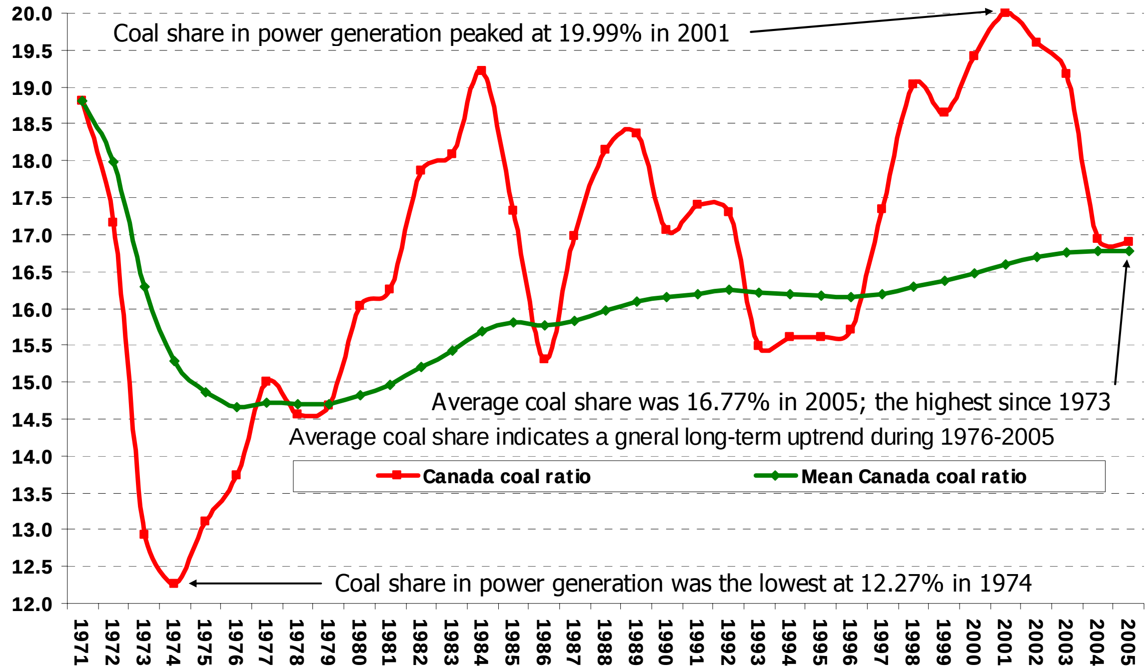
SOURCE: Calculated based on "IEA World Energy Statistics and Balances - Energy Balances of OECD Countries - Energy Balances Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD* and "IEA World Energy Statistics and Balances - Energy Balances of Non-OECD Member Countries - Energy Balances (ktoe) Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD*.

Figure A.7 indicates that Canada's coal electricity output on the average grew at 3.11 percent, a higher rate than those of total OECD and OECD Europe. However, the growth rate was higher in OECD Pacific (more than double the rate in Canada), non-OECD countries, world, OECD North America and the US compared to the Canadian growth rate.

A.2.3 Coal Electricity Output: Share in Total Electricity Generation in Canada

Figure A.8 shows that coal power's share in total electricity generation in Canada was as high as 18.80 percent in 1971. Through a rather sharp decline, the share reduced to 12.27 per cent in 1974. However, the share then underwent an uptrend to take a local peak at 19.21 per cent to the year 1984. Although it had ups and downs in between, the share set a 1971-2005 all time peak at 19.99 per cent in 2001; but gradually declined afterwards to reach 16.91 per cent in 2005. It is noticeable that the average share was 16.77 per cent in 2005; the highest since 1973; and that the average share was generally on the rise during 1976-2005 implying a long-term rising trend.

Figure A.8
Share of Coal in the Canadian Total Electricity Generation; 1971-2005
(per cent)



SOURCE: Calculated based on "IEA World Energy Statistics and Balances - Energy Balances of OECD Countries - Energy Balances Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD*.

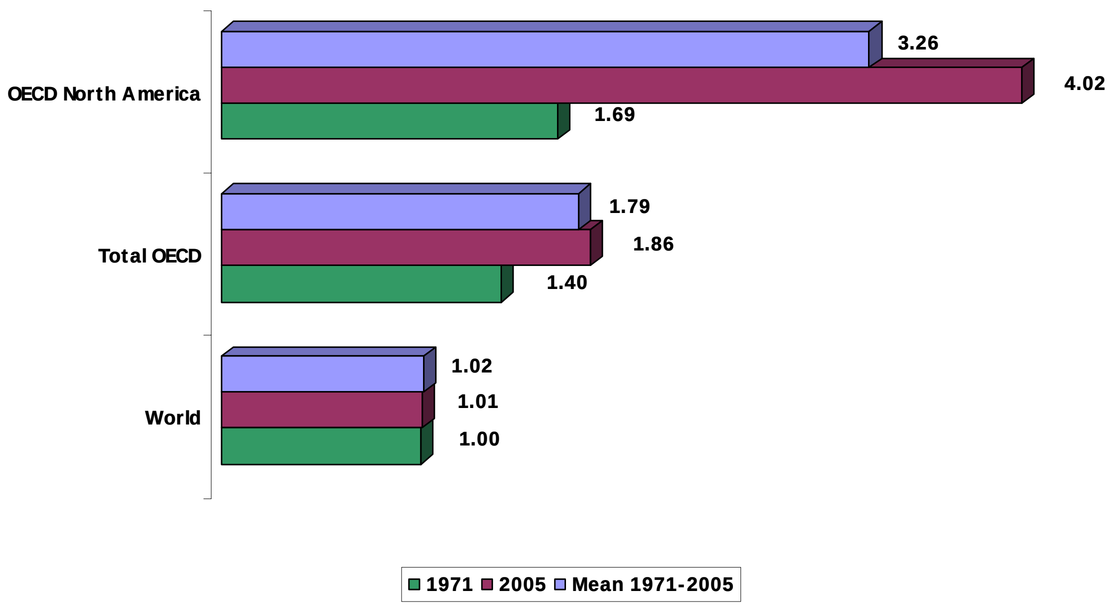
A.3 Power Generation: Natural Gas Electricity Output (GEO)

The previous section analyzed Canada's coal electricity output. The following sections address Canada's world and regional shares in electricity generation from natural gas, and compare its natural gas electricity generation growth rate to world, regional and country rates.

A.3.1 Natural Gas Electricity Output: World and Regional Share

Canada generated 6,976 gigawatt hours of electricity from natural gas, equivalent to 1.00 per cent of the global total, in 1971. Through an average 7.66 per cent annual growth, Canada's GEO rose to 36,324 gigawatt hours, equivalent to nearly the same 1.01 percent of global output, in 2005. Figure A.9 presents Canada's share in global and regional GEO.

Figure A.9
Share of Canada in World and Regional GEO;
1971, 2005 and Average Over 1971-2005
(per cent)



SOURCE: Calculated based on "IEA World Energy Statistics and Balances - Energy Balances of OECD Countries - Energy Balances Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD* and "IEA World Energy Statistics and Balances - Energy Balances of Non-OECD Member Countries - Energy Balances (ktoe) Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD*.

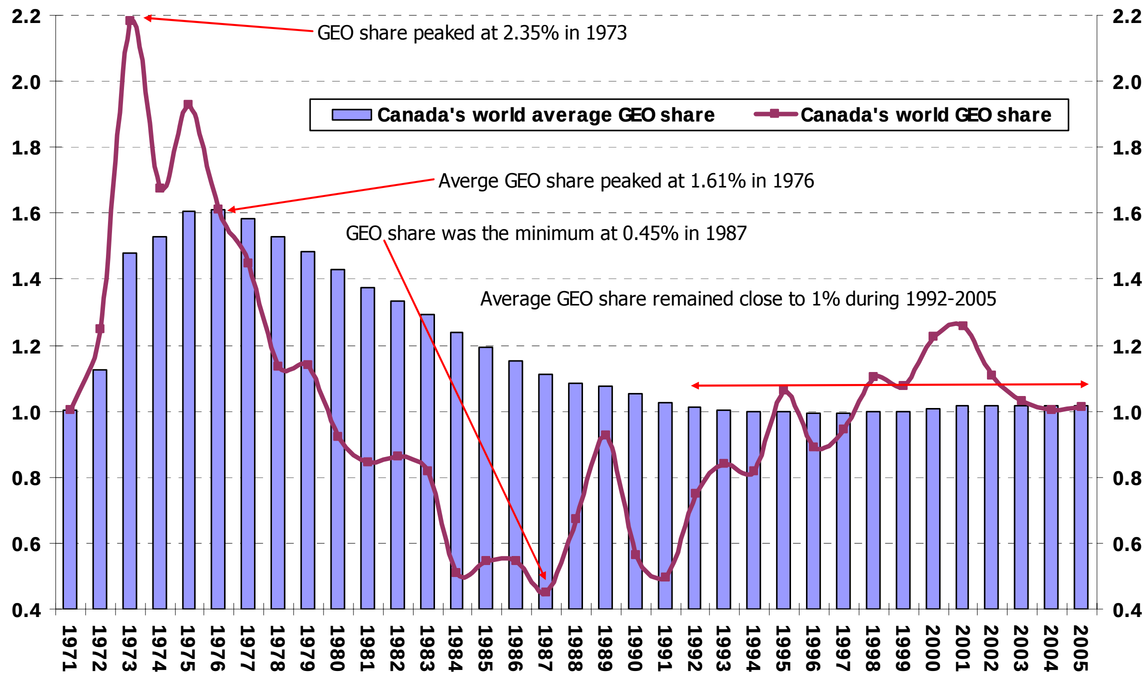
Figure A.9 indicates that Canada's 1.02 per cent average 1971-2005 global share of GEO was close to twice its global population share (0.54 per cent), slightly more than half its world GDP share (1.95 per cent), less than one third of its global total primary energy production share (3.25 per cent), and also slightly less than a quarter of its world electricity generation share (4.25 per cent). The fact that the 1971 and 2005 average share are all very close to 1 per cent shows that Canada's world share remained quite stable during 1971-2005.

Canada's OECD share underwent a moderate rise as both the average and the 2005 shares were higher than the share in 1971.

The share of Canada in electricity generation from natural gas in North America registered a more significant rise over time as the average 1971-2005 share was about twice the 1971 share, and the share in 2005 was close to two and a half times the 1971 share.

Figure A.10 compares Canada's share in world GEO and its time average. Each average point represents the average share from 1971 to the year in question.

Figure A.10
Canada's Share in World Total GEO and its Average; 1971-2005
(per cent)



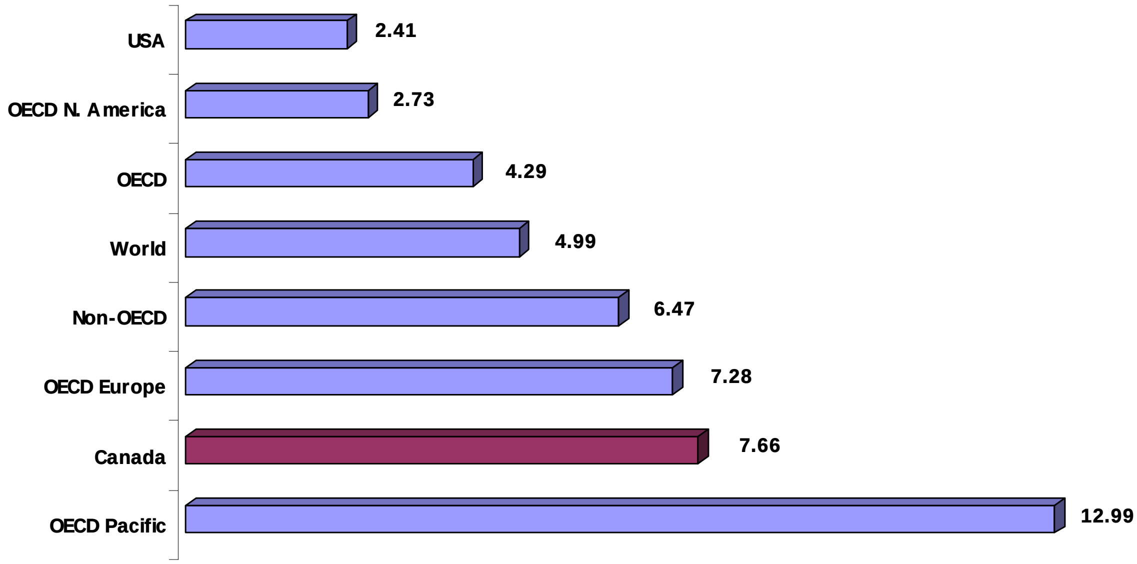
SOURCE: Calculated based on "IEA World Energy Statistics and Balances - Energy Balances of OECD Countries - Energy Balances Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD* and "IEA World Energy Statistics and Balances - Energy Balances of Non-OECD Member Countries - Energy Balances (ktoe) Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD*.

Figure A.10 indicates that, Canada's GEO world share was 1.00 percent, close to its historical 1971-2005 average, in 1971. It registered a sharp rise to its historical 1971-2005 peak at 2.35 percent within 2 years in 1973. However, the share underwent a steep decline from 1974 to register a 1971-2005 minimum at 0.45 percent in 1987 and pulling the average GEO share down from its 1.61 per cent peak in 1976 to around 1 per cent in 1992. From 1988, there was a general uptrend until 2001 followed by a moderate downtrend through to 2003 after which the share stabilized around 1.00 per cent or close to its historical average. The average GEO share remained close to 1 per cent in recent years.

A.3.2 Natural Gas Electricity Output: Comparison of Growth Rates

Figure A.11 presents average growth rates in GEO in Canada and other countries and regions for the whole 1972-2005 period.

Figure A.11
Average Annual GEO Growth Rate; 1972-2005
(per cent)



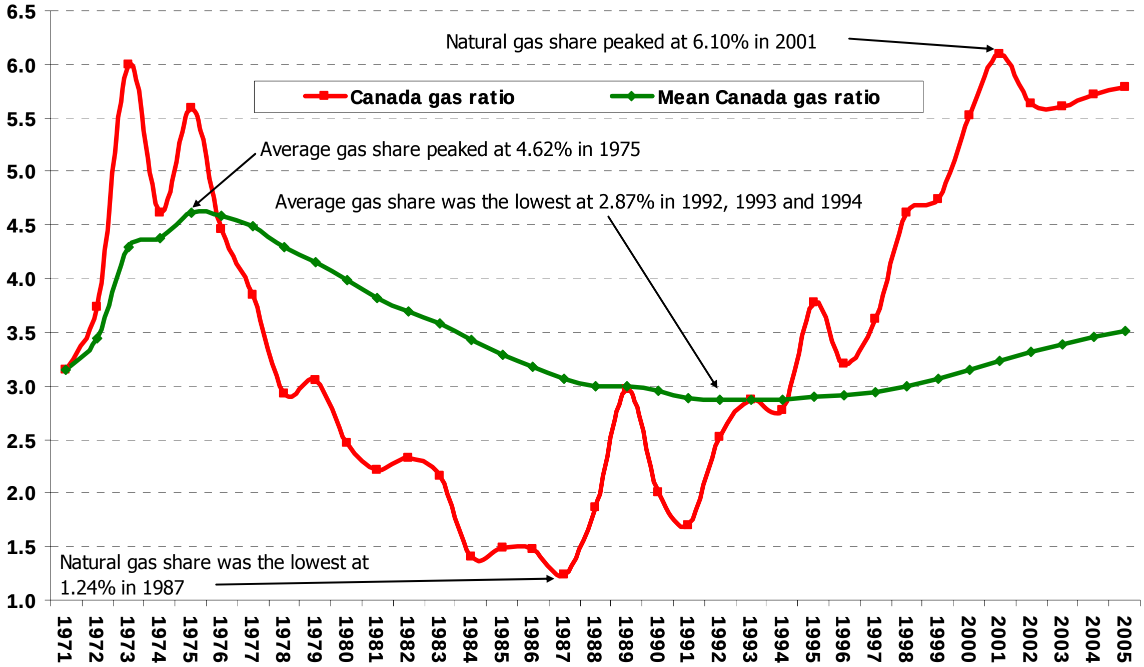
SOURCE: Calculated based on "IEA World Energy Statistics and Balances - Energy Balances of OECD Countries - Energy Balances Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD* and "IEA World Energy Statistics and Balances - Energy Balances of Non-OECD Member Countries - Energy Balances (ktoe) Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD*.

Figure A.11 indicates that Canada's electricity output from natural gas on the average grew at 7.66 percent, a higher rate than those of OECD Europe, Non-OECD, world, OECD, North America, and US. However, the growth rate was higher in OECD Pacific countries.

A.3.3 Natural Gas Electricity Output: Share in Total Electricity Generation in Canada

As shown in Figure A.12, natural gas's share in total electricity generation in Canada was 3.14 per cent in 1971. There was a general sharp uptrend until 1974 pushing the average share to its 1971-2005 high at 4.62 per cent in 1975. However, the share of natural gas declined sharply afterwards, remained below its average and set a 1971-2005 low at 1.24 per cent in 1987. The share took an uptrend afterwards but remained below average pulling the average to its 1971-2005 minimum at 2.87 per cent in 1992. The share of natural gas in total electricity generation in Canada continued its uptrend and remained above average from 1995 onwards and set its historical 1971-2005 peak at 6.10 per cent in 2001. The share of natural gas was generally on the rise until 2005.

Figure A.12
Share of Natural Gas in Canadian Total Electricity Generation; 1971-2005
(per cent)



SOURCE: Calculated based on "IEA World Energy Statistics and Balances - Energy Balances of OECD Countries - Energy Balances Vol. 2007 release 01"; International Energy Agency; France; 2008; accessed online via *Source OECD*.

A.4 Global Power Generation: Future Projections

This section examines the impact of energy technologies on future world electricity generation. The International Energy Agency, in its report[84] "*Energy Technology Perspectives 2006: Scenarios and Strategies to 2050",* examines the impact of key technologies on the global primary energy supply, electricity generation and green house gas emissions.

The IEA has developed one energy technology perspective baseline scenario, five Accelerated Technology (ACT) scenarios and one TECH Plus scenario. The five ACT scenarios consist of Map, low renewable, low nuclear, no carbon captured and sequestration (CCS), and low efficiency. In the following sub-sections the assumptions of scenarios and their associated power generation implications will be presented.[85]

[84] International Energy Agency; *Energy Technology Perspectives 2006; Scenarios and Strategies to 2050;* Paris, France, 2006.
[85] The IEA scenarios were briefly described, without analysis of their power generation implications, in a previous CERI report entitled " *World Energy: The Past and Possible Futures*" prepared for the Canadian Nuclear Association and printed in February 2008.

This section is divided into two parts. The first reviews the energy scenario assumptions, while the second discusses the future of world power generation and the impact of the various alternative energy technology scenarios.

A.4.1 Energy Scenario Assumptions

The ACT and Tech Plus scenarios focus on key technologies, which have the potential to reduce CO_2 emissions relative to what we are experiencing today. The ACT scenario technologies include renewables, nuclear, CCS, biofuels, and end-use efficiency. The TECH Plus scenario considers the above five technologies plus hydrogen fuel cells.

The macroeconomic and demographic assumptions are the same for all scenarios. World economic growth is taken to be 2.9 per cent per year between 2003 and 2050, with per capita incomes rising 2 per cent per year on average. Energy prices in each scenario reflect scenario-specific changes to energy demand and supply. The distinguishing features of each scenario are presented in Table A.1.

Table A.1
Overview of Scenario Assumptions for ACT and TECH Plus Scenarios

Scenario	Renewables	Nuclear	CCS	H2 fuel cells	Advanced biofuels	End-use efficiency
ACT Map	Relatively optimistic across all technology areas					2.0% p.a global improvement
ACT Low Renewables	Pessimistic slower cost Reductions					
ACT Low Nuclear		Pessimistic Lower public acceptance				
ACT No CCS			No CCS		1.7% p.a global improvement	
ACT Low Efficiency						Pessimistic
TECH Plus	Optimistic Stronger cost reductions	Optimistic Stronger cost reductions & technology improvements		Optimistic Break through for FC	Optimistic Stronger cost reductions & improved feedstock availability	

SOURCE: IEA, Energy Technology Perspectives 2006, P 43

Baseline Scenario: The Energy technology perspective baseline scenario is focused on the current enacted government policies that will affect technology developments and improvements in energy efficiency.

ACT Scenarios: The key features of the **ACT Map** scenario that distinguish this scenario from the others are**:**

- Continuing cost reductions for renewable energy technologies.
- Resolving waste management issues and increasing public acceptance of nuclear power generation expansion.
- Overcoming barriers to the capture and storage of CO_2.
- Achieving steady gains in energy efficiency and improvements in energy use in the transportation, construction, and industrial sectors, due to the adoption and implementation of more energy-efficient technologies.
- Substituting bio-fuels for petroleum products to a greater extent.

ACT Low renewables represents slower cost reductions for wind and solar energy technologies compared to the ACT Map.

ACT Low nuclear represents limited growth for nuclear energy if related waste issues are not resolved satisfactorily.

ACT no CCS assumed the CCS technologies will not become commercially available.

ACT Low Efficiency assumed the global energy efficiency improvements would be 0.3 percentage points per year lower than in the ACT Map scenario.

TECH Plus Scenario: The TECH Plus scenario makes more optimistic assumptions than the ACT Map scenario about progress in overcoming technological barriers. For example, greater cost reductions for fuel cells, more rapid progress in renewable electricity generation technologies, biofuels and nuclear technologies. Under this scenario, the shares of both renewable and nuclear energy in electricity generation will increase, and hydrogen fuel cell vehicles (FCVs) will gain significant market share.

A.4.2 World Power Generation: Future Projections

This section is divided into four sections: Baseline scenario, ACT scenarios, Tech Plus scenario and conclusions.

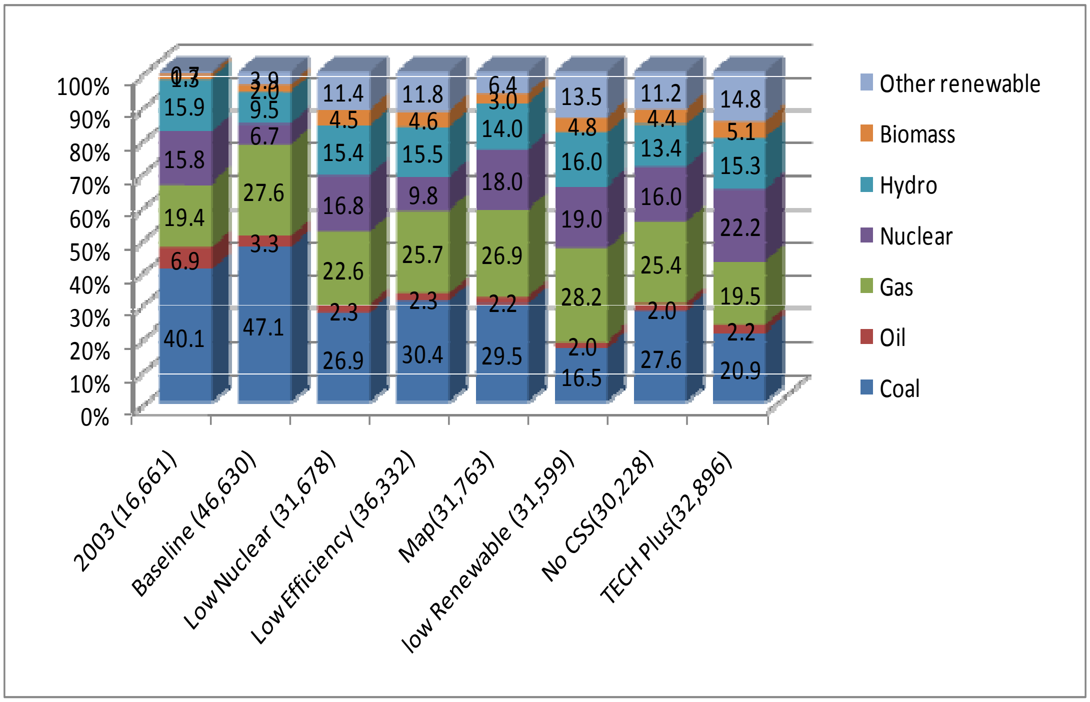
A.4.2.1 Baseline Scenario

In the baseline scenario, electricity demand grows an average of 2.2 per cent per year over the period 2003 to 2050. Many factors impact on the demand for electricity including rapid growth of population and incomes in developing countries, continuing increase in demand for electronic equipment and appliances in the residential and commercial sectors, and expansion of industrial activities.

In this scenario, the trend of coal-fired generation continues because of coal base expansion in developing countries. Moreover, two-thirds of coal-fired plants, which are older than 20 years (29 per cent efficiency), are to be replaced by new, efficient plants (46 per cent) before 2030.

In 2050, the generation of coal-fired plants increases to 21,958 TWh, almost three times the 2003 level. Natural gas generation increases to 12.881 TWh, almost four times the 2003 level. By the end of the forecast period, new reactors replace all of today's nuclear capacity and nuclear base generation reaches 3,107 TWh. The share of resources use for electricity generation in 2003 and 2050 are illustrated in Figure A.13.

Figure A.13
World Electricity Generation by Resources (Percent) in 2003 and 2050 Alternative Scenarios



SOURCE: IEA, Energy Technology Perspectives 2006

A.4.2.2 ACT Scenarios

In the ACT scenario, the share of coal power generation decreases because coal-fired plants are replaced by gas-fired plants or by natural gas combined-cycle plants (NGCC). The NGCC technology emits less than half as much CO_2 as coal-fired plants.

Integrated gasification combined-cycle (IGCC) is another technology, which can process all carbonaceous resources such as coal, petroleum coke, and biomass. This technology can impact fuel switching and improve the plant efficiency in both ACT and TECH Plus scenarios.

In all of the ACT scenarios, gas-based generation remains relatively strong while the share from oil declines in the years between 2003 and 2050.

CO_2 capture and storage is another important technology that enables coal to play a significant role even in a CO_2 constrained world. It is expected CCS technologies will become commercial in the period 2015 to 2020.

In the ACT scenarios, coal-fired plants with and without CCS maintain important market share but significantly lower than the baseline.

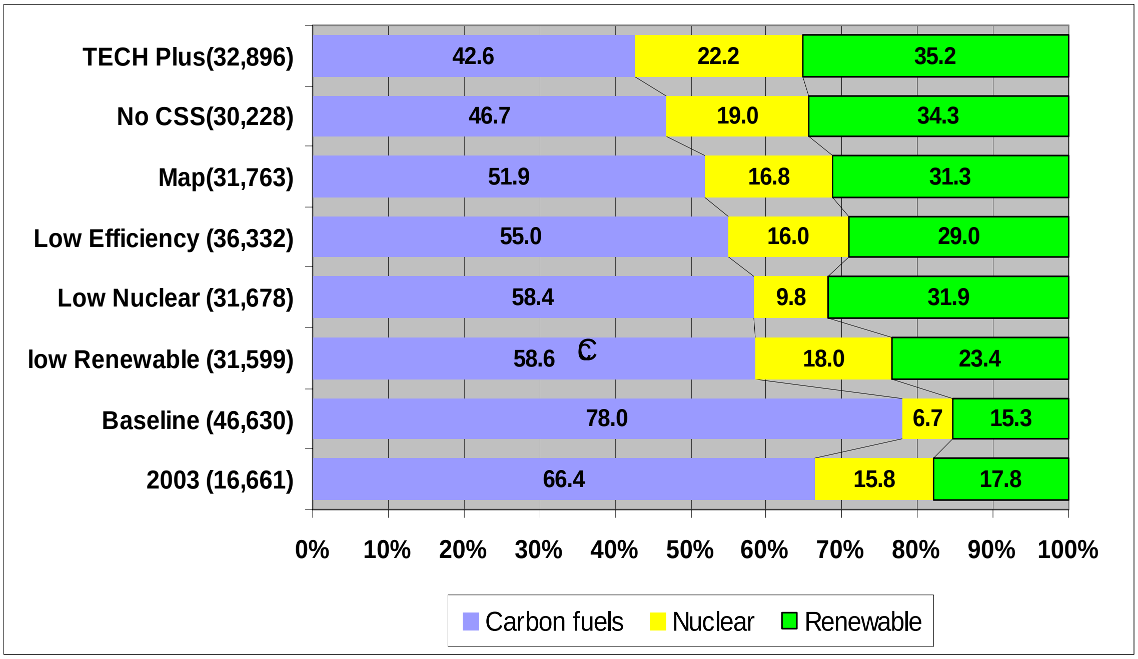
In contrast to the baseline, the nuclear plants in all ACT scenarios play a significant share in electricity generation. In the baseline, the share of nuclear power is projected to be 6.7 per cent in 2050 while in the ACT scenarios the share of nuclear varies from a minimum of 9.8 per cent to a maximum of 19 per cent. In the ACT scenarios, except for the low renewable scenario, electricity generation from hydropower is estimated to be approximately 10 per cent higher than the baseline by 2050. Biomass and other renewables (wind, solar, geothermal, tidal and wave) should see significant growth rates in comparison to the baseline.

A.4.2.3 TECH Plus Scenario

In the TECH Plus scenario, electricity generation is almost 4 per cent higher than in the Map scenario due to the assumption of electricity requirement for hydrogen (hydrogen fuel cells) production. In the Map scenario, the average annual growth rate for electricity demand is approximately 1.4 per cent.

Furthermore, fossil fuel base electricity generation is lower in the TECH Plus scenario than in the ACT Map, but electricity generation from nuclear power and renewables is more than ACT Map (Figure A.14). In the TECH Plus scenario, nuclear base electricity generation in 2050 is 202 per cent higher than the 2003 level.

Figure A.14
Share of Carbon Fuels, Nuclear and Renewable in Electricity Generation in 2003 and 2050 by Alternative Scenarios



SOURCE: IEA, Energy Technology Perspectives 2006

The IEA considers four generation-types for nuclear power:

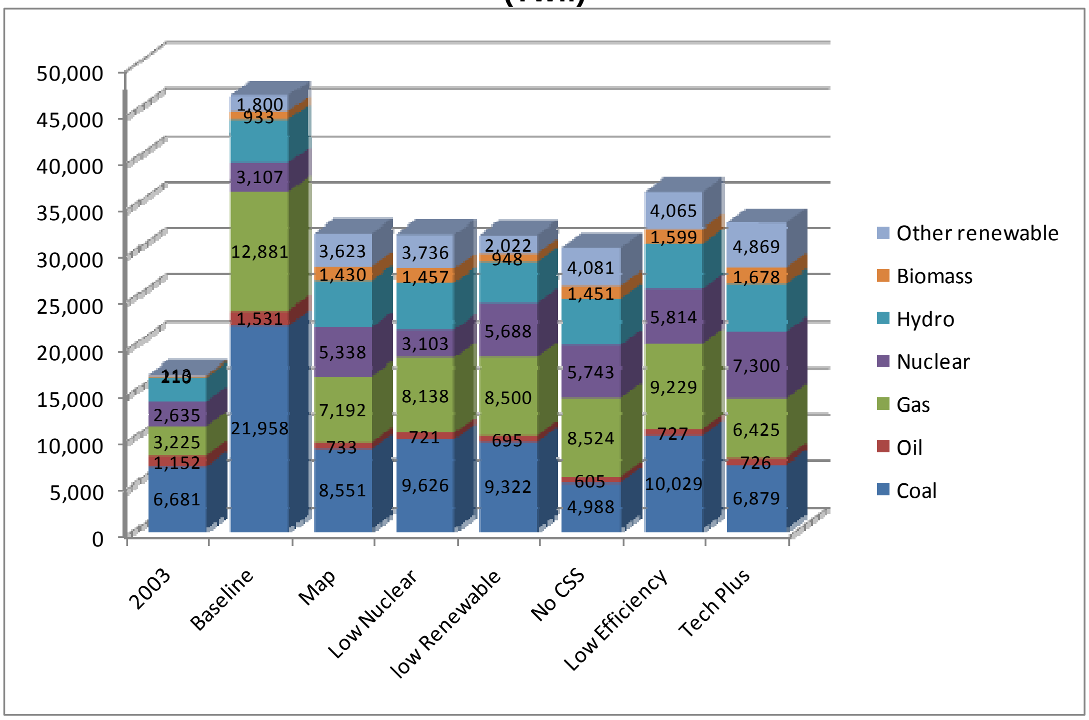
- Historical Generation I (1950s -1960s) represents prototype reactors; most are presently due to be decommissioned.
- Historical Generation II (1970s-1990s) represents commercial reactors.
- Generation III (1995-2010) represents advances in technology and safety, and improved economics. Generation III includes commercial advanced boiling water reactors (ABWR), and advance pressurized water reactors (APWR).
- Generation III+ and Generation IV represent reduction of capital cost, reduction of construction time, longer operating life, and less vulnerability to operational upsets.
- Generation III+ includes the pebble bed modular reactor (PBMR), which can be built in small units, and the AP1000. Generation III+ is assumed to become operational by 2010 and Generation IV is expected to be commercial by 2030.

In the year 2050, Generation II and III reactors, which are part of the assumptions of ACT scenarios, are expected to reduce CO_2 emissions by 1.8 Gt CO_2 per year below the baseline scenario. In the same year, nuclear generation IV that is part of the assumptions of the TECH Plus scenario, is expected to reduce CO_2 emissions by 1.9 GT CO_2 per year below the baseline.

A.4.2.4 Conclusions: World Power Generation

The world power generation in 2003, and the impact of alternative energy technology scenarios on 2050 power generation (TWh) are summarized and presented in Figure A.15.

Figure A.15
World Electricity Generation by Resources in 2003 and 2050 Alternative Scenarios (TWh)



SOURCE: IEA, Energy Technology Perspectives 2006

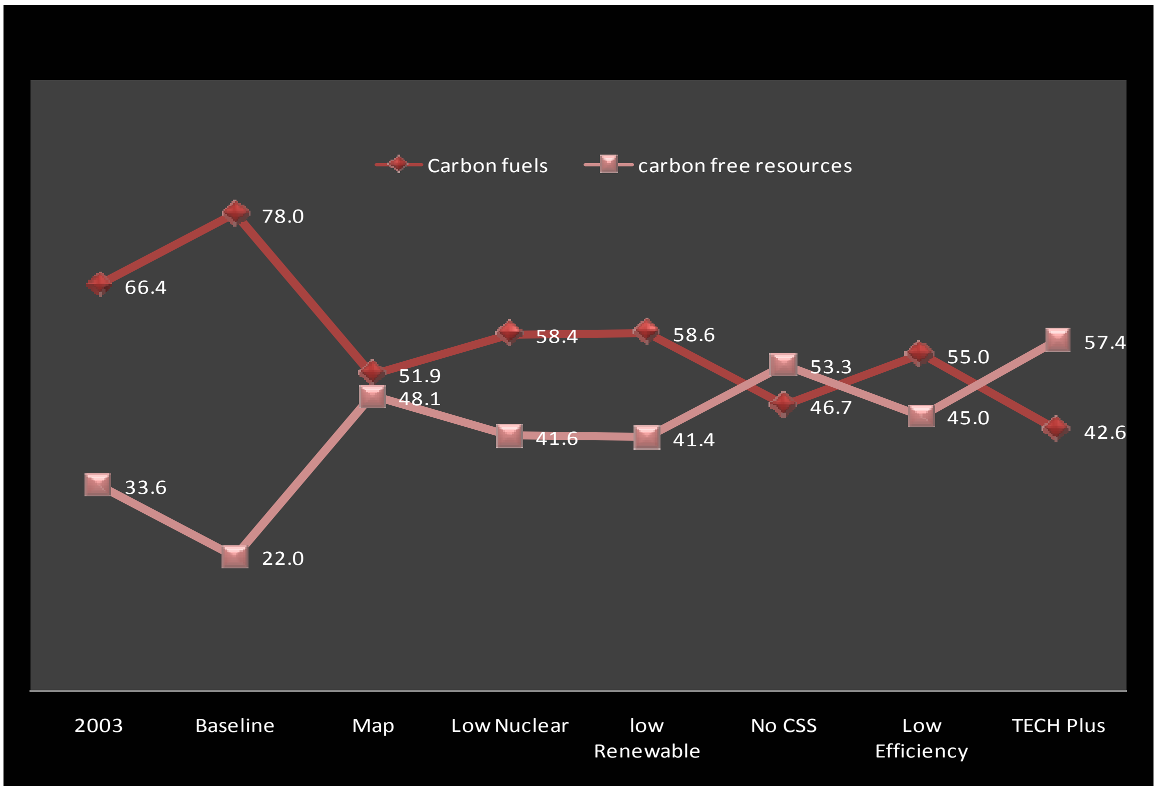
The EIA examines alternative scenarios and technologies for mitigating CO_2 emissions and decarbonization of power generation through fuel switching, improving the efficiency of fossil fuel power plants, and CO_2 capture and storage.

The IEA projects that in the baseline scenario, the carbon fuels for electricity generation in 2050 will increase to 78 per cent, while the share of nuclear will be 6.7 per cent (Figure A.15). Overall, the baseline scenario is a pessimistic scenario for decarbonization (carbon free) of electricity generation.

In the ACT scenarios, substantial decarbonization of electricity supply can be observed as the power generation mix shifts towards nuclear power, renewables, low carbon natural gas, and high carbon coal with CO_2 capture and storage. In the ACT scenarios, the world CO_2 emissions will vary between 6 to 27 per cent above the 2003 level (Figure A.16) by 2050. The ratio of carbon fuels (51.9 per cent) and carbon free resources (48.1 per cent) are very close in the ACT Map scenario.

The TECH Plus is an optimistic scenario: it assumes that the ratio of carbon free resources (57.4 percent) exceeds carbon fuels (42.6) in 2050. The world CO_2 emissions will stabilize about 16 percent below 2003 level, under this scenario.

Figure A.16
Share of Carbon Fuel vs. Carbon Free Resources
Electricity Generation in 2003 and 2050
Baseline and other Scenarios



A.5 Power Generation in Canada: Future Projections

The objective of this section is to examine the future share of carbon fuels and carbon free resources particularly nuclear in Canadian electricity generation. For this purpose we focused on the National Energy Board (NEB) report entitled "Canada's Energy Future, Reference Case and Scenario to 2030".

The report reviews important economic, demographic and energy factors which influence long-term energy demand and supply outlook. The NEB by developing a reference case (2005 to 2015) and three scenarios (2005 to 2030) examines the impact of alternative energy prices and economic growth rates on energy demand, supply and their associated GHG emissions. The three scenarios are named "Continuing Trends", "Triple E" and "Fortified Islands".

The aim of reference case and scenario analysis is to give a picture of the possible future energy states by the year 2015 and 2030 in comparison with the actual data of year 2004. The scenario analysis will determine the degree and direction of change in energy supply and demand including electricity.

As such, this section is divided into five sections: reference case, continuing trends, triple E, fortified islands and conclusions.

A.5.1 Reference Case

The reference case is the most likely scenario that deals with a medium–term outlook from 2004 to 2015. The reference case assumes strong GDP growth rate and consequently strong macro economic outlook (Table A.2). Over the period 2004 to 2015, energy demand will grow on average by 1.8 per cent and electricity generation capacity (115,907 MW) by almost 2 per cent per year.

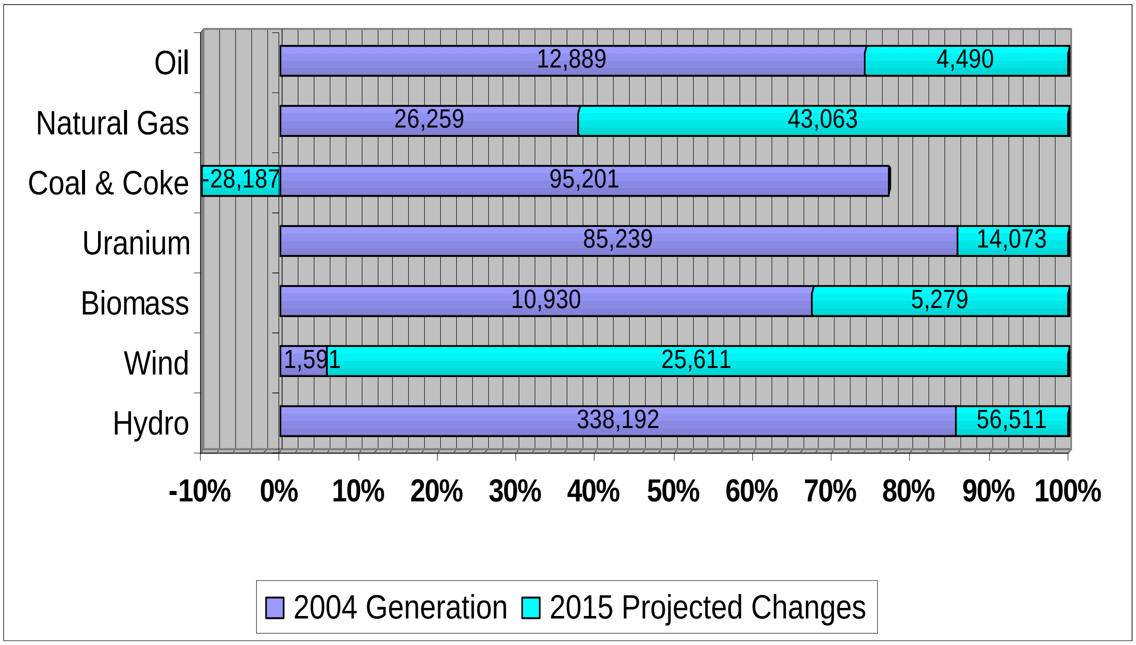
Table A.2
Summary of key Assumptions and Quantitative Results
Reference Case and Three scenarios

	Key Assumptions		**Quantitative Results**		
	Real GDP	Energy Prices	Energy Demand	Oil & Gas Production	GHG Emissions
Reference Case (2005-2015)	2.9 per cent	Oil: $50/bbl Gas: $7/MMBtu	1.8 per cent	Oil: 4.4 per cent Gas: -0.9 per cent	1.5 per cent
Continuing Trends (2005-2030)	2.5 per cent	Oil: $50/bbl Gas: $7/MMBtu	1.4 per cent	Oil: 2.3 per cent Gas: -1.8 per cent	1.2 per cent
Triple E (2005-2030)	2.2 per cent	Oil: $35/bbl Gas: $5.50/MMBtu	0.3 per cent	Oil: 0.7 percent Gas: -4.8 percent	-0.1 per cent
Fortified Islands (2005-2030)	1.8 per cent	Oil: $85/bbl Gas: $12/MMBtu	0.7 per cent	Oil: 3.0 per cent Gas: 0.4 per cent	0.6 per cent

SOURCE: NEB, Canada’s Energy Future, Reference Case & Scenarios to 2030.

The NEB projected that total electricity generation will increase from 570,301 GWh in 2004 to 691,141 GWh in 2015 representing average annual growth rate of 1.7 per cent. Over the same period, the NEB projects that the electricity generation from coal and cokes will decrease by 28,187 GWh (Figure A.17). As a result, the share of coal in electricity generation will decline from 16.6 per cent in 2004 to almost 9.6 per cent in 2015. The largest reduction in coal-fired generation is expected to occur in Ontario, while new conventional coal-fired generation is likely to be constructed in Alberta, Nova Scotia and Saskatchewan.

Figure A.17
Reference Case - 2004 Canada Electricity Generation and 2015 Projected Changes by Fuel (GWh)



Hydro includes Wave & Tidal
Biomass includes Landfill Gas & Waste
SOURCE: NEB - Canada's Energy Future, Reference Case and Scenario to 2030

In this scenario the generation share from all other sources is increasing. For example, electricity generation from nuclear will increase from 85,239 GWh in 2004 to 99,312 GWh in 2015. The sources of additional nuclear generations are (2,650 MW capacity) new CANDU reactors and return two Ontario's Bruce A units to the operation.

- The Ontario's Bruce "A" with four reactors had a combined generation capacity of 3,000 MW. They were commissioned between 1977 and 1979 but during 1995 and 1998 all four reactors were removed from service. Later, two of the reactors were returned back to service. It is planned the other two reactors each with capacity of 825 MW return to service in 2009 and 2010.

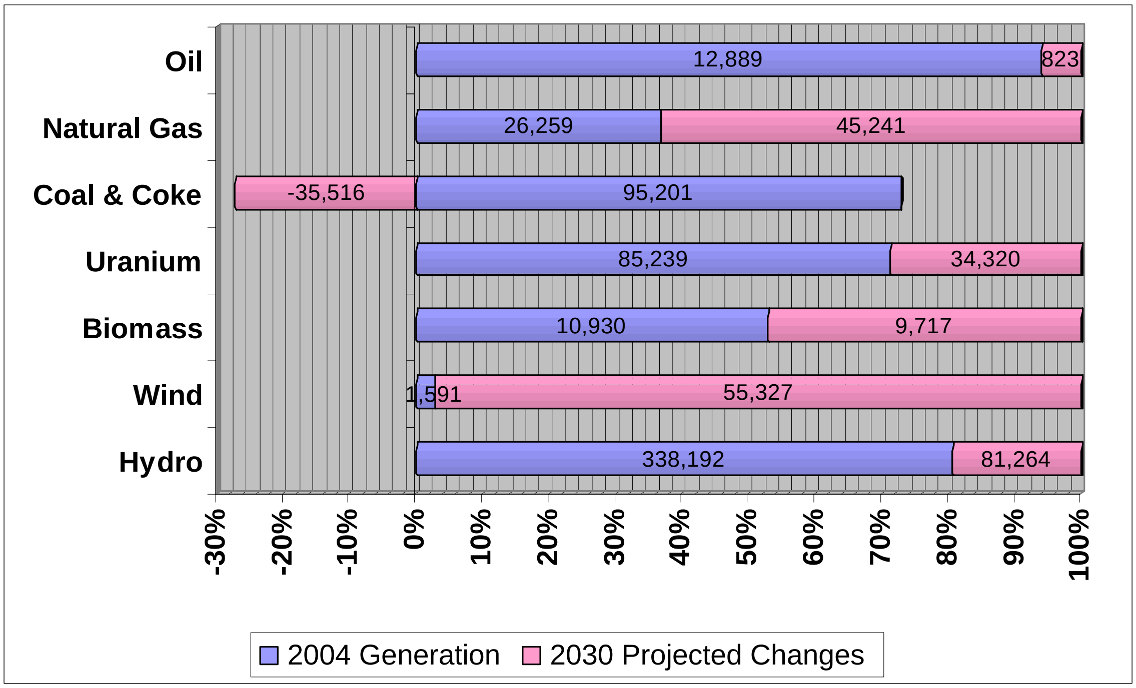
- Quebec's Gentilly 2 and New Brunswick's Point Lepreau generating stations, each with capacity of 635 MW, are assumed to be refurbished before 2015.

A.5.2 Continuing Trends

In this scenario, Canada experiences strong economic growth along with moderate oil and gas prices. The economic growth will guarantee Canadian energy demand growth and consequently robust energy production. The trend of greenhouse gas emissions will decline mainly through improvements in energy efficiency (business as usual).

In the continuing trends scenario, total electricity generation increases from 570,301 GWh in 2004 to 761,477 GWh in 2030 representing an average annual growth rate of slightly more than 1 per cent (Figure A.18). Furthermore, the strong demand for electricity will encourage electricity generation from renewable.

Figure A.18
Continuing Trend Scenario - 2004 Canada Electricity Generation and 2030 Projected Changes by Fuel (GWh)



Hydro includes Wave & Tidal
Biomass includes Landfill Gas & Waste
SOURCE: NEB - Canada's Energy Future, Reference Case and Scenario to 2030

During 2004 to 2030, the contribution of coal and coke in electricity generation will decline. In 2030, the level of electricity generation from coal and coke will be reduced by 35,516 GWh. In the same year, the electricity generation from wind, hydro, biomass, natural gas and uranium will offset the declining impact of the coal and coke.

In the continuing trends scenario, the contribution of nuclear power is significantly larger than the other two scenarios. From 2004 to 2030 approximately 5,650 MW will be added to the nuclear capacity and nuclear generation increases from 85,239 GWh in 2004 to 119,559 GWh in 2030. About 2,650 MW of the above capacity was explained under the reference case (2004 to 2015). The remaining additional capacities (2016 to 2030) are as follows:

- Pickering station A (units 1 to 4) went to operation during 1971 to 1973, and currently 2 of them are operational. Pickering Station B (units 5 to 8) went to operation during 1983 to

1986 and all 4 units are currently operational. It is expected that the two 1,000 MW units come to the market in years 2028 and 2030, when the two units at Pickering station A are retired.

- A 1,000 MW Advanced Canadian Reactor (ACR) is expected in New Brunswick to come to the market in 2024, with the retiring oil and Orimulsion fired steam units.

A.5.3 Triple E Scenario

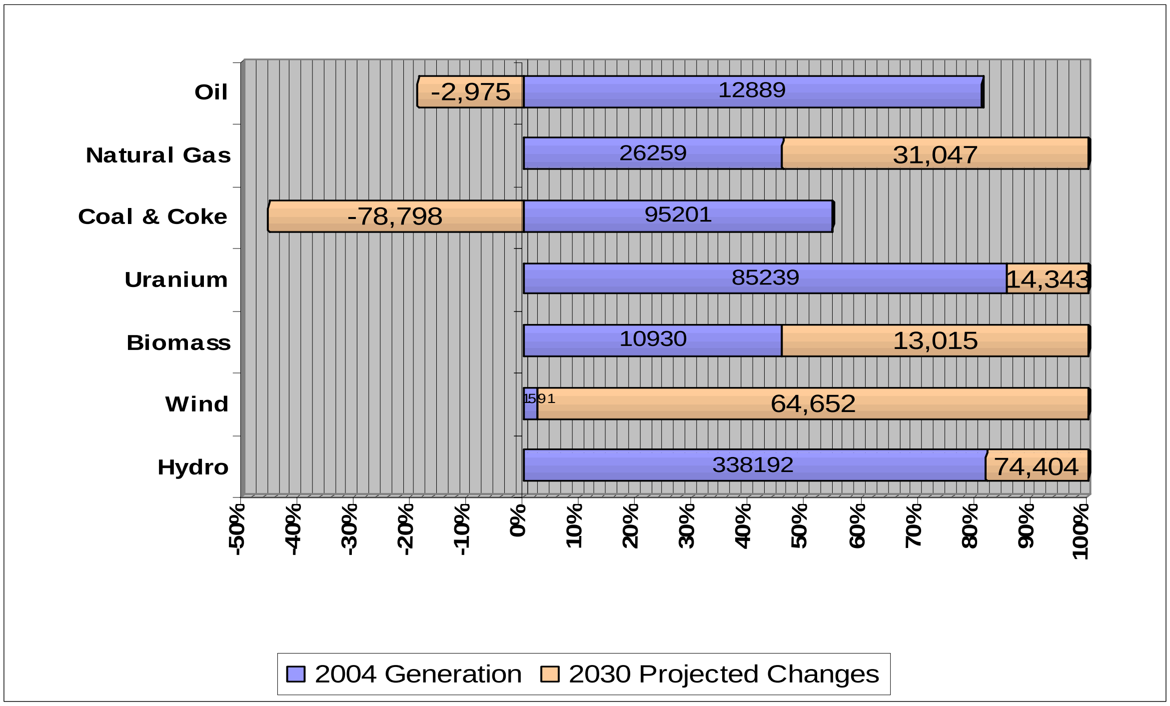
The name of this scenario is taken from balance of triple E namely economic, environment, and energy. This scenario represents a modest economic growth rate (2.2 per cent) with the low oil and gas prices. In this scenario GHG emissions decline due to energy demand growth rate of 0.3 per cent (2004 to 2030), which is substantially lower than the historical growth rate of 1.8 per cent. The major factors that influence low energy demand growth rate are energy efficiency, conservation, shift to less carbon-intensive fuels (ethanol and biodiesel), as well as energy demand management programs and policies.

In this scenario, total electricity generation increases from 570,301 GWh in 2004 to 685.989 GWh in 2030 representing an average annual growth rate of almost 0.7 per cent (Figure A.19).

In the triple E (environmental scenario), the contribution of carbon intensive fuels such as coal and coke in electricity generation will decline by 78,798 GWh and oil by 2,975 GWh in 2030 in comparison to 2004. The electricity generation from renewable sources, natural gas and nuclear will offset the declining impact of the carbon intensive fuels.

In 2030, generation of electricity from nuclear power will increase by 14,343 GWh in comparison to 2004. The assumptions of nuclear capacity are the same as continuing trends scenario.

Figure A.19
Triple E Scenario - 2004 Canada Electricity Generation And 2030 Projected Changes by Fuel (GWh)



Hydro includes Wave & Tidal
Biomass includes Landfill Gas & Waste
SOURCE: NEB - Canada's Energy Future, Reference Case and Scenario to 2030

A.5.4 Fortified Islands

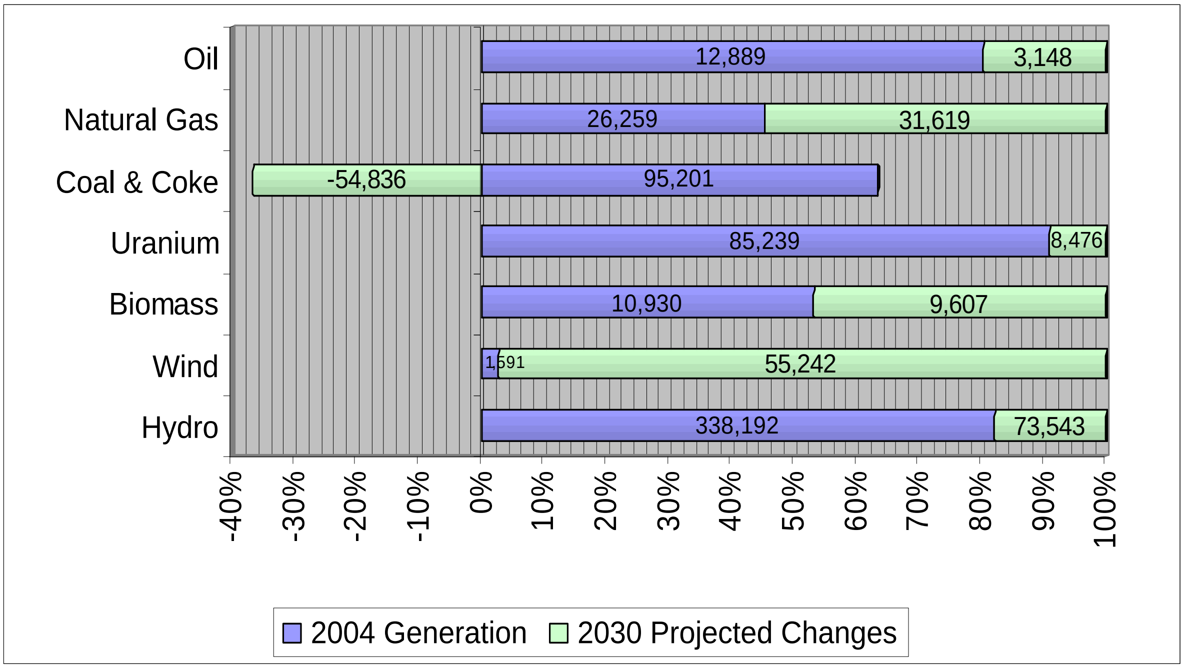
In this scenario, energy supply issues will put upward pressure on energy prices and consequently low growth rate of energy demand (0.7 per cent). The fortified islands scenario portrays the highest oil and gas prices in comparison to other scenarios.

The interaction of the above factors will cause low Canadian economic growth rate (1.8 per cent), lower electricity demand (after 2020) and consequently low GHG emissions (0.6 per cent). Electricity generation will increase from 570,031 GWh in 2004 to 697,100 GWh in 2030 (Figure A.20).

In this scenario, electricity generation from coal and coke will reduce by 54,836 GWh in 2030 in comparison to 2004. However, additional electricity generation from other sources particularly from renewable will offset the impact of additional demand as well as the decline in electricity generation from coal and coke.

In fortified islands scenario, the generation of electricity from nuclear power will increase by 8,476 GWh in 2030 in comparison to 2004 where the assumptions of nuclear capacity are the same as continuing trends scenario.

Figure A.20
Fortified Islands Scenario - 2004 Canada Electricity Generation And 2030 Projected Changes by Fuel (GWh)



Hydro includes Wave & Tidal
Biomass includes Landfill Gas & Waste
SOURCE: NEB - Canada's Energy Future, Reference Case and Scenario to 2030

A.5.5 Conclusions

The reference case and scenarios (continuing trend, triple E, and fortified islands) are distinguished by key assumptions of energy prices, and economic growth rates. Both of the above assumptions influence on Canadian energy supply and demand including electricity generation and their associated GHG emissions.

Electricity generations among scenarios, show a variation from minimum 691,000 GWh to maximum 761,000 GWh in 2030. The contribution of electricity generation from coal and coke has been predicted to decline from minimum 35,516 GWh to maximum 78,798 GWh in 2030. The contribution of oil is also expected to reduce by 2,975 GWh (triple E scenario) in 2030. Table A.3 shows a summary of electricity generation by resources.

Although, the electricity generation from nuclear power varies among the scenarios, their capacity expansion is the same. Under all three scenarios the capacity of electricity generation from nuclear power will increase by 5,650 MW in 2030. The details of capacity expansion are summarized as follows:

- The two reactors of Ontario's Bruce "A" each with capacity of 825 MW (removed from services in 1995) is expected return to service in 2009 and 2010.
- A new CANDU rector with capacity of 1000 MW is expected to be replaced with the Ontario retiring coal units in 2015.
- A new Advanced Canadian Reactor with capacity of 1000 MW is expected to be replaced with the New Brunswick retiring oil and Orimulsion fried steam units in 2024.
- Two new 1000 MW units are expected to replace in 2028 and 2030 with two Ontario Pickering station "A" retiring units.

In 2030, the generation of electricity from nuclear power is predicted to vary from 93,715 GWh to 119,559 GWh, where their shares vary from 13.44 per cent to 15.70 per cent.

Table A.3
Projection of Canadian Electricity Generation by Resources
Reference case and Three Scenarios

Electricity Generation by Fuel - GW.h					
Resources	**2004**	**Reference Case 2015**	**Continuing Trends 2030**	**Triple-E 2030**	**Fortified Islands 2030**
Hydro	338,192	394,703	419,456	412,596	411,735
Wind	1,591	27,202	56,918	66,243	56,833
Biomass	10,930	16,209	20,647	23,945	20,537
Uranium	85,239	99,312	119,559	99,582	93,715
Coal & Coke	95,201	67,014	59,686	16,404	40,366
Natural Gas	26,259	69,321	71,500	57,305	57,878
Oil	12,889	17,379	13,712	9,914	16,036
Total	**570,301**	**691,141**	**761,477**	**686,305***	**697,100**
Share of Electricity Generation					
Hydro	59.30	57.11	55.08	60.12	59.06
Wind	0.28	3.94	7.47	9.65	8.15
Biomass	1.92	2.35	2.71	3.49	2.95
Uranium	14.95	14.37	15.70	14.51	13.44
Coal & Coke	16.69	9.70	7.84	2.39	5.79
Natural Gas	4.60	10.03	9.39	8.35	8.30
Oil	2.26	2.51	1.80	1.44	2.30
Total	**100.00**	**100.00**	**100.00**	**99.95**	**100.00**

* includes other (316 GWh)
SOURCE: NEB - Canada's Energy Future, Reference Case and Scenario to 2030

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APPENDIX B
NUCLEAR POWER IN CANADA

Appendix B is complementary to Chapter 3, Nuclear Power in Canada. This appendix is divided into two parts. The first discusses nuclear research in Canada, which is conducted by a number of bodies including: Atomic Energy of Canada Limited (AECL), the CANDU Operators Group (COG), and the National Research Council (NRC), nuclear power generating companies, MDS Nordion, several private sector companies, universities, and other institutions. This section also reviews Canada's research reactors.

The second part steps away from power generation to examine various significant nuclear products. While the production of nuclear electricity is a key activity in the Canadian economy, there are also a number of important nuclear products either being developed or used in Canada. In areas such as medicine, nuclear products are saving lives; in agriculture they are increasing crop yields. Manufacturers use nuclear products to strengthen plastics and bond composites. This section will discuss medical isotopes and the main global producer, MDS Nordion. It will also briefly discuss electron beam technology, neutron radiology, food irradiation, insect sterilization and other common uses of nuclear products.

B.1 Research and Development

Nuclear research in Canada is conducted by a number of bodies including: AECL, CANDU Operators Group (COG), the National Research Council (NRC), the nuclear power generating companies, MDS Nordion, other private sector companies, universities and other institutions.

B.1.1 Atomic Energy of Canada Limited (AECL)

Canada has a long, rich history in the field of peaceful nuclear energy and the AECL has been Canada's main nuclear body of research since the 1950s. With the conclusion of World War II, the Government of Canada eschewed any aspirations to become a nuclear power and, subsequently, embarked on the development of peaceful uses of nuclear technology. In 1952, AECL was created to take over the Chalk River Nuclear Laboratories from the National Research Council. With Chalk River the hub of research and development, AECL was charged with the development of technology for nuclear electricity generation. AECL's research and development program included work needed to ensure that the CANDU technology had a solid technical base, and applied programs that resulted in qualification of equipment, processes and systems for power and research reactors.[86] AECL's research has focused primarily on eight key technologies:

- safety;
- fuel and fuel cycles;
- fuel channels;

[86] CERI, "Economic Impact of the Nuclear Industry in Canada", submitted to CNA, Sept. 2003, p. 9.

- components and systems;
- heavy water production and processing;
- environment, emissions and waste management;
- control and information; and
- constructability.

The NRU (National Research Universal) reactor started up in 1957, soon after the creation of AECL. At nearly 200 MWt, the NRU was a much larger reactor than the NRX. The NRU, also located at Chalk River, is still known for its versatility and high neutron flux.[87] Like its predecessor, the NRU uses natural uranium and is heavy-water-moderated. According to the Canadian Neutron Beam Center, there are plans to further refurbish the NRU, enabling operation to continue to around 2012.

Following the mandate to develop nuclear energy for peaceful purposes, the first nuclear electricity generation in Canada occurred in 1962 at the Rolphton NPD (Nuclear Power Demonstration) plant. The NPD, also located near Chalk River, was the first CANDU-type reactor. Using heavy water technology and natural uranium, the reactor was designed and constructed jointly by Ontario Hydro (now Ontario Power Generation), Canadian General Electric (G.E. Canada Inc.), and AECL.[88] The unique benefit of AECL's CANDU reactor technology is its ability to use uranium enriched to a lesser extent than other nuclear reactor technologies, thus making fuel acquisition, preparation, and handling cheaper and safer.[89] The reactor ushered in a new era of commercial reactors and was shut down in 1987.

Douglas Point, which commenced operating in late 1966, followed the Rolphton NPD plant. The large prototype CANDU reactor had a net-installed-capacity of 208 MW and was removed from service in 1984. As discussed in the previous section, Pickering A's four units went into operation between 1971 and 1973 and Bruce A, a station with four 900 MW class units, came on-line in 1977. More CANDUs were constructed during the 1980s: a 600 MW class unit at Point Lepreau, New Brunswick; a similar unit at Gentilly, Quebec; four 600 MW class units at Pickering B in Ontario; and four 900 MW class units at Bruce B in Ontario. As well, the four 935 MW units at Darlington station in Ontario were completed in 1993.

Prior to the 1990s, AECL had built and sold four reactors outside of Canada (see Table B.1), two in India (1972 and 1980), one in South Korea (1983), and one in Argentina (1984). AECL has built seven additional reactors outside Canada since the late 1990's: three in South Korea, two in China (two 728 MWe reactors at Qinshan in eastern China) and two in Romania (Cernavoda 1 & 2). The second unit was commissioned in November, 2007. Romania is considering a third CANDU unit at the same location. It is also important to note that the Rajastan 1 is currently laid-up. The future of this unit has not been revealed by the Nuclear Power Corporation of India Limited (NPCIL).

[87] http://science.uwaterloo.ca/~cchieh/cact/nuctek/canhistory.html
[88] Bothwell, Robert, "Nucleus: The History of Atomic Energy of Canada Limited", pp. 228-232.
[89] Timilsina, Govinda et al., "GHG Emissions and Mitigation Measures for the Oil & Gas Industry in Alberta", CERI, 2006.

Table B.1
CANDU Reactors Outside of Canada

Reactor	Country	Capacity (net MW)	Year in Service
Rajastan 1	India	1 x 90	1972
Rajastan 2	India	1 x 187	1980
Wolsong 1	South Korea	1 x 629	1983
Wolsong 2	South Korea	1 x 629	1997
Wolsong 3	South Korea	1 x 629	1998
Wolsong 4	South Korea	1 x 629	1999
Embalse	Argentina	1 x 600	1984
Cernavoda 1	Romania	1 x 655	1996
Cernavoda 2	Romania	1 x 650	2007
Qinshan 1	China	1 x 728	2002
Qinshan 2	China	1 x 728	2003

Sources: International Energy Agency, Energy Policies of IEA Countries: Canada 2004 Review, p. 142; http://www.world-nuclear.org

China has ten nuclear generating units in operation, two of them employing CANDU technology. China has a total installed capacity of 7,572 MWe, but is embarking upon an ambitious nuclear construction program. According to the WNA, China is planning to increase its nuclear capacity fivefold by 2020. China has developed its own nuclear design and construction capability, although it also encourages international cooperation. It has selected PWR as the main, but not sole, reactor type. The 1000-MWe Tianwan-1 began operation in May 2006 while the Tianwan-2 began operation in August 2007. South Korea has 20 nuclear units on line (four of them employing CANDU technology) totaling 16,840 MW. Currently, four additional units are under construction and a further four are planned to come on stream by 2015, none of which are PHWR. Argentina is also constructing a PHWR reactor, the Atucha-2, which is to be completed in 2010.

In 1994, the federal government altered AECL's mandate, requiring it to concentrate on "its role as a reactor designer and vendor".[90] In addition, AECL was forced to streamline operations to make it more cost-effective.

AECL is still responsible for most nuclear R&D occurring in Canada, and it develops markets and manages the construction of CANDU power reactors, one of AECL's core business products. AECL also provides engineering and consulting services to owners of CANDU reactors and other reactors at home and abroad, and offers radioactive waste management products and services.

Sales of CANDU reactors abroad have a positive impact on AECL and the Canadian economy to the extent that goods and services used in their construction are imported from Canada. In addition, a number of the reactor components are manufactured in Canada. When CANDU reactors are exported there is a positive economic impact on Canada as AECL receives license fees and sells its project management and other consulting services to the importing country.

[90] AECL, "Report of the AECL Research & Development Advisory Panel for 2001". p. 8.

The AECL R&D program includes work needed to ensure that CANDU technology maintains a solid technical base, and applied programs that result in qualification of equipment, processes and systems for power and research reactors.

AECL is currently pursuing detailed work on a "next generation" design of the CANDU Reactor – the ACR-1000. This new design is expected to have lower capital cost, shorter construction time, and less production of waste than the current generation of CANDUs.

B.1.2 CANDU Operators Group (COG)

To aid in nuclear research, COG was formed in 1984 by an agreement among the Canadian CANDU-owning utilities Ontario Hydro (now Ontario Power Generation), Hydro-Québec and New Brunswick Power, plus AECL. The purpose of COG is to provide programs for co-operation, mutual assistance and exchange of information for the successful support, development, operation, maintenance and economics of CANDU technology. The foreign organizations that own CANDU units are now also members of COG.

Under the original agreement, the former Ontario Hydro was the administrator of COG, reporting to a Directing Committee comprised of representatives of the four Canadian Members. However, in 1999 COG was registered as a not-for-profit corporation, and a Board of Directors was appointed to replace the previous Directing Committee. In 2001, Bruce Power joined COG as an independent Canadian member. COG membership includes six Canadian and six offshore members (Argentina, Romania, Pakistan, India, South Korea and, most recently, China).

The COG Research & Development Program addresses current and emerging operating issues to support the safe, reliable and economic operation of CANDU reactors in the areas of safety and licensing, fuel channels, health and environment, and chemistry, materials and components.

B.1.3 National Research Council (NRC)

The NRC operates a neutron beam laboratory at Chalk River, not as a facility for "nuclear R&D" as such, but to use neutrons from the Chalk River nuclear research reactor to probe materials of all kinds to extract information about molecular structures and dynamics.

The NRC operates a suite of five neutron beam instruments as an international facility to which researchers and students travel to carry out experimental measurements on a wide range of materials in all physical science disciplines. In addition, this laboratory operates as a centre for the training of highly qualified personnel. It supports graduate student research (about 40 graduate student research visitors each year), and projects by post-doctoral and other young researchers from universities across Canada and abroad.

B.1.4 Research Reactors

There are currently eight operating research reactors in Canada: two at AECL's Chalk River Laboratories and six at universities. These non-power reactors, shown in Table B.2, have a wide range of uses, including analysis and testing of materials and production of radioisotopes.

Table B.2
Research Reactors in Canada

Non-Power Reactors	Annual Operating Cost ($CDN Million)	Thermal Power (kW)	Owner	Criticality Date
Chalk River (NRU)	20	135,000	AECL	1957
Chalk River (ZED-2)	.3	0.2	AECL	1960
Chalk River (MMIR-1)	n/a	10,000	Nordion Int'l Inc.	n/a
Chalk River (MMIR-2)	n/a	10,000	Nordion Int'l Inc.	n/a
McMaster University (MTR-type)	1.1	5,000	McMaster University	1959
Ecole Polytechnique (Slowpoke-2)	.22	20	University of Montreal	1976
Dalhousie University (Slowpoke-2)	.12	20	Dalhousie University	1976
Saskatchewan Research Council (Slowpoke-2)	.05	20	SRC	1981
University of Alberta (Slowpoke-2)	0.1	20	University of Alberta	1977
Royal Military College of Canada (Slowpoke-2)	1	20	RMC	1985

SOURCE: International Atomic Energy Agency (IAEA) http://www.iaea.org/worldatom/rrdb/. Accessed March 2008.

While research reactors comprise a wide range of civil and commercial nuclear reactors, often the primary purpose of research reactors is to provide a neutron source for research and other non-power related purposes. The following section reviews briefly Canada's research reactors and their principle function.

The Chalk River reactors are, for research purposes, categorized as industry reactors. The Chalk River reactors are the 135 MWt NRU and a zero-energy test reactor called the ZED-2. The latter is a small 250 Wt reactor. Chalk River is an important hub for AECL's R&D activities. Recall the development of CANDU reactors started in Chalk River, an evolution from the creation of the ZEEP, NRX and NRU reactors. Other important developments in nuclear physics occurring in Chalk River are the first phase of Tandem Accelerator and Super Conducting Cyclotron (TASCC) completed and entered into operation in 1991, as well as the Tri University Meson Facility (TRIUMF), established in 1975 by physicists in Chalk River to conduct particle physics in Canada. Incidentally, this facility operates in collaboration with the University of British Columbia, the University of Victoria, Simon Frasier University, and the University of Alberta, creating ion beams shot onto special targets to study the subatomic fragments that result from collision. TRIUMF produces radioisotopes such as cobalt-57, gallium-67, and indium-111. MDS Nordion in turn markets these radioisotopes.

Chalk River is also the site of AECL's latest research reactor technology. The MMIR 1 and 2, better known as MAPLE 1 & 2, are 10 MW each. The MAPLE (Multipurpose Applied Physics Lattice Experiment) project was a joint collaboration by the AECL and MDS Nordion, the world's leading supplier of medical isotopes. This project was cancelled in 2008. The MMIR-1 was expected to become operational in October 2008, but further delays were anticipated due to the reactor's positive power coefficient.[91]

The twin reactors would have been able to meet the world's demand for medical isotopes, including Molybdemum-99, medical Cobalt-60, Xenon-133, Iodine-131 and Iodine-125.[92] The MAPLE was a pool-type reactor with a compact core of low-enriched uranium fuel surrounded by a vessel of heavy water.

The university research reactors include five 20 kWt SLOWPOKE-2[93] reactors and one 5 MWt MTR-type reactor.[94] The 20 kWt reactors are located at the University of Alberta (Edmonton), Saskatchewan Research Council (Saskatoon), Royal Military College (Kingston), Dalhousie University (Halifax), and L'Ecole Polytechnique (Montreal). The 5 MWt MTR-type reactor is located at McMaster University (Hamilton). A Canadian-supplied SLOWPOKE-2 is also operated at the Centre for Nuclear Sciences in Kingston, Jamaica, and an additional two SLOWPOKE-2 units - the original prototype at the University of Toronto and one at MDS Nordion's facility in Kanata - have been shut down. AECL also designed a scaled-up version (2-10 MWt) of SLOWPOKE for district heating.

Radioactive isotopes are produced in abundance using the SLOWPOKE reactors; some radioisotopes are sold for use in medicine, science and industry. Canada is the world's largest supplier of molybdenum-99 & cobalt-60. In fact, researchers use these reactors to study a broad range of problems, including issues in archaeology, material science, fusion research and environmental science. This chapter will most closely review the benefits of SLOWPOKE nuclear R&D on medical science.

The reactor at McMaster University, often called McMaster Nuclear Reactor (MNR), is the only research reactor in Canada that is not a SLOWPOKE-2. The 5 MWt pool-type reactor has the highest flux of any university reactor in Canada. As a multidisciplinary facility, McMaster University is home to research in a variety of areas in nuclear science, engineering, and health and radiation physics. The experiments in the facility include neutron beam, isotope production, neutron activation research, and neutron radiography research.

[91] http://www.magma.ca/~drcanrt/aeclmaple4more.htm
[92] http://www.nuclearfaq.ca/cnf_sectionH.htm#g
[93] The SLOWPOKE-2 is a low-energy, pool-type research reactor designed by AECL. It uses passive cooling and safety systems, and is licensed to run unattended for short periods of time (e.g. overnight).
[94] http://www.cns-snc.ca/nuclear_info/canadareactormap.gif

B.2 Other Nuclear Products

There are a number of other important nuclear products either being developed or used in Canada. In areas such as medicine, nuclear products are saving lives; in agriculture they are increasing crop yields. Manufacturers use nuclear products to strengthen plastics and bond composites. Canadians may also find radioactive materials in photocopiers, smoke detectors, watches, and other items in daily use. The importance of several of these nuclear products was reviewed briefly in the previous section discussing Canada's research reactors. This section will briefly discuss other important products using nuclear technology, such as medical isotopes, electron beam technology, neutron radiology, food irradiation and insect sterilization.

B.2.1 Medical Isotopes

The main producer of isotopes in Canada is MDS Nordion, a company formed originally in 1946 as the radium sales department of Eldorado Mining and Refining (1944) Ltd. The department was soon transferred to AECL and began to market a variety of radioisotopes produced at the NRC's reactor at Chalk River. As a result of research and development conducted at AECL, the division began to produce isotopes for commercial use in 1972. In 1991 the commercial products division of AECL – known as Nordion International Inc. – was sold to MDS Health Group. It is now known as MDS Nordion, and is the world's leading supplier of medical isotopes.

MDS Nordion specializes in radioisotopes, radiation and related technologies used to diagnose, prevent, and treat disease in over 70 countries. MDS Nordion supplies over two-thirds of the world's medical isotopes. An estimated 15 to 20 million nuclear medicine imaging and therapeutic procedures are performed globally each year.

Canada accounts for some 75 percent of the world supply of cobalt-60, which is produced by irradiating naturally occurring cobalt-59 with neutrons. There are an estimated 1,200 cobalt-60 machines around the world, delivering about 15 million cancer treatments each year.

B.2.2 Electron Beam Technology

Acsion Industries Inc. of Pinawa, Manitoba markets electron beam technology for use in sterilization and processing. In addition to sterilization, electron beam technology serves the healthcare market through the cross-linking of medical plastics to improve performance properties such as stiffness of catheters and the wear properties of artificial joints. This technology is also used in the aerospace market for both manufacture and repair of composite and metal bonded structures, including flight control surfaces, fairing panels, engine cowls, duct work and interior passenger and cargo compartment floor panels.

B.2.3 Neutron Radiography

Nray Services Inc. of Dundas, Manitoba, a spin-off from AECL, specializes in neutron radiography, a non-destructive testing technique that serves as an alternative to x-ray and ultrasound testing methods. Among the applications to date are reliability testing of detonators in explosive devices; testing of explosives for presence of transmitters and receivers; testing for cracks, inclusions, voids, bubbles, density variations and misalignments, determining bonding flaws in adhesives, inspecting radioactive objects, inspection of artifacts from archaeological digs, testing for aluminum corrosion products, and testing for missing or misplaced o-rings.

B.2.4 Food Irradiation

Food irradiation is widely practiced, and makes food safer by eliminating such harmful bacteria as E. coli 0157:H7, salmonella, campylobacter, and listeria monocytogenes. It also provides quarantine treatments for fruits and vegetables to ensure that insect pests are not transported across borders and extends the shelf life of foods by destroying micro-organisms that cause spoilage, by slowing the ripening process and by inhibiting the sprouting of root vegetables such as potatoes and onions. Irradiation has been approved for more than 50 food products in 40 countries. Cobalt-60 is often used as the source of radiation, in a process resembling the X-raying of luggage at airports.

B.2.5 Insect Sterilization

In agriculture, harmful insects can be eliminated through sterilization of the males of the species using radiation. This approach has been used to bring the codling moth in British Columbia's apple orchards under control. Nuclear techniques are also used to measure the efficiency of fertilizer use by crops, and to monitor crop moisture content.

APPENDIX C

Appendix C provides a brief discussion of nuclear, natural gas and coal-fired technologies. Section C.1 is divided into three parts. The first two discuss briefly the domestic Advanced CANDU Reactor (ACR) and Pressurized Water Reactor (PWR) from a technical perspective. It is important to provide a concise guideline for the comparison between Canada's unique and effective technology and the popular PWR. The third part of this section looks into future Canadian technology, with comment on Canada's involvement in the Generation IV forum. Section C.2 reviews natural gas-fired technologies, including steam turbine systems, gas turbine systems and reciprocating engine technologies. Section C.3 explores sub-critical and supercritical pulverized coal combustion, as well as briefly reviewing emerging technologies such as atmospheric, fluidized and pressurized fluidized bed combustion.

C.1 Nuclear Power Technologies

While the nuclear power industry is developing reactor technology rapidly and the types of reactors available presently or in the near future are increasing, nuclear reactors operate on the same basic principles. Several components are common in most types: fuel, the control rods, coolant and the moderator.

Control rods regulate the chain reaction of the splitting of atoms. The coolant, like a radiator in an automobile, carries away the heat produced by the fission process so that the reactor core does not overheat, and it produces steam through heat exchange. The moderator controls the speed at which the atoms travel. The slowing down of the atoms actually increases their opportunity to split and, therefore, increases the amount of energy released. The moderator provides an important distinction between the two technologies.

Nuclear reactors produce, contain and control the release of energy from splitting of U-235 atoms. In electric power plants, this energy heats water to make steam. The steam, in turn, drives the turbine-generators to make electricity. The fissioned uranium is used as a source of heat in a nuclear power station in the same way that ignited coal, gas, or oil is used as a source of heat in a fossil fuel power plant. Nuclear reactors are essentially large steam engines.

In spite of the influx of many complex engineering designs, however, there are two main nuclear power types: those moderated by light water and those moderated by heavy water. Light water reactors are divided further into PWRs and BWRs. They comprise of 61 per cent and 21 per cent, respectively, of reactor types currently used worldwide.

Canada's innovative and competitive CANDU is categorized as a PHWR and makes up 10 per cent of reactors used worldwide. More detailed information regarding the various reactor types, nations involved, numbers of units and other data specific to the reactors is provided in Table C.1. The table does not include laid-up or shut down reactors.

Table C.1
Nuclear Power Plants in Commercial Operation

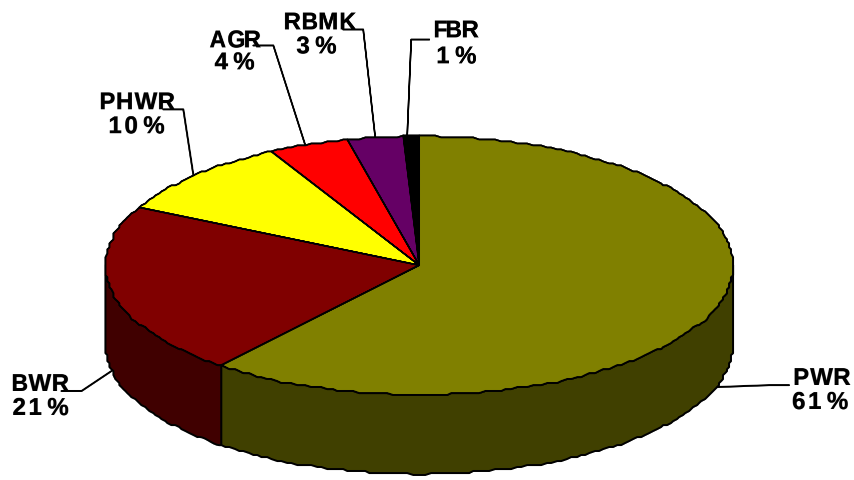
Reactor Type	Main Countries	Number	GWe	Fuel	Coolant	Moderator
Pressurized Water Reactor (PWR & EPR)	France, Japan, US, Russia	267	250	Enriched UO_2	Water	Water
Boiling Water Reactor (BWR & ABWR)	US, Japan Sweden	94	86	Enriched UO_2	Water	Water
Pressurized Heavy Water Reactor 'CANDU' (PHWR)	Canada, India	43	24	Natural UO_2	Heavy Water	Heavy Water
Gas-Cooled Reactor (Magnox & AGR)	UK	18	11	Natural U (metal), enriched UO_2	CO_2	Graphite
Light Water Graphite Reactor (RBMK)	Russia	12	13	Enriched UO_2	Water	Graphite
Fast Neutron Reactor(FBR)	Japan, France, Russia	4	1	PuO_2, UO_2	Liquid Sodium	None
	TOTAL	**439**	**385**			

SOURCE: World Nuclear Association.

As indicated in Table C.1, the PWR is the most common type of nuclear reactor in the world. According to the WNA there are 267 of them worldwide, with 69 PWR reactors in use for power generation in the US alone. In fact, virtually all power reactors in the US are either PWR or BWR.

Figure C.1 illustrates the reactor types in use worldwide in the 2007.

Figure C.1
Reactor Types in Use Worldwide, 2007



SOURCE: World Nuclear Association.

The purpose of the following section is to discuss briefly the domestic Advanced CANDU Reactor and Pressurized Water Reactor from a technical perspective. Table C.2, from the AECL website, provides a concise guideline for the comparison between the two technologies presented in this study.

Table C.2
Technical Comparison of ACR vs. PWR

<table>
<tr><td colspan="2">Similarities
Light water coolant — Spent fuel storage concept
Safety rationale/concept — Turbine generator and BOP
Decommissioning process

Differences</td></tr>
<tr><td>ACR (Advanced CANDU Reactor)</td><td>PWR (Pressurized Water Reactor)</td></tr>
<tr><td>Pressure tubes
Heavy water moderator
Slightly enriched fuel (~2%)
Simple short fuel bundle
Low neutron absorption
On-line refueling
Modular construction</td><td>Pressure vessel
Light water moderator
Enriched fuel (~4%)
Full-length fuel string
Moderate neutron absorption
Refueling outage
Traditional/modular construction</td></tr>
</table>

SOURCE: AECL

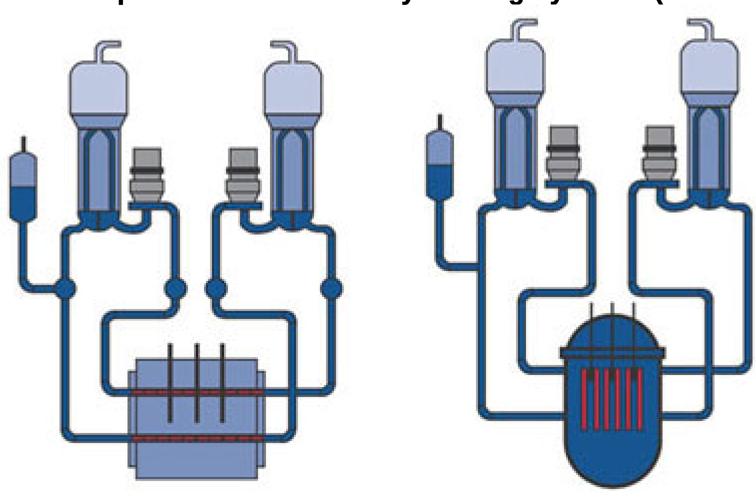
C.1.1 Advanced CANDU Reactor

The ACR-1000 is the latest in the evolution of CANDU technology from the AECL. The ACR-1000 includes some modifications that make it even more competitive while retaining its unique, proven elements. The ACR-1000 is a Generation III+, 1200 MWe class heavy water reactor. While the ACR has never been built, AECL has received positive response from prospective clients. ACR is moving towards design certification in Canada, with the first ACR unit expected to be in operation by 2016 in Ontario. Other prospective clients include China, US and UK. In 2007 AECL applied for UK generic design assessment. In March 2008, Britain's nuclear regulators approved the ACR's design and are invited to participate in the licensing approval process. Britain is looking to update their aging fleet of 19 nuclear reactors. Units will be assembled from prefabricated modules, cutting construction time to 3.5 years. They will have a 60 year design life overall but will require mid-life pressure tube replacement.

The CANDU reactor designs have been developed in Canada since the 1950s. Canada and India are the sole nations to design the pressurized heavy water reactor. The ACR is a progression from the reliable CANDU 6 reactors that are successfully operating in five countries.

Much like its predecessors, the new ACR has retained the following features: horizontal fuel channels, fuel bundle design, low-pressure heavy water moderator, high neutron efficiency and on-power fuelling. However, the ACR has incorporated features from the PWR. In fact, according to the AECL, nearly 75 per cent of the internal components are the same as the PWR technology. Below in Figure C.2 is a schematic comparison of cooling systems for the ACR-700, on the left, and the PWR, on the right. The most important similarity is the ACR's adoption of light water as a coolant.

Figure C.2
Schematic Comparison of the Primary Cooling Systems (ACR vs. PWR)



SOURCE: AECL

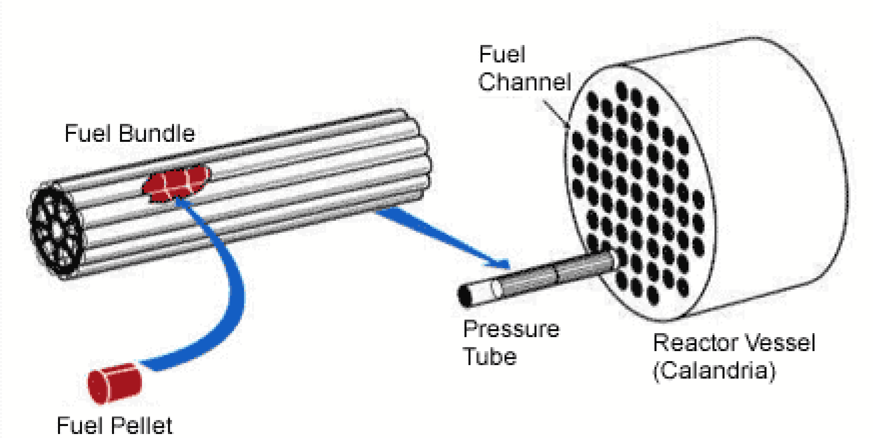
The ACR is physically smaller and more efficient – in terms of capacity and cost – than the CANDU 6. The ACR uses low-enriched uranium (1.5 to 2.1 per cent U-235), rather than the natural uranium that fuelled its forerunner. Traditionally, CANDUs used natural uranium (0.7 per cent U-235) fuel and heavy water (D_2O) as a moderator and coolant. ACR technology, however, requires uranium enriched to 2.1 per cent U-235 as fuel; it employs heavy water as a moderator but light (ordinary) water as a coolant. The 2.1 per cent level of enrichment would be achieved by employing both natural uranium (0.7 percent U-235) and enriched uranium (3 to 4 per cent U-235).

The ACR uses horizontal pressure tubes. This is unchanged from the CANDU 6 design. Several hundred horizontal pressure tubes are submerged in the moderator. Due to the horizontal pressure tube design, the reactor can be refueled on-line. Reactors employing PWR technology need to be shut down while refueling occurs. Refueling outage can last up to two months with some reactors.

One of the unique traits of the ACR is the simple, short fuel bundles compared to the full-length fuel string design for PWRs. When the process of fuel fabrication transforms the uranium oxide into ceramic pellets by pressing the uranium oxide into cylindrical shapes and baking them at a high temperature (over 1400° C), the pellets are encased in metal tubes to form fuel bundles. In a CANDU reactor, a fuel bundle consists of fuel pellets loaded in 37 half-meter long rods.

As demonstrated in Figure C.3, the fuel bundles or pressure tubes grouped together are called a fuel channel. In an ACR there are twelve 43-element bundles, lying end-to-end, that make up the fuel assembly.

Figure C.3
Fuel Bundle and Fuel Channel Relationship



Fuel bundle and fuel channel relationship.

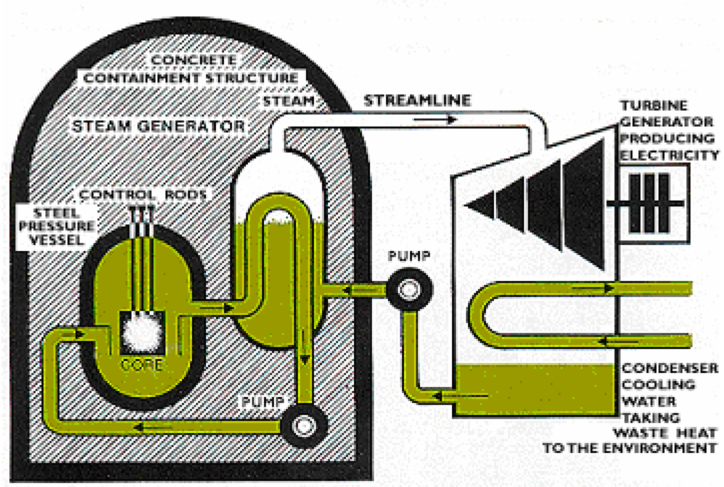
SOURCE: AECL

C.1.2 Pressurized Water Reactors

The PWR is the most common type of nuclear reactor in the world. According to the WNA there are 265 of them worldwide, with 69 PWR reactors in use for power generation in the US alone. In fact, virtually all power reactors in the US are either PWR or BWR.

In the BWR, the water heated by the reactor core turns directly into steam in the reactor vessel as it is allowed to boil. It is then used to power the turbine-generator. In a PWR, the water passing through the reactor core is kept under pressure so that it does not turn to steam at all – it remains liquid. The PWR is distinguished by having a primary cooling circuit and a secondary circuit. The former allows the pressurized water to be circulated in a closed system of pipes. In the process the heat from this circuit heats up the secondary circuit. Because the secondary circuit has less pressure, the water within it is permitted to boil and the steam powers the turbine. The design of the PWR is indicated below in Figure C.4.

Figure C.4
Pressurized Water Reactor – A Common Type of Light Water Reactor (LWR)



SOURCE: World Nuclear Association.

The PWR uses enriched uranium (~4 percent U-235), rather than low-enriched uranium that fuels the ACR. In addition, while ACR technology employs heavy water as moderator and light (ordinary) water as coolant, the PWR uses ordinary water as both coolant and moderator.

Other differences between the two technologies include the use of a pressure vessel instead of the ACRs horizontal pressure tubes. The former cannot, however, be refueled on-line. Reactors employing PWR technology needs to be shut down while refueling occurs. Refueling outage can last up to two months with some reactors, approximately between 18 and 24 months.

The enriched uranium is fabricated into long zirconium-alloy tubes. While the ACR has simple short fuel bundles, the PWR technology uses a full-length fuel string design.

In a pressurized reactor, the fuel assemblies encase between 200 and 300 rods each. According to the WNA a large reactor can have between 150 and 200 fuel assemblies, carrying between 80 and 100 tonnes of uranium.

C.1.3 Potential Future Technology Trends

The PWR discussed in the previous section is known as a Generation II reactor, as is the CANDU 6. The ACR on the other hand, while being an evolutionary design, is commonly known as a Generation III+, due its improvements in technology and economics. Its basic design, however, stems from the Generation II reactors. While AECL is marketing it latest technology, the ACR-1000, the organization is already looking to the future.

Canada, led by Natural Resources Canada (NRCan), and using the expertise of AECL, is a member of the Generation IV forum (GIF). Established in 2000, the GIF's mandate is to develop the next generation of nuclear energy systems. Member nations include the United States, Argentina, Brazil, Canada, France, Japan, South Korea, South Africa and Switzerland. The European Union, Russia and China joined the organization in 2006.

The international task force reviewed nearly 100 nuclear systems and has decided to pursue six systems, four of which are fast neutron reactors. The six technologies are Gas-Cooled Fast Reactor (GFR), Very High Temperature Reactor (VHTR), Supercritical Water-Cooled Reactor (SCWR), Sodium-Cooled Fast Reactor (SFR), Lead-Cooled Fast Reactor (LFR) and Molten Salt Reactor (MSR).[95] The task force's objective is to develop these systems commercially by 2020 to 2030. Table C.3 illustrates some of technical characteristics of the six nuclear technologies such as neutron spectrum, size, temperature, pressure, fuel and fuel cycle.

[95] http://www.gen-4.org/Technology/systems/index.htm

Table C.3
GIF Reactor Technologies

Reactor Type	Neutron Spectrum	Size (MW)	Temp. (°C)	Pressure	Fuel	Fuel Cycle
Gas-Cooled Fast Reactors	Fast	288	850	High	U-238*	Closed, on site
Lead-Cooled Fast Reactors	Fast	300-400 1,200	550-800	Low	U-238*	Closed, regional
Molten Salt Reactors	Epithermal	1,000	700-800	Low	UF in salt	Closed
Sodium-Cooled Fast Reactors	Fast	150-500 500-1,500	550	Low	U-238 & MOX	Closed
Supercritical Water-Cooled Reactors	Thermal or Fast	1,500	510-550	Very High	UO_2	Open (thermal), Closed (fast)
Very High Temperature Gas Reactors	Thermal	250	1,000	High	UO_2 (prism or pebbles)	Open

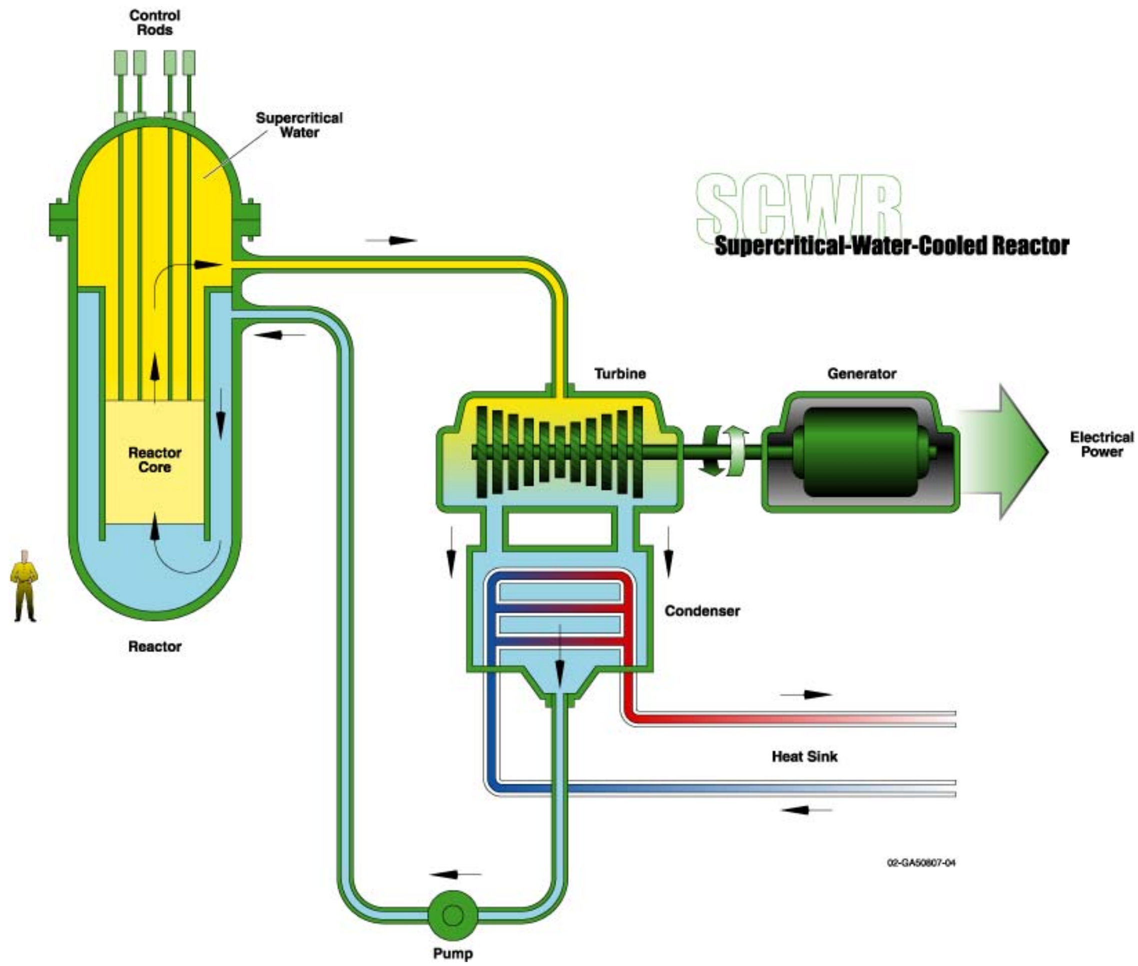
SOURCE: World Nuclear Association.

Note: *with U-235 or Pu-239

While member nations specialize in the various technologies, Canada and Japan are taking a leadership role in developing the Supercritical Water-Cooled Reactors (SCWR). Canada is the world's authority on SCWR technology, as the high temperature, high-pressure water–cooled reactor is a variation of the ACR. The SCWR is often referred to as the CANDU X. Much of the following information regarding the SCWR system is available on the Generation IV International Forum website.

Figure C.5 shows the design schematic of the SCWR.

Figure C.5
Supercritical Water-Cooled Reactor (SWCR) System



SOURCE: Gen. IV International Forum.

The SCWR system is primarily designed for efficient electricity production, with an option for actinide management based on two options in the core design. As shown in Table 3.11, the SCWR may have a thermal or fast-spectrum reactor neutron spectrum. Using fast neutrons with higher kinetic energies would enable the system to produce at least as much fissile material as it consumes. The second option is regarding the fuel cycle, either a closed cycle with a fast-spectrum reactor and full actinide recycle based on advanced aqueous processing at a central location.

The supercritical water coolant enables a thermal efficiency about one-third higher than current light-water reactors, as well as simplification in the balance of plant. The supercritical water directly drives the turbine, without any secondary steam system. Passive safety features are similar to those of simplified boiling water reactors. The operating pressure of the supercritical water is 25 MPa and at a temperature range between 510-550 degrees Celsius.

The fuel for the SCWR is uranium oxide, enriched in the case of the open fuel cycle option. However, the SCWR can also be built as a fast reactor with full actinide recycle based on conventional reprocessing. The size range is expected to be between 350 and 1,500 MW. The size will depend on the number of fuel channels used. The reactor is expected to be ready for commercialization by 2020.

While the SCWR is a variation of the ACR, its system also uses existing light water reactor technology. There is extensive experience in constructing and operating this technology.

There are, however, several challenges that need to be addressed. First, this concept has a tendency to have a positive void reactivity coefficient. Second, potential loss-of-coolant accidents need to be addressed. Other major challenges for the SCWR are to develop a viable core design, accurately estimate the heat transfer coefficient and develop materials for the fuel and core structure that will be sufficiently corrosion-resistant to withstand SCWR conditions.

C.2 Natural Gas-Fired Technologies

Natural gas or other fossil fuel-fired (central power) plants use either steam or combustion turbines to provide the mechanical power to electrical generators. In steam turbines, steam at high temperature and pressure; and in combustion (gas) turbines, gas expansion through various stages of a turbine, transfer energy to rotating turbine blades. The turbine is mechanically coupled to a generator, which produces electricity.

If the steam and gas plants are not equipped with the additional equipment such as recuperator or heat recovery steam generator (HRSG) then the useful output of the plants will be power only. The recuperator and HRSGs increase the efficiency of the power plants where the captured waste heat is employed either for additional electricity generation or an industrial process. The latter is referred to the combined heat and power (CHP) production.

The word combined is common to both CHP and combined-cycle. The difference lies in what is being combined. In CHP there is the simultaneous production of electricity and useful heat. In combined-cycle, the same thermal energy is used twice to produce electricity, first in a combustion turbine and then in a steam turbine which recovers heat from the exhaust gases of the steam turbine. CHP and combined-cycle are not mutually exclusive: low-pressure steam from a steam turbine in combined-cycle may be used for process heat.

This section will provide a brief description of steam and combustion gas turbine technologies. More specifically, this section discusses steam turbine systems, gas turbine systems, reciprocating engines and combined-cycle systems.

Steam Turbine Systems

The most basic natural gas-fired electric generation requires boiling feed water treatment (BFW), a boiler or once through steam generator (OTSG),[96] steam separator, steam turbine (ST) and steam generator (SG).

The fossil fuels (natural gas) are burned in a boiler and the feed water in the OTSG is heated and generates high pressure, high temperature steam. The steam separator directs high pressure, high temperature steam to the steam turbine. The steam expands through a steam turbine to produce mechanical energy, which drives an electric generator to generate electricity. These basic steam generation units have fairly low energy efficiency in the range of 33 to 35 per cent for electricity generation.

The energy in steam that enters the turbine is in two forms; the heat of vaporization (change water from a liquid state into a vapour), and the energy from heating it to higher temperature and pressure. The steam at the point of vaporization is referred to as saturated steam, and heated beyond the saturated point is termed superheated steam.

The superheated steam that enters the turbine of an electric generating plant is of a very high value because of its high temperature and pressure (high quality steam). The steam that exits the turbine contains heat but is of much lower value since its temperature and pressure have been substantially reduced. Only about one third of the heat in the steam that is supplied to the turbine can be converted to electricity in the steam cycle.

It should be noted that the steam leaving the turbine is condensed to water (it is in the form of heat vaporization) and along with the low temperature steam through steam separator is returned to the boiling water treatment (BFW). This recycling increases the temperature of water in the BFW and reduces fuel requirements for boiling the water.

The simplest example of the CHP production is the time that the system is equipped with a back-pressure turbine, where high pressure steam is expanded in the turbine and exhausted at the pressure and temperature needed for the industrial process heat. In many industrial situations a turbine is used to recover electricity when steam is produced at a pressure higher than needed in the industrial process. This system gives a high degree of flexibility.

Gas Turbine Systems

Gas turbines and combustion engines are also used to generate electricity. In these types of units, instead of heating steam to turn a turbine, hot gases from burning fossil fuels (particularly natural gas) are used to turn the turbine and generate electricity. Gas turbine and combustion

[96] "Once Through Steam Generation, OTSG" is an innovative steam technology that is replaceable with traditional drum less "heat recovery steam generators, HRSG". The continuous-flow steam generator of the OTSG system converts all feed-water into high-purity, superheated steam. The OSTG's are suited for combined-cycle, gas and steam turbine based on the CHP. Source: http://www.otsg.com/

engine plants are traditionally used primarily for peak-load demands,[97] as it is possible to quickly and easily turn them on. These plants are still traditionally slightly less efficient than large steam-driven power plants.

The most common of the CHP is a topping gas turbine system, which produces electricity first; the remaining thermal energy is used for purposes such as industrial processes, water and space heating. The gas turbine and combustion engine consists of gas turbine (GT), gas generator (GG), drum boiler (DB), heat recovery steam generator (HRSG)[98], boiling feed water (BFW), steam separator, and once through steam generator (OTSG).

There are two types of gas turbines on the market: industrial gas turbines and aero-derivative gas turbines. Industrial gas turbines are designed for power generation and mechanical drive applications. Aero-derivative gas turbines are modified gas generators from aero engines, which are connected to an industrial turbine, with a generator.

The range of gas turbine systems in electricity generation from 200 kW to 250 MW and they have an average heat-to-power ratio of 2:1. Supplemental heating through secondary firing of exhaust gases can increase this ratio to 5:1. Steam injection increases electrical output by 15 per cent.

Reciprocating Engine Systems

These types of engines are also commonly known as combustion engines. They convert the energy contained in fossil fuels into mechanical energy, which rotates a piston to generate electricity.

A reciprocating engine is an engine that utilizes one or more pistons in order to convert pressure into a rotating motion. An automobile engine is an excellent example. The burning fuel such as gasoline, diesel fuel, oil or natural gas provides pressure. Each piston is located inside a cylinder, into which a fuel and air mixture is introduced, and then ignited. The now hot gases expand, pushing the piston away. The linear movement of the piston is converted to a circular movement via a connecting rod and a crankshaft.

The more cylinders a piston engine has, the more power it is capable of producing. These engines are known collectively as internal-combustion engines.[99] In most applications of steam power, the piston engine has been replaced by the more efficient turbine.

Gas-fired reciprocating engines typically generate from 20 kW to 50 MW. The range of generation indicates that they can be used as a small scale residential backup generator, to a base load generator in industrial settings (on-site generation).

[97] http://www.naturalgas.org/overview/uses_eletrical.asp

[98] HRSG generates steam by use of exhaust heat from gas turbine and feed it to steam turbine. The HRSG is an important part of the CHP.

[99] An internal combustion engine is an engine that is powered by the expansion of hot combustion products of fuel directly acting within an engine.

Reciprocating engines can convert up to about 30 per cent of the input energy to mechanical rotary energy. As in all heat engines, the remaining energy is converted to heat and must be removed or rejected from the engine. Thus, as much as 70 per cent of the engine input energy is potentially available for recovery and use (CHP system).

The heat-to-power ratio ranges of the reciprocating engine systems are from 0.5:1 to 2.5:1. Supplementary firing can increase thermal output. Exhaust gases are of high temperature, up to 400° C, but the engine cooling system provides only low-grade heat below 90 $^{\circ}$C. These systems produce more electrical energy per unit of fuel, than either steam or gas turbines.

Combined-cycle Systems

Combined-cycle systems use both gas turbines and steam turbines for electricity generation. Many of the new natural gas-fired power plants are what are known as 'combined-cycle' units. The hot exhaust gases from the gas turbine produce steam for the steam turbine. The thermal output remaining in the steam exhausted from the steam turbine goes to process applications. These systems increase electric power output at the expense of recoverable heat.

Because of this efficient, use of the heat energy released from the natural gas, combined-cycle plants are much more efficient than steam units or gas turbines alone. In fact, combined-plants can achieve thermal efficiencies of up to 50 to 60 per cent.

C.3 Coal-Fired Technologies

Since the onset of the Industrial Revolution, coal has been the most widely used fuel for power generation. This section provides a brief description of coal combustion technologies. While the dominant technology is sub-critical and supercritical steam pulverized coal combustion, there are various technologies that have been developed in order to reduce the environmental impacts of using coal as a combustion fuel for power generation. A basic approach to the "cleaner" use of coal is to reduce emissions by reducing the formation of pollutants. A parallel approach is to develop more thermally efficient systems so that less coal is used to generate the same amount of power.

Clean Coal Technologies (CCTs) are those that facilitate the use of coal to meet various regulations covering emissions[100], effluents, and residues. The CCTs can be categorized into two major groups of combustion and gasification.

Combustion technologies can be categorized into pulverized coal combustion with sub-critical or supercritical steam cycle; and advanced clean coal technologies such as fluidized-bed combustor (FBC), pressurized fluidized-bed combustors (PFBC), and atmospheric fluidized-bed combustors (AFBC).

[100] When coal burns, the impurities are released into the air. Sulphur can then combine with water vapour to form acid rain while carbon can combine with oxygen in the air to form carbon dioxide.

Sub-critical and Supercritical Steam Pulverized Coal Combustion

Pulverized coal combustion (PCC) is the most commonly used method in coal-fired power plants[101]. The pulverized coal power plant design is based on the utilization of pulverized coal feeding a conventional steam boiler and steam turbine.

Before coal arrives at the power plant one way of cleaning the coal is by simply crushing it into small chunks and washing it in the coal preparation plants. The coal floats to the surface while the sulphur impurities sink. Unfortunately, not all of coal's sulphur can be removed by washing because some of the sulphur in coal is chemically connected to coal's carbon molecules (organic sulphur). Most modern power plants are required to have special devices installed that clean the organic sulphur from the coal's combustion gases before the gases go up the smokestack. The technical devices are called flue gas desulphurization (FGD) units or scrubbers that scrub the sulphur out of the smoke released by coal combustion[102].

Most scrubbers rely on a common substance found in nature called limestone. Limestone can be made to absorb sulphur gases like a sponge absorbs water. In most scrubbers, limestone is mixed with water and sprayed into the coal combustion gases (called flue gases). The limestone captures the sulphur and "pulls" it out of the gases. The limestone and sulphur combine to form either a wet paste or a dry powder. In either case, the sulphur is trapped and prevented from escaping into the air.

The coal is prepared by grinding (typically, 70 percent of the coal is ground to pass through a mesh screen) to a very fine consistency for combustion. Then pulverized coal is blown with part of the combustion air into the plant through a series of burner nozzles. Combustion takes place at temperature from 1300 to 1700°C. Ash is formed in the combustion chamber while coal combusts. The primary advantage of PCC combustion is the very fine nature of the fly ash produced.[103] In general, PCC combustion results in approximately 65–85 per cent fly ash, and the remainder is coarser bottom ash[104] or boiler slag.[105]

Figure C.6 shows a simple flow diagram of a PCC plant.

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[101] The PCC refers to any combustion process that use very finely ground (pulverized) coal in the process.

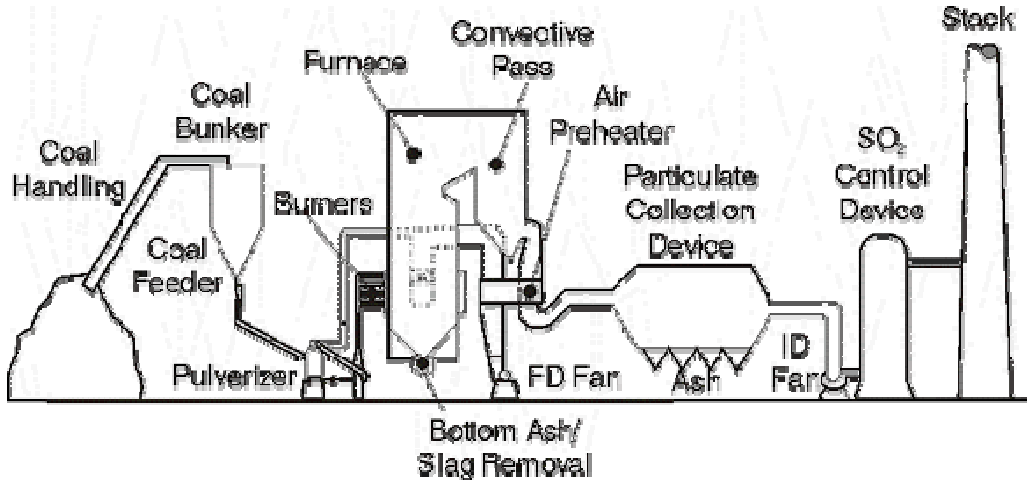
[102] There is also a family of new technologies that work like "scrubbers" by cleaning NOx from the flue gases (NOx scrubbers). Some of these devices use special chemicals called "catalysts" that break apart the NOx into non-polluting gases. Although these devices are more expensive than "low-NOx burners," they can remove up to 90 percent of NOx pollutants.

[103] Fly ash is the coal ash that exits a combustion chamber in the flue gas and is captured by air pollution control equipments such as electrostatic precipitators, baghouses, and wet scrubbers.

[104] Bottom ash consists of agglomerated ash particles formed in pulverized coal boilers that are too large to be carried in the flue gases and impinge on the boiler walls or fall through open grates to an ash hopper at the bottom of the boiler. Bottom ash is typically gray to black in colour, is angular in shape, and has a porous surface structure.

[105] Boiler slag is a molten ash collected at the base of slag tap and cyclone boilers that is quenched with water and shatters into black, angular particles having a smooth glassy appearance.

Figure C.6
A Simple Schematic Flow Diagram of Pulverized Coal Combustion



Various technologies or components have been developed in order to reduce the environmental impacts of using coal for power production in new plants.

Since both the highest and lowest temperatures of the working fluid govern the efficiency of the plants, strict temperature and pressure limits are indicative of more advanced technology. Most of the PCC plants use sub-critical steam cycles with pressures less than 22 megapascals (MPa) while supercritical steam cycles utilize steam at a pressure of 24 MPa, and temperature ranges (540 to 560° C). The higher steam pressure in supercritical plants results in higher energy efficiency.

<u>Atmospheric, Fluidized and Pressurized Fluidized Bed Combustion</u>

This section reviews briefly the following three technologies: Fluidized Bed Combustion (FBC), Atmospheric Pressurized Fluidized Bed Combustion (AFBC) and Pressurized Fluidized Bed Combustion (PFBC).

FBC processes are commonly used with high-sulphur coal. In a fluidized bed boiler the red-hot mass of floating coal (called bed) bubbles and tumbles around-hence the term "fluidized". Upward blowing jets of air suspend burning coal, allowing it to mix with limestone that absorbs sulphur pollutants. As coal burns in a fluidized bed boiler, it releases sulphur but the limestone tumbling around beside the coal captures the sulphur. A chemical reaction occurs, and the sulphur gases are changed into a dry powder that can be removed from the boiler.

The AFBC plants operate at atmospheric pressure, and NO_x generation is minimized due to lower combustion temperatures (815-875^{o} C) than in conventional PCC plants.

The PFBC plants are typically more compact than similar capacity AFBC and PCC plants due to the boiler, cyclones (cone-shaped air-cleaning), bed re-injection vessels, and associated hardware that are encapsulated in a pressure vessel. The PFBC plants are a more efficient way to burn coal because they use less fuel to produce the same amount of power. Higher efficiency reduces the amount of carbon dioxide released from coal-burning power plants.

The PFBC plants use the same process as AFBC plants to fluidize or float coal/sorbent mixtures. The operating temperature of fluidized beds is between 760° and 870° C, approximately half the temperature of a conventional boiler. In both technologies the use of both steam and gas turbines improve performance by creating a highly efficient combined-cycle system.

The hot, clean combustion gases enter the gas turbine for electricity generation. Also the hot gases exiting the gas turbine, absorbing more heat from a tube bundle in the fluid bed, enter the steam turbine and generate more electricity.

APPENDIX D

This appendix complements Section 4.2 of Chapter 4. Samples of the designed spreadsheets tables are presented here. Table D.1 depicts the spreadsheet used to collect information and data for upstream transportation of a process like refining or conversion in nuclear electricity system. While in Table G.1 it is assumed that transportation mode is road transport, the mode of transportation can be rail or pipeline too. Table D.2 shows the spreadsheet that is provided for material and energy balance of a process. Table D.3 demonstrates the spreadsheet designed to collect emission data associated with the operation of a process (Life Cycle Inventory). These spreadsheets have been designed based on Annex A of ISO 14044.

The appendix also includes Figure D.1 through D.11 which demonstrate sample spreadsheet of emissions calculation for various stages of power generation from nuclear and coal.

Table D.1
Upstream Transportation Table for a specific process

	Upstream Transportation						
Name of intermediate product	**Road transport**						
	Distance km	**Truck capacity** tonnes		**Actual load** tonnes		**Empty return** (Yes/No)	
		2005	**2006**	**2005**	**2006**	**2005**	**2006**

Table D.2
Material Balance and Energy Balance of a Process

Completed by:	**Date of completion:**					
Unit process identification:	**Reporting location:**					
Time period: Year 2005,2006	**Starting month**	**Ending month:**				
Description of unit process: (attach additional sheet if required)						
Material inputs	**Units**	**Quantity**		**Description of sampling procedures**	**Origin**	
		2005	**2006**		**2005**	**2006**
Water consumption [a]	**Units**	**Quantity**		**Description of sampling procedures**	**Origin**	
		2005	**2006**		**2005**	**2006**
Energy inputs [b]	**Units**	**Quantity**		**Description of sampling procedures**	**Origin**	
		2005	**2006**		**2005**	**2006**
Material Outputs (including produc	**Units**	**Quantity**		**Description of sampling procedures**	**Destination**	
		2005	**2006**		**2005**	**2006**
NOTE The data in this data collection sheet refer to all unallocated inputs and outputs during the specified time period.						

[a] For example, surface water, drinking water

b For example, heavy fuel oil, meduim fuel oil, light fuel oil, kerosene, gasoline, natural gas, propane, coal, biomass, grid electricity

Table D.3
Emission inventory due to operation of a process

	Life cycle inventories			
Unit process identification:				**Reporting location:**
Emissions to air [a]	**Units**	**Quantity**		**Description of sampling procedures** (attach sheets if
		2005	**2006**	
Emissions to water [b]	**Units**	**Quantity**		**Description of sampling procedures** (attach sheets if
		2005	**2006**	
Emissions to Land [c]	**Units**	**Quantity**		**Description of sampling procedures** (attach sheets if
		2005	**2006**	
Other releases [d]	**Units**	**Quantity**		**Description of sampling procedures** (attach sheets if
		2005	**2006**	
Describe any unique calculations, data collection, sampling, or variation from description of unit process functions				

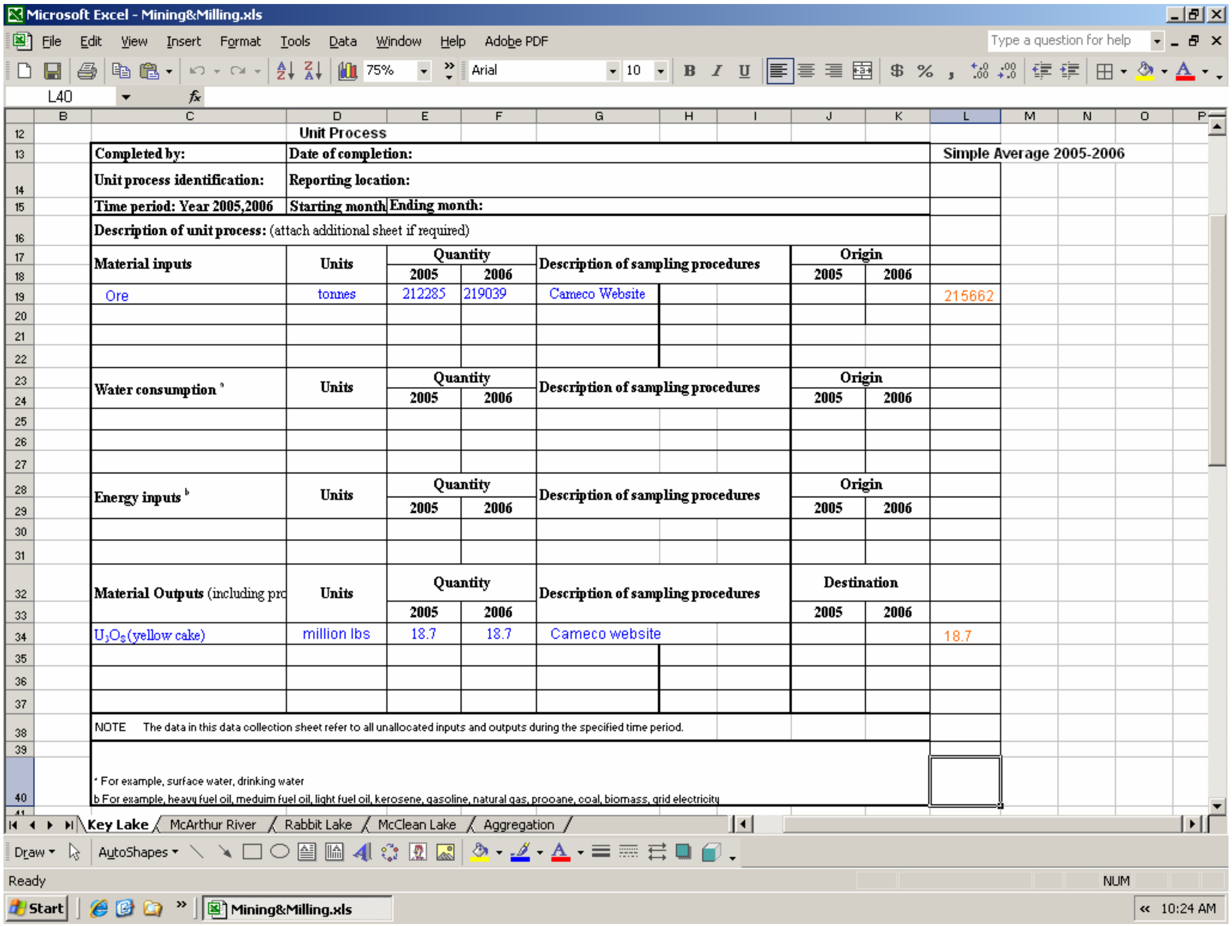
a For example inorganics: Cl_2, CO, CO_2, dust/particulates, F_2, H_2S, H_2SO_4, HCl, HF, N_2O, NH_3, NO_x, SO_x; and organics: hydrocarbons, PCB, dioxins, phenols; metals Hg, Pb, Cr, Fe, ZN, Ni.

b For example: BOD, COD, acids, Cl_2, CN_2^-, detergents/oils, dissolved organics, F^-, Fe ions, Hg ions, hydrocarbons, Na^+, NH_4^+, NO_3^-, organochlorides, other metals, other nitrogen compounds, phenols, phosphates, SO_4^{2-}, suspended solids.

c For example: mineral waste, mixed industrial waste, municipal solid waste, toxic wastes (please list compounds included in this data category).

d For example: noise, radiation, vibration, odour, waste heat

Figure D.1
Uranium Mining and Milling (I)



Microsoft Excel - Mining&Milling.xls

Unit Process

Completed by:	Date of completion:						Simple Average 2005-2006
Unit process identification:	Reporting location:						
Time period: Year 2005,2006	Starting month	Ending month:					
Description of unit process: (attach additional sheet if required)							
Material inputs	Units	Quantity 2005	Quantity 2006	Description of sampling procedures	Origin 2005	Origin 2006	
Ore	tonnes	212285	219039	Cameco Website			215662
Water consumption [a]	Units	Quantity 2005	Quantity 2006	Description of sampling procedures	Origin 2005	Origin 2006	
Energy inputs [b]	Units	Quantity 2005	Quantity 2006	Description of sampling procedures	Origin 2005	Origin 2006	
Material Outputs (including pro	Units	Quantity 2005	Quantity 2006	Description of sampling procedures	Destination 2005	Destination 2006	
U_3O_8 (yellow cake)	million lbs	18.7	18.7	Cameco website			18.7

NOTE The data in this data collection sheet refer to all unallocated inputs and outputs during the specified time period.

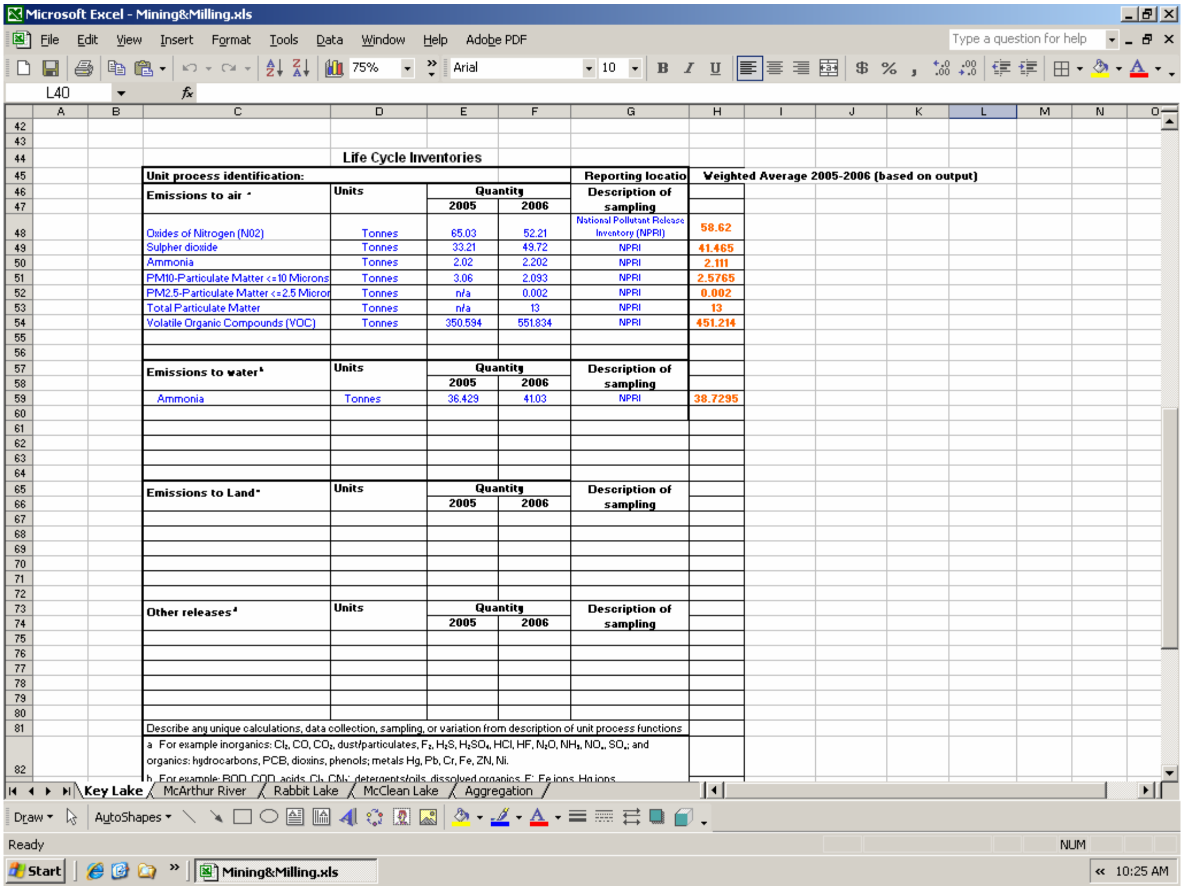
[a] For example, surface water, drinking water

b For example, heavy fuel oil, meduim fuel oil, light fuel oil, kerosene, gasoline, natural gas, propane, coal, biomass, grid electricity

Key Lake / McArthur River / Rabbit Lake / McClean Lake / Aggregation

Figure D.1 is a "print screen" of the spreadsheet used to record data for the mining and milling process in the LCA study. Displayed is the data collected for the Unit Process of yellow cake or U_3O_8 for Key Lake mine. Similar procedures are done for the rest of the uranium mines.

Figure D.2
Uranium Mining and Milling (II)



Life Cycle Inventories

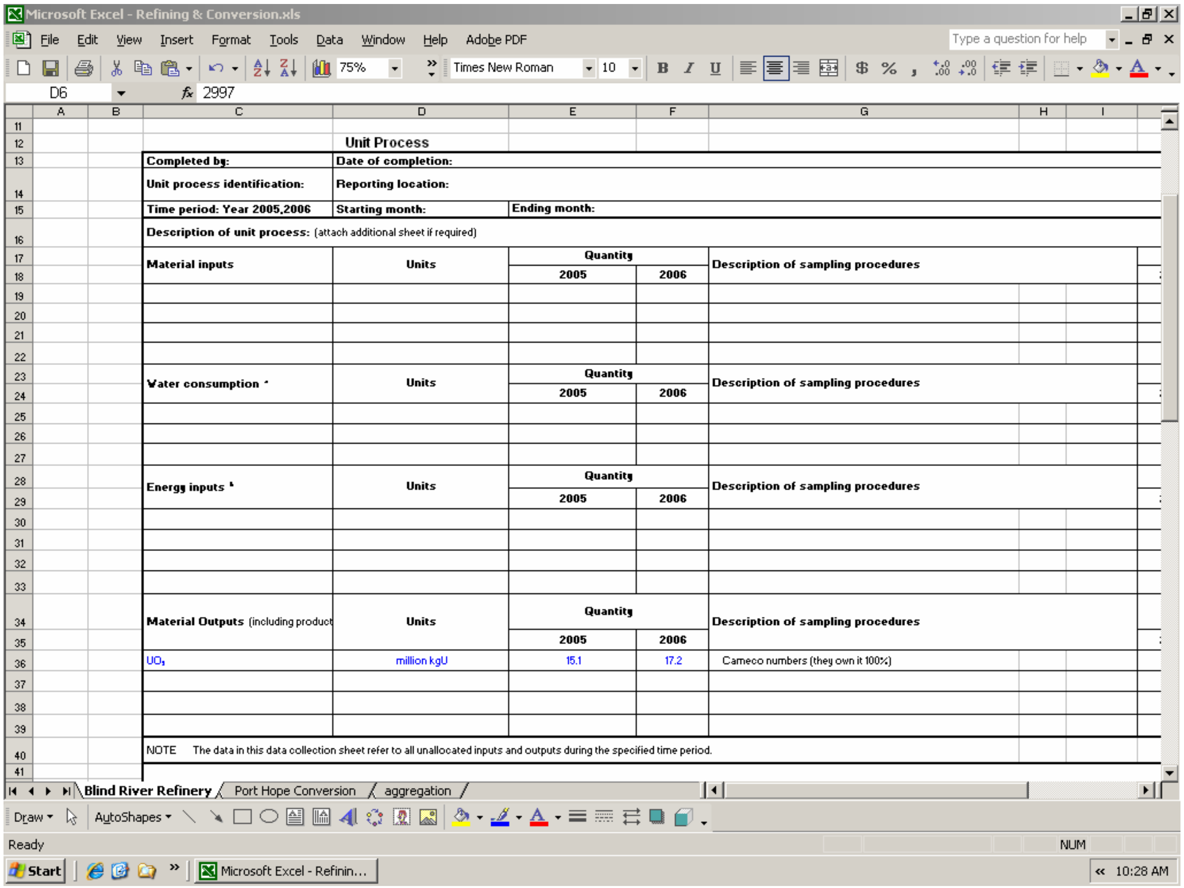
Unit process identification:				Reporting locatio	Weighted Average 2005-2006 (based on output)
Emissions to air [a]	**Units**	**Quantity 2005**	**Quantity 2006**	**Description of sampling**	
Oxides of Nitrogen (N02)	Tonnes	65.03	52.21	National Pollutant Release Inventory (NPRI)	58.62
Sulpher dioxide	Tonnes	33.21	49.72	NPRI	41.465
Ammonia	Tonnes	2.02	2.202	NPRI	2.111
PM10-Particulate Matter <=10 Microns	Tonnes	3.06	2.093	NPRI	2.5765
PM2.5-Particulate Matter <=2.5 Micror	Tonnes	n/a	0.002	NPRI	0.002
Total Particulate Matter	Tonnes	n/a	13	NPRI	13
Volatile Organic Compounds (VOC)	Tonnes	350.594	551.834	NPRI	451.214
Emissions to water [b]	**Units**	**Quantity 2005**	**Quantity 2006**	**Description of sampling**	
Ammonia	Tonnes	36.429	41.03	NPRI	38.7295
Emissions to Land [c]	**Units**	**Quantity 2005**	**Quantity 2006**	**Description of sampling**	
Other releases [d]	**Units**	**Quantity 2005**	**Quantity 2006**	**Description of sampling**	
Describe any unique calculations, data collection, sampling, or variation from description of unit process functions					

a For example inorganics: Cl_2, CO, CO_2, dust/particulates, F_2, H_2S, H_2SO_4, HCl, HF, N_2O, NH_3, NO_x, SO_x; and organics: hydrocarbons, PCB, dioxins, phenols; metals Hg, Pb, Cr, Fe, ZN, Ni.

b For example: BOD, COD, acids, Cl_2, CN_2, detergents/oils, dissolved organics, F, Fe ions, Hg ions

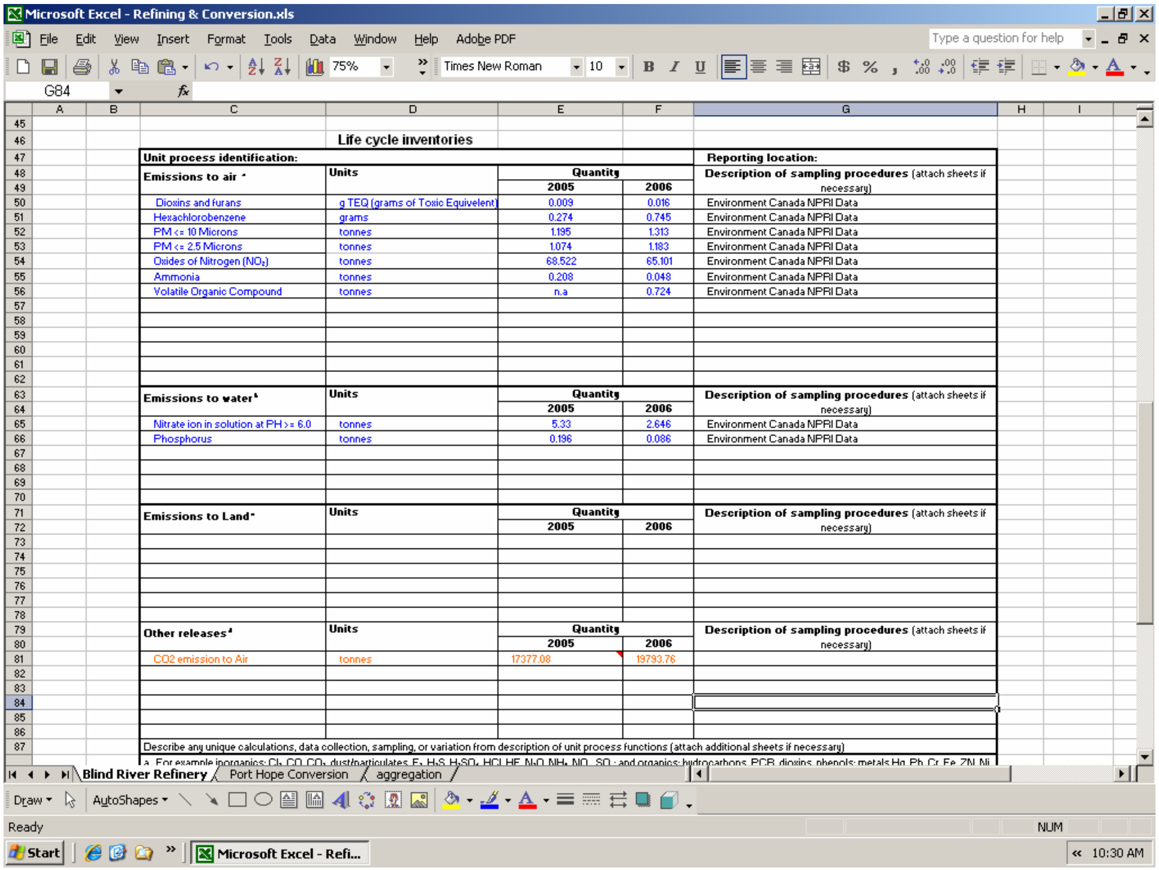
Moreover, the Life Cycle Inventory table shown in Figure 1b show recordings of CAC contaminants that are emitted from Key Lake mine. Data was collected from NPRI.

Figure D.3
Uranium Refining and Conversion (I)



Moving on to the refining stage, the yellow cake produced from the mills is transported to Blind River Refinery to produce UO_3. Figure D.3 shows Cameco's numbers of their 100% owned refinery.

Figure D.4
Uranium Refining and Conversion (II)



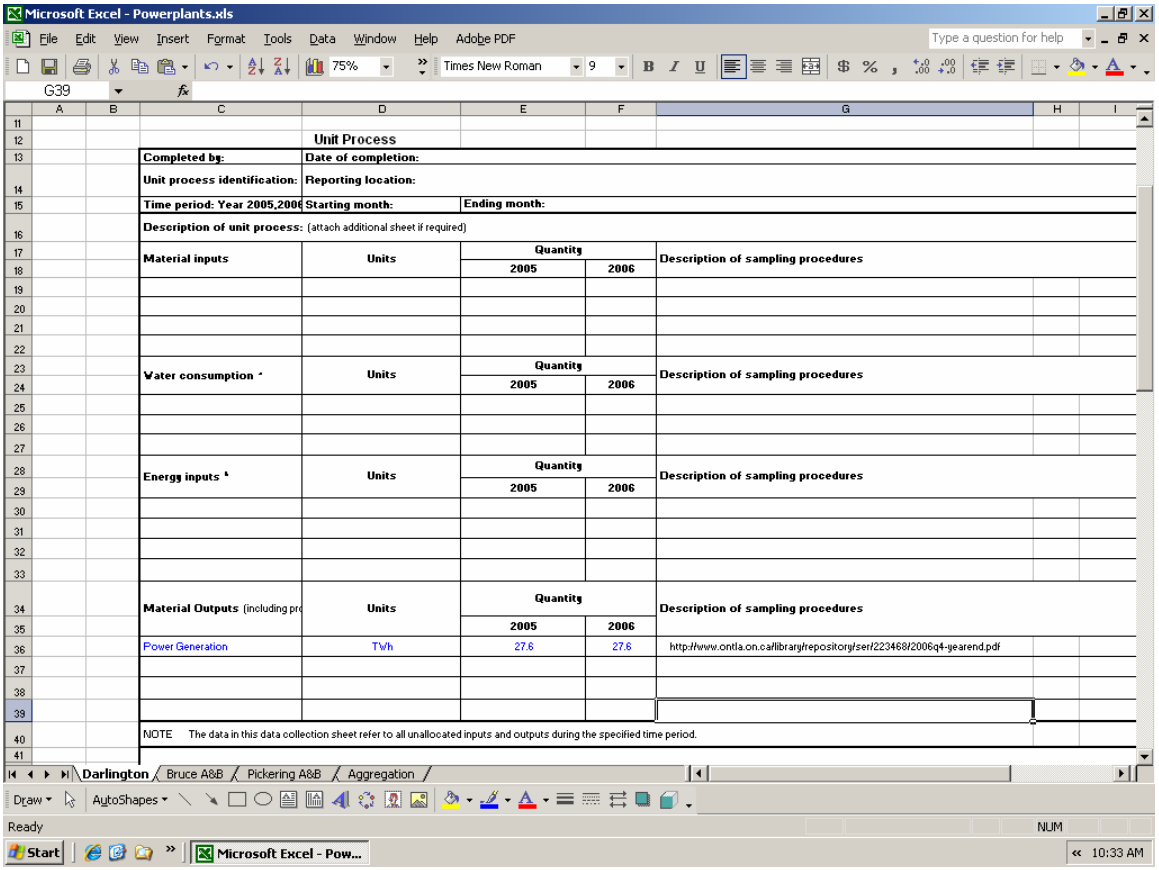
Life cycle inventories

Unit process identification:				**Reporting location:**
Emissions to air [a]	**Units**	**Quantity**		**Description of sampling procedures** (attach sheets if necessary)
		2005	**2006**	
Dioxins and furans	g TEQ (grams of Toxic Equivelent)	0.009	0.016	Environment Canada NPRI Data
Hexachlorobenzene	grams	0.274	0.745	Environment Canada NPRI Data
PM <= 10 Microns	tonnes	1.195	1.313	Environment Canada NPRI Data
PM <= 2.5 Microns	tonnes	1.074	1.183	Environment Canada NPRI Data
Oxides of Nitrogen (NO_2)	tonnes	68.522	65.101	Environment Canada NPRI Data
Ammonia	tonnes	0.208	0.048	Environment Canada NPRI Data
Volatile Organic Compound	tonnes	n.a	0.724	Environment Canada NPRI Data
Emissions to water [b]	**Units**	**Quantity**		**Description of sampling procedures** (attach sheets if necessary)
		2005	**2006**	
Nitrate ion in solution at PH >= 6.0	tonnes	5.33	2.646	Environment Canada NPRI Data
Phosphorus	tonnes	0.196	0.086	Environment Canada NPRI Data
Emissions to Land [c]	**Units**	**Quantity**		**Description of sampling procedures** (attach sheets if necessary)
		2005	**2006**	
Other releases [d]	**Units**	**Quantity**		**Description of sampling procedures** (attach sheets if necessary)
		2005	**2006**	
CO2 emission to Air	tonnes	17377.08	19793.76	

Describe any unique calculations, data collection, sampling, or variation from description of unit process functions (attach additional sheets if necessary)

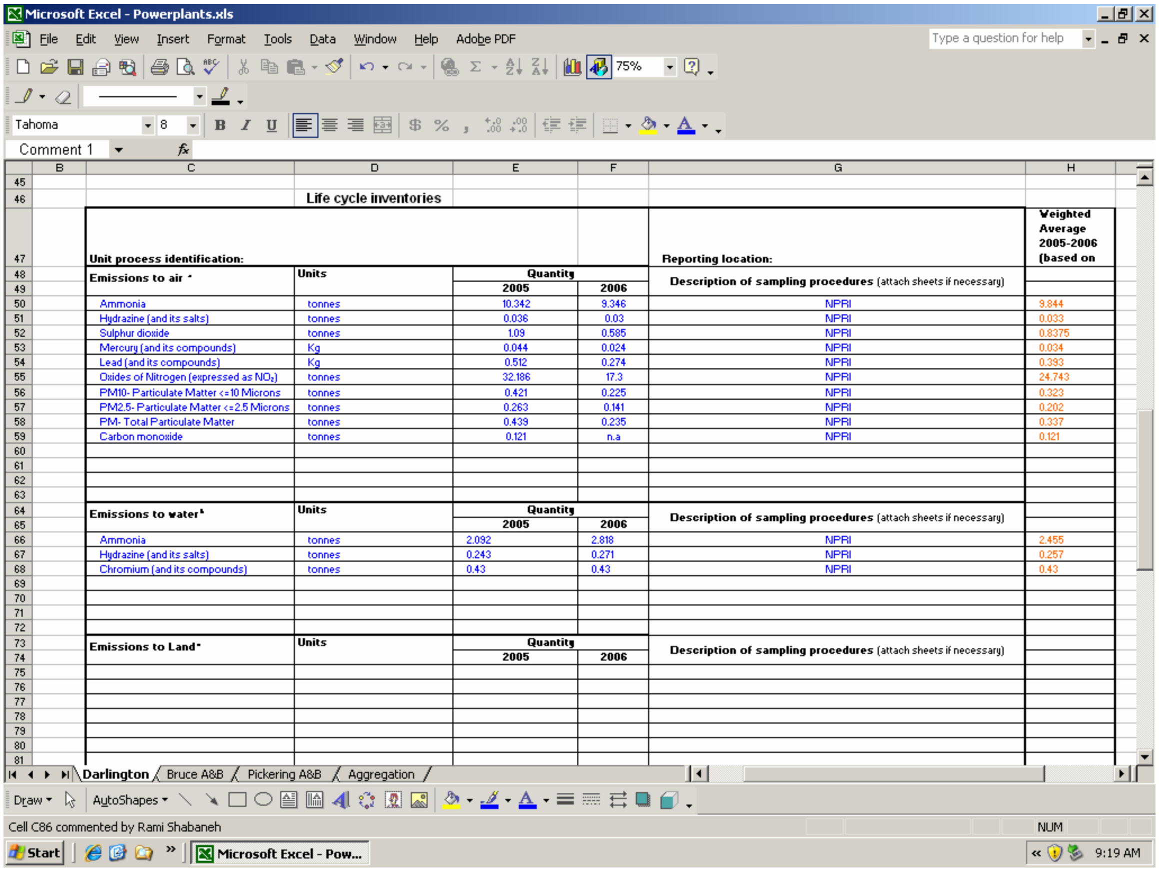
Continuing on the same page, CAC for Blind River Refinery are collected from NPRI and recorded into the table as shown in Figure D.4. Similar steps were taken to get Port Hope Conversion data.

Figure D.5
Nuclear Power Generation (I)



Figures D.5, D.6 and D.7 show the final process of the nuclear LCA. Figure D.5 displays total generation of the Darling Nuclear Power Plant for 2005 and 2006. Similar approach is repeated for Bruce and Pickering.

Figure D.6
Nuclear Power Generation (II)

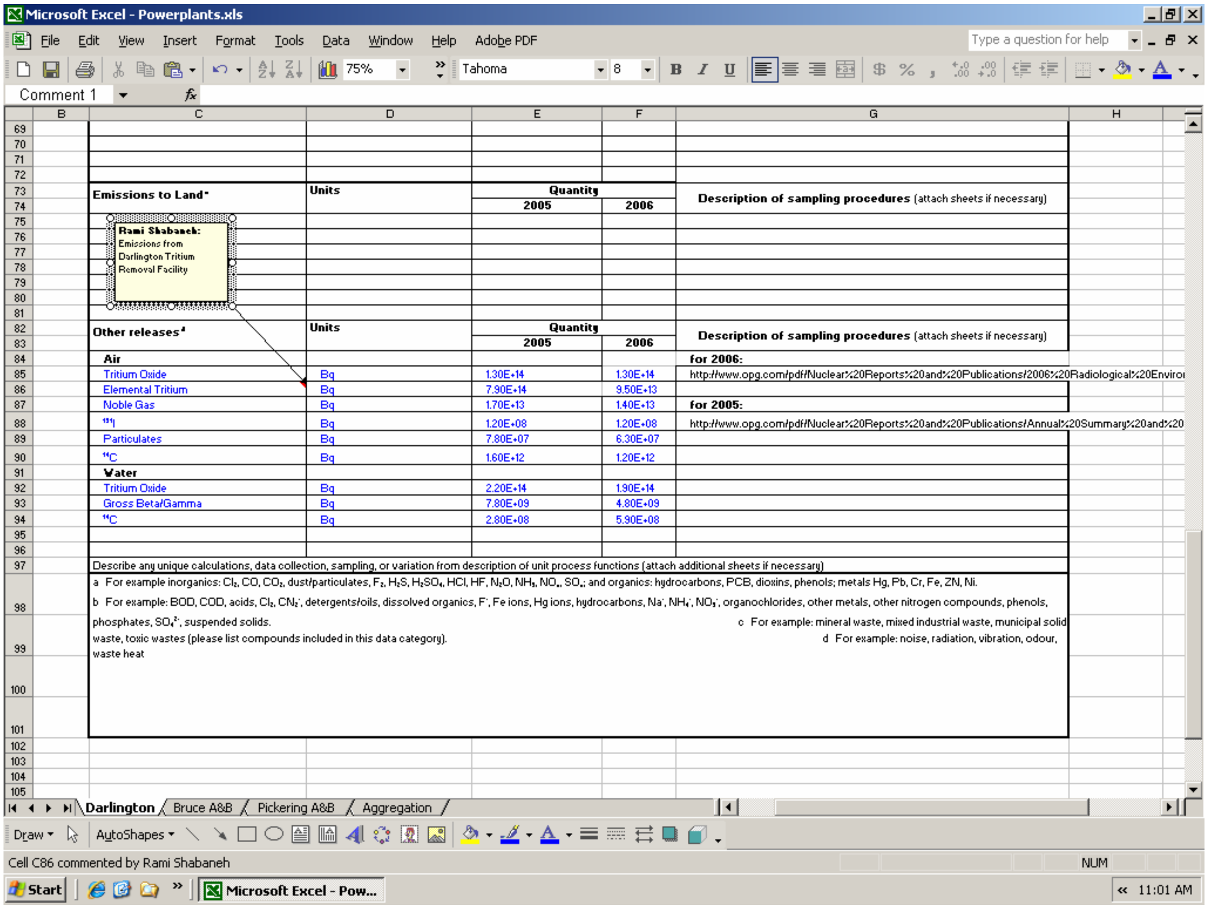


Life cycle inventories

Unit process identification:				Reporting location:	Weighted Average 2005-2006 (based on
Emissions to air	**Units**	**Quantity 2005**	**Quantity 2006**	**Description of sampling procedures** (attach sheets if necessary)	
Ammonia	tonnes	10.342	9.346	NPRI	9.844
Hydrazine (and its salts)	tonnes	0.036	0.03	NPRI	0.033
Sulphur dioxide	tonnes	1.09	0.585	NPRI	0.8375
Mercury (and its compounds)	Kg	0.044	0.024	NPRI	0.034
Lead (and its compounds)	Kg	0.512	0.274	NPRI	0.393
Oxides of Nitrogen (expressed as NO_2)	tonnes	32.186	17.3	NPRI	24.743
PM10- Particulate Matter <=10 Microns	tonnes	0.421	0.225	NPRI	0.323
PM2.5- Particulate Matter <=2.5 Microns	tonnes	0.263	0.141	NPRI	0.202
PM- Total Particulate Matter	tonnes	0.439	0.235	NPRI	0.337
Carbon monoxide	tonnes	0.121	n.a	NPRI	0.121
Emissions to water	**Units**	**Quantity 2005**	**Quantity 2006**	**Description of sampling procedures** (attach sheets if necessary)	
Ammonia	tonnes	2.092	2.818	NPRI	2.455
Hydrazine (and its salts)	tonnes	0.243	0.271	NPRI	0.257
Chromium (and its compounds)	tonnes	0.43	0.43	NPRI	0.43
Emissions to Land	**Units**	**Quantity 2005**	**Quantity 2006**	**Description of sampling procedures** (attach sheets if necessary)	

Moving down on the same spreadsheet, Figure D.6 displays CAC emitted when operating Darlington Power Plant. Data for all power plants' CAC were collected from NPRI.

Figure D.7
Nuclear Power Generation (III)



Emissions to Land[c]	Units	Quantity 2005	Quantity 2006	Description of sampling procedures (attach sheets if necessary)

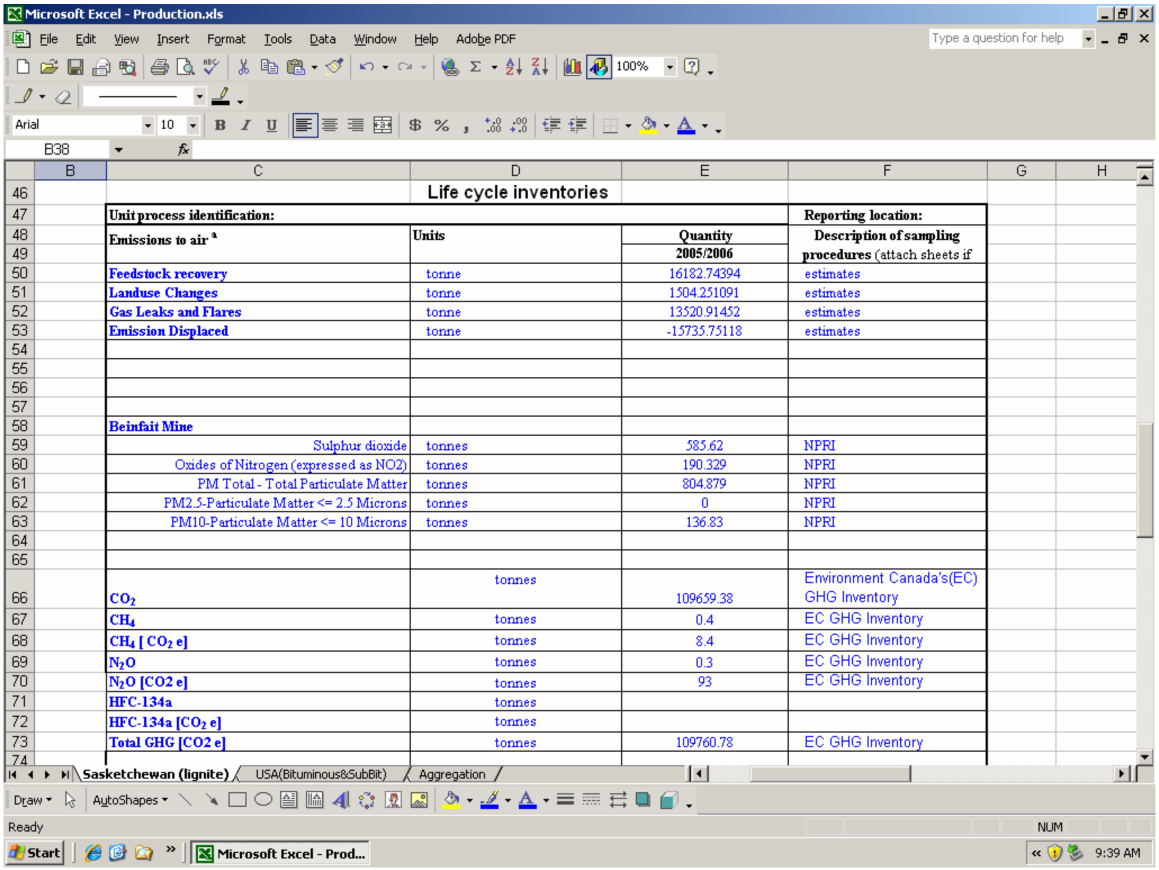
Other releases[d]	Units	Quantity 2005	Quantity 2006	Description of sampling procedures (attach sheets if necessary)
Air				for 2006:
Tritium Oxide	Bq	1.30E+14	1.30E+14	http://www.opg.com/pdf/Nuclear%20Reports%20and%20Publications/2006%20Radiological%20Enviro
Elemental Tritium	Bq	7.90E+14	9.50E+13	
Noble Gas	Bq	1.70E+13	1.40E+13	for 2005:
^{131}I	Bq	1.20E+08	1.20E+08	http://www.opg.com/pdf/Nuclear%20Reports%20and%20Publications/Annual%20Summary%20and%20
Particulates	Bq	7.80E+07	6.30E+07	
^{14}C	Bq	1.60E+12	1.20E+12	
Water				
Tritium Oxide	Bq	2.20E+14	1.90E+14	
Gross Beta/Gamma	Bq	7.80E+09	4.80E+09	
^{14}C	Bq	2.80E+08	5.90E+08	

Describe any unique calculations, data collection, sampling, or variation from description of unit process functions (attach additional sheets if necessary)

a For example inorganics: Cl_2, CO, CO_2, dust/particulates, F_2, H_2S, H_2SO_4, HCl, HF, N_2O, NH_3, NO_x, SO_x; and organics: hydrocarbons, PCB, dioxins, phenols; metals Hg, Pb, Cr, Fe, ZN, Ni.
b For example: BOD, COD, acids, Cl_2, CN_2^-, detergents/oils, dissolved organics, F^-, Fe ions, Hg ions, hydrocarbons, Na^+, NH_4^+, NO_3^-, organochlorides, other metals, other nitrogen compounds, phenols, phosphates, SO_4^{2-}, suspended solids.
c For example: mineral waste, mixed industrial waste, municipal solid waste, toxic wastes (please list compounds included in this data category).
d For example: noise, radiation, vibration, odour, waste heat

Finally, Figure D.7 is a snapshot of the bottom part of the spreadsheet which record radioactive emissions released from the power plants. Data for Darlington and Pickering power plants were collected from publications found in the Ontario Power Generation website, whereas Bruce Power Plant's data were collected from Bruce Power website.

Figure D.8
Coal Production

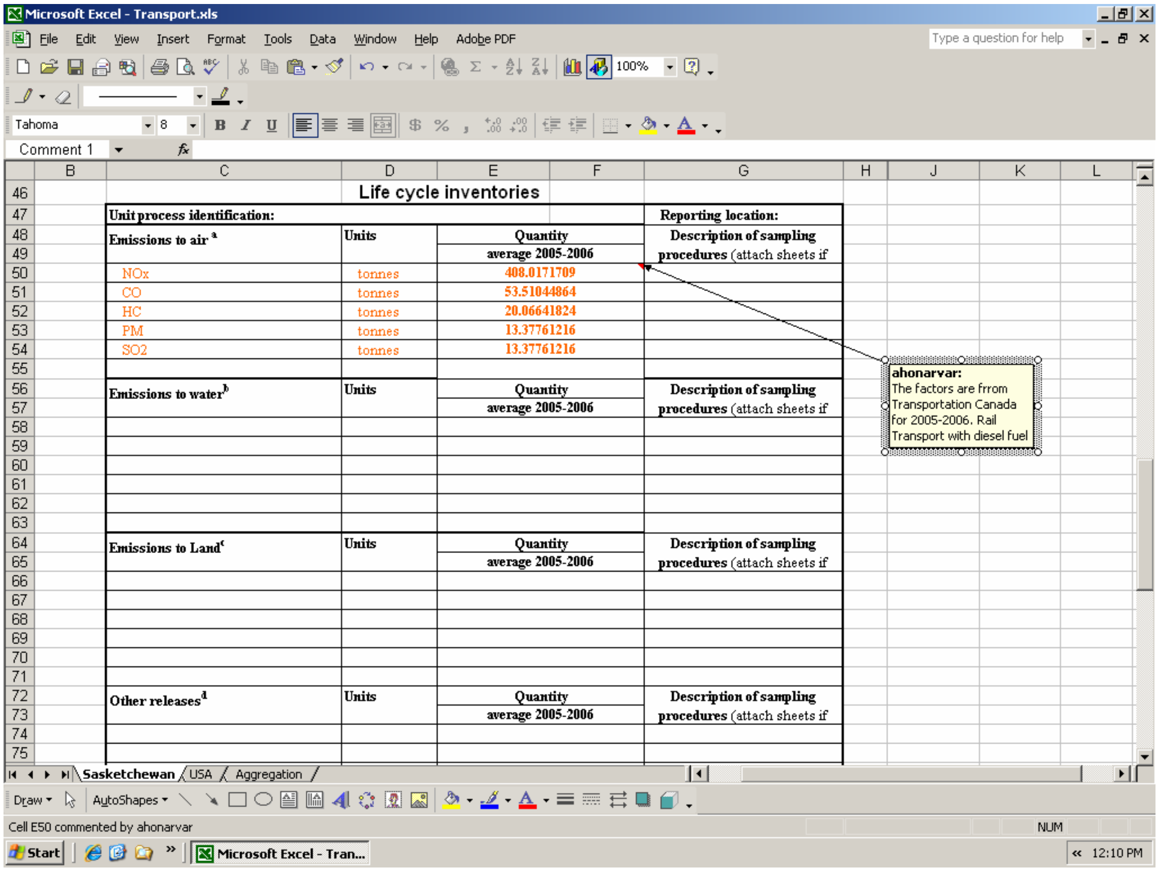


Life cycle inventories

Unit process identification:			Reporting location:
Emissions to air [a]	Units	Quantity 2005/2006	Description of sampling procedures (attach sheets if
Feedstock recovery	tonne	16182.74394	estimates
Landuse Changes	tonne	1504.251091	estimates
Gas Leaks and Flares	tonne	13520.91452	estimates
Emission Displaced	tonne	-15735.75118	estimates
Beinfait Mine			
Sulphur dioxide	tonnes	585.62	NPRI
Oxides of Nitrogen (expressed as NO2)	tonnes	190.329	NPRI
PM Total - Total Particulate Matter	tonnes	804.879	NPRI
PM2.5-Particulate Matter <= 2.5 Microns	tonnes	0	NPRI
PM10-Particulate Matter <= 10 Microns	tonnes	136.83	NPRI
CO_2	tonnes	109659.38	Environment Canada's(EC) GHG Inventory
CH_4	tonnes	0.4	EC GHG Inventory
CH_4 [CO_2 e]	tonnes	8.4	EC GHG Inventory
N_2O	tonnes	0.3	EC GHG Inventory
N_2O [CO2 e]	tonnes	93	EC GHG Inventory
HFC-134a	tonnes		
HFC-134a [CO_2 e]	tonnes		
Total GHG [CO2 e]	tonnes	109760.78	EC GHG Inventory

Figure D.8 lists both CAC and GHG weighted average emissions released from the production phase of the coal LCA. Saskatchewan's Benfait Coal Mine is chosen as an illustration. CAC and GHG emissions are collected from NPRI and Environment Canada's GHG Inventory respectively.

Figure D.9
Coal Transportation

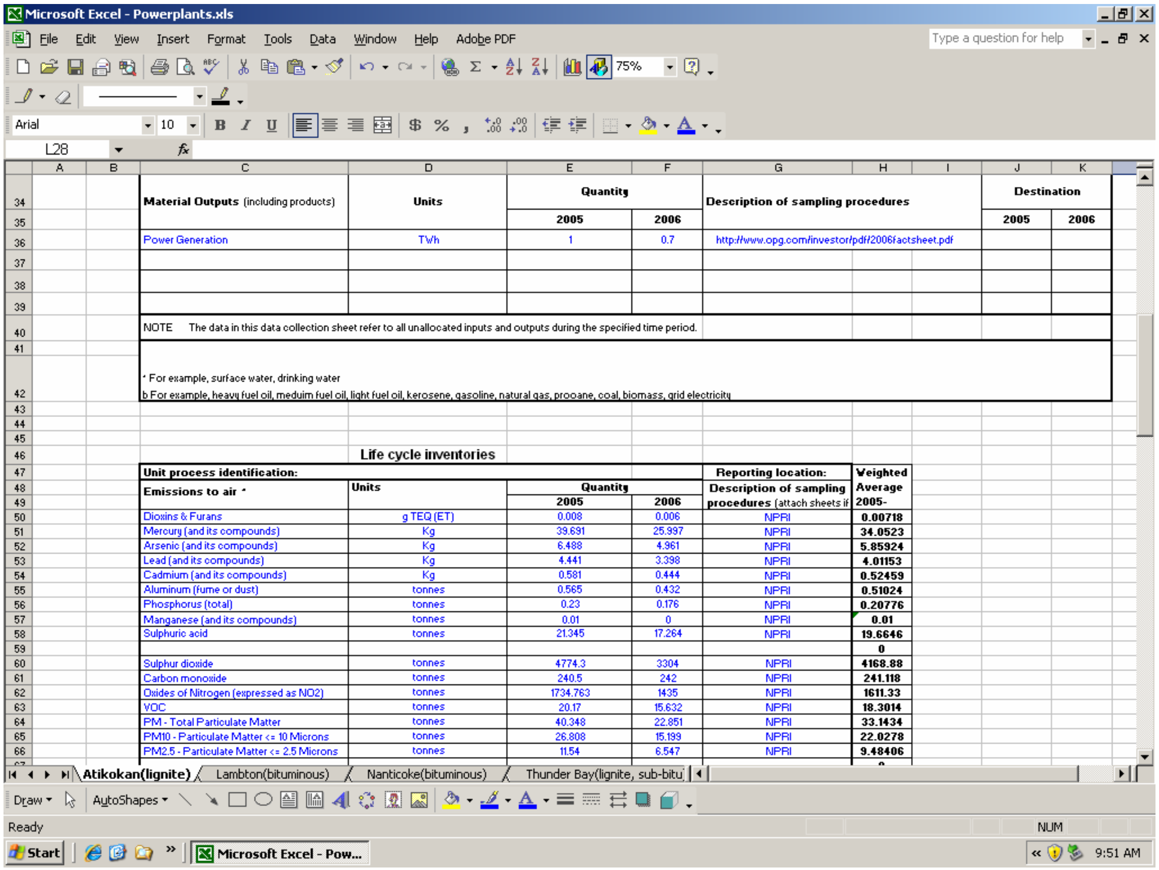


Life cycle inventories

Unit process identification:			Reporting location:
Emissions to air [a]	Units	Quantity average 2005-2006	Description of sampling procedures (attach sheets if
NOx	tonnes	408.0171709	
CO	tonnes	53.51044864	
HC	tonnes	20.06641824	
PM	tonnes	13.37761216	
SO2	tonnes	13.37761216	
Emissions to water[b]	Units	Quantity average 2005-2006	Description of sampling procedures (attach sheets if
Emissions to Land[c]	Units	Quantity average 2005-2006	Description of sampling procedures (attach sheets if
Other releases[d]	Units	Quantity average 2005-2006	Description of sampling procedures (attach sheets if

Figure D.9 shows estimated figures of CAC emitted from the transportation sector for coal. The estimates were generated using CO_2 conversion factors explained thoroughly in the report.

Figure D.10
Power Generation from Coal (I)



Material Outputs (including products)	Units	Quantity 2005	Quantity 2006	Description of sampling procedures	Destination 2005	Destination 2006
Power Generation	TWh	1	0.7	http://www.opg.com/investor/pdf/2006factsheet.pdf		

NOTE The data in this data collection sheet refer to all unallocated inputs and outputs during the specified time period.

ᵃ For example, surface water, drinking water
b For example, heavy fuel oil, meduim fuel oil, light fuel oil, kerosene, gasoline, natural gas, prooane, coal, biomass, grid electricity

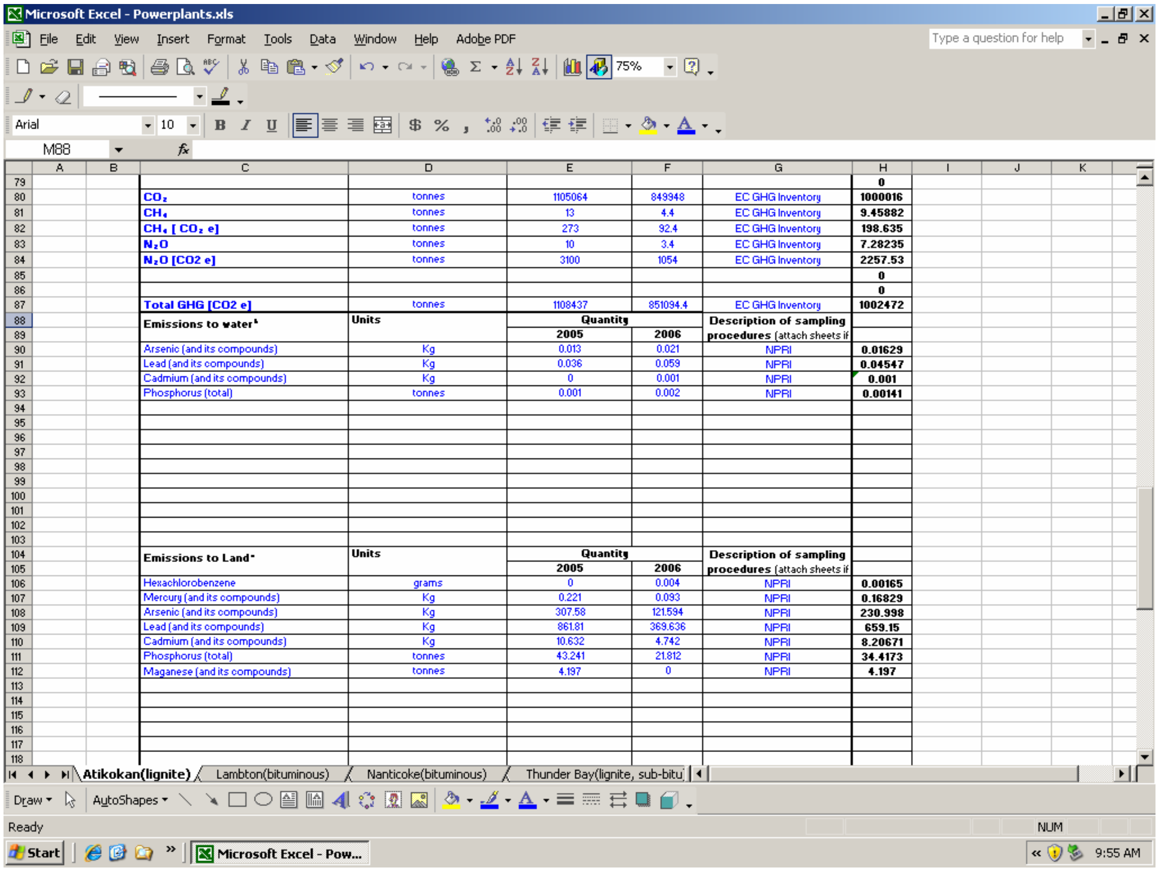
Life cycle inventories

Unit process identification:

Emissions to air ᵃ	Units	Quantity 2005	Quantity 2006	Reporting location: Description of sampling procedures (attach sheets if	Weighted Average 2005-
Dioxins & Furans	g TEQ (ET)	0.008	0.006	NPRI	0.00718
Mercury (and its compounds)	Kg	39.691	25.997	NPRI	34.0523
Arsenic (and its compounds)	Kg	6.488	4.961	NPRI	5.85924
Lead (and its compounds)	Kg	4.441	3.398	NPRI	4.01153
Cadmium (and its compounds)	Kg	0.581	0.444	NPRI	0.52459
Aluminum (fume or dust)	tonnes	0.565	0.432	NPRI	0.51024
Phosphorus (total)	tonnes	0.23	0.176	NPRI	0.20776
Manganese (and its compounds)	tonnes	0.01	0	NPRI	0.01
Sulphuric acid	tonnes	21.345	17.264	NPRI	19.6646
					0
Sulphur dioxide	tonnes	4774.3	3304	NPRI	4168.88
Carbon monoxide	tonnes	240.5	242	NPRI	241.118
Oxides of Nitrogen (expressed as NO2)	tonnes	1734.763	1435	NPRI	1611.33
VOC	tonnes	20.17	15.632	NPRI	18.3014
PM - Total Particulate Matter	tonnes	40.348	22.851	NPRI	33.1434
PM10 - Particulate Matter <= 10 Microns	tonnes	26.808	15.199	NPRI	22.0278
PM2.5 - Particulate Matter <= 2.5 Microns	tonnes	11.54	6.547	NPRI	9.48406

Figure D.10 shows total generation and CAC emissions recorded for Atikokan Coal Power Plant for 2005 and 2006. Data was extracted from NPRI and the Ontario Power Generation's website respectively. Same procedures are seen for all the coal power plants.

Figure D.11
Power Generation from Coal (II)



Microsoft Excel - Powerplants.xls

	C	D	E	F	G	H
79						0
80	CO_2	tonnes	1105064	849948	EC GHG Inventory	1000016
81	CH_4	tonnes	13	4.4	EC GHG Inventory	9.45882
82	CH_4 [CO_2 e]	tonnes	273	92.4	EC GHG Inventory	198.635
83	N_2O	tonnes	10	3.4	EC GHG Inventory	7.28235
84	N_2O [CO2 e]	tonnes	3100	1054	EC GHG Inventory	2257.53
85						0
86						0
87	Total GHG [CO2 e]	tonnes	1108437	851094.4	EC GHG Inventory	1002472
88	Emissions to water[1]	Units	Quantity		Description of sampling	
89			2005	2006	procedures (attach sheets if	
90	Arsenic (and its compounds)	Kg	0.013	0.021	NPRI	0.01629
91	Lead (and its compounds)	Kg	0.036	0.059	NPRI	0.04547
92	Cadmium (and its compounds)	Kg	0	0.001	NPRI	0.001
93	Phosphorus (total)	tonnes	0.001	0.002	NPRI	0.00141
94–103						
104	Emissions to Land*	Units	Quantity		Description of sampling	
105			2005	2006	procedures (attach sheets if	
106	Hexachlorobenzene	grams	0	0.004	NPRI	0.00165
107	Mercury (and its compounds)	Kg	0.221	0.093	NPRI	0.16829
108	Arsenic (and its compounds)	Kg	307.58	121.594	NPRI	230.998
109	Lead (and its compounds)	Kg	861.81	369.636	NPRI	659.15
110	Cadmium (and its compounds)	Kg	10.632	4.742	NPRI	8.20671
111	Phosphorus (total)	tonnes	43.241	21.812	NPRI	34.4173
112	Maganese (and its compounds)	tonnes	4.197	0	NPRI	4.197
113–118						

Atikokan(lignite) / Lambton(bituminous) / Nanticoke(bituminous) / Thunder Bay(lignite, sub-bitu

Figure D.11 displays more data on emissions from power generation from coal.

APPENDIX E

This appendix complements Section 4.3.3 of Chapter 4. Tables E.1 through E.4 provide details of sources and factors used in calculation of emissions from production, transportation and utilization of natural gas used for electricity generation in Ontario. Figures E.1 through E.5 present print-screens of the spreadsheets used in calculations of emissions relating to power generation from natural gas.

Table E.1
Average Fugitive Emissions from Pipeline Operation between Alberta and Ontario

Fitting	Methane Release Kg/hr/fitting	Fitting Alberta to Ontario	Total Fugitive Emissions Kg/hr	Total Fugitive Emissions $m^3/10^3\,m^3$
Valves (Sweet Gas)	0.04351	120	5.22	0.0009
Flanges/Connectors (Sweet Gas)	0.00253	1056	3.10	0.0005
Compressor seals	0.80488	544	528	0.0773
Pressure control valve (vented to atmosphere)	0.12096	272	39.67	0.0058
Total			575.99	0.0845

Source: Canadian Association of Petroleum Producers (CAPP): Calculating Greenhouse Gas Emissions (column 2), page 1-19

Engineering Data Book – SI – Version – Volume II page 23-2 shows the density of natural gas at 15 C^0 and 101.235 kpa pressures is 1.14739 m^3 gas /kg. The above information will help to convert the fugitive emissions from Kg/hr to m^3/ hr.

Table E.2

Average Fugitive Emissions from Alberta Gas Gathering - Zama to Empress

Fitting	Methane Release Kg/hr/fitting	Fitting - Zama to Empress	Total Fugitive Emissions Kg/hr	Total Fugitive Emissions $m^3/10^3\,m^3$
Valves (Sweet Gas)	0.04351	38	1.63	0.0003
Flanges/Connectors (Sweet)	0.00253	435	1.10	0.0002
Compressor seals	0.80488	240	193.17	0.0341
Pressure control valve (vented to atmosphere)	0.12096	120	14.52	0.0026
Total			210.42	0.0372

Source: Canadian Association of Petroleum Producers (CAPP): Calculating Greenhouse Gas Emissions (column 2), page 1-19

Engineering Data Book – SI – Version – Volume II page 23-2 shows the density of natural gas at 15 C^0 and 101.235 kpa pressures is 1.14739 m^3 gas /kg. The above information will help to convert the fugitive emissions from Kg/hr to m^3/ hr.

`Table E.3
Estimation of GHG Emissions from Natural Gas Use for Electricity Generation in Ontario
(1MWh of electricity generation use 238 m^3 gas)[1]

System Boundry	Natural Gas[2]	Emission Factors[3]			GHG Emissions			CO_2E	
	intensity	CO_2	N_2O	CH_4	CO_2	N_2O	CH_4		
	(m^3 / m^3)	g/m^3	g/m^3	g/m^3	t/TWh	t/TWh	t/TWh	t/TWh	%
Field Operation									
Combustion- Raw Gas	0.07939	2281	0.004	10.85	43,099	0.076	205	47,428	
Combustion- Process Gas	0.02894	1891	0.0347	0.0363	13,025	0.239	0.250	13,104	
Flaring- Raw Gas	0.00464	2281	0.004	10.85	2,519	0.004	12	2,772	
Flaring-Process Gas	0.00003	1853	0.004	13.6	13	0.000	0.097	15	
Venting - Raw Gas	0.00287	0.000	0.000	0.6784	0.000	0.000	0.463	10	
Total Emissions					**58,656**	**0.319**	**218**	**63,329**	**11.6**
Pipeline Operation									
Gathering System									
Combustion	0.02	1891	0.0347	0.0363	9,001	0.165	0.173	9,056	
Flaring	0.00031	1853	0.004	13.6	137	0.000	1.003	158	
Venting	0.000037	0.000	0.000	0.6784	0.000	0.000	0.006	0.125	
Natural Gas Export					0.000	0.000	0.000	0.000	
Combustion	0.05	1891	0.0347	0.0363	22,503	0.413	0.432	22,640	
Venting	0.00008	0.000	0.000	0.6784	0.000	0.000	0.014	0.287	
Total Emissions					**31,641**	**0.578**	**1.628**	**31,854.3**	**5.8**
Power Plant Operation	m^3 / MWh								
Total Emissions	238.00	1891	0.0347	0.0363	**450,058**	**8.259**	**8.639**	**452,800**	**82.6**
Total Emissions - LCA					**540,355**	**9.2**	**228.1**	**547,983**	**100**

1) Statistics Canada: Electric Power Generation, Transmission and Distribution. 2005, Catalogue No.57-202 -XIE
2) Cubic meters (m^3) of gas consumed per m^3 of natural gas production. See Alberta Energy and Utilities Board (AEUB) ST3-2003, 2004 & 2005; and ST60B-2005
3) Canadian Association of Petroleum Producers (CAPP): Calculating Greenhouse Gas Emissions, April 2003
4) For example consider estimation of CO_2 emission for raw gas consumption in field operation
CO_2 emission = (238 m^3 / MWh) * (0.07939 m^3 /m^3) * (2281 g/m^3) = 43,099 g/ MWh or t/TWh

Table E.4
Criteria Air Contaminant (CAC) Emissions in Moving Natural Gas from Alberta to Ontario via TCPL Northern Leg

CAC Base[1]			CAC - TCPL Northern Leg[2]			
Provinces	Description	tonnes(t)	%	tonnes(t)	$t/10^6\ m^3$ gas	t/TWh
	CAC - CO					
AB	Prov all pipelines	1,983	37	734	0.0170	4.0
SK	Prov TCPL total	759	74	562	0.0130	3.1
MB	Prov TCPL total	348	74	258	0.0060	1.4
ON	TCPL Stn 84-130	1,303	100	1,303	0.0302	7.2
Total					**0.0661**	**15.7**
	CAC - NO_2					
AB	Prov all pipelines	6,539	37	2,419	0.0560	13
SK	Prov TCPL total	3,088	74	2,285	0.0529	13
MB	Prov TCPL total	1,372	74	1,015	0.0235	6
ON	TCPL Stn 84-130	4,712	100	4,712	0.1091	26
Total					**0.2415**	**57**
	CAC - VOC					
AB	Prov all pipelines	23	37	9	0.0002	0.047
SK	Prov TCPL total	0	74	0	0.0000	0.000
MB	Prov TCPL total	0	74	0	0.0000	0.000
ON	TCPL Stn 84-130	0	100	0	0.0000	0.000
Total					**0.0002**	**0.047**
	CAC - PM_{10}					
AB	Prov all pipelines	43.0	37	16	0.0004	0.09
SK	Prov TCPL total	26.0	74	19	0.0004	0.11
MB	Prov TCPL total	10.0	74	7	0.0002	0.04
ON	TCPL Stn 84-130	43.4	100	43	0.0010	0.24
Total					**0.0020**	**0.47**
	CAC - $PM_{2.5}$					
AB	Prov all pipelines	48.0	37	18	0.0004	0.10
SK	Prov TCPL total	26.0	74	19	0.0004	0.11
MB	Prov TCPL total	10.0	74	7	0.0002	0.04
ON	TCPL Stn 84-130	43.8	100	44	0.0010	0.24
Total					**0.0020**	**0.49**
Method of Calculation		a	b	c= a * b	d = c / 43200[3]	e = d * 238[4]

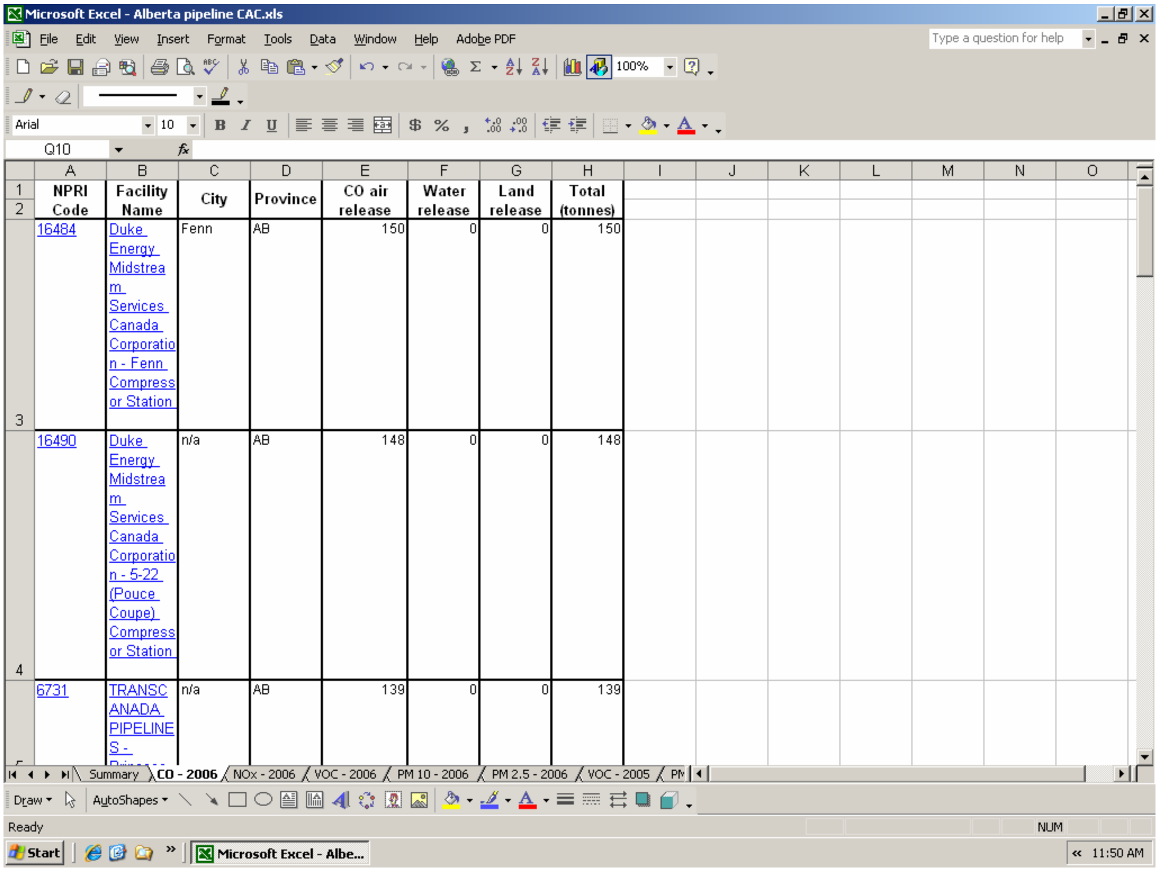
1) Canada's National Pollutant Release Inventory (NPRI): 2005 Facility & Substance Information for TRANSCANADA PIPELINES (TCPL)
2) TCPL Northern Leg splits near Winnipeg into two separate eastward routes.
3) 43,200 $10^6 m^3$ of gas entered TCPL mainline at Empress crossed from Manitoba into Northern leg of TCPL in 2005.
4) 238 $10^6\ m^3$ of natural gas is required to generate one TWh of electricity generation.

Figure E.1
Extraction and Production Phase of Natural Gas

	Facility ID	Facility Type	Facility Sub Type Short Descripti	Facility Name	Year Month	AB Receipt (1000 cu.m.)	Non AB Receipt (1000 cu.m.)
2	ABGS0002203	GS	Gas Gathering System	Gulf Westerose South	200512	7965.1	0
3	ABGS0002203	GS	Gas Gathering System	Gulf Westerose South	200511	8148.8	0
4	ABGS0002203	GS	Gas Gathering System	Gulf Westerose South	200510	8586.3	0
5	ABGS0002203	GS	Gas Gathering System	Gulf Westerose South	200509	7655.1	0
6	ABGS0002203	GS	Gas Gathering System	Gulf Westerose South	200508	7957.5	0
7	ABGS0002203	GS	Gas Gathering System	Gulf Westerose South	200507	5134.1	0
8	ABGS0002203	GS	Gas Gathering System	Gulf Westerose South	200506	7627.1	0
9	ABGS0002203	GS	Gas Gathering System	Gulf Westerose South	200505	7098.3	0
10	ABGS0002203	GS	Gas Gathering System	Gulf Westerose South	200504	6499.9	0
11	ABGS0002203	GS	Gas Gathering System	Gulf Westerose South	200503	6960.4	0
12	ABGS0002203	GS	Gas Gathering System	Gulf Westerose South	200502	6718.9	0
13	ABGS0002203	GS	Gas Gathering System	Gulf Westerose South	200501	7582	0
14	ABGS0002237	GS	Gas Gathering System	Crestar Three Hills Creek	200512	10719.2	0
15	ABGS0002237	GS	Gas Gathering System	Crestar Three Hills Creek	200511	10561.6	0
16	ABGS0002237	GS	Gas Gathering System	Crestar Three Hills Creek	200510	10368.4	0
17	ABGS0002237	GS	Gas Gathering System	Crestar Three Hills Creek	200509	10584.6	0
18	ABGS0002237	GS	Gas Gathering System	Crestar Three Hills Creek	200508	11320	0
19	ABGS0002237	GS	Gas Gathering System	Crestar Three Hills Creek	200507	11465	0
20	ABGS0002237	GS	Gas Gathering System	Crestar Three Hills Creek	200506	9369.2	0
21	ABGS0002237	GS	Gas Gathering System	Crestar Three Hills Creek	200505	11689	0
22	ABGS0002237	GS	Gas Gathering System	Crestar Three Hills Creek	200504	11223.9	0
23	ABGS0002237	GS	Gas Gathering System	Crestar Three Hills Creek	200503	11525.9	0
24	ABGS0002237	GS	Gas Gathering System	Crestar Three Hills Creek	200502	9938.4	0
25	ABGS0002237	GS	Gas Gathering System	Crestar Three Hills Creek	200501	11084.7	0
26	ABGS0002240	GS	Gas Gathering System	Imperial Golden Spike	200512	4986.2	0
27	ABGS0002240	GS	Gas Gathering System	Imperial Golden Spike	200511	4748.9	0
28	ABGS0002240	GS	Gas Gathering System	Imperial Golden Spike	200510	5337	0
29	ABGS0002240	GS	Gas Gathering System	Imperial Golden Spike	200509	5443	0
30	ABGS0002240	GS	Gas Gathering System	Imperial Golden Spike	200508	5582.6	0
31	ABGS0002240	GS	Gas Gathering System	Imperial Golden Spike	200507	6027.6	0

Figure E.1 shows the downloaded ERCB data for natural gas production in Alberta in 2005. This was used to estimate total production in Alberta from various gas plants and gathering systems. One by one, the natural gas production facilities were entered to the NPRI data search to get their respective emission data. Similar methodology was used for 2006.

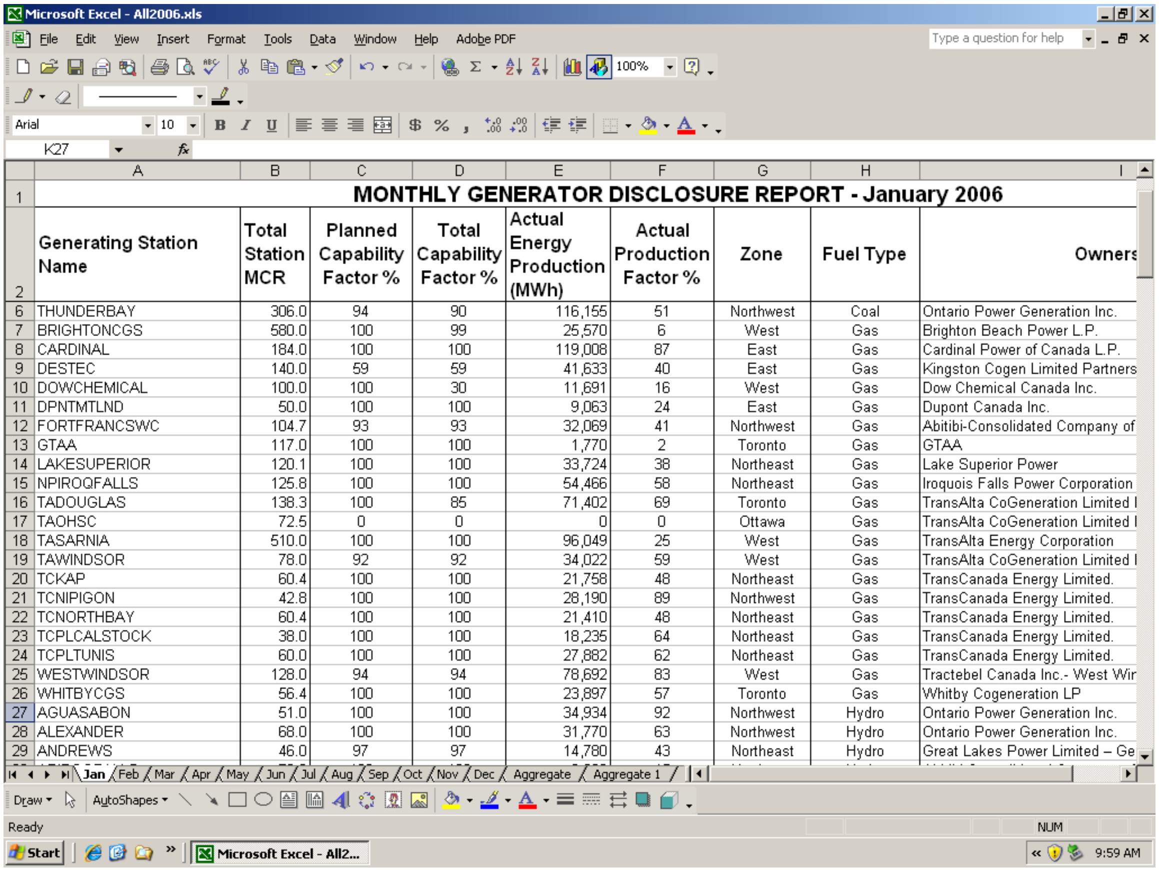
Figure E.2
Transportation Phase of Natural Gas



NPRI Code	Facility Name	City	Province	CO air release	Water release	Land release	Total (tonnes)
16484	Duke Energy Midstream Services Canada Corporation - Fenn Compressor Station	Fenn	AB	150	0	0	150
16490	Duke Energy Midstream Services Canada Corporation - 5-22 (Pouce Coupe) Compressor Station	n/a	AB	148	0	0	148
6731	TRANSCANADA PIPELINES -	n/a	AB	139	0	0	139

Pipeline Transportation of Natural Gas (NAICS Code: 4862) can be extracted from the NPRI website. Figure 8 shows emissions released from Alberta natural gas pipelines by pollutant in tones. Similar search was done for Saskatchewan, Manitoba, and Ontario.

Figure E.3
Power Generation Phase of Natural Gas (I)

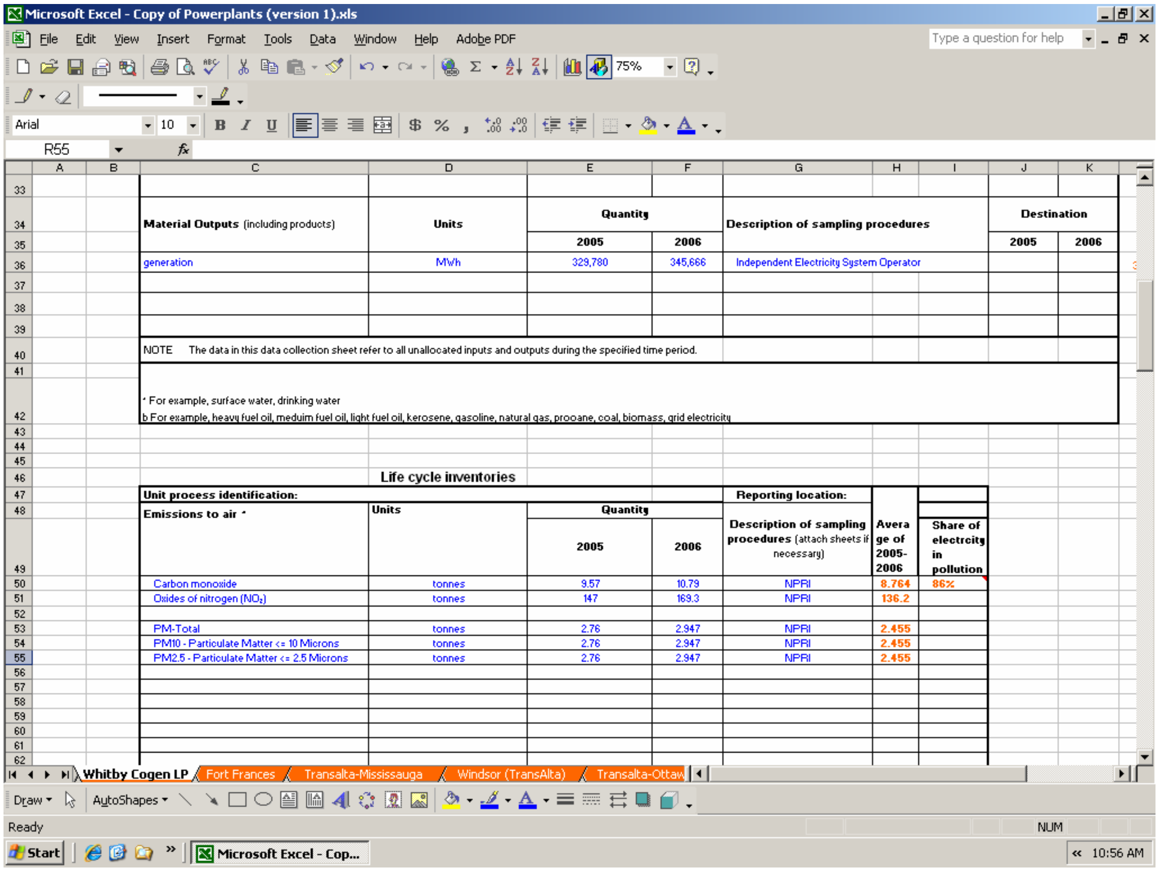


MONTHLY GENERATOR DISCLOSURE REPORT - January 2006

	Generating Station Name	Total Station MCR	Planned Capability Factor %	Total Capability Factor %	Actual Energy Production (MWh)	Actual Production Factor %	Zone	Fuel Type	Owners
6	THUNDERBAY	306.0	94	90	116,155	51	Northwest	Coal	Ontario Power Generation Inc.
7	BRIGHTONCGS	580.0	100	99	25,570	6	West	Gas	Brighton Beach Power L.P.
8	CARDINAL	184.0	100	100	119,008	87	East	Gas	Cardinal Power of Canada L.P.
9	DESTEC	140.0	59	59	41,633	40	East	Gas	Kingston Cogen Limited Partners
10	DOWCHEMICAL	100.0	100	30	11,691	16	West	Gas	Dow Chemical Canada Inc.
11	DPNTMTLND	50.0	100	100	9,063	24	East	Gas	Dupont Canada Inc.
12	FORTFRANCSWC	104.7	93	93	32,069	41	Northwest	Gas	Abitibi-Consolidated Company of
13	GTAA	117.0	100	100	1,770	2	Toronto	Gas	GTAA
14	LAKESUPERIOR	120.1	100	100	33,724	38	Northeast	Gas	Lake Superior Power
15	NPIROQFALLS	125.8	100	100	54,466	58	Northeast	Gas	Iroquois Falls Power Corporation
16	TADOUGLAS	138.3	100	85	71,402	69	Toronto	Gas	TransAlta CoGeneration Limited I
17	TAOHSC	72.5	0	0	0	0	Ottawa	Gas	TransAlta CoGeneration Limited I
18	TASARNIA	510.0	100	100	96,049	25	West	Gas	TransAlta Energy Corporation
19	TAWINDSOR	78.0	92	92	34,022	59	West	Gas	TransAlta CoGeneration Limited I
20	TCKAP	60.4	100	100	21,758	48	Northeast	Gas	TransCanada Energy Limited.
21	TCNIPIGON	42.8	100	100	28,190	89	Northwest	Gas	TransCanada Energy Limited.
22	TCNORTHBAY	60.4	100	100	21,410	48	Northeast	Gas	TransCanada Energy Limited.
23	TCPLCALSTOCK	38.0	100	100	18,235	64	Northeast	Gas	TransCanada Energy Limited.
24	TCPLTUNIS	60.0	100	100	27,882	62	Northeast	Gas	TransCanada Energy Limited.
25	WESTWINDSOR	128.0	94	94	78,692	83	West	Gas	Tractebel Canada Inc.- West Wir
26	WHITBYCGS	56.4	100	100	23,897	57	Toronto	Gas	Whitby Cogeneration LP
27	AGUASABON	51.0	100	100	34,934	92	Northwest	Hydro	Ontario Power Generation Inc.
28	ALEXANDER	68.0	100	100	31,770	63	Northwest	Hydro	Ontario Power Generation Inc.
29	ANDREWS	46.0	97	97	14,780	43	Northeast	Hydro	Great Lakes Power Limited – Ge

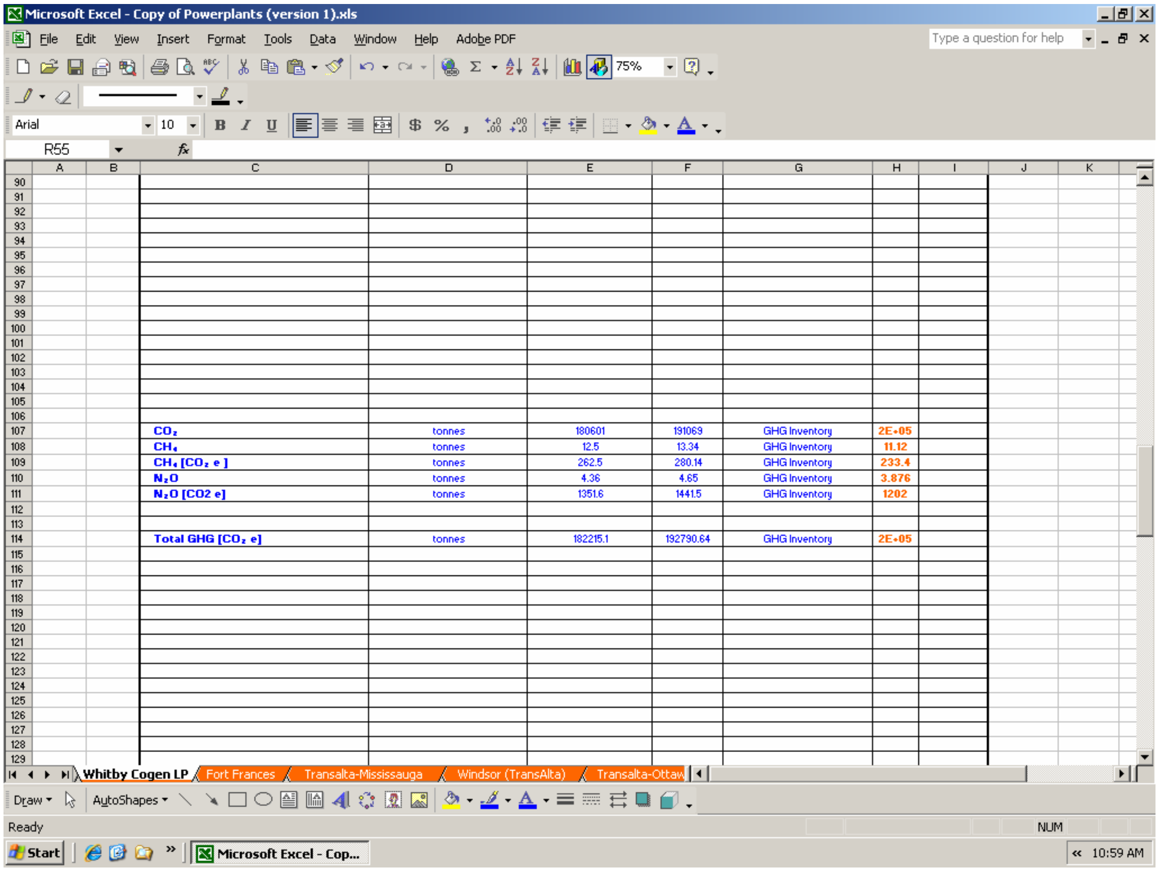
Monthly generation data of all power plants connected to the Ontario electricity grid are recorded by the Independent Electric System Operator (IESO). Figure E.3 shows generation data for natural gas power plants in January 2006.

Figure E.4
Power Generation Phase of Natural Gas (II)



Furthermore the data is then recorded annually in the LCA tables for 2005 and 2006. In this case, Whitby Cogen LP power plant is demonstrated as an example in Figure E.4.

Figure E.5
Power Generation Phase of Natural Gas (III)



	C	D	E	F	G	H
107	CO_2	tonnes	180601	191069	GHG Inventory	2E+05
108	CH_4	tonnes	12.5	13.34	GHG Inventory	11.12
109	CH_4 [CO_2 e]	tonnes	262.5	280.14	GHG Inventory	233.4
110	N_2O	tonnes	4.36	4.65	GHG Inventory	3.876
111	N_2O [CO2 e]	tonnes	1351.6	1441.5	GHG Inventory	1202
114	Total GHG [CO_2 e]	tonnes	182215.1	192790.64	GHG Inventory	2E+05

Figure E.5 display recordings of GHG emissions.

APPENDIX F
EMISSIONS VERSUS COLLECTIVE DOSES: THE SPECIAL CASE OF RADIATION

Largely to avoid the cost and complexity of estimating collective doses, this study has adopted release rates as its comparative measure of environmental consequences of electricity generation from coal, natural gas and nuclear fuel. If, hypothetically, the release rate of carbon monoxide or lead from coal-fired generation were to be double that from natural gas-fired generation, one could reasonably assume that a coal-fired power plant on a given site would produce twice as large a collective dose of carbon monoxide or lead as a gas-fired plant of the same capacity and output.

One should be somewhat less sanguine about the use of release rates in fuel-supply comparisons, because the fuels come from different places with different population densities. For example, subbituminous coal comes to Ontario from mines in Wyoming and possibly Montana, with state population densities slightly above two persons per square kilometre; subbituminous coal comes from southern Saskatchewan where the population density is below two persons per square kilometre, and bituminous coal comes from Appalachian states whose population density ranges from 29 to 107 persons per square kilometre. Natural gas is deemed to come from (a variety of locations in) Alberta, whose population density is 5.1 persons per square kilometre, whereas uranium is mined and milled in far northern Saskatchewan, in a census division with a population density of only 0.13 persons per square kilometre. On this basis, it would appear that coal and natural gas are essentially tied in terms of population density and uranium is strongly favoured. Taking into account the higher population densities at Ontario's refining and conversion facilities (Blind River being located in Algoma District and Port Hope in Northumberland County, with population densities of 2.4 and 16.0 persons per km^2 respectively), the population-density advantage for uranium over coal and natural gas is somewhat reduced. Nevertheless, conclusions drawn from a life-cycle comparison of criteria air contaminants or heavy metals associated with utilizing the three fuels in terms of release rates should not be markedly different from those drawn from a comparison in terms of collective doses.

Unfortunately, radiation does not lend itself so readily to such a simplification. Starting from a becquerel-unit estimate of a radionuclide's release rate, calculation of the corresponding collective dose in person-sieverts takes into account the following considerations (some of which also apply to criteria air contaminants and heavy metals):

- The amount of energy released per decay, typically measured in millions of electron-volts (MeV)
- Physical half-life, the amount of time required for half of a quantity of a given radionuclide to decay

- Biological half-life, the amount of time required for an organ or organism to eliminate half of the intake quantity of a radionuclide
- Pathway: inhalation (breathing in), ingestion (eating or drinking), or direct (external) exposure
- Regional population density
- Wind patterns – downwind populations are more heavily exposed than upwind populations

Radionuclide releases at natural gas processing plants, coal mines, coal-fired power plants, uranium mines and mills and uranium refining and conversion facilities consist largely of uranium-238 (physical half-life 4.5 billion years), thorium-232 (physical half-life 14 billion years) and uranium- 235 (physical half-life 700 million years). None of these nuclides or the products of their respective decay chains are readily eliminated from the body. The half-lives of uranium-238, thorium-232 and uranium-235 are long relative to their daughter radionuclides, so in nature the radionuclides are in "secular equilibrium": the rate of decline in radiation for each of the three decay chains is governed by the parent radionuclides's half-life. Barring significant variations in terms of population density or wind patterns, comparisons of radionuclide releases from these facilities should yield conclusions similar to those derived from comparisons of collective doses.

In contrast, radon-222 with a half-life of 3.8 days is the predominant radionuclide in natural gas as it is burned in gas-fired power plants, whereas releases of radionuclides to both air and water from CANDU nuclear power plants and, to a lesser extent, light-water reactors as well, are dominated by tritium with a physical half-life of 12.3 years and a biological half-life of about ten days. (Emission rates for several isotopes of krypton and xenon are higher, but since these noble gases are expelled almost entirely by the lungs without entering biological processes their biological half-lives can effectively be numbered in minutes.) Carbon-14 releases to air (physical half-life of 5,730 years and biological half-life of 12 days) from nuclear power plants are also important. This produces an entirely different relationship between releases and collective doses than one finds where radioisotope releases are dominated by uranium, thorium and their respective decay chains. The following table from the 2000 report to the U.N. General Assembly of the United Nations Scientific Committee of the Effects of Atomic Radiation (UNSCEAR) illustrates this relationship:

Table F.1
Collective Effective Dose per Unit
Release of Radionuclides from Reactors

Type of Release	Radionuclide	Pathway	Collective Dose per Unit Release (person-Sv/PBq)
Airborne	Noble gases:		
	PWR	Immersion	0.11
	BWR	Immersion	0.43
	GCR	Immersion	0.90
	Tritium	Ingestion	2.1
	Carbon-14	Ingestion	270
	Iodine	External	4.5
		Ingestion	250
		Inhalation	49
		All pathways	300
	Particulates	External	1,080
		Ingestion	830
		Inhalation	33
		All pathways	2,000
Liquid	Tritium	Ingestion	0.65
	Particulates	Ingestion	330

SOURCE: Taken from UNSCEAR 2000 Report, Annex C, Table 38

The National Commission on Radiation Protection and Measurements[106] determined that for a 1 GW nuclear power plant in the United States the collective annual dose equivalents were 0.94 person-sieverts per year [0.13 person-Sv/TWh] in mining and 0.25 [0.036 person-Sv/TWh] in milling compared to just 0.048 [0.0068 person-Sv/TWh] from the power plant. The total life-cycle collective effective yearly dose for nuclear power was found to be 1.36 person-sieverts [0.19 person-Sv/TWh]. By way of comparison, the yearly collective effective dose from a coal-fired power plant of similar capacity was found in another NCRP report[107] to be 4.9 person-sieverts [0.70 person-Sv/TWh] – more than one hundred times as large as the collective effective dose from the corresponding nuclear plant, and considerably higher than the collective effective dose from the entire nuclear fuel cycle. NCRP did not attempt to estimate the collective effective dose for the life cycle of gas-fired or coal-fired generation, just for a coal-fired power plant. No similar dose analysis has been performed for CANDU nuclear technology or for Canada's nuclear fuel supply.

[106] NCRP Report No. 92, "Public Radiation Exposure from Nuclear Power Generation in the United States," 1987, Table 15.3 on p. 160.

[107] NCRP Report NO. 95, "Radiation Exposure of the U.S. Population from Consumer Products and Miscellaneous Sources," Table 3.13 on p. 34.

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GLOSSARY AND ABBREVIATIONS

Glossary

Air pollution: Any substance (such as carbon monoxide or sulphur dioxide) in air that in a high enough concentration will damage the health of humans, animals, or vegetation.

Base load: The minimum amount of electric power delivered or required at a steady rate over a given period of time.

Bituminous: An intermediate ranked coal between anthracite (coal of the highest rank) and sub-bituminous coal. It has high carbon content and is low in moisture content. Bituminous coal can be used for both steelmaking and power generation.

Boiler: A device for generating steam for power, processing, or heating purposes, or for producing hot water for heating purposes or hot water supply. Heat from an external combustion source is transmitted to a fluid contained within the tubes in the boiler shell. This fluid is delivered to an end use at a desired pressure, temperature, and quality.

Bq (Becquerel): The International System unit of radioactivity, equal to one nuclear decay per second.

CAC: Criteria Air Contaminants including sulfur dioxide, carbon monoxide, oxides of nitrogen, volatile organic compounds, and particulate matter

CANDU: Canadian Deuterium Uranium Reactor. A standardized design for nuclear generating stations developed in Canada. All nuclear generating units in Canada use the CANDU design.

Capacity: The maximum power capability of a generating unit in kilowatts or megawatts.

Carbon Dioxide (CO2): A colourless, odourless, non-poisonous gas that is a normal part of the earth's atmosphere. Carbon dioxide is a product of fossil-fuel combustion as well as other processes. It is considered a greenhouse gas as it traps heat (infrared energy) radiated by the earth into the atmosphere and thereby contributes to the potential for global warming.

Carbon Dioxide equivalent (CO2 eq.): Every greenhouse gas has a Global Warming Potential (GWP), based on a 100-year timeframe. CO2 eq. describes the impact of each greenhouse gases in terms of GWP relative to carbon. The GWP of the main greenhouse gases are carbon dioxide (1), methane (21), nitrous oxide (310). For example, the impact of one tonne of methane on global warming is 21 times that of one tonne of carbon dioxide.

Coal: A black or brownish-black solid combustible substance formed by the partial decomposition of vegetable matter without access to air. The rank of coal, which includes anthracite, bituminous coal, sub-bituminous coal, and lignite, is based on fixed carbon, volatile matter, and calorific value.

Coal-fired electricity: electricity produced using coal as fuel.

Cogeneration: Combined heat and power generation, in which heat otherwise wasted is used for industrial purposes

Combined Cycle Generation: An electric generating method in which electricity is produced from otherwise lost waste heat created by one or more gas (combustion) turbines. The heat is routed to a conventional boiler or to a heat recovery steam generator for utilization by a steam turbine in the production of additional electricity.

Combustion: The combining of oxygen with other elements through a chemical reaction that generates heat.

Decarbonization of electricity: Transition of electricity generation to an energy source that is essentially free of carbon, such as uranium and renewables, or to less carbon-intensive fuels such as natural gas or to the capture and sequestration of CO_2 in to sharply reduce the associated CO_2 emissions.

Emissions: Anthropogenic releases of gases to the atmosphere. In the context of global climate change, they consist of greenhouse gases (e.g. the release of carbon dioxide during fuel combustion).

Energy Mix: The combination of energy sources (coal, oil, gas uranium, wind, etc) used to provide energy at any given time and place.

Enriched nuclear fuel: For use as nuclear fuel, enriched UF_6 is converted into uranium dioxide (UO_2) powder that is then processed into pellet form.

Facility: An existing or planned location or site at which prime movers, electric generators, and/or equipment for converting mechanical, chemical, and/or nuclear energy into electric energy are, or will be, situated. A facility may contain generating units of either the same or different prime mover types.

FBC (Fluidized Bed Combustion): A process which has a high capability of removing sulphur from coal during combustion.

FBR (Fast Breeder Reactors): This process allows the extraction of up to 100 times as much energy from uranium as is possible using light water reactors.

FGD (Flue Gas Desulphurization): The devices that scrub the sulphur out of the smoke released by coal combustion.

Fission: Uranium is the fuel used in most types of nuclear reactors. When uranium is hit by a slow neutron, its atom is split in two and releases large amounts of energy.

Fuel Fabrication: Facilities that converting uranium dioxide (UO2) or uranium hexafluoride (UF6) to synthetic fuel to be used in nuclear power plants.

Fuel: Any substance that can be burned to produce heat. It can also be a material that can be fissioned in a nuclear reaction to produce heat.

Gas –fired electricity: A power plant burning natural gas for electricity generation.

Gas Hydrates: Crystalline solid whose building blocks consist of a gas molecule surrounded by a cage of water molecules.

GCR (Gas-cooled Graphite Reactors): The two moderators available for use in gas cooled reactors are graphite and beryllium. Graphite has excellent heat resistant properties. Beryllium is a toxic rare metal.

Generating Unit: Any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power.

Generator: A machine that converts mechanical energy into electrical energy.

Gigawatt (GW): One billion watts

Gigawatt-Hour (GWh): One billion watt-hours

Global Warming: The theoretical escalation of global temperatures caused by the increase of greenhouse gas concentrations in the lower atmosphere.

Greenhouse Effect: The increasing mean global surface temperature of the earth caused by gases in the atmosphere (including carbon dioxide, methane, nitrous oxide, ozone, and chlorofluorocarbons). The greenhouse effect allows solar radiation to penetrate but absorbs the infrared radiation returning to space.

Greenhouse Gases (GHG): A collection of gaseous substances, primarily consisting of carbon dioxide, methane, and nitrogen oxides that have been shown to warm the earth's atmosphere by trapping solar radiation. Greenhouse gases also include chlorofluorocarbons (CFCs), a group of chemicals used primarily in cooling systems and which are now either outlawed or severely restricted by most industrialized nations.

Heat Rate: A measure of efficiency which is the ratio of the heat content of the fuel used (expressed in kJ or Btu) in the unit or plant to kWh of net electrical energy produced.

Heavy Water (D_2O): Water composed of heavy isotopes of hydrogen.

Hydrogen: A colourless, odourless, highly flammable gaseous element. It is the lightest of all gases and the most abundant element in the universe, occurring chiefly in combination with oxygen in water and also in acids, bases, alcohols, petroleum, and other hydrocarbons.

IGCC (Integrated Gasification-Combined Cycle Technology): Coal, water, and oxygen are fed to gratifier, which produces syngas. This medium-Btu gas is cleaned (particulates and sulphur compounds removed) and is fed to a gas turbine. The hot exhaust of the gas turbine and heat recovered from the gasification process are routed through a heat-recovery generator to produce steam, which drives a steam turbine to produce electricity.

Joule: It is the energy produced by the power of one watt operating for one second. There are 3.6 megajoules in a kilowatt-hour (or 3.6 gigajoules in a megawatt-hour).

Kilowatt (kW): A standard unit used to measure electric power, equal to 1,000. A kilowatt can be visualized as the total amount of power required to light ten 100-watt light bulbs.

Kilowatt hour (kWh): One thousand watt-hours of electrical energy.

LCA (Life Cycle Assessment): Examines the environmental impacts of an activity from inception to completion, or from cradle to grave.

Light Water: ordinary water (H_2O), as distinct from heavy water (D_2O)

Methane: the principal component of natural gas. It is radioactive if the carbon atom is the isotope C-14.

Molecule: the smallest possible quantity of a chemical compound.

Natural Gas: a mix of hydrocarbons consisting primarily of methane and quantities of ethane, propane, butane, and pentane plus. Impurities of natural gas (carbon dioxide, nitrogen, helium and hydrogen sulfide) should be removed before it enters a transmission pipeline.

Nitrogen Oxides (NOx): Formed when nitrogen (N_2) combines with oxygen (O_2) in the burning of fossil fuels. The primary source of nitrogen oxide emissions is vehicle exhaust.

NOx Scrubbers: Those devices that use special chemicals "catalysts" that break apart the NOx into non-polluting gases.

NRCan: Natural Resources Canada Nuclear Electric Power (Nuclear Power): Electricity generated by the use of the thermal energy released from the fission of nuclear fuel in a reactor.

Nuclear Fission: The process of splitting or fissioning atoms.

Nuclear Power Plant: A generating plant in which heat produced in a nuclear reactor by the fissioning of nuclear fuel is used to drive a steam turbine.

Nuclear Radiation: energy emitted in the form of rays or particles by substances such as uranium, plutonium, and tritium (whose atoms are not stable and are spontaneously decaying) that may cause severe or fatal health problems to people who are exposed to it.

Nuclear Reactor: A device in which a fission chain reaction can be initiated, maintained, and controlled. Nuclear reactors are used in the power industry to produce steam used for the generation of electricity.

PCC: Pulverized Coal Combustion (Powdered or pulverized coal is blown into the combustion zone of a furnace and burns more rapidly and efficiently than larger particles).

Primary Energy: Energy embodied in natural resources, (e.g. coal, crude oil, sunlight, uranium) that has not undergone any anthropogenic conversion or transformation beyond what is required to make them marketable*.*

Prime Mover: The engine, turbine, water wheel, or similar machine that drives an electric generator.

Radioactive Waste: Materials left over from making nuclear energy. Radioactive waste can destroy living organisms if it is not stored safely.

Radionuclide: A nuclide (A type of atom specified by its atomic number, mass, and energy state) that exhibits radioactivity,

Reliability: The degree to which the performance of the elements of a system results in power being delivered to consumers within accepted standards and in the amount desired. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on consumer service.

Run-of-River: A hydroelectric generating power plant that operates based only on available stream flow because it lacks water storage capacity.

Scrubber: Any of several forms of chemical/physical devices which operate to remove sulphur compounds formed as a result of fossil-fuel combustion.

Single Cycle Generation: An electric generating method in which electricity is produced from combustion of natural gas or oil in which the resultant heat is not utilized to produce more electricity.

Subbituminous coal: It has low carbon content and high percentages of moisture and volatile material. Subbituminous coal is mainly used for generating electricity; its heating value ranks between bituminous coal and lignite (low rank coal).

Sulphur Oxides (SOx): A family of gases, including sulphur dioxide (SO_2) formed when sulphur, or fossil fuels containing sulphur, burn in air.

System boundary: Specification of the functional units that are included in or excluded from the processes to be analyzed in process life cycle analysis.

TBq (terabecquerel): 10^{12} becquerels (10^{12} nuclear decays per second).

Terawatt (TW): One trillion watts of capacity.

Terawatt hour (TWh): One trillion watt-hours of electric energy.

Thermal Efficiency: Output in energy units expressed as a percentage of the energy contained in the fuel from which it is derived. Because there are 3.6 megajoules in a kilowatt-hour, a heat rate can also be obtained by taking 100% of 3.6 divided by the heat rate of the generating unit in MJ/kWh.

Thermal Efficiency: The percentage of total energy content of a fuel that is converted to useful output; in other words, the ratio of useful work (energy output) to total work (energy input).

Tonne: A metric unit of weight equivalent to 1000 kg or 2,204.6 pounds. This is also known as a "metric ton" . However, the "short ton" (Ton) is an Imperial unit of weight equivalent to 2,000 pounds or 907.2 kg.

Turbine: A machine for generating rotary mechanical power from the energy of a stream of fluid (such as water, steam, or hot gas). Turbines convert the kinetic energy of fluids to mechanical energy through the principles of impulse, reaction, or a mixture of the two.

Uranium (U): A heavy, naturally radioactive, metallic element (atomic number 92). Its two principally occurring isotopes are uranium-235 and uranium-238. Uranium-235 is indispensable to the nuclear industry because it is the only uranium isotope existing in nature, to any appreciable extent, that is fissionable by thermal neutrons. Uranium-238 is also important because it absorbs neutrons to produce a radioactive isotope that subsequently decays to the isotope plutonium-239, which also is fissionable by thermal neutrons.

Water pollution: Contamination of water resources by harmful chemical or waste material discharged into the water. Water pollutants include the heavy metals lead, mercury, arsenic, and uranium.

Watt: The standard unit of electrical power. One watt is equal to one joule per second. It also equals one ampere flowing under a pressure of one volt at unit power factor.

Watt-Hour: The standard unit of electrical energy. It is equal to one watt of power operating steadily for one hour.

Yellowcake (U_3O_8): Obtain through the milling and chemical processing of uranium ore. It is a coarse powder which is insoluble in water and melts at approximately 2878°C.

Abbreviations

ACR: Advanced CANDU Reactor

AECL: Atomic Energy of Canada Limited

AEUB: Alberta Energy and Utilities Board

AFBC: Atmospheric Fluidized-Bed Combustors

AGR: Advanced Gas Cooled, Graphite Moderated Reactor

AUC: Alberta Utilities Commission

AWG: Athabasca Working Group

BFW: Boiling Feed Water

BWR: Boiling Light Water Cooled and Moderated Reactor

CAPP: Canadian Association of Petroleum Producers

CCT: Clean Coal Technologies

CEA: Canadian Electricity Association

CEO: Coal Electricity Output

CHP: Combined Heat and Power

CIEEDAC: Canadian Industrial Energy End-Use Data and Analysis Centre

CNSC: Canadian Nuclear Safety Commission

COG: CANDU Operators Group

CPPI: Canadian Petroleum Products Institute

EIO: Economic Input-Output

EPA: Environmental Protection Agency

FERC: Federal Energy Regulatory Commission

GCHWR: Gas Cooled, Heavy Water Moderated Reactor

GEO: Gas Electricity Output

HRSG: Heat Recovery Steam Generator

HTGR: High Temperature Gas Cooled Reactor

HWLWR: Heavy Water Moderated, Boiling Light Water Cooled Reactor

IAEA: International Atomic Energy Agency

IEA: International Energy Agency

IPCC: Intergovernmental Panel on Climate Change

ISO: International Organization for Standardization

ISSC: International Ship Security Certificate

LCIA: Life Cycle Impact Assessment

LEU: Low-enriched uranium (use in power plants)

LFR: Lead-Cooled Fast Reactor

LGR: Light (Water Cooled, Graphite Moderated) Reactor

LMFBR: Liquid Metal Fast Breeder Reactor

MNR: McMaster Nuclear Reactor

MSR: Molten Salt Reactor

MTSR: Marine Transportation Security Regulations

NEB: National Energy Board

NEO: Nuclear Electricity Output

NGCC: Natural gas combined-cycle power plant

NPCIL: Nuclear Power Corporation of India Limited

NPRI: The National Pollutant Release Inventory maintained by Environment Canada

NRC: National Research Council

NRCan: Natural Resources Canada

NWMO: Nuclear Waste Management Organization

OECD: Organization for Economic Co-operation and Development

OPA: Ontario Power Authority

OTSG: Once through steam generator

PFBC: Pressurized Fluidized-Bed Combustors

PHWR: Pressurized Heavy Water Moderated and Cooled Reactor

PSAC: Petroleum Services Association of Canada

PWR: Pressurized Water Reactor

SCWR: Supercritical Water-Cooled Reactor

SETC: Society of Environmental Toxicology and Chemistry

SFR: Sodium-Cooled Fast Reactor

SG: Steam Generator

SRC: Saskatchewan Research Council

ST: Steam Turbine

TCPL: TransCanada PipeLines

TEO: Total electricity output

UNSCEAR: United Nations Scientific Committee on the Effects of Atomic Radiation

VHTR: Very High Temperature Reactor

WNA: World Nuclear Association

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