

EVALUATION OF ENVIRONMENTAL  
PERFORMANCE OF CARBON CAPTURE AND  
STORAGE PROJECT IN CANADA USING LIFE  
CYCLE ASSESSMENT METHODOLOGY

A Thesis

Submitted to the Faculty of Graduate Studies and Research

In Partial Fulfillment of the Requirements

for the Degree of Doctor of Philosophy

in Environmental Systems Engineering

University of Regina

by

Anastassia Manuilova

Regina, Saskatchewan

March, 2011

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*Your file Votre référence*  
ISBN: 978-0-494-79965-9  
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Anastassia Manuilova, candidate for the degree of Doctor of Philosophy in Environmental Systems Engineering, has presented a thesis titled, ***Evaluation of Environmental Performance of Carbon Capture and Storage Project in Canada Using Life Cycle Assessment Methodology***, in an oral examination held on Friday, October 29, 2010. The following committee members have found the thesis acceptable in form and content, and that the candidate demonstrated satisfactory knowledge of the subject material.

External Examiner: \*Dr. Kourosh E. Zanganeh,  
CanmetENERGY, Natural Resources Canada

Supervisor: Dr. Malcolm Wilson, Faculty of Engineering and Applied Science

Committee Member: Dr. Dena McMartin, Environmental Systems Engineering

Committee Member: Dr. Raphael Idem, Industrial Systems Engineering

Committee Member: Dr. Hairuo Qing, Department of Geology

Chair of Defense: Dr. W. R. Dolmage, Faculty of Education

\*Not present at defense

## ABSTRACT

Carbon dioxide capture and storage (CCS) is increasingly seen as an important component of any broadly-based greenhouse gas reduction program, such as the use of renewable energy sources or nuclear energy. Although a fossil fuel power plant is a large source of CO<sub>2</sub> and other emissions, with CO<sub>2</sub> capture not only will CO<sub>2</sub> emissions be reduced substantially, but also other emissions such as sulphur oxides. However, it must be recognized that CO<sub>2</sub> capture significantly decreases power plant efficiency; therefore, extra resources (for example, coal in the case of a coal-fired power plant) are needed to compensate for the lost capacity. Other environmental impacts associated with construction, operation and decommissioning of CO<sub>2</sub> capture unit and CO<sub>2</sub> transport and storage should also be taken into account.

Most of the research conducted to date has focused primarily on the carbon footprint impacts of CCS. Other environmental impacts (e.g. ozone depletion, smog formation, acidification, eutrophication, impacts on human health and eco-systems) were often ignored. To accommodate this absence of information, the goal of this study is to fully understand the implications of CCS activities by considering other environmental impacts of CCS from a full life cycle perspective.

A Life Cycle Assessment (LCA) of a real CCS system consisting of an 882 MW<sub>e</sub> lignite coal-fired power plant with a CO<sub>2</sub> post-combustion capture unit, CO<sub>2</sub> pipeline transport, CO<sub>2</sub>-EOR operations and storage was conducted in this study. SaskPower's proposed Clean Coal project at the Boundary Dam Power Station and the Weyburn EOR projects in Saskatchewan, Canada, provide case studies.

The environmental impacts for acidification, eutrophication, ozone depletion, smog formation, human health, and eco-toxicity impact categories were assessed and reported. The results of the LCA analysis of the power plant with CO<sub>2</sub> capture showed an impact increase in several environmental impacts categories compared to the plant without CO<sub>2</sub> capture, except for the acidification category and human health air-point source category (kg PM2.5 equiv.), where the decrease was observed.

Since energy content of oil is higher than in coal, the full LCA of CCS showed improvement from no capture to capture scenarios in several environmental impact categories. An increase in three impact categories (human health non cancer water, ecotoxicity water and eutrophication water) was observed. This increase was mostly due to the high impacts from the refinery operations.

The results of the study demonstrated that more attention should be paid to the choice of functional unit and system boundaries in the CCS studies, as well as to the environmental impact categories studied in this research. The areas where improvement is needed were identified.

## **ACKNOWLEDGEMENTS**

I would like to acknowledge my supervisor Dr. Malcolm Wilson for his diligent assistance and advice and to my PhD committee members Dr. Dena McMartin, Dr. Raphael Idem and Dr. Hairuo Qing for checking and correcting my work.

I would also like to acknowledge the financial support from the International Performance Assessment Centre for Geologic Storage of Carbon Dioxide (IPAC-CO<sub>2</sub>) <http://www.ipac-co2.com/> and the Faculty of Graduate Studies and Research, University of Regina.

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## **ABBREVIATIONS**

CCS – Carbon Capture and Storage

CEA – Cumulative Effect Assessment

CFCs – Chlorofluorocarbons

CO<sub>2</sub> – Carbon dioxide

EA – Environmental Assessment

EIA – Environmental Impact Assessment

EOR – Enhanced Oil Recovery

GHG – Greenhouse gas

GWP - Global Warming Potential

HCFCs – Hydrochlorofluorocarbons

IGCC – Integrated Gasification Combined Cycle

LCA – Life cycle Assessment

LCI – Life Cycle Inventory

LCIA – Life Cycle Impact Assessment

MEA – Monoethanolamine

MFA - Material Flow Analysis

NGCC – Natural Gas Combined Cycle

PPP – Policies, Programs and Plans

SEA – Strategic Environmental Assessment

SEEA - System of Economic and Environmental Accounting

UV – Ultraviolet

VEC - Valued Ecosystem Component

# **1. INTRODUCTION**

## **1.1 Background**

Carbon dioxide (CO<sub>2</sub>) is considered to be the principal greenhouse gas contributing to the greenhouse effect<sup>1</sup>. In order to significantly reduce the impact of CO<sub>2</sub>, it can be captured and stored geologically. Due to the economics of scale of CO<sub>2</sub> capture, transport and storage, it is likely to be applied to large sources, such as fossil fuel power plants. In the IPCC 2005, report large sources of stationary CO<sub>2</sub> emissions are described as emissions sources of more than 0.1 MtCO<sub>2</sub> per year. Geological storage options include deep saline aquifers, depleted oil and gas reservoirs, enhanced oil and gas recovery, and enhanced coal bed methane recovery.

Although CO<sub>2</sub> capture and storage keeps the CO<sub>2</sub> away from the atmosphere, the processes should be studied from a life cycle perspective in order to obtain the total environmental framework and put it in an economic context. It is also important to understand the full ramification of the process if comparisons are to be made to other alternatives for greenhouse gas (GHG) emissions reduction.

In order to create a framework for comparison, the Life Cycle Assessment (LCA) methodology is used in this research. It offers a mechanism for comparison and evaluation of the environmental performance of CO<sub>2</sub> capture and storage (CCS). LCA

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<sup>1</sup> Greenhouse effect refers to the change in the thermal equilibrium temperature of a planet by the presence of gases that absorb infrared radiation. The six greenhouse gases (GHG) covered by the Kyoto Protocol are carbon dioxide (CO<sub>2</sub>), methane (CH<sub>4</sub>), nitrous oxide (N<sub>2</sub>O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulphur hexafluoride (SF<sub>6</sub>).

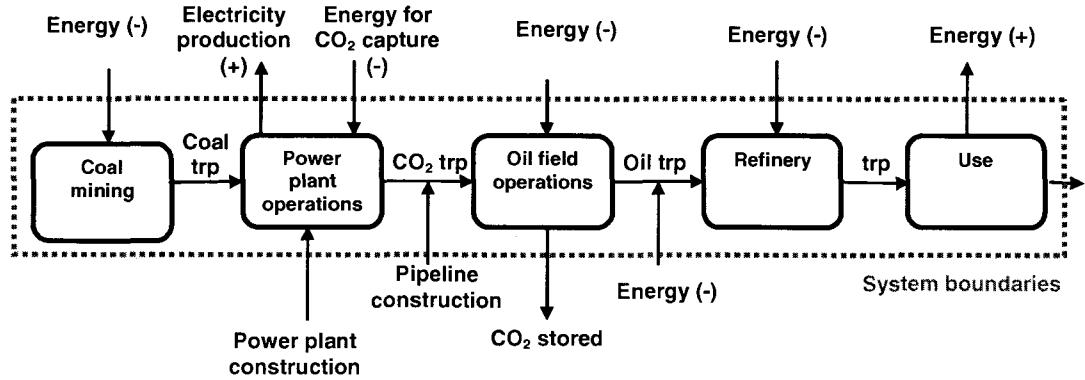
also provides some mechanisms for understanding additionality and effective net emissions inventorying from an integrated electric power to geological storage system.

This thesis is a comprehensive study of an entire life cycle of the CO<sub>2</sub> capture and geological storage. The study is a cradle to grave study, starting from the coal mining, power plant construction and operations, and the CO<sub>2</sub> capture at the power plant through construction of the CO<sub>2</sub> pipeline and the CO<sub>2</sub> transportation to the oil field for enhanced oil recovery (EOR) (Figure 1.1). In order to account for the environmental impact of the extra oil extracted due to CO<sub>2</sub>-EOR, the environmental impact from the refinery and final use of oil products are included. The study takes into account all associated emissions, wastes, resource and energy consumption during all life cycle stages, and assesses the implications of these waste streams and resource use on the environment.

The proposed SaskPower clean coal power plant at the Boundary Dam in Saskatchewan (also called “Integrated Carbon Capture and Sequestration Demonstration Project”) and EnCana’s EOR operations at the Weyburn oil field in Saskatchewan are selected as base cases for the study. The focus of this study is on coal mining, power plant construction and operations, and on CO<sub>2</sub> capture unit, its construction and operation. CO<sub>2</sub> transportation and sequestration steps are also included, but to a lesser extent. This part will be covered in details by a complementary research study performed at the University of Regina.

TRACI Life Cycle Impact Assessment methodology is applied in this research. TRACI, the Tool for the Reduction and Assessment of Chemical and Other Environmental Impacts, is developed by the U.S. Environmental Protection Agency.

This research is focused on all impact assessment categories except for Global Warming Potential (GWP) and Resource Depletion. These categories are analyzed in a complementary research project. The impact categories under study include ozone depletion, smog formation, eutrophication, acidification, human and eco-toxicity.



**Figure 1.1** Life Cycle Assessment of CO<sub>2</sub> capture and storage

(original in color)

## **1.2 Nature of the problem**

CO<sub>2</sub> capture reduces CO<sub>2</sub> emissions; however, this process should be studied from a life cycle perspective in order to obtain the total environmental picture. The research undertaken to date has dealt only with the mass balance of CO<sub>2</sub> throughout the life cycle and results were presented as “avoided” CO<sub>2</sub> emissions due to the CO<sub>2</sub> sequestration. This approach does not provide a solid ground for decision-making. Although CO<sub>2</sub> is the most important greenhouse gas, other greenhouse gas emissions such as CH<sub>4</sub> and N<sub>2</sub>O as well as other emissions (for example, SO<sub>2</sub>, NO<sub>x</sub>, mercury), energy and resource consumption should also be included in the study to fully understand implications of energy production and CO<sub>2</sub> reduction.

The starting point of this research is to develop the LCA database. In this case, it is a database specific to Saskatchewan and Canada, with the CO<sub>2</sub> coming from the low grade coal (lignite) and captured by means of the proposed post-combustion power plant being developed by SaskPower. To the extent possible, the data for LCA come directly from SaskPower, looking at the major components in the plant and developing the appropriate data-files for the construction and operation of the power plant.

The captured CO<sub>2</sub> is then assumed to be moved to Weyburn oil field and utilized for enhanced oil recovery. The oil produced from Weyburn is moved to an eastern US refinery for the production of finished product.

The value to this work, therefore, includes:

- The development of an annotated (quality controlled) database for carbon capture and storage in Saskatchewan, Canada.

- The development of database that is based on the real industrial data, not generic studies.
- The development of a full understanding of the emissions, wastes, resource use and energy consumption in the life cycle of the CCS. This will help to better describe the project boundaries and net emissions reductions for credit or taxation based systems. It also defines the ancillary benefits that could accrue from reduced criteria air contaminant emissions. This is also important in understanding the cost centers (i.e. how different costs will be assigned, for example, whether or not one allocates sulphur reduction costs to the CO<sub>2</sub> capture) in a CCS environment.
- The identification of the best alternatives and “hot-spots” (the life cycle stages with the most significant environmental impact) in the life cycle of the CCS. The results will provide a basis for decision-making for changes in the life cycle.

### **1.3 State of the art**

The main objective of this thesis is to provide industry with a solid assessment technique for accounting for the benefits of CO<sub>2</sub> capture from a major industrial source and storage in oil wells. The question “whether it is better not to capture CO<sub>2</sub>, produce additional electricity and not extract extra oil” can only be answered by conducting this research.

LCA deals with the CCS project from the life cycle perspective. All upstream and downstream activities are included within system boundaries, thus, taking into account all environmental impacts along a life cycle. By understanding project boundaries, one can comprehend more about social (i.e. “not in my backyard” issues) and economic (i.e. creation of jobs, payment of additional cost for electricity, etc.) impacts of the CCS project.

Moreover, the LCA permits the in-depth testing of different alternatives. The hot-spots in the life cycle of CCS can also be identified using LCA methodology, thus assisting a decision-maker in her decisions to improve the processes, reduce environmental impact and, in the long-term, to reduce costs.

The detailed LCA methodology has never been applied to these types of studies in Canada and is a break-through for Canadian petroleum industry. This research is a starting point for development of a unique to the province of Saskatchewan expertise in LCA studies.

## **1.4 Previous work in Saskatchewan**

To the best knowledge of the author, no environmental evaluation of CCS using LCA has been done in Saskatchewan before, at least in the public domain. An introductory CO<sub>2</sub> emissions accounting study for Weyburn project has been carried out as part of the University of Regina MSc project (Suebsiri 2006); however, the study presents only a simple mass balance of CO<sub>2</sub> throughout the life cycle.

SaskPower has recently introduced LCA technique for assessment of different power generation options. The company is using a newly-developed impact assessment procedure ASTM E06.71.10 “Standard Practice for Comparing the Environmental Performance of the Electric Power Generation Facilities and Infrastructure” (SCS 2006). The method is developed by Scientific Certification Systems (SCS 2007).

## **2. THESIS OBJECTIVES**

### **2.1 Objectives**

- To study environmental performance over the full life cycle of CCS; to analyze environmental effects of CCS such as ozone depletion, acidification and eutrophication, smog formation, toxicity and eco-toxicity; and to give recommendations on potential improvements and alternatives to decision-makers.
- To create a database on CCS in Saskatchewan/Canada - a database that contains data on all processes (coal mining; construction, operations and decommissioning of power plant with and without CO<sub>2</sub> capture unit; construction, operations and decommissioning of CO<sub>2</sub> pipeline; drilling and completion of wells and CO<sub>2</sub>-EOR operations at the oil field) included within the system boundaries.
- To give recommendations on how LCA methodology and results can be integrated into already adopted environmental management procedures, such as Environmental Impact Assessment (EIA) and Strategic Environmental Assessment (SEA) using CCS as a case study.

## **2.2 Long-Term Objectives**

- To develop a unique to Saskatchewan expertise in LCA studies, as well as to create a group of researchers and students experienced in performing LCA studies of products, processes and services.
- To create a broadly usable database for LCA studies in carbon dioxide capture and storage in Canada.
- To provide industry with a solid assessment technique for accounting for the benefits of CO<sub>2</sub> capture and storage in oil wells. The question “whether it is better not to capture CO<sub>2</sub>, produce additional electricity and not extract extra oil” can be answered by conducting this research.

### **3. CARBON CAPTURE AND STORAGE**

#### **3.1 Introduction**

Global warming is the increase in the average temperature of the earth. This effect is caused by anthropogenic greenhouse gases (GHG) released to the atmosphere. There are six greenhouse gases covered by the Kyoto Protocol with carbon dioxide (CO<sub>2</sub>) considered to be the principal greenhouse gas due to the very large quantities emitted.

Carbon capture and storage (CCS) is one of technological solutions for emission reduction being given serious consideration globally. It is a technique used to capture CO<sub>2</sub> from large stationary sources and store it in underground formations, thereby reducing the effects of global warming. Examples of large sources of CO<sub>2</sub> are fossil fuel power plants, major CO<sub>2</sub>-emitting industries such as cement and steel production, refineries, oil and gas processing plants. Geological storage options include deep saline aquifers, depleted oil and gas reservoirs, enhanced oil and gas recovery, and enhanced coal bed methane recovery (IEA 2008).

#### **3.2 CO<sub>2</sub> capture, transport and storage**

##### 3.2.1 Current status of CCS technology

According to the recent IPCC report on Carbon Dioxide Capture and Storage (IPCC 2005), the technical maturity of different components of CCS system varies greatly. For example, CO<sub>2</sub>-EOR, as one of the interests of our research, is a feasible technology used worldwide. However, if this technology is “used for CO<sub>2</sub> storage, it is only economically

feasible under specific conditions” (IPCC 2005). This feasibility is related to oil prices, CO<sub>2</sub> costs and the value of CO<sub>2</sub> in the marketplace.

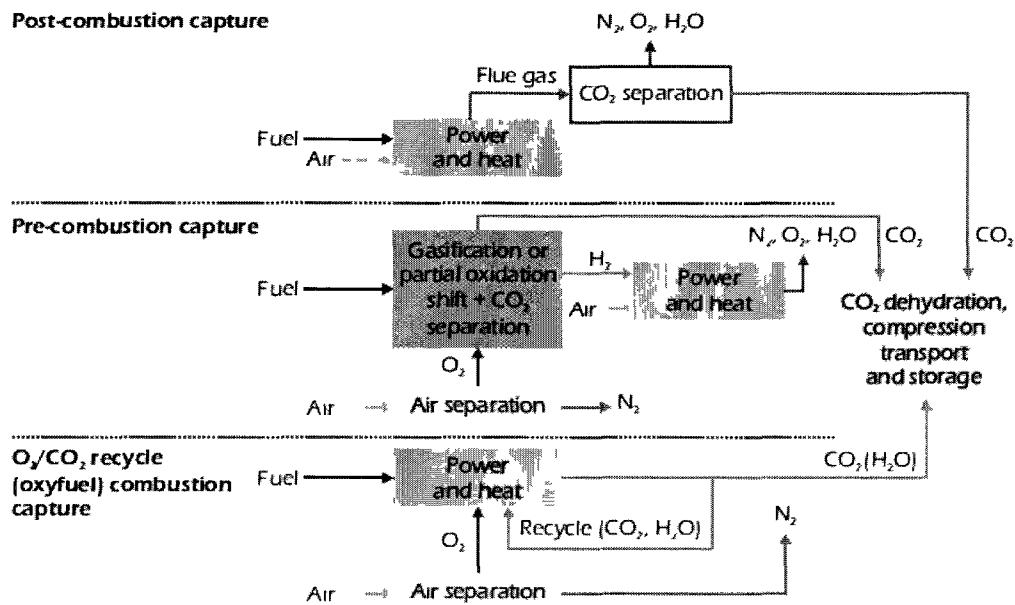
### *CO<sub>2</sub> capture*

There are three main technology options to capture CO<sub>2</sub>: post-combustion, pre-combustion and oxyfuel combustion (Figure 3.1). The choice of CO<sub>2</sub> capture technology depends on the power plant characteristics and type of fuel used. Post-combustion capture is usually applied to coal- and gas- fired power plants. The CO<sub>2</sub> is separated from flue gases produced by the combustion of the fuel in air. It is based on chemical absorption using different organic solvents, for example monoethanolamine (MEA), or ammonia. Post-combustion is the only retrofittable technology for existing facilities.

Pre-combustion capture is the coal-fired integrated gasification combined cycle (IGCC) process. This process can also be used in natural gas-based plants. In this technology, the fuel is partially reacted first with oxygen and steam to produce heat to volatilize the remainder of the coal. Then, it is further processed in a shift reactor and a mixture of hydrogen and CO<sub>2</sub> is produced. The CO<sub>2</sub> is captured, and hydrogen is used to generate electricity and heat.

Oxyfuel systems use oxygen instead of air for fuel combustion with a recirculation of an approximately 70% flue gas stream to dilute the oxygen. The flue gas produced consists mainly of water vapour and CO<sub>2</sub> (IPCC 2005, IEA 2008).

It should be noted that post-combustion and pre-combustion systems are economically feasible under specific conditions; oxyfuel combustion is still in demonstration phase (IPCC 2005).



**Figure 3.1 CO<sub>2</sub> capture processes**

(original in color)

Source: IPCC 2005

CO<sub>2</sub> capture at power or other industrial plants is the largest cost component in the whole CCS system. CO<sub>2</sub> capture reduces efficiency and increases resource consumption and cost of electricity. The cost of CCS ranges from 0.02 – 0.05 US\$/kWh for pulverized coal (PC) power plants and 0.01 – 0.03 US\$/kWh for NGCC plants (both using post-combustion capture). However, when used with CO<sub>2</sub>-EOR, the cost of CCS can be reduced by approximately 0.01-0.02 US\$/kWh due to revenues from the EOR (IPCC 2005). With further development of CCS technology, it is believed that the cost of building and operating CCS systems will decline.

Commercial application of CO<sub>2</sub> capture technology at large scale and on industrial facilities is still in an early development stage. The Saskatchewan Power Corporation (SaskPower) in Canada is currently working on the development of one of the first and largest integrated clean coal/carbon capture demonstration projects in the world. The project would rebuild one of the units at the Boundary Dam Power Station in Estevan, Saskatchewan, with post-combustion carbon capture technology (SaskPower 2009). This 150MW unit is expected to be fully operational by 2014. The CO<sub>2</sub> capture unit would capture approximately one million tonnes of carbon dioxide annually.

### *CO<sub>2</sub> transport*

Transport of CO<sub>2</sub> by pipeline is a well established technology that has excellent safety records. The CO<sub>2</sub> is compressed to a pressure above 8 MPa (this puts the CO<sub>2</sub> in the liquid state) before transportation in order to make it easier and decrease the cost (IPCC 2005). Other options of CO<sub>2</sub> transport include ships, road and rail tankers where CO<sub>2</sub> is transported as a liquid (liquefied cryogenically). Transport of CO<sub>2</sub> by ship may be more economically attractive if CO<sub>2</sub> is transported over large distances. The cost of ship

transport, including intermediate storage facilities, harbour fees, fuel costs, cost for liquefaction, and loading and unloading activities varies from US\$ 15 for 1,000 km to US\$ 30 per tonne of CO<sub>2</sub> for 5,000 km (IEA GHG 2004, IPCC 2005). The properties of liquefied CO<sub>2</sub> are similar to those of liquefied petroleum gases (LPG) that are already transported by ships on a large commercial scale.

With development of CCS, the standard for CO<sub>2</sub> pipelines would emerge. Currently, the CO<sub>2</sub> pipelines are built mainly to transport CO<sub>2</sub> for EOR operations. The CO<sub>2</sub> for EOR requires low nitrogen content, a requirement that would not be important for storage applications within reason (high levels of N<sub>2</sub> would make compression prohibitively expensive). Other contaminants may be more problematic, for example, if the pipeline passes through a populated area, the H<sub>2</sub>S content may be regulated. It should be noted that in the future with introduction of, for example, oxyfuel technology some other compounds (SO<sub>2</sub>, SO<sub>3</sub>) may be a problem. The CO<sub>2</sub> leakage from pipelines is very small. In case of transport by ship, the total loss of CO<sub>2</sub> to the atmosphere is about 3 to 4% per 1,000 km if boil-off and exhaust from ship engines are included (IPCC 2005).

### *CO<sub>2</sub>-EOR*

EOR using CO<sub>2</sub> injection is a mature technology that has been applied on a commercial scale in many projects around the world. This technique helps to extract an additional 5 to 20% of the original oil in place from depleted or marginal wells (Tzimas et al. 2005, Stevens et al. 2001). Two processes have been developed for CO<sub>2</sub>-EOR. These are miscible displacement and immiscible displacement (Tzimas et al. 2005). Under favourable reservoir conditions (generally >22° API oil gravity and >1200 m reservoir depth), injected supercritical CO<sub>2</sub> becomes miscible with residual oil (Stevens et al.

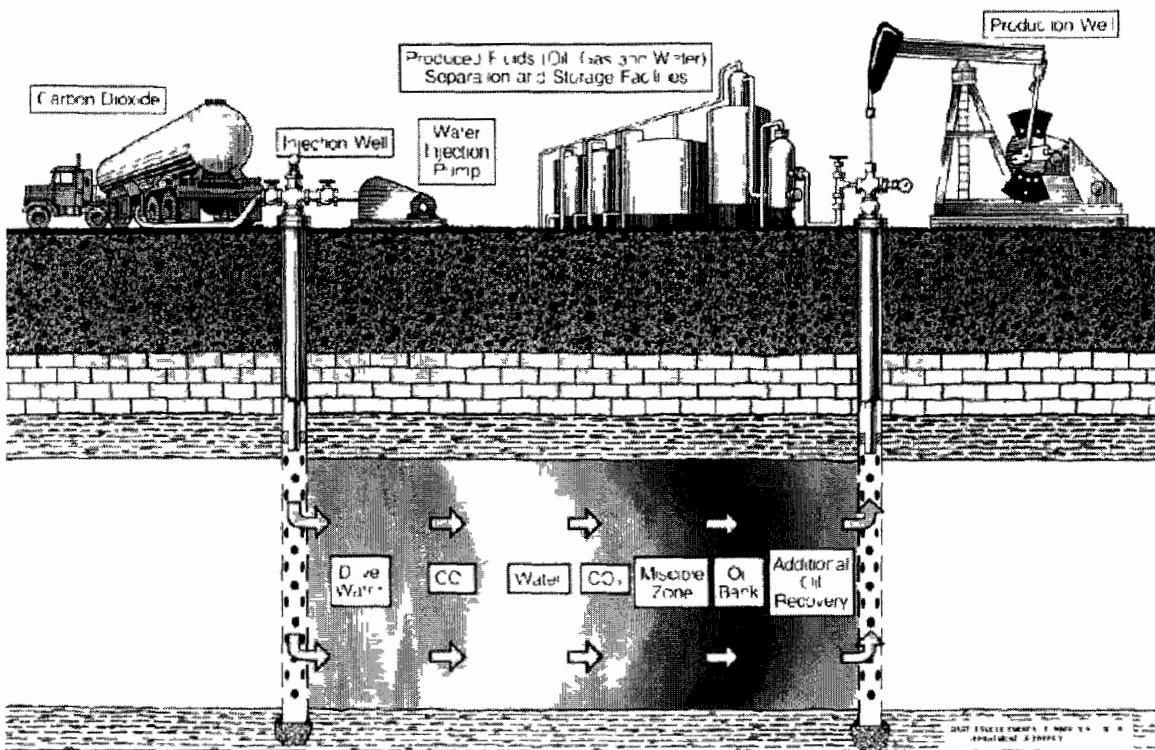
2001). When injected, it decreases oil viscosity and improves its mobility, thus increasing oil recovery (Figure 3.2). The conditions in some reservoirs (i.e. low pressure) and crude oil composition (i.e. heavy oil) prevent CO<sub>2</sub> becoming fully miscible with oil. However, in the case of immiscible oil displacement, the injection of CO<sub>2</sub> in a reservoir can also increase oil recovery. The role of CO<sub>2</sub> in immiscible displacement is similar to that of water in secondary oil recovery – it helps to raise and maintain reservoir pressure (Tzimas et al. 2005).

Much of the CO<sub>2</sub> injected in a reservoir is produced with oil, then separated and re-injected into the reservoir. At the end of the oil recovery, the CO<sub>2</sub> will be stored in the depleted oil reservoir.

Onshore miscible displacement is a commercial technology. The USA is leading in implementation of the method with 94% of the world CO<sub>2</sub>-EOR oil production (Tzimas et al. 2005). CO<sub>2</sub>-EOR costs vary depending on the size of the field, location, pattern spacing and existing facilities (IEA 2008). According to the latest data, with EOR, total production costs (excluding CO<sub>2</sub> costs) are approximately US\$ 7/bbl to US\$ 14/bbl oil or about 45-90 US\$/t of oil (IEA 2008). These include capital costs, operating costs, royalty taxes and insurance.

#### *CO<sub>2</sub> storage*

Suitable formations for CO<sub>2</sub> storage can occur in both onshore and offshore sedimentary basins. The IEA report on Carbon Capture and Storage (IEA 2008) identifies that highly prospective geological basins for CO<sub>2</sub> storage are mainly found in the United States and Canada, Siberia, the Middle East, and North and West Africa within existing oil and gas regions.



**Figure 3.2 Schematic of WAG miscible CO<sub>2</sub>-EOR operations**

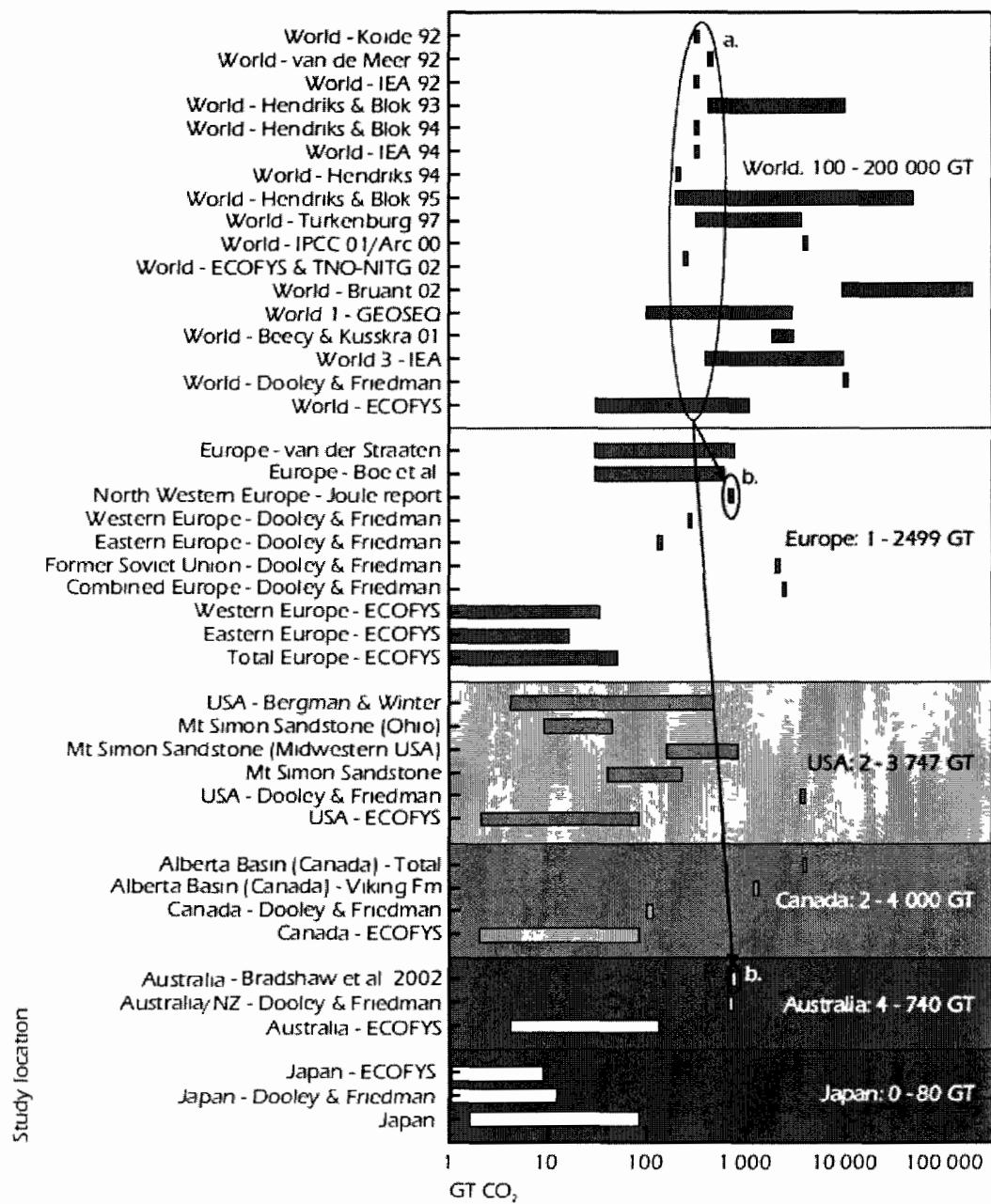
Source: NETL 2009

(original in color)

Storage capacity estimates found in published literature vary widely. Some examples of regional and worldwide estimates are presented in Figure 3.3. According to Bachu (2003), the sedimentary basins most suitable for CO<sub>2</sub> storage in Canada are Alberta and Williston Sedimentary Basins (Figure 3.4). The effective CO<sub>2</sub> sequestration capacity in more than 25,000 gas reservoirs in the Western Canada Sedimentary Basin is estimated at approximately 8.5 Gt CO<sub>2</sub> (Bachu 2004).

The injection of CO<sub>2</sub> in geological formations involves technologies that are already in use in the oil and gas industry, such as well-drilling and injection, computer simulation of reservoir dynamics and monitoring methods. The reservoir depth for CO<sub>2</sub> storage should be below 800 meters. At this depth, CO<sub>2</sub> is in a liquid or supercritical state. Under these conditions, the density of CO<sub>2</sub> is close to density of crude oils, reducing the buoyant forces that tend to drive CO<sub>2</sub> upwards. The IPCC report (IPCC 2005) defines three main mechanisms for CO<sub>2</sub> storage in the subsurface and with water present as one of the fluid phases in the reservoir:

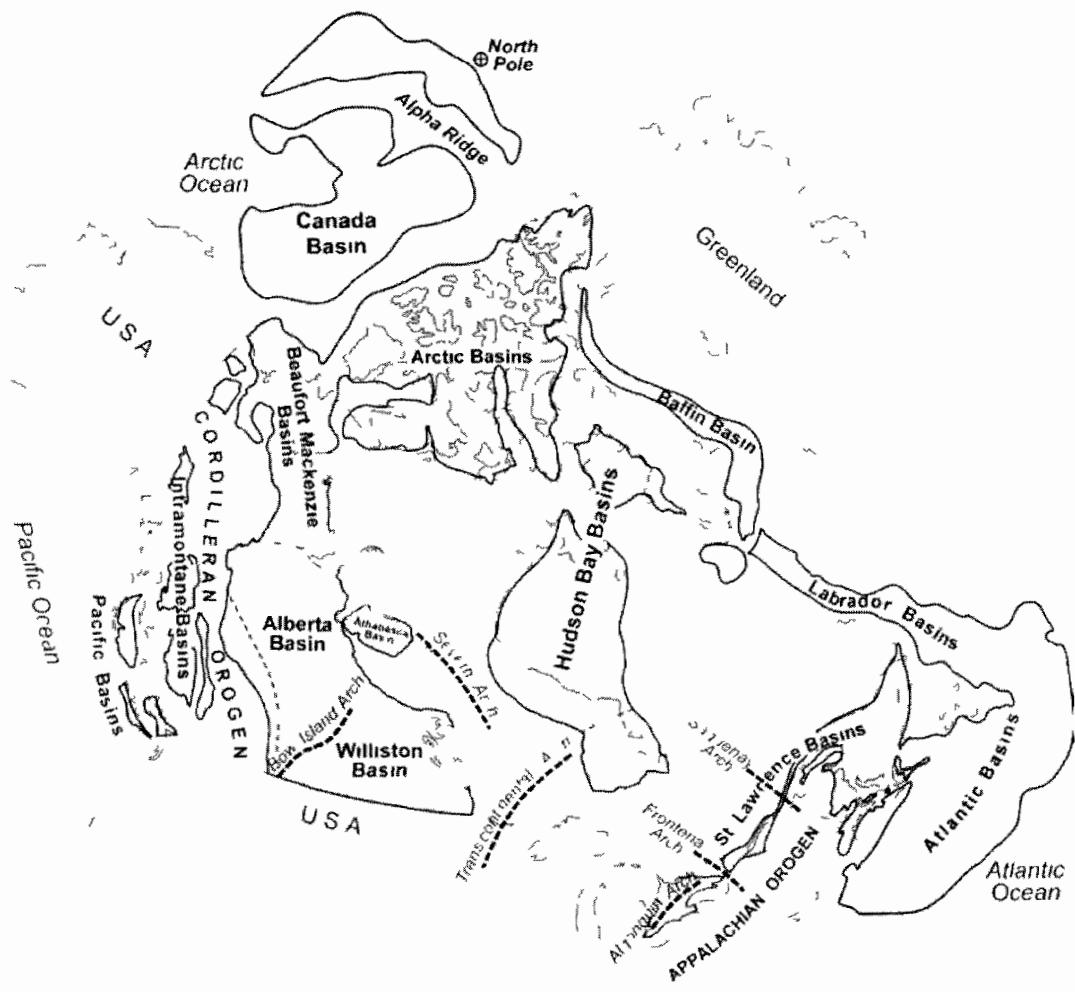
- *Physical trapping.* These can take two main forms: static trapping where upwards movement of CO<sub>2</sub> is blocked by impermeable layer of shale or clay rock, also called a “cap rock”, and residual-gas trapping in a porous structure provided by capillary forces.
- *Chemical trapping.* This occurs by dissolution or by ionic trapping. Once dissolved, the CO<sub>2</sub> reacts chemically with minerals in the geological formation (mineral trapping) or adsorbs on the mineral surface (adsorption trapping). Dissolution of CO<sub>2</sub> also causes a weight increase in water density eliminating buoyancy effect.



**Figure 3.3 Regional and worldwide CO<sub>2</sub> storage potential estimates**

(original in color)

Source: IEA (2008)



**Figure 3.4 Distribution of sedimentary basins in Canada**

Source: Bachu (2003)

- *Hydrodynamic trapping.* The CO<sub>2</sub> migrates upward at a very low velocity and is being trapped in intermediate layers. Large quantities of CO<sub>2</sub> could be stored using this mechanism, since the migration to the surface would take millions of years.

The CO<sub>2</sub> storage in geological formations is expected to last for thousands of years.

However, there is a small possibility that CO<sub>2</sub> will leak from the reservoir. Some potential leakage pathways include undetected faults and fractures in the subsurface; geological faults and new and abandoned wells intersecting the storage formation; permeable zones existing in the cap rock; fractures caused by seismic movements.

The cost of geological storage of CO<sub>2</sub> is highly site specific. It depends on factors such as the number of wells needed for injection and location of the project (onshore or offshore). Estimates of CO<sub>2</sub> storage costs vary from 0.5 to 8 US\$/tCO<sub>2</sub> injected. Some additional costs include cost of monitoring that is estimated to be 0.1-0.3 US\$/tCO<sub>2</sub> (IPCC 2005).

### 3.2.2 Financial, legal and regulatory issues of CCS

The IPCC Special report on Carbon Capture and Storage (IPCC 2005) identifies four major non-technical challenges for successful implementation of CCS. These are:

1. Financing demonstration projects;
2. Setting a long-term, stable price for CO<sub>2</sub>;
3. Establishing legal and regulatory frameworks; and
4. Increasing public awareness and acceptance.

CCS reduces power plant efficiency, increases fuel consumption and the cost of electricity. It is unlikely that countries will proceed with commercial implementation of CCS without incentives from the government. CO<sub>2</sub>-EOR can provide attractive opportunities for development of CCS infrastructure due to the value of additional recovered oil. However, a reasonable, long-term and stable price of CO<sub>2</sub> should be set to make these projects profitable and predictable.

There is also a lack of a legal and regulatory framework for CO<sub>2</sub> storage in geological formations. A few countries have begun to work on the development of relevant legislation. Existing laws from oil and gas, mining and industrial sectors do not provide effective regulatory mechanisms for CO<sub>2</sub> storage (Clifton Associates 2004, IPCC 2005). For the successful implementation of CCS projects, more work is needed to establish procedures for site selection, injection, abandonment and monitoring. The consultations and discussions with the public should also be conducted to expose the public to the concept of CO<sub>2</sub> storage and its inherent risks.

### **3.3 Current CCS projects**

Geological storage of CO<sub>2</sub> is ongoing in a number of projects worldwide. Three large industrial scale projects are described here: the Weyburn project in Saskatchewan, Canada, the Sleipner project in the North Sea, and the In Salah project in Algeria.

#### 3.3.1 Weyburn project, Saskatchewan, Canada

The IEA GHG Weyburn CO<sub>2</sub> monitoring and storage project is a large scale CO<sub>2</sub>-EOR project located in Weyburn oilfield in southeastern Saskatchewan, Canada. The main goal

of the Weyburn project is to assess and verify the ability to safely store CO<sub>2</sub> in oil reservoirs. A Canadian company, EnCana, is the operator of the Weyburn oil field. The field contains approximately 1.4 billion barrels of original oil in place, and is one of the largest medium-sour crude oil reservoirs in Canada (EnCana 2008). The project is using CO<sub>2</sub> from a North Dakota (USA) coal gasification facility. The CO<sub>2</sub> is transported via 320-kilometer pipeline and injected into the reservoir (Wilson and Monea 2004). A significant portion of the CO<sub>2</sub> injected for EOR is produced with the oil, from which it is separated and then re-injected. At the end of oil recovery, the CO<sub>2</sub> will be stored in the geological formation (approximately 30 million tonnes).

The first phase of the research project began in 2000 and was concluded in 2004. From Phase I it was learnt “that EOR works well as a storage mechanism for CO<sub>2</sub>” (IEA GHG Weyburn 2009). Several technologies and techniques (i.e. 4D seismic surveying) were identified and used effectively to observe and track CO<sub>2</sub> movement in the reservoir. The project demonstrated that the method is safe and economically and technically feasible. The final phase of the research project is now underway, even though the oil field operations will continue until approximately 2030. More than 13 million tonnes of CO<sub>2</sub> have been sequestered in the oil reservoir since the beginning of CO<sub>2</sub>-EOR operations (EnCana 2008), making this the largest CO<sub>2</sub> storage project globally.

### 3.3.2 In Salah project, Algeria

The In Salah CCS project was launched in 2004. In Salah is a joint venture between Sonatrach, the Algerian national energy company, BP and StatoilHydro. It is a multi-field natural gas development in the Algerian desert. The gas fields contain from 1 to 9% CO<sub>2</sub> which must be removed prior to sale. Rather than venting the CO<sub>2</sub>, it is being compressed

and injected back to the reservoir formation (downdip from the gas field). Around 1.2 million tonnes of CO<sub>2</sub> is injected into the reservoir every year (Riddiford et al. 2006). The goal of the project is to demonstrate that secure CO<sub>2</sub> geological storage can be cost-effectively verified, and that short-term monitoring can provide a long-term safety assurance (Wright 2006).

### 3.3.3 Sleipner project, Norway (North Sea)

Sleipner is a gas field in the middle of the North Sea in Norway. The gas contains from 4 to 9.5% CO<sub>2</sub> that is being separated from the natural gas and re-injected into a saline formation, which lies 1,000 metres below the sea bottom (Solomon 2007). An important driver for the project was a CO<sub>2</sub> emissions tax. It was more economical to store the CO<sub>2</sub> once captured than to vent it.

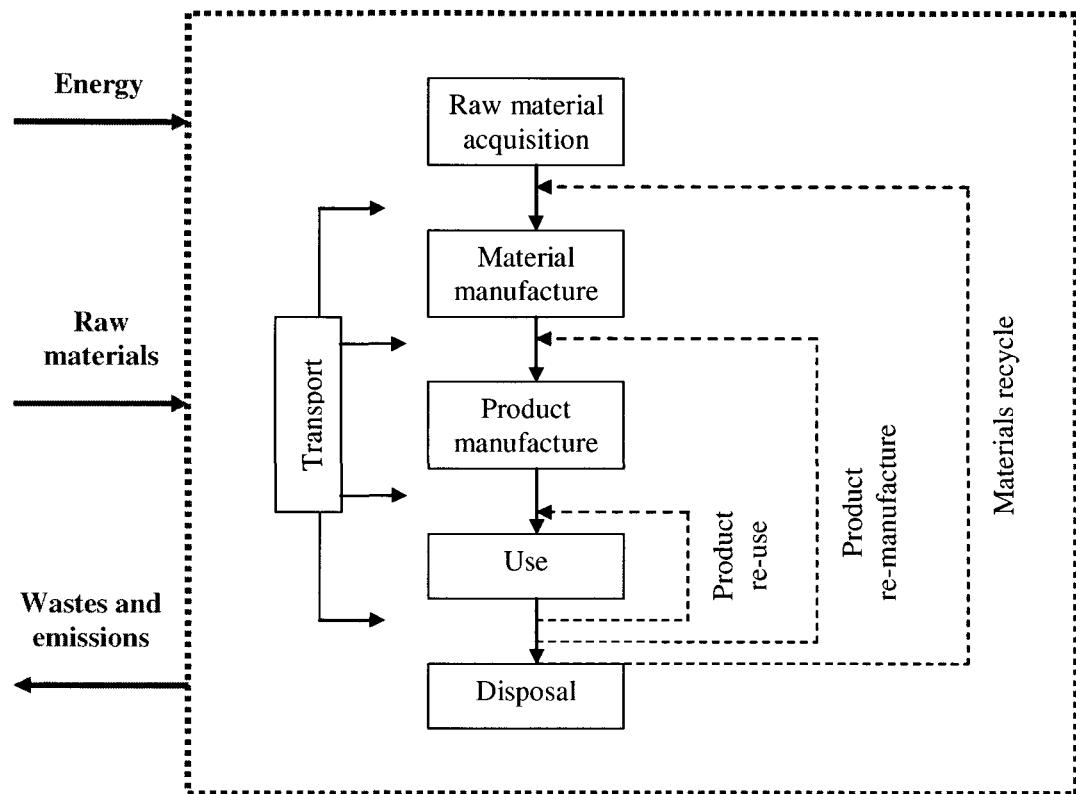
The Sleipner project is operated by the Norwegian oil and gas company StatoilHydro. The company has been injecting one million tonnes of CO<sub>2</sub> per year since 1996 without leakage. The project demonstrated that CO<sub>2</sub> storage in deep saline aquifers is safe, and CO<sub>2</sub> is securely stored in such formations.

## **4. LIFE CYCLE ASSESSMENT**

### **4.1 Introduction**

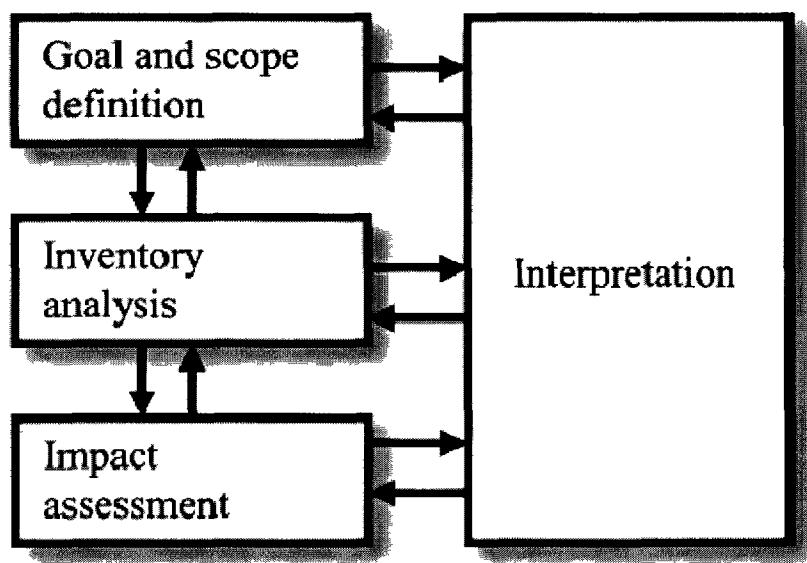
Life Cycle Assessment is a technique that addresses the environmental aspects and potential environmental impacts (e.g. use of resources and environmental consequences of releases) throughout a product's life cycle from raw materials acquisition through production, use, end-of-life treatment, recycling and final disposal (i.e. cradle-to-grave) (ISO 14044, 2006).

Figure 4.1 presents a simplified diagram that shows the major stages of a product life cycle. However, LCA is more than that. LCA can also be described as a whole procedure for how such environmental studies are performed and interpreted. First, the goal and scope of the study are defined (Figure 4.2). Then, the inventory analysis phase (LCI) is performed to construct the life cycle model and calculate emissions produced and the resources used during the life cycle. In the third phase of the LCA called the life cycle impact assessment (LCIA), the emissions and resources are related to various environmental problems through the act of classification and characterization. Weighting may also be used here to put different environmental impacts related to the life cycle on the same scale. Finally, the interpretation is performed to summarize and discuss the results of an LCI or an LCIA as a basis for conclusions, recommendations and decision-making in accordance with the goal and scope definition (Baumann & Tillman, 2004; ISO 14044, 2006).



**Figure 4.1 Major stages of a product life cycle**

(original in color)



**Figure 4.2** LCA framework

Source: ISO 14044, 2006

## **4.2 Development of the LCA concept**

The first person to suggest and develop the idea of life cycle inventory analysis was the Scottish economist and biologist Patrick Geddes who brought up this concept in 1884 (Weidema 1997). His considerations were caused by the increasing use of coal as a non-renewable resource. Geddes focused on a possible efficiency improvements in the entire life cycle of the process chain. However, the discovery and development of oil fields in America and the Middle East as well as two World wars placed other issues at the top of the economists' agenda.

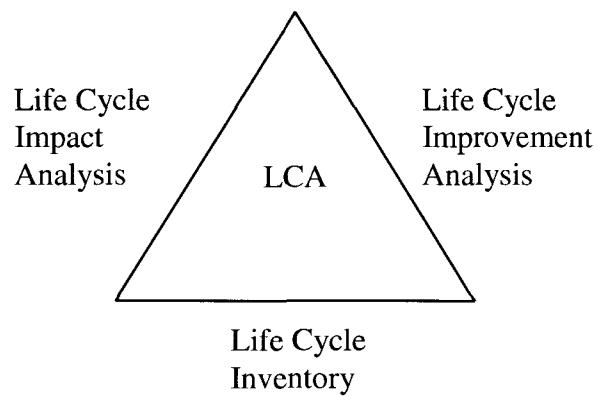
The beginnings of modern LCA can be traced back to the 1960s. The studies of this period dealt with issues such as energy efficiency, consumption of raw materials and to a lesser degree with waste production or disposal of waste materials (Curran 1996, Weidema 1997). The focus of these early studies was mainly on cumulative energy requirements for production of chemical products, agricultural products and packaging materials.

In 1969, the Coca-Cola Company initiated and financed a study conducted by the Midwest Research Institute in the US to compare different beverage containers and to determine which container had the lowest emissions to the environment and the lowest consumption of natural resources (Weidema 1997, Baumann & Tillmann 2004). This technique of quantifying the resource use and environmental emissions of products became known as a Resource and Environmental Profile Analysis, REPA.

In the early 70's approximately 15 REPA's were performed, and a standard research methodology evolved. Energy studies particularly gained momentum during this period

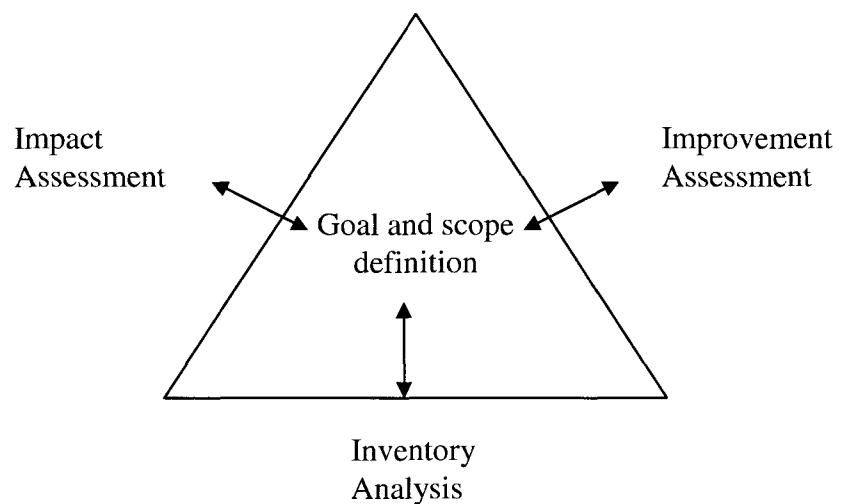
because of the oil crisis. The combination of the debate on wasteful resource use and the oil crisis is probably a reason why LCA has become such a comprehensive methodology, including resource use, energy consumption, emissions and waste production in the analysis (Schenck 2000, Baumann & Tillmann 2004).

Later, the Society of Environmental Toxicology and Chemistry (SETAC), and especially its European branch, shaped the development of LCA through a series of workshops and publications which in the early 1990's set the conceptual and methodological basis for the LCA structure (Wenzel et al. 1997). The first workshop was held in 1990 at Smuggler's Notch, Vermont. The meeting resulted in a monograph "A Technical Framework for Life Cycle Assessment" which based the LCA framework on Life Cycle Inventory (Schenck 2000). LCA was conceived to be a triangle, with inventory at the base, and impact analysis and improvement analysis as the other sides (Figure 4.3). In 1992, the second workshop was held in Florida on the role of Life Cycle Impact Analysis. The monograph resulted from this workshop "A Conceptual Framework for Life Cycle Impact Assessment", identified the main steps of impact assessment as classification, characterization and valuation. The goal and scope of the study was identified as central to LCA (Figure 4.4). At the same time the researchers at Chalmers University of Technology in Sweden proposed their own interpretation of the SETAC framework (Figure 4.5).



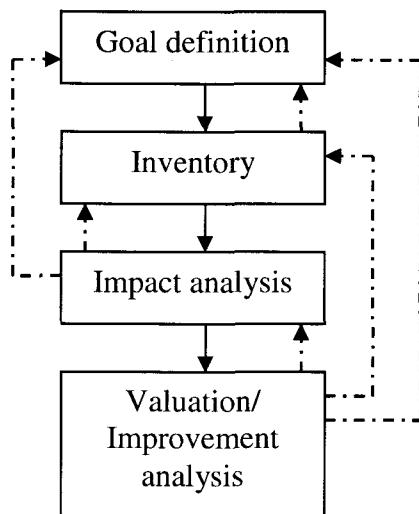
**Figure 4.3 LCA framework after Smuggler's Notch workshop in 1990**

Source: SETAC 1991



**Figure 4.4 LCA framework after Florida's workshop in 1992. SETAC Code of Practice**

Source: SETAC 1993



**Figure 4.5 Chalmers interpretation of the SETAC framework**

Source: Ekvall et al. 1992

The structure proposed by SETAC was further refined and improved by work done for the Nordic Council of Ministers and individual contributions from different research centers and universities.

However, there was a great need to develop LCA databases in order to enable easy access to the LCI data. The international Society for the Promotion of Life Cycle Development (SPOLD) was formed in 1992 (Baumann & Tillmann 2004). The society's first priority was to make life cycle inventory data publicly available and develop data documentation format and structures for LCA databases. Another database format for LCA called SPINE was developed in Sweden. It was implemented in the member companies of the Centre for Environmental Assessment of Products and Materials (CPM) (Steen et al. 1995). Later, both these formats were transformed into an ISO standard for LCA data documentation format (ISO/TS14048, 2002).

In 1992, as a result of the Rio World Environmental Summit, the U.N. asked the International Organization for Standardization (ISO) to evaluate whether any international environmental standards were appropriate. ISO formed the Strategic Advisory Group on the Environment (SAGE) to evaluate the issue and return the recommendations. This is how ISO 14000 was born (Schenck 2000). A whole series of LCA standards have been published since (Table 4.1).

**Table 4.1 LCA documents published by the International Organization for Standardization**

June 1997	ISO 14040 Life Cycle Assessment – Principles and framework. Edition 1.
October 1998	ISO 14041 Life Cycle Assessment – Goal and scope definition and inventory analysis
March 2000	ISO 14042 Life Cycle Assessment – Life cycle impact assessment
March 2000	ISO 14043 Life Cycle Assessment – Life cycle interpretation
2002	ISO/TS14048 Life Cycle Assessment – Data documentation format
2003	ISO/TR 14047 Environmental management -- Life cycle impact assessment -- Examples of application of ISO 14042
2006	ISO 14040 Environmental management -- Life cycle assessment -- Principles and framework. Edition 2
2006	ISO 14044 Environmental management -- Life cycle assessment -- Requirements and guidelines

Source: ISO 2008

In 2002, the United Nations Environment Programme (UNEP) joined forces with the SETAC to launch the Life Cycle Initiative, an international partnership (SAIC 2006).

Three programs were established. These are:

1. The Life Cycle Management (LCM) program – the goal of the program is to create awareness and improve the skills of decision-makers by producing information materials, establishing forums for sharing best practice, and carrying out training programs in all parts of the world.
2. The Life Cycle Inventory (LCI) program – to improve global access to life cycle data that is of high quality and transparent. The program hosts and facilitates expert groups whose work results in web-based information systems.
3. The Life Cycle Impact Assessment (LCIA) program – to increase quality and global reach of life cycle indicators by promoting the exchange of views among experts whose work results in a set of recommendations.

For a long time, LCA has mainly been applied as a stand-alone technique. However, the full benefits from LCA will only be obtained if the technique is integrated in day-to-day management routines (i.e. purchasing decisions, product management, logistics, marketing, administration, strategic planning etc.). Today, most of the leading companies have already adopted life cycle management and life cycle thinking. Attempts to integrate LCA, Life Cycle Costing (LCC) and Risk Assessment (RA) have been made by several research institutions (DANTES 2005).

## **4.3 Modern LCA methodology**

### 4.3.1 Introduction

Life Cycle Assessment provides a methodology to evaluate the potential environmental impacts of a product (i.e. any good or service) over the entire period of its life cycle. It is conducted according to internationally recognized ISO 14040 standards – Environmental Management – Life Cycle Assessment (ISO 14044, 2006).

The framework of LCA includes the following phases:

- Definition of goal and scope of the study;
- Inventory analysis (LCI);
- Impact assessment (LCIA), and
- Interpretation of the results.

The intended use of the LCA, reasons to carry out the study and the intended audience are defined in the goal of the study. In the scope of the LCA, a number of items are considered and clearly described. These are the product system under study, system boundaries, allocation procedures, LCIA methodology and types of impacts, data requirements and data quality, assumptions and limitations. The functional unit is selected, which is the function or service that determines the reference flow of products.

For example, the functional unit for power production would be 1 kWh of electricity produced.

During the inventory analysis phase the input data (resources and raw materials) and output data (products, waste and emissions) for all the processes in the product system

boundaries are collected. These data are related to the functional unit. The data for different processes are typically aggregated over the life cycle and presented as total emissions of substance A or total use of resource B.

The impact assessment phase translates inventory data on input and output into information about the product system's impacts on the environment, human health, and resources.

In the interpretation phase, results are evaluated according to the study's goal. Sensitivity analysis is usually conducted here to qualify the results and the conclusions.

The goal and scope of the study and life cycle inventory phases are very straightforward and performed by all practitioners in a similar way. The situation is very different in the case of the impact assessment phase. With several existing impact assessment methods and a number of new methods under development, it makes the selection process of the best suitable for the study impact assessment method quite complicated.

#### 4.3.2 System boundaries

There are several system boundaries that need to be specified during the goal and scope definition phase. These are:

- *Boundaries between technological and natural systems.* Here the practitioner determines where the flow leaves the technological system under human control and enters a natural system. A life cycle usually begins with the extraction of resources, through processing of raw materials to production and use of products, recycling and end-of-life stages. The practitioner has to decide whether to include all stages from resource extraction to recycling/end-of-life (i.e. cradle to grave) or

restrict the analysis to some of the life cycle stages (i.e. cradle to gate, gate to grave, gate to gate or cradle to cradle analysis). The level of detail of unit processes within the system boundaries is also determined here. A unit process can be excluded (i.e. cut-off) if its deletion does not significantly change the results of the study. The reasons for cut-off are clearly explained and the implications evaluated (ISO 14044, 2006).

- *Geographical boundaries.* Geographical area from which data is collected is defined here. Geography plays a crucial role in most LCA studies due to the following reasons (Baumann and Tillman, 2004):
  - Different parts of a life cycle can occur in different parts of the world.
  - Infrastructure (electricity production, waste management and transport systems) varies from one region to another.
  - The sensitivity of the environment to pollutants varies in different geographical areas.
- *Technological boundaries.* Here the practitioner determines a specific technology or technology mix for analysis. It may be a best available technology, technology currently in use or future technology.
- *Temporary boundaries.* LCAs are carried out to evaluate present impacts and predict future scenarios. Thus, LCA studies can be retrospective or prospective. Prospective or change-oriented studies analyze future scenarios, while retrospective LCAs account for past and present environmental impacts of a product.

## 4.4 Life Cycle Impact Assessment

Life Cycle Impact Assessment (LCIA) is aimed at evaluating the significance of potential environmental impacts using the results of the life cycle inventory (LCI) analysis.

According to ISO 14044, LCI results are classified into impact categories, each with a category indicator. The category indicator can be located at any point in the cause-effect chain between the LCI results and the category endpoints/damage (Figure 4.6).

Two main schools of impact assessment methods have developed within this framework. These are (Jolliet et al. 2003, Hauschild 2005):

- Classical impact assessment methods (for example, EDIP, CML) – these methods group LCI results in so-called midpoint categories, according to themes (e.g. climate change, eco-toxicity, etc.). The quantitative modeling is done in relatively early stages in the cause-effect chain to limit uncertainties.
- Damage oriented methods (for example, Eco-indicator 99, EPS) – these methods model the cause-effect chain up to the endpoint or damage. As a result, these methods have higher uncertainties.

Recently, the SETAC/UNEP Life Cycle Initiative study suggested utilizing advantages of both schools by grouping similar category endpoints into a structured set of damage categories (Jolliet et al. 2003). The proposed concept also works with midpoint categories, each midpoint category relating to one or several damage categories. Figure 4.7 presents the IMPACT 2002+ life cycle impact assessment framework, where LCI results are linked via the midpoint categories to damage categories.

As shown in Figures 4.6 and 4.7, a midpoint indicator characterizes the elementary flows and other environmental interventions that contribute to the same impact. The term “midpoint” means that this point is located somewhere between the LCI results and the damage/endpoint.

#### 4.4.1 Steps in LCIA

According to ISO 14044, LCIA consists of both mandatory and optional steps. The mandatory steps are:

- Classification – where the inventory data is assigned to impact categories, and
- Characterization – where modeling of the inventory data within impact categories is performed.

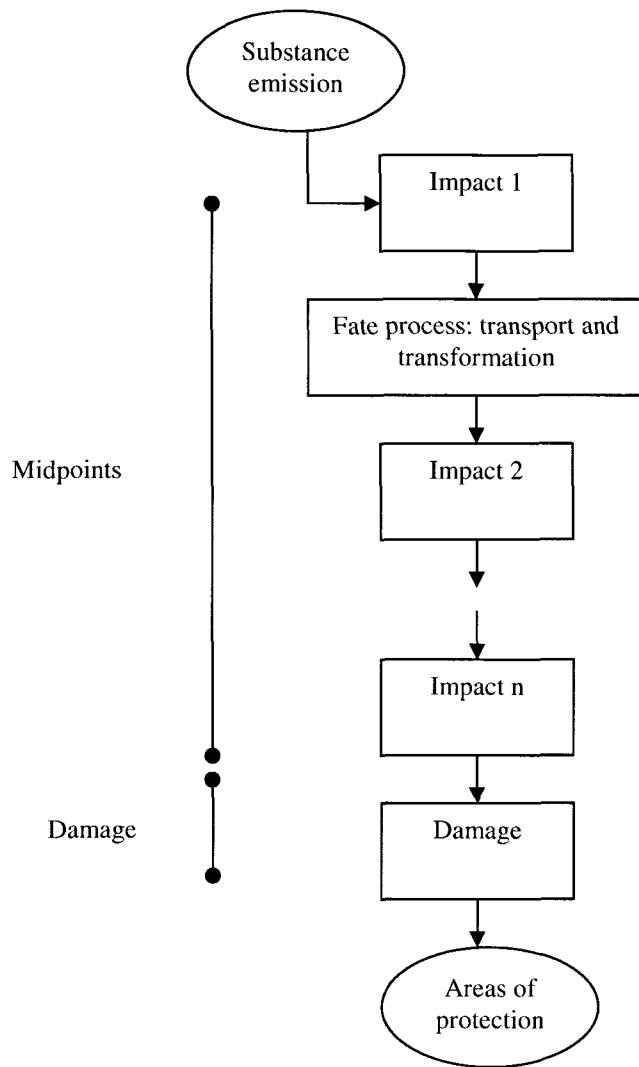
The optional steps are:

- Normalization – where calculation of different impact scores relative to a reference value(s) is performed, and
- Weighting – where the results are aggregated.

The normalization and weighting steps help to assess the relative importance of each environmental impact category.

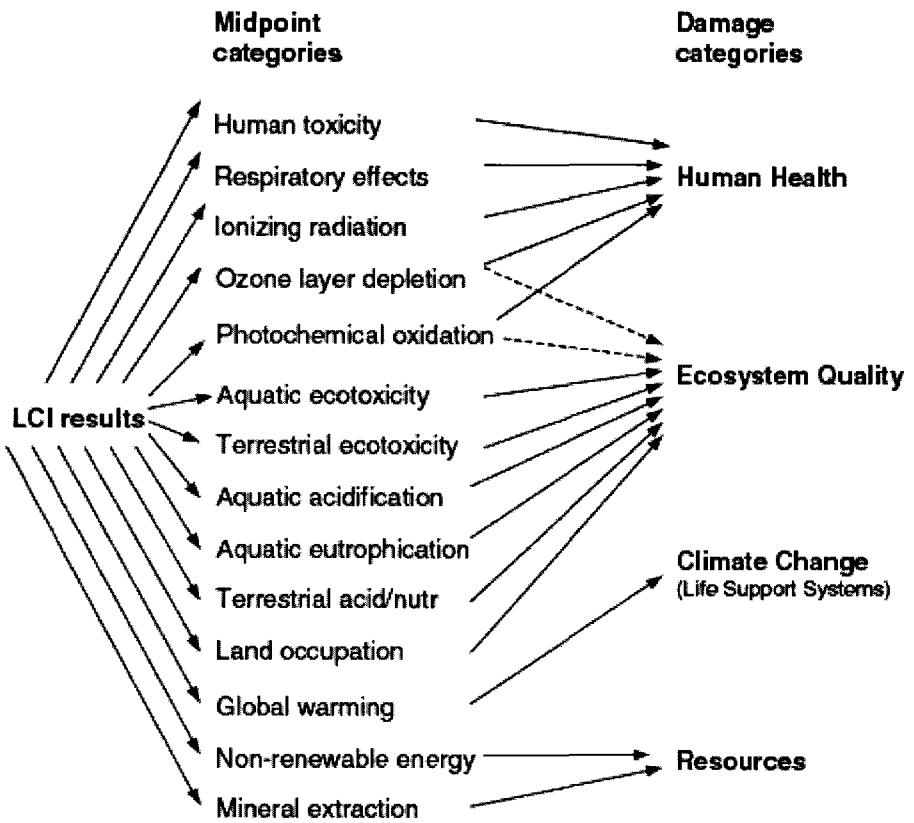
The LCIA process is illustrated in Figure 4.8.

A description of commonly used impact assessment categories is presented below. More information on impact assessment categories and LCIA methodologies employing these categories can be found in Pennington et al. 2004.



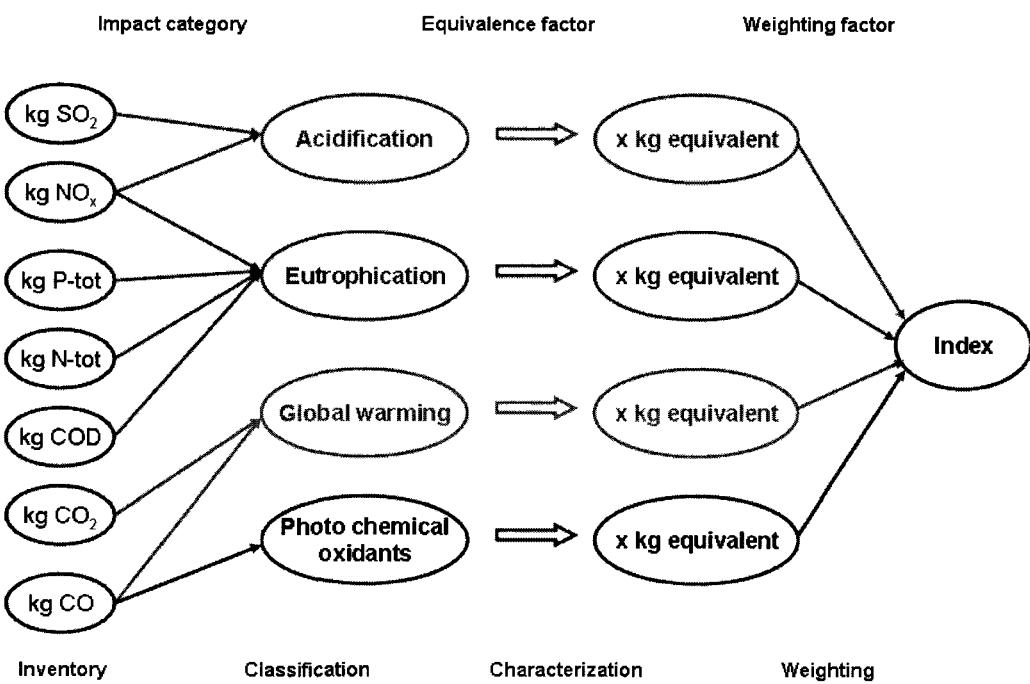
**Figure 4.6 Impacts at midpoint and damage level in LCIA**

Source: Hauschild 2005



**Figure 4.7 IMPACT 2002+ framework**

Source: Jolliet et al. 2003



**Figure 4.8    Life Cycle Impact Assessment Procedure**

(original in color)

***Resource depletion (biotic and abiotic resources)*** – Biotic (or living) resources can be considered from two key perspectives: their availability for future generations, and their contributions to ecosystem functioning and biodiversity. Biotic resources are renewable, but overexploitation can lead to damages such as population decrease and eventually species extinction.

Non-living, or abiotic, resources are addressed in terms of their availability for present and future generations.

***Global Warming Potential (GWP)*** – Heat is trapped in the atmosphere by the infrared adsorption of reflected sunlight (infrared radiation released from a warmed surface). Changes in the adsorption capacity can result in changes in the earth's climate. Anthropogenic emissions contributing significantly to this capacity include carbon dioxide ( $\text{CO}_2$ ), methane ( $\text{CH}_4$ ), nitrous oxide ( $\text{N}_2\text{O}$ ), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulphur hexafluoride ( $\text{SF}_6$ ).

The relative contributions of different chemical emissions to climate change are calculated using GWPs. GWPs are referenced to 1 mass unit of carbon dioxide. For example, a GWP<sub>i</sub> of 100 implies that 1 kg of chemical (i) has the same predicted climate change effect, over the example time horizon of 500 years, as 100 kg of carbon dioxide. The Intergovernmental Panel for Climate Change (IPCC) proposed a time horizon of 100 years.

The GWPs shown in the Table 4.2 are 100-year GWPs from the 1996 IPCC report, referring to their effect relative to  $\text{CO}_2$  over a 100-year timeframe.

**Table 4.2 GHG and Global Warming Potential, 1996 IPCC report**

<b>GHG</b>	<b>GWP (100 yrs)</b>
CO <sub>2</sub>	1
CH <sub>4</sub>	21
N <sub>2</sub> O	310
HCFCs	140 – 11,700
PFCs	6,500 – 9,200
SF <sub>6</sub>	23,900

Source: U.S. EPA 2002

**Stratospheric Ozone Depletion** – this refers to the loss of the ultraviolet (UV) absorption capacity through the destruction of ozone in the stratosphere. Ozone depletion potentials express the ozone depleting capacity of chlorofluorocarbons (CFCs), hydrochlorofluorocarbons (HCFCs), and halons relative to the reference substance CFC-11. Some of the consequences of increased short-wavelength UV radiation at the earth's surface are known, especially skin cancer formation. It should be noted that the most problematic ozone depleting chemicals are now banned.

**Acidification Potential (AP)** – refers to an increase in acidity, the hydrogen ion concentration, in water and soil systems. The acidification potential is expressed as an equivalent emission of a reference substance. The reference substance used is SO<sub>2</sub>, which is one of the most important man-made acidifying substances.

**Land use** – land use is currently divided into two types: (1) land occupation (continuous use for the same process types, in units of area multiplied by time [m<sup>2</sup>\*y], and (2) land transformation (net change from one land use type to another, or changing quality, in units of area [m<sup>2</sup>]. Occupation and transformation relate to different impacts. Occupation leads to positive, or negative, impacts in terms of the stress on surrounding ecosystems, and can prevent restoration processes relative to some equilibrium or baseline. Transformation leads to net positive, or negative, impacts on the transformed area itself. The sign of the impact depends on the baseline, or on the land use just before transformation, respectively.

**Human and Eco-Toxicity Potentials** – toxicological effect is an adverse change in the structure or function of a species as a result of exposure to a chemical.

Human Toxicity Potential (HTP) takes account of releases of materials toxic to humans in three distinct media - air, water and soil. The toxicological factors are calculated using scientific estimates for the acceptable daily intake or tolerable daily intake of the toxic substances. The human toxicological factors are still at an early stage of development so that HTP can only be taken as an indication and not as an absolute measure of the toxicity potential.

***Eutrophication Potential (EP)*** – two types of eutrophication can be distinguished: aquatic eutrophication and terrestrial eutrophication.

Aquatic eutrophication is the result of nutrient enrichment in aquatic environments. LCA commonly takes nutrient emissions as a basis for characterization factors for aquatic eutrophication. Characterization factors are often based on the relative ratio of the phosphorus and nitrogen in the phytoplankton.

Under natural conditions, the supply of nutrients to water is in balance with the growth of biomass. Anthropogenic nutrient inputs can disturb this balance, leading to increases in algae growth that makes the water turbid and decreases the oxygen content. This leads to increases in fish mortality and ultimately disappearance of bottom fauna.

Terrestrial eutrophication is associated with the nutrient enrichment of soils. The growth of plants is commonly controlled by the limited availability of nitrogen (phosphorus seldom limits plant growth in terrestrial ecosystems).

***Photooxidant or smog formation*** – photooxidants are secondary pollutants formed in the lower atmosphere from NO<sub>x</sub> and hydrocarbons in the presence of sunlight. Ozone is considered the most important of these oxidizing compounds, along with peroxyacetyl nitrate (PAN). Photooxidant formation is also known as summer smog or Los Angeles smog.

***Other physical interventions (odour, ionization damage, nuisance, noise)*** – only a few methods exist for addressing impacts from other physical interventions.

More information on LCIA methodology can be found in SETAC 1998, Pennington et al. 2004, Hauschild 2005.

#### 4.4.2 Spatial differentiation

Life cycle assessment is well developed to evaluate global environmental impacts such as global warming and ozone layer depletion. However, evaluation of regional and local environmental impacts (i.e. eutrophication, acidification, toxicity, land use, biodiversity loss, etc. - categories for which the level of impact depends on the location of emissions) requires collection of regional/local data and use of regional/local characterization factors (Characterization factors are applied to convert results from LCI phase to the common unit of the category indicator (ISO 14044, 2006)). If the generic data is used, it may lead to inaccurate results due to differences in fate and exposure mechanisms and differences in sensitivity of receiving environments (Potting and Hauschild, 2006).

Potting and Hauschild (2006) defined three levels of spatial differentiation:

1. Site-generic - All sources contribute to the same generic receiving environment.

2. Site-dependent – Distinction between classes of sources and their receiving environments is performed. Source categories are defined at the level of countries or regions within 50 to 500 km. The receiving environments are defined with even higher resolution of maximum 150 km.
3. Site-specific – Very detailed spatial differentiation considering sources at specific locations. Allows the modeling of impacts very close to the source with great accuracy.

Site-dependent impact modeling is the most relevant level of spatial differentiation for characterization modeling. Site-specific level is often considered unrealistic for the whole product system, but may be applied for some processes within the system.

Regional differentiation is already applied in the Life Cycle Inventory (LCI) phase, since LCI data is available for specific countries and regions (Sedlbauer et al. 2007). As an example, country specific electricity generation mixes and LCIs for production of many commodities exist for several countries.

The development of site dependent impact assessment methodologies has already started. Site-dependent methodologies exist for Europe (IMPACT 2002+ and EDIP2003), Japan (LIME), US (TRACI and LSCEA) and Canada (LUCAS).

#### 4.4.3 LCIA methods

To date, several LCIA methodologies have been developed. The methodologies are mostly developed for Europe and America. However, there are also newly developed LCIA methodologies for Japan and Canada. The LCIA methods most frequently used by

LCA practitioners are reviewed below. The summary of impact assessment methods reviewed can be found in Table 4.4.

### **Eco-indicator 99**

Eco-indicator 99 method employs the damage-oriented approach. This is a top-down method; developers of the method took weighting as a starting point and worked top down to complete the method (Eco-indicator 99 2008). Three damage categories are used: damage to human health (expressed as disability adjusted life years, DALY); damage to ecosystem quality (expressed as the loss of species over certain area, during a certain time); and damage to resources (expressed as the surplus energy for future extraction of minerals and fossil fuels). More information on the method can be found at <http://www.pre.nl/eco-indicator99/>.

### **Swiss Ecoscarcity Method (Ecopoints)**

The method of environmental scarcity, also called Swiss Ecopoints method, allows a comparative weighting and aggregation of various environmental interventions by use of so-called eco-factors. It is one of the earliest systems for impact assessment with a single score (SAEFL 1998). The method is based on the distance-to-target method. The Ecopoints method does not use a classification. It assesses impacts individually. During the normalization step, the Ecopoints system uses target values rather than current values. The method is based on policy levels instead of sustainability levels, and policy levels are usually a compromise between political and environmental considerations.

The eco-factors were originally developed for the area of Switzerland. Later, sets of eco-factors were also made available for other countries, such as Belgium and Japan.

## **EDIP97 & EDIP2003**

The Danish method for Environmental Design of Industrial Products (EDIP) was developed in 1996 (Wenzel and Alting 1999). EDIP97 is a midpoint approach covering most of the emission-related impacts, resource use and environment impacts with normalization based on person equivalents and weighting based on political reduction targets for environmental impacts and supply horizon for resources.

EDIP2003 methodology supports spatially differentiated characterization modeling which covers a larger part of the environmental mechanism than EDIP97 and lies closer to a damage-oriented approach (Potting and Hauschild 2005). This part of the general method development and consensus programme covers investigations of the possibilities for inclusion of exposure in the life cycle impact assessment of non-global impact categories (photochemical ozone formation, acidification, nutrient enrichment, ecotoxicity, human toxicity, noise).

## **EPS 2000**

The EPS 2000 impact assessment methodology (Environmental Priority Strategies in product design) is a damage oriented method (EPS 2008). In the EPS system willingness to pay to restore changes in the safeguard subjects is chosen as the monetary measure. The indicator unit is ELU (Environmental Load Unit). This method includes characterization and weighting. Normalization is not applied. The method is developed to be used for supporting choice between two product concepts. More information about the method can be found at <http://eps.esa.chalmers.se/>.

## **IMPACT 2002+**

The IMPACT 2002+ life cycle impact assessment methodology uses a combined midpoint/damage approach: 14 midpoint categories are linked to four damage categories (Figure 4.7).

New concepts and methods have been developed, especially for the comparative assessment of human toxicity and eco-toxicity (Jolliet et al. 2003). Both human toxicity and eco-toxicity effect factors are based on mean responses rather than on conservative assumptions. Other midpoint categories are adapted from existing characterizing methods (Eco-indicator 99 and CML 2002). This method allows normalization to be performed either at midpoint or at damage level. The IMPACT 2002+ method presently provides characterization factors for almost 1500 different LCI-results, which can be downloaded at <http://www.epfl.ch/impact>.

## **LIME**

National Institute of Advanced Industrial Science and Technology in Japan developed a damage oriented impact assessment method called LIME - Life-cycle Impact assessment Method based on Endpoint modeling (Itsubo and Inaba, 2003).

The LCIA includes 3 steps: (1) characterization; (2) damage assessment; (3) weighting. LIME has 11 impact categories: global warming, ozone-layer depletion, acidification, eutrophication, photochemical oxidant creation, urban air pollution, human toxicity, eco-toxicity, land use, resource consumption and waste. Characterization factors for local impact categories were developed to reflect the Japanese environment (Figure 4.9).

According to LIME, damage assessment has four safeguard categories: human health, social welfare, biodiversity, and plant production. These categories are expressed in DALY (Disability Adjusted Life Year), Japanese Yen, EINES (Expected Increase in Number of Extinct Species) and NPP (Net Primary Production), respectively.

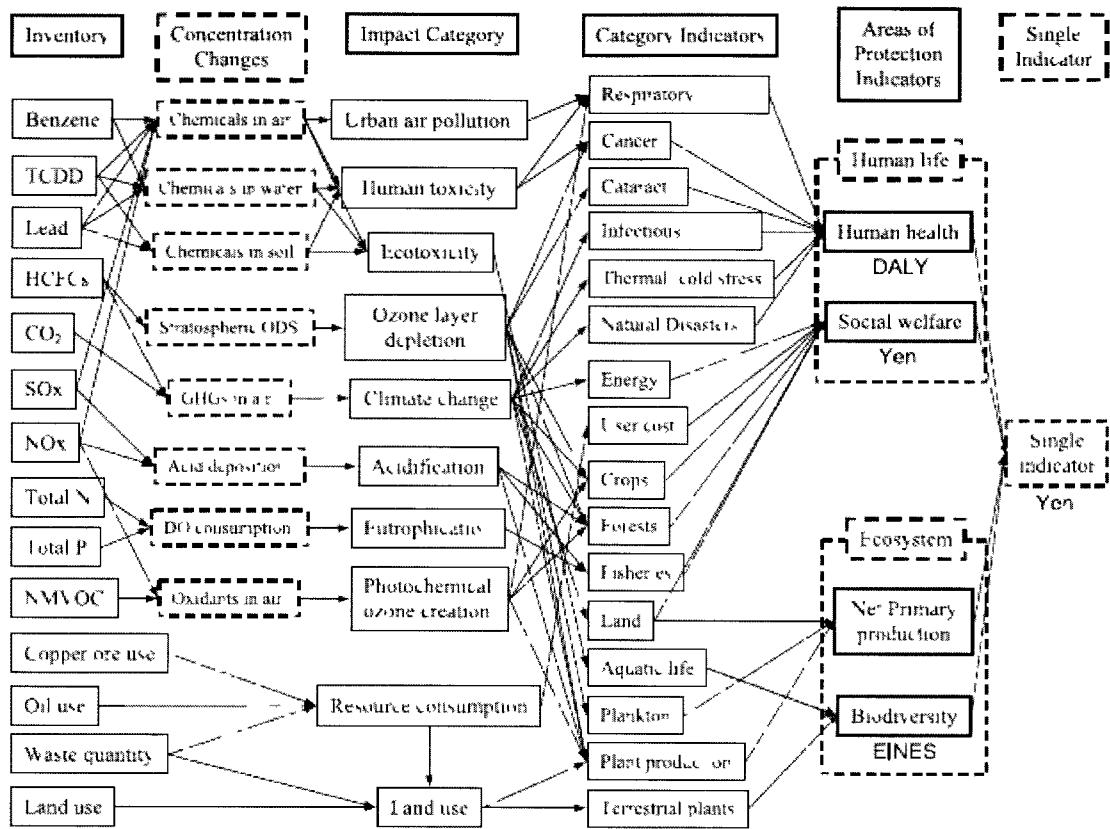
The final stage of LCIA, weighting, gives an integrated environmental impact – a single index that can be presented as the amount of willingness to pay or dimensionless indicator.

## **TRACI**

TRACI, the Tool for the Reduction and Assessment of Chemical and Other Environmental Impacts, is an impact assessment methodology developed by the U.S. Environmental Protection Agency (Bare et al. 2003). The tool is originally designed for use with LCA, but it is expected to find other applications in the future.

The methodology employs 12 midpoint impact categories: ozone depletion, global warming, smog formation, acidification, eutrophication, human health cancer, human health noncancer, human health criteria pollutants, eco-toxicity, fossil fuel depletion, land use and water use.

The developed methodology reflects state-of-the-art developments and best-available practice for life-cycle impact assessment in the United States. More information about the method can be found at [http://epa.gov/ORD/NRMRL/std/sab/iam\\_traci.htm](http://epa.gov/ORD/NRMRL/std/sab/iam_traci.htm).



**Figure 4.9    Japanese national method LIME**

Source: Pennington et al. 2003

## **LUCAS**

Canadian LCA practitioners often use European and American LCIA methodologies when conducting LCAs. However, these methods may not accurately represent Canadian conditions. Thus, researchers from CIRAI have developed a new LCIA method called LUCAS – LCIA method Used for a Canadian-Specific context (Toffoletto et al. 2007). The method is developed by adapting existing LCIA models to the Canadian context. The models used to develop LUCAS are site-dependent models: EDIP2003, IMPACT 2002+ and TRACI.

LUCAS is based on a midpoint characterization approach. It provides characterization factors for the 15 Canadian terrestrial ecozones. 10 impact categories are characterized. These are: (1) climate change; (2) ozone depletion; (3) acidification; (4) smog formation; (5) aquatic eutrophication; (6) terrestrial eutrophication; (7) ecotoxicity (aquatic and terrestrial); (8) toxicity; (9) land-use and (10) abiotic resource depletion.

## **LCSEA**

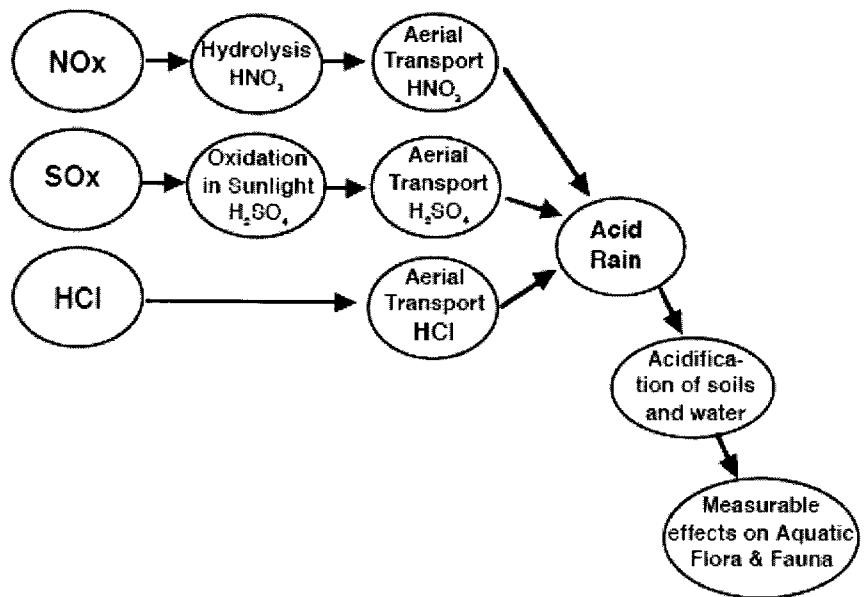
US company Scientific Certification Systems (SCS) has developed the Life-Cycle Stressor-Effects Assessment (LCSEA) Model – a site dependent LCIA technique that complies to the ISO 14044 standard. In the LCSEA Model, the physical, chemical or biological environmental mechanisms that link an industrial input, output or activity (i.e., the “stressor”) to an observable impact (i.e., the “effect”) are modeled as a “stressor-effect networks” (Figure 4.10).

The following environmental indicators are considered in the model:

- Resource Depletion (Energy Resource Depletion, Water Resource Depletion)

- Physical Disruption (Terrestrial Habitat Disruption, Aquatic Habitat Disruption, Riparian Habitat Disruption, Disruption of Key Species (by species))
- Emission Loadings (Greenhouse Gas Loading, Acidification Loading, Ground Level Ozone Loading, Particulate Loading, Neurotoxic Chemical Loading, Non-Cancer Chemical Loading (Pulmonary), Carcinogenic Chemical Loading (Systematic & Pulmonary))
- Hazardous Waste Loading (Radioactive Waste Loading, Other Hazardous Wastes).

The model was developed mainly for the electricity sector. It was applied to an LCA study of electric power generation systems - “An Environmental Assessment of Selected Canadian Electric Power Generation Systems Using a Site-Dependent Life-Cycle Impact Assessment Approach” prepared for Canadian Electricity Association and Natural Resources Canada in February 2005. The subject of the study is comparison of individual power generation systems — coal, nuclear, natural gas, wind, and hydropower in Canada (Scientific Certification Systems 2005).



**Figure 4.10 LCSEA Stressor – Effect Network**

Source: Scientific Certification Systems 2005

#### 4.4.4 Conclusions

Our research is specific to Saskatchewan/Canada, and the selected impact assessment methodology should represent Canadian or US environmental conditions for the accurate environmental impacts evaluation. Thus, the choice of LCIA methodology should be made between three methods:

TRACI – LCIA method developed by the U.S. EPA;

LUCAS – a Canadian site-dependent model; and

LCSEA – a methodology developed by SCS for the US and Canada.

All three methods are site-dependent. TRACI is a well-established methodology that has been applied to LCA studies by several practitioners. LUCAS and LCSEA methods are still in the development stage. LUCAS has been developed by adapting existing LCIA models to the Canadian context. The models that have been used to develop LUCAS are European models EDIP and IMPACT 2002+ and the US model TRACI. However, the work on characterization factors for LUCAS model is not yet finished. Thus, LUCAS cannot be used in this study.

The LCSEA model was developed mainly for the electricity sector. It was applied to several LCA studies of electric power generation systems in Canada. The environmental impact categories in the LCSEA model mainly focus on biological and environmental habitat disruption and require an extensive collection of inventory data that is not easily available.

TRACI impact assessment methodology was therefore applied in this research.

**Table 4.4 LCIA methods overview**

LCIA method	Number of impact categories	Country	Characteristics	Reference
<b>Eco-indicator 99</b>	3 damage categories	Europe	Site-generic – all sources are considered to contribute to the same generic receiving environment.	Eco-indicator 99 2008
<b>Swiss Ecoscarcity Method (Ecopoints)</b>		Europe	Site-dependent. Based on distance-to-target approach.	SAEFL 1998
<b>EPS 2000</b>	5 damage categories	Europe	Evaluates environmental impact according to the willingness to pay.	EPS 2008
<b>IMPACT 2002+</b>	14 midpoint categories and 4 damage categories	Europe	Site-dependent	Jolliet et al. 2003
<b>EDIP2003</b>	8 midpoint categories	Europe	Site-dependent. Weighting is based on the distance-to-target approach.	Hauschild et al. 2003
<b>LIME</b>	11 midpoint categories and 16 damage categories	Japan	Site-dependent	Itsubo and Inaba 2003
<b>TRACI</b>	12 midpoint categories	US	Site-dependent	Bare et al. 2003
<b>LUCAS</b>	10 impact categories	Canada	Site-dependent	Toffoletto et al. 2007
<b>LCSEA</b>	4 groups, 15 impact categories	US /Canada	Site-dependent	SCS 2005

Source: Based on Toffoletto et al. 2007

## **4.5 The role of LCA in decision-making**

A life cycle assessment carried out in a scientifically correct way is a very valuable tool for environmental decision-making. Following are some examples what LCA can do (ACLCA 2004):

- LCA supports the concept of sustainability and sustainable development. In the Malmö Declaration<sup>2</sup>, LCA, Life Cycle Management, and Life Cycle Thinking have been identified as key tools to achieve sustainable development.
- LCA supports science-based legislation that leads to overall environmental improvement, not impact shifting. Since the LCA evaluates a product or service from the life cycle perspective, improvements can be made not only in one area at the cost of another, but in each stage of the product life cycle in an integrated way.
- LCA provides a framework for companies to manage their environmental issues. Many companies that used LCA to evaluate the environmental performance of their processes and products not only found sustainable decisions to their environmental problems, but also reduced resource consumption and saved costs (DANTES 2005).
- LCA engages the public in environmental decision-making. The results of the LCA can be presented as Environmental Performance Indicators, Environmental Product Declarations, as well as used for Eco-labeling. These documents can be

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<sup>2</sup> In May 2000, world's environment ministers gathered in Malmo, Sweden to review important and emerging environmental issues, and adopted an action-oriented Malmo Declaration. The full text of declaration can be found here [http://www.unep.org/malmo/malmo\\_ministerial.htm](http://www.unep.org/malmo/malmo_ministerial.htm)

easily understood by different stakeholders/general public, thus, enabling their participation in the environmental decision-making process.

- LCA provides a framework to identify where the research dollars should be spent. LCA helps to identify technology and infrastructure gaps helping to focus research funding for environmental engineering.

Thus, the LCA tool will have its greatest impact in determining which process or product or course of action is more environmentally friendly. The strength of LCA is that it studies a whole process or product system (from cradle to grave or cradle to cradle) and provides a quantitative assessment of different alternatives. The results of LCA are related to the function of a product/process, which allows comparisons between different alternatives. LCA is also an engineering tool allowing for in-depth study of technical systems and identification of potential changes in the product or process systems.

## **4.6 LCA use in the world**

LCA is incorporated widely today as an important tool for policy, environmental marketing and industrial decision-making in Europe and Japan. It is increasingly used for the same purposes in the United States, Australia, India, Brazil, China and Thailand (EU 2007).

### 4.6.1 Europe

Europe is a leader in LCA application and research. The European Union has several directives and policies to improve environmental performance of a broad range of products (i.e. Integrated Product Policy). LCA results are also used as a basis for Eco-labeling, Environmental Product Declarations (EPD), and Sustainability Performance Indicators (SPI).

There are several LCA centers in Europe that coordinate their activities with governmental policy (EU 2007). Several databases and LCA software programs have been developed in the past decades. These databases represent mainly European industrial processes.

### 4.6.2 Asia

Japan is a leader in LCA among other Asian countries such as India, China and Thailand, where LCA has started to come into use quite recently. The Life Cycle Assessment Society of Japan was formed in 1996. However, Japan has been holding an annual EcoBalance conference since 1994. A national LCA database was developed in Japan

with the support of the Japanese Federal Government that allocated 1.28 billion yen for this purpose.

#### 4.6.3 United States

The US is behind Europe and Japan in the development and application of LCA. However, there are number of initiatives created to promote use of LCA in the US (Fava and Cooper 2004). These are:

- The United Nations Environment Program/Society of Environmental Toxicology and Chemistry (UNEP/SETAC) Life Cycle Initiative (<http://lcinitiative.unep.fr/>).
- The American Centre for Life Cycle Assessment (<http://www.lcacenter.org/>).
- The International Society for Industrial Ecology (<http://www.is4ie.org/>).
- The US Green Building Council that recently established task forced to determine how to best incorporate LCA in their Leadership in Energy and Environmental Design (LEED) green building rating program ([www.usgbc.org/](http://www.usgbc.org/)).
- The California Environmentally Preferred Product Database, which has began to incorporate LCA into product standards developed by the California Division of the State Architect as part of the California Sustainable Schools Program (<http://www.eppbuildingproducts.org/>).

## **4.7 Life Cycle Assessment in Canada**

LCA is slowly spreading within Canada. The literature review showed that there are a significant number of institutions conducting LCA activities and research in Canada.

Canadian government supports LCA activities by conducting LCA studies, workshops and conferences. Below are some examples of these activities.

Natural Resources Canada together with the United Nations Environment Programme (UNEP), the Society of Environmental Toxicology and Chemistry (SETAC), the Asia Pacific Economic Cooperation (APEC), the International Council on Mining and Minerals (ICMM) organized the International Workshop on Life-Cycle Assessment and Metals (<http://www.nrcan.gc.ca/mms/canmet-mtb/mmsl-lmsm/enviro/lifecycle/>) in Montréal in 2002. Different issues related to LCA and metals were discussed. Sixty technical experts, from 15 countries with different perspectives (LCA, life-cycle impact assessment, risk assessment, economy, and geology) and from diverse sectors (industry, academia, consultant, government) attended the workshop.

Environment Canada supported LCA capacity and education with a number of documents and publications. For example, a study called Environmental Life Cycle Management: A Guide for Better Business Decisions (<http://www.ec.gc.ca/ecocycle/en/lcmguid.cfm>) was published in 1997, and the Ecocycle newsletter was published from 1995 to 2000 (<http://www.ec.gc.ca/ecocycle/en/index.cfm>).

A study “Understanding the Environmental Aspects of Electronic Products: A Life Cycle Assessment Case Study of a Business Telephone” was conducted by Environment

Canada and Nortel Networks to analyze the material, energy and environmental aspects of a common consumer product — the telephone Norstar M3710 ([http://www.ec.gc.ca/nopp/chemical/telephone/index\\_e.html](http://www.ec.gc.ca/nopp/chemical/telephone/index_e.html)). The study was completed in 1997.

Natural Resources Canada developed the GHGenius model – a model for Life Cycle Assessment of transportation fuels. It is based on the 1998 version of Dr. Mark Delucchi's Lifecycle Emissions Model (LEM). GHGenius is capable of analyzing the emissions of many contaminants associated with the production and use of traditional and alternative transportation fuels. (<http://www.ghgenius.ca/>).

The Athena Institute (<http://www.athenasm.org/about/>) for more than a decade has been conducting LCAs to evaluate the environmental impacts of new and existing buildings. Two software tools for the life cycle assessment of whole buildings and assemblies were developed at the Institute. These are:

*The ATHENA® Impact Estimator for Buildings*, which is capable of modeling 95% of the building stock in North America—including industrial, institutional, office and residential designs—and simulating over 1,000 assembly combinations; and

*The ATHENA® EcoCalculator for Assemblies* that provides instant LCA results for common building assemblies based on detailed assessments previously conducted using the *Estimator*.

The Athena Institute has also developed LCA databases that cover 90-95% of the structural and envelope systems typically used in residential and commercial buildings. The Institute also maintains databases for energy use and related air emissions for on-site

construction of a building's assemblies, for maintenance, repair and replacement effects through its operating life, and for demolition and disposal.

National Research Council Canada (NRC/CNRC), Institute for Research in Construction ([http://irc.nrc-cnrc.gc.ca/index\\_e.html](http://irc.nrc-cnrc.gc.ca/index_e.html)) is also actively involved in the LCA of buildings.

The Interuniversity Reference Centre for the Life-Cycle Assessment, Interpretation and Management of Products, Processes and Services (CIRAI) at the École Polytechnique de Montréal (<http://www.polymtl.ca/cirai/>) was founded in 2001. Since then, it has created a research program based on seven research themes. These are:

Theme 1: Developing and validating a reliable LCA method.

Theme 2: Developing and validating a Canadian life cycle impact assessment method - the LUCAS method was developed in 2005.

Theme 3: Developing a decision-making system based on enviro-economic performance indicators in an integrated product policy (IPP).

Theme 4: Studying the regulatory and legal impacts of LCM.

Theme 5: Studying the social impacts of LCM.

Theme 6: Process integration.

Theme 7: Ecodesign.

The non-profit Pembina Institute for Appropriate Development ([www.pembina.org](http://www.pembina.org)) working primarily on the oil and gas energy sector, has developed their own Life Cycle Value Assessment methodology (Young 2003). The methodology was applied to a

number of studies, for example the “Life-Cycle Value Assessment (LCVA) of Fuel Supply Options for Fuel Cell Vehicles in Canada” (Pembina 2002).

Universities in Canada are also actively involved in development and teaching of LCA concept. The Faculty of Environmental Studies at University of Waterloo has developed an Environment and Business teaching program that has recently been placed first in a national survey of how well sustainability considerations are integrated into university programs, student initiatives and courses (<http://www.fes.uwaterloo.ca/>). The University also hosts two projects:

1. The Integrated Waste Management Model for Municipalities (<http://www.iwm-model.uwaterloo.ca/>) – a desktop LCA tool for the evaluation of life cycle environmental and economic effects of waste management systems; and
2. Canadian Raw Materials Database (<http://crmd.uwaterloo.ca/>) - a voluntary project involving Canadian materials industries to develop a database profiling the environmental inputs and outputs associated with the production of Canadian commodity materials.

Professor Heather MacLean in Civil Engineering Department at University of Toronto leads the LCA group in Toronto with a focus on the energy and transportation sectors (<http://www.civil.engineering.utoronto.ca/infoabout/staff/professors/maclean.htm>). The research group is also involved in the collaborative project between University of Toronto and University of Calgary called “Life Cycle Assessment of Oil Sands Technologies” (<http://www.ucalgary.ca/lcaos/>). The project goal is to assess economy-wide upstream impacts of current and proposed oil sands operations. The Economic Input Output Life Cycle Assessment model (EIO-LCA) of the Canadian economy implemented

by Professor MacLean's research group, is used as an LCA model in this project (Bjorn et al. 2005, Bergerson and Keith 2006).

Other universities involved in LCA teaching or research are Queens University, Dalhousie University, Carlton, Université Laval, and Memorial University in Newfoundland.

Companies in Canada that have utilized LCA include Interface, Canfor, Suncor, Alcan, Magna International, Consumer Gas, Siemens North American Motor Operations, and many others. LCA studies are also commonly conducted by industry associations and research organizations, e.g., Canadian Wood Council, International Copper Association, International Lead and Zinc Research Organization, International Iron and Steel Institute, International Aluminum Institute and the Nickel Development Institute. (FiveWinds 2007).

In Saskatchewan, SaskPower Corporation has recently introduced an LCA technique for assessment of different power generation options. The company is using a newly-developed impact assessment procedure ASTM E06.71.10 "Standard Practice for Comparing the Environmental Performance of the Electric Power Generation Facilities and Infrastructure" (SCS 2006). The method is developed by Scientific Certification Systems (SCS 2007).

## **4.8 Problem definition**

LCA databases representing industry-average data are widely available for European and Japanese industry. However, there is only one proprietary database in the US - that of Franklin Associates, Ltd (<http://www.fal.com/lifecycle.htm>). No complete and open public LCA database exists in Canada at the moment.

Before Life Cycle Inventory data on generic processes becomes widely available in Canada, product manufacturers must be willing to study and report on their internal processes and the environmental performance of their products. Many companies are now starting to use LCA tools internally, but they are hesitant to publish detailed Life Cycle Assessments. There are several reasons for this, for example:

- The company does not want to reveal trade secrets to competitors.
- After the results are published, anything that looks negative in the study may be taken out of context and used against the company by competitors or environmental activists.
- The study might show that their product is not the best choice environmentally.

To overcome this resistance from companies, there is a need to create incentives for manufacturers to provide LCA results on their products. It can be done by collecting commitments from governments and companies to give preference to those products for which LCA data is available. In addition, standard formats for companies to use in reporting on their LCA data should be developed.

## **5. APPLICATION OF LCA METHODOLOGY TO ENERGY SYSTEMS**

### **5.1 LCA on power production in different countries**

Life cycle assessment studies of power production systems have been extensively conducted worldwide over the past two decades [Spath et al. 1999; Meier 2002; Dones et al. 2003; Hondo 2005; Odeh and Cockerill 2008a]. The focus of our research is on coal-fired power plants. Thus, a summary of LCA of different coal-fired power plants in the world is presented below. Results of three LCA studies are compared in Table 5.1.

Spath et al. (1999) performed an LCA of pulverized coal power production systems. The authors studied three systems:

1. a plant that represents the average emissions and efficiency of currently operating coal-fired power plants in the US;
2. a new coal-fired power plant;
3. a future highly advanced coal-fired power plant utilizing a low emission boiler system.

CO<sub>2</sub> emissions from these plants are 1022 g/kWh, 941 g/kWh, and 741 g/kWh, respectively. The results of LCA for the average plant are shown in the Table 5.1. For the average system using surface mining, CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O were found to be emitted at rates of 1,021.5 g/kWh, 0.9 g/kWh, and 0.004 g/kWh, respectively.

**Table 5.1 Comparison of results from LCA studies on coal-fired power plants**

Study Parameter	Spath et al. (1999)	Hondo (2005)	Odeh and Cockerill (2008a)
<b>Country</b>	US	Japan	UK
<b>Emissions considered</b>	CO <sub>2</sub> , CH <sub>4</sub> , N <sub>2</sub> O	CO <sub>2</sub> , CH <sub>4</sub>	CO <sub>2</sub> , CH <sub>4</sub> , N <sub>2</sub> O
<b>Assumptions<sup>3</sup></b>	360MW, 60%LF (Load Factor), 32% efficiency, 30 years lifetime.	1000MW, 70% LF, 36.8% efficiency, 30 years lifetime.	660MW, 80% LF, 35% efficiency, 40 years lifetime.
<b>Total LCA emissions, g CO<sub>2</sub>-e<sup>4</sup>/kWh</b>	<b>1042.1</b> (considering CO <sub>2</sub> , CH <sub>4</sub> , N <sub>2</sub> O)	<b>975.2</b> (considering CO <sub>2</sub> and CH <sub>4</sub> )	<b>989.7</b> (considering CO <sub>2</sub> , CH <sub>4</sub> , N <sub>2</sub> O)
<b>Total CO<sub>2</sub> emissions, g CO<sub>2</sub>/kWh</b>	<b>1022.0</b>	<b>922.0</b>	N/A
<b>Construction, % (g-CO<sub>2</sub>/kWh)</b>	<b>0.5 (5)</b>	<b>0.4 (3.6)</b>	<b>0.1 (1.1)</b>
<b>Power generation, % (g-CO<sub>2</sub>/kWh)</b>	<b>97.0 (991)</b> <ul style="list-style-type: none"> <li>• Combustion: &gt;93%</li> </ul>	<b>91.6 (893.5)</b> <ul style="list-style-type: none"> <li>• Combustion: 90.9% or 886.8 g-CO<sub>2</sub>/kWh</li> <li>• Other generation: 0.7% or 6.7 g-CO<sub>2</sub>/kWh</li> </ul>	<b>92.6 (915.6)</b> <ul style="list-style-type: none"> <li>• Combustion: 89.1% or 881.6 g-CO<sub>2</sub>/kWh</li> <li>• Material production and transport: 3.5% or 34 g-CO<sub>2</sub>/kWh</li> </ul>
<b>Mining and coal transport, % (g-CO<sub>2</sub>/kWh)</b>	<b>2.6 (26)*</b> <ul style="list-style-type: none"> <li>• CO<sub>2</sub> emissions from mining: 0.9% or 9 g-CO<sub>2</sub>/kWh</li> </ul>	<b>8.0 (78.2)*</b> <ul style="list-style-type: none"> <li>• CO<sub>2</sub> emissions from mining: 1.0% or 9.7 g-CO<sub>2</sub>/kWh</li> </ul>	<b>7.3 (72.9)*</b> <ul style="list-style-type: none"> <li>• Coal mining and transport: 0.8% or 8.1 g-CO<sub>2</sub>/kWh</li> </ul>

<sup>3</sup> All numbers hereafter are related to kWh of electrical power.

<sup>4</sup> CO<sub>2</sub>-e or CO<sub>2</sub>-equivalent – is a quantity that describes, for a given mixture and amount of greenhouse gas, the amount of CO<sub>2</sub> that would have the same global warming potential (GWP), when measured over a specified timescale (generally, 100 years).

<b>Study Parameter</b>	<b>Spath et al. (1999)</b>	<b>Hondo (2005)</b>	<b>Odeh and Cockerill (2008a)</b>
	<ul style="list-style-type: none"> <li>• Coal transport: 1.7% or 17 g-CO<sub>2</sub>/kWh</li> </ul>	<ul style="list-style-type: none"> <li>• Methane leakage from mining: 5.4% or 52.9 g-CO<sub>2</sub>/kWh</li> <li>• Coal transport: 1.6% or 15.6 g-CO<sub>2</sub>/kWh</li> </ul>	<ul style="list-style-type: none"> <li>• Methane leakage from mining: 6.5% or 64.8 g-CO<sub>2</sub>/kWh</li> </ul>

Source: Adapted from Odeh and Cockerill 2008a

\* It should be noted that the difference between mining and coal transport emissions for three studies are mainly due to differences in coal mining and coal origin. Spath et al. (1999) uses local Illinois No. 6 coal (both surface and underground mining were studied) transported by barge, truck or train, while Hondo (2005) assumed that coal is transported from Australia by train and ship and Odeh and Cockerill (2008a) assumed coal mining in UK (40% surface and 60% deep mining) and transport via rail (44 km) to the power plant.

Applying the appropriate Greenhouse Warming Potential (GWP) factors (21 for methane and 310 for nitrous oxide), this comes to 1,021.5, 19.2, and 1.4 g CO<sub>2</sub>-e/kWh, respectively. Thus, the total GWP of the system is 1,042.1 g of CO<sub>2</sub>-e/kWh, and the power plant operations represent the largest source of these emissions (97% or 991 g CO<sub>2</sub>-e/kWh). The authors also stated that most of the SO<sub>2</sub> and NO<sub>x</sub> come from the power plant, while mining was the main source of methane.

Hondo (2005) used a combined method of process analysis and input-output analysis to estimate Greenhouse Gas (GHG) emissions per kWh of electricity for nine different types of power generation systems. The systems examined were: coal-fired, oil-fired, LNG-fired, LNG-combined cycle, nuclear, hydropower, geothermal, wind power and solar-photovoltaic. The results of the analysis for coal-fired system are shown in the Table 2.2. Hondo calculated that total emissions from Japanese coal-fired power plants are 975 g CO<sub>2</sub>-e/kWh with 90.9% coming from direct combustion.

Odeh and Cockerill (2008a) presented the results of LCA of GHG emissions from UK coal-fired power generation systems. A typical UK coal-fired plant emits approximately 990 g CO<sub>2</sub>-e/kWh of electricity generated. The majority of these emissions result from direct fuel combustion (882 g/kWh) with methane leakage from mining operations accounting for 60% of indirect emissions.

The literature review showed that some variations among studies can be noted. This is due to differences in the scope of the work, the system boundaries and different assumptions made by authors. Reported figures also depend on the fuel used (for example, lignite or hard coal), coal origin and mining methods (surface or underground mining) and the power production technology (for example, conventional PC (pulverized

coal) or IGCC (Integrated Gasification Combined Cycle) power plant). Some LCA studies that are based on the full life cycle of the fuel give higher CO<sub>2</sub> emissions than studies that consider the combustion only. Furthermore, some studies include other GHG emissions (CH<sub>4</sub> and N<sub>2</sub>O) in addition to CO<sub>2</sub>, and so, these latter studies report higher LCA emissions.

## **5.2 Energy systems with CO<sub>2</sub> capture and storage**

A literature research has shown that many studies have been undertaken all over the world on Life Cycle Assessment of energy systems with CO<sub>2</sub> capture and storage (CCS).

Table 5.2 gives a summary of LCA studies on energy systems with CCS.

Life Cycle Assessment on CO<sub>2</sub> capture at the power plant include research done by Doctor et al. 2001, Rao and Rubin 2002, Lombardi 2003, Benetto et al. 2004, Ramezan et al. 2006.

Earlier works on LCA of CCS (Livengood et al. 1993; Summerfield et al. 1995; and Waku et al. 1995) focused mainly on mass and energy balances and emissions inventories. The results were presented as reduction in power plant energy efficiency and decrease in CO<sub>2</sub> emissions due to CO<sub>2</sub> capture and storage.

Livengood et al. (1993) studied an integrated gasification combined cycle power generation process (IGCC) with CO<sub>2</sub> recovery, CO<sub>2</sub> transport by pipeline and land-based sequestering in geological reservoirs. The authors showed the emission rate reduction from 872 g CO<sub>2</sub>-e/kWh (without CCS) to 218 g CO<sub>2</sub>-e/kWh (with CCS).

**Table 5.2 Summary of LCA studies on energy systems with CCS**

<b>Author</b>	<b>CCS phase</b>				<b>Impacts</b>
	<b>Power plant</b>	<b>CO<sub>2</sub> capture</b>	<b>Transport</b>	<b>Storage</b>	
Livengood et al. 1993	458 MW <sub>e</sub> IGCC	MEA process Selexol process Chilled methanol	500 km pipeline	Geological storage	CO <sub>2</sub> Energy efficiency
Summerfield et al. 1995	500 MW <sub>e</sub> NGCC IGCC Pulverized coal fired supercritical steam turbine plant (PF+FGD)	Chemical solvent for NGCC Physical solvent for IGCC Selective catalytic NO <sub>x</sub> reduction and flue gas desulphurization with associated CO <sub>2</sub> capture for PF+FGD	Pipeline	Gas field for NGCC Ocean for IGCC Managed forest for PF+FGD	CO <sub>2</sub> , NO <sub>x</sub> , N <sub>2</sub> O, particulates
Waku et al. 1995	600 MW <sub>e</sub> IGCC Liquefied NGCC	90% Selexol process for IGCC MEA process for liquefied NGCC	Pipeline (100 and 500 km) Ship (100, 500, 5000 and 12 000 km)	Underground for IGCC (2000 m) Ocean (3000 m) for liquefied NGCC	CO <sub>2</sub> Energy efficiency
Spath and Mann 2001 and 2004	600 MW <sub>e</sub> PC NGCC	90% MEA process	300-1800 km pipeline	Geological storage (800 m)	GWP (CO <sub>2</sub> , CH <sub>4</sub> and N <sub>2</sub> O)
Khoo and Tan 2006a	Coal-fired plant	95% MEA process 82% Membrane separation	Ship (100km) for ocean sequestration Pipeline for geological storage	Ocean sequestration Geological sequestration (EOR and enhanced coalbed)	GWP Acidification Eutrophication

Author	CCS phase				Impacts
	Power plant	CO <sub>2</sub> capture	Transport	Storage	
		90% Cryogenics 85% Pressure swing adsorption		methane (ECBM) recovery) Sequestration of CO <sub>2</sub> in a saline aquifer	Ecotoxicity Human toxicity Wastes Resources
Viebahn et al. 2007	700 MW <sub>e</sub> PC (hard coal) IGCC (hard coal) Pulverized lignite NGCC	88% MEA process for PC and NGCC 88% Physical absorption with Rectisol for IGCC 99.5% Oxyfuel for PC	300 km pipeline	Geological storage in empty natural gas fields in Northern Germany	GWP (CO <sub>2</sub> , CH <sub>4</sub> and N <sub>2</sub> O) Photooxidant formation Eutrophication Acidification Human toxicity Cumulated energy demand
Mayer-Spohn (2006) and Mayer-Spohn et al. (2007)	IGCC	80%	80 km pipeline and 1000 km ship	Underground storage	GWP Acidification Eutrophication Summer smog Stratospheric ozone depletion
Odeh and Cockerill 2008b	Supercritical PC NGCC IGCC	90% MEA process for PC and NGCC Selexol process for IGCC	300 km pipeline to the Southern North Sea	Injection in depleted gas fields	GWP Other emissions (NO <sub>x</sub> , SO <sub>2</sub> , particulates, NH <sub>3</sub> )
Hertwich et al. 2008	832 MW <sub>e</sub> NGCC	90% MEA process	150 km pipeline to the Southern North Sea	EOR	GWP Acidification

<b>Author</b>	<b>CCS phase</b>				<b>Impacts</b>
	<b>Power plant</b>	<b>CO<sub>2</sub> capture</b>	<b>Transport</b>	<b>Storage</b>	
Pehnt and Henkel 2009	PC IGCC	Amine post-combustion Selexol pre-combustion Oxyfuel	325 km pipeline	Geological storage	GWP Cumulative energy demand Summer smog Eutrophication Acidification Health impacts
Nie 2009	PC	Post-combustion with chemical adsorption Oxyfuel	Pipeline	Saline aquifer	GWP Stratospheric ozone depletion Eutrophication Acidification Photo-oxidant formation Ecotoxicity Human toxicity Depletion of abiotic resources Land use

Summerfield et al. (1995) studied three fossil fuelled plant options with different CO<sub>2</sub> capture and storage techniques. These are:

- A natural gas fired combined cycle gas turbine plant (NGCC) with chemical solvent scrubbing of the flue gas and gas field disposal of CO<sub>2</sub>.
- A coal fired Integrated Gasification Combined Cycle (IGCC) with shift reactor and physical solvent scrubbing of the fuel gas coupled to ocean disposal of CO<sub>2</sub>.
- A pulverized coal fired supercritical steam turbine plant with selective catalytic NO<sub>x</sub> reduction and flue gas desulphurization with associated CO<sub>2</sub> capture from the atmosphere by a managed forest.

The authors focused on mass and energy balances of the full fuel cycles, economic analysis and emissions inventories of the fuel cycles.

The study performed by Waku et al. (1995) evaluated life cycle energy balance and CO<sub>2</sub> emissions for LNG combined cycle and IGCC power generation systems with carbon capture and sequestration technologies. The authors concluded that CO<sub>2</sub> recovery and sequestration can lower CO<sub>2</sub> emissions to 61-76% depending on the type of power generation system.

Recent LCA studies on CCS (Spath and Mann 2001, Spath and Mann 2004, Khoo and Tan 2006a, Viebahn et al. 2007, Mayer-Spohn 2006, Mayer-Spohn et al. 2007, Odeh and Cockerill 2008b, Hertwich et al. 2008 and Pehnt and Henkel 2009, Nie 2009) accounted for a broader range of impacts on the environment, human health and resource use (GWP, acidification and eutrophication potentials, human- and eco-toxicity, waste and resource use). Thus, these studies allowed the better understanding of the full life cycle effect of

CCS. This is particularly important as increased resource consumption to compensate for loss in power plant efficiency due to the addition of CO<sub>2</sub> capture unit is required. The emission profile of the power plant is also different if a CO<sub>2</sub> capture unit is added, resulting in different environmental impacts. For example, if a MEA (monoethanolamine) process is used to capture CO<sub>2</sub>, it results in the increase in the acidification potential due to the NH<sub>3</sub> emitted from the capture plant.

Spath and Mann (2001) studied the CO<sub>2</sub> capture from the flue gas of a coal-fired power plant and subsequent sequestration of captured gas. CO<sub>2</sub> capture and sequestration consumes additional energy that should be compensated by use of additional fossil fuel or another source of energy. The authors' goal was to determine the actual reduction in global warming potential while maintaining power generation capacity of the plant. The authors used a life cycle approach to account for CO<sub>2</sub>, CH<sub>4</sub> and N<sub>2</sub>O emissions expressed in terms of CO<sub>2</sub>-equivalents. The system boundaries included coal mining, transportation, power plant operations, and CO<sub>2</sub> capture and sequestration. It was found that after adding CO<sub>2</sub> capture and compression, the capacity of the coal-fired power plant was reduced to 457 MW from original 600 MW. Pipeline transportation accounted for an additional 145 MW reduction in capacity. Maintaining an original plant capacity means that additional electricity production must come from another source, most likely fossil. Therefore, sequestering 90% of the CO<sub>2</sub> from the power plant flue gas does not equal a 90% reduction in the global warming potential per kWh of electricity produced.

Spath and Mann (2004) study examined power generation for two fossil based technologies, coal-fired power production and natural gas combined-cycle, and two biomass technologies, a biomass-fired integrated gasification combined cycle (IGCC)

system using a biomass energy crop, and a direct-fired biomass power plant using biomass residue as well as a biomass residue/coal co-fired system. Here, we will focus only on findings from coal-fired and NGCC power systems. The size of the power plant studied is 600 MW prior to adding CO<sub>2</sub> capture. The loss in capacity for CO<sub>2</sub> capture is compensated for by an NGCC plant. MEA process is used to capture CO<sub>2</sub> from the flue gases. It was assumed that 90% of CO<sub>2</sub> is captured and sequestered. The authors found that GWP decreased from reference coal-fired system by 71% for both PC and NGCC plants. In case of PC plant, the emissions reduced from 847 g/kWh to 247 g/kWh and for NGCC plant emissions reduced from 499 g/kWh to 245 g/kWh. However, in order to maintain constant capacity of the plant, the fossil energy consumption increased by 16% for PC plant and by 11% for NGCC plant compared to reference systems without CCS.

Khoo and Tan (2006a) investigated further the environmental impact of four different CO<sub>2</sub> recovery technologies used at a coal-fired power plant, combined with nine CO<sub>2</sub> sequestration systems. CO<sub>2</sub> recovery technologies studied include chemical absorption, membrane separation, cryogenics and pressure swing adsorption. For CO<sub>2</sub> sequestration, six ocean sequestration technologies, geological sequestration with enhanced oil recovery, geological sequestration with enhanced coalbed methane (ECBM) recovery, and sequestration of CO<sub>2</sub> in a saline aquifer were studied. It was found that geological sequestration methods have the least environmental impact. The most promising method to prevent global warming and at the same time reduce resource depletion was found to be ECBM combined with chemical absorption. The next three technologies with the highest environmental benefits are geological sequestration, EOR with chemical

absorption, and ECBM combined with membrane separation and with pressure swing adsorption.

Viebahn et al. (2007) performed a screening LCA and a cost assessment of CCS in Germany, as well as compared CCS with renewable energy technologies. The authors studied future power plant technology. The reference year of 2020 was chosen for the first commercially operated power plant with CCS to start operation. Pulverized hard coal, IGCC (hard coal), pulverized lignite and NGCC power plants were compared with each other, as well as with wind offshore and solar thermal power plants. The LCA showed that CO<sub>2</sub> emissions reduction is in the range of 72-79% and GHG emissions in the range of 65-79%. Oxyfuel combustion with a CO<sub>2</sub> capture rate of 99.5% resulted in a reduction of 90% (CO<sub>2</sub>) and 78% (GHG), respectively. However, all other impact categories (eutrophication, acidification, PM10 equivalents and cumulative energy demand) increased by about 40%, mainly due to the additional energy consumption required for the different phases of CCS. Photooxidant formation impact category showed an increase by about 60% caused by the monoethanolamine production.

Odeh and Cockerill (2008b) studied three types of fossil-fuel power plants with and without CCS. These are supercritical PC, NGCC and IGCC power plants. The authors showed that with 90% CO<sub>2</sub> capture efficiency, GHG emissions are reduced by 75-84% depending on the technology used. IGCC (GHG emissions less than 170 g/kWh) was found to be favorable to NGCC with CCS. The sensitivity analysis showed that varying the CO<sub>2</sub> capture efficiency and the coal transport distance has more pronounced effect on GHG emissions than changing the length of CO<sub>2</sub> pipeline. In addition to GHG emissions, other air pollutants such as NO<sub>x</sub>, SO<sub>2</sub>, particulates and NH<sub>3</sub> were studied. The authors

concluded that “the reduction of CO<sub>2</sub> emissions is achieved at the expense of increasing other missions like NO<sub>x</sub> and NH<sub>3</sub>”. Authors also made some general conclusions about eutrophication and acidification potentials of power plant with CO<sub>2</sub> capture unit. The eutrophication potential of PC plant with CO<sub>2</sub> capture unit may double compare to plant without capture. Acidification potential is also expected to increase due to increase in NO<sub>x</sub> concentrations. MEA solvent used in CO<sub>2</sub> capture may lead to increase in human toxicology potential. However, no quantitative assessment of these environmental impacts was performed.

Hertwich et al. (2008) applied LCA method to study EOR project in Norway. The authors included into system boundaries an NGCC power plant with post-combustion capture, pipeline transport and injection of CO<sub>2</sub> in a North Sea oil field for EOR. The authors modeled processes on a specific platform with and without EOR. Please find more information about the study and results in Chapter 6: Table 6.1.

The most recent study on life cycle assessment of carbon dioxide capture and storage from lignite power plants was published by Pehnt and Henkel in 2009. Five systems were compared: conventional PC power plant, PC power plant with amine post-combustion CO<sub>2</sub> capture, IGCC power plant, IGCC power plant with Selexol pre-combustion CO<sub>2</sub> capture and oxyfuel power plant with CO<sub>2</sub> capture. Only electric power as a product was considered. Environmental impacts such as cumulative energy demand, global warming, summer smog, eutrophication, acidification and health impacts were analyzed. It was found that GHG emissions were reduced by 80 and 84% for the conventional PC and the IGCC power plants, respectively. Oxyfuel CO<sub>2</sub> separation resulted in reduction of CO<sub>2</sub> emissions by 86%. However, environmental impact in all other impact categories

increased in case of conventional PC power plant with post-combustion CO<sub>2</sub> capture. This was due to additional fuel input to compensate for the plant lost capacity, emissions from the CO<sub>2</sub> capture process and solvent production. Additional NH<sub>3</sub> emissions occurred due to solvent degradation and production. In case of pre-combustion capture, a reduction in all environmental impact categories was noticed. Oxyfuel technology is still in early development stage. Authors mentioned that there are some uncertainties regarding the energy requirement for oxygen production (air separation process) and possibility of co-capture of pollutants other than CO<sub>2</sub>. Thus, it is difficult to evaluate environmental impact of oxyfuel process. However, the authors stated that “if co-capture were possible, oxyfuel could lead to a near-zero emissions from power plant”.

In conclusion, it should be noted that most of the studies focused primarily on GHG emissions of CCS. Some of the research papers also considered other environmental impacts of CCS such as photooxidant formation, acidification, eutrophication, human- and eco-toxicity and cumulative energy demand. However, these impacts were studied to the less extent.

## **6. APPLICATION OF LCA METHODOLOGY TO EOR TECHNIQUES AND CO<sub>2</sub> STORAGE IN GEOLOGICAL RESERVOIRS**

A literature review revealed that the research in application of LCA methodology to enhanced oil recovery techniques and CO<sub>2</sub> storage in geological reservoirs reported so far has been quite limited. The first studies in this field have been done by Aycaguer et al. (2001). The authors conducted an LCA to determine the benefits of storing CO<sub>2</sub> in active reservoirs while enhancing the extraction of oil. The potential for CO<sub>2</sub> storage in a specific oil reservoir in Texas was demonstrated. The study focused on CO<sub>2</sub>, CH<sub>4</sub> and N<sub>2</sub>O only; no other emissions and discharges were included in the scope of the study. Another limitation of the study was the selected system boundaries – the analysis was limited to the boundary of the facility and included the extraction of oil and gas from the reservoir, the processing of the gas for separation of different components, the compression of CO<sub>2</sub>, and the transport and injection of CO<sub>2</sub> in the oil reservoir. The authors concluded that greenhouse gas emissions during the CO<sub>2</sub> storage process are minimal and the EOR activity is almost carbon-neutral when comparing net storage potential and gasoline emissions from the additional oil recovery.

The study by Khoo and Tan (2006a) was reviewed in the previous section (please see Chapter 5: Tables 5.1 and 5.2. The authors studied the environmental impact of four different CO<sub>2</sub> recovery technologies used at a coal-fired power plant, combined with nine CO<sub>2</sub> sequestration systems.

Another study carried out by Khoo and Tan (2006b) presented two case studies of enhanced resource recovery methods, for oil and natural gas, alongside CO<sub>2</sub> sequestration. The authors studied an offshore EOR project in Norway and enhanced coal-bed methane (ECBM) recovery project in Japan. CO<sub>2</sub> capture, compression, transportation, and injection into a geological formation were included into system boundaries. The authors compared conventional oil and natural gas production with EOR and ECBM with CO<sub>2</sub> sequestration. Total amount of CO<sub>2</sub> sequestered was in the range of 90 to 95%. SimaPro's environmental design of industrial products (EDIP) impact assessment method was used to calculate GWP, acidification, human toxicity, eutrophication, wastes, and resources. Normalization and weighting was performed to obtain the final scores for different alternatives. The authors showed that GWP can be substantially reduced by using EOR and ECBM. However, acidification, eutrophication, and wastes are higher than for conventional oil and natural gas production.

The most recent study "Life Cycle Assessment of Carbon Dioxide Capture for Enhanced Oil Recovery was carried by Hertwich et al. (2008) in Norway. The authors used a hybrid LCA method to evaluate environmental impact of the system that consists of a natural gas combined cycle power plant with post-combustion CO<sub>2</sub> capture, pipeline transportation and injection of CO<sub>2</sub> in the North Sea oil field for enhanced oil recovery. The impacts associated with the CO<sub>2</sub> capture was allocated to the electricity production, and the impacts from transportation and storage of CO<sub>2</sub> - to the oil produced. The enhanced oil recovery was investigated in detail by modeling the processes on a specific platform using engineering process modeling software HYSYS. Two cases were modeled – a basic case without EOR and an EOR case. Global warming and acidification impacts were

studied. The authors concluded that there is a substantial reduction of greenhouse gas emissions from power production, i.e. by 80% to 75g/kWh. However, the acidification potential increased due to the NH<sub>3</sub> emitted from the capture plant. The authors also indicated a reduction of the emissions associated with oil production per unit of oil produced.

The summary of LCA studies on EOR is presented in Table 6.1.

The literature review showed that more research is needed in the area of LCA of enhanced oil recovery techniques and application of LCA methodology to the actual EOR projects. Thus, the main objective of this research is to conduct a full Life Cycle Assessment of CO<sub>2</sub> capture at the power plant and use for EOR. The boundary of the life cycle includes all the processes starting from power plant construction, coal mining and transport, power production, and the CO<sub>2</sub> capture at the power plant through building a pipeline for the CO<sub>2</sub> transport to the oil field, transport of the CO<sub>2</sub>, use of the CO<sub>2</sub> in the oil field, transportation of crude oil to a refinery and final use of refinery products by consumers.

**Table 6.1 Summary of LCA studies on EOR and CO<sub>2</sub> storage**

Study	Technology	Results
Aycaguer et al. (2001)	<p><b>Technology:</b> EOR (WAG process, 40 years of oil production). CO<sub>2</sub> comes from natural reservoirs and from the produced-gas recycling plant.</p> <p>System boundaries include the extraction of the oil and associated gas from the oil reservoir, the processing of the associated gas for separation of the different compounds (water, H<sub>2</sub>S, CO<sub>2</sub>, CH<sub>4</sub>, natural gas liquids), the compression of the CO<sub>2</sub> for injection, and the transport and injection of the CO<sub>2</sub> in the oil reservoir.</p>	<ul style="list-style-type: none"> <li>Amount of CO<sub>2</sub> stored (or avoided) is 2.6 kg per kg oil.</li> <li>40 years of EOR operations correspond to 12 years of emissions avoided from the 300MW coal power plant where 8000 tons of CO<sub>2</sub> is captured per day.</li> </ul>
Khoo and Tan (2006b)	<p><b>Technology:</b> EOR and ECBM.</p> <p><b>CO<sub>2</sub> capture:</b> Coal-fired power plant.</p> <p><b>Transport:</b> In case of EOR, 682 km pipeline from</p>	<ul style="list-style-type: none"> <li><b>Energy requirements (EOR):</b> CO<sub>2</sub> recovery – 330 kWh/t CO<sub>2</sub>; compression and pipeline transport - 130 kWh/t CO<sub>2</sub>; recompression and injection – 7-9 kWh/t CO<sub>2</sub>; oil recovery – 94 kWh/t oil.</li> </ul>

Study	Technology	Results
	<p>coal-fired power plant to EOR site in the North Sea.</p> <p><b>Storage:</b> Injection into a geological reservoir for EOR (extraction of 0.18 and 0.4 kg of oil per ton of CO<sub>2</sub> injected); injection into underground coal seams for ECBM (extraction of 0.33 and 0.67 kg of natural gas per ton of CO<sub>2</sub> injected).</p>	<ul style="list-style-type: none"> <li>• <b>Energy requirements (ECBM):</b> CO<sub>2</sub> recovery – 330 kWh/t CO<sub>2</sub>; compression and pipeline transport - 100 kWh/t CO<sub>2</sub>; recompression and injection – 7-9 kWh/t CO<sub>2</sub>; natural gas recovery – 38 kWh/ t natural gas.</li> <li>• <b>Environmental impacts:</b> The total sum of the environmental burdens generated for EOR and ECBM is outweighed by the environmental benefits of preventing global warming.</li> </ul>
Khoo and Tan (2006a)	<p><b>Power plant:</b> Coal-fired plant.</p> <p><b>CO<sub>2</sub> capture:</b> 4 technologies were studied: chemical absorption (MEA process, 95% CO<sub>2</sub> capture); membrane separation (82% CO<sub>2</sub> recovery), cryogenics (90% CO<sub>2</sub> recovery); pressure swing adsorption (85% CO<sub>2</sub> capture). CO<sub>2</sub> generation from power plant is 950 kg/MWh.</p>	<ul style="list-style-type: none"> <li>• In case of GWP, sequestration of CO<sub>2</sub> in a saline aquifer offers the biggest potential followed by ECBM and EOR.</li> <li>• For ocean sequestration, vertical injection appears to be the most promising option in terms of both the final amount of CO<sub>2</sub> stored and amount of energy spent in the sequestration process.</li> <li>• The most promising environmental benefit stems from</li> </ul>

Study	Technology	Results
	<p><b>Storage:</b> 9 technologies were compared:</p> <ul style="list-style-type: none"> <li>• ocean sequestration (vertical injection, inclined pipeline, pipe towed by ship, dry ice, gaslift advanced dissolution (GLAD) system, and CO<sub>2</sub>-hydrate);</li> <li>• geological sequestration (EOR and enhanced coalbed methane (ECBM) recovery);</li> <li>• sequestration of CO<sub>2</sub> in a saline aquifer.</li> </ul>	<p>using ECBM combined with chemical absorption (95%-98% CO<sub>2</sub> recovery). The next three highest benefits stems from geological sequestration, EOR with chemical absorption, and ECBM combined with membrane separation and with PSA.</p>
Hertwich et al. (2008)	<p><b>Power plant:</b> 832 MW NGCC plant.</p> <p><b>CO<sub>2</sub> capture:</b> MEA process, 90% CO<sub>2</sub> capture.</p> <p><b>Transport:</b> 150 km pipeline to the Southern North Sea.</p> <p><b>Storage:</b> EOR.</p>	<ul style="list-style-type: none"> <li>• GHG emissions reduced by 80% (75 g/kWh).</li> <li>• Increase in the acidification potential due to the NH<sub>3</sub> emitted from the capture plant.</li> </ul>

## **7. ENVIRONMENTAL IMPACT ASSESSMENT**

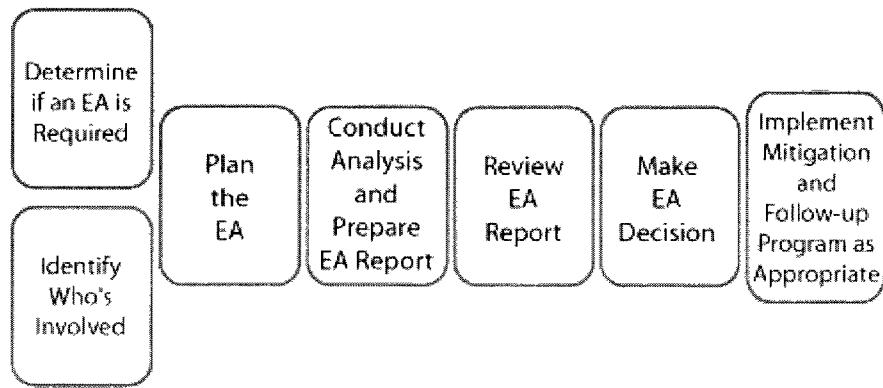
### **ENHANCEMENT USING LCA**

#### **7.1 Environmental Impact Assessment (EIA)**

##### **7.1.1 Introduction**

An Environmental Impact Assessment is a tool to identify, predict and communicate the environmental impacts of proposed initiatives such as projects, plans or proposals. The main purpose of EIA is to minimize or avoid adverse environmental impacts of a project before they occur, as well as to incorporate environmental concerns into decision making (CEAA 2003). The EIA in Canada is regulated under the Canadian Environmental Assessment Act (The EAA 1992). However, each province has its own provincial EIA process. For example in Saskatchewan, the assessment of a proposed project is reviewed under “The Environmental Assessment and Review Process” administered by the Environmental Assessment Branch of Saskatchewan Environment (EA SK 2009). EIA processes and requirements vary from country to country; however, they follow the same key principles (Figure 7.1).

The first step in the process is to determine whether the Environmental Assessment (EA) (Canada’s federal environmental impact assessment process is referred to as environmental assessment. Both terms are used in this report) is required and if yes, the level of detail. This stage is called screening. A responsible party (i.e. responsible authority) identifies whether other federal parties may have the responsibilities to ensure the conduct of the EA and contributes expert information.



**Figure 7.1 Canadian Environmental Assessment process**

(original in color)

Source: CEAA 2003

The responsible authority then determines how to conduct the EA. It identifies scope of the project, issues and impacts that will be considered and time lines. This stage is called scoping. As the next step in the process, an analysis is conducted by environmental assessment practitioners to identify potential environmental impacts and measures to mitigate the impacts. The findings are presented in the environmental assessment report. The responsible authority reviews the report and, based on the findings, decides whether adverse environmental effects of the proposed project are likely to be significant. If the decision is made to proceed with the project, the mitigation measures identified in the report are incorporated into the design plans and implemented with the project.

There are four types of EA that may be required under Canadian regulations. These are Screening, Comprehensive Study, Mediation and Review Panel. Screening and comprehensive study are self-directed assessments undertaken by a project proponent. Independent assessments are conducted by a mediator or a review panel appointed by the Minister of the Environment (CEAA 2003). The project may be referred to a mediator or a review panel if there are uncertainties in determining whether the project is likely to cause significant adverse environmental impacts and/or if there are public concerns about the project.

The screening type of Environmental Assessment is used for a wide range of smaller projects with known effects that can be easily mitigated. It is applicable to small-scale projects that are routine and replicable, such as dredging, installation of culverts and realignments to an existing road. There are two types of class screenings: a model class screening used to streamline the process and a replacement class screening used instead of a project-specific assessment. Model class screenings provide a generic assessment of

all projects within a class: the responsible authority uses a model report as a template, accounting for location and project-specific information. Replacement class screenings apply to projects for which no location or project-specific information is needed. A comprehensive study is performed for large projects having significant environmental impacts. Examples of projects that require comprehensive review are large oil and gas developments, power generation projects, and large industrial plants (CEAA 2003).

#### 7.1.2 System boundaries

Spatial and temporal boundaries are set during the scoping stage of EIA. Traditionally, spatial boundaries in EIA are set around the project site, thus only local effects are being considered. The main implication of selection of local boundaries is that regional and long-term effects are not included into analysis. Now, the best practices of EIA recommend setting different (or multiple) boundaries for different environmental effects. For example, boundaries selected for air quality effects may be quite different from those for effects on wildlife species. Spatial boundaries may extend beyond the project site to the whole area affected by the project. Temporal boundaries often extend to the operational life of a project, i.e. exploration, construction, operations, and abandonment.

#### 7.1.3 Impact assessment

Environmental impact assessment has evolved to consider environmental and cumulative effects, as well as health, social, economic and cultural effects. Environmental Effect, in respect of a project, as defined in Canadian Environmental Assessment Act (The EAA 1992) is:

- “any change that the project may cause in the environment, including any effect of any such change on health and socio-economic conditions, on physical and cultural heritage, on the current use of lands and resources for traditional purposes by aboriginal persons, or on any structure, site or thing that is of historical, archeological, paleontological or architectural significance, and
- any change to the project that may be caused by the environment, whether any such change occurs within or outside Canada”.

However, trans-boundary impacts (e.g., animal migration) and global scale effects (e.g., global warming, ozone layer depletion) often present practical difficulties to identify and quantify, thus, tend to be neglected in the analysis.

#### *Cumulative Effect Assessment*

In the impact assessment part of the EIA study, Cumulative Effects Assessment (CEA) may be conducted. It usually deals with a broader range of environmental impacts, including global impacts, and considers a study area larger than the area around the project site. CEA is increasingly seen as a best practice in conducting EIAs, and it is required in Canadian federal legislation under the Canadian Environmental Assessment Act (Hegmann et al. 1999). When analyzing effects of a proposed project or activity, the independent effects may be considered insignificant, however, if assessed in combination with other effects of various actions, the combined impact may be important to consider. Thus, Cumulative Effects Assessments are done to ensure that effects from all relevant past, existing and future projects that are likely to act in combination with the environmental effects of the proposed project are assessed (FEARO 1994a). It should be noted that CEA methodology is mostly applicable to large projects where more resources,

such as time, budget, and staff are available. The EIA framework for cumulative effects assessment is presented in Table 7.1.

### *Significance of impacts*

Another critical step in the EIA is to determine the significance of the impacts. A Reference Guide for the Canadian Environmental Assessment Act (FEARO 1994b) offers the following framework to determine whether environmental effects are adverse, significant, and likely:

1. *Decide whether the environmental effects are adverse.* Here the quality of the existing environment is compared with the predicted quality of the environment after project implementation.
2. *Decide whether the adverse environmental effects are significant.* In this step, several criteria should be taken into account. These include magnitude, geographical extent, duration and frequency, and degree of reversibility or irreversibility of the adverse environmental effects. The most common method applied to determine significance of the adverse environmental effects is use of environmental standards, guidelines and/or objectives. The problem with determining significance is that different jurisdictions (federal, provincial, municipal departments, ministries, etc.) provide different guidelines for what is considered significant. Moreover, guidelines and standards are prepared only for a limited number of chemicals and hazardous materials and do not consider cumulative effects. Other methods such as risk assessment, weighting and ranking methods can also be used to determine the significance.

**Table 7.1 EIA framework for cumulative effects assessment**

<b>Basic EIA Steps</b>	<b>Tasks to complete for a CEA</b>
1. Scoping	Identify regional issues of concern Select appropriate regional VECs <sup>1</sup> Identify spatial and temporal boundaries Identify other actions that may affect the same VECs Identify potential impacts due to actions and possible effects
2. Analysis of Effects	Complete the collection of regional baseline data Assess effects of proposed action on selected VECs Assess effects of all selected actions on selected VECs
3. Identification of Mitigation Measures	Recommend mitigation measures
4. Evaluation of Significance	Evaluate the significance of residual effects Compare results against thresholds or land use objectives and trends
5. Follow-up	Recommend regional monitoring and effect management

<sup>1</sup>Valued Ecosystem Components (VECs) – any part of the environment that is considered important. For example, air and water quality VECs can be environmental, economic, social, aesthetic or ethical in nature.

Source: Hegmann et al. 1999

3. *Decide whether the significant adverse environmental effects are likely.* Two criteria are used to determine likelihood: probability of occurrence and scientific uncertainty.

## 7.2 Strategic Environmental Assessment

A tool related to EIA is Strategic Environmental Assessment (SEA). Strategic Environmental Assessment is used to assess the environmental effects of proposed and existing policies, programs and plans (PPP). The main purpose of SEA is to assist in considering early potential environmental impacts in strategic decision-making.

There are several differences between SEA and EIA tools. SEA is used to evaluate environmental consequences of proposed PPPs, while EIA is conducted to assess environmental effects of a proposed project. Thus, SEA is applied to the higher level of decision-making. It also considers the broader range of alternatives than the project EIA. According to Abaza et al. 2004, the distinctive characteristics of SEA compared to EIA, include:

- greater uncertainty about the effects of a proposed policy, plan or program (general directive) compared to a project (concrete actions);
- broader range of environmental effects to be considered;
- more interrelations with environmental, economic and social issues (for example, development of a national energy policy compared to construction of a power station); and
- larger areas and longer time frames used to assess environmental effects.

In Canada, the development of SEA started in 1990 when Cabinet directed departments to consider environmental issues at the strategic level of policies, plans and programs development. This Directive was updated in 1999 by releasing a Cabinet Directive on SEA and guide to the SEA process (CEAA 2004).

The Directive does not prescribe any specific methodology for conducting SEAs. It however encourages developing approaches specific for particular needs of federal departments and agencies. In general, SEA has to address the following issues (CEAA 2004):

1. Potential direct and indirect outcomes of the proposal;
2. Interaction of these outcomes with the environment;
3. Scope and nature of these environmental interactions;
4. Mitigation of the adverse environmental effects or enhancement of positive environmental effects; and
5. The overall potential environmental effects of the proposal after mitigation measures have been incorporated.

SEA methodology usually follows EIA framework. However, Noble (2005) proposed an alternative approach to extend the methodology upstream. The proposed framework has the following seven phases:

1. *Scope the assessment issues and identify the baseline conditions.* This stage is similar to the scoping stage in EIA process. The objective here is to identify the strategic problems and/or questions to be addressed, the intended objectives, data availability, and assessment level.

2. *Identify and describe the alternatives.* At this phase, the alternatives to a proposed PPP are identified.
3. *Scope the assessment components and factors.* Factors (i.e. valued system components related to, for example, public health and safety or water and air quality) and associated assessment criteria (i.e. standards or rules against which potential impacts and alternatives are evaluated) are determined in this phase.
4. *Determine criterion significance.* This phase is similar to determining significance of impacts in EIA. Noble (2005) suggests using weighting methods such as ranking, rating, trade-off analysis, etc.
5. *Evaluate the potential impacts of each alternative.* The methods for evaluation of the potential impacts can include policy- or analytic-based assessment methods and techniques.
6. *Compare the alternatives.* Here the impact assessment results are summarized for each alternative and compared.
7. *Identify the best practicable environmental option.* The output of SEA may be presented “in terms of one- or multi-dimensional order or ranking of alternatives”. The uncertainties analysis is recommended here.

To conclude, it should be noted that while SEA is required on a federal level, there is still no formal system of SEA at the provincial level in Canada. The only province that introduced legislative requirements for SEA is Saskatchewan; however, these requirements are limited to the forest sector (Noble 2004; Noble 2005).

### **7.3 Application of EIA and SEA to Carbon Capture and Storage**

Publications on EIA and SEA of the full CCS life cycle that includes CO<sub>2</sub> capture, transport and storage are limited to couple of studies. Koornneef et al. 2008 evaluated application of EIA and SEA procedures to CCS in the Netherlands. Manuilova et al. 2009 reviewed Canadian EIA guidelines and their application to CCS activities. Both studies identified the lack of experience in applying EIA to CCS projects and deficiencies in procedures. In practice, the EIA studies are conducted for each part of CCS (capture, transport and storage) separately. Koornneef et al. 2008 suggests that it would be beneficial to treat all three parts of CCS project as one or at least establish a close linkage between them. Manuilova et al. 2009 noted that the EIA regulations for CCS projects in Canada are in the early development stage and any further legal frameworks and regulations should be developed with a life cycle perspective in mind.

The SEA study has been conducted by Vattenfall in Sweden (Eriksson et al. 2006) to analyze and evaluate different technical alternatives of CO<sub>2</sub> capture, transport and storage. In the case of CO<sub>2</sub> capture, pre-combustion, post-combustion and oxyfuel technologies have been compared. Transportation options via pipeline (onshore and offshore) and by ship have been evaluated. Storage options assessed include saline aquifers, EOR, enhanced gas recovery and storage in depleted hydrocarbon reservoirs. The report summarized the current knowledge on environmental aspects of CCS. The authors noted that SEA methodology is very useful tool for assessment of different CCS alternatives and for communication with stakeholders.

Parsons et al. 2004 researched regulatory and legal mechanisms applicable to the long-term storage of CO<sub>2</sub> underground. The authors suggested the generic outline contents for the EIA study of a CO<sub>2</sub> storage facility. The primary issues that are likely to be considered significant in EIA of CO<sub>2</sub> storage include site location; disposal methodology; impacts to local and regional environmental components, including receptors; long term storage methodology and quality assurance of long term stability of storage; cost benefit analysis; parties that pay for both capital and long term monitoring; and contingency scenarios (“what if” scenarios).

In Canada, application of EIA procedures to the proposed projects is regulated under the Canadian Environmental Assessment Act (The EAA 1992). As it is stated in the Comprehensive Study List Regulations (CEAA 1994), projects that are likely to have significant adverse environmental impacts require a comprehensive study. The following are examples of projects’ categories that require a comprehensive study (CEAA 1994):

- national parks and protected areas;
- electrical generation stations and transmission lines;
- oil and gas projects;
- minerals and mineral processing;
- nuclear and related facilities; and
- transportation.

Projects and classes of projects relevant to the CCS, for which comprehensive study is required in Canada, are summarized in Table 7.2.

**Table 7.2 Projects and classes of projects relevant to the CCS for which comprehensive study is required in Canada**

Relevance to CCS project	Project/Class of projects	Description
All or any life cycle stages	National parks and protected areas	<ul style="list-style-type: none"> <li>• The proposed construction, decommissioning or abandonment in relation to a physical work in or on a national park, national park reserve, national historic site or historic canal that is contrary to its management plan.</li> <li>• The proposed construction, decommissioning or abandonment, in a wildlife area or migratory bird sanctuary, of an electrical generating station or transmission line; an oil or gas facility or oil and gas pipeline; a mine; an industrial facility; a waste management facility.</li> </ul>
Coal mining	Minerals and mineral processing	<ul style="list-style-type: none"> <li>• The proposed construction, decommissioning or abandonment of a coal mine with a coal production capacity of 3000 t/d or more.</li> <li>• The proposed expansion of an existing coal mine (50% or more increase in coal production, or 1500 t/d or more, if the increase would raise the total coal production capacity to 3000 t/d or more).</li> </ul>
Power plant	Electrical generation stations and	<ul style="list-style-type: none"> <li>• The proposed construction, decommissioning or abandonment of 200 MW or more fossil fuel-fired power station</li> </ul>

<b>Relevance to CCS project</b>	<b>Project/Class of projects</b>	<b>Description</b>
	transmission lines	<ul style="list-style-type: none"> <li>The proposed expansion of fossil fuel-fired power station (50% or more and 200 MW or more).</li> </ul>
Transport	Oil and gas projects	<ul style="list-style-type: none"> <li>The proposed construction of an oil and gas pipeline more than 75 km in length on a new right of way.</li> </ul>
Storage (EOR application)	Oil and gas projects	<ul style="list-style-type: none"> <li>The proposed construction, decommissioning or abandonment of a heavy oil or oil sands processing facility with an oil production capacity of more than 10 000 m<sup>3</sup>/d.</li> <li>The proposed expansion of a heavy oil or oil sands processing facility (capacity increase that would exceed 5000 m<sup>3</sup>/d and would raise the total oil production capacity to more than 10 000 m<sup>3</sup>/d).</li> </ul>
Storage	Waste management	<ul style="list-style-type: none"> <li>The proposed construction, decommissioning or abandonment of a facility used exclusively for the treatment, incineration, disposal or recycling of hazardous waste, or an expansion of such a facility that would result in an increase in its production capacity of more than 35%.</li> </ul>

Source: CEAA (1994)

However, as it is shown in the Table 7.2, many of the projects have thresholds or certain conditions, such as production capacity or size of physical work that trigger the comprehensive study. If those thresholds are not exceeded, the project would not require the comprehensive study and a simple screening environmental assessment would be carried out.

An example of how threshold value can influence the type environmental assessment study is a construction of the Souris Valley CO<sub>2</sub> Pipeline to transport CO<sub>2</sub> from the Dakota Gasification Company in North Dakota, US to the Weyburn oil field in Saskatchewan, Canada for EOR. Only 61 km of the 320 km pipeline are located in Canadian territory (National Energy Board 1998). However, under the Comprehensive Study List Regulations (CEAA 1994), a comprehensive study would be required if the proposed pipeline is more than 75 km in length. An environmental screening was conducted as part of the Saskatchewan provincial regulations (National Energy Board 1998). If the full length of the pipeline had been considered, this project would have triggered a comprehensive study.

Manuilova et al. 2009 also discussed the application of Canadian EIA guidelines and issues with threshold values to the CO<sub>2</sub>-EOR Weyburn project and the proposed by SaskPower Integrated Carbon Capture and Sequestration Demonstration project at the Boundary Dam Power Station. If new regulations for CCS are not developed in the near future, the proposed CO<sub>2</sub> capture, transport and storage projects would be treated as separate projects and a comprehensive study under the EIA procedures would not be triggered if threshold values are not exceeded.

## **7.4 EIA and SEA enhancement using LCA**

### 7.4.1 Tools comparison

There is no single tool or procedure to address all the questions and problems of environmental impact assessment and management. Several studies have been conducted to show how different environmental tools can complement and enhance each other (SETAC 1997; Tukker 2000; Finnveden et al. 2003; Finnveden and Moberg 2005; Manuilova et al. 2009). SETAC (1997) has established a working group on Conceptually Related Programmes in 1993 to discuss the relationship between LCA and other tools and approaches such as Environmental Risk Assessment, Environmental Impact Assessment, Cost Benefit Analysis, etc. The group developed a framework to compare these tools and approaches, and came with the conclusion that LCA may provide further information about the object of study when used in EIA procedure.

Finnveden and Moberg (2005) also studied and characterized environmental impact assessment tools such as EIA, SEA, LCA, System of Economic and Environmental Accounting (SEEA), and Material Flow Analysis (MFA). The goal of the research was to better understand the relationship between these tools and their possible application areas. The authors suggested that analytical tools such as LCA can be used in procedural EIA and SEA tools. Finnveden et al. (2003) further studied SEA methodology and suggested a framework for integration of analytical tools (e.g. LCA) in the SEA process. The framework is shown in Figure 7.2.

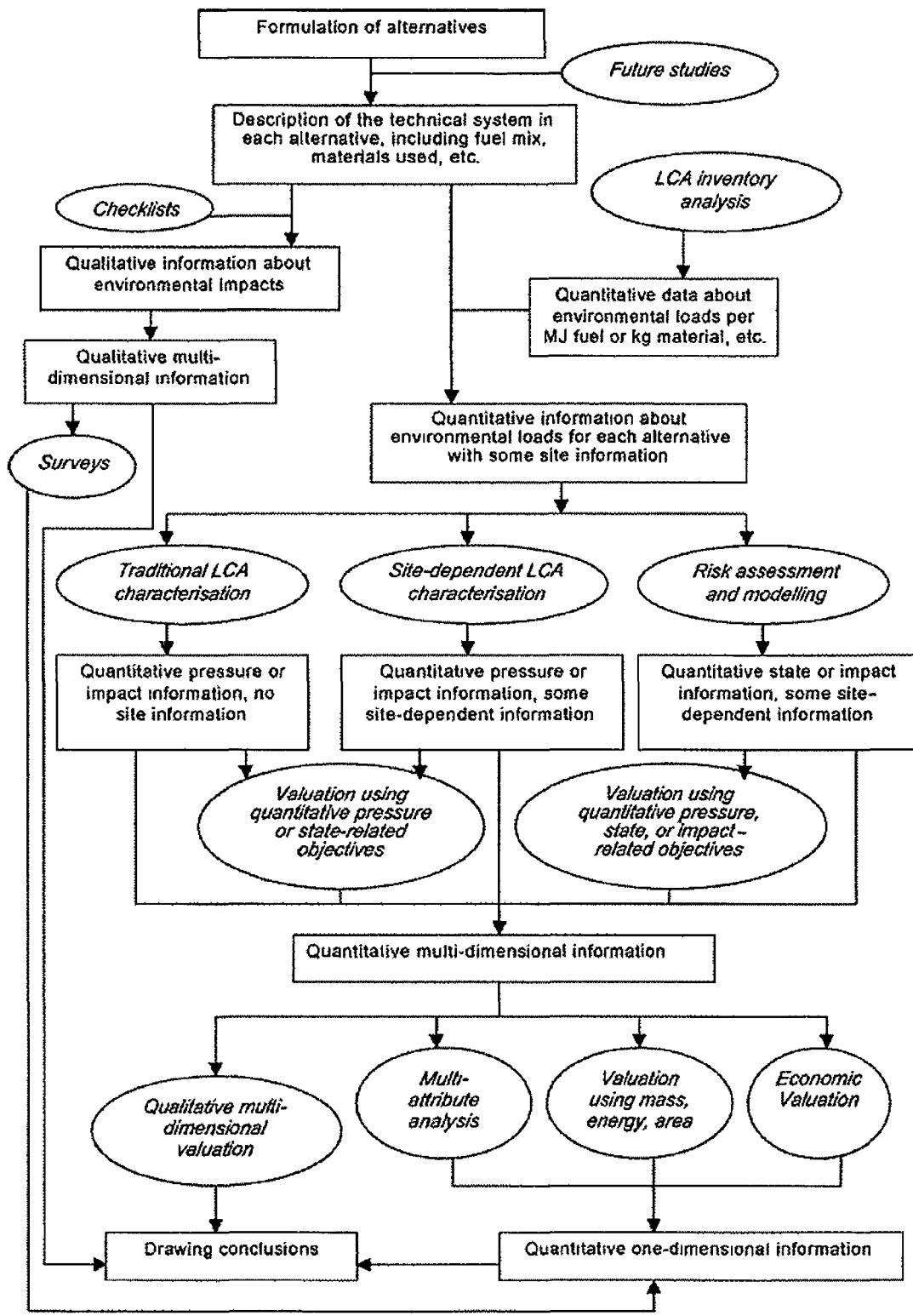


Figure 7.2 Framework for integration of different tools into SEA methodology

Source: Finnveden et al. 2003

Tukker (2000) showed that there are no fundamental differences between EIA/SEA and LCA. Some elements of LCA can be successfully used in EIA and SEA procedures, especially if EIA and SEA are used to compare different alternatives, such as goal and policy, process, abatement and location alternatives. The author also mentioned that LCA methodology was applied to a number of EIA and SEA studies in the Netherlands. These studies include Dutch electricity plan (policy alternative), Dutch National Waste Management Plans (policy alternative), oil desulphurization plant (process alternative), and flue gas treatment (abatement alternative).

The comparison of LCA, EIA and SEA methodologies are presented in Table 7.3.

#### *System boundaries*

#### Spatial boundaries

LCA is a qualitative tool allowing for a comprehensive environmental assessment from a life cycle perspective. This means that all stages of the life cycle of a product or activity (i.e. raw materials acquisition, materials and product manufacturing, product use, waste disposal, and transportation activities) are included in the analysis. All associated emissions, wastes, energy consumption and resource use during these life cycle stages are taken into account. In case of CCS, it means that all three stages of CCS (CO<sub>2</sub> capture, transport and storage) are treated as one, thus preventing possible deficiencies in the assessment process. For example, if a power plant with CO<sub>2</sub> capture unit is assessed separately from CO<sub>2</sub> transport and storage stages that also contribute to an increase in emissions and waste generation, as well as an increase in energy and other resource consumption, the results of the assessment would not be correct.

**Table 7.3 Comparison of environmental assessment tools**

	<b>LCA</b>	<b>EIA</b>	<b>SEA</b>
Objective	To evaluate environmental performance of a process, product or service and identify possible improvements on a life cycle basis	To assess positive and negative impacts on the environment of a planned, future project	To evaluate environmental consequences of proposed policies, plans or programs (PPP)
Type of tool	Analytical	Procedural	Procedural
Main use	To improve a product, process or service  To communicate environmental impact of a product  Long term strategic planning	To meet legislative requirements  To identify the need for changes to the project to mitigate impacts	To identify early environmental considerations in PPP  To identify desirable outputs and alternative means  To develop plans and strategies for actions, such as policy changes, new proposals, etc.
System boundaries	Considers global and regional impacts throughout the life cycle	Limited to a project  Considers local impacts of a project	Not project specific  Addresses areas, regions or sectors of

	<b>LCA</b>	<b>EIA</b>	<b>SEA</b>
			development May have local, regional and/or national boundaries
Time	Retrospective and prospective	Prospective	Prospective
Spatial focus	Generally, not site-specific, but some life cycle impact assessment methods are site-dependent	Site-specific	Not site-specific; may use data on local, regional and/or national levels
Types of impacts considered	Overall potential environmental impacts	All effects of the planned project on the local environment (i.e. environmental, cumulative, health, social, economic, and cultural impacts)	Environmental, social and economic impacts and their interrelations
Strengths	Comprehensive analysis of impacts based on cradle-to-grave life cycle approach	Assesses both positive and negative effects  Considers socio-economic effects of a	Assesses both positive and negative effects  Creates a framework against which

	<b>LCA</b>	<b>EIA</b>	<b>SEA</b>
	<p>High degree of quantification</p> <p>Complete evaluation of alternatives</p>	<p>project and cumulative effects of past, present and future projects</p> <p>Public participation</p>	<p>impacts and benefits can be measured</p> <p>Focused on alternatives</p> <p>Proactive: attempts to avoid, eliminate and/or minimize potentially negative actions and enhance positive environmental effects</p> <p>Continuing process aimed at providing information at the right time</p>
Weaknesses	<p>Does not address the economic and social aspects</p> <p>LCI data must be used cautiously since production processes differ from country to country</p> <p>Preserving the confidentiality of some commercially-sensitive LCI data</p>	<p>Boundaries limited to a proposed project</p> <p>Cannot easily address regional and global effects or effects along the life cycle</p> <p>No specific environmental impact assessment methodology is used to</p>	<p>It may be hard to predict environmental effects of policies, plans and programs and difficult to develop quantifiable objectives</p>

	<b>LCA</b>	<b>EIA</b>	<b>SEA</b>
	without reducing the credibility of LCA can be a problem	assess the impacts	
CCS application	To evaluate environmental performance of CCS projects  To compare environmental performance of different CO <sub>2</sub> capture technologies, transportation modes and storage options	To assess positive and negative impacts of proposed CCS project  Usually performed separately for each stage of CCS (capture, transport, storage)	To evaluate environmental effects of proposed policies, plans and programs related to CCS  To evaluate policy, process, technology, abatement and location alternatives for CCS projects

EIA studies usually focus on the project site, thus taking into account only local effects of the project. The main weakness of selection of local boundaries in EIA is that regional and global effects are not considered. Very often, downstream and upstream life cycle stages are not included into the analysis.

Cumulative effects assessment (CEA) in EIA usually considers a larger study area than the area around the project site. However, CEAs are mostly conducted in case of large projects (when comprehensive study is required) where more resources are available to the practitioner.

The selection of spatial boundaries in EIA may benefit from the life cycle approach where all upstream and downstream processes and activities are included. This approach may help to increase the accuracy of environmental assessment by increasing the level of detail used in the analysis.

### Temporal boundaries

LCA studies can be retrospective or prospective. The analysis is carried out to evaluate present impacts and/or predict future impacts of a product, process or activity. EIA is a prospective tool that helps to identify and predict the environmental impacts of proposed projects and plans. Temporal boundaries in EIA often extend through the operational life of a project to include exploration, construction, operations, and abandonment activities. However, long-term effects are usually not considered. SEA is also a prospective tool for evaluation of environmental effects of policies, programs and plans. It may, however, be hard to predict environmental effects of PPPs and develop quantifiable objectives because of the long time horizons in SEA.

### *Impact assessment*

Several environmental effects are considered in EIA. These include environmental, cumulative, socio-economic, and health effects, effects on physical and cultural heritage, on structure and sites of any historical, archeological, paleontological or architectural significance, and on the land and resources used for traditional purpose by aboriginal persons. Cumulative environmental effects assessment helps to estimate the combined impact of all relevant past, present and future activities. Thus, the environmental impact assessment in EIA extends to the broad variety of areas and considers different environmental aspects. However, it is difficult to identify and quantify trans-boundary and global scale impacts in EIA. There is also no common methodology for conducting impact assessments. Several methods are employed in EIA to evaluate and communicate environmental impacts. These are checklists, matrices, networks, and simulation modeling (Baker and Rapaport 2005).

LCA methodology, on the other hand, offers different methods that may be useful in quantification and evaluation of local, regional and global environmental impacts. With the recent development of site-dependent impact assessment methodologies (EDIP2003, IMPACT 2002+, TRACI, LCSEA, LUCAS) described earlier in this article, the evaluation of environmental impacts of a project at a specific location became possible. These models use characterization factors specific for a certain country or region thus having a potential to be used in EIA studies.

LCA considers impacts on the environment, human health, and resource use. Environmental impacts are assigned into different categories - global warming, resource depletion, stratospheric ozone depletion, acidification, eutrophication, photooxidant

formation, land use, human and eco-toxicity, etc. LCA typically does not address the social and economic aspects (ISO 14044 2006); however, LCA the methodology can be applied to these aspects.

Use of LCIA methods in impact assessment phase of EIA would be beneficial for practitioners since these methods have been developed and applied for decades and are well-tested and proven. It would also improve the quality of the assessment since all inputs and outputs from each life cycle stage would be considered.

## **7.5 Conclusions**

The methodologies and procedures of environmental assessment tools LCA, EIA and SEA and their application to CO<sub>2</sub> capture and storage activities were reviewed in this chapter. It can be shown that LCA methodology and results may add value to procedural EIA and SEA tools especially if comparison of different alternatives is made. LCA also increases level of detail of analysis and provides additional information on the subject of the study.

A number of weaknesses were identified in the EIA procedures, such as focus on local impacts of a project, difficulties with assessment of regional and global effects, exclusion of upstream and downstream activities, and lack of specific environmental assessment methodology developed for EIA. These are the areas where LCA has its strength and therefore may be successfully applied to enhance EIA methodology and results.

Several LCA studies have been conducted to evaluate environmental performance of the full life cycle of CO<sub>2</sub> capture and storage. However, application of EIA and SEA procedures to CCS has been limited. There are also no regulations for EIA of CCS projects developed in Canada. CCS activities in EIA are usually treated as separate projects thus increasing a probability of erroneous conclusions of the assessment. Thus, the development of a regulatory framework for CO<sub>2</sub> capture, transport and storage with a life cycle perspective in mind is necessary to prevent any adverse impact on society and environment.

## 8. METHODOLOGY

### 8.1 Goal and scope of the study

#### 8.1.1 Goal of the study

The goal of this LCA is to study environmental performance over the full life cycle of carbon capture and storage. The reasons for carrying out the study include:

- The need for development of a full understanding of the emissions, wastes, resource use and energy consumption in the full life cycle of the CCS;
- The need to better understand net emissions reductions from CCS for credit or taxation based systems;
- The need to define the ancillary benefits that could accrue from reduced criteria air contaminant emissions (for example, should one allocate sulphur reduction costs to the CO<sub>2</sub> capture or not in a CCS environment).

The intended audience of this study is researchers and decision makers in resource, energy and environmental sectors.

#### 8.1.2 Scope of the study

##### *8.1.2.1 Functional unit*

**GJ of energy produced per average year** was chosen as a functional unit for this study.<sup>5</sup> The choice of functional unit was directed by outputs of two systems (electricity production at the power plant and crude oil production from CO<sub>2</sub>-EOR). The output of

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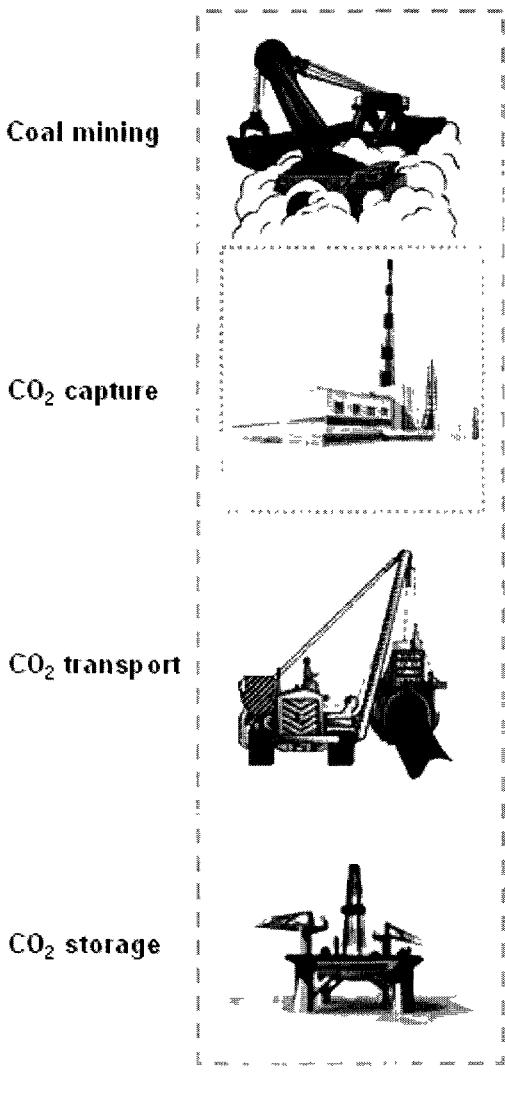
<sup>5</sup> Please note, results for power plant are also presented per MWh of electrical energy produced.

the power plant is MWh of electricity produced; however, the output from EOR operations at the oil field is barrel of crude oil. In order to compare two systems, a common functional unit must be selected. In this case, it could be Joules or toe (tonne of oil equivalent). We have chosen gigajoule (GJ) because the goal is to relate environmental impacts to CO<sub>2</sub> capture (e.g. a power plant with CO<sub>2</sub> capture unit). The environmental impact from crude oil is accounted for by including crude oil transportation, refining and use stages in the life cycle of CCS. It should be noted that this LCA study is not a product LCA. In contrast, the carbon capture and storage is studied as a process over a 45 year time horizon. It should also be noted that the life time of power plant with and without capture unit and pipeline is assumed to be 30 years. However, the CO<sub>2</sub> EOR and storage operations using the amount of CO<sub>2</sub> captured during 30 years will continue for 45 years. Thus, the functional unit selected is GJ of energy produced per average operational year. No allocation of environmental impacts to any of the products (electricity or crude oil) is necessary.

#### *8.1.2.2 System boundaries*

##### Boundaries between technological and natural systems

This study is a cradle to grave study that takes into account coal mining, power plant construction and operations, the CO<sub>2</sub> capture unit construction and operations, construction of the CO<sub>2</sub> pipeline and the CO<sub>2</sub> transportation to the oil field for enhanced oil recovery (Figure 8.1).



### Coal mining

- Lignite coal
- Surface coal mining in southeast Saskatchewan

### Power plant

- Boundary Dam Power Station,  
Saskatchewan Power Corporation

*(includes power plant and CO<sub>2</sub> capture unit construction and operation, raw materials and products acquisition and all transportation activities involved)*

### CO<sub>2</sub> pipeline

- Two 100 km pipelines
- (includes CO<sub>2</sub> pipeline construction and operation)*

### CO<sub>2</sub>-EOR and storage

- Weyburn oil field, Saskatchewan
- (includes construction and operation of facilities above ground and wells drilling and completion)*

### Refinery

- US refinery operations

### Consumer

- Consumption of refined products in mobile applications

**Figure 8.1 Life cycle of carbon capture and storage**

(original in color)

The upstream processes (extraction, production and transportation of raw materials and products, for example MEA, limestone, steel, and concrete) and downstream processes (refining and use of refined products) are also taken into account. The downstream processes are considered in order to account for the environmental impact of extra oil extracted due to CO<sub>2</sub>-EOR.

Emphasis in this study is on power plant operations with and without CO<sub>2</sub> capture unit. Each unit (boiler, electrostatic precipitator, flue gas desulphurization, CO<sub>2</sub> capture, and CO<sub>2</sub> compression) at the power plant is modeled separately.

CO<sub>2</sub>-EOR operations at the Weyburn oil field include construction and operation of facilities above ground (pumps and compressors) and wells drilling and completion.

#### Spatial boundaries

Coal mining, power plant operations, CO<sub>2</sub> transport and CO<sub>2</sub> enhanced oil recovery and storage life cycle stages take place in Saskatchewan, Canada. The data for these operations come from Saskatchewan companies and organizations as follows:

- Power plant operations – SaskPower,
- CO<sub>2</sub> capture unit operations – SaskPower and International Test Centre for CO<sub>2</sub> Capture;
- CO<sub>2</sub> unit construction - Stantec;
- Weyburn oil field operations - EnCana, Petroleum Technology Research Centre and Government of Saskatchewan.

Saskatchewan electricity mix is used for all life cycle stages in the province (Appendix A, Table A.1).

Data for production of concrete and cement are Canadian averages; steel production dataset is world average. Dataset for steel production comes from World Steel Association. Datasets for concrete and cement production originate from Athena Institute (Athena Institute 2005).

Dataset from GaBi4 for the surface lignite coal mining in the US is adjusted to represent Saskatchewan coal mining operations. Methane emissions to air were modified according to data from Environment Canada (Greenhouse Gas Division 2008).

Power plant construction data per 1 MW of plant capacity is extracted from Spath et al. 1999 (i.e. the following numbers are used: 158,758 kg of concrete/MW of plant capacity and 50,721 kg of steel/MW of plant capacity). Limestone production dataset is taken from GaBi4. MEA production dataset is adapted from Althaus et al. 2004 and Koornneef 2008 (Appendix A, Table A.2). Capture plant construction dataset is compiled using Stantec report (Stantec 2007) and personal communication with Stantec staff. The main inputs are concrete for building construction (14,432 kg/MW) and structural steel for building and equipment (6,706 kg/MW).

Pipeline construction and operation is modeled in the complimentary research conducted by Jitsopa Suebsiri (Suebsiri 2010). Details on modeling of pipeline operations can be found in Appendix A (Equations A1-1 to A1-6). Life cycle inventory data for 100 km of 12 inch assembled pipeline is presented in Appendix A, Table A.3.

The Weyburn oil field and other mature oil fields suitable for CO<sub>2</sub>-EOR operations are located in the range of 50-100 km from SaskPower's Boundary Dam Power Station (Figure 10.1). It is assumed that CO<sub>2</sub> will be injected into two oil fields. Thus, two 100 km pipelines are necessary. The flow in pipelines is driven by compressors at the upstream end (in this case at the power plant), although some pipelines have intermediate (booster) compressor stations (IPCC 2005). Booster stations are usually positioned at every 150 km of pipeline to maintain the necessary pressure. In this study, it is assumed that no booster station is necessary due to the pipeline length of less than 150 km.

CO<sub>2</sub>-EOR operations at the Weyburn oil field include construction and operation of facilities above ground (pumps and compressors) and injection and production wells drilling and completion.

It is assumed that extracted crude oil is transported via pipeline to a refinery in the US. Dataset for operations at the refinery come from Gabi4 database and is average for crude oil refining in the US.

#### Temporal boundaries

The assumed lifespan of power plant, CO<sub>2</sub> capture unit and CO<sub>2</sub> pipeline is 30 years. The CO<sub>2</sub>-EOR operations are based on data for Weyburn oil field operated by EnCana. The Weyburn CO<sub>2</sub>-EOR project started in 2000 and will run for 30 years. However, there are many other mature oil reservoirs in Weyburn-Midale oil field that may be used for CO<sub>2</sub>-EOR and storage. Here, it is assumed that CO<sub>2</sub> will be injected into two oil fields. CO<sub>2</sub> injection into Weyburn oil field will last for 15 years; another 15 years of “no new CO<sub>2</sub>” will be injected into Weyburn field due to the recycling and produced CO<sub>2</sub> that will be

recycled. Another 15 years of CO<sub>2</sub> injection will occur into another mature oil field in the region. Thus, the CO<sub>2</sub> injection is assumed to last for 30 years and CO<sub>2</sub>-EOR operations will last for 45 years in total, even though new CO<sub>2</sub> will not be required for the entire 45 years (Figure 8.2).

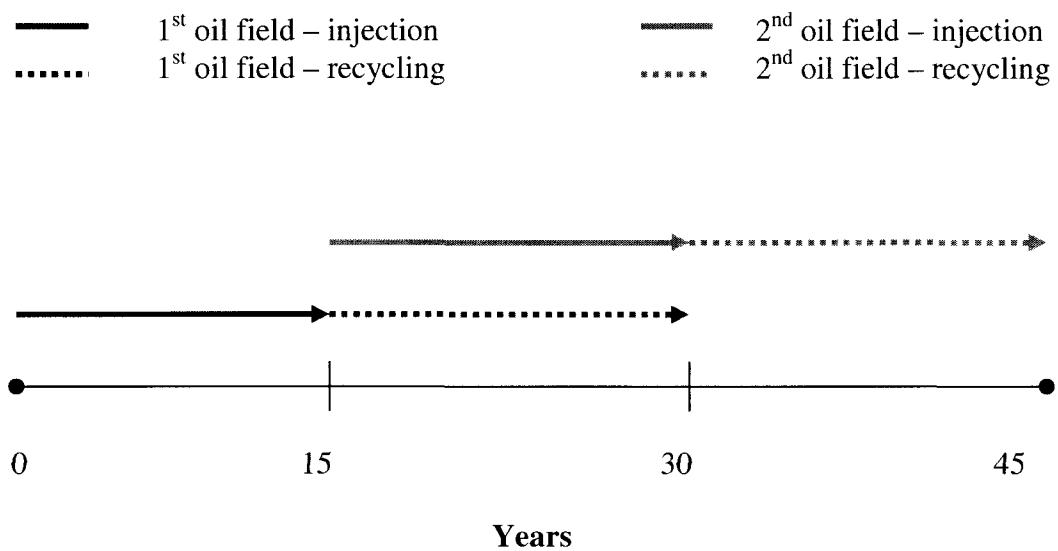
### Technological boundaries

*Power plant:* Current operations at Boundary Dam Power Station (BDPS). This includes tangentially fired sub-critical boilers and electrostatic precipitators (ESP).

*Power plant with CO<sub>2</sub> capture:* BDPS retrofit of Unit 3 (150 MW) to include CO<sub>2</sub> capture: boiler, electrostatic precipitator (ESP), flue gas desulphurization (FGD) and post-combustion CO<sub>2</sub> capture using MEA.

*CO<sub>2</sub> pipeline:* Two 100 km pipelines.

*CO<sub>2</sub>-EOR and storage:* 100 wells. CO<sub>2</sub>-flooding (WAG - water alternating gas injection).



**Figure 8.2      Timeline of CO<sub>2</sub>-EOR operations at two mature oil fields**

(original in color)

#### *8.1.2.3 LCIA methodology and types of impacts*

TRACI life cycle impact assessment methodology is applied in this study. As it was mentioned earlier, the CIRAI group has not finalized the characterization factors for Canadian LCIA method LUCAS. Thus, it cannot be applied in this research.

#### Environmental flows

The study takes into account all associated emissions, wastes, resource and energy consumption during all life cycle stages.

Using TRACI methodology, results can be presented for 12 midpoint impact categories: ozone depletion, global warming, smog formation, acidification, eutrophication, human health cancer, human health noncancer, human health criteria pollutants, eco-toxicity, fossil fuel depletion, land use and water use.

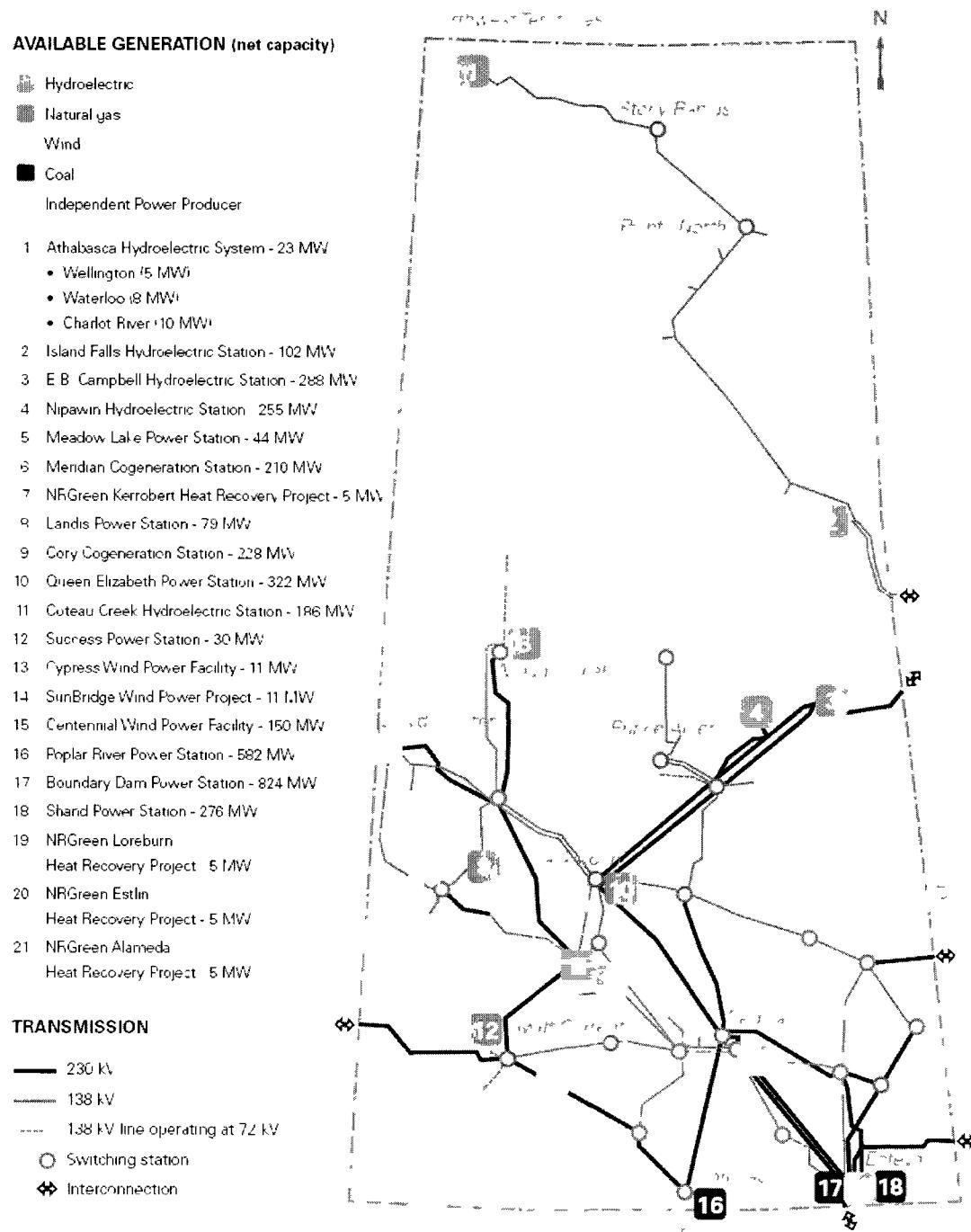
The main focus of this research is on all environmental impact categories except for global warming potential and resource depletion. These categories are reviewed in details in parallel research project (Suebsiri 2010).

## **9. LIFE CYCLE INVENTORY MODELLING OF POWER PLANT WITH AND WITHOUT CO<sub>2</sub> CAPTURE**

### **9.1 Introduction**

Saskatchewan Power Corporation's (SaskPower) Boundary Dam Power Station (BDPS) in Estevan, Saskatchewan was chosen as a case study for modeling of operations at the power plant. SaskPower is currently working on the development of one of the first and largest integrated clean coal/carbon capture demonstration projects in the world. The project would rebuild one of the units (Unit 3) of Boundary Dam Power Station with post-combustion carbon capture technology (SaskPower 2009). This 150MW unit is expected to be fully operational by 2014. The CO<sub>2</sub> capture unit would capture approximately one million tonnes of carbon dioxide annually.

BDPS is a lignite coal-fired station located near Estevan (Figure 9.1). There are six units with a combined generating capacity of 882 MW gross (Table 9.1). The first two units (Unit 1 and 2) are 66 MW gross and were built in 1959. Two 150 MW units were added in 1970 and one 150 MW unit was added in 1973. The last unit 300 MW unit was added in 1978. BDPS was equipped with electrostatic precipitators (ESP) on all units in July 2003 (SaskPower.com 2009).



**Figure 9.1** SaskPower's electricity generation system map

(original in color)

Source: SaskPower.com 2009

**Table 9.1      Boundary Dam Power Station characteristics**

	<b>Unit 1</b>	<b>Unit 2</b>	<b>Unit 3</b>	<b>Unit 4</b>	<b>Unit 5</b>	<b>Unit 6</b>
<b>Gross Capacity, MW</b>	66	66	150	150	150	300
<b>Gross Cycle Heat Rate, kJ/kWh</b>	12,500	12,900	10,500	10,400	10,800	9,900
<b>Capacity Factor, %</b>	72.61	82.36	59.14	88.85	84.30	83.89

Source: Smith 2009

## 9.2 Modeling of power plant operations

Power plant information was collected directly from SaskPower (Smith 2009). As it was mentioned earlier, BDPS has 6 units. All 6 units are equipped with subcritical boilers and electrostatic precipitators. Unit 1 boiler type is front wall fired, Units 2-5 are tangentially fired boilers and Unit 6 boiler is a tangentially fired, split furnace. In order to simplify the calculation methodology, all boilers are assumed to be tangentially fired.

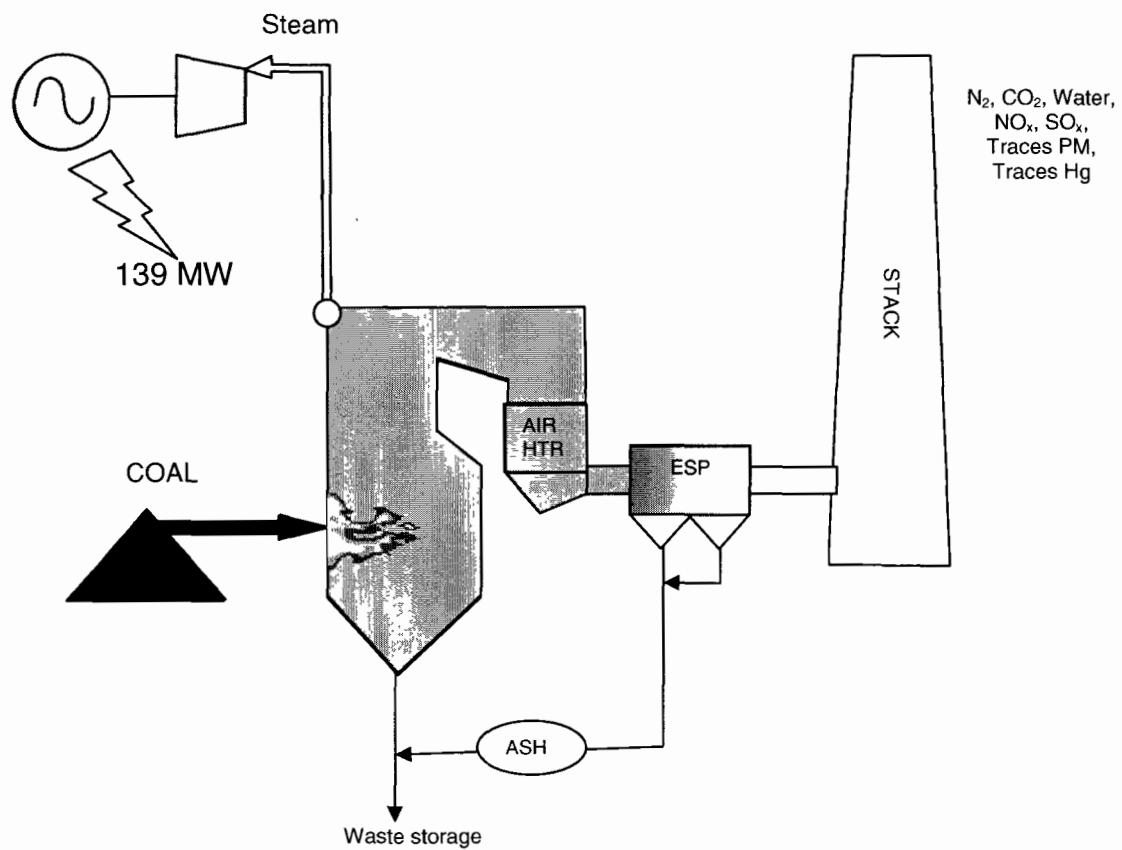
No chemicals are added to reduce emissions at the power plant. There are only limited NO<sub>x</sub> combustion controls in place. Concentric firing has been installed at Unit 6. Other units have an extra air register at the top of the burners to reduce combustion intensity thus, reduce NO<sub>x</sub> emissions.

Process diagram of Unit 3 is presented in Figure 9.2. Power plant operations were modeled using power plant data presented in Table 9.1 (power plant characteristics) and Table 9.2 (fuel characteristics). Knowing these data it is possible to calculate the mass flow rate and composition of the gaseous and solid streams in the power plant. The detailed calculation procedure is described below.

### 9.2.1 Coal consumption

The amount of lignite coal needed to produce gross electric capacity, 882 MWg, depends on the gross cycle heat rate ( $HR_{cycle}$ , kJ/kWh) and higher heating value of coal ( $HHV_{coal}$ , kJ/kg) (Rubin et al. 1991):

$$M_{coal} = \frac{MWg \times HR_{cycle}}{HHV_{coal}}, \quad (9.1)$$



**Figure 9.2 Boundary Dam Power Station Unit 3 process diagram**

(original in color)

Courtesy of Saskatchewan Power Corporation

**Table 9.2 Coal composition and heating value<sup>6</sup>**

Parameter	Unit	Value
Heating value	kJ/kg	15,119.00
Moisture	%	35.00
Carbon	%	41.70
Hydrogen	%	2.61
Nitrogen	%	0.79
Sulfur	%	0.54
Ash	%	9.47
Oxygen	%	9.90
Mercury	ppb	79.00
Chlorine	ppm	10.20

Source: Smith 2009

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<sup>6</sup> Please note that values are averages based on regular measurements performed by SaskPower.

where  $HR_{cycle}$  depends on the boiler efficiency ( $\eta_{boiler}$ ) and steam heat rate ( $HR_{steam}$ ,  $\text{kJ/kWh}$ ):

$$HR_{cycle} = \frac{HR_{steam}}{\eta_{boiler}} \quad (9.2)$$

### 9.2.2 Air, flue gas and solid waste streams from combustion

The amount of oxygen needed for stoichiometric combustion of fuel is the sum of oxygen needed to convert carbon to carbon dioxide ( $C + O_2 \rightarrow CO_2$ ), hydrogen to water ( $2H_2 + O_2 \rightarrow 2H_2O$ ) and sulphur to sulphur dioxide ( $S + O_2 \rightarrow SO_2$ ) minus any oxygen in fuel.

$$Moxygen = \left( \frac{C \times (1-u)}{12.01} + \frac{H}{4 \times 1.01} + \frac{S}{32.06} - \frac{O}{2 \times 16.00} \right) \times M_{coal} \times 2 \times 16, \quad (9.3)$$

Where  $C$ ,  $H$ ,  $S$  and  $O$  are mass fractions of carbon, hydrogen, sulphur and oxygen in fuel and  $u$  is the amount of unburned carbon, for this purpose of this coal assumed to be 1% (Smith 2009).

In this calculations we assumed that dry air consist of 79% nitrogen and 21% oxygen. Then, the amount of nitrogen is calculated using the following equation:

$$M_{nitrogen} = 3.76 \times Moxygen \quad (9.4)$$

In order to minimize incomplete fuel combustion, the combustion air entering the boiler is more than the stoichiometric air requirement. This additional air is called excess air ( $e_{boiler}$ ). In case of lignite coal combustion, the excess air is usually 20%. Please note that the leakage air across the air preheater is not accounted for in these calculations.

$$M_{combair} = (1 + e_{boiler}) \times (M_{nitrogen} + Moxygen) \quad (9.5)$$

The combustion air contains some moisture. The specific humidity,  $\omega$  at 27°C and 60% relative humidity is 0.013 kg H<sub>2</sub>O per kg dry air. The wet combustion air is then calculated using the following equation:

$$M_{\text{wetcombair}} = (1 + \omega) \times M_{\text{combair}} \quad (9.6)$$

The products of combustion can be calculated from a molar balance of the air and the fuel entering the boiler:

$$M_{H_2O} = M_{\text{coal}} \times H \times \frac{18.02}{2 \times 1.01} + (M_{\text{coal}} \times \omega) \quad (9.7)$$

$$M_{O_2(\text{out})} = M_{\text{oxygen}} \times e_{\text{boiler}} \quad (9.8)$$

$$M_{N_2(\text{out})} = 3.76 \times (1 + e_{\text{boiler}}) \times M_{\text{oxygen}} + M_{\text{coal}} \times N \quad (9.9)$$

The carbon in the fuel can oxidize to carbon monoxide, carbon dioxide or it can remain unburned. The amount of carbon monoxide is assumed to be zero – excess O<sub>2</sub> environment allows for complete oxidation of the carbon. The amounts of carbon dioxide and unburned carbon are determined with Equation 9.10 and 9.11, respectively.

$$M_{CO_2} = M_{\text{coal}} \times C \times (1 - u) \times \frac{44.01}{12.01} \quad (9.10)$$

$$M_{C(\text{unburned})} = M_{\text{coal}} \times u \quad (9.11)$$

The sulphur in the fuel can oxidize to either sulphur dioxide or sulphur trioxide. Sulphur also can be retained in the ash ( $S_{\text{ret}}$ ). The ash at Boundary Dam Power Station is quite alkaline, thus it can be assumed that 10 to 25% of sulphur is captured in the ash. The following equations are used to calculate sulphur dioxide, sulphur trioxide, sulphur in flyash and in bottom ash:

$$M_{SO_2} = M_{\text{coal}} \times S \times 0.85 \times \frac{64.06}{32.06} \quad (9.12)$$

$$M_{SO_3} = M_{coal} \times S \times 0.01 \times \frac{80.06}{32.06} \quad (9.13)$$

$$M_{Sflyash} = M_{coal} \times S \times 0.01 \quad (9.14)$$

$$M_{Sbottomash} = M_{coal} \times S \times 0.13, \quad (9.15)$$

Where  $S$  is sulphur content in coal (fraction).

Other combustion products were calculated using emissions factors for pulverized coal tangentially-fired dry bottom boilers extracted from the U.S. Environmental Protection Agency report for lignite coal combustion (US EPA 1998). Emissions factors are summarized in Table 9.3.

$N_2O$  emissions were estimated using emission factor for coals from Environment Canada (Greenhouse Gas Division 2008):

$$N_2O = 0.032 \text{ g/kg of coal} \quad (9.16)$$

With the mass flow rate of coal determined, it is possible to estimate the mass flow rate of solid streams in the power plant, i.e. bottom ash and flyash mass flow rates.

$$M_{bottomash} = M_{coal} \times A + M_{Sbottomash} + M_{Cunburned} - M_{flyash}, \quad (9.17)$$

where  $A$  is ash content in coal (fraction).

$$M_{flyash} = M_{PM} + M_{PM10} + M_{Sflyash} \quad (9.18)$$

Mercury in the flue gas can be found in three main forms: elemental mercury ( $Hg^0$ ), oxidized mercury ( $Hg^{2+}$ ) and particulate mercury ( $Hg_{part}$ ). In this research we have not made any differentiation between these three types of mercury and presented results as total mercury emissions from lignite combustion.

**Table 9.3 Emissions factors for lignite combustion in pulverized coal tangentially-fired dry bottom boilers, kg/tonne of coal**

PM	3.2A
PM10	1.15A
NO	0.95*3.16
NO <sub>2</sub>	0.05*3.16
HCl	0.6
HF	0.075
CH <sub>4</sub>	0.02
Total VOC	0.02

Where A is ash content in coal (fraction)

Source: US EPA 1998

**Table 9.4 Emissions factors for trace elements emissions from an average coal-fired power plant in US, kg/kWh of net electricity**

Trace element	Flue gas emissions	Solid emissions
Antimony	0.0041	0.015
Arsenic	0.049	0.13
Barium	0.013	0.44
Beryllium	0.0016	0.014
Cadmium	0.0041	0.0098
Chromium	0.059	0.22
Cobalt	0.0069	0.047
Copper	0.023	0.11
Lead	0.03	0.10
Manganese	0.0043	0.27
Molybdenum	0.038	0.039
Nickel	0.058	0.016
Selenium	0.41	0.01
Vanadium	0.088	0.32

Source: Spath and Mann, 1999

Total mercury emissions were calculated using the following equations (Mniszek 1994):

$$M_{Hg} = 0.9 \times Hg_{coal} \times M_{coal}, \quad (9.19)$$

Where 0.9 is a constant with a correlation coefficient ( $R^2$ ) of 0.9995;  $Hg_{coal}$  is mercury content in coal (g Hg/tonne); and  $M_{coal}$  is coal mass flow rate (tonne/hr).

Other trace elements emissions were calculated using emissions factors presented in Table 9.4.

### 9.2.3 Electrostatic precipitator

Electrostatic precipitators (ESP) are installed at all units of Boundary Dam Power Station. Particulates removal efficiency is assumed to be 99%. Some  $SO_3$  and mercury removal is also achieved in ESP. Here, we assumed 25% for  $SO_3$  removal efficiency and 7.5% for mercury removal efficiency in ESP (Rubin et al.1991). This is mostly oxidized mercury ( $Hg^{2+}$ ) and a small amount of elemental mercury ( $Hg^0$ ). Other trace elements removal rates are shown in Table 9.5.

### 9.2.4 Power plant auxiliary power requirement

Auxiliary power requirement at power plant is caused by forced draft fans, cooling system, steam cycle pumps and coal pulveriser. The following data was found from the literature (Rubin et al.1991):

Coal pulveriser:	0.60 %MWg
Steam cycle pumps:	0.65 %MWg
Forced draft fans:	1.5 %MWg
Cooling system:	1.8 %MWg
Miscellaneous:	1.3 %MWg

**Table 9.5 Average trace elements removal efficiency in ESP, %**

Trace element	Removal efficiency, %
Antimony	98
Arsenic	81
Barium	96.9
Beryllium	93.7
Cadmium	94.1
Chromium	96.4
Cobalt	99
Copper	98
Lead	98.5
Manganese	98.3
Molybdenum	98
Nickel	97.5
Selenium	50.9
Vanadium	98

Source: Nie 2009

Electrostatic precipitator: 0.12 %MWg

Total: 5.97 %MWg

In case of Boundary Dam Power Station, auxiliary power requirements for the whole power plant (boiler and ESP) are about 6.9-7%MWg (Smith 2009). The value of 6.9%MWg of auxiliary power requirements was used in this research. The internal plant power use only is considered. Electricity requirements for coal mining are accounted for in the coal production life cycle inventory.

### **9.3 Modeling of carbon dioxide capture operations**

#### 9.3.1 Flue gas desulfurization unit

This section describes wet flue gas desulfurization (FGD) unit that needs to be installed before CO<sub>2</sub> capture. Post-combustion CO<sub>2</sub> capture process using MEA as a solvent is very sensitive to SO<sub>x</sub> emissions. One of several requirements to be met for power plant flue gas to be processed by amine scrubbing is for SO<sub>2</sub> concentration to be less than 10-ppmv (~20 mg/Nm<sup>3</sup>) (Smith et al. 2008).

Thus, 99% SO<sub>2</sub> removal efficiency is necessary before the flue gas enters CO<sub>2</sub> capture unit. Based on the discussion with SaskPower's staff (Olson 2009) and data from literature (Rubin et al. 1991), the following removal efficiencies for SO<sub>2</sub>, SO<sub>3</sub>, HCl, particulates and mercury were assumed:

SO<sub>2</sub> removal 99.00%

SO<sub>3</sub> removal 50.00%

HCl removal 90.00%

PM removal 70.00%

Mercury 25.00%

Other trace elements removal efficiencies are based on Nie 2009 and are presented in Table 9.6.

Then, the mass flow rate of removed sulfur ( $M_{removedS}$ ) can be found from the following equation:

$$M_{removedS} = \eta_{SO_2} \times M_{m_{SO_2}} + \eta_{SO_3} \times M_{m_{SO_3}} \quad (9.20)$$

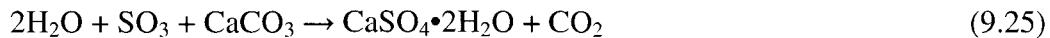
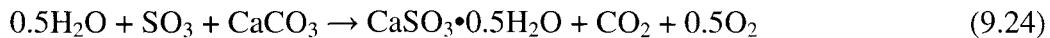
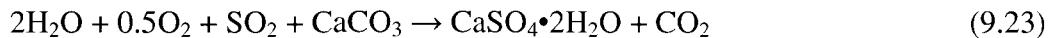
The reagent for the wet scrubber can be either lime or limestone. In this research, limestone ( $\text{CaCO}_3$ ) was used as a reagent. The purity of reagent ( $R_{purity}$ ) was assumed to be 92.4%.

The molar stoichiometry (moles of calcium required per mole of sulfur removed),  $\sigma$  is equal to 1.03.

The mass flow of limestone is calculated using the following equation:

$$M_{Limestone} = \frac{100.09 \times (\frac{\eta_{SO_2} \times M_{SO_2}}{64.06} + \frac{\eta_{SO_3} \times M_{SO_3}}{80.06}) \times \sigma}{R_{purity}} \quad (9.21)$$

The sulfur dioxide and sulfur trioxide are removed from the flue gas in the scrubber by a set of complex chemical reactions. The simplified chemical reactions in the scrubber are presented below:



**Table 9.6 Average trace elements removal efficiency in FGD, %**

Trace element	Removal efficiency (solid), %
Antimony	90
Arsenic	91
Barium	90
Beryllium	95
Cadmium	80
Chromium	88
Cobalt	90
Copper	69
Lead	90
Manganese	93
Molybdenum	90
Nickel	86
Selenium	58
Vanadium	92

Source: Nie 2009

The composition of the flue gas exiting the scrubber was determined using these reactions (9.22-9.25). It is assumed that the oxygen needed to oxidize the calcium sulfite to calcium sulfate is taken from the flue gas (reaction 9.23). The moisture content in the scrubber is assumed to come from makeup slurry, thus it does not reduce the moisture content of the flue gas. It is also assumed that 90% of calcium sulfite oxidizes to calcium sulfate (e.g.  $Ox = 0.9$ ).

The following equation (9.26 – 9.36) were used to calculate exit mass flow rates of nitrogen and nitrogen oxides (internal reactions of nitrogen in coal and in the air to form NO, N<sub>2</sub>O and NO<sub>2</sub>); oxygen; water vapour; carbon dioxide, sulphur oxides; hydrochloric acid; particulate matter; and mercury.

$$M_{exit_{N_2}} = M_{m_{N_2}} \quad (9.26)$$

$$M_{exit_{NO}} = M_{m_{NO}} \quad (9.27)$$

$$M_{exit_{NO_2}} = M_{m_{NO_2}} \quad (9.28)$$

$$M_{exit_{O_2}} = M_{m_{O_2}} + (0.5 \times (1 - Ox) \times M_{m_{SO_3}} - 0.5 \times Ox \times M_{m_{SO_3}}) \times \eta_{SO_2} \quad (9.29)$$

$$M_{exit_{H_2O}} = M_{m_{H_2O}} + M_{evaporated\ H_2O} \quad (9.30)$$

$$M_{exit_{CO_2}} = M_{m_{CO_2}} + M_{removed_s} \quad (9.31)$$

$$M_{exit_{SO_2}} = M_{m_{SO_2}} - M_{m_{SO_2}} \times \eta_{SO_2} \quad (9.32)$$

$$M_{exit_{SO_3}} = M_{m_{SO_3}} - M_{m_{SO_3}} \times \eta_{SO_3} \quad (9.33)$$

$$M_{exit_{HCl}} = M_{m_{HCl}} - M_{m_{HCl}} \times \eta_{HCl} \quad (9.34)$$

$$M_{exit_{PM}} = M_{m_{PM}} - M_{m_{PM}} \times \eta_{PM} \quad (9.35)$$

$$M_{exit_{Hg}} = M_{m_{Hg}} - M_{m_{Hg}} \times \eta_{Hg} \quad (9.36)$$

Water consumption in wet FGD is estimated to be 6.18E-6 m<sup>3</sup>/s per megawatt electricity generated (Berkenpas et al 1999).

The solid waste streams from FGD include unreacted reagent, inert materials introduced with the reagent (depends on level of reagent purity), flyash that has been removed by the scrubber (depends on particulate matter removal efficiency) and oxidation products (calcium sulfite and calcium sulfate). The mass flow rates of solid waste components are presented below.

$$M_{ash} = M_{in_{PM}} \times \eta_{PM} \quad (9.37)$$

$$M_{CaSO_3 \cdot 0.5H_2O} = \frac{M_{Limestone} \times 129.14}{100.09} \times (1 - Ox) \times \eta_{PM} \quad (9.38)$$

$$M_{CaSO_4 \cdot 2H_2O} = \frac{M_{Limestone} \times 172.17}{100.09} \times Ox \times \eta_{PM} \quad (9.39)$$

$$M_{inerts} = M_{Limestone} \times (1 - R_{purity}) \quad (9.40)$$

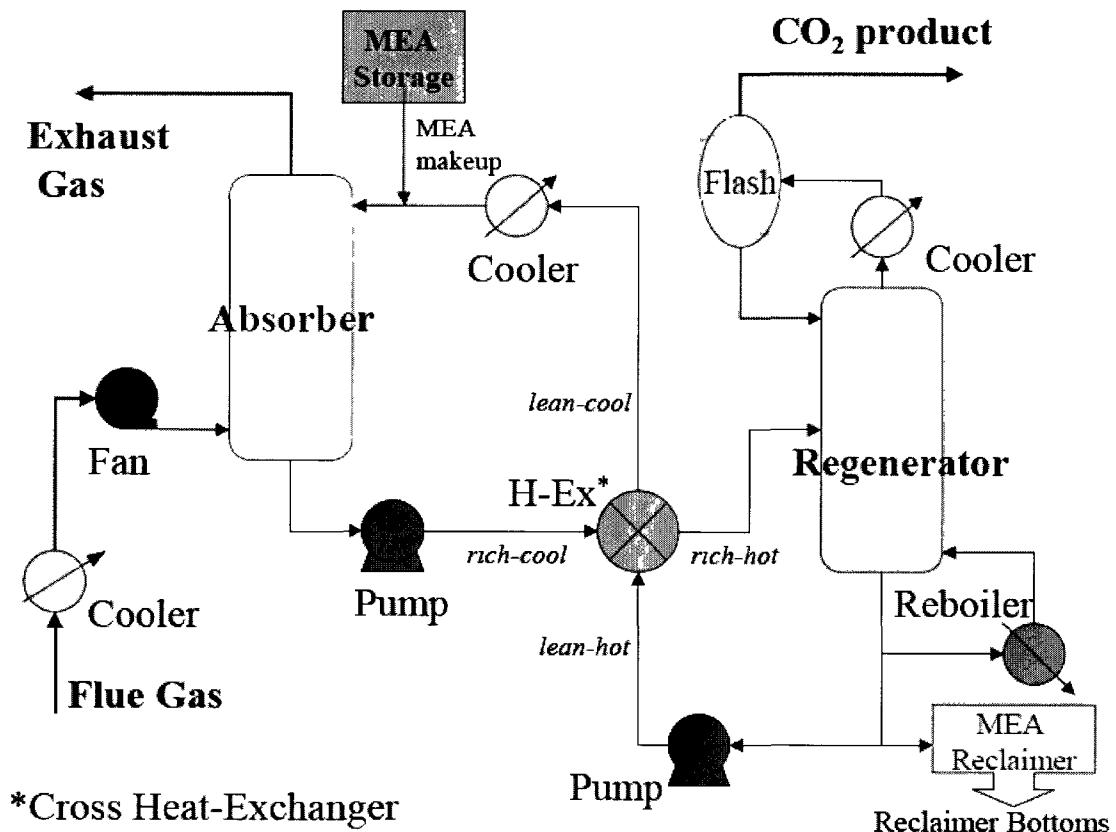
FGD power requirements were estimated to be 3.8% MWg (Rubin et al. 1991).

### 9.3.2 Carbon dioxide capture unit

#### *9.3.2.1 Process description*

Post-combustion amine-based adsorption of CO<sub>2</sub> from flue gases and CO<sub>2</sub> compression was modeled. 30%wt monoethanolamine (MEA) was used as the sorbent. Process diagram of post-combustion capture plant is presented in Figure 9.3. Process diagram of BDPS Unit 3 retrofit is shown on Figure 9.4. The system consists of two main components: an absorber, where CO<sub>2</sub> is absorbed into a sorbent and a regenerator (stripper), where CO<sub>2</sub> is released in concentrated form and the original sorbent is recovered. Other CO<sub>2</sub> capture and separation system equipment include:

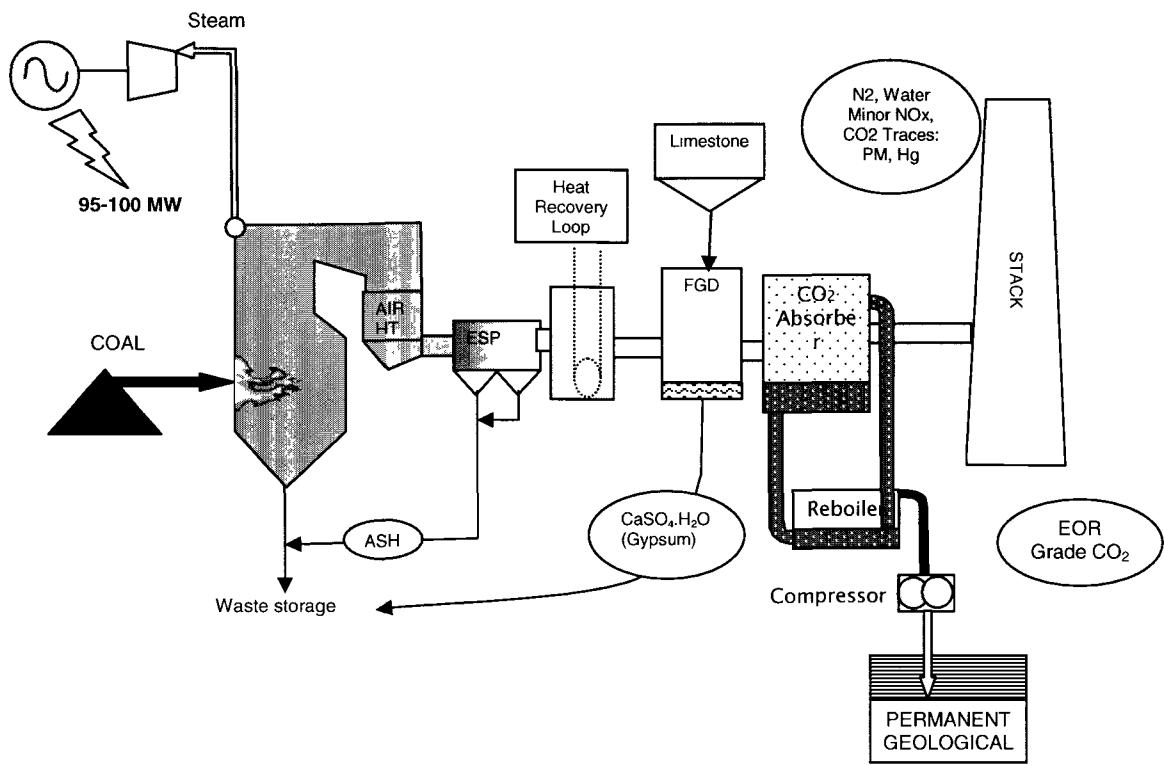
Direct contact cooler (DCC) – The flue gases coming from power plant need to be cooled down to about 45-50 °C. This will help to improve the absorption process and minimize sorbent losses. In case of coal-fired power plant equipped with wet SO<sub>2</sub> scrubber, the temperature of flue gases is about 60 °C, thus, additional cooling may not be required.



**Figure 9.3 The process flow diagram of post-combustion CO<sub>2</sub> capture from flue gases using amine-based system**

(original in color)

Source: Rao et al. 2004



**Figure 9.4 Boundary Dam Power Station Unit 3 retrofit process diagram**

(original in color)

Courtesy of Saskatchewan Power Corporation

Flue gas blower – Cooled flue gas needs to be pressurized before it enters the absorber so that it can overcome pressure drop as it passes upwards through absorber column.

Rich/lean heat exchanger – In order to regenerate the sorbent and strip off CO<sub>2</sub>, the CO<sub>2</sub> rich solvent needs to be heated. On the other hand, the sorbent coming from the regenerator must be cooled down before entering the absorber column. The heat exchange occurs in a cross heat exchanger.

Reboiler – Here a low-pressure steam from the power plant is used to heat the rich sorbent.

Steam extractor – Steam extractor needs to be installed to take low-pressure steam from the steam turbines of coal-fired power plant (technically, from between intermediate and low pressure turbines).

MEA reclaimer – Different acid gas impurities such as SO<sub>2</sub>, SO<sub>3</sub>, NO<sub>2</sub> and HCl in the flue gases lead to formation of heat stable salts. In order to avoid accumulation of these salts in the sorbent, as well as to recover some MEA losses, a strong alkali (for example, caustic-NaOH) may be added. The recovered MEA is recycled to the sorbent stream and the bottom sludge from the reclaimer (reclaimer waste) is sent for disposal.

Sorbent processing area – The sorbent processing area has a sorbent cooler (to cool regenerated sorbent to about 40 °C), MEA storage tank and a mixer (a small quantity of MEA must be added to the sorbent stream to compensate for sorbent losses), and an activated carbon bed filter (adsorbs impurities such as degradation products of MEA from the sorbent stream).

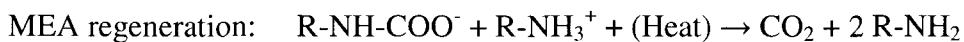
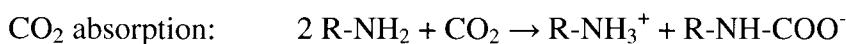
CO<sub>2</sub> drying and compression – CO<sub>2</sub> product will be carried via pipeline. Thus, it should not contain any moisture in order to prevent corrosion. CO<sub>2</sub> also needs to be compressed

to the liquid stage in order to overcome the pressure losses during the pipeline transport.

### 9.3.2.2 Process chemistry

Amine-based CO<sub>2</sub> capture is based on the principle of chemical absorption. The process is accompanied by a chemical reaction thus making this system more efficient, since chemical reaction enhances the mass transfer from gas to liquid phase.

The process chemistry is complex, but can be presented by the following main reactions (Rao et al. 2004):



Where,

R-NH<sub>2</sub> is MEA and R represents HO-CH<sub>2</sub>CH<sub>2</sub>.

As it can be seen from the equations above, two moles of amine is required to absorb one mole of CO<sub>2</sub>. It also takes a large amount of energy to break the bonds in carbamate (R-NH-COO<sup>-</sup>) formed during the absorption phase to regenerate the sorbent. The theoretical minimum heat requirement is about 1900 kJ/kgCO<sub>2</sub> (Rao et al. 2004).

### 9.3.2.3 Environmental impacts of amines

Some amines and their degradation products can have negative impacts on human health and be toxic to animals and aquatic organisms. Eutrophication and acidification problems may also arise from nitrogen and ammonia emissions generated from amine decomposition (Shao and Stangeland 2009).

Once emitted from the capture plant, amine begins to degrade to other products such as amides, nitramines, aldehydes and nitrosamines. Nitrosamines are probably degradation products with the most adverse environmental impacts. They can cause cancer, drinking

water contamination, and adverse effects on aquatic organisms. However, these impacts represent a worst case scenario where amine emissions are at their maximum. Thus, it is very important to know what happens to amines in the atmosphere, their degradation paths, yields and products, as well as effects of amines on aquatic and terrestrial environments.

There is some research in this area currently underway in Australia and Norway. So far, the results have shown that the environmental and health risks caused by amines from CO<sub>2</sub> capture are manageable and do not give reasons to slow down the deployment of CCS (Shao and Stangeland 2009). MEA, the most common amine used in CO<sub>2</sub> capture, has a relatively high biodegradability and in itself has no adverse effect on human health, animals, vegetation and water organisms.

#### *9.3.2.4 CO<sub>2</sub> capture model*

CO<sub>2</sub> capture model for this study was developed using results of two research groups: the University of Regina's International Test Centre for CO<sub>2</sub> Capture and Carnegie Mellon University's IECM model development group.

Rao et al. 2004 derived performance equations using two process simulators: ASPEN-Plus and ProTreat. The following regression equations were obtained:

$$L/G = \exp(-1.4352 + 0.1239 \times y_{CO_2} + 3.4863 \times \phi_{lean} + 0.0174 \times \eta_{CO_2} - 0.0397 \times C_{MEA} + 0.0027 \times T_{fg,in}) \quad (9.41)$$

$$R^2 = 0.92$$

$$T_{fg,out} = 41.15 + 0.062 \times T_{fg,in} + 1.307 \times y_{CO_2} - 18.872 \times \phi_{lean} + 0.270 \times C_{MEA} \quad (9.42)$$

$$R^2 = 0.92$$

$$mw_{lean} = 16.907 + 2.333 \times \phi_{lean} + 0.204 \times C_{MEA} \quad (9.43)$$

$$R^2 = 0.95$$

$$e_{compressor} = -51.632 + 19.207 \times \ln P_{CO_2} + 14.7 \quad (9.44)$$

$$R^2 > 0.99$$

where,

$L$  Sorbent flow rate (kmole/hr)

$G$  Inlet flue gas flow rate (kmole/hr)

$L/G$  Ration of molar flow rates of total sorbent applied per unit flue gas flow rate in absorber

$y_{CO_2}$  CO<sub>2</sub> concentration in inlet flue gas (mole %)

$\Phi_{lean}$  Lean sorbent CO<sub>2</sub> loading (0.2 mole CO<sub>2</sub>/mole MEA)

$\eta_{CO_2}$  CO<sub>2</sub> capture efficiency (%)

$C_{MEA}$  MEA concentration in the sorbent (30 wt %).

$T_{fg,in}$  Temperature of the flue gas entering the CO<sub>2</sub> absorber (50 °C)

$T_{fg,out}$  Temperature of the flue gas leaving the CO<sub>2</sub> absorber (°C)

$mw_{lean}$  Average molecular weight of the lean sorbent (kg/kmole sorbent)

$e_{compressor}$  Unit energy requirement for CO<sub>2</sub> compression (kWh/tonne CO<sub>2</sub>)

$P_{CO_2}$  Desired CO<sub>2</sub> product pressure (2000 psig).

### Removal efficiencies

The following acid gases removal efficiencies were used in this model:

CO<sub>2</sub> 90%

SO<sub>2</sub> 99.5% MEA loss (mole MEA/mole acid gas) = 2

SO<sub>3</sub> 99.5% MEA loss (mole MEA/mole acid gas) = 2

NO<sub>2</sub> 25% MEA loss (mole MEA/mole acid gas) = 2

HCl            95%            MEA loss (mole MEA/mole acid gas) = 1

NO            0%            MEA loss (mole MEA/mole acid gas) = 0

Particulates removal efficiency was assumed at 50%. Since there is no literature found on quantifying trace elements removal rates in CO<sub>2</sub> capture systems, 80% removal rate was assumed (Nie 2009).

Total quantity of CO<sub>2</sub> captured was estimated using the following equation:

$$M_{CO_2captured} = M_{m_{CO_2}} \times \eta_{CO_2} \quad (9.45)$$

### MEA losses

Losses of MEA ( $M_{MEA\ makeup}$ ) occur due to oxidation of acids, polymerization, heat-stable salts (HSS) formation and loss with flue gas exhaust. Very low concentrations of acid gases (SO<sub>2</sub>, HCl, NO<sub>2</sub>) are desirable to avoid losses of MEA. The main problem here is with SO<sub>2</sub>, NO<sub>x</sub> is less of a problem. Thus, flue gas desulphurization unit should be installed before CO<sub>2</sub> capture. MEA losses with the flue gas are not very significant. The solvent content in flue gases is estimated at 47 g/tonne CO<sub>2</sub> captured (IEA GHG 2006). In general, nominal loss of MEA is estimated as about 1.36077 kg MEA/tonne CO<sub>2</sub>.

$$M_{MEA\ makeup} = 1.36077 \times M_{CO_2captured} \quad (9.46)$$

Total sorbent circulation flow rate (m<sup>3</sup>/hr):

$$L_{tot} = \{G \times (L/G) \times mw_{lean} + M_{MEA\ makeup} \times (100/C_{MEA})\} \times \rho_{sorbent} \quad (9.47)$$

where,  $\rho_{sorbent}$  is density of the solvent (solvent contains 70% of water, thus the density of the solvent is assumed to be 1000 kg/m<sup>3</sup>).

### Waste generated from reclaimer

Mass of the reclaimer waste is typically 3.2 kg/tonne CO<sub>2</sub> captured (IEA GHG 2006). It includes not only lost amine, but also flyash and other compounds formed in the process.

### Activated carbon consumption

Activated carbon helps to remove long chained cyclic polymeric compounds formed from the degenerated MEA. Over a period of time, usually 3 to 6 months the carbon bed needs to be replaced. A typical amount of activated carbon is estimated to be about 0.075 kg C/tonne CO<sub>2</sub> captured (Rao 2002).

### Caustic consumption in reclaimer

Caustic (NaOH) may be added to the reclaimer to regenerate some of the MEA from heat-stable salts (HSS). A typical value is about 0.13 kg NaOH/tonne CO<sub>2</sub> captured.

### NH<sub>3</sub> formation

The oxidation of MEA to organic acids leads to formation of ammonia (NH<sub>3</sub>). Each mole of MEA lost in oxidation, liberates a mole of NH<sub>3</sub>.

The rate of NH<sub>3</sub> generation is 0.136 kg NH<sub>3</sub>/tonne CO<sub>2</sub> (Rao 2002).

### Process water requirements

Process water makeup ( $M_{pw}$ ) is usually 0.114 tonne/hr per MW (net) (Rao 2002).

The required cooling water flow rate ( $M_{cw}$ ), tonne/hr can be estimated from the following equation:

$$M_{cw} = M_{fg} \times (\Delta T_{fg} / \Delta T_w) \times (SH_{fg} / SH_w) \quad (9.48)$$

where,

$M_{fg}$  Mass flow rate of flue gas (tonne/hr)

$\Delta T_{fg}$  Drop in flue gas temperature  $\Delta T_{fg} = (T_{fg,i} - T_{fg})$  (°C)

$T_{fg,i}$  Temperature of flue gas entering the direct contact cooler (60.06 °C)

$T_{fg}$  Temperature of flue gas exiting the direct contact cooler (50 °C)

$\Delta T_w$  Temperature rise in cooling water (15 °C)

$SH_{fg}$  Specific heat of flue gas (1.2 kJ/kg °C)

$SH_w$  Specific heat of water (4.2 kJ/kg °C)

Total water requirements are:

$$M_w = M_{pw} + M_{cw} \quad (9.49)$$

### Steam requirement

Low pressure steam is used in order to provide the sorbent regeneration heat in the reboiler. The mass flow rate of steam depends on regeneration heat requirement and enthalpy of regeneration steam. Sorbent regeneration heat requirement ( $Q$ ) is obtained from University of Regina's CO<sub>2</sub> capture pilot plant tests, and is assumed to be 3600 kJ/kg (Adams 2009). Enthalpy of steam ( $q_{steam}$ ) is estimated to be 2000 kJ/kg steam. Efficiency of the reboiler ( $\eta_{reboiler}$ ) is assumed at 85%. Then, the mass flow rate of steam (tonne/hr):

$$M_{steam} = \frac{Q}{q_{steam} \times \eta_{reboiler}} \quad (9.50)$$

### Auxiliary power requirements

Extraction of low pressure steam results in loss of power generation capacity of the plant. Heat to electricity factor ( $F_{HE}$ ) gives the equivalent loss of power generation capacity due to the heat requirement for solvent regeneration. The value of heat to electricity factor is assumed to be 14%.

Then, the energy loss due to solvent regeneration can be calculated from the following equation:

$$E_{regeneration} = F_{HE} \times M_{steam} \times q_{steam} \quad (9.51)$$

Electricity consumption for blowers and pumps ( $E_{blower+pumps}$ ), kW is calculated using the following equation (Chapel et al. 1999):

$$E_{blower+pumps} = 9.6 + \frac{393.6}{vol\%CO_2} \quad (9.52)$$

where,

$vol\%CO_2$       Volume concentration of CO<sub>2</sub> in the flue gas.

CO<sub>2</sub> has to be compressed to high pressure where it gets liquefied to transport to via pipeline. The CO<sub>2</sub> pressure ( $P_{CO_2}$ ) used in this research is 2000 psig. Compressor efficiency ( $\eta_{compressor}$ ) is assumed to be 80%. Energy required for CO<sub>2</sub> compression is calculated using the following equation:

$$E_{compressor} = e_{compressor} \times M_{CO_2captured} \times \eta_{compressor} \quad (9.53)$$

# **10. LIFE CYCLE INVENTORY MODELING OF CO<sub>2</sub> TRANSPORT, CO<sub>2</sub>-ENHANCED OIL RECOVERY, REFINING AND USE**

## **10.1 CO<sub>2</sub> transport**

Pipeline construction and operation is modeled in the parallel research conducted by Jitsopa Suebsiri (Suebsiri 2010). The Weyburn oil field and other mature oil fields suitable for CO<sub>2</sub>-EOR operations are located in the range of 50-100 km from SaskPower's Boundary Dam Power Station (Figure 10.1). In this research it is assumed that CO<sub>2</sub> will be injected into two oil fields. Thus, two 100 km pipelines will be necessary.

### 10.1.1 CO<sub>2</sub> pipeline construction

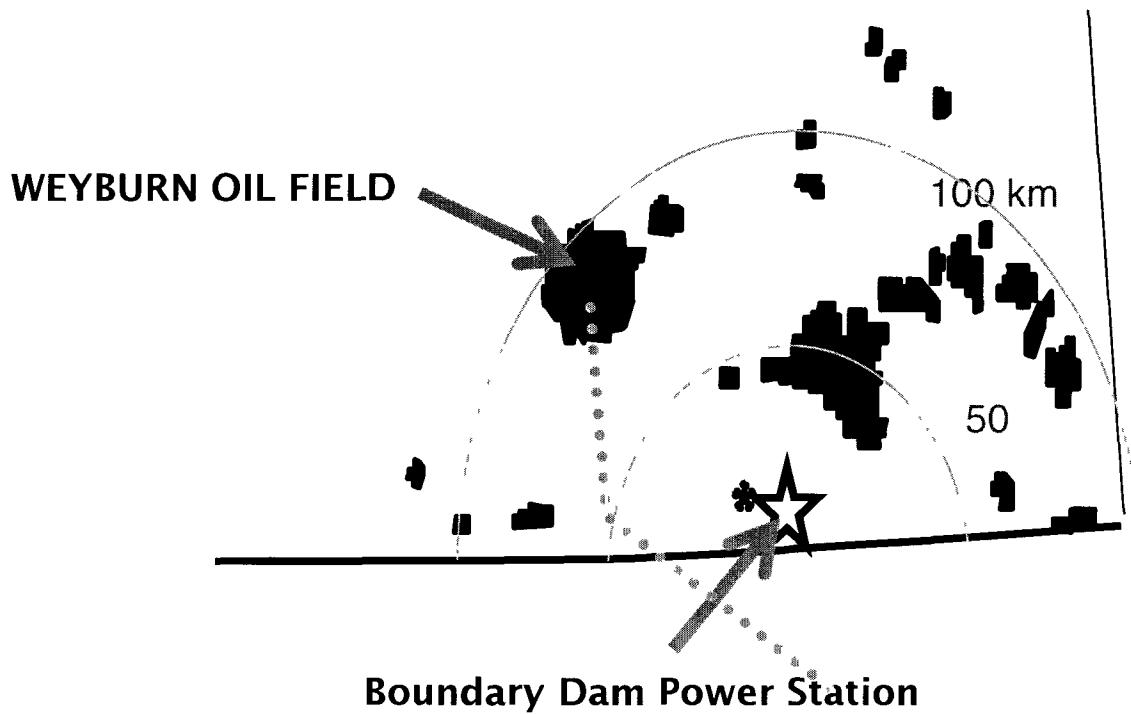
The pipeline with the following characteristics was modeled in this study:

Diameter: 305 mm (12 inch)

Wall thickness: 12.7 mm (0.50 inch)

Weight: 97.33 kg/m (65.4 lb/ft)

It was assumed that one half of the pipe was manufactured in Yokohama, Japan and another half in Tampa, Mexico (Suebsiri 2010). The transportation methods and distances are presented in Table 10.1.



**Figure 10.1 Location of SaskPower's Boundary Dam Power Station and mature oil fields suitable for EOR**

(original in color)

Courtesy of Saskatchewan Power Corporation

**Table 10.1 Pipeline transportation**

From-To	Mode of transport	Distance (km)	Source
Japan-Houston	Ship	17,150	<a href="http://www.maritimechain.com">www.maritimechain.com</a>
Mexico-Houston	Ship	1,340	<a href="http://www.maritimechain.com">www.maritimechain.com</a>
Houston-Saskatchewan	Rail	2,500	Estimate

Source: Suebsiri 2010

As it was mentioned before, world average dataset for steel production is used for production of steel for pipeline. 85% of recycled steel is used as a raw material for manufacturing of steel. In this research, it is assumed that the pipeline is not going to be removed from the ground after the end of operations. Thus, no decommissioning and recycling of pipeline is accounted for. Life cycle inventory data for 100 km of 12 inch assembled pipeline is presented in Appendix A, Table A.3.

#### 10.1.2 CO<sub>2</sub> pipeline operation

Recompression is needed for pipelines longer than 150 km. A booster station is required for every 150 km. Since the pipeline used in this research is only 100 km, no booster station is necessary. More information about pipeline operations can be found in parallel research study (Suebsiri 2010).

## **10.2 CO<sub>2</sub>-Enhanced Oil Recovery**

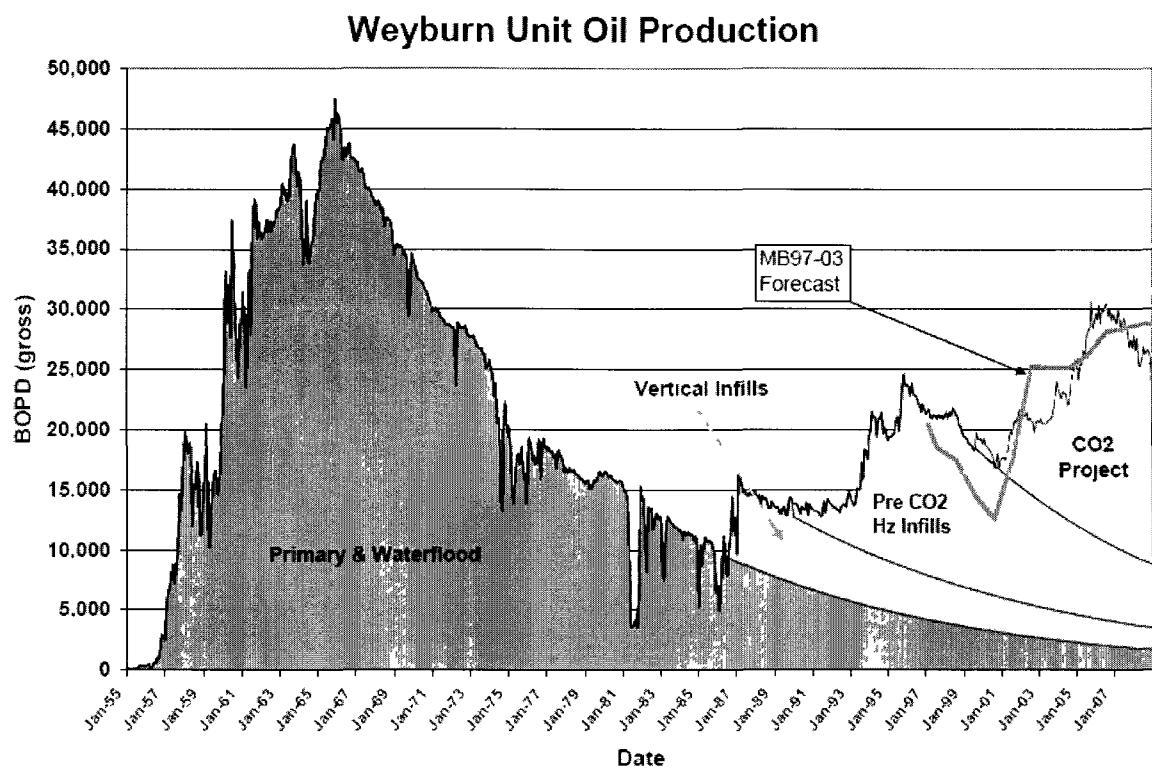
### 10.2.1 EnCana's Weyburn oil field

EnCana's Weyburn oil field in southeastern Saskatchewan is one of the largest medium-sour crude oil reservoirs in Canada. It has approximately 1.4 billion barrels of original oil in place. The Weyburn oil field area is more than 210 square kilometres. It was discovered in 1954 and has been on water flood since 1964 (EnCana 2008).

Oil at Weyburn is produced from the Midale beds of the Mississippian Charles formation, which is comprised of two layers: the Marly zone and the Vuggy zone. Both zones are approximately 1,400 metres underground. At Weyburn, the water flood has recovered most of the oil from the Vuggy zone, but much less from the less-permeable Marly zone. To extract more oil from the Marly zone, the CO<sub>2</sub>-EOR was introduced in 2000.

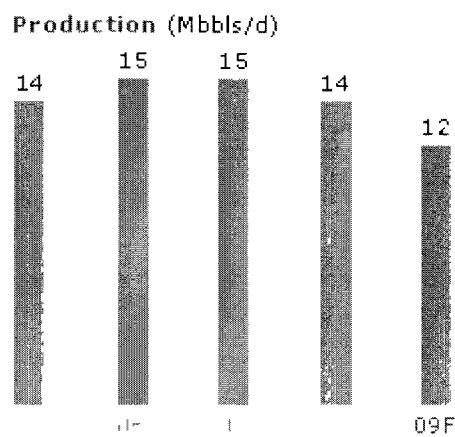
EnCana currently produces approximately 28,000 barrels of oil per day at Weyburn — an 18,000 barrel per day increase over the 10,000 barrels (or less) of oil per day that would be produced without the carbon dioxide flood (Figure 10.2). The production rate due to CO<sub>2</sub> flood is shown in Figure 10.3.

The new facilities were installed for the CO<sub>2</sub>-EOR in 2000. These include a free water knock-out vessel, a battery gas and recycle compressor package, and a flare system. CO<sub>2</sub>-EOR operations at the Weyburn oil field modeled in this research include construction and operation of facilities above ground (pumps and compressors) and injection and production wells drilling and completion (Figure 10.4).



**Figure 10.2 Weyburn unit oil production**

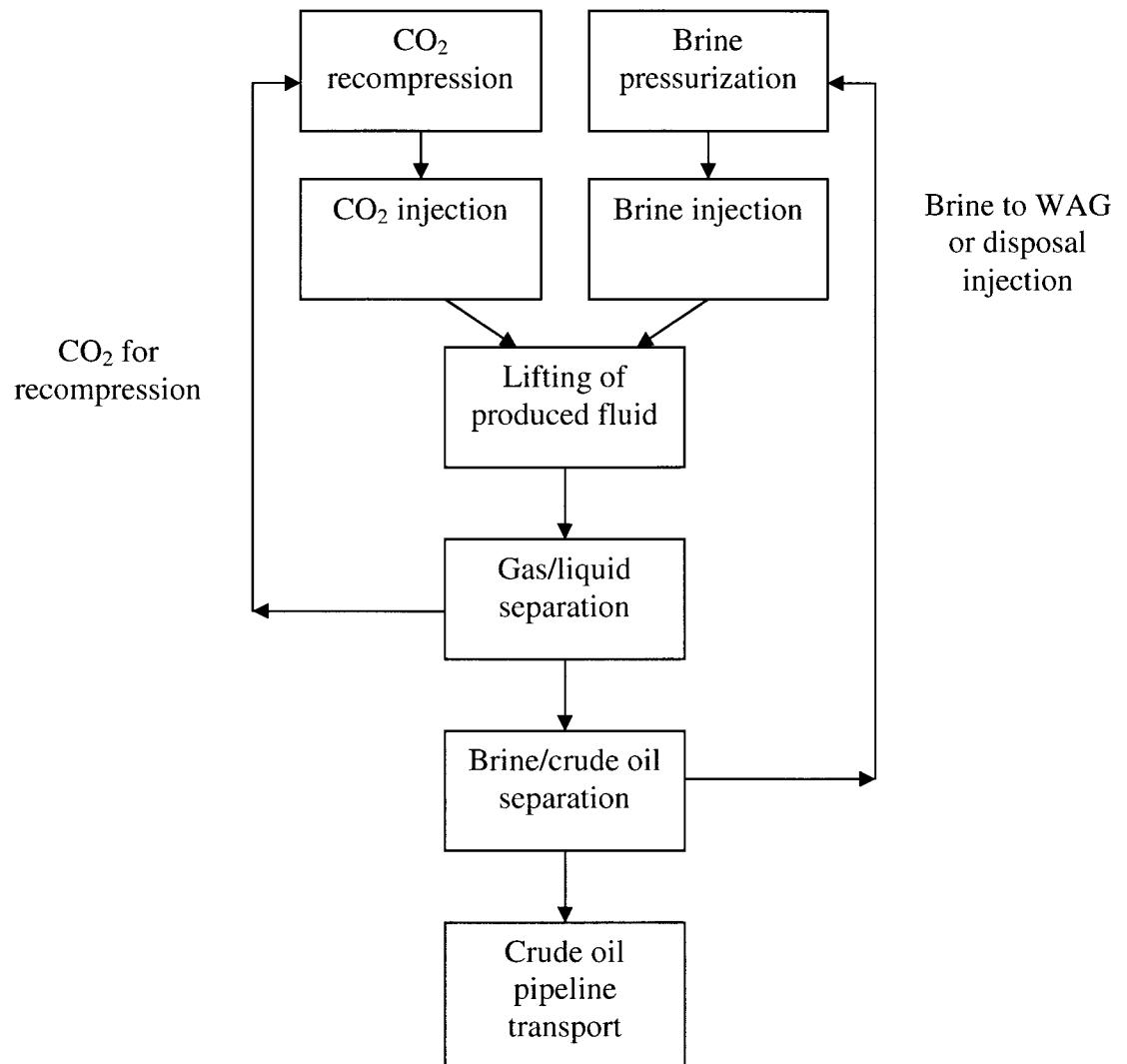
Source: EnCana 2009a



**Figure 10.3 Production data due to CO<sub>2</sub> flood**

(original in color)

Source: EnCana 2009b



**Figure 10.4 CO<sub>2</sub>-EOR operations at Weyburn oil field**

The separation and treatment of produced gas and liquid and brine and crude oil separation were excluded from the scope of the study due to the lack of available data. However, to the best author's knowledge, the impact of these operations is not expected to exceed 1% of total life cycle impact.

The CO<sub>2</sub> supply originally was approximately 95 million cubic feet per day (MMcf/d). In 2007, the purchase of CO<sub>2</sub> increased to approximately 125 MMcf/d. Approximately 2 MMt of CO<sub>2</sub> is stored in the Weyburn oil field annually (Figure 10.5). Thus, more than 13 million tonnes of CO<sub>2</sub> have been safely sequestered at Weyburn since start-up of the CO<sub>2</sub> flood. Over the life of the field, it is projected that about 30 million tonnes of CO<sub>2</sub> will be stored in total (Figure 10.6). This data is used in this research (see Table 10.2).

### 10.2.2 CO<sub>2</sub>-EOR model

#### *Wells drilling and completion*

It is assumed that two oil fields will be needed for CO<sub>2</sub> injection during 30 years timeline. 100 injection and production wells are assumed to be constructed for CO<sub>2</sub>-EOR operations at these two oil fields.

Average well depth in Weyburn oil field is 1450 meters (Wilson and Monea 2004). Casing size used for wells is 16.83 cm (6 5/8 inch). Material requirements for one well bore are:

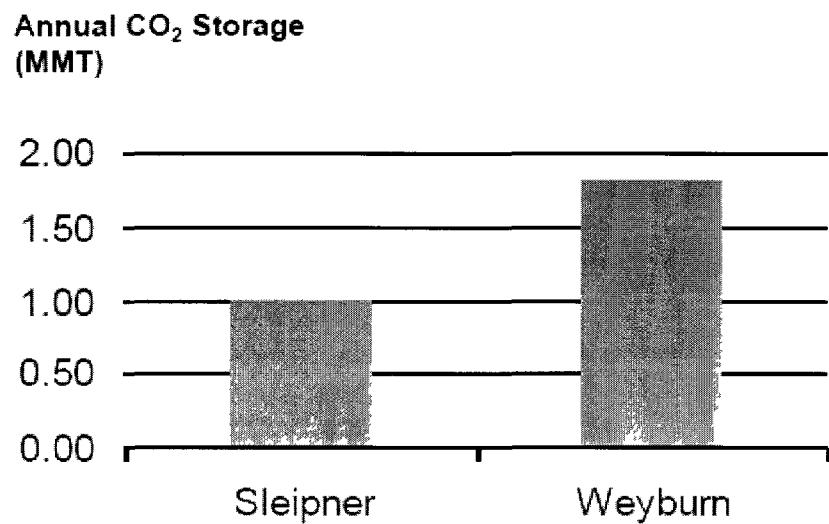
- 47 tonnes of portland cement (water content: 38% by weight; wall thickness: 5cm; specific gravity: 3.14), and

- 51 tonnes of steel pipe (ISO11960/API5CT/5B steel with wall thickness of 8.940mm, and plain end weight of 35.15 kg/m).

LCI data for drilling and completion of one well is presented in Appendix A, Table A.4.

#### *CO<sub>2</sub> compression and recycling*

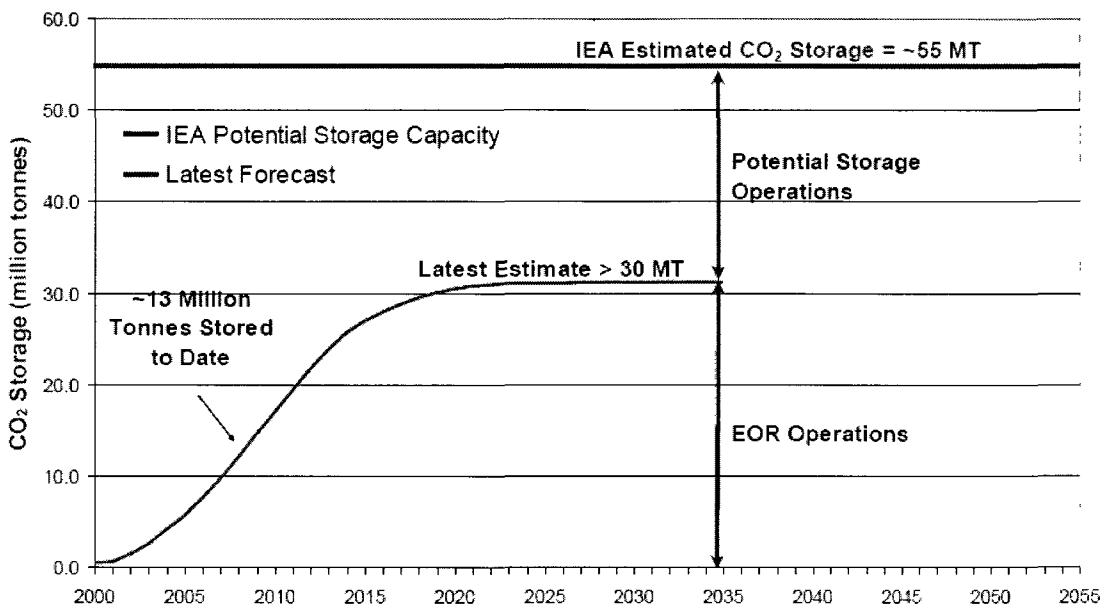
A network of medium pressure gas gathering lines transports solution gas and CO<sub>2</sub> from the production facilities to a central compression station. At the station, recycled CO<sub>2</sub> is blended with purchased CO<sub>2</sub> and is then injected into the reservoir using the CO<sub>2</sub> injection network of pipelines and wells. Compressors are electrically driven with 60% efficiency. The recompression pressure is 2500 psi. Please see Appendix A (equations A1-7 and A1-8) for calculations of CO<sub>2</sub> re-compression before re-injection into the reservoir.



**Figure 10.5 Annual storage of CO<sub>2</sub> for Weyburn and Sleipner projects**

(original in color)

Source: EnCana 2009a



**Figure 10.6 Weyburn CO<sub>2</sub> storage capacity**

(original in color)

Source: EnCana 2009a

**Table 10.2 Weyburn oil field reservoir characteristics**

Parameter	Value
Original oil in place, billion bbl	1.4
Reservoir depth, m	1,450
Field area, km <sup>2</sup>	210
Total CO <sub>2</sub> injected, MM tCO <sub>2</sub> /project life	30
Total CO <sub>2</sub> recycled, MM tCO <sub>2</sub> /project life	30 <sup>*</sup> <small>*assumption, real amount might be slightly higher</small>
Storage, %	100% <sup>*</sup> <small>*assumed that all injected CO<sub>2</sub> will be stored</small>
Expected oil recovery, MMbbl	155
Useful life, yr	30
CO <sub>2</sub> injection, yr	15

### **10.3 Crude oil refining and use of refined products**

It is assumed that extracted crude oil is transported via pipeline to a refinery in the US.

The pipeline transportation of crude oil is excluded from the analysis since its impact is less than 1%. The dataset for operations at the refinery (production of diesel, gasoline, jet fuel, light fuel oil, heavy fuel oil and kerosene) comes from Gabi4 database and is average for crude oil refining in the US. The impact of refining 1 kg of crude oil is presented in Appendix A, Table A.5.

Average US refinery yield is given in Table 10.3. It is assumed that diesel fuel is used in diesel engines with 45% efficiency. Still gas is used for the operations at the refinery.

Efficiency of motor gasoline (fuel to power) is assumed to be 30%. The impact of use stage of other petroleum products and lubricant is not accounted for due to their use for non-combustion applications. The efficiency of other products is assumed to be 30%.

Emission factors for the use stage of refined products (kg/GJ) are presented in Table 10.4.

Calculated emissions from fossil fuels use are given in Appendix A, Table A.6.

**Table 10.3 Average US refinery yield (%) in the period from 2003 to 2008**

Petroleum products	Average US refinery yield, %
Motor gasoline	46.0
Distillate fuel oil	25.0
Jet fuel	9.6
Petroleum coke	5.0
Still gas	4.2
Residual heavy fuel oil	4.0
Liquefied Refinery Gases	4.0
Naphtha for petroleum feedstock use	1.5
Lubricant	1.0
Other petroleum products	0.4
Kerosene	0.3

Source: EIA, 2009

**Table 10.4 Emission factors of different fuels (mobile application), kg/GJ**

Petroleum product	CO <sub>2</sub> , kg/GJ	N <sub>2</sub> O, kg/GJ	CH <sub>4</sub> , kg/GJ	SO <sub>2</sub> , kg/GJ	NO <sub>x</sub> , kg/GJ	VOC, kg/GJ	CO, kg/GJ
Distillate fuel oil	74	0.0042	0.0028	0.234	0.224	0.0635	0.2735
Gasoline	73	0.0024	0.0342	0.005	0.861	1.1558	6.8344
Jet fuel	72	0.002	0.0045	0.005	0.292	0.0419	0.2061
Refinery gas	56.9	0.001	0.004	0	0.06	0.004	0.0130
Heavy fuel oil, marine	74	-	0.04	0.45	0.2	0.36	0.0074

# **11. LIFE CYCLE ASSESSMENT RESULTS**

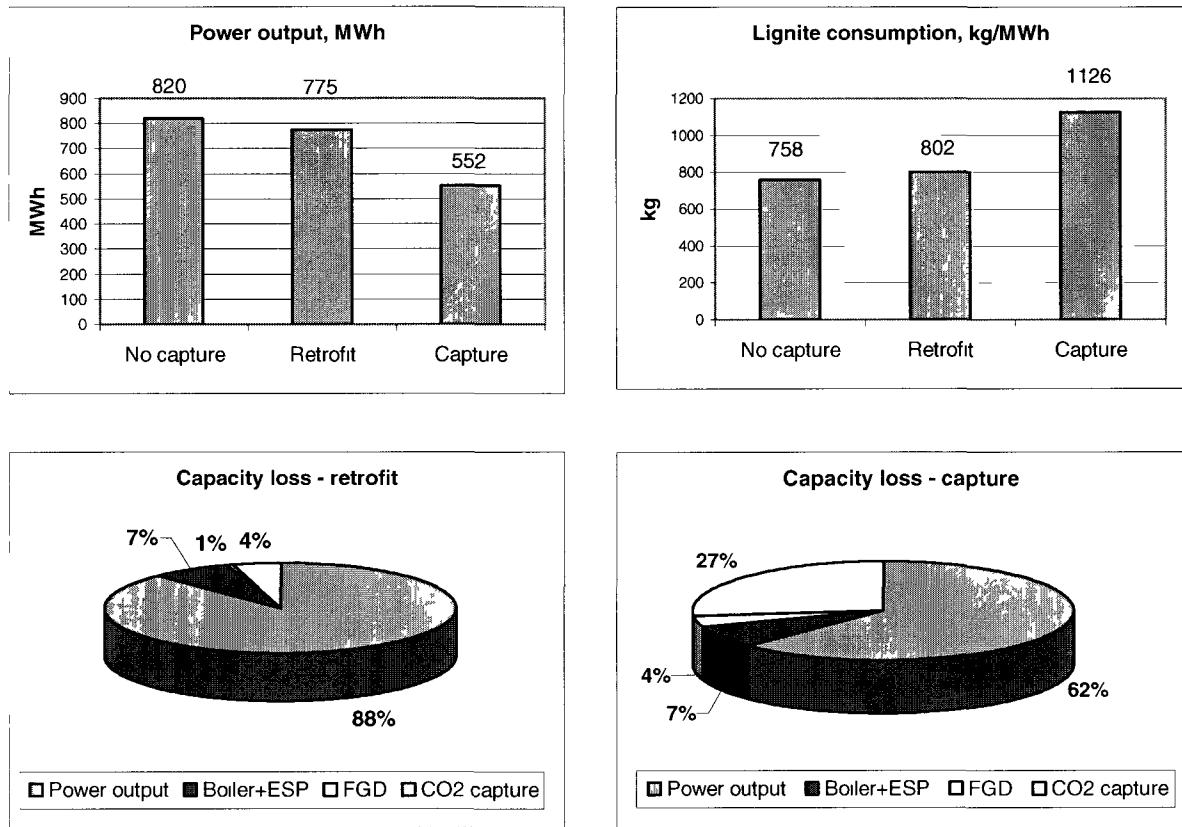
## **11.1 Power plant**

The results of environmental impacts from power plant with and without capture are presented in this chapter. Since the focus of this work was on power plant operations with and without capture, the results for power plant are presented per functional unit of MWh of electricity produced and delivered to the grid. Three scenarios are reviewed:

1. Power plant without capture (hereafter called “no capture”);
2. Retrofit of only one 150 MW unit (Unit 3) with FGD and CO<sub>2</sub> capture (hereafter called “retrofit”). The rest of units remain unchanged; and
3. Power plant with FGDs and CO<sub>2</sub> capture on all six units (hereafter called “capture”).

The power output for three scenarios is presented in Figure 11.1a. As it is shown, there is a 5.5% decrease in power output in Retrofit scenario and 33% decrease in Capture scenario compared to power output from power plant without capture.

In order to compensate for loss in power, additional coal may be burned. The Figure 11.1b demonstrates how much additional coal is needed to compensate for power loss in Retrofit and Capture scenarios. As it is shown, 5.8% extra coal is needed for Retrofit and 48.6% for Capture scenarios.



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**Figure 11.1 (a) Net power output; (b) lignite consumption to compensate for power loss; capacity loss in (c) retrofit and (d) capture scenarios; (e) and (f) global warming potential, GWP for different scenarios**

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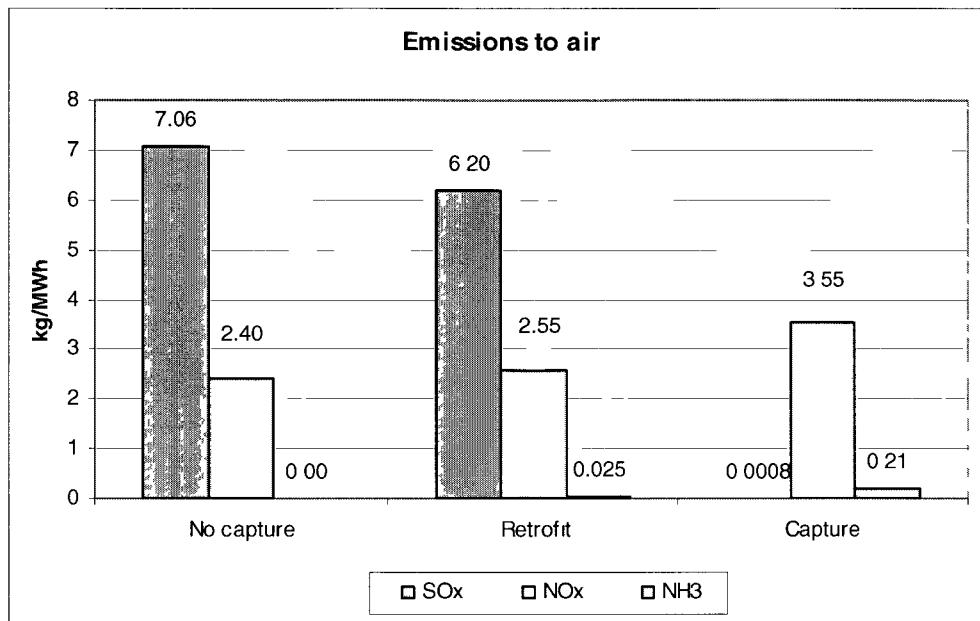
Auxiliary power requirement for each unit at the power plant is presented in Figures 11.1c and 11.1d. Current operations at the BDPS (boilers and ESPs) consume approximately 7% of total plant power output. If FGD and CO<sub>2</sub> capture is added on one unit, additional 5% of plant power output is lost. If CO<sub>2</sub> capture is installed on all 6 units of the power plant, 38% of the total plant power output is required. It should be noted that auxiliary power requirement for CO<sub>2</sub> capture also includes power needed for CO<sub>2</sub> compression.

Global warming potential (GWP) is reduced by 9.6% in case of retrofit scenario and by 80.5% in capture scenario (Figure 11.1e)<sup>7</sup>. The overview of GHG emissions from coal mining, power plant construction and plant operations for capture scenario is given in Figure 11.1f. As it is shown, 74% of GHG emissions come from power plant operations and 26% from coal mining. Impact of power plant construction is minimum. The picture is quite different in case of no capture scenario: 97% of GHG emissions originate from power plant operations and only 3% from coal mining. The substantial percentage increase in coal mining GHG emissions is due to increase in coal consumption by almost 50% in capture scenario and decrease in GHG emissions from power plant operations due to 90% CO<sub>2</sub> capture.

Emissions to air (SO<sub>x</sub>, NO<sub>x</sub> and ammonia) are shown in Figure 11.2. As it can be seen from the Figure, SO<sub>x</sub> emissions are reduced due to FGD installation. However, amount of NO<sub>x</sub> emissions increased per MWh of electricity to the grid due to increase in auxiliary power requirements.

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<sup>7</sup> Note: hereafter all data is presented per net power output to the grid unless mentioned otherwise.



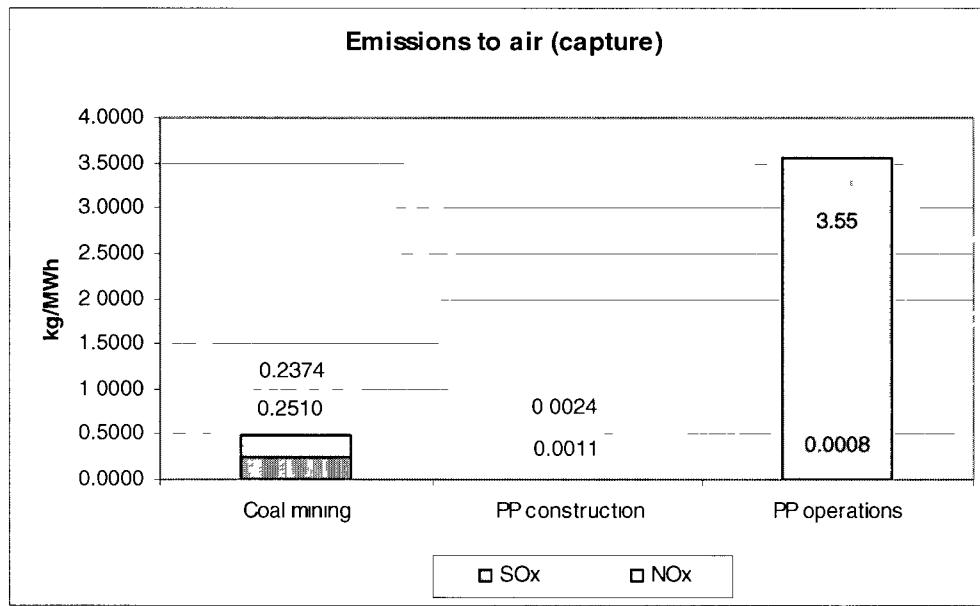
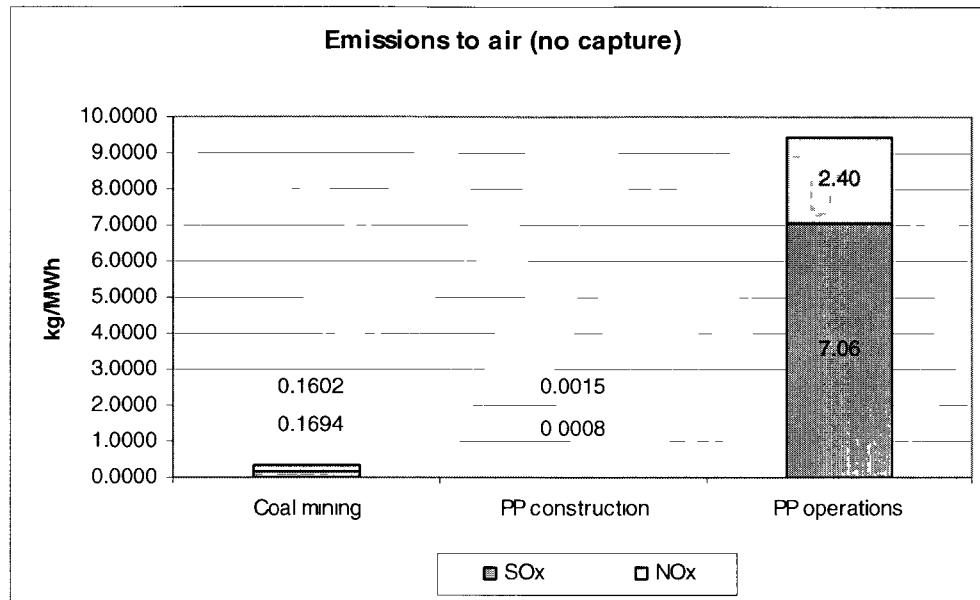
**Figure 11.2 SO<sub>x</sub>, NO<sub>x</sub> and NH<sub>3</sub> emissions to air from power plant**

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Figure 11.3 shows SO<sub>x</sub> and NO<sub>x</sub> emissions to air from different life cycle stages (i.e. coal mining, power plant construction with and without CO<sub>2</sub> capture unit and power plant operations) in no capture and capture scenarios. As it is shown in the Figure 11.3, SO<sub>x</sub> and NO<sub>x</sub> emissions from coal mining increased in the capture scenario due to the additional coal mining required to sustain power plant capacity.

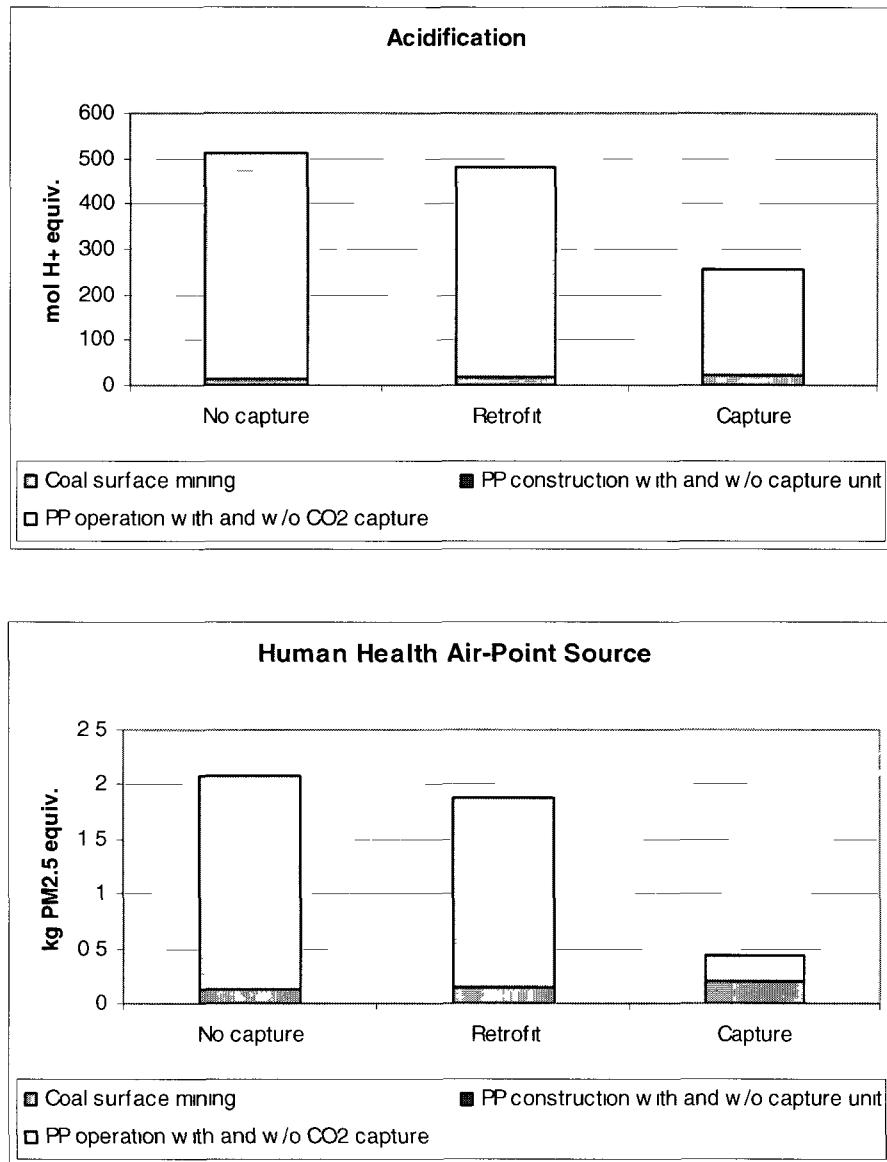
The US EPA's TRACI life cycle impact assessment methodology was applied to analyze environmental impacts of CO<sub>2</sub> capture at the power plant. Results are presented per MWh of electricity delivered to the grid. The results are shown in Figures 11.4 -11.11.

The decrease in acidification potential (6% in retrofit scenario and 50% in capture scenario) is mainly due to SO<sub>x</sub> removal in FGD. As it was mentioned earlier, post-combustion CO<sub>2</sub> capture process using MEA is very sensitive to SO<sub>x</sub> in the flue gas; therefore, an FGD needs to be installed prior to CO<sub>2</sub> capture. The observed decrease in the human health air-point source impact category (9.6% in retrofit and 79% in capture scenario) is due to reduction of primary particulates (total suspended particulates or PM10 and PM2.5) and SO<sub>x</sub> emissions (which lead to the formation of so-called secondary particulate sulfate) release due to the FGD and CO<sub>2</sub> capture unit installation.



**Figure 11.3  $\text{SO}_x$  and  $\text{NO}_x$  emissions to air from coal mining and power plant construction and operations with and without  $\text{CO}_2$  capture**

(original in color)



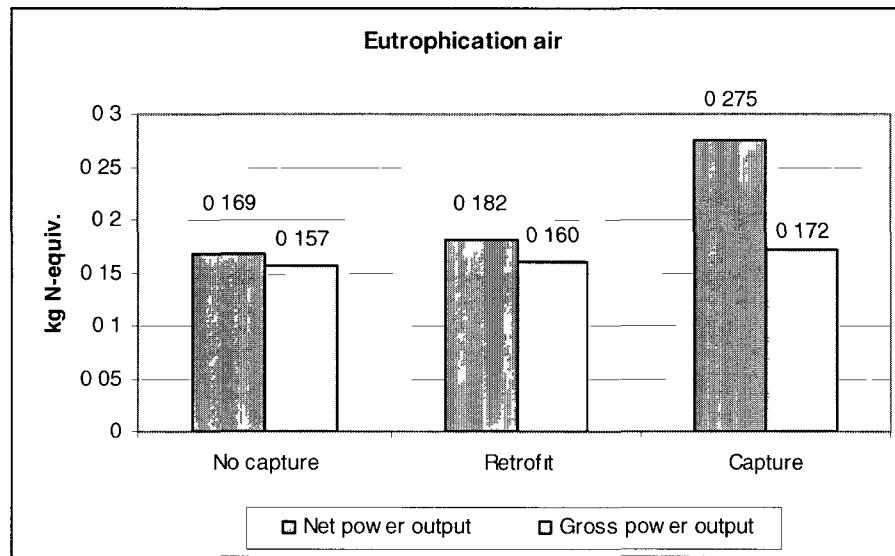
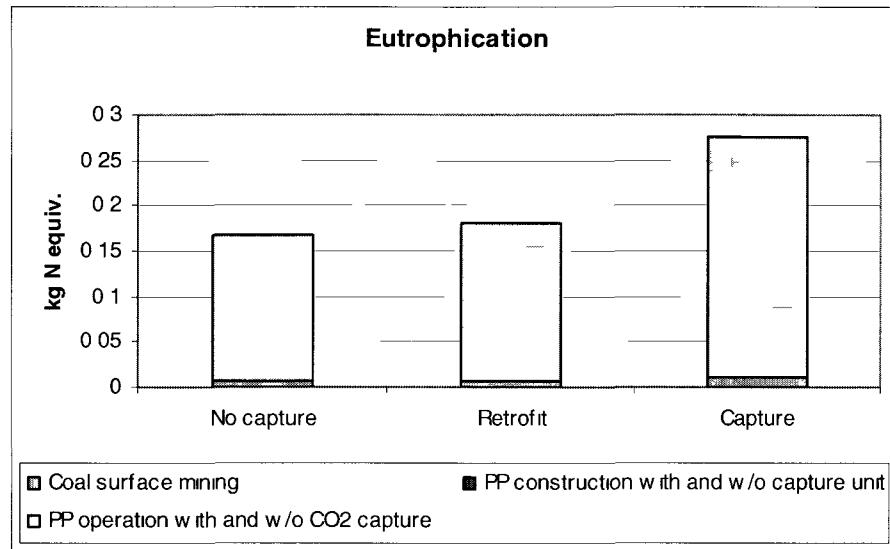
**Figure 11.4 Acidification Air and Human Health Air-Point Source impacts from coal mining and power plant construction and operations**

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Eutrophication is caused by release of nutrients, such as nitrogen compounds ( $\text{NO}$ ,  $\text{N}_2\text{O}$ ,  $\text{NO}_2$ ,  $\text{NH}_3$ ). The observed increase in eutrophication air impact category is 7.7% in retrofit and 63% in capture scenarios (Figure 11.5a). As it was already shown in Figure 11.2,  $\text{NO}_x$  emissions per net electricity to the grid from power plant operations increased due to addition of capture unit (mainly due to the loss in plant capacity). Ammonia ( $\text{NH}_3$ ) and MEA emissions releases, as well as ethylene emissions from production of MEA also contribute to the increase in eutrophication potential. The eutrophication impact category was investigated further in order to show an impact of the capture unit addition. The results per gross energy output from the power plant are presented in Figure 11.5b. The increase in eutrophication air impact category calculated per gross power output is 1.8% in retrofit and 9.9% in capture scenarios. This increase is due to  $\text{NH}_3$  and MEA emissions from capture unit and ethylene emissions from MEA production.

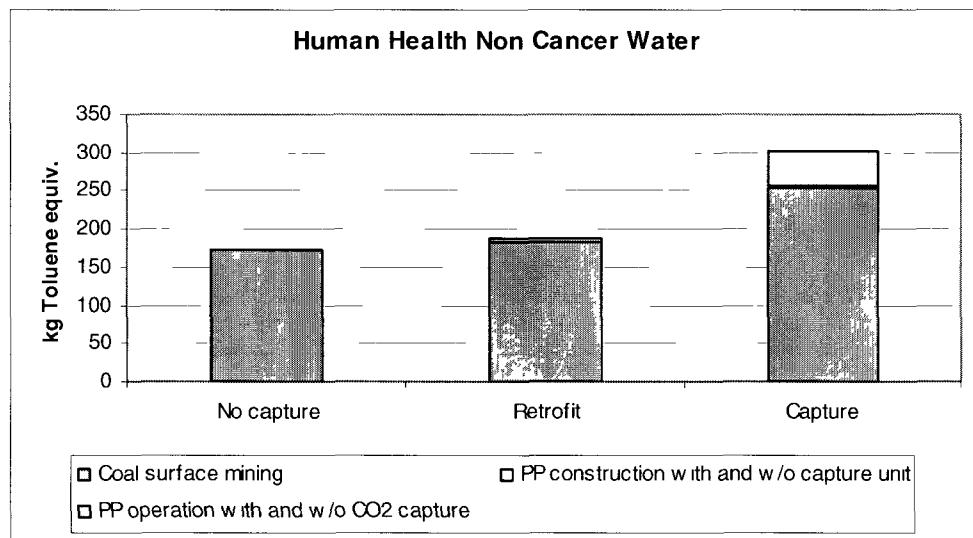
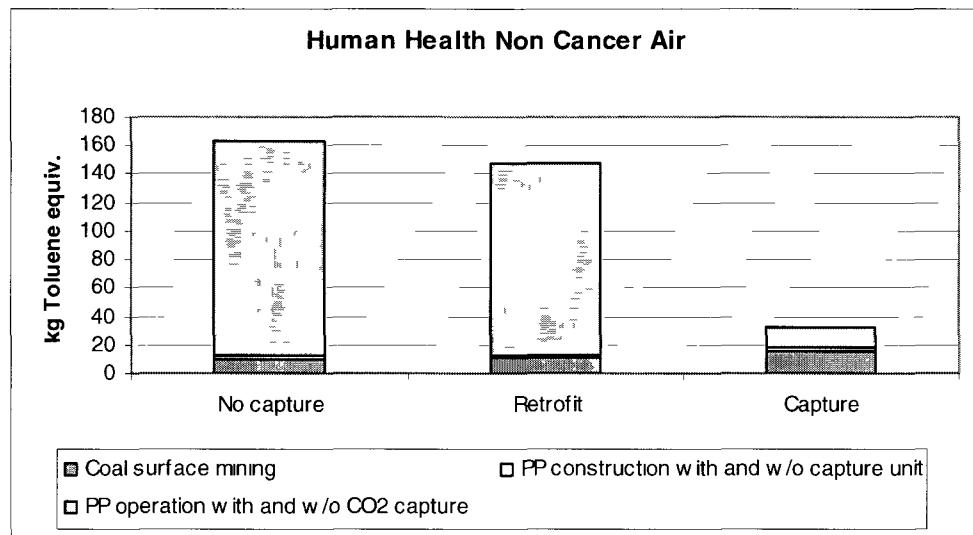
The significant increase is also observed in the eutrophication water impact category (Figure 11.7a). It is 84% in retrofit and 685% in capture scenarios.

Human health non cancer air impacts and human health cancer air (caused by release of heavy metals, VOCs and different inorganic emissions to air) originate mainly from power plant operations (Figure 11.6a and 11.10b). The decrease noticed in these impact categories is approximately 10% in retrofit and 80% in capture scenarios. The decrease in human health non cancer air impact category is due to retention of heavy metals in FGD and  $\text{CO}_2$  capture unit. Heavy metals release to the atmosphere is reduced significantly with introduction of  $\text{SO}_2$  and  $\text{CO}_2$  capture.



**Figure 11.5 Eutrophication Air impacts from coal mining and power plant construction and operations per (a) net and (b) net and gross power output from the plant**

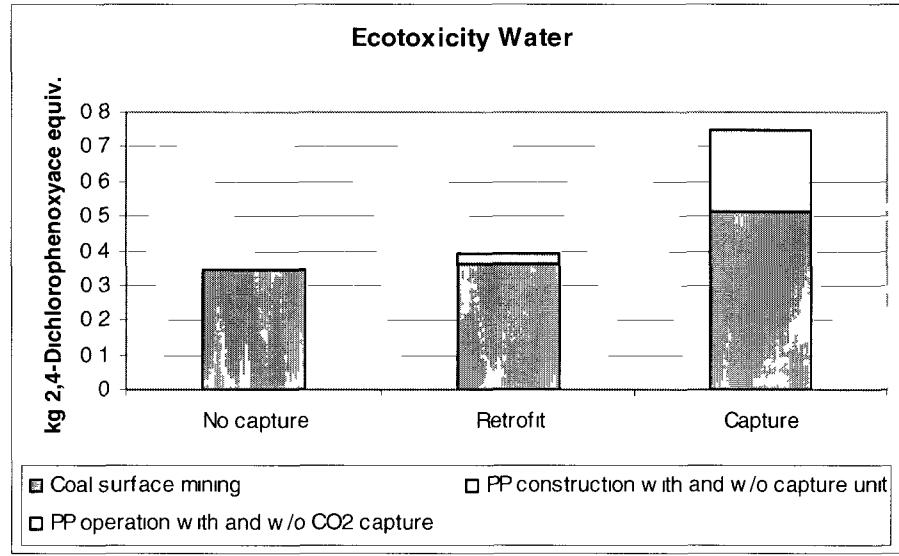
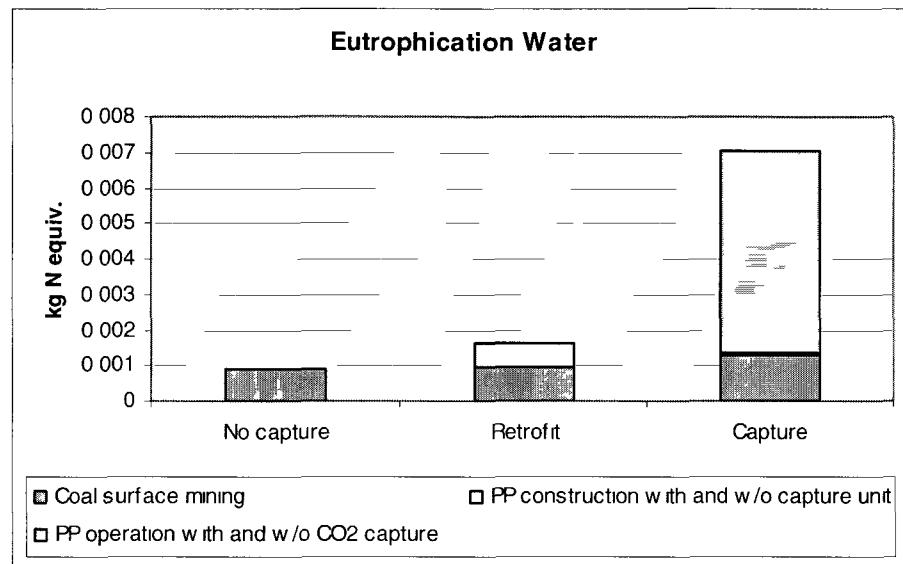
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**Figure 11.6 Human Health Non Cancer Air and Human Health Non Cancer Water**

**impacts from coal mining and power plant construction and operations**

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**Figure 11.7 Eutrophication Water and Ecotoxicity Water impact from coal mining and power plant construction and operations**

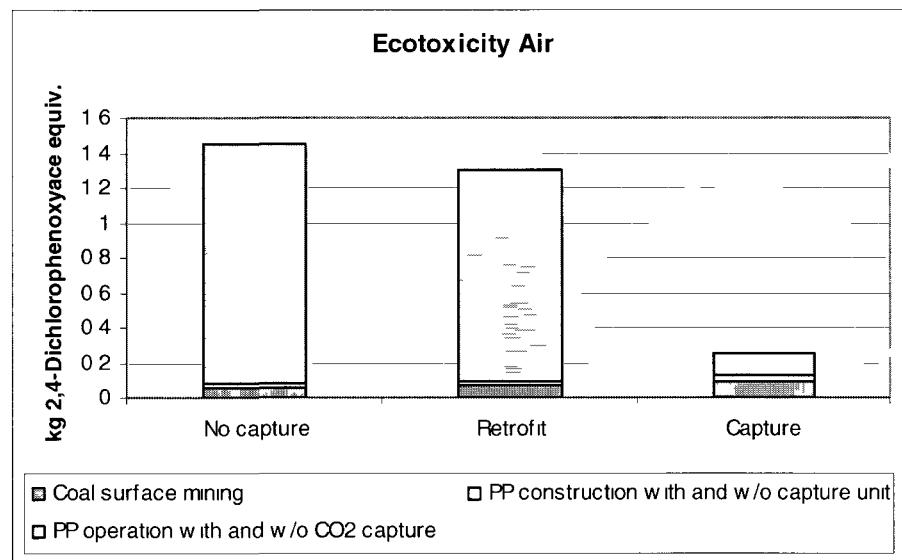
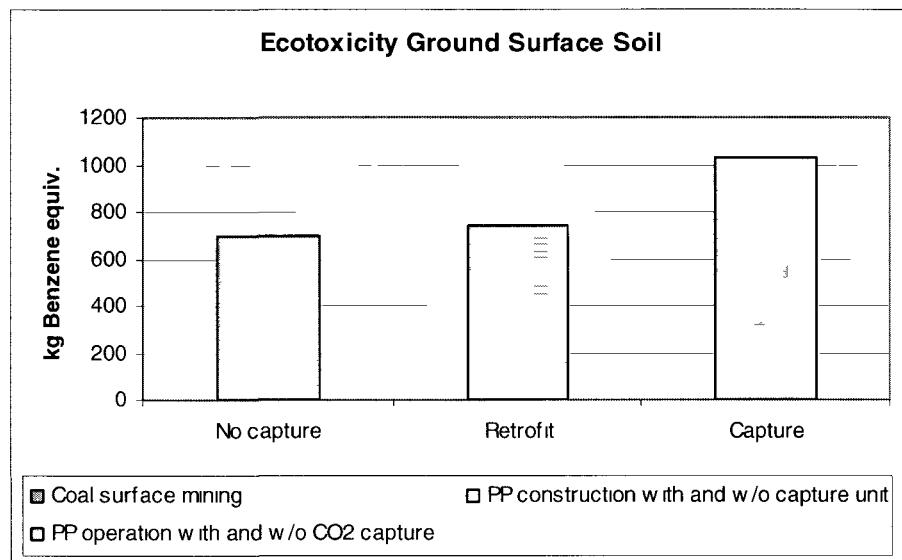
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The impacts in ecotoxicity water and human health non cancer water categories originate mainly from coal mining (Figures 11.6b and 11.7b). The increase in human health non cancer water impact category is 9% in retrofit and 75.5% in capture scenarios. The increase in ecotoxicity water impact category is 14% in retrofit and 117% in capture scenarios. This increase is mainly due to heavy metals removal from the flue gas stream in scrubbing operations during CO<sub>2</sub> capture.

The majority of trace elements leave the power plant with the boiler bottom ash. The main fraction of trace elements in the flue gases that come out from the boiler is captured in ESP (trace metals removal efficiency in ESP is about 80-90% depending on a trace metal); thus, this fraction also ends up in the bottom ash. The removal efficiencies of trace metals across FGD system are also high (60-90% depending on a trace metal). Almost 80% of heavy metals that remain in the flue gas after FGD can be eliminated by in-line mist eliminators during regeneration.

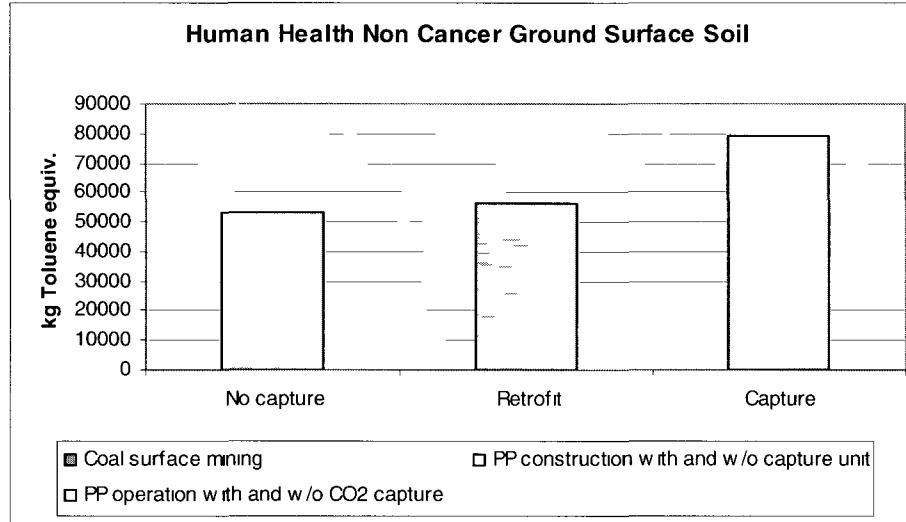
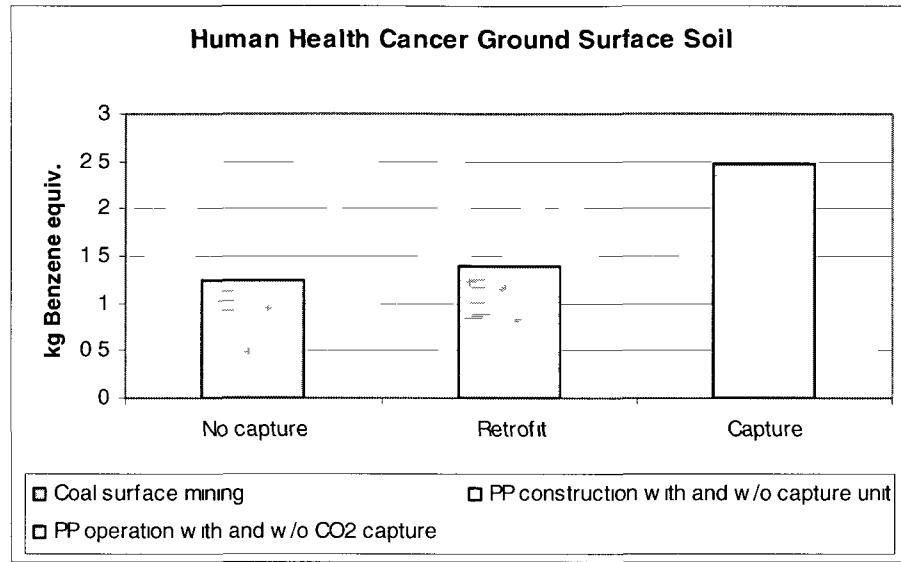
The trace elements from bottom ash will eventually leak to the soil and then to the groundwater when landfilled. Thus, an increase in the ecotoxicity ground surface soil, human health cancer ground surface soil and human health non cancer ground surface soil impact categories is observed (Figures 11.8a, 11.9a and 11.9b).

The percentage change (from no capture scenario) in environmental impacts categories for retrofit and capture scenarios is shown in Figure 11.12.



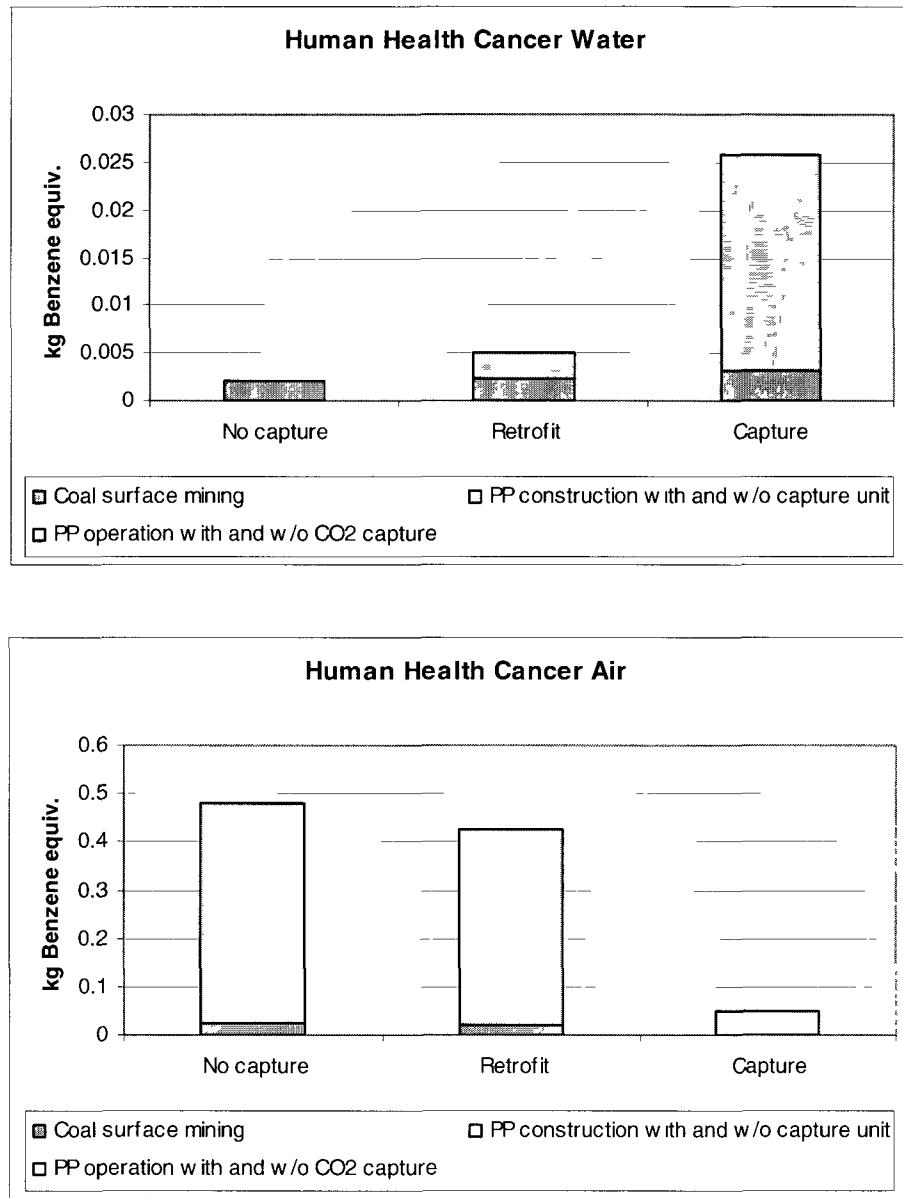
**Figure 11.8 Ecotoxicity Ground Surface Soil and Ecotoxicity Air impacts from coal mining and power plant construction and operations**

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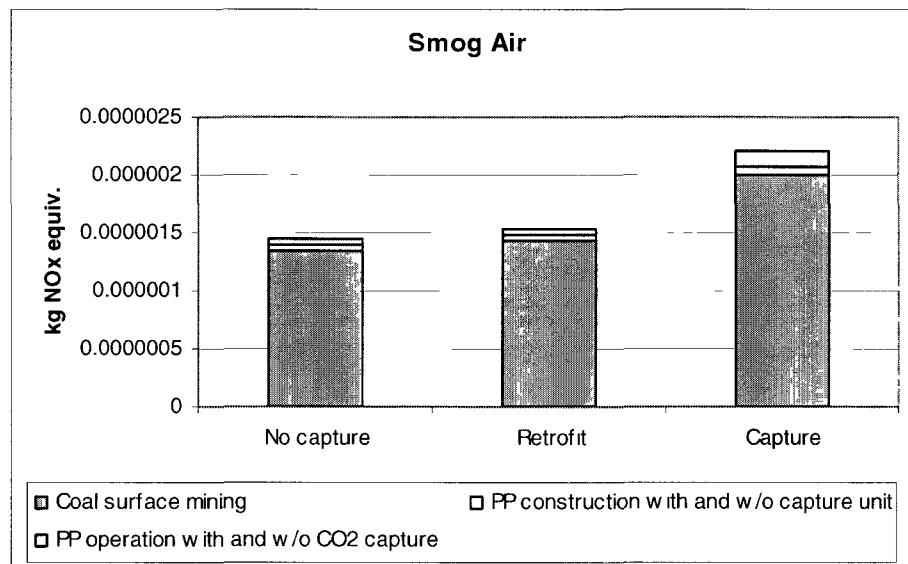
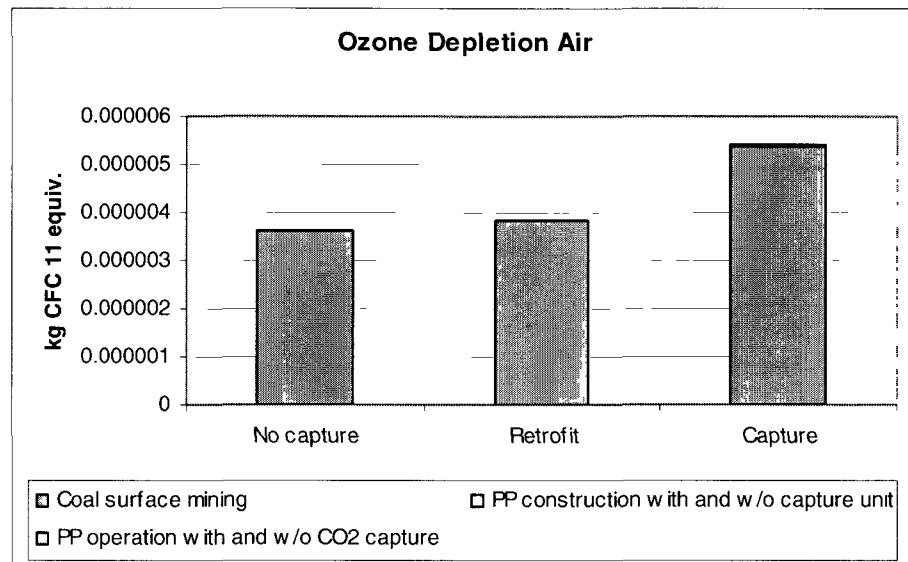
**Figure 11.9 Human Health Cancer Ground Surface Soil and Human Health Non Cancer Ground Surface Soil impacts from coal mining and power plant construction and operations**

(original in color)



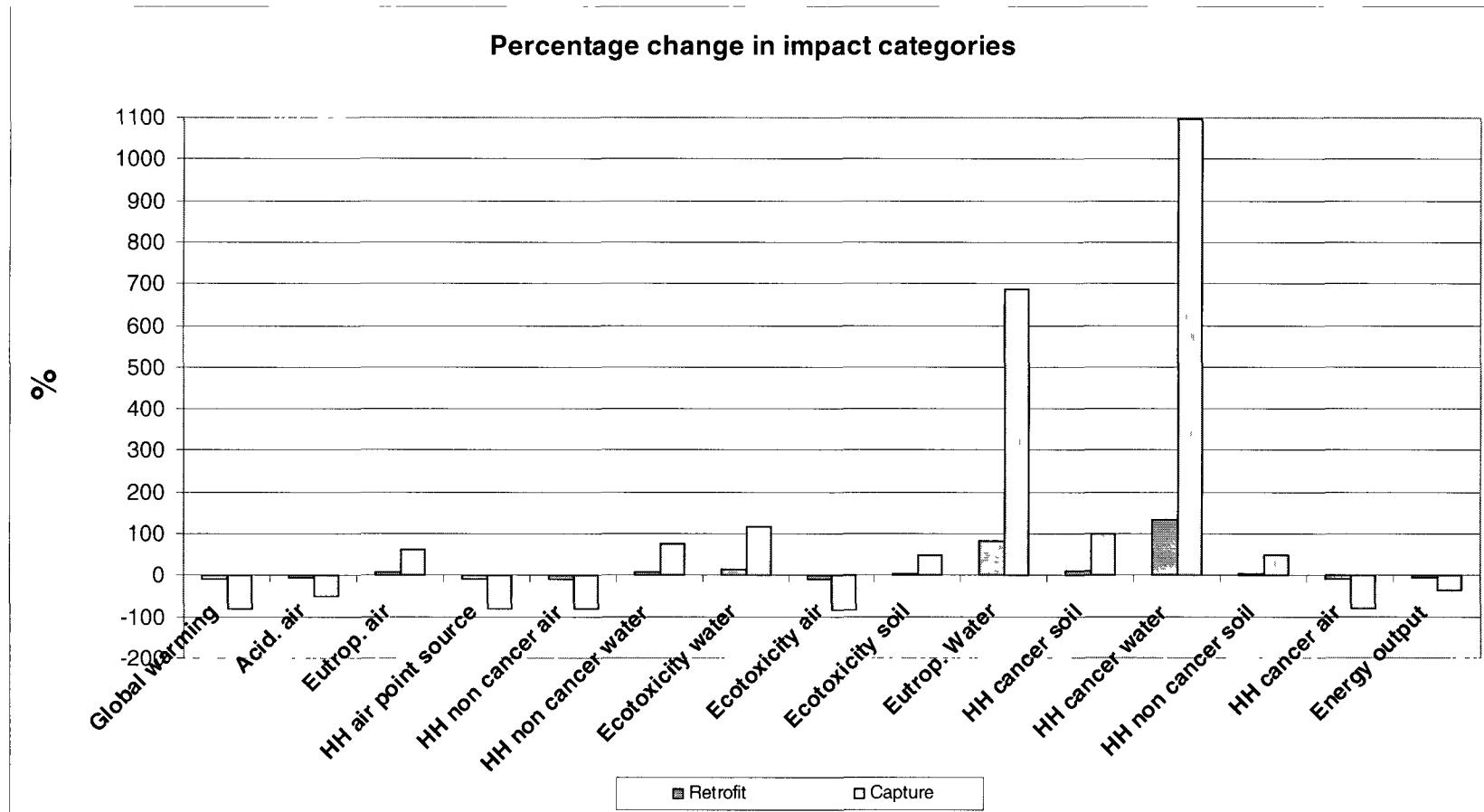
**Figure 11.10 Human Health Cancer Water and Human Health Cancer Air impacts from coal mining and power plant construction and operations**

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**Figure 11.11 Ozone Depletion Air and Smog Air impacts from coal mining and power plant construction and operations**

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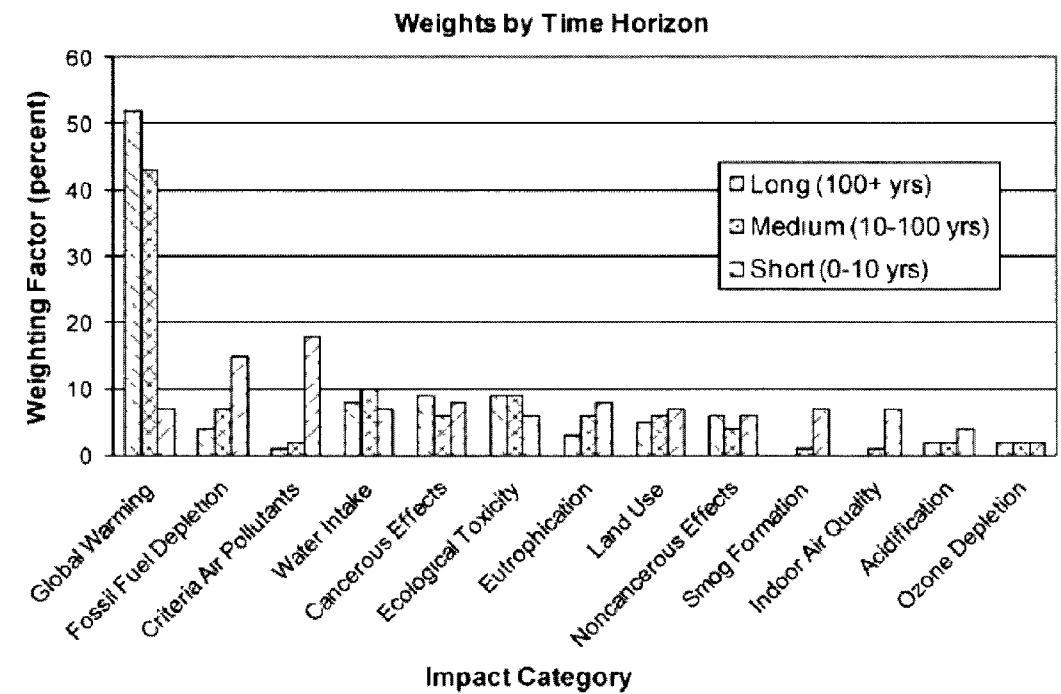
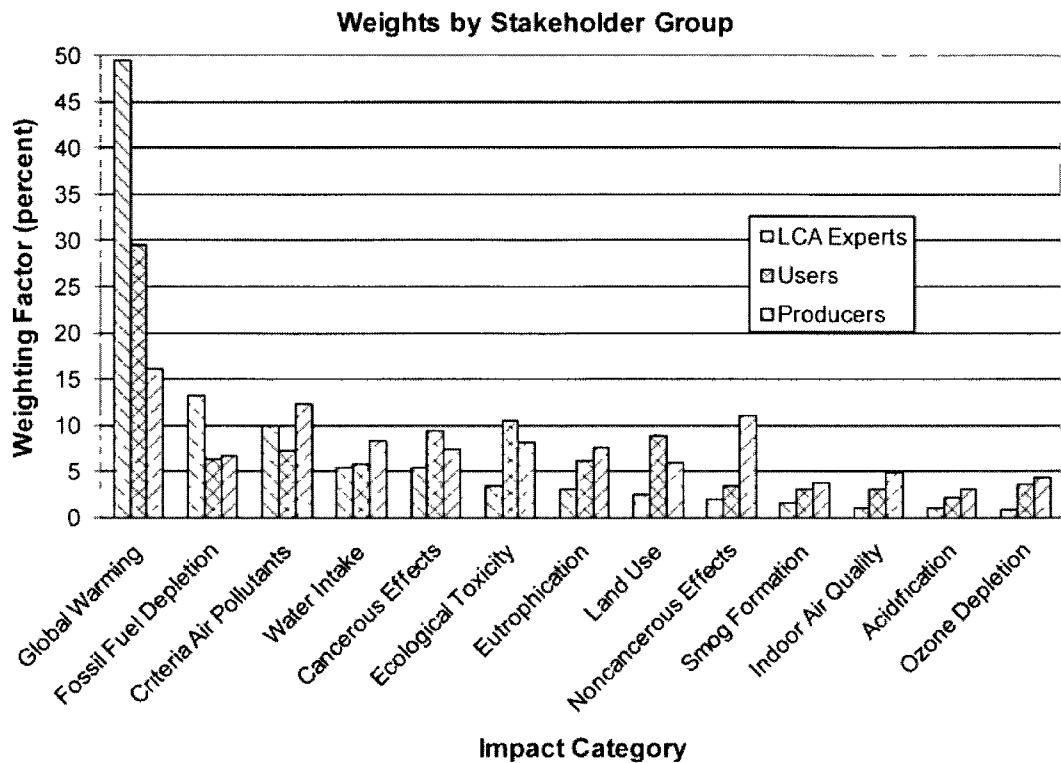
**Figure 11.12 Percentage change in environmental impact categories for retrofit and capture scenarios**

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The significance of environmental impacts categories should be discussed here. What is more important: a decrease in GWP and air pollutants or an increase in eutrophication and eco-and human water and soil toxicity impact categories? No final conclusion can be made from the results presented above (Figures 11.1-11.11), as not all the effects are considered to be of equal importance. In order to estimate the importance of each of the environmental impact category, a weighting factor representing the relative importance of the effect should be used. This is usually done in the optional steps of LCA called normalization and weighting. During the normalization step of LCA the calculation of different impact scores relative to a reference value(s) is performed. The produced results are aggregated in the weighting step.

The TRACI LCIA methodology applied in this study does not employ the normalization and weighting steps. Thus, the results of Gloria et al. 2007 study are used here to estimate the relative importance of impact categories. The weight set in Gloria et al. 2007 study was created by a multi-stakeholder panel. It represents a synthesis of panelists' perspectives on the relative importance of each environmental impact category. The relative importance of impact categories by stakeholder group and by time horizon are presented in Figures 11.13a and 11.13b, respectively.

As it can be seen from the Figures 11.9, the global warming was selected as most important impact category. The LCA practitioners ranked it much higher compared to the LCA users and producers. However, decisions cannot be made only on the basis of this impact category.



**Figure 11.13 Environmental impact importance (a) by stakeholder group and (b) by time horizon**

Other impact categories in the order of relative importance are fossil fuel depletion, criteria air pollutants, water use, human health cancerous effects, ecotoxicity, eutrophication, land use, and human health noncancerous effects. The lowest weights were assigned to the smog formation, acidification and ozone depletion impact categories.

In this study, with a decrease of global warming due to CO<sub>2</sub> capture we also decrease various air pollutants both cancerous and non cancerous. The environmental impact is shifted to other environmental compartments – soil and water. The solid waste can be safely stored at the industrial waste landfill with a minimum impact on the environment. The water stream from power plant is usually well treated before the release to the environment, thus minimizing impact on the environment. Applying the weighting factors presented above to the results of this study, the conclusion can be made that the decrease in global warming potential and air pollutants impact categories due to SO<sub>2</sub> removal and CO<sub>2</sub> capture is weighted more important than the increase in impact categories affecting water and soil environmental compartments. However, it should be noted that CO<sub>2</sub> capture substantially decreases power output from the plant (by 5.5% in retrofit and 33% in capture scenarios) and thus, increases coal consumption by almost 50% in capture scenario. Fossil fuel depletion category is weighted second high among the stakeholders after the global warming impact category. Thus, the development of efficient SO<sub>2</sub> and CO<sub>2</sub> capture technologies should be encouraged, as well as gradual substitution of coal with natural gas or renewable sources of energy.

## **11.2 Carbon Capture and Storage life cycle results**

This chapter presents results of the full life cycle of carbon capture and storage. This includes coal mining, power plant with and without CO<sub>2</sub> capture construction and operations, CO<sub>2</sub> pipeline transport, EOR operations at the oil field, operations at the refinery and use of refined products.

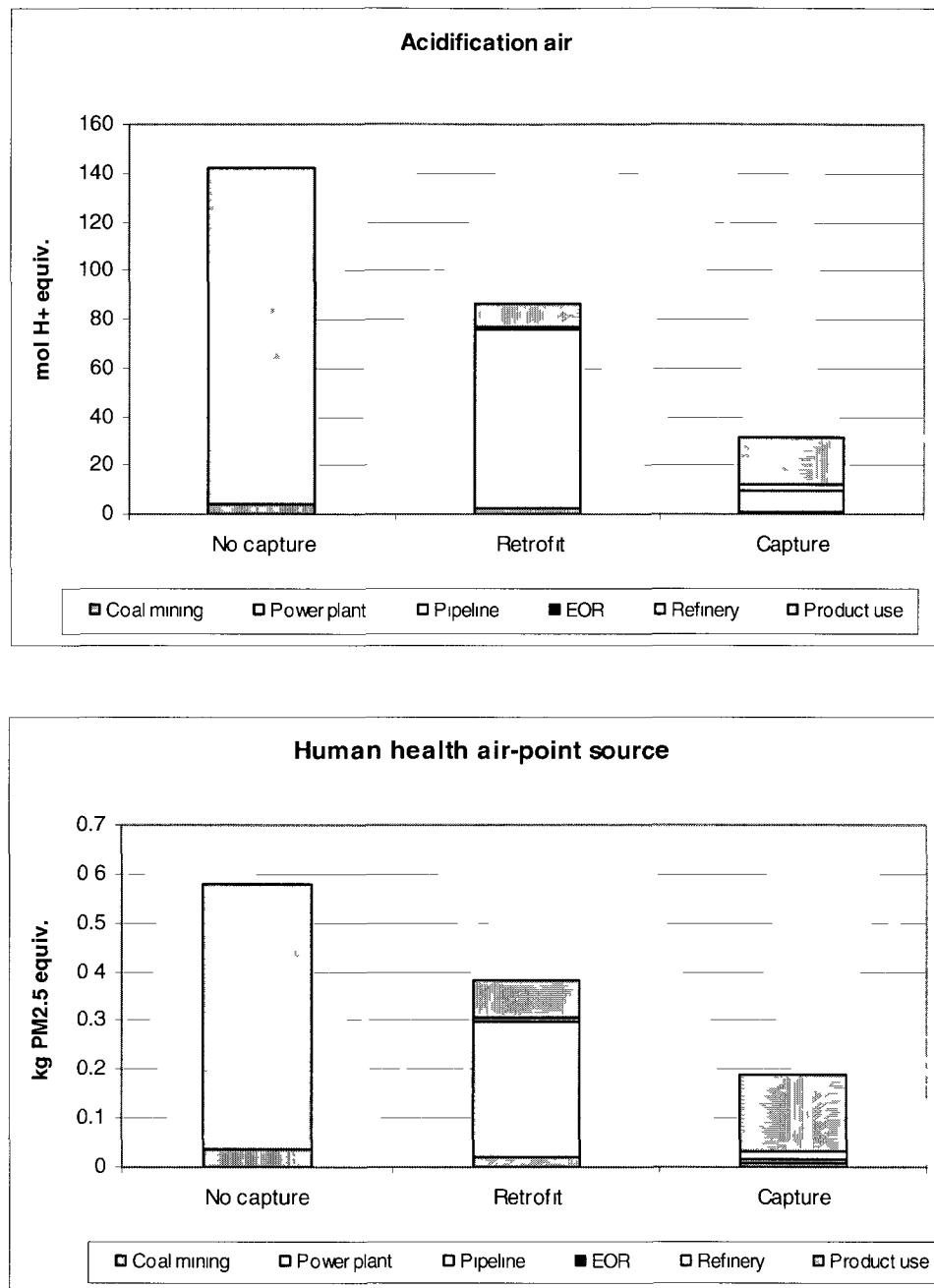
One of the goals of this study is to evaluate environmental performance of CCS as a process. Thus, the common functional unit of GJ of energy produced in an average year from the whole life cycle of CCS is chosen. The choice of functional unit was directed by outputs of two systems: electricity production at the power plant in MWh and crude oil production from CO<sub>2</sub>-EOR in barrels of crude oil.

The total environmental impacts over the life cycle of CCS were normalized to GJ using the total amount of energy produced over the life time from all the processes (e.g. electricity from power plant and crude oil from EOR operations) in different scenarios.

It should be noted that in case of no capture scenario the total energy output results only from the power plant operations. However, in retrofit and capture scenarios the total energy output is a sum of energy produced from the power plant and energy contained in the crude oil products.

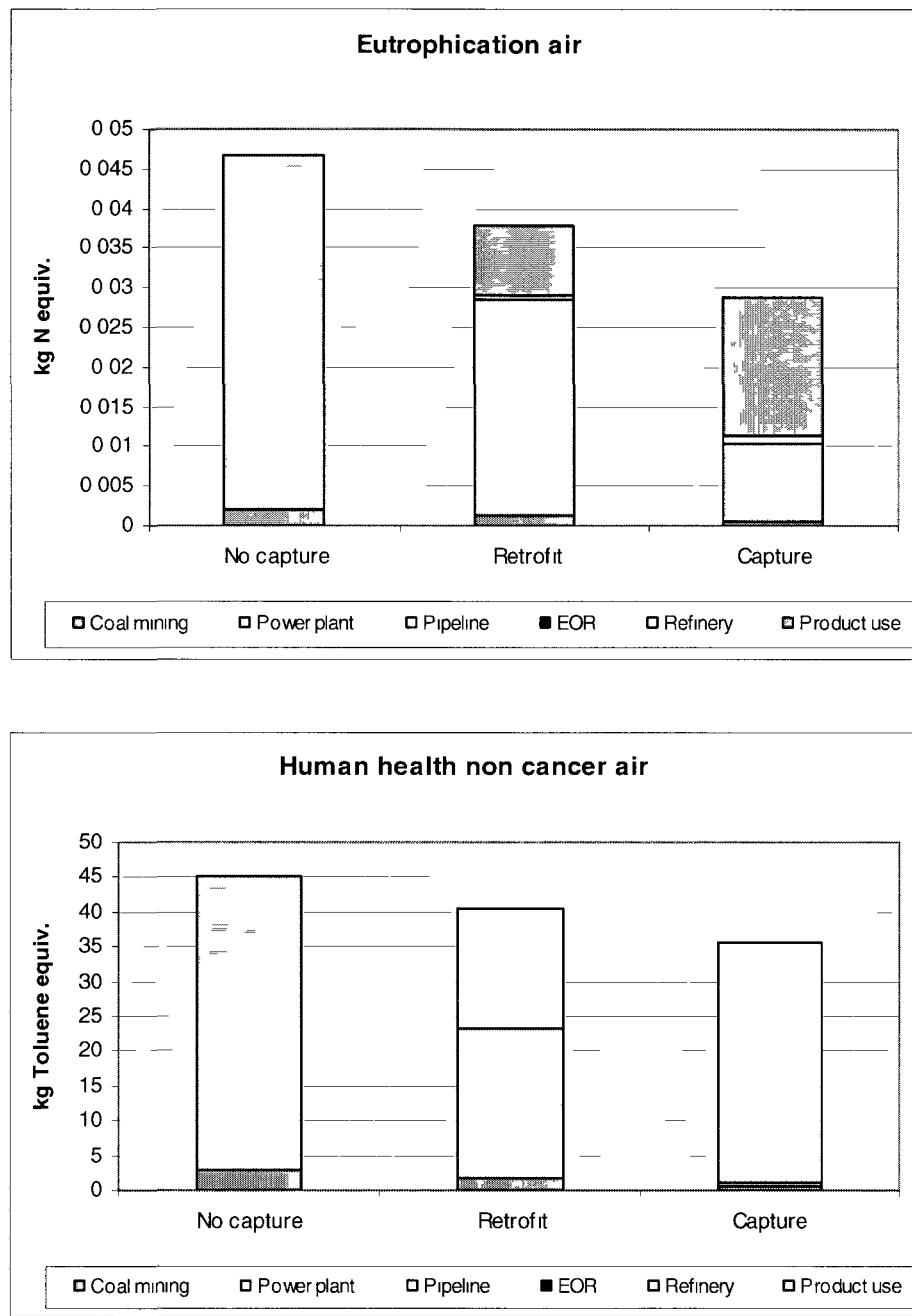
Figure 11.14 shows environmental impacts of CCS in acidification air and human health air-point source impact categories. There is a decrease in impact in retrofit and capture scenarios observed. As it was shown in the previous chapter (environmental impact of the power plant), these two categories have also shown a decrease in the environmental impact compared to the business as usual scenario. If impact of a full life cycle of CCS is taken into account, there is a 39% decrease in retrofit and 78% decrease in capture scenarios in the acidification air impact category and 34% decrease in retrofit and 68% in capture scenarios in human health air-point source impact category. The impacts in no capture and retrofit scenarios originate mainly from power plant operations. In case of capture scenario, impacts come mainly from product use stage (nitrogen and sulphur oxides emissions to the atmosphere from fuel combustion).

The decrease (19% in retrofit and 38% in capture scenarios) in eutrophication air impact category was also observed (Figure 11.15). The impact originates from power plant operations and product use life cycle stages (e.g. NO<sub>x</sub> emissions from the product use stage).



**Figure 11.14 Acidification Air and Human Health Air-Point Source impacts from carbon capture and storage**

(original in color)



**Figure 11.15 Eutrophication Air and Human Health Non Cancer Air impacts from carbon capture and storage**

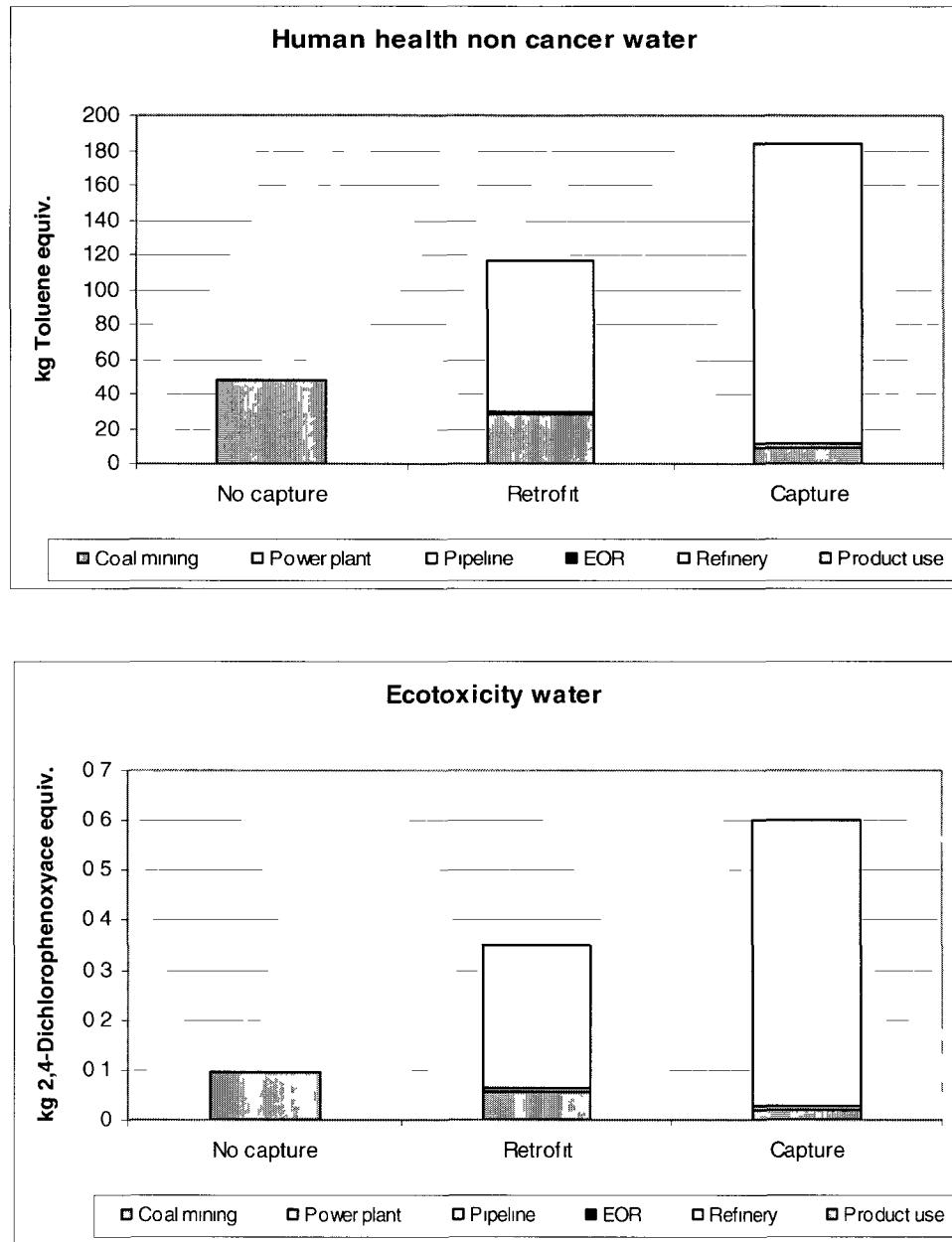
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As it was mentioned in the previous chapter, the human health non cancer air and ecotoxicity air impacts are caused by release of heavy metals and different organic compounds to the atmosphere. Figures 11.15 and 11.17 show that impact in these categories mainly originates from power plant and refinery operations. The main contributors here are heavy metals and VOC.

The impacts in human health non cancer water and ecotoxicity water originate mainly from coal mining and refinery operations (Figure 11.16). A significant increase in these impact categories is observed from no capture to capture scenarios.

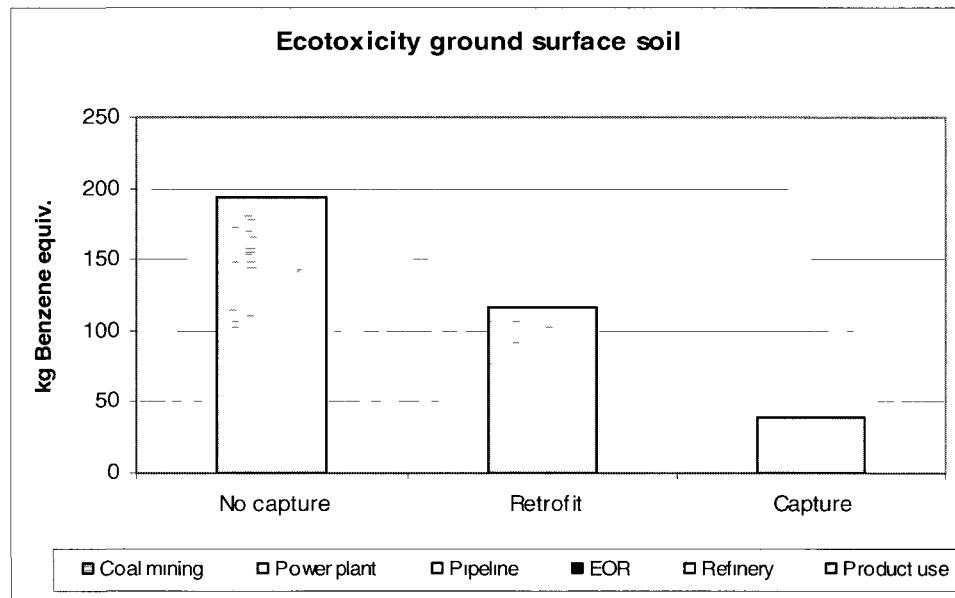
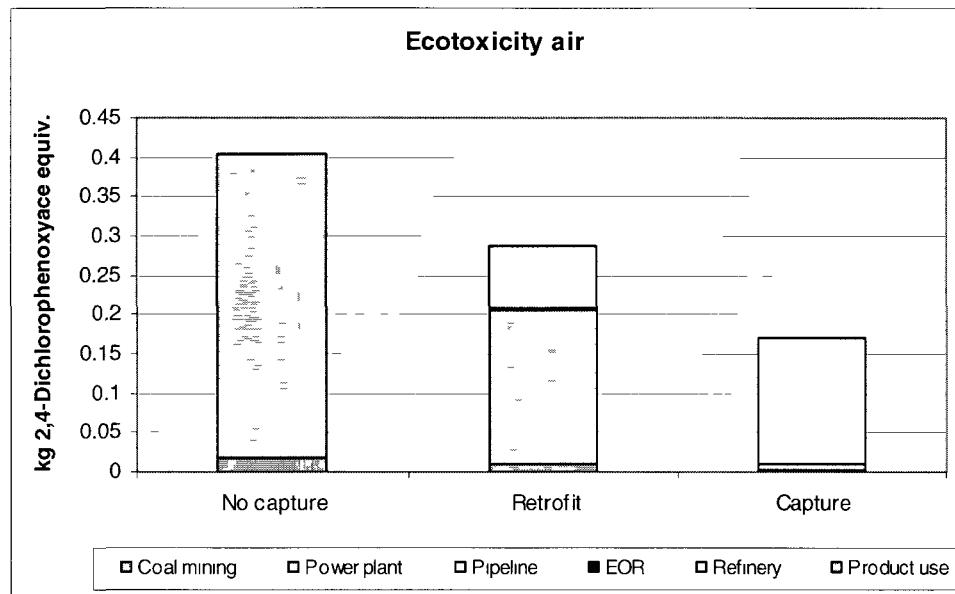
Ecotoxicity ground surface soil and human health cancer ground surface soil impacts originate solely from power plant operations (Figures 11.17 and 11.18). The decrease is noticed in these impact categories from no capture to capture scenarios.

Human health cancer water and eutrophication water impact categories showed an increase in impact from no capture to capture scenarios (Figure 11.18 – 11.19). The eutrophication water impacts are caused by the release of nutrients (such as nitrogen compounds NO, N<sub>2</sub>O, NO<sub>2</sub>, NH<sub>3</sub>) to the fresh and/or sea water. Figure 11.18 shows that impacts in eutrophication water impact category originate primarily from the coal mining, power plant and refinery. The increase in eutrophication water potential from business as usual scenario in retrofit and capture scenarios are 82% and 162%, respectively.



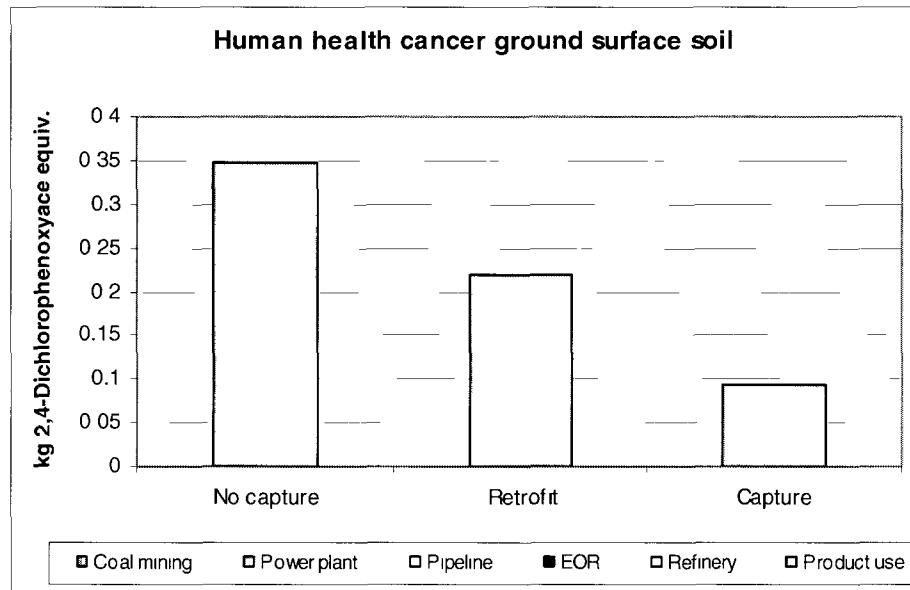
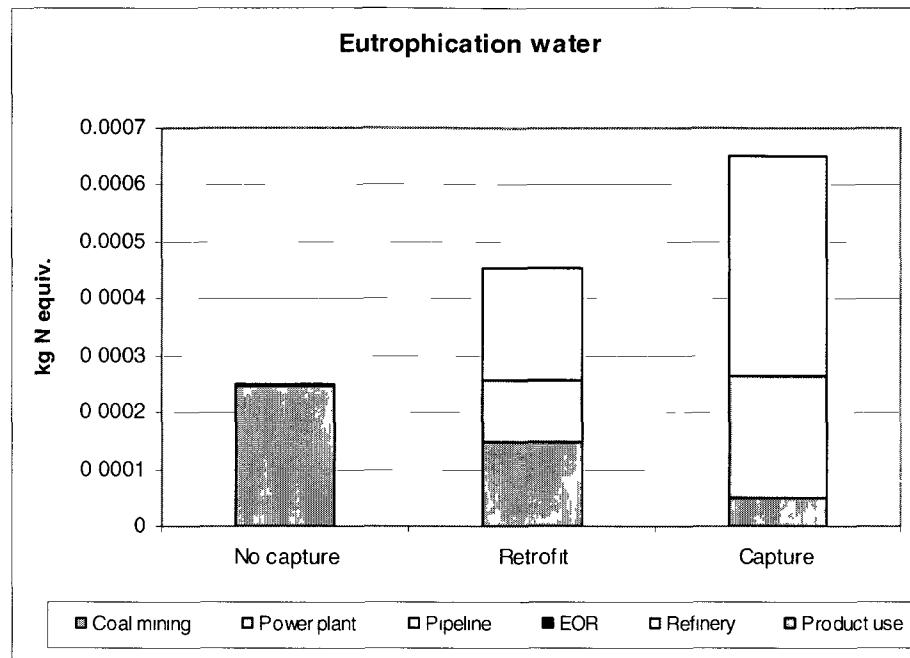
**Figure 11.16 Human Health Non Cancer Water and Ecotoxicity Water impacts from carbon capture and storage**

(original in color)



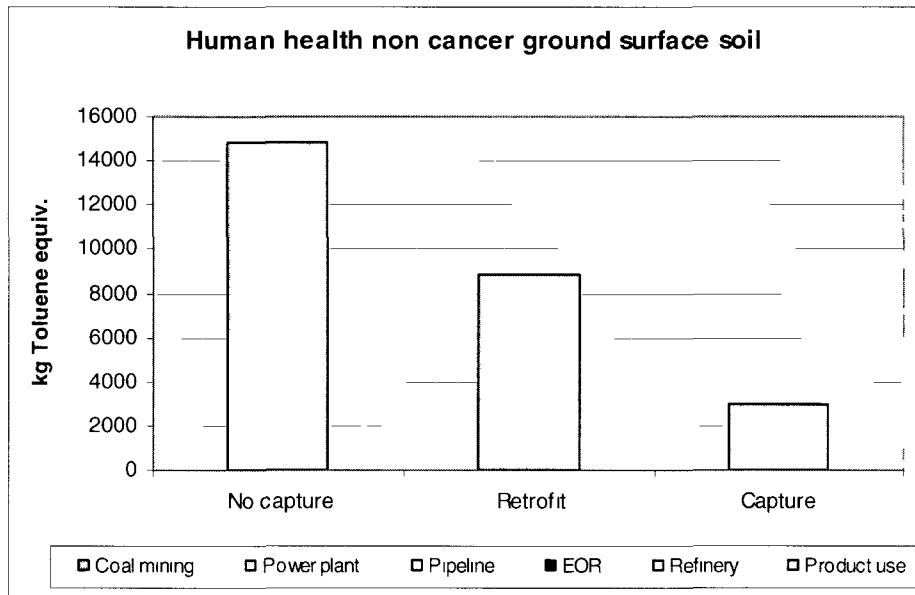
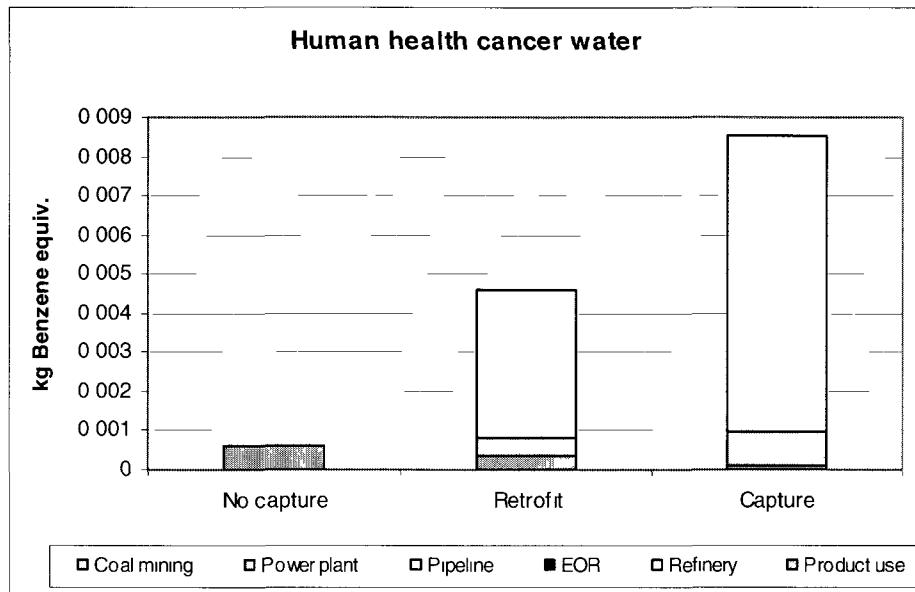
**Figure 11.17 Ecotoxicity Air and Ecotoxicity Ground Surface Soil impacts from carbon capture and storage**

(original in color)



**Figure 11.18 Eutrophication Water and Human Health Cancer Ground Surface Soil impacts from carbon capture and storage**

(original in color)



**Figure 11.19 Human Health Cancer Water and Human Health Non Cancer Ground Surface Soil impacts from carbon capture and storage**

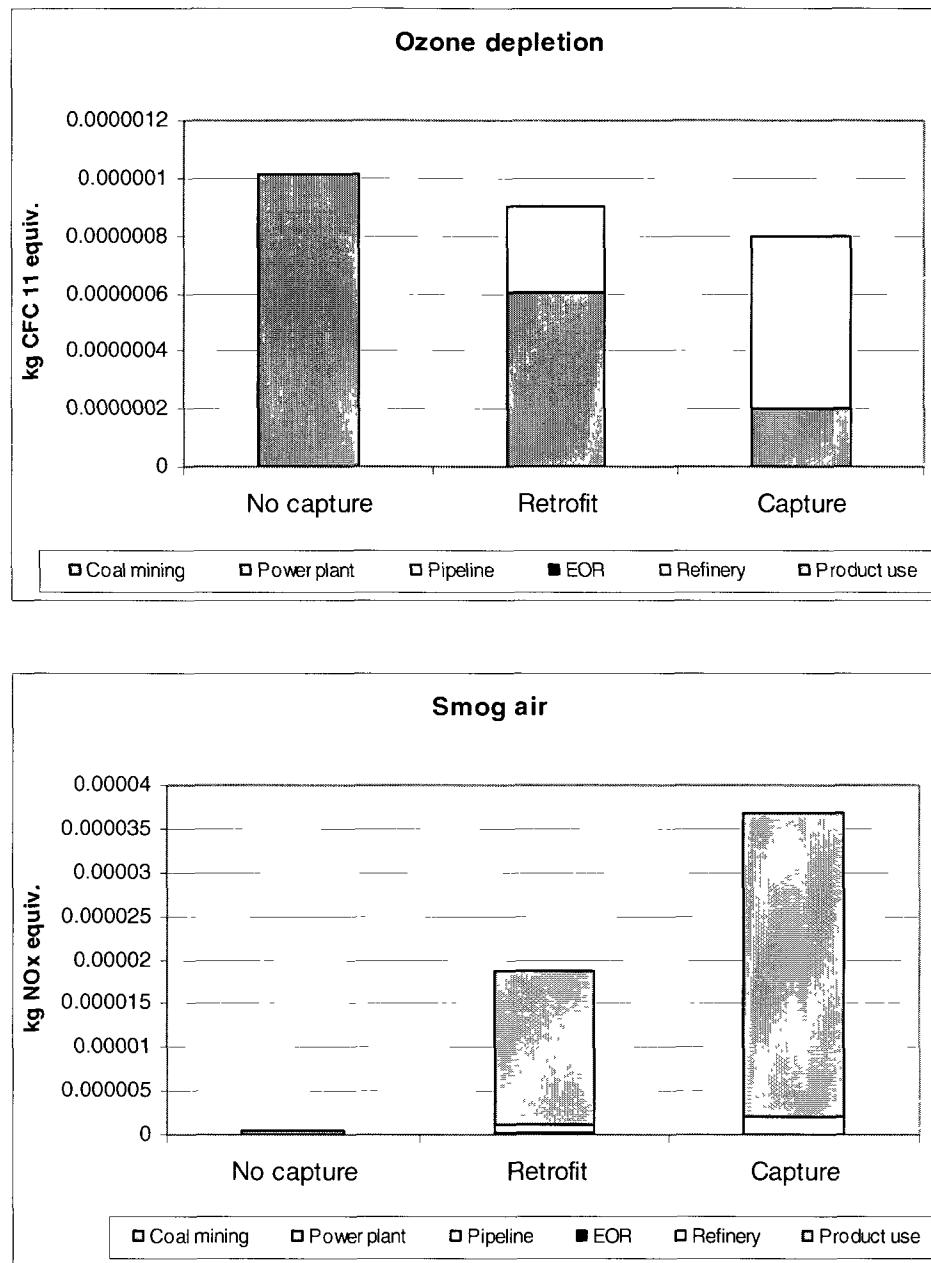
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The ozone depletion impacts in CCS life cycle come from halogenated organic emissions to air. The ozone depletion potential is presented in Figure 11.20. As it can be seen from the figure, the ozone depletion impact originates from coal mining and refinery operations. There is a decrease in impact in retrofit and capture scenarios compared to no capture scenario.

The smog air impact category (Figure 11.20) shows that impacts are caused primarily by product use, with only small portion coming from refinery operations in retrofit and capture scenarios. Smog impacts in the CCS life cycle are caused by release of carbon monoxide (~95%) and organic (4.7%) emissions to air.

To conclude, if the total life cycle impacts of CCS over a life time are considered, a decrease in several impact categories compared to the business as usual scenario is observed (Figure 11.21). Since energy content of oil is higher than in coal, the full LCA of CCS showed improvement from no capture to capture scenarios in several environmental categories.

However, applying a mass balance approach (oil production, refinery and product use studied over 45 years), absolutely opposite conclusions can be drawn. In this approach, an increase in most of categories due to refinery operations and product use is observed. The decrease in acidification air, eutrophication air and human health air point source impact categories only is noticed. The decrease in these three impact categories is primarily due to the high emissions streams from the power plant without capture that contribute to these categories.



**Figure 11.20 Ozone Depletion and Smog Air impacts from carbon capture and storage**

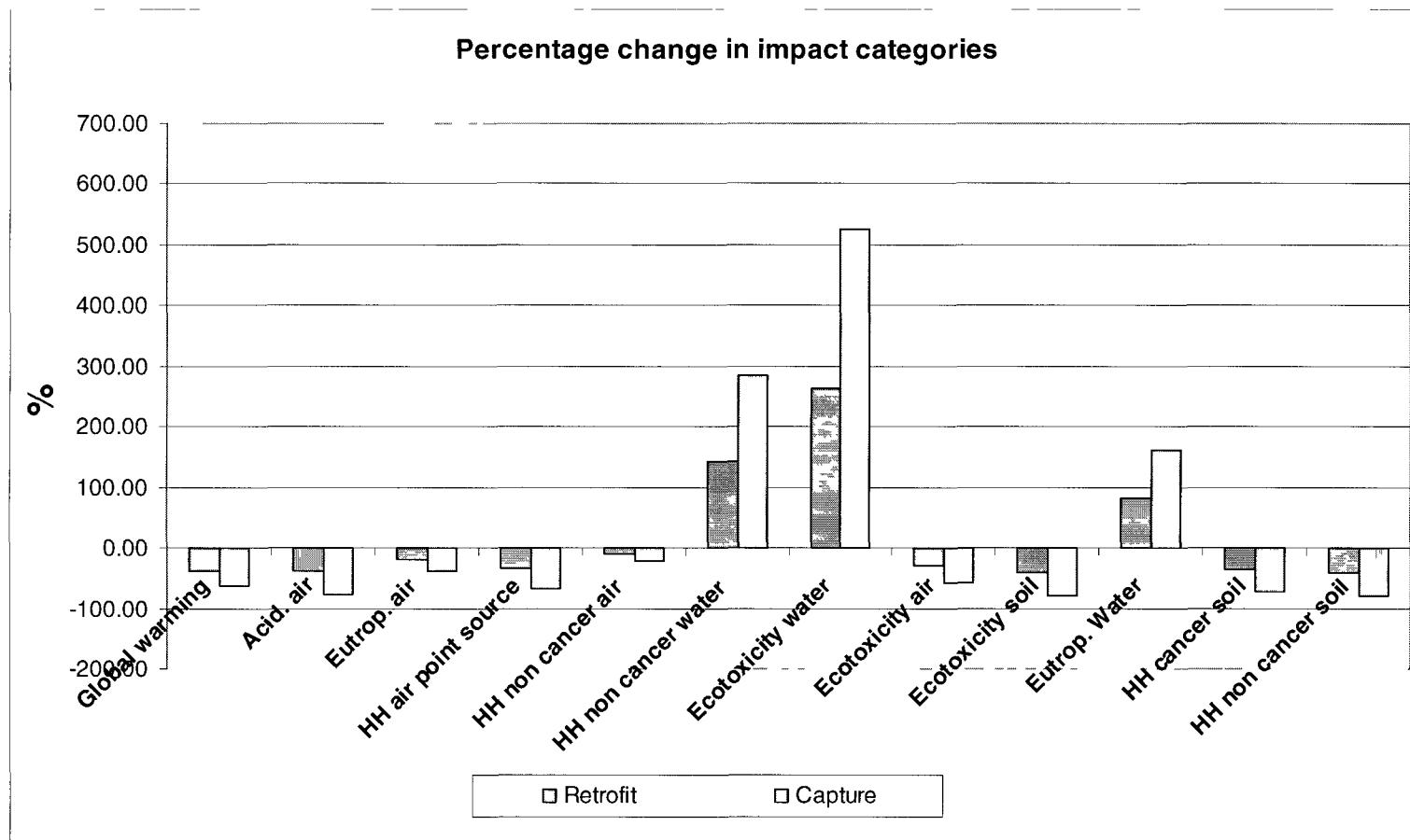
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Thus, the choice of functional unit and system boundaries for the LCA analysis of CCS systems should be done with outmost care. One of the recommendations for future research is to substitute oil coming from CO<sub>2</sub>-EOR operations by oil from Saudi Arabia, tar sands, etc. If we assume that oil will come to the refinery anyways, we may discount the refinery operations.

The overall conclusion from the analysis is that while trying to decrease CO<sub>2</sub> emissions from the power plant, the increase in some impact categories has occurred. The power output from the power plant dropped by about 30% in capture scenario. In order to compensate for loss in power, additional coal may be burned. The additional coal requirement to compensate for power loss in retrofit and capture scenarios is 5.8% and 48.6%, respectively.

Additional coal consumption leads to the increase in environmental impacts. Addition of CO<sub>2</sub> capture unit in retrofit and capture scenarios also has its impact. NO<sub>x</sub> emissions per net electricity to grid from power plant operations increased due to CO<sub>2</sub> capture operations. Ammonia (NH<sub>3</sub>) and MEA emissions releases, as well as ethylene emissions from production of MEA also contributed to the increase in environmental impacts from the power plant operations (i.e., increase in eutrophication potential).

The main recommendation here would be to further increase efficiencies of all processes at the power plant (boiler; ESP; FGD; CO<sub>2</sub> capture, especially steam consumption for regeneration of MEA solvent). It would help to minimize ancillary power requirements at the power plant and reduce amount of fuel consumed. This will lead to decrease in emissions and wastes that contribute to environmental impacts in different impact categories.



**Figure 11.21 Percentage change in impact categories for retrofit and capture scenarios**

(original in color)

## CONCLUSIONS

- LCA is slowly spreading within Canada. There are a significant number of institutions conducting LCA activities and research in Canada. However, companies are still hesitant to publish detailed LCA studies. There is also no complete and open public LCA database exists in Canada at the moment. Before Life Cycle Inventory data on generic processes becomes widely available in Canada, product manufacturers must be willing to study and report on their internal processes and the environmental performance of their products. The incentives for manufacturers to provide LCA results on their products should be created. It can be done by collecting commitments from governments and companies to give preference to those products for which LCA data is available. In addition, standard formats for companies to use in reporting on their LCA data should be developed.
- The life cycle inventory database on CCS in Saskatchewan/Canada was created during this work. The database contains data on all processes within the CCS system boundaries: surface coal mining; construction, operations and decommissioning of power plant with and without CO<sub>2</sub> capture unit; construction, operations and decommissioning of CO<sub>2</sub> pipeline; drilling and completion of wells and CO<sub>2</sub>-EOR operations at the oil field; operations at the refinery and refined product use. Other processes such as steel, concrete, limestone and MEA production and all transportation activities are also included. The created database is specific to Saskatchewan and Canada, with the CO<sub>2</sub> coming from the low grade

coal (lignite) and captured by means of the proposed post-combustion power plant being developed by SaskPower. The majority of LCI data for the power plant operations came directly from SaskPower; the major components in the plant were modeled and the created model was transferred into LCA GaBi4 software. Thus, the database is based on real industrial data, not generic studies.

- Literature review of energy systems with CO<sub>2</sub> capture and storage showed that most of the LCA studies focused primarily on GHG emissions of CCS. Some of the research papers also considered other environmental impacts of CCS such as photooxidant formation, acidification, eutrophication, human- and eco-toxicity and cumulative energy demand. However, these impacts were studied to the less extent.
- The published research papers on application of LCA methodology to enhanced oil recovery techniques and CO<sub>2</sub> storage in geological reservoirs are also quite limited. Only four publications in this area were found. Thus, one of the recommendations of this study is that more research is needed in the area of LCA of enhanced oil recovery techniques and application of LCA methodology to the actual CO<sub>2</sub>-EOR projects.
- In this study, the environmental performance over the full life cycle of CCS was studied using Life Cycle Assessment methodology. The U.S. EPA's TRACI Life Cycle Impact Assessment method was applied to evaluate the results in the following midpoint impact categories: ozone depletion, smog formation, acidification, eutrophication, human health cancer, human health non cancer, human health criteria pollutants, and eco-toxicity.

- The results of the LCA analysis of the power plant with CO<sub>2</sub> capture showed an impact increase in several environmental impacts categories compared to the plant without CO<sub>2</sub> capture, except for the acidification category and human health air-point source category (kg PM2.5 equiv.), where the decrease was observed. The decrease in acidification potential was mainly due to SO<sub>x</sub> removal in FGD. The observed decrease in the human health air-point source impact category was due to reduction of primary particulates (total suspended particulates or PM10 and PM2.5) and SO<sub>x</sub> emissions (which lead to the formation of so-called secondary particulate sulfate) release due to the FGD and CO<sub>2</sub> capture unit installation.
- There is a need to further increase efficiencies of all processes at the power plant (boiler; ESP; FGD; CO<sub>2</sub> capture, especially steam consumption for regeneration of MEA solvent). It would help to minimize ancillary power requirements at the power plant and reduce amount of fuel consumed. This will lead to decrease in emissions and wastes that contribute to environmental impacts in different impact categories.
- Since energy content of oil is higher than in coal, the full LCA of CCS showed improvement from no capture to capture scenarios in several environmental impact categories.
- If the total life cycle impacts of CCS over an average year are considered, an increase in three impact categories (human health non cancer water, ecotoxicity water and eutrophication water) compared to the business as usual scenario is observed. This increase is mostly due to the high impacts from the refinery.

- CO<sub>2</sub> transport by pipeline and enhanced oil recovery operations contribute to less than 1% of impact in all impact categories.
- Applying a mass balance approach (oil production, refinery and product use studied over 45 years), environmental impacts over the life cycle of CCS normalized to GJ of total energy output showed a decrease in environmental impacts from no capture to capture scenarios in acidification air, eutrophication air and human health air point source impact categories. The increase in environmental impacts in all other impact categories was observed. The decrease in three impact categories is primarily due to the high emissions streams from the power plant without capture that contribute to these categories. With introduction of CO<sub>2</sub> capture at the power plant, the impacts in these categories per GJ of total energy produced over 45 years decrease substantially.
- LCA and mass balance approach should be applied to CCS studies with outmost caution, since different conclusions can be drawn based on the approach. Definition of functional unit and system boundaries is crucial here.
- This research also showed that LCA methodology and results may add value to procedural EIA and SEA tools especially if comparison of different alternatives is made. A number of weaknesses were identified in the EIA procedures used in Canada, such as focus on local impacts of a project, difficulties with assessment of regional and global effects, exclusion of upstream and downstream activities, and lack of specific environmental assessment methodology developed for EIA. These are the areas where LCA has its strength and therefore may be successfully applied to enhance EIA methodology and results.

- Several LCA studies have been conducted to evaluate environmental performance of the full life cycle of CO<sub>2</sub> capture and storage. However, application of EIA and SEA procedures to CCS has been limited. There are also no regulations for EIA of CCS projects developed in Canada. CCS activities in EIA are usually treated as separate projects thus increasing a probability of erroneous conclusions of the assessment. Thus, the development of a regulatory framework for CO<sub>2</sub> capture, transport and storage with a life cycle perspective in mind is necessary to prevent any adverse impact on society and environment.

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## Appendix A

### Life Cycle Inventory Data

**Table A.1. Saskatchewan electricity mix**

Inputs	Value	Unit
Lignite coal	484,900,000	kg
Crude oil	3,858,000	kg
Natural gas	10,550,000	kg
Outputs		
<i>Emissions to air</i>		
CH <sub>4</sub>	3,870,000	kg
CO <sub>2</sub> , fossil	870,500,000	kg
PM10, dust	440,000	kg
HC, VOC	5,900	kg
HCl	185,000	kg
HF	9,100	kg
NO <sub>x</sub>	2,410,000	kg
SO <sub>2</sub>	6,980,000	kg
<i>Energy</i>		
Electric power	1,000,000	MWh

Source: SCS 2005

**Table A.2. MEA production**

Inputs	Value	Unit
Ethylene oxide	816	g
Ammonia	788	g
Electricity	0.333	kWh
Natural gas	2	MJ
Transport (truck and train)	11.23	tonne × km
Chemical plant infrastructure	$4 \times 10^{10}$	p
Outputs		
Monoethanolamine	1	kg
Waste heat	1.2	MJ
Ethylene oxide to air	1.63	g
Ethylene oxide to water	1.47	g
Ammonia to air	1.58	g
Ammonia to water	3.04	g
CO <sub>2</sub>	26.5	g
Nitrate (NO <sub>3</sub> ) to water	6.97	g
COD, BOD	21.3	g
TOC, DOC	8.02	g

Source: Althaus et al 2004, Koornneef 2008

**Table A.3. CO<sub>2</sub> pipeline construction (100 km of 12 inch pipeline)**

Inputs	Value	Unit
<i>Energy resources</i>		
Crude oil	94,781	kg
Hard coal	2,836,391	kg
Lignite	20,782	kg
Natural gas	819,419	kg
Uranium	4.80	kg
<i>Material resources</i>		
Iron	4,395,581	kg
<b>Outputs</b>		
<i>Emissions to air</i>		
Carbon dioxide	11,409,231	kg
Carbon monoxide	78,942	kg
Hydrogen chloride	612.54	kg
Hydrogen sulphide	361.41	kg
Nitrogen oxides	24,578	kg
Sulphur dioxide	36,659	kg
Methane	11,996	kg
VOC	1,392	kg
Dust	12,467	kg

**Table A.4. Well drilling and completion (per one well of 1,450 m depth)**

<b>Inputs</b>	<b>Value</b>	<b>Unit</b>
<i>Energy resources</i>		
Crude oil	623	kg
Hard coal	15,639	kg
Lignite	41,999	kg
Natural gas	9130	kg
Uranium	0.03	kg
<i>Material resources</i>		
Iron	25,709	kg
<b>Outputs</b>		
<i>Emissions to air</i>		
Carbon dioxide	118,651	kg
Carbon monoxide	453.40	kg
Nitrogen oxides	484.67	kg
Sulphur dioxide	270.35	kg
Methane	99.99	kg
VOC	12.71	kg
Dust	67.74	kg

**Table A.5. Operations at the refinery**

<b>Inputs</b>	<b>Value</b>	<b>Unit</b>
<i>Energy resources</i>		
Crude oil	1	kg
<b>Outputs</b>		
Diesel	0.2614065	kg
Gasoline	0.4659126	kg
Heavy fuel oil	0.0361872	kg
Jet fuel	0.0956946	kg
Kerosene	0.0030785	kg
Other petroleum products	0.1377360	kg
<i>Emissions to air</i>		
Carbon dioxide	0.4589437	kg
Carbon monoxide	0.0005285	kg
Nitrogen oxides	0.0010763	kg
Sulphur dioxide	0.0014983	kg
Methane	0.0033302	kg

**Table A.6. Use of refined products (per 1 kg of refined products mix)**

Outputs	Value	Unit
<i>Emissions to air</i>		
Carbon dioxide	2.9447	kg
Carbon monoxide	0.14105	kg
Nitrogen oxides	0.021445	kg
Sulphur dioxide	0.0033429	kg
Methane	0.00012327	kg
VOC	0.00058234	kg

## Pipeline transport and CO<sub>2</sub>-EOR model

Pipeline construction and operation and CO<sub>2</sub>-EOR operations are modeled in the complimentary research conducted by Jitsopa Suebsiri (Suebsiri 2010). Main equations used in the model are presented below.

Steel requirements for construction of CO<sub>2</sub> pipeline and well casing were estimated using the following equation:

$$\text{Steel for pipeline and casing} = \rho_{st}\pi DLt \quad (\text{A1-1})$$

Where,

$\rho_{st}$  - Steel density (7,850 kg/m<sup>3</sup>)

$D$  - Pipe diameter, m

$L$  - Pipe length, m

$t$  - Pipe thickness, m

Pump efficiency can be calculated using equation (A1-2).

$$\eta_p = \frac{q \times (P_d - P_s)}{\eta_m \times P_h} \quad (\text{A1-2})$$

Where

$\eta_p$  - Pump efficiency, %

$q$  - Design flow capacity, m<sup>3</sup>/s

$p_d$  - Discharge pressure, Pa

$p_s$  - Suction pressure, Pa

$\eta_m$  - Motor efficiency, %

$P_h$  - Electrical power, W

Equation A1-3 is used to verify the pump efficiency using motor efficiency of 95%.

$$\eta_p = \frac{Q \times (P_d - P_s)}{3.6 \times 10^6 \times \eta_m \times P_h} \quad (\text{A1-3})$$

Where

$$3.6 \times 10^6 = (3,600 \text{ s/h}) * (1,000 \text{ W/kW})$$

Input data and results of pumping station modeling are shown in Table A.7. The pump efficiency used in this study is 67%. This efficiency was used to calculate energy consumption of the pumping unit.

Electricity consumption by pumps was calculated using the following equation:

$$BHP = \frac{Q \times (P_d - P_s)}{3.6 \times 10^6 \times \eta_p} \quad (\text{A1-4})$$

Where

$BHP$  - Input power (brake horsepower), kW

$Q$  - Flow rate,  $\text{m}^3/\text{h}$

$p_d$  - Discharge pressure, Pa

$p_s$  - Suction pressure, Pa

$3.6 \times 10^6$   $(3,600 \text{ s/h}) \times (1,000 \text{ W/kW})$

$\eta_p$  - Pump efficiency, % (for example 90% is  $\eta_p = 0.90$ )

Darcy–Weisbach equation:

$$\Delta p = f \cdot \frac{L}{D} \cdot \frac{\rho V^2}{2} \quad (\text{A1-5})$$

Where

$\Delta p$  - Pressure loss

$L$  - Length of the pipe, m

$D$  - Hydraulic diameter of the pipe (equals to the internal diameter of the pipe), m

$V$  - Average velocity of the fluid flow (equals to the volumetric flow rate per unit of cross-sectional wetted area,  $Q/A$ ), m/s

$f$  - A dimensionless coefficient called the Darcy friction factor

Pressure loss can be calculated using the equation below:

$$\Delta p = 8f \cdot \frac{Q^2}{\pi^2} \cdot \frac{L}{D^5} \quad (\text{A1-6})$$

Where

$\Delta p$  - Pressure loss

$L$  - Length of the pipe, m

$D$  - Hydraulic diameter of the pipe, m

$Q$  - Mass flow rate, kg/s

$f$  - A dimensionless coefficient (0.015)

**Table A.7. Use of refined products (per 1 kg of refined products mix)**

<b>Input data</b>	<b>Unit</b>	<b>Input unit</b>	<b>SI Unit</b>
Design Flow Capacity	1,734 gpm	394 m <sup>3</sup> /h	m <sup>3</sup> /s
Suction Pressure	1,900 psi	13,100,500 Pa	Pa
Discharge Pressure	2,850 psi	19,650,750 Pa	Pa
Electrical Power	1,500 HP	1,119 kW	W
Motor Efficiency		95 %	

<b>Conversion factors</b>
1 gpm = 0.227 m <sup>3</sup> /h
1 psi = 6,895 Pa
1 kW = 1,000 Nm/s
1 HP = 0.746 kW
1 h = 3,600 s
1 Pa = N/m <sup>2</sup>

It is assumed that CO<sub>2</sub> and other gases are re-compressed by two 6,000 HP electrically driven compressors (60% efficiency). The capacity of the compressors is in the range of 2,630 to 2,946 tonnes of CO<sub>2</sub> per day (or 125 tonnes/hour).

Energy consumption for re-compression of CO<sub>2</sub> to prepare it for re-injection into the reservoir can be calculated using the following equation:

$$\text{Energy consumption for re- compression of CO}_2 \text{ (kWh)} = R_p \times Q \quad (\text{A1-7})$$

Where

$R_p$  - Energy consumption for re-compression of CO<sub>2</sub> (0.12 kWh/(kg/h))

$Q$  - Mass flow rate of CO<sub>2</sub>, kg/h

$$R_p = \frac{2 \times 6,000 \times 0.746}{125,000 \times 0.60} = 0.12 \quad (\text{A1-8})$$

Where

$R_p$  = Energy consumption for re-compression, kWh/(kg/h)

2 compressors at 6,000 HP

1 HP = 0.746 kWh

Compression capacity = 125,000 kg/h

Compressor efficiency = 0.60

## Appendix B

### Modeling results

**Table B.1 Modeling results of 882 MW coal-fired power plant equipped with ESPs<sup>8</sup>**

Parameter	Modeling results	SaskPower average data	Unit
Gross generation (annual)	6,153,330	6,057,779	MWh/yr
Auxiliary power requirements	61.74		MW
Net electrical output	820.26		MW
Coal consumption	757.95		kg/MWh
CO <sub>2</sub>	1,147.32	1,064	kg/MWh
SO <sub>2</sub>	6.9580	6.8520	kg/MWh
SO <sub>3</sub>	0.0767		kg/MWh
S to fly ash	0.0409		kg/MWh
S to bottom ash	0.5321		kg/MWh
NO <sub>x</sub>	2.4194	2.828	kg/MWh
HCl	0.4548		kg/MWh
HF	0.0568		kg/MWh
CH <sub>4</sub>	0.0152		kg/MWh
Total VOC	0.0152		kg/MWh
Particulates	0.3122	0.3190	kg/MWh
Bottom ash	48.6661		kg/MWh
Fly ash disposed	30.9115		kg/MWh
Mercury (Hg) in flue gas	0.00004985	0.00004546	kg/MWh
Mercury (Hg) in bottom ash	0 00000404		kg/MWh

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<sup>8</sup> Hereafter all data is presented per MWh electricity to grid (i.e. net electricity production)

**Table B.2 Modeling results of 882 MW coal-fired power plant equipped with ESPs and FGDs<sup>9</sup>**

Parameter	Modeling results	Unit
Gross generation (annual)	6,153,330	MWh/yr
Auxiliary power requirements	95.26	MW
Net electrical output	786.74	MW
Coal consumption	790.24	kg/MWh
Water consumption	24.94	kg/MWh
Limestone consumption	12.58	kg/MWh
CO <sub>2</sub>	1,203.43	kg/MWh
SO <sub>2</sub>	0.0722	kg/MWh
SO <sub>3</sub>	0.0400	kg/MWh
NO <sub>x</sub>	2.5225	kg/MWh
HCl	0.0474	kg/MWh
HF	0.0178	kg/MWh
CH <sub>4</sub>	0.0158	kg/MWh
Total VOC	0.0158	kg/MWh
Particulates	0.0977	kg/MWh
Mercury (Hg) in flue gas	0.00003963	kg/MWh
FGD solid waste generation	16.29	kg/MWh
Bottom ash	48.6661	kg/MWh
Fly ash disposed	30.9115	kg/MWh
Mercury (Hg) in FGD solid waste	0.000001234	kg/MWh

<sup>9</sup> All six units are equipped with FGD

**Table B.3 Modeling results of 882 MW coal-fired power plant equipped with ESPs, FGDs and post-combustion CO<sub>2</sub> capture<sup>10</sup>**

Parameter	Modeling results	Unit
Gross generation (annual)	6,153,330	MWh/yr
Auxiliary power requirements	329.74	MW
Net electrical output	552.26	MW
Coal consumption	1,125.77	kg/MWh
Water consumption	1,792.67	kg/MWh
Limestone consumption	17.93	kg/MWh
Steam consumption	3,267.43	kg/MWh
Caustic (NaOH) consumption	0.2006	kg/MWh
Activated carbon consumption	0.1157	kg/MWh
MEA makeup	2.0996	kg/MWh
CO <sub>2</sub>	171.44	kg/MWh
CO <sub>2</sub> captured	1542.95	kg/MWh
SO <sub>2</sub>	0.0005142	kg/MWh
SO <sub>3</sub>	0.0002850	kg/MWh
NO <sub>x</sub>	3.5490	kg/MWh
HCl	0.0034	kg/MWh
HF	0.0253	kg/MWh
CH <sub>4</sub>	0.0225	kg/MWh
Total VOC	0.0225	kg/MWh
Particulates	0.0696	kg/MWh

<sup>10</sup> All six units are quipped with FGD and CO<sub>2</sub> capture

<b>Parameter</b>	<b>Modeling results</b>	<b>Unit</b>
NH <sub>3</sub>	0.2098	kg/MWh
Mercury (Hg) in flue gas	0.00005645	kg/MWh
Mercury (Hg) in bottom ash	0.00000600	kg/MWh
FGD solid waste generation	23.2099	kg/MWh
Reclaimer waste	4.9374	kg/MWh
Bottom ash	72.28	kg/MWh
Fly ash disposed	45.91	kg/MWh
Mercury (Hg) in FGD solid waste	0.00001758	kg/MWh
S in fly ash	0.0608	kg/MWh
S in bottom ash	0.7903	kg/MWh
MEA to flue gas	0.0725	kg/MWh

**Table B.4 Modeling results of 882 MW coal-fired power plant equipped with ESPs and FGD on Unit 3<sup>11</sup>**

Parameter	Modeling results	Unit
Gross generation (annual)	6,153,330	MWh/yr
Auxiliary power requirements	67.44	MW
Net electrical output	814.56	MW
Coal consumption	763.25	kg/MWh
Water consumption	4.10	kg/MWh
Limestone consumption	2.04	kg/MWh
CO <sub>2</sub>	1,156.52	kg/MWh
SO <sub>2</sub>	5 8445	kg/MWh
SO <sub>3</sub>	0.0708	kg/MWh
NO <sub>x</sub>	2.4363	kg/MWh
HCl	0.3889	kg/MWh
HF	0.0505	kg/MWh
CH <sub>4</sub>	0.0153	kg/MWh
Total VOC	0 0153	kg/MWh
Particulates	0.2776	kg/MWh
Mercury (Hg) in flue gas	0.00004820	kg/MWh
FGD solid waste generation	2 6362	kg/MWh
Bottom ash	48 6661	kg/MWh
Fly ash disposed	30 9115	kg/MWh
Mercury (Hg) in FGD solid waste	0 00000200	kg/MWh

<sup>11</sup> Only one 150 MW unit (Unit 3) is equipped with FGD

**Table B.5 Modeling results of 882 MW coal-fired power plant equipped with ESPs, FGDs and post-combustion CO<sub>2</sub> capture<sup>12</sup>**

Parameter	Modeling results	Unit
Gross generation (annual)	6,153,330	MWh/yr
Auxiliary power requirements	39.28	MW
Net electrical output	775.28	MW
Coal consumption	801.92	kg/MWh
Water consumption	214.30	kg/MWh
Limestone consumption	2.14	kg/MWh
Steam consumption	389.92	kg/MWh
Caustic (NaOH) consumption	0.0239	kg/MWh
Activated carbon consumption	0.0138	kg/MWh
MEA makeup	0.2506	kg/MWh
CO <sub>2</sub>	1,037.09	kg/MWh
CO <sub>2</sub> captured	184.13	kg/MWh
SO <sub>2</sub>	6.1284	kg/MWh
SO <sub>3</sub>	0.0676	kg/MWh
NO <sub>x</sub>	2.4074	kg/MWh
HCl	0.4010	kg/MWh
HF	0.0531	kg/MWh
CH <sub>4</sub>	0.0160	kg/MWh
Total VOC	0.0160	kg/MWh
Particulates	0.1263	kg/MWh

<sup>12</sup> Only one 150 MW unit (Unit 3) is equipped with FGD and CO<sub>2</sub> capture

Parameter	Modeling results	Unit
NH <sub>3</sub>	0.0250	kg/MWh
Mercury (Hg) in flue gas	0.00004021	kg/MWh
Mercury (Hg) in bottom ash	0.00000428	kg/MWh
FGD solid waste generation	2.77	kg/MWh
Reclaimer waste	0.5892	kg/MWh
Bottom ash	51.49	kg/MWh
Fly ash disposed	32.70	kg/MWh
Mercury (Hg) in FGD solid waste	0.00000210	kg/MWh
S in fly ash	0.0433	kg/MWh
S in bottom ash	0.5630	kg/MWh
MEA to flue gas	0.0087	kg/MWh