Integration of Nuclear Power with Oil Sands Extraction Projects in Canada

By Ashley Finan

S.B. Physics
Massachusetts Institute of Technology, 2006

SUBMITTED TO THE DEPARTMENT OF NUCLEAR SCIENCE AND ENGINEERING IN PARTIAL FULFILLMENT OF THE REQUIREMENTS FOR THE DEGREES OF

MASTER OF SCIENCE IN NUCLEAR SCIENCE AND ENGINEERING
AND
BACHELOR OF SCIENCE IN NUCLEAR SCIENCE AND ENGINEERING

AT THE

MASSACHUSETTS INSTITUTE OF TECHNOLOGY

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Abstract

One of the largest oil reserves in the world is not in the Middle East or in Alaska, but in Canada. This fuel exists in the form of bitumen in Alberta's oil sands. While it takes a tremendous amount of energy to recover this bitumen and refine it into petroleum products, with oil prices nearing all time highs, it is profitable to do so. Oil sands recovery involves either strip mining the sands and extracting the oil, or pumping large quantities of steam into the ground in order to free the bitumen from the sand. Traditionally, the energy to produce the steam and hot water used in this process has come from natural gas. The use of natural gas for oil sands recovery presents a number of problems, among which are the environmental impact of the greenhouse gases and the price volatility of the natural gas market.

This thesis explores the possibility of using nuclear energy to power oil sands recovery. Once operational, nuclear reactors produce no greenhouse gas emissions of carbon dioxide and offer relatively low and stable fuel and operation and maintenance costs. Uranium is not subject to the same market volatility as natural gas. There are, however, several trade-offs as well. This thesis compares the benefits and the drawbacks, and puts forth several complete scenarios for the introduction of nuclear technology into the oil sands recovery process.

Nuclear energy used for steam production is found to be competitive with natural gas prices as low as \$3.75/MMBtu (CAD). For electricity production, nuclear becomes

competitive at natural gas prices of $8.50/MMBtu (CAD). The greenhouse gas impact of nuclear is to reduce emissions in the oil sands region, as much as 3.3 million metric tons per year avoided for a 100k barrel per day (bpd) bitumen production Steam Assisted Gravity Drainage (SAGD) facility, or 2.7 million metric tons per year for the replacement of 700MWe of grid electricity with nuclear power. For a steam supply scenario, the PBMR reactor is found to be well-sized to supply a 50,000 bpd SAGD plant, whereas the CANDU and ACR reactors considered are found to be too large, with too low pressure steam to be practical in that application. All of the reactors have potential for supplying heat and electricity for direct mining operations, however. In summary, nuclear energy applications appear to be well suited for long term oil sands production in an economically competitive, CO_2 emission free way which would greatly help Canada in meeting its Kyoto greenhouse gas emission commitments and to continue responsible development of its rich oil sands resources.

Chapter One lays out the background information regarding the basic methods of production used in the oil sands today and the technologies that are being studied for possible future use. Chapter Two describes the challenges that face the oil sands industry in the current development environment, while Chapter Three details the energy requirements of the oil sands industry and surveys the energy generation options available in the region. Chapter Four provides a description of the reactors that have been suggested for this application, and sets out their steam capacities for the SAGD application. Chapter Five proposes a set of possible scenarios for integrating nuclear energy into oil sands projects and sets forth the steps that need to be taken to accomplish that integration, as well as the requisite benefits and economic implications of doing so. Finally, Chapter 6 concludes with a discussion of the results and makes recommendations for future work.

Acknowledgements

I would like to express my heartfelt appreciation for the guidance that Professor Andrew Kadak has given me during this project. His enthusiasm and insight have been an inspiration to me, and his patience and support have been invaluable. Reiner Kuhr has also been an indispensable mentor, and his encouragement has been crucial to this work.

I would also like to extend my thanks to my parents and my brother, Parker, for their steadiness, love and support throughout my years at MIT. To Dr. Steven Kleiner, for helping me to focus on the most important things in life, and to my dog Fred, for always putting a smile on my face. To the many people who have been planning my wedding while I have not had the time, I appreciate all that you have done. To Daniel, my husband-to-be, I offer my sincerest thanks for his love and his support in this and in all that I do.

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List of Acronyms

ACR-1000	Advanced CANDU Reactor 1000
ACR-700	Advanced CANDU Reactor 700
AECL	Atomic Energy of Canada, Limited
ARC	Alberta Research Council
BNSF	Burlington Northern Santa Fe (Railroad)
BWR	Boiling Water Reactor
CANDU	Canada Deuterium Uranium (Nuclear Reactor)
CEAA	Canadian Environmental Assessment Act
CN	Canadian National (Railroad)
CNRL	Canadian Natural Resources Limited
CNSC	Canadian Nuclear Safety Commission
COL	Construction and Operating License
CP	Canadian Pacifica (Railroad)
CPF	Central Processing Facility
CSS	Cyclic Steam Stimulation
EA	Environmental Assessment
ESP	Early Site Permit
ES-SAGD	Enhanced Solvent Steam Assisted Gravity Drainage
EUB	(Alberta) Energy and Utilities Board
GHG	Greenhouse Gas
GPGC	Grand Prairie Grand Cache
HRSG	Heat Recovery Steam Generator
HTGR	High Temperature Gas Reactor
IAEA	International Atomic Energy Agency
IHX	Internal Heat Exchanger
ISC	In-Situ Combustion
LOCA	Loss of Cooling Accident
LP-SAGD	Low Pressure Steam Assisted Gravity Drainage
LULUCF	Land Use, Land Use Change, and Forestry
NEI	Nuclear Energy Institute
NFW	Nuclear Fuel Waste
NG	Natural Gas
NRC	Nuclear Regulatory Commission
NSCA	Nuclear Safety and Control Act
NTCL	Northern Transportation Company Limited
NWMO	Nuclear Waste Management Organization
OTSG	Once Through Steam Generator
PBMR	Pebble Bed Modular Reactor
PWR	Pressurized Water Reactor
RLMN	RaiLink Mackenzie Northern
RLW	RaiLink Lakeland & Waterways
SAGD	Steam-Assisted Gravity Drainage
SEU	Slightly Enriched Uranium
SMR	Steam Methane Reforming

SOR	Steam to Oil Ratio
THAI	Toe to Heel Air Injection
VAPEX	Vaporized Extraction
WTI	West Texas Intermediate

CHAPTER 1

1 Introduction

The Canadian oil sands industry has grown tremendously in the last five years, and promises to continue in steady growth for decades to come. As a significant world oil source with reserves second only to Saudi Arabia and daily production scheduled to approach 5 million barrels per day by 2020, the oil sands in Alberta are worthy of much attention from investors and consumers alike. In 2006, oil sands production accounted for roughly half of Canada's total oil production, and by 2010, it is expected to represent two-thirds of the country's total production.[1] Over $40 billion have already been spent on oil sands projects, and an additional $54 million are projected by 2012.

However, with these great resources also come great costs. Oil sands recovery may consume nearly 20% of western Canada's yearly natural gas output by 2020. The greenhouse gas emissions are a significant barrier to reaching Canada's climate change goals, and the scarcity of fresh water in the region is a threat to the ecosystem and the inhabitants as well as to the viability of the oil industry. Alternative recovery technologies and alternative energy sources used in the production of oil from oil sands are a key ingredient for the continuing health of the industry and of Alberta's residents and environment.

The oil sands in Canada are concentrated in three formations in northeastern Alberta - Athabasca, Cold Lake, and Peace River. Athabasca is the largest, and Peace River the smallest. Direct surface mining techniques are only being employed in the Athabasca region at this point, while Peace River and Cold Lake are only being developed through in-situ methods [2] . The nearby town that supports most of the industry is known as Fort McMurray, and is located in the municipality of Wood Buffalo (population 51,496), about 750km NNE of Calgary [3]. About 450 km south of Wood Buffalo lies Edmonton.

With a population of close to one million and better freight transportation systems, Edmonton shows possible promise as a center of production for the industry [4].

2 Bitumen Extraction

The valuable resource in the oil sands comes in the form of bitumen. Bitumen is a highly viscous hydrocarbon with a high carbon to hydrogen ratio that has traditionally been used for road paving and other 'tar' applications like roofing. It has usually been obtained as a byproduct of conventional crude oil distillation. The bitumen in the Canadian oil sands is present in high enough concentration that it is economical at current oil prices to extract the bitumen from the earth and put it through a long chain of processing and refining in order to fabricate synthetic crude oil. As shown in Figure 1, the sand is surrounded first by a layer of water and then by bitumen. It is by heating the water and bitumen that they can be most easily released from the sand. The sand is then discarded as a byproduct.

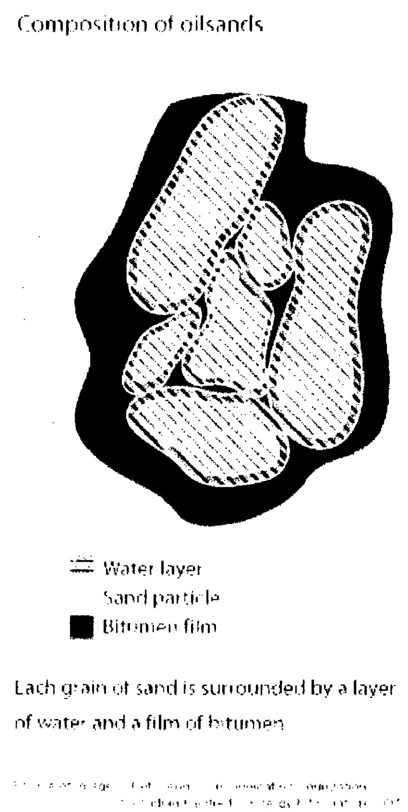


Figure 1: Composition of Oil sands [5]

The Canada Energy Research Institute estimates that oil sands projects require a West Texas Intermediate (WTI) crude oil price of $25/barrel to earn an adequate return [6]. Recent prices for WTI are shown in Figure 2 below, and indicate a significant margin for profitable operations. The average price for April, 2007 was $60.82/bbl [7].

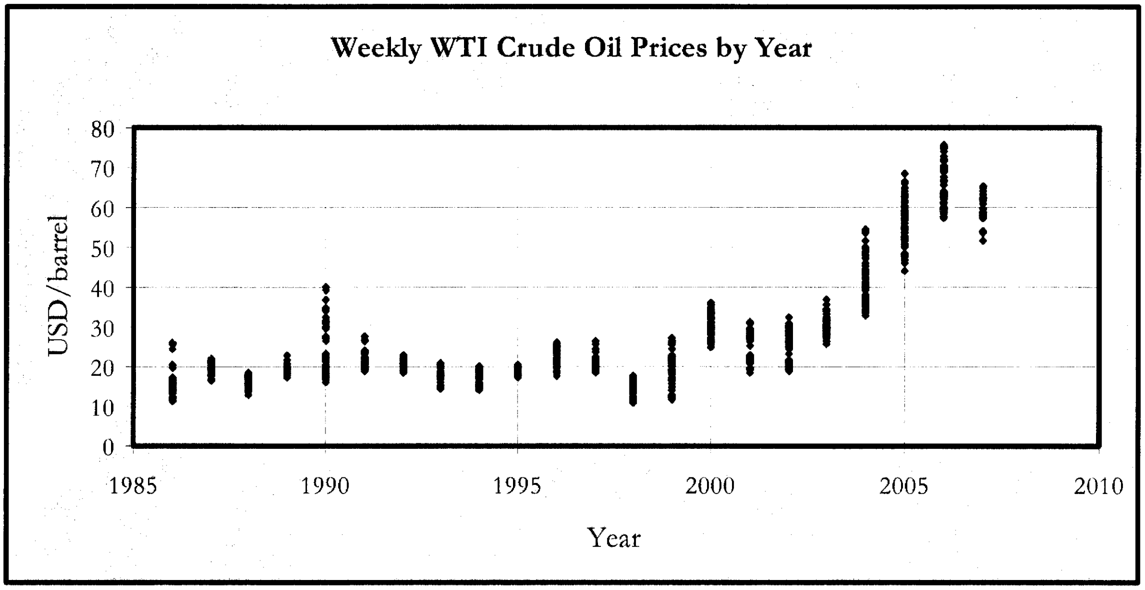


Figure 2: WTI Crude Oil Price [8]

The bitumen-rich layer of geology in the oil sands area is found buried at various depths. In some areas, particularly closer to the Athabasca riverbed, the bitumen is found very near the surface, whereas in other nearby areas it can be as deep as 750 meters below ground [9]. For the near-surface deposits, the most effective method of recovery is direct mining. In general, this method is feasible to a depth of about 80 meters. If the bitumen layer is significantly deeper, an in-situ method is used for recovery. Approximately 20% of the total resource is within the range of surface mining, while 80% must be recovered using in-situ techniques. The surface mining has been the most productive method to this point, but that ratio is changing with time, as shown in Figure 3 below.

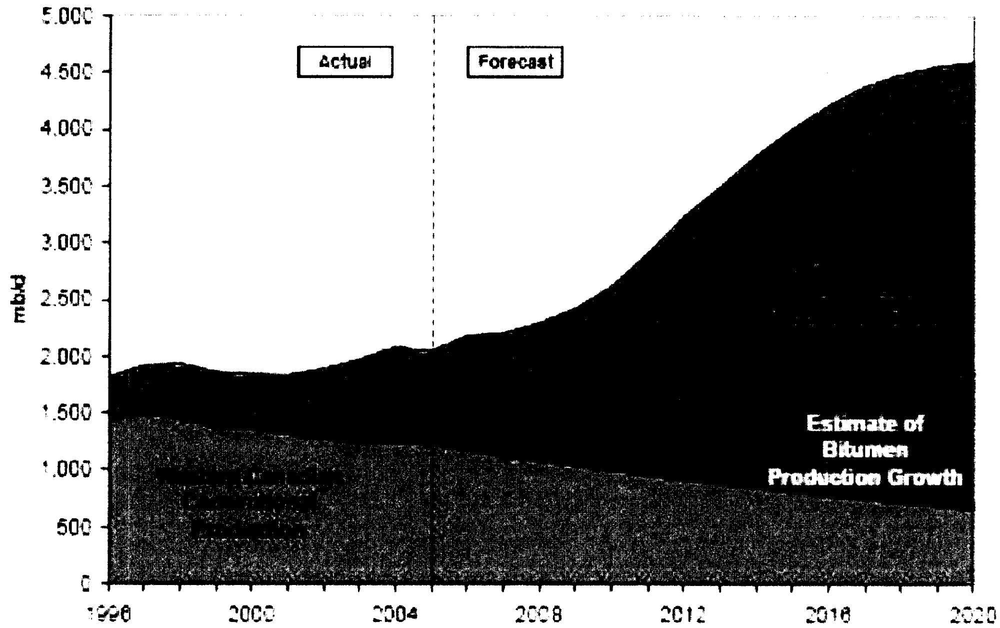


Figure 3: Future Production Trends for the Oil Industry in Western Canada

The total recoverable bitumen in the Alberta oil sands is estimated to be about 270 billion barrels, of which 250 billion can be recovered using in-situ and 18 billion can be recovered through direct mining [10]. A summary of the locations and recovery methods for the recoverable bitumen in Alberta is given in Table 1.

Table 1: Recoverable Bitumen Reserves in Alberta, According to the Petroleum Technology Alliance Canada (PTAC)

(billion m^3)	Surface Mineable Area	In-Situ	Total	Percent Total
Athabasca	17.5	200	217.5	80.6%
Cold Lake	0	31.9	31.9	11.8%
Peace River	0	20.5	20.5	7.6%
Total	17.5	252.4	269.9	100.0%

2.1 *Direct Mining*

Direct mining and extraction comprise a process in which the most valuable soil is dug out of the ground and the bitumen is then separated by mechanical and thermal means. Mining begins with the removal of the layer of muskeg at the surface, and then the 'overburden' (a mixture of sand, rock, and clay) above the valuable bitumen layer. Some overburden is used to build earth walls around the future tailings ponds (for wastewater storage), and some is stored for later use in reclaiming the land. The muskeg is a very important component of the ecosystem, and is also used for reclamation.

Mining of the bitumen layer is accomplished using large hydraulic shovels, often with scoop sizes of one to two tons of material. The oil sands are loaded into large dump trucks, which transport the material to the processing assembly line. The main truck used to transport the raw material is the Caterpillar 797, shown in Figure 4.

Figure 4: The Caterpillar 797 has a 380 ton capacity and 3370 horsepower. The truck has a 1,800 gallon fuel tank and stands about 25 feet tall by 32 feet wide by 48 feet long. A representative 5′10″ tall person is shown for reference.

Raw material is first dumped through a crusher, which removes some stones and breaks the sands down into smaller chunks. The output from the crusher is then mixed with hot water (40-50°C) and sometimes steam. This mixture may optionally be slurried and run through another filter to remove smaller rocks and clumps of clay. During transport, the sand, water, and bitumen begin to separate. In the central processing facility, the mixture enters a large pool. The sand sinks to the bottom and the bitumen forms a frothy layer on the surface of the water. The bitumen can then be skimmed off of the surface of the pool and treated to remove impurities. The water is recycled as much as possible, and the sand is used for reclamation. The bitumen can then be combined with diluent for shipment, or processed further and refined into retail fuels.

2.2 *In-Situ Methods*

In-situ methods involve performing the thermal separation underground, so that most of the soil is heated in place until the bitumen reaches a viscosity at which it drains through the soil and can be pumped to the surface. The major in-situ methods that are currently used in the oil sands are Steam-Assisted Gravity Drainage (SAGD) and Cyclic Steam Stimulation (CSS). Other methods are under development, and show promise for future application, but are not yet ready for industrial implementation. Of the two main methods, SAGD is dominant in the Alberta oil sands, and is also better suited to a possible nuclear power application because it requires a constant steam supply, rather than a cyclic one.

2.2.1 Steam Assisted Gravity Drainage (SAGD)

A SAGD operation is a system of well pairs vertically aligned and horizontally drilled, as illustrated in Figure 5 below. Hot steam is pumped into the upper 'injection' well, and is used to heat the surrounding oil sands. As the bitumen heats, it falls away from the sand and gradually filters down to the lower 'production' well. The bitumen and water are pumped back to the surface from that well. In a field, well pairs are aligned adjacent to one another as shown in Figure 6. There is a break-in period of about 2 to 3 months for each well, followed by a fairly steady production lifetime of 6 to 10 years, and finally a winding down period of up to 4 years [11]. During the break-in period, steam is injected into both wells prior to initial production. This step establishes thermal communication between the two wells and does not recover any bitumen. Steady production is generally characterized by a steam to oil ratio (SOR) of two to three. This means that for each barrel of bitumen produced by the well, two to three barrels of water must be heated to 100% steam and pumped into the injection well. Generally about 50-70% of the bitumen in place can be recovered using SAGD.

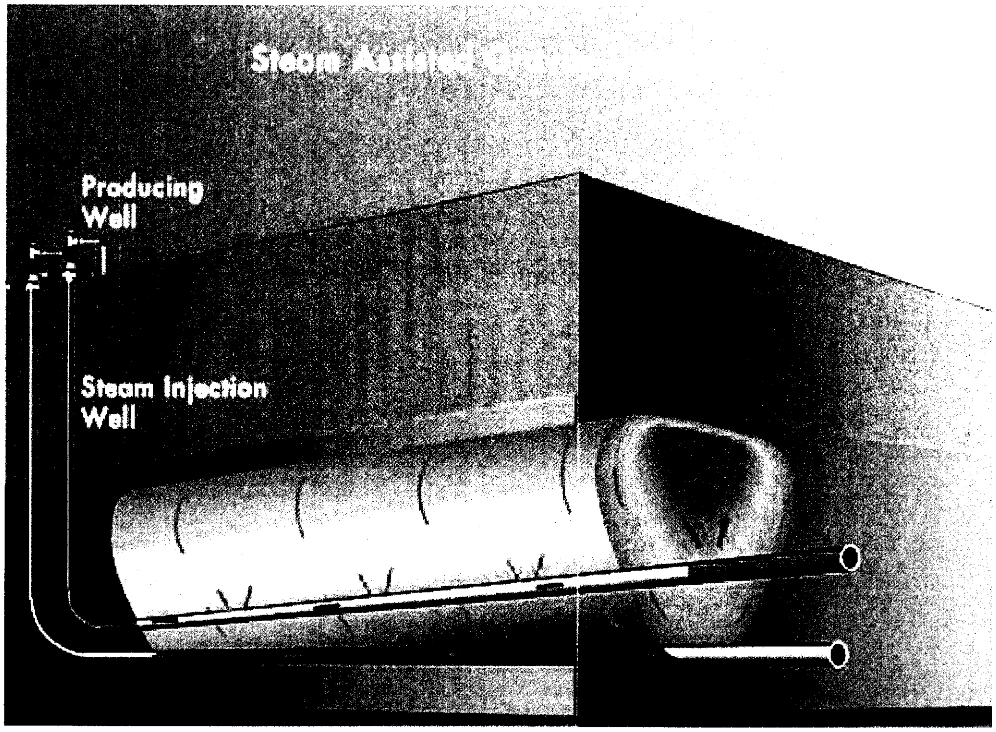


Figure 5: SAGD Well Arrangement
[© EnCana]

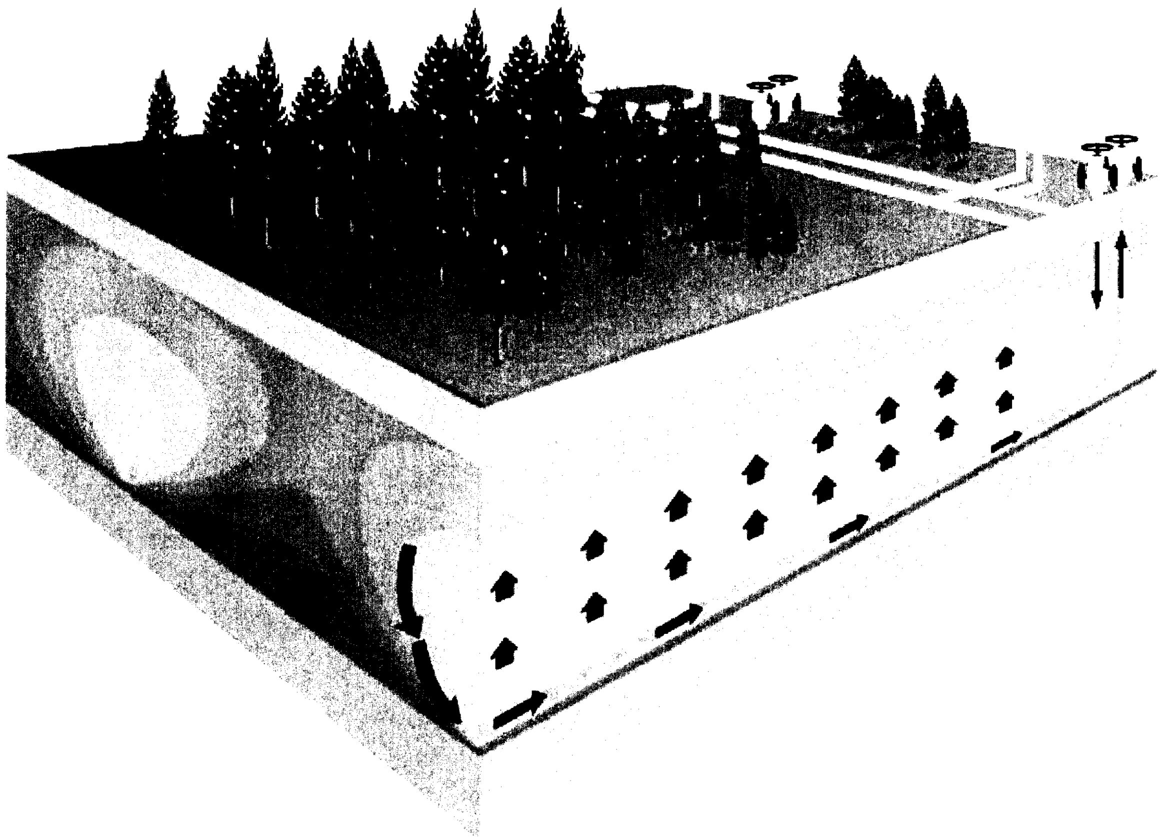


Figure 6: SAGD Field Well Arrangement [© Suncor]

Steam production for SAGD is a very energy intensive process that is currently fueled predominantly by natural gas. The specific energy requirements of this and other extraction methods are described in further detail in Chapter 5: Energy Requirements for Bitumen Production.

2.2.2 Cyclic Steam Stimulation (CSS)

CSS is a three stage process for recovering bitumen. Steam is first pumped down a well for a period of time. Next, the well is closed while the bitumen heats up and seeps inward, and finally the bitumen that has mobilized is pumped up through the same well. The process is illustrated below in Figure 7. This process is repeated multiple times for a given well, until the cost of repeating the cycle fails to justify the expected return. CSS is used primarily in the Cold Lake area of the oil sands, but elsewhere it has not been successful. It was tried at the Long Lake project with poor results, and is discussed in a number of applications for in-situ projects that state that SAGD is a better technology for the region [12].

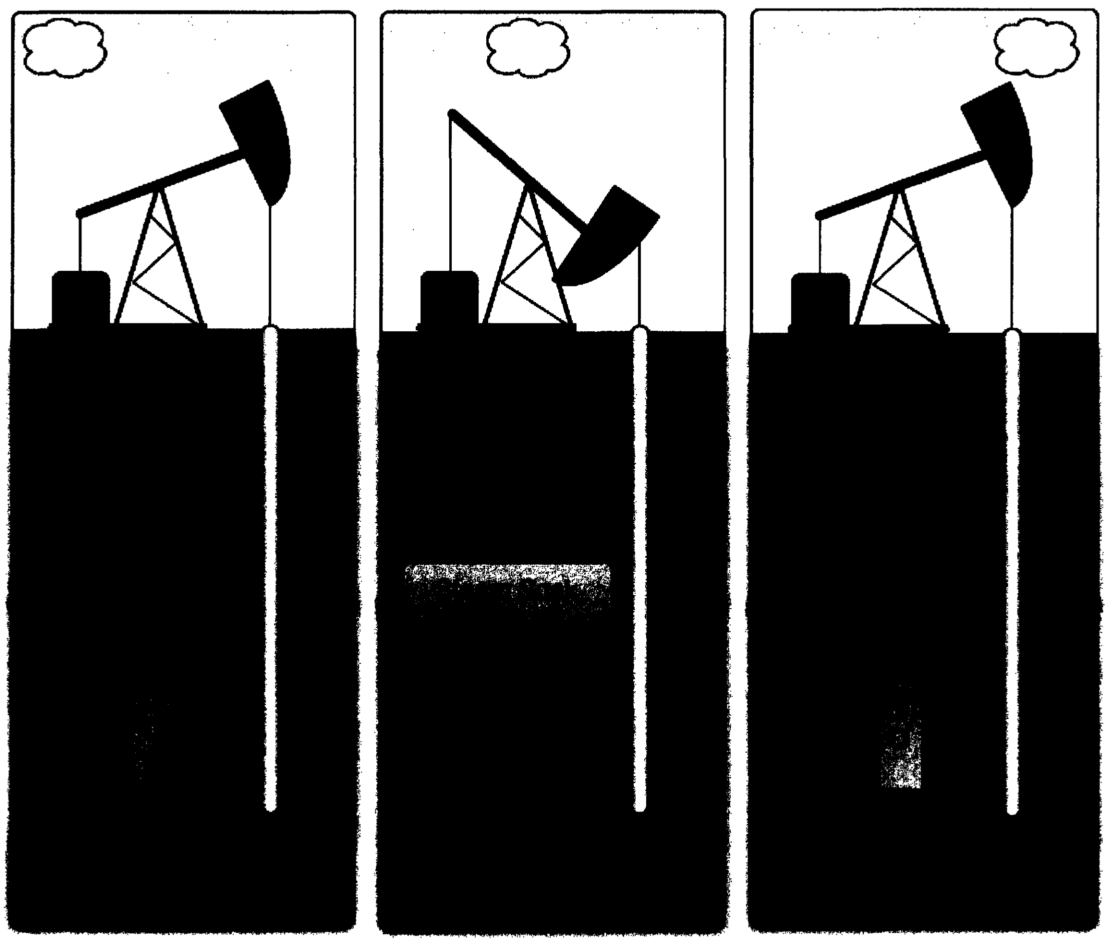


Figure 7: Cyclic Steam Stimulation Extraction Process

2.2.3 OTHER IN-SITU

2.2.3.1 Vaporized Extraction (VAPEX)

Vaporized Extraction (VAPEX) replaces the steam injected in SAGD with a solvent, typically propane or butane. This serves the same purpose as the steam in SAGD, stripping the bitumen particles from the sand so that they can flow and be recovered. VAPEX has the advantage of using very little water as compared with SAGD, and also has lower greenhouse gas emissions and natural gas consumption. A modification to this technology called 'solvent co-injection' (also known as Enhanced-Solvent SAGD) is also being piloted in the oil sands industry. This technique continues to inject some steam with the solvent [13]. VAPEX is being pilot tested at the Dover VAPEX project (DOVAP),

2.2.3.2 Enhanced Solvent Steam Assisted Gravity Drainage

Enhanced-Solvent-SAGD (ES-SAGD), also called Expanding-Solvent SAGD, is a co-injection technology that is under development, and may decrease the natural gas intensity of in-situ recovery. One steam solvent split that has been tested with success is 90% steam, 10% solvent. The solvent is some type of hydrocarbon, so recovering it is of substantial economic importance. Dr. Tawfik Nasr of the Alberta Research Council (ARC) has studied ES-SAGD and found that for the best results, the solvent and the water should transition from water to steam and steam to water together. The hydrocarbon solvent chosen depends on the specific temperature and pressure conditions used for a given injection site [16]. Dr. Nasr and his lab found that in experiments they performed, the used of ES-SAGD reduced the natural gas intensity by about 25% compared to traditional SAGD [17]. A pilot ES-SAGD project operated from February to April, 2006 at the Long Lake SAGD site [14]. TOTAL also has plans to pilot an ES-SAGD test at its Surmont site [15].

2.2.3.3 In-Situ Combustion (ISC)

In-Situ Combustion (ISC) is a method that involves injecting air or oxygen into the oil sands and igniting the bitumen. The ignited portion moves through the earth (controlling how it moves is a key obstacle), and heats the bitumen around it so that it can seep down to the production well. The bitumen must reach temperatures of 350-400°C in order to be effective. At sufficiently high temperatures, some in-situ upgrading of the product takes place by thermal cracking. Interest in ISC processes is growing because they use very little water, and much less natural gas than SAGD and the other steam-based processes. Combustion techniques have been applied in the Athabasca region before, first in 1920, later in 1958, and in at least 30 instances since then. Husky Oil, Petro-Canada, and BP Resources Canada have all operated ISC wells at one time, and Husky currently uses ISC for heavy oil recovery [18]. One type of ISC technology that is currently receiving a lot of attention and research and development effort is Toe to Heel Air Injection.

2.2.3.4 Toe to Heel Air Injection (THAI)

Toe to Heel Air Injection (THAI), one form of In-Situ Combustion (ISC), is a method that burns some of the hydrocarbons underground, creating a combustion "front." The front travels through the soil heating up the bitumen so that the bitumen will flow into the horizontal collection well. Since the heat of the fire can cause thermal cracking of the bitumen, the upgrading process begins before the bitumen is even brought above ground [19]. The THAI method uses much less natural gas and water than SAGD. Though THAI could be a valuable recovery process for the industry, it is not widely used at this point. Difficulties in controlling the combustion front, as well as the risk of unwanted fire have kept THAI from becoming popular, however some believe that that will change as advances are made in THAI technique. Projections indicate that THAI could recover a higher percentage of the bitumen in place than traditional SAGD, with ultimate recovery of upwards of 80%.

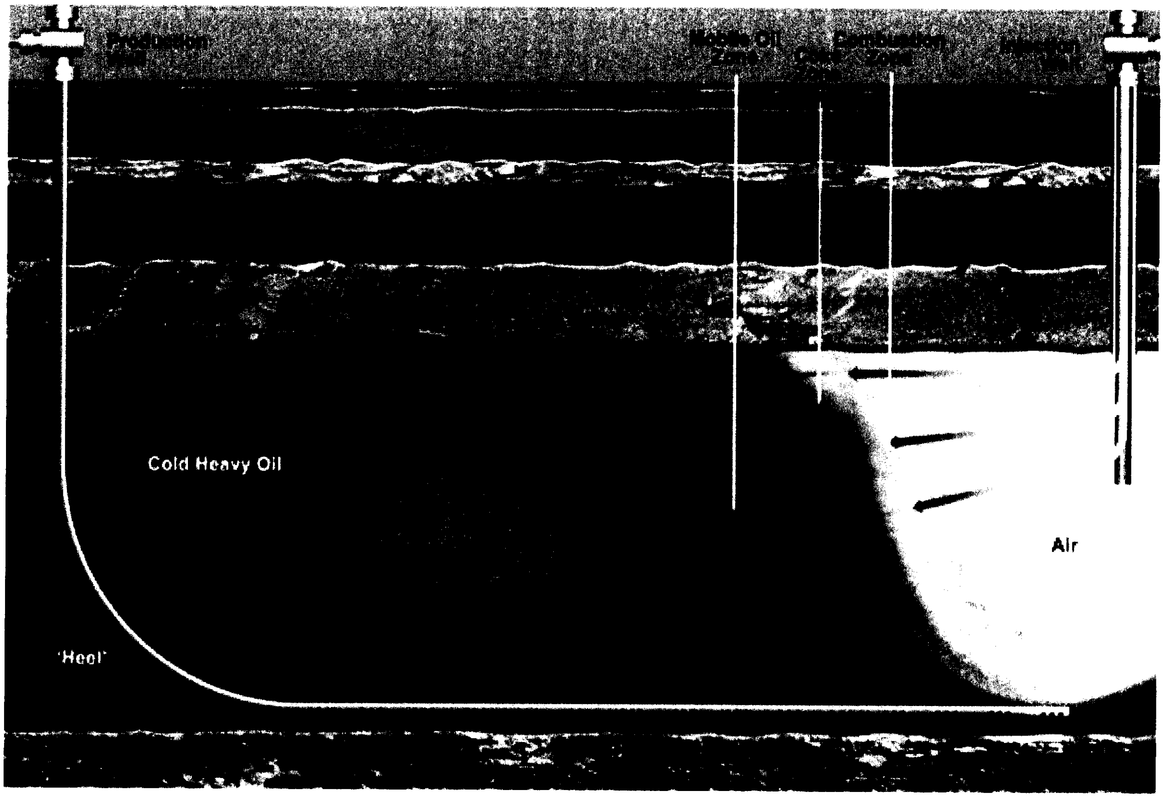


Figure 8: Toe to Heel Air Injection Process [22]

The WHITESANDS project, a currently operating THAI pilot project, has reported positive results, meeting and exceeding forecasts for oil production. WHITESANDS began preheating in March 2006, began injection and combustion in July 2006, and is now operating at a full production rate. As such, the first well pair is producing nearly double what had been predicted. WHITESANDS consists of three 500m horizontal wells. The project has seen temperatures in the reservoir of up to 800°C, and has demonstrated that thermal cracking does occur during heating [19]. Plans for expansion of the project are underway. The majority holder in the project company, Petrobank Energy and Resources, Ltd., contends that THAI is better than SAGD in nearly every. THAI uses less water and natural gas, emits fewer greenhouse gases, can be applied to lower quality reservoirs than SAGD, and will recover a higher percentage of the bitumen in place. Petrobank Energy also states that THAI has lower capital and operating costs and a shorter construction time [20]. The environmental effects of THAI and other ISC processes are not yet well-understood.

2.2.3.5 Polymer Flooding

Canada Natural Resources Limited (CNRL) is actively pursuing a pilot project to explore the injection of a polymer/water mixture into the wells. The mixture has a much higher viscosity than water alone, and so it is less prone to seeping quickly through the oil sands without loosening the bitumen. By preventing the water from passing through the ground too quickly, this method could reduce the total volume of water drawn by a project.

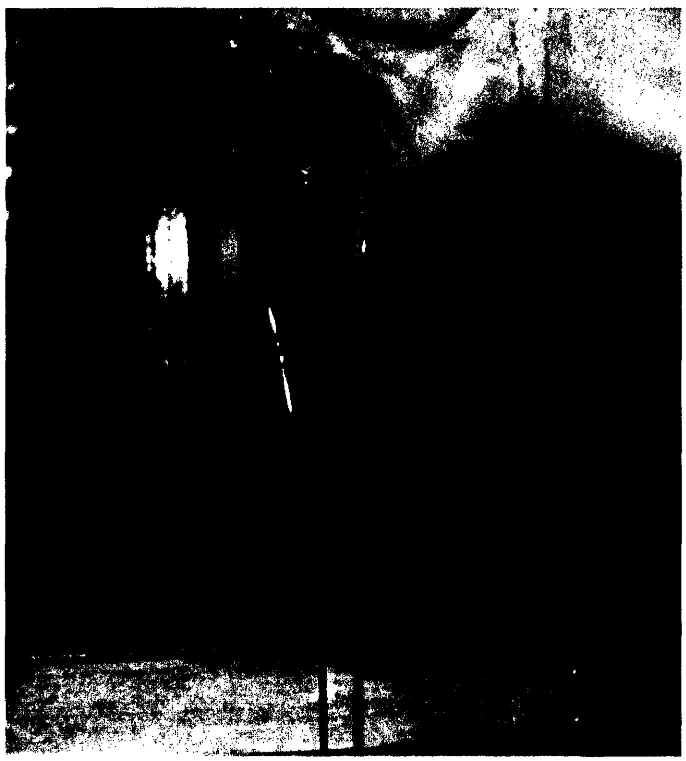


Figure 9: Polymer Being Tested at CNRL for Injection [© CNRL]

2.2.3.6 Low Pressure Steam Assisted Gravity Drainage

Low Pressure Steam Assisted Gravity Drainage (LP-SAGD) is very similar to conventional SAGD; the only difference is that the operating pressures are lower. This is beneficial for taking advantage of bitumen-rich areas that are too geologically fragile to withstand the pressures of traditional SAGD. Proponents of LP-SAGD also say that it will achieve a higher Steam-Oil Ratio (SOR) than SAGD and consequently use less natural gas and water [23]. Deer Creek Energy, EnCana, and Suncor are all testing the LP-SAGD process on their oil sands leases.

These are by no means all of the extraction technologies being explored, but they are some of the most popular at this time. The surge in activity in the oil sands industry has spawned many research projects and innovative ideas.

3 Bitumen Processing and Transport

Bitumen in its natural form is not used as a fuel and, furthermore, cannot be transported by pipeline. Bitumen can be piped if it is first diluted with a lower viscosity hydrocarbon referred to as the diluent to make 'dilbit'. While dilbit allows for transportation, it is still not used as a fuel source. The bitumen must ultimately be converted to synthetic crude oil to produce consumable petroleum products. Synthetic crude oil, also called syncrude, is functionally equivalent to conventional crude oil, but is named as such because it is an upgraded bitumen product, rather than a natural substance. Currently, some companies upgrade mined bitumen to syncrude adjacent to the mine site. Others pipe their bitumen as dilbit to upgrading facilities in other parts of Canada or the United States. The value added in bitumen upgrading is compelling, and efforts are underway in Alberta to increase the amount of bitumen that is upgraded in the province, rather than shipped out as dilbit.

Before upgrading begins, the diluent is separated from the dilbit and piped back to the oil sands to be reused. Upgrading begins with either delayed coking or fluid coking. In both cases, the bitumen is heated to about 500°C, and is separated into petcoke and gas vapor. Petcoke, a carbon-based solid, is a byproduct of the process. It is sometimes burned as a fuel later in the upgrading process, but there is generally an excess, which is stored. A great deal of petcoke has been amassed by upgrading facilities in Alberta, and holders of the petcoke are considering a number of options for its use, including gasification and direct burning. Coking thermally 'cracks' the hydrocarbon molecules of bitumen into shorter chains that are easier to refine [24]. Bitumen molecules can contain more than 2000 atoms, while crude oil molecules range from about 20 to 60 atoms.

Following coking, another cracking process called catalytic conversion takes place. Catalytic conversion takes place at higher temperatures, and includes the addition of hydrogen to transform the carbon-heavy molecules into more hydrogen-rich variations. The mixture of hydrocarbons is next distilled to separate the lighter molecules from the heavier ones. Last, the product is hydrotreated by mixture with hydrogen at high (300-400°C) temperatures. This lightens the molecules further, and stabilizes them by saturating those carbon chains that were not fully populated with hydrogen atoms.

The resulting product is syncrude, which is generally shipped via pipeline and can be easily refined into consumer products, including gasoline.

CHAPTER 2

4 Challenges Facing the Oil Sands Industry

An understood goal for the oil sands industry is to maximize returns in a socially and environmentally responsible way. Currently, a number of challenges threaten that goal, and the expected rapid growth of the industry is likely to bring those challenges to the forefront. Between 2005 and 2020, both in-situ and surface mining bitumen outputs are projected to more than quadruple. From 2005 to 2010, oil sands production will roughly double from just short of 1.0 million bbl/day to 2.1 million bbl/day in 2010 and 4.0 million bbl/day in 2020 [25].

The increasing demand for natural gas and the volatility of its prices endanger the profitability of the industry. The increasing demand of natural gas also threatens to drive home heating prices up for Canadians and Americans. Mounting greenhouse gas emissions from the industry's natural gas use, electricity use, and proposed burning of petcoke will have a large impact on Canada's ability to meet its climate change goals in the decades to come. Other environmental issues, including water usage, land and wildlife disruption, and disposal of byproducts and waste are becoming more serious as the industry expands, and highlight the stress on the local ecosystem caused by the oil sands operations. In addition, a shortage of labor and materials in the rapidly expanding industry is driving project costs well above original estimates and causing delays.

4.1 Natural Gas Supply

The predicted rapid growth of bitumen in the oil sands output will require a commensurate increase in energy use. Daily production of 2.1 million bbl could require approximately 1.4 to 1.8 billion cubic feet of gas per day, or approximately 10% of western Canada's natural gas production [25]. This is equal to the maximum throughput of the proposed Mackenzie Valley Pipeline, expected to go online in November 2009 [26]. 4.0 million bbl/day of bitumen production (subsequently upgraded) could consume as much as 3.1 billion cubic feet of gas per day, or nearly 20% of the projected natural gas production in Western Canada in 2020 [27].

4.2 Shortage of Labor/Material

The sudden massive investment in construction in the oil sands industry has led to serious shortages of labor and materials. Labor shortages have been widely publicized, and have resulted in year to year regional wage increases at least double the national average [28][29][30][31].

According to Alberta Industry Minister Iris Evans, the province currently has a shortage of about 100,000 skilled workers, and will need at least 400,000 more skilled workers in the next ten years [32]. CNRL's Horizon mine project may have up to 7,000 construction workers on site during the summer of 2007, and many other projects will be competing for employees during the mild summer season. One technique being used to fill the labor shortage is the importation of foreign workers. From 1996 to 2006, the number of the province's temporary foreign workers has more than tripled to about 22,000[33].

The labor shortage is coupled with a significant productivity loss in the industry. Since skilled workers are difficult to find, many companies have to hire inexperienced workers. For example, Nexen Inc. found last spring that labor productivity fell 20% short of their projections due to the inexperienced workforce [34].

The housing market in Fort McMurray has taken off, with the average price of a single-family home at $509,880[1] in February, 2007, and the average price of a mobile home

[1] All dollars are in Canadian dollars unless noted otherwise.

with land at $306,600 [35]. Home prices have continued to rise despite rapid building. In 2006, nearly 5 homes were completed in the Ft. McMurray area each day [36]. Due to the shortage of labor in the immediate area, a number of large oil sands companies have runways at their sites, or have plans to build one, so that labor can be easily flown in from Eastern Canada for 6 week shifts.

The labor shortage in Alberta may give wages upward momentum, but it is accompanied by a rise in the cost of living, and it is causing companies to lose productivity and to fall behind schedule. Should the labor shortage persist, it is likely to hinder the planned oil sands developments' profitability and construction schedules.

4.3 Water Usage

On average, each barrel of produced synthetic crude oil requires 2-5 barrels of water [41]. Water is an integral part of the process; it is used for steam production for SAGD, extraction of bitumen from sands in direct mining, power production, and heat generation. Efforts are being made to reduce the water requirements of the oil sands production process, but in the near future there are no prospects for better than incremental improvements in water usage, and the expansion of the industry will far outpace those improvements.

Both water recycling and saline water use are being widely implemented in SAGD projects with great success. For example, the Long Lake South project will produce 140,000 bpd of bitumen, but will draw only 193 m^3/day of fresh water. In fact, the fresh water is only needed for potable water use. All other water for SAGD recovery will either be saline water, recycled water, or surface water collected on the project site [38]. Total SAGD saline water requirements for the project amount to just under 10,000 m^3/day. However, the upgrader, which will process the same 140,000 bpd of bitumen into syncrude, will draw just over 10,000 m^3/day of fresh water.

Ironically, despite the fact that SAGD appears to be more water-intensive, with its massive steam requirements, it is actually direct surface mining that should be of greater concern at this time. In the process of digging a surface mine in the oil sands, the groundwater in the area is purposely lowered so that the mine will not flood. Often aquifers found under the surface in a mineable area are drained and reinjected into a separate aquifer at a safe distance from the mine. This can affect the supply of water available to area wetlands, and has caused the destruction of some peat and wetlands areas that were not directly removed through the excavation of the overburden [40].

Current direct mining extraction technology requires fresh water, and the concentration of most of the mines around the Athabasca River puts a particularly focused burden on that watershed. The TrueNorth Energy Corporation estimated in its application to the Alberta Energy and Utilities Board (EUB) that the Fort Hills direct mining project would have an average fresh water draw of 81,643m^3/day for the production of 188,000 bpd of bitumen. To account for peak flow requirements, TrueNorth requested a permit for the withdrawal of 124,110 m^3/day (about 780k barrels, or 124 million liters, or 32.8 million gallons per day). Fresh water for direct mining projects is predominantly drawn from the Athabasca River for direct mining extraction and upgrading, and only about 10% is returned to the river. Most of the water becomes contaminated with the bitumen, heavy metals, industrial chemicals, and soil, and are directed into tailings ponds, where they will sit for decades until the silt filters out of the water and it can be reclaimed. Reclamation of the water has not yet been demonstrated. For the foreseeable future, this water will not be returned to the river or other natural water reservoirs [41]. While only 1% of the Athabasca River is currently allocated to oil sands, many groups are concerned about the health of the river's ecosystem as flow could easily reach 3% [43]. This comes primarily as a result of the fluctuation in the river's actual flow throughout the year. While the yearly average flow through Ft. McMurray is 650 m^3/s, monthly averages during the winter are usually lower than 180 m^3/s, and flow sometimes falls as low as 90 m^3/s, or less than 14% of the average flow [43]. During the winter, the 3% allocation to the oil sands actually amounts to closer to 10.8% of the flow for that time of year, and should the flow fall to 90 m^3/s, the oil sands allocations would account for 21.7% of the river's water flow.

While a number of technologies that would preserve water are being explored for SAGD use (THAI, ES-SAGD, LP-SAGD, etc.), there is little prospect for great change in the water use trend for direct mining. As far as the use of fresh water is concerned, the direct mining impact is significant, while SAGD plays a minimal role in its consumption.

4.4 Greenhouse Gas Emissions and Canada's Climate Change Plan

The GHG emissions due to natural gas use in 2020 could be over 150 megatons of CO_2e due to oil sands extraction and upgrading. This would account for approximately 17% of Canada's total forecasted emissions for that year. (The total forecasted GHG emissions is 897 megatons [44].) For an industry that is tucked into a fairly small portion of the country, this indicates a staggering GHG emissions intensity that must be reduced if Canada hopes to decrease its greenhouse gas emissions appreciably.

4.4.1 The Kyoto Protocol

Canada signed the Kyoto Protocol on April 29th, 1998, and formally ratified the document on December 17th, 2002 [50]. The protocol required Canada to reduce its greenhouse gas emissions by 6% relative to 1990 levels between 2008 and 2012 [46]. However, by 2004, Canada's greenhouse gas emissions had risen to level 26.6% higher than 1990 levels [47]. This emissions increase is predominantly in the form of increased CO_2 emissions, and is overwhelmingly due to energy sector emissions increases.

The Kyoto Protocol formally became international law on February 16, 2005 [48]. On April 13th of the same year, Canada announced its implementation plan for meeting Kyoto targets, but debate and objections to the plan have been ongoing since then. On February 8th, 2007, the Minister of the Environment, John Baird, announced that Canada would abandon its Kyoto targets [49]. An alternative plan entitled "Turning the Corner" was released on April 26th, 2007.

4.4.2 "Turning the Corner"

Canada's new climate change action plan, coined "Turning the Corner," has as its goal an absolute reduction in industrial greenhouse gas emissions of 150 megatons by 2020, or roughly a 20% reduction compared with national 2006 levels [51] below. It also calls for other forms of air pollution from industry to be reduced in varying amounts by 2015. John Baird, Minister of the Environment, when announcing the new plan, said "Canadians want action, they want it now, and our government is delivering. We are serving notice that beginning today, industry will need to make real reductions [52] below."

The Turning the Corner plan gives industry many options for meeting the required reductions. Companies can meet their obligations by reducing their own emissions, contributing money to a fund that will support new technologies to reduce GHG emissions, trading emissions credits with other Canadian companies, by purchasing offsets from unregulated industries that are reducing their emissions, and by engaging in reduced emissions projects in developing countries. In the future, the plan calls for a larger North American emissions credit trading market, should the US and/or Mexico decide to join Canada in taking action on climate change. Companies that have already taken action to reduce their GHG emissions (between 1992 and 2006) will receive a one-time credit in recognition of their efforts, and newly constructed facilities will have a three-year period to begin efficient operation before they are under the obligations of the plan [53] below.

4.4.3 Effects on the Oil Sands Industry

Despite the strong words of the Turning the Corner campaign, the real extent of its effect on the oil sands industry remains to be seen. Emissions targets for each sector are to be validated by June 2007. Sector targets are being determined by benchmarking them against the most stringent of the standards found in other countries, the current emissions of the best technology, and the current emissions most prevalent in the industry. Little information has been given to date on the specifics of the targets, but for the oil sands industry, the Ministry of Energy offered the following analysis:

> *...for the oil sands sector, which is unique to Canada, there are no comparable regulated sectoral emissions limits in other countries that would enable a comparison with other jurisdictions. In this case, sectoral targets were established using a multi-step approach. This included an evaluation of performance for similar activities, equipment, and processes at similar sources of emissions in other jurisdictions, such as heavy oil refineries; an examination of the potential for reductions using selected emission control technologies; and a comparison of emission-intensity performance of individual oil sands facilities within Canada.*

The guidelines differentiate between fixed-process emissions and non-fixed process emissions. Fixed-process emissions are those in which emissions are tied to production, and there is no known way to reduce emissions besides reducing production. Non-fixed process emissions can be reduced using known technology. The reduction targets in the Turning the Corner plan apply "only to combustion and non-fixed process emissions [53]."

Given that oil sands emissions in the SAGD process come primarily from the combustion of natural gas, there should be no debate about the necessity of reductions in that area. However, should the government determine that the natural gas burning for the oil sands is "production tied," it would seriously undermine the GHG reduction plan in Canada. Given that there are alternatives to the use of natural gas as a heat source for steam, electricity, and possibly hydrogen production, claims made about natural gas being production tied could be challenged.

4.5 Other Environmental Issues

Other environmental issues facing the oil sands direct mining industry include the destruction of boreal forest, disruption of wildlife, and sulfur production. Depending on the form of oil sands extraction, these impacts are lower for some forms such as SAGD. While greenhouse gas emissions and water usage and contamination are generally considered to be the largest unwanted byproducts of oil sands operations, the additional effects on land and wildlife only serve to magnify the cumulative environmental damage. The impact of oil sands activity on traditional land use and the aboriginal lifestyle is also closely watched and contested. Public and political debate regarding the negative impacts of the oil sands industry is ongoing, and could result in associated costs and restrictions for the industry in the future particularly in the area of carbon taxes or their equivalents.

CHAPTER 3

5 Energy Requirements for Bitumen Production

5.1 SAGD Heat and Steam

SAGD fields vary significantly in their steam requirements. Some fields operate using steam generated at 9-11MPa and 310-320°C (Suncor's Firebag, EnCana's Foster Creek), while others may use steam generated at about 6.0 MPa (275°C) with similar success (e.g. Shell's Blackrock project) [54][55]. The desired steam generation temperature is affected by the geological characteristics of the area, the distance over which the steam must be piped, and the quality of the bitumen reserve (including viscosity, saturation and porosity). Steam pressure is limited by the fracture pressure of the formation. At some pressure, the integrity of the soil and rock is jeopardized, and the oil sands companies are not permitted to exceed those pressures (nor would it be to their advantage to do so). Fracture pressures range considerably, but as an example, in Shell's BlackRock Orion SAGD project, the formation fracture pressure is 10MPa.

Pilot projects are currently underway to determine the feasibility of using Low-Pressure SAGD. Steam is typically produced at a quality of approximately 80% and is subsequently separated to 100% quality. After pressure drops due to friction and flow splitting (directing streams to separate well pads), the steam is closer to 4.5 to 6.5 MPa when it reaches an injection well. A typical Steam to Oil Ratio (SOR) is between 2 and 4, with the goal of course being at the lower end. The actual SOR for any given well depends on the quality of the deposit and specific geology in the region. For this analysis, steam production will be assumed to be between 6MPa and 11MPa saturated steam with a related SOR of 2 to 3. Thus, over the lifetime of a given well, one barrel of bitumen is recovered for every 2 to 3 barrels of steam injected (cold water equivalent).

Most SAGD project phases in the Athabasca region are between 10k and 60k bbl/day. Peak production rates are projected to range up to about 210k bbl/day (at EnCana's Foster Creek project, for example), with most of the larger proposed projects in the range of 100k bbl/day. The amount of time budgeted to reach peak output varies by project, ranging from 5 years or less for small projects up to 40 years for some of the larger ones [56]. Depending on the field and the strategy of the company however, even the projects with capacity upwards of 100k bbl per day can reach full production within 7-10 years.

The largest projects that have peak production over 100k bbl/day do not, in general, rely on a single steam supply location. For example, the Opti-Nexen integrated in-situ production and upgrading project, "Long Lake," plans a number of Central Processing Facilities (CPFs) with steam production, each of which will serve about 70,000 bpd of SAGD production. The steam generation in a CPF amounts to about 230,000 bpd of steam (CWE). This will be provided by eleven natural gas fired Once-Through-Steam-Generators (OTSGs) of 92 MWth each, as well as a 360 MWth Heat Recovery Steam Generator (HRSG). This totals 1372 MWth (gross) [57]. By spreading the steam capacity out into separate CPFs, the companies avoid piping the steam over long distances to reach the well pads. The shorter distance results in less pressure drop and higher efficiency. A smaller project, Shell's BlackRock Orion SAGD operation, was originally expected to produce 20,000 bpd of bitumen. Project plans called for five 75MWth (250 MMBtu) natural gas fired OTSGs to provide the necessary steam, in this case all from one location [58]. [Note: Shell has since decided to increase the size of the project to 30,000 bpd.]

A general estimate for in-situ SAGD recovery is that each barrel of bitumen recovered demands 1.0-1.5 Mcf of natural gas [61][60]. An SOR of 2.5 corresponds to a natural gas requirement of 1.1 Mcf/bbl. An SOR of 3.0 is used for Table 2 below, corresponding to a natural gas intensity of 1.3 Mcf/bbl. (One Mcf is equivalent to 1.027 MMBtu.) Table 2 shows the natural gas consumption and resulting GHG emissions per day (and per year) of varying amounts of SAGD bitumen production per day.

Table 2: SAGD Steam Natural Gas Consumption and GHG Emissions

Barrels of Bitumen per Day	Natural Gas for Steam production (MMBtu/day)	Resulting GHG emissions (metric tons of CO_2e/day)[2]	GHG emissions in kilotons CO_2e per yr
30,000	40,053	2,603	950
60,000	80,106	5,207	1,900
100,000	133,510	8,678	3,170
200,000	267,020	17,356	6,340
500,000	667,550	43,391	15,840
1,000,000	1,335,100	86,781	31,680
2,000,000	2,670,200	173,562	63,350

[1] Table 2 assumes 1.3 Mcf of natural gas used per barrel of bitumen recovered.

[2] A conversion ratio of 65 kg CO_2 per MMBtu of natural gas burned is used.

5.2 SAGD Steam Piping Distance

A simple model of a pipe carrying SAGD steam was created in Applied Flow Technology's "Arrow" software to verify the estimates of industry experts that that practical limit on piping steam is about 10-15 km. The model was run for two cases, specified below in Table 3.

Table 3: SAGD Steam Pipe Model Results

	Case A	Case B
Distance (km)	10	10
Inlet Pressure (MPa)	7.0	10.0
Inlet Temperature (°C)	286	315
Mass Flow Rate (kg/s)	300	300
Ambient Temperature (°C)	-12	-12
Wind speed (mph)	15	15
Pipe Inner Diameter (inches)	25	23
Pipe Wall (inches)	3.05	2.8
Pipe Material	Carbon steel	Carbon steel
Insulation Material	Calcium Silicate	Calcium Silicate
Insulation Thickness (inches)	4	4
Heat Loss (kW)	144.6	151
Outlet Pressure (MPa)	4.26	7.3
Outlet Temperature (°C)	247	287

The outlet pressure at 10 km for steam produced at 7.0 MPa was found to be 4.3 MPa, which is at the very low end of most SAGD steam injection pressures. Additionally, the model through a single pipe over 10 km does not account for the pressure drop due to form losses in any valves, bends, or pipe diameter variations that would certainly exist in a practical field. The combination of this evidence and the expert opinion that 10-15 km represents a practical limit was the motivation for choosing 10 km as the maximum distance for piping steam in the analyses of the steam generation options explored in this thesis.

The maximum well density was chosen based on a survey of industry documents. A review of well field development planning maps indicated that the well pad density in a field varies greatly, ranging from about 1 well pad per 2 sections to 2 well pads per section. The density chosen for this analysis was approximately 1 well pad per section with 8 well pairs per well pad.

5.3 SAGD Electricity

SAGD projects require relatively little electric power relative to their required thermal power. Electricity is used primarily for pumping the fluids used in the process. A typical SAGD project uses about 9 kWh per barrel of bitumen produced 0. Table 4 summarizes the SAGD electricity requirements for various production rates of bitumen per day and the resulting GHG emissions based on the grid emissions factor.

Table 4: SAGD Electricity Supply and GHG Emissions

Barrels of bitumen per day	Electricity requirement MWe	GHG emissions CO_2e metric tons/day	GHG emissions CO_2e kilotons/yr
10,000	3.75	30	11.0
30,000	11.3	90	32.9
60,000	22.5	180	65.7
100,000	37.5	300	109.5
200,000	75.0	600	219.0

Assumes 0.15 Metric tons per MWhr and 45% electrical efficiency 0000

5.4 Direct Mining and Extraction Electricity

The direct mining and extraction process uses about 16 kWh of electricity per barrel of bitumen recovered 00. Roughly 10% of the electricity is used in the mining process, 80% is used for bitumen extraction and cleaning, and 10% is used for utilities and other miscellanies. Table 5 provides a summary of electricity requirements for direct mining and consequential GHG emissions of gas fired units.

Table 5: Direct Mining Electricity Supply and GHG Emissions

Barrels of bitumen per day	Electricity supply requirement MWe	GHG emissions CO_2e metric tons/day	GHG emissions CO_2e kilotons/yr
10,000	6.7	53	19
30,000	20.0	160	58
60,000	40.0	320	116
100,000	66.7	533	193
200,000	133.3	1067	387

Assumes 0.15 Metric tons per MWhr and 45% electrical efficiency

5.5 Direct Mining and Extraction Steam/Hot water/Heat

A review of current direct mining activity indicates that the thermal energy requirements to extract one barrel of bitumen from the mined oil sands is equivalent to approximately 1 Mcf of natural gas per barrel, or about 12 kWth per barrel per day capacity [61]. However, since most large direct mining projects also have on-site upgraders, the majority of that requirement is provided by waste heat from the upgrader. The remainder of the heat that is provided by dedicated gas-fired boilers is equivalent to about 0.28 Mcf of natural gas per barrel, or 3.5 kWth per bpd of production. Due to the typical arrangement of sharing heat between the upgrader and the extraction plant, only the extraction-dedicated energy production will be attributed to the extraction operation here. The heat that is initially provided to the upgrader will be assessed only to the upgrader to avoid double-counting. The hot water and steam used in the extraction process have a variety of purposes that are described in Table 6 below.

Table 6: Extraction Steam Properties and Uses [67]

Steam Properties	Purpose
High pressure, 4-5 MPa	Hydrogen plant Steam turbines Velocity steam Diluent heater Sulfur plant reheater Naphtha hydrotreater heater Gas oil hydrotreater stripping steam
Medium pressure, 1-1.5 MPa	Sour water stripper reboiler Heat tracing Ejectors Diluent heater Stripping steam Coke drum purges
Low Pressure, 0.4-0.6 MPa	Sulfur plant heat tracing/jacketing Froth deaeration Extraction water heating Utility steam Stripping steam

Table 7: Direct Mining Extraction Heat Requirements, Natural Gas Consumption, and GHG Emissions

Bitumen bpd	Natural Gas for Steam and Hot Water production (MMBtu/day)	Resulting GHG emissions (metric tons CO_2e/day)	GHG emissions in kilotons CO_2e per [illegible]
10,000	2,875	187	68
30,000	8,627	561	205
60,000	17,254	1,121	409
100,000	28,756	1,869	682
200,000	57,512	3,738	1,364

Assumes 65 kg CO_2 per MMBtu NG burned (One Mcf is equivalent to 1.027 MMBtu)

Mining/Extraction: 0.28 Mcf gas per bbl bitumen

5.6 Upgrading Electricity

Upgrading requires about 9.2 kWh of electricity per barrel of bitumen processed, or about 10.6 kWh per barrel of upgraded product, assuming a conversion efficiency of 86% [67]. Shown in Table 8 are the electricity requirements for upgrading and consequential GHG emissions produced by gas fired units.

Table 8: Upgrading Electricity Requirements and GHG Emissions

Barrels of bitumen per day (barrels of product)	Electricity supply requirement MWe	Resulting GHG emissions in metric tons CO_2e/day	GHG emissions in kilotons CO_2e per yr
10,000 (8,600)	3.8	31	11
30,000 (25,800)	11.5	91	33
60,000 (51,600)	23.0	183	67
100,000 (86,000)	38.4	305	111
200,000 (172,000)	76.6	610	222

[55], [56].

5.7 Upgrading Steam/Heat

The steam and hot water used in the upgrading process requires between 0.15 and 0.4 GJ/barrel of bitumen upgraded (0.3 to 0.45 Mcf/barrel). The calculations performed for this analysis are based on thermal energy consumption of 0.25 GJ/barrel, about 69 kWh/barrel. This is equivalent to 0.23 Mcf of natural gas per barrel of bitumen, or 0.27 Mcf natural gas per barrel of upgraded product [66][67].

Table 9: Upgrading Heat Requirements, Natural Gas Consumption, and GHG Emissions

Barrels of bitumen per day (barrels of product)	Natural Gas for Steam and Hot Water production (MMBtu/day)	Resulting GHG emissions in metric tons CO_2e/day	GHG emissions in kilotons CO_2e per yr
10,000 (8,600)	2,362	154	56
30,000 (25,800)	7,086	461	168
60,000 (51,600)	14,173	921	336
100,000 (86,000)	23,621	1,535	560
200,000 (172,000)	47,242	3,071	1,121

5.8 Upgrading Hydrogen

Bock and Donnelley report that upgrading requires 2200 SCF, or 0.00532 tons of hydrogen per barrel of syncrude [68].

Table 10: Upgrading Hydrogen Requirements

Barrels of bitumen per day (barrels of product)	Hydrogen Required (Million SCF)
10,000 (8,600)	22
30,000 (25,800)	66
60,000 (51,600)	132
100,000 (86,000)	220
200,000 (172,000)	440

6 Possible Energy Sources

While the industry currently derives most of its energy from natural gas, it is clear that future growth may mandate a change from the status quo. All other forms of power should be considered as options, and many different technologies are likely to play a role.

6.1 Wind

While wind power has a number of environmental issues of its own, it is an electricity source with no direct emissions that has recently been gaining capacity in Alberta and other parts of Canada. Its drawbacks include land intensity, danger to wildlife (particularly bats), vibration in the immediate vicinity, noise, and detriment to scenery [71][72][73]. Wind power typically has had reliability issues as well, and may not be suitable for base load generation. In response to that challenge, the Alberta Electric System Operator (AESO) has placed a cap of 900MW on the amount of wind generation that Alberta can use. This cap is designed to avert the destabilization of the Alberta grid due to wind power's inherent common mode unavailability.

Wind power is not poised to provide steam to the oil sands since it does not employ a steam loop, but it does have some potential to provide electricity to the oil sands and to expand a company's green energy portfolio. In the situation where an oil sands company produces its own electricity on-site, wind power's weaknesses are the most problematic. Since the company would wish to minimize transmission costs and to place the turbines on its own property, the turbines would be subject to relatively uniform wind patterns, and the system's reliability would suffer. However, from a public relations perspective and a political perspective, wind power confers an image of environmental awareness, and may be a good investment for that benefit alone. Additionally, the federal government subsidizes the wind generation at a rate of $10/MWh for the first ten years of operation [74]. In addition, wind energy can be used to 'offset' a company's oil sands emissions in accounting for its total greenhouse gas impact, as Suncor has done in other parts of Canada [75].

6.2 Hydroelectric

Canada has a great hydroelectric resource, and already obtains about 60% of its power from hydro generation. There has not been a lot of recent hydroelectric development because most resources within transmission distance of major energy consumption areas have been developed. Ft. McMurray and the oil sands constitute a newly developed energy demand market, so there is an opportunity for the creation of new hydroelectric plants in the area. Before building such a facility, a company would have to research adequate dam locations. One caveat peculiar to the oil sands industry threatens the ability of the province to find a suitable location. Since water usage by the industry is a limiting factor in its growth, the flow interruption of water sources could be harmful to that aspect of the oil sands industry's resource needs. Barging components to the oil sands project sites is being considered as well, and the presence of hydroelectric dams would certainly pose problems for the success of that effort.

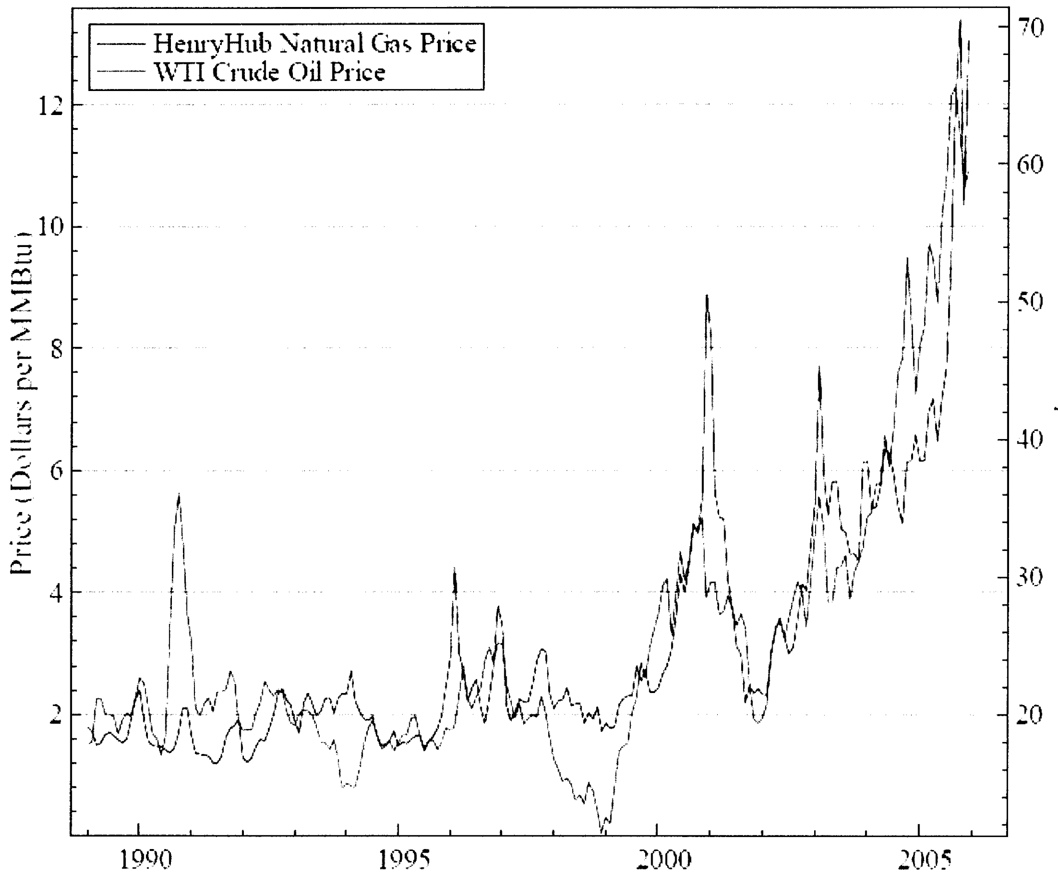
6.3 Geothermal

The possible use of geothermal energy for SAGD heat supply is being heavily investigated by researchers and the oil sands industry. An industry consortium called GeoPOS ("Geopower in the Oil Sands") was formed in order to support the inquiry into this source of energy. So far, geothermal prospects are very promising. A demonstration well is in the planning stages, and the success of that project will have significant bearing on the extent to which geothermal is pursued for this application. Experts in the field estimate that development will need 15 years before the proposed Enhanced Geothermal Systems (EGS) are ready for commercial use [76].

6.4 Natural Gas

Natural gas is the fuel currently used most widely (and almost solely) to provide energy to the oil sands industry. Natural gas has historically been a very convenient fuel source; it is drilled for in great quantities in Western Canada, in Alaska, and offshore, and many of the companies now involved in oil sands mining also have divisions that produce natural gas in the area. Pipelines are already in place near Fort McMurray, and in fact, before the oil sands became economic, drilling for natural gas was taking place in the same fields. Natural gas fired capacity is built easily and quickly, requires relatively low capital investment, and has high reliability.

It is easy to see why natural gas has been the fuel of choice for the oil sands. However, as discussed in Chapter 2, the industry currently faces a number of issues strongly tied to its natural gas consumption. Natural gas prices have risen markedly in the past decade, and the consumption of the oil sands sector is quickly moving towards rivaling all other domestic consumption. Natural gas prices are also fairly volatile when compared with most other fuel options (excluding oil), as illustrated in Figure 10. The close relationship between oil and natural gas prices also prevents oil sands profits from rising as much as they could when oil prices rise. With a more stable energy source, those spikes could be to the great advantage of the oil sands companies.



Source Energy Information Administration. *Short-Term Energy Outlook*, various issues

Figure 10: Henry Hub and WTI Prices (1989-2005) [77]

From an environmental standpoint, natural gas emits far less greenhouse gas than coal, oil, or bitumen. However, the shear scale of the industry results in emissions that are highly significant to Canada's total emissions, and thus have a large impact on Canada's ability to reduce or even stabilize its total emissions. Should the cost of emissions to the emitter become significant in the near future, the cost of using natural gas will become even higher. In the aggregate, while natural gas is well-suited to this application in energy and in deployable size, the difficulties with natural gas tend to make it expensive, and this has prompted the industry to begin investigating other fuel options in earnest.

6.5 Petcoke

One of the options that the industry is exploring to supplement or replace natural gas usage is the burning of petcoke (similar to coal), which is a byproduct of oil sands upgrading. Since petcoke is a byproduct, it is very inexpensive, and is currently a liability to handle, store, and dispose of. It is being burned in small quantities by a few companies, but is not widely used because it is a very dirty fuel, with emissions similar to coal.

6.6 Bitumen

An obvious option is to burn some of the product bitumen. Were it burned before upgrading, it would be a very high-emissions fuel, and after upgrading, it is so valuable that it does not make economic sense to use it onsite unless natural gas becomes prohibitively expensive.

6.7 Nuclear

Nuclear power is being considered as a possibility for oil sands use because it is a base load generating resource, it has no greenhouse gas emissions, it is proven technology, is very less sensitive to fluctuations in fuel costs, and it has the potential to offer cost savings. However, nuclear energy brings with it a few unique characteristics that are foreign to the oil sands industry. There has not previously been any nuclear power in Alberta, or in the oil sands business. This is a significant obstacle to nuclear energy's introduction into the oil sands business requiring a new model for operations to allow for successful application..

On the other hand, nuclear energy has the potential to provide steam, electricity, and eventually hydrogen to the oil sands industry with no direct greenhouse gas emissions and at a cost that may be competitive with natural gas [77][78][79][80][81]. There is a growing consensus that greenhouse gas emissions must be decreased, and that nuclear power will be a part of the solution. The oil sands industry presents itself as a prime candidate for making nuclear energy a part of its environmental strategy, but the key question that must be answered is whether the benefits of introducing nuclear power outweigh the difficulties involved. The remainder of this report will focus on evaluating the aspects that contribute to that decision.

CHAPTER 4

7 EVALUATION OF REACTOR OPTIONS

A few specific types of nuclear reactors have been proposed for use in the oil sands, namely the Enhanced CANDU 6, the ACR-1000 (Advanced CANDU Reactor), and the high temperature helium cooled gas-cooled reactors such as the Pebble Bed Modular Reactor (PBMR) and AREVA's ANTARES prismatic design. For the purpose of this study, since the PBMR is further along in development, it will be used as the reference high temperature gas reactor.

In each case, the capacity of the nuclear reactor for producing steam has been modeled using the Aspen Plus program. The inputs and modeling conditions are described in detail in the appendix. The results of this simplified analysis do not represent exact reactor outputs, nor do they represent the outputs that may have been calculated be the owners of the technologies. Detailed design information was not available, and an analysis of such information could yield somewhat different results. The analysis performed for this thesis was intended to determine the approximate steam production capacity for each reactor for the purpose of comparing that output to the needs of an oil sands project. Diagrams, flowcharts, or other figures depicting the reactors are conceptually produced for this specific analysis and do not necessarily represent what a vendor might propose but are judged to be indicative of what nuclear applications might be capable of in the applications noted.

7.1 Enhanced CANDU 6

The Enhanced CANDU 6 has some clear advantages from a practical perspective. The CANDU line has been the reactor of choice in Canada since the nuclear power industry began there, and as such has been licensed by the Canadian Nuclear Safety Commission (CNSC). In fact, it is the only type of reactor that the CNSC has any recent experience licensing. An aerial photo of the CANDU 6 units in Qinshan, China is shown in Figure 11. Six CANDU reactors have been built internationally since 1996 on budget and on or ahead of schedule, which should alleviate some of the business community's concern that a nuclear plant will always take longer and cost more to build than expected. In Ft. McMurray or Edmonton, of course, any construction project would be subject to the unusual difficulties, labor shortages, and cost inflation that typify the region, but because of its very close relationship with the CANDU 6, the Enhanced CANDU would be less likely to bring additional inherent difficulties of its own, such as first of a kind engineering or construction complications and delays beyond the norm for the region.

The Enhanced CANDU is a Pressurized Heavy Water Reactor (PHWR), using heavy water as both a coolant and a neutron moderator. It provides approximately 740 MWe (2064 MWth) in a two loop primary cooling configuration with four steam generators. The plant's expected operating conditions are shown in Table 11.

Table 11: Enhanced CANDU Reactor Operating Data [85]

Enhanced CANDU Reactor Operating Data	
Heat Output	2064 MWth
Electricity Output (max, for electric plant only)	740 MWe
Fuel	1.7% enriched uranium (UO2)
Coolant	Heavy Water
Moderator	Heavy Water (65°C)
Reactor Inlet Temperature	266°C
Reactor Inlet Pressure	11.25 MPa
Reactor Outlet Temperature	309°C
Reactor Outlet Pressure	9.89 MPa
Primary Side Flow Rate	7.7 Mg/s
Secondary Side Fluid	Water
Secondary Side Inlet Temperature	187°C
Secondary Side Outlet Temperature	260°C
Secondary Side Steam Pressure	4.7 MPa
Secondary Side Flow Rate	1 Mg/s

The core is configured as a horizontal calandria, with 380 horizontal pressure tubes containing the fuel elements in heavy water coolant. The heavy water moderator surrounds the pressure tubes in the calandria, and is kept at a lower temperature and pressure than the coolant. The reactor can be refueled online (while it is running), so the shutdown requirements are less frequent than those of Pressurized Water Reactors (PWRs) and Boiling Water Reactors (BWRs) used in many other countries [82].

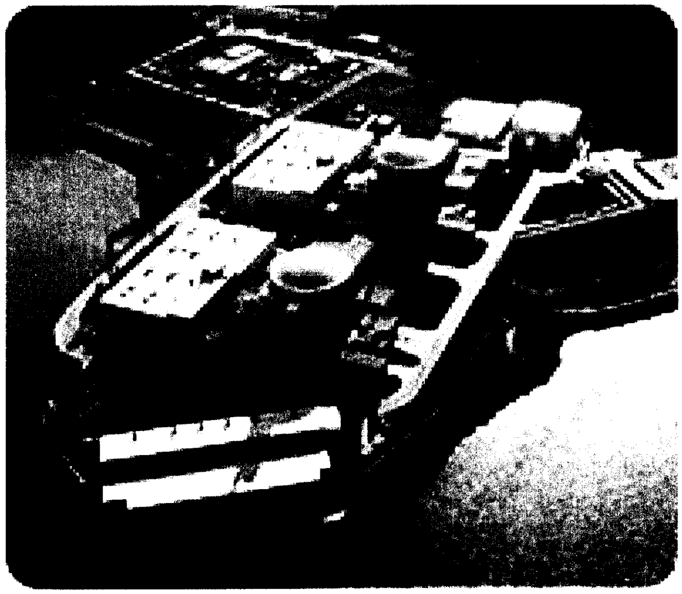


Figure 11: Two 728Mwe CANDU 6 nuclear plants at Qinshan, China [82]

While the Enhanced CANDU has the benefit of being based on proved technology with many projects completed, it is also fundamentally based on dated technology that does not incorporate some of the advances made in nuclear technology in the last 25 years - particularly passive safety systems and higher temperatures and pressures of operation. Higher temperatures and pressures could be particularly relevant to the oil sands steam supply application.

The Enhanced CANDU 6 is not fundamentally different from the traditional CANDU 6, but does have a number of updates that help to improve the plant's severe accident behavior. The most substantial difference is that the fuel is changed to increase the safety margins of the reactor. The traditional CANDU 6 is fueled with natural uranium, while the new Enhanced CANDU 6 uses slightly enriched uranium (SEU) of 1.7% enrichment in U-235 [85]. The conceptual layout of the Enhanced CANDU site is shown in Figure 12, and the heat transport system layout is shown in Figure 13.

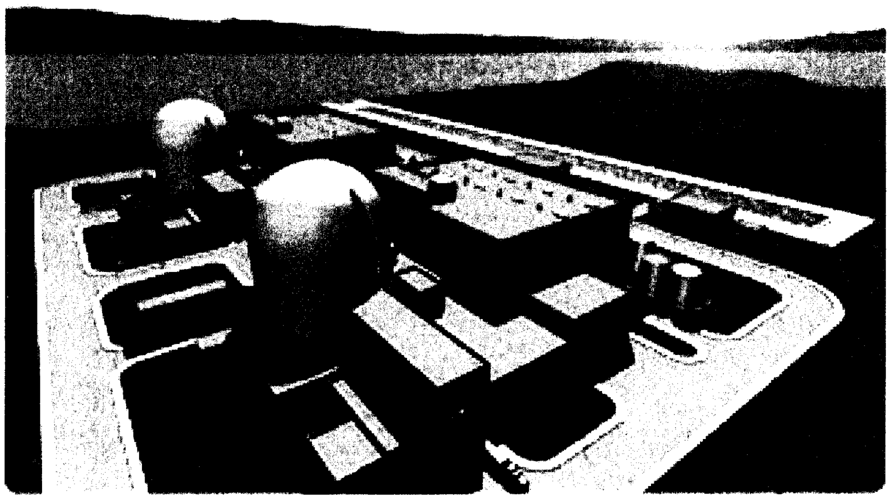


Figure 12: Conceptual Layout of the Enhanced CANDU 6 Two-Unit Site, 740 MWe per unit [82]

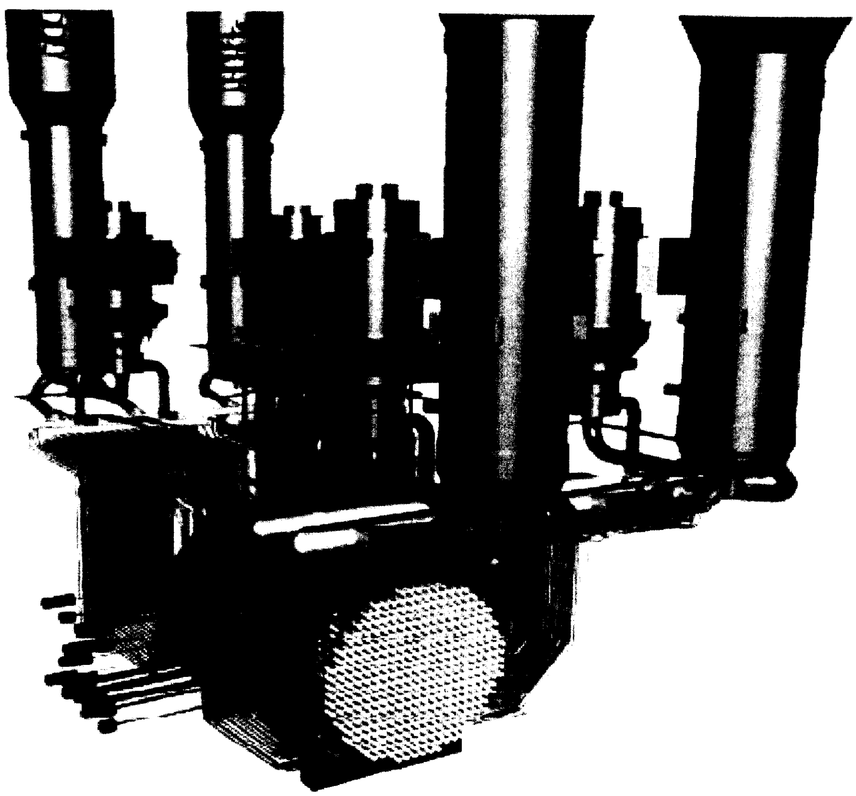


Figure 13: CANDU 6 Heat Transport System Layout [84]

7.1.1 CANDU Fuel

The original CANDU 6 reactor uses natural uranium as a fuel. This lowers the cost of manufacturing fuel, since enrichment is not required, but it also produces more spent fuel and generally requires a larger reactor than an equivalent power reactor using enriched uranium fuel. The Enhanced CANDU will use Slightly Enriched Uranium (SEU; 1.7% enriched in U-235) with one natural uranium rod at the center of each fuel assembly. The fuel bundles are called CANFLEX bundles, and have been used successfully in many CANDU reactors to date. A photo of a CANFLEX assembly is shown in Figure 14.

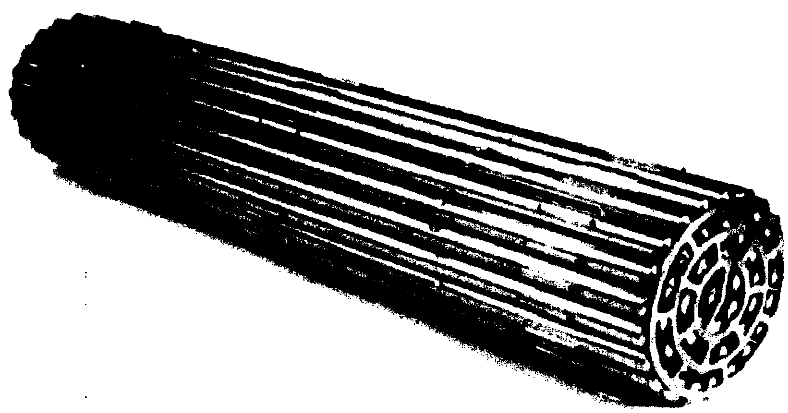


Figure 14: The CANFLEX Fuel Bundle [84]

7.1.2 Steam Supply Capability

At only 4.7 MPa, the Enhanced CANDU's steam output is at too low a pressure for most SAGD projects. While the CANDU is not designed for secondary loop pressures of other than 4.7 MPa, an analysis of the possible steam output of the CANDU at 6.5 MPa has been included here. Such a change would require a complete system analysis to determine the effect on the reactor operation, and would likely require greater pumping power in the secondary loop. The results are summarized in Table 12 below.

Table 12: Enhanced CANDU 6 Steam Supply Capability

Steam Pressure (MPa)	Steam Quality	Steam Flow Rate (Kg/h)	Barrels of Steam (CWE) per day	Bitumen bbl/day (SOR = 3.0)	Bitumen bbl/day (SOR = 2.0)
4.7	0.90	5.76×10^6	871,061	290,353	435,530
6.5	0.90	1.08×10^6	653,296	217,765	326,648

Opportunities may exist for using secondary natural gas fired boilers to boost the heat content of the steam after it is heated by the CANDU, but that scenario will not be considered here. LP-SAGD, which requires much lower pressure steam than conventional SAGD, could be a better match for the Enhanced CANDU. LP-SAGD is only beginning to be used in commercial operation, but if it is successful, it could be adopted on a wide scale due to its water and energy savings. Since the pressures required by LP-SAGD are much lower, piping the steam from an Enhanced CANDU to the outskirts of a large field might well be feasible. Since the economics of the LP-SAGD process are highly speculative at this time, it is too soon to tell whether the CANDU might prove economic in that application.

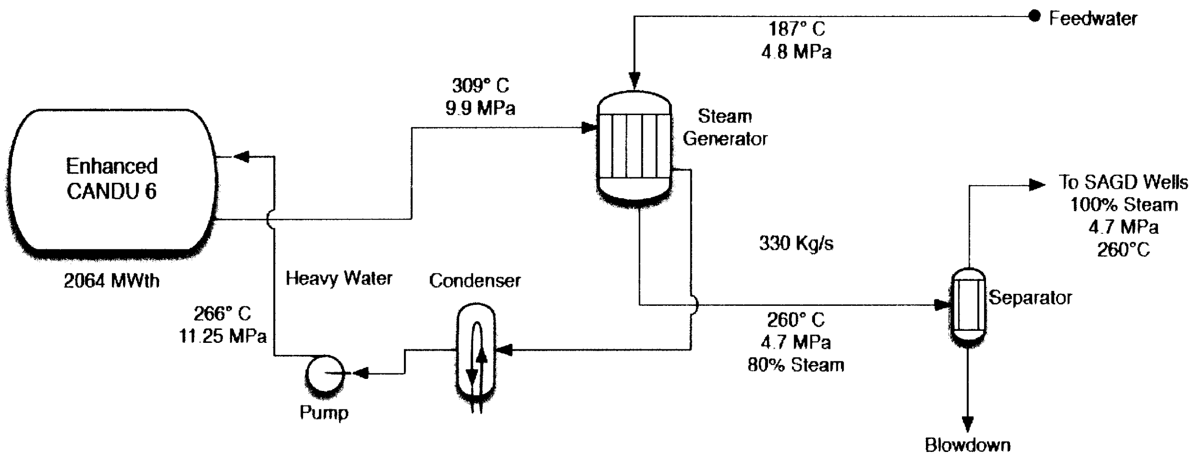


Figure 15: Enhanced CANDU 6 Steam Supply Flowchart (1 of 4 Loops)

As Table 12 illustrates, the amount of steam produced by the CANDU 6 is quite large. While a 200k bpd SAGD site is within the range of proposed projects, the 300k-400k bpd range is not being explored at this time.

7.1.3 Project Lifetime Matching

CANDU reactors have a lifetime ranging from 40 to 60 years. Most SAGD operations are not expected to last this long, particularly if they are of the massive size suggested by the steam output of the CANDU. Since each well might be expected to produce about 500 bpd for 10 years, a 40 year 220,000 bpd SAGD site might use a total of 1,760 well pairs over its lifetime, or 220 well pads of 8 wells each. Currently, the Petro-Canada MacKay River in-situ project as well as a number of other projects are placing about 8 wells per section (2.58 km^2) in the best areas. 1,760 wells at that density would fill a field of a 13.5 km radius, which is beyond typical industry figures at this time. Thus we conclude that for conventional SAGD, an Enhanced CANDU 6 would be too large for steam production. Since LP-SAGD wells are expected to last longer than conventional SAGD wells, the 60 year lifetime of the CANDU would also be more in line with this concept. This is a combination that could be considered in the future, should LP-SAGD prove to be a technology well-suited to the Alberta oil sands. Should the Enhanced CANDU be used for electricity production or hydrogen production in a central location (e.g. Edmonton or perhaps Fort McMurray), there should be no difficulty in utilizing the reactor for its full lifetime. It would likely provide services for many oil sands projects in the region.

7.1.4 Transportation Issues

The Enhanced CANDU reactor has some very large components that would be difficult to transport to the site since Fort McMurray and Edmonton are far from any ports. The largest component is the calandria, which is 7.6 meters in diameter. It is likely that the first approach would be to investigate the possibility of either manufacturing the component in Alberta or transporting it in sections to be assembled on-site. At its full size, it might be possible to transport it on a flatbed truck, but the railways entering the area from major ports do not have adequate clearance to carry it. Cold Lake, Fort McMurray, and Athabasca are all located on major rail lines originating in Edmonton, Alberta. Canadian National (CN) and Canadian Pacific (CP) both have lines from Vancouver to Edmonton, but the horizontal clearance on those routes is at best 4 meters (13 feet and 4 inches). It is also possible to transport equipment by train from Duluth, Minnesota, a shipping port on Lake Superior, accessible via the St. Lawrence Seaway. The maximum horizontal clearance on that route is 4.3 meters (14 feet and 4 inches), which makes it more useful than the Vancouver route for shipping large equipment. Also, if necessary, the three oil sand regions can be approached closely from Edmonton using lines owned by RaiLink Mackenzie Northern (RLMN), RaiLink Lakeland & Waterways (RLW), Grand Prairie Grand Cache (GPGC), Burlington Northern Santa Fe (BNSF), CN, and CP. There are few tunnels or bridges in that area, so transporting large equipment is not difficult, and in fact CN and BNSF have a great deal of recent experience shipping oversized loads to the Fort McMurray region [86][87].

The port of Duluth has handled many of the large components shipped to the oil sands projects in the past few years. Some components over 800 tons, and others over 50 meters long have been shipped from the port to Fort McMurray by rail using high-capacity rail cars. The highest capacity car, which was designed to ship large nuclear reactor components, is the 36-axle Schnabel railcar designed by Combustion Engineering (now Westinghouse Nuclear). The 36-axle Schnabel car pictured in Figure 16 has a maximum load capacity of 5.3 thousand metric tons, and a length restriction of 113 feet. These would accommodate any reactor components that would need to be transported, but the limiting clearances would likely be dictated by the track route through tunnels and tight spaces.

Figure 16: The Schnabel car en route to Commerce City, Colorado from Houston Texas loaded with a 570 metric ton refinery reactor Left: in Trinidad, CO on April 9, 2005 (© Nathan Daniel Holmes 2005) Right: in Larkspur, CO on April 15, 2005 (© Kevin Morgan 2005).

Another possibility exists for the largest components that cannot be shipped by rail or truck from Duluth. It has been suggested that a barge route could be run from the Beaufort Sea down the rivers in Northern Alberta to the Athabasca River and Fort McMurray. Northern Transportation Company Limited (NTCL) has embraced the idea, and is actively making preparations to begin commercial operation of a freight route to Fort McMurray. NTCL sponsored a test run of the route in 2006, when a 230 foot long tug and barge rig made its way down the route. A portage is required around four sets of rapids on the way, and the road used (Highway 5) is currently restricted to 1,000 tons, but NTCL and others believe that heavier loads could be carried on it, and an extension of the legislated capacity is being sought [88].

While the transportation of components poses a challenge, it is not an insurmountable one. Other complications for the construction phase include seasonal weather patterns and the high demand for skilled labor. The CANDU reactor construction includes the laying of a large amount of concrete, and for the best results, that should not be done during the coldest times of the year. Nuclear reactors typically require a lot of welding that must meet particularly high standards, and the shortage of welders in the oil sands region would certainly be a challenge for nuclear construction. Generally though, nuclear construction would face the same challenges typical to that region.

7.2 Advanced CANDU Reactor: ACR-700

The ACR-700 is a 753 MWe (gross), 2034 MWth plant, similar in many basic design features to the earlier CANDU reactors. It has a horizontal calandria core with pressure tubes holding the fuel assemblies in light water coolant, rather than heavy water. The moderator surrounding the pressure tubes continues to be a lower temperature, lower pressure heavy water, and the reactor can be refueled while in service. The ACR has some additional passive safety features originating from Generation III+ design principles that enhance the safety of the plant during accident conditions. In order to keep radiation exposure to the public within allowable limits under accident conditions, the plant is designed to be suitable for a small emergency planning zone with a 500 m radius. The exclusion zone would fall within the property of the plant owner, and would require authorization for entry. Operating figures for the ACR- 700 are given in Table 13. The secondary loop pressure in the ACR-700 is much higher than in the CANDU6 (6.4 MPa versus 4.7 MPa), and so it is a more promising choice to provide steam to the SAGD process at useful pressures.

Figure 17: Conceptual Layout of a Two-Unit ACR-700 Power Plant

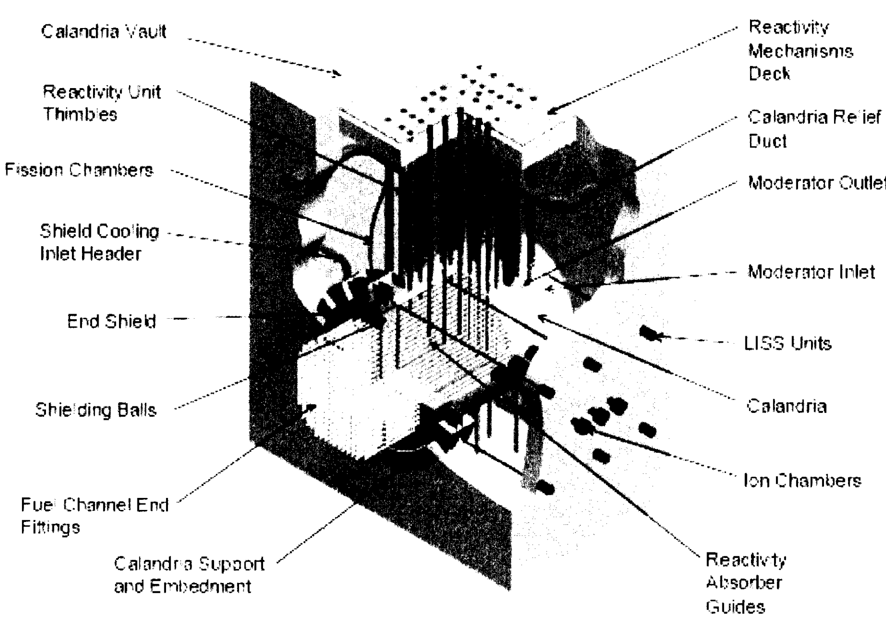


Figure 18: Cutaway View of the ACR-700 Calandria and Surrounding Core Structures

Table 13: ACR-700 Reactor Operating Data

ACR-700 Reactor Operating Data	
Heat Output	2030 MWth
Electricity Output (electric plant only)	753 MWe (703)
Fuel	SEU (2%)
Coolant	Water
Moderator	Heavy Water
Reactor Inlet Temperature	280°C
Reactor Inlet Pressure	13.3 MPa
Reactor Outlet Temperature	326°C
Reactor Outlet Pressure	12.1 MPa
Primary Side Flow Rate (2 SG's)	7.13 Mg/s
Secondary Side Fluid	Light Water
Secondary Side Inlet Temperature	215°C
Secondary Side Outlet Temperature	281°C
Secondary Side Steam Pressure	6.4 MPa
Secondary Side Flow Rate (per SG)	550 kg/s

Unlike the CANDU, the ACR has never been licensed or built before, but it is undergoing pre-licensing review with the CNSC and is a somewhat similar technology to the CANDU, so it is expected that it will be easier to license than a foreign reactor would be.

7.2.1 Steam Supply Capability

The ACR-700 may have some degree of flexibility in the amount of steam that it can deliver, depending on the steam pressure that is required. The design pressure for steam production is 6.4 MPa, but the reactor could potentially yield other pressures with modifications to the secondary loop. The heat transport system and the steam generator of the ACR-700 are shown in Figure 19 and Figure 20, respectively. Steam production results based on three different pressures are summarized in Table 14.

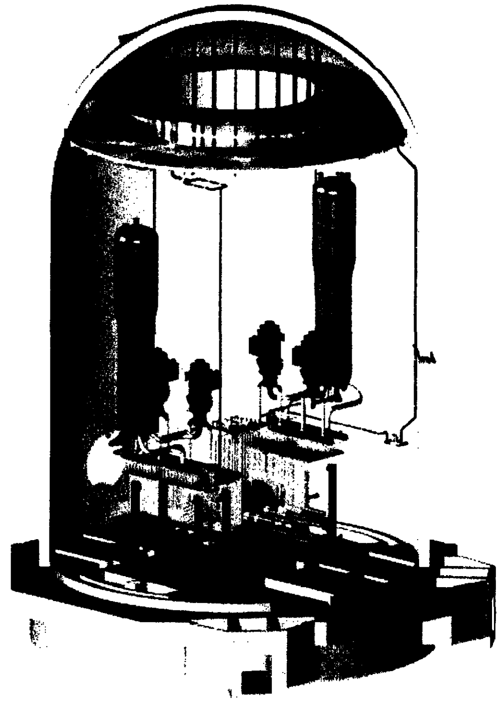


Figure 19: ACR-700 Heat Transport System Layout in Containment [84]

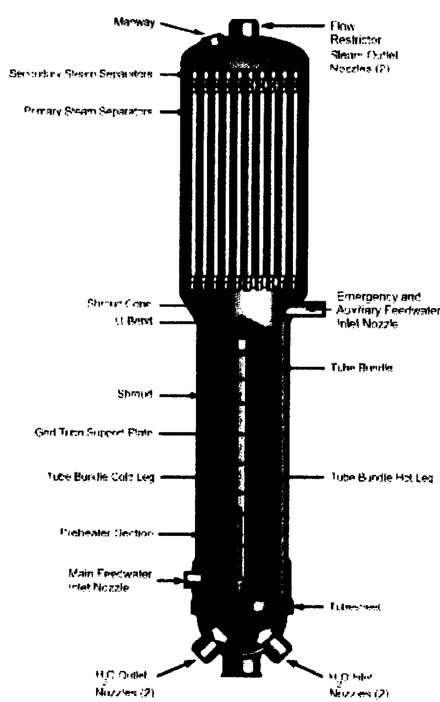


Figure 20: ACR-700 Steam Generator[91]

Table 14: ACR-700 Steam Supply Capability

Steam Pressure (MPa)	Steam Quality	Barrels of Steam (CWE) per day	Bitumen bbl/day (SOR = 3.0)	Bitumen bbl/day (SOR = 2.0)
4.0	0.84	707,858	235,953	353,929
6.5	0.80	697,872	232,624	348,935
10.0	0.81	652,910	217,637	326,454

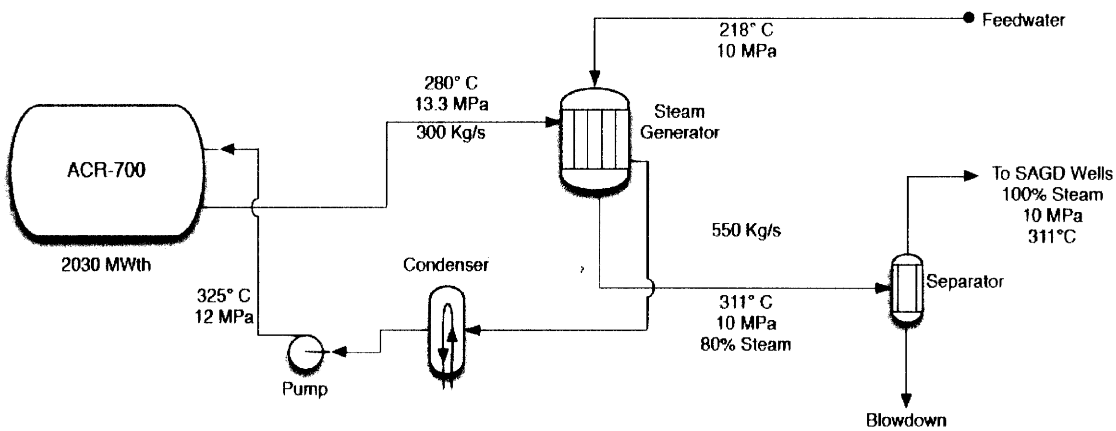


Figure 21: ACR-700 Steam Supply Flowchart (1 of 2 Loops)

One ACR-700 is sized to provide steam for a project of 200k-350k bpd. However, with steam generator outlet pressures of only 6.5 to 10 MPa, and given the large size of a field necessary to support this production, piping the steam to the outer parts of the 200k+ bpd field would not be possible without significant pressure drop that would render the steam too low in pressure for traditional SAGD.

7.2.2 Project Lifetime Matching

The ACR is designed to operate for 40 to 60 years. While the ACR-700's energy capacity would be added all at one time, it is not likely that 200k+ bpd of SAGD capacity could be installed at the same time. SAGD projects are generally installed in phases of not more than 70,000 bpd, and to install a greater capacity would require greater capital outlay, much more heavy machinery, and much more labor, both of which are in short supply. To complicate matters further, the steam from the ACR would have to be pumped to an area large enough to sustain the 200k+ bpd production for 60 years to last for the lifetime of the plant. Figure 22 shows the maximum realistic density of well pads in a 10 km radius field, assuming that ideal conditions existed throughout that radius. Figure 23 illustrates the density of well pads that would be needed to require the full capacity of the ACR-700. It is quite clear that such a density is far above the most optimistic reasonable case, and so the ACR-700 is not suitable solely as a steam supply plant using the current in-situ technology.

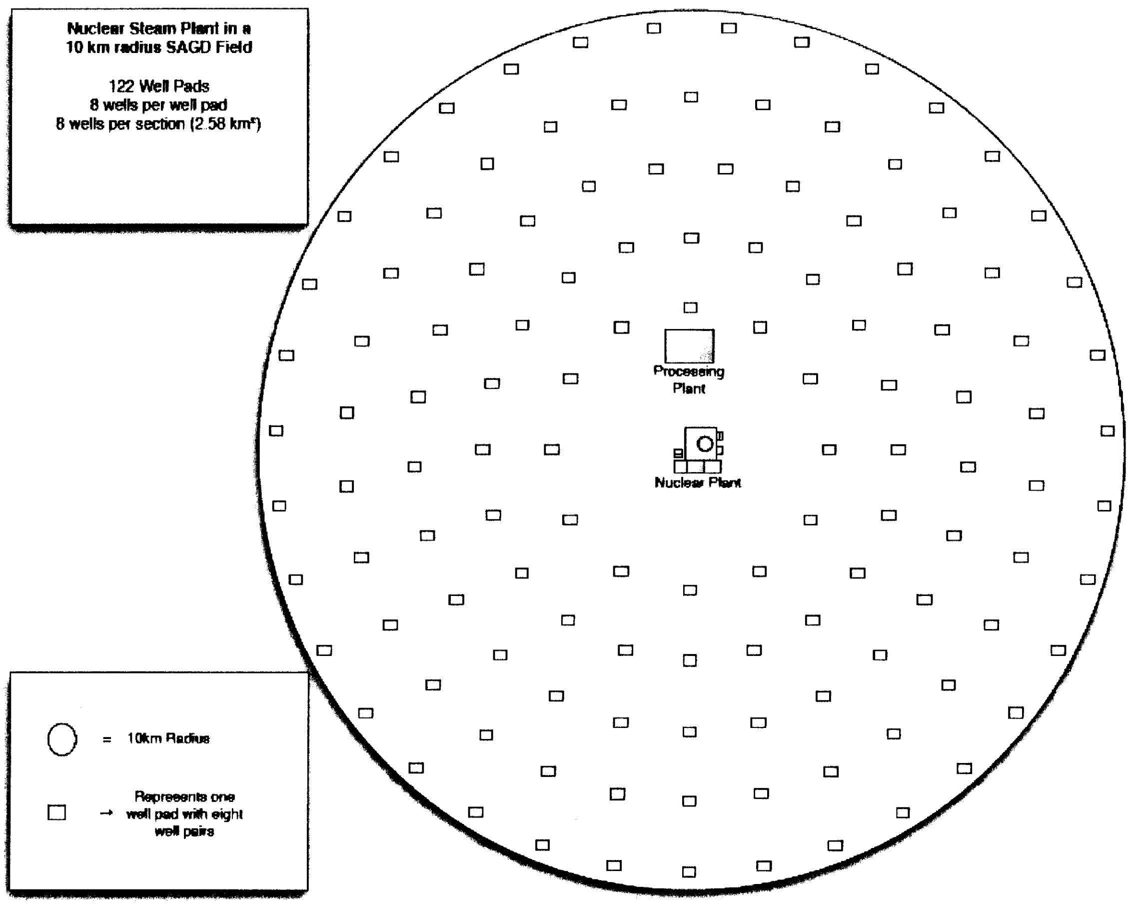


Figure 22: Nuclear Steam Plant in a 10km SAGD field with Maximum Well Density

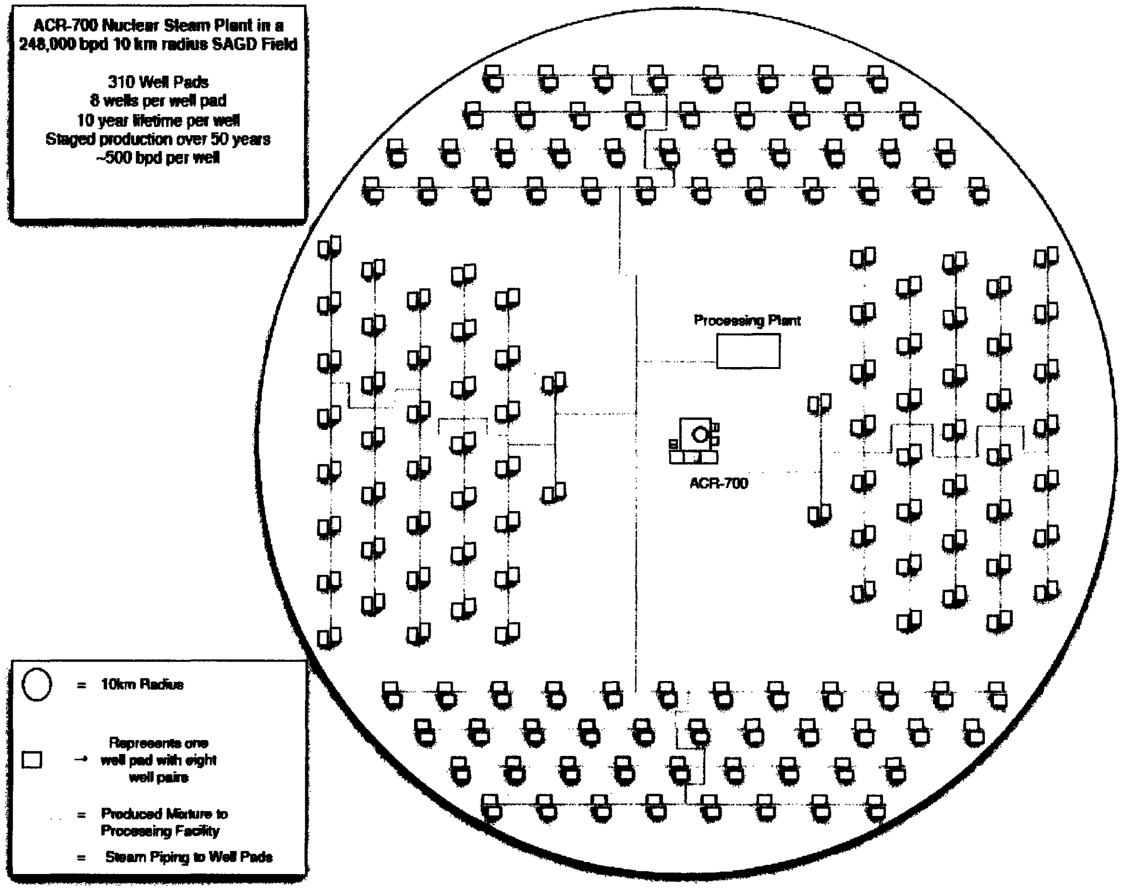


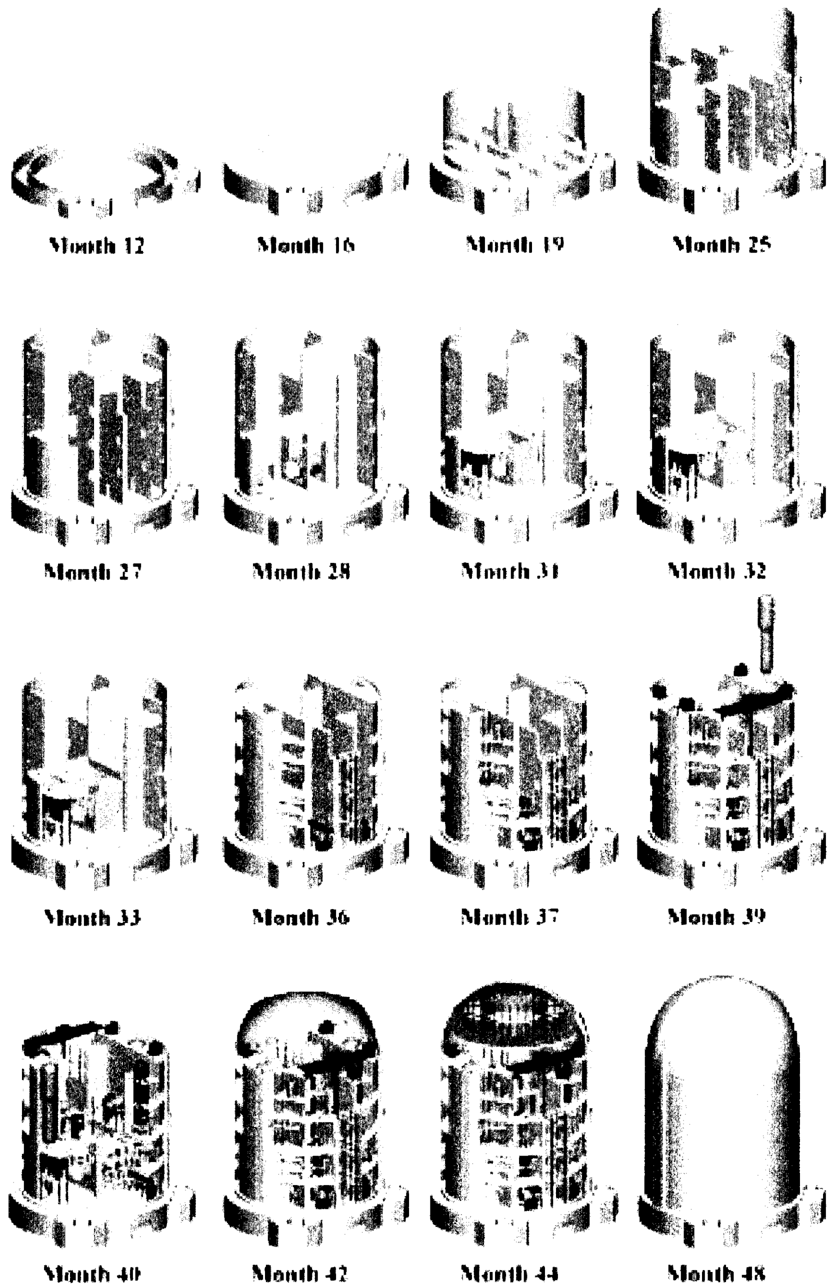
Figure 23: ACR-700 in a 248,000 bpd SAGD field

LP-SAGD, which requires much lower pressure steam than conventional SAGD, could be a better match for the ACR. LP-SAGD is still in the testing stages, but if it is successful, it could be adopted on a wide scale due to its water and energy savings. Since the pressures required by LP-SAGD are much lower, piping the steam from an ACR to the outskirts of a large field might well be feasible. However, since the process requires less steam per barrel of bitumen recovered, the size of the field that would consume all of the steam from the reactor would grow relative to the SAGD case. Further research into the operating characteristics of LP-SAGD wells will be needed in order to evaluate this possible use of the ACR. The economics of the LP-SAGD process are highly speculative at this time, so it is too soon to tell whether the ACR might prove economic in that application. Since LP-SAGD wells are expected to last longer and recover bitumen more slowly than conventional SAGD wells, the 60 year lifetime of the ACR would be more likely to match the lifetime of the field operations.

The ACR-700 may be better-designed for SAGD projects with significant electrical power requirements in addition to steam requirements, or for projects that require an extended use of electricity or heat for upgrading even after the local field has been depleted. These options will be discussed in more detail in Chapter 5.

7.2.3 Construction Process

The construction process for the ACR-700 uses parallel construction techniques and modular assembly to decrease schedule and cost overruns. Of particular importance to this project is the assembly of the reactor building, since that could prove to be the most difficult undertaking far from a seaport. A detailed plan has been made for the construction of the reactor building, as illustrated in Figure 24. The partially modular design of the ACR should minimize the labor costs of the project, since the assembly that will need to be done on-site will be minimized. In particular, many fewer welds will need to be done on-site. A large fraction of the construction would be done on modules in Edmonton, and the modules could then be shipped by road up to the project site. A schematic of a few of the representative modules for the reactor building is shown in Figure 25.



Note: The plant will be in service in Month 60.

Figure 24: Reactor building Construction Sequence for the First ACR-700 Unit

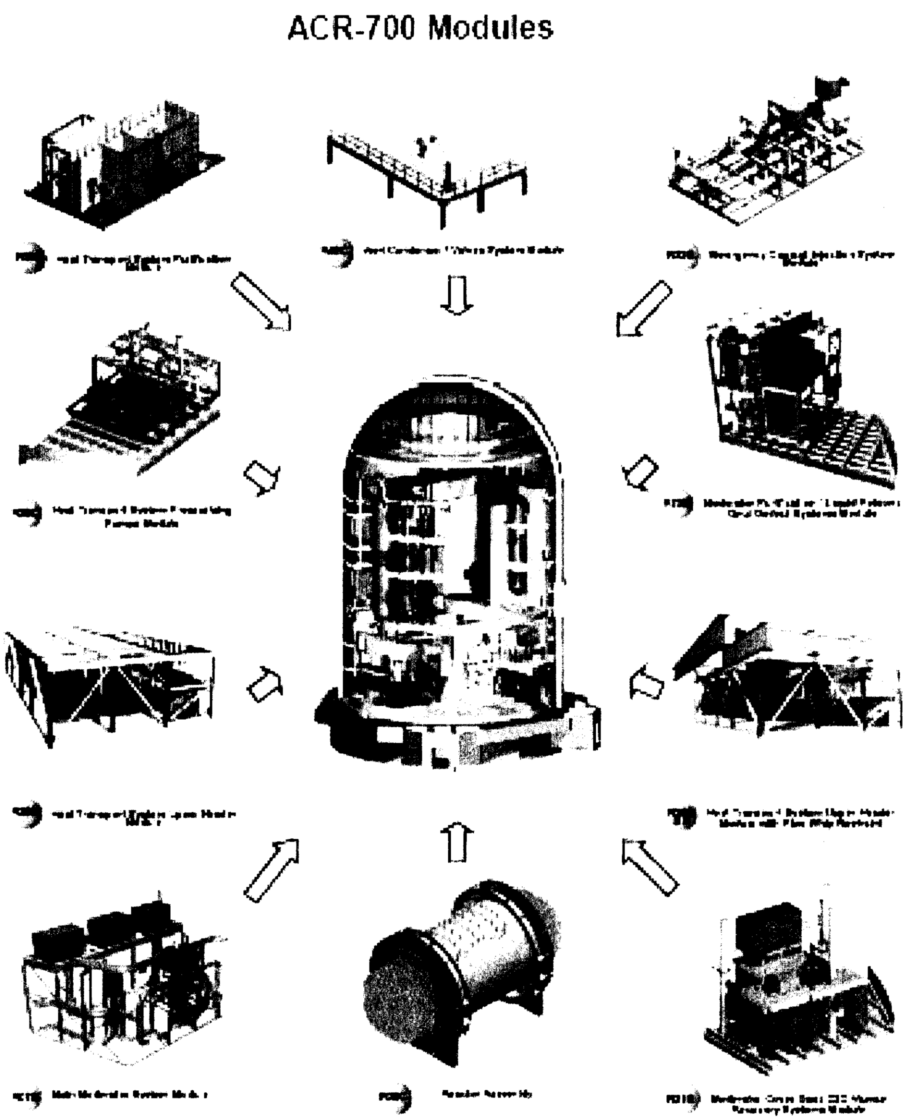


Figure 25: ACR-700 Representative Reactor Building Modules

The calandria vessel for the ACR-700 is considerably smaller than that for either the CANDU 6 or the ACR-1000, as shown in Figure 26. The ACR-700 calandria diameter is 5.2 m, versus 6.3 m for the ACR-1000 and 7.6 m for the CANDU 6. This makes the vessel easier to ship, but still prevents rail transit from most areas in its fully assembled form. The transportation options for the ACR-700 are the same as those for the Enhanced CANDU 6, as discussed in 7.1.4.

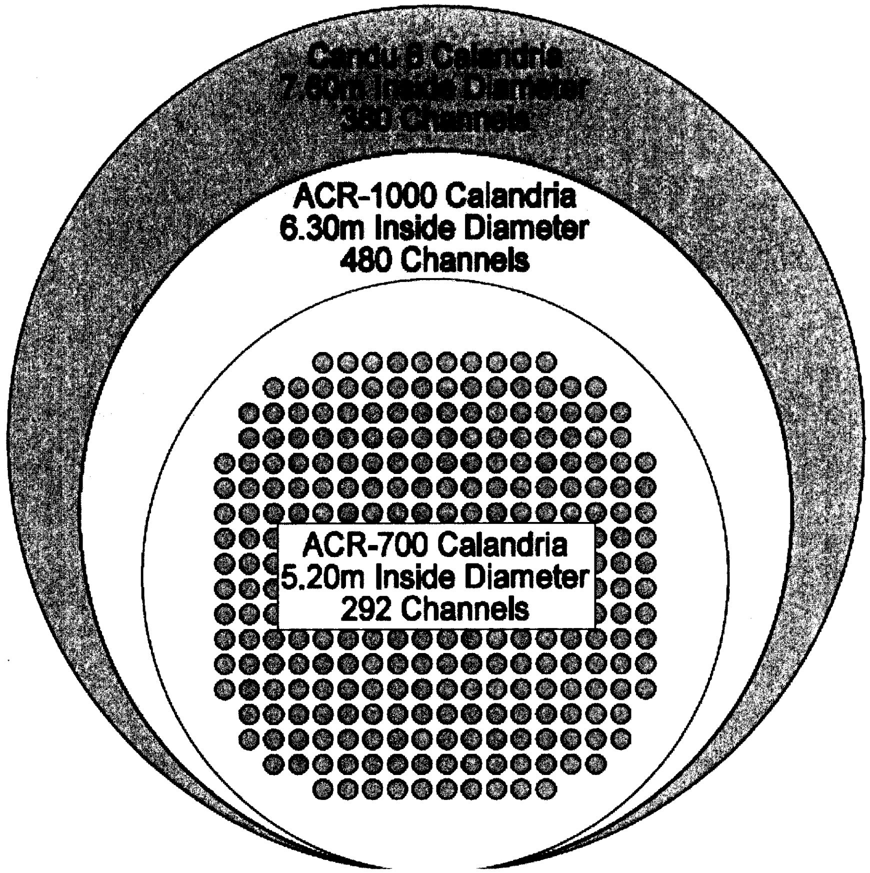


Figure 26: ACR-700 Calandria Size versus Other CANDU Reactors

7.3 Advanced CANDU Reactor: ACR-1000

The ACR-1000 is a 1200 Mwe plant, essentially a larger version of the ACR-700. Expected operating figures for the ACR-1000 are given in Table 15.

Table 15: ACR-1000 Reactor Operating Data

ACR-1000 Reactor Operating Data	
Heat Output	3243 MWth
Electricity Output (max, gross)	1200 MWe
Fuel	SEU (2%)
Coolant	Water
Moderator	Heavy Water
Reactor Inlet Temperature	280°C
Reactor Inlet Pressure	13.3 MPa
Reactor Outlet Temperature	326°C
Reactor Outlet Pressure	12.1 MPa
Secondary Side Fluid	Light Water
Secondary Side Inlet Temperature	215°C
Secondary Side Outlet Temperature	281°C
Secondary Side Steam Pressure	6.4 MPa

Given the considerable issues presented when positing the use of the ACR-700 for SAGD steam-only, the ACR-1000 will not be considered for that application here. Many of the difficulties in matching the ACR-700 with the SAGD steam application are related to the large size of the reactor, and the increased size of the ACR-1000 only accentuates the difficulties. The ACR-1000 is better suited to projects where significant electricity production is also desired. These projects will be discussed in Chapter 5.

7.4 PBMR

The Pebble Bed Modular Reactor (PBMR) is a modular High-Temperature Gas-cooled Reactor (HTGR) that utilizes a spherical fuel element, and is fundamentally different from the PWRs, BWRs, and PHWRs most widely used today. The most significant differences are the passive safety features, unique fuel design and on-line refueling process, smaller size, and the absence of a pressure-retaining containment building. The PBMR has been developed by PBMR Pty. Ltd. of South Africa based on a long history of German design and pebble bed reactor operation. The PBMR as it is currently designed has never been built before, but work is underway to construct a Demonstration Power Plant (DPP) in Koeberg, South Africa, in cooperation with ESKOM, the South African government-owned utility. Construction on the Koeberg plant is expected to begin in late 2008. The PBMR is undergoing a pre-application licensing review in the United States, and is in the process of being licensed in South Africa, but it has not yet been formally introduced to the CNSC.

A model of the DPP including the helium Brayton power conversion unit is shown in Figure 27. The steam production version is much simpler since all of the electricity generation equipment can be removed. The design of the reactor with two primary loops for a steam only process heat plant is shown in Figure 28.

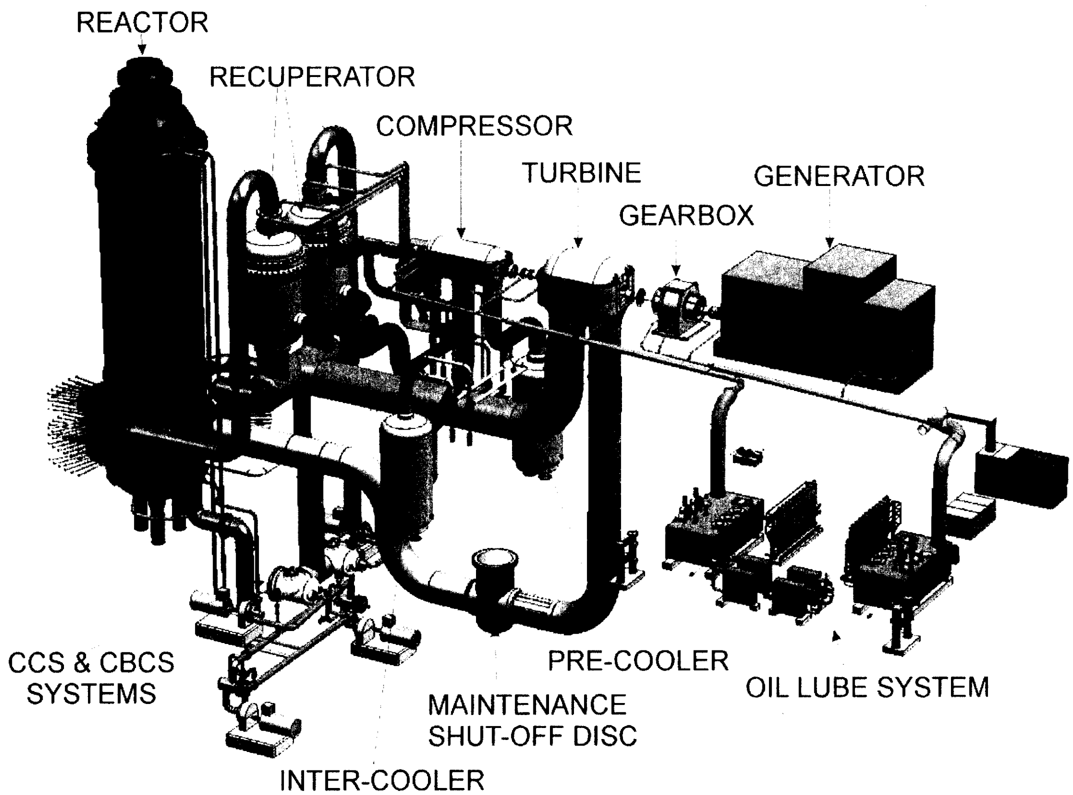


Figure 27: PBMR Demonstration Power Plant Layout for Electricity Generation [Used with Permission from PBMR (Pty) Ltd. 2007]

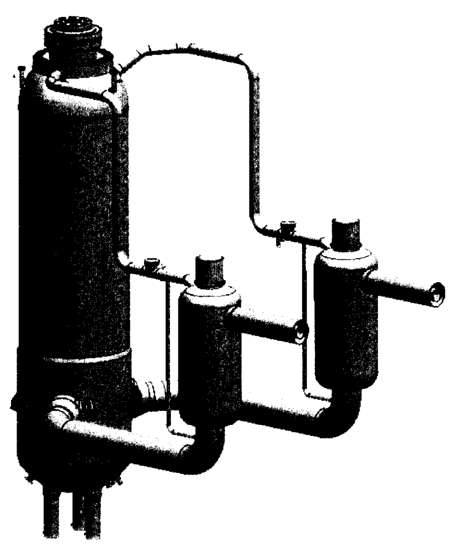


Figure 28: PBMR for Process Heat Applications (excluding the steam generators) [Used with Permission from PBMR (Pty) Ltd. 2007]

Figure 28 shows the reactor vessel and the two primary helium loops with heat exchangers (IHX's). The simplest reactor configuration being considered here is one with a single PBMR reactor with two primary helium loops, each coupled to its own secondary helium loop. The secondary loop transfers heat through a steam generator, and the steam is sent to the SAGD wells for production of bitumen. This configuration is illustrated below in Figure 29. The secondary loop is chosen for this application in order to isolate the reactor from the possibility of steam ingress or contamination from feedwater impurities, and to allow normal (non-nuclear) maintenance on the steam generators during operation of the nuclear plant. The choice of two primary loops gives added reliability to the steam supply, in that a maintenance requirement in one loop may not require full shutdown, and also results in smaller components that are more easily transported to the site. The operating points of the PBMR PHP Steam Plant are given in Table 16.

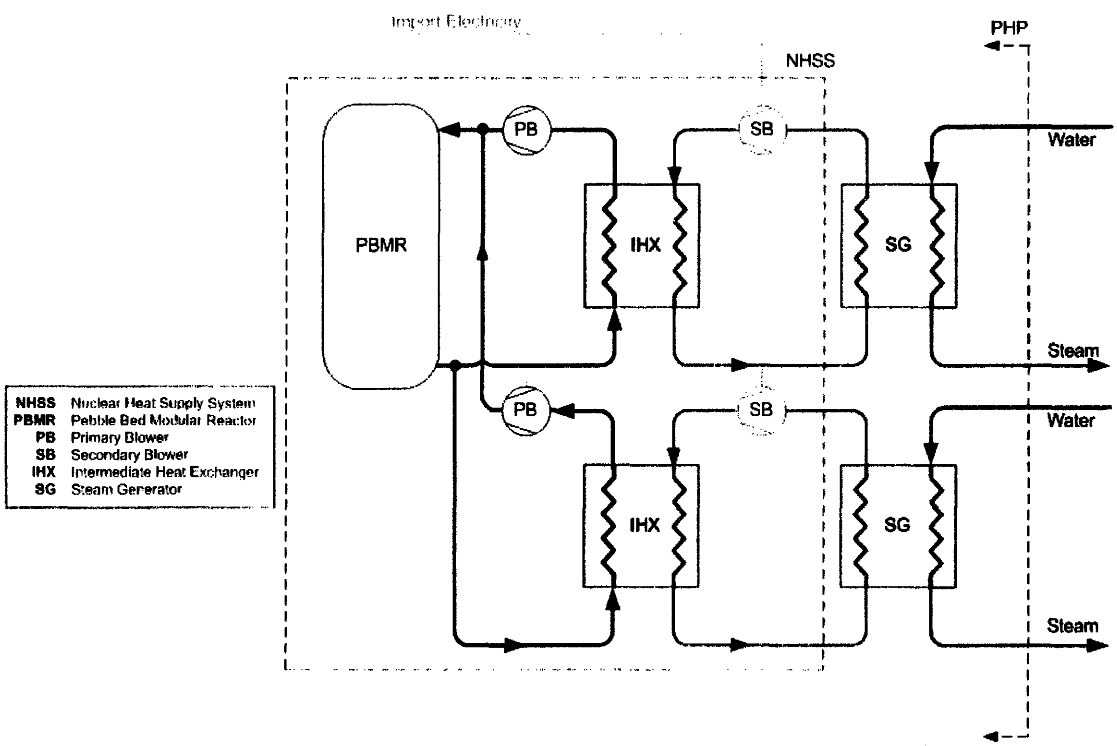


Figure 29: PBMR SAGD Steam-Only Solution - Single Reactor, Two Primary Loops [Used with Permission from PBMR (Pty) Ltd. 2007]

Table 16: PBMR Reactor Operating Data [90]

PBMR Reactor Operating Data	
Heat Output	500 MWth
Fuel	TRISO Fuel Pebbles
Coolant	Helium
Moderator	Graphite
Reactor Inlet Temperature	280°C
Reactor Inlet Pressure	8.5 MPa
Reactor Outlet Temperature	750°C
Reactor Outlet Pressure	8.2 MPa
Total Primary Side Flow Rate	205 kg/s
Secondary Side Fluid	Helium
Secondary Side Inlet Temperature	235°C
Secondary Side Outlet Temperature	720°C
Secondary Side Pressure	8.6 MPa
Secondary Side Flow Rate	102.5 kg/s for each of two loops

7.4.1 PBMR Fuel

The PBMR is a so-called "pebble bed" reactor because of its unique fuel system. The basic fuel unit is a 0.5 mm "kernel" of uranium dioxide with enrichment of up to 10%. The kernel is coated with four important layers that form a major part of the safety system of the reactor by containing fission products within the fuel. The kernels are embedded in a graphite fuel "pebble" of 60 mm diameter containing about 14,500 TRISO particles, and about 450,000 of these pebbles fill the reactor core during operation. The layered structure of the fuel is illustrated in Figure 30, and a photo of the fuel pebbles is shown in Figure 31.

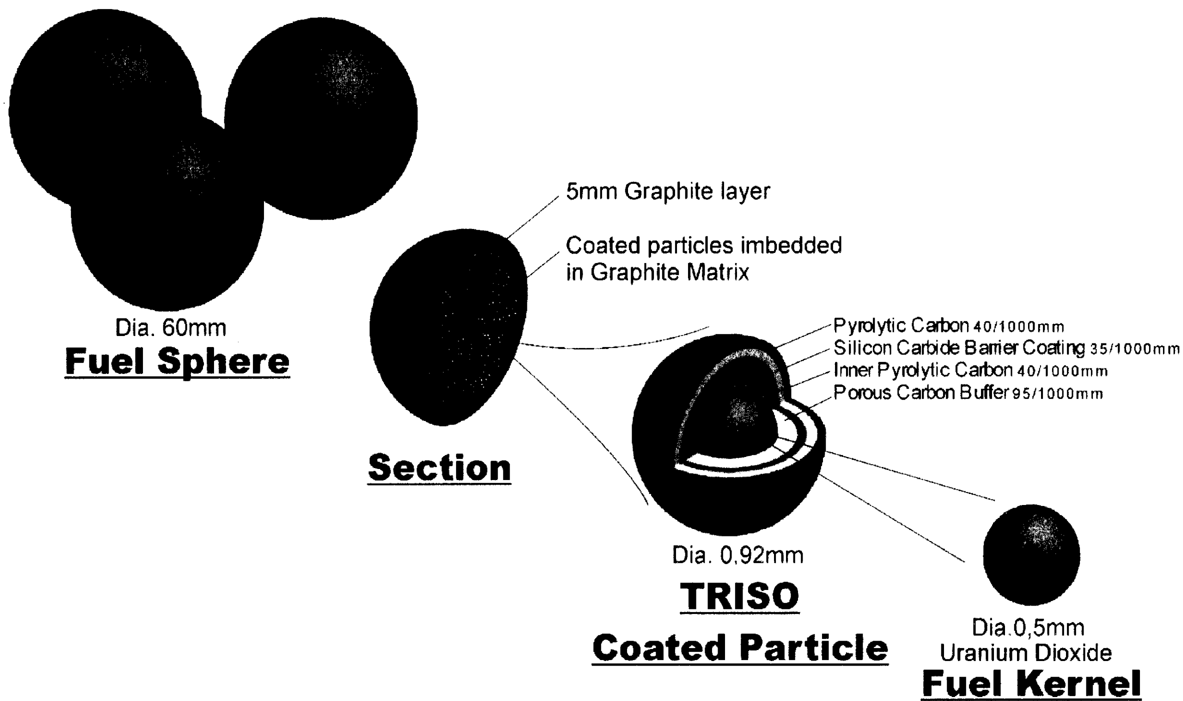


Figure 30: PBMR Fuel Structure
[Used with Permission from PBMR (Pty) Ltd. 2007]

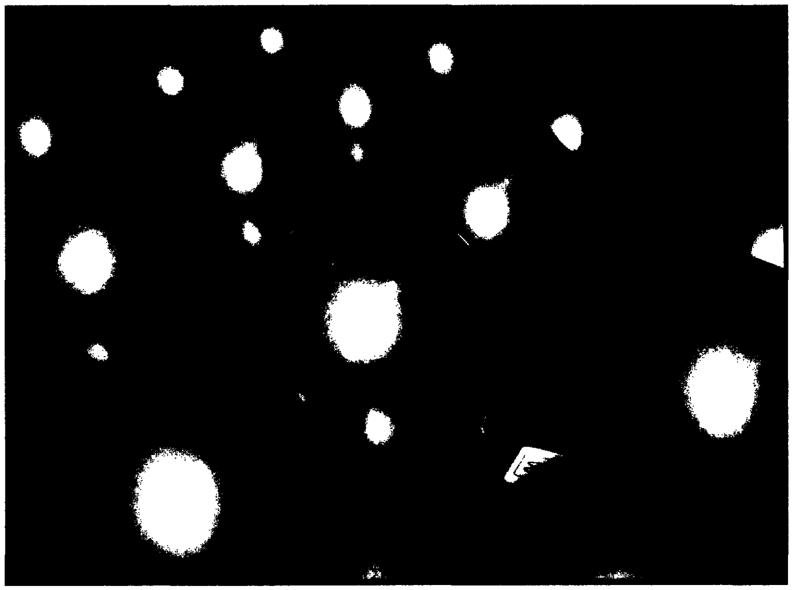


Figure 31: PBMR Fuel "Pebbles"
[Used with Permission from PBMR (Pty) Ltd. 2007]

The pebbles are circulated downwards through the core during operation, with pebbles being removed at the bottom of the reactor, tested for damage and burnup, and reinserted at the top of the core. Pebbles are recycled 6 times before being transitioned to spent fuel storage, unless damage or high burnup cause them to be removed from the cycle earlier. This process provides for online refueling of the reactor, and allows for easy identification and removal of damaged elements [95].

7.4.2 Steam Supply Capability

Steam production for a single PBMR is given in Table 17 assuming 20% blowdown and 94% availability (where the availability limitation is the maintenance of the steam generators). It is important to note that in this case the PBMR would require about 33Mwe for its own electrical load, and since the PBMR would not be configured to produce electricity in the steam production only case, that would need to be provided by an auxiliary source or purchased off of the grid.

Table 17: PBMR Steam Supply Capability

Steam Pressure (MPa)	Steam Quality	Barrels of Steam (CWE) per day	Bitumen bbl/day (SOR = 3.0)	Bitumen bbl/day (SOR = 2.5)	Bitumen bbl/day (SOR = 2.0)
11.0	0.80	130,000	43,300	52,000	65,000

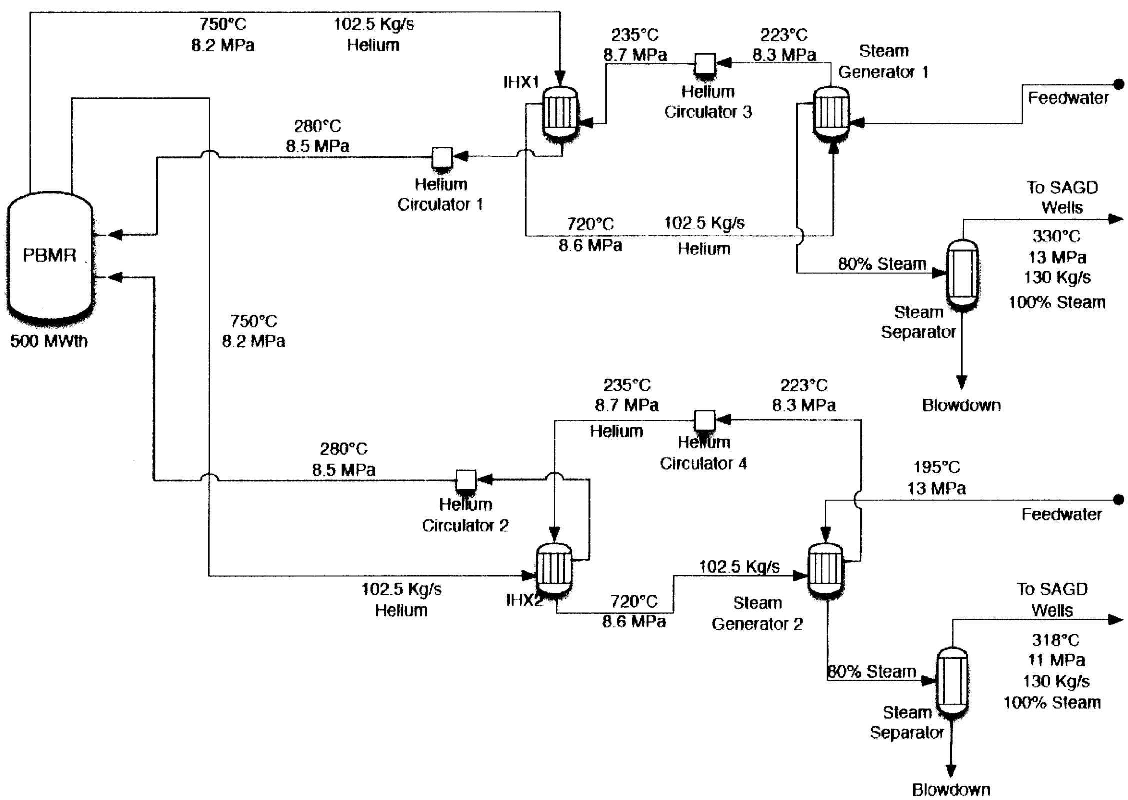


Figure 32: Pebble Bed Steam Supply Flowchart Used in Analysis

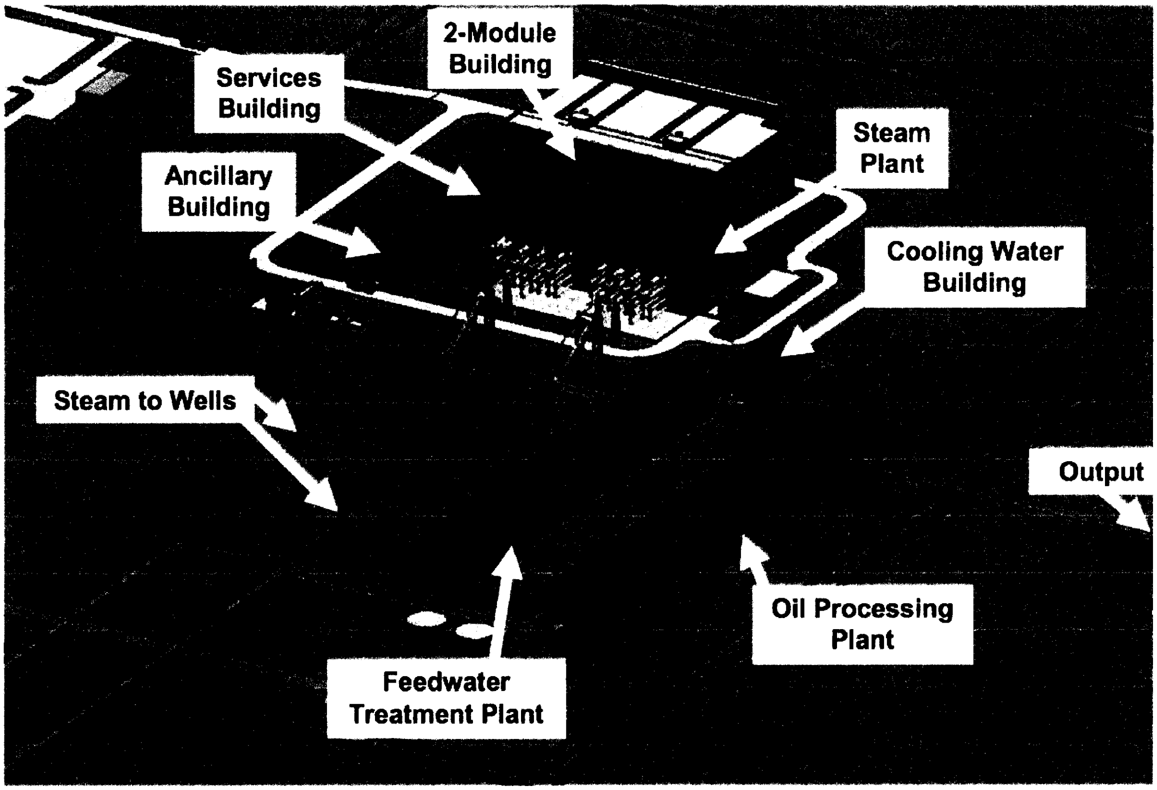


Figure 33: A SAGD Plant with 2 PBMR Modules. For clarity, the steam generator enclosure has not been shown.

A conceptual layout of a two-unit PBMR steam supply plant in a SAGD field is shown in Figure 33.

7.4.3 Project Lifetime Matching

One PBMR is a good size for a SAGD operation of 50k-80k bpd depending on the SOR, or two PBMRs could be used for a SAGD site with a peak output of ~100k-150k bpd. Each PBMR has its own electrical load that would need to be purchased if it was not generated onsite. This amounts to 33Mwe for each PBMR module; which includes all circulators as well as the PBMR plant house load.

Since the PBMR can be installed in modules, it can be easily integrated with the phased development typical of SAGD projects. One module can be installed to produce steam for the first phase of SAGD, and then, with production already underway, a second

PBMR module could be added to provide steam for future development or to provide electrical power. A PBMR is designed to operate for 40 years, and given its smaller size, it would be possible to maintain production within reach of the reactor's steam supply for that length of time. Figure 34 in section 8.1.1 illustrates the number of well pads that would be needed in a 7 km field to draw all of the PBMR's steam production.

Another option for the PBMR would be to supply steam to the SAGD field for 20 to 30 years, and subsequently to convert the reactor into an electricity generation plant to provide power to other oil sands projects or to sell electricity to the grid. Other options, including hydrogen production and heat and electricity production for upgrading will be discussed in Chapter 5.

7.4.4 Practical issues

The transportation options for the PBMR are the same as those for the Enhanced CANDU 6, as discussed in 7.1.4. The core barrel, the largest diameter (7.5m) single piece of the PBMR, is too large for rail travel, and so would either need to be barged or site-constructed. The PBMR does not present any unique construction difficulties, but it does present a challenge in terms of licensing. The Canadian Nuclear Safety Commission (CNSC) has only licensed Pressurized Heavy Water Reactors, and there is very little experience worldwide with licensing a reactor like the PBMR. A strictly deterministic set of water coolant based requirements would not be applicable to the PBMR, and thus could cause difficulties in licensing the reactor. Fortunately for the PBMR, the CNSC's new licensing process is technology neutral, so the PBMR would be able to be licensed within that generic framework based on proving its safety case. However, the expertise does not currently exist within the CNSC to evaluate the technical aspects of the PBMR, so resources would need to be acquired in order to license the reactor, as is being done in South Africa.

CHAPTER 5

8 POSSIBLE REACTOR INTEGRATION SCENARIOS

In this Chapter, the opportunities for using a nuclear plant to provide energy are assessed for the cases of steam supply, steam and electricity supply, electricity supply only, and hydrogen production. The end uses considered are SAGD, direct mining, and upgrading. In each case, the capacity of the nuclear reactor for producing steam and electricity was modeled using the Aspen Plus program. The inputs and modeling conditions are described in detail in the appendix. It is important to note that in the case of the HTGR, the high temperature helium gives the reactor a great deal of flexibility in configurations for combined heat and power that could not be fully explored with the design information that is publicly available. Thus the full flexibility has not been accounted for here.

8.1 SAGD Steam Only

For the steam supply only case, each nuclear reactor will be discussed with reference to the SAGD field for which it is a best fit.

8.1.1 One PBMR

One PBMR is a good fit for a SAGD operation of 52k bpd given an SOR of 2.5, or two PBMRs could be used for a SAGD site with a peak output of ~100k bpd. Since no electricity is produced by the reactor in this scenario, a source of power for the PBMR's internal requirements would be necessary. Power could be purchased off the grid or produced locally using a natural gas or other type of power plant. Each PBMR has a power requirement of about 33MW(e), which includes the electricity for all circulators in the plant as well as all the ancillary buildings. As shown in Figure 34, the PBMR can support a 55,000 bpd SAGD site well within the 10 km limit.

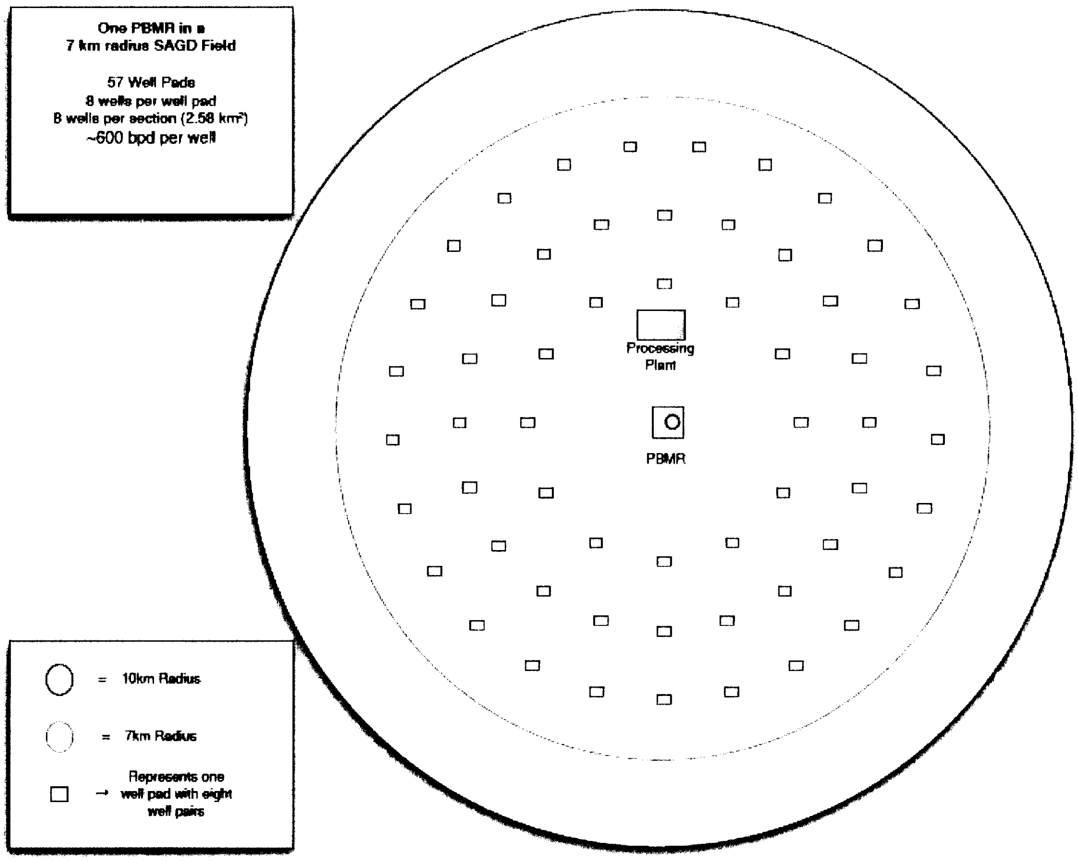


Figure 34: PBMR Nuclear Steam Plant in a 55,000 Barrel per Day SAGD Field

8.1.2 One ACR-700

The ACR-700, at approximately 2030 MWth, is sized to produce about 650,000 barrels of steam per day (CWE). This is enough for a SAGD operation of 217,000 to 325,000 barrels per day. In general, piping the steam a distance much greater than 10 km is considered impractical, so applying the ACR to a steam-only SAGD production case would require a field that could produce 217k to 325k bpd for 40 years or more within a 10 km radius. As discussed in 7.2.2, such a field would be well beyond the average performance expected of fields currently known. Because of this limitation, the application of the ACR-700 and other larger reactors to the traditional SAGD steam production is not reasonable under current well development and steam distribution methods. The ACR-700 could become practical if a more efficient way to transport steam can be devised, so that the steam delivery is not limited to the small radius of projects today. The cost savings associated with producing the steam in such large quantities with zero CO_2 emissions could justify additional spending on distribution systems. The ACR-700 would be more practical in an application that included electricity production, since it is so large. Additionally, it has an internal requirement of about 50MW(e) which would have to be provided off the grid or from another electric plant in this case.

8.1.3 Enhanced CANDU 6

The Enhanced CANDU produces a much lower pressure steam product than the ACR and the PBMR, and, as discussed in 7.1.2, is not suitable on its own for most SAGD projects for that reason. Opportunities may exist for using secondary natural gas fired boilers to boost the heat content of the steam after it is heated by the CANDU, but that scenario will not be considered here.

8.2 SAGD Steam and Electricity

For the case of steam and electricity production, SAGD fields of 50,000 bpd, 100,000 bpd, and 200,000 bpd are considered, and the most viable nuclear options for each are identified.

8.2.1 SAGD 50,000 Barrels per Day

A 50,000 bpd SAGD stage requires about 100k-150k bpd of steam and 15-20 MWe.

An ACR-700 producing 150k bpd steam would also have the capacity to produce 518 MWe. This is far more than the 15-20 MWe required by a SAGD project and the 50 MWe required internally by the ACR. To this point in the oil sands development, companies have not found that it is not economically favorable to produce excess electricity to sell on the grid due to the high costs of building the generation capacity in the oil sands and the high cost of the natural gas generation. In the case of the ACR, the high cost of building the reactor in the oil sands would still be a negative factor, but if natural gas continues to be the main electricity production method, and particularly if a carbon pricing scheme is instituted, it is possible that the ACR could provide electricity at competitive prices.

A PBMR co-generation plant producing 48Mwe (33Mwe for internal load and 15Mwe for the SAGD load), has its steam capacity is reduced to ~100,000 bpd, supporting bitumen production of 33k to 50k barrels per day (given an SOR from 3.0 down to 2.0). With an SOR close to 2.0, the PBMR could support 50,000 bpd of SAGD production. However, should the SOR be less favorable, the PBMR would not be sufficient. A small supplementary gas-fired boiler could provide a back-up source of power for peak loads.

8.2.2 SAGD 100,000 Barrels per Day

A 100,000 bpd SAGD project requires 200k-300k bpd of steam and 18-36 MWe

The ACR-700, assuming a 33% electrical efficiency, requires 90 MWth for electrical supply to SAGD plus 150 MWth for supply to the house load. The total power production is 80 Mwe. The ACR then has a steam capacity that supports bitumen recovery from 190k barrels per day (SOR = 3) to 285k barrels per day (SOR = 2). The ACR is much better suited to power this size SAGD project than the smaller project discussed above, but it would still require either an unusually excellent bitumen resource or a method of piping steam that would enable a field radius greater than 10 km. Alternatively, the ACR could be used in a field with particularly poor SAGD recovery characteristics. Such a field would have a much higher SOR, and would utilize the ACR's steam more quickly.

A two reactor PBMR plant would be needed for a project of this size. The project, including the total PBMR plant internal load of 70 MWe, requires ~100 MWe, so the plant could contain one steam-only reactor and one reactor with steam and electricity production. For reliability reasons and to enable phased construction, it may actually be preferable to use two reactors that both split their energy between steam and electricity production. Two co-generation PBMR reactors producing 100 MWe (total) would have a steam capacity supporting bitumen production of 65k-100k barrels per day, based on an

SOR between 2.0 and 3.0. To broaden the range of the steam supply, two co-generating PBMR's could be sited at some distance from one another in the field. However, there are cost advantages to siting multiple units adjacent to one another due to the equipment sharing that is possible.

8.2.3 SAGD 200,000 Barrels per Day

A 200,000 bpd SAGD project requires ~400k-600k bpd steam and 38-72 MWe

A 200k bpd SAGD project, as the largest size considered here, provides the closest steam supply size match for an ACR-700. The power requirements would be 110 MWe including the internal ACR load, and this would leave the ACR with a steam production capacity of 544k barrels of steam per day, or enough to support bitumen production between 180k and 270k barrels per day. This would supply between 188 and 280 well pads, which are still too many for a 10 km radius, but it would be possible to boost the steam from the ACR or to heat or insulate the piping more heavily to increase the diameter of the usable field.

A 150-180k bpd production scenario would require 4 PBMR reactors, with a full reactor capacity devoted to electricity production. The resulting steam capacity would support 150-180k bpd bitumen production, depending on the SOR (2 to 2.5). This is an excellent possible configuration. The steam producing PBMR's could be located in separate areas, either each reactor individually, or more likely in pairs (to share more common systems). The economic advantage of the sharing of systems is not accounted for in this thesis.

8.3 SAGD with Upgrading Steam and Electricity

A 100,000 bpd SAGD project requires 200k-300k bpd of steam and 18-36 MWe for the in-situ SAGD, and an additional 30 MWth and 40 MWe for upgrading.

This project would require 3 PBMR reactors, of which two could be fully dedicated to steam production (and separated in distance if desired), and one would be split between thermal and electrical production. Electrical production in this case would also include 100 MWe for the PBMR internal loads.

An ACR-700 in this scenario would require 50 MWe for its internal load, so the total electrical load at the site would be about 125 MWe. The ACR would produce over 410 MWe, so about 285 MWe would be excess available to sell to the grid.

A 200,000 bpd SAGD project requires ~400k-600k bpd steam and 38-72 MWe for the in-situ SAGD, and an additional 60 MWth and 80 MWe for upgrading.

An ACR-700 in this scenario would require 50 MWe for its internal load, so the total electrical load at the site would be about 200 MWe. The ACR could produce the 200 MWe and the required steam without any significant excess capacity. It would be an excellent size for this project if it were feasible to pipe the steam over a 200,000 bpd field.

Four PBMRs would draw 132 MWe, bringing the total electrical load to 285 MWe. Thus, 1 PBMR could be fully dedicated to electricity production, two could be dedicated to steam production, and one could be split between the two. Under these circumstances, the PBMRs would easily provide 400k bpd of steam, but could not provide the full 600k bpd. It is important to note that there are many possible configurations to integrate the

PBMR with a direct mining operation which have not been considered here. Once a site is chosen, a detailed analysis could be performed to determine the best configuration for that project.

8.4 Direct Mining Heat and Electricity

A 100,000 bpd direct mining project requires 350 MWth for steam and hot water production as well as 67 MWe for electrical power needs.

This is much smaller than the output of any of the CANDU reactors and any use of one of the large reactors would result in a lot of excess power. It is possible that it would be of interest to the owner of the nuclear plant to provide electricity to other projects in the region, but in this case electricity would be the primary output of the plant.

One PBMR would not be sufficient to support a direct mining operation of this size, while two would have too much capacity. Two PBMRs would work very well for a 150,000 bpd project.

A 200,000 bpd direct mining project requires 700 MWth for steam and hot water production as well as 133 MWe for electrical power needs.

Three PBMR units would be sized ideally for a 200,000 bpd mining project, or one ACR-700 or an Enhanced CANDU 6 would also be good options. While the ACR or CANDU would generate significant excess electricity, (about 350 MWe) it is expected that in the more centralized context of a direct mining project, it might be of interest to the owner of the nuclear plant to provide electricity to other projects in the region.

8.5 Direct Mining with Upgrading Heat and Electricity

A 100,000 bpd direct mining project with upgrading requires 380 MWth for steam and hot water production as well as 107 MWe for electrical power needs.

Two PBMRs for this application would provide the needed electricity (165 MWe from a electric Brayton cycle plant) as well as the heat needed from a steam-only plant. The CANDU reactors are all clearly oversized for this project, with the caveat that a reactor with a primary purpose of producing electricity, a small fraction of the heat could then be used for the direct mining processes.

A 200,000 bpd direct mining project with upgrading requires 760 MWth for steam and hot water production as well as 213 MWe for electrical power needs.

An ACR for this application is again too large, with at least 250MWe of excess capacity. The CANDU is similarly mismatched, and thee PBMR option requires three reactors, of which one could be wholly thermal-energy dedicated, one could be an electric plant, and one would need to provide both steam and electricity. While the ACR or CANDU would generate significant excess electricity, (about 250 MWe) it is again possible that it would be of interest to the owner of the nuclear plant to provide electricity to other projects in the region.

8.6 Electricity Supply Only

Electricity could be supplied equally well by any of the CANDU reactors. In the near term, the Enhanced CANDU 6 is likely to be ready the earliest, but the ACR's are said to be more economic and efficient. PBMRs for electricity would be different from the steam production plants in that they would not have secondary steam loops. Instead, they would utilize a helium Brayton cycle which would have some efficiency benefits. Table 18 summarizes the electrical output of each of the reactor technologies.

Table 18: Reactor Electrical Power Outputs

Reactor	Power (MWe, net)	Example of Oil Sands Projects Powered
Enhanced CANDU 6	728	~600,000 bpd of direct mining with upgrading projects
ACR-700	703	~600,000 bpd direct mining with upgrading projects
ACR-1000	1150	~1,100,000 bpd direct mining with upgrading projects
Single-Unit PBMR (400 MWth)	165	Partial contribution to any project
Two-Unit PBMR (800 MWth)	330	250,000 bpd direct mining with upgrading projects
Four-Unit PBMR (1600 MWth)	660	520,000 bpd direct mining with upgrading projects

8.7 Hydrogen Production for Upgrading

Upgrading requires from 1500 to 2200 SCF, or 0.00363 to 0.00532 tons, of hydrogen per barrel of syncrude produced. Through water electrolysis, one kilogram of hydrogen may be produced by expending about 50kWh. Electrolysis is the only technology for nuclear-powered Hydrogen production that is currently available although other thermo-chemical means are being researched. Thus it is the technology assumed in this analysis [68]. Hydrogen production capacities for each of the reactors considered are given in Table 19. The most likely near term option is to use nuclear heat for Steam Methane Reforming saving some natural gas for heating and reducing CO_2 emissions but this was not considered in this analysis.

Table 19: Nuclear Reactor Hydrogen Production Capacity using Electrolysis

Nuclear Reactor	Electrolysis H_2 Capacity (kg/day)	Barrels of Syncrude (based on 2200 SCF H_2/bbl)
Enhanced CANDU 6	355,200	66,767
ACR-700	361,440	67,940
ACR-1000	576,000	108,271
One-Unit PBMR	79,200	14,887
Two-Unit PBMR	158,400	29,774
Four-Unit PBMR	316,800	59,550

8.8 Summary of Reactor Integration Scenarios

The results of this analysis show that the size of the ACR and CANDU reactors is not suitable for the most common single project needs. These plants are not found to be good candidates for placement in a SAGD field, or in any but the largest direct mining operations. They are good candidates for bulk electricity production, however, either in the oil sands region (perhaps Edmonton or Ft. McMurray) or elsewhere. The PBMR process heat plant is found to be an excellent option for SAGD steam supply in addition to electricity supply, since it is roughly the size of most medium SAGD fields.

8.9 Licensing a New Nuclear Power Plant in Canada

8.9.1 The Nuclear Licensing Process

All nuclear power plants in Canada are licensed and regulated by the Canadian Nuclear Safety Commission (CNSC). The CNSC has a new regulatory framework for licensing reactors that has not yet been tested, since no reactor applications have been submitted. The new framework is based on the "Nuclear Safety and Control Act" (NSCA, May

2000). Five phases of reactor life are identified by the Act, and a separate license is required for each of them. Additionally, an Environmental Assessment (EA) is required for each phase and is performed according to the Canadian Environmental Assessment Act (CEAA). The five licenses required are the license to prepare a site, license to construct the reactor, license to operate, license to decommission, and license to abandon the site.

1. License to prepare a site:

In reviewing the license to prepare the site, the CNSC requires that the applicant identify any characteristics of the site that may impact Canadian health, safety, security, or environment. The applicant must satisfy the CNSC that it will be possible to design and operate the proposed reactor in such a way that will protect those key areas of Canadian life. During this licensing stage, both the CNSC and the applicant would consider external events such as earthquakes, tornadoes, and floods, radiation transport properties of the site, and the density and characteristics of the population nearby that might affect human safety. At least one public hearing is held during the licensing review so that interveners and affected citizens have the opportunity to participate in the process.

2. License to construct the reactor:

The detailed engineering and safety of the proposed reactor design is carefully reviewed before the license to construct can be issued. The CNSC must find that the reactor design is such that the reactor would operate safely before the process moves forward. This involves detailed engineering and scientific analysis of the operating conditions of the plant, and particularly the plant's behavior under accident conditions. The risk posed to the public must be found to be acceptable for the license to be issued. The applicant must submit a Preliminary Safety Analysis Report, a plan for minimizing and mitigating the impact of the construction, operation, and decommissioning of the plant on the environment and on human health and safety, and a plan for hiring and training well-qualified operating and maintenance personnel.

3. License to operate the reactor:

The applicant must demonstrate to the CNSC that the reactor has been constructed according to design and that the necessary policies and procedures are in place to ensure that the nuclear staff will operate the plant safely. Emergency planning must be completed, and local and regional authorities must be aware of the plans and ready to assist with them. A Final Safety Analysis Report is required at this stage. Approval of the license to operate allows the applicant to move forward with reactor preparation and fuel loading, and to begin bringing the reactor up to low power levels. The startup process is called the commissioning stage, and during that time the applicant must run numerous tests on the reactor to demonstrate that it is performing according to the design. The CNSC monitors the entire process, and must approve each step forward in the startup and power up. The CNSC continues to monitor the performance and safety of the plant throughout its operating life.

4. License to decommission the reactor:

Before the applicant is permitted to decommission the plant, the CNSC must be satisfied that proper plans have been made (and funds secured) to ensure that all components will be properly handled and that any risk to the environment or human health and safety has been assessed and minimized. The CNSC also judges the technical soundness of the disposal plans and the monitoring program.

5. License to abandon the site

The license to abandon the site can be obtained only after the site has been decommissioned and the CNSC is satisfied that it has been adequately reclaimed.

The first three licenses may be submitted and approved in parallel, but before any of the licenses are granted, an environmental assessment must be performed and deemed acceptable. The EA for a nuclear power plant must be what is called a "comprehensive study," which is considerably more detailed and rigorous than the "screenings" that most federal projects undergo, and also has mandatory elements of public participation. One other possibility for an EA is that it be referred to a panel review instead of the comprehensive study. The CNSC or the Minister of Environment can make the decision to refer the EA for review. Some potential exists for duplicating this procedure with the provincial government. Appropriate agreements can be made between the national and provincial authorities to eliminate the need for redundancy, but if an agreement could not be reached, there would be a provincial EA that would also need to be filed and approved [98]. The nuclear reactor licensing process has a lot in common with the process by which oil sands projects are currently approved in Alberta. The major differences are the great breadth and depth of the safety analysis for the nuclear plant, and the very thorough technical review of the reactor design that is undertaken by the CNSC.

The exact requirements associated with each of the licenses granted by the CNSC is still under development, but the general philosophy is that they will be technology neutral, based on safety requirements that can be applied to any type of reactor. The CNSC has been actively involved in the IAEA's development of an international nuclear safety standard, and it is expected that the CNSC's regulations will bear some resemblance to the IAEA standard. The new Licensing Basis (LB) for the reactors will be risk-informed, as opposed to wholly deterministic, and the LB will first be applied to the Advanced CANDU Reactor, according to the "Canadian National Report for the Convention on Nuclear Safety" of 2004 [99].

Other important laws by which nuclear power plants must abide include the Nuclear Liability Act and the Nuclear Fuel Waste Management Act. These govern the liability structure of the nuclear operation and the insurance issues associated with it, as well as the integration of the operation's nuclear waste plan with Canada's national strategy.

Off-site liability for a nuclear accident is insured under the Nuclear Liability Act (1976). Under this legislation, all liability up to a limit of C$75m is the responsibility of the nuclear operator. This would include any damage to the oil sands facilities or loss of the resource due to an accident. For claims over the C$75 million limit, a government commission would be established to handle compensation for all affected parties. There are no conditions on this guarantee to the public, in that negligence of the nuclear operator need not be proved. Any damage caused by a nuclear incident related to the plant is reimbursable under the Act.

All nuclear fuel waste in Canada – that of utilities, universities and other owners, will be managed and disposed of by the Nuclear Waste Management Organization (NWMO), which was established by the Nuclear Fuel Waste (NFW) Act. The NFW Act requires "nuclear energy corporations" to establish a trust fund to pay for the long-term management of the nuclear fuel waste. Canada has also founded a National Laboratory for nuclear waste storage, and is moving forward with plans to design a deep geological repository, possible for placement in the Canadian Shield, a large granite rock formation in northern Canada

8.9.2 Licensing Timeframe

The timeframe of the licensing process for a new nuclear plant in Canada depends upon a number of factors, but experience indicates that it could take up to 3 years to complete the EA process. This process is a pre-requisite to moving forward with the site license application for the CNSC. The time required for the site license, construction license, and operating license will depend heavily on the quality of the submission by the applicant (both the completeness of the application and the safety of the reactor design), and on the resources of the CNSC, but currently the CNSC estimates that the process of obtaining those three licenses would take about 10 years [100].

For comparison, the United States Nuclear Regulatory Commission (NRC) has a slightly different permitting system than CNSC's, though both are untested at this point. The NRC uses a Design Certification to approve the reactor design, an Early Site Permit (ESP) to approve a potential site, and a combined Construction and Operating License (COL) to approve a new reactor project. According to the Nuclear Energy Institute

(NEI), the NRC estimates that it would take about 33 months to complete an ESP review, 36 to 60 or more months to complete a design certification, and as long as 42 months for the first set of COLs. Performed in series, these could easily take twelve years. However, a number of ESPs are in progress or completed, as are a number of design certifications. In Canada, there does not appear to have been quite as much progress, although the new Advanced CANDU Reactor, ACR-1000 is undergoing a pre-licensing review with the CNSC at this time, and is forecasted for service in 2016 by AECL [101].

8.9.3 CNSC Workforce Shortage

Should new reactor applications be submitted to the CNSC, they will likely face delays due to inadequate staffing. Since Canada has not licensed a new reactor in the past twenty five years, there has been no need to keep up a full staff of licensing engineers, and no funding to support them. (Licensing costs are largely funded by application fees.) The CNSC has declared the licensing of new reactors to be its third priority, should it arise. The first priority is maintaining the safety of the operating fleet, and the second priority is the refurbishment of today's reactors [102]. According to the CNSC President and CEO Linda Keen, the CNSC is "already experiencing difficulties in hiring staff which will delay projects." And, "Without more qualified people, operators will be required to wait. Timelines could suffer but safety will not take a back seat in this process [102]."

The CNSC will be faced with an employee shortage that will greatly hinder timely construction of new plants if appropriate planning does not begin now. New hires require a great deal of training before they are able to evaluate the safety of potential reactors. People with prior experience will be in even tighter supply than inexperienced engineers, since many of the people who began working in the nuclear industry during its heyday are nearing retirement. To compound the difficulties, if new nuclear plants are planned, the CNSC will be competing with many private nuclear companies in Canada and possibly internationally for the same people.

8.10 BUSINESS MODEL

While oil sands companies might wish to have some investment stake in a nuclear plant in the region, it is not likely that the plant would be solely owned or operated by one of the mining or in-situ companies. The likely scenario is that a solicitation will be made by the oil sands companies for an energy supplier for either steam and/or electricity and possibly energy for a hydrogen plant to provide under contract energy needs for specific oil sands applications. This thesis outlines many options available for such applications. The business arrangement is similar to current energy contracts for oil sands production facilities Under this arrangement, the oil sands companies would have little or no responsibility in the licensing process, and no liability for the nuclear waste or for damage in the case of an accident. The company retained would be the licensee who would also be responsible for design, construction and operation of the energy plant. An experienced operating company like Bruce Power, or Ontario Power Generation or other nuclear operating companies would need to be hired to run the plant. These companies would have to address the labor for construction and operation relieving the oil sands companies of the obligations.

Depending on the business interests of the oil sands company, equity ownership may be desirable to control risks and costs. In the early days of commercial nuclear expansion, electric utilities decided to form special purpose generating companies such as the Yankee Atomic Electric Company to design, oversee construction and operate a nuclear power station for 10 original utility owners in a separate company arrangement. Each utility would own a percentage of the plant and receive a similar percentage of the output. As a separate generating company, there were certain tax, risk sharing, liability and operating advantages. Such an appropriate might be very viable for oil sands companies as they look to the future of their industry.

One of the comments often made by oil sands companies is that the licensing process takes so long that other more certain alternatives are or will be available. While this may be true, what is needed in the oil sands industry is a collection of alternatives, sometimes referred to as a tool box of alternatives, from which to choose in the event of restrictions on their operations. These restrictions will most likely come in three major areas – carbon emission limitations or taxes, high price or restrictions on natural gas use and limitations on the use of water. To be prepared to address at least two of these three top challenges, it might be prudent to begin the process of considering the implementation of nuclear energy by teaming with industrial organizations familiar with nuclear technologies that might be appropriate for specific applications. Once the feasibility and economics of the nuclear energy application are established, it would then be necessary to begin the design and licensing process such that by the time that the challenges need to be faced, the nuclear energy option is available as one of the tools in the "tool box". The initial conceptual design process is not expensive yet will provide an early indication of value. While the licensing process of the first unit could take up to 10 years, subsequent plants should go much more quickly allowing for timely and efficient deployment.

8.11 SAFETY

Nuclear safety in Canada is regulated by the Canadian Nuclear Safety Commission (CNSC). The CNSC's mission is

> *...to regulate the use of nuclear energy and materials to protect health, safety, security, and the environment and to respect Canada's international commitments on the peaceful use of nuclear energy.[103]*

The Canadian nuclear power industry has never had an accident with an offsite release of radiation, and internationally, only the Chernobyl accident has had significant effects on the public health and safety. The accident at Chernobyl was a result of an experimental use of the reactor that did not follow standard operating procedures, and involved disabling or ignoring many of the safety alarms set off by the reactor's divergence from normal and acceptable operating conditions. The Chernobyl reactor also had very little in common with the reactors considered in this analysis, which behave much more safely under accident conditions. Three Mile Island, the only accident to occur in the United States, was quite severe by reactor damage standards. A large fraction of the core was uncovered and melted, but despite that, the containment successfully prevented any significant off-site release of radiation. The containment structures of the CANDU and ACR reactors would perform the same function under accident conditions. The PBMR incorporates a confinement structure to perform the same function due to its unique safety features discussed below.

Defense in Depth

The nuclear industry is operated according to the principles of "Defense-in-Depth." The Defense-in-Depth safety philosophy calls for multiple layers of safety protection. This is achieved through a combination of multiple physical barriers to release of radioactive materials and safety systems that are redundant, reliable, and diverse (resistant to common-cause failures), as well as a system of quality control in design, fabrication and monitoring of key system components and functions [104].

8.11.1 CANDU

Adhering closely to the Defense-in-depth philosophy, the CANDU reactors have five distinct and independent barriers to radioactivity release. The first is the nuclear fuel, which is composed of a diffusion resistant ceramic material, and the next layer is the fuel sheathing, which is sealed to contain fission products using the highest vacuum technology standards. The heat transport system prevents leaks by maintaining cooling and thereby preventing core melting. The system has very low leakage rates, and is very massive, particularly in the moderator chamber. This means that it has a great deal of heat capacity to absorb accident scenario heat from the system and prevent leakage or melting. As a final physical barrier, the robust containment of the CANDU is designed to contain any harmful materials under accident conditions. The CANDU has an owner controlled zone of a 3000 ft radius. This zone allows for atmospheric dilution of any radioactive products should an unlikely accident occur and radioactive materials be released from containment. The five layers of protection together provide an attenuation of 10^8 or 10^9 for released radioactive particles which would bring the allowed releases to within acceptable safety limits [104].

This size could dictate the footprint needed by the plant in the integrated oil sands production facility design for the most conservative application. The nuclear plant could also be sited integrally with other facilities but special security measures for access would still need to be required. This would apply to all nuclear installations.

8.11.2 ACR

The Advanced CANDU Reactor follows the current trend towards passive safety with its two independent shut-down systems. In shut-down system one, the control rods, driven by gravity, drop into the moderator. In shut-down system two, pressurized gas is used to inject liquid absorber into the moderator and reflector. For emergency core cooling, the reactor has a two-stage system. First, pressurized tanks in the containment inject water into the reactor through the emergency coolant injection system, and then long term cooling is provided by sump pump. The emergency coolant injection system utilizes one way rupture disks to provide isolation from the reactor cooling system, and has nitrogen-pressurized accumulators, as well as an elevated reserve water storage tank, as shown in Figure 35.

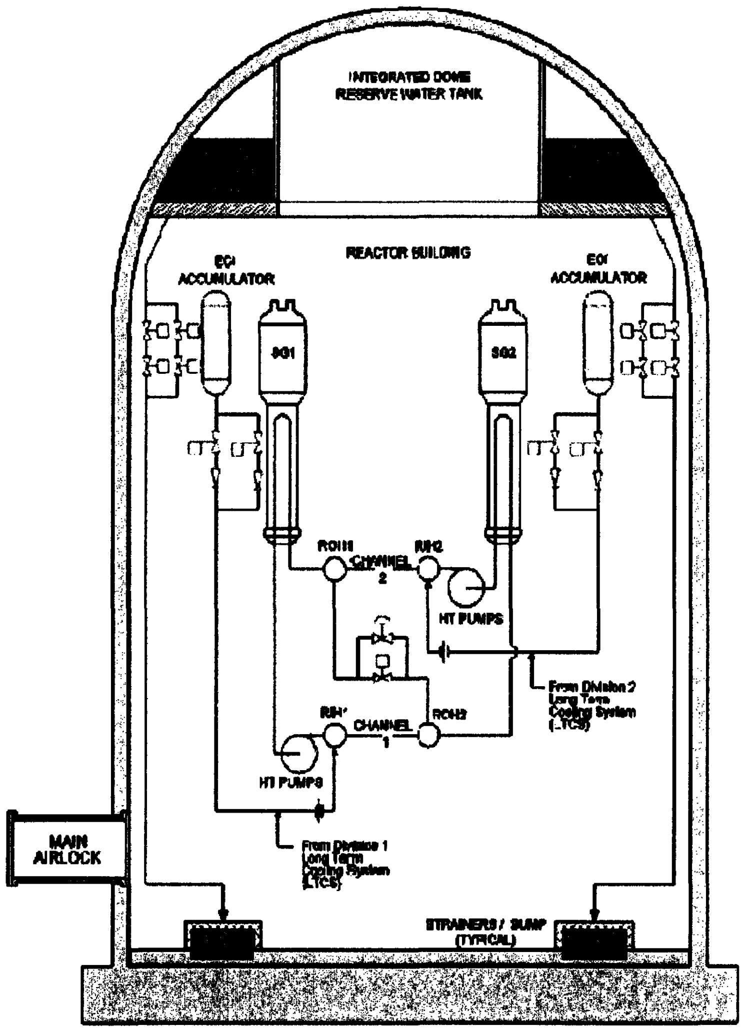


Figure 35: ACR Emergency Core Cooling System

The containment of the ACR is steel lined, and has air coolers and a hydrogen-recombination system to remove hydrogen gas from the dome in the case of an accident. In a loss-of-cooling accident (LOCA) simultaneous with a loss-of emergency core cooling, the moderator can be used as a coolant to prevent fuel melting. In the case of a severe core damage scenario, which can only be caused by highly improbable multiple failure modes, the moderator and shielding water can be boiled off to delay damage, and the fuel can be contained in the calandria using the reserve water system for make-up to the shield tank [105] .

8.11.3 PBMR

The PBMR's most unusual and revolutionary safety feature is that the fuel is designed as the primary containment of the fission products and will withstand the full range of operating and accident conditions. The fuel also provides integrity for long term storage. The fuel has a negative temperature reactivity coefficient, which means that in a fault condition; as the temperature of the fuel increases, the rate of the nuclear reaction decreases, causing the reactor to shut down automatically. The reactor is designed such that there is enough passive cooling after shutdown to keep the fuel below its design temperature limits. The fundamental characteristics of the fuel and the passive cooling system of the reactor make it physically impossible to have a nuclear accident like either Three Mile Island or Chernobyl. The unique design feature of pebble bed reactors is that it is a low power density core surrounded by a large amount of graphite which can absorb decay heat such that there is no possibility of a core melt accident which is possible (however remote) for water cooled reactors.

Control of reactor power is provided by borated control rods outside of the core in the outer reflector, and a reserve shut down systems consisting of an absorber ball system utilizing channels in the outer reflector. If an accident were to occur, gravity could lower the control rods to the fully inserted position with no mechanical assistance. The control rods in the outer reflector are used to control the PBMR power level. In addition, these rods, can be fully inserted to shut down the reactor if needed.

Because the reactor is located within the security area of the plant there is no significant radiation exposure to workers at or near the plant. This combined with the design safety criteria allows the reactor to be located adjacent to other industrial operations with only a small exclusion area of 200 meters and no need for extensive emergency evacuation planning beyond that of other typical industrial facilities.

8.11.4 Overall Nuclear Safety

An assessment of the overall safety of nuclear plants proposed for application in the oil sands industry is an important issue that will be determined by the safety case made by the developers to the Canadian Nuclear Safety Regulator. Some publicly available information on each of the major designs evaluated is shown on Figure 37 below. Since nuclear plants were introduced more than 40 years ago, considerable safety improvements have been made to reduce the risk of accidents even further.

Shown on Figure 37 is a summary of some of the probabilistic risk analysis data available on the CANDU and PBMR reactors in comparison with more recognizable dose limits. The figure plots the Total Effective Dose Equivalent (TEDE) in Rem versus the frequency of occurrence of the event per year resulting in the dose. The dose is that received by a person located at the exclusion area boundary of the plant during the accident postulated according to the likelihood of the event. In some cases that person is assumed to move within a couple hours to an area farther away. The meaning of the TEDE is illustrated in Figure 36.

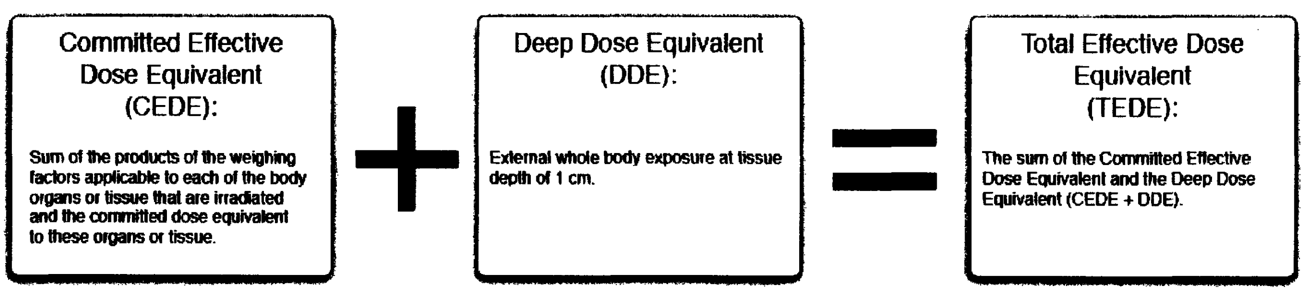


Figure 36: Total Effective Dose Equivalent

The probabilistic risk analysis results plotted for the PBMR are not for the exact reactor being considered for the oil sands application. They are taken from an NRC submission referencing an earlier design, and so they are only used for illustrative purposes. The error bars have been removed from the data points for visual clarity, but the plot of the full accident range with error bars as submitted to the NRC is shown in Figure 38. This figure provides detailed results for postulated accidents, their likelihood of occurrence and dose consequences to people that may be at the size boundary which for the PBMR is 200 meters. Shown on this chart are the ranges of acceptable and unacceptable safety consequences according to regulatory safety goals and regulations. As can be seen from Figure 38, there is considerable safety margin available to regulatory limits.

Likewise, the source of the CANDU accident data is a probabilistic risk assessment of a CANDU 9 reactor at Darlington, and so it is only illustrative of the CANDU technology. According to AECL, the Advanced CANDU Reactors have improved safety characteristics over the CANDU, and so the ACR accident scenarios are assumed to be bounded by the CANDU data. The parallel ACR data are not publicly available at this time. The accident scenarios plotted are among the worst considered in nuclear reactor licensing. The PBMR accidents are "design basis" as well as "beyond-design-basis" accidents, and the CANDU accidents all involve containment failure.

The horizontal lines on the graph of Figure 30 represent a variety of internationally accepted dose standards. The log/log scale of the axes should be noted in comparing dose levels in the chart. The red line at the top of the figure represents radiation dose of 350 Rem, sudden exposure – the dose at which 50% of the population is expected to perish within one week. At 20 Rem is a line showing the dose level at which research has conclusively shown that there are no clinical effects due to a sudden exposure. It should be noted that nearly every accident on the chart falls below this level. The next line, at 5 Rem, is the cumulative yearly dose limit for radiation workers as legislated by the Nuclear Regulatory Commission in the US. The next line (360 millirem - 0.001 Rem) represents the average cumulative yearly public dose to a person in the US, and the lowest line (3 mrem) represents the NRC's yearly limit for the cumulative dose at a nuclear plant boundary under normal operating conditions.

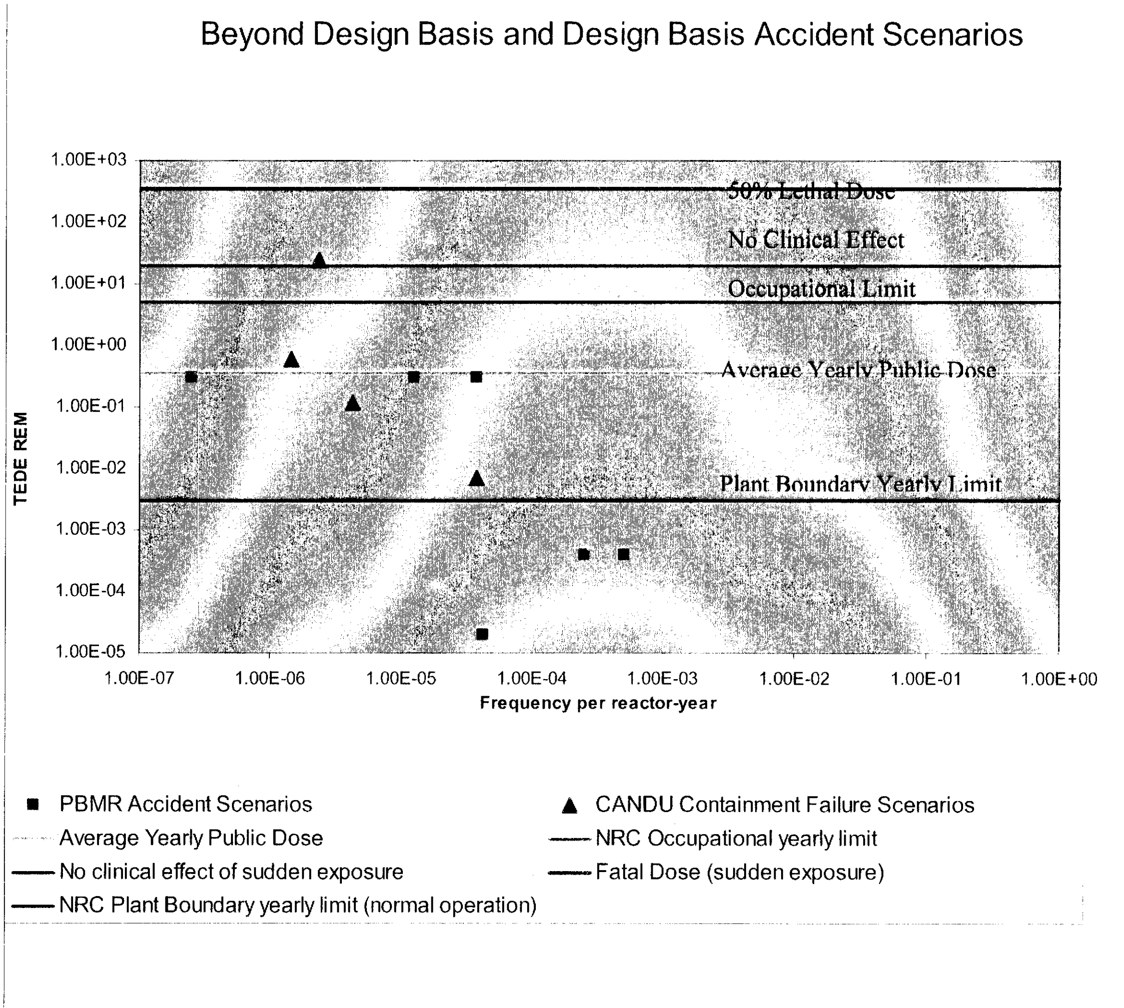


Figure 37: Accident Dose-Frequency Data for the CANDU and PBMR reactors

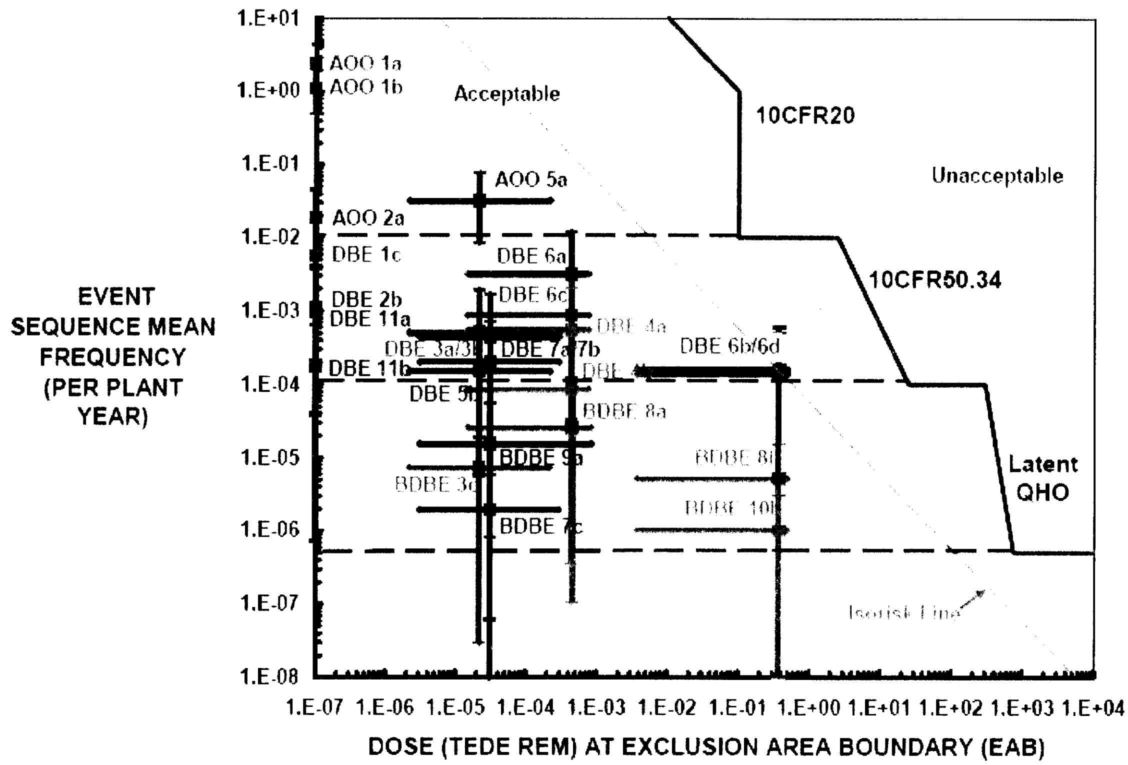


Figure 38: Frequency-Consequence Chart for all Three Categories of Licensing Basis Events [as submitted to the NRC in NRC Document No. 040251]

As these reactor designs have matured, the risk of reactor operation have been greatly reduced over past designs. The results show that the likelihood of a major accident releasing any significant radiation is on the order of 10^{-6} which is still below levels at which epidemiological data suggests any biological effect. The PBMR results show even lower doses at comparable risk levels. The other issue of land contamination is addressed by the emergency planning zone boundary which for the PBMR is 200 m, for the Enhanced CANDU 6 is 3 km, and for the Advanced CANDU reactors is 500 meters. Should such an unlikely event occur, the impacts would be limited by the designs of the plant itself which would need to be addressed separately. What is typically of concern in co-location of nuclear facilities with other industries such as oil refineries or chemical plants is the impact of the other facility on the nuclear plant and not the other way around since fires and accidents releasing chemicals and explosions are much more likely than nuclear accidents. This issue will be a question raised by nuclear regulators.

8.12 SOCIOECONOMIC EFFECTS

The introduction of nuclear energy into the oil sands industry would have a number of positive socioeconomic effects. Since nuclear energy use would lower the operating costs of the oil sands projects, the royalties paid to the province of Alberta could also be expected to increase, since they are based on revenue minus operating expenses. It would also decrease the pressure on the natural gas supplies in Western Canada, presumably freeing up more of the fuel for home heating use and potentially for export. A nuclear plant would directly create between 400 and 700 permanent skilled jobs in the area. In the US, those jobs have typically received wages about 36% higher than the average for the area [107]. Construction jobs could range from 1,400 up to 2,400 during peak periods, and indirect permanent jobs would be added in about the same number as direct jobs. While construction workers are abundant in the Fort McMurray area (although in greater demand than supply), skilled engineering and scientific people are less common. A nuclear power plant would need to bring in a significant population of well-educated specialized employees, and the process of enticing those people to leave their current homes to work in Fort McMurray could prove difficult and expensive. This is an issue particularly significant for the nuclear energy industry, since there is currently no nuclear base in Alberta. The shortage of local nuclear workers will need to be addressed if a nuclear plant is built in the area.

Since nuclear plant construction requires a higher level of inspection and quality control than conventional construction, qualified labor for construction will need to be addressed. Since Alberta has a relatively harsh environment during the winter, special facilities and employee needs for operation will need to be provided to attract and retain a qualified work force for construction and operation. These facilities might include housing, recreational facilities and special provisions to accommodate permanent staff. This type of approach is used in China will great success in that employees are provided reasonably priced housing and other facilities to allow them to work a the site for the work week and return home for the weekends. A similar accommodation might be needed for nuclear power stations. This issue needs to be explored further in the context of an overall implementation plan for the introduction of nuclear energy into the oil sands business.

8.13 GREENHOUSE GAS EMISSIONS REDUCTIONS IN THE OIL SANDS REGION

One of the major reasons for considering nuclear energy in the oil sands business is to reduce the carbon footprint in the context of reducing CO_2 emissions in accordance with the Kyoto protocols. As described, the many applications of nuclear from simple steam production to a complete integrated plant producing electricity and energy for hydrogen production offer the capability of significant CO_2 emission avoidance as compared to natural gas usage.

The average nuclear plant avoids the emissions of approximately 10,000 tons of nitrogen oxides (NO_x) and 32,000 tons of sulfur dioxide (SO_2) each year, in addition to eliminating millions of tons of CO_2 per year. Shown on Table 20 are the CO_2 emissions reduction for a number of oil sands production capacities. If these number are realized in the future expansion plans of the oil sands producers based on estimates of new oil sands developments announced or disclosed for start-up between 2017 and 2020, the total reduction in CO_2 emissions in the oil sands region would be 745 x 10^6 metric tons. This assumes that the first application of nuclear could occur in 2017 to provide 10 years for licensing and preparation. With more nuclear plants in the future the emissions reductions would increase with time.

Table 20: Greenhouse Gas Emissions Reductions in the Oil Sands Region in Representative Reactor Scenarios

Reactor(s)	Oil Sands Site	Input Provided	GHG reductions in metric tons of CO_2e per yr	Lifetime (40 yr) GHG reductions in metric tons CO_2e
2 PBMRs	100k bpd SAGD	Steam and Electricity	3.3×10^6	131×10^6
4 PBMRs	200k bpd SAGD	Steam and Electricity	6.6×10^6	262×10^6
3 PBMRs	100k bpd SAGD with Upgrading	Steam, Heat, and Electricity	4.0×10^6	158×10^6
1 CANDU 6 or 1 ACR-700 or 3 PBMRs	200k Direct Mining	Steam, Heat, and Electricity	1.8×10^6	70×10^6
3 PBMRs	200k Direct Mining with Upgrading	Steam, Heat, and Electricity	3.1×10^6	124×10^6
Enhanced CANDU 6	Any	Electricity	2.7×10^6	208×10^6
ACR-700	Any	Electricity	2.7×10^6	107×10^6
ACR-1000	Any	Electricity	4.3×10^6	170×10^6
PBMR	Any	Electricity	0.7×10^6	26×10^6

8.14 Economic Analysis

Economic analysis is performed for two scenarios in detail in this section. The supply of electricity is analyzed and the supply of steam is analyzed.

8.14.1 Electricity Production

A comparison is made among the three nuclear reactors considered in this report and a combined cycle natural gas plant (100 MWe) for the purpose of supplying electricity to the oil sands industry. The levelized cost of each option was calculated, and sensitivity analysis was performed on the natural gas price and the capital costs of the nuclear plants. The assumptions made in this analysis are detailed in Tables 21 through 26. All dollars are in Canadian dollars unless stated otherwise, and where an exchange rate was used to convert from US dollars, the rate of $0.90 USD per CAD was used. Construction for any project was assumed to start in 2010.

Table 21: Assumptions Made in Calculating the Capital Charge Rate for the Nuclear Plants

General Inflation	2.00%
Term, years	40
Federal Tax Rate	22.1%
Provincial Tax Rate	8.00%
Debt Ratio	50%
Loan Term, yrs	40
Interest Rate	8.00%
Equity Return	14.75%
Prop Tax & Insurance	1.50%
Tax Credit Rate	0.00%
Tax Life, Years	20
Declining Balance Rate	100%
Real Return	12.50%
Resulting Capital Charge Rate	0.14441 in current dollars (Canadian)

Table 22: Assumptions Made in Calculating the Capital Charge Rate for the Natural Gas Plant

General Inflation	2.00%
Term, years	20
Federal Tax Rate	22.1%
Provincial Tax Rate	8.00%
Debt Ratio	50%
Loan Term, yrs	20
Interest Rate	8.00%
Equity Return	12.71
Prop Tax & Insurance	1.50%
Tax Credit Rate	0.00%
Tax Life, Years	20
Real Return	10.50%
Resulting Capital Charge Rate	0.15236 in current CAD

Table 23: Assumptions Specified for the Combined Cycle Natural Gas Plant

Generation (MWe)	100
Overnight $/kWe	900
Construction Period	2 years
Construction Interest	12.71% on ½ of construction period escalation of overnight costs
O&M	$11 million per year[1]
Heat Rate (btu/kWh)	6800
Natural Gas Price	Varies

[1] Source: "Electricity Generation Technologies: Performance and Cost Characteristics" Prepared for the Ontario Power Authority by the Canadian Energy Research Institute, August 2005.

Table 24: Assumptions Specified for the Enhanced CANDU 6 Nuclear Plant

Generation (MWe)	728
Overnight $/kWe	3375[1]
Construction Period	6 years[1]
Construction Interest	14.75% on construction capital outlay sequence - yr1: 8%, yr2: 21% yr3: 27.1%, yr4: 19.6%, yr5: 12%, yr6: 7.2%, yr7: 5.1%[1]
O&M	$90 million per year [1]
Nuclear Fuel Cost	3.75 $/MWh [1]

[1]Source: "Electricity Generation Technologies: Performance and Cost Characteristics" Prepared for the Ontario Power Authority by the Canadian Energy Research Institute, August 2005.

Table 25: Assumptions Specified for the ACR-700 Nuclear Plant

Generation (MWe)	703
Overnight $/kWe	2740 (CERI) [1]
Construction Period	6 years[1]
Construction Interest	14.75% on construction capital outlay sequence - yr1: 8%, yr2: 21% yr3: 27.1%, yr4: 19.6%, yr5: 12%, yr6: 7.2%, yr7: 5.1%[1]
O&M	$100 million per year[1]
Nuclear Fuel Cost	5.45 $/MWh[1]

[1] Source: "Electricity Generation Technologies: Performance and Cost Characteristics" Prepared for the Ontario Power Authority by the Canadian Energy Research Institute, August 2005.

Table 26: Assumptions Specified for the PBMR Nuclear Plant

Generation (MWe)	172
Overnight $/kWe	3333
Construction Period	3 years
Construction Interest	12.71% on ½ of construction period escalation of overnight costs
O&M	$10.5 million per year[1]
Nuclear Fuel Cost	21.25 million $/year[1]

[1] Source: PBMR (Pty) Ltd.

Given the assumptions detailed above, the analysis showed that the breakeven natural gas prices where each of the nuclear plants are competitive with the combined cycle natural gas plant are at approximately $8.50, $8.90, and $10.10 for the ACR-700, PBMR, and CANDU 6, respectively. These results are illustrated graphically in Figure 39.

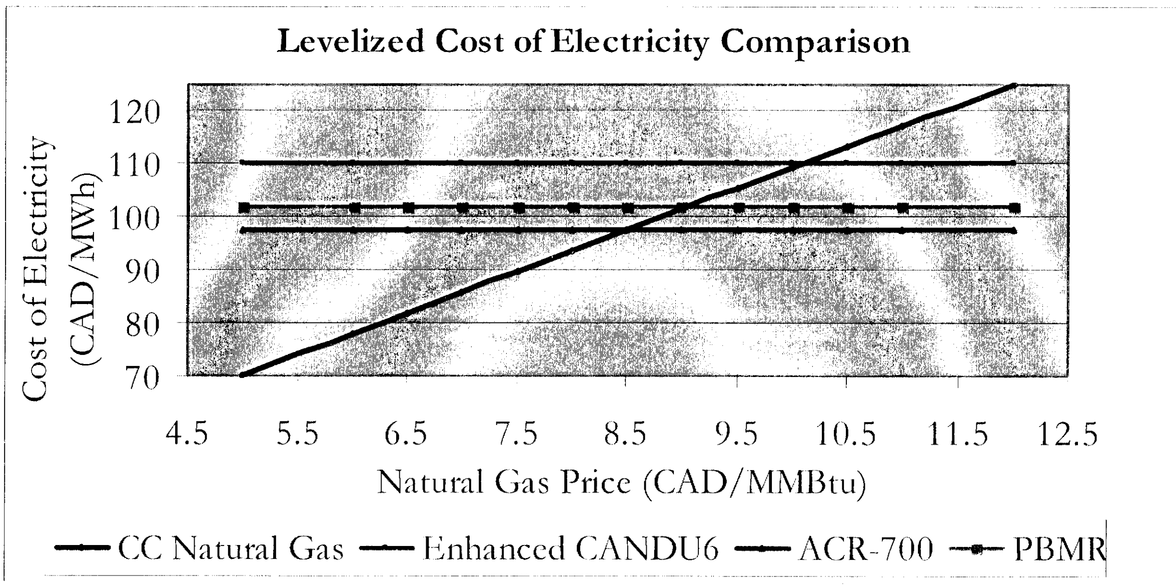


Figure 39: Levelized Cost of Electricity Comparison

A sensitivity analysis was performed on the overnight capital costs of the nuclear power plants. While the cost of the natural gas plant and all other factors were kept constant, the overnight costs of the nuclear plants were all raised by 10%, 20%, 40%, and 60% in turn. This was done to show the impact of a cost overrun on the ultimate cost of the electricity produced. The analysis was performed first at $8/MMBtu natural gas, and then at $12/MMBtu natural gas, and the results are shown below in Figure 40 and Figure 41.

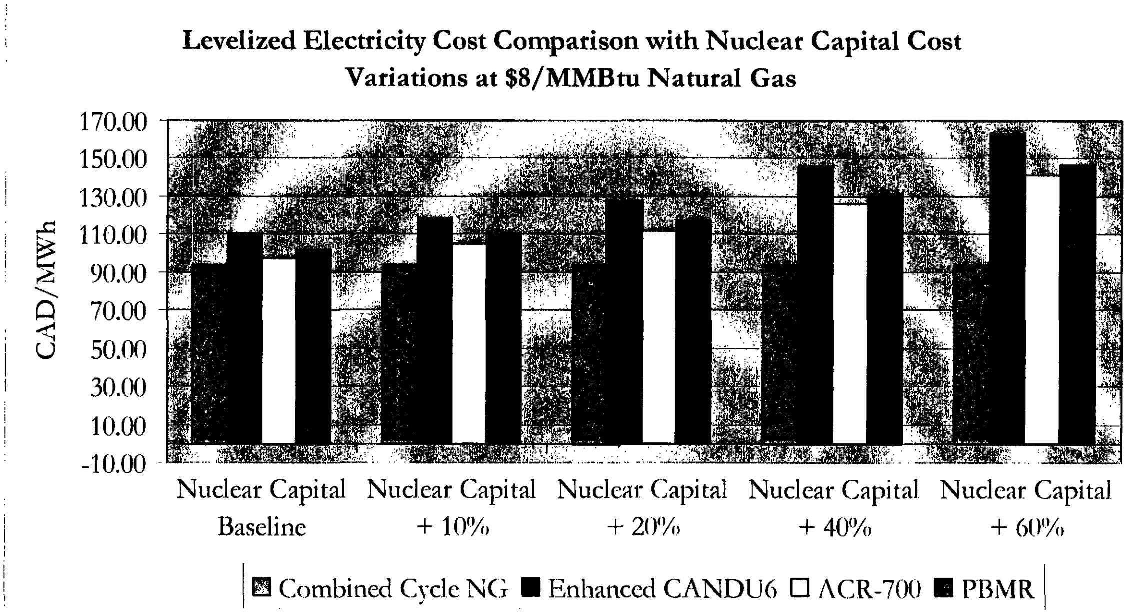


Figure 40: Levelized Cost of Electricity with Varying Nuclear Capital Costs at $8/MMBtu Natural Gas

In the $8 gas case, none of the nuclear plants were found to be competitive at the baseline capital cost.

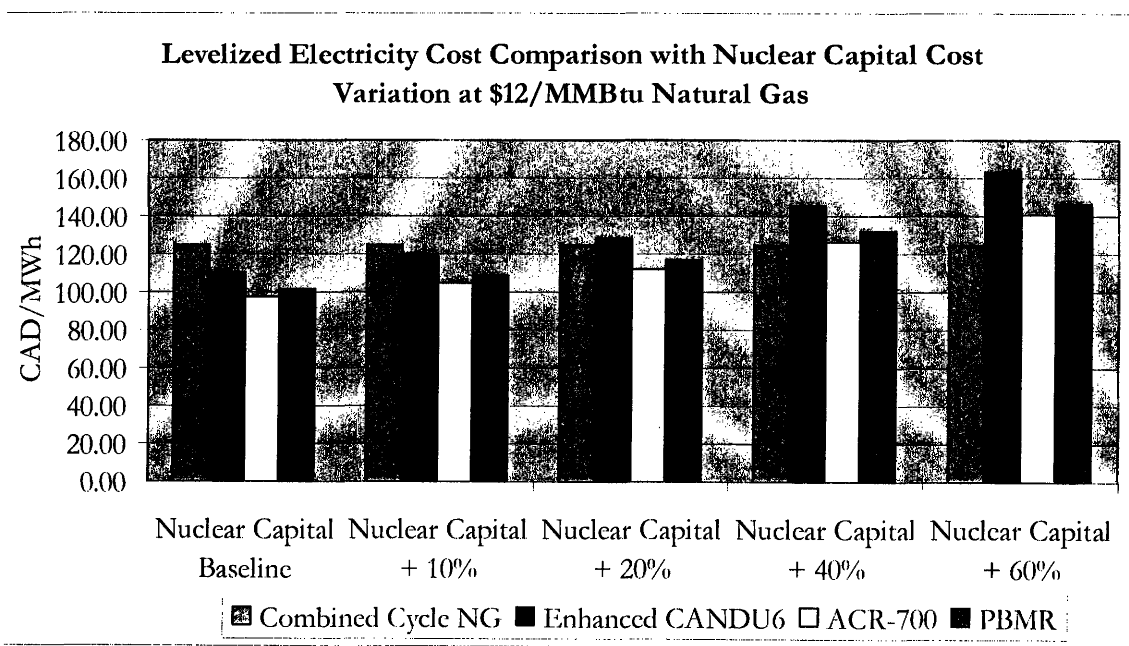


Figure 41: Levelized Cost of Electricity with Varying Nuclear Capital Costs at $12/MMBtu Natural Gas

In the $12 gas case, all three of the nuclear plants were found to be competitive at the baseline capital costs, but at a 40% overrun, the CANDU 6 and the PBMR were shown to be more expensive than gas, and at 60%, the ACR-700 also appears slightly too expensive.

8.14.2 Steam Production

Estimating the costs of the steam production plants was more difficult because the data available publicly is generally applicable to electric plants. For the sake of consistency, in each nuclear plant case it was assumed that the costs associated with the electricity generation accounted for 1/3 of the overnight capital costs of the nuclear plants. The cost of that equipment is dominated by the turbine-generator, moisture separators and reheaters, oil lubrication systems, and the electrical switchyard. The steam production assumed for each plant is given in Table 27 below. The plants are rated in this case based on their thermal capacity, but the thermal capacity used was the net capacity after providing the heat needed for the house load. The cost of the steam generated from a natural gas boiler was approximated from a reference and is shown in Figure 42 [108].

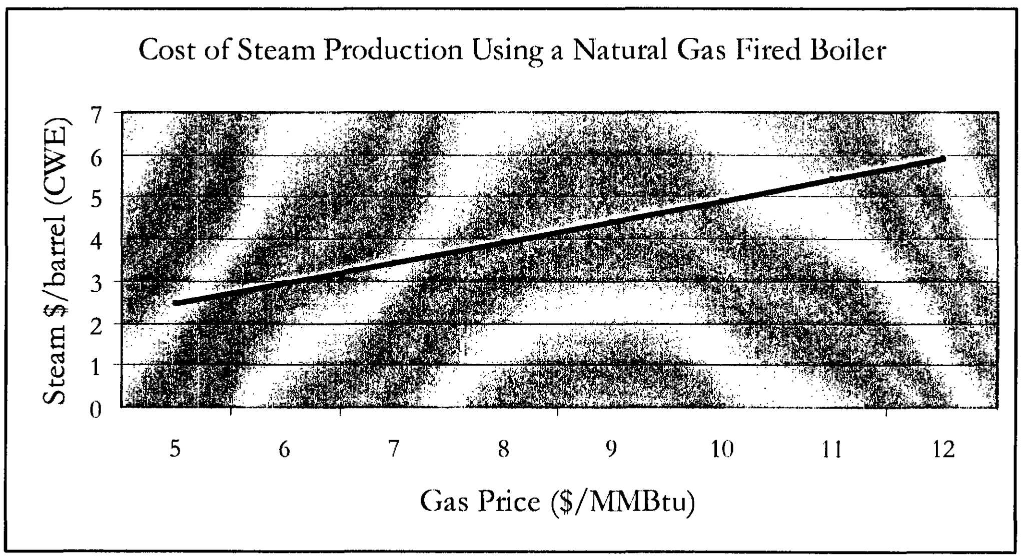


Figure 42: Cost of Steam Production from a Natural Gas Fired Boiler

Table 27: Levels of Steam Production for each Generation Option

Plant Type	Steam Production (bpd)
2030 MWth Enhanced CANDU 6	653,000
1895 MWth ACR-700	697,000
412 MWth PBMR	130,000

The results of the analysis were overwhelmingly in support of nuclear energy use for steam production. The baseline cost to produce one barrel of steam (CWE) from the nuclear reactors was \$2.15 for the Enhanced CANDU 6, \$1.78 for the ACR-700, and \$1.87 for the PBMR. For the natural gas plant, at \$5/MMBtu gas, the cost found was \$2.45. These results are shown in Figure 43 below.

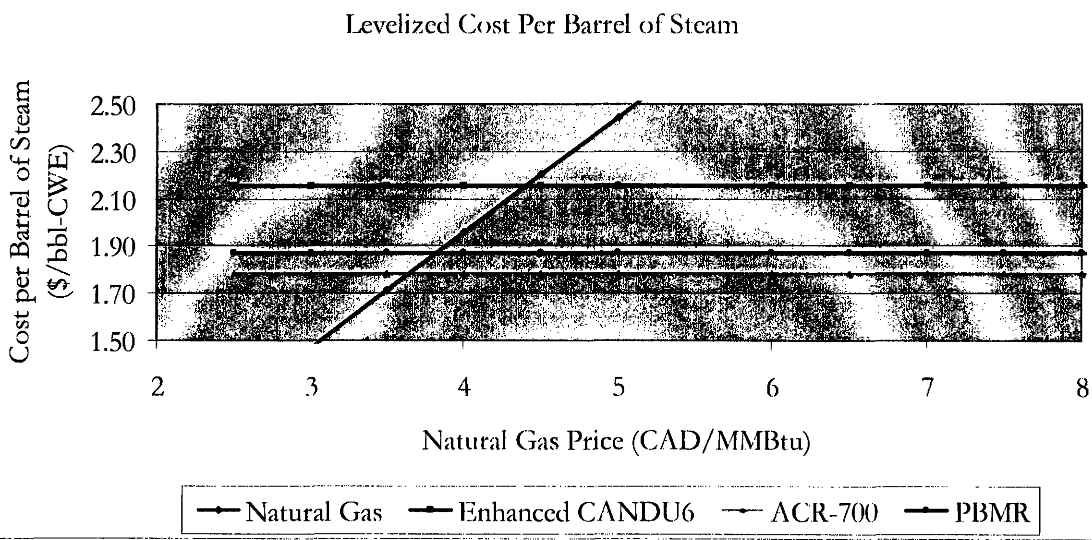


Figure 43: Levelized Cost per Barrel of Steam

A sensitivity analysis was again performed on the overnight capital costs of the nuclear power plants. While the cost of the natural gas plant and all other factors were kept constant, the overnight costs of the nuclear plants were all raised by 10%, 20%, 40%, and 60% in turn. This was done to show the impact of a cost overrun on the ultimate cost of the steam produced. The analysis was performed for \$8/MMBtu natural gas and for \$11/MMBtu natural gas, and the results are shown below in Figure 44 and Figure 45.

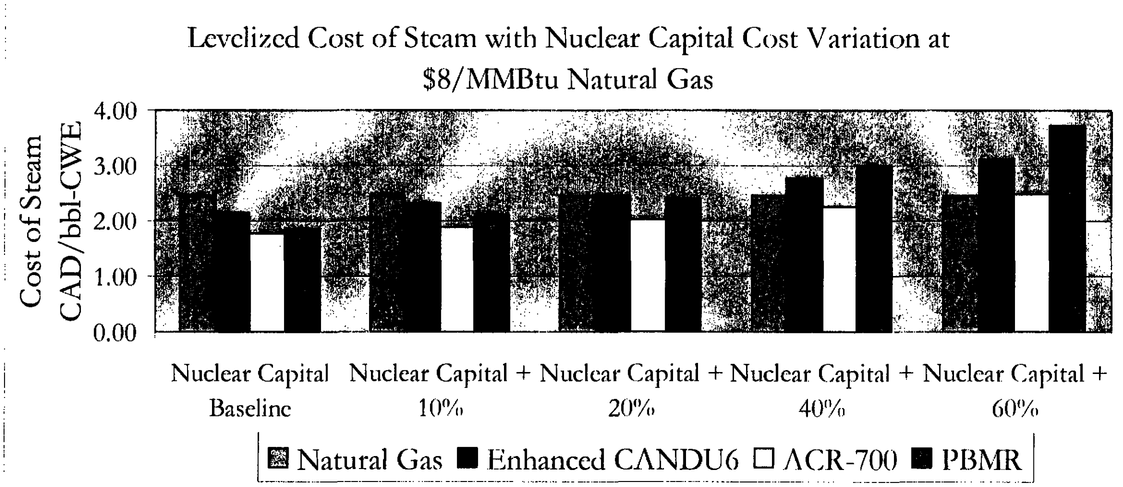


Figure 44: Levelized Cost of Steam Production with Varying Nuclear Capital Costs ($8 NG)

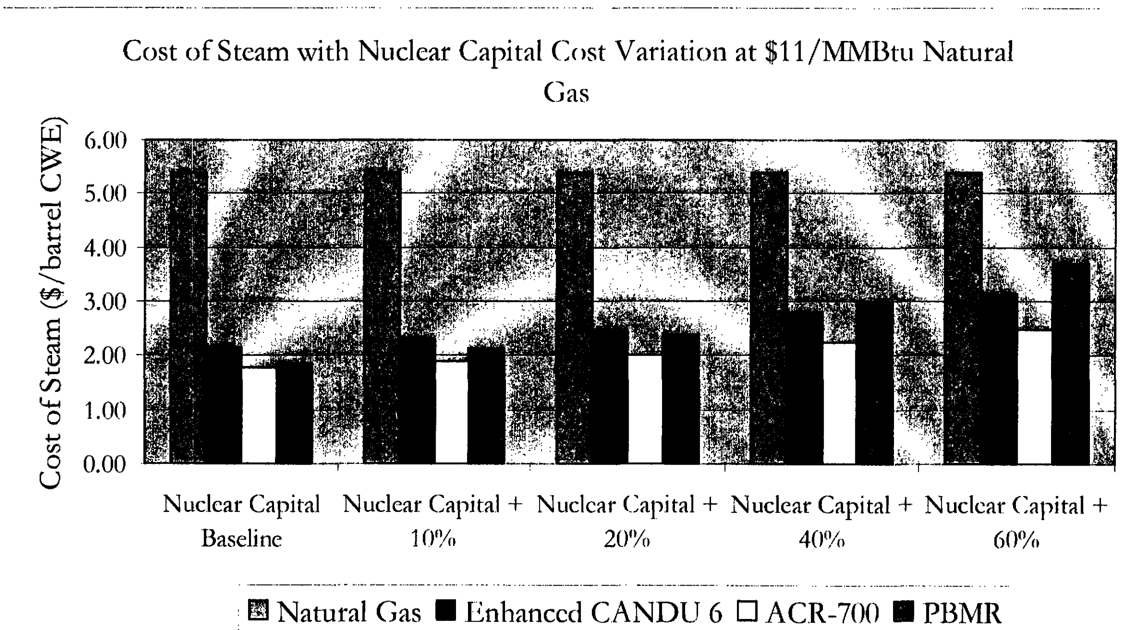


Figure 45: Levelized Cost of Steam Production with Varying Nuclear Capital Costs ($11 NG)

The results showed that the costs for producing steam with a nuclear plant continued to be much less expensive than natural gas fired production, even when the capital costs were overrun by 60%. This is a simplified model that makes a significant simplifying assumption in taking electricity generation facilities to be responsible for 1/3 of the nuclear plant capital cost, but the trend is clear – nuclear steam is highly competitive with natural gas, even when great risks are assumed in the capital costs, and nuclear electricity has the potential to compete with natural gas at current nuclear cost estimates, and likely future gas prices.

CHAPTER 6

9 Conclusions

The purpose of this thesis has been to assess the feasibility, economics and possible advantages of using nuclear energy in the oil sands industry based on typical conditions in the Fort McMurray region. The nuclear reactor technologies assessed are two Canadian reactors (Enhanced CANDU 6, and ACR -700) and a high temperature helium gas reactor (the South African designed Pebble Bed Modular Reactor since it is the most developed).

Several specific nuclear energy applications were assessed from steam only production, steam and electricity, steam, electricity and upgrading and finally steam, electricity, upgrading and hydrogen production. In the context of steam only production for SAGD, it was found that the steam pressure of the CANDU reactors was too low and the size of the reactors was generally too large for typical deployment within a 10 km radius well field.

The smaller 500 MWth high-temperature pebble bed gas reactor proved to be well-suited to the steam production for two reasons. First, the steam pressures produced by the reactor are at or around the industry standard. Second, the size of the reactor is compatible with placement in a typical SAGD project. Although the PBMR was used as an example in representing the high-temperature gas reactor, other high temperature gas reactors such as the AREVA ANTARES or General Atomics GT-MHTR could be used but they are less developed..

When electricity generation was included as a reactor output, the results were largely the same for all reactor technologies. For the ACR-700, providing steam and electricity for typical fields leaves the reactor significantly over-powered with electricity, and while the

ACR can produce electricity competitively under certain conditions, the cost of that electricity production would not likely justify the placement of the power source in a remote SAGD location far from existing grid infrastructure. The PBMR is found to be more versatile in the combined heat and power role due in part to its relatively small size. Since capacity can be added in units of 500 MWth, the PBMR is sized such that nuclear energy output could be adjusted to fit the needs of a specific project.

In the direct mining application, the reactors were analyzed for their suitability to provide heat and electricity to a direct mining and extraction project. In this case, the steam pressures required of any of the processes are within the operating range of the Enhanced CANDU 6, and so it could once again be considered. The PBMR again proved to be highly versatile, and could certainly be a good fit for most medium to large direct mining projects. The CANDU 6 and the ACR-700 were found to be better sized for a direct mining operation with a production of about 200,000 barrels per day of bitumen. This is of great interest, since that is a very typical size for a mining project. In this case, however, the reactor would produce excess electricity that would need to be sold to other companies in the region. It is expected that in the direct mining application, CANDUs are more desirable than in the SAGD application, since the reactor would be located in the vicinity of other electricity-consuming projects. An upgrading operation could also be easily supported by any of the reactors. Electricity could be produced for the industry by any of the reactors.

Hydrogen production could be provided through electrolysis, but it is generally not thought to compete with steam-methane reforming. Indeed a quick look at the cost of producing the needed electricity shows that the cost of production would be in the range of $4.50 per kg of hydrogen, which is well above the typical costs of SMR ($2.50-$3.50 per kg). Other hydrogen production techniques that are not yet ready for commercial application show promise for the future. These include high temperature steam electrolysis as well as thermo-chemical cycles such as the sulfur-iodide and the hybrid sulfur process. It is expected that if a hydrogen facility was co-located with a nuclear plant, the heat from the reactor could be used in a steam methane reforming process reducing the need for natural gas as a heat source for hydrogen production.

The economics of electricity production using nuclear power were found to be favorable at natural gas prices of approximately \$8.50, \$8.90, and \$10.10 for the ACR-700, PBMR, and CANDU 6, respectively.. An exchange rate of 0.90 was used, and so in US dollars those prices are equivalent to USD 7.65, USD 8.01, and USD 9.09. The assumptions implicit in this analysis are set forth in section 8.14. The economic analyses for steam production using nuclear power were eminently favorable for all of the reactor choices. The cost of the steam produced by nuclear was less than 1/3 of the cost produced by natural gas fired energy, and so it is merely a matter of matching the size of the nuclear plant with the size of the project, as well as resolving the political and social issues that are raised by this option.

The replacement of the natural gas and electricity supply to a 100k bpd SAGD operation with nuclear energy could reduce emissions in the region by 3.3 million metric tons of CO_2e per year of operation. A 200k direct mining operation supplied with nuclear energy would reduce CO_2e emissions by 3.1 million metric tons per year in the oil sands region. Should an ACR be installed purely to provide electricity to the region, the CO_2e emissions reduction would be 2.7 million metric tons per year for an ACR-700, and 4.3 million metric tons per year for an ACR-1000.

Greenhouse gas emissions reduction goals are a strong incentive for introducing nuclear energy into the oil sands sector. While nuclear energy application show economic promise, a great deal depends on the cost of construction of these plants. Should the economic assumptions of this thesis hold true, it appears that nuclear energy has a place in the oils sands industry on purely economic grounds. Should carbon taxes or caps be implemented or carbon capture or sequestration be required, the economics of nuclear energy become even more attractive. Without some action by the oil sands industry, the environmental goals of the nation will be difficult to meet especially since the oil sands industry could account for nearly one-fifth of Canada's GHG emissions in the next ten to fifteen years. Nuclear energy provides the most dependable and proven technology to significantly lower emissions at a price advantage to natural gas.

In order to take advantage of the nuclear option, oil sands companies need to give serious consideration to a long term strategy for deployment which may include equity interest in a nuclear company formed for the purpose of design, construction and operation of the nuclear energy plant for a specific project being considered in the next 10 to 15 years. This early effort would identify specific design features, integration needs and a conceptual design to allow for a step by step licensing process such that the technology will be available when needed to address future challenges either on economic grounds or carbon limitations in operations.

The public still has concerns about nuclear plant safety, although the public support for nuclear energy has become much more favorable in recent years due in part to the excellent safety record, global warming concerns and stable prices.. For any nuclear project to be successful, the safety of the facilities needs to be demonstrated in both the licensing process and in the opinion of the public.

The nuclear licensing process is found to be fairly simple and technology-neutral. Thus, the high-temperature gas reactor could be licensed in Canada based on generic functional risk informed safety requirements. While the Canadian Nuclear Safety Commission is more equipped to accommodate a CANDU-based licensing request, it will need to allocate resources to increase staffing for any serious licensing project, or the process could be delayed.

The logistical difficulty of transporting large nuclear reactor components to the sites in Alberta was analyzed for technical feasibility, although not for cost. In general, items that could be shipped by rail from Duluth, Minnesota would be traveling the same route that many other large oil-sands-bound components have traveled. There is some uncertainty at this time about the possibility of transporting some of the largest components by rail, and while it is sure to be expensive, the possibility of establishing a barge route from the Beaufort Sea down to Fort McMurray is being actively explored. This would enable the shipment of virtually any size component.

The business model for the integration of nuclear energy into the oil sands production industry suggests that the energy needed, either in steam, electricity, hot water or hydrogen could be sub-contracted to experienced nuclear and/or hydrogen production operators who would be responsible for ownership, design, licensing , construction and operation. Oil sands companies could and might likely desire to become equity owners to move these projects forward.

In summary, based on this analysis, it appears that integration of nuclear energy is the oil sands business in a viable path forward on many levels: feasibility, flexibility, economics, CO_2 emission reductions and operability. Appropriate business models need to be developed based on the interests of the individual company's long term objectives. The licensing process and public acceptance issues will need to be addressed by a thought out and planned program of communication both with the regulator and the public in the area. Thus, it was found that nuclear energy offers an opportunity to allow for continued expansion of the oil sands resource without compromising environmental quality.

10 Recommendations

It is recommended that a number of development initiatives be supported by the Alberta government and academics, the oil sands industry, and the environmentally conscious.

1. A public awareness campaign for nuclear energy should be pursued, as the province of Alberta has no experience with nuclear power in the past. The decision to install nuclear capacity is generally accepted to be one that must be made not only by a utility or a business, but by the whole community in the region of the plant, including the government and the members of the public. The public outreach campaign should be developed with an objective focus on benefits and risks of moving forward with any and all available alternatives. It is our belief that if presented in this manner, the choice for nuclear energy will be obvious.

2. This study presented a high level view of how nuclear energy could be incorporated into the oil sands business and outlined many options. What is now needed is a more detailed specific site study of a future project to determine how and what specific nuclear energy applications could be developed. This would entail a conceptual design and economic analysis.

3. Workforce issues are serious to the expansion of the oil sands production. A special task force needs to be assembled to address not only construction but also long term operation of nuclear facilities in the oil sands business. Regulatory preparedness to review non-traditional Canadian technologies should also be reviewed in this context.

4. An integrated oil sands industry strategy needs to be developed concerning the energy needs of the industry, particularly in the field of electricity production. Clearly the costs of building electric generating stations in the Fort McMurray area are higher than in other parts of Canada. The industry should work together to develop a mutually beneficial electricity supply strategy. Depending on the life of the oil sands field, the nuclear plants could be designed for easy conversion to electric power operation once the oil sand field is exhausted.

5. While the effects of a carbon penalty were not considered in the economic evaluation in this thesis, it is clear that such penalties are expected in the next few years. A follow-up study that should be considered would determine the impact of carbon taxes on oil sands production. This could include direct application of nuclear in the oil sands operations or by investing in nuclear plants in other regions of the country to offset any CO_2 emissions by obtaining credits for nuclear electric production. Identifying the best strategy for dealing with the possibility of carbon taxes, caps or sequestration in an alternatives analysis is recommended.

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APPENDIX: ASPENPLUS 2006 Input and Reports

A.1 Enhanced CANDU 6 ASPEN Files

```
;Input Summary created by Aspen Plus Rel. 20.0 at 00:36:20 Mon May 28, 2007
;Directory C:\Documents and Settings\All Users\Application Data\AspenTech\Aspen
Plus 2006
;


DYNAMICS
   DYNAMICS RESULTS=ON

IN-UNITS MET VOLUME-FLOW='cum/hr' ENTHALPY-FLO='Gcal/hr'  &
      HEAT-TRANS-C='kcal/hr-sqm-K' PRESSURE=bar TEMPERATURE=C  &
      VOLUME=cum DELTA-T=C HEAD=meter MOLE-DENSITY='kmol/cum'  &
      MASS-DENSITY='kg/cum' MOLE-ENTHALP='kcal/mol'  &
      MASS-ENTHALP='kcal/kg' HEAT=Gcal MOLE-CONC='mol/l'  &
      PDROP=bar

DEF-STREAMS CONVEN ALL

SIM-OPTIONS NPHASE=2 MASS-BAL-CHE=NO

DESCRIPTION "
   General Simulation with Metric Units :
   C, bar, kg/hr, kmol/hr, Gcal/hr, cum/hr.

   Property Method: None

   Flow basis for input: Mole

   Stream report composition: Mole flow
   "

DATABANKS PURE20 / AQUEOUS / SOLIDS / INORGANIC / &
      NOASPENPCD

PROP-SOURCES PURE20 / AQUEOUS / SOLIDS / INORGANIC

COMPONENTS
   DEUTE-01 D2O /
   WATER H2O
```

```
FLOWSHEET
  BLOCK B1 IN=1 3 OUT=2 4

PROPERTIES IDEAL

STREAM 1
  SUBSTREAM MIXED TEMP=309. PRES=10. <MPa>  &
    MASS-FLOW=1783. <kg/sec>
  MASS-FRAC DEUTE-01 1. / WATER 0.

STREAM 2
  SUBSTREAM MIXED TEMP=266. PRES=10. <MPa>  &
    MASS-FLOW=1783. <kg/sec>
  MASS-FRAC DEUTE-01 1.

STREAM 3
  SUBSTREAM MIXED TEMP=187. PRES=4.7 <MPa>  &
    MASS-FLOW=330. <kg/sec>
  MASS-FRAC DEUTE-01 0. / WATER 1.

STREAM 4
  SUBSTREAM MIXED TEMP=260. PRES=47. MASS-FLOW=330. <kg/sec>
  MASS-FRAC DEUTE-01 0. / WATER 1.

BLOCK B1 HEATX
  PARAM CALC-TYPE=SIMULATION LMTD-CORRECT=1. U-
OPTION=CONSTANT  &
    F-OPTION=CONSTANT CALC-METHOD=SHORTCUT SCUT-INTVLS=NO  &
    UA=2254242.21
  FEEDS HOT=1 COLD=3
  PRODUCTS HOT=2 COLD=4
  HEAT-TR-COEF U=1122.96
  HOT-SIDE DP-OPTION=CONSTANT
  COLD-SIDE DP-OPTION=CONSTANT

EO-CONV-OPTI

STREAM-REPOR MOLEFLOW MASSFLOW
;
;
;
;
;

BLOCK:  B1      MODEL: HEATX
```

```
-----------------------------
 HOT SIDE:
 ---------
 INLET STREAM:        1
 OUTLET STREAM:       2
 PROPERTY OPTION SET:  IDEAL    IDEAL LIQUID / IDEAL GAS
 COLD SIDE:
 ----------
 INLET STREAM:        3
 OUTLET STREAM:       4
 PROPERTY OPTION SET:  IDEAL    IDEAL LIQUID / IDEAL GAS

           ***  MASS AND ENERGY BALANCE  ***
                        IN          OUT       RELATIVE DIFF.
  TOTAL BALANCE
    MOLE(KMOL/HR )         386445.        386445.        0.00000
    MASS(KG/HR  )       0.760680E+07   0.760680E+07    0.00000
    ENTHALPY(GCAL/HR )     -24399.5       -24399.5        0.00000

             ***  INPUT DATA  ***

 FLASH SPECS FOR HOT SIDE:
 TWO    PHASE     FLASH
 MAXIMUM NO. ITERATIONS                          30
 CONVERGENCE TOLERANCE                              0.000100000

 FLASH SPECS FOR COLD SIDE:
 TWO    PHASE     FLASH
 MAXIMUM NO. ITERATIONS                          30
 CONVERGENCE TOLERANCE                              0.000100000

 FLOW DIRECTION AND SPECIFICATION:
   COUNTERCURRENT   HEAT EXCHANGER
   SPECIFIED EXCHANGER AREA
   SPECIFIED VALUE             SQM             7226.6795
   AREA TOLERANCE               SQM              0.01000
   MINIMUM APPROACH TEMPERATURE  C                          1.00000
   MAXIMUM NO. ITERATIONS                        20
   LMTD CORRECTION FACTOR                         1.00000

 PRESSURE SPECIFICATION:
   HOT  SIDE PRESSURE DROP        BAR              0.0000
   COLD SIDE PRESSURE DROP        BAR               0.0000

 HEAT TRANSFER COEFFICIENT SPECIFICATION:
   OVERALL COEFFICIENT          KCAL/HR-SQM-K       1122.9600
```

```
                *** OVERALL RESULTS ***

STREAMS:
          --------------------------------------
          |                           |
1     ----->|          HOT           |-----> 2
T= 3.0900D+02 |                       |   T= 2.6901D+02
P= 1.0000D+02 |                       |   P= 1.0000D+02
V= 0.0000D+00 |                       |   V= 0.0000D+00
          |                           |
4     <-----|          COLD          |<----- 3
T= 2.6015D+02 |                       |   T= 1.8700D+02
P= 4.7000D+01 |                       |   P= 4.7000D+01
V= 8.1630D-01 |                       |   V= 0.0000D+00
          --------------------------------------

DUTY AND AREA:
 CALCULATED HEAT DUTY          GCAL/HR              519.4364
 CALCULATED (REQUIRED) AREA    SQM                  7226.6794
 ACTUAL EXCHANGER AREA         SQM                  7226.6795
 PER CENT OVER-DESIGN                               0.0000

HEAT TRANSFER COEFFICIENT:
 AVERAGE COEFFICIENT (DIRTY)   KCAL/HR-SQM-K        1122.9600
 UA (DIRTY)                    CAL/SEC-K            2254242.2056

LOG-MEAN TEMPERATURE DIFFERENCE:
 LMTD CORRECTION FACTOR                             1.0000
 LMTD (CORRECTED)              C                    64.0063
 NUMBER OF SHELLS IN SERIES                         1

PRESSURE DROP:
 HOTSIDE, TOTAL                BAR                  0.0000
 COLDSIDE, TOTAL               BAR                  0.0000

PRESSURE DROP PARAMETER:
 HOT SIDE:                                          0.0000
 COLD SIDE:                                         0.0000
```

```
                                    +
                                  + + +
                                  + + +
                                  + + +
                            +     + + +     +
                          + + +   + + +   + + +
                          + + +   + + +   + + +
                          + + +   + + +   + + +
                    +     + + +   + + +   + + +     +
                  + + +   + + +   + + +   + + +   + + +
                  + + +   + + +   + + +   + + +   + + +
                  + + +   + + +   + + +   + + +   + + +
            +     + + +   + + +   + + +   + + +   + + +     +
          + + +   + + +   + + +   + + +   + + +   + + +   + + +
          + + +   + + +   + + +   + + +   + + +   + + +   + + +
          + + +   + + +   + + +   + + +   + + +   + + +   + + +
          + + +   + + +   + + +   + + +   + + +   + + +   + + +
          + + +   + + +   + + +   + + +   + + +   + + +   + + +
          + + +   + + +   + + +   + + +   + + +   + + +   + + +
          + + +   + + +   + + +   + + +   + + +   + + +   + + +
          + + +   + + +   + + +   + + +   + + +   + + +   + + +
            +     + + +   + + +   + + +   + + +   + + +     +
                  + + +   + + +   + + +   + + +   + + +
                  + + +   + + +   + + +   + + +   + + +
                  + + +   + + +   + + +   + + +   + + +
                    +       +     + + +     +       +
                                  + + +
                                  + + +
                                  + + +
ASPENTECH                         + + +
                                  + + +
FLOWSHEET SIMULATION              + + +
FOR THE PROCESS INDUSTRIES        + + +
                                    +
```

```
TM
 AAAAA   SSSSS   PPPPP   EEEEE   NN     N   PPPPP   L       U   U
SSSSS
 A   A   S       P   P   E       N N    N   P   P   L       U   U   S
 AAAAA   SSSSS   PPPPP   EEEEE   N   N N    PPPPP   L       U   U
SSSSS
 A   A       S   P       E       N    NN    P       L       U   U
S
 A   A   SSSSS   P       EEEEE   N      N   P       LLLLL   UUUUU
SSSSS
```

ASPEN PLUS IS A TRADEMARK OF
ASPEN TECHNOLOGY, INC.
TEN CANAL PARK
CAMBRIDGE, MASSACHUSETTS 02141
617/949-1000

HOTLINE:
U.S.A. 888/996-7100
EUROPE (32) 2/701-9555

```
PLATFORM: WIN32                                              MAY 23, 2007
VERSION: 20.0   Build 74                                     WEDNESDAY
INSTALLATION:                                                6:07:37 P.M.

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    CONTRACTOR/SUBCONTRACTOR: ASPEN TECHNOLOGY, INC. TEN CANAL PARK,
    CAMBRIDGE, MA 02141.
*** INPUT SUMMARY ***

>>CURRENT RUN

  ORIGINAL RUN                            MAY 23, 2007
  6:07:37 P.M.                            WEDNESDAY
  INPUT FILE: _5255ekf.inm
  RUN ID : _5255ekf
        ;
        ;Input file created by Aspen Plus Rel. 20.0 at 18:07:35
Wed May 23, 2007
        ;Directory C:\Documents and Settings\All
Users\Application Data\AspenTech\Aspen Plus 2006  Runid test2candu
        ;



        DYNAMICS
            DYNAMICS RESULTS=ON

        IN-UNITS MET VOLUME-FLOW='cum/hr' ENTHALPY-FLO='Gcal/hr'
&
                HEAT-TRANS-C='kcal/hr-sqm-K' PRESSURE=bar
TEMPERATURE=C  &
                VOLUME=cum DELTA-T=C HEAD=meter MOLE-
DENSITY='kmol/cum'  &
                MASS-DENSITY='kg/cum' MOLE-ENTHALP='kcal/mol'  &
                MASS-ENTHALP='kcal/kg' HEAT=Gcal MOLE-
CONC='mol/l'  &
                PDROP=bar

        DEF-STREAMS CONVEN ALL

        SIM-OPTIONS NPHASE=2 MASS-BAL-CHE=NO

        DESCRIPTION "
            General Simulation with Metric Units :
```

```
    C, bar, kg/hr, kmol/hr, Gcal/hr, cum/hr.

    Property Method: None

    Flow basis for input: Mole

    Stream report composition: Mole flow
    "

DATABANKS PURE20  / AQUEOUS  / SOLIDS  / INORGANIC  /  &
        NOASPENPCD

PROP-SOURCES PURE20  / AQUEOUS  / SOLIDS  / INORGANIC

COMPONENTS
    DEUTE-01 D2O /
    WATER H2O

FLOWSHEET
    BLOCK B1 IN=1 3 OUT=2 4

PROPERTIES IDEAL

STREAM 1
    SUBSTREAM MIXED TEMP=309. PRES=10. <MPa>  &
        MASS-FLOW=6480000. <kg/sec>
    MASS-FLOW DEUTE-01 6480000. <kg/sec> / WATER 0. <kg/sec>

STREAM 2
    SUBSTREAM MIXED TEMP=286. PRES=10. <MPa>  &
        MASS-FLOW=6480000. <kg/sec>
    MASS-FLOW DEUTE-01 6480000. <kg/sec>

STREAM 3
    SUBSTREAM MIXED TEMP=187. PRES=4.7 <MPa>  &
        MASS-FLOW=400. <kg/sec>
    MASS-FRAC DEUTE-01 0. / WATER 1.

STREAM 4
    SUBSTREAM MIXED TEMP=260. PRES=47. MASS-FLOW=400.
    MASS-FRAC DEUTE-01 0. / WATER 1.

BLOCK B1 HEATX
    PARAM CALC-TYPE=SIMULATION LMTD-CORRECT=1. U-OPTION=CONSTANT  &
        F-OPTION=CONSTANT CALC-METHOD=SHORTCUT SCUT-INTVLS=NO  &
        UA=2254242.21
    FEEDS HOT=1 COLD=3
    PRODUCTS HOT=2 COLD=4
    HEAT-TR-COEF U=1122.96
    HOT-SIDE DP-OPTION=CONSTANT
    COLD-SIDE DP-OPTION=CONSTANT

EO-CONV-OPTI
```

```
STREAM-REPOR MOLEFLOW MASSFLOW
;
;
;
;
;


 *** INPUT TRANSLATOR MESSAGES ***



 PDF updated
TIME =        3.75


 *** CALCULATION TRACE ***


 *** FLOWSHEET ANALYSIS MESSAGES ***

 FLOWSHEET CONNECTIVITY BY STREAMS

   STREAM      SOURCE      DEST            STREAM      SOURCE      DEST
   3           ----        B1              1           ----        B1
   2           B1          ----            4           B1          ----

 FLOWSHEET CONNECTIVITY BY BLOCKS

   BLOCK         INLETS                          OUTLETS
   B1            1 3                             2 4

      COMPUTATION ORDER FOR THE FLOWSHEET IS:
      B1

Calculations begin
time       0.17


 SIMULATION CALCULATIONS BEGIN
TIME =        0.17

      ENTHALPY CALCULATION FOR INLET STREAM 1 OF BLOCK B1
TIME =        0.17
      KODE = 2  NTRIAL =    1  T = 582.1500  P = 1.000000E+07  V =
0.00000       Q =  0.00000

      ENTHALPY CALCULATION FOR INLET STREAM 3 OF BLOCK B1
TIME =        0.17
      KODE = 2  NTRIAL =    1  T = 460.1500  P = 4.700000E+06  V =
0.00000       Q =  0.00000

      ENTHALPY CALCULATION FOR OUTLET STREAM 2 OF BLOCK B1
TIME =        0.17
```

```
     KODE = 2  NTRIAL =    1  T = 559.1500   P = 1.000000E+07   V =
0.00000       Q =  0.00000

     ENTHALPY CALCULATION FOR OUTLET STREAM 4 OF BLOCK B1
TIME =       0.17
     KODE = 2  NTRIAL =    1  T = 533.1500   P = 4.700000E+06   V =
0.00000       Q =  0.00000

     UOS BLOCK B1        MODEL: HEATX
TIME =       0.17
     SPECIFICATION: EXCHANGER AREA        7226.7
     FLOW TYPE:     COUNTERCURRENT
     HOT:  TIN=  582.15  PIN=0.10000E+08   TOUT=  582.14
POUT=0.10000E+08
     COLD: TIN=  460.15  PIN=0.47000E+07   TOUT=  533.30
POUT=0.47000E+07
     AREA= 7226.7          DUTY=0.75429E+09       FT=1.00000


*** INPUT SPECIFICATION MESSAGES ***

 CHANGES WERE MADE TO STREAM       3         05/23/2007   18:10:47:70
 STREAM 3
    SUBSTREAM MIXED TEMP=187. PRES=6.5 <MPa>  &
        MASS-FLOW=400. <kg/sec>
    MASS-FRAC DEUTE-01 0. / WATER 1.

 CHANGES WERE MADE TO STREAM       4         05/23/2007   18:10:47:70
 STREAM 4
    SUBSTREAM MIXED TEMP=260. PRES=65. MASS-FLOW=400.
    MASS-FRAC DEUTE-01 0. / WATER 1.

 PDF updated
TIME =     186.82
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Calculations begin
time    186.88


     ENTHALPY CALCULATION FOR INLET STREAM 3 OF BLOCK B1
TIME =     186.89
     KODE = 2  NTRIAL =    1  T = 460.1500   P = 6.500000E+06   V =
0.00000       Q =  0.00000

     ENTHALPY CALCULATION FOR OUTLET STREAM 4 OF BLOCK B1
TIME =     186.89
     KODE = 2  NTRIAL =    1  T = 533.1500   P = 6.500000E+06   V =
0.00000       Q =  0.00000

     UOS BLOCK B1        MODEL: HEATX
TIME =     186.89
```

```
      SPECIFICATION: EXCHANGER AREA        7226.7
      FLOW TYPE:     COUNTERCURRENT
      HOT:  TIN=  582.15  PIN=0.10000E+08   TOUT=  582.14
POUT=0.10000E+08
      COLD: TIN=  460.15  PIN=0.65000E+07   TOUT=  554.00
POUT=0.65000E+07
      AREA= 7226.7           DUTY=0.60396E+09       FT=1.00000



*** INPUT SPECIFICATION MESSAGES ***

 CHANGES WERE MADE TO STREAM       3         05/23/2007   18:11:19:00
 STREAM 3
     SUBSTREAM MIXED TEMP=187. PRES=6.5 <MPa>  &
         MASS-FLOW=350. <kg/sec>
     MASS-FRAC DEUTE-01 0. / WATER 1.

 CHANGES WERE MADE TO STREAM       4         05/23/2007   18:11:19:00
 STREAM 4
     SUBSTREAM MIXED TEMP=260. PRES=65. MASS-FLOW=350.
     MASS-FRAC DEUTE-01 0. / WATER 1.

 PDF updated
TIME =    218.11
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Calculations begin
time    218.17


      ENTHALPY CALCULATION FOR INLET STREAM 3 OF BLOCK B1
TIME =    218.19
      KODE = 2  NTRIAL =   1  T = 460.1500  P = 6.500000E+06  V =
0.00000      Q =  0.00000

      ENTHALPY CALCULATION FOR OUTLET STREAM 4 OF BLOCK B1
TIME =    218.19
      KODE = 2  NTRIAL =   1  T = 533.1500  P = 6.500000E+06  V =
0.00000      Q =  0.00000

      UOS BLOCK B1        MODEL: HEATX
TIME =    218.19
      SPECIFICATION: EXCHANGER AREA        7226.7
      FLOW TYPE:     COUNTERCURRENT
      HOT:  TIN=  582.15  PIN=0.10000E+08   TOUT=  582.14
POUT=0.10000E+08
      COLD: TIN=  460.15  PIN=0.65000E+07   TOUT=  554.00
POUT=0.65000E+07
      AREA= 7226.7           DUTY=0.60396E+09       FT=1.00000
```

```
*** INPUT SPECIFICATION MESSAGES ***

 CHANGES WERE MADE TO STREAM       3        05/23/2007   18:11:49:15
 STREAM 3
     SUBSTREAM MIXED TEMP=187. PRES=6.5 <MPa>  &
         MASS-FLOW=300. <kg/sec>
     MASS-FRAC DEUTE-01 0. / WATER 1.

 CHANGES WERE MADE TO STREAM       4        05/23/2007   18:11:49:15
 STREAM 4
     SUBSTREAM MIXED TEMP=260. PRES=65. MASS-FLOW=300.
     MASS-FRAC DEUTE-01 0. / WATER 1.

 PDF updated
TIME =    248.27
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Calculations begin
time    248.33


      ENTHALPY CALCULATION FOR INLET STREAM 3 OF BLOCK B1
TIME =    248.33
      KODE = 2  NTRIAL =    1  T = 460.1500  P = 6.500000E+06  V =
0.00000      Q =  0.00000

      ENTHALPY CALCULATION FOR OUTLET STREAM 4 OF BLOCK B1
TIME =    248.35
      KODE = 2  NTRIAL =    1  T = 533.1500  P = 6.500000E+06  V =
0.00000      Q =  0.00000

      UOS BLOCK B1       MODEL: HEATX
TIME =    248.35
      SPECIFICATION: EXCHANGER AREA       7226.7
      FLOW TYPE:     COUNTERCURRENT
      HOT:  TIN=  582.15  PIN=0.10000E+08   TOUT=  582.14
POUT=0.10000E+08
      COLD: TIN=  460.15  PIN=0.65000E+07   TOUT=  554.00
POUT=0.65000E+07
      AREA= 7226.7         DUTY=0.60396E+09      FT=1.00000

 Report Writer entered
Time =   2107.08

 Results generated
Time =   2107.14

 Report Writer entered
Time =   2107.36

 Results generated
Time =   2107.38

RUN SAVED
```

```
 NO ERRORS OR WARNINGS GENERATED


 *** CALCULATION TRACE ***



*** INPUT SPECIFICATION MESSAGES ***

 CHANGES WERE MADE TO STREAM       1        05/23/2007   21:33:45:98
 STREAM 1
     SUBSTREAM MIXED TEMP=309. PRES=10. <MPa>  &
         MASS-FLOW=300. <kg/sec>
     MASS-FLOW DEUTE-01 6480000. <kg/sec> / WATER 0. <kg/sec>

 CHANGES WERE MADE TO STREAM       2        05/23/2007   21:33:45:98
 STREAM 2
     SUBSTREAM MIXED TEMP=286. PRES=10. <MPa>  &
         MASS-FLOW=300. <kg/sec>
     MASS-FLOW DEUTE-01 6480000. <kg/sec>

 PDF updated
TIME =     264.59
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   *   WARNING IN A "STREAM" PARAGRAPH
      STREAM NAME: 1
(STSTRM.30)
      COMPONENT MASS FLOWS OF SUBSTREAM: "MIXED"
      ARE NORMALIZED TO THE TOTAL MASS FLOW VALUE.

   *   WARNING IN A "STREAM" PARAGRAPH
      STREAM NAME: 2
(STSTRM.30)
      COMPONENT MASS FLOWS OF SUBSTREAM: "MIXED"
      ARE NORMALIZED TO THE TOTAL MASS FLOW VALUE.



Calculations begin
time    265.12


 SIMULATION CALCULATIONS BEGIN
TIME =     265.14

      ENTHALPY CALCULATION FOR INLET STREAM 1 OF BLOCK B1
TIME =     265.14
      KODE = 2  NTRIAL =   1  T = 582.1500  P = 1.000000E+07  V =
0.00000       Q =  0.00000
```

```
      ENTHALPY CALCULATION FOR OUTLET STREAM 2 OF BLOCK B1
TIME =    265.17
      KODE = 2  NTRIAL =    1  T = 559.1500  P = 1.000000E+07  V =
0.00000      Q =  0.00000

      UOS BLOCK B1       MODEL: HEATX
TIME =    265.17
      SPECIFICATION: EXCHANGER AREA        7226.7
      FLOW TYPE:     COUNTERCURRENT
      HOT:  TIN=  582.15  PIN=0.10000E+08   TOUT=  479.69
POUT=0.10000E+08


      COLD: TIN=  460.15  PIN=0.65000E+07   TOUT=  554.00
POUT=0.65000E+07
      AREA= 7226.7           DUTY=0.22257E+09       FT=1.00000


*** INPUT SPECIFICATION MESSAGES ***

 CHANGES WERE MADE TO STREAM       1        05/23/2007   21:38:41:87
 STREAM 1
     SUBSTREAM MIXED TEMP=309. PRES=10. <MPa>  &
         MASS-FLOW=1925. <kg/sec>
     MASS-FRAC DEUTE-01 1. / WATER 0.

 CHANGES WERE MADE TO STREAM       2        05/23/2007   21:38:41:87
 STREAM 2
     SUBSTREAM MIXED TEMP=286. PRES=10. <MPa>  &
         MASS-FLOW=1925. <kg/sec>
     MASS-FLOW DEUTE-01 6480000. <kg/sec>

 PDF updated
TIME =    560.47
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  *   WARNING IN A "STREAM" PARAGRAPH
      STREAM NAME: 2
(STSTRM.30)
      COMPONENT MASS FLOWS OF SUBSTREAM: "MIXED"
      ARE NORMALIZED TO THE TOTAL MASS FLOW VALUE.




Calculations begin
time    560.55


      ENTHALPY CALCULATION FOR INLET STREAM 1 OF BLOCK B1
TIME =    560.56
      KODE = 2  NTRIAL =    1  T = 582.1500  P = 1.000000E+07  V =
0.00000      Q =  0.00000

      ENTHALPY CALCULATION FOR OUTLET STREAM 2 OF BLOCK B1
TIME =    560.56
```

```
      KODE = 2  NTRIAL =    1  T = 559.1500   P = 1.000000E+07   V =
0.00000       Q =  0.00000

      UOS BLOCK B1        MODEL: HEATX
TIME =     560.56
      SPECIFICATION: EXCHANGER AREA        7226.7
      FLOW TYPE:      COUNTERCURRENT
      HOT:  TIN=  582.15  PIN=0.10000E+08   TOUT=  551.94
POUT=0.10000E+08
      COLD: TIN=  460.15  PIN=0.65000E+07   TOUT=  554.00
POUT=0.65000E+07
      AREA= 7226.7           DUTY=0.50814E+09       FT=1.00000


*** INPUT SPECIFICATION MESSAGES ***

 CHANGES WERE MADE TO STREAM       1        05/23/2007   21:42:17:79
 STREAM 1
     SUBSTREAM MIXED TEMP=309. PRES=10. <MPa>  &
         MASS-FLOW=1783. <kg/sec>
     MASS-FRAC DEUTE-01 1. / WATER 0.

 CHANGES WERE MADE TO STREAM       2        05/23/2007   21:42:17:79
 STREAM 2
     SUBSTREAM MIXED TEMP=266. PRES=10. <MPa>  &
         MASS-FLOW=1783. <kg/sec>
     MASS-FRAC DEUTE-01 1.

 STREAM        3         IS GENERATED BECAUSE OF OTHER CHANGES 05/23/2007
21:42:17:79
 STREAM 3
     SUBSTREAM MIXED TEMP=187. PRES=6.5 <MPa>  &
         MASS-FLOW=300. <kg/sec>
     MASS-FRAC DEUTE-01 0. / WATER 1.

 CHANGES WERE MADE TO STREAM       4        05/23/2007   21:42:17:79
 STREAM 4
     SUBSTREAM MIXED TEMP=266. PRES=47. MASS-FLOW=300.
     MASS-FRAC DEUTE-01 0. / WATER 1.

 PDF updated
TIME =     776.40
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Calculations begin
time    776.48


      ENTHALPY CALCULATION FOR INLET STREAM 1 OF BLOCK B1
TIME =     776.50
      KODE = 2  NTRIAL =    1  T = 582.1500   P = 1.000000E+07   V =
0.00000       Q =  0.00000
```

```
      ENTHALPY CALCULATION FOR INLET STREAM 3 OF BLOCK B1
TIME =     776.50
      KODE = 2  NTRIAL =    1  T = 460.1500  P = 6.500000E+06  V =
0.00000       Q =  0.00000

      ENTHALPY CALCULATION FOR OUTLET STREAM 2 OF BLOCK B1
TIME =     776.50
      KODE = 2  NTRIAL =    1  T = 539.1500  P = 1.000000E+07  V =
0.00000       Q =  0.00000

      ENTHALPY CALCULATION FOR OUTLET STREAM 4 OF BLOCK B1
TIME =     776.50
      KODE = 2  NTRIAL =    1  T = 539.1500  P = 4.700000E+06  V =
1.00000       Q =  0.00000

      UOS BLOCK B1       MODEL: HEATX
TIME =     776.50
      SPECIFICATION: EXCHANGER AREA        7226.7
      FLOW TYPE:     COUNTERCURRENT
      HOT:  TIN=  582.15  PIN=0.10000E+08   TOUT=  549.76
POUT=0.10000E+08
      COLD: TIN=  460.15  PIN=0.65000E+07   TOUT=  554.00
POUT=0.65000E+07
      AREA= 7226.7           DUTY=0.50095E+09       FT=1.00000


*** INPUT SPECIFICATION MESSAGES ***

 CHANGES WERE MADE TO STREAM       3        05/23/2007   21:43:05:68
 STREAM 3
     SUBSTREAM MIXED TEMP=187. PRES=6.5 <MPa>  &
         MASS-FLOW=275. <kg/sec>
     MASS-FRAC DEUTE-01 0. / WATER 1.

 CHANGES WERE MADE TO STREAM       4        05/23/2007   21:43:05:68
 STREAM 4
     SUBSTREAM MIXED TEMP=266. PRES=47. MASS-FLOW=275. <kg/sec>
     MASS-FRAC DEUTE-01 0. / WATER 1.

 PDF updated
TIME =     824.28
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Calculations begin
time     824.36


      ENTHALPY CALCULATION FOR INLET STREAM 3 OF BLOCK B1
TIME =     824.37
      KODE = 2  NTRIAL =    1  T = 460.1500  P = 6.500000E+06  V =
0.00000       Q =  0.00000
```

```
      ENTHALPY CALCULATION FOR OUTLET STREAM 4 OF BLOCK B1
TIME =     824.37
      KODE = 2  NTRIAL =    1  T = 539.1500  P = 4.700000E+06  V =
1.00000      Q =  0.00000

      UOS BLOCK B1       MODEL: HEATX
TIME =     824.37
      SPECIFICATION: EXCHANGER AREA        7226.7
      FLOW TYPE:     COUNTERCURRENT
      HOT:  TIN=  582.15  PIN=0.10000E+08   TOUT=  549.76
POUT=0.10000E+08
      COLD: TIN=  460.15  PIN=0.65000E+07   TOUT=  554.00
POUT=0.65000E+07
      AREA= 7226.7          DUTY=0.50095E+09       FT=1.00000



*** INPUT SPECIFICATION MESSAGES ***

 CHANGES WERE MADE TO STREAM       3        05/23/2007   21:43:42:50
 STREAM 3
     SUBSTREAM MIXED TEMP=187. PRES=6.5 <MPa>  &
         MASS-FLOW=270. <kg/sec>
     MASS-FRAC DEUTE-01 0. / WATER 1.

 CHANGES WERE MADE TO STREAM       4        05/23/2007   21:43:42:50
 STREAM 4
     SUBSTREAM MIXED TEMP=266. PRES=47. MASS-FLOW=270. <kg/sec>
     MASS-FRAC DEUTE-01 0. / WATER 1.

 PDF updated
TIME =     861.09
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Calculations begin
time    861.17


      ENTHALPY CALCULATION FOR INLET STREAM 3 OF BLOCK B1
TIME =     861.17
      KODE = 2  NTRIAL =    1  T = 460.1500  P = 6.500000E+06  V =
0.00000      Q =  0.00000

      ENTHALPY CALCULATION FOR OUTLET STREAM 4 OF BLOCK B1
TIME =     861.26
      KODE = 2  NTRIAL =    1  T = 539.1500  P = 4.700000E+06  V =
1.00000      Q =  0.00000

      UOS BLOCK B1       MODEL: HEATX
TIME =     861.26
      SPECIFICATION: EXCHANGER AREA        7226.7
      FLOW TYPE:     COUNTERCURRENT
```

```
      HOT:  TIN=  582.15  PIN=0.10000E+08   TOUT=  549.76
POUT=0.10000E+08
      COLD: TIN=  460.15  PIN=0.65000E+07   TOUT=  554.00
POUT=0.65000E+07
      AREA= 7226.7          DUTY=0.50095E+09       FT=1.00000


*** INPUT SPECIFICATION MESSAGES ***

 CHANGES WERE MADE TO STREAM       4        05/23/2007   21:44:14:03
 STREAM 4
     SUBSTREAM MIXED TEMP=266. PRES=65. MASS-FLOW=270. <kg/sec>
     MASS-FRAC DEUTE-01 0. / WATER 1.

 PDF updated
TIME =    892.61
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Calculations begin
time    892.67


      ENTHALPY CALCULATION FOR INLET STREAM 4 OF BLOCK 4
TIME =    892.70
      KODE = 2  NTRIAL =   1  T = 539.1500  P = 6.500000E+06  V =
0.00000      Q =  0.00000



*** INPUT SPECIFICATION MESSAGES ***

 CHANGES WERE MADE TO STREAM       4        05/23/2007   21:44:58:68
 STREAM 4
     SUBSTREAM MIXED TEMP=280. PRES=65. MASS-FLOW=270. <kg/sec>
     MASS-FRAC DEUTE-01 0. / WATER 1.

 PDF updated
TIME =    937.26
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Calculations begin
time    937.33


      ENTHALPY CALCULATION FOR INLET STREAM 4 OF BLOCK 4
TIME =    937.36
      KODE = 2  NTRIAL =   1  T = 553.1500  P = 6.500000E+06  V =
0.00000      Q =  0.00000
```

```
*** INPUT SPECIFICATION MESSAGES ***

 STREAM       4        IS GENERATED BECAUSE OF OTHER CHANGES 05/23/2007
21:46:13:62
 STREAM 4
     SUBSTREAM MIXED TEMP=280. PRES=65. MASS-FLOW=270. <kg/sec>
     MASS-FRAC DEUTE-01 0. / WATER 1.

 PDF updated
TIME =   1012.19
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Calculations begin
time   1012.26


      ENTHALPY CALCULATION FOR INLET STREAM 4 OF BLOCK 4
TIME =   1012.30
      KODE = 2  NTRIAL =    1   T = 553.1500   P = 6.500000E+06   V =
0.00000       Q =  0.00000

 Report Writer entered
Time =   1183.14

 Results generated
Time =   1183.26

 Report Writer entered
Time =   1183.47

 Results generated
Time =   1183.48

RUN SAVED


 *** SUMMARY OF ERRORS ***

                 PHYSICAL
                 PROPERTY  SYSTEM  SIMULATION
 TERMINAL ERRORS     0        0        0
   SEVERE ERRORS     0        0        0
          ERRORS     0        0        0
        WARNINGS     0        0        3


 *** CALCULATION TRACE ***


*** INPUT SPECIFICATION MESSAGES ***
```

```
 CHANGES WERE MADE TO STREAM       3        05/23/2007   21:56:52:70
 STREAM 3
     SUBSTREAM MIXED TEMP=187. PRES=4.7 <MPa>  &
         MASS-FLOW=300. <kg/sec>
     MASS-FRAC DEUTE-01 0. / WATER 1.

 CHANGES WERE MADE TO STREAM       4        05/23/2007   21:56:52:70
 STREAM 4
     SUBSTREAM MIXED TEMP=260. PRES=47. MASS-FLOW=300. <kg/sec>
     MASS-FRAC DEUTE-01 0. / WATER 1.

 PDF updated
TIME =      71.72
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Calculations begin
time     71.79


 SIMULATION CALCULATIONS BEGIN
TIME =      71.81

      ENTHALPY CALCULATION FOR INLET STREAM 3 OF BLOCK B1
TIME =      71.81
      KODE = 2  NTRIAL =    1  T = 460.1500   P = 4.700000E+06   V =
0.00000       Q =  0.00000

      ENTHALPY CALCULATION FOR OUTLET STREAM 4 OF BLOCK B1
TIME =      71.81
      KODE = 2  NTRIAL =    1  T = 533.1500   P = 4.700000E+06   V =
0.00000       Q =  0.00000

      UOS BLOCK B1        MODEL: HEATX
TIME =      71.81
      SPECIFICATION: EXCHANGER AREA         7226.7
      FLOW TYPE:     COUNTERCURRENT
      HOT:  TIN=  582.15  PIN=0.10000E+08   TOUT=  542.16
POUT=0.10000E+08
      COLD: TIN=  460.15  PIN=0.47000E+07   TOUT=  533.30
POUT=0.47000E+07
      AREA= 7226.7           DUTY=0.60410E+09       FT=1.00000
```

```
*** INPUT SPECIFICATION MESSAGES ***

 CHANGES WERE MADE TO STREAM       3        05/23/2007   21:57:28:92
 STREAM 3
     SUBSTREAM MIXED TEMP=187. PRES=4.7 <MPa>  &
         MASS-FLOW=320. <kg/sec>
     MASS-FRAC DEUTE-01 0. / WATER 1.

 CHANGES WERE MADE TO STREAM       4        05/23/2007   21:57:28:92
 STREAM 4
     SUBSTREAM MIXED TEMP=260. PRES=47. MASS-FLOW=320. <kg/sec>
     MASS-FRAC DEUTE-01 0. / WATER 1.

 PDF updated
TIME =    107.93
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Calculations begin
time    108.00


      ENTHALPY CALCULATION FOR INLET STREAM 3 OF BLOCK B1
TIME =    108.01
      KODE = 2  NTRIAL =    1  T = 460.1500  P = 4.700000E+06  V =
0.00000       Q =  0.00000

      ENTHALPY CALCULATION FOR OUTLET STREAM 4 OF BLOCK B1
TIME =    108.01
      KODE = 2  NTRIAL =    1  T = 533.1500  P = 4.700000E+06  V =
0.00000       Q =  0.00000

      UOS BLOCK B1       MODEL: HEATX
TIME =    108.01
      SPECIFICATION: EXCHANGER AREA        7226.7
      FLOW TYPE:     COUNTERCURRENT
      HOT:  TIN=  582.15  PIN=0.10000E+08   TOUT=  542.16
POUT=0.10000E+08
      COLD: TIN=  460.15  PIN=0.47000E+07   TOUT=  533.30
POUT=0.47000E+07
      AREA= 7226.7          DUTY=0.60410E+09       FT=1.00000


*** INPUT SPECIFICATION MESSAGES ***

 CHANGES WERE MADE TO STREAM       3        05/23/2007   21:57:52:37
 STREAM 3
     SUBSTREAM MIXED TEMP=187. PRES=4.7 <MPa>  &
         MASS-FLOW=330. <kg/sec>
     MASS-FRAC DEUTE-01 0. / WATER 1.

 CHANGES WERE MADE TO STREAM       4        05/23/2007   21:57:52:37
 STREAM 4
     SUBSTREAM MIXED TEMP=260. PRES=47. MASS-FLOW=330. <kg/sec>
```

```
     MASS-FRAC DEUTE-01 0. / WATER 1.

 PDF updated
TIME =     131.39
 THIS COPY OF ASPEN PLUS LICENSED TO MASS INSTITUTE OF TECH


Calculations begin
time    131.47


      ENTHALPY CALCULATION FOR INLET STREAM 3 OF BLOCK B1
TIME =    131.47
      KODE = 2  NTRIAL =    1  T = 460.1500  P = 4.700000E+06  V =
0.00000       Q =  0.00000

      ENTHALPY CALCULATION FOR OUTLET STREAM 4 OF BLOCK B1
TIME =    131.47
      KODE = 2  NTRIAL =    1  T = 533.1500  P = 4.700000E+06  V =
0.00000       Q =  0.00000

      UOS BLOCK B1       MODEL: HEATX
TIME =    131.47
      SPECIFICATION: EXCHANGER AREA        7226.7
      FLOW TYPE:     COUNTERCURRENT
      HOT:  TIN=  582.15  PIN=0.10000E+08   TOUT=  542.16
POUT=0.10000E+08
      COLD: TIN=  460.15  PIN=0.47000E+07   TOUT=  533.30
POUT=0.47000E+07
      AREA= 7226.7          DUTY=0.60410E+09       FT=1.00000

 Report Writer entered
Time =    195.47

 Results generated
Time =    195.48

 Report Writer entered
Time =    195.81

 Results generated
Time =    195.82

RUN SAVED


 NO ERRORS OR WARNINGS GENERATED
```

A.2 ACR-700 ASPENPLUS Files

```
                                +
                              + + +
                              + + +
                              + + +
                      +       + + +       +
                    + + +     + + +     + + +
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            +       + + +     + + +     + + +       +
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          + + +     + + +     + + +     + + +     + + +
            +         +       + + +       +         +
                              + + +
                              + + +
                              + + +
ASPENTECH                     + + +
                              + + +
FLOWSHEET SIMULATION          + + +
FOR THE PROCESS INDUSTRIES    + + +
                                +
```

```
TM
 AAAAA   SSSSS   PPPPP   EEEEE   NN    N   PPPPP   L        U   U
SSSSS
 A   A   S       P   P   E       N N   N   P   P   L        U   U    S
 AAAAA   SSSSS   PPPPP   EEEEE   N   N N   PPPPP   L        U   U
SSSSS
 A   A       S   P       E       N    NN   P       L        U   U
S
 A   A   SSSSS   P       EEEEE   N     N   P       LLLLL    UUUUU
SSSSS
```

```
ASPEN PLUS IS A TRADEMARK OF           HOTLINE:
ASPEN TECHNOLOGY, INC.                 U.S.A. 888/996-7100
TEN CANAL PARK                         EUROPE (32) 2/701-9555
CAMBRIDGE, MASSACHUSETTS 02141
617/949-1000

PLATFORM: WIN32                                          APRIL 11, 2007
VERSION: 20.0   Build 74                                 WEDNESDAY
INSTALLATION:                                            12:32:49 P.M.

THIS COPY OF ASPEN PLUS LICENSED TO MASS INSTITUTE OF TECH

     ASPEN PLUS (R) IS A PROPRIETARY PRODUCT OF ASPEN TECHNOLOGY, INC.
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THE
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     (i) FAR 52.227-14, Alt. III, (ii) FAR 52.227-19, (iii) DFARS
     252.227-7013(c)(1)(ii), or (iv) THE ACCOMPANYING LICENSE
AGREEMENT,
     AS APPLICABLE. FOR PURPOSES OF THE FAR, THIS SOFTWARE SHALL BE
DEEMED
     TO BE "UNPUBLISHED" AND LICENSED WITH DISCLOSURE PROHIBITIONS.
     CONTRACTOR/SUBCONTRACTOR: ASPEN TECHNOLOGY, INC. TEN CANAL PARK,
     CAMBRIDGE, MA 02141.
*** INPUT SUMMARY ***

>>CURRENT RUN

  ORIGINAL RUN                          APRIL 11, 2007
  12:32:49 P.M.                         WEDNESDAY
  INPUT FILE: _0210zud.inm
  RUN ID : _0210zud
      ;
      ;Input file created by Aspen Plus Rel. 20.0 at 12:32:48
Wed Apr 11, 2007
      ;Directory C:\Documents and Settings\All
Users\Application Data\AspenTech\Aspen Plus 2006  Runid ACRVAR1
      ;


      DYNAMICS
          DYNAMICS RESULTS=ON

      IN-UNITS MET VOLUME-FLOW='cum/hr' ENTHALPY-FLO='Gcal/hr'
&
              HEAT-TRANS-C='kcal/hr-sqm-K' PRESSURE=bar
TEMPERATURE=C  &
              VOLUME=cum DELTA-T=C HEAD=meter MOLE-
DENSITY='kmol/cum'  &
              MASS-DENSITY='kg/cum' MOLE-ENTHALP='kcal/mol'  &
              MASS-ENTHALP='kcal/kg' HEAT=Gcal MOLE-
CONC='mol/l'  &
              PDROP=bar

      DEF-STREAMS CONVEN ALL

```

```
SIM-OPTIONS NPHASE=2

DESCRIPTION "
    General Simulation with Metric Units :
    C, bar, kg/hr, kmol/hr, Gcal/hr, cum/hr.

    Property Method: None

    Flow basis for input: Mole

    Stream report composition: Mole flow
    "

DATABANKS PURE20    / AQUEOUS    / SOLIDS    / INORGANIC    /   &
        NOASPENPCD

PROP-SOURCES PURE20    / AQUEOUS    / SOLIDS    / INORGANIC

COMPONENTS
    DEUTE-01 D2O /
    WATER H2O

FLOWSHEET
    BLOCK B1 IN=1 3 OUT=2 4

PROPERTIES IDEAL

STREAM 1
    SUBSTREAM MIXED TEMP=325. PRES=12. <MPa>   &
        MASS-FLOW=300. <kg/sec>
    MASS-FRAC WATER 1.

STREAM 2
    SUBSTREAM MIXED TEMP=278.5 PRES=12. <MPa>
    MASS-FLOW WATER 1. <kg/sec>

STREAM 3
    SUBSTREAM MIXED TEMP=218. PRES=6.3 <MPa>   &
        MASS-FLOW=269. <kg/sec>
    MASS-FLOW DEUTE-01 0. <kg/sec> / WATER 269. <kg/sec>

BLOCK B1 HEATX
    PARAM DUTY=495. <MW> CALC-TYPE=RATING U-
OPTION=CONSTANT   &
        F-OPTION=CONSTANT CALC-METHOD=SHORTCUT   &
        UA=38425000. <Btu/hr-R>
    FEEDS HOT=1 COLD=3
    PRODUCTS HOT=2 COLD=4
    HEAT-TR-COEF U=230. <Btu/hr-sqft-F>
    HOT-SIDE DP-OPTION=CONSTANT
    COLD-SIDE DP-OPTION=CONSTANT

EO-CONV-OPTI

STREAM-REPOR MOLEFLOW MASSFLOW
;
;
```

```
;
;
;
```

```
 *** INPUT TRANSLATOR MESSAGES ***



 PDF updated
TIME =       4.17


 *** CALCULATION TRACE ***


 *** FLOWSHEET ANALYSIS MESSAGES ***

 FLOWSHEET CONNECTIVITY BY STREAMS

   STREAM      SOURCE      DEST           STREAM      SOURCE      DEST
   3           ----        B1             1           ----        B1
   2           B1          ----           4           B1          ----

 FLOWSHEET CONNECTIVITY BY BLOCKS

   BLOCK        INLETS                         OUTLETS
   B1           1 3                            2 4

      COMPUTATION ORDER FOR THE FLOWSHEET IS:
      B1

Calculations begin
time      0.21


 SIMULATION CALCULATIONS BEGIN
TIME =       0.21

      ENTHALPY CALCULATION FOR INLET STREAM 1 OF BLOCK B1
TIME =       0.24
      KODE = 2  NTRIAL =    1  T = 598.1500  P = 1.200000E+07  V =
1.00000       Q =  0.00000

      ENTHALPY CALCULATION FOR INLET STREAM 3 OF BLOCK B1
TIME =       0.63
      KODE = 2  NTRIAL =    1  T = 491.1500  P = 6.300000E+06  V =
0.00000       Q =  0.00000

      ENTHALPY CALCULATION FOR OUTLET STREAM 2 OF BLOCK B1
TIME =       0.64
      KODE = 2  NTRIAL =    1  T = 551.6500  P = 1.200000E+07  V =
0.00000       Q =  0.00000

      UOS BLOCK B1        MODEL: HEATX
TIME =       0.64
      SPECIFICATION: EXCHANGER DUTY       0.49500E+09
      FLOW TYPE:     COUNTERCURRENT
      HOT:  TIN=  598.15  PIN=0.12000E+08   TOUT=  550.37
POUT=0.12000E+08
```

```
      COLD: TIN=  491.15  PIN=0.63000E+07   TOUT=  551.94
POUT=0.63000E+07
                              DUTY=0.49500E+09

      GENERATING RESULTS FOR UOS BLOCK B1       MODEL: HEATX
TIME =      0.89
      SPECIFICATION: EXCHANGER DUTY       0.49500E+09
      FLOW TYPE:     COUNTERCURRENT
      HOT:  TIN=  598.15  PIN=0.12000E+08   TOUT=  550.37
POUT=0.12000E+08
      COLD: TIN=  491.15  PIN=0.63000E+07   TOUT=  551.94
POUT=0.63000E+07
      AREA= 7226.7          DUTY=0.49500E+09       FT=1.00000


*** INPUT SPECIFICATION MESSAGES ***

 CHANGES WERE MADE TO STREAM       3        04/11/2007   12:33:55:92
 STREAM 3
     SUBSTREAM MIXED TEMP=218. PRES=6.3 <MPa>  &
        MASS-FLOW=250. <kg/sec>
     MASS-FLOW DEUTE-01 0. <kg/sec> / WATER 250. <kg/sec>

 PDF updated
TIME =      62.19
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Calculations begin
time     62.25


      ENTHALPY CALCULATION FOR INLET STREAM 3 OF BLOCK B1
TIME =      62.27
      KODE = 2  NTRIAL =   1  T = 491.1500  P = 6.300000E+06  V =
0.00000       Q =  0.00000

      UOS BLOCK B1        MODEL: HEATX
TIME =      62.27
      SPECIFICATION: EXCHANGER DUTY       0.49500E+09
      FLOW TYPE:     COUNTERCURRENT
      HOT:  TIN=  598.15  PIN=0.12000E+08   TOUT=  550.37
POUT=0.12000E+08
      COLD: TIN=  491.15  PIN=0.63000E+07   TOUT=  551.94
POUT=0.63000E+07
                              DUTY=0.49500E+09

      GENERATING RESULTS FOR UOS BLOCK B1       MODEL: HEATX
TIME =      62.27
      SPECIFICATION: EXCHANGER DUTY       0.49500E+09
      FLOW TYPE:     COUNTERCURRENT
      HOT:  TIN=  598.15  PIN=0.12000E+08   TOUT=  550.37
POUT=0.12000E+08
      COLD: TIN=  491.15  PIN=0.63000E+07   TOUT=  551.94
POUT=0.63000E+07
      AREA= 7226.7          DUTY=0.49500E+09       FT=1.00000
```

```
*** INPUT SPECIFICATION MESSAGES ***

 CHANGES WERE MADE TO STREAM       3        04/11/2007   12:36:26:62
 STREAM 3
     SUBSTREAM MIXED TEMP=218. PRES=13. <MPa>  &
         MASS-FLOW=192. <kg/sec>
     MASS-FLOW DEUTE-01 0. <kg/sec> / WATER 250. <kg/sec>

 PDF updated
TIME =    212.83
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  *   WARNING IN A "STREAM" PARAGRAPH
      STREAM NAME: 3
(STSTRM.30)
      COMPONENT MASS FLOWS OF SUBSTREAM: "MIXED"
      ARE NORMALIZED TO THE TOTAL MASS FLOW VALUE.



Calculations begin
time    212.89


      ENTHALPY CALCULATION FOR INLET STREAM 3 OF BLOCK B1
TIME =    212.89
      KODE = 2  NTRIAL =   1  T = 491.1500  P = 1.300000E+07  V =
0.00000      Q =  0.00000

      UOS BLOCK B1       MODEL: HEATX
TIME =    212.89
      SPECIFICATION: EXCHANGER DUTY       0.49500E+09
      FLOW TYPE:     COUNTERCURRENT

  **  ERROR WHILE EXECUTING UNIT OPERATIONS BLOCK: "B1" (MODEL:
"HEATX")

(HEATX.4)
      TEMPERATURE CROSSOVER DETECTED
      RE-CALCULATING WITH MINIMUM APPROACH TEMP. SPEC
      HOT:  TIN=  598.15  PIN=0.12000E+08   TOUT=  597.71
POUT=0.12000E+08
      COLD: TIN=  491.15  PIN=0.13000E+08   TOUT=  597.15
POUT=0.13000E+08
                              DUTY=0.16858E+09

      GENERATING RESULTS FOR UOS BLOCK B1       MODEL: HEATX
TIME =    213.03
      SPECIFICATION: EXCHANGER DUTY       0.49500E+09
      FLOW TYPE:     COUNTERCURRENT

  **  ERROR WHILE GENERATING RESULTS FOR UNIT OPERATIONS BLOCK: "B1"
(MODEL:
      "HEATX")
(HEATX.4)
```

```
      TEMPERATURE CROSSOVER DETECTED
      RE-CALCULATING WITH MINIMUM APPROACH TEMP. SPEC
      HOT:  TIN=  598.15  PIN=0.12000E+08   TOUT=  597.71
POUT=0.12000E+08
      COLD: TIN=  491.15  PIN=0.13000E+08   TOUT=  597.15
POUT=0.13000E+08
      AREA= 5708.8          DUTY=0.16858E+09       FT=1.00000

*** INPUT SPECIFICATION MESSAGES ***

 CHANGES WERE MADE TO STREAM        3         04/11/2007   12:38:32:15
 STREAM 3
     SUBSTREAM MIXED TEMP=192. PRES=13. <MPa>  &
        MASS-FLOW=250. <kg/sec>
     MASS-FLOW DEUTE-01 0. <kg/sec> / WATER 250. <kg/sec>

 PDF updated
TIME =     338.35
 THIS COPY OF ASPEN PLUS LICENSED TO MASS INSTITUTE OF TECH


Calculations begin
time    338.41


      ENTHALPY CALCULATION FOR INLET STREAM 3 OF BLOCK B1
TIME =     338.50
      KODE = 2  NTRIAL =    1  T = 465.1500   P = 1.300000E+07   V =
0.00000       Q =  0.00000

      UOS BLOCK B1        MODEL: HEATX
TIME =     338.50
      SPECIFICATION: EXCHANGER DUTY        0.49500E+09
      FLOW TYPE:     COUNTERCURRENT

  **  ERROR WHILE EXECUTING UNIT OPERATIONS BLOCK: "B1" (MODEL:
"HEATX")

(HEATX.4)
      TEMPERATURE CROSSOVER DETECTED
      RE-CALCULATING WITH MINIMUM APPROACH TEMP. SPEC
      HOT:  TIN=  598.15  PIN=0.12000E+08   TOUT=  597.71
POUT=0.12000E+08
      COLD: TIN=  465.15  PIN=0.13000E+08   TOUT=  597.15
POUT=0.13000E+08
                              DUTY=0.25901E+09

      GENERATING RESULTS FOR UOS BLOCK B1        MODEL: HEATX
TIME =     338.50
      SPECIFICATION: EXCHANGER DUTY        0.49500E+09
      FLOW TYPE:     COUNTERCURRENT

  **  ERROR WHILE GENERATING RESULTS FOR UNIT OPERATIONS BLOCK: "B1"
(MODEL:
      "HEATX")
(HEATX.4)
      TEMPERATURE CROSSOVER DETECTED
```

```
      RE-CALCULATING WITH MINIMUM APPROACH TEMP. SPEC
      HOT:  TIN=  598.15  PIN=0.12000E+08   TOUT=  597.71
POUT=0.12000E+08
      COLD: TIN=  465.15  PIN=0.13000E+08   TOUT=  597.15
POUT=0.13000E+08
      AREA= 7367.1          DUTY=0.25901E+09       FT=1.00000


*** INPUT SPECIFICATION MESSAGES ***

 CHANGES WERE MADE TO STREAM       3         04/11/2007   12:39:26:10
 STREAM 3
     SUBSTREAM MIXED TEMP=192. PRES=10. <MPa>  &
         MASS-FLOW=250. <kg/sec>
     MASS-FLOW DEUTE-01 0. <kg/sec> / WATER 250. <kg/sec>

 PDF updated
TIME =     392.30
 THIS COPY OF ASPEN PLUS LICENSED TO MASS INSTITUTE OF TECH


Calculations begin
time     392.36


      ENTHALPY CALCULATION FOR INLET STREAM 3 OF BLOCK B1
TIME =     392.36
      KODE = 2  NTRIAL =    1  T = 465.1500  P = 1.000000E+07  V =
0.00000       Q =  0.00000

      UOS BLOCK B1        MODEL: HEATX
TIME =     392.38
      SPECIFICATION: EXCHANGER DUTY        0.49500E+09
      FLOW TYPE:     COUNTERCURRENT
      HOT:  TIN=  598.15  PIN=0.12000E+08   TOUT=  550.37
POUT=0.12000E+08
      COLD: TIN=  465.15  PIN=0.10000E+08   TOUT=  584.06
POUT=0.10000E+08
                              DUTY=0.49500E+09

      GENERATING RESULTS FOR UOS BLOCK B1        MODEL: HEATX
TIME =     392.38
      SPECIFICATION: EXCHANGER DUTY        0.49500E+09
      FLOW TYPE:     COUNTERCURRENT
      HOT:  TIN=  598.15  PIN=0.12000E+08   TOUT=  550.37
POUT=0.12000E+08
      COLD: TIN=  465.15  PIN=0.10000E+08   TOUT=  584.06
POUT=0.10000E+08
      AREA= 9589.3          DUTY=0.49500E+09       FT=1.00000

 Report Writer entered
Time =     526.55

 Results generated
Time =     526.57
```

```
 Report Writer entered
Time =    526.74

 Results generated
Time =    526.75

RUN SAVED



 *** SUMMARY OF ERRORS ***

                  PHYSICAL
                  PROPERTY  SYSTEM  SIMULATION
 TERMINAL ERRORS      0        0         0
   SEVERE ERRORS      0        0         0
          ERRORS      0        0         4
        WARNINGS      0        0         1


 *** CALCULATION TRACE ***



*** INPUT SPECIFICATION MESSAGES ***

 CHANGES WERE MADE TO STREAM       1        05/23/2007   21:51:48:78
 STREAM 1
     SUBSTREAM MIXED TEMP=325. PRES=12. <MPa>  &
         MASS-FLOW=1925. <kg/sec>
     MASS-FRAC WATER 1.

 CHANGES WERE MADE TO STREAM       2        05/23/2007   21:51:48:78
 STREAM 2
     SUBSTREAM MIXED TEMP=278.5 PRES=12. <MPa>  &
         MASS-FLOW=1925. <kg/sec>
     MASS-FLOW WATER 1. <kg/sec>

 CHANGES WERE MADE TO STREAM       3        05/23/2007   21:51:48:78
 STREAM 3
     SUBSTREAM MIXED TEMP=218. PRES=10. <MPa>  &
         MASS-FLOW=350. <kg/sec>
     MASS-FLOW DEUTE-01 0. <kg/sec> / WATER 350. <kg/sec>

 PDF updated
TIME =    114.72
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  *   WARNING IN A "STREAM" PARAGRAPH
      STREAM NAME: 2
(STSTRM.30)
      COMPONENT MASS FLOWS OF SUBSTREAM: "MIXED"
      ARE NORMALIZED TO THE TOTAL MASS FLOW VALUE.


Calculations begin
time    114.81
```

```
 SIMULATION CALCULATIONS BEGIN
TIME =     114.81

      ENTHALPY CALCULATION FOR INLET STREAM 1 OF BLOCK B1
TIME =     114.81
      KODE = 2  NTRIAL =    1  T = 598.1500  P = 1.200000E+07  V =
1.00000      Q =  0.00000

      ENTHALPY CALCULATION FOR INLET STREAM 3 OF BLOCK B1
TIME =     114.81
      KODE = 2  NTRIAL =    1  T = 491.1500  P = 1.000000E+07  V =
0.00000      Q =  0.00000

      ENTHALPY CALCULATION FOR OUTLET STREAM 2 OF BLOCK B1
TIME =     114.81
      KODE = 2  NTRIAL =    1  T = 551.6500  P = 1.200000E+07  V =
0.00000      Q =  0.00000

      UOS BLOCK B1        MODEL: HEATX
TIME =     114.81
      SPECIFICATION: EXCHANGER DUTY        0.49500E+09
      FLOW TYPE:      COUNTERCURRENT
      HOT:  TIN=  598.15  PIN=0.12000E+08   TOUT=  597.71
POUT=0.12000E+08
      COLD: TIN=  491.15  PIN=0.10000E+08   TOUT=  584.06
POUT=0.10000E+08
                              DUTY=0.49500E+09

      GENERATING RESULTS FOR UOS BLOCK B1       MODEL: HEATX
TIME =     114.83
      SPECIFICATION: EXCHANGER DUTY        0.49500E+09
      FLOW TYPE:      COUNTERCURRENT
      HOT:  TIN=  598.15  PIN=0.12000E+08   TOUT=  597.71
POUT=0.12000E+08
      COLD: TIN=  491.15  PIN=0.10000E+08   TOUT=  584.06
POUT=0.10000E+08
      AREA= 8292.1          DUTY=0.49500E+09       FT=1.00000

*** INPUT SPECIFICATION MESSAGES ***

 CHANGES WERE MADE TO STREAM       3        05/23/2007   21:52:33:90
 STREAM 3
     SUBSTREAM MIXED TEMP=218. PRES=10. <MPa>  &
         MASS-FLOW=450. <kg/sec>
     MASS-FLOW DEUTE-01 0. <kg/sec> / WATER 450. <kg/sec>

 PDF updated
TIME =     159.80
 THIS COPY OF ASPEN PLUS LICENSED TO MASS INSTITUTE OF TECH


Calculations begin
time    159.86
```

```
      ENTHALPY CALCULATION FOR INLET STREAM 3 OF BLOCK B1
TIME =     159.86
      KODE = 2  NTRIAL =    1  T = 491.1500  P = 1.000000E+07  V =
0.00000       Q =  0.00000

      UOS BLOCK B1        MODEL: HEATX
TIME =     159.88
      SPECIFICATION: EXCHANGER DUTY        0.49500E+09
      FLOW TYPE:     COUNTERCURRENT
      HOT:  TIN=  598.15  PIN=0.12000E+08   TOUT=  597.71
POUT=0.12000E+08
      COLD: TIN=  491.15  PIN=0.10000E+08   TOUT=  584.06
POUT=0.10000E+08
                              DUTY=0.49500E+09

      GENERATING RESULTS FOR UOS BLOCK B1        MODEL: HEATX
TIME =     159.88
      SPECIFICATION: EXCHANGER DUTY        0.49500E+09
      FLOW TYPE:     COUNTERCURRENT
      HOT:  TIN=  598.15  PIN=0.12000E+08   TOUT=  597.71
POUT=0.12000E+08
      COLD: TIN=  491.15  PIN=0.10000E+08   TOUT=  584.06
POUT=0.10000E+08
      AREA= 8292.1           DUTY=0.49500E+09        FT=1.00000


*** INPUT SPECIFICATION MESSAGES ***

 CHANGES WERE MADE TO STREAM       3        05/23/2007   21:53:02:59
 STREAM 3
     SUBSTREAM MIXED TEMP=218. PRES=10. <MPa>  &
         MASS-FLOW=300. <kg/sec>
     MASS-FLOW DEUTE-01 0. <kg/sec> / WATER 300. <kg/sec>

 PDF updated
TIME =     188.50
 THIS COPY OF ASPEN PLUS LICENSED TO MASS INSTITUTE OF TECH


Calculations begin
time    188.66


      ENTHALPY CALCULATION FOR INLET STREAM 3 OF BLOCK B1
TIME =     188.67
      KODE = 2  NTRIAL =    1  T = 491.1500  P = 1.000000E+07  V =
0.00000       Q =  0.00000

      UOS BLOCK B1        MODEL: HEATX
TIME =     188.67
      SPECIFICATION: EXCHANGER DUTY        0.49500E+09
      FLOW TYPE:     COUNTERCURRENT
      HOT:  TIN=  598.15  PIN=0.12000E+08   TOUT=  597.71
POUT=0.12000E+08
```

```
      COLD: TIN=  491.15  PIN=0.10000E+08   TOUT=  584.06
POUT=0.10000E+08
                                DUTY=0.49500E+09

      GENERATING RESULTS FOR UOS BLOCK B1       MODEL: HEATX
TIME =     188.67
      SPECIFICATION: EXCHANGER DUTY       0.49500E+09
      FLOW TYPE:     COUNTERCURRENT
      HOT:  TIN=  598.15  PIN=0.12000E+08   TOUT=  597.71
POUT=0.12000E+08
      COLD: TIN=  491.15  PIN=0.10000E+08   TOUT=  584.06
POUT=0.10000E+08
      AREA= 8292.1          DUTY=0.49500E+09       FT=1.00000

 Report Writer entered
Time =     339.47

 Results generated
Time =     339.48

 Report Writer entered
Time =     339.80

 Results generated
Time =     339.81

RUN SAVED



 *** SUMMARY OF ERRORS ***

                  PHYSICAL
                  PROPERTY  SYSTEM  SIMULATION
 TERMINAL ERRORS      0        0         0
   SEVERE ERRORS      0        0         0
          ERRORS      0        0         0
        WARNINGS      0        0         1
```

+

A.3 PBMR ASPEN Files

```
;
;Input Summary created by Aspen Plus Rel. 20.0 at 06:51:55 Mon May 28,
2007
;Directory C:\Documents and Settings\All Users\Application
Data\AspenTech\Aspen Plus 2006  Filename
C:\DOCUME~1\Ashley\LOCALS~1\Temp\~ap31.tmp
;
```

```
DYNAMICS
    DYNAMICS RESULTS=ON

IN-UNITS MET VOLUME-FLOW='cum/hr' ENTHALPY-FLO='Gcal/hr'  &
        HEAT-TRANS-C='kcal/hr-sqm-K' PRESSURE=bar TEMPERATURE=C  &
        VOLUME=cum DELTA-T=C HEAD=meter MOLE-DENSITY='kmol/cum'  &
        MASS-DENSITY='kg/cum' MOLE-ENTHALP='kcal/mol'  &
        MASS-ENTHALP='kcal/kg' HEAT=Gcal MOLE-CONC='mol/l'  &
        PDROP=bar

DEF-STREAMS CONVEN ALL

SIM-OPTIONS FLASH-MAXIT=75 NPHASE=2 PARADIGM=SM

DESCRIPTION "
    General Simulation with Metric Units :
    C, bar, kg/hr, kmol/hr, Gcal/hr, cum/hr.

    Property Method: None

    Flow basis for input: Mole

    Stream report composition: Mole flow
    "

DATABANKS PURE20  / AQUEOUS  / SOLIDS  / INORGANIC  / PURE13  &
         / PURE11  / PURE93  / PURE856  / PURE10  / PURE12  &
         / NOASPENPCD

PROP-SOURCES PURE20  / AQUEOUS  / SOLIDS  / INORGANIC  /  &
        PURE13  / PURE11  / PURE93  / PURE856  / PURE10  /  &
        PURE12

COMPONENTS
    WATER H2O /
    HELIUM HE-4

SOLVE
    PARAM

FLOWSHEET
    BLOCK SG2 IN=1 RETURN2 OUT=4 TOSAGD2
    BLOCK IHX2 IN=8 4 OUT=10 1
    BLOCK COMB1 IN=11 18 OUT=TOPBMR
    BLOCK SPLIT2 IN=FROMPBMR OUT=8 17
    BLOCK IHX1 IN=17 20 OUT=19 16
    BLOCK SG1 IN=16 RETURN1 OUT=20 TOSAGD1
    BLOCK CIRC2 IN=10 OUT=11
    BLOCK CIRC1 IN=19 OUT=18

PROPERTIES IDEAL FREE-WATER=STEAMNBS
    PROPERTIES STEAMNBS
    PROPERTIES IDEAL / P-1

PROP-REPLACE P-1 STEAMNBS
```

```
PCES-PROP-DATA
    IN-UNITS MET VOLUME-FLOW='cum/hr' ENTHALPY-FLO='Gcal/hr'  &
        MOLE-HEAT-CA='kJ/kmol-K' HEAT-TRANS-C='kcal/hr-sqm-K'  &
        PRESSURE=bar TEMPERATURE=C VOLUME=cum DELTA-T=C  &
        HEAD=meter MOLE-DENSITY='kmol/cum' MASS-DENSITY='kg/cum'  &
        MOLE-ENTHALP='kcal/mol' MASS-ENTHALP='kcal/kg' HEAT=Gcal  &
        MOLE-CONC='mol/l' PDROP=bar
    CPIG HELIUM 80 5.19

DEF-STREAMS CONVEN 1 TOSAGD2 RETURN2 4 8 10 11 FROMPBMR  &
        TOPBMR 16 17 18 19 20 RETURN1 TOSAGD1

STREAM 1
    SUBSTREAM MIXED TEMP=719. PRES=86.31 MASS-FLOW=102.5 <kg/sec>  &
        FLASH-OPTION=NOFLASH
    MASS-FLOW HELIUM 102.5 <kg/sec>

STREAM 4
    SUBSTREAM MIXED TEMP=223. PRES=82.97 MASS-FLOW=102.5 <kg/sec>
    MASS-FLOW HELIUM 102.5 <kg/sec>

STREAM 8
    SUBSTREAM MIXED TEMP=750. PRES=81.55 MASS-FLOW=102.5 <kg/sec>
    MASS-FLOW HELIUM 102.5 <kg/sec>

STREAM 10
    SUBSTREAM MIXED TEMP=267. PRES=81.06 MASS-FLOW=102.5 <kg/sec>
    MASS-FLOW HELIUM 102.5 <kg/sec>

STREAM 11
    SUBSTREAM MIXED TEMP=280. PRES=85. MASS-FLOW=102.5 <kg/sec>
    MASS-FLOW HELIUM 102.5 <kg/sec>

STREAM 16
    SUBSTREAM MIXED TEMP=267. PRES=81.06 MASS-FLOW=102.5 <kg/sec>
    MASS-FLOW HELIUM 102.5 <kg/sec>

STREAM 17
    SUBSTREAM MIXED TEMP=750. PRES=81.55 MASS-FLOW=102.5 <kg/sec>
    MASS-FLOW HELIUM 102.5 <kg/sec>

STREAM 18
    SUBSTREAM MIXED TEMP=280. PRES=85. MASS-FLOW=102.5 <kg/sec>
    MASS-FLOW HELIUM 102.5 <kg/sec>

STREAM 19
    SUBSTREAM MIXED TEMP=719. PRES=86.3 MASS-FLOW=102.5 <kg/sec>
    MASS-FLOW HELIUM 102.5 <kg/sec>

STREAM 20
    SUBSTREAM MIXED TEMP=223. PRES=83.13 MASS-FLOW=102.5 <kg/sec>
    MASS-FLOW HELIUM 102.5 <kg/sec>

STREAM FROMPBMR
    SUBSTREAM MIXED TEMP=750. PRES=81.5 MASS-FLOW=205. <kg/sec>
    MASS-FLOW HELIUM 205. <kg/sec>
```

```
STREAM RETURN1
    SUBSTREAM MIXED TEMP=192. PRES=130. MASS-FLOW=161.3 <kg/sec>
    MASS-FLOW WATER 161.3 <kg/sec>

STREAM RETURN2
    SUBSTREAM MIXED TEMP=192. PRES=130. MASS-FLOW=161.3 <kg/sec>
    MASS-FLOW WATER 161.3 <kg/sec>

STREAM TOPBMR
    SUBSTREAM MIXED TEMP=280. PRES=85. MASS-FLOW=205. <kg/sec>
    MASS-FLOW HELIUM 205. <kg/sec>

STREAM TOSAGD1
    SUBSTREAM MIXED TEMP=318. PRES=110. MASS-FLOW=161.3 <kg/sec>
    MASS-FLOW WATER 161.3 <kg/sec>

STREAM TOSAGD2
    SUBSTREAM MIXED TEMP=318. PRES=110. MASS-FLOW=161.3 <kg/sec>
    MASS-FLOW WATER 161.3 <kg/sec>

BLOCK COMB1 MIXER
    PARAM PRES=84.5 T-EST=280.

BLOCK SPLIT2 FSPLIT
    MASS-FLOW 8 102.5 <kg/sec>
    STREAM-ORDER 8 1 / 17 2

BLOCK IHX1 HEATX
    PARAM T-COLD=719. U-OPTION=CONSTANT
    FEEDS HOT=17 COLD=20
    PRODUCTS HOT=19 COLD=16

BLOCK IHX2 HEATX
    PARAM T-HOT=267. CALC-TYPE=DESIGN MIN-TAPP=5.
    FEEDS HOT=8 COLD=4
    PRODUCTS HOT=10 COLD=1

BLOCK SG1 HEATX
    PARAM T-HOT=223. MIN-TAPP=1. U-OPTION=CONSTANT
    FEEDS HOT=16 COLD=RETURN1
    PRODUCTS HOT=20 COLD=TOSAGD1

BLOCK SG2 HEATX
    PARAM T-HOT=223. CALC-TYPE=DESIGN
    FEEDS HOT=1 COLD=RETURN2
    PRODUCTS HOT=4 COLD=TOSAGD2
    HOT-SIDE DP-OPTION=CONSTANT

BLOCK CIRC1 COMPR
    PARAM TYPE=ISENTROPIC PRES=85. SEFF=0.85 NPHASE=1
    BLOCK-OPTION FREE-WATER=NO

BLOCK CIRC2 COMPR
    PARAM TYPE=ISENTROPIC PRES=85. SEFF=0.85 NPHASE=1
    BLOCK-OPTION FREE-WATER=NO
```

```
EO-CONV-OPTI

STREAM-REPOR NOSORT NOZEROFLOW MOLEFLOW MASSFLOW NOATTR-DESC  &
        NOSUBS-ATTR INCL-STREAMS=FROMPBMR TOPBMR TOSAGD1 RETURN1  &
        TOSAGD2 RETURN2 EXCL-STREAMS=1 4 8 10 11 16 17 18  &
        19 20

PROPERTY-REP PCES NOPARAM-PLUS
;
;
;
;
;
```

```
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                   + + +   + + +   + + +   + + +   + + +
                     +       +     + + +     +       +
                                   + + +
                                   + + +
                                   + + +
 ASPENTECH                         + + +
                                   + + +
 FLOWSHEET SIMULATION              + + +
 FOR THE PROCESS INDUSTRIES        + + +
                                     +


TM
 AAAAA   SSSSS   PPPPP   EEEEE   NN    N   PPPPP   L       U   U
SSSSS
 A   A   S       P   P   E       N N   N   P   P   L       U   U   S
 AAAAA   SSSSS   PPPPP   EEEEE   N   N N   PPPPP   L       U   U
SSSSS
 A   A       S   P       E       N    NN   P       L       U   U
S
 A   A   SSSSS   P       EEEEE   N     N   P       LLLLL   UUUUU
SSSSS
```

ASPEN PLUS IS A TRADEMARK OF
ASPEN TECHNOLOGY, INC.
TEN CANAL PARK
CAMBRIDGE, MASSACHUSETTS 02141
617/949-1000

HOTLINE:
U.S.A. 888/996-7100
EUROPE (32) 2/701-9555

```
PLATFORM: WIN32                                          MARCH 7, 2007
VERSION: 20.0   Build 74                                 WEDNESDAY
INSTALLATION:                                            12:55:29 A.M.
```


```
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```


```
*** INPUT SUMMARY ***

>>CURRENT RUN

  ORIGINAL RUN                            MARCH 7, 2007
  12:55:29 A.M.                           WEDNESDAY
  INPUT FILE: _3223edj.inm
  RUN ID : _3223edj
     ;
     ;Input file created by Aspen Plus Rel. 20.0 at 00:55:29 Wed Mar 7, 2007
     ;Directory C:\Documents and Settings\All Users\Application Data\AspenTech\Aspen Plus 2006  Runid PBMR  BENCHMARK EXPANDEDNOCOMP
     ;



     DYNAMICS
         DYNAMICS RESULTS=ON

     IN-UNITS MET VOLUME-FLOW='cum/hr' ENTHALPY-FLO='Gcal/hr' &
             HEAT-TRANS-C='kcal/hr-sqm-K' PRESSURE=bar TEMPERATURE=C  &
             VOLUME=cum DELTA-T=C HEAD=meter MOLE-DENSITY='kmol/cum'  &
             MASS-DENSITY='kg/cum' MOLE-ENTHALP='kcal/mol'  &
             MASS-ENTHALP='kcal/kg' HEAT=Gcal MOLE-CONC='mol/l'  &
             PDROP=bar

     DEF-STREAMS CONVEN ALL

     SIM-OPTIONS FLASH-MAXIT=75 NPHASE=2 PARADIGM=SM

     DESCRIPTION "
         General Simulation with Metric Units :
```

```
    C, bar, kg/hr, kmol/hr, Gcal/hr, cum/hr.

    Property Method: None

    Flow basis for input: Mole

    Stream report composition: Mole flow
    "

DATABANKS PURE20  / AQUEOUS  / SOLIDS  / INORGANIC  / PURE13  &
        / PURE11  / PURE93  / PURE856  / PURE10  / PURE12  &
        / NOASPENPCD

PROP-SOURCES PURE20  / AQUEOUS  / SOLIDS  / INORGANIC  / &
        PURE13  / PURE11  / PURE93  / PURE856  / PURE10 / &
        PURE12

COMPONENTS
    WATER H2O /
    HELIUM HE-4

SOLVE
    PARAM

FLOWSHEET
    BLOCK B1 IN=1 3 OUT=4 2
    BLOCK B6 IN=8 4 OUT=10 1
    BLOCK B9 IN=11 18 OUT=15
    BLOCK B10 IN=14 OUT=8 17
    BLOCK B12 IN=17 20 OUT=19 16
    BLOCK B13 IN=16 22 OUT=20 23
    BLOCK B4 IN=10 OUT=11
    BLOCK B5 IN=19 OUT=18

PROPERTIES IDEAL FREE-WATER=STEAMNBS
    PROPERTIES STEAMNBS
    PROPERTIES IDEAL / P-1

PROP-REPLACE P-1 STEAMNBS

PCES-PROP-DATA
    IN-UNITS MET VOLUME-FLOW='cum/hr' ENTHALPY-FLO='Gcal/hr'  &
        MOLE-HEAT-CA='kJ/kmol-K' HEAT-TRANS-C='kcal/hr-sqm-K'  &
        PRESSURE=bar TEMPERATURE=C VOLUME=cum DELTA-T=C &
        HEAD=meter MOLE-DENSITY='kmol/cum' MASS-DENSITY='kg/cum'  &
        MOLE-ENTHALP='kcal/mol' MASS-ENTHALP='kcal/kg' HEAT=Gcal  &
        MOLE-CONC='mol/l' PDROP=bar
    CPIG HELIUM 80 5.19
```

```
DEF-STREAMS CONVEN 1 2 3 4 8 10 11 14 15 16 17 18 19  &
        20 22 23

PROP-SET THERMAL HMX CPMX KMX UNITS='cal/gm' 'cal/gm-K'
&
        SUBSTREAM=MIXED PHASE=V L
;  "Enthalpy, heat capacity, and thermal conductivity"


STREAM 1
    SUBSTREAM MIXED TEMP=719. PRES=86.31 MASS-FLOW=102.5
<kg/sec>  &
        FLASH-OPTION=NOFLASH
    MASS-FLOW HELIUM 102.5 <kg/sec>

STREAM 2
    SUBSTREAM MIXED TEMP=318. PRES=110. MASS-FLOW=161.3
<kg/sec>
    MASS-FLOW WATER 161.3 <kg/sec>

STREAM 3
    SUBSTREAM MIXED TEMP=192. PRES=130. MASS-FLOW=161.3
<kg/sec>
    MASS-FLOW WATER 161.3 <kg/sec>

STREAM 4
    SUBSTREAM MIXED TEMP=223. PRES=82.97 MASS-FLOW=102.5
<kg/sec>
    MASS-FLOW HELIUM 102.5 <kg/sec>

STREAM 8
    SUBSTREAM MIXED TEMP=750. PRES=81.55 MASS-FLOW=102.5
<kg/sec>
    MASS-FLOW HELIUM 102.5 <kg/sec>

STREAM 10
    SUBSTREAM MIXED TEMP=267. PRES=81.06 MASS-FLOW=102.5
<kg/sec>
    MASS-FLOW HELIUM 102.5 <kg/sec>

STREAM 11
    SUBSTREAM MIXED TEMP=280. PRES=85. MASS-FLOW=102.5
<kg/sec>
    MASS-FLOW HELIUM 102.5 <kg/sec>

STREAM 14
    SUBSTREAM MIXED TEMP=750. PRES=81.5 MASS-FLOW=205.
<kg/sec>
    MASS-FLOW HELIUM 205. <kg/sec>

STREAM 15
    SUBSTREAM MIXED TEMP=280. PRES=85. MASS-FLOW=205.
<kg/sec>
    MASS-FLOW HELIUM 205. <kg/sec>

STREAM 16
```

```
          SUBSTREAM MIXED TEMP=267. PRES=81.06 MASS-FLOW=102.5 <kg/sec>
          MASS-FLOW HELIUM 102.5 <kg/sec>

    STREAM 17
          SUBSTREAM MIXED TEMP=750. PRES=81.55 MASS-FLOW=102.5 <kg/sec>
          MASS-FLOW HELIUM 102.5 <kg/sec>

    STREAM 18
          SUBSTREAM MIXED TEMP=280. PRES=85. MASS-FLOW=102.5 <kg/sec>
          MASS-FLOW HELIUM 102.5 <kg/sec>

    STREAM 19
          SUBSTREAM MIXED TEMP=719. PRES=86.3 MASS-FLOW=102.5 <kg/sec>
          MASS-FLOW HELIUM 102.5 <kg/sec>

    STREAM 20
          SUBSTREAM MIXED TEMP=223. PRES=83.13 MASS-FLOW=102.5 <kg/sec>
          MASS-FLOW HELIUM 102.5 <kg/sec>

    STREAM 22
          SUBSTREAM MIXED TEMP=192. PRES=130. MASS-FLOW=161.3 <kg/sec>
          MASS-FLOW WATER 161.3 <kg/sec>

    STREAM 23
          SUBSTREAM MIXED TEMP=318. PRES=110. MASS-FLOW=161.3 <kg/sec>
          MASS-FLOW WATER 161.3 <kg/sec>

    BLOCK B9 MIXER
          PARAM PRES=84.5 T-EST=280.

    BLOCK B10 FSPLIT
          MASS-FLOW 8 102.5 <kg/sec>
          STREAM-ORDER 8 1 / 17 2

    BLOCK B1 HEATX
          PARAM T-HOT=223. CALC-TYPE=DESIGN
          FEEDS HOT=1 COLD=3
          PRODUCTS HOT=4 COLD=2
          HOT-SIDE DP-OPTION=CONSTANT

    BLOCK B6 HEATX
          PARAM T-HOT=267. CALC-TYPE=DESIGN MIN-TAPP=5.
          FEEDS HOT=8 COLD=4
          PRODUCTS HOT=10 COLD=1

    BLOCK B12 HEATX
          PARAM T-COLD=719. U-OPTION=CONSTANT
          FEEDS HOT=17 COLD=20
          PRODUCTS HOT=19 COLD=16
```

```
BLOCK B13 HEATX
    PARAM T-HOT=223. MIN-TAPP=1. U-OPTION=CONSTANT
    FEEDS HOT=16 COLD=22
    PRODUCTS HOT=20 COLD=23

BLOCK B4 COMPR
    PARAM TYPE=ISENTROPIC PRES=85. SEFF=0.85 NPHASE=1
    BLOCK-OPTION FREE-WATER=NO

BLOCK B5 COMPR
    PARAM TYPE=ISENTROPIC PRES=85. SEFF=0.85 NPHASE=1
    BLOCK-OPTION FREE-WATER=NO

EO-CONV-OPTI

STREAM-REPOR MOLEFLOW MASSFLOW MASSFRAC
PROPERTIES=THERMAL

PROPERTY-REP PCES NOPARAM-PLUS
;
;
;
;
;
```

*** INPUT TRANSLATOR MESSAGES ***

PDF updated
TIME = 0.20

*** CALCULATION TRACE ***

*** FLOWSHEET ANALYSIS MESSAGES ***

FLOWSHEET CONNECTIVITY BY STREAMS

STREAM	SOURCE	DEST	STREAM	SOURCE	DEST
3	----	B1	14	----	B10
22	----	B13	4	B1	B6
2	B1	----	10	B6	B4
1	B6	B1	15	B9	----
8	B10	B6	17	B10	B12
19	B12	B5	16	B12	B13
20	B13	B12	23	B13	----
11	B4	B9	18	B5	B9

FLOWSHEET CONNECTIVITY BY BLOCKS

BLOCK	INLETS	OUTLETS
B1	1 3	4 2
B6	8 4	10 1
B9	11 18	15
B10	14	8 17

```
   B12            17 20                            19 16
   B13            16 22                            20 23
   B4             10                               11
   B5             19                               18

      BLOCK $OLVER01 (METHOD: WEGSTEIN) HAS BEEN DEFINED TO CONVERGE
               STREAMS: 20

      BLOCK $OLVER02 (METHOD: WEGSTEIN) HAS BEEN DEFINED TO CONVERGE
               STREAMS: 4

      COMPUTATION ORDER FOR THE FLOWSHEET IS:
      B10
      $OLVER01 B12 B13
      (RETURN $OLVER01)
      B5
      $OLVER02 B6 B1
      (RETURN $OLVER02)
      B4 B9

Calculations begin
time      0.27


 SIMULATION CALCULATIONS BEGIN
TIME =       0.27

      ENTHALPY CALCULATION FOR INLET STREAM 14 OF BLOCK B10
TIME =       0.27
      KODE = 2  NTRIAL =    1  T =1023.1500   P = 8.150000E+06   V =
1.00000      Q =  0.00000

      UOS BLOCK B10       MODEL: FSPLIT
TIME =       0.27
      SPLIT FRACTIONS:  0.50000D+00    0.50000D+00

      CONVERGENCE BLOCK $OLVER01  METHOD: WEGSTEIN
TIME =       0.28

      ENTHALPY CALCULATION FOR INLET STREAM 20 OF BLOCK B12
TIME =       0.28
      KODE = 2  NTRIAL =    1  T = 496.1500   P = 8.313000E+06   V =
1.00000      Q =  0.00000

      UOS BLOCK B12       MODEL: HEATX
TIME =       0.28
      SPECIFICATION: COLD OUTLET TEMP       992.15
      FLOW TYPE:     COUNTERCURRENT
      HOT:  TIN= 1023.15  PIN=0.81500E+07   TOUT=  527.15
POUT=0.81500E+07
      COLD: TIN=  496.15  PIN=0.83130E+07   TOUT=  992.15
POUT=0.83130E+07
                               DUTY=0.26402E+09

      ENTHALPY CALCULATION FOR INLET STREAM 22 OF BLOCK B13
TIME =       0.30
```

```
      KODE = 2  NTRIAL =    1  T = 465.1500  P = 1.300000E+07  V =
0.00000       Q =  0.00000

      UOS BLOCK B13       MODEL: HEATX
TIME =       0.30
      SPECIFICATION: HOT OUTLET TEMP       496.15
      FLOW TYPE:     COUNTERCURRENT
      HOT:  TIN=  992.15  PIN=0.83130E+07   TOUT=  496.15
POUT=0.83130E+07
      COLD: TIN=  465.15  PIN=0.13000E+08   TOUT=  603.89
POUT=0.13000E+08
                              DUTY=0.26402E+09

      CONVERGENCE BLOCK $OLVER01  METHOD: WEGSTEIN
TIME =       0.32

  LOOP $OLVER01 ITER    1:     *** CONVERGED *** , MAX ERR/TOL
0.0000        TIME =      0.32

      UOS BLOCK B5        MODEL: COMPR
TIME =       0.32
      OUTLET TEMP =   537.7       OUTLET PRES =  0.8500E+07   INDICATED
HP =  0.5599E+07   BRAKE HP =  0.5599E+07
      ISENTR TEMP =   536.1      CALC ISENTR EFF =  0.8500      ISENTR
HP =  0.4759E+07  HP =  0.1434E+09

      CONVERGENCE BLOCK $OLVER02  METHOD: WEGSTEIN
TIME =       0.33

      ENTHALPY CALCULATION FOR INLET STREAM 4 OF BLOCK B6
TIME =       0.35
      KODE = 2  NTRIAL =    1  T = 496.1500  P = 8.297000E+06  V =
1.00000       Q =  0.00000

      UOS BLOCK B6        MODEL: HEATX
TIME =       0.35
      SPECIFICATION: HOT OUTLET TEMP       540.15
      FLOW TYPE:     COUNTERCURRENT
      HOT:  TIN= 1023.15  PIN=0.81500E+07   TOUT=  540.15
POUT=0.81500E+07
      COLD: TIN=  496.15  PIN=0.82970E+07   TOUT=  979.15
POUT=0.82970E+07
                              DUTY=0.25710E+09

      ENTHALPY CALCULATION FOR INLET STREAM 3 OF BLOCK B1
TIME =       0.35
      KODE = 2  NTRIAL =    1  T = 465.1500  P = 1.300000E+07  V =
0.00000       Q =  0.00000

      UOS BLOCK B1        MODEL: HEATX
TIME =       0.35
      SPECIFICATION: HOT OUTLET TEMP       496.15
      FLOW TYPE:     COUNTERCURRENT
      HOT:  TIN=  979.15  PIN=0.82970E+07   TOUT=  496.15
POUT=0.82970E+07
      COLD: TIN=  465.15  PIN=0.13000E+08   TOUT=  603.89
POUT=0.13000E+08
```

```
                          DUTY=0.25710E+09

      CONVERGENCE BLOCK $OLVER02  METHOD: WEGSTEIN
TIME =       0.36

  LOOP $OLVER02 ITER    1:      *** CONVERGED *** , MAX ERR/TOL
0.0000        TIME =      0.36

      UOS BLOCK B4        MODEL: COMPR
TIME =       0.36
      OUTLET TEMP =   550.9       OUTLET PRES =  0.8500E+07   INDICATED
HP =  0.5737E+07   BRAKE HP =  0.5737E+07
      ISENTR TEMP =   549.3      CALC ISENTR EFF =  0.8500       ISENTR
HP =  0.4877E+07  HP =  0.1469E+09

      ENTHALPY CALCULATION FOR OUTLET STREAM 15 OF BLOCK B9
TIME =       0.38
      KODE = 2  NTRIAL =    1  T = 553.1500  P = 8.500000E+06  V =
1.00000      Q =  0.00000

      UOS BLOCK B9        MODEL: MIXER
TIME =       0.38
      NO. TEMP ITER =    8      TEMP =  544.299
      KODE = 1  NTRIAL =   2  T = 544.2988  P = 8.450000E+06  V =
1.00000      Q =  0.00000

      GENERATING RESULTS FOR UOS BLOCK B1       MODEL: HEATX
TIME =       0.39
      SPECIFICATION: HOT OUTLET TEMP       496.15
      FLOW TYPE:     COUNTERCURRENT
      HOT:  TIN=  979.15  PIN=0.82970E+07   TOUT=  496.15
POUT=0.82970E+07
      COLD: TIN=  465.15  PIN=0.13000E+08   TOUT=  603.89
POUT=0.13000E+08
      AREA= 2435.2           DUTY=0.25710E+09       FT=1.00000

      GENERATING RESULTS FOR UOS BLOCK B6       MODEL: HEATX
TIME =       0.39
      SPECIFICATION: HOT OUTLET TEMP       540.15
      FLOW TYPE:     COUNTERCURRENT
      HOT:  TIN= 1023.15  PIN=0.81500E+07   TOUT=  540.15
POUT=0.81500E+07
      COLD: TIN=  496.15  PIN=0.82970E+07   TOUT=  979.15
POUT=0.82970E+07
      AREA= 6874.3           DUTY=0.25710E+09       FT=1.00000

      GENERATING RESULTS FOR UOS BLOCK B12      MODEL: HEATX
TIME =       0.41
      SPECIFICATION: COLD OUTLET TEMP      992.15
      FLOW TYPE:     COUNTERCURRENT
      HOT:  TIN= 1023.15  PIN=0.81500E+07   TOUT=  527.15
POUT=0.81500E+07
      COLD: TIN=  496.15  PIN=0.83130E+07   TOUT=  992.15
POUT=0.83130E+07
      AREA= 10020.           DUTY=0.26402E+09       FT=1.00000
```

```
      GENERATING RESULTS FOR UOS BLOCK B13       MODEL: HEATX
TIME =        0.41
      SPECIFICATION: HOT OUTLET TEMP        496.15
      FLOW TYPE:     COUNTERCURRENT
      HOT:  TIN=  992.15  PIN=0.83130E+07   TOUT=  496.15
POUT=0.83130E+07
      COLD: TIN=  465.15  PIN=0.13000E+08   TOUT=  603.89
POUT=0.13000E+08
      AREA= 2197.6          DUTY=0.26402E+09       FT=1.00000

 Report Writer entered
Time =        0.47

 Results generated
Time =        0.55

RUN SAVED



 NO ERRORS OR WARNINGS GENERATED

RUN SAVED



 NO ERRORS OR WARNINGS GENERATED


 *** CALCULATION TRACE ***



RUN SAVED



 NO ERRORS OR WARNINGS GENERATED


*** INPUT SPECIFICATION MESSAGES ***

 RENAME        IS  NEW 04/20/2007   11:54:32:23
 RENAME
     BLOCK "B1" "SG2" / "B12" "IHX1" / "B13" "SG1" / "B6" "IHX2" / "B5"
&
         "CIRC1" / "B4" "CIRC2" / "B10" "SPLIT2" / "B9" "COMB1"
     STREAM "23" "TOSAGD1" / "22" "RETURN1" / "3" "RETURN2" / "2"  &
         "TOSAGD2" / "14" "FROMPBMR" / "15" "TOPBMR"

 FLOWSHEET     IS  NEW 04/20/2007   11:54:32:23
 FLOWSHEET
     BLOCK SG2 IN=1 RETURN2 OUT=4 TOSAGD2
     BLOCK IHX2 IN=8 4 OUT=10 1
     BLOCK COMB1 IN=11 18 OUT=TOPBMR
     BLOCK SPLIT2 IN=FROMPBMR OUT=8 17
     BLOCK IHX1 IN=17 20 OUT=19 16
```

```
      BLOCK SG1 IN=16 RETURN1 OUT=20 TOSAGD1
      BLOCK CIRC2 IN=10 OUT=11
      BLOCK CIRC1 IN=19 OUT=18

 PDF updated
TIME =     752.26
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Calculations begin
time    753.06


 Report Writer entered
Time =     753.07

 Results generated
Time =     754.51

RUN SAVED


 NO ERRORS OR WARNINGS GENERATED


 NO ERRORS OR WARNINGS GENERATED

 Report Writer entered
Time =    1001.32

 Results generated
Time =    1001.40


*** INPUT SPECIFICATION MESSAGES ***

 TITLE        IS  NEW 04/20/2007   11:59:27:34
 TITLE

 PDF updated
TIME =    1047.34
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Calculations begin
time   1047.50


 Report Writer entered
Time =    1047.51

 Results generated
Time =    1047.59
```

```
*** INPUT SPECIFICATION MESSAGES ***

 CHANGES WERE MADE TO STREAM-REPOR 04/20/2007   11:59:36:01
 STREAM-REPOR NOSORT MOLEFLOW MASSFLOW MASSFRAC  &
         PROPERTIES=THERMAL

 PDF updated
TIME =    1056.01
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Calculations begin
time   1056.23


 Report Writer entered
Time =    1056.23

 Results generated
Time =    1056.31


*** INPUT SPECIFICATION MESSAGES ***

 CHANGES WERE MADE TO STREAM-REPOR 04/20/2007   11:59:47:56
 STREAM-REPOR NOREPORT

 PDF updated
TIME =    1067.56
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Calculations begin
time   1067.59


 Report Writer entered
Time =    1067.61

 Results generated
Time =    1067.62


*** INPUT SPECIFICATION MESSAGES ***

 CHANGES WERE MADE TO STREAM-REPOR 04/20/2007   11:59:49:07
 STREAM-REPOR NOSORT MOLEFLOW MASSFLOW MASSFRAC  &
         PROPERTIES=THERMAL

 PDF updated
TIME =    1069.06
```

```
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Calculations begin
time    1069.11


 Report Writer entered
Time =    1069.12

 Results generated
Time =    1069.18


*** INPUT SPECIFICATION MESSAGES ***

 CHANGES WERE MADE TO STREAM-REPOR 04/20/2007   12:00:29:87
 STREAM-REPOR NOSORT MOLEFLOW MASSFLOW MASSFRAC  &
         PROPERTIES=THERMAL INCL-STREAMS=FROMPBMR RETURN1 RETURN2  &
         TOPBMR TOSAGD1 TOSAGD2

 PDF updated
TIME =    1109.89
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Calculations begin
time    1109.95


 Report Writer entered
Time =    1109.97

 Results generated
Time =    1110.03


*** INPUT SPECIFICATION MESSAGES ***

 CHANGES WERE MADE TO STREAM-REPOR 04/20/2007   12:00:43:42
 STREAM-REPOR NOSORT MOLEFLOW MASSFLOW MASSFRAC  &
         PROPERTIES=THERMAL INCL-STREAMS=FROMPBMR RETURN1 TOPBMR  &
         RETURN2 TOSAGD1 TOSAGD2

 PDF updated
TIME =    1123.42
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Calculations begin
time    1123.48
```

```
 Report Writer entered
Time =    1123.50

 Results generated
Time =    1123.54


*** INPUT SPECIFICATION MESSAGES ***

 CHANGES WERE MADE TO STREAM-REPOR 04/20/2007   12:00:47:67
 STREAM-REPOR NOSORT MOLEFLOW MASSFLOW MASSFRAC  &
         PROPERTIES=THERMAL INCL-STREAMS=FROMPBMR TOPBMR RETURN1  &
         RETURN2 TOSAGD1 TOSAGD2

 PDF updated
TIME =    1127.67
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Calculations begin
time   1127.73


 Report Writer entered
Time =    1127.76

 Results generated
Time =    1127.82


*** INPUT SPECIFICATION MESSAGES ***

 CHANGES WERE MADE TO STREAM-REPOR 04/20/2007   12:00:52:82
 STREAM-REPOR NOSORT MOLEFLOW MASSFLOW MASSFRAC  &
         PROPERTIES=THERMAL INCL-STREAMS=FROMPBMR TOPBMR RETURN1  &
         TOSAGD1 RETURN2 TOSAGD2

 PDF updated
TIME =    1132.82
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Calculations begin
time   1133.04


 Report Writer entered
Time =    1133.07

 Results generated
Time =    1133.12
```

```
*** INPUT SPECIFICATION MESSAGES ***

 CHANGES WERE MADE TO STREAM-REPOR 04/20/2007   12:00:56:60
 STREAM-REPOR NOSORT MOLEFLOW MASSFLOW MASSFRAC  &
         PROPERTIES=THERMAL INCL-STREAMS=FROMPBMR TOPBMR TOSAGD1  &
         RETURN1 RETURN2 TOSAGD2

 PDF updated
TIME =   1136.61
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Calculations begin
time   1136.67


 Report Writer entered
Time =   1136.68

 Results generated
Time =   1136.75


*** INPUT SPECIFICATION MESSAGES ***

 CHANGES WERE MADE TO STREAM-REPOR 04/20/2007   12:01:00:12
 STREAM-REPOR NOSORT MOLEFLOW MASSFLOW MASSFRAC  &
         PROPERTIES=THERMAL INCL-STREAMS=FROMPBMR TOPBMR TOSAGD1  &
         RETURN1 TOSAGD2 RETURN2

 PDF updated
TIME =   1140.12
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Calculations begin
time   1140.18


 Report Writer entered
Time =   1140.20

 Results generated
Time =   1140.25


*** INPUT SPECIFICATION MESSAGES ***

 CHANGES WERE MADE TO STREAM-REPOR 04/20/2007   12:01:16:54
 STREAM-REPOR NOSORT MOLEFLOW MASSFLOW MASSFRAC NOCOMP-ATTR  &
         PROPERTIES=THERMAL INCL-STREAMS=FROMPBMR TOPBMR TOSAGD1  &
         RETURN1 TOSAGD2 RETURN2
```

```
 PDF updated
TIME =    1156.54
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Calculations begin
time   1156.57


 Report Writer entered
Time =    1156.59

 Results generated
Time =    1156.64


*** INPUT SPECIFICATION MESSAGES ***

 CHANGES WERE MADE TO STREAM-REPOR 04/20/2007   12:01:18:18
 STREAM-REPOR NOSORT MOLEFLOW MASSFLOW MASSFRAC  &
         PROPERTIES=THERMAL INCL-STREAMS=FROMPBMR TOPBMR TOSAGD1   &
         RETURN1 TOSAGD2 RETURN2

 PDF updated
TIME =    1158.18
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Calculations begin
time   1158.23


 Report Writer entered
Time =    1158.23

 Results generated
Time =    1158.28


*** INPUT SPECIFICATION MESSAGES ***

 CHANGES WERE MADE TO STREAM-REPOR 04/20/2007   12:01:19:68
 STREAM-REPOR NOSORT MOLEFLOW MASSFLOW MASSFRAC NOSUBS-ATTR  &
         PROPERTIES=THERMAL INCL-STREAMS=FROMPBMR TOPBMR TOSAGD1   &
         RETURN1 TOSAGD2 RETURN2

 PDF updated
TIME =    1159.68
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Calculations begin
time   1159.73
```

```
 Report Writer entered
Time =    1159.73

 Results generated
Time =    1159.78


*** INPUT SPECIFICATION MESSAGES ***

 CHANGES WERE MADE TO STREAM-REPOR 04/20/2007   12:01:21:93
 STREAM-REPOR NOSORT MOLEFLOW MASSFLOW MASSFRAC NOATTR-DESC  &
         NOSUBS-ATTR PROPERTIES=THERMAL INCL-STREAMS=FROMPBMR  &
         TOPBMR TOSAGD1 RETURN1 TOSAGD2 RETURN2

 PDF updated
TIME =    1161.93
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Calculations begin
time   1161.98


 Report Writer entered
Time =    1161.98

 Results generated
Time =    1162.03

 Report Writer entered
Time =    1176.54

 Results generated
Time =    1176.59


*** INPUT SPECIFICATION MESSAGES ***

 Report Writer entered
Time =    1249.78

 Results generated
Time =    1249.82


*** INPUT SPECIFICATION MESSAGES ***

 CHANGES WERE MADE TO STREAM-REPOR 04/20/2007   12:02:52:21
 STREAM-REPOR NOSORT MOLEFLOW MASSFLOW NOATTR-DESC NOSUBS-ATTR  &
         PROPERTIES=THERMAL INCL-STREAMS=FROMPBMR TOPBMR TOSAGD1  &
         RETURN1 TOSAGD2 RETURN2
```

```
 PDF updated
TIME =    1252.20
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Calculations begin
time   1252.25


 Report Writer entered
Time =    1252.25

 Results generated
Time =    1252.29


*** INPUT SPECIFICATION MESSAGES ***

 CHANGES WERE MADE TO STREAM-REPOR 04/20/2007   12:02:58:81
 STREAM-REPOR NOSORT NOZEROFLOW MOLEFLOW MASSFLOW NOATTR-DESC  &
         NOSUBS-ATTR PROPERTIES=THERMAL INCL-STREAMS=FROMPBMR  &
         TOPBMR TOSAGD1 RETURN1 TOSAGD2 RETURN2

 PDF updated
TIME =    1258.90
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Calculations begin
time   1258.95


 Report Writer entered
Time =    1258.95

 Results generated
Time =    1259.00


*** INPUT SPECIFICATION MESSAGES ***

 CHANGES WERE MADE TO STREAM-REPOR 04/20/2007   12:03:09:25
 STREAM-REPOR NOSORT NOZEROFLOW MOLEFLOW MASSFLOW NOATTR-DESC  &
         NOSUBS-ATTR PROPERTIES=THERMAL INCL-STREAMS=FROMPBMR  &
         TOPBMR TOSAGD1 RETURN1 TOSAGD2 RETURN2 EXCL-STREAMS=1 4   &
         8 10 11 16 17 18 19 20 FROMPBMR RETURN1 RETURN2  &
         TOPBMR TOSAGD1 TOSAGD2

 PDF updated
TIME =    1269.25
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  *   WARNING IN A "STREAM-REPOR" PARAGRAPH
(STRSM1.3)
     BOTH INCL-STREAMS AND EXCL-STREAMS SENTENCES ARE
```

```
      SPECIFIED IN THE STREAM STANDARD REPORT
      ONLY INCL-STREAMS SENTENCE IS PROCESSED



Calculations begin
time   1269.31


 Report Writer entered
Time =    1269.34



 Results generated
Time =    1269.39

*** INPUT SPECIFICATION MESSAGES ***

 CHANGES WERE MADE TO STREAM-REPOR 04/20/2007   12:03:20:50
 STREAM-REPOR NOSORT NOZEROFLOW MOLEFLOW MASSFLOW NOATTR-DESC  &
         NOSUBS-ATTR PROPERTIES=THERMAL INCL-STREAMS=FROMPBMR  &
         TOPBMR TOSAGD1 RETURN1 TOSAGD2 RETURN2 EXCL-STREAMS=1 4  &
         8 10 11 16 17 18 19 20

 PDF updated
TIME =    1280.51
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  *   WARNING IN A "STREAM-REPOR" PARAGRAPH
(STRSM1.3)
      BOTH INCL-STREAMS AND EXCL-STREAMS SENTENCES ARE
      SPECIFIED IN THE STREAM STANDARD REPORT
      ONLY INCL-STREAMS SENTENCE IS PROCESSED



Calculations begin
time   1280.61


 Report Writer entered
Time =    1280.64

 Results generated
Time =    1280.68


*** INPUT SPECIFICATION MESSAGES ***

 CHANGES WERE MADE TO STREAM-REPOR 04/20/2007   12:03:28:60
 STREAM-REPOR NOSORT NOZEROFLOW MOLEFLOW MASSFLOW NOATTR-DESC  &
         NOSUBS-ATTR INCL-STREAMS=FROMPBMR TOPBMR TOSAGD1 RETURN1  &
         TOSAGD2 RETURN2 EXCL-STREAMS=1 4 8 10 11 16 17 18  &
         19 20
```

```
 PDF updated
TIME =    1288.59
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   *   WARNING IN A "STREAM-REPOR" PARAGRAPH
(STRSM1.3)
      BOTH INCL-STREAMS AND EXCL-STREAMS SENTENCES ARE
      SPECIFIED IN THE STREAM STANDARD REPORT
      ONLY INCL-STREAMS SENTENCE IS PROCESSED



Calculations begin
time   1288.64


 Report Writer entered
Time =    1288.65

 Results generated
Time =    1288.68

RUN SAVED


 *** SUMMARY OF ERRORS ***

                   PHYSICAL
                   PROPERTY  SYSTEM  SIMULATION
 TERMINAL ERRORS      0        0         0
   SEVERE ERRORS      0        0         0
          ERRORS      0        0         0
        WARNINGS      0        0         3

 *** SUMMARY OF ERRORS ***

                   PHYSICAL
                   PROPERTY  SYSTEM  SIMULATION
 TERMINAL ERRORS      0        0         0
   SEVERE ERRORS      0        0         0
          ERRORS      0        0         0
        WARNINGS      0        0         3

RUN SAVED


 *** SUMMARY OF ERRORS ***

                   PHYSICAL
                   PROPERTY  SYSTEM  SIMULATION
 TERMINAL ERRORS      0        0         0
   SEVERE ERRORS      0        0         0
          ERRORS      0        0         0
        WARNINGS      0        0         3
```