Integration of Nuclear Energy with Oil Sands Projects For Reduced Greenhouse Gas Emissions and Natural Gas Consumption

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Executive Summary

The oil sands of Alberta are a huge natural resource and bitumen production has expanded dramatically in the past five years as the price of oil has risen to record levels. Bitumen recovery from oil sands deposits involves either strip mining the sands and extracting the oil, or pumping large quantities of steam into the ground to free the bitumen from the sand which is then pumped above ground for upgrading. Traditionally, the energy to produce the steam and hot water used in these processes has come from natural gas. The use of increasingly large amounts of natural gas for oil sands recovery presents a number of economic and environmental problems. Steam generation and upgrading processes will contribute large amounts of greenhouse gas emissions while Canadian and regional environmental policies seek long term reductions. Large planned increases in natural gas consumption will cause western Canada to become a net importer of gas, with potentially serious impacts on regional natural gas pricing and market volatility. This is likely to impact not only the profitability of the oil sands business but also the price and availability of natural gas to home owners, commercial uses and other industries.

This paper explores the feasibility and economics of using nuclear energy to power future oil sands production and upgrading activities. Although more expensive to build than conventional facilities, nuclear reactors produce no greenhouse gas emissions and offer relatively low and stable fuel and operating costs. Although uranium has been subject to recent price increases as a result of improved operation of existing reactors and plans for new plants, nuclear energy production costs are relatively insensitive to uranium costs. There are, however, several trade-offs. This paper compares the benefits and the drawbacks, and puts forth several nuclear energy application scenarios for steam or steam and electricity for upgrading bitumen from both in-situ and surface mining operations.

This review includes the Enhanced CANDU 6, the Advanced CANDU Reactor (ACR) and representing high temperature gas reactor technology, the Pebble Bed Modular Reactor (PBMR) which represents the first advanced high temperature gas reactor technology to become commercially available within the next decade. Based on reasonable projections of available cost information, nuclear energy used for steam production is expected to be less expensive than steam produced by natural gas at current natural gas prices. For electricity production, nuclear becomes competitive with natural gas plants at natural gas prices of $10-13/MMBtu (CAD). Costs of constructing nuclear plants in Alberta are affected by higher local labor costs which this paper took into account in making these estimates. Although more definitive analysis of construction

costs and project economics will be required to confirm these findings, there appears to be sufficient merit in the potential economics to support further study.

The primary environmental benefit of nuclear energy in this application is to reduce CO_2 emissions by up to 3.1 million metric tons per year for each 100,000 barrel per day (bpd) bitumen production Steam Assisted Gravity Drainage facility, or 2.0 million metric tons per year for the replacement of 700MWe of grid electricity with a nuclear power plant. The potential impact on future regional gas markets can be dramatic considering that natural gas use to support current plans for oil industry expansion through the year 2020 represents 20% of projected western Canadian gas production.

A single PBMR reactor is able to supply high pressure steam for a 40,000 to 60,000 bpd SAGD plant, whereas the CANDU and ACR reactors are too large and unable to produce sufficient steam pressures to be practical in that application. A single module PBMR cogenerating its own power requirements can supply steam for SAGD operations from 30,000 to 50,000 bpd in size.[1] The CANDU, ACR and PBMR reactors have potential for supplying heat and electricity for surface mining operations.

Key challenges to deployment of new nuclear plants in Alberta include obtaining public acceptance, achieving acceptable construction costs, transportation of large components, resolving workforce issues and addressing nuclear licensing requirements. All would require an integrated planning process to address the prerequisites to make nuclear energy a realistic option in the near future. Recommendations are provided which include development of conceptual designs of specific nuclear energy oil sands applications; developing and implementing a public information program; the development of an integrated oil sands energy strategy including nuclear to address electricity, work force issues, natural gas supply, greenhouse gas reductions and licensing such that nuclear energy can be a viable option for the future.

A number of current initiatives have been announced that will consider options to utilize bitumen derived fuels in advanced gasification systems with CO_2 capture and sequestration. Since nuclear energy can be an alternative to these projects which are also capital intensive and challenging, a study comparing nuclear options with other proposals to address future gas supply constraints and options for achieving greenhouse gas reductions would be beneficial.

With the possible imposition of carbon taxes, limits on natural gas availability, or restrictions on natural gas use, it would be prudent to begin to seriously investigate nuclear energy as an alternative to growing utilization of natural gas and expensive carbon capture schemes using bitumen or coke gasification. If the oil sands development plans currently being discussed are implemented in the 2017 to 2020 timeframe, should nuclear energy be used instead of natural gas, the total reduction in CO_2 emissions could be as high as 745 million metric tons over the lifetime of the operation.

[1] Based on a steam to oil ratio of 2.0 to 3.0

In summary, nuclear energy applications appear to be well suited for long term oil sands production and are likely to provide an economically competitive, CO_2 emission free option to greatly help Canada in meeting its Kyoto greenhouse gas emission commitments and reduce pressure on limited regional gas supply, allowing more responsible development of its rich oil sands resources.

ACKNOWLEDGEMENTS:

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1 Introduction

The Canadian oil sands industry has grown tremendously in the last five years, and promises to continue its steady growth for decades to come. 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[2] billion have already been spent on oil sands projects, and an additional \$54 billion are projected by 2012.

The total recoverable bitumen in the Alberta oil sands is estimated to be about 270 billion cubic meters, of which 250 billion can be recovered using in-situ and 18 billion can be recovered through surface mining [2]. 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[3]

(Billion m^3)	**Surface Mining**	**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%

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. 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.

Currently, bitumen recovery is primarily accomplished either by surface mining and later extraction through thermal processing, or by in-situ means such as Steam-Assisted Gravity Drainage (SAGD). The economics of surface recovery are dominated by the cost of mining equipment, operations, and reclamation. The economics of in-situ production are dominated by the cost of natural gas used to make steam for injection and power for pumping. High oil prices make both approaches profitable, supporting rapid expansion subject to incremental approvals by the Alberta Ministry of Energy. The Ministry manages public ownership of the resource by awarding production leases. Both of the recovery methods use natural gas as an energy source in most cases, releasing greenhouse

[2] Unless otherwise stated all \$ are in Canadian dollars.
[3] According to the Petroleum Technology Alliance Canada (PTAC)

gases into the environment. Nuclear energy may be a viable alternative to natural gas for a large part of the energy supply, and would offer the benefits of having a more stable and predictable energy cost and releasing no greenhouse gas emissions during operation.

2 Challenges Facing the Oil Sands Industry

Given public ownership of the oil sands resource, the oil sands industry is driven 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 increasing to 4.0 million bbl/day in 2020 [2]. If serious changes to the production methods are not made, greenhouse gas emissions will increase accordingly, and competition for limited natural gas supply is likely to drive up regional prices and negatively impact other gas consumers.

The increasing demand for natural gas and the volatility of its prices not only endanger the profitability of the industry, but also threaten to drive home-heating prices up for Canadians. 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. The region's current planning focus on a large scale carbon capture and sequestration strategy is likely to encounter high costs and risks in implementation. 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 are highlighting 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.

2.1 Natural Gas Price and Supply

The predicted rapid growth of bitumen production will require a commensurate increase in energy use. Daily production of 2.1 million bbl in 2010 is expected to consume approximately 1.4 to 1.8 billion cubic feet of gas per day, or approximately 10% of western Canada's natural gas production [5]. This is roughly equal to the maximum throughput of the proposed Mackenzie Valley Pipeline, expected to go online in November 2009 [6]. 4.0 million bbl/day of bitumen production in 2020 (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 [6]. Diversion of this supply to support the oil sands industry can be expected to significantly impact regional markets.

Natural gas has historically been a very convenient fuel source. It is drilled for in great quantities in Western Canada, in Alaska, and offshore. Many of the companies now involved in oil sands mining also have divisions that produce natural gas in the area. Natural gas pipelines were developed to support natural gas production before the oil sands production was undertaken, and the oil sands industry has taken advantage of the existing infrastructure. Gas fired steam boilers and gas fired combustion turbine cogeneration plants are the primary natural gas consumers. These natural gas fired facilities are built easily and quickly, require relatively low capital investment, and have high reliability.

Natural gas has also been the fuel of choice for in-situ production. However, 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 gas use in the oil sands sector is quickly moving towards rivaling all other domestic consumption. Natural gas and oil prices are somewhat related but quite volatile when compared with most other fuel options as illustrated in Figure 1. High natural gas prices can threaten the profitability of in-situ operations. With a more stable energy source, variations in gas price would no longer threaten in-situ production economics.

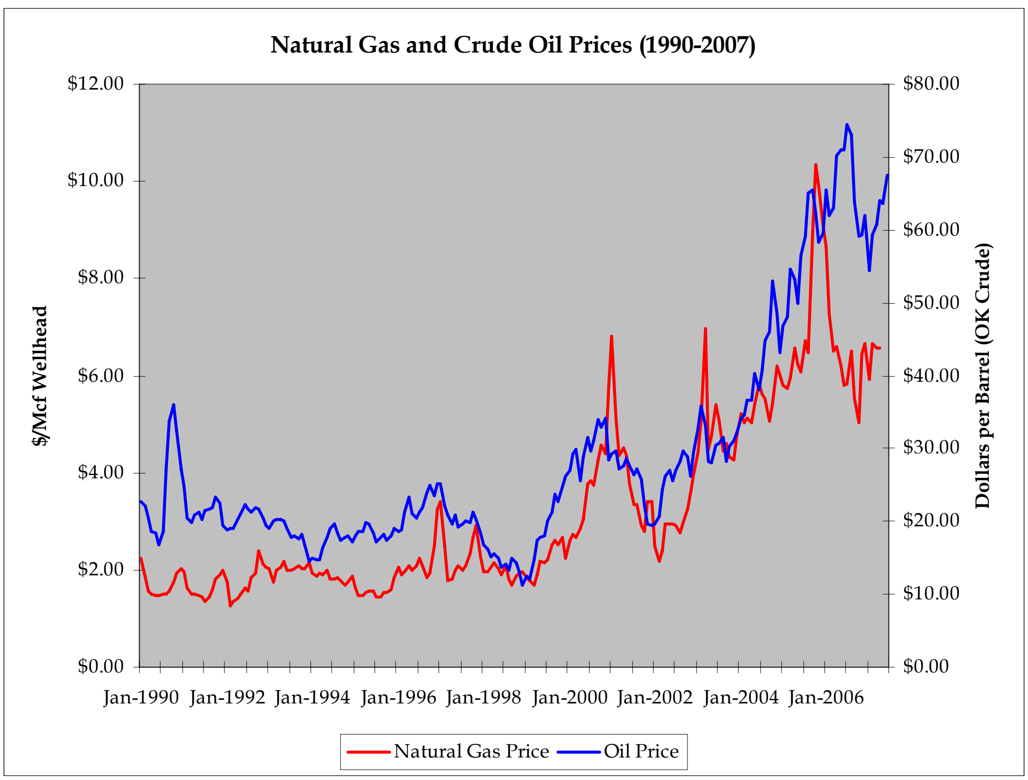

Figure 1: Comparison of Natural Gas and Oil Prices [33]

From an environmental standpoint, natural gas combustion emits far less greenhouse gas than burning coal, oil, or bitumen. However, the sheer scale of the industry's projected use of gas results in emissions that are significant relative to Canada's total emissions, and thus have a large impact on Canada's ability to reduce or even stabilize its total emissions. Increasing pressure to reduce carbon emissions will encourage additional use of gas as a replacement for coal and oil before more expensive installations that involve carbon capture and sequestration are deployed. In summary, the gas markets in western Canada and the northern U.S. are likely to encounter regional shortages due to (1) gas demand increases for oil sands recovery, (2) increased reliance on gas as a premium fuel in North America, and (3) further incentives to use gas as the lowest cost of compliance with reduced CO_2 emission targets. Further study of oil sands industry gas market constraints should be undertaken to understand the full benefits of energy alternatives.

2.2 Greenhouse Gas Emissions and Canada's Climate Change Plan

The GHG emissions due to natural gas use for oil sands extraction and upgrading in 2020 could be over 150 megatons (millions of tons) of CO_2e (CO_2 equivalent). This would account for approximately 17% of Canada's total forecasted emissions for that year[4]. 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. If the oil sands are to continue to grow rapidly, they will have to become carbon-neutral, or they will impair any progress towards addressing climate change.

2.2.1 The Kyoto Protocol

Canada signed the Kyoto Protocol on April 29th, 1998, and formally ratified the document on December 17th, 2002 [16]. The protocol required Canada to reduce its greenhouse gas emissions by 6% relative to 1990 levels between 2008 and 2012 [17]. However, by 2004, Canada's greenhouse gas emissions had risen to a level 26.6% higher than 1990 levels [15]. 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 went into effect on February 16, 2005 [17]. 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 . On February 8th, 2007, the Minister of the Environment, John Baird, announced that Canada would abandon its Kyoto targets [20]. An alternative plan entitled "Turning the Corner" was released on April 26th, 2007.

2.2.2 "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

[4] The total forecasted GHG emissions are 897 megatons [18].

roughly a 20% reduction compared with national 2006 levels [22]. 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 [21]."

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,
- Purchasing offsets from unregulated industries that are reducing their emissions, and
- 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 [22].

2.2.3 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 established 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 [22].*

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.”

Given that oil sands emissions from in-situ operations come primarily from the combustion of natural gas, the question becomes whether those emissions will be targeted for reduction. If the government determines that the natural gas burning for the oil sands is “production tied,” those emissions could be exempted. Natural gas burning may be considered the preferential method of CO_2 reduction until alternatives are demonstrated to be practical and economic.

3 Energy Requirements for Bitumen Production

3.1 SAGD Heat and Electricity

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) [3][28][29]. The desired steam generation pressure is affected by the geological characteristics of the area, the distance over which the steam must be piped, and the depth and 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, possibly resulting in failure of proper steam distribution. Fracture pressures range considerably, but as an example, in Shell’s BlackRock Orion SAGD project, the formation fracture pressure is 10MPa.

Saturated steam is produced at sufficient pressure to support control, distribution and injection. 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)[5] is between 2 and 4, with the goal being at the lower end which may be achieved as SAGD methods are improved. 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 6 MPa and 11 MPa 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).

[5] Steam to Oil Ratio (SOR) is a measure of the amount of steam needed in terms of cold water equivalent to produce a barrel of bitumen.

Most SAGD project phases where power and steam capacity is incrementally added in the Athabasca region are between 10k and 60k bbl/day. Peak project production rates are expected 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 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) [3]. 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 energy efficiency.

In-situ SAGD recovery uses about 1.0-1.5 Mcf of natural gas for each barrel of bitumen recovered [24][23][3][25]. 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 (SOR = 3.0)

Barrels of Bitumen per Day	Natural Gas for Steam production (MMBtu/day)[1]	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.

SAGD projects require relatively little electric power relative to their required thermal energy. Electricity is used primarily for pumping feedwater to support required steam pressures. A typical SAGD project uses about 9 kWh of electricity per barrel of bitumen produced. Table 3 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 3: 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

[1] Based on 0.15 Metric tons of CO_2 per MWh for natural gas generation and 45% electrical efficiency for combined cycle gas plant.

3.2 Surface Mining and Extraction Heat and Electricity

The surface mining and extraction process uses about 16 kWh of electricity per barrel of bitumen recovered [3][24][25]. 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 4 provides a summary of electricity requirements for surface mining and consequential GHG emissions of gas fired units. Heat requirements are summarized in Table 5.

Table 4: Surface 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

[1] Based on 0.15 Metric tons per MWh for natural gas generation and 45% electrical efficiency for combined cycle gas plant.

A review of current surface 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 [3][24][25]. However, since most large surface 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.

Table 5: Surface 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)[1]	GHG emissions in kilotons CO_2e per yr
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

[1] Based on 65 kg CO_2 per MMBtu NG burned (One Mcf is equivalent to 1.027 MMBtu)
Mining and extraction require approximately 0.28 Mcf gas per bbl bitumen [3][24][25].

The oil sands industry is planning to produce most of its additional energy from natural gas at rates that can dramatically influence regional gas availability and pricing. These quantities demonstrate the size of the potential market for other forms of power and steam that can compete with natural gas.

4 Evaluation of Nuclear Energy Options

Nuclear power is being considered as an energy source for oil sands recovery because it is a base load generating resource, it has no greenhouse gas emissions, it is proven technology, is much less sensitive to fluctuations in fuel costs, and it has the potential to offer long-term cost savings. However, nuclear energy brings with it a few unique characteristics that are unfamiliar to the oil sands industry. Other than a university research reactor, there are no nuclear reactors in Alberta or in the oil sands industry. This is a significant obstacle to nuclear energy's introduction into the oil sands and will require new business and operation models 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 [34][35][36][37]. There is a growing consensus that greenhouse gas emissions must be decreased, and that nuclear energy can 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 risks and difficulties involved. The remainder of this report will focus on evaluating key aspects that contribute to that decision.

A few specific types of nuclear reactors have been proposed for use in the oil sands, namely the Enhanced CANDU 6, the ACR-700 and 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 [27]. Shown in the appendix is a sample of the model used for the analysis. The analysis performed for this report is 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.

4.1 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, and as such has been licensed by the Canadian Nuclear Safety Commission (CNSC). 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 6.

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 [35][36][38].

While the Enhanced CANDU has the benefit of being based on proved technology with many projects completed and extensive operating histories, 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 CANDU6 does have a number of design updates that help to improve the plant's accident behavior. The most substantial difference is that the fuel enrichment is increased to increase the safety margins of the reactor. The layout of a two-unit CANDU 6 site is shown in Figure 2 and the heat transport system layout is shown in Figure 3. Due to the differences in design from the basic CANDU 6, namely the higher enrichment, the regulatory authorities will need to perform an additional safety review and assessment in the licensing process.

Table 6: Enhanced CANDU Reactor Operating Data [38]

Enhanced CANDU Reactor Operating Data	
Heat Output	2064 MWth
Electricity Output (max, for electric plant only)	740 MWe
Fuel	1.7% enriched uranium (UO_2)
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	7,700 kg/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	1,000 kg/s

Figure 2: Qinshan CANDU 6 Units 1 & 2, located in Zhejiang China

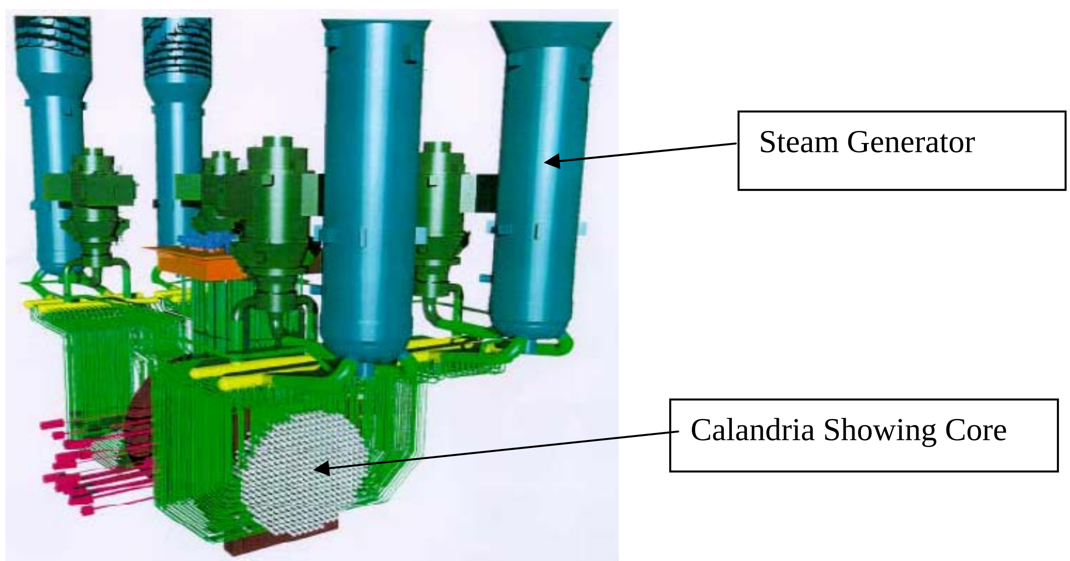

Figure 3: CANDU 6 Heat Transport System Layout

4.1.1 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 4.

Figure 4: The CANFLEX Fuel Bundle

4.1.2 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 and redesign to modify the reactor operation, which would likely require greater pumping power and higher pressure in the secondary loop. A regulatory review of these changes would also be required. Assuming that modifying the design to increase the pressure to 6.5 MPa was done, the resulting steam capabilities are summarized in Table 7 below.

Table 7: Enhanced CANDU 6 Steam Supply Capability (260°C Steam)

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

As Table 7 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.

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. Low Pressure-Steam Assisted Gravity Drainage (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.

4.1.3 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. 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. 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.

4.2 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. Operating figures for the ACR-700 are given in Table 8. 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 [38][45][51].

Table 8: 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.

The conceptual layout of a two-unit ACR-700 power plant is shown in Figure 5, and the heat transport system layout for one ACR-700 is illustrated in Figure 6.

Figure 5: Conceptual Layout of a Two-Unit ACR-700 Power Plant

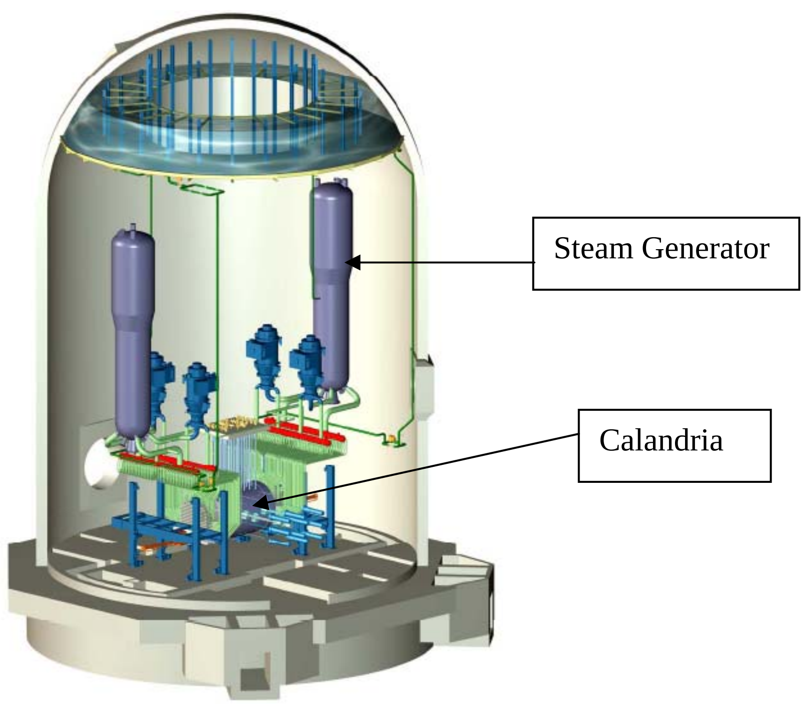

Figure 6: ACR-700 Heat Transport System Layout in Containment

4.2.1 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. Steam production results based on three different pressures are summarized in Table 9.

Table 9: ACR-700 Steam Supply Capability (281°C Steam)

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

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.

4.2.2 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 than needed would not be economically justified. 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 40 years to last for the lifetime of the plant. Figure 7 shows the maximum realistic density of well pads in a 10 km radius field, assuming that ideal conditions existed throughout that radius. The 10km radius was determined to be a feasible distance to pipe steam based on simple calculations of pressure drop and heat loss through typical insulated pipes for this application. The option of heated pipes was not considered. Figure 8 illustrates the density of well pads that would be needed to utilize 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.

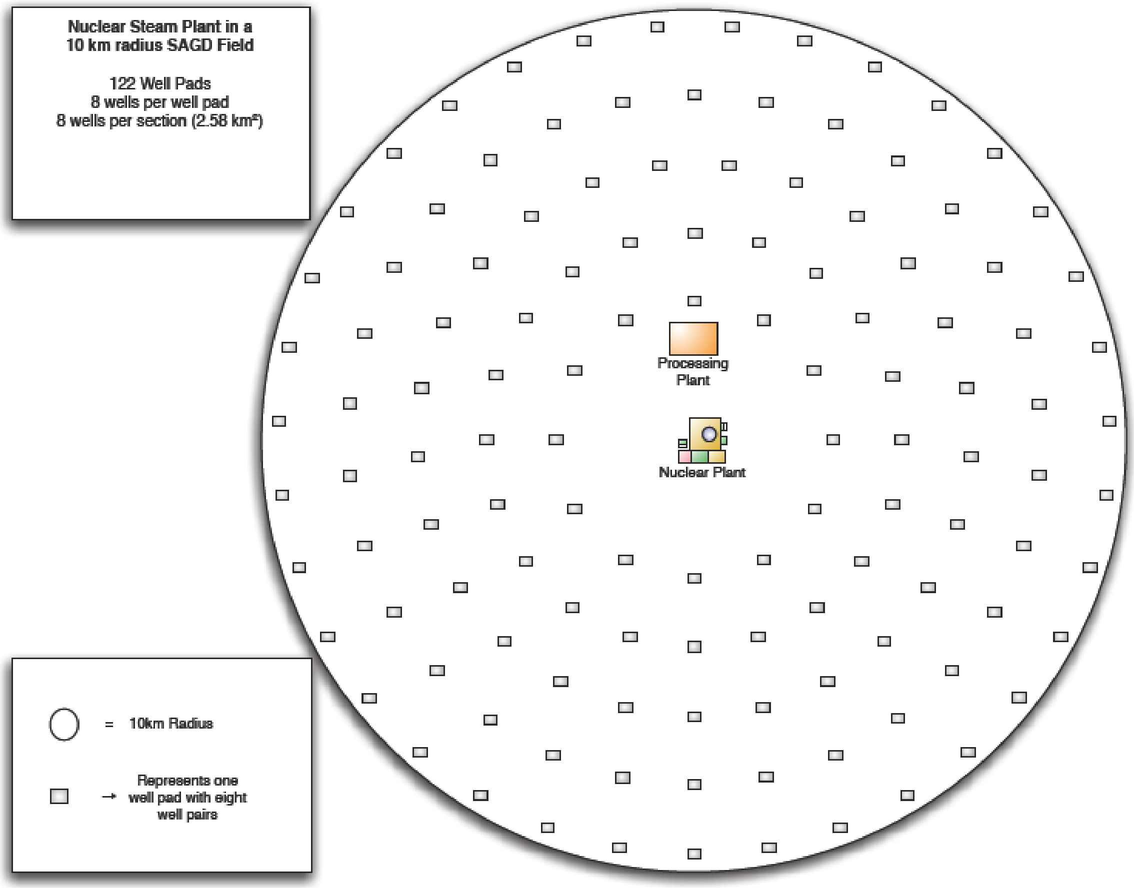

Figure 7: Nuclear Steam Plant in a 10km SAGD field with Maximum Well Density

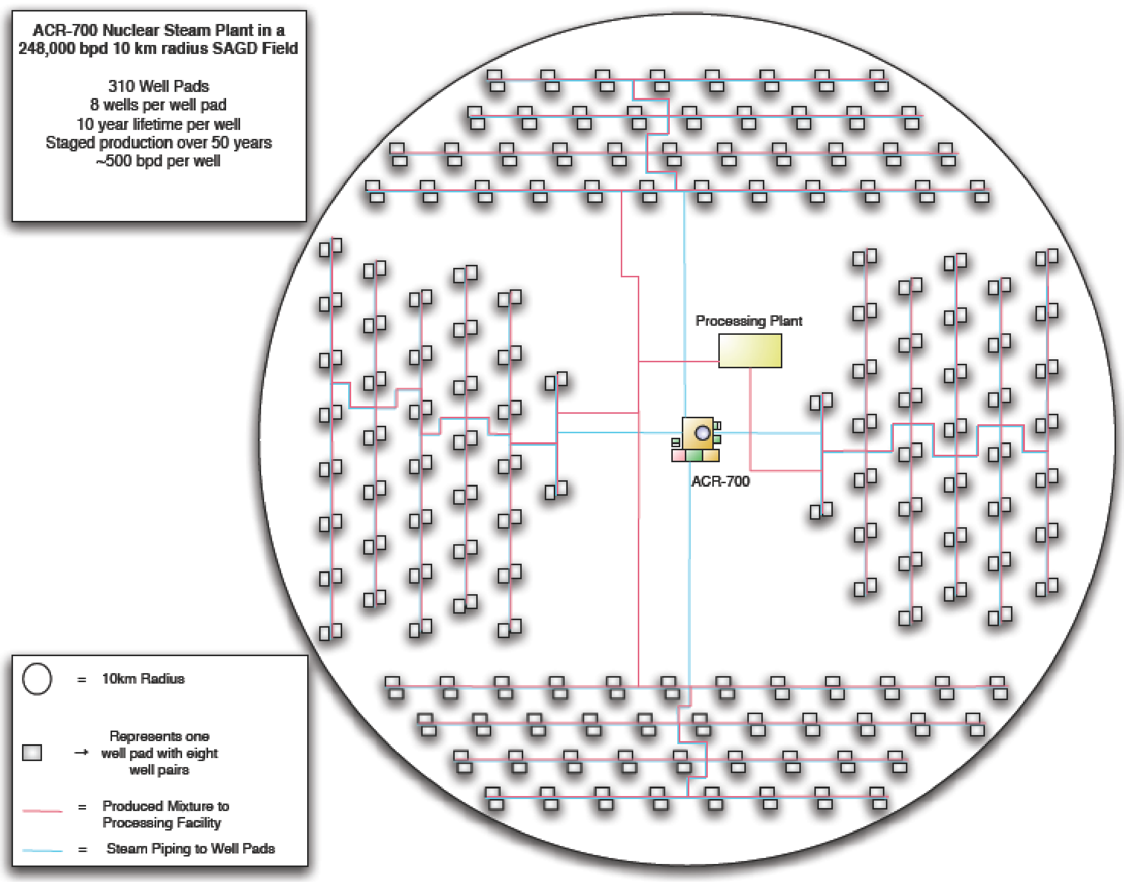

Figure 8: ACR-700 in a 248,000 bpd SAGD Field

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 Section 5.

4.3 Pebble Bed Modular Reactor

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 high reactor outlet temperatures, passive safety features, unique fuel design and on-line refueling process, smaller size, and the replacement of a pressure-retaining containment building with a vented confinement building. The PBMR has been developed by Pebble Bed Modular Reactor (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 implements many improvements to the German design but has never been built before. Work is underway to construct a single module 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 2009. 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 [46].

A model of the electricity generating power plant including the helium gas turbine (Brayton) power conversion unit is shown in Figure 9. The PBMR steam production version is much simpler since all of the electricity generation equipment can be removed. The design of the PBMR reactor with two primary loops for a steam only process heat plant is shown in Figure 10.

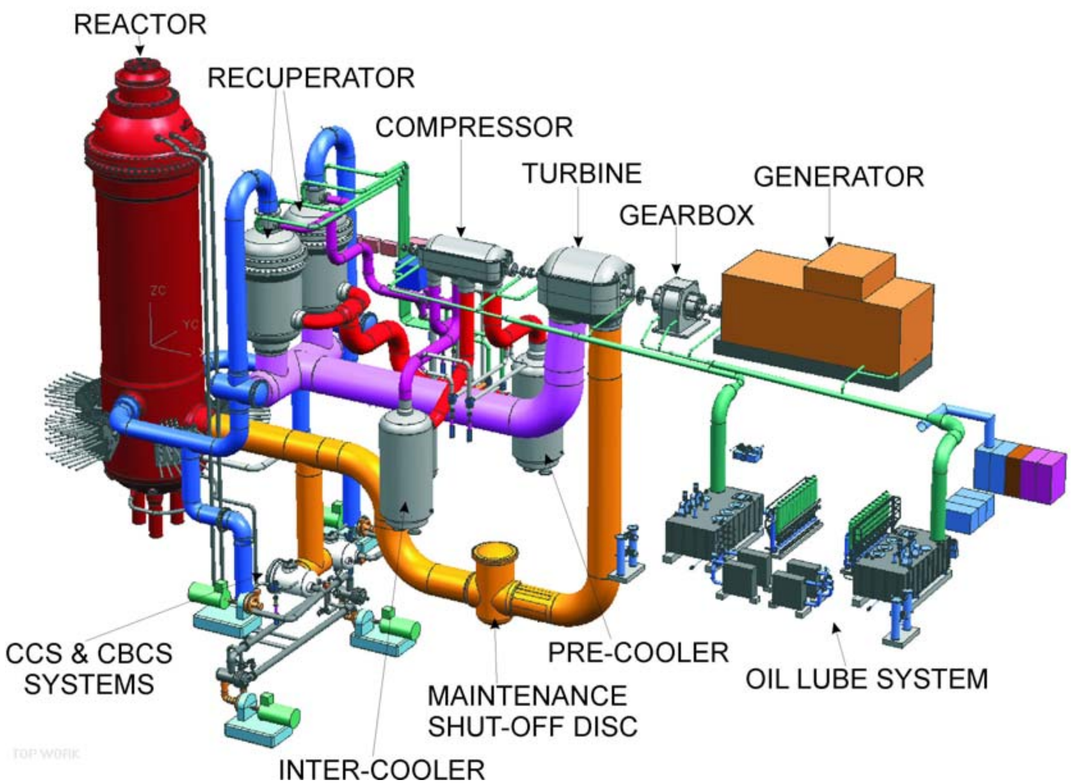

Figure 9: PBMR Demonstration Power Plant Layout for Electricity Generation

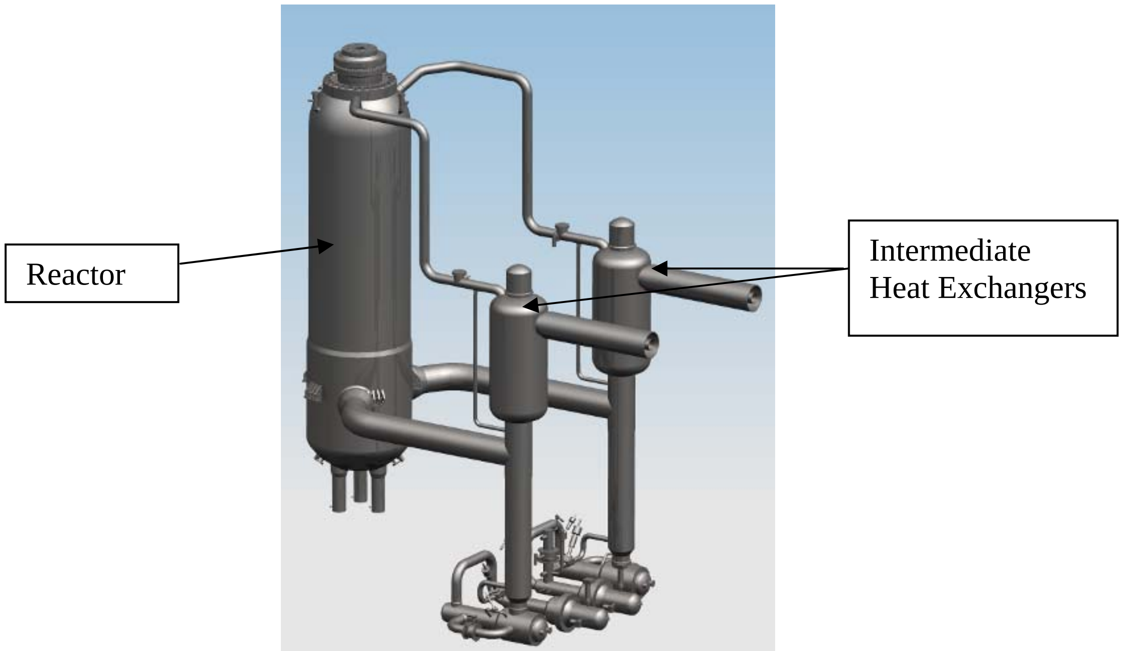

Figure 10: PBMR for Process Heat Applications
(Excluding the Steam Generators)

Figure 10 shows the reactor vessel and the two primary helium loops with two intermediate 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 11. Other secondary side configurations are possible. 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 Process Heat Plant (PHP) Steam Plant are given in Table 10.

Table 10: PBMR Reactor Operating Data [43]

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	8.7 MPa
Secondary Side Flow Rate	102.5 kg/s for each of two loops

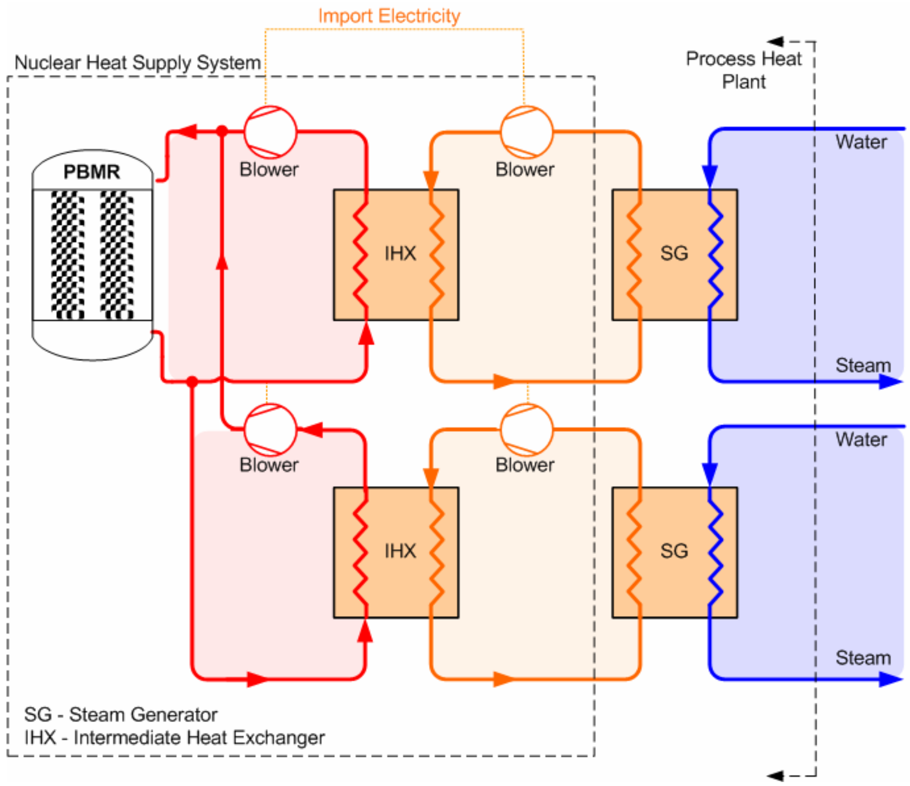

Figure 11: PBMR SAGD Steam-Only Solution – Single Reactor, Two Primary Loops

4.3.1 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 to form a TRISO[6] particle which is the major component 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 12, and a photo of the fuel pebbles is shown in Figure 13. It is important to note that this specific design of fuel was used successfully for more than 14 reactor power years between 1967 and 1988 to power the German AVR research reactor [44].

[6] TRISO – Tri-structural Isotropic

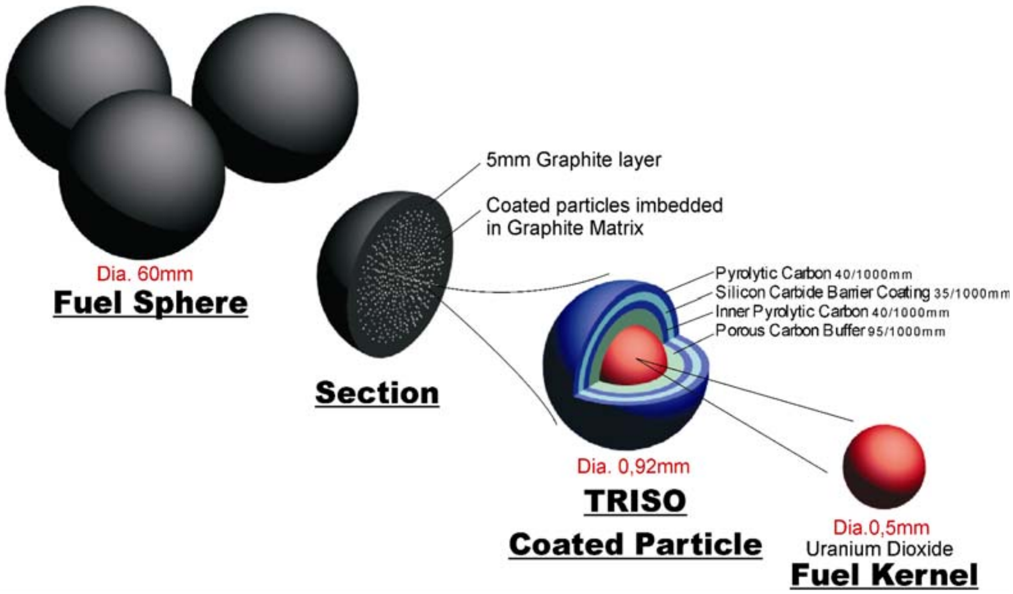

Figure 12: PBMR Fuel Structure

Figure 13: PBMR Fuel "Pebbles"

The pebbles are circulated downwards through the core during operation, with pebbles being removed at the bottom of the reactor, tested for damage and fuel utilization, and reinserted at the top of the reactor. Pebbles are recycled until they reach the target fuel utilization before being transitioned to spent fuel storage, unless damage or complete fuel utilizationcause 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 [43][46].

4.3.2 Steam Supply Capability

Steam production for a single PBMR is given in Table 11. It is important to note that in this case the PBMR would require about 33MWe for its own electrical load, based on very preliminary designs. Since the PBMR would not be configured to produce electricity in the steam production only case, electricity would need to be provided by an auxiliary source or purchased off of the grid.[7]

Table 11: PBMR Steam Supply Capability (1 Module) (318°C Steam)

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	1.0	130,000	43,300	52,000	65,000

The actual steam output and quality depends somewhat on the steam generator and separator designs, which may be determined by the needed output. A typical output requirement and steam generation design has been assumed for this analysis.

A conceptual layout of a two-unit PBMR steam supply plant in a SAGD field is shown on Figure 14.

[7] Alternatively, should electricity not be available to power the 33MWe for the steam only case; then a cogeneration solution could be employed to produce the house load as well as excess electricity if needed.

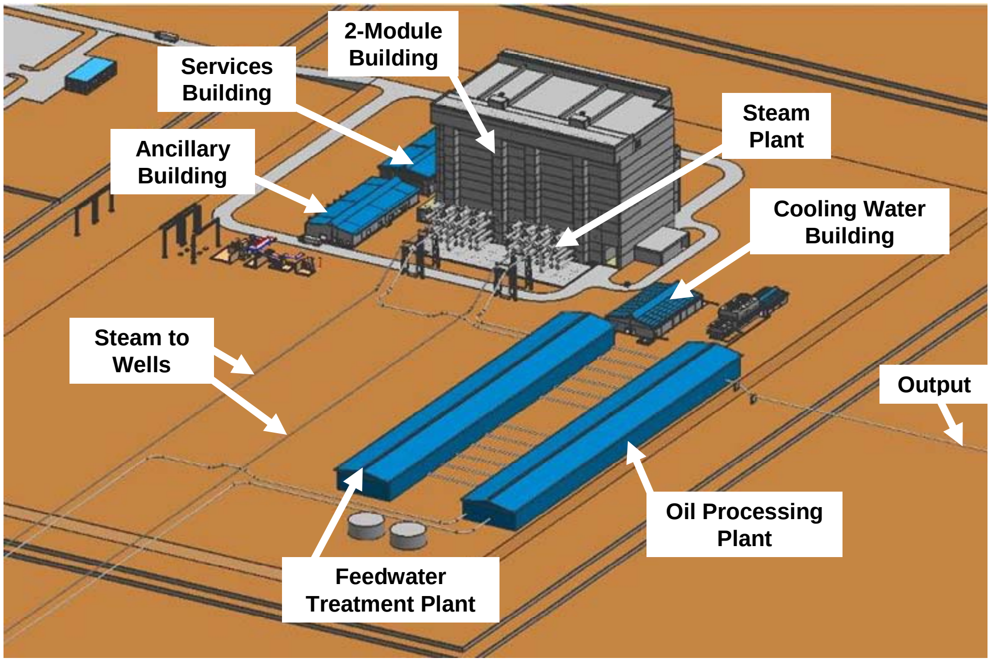

Figure 14: A SAGD Plant with 2 PBMR Modules.
For clarity, the steam generator enclosure has not been shown.

4.3.3 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-160k bpd. Each PBMR has its own electrical load that would need to be purchased if it was not generated onsite. This amounts to 33 MWe for each PBMR module; which includes all circulators as well as the PBMR plant house load. While this design is not optimized, it will be used as basis for this analysis.

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 15 illustrates the number of well pads that would be needed in a 7 km field to draw all of the PBMR's steam production.

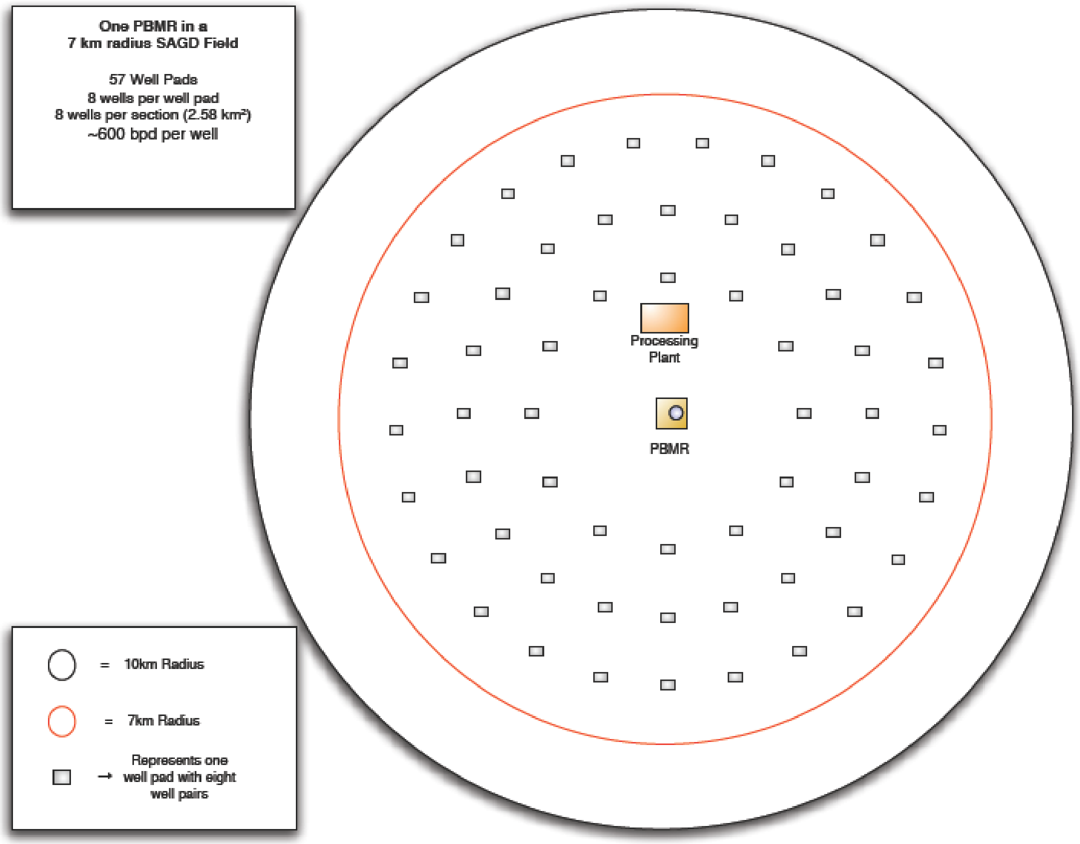

Figure 15: PBMR Nuclear Steam Plant in a 55,000 Barrel per Day SAGD Field

Another option for the PBMR would be to supply steam to the SAGD field for 20 to 30 years, and subsequently to convert the nuclear heat plant, utilizing the same reactor configuration, 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 Section 5.

5 Possible Nuclear Energy Integration Scenarios

In this section, 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, surface mining, and upgrading. In each case, the capacity of the nuclear reactor for producing steam and electricity was modeled using the Aspen Plus™ program. A sample analysis is included in Appendix A. It is important to note that for the HTGR and the CANDU reactor systems, this analysis is somewhat limited since much of the design information is not publicly available. Thus, the full flexibility of these reactor types for combined heat and power options has not been accounted for.

5.1 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.

5.1.1 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 from existing generation. 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.[8] As shown in Figure 15, the PBMR can support a 55,000 bpd SAGD site well within the 10 km limit.

5.1.2 Enhanced CANDU 6 and ACR-700

The Enhanced CANDU 6 is not considered a viable nuclear energy source for SAGD steam production due to its low pressure steam. It is excluded for all SAGD options. The ACR-700 produces somewhat higher pressure steam, but it is too large to provide only steam for SAGD projects of the size being considered for the foreseeable future.

5.2 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.

5.2.1 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 found that it is not economically attractive to produce excess electricity to sell on the grid due to the high costs of building the generation capacity in the oil sands production area 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

[8] Note that the per module electrical power requirement will decrease in the multi-module scenario due to sharing of common equipment and facilities.

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 reduced to ~100,000 bpd, supporting bitumen production of 33k to 50k barrels per day for an SOR of 3.0 to 2.0 respectively. However, should the SOR be less favorable, a single-module PBMR would not be sufficient and a second unit would need to be installed. A small supplementary gas-fired boiler could provide a back-up source of power for peak loads. Reductions in PBMR internal load requirements could increase steam output.

5.2.2 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 (50 MWe) to supply the ACR internal power requirements. If designed for a total power production of 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). To make ACR attractive for this size application, it would 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 66 MWe, requires ~100 MWe, so the plant could contain two reactors with some combination of steam and power 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 major cost advantages to siting multiple units adjacent to one another due to the sharing of equipment and structures.

5.2.3 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.

4 PBMR reactors, with a full reactor capacity devoted to electricity production would be required for a 130-195k bpd production scenario depending on the SOR (2.0 to 3.0). Due to the modularity of the PBMR, 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) to grow with the expanding SADG field. The economic advantage of the sharing of systems is not accounted for here.

5.3 Surface Mining Heat and Electricity

5.3.1 Surface Mining 100,000 bpd

A 100,000 bpd surface 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 surface mining operation of this size, while two would have too much capacity. Two PBMRs would work very well for a 150,000 bpd project.

5.3.2 Surface Mining 200,000 bpd

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

Three cogenerating 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 surface mining project, it might be of interest to the owner of the nuclear plant to provide electricity to other projects in the region.

5.4 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 intended 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 due to the high temperature utilization. Table 12 summarizes the electrical output of each of the reactor technologies.

Table 12: Reactor Electrical Power Outputs

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

5.5 Hydrogen Production

Upgrading requires from 1500 to 2200 SCF, or 3.63 to 5.32 kg, of hydrogen per barrel of syncrude produced. Through water electrolysis, one kilogram of hydrogen may be produced by expending about 50 kWh [26]. Electrolysis is the only technology for nuclear-powered hydrogen production that is currently available, but it is generally not thought to compete with conventional 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 a high-temperature reactor could be used in a steam methane reforming process reducing the need for natural gas as a heat source for hydrogen production.

5.6 Summary of Nuclear Energy Integration Scenarios

The results of this analysis show that the sizes of the ACR and CANDU reactors are 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 surface mining operations. They are good candidates for bulk electricity production, but they should be situated where the cost of construction might be less than in the Fort McMurray area. If transmission line siting is possible, the power could be transmitted to the oil sands region. 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. Shown on Table 13 below is a summary of the nuclear integration options identified.

Table 13: Summary of Nuclear Energy Integration Options

Application	Production	Nuclear Energy Options
SAGD Steam and Electricity	50k bpd	1 PBMR[9]
SAGD Steam and Electricity	100k bpd	2 PBMRs[10]
SAGD Steam and Electricity	200k bpd	4 PBMRs
Surface Mining Steam, Heat, and Electricity	200k bpd	1 CANDU 6 or 1 ACR-700 or 3 PBMRs
Electricity	728 MWe	Enhanced CANDU 6
Electricity	703 MWe	ACR-700
Electricity	1150 MWe	ACR-1000
Electricity	165 MWe	PBMR

[9] Output varies slightly depending on whether steam only or cogeneration solution is employed.
[10] Output varies slightly depending on whether steam only or cogeneration solution is employed.

6 Nuclear Safety

6.1 Safety of Nuclear Energy Options Evaluated

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" [53].*

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 from an accident at a nuclear power plant. 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 and are designed with containments and other safeguards. Three Mile Island, the only major nuclear power reactor 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 has intrinsic safety features that make it impossible for any Chernobyl or Three Mile Island type of accident to occur.

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 [55].

6.1.1 Enhanced CANDU 6

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 reactor cooling and emergency systems are designed to maintain cooling in the event of an accident and thereby preventing core melting. The system 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 which help to prevent core overheating and melting. As a final physical barrier, the robust containment of the CANDU is designed to contain any harmful materials under accident conditions. The CANDU traditionally has an exclusion zone of a 1km radius that is owned by the utility and surrounded by a fence [54]. 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 [56]. The primary emergency planning zone is the area in which communications and evacuation plans should be prepared for immediate deployment in the case of a maximum credible accident. For the CANDU reactors, this primary emergency planning zone is approximately defined to comprise the region within a 10km radius of the reactor building [54].

6.1.2 Advanced CANDU Reactor

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 neutron 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 [57]. 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 16.

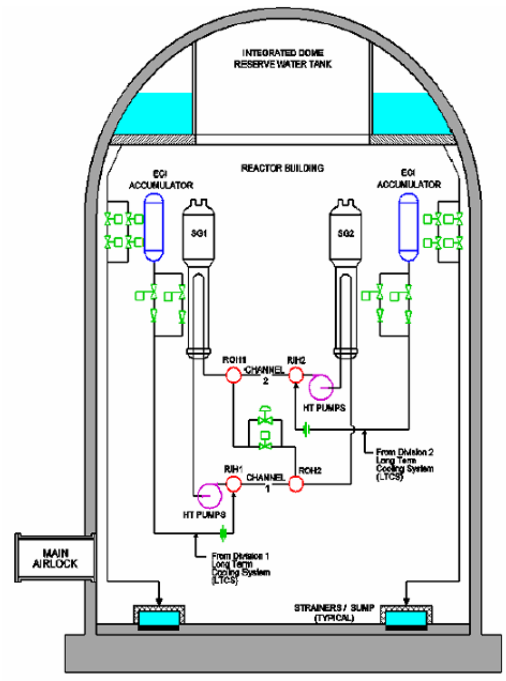

Figure 16: ACR Emergency Core Cooling System

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. Compared with it predecessor, the CANDU 6, the ACR-700 has a very small emergency planning zone with a radius of 500 m (versus 10 km for the CANDU).

6.1.3 Pebble Bed Modular Reactor

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 waste 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 naturally. The reactor is designed such that there is enough passive cooling during 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 still possible (however remote) for water cooled reactors. Due to the configuration of the fuel and the reactor, the PBMR fuel will not melt even if all of the helium coolant and active cooling systems are lost. Should the reactor lose all cooling flow, the reactor will shut itself down without any operator action due to its unique design.

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 center reflector. The control rods in the outer reflector are used to control the PBMR power level under normal operating conditions and can be fully inserted to shut down the reactor if needed. If reactor control were lost, gravity could be used to lower the control rods to the fully inserted position with no mechanical assistance.

This inherent safety combined with the design safety criteria allows the reactor to be located adjacent to other industrial operations with only a small emergency planning zone of 400 meters and thus no need for extensive emergency evacuation planning beyond that of other typical industrial facilities.

6.2 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 project developers to the Canadian Nuclear Safety Regulator.

As these reactor designs have matured, the risk of reactor failure has been greatly reduced over past designs. The results show that the likelihood of a major CANDU accident releasing any significant radiation is on the order of 10^{-6} events per year. At that frequency, the resulting accident radiation release is still below the levels that epidemiological data suggest have any biological effect. The PBMR results show even lower doses at comparable risk levels. The issue of possible land contamination is addressed by the emergency planning zone boundary which for the PBMR is 400 m, for the Enhanced CANDU 6 is 10 km, and for the Advanced CANDU reactors is 500 m. Should such an unlikely event occur, the impacts would be limited by the design of the plant itself which would be site specific. Co-location of nuclear facilities with other industries such as oil refineries or chemical plants must address the potential impact of the other facility on the nuclear plant since fires and accidents releasing chemicals and explosions are much more likely than nuclear accidents. This question will likely be raised by nuclear regulators when such configurations are proposed.

7 Licensing a New Nuclear Power Plant in Canada

7.1 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 applications for new nuclear reactor construction have been submitted since the 1980's. 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 [48].

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 intervenors 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 determine that the reactor design is such that the reactor would operate safely before the construction begins. 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 the approved 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 redundancy, but if an agreement could not be reached, there would be a provincial EA that would also need to be filed and approved [50]. 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 [49].

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 generators, 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.

7.2 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 [50].

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 [38].

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. By the time the CNSC would be considering the pebble bed reactor, there will have been significant regulatory interaction with the South African and the US Nuclear Regulatory Commission upon which to build a regulatory safety case for the PBMR technology. In addition, there is considerable experience in licensing gas-cooled reactors in the U.K., and some of this experience is embedded in CNSC staff.

7.3 CNSC Workforce Shortage

New reactor applications submitted to the CNSC could face delays due to inadequate staffing at CNSC. 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 [52]. 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 [52]."

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 a limited number of qualified individuals.

8 Economic Analysis

Economic analysis is performed for two scenarios in detail in this section: electricity and steam production. Hydrogen was not included since it was deemed that the best option was to continue to use steam methane reforming in the short term with the future possibility of using nuclear heat in that process but it was not evaluated for cost effectiveness.

8.1 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 14 through 19. 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. For simplicity, construction for any project was assumed to start in 2010 in the Edmonton area where it is most likely such a plant might be built. Regional labor adjustments were made to the base costs for overnight capital and for operations and maintenance. Overnight capital was assumed to be 40% labor-related, and for the location of an electric plant in Edmonton, the labor rates were assumed to be 50% above the base rate provided for a site in Ontario for CANDUs and at a coastal location for the PBMR. Thus, the overnight capital costs were increased by 20%. Similarly, O&M was assumed to be 50% labor, and so was increased 25% over the base cost.

Table 14: 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	0.144 in current dollars (Canadian)

Table 15: Assumptions Made in Calculating the Capital Charge Rate for the Natural Gas Electric 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	0.152 in current CAD

Table 16: Assumptions Specified for the Combined Cycle Natural Gas Plant

Generation (MWe)	100
Overnight $/kWe in Ontario	900
Overnight $/kWe in Edmonton, Alberta[2]	1080
Construction Period	2 years
Construction Interest	12.71% on ½ of construction period escalation of overnight costs
O&M in Ontario	$8 million per year[1]
O&M in Edmonton[3]	$10 million per year
Heat Rate (btu/kWh)	6800
Natural Gas Price	Varies
Natural Gas Price Nominal Escalation	2% above inflation

[1] Source: "Electricity Generation Technologies: Performance and Cost Characteristics" Prepared for the Ontario Power Authority by the Canadian Energy Research Institute, August 2005.
[2]A 20% penalty is applied to account for the increase in labor rates for Edmonton. This is based on the assumption that labor costs account for 40% of overnight costs, and labor rates are 50% higher in Edmonton than Ontario
[3]A 25% penalty is applied to account for the increase in labor rates for Edmonton. This is based on the assumption that labor costs account for 50% of O&M costs, and labor rates are 50% higher in Edmonton than Ontario.

Table 17: Assumptions Specified for the Enhanced CANDU 6 Nuclear Electric Plant

Generation (MWe)	728
Overnight $/kWe in Ontario	3375[1]
Overnight $/kWe in Edmonton, Alberta[2]	4050
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 in Ontario	$90 million per year [1]
O&M in Edmonton[3]	$112.5 million per year
Nuclear Fuel Cost	3.75 $/MWh [1]
Nuclear Fuel Price Nominal Escalation	0.5% above inflation

[1]Source: "Electricity Generation Technologies: Performance and Cost Characteristics" Prepared for the Ontario Power Authority by the Canadian Energy Research Institute, August 2005.
[2]A 20% penalty is applied to account for the increase in labor rates for Edmonton. This is based on the assumption that labor costs account for 40% of overnight costs, and labor rates are 50% higher in Edmonton than Ontario.
[3]A 25% penalty is applied to account for the increase in labor rates for Edmonton. This is based on the assumption that labor costs account for 50% of O&M costs, and labor rates are 50% higher in Edmonton than Ontario.

Table 18: Assumptions Specified for the ACR-700 Nuclear Electric Plant

Generation (MWe)	703
Overnight $/kWe	2740 (CERI) [1]
Overnight $/kWe in Edmonton, Alberta[2]	3288
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 in Ontario	$100 million per year[1]
O&M in Edmonton[3]	$125 million per year
Nuclear Fuel Cost	5.45 $/MWh[1]
Nuclear Fuel Price Nominal Escalation	0.5% above inflation

[1] Source: "Electricity Generation Technologies: Performance and Cost Characteristics" Prepared for the Ontario Power Authority by the Canadian Energy Research Institute, August 2005.
[2]A 20% penalty is applied to account for the increase in labor rates for Edmonton. This is based on the assumption that labor costs account for 40% of overnight costs, and labor rates are 50% higher in Edmonton than Ontario.

[3]A 25% penalty is applied to account for the increase in labor rates for Edmonton. This is based on the assumption that labor costs account for 50% of O&M costs, and labor rates are 50% higher in Edmonton than Ontario.

Table 19: Assumptions Specified for the PBMR Nuclear Electric Plant

Generation (MWe) [1]	172
Overnight $/kWe for a 4-module plant	3333
Overnight $/kWe for a single module plant[2]	4000
Overnight $/kWe in Edmonton, Alberta[3] (single module)	4800
Construction Period	3 years
Construction Interest	12.71% on ½ of construction period escalation of overnight costs
O&M at the Base Labor Rate	$10.5 million per year[1]
O&M in Edmonton[4]	$13.13 million per year
Nuclear Fuel Cost	$21.25 million year[1]
Nuclear Fuel Price Nominal Escalation	0.5% above inflation

[1] Source: Pebble Bed Modular Reactor (Pty) Ltd.
[2]A 20% penalty is applied to account for the increase in costs for a single-module plant over a 4-module plant. This penalty is due to the loss of economies of shared systems.
[3]A 20% penalty is applied to account for the increase in labor rates for Edmonton. This is based on the assumption that labor costs account for 40% of overnight costs, and labor rates are 50% higher in Edmonton than in the base case.
[4]A 25% penalty is applied to account for the increase in labor rates for Edmonton. This is based on the assumption that labor costs account for 50% of O&M costs, and labor rates are 50% higher in Edmonton than Ontario.

The reader may note that the operating and maintenance costs for the PBMR are unusually low for a nuclear power plant. Low O&M cost is a design objective for the PBMR and for Generation IV systems, and is based on the reduction in the number of systems needed to run the reactor safely.

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 $10.15, $12.10, and $12.65 for the ACR-700, CANDU 6, and PBMR, respectively. This analysis assumes that natural gas prices are assumed to escalate at 2.0% above inflation over the life of these projects. These results are illustrated graphically in Figure 17.

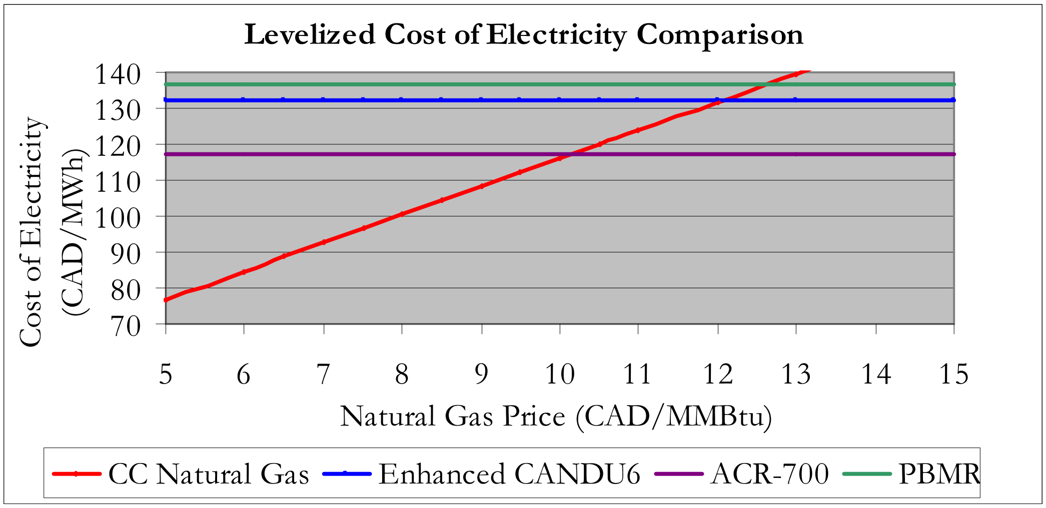

Figure 17: Levelized Cost of Electricity Comparison

A sensitivity analysis was also performed on the overnight capital costs of the nuclear power plants since there is much speculation as to what the capital costs might actually be. 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 20%, 30%, 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 $5/MMBtu natural gas, and then at $11/MMBtu natural gas, and the results are shown below in Figure 18 and Figure 19.

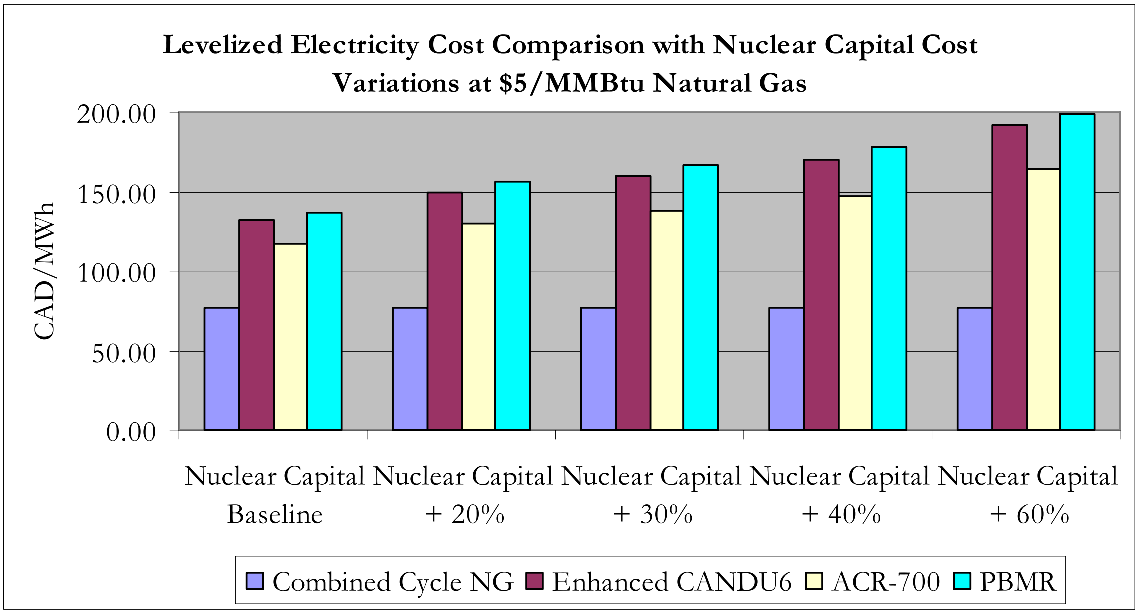

Figure 18: Levelized Cost of Electricity with Varying Nuclear Capital Costs at $5/MMBtu Natural Gas

In the $5 gas case, none of the nuclear plants were found to be competitive at the baseline capital cost.

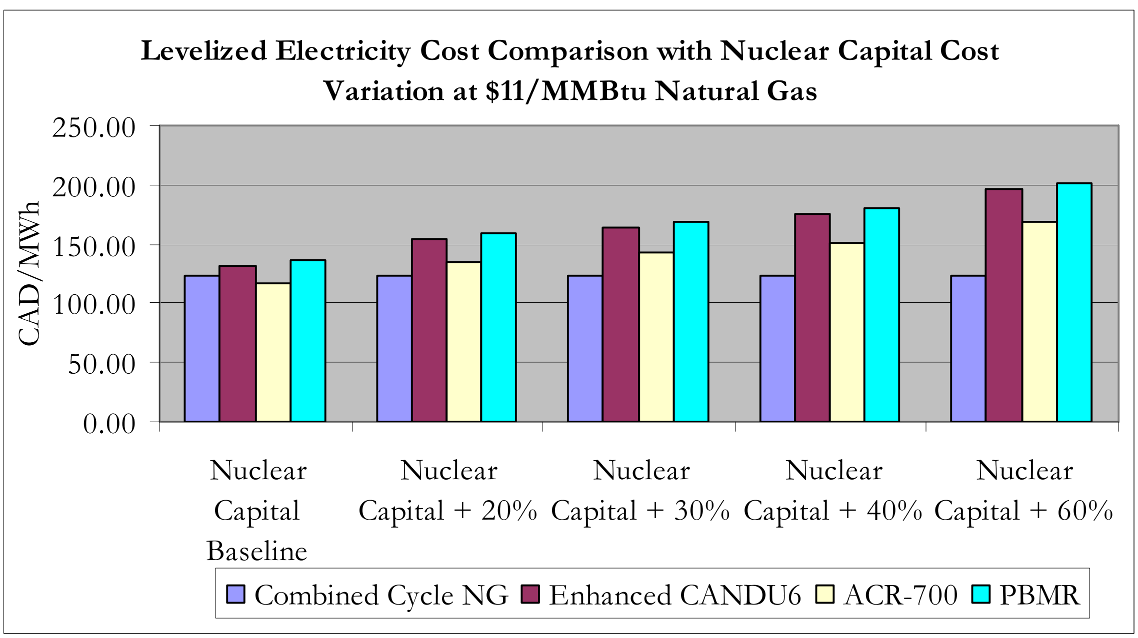

Figure 19: Levelized Cost of Electricity with Varying Nuclear Capital Costs at $11/MMBtu Natural Gas

In the $11 gas case, the ACR-700 was found to be competitive at the baseline capital costs, but at a 20% overrun it was slightly more expensive than natural gas.

It should be noted that other sensitivities should be considered in the economic evaluation. The cost of capital is a significant parameter affecting the cost of nuclear and other capital intensive projects. Alternative financing mechanisms that reduce the cost of capital will have a dramatic impact on the levelized cost. Should public or government support in the form of loan guarantees, low interest loans, or low interest environmental bonds be made available, the cost of the nuclear option would be greatly reduced. In addition, the future rate of natural gas price growth is also a very important parameter for which sensitivity studies need to be made to fully appreciate the economics of alternatives.

8.2 Steam Production

Estimating the costs of the steam production plants was difficult because the data available publicly is generally applicable to electric plants. Adjustments were made to account for two effects. First, the movement from Edmonton (for an electric plant) to Fort McMurray (for a steam plant) was predicted to increase labor rates from 50% over base rates to 100% over base rates. Additionally, the conversion from an electric power plant to a steam plant eliminates a number of expensive systems, reducing the overall cost of the plant. 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 basis for that assumption is that the typical light water reator has approximately a 60/40 division between the steam plant and the electricity generating plant, as illustrated in Table 20. Thus, the assumption that the nuclear heat plant has a cost two-thirds that of the nuclear electric plant is conservative, since it is less favorable to the economics of the steam plant than a 60/40 split. The cost adjustments made to the nuclear plants are shown in Table 21.

Table 20: Typical Allocation of Costs for an LWR

Project Cost Component	Percentage of Overnight Project Costs	Overall Percentage Allocated to the Steam Plant
Reactor Equipment	30	30
Balance of Plant Equipment	24	4
Structures and Construction	20	13
Owner’s and other Indirects	26	13
Total	100	60

Table 21: Cost Adjustments for the Nuclear Steam Plant

	Enhanced CANDU 6	ACR-700	PBMR
Overnight $/kWe (equivalent) [1]	3150	2557	3733
O&M	$135 million/yr	$150 million/yr	$15.75 million/yr

[1] Equivalent represents the 'would-be' electric power of the plant using the actual MWth and the efficiency of that plant's conversion cycle in the electric case. This notation is chosen so that the relative cost can be compared with that of the nuclear electric plant.

The steam production assumed for each plant is given in Table 22 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 20 [59].

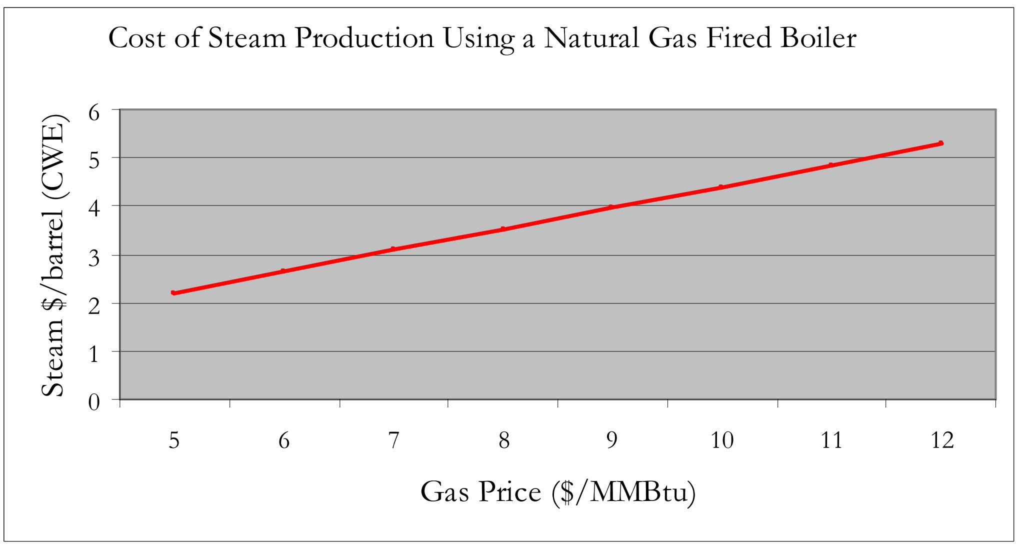

Figure 20: Cost of Steam Production from a Natural Gas Fired Boiler

Table 22: 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
500 MWth PBMR	130,000

The baseline cost to produce one barrel of steam (Cold Water Equivalent, or CWE) from the nuclear reactors was $3.02 for the Enhanced CANDU 6, $2.49 for the ACR-700, and $2.97 for the PBMR. For the natural gas plant, at $5/MMBtu gas, the cost found was $2.20. The breakeven natural gas prices were $6.85/MMBtu for the Enhanced CANDU

6, $5.65/MMBtu for the ACR-700, and $6.75/MMBtu for the PBMR. These results are shown in Figure 21 below. For reference, the June 2007 average NYMEX natural gas price was approximately $ 7/MMBtu.

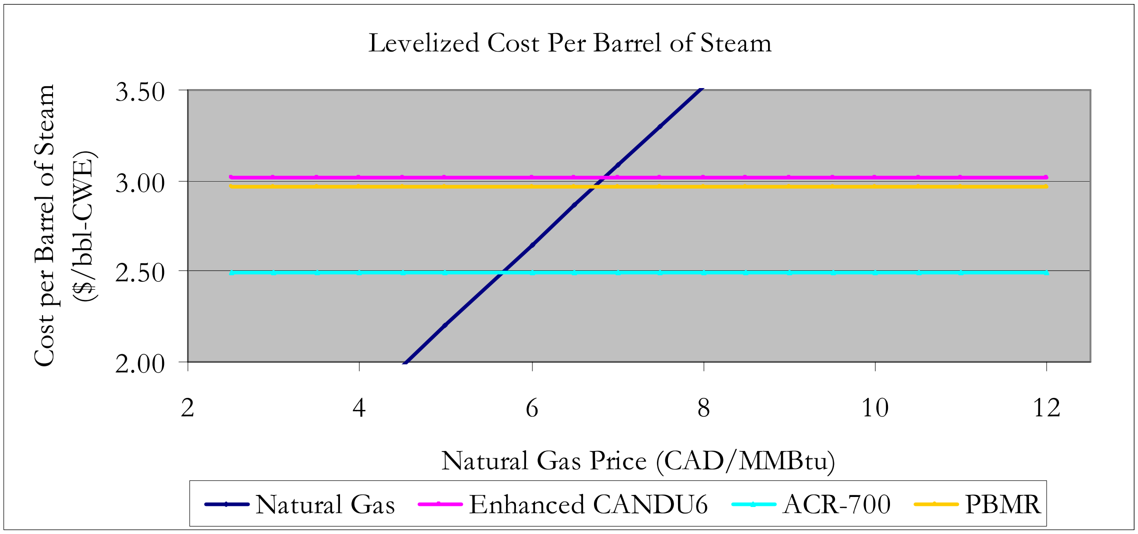

Figure 21: Levelized Cost per Barrel of Steam

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 20%, 30%, 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 $5/MMBtu natural gas and for $11/MMBtu natural gas, and the results are shown below in Figure 22 and Figure 23.

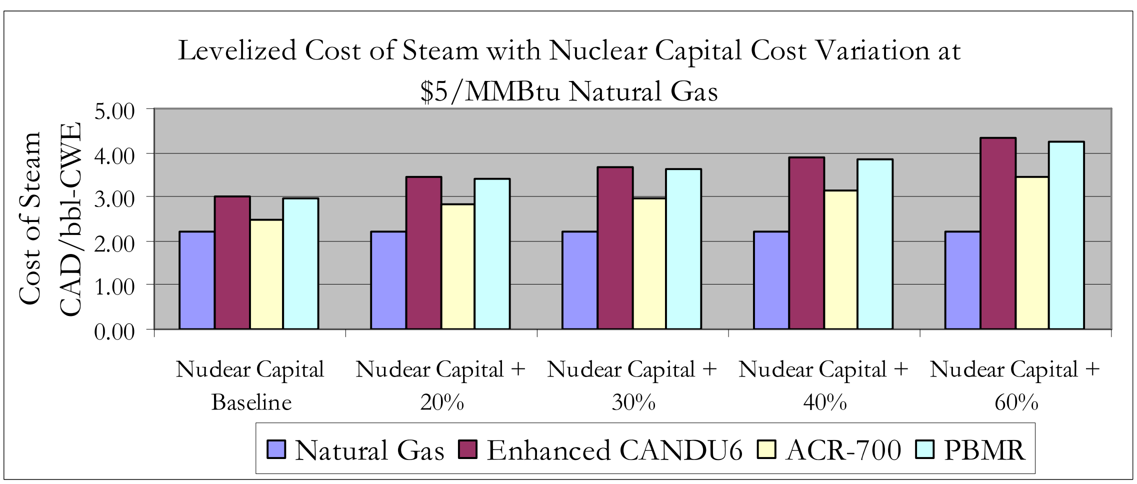

Figure 22: Levelized Cost of Steam Production with Varying Nuclear Capital Costs ($5 NG)

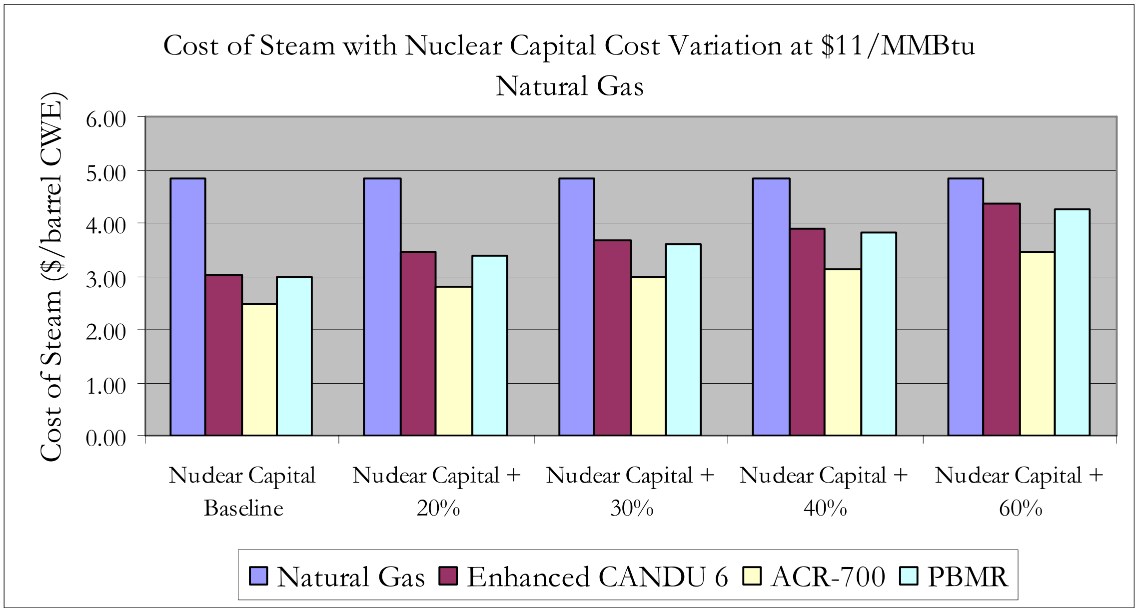

Figure 23: Levelized Cost of Steam Production with Varying Nuclear Capital Costs ($11 NG)

In the $5 gas case, none of the nuclear plants proved to be more economic than a natural gas plant. In the $11 gas case, the results showed that the costs for producing steam with a nuclear plant were much less expensive than natural gas fired production, even when the capital costs were overrun by 60%. It is clear that nuclear steam can be competitive with natural gas at foreseeable gas prices, even when great risks are assumed in the capital costs. Nuclear generation at the assumed costs is not shown to be competitive with natural gas for production of electricity until gas prices are as high as $ 10 /MMBtu. The likely reasons for this distinction lie in the very high efficiencies of the natural gas combined cycle electric plant versus the lower efficiencies and wasted heat associated with a nuclear electric power plant. In the steam case, however, it is much simpler to utilize the full heat output of the nuclear plant, and the comparison with a one-through natural gas boiler is favorable.

This economic analysis has been based on firm foundations with capital costs that are believed to be accurate given the commodity prices at the time of their estimation. However, the recent surge in materials costs affects all large construction projects, and will likely raise the costs of any project, including coal and natural gas plants. When Duke Energy began planning for the construction of two 800 MW coal plants in North Carolina (2004), the cost estimate was for $2 billion. In 2006 it was $3 billion, and in 2007 one unit was canceled and the price for a single unit was projected to be $1.83 billion. This is indicative of the general trend of escalating prices on materials costs throughout North America. When combined with the elevated labor costs of the Fort McMurray area, the resulting project will tend to be much more expensive now than may have been expected ten years ago.

9 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 given the lack of nuclear operating experience. 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 to provide energy for specific oil sands applications under contract. 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 hold the nuclear license and 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 secure the labor for construction and operation relieving the oil sands companies of the obligations.

Depending on the business interests of the oil sands company, participation in equity ownership may be desirable to have some control over 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 owned 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 arrangement with multiple owners representing commercial stakeholders might be considered for oil sands companies to provide an appropriate commercial framework especially for an electric generating station.

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, the oil sands industry should benefit from the development of options, from which to choose in the event of restrictions on their operations. These restrictions will most likely come in carbon emission limitations or taxes, and high price or restrictions on natural gas use and limitations on the use of water. To be prepared to address these 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 an alternative. The initial conceptual design process is not expensive but can 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.

10 Socioeconomic Effects

The introduction of nuclear energy into the oil sands industry would have a number of positive socioeconomic effects. Should nuclear energy use lower the operating costs of the oil sands projects, the royalties paid to the province of Alberta could 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 [58]. 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 workforce base in Alberta. The shortage of local skilled 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 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 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.

11 Challenges for Nuclear Energy in the Oil Sands

11.1 Public Acceptance

The perception that nuclear power suffers from poor public acceptance may be incorrect. Particularly in North America after the Three Mile Island accident in 1979, there was a distinctly higher level of disapproval in the public than before or since. However, most people recognize now that TMI resulted in no negative health effects and only caused insignificant off-site radiation release. Nonetheless, nuclear power has generated public concern over the years. This concern has caused many delays in nuclear power plant construction as well as the total cancellation of some projects in the US after the Three Mile Island accident. However, that perception is changing due in large part to the excellent operating performance of nuclear plants since Three Mile Island and the concern about global warming. In the United States close to 70% of the population believe that nuclear energy should play a role in its future energy plans according to a public opinion survey conducted in 2006 [64].

Nuclear power is carefully regulated and monitored for continuing safety performance. Nonetheless, there is always risk in all endeavors. It is the challenge of all technologies to minimize that risk in comparison to other risks people normally accept but sometimes do not recognize.

According to Wayne Henuset of Energy Alberta, a poll of 500 Albertans that he commissioned in December 2005 indicated that 42% of respondents were in favor of nuclear power and 33% were neutral [62]. While this certainly does not indicate overwhelming support for nuclear power in Alberta, it does indicate that up to 75% are currently willing to consider the option. Providing the public with educational materials and information about currently operating nuclear power plants and the changes that have been made in the industry since the 1970s would enable more people to understand the technology and more effectively judge the merits and disadvantages of its use. New technologies that have higher levels of intrinsic safety could increase public acceptance if communicated properly.

The public is critical of the environmental impacts of the oil sands development at this time. According to a poll commissioned by the Pembina Institute [60], 71% of Albertans believe that the government should suspend further oil sands development until infrastructure and environmental management issues are addressed. 85% would like to see increased government investment in environmental protection in the oil sands. 92% believe that oil sands companies should be required to reduce GHG emissions in each of their plants, 70% feel so strongly, while 22% feel so moderately [60][61]. 70% are in favor of absolute reductions, while only 20% believe that intensity reductions (per barrel of oil produced) are a good measure [60].

The Alberta public's opposition to the environmental harm caused by the oil sands, particularly in GHG emissions, could reflect support for nuclear energy use in the oil sands. Since nuclear energy would significantly reduce absolute emissions in Alberta if it replaced other energy sources, it is a clear answer to some of the public's concerns.

11.2 Transportation Challenges

The Enhanced CANDU reactor has some very large components that would be difficult to transport to a site near Fort McMurray and Edmonton which 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.

The calandria vessel for the ACR-700 is considerably smaller than that for either the CANDU 6 or the ACR-1000. 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.

The transportation options for the PBMR are the same as those for the Enhanced CANDU 6. The core barrel, the largest diameter (7.5m) single piece of the PBMR, is too large for rail travel, and so would need to be barged.

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 [39][40].

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 24 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 24: 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
Right (© Nathan Daniel Holmes 2005); Left (© 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 [41]. While the transportation of components poses a challenge, it does not seem to be insurmountable

11.3 Construction Challenges

Construction in the Ft. McMurray area pose additional challenges that are well understood by the industry. These complications for the construction phase include seasonal weather patterns and the current high demand for skilled labor. It is not clear whether the current trend to very high labor costs will abate over the next decade as growth rates stabilize and the labor market adjusts.

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. Nuclear construction would face the same challenges controlling other developments in that region.

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. 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 if possible away from easy access to shipping [57]. 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.

The PBMR does not present any prohibitive construction difficulties when compared to the CANDU reactors or general construction in the area..

11.4 Workforce Issues

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 [9].

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 [13]. 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 [7][8][10][11]. 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 [12].

As discussed in Section 10, the construction of a nuclear energy plant will require a significant number of construction workers and nuclear plant operating and maintenance staff. Special considerations will be needed to attract the level of worker needed for construction and sustained level low turnover operating staff. This is viewed as a priority area for future nuclear development plans in Alberta which needs to be explored further in the context of an overall implementation plan for the introduction of nuclear energy into the oil sands business.

12 Advantages for the Oil Sands with Nuclear Energy

12.1 CO_2 Emission Reductions

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 range of nuclear applications from simple steam production to a complete integrated plant producing electricity and energy for hydrogen production offers the capability of significant CO_2 emission avoidance by displacing natural gas or other fuels.

A 3000 MWth (1000 MWe) 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 over 4 million metrico tons of CO_2 per year. Shown in Table 23 are the potential CO_2 emissions reductions 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 million 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 23: 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
1 PBMR	50k bpd SAGD	Steam and Electricity	1.5×10^6	63×10^6
2 PBMRs	100k bpd SAGD	Steam and Electricity	3.1×10^6	125×10^6
4 PBMRs	200k bpd SAGD	Steam and Electricity	6.2×10^6	250×10^6
Enhanced CANDU 6	740 MWe	Electricity	2.2×10^6	86×10^6
ACR-700	753 MWe	Electricity	2.2×10^6	87×10^6
ACR-1000	1200 MWe	Electricity	3.5×10^6	140×10^6
PBMR	165 MWe	Electricity	0.5×10^6	19×10^6

This data is also illustrated graphically in Figure 25 where each data point corresponds to the same scenarios as that shown in Table 23. In the case of the windmills, the last data point, included for the reader's reference, each windmill is assumed to have a rated capacity of 1 MW (electricity supply only) and a capacity factor of 25%.

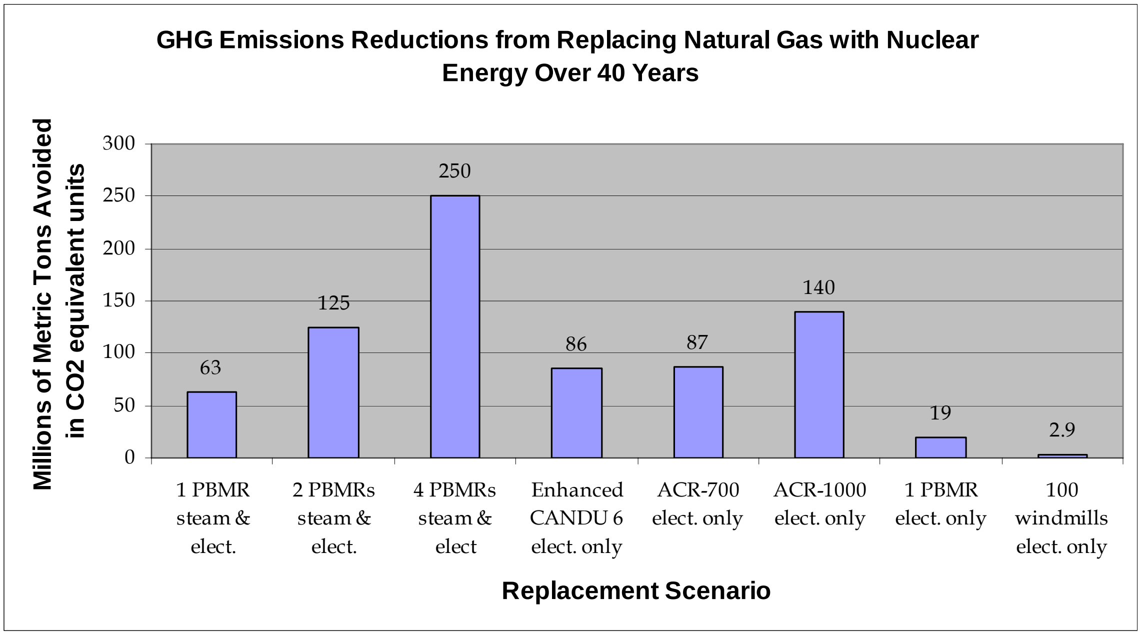

Figure 25: Emissions Reductions of Replacement of Natural Gas with Nuclear Energy

Nuclear energy is a proven technology that has been the largest source of carbon free emission energy in the world. Nuclear energy provided over 16% of the world's electricity supply in 2006. On a world wide basis, this generation avoided the emission of over 2 billion metric tons of CO_2 per year. Carbon capture and sequestration is being considered as another CO_2 mitigation strategy. Carbon capture and sequestration requires that a chemical plant be added to capture and separate CO_2 from the flue gas and then compress it to supercritical pressures for transport and injection into deep geological formations. Carbon capture and sequestration requires about 30% of the energy of the basic source for capture and disposal and thus adds to the cost of the final product.

According to the MIT Future of Coal study [65], there are still a number of broad concerns regarding technical integration of CO_2 capture storage and sequestration technologies in large production operations. In addition, concerns about injection of CO_2 in terms of leakage and ultimate long term safety of geological disposal need to be addressed.

The use of carbon sequestration will require new regulatory structures and consider the environmental and potential safety risks of disposing of massive amounts of carbon dioxide in the ground.

Some relative electricity cost comparison estimates for carbon capture are shown in Table 24 for pulverized coal and Integrated Gasification Combined Cycle power stations. These costs are for the capture of the CO_2 stream only, and do not include piping or sequestration costs. They assume a 90% capture rate. All costs are normalized with respect to the reference cost, which is that of a pulverized coal plant with no capture.

Each case compares the relative cost of the electricity produced by a capture technology compared with the reference case. The costs are for adding capture capability only – not sequestration or transportation, as mentioned above. The capture is predicted to add anywhere from 33% to 84% to the cost of the electricity.

Table 24: Relative Cost of Electricity with and without CO_2 Capture

Relative Cost of Electricity: Pulverized Coal and IGCC, with and without CO_2 Capture				
	MIT	GTC	AEP	GE
PC no-capture, reference	1.0	1.0	1.0	1.0
IGCC no-capture	1.05	1.11	1.08	1.06
IGCC capture	1.35	1.39	1.52	1.33
PC capture	1.60	1.69	1.84	1.58

[1] Includes results from: The MIT Coal Study (MIT), the Gasification Technology Council (GTC), American Electric Power (AEP), and General Electric (GE) [65]

12.2 Economics and Fuel Price Instability

As discussed in Section 8, nuclear energy could offer competitive energy at current natural gas prices for steam delivery, and at possible future natural gas prices in the case of electricity production. Additionally, nuclear energy offers price stability that is not available from natural gas. Natural gas volatility is a major concern for oil sands companies because the fuel costs are such a large portion of the production costs. For nuclear power, the capital costs are the most significant. While those costs may not be 100% predictable before the plant is built, the production costs are predictable once the plant is operating which is viewed as a major advantage for the plant's 40 year operating life.

13 Conclusions

The purpose of this paper 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 was chosen for this analysis since it is the most developed.

Several specific nuclear energy applications were assessed from steam only and steam and electricity 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-MHR could be used but require more development.

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 surface mining application, the reactors were analyzed for their suitability to provide heat and electricity to a surface 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 surface mining projects. The CANDU 6 and the ACR-700 were found to be better sized for a surface 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 surface 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 surface 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. Currently there is an excess of electricity generation in northern Alberta, so unless that changes, it may not be sensible to introduce a large electrical power plant.

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 processes. 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 $10.15, $12.10, and $12.65 Canadian for the ACR-700, CANDU 6, and PBMR, respectively. An exchange rate of 0.90 was used, and so in US dollars those prices are equivalent to USD 9.14, USD 10.89, and USD 11.39. The assumptions implicit in this analysis are set forth in Section 8. The economic analyses for steam production using nuclear power were favorable for all of the reactor choices. The breakeven natural gas prices for steam production were $5.65/MMBtu for the ACR-700, $6.85/MMBtu for the Enhanced CANDU 6, and $6.75/MMBtu for the PBMR (USD 5.08, USD 6.16, and USD 6.07, respectively). The likely reasons for this distinction lie in the very high efficiencies of the natural gas combined cycle electric plant versus the lower efficiencies and wasted heat associated with a nuclear electric power plant. In the steam case, however, it is much simpler to utilize the full heat output of the nuclear plant, and the comparison with a one-through natural gas boiler is favorable.

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 surface 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 2.1 million metric tons per year for an ACR-700, and 3.5 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 oil 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 need to be demonstrated in both the licensing process and in the opinion of the public. The safety comparison shows that the advanced design of the pebble bed reactor with its ability to naturally shut down upon a loss of coolant accident and no possibility of a meltdown might be viewed by the public more favorably than older designs.

The nuclear licensing process is found to be fairly simple and technology-neutral. 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 high-temperature gas reactor could be licensed in Canada based on generic functional risk informed safety requirements, although the lack of existing expertise regarding HTGRs within the CNSC would require more time for licensing or they would need to contract for the necessary expertise.

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 in the oil sands business is 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.

14 Recommendations

It is recommended that a number of development initiatives be supported by the Alberta government, 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. The decision to install nuclear capacity is 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, and would include a start-up analysis of the steam requirements of a field, and the eventual blowdown requirements. A more detailed study should also focus carefully on the ability of a nuclear plant to be modularized and then assembled onsite.

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 sands field is exhausted.

5. While the effects of a carbon penalty were not considered in the economic evaluation in this paper, 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. It may be economically advantageous to build a nuclear plant simply for the sake of selling CO_2 credits to fossil fuel utilities, and this possibility should be explored fully.

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16 Appendix

Sample Aspen™ Model

The ASPEN Plus™ software was used to model the mass and energy balances for the proposed nuclear energy options. Shown on Figure 26 is the pebble bed model of pressures, temperatures and steam flows for the steam only option.

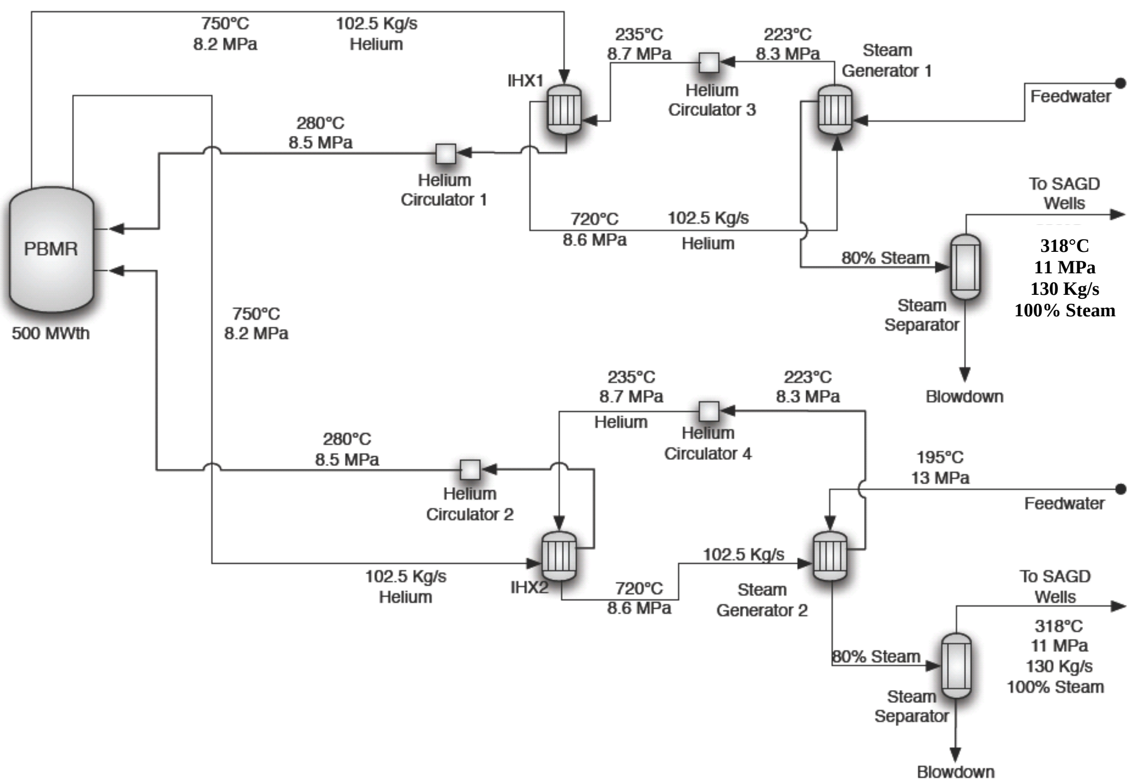

Figure 26: Pebble Bed Steam Supply Flowchart Used in Analysis

"Aspen Plus is a process modeling tool for steady state simulation, design, performance monitoring, optimization and business planning for chemicals, specialty chemicals, petrochemicals and metallurgy industries…. Aspen Plus is a component of the Aspen Engineering Suite™ (AES™), an integrated set of products.… Aspen Plus contains data, physical properties, unit operation models, built-in defaults, reports and other features and capabilities developed for specific industrial applications…. Aspen Plus uses thermophysical property models, data and estimation methods available in Aspen Properties™. It has design specification capabilities to automatically calculate operating conditions or equipment parameters to meet specified performance targets… and allows for detailed heat exchanger design and rating [27]."