MPR ASSOCIATES INC.
ENGINEERS

MPR-3254
Revision 0
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Evaluation of High Temperature Reactors for Potential Application to Thermal In-situ Recovery of Oil Sands

Prepared for

Petroleum Technology Alliance Canada
Calgary, Alberta, CAN

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Executive Summary

Oil produced from the oil sands region in northern Alberta Canada is an increasingly important contributor to the world's oil supply. The thermal, in-situ recovery of bitumen from oil sands is an energy intensive process. Currently, most in-situ oil sands plants create steam for this process by burning natural gas, a high quality fuel with volatile pricing that is in demand for other uses such as home heating, electric power generation and chemical feedstock. Canada has made commitments to reduce atmospheric carbon dioxide emissions. These commitments, in combination with the desire by the oil sands producers to make better use of natural gas and other fossil fuels has resulted in interest among the Alberta oil sands producers in nuclear power as a source of oil sands process heat. For the current phase of this study, the Petroleum Association of Canada (PTAC) has contracted MPR Associates to evaluate the potential application of next-generation, high temperature reactors (HTRs) in this application.

This evaluation considered the potential application of three different HTR designs to a hypothetical, green-field, 120,000 barrel per day (bpd), thermal in-situ recovery plant located in the Athabasca oil sands fields in Alberta, Canada. The reactor designs considered were the:

- Toshiba "Super Safe, Small and Simple" (4S) liquid sodium-cooled reactor,
- General Atomics "Modular High Temperature Gas-cooled Reactor" (MHTGR) using prismatic-type fuel, and
- PBMR Pty Ltd Pebble Bed Modular Reactor (PBMR) which is a high temperature gas-cooled reactor using spherical fuel.

The hypothetical plant would generate high pressure steam for use in the steam assisted gravity drain (SAGD) method and would provide electricity required by the central processing plant, the field well pads and the HTRs themselves. It would be built in four 30,000 bpd stages, to be initiated at three-year intervals.

Each of the basic HTR technologies being considered has been previously proven by operation in a number of different reactors, and each is being developed for use in other applications, such as electricity production and hydrogen generation. The application of each of these technologies in a new reactor design to be applied to oil sands recovery, however, is considered to be developmental. In all cases, significant changes and unproven features and equipment would be required for the oil sand application.

The purpose of this evaluation was to determine whether the various technologies could be applied in the Alberta oil sands applications and to identify any significant differences among them in the following key areas:

- Capability: Each of the designs, when fully developed, is expected to be capable of delivering the steam and electricity required for oil sand process heat applications over the planned 30 year life of an oil sands project. In all three cases, the sizes of the individual reactors are such that they can be applied in stages to match steam and power demand consistent with typical staged development of oil sands projects.

- Nuclear Safety and Security: Each of the designs can de operated safely and securely.

- Environmental Impact: Each of the designs, when developed, is expected to have minimal adverse environmental impact. The likelihood and magnitude of radioactive releases are small.

- Licensability and Public Acceptance in Canada: All of the technologies are expected to be licensable in Canada, but the regulatory infrastructure in Canada is not currently in place for reactors of these types. Therefore, the regulatory and construction process is estimated to exceed the current nine-year expected span for new water-cooled reactors by about two years for these First-of-a-Kind HTR applications. Licensing and public acceptance is not expected to be a significant differentiator among the technologies

- Constructability: All of the technologies can be constructed at a remote northern Alberta site. There are construction tradeoffs between having a few large reactors and many small reactors. The PBMR and MHTGR designs have some very large components, for which transport to the site could be challenging and more affected by weather and other logistics factors than the 4S design. However, this transportation difference is expected to be manageable by effective planning, which may include an early decision to modify component design or assembly plans. While all of the designs are modular to some extent, the modularity features of the 4S are an advantage compared to the PBMR and MHTGR in minimizing the amount of on-site labor for construction. For all plants, delays in the construction schedule are in the critical path to initial criticality of the reactor.

- Operability and Reliability: As new plant design applications of advanced reactor technologies, each of the HTRs has great uncertainty in its overall operability, maintainability and reliability. MPR considers that it is premature to distinguish between these reactor types from an operability and maintainability standpoint.

- Capital and Operating Costs**:** Typically, nuclear power plants have much higher capital costs but much lower operating costs than conventional steam generation facilities. Although this same relationship is expected to be the case for the HTRs, both capital and operating costs are highly uncertain at this point since the HTR plant design concepts are at such an early stage for an oil sands application. Based on current HTR vendors' cost estimates, adjusted to be on a common basis, the overnight capital cost of a facility sized to support a 120,000 bpd oil sands plant should be about C$5 billion, or about C$3500 per kilowatt-thermal (2008 dollars). Operating and maintenance (O&M) costs are projected to be on the order of C$160 million to C$280 million per year, or about C$3.80 to C$6.70 per bbl of bitumen (at 95% of design capacity). MPR considers that it is premature to distinguish between these reactor types from a capital or operations cost standpoint.

- Deployment Readiness**:** Due to the current incomplete stage of development and the extended licensing process, none of the HTR designs are expected to be deployable prior to 2020. Of the three technology vendors, only PBMR has a large organization currently involved in completing a similar core design (to its oil sands plant) and constructing a demonstration reactor, but it has experienced many delays. None of the vendors have advanced the process heat plant version of their technology past the pre-conceptual design level. Another critical element of HTR deployment is qualification and production of fuel. Only PBMR has taken significant steps in this regard, but it remains many years away from producing sufficient fuel for a multi unit process heat reactor application.

MPR considers that construction of a full scale HTR oil sands process heat plant from any vendor will be a First-Of-A-Kind plant. In order to support construction of a First-of-a-Kind plant for the oil sands application, there are a number of activities in conceptual and detailed design, component testing, licensing, fuel development and qualification, operations readiness and ultimately construction that could affect the critical path. The lengthiest and most uncertain single critical path element is licensing, which controls the estimated 11 year time span (in Canada) for initial operation of the HTR plan. However, there are a number of parallel activities that would need to be initiated very promptly, as well, in order to construct a demonstration process heat plant even in the 2020 time frame. These include:

- Identification of Plant Operations Strategy: Initiating the licensing process requires that a nuclear plant operator be identified and engaged by the oil sands sponsor. This will likely be challenging due to the limited number of potential operators interested in third party operations of new reactor technologies.

- Process Heat Plant Component Design and Component Qualification Testing: Each of the candidate designs considered in this study requires some technology development and testing to convert high temperature reactor heat to steam. The extent to which component design and testing will need to be in series with licensing efforts is uncertain.

- Fuel Strategy**:** Fuel must be available in sufficient quantities from a reliable, qualified manufacturing facility. To meet this need, a new fuel manufacturing facility will need to be designed, licensed, constructed and qualified and then initial core loads of fuel produced. These activities collectively would be expected to take about as long as or longer than nuclear plant licensing.

This report concludes that any of the HTRs could be configured to meet the technical requirements for the oil sands recovery plant application. The three HTRs were difficult to distinguish from one another on an absolute basis; however, tradeoffs exist and technical and logistical differences exist which could provide a basis of preference by the oil sands developer. Other factors such as capability, resources and responsiveness of supporting organizations should also be considered in determining which, if any, of the HTRs should be considered for further evaluation.

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Acronyms and Abbreviations

4S	Toshiba Super Safe, Small and Simple Reactor
ABCTU	Alberta Building Trades Council of Unions
ABSA	Alberta Boiler Safety Association
AE	Alberta Energy
AE&I	Alberta Employment and Immigration
AECL	Atomic Energy of Canada Limited
AEI	Alberta Employment and Immigration
AENV	Alberta Environment
AGR	Advanced Gas Reactor
AIT	Alberta Infrastructure and Transportation
ALARA	As Low as Reasonably Achievable
AUC	Alberta Utilities Commission
AVR	Arbeitsgemeinschaft Versuchsreaktor
BFW	Boiler Feedwater
BFWOP	Boiler Feedwater Operating Practices
BL	Battery Limit
BN	Russian sodium-cooled fast reactor
bpd	Barrel Per Day
BWR	Boiling Water Reactor
C$	Canadian Dollars
CANDU	Canadian Deuterium Uranium
CCS	Carbon Capture and Storage
CDF	Core Damage Frequency

Acronyms and Abbreviations (cont'd.)

CEAA	Canadian Environmental Assessment
CEAA	Canadian Environmental Assessment Act
CLAC	Christian Labor Alliance of Canada
CNSC	Canadian Nuclear Safety Commission
CSS	Cyclic Steam Stimulation
CWE	Cold Water Equipment
DOE	Department of Energy
DPP	Demonstration Power Plant
EA	Environmental Assessment
EBR	Experimental Breeder Reactor
ECA	Energy Conversion Area
EFPY	Effective Full Power Year
EIA	Environmental Impact Assessment
EIS	Environmental Impact Statement
EM	Electro Magnetic
EMP	Electro Magnetic Pump
EPC	Engineering, Procurement, and Construction
EPCM	Engineering, Procurement, Construction, and Management
ERCB	Alberta Energy and Resources Conservation Board
EVST	Ex-Vessel Storage Tank
FEED	Front End Engineering Design
FFTF	Fast Flux Test Facility
FHSS	Fuel Handling and Storage System
GA	General Atomics
GVM	Gross Vehicle Movement

Acronyms and Abbreviations (cont'd.)

HP	High Pressure
HTGR	High -Temperature Gas Cooled Reactor
HTRs	High Temperature Reactors
IAEA	International Atomic Energy Agency
IHX	Intermediate Heat Exchanger
IMV	IMV Projects
IRACS	Intermediate Reactor Auxiliary Cooling System
JOYO	Japanese sodium-cooled fast breeder experimental reactor
JRP	Joint Review Panel
JSW	Japan Steel Works
kbpd	Thousands of barrels per day
kWe	Kilowatt Electric
kWt	Kilowatt Thermal
LC	License to Construct
LEU-TRISO	Low Enriched Uranium Triple-coated Isotropic
LO	License to Operate
LP	Low Pressure
LPS	License to Prepare Site
LWR	Light Water Reactor
MHR	Modular Helium Reactor
MHTGR	Modular High Temperature Gas-cooled Reactor
MMTCDE	Million Metric Tonnes of Carbon Dioxide Equivalent
MPa	Megapascal
MPR	MPR Associates, Inc.
MWe	Megawatt Electric

MWt	Megawatt Thermal
NEB	National Energy Board
NGNP	Next Generation Nuclear Plant
NI	Nuclear Island
NIAC	Nuclear Insurance Association of Canada
NLA	Nuclear Liability Act
NPP	Nuclear Power Plant
NRC	Nuclear Regulatory Commission
NSCA	Nuclear Safety and Control Act
NUREG	Nuclear Regulatory Document
NWMO	Nuclear Waste Management Organization
O&G	Oil and Gas
O&M	Operations and Maintenance
OHS	Occupational Health and Safety
OP	Operating Practices
OPG	Ontario Power Generation
OSP	Oil Sands Plant
OTSGs	Once-Through Steam Generators
PBMR	Pebble Bed Modular Reactor
PHTS	Primary Heat Transport System
PPDR	Pre-Project Design Review
PRISM	Power Reactor Innovative Small Module
PSID	Preliminary Safety Information Document
PTAC	Petroleum Technology Alliance Canada
Pty Ltd	Proprietary Company-Privately Owned not Public

PW	Produced Water
PWR	Pressurized Water Reactor
QA	Quality Assurance
RCCS	Reactor Cavity Cooling System
RCS	Reactivity Control System
RD	Regulatory Documents
REA	Rural Electrification Associations
RPV	Reactor Pressure Vessel
RSS	Reserve Shutdown System
RV	Reactor Vessel
RVACS	Reactor Vessel Auxiliary Cooling System
SAGD	Steam-Assisted Gravity Drainage
SCS	Shutdown Cooling System
SG	Steam Generator
SHTS	Secondary Heat Transport System
SOR	Steam to Oil Ratio
THTR	Thorium High Temperature Reactor
TRISO	Triple-Coated Isotropic
US or U.S.	United States
US$	Unites States Dollars
USA	Unites States of America
WT	Water Treatment
Wt%	Percentage by weight

1 Introduction

1.1 Background

The thermal, in-situ recovery of bitumen from oil sands is an energy intensive process. Currently, most thermal, in-situ plants create steam for this process by burning natural gas. Natural gas is in high demand for other uses such as electric power production, home heating and chemical feedstock. Burning natural gas also results in the emission of carbon dioxide, a greenhouse gas. In 2002, Canada ratified the Kyoto Protocol requiring it to reduce greenhouse gas emissions during the 2008-2012 to 6% below 1990 levels; however, as of 2006, emissions were 27% above 1990 levels. The projected emissions gap between the Kyoto Protocol commitment and business-as-usual is estimated at 256 million metric tonnes of carbon dioxide equivalent (MMTCDE) per year. In 2007, Canada’s updated environmental targets were issued and then augmented in 2008. The targets are intensity-based, with industrial sectors required to reduce their 2010 emissions intensity by 18% from 2006 levels, with continuous 2% improvement every subsequent year.

Notably, for oil sands producers and upgraders, specific and tougher requirements were set, including drastic cuts in emissions by 2018 for facilities that come into operation in 2012 or after. These cuts are based on emission levels theoretically achievable with carbon capture and storage (CCS), but the emission levels could also be met with other “green” technologies. As a result of these proposals, the government stated new emission targets of 20% below 2006 levels by 2020 (2% above 1990 levels) and 60-70% below 2006 levels by 2050. Meeting these targets will require substantial investment if Alberta is to sustain and grow bitumen production.

Canadian commitments to reduce atmospheric carbon emissions, in combination with these other considerations, led to studies of alternate energy sources to natural gas. This study evaluates the potential application of next-generation, high temperature reactors (HTRs) as alternative energy sources.

1.2 Purpose

The purpose of this study was to assess the feasibility and compare the merits of three different HTR designs as the energy source (providing both process steam and electricity) for a hypothetical, thermal, in-situ bitumen recovery plant using the Steam Assisted Gravity Drainage (SAGD) technology. The hypothetical plant was designated as a green-field 120,000 barrel per day (bpd) plant located in the Athabasca oil sands fields in Alberta, Canada. It would be built in four, 30,000 bpd stages, initiating operations at three year intervals.

The reactor designs considered were:

- Toshiba "Super Safe, Small and Simple" (4S), a high temperature, sodium-cooled reactor
- General Atomics (GA) Modular High Temperature Gas-cooled Reactor (MHTGR) using prismatic-type fuel
- PBMR Pty Ltd Pebble Bed Modular Reactor (PBMR), a high temperature gas-cooled reactor using spherical fuel.

The three HTR designs were evaluated based on their current state of design and development (e.g., plant size) and applied on a best fit basis to the hypothetical plant.

This study will provide the basis for possible selection by PTAC of one or more of the HTR designs for a subsequent life-cycle cost analysis comparison to a natural gas-powered oil sands plant.

1.3 APPROACH

The first step determined the requirements for the hypothetical thermal, in-situ plant including process functional and operational requirements, construction in the Alberta oil sands region, and public outreach for typical oil sands plants. This step included:

- Interactions with industry experts to establish key design parameters for the hypothetical plant, such as steam-to-oil ratio (SOR), steam conditions and feed water conditions
- Obtaining factual information about nuclear licensing and nuclear public outreach in Canada.

The second step established a set of criteria to be considered and used by MPR in evaluating the candidate designs and in developing the conclusions of this report. In addition, information was obtained by MPR from the three HTR vendors on how their technologies would best be applied to the hypothetical oil sands plant.

The third step evaluated the different designs regarding the ability to meet the required functional and operational requirements for the hypothetical plant, suitability to the remote site, licensability and public acceptance, capital cost, acceptability of safety, security and environmental impact, construction, operation, and readiness for implementation in the near future. These evaluations identified pros and cons of the individual designs for the particular application both relative to one another and on an absolute basis. The evaluations also identified methods for mitigating risks and uncertainties.

2
Conclusions and Summary

Three nuclear High Temperature Reactors (HTRs) were evaluated for potential application to thermal, in-situ recovery of bitumen in the Athabasca oil sands region of Alberta, using High Pressure (HP) Steam Assisted Gravity Drainage (SAGD), providing both process steam and electricity. For this evaluation, a hypothetical plant size of 120,000 bpd was assumed to be built in four stages of 30,000 bpd each, with three years between each stage. Assumed plant conditions included a steam to oil ratio (SOR) of 2.5, feed water from tower evaporators at 160°C pumped to the HTR site, and saturated steam at 9.5 MPa provided as output to the oil sands plant from the HTR site.

The three nuclear reactors that were evaluated were the Toshiba "Super Safe, Small and Simple" (4S) liquid sodium-cooled reactor, the General Atomics "Modular High Temperature Gas-cooled Reactor" (MHTGR) using prismatic-type fuel, and the PBMR Pty Ltd Pebble Bed Modular Reactor (PBMR) which is a high temperature gas-cooled reactor using spherical fuel.

2.1 OVERVIEW

2.1.1 Good Fit:

The report identifies the requirements for the hypothetical oil sands plant and shows how all three HTR conceptual design plants could be applied to satisfy the needs of the four stages of the oil sands plant. If the modular HTR plants perform as designed, they would provide a good match for the step-wise build up in energy needs of a major oil sands project. The ability to shift between steam production and electrical production can provide desirable flexibility for these plants to maintain production of bitumen over variable steam to oil ratios over the life of the oil fields.

2.1.2 Conceptual Plants Not Yet Ready:

These HTR plant design concepts have not yet been built and proven, although earlier versions of plants using these HTR technologies were demonstrated. They were originally designed for electric generation (gas-cooled and sodium cooled) or for fuel breeding (sodium-cooled) but are currently being adapted to process heat applications such as oil refining, chemical processing, and hydrogen generation. The customization of these designs for thermal in-situ oil sands recovery applications is still at an early conceptual stage. This precludes providing accurate comparisons between plant designs for construction costs, risks and schedules, and for evaluations of how the HTRs meet certain critical design criteria. As a result, for many of the evaluation criteria, the HTR designs could not be distinguished from one another.

2.1.3 Licensing is the Likely Limiting Step:

The earliest and most uncertain critical path element is licensing (see Section 6), which controls the estimated 11-year time span (of a First-of-a-Kind HTR plant) from initial license application until initial operation. This estimate has a high degree of uncertainty, as explained in Section 6, and it is about two years longer than the nine-year minimum time span for initial criticality predicted for licensing new water-cooled reactors in Canada. A significant amount of design and development effort, including component and fuel testing will be needed to support the licensing process. Furthermore, the HTR reactor is a new technology-type in Canada for which regulations and analytical models will have to be developed first and with which regulatory staff will have to be familiarized.

2.1.4 Pros/Cons

The report evaluates the three designs on the basis of critical criteria, risks, fit of the designs, cost and readiness to proceed. A summary of the key differences and the pros and cons of each HTR are identified and discussed in Table 2-1.

Table 2-1. HTR Pros and Cons

4S	
Pros	**Cons**
Transportation – The 4S features a small diameter, relatively light reactor vessel design that will be transportable to the site. Construction – The 4S modular design requires less onsite construction and fabrication required per reactor. Test Facility – A sodium test facility is currently available for the testing of 4S components. Toshiba Infrastructure – Toshiba has a large corporate infrastructure with respect to the design of new nuclear plants. However, it is currently devoted to light water reactor development.	Refueling – A refueling procedure does not currently exist. While on-site refueling is likely achievable, it will be challenged by the need to work with the sodium coolant. Maintenance – The inspection of double-walled piping and other components will be difficult and further challenged by the presence of the sodium coolant. Future Applications – The operating temperature capability of the 4S is too low to be viable in high temperature process heat applications such as upgrading or hydrogen generation. Fast reactor technology is a further departure from thermal reactors for CNSC regulators. Two plant designs and eleven reactors will add additional complexity for licensing, startup and operation. Steam-only and electric-only designs lack flexibility for shifting energy to provide additional steam when desired.

MHTGR	
Pros	**Cons**
Design Pedigree – The prismatic fuel and basic MHTGR core design has been licensed and operated successfully the US NRC. Design Maturity – The MHTGR electric plant design is relatively mature. A Preliminary Safety Information Document (PSID) was prepared and submitted to the US NRC in the 1980's. Future Applications – The capability of the MHTGR allows for the use of this design in high temperature process heat applications such as upgrading or hydrogen generation.	Transportation – GA has not focused on issues or strategies for transportation in the Athabasca area. Heavy and large reactor vessels will be very challenging and could require changes in manufacturing strategy and/or design. Refueling Schedule – The MHTGR requires a 30 day refueling outage every 18 months. This decreases plant availability and, as a result, bitumen recovery. Test Facility – A component test facility needs to be built or rented to develop the MHTGR design. Infrastructure – GA does not currently have the necessary engineering infrastructure in place to carry out this design. Fuel manufacturing capability of the 1980's has been scrapped and startup and certification of a new facility to make and use 18% enriched fuel lacks momentum or plans to begin.

PBMR	
Pros	**Cons**
Continuous refueling capability holds promise for reduced effort for refueling operations. Technology Development – PBMR has invested significant effort into technology development for the Demonstration Power Plant (DPP) in South Africa and many components are similar to those intended for an oil sands plant. Test Facility – PBMR has access to a component test facility used for the DPP but may not be able to acquire sufficient time to use it. Fuel Manufacturing – There is a fuel manufacturing plan in place for the DPP which will aid in developing a facility for oil sands plants. Licensing – PBMR has engaged U.S. and Canadian regulators regarding licensing strategies for a process heat plant. Future Applications – The capability of the PBMR allows for the use of this design in high temperature process heat applications such as upgrading or hydrogen generation.	Transportation – Heavy and large reactor vessels will be very challenging and will require close management and/or change in manufacturing strategy and design. Planned use of barges would require significant infrastructure changes and the practicality is uncertain. Fuel Handling – Long term success of the mechanical hardware necessary for continuous refueling capability has a high risk uncertainty due to operational consequences of failure. IHX – The PBMR intermediate heat exchanger (IHX) design is compact and uses thin plate heat exchanging surfaces, which will require new design methods and rules. Infrastructure – Nearly all of PBMR's sizeable infrastructure is devoted to the DPP effort as first priority. Issues unique to developing a process heat plant will require a strong influx of personnel for that purpose.

2.2 NEXT STEPS

2.2.1 Proceeding with Further Evaluation:

The purpose of the report was to provide an evaluation and comparison of three HTR designs for possible application to the hypothetical, thermal, in-situ oil sands recovery plant, with the goal of choosing one or more of these designs for a more in depth life-cycle cost analysis comparison with natural gas as the current energy source used. The report showed that all three conceptual HTR modular plants could fit the energy needs for the hypothetical thermal, in-situ oil sands recovery plant, and concluded that the cost estimates for the hypothetical plants are too uncertain, at this stage in conceptual designs, to single out a clear, lowest-cost design. In addition, the cumulative pros and cons and risks, do not, on an absolute scale, produce a convincing advantage for any of the three designs. On this basis, if the capital, operating costs and project schedule identified by this report are of interest, one or more of the HTR designs could be selected for further evaluation.

On the other hand, if a given oil sands developer had particular technical preferences among the comparative design criteria, that could lead to a clearer choice of the three HTR designs for that developer. For example, a developer might prefer a design which had no planned refueling outages, or one whose transportation loads were all below 200 tonnes, or one that didn't rely on liquid sodium, etc.

If the basis for selection depends on non-technical reasons, they could involve an assessment by PTAC of the degree of maturity of the current efforts, or the interest and responsiveness shown, or the willingness and ability of the organizations to commit a sufficient staffing of qualified personnel in the desired timeframe to ensure the chance of success toward a specific targeted completion date. This may be something that could be determined by meeting with the individual vendor organizations.

MPR notes that, given the state of design and development of the three HTR plant applications for the oil sands recovery plant, the life-cycle cost estimates for the HTR plants will still have large uncertainties when an analysis is performed.

2.2.2 Picking a Strategy for HTR Use in Thermal, In-situ Oil Sands Plants:

Different options exist for the oil sands developer to proceed with the future pursuit and implementation of an HTR for application to the oil sands recovery plants. One would be to "sit back and wait" for the technology to be developed by other parties, such as PBMR's DPP plant in South Africa or the U.S. program for the Next Generation Nuclear Plant (NGNP). Another would be to become partners in the development with NGNP or other consortia.

One advantage of being involved in the earliest application of these First-of-a-Kind modular HTR applications is that the early development efforts by the vendor would produce a detailed design directly applicable to the oil sands. Vendor flexibility to customize the HTR to later applications may be more difficult as early design shifts into a production mode. A second advantage is to get the design into the CNSC process while they are still formulating their regulatory guidelines and before too many nuclear electric plant applications begin to swamp the available resources. A third advantage is that, while the timing is for the first plant to become operational soon after 2020, the availability of raw material and component vendor commitments is likely to be strained while the nuclear industry appetite for new plants exceeds its atrophied production capabilities. Lastly, projections for in-situ oil sands developments from 2020 to 2050 indicate that the potential exists for application of 80 HTRs (sized at 500 MWt each, or ~40 MMscf/day) to meet these energy needs, and the costs of fossil fired alternatives including stricter limits on greenhouse gas emissions are likely to become increasingly stringent.

2.2.3 Course of Action for Quickest Approach to HTR as Alternate Energy Source

If a quickest path to implementation is selected, it would be prudent to proceed with the First-of-a-Kind plant as a single module prior to proceeding with a commitment to a multi-stage roll-out of the HTR design plants to large scale oil sands projects. This would have the advantage of simplifying the design and licensing process and minimizing the risks due to uncertainties in development, costs and scheduling. The project might be initiated as a follow stage at an existing oil sands development, so that the complexities of mixing the two licensing processes would be minimized and "backup steam" would be present from the start without the additional cost of this contingency. The site selected could be optimized for other features that minimize the risks of a first time HTR plant, such as transportation problems or preexisting electrical grid maturity. Once the progress toward the first plant was considered successfully established and successful operation of the plant in the application was shown, the HTR plant could be deployed a on a larger scale, such as the hypothetical 4-Stage 120,000 bpd SAGD project analyzed and discussed in this report.

For the earliest possible application of an HTR plant design to the oil sands, actions should commence in 2009 in order to achieve an operating HTR demonstration plant in about the early 2020s. The first steps to be taken should be as follows (as discussed in detail in Section 7):

- Conduct feasibility study and completion of the conceptual design (needed for licensing step) – this could be for more than one HTR concept with a down-select at the end.

- Identification and engagement with a plant operator – needed for licensing.

- Commence development and qualification of a fuel manufacturer – to ensure this doesn't become more limiting than the licensing schedule.

- Submit a Pre-Project Design Review to the CNSC – to jumpstart the licensing clock.

2.3 CONCLUSIONS OF THE REPORT ON NUCLEAR TECHNOLOGY

Each basic reactor technology of each HTR is discussed in depth in Section 3.

Predecessors
There is considerable experience for both sodium and gas-cooled reactor designs. Commercial gas-cooled reactors operated successfully in England and France. High-Temperature Gas Cooled

Reactor (HTGR) technology with prismatic block fuel similar to the MHTGR has been developed in the U.S. since the 1950s and is a proven technology. Likewise, pebble-bed fuel reactors have been successfully operated on in Germany and China with plans for the development of a commercial-scale demonstration of the PBMR technology in South Africa. There is experience as well with sodium-cooled designs; several reactors have been developed throughout the world, but their reliable long-term operation has proven to be challenging.

Table 2-2. Reactor Module Design Comparison

Attribute	4S	MHTGR	PBMR
Core Thermal Power (MWt)	135	350	500
Coolant	Sodium	Helium	Helium
Moderator	N/A	Graphite	Graphite
Core Inlet Temperature (˚C)	355	258	280
Core Outlet Temperature (˚C)	510	687	750
Heaviest Transported Component/ weight (tonnes)	RV / 100	RPV / 648	RPV / 815
Largest Transported Component/ dimensions (m)	RV/ 23 x 3.6 x 3.6	RPV/ 18 x 7.6 x 7.6	RPV/ 23 x 8 x 8
Fuel Enrichment	18 Wt% U-235	19.9 Wt% U-235	9.6 Wt% U-235
Refueling Mode	Batch	Batch	On-line
Outage Schedule	30 days/10 yrs	30 days/1.5 yrs	4 days/yr + 30 days/6 yrs
Design Life (years)	30	40	35

Key Design Differences

Each design has key differences. These include thermal power, coolant, operating conditions, and refueling/maintenance schedules. Table 2-2 lists these differences.

Safety

Each HTR design applies the principles of defense-in-depth in which diverse safety features are used to ensure the safe operation of the plant. These features include the inherent safety of the reactor design, passive safety systems, and engineered active safety systems and required operator actions that will ensure acceptable levels of safety.

2.4 CONCLUSIONS ON FUNCTIONAL AND OPERATIONAL REQUIREMENTS

The functional and operational requirements of the thermal, in-situ recovery project are described in Section 4. The HTR plants are then evaluated based on these requirements.

Steam and Electric

Based on an SOR of 2.5, the injection steam requirement is 284 MWt per 30,000 bpd stage. The electric power demand for the central plant and its well pads is approximately 26.5 MWe per stage. Table 2-3 details these requirements. For all three HTR designs, the basic steam and electric requirements of the thermal, in-situ recovery project can be met. Slight differences in the amounts of steam and electricity produced for each plant are due to matching preexisting HTR modular thermal capacities with the specified hypothetical plant application. For the total, four-stage, 120,000 bpd project, this is accomplished using eleven 4S modules, four MHTGR modules, and three PBMR modules.

Table 2-3. Steam and Electric Requirements for 120,000 bpd Plant

Stage	1	2	3	4
Steam (MWt)	284	568	852	1136
Electric (MWe)	23	46	79	106

Startup Requirements

The initial operation for startup/circulation of steam to fresh wells requires that a low level flow of steam be supplied to the well heads. Each of the HTR designs uses a single large process steam generator. It is unlikely that the steam generators for PBMR or MHTGR would be able to operate acceptably below 10% of their rated flow. A backup steam supply capable of producing 28 MWt of steam for startup of the wells in Stage 1 would be needed.

Reliability

A prolonged loss of steam to a SAGD well can result in cooling and blockage within the well from which it may be difficult to recover. Lower steam output can be tolerated for short periods, whereas long outages must have a higher sustained steam flow. The sensitivity to inadvertent outages and prolonged forced outages is summarized as follows:

- **Up to One Week**: For a one week duration, at least 33% of the steam load would have to be maintained. Backup steam would be not be required for this contingency for 4S in any stage. MHTGR and PBMR would require backup steam in Stage 1.

- **Up to One Month**: For a one month shutdown period, at least 67% of the steam load would have to be maintained. Backup steam would be required for all HTR plants in Stage 1 and for the MHTGR in Stage 2.

- **Beyond One Month**: Steam output cannot be lost for longer than one month. Therefore, no reactor module can shut down for longer than one month or a backup steam source must be provided. Should a 4S steam module shut down for longer than one month at any stage of plant operation, 135 MWt of backup steam must be provided. At Stage 1, 284 MWt of backup steam must be provided for both the MHTGR and PBMR. By the completion of Stage 4, the MHTGR requires 86 MWt of backup steam, and the PBMR requires 136 MWt.

Although startup and planned outages require some amount of backup steam, as noted above, it is likely that unexpected and prolonged outages will occur in any of these First-of-a-Kind plant designs because of their developmental nature and lack of experience. Furthermore, these outages, as noted above, can have unacceptable consequence on the long term production of the wells. Therefore, MPR recommends that initial application of HTR technology be required to provide a minimum amount of backup steam supply that is sufficient to accommodate any one reactor in the overall plant being in an outage longer than one month.

Plant Lifetime Plus

All of the HTRs can meet or exceed the 30-year lifetime requirement for the oil sands fields. Some or all of the HTRs may be able to extend their lifetime based on experience with earlier generations of nuclear reactors. If this is possible, options for utilizing the plant's extended life include electricity generation, providing steam to other fields, using steam or process heat for other industrial processes (hydrogen production, upgrading) near the oil sands site.

2.5 CONSTRUCTION IN ALBERTA

The construction of each HTR plant with respect to labor, transportation and other important requirements such as excavation was considered in Section 5. Key conclusions are summarized below.

Labor

The construction of a nuclear plant requires labor with special skills and qualifications that will be difficult to acquire in Northern Alberta. Maximizing the modularization of an HTR plant design will decrease the need for providing labor with these special skills at the plant site.

Transportation

The large and heavy components of the HTR plants will require special planning and permits for transportation to the plant site. The largest components required for transportation of the 4S, MHTGR and the PBMR are shown in Table 2-4. Transporting the reactor vessels for PBMR and MHTGR will be very challenging, and barge transportation is being considered. Vessels up to 1000 tonnes can be moved by barge and over selected roads, but portages for river travel require infrastructure improvements be made along the river ways and bridges are the most restrictive obstacles for a heavy move by truck. Careful management will be required for heavy component transportation, and PBMR and MHTGR may require changes to design, manufacture and assembly strategies in order to transport vessels to selected sites in the Athabasca oil sands area. Transportation should not be a significant challenge for the 4S, as its largest component is of a size previously shipped by rail and truck.

Table 2-4. Comparison of Maximum HTR Component Weights and Sizes

	WEIGHT	HEIGHT	WIDTH	LENGTH
4S - Reactor Vessel	**100 tonnes**	**3.6 m**	**3.6 m**	**23 m**
MHTGR - Reactor Vessel	**648 tonnes**	**7.6 m**	**7.6 m*** **	**18 m**
PBMR - Reactor Vessel	**815 tonnes**	**8 m**	**8 m*** **	**23 m**
Northern Alberta Truck GVW limits —— without permit	295 tonnes	7.3 m	7.3 m	31 m
Example of a heavy transport by rail in Alberta	676 tonnes	4.1 m	4.1 m	31 m
Example of a heavy transport by road* in Alberta	426 tonnes	11.6 m	10 m	30 m
Barge transportation study**	> 1000 tonnes			

* Load crossed Athabasca River bridge at Ft. McMurray. Heavier loads can be done where no bridges are crossed.
** This would require some infrastructure improvements along the river.
*** These widths cannot be shipped by rail.

2.6 Regulatory and Public Outreach

The requirements to license a thermal, in-situ recovery project using a nuclear heat source are considered in Section 6, and the licensing status of each HTR is evaluated. Actions to take with respect to public outreach are also discussed.

Nuclear Licensing

The Canadian Nuclear Safety Commission (CNSC) reviews applications for nuclear power plant licenses. Separate licenses are required to prepare the site, construct, operate, decommission, and ultimately abandon the site. Based on the newly defined Canadian nuclear licensing framework applied to a large, water cooled reactor, a schedule of about nine years before receiving a license to operate is estimated. Though none of the three vendors have experience with licensing an actual plant in Canada, all three designs could be licensable by the CNSC eventually. The HTRs will not be as familiar to the CNSC as water-cooled reactors and could, therefore, encounter additional delays. There is not a body of regulatory guidance nor regulator experience to facilitate review of HTRs. Additional resources from the applicant to assist CNSC reviewers and close management attention will be required to minimize additional delays. Given these challenges, MPR considers that an additional, cumulative two years should be anticipated for this new-technology, First-of-a-Kind plant to receive its operating license. There are some ways to save time in the licensing process (see Section 6.4) and these should be managed carefully (e.g., the Pre-Project Design Review (PPDR) process is a very important preliminary step in which the vendor can familiarize the CNSC staff with the HTR technology and begin to discuss any unique concerns with the project) without a large resource commitment.

Public Outreach

The development of a thermal, in-situ recovery project using a nuclear heat source will likely evoke public concern. This should be addressed as soon as possible with a proactive effort to ensure that these concerns are understood and addressed. This public outreach initiative should be undertaken in cooperation between the nuclear technology suppliers and potential industry users and should be supported by broad, high level studies of long term regional energy needs and supplies, environmental compliance and sustainability, industrial and economic development, quality of life, and international relationships.

2.7 SCHEDULE

In Section 7, the fundamental schedule considerations for developing and demonstrating an HTR plant in support of a thermal, in-situ oil sand recovery plant in Alberta are discussed. The same schedular steps and timing would apply for the First-of-a-Kind plant for any of the three HTR concepts whether it was a single HTR module in a single oil sands development stage or the first of multiple HTR modules in multiple stages.

The application of HTR technology to an oil sands plant would be the first application of an HTR nuclear plant in Canada and the first application of an HTR technology to provide process steam for a commercial oil sands production process. The designs for the oil sands applications of these HTRs are currently in the pre-conceptual stage; therefore, the schedule considerations reflect the lack of maturity of the design, components, fuel manufacture, licensing, and construction that would be required to complete and begin operation of the first of these plants.

If actions begin in 2009, a demonstration plant could be in operation by the early 2020s. These actions are discussed in detail in Section 7 and summarized in Figure 2-1. As can be seen, the first actions require completion of the plant conceptual design, identifying the HTR operator, pre-project design review for licensing, and long lead development and qualification for fuel manufacturer. Once the licensing process has been established, it is probable that the time for licensing of modular HTRs will be at least as good as that for water-cooled plants thereafter.

2.8 COST

Cost data were obtained from the three HTR vendors for the hypothetical 120,000 bpd thermal, in-situ bitumen recovery plant. Adjustments were made to these costs to allow for comparison on a common basis. The bottom-line costs of the three plants designs were fairly close. It should be understood that, at this stage in the conceptual designs of the three HTR plants, the estimates of the capital costs and operating costs are very approximate. The basis for assessing the costs is discussed in detail in Section 8. Although some estimates were more complete than the others, the lack of accuracy of the data at this stage of development does not permit a high assurance in making a distinction among the three designs based on comparative costs. The overnight capital cost for the project is estimated to be around C$5 billion based on individual preliminary estimates for the three technologies that ranged from C$4.7 to C$4.9 billion. The normalized overnight capital costs for these three estimates ranged from about C$3100 to C$3500 per kilowatt-thermal. The operating and maintenance (O&M) costs are estimated to be between C$160 Million and C$280 Million per year (2008 dollars) or C$3.80 to C$6.70 per barrel of bitumen (assuming 95% of design capacity).

If a decision is made by PTAC to proceed with a comparison of life cycle costs between an HTR-powered oil sands plant and a natural gas fired plant, it should be possible for the vendor(s) selected to provide a substantially more detailed estimate for the plant(s) selected after a concerted, short-term (three to four month) effort. However, the degree of uncertainty in such an estimate will still be large due to the early stages of the design concepts, plant optimizations for the oil sands application, unknown impacts of licensing, costs of fuel manufacturing, etc. Nevertheless, a comparison could be made to natural gas-fired plants using the current estimates of capital and operating costs to see if it would be worth continuing or to define desired cost objectives. Alternatively, it could be done as part of a next step (Section 2.2) to work with vendor(s) for a feasibility study associated with a specific site or demonstration project.

2.9 RISKS

The many risks normally associated with a new nuclear plant project are greatly exacerbated by the uncertainties associated with building a First-of-a-Kind design in a First-of-a-Kind application (process steam for oil sands) in a country whose regulator has no prior regulatory basis or experience in the selected HTR technology. Risks are addressed in detail in Section 9 and are broadly summarized in the table below. It should be recognized that these risks pertain to the First-of-a-Kind application of the HTR design in a demonstration plant. Subsequent application of the design to follow plants will have many of these risks greatly reduced, based on the increased certainty and lessons learned from the demonstration plant.

Table 2-5. Assessment of First-of-a-Kind Risks

Risks	4S	MHTGR	PBMR
TECHNICAL – Design/Test/Qualify Components & Fuel and Operate Plant Reliably	High	High	High
BUSINESS – Project Management Infrastructure, Schedules and Costs	High	High	High
REGULATORY – Ability to Get Plant Licensed	Medium	Medium	Medium
SECURITY – Susceptibility to Sabotage	Low	Low	Low
CONSTRUCTION – Ability to Complete and Test the Plants	Medium	Medium	Medium

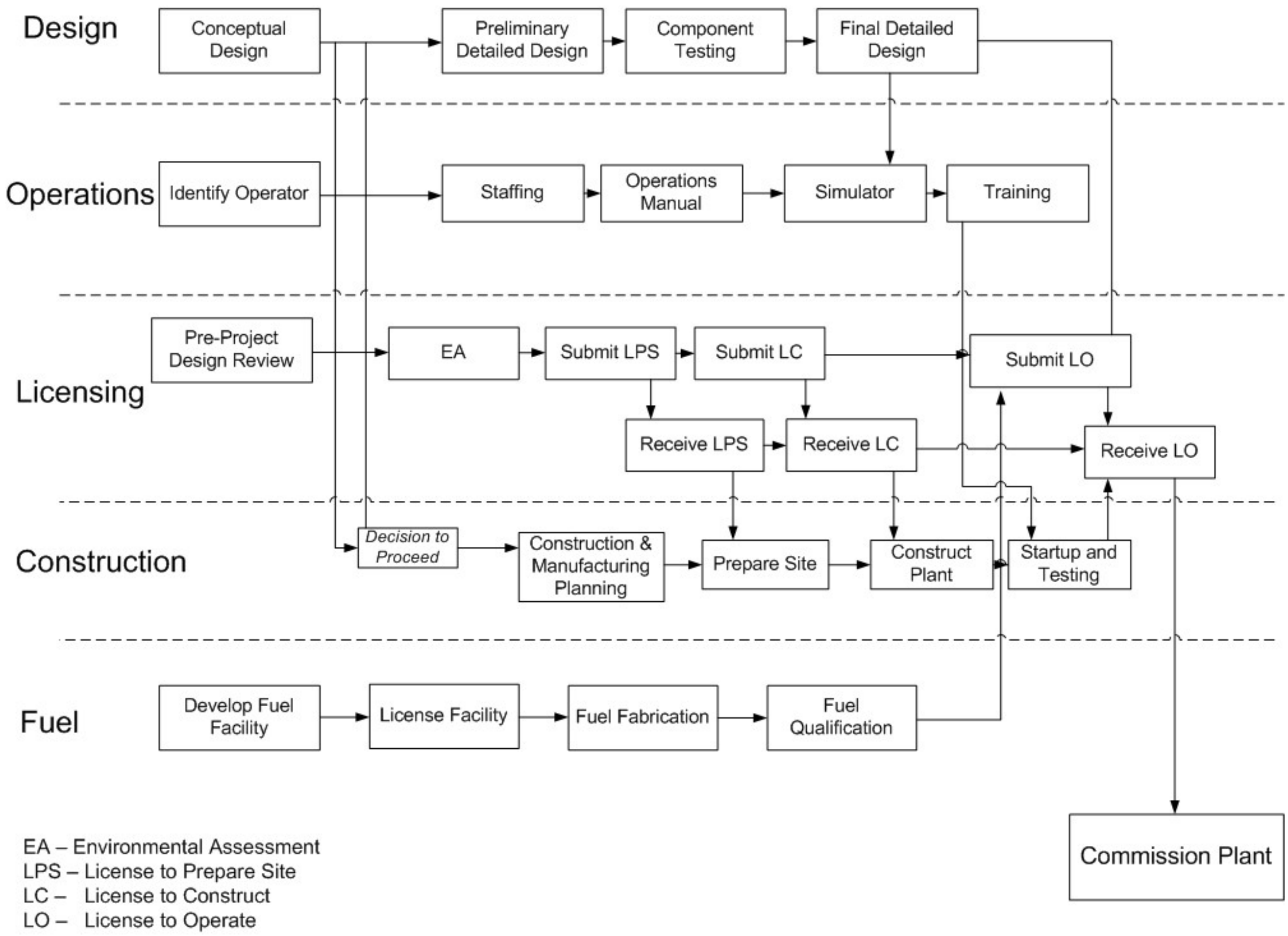

Figure 2-1. HTR First-of-a-Kind Development Tasks

2.10 EVALUATION

A list of criteria (see Table 10-1) was agreed upon that represents the most important issues that need to be met by an HTR modular plant when applied to the oil sands plant. The three HTR plant concepts were evaluated to these criteria and compared to each other. This evaluation is discussed in detail in Section 10.

Most of the designs are difficult to distinguish from one another clearly at this stage in conceptual development. In 12 of the 20 criteria categories, all three designs ranked the same. In the other nine, the differences were marginal. There were three critical areas where all HTRs were had a similar concern:

- Lack of Canadian Experience – none have had experience with licensing issues in Canada.
- Being Ready to Operate by 2020 – The early 2020's is the earliest realistic target for initial operation of an HTR plant in the oil sands region based on starting the process in 2009.

- Reliability and Longevity to 30 Years – The uncertainties with a First-of-a-Kind plant design having critical, untried new features, makes it difficult to predict that the first plant will not have some serious technical problems, which could impact its availability and the design life. Costly and time-consuming maintenance could be required. This is why sufficient backup steam supply should be provided for the first application of an HTR oil sands plant to cover the possibility that the single module HTR plant could be down in excess of one month.

The ratings of any plant design after some years of successful operations and/or lessons learned from a demonstration plant will improve across the board. This is the same growth in confidence and performance that previously occurred in the water-cooled reactor experience.

3 Nuclear Technology

This section provides an overview of the three HTR module designs being evaluated. The key nuclear engineering important to understand these reactor designs and their differences from the current fleet of operating commercial plants in North America is discussed first (for some basic principles, see Appendix D). Next, the history of similar reactors is provided. Following these initial sections, subsequent sections provide information each of the designs in more detail.

3.1 NUCLEAR REACTOR PHYSICS

This section provides a brief description of how a reactor generates power controllably and a discussion of unique nuclear concerns.

A fissionable fuel (for all reactors under consideration, this is uranium enriched in the fraction of isotope 235 from a natural concentration of 0.7%) is arranged in a reactor core so that a stable nuclear reaction can be established. The fuel naturally fissions at a slow rate, releasing neutrons that can cause other fissions, with each fission releasing a small amount of heat. "Fast" reactors use the fission neutrons directly to cause more fissions. "Thermal" reactors require the neutrons to be lowered in energy (slowed down) by use of a moderator such as water or graphite; if the moderator density decreases, the rate of the fission reaction is affected since more neutrons will escape from the core and be ineffective in maintaining the fission reaction.

Control is provided by movable neutron absorber or reflector devices. Movement of reflectors changes the number of neutrons that escape from the core without sustaining the fission reaction. Movement of neutron absorbers changes the number of neutrons available within the core. In either case, repositioning the control devices to increase the number of neutrons available to cause fission (reactor startup) will result in a self-sustaining reaction where an essentially constant number of neutrons causes an essentially constant number of fissions. This stable condition is referred to as a "critical reactor," whereas one that is shut down is "sub-critical." Actions that increase the fission rate are measured in terms of adding to the "reactivity" of the core. Cores are designed with negative reactivity coefficients for operating conditions, which means that if there is an unexpected increase in the fission rate, the reactivity coefficient will quell the fission reaction, ensuring the reactor is stable or that its power decreases.

The uranium fuel is gradually consumed, "burned up," as more of it fissions – this both reduces the number of fissions that can occur and also introduces neutron absorbing leftovers of the fission reaction. The effect is offset by withdrawing the control devices. Eventually, the fuel loses enough reactivity that it can no longer achieve a critical condition and must be refueled.

The safety concerns associated with nuclear power reactors are those that could result in release of radioactivity from the core. The two mechanisms necessary to maintain the core intact are:

1) ensuring control of the fission reaction so that the core does not overheat, and 2) removing the "decay heat" from the core after its nuclear fission reaction is shut down.

The first risk is addressed by designing the core to have negative reactivity coefficients and by ensuring that there are ways to very reliably reposition the neutron control devices or to provide other means to absorb neutrons to prevent a self-sustaining fission reaction. Current regulations require two different and independent means to assure nuclear shut down (i.e., subcriticality).

Second, decay heat refers to the energy released by the remnants of the fission process: after a fission, the uranium nucleus consists of some pieces – fission products – that are radioactive and continue to release small amounts of energy at predictable rates. Following shut down of the self-sustaining fission reaction, the decay heat trails off at a known rate from about 7% of the operating power immediately after shut down, to less than 1% after a day, to about 0.1% after six months. If this decay heat is not removed, the core could overheat and release radioactivity, even though it is no longer critical. Therefore, multiple means must be provided to ensure decay heat can be removed from the fuel to prevent damage, even though the reactor is shut down. "Passive" methods are preferred, where passive means that natural forces such as gravity-driven natural circulation provide the function, without the need for human action or electric power.

Finally, as a defense in depth to provide safety of personnel, the public, and the environment, additional measures to ensure the core is cooled and to contain radioactivity are required for nuclear reactors. Additional cooling methods include alternate heat transfer loops. Containment barriers include the fuel itself, the primary cooling system boundary and surrounding structures.

Thus, to provide safety, reactor designs must properly stabilize the fission reaction by controlling reactivity, must ensure removal of decay heat, and must provide additional protection by containment of radioactivity. To provide for a reliable energy source, these safety criteria must be met without unnecessarily shutting down the fission reaction.

One other aspect of radioactivity must be considered. During operation, some neutrons interact with other substances than the fuel. This can result in "activation" of those substances so that they become radioactive due to creation of specific isotopes. For example, activation of cobalt creates cobalt-60 and activation of sodium creates sodium-24. Different radioactive isotopes become non-radioactive (i.e., decay) at different rates, and some remain hazardous for years. The reactor designer must consider the creation and decay of these radioactive isotopes in assuring the protection of workers, the public, and the environment and in making plans for eventual decommissioning of the plant. Also, controlling these activation products is necessary to allow maintenance to be performed.

3.2 HISTORY OF SIMILAR REACTORS

To aid in understanding the maturity and risk of the different technologies, this section briefly discusses the history of operation of reactors with key features (i.e., coolant, fuel design) similar to those under consideration. It should be noted that the total relevant experience base of each of these technologies is a few hundred reactor-years, whereas commercial light water reactors have accumulated over 12,000 reactor-years worldwide.

3.2.1 Water Reactors

The United States Navy chose water to cool the reactors that would power its submarines and ships. Gas-cooled reactors would be too large for the submarines. Sodium was seriously considered and was used in the *SEAWOLF*, the U.S. Navy's second nuclear powered submarine. Ultimately, pressurized water was chosen as the coolant for the U.S. Navy based on familiarity with components and pressure vessel codes from previous experience with steam and chemical plants and ease of maintenance. The Navy program was given responsibility for design and construction of the first large central station powered by a nuclear reactor, at Shippingport in Pennsylvania (Reference 1).

The U.S. commercial power industry followed suit and began to develop light water-cooled designs. Both pressurized water reactor (PWR) and boiling water reactor (BWR) designs were developed. In a BWR, the water in the reactor core boils, and the steam generated there is passed directly to the turbine generator for use in power generation. In a PWR, the water in the reactor core is slightly subcooled and passed to a steam-generating heat exchanger where it raises steam for the turbine-generator set in a separate, lower-pressure cycle. PWR and BWR fuel is slightly enriched (less than 5% U-235) and formed into ceramic uranium dioxide pellets contained in a zircaloy cladding tube. In Canada, the decision was made to pursue pressurized heavy water-cooled reactor designs that use unenriched natural uranium as fuel. These CANadian Deuterium Uranium (CANDU) designs comprise all of the power reactors in Canada, and a few are operating in other countries (Reference 1).

3.2.2 Sodium Reactors (4S Predecessors and Key Design Issues)

Sodium cooled reactors have been developed further than the *SEAWOLF*, although there has been no commitment to a single design (Reference 2). They are either pool-type like the 4S or loop type (i.e., the sodium from the core exits the reactor vessel as part of its flow path). In the U.S., the Experimental Breeder Reactor (EBR) I and II operated for a number of years – EBR-I from 1951 to 1964 (EBR-I was the first reactor to produce electricity, in 1951) and the 62 MWt EBR-II from 1964 to 1994. The only U.S. and first commercial Liquid Metal Fast Breeder Reactor, the 94 MWe Fermi plant near Detroit, Michigan operated from 1963 until 1966 when a loose piece of metal blocked coolant flow leading to partial core melting. The U.S. Fast Flux Test Facility was an experimental sodium-cooled design operating from 1980 to 1993.

Russian designs began with small prototypes and evolved to the BN sodium-cooled fast reactor design sized from 350 MWe to 800 MWe. A BN-350 at Aktau in Kazakhstan operated from 1973 until the late-1990s when it was closed due to a lack of funding and technical support. A BN-600 (1475 MWt) was built in 1980 at the Beloyarsk Nuclear Power Station, in Zarechny, Sverdlovsk Oblast, Russia, and is still operating.

France built the 580 MWt Phenix reactor, which started up in 1973 and operated reliably until 1990 when it started a period of renovations that kept it shut down until restarted in 2003, limited to two loops and two-thirds power (Reference 3). The French Super-Phenix breeder project was started in 1968 but the reactor did not operate until 1985. For a number of years it had a low availability for both technical and political/administrative reasons. The plant was shut down late in 1996 to perform maintenance and never restarted, largely for political reasons.

In Japan, the JOYO fast breeder experimental reactor has operated with three cores with increasing power rating over the period 1977 to the present. Also, Japan built one demonstration reactor, Monju, in Tsuruga, Fukui Prefecture, rated at 714 MWt that started operations in 1994 but was shut down 20 months later following a sodium leak and fire in a secondary sodium loop; it is expected to restart in the near future.

The 4S is designed to address several of the design concerns associated with predecessor reactors. The double-walled heat exchangers allow detection of sodium leaks early and minimize the potential for sodium fires, a significant concern for sodium reactors. A similar reactor, PRISM, was assessed by the U.S. NRC for licensability, with the results reported in NUREG-1368 (Reference 4). Specific concerns such as reactivity coefficient for sodium voiding and coast down characteristics of the electromagnetic pumps were raised; Toshiba has designed the 4S to address these.

3.2.3 Gas Reactors

Gas-cooled reactors were developed in France and England that also used natural uranium as fuel. In these designs, the heat in the cooling gas is transferred to a secondary water loop to generate steam for a turbine-generator set. Carbon dioxide was used as the cooling gas, though helium would have been the preferable choice. Carbon dioxide reacts with graphite, which was the moderator in these plants, at high temperatures and pressures (Reference 1). Helium, however, was not available on a large enough scale in Europe to support its use a coolant in these plants. Over 40 gas-cooled reactors were constructed and operated in Europe.. Today, gas-cooled reactors represent approximately 11,000 MWe of capacity in England. This is nearly one-fifth the country's electricity demand (Reference 5).

MHTGR Predecessors and Key Design Issues

High-Temperature Gas Cooled Reactor (HTGR) technology has been under development since the middle 1950s for both electricity production and process heat. Peach Bottom I, which ran from 1967 to 1974, was the first prismatic design HTGR built and operated in the U.S. Generating 115MWt and 40MWe, it achieved an overall average system availability of 88% (Reference 6). It was followed by the 842MWt (330MWe) Fort St. Vrain plant which operated sporadically from 1974 to 1989. While there were no problems with the core and fuel, Fort St. Vrain was forced to shutdown for extended periods of time by other plant equipment (e.g., water leaking from the bearing cooling system for the helium circulators) (Reference 7). Also, on a few occasions, a few control rods failed to scram due to corrosion in the drive mechanism caused by moisture in the helium coolant. Follow-on design, upon which the GA MHTGR is based, had the objective of eliminating this problem area.

Based on nuclear licensing and safety concerns and utility input, a passively safe, modular gas-cooled reactor with a prismatic annular core operating at 350MWt was designed in 1987. Key features of this design were: (1) core size and power density were limited such that fission products are retained within coated fuel particles even during loss of coolant flow or coolant pressure accidents; (2) multiple reactor modules can be built consecutively or as a cluster for the best fit to the utility's growth requirement and its financial constraints; (3) major portions of the nuclear island can be factory fabricated to nuclear standards while the balance of plant can be manufactured and constructed to conventional fossil-fuel plant standards.

Further development has led to the current reference prismatic annular core modular helium reactor (MHR) operating at 600MWt. A pre-application for review of this design was submitted to the U.S. NRC which resulted in extensive discussion during 2002 and 2003. The reactor can also be coupled with a steam cycle to produce steam, which can be used both for electricity generation and/or process heat. A joint US-Russian Program is currently exploring the possibility of this design's use in the disposal of weapons-grade plutonium while generating electricity.

PBMR Predecessors

The original demonstration pebble reactor was the German 15 MWe Arbeitsgemeinschaft Versuchsreaktor (AVR), built in Jülich, West Germany (Reference 8). From its initial criticality in 1966, it ran successfully for 21 years. A full scale power station (the Thorium High Temperature Reactor (THTR-300)) rated at 300 MWe was constructed, taken critical in 1983, and operated for power generation from 1985 to 1989, achieving about a 50% capacity factor over that period. THTR-300 suffered a number of technical difficulties and, due to these and political issues in Germany, was closed after only three years of operation. THTR-300 was deactivated due to its cost and increased public scrutiny following both the Chernobyl accident. While operating in 1985, a fuel sphere was damaged due to control rod insertion into the pebble bed (Reference 9). The control rods in PBMR's design do not enter the pebble bed region.

China licensed the pebble bed technology and built the 10-MWt High-Temperature gas-cooled pebble bed Reactor (HTR-10), which started testing in 2000 and was generating power by 2003. The following year, a demonstration transient was performed to show that the design was passively safe (Reference 10). The technology has also been licensed in South Africa, leading to the formation of the company, Pebble Bed Modular Reactor (Pty) Limited (PBMR) in 1999. In 2007, environmental roadblocks to building a Pilot Fuel Plant were lifted, and manufacturing of the first fuel spheres containing low enriched uranium started. The company is actively working to start construction in 2010 of its Demonstration Power Plant (DPP) and for the first fuel to be loaded four years later, assuming regulatory approvals are obtained. Construction of the first commercial modules are planned to start three years after successful demonstration of the first reactor.

3.3 KEY DESIGN APPROACHES

3.3.1 Reactor Coolant

The 4S reactor core is cooled by liquid sodium, while the MHTGR and the PBMR are helium-cooled. The purpose of the reactor, or primary, coolant in a nuclear plant is to remove heat from the reactor and, during operation, transport it to where it can be converted to a more useful form. In the early development of nuclear power, several coolants were considered. These included sodium, gas (several options), and water.

As each coolant has its own set of advantages and disadvantages (shown in Table 3-1), the choice ultimately depends on the specific application and resource constraints. The high heat capacities of sodium and water allow the storage of more heat per unit volume and, therefore, decrease the necessary size of the reactor and heat transfer surface area per megawatt. The characteristics of sodium and gas make it possible for reactors to be operated at high temperatures and while maintaining relatively low pressures. Sodium and helium can maintain a high neutron energy level needed for a fast reactor but need a separate moderator for a thermal reactor, while water limits the neutron energy level but also serves as a moderator and can only be used in a thermal reactor.

Table 3-1. Reactor Coolant Options

	Advantages	Disadvantages
Sodium	- High heat capacity - High temperature at low pressure (High boiling point) - Low neutron scattering (maintain High neutron energy level) - Less corrosive environment than water for piping	- Chemical reactivity - Must be heated above melting point during shutdown - Difficult to handle
Gas	- High temperature at low pressure - Low neutron scattering (maintain High neutron energy level) - Less corrosive environment for piping	- Low density and low heat transfer capabilities require larger reactors and more heat transfer surface area - Thermal reactor requires separate moderator
Water	- High moderator - High heat capacity - Familiar fluid for piping systems	- Low boiling point (coolant must be kept under pressure) - Corrosive at operating temperatures

3.3.2 Moderator

In thermal reactors, a neutron moderator is present. The moderator is a medium which decreases the velocity of the fast neutrons released in a fission reaction. This transforms the fast neutrons into thermal neutrons. These thermal neutrons more readily sustain a nuclear chain reaction involving uranium-235. The most common moderator is water.. Graphite is used in gas reactors, while heavy water is used in CANDU reactors. Thermal reactors represent the vast majority of power reactors in operation throughout the world today.

In fast reactors, such as the 4S, the nuclear chain reaction is sustained by the capture of high-energy neutrons, or fast neutrons. Therefore, the neutrons are not slowed down, and no moderator is necessary. Several fast reactors have operated successfully throughout the world, including the EBR-I and II, Phenix and Super-Phenix, Joyo, and MONJU reactors. Most have been on a prototype scale.

The MHTGR and the PBMR are graphite-moderated thermal reactors. There is extensive experience with the use of graphite as the moderator of thermal reactors. It has the advantage of being a moderator that is readily available, of reasonable cost, and with high mechanical and thermal properties. It can, however, react with air, carbon dioxide, or water at high temperatures.

It can also form carbides with some metals and metal oxides. Also of concern is that its size and properties can change when exposed to radiation, unless it is maintained above a certain temperature.

3.3.3 Temperature

The operating temperature of a commercial nuclear reactor has significant economic consequences. From the standpoint of electricity production, a higher operating temperature is desirable because it yields higher electrical conversion efficiency. From a process steam perspective, the reactor outlet temperature must be high enough to generate steam at the required temperature and pressure.

Today’s commercial water reactors operate with a reactor outlet temperature of approximately 320˚C and a resulting thermal efficiency of 32% for electric production in a Rankine cycle. A second generation of British carbon dioxide-cooled reactor, the advanced gas reactor (AGR), has an outlet temperature of approximately 650˚C and a resulting thermal efficiency of 42%. Because graphite reacts with carbon dioxide at high temperatures and pressures, the AGR design ensured that the graphite would remain sufficiently cool during operation (Reference 11). Helium-cooled designs, however, do not have this concern and as long as the reactor coolant system precludes in-leakage of air.

Higher temperature helium reactors were also developed, designed and operated in the U.S. Peach Bottom Unit 1 was a 115 MWt experimental reactor with a reactor outlet temperature of 750˚C (Reference 6). Fort St. Vrain was an 829 MWt commercial power reactor with a reactor outlet temperature of 775˚C (Reference 7).

Table 3-2 provides a comparison of some of the designs discussed as well as the HTRs being evaluated based on their reactor outlet temperature, steam temperature (steam for electric production, not process steam) and pressure.

Table 3-2. Reactor Operating Temperatures

	Outlet Temp. (˚C)	Steam Temp. (˚C)	Steam Pres. (MPa)
4S	510	453	10.5
MHTGR	687	538	17.2
PBMR	750	538	13
AGR	650	540	17.0
Fort St. Vrain	775	538	16.5
PWR	~320	~280	7.2
BWR	~280	~280	7.2

3.4 TOSHIBA 4S

The 4S is a small, sodium-cooled, fast reactor. The design was developed for low-power demand, isolated locations and was kept small to ensure transportability. The Toshiba concept for thermal, in-situ oil recovery involves two similar designs with operating conditions of one optimized for steam production and the other for electrical production.

The 4S has a reactor power level of 135 MWt, and its electric variant produces 50 MWe net. The sodium primary loop transfers heat to a sodium secondary loop which then generates steam in a tertiary loop. The entire primary sodium loop is contained within the reactor vessel (since the primary is at almost atmospheric pressure, it is not a "pressure vessel"), which itself is partially enclosed within a guard vessel that provides a containment barrier. This keeps the radioactive sodium-24, generated during operations, inside the reactor vessel and isolated from the production steam by the intermediate sodium loop.

3.4.1 Reactor Unit

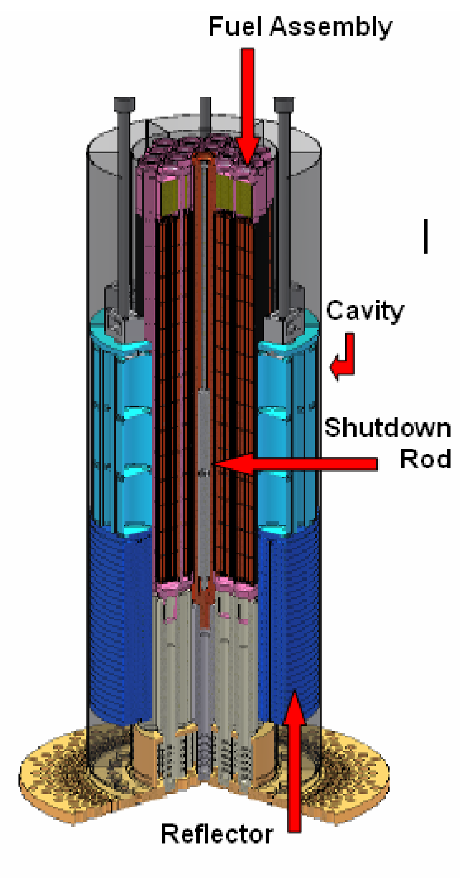

Figure 3-1. 4S Core

The purpose of the reactor unit system is to safely generate heat from nuclear fission and to ensure that the nuclear reaction can be controlled at all times and can be shut down at any time.

The reactor vessel, weighing less than 100 tonnes, is 23 meters high and 3.6 meters in outer diameter. It is the largest item, both in terms of weight and size, that requires transport to the plant site. It is constructed from 304 SS for corrosion resistance. In addition to the core, two electromagnetic pumps, an intermediate heat exchanger (IHX), core support structure, a partition wall, a shield, a reflector, a fixed absorber, and nuclear reactor instrumentation are enclosed in the reactor vessel. The core has an encircling diameter of one meter, is 2.5 meters tall, and is described in detail in the next subsection.

The 4S design has two diverse reactivity control systems that can both be used to shut down the reactor: reflectors and a shutdown rod. Reactivity and power are controlled by means of six reflectors surrounding the core. All reflectors are raised together to reduce neutron leakage from the core to achieve criticality. They can be rapidly inserted for scram shutdown. Insertion of the reflector is sufficient to maintain the reactor shut down at all times in core life and at all temperature and pressure conditions. The single, back-up, neutron absorbing shutdown rod located centrally in the core has sufficient worth to take the core subcritical even with the reflectors remaining at any withdrawn position. It is inserted by de-energizing its mechanism and letting the rod drop into the core by gravity. The maximum reactivity addition rate associated with withdrawal of the reflectors is controllable (i.e., power controlled and primary coolant system not over-pressurized).

As the uranium fuel is used and loses reactivity, the movable reflector is gradually moved to compensate and maintain the reactor critical. Minor perturbations to reactivity are inherently controlled by reactivity coefficients of the design, without the need to move the reflector. This allows a change in steam demand to be automatically matched by the reactor power generation, facilitating load demand follow.

The primary coolant system is completely housed within the reactor vessel and is described in the subsection 3.4.3.

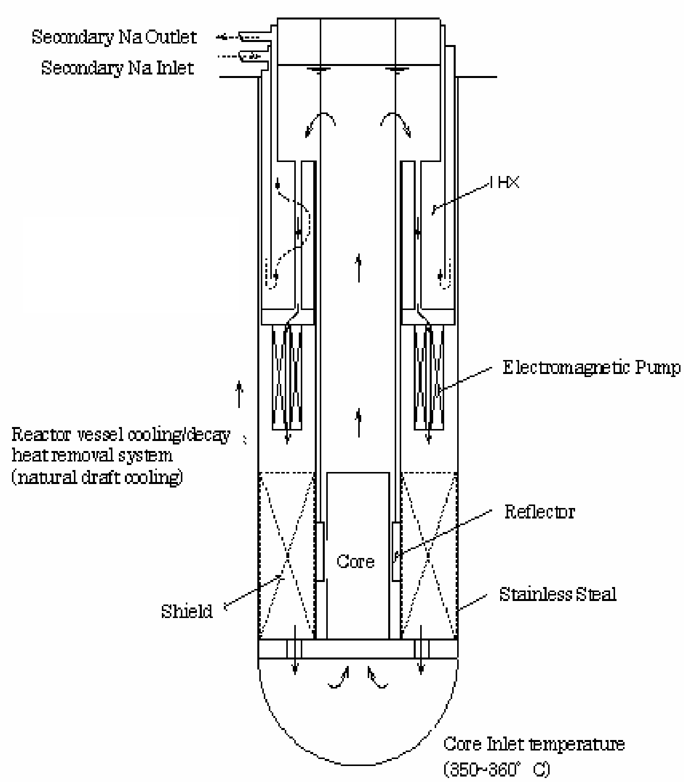

Figure 3-2. 4S Reactor Vessel Flow Paths

3.4.2 Fuel

The 4S core is composed of 18 hexagonal fuel assemblies and one assembly including fixed absorber and shutdown rod. Fuel design is based on data from two prior reactor designs (EBR-II and FFTF) including blanket fuel data for 30-year irradiation. The fuel is HT-9 ferritic steel clad U-10%Zr alloy, with the uranium enriched to slightly less than 20% U-235. The number of fuel pins in each assembly is 169. Grid spacers keep gaps between pins to prevent contact. The active core is 2.5m in high and the fission gas plenum above the core is 2.7m high.

A unique feature of the 4S design is the long time between refuelings. Due to the above normal enrichment, each core is capable of ten years of full power operation before a refueling is required. At this time, the core would be replaced by a new one. The spent fuel from the old core would be stored in the ex-vessel storage tank (EVST) until the decay heat had decreased to a point (two years) where the fuel could be stored in dry casks for eventual shipment to a Canadian Nuclear High Level Waste storage vault. The capacity of the EVST is sufficient to house fuel removed from each reactor and allow for cooling over a two year period (60 assemblies/ three cores).

3.4.3 Heat Transport

Sodium coolant comes out of the core and flows upward through the central part of the reactor vessel, being led into the IHX and descending inside of it. Then, the coolant passes through the primary electromagnetic pumps, which provide the motive force to drive it around the shield region to the lower plenum and again into the core. The sodium coolant enters the 4S core at a temperature of about 355°C and a pressure of 4 MPa and exits at a temperature of 510°C. Flow paths within the vessel are shown in Figure 3-2.

Two main circulation electromagnetic pumps are installed in the reactor vessel; each pump is immersed in sodium and circulates the primary coolant sodium. These pumps are installed in the perimeter of the core shroud in the nuclear reactor center. There is shielding under the pump and an IHX above the pump. The rated flow is $50m^3$/min and the rated pump head is 0.1 MPa for each pump.

The IHX transfers heat to a secondary sodium cooling system. The IHX is a vertical shell and tube type, and the primary coolant flows downward inside of straight heat transfer tubes, which are circularly arranged in the annular heat exchanger shell. The shell is designed to be double annular structure with the outer side being the low temperature flow path of the secondary inlet coolant. The IHX is made of austenitic stainless steels.

The secondary loop sodium exits the reactor vessel and is routed to the steam generator (SG) The purpose of the IHX is not only to transfer heat between these two sodium loops but also to provide an additional physical barrier between the primary coolant system, which will have some fission products in it plus radioactive sodum-24[1], and the water loops that will be used in in-situ thermal recovery and electricity generation.

The secondary cooling, or intermediate heat transport, system consists of a loop formed by a steam generator, an air cooler, a main circulating electromagnetic pump, an electromagnetic flow-meter, piping, etc. Most of this system is installed in the reactor building from which secondary cooling system piping penetrates the top dome of the guard vessel and connects with an inlet/outlet header of the intermediate heat exchanger.

A helical coil SG with double wall tube is installed to transfer heat from the intermediate heat transport loop to the tertiary steam system. The double tube provides a wire-meshed layer between inner and outer tube, in order to detect one boundary failure out of the two boundaries (tubes) before a sodium/water reaction occurs. The inner and outer tube interface of the double tube is filled with helium gas at ~0.60 MPa, and open to the plenum between water side tube sheet of feed water and steam nozzle and sodium side tube sheet. Sodium flows into the top of the heat transfer tube bundle through a distributing header at the SG top. Water and steam flow into heat transfer tubes from three feed water nozzles. While rising through the heat transfer bundle of helical coil, water is heated, becoming steam which flows out from three steam nozzles.

The steam outlet conditions are 453 ˚C and 10.5 MPa for use in a turbine in the electrical modules and are 310 ˚C and 10 MPa for use for in-situ thermal recovery processing. The system configurations of the steam and electric plants are shown in Figure 3-3 and Figure 3-4, respectively. In the figures, EMP refers to the electromagnetic pumps, and ACS refers to the IRACS safety system discussed in subsection 3.4.5.

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[1] Sodium passing through the core region interacts with some neutrons, becoming temporarily radioactive Na-24. The Na-24 decays quickly and has lost most of its radioactivity within a few days after reactor shutdown, but it would pose a hazard if released from an operating reactor and would require additional radiation shielding if the coolant circulated outside the reactor vessel.

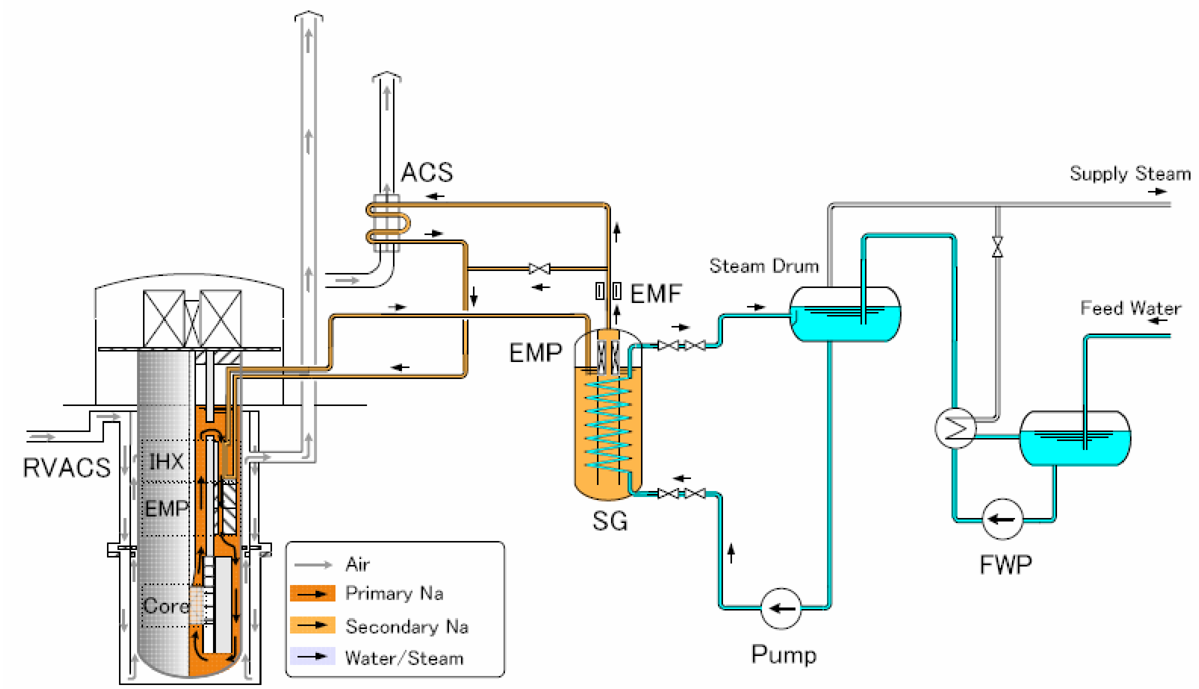

Figure 3-3. System Configuration, 4S Steam Plant

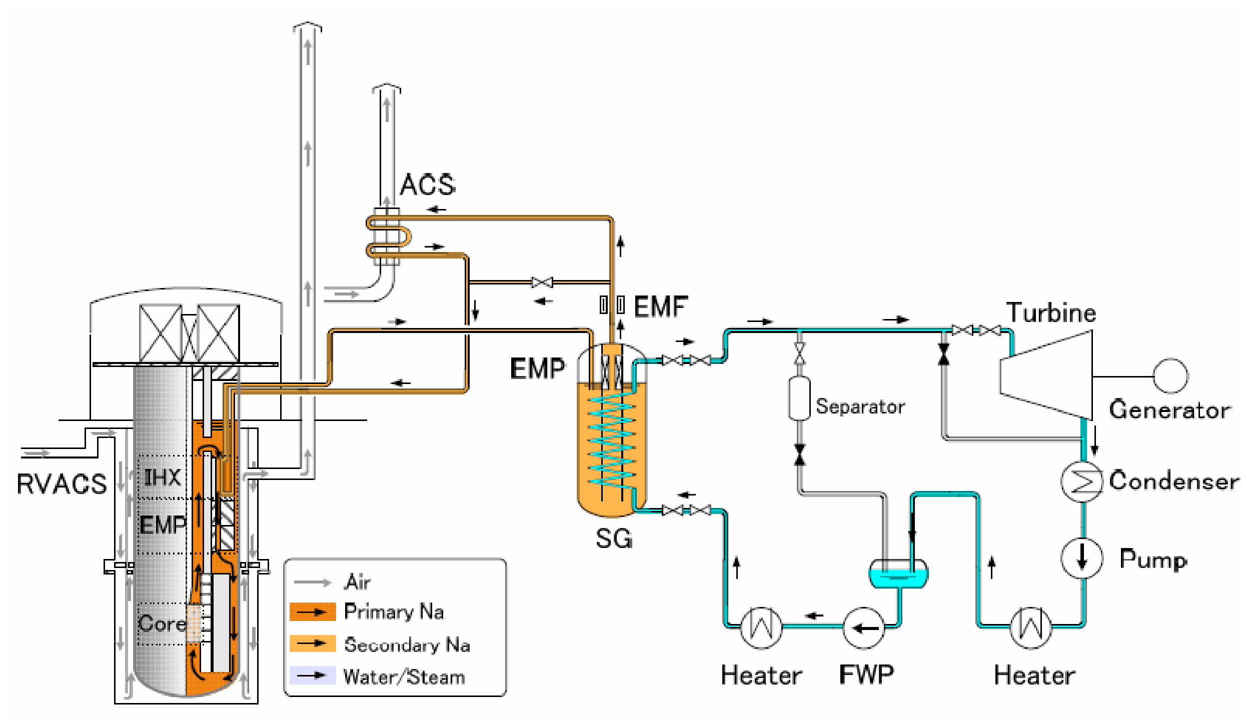

Figure 3-4. System Configuration, 4S Electric Plant

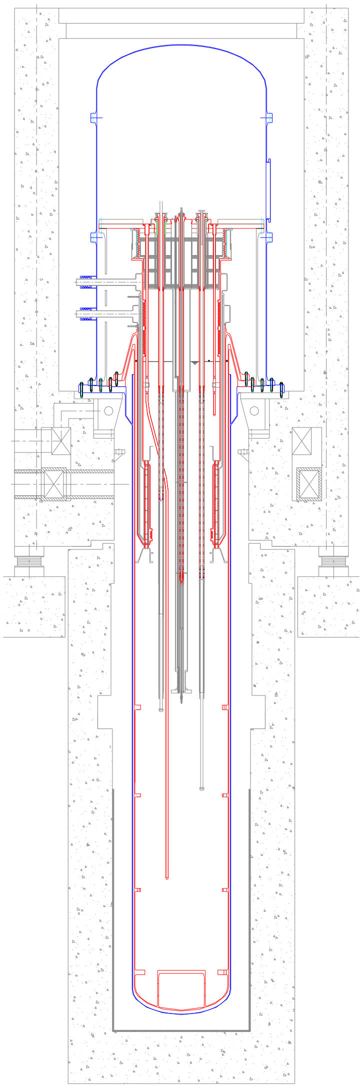

Figure 3-5. 4S Containment Boundaries

3.4.4 Reliability

Toshiba projects the availability of a single 4S module to be 99%. This value includes planned outages, which consist of a 30-day refueling and maintenance outage every 10 years but does not include the consideration of forced outages due to component failure or unexpected events. Therefore, it is unlikely to be achievable, especially for a First-of-a-Kind plant. In an effort to remove some of the uncertainty in predicting the performance of their design, Toshiba has been running a series of tests and continues to perform others to better understand how the reactor and its components perform.

The design life of a 4S module is 30 full power years based on thermal in-situ recovery plant needs. This value could be extended through the use of performance-based life-extension and surveillance specimens.

3.4.5 Safety

The 4S design applies the principles of defense-in-depth in which diverse safety features are used to ensure the safe operation of the plant. These features include the inherent safety of the reactor design, passive safety systems, engineered active safety systems, and potential operator actions that will ensure acceptable levels of safety.

The containment system, which is a steel cylindrical vertical shell constituting the reactor building confinement area, consists of a hemispherical top dome, an air lock and a penetration sleeve, and a guard vessel. Its purpose is to prevent radioactive exposure of the public and employees in the plant vicinity due to diffusion of radioactive materials in the unlikely case of a nuclear power reactor accident.

The guard vessel is an engineered safety feature which ensures the coolant liquid level required for the reactor core cooling in the event of rupture of the reactor vessel and enables removal of decay heat. The guard vessel is slightly larger than the reactor vessel, and the space between the reactor vessel and the guard vessel is limited to the volume such that the liquid level in the reactor vessel can be maintained in the event of sodium leakage due to rupture of the reactor vessel.

The outside of the guard vessel is constantly under natural draft air flow. Outdoor air is taken in from Reactor Vessel Auxiliary Cooling System (RVACS) inlet duct, cools the heat collector and the guard vessel, passes through RVACS outlet duct, and is released to the atmosphere from the stack.

There are several inherent and passive design features of the 4S that contribute to its safety. These include:

- Core damage frequency (CDF) for a single reactor module is expected to be very small (approximately 5×10^{-10} per reactor-year at a point estimate value).

- Reduced probability of component failure through:
  - Elimination of active control systems during normal operation.
  - Elimination of components which consist of rotating parts (i.e., use of EM pumps).
  - Limitation of radioactivity containment area.

- Two fully passive shutdown heat removal systems:
  - RVACS: natural circulation of primary sodium and natural air draft around the Guard Vessel with no active components
  - Intermediate Reactor Auxiliary Cooling System (IRACS): natural circulation of secondary sodium and natural air draft through an air heat exchanger with no active components, only a damper must open for it to be effective.

- A negative reactivity feedback coefficient, meaning that as temperature increases, reactivity decreases. This ensures that excess heat can removed from the reactor without uncontrolled power excursions.

- Low power density (about 12% of EBR-II's) and high thermal capacity, which means that any change in fuel temperature would occur relatively slowly during an accident.

- Reactivity Control System (reflectors) and Back-up Control Rod that are gravity driven.

- The primary coolant system is low pressure, making loss of coolant accidents of low significance and the guard vessel ensures the fuel is not uncovered.

- To prevent sodium leakage, and to mitigate its impact/influence if it occurred:
  - Double sodium boundaries with leak detection system for small leakage of each boundary: 1) Reactor and Guard Vessel for primary sodium, 2) Double-walled tubes of the Steam Generator.
  - If a sodium-water reaction occurs, increased cover gas pressure in the SG makes the secondary sodium drain rapidly to the dump tank through rupture disks.

Note that while these inherent and passive design features of the 4S provide sufficient safety, the defense-in-depth design of the 4S also includes diverse active cooling systems.

3.4.6 Security

With respect to nuclear plants, security is generally considered protection from radiological sabotage or theft and diversion of special materials. The 4S fuel is resistant to radiological sabotage because the reactor modules are below grade and the primary loop contained entirely within the reactor vessel, which is also protected by the guard vessel. The infrequency of refuelings, at once every 10 years, reduces the need to handle fuel.

3.5 MHTGR

The MHTGR is a 350 MWt, helium cooled, graphite moderated, thermal neutron spectrum nuclear reactor. The MHTGR plant is separated into two major areas: a Nuclear Island (NI) and the Energy Conversion Area (ECA).

The Nuclear Island (NI) contains the Reactor Module, the safety systems, and other systems which contain radionuclides. They are separated physically and functionally from the remainder of the facility.

The Energy Conversion Area (ECA) contains conventional power plant structures and equipment separate from the NI. The principal structures are the Operations Center (including the control room), turbine building, and various support structures. Equipment includes the Re-Boiler (Steam-to-Steam Heat Exchanger), the Turbine Generator, the Main Condenser, and supporting pumps and heat exchangers.

3.5.1 Reactor System

The Reactor System consists of a Reactor Core Subsystem, a Neutron Control Subsystem, and a Reactor Internal Subsystem housed in a reactor pressure vessel, which is connected to a steam generator vessel by a concentric cross-duct. The reactor system is part of the reactor module, which is shown in elevation in Figure 3-6.

The primary functions of the Reactor System are to generate heat from fission energy, to transfer that heat to the primary coolant, to control neutron generation rate in the core, and to support and restrain the core. The Reactor System also offers barriers to the release of radioactivity to the primary coolant, provides sufficient reactivity control for shutdown assurance under all postulated conditions, and shields the reactor vessel from direct neutron irradiation.

The Reactor Core Subsystem consists of hexagonal graphite fuel and reflector elements, plenum elements, startup sources, and reactivity control material, located inside the reactor pressure vessel. The active core consists of fuel elements containing blind holes for fuel compacts and full-length channels for helium coolant flow. Columns of fuel elements in 12 locations also contain channels for reserve shutdown material.

The fuel elements are stacked to form columns (10 fuel elements per column). The columns of the active core form an annulus with columns of hexagonal graphite reflector elements in the central and outer regions. Six central reflector elements and 24 side reflector elements contain channels for control rods.

The annular core configuration is selected, in combination with the power density (5.9 MW/m^3), to achieve maximum power rating and still permit passive core decay heat removal while maintaining the maximum fuel temperature below 1,600°C (2,912°F) during a conduction cooldown event.

The core reactivity is controlled by a combination of fixed lumped burnable poison, movable poison and a negative temperature coefficient. The fixed poison is in the form of lumped burnable poison rods; the movable poison is in the form of metal-clad control rods. In the event that the control rods become inoperable, a reserve shutdown control capability is provided in the form of borated pellets, housed in hoppers above the core, which may be released to drop into channels in the active core. The operational mechanisms for the control rods and for the reserve shutdown material are part of the Neutron Control Subsystem.

The control rods are fabricated from natural boron in annular graphite compacts with metal cladding for structural support. The rods are located in channels in the outer ring of the central reflector elements and in the inner ring of the side reflector. These control rods enter the core through top reactor vessel penetrations in which the control rod drives are housed. The 24 control rods located in the side reflector are used for normal control and for trip from high power. The location of the rods in the side reflector prevents damage during depressurized or pressurized passive decay heat removal. The six control rods in the central reflector are inserted only for cold shutdown.

The core incorporates a graded LEU/Th fuel cycle with an initial cycle length of 1.4 effective full power year (EFPY). Equilibrium burnup cycles are 3.3 years, with one-half of the fuel elements replaced every 1.65 years.

When the reactor is shut down for maintenance or refueling, decay heat is removed from the core by the normal Heat Transport System described below, or by the independent Shutdown Cooling System (SCS). The SCS consists of a motor-driven circulator coupled with a compact heat exchanger mounted below the reactor core within the reactor vessel. The shutdown heat exchanger is water cooled. The SCS is not safety related. A third means of providing decay heat removal, a safety related Reactor Cavity Cooling System (RCCS), shown schematically in Figure 3-7 is provided to remove heat radiated from the uninsulated reactor vessel. Reactor cavity cooling is accomplished by natural circulation of outside air through enclosed cooling panels along the reactor cavity walls. Because air naturally circulates through the RCCS continuously, it is always available to remove decay heat under accident conditions without reliance on active components, power supplies, or operator action. The RCCS provides cooling of the reactor cavity concrete during normal operation.

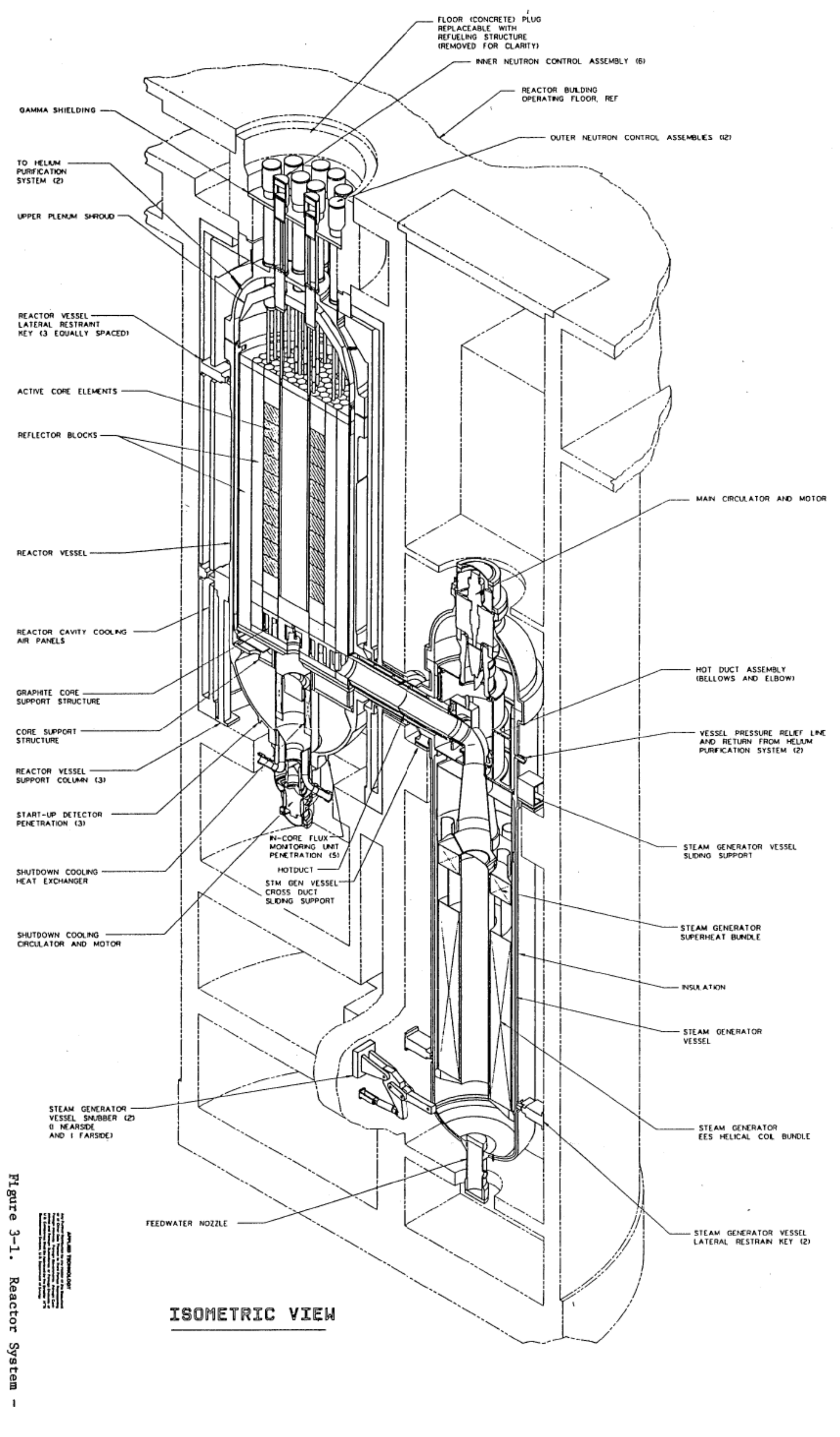

Figure 3-6. MHTGR Module Cutaway View (Reference 12)

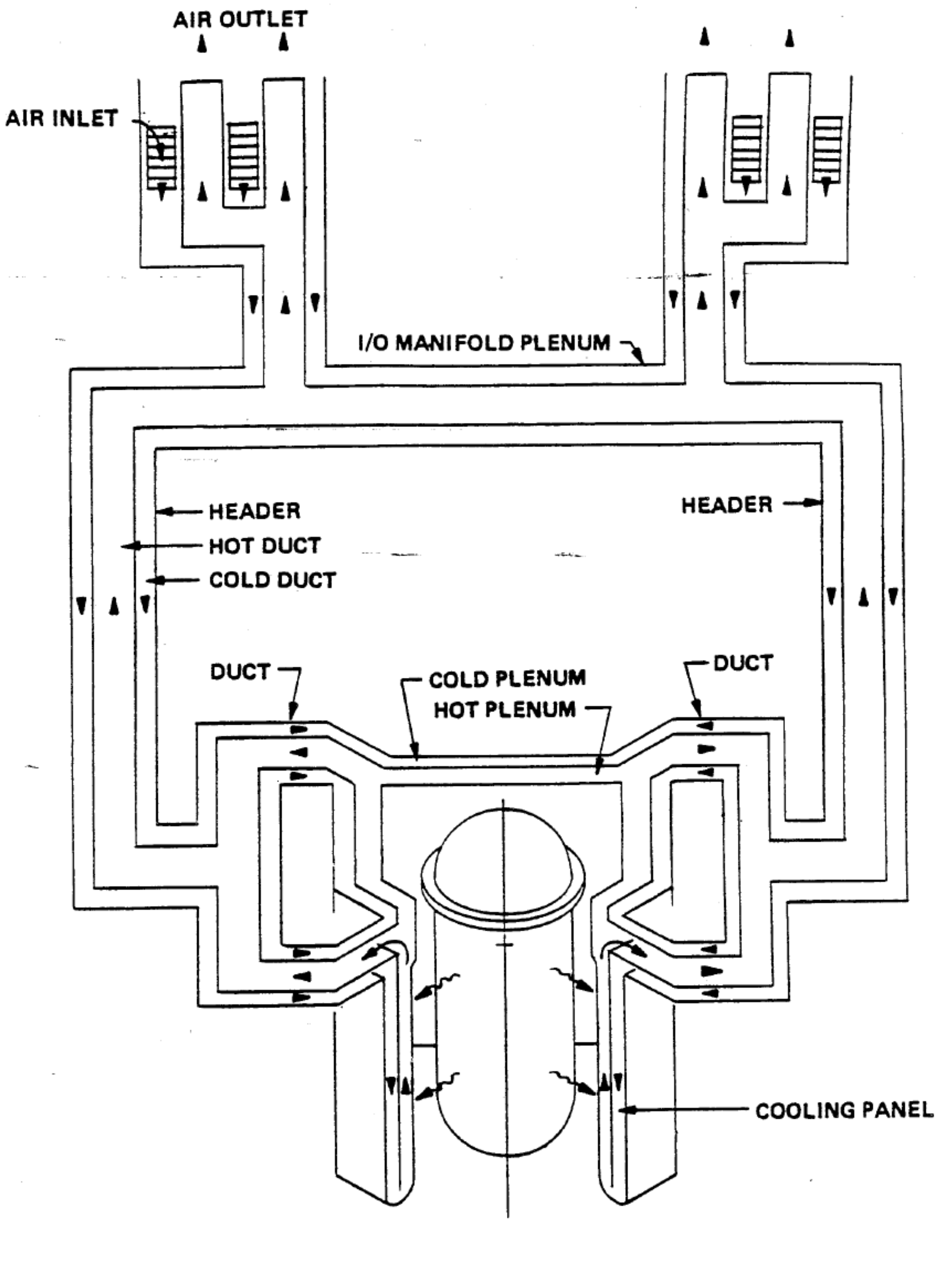

Figure 3-7. MHTGR Reactor Cavity Cooling System (RCCS) (Reference 12)

3.5.2 Fuel

The MHTGR fuel element is prismatic graphite block, shown in Figure 3-8. The fissile fuel is a two-phase mixture of 19.8 percent enriched UO_2 and UC_2, usually referred to as UCO. The fertile fuel is thorium in the form of ThO_2. Both fertile and fissile fuels are in the form of dense microspheres and are coated with a TRISO coating whose primary purpose is to retain fission products. The coated fissile and fertile particles are blended and bonded together with a carbonaceous binder into the form of fuel compacts, which are stacked into the fuel holes in the graphite fuel element.

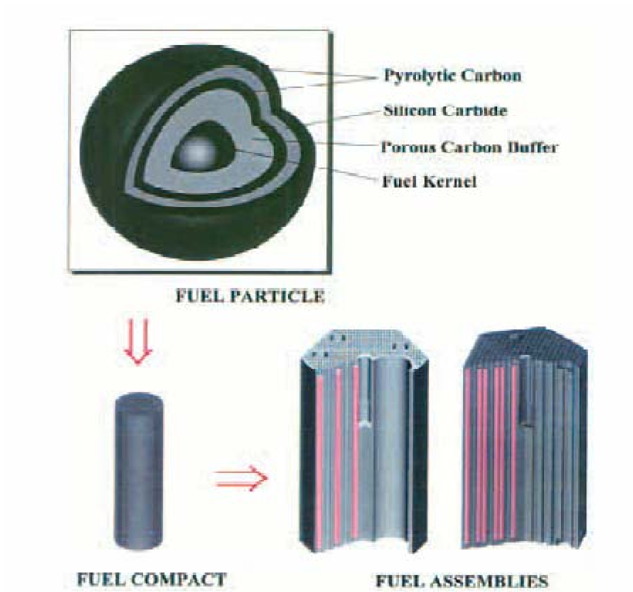

Figure 3-8. MHTGR Fuel Element

3.5.3 Heat Transport System

Within the vessel system, helium coolant flows from the helium circulator to the reactor vessel in the outer annular region of the cross duct, flows down through the core, returns through the center region of the cross duct, down through the steam generator bundle, then up the annular region around the steam generator back to the inlet of the single helium circulator. On the secondary side, feed water enters the steam generator vessel at the bottom, flows up through the helical coil tube bundle, exiting as superheated steam at the upper side of the vessel which is delivered to the re-boiler outside the NI in the ECA. The steam generator is a helical coil shell and tube design. The tube material is Alloy 800H.

In the Re-boiler, heat is transferred to the returning condensate from the water purification system (provided by others) and produces process 100% quality steam for delivery to the oil sands field. The steam outlet conditions are 9.5 MPa (1378 psi) and 307ºC (585ºF). Surplus steam from the steam generator is provided to a steam turbine for conversion into electrical energy.

Figure 3-9 is a simplified flow diagram illustrating how reactor heat is transferred and produces process steam in normal operation. The core inlet coolant temperature is 250°C (498°F), and the average core exit coolant temperature is 687°C (1,268°F).

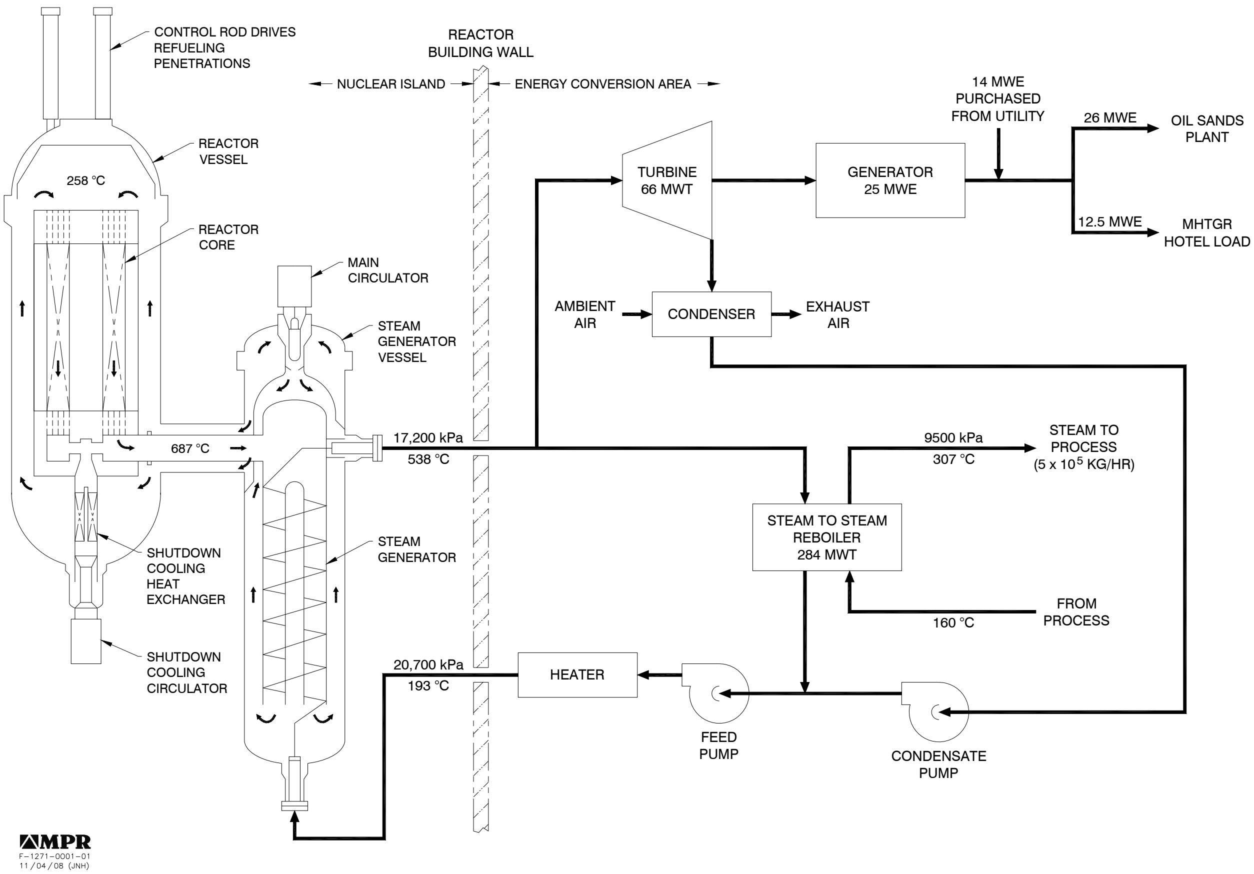

Figure 3-9. MHTGR Flow Diagram and Heat Balance

3.5.4 Reliability/Availability

The design life of an MHTGR module is 40 years. The availability realized from the first operating plant (Peach Bottom) over a period of seven years was 88%, while the availability of Fort St. Vrain was much lower. The projected availability for each module is 90%. This value includes planned outages, which consist of a 30 day refueling outage every 18 months.

3.5.5 Safety

A significant feature of the MHTGR design is its capability of passively rejecting decay heat from the reactor. In the unlikely event that both the normal and shutdown cooling systems are unavailable, decay heat is rejected by radiation, conduction, and natural convection through the reactor vessel wall to the reactor cavity. This heat is then removed from the reactor cavity by the natural circulation of outside air through enclosed panels on the cavity walls. The fuel temperatures that occur during an extended heatup and cooldown in the passive mode are below those temperatures that would cause significant fuel damage and release of fission products to the primary system. Operator error is another potential cause of severe accidents. A characteristic of the MHTGR plant is its benign response, which combined with passive decay heat rejection, simplifies the operator's role and provides long time intervals for deliberate actions before equipment is damaged. These attributes stem from the following inherent features:

- Low power density and high thermal capacity – Any change in fuel temperature would occur relatively slowly during an accident.

- Graphite Core – The high heat capacity and low power density of the core result in very slow and predictable temperature transients. In addition, the strength of graphite increases with temperature up to levels well above those associated with licensing basis events.

- Ceramic Fuel Particles – The main fission product barrier in the MHTGR is the three ceramic coatings surrounding the fuel kernels. Tests have shown that coating integrity is maintained up to sustained fuel temperatures of 1,760°C (3,200°F). The retention of fission products within fuel particle coatings over the spectrum of licensing basis events, which include events that expose the particles to extreme thermal and chemical (air or moisture) environments, is the approach taken for reactor safety. The design ensures fission product retention by passive means and without operator action. Calculated radiation releases at the plant boundary for licensing basis events are less than the US criteria for which public sheltering is recommended. Accordingly, there is no technical reason to involve the public in emergency planning.

3.5.6 Security

The nature of the fissile material being contained in a myriad of tiny particles with three coats of a ceramic material makes the attractiveness of this fuel to a potential terrorist negligible.

The location of the reactor module below grade and within a concrete reactor module wall results in a sabotage resistant situation.

3.6 PBMR

The PBMR is a helium-cooled, graphite-moderated HTR. The thermal, in-situ recovery module design is an evolution of the South African Demonstration Power Plant (DPP). This high temperature gas reactor design was originally developed in Germany. Its name refers to the spherical fuel elements, or pebbles.

The PBMR DPP has a reactor power level of 400 MWt and employs a closed, recuperated Brayton power cycle to generate 165 MWe (Reference 13). The PBMR in-situ thermal recovery HTR module has a reactor power level of 500 MWt and uses the reactor as a heat source to generate steam for use in a conventional Rankine cycle as well as for the in-situ thermal recovery of bitumen.

3.6.1 Reactor Unit

The purpose of the reactor unit system is to safely generate heat from nuclear fission and to ensure that the nuclear reaction can be controlled at all times and can shut down at any time. As the primary structural component of the reactor unit system, the reactor pressure vessel (RPV) houses the metallic core barrel, which supports the fuel core. The fuel core consists of the fuel spheres arranged in a pebble bed in an annular space formed between inner and outer graphite reflectors, which help maintain the nuclear reaction inside the core.

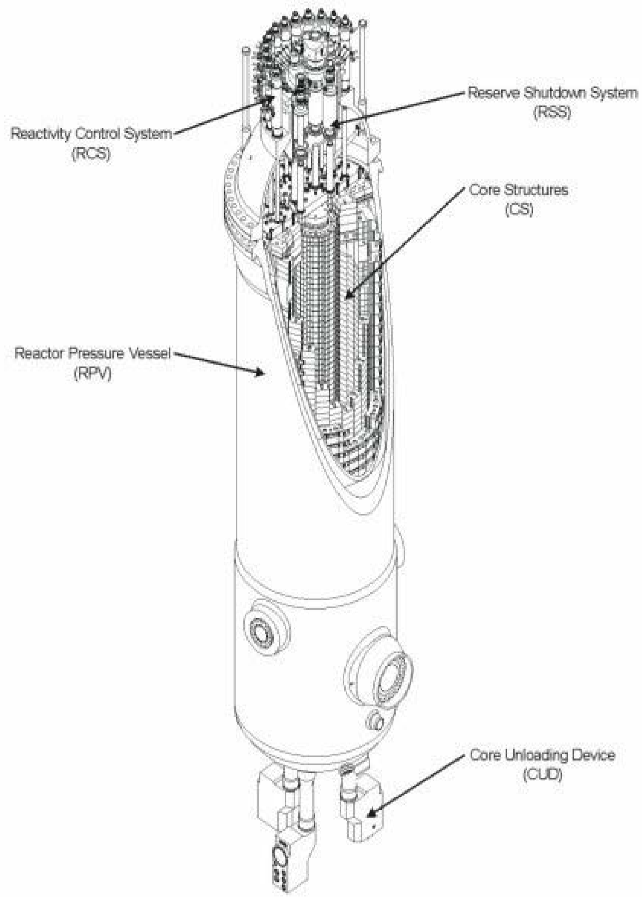

Figure 3-10. PBMR Reactor Vessel Cutaway View

The RPV, weighing 815 tonnes, is 23 meters high and 8 meters in outer diameter. It is the largest item, both in terms of weight and size, that requires transport to the plant site. It is constructed from SA 533 carbon steel for plates and SA 508 carbon steel for forgings.

The PBMR design has two diverse reactivity control systems that can both be used to shut down the reactor. One is the reactivity control system (RCS), consisting of 24 control rods that are inserted into the top reflector to control the rate of the fission reaction within the core. These rods are used to control reactivity during normal operating modes and also to provide emergency shutdown capabilities. The Reserve Shutdown System (RSS) is used for planned maintenance shutdowns of the reactor via the gravitational insertion of Small Absorber Spheres and subsequent pneumatic removal for restart.

3.6.2 Fuel

The PBMR fuel element, shown in Figure 3-11, is a graphite sphere, or pebble, about the size of a billiard ball. Thousands of particles of enriched uranium dioxide coated with silicon carbide and pyrolytic carbon are encased within the sphere. The outer section of the fuel sphere does not contain these particles and, therefore provide mechanical protection for the particles. These particles are known as low enriched uranium triple-coated isotropic (LEU-TRISO) particles. This fuel is similar to that of the GA MHTGR but with a lower enrichment. The enrichment required for the fuel at the initial start-up of each module is 4.2% U_{235} by weight. The enrichment required for all additional fuel is 9.6% U_{235} by weight. The PBMR fuel is intended to match the fuel that demonstrated excellent performance as part of the German HTR programs in the 1980s.

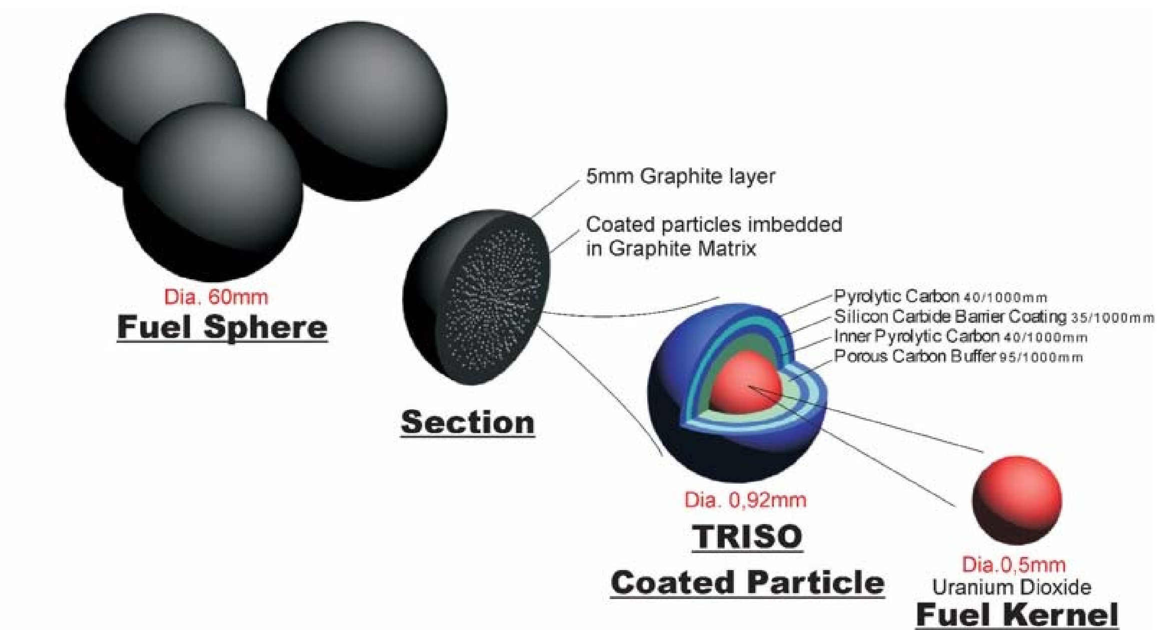

Figure 3-11. PBMR Fuel Element

A unique feature of the PBMR design is online refueling. Fresh fuel spheres are inserted at the top of the core, and used ones removed at the bottom via the fuel handling and storage system (FHSS). The amount of fissionable material left in the fuel pebbles is measured following each pass through the reactor core. If a pebble has an adequate amount left, it is re-inserted into the reactor core. A cycle through the reactor core for a fuel pebble takes approximately six months, and each pebble experiences approximately six cycles. The percentage of enriched uranium used, or burn-up, is significantly greater in the PBMR than in traditional power reactors.

With respect to fuel supply, PBMR is currently developing a fuel supply strategy for its planned reactors in North America.

PBMR's plan for spent fuel storage is to store the spent fuel on site while the plant is operating using on-site passively cooled protected vaults. Upon the decommissioning of the plant, the spent fuel will be transported to a Canadian Nuclear High Level Waste Storage Vault.

3.6.3 Heat Transport

The heat transport system of the PBMR consists of a primary helium loop (primary heat transport system (PHTS), shown in red in Figure 3-12) that removes the heat generated by the nuclear fission reaction and a secondary helium loop (secondary heat transport system (SHTS), shown in yellow in Figure 3-12) that removes heat from the PHTS and transfers it to the water loops (shown in purple and blue in Figure 3-12) to generate steam. The helium coolant of the PHTS enters the PBMR RPV at a temperature of about 280°C and a pressure of 9 MPa. The gas flows down in between the core barrel and the RPV to keep the pressure boundary cool, then up through the side reflector and down again through the pebble bed fuel core, after which it leaves the bottom of the vessel having been heated to a temperature of about 750°C.

Once out of the reactor, the primary helium flows to the intermediate heat exchanger (IHX), which transfers heat to the SHTS. The purpose of the IHX is not only to transfer heat between these two helium loops but is also to provide an additional physical barrier between the PHTS, which will have some fission products in it, and the water loops that will be used in in-situ thermal recovery and electricity generation. The design of the IHX has not started, but the design concept is likely to be a metallic compact heat exchanger. Compact heat exchangers have heat transfer surfaces with a relatively high surface area per unit of volume. The IHX is expected to be constructed of a nickel-based super alloy, either Alloy 800H or Alloy 617. Another important component within the PHTS is the electrically driven gas circulator, which provides the motive force to drive the helium through the loop.

The SHTS is a parallel closed loop, as shown in Figure 3-12. The first parallel loop transfers heat to a steam generator (the power boiler) which generates steam that run through a turbine in traditional Rankine cycle at 538 ˚C and 13 MPa. The second parallel loop transfers heat to a steam generator (the process steam boiler) which generates saturated steam at 9.5 MPa to be used in thermal, in-situ recovery processing.

3.6.4 Reliability

The projected availability of a single PBMR module is greater than 95%. This value includes planned outages, which consist of an annual four day maintenance outage and a 30-day outage for the circulators and support systems every six years. After 24 years, the central reflector of the PBMR has to be replaced. This will require a longer (~6 months) outage. Since the PBMR has online refueling capabilities, no refueling outages need be considered in plant availability.

The design life of a PBMR module is 35 full power years. The design life is based on the design code cases for the metal and graphite structures within the plant. Life extension is possible, however, through the analysis of plant performance and surveillance specimens.

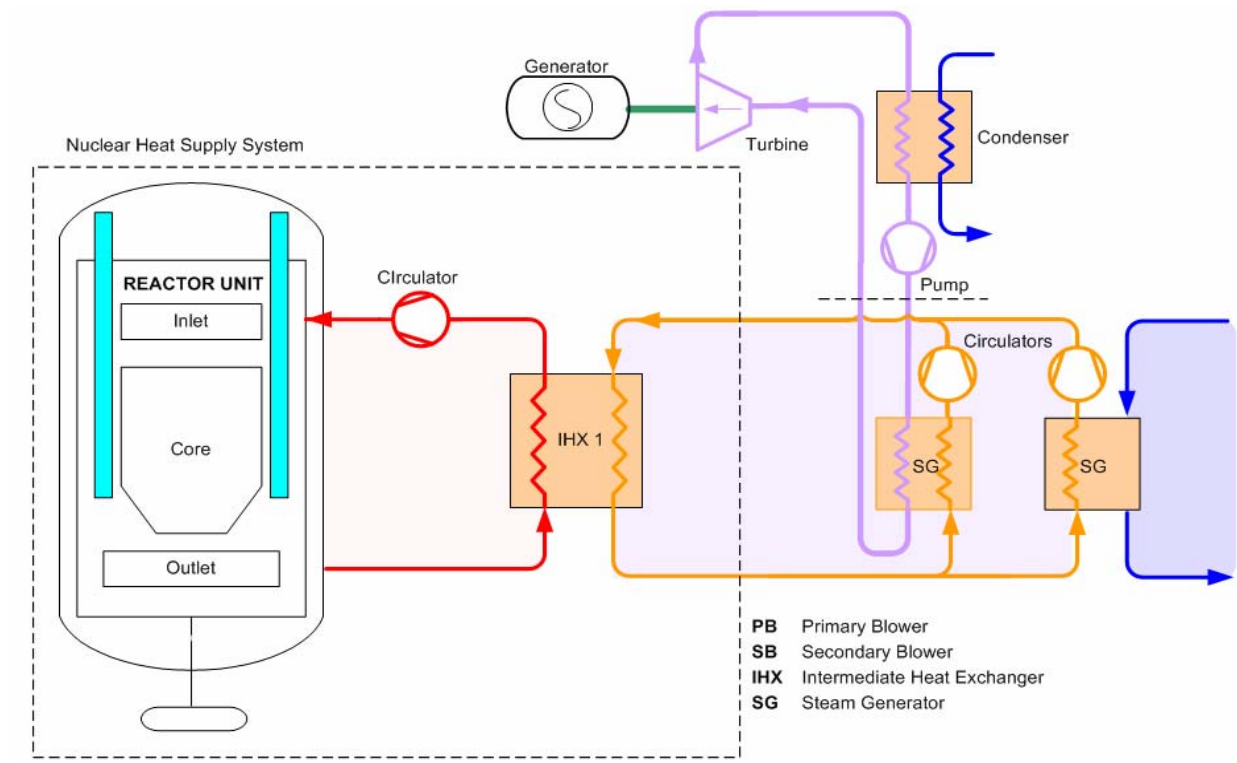

Figure 3-12. PBMR Plant Configuration

Figure Notes:

- Primary Heat Transport System (Helium) – Red
- Secondary Heat Transport System (Helium) – Yellow
- Process Steam and Cooling Water Loops (Water) – Blue
- Electric Steam Cycle (Water) – Purple

3.6.5 Safety

The PBMR design applies the principles of defense-in-depth in which diverse safety features are used to ensure the safe operation of the plant. These features include the inherent safety of the reactor design, passive safety systems, engineered active safety systems, and potential operator actions that will ensure acceptable levels of safety.

There are several inherent and passive design features of the PBMR that contribute to its safety and prevent the need for operator actions. These include:

- The ceramic particles and spheres which contain the fuel can withstand very high temperatures (design temperature of approximately 1600˚C is well below qualification limit of 1800˚C)

- The graphite moderator, which can withstand very high temperatures and store large amounts of heat.

- A negative reactivity feedback coefficient, meaning that as temperature increases, reactivity decreases. This ensures that excess heat can removed from the reactor without uncontrolled power excursions.

- Low power density and high thermal capacity, which means that any change in fuel temperature would occur relatively slowly during an accident.

- Reactivity Control System (control rods) and Reserve Shutdown System that are gravity driven.

- The primary coolant pressure boundary (RPV, PHTS).

- The reactor building, which confines the reactor unit.

- Reactor Cavity Cooling System (RCCS), which has the same function as that of the MHTGR (removes heat from the reactor vessel to the environment). This system is designed to operate during all design basis accidents.

Note that while these inherent and passive design features of the PBMR provide sufficient safety, the defense-in-depth design of the PBMR also includes diverse active cooling systems.

3.6.6 Security

With respect to nuclear plants, security is generally considered protection from radiological sabotage or theft and diversion of special materials. The PBMR fuel is resistant to radiological sabotage because it has such a small kernel of uranium oxide which is well protected within coatings to prevent release of the radioactivity to the environment. The presence of a full load of spent fuel in the fuel handling system is located entirely within the reactor building and inaccessible until fuel removal at end of planned life.

3.7 SUMMARY

There are major differences and close similarities in the three designs. The 4S uses sodium coolant versus the helium coolant for the MHTGR and PBMR. The 4S has metallic alloy fuel, whereas the MHTGR and PBMR each use ceramic TRISO particles but embed them in entirely different fuel element forms. The different thermal ratings provide varying matches to output needs as each stage is brought on-line. All designs are based on technologies that have a strong foundation in past reactor operation, and all have technically unique and challenging features. All designs have passive means for providing core cooling. From a safety and security standpoint, each design has features that provide reasonable assurance of being able to meet regulatory requirements.

Table 3-3 summarizes the key characteristics of each reactor module design.

Table 3-3. Reactor Module Design Comparison

	4S	MHTGR	PBMR
Core Thermal Power (MWt)	135	350	500
Coolant	Sodium	Helium	Helium
Moderator	N/A	Graphite	Graphite
Core Inlet Temperature (˚C)	355	258	280
Core Outlet Temperature (˚C)	510	687	750
Heaviest Transported Component/ weight (tonnes)	RV/100	RPV (lower section)/ 648	RPV/815
Largest Transported Component/ dimensions (m)	RV/23 x 3.6 x 3.6	Steam generator/ 28 x 5.2 x 5.2	RPV/23 x 8 x 8
Fuel Enrichment	18 Wt% U-235	19.9 Wt% U-235	9.6 Wt% U-235
Refueling Mode	Batch	Batch	On-line
Outage Schedule	30 days/10 yrs	30 days/1.5 yrs	4 days/yr + 30 days/6 yrs
Design Life (years)	30	40	35
Projected Availability[1]	99%	90%	95%

Note 1: The projected availability values are vendor estimates. MPR does not judge there to be an appreciable difference in the expected availability of the First-of-a-Kind designs at this point.

4 Functional and Operational Requirements

The goal of this report is to evaluate and compare the use of three conceptual HTR designs as an alternate energy source for a hypothetical 120,000 bpd in-situ bitumen recovery plant, built in four equal stages. The first step of this process is to determine what the functional and operational requirements for such a plant would be, based on prior experience with plants of this type. Note that the HTR plant is assumed to be providing both process steam and electricity. The next step is to evaluate how the three candidate design concepts match up with these requirements on both an absolute and relative basis.

4.1 In-Situ Thermal Recovery Project Requirements

IMV Projects (IMV) performed a study to determine the functional and operational requirements of the conceptual 120,000 bpd thermal, in-situ recovery project and the corresponding functional and operational requirements of the HTR plant (see Attachment A). These requirements are summarized below.

4.1.1 Location

The target location for the thermal, in-situ recovery project was chosen to be the Athabasca oil sands region in northeastern Alberta.

4.1.2 Recovery Method

The specific recovery method chosen as the focus for this study was high pressure (HP) steam-assisted gravity drainage (SAGD) recovery, which is used increasingly in the Athabasca oil sands region and is considered a burgeoning technology. However, the conclusions of this report will also be relevant to low pressure (LP) SAGD and Cyclic Steam Stimulation (CSS) methods which also are used in thermal, in-situ recovery, depending on the geological characteristics of the oil sands deposits.

The SAGD Process

In the HP SAGD process, saturated steam at about 9.5 MPa (about 307°C) is sent from the oil sands plant steam generators out to the well heads, which may be located as far away as 10 km from the steam generators. From the well heads, the steam flows underground via drilled wells which descend downward until they reach the oil sands layer and then extend horizontally outward through the layer. The steam flows through the injector well into the porous, bitumen-laden oil sands where it transfers heat to the layer, thereby reducing the viscosity of the bitumen as the thermal wave moves outward. After a period of time the oil becomes sufficiently hot to flow downward to a second, horizontal drilled well (product well) located about five meters below the first well and a mixture of condensed water, sand and flowing bitumen are pumped back to the surface, at close to 200°C. The exiting mixture of product flows back to the oil sands recovery plant.

At the recovery plant, the sand and water are separated from the bitumen. The bitumen is diluted with organic diluent and the resultant "dilbit" is sent away by pipeline to the remote upgrading or refinery areas. The water that has been separated from sand and bitumen is known as produced water, which then undergoes further processing and water treatment to remove excess contaminants before it is sent as an output from tower evaporators back to the process steam generators to complete the steam/water cycle.

The phases of a SAGD project are (Reference 14):

1. **Start up/circulation** - Steam is circulated in both the injector and producer for 2-4 months to heat up the region between the wells. The SAGD process can begin once the near well region is mobilized and there is fluid communication between the injector and producer.

2. **Ramp up** - Injection and production rates increase as the steam chamber grows to the top of the reservoir. This ramp up stage can take 6-18 months depending on the operating conditions.

3. **Plateau –** At this point, the steam chamber has reached the top of the reservoir and begins to spread laterally. This period is characterized by the best (peak) production rate. This peak rate period can last anywhere from 18-60 months depending on reservoir quality and thickness.

4. **Wind down** - When the SAGD steam chamber is mature and recovery is greater than 45% the operation goes into wind down mode. Production rates begin to decline due to the shallower drainage angle of the chamber interface. The Steam Oil Ratio (SOR) at this time begins to increase due to lower bitumen rates and increased heat loss to the reservoir.

4.1.3 Water Treatment

For this evaluation, the following assumptions are made with respect to water treatment:

- 100% of the produced water (PW) is treated at the central plant. PW water treatment (WT) equipment would consist of a low pressure, steam driven evaporator and crystallizer. The target standard for water purity is from the ASME Boiler Feedwater (BFW) Operating Practices, but the low pressure evaporators are not able to meet this specification due to the presence of volatile organic compounds and carryover of silica. As a result, this water may not be suitable for use in superheaters or steam turbines. The temperature of the BFW sent to the steam generator is 160˚C.

- The BFW make-up water need is 10%.

- The treatment of make-up water is performed within the HTR plant.

4.1.4 Steam Requirements

For HP SAGD recovery, 100% quality steam at 9.5 MPa (saturation temperature = 307˚C) is required to be received from the process steam generator outlet.

For this evaluation, an average steam to oil ratio (SOR) of 2.5 is assumed. For this SOR and the feed water temperature of 160°C, the calculated steam flows and thermal power required for each development stage are shown in Table 4-1. CWE means Cold Water Equivalent.

Table 4-1. Steam Flow Requirements

Plant Size (HP SAGD)	Volume Rate (CWE)	Mass Rate	Thermal Power
bpd	*m^3/d*	*kg/d*	*MWt*
30,000	11,925	1.19E+07	284
60,000	23,850	2.39E+07	568
90,000	35,775	3.58E+07	852
120,000	47,700	4.78E+07	1136

4.1.5 Electrical Requirements

The estimated electrical demand for the central plant and the well pads is shown in Table 4-2.

Table 4-2. Electrical Demand

Plant Size (HP SAGD)	Central Plant	Well Pads	Total Demand
bpd	*MWe*	*MWe*	*MWe*
30,000	18	5	23
60,000	36	10	46
90,000	54	25	79
120,000	72	34	106

Note that well pad demand loads vary with the later stages' increasing distance from the central plant, and, as a result, the increase in total electrical demand is non-linear. Also, note that these electrical demands are solely for the central plant and well pads, including feedwater pumping power. HTR plant electrical demands are considered in Section 4.2 for each design.

4.1.6 Flexibility of Operation

The startup of an in-situ thermal well is a slow process that requires varying amounts of steam. Initial heatup of the oil sands field requires low rates of steam input (about 10% of the expected steam flow at full rated power for the field) over a considerable length of time. Today's practices generally employ four Once-Through Steam Generators (OTSGs) for each 30,000 bpd plant. The minimum turn down for one OTSG is about 40% of its rated power, or about 1,200 m^3/d cold water equivalents (CWE) at 28 MWt. Therefore, the HTR plant should be able to generate as low a level of process steam for the oil field as 28 MWt under stable operating conditions.

4.1.7 Reliability Requirements

A long-term loss of steam supply should be avoided as reservoir cool-down and disruption is expensive and difficult to recover from. The HTR plant should be able to provide steam supplies to the following supply parameters:

- A complete of loss steam production is permitted for no longer than one day.
- A 67% loss of steam production is permitted for no longer than one week.
- A 33% (or less) loss of steam production is permitted for no longer than one month.

4.1.8 Field Life

- The expected operating life of each stage is approximately 30 years (Attachment A). The HTR plant should be able to function throughout the lifetime of each stage.

4.2 HTR Evaluation

Each HTR design is evaluated below based on how well it can meet the defined functional and operating requirements of the in-situ thermal recovery project. The key considerations for each plant design in meeting these requirements are:

- The ability to meet the steam and electrical demands of the central plant for each stage.
- The ability of the HTR to function in the harsh weather conditions and remoteness of the Athabasca oil sands region of Northern Alberta.
- The flexibility to meet low steam demands and variable steam demands for startup.
- The ability to meet the reliability requirements.
- The ability to function for the lifetime of the in-situ thermal recovery project.
- The need for additional feedwater treatment before it passes through the steam generators.

4.2.1 Toshiba 4S Modular Reactor

Steam and Electrical Output

The 4S approach to meeting the in-situ thermal recovery project steam and electric requirements is to deploy modules that are specialized to generate steam or electricity. Each steam module can supply enough steam to recover approximately 14,250 bpd of bitumen. Each electrical module generates 55 MWe gross. It must meet its internal electrical demand (5 MWe) as well as that of the steam modules (4 MWe each), the central plant, and the well pads.

This stage-wise approach to meeting the project requirements is summarized in Table 4-3. It is capable of meeting the steam and electrical requirements of the in-situ, thermal recovery project within a few thousand bpd. During the period in which the stages are still being developed, the 4S modules will be generating excess electricity that can be sold to the electrical grid. When all four stages are complete, the electrical modules should be capable of meeting the electrical demand for the HTR modules, central plant, and the well pads. If an electric module must be taken off-line, needed electricity can be supplied by the grid.

Table 4-3. 4S Project Development Approach

		Stage 1	**Stage 2**	**Stage 3**	**Stage 4**
Steam	**Number of Steam Modules**	2	4	6	8
	Bitumen at 2.5 SOR (kbpd)	29	57	86	114
Electric	**Number of Electric Modules**	1	2	3	3
	Gross Electric Production (MWe)	55	110	165	165
	HTR Loads (MWe)	13	26	39	47
	Central Plant Loads (MWe)	23	46	79	106
	Excess Electrical Capacity (MWe)	19	38	47	12

Low Steam Supply

It is unlikely that a steam generator for a 4S steam module would be able to operate acceptably at 28 MWt (~20% of rated flow). A backup steam supply for startup of the wells in Stage 1 would, therefore, be needed. In later stages, adding a 10% increment of steam flow needed for new wells to existing steam loads should not be a problem.

Ease of Operation

The operation of the 4S steam and electric plants should not be affected by severe weather nor the remoteness of the plant location any more than a gas-fired plant. The 4S concept was identified as having the potential as a “nuclear battery” suitable for nearly unattended operation in a remote location in Alaska.

The steam plant (eight modules) and electric plant (three modules) are each intended to be operated by six operators per shift. Operating eight independent modules will require showing the CNSC that operational control is satisfactory.

Reliability

With a projected availability of 99%, each 4S module has a very high degree of expected reliability. Forced outages such as those resulting from a component failure or initiating event are, therefore, expected by Toshiba to be extremely unlikely. However, for a First-of-a-Kind plant, it is very unlikely that this availability will be achieved. See Subsection 9.5.1 for a discussion of the risk of forced outages affecting the reliability of a First-of-a-Kind HTR plant.

Should a forced shutdown occur, the small size of the 4S gives it an advantage with respect to meeting the steam production reliability requirements. Upon the completion of Stage 1, two 4S steam modules will have been built. Therefore, should one of the modules be forced to shut down, 50% of the required steam production will be available. This will allow for a forced shutdown of one module for up to one week. To allow for a shutdown of up to a month before the completion of Stage 2, a backup steam supply of 46 MWt will have to be provided. To allow for a shutdown of up to a month before the completion of Stage 2, a backup steam supply of 46 MWt will have to be provided. For a shutdown beyond one month, a backup steam supply of 135 MWt will have to be provided.

Upon the completion of Stage 2, four 4S steam modules will have been built. The forced shutdown of any one of these modules can be sustained for up to one month without backup steam. For a shutdown beyond one month, a backup steam supply, again of 135 MWt, will have to be provided.

With respect to planned outages, each module has a refueling outage every ten years that lasts 30 days. For the week long maintenance outage, 33% of the required steam production must be available. This can be accommodated in all stages. The 30-day refueling outage will also be satisfactory, as there will several modules available to back up the shutdown reactor. Note that the length of the refueling outages leaves little margin for extension of the outage if the HTR plant reliability requirements are to be met.

Plant Lifetime

The expected plant operating lifetime of the 4S is 30 years. Therefore, the modules fit well with the expected 30-year life of each stage of the in-situ recovery project.

Water Treatment Needs

Because the 4S approach is to have separate plants for the generation of electricity and the generation of process steam, the electric steam cycle will remain isolated from the process steam cycle. As such, the treatment of makeup water for this system would not affect the process steam cycle.

The treatment of the PW in the process steam cycle via evaporators is expected to be sufficient for the quality of steam required. If residual contaminants, such as volatile organic compounds and silica, become a concern for the process steam boiler, steam generator chemistry adjustment, further treatment of PW, or periodic maintenance of the steam generator would be considered.

4.2.2 General Atomics MHTGR

Steam and Electrical Output

The MHTGR approach to meeting the thermal, in-situ recovery project requirements is to deploy four HTR modules generating 350 MWt each. The staged approach of the MHTGR is summarized in Table 4-4. It is capable of meeting the steam requirements of the in-situ thermal recovery project. When all four stages are complete, the HTR plant will require 45 MWe to be supplied by the grid.

Table 4-4. MHTGR Project Development Approach

	Stage 1	Stage 2	Stage 3	Stage 4
Number of Modules	1	2	3	4
Bitumen at 2.5 SOR (kbpd)	30	60	90	120
Gross Electric Production (MWe)	28	55	83	111
HTR Loads (MWe)	12.5	25	37.5	50
Central Plant Loads (MWe)	23	46	79	106
Excess Electrical Capacity (MWe)	-7.5	-16	-33.5	-45

Low Steam Supply

The MHTGR has the ability to operate at partial load down to about 10% power. It is unlikely that its steam generator would be able to operate acceptably at 28 MWt (8% of rated flow). A backup steam supply for startup of the wells in Stage 1 would, therefore, be needed. In later stages, adding a 10% increment of steam flow needed for new wells to existing steam loads should not be a problem.

Ease of Operation

The operation of the MHTGR plants should not be affected by severe weather nor the remoteness of the plant location any more than a gas-fired plant.

Reliability

With a projected availability of 90%, the MHTGR has the lowest projected single unit availability. However, at this point in the design of the plant, it is not certain that it will achieve a lower availability than the other HTRs. The MHTGR also has the most frequent refueling shutdowns, with one occurring every 18 months.

The MHTGR approach is to build one module for Stage 1. Therefore, if a forced shutdown should occur, there will need to be a backup steam supply of 94 MWt (33% of the total thermal power for steam generation during Stage 1) for the module to be shut down for one week. To allow for a shutdown of one month, there will need to be a backup steam supply of 190 MWt (67% of the total thermal power for steam generation during Stage 1). For a shutdown beyond one month, a backup steam supply of 284 MWt will have to be provided.

Upon the completion of Stage 2, two modules will have been built. Therefore, should one of the modules be forced to shut down, 62% of the required steam production will be available, assuming the steam generators are sized for the full thermal power of the plant. This will allow for a forced shutdown of one module for up to one week. To allow for a longer shutdown (up to and beyond month) before the completion of Stage 3, a backup steam supply will have to be supplied.

Upon the completion of Stage 3, three MHTGR modules will have been built. The forced shutdown of one of these modules can take place for up to one month. For a shutdown beyond one month, a backup steam supply will have to be provided.

Plant Lifetime

MHTGR plants were designed with the intent for operational lifetimes of at least 40 years and should be able to support the thermal, in-situ recovery plant objective of 30 years.

Water Treatment Needs

The MHTGR design incorporates a separate steam cycle for electric generation. Because the electric steam cycle will remain isolated from the process steam cycle, the treatment of makeup water for this system would not affect the process steam cycle.

The treatment of the PW in the process steam cycle via evaporators is expected to be sufficient for the quality of steam required. If residual contaminants, such as volatile organic compounds and silica, become a concern for the process steam boiler, steam generator chemistry adjustment, further treatment of PW, or periodic maintenance of the steam generator would be considered.

4.2.3 PBMR Pty Ltd. PBMR

Steam and Electrical Output

The PBMR approach to meeting the in-situ thermal recovery project requirements is to deploy three HTR modules generating 500 MWt each. The staged approach of PBMR is summarized in Table 4-5.

Table 4-5. PBMR Project Development Approach

	Stage 1	Stage 2	Stage 3	Stage 4
Number of Modules	1	2	3	3
Bitumen at 2.5 SOR (kbpd)	30	60	90	120
Gross Electric Production (MWe)	86	172	259	155
HTR Loads (MWe)	28	56	84	84
Central Plant Loads (MWe)	23	46	79	106
Excess Electrical Capacity (MWe)	35	70	96	-35

This approach is capable of meeting the steam and electrical requirements of the in-situ, thermal recovery project. During the period in which the stages are still being developed, the PBMR modules will be generating excess electricity that can be sold to the electrical grid. When all four stages are complete, the HTR plant will require 35 MWe from the grid to meet the entire electrical demand of the thermal, in-situ recovery project.

Low Steam Supply

The PBMR has the ability to operate at partial load down to about 50% power. It is unlikely that its steam generator would be able to operate acceptably at 28 MWt (~6% of rated flow). A backup steam supply for startup of the wells in Stage 1 would, therefore, be needed. In later stages, adding a 10% increment of steam flow needed for new wells to existing steam loads should not be a problem.

Ease of Operation

The operation of the PBMR plant should not be affected by severe weather nor the remoteness of the plant location any more than a gas-fired plant.

Reliability

With a predicted availability of greater than 95%, each PBMR module has a high degree of expected reliability. Forced outages such as those resulting from a component failure or initiating event are, therefore, calculated to be extremely unlikely by PBMR. However, for a First-of-a-Kind plant, it is very unlikely that this availability will be achieved. See Subsection 9.5.1 for a discussion of the risk of forced outages affecting the reliability of a First-of-a-Kind HTR plant.

PBMR's approach is to build one module for Stage 1. Therefore, if a forced shutdown should occur, there will need to be a backup steam supply of 95 MWt (33% of the total thermal power for steam generation during Stage 1) for the module to be shut down for one week. To allow for a shutdown of one month, there will need to be a backup steam supply of 190 MWt (33% of the total thermal power for steam generation during Stage 1). For a shutdown beyond one month, a backup steam supply of 284 MWt will have to be provided.

Upon the completion of Stage 2, two PBMR modules will have been built. Therefore, should one of the modules be forced to shut down, 67% of the required steam production will be available, assuming that the steam generators are sized for the full thermal power of the plant. This will allow for a forced shutdown of one module for up to one month. For a shutdown beyond one month, a backup steam supply will have to be provided.

With respect to planned outages, the PBMR does not shut down for refueling, but each module has a planned annual maintenance outage that lasts four days and a longer 30-day planned outage every six years. For the week long maintenance outage, 33% of the required steam production must be available. This can be accommodated in Stages 2 and 3, when at least two modules will be present. During Stage 1, when only one module will be available, a backup steam supply will be required. The 30-day outage should be acceptable, as there will be three modules available at that point in time. Note that the length of this outage leaves little margin for extension of the outage if the HTR plant reliability requirements are to be met.

An additional item regarding the PBMR operating schedule is replacement of the central neutron reflector in each module, which is scheduled to take place after 24 years of operation. This would require a long outage (more than one month), but given that this activity can be planned years in advance, the outage of the HTR plant should be capable of being accommodated.

Plant Lifetime

The expected plant operating lifetime of the PBMR is 35 full power years. This is sufficient to accommodate the expected 30-year life of each stage of the in-situ recovery project.

Water Treatment Needs

The PBMR design incorporates a separate steam cycle for electric generation. Because the electric steam cycle will remain isolated from the process steam cycle, the treatment of makeup water for this system would not affect the process steam cycle.

The treatment of the PW in the process steam cycle via evaporators is expected to be sufficient for the quality of steam required. If residual contaminants, such as volatile organic compounds and silica, become a concern for the process steam boiler, steam generator chemistry adjustment, further treatment of PW, or periodic maintenance of the steam generator would be considered.

4.3 SUMMARY

The demands of the in-situ thermal recovery project require that the HTR plant provide reliable steam and electricity. The different module sizes, configurations, predicted availabilities, and maintenance schedules of each provide insight into the suitability of the plant to the thermal recovery project.

4.3.1 HTR Plant Fit

The injection-steam heat load for the hypothetical plant was 284 MWt per 30,000 bpd stage, and the electric power demand for the plant and its well pads was approximately 26.5 MWe per stage (or 70 MWt equivalent) for a total thermal load per SAGD stage of 354 MWt. When the internal HTR plant electric loads are included, the net heat load requirement per stage is about 400 MWt or 1600 MWt for the 4-stage plant. Based on the size of the existing vendor modules, and to avoid using a larger number of reactors that would leave too much power unused, the numbers of modules proposed by the vendors to meet the design conditions were: eleven for 4S (1485 MWt); four for MHTGR (1400 MWt) and three for PBMR (1500 MWt). Both MHTGR and PBMR had sufficient power for the 1136 MWt of injection steam needed for 120 kbpd under the design assumptions of 2.5 SOR. However, 4S proposed eight steam-only modules that produced 1080 MWt which would support 114 kbpd and that became their design rating. A ninth module for steam would use 56MWt for injection steam and have an excess of 99 MWt, and so it wasn't proposed.

For the MHTGR and PBMR plants, each was conceptually capable of providing the required injection-steam for the project, while the slight shortages of total needed power for the completed plant could be accommodated by buying the balance of needed electricity from the grid. The ability to adjust steam load for variations in SOR with time could be advantageous. For plants that provide both electric power and process injection steam from the same modules, the process steam load for bitumen recovery at each stage can be increased by adjusting the amount of the total electrical demand that is taken from the grid. Thus, the amount of electrical load taken from the grid can provide the necessary margin to fit the HTR modular reactor injection-steam production to meet changes in demand from the conceptual plant. For HTR modules that can make both steam and electricity, sizing the process steam generator large enough to handle the full thermal capacity of the reactor would maximize this flexibility.

This flexibility is not available for a plant whose modules produce only steam or only electric power. Because Toshiba proposed two separate 4S module variants (one steam-only and one electric power-only) in order to utilize their electric-only baseline design, this flexibility would not be realized for this approach. However, if this became a design criteria, the 4S design could be evaluated for modification to provide a single plant module with both steam and electric production..

4.3.2 Low Steam Supply Flow

The initial operation for startup/circulation of steam to fresh wells requires that a low level flow (about 10% of the full load for the stage or 28 MWt for Stage 1) of in-specification steam be supplied to the well heads for two to four months, followed by a ramp-up over the next 6 to 18 months. Each of the HTR designs uses a single large steam generator for process steam to the wells, and it is unlikely that the steam generators for PBMR or MHTGR would be able to operate acceptably below 10% of their rated flow. A backup steam supply capable of producing 28 MWt of steam for startup of the wells in Stage 1 would be needed. In later Stages, adding a 10% increment of steam flow needed for new wells to existing steam loads should not be a problem.

4.3.3 HTR Plant Reliability

The reliability of each HTR plant can be judged based on module availability, planned outages, and the availability of backup steam. As discussed in subsection 9.5.1, the reliability of a First-of-a-Kind design has considerable uncertainty and is a risk consideration. Reliability not only affects the viability of the thermal recovery project but also its economics. MHTGR also has the most planned outages, with a 30 day refueling outage every 18 months. The need for backup steam for nuclear plant outages up to one week, up to one month, and beyond one month is considered for each plant below.

- **Up to One Week**: Backup steam would be not be required for this contingency for 4S in any stage, whereas MHTGR and PBMR would require backup steam in Stage 1.

- **Up to One Month**: For a one month shutdown period, at least 67% of the steam load would have to be maintained. Backup steam would be required for all alternatives in Stage 1 and for MHTGR in Stage 2.

- **Beyond One Month**: Steam output cannot be lost for longer than one month. Therefore, no reactor module can shutdown for longer than one month without backup steam being provided. Should a 4S steam module shut down for longer than one month at any stage, 135 MWt of backup steam must be provided. Should an MHTGR or PBMR module shutdown for longer than one month during Stage 1, 284 MWt of backup steam must be provided. By the completion of Stage 4, the MHTGR requires 86 MWt of backup steam, and the PBMR requires 136 MWt.

Table 4-6 provides a summary of the steam output capabilities with all modules operating and one module shutdown for each HTR plant.

4.3.4 Backup Steam Supply

Based on the low steam supply flow and high reliability requirements of the thermal, in-situ recovery project, it will be mandatory for each plant to have a supply of backup steam. It would be prudent to assume that unplanned outages, even over a month in length, might occur for all three of these First-of-a-Kind plants, particularly in the first years of operation.

4.3.5 Plant Lifetime Plus

All of the HTRs can meet or exceed the 30-year lifetime requirement for the oil sands fields. Moreover, some or all of the HTRs may be able to extend their lifetime based on experience with earlier generations of nuclear reactors. If this occurs, there are a number of potential options for utilizing the continued supply of energy. These include:

- Continue to generate electrical energy for the grid, or other plants, including expansion/upgrade of electrical capability to full power for the reactor module;

- Use superheat or other means to extend the distance that steam can travel beyond 10 km.

- Provide steam for other industrial processes. These could include bitumen upgrading or refining, hydrogen production, coal to gas or coal to liquid, desalination, etc.

Table 4-6. HTR Plant Output and Reliability[1]

		Stage 1	Stage 2	Stage 3	Stage 4
4S					
Rated Full Steam Output[2]		270	540	810	1080
Steam Output (One Module Down)[3]		135	405	675	945
Up to One Week	Steam Required	90	180	270	360
	Backup Steam Required[4]	N/A	N/A	N/A	N/A
Up to One Month	Steam Required	181	362	543	724
	Backup Steam Required	**46**	N/A	N/A	N/A
Beyond One Month	Steam Required	270	540	810	1080
	Backup Steam Required	**135**	**135**	**135**	**135**
MHTGR					
Rated Full Steam Output		284	568	852	1136
Steam Output (One Module Down)		0	350	700	1050
Up to One Week	Steam Required	95	189	284	379
	Backup Steam Required	**95**	N/A	N/A	N/A
Up to One Month	Steam Required	190	381	571	761
	Backup Steam Required	**190**	**31**	N/A	N/A
Beyond One Month	Steam Required	284	568	852	1136
	Backup Steam Required	**284**	**218**	**152**	**86**
PBMR					
Rated Full Steam Output		284	568	852	1136
Steam Output (One Module Down)		0	500	1000	1000
Up to One Week	Steam Required	95	189	284	379
	Backup Steam Required	**95**	N/A	N/A	N/A
Up to One Month	Steam Required	190	381	571	761
	Backup Steam Required	**190**	N/A	N/A	N/A
Beyond One Month	Steam Required	284	568	852	1136
	Backup Steam Required	**284**	**68**	N/A	**136**

Note 1: All values in MWt.
Note 2: Rated steam output to achieve design bitumen production.
Note 3: Maximum amount of steam available for bitumen if all steam from remaining modules can be used for bitumen production (e.g., drop electrical production).
Note 4: Amount of supplemental steam needed to meet bitumen production when 1 module is down.

5 Construction in Alberta

A study was conducted to evaluate construction related to the Athabasca oil sands region of Alberta. This study included special issues such as the amount and type of labor skills that are available and the difficulties of transporting large and heavy loads into this region. The detailed study is included with this report as Attachment A.

5.1 Background

Construction is of concern in any large, capital intensive project. Special considerations and planning must be utilized to meet project goals. It is an even larger concern in the Athabasca oil sands region of Alberta due to the unique conditions present in that area that will make construction more difficult. Of particular note are the remote location, with limited transportation infrastructure; severe and variable climatic conditions; and minimal local labor pool. Therefore, it is important that the implications of the site characteristics on construction of the different types of HTRs being evaluated be identified. In addition, the unique requirements imposed by the nuclear aspects on all designs are addressed. This section considers:

- Labor
- Transportation
- Complexity of Design Relative to Construction
- Footprint/Excavation
- Schedule

5.2 Labor

5.2.1 Common to all HTR Designs

Labor Force: The construction study discusses the general availability of labor, general restrictions for its employment, and union relationships. Due to the remote location and meager existing habitat, a construction camp for temporary housing will be required. If the industry expands, there is reason to expect that a permanent construction force will migrate and plan on living in the area if suitable infrastructure regarding schools and entertainment were provided.

Union and Non-union Sources: Large sites often require more construction labor than can be met from organized labor. The owner or interested construction companies may work with the Government of Alberta Employment and Immigration (AE&I), ABCTU, and CLAC to develop a site agreement that holds for the duration of the project. (Refer to Attachment A for an explanation of the union identities.) While there is strong union presence, the shortage of labor to meet the needs augers well for having different unions and non-union labor working amicably side by side. It is possible to negotiate site agreements that go beyond the guidelines described in Attachment A regarding shift durations and length of time between rehabilitation trips home. Past experience can be obtained by referring to other industry agreements that have been ratified and published by the AE&I.

It is predicted that there will be a shortage of labor due to a high demand in other projects that is predicted to remain for the foreseeable future. To compete with other projects, premium rates of pay will probably be required.

Nuclear Level Skills and Quality Assurance: Even though a full range of construction skills for the oil sands development exist within Alberta, there will be a need for workers with special qualifications in the construction of a nuclear plant. Those particular skills unique to constructing the nuclear portion of the plant are presently not available in Alberta. These special qualifications will require either importation from areas of existing nuclear plants or, rather, locally development by giving special training to workers with the basics already in hand, such as welders. The use of special materials in nuclear applications requires particular welding procedures that are carried out by specially qualified welders, who are already in high demand. Quality Control and Quality Assurance inspectors who are knowledgeable of specialized nuclear requirements will be needed. However, nuclear QA inspectors, for instance, require a level of experience to be useful. Local training will not be applicable to this shortage.

Nuclear Operators Necessary for Plant Test Programs: When the final construction is completed, testing of the nuclear reactor plant will be necessary, and operators who are already qualified and licensed for this must have appropriate background, training and certifications. This will include the development and certification of the plant simulators and the training of individual operators, which will become part of the critical path to placing the HTR into operation (see Appendix D, Operator Qualification). This is still another skilled group that must be obtained on a continual basis for the future to complete the construction phase and operate the plant throughout its life.

Nuclear Fitness: Those construction workers who are used in nuclear construction will be compelled to meet "Fitness for Duty" requirements such as drug free testing and lack of a criminal record, which may limit the fraction of the available workforce. Additional limitations on hours per day or sequential days for nuclear workers may be imposed by the nuclear regulator under "Fitness for Duty" guidelines. Plant operating and security staff have additional fitness for duty requirements.

Nuclear Procedures: The labor force will require special training to ensure that it carries out the unique procedures associated with constructing a nuclear power plant. Examples are:

- Control of the work by use of traveler forms
- Documentation of all work, changes in procedures, tests, and inspections

- Material control such that only pedigreed pieces are used and documented
- All work done by qualified personnel, where required
- Test programs must be performed including initial criticality of the nuclear plant.

Nuclear Security and Stage-wise Construction: A unique consideration for this project involves the incremental construction of power plants to meet the schedule of bringing four stages on line in three year increments. Once a nuclear plant is ready to operate, added security measures are required. Access to the “vital” nuclear plant areas must be controlled with fences, detection systems, and guards. Personnel working within the confines must pass additional background checks and carry badges to obtain access. The on-going construction effort of the not yet completed reactors must be segregated from the operating portions of the plant in a manner to meet security requirements, minimize lost productivity, and avoid the need to authorize an excessive number of workers to access nuclear areas. The oil sands plant itself will be outside the nuclear fence and should not be affected by the nuclear plant’s security requirements.

Number of Different Module Designs: If more than one design exists for the reactor modules, the number of analyses, procedures, drawings, specifications, etc., increases about proportionally. This translates to more administrative and work controls and materials accounting effort. It will require separate control stations and consideration of how personnel are trained to operate the different reactors.

Total Number of Modules: The total amount of labor required for construction will be higher if the number of separate modules is greater.

Multipliers on Labor Cost in the Northern Alberta Regions: As noted in the construction study in Attachment A and confirmed by return costs in prior construction of oil sands plants, standard methods of comparing construction efficiency for Alberta with construction efficiency in more standard regions are used. These efficiency multipliers can be used to assist nuclear vendors with predicting costs of labor in Alberta. After evaluating a list of aspects, the study suggested that a labor rate multiplier of 2.3 should be used for Ft. McMurray/Athabasca areas for construction labor compared to what would have been expended on a similar project in the Gulf States of the USA. The same factor can be used for nuclear work in this area if the additional complexity and controls for nuclear work are already added to the estimate for construction; otherwise, this factor would increase to 2.8 for the same work being done as nuclear work in the same area of Alberta.

Modular Construction: The scarcity of workers and the premiums paid to staff construction in the Athabasca area demonstrate that it is important to minimize the amount of on-site work performed. The amount of site labor, particularly the specialized crafts, can be reduced by the use of modular construction. Different nuclear designs are more amenable to modular construction. Limitations (i.e., weight, physical dimensions) on transportation will limit the degree to which modularization can be applied.

Amount of Backup Steam Using Fossil or Electric Power Steam Generators: As noted in Section 4, each of the three designs will need to have backup steam supplies for startup and contingency shutdowns of modules. The amount of backup steam supply for the three reactor designs will vary, and those with greater needs will have somewhat higher construction costs. The 4S need will be for about 135 MWt and the other two designs will need up to 284 MWt, at least for initial construction. The approximate capital cost for 284 MWt of backup steam is about C$80 Million.

5.2.2 Unique To Different HTR Designs

The three HTR designs have significant differences that in some cases will affect the labor requirements. Table 5-1 is a summary comparison of issues that affect labor.

Number of Reactors: Chief among these is the number of reactors. The PBMR will not require an additional reactor plant to meet the demands of the fourth stage. This results in probably one quarter less labor needed for construction of the total project over four stages than the MHTGR, earlier availability of full steam production capacity, and earlier expenditure of capital funding. The 4S requires three reactor modules each for the first three stages except the last, when it uses two plants. This, on the surface, multiplies the labor to make the multiple installations.

Modularization Effects on the Mix of Crafts: While differences exist in the mix of crafts for the different designs, the differences are not controlling. If transport in sections of the heavy walled vessels associated with the MHTGR and PBMR is required to meet transportation limitations, specially qualified welders and facilities will be needed to assemble the sections on site.

Modularization Effects on the Amount of Construction Labor: Because the 4S has multiple smaller units, there will be less stick type effort relative to the nuclear island. Furthermore, smaller components and piping size usually lead to easier construction. However, the complications involved with the controls for multiple units and the fabrication of the process steam manifolds are tradeoffs.

Nuclear Skills: Fundamental welding qualifications and testing will be the same for all three HTR designs. Controls imposed on the construction process will be consistent.

Test Programs: In the case of the 4S design, the testing of as many as three reactors of two types for each stage will require a longer testing schedule, more trained operators and support test personnel than those designs with one reactor per stage. The PBMR design does not require a reactor for the fourth stage; therefore, there will be no effort needed for nuclear testing as part of the last stage.

Fitness for Duty: The program to comply with “Fitness For Duty” will be identical for all three of the HTR Designs. While compliance will affect the labor pool and will cause some loss in productivity, the effects are identical.

Procedures: There will be specialized procedures for construction of nuclear portions. Stringent nuclear quality level will be required, and any deviations must be documented and approved before they are implemented. High quality level procedures are equally applicable to all designs and will include design, concrete, reinforcement bar, structural steel, piping systems, instrument/control systems, and testing. This may affect schedule, but if prior corporate" buy-in" is made, the effect should be minimal. This is more of an issue for those designs that involve more site work and more reactor test programs.

Security: The concept of sequential development of the oil sands plot in four stages of 30,000 bpd units, each separated by three years, creates a situation whereby there will be construction adjacent to an operating plant. Where there is commonality of space being shared by the operating plant and the plant in construction, the construction personnel who need access to the shared space will be required to meet a higher standard of security vetting than the regular construction crew. In addition, there will be temporary physical barriers set up until the new plant becomes operational and is part of the security barrier of the older plant. All of this adds to the loss in labor efficiency that will be experienced by the HTR design with the larger number of units. By careful planning, the effect can be minimized.

Modular Construction: The PBMR design has developed a conceptual plan to maximize modularization in the construction of their design. It includes the packaging of systems with piping sections, cable trays, and small components that can be lowered into place via the "Open Top" approach to construction. This will be reflected in a shorter duration for construction. The 4S has smaller components which are amenable to modularization because of their size. GA planned for extensive modularization in the 1987 MHTGR electric plant design, but this must be reappraised for addition of process steam system and for transportation limitations on the size of modules in Alberta area.

Table 5-1. HTR Labor Issues Comparison
(Pertaining only to the HTR Battery Limits)

Labor Issue	4S	MHTGR	PBMR
Number of Modules Stage 1	3	1	1
Total Number of Modules for 4 Stages	11	4	3
Number of Different Module Designs	2	1	1
Total Labor Needed	Medium	High	High
Nuclear Skills	Same	Same	Same
Test Programs	3 per Stage for 3 Stages; 2 for Last Stage	1 per Stage	1 per Stage for only 3 Stages
Fitness for Duty	Same	Same	Same
Procedures	More	Less	Less
Security	More Effort	Less Effort	Least Effort
% of Modular Construction	Most	Less	Less
Amount of Backup Steam to Accommodate One Modular Reactor Down for Over 1 Month	135 MWt for all Stages	284 MWt at Stage 1 down to 86 MWt at Stage 4	284 MWt at Stage 1 down to 96 MWt at Stage 4

5.3 TRANSPORTATION

5.3.1 Common to All Designs

Conditions to be Considered: Nuclear power plants are composed of large and heavy components to house the fuel (reactor pressure vessel) and to convert primary coolant thermal energy to steam (intermediate heat exchangers and steam generators). Due to difficulties for fabrication/construction on site because of labor and climate conditions and since special materials and special welding procedures are used in the fabrication of the pressure vessels and the piping, it is beneficial to maximize fabrication offsite with transportation of sub-assemblies to site. However, the following conditions affect the degree of pre-fabrication that can be exercised for construction in Alberta:

- Limited road and rail infrastructure to the existing and new development areas.
- The carrying capacity of the existing road and rail systems.
- The design load limitations of road and rail bridges.
- Seasonal restrictions.

- Clearance heights of bridges, highway overpasses and overhead electrical cables.

Typically, nuclear reactor sites are selected so that heavy and large nuclear components can be transported to the intended site by barge. However, the SAGD oil sands recovery plants must be built in the vicinity of the in-situ oil fields which are usually a significant distance removed from river access; thus, transportation must rely on some over land methods (e.g., for portage and/or final approach to site). Heavy loads on land in some locations are restricted to cold weather and on water are restricted to warm weather. Therefore, if a combined form of travel is selected, it may require a layover in mid-transit while the seasons change.

Regulatory Influence: Alberta Infrastructure and Transportation (AIT) regulations relative to weights and sizes are outlined in the Attachment A study. However, there is a history of special exemptions that have been granted by the AIT. When permits are required for large and heavy loads, these are required to be submitted before manufacture to ensure their transportability will be permitted when completed. Power companies and Rural Electrification Associations (REA) dictate escort and wire lifting requirements and can refuse load movement on the basis of service disruption to their clients. Refusal to escort or lift wires on a route results in no movement until the objection is removed. AIT can deny or approve the permit to move large loads.

Despite the limitations, restrictions, and regulations for transport logistics, large and heavy loads have been moved to the oil sands areas by road and rail. Examples are noted in Table 5-2. Very large loads will require special transporters and support rigs, and coordination with the province.

Careful advance planning will be essential to ensure that components and material are available on site to meet the construction schedule.

Nuclear Fuel: Special regulations, restrictions, and considerations will be enforced for the transportation of new nuclear fuel, spent nuclear fuel, and radioactive waste. The CNSC imposes requirements for shipment of fuel and radioactive cargoes. For purpose of this study, this will not be considered a differentiator between HTR designs.

Concrete: Nuclear power plants use large amounts of concrete in their construction. Special specifications are used for nuclear construction to ensure design strength is met. Thorough inspections are instituted to ensure compliance with the specifications. A batch plant will be required. The pouring of concrete is preferred to be done in the summer months. However, the allowable loadings of the trucks for over the road transport are reduced during the summer months. Due to seasonal restrictions on road usage, special storage areas may be required to ensure availability of material onsite during periods when transportation is limited.

Many truck loads of aggregate and cement will be required as there is no local supply. Haul trips of 200 km plus for aggregate should be anticipated. Haul trips of 900 km plus for cement in the quantity needed for a nuclear plant construction should be anticipated.

5.3.2 Unique to different designs

Weight and Size of Components: The largest package for any of the designs is the PBMR reactor vessel main section at 815 tonnes and dimensions of 23 m long by 8 m in diameter, with the next largest item, the core barrel, at 312 tonnes. The heaviest MHTGR component is a part of the reactor vessel at 648 tonnes. The longest MHTGR component is the steam generator with dimensions of 28 m long by 5.2 m in diameter. The MHTGR steam generator tube bundle weighs 208 tonnes.

The only design whose heaviest component is less by weight than the precedents identified in the Attachment A study is the 4S. Nevertheless, even for these 4S components, special permits will be required since the regular over-the-road limit (without special permits) is exceeded. The PBMR reactor vessel is almost twice as heavy as any of the identified precedents by road over the Athabasca river bridge (See Attachment A) and the MHTGR reactor vessel is 1.5 times as heavy. Moves of up to 1000 tonnes are achievable along sections of road not involving bridges and by barge along rivers. However, movement by barge to Ft. McMurray will require a 30 km portage around rapids at Ft. Smith and infrastructure improvements will be needed for offloading and reloading barges at the portage and final destinations (Reference 15).

The diameter of the PBMR reactor vessel is 8 meters. The MHTGR reactor vessel is 7.6 meters in diameter. These vessels are too wide for rail shipment (maximum of 4.4 meters).

For PBMR and MHTGR reactor vessels, some special approach is needed for transportation involving a combination of barge and/or special land transporter, or a process must be developed for final fabrication close to the site, or a design change must be made to use smaller vessels. It is understood that the PBMR vendor has a plan for such barge transportation, but it is dependent on some infrastructure improvements along the Athabasca River. Therefore, as part of any decision in favor of the PBMR or MHTGR, a strategy for finalizing the special approach for transportation of heavy vessels should be confirmed.

Table 5-2, below, shows the comparison of weights and sizes of the different designs with allowables and precedents.

Table 5-2. Comparison of Maximum HTR Weights and Sizes

	Weight	Height	Length	Width[1]
4S Reactor Vessel	100 tonnes	3.6 m	23 m	3.6 m
MHTGR Reactor Vessel	648 tonnes	7.6 m	18 m	7.6 m[2]
PBMR Reactor Vessel	815 tonnes	8 m	23 m	8 m
Road load limits in Northern Alberta without special permit (Gross Vehicle Weight, GVW)	37 tonnes per 16-wheel Support	9 m (loaded)	31 m	7.3 m
Example of precedent vessel over the road	426 tonnes	11.6 m	30 m	10 m
Example of precedent vessel by rail Schnabel car	676 tonnes	4.1 m	31 m	4.1 m
Example of precedent GVW by rail Schnabel car	1,057 tonnes	6.3 m	102 m	4.4 m
Example of precedent GVW over Athabasca River at Ft. McMurray (Reference 16)	816 tonnes	13 m	88 m	10.3 m
Barge Capability (Study – (Northern Route) (Reference 15)	>1000 tonnes			

Note 1: For road travel load widths greater than 7.3 m, approval must be received prior to fabrication.
Note 2: Railroad transport is prohibited for widths above 4.3 m and heights above 6.1 m.

Planning: Transportation offers a significant risk for delays in the project. The loads are heavy and large. The weather conditions are extreme and have a controlling effect on the transportation methods. Advance planning and preparations as much as two years in advance are necessary.

Modular Construction to Meet Limitations: Size and weight limitations can be avoided by careful fabrication of heavy/large components into sub-assemblies for completion on the site. This will require special skills and all weather facilities with heavy duty flooring, several bridge cranes, and modern automatic welding equipment.

5.4 Complexity of Design Relative to Construction

Complexity of design is an important factor for evaluation of the three designs due to its effect on construction site coordination, quality assurance, risk of errors and the effort to complete the project.

Number of Reactor Modules: The MHTGR requires constructing one reactor module for each of the four stages. The PBMR requires constructing one reactor module for each of the first three stages, and these have enough capacity to satisfy the fourth stage without a fourth reactor module. The 4S requires constructing three reactors for each of the first three stages, two to meet the steam requirements and one to meet the electric requirements and requires two reactors to meet the remaining steam requirement for Stage 4. The 4S plan for construction of multiple reactors and steam plants for each stage increases the amount and complexity of engineering, planning, and execution of work, increases the number of standardized parts and the tracking of equipment, the correct construction equipment and utilization of labor. The possibility of the testing of multiple reactors for each stage will increase the duration and labor needed for the testing phase.

Plant Arrangement: The MHTGR and the PBMR each consist of a single energy conversion loop. The steam is split to serve the process needs and the electric generation. The 4S has two different plant designs, one which converts energy from sodium to process steam, and a second that converts energy from sodium to steam to drive turbine generators for electricity production. There is a tradeoff between the resulting increased simplicity of the reactor plant, to have only one of the two functions, and the fact that there are two different plant designs rather than only one, as in the cases of MHTGR and PBMR. Since there are eight total 4S modules feeding the process steam header, the amount of piping from these will be more complex and numerous than for the MHTGR with four modules and the PBMR with three modules.

The heat transfer loops from the reactor to the process steam outlet for the MHTGR and the PBMR differ in complexity. The MHTGR has only three heat transfer systems or loops: its primary heat transfer loop is helium and its secondary heat transfer loop is steam, with the steam, in turn, leaving the nuclear island and powering a turbine generator for electric power and a reboiler to make process steam in the tertiary heat transfer loop. The PBMR has four heat transfer systems: its primary heat transfer loop is helium, and its secondary or intermediate heat transfer loop is also helium which, in turn, leaves the nuclear island and feeds parallel steam generators, one for process steam in one tertiary loop and another one for turbine steam in a second tertiary loop.

Coolant: Loading the primary coolant prior to initial testing is part of construction. The 4S design uses liquid sodium which will add more complications than handling gaseous helium. These include the need for great care in handling the sodium which can react violently in contact with air and water, complex double wall piping with helium in the intermediate annulus for leak detection, melting the sodium before injection to the primary and intermediate loops, maintaining the plant warm to keep the coolant liquid even when shut-down, and protective domes to keep air away from areas where sodium leaks could otherwise be a fire concern.

5.5 LAND AREA AND EXCAVATION

General: Construction of the nuclear plants will require tree removal, ground dewatering, and muskeg stripping. Excavation depths as deep as 50 meters with an area greater than 270 square meters for the nuclear plants can be expected. Excavated material will be saved for eventual site reclamation.

The footprint comparison is based on vendor data. However, 4S design included only the reactor and turbine generator buildings (11,200 m^2) and not the whole HTR battery limit. MPR used a factor of six on this area to estimate the total footprint based on using the same relationship between (overall footprint area) and (reactor plus turbine generator building area) as for the MHTGR plant footprint.

Table 5-3 provides a comparison of land area and excavation depths for the three HTR designs.

Table 5-3. Land Area and Excavation

	PBMR (Total Project)	**MHTGR (Total Project)**	**4S (Total Project)**
Maximum Excavation Depth (m)	11	50	16
Reactor Module Excavation Area (m^2)	8,070[1]	1080	880
Footprint Area (m^2)	83,900	93,000	67,400[2]

Footprint = HTR Battery Limit (fence line)

Notes:

1. PBMR, with three reactor modules (5380 m^2 for a twin unit;1.5 x twin)
2. Footprint for 11 reactor modules and 3 TG Buildings 11,200m^2 (x6 factor for site based on MHTGR relationship)

Prior to the start of construction, many tasks must be accomplished to ensure the success of the construction schedule. Once a license to construct is issued, the critical path to first operation of the plant rests squarely on meeting the construction schedule. Final license to operate is submitted after construction approaches a stage of completion that can justify the operating license submittal.

Alberta area additional issues include climate and weather changes, animal migration or mating in the area, inadequate water flow in rivers, etc., which can suddenly close windows of opportunity for certain operations until the condition changes for the better.

Table 5-4 shows vendor estimated time to prepare for the start of a hypothetical oil sands plant construction, and then to perform the construction work. A project start in 2011 was selected as a measure of determining who might be better prepared for an early start, and it was assumed that licensing would not be limiting. The goal was to get a broad idea of how much time might be needed to prepare (i.e., development readiness) and how much time might be needed to construct. The vendor estimates were based on judgments and contained few construction details at this stage of pre-conceptual design. The overall time from project start to first operations generating production steam is estimated from eight to ten years, and this in the same range expected for new water reactors in Canada.

The variations in estimated time until the start of site construction may reflect differences in time needed to finish development tasks or differences in strategies for modularization and prefabrication. As the designs are further finalized, the work done in preparation should be synchronized to match up with expectations for receipt of the license to construct. Efforts to shorten the construction time can shorten the time needed to reach first operations.

Because of the lack of details in these estimates, it is not prudent to make HTR selections solely on their cross-comparisons.

Table 5-4. Project Schedules

	PBMR	MHTGR	4S
From Notice to Proceed until Start of Site Work (months)	36	43	75
From Start of Site Work until Commercial Operation (months)	60	64	45
From Notice to Proceed until Commercial Operation of First Unit (months)	96	107	120

Notes:
1. MHTGR based on Gulf Coast location and earlier electric-only design.
2. Assumes time for licensing/regulatory approvals are not on critical path.

5.6 SITE CONDITIONS, CLIMATE, ENVIRONMENTAL EFFECTS

General: The nuclear reactor and its support facilities will be designed for proper operation in the Alberta climate, which reaches temperatures as low as -40°C in the winter. Therefore, discussion of site, climate, and environmental effects will focus on construction impact.

Construction planning must account for limitations on when certain activities can occur (e.g., pouring concrete in winter, transport restrictions already noted) and the cost premiums for work performed in the area.

Construction planning must also consider environmental effects. The Environmental Assessment Act and Provincial regulations specify what environmental evaluations are required. Portions of the wilderness areas are particularly vulnerable during certain seasons.

Comparison: The smaller components associated with the 4S design give an advantage when planning transportation in this region. The embedded designs of the MHTGR and 4S permit quick forming of the reactor building which can be roofed for ease of construction of internal systems in colder weather.

5.7 SEQUENTIAL SCENARIO OF STAGES EFFECTS

Common facilities to be utilized for all stages will be provided at the time of Stage 1 construction with concomitant larger costs associated with this first stage than following stages. Depending on the particular site and plant layout, it may be economical to perform most, if not all, civil building work prior to initial plant operation, even though this involves capital investment several years earlier than if each stage is built separately.

As noted in Subsection 5.2.1, stringent security measures are required for operating nuclear plants. Access to the “vital” nuclear plant areas must be controlled with fences, detection systems, and guards. Since personnel working within the confines must pass additional background checks and carry badges to obtain access, the majority of the construction activity should be kept “outside the fence” once security is implemented when fuel first arrives. Segregating on-going construction effort of the not yet completed reactors from the operating portions of the plant is essential to minimize lost productivity and avoid the need to authorize an excessive number of workers to access to nuclear areas. Still, some construction inside secure areas will be needed, and additional time required to meet security requirements must be built into the schedule and calculation of productivity.

The main steam supply line to the fields for the first stage must be sized to accommodate additional steam from later stages. Adequate inlet nozzles (with isolation, cut-off valves) must be provided so that later stages can be cut in without interrupting the flow from previous stages.

5.8 HTR Evaluation

Based on the evaluation of the various construction issues noted above, the following conclusions are summarized regarding the three different HTR designs:

Each design can be built to satisfy the schedule objective of powering a 30,000 bpd capacity increase every three years. The three nuclear alternatives involve two construction scenarios: 1) a few large reactor modules brought into operation no faster than one unit per stage (MHTGR and PBMR), and 2) multiple, small reactor modules with up to three constructed and taken into operation at each stage (4S).

Having a fewer number of reactors has the potential for economy of scale and reduction of construction interferences. However, the MHTGR and the PBMR involve some very large components requiring specialized transportation arrangements that could severely affect schedule (e.g., cause delays of six months) if movement windows are missed. Even well orchestrated moves of these components will be expensive. It would be prudent to order the largest components for early delivery with at least one year of margin to the earliest required at-site date to allow margin for manufacturing slips, licensing delays, or weather constraints. Even once the components are on site, the MHTGR and PBMR have more stick-built construction that will require a larger workforce per reactor module and larger lifting capacity needs, compared to the 4S modules. Heavy lifts may be restricted in mid-winter due to weather. The tradeoff for the 4S modules is that multiple 4S reactors at each stage will require more work and a more complex orchestration of on-site activities. Testing and startup of multiple reactors must be done in series, extending the duration of this evolution relative to other designs. However, the repetitive nature of the jobs for successive modules provides the opportunity to improve productivity by moving up the learning curve if workers are retained.

Overall, the net benefit of large against small modules is not known at this time.

6 Regulatory and Safety Considerations

The combination of a nuclear plant power source with a thermal, in-situ recovery plant involves two essentially independent regulatory frameworks. The recovery plant regulatory process is well developed within Alberta. Nuclear regulation is a federal responsibility but has environmental assessments that involve provincial participation. For both portions of the project, a public outreach process is essential to ensure people nearby and in the province understand the benefits and costs of the project. The following section provides an overview of the regulatory and outreach requirements and actions that must be considered in combining HTR technology as an alternate energy source for thermal, in-situ oil sands recovery applications in Alberta.

6.1 Thermal In-Situ Plant Considerations

As part of evaluating HTR technologies for applicability to oil sands recovery plants, a detailed review was performed of the regulatory requirements for constructing and licensing a thermal, in-situ oil sands recovery plant (Attachment A). Based on the Attachment A review, the requirements applicable to a thermal, in-situ recovery plant in the Athabasca area are discussed.

6.1.1 Regulation in Alberta

The regulators affecting oil sands development are:

- Alberta Energy (AE) manages provincially owned energy and mineral resources.
- Alberta Environment (AENV) regulates environmental compliance issues.
- Alberta Energy and Resources Conservation Board (ERCB) regulates energy resources, as well as the construction and operation of energy developments.
- Alberta Utilities Commission (AUC) regulates investor-owned utilities and certain municipally owned electric utilities.
- Alberta Employment and Immigration (AEI) regulates Immigration; Labour Relations; Occupational Health and Safety (OHS) and Workers Compensation.
- Alberta Boiler Safety Association (ABSA) is the pressure equipment safety authority.
- National Energy Board (NEB) regulates international and interprovincial aspects of energy utility industries.
- Association of Professional Engineers, Geologist and Geophysicists of Alberta regulates engineers, geologist and geophysicists.

6.1.2 Technical Regulation in Alberta

Engineering and geosciences are regulated professions in Canada. They are practiced under Federal and Provincial Acts and are regulated by Professional Associations in each province. All professional documents issued for execution are stamped and signed by the individual Professional Engineer or Professional Geoscientist responsible for their preparation. Firms that practice engineering or geosciences, including oil and gas (O&G) companies, manufacturers, engineering, procurement, construction, and management (EPCM) contractors and consulting firms, are licensed by the relevant provincial professional association.

6.1.3 Trade Craft in Canada

Canada ensures a high and consistent standard of safety and quality in the delivery of craft and trade skills in manufacture, fabrication, and construction services. It provides for the certification and mobility of skilled workers through a listing of 45 designated trades that are regulated by license in Canada. This mechanism ensures that trades people have an appropriate level of education, training, and practical experience.

6.1.4 Trade Craft Regulation in Alberta

The programs for training trades and craft personnel are delivered in Alberta through apprenticeship boards and trade colleges. Formal and regulatory testing of pressure vessel and pipe welders, and other safety critical craft operations, is a certificated process that is continued on a regular calendar basis and also on a project or locational basis. Work shops and job sites at which the fabrication of pressure vessels, piping, structures, pressure, electrical and electronics components, etc. take place are also regulated in Alberta. Each location must have a documented program for quality, safety, worker competency, licenses and test certificates, OHS and human resources records. This documentation is subject to inspection and approval by the appropriate provincial regulatory board staff.

6.1.5 Welding Trades Regulation in Alberta

While all construction trades employed on O&G sites in Alberta require evidence of competency, the trade of welding is of special significance. The Alberta Safety Codes Act establishes competency and certification requirements for pressure welders, machine welding operators and welding examiners. ABSA oversees all pressure welding practices in Alberta, including the examination and certification of welders and examiners.

6.1.6 The Regulatory Process

Approval to construct and operate a thermal, in-situ heavy-oil extraction plant, with production over 2,000 m^3/day (~13,000 bpd), is a multi-step procedure that requires a variety of permits and approvals from separate regulatory bodies in various jurisdictions and levels of government. Currently, the entire regulatory process is expected to take up to three years for approval of the plant (e.g., up to a year to prepare applications (including the Environmental Impact Assessment) and approximately two years from submission of the application.) The bulk of the regulatory approval time involves submissions and receipt of approvals from both AENV and ERCB. The legislation in Alberta pertaining directly to recovery of oil sands in the province is the Oil Sands Conservation Act and the subsequent Oil Sands Conservation Regulation (AR 76/1988).

The Oil Sands Conservation Act requires that a proponent of an in-situ, thermal oil sands recovery plant (facility) make application to the ERCB and receive Scheme Approval prior to construction or operation of the facility. Approval must also be received from AE, under the Environmental Protection and Enhancement Act, to construct, operate and reclaim the in-situ thermal heavy oil facilities. Typically a Water Act Approval is also required from AENV either for use of groundwater and/or for surface water diversion.

The acquisition of these approvals is accomplished through a joint (integrated) Application and Environmental Impact Assessment (EIA) submission to the ERCB and AENV. The requirement for an EIA is specified in the Environmental Assessment (Mandatory and Exempted Activities) Regulation, AR 111/93.

Preparation and submission of an EIA is, in itself, a multi-step process with considerable input from AENV and potentially the public. The impact of the project alone, the cumulative impact of the project with existing developments in the area, and the potential cumulative impact of the project with proposed new and existing developments must be evaluated. Potential adverse effects from the proposed project must be mitigated to the government’s satisfaction. Once approval for the oil sands recovery scheme and the facility and associated infrastructure are received from the ERCB and AENV, and all Public and Industry Notification requirements are complete, applications for Facility and Associated Pipeline Licenses can be submitted. Once these licenses are received, construction may commence. Other approvals that are required for construction and operation of the project include, but may not be limited to Well License (bitumen); Pipeline Licenses; Surface Dispositions from Alberta Sustainable Resource Development (facility); Disposal Well Licenses; power generation or connection approvals (from Alberta Utilities Commission); and Municipal Development and Building Permits.

6.2 PUBLIC OUTREACH

As part of evaluating alternate energy sources for applicability to oil sands recovery plants, detailed reviews were performed of the public outreach requirements and practices in support of constructing and licensing a thermal, in-situ oil sands recovery plant (Attachment A) and constructing and licensing a nuclear power plant (Attachment C). This section uses that material and discusses how public outreach should apply to applications of HTR technologies to thermal in-situ oil sands recovery plants.

Any large project with potential economic and environmental effects will evoke public concern that should be addressed at the outset with a proactive effort to ensure issues are understood. When the project involves a nuclear power plant, additional concerns arise. The key for this project is early, open, and understandable communications continued throughout the preparation and construction stages and on into operations. Sometimes, the concerns voiced are based on insufficient explanation of the project and its risks and benefits. For an HTR-powered thermal, in-situ recovery plant, a well-thought public outreach program must be developed at the earliest time in the project. This may include Internet sites, town hall meetings, project description mailings, open houses, newspaper advertisements, telephone conversations, media orientations, etc. In addition to the proactive public outreach, the environmental assessment regulations stipulate specific interactions that must be performed; these are covered by separate guidance for the nuclear and non-nuclear portions of the project.

6.2.1 Nuclear

In order for the opportunities provided by HTR technology to be realized, various mechanisms of a public and government outreach program should be initiated. The manner in which the public perceives risks must be considered in developing the public outreach program. Because of the lack of a significant nuclear presence in Alberta, there is little experience in assessing and addressing the public reaction to a nuclear project. Therefore, this program should engage the public openly at the very early stages of project development and provide information from credible sources in accessible formats. By ensuring that sound, factual information and judgments about nuclear energy are made available to the public from trustworthy sources, chances of achieving timely project implementation can be improved.

Public outreach initiatives should be undertaken in cooperation between the nuclear technology suppliers and potential industry users. Without some collaboration, there are risks that aggressive promotion of nuclear technology benefits could appear to be at odds with industry efforts to support other technologies' environmental compliance strategies and sustainability initiatives. A combined effort should seek public acceptance of nuclear technology as a complementary option to other strategies to avoid divisive support or confrontations between industries and technologies. In other words, nuclear should be offered as part of the comprehensive strategy for improving the overall environmental impact of bitumen recovery in the Athabasca region without denigrating the use of conventionally fueled plants.

Outreach initiatives will need to be supported by broad, high level studies of long term regional energy needs and supplies, environmental compliance and sustainability, industrial and economic development, quality of life, and international relationships. Some of these studies have already been undertaken as first steps toward identifying possible roles for advanced nuclear technology, but additional studies will be needed to provide sufficient understanding of the justification for the project. For example, in April 2008, the Alberta government appointed an expert panel to study the potential use of nuclear energy in Alberta. Its findings are expected to form the basis for future public debates and eventually a nuclear energy policy in Alberta. A supportive nuclear energy policy for oil sands applications is a vital component to a successful project and, therefore, engagement in these discussions is critical.

Given the current uncertainty regarding public perceptions and support for new nuclear projects in Alberta and the long lead time for a nuclear project (being constrained by the nuclear licensing process), the project will require not only an early but also a sustained program to keep the public and non-nuclear regulators informed of issues and plans for their resolution. As suggested by Stone & Webster, the use of the HTR as the energy source can be treated as contingent upon addressing public and regulatory issues while progress is made on nuclear plant licensing.

6.2.2 Non-nuclear

Public consultation with potential stakeholders for a SAGD facility should begin as early in the project initiation phases as possible to determine any issues of local concern with this proposed development or common issues with previous developments. When the environmental assessment (EA) process begins, consultation items are included as part of the initial disclosure documentation. This would include the proposed terms of reference, advertising plan, public notice, details on any completed or ongoing consultation items (including responses and/or issues identified), and planned consultation to complete the requirements.

Public consultation is an important element and can have requirements throughout the different stages of the EA process. These usually include notices published in several newspapers and will include at least one Aboriginal newspaper if the First Nations Consultation guidelines apply.

When a project is deemed to require an EA and may infringe upon existing treaty or other constitutional rights in relation to Crown lands, First Nations consultation is required. A specific First Nations Consultation Plan is required.

Public consultation is an ongoing element throughout the EA process. Feedback from the public or any affected groups regarding the proposed development (via the various notices) is part of the assessment documentation and is a mandatory requirement. The intent of the consultation process is to establish an open, non-controversial path of communication between the proponent and stakeholders that will set the framework for successful completion of the project.

6.3 NUCLEAR PLANT CONSIDERATIONS

As part of evaluating HTR technologies for applicability to oil sands recovery plants, a detailed review was performed of the regulatory requirements for constructing and licensing a nuclear reactor in Alberta (Attachment B). Part of this review involved four private meetings with CNSC by members of the MPR Team over the last 3 years to discuss the use of HTR technologies in oil sands applications. These included discussions about likely nuclear licensing requirements that may be applicable to HTRs, logistical and site constraints for oil sands, necessary pre-licensing activities for HTR, the opportunity and benefits for pre-project reviews and the need for the formation of new licensing requirements for HTR-type reactor designs. CNSC attendees included the Director General of Power Reactor Regulation, the Director of New Reactor Licensing, the Director General of Assessment and Analysis and many other managers and leading technical people. While CNSC was receptive to the meetings and the briefings, they made it clear that CNSC will not able to address HTR technology formally in their planning or activities until there is an application for a specific project.

The MPR Team members also attended two public meetings that were held by the CNSC to discuss revisions of the “Regulatory Guidance Document” framework, “Site Evaluation for New Nuclear Plants” and “Design of New Nuclear Power Plants,” and comments relating to HTR interests were provided and accepted in the record. The meetings with CNSC, as well as study of the new CNSC regulatory documents provide the basis for the Attachment B study and the discussion in this section.

Overall, the regulatory requirements for constructing and licensing a nuclear reactor in Alberta are similar to those for a typical oil sands plant in that there are several steps and permits required. The applicable regulatory body is different, however, and the process for nuclear licensing continues right up to the point of beginning to operate the plant; whereas, the oil sands regulatory process is generally over within about the first four years. The nuclear licensing is likely to take as long as ten or eleven years for a First-of-a-Kind nuclear plant.

6.3.1 New Reactor Nuclear Regulation in Canada

As in many countries, Canada had a substantial nuclear plant building and licensing program until the 1980's but has done little since then other than operate and regulate the operation of existing reactors. All Canadian power reactors are CANDU (CANadian Deuterium Uranium) designs, originated natively by Atomic Energy of Canada Limited (AECL). Unlike the regulations in some other countries, the Canadian nuclear safety requirements have been generally high level, with details settled in the individual licensing proceedings. This worked reasonably well when all Canadian reactors were of similar technology.

Anticipating a resurgence of interest in nuclear power generation, Canada has been developing new guidance to implement a well-thought process to ensure safe plants are designed and built. The Nuclear Safety and Control Act (NSCA) was passed in 1997 and became effective in 2000 with the stated intent, regarding regulation, being that it is "essential in the national interest that consistent national and international standards be applied to the development, production and use of nuclear energy." The NSCA established the nuclear regulatory authority for Canada: the Canadian Nuclear Safety Commission (CNSC). The following information is derived from the CNSC document INFO-0756, Licensing Process for New Nuclear Power Plants in Canada (Reference 17).

CNSC Organization

The CNSC is an independent agency reporting to Parliament through the Minister of Natural Resources. Since nuclear regulation is solely a federal jurisdiction, the CNSC has no provincial counterparts, but the provinces do become involved in the Environmental Assessment (EA) process described below. The CNSC is comprised of the Commission Tribunal and the CNSC staff organization. The Commission Tribunal is a quasi-judicial tribunal and court of record, which is responsible to make transparent decisions on the licensing of nuclear-related activities in Canada; establish legally binding regulations; and set regulatory policy direction on matters relating to health, safety, security and environmental issues affecting the Canadian nuclear industry.

The CNSC staff reviews applications for licenses, according to the regulatory requirements of the NSCA, as well as CNSC regulations and regulatory documents, while taking into consideration input from other departments and agencies. The staff also makes recommendations to the Commission, and enforces compliance with the NSCA, regulations, and any license conditions imposed by the Commission. The CNSC – like many organizations and like the US Nuclear Regulatory Commission – is currently affected by demographics that lead to concerns regarding its ability to find sufficient, qualified staff to handle an increased workload.

Additionally, the CNSC:

- Administers the Nuclear Liability Act
- Conducts EAs under the Canadian Environmental Assessment Act (CEAA)
- Implements Canada's bilateral agreement with the International Atomic Energy Agency (IAEA) on nuclear safeguards verification
- Has a duty to consult with Aboriginal peoples.

These tasks also play a part in obtaining a license to operate a nuclear reactor. .

Nuclear Reactor Licensing

Nuclear power plants are defined as Class I nuclear facilities, and the regulatory requirements for these facilities are found in the Class I Nuclear Facilities Regulations, which require separate licenses for each of five phases:

1) License to Prepare Site
2) License to Construct
3) License to Operate
4) License to Decommission
5) License to Abandon

A license application for the development of a new reactor project requires a proponent (i.e., license holder and operator) who will submit the application, fulfill the financial obligations of an applicant, commit to the obligation for information submittals throughout the licensing process, and be prepared to operate the plant within the regulatory regime as described by such a license. The CNSC's assessment is carried out along with input from other federal and provincial government departments and agencies responsible for regulating health and safety, environmental protection, emergency preparedness, and the transportation of dangerous goods. Separate licenses are granted for each phase in the lifecycle of the nuclear power plant, but these steps are not wholly sequential. The applications to prepare a site, to construct, and to operate a new nuclear power plant may be assessed in parallel and would need to be done that way to avoid very long licensing times. Also, although it does not have to be detailed, information on decommissioning is required in the application to prepare a site. A reactor is also defined as a "high-security site" for purposes of establishing requirements under the "Nuclear Security Regulations" of the NSCA.

While not formally a step of the licensing process, a Pre-Project Design Review (PPDR) process is now available to license applicants. It seeks to facilitate the licensing process by identifying and discussing unique application issues associated with the technology or application and framing regulatory areas that concern the CNSC well before a license application is filed. This process is also valuable for technologies that are unfamiliar to the CNSC or for which the CNSC has an incomplete regulatory basis for formal review. MPR considers an essential aspect of the thermal, in-situ recovery project would be to have the selected vendor initiate a PPDR to begin to familiarize the CNSC staff with the vendor's unique technology.

The time required to review and approve the submissions supporting the nuclear licenses to prepare, construct and operate the facility will depend heavily on the quality of the submission by the applicant (both the completeness of the application and the quality of the reactor design safety report and references). The timeline for the reviews prior to beginning plant operation is discussed later in detail – a current expectation for water cooled reactors is nine years from license application to initial criticality, with an assumed on-site construction time of 50 months. The overall time could be considerably longer for an unfamiliar technology.

In addition to the five step licensing process, the CEAA stipulates that an EA must be carried out, so as to identify whether a project is likely to cause significant adverse environmental effects, before any federal authority could issue a permit or license, grant an approval, or take any other action for the purpose of enabling the project to be carried out in whole or in part.

EA Process

As noted, the CNSC conducts EAs under the CEAA. The nuclear EA process is somewhat different from that at other federal departments and agencies because the Commission Tribunal is responsible for making most EA decisions under the CEAA. If an EA is required for a particular project, the Commission must make the EA decision before considering if the project can proceed to licensing.

EAs help guide the decision-making process and map out the design and implementation of a proposed project before it proceeds. The implementation of the CEAA by federal authorities ensures that:

- Proposed projects are carefully reviewed before federal authorities take action, and do not cause significant negative environmental effects.
- There is opportunity for public participation in the EA process.
- Development in Canada does not cause significant negative environmental effects in the surrounding areas.
- Federal authorities take actions that promote sustainable development.
- There is improved cooperation and coordination on EAs between federal and provincial governments, as well as enhanced communication and cooperation between federal authorities and Aboriginal Peoples.

There are individual federal-provincial EA cooperation agreements to form, among other purposes, the basis for cooperation where federal and provincial environmental assessment legislation applies to the same project and to preserve each government's authority and legislative requirements. The existing 2005 Canada-Alberta Agreement on Environmental Assessment Cooperation does not explicitly deal with nuclear reactor projects.

For new nuclear power plants, the CNSC initiates an EA when an applicant applies for a license to prepare the site and submits a complete Project Description. The selected reactor design does not need to be identified at this stage. This Project Description is used to determine the need for any associated regulatory decisions if an EA under CEAA will be required. Before any licensing decision can be made with respect to a new nuclear power plant, the EA must be completed. EAs examine the five phases in the lifecycle of a nuclear power plant: siting, construction, operation, decommissioning, and abandoning.

Large-scale and environmentally-sensitive projects, such as nuclear power plants, usually undergo an EA called a comprehensive study, which mandates public participation (nuclear power plants are included in the CEAA's Comprehensive List Study Regulations, identifying the projects for which comprehensive studies are mandatory). The EA for a new nuclear power plant project would not be conducted as a comprehensive study if the project is referred to a panel or a mediator by the federal Minister of the Environment, following a recommendation by the Commission. A project's EA is referred to a review panel in the following cases:

- When it may cause significant adverse environmental effects, even after taking into account mitigation measures;
- When it is uncertain whether a project will cause significant environmental effects, given the implementation of mitigation measures; or
- Where public concerns warrant referral.

If a decision is made to refer the EA of a new nuclear power plant to a review panel, the CEAA provides for one of the following three approaches to be taken:

- A review conducted by a panel appointed by the Minister of the Environment;
- A substitution arrangement, whereby the Commission process is used as a complete substitute for a review panel; or
- A joint review (panel) process, through the Panel of the Commission, whereby the Commission (represented by two or more members) is supplemented with temporary member(s) appointed by the Minister of the Environment.

The approach chosen for the review of the environmental assessment by a panel would require approval by the federal Minister of the Environment. One option available to speed up the EA process is for the responsible authority to immediately recommend that the EA is referred to a joint review rather than wait for the Minister to make such a decision later in the process. This immediate referral potentially saves up to eight months in the approximate three-year EA process.

The key documents involved in a review panel are:

- Terms of Reference for the panel: issued by the Minister of the Environment, after public consultation;
- Environmental Impact Statement (EIS) Guidelines: developed by federal departments and agencies or the panel, after public consultation, and issued to the license applicant, which also include information requirements for the site preparation license decision;
- EIS: developed by the proponent (license applicant), in response to the requirements of the EIS Guidelines;
- Report of the review panel: prepared by the panel following public hearings about the EIS submitted to the Minister of the Environment, and made available to the public; and
- Government Response: prepared by the responsible authority (the CNSC with the Canadian Environmental Assessment Agency), in consultation with other federal government departments, and submitted for approval by the Governor in Council, before being released to the proponent and the public.

The Commission Tribunal then considers whether or not to proceed with licensing the project.

CNSC currently has three major projects undergoing an environmental assessment by a joint review panels, pursuant to the CEAA and the NSCA. These joint review panel agreements allow for the consideration of some preliminary licensing information (such as site preparation and/or construction) as part of the EA process. The two new reactor projects under consideration involve joint review panels, and a HTR-powered, thermal, in-situ recovery project would certainly involve one.

Regulatory Requirements

The NSCA establishes the regulatory framework for nuclear matters in Canada. The CNSC expands on requirements set out in the NSCA using regulatory documents that provide a basis for regulatory expectations and decisions. Starting in 2007, documents categorized as "RD" provide guidance on requirements that are set out in regulations and license conditions. Regulatory documents provide clarifications and additional details to the requirements set out in the NSCA and the regulations made under the NSCA. Each regulatory document aims at disseminating objective regulatory information to stakeholders, including licensees, applicants, public interest groups and the public on a particular topic to promote consistency in the interpretation and implementation of regulatory requirements. A CNSC regulatory document, or any part thereof, becomes a legal requirement when it is referenced in a license or any other legally enforceable instrument. The key documents for the HTR-powered, thermal, in-situ recovery project are: 1) RD-337: Design of New Nuclear Power Plants (Reference 18) and 2) RD-346: Site Evaluation for New Nuclear Power Plants (Reference 19), which will be discussed in more detail.

Some regulatory documents published prior to 2007, which include Policies (P), Standards (S), Guides (G), and Requirements (R) documents, contain requirements. When these documents are revised, the requirements will either be set out in regulations, or incorporated into license conditions, as applicable, and the guidance information will remain in regulatory documents. At the end of this section, Table 6-6 provides a list of current and draft regulatory documents that may be applicable to the HTR-powered, thermal, in-situ recovery project (Reference 20). Draft documents have not yet been finalized; they have comment periods, which are now closed, but CNSC personnel have not yet revised, reissued for further comment, withdrawn, or formalized these drafts as regulatory documents. Another category of key CNSC documents is the review guides used by the staff to process an application. While many guides are in preparation for new reactors, they are all focused on water reactor technology; the absence of such guidance for HTR designs will result in the need for additional time and effort during CNSC review.

In addition to the requirements to obtain Licenses for the facility, specific individuals at a facility – operators – must be certified by the CNSC (see Attachment D). The basis for such certification is the individual meets the applicable qualification requirements referred to in the license, has successfully completed the applicable training program and examination referred to in the license, and is capable, in the opinion of the licensee, of performing the duties of the position.

License Application

A License Application has specifically required information. Types of information required are:

- Description of the site, including location of any exclusion zone and any structures within that zone;
- Plans showing location, perimeter, areas, structures and systems of the nuclear facility;
- Evidence that the applicant is the owner of the site or has authority from the owner of the site to carry on the activity to be licensed;
- Proposed quality assurance program for the activity to be licensed;
- Name, form, characteristics and quantity of any hazardous substances that may be on the site while the activity to be licensed is carried on;
- Proposed worker health and safety policies and procedures;
- Proposed environmental protection policies and procedures;
- Proposed effluent and environmental monitoring programs;
- Information required by the Nuclear Security Regulations;
- Proposed program to inform persons living in the vicinity of the site of the general nature and characteristics of the anticipated effects on the environment and the health and safety of persons that may result from the activity to be licensed; and
- Proposed plan for the decommissioning of the nuclear facility or of the site.

<u>License to Prepare Site</u>

An application for a license to prepare a site for a Class I nuclear facility must update previously provided information and contain the following information in addition to that listed above:

- Description of the site evaluation process and of the investigations and preparatory work that have been and will be done on the site and in the surrounding area;
- Description of the site's susceptibility to human activity and natural phenomena, including seismic events, tornadoes and floods;
- Proposed program to determine the environmental baseline characteristics of the site and the surrounding area;
- Proposed quality assurance program for the design of the nuclear facility; and
- Effects on the environment and the health and safety of persons that may result, and the measures that will be taken to prevent or mitigate those effects.

An application for a license to prepare a site does not require detailed information or determination of a reactor design. At least one public hearing is required to be held during the licensing review, giving local public officials and affected citizens (including interveners) the opportunity to participate in the process. It is expected to take about two years to complete the Environmental Impact Statement and then another 12 to 20 months for CNSC to approve the license to prepare site.

<u>License to Construct</u>

As opposed to an application to prepare a site, an application for a License to Construct the facility must contain detailed information about the chosen reactor design and a supporting safety case. Prior to making the license application, an independent safety assessment must be performed to assess compliance with CNSC requirements. For a mature reactor design this application is normally submitted about two to three years before planned release of procurement and construction, as it requires that preliminary engineering for the project be sufficiently completed to address safety issues. CNSC is expected to require 24 to 36 months to review and approve such an application. This approval process is the one most likely to take longer for the new technology and to have the greatest impact on reaching plant operations. For a License to Construct, the following additional information is required:

- Description of the proposed design, including the manner in which the physical and environmental characteristics of the site are taken into account in the design;
- Description of environmental baseline characteristics of the site and the surrounding area;
- Proposed construction program, including its schedule;
- Description of structures proposed to be built, including design and characteristics;
- Description of systems and equipment to be installed, including their design and operating conditions;
- Preliminary safety analysis report demonstrating the adequacy of the design;
- Proposed quality assurance program for the design of the nuclear facility;
- Proposed measures to facilitate Canada's compliance with any applicable safeguards agreement;
- Effects on the environment and the health and safety of persons that may result from the construction, operation and decommissioning, and the measures that will be taken to prevent or mitigate those effects;
- Proposed location of points of release, the maximum quantities and concentrations, and the anticipated volume and flow rate of releases of nuclear and hazardous substances into the environment, including their physical, chemical and radiological characteristics;
- Proposed measures to control releases of nuclear substances and hazardous substances;
- Proposed program and schedule for recruiting, training and qualifying workers in respect of the operation and maintenance; and
- Description of any proposed full-scope training simulator for the nuclear facility.

<u>License to Operate</u>

The application to operate the reactor is normally completed while the plant is under construction and submitted three years before expected fuel load and startup of the plant. As such, it is not usually expected to become the critical path, compared to the need to complete construction. The CNSC staff is expected to need 24 to 36 months to review and approve this application. The applicant must demonstrate to the CNSC that the reactor has been constructed according to design and that the necessary policies and procedures are in place to ensure that the plant staff are trained and well qualified and 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 as necessary. The license to operate requires the following additional information:

- Final safety analysis report demonstrating the adequacy of the design;
- Proposed measures, policies, methods and procedures for operating and maintaining the nuclear facility;

- Proposed procedures for handling, storing, loading and transporting nuclear and hazardous substances;
- Proposed commissioning program for the systems and equipment;
- The proposed measures to prevent or mitigate the effects of accidental releases of nuclear substances and hazardous substances on the environment, the health and safety of persons and the maintenance of national security, including measures to
    - (i) Assist off-site authorities in planning and preparing to limit the effects of an accidental release,
    - (ii) Notify off-site authorities of an accidental release or the imminence of an accidental release,
    - (iii) Report information to off-site authorities during and after an accidental release,
    - (iv) Assist off-site authorities in dealing with the effects of an accidental release, and
    - (v) Test the implementation of the measures to prevent or mitigate the effects of an accidental release;
- The proposed measures to prevent acts of sabotage or attempted sabotage at the nuclear facility, including measures to alert the licensee to such acts;
- The proposed responsibilities of and qualification requirements and training program for workers, including the procedures for the requalification of workers; and
- The results that have been achieved in implementing the program for recruiting, training and qualifying workers in respect of the operation and maintenance of the nuclear facility.

Although it is not necessary for an existing Canadian license holder to be the operating license applicant or part of a consortium holding the operating license, it is extremely important for the applicant to understand and prepare for its operational responsibilities and appropriately plan for this experience to be developed well in advance of applying for the license. The level of effort to be a nuclear plant owner and operator is considerable. Development of such necessary experience includes: participation in managerial and technical improvement initiatives, such as those operated by nuclear industry professional associations, participation in peer review activities prior to operation (and commitment to such activities during operation), and early development of operator training concepts. Arranging with an existing plant operator to run the HTR plant, or even to own it, might be beneficial and is briefly discussed in Attachment D.

Fees

Estimated Annual Fee – The CNSC recoups its costs by charging licensing fees on a per application and annual basis. The annual fee is recalculated each year and each applicant or licensee is sent an invoice quarterly for an amount equal to 25% of the estimated annual fee payable within 30 days. After the end of each fiscal year, the CNSC calculates its actual costs and sets an additional amount or refund (Reference 21).

Application Fee – For a new reactor facility, an Initial Application requires a deposit of $25,000. On receipt of the application the estimated annual fee for the current fiscal year is calculated, and the applicant is invoiced for the amount owed. From that point forward, the applicant is required to pay the annual fee on a quarterly basis, as done for operating facilities. Additionally, the CNSC assesses fees for other activities under its jurisdiction, such as transport of radioactive material.

Based on current reactor fees, representative fee amounts are shown in the following table.

Table 6-1. Indicative CNSC Costs Prorated from Existing Facilities

Task	Cost (C$m)	Duration (years)
Pre-Project Design Review	3	2
License to prepare the site	5	2
License to construct	20	3
License to operate	8	3
Annual operational oversight fee	2	plant life

Licensing Timeline

The depth of information required, the multiple steps in the process, and the process of obtaining stakeholder input and CNSC approval are time-consuming. Table 6-3 below, from INFO-0756 (Reference 17), provides a timeline of nine years (108 months) from initial submittal to starting operations. However, no facility has yet proceeded through the full process laid out in the NSCA, so a representative timeline has not been demonstrated. However, it is instructional to look at the proposed timelines shown in Table 6-2 for two reactors that have entered the process – the proposed Ontario Power Generation Darlington station and Bruce Power station in Tiverton (Reference 22). [Bruce Power is also beginning the process for new power reactor sites in Peace Country in Alberta and in Ontario.]

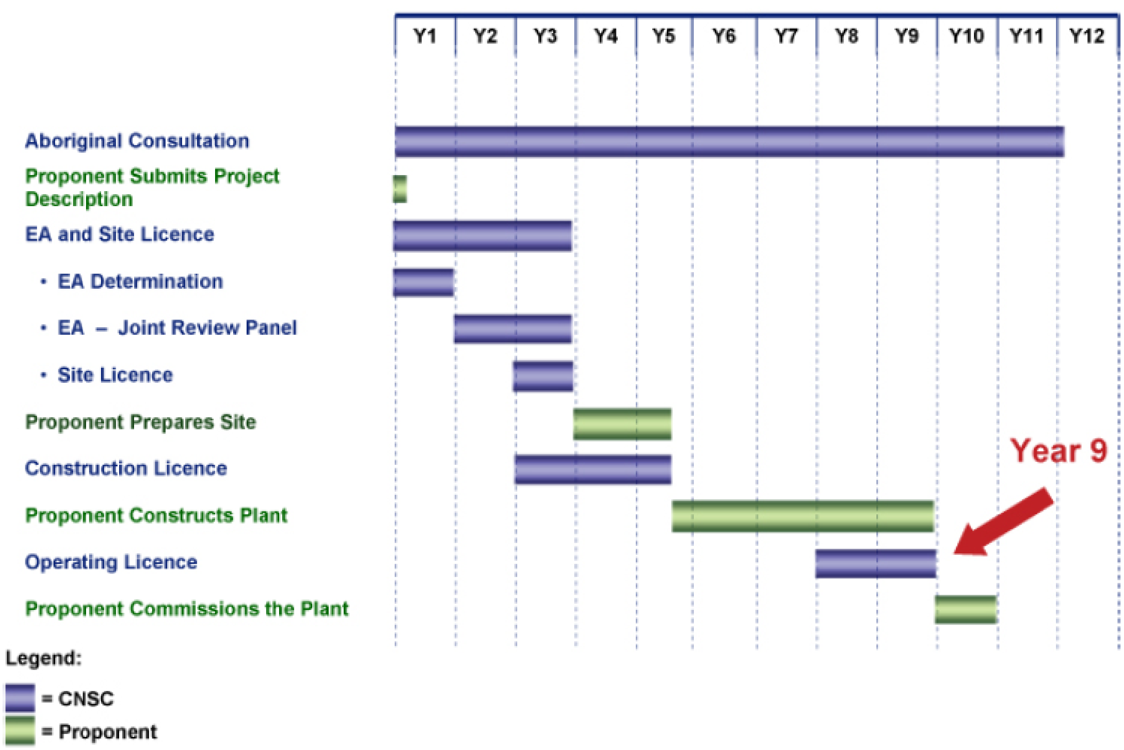

Figure 6-1. Generic Reactor Licensing Timeline

Table 6-2. Current Reactor Project Licensing Timelines

Action (dates in *italics* are in the future)	Darlington	Bruce
Application submitted for License to Prepare Site	Sep 06	Aug 06
Notice of Environmental Assessment (EA) by CNSC	May 07	Feb 07
EA referred to Joint Review Panel (JRP)	Mar 08	Jun 07
Draft EIS Guidelines and JRP Agreement for comment	Sep 08	Apr 08
Draft EIS Guidelines and JRP Agreement comment period	Sep-Nov 08	Apr-Jun 08
Final EIS Guidelines and JRP Agreement published	*Dec 08*	Aug 08
Appointment of JRP	*May 09*	Aug 08
Applicant submits EIS for License to Prepare Site to JRP	*Jun 09*	Sep 08
JRP Notice of EIS review period	*Jun 09*	Oct 08
Review of EIS, including public review	*Jun-Dec 09*	*Oct 08-Apr 09*
Application submitted for License to Construct	*Oct 09*	*May 09*
JRP holds Public Hearings	*Apr-May 10*	*Aug-Sep 09*
JRP submits Report to Federal Government	*Aug 10*	*Dec 09*
Federal Government's Response to Report	*Oct 10*	*Feb 10*
JRP issues License to Prepare Site	*Dec 10*	*Apr 10*
CNSC Public Hearings on License to Construct	*2012*	*2011*
Application submitted for License to Operate	*2013*	*2013*
CNSC Public Hearings on License to Operate	*2015*	*2015*

Based on the above, an optimistic licensing schedule for the Athabasca project would be as shown below in Table 6-3. The importance of high quality applications and submissions must be emphasized. A complete initial license application will enable the CNSC to recommend the EA process directly to a joint panel review, which has the potential to save up to eight months on the EA schedule and support early consideration of license applications. However, the new plant location and the unique, First-of-a-Kind nature of the plants under consideration add additional uncertainty and could result in additional time for licensing reviews. The need for the CNSC staff to become knowledgeable in the new technology, to develop review guidance, and to qualify analytical tools (e.g., computer codes) will likely substantially increase the licensing time. There are other actions and issues that could have an effect to lengthen, or shorten, the licensing time. Table 6-4 lists the reason and schedule impact of some of the various issues that could affect licensing. For each item identified, the middle column estimates the effect on licensing duration (e.g., getting the CNSC to refer the EA immediately to a Joint Review Panel could save eight months). It should be noted that, without an applicant – i.e., an identified owner/operator – and without an identified site, the process will not proceed at all.

Table 6-3. Representative Timeline for Licensing of New Reactor

Action	Months from Start
Application submitted for License to Prepare Site	0
Notice of Environmental Assessment (EA) by CNSC	6
EA referred to Joint Review Panel (JRP)	12
Draft EIS Guidelines and JRP Agreement for comment	18
Draft EIS Guidelines and JRP Agreement comment period	21
Final EIS Guidelines and JRP Agreement published	23
Appointment of JRP	25
Applicant submits EIS for License to Prepare Site to JRP	27
JRP Notice of EIS review period	27
Review of EIS, including public review	*33*
Application submitted for License to Construct	*33*
JRP holds Public Hearings	*37*
JRP submits Report to Federal Government	*40*
Federal Government's Response to Report	*43*
JRP issues License to Prepare Site	*45*
CNSC Public Hearings on License to Construct	*60*
Application submitted for License to Operate	*84*
CNSC Public Hearings on License to Operate	*108*

Table 6-4. Possible Licensing Schedule Impacts

Scenario Description	Impact	Note
Early reference to Joint Review Panel	-8m	To EA
Parallel prepare/construct application	-12m	To construct license
No existing nuclear licensee	+12m	Unless otherwise mitigated
No rig tests	+24m	Delay to construct license
No approved safety case*	+30m	Unless otherwise mitigated
No home country license	+12m	Unless otherwise mitigated
No operating experience	+12m	Delay to operate license
Supply chain availability/design readiness	-12m	Use of float in example schedule

* Includes lack of qualified computer codes and detailed review guides.

New Reactor Licensing Requirements

The major requirements applicable to a nuclear reactor for thermal, in-situ recovery plant are contained in RD-337 (Reference 18) and RD-346 (Reference 19). RD-337 discusses high level safety objectives and then specifies certain design and analytical requirements. For example, the probability of damaging the reactor core and of releasing radioactivity to the environment is quantitatively specified. Safety management during design requires specific management attributes, quality assurance, a foundation in test experience, certain analyses, and controlled documentation. An area around the nuclear reactor, the exclusion zone, must have access controlled by the operator to ensure radiation dose is limited in an accident. Specific guidance is given for pressure-retaining components, instrumentation and control, fire protection, seismic protection, and other considerations. System by system requirements are called out for the core, reactor coolant system, steam system, containment, etc. RD-337 states that its expectations "are intended to be technology neutral for <u>water-cooled</u> designs" [emphasis added]. Alternative approaches (RD-337, Section 11.0) can be proposed but must demonstrate equivalence to outcomes associated with the use of the expectations of RD-337. Thus, a design that is not water-cooled will require additional effort and burden to prove an acceptable safety basis.

RD-346 deals with siting of a nuclear plant. Meteorological, geological, surface and ground water, and biological data are necessary at the start of the licensing process. Protection against natural hazards such as earthquake and flood and human-induced events such as fires and explosions must be evaluated. Placing the reactor close to the thermal, in-situ recovery plant will add some complexity to the human events evaluations but should not be difficult to show is acceptable provided adequate precautions are included in the design (e.g., separation, barrier such as a berm).

Effect of Reactor Technology on Licensing

As noted, Canada has in the past licensed only a single technology for power reactors – the CANDU by AECL. The new licensing framework being established by the CNSC under the NSCA is not technology specific. However, the majority of existing detailed requirements apply to the CANDU design and much of the work being carried out in support of new reactors focuses on light water reactors.

The reactor vendor must have in place the necessary detailed engineering and testing/validation to support the construction license application under the alternative approaches (RD-337, Section 11.0) methodology or incur the real possibility of schedule delays. The licensing of any new nuclear plant in Canada will be undertaken in the context of a regulatory framework that is still under development and, thus, is not completely predictable to the applicant. Applicants with novel nuclear plant designs or new applications for nuclear energy must engage the CNSC in discussions early in the planning process (e.g., utilizing the PPDR process), enabling an appropriate approach for the assessment of the technology by the CNSC to be formulated. The reactor vendor has to commit considerable resources and use a project approach to the formal nuclear licensing interaction with the CNSC to reduce the potential for licensing delays.

Another consideration is qualification of computer codes for analysis of non-water reactors. CNSC performs its own analyses to confirm certain aspects of a design, but currently does not have any codes that would be qualified for use for the HTRs. Even more important, they do not have codes that they have accepted for applicant use for HTRs. Qualifying computer codes usually is a time-consuming process requiring a strong foundation on test data and is the responsibility of the reactor vendor. Obtaining CNSC agreement for design computer codes may add additional delay to the licensing process.

6.4 HTR Licensing Evaluation

The thermal, in-situ recovery project is considering three reactors that have no licensing background in Canada. The CNSC would consider that the British have many years of successful operation of numerous gas-cooled designs and the French nuclear program has built sodium cooled reactors, and that a sodium cooled fast reactor, Fermi, was licensed and operated in the US. However, the PBMR, the MHTGR, and the 4S reactors differ significantly from previously licensed designs. This increases the uncertainty in timing and effort to obtain a license. If the CNSC is over-extended due to low staffing and heavy workload, the thermal, in-situ recovery project reactor review could suffer delays. Even with application of necessary resources, CNSC is likely to take longer to assess an HTR due to lack of staff familiarity and of licensing review guidance for non-water reactors.

The success of licensing in other countries may have a salutary effect on the effort required in Canada. Since CNSC evaluates its nuclear safety requirements against those of the International Atomic Energy Agency (IAEA) and is highly familiar with US NRC standards, obtaining a license in another country could be beneficial in facilitating a CNSC review. For the three designs, the licensing initiatives in various countries vary, as shown in Table 6-5. Except in South Africa where PBMR is the focus, there has only been some pre-licensing technical evaluation. Most regulatory agencies have concentrated on the water cooled reactor designs being actively considered by a number of customers.

Table 6-6 lists the CNSC documentation containing requirements and guidance that would be applicable to design, construction, and operation of the nuclear plant supporting the thermal, in-situ recovery process. This documentation includes requirements for personnel, radiation protection, and shipping of radioactive materials and some of it is CANDU specific. As previously noted, the CNSC has not prepared a licensing framework for use for a non-water cooled reactor. Therefore, licensing one of the three alternative designs will likely involve considerable additional effort and time.

Regarding licensing an HTR for a thermal, in-situ recovery plant, it is likely that the First-of-a-Kind HTR will require longer than the water-cooled reactor timeframe target of nine years. Licensing time span may well be controlling path in the plant completion schedule. Therefore, the following should be considered:

- The vendor should promptly initiate a Pre-Project Design Review to allow the CNSC to become familiar with the technology and develop review guidance and qualified analytical methods in parallel with preparing an application for a License to Prepare Site.

- The applicant should attempt to have CNSC recommend immediate referral of the EA to a joint review panel.

- Consideration should be given to establishing a formal agreement for management of the HTR by an existing Canadian nuclear plant owner/operator to eliminate the need to establish that a new organization meets regulatory requirements.

Regarding the licensing of a thermal, in-situ oil sands recovery plant, some additional concerted outreach strategy should be applied. The normal Alberta process of determining whether a new oil sands recovery plant will have an impact on existing or new developments in the area will be breaking new ground with the HTR plants being used as an energy source. A concerted outreach effort to open communication and education processes, as discussed in the outreach sections above, is needed to ensure that the Alberta officials and organizations and the public are kept informed and their needs for involvement satisfied.

Table 6-5. Status of Reactor Licensing outside Canada

4S		
US	In Feb. 2005, NRC staff met with the city manager and vice mayor of Galena, Alaska to discuss and answer questions on the city's plans to build a Toshiba 4S reactor to provide its electricity. Toshiba began pre-application discussions with NRC staff in Oct. 2007. A similar reactor, PRISM, was assessed by the NRC for licensability, with the results reported in NUREG-1368 (Reference 4). Specific concerns such as reactivity coefficient for sodium voiding and coast down characteristics of the EM pumps were raised -Toshiba has designed the 4S to address these. The Fermi sodium reactor was licensed in the 1960's.	Toshiba planned to submit a design application in 2009. NRC's latest work plan shows 4S Design Certification pre-application effort not beginning until 2011.
MHTGR		
US	MHTGR Preliminary Safety Information Document (PSID) (Reference 23) prepared and submitted to the NRC in the 1980's. GA went through two rounds of questioning based on this submittal, and NRC issued a Preliminary Safety Evaluation Report (Reference 24). These documents would provide the basis for the safety case of the MHTGR but would require significant revision for the thermal, in-situ MHTGR version and to address an NRC fuel performance concern. Similar to PBMR, GA is working with the U.S. DOE on the NGNP project, and MHTGR could be licensed as part of NGNP.	No effort outside NGNP. NRC work plan shows continuing NGNP effort, but NGNP time frame may be later than needed for HTR for thermal, in-situ recovery plant.
PBMR		
South Africa	Application in process for Demonstration Power Plant; plan is to begin construction in 2010.	Action no sooner than 2009.
US	Exelon started review in 2001 but requested closure in mid-2002. PBMR (Pty) Ltd notified NRC in Feb. 2004 of intent to apply for Design Certification in the future and requested discussions with the NRC to plan the scope and content of the pre-application review. NRC work proceeded at a low level, with public meetings beginning in 2005, submittal of various pre-application information by PBMR through 2007, and issue of Requests for Additional Information in Sep 2007. Initial responses were delivered from early 2008. In 2007, PBMR began developing licensing strategies as a contract to the US DOE's NGNP and continues to develop generic licensing pre-application activities that align with PBMR applications. In Aug. 2008, the U.S. DOE & NRC submitted to Congress the licensing strategy for NGNP. DOE-funded licensing tasks completed to date have included definition of the US licensing strategy and activity planning and are developing a gas-reactor specific licensing requirements document. PBMR and NGNP are working together on application development to support NGNP operation around 2020.	PBMR Pty Ltd planned to submit a design application in 2009. NRC's latest work plan shows PBMR Design Certification pre-application effort not beginning until 2011. NRC work plan shows continuing NGNP effort, but NGNP time frame may be later than needed for HTR for thermal, in-situ recovery plant.

Table 6-6. CNSC Regulatory Documentation Applicable to a New Reactor

Regulatory Documents		
Number	**Title**	**Issued**
RD-58	Thyroid Screening for Radioiodine	Aug-08
RD-310	Safety Analysis for Nuclear Power Plants	Feb-08
RD-204	Certification of Persons Working at Nuclear Power Plants	Feb-08
RD-337	Design of New Nuclear Power Plants	Nov-08
RD-346	Site Evaluation for New Nuclear Power Plants	Nov-08
RD-353	Testing the Implementation of Emergency Measures	Nov-08
RD-363	Nuclear Security Officer Medical, Physical, and Psychological Fitness	Nov-08

Guides		
Number	**Title**	**Issued**
G-323	Ensuring the Presence of Sufficient Qualified Staff at Class I Nuclear Facilities - Minimum Staff Complement	Aug-07
G-320	Assessing the Long Term Safety of Radioactive Waste Management	Dec-06
G-306	Severe Accident Management Programs for Nuclear Reactors	May-06
G-144	Trip Parameter Acceptance Criteria for the Safety Analysis of CANDU Nuclear Power Plants	May-06
G-129	Keeping Radiation Exposures and Doses "As Low as Reasonably Achievable (ALARA)"	Oct-04
G-217	Licensee Public Information Programs	Jan-04
G-205	Entry to Protected and Inner Areas	Nov-03
G-91	Ascertaining and Recording Radiation Doses to Individuals	Jun-03
G-278	Human Factors Verification and Validation Plans	Jun-03
G-276	Human Factors Engineering Program Plans	Jun-03
G-147	Radio-bioassay Protocols for Responding to Abnormal Intakes of Radionuclides	Jun-03
G-273	Making, Reviewing and Receiving Orders under the Nuclear Safety and Control Act	May-03
G-208	Transportation Security Plans for Category I, II or III Nuclear Material	Mar-03
G-225	Emergency Planning at Class I Nuclear Facilities and Uranium Mines and Mills	Aug-01
G-228	Developing and Using Action Levels	Mar-01
G-149	Computer Programs Used in Design and Safety Analyses of Nuclear Power Plants and Research Reactors	Oct-00
G-219	Decommissioning Planning for Licensed Activities	Jun-00
G-206	Financial Guarantees for the Decommissioning of Licensed Activities	Jun-00

Standards Documents		
Document	**Title**	**Issued**
S-210	Maintenance Programs for Nuclear Power Plants	Jul-07
S-106	Technical and Quality Assurance Requirements for Dosimetry Services	May-06
S-296	Environmental Protection Policies, Programs and Procedures at Class I Nuclear Facilities and Uranium Mines and Mills	Mar-06
S-98	Reliability Programs for Nuclear Power Plants	Jul-05
S-294	Probabilistic Safety Assessment (PSA) for Nuclear Power Plants	Apr-05
S-260	Making Changes to Dose-Related Information Filed with the National Dose Registry	Oct-04
S-99	Reporting Requirements for Operating Nuclear Power Plants	Mar-03
S-106	Technical and Quality Assurance Standards for Dosimetry Services in Canada	Mar-98

Policies		
Document	**Title**	**Issued**
P-325	Nuclear Emergency Management	May-06
P-299	Regulatory Fundamentals	Apr-05
P-290	Managing Radioactive Waste	Jul-04
P-211	Compliance	May-01
P-223	Protection of the Environment	Feb-01
P-242	Considering Cost-benefit Information	Oct-00
P-119	Policy on Human Factors	Oct-00

Other Documents		
Document	**Title**	**Issued**
R-9	Requirements for Emergency Core Cooling Systems for CANDU Nuclear Power Plants	Feb-91
R-8	Requirements for Shutdown Systems for CANDU Nuclear Power Plants	Feb-91
R-7	Requirements for Containment Systems for CANDU Nuclear Power Plants	Feb-91
R-85	Radiation Protection Requisites for the Exemption of Certain Radioactive Materials from Further Licensing Upon Transferal for Disposal	Aug-89
R-105	The Determination of Radiation Doses from the Intake of Tritium Gas	Oct-88
R-77	Overpressure Protection Requirements for Primary Heat Transport Systems in CANDU Power Reactors Fitted with Two Shutdown Systems	Oct-87
R-100	The Determination of Effective Doses from the Intake of Tritiated Water	Aug-87
R-10	The Use of Two Shutdown Systems in Reactors	Jan-77

Nuclear Substance Regulation Documents		
Document	**Title**	**Issued**
G-313	Radiation Safety Training Programs for Workers Involved in Licensed Activities with Nuclear Substances and Radiation Devices, and with Class II Nuclear Facilities and Prescribed Equipment	Jul-06
R-117	Requirements for Gamma Radiation Survey Meter Calibration	Jan-95
R-116	Requirements for Leak Testing Selected Sealed Radiation Sources	Jan-95

Draft Regulatory Documents		
Document	**Title**	**Issued**
G-340	Nuclear Security Officer Authorization and Training	Feb-07
S-340	Nuclear Security Officer Medical, Physical and Psychological Fitness Requirements	Feb-07
G-341	Control of the Export and Import of Risk-Significant Sealed Sources	Feb-07
S-322	Physical Security Requirements for the Storage of Sealed Sources	Nov-06
S-308	Safety Analysis for Non-Power Reactors	Sep-06
S-339	Nuclear Facility Access Authorization	Dec-05
G-323	Ensuring the Presence of Sufficient Qualified Staff at Class I Facilities – Minimum Staff Complement	Oct-05
	Purpose and Scope Sections Proposed Regulatory Documents	Feb-05
G-224	Environmental Monitoring Program at Class I Nuclear Facilities and Uranium Mines and Mills	Jul-04
S-224	Environmental Monitoring Program at Class I Nuclear Facilities and Uranium Mines and Mills	Jul-04
C-287	Draft Regulatory Guide - Public Access to Information held at the CNSC	Jan-03
C-138	Draft Regulatory Guide - Software in Protection and Control Systems	Oct-99
C-006	Draft Regulatory Guide - Requirements for the Safety Analysis of CANDU Nuclear Power Plants	Sep-99

7

Schedule Considerations

In this section, the fundamental schedule considerations for developing and demonstrating an HTR plant in support of a thermal, in-situ oil sands recovery plant in Alberta are discussed. The same schedular steps and timing would apply for the First-of-a-Kind plant for any of the three HTR concepts whether it was a single HTR module in a single oil sands development stage or multiple HTR modules in multiple stages.

Although each HTR technology has some prior operational plant experience, the application of HTR technology to an oil sands plant would be the first application of an HTR nuclear plant in Canada and the first application of an HTR technology to provide process steam for a commercial oil sands production process. The designs for the oil sands applications of these HTRs are currently in the pre-conceptual stage; therefore, the schedule considerations of this section reflect the lack of maturity of the design, components, fuel manufacture, licensing, construction and business infrastructure that would be required to complete and begin operation of the first of these plants.

Figure 7-1 provides a high-level, graphical representation of the relative schedule for a First-of-a-Kind HTR oil sands plant project in Canada. Five major aspects are involved:

1. Design – This effort consists of conceptual and detailed plant designs. Sufficient component development testing is needed to complete the detailed design. The use of a component test facility will be required.
2. Operations – The preparation and training for operations of the plant must be performed in time to support licensing and startup and testing of the HTR plant. This includes the development of a full plant simulator.
3. Licensing – This effort is discussed in detail in Section 6. The receipt of a license to prepare the site, license to construct, and license to operate will be required. There are several factors that differentiate an HTR plant from traditional water reactors that will likely extend the standard licensing/construction schedule of 108 months.
4. Construction – This effort is discussed in detail in Section 5. It includes preparation of the site, construction of the plant, and startup and testing. Once the license to construct is approved, the construction schedule becomes the critical path to plant operation. Notable delays to construction in Alberta include transportation, labor, climate and wildlife.
5. Fuel – The vendor must license and build a fuel production factory, qualify the production process, and manufacture necessary quantities of fuel. The factory licensing requires detailed plant design and safety analyses to meet nuclear regulatory requirements. The qualification effort requires irradiation tests of several batches of fuel under normal and accident conditions and can take four to five years. These collective activities, if not well managed, could take longer than design, licensing and construction of the reactor itself.

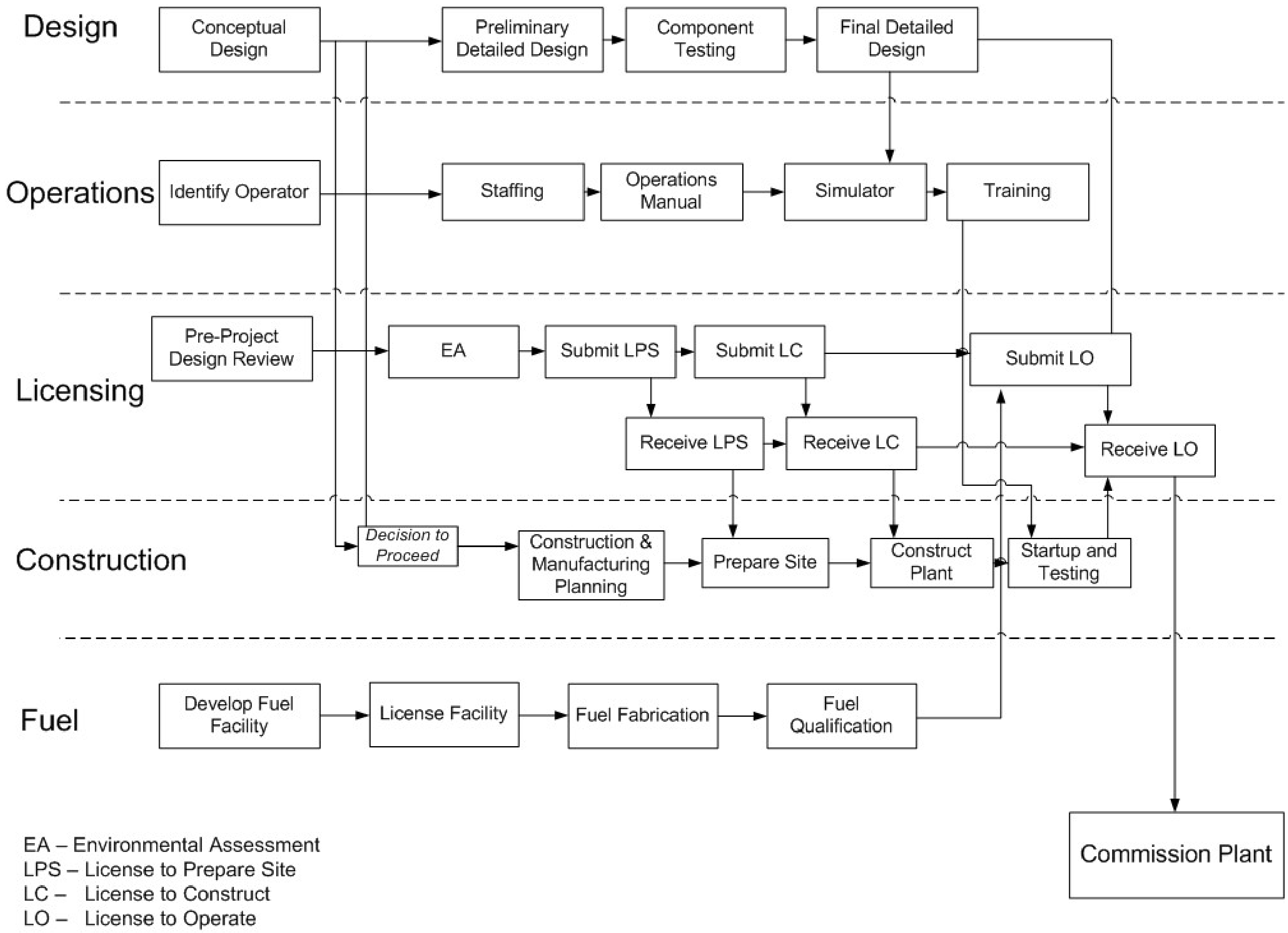

Figure 7-1. HTR First-of-a-Kind Plant Schedule

7.1 Initial Actions

Assuming that minimizing the time required to begin operation of the first plant is desired, the first step, as shown in Figure 7-1, is a parallel effort consisting of conceptual design, identification of the HTR plant owner/operator, the development of a fuel manufacturing scheme, and the submittal of a Pre-Project Design Review. The pre-conceptual HTR oil sands recovery plant design must be sufficiently completed to support a decision to proceed with initial licensing requirements. The owner/operator (see Attachment D) needs to be closely involved with the conceptual design of the HTR plant to ensure that its requirements are met and should, therefore, be identified as early as possible in this schedule. The fuel manufacturing process needs to be started in parallel with conceptual design to decrease the likelihood that the fuel manufacturing and qualification schedule will become critical path. An additional important step at this point is the submittal of a Pre-Project Design Review to allow the CNSC to become familiar with the project and the new concepts involved.

As of now, all three oil sands HTR designs are in the pre-conceptual phase, no owner/operators are lined up, and no licensing actions have been initiated. PBMR may have an advantage because of experience from the fuel qualification efforts and manufacturing planning currently taking place for the DPP in South Africa; however, the manufacturing plant being built for the DPP may or may not be available to supply fuel for plants in North America, as its capacity will need to supply fuel for the DPP and other planned PBMR plants in South Africa. Other than this, the key factor for a timely start of the project is who can bring the necessary team together quickly to support it. Each vendor, however, does not currently have the resources applied to an HTR oil sands plant to begin this effort in earnest and would need to develop and staff their organizations significantly.

7.2 Detailed Design and Licensing

Upon the identification of an owner/operator and the completion of a conceptual design, the owner/operator can decide whether or not to proceed. With respect to design, the next step is to begin a preliminary detailed design and begin component testing to support a final detailed design. Components or component features that are developmental in nature should be tested to ensure their adequacy and longevity; this often requires the availability of high temperature test facilities.

4S and PBMR are at an advantage with respect to component testing. Toshiba opened a sodium test facility in early 2008. Also, a test facility has been constructed in South Africa in support of the DPP and follow-on PBMR plant designs; however, this may not be suitable for component testing unique to an oil sands PBMR plant design. A component test facility must be constructed or rented for MHTGR, and there are some in Germany, Japan and elsewhere. Should the NGNP project proceed in the U.S., and its planned high temperature gas loop is completed, synergies may be possible with respect to component testing.

The licensing process begins in earnest once the conceptual design is done and the owner/operator decides to proceed. It requires substantial involvement from the HTR plant vendor *and* the owner/operator. All parties must be intimately involved to ensure success in this portion of the project. The application for the license to prepare the site should be submitted, and work should begin on the application for the license to construct the plant. This application should be submitted as soon as design finalization and supporting analysis allows.

All three HTR designs are outside the current focus of the CNSC regulatory processes. Lack of regulatory guidance applicable to HTRs, compounded by CNSC staff unfamiliarity with key aspects of the HTR technologies, will likely lead to licensing/construction timelines for the First-of-a-Kind HTR applications that are longer than those currently being predicted for water cooled reactor projects (108 months from regulatory notification to issue of License to Operate). However, once the licensing process has been established, it is probable that the time for licensing will be at least as good for later applications as that for water-cooled plants. It is possible, because of the Generation IV passive safety features of the HTRs and their small size, that licensing of Nth-of-a-Kind HTRs may be faster, which was one of the original objectives of the Generation IV designs.

7.3 Construction

Construction begins when the appropriate licenses are issued (license to prepare site and license to construct plant). The schedule depends on readiness of the design, availability of component manufacturing, ability to deliver components and materials to the site, and on-site construction issues such as weather and skilled labor availability. As discussed in Section 5, different levels of modularity and size of components affect timing and potential causes for delay. The small size of the 4S components, therefore, provides an advantage.

Upon completion of plant construction, startup and testing will commence. The startup and testing schedule is affected by the ability to properly predict behavior in advance, "groom" systems, and verify proper operation. A nuclear reactor requires additional testing to ensure its behavior is well understood. If multiple small reactors are required for a given stage, multiple reactor test programs will be required. This will add time and effort to the startup and testing phase.

Training of operators in advance of startup is also essential to ensure the test program goes smoothly. The plant operator must ensure that a sufficient number of qualified operations personnel are made available early in the project to become knowledgeable and proficient with the reactor design. If training is not given adequate priority and if an accurate plant simulator is not available, operator training could become limiting to plant startup. See Attachment D for more discussion of operator training.

If the project is started in conjunction with a green field thermal, in-situ recovery plant, the project schedule would have to be synchronized with the schedule for the conventional licensing of such a plant in Alberta. A typical schedule for a four-stage 120,000 bpd plant is noted in Attachment A and summarized as follows:

- Conceptual design – 4 to 5 months
- Front end engineering design (FEED) studies – 12 to 13 months
- Non-nuclear regulatory process documentation and due process - 18 months
- Detailed engineering, procurement and delivery of major equipment - 30 months

- Construction and commissioning of Stage 1, including early building of common infrastructure facilities for subsequent stages - 42 months
- Construction of three subsequent stages - three years between each stage

In the absence of a nuclear plant, it takes about nine years to begin operating the first stage of an oil sands plant; however, the regulatory requirements are expected to be over after about three years, and completion of construction is then the only critical path work. By comparison, the nuclear process is expected to take nine years for a standard water-cooled reactor based on completion of the license to construct being received after about five years. Unlike the better proven oil sands regulatory process, the uncertainties in the nuclear regulatory process for First-of-a-Kind HTRs are estimated to significantly extend the licensing process by about two years. In addition, the construction timetable is likely to take longer than planned because of the unknowns of the new design and also construction in a new and less forgiving location. For these reasons, it is not expected that the oil sands plant and well pads will the limiting part of the first combined Oil Sands Plant with an HTR Energy Source. However, the gap should narrow in the future for subsequent plants as licensing gets streamlined and construction lessons are learned.

7.4 OPERATION DATE CONSIDERATIONS

If the goal was to begin operation of a First-of-a-Kind HTR oil sands plant as soon as practicable, and the initial actions identified above began in 2009, operation of a First-of-a-Kind HTR oil sands plant in the early 2020's would be possible. The schedule for bringing a First-of-a-Kind HTR plant into operation, however, involves considerable uncertainty. Each aspect - design, licensing, construction, and fuel - has numerous risks that may delay the schedule. See Section 9 for a detailed discussion of these risks.

8 Cost Considerations

Each of the HTR plant vendors provided estimates of the capital and the operations and maintenance (O&M) costs to support the evaluation of HTR applications to the thermal, in-situ oil recovery. The details of each estimate, which the vendors requested remain confidential, are not discussed here but are provided separately.

The estimates are highly uncertain due to their preliminary nature, the need to resolve First-of-a-Kind issues, adjustment for location in the Athabasca region, and the industry-wide challenge in developing nuclear plant construction estimates in a period of volatility in commodity and labor costs (water-cooled reactor construction estimates have recently varied by a factor of four). In order to evaluate the reasonableness of the estimates, MPR compared them to recent U.S. light water reactor (LWR) capital and operating cost estimates, while recognizing that there are a number of factors that distinguish HTR costs from LWR costs as well as differences in costs associated with the northern Alberta location. Although the estimates are not sufficiently accurate to distinguish between the HTR technologies on a quantitative basis, some differences among the technologies that affect cost are discussed.

MPR considers that, although highly uncertain, costs are sufficiently well bounded to provide for comparison to non-nuclear thermal, in-situ recovery plants. Based on our understanding of those costs, MPR considers further evaluation of HTRs for thermal, in-situ recovery is warranted.

8.1 CAPITAL COSTS

The overnight capital cost of the HTR plants discussed in this report includes the engineering, procurement, and construction (EPC) contract cost (labor, materials, equipment and fees) and owner's costs (licensing fees, owner's project management and oversight and site development costs). Costs incurred outside of the HTR plant battery limit (oil sands recovery plant site) were not included. Adjustments were made to permit comparisons of the three vendors' estimates on a common basis (e.g., October 2008 Canadian dollars, site infrastructure, licensing, component transport, owner's costs). The overnight capital costs for the construction of all four stages of the HTR plants came to about C$4.7 to C$4.9 billion, or C$3100 to C$3500 per kWt.

The overall capital cost adds to the overnight estimate the costs of capitalized interest incurred during construction. This is dependent on the sources of capital, finance charges, rate of capital expenditures, commencement of repayment, etc. Because the overall capital costs are highly dependent on the specific circumstances for each plant and owner, no estimate of overall capital cost is provided in this report.

It should be recognized that the capital cost provided above does not include the First-of-a-Kind development costs that must be incurred by the HTR vendors. PBMR has spent a significant amount on development already for the DPP, and some development has been performed on the other designs; however, each plant has First-of-a-Kind development costs remaining that are likely in the hundreds of millions of dollars. One large portion of this cost will be for the development of a fuel manufacturing facility. It is assumed here that these costs are ultimately amortized over a larger fleet of reactors.

The differences in the vendor technology that could potentially affect costs include:

- **Number of Reactor Modules –** A larger reactor module size typically would be expected to contribute to lower costs per unit energy. If all other factors were the same among the technologies, the PBMR plant (3 modules) would have a cost advantage over the MHTGR (4 modules) and the 4S (11 modules).

- **Degree of Modularization –** Increased modularization would be expected to contribute to lower costs since, with more modularization, there is less labor required on-site. This would potentially allow lower costs of labor and a more efficient construction environment compared to on-site construction in Athabasca. Modularization will likely be limited by transportation capabilities. While all of the vendors can ultimately consider modularization in their detailed designs, it is likely that the 4S plant will be able to achieve the highest degree of modularization among the three vendors because it will be less limited by transportation with its smaller unit size. Note that in this case the small size of the 4S is an advantage that may offset the disadvantage of requiring more modules cited above.

- **Transportation Requirements –** Large and heavy components can require special arrangements that can raise transport costs and disrupt the project schedule. All reactor module designs have transportation requirements that require special vehicles, permits, and shipping conditions. While the 4S will have to transport more reactor modules, their smaller size will allow for less costly transportation methods.

- **Backup Steam Requirements –** Additional capital will be required to provide a backup steam supply for unexpected or prolonged reactor outages. Small plants like the 4S have the benefit of only requiring a small amount of steam to replace one module that is shut down. Large plants with combined steam-electric capabilities (MHTGR and PBMR), however, have the benefit of being able to shift production of electricity to production of steam (assuming the steam generators are sized large enough) should one module shut down. The capital costs for conventional backup steam supply are expected to be low (C$40 to C$80 million (Attachment A)) in relation to HTR costs and to the overall costs of the four-stage in-situ oil sands plant and are not a significant differentiator among the HTR designs.

8.1.1 Capital Cost Extrapolation from Current Project Estimates

A check on the above capital cost projection was made by comparing current estimates for the cost of electricity from U.S. LWR projects. Although some steps have been taken to commit to build new electrical generating station reactors, there remains considerable uncertainty in the overnight construction costs. U.S. nuclear plant overnight capital estimates in the last two years have varied widely:

•	NRG Energy	\$2900/kWe (May 2007)	(Reference 25)
•	Georgia Power	\$4360/kWe (July 2008)	(Reference 25)
•	SCE&G	\$2200/kWe (2007)	(Reference 25)
•	Progress Energy	\$4260/kWe (March 2008)	(Reference 26)
•	Florida Power & Light	\$3108-4540/kWe (Fall 2007)	(Reference 26)
•	Congressional Budget Office	\$2360/kWe (2007)	(Reference 26)
•	The Keystone Center	\$2950/kWe (June 2007)	(Reference 27)

The differences among these estimates result from differences in scope and assumptions. Based on these data and other MPR projects, we consider a reasonable estimate for new LWRs on an overnight capital basis to be \$3000 to \$4500/kWe (October 2008 US\$). Comparing these values to the vendor estimates discussed above requires conversion to an equivalent thermal energy basis - roughly dividing by a factor of three to adjust for the efficiency of generation of electricity. On this basis, the estimated HTR capital costs for the oil sands plant are about triple the LWR costs. MPR considers this to be a reasonable validation of the vendor estimates. HTR costs would be expected to be higher due to the increased cost of construction labor at Ft. McMurray, first of a kind costs, higher transportation costs, economy of scale factor (3300 MWt LWRs versus 135 - 500 MWt HTRs) and Canadian currency conversion factor.

8.1.2 Capital Cost Profile

At this conceptual stage of planning, the uncertainty of the capital costs and schedules is large, as previously noted. Therefore, combining the projections to provide a notional project capital spending profile magnifies the uncertainties and should be viewed skeptically. MPR used the middle of the overnight capital cost estimates, C\$4.8 billion, from Section 8.1, to develop a very rough spending profile. Due to the relatively long schedule for licensing and completing work on a First-of-a-Kind HTR, costs for the first four years are assumed to be relatively low since this will be a period of preparatory work (e.g., pre-licensing). Much larger outlays then begin for long lead components for three years, followed by construction for the next four years, resulting in initial operation of Stage 1 at the 12th year of the project. Since common facilities will be needed for Stage 1, another assumption is that 75% of the on-site construction cost and 57% of the component cost are expended by the time Stage 1 is operational. After Stage 1 starts up, construction and long lead component spending is then spread evenly over the remaining years of the project, although component spending finishes a year before construction ends.

Figure 8-1 depicts a notional, annual, capital spending profile. For comparison purposes, the figure also shows the NGNP projected funding profile based on pre-conceptual design cost estimates and a 12-year project span (Reference 28). NGNP is similar to the HTRs for the thermal, in-situ recovery plant in that it involves a First-of–a-Kind design. However, spending is compressed because NGNP's four reactors (each 500 to 600 MWt) are built in a single stage, rather than three to eleven reactors in four stages for the oil sands application. Also, construction is performed in a less costly locale and the NGNP amounts do not include most owner's costs. The dollar values in the figure are adjusted to Canadian 2008 dollars.

The spending profile shows that the first few years of the oil sands project will likely need significant expenditure to get things started (tens of millions of dollars) but that the increases in expenditures for long lead items would be a few years off.

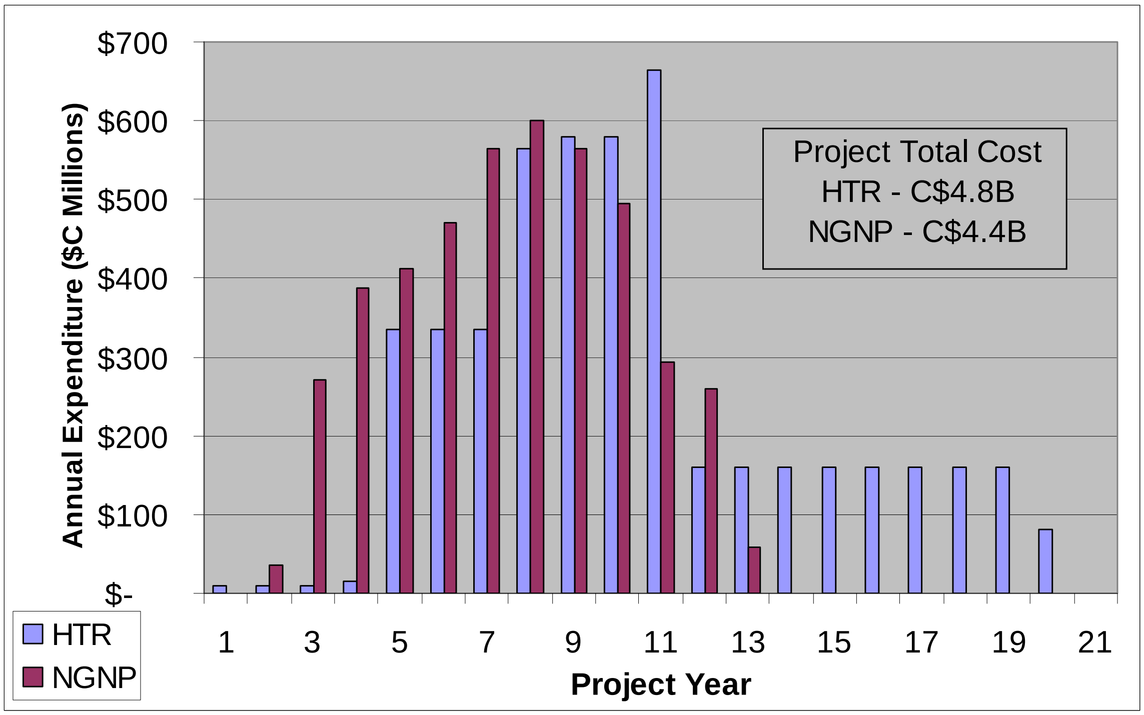

Figure 8-1. Spending Profile

8.2 OPERATING AND MAINTENANCE COSTS

Each of the vendors provided estimates of the operation and maintenance (O&M) costs of the HTR plant. Those estimates are dependent on the amount of staffing required at the plant site as well as the annualized costs of fuel and maintenance. MPR normalized all the estimates to include common considerations and to be based on 2008 Canadian dollars and labor rates in the Athabasca oil sands region. When compared on a common basis, the estimated O&M costs range from about C$160 million to about C$280 million per year (2008 dollars), which would correspond to C$3.80 to C$ 6.70 per barrel of bitumen.

If the O&M costs are allocated by the thermal fractions used only for injection steam, the cost of steam per barrel of bitumen produced (at 95% of design capacity) would be about C$2.90 to C$5.40 per barrel. This cost does not include any costs for electricity which would have to be provided for plant operation and recovery of bitumen, but it provides a focal point from which to evaluate an optimized strategy for how electricity might best be provided for the HTRs.

The total annual cost for a plant would combine the O&M costs with annualized cost of amortized construction capital and interest. Similar to the discussion of capital costs in Section 8.1, above, the actual annualized cost of construction capital and financing is highly dependent on the methods of capital acquisition, interest rates, loan guarantees, government assistance, methods and timing of repayment, etc. Because the actual payments are so dependent on the particular circumstances of each owner and plant, no estimates of annualized capital costs are made in this report. However, since the capital costs of the HTR plants are large and similar in magnitude for each HTR design, adding the annualized cost of capital to the O&M costs will tend to reduce the proportional differences between annual costs for the three designs.

The operating cost estimates are in all cases very preliminary, and MPR does not consider them to be sufficiently precise to distinguish among the designs.

To assess the reasonableness of the operating cost estimates, with no directly applicable operating experience available, MPR reviewed current, actual 2007 LWR operating costs in the U.S., which averaged about 1.8 cents/kWe-hr (Reference 29). Thus, the average cost outlay for an 1100 MWe (~3400 MWt) reactor is about US$200 million. This is in a similar range as that estimated for the HTR plants. The ratings of the individual reactor units typically have a much lower effect on O&M costs than does the number of reactors at a site and component count. Although the in-situ, thermal recovery plant has multiple reactors, the number of systems and components per reactor are lower than in LWRs, so the HTR O&M costs may be in the same approximate zone as for LWRs. However, when higher local cost of labor in Athabasca, and higher costs of fuel (enriched at 9% and 18% for HTRs, compared to 4% for LWRs), as well as the exchange rate between Canadian and U.S. 2008 dollars are considered, the HTR reactor operating costs may actually be lower overall than for LWRs on a comparable basis. This may be possible considering the simplicity of the HTRs compared to LWRs; however, until more precise bottom up O&M estimates are developed, MPR considers that PTAC should anticipate costs to be equal to the upper end of the vendor estimated cost range.

8.2.1 Non-Fuel O&M

One significant difference among the designs that could potentially affect maintenance costs is the approach for refueling. More frequent refuelings involve more periods of intense maintenance activity that require added staffing, special training, and possible overtime. If the design rarely requires refueling and allows maintenance without shutting down a reactor, it can be accommodated with lesser impact – and lower cost. The HTR designs' need for fewer safety systems (e.g., no emergency core cooling system) with fewer active components (e.g., pumps) than LWRs could reduce costs sufficiently to offset the HTR premium for working with unfamiliar technology and with additional loops. Assessing the basis for vendor estimates for O&M costs would require further evaluation with access to more detailed vendor information.

8.2.2 Fuel

For U.S. LWRs, fuel costs are on the order of US 0.47 cents/kWe-hr, comprising one-quarter to one-third of the O&M costs of a nuclear plant (Reference 30). With no fuel manufacturing facilities available, production costs for HTR fuel are unknown at this time, although two of the vendors have provided estimates. In addition, there are significant differences between LWR and HTR fuel and among the HTR technologies (including but not limited to configuration, required hardware, manufacturing process, and enrichment levels). However, as a first approximation, it can be assumed that the HTR reactor fuel costs are similar for each technology but more expensive than LWR fuel. The higher cost would be due to low volume manufacturing, higher enrichment, and specialized manufacturing processes (e.g., working with sodium) or larger fuel volume (i.e., MHTGR and PBMR). On this basis, the estimate for fuel costs of the full HTR plant would be greater than the LWR equivalent of about C$25 million per year based on current uranium prices. Current LWR fuel enrichment is about one third of overall fuel cost, and the HTRs will require enrichment levels of two to four times that of LWRs. Waste fund contributions are only about 17% of LWR fuel costs. These considerations make it likely that HTR fuel costs will make up a larger fraction of O&M costs than in LWRs.

In addition to the specialized manufacturing costs, a small factor in fuel costs is the price of uranium, which has fluctuated greatly recently. Uranium prices were as low as C$25/lb in 2005 but rose to over C$140/lb in 2007 (Reference 31). Currently, the price of uranium is approximately C$65/lb. However, the price of uranium is about a third to a half of the cost of LWR fuel which itself is only about a fourth of O&M costs (Reference 27 and Reference 30).

8.3 DECOMMISSIONING COSTS

Owners/operators of nuclear plants must also accrue funds for end of life decommissioning over the operating life of the reactors. For LWRs, these costs are typically estimated to be on the order of 10% of capital cost, and are an operating cost since they are required to be funded by annual contributions to a decommissioning fund. As a first approximation this cost percentage can be assumed to be similar for HTRs. Similarly, costs for long term radioactive waste disposal or long term spent fuel disposition must be funded. In Canada as in the U.S., the plant licensee also provides annual payments to defray eventual costs to disposition spent fuel; this was noted as part of fuel cost above.

9 Risks

In this section, risk refers to an uncertain event or condition that, if it occurs, can adversely affect the project objective and is the product of the likelihood and consequences. Table 9-1 groups the risks into three categories: low, medium, and high. The application of an HTR plant to a thermal, in-situ recovery project involves numerous risks. This section categorizes, identifies, assesses and provides mitigation strategies for risks that are considered to have either a significant or critical consequence.

Table 9-1. Qualitative Risk Assessment Terms

		Consequences			
		Negligible	**Marginal**	**Significant**	**Critical**
Likelihood	**Very Unlikely**	Low	Low	Low	Low
	Unlikely	Low	Low	Medium	Medium
	Likely	Low	Medium	High	High
	Highly Likely	Medium	Medium	High	High

The primary cause of the risks discussed in this section is the First-of-a-Kind nature of the HTR plant designs. While the basic technology used in these plants has been used in proven designs, these plants are substantially different from their predecessors. There will likely be lessons learned from the operation of a First-of-a-Kind plant. It is difficult to predict the exact nature of the these lessons, but the operation of the First-of-a-Kind HTR oil sands plant will likely be challenged such that meeting performance specifications will be difficult. Several specific risks that reflect this First-of-a-Kind uncertainty are discussed in this section.

9.1 TECHNICAL

9.1.1 Primary-Secondary Heat Exchanger Feasibility

Risk

The primary-secondary heat exchanger is a very important component, as it is the physical boundary between primary and secondary coolants. Its development will by challenged by concerns with high operating temperatures, corrosion, pressure transients, and maintenance viability.

The primary-secondary heat exchanger heat transfer surface will experience the maximum operating temperature of the HTR and is, therefore, susceptible to creep-rupture, creep fatigue, and corrosion. In addition, transients, in which one system rapidly depressurizes, thereby placing a large differential pressure across the heat transfer material, must be accounted for.

The maximum operating temperature of the 4S is 510˚C. The 4S primary-secondary heat exchanger, or intermediate heat exchanger (IHX), is a sodium-to-sodium shell and tube heat exchanger constructed of Type 304 Austenitic Stainless Steel. Stainless steels are used in higher temperature applications, as they have high corrosion and creep resistance. The heat transfer section of the reheat and main steam systems in fossil-fired plants operate at temperatures near 600˚C in supercritical units. Because the 4S IHX operating temperatures and material do not push the boundaries of today's operating experience, the risk of poor mechanical performance of the 4S IHX is low. However, the effects of the sodium environment on the corrosion of the IHX material will need to be accounted for in design and maintenance.

The maximum operating temperature of the MHTGR is 687˚C. The MHTGR primary-secondary heat exchanger is a superheated steam generator with a helical coil shell and tube design. The tubes are to be constructed of Alloy 800H. Nickel-based alloys such as Alloy 800H and Alloy 617 exhibit relatively exceptional high temperature strength and corrosion resistance.

The maximum operating temperature of the PBMR is 750˚C. The PBMR IHX is a compact gas-to-gas heat exchanger design. Compact heat exchangers have heat transfer surfaces with a relatively high surface area per unit of volume. They usually employ thin plates upon which gas flows over and under to maximize heat transfer per surface area. These plates are to be constructed of Alloy 800H or Alloy 617. There are several design concerns that must be resolved for compact heat exchangers:

- Compact heat exchangers are particularly susceptible to transient startup and shutdown stresses.
- Compact heat exchangers are difficult to test and repair if damaged.
- Because of their very thin plates, compact heat exchangers can only tolerate very small amounts of material loss due to corrosion. In addition, these plates must be thin enough to ensure an effective compact design but not so thin such that the depressurization of one coolant system will result in component failure.

Despite these concerns, the operating temperature of 750˚C is likely achievable with these materials, based on previous experiences and code cases. More effort will be required to develop a compact design, however.

Risk Assessment

Because the 4S IHX operating temperatures and material do not push the boundaries of today's operating experience, poor mechanical performance of the 4S IHX is unlikely. The use of sodium, a coolant with limited experience, increases risk. The performance of the MHTGR steam generator is also unlikely to be poor, but the higher operating temperatures increase the risk. The intended application of a compact heat exchanger for the PBMR presents significant design challenges that increase risk.

The risk of the mechanical performance of the primary-secondary heat exchanger negatively impacting the performance and availability of the HTR is qualitatively judged to be as follows:

HTR	Likelihood	Consequence	Risk
4S	Unlikely	Critical	Medium
MHTGR	Unlikely	Critical	Medium
PBMR	Likely	Critical	High

Mitigation Strategies

The risk of poor mechanical performance of the primary-secondary heat exchanger for each plant can be mitigated by ensuring that the design is promptly finalized, the necessary material qualification and testing are begun, and the component undergoes extensive testing.

9.1.2 Primary-Secondary Heat Exchanger Codification

Risk

Subsection NH of Section III of the ASME Code, which is used for high temperature service of nuclear-related pressure vessels in Canada, will have to be augmented to accommodate the development of the primary-secondary heat exchangers. The qualification of design rules and materials needed for addition to the ASME Code may delay the schedule for the operation of an HTR demonstration plant in the early 2020's.

Design Rules

The design rules of Subsection NH were developed for shell-like structures. Therefore, the traditional heat exchanger design such as the 4S shell-and-tube IHX (Type 304) or the helical coil shell-and-tube MHTGR steam generator (Alloy 800H) can be evaluated using these rules. Design rules do not exist for compact plate heat exchanger designs, the design proposed for the PBMR IHX (Alloy 800H or Alloy 617). New rules and analysis methods will, therefore, have to be established.

Material Qualification

Type 304 Stainless Steel is qualified for use in Section III of the ASME Code, and its application in the 4S IHX should not require additional testing or codification. Alloy 617 is not qualified for use in Section III of the ASME Code but is for Section VIII, which pertains to non-nuclear service. A code case has been drafted, but there remain significant data needs to qualify Alloy 617 under Section III for temperature service greater than 650˚C. Alloy 800H is certified for use in ASME Code Section VIII for temperatures up to 760˚C, but little data are available with respect to the effect of different impurities within a helium environment.

Risk Assessment

The remaining ASME Code development tasks for the design of the primary-secondary heat exchangers for each HTR vendor are significant but achievable and should not delay the HTR plant schedule. The PBMR has slightly more qualification work required.

The risk of the ASME Code material qualification effort negatively impacting the timely availability of the primary-secondary heat exchanger is judged to be as follows:

HTR	Likelihood	Consequence	Risk
4S	Very Unlikely	Significant	Low
MHTGR	Very Unlikely	Significant	Low
PBMR	Unlikely	Significant	Medium

Mitigation Strategies

To ensure that the codification necessary for the design of the primary-secondary heat exchanger is completed on schedule, the design must be finalized and the codification exercises, including long term testing and design analyses and code development, must begin promptly.

9.1.3 Fuel Manufacturing and Qualification

Risk

The development of a large scale fuel manufacturing facility with a qualified fuel fabrication process may delay the HTR demonstration plant schedule (operation by early 2020's). None of the fuel designs have been manufactured on a production scale required to support the HTR for the thermal, in-situ recovery plant. Establishing a fuel manufacturing facility requires licensing from the nuclear regulator, which can be nearly as time-consuming as for a reactor. In addition, to be accepted by the CNSC for use in Canada, the HTR fuel must be shown to perform acceptably, and the production facility must be able to produce this fuel with acceptable and repeatable quality. If in-specification fuel cannot be made on schedule and shown to meet the quality and performance requirements, project delays and increased costs will occur.

Risk Assessment

4S fuel is very similar to that used in other sodium-cooled reactors such as EBR-II and FFTF. A number of tests have been performed to demonstrate that the planned fuel design performs acceptably. However, additional testing is required to qualify the specific fuel design for 4S to CNSC requirements and to demonstrate the capability of the production fuel facility to produce fuel that is also satisfactory. Establishing such a facility will require time and a substantial investment which will have to be recovered over time with fuel costs.

MHTGR fuel design is extremely close to that used in Fort St. Vrain, but the fuel for Fort St. Vrain was essentially custom made. The facilities used to make that fuel are no longer available and would need to be reconstituted. Thus, the basic fuel design has been proven to be satisfactory but the effort to re-qualify the actual fuel this time to CNSC requirements and to establish a production facility will be large.

PBMR has plans for the construction of a fuel manufacturing facility to support the DPP in South Africa. If this facility is completed and the commercial-scale fuel fabrication process is qualified, this will greatly ease the process of expanding the South African facility or constructing a similar facility in North America to supply fuel to its intended fleet of reactors in the region. Nevertheless, the development of a North American facility and qualification of the fabrication process within a timeframe needed to support an operating reactor by the early 2020's will be very difficult.

The risk of a qualified fuel not being available in time to support operating the HTR by the early 2020's is judged to be as follows:

HTR	Likelihood	Consequence	Risk
4S	Highly Likely	Critical	High
MHTGR	Highly Likely	Critical	High
PBMR	Likely	Critical	High

Mitigation Strategies
The construction of a manufacturing facility and qualification of the fuel fabrication process to CNSC requirements could be the limiting task with respect to the thermal, in-situ project development schedule. The owner/operator and HTR vendor should establish a strategy and schedule for providing fuel to support initial Stage 1 and subsequent stage fuel loading scheduled dates that recognize this high risk.

9.1.4 Availability of Enriched Uranium

Risk
Each of the designs requires fuel enriched above that normally produced for light water reactors. Uranium enriched at the required level may not be available in the needed quantities to fuel a fleet of HTR plants.

Risk Assessment
Currently, there are existing stocks of high enriched uranium from weapons stockpiles in several countries. This enriched uranium can be downblended to the needed enrichment level. While this source will likely be available for the demonstration HTR plant, these stocks will eventually disappear. Another source of high enriched uranium will, therefore, be needed to support a fleet of HTR plants. Enrichment facilities are licensed by regulatory agencies for certain maximum enrichment levels and providing a higher enrichment will require a lengthy license amendment process in addition to the physical modifications to the process equipment.

The risk of the enriched uranium required for each HTR plant not being available in sufficient quantities to support a demonstration plant and subsequent fleet operation is judged to be as follows:

HTR	Likelihood	Consequence	Risk
4S	Unlikely	Critical	Medium
MHTGR	Unlikely	Critical	Medium
PBMR	Unlikely	Critical	Medium

Mitigation Strategies

Again, HTR plant owners should contractually ensure that fuel will be available at the required enrichment levels. The HTR vendors should be requested to formally begin to develop their uranium acquisition strategies.

9.2 REGULATORY

9.2.1 Licensing Delays

Risk

Competition with "larger" and in-process projects for scarce CNSC resources, the need to adapt the existing CNSC regulations to an HTR plant, and additional requirements by Alberta may lengthen the timeline for licensing/construction beyond the generic 108 months currently estimated for the licensing of new water cooled reactor.

CNSC knowledge of non-water reactor design and safety has not previously been necessary. Overcoming this will require high quality documentation and considerable effort on the part of the HTR vendor and the applicant to bring CNSC knowledge up to the level necessary for them to be comfortable licensing a non-water cooled design. As noted earlier, considerable effort and time may be required to qualify computer codes used for analysis of an HTR. All of these considerations increase the likelihood of a schedule delay.

The CNSC has requirements for organizational attributes of its license applicants. A company new to nuclear power would need to establish appropriate measures and be accepted by the CNSC as a suitable applicant.

Though the provincial authorities in Alberta do not partake in the nuclear licensing process, there is also concern that the regulatory agencies in Alberta responsible for the licensing of the thermal, in-situ plant may place extra requirements on the project if it were to use a nuclear heat source, thereby delaying the project.

Risk Assessment

It would be prudent to assume, for any design selected, at least a 120 month (10 year), and possibly 130 month, licensing span from application for a License to Prepare Site until issue of the operating license for the first HTR. The PBMR has initiated licensing in South Africa and pre-licensing in the U.S. The 4S has also started pre-licensing discussions with the U.S. NRC and can build on the PRISM assessment that was performed in 1994. In the 1980's, MHTGR went through a pre-application licensing review process by the US NRC and submitted a complete design to the NRC with six volumes of preliminary safety information documents. The design of this reactor was the same as proposed for the oil sands application except it was for an electric-power only application, so it would provide a good starting point for documentation to be provided to CNSC.

The risk that regulatory delays negatively impact the HTR demonstration plants ability to operate by the early 2020's is judged to be as follows:

HTR	Likelihood	Consequence	Risk
4S	Likely	Significant	High
MHTGR	Likely	Significant	High
PBMR	Likely	Significant	High

Mitigation Strategies

The HTR vendor should promptly initiate a Pre-Project Design Review to allow the CNSC to become familiar with the technology and develop review guidance and qualified analytical methods in parallel with preparing an application for a License to Prepare Site. The applicant for the License to Prepare Site should attempt to have CNSC recommend immediate referral of the EA to a joint review panel. Establishing a formal agreement for management of the HTR by an existing Canadian nuclear plant owner/operator may eliminate the need to establish that a new organization meets regulatory requirements.

9.2.2 Containment Performance Requirements

Risk

Water reactors, as well as the 4S, have pressure-retaining containment buildings that provide a final backup barrier to protect the public and environment against the uncontrolled release of radioactive fission products in the event of an accident. This feature has been emphasized as important to enhancing public confidence in nuclear power.

For HTGRs, if there is a loss of reactor coolant due to an accident, the fuel adequately contains the fission product or there is a long delay before the release of radioactive materials. As a result, the designers of the MHTGR and PBMR do not consider the traditional containment method necessary. These designs instead incorporate a confinement concept. In this approach, the confinement building would be at negative pressure. The building would vent to the atmosphere upon a large primary coolant leak until the pressure was relieved and then the vents would re-close, and negative pressure would be re-established. There is concern that the CNSC may not accept this HTGR approach to containment/confinement, which could significantly increase the capital cost of the MHTGR and PBMR.

Risk Assessment

CNSC regulatory document R-7 requires concrete pressure-retaining containment buildings but specifically applies to water reactors. There is not a clearly defined regulatory position on this issue with respect to gas reactors in Canada. In 1993, the U.S. NRC considered this issue in a commission paper and proposed a preliminary set of criteria that the reactor design must meet to allow for the use of a confinement approach. This topic, however, is still being discussed, and there is no official NRC regulatory policy at this time.

Fort St. Vrain and other gas-cooled reactors throughout the world have employed confinement buildings. The safety case for using a confinement approach can therefore garner regulatory approval, but this approach does represent a departure from the requirements to which experienced water reactor regulators are accustomed.

HTR	Likelihood	Consequence	Risk
4S	N/A	N/A	N/A
MHTGR	Unlikely	Critical	Medium
PBMR	Unlikely	Critical	Medium

Mitigation Strategies

The HTR vendor should develop a comprehensive safety case for the confinement approach and present it during the Pre-Project Design Review to allow the CNSC to become familiar with and voice any concerns early in the regulatory process.

9.3 CONSTRUCTION

Building a high technology, First-of-a-Kind plant in a remote region with sparse infrastructure and an oversubscribed workforce without all of the requisite (nuclear) skills is difficult. Mitigating actions are essential to increase the likelihood of meeting construction schedules.

9.3.1 Transportation

Risk

Weather or other impediments may delay the delivery of large HTR components, with a direct effect on the HTR plant completion date.

Risk Assessment

Smaller module size with components potentially available from multiple sources is an advantage of the 4S. Several PBMR and MHTGR components are more susceptible to this risk. Early contact with transportation regulators will be required for all designs, even prior to the fabrication of the components.

The risk that the delivery of large HTR components is delayed is judged to be as follows:

HTR	Likelihood	Consequence	Risk
4S	Unlikely	Significant	Medium
MHTGR	Likely	Significant	High
PBMR	Likely	Significant	High

Mitigation Strategies
Transportation strategies for the heavy components for PBMR and HTGR must be identified early in the feasibility study so that decisions will be made among the various options, which include barges, local assembly and use of redesigned components. Assuming feasible strategies are identified, early delivery (12 to 18 months) should be specified, even though this will require very early start of fabrication of these components.

9.3.2 Labor

Risk
All HTRs will require on-site construction personnel experienced with specific skills and familiarity with nuclear Quality Assurance requirements. Many of the skills sets needed (e.g., nuclear grade welding) are not readily available in Alberta and will require obtaining workers from outside the province.

Risk Assessment
The more modular 4S design reduces the magnitude of construction effort per module but requires coordination of multiple module installation in each stage.

The risk that the labor required for the construction of the HTR plant is not readily available, thereby delaying the construction schedule and increasing cost is judged to be as follows:

HTR	Likelihood	Consequence	Risk
4S	Likely	Significant	High
MHTGR	Likely	Significant	High
PBMR	Likely	Significant	High

Mitigation Strategies
To mitigate this risk, the vendors should maximize the degree of modularization for their plant designs. In addition, having a good understanding of the required skills and the numbers of workers as soon as possible is important. This will allow for the establishment of organizations to train new workers and recruit qualified workers from outside the province.

9.3.3 Procurement of Forgings for Heavy Equipment

Risk
There is currently one company in the world that is supplying ring forgings for large reactor vessels, Japan Steel Works (JSW). JSW manufactures about five vessels per year and is booked with orders until 2016. It is likely that JSW will increase its production capacity and other firms have stated they are evaluating developing production capacity of their own. The lack of sufficient suppliers may be a significant bottleneck that could affect the cost and schedule of the HTR plant.

Risk Assessment

The 4S plant, with its smaller reactor vessel, has the option of obtaining components from multiple sources, and Toshiba already has corporate relationships within the nuclear supply chain. The PBMR and MHTGR, however, could consider RPV constructed from rolled plate, which can be more easily acquired.

The risk that a lack of sufficient suppliers of forgings for heavy equipment will negatively impact the cost and schedule of the HTR plant construction is judged to be as follows:

HTR	Likelihood	Consequence	Risk
4S	Unlikely	Significant	Medium
MHTGR	Unlikely	Significant	Medium
PBMR	Unlikely	Significant	Medium

Mitigation Strategies

Large RPV designs constructed from rolled plate can work around the potential heavy forging procurement bottleneck.

9.3.4 Erection of Site

Risk

Though construction projects take place readily in this region, the component size and quality controls required for the HTR project will be First-of-a-Kind challenges that could delay the construction schedule.

Risk Assessment

The largest MHTGR and PBMR components will not only be challenged in terms of transportation but will also require special cranes that will have to be rented, large excavations and corresponding concrete pours. Therefore, this represents a unique scheduling risk. The 4S plant, with its smaller components, will not have this concern. All of the HTR designs, however, will be challenged by the extreme weather conditions of Northern Alberta.

The risk that the erection of the HTR plant is delayed is judged to be as follows:

HTR	Likelihood	Consequence	Risk
4S	Unlikely	Significant	Medium
MHTGR	Unlikely	Significant	Medium
PBMR	Unlikely	Significant	Medium

Mitigation Strategies

A detailed plan with respect to the transportation and erection of the large components of the MHTGR and PBMR with margin and flexibility to handle delays will mitigate the risk of construction delays. Working in construction tents can mitigate the risk of construction delays due to severe weather.

9.4 SECURITY

Risk
Security for an HTR plant concerns theft of fuel and radiological sabotage.

Risk Assessment and Mitigation
Security for any of the proposed designs should be a straightforward application of a combination of physical security barriers, intrusion detection systems, and a well-trained guard force. This is adequate mitigation for this risk.

The risk that the HTR plant is subject to theft or radiological sabotage is:

HTR	Likelihood	Consequence	Risk
4S	Very Unlikely	Critical	Low
MHTGR	Very Unlikely	Critical	Low
PBMR	Very Unlikely	Critical	Low

9.5 OPERATIONAL

9.5.1 Reliability Requirements Not Met

Risk
The in-situ, thermal recovery plant has a requirement for very high process steam reliability to avoid cooldown of the oil field leading to a loss or delay in production.

Risk Assessment
Despite all design, analysis, modeling, testing and qualification of design features, unexpected problems have a greater likelihood of occurring on a First-of-a-Kind plant design, which could lead to shorter lifetime or reduced operating capability.

The risk that the plant reliability requirements will not be met for a First-of-a-Kind HTR plant due to forced outages and/or delays in scheduled outages is judged to be as follows:

HTR	Likelihood	Consequence	Risk
4S	Likely	Critical	High
MHTGR	Likely	Critical	High
PBMR	Likely	Critical	High

Mitigation Strategies

It is prudent to assume that a module could be thus affected and provide for a backup steam supply to ensure oil field productivity. Provide non-nuclear steam generating capability equal to the project 1st Stage steam demand, or sufficient to compensate for one reactor module being shut down for an extended time, for the First-of-a-Kind demonstration HTR plant.

9.5.2 Contamination of Fields

Risk

The presence of radioactivity in the reactor coolant system raises the possibility that the radioactivity may leak or be transferred to the steam flowing to the oil sands.

Risk Assessment

The HTR designs transfer heat from the primary coolant system, which contains radioactivity, to a secondary system via an intermediate heat exchanger, and finally to a tertiary system via steam generators from which process steam is sent to the oil sands well heads. Thus, there are two heat exchangers which are pressure boundaries to any transfer of radioactivity form the primary coolant. The combination of these barriers and the ability to quickly isolate the steam system in the event of a leak across the heat exchanger (radiation is readily detectable) is expected to prevent contamination from reaching the oil sands. In the higher temperature plants, the MHTGR and PBMR, the diffusion of radioactive substances, such as tritium, across these heat exchangers and into the process steam must be considered in the plant design. Coolant purification systems and heat exchanger coatings are likely mitigating design features that can eliminate this concern.

The risk that radioactivity contaminates the oil sands is judged as follows:

HTR	Likelihood	Consequence	Risk
4S	Very Unlikely	Critical	Low
MHTGR	Very Unlikely	Critical	Low
PBMR	Very Unlikely	Critical	Low

Mitigation Strategies

Two heat exchanger barriers and the ability to quickly isolate the steam system should prevent contamination from reaching the oil sands. Minor amounts of gas may be able to diffuse through the heat exchanger pressure boundaries, so additional assurance could be provided against this potential small transfer by the installation of contaminant removal systems (especially in the intermediate heat transfer loop) or additional diffusion-resistant coatings.

9.5.3 Plant Life

Risk

The HTR may not be able to achieve its full 30-year design life with extensive maintenance or refurbishment.

Risk Assessment

Operational experience with the current fleet of water reactors suggests that the full lifetime performance of a First-of-a-Kind technology will be challenging. The HTR demonstration plant may well require extensive maintenance to meet its design life. However, as evidenced by water reactor designs, the lessons learned from initial units will likely allow subsequent HTR plants to meet their performance objectives such as availability and plant life.

The risk that the initial HTR plant will not be able to economically operate for its design life at design rated capacity is judged to be as follows:

HTR	Likelihood	Consequence	Risk
4S	Likely	Significant	High
MHTGR	Likely	Significant	High
PBMR	Likely	Significant	High

Note: MPR judges that after successful demonstration of the First-of-a-Kind and subsequent HTRs that factor in the lessons from the first few plants of the same design, an Nth-of-a-kind plant would be Very Unlikely, and the risk would be low.

Mitigation Strategies

Extensive plant testing, component testing and analysis will aid in reducing plant performance uncertainty. Other mitigation strategies include a well-planned maintenance schedule and a plant design with easy access to components for maintenance.

9.5.4 Project Infrastructure

Risk

The infrastructure required to execute a demonstration plant project is not present at this time. To support the operation of a demonstration plant by the early 2020's, this infrastructure will have to be put in place quickly. This will require significant staffing to develop project management, design, licensing, and QA organizations. A test facility will have to be developed or perhaps rented from the few that are available. A fuel manufacturing facility will need to be constructed and qualified. The vendor supply chain will have to be developed, as well.

Risk Assessment

Toshiba has significant corporate resources and is actively building nuclear plants. PBMR is developing this kind of infrastructure to support the DPP but would need to expand it to support the oil sands plant. GA also does not have the needed infrastructure in place, but has substantial corporate experience in HTR design, licensing, construction, and operation.

The risk that delays in the successful development of infrastructure required to support all phases of an HTR project negatively impact the ability to deliver a plant in the early 2020's is judged to be as follows:

HTR	Likelihood	Consequence	Risk
4S	Likely	Significant	High
MHTGR	Likely	Significant	High
PBMR	Likely	Significant	High

Mitigation Strategies

To support an HTR First-of-a-Kind plant, a host oil sands facility, an owner/operator and HTR vendor should be identified early. These organizations then must work closely to ensure the development of the necessary resources to support the execution of the project and ensure its success.

10 HTR Evaluation

The criteria shown in Table 10-1 were used to assess how each plant design meets the desired objectives. The relative importance of each criterion depends on multiple factors, including owner/operator priorities and the specific HTR application.

Because each of the reactor designs has yet to be built, and a reactor has not been built and licensed in Canada in the last 25 years, there is large uncertainty in assessing these criteria. MPR has obtained information from the reactor vendors, reviewed CNSC regulations and guidance, and assessed the status of each reactor vendor's licensing and construction activities as to the suitability of each design to use for thermal, in-situ recovery. Still, some items such as actual plant reliability and capital cost have a much larger uncertainty than others. This uncertainty is considered in making conclusions regarding this evaluation.

The ability of each HTR plant and vendor to meet each criterion was assessed based on their current status; i.e., each HTR is a First-of-a-Kind plant (not an Nth-of-a-Kind). The following terms are used in the evaluation:

- Good – The HTR plant can satisfy the criterion.
- Medium – The HTR plant should be able to satisfy the criterion.
- Challenging – The HTR plant requires significant effort to satisfy the criterion.

The following sections discuss the uncertainty and assigned value for these factors for each of the reactors.

Table 10-1. Reactor Evaluation Criteria

Evaluation Criterion	Description
Predicted reliability	High HTR plant steam production reliability is desired.
Safety	A low risk of accidents and a low consequence for accidents that might occur are desired.
Environmental impact	A low effect on the surrounding environment is desired.
Ready in 2020	A plant capable of being brought on-line by the early 2020's is desired.
Licensability	The ability to meet CNSC requirements and a proven record of licensing success is desired.
Operating cost	A low average yearly cost to operate at full power is desired.
Technology development	Minimal R&D remaining to deliver design is desired.
Suitability to site	High constructability considering excavation, local work force, and transportation is desired.
Capital cost	Low capital cost to build the HTR plant is desired.
Longevity	The ability of the First-of-a-Kind plant to operate without major maintenance for 30 years is desired.
Public acceptance	A high potential for acceptance by the public is desired.
Fit to plant	A good fit of the HTR plant (thermal and electrical output, outage schedules, reliability, availability, and lifetime) with the thermal in-situ process is desired.
Canadian experience	Vendor experience with construction projects & CNSC licensing in Canada is desired.
Ease of operation	A minimal need for operator actions and maintenance is desired.
Support infrastructure	The support infrastructure required to execute an HTR plant project is desired.
Local construction effort	A low amount of construction effort on site is desired to lower costs and the demand for onsite labor.
Maintainability	Simple, routine maintenance requirements are desired.
Security	Robustness against theft and nuclear sabotage is desired.
Decommissioning	A low cost and a suitable design for decommissioning are desired.
Spent Fuel	Ease in dealing with handling, storage, and disposal of spent fuel is desired.

10.1 Predicted Reliability

Reliability is a paramount consideration for an in-situ thermal recovery plant, more so than for an electrical generating station, because of the extended loss of bitumen production following a period of no steam flow for heating of the field. As discussed in Section 9, there is considerable uncertainty in the vendor's ability to accurately predict the reliability for a First-of-a-Kind plant.

Uncertainty: High.

4S – Medium. The 4S design benefits from small size, limited moving parts, building upon past experience, and the ability to withstand a single module unavailable without a large impact on steam output. However, it has many novel features brought together for the first time that increase the risk that equipment problems may affect operability. The experimental EBR-II and FFTF reactors and the Phenix, BN-350, and BN-600 power reactors each operated with acceptable reliability, but the Fermi, Monju, and Super-Phenix plants had early problems leading to long shutdowns – permanently for two of them (see Subsection 3.2.2 for discussion of experience with these and similar reactors).

MHTGR – Medium. The MHTGR design benefits from operational experience with the prismatic core in the Unites States. The Peach Bottom plant operated successfully as a First-of-a-Kind with an average availability of 88% as a power generating facility for seven years. The problems at the Fort St. Vrain plant were associated with auxiliary components that have been modified in the present design. The prismatic core operated satisfactorily. There is testing data to support of the integrity of the micro sphere fuel particles with TRISO coating under operating conditions of temperature, pressure, and irradiation. The applications of a circulator in the steam generator and the emergency circulator in the bottom of the reactor vessel have not been proven. The use of magnetic bearings is a proven technology. However, the catcher bearing for the vertically mounted circulator during shutdown does not have extensive experience in this environment.

PBMR – Medium. With the exception of the fuel feed system and the duration of fuel sphere residence in the reactor, gas technology has a reasonably broad experience base. The AVR ran successfully for 21 years, but its successor, the THTR-300 achieved only about a 50% capacity factor over a four-year period, encountering a number of technical difficulties. The South African Demonstration Power Plant is scheduled to be in operation two or more years prior to the earliest date for the thermal, in-situ recovery plant, allowing its experience to be factored into future plants, although too late to affect the basic design.

10.2 Safety

Any reactor design must meet high levels of safety to be considered. These designs were pursued in part to provide improved safety while simplifying the overall design. Each technology has particular safety features to ensure protection of the public, the environment, and personnel on-site. The distinctions among plant designs are more likely to come into play in licensing, rather than in actual plant performance. Licensability is a separate parameter discussed below.

Uncertainty: Low.

4S – Good. The 4S has inherent safety features such as negative reactivity coefficients and passive heat removal. Its maximum allowable fuel temperature is considerably lower than that of the two gas reactors; the good heat transfer characteristics of sodium and provision of a decay heat removal loop that is not dependent on electrical power yield high assurance of core cooling. Because the reactor coolant is not pressurized, a loss of coolant is not an issue. The double-walled heat exchangers allow detection of sodium leaks early and minimize the potential for sodium fires. The design addresses safety concerns raised for previous similar reactors.

MHTGR – Good. The fuel has the capability to withstand very high temperatures without damage. The large core has a low power density. These, in combination, provide high assurance that the fuel cannot reach temperatures that would result in a radioactive release of concern.

PBMR – Good. The fuel has the capability to withstand very high temperatures without damage. The large core has a low power density. These, in combination, provide high assurance that the fuel cannot reach temperatures that would result in a radioactive release of concern. Analysis for a loss of the helium coolant has shown that, although the fuel initially heats up, temperatures will peak with margin to the fuel damage limit and turn downward over a period of a few days. In a test in the AVR where reactor coolant flow was stopped and the control rods were left withdrawn, the core shut itself down (went non-critical) within a few minutes and was not damaged.

10.3 Environmental Impact

The environmental aspects of the designs are simple to define based on past operation of similar technologies. None of the designs has any routine release of radioactive, environmentally unfriendly, or toxic materials. Nuclear has a small impact on environmental quality during construction and negligible in operation, except for the potential consequences of a very unlikely accident. The high degree of safety discussed above removes this as a distinguishing characteristic. All of the plants would have to eventually transfer spent fuel to the Canadian authority for storage, although the 4S plant has more compact fuel, leading to less spent fuel bulk requiring eventual disposition.

Uncertainty: Low.

All – Good.

10.4 Readiness

Considering First-of-a-Kind issues and regulatory approvals, a possible objective for building a demonstration HTR plant is to have it in operation by the early 2020’s. As previously noted, the designs under consideration have not yet been built anywhere and their designs are not yet finalized. For all of these technologies, significant design development remains. In addition, to reach a level of organizational maturity that can support operation of a reactor by 2020 involves establishing corporate relationships for manufacturing and building the associated infrastructure.

Uncertainty: High.

4S – Challenging. Toshiba is a large corporation with considerable resources and a growing presence in the nuclear industry via its version of the Advanced Boiling Water Reactor (currently selected for two units at South Texas Project) and its Westinghouse division. However, the company has limited experience building fast or sodium cooled reactors. While the 4S heavy equipment manufacturing development and time span is simplified by the small module size, some very complex components such as the double-walled heat exchangers must be successfully fabricated. Currently, Toshiba has no 4S fuel manufacturing facility or defined source for the required near-20% enriched uranium.

MHTGR – Challenging. Although the technology has few developmental features, successful delivery must overcome substantial inertia from the currently low level effort on the design. Little of the documentation provided to MPR for this study had been updated in the past 15 years. GA would need to ramp up very quickly, establishing manufacturing relationships, finding a facility to fabricate their unique fuel, and updating the design and supporting analyses to satisfy current regulations. Currently, GA has no defined source for the required near-20% enriched uranium.

PBMR – Medium. PBMR Pty Ltd is aggressively working to begin power operation of its Demonstration Power Plant (DPP) and is investing heavily to support that. The DPP provides some of the advance development needed to take off some of the First-of-a-Kind edge.

10.5 Licensability

Canada has not licensed a new reactor in over 25 years and has developed a new framework for licensing reactors; this new framework is just beginning to be used. Additionally, the framework and the experience of regulatory personnel are focused in the water cooled reactor area. Any of the three possible designs will involve considerable effort to allow the regulators to understand the design and its safety features. This will increase not only the resources required but also the possible timeline for the review.

MPR considers that each of the designs is licensable but that each will require considerable effort on the part of both the vendor and plant owner and that the licensing timeframe will likely be longer than the nine years predicted for more common designs.

Uncertainty: Moderate.

4S – Medium. Toshiba has initiated discussions with the U.S. NRC regarding siting a 50 MWt 4S in Galena, Alaska to produce 10 MWe electricity. Little progress has been made to date, partially due to NRC resource constraints, but the company expects to submit a design approval application in 2009. No similar reactors have been licensed elsewhere over the past 20 years, although Japan has had to obtain its regulator’s agreement to restart the Monju reactor. Few regulators are familiar with fast or sodium-cooled reactors. The NRC did review a similar reactor, PRISM, and identify issues that could be impediments to licensing that Toshiba has factored into the current 4S design. The Fermi sodium cooled reactor was licensed in the U.S. in the 1960s.

MHTGR – Medium. The MHTGR Preliminary Safety Information Document was prepared and submitted to the NRC in the 1980's, and GA went through two rounds of questions based on this submittal. These documents would provide the basis for the safety case of the MHTGR but would require significant revision for the thermal, in-situ MHTGR version. GA's plans for licensing its design depends on it being selected as part of the DOE Next Generation Nuclear Plant (NGNP). If it is selected, NRC licensing effort will proceed. If not, it is likely that the thermal, in-situ recovery plant would be the first licensing effort for an HTR process heat plant in the world. Both the MHTGR and PBMR, there is benefit to some extent from the long, successful experience with gas cooled reactors in the UK, although the UK designs are substantially different and would require modifications to be licensed today.

PBMR – Good. Although the need for plant containment is an open issue, licensing the Demonstration Power Plant is underway in South Africa with a goal that it will support initiation of construction in 2010 and fuel load in 2014. PBMR is in pre-application discussions with the U.S. NRC and plans submittal of a formal application for design certification. These efforts provide an advantage over the two competing designs.

10.6 OPERATING COST

A major advantage of nuclear power is low operating cost compared to other power sources. Operating costs are composed primarily of fuel, personnel, and equipment maintenance, as in any power plant, but the fuel is a small portion compared to alternatives. Because each of the designs is new and because fuel production facilities do not exist yet for any of them, operating costs are hard to define. Additionally, if the plant were to encounter equipment problems, unexpected costs may be incurred.

Uncertainty: High.

4S – Good. Infrequent refueling and few moving components contribute to lowering costs. Although a larger number of reactors would be required, the passive capabilities may be sufficient to obtain CNSC agreement of reduced operating staff (i.e., a single operator monitors and controls more than one reactor). Due to the encapsulation of the entire primary in the reactor vessel and the use of sodium, the cost of unexpected reactor maintenance could be quite high, but this concern is addressed by the Maintainability criterion.

MHTGR – Good. If the reactor performs reliably, as designed, operating costs would be low. The 30 day refueling outages scheduled for every 18 months will increase costs and result in lost revenue from bitumen recovery.

PBMR – Good. On-line, continuous, automatic refueling eliminates one source of outage costs.

10.7 TECHNOLOGY DEVELOPMENT

All three designs under consideration involve technology development. Fuel fabrication must be demonstrated in a production environment. The ability to manufacture and successfully operate some components must be demonstrated. The issues requiring further work are known but, as with any complex technology, it is hard to predict by when and how much effort must be spent to deliver satisfactory solutions. There are no show-stoppers, but each plant has a significant amount of development work remaining.

Uncertainty: Moderate.

4S – Medium. The 4S design requires the most development to deliver a reliable plant because of unique features and low amount of relevant experience. Toshiba has been performing a number of test programs: a critical experiment, fuel hydraulic test, reflector drive mechanism test, heat transfer test of the RVACS, test of the EM pump in sodium, test of steam generator sodium leak detection, and seismic isolator test.

MHTGR – Medium. Finishing the necessary MHTGR technology development will involve not only dedicating the resources but also identifying people with the appropriate knowledge.

PBMR – Medium. Most of the requisite technology is under development to support the planned DPP. However, the intermediate heat exchanger design is not part of the DPP and will need to be developed; it is a design challenge and will affect overall system interactions. Materials testing and code development will be required for this component (see Section 9).

10.8 SUITABILITY TO SITE

Each plant can be tailored to suit the thermal, in-situ recovery needs and siting, within design constraints. However, weather and surface conditions will hinder component transport and construction. All designs require substantial size and depth excavations. Once in operation, weather conditions in Alberta are not likely to adversely affect one design more than any other.

Uncertainty: Low

4S – Good. Overall, the plant should be constructible. Maximum size components are transportable by road or rail. Small component size and the largest off-site construction fraction will facilitate getting equipment to the site and installing it, although there will be more shipments because of eleven reactors.

MHTGR – Challenging. Overall, the plant should be constructible. However, several heavy and large MHTGR components are significantly heavier than past precedents moved by road in Alberta. Moving by truck or barge might be feasible but will be costly and slow and can be affected by adverse weather (see PBMR). The design requires excavation three times deeper (50 m) than other two designs that may lead to water table difficulties during construction.

PBMR – Challenging. Overall, the plant should be constructible. However, several of the heaviest PBMR components to be transported are significantly heavier than past precedents in Alberta. Current strategy to transport by barge may not be realized due to lack of needed infrastructure improvements. Alternatives may include local assembly or redesign of smaller components. The need for only three reactors does mean that fewer components need to be delivered.

10.9 CAPITAL COST

The capital cost of the HTR plant includes the engineering, procurement, and construction (EPC) contract cost plus inflation and escalation during the construction period, project contingencies and capitalized interest during construction. The EPC contract costs are made up of design support costs, material costs (equipment manufacture and supply) and construction labor costs.

Uncertainty: High

4S – Medium. Generally, building more, smaller units to achieve the same capacity results in higher cost due to loss of economy of scale. However, the small module size, the lower level of on-site effort, the simplified transportation logistics, and benefits of the learning curve for later units may result in sufficient advantages to more than offset the premium of more units.

MHTGR – Medium. The MHTGR offers a medium range size and decent economy of scale. High transportation costs may be a concern.

PBMR – Medium. The PBMR reactor module has the largest power rating, and it offers the best economy of scale. Some of this advantage, however, may be lost in the considerably higher per shipment costs to transport the large components to the site and decreased modularity and prefabrication for construction.

10.10 LONGEVITY

Operational experience with the current fleet of water reactors suggests that the full lifetime performance of a First-of-a-Kind technology will be challenging. The HTR demonstration plant will likely require extensive maintenance to meet its design life. However, as evidenced by water reactor designs, the lessons learned from initial units will likely allow subsequent HTR plants to meet their performance objectives such as availability and plant life.

Uncertainty: High

4S – Challenging. The original 4S concept was a reactor that could operate virtually unattended for 30 years. Among the small amount of experience with liquid sodium reactors, plant life approaching 30 years has been achieved in some cases.

MHTGR – Challenging. Although there has been no long-term operation of this design, there has been extensive experience with both gas-cooled and graphite reactors, many of which have surpassed 30 years of operations.

PBMR – Challenging. The major PBMR innovation of potential concern is the fuel circulating system, for which little past experience is available. A portion of the vessel internal graphitic structure would need to be replaced to operate the plant longer than 24 years.

10.11 PUBLIC ACCEPTANCE

Public acceptance is an important consideration but one that is difficult to quantify. Generally, the issue will be one of nuclear vs. non-nuclear, rather than of the particular technology chosen. The recognition of the need to reduce greenhouse gas emissions and concerns about use of resources that are more valuable in other applications gives nuclear increased acceptability for substitution for natural gas in thermal, in-situ recovery. None of the reactor types under consideration is sufficiently well known to the public to have wide acceptance or resistance.

Since each of the options is nuclear, some public resistance is a given, no matter which design is chosen. Any design will require an equivalent public information program.

Uncertainty: Low.

All – Medium.

10.12 FIT TO PLANT

This criterion measures how well the proposed technologies and construction plans match the study's criteria for quantity and quality of steam and electricity (but excluding Predicted Reliability which was addressed above). All three can meet the steam output condition specifications. Table 4-3 through Table 4-5 summarize how each reactor matches the output goals. Each can be tailored to fit the demand profile of the various stages, although match of steam and electrical supply involves economic tradeoffs in capital and operating costs.

Uncertainty: Low

All – Medium

10.13 CANADIAN EXPERIENCE

This item considers experience in dealing with construction and associated work, personnel, finance, and legal issues in Canada (licensing is discussed in Licensability). None of the vendors has a presence in Canada that would give it an advantage in bringing a plant into operation.

Uncertainty: None.

All – Challenging.

10.14 EASE OF OPERATION

Again noting that none of these designs have actually been built and operated, ease of operation is highly uncertain. All HTR plants are intended to be easier to operate and utilize smaller crews than existing nuclear plants. Each will be more difficult to operate and require more staff than existing natural gas plants.

Uncertainty: High

4S – Good. The 4S concept was originally intended for the possibility of unsupervised operation. While it is unlikely a regulator in any country would accept a nuclear plant without continuous operator monitoring, the plant should require very little operator interaction, being essentially self-regulating. Issues of working with sodium are considered under Maintainability. Having an electric output design and steam output design with different plant operating conditions could make operator training more complex.

MHTGR – Medium. The MHTGR will require more operator interaction than the 4S but is not expected to be demanding. Fewer modules than the 4S simplifies coordination.

PBMR – Medium. The PBMR will require more operator interaction than the 4S but is not expected to be demanding. Fewer modules than the 4S simplifies coordination.

10.15 SUPPORT INFRASTRUCTURE

Currently, the vendors for the three designs under consideration do not have the support infrastructure required to develop and implement the HTRs. As a result, all of the vendor will face the challenge of being part of a First-of-a-Kind project in parallel with the additional costs and difficulties of building up and maintaining their own organizations and developing a supply chain. In addition, if the reactor design is implemented at no more than one or two sites, then there is an increased risk that vendor support could erode or even disappear, forcing the plant owner to find expensive customized replacement support.

Uncertainty: Moderate.

4S – Challenging. Toshiba does not have in place the infrastructure needed to support the development of a sodium cooled reactor. It is, however, a large corporation with other major nuclear commitments and the wherewithal to support the design as required.

MHTGR – Challenging. GA also does not have the needed infrastructure in place, but has substantial corporate experience in HTR design, licensing, construction, and operation.

PBMR – Medium. PBMR has a small advantage given the existing organization that is committed to the DPP. A similar organization would need to be developed for an HTR plant in Canada.

10.16 LOCAL CONSTRUCTION EFFORT

Local construction means local jobs, which is usually favorably viewed, both politically and economically. However, the Athabasca region is likely to continue to have a long-term shortage of labor and already needs to spend extra to obtain workers. Building a nuclear plant will make this more acute because of the need for particular skills and qualifications. Also, a large influx of additional workers may be socially and environmentally detrimental.

Uncertainty: Low

4S – Good. The majority of the plant components are designed to be transported to a site and readily installed. The modularity and small size should require a smaller workforce, thus decreasing the local construction effort.

MHTGR and PBMR – Medium. The decreased modularity of these plant designs will require a larger effort at the plant site for construction. The lower power density requires a larger facility.

10.17 MAINTAINABILITY

This parameter reflects the level of effort expected for known preventive and unknown emergent maintenance. Poor maintainability would adversely affect plant reliability and increase operating costs, two factors separately considered. In a nuclear plant, the presence of radioactivity complicates work because additional precautions are necessary, so it is essential that the design facilitate maintainability. No operating experience with these technologies and a mixed record of good and poor performance in those similar reactors that have operated contribute to difficulty in accurately predicting this parameter.

Uncertainty: Moderate.

4S – Medium. Working with sodium is difficult, requiring special precautions. Any maintenance or inspections of the sodium loops will present unique challenges. The original 4S design concept was a reactor that was not opened for 30 years, requiring very low chance of in-vessel problems but increasing the cost should vessel access be needed for an equipment problem such as an intermediate heat exchanger leak or an electromagnetic pump failure. Although there is a means to detect leakage in the steam generator, resolving the leakage could be costly and lead to a lengthy plant shutdown.

Lastly, though occurring only once a decade, a refueling will be a complex evolution involving working with sodium and could likely take longer than the 30 days estimated. Details of refueling operations have not been defined. Developing the refueling process is likely achievable, but will have challenges. Because of the small core size, handling the 4S fuel will be relatively simple. Again, however, working with sodium will provide the greatest challenge.

MHTGR – Medium. Due to the fact that the fission products are contained within the TRISO coating on the micro spheres of fuel in an immobile carbon block, there is a low level of residual radioactivity with which to contend in the helium coolant or associated components. This minimizes that aspect of maintenance. Except for the circulators and control rod drives, the other major parts of the primary loop are static. The moving parts of the circulators are suspended by magnetic bearings to eliminate any wearing surfaces. Wearing surfaces only come in to consideration during startup and shutdown. However, the access to the circulators is a major process if they need maintenance. The superheated steam intermediate loop could be more difficult to maintain than a saturated system. The steam reboiler will require water chemistry control in an additional system. Refuelings are necessary every year and a half.

PBMR – Medium. The maintenance advantages from the TRISO fuel for the MHTGR also exist for the PBMR but could be offset by creation of dust from fuel spheres rubbing against one another. In previous pebble bed reactors, this dust required additional maintenance precautions and the radioactive consequences of its spread had to be considered in a reactor coolant leak event. A blockage in the fuel circulation system could be costly and lead to a lengthy plant shutdown. The use of a compact heat exchanger for the IHX will represent a maintenance and inspection challenge for the PBMR, as there will be no prior operational experience with the component and the location of leaks will be difficult to detect in this component. The impact of extended maintenance would be greatest for PBMR, since it has the fewest number of reactors in the full output configuration.

10.18 SECURITY

There are two aspects to security: protection of new fuel from theft and protection against radiological sabotage of the reactor or spent fuel storage. New fuel less than 20% enrichment is technically desirable to avoid a nuclear weapons proliferation concern, and each of the three designs meets this criterion. Protection against radiological sabotage is provided by building and site design, including use of barriers and intrusion detection systems, and by guard forces. All three of the designs are well-protected against the assumed threats and considered equivalent.

Uncertainty: Low.

All – Good.

10.19 DECOMMISSIONING

Although decommissioning of the reactors should not occur until after 2050 at the earliest, engineering prudence – and Canadian law – require considering it up front. Decommissioning techniques continue to evolve to reduce effort and risk. The major advantage a plant may have in decommissioning is structures that can be packaged for shipment for disposal without a lot of processing or segmentation and lack of hazardous materials. Uncertainty is more dependent on evolution of environmental regulation than on the level of understanding of dismantlement of the plants.

Uncertainty: Moderate.

4S – Good. The 4S has a disadvantage of having sodium primary coolant, which will remain radioactive for some time and will need to be safely removed and dispositioned. Means for doing so have been successfully demonstrated for previous sodium reactors. The 4S has a distinct advantage in its small module size, which will facilitate disposal without a large amount of on-site segmentation.

MHTGR – Medium. The MHTGR involves large components and quantities of graphite. While not particularly difficult to handle, considerable on-site effort will be involved working with highly radioactive material to prepare and package it for disposal. Very large components would likely need to be sectioned for shipment.

PBMR – Medium. The PBMR is similar to the MHTGR but with slightly larger components. Very large components would likely need to be sectioned for shipment. Also, the whole fuel inventory for operation of the plant will still be at the site, since spent fuel shipments do not occur until the fuel sphere handling system is unloaded at end of life.

10.20 SPENT FUEL

All reactors generate spent fuel as a result of the power generation process, and the amount of radioactivity is largely a function of the energy generated. There will be slight differences due to the lower enrichment of the PBMR fuel, but this is expected to be minor. The 4S fuel is more compact but will need to be cleaned of sodium before being stored dry. There will also be handling differences. The PBMR will store all its fuel in its fuel handling system for a 30+ year period of operation. The 4S will need to be refueled only once every 10 years with its fuel storage in the Ex-Vessel Storage Tank for two years until it can be moved to dry storage. The MHTGR is partially refueled every 18 months and its fuel can be stored in a dry storage area after a cooling period of a few months. None of the fuel compositions is currently generated in Canada, so any of the designs will require technical evaluation different from existing CANDU fuel for eventual disposition. Custody for all reactor fuel is eventually accepted by the federal government which is currently assessing long-term disposition options.

Uncertainty: Moderate.

4S – Medium. The 4S infrequent refueling and small spent fuel volume is advantageous. The need to clean the fuel of sodium is a handling disadvantage.

MHTGR – Medium. With relatively frequent refuelings and, subsequently, larger volume of spent fuel, the MHTGR will likely require more effort and more disposition expense than the other two designs.

PBMR – Good. PBMR automatic refueling system generates small amounts of spent fuel that must be stored continually. While not particularly compact, its fuel is in the form of relatively small spheres that offer flexibility in handling and disposition. Spent fuel spheres automatically are sent into storage tanks in the module building that can store all spent fuel for 30 years of operation.

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A

Alternative Energy Resources for In-Situ Thermal Recovery Plants

MPR Associates Inc.

Alternative Energy Sources for In-situ Thermal Recovery Plants

STUDY REPORT

REV	DATE	DESCRIPTION	ORIGINATOR	APPROVALS				
				PE	PM	CLIENT		
						PM	PE	VP
A	29 Aug 2008	Issued for Review	J M Davies	JO	JMD			
B	15 Sept 2008	Updated	J M Davies	JO	JMD			
C	6 Oct 2008	Updated	J M Davies	JO	JMD			
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Engineer's Stamp		
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Table of Contents

1.0 Introduction

MPR Associates Inc. of Alexandria, Virginia, USA (MPR) has been awarded the study project "Compare Alternative Energy Sources (AES) for In-situ Thermal Oil Recovery Plants in Alberta". This study is part of a larger initiative to find alternate energy solutions to replace natural gas for oil sands development in Alberta.

In support of this project MPR has requested IMV Projects (IMV) to provide design, regulatory, logistics and construction details and data of in-situ methods for thermal oil sands recovery plants in Alberta. This document is IMV Projects' study report.

The definitions used in this report are those given in **Attachment 1 Glossary of Oil Sands Terms**.

2.0 Process Functional and Operational Issues

2.1 Objectives

This section deals with process functional and operational issues of the study. They are as follows:

- The provision of AES generated steam to replace natural gas as the main source of energy for on plant steam generation for in-situ thermal recovery plants in Alberta; and
- The provision of AES generated electrical power to replace that provided from the local utilities supplies.

2.2 The Study Plant Model Assumptions

2.2.1 Target Locations for the Plant Site

The four main areas of activity for in-situ thermal recovery of oil sands in Alberta are:

i. North Athabasca

ii. South Athabasca

iii. Cold Lake

iv. Peace River

The target location for the study plant model is the Athabasca region.

2.2.2 The Study Plant Model

The AES will be located adjacent to the central thermal plant or within reasonable pipelining distance for above ground high pressure pipelines.

This investigation is based on the energy requirements of a conceptual 120,000 bopd commercial in-situ thermal oil sands recovery plant development of 4 phases of 30,000 bopd each. The plant facility process will be that associated with high pressure SAGD in-situ recovery.

Approximate energy quantities for steam, electrical power and natural gas consumption were calculated for the specified plant duties. A model plant configuration was identified and relevant background details of oil sands development in Alberta will be outlined.

The study plant model includes the following features:

- **Attachment 2** (BFD 1) illustrates the current, common design practice for SAGD in-situ recovery plants Alberta; except where noted otherwise in this report. The BFD illustrates a typical in-situ thermal plant process design for oil treating, produced water (PW), PW deoiling, water treatment (WT) that includes warm lime softening (WLS) and strong or weak acid cation (SAC/WAC), OTSGs, produced and fuel gas, tankage, sales oil, etc.
- **Attachment 3** (BFD 2) represents the changes required to the study plant in order to utilize an AES steam generation system; these would include the following features:

- Remove the OTSG's as the main steam generation source. Some OTSG's may be retained for start-up duty, and to meet short term standby steam requirements.
- Replace the currently used Water Treatment (WT) system with evaporator/crystallizer treatment equipment.
- The boiler feed water (BFW) boost and charge pumps would be located in the plant.
- The AES steam generator BFW make-up water supply and treatment of 10% plus of PW flow will be in the AES scope of supply.

- **Attachment 4** (BFD 3) – is a typical SAGD Schematic using the current technology and giving more details than the high level Attachment 3.

2.3 In-Situ Thermal Recovery of Alberta Oils Sands

The following is extracted from the Alberta Geological Survey (AGS) and the Alberta Energy Resources Conservation Board (ERCB) website (2); it provides a brief introduction of the in-situ recovery of bitumen from the Alberta oil sands:

- *Oil sands (also called 'tar sands') are found in about 70 countries in the world, from Venezuela and Trinidad/Tobago in the Caribbean to as far north as Russia. By far, the main deposits are hosted within Cretaceous rocks of Venezuela and Canada, and among these, the largest is the Athabasca oil sands of northeast Alberta.*
- *Oil sands consist of bitumen (soluble organic matter, solid at room temperature) and host sediment, with associated minerals, and excluding any related natural gas. The crude bitumen within the sands is a naturally occurring viscous mixture of hydrocarbons (generally heavier than pentane), often with sulphur compounds, that will not flow to a wellbore in its natural state. Upon heating the bitumen will flow.*
- *The oil sands of Alberta are unconsolidated, held together by the pore-filling bitumen. The bitumen is a natural, tar-like mixture of hydrocarbons, that when heated has a consistency of molasses. In its natural state, bitumen (density range of 8° to 12° API; at room temperature viscosity >50,000 centipoises) will not flow to a wellbore.*
- *In Alberta other heavy oil in sand is also considered as 'oil sands' if located within the oil sand application areas. However because the pore-fluid is heavy oil and will flow to a well, these deposits are referred to as 'primary in-situ crude bitumen.'*
- *The major challenge of recovering bitumen from depth is to overcome its high viscosity to allow it to flow to the wellbore. To do this, thermal (or other non-primary) in-situ methods are used, most commonly Cyclic Steam Stimulation (CSS) and Steam Assisted Gravity Drainage (SAGD).*
- *Canada's largest in-situ bitumen recovery project uses CSS at Cold Lake. Steam injected down the wellbore into the reservoir heats the bitumen, followed by a soak time, and then the same wellbore is used to pump up fluids. At Cold Lake, about 3200 wells are currently operating from multiple pads, with two above ground pipelines, one to deliver steam and the other to transport fluids back to the processing plant.*

- *At Athabasca, the SAGD technology is used. Horizontal well pairs (700 metres long with 5-metre vertical separation) are drilled from surface pads to intersect bitumen pay. Steam from the upper injector well expands, reducing the viscosity of the bitumen, allowing the bitumen to flow. A shell forms at the cold interface with the unheated reservoir, along which heated bitumen/condensate drain by gravity to the lower producing well. Locally electrical submersible pumps may assist in lift.*
- **Attachment 5 Map of Alberta Oil Sands Projects** lists the location, status and proposed recovery method of currently planned oil sands projects.

2.4 Alberta Oil Sands Categories

The AGS and the ERCB recognize three categories of oil sands, differentiated by their appropriately selected recovery method, these are:

2.4.1 Oil Sands Mining

Reserves economically recoverable by strip mining. Employed from surface to about 80 meters depth, this type of recovery is used in the Northern Athabasca area.

2.4.2 Oil Sands Primary Production

Reserves economically recoverable by primary means; this *in-situ* crude bitumen has a lower viscosity range and is directly recoverable without dilution or heating. This may involve sand included production and separation. Typical of this type of recovery is that used in the Lloydminster area

2.4.3 Oil Sands In-situ Recovery

Bitumen too deep to mine and too viscous to recover cold is the subject of in-situ recovery by thermal, solvent or other tertiary stimulation method This is used to mobilize the bitumen in the reservoir and permit it to be pumped or otherwise lifted to the surface for processing. These methods are used in all oil sand zones.

2.5 In-situ Recovery Methods

Several methods exist for the in-situ recovery of oil sands but that using high pressure steam is the current dominant practice. Two main variants exist; both employ high pressure steam stimulation: CSS and SAGD.

The remaining in-situ recovery methods are still the subject of various levels of development and have not yet gained commercial acceptability.

The CSS and SAGD recovery methods referenced are briefly described below. The values for reservoir depths, production ratios and pressures are representative averages taken from IMV's experience in study and detail engineering projects over recent years.

2.5.1 Cyclic Steam Stimulation

The CSS reservoir depth is generally from 150 to 1,000 meters. Horizontal or vertical wells are used; multiple completion zones may be employed in stratified and thin formations.

Well pads typically have ten to twenty five wells drilled from vertical to directionally sloped and horizontal configurations. Pumps are typically sucker rod operated plunger type; these are robust and effective at greater depths.

2.5.2 Steam Assisted Gravity Drainage

SAGD recovery is used mainly in the Athabasca area but its use is spreading to other areas where reservoir conditions are suitable. The depth of reservoir is generally from 150 to 800 meters. The method is employed in thicker formations (10 meters and greater) and it generally has a higher oil recovery rate than CSS. SAGD is a burgeoning technology and many recent developments employ this method where the reservoir permits its use.

Well pads typically have four to eight well pairs drilled directionally to a horizontal configuration. Well pumps are down-hole, rotary type; these are less robust and at greater depths this can limit the use of SAGD. Alternatively compressed natural and/or produced gas may be injected into the well to produce oil using the gas-lift process.

2.5.3 Water Treatment

- **Water Use Limitations**

  The availability of water for process and cooling is strictly limited for in-situ recovery plants in Alberta. Fresh water (TDS < 4,000 ppm) extraction from lakes, rivers and aquifers is the subject of licensing by Alberta Environment. River and lake water extraction is almost never permitted for in-situ plants.

  Process feed water for first fill may be obtained from fresh water source wells; where available and permitted.

  Brackish water and that produced from oil wells has to be accounted for in plant designs and operations. Increasingly, brackish water only, for startup and makeup is being employed. Water reuse is practiced vigorously and water recycle ratios declared in design applications and operations reports.

  Water is not normally used for cooling and aerial heat exchange cooling predominates.

- **Water Treatment**

  The treatment of water and the choice of steam generation equipment are of the essence of the design of in-situ thermal recovery oil sands plants. In such plants 100% of the produced and make up water has to be treated to boiler feed water (BFW) standards on every cycle of water/steam through the plant. This is compared to power and utilities steam generation, where a high proportion of clean steam condensate is returned from generation and process duties to form BFW; thus only the BFW make up water needs treatment.

The following sections discusses the WT requirements of OTSG's in comparison to that of drum boilers and that proposed for AES steam generation.

- **Study Plant Water Chemistry**

  The four significant water streams for the study plant model are:

  - Brackish water flow to the BFW system as make up.
  - Produced water flow from the deoiling system.
  - Warm Lime Softener outlet flow for the OTSG case.
  - Evaporator outlet flow for the AES steam generation case.

  Attachment 6 Chemical Compositions of Main Water Streams provides typical chemical compositions for the study plant main interface water streams. The values in Attachment 6 have been taken from several differing sources; they are indicative only and have not been the subject of integrated, process engineering mass or water balances.

  The given brackish water TDS of 5,000 mg/l is a low range concentration, values up to 11,000 mg/l are experienced from some oil sands formations.

- **Water Treatment for OTSG's**

  OTSG's operating at up to 80% steam quality permit residual water contaminants to be carried over in the fluid water phase; the contaminants are then either injected with the steam (CSS) or separated in the steam blowdown (BD) before steam injection to the wells (SAGD). The simplicity of design and less demanding BFW water treatment (WT) requirements of OTSG's have led to their dominant use as oil field steam generators in Alberta and elsewhere.

  Produced water is deoiled then treated in a warm lime softener (WLS) to remove residual oil, hardness and silicates. Weak or strong acid cation (WAC/SAC) units are used to treat make up water and polish treated PW to OTSG BFW water specification standards.

- **Water Treatment for Drum Boilers**

  While the above method of WT is adequate for OTSG's the resulting water purity is inadequate for drum boilers; as used on some of the newer LP SAGD plants. For the latter low pressure PW evaporators, with or without crystallizers, are used to treat the total flow of produced and makeup waters.

  The target standard for water purity for drum boilers is specified in the publication ASME BFW Operating Practices (ASME BFWOP - 4); in this the level of BFW contaminants is set by the requirements of anticipated downstream drum boilers with superheaters and steam turbines. The low pressure evaporators currently available have difficulty in meeting the ASME standard; where low concentrations of volatile organic carbons (VOC), oil and grease are not removed and are carried over into the evaporator condensate. Neither superheaters nor steam turbines are currently used in the SAGD application; so the excess contaminant level in the BFW has recently been accepted by the drum boiler vendors; performance thus far on a number of plants appears satisfactory.

- **Water Treatment for AES Steam Generation**

  The AES steam generator would recieve100% of the treated PW as BFW makeup. PW WT equipment would comprise a low pressure, steam driven, evaporator and crystallizer. This would provide BFW water quality equivalent to that currently provided to SAGD drum boiler applications.

  The WT equipment would be located at the central plant; the clean and deaerated BFW would then be pumped and pipelined back to the AES steam generator.

  The AES steam generator BFW make-up water supply and treatment (10% plus of PW flow) would be in the AES supply.

  If the AES utilizes steam turbines for electrical power generation, or other applications, a clean steam and water system, separate from that of the SAGD steam production circuit, would be installed. This would have its own WT and water and steam quality control.

  Availability of water sources, WT for the AES and the achievable water recycle ratios should be the subjects of detailed consideration for any particular location and application.

2.6 Generated Steam Considerations

2.6.1 CSS Steam

The CSS steam production at the central plant is typically an ANSI/ASME Class 1500 system. Steam is produced in OTSG's at around 16,000 kPa and up to 80% quality. Steam is injected wet, directly from OTSG's, i.e. without steam BD separation.

2.6.2 SAGD Steam

The SAGD steam production system at the central plant is typically ANSI/ASME Class 600 for low pressure applications and ANSI 900 for high pressure. High pressure designs are associated with larger developments with large steam distribution systems and greater well depths. Steam is produced in OTSG's at around 9,500 kPa (HP) or 7,000 kPa (LP) and up to 80% quality.

Dry saturated steam is separated in a high pressure separator immediately downstream of the OTSG's; then injected into the oil wells. BD liquid from the steam separator is recovered and used in plant heat recovery as far as is possible. The liquid BD residues and WT regeneration wastes are disposed of to subsurface wells, salt caverns, evaporator ponds or managed off-site by a specialist disposal contractor.

Some recent low pressure SAGD applications have used drum boilers, generating steam at around 7,700 kPa and 100% quality. Steam is injected dry, i.e. directly from the drum boilers.

2.6.3 Steam and Water to Oil Ratios

The steam to oil ratio (SOR) is a basic parameter of an in-situ thermal oil sands development. It is calculated at the plant battery limit (BL); the steam cold water equivalent (CWE) volume in m^3/d is expressed as a ratio to the dry bitumen produced in m^3/d.

The related water to oil ratio (WOR) is the PW in m^3/d expressed as a ratio to the dry bitumen produced in m^3/d. Numerically the WOR and SOR are often similar, as PW comprises mainly steam condensed in the well. The WOR varies with the plant and the field water evaporation losses and the water that may be gained from the reservoir formation.

The CSS SOR is generally in the range 2.0 to 4.0; this includes both the liquid and vapor phases of the <80% quality steam. The SAGD SOR is generally in the range 1.7 to 3.0; this is calculated for the separated, dry steam phase only.

This study uses an assumed average SOR of 2.5; steam and electrical consumption was calculated as a function of this value. A WOR of 2.5 is assumed in calculating PW and make up water quantities.

2.6.4 Water Recycle Ratio

The plant water recycle ratio (WRR) is a target value calculated for regulatory purposes, where:

WRR = <u>CWE volume of steam to reservoir – fresh make up water volume</u>

Produced water volume

CWE is at 15^0C.

The WRR at many existing plants is <80%. For new in-situ recovery plants the ERCB currently specifies WRR's of 90% or higher for fresh water; and requires that brackish WRR's be calculated and included in the plant regulatory application. Higher water recycle ratios are required for new plants and are being retroactively enforced for existing plants.

The trend for WRR regulation is towards zero liquid discharge (ZLD) on fresh water; and for all water to be regulated independent of its source. In **Attachment 7** the additional WRR requirements from the ERCB's latest consultative water use documents are given for reference.

2.6.5 Steam Pressures and Flows

Table 2-1 on the following page summarizes the average steam conditions for CSS and SAGD.

Table 2-1 Average Steam Conditions for CSS and SAGD

Recovery Method	Steam Conditions						ANSI Pressure Class
	Plant Steam Generator Outlet			Well Pad Inlet			
	Design Pressure	Operating Pressure	Steam Quality	Design Pressure	Operating Pressure	Steam Quality	
	kPa	kPa	%	kPa	kPa	%	
CSS	17,225	< 16,000	< 80 (1)	17,225	< 13,000	< 80	1,500
HP SAGD	11,200	< 9,500	< 80 (1)	11,200	< 6,000	< 100	900
LP SAGD	7,700	< 7,000	< 80 (2)	7,700	< 4,500	< 100	600

Note: 1. For OTSG Design

2. For OTSG Design; for Drum Boiler Design Quality is <100%

It has been assumed that steam imported from the AES to the central plant should meet the HP SAGD operating pressure of 9,500 kPa and be 100% quality at the BL.

For the SOR of 2.5 the calculated steam flows for the study model plant development phases are:

- 30,000 bopd (4,770 m^3/d) - steam CWE volume = 11,925 m^3/d
- 60,000 bopd (9,539 m^3/d) - steam CWE volume = 23,848 m^3/d
- 90,000 bopd (14,308 m^3/d) - steam CWE volume = 35,770 m^3/d
- 120,000 bopd (19,078 m^3/d) - steam CWE volume = 47,695 m^3/d

2.6.6 Reliability Requirements for SAGD Steam Supply

Oil sands in-situ thermal well sites start up slowly and need at times to vary steam supplies. A current design equipment line up of four (4) OTSG's for a 30,000 bopd would provide a minimum steam production turn-down of 40% of one OTSG or about 1,192 m^3/d CWE. The equivalent turn-down for the AES would be 2.5% of the steam flow required for the final 120,000 bopd development phase.

For SAGD operations the steam usage increases in rate is approximately linear (saw tooth linear) from the first warm up phase until the available reservoirs are exhausted. Small steps occur as each new well pad is commissioned and upset conditions, maintenance, etc, can cause some short term demand fluctuations.

The steam demand is maintained by the drilling and commissioning of new well pads. The plant demand factor is typically 97%.

A short term failure of steam supply is not usually critical in terms of safety and operations; standby electrical power and glycol heating systems maintain critical operations. The reservoirs are such huge heat sinks that they only respond slowly. Known variations in steam supply are usually associated with commissioning and maintenance activities and can be planned for.

A long term failure of steam supply should be avoided as reservoir cool-down and disruption is expensive, may be difficult to recover from and can require recompletion of wells. The AES should be able to provide steam supplies to the following supply parameters:

- A complete loss of steam production is permitted for no longer than one day.
- A 67% loss of steam production is permitted for no longer than one week.
- A 33% (or less) loss of steam production is permitted for no longer than one month.

It is possible for the AES applications that Natural Gas-fuelled backup steam generation capacity may be required for plant commissioning, maintenance work, startups, and AES supply interruptions. If the required standby steam generation capacity were as high as 100% of the steam demand for the in-situ plant first phase only, an assessment is provided for the type of steam generators and the capital cost of their installation. The functional requirements of this steam backup steam supply are as follows:

- Standby generator can be fired from cold layup within 24 hours.
- Plant and field steam piping and pipeline systems circulated to operating temperature: 3 to 4 days, if piping not already warmed up.
- First well pad warmed up and producing emulsion: 8 to 12 weeks at 25 to 33% of steam design flow rate.
- The standby steam BFW to be supplied from the in-situ plant, evaporative WT system; this is of sufficient quality to supply water tube type drum boilers.

The choice of standby steam generator is between four 25% capacity OTSG's or drum boilers or two 50% drum boilers. The drum boiler options have an overall energy advantage of 3 to 4% over the OTSG option. The estimated total installed cost of two drum boilers would be approximately 20% less than that of the OTSG alternate; so two 50% drum boilers would be installed for steam generation standby duty. Cost data on these two options are shown in **Attachment 8**.

2.6.7 Fuel Gas Consumption

The fuel for OTSG's is a mixture of natural gas to pipeline specification and produced gas. The estimated fuel consumptions for the study model plant design are shown in **Table 2-2** on the following page:

Table 2-2 Estimated Fuel Consumptions for the Study Model Plant Design

Phase	LHV (Sm^3/d)	HHV (Sm^3/d)
30,000 bopd	860,557	854,838
60,000 bopd	1,721,114	1,709,675
90,000 bopd	2,581,671	2,564,513
120,000 bopd	3,442,228	3,419,350

Gas consumption estimate basis:

Lower heating value (LHV) for fuel gas - 32,110 kJ/Sm^3

Higher heating value (HHV) for fuel gas - 35,660 kJ/Sm^3

SOR - 2.5

Steam quality - 77%

Flows to tank blanket gas, flare, etc. are 5% of OTSG flow

OTSG thermal efficiency (LHV basis) - 95.16%

OTSG thermal efficiency (HHV basis) - 86.26%

2.7 Electrical Requirements

2.7.1 Central Plant

Most existing and planned in-situ thermal recovery plants receive electrical power from the local public utility company at 14.4 kV at the plant BL. On-plant step down transformers reduce the voltage to 5 kV and 600 V for on-plant distribution. Emergency power for critical plant processes and utilities is supplied by an automatically starting, diesel driven, generator.

The connected electrical load for the central plant is calculated against the Mechanical Equipment List power duties. **Attachment 9** is the power estimate for a typical 30,000 bopd phase central plant using the current study plant design, employing natural gas fired OTSG's and WLS/WAC/SAC water treatment.

A small minority of plants include natural gas fired turbo-generator equipment that supplies the plant electrical power and employs heat recovery steam generators (HRSG). The utilities company still provides connection for full load supplies and emergency generators are installed. A contractual arrangement to sell the excess electricity to the utilities company is a feature of this arrangement.

2.7.2 Well Pad Electrical Supplies

The well pads typically receive electrical power from the local public utility company at 14.4 kV. Depending on the site requirements, step down transformers reduce the voltage to 5kV and/or 600 V for on pad distribution.

2.7.3 AES Electrical Supply Basis

It is proposed that the AES electrical generator supplies electricity to the plant BL at 14.4 kV. On plant step down transformers and local power distribution would be installed in a similar manner to the current plants and well site facilities.

Attachment 10 Electrical Single Line Diagram - Distribution with ISD shows the proposed electrical interconnectivity for the AES - OSDP cogeneration system. The electrical power from the utilities is transformed down from the main 240kV high voltage distribution to 14.4kV, the level appropriate for cogeneration of permitted Industrial Site Designation (ISD) operations.

The connected load would be reduced by the power currently absorbed by the OTSG's and their ancillaries, and increased by the power absorbed by the 100% PW WT evaporators and crystallizers. The estimated electrical power levels for the proposed plant developments using AES sourced steam, including that to the well pads, are given in **Table 2-3** on the following page:

Table 2-3 AES Electrical Load List Estimate (MW)

Equipment Designation	Case Note	30,000 bopd		60,000 bopd		90,000 bopd		120,000 bopd	
		Demand Load	Connected Load	Demand Load	Connected Load	Demand Load	Connected Load	Demand Load	Connected Load
CPF with WLS and inc. OTSG's and BFP's	1	9.42	13.46	18.84	26.92	28.27	40.38	37.69	53.84
Delete WLS WT and associated equipment	2	-0.24	-0.34	-0.48	-0.68	-0.71	-1.02	-0.95	-1.36
Delete OTSG's and associated equipment	3	-0.77	-1.10	-1.54	-2.20	-2.31	-3.30	-3.08	-4.40
Add Evaporator WT equipment	4	8.93	12.76	17.86	25.51	26.79	38.27	35.72	51.03
Add Crystallizer, Dryer and Cond. Polisher	5	0.64	0.91	1.28	1.83	1.92	2.74	2.56	3.66
CPF Totals		17.98	25.69	35.97	51.38	53.95	77.07	71.94	102.77
Add Well pads	6	4.90	7.00	10.50	15.00	25.20	36.00	34.30	49.00
CPF and Well Pad Totals		22.88	32.69	46.47	66.38	79.15	113.07	106.24	151.77

Notes:

1. Base Case without AES; using Load List given in **Attachment 9**, a demand factor of 0.7 and linear extrapolation for production rates.
2. WLS removed; boiler boost and charge feed pumps (BFP) retained.
3. OTSG's removed; boiler boost and charge feed pumps retained. OTSG's may be retained for start-up and to meet standby steam requirement; in this latter case the electrical power values should be added to the non-AES source e.g. from the grid.
4. Evaporator added; boiler boost and charge feed pumps retained; BFW to sub-ASME quality.
5. Crystallizer, solids dryer and condensate polisher added; boiler boost and charge feed pumps retained. BFW quality to AES should comply with ASME BFW recommendations.
6. Well pad demand loads vary with the increasing distance of the later phases from the central plant; i.e. hydraulic and electrical distribution losses increase with distance.

2.8 Plant Life and Location Issues

2.8.1 Location Criteria for Oil Sands Facilities

The location of oil sands facilities and pipelines are subject to several regulatory and practical limitations. The following criteria outline the more important location considerations:

- Comply with facility spacing criteria; these include:
    - ERCB Directive 56 - Energy Development Applications and Schedules;
    - Global Asset Protection Services - Oil and Chemical Plant Layout and Spacing i.e. insurance industry standards; and
    - Noise Limitations – ERCB and OH&S guidelines.
- Avoid reservoir "high pay" areas.
- Near to first well pads to be developed.
- Within economic steam pipeline distribution limits; <10km from the central plant to the far well pad.
- Near to existing roads.
- Near to existing utilities.
- Locate on elevated land:
    - Avoid flood plains;
    - Minimize wet land construction; and
    - Optimize earth cut and fill.
- Avoid:
    - Natural Reserves;
    - National and provincial parks;
    - Caribou habitat/migration zones;
    - Mature stands of trees;
    - Areas of archeological significance; e.g. native burial grounds; and
    - Prime agricultural land.
- For pipeline routes utilize where possible existing:
    - Pipeline Right of Way (ROW);
    - Road margins;
    - Utilities corridors; and
    - Geophysical cut lines.

2.8.2 Area and Plant Plot Plans

Area and plant plot plans are provided to illustrate layout considerations for the 30,000 to 120,000 bopd study in-situ oil sands thermal plant:

a. **Attachment 11** gives a typical area site plan for the final 120,000 bopd phase development. Indicated is the central plant, well pads, interconnecting pipelines and drilling, construction and operations camps.

   A sixteen pad, single sided pipeline layout is shown. Various other arrangements might be appropriate, depending upon the requirements of the lease size and shape, reservoir limitations and land topology. The pipeline run-out from the plant to the most distant wells is at the current, recommended maximum of approximately 10 km.

   Each pipeline main branch is indicative of a 30,000 bopd phase; the assigned well number gives a suggested order of development.

b. **Attachment 12** gives a typical plot plan for the central plant showing the current layout style with natural gas fired steam generators.

   The plant plot plan has been laid out following a phased, production train, approach. The plant plot area would be prepared and graded sufficient for all four phases of 30,000 bopd and constructed as follows:

   - Facilities common to all phases would be installed for the 120,000 bopd phase. These are shown in green line in the plot plan and would be built during the first phase of construction.
   - The first process development phase for 30,000 bopd is shown in red line on the plot plan.
   - The second process development phase for 60,000 bopd is shown in blue line on the plot plan.
   - The third process development phase for 90,000 bopd is shown in orange line on the plot plan.
   - The fourth process development phase for 120,000 bopd is shown in brown line on the plot plan.

c. **Attachment 13** – typical plot plan for the central plant showing the layout style with steam provided from the AES steam generator; this includes the following features:

   - The OTSG's and associated BD ponds have been removed.
   - An Evaporator and BFW pumping equipment area is added.
   - A steam inlet and BFW outlet manifold area is added.
   - Area for AES source plant is indicated.

The AES plot area is subject to confirmation when the following information has been established:

- The AES vendor has been selected and its plant plot size is known.
- If location of the AES within the in-situ plant plot area will be permitted by its internal operations requirements e.g. for recommended spacing or exclusion zones.
- If the location of the AES is subject to regulatory constraints.
- If steam supply reliability will depend solely on the AES; or back-up steam will be required.

2.8.3 Plant Design and Expected Life Issues

Equipment within the in-situ plant is designed to code and has a typical initial design life of 20 years.

Plants are typically referred to as 30 year plants, but many are anticipated to exceed this; with appropriate maintenance, debottlenecking and development.

Individual well development phases may be as low as 8-10 years of economic production, low production rates may continue thereafter. Some equipment is designed to be relocated to future well pads, in which case a longer design life is required.

Interconnection of existing central plants to new leases with new plants, or simple steam raising and emulsion handling plants may also be used to extend the life of a field. This design mechanism may also be employed to overcome the 10km limit currently placed on the economic length of steam distribution systems.

2.9 Development Schedule

The overall schedule for a 120,000 bopd, commercial, in-situ, thermal oil sands recovery plant, developed, in 4 phases of 30,000 bopd each, would require the main activities and durations outlined below.

- Conceptual design studies to identify plant and well site processes and locations; duration 6 months.
- Front end engineering design studies (FEED) sufficient to support a regulatory application; duration 12 months.
- Regulatory process documentation and due process; duration 18 months.
- Detailed engineering, procurement and contracting and delivery of major equipment; duration 30 months.
- Construction and commissioning of Phase 1, including prebuilding of infrastructure for, and common facilities with, subsequent phases; duration 3.5 years.
- Construction of three subsequent phases; 3 years per phase.

Attachment 14 is a typical milestone schedule that provides more detail than that given above. It gives the possible overlaps in activities to yield the project earliest, four phase finish.

The proposed schedule presumes that at commencement of the FEED phase the following information is available or assumptions are valid:

- Land issues have been resolved.
- Geology, geophysics and reservoir engineering is advanced to the point where oil reserve areas (high pay zones) have been delineated.
- Plant size and phasing is identified.
- SOR and WOR have been estimated with reasonable accuracy.
- Engineering resources availability is approximately similar to those currently being experienced.
- Equipment delivery times are approximately similar to those currently being experienced.
- Field labor and construction equipment resources availability are approximately similar to those currently being experienced.

2.10 References

(1) http://www.ptac.org/osd/dl/osdp0601g.pdf

(2) http://www.ags.gov.ab.ca/activities/

(3) http://www.energy.alberta.ca/News/1032.asp#Maps

(4) ASME Consensus on Operating Practices for the Control of Feedwater Boiler Water Chemistry in Modern Industrial Boilers: 2003

3.0 Construction in the Alberta Oil Sands Regions

3.1 Construction Skills

3.1.1 Earthwork and Excavations

Alberta earthworks and mining contractors have extensive experience in large excavations for oil sands upgrading plants and foundations for high rise buildings in Calgary and Edmonton.

The excavation for the AES foundations may need special consideration; the anticipated foundation depth of ~ 50 meters is achievable, but extensive dewatering during construction in deep muskeg areas may be required.

3.1.2 Concrete and Foundation Construction

Foundation designs for oil sands areas must contend with ambient temperatures that vary from -45^{0}C to 35^{0}C. However the engineering and construction skills to deal with Alberta's climatic conditions are well developed.

Winter ground frost levels vary in the oils sands areas, down to 3m deep in the North Athabasca. Deep burying of liquids pipelines is normal; above ground liquids lines must be drained when not in use or insulated and heat traced. Piled foundations and concrete ground beams, set on void form materials, are widely employed to combat "frost heave".

Pouring of mass concrete is preferably completed in the warmer months of May to October. Pouring during lower ambient temperatures can be achieved by the use of low temperature concrete mixes; or by temporary enclosure and heating of excavations and formwork.

Skills in the preparation and pouring of large mass concrete foundations have been developed in the construction of power, refining and oil sands upgrading plants and foundations for high rise buildings in Calgary and Edmonton and other locations.

An example of a very large foundation and structural concrete pour in Alberta is:

- Bow Towers is a high-rise office building under construction for the Calgary headquarters of EnCana; it will provide space for more than 3,000 employees. The structure will stand 775 feet high with 59 stories, 22 elevators, three sky gardens, and a six-floor parking garage.
- Date of foundation pour 10 May 2008.
- The slab foundation of Canada's first "trussed-tube" skyscraper is 4,600 m^2 and is 3 m deep.
- At 13,000 m^3 of concrete this is Canada's largest continuous concrete pour; it ranks third in the world, behind only the Venetian hotel in Las Vegas and the Al Attar Sky Spiral Project in Dubai.
- Concrete production equipment included 4 concrete batch plants, 11 pumps, and 95 ready mix trucks. Crews worked 36 hours straight on the project.
- The concrete supplier is Inland Concrete Ltd.

- Inland will also supply concrete for the structure's 60-foot steel columns. These will be to be filled by pumping self consolidating concrete from the bottom up.

3.1.3 Equipment Heavy Lifts

Alberta construction contractors have extensive experience in heavy lifts for equipment installation in power, refining and oil sands upgrading plants.

Heavy-lift cranes, lift methods and rigging study skills are available within Alberta, and at locations that cover the oil sands development areas. However resources of labor and equipment for heavy lifts can be restricted and forward scheduling with sufficient lead time is necessary.

Examples of heavy equipment lift services available and lifts completed in Alberta include:

- In early 2007 Mammoet Canada Western Ltd moved a steel vessel 58 meters long and weighing 495 tonnes from Cessco Fabrication in southwest Edmonton and erected it at the Horizon Oil Sands Project north of Fort McMurray.
- In early 2008 a Kroll tower crane with a reach of 102 m, a tip height of 129 m and a lifting capacity of 100 tonnes at the tip. This was used on the Syncrude Sulphur Emission Reduction Project. There are only 14 Kroll K10000 cranes in the world; 13 are in Asia and the Middle East. This was the first time a tower crane of this size was used in Canada and only the third time in North America.
- Sterling Crane has depots throughout Alberta with a complete range of mobile cranes. Heavy lifts completed in Alberta over recent years include coker, reactor and other pressure vessels at the plants of Suncor, Syncrude, Dow Chemicals, et al. Lift loads have been up to 1,000 tonnes using a Demag 1375 tonnes capacity main lift crane with 660 tonnes capacity tailings cranes. Sterling provides full lifting services including engineered surveys, lifting studies, design drawings, lift tackle design and fabrication as well as the provision of cranes and operatives.

3.1.4 Equipment Modularization

Modular fabrication, or modularization, of equipment, buildings and piperacks is maximized on most in-situ oil sands projects in Alberta. Modularization is employed in an effort to mitigate the effect of Alberta's sometimes harsh climate, and the shortage of jobsite construction and fabrication labor and equipment resources.

The advantages modularization offers include:

- A large proportion of the construction labor effort that would be employed using traditional "stick built" construction is transferred from the jobsite to the fabrication shop. This aids in labor supply and organizational management.
- Fabrication and assembly are conducted under controlled working conditions and the quality level is higher.

- Reducing fieldwork minimizes the labor intensity on the jobsite; this is especially significant for projects in an operating plant.
- The cost of jobsite accommodation is reduced.
- Jobsite travel cost and site access road loading are reduced.
- Lay-down space is minimized; an important benefit when the jobsite is small or congested.
- Delays due to adverse weather conditions are reduced by constructing indoors.
- Crane operations and overhead working are reduced.
- Foundations can be simplified.
- Fewer site fitting errors and re-work are experienced.
- Highly skilled labor requirements onsite are minimized.
- Concurrent logistical and fabrication processes can be more readily executed.

There are a number of limitations to modularization; these include:

- The total installed costs can be higher as more structural materials are used; assembly and welding are greater than with stick built construction.
- Module complexity drift can be an issue during detail design, leading to greater costs and heavier structures.
- Fabrication shop space and labor shortages and long lead times can extend schedules.
- Heavy module loads increase logistical complexity and limit seasonal deliveries.
- Larger cranes and lifting equipment and greater load management skills are required.
- If jobsite delays occur lay down and warehouse storage are required for modules due for delivery. This can lead to double handling, lay down area congestion and higher costs for storage or non-delivery charges.
- Bulk materials management can become complex and difficult to manage if central procurement and supply is utilized with multiple module shops.

3.2 Construction Labor

3.2.1 Construction Management and Labor Organizations

Construction labor information and data for this report are taken from IMV's own construction management (CM) experience and that provided by the organizations listed below. A brief profile of each organization is provided that identifies its relevance to the study.

i. Government of Canada: Construction Sector Council (CSC)

The CSC is a national organization financed by government and industry; representation includes the National Construction Labor Relations Alliance, the Building and Construction Trades Department and its affiliates, and the Canadian Construction Association. The CSC provides advice and detailed statistical analysis at the national and provincial levels.

ii. Government of Canada Weather Office - Archives

The National Climate Data and Information Archive provide detailed historical climatic data for all areas of Canada.

iii. Government of Alberta Employment and Immigration (AE&I)

The AE&I includes the Employment and Immigration Labor Relations and the Workers' Compensation Boards. AE&I provides regular statistics for construction activity.

iv. Alberta Construction Association (ACA)

The ACA consist of member companies involved in institutional, commercial and industrial sectors that include general contractors, trade contractors, and manufacturers and suppliers.

v. Construction Owners Association of Alberta (COAA)

The COAA is comprised of Principal Members who are users of construction services and Associate Members who provide construction services. COAA provides construction planning statistics that reflect present and future project activities in the province.

vi. Alberta Building Trades Council of Unions (ABTCU)

The ABTCU is an organization that represents 16 trade unions, with 22 locals; it covers all trades across Alberta.

vii. Christian Labor Alliance of Canada (CLAC)

CLAC is an independent Canadian labor union with regional offices across Canada; it is active in Alberta. CLAC provides an alternative labor association to that of the ABTCU and its union locals.

viii. Third Party and Subcontract Labor Providers

Labor agency companies that provide subcontract labor for long or short term projects, peak overloads and plant shutdowns, to owners, projects or construction contractors. Their services include the recruitment and management of out of province sourced and foreign labor.

3.2.2 Construction Labor Skills and Availability

A full range of construction skills for oil sands development is available within Alberta. However the supply of construction labor has been tight for several years; it is anticipated to remain so for the foreseeable future.

CSC forecasts indicate that labor shortages for many key trades will continue until 2016, the limit of the current forecast model. The CSC 2008-2016 abbreviated highlight report is given in **Attachment 15**.

COAA forecasts indicate high construction labor demand until 2014 for currently identified industrial construction projects. The COAA labor distribution forecast chart Industrial Construction Projects 2004 to 2015 is given in **Attachment 16**.

It is anticipated that construction labor for any future project that employs new technology, such as the AES, will need to be populated in part with labor from out of province. This may include sources in the USA, Ontario and other Canadian provinces that have the skill sets and labor that are underutilized; lower cost labor from overseas may also be required.

The construction and fabrication skills culture and organization for an AES project is present in Alberta; however it is anticipated that an AES project would require investment in improved quality standards and management, to those currently employed in the oil sands area.

3.2.3 Construction Labor Organization

The current Alberta's employment statistics include:

- Total labor force - 2,080,000
- Unemployment rate - 3.5%
- Union Membership - 44,000
- Construction labor force - 170,000
- Construction union membership - ~ 20% or about 34,000

Alberta construction companies have affiliations to ABTCU if they employ exclusively international union members. Non-aligned construction companies are affiliated to CLAC or have no affiliation.

Manufacturing shops, operations and project sites also follow the union, CLAC or non-union model; some have an Open Shop agreement that permits mixed work forces. Large sites often demand construction labor forces that are beyond the resources available from either union or CLAC; here the owner or interested construction companies may work with AE&I, ABTCU and CLAC to develop a site agreement that holds for the duration of a project.

ABTCU affiliated unions claim to have higher skill levels and safety standards than other organizations. CLAC emphasizes its flexibility and lesser degree of trade demarcation; it also has slightly lower base and overtime hourly rates of pay. Owners and construction managers often value the greater flexibility of CLAC labor as an aid to site management.

3.2.4 Construction Work Hours and Shift Rotations

The AE&I provincial labor standards mandate:

- A standard 40 hour week with a maximum 10 hour day. Beyond which overtime is paid at a rate of 1.5 times for 8 to 10 hours per week day and double time for hours beyond this.
- Two weeks paid annual vacation.
- Nine paid annual statutory holidays.

Due to the remote location of most oil sands in-situ sites extended work days and shift rotations are normally implemented; two main ones are in common use, these are:

- Ten 10-hour work days on site with 4 days off. This is most usual rotation and is used within Alberta or for nearby province based labor.
- Twenty one 10-hour work days on site with seven days off. This rotation is used with labor mobilized from the Canadian east coast or abroad; where long plane journeys are employed.
- The construction contractor typically pays for labor travel time for first project mobilization and final demobilization. Shift rotation travel time is not normally paid.

Company, trade union, industry or site agreements may designate payment systems that go beyond the above guidelines. AE&I publishes industry agreements that it ratifies.

3.2.5 Construction Labor Productivity

Construction labor productivity is often referenced to a “Gulf Coast Norm”; IMV interprets this as outlined below.

a. Oil and Gas Project Construction Productivity

   IMV typically uses a 2.3 labor productivity multiplier for O&G construction projects in the Athabasca areas. This factor is used in conjunction with the operations man hour durations and efficiency calculations recommended in *Estimators Equipment Installation Man-Hour Manual: John S Page; 3rd Edition 1999; Gulf Professional Publishing; and the other Estimating Manuals by Page*.

   Attachment 17 provides a typical O&G construction productivity calculation for work in the Athabasca area.

b. AES Project Construction Productivity

   It is anticipated that the O&G productivity multiplier will be further increased by the demands of an AES construction project. Anecdotal information from construction contractors working in both Athabasca and AES environments suggest that a labor multiplier of 2.8 or higher could be expected for an Alberta AES site.

3.3 Jobsite Environmental Conditions

3.3.1 Climatic Conditions

Climatic data is available for any area of Alberta from the National Climate Data and Information Archive. Civil/structural guidance on climatic and environment design limitations is provided in the Alberta Building Code.

The table in **Attachment 18** gives a typical jobsite profile for a location in the Firebag area of the North Athabasca; this may be regarded as outlining the more onerous of site design parameters that will be met in the oil sands area.

3.3.2 Site Conditions and Construction

The oil sands areas are to great extent wilderness that, until resource development commenced, supported hunting and trapping communities. Thus modern roads and infrastructure are either absent or quite rudimentary. The vegetation is dominated by pine and spruce forests interspersed with parkland and extensive muskeg areas and water ways.

Muskeg is the Canadian and Alaskan term for peat land. It consists of dead plants in various states of decomposition to peat; ranging from sphagnum moss, to sedge peat and decomposed muck. Muskeg can be as deep as 3m and it usually has a high water table.

Motor vehicle travel over muskeg is possible during winter, when it is frozen. Well drilling and movement of heavy equipment over temporary gravel roads is concentrated from December to early March. At other times low surface load, all terrain vehicles (ATV) are employed for surveying and general transport.

Tree removal, ground dewatering and muskeg stripping are necessary to build in-situ plants and well pads. Indigenous soils, gravel and sand are used to form all-weather roads and plant and well pad grades. The location of near-by gravel “borrow areas” is a desirable economic feature of site development.

There are seasonal restrictions on construction in many parts the oil sands area for the protection of caribou and song and water birds.

Soils preservation and site restoration are features of the Alberta regulatory regime for O&G developments. Muskeg, top soils and subsoil must be separately piled and preserved for the life of the plant or site; then reused in the later restoration of the site.

3.3.3 Remote Location Jobsite Requirements

Most oil sands areas are sufficiently remote as to require jobsite accommodation, in purpose built labor built camps.

Camps are provided for drilling operations, site labor, owner management and long term plant operations. These may be integrated, or separate, depending on the size of the development and the schedule for any particular operation.

All camps are built to a modern, high standard of comfort; with 24 hour catering and security. Indoor and outdoor recreational facilities are provided. Camp construction and operations are usually contracted by the owner.

Transport to and from the jobsite to the nearest major city, or mobilization base, is provided on buses. Some owners own or contract planes for travel to and from the jobsite; landing at the nearest city or local air field.

Some recent large oil sands sites have built larger air fields that can accommodate commercial passenger and transport planes. These transfer staff and site labor from and to Alberta bases; typically Edmonton or Calgary, and to more distant locations from where labor has been mobilized.

Transport is provided at the beginning and end of each shift rotation. The scheduling of work shifts to avoid congestion and optimize transport and camp accommodation is a major logistical task on large sites.

4.0 Transport Logistics in the Oil Sands Developments Areas

Transportation of materials and equipment to the oils sands development areas is limited by:

- Limited road and rail infrastructure to the existing and new development areas.
- The carrying capacity of the existing road and rail systems.
- The design load limitations of road and rail bridges.
- Seasonal load restrictions on roads and railways.
- Clearance heights of bridges, highway overpasses and overhead electrical power cables.
- Limited access for heavy loads from the ocean by river and thence overland to the jobsite.

The following narrative and attached tables outline the main logistical guidelines for moving general freight and large loads to and within Alberta.

4.1 Seasonal Restrictions

Roads in Alberta and other provinces in Canada are affected by extreme ambient and ground temperature variations. The presence or not of water, or ice lenses, in the substrates of highways and rail roads leads to seasonal limitations on use. Road load limitations are set by the provincial and local regulatory authorities.

Typical over the road shipping seasons and load limits are:

- Spring Ban - Typically March to May; the allowable weight per 16 wheel group is 28,000kg.
- Post Ban - Typically June; the allowable weight per 16 wheel group is 30,000kg.
- Summer - Typically July to August; the allowable weight per 16 wheel group is 32,000kg.
- Fall - Typically September to November; the allowable weight per 16 wheel group is 34,000kg.
- Winter - Typically December to February; the allowable weight per 16 wheel group is 37,000kg.

4.2 Load Size Limitations

All weights and sizes must comply with Alberta Infrastructure and Transportation (AIT) regulations. The following are based on a 16 wheel grouping on a typically spaced hydraulic platform trailer.

- Maximum loaded height of 29 feet 6 inches
- Maximum allowable weights during each of the 5 shipping seasons

- Restricted by overhead power lines
- Restricted by bridge capacities
- Road Routes are regulated

Attachment 19 outlines the High Load Corridors, Load Pilot Car Requirements, Dimensional Guidelines, and Dimensional Guidelines for Transporting Large Vessels to and within Alberta.

AIT can deny or approve the permit to move large loads.

Power companies and Rural Electrification Associations (REA) dictate escort and wire lifting requirements. These organizations can refuse load movement on the basis of service disruption to their clients; refusal to escort or lift wires on route results in no load movement.

4.3 Examples of Large Loads Moved in Alberta

Despite the limitations and restrictions for transport logistics large loads have been moved to the oil sands areas; two typical examples of transportation outside of the Albert Shipping Envelope follow:

4.3.1 Example 1

- Vessel weight 748,547 lb
- The Gross Vehicle Weight (GVW) permitted 1,659,241lbs.
- 42’ 6” high loaded on the trailer
- It had an “out to out” width of 38’ 8” – out to out includes all protrusions such as nozzles & flanges
- Vessel was 97’ long
- Total length of the transport configuration was 262’ 5”
- Fabricated in Edmonton
- The capacity of the bridge over the Athabasca River is 345,000 lbs; this rating is for loads that do not fall under a controlled and supervised move.
- The vessel was transported on 2 each 4 file 10 line Scheuerle trailers; one at the front and one at the back.

4.3.2 Example 2

In January and February of 2005 two Coker vessels were transported from Edmonton to the Oil Sands area. This took two years of planning with the Specialized Heavy Haul Carrier (SHHC), engineering company and Alberta Infrastructure.

The SHHC developed, engineered and supplied the transport frame that surrounded the vessel which allowed these moves to cross the bridges on the way to Fort McMurray.

- The vessels were 290’ long (with the lead tractor unit) x 34’w x 38’ high (loaded).

- The GVW was 1,800,000 lbs
- Vessel weight was 940,000lbs

The trip was 800kms long and lasted 9 days. Obstacles en route ranged from days when it was too cold to move to days when warm weather caused pavement loading concerns and power lines to droop. Seven tractor units were needed to “push – pull” the vessels up hills.

Both the above vessels were transported safely and without incident.

The key points with any movement of the above magnitudes are to ensure that transportation and logistics personnel are involved from the beginning; and that planning is commenced as soon as outline designs have identified key size and weight parameters.

4.4 Availability and Sources of Construction Materials

Large concrete foundations and structures have a high demand for concrete, over a long duration; this is a constraint for jobsites remote from urban, ready-mixed concrete supply sources. Large and remote sites employ central, jobsite based, concrete batch mix plants to prepare concrete throughout basic construction.

The locations of indigenous aggregates from borrow or commercial pits are often an issue; haul trips of 200 km plus are being experienced on some current oil sands sites.

Cement for mix plants in Alberta is sourced mainly from Exshaw, 90 km east of Calgary; the trip to the Firebag River area, of Northern Athabasca, is 900 km plus. Lesser quantities of cement are available through Edmonton; at approximately 600 km to the Firebag area.

Raw materials for a remote concrete batch plant needs careful planning and cost estimating. Planning and procurement arrangements with the main Alberta cement suppliers are recommended.

5.0 Oil Sands Plant Development Regulations

5.1 The Regulators in Alberta

The regulators affecting in-situ oil sands development are:

- Alberta Energy (AE) manages the development of provincially owned energy and mineral resources by industry, and the assessment and collection of non-renewable resource revenues in the form of royalties, freehold mineral taxes, rentals and bonuses.
- Alberta Environment (AENV): regulates environmental compliance issues; environmental impact studies; fresh water use; etc.
- Alberta Energy and Resources Conservation Board (ERCB): regulates energy resources including oil, natural gas, oil sands, coal, and pipelines, as well as the construction and operation of energy developments, such as in-situ thermal heavy oil facilities.
- Alberta Electrical System Operator (AESO), in conjunction with AUC, is responsible for the safe, reliable and economic planning and operation of the distribution and transmission of electrical power. The system is designated as the Alberta Interconnected Electric System (AIES).
- Alberta Utilities Commission (AUC): regulates investor-owned natural gas, electric, and water utilities and certain municipally owned electric utilities.
- Alberta Employment and Immigration (AE&I): regulates Immigration; Labor Relations; Occupational Health and Safety (OHS); Workers Compensation.
- Alberta Boiler Safety Association (ABSA) is the pressure equipment safety authority; it regulates pressure vessels, boilers, plant piping design, welding certification, plant operators and related skills.
- National Energy Board (NEB) regulates international and interprovincial aspects of the oil, gas and electric utility industries; e.g. pipelines and power utilities that cross provincial or national boundaries.
- Association of Professional Engineers, Geologist and Geophysicists of Alberta regulates engineers, geologist and geophysicists under the Alberta Engineers, Geologist and Geophysicists (EEG) Act.

5.2 Technical Regulation in Alberta

5.2.1 Engineering and Geosciences Competence and Licensing

Engineering and geosciences are regulated professions in Canada. They are practiced under Federal and Provincial Acts and are regulated by Professional Associations in each province.

In Canada the design, fabrication and construction of energy developments, including all infrastructure, major structures and buildings, pressure and electrical equipment, etc., are conducted under the statutory supervision of Professional Engineers and Geoscientists (PE/PG). Equipment and components used in the above, engineer defined systems, are also regulated and many are registered components; e.g. pressure vessels, pipe fittings, well heads, electrical components, etc.

Provincial and discipline PE associations are affiliated to the Canadian Council of Professional Engineers (CCPE). The CCPE coordinates inter-provincial regulatory issues, mobility and international accreditation for PE's; e.g. with state regulators in the US with the Engineering Council in the UK. The Canadian Council of Professional Geoscientists (CCPG) provides similar services to PG's.

The titles Engineer, Geologist, Geophysicist, are reserved by Canadian provincial law; such titles may only be used by persons appropriately licensed. Title misuse or discipline malpractices are severely punished under the provincial EGG acts. All professional documents issued for execution are stamped and signed by the individual PE or PG responsible for their preparation.

Firms that practice engineering or geosciences, including O&G companies, manufacturers, EPCM contractors and consulting firms, are licensed by the relevant provincial professional association. PE and PG firms are assigned permit numbers; these appear on all professional documents that the firm issues for execution. Licensed firms carry the legal liability and insurance coverage for their deliverables and the activities of their personnel.

5.2.2 Trade Craft in Canada

Canada ensures a high and consistent standard of safety and quality in the delivery of craft and trade skills in manufacture, fabrication and of construction services. It provides for the certification and mobility of skilled workers throughout the country with "The Interprovincial Standards Red Seal Program for Trades"; this lists 45 designated trades that are regulated by license in Canada. This mechanism ensures that trades people have an appropriate level of education, training and practical experience.

5.2.3 Trade Craft Regulation in Alberta

The programs for training trades and craft personnel are delivered in Alberta through apprenticeship boards and trade colleges. Formal and regulatory testing of pressure vessel and pipe welders, and other safety critical craft operations, is a certificated process that is continued on a regular calendar and project or location basis.

Work shops and job sites at which the fabrication of pressure vessels, piping, structures, pressure, electrical and electronics components, etc. take place are also regulated in Alberta. Each location must have a documented quality program, safety program, worker competency, licenses and test certificates and OHS and human resources record. The documentation and is subject to approval and inspection by the appropriate provincial regulatory board staff.

5.2.4 Welding Trades Regulation in Alberta

While all construction trades employed on O&G sites in Alberta require evidence of competency the trade of welding is of special significance. Following is a brief outline of welding requirements for boilers, pressure vessels, piping, pipelines and steel structures:

a) Pressure Equipment Welding

The Alberta Safety Codes Act establishes competency and certification requirements for pressure welders, machine welding operators and welding examiners. ABSA oversees all pressure welding practices in Alberta, including the examination and certification of welders and examiners.

Standards for pressure welding are defined in the Pressure Welders Regulation (AR 169/2002). This establishes that no person shall weld on a boiler, pressure vessel, pressure piping system, or fitting by any method, unless the person is named on a Pressure Welding Certificate of Competency and has a valid Performance Qualification card that specifically authorizes the person and the welding method to be used.

Pipeline welding for O&G developments is executed in compliance with CSA Z622 Oil and Gas Pipeline Systems and the Alberta pressure welding regulations.

b) Structural Welding

The welding of steel structures in Alberta is done in compliance with the following Canadian standards:

- CSA W47.1; Certification of Companies for Fusion Welding of Steel Structures
- CSA W48; Filler Metals and Allied Materials for Metal Arc Welding
- CSA W59 Welded Steel Construction (Metal Arc Welding)
- CSA W178.1; Certification of Welding Inspection
- CSA W178.2; Certification of Welding Inspectors

Structural welding processes, welder's qualifications, inspection and examination are managed at the fabrication or construction company level, and are documented in the company's quality manual; i.e. without a separate regulatory equivalent to ABSA.

5.2.5 Operations Regulation in Alberta

In Alberta, the operation of power generation and O&G facilities is subject to the Occupational Health and Safety Act (OH&S) and it's General Safety Regulations. Plant and equipment operatives are regulated under the Power Engineering requirements by ABSA.

Plant operators in Alberta are certified for the type and level of equipment they may operate. Oil and gas processing operators are required to take additional on-job and college training beyond that required for heat and power boiler operators. The registered designation of O&G operatives is Power Engineer or Operating Engineer. There are up to four classes of designation and various specialisms; these depend on experience, training and the intended plant to be operated.

5.2.6 Regulation

AESO coordinates the transmission of electrical power in Alberta. The electrical power distributions systems are owned and operated by two provincially designated companies: Fortis and ATCO Electric.

Electrical power is transmitted within the province at the 500 kV, 240kV, 144kV, and 72kV. 72kV is currently being eliminated in an effort to standardize on three transmission voltage classes. The primary distribution voltage used within the province by both Fortis and ATCO Electric is primary three phase 25kV, but both companies impose different limits to the maximum capacity of these systems.

An industrial site which generates a sufficient amount of power to be self sufficient, may apply to the AESO for an ISD which when granted allows the owner the right to distribute power between all sites associated with the operation of the industrial complex.

Without an ISD designation, the distribution of power is limited to within the boundaries of a township's designated road allowances. Hence if the plant facilities are located in an area surrounded by designated road allowance, and the well pads are located on the other side of the designated road allowances, the distribution of electrical power to the pads from the CPF is not permitted. Thus if the distribution of power is required across designated road allowances and the owner does not have an ISD, one of the two provincially designed companies must install, own and operate the distribution equipment.

The exception to the restriction of power distribution outlined above occurs when the distribution voltage does not exceed 600 VAC. Due to the distances involved between various production sites, if the distance is significant and the load exceeds 100kVA it soon becomes impractical to distribute a sufficient amount of power at 600VAC and the provincial high voltage regulations become applicable.

5.3 Oil Sands Plant Development Regulation in Alberta

5.3.1 Oil Sands Development Regulatory Process Overview

Approval to construct and operate an In-situ, Thermal Heavy Oil Extraction Plant, with production over 2000 m^3/day, is a multi-step procedure that requires a variety of permits and approvals from separate regulatory bodies in various jurisdictions and levels of government. Currently, the entire regulatory process for approval of an in-situ, thermal oil sands recovery plant is expected to take up to a year to prepare applications (including the Environmental Impact Assessment) and approximately two years from submission of the Application. The bulk of the regulatory approval time involves submissions and receipt of Approvals from both AENV and ERCB.

The legislation in Alberta pertaining directly to recovery of oil sands in the province is the Oil Sands Conservation Act and the subsequent Oil Sands Conservation Regulation (AR 76/1988). The purpose of the Act is as follows

a) To effect conservation and prevent waste of the oil sands resources of Alberta,

b) To ensure orderly, efficient and economical development in the public interest of the oil sands resources of Alberta,

c) To provide for the appraisal of Alberta's oil sands resources,

d) To provide for appraisals of oil sands, crude bitumen, derivatives of crude bitumen and oil sands product requirements in Alberta and in markets outside Alberta,

e) To assist the Government in controlling pollution in the development and production of the oil sands resources of Alberta,

f) To provide for the recording and for the timely and useful dissemination of information regarding the oil sands resources of Alberta, and

g) To ensure the observance, in the public interest, of safe and efficient practices in the exploration for and the recovery, storing, processing and transporting of oil sands, discard, crude bitumen, derivatives of crude bitumen and oil sands products.

The Oil Sands Conservation Act requires that a proponent of an in-situ, thermal oil sands recovery plant (facility) make application to the ERCB and receive Scheme Approval prior to construction or operation of the facility. Approval must also be received from Alberta Environment, under the Environmental Protection and Enhancement Act, to construct, operate and reclaim the in situ thermal heavy oil facilities. Typically a Water Act Approval is also required from AENV either for use of groundwater and/or for surface water diversion.

The acquisition of these Approvals is accomplished through a joint (integrated) Application and Environmental Impact Assessment (EIA) submission to the ERCB and AENV. The requirement for an EIA is specified in the Environmental Assessment (Mandatory and Exempted Activities) Regulation, AR 111/93. (This requirement to submit an EIA for an in-situ, thermal oil sands recovery plant producing greater than 2000 m^3/day is being evaluated internally at AENV, and other, more streamlined environmental assessment provisions for these types of plants may be forthcoming prior to the end of 2009, but cannot be confirmed before official ratification by AENV).

Preparation and submission of an EIA is, in itself, a multi-step process with considerable input from AENV and potentially the public. The impact of the project alone, the cumulative impact of the project with existing developments in the area, and the potential cumulative impact of the project with proposed new and existing developments must be evaluated. Potential adverse effects from the proposed project must be mitigated to the government's satisfaction.

Once Approval for the oil sands recovery scheme and the facility and associated infrastructure are received from the ERCB and AENV, and all Public and Industry Notification requirements are complete, ERCB Directive 56 applications for Facility (Central Processing Facility and wellpads) and associated Pipeline Licenses can be submitted. Once these Licenses are received, construction may commence.

Other approvals that are required for construction and operation of the Project include, but may not be limited to Well License (bitumen); Pipeline Licenses; Surface Dispositions from Alberta Sustainable Resource Development (facility; Disposal Well Licenses; power generation or connection Approvals (from Alberta Utilities Commission); Municipal Development and Building Permits;

5.3.2 Public Consultation

Public consultation with potential stakeholders for a SAGD facility should begin as early in the project initiation phases as possible to determine any issues of local concern with this proposed development or common issues with previous developments. This consultation may include Town Hall Meetings, Project Description mail-outs, Open Houses, newspaper advertisements, telephone conversations, etc.

When the environmental assessment process begins, consultation items are included as part of the initial disclosure documentation. This would include the proposed terms of reference, advertising plan, public notice, details on any completed or ongoing consultation items (including responses and/or issues identified), and planned consultation to complete the requirements.

Public Consultation is an important element and can have requirements throughout the different stages of the assessment process. These usually include notices published in several newspapers and will include at least one Aboriginal newspaper if the First Nations Consultation guidelines apply. The types of notices include:

- Notice of Further Assessment
- Notice of Proposed Terms of Reference
- Notice of Environmental Impact Assessment (typically combined with Public Notice of Application)
- Notice of Final Terms of Reference (published by AENV)
- Public Notice of Application (published by AENV)

When a project is deemed to require an EIA and may infringe upon existing treaty or other constitutional rights in relation to Crown lands, First Nations consultation is required and is based on Part III of Alberta's First Nations Consultation Guidelines on Land Management and Resource Development. This part of the disclosure documentation requires a specific First Nations Consultation Plan. This plan would encompass the following:

- Project proponent contact information
- A list of First Nations to be consulted
- Plain language project specific information
- Delivery methods for providing project information and direct notices to First Nations
- Any information regarding potential adverse impacts to First Nations
- Timelines and schedules for consultation activities
- Procedures for reporting to AENV on the progress and results of the consultation

Public consultation is an ongoing element throughout the Environmental Assessment process. Feedback from the public or any affected groups regarding the proposed development (via the various notices) is part of the assessment documentation and is a mandatory requirement. If during the Assessment there are Supplementary Information Requests (SIR) from AENV or there are changes proposed to the Terms of Reference, re-advertising is required as part of the consultation process.

The intent of the consultation process is to establish an open, non-controversial path of communication between the Proponent and Stakeholders that will set the framework for successful completion of the Project.

5.4 Regulatory Legislation Outline

The AE web page document Petrochemical Tool Kit - "Want to Build a Petrochemical Facility in Alberta" outlines the current legislation for in-situ thermal heavy oil plants and similar developments in Alberta; a copy of the outline is given in **Attachment 20**

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Attachment 1 - Glossary of Oil Sands Terms

PTAC

Expanding Heavy Oil and Bitumen Resources while Mitigating GHG Emissions and Increasing Sustainability - A Technology Roadmap

Appendix D – Glossary of Terms

Accessible Bitumen: Bitumen from deposits that are currently being produced with economic recoveries assigned to them by the AEUB.

AEUB: Alberta Energy and Utilities Board.

Barrel: One barrel is equal to:

- 42 U.S. gallons, or
- 158.99 litres, or
- 0.159 cubic metres.

Bitumen or Crude Bitumen: A highly viscous hydrocarbons mixture similar to crude oil that is too viscous to flow in its natural condition.

Blended Bitumen: Bitumen blended with diluent to reduce viscosity and density for the purpose of improving its ability to flow.

Carbonate Formation: Sub-surface deposits of calcium carbonate in various forms and physical states, which were created by reef building organisms over geologic time and subsequently buried.

Coal Bed Methane: Methane gas produced during the transformation of organic matter into coal and naturally found in coal deposits.

Composite Tails: Fine tailings combined with gypsum and sand as the tailings are deposited in order to allow the tailings to settle faster; Also known as consolidated tails.

Condensate: A hydrocarbon mixture generally composed of pentanes and heavier hydrocarbons recovered from natural gas processing plants.

Conventional Crude Oil: Crude oil which can be technically and economically produced using a well and normal production practices from an underground reservoir.

Cyclic Steam Stimulation (CSS): A bitumen recovery method using steam injection to establish communication, to heat the reservoir for reducing the viscosity of the oil, and to provide pressure for production. Oil production takes place in cycles, beginning with a period of steam injection, followed by a soak time and a period of production, all from the same well.

Density: Mass per unit volume.

DilBit: Blended bitumen where the diluent is condensate or naphtha.

DilSynBit: Blended bitumen where the diluent is condensate and synthetic crude oil.

Diluent: Light oil fractions or liquid hydrocarbon mixtures blended into crude bitumen for reducing bitumen viscosity and allowing transportation in pipelines.

Distillate: Fraction of crude oil that generally includes naphtha, diesel, kerosene and fuel oils.

Economic Strip Ratio: Ratio of overburden material covering mineable ore to mineable ore. This ratio is used to estimate the economic depth for surface mining.

Enhanced Oil Recovery: A method for increasing oil recovery from a reservoir beyond what would be obtained through primary recovery.

Established Reserves: The fraction of volume in place that is recoverable on the basis of current technology and present and anticipated economic conditions. Established reserves are calculated by applying a recovery factor to volume in place.

Glacial Till: Course and extremely heterogeneous till deposited by glaciers on top of underlying geologic deposits which at one time were covered by the glacier or ice sheet.

Greenhouse Gases (GHGs): Air emissions from operations, which are usually taken to include mainly carbon dioxide and methane from upstream oil and gas operations. Although water and Volatile Organic Compounds also contribute to the greenhouse gas effect.

Heavy Crude Oil: Crude oil with a density of 900 kg/m3 or greater.

Horizontal Well: A well that deviates from the vertical and is drilled horizontally along the pay zone.

Inaccessible Bitumen: Bitumen from deposits that are currently not being produced and assigned 0% potential recoveries by the AEUB or other regulators.

Initial Established Reserves: Established reserves before any production from the reservoir.

Initial Volume in Place: The volume in place before any production from the reservoir.

In Situ Recovery: Bitumen process for oil sands deposits too deep for surface mining.

Light-Medium Crude Oil: Crude oil with a density of less than 900 kg/m3.

Muskeg: A water-soaked layer of decaying plant material, one to three metres thick that supports the growth of shallow root trees such as black spruce and tamarack.

Oil Sands: The term is generally used to designate a naturally occurring mixture of uncemented sands and crude bitumen; its use also extends to mixtures of rock materials such as carbonates with bitumen, and to very heavy oil produced from the Oil Sands Area of Alberta.

Oil Sands Deposit: A heavy oil reservoir containing oil sands.

Overburden: The layers of sand, gravel and shale that overlie the oil sands and that must be removed for recovery by surface mining.

Primary Recovery: Recovery of crude oil from a reservoir by utilizing the natural energy available in the reservoir and conventional pumping techniques; also referred to as primary production.

Reclamation: The process of returning disturbed land to a stable, biologically-productive state.

Reservoir: A porous and permeable underground rock or sand formation containing a natural accumulation of crude oil.

Solvent: A suitable mixture of hydrocarbons ranging from methane to pentanes plus but consisting generally of methane to butanes for use in enhanced-recovery processes.

Steam-Assisted Gravity Drainage (SAGD): A bitumen recovery method generally using a pair of horizontal wells. Steam is continuously injected into the top horizontal well. Heated bitumen drains, by gravity, into the producing bottom horizontal well.

Sterilization: The designation of an otherwise recoverable deposit as unrecoverable, generally for environmental reasons.

Sustainability: Assumed to be a case that allows development while meeting an balance of economic, environmental and security factors which are acceptable to Canadian society.

SynBit: Blended bitumen where the diluent is synthetic crude oil.

Synthetic Crude Oil: Crude oil that is derived from crude bitumen. It is generally similar to light sweet crude oil but it may also contain sulphur compounds.

THAI: Toe to Heel Air Injection is a bitumen recovery method involving in situ combustion of some of the oil present in the reservoir in order to create heat and pressure that will mobilize another portion of the oil present in the reservoir. A horizontal well is used to produce the oil.

VAPEX™: Vaporized Extraction is a bitumen recovery method similar to SAGD in that it uses a pair of horizontal wells. However, a vaporized hydrocarbon solvent, instead of steam, is injected into the top horizontal well to reduce bitumen viscosity. Softened bitumen drains, by gravity, into the producing bottom horizontal well.

Viscosity: The measure of the resistance of a fluid to flow.

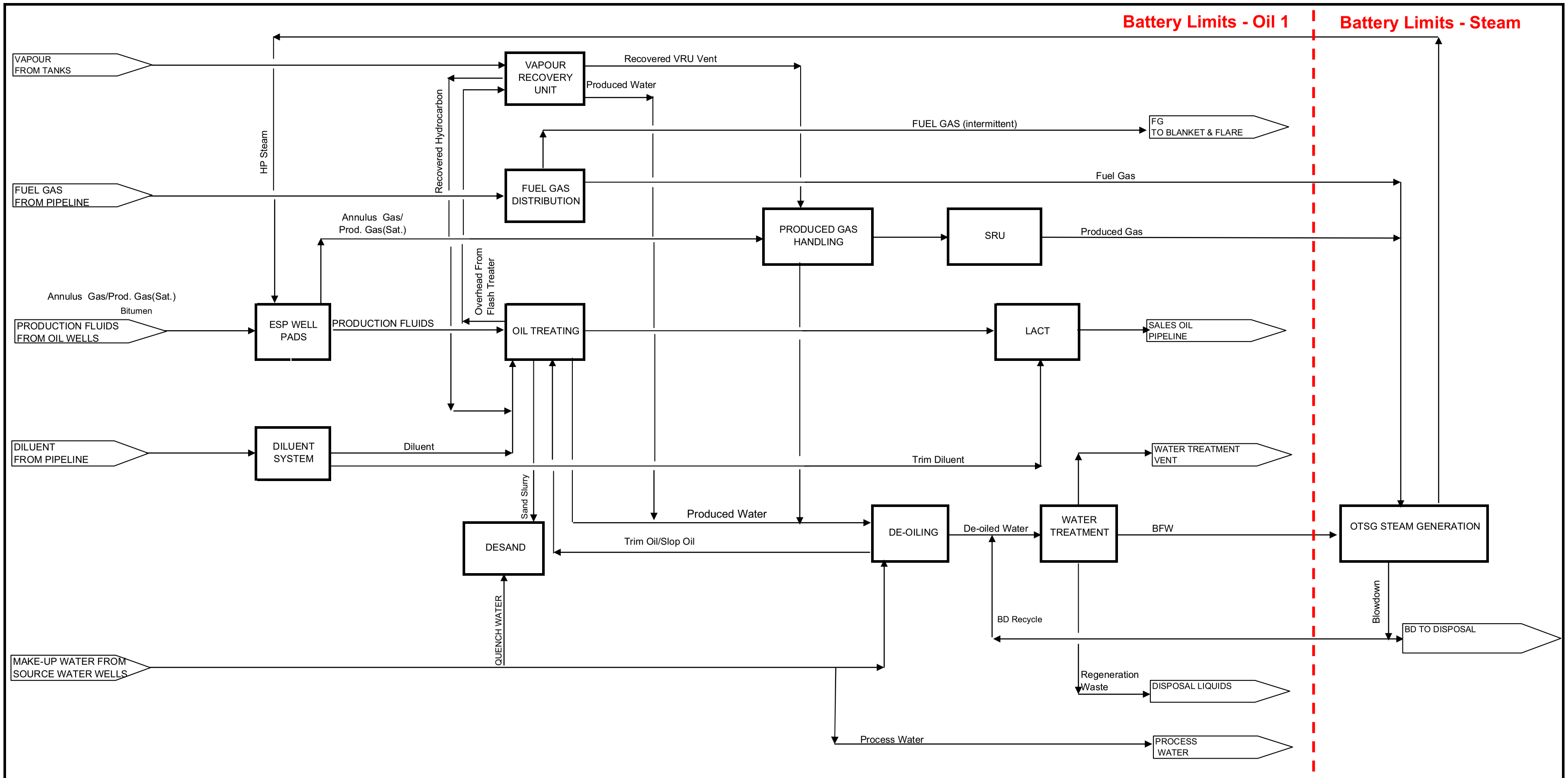
Volume in Place: The quantity of resources calculated or interpreted to exist in a reservoir. Volume in place is specifically proven by drilling, testing or production. It also includes the portion of contiguous resources that are interpreted to exist from geological, geophysical or similar information with reasonable certainty.

Ultimate Recoverable Potential: An estimate of the initial established reserves that will have been discovered by the time all exploratory and development activity have ceased. Ultimate recoverable potential includes initial established reserves from discovered resources and adds an estimate of future reserves additions, extension and revisions resulting from new discoveries. Discovered resources are those that have been confirmed by wells drilled while undiscovered resources are expected to be discovered by future drilling.

Ultimate Volume in Place: An estimate of the initial volume in place that will have been discovered by the time all exploratory and development activity has ceased. Ultimate volume in place includes initial volume in place and adds an estimate of future additions, extension and revisions resulting from new discoveries.

Unconventional Crude Oil: Crude oil that is not considered to be conventional crude oil.

Attachment 2 - BFD 1 - OTSG Case



DESIGN BASIS DESCRIPTION	REV.	DESCRIPTION	BY	DATE	CHK	APP.	CLIENT
	D	Updated	MD	22 Oct 08			
	C	Updated	MD	6 Oct 08			
	B	Updated					
	A	BFD 1	AM	August 25 2008			

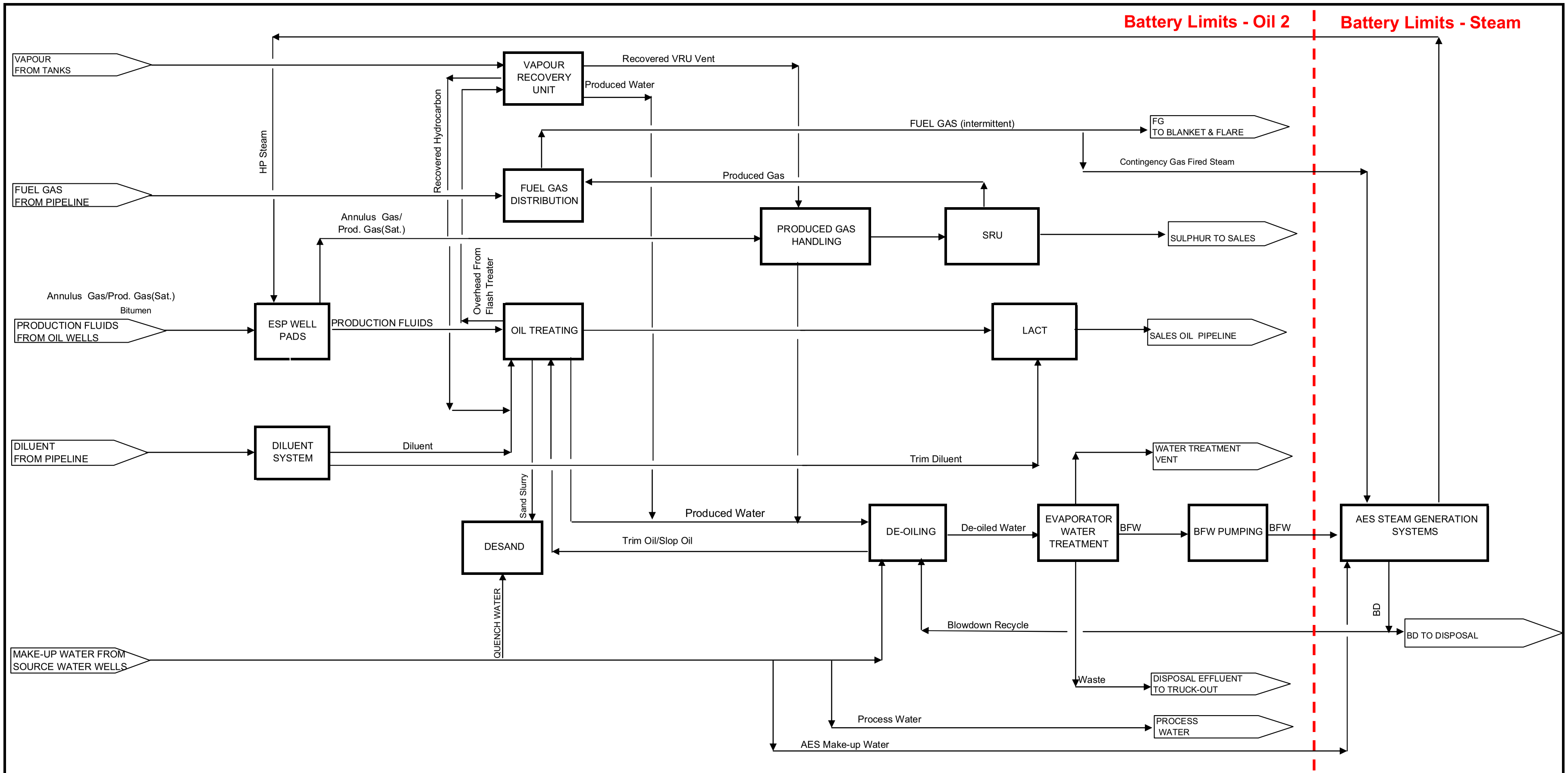
IMV Projects

TITLE

AES In-situ Thermal Recovery Plant
OTSG Current Practice Design
BLOCK FLOW DIAGRAM

SCALE	JOB NO.	DRAWING NO.	REV.
N.T.S.	Z07901	Attachment 2 - BFD 1	E

Attachment 3 -
BFD 2 - AES Steam Generator Case



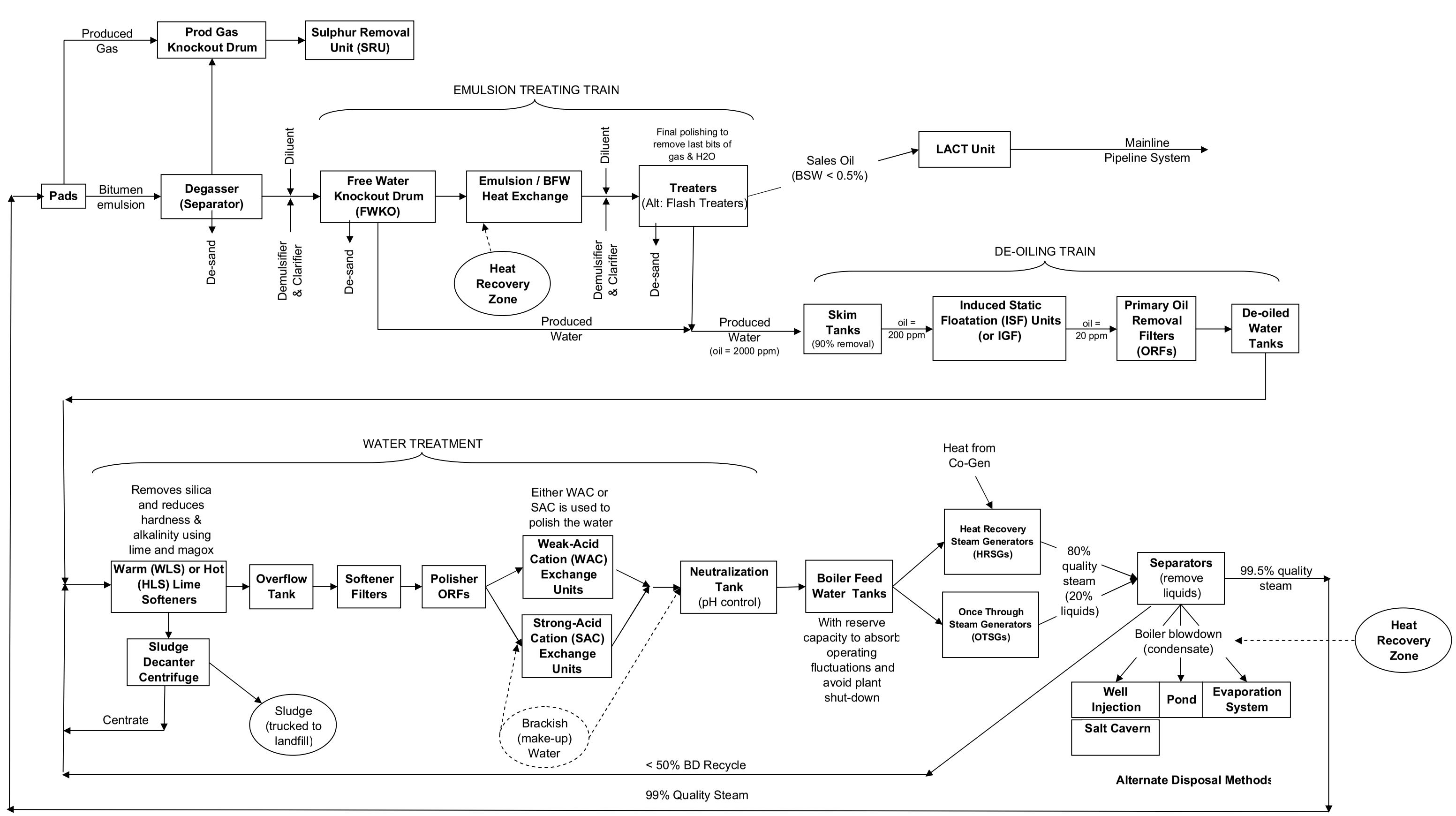
	REV.	DESCRIPTION	BY	DATE	CHK	APP.	CLIENT
	D	Updated	MD	22 Oct 08			
	C	Updated	MD	6 Oct 08			
	B	Updated					
	A	BFD 1	AM	August 25 2008			
DESIGN BASIS DESCRIPTION	REV.	DESCRIPTION	BY	DATE	CHK	APP.	CLIENT

IMV Projects

TITLE
AES In-situ Thermal Recovery Plant
AES Steam Generator Case
BLOCK FLOW DIAGRAM

SCALE	JOB NO.	DRAWING NO.	REV.
N.T.S.	Z07901	Attachment 3 - BFD 2	E

Attachment 4 -
BFD 3 - SAGD with Current Technology



DESIGN BASIS DESCRIPTION	REV.	DESCRIPTION	BY	DATE	CHK	APP.	CLIENT
	D	Updated	MD	22-Oct-08			
	C	Updated	MD	6-Oct-08			
	B	Updated					
	A	BFD 3	AM	August 25 2008			

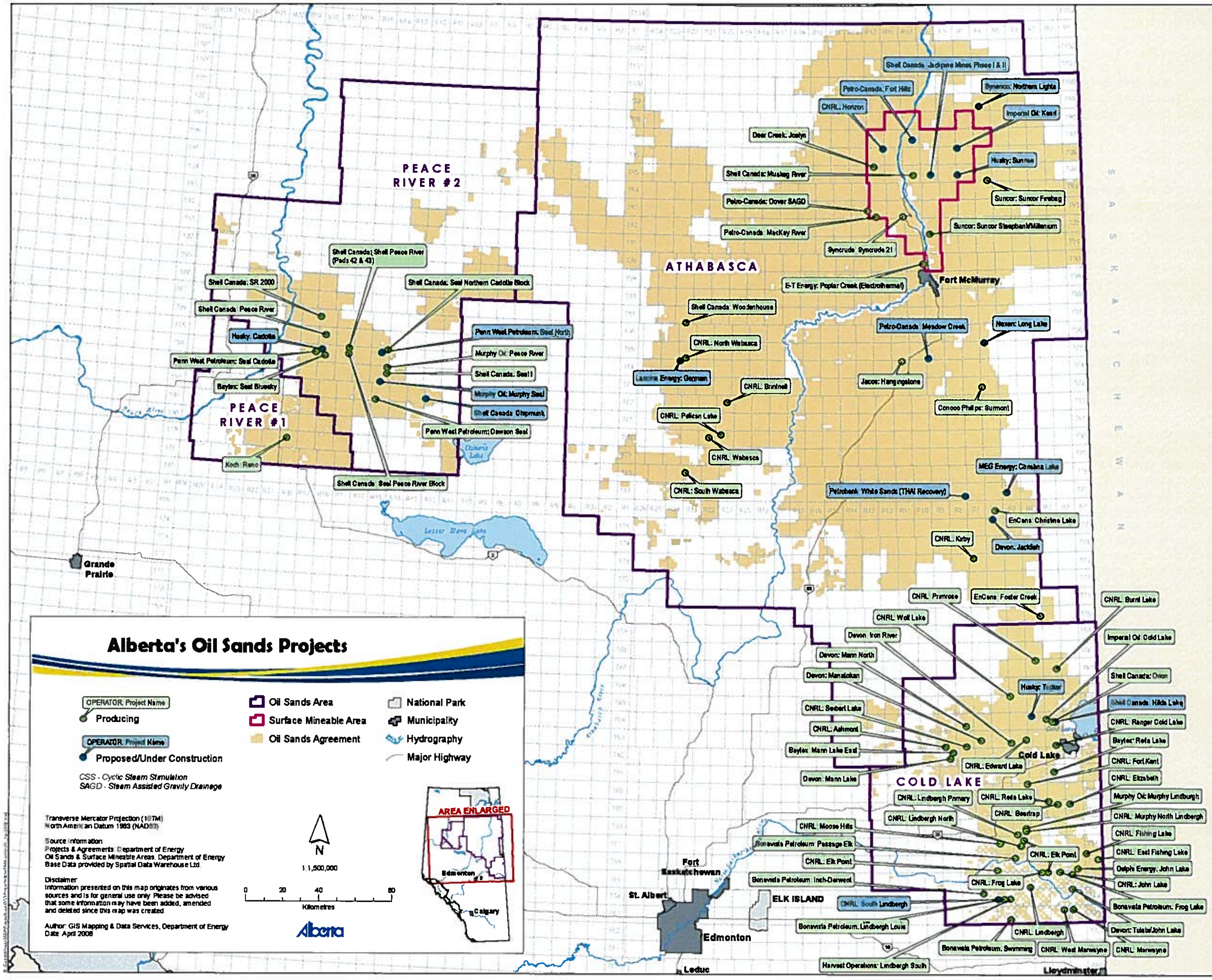
IMV Projects

TITLE

AES In-situ Thermal Recovery Plant
Typical SAGD Schematic Using the Current Technology
BLOCK FLOW DIAGRAM

SCALE	JOB NO.	DRAWING NO.	REV.
N.T.S.	Z07901	Attachment 4 - BFD 3	E

Attachment 5 -
Map of Alberta Oil Sands Projects



Athabasca Oil Sands Area	Stage of Development
Mining Projects	
Fort Hills	Proposed
Northern Lights	Proposed
Mining Projects with Upgraders	
Horizon	Under Construction
Jackpine Mines Phase I & II	Under Construction
Kearl	Proposed
Muskeg River	Producing
Suncor Steepbank/Millenium	Producing
Syncrude 21	Producing
SAGD Projects	
Christina Lake - EnCana	Producing
Christina Lake - MEG Energy	Under Construction
Dover SAGD	Producing
Foster Creek	Producing
Germain	Proposed
Hangingstone	Pilot Plant
Jackfish	Proposed
Joslyn	Producing
Kirby	Not Producing
MacKay River	Producing
Meadow Creek	Proposed
Suncor Firebag	Producing
Sunrise	Proposed
SAGD Projects with Upgraders	
Long Lake	Under Construction
Surmont	Producing
Primary Projects	
Brintnell	Producing
North Wabasca	Producing
Pelican Lake	Producing
South Wabasca	Producing
Wabasca	Producing
Woodenhouse	Producing
Other Projects	
Poplar Creek (Electrothermal)	Not Producing
White Sands (THAI Recovery)	Proposed
Cold Lake Oil Sands Area	
CSS Projects	
Cold Lake	Producing
Elk Point Crown Agreement	Producing
Lindbergh Crown Agreement	Producing
Murphy Lindburgh Crown Agreement	Producing
Primrose	Producing
SAGD Projects	
Burnt Lake	Producing
Hilda Lake	Proposed
Orion	Experimental
Tucker	Proposed
Wolf Lake	Producing
Primary Projects	
Ashmont	Producing
Beartrap	Producing
East Fishing Lake	Producing
Edward Lake	Producing
Elizabeth	Producing
Elk Point - CNRL	Producing
Elk Point - CNRL	Producing
Fishing Lake	Producing
Fort Kent	Producing
Frog Lake - CNRL	Producing
Frog Lake - Bonavista Petroleum	Producing
Inch-Derwent	Producing
Iron River	Producing
John Lake - Delphi Energy	Producing
John Lake - CNRL	Not Producing
Lindbergh Louis	Producing
Lindbergh North	Producing
Lindbergh Primary	Producing
Lindbergh South	Producing
Manatokan	Producing
Mann Lake	Producing
Mann Lake East	Producing
Mann North	Producing
Marwayne	Producing
Moose Hills	Producing
Murphy North Lindbergh	Producing
Passage Elk	Producing
Ranger Cold Lake	Producing
Reita Lake - CNRL	Producing
Reita Lake - Baytex	Producing
Seibert Lake	Producing
South Lindbergh	Proposed
Swimming	Producing
Tulabi/John Lake	Producing
West Marwayne	Producing
Peace River Oil Sands Area	
Primary Projects	
Cadotte	Proposed
Chipmunk	Proposed
Dawson Seal	Producing
Murphy Seal	Proposed
Peace River	Producing
Reno	Producing
Seal Bluesky	Producing
Seal I	Producing
Seal Cadotte	Pilot
Seal North	Under Construction
Seal Northern Cadotte Block	Producing
Seal Peace River Block	Producing
CSS Projects	
Peace River	Producing
Shell Peace River (Pads 42 & 43)	Producing
SR 2000	Producing

Attachment 6 -
Chemical Compositions of Main Water Streams:

- **Brackish Makeup**
- **Produced Water**
- **Warm Lime Softener Outlet**
- **Evaporator Outlet**

Summary of Chemical Compositions for AES Study Plant Interface Water Streams (3)

Typical Brackish Make-Up Water	
Parameters	**mg/L**
Calcium (Ca ++)	8
Magnesium (Mg ++)	8
Sodium (Na ++)	1600
Potassium (K ++)	4.5
Iron (Fe++)	1
Manganese (Mn++)	0.01
Bicarbonate (HCO_3-)	850
Carbonate (CO_3-)	25
Sulphate (SO_4-)	1.1
Chloride (Cl-)	1900
Total Dissolved Solids	5000
Ph	8.3
Total Hardness (Ca & Mg)	50 as $CaCO_3$
Total Alkalinity	700 as $CaCO_3$
Silica (SiO_2)	16 as SiO_2
Inlet Turbidity	5 NTU

Typical Water Treatment Chemistry Comparison - SAGD Facility (from GE - RCCI Analysis)							
Parameters		**Produced Water - INLET (1)**		**Warm Line Softener - OUTLET**		**Evaporator - OUTLET**	
		mg/l as ion	mg/l as $CaCO_3$	mg/l as ion	mg/l as $CaCO_3$	mg/l as ion	mg/l as $CaCO_3$
Calcium (Ca ++)		22.0	55	0.04	0.1	0.023	0.058
Magnesium (Mg ++)		11	45.3	0.02	0.1	0.012	0.049
Sodium (Na ++)		780	1700.4	852.9	1800.5	1.088	2.372
Potassium (K ++)		13	16.6	13	16.6	0.014	0.018
Iron (Fe++)		0.3	0.5	0	0	0.0003	0.0005
Manganese (Mn++)		0	0	0	0	0	0
Hydrogen (H+)		0	0	0	0	0	0
Barium (BA++)		0	0	0	0	0	0
Strontium (Sr++)		0	0	0	0	0	0
Sum Cations			**1817.9**		**1817.3**		**2.5**
Bicarbonate (HCO_3-)		489	401	0	0	0.512	0.4
Carbonate (CO_3-)		0	0	240.1	401	0	0
Hydroxide (OH-)		0	0	0.5	1.6	0	0.5
Sulphate (SO_4-)		58	60.3	58	60.3	0.062	0.1
Chloride (Cl-)		962	1356.4	962	1356.4	1.022	1.4
Sum Anions			**1817.7**		**1819.3**		**2.4**
Total Dissolved Solids		2585.3		2149.1		3	
pH (Units)		7.7		9.5		9	
Total Hardness			100.9		0.2		0.1
Carbon Dioxide (CO_2)							
Silica (SiO_2)		250		50		0.266	
Insoluble Oil (oil & grease)		20		0		0.021	
Total Organic Carbon							
Normal (2)	Non-volatile organics	200		200		0.6	0.6
	Volatile organics						30
Maximum (2)	Non-volatile organics	300		300		0.9	0.9
	Volatile organics						46
Temperature ^0C		85		85		90	

Notes
1. Approximated chemical composition in PW from De-oiling stage.
2. Volatile organics will carry over into drum boiler steam.
3. The values in these tables have been taken from several differing sources; they are indicative only, they have not been the subject of integrated, process engineering mass, chemical or water balance analyses by IMV.

Attachment 7 –
ERCB Draft Requirements for Water Use

The ERCB issued a draft directive for review of the Requirements for Water Measurement, Reporting and Use for Thermal In-Situ Oil Sand Schemes. The summary below lists the use criteria for each class of water:

- **Produced Water Use**

  The criterion for thermal plant operations water recycle is defined in the equation:

  Produced water use (%) =

  $$\frac{[(\text{Total Steam Injected} + \text{Total Water Disposal}) - \text{Total Fresh In} - \text{Total Brackish In}] \times 100}{(\text{Total Steam Injected} + \text{Total Water Disposal})}$$

  Produced water use for each calendar year must not be less than:

  90% if fresh water only is used for make up, or

  75% if brackish and fresh water are used for make up

- **Fresh Water Make-Up**

  Fresh water make-up is calculated using the following equation:

  $$\text{Fresh water Make-up (\%)} = \frac{(\text{Total Fresh Water In}) \times 100}{(\text{Total Steam Injected} + \text{Total Water Disposal})}$$

  The maximum limit of fresh water make-up on an annual basis = 10%.

- **Brackish Water Make-Up**

  Brackish water make-up is calculated using the following equation:

  $$\text{Brackish water Make-up (\%)} = \frac{(\text{Total Brackish Water In}) \times 100}{(\text{Total Steam Injected} + \text{Total Water Disposal})}$$

  The maximum limit of brackish water make-up on an annual basis = (25% - Fresh water makeup). Brackish water make up can be a maximum of 25%, but only if there is no fresh water make up.

  The total make up water (Brackish + Fresh) must not exceed 25% on an annual basis.

Attachment 8 - Standby Steam Generator Cost Estimates – OTSG and Drum Boiler Alternates

IMV Projects

LEVEL 1
OTSG Option

Client: MPR Associates Inc.
Project: Oil Sand Replecement Study (OTSG Option)
IMV Job No: Z07902

BY: MA
DATE: Nov.13/08
REV: A

COST CODE			ITEM DESCRIPTION	MATERIAL			FIELD LABOUR		SERVICE CONTRACT (S/C)			COSTS			TOTAL
				Quantity		$ / Unit	Quantity		Quantity		$ / Unit				
Client	IMV	% OF TIC		EXP'D	UNIT	EXP'D	EXP'D	UNIT	EXP'D	UNIT	EXP'D	MAT.	SHOP	FIELD	
		3%	Piperacks				4,432	hrs				$ -	$ 2,478,094	$ 497,906	$ 2,976,000
		2%	Field Erected Buildings				5,591	hrs				$ -	$ -	$ 1,620,000	$ 1,620,000
		62%	Mechanical Equipment				158,346	hrs				$ 26,592,451	$ 13,497,859	$ 21,945,198	$ 62,035,508
			Total Direct Costs				168,369	hrs				**$ 26,592,451**	**$ 15,975,953**	**$ 24,063,104**	**$ 66,631,508**
		2%	Camp Cost (Excluding Camp Initial Setup Cost)	$ 124	manday									$ 2,413,917	$ 2,413,917
		4%	Construction Management Team	6%	of TDC		26,149	hrs						$ 3,997,890	$ 3,997,890
			Total Indirect Costs				26,149	hrs				**$ -**	**$ -**	**$ 6,411,808**	**$ 6,411,808**
		10%	Engineering and Procurement	15%	of TDC									$ 9,994,726	$ 9,994,726
		1%	Owners cost	1%	of TDC									$ 666,315	$ 666,315
		3%	Commissioning	4%	of TDC									$ 2,665,260	$ 2,665,260
			Total Costs				194,518	hrs				**$ 26,592,451**	**$ 15,975,953**	**$ 43,801,214**	**$ 86,369,617**
		13%	Contingency	15%											$ 12,955,443
		100%	**Total Installed Cost (Rounded)**				194,518	hrs							**$ 99,400,000**

Canadian Dollars

IMV Projects

LEVEL 1
Boiler Option

Client: MPR Associates Inc.
Project: Oil Sand Replecement Study (Boiler Option)
IMV Job No: Z07902

BY: MA
DATE: Nov.13/08
REV: A

COST CODE			ITEM DESCRIPTION	MATERIAL			FIELD LABOUR		SERVICE CONTRACT (S/C)			COSTS			TOTAL
				Quantity		$ / Unit	Quantity		Quantity		$ / Unit				
Client	IMV	% OF TIC		EXP'D	UNIT	EXP'D	EXP'D	UNIT	EXP'D	UNIT	EXP'D	MAT.	SHOP	FIELD	
		2%	Piperacks				2,216	hrs				$ -	$ 1,239,047	$ 248,953	$ 1,488,000
		1%	Field Erected Buildings				3,261	hrs				$ -	$ -	$ 945,000	$ 945,000
		64%	Mechanical Equipment				132,135	hrs				$ 22,442,339	$ 11,193,163	$ 18,201,610	$ 51,837,113
			Total Direct Costs				137,612	hrs				$ 22,442,339	$ 12,432,210	$ 19,395,563	$ 54,270,113
		2%	Camp Cost (Excluding Camp Initial Setup Cost)	$ 124	manday									$ 1,972,034	$ 1,972,034
		4%	Construction Management Team	6%	of TDC		21,298	hrs						$ 3,256,207	$ 3,256,207
			Total Indirect Costs				21,298	hrs				$ -	$ -	$ 5,228,241	$ 5,228,241
		10%	Engineering and Procurement	15%	of TDC									$ 8,140,517	$ 8,140,517
		1%	Owners cost	1%	of TDC									$ 542,701	$ 542,701
		3%	Commissioning	4%	of TDC									$ 2,170,805	$ 2,170,805
			Total Costs				158,910	hrs				$ 22,442,339	$ 12,432,210	$ 35,477,827	$ 70,352,376
		13%	Contingency	15%											$ 10,552,856
		100%	Total Installed Cost (Rounded)				158,910	hrs							$ 81,000,000

Canadian Dollars

Attachment 9 -

Electrical Load List for 30,000 bopd Phase Using Current Technology

High Temperature Reactor For Oil Sands Application Study
Typical Load List for a 30,000 BOPD SAGD Plant

Description	Motor Nameplate (kW)	Usage	VFD (Y/N)	Emer. Power (Y/N)	Emergency Power (kW)
Oil Removal Filter Agitator Motor	30	Int.	N	N	0
Oil Removal Filter Agitator Motor	30	Int.	N	N	0
Oil Removal Filter Agitator Motor	30	Int.	N	N	0
Softener Filter Agitator Motor	30	Int.	N	N	0
Softener Filter Agitator Motor	30	Int.	N	N	0
Softener Filter Agitator Motor	30	Int.	N	N	0
Softener Filter Agitator Motor	30	Int.	N	N	0
MagOx Slurry Mixer Motor	19.0	Int.	N	Y	19
Lime Slurry Mixer Motor	19.0	Int.	N	Y	19
Sludge Centrifuge Motor	56.0	Cont.	N	N	0
MagOx Rotary Valve Motor	2.4	Int.	N	N	
MCC/Electrical Building Exhaust Fan Motor	0.25	Int.	N	Y	0.25
MCC/Electrical Building Exhaust Fan Motor	0.25	Int.	N	Y	0.25
Steam Generator Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
Steam Generator Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
Steam Generator Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
Steam Generator Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
Steam Generator Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37

Description	Motor Nameplate (kW)	Usage	VFD (Y/N)	Emer. Power (Y/N)	Emergency Power (kW)
Steam Generator Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
Steam Generator Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
Steam Generator Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
Steam Generator Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
Steam Generator Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
Steam Generator Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
Steam Generator Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
BFW Charge Pump Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
BFW Charge Pump Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
BFW Charge Pump Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Lab Exhaust Fan Motor	0.06	Int.	N	Y	0.06
MCC/Electrical Building Exhaust Fan Motor	0.25	Int.	N	Y	0.25
FWKO/Treater Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37

Description	Motor Nameplate (kW)	Usage	VFD (Y/N)	Emer. Power (Y/N)	Emergency Power (kW)
FWKO/Treater Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
Desand/Decant Pump Building Exhaust Fan Motor	0.25	Int.	N	Y	0.25
Flash Treater Building Exhaust Fan Motor	0.56	Int.	N	Y	0.56
Flash Treater Building Exhaust Fan Motor	0.56	Int.	N	Y	0.56
FWKO Sample Box Vent Hood and Fan Motor	0.75	Int.	N	Y	0.75
FWKO Sample Box Vent Hood and Fan Motor	0.75	Int.	N	Y	0.75
Treater Sample Box Vent Hood and Fan Motor	0.75	Int.	N	Y	0.75
Treater Sample Box Vent Hood and Fan Motor	0.75	Int.	N	Y	0.75
Treater Sample Box Vent Hood and Fan Motor	0.75	Int.	N	Y	0.75

Description	Motor Nameplate (kW)	Usage	VFD (Y/N)	Emer. Power (Y/N)	Emergency Power (kW)
Treater Sample Box Vent Hood and Fan Motor	0.75	Int.	N	Y	0.75
FWKO/Treater Building Laboratory Vent Hood and Fan	0.75	Int.	N	Y	0.75
VRU Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
VRU Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
VRU Building Exhaust Fan Motor	0.37	Int.	N	Y	
VRU Building Exhaust Fan Motor	0.37	Int.	N	Y	
LACT Booster Pump Building Wall Exhaust Fan Motor	0.37	Int.	N	Y	
SRU Building Exhaust Fan Motor	0.25	Int.	N	Y	0.25
Emergency Generator Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
Instrument Air Package Building Exhaust Fan Motor	0.25	Int.	N	Y	
Glycol Heater Building Exhaust Fan Motor	0.03	Int.	N	Y	0.03
Deoiling Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
Deoiling Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
Deoiling Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
Deoiling Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
MCC/ Electrical (BU-0704) Exhaust Fan Motor	0.25	Int.	N	Y	0.25
MCC/Electrical Building Exhaust Fan Motor	0.25	Int.	N	Y	0.25
Culligan Building Exhaust Fan Motor	0.25	Int.	N	Y	0.25

Description	Motor Nameplate (kW)	Usage	VFD (Y/N)	Emer. Power (Y/N)	Emergency Power (kW)
Lime Slurry Tank Exhaust Fan Motor	0.12	Int.	N	Y	
Lime Skirt Exhaust Fan Motor	0.12	Int.	N	Y	0.12
Water Treatment Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
Water Treatment Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
Water Treatment Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
Water Treatment Building Exhaust Fan Motor	0.37	Int.	N	Y	0.37
MagOx Skirt Exhaust Fan Motor	0.12	Int.	N	Y	0.12
WLS Building Exhaust Fan Motor	0.25	Int.	N	Y	
WLS Building Exhaust Fan Motor	0.25	Int.	N	Y	
MagOx Slurry Tank Exhaust Fan Motor	0.12	Int.	N	Y	0.12
BFW Charge Pump Lube Oil Heater	1.00	Int.	N	N	
BFW Charge Pump Lube Oil Heater	1.00	Int.	N	N	
BFW Charge Pump Lube Oil Heater	1.00	Int.	N	N	
MCC/Electrical Building Electric Unit Heater Motor	0.37	Int.	N	Y	0.37
MCC/Electrical Building Electric Unit Heater Motor	0.37	Int.	N	N	0
MCC/Electrical Building Electric Unit Heater Motor	0.19	Int.	N	Y	0.19
MCC/Electrical Building Electric Unit Heater Motor	0.19	Int.	N	N	0

Description	Motor Nameplate (kW)	Usage	VFD (Y/N)	Emer. Power (Y/N)	Emergency Power (kW)
MCC/ Electrical Room (BU-0704) Electric Unit Heater Motor	0.19	Int.	N	Y	0.19
MCC/ Electrical Room (BU-0704) Electric Unit Heater Motor	0.19	Int.	N	N	0
MCC/Electrical Building Electric Unit Heater Motor	0.19	Int.	N	Y	0.19
MCC/Electrical Building Electric Unit Heater Motor	0.19	Int.	N	N	0
Inlet Vapour Air Cooler Motor	22.4	Cont.	Y	N	0
Inlet Vapour Air Cooler Motor	22.4	Cont.	N	N	0
Glycol Air Cooler Motor	30	Cont.	N	N	0
Glycol Air Cooler Motor	30	Cont.	Y	N	0
Glycol Air Cooler Motor	30	Cont.	N	N	0
Glycol Air Cooler Motor	30	Cont.	Y	N	0
Glycol Air Cooler Motor	30	Cont.	N	N	0
Glycol Air Cooler Motor	30	Cont.	Y	N	0
Glycol Air Cooler Motor	30	Cont.	N	N	0
Glycol Air Cooler Motor	30	Cont.	Y	N	0
Glycol Air Cooler Motor	30	Cont.	N	N	0
Glycol Air Cooler Motor	30	Cont.	Y	N	0
Glycol Air Cooler Motor	30	Cont.	N	N	0

Description	Motor Nameplate (kW)	Usage	VFD (Y/N)	Emer. Power (Y/N)	Emergency Power (kW)
Glycol Air Cooler Motor	30	Cont.	Y	N	0
Glycol Air Cooler Motor	30	Cont.	N	N	0
Glycol Air Cooler Motor	30	Cont.	Y	N	0
Glycol Air Cooler Motor	30	Cont.	N	N	0
Glycol Air Cooler Motor	30	Cont.	Y	N	0
Glycol Air Cooler Motor	30	Cont.	N	N	0
Glycol Air Cooler Motor	30	Cont.	Y	N	0
Glycol Air Cooler Motor	30	Cont.	N	N	0
Glycol Air Cooler Motor	30	Cont.	Y	N	0
Emergency Generator Cooler Fan Motor	56	Int.	N	Y	56
Sludge Centrifuge Oil Cooler Motor	0.75	Cont.	N	N	0
Steam Generator Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Steam Generator Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Steam Generator Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Steam Generator Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Steam Generator Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Steam Generator Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Steam Generator Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37

Description	Motor Nameplate (kW)	Usage	VFD (Y/N)	Emer. Power (Y/N)	Emergency Power (kW)
Steam Generator Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Steam Generator Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Steam Generator Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Steam Generator Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Steam Generator Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Steam Generator Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Steam Generator Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Steam Generator Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Steam Generator Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Steam Generator Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Steam Generator Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Steam Generator Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Steam Generator Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Steam Generator Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Steam Generator Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Steam Generator Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Steam Generator Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Steam Generator Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37

Description	Motor Nameplate (kW)	Usage	VFD (Y/N)	Emer. Power (Y/N)	Emergency Power (kW)
Steam Generator Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Steam Generator Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Steam Generator Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Steam Generator Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Steam Generator Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
BFW Charge Pump Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
BFW Charge Pump Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
BFW Charge Pump Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
BFW Charge Pump Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
BFW Charge Pump Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
BFW Charge Pump Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
BFW Charge Pump Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
BFW Charge Pump Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
BFW Charge Pump Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
BFW Charge Pump Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37

Description	Motor Nameplate (kW)	Usage	VFD (Y/N)	Emer. Power (Y/N)	Emergency Power (kW)
FWKO/Treater Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37

Description	Motor Nameplate (kW)	Usage	VFD (Y/N)	Emer. Power (Y/N)	Emergency Power (kW)
FWKO/Treater Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
FWKO/Treater Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Desand/Decant Pump Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Flash Treater Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Flash Treater Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
LACT Booster Pump Building Glycol Unit Heater Motor	0.37	Int.	N	Y	
LACT Booster Pump Building Glycol Unit Heater Motor	0.37	Int.	N	Y	

Description	Motor Nameplate (kW)	Usage	VFD (Y/N)	Emer. Power (Y/N)	Emergency Power (kW)
VRU Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
VRU Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
VRU Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
VRU Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
VRU Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Emergency Generator Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Glycol Heater Building Glycol Unit Heater Motor	0.19	Int.	N	Y	0.19
SRU Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Instrument Air Package Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Deoiling Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Deoiling Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Deoiling Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Deoiling Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Deoiling Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Deoiling Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Deoiling Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Deoiling Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Deoiling Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37

Description	Motor Nameplate (kW)	Usage	VFD (Y/N)	Emer. Power (Y/N)	Emergency Power (kW)
Deoiling Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Water Treatment Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Water Treatment Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Water Treatment Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Water Treatment Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Water Treatment Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Water Treatment Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Water Treatment Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Water Treatment Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Water Treatment Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Water Treatment Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Water Treatment Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
Water Treatment Building Glycol Unit Heater Motor	0.37	Int.	N	Y	0.37
WLS Building Glycol Heater Motor	0.37	Int.	N	Y	0.373
WLS Building Glycol Heater Motor	0.37	Int.	N	Y	0.373
BU-0808 Glycol Unit Heater Motor	0.37	Int.	N	Y	
Combustion Air Blower Motor	298	Cont.	N	N	0
Combustion Air Blower Motor	298	Cont.	N	N	0

Description	Motor Nameplate (kW)	Usage	VFD (Y/N)	Emer. Power (Y/N)	Emergency Power (kW)
Combustion Air Blower Motor	298	Cont.	N	N	0
Combustion Air Blower Motor	298	Cont.	N	N	0
Combustion Air Blower Motor	298	Cont.	N	N	0
Combustion Air Blower Motor	298	Cont.	N	N	0
VRU Compressor Motor	187	Cont.	N	N	0
VRU Compressor Motor	187	Cont.	N	N	0
VRU Compressor Motor	187	Spare	N	N	0
VRU Compressor Motor	187	Spare	N	N	0
Glycol Heater Blower Motor	45	Cont.	N	Y	44.8
Instrument Air Compressor Motor	149	Int.	N	Y	149
Instrument Air Compressor Motor	149	Int.	N	Y	149
Instrument Air Compressor Motor	149	Int.	N	Y	149
SRU Process Air Compressor Motor	19	Cont.	N	N	0
BFW Booster Pump Motor	298	Cont.	N	N	0
BFW Booster Pump Motor	298	Cont.	N	N	0
BFW Booster Pump Motor	298	Cont.	N	N	0
BFW Charge Pump Motor	1865	Cont.	N	N	0
BFW Charge Pump Motor	1865	Cont.	N	N	0

Description	Motor Nameplate (kW)	Usage	VFD (Y/N)	Emer. Power (Y/N)	Emergency Power (kW)
BFW Charge Pump Motor	1865	Cont.	N	N	0
Chelant Injection Pump Motor	0.37	Cont.	Y	N	0
Chelant Injection Pump Motor	0.37	Cont.	Y	N	0
Filming Amine Injection Pump Motor	0.37	Cont.	Y	N	0
BFW Charge Pump Auxillary Lube Oil Pump Motor	1.5	Cont.	N	N	0
BFW Charge Pump Auxillary Lube Oil Pump Motor	1.5	Cont.	N	N	0
BFW Charge Pump Auxillary Lube Oil Pump Motor	1.5	Cont.	N	N	0
Steam Generator Bldg Sump Pump Motor	7.5	Int.	N	Y	7.5
Flash Treater Oil Pump Motor	45	Int.	N	N	0
Flash Treater Oil Pump Motor	45	Int.	N	N	0
Flash Treater OVHD Separator Liquid Pump Motor	1.1	Int.	N	N	0
Flash Treater OVHD Separator Liquid Pump Motor	1.1	Int.	N	N	0
Flash Treater OVHD Separator Liquid Pump Motor	1.1	Int.	N	N	0
Desand Jet Water Pump Motor	30	Int.	N	N	0
Demulsifier Injection Pump Motor	0.37	Cont.	Y	N	0
Demulsifier Injection Pump Motor	0.37	Cont.	Y	N	0
Demulsifier Injection Pump Motor	0.37	Cont.	Y	N	0
Demulsifier Injection Pump Motor	0.37	Cont.	Y	N	0

Description	Motor Nameplate (kW)	Usage	VFD (Y/N)	Emer. Power (Y/N)	Emergency Power (kW)
Clarifier Injection Pump Motor	0.37	Cont.	Y	N	0
Clarifier Injection Pump Motor	0.37	Cont.	Y	N	0
Clarifier Injection Pump Motor	0.37	Cont.	Y	N	0
Clarifier Injection Pump Motor	0.37	Cont.	Y	N	0
Flash Oil Recycle Pump Motor	11.2	Int.	N	N	0
Flash Treater Solids Pumps Motor	7.5	Int.	N	N	0
Desand Tank Decant Pump Motor	7.5	Int.	N	N	0
Desand Tank Decant Pump Motor	7.5	Spare	N	N	0
Desand Tank Vapour Separator Pump Motor	11.2	Int.	N	N	0
FWKO/Treater Building Sump Pump Motor	7.5	Int.	N	Y	7.5
Seal Flush Water Booster Pump Motor	1.1	Int.	N	N	0
Demulsifier Transfer Pump Motor	2.2	Int.	N	N	0
Clarifier Circulation/Transfer Pump Motor	3.7	Cont.	N	N	
Clarifier Circulation/Transfer Pump Motor	3.7	Int.	N	N	
LACT Booster Pump Motor	187	Cont.	N	N	0
LACT Booster Pump Motor	187	Cont.	N	N	0
Diluent Pump Motor	93	Cont.	N	N	0
Diluent Pump Motor	93	Cont.	N	N	0

Description	Motor Nameplate (kW)	Usage	VFD (Y/N)	Emer. Power (Y/N)	Emergency Power (kW)
VRU Suction Scrubber Pump Motor	11	Int.	N	N	0
VRU Suction Scrubber Pump Motor	11	Spare	N	N	0
Glycol Circulation Pump Motor	187	Cont.	N	Y	186.5
Glycol Circulation Pump Motor	187	Cont.	N	Y	186.5
Methanol Pump Motor	0.75	Int.	Y	Y	0.75
Fuel Transfer Pump Motor	0.25	Int.	N	Y	0.25
Oil Recycle Pump Motor	11	Int.	Y	N	
Oil Recycle Pump Motor	11	Spare	Y	N	
Water Recycle Pump Motor	5.6	Int.	N	N	
Water Recycle Pump Motor	5.6	Int.	N	N	
Deoiled Water Pump Motor	44.80	Cont.	N	N	0
Deoiled Water Pump Motor	44.80	Cont.	N	N	0
Deoiled Water Pump Motor	45	Cont.	N	N	0
ORF Feed Pump Motor	149	Cont.	N	N	0
ORF Feed Pump Motor	149.1	Cont.	N	N	0
Deoiling Building Sump Pump Motor	3.7	Int.	N	Y	3.7
De-Oiling Polymer Pump Motor	0.6	Cont.	Y	N	0
De-Oiling Polymer Pump Motor	0.6	Cont.	Y	N	0
IGF Eductor Feed Pump Motor	44.7		N	N	

Description	Motor Nameplate (kW)	Usage	VFD (Y/N)	Emer. Power (Y/N)	Emergency Power (kW)
IGF Eductor Feed Pump Motor	44.70		N	N	
IGF Eductor Feed Pump Motor	44.70		N	N	
IGF Eductor Feed Pump Motor	44.70		N	N	
Soft Make-Up Water Pump Motor	149	Cont.	N	N	0
Sludge Recycle Pump Motor	15	Cont.	N	Y	14.9
Sludge Recycle Pump Motor	15	Spare	N	Y	14.9
MagOx Slurry Pump Motor	15	Cont.	N	N	
MagOx Slurry Pump Motor	15	Spare	N	N	
Lime Slurry Pump Motor	15	Cont.	N	N	
Lime Slurry Pump Motor	15	Spare	N	N	
Sludge Waste Pump Motor	7.5	Spare	Y	N	0
Raw Brackish Water Pump Motor	75	Cont.	N	N	0
Sludge Centrifuge Oil Pump Motor	0.75	Cont.	N	N	0
Filter Feed Pump Motor	187	Cont.	N	N	0
Centrifuge Feed Pump Motor	11	Cont.	Y	N	0

Description	Motor Nameplate (kW)	Usage	VFD (Y/N)	Emer. Power (Y/N)	Emergency Power (kW)
Polymer Pump Motor	TBA	Int.	N	N	
Polymer Pump Motor	TBA	Int.	N	N	
Produced Water Booster Pump Motor	148	Cont.	Y	N	0
Produced Water Booster Pump Motor	148	Cont.	Y	N	0
Produced Water Booster Pump Motor	148	Spare	Y	N	
Water Treatment Building Sump Pump Motor	7.5	Int.	N	Y	7.5
Culligan Building Sump Pump Motor	TBA	Int.	N	Y	
Sludge Pump Building Sump Pump Motor	7.5	Int.	N	Y	7.5
Lime/MagOx Building Sump Pump Motor	7.5	Int.	N	Y	7.5
MagOx Vibrating Bin Discharger Motor	TBA	Int.	N	N	
WLS Turbine Drive Motor	11	Cont.	Y	Y	
WLS Rake Drive Motor	3.7	Cont.	Y	Y	
Vibrating Bin Discharger Motor	TBA	Int.	N	N	
Lime Rotary Valve Motor	TBA	Int.	N	N	
BFW Charge Pump Discharge Motor Operated Valve	2.4	Int.	N	N	
BFW Charge Pump Discharge Motor Operated Valve	2.4	Int.	N	N	
BFW Charge Pump Discharge Motor Operated Valve	2.4	Int.	N	N	
Convection Section Motor Operated Valve	2.4	Int.	N	N	

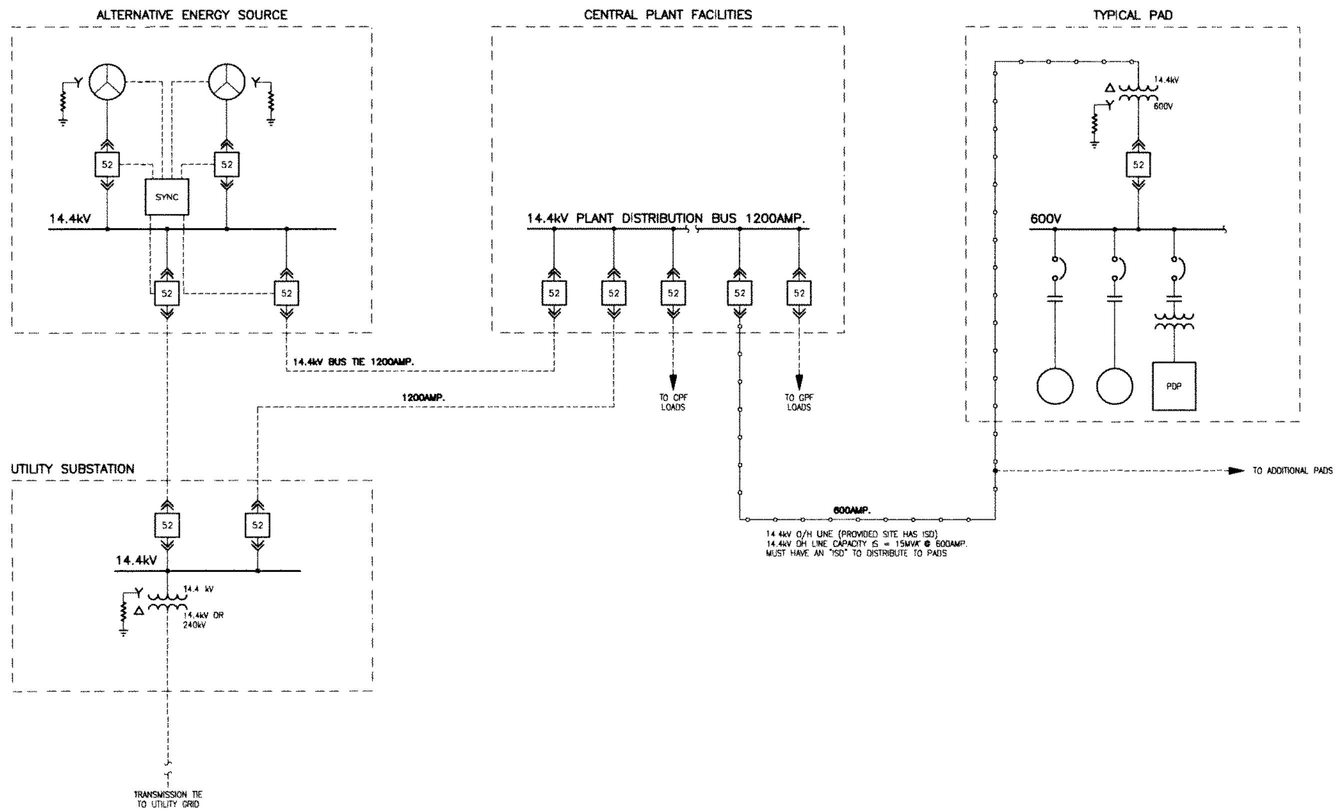
Description	Motor Nameplate (kW)	Usage	VFD (Y/N)	Emer. Power (Y/N)	Emergency Power (kW)
Radiant Section Motor Operated Valve	2.4	Int.	N	N	
Convection Section Motor Operated Valve	2.4	Int.	N	N	
Radiant Section Motor Operated Valve	2.4	Int.	N	N	
Convection Section Motor Operated Valve	2.4	Int.	N	N	
Radiant Section Motor Operated Valve	2.4	Int.	N	N	
Convection Section Motor Operated Valve	2.4	Int.	N	N	
Radiant Section Motor Operated Valve	2.4	Int.	N	N	
Convection Section Motor Operated Valve	2.4	Int.	N	N	
Radiant Section Motor Operated Valve	2.4	Int.	N	N	
Convection Section Motor Operated Valve	2.4	Int.	N	N	
Radiant Section Motor Operated Valve	2.4	Int.	N	N	
WLS Rake Lift Motor	1.1	Int.	N	Y	

Total connected emergency power ----> 1097 kW

Total Electrical power 13456 KW

Attachment 10 – Electrical Single Line Diagram - Distribution with ISD

DISTRIBUTION ASSUMING OWNER HAS AN ISD



NOTES:

1. VOLTAGE OUTPUT ON ALTERNATORS ARE TYPICALLY 14.4kV.
2. TRANSMISSION VOLTAGES ARE 14.4kV OR 240kV.
3. AES & UTILITY SUBSTATION SHOULD BE CLOSE COUPLED ie <50m FROM ALTERNATORS SO THAT 2000A BUS TIES CAN BE USED.
4. TYPICAL 30000 BPD SAGD IS 32MVA PEAK OR 1285AMPS @ 14.4kV.
5. "ISD" MEANS INDUSTRIAL SITE DESIGNATION FROM AESO.
6. "AESO" MEANS ALBERTA ELECTRICAL SYSTEM OPERATOR.

LEGEND:

- WIRING
- FIELD WIRING
- BUS BAR
- O/H LINE

DRAWING NO.	REFERENCE DRAWINGS
—	

IMV Projects Inc. Z07901

REV.	DESCRIPTION	BY	DATE	CHK	APP.	PE
A	ISSUED FOR REVIEW	MPB	08/11/12			

DRAWN: MPB	DATE 08/11/12
DESIGNED: TC	DATE 08/11/12
CHECKED:	DATE
APPROVED:	DATE
PE:	DATE

IMV Projects

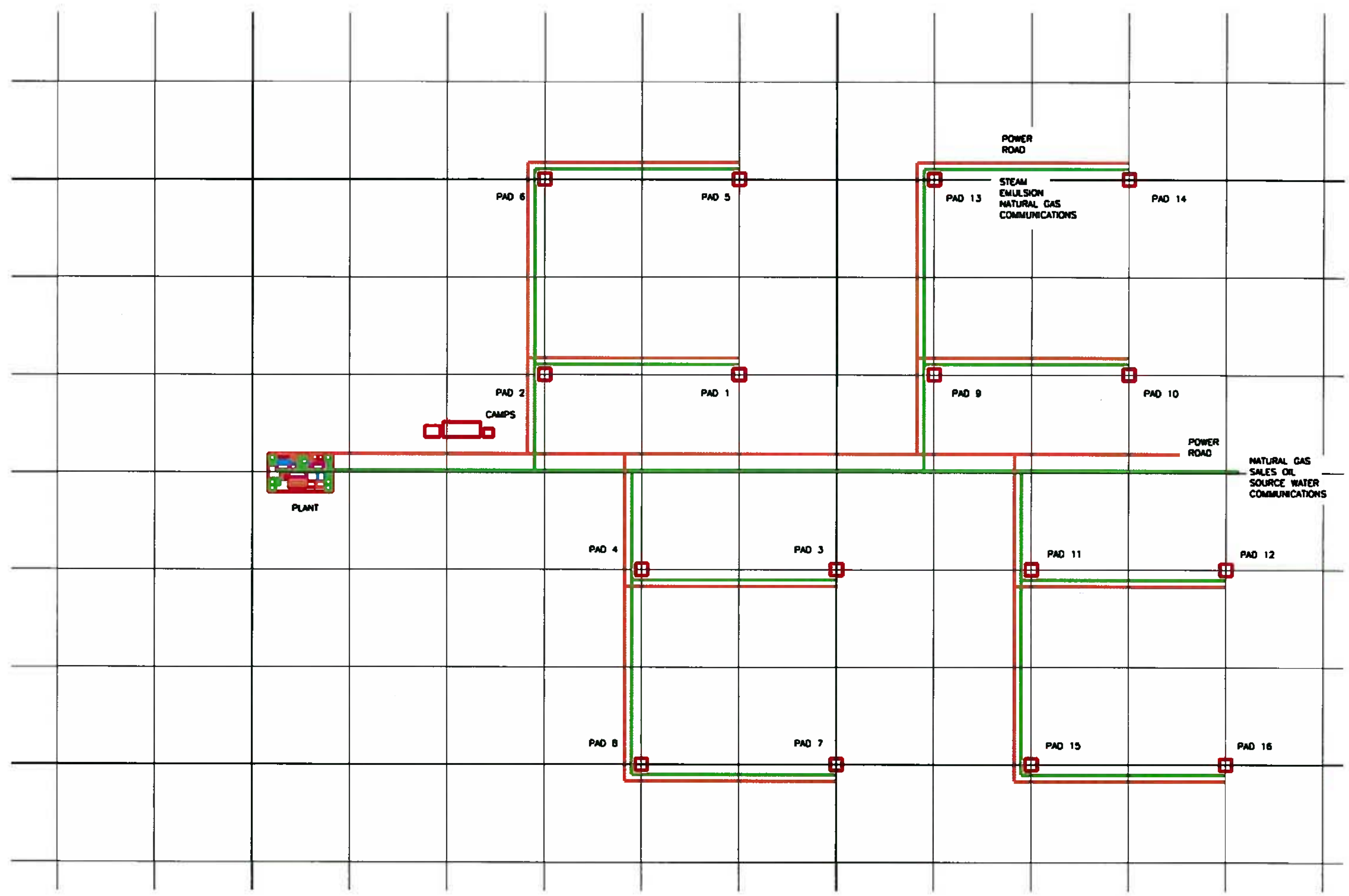
TITLE

AES OIL SANDS STUDY
SINGLE LINE DIAGRAM
DISTRIBUTION WITH ISD

SCALE	JOB NO.	DRAWING NO.	REV.
N.T.S.	Z07901	Z07901-0000-SLD-001	A

SCALE APPLIES IF PLOTTED ON SIZE "D" (22"x34")

Attachment 11 – Typical Oil Sands In-Situ Site Plan



SCALE - GRID is 1 Km x 1 Km

REV.	DESCRIPTION	BY	DATE	CHK	APP.	PE
A	ISSUED FOR REVIEW					

DRAWN: DATE
DESIGNED: DATE
CHECKED: DATE
APPROVED: DATE
PE: DATE

MW Projects

TITLE
MPR - AES OIL SANDS
SITE PLAN - ALTERNATE ENERY SOURCE
Z07901 120,000 Bbl/Day

SCALE | JOB NO. | DRAWING NO. Z07901-SK-0001 | REV. A

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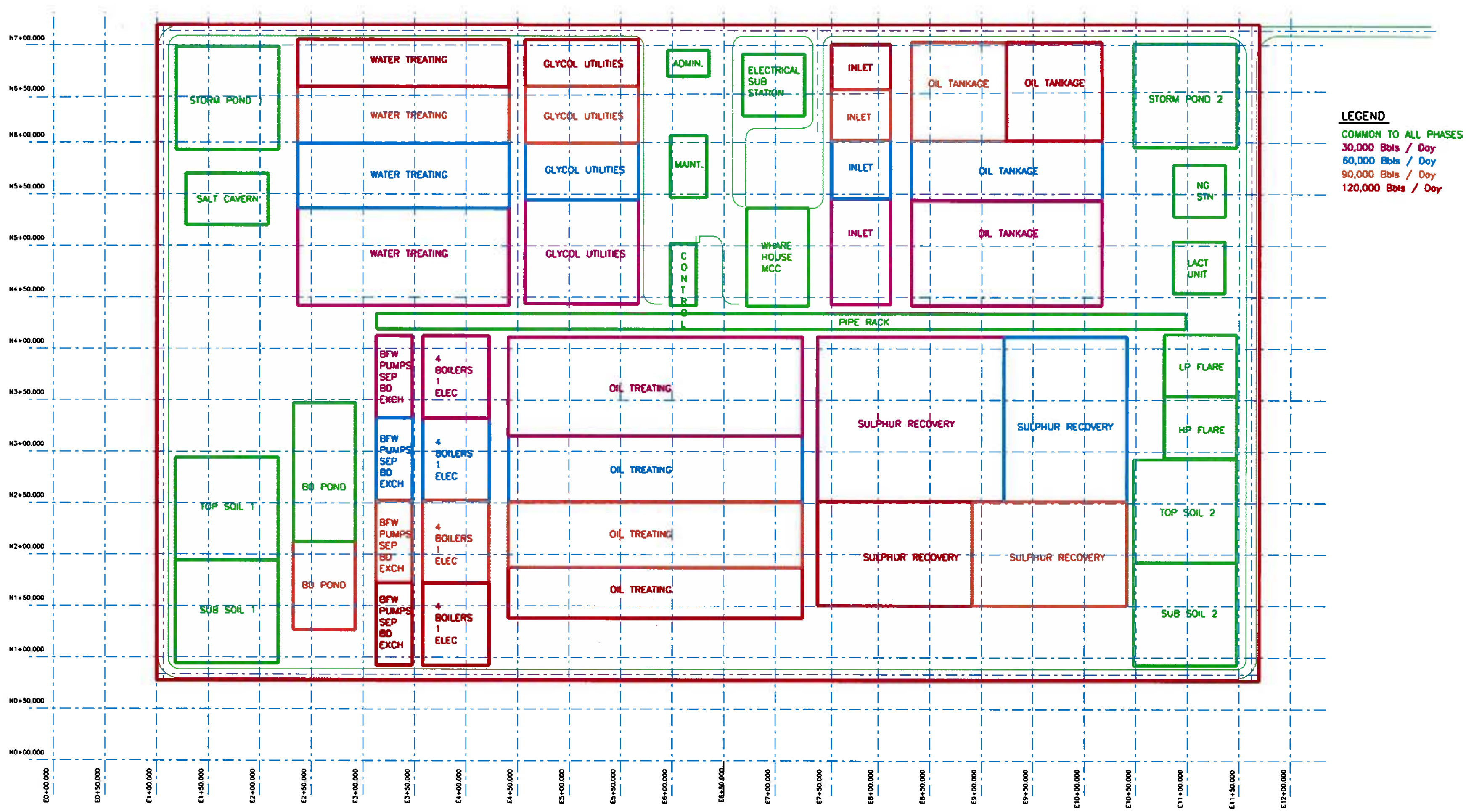
Attachment 12 – Conceptual Plant Plot Plan with OTSGs



REV.	DESCRIPTION	BY	DATE	CHK	APP.	PE
A	ISSUED FOR REVIEW					

DRAWN:	DATE
DESIGNED:	DATE
CHECKED:	DATE
APPROVED:	DATE
PE:	DATE

IMV Projects

TITLE
MPR – AES OIL SANDS
PLOT PLAN – OSTG's
Z07901 120,000 Bbl/Day – 680500 sq M

SCALE	JOB NO.	DRAWING NO.	REV.
NTS		Z07901–SK–1001	A

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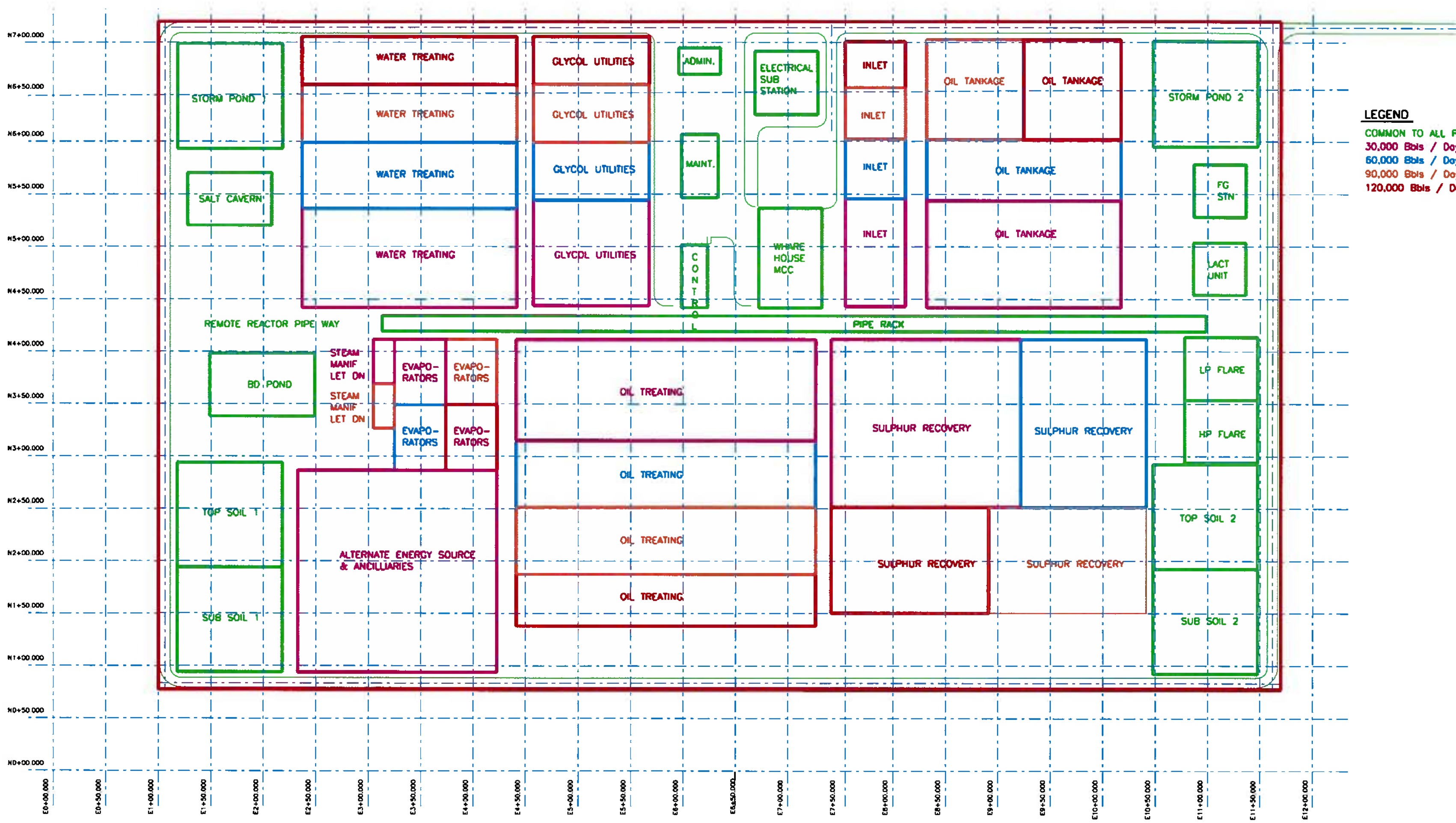
Attachment 13 -

Conceptual Plant Plot Plan with AES Steam Generation



LEGEND

COMMON TO ALL PHASES
30,000 Bbls / Day
60,000 Bbls / Day
90,000 Bbls / Day
120,000 Bbls / Day

REV.	DESCRIPTION	BY	DATE	CHK	APP.	PE
A	ISSUED FOR REVIEW					

DRAWN:	DATE
DESIGNED:	DATE
CHECKED:	DATE
APPROVED:	DATE
PE:	DATE

MW Projects

TITLE
MPR – AES OIL SANDS
PLOT PLAN – ALTERNATE ENERGY SOURCE
Z07901 120,000 Bbl/Day – 680500 sq M

SCALE	JOB NO.	DRAWING NO.	REV.
NTS		Z07901-SK-1002	A

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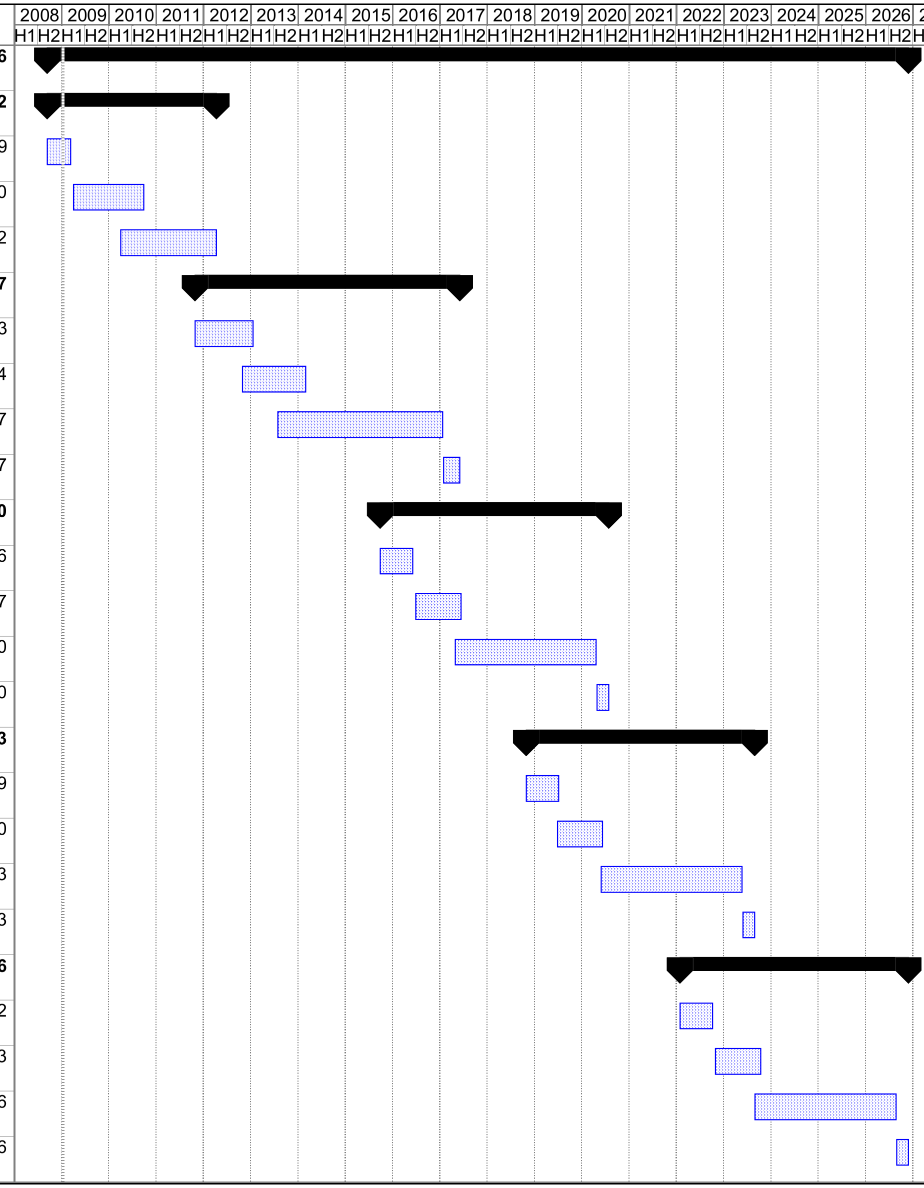
Attachment 14 - Typical Development Schedule

ID	Task Name	Duration	Start	Finish
1	**MPR Model 120,000 bopd In-situ Thermal Plant**	**4750 days**	**Tue 9/16/08**	**Mon 11/30/26**
2	**Preliminary Design and Regulatory**	**934 days**	**Tue 9/16/08**	**Fri 4/13/12**
3	Conceptual Design	130 days	Tue 9/16/08	Mon 3/16/09
4	Front End Eng Design	390 days	Mon 4/6/09	Fri 10/1/10
5	Regulatory Application	530 days	Mon 4/5/10	Fri 4/13/12
6	**Phase A Execution**	**1461 days**	**Tue 11/1/11**	**Tue 6/6/17**
7	Detail Engineering Phase A and Infrastructure	320 days	Tue 11/1/11	Mon 1/21/13
8	Procurement and Delivery	350 days	Thu 11/1/12	Wed 3/5/14
9	Construction Phase A	910 days	Thu 8/1/13	Wed 1/25/17
10	Commissioning Phase A	90 days	Wed 2/1/17	Tue 6/6/17
11	**Phase B Execution**	**1262 days**	**Wed 9/30/15**	**Thu 7/30/20**
12	Detail Engineeing	180 days	Wed 9/30/15	Tue 6/7/16
13	Procurement and Delivery	250 days	Fri 7/1/16	Thu 6/15/17
14	Construction Phase B	780 days	Mon 5/1/17	Fri 4/24/20
15	Commissioning Phase B	65 days	Fri 5/1/20	Thu 7/30/20
16	**Phase C Execution**	**1260 days**	**Thu 11/1/18**	**Wed 8/30/23**
17	Detail Engineeing	180 days	Thu 11/1/18	Wed 7/10/19
18	Procurement and Delivery	250 days	Mon 7/1/19	Fri 6/12/20
19	Construction Phase C	780 days	Mon 6/1/20	Fri 5/26/23
20	Commissioning Phase C	65 days	Thu 6/1/23	Wed 8/30/23
21	**Phase D Execution**	**1260 days**	**Tue 2/1/22**	**Mon 11/30/26**
22	Detail Engineeing	180 days	Tue 2/1/22	Mon 10/10/22
23	Procurement and Delivery	250 days	Tue 11/1/22	Mon 10/16/23
24	Construction Phase D	780 days	Fri 9/1/23	Thu 8/27/26
25	Commissioning Phase D	65 days	Tue 9/1/26	Mon 11/30/26



Project: MPR Schedule Rev A
Date: Wed 1/7/09

Task — Milestone — External Tasks
Split — Summary — External Milestone
Progress — Project Summary — Deadline

Attachment 15 -

CSC Construction Looking Forward - Highlight Report 2008 - 2016

ALBERTA

Construction Looking Forward 2008-2016 Key Highlights

Alberta's remarkable construction run continues under the current construction outlook scenario. Aside from brief pauses in activity as some major projects end, new industrial and engineering projects are expected later in the forecast period.

- Engineering construction investment cycles around an upward trend over the forecast period driven by oil sands investment. The oil sands and related upgrader projects will soon represent more construction than all other non-residential building in Alberta.
- Growth in industrial building construction averages almost 4% per year over the forecast period as firms increase capacity to meet demand.
- Commercial building construction rises in 2007 and 2008. It then remains flat to 2011 as economic growth slows, and rises again as business activity and population growth increase. Growth averages 2.8% for the forecast period as a whole.
- New housing investment peaks in 2007 and then declines gradually in line with the reduction in housing starts. It then recovers later in the forecast period as population growth increases to facilitate stronger oil sands investment growth.
- Renovation investment expenditures continue to grow throughout the period in line with rising real after-tax household income, household growth and a relatively low interest rate. Expenditures adjusted for inflation grow on average 3.5% over the forecast period.

Construction labour market conditions in Alberta, which has become Canada's largest employment centre, will remain tight over the forecast period. In recent years the apprenticeship and industry training system has responded to the needs of industry with record numbers of registered apprentices. Recruiting difficulties and concerns about skills shortages, however, are a concern for many trades associated with large engineering and industrial projects. Recruiting may also have reached the limits of interprovincial mobility, as demand for engineering and industrial trades is strong all across Canada.

Requirements for skilled trades in the province are such that the industry has turned to temporary foreign workers to meet demands. Efforts to improve the selection, arrival and integration of this group are increasing.

- Major increases in oil sands and related activity from 2004 to 2008 raised employment to new record levels. Many tradespeople in Alberta now come from out of the province.
- Costs are rising and recruiting initiatives are reaching out to more distant locations.

As well, many workers are expected to retire later in the forecast period, creating tight labour market conditions. The construction labour market rankings for Alberta are shown in the table (over).

In Alberta, about 21,000 construction workers are expected to retire over the 2007-2016 period. Apart from retirements, another 31,000 new workers would be needed to meet requirements attributable to the expected rise in construction activity.

Funded by the Government of Canada Sector Council Program

Canada

CONSTRUCTION SECTOR COUNCIL / CONSEIL SECTORIEL DE LA CONSTRUCTION

MARKET RANKINGS FOR TRADES AND OCCUPATIONS IN ALBERTA

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Boilermakers	4	4	4	4	4	4	4	5	4	3
Bricklayers	4	3	3	3	3	3	3	4	4	4
Carpenters	4	4	4	3	3	3	3	4	4	3
Concrete Finishers	4	5	4	4	4	4	4	4	4	3
Construction Managers	4	4	3	3	3	3	3	4	4	3
Construction Millwrights and Industrial Mechanics (except textile)	4	4	4	4	4	4	4	4	3	3
Contractors and Supervisors	4	4	4	4	4	4	4	4	4	3
Crane Operators	5	4	5	5	4	4	5	5	4	2
Drillers and Blasters – Surface Mining, Quarrying and Construction	4	4	4	4	2	3	4	3	3	1
Electricians (including industrial and power system)	4	4	4	4	3	3	3	4	4	3
Elevator Constructors and Mechanics	4	4	4	3	3	3	4	4	4	4
Floor Covering Installers	4	4	3	3	3	3	3	4	4	3
Gasfitters	5	5	4	4	3	3	4	4	4	2
Glaziers	4	4	4	4	4	3	3	3	4	3
Heavy Equipment Operators (except crane)	4	4	4	4	3	4	4	4	3	3
Heavy-Duty Equipment Mechanics	4	3	4	4	3	3	4	4	4	2
Industrial Instrument Technicians and Mechanics	4	4	4	4	4	4	4	4	3	2
Insulators	4	4	5	4	3	3	4	4	3	2
Ironworkers and Structural Metal Fabricators and Fitters	4	4	5	4	4	4	4	4	3	2
Painters and Decorators	4	3	3	3	3	3	3	4	4	4
Plasterers, Drywall Installers and Finishers, and Lathers	4	4	4	3	3	3	3	4	4	3
Plumbers	4	4	4	4	3	3	3	4	3	3
Refrigeration and Air Conditioning Mechanics	4	4	4	4	3	3	3	3	4	4
Residential and Commercial Installers and Servicers	4	4	3	3	3	3	3	3	4	4
Roofers and Shinglers	4	3	3	3	3	3	3	3	3	3
Sheet Metal Workers	4	4	5	5	4	4	4	4	3	2
Steamfitters, Pipefitters and Sprinkler System Installers	5	4	5	4	4	4	4	4	4	2
Tilesetters	3	3	3	2	2	2	3	4	4	4
Trades Helpers and Labourers	4	4	4	4	3	3	4	4	4	3
Truck Drivers	4	4	4	5	4	4	4	5	4	3
Welders and Related Machine Operators	4	4	5	5	4	4	4	4	4	2

Source: Construction Sector Council.

MARKET RANKINGS

1 Workers are available, excess supply is apparent and there is a risk of losing workers to other markets.

2 Workers are available to meet an increase in demand.

3 The availability of workers may be limited by large projects, industrial maintenance or other short-term increases in demand.

4 Workers are generally not available. Employers will need to compete to attract additional workers.

5 Workers are not available to meet demand. Competition for workers is intense and projects or production may be delayed or deferred.

Timely construction forecast data is available online at **www.constructionforecasts.ca**. Create customized reports on a broad range of selected categories within sector, trade or province covering up to 10 years.

The full report, *Construction Looking Forward, An Assessment of Construction Labour Markets from 2008 to 2016 for Alberta*, is part of the Construction Sector Council's Labour Market Information Program, and is available electronically **at www.csc-ca.org**.

For more information or copies contact

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Ottawa, Ontario, K1P 5Z9
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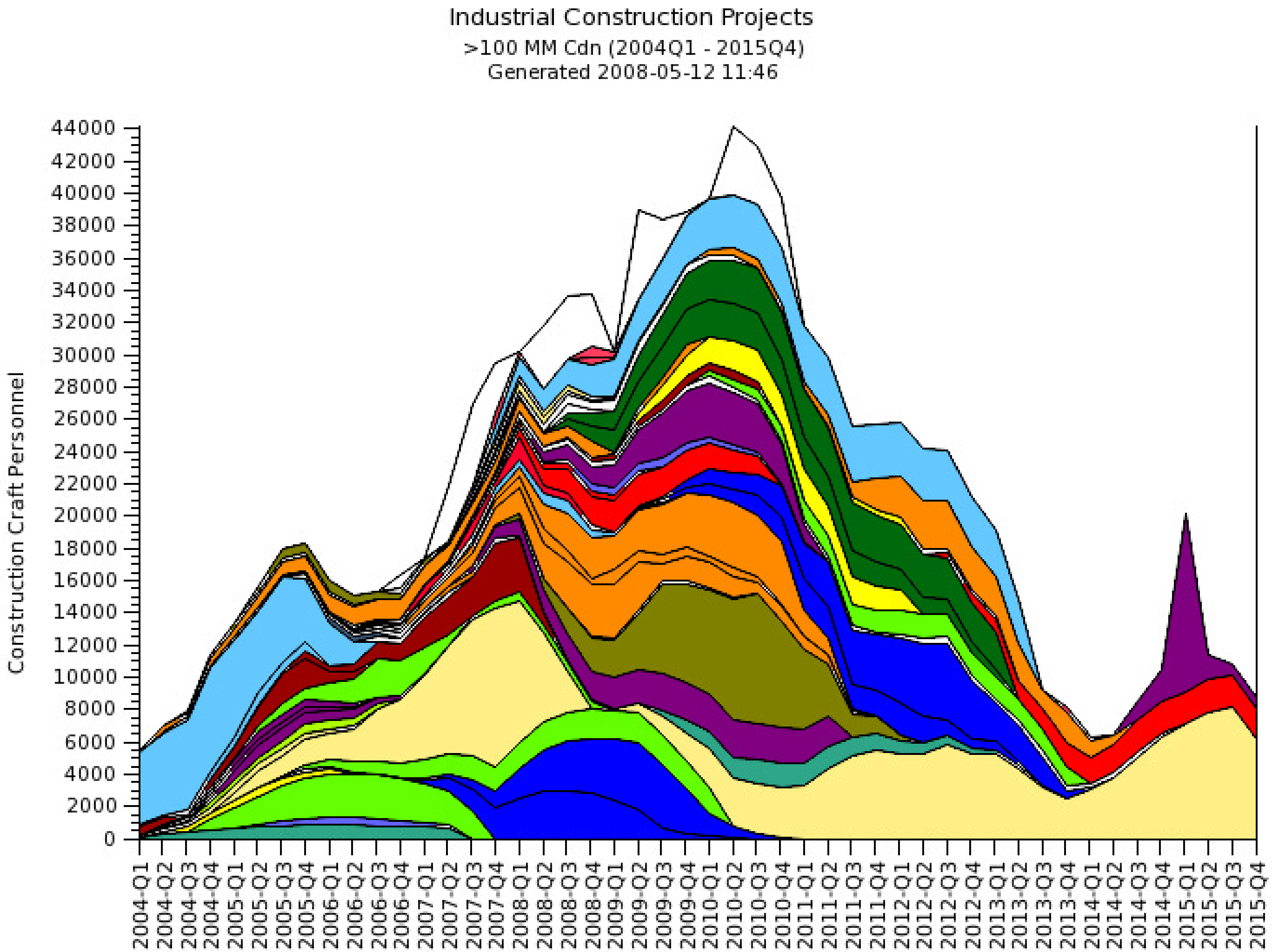
Fax: (613) 569-1220
info@csc-ca.org

Attachment 16 -

COAA Industrial Construction Projects - Labor Distribution 2004 - 2015



This graph was generated by the Construction Sector Council (CSC) Labour Market Information (LMI) forecasting website in partnership with the Construction Owners Association of Alberta (COAA) and is based in part on information not within the control of thee CSC/COAA. CSC/COAA has not made an analysis, verified, or rendered an independent judgement of the validity of the information obtained from outside sources. CSC/COAA does not guarantee the accuracy of this graph and use or reliance upon this graph for any reason by any party shall constitute a release and agreement by such party to defend and indemnify CSC/COAA against any liability (including but not limited to liability for special, indirect, consequential damages) in connection with such use whether arising in contract, tort, strict liability, or other theory of legal liability to the maximum extent, scope or amount allowable by law. Notwithstanding the foregoing, neither the graph nor any portion of the graph nor any information contained therein may be used in connection with any proxy, proxy statement, proxy soliciting material, prospectus, Securities Registration Statement or similar document without the express written consent of CSC, except as may be required by law. In no event shall the name of CSC be used without CSC's prior written consent.

1. Conoco Phillips - Surmont Phase 1 (Updated 2008-03-27)
2. Devon Canada Corporation - Devon Jackfish SAGD Project
3. OPTI Canada/Nexen - Long Lake Commercial SAGD
4. Shell - Ultra Low Sulphur Diesel (ULSD)
5. TransCanada - Edson Gas Storage
6. Albian Sands-Shell/Chevron/Western Oil Sands - Albian Sands Expansion 1
7. Albian Sands-Shell/Chevron/Western Oil Sands - Scotford Upgrader Expansion 1
8. BA Energy - Heartland Upgrader (Updated 2008-04-15)
9. CNRL - Horizons Project Phase 1 (Updated 2008-03-09)
10. CNRL - Primrose North Plant, Pipelines, Pads 31, 54-54
11. Husky Energy Ltd. - Tucker Thermal Project
12. Imperial Oil - Cold Lake Expansion (14-16)
13. Imperial Oil - Cold Lake Expansion (9-10)
14. Imperial Oil - Prism ULSD
15. OPTI Canada/Nexen - Long Lake Debottlenecking of Commercial SAGD (Updated 2008-05-08)
16. OPTI Canada/Nexen - Opti Canada Inc. - Long Upgrader Project
17. Petro Canada - Edmonton Diesel Desulphurization
18. Petro Canada - RCP 1.1 (Updated 2007-10-02)
19. Petro Canada - SIG - Sulfer & Gasoline Requirement
20. Syncrude - Southwest Quadrant Replacement Project
21. Syncrude - Upgrading Expansion - 1
22. Terasen Pipelines (Trans Mountain) Inc. - Trans Mountain Pump Station Expansion
23. Ainswoth Lumber Co. Ltd. - G.P.2 OSL Project
24. Suncor - Suncor Firebag Expansion (Updated 2007-06-08)
25. CNRL - Horizon Expansions (Updated 2008-04-08)
26. Conoco Phillips - Surmont Phase 2 (Updated 2008-03-27)
27. North West Upgrading Inc. - North West Upgrader (Updated 2007-09-21)
28. Petro-Canada, UTS, Teck Cominco - Fort Hills Oil Sands Project (Updated 2007-10-01)
29. Shell - Orion Phase 2 (Updated 2007-09-27)
30. Suncor - Firebag Program (Updated 2008-04-02)
31. Suncor - Mining and Extraction (Updated 2008-04-02)
32. Suncor - Voyageur (Updated 2008-04-02)
33. Syncrude - Syncrude Emission Reduction project
34. Terasen Pipelines (Corridor) Inc. - Corridor Pipeline Expansion
36. Albian Sands-Shell/Chevron/Western Oil Sands - Athabasca Oil Sands Expansion 2 and 3 - BBF (Updated 2007-09-28)
37. Albian Sands-Shell/Chevron/Western Oil Sands - Athabasca Oil Sands Expansion 2 and 3 - Mine (Updated 2007-09-28)
38. CNRL - Wolf Lake Expansion, Wolf Lake Pad Z11, Wolf Lake 4
39. Connacher Oil and Gas Limited - Great Divide
40. DCEL - Joslyn North Mine Project
41. DCEL - Joslyn Project SAGD Phase III
42. Devon Canada Corporation - Devon Jackfish 2 SAGD Project
43. Imperial Oil - Oilsands Mine Project
44. North American Oil Sands Corporation - NAOSC Kai Kos Dehseh Project
45. OPTI Canada/Nexen - Long Lake South Phase 1 SAGD (Updated 2007-10-01)
46. Petro Canada - McKay River Expansion - MRX (Updated 2007-10-02)
47. Shell - Carmon Creek Phase 1 (Updated 2007-09-27)
48. Suncor - Upgrading Projects (Updated 2008-04-02)
49. Synenco Energy Inc. - Norhtern Lights Project - Up Stream (Updated 2007-10-27)
50. Synenco Energy Inc. - Northern Lights Project - Down Stream (Updated 2007-10-27)
51. Terasen Pipelines (Trans Mountain) Inc. - Trans Mountain Expansion Phase 1 (Anchor Loop)
52. TransAlta/EPCOR - Keephills 3
53. CNRL - CNRL Thermal Projects
54. CNRL - Primrose East Plant, Pipelines, Pads
55. DCEL - Joslyn South Mine Project
56. Encana - Foster Creek SAGD - Phase 1C
57. Encana - Foster Creek SAGD - Phase 2
58. Japan Canada Oil Sands Limited - JACOS Hangingstone West
59. Suncor - Voyageur - South (Updated 2008-04-02)
60. Syncrude - Stage 3 Debottleneck
61. TransCanada - Dickins Lake and Vardie River Pipelines (Updated 2008-04-04)
62. TransCanada - Fort McKay Area Pipeline Projects
63. TransCanada - Fort McMurray Area Projects (Updated 2007-10-04)
64. TransCanada - NCC Loop (Buffalo Creek West Section) (Updated 2008-04-04)
65. TransCanada - North Central Corridor (Updated 2008-04-04)
66. Various owners across the Province - ROSE Committee Maintenance Shutdowns
67. Imperial Oil - Mackenzie Gas Project

Attachment 17 -
O&G Construction Productivity Estimate

Estimate of Construction Efficiency for AES Plant

Productivity Aspects (1)		Estimate Values			
Major Classification	**Sub-classification**	**Status**	**Productivity %**	**Class Weight**	**Net Pruductivity %**
General Economy	Business outlook	Busy			
	Construction volume	High			
	Employment situation	Tight			
	Impact		25	0.1	2.5
Project Supervision	Experience	Low			
	Supply	Low			
	Pay	High			
	Impact		25	0.12	3
Labour Conditions	Experience	Low			
	Supply	Low			
	Pay	Average			
	Impact		25	0.15	3.75
Job Conditions	Scope of work	Average			
	Site conditions	Average			
	Material procurement	Average			
	Manual & mech. ops.	Average			
	Accomodation	Good			
	Impact		60	0.15	9
Construction Equipment	Usability	Good			
	Condition	Good			
	Maintenance & repair	Good			
	Impact		65	0.12	7.8
Weather	Past reports	Excellent			
	Rain or snow	4/5 months light			
	Hot	2 months			
	Cold	5 months			
	Impact		40	0.12	4.8
Site Access (2)	Location	Remote			
	Access	Slow			
	Infrastructure	Poor			
	Impact		20	0.09	1.8
AES Site Comparison (3)	Skill level	Average			
	Quality Control	High			
	Procedural Effects	High			
	Impact		20	0.15	3
Totals (4)				1.00	35.65
Labour Rate Multiplier					2.81

Notes

1 Methodology adopted from that given in *Estimators Equipment Installation Man-Hour Manual: John S Page; 3rd Edition 1999; Gulf Professional Publishing.*

2 Access is assumed to be from mobilization in Calgary to a jobsite in Northern Athabasca.

3 The effect of working on an AES site when compared to that of an O&G site *(Canadian West Coast source).*

4 Page's installation manhour tables contain a 70% "average efficiency factor".

Attachment 18 -
Typical Jobsite Environmental Design Profile

Main Plant Location	North East Athabasca
Plant Elevation	500 m above sea level
Atmospheric Pressure	95 kPa (absolute)
Basic hourly wind pressures 1/10 chance of being exceeded in any year 1/30 chance of being exceeded in any year 1/100 chance of being exceeded in any year	(Based on Fort McMurray Data) 0.27 kPa (20.4 m/s) 0.32 kPa (22.2 m/s) 0.38 kPa (24.2 m/s)
Prevailing Winds	From the North and from the West
Alberta and National Building Code seismic acceleration coefficients. Typical values for Athabasca area in-situ plant.	Sa (0.2) = 0.12 Sa (0.5) = 0.06 Sa (1.0) = 0.02 Sa (2.0) = 0.01 Site Class = 0.6/D
Ambient Temperatures Air Cooler Design Temperature	35°C (summer design dry bulb) 28°C (summer dry bulb 2 ½%) 19°C (summer design wet bulb 2 ½%) -45°C (winter design dry bulb) -39°C (winter dry bulb 2 ½%) 30°C (design)
Rainfall (for building design) 15 minute rain One day rain Annual Rain	(Based on Fort McMurray Data) 13 mm (would be exceeded once in 10 years on the average or have a one chance in 10 of being exceeded in any one year) 85 mm (would be exceeded once in 30 years on the average or have a one chance in 30 of being exceeded in any one year) 460 mm (design annual rainfall)
Rainfall (for storm pond design) 1 in 25 year 24 hour storm event	 80 mm

Attachment 19 -
High Load Corridors in Alberta

Primary routes available out of Edmonton

- **Route 1**

  #16 east to Range Road 232 & Township Road 534

  #45 to #831

  #831 north to #28

  #28 west to #63

- **Route 2**

  #14 to #834

  #834 north to #15

  #15 west to #831

  #831 north to #28

  #28 west to #63

- **Heavy Load Route**

  #14 to #36

  #36 north to #28

  #28 west to #63

  Total Gross Vehicle Weight (GVW) not to exceed 195,000 kg

Primary routes available out of Calgary

- **Route 1**

  #560 east to #797

  #797 north to #1

  #1 east to Hwy 36

  #36 north to #14

  #14 west to #834

  #834 north to #15

  #15 west to #831

  #831 north to #28

#28 west to #63

- **Heavy Load Route**

  #560 east to #797

  #797 north to #1

  #1 east to #36

  #36 north to #28

  #28 west to Hwy 63

  Total Gross Vehicle Weight (GVW) not to exceed 131,500kgs

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Load Pilot Car

Pilot Car Guideline

- **3.85 meters (12' 6") – 1 pilot**

  No travel after 3:00 PM Friday, This type of load can start traveling again at 12:00 am Sat morning but must shutdown by 11:59 pm the same night.

  No travel Sunday or statutory holidays.

- **4.45 meters (14' 6") – 2 pilots**

  No travel after 3:00 PM Friday, Sunday or statutory holidays.

  Daylight hours only.

- **5.5 meters (18') - 3 pilots**

  No travel after 3:00 PM Friday, Sunday or statutory holidays.

  Daylight hours only.

Dimensional Load Guidelines to and within Alberta

These are the “day to day” shipments that fall into the Shipping Envelope in Alberta.

Alberta Infrastructure deems that Modules will not be considered for a “Controlled and Supervised Move”.

Load Type	Shipping Dimensions	Comments
Pipe Spools	Calgary/ Edmonton – must fit within a shipping envelope of 14.5 feet wide by 25.5 (29.5 feet above pavement) feet high by 60 feet long. Other Alberta – must fit within a shipping envelope of 14.5 feet wide by 9.5 (13.5 feet above pavement) feet high by 60 feet long. Canada outside Alberta – must fit within a shipping envelop of <12.5 feet by 9.5 (13.5 feet above pavement) feet high by 60 feet long. USA (west of Chicago/New Orleans Line) – must fit within a shipping envelope of <12.5 feet by 9.5 (13.5 feet above pavement) feet high by 60 feet long. USA (eastern seaboard) -- must fit within a shipping envelope of <12.0 feet by 9.5 (13.5 feet above pavement) feet high by 60 feet long.	Within Alberta spools can be tilted up to 30 degrees to allow width wider than 14.5 feet. Spools can be stood upright within the limits of the high load corridor. Lengths longer than 60 feet to a maximum of 80 feet can be accommodated if spool is self supporting Outside Alberta widths equal to or wider than 12.5 (12.0 feet USA eastern seaboard) feet can be accommodated by special arrangements at great expense.
Modules – Building, Piperack, Cable Tray	Calgary/ Edmonton – width not exceeding 24 feet overall and loaded height not to exceed 29.5 feet (including shipping beams under bottom transverse beam or under module legs). Eaves on buildings may extend moderately beyond 24 feet in width. Sleeper piperack restricted to a width of 14.5 feet. Weights restricted to “unsupervised” bridge crossings weight limits.	Double stacked sleeper piperacks must be structurally bolted together. Alberta Infrastructure will not permit modules wider than 24 feet regardless of technical justification.
Process Modules	Calgary/ Edmonton – width not exceeding 24 feet overall and loaded height not to exceed 29.5 feet (including shipping beams under bottom transverse beam or under	Alberta Infrastructure will not permit modules wider than 24 feet regardless of technical justification.

	module legs). Weights restricted to “unsupervised” bridge crossings weight limits.	
Flat Skids without Equipment	Within Alberta – width not exceeding 24 feet overall and height not exceeding 25.5 (29.5 feet loaded to truck) feet permitted. Weights restricted to “unsupervised” bridge crossings weight limits.	Alberta Infrastructure will not permit modules wider than 24 feet regardless of technical justification.
Equipment Skids with Equipment Installed	Within Alberta – width not exceeding 24 feet overall and height not exceeding 25.5 (29.5 feet loaded to truck) feet permitted. Weights restricted to “unsupervised” bridge crossings weight limits.	Approval for equipment skids with widths wider than 24 feet will require technical justification. Approval must be obtained prior to the commencement of fabrication and not easily obtained.
One Piece Vessels (PWHT)-Undressed	Calgary/Edmonton North – widths not exceeding 24 feet overall height not to exceed 25.5 (29.5 feet loaded to truck) feet permitted. Loads wider than 24 permitted by special arrangement based on technical justification Weights restricted to “supervised and controlled” bridge crossings weight limits.	Approval for widths wider than 24 feet will require detailed and extensive technical justification. Approval must be obtained prior to the commencement of fabrication.
One Piece Vessel – Dressed	Alberta Infrastructure has placed the following shipping restrictions on dressed vessels: On the side of the truck to the ditch - dressing is permitted up to 12 feet from the centerline of the trailer. On the side of the trailer to the centerline of the road that area of the vessel in an arc from bottom dead center to 135 degrees above bottom dead center – dressing may not extend beyond the side of the trailer. On the side of the trailer to the centerline of the highway in an arc from 135 degrees from bottom dead center to top dead center - dressing would be permitted within a radius of 12 feet from the center of the vessel.	Vessel dressing material may be bolted or welded to vessel.
Multi-piece Bolted Vessels	Edmonton North – widths not exceeding 24 feet overall and heights not exceeding 25.5 feet permitted.	Approval for widths wider than 24 feet will require technical justification.

	Loads wider than 24 feet permitted by special arrangement based on technical justification Weights restricted to “unsupervised” bridge crossings weight limits.	Approval must be obtained prior to the commencement of fabrication.
Fabricated Tanks	Calgary/ Edmonton North – widths not exceeding 24 feet overall and heights not to exceed 25.5 (29.5 feet loaded to truck) feet permitted Loads wider than 24 feet not permitted. Weights restricted to “unsupervised” bridge crossings weight limits.	Alberta Infrastructure does not believe there is any technical justification for a welded tank to be wider than 24 feet.

Guidelines for Transporting Large Vessels to and within Alberta

Province/ State	Origin City	Maximum Diameter	Maximum Length	Truck/Rail	Maximum Height	Maximum Weight (lb)	Comments
Alberta	Edmonton	24' 0"	100' 0"	Truck	24' 0"	650,000	Larger vessels can be transported provided that approval based on technical justification submitted by owners and approved by Alberta infrastructure prior to fabrication
	Calgary	24' 0"	100' 0"	Truck	24' 0"	220,000	Time of year could affect weights
	Lloydminster	20' 0"	100' 0"	Truck	20' 0"	220,000	Time of year could affect weights
British Columbia	Kelowna	12' 0"	23' 0"	Truck	12' 6"	60,000	Time of year could affect weights
	Vancouver	12' 0"	23' 0"	Truck	12' 6"	60,000	Time of year could affect weights
Saskatchewan	Regina	12' 0"	23' 0"	Truck	12' 6"	60,000	Time of year could affect weights
	Saskatoon	12' 0"	23' 0"	Truck	12' 6"	60,000	Time of year could affect weights
Manitoba	Winnipeg	12' 0"	23' 0"	Truck	12' 6"	60,000	Time of year could affect weights
Ontario	Toronto	12' 0"	23' 0"	Truck	12' 6"	60,000	Time of year could affect weights
	Cambridge	12' 0"	23' 0"	Truck	12' 6"	60,000	Time of year could affect weights
	Niagara	12' 0"	23' 0"	Truck	12' 6"	60,000	Time of year could affect weights
Quebec	Quebec City	12' 0"	23' 0"	Truck	12' 6"	60,000	Time of year could affect weights
	Montreal	12' 0"	23' 0"	Truck	12' 6"	60,000	Time of year could affect weights
Nova Scotia	Halifax	12' 0"	23' 0"	Truck	12' 6"	60,000	Time of year could affect weights
Texas	Houston	12' 0"	23' 0"	Truck	12' 6"	45,000	Time of year could affect weights

Province/ State	Origin City	Maximum Diameter	Maximum Length	Truck/Rail	Maximum Height	Maximum Weight (lb)	Comments
	Wichita	12' 0"	23' 0"	Truck	12' 6"	45,000	Time of year could affect weights
Oklahoma	Tulsa	12' 0"	23' 0"	Truck	12' 6"	45,000	Time of year could affect weights
New York	Olean	12' 0"	23' 0"	Truck	12' 6"	45,000	Time of year could affect weights
	Painted Post	12' 0"	23' 0"	Truck	12' 6"	45,000	Time of year could affect weights
Pennsylvania	Pittsburgh	12' 0"	23' 0"	Truck	12' 6"	45,000	Time of year could affect weights
Ohio	Cleveland	12' 0"	23' 0"	Truck	12' 6"	45,000	Time of year could affect weights
Off Shore	Duluth	14' 6"	100' 0"	Rail	14' 6"	950,000	Maximum net weight depends on rail car configuration, general rule of thumb gross vehicle weight accepted by rail companies in Canada 65,000Lbs per axle
	Montreal	12' 6"	60' 0"	Rail	13' 0"	400,000	Time of year could affect weights
	Halifax	12' 6"	60' 0"	Rail	13' 0"	400,000	Time of year could affect weights
	Vancouver	12' 0"	60' 0"	Rail	13' 0"	300,000	Time of year could affect weights

Attachment 20 -

Alberta Energy: Petrochemical Tool Kit - "Want to Build a Petrochemical Facility in Alberta"

Related Links

Energy Resources Conservation Board

Alberta Utilities Commission (AUC)

Petroleum Registry of Alberta

ETS- Electronic Transfer System

Information Letters.

Questions and Comments

Tell us what you think

Alberta's Oil Sands

Budget 2008

I commit to one simple act.

Petrochemical Tool Kits

Want to Build a Petrochemical Facility in Alberta?

Like every jurisdiction in the world, Alberta has rules and requirements for industrial and business development within its borders. The following index assists individuals or companies who wish to explore the framework for investment in petrochemical manufacturing in Alberta (see *disclaimer*). Alberta's legislation is published and distributed by Alberta Queen's Printer. Copies of legislation may be purchased or viewed for free (in TEXT format) through their on-line catalogue.

Provincial Legislation: Government of Alberta - Ministry Links

- [Corporate]
- [Land and Infrastructure]
- [Plant and Equipment Installation]
- [Operations and Maintenance]

Municipal Government Legislation

Federal Government Legislation

Corporate

Activity	***Legislation***	**Alberta Ministry**
Liability and/or Corporate Insurance	*Debtors' Assistance Act* *- Debtors' Assistance Regulation* *Personal Property Security Act* *- Personal Property Security Forms Regulation* *- Personal Property Security Regulation*	Government Services
Registered Name and Corporate Structure	*Business Corporations Act* *- Business Corporations Regulation* *Companies Act* *- Companies Regulation* *Partnership Act* *- Partnership Regulation*	Government Services
	Securities Act *- Securities Regulation*	Revenue
Users of the Statutes of Alberta	*Freedom of Information and Protection of Privacy Act* *- Freedom of Information and Protection of Privacy Regulation*	Government Services
	Arbitration Act *Daylight Saving Time Act* *Defamation Act* *Interpretations Act* *Languages Act* *Regulations Act* *- Regulations Act Regulation*	Justice and Attorney General

	Unconscionable Transactions Act	
	Financial Administration Act *- Charging of Interest on Amounts Owing to the Crown Regulation*	Revenue
	Government Organization Act	Various

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Shell Chemicals Scotford Plant at Fort Saskatchewan, Alberta
Courtesy of Alberta's Industrial Heartland Website

Land and Infrastructure

Activity	***Legislation***	**Alberta Ministry**
Land Purchase	*Agricultural and Recreational Land Ownership Act* *- Foreign Ownership of Land Regulation* *Land Titles Act* *- Forms Regulation* *- Metric Conversion Regulation* *- Name Search Regulation* *- Tariff of Fees Regulation* *Law of Property Act*	Government Services
	Government Organization Act	Infrastructure

	- *Calgary Restricted Development Area Regulations* - *Edmonton-Devon Restricted Development Area Regulations* - *Edmonton Restricted Development Area Regulations* - *Sherwood Park West Restricted Development Area Regulations*	
Land and Development Zoning Permits	*Municipal Government Act*	Municipal Affairs (and Accredited Municipalities)
Leases: Public Land (e.g. Mineral Surface, Surface Materials)	*Wilderness Areas, Ecological Reserves and Natural Areas Act*	Community Development
	Environmental Protection and Enhancement Act	Environment
	Special Areas Act - *Special Areas Disposition Regulation* - *Special Areas Service Fees Regulation*	Municipal Affairs
	Government Fees and Charges Review Act - *Disposition and Fees Regulation*	Revenue
	Public Lands Act	Sustainable Resource Development
Leases: Subsurface	*Mines and Minerals Act*	Energy
Petrochemical Site Permitting	*Energy Resources Conservation Act* *Mines and Minerals Act* - *Crown Minerals Registration Regulation* - *Mines and Minerals Administration Regulation* - *Natural Gas Royalty Regulation, 2002* - *Petroleum and Natural Gas Tenure Regulation* *Oil and Gas Conservation Act*	Energy
Pipelines	*Environmental Protection and*	Environment

	Enhancement Act *- Environmental Appeal Board Regulation* *- Environmental Protection and Enhancement (Miscellaneous) Regulation* *Water Act* *- Code of Practice for Pipelines and Telecommunications Lines Crossing a Water Body* *- Code of Practice for Watercourse Crossings* *- Code of Practice for the Temporary Diversion of Water for Hydrostatic Testing of Pipelines*	
Plant Design	*Pipeline Act* *- Pipeline Regulation*	Energy
Railroad Access	*Engineering, Geological and Geophysical Professions Act* *- General Regulation*	Human Resources and Employment
Right of Way, Easement (e.g. access road, utility corridor, pathway, parking, etc.)	*Land Titles Act* *- Forms Regulation* *- Metric Conversion Regulation* *- Name Search Regulation* *- Tariff of Fees Regulation*	Government Services
	Land Surveyors Act	Human Resources and Employment
	Expropriation Act *Trespass to Premises Act*	Justice and Attorney General
	Special Areas Act *- Special Areas Disposition Regulation* *- Special Areas Service Fees Regulation*	Municipal Affairs
	Expropriation Act *- Expropriation Act Forms Regulation* *- Expropriation Act Rules of Procedure and Practice* *Public Lands Act*	Sustainable Resource Development

	- Exploration Regulation *Surveys Act*	
	Railway (Alberta) Act *- Railway Regulation*	Transportation
Storage: Above Ground Tanks	*Alberta Fire Code*	Municipal Affairs
	Public Highways Development Act *- Highway Development Control Regulation* *- Irrigation Districts Bridge Structures and Culverts Regulation*	Transportation
Storage: Underground Caverns	*Dangerous Goods Transportation and Handling Act* *- Dangerous Goods Transportation and Handling Regulation*	Transportation
Storage: Water Ponds	*Mines and Minerals Act* *- Natural Gas Royalty Regulation, 2002* *Oil and Gas Conservation Act* *- Oil and Gas Conservation Regulation*	Energy
	Water Act *- Water (Ministerial) Regulation* *- Water (Offences and Penalties) Regulation*	Environment
Utilities: Electricity (e.g. generator, fuel, wires)	*Electric Utilities Act* *- Isolated Generating Units and Customer Choice Regulation* *Hydro and Electric Energy Act* *- Hydro and Electric Energy Regulation* *Public Utilities Board Act* *- Designation Regulation* *Water, Gas and Electric Companies Act*	Energy
Utilities: Natural Gas	*Gas Utilities Act* *- Gas Utilities Core Market Regulation* *Natural Gas Marketing Act* *- Natural Gas Marketing Regulations* *Natural Gas Price Administration Act* *Natural Gas Price Protection Act* *- Natural Gas Price Protection*	Energy

	Regulation *Natural Gas Pricing Agreement Act* *Public Utilities Board Act* *- Designation Regulation* *Water, Gas and Electric Companies Act*	
	Water Act *-Code of Practice for Pipelines and Telecommunications Lines Crossing a Water Body*	Environment
Utilities: Telecommunications	*Telecommunications Act*	Economic Development
	Public Utilities Board Act *- Designation Regulation*	Energy
	Water Act *- Code of Practice for Pipelines and Telecommunications Lines Crossing a Water Body*	Environment
Utilities: Water, Sewage and Waste Management	*Public Utilities Board Act* *- Designation Regulation* *Water, Gas and Electric Companies Act*	Energy
	Environmental Protection and Enhancement Act *- Approvals and Registrations Procedure Regulation* *- Activities Designation Regulation* *- Environmental Appeal Board Regulation* *- Environmental Protection and Enhancement (Miscellaneous) Regulation* *- Potable Water Regulation* *- Waste Control Regulation* *- Wastewater and Storm Drainage (Ministerial) Regulation* *- Wastewater and Storm Drainage Regulation* *Water Act* *- Water (Ministerial) Regulation* *- Water (Offences and Penalties) Regulation*	Environment

Well Licences	*Oil and Gas Conservation Act* *- Oil and Gas Conservation Regulations*	Energy
	Environmental Protection and Enhancement Act *- Code of Practice for Compressors and Pumping Stations and Sweet Gas Processing Plants* *- Code of Practice for the Release of Hydrostatic Test Water From Hydrostatic Testing of Petroleum Liquid and Gas Pipelines* *- Conservation and Reclamation Regulation* *- Environmental Appeal Board Regulation*	Environment

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Plant and Equipment Installation

Activity	***Legislation***	**Alberta Ministry**
Boilers and Pressure Vessels	*Pressure Vessels Regulations* *- Engineers' Regulations* *- Pressure Welders Regulation* *Safety Codes Act* *- Boilers and Pressure Vessels Exemption Order* *- Boilers and Pressure Vessels Regulation* *- Boilers Delegated Administration Regulation* *- Design, Construction and Installation of Boilers and Pressure Vessels Regulation*	Municipal Affairs
Building Permits	*Environmental Protection and Enhancement Act* *- Potable Water Regulation*	Environment
	Builders' Lien Act	Government Services
	Safety Codes Act	Municipal

	- *Alberta Building Code* - *Alberta Fire Code* - *Alberta Gas Code* - *Alberta Plumbing Code*	Affairs
Construction Camp	*Public Health Act* - *Work Camps Regulation*	Health and Wellness
Industrial Machinery	*Fuel Tax Act* - *Fuel Tax Regulation*	Revenue
Patents, Copyrights, Technological or Industrial Design Processes, Trademarks	*Companies Act*	Government Services
	Alberta Science and Research Authority Act - *Alberta Science and Research Authority Grant Regulation*	Innovation and Science
Property Taxes	*Municipal Government Act* - *Assessment Complaints and Appeals Regulation* - *Matters Relating to Assessment and Taxation Regulation* - *Standards of Assessment Regulation* - *Well Drilling Equipment Tax Rate Regulation*	Municipal Affairs
Sulphur Handling Equipment	*Dangerous Goods Transportation and Handling Act* - *Dangerous Goods Transportation and Handling Regulation*	Transportation

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Operations and Maintenance

Activity	*Legislation*	Alberta Ministry
Air Quality (e.g. monitoring, testing and control)	*Environmental Protection and Enhancement Act* - *Activities Designation Regulation* - *Air Emissions Regulation* - *Approvals and Registrations Procedure Regulation* - *Environmental Protection and*	Environment

	Enhancement (Miscellaneous) Regulation *- Ozone-Depleting Substances Regulation* *- Release Reporting Regulation* *- Substance Release Regulation*	
Public Safety	*Weed Control Act* *- Weed Control Regulation*	Agriculture, Food and Rural Development
	Petty Trespass Act *Trespass to Premises Act*	Justice and Attorney General
	Disaster Services Act *- Disaster Recovery Regulation* *- Government Emergency Planning Regulation*	Municipal Affairs
Contractor Relations	*Dangerous Goods Transportation and Handling Act* *- Dangerous Goods Transportation and Handling Regulation*	Transportation
Corporate Taxes	*Fair Trading Act*	Government Services
Customer Relations	*Alberta Taxpayer Protection Act*	Finance
	Fair Trading Act	Government Services
	Alberta Corporate Tax Act *- Alberta Corporate Tax Regulation*	Revenue/Finance
Natural Gas and Natural Gas Liquids Marketing, Purchasing	*Natural Gas Marketing Act* *- Natural Gas Marketing Regulation* *- Prescribed Deregulation Date Regulation* *Take-or-pay Costs Sharing Act*	Energy
	Fair Trading Act *- General Licensing and Security Regulation*	Government Services
	Factors Act	Justice and

	Sale of Goods Act	Attorney General
Human Resource Management/ Occupational Health and Safety	*Human Rights, Citizenship and Multiculturalism Act*	Community Development
	Environmental Protection and Enhancement Act *- Potable Water Regulation*	Environment
	Government Fees and Charges Review Act *Employment Pension Plans Act*	Finance
	Public Health Act	Health and Wellness
	Employment Standards Code *- Employment Standards Regulation* *- Labour Relations Code* *Engineering, Geological and Geophysical Professions Act* *- General Regulation* *Occupational Health and Safety Act* *- Chemical Hazards Regulation* *- First Aid Regulation* *- General Safety Regulation* *- Joint Work Site Health and Safety Committee Regulations* *- Noise Regulation* *- Ventilation Regulation* *Student and Temporary Employment Act* *- Student and Temporary Employment Regulation*	Human Resources and Employment
	Protection from Second-hand Smoke in Public Buildings Act	Infrastructure
	Alberta Bill of Rights *Arbitration Act* *Factors Act* *Fatal Accidents Act* *Fatality Inquiries Act*	Justice and Attorney General
	Apprenticeship and Industry Training Act	Learning

	- Appeal Rules Regulation *- Apprenticeship and Industry Training Administration Regulation* *- Apprenticeship Program Regulation* *- Boilermaker Trade Regulation* *- Communication Electrician Trade Regulation* *- Designated Occupations Regulation* *- Designation of Optional Certification Trades Regulation* *- Electrical Motor Systems Technician Trade Regulation* *- Electrician Trade Regulation* *- Electronic Technician Trade Regulation* *- Gas Utility Operator Occupation Regulation* *- Gasfitter Trade Regulation* *- Heavy Equipment Technician Trade Regulation* *- Instrument Technician Trade Regulation* *- Millwright Trade Regulation* *- Steamfitter - Pipefitter Trade Regulation* *- Warehousing Occupation Regulation* *- Water Well Driller Trade Regulation* *- Welder Trade Regulation* *Banff Centre Act* *Colleges Act* *Technical Institutes Act* *Universities Act*	
	Safety Codes Act *- Engineers' Regulations*	Municipal Affairs
	Alberta Personal Income Tax Act *- Personal Income Tax Withholding Regulation*	Revenue
	Blind Workers' Compensation Act *Workers' Compensation Act* *- Workers' Compensation Regulation*	Human Resources and Employment
Import/Export Activities	*International Commercial Arbitration Act*	Justice and Attorney General

	International Trade and Investment Agreements Implementation Act	International and Intergovernmental Relations
Land Abandonment and Reclamation	*Environmental Protection and Enhancement Act* *- Activities Designation Regulation* *- Approvals and Registrations Procedure Regulation* *- Conservation and Reclamation Regulation* *- Environmental Protection and Enhancement (Miscellaneous) Regulation*	Environment
Manufacturing	*Dangerous Goods Transportation and Handling Act* *- Dangerous Goods Transportation and Handling Regulation*	Transportation
Regulatory Reporting	*Oil and Gas Conservation Act* *- Oil and Gas Conservation Regulations*	Energy
Research and Development Laboratory	*Alberta Heritage Foundation for Science and Engineering Research Act* *Alberta Science and Research Authority Act*	Innovation and Science
Sulphur Management	*Freehold Mineral Tax Act* *- Freehold Mineral Tax Regulation* *Mines and Minerals Act* *- Crown Minerals Registration Regulation* *- Mines and Minerals Administration Regulation* *- Natural Gas Royalty Regulation, 2002* *- Petroleum and Natural Gas Tenure Regulation* *Oil and Gas Conservation Act* *- Oil and Gas Conservation Regulations*	Energy
	Environmental Protection and Enhancement Act	Environment

	- Activities Designation Regulation *- Approvals and Registrations Procedure Regulation*	
Supplier Relations	*Fair Trading Act*	Government Services
Trucks/Tankers for moving products, delivering services	*Occupational Health and Safety Act* *- Chemical Hazards Regulation*	Human Resources and Employment
	Warehouse Receipts Act	Justice and Attorney General
	Dangerous Goods Transportation and Handling Act *- Dangerous Goods Transportation and Handling Regulation* *Motor Transport Act* *- Bill of Lading and Conditions of Carriage Regulation* *- Commercial Vehicle Maintenance Standards Regulation* *- Drivers' Hours of Service Regulation* *- Local Government Control of Secondary and Rural Roads Regulation* *- Public Vehicle Certificate and Insurance Regulation* *- Public Vehicle Classification, Fees and Permit Regulation* *- Public Vehicle Dimension and Weight Regulation* *- Public Vehicle General Equipment and Safety Regulation* *- Transportation of Anhydrous Ammonia and Other Fertilizers Regulation* *Motor Vehicle Administration Act* *- Motor Vehicle Administration Order* *- Motor Vehicle Collision Report Regulation* *- Prescribed Acts and Regulations Regulation* *- Section 112 Motor Vehicle Seizure and Immobilization Regulation* *Regulations under the Motor Vehicle*	Transportation

	Administration Act *Traffic Safety Act* *- Licence Suspension Program Regulation* *- Traffic Safety Act Transitional Regulation*	
Well Abandonment and Reclamation	*Oil and Gas Conservation Act* *- Oil and Gas Conservation Regulations*	Energy
	Environmental Protection and Enhancement Act *- Reclamation Criteria for Wellsites and Associated Facilities*	Environment

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Municipal Government Legislation

Most municipalities have been delegated the authority to determine and collect property taxes. In addition, they will also have land-use bylaws that can affect industrial development within each of their jurisdictions. The Alberta Industrial Heartland Association (AIHA), a partnership of four municipalities (Strathcona County, Fort Saskatchewan, Sturgeon County and Lamont County), has developed a report of their member Complementary Area Structure Plans. To view the report and relevant bylaws in these municipalities visit the AIHA website. Top of Page

Federal Government Legislation

The Government of Canada also has requirements for industrial activities such as taxation (goods and services taxes, income taxes) and trade agreements (*North American Free Trade Agreement*). For more information on federal legislation visit the Government of Canada website.

Last reviewed/revised: 2008-04-30

Alberta Government

B

Canadian Nuclear Licensing Needs to Support an Advanced Nuclear Reactor Technology Plant

Project Report

Summary of Canadian Nuclear Licensing Needs to Support Deployment of Advanced Nuclear Reactor Technologies

Submitted to

MPR Associates

October 28, 2008

Shaw® Stone & Webster Management Consultants, Inc.

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1 Executive Summary

The objective of this report is to provide an overview of how Canadian nuclear regulatory requirements are likely to impact planning for new nuclear technology projects to support expansion of the oil sands industry in Canada. Technologies being considered for these applications include the Pebble Bed Modular Reactor, the General Atomics Modular Helium Reactor, and the Toshiba 4S Reactor. All of these technologies are likely to encounter similar issues and requirements.

1.1 Canadian Nuclear Regulatory Requirements

All nuclear power plants in Canada are licensed and regulated by the Canadian Nuclear Safety Commission (CNSC). Whilst many large power reactors[1] have been licensed and operated in Canada the CNSC has introduced a range of new regulatory documents for licensing new reactors that to date have not been fully tested. No new license applications have yet been approved under this developed framework.

A license application for the development of a new reactor project requires a proponent who will submit the application, fulfill the financial obligations of an applicant, commit to the obligation for information submittals throughout the licensing process and be prepared to operate the plant within the regulatory regime as described by such a license.

While not formally part of the licensing process, a Pre-Project Design Review (PPDR) process is now available to license applicants. It seeks to facilitate the licensing process by identifying and discussing unique application issues associated with the technology or application and framing regulatory areas that concern the CNSC well before a license application is filed. This process is also valuable for technologies that are unfamiliar to the CNSC or for which the CNSC has an incomplete regulatory basis for formal review.

The formal licensing framework is defined by the Nuclear Safety and Control Act (NSCA). Five phases of reactor life are identified by the NSCA and a separate license is required for each of them, the three licenses required for commercial operation are 1) to prepare the site, 2) construct the plant and 3) to operate the facility. The exact requirements associated with granting licenses under this new regulatory framework are still under development, but the general philosophy is that they will be technology-neutral, based on safety requirements that can be applied initially to a traditional large power reactor and later to any type of reactor. Filing of the initial nuclear license application additionally triggers an Environmental Assessment (EA) under the Canadian Environmental Assessment Act (CEAA) which is separately established under federal legislation to determine whether the project may cause significant, adverse environmental effects, taking available mitigating measures into account.

The timeframe of the licensing process for a new nuclear plant in Canada depends upon a number of factors, but recent experience with conventional oil sands projects indicates that it could take up to three years just to complete the necessary EA process. The CEAA requires that all projects undergo a simplified screening process by the responsible authority (in this case the CNSC) to determine the environmental significance of the project and any mitigation measures. On completion of the screening if

[1] 22 Power reactors in Ontario, Quebec and New Brunswick

further review is thought necessary the project may be referred to a mediator to resolve outstanding issues or to a review panel that will carry out a comprehensive review to determine and decide on the environmental significance of the project and whether it should be given approval to proceed.

Nuclear power projects fall under the category of projects identified in the Comprehensive Study List Regulations (SOR/94-638) that are mandated to undergo comprehensive study and as follows from past custom and practice likely to be required to have a review panel appointed (and in fact a joint federal and provincial review panel hereafter referred to as a "joint panel"). Therefore, one option available to speed up the EA process is for the responsible authority to immediately recommend that the EA is referred to a joint review rather than wait for the Minister to make such a decision later in the process. This immediate referral potentially saves up to 8-months in the approximate 3-year EA process discussed above. The achievement of the 3-year EA process schedule is heavily dependent on the quality of the submissions by the applicant and a further complication will be the degree of cooperation between the applicant and the oil sands producer (who could be one and the same) as the oil sands expansion EA approval process will be being undergone at the same time as the nuclear facility EA and will be dependent on similar if not identical site and environmental information for the production of EA submissions.

Similarly, the time required to review and approve the submissions supporting the nuclear licenses to prepare, construct and operate the facility will depend heavily on the quality of the submission by the applicant (both the completeness of the application and the quality of the reactor design safety report and references). There is also concern about the availability of suitable resources within the CNSC to meet the timescales being proposed and whilst a major recruitment program is underway to satisfy the requirements of the confirmed Ontario and the potential Alberta/Saskatchewan new build programs where a novel reactor system design review would sit in priority is subject to some conjecture.

Currently the CNSC estimates that the process of obtaining the necessary licenses to prepare the site, construct and operate the plant for a well developed novel reactor would take about 9-years with the first 3-years work being carried out in parallel with the described EA process. This 9-year schedule anticipates the completion of first-of-a-kind design work and testing to support the safety report which will have a direct delay to schedule but excludes any early joint review panel referral, parallel license application or home country licensing benefit further quantified below.

1.2 Conclusions and Recommendations

Licensing is likely to impact the critical path of project implementation for the novel nuclear technologies being considered here.

The CNSC has made a commitment to a technology-neutral licensing framework that will be equally accessible to all license applicants. However, at this stage the new regulations are only written to deal with traditional large power reactors for power generation and they require the novel reactor designer to already have an approved design or to set in place work itself to support such approval in Canada.

- The reactor vendor must have in place the necessary detailed engineering and testing/validation to support his construction license application under the "alternative approaches" methodology or incur the real possibility of schedule delays

The licensing of any new nuclear plant in Canada will be undertaken in the context of a regulatory framework that is still under development and thus is not completely predictable to the applicant. Given that reality, it is crucial that license applicants with novel nuclear plant designs or new applications for nuclear energy engage the CNSC in discussions early in the planning process (e.g., utilizing where necessary the PPDR process), enabling an appropriate approach for the assessment of the technology by the CNSC to be formulated.

- Use of the PPDR process should be seriously considered to ensure that the ultimate construction license application submissions meet the CNSC's expectations when first submitted.

The importance of high quality applications and submissions cannot be underestimated. A complete initial license application will enable the CNSC to recommend the EA process directly to a joint panel review, which has the potential to save up to 8 months on the EA schedule and support early consideration of license applications.

- The reactor vendor has to commit real resources and a project approach to the formal nuclear licensing interaction with the CNSC otherwise schedule delays are likely to occur

Once a project site is identified and an overall EA approach (for both the oil sands expansion and the nuclear heat supply) is coordinated and agreed with the host oil sands producer a comprehensive and complete license application to prepare the site should be drafted and submitted to the CNSC to initiate the overall nuclear licensing process. In order to make these technologies available as options to the oil sands industry, site license applications (based on very preliminary project designs) should be filed as soon as possible to initiate the necessary resource development and long chain of events associated with such first-of-a-kind projects.

- Once a reactor has been developed to preliminary project design with the exception of the vendor initiated PPDR process the nuclear licensing process cannot be pursued in isolation and the potential for delivery of a real project requires close coordination with host oil sands producer(s).

2 Canadian Nuclear Regulatory Requirements

2.1 Overview

We define "Nuclear Licensing" for the purposes of this document as the process by which a Canadian nuclear facility (in this case a nuclear reactor used to produce steam and electricity) receives the necessary approvals and licenses to certify the nuclear technology for a particular site, to release procurement and construction, to test the facility and allow fuel loading, and to commence commercial operation.

Nuclear licensing requirements for novel nuclear reactor technologies will require adaptation of the existing Canadian nuclear regulatory framework imposed by the federal government. This framework of policy, standards, guides, and regulations has evolved to manage the construction, operation, and refurbishment of Candu® technology plants from developmental to commercial designs, but has only recently been further developed and extended to introduce "technology-neutral" design evaluation concepts. Current efforts by the CNSC are focused on expanding this regulatory framework to allow the potential introduction of large electricity generating Advanced Light Water Reactor (ALWR) technologies in Canada and although the regulations recognize the advanced nuclear heat/cogeneration technologies under review in this report they are not drafted to allow assessment of such technologies at this stage. The regulations permit such novel technologies but only through the use of a special clause that requires proponents to provide all necessary information, testing results and codes to support an application and as such places clear emphasis on the reactor designer to already have an approved design or set in place work itself to support such approvals. However, initial discussions with the CNSC and other government agencies indicate that a strong supportive government policy will be needed to reallocate resources and priorities to prepare for the eventual evaluation of such advanced nuclear plant designs.

2.2 Nuclear Regulatory Framework

The term "Nuclear Regulatory Framework" applies to the organizations, processes, documentation, and responsibilities associated with implementing laws and government policy that define oversight of the nuclear industry in Canada.

2.2.1 Background

All nuclear power plants in Canada are licensed and regulated by the Canadian Nuclear Safety Commission (CNSC). The CNSC is an independent, quasi-judicial administrative tribunal and regulatory agency that reports to federal Parliament through the Minister of Natural Resources. The CNSC regulates 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. Nuclear regulation is solely under federal jurisdiction, and the CNSC has no provincial counterparts.

Though the early aspects of the nuclear licensing process as traditionally understood has been overtaken and paralleled in some respects by the introduction of the CEAA and EA processes the nuclear legislation is complete and has been thoroughly overhauled and updated to reflect modern concepts.

The CNSC itself consists of two components: a Commission tribunal and CNSC staff. Members of the Commission are appointed by the Governor in Council, and their appointment is based on their professional achievements. The tribunal is a court of record and is responsible for establishing regulatory policies on matters related to health, safety, security, and the environment, making legally binding regulations and licensing decisions based on law and regulations. CNSC staff is responsible for providing advice and technical support to the Commission tribunal, implementing tribunal decisions, and enforcing compliance with regulatory requirements.

2.2.2 Nuclear Licensing Requirements

The licensing framework is defined by the Nuclear Safety and Control Act (NSCA) [1]. Five phases of reactor life are identified by the NSCA and a separate license is required for each of them. The five required licenses (one for each phase of reactor life) are: (1) the license to prepare a site, (2) the license to construct the reactor, (3) the license to operate, (4) the license to decommission, and (5) the license to abandon the site.

Three nuclear license applications will be required to allow commercial operation of the plant: (1) the application to prepare the site, (2) the application to construct, and (3) the application to operate the reactor(s). These license applications can be evaluated by the CNSC in parallel although they do not necessarily need to be submitted together.

The nuclear license application is defined under S 24(2) of the NSCA and triggers an EA under the CEAA to determine whether the project may cause significant adverse environmental effects, taking available mitigating measures into account. The EA is carried out in parallel with consideration of the initial nuclear license application and granting of the initial or any further nuclear licenses can only be made following a positive EA decision.

Existing Canadian reactors are essentially of one type, the pressurized heavy water reactor and the regulatory infrastructure has developed in response to the Candu® design. The CNSC is developing a new regulatory framework for licensing a wider range of nuclear reactors developed from its existing regulatory documentation suite to allow the introduction of a "technology neutral" position that would additionally allow the assessment of traditional large power reactor such as the "Advanced Light Water Reactors" but not the novel reactor systems under consideration in this document. However, the existence of such advanced novel reactor systems has been recognized in draft RD-337 Design of New Nuclear Power Plants [2] and handled through the introduction of a special clause 11.0 dealing with "alternative approaches" as follows; "The Commission will consider alternative approaches to the expectations in this document where there are special circumstances." and "Any such alternative approaches shall demonstrate equivalence to the outcomes associated with the use of the expectations here, and such a demonstration will be examined in greater depth by the Commission to gain such an assurance.". It must be noted that although the existing regulatory framework has been in continuous operation for the existing power reactors and is used as the basis for continuous review of design safety neither the "technology neutral" nor the "alternative approaches" discussed above have been fully tested since to date no reactor applications have yet been approved under this framework.

Three applications for licenses to prepare a site for large central station nuclear power generation plants have been submitted to date. Bruce Power has submitted two applications, one draft application for a site in Peace River, Alberta site (4000MW of undefined design), one formal application for a site in Tiverton, Ontario (4000MW of Generation III Canadian, e.g. 1000MW class Advanced Candu Reactor (ACR) or foreign design ALWRs) and Ontario Power Generation, a provincially owned utility has submitted a formal application for the Darlington site (4800MW and 4 reactors of ALWR, ABWR or hybrid PHWR e.g. ACR-1000).

While not formally part of the nuclear licensing process, a Pre-Project Design Review (PPDR) is in progress funded by the reactor designer Atomic Energy of Canada Limited (AECL) for the ACR-1000. This step was specially requested by AECL to address new Candu® technology concepts (enriched fuel, light water coolant etc.) and is meant to speed up the licensing process, although it is yet to be seen if it will actually do so. During the contracted PPDR paid for by the reactor vendor (or proponent), the regulator and the licensee aim to identify areas of concern that may interest the regulator during formal licensing and to understand how the regulator would treat those areas. Whether or not a reactor design has been licensed in its home country serious consideration should be given to participation in the PPDR process to reduce the risk of delays due to technical unfamiliarity and to address the treatment of novel concepts e.g. fuel design etc.

The timeframe of the licensing process for a new nuclear plant in Canada depends upon a number of factors, but recent experience with conventional oil sands projects indicates that it could take up to 3-years just to complete the necessary EA process. The CEAA requires that all projects undergo a simplified screening process by the responsible authority (in this case the CNSC) to determine the environmental significance of the project and any mitigation measures. On completion of the screening if further review is thought necessary the project may be referred to a mediator to resolve outstanding issues or to a review panel that will carry out a comprehensive review to determine and decide on the environmental significance of the project and whether it should be given approval to proceed.

Nuclear power projects fall under the category of projects identified in the Comprehensive Study List Regulations (SOR/94-638) [3] that are mandated to undergo comprehensive study and as follows from past custom and practice likely to be required to have a review panel appointed (and in fact a joint federal and provincial review panel hereafter referred to as a "joint panel"). Therefore, one option available to speed up the EA process is for the responsible authority to immediately recommend that the EA is referred to a joint review rather than wait for the Minister to make such a decision later in the process. This immediate referral potentially saves up to 8-months in the approximate 3-year EA process discussed above. The achievement of the 3-year EA process schedule is heavily dependent on the quality of the submissions by the applicant and a further complication will be the degree of cooperation between the applicant and the oil sands producer (who could be one and the same) as the oil sands expansion EA approval process will be being undergone at the same time as the nuclear facility EA and will be dependent on similar if not identical site and environmental information for the production of EA submissions.

The approximately 3-year EA process as envisaged above is administered by the CNSC through a newly formed agency, the Environmental Assessment and Protection Directorate. As described above the timeline for EA approval can be reduced through a number of actions, including: early CNSC recommendation to a joint review panel, submission of a comprehensive and complete application package (as evidenced by the early acceptance of certain recent project descriptions), completion of any outstanding safety issues (as raised by the design's domestic nuclear safety regulator), and suitability of the chosen safety analysis regime.

While the CNSC will make decisions regarding these licenses in sequence, there are licensing processes that license applicants may pursue in parallel. All regulatory work performed by the CNSC in reviewing and assessing the information pursuant to license applications is billed to the license applicants under arrangements agreed at license application. The values in Table 1 are indicative CNSC (only) costs (estimated and prorate for thermal capacity and safety class) for a representative PPDR, the first three licensing phases and yearly operational costs.

Table 1 - Indicative CNSC Costs prorated from Existing Facilities

Task	Cost (C$m)	Duration (years)
PPDR	3	2
License to prepare the site	5	2
License to construct	20	3
License to operate	8	3
Annual operational oversight fee	2	plant life

The project developer/owner will have to budget for these costs, and may choose to seek support from the provincial or federal government for these and other first project costs which could be extensive and greater than the CNSC component especially if a significant CNSC mandated testing or validation program has to be initiated to support the safety report. After first-of-a-kind projects are licensed and operational it is expected that the cost and duration of CNSC licensing review will be less but annual oversight fees will remain as indicated.

2.2.2.1 License to Prepare a Site

The license to prepare a site initiates the EA process, and allows the beginning of the chain of licensing activities critical to the schedule of a new project. CNSC may require 2 to 3 months to review and approve an application, depending on the level of public and intervener interactions. The required project description can take a year or longer to prepare, since it requires collection of site environmental and meteorological data should this not already exist.

As neither the NSCA nor its regulations specify limits as to the time interval between issuance of the different licenses or the review period of a proposed license application, the CNSC staff's assessment of one or more components of a license application may be carried out concurrently and may proceed while the EA is underway.

The first three licenses may be submitted and approved in parallel (whilst recognizing that it is not advantageous to do so with the operational license), but before any of the licenses are granted, an EA must be performed and deemed acceptable. Both the Darlington site EA and the Tiverton site EA have been referred by the Minister of Environment to a review panel, in response to a request by the CNSC. The joint review panel procedure enables more public comment than the comprehensive study. Whilst the joint review panel procedure enables more public comment than the comprehensive study, the reduced possibility of legal challenge during the process (from perceived insufficient consultation) and a potentially earlier decision offers schedule advantages to the project proponent.

Whilst the province currently has no experience with nuclear licensing, discussions between the province and CNSC have occurred to define joint responsibilities in the EA process as the EA process has a precedent that when a federal agency is involved (such as CNSC), that agency will take the lead and coordinate a joint assessment with other federal agencies/departments and the province. This arrangement currently is the case for other major infrastructure projects in the oil sands where those projects interact with federal responsibilities (e.g. Ministry of Natural Resources, Fisheries and Oceans, Environment etc.) with joint review panels being the norm for such developments.

Under the regulations, an applicant, for any license, must submit inter alia a project description of the facility and plans showing the location, perimeter, areas, structures, and systems of the facility. An application for a license to prepare a site does not require detailed information or determination of a reactor design. Examples of such successful "generic" project descriptions now exist that do not even define the nuclear technology to be implemented and can be used as templates. Therefore, an application for a license to prepare a site can be submitted even if only conceptual engineering has been completed for a project. It should be noted that the next phase application for a license to construct the facility must contain detailed information about the reactor design and a supporting safety case, which requires completion of preliminary engineering for the project.

The three options concerning submission of information on reactor designs pursuant to an initial application to prepare a site are: (1) the license applicant may identify a single design, resulting in the EA focusing on the potential environmental impacts of that design, (2) the applicant may identify two or more designs, resulting in the EA focusing on the potential environmental impacts of each reactor design, and (3) the applicant may not identify any specific design in detail and only provide a proposed performance envelope for the plants, resulting in the EA focusing on a broad envelope of potential environmental impacts associated with multiple designs identified by the applicant. In all cases, the determination of the EA will be based upon the option chosen by the applicant and, in the final analysis; the identified impacts to the environment will need to sufficiently encompass the applicant's final technical proposal.

In reviewing the license to prepare the site, the CNSC requires that the applicant identify any characteristics of the site that may impact the 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 will consider how external events such as earthquakes, tornadoes, and floods, might affect human safety by analyzing the radiation transport properties of the site and the density and characteristics of the nearby population. At least one public hearing is required to be held during the licensing review, giving local public officials and affected citizens (including interveners) the opportunity to participate in the process.

While the licensing process is discussed in more detail in INFO-0756, Licensing Process for New Nuclear Power Plants in Canada [4], factors that may influence the duration of the licensing process (as identified in Figure 3, page 16 of INFO-0756) include:

- the EA process, which could take up to 36 months, as a best estimate based on past experience;
- the comprehensiveness and completeness of information required to accompany the application;
- the time required by the applicant to carry out its activities;
- safety issues that may require resolution before CNSC staff prepare their recommendations to the Commission; and
- the availability of resources for the CNSC to carry out its review in a timely manner (which can be impacted by priorities set by government policy).

2.2.2.2 License to Construct the Reactor

As opposed to an application to prepare a site, an application for a license to construct the facility must contain detailed information about the chosen reactor design and a supporting safety case. For a mature reactor design this application is normally submitted about 2-3 years before planned release of procurement and construction, as it requires preliminary engineering for the project completed sufficiently to address safety issues. CNSC is expected to require 24 to 36 months to review and approve such an application.

The reactor design review may be carried out in parallel with the EA process and will require the submission of information required under the regulations about the design, the preliminary safety analysis, and final safety analysis. The CNSC must find that the reactor design can be safely operated in Canada before the process moves forward. This review involves detailed engineering and scientific analysis of the operating conditions of the plant, with particular focus on the plant's behavior under normal and accident conditions. The current expectation is that the review will be carried out in accordance with the draft Regulatory Standard S-310, Safety Analysis for Nuclear Power Plants [5] (based on the existing Candu® Pressurized Heavy Water Reactor standard modified for a "technology-neutral" environment).

The radiological risk posed to the public must be found to be acceptable for the license to be issued. The applicant must additionally submit a plan for minimizing and mitigating the impact of the construction, operation, and decommissioning of the plant on the environment (linked to the EA requirements) and on human health and safety, as well as a plan for hiring and training well-qualified operating and maintenance personnel.

Based on the submitted information from the license applications and/or the EA process, the CNSC staff may engage in discussions with applicants to clarify the understanding of the CNSC's regulatory requirements. License applicants have to provide their own resources, including, if necessary, third-party analyses, to ensure that an independent safety assessment is performed before the design is submitted to the CNSC. These costs are borne by the applicants in addition to the cost of CNSC services identified in Table 1 above.

Under the NSCA, as is the case for all other nuclear facilities, the applicant is solely responsible for the safety of the facility and for satisfying the Commission through a public licensing process that it is qualified and that it will make adequate provision for the protection of health, safety, security, and the environment, and Canada's international obligations in carrying out the proposed activities throughout the intended life of the project.

The review of the detailed engineering and safety of the proposed reactor design can be completed early but as with the license to prepare the site the construction license cannot be issued until the completion of the EA, with a recommendation to proceed. In practice EA process can be concluded using a generalized design envelope before detailed engineering and safety reviews are undertaken in support of the license to build the plant.

2.2.2.3 License to Operate the Reactor

The application to operate the reactor is normally completed while the plant is under construction and submitted 3 years before expected fuel load and startup of the plant. The CNSC staff is expected to need 24 to 36 months to review and approve this application.

The applicant must demonstrate to the CNSC that the reactor has been constructed according to design and that the necessary policies and procedures are in place to ensure that the plant staff are trained and well qualified and 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 as necessary. 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.

Discussion with CNSC has revealed that although it is not necessary for an existing Canadian license holder to be the operating license applicant or part of the consortium holding the operating license, it is extremely important for the applicant to understand and prepare for its operational responsibilities and appropriately plan for this experience to be developed well in advance of applying for the license, this may extend the review period required by the CNSC if the appropriate planning and preparations have not been made. Development of such necessary experience includes: participation in managerial and technical improvement initiatives, such as those operated by INPO and WANO, participation in peer review activities prior to operation (and commitment to such activities during operation), and early development of operator training concepts.

2.2.2.4 License to Decommission the Reactor

A plant owner must plan to submit an application for a license to decommission the reactor in anticipation of the end of the life of the project. This license will allow the owner to initiate a decommissioning project which entails demolition and removal of the facility and restoration of the site.

Although an operating license application requires a decommissioning design and cost estimate to quantify operational financial obligations, the details of how this is implemented can be finalized later during plant commercial operations as actual decommissioning approaches.

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. An application for a license to decommission the reactor would be submitted several years before intended decommissioning, or quickly in response to an event or decision that leads to early end of life.

The CNSC requires that a preliminary (or generic) decommissioning plan be filed as early as possible in the life cycle of intended project, with decommissioning concepts being considered in the detailed design necessary for the construction license and due to the impact of design decisions on the decommissioning cost estimate necessary for pre-operational financial guarantees. This preliminary plan should be revisited and updated throughout the operational cycle, with a detailed decommissioning plan required to be submitted for approval by the CNSC before the commencement of decommissioning activities.

The preliminary decommissioning plan will contain the design, construction, and operational practices that support the decommissioning processes, the intended or preferred decommissioning methodology, quality arrangements, materials handling, proposed clearance levels, waste management, radiological surveys, health and safety practices, security, emergency response, financial guarantee program, and end state reporting. Detailed content requirements for such plans are available from CNSC.

The CNSC also requires that nuclear licensees make adequate provisions for the safe operation and decommissioning of operations. This requirement necessitates the provision of adequate decommissioning plans, credible estimates of the cost of implementing such plans, measures to support achievement of such costs, and the successful delivery of such decommissioning plans. Each licensee is tasked with submitting adequate decommissioning plans and the financial guarantees considered appropriate to ensure their achievement.

Decommissioning cost estimates have to be submitted along with the preliminary decommissioning plan, but the level of confidence of the estimates may vary and hence the amount of contingency that is necessary will vary according to predetermined levels.

Funding of decommissioning liabilities is required to be through an arm's length arrangement that ensures that such funds can be released should the licensee not be in a position to fulfill. Financial guarantees are required to assure that payout of funds is not prevented, unduly delayed, or compromised. Such guarantees must be in the form of cash, irrevocable letters of credit, surety bonds, insurance, or expressed commitments from a Government entity. Parent company guarantees are not acceptable. Periodic review of such guarantees and the performance of instruments associated with those guarantees are necessary to ensure their adequacy for their intended purpose.

2.2.2.5 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. An application to abandon the site is prepared and issued during the decommissioning project. Once this license is obtained, the owner's further responsibilities at the site are released, with the possible exception of long term temporary fuel storage facilities it they have to be maintained at the site until the federal government removes the spent fuel. Such extended costs would be the responsibility of the government given its responsibility for ultimate spent fuel management and disposal.

2.2.3 Licensing Process

The exact requirements associated with each of the licenses granted by the CNSC are still under revision. Initial discussions with CNSC and other current indications are that requirements will be technology-neutral, based on safety requirements that can be applied to any type of reactor although prioritized to traditional large power reactors.

The CNSC has been actively involved in the IAEA's development of international nuclear safety standards and it is expected that the CNSC's regulations will bear some resemblance to IAEA standards. CNSC Regulatory Document (RD) 310, "Safety Analysis for Nuclear Power Plants" (February 2008) [6] lays out the current risk-informed requirements for the safety analysis of new Nuclear Power Plants (NPPs). It sets forth the methods to be used in selecting initiating events, acceptance criteria, analysis methods, and review processes. The guidelines in RD-310 are technology-neutral, and can be applied to LWRs, PHWRs, and HTGRs alike. Guidance identifies that Probabilistic Safety Assessments (PSAs) in Canada are to be conducted in accordance with IAEA level 1 and level 2 PSA standards.

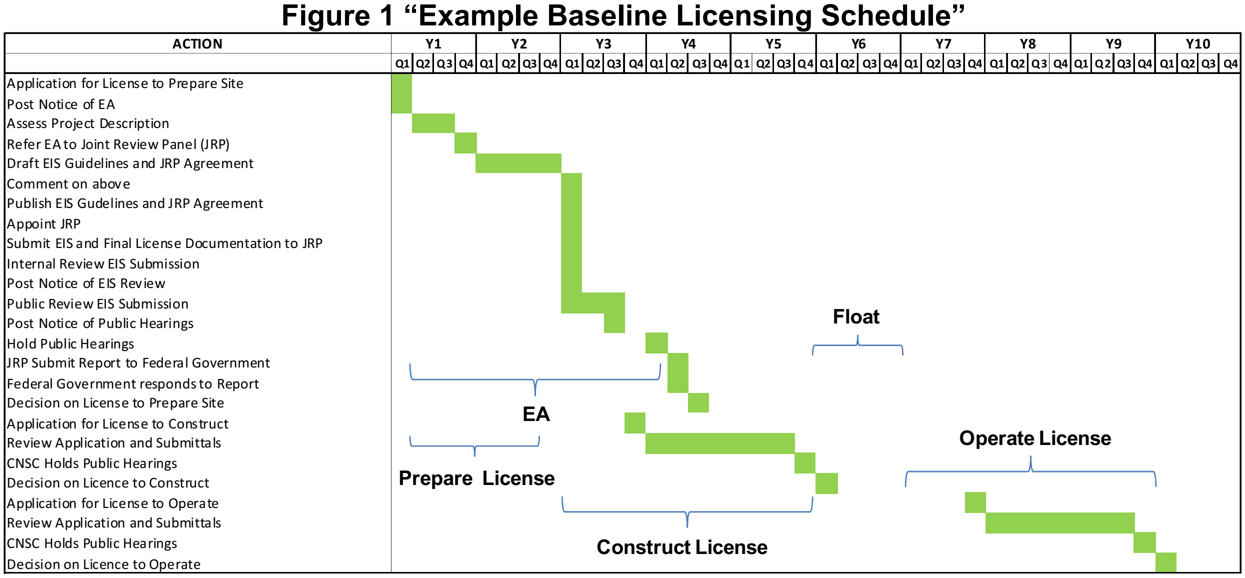
A number of draft RDs have recently been issued by the CNSC, including RD-346 "Site Evaluation for New Nuclear Power Plants" (October 2007) [7], and RD-337 "Design of New Nuclear Power Plants" (October 2007) [2]. RD-346 is adapted from the IAEA document NS-R-3 "Site Evaluation for Nuclear Installations" and provides an overview of criteria to be considered in siting a new NPP. RD-337 also draws heavily on IAEA guidelines and is intended to be technology-neutral.

2.2.4 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. As explained above referral of the EA to a panel review could save about 8 months. Completion of the EA process is a pre-requisite for approval of the site license application to the CNSC. The times 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. Therefore, the first time a technology is proposed for a project there may need to be additional effort to develop quality supporting information and to explain it to CNSC. Currently the CNSC estimates that the process of obtaining those three licenses in series (the initial license application also initiating the parallel EA process) would take about nine years, see Figure 1 “Example Baseline Licensing Schedule”. Figure 1 is based on CNSC data for a traditional large power reactor and has been annotated for clarity. A number of factors can influence this baseline schedule such as for example “pursuing the licenses concurrently” which may offer some reduction in the total time required for licensing but such an approach will be limited by the availability of detailed engineering and safety analysis work, especially for a first time project. If a complete reactor design/safety case is already licensed in another jurisdiction this could potentially allow significant schedule improvements especially for the first project.

For comparison, the United States Nuclear Regulatory Commission (NRC) has a slightly different nuclear licensing framework than CNSC’s. The NRC uses a Design Certification (DC) to approve the reactor design, an Early Site Permit (ESP) to approve a potential site, and a combined Construction and Operating License (COL) to approve a new reactor project. The DC and ESP steps are optional and, if undertaken early, could shorten the effort required to obtain a COL. The DC effort in the US loosely relates to the PPDR process in Canada. The PPDR is less formal being driven by the proponent but intends to achieve acceptance of key technology design and safety approaches in advance of a site specific project.

Figure 1 “Example Baseline Licensing Schedule”



To assist in understanding the potential schedule risks in the nuclear licensing process an estimate of possible schedule impacts of a series of scenarios has been tabulated in Table 2 below for novel nuclear technologies of the type being considered in this report and these can be applied to the Example Baseline

Licensing Schedule in Figure 1 as necessary.

Table 2 - Possible Licensing Schedule Impacts

Scenario Description	Impact	Note
Early reference to joint review panel	-8m	To EA
Parallel prepare/construct application	-12m	To construct license
No proponent	100%	Delay to start
No defined site	100%	Delay to start
No existing nuclear licensee	+12m	Unless otherwise mitigated
No rig tests	+24m	Delay to construct license
No approved safety case	+30m	Unless otherwise mitigated
No home country license	+12m	Unless otherwise mitigated
No operating experience	+12m	Delay to operate license
Supply chain availability/design readiness	-12m	Use of float in example schedule

2.3 Key Nuclear Licensing Issues and Risks

2.3.1 CNSC Resources

When new reactor applications are submitted to the CNSC, there is a risk that they will face delays due to inadequate staffing since Canada has not licensed a new reactor in the past 25 years there has been no need to keep up a full staff of new project licensing engineers.

The CNSC has publicly restated [8] its priorities as to "Ensure baseline compliance on existing facilities whilst regulating new major facilities". The CNSC has become a recent signatory to the Major Projects Management Office initiative which is committed to streamlining of regulation. The establishment of a New Projects program within the CNSC has already been funded through federal budget changes and has allowed the commencement of a major recruitment program to service the forecast new build program and support the PPDR being carried out on AECL's ACR-1000. Whilst such recruitment is underway to satisfy the requirements of the confirmed Ontario and the potential Alberta/Saskatchewan new build programs where a novel reactor system design review would sit in CNSC work prioritization without a PPDR or license application is subject to some conjecture.

Discussions are being held with both Areva and Westinghouse regarding the use of the PPR process on their designs. For different technologies, there is even a greater imperative for early engagement with the CNSC and the development of a PPDR program.

A critical new component of the nuclear licensing process is the introduction of a "Regulatory Contract" between the CNSC and license applicant defining requirements, costs, roles, responsibilities, deliverables and deadlines and this offers some certainty to the proponent as to the cost and timeline for licensing.

2.3.2 Computer Program Qualification

The CNSC has qualified computer programs that it has historically used for the technical and safety oversight of Candu® reactors and those are used in safety assessments. However, the programs currently in use will not be appropriate for all non-Candu® reactor technologies and so suppliers of new technologies may need to present new computer modeling programs for regulatory acceptance. Any new programs will have to undergo validation and verification design reviews. The guidelines for this process are set forth in CNSC Regulatory Guide G-149 "Computer Programs Used in Design and Safety Analysis of Nuclear Power Plants and Research Reactors." [9]. This requirement is likely to have a greater impact on gas-cooled reactors than LWRs, since no computer programs for gas-cooled reactors have been validated with either the CNSC or the NRC. LWR computer programs have undergone similar validation with the NRC, which is likely to expedite the process with the CNSC considerably.

2.3.3 Co-Location with Industrial Process Plants

Whilst there is no precedent in Canada for the licensing of a NPP in close proximity or in thermal communication with an oil processing facility, the Bruce A site has supplied steam and power to the local industrial park (Bruce Energy Centre) who have operated plastics and chemical production facilities for a number of decades.

The safety case for the advanced nuclear reactor design will have to consider such unique features that co-location in an oil sands application presents as compared with the large central station nuclear power stations and will require additional analysis by the license applicant. Two key issues will be the identification of potential hazards by the host site provider in support of plant safety analyses, and the evaluation of long term commitments made by the site host to avoid the introduction of unacceptable hazards in the future which could undermine an operating license.

2.3.4 Nuclear Fuel Supply and Disposal

The nature and design of nuclear fuel will have impacts in the licensing process as historically Canada has used natural uranium fuel in their Candu® reactors and does not have any enrichment capability. However, this issue is not what it once was in that low enrichment fuel is being qualified for use in the commercial Candu® fleet and similar fuel will be used in the ACR-1000. The necessary international frameworks are in place for the import of enrichment services and fuels and should not prove an insurmountable obstacle for the fuel types being considered in this report.

Spent nuclear fuel disposal is regulated under the Nuclear Fuel Waste Act, June 2002 [10] and the strategy has been defined by the Nuclear Waste Management Organization (NWMO) as one of "Adaptive Phased Management". The strategy is based upon a centralized repository concept, but with a phased approach that includes public consultation and "decision points" along the way, as well as several concepts associated with centralized storage (vs. disposal), and the ability to modify the long-term strategy in accordance with evolving technology or societal wishes. The approach of Adaptive Phased Management was formally accepted by the federal government on June 14, 2007. The chosen spent fuel approach appears compatible with the technologies being considered in the report although it may not be relevant for fuels capable and chosen for later reprocessing.

2.4 Licensing Strategy

The licensing of any new NPP in Canada will be undertaken in the context of a regulatory framework that is still under development and thus is not completely predictable to the applicant. Given that reality, it is crucial that license applicants take full advantage of the optional PPDR process to address unique issues regarding design features, safety case philosophy acceptable analytical methods and environmental differences from other well understood technologies. Discussions with the CNSC will have to be initiated by the applicant to identify new expectations between the planned submissions of the applicants and the expectations of the CNSC.

Prior to the initiation of a license application, validation and verification of any necessary computer programs must be completed. A review of this work during the PPDR is essential, since the rejection of the modeling qualification would be a major impediment to the licensing process adding delay risk and extra cost. Since qualification of computer models may require additional time consuming experimental procedures, it is in the interest of the applicant to identify issues at the outset and to prepare supporting analysis and testing in advance. This is likely to represent a major investment by the nuclear technology supplier.

In addition to computer program qualification, a PPDR should include a review of the issues related to co-location of a NPP with an industrial facility if that is planned for the NPP in question. Key issues will include process industry facilities associated with potential chemical release and explosion hazards. If the applicant plans to use any "alternative approaches" to fulfilling the design safety analysis, as provided for in the draft version RD-337 (October 2007), these should be brought forward during the PPDR. Any alternative approach will require a more detailed review than the approach outlined in the regulatory documents. Thus, the acceptability of the approach to the CNSC should be confirmed prior to license application.

During the PPR, the applicant should also introduce any ancillary facilities or functions that are unfamiliar to the CNSC and that may require review and approval. These may include fuel manufacturing facilities, fuel transport equipment or certain processes and any manufacturing plants to be used in the construction of the NPP. In the case of the gas-cooled reactor, the CNSC may need to be familiarized with quality control standards for graphite or helium, as well as with the design, qualification and manufacturing process for the fuel elements.

The PPR should be taken very seriously to ensure that the ultimate construction license application package meets the CNSC's expectations. In order to accelerate the site preparation licensing process, a license application should be initiated as soon as a site can be identified and a comprehensive and complete application can be submitted, allowing the EA process to begin.

2.5 Conclusions

The CNSC has made a commitment to a technology-neutral licensing framework that will be equally accessible to all license applicants, this sets the stage for licensing of advance reactor designs. While next-generation nuclear power plants will be less familiar to the CNSC compared with the indigenous Candu® technology, this is largely a result of a lack of exposure to the technology, rather than an inherent bias in the regulations. However, the CNSC seems enthusiastic about learning about other designs and is heavily involved in the IAEA efforts to create an international technology-neutral licensing standard. This emphasizes the need for a PPDR process to be established at the earliest possible time to assist in development of a stable licensing requirement set for novel advanced reactors, assist the CNSC in its familiarity with the technology and prepare them for design review. Additionally, each of the licensing risk issues can be better framed and mitigated once there is a formal means for engagement with the regulator.

3 Glossary of Terms and Acronyms

ABWR	Advanced Boiling Water Reactor
ACR	Advanced Candu® Reactor
AECL	Atomic Energy of Canada Limited
Alberta Energy	Alberta Ministry of Energy
Alberta Environment	Alberta Ministry of the Environment
ALWR	Advanced Light Water Reactor
CANDU®	CANada Deuterium Uranium
CEAA	Canadian Environmental Assessment Act
CNSC	Canadian Nuclear Safety Commission
CO_2	Carbon Dioxide
COL	Construction and Operating License
DC	Design Certification
EA	Environmental Assessment
Environment Canada	Federal Ministry of the Environment
ERCB	Alberta Energy Resources Conservation Board
ESP	Early Site Permit
IAEA	International Atomic Energy Agency
INPO	Institute of Nuclear Power Operations
LWR	Light Water Reactor
MW_t	Megawatt-thermal
NEI	Nuclear Energy Institute
NPP	Nuclear Power Plant
NRC	United States Nuclear Regulatory Commission
NRCan	Federal Ministry of Natural Resources
NSCA	Nuclear Safety and Control Act
NWMO	Nuclear Waste Management Organisation
PHWR	Pressurized Heavy Water Reactor
PPDR	Pre-Project Design Review
PSA	Probabilistic Safety Assessment
RD	Regulatory Document
WANO	World Association of Nuclear Operators

4 References

[1] Nuclear Safety and Control Act, 1997, c. 9, N-28.3, [Assented to March 20th, 1997]

[2] RD-337, Design of New Nuclear Power Plants, October 2007

[3] Comprehensive Study List Regulations (SOR/94-638)

[4] INFO-0756, Licensing Process for New Nuclear Power Plants in Canada

[5] Regulatory Standard S-310, Safety Analysis for Nuclear Power Plants

[6] RD-310, Safety Analysis for Nuclear Power Plants, February 2008

[7] RD-346 Site Evaluation for New Nuclear Power Plants, October 2007

[8] T Jamieson "Licensing Nuclear Reactors in Canada, Recent Changes to the CNSC Approach", 10th International Canadian Nuclear Society Fuel Conference on Candu Fuel – October 2008

[9] Regulatory Guide G-149, Computer Programs Used in Design and Safety Analysis of Nuclear Power Plants and Research Reactors

[10] Nuclear Fuel Waste Act, June 2002

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Canadian Outreach Needs to Support an Advanced Nuclear Reactor Technology Plant

Project Report

Summary of Canadian Outreach Needs to Support Deployment of Advanced Nuclear Reactor Technologies

Submitted to

MPR Associates

October 30, 2008

Shaw® Stone & Webster Management Consultants, Inc.

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1 Executive Summary

The objective of this report is to provide an overview of the outreach initiatives needed to support the nuclear and environmental licensing process, the development of Canadian and Alberta nuclear energy policy, and public understanding related to the commercialization of advanced nuclear technologies, such as high temperature (gas-cooled or liquid sodium-cooled) modular reactors. Outreach initiatives are needed to assist industry, public, and government stakeholders in understanding complex nuclear technology and safety issues. These outreach initiatives will exceed the minimum regulatory requirements for public consultation.

Successful commercialization of advanced nuclear energy technology requires not only technology development and first-of-a-kind nuclear licensing initiatives, but also widespread public acceptance and government policies that encourage and support new projects. An informed public acceptance of advanced nuclear energy technologies and recognition of its new, next generation safety paradigm are important to support a publicly accessible licensing and permitting process and also to satisfy industry users that their own relationships with the government, with the public, with customers, and with investors will be supportive of their association with nuclear energy. Branding, corporate image, future environmental licensing interactions and stock values could be impacted by public announcements that indicate plans to associate future industrial operations with nuclear energy.

In order for the opportunities provided by advanced nuclear energy technology to be realized, various mechanisms of a public and government outreach program should be initiated. The manner in which the public perceives risks must be considered in developing a public outreach program. This program should engage the public openly at the very early stages of commercialization and project development and provide accurate information from credible sources in accessible formats. The public will have its say in energy and environmental policymaking, especially as easier access to information about new energy and environmental technology becomes available through the internet and educational institutions. By ensuring that sound, factual information and judgments about nuclear energy are made available to the public from trustworthy sources, advanced nuclear energy technologies can improve their chances of achieving timely project implementation.

Public outreach initiatives should be undertaken in cooperation between the nuclear technology suppliers and potential industry users. Without some collaboration, there are risks that aggressive promotion of nuclear technology benefits could appear to be at odds with industry efforts to promote environmental compliance strategies and sustainability initiatives that include other technologies. A combined effort should seek public acceptance of nuclear technology as a complementary option to other strategies to avoid divisive support or confrontations between industries and technologies.

Outreach initiatives in support of the formation of new government policy, development of new regulations, rulemaking and legislation that encourage implementation of advanced nuclear technology will need to be supported by broad, high level studies of long term regional energy needs and supplies, environmental compliance and sustainability, industrial and economic development, quality of life, and international relationships. Some of these studies have already been undertaken as first steps toward identifying possible roles for advanced nuclear technology, additional studies will be needed to provide sufficient impetus for new government policy and regulatory directions. For example, Petroleum Technology Alliance Canada (PTAC) would be in a position to guide oil sands industry inputs to this process by coordinating the development of properly scoped studies and integrating technical, economic, and planning information into useful formats and venues.

Given the current uncertainty regarding public perceptions and support for new nuclear projects in Alberta, a given industrial user interested in assessing the nuclear energy option can involve the public as it initially evaluates new nuclear projects through a collaborative option strategy. Project development and nuclear licensing can be undertaken by a separate entity that will own and operate the nuclear energy facility. Given the long lead time for a nuclear project as constrained by the nuclear licensing process, the industry host, a possible steam and power off-taker from the nuclear plant, can tentatively plan a new expansion based on interchangeable conventional and nuclear options. The shorter lead time for a conventional cogeneration or steam production option allows the decision to proceed with final commitments toward implementation of a nuclear project to be made several years after the nuclear licensing process is initiated. Preliminary industry support to a nuclear project developer can be limited and conditional, with the nuclear project being a one of several options that is contingent on subsequent resolution of public acceptance and government policy, the refinement of project design and costs, and confirmation of long term project economics with government support for early projects. Early project planning must be undertaken to start long critical path nuclear licensing process needed to enable the nuclear option; however, final commitments need to be made only after consultation with public and government stakeholders based on a more complete project definition and resolution of stakeholder concerns.

2 Background and Introduction

Public interest in nuclear energy in Canada has grown dramatically in recent years. This increased public interest is a result of several decades of safe and economic operation of nuclear plants worldwide as well as growing concerns about global warming and the cost and long term availability of the premium fossil fuels that are currently the predominant energy sources. However, the energy consumption mix in Canada (shown in Figure 1) will only shift towards more nuclear energy with public acceptance and supportive government policies. Government energy and environmental policies reflect public opinion and set the basis for regulation and financial support for new nuclear plants. Both regulation and financial support are critical, as nuclear energy technology has historically relied on public and government approval to support capital financing in addition to permitting and licensing.

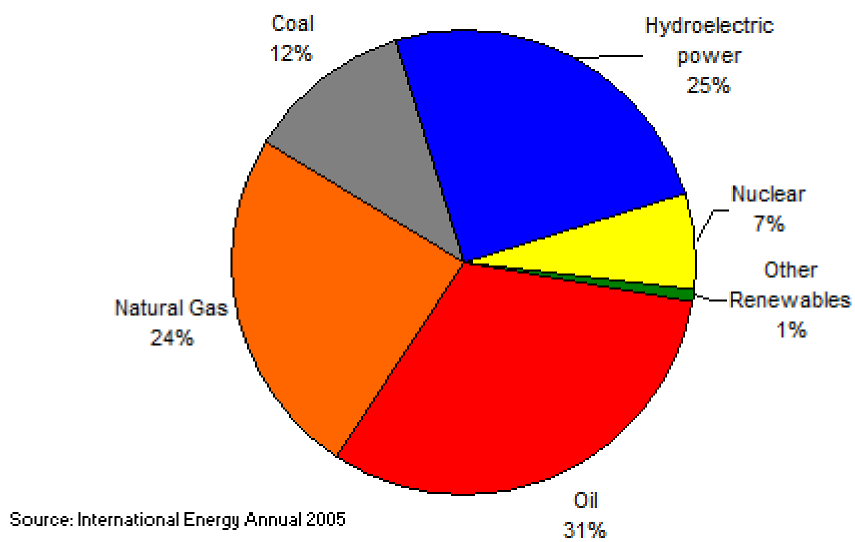


Figure 1. Total Energy Consumption in Canada by Source (2005)

Non-traditional applications for nuclear energy, such as providing steam and power for oil sands bitumen production and recovery, create new combinations of issues and involve new stakeholders. Companies considering using nuclear energy in oil sands applications have not previously associated with the nuclear industry and they now must evaluate the consequences of announcing their participation or support for new nuclear projects that could be perceived positively or negatively by the public and could directly impact stock values and investor decisions.

The emergence of nuclear oil sands applications will undoubtedly result in an intense level of public scrutiny, which can have a major impact on the viability of early projects. As real projects evolve and participants from outside the nuclear industry begin to evaluate the real and perceived project risks, public acceptance will become increasingly important. New nuclear technologies have the opportunity to build on the lessons learned from previous nuclear energy programs and to frame the public debate in the context of the increasing focus on climate change in the energy arena. This opportunity must be acted on very early in the development of the fleet as poor initial public impressions are difficult to reverse.

Public acceptance and supportive government policies will only be obtained through a comprehensive public and government outreach program. Such a program will involve engaging a multitude of stakeholders, including those in government, academia, and the general public. An effective outreach program needs to engage these stakeholders in an open manner in the early stages of a project and needs to address the key concerns associated with the advanced nuclear energy technology.

3 History of the Nuclear Industry in Canada and Alberta

The history of the nuclear industry in Canada and Alberta is vital to understanding the current public and government baselines throughout the country and province. The Canadian nuclear industry dates back to 1942 when a joint British-Canadian laboratory was established to develop a heavy water nuclear reactor. This research led to the first self-sustained nuclear reaction outside of the United States and the development of the CANDU® (CANada Deuterium Uranium) power reactor design that has been implemented in a fleet of commercial power plants in Canada and abroad. Currently, Canada has 18 CANDU® reactors in operation, generating about 15% of Canada's electricity and employing about 21,000 people directly and 10,000 indirectly. Ontario has 16 operating reactors and two reactors undergoing refurbishment, while Quebec and New Brunswick have one operating reactor each. Alberta has never had a commercial nuclear power reactor, but the University of Alberta in Edmonton does have a research reactor that is used as a source of neutrons for radionuclide production, neutron activation analysis, and other research. Commercial nuclear power in Alberta may exist relatively soon, however, as Bruce Power, with its acquisition of Energy Alberta, recently announced plans to construct a nuclear power plant in the Alberta's Peace River region.

Related Canadian industries include the uranium industry and the nuclear isotope industry, both of which are world-class. Canada's uranium industry dates back to 1929, notably supplied the uranium for the Manhattan Project in 1942, and has since grown substantially. Canada is currently the world's largest producer of uranium, with about one third of the world's production coming from mines in Saskatchewan. Canada's nuclear isotope industry is also substantial, with 85% of the world's medical and industrial cobalt-60 and 60% of the world's molybdenum-99 being produced in Ontario's Chalk River Laboratories and select CANDU power reactors.

4 Energy and Environmental Policy in Canada

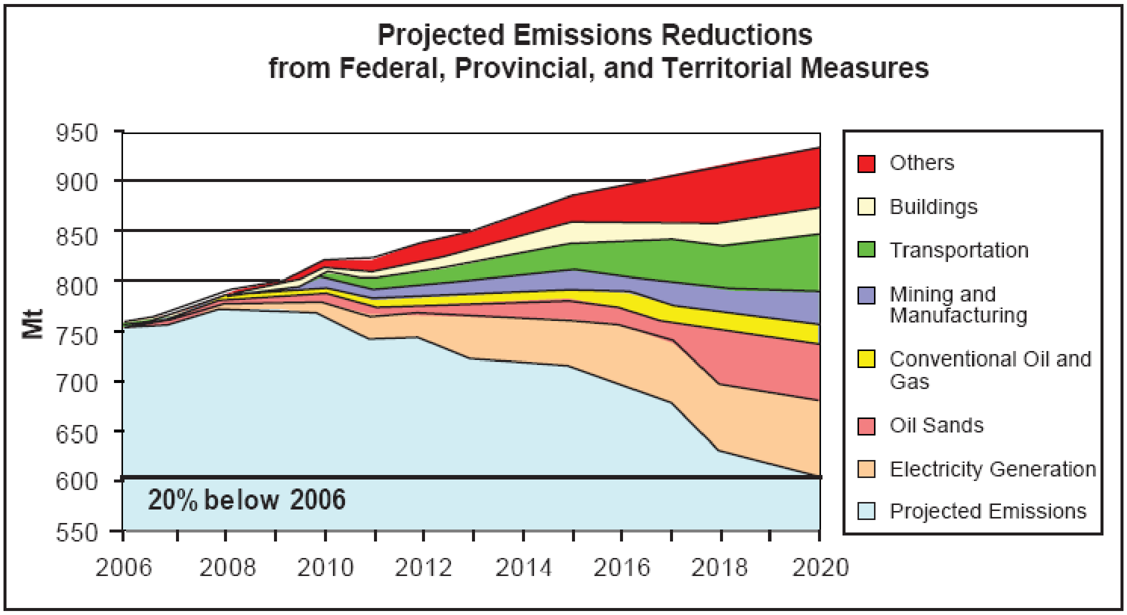
Government outreach is needed at both the federal and provincial levels in order to help shape energy and environmental policies that will allow nuclear energy to serve as the reliable, cost-efficient, greenhouse gas emission-free source of energy for oil sands operations that it has the potential to be. In Canada, the federal and provincial governments share jurisdiction over energy and environment. Provincial governments have jurisdiction over the exploration, development, conservation, and management of non-renewable natural resources as well as electricity production within their borders, while the federal government has jurisdiction over inter-provincial and international trade and commerce and the use of federal lands.

4.1 Federal Energy and Environmental Policy

The key energy and environmental governmental organizations at the federal level in Canada are the Ministry of Natural Resources (NRCan) and the Ministry of the Environment (Environment Canada). The National Energy Board (NEB) is an independent federal regulatory agency that regulates the Canadian energy industry, but is mainly concerned with issues associated with inter-provincial and international trade and commerce.

In 2002, Canada ratified the Kyoto Protocol requiring it to reduce greenhouse gas emissions to 6% below 1990 levels during the 2008-2012 period; however, as of 2006, emissions were 27% above 1990 levels. The projected emissions gap between Kyoto Protocol commitment and business-as-usual is estimated at 256 million metric tonnes of carbon dioxide equivalent (MMTCDE) per year (business as usual projection of 819 MMTCDE per year in 2010 versus Kyoto Protocol commitment of 563 MMTCDE per year).

In 2007, Canada's updated environmental targets were issued in a report entitled, *Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions*, which were augmented with additional details in 2008. The targets included in this document are intensity-based, with industrial sectors required to reduce their emissions intensity by 18% from 2006 levels by 2010, with continuous 2% improvement every subsequent year. Notably, for oil sands producers and upgraders, specific tougher requirements were specified, including drastic cuts in emissions by 2018 for facilities that come into operation in 2012 or after. These cuts are based on emission levels theoretically achievable with carbon capture and storage (CCS), but the emission levels could also be met with other "green" technologies. As a result of these proposals, the government stated new emission targets of 20% below 2006 levels by 2020 (2% above 1990 levels) and 60-70% below 2006 levels by 2050. The projected emission reductions between 2006 and 2020 are shown by sector in Figure 2. Given that these targets are less strict than those agreed to in the Kyoto Protocol and advised by the Intergovernmental Panel on Climate Change (IPCC), Canada may face continued domestic and international pressure to form a more restrictive climate change policy.



Source: Environment Canada.

Figure 2. Canadian Federal Emission Reductions by Sector

4.2 Alberta Energy and Environmental Policy

The key energy and environmental governmental organizations at the provincial level in Alberta are the Alberta Ministry of Energy (Alberta Energy) and Alberta Ministry of the Environment (Alberta Environment). Within Alberta Energy, the Alberta Energy Resources Conservation Board (ERCB) regulates the oil and gas industry, while the Alberta Utilities Commission (AUC) regulates the utilities industry. The Alberta government owns about 80% of the province's mineral rights (including oil, natural gas, coal, and oil sands) and is responsible for the exploration, development, conservation, and management of non-renewable natural resources, including assessing and collecting non-renewable resource royalties.

In 2008, Alberta issued a climate change action plan in which Alberta's greenhouse gas emissions would be reduced compared to business-as-usual by 50 MMTCDE per year in 2020 and 200 MMTCDE per year in 2050. As shown in Figure 3, Alberta's reduction commitments are less severe than the federal commitments, with emissions continuing to rise until 2020, and 70% of these reductions are proposed to be obtained through CCS. Relying so heavily on CCS technology to meet emission reduction targets is troublesome as the technology is uncertain and has recently been facing escalating cost estimates. Government outreach is necessary in order to inform policymakers about the potential of using nuclear energy in oil sands applications, enabling nuclear energy to make a significant contribution to Alberta's emission reduction targets. For example, a nuclear reactor that exports 440 MW_t of net high temperature heat (after internal energy consumption) in an oil sands application will displace up to 700,000 tonnes of CO_2 per year, roughly equivalent to the emissions from a large conventional gas-fired combustion turbine plant (e.g., GE 7FA). With a fleet of 20 such reactors, providing energy for only a fraction of Alberta's oil sands operations, about 13 MMTCDE per year would be displaced, over 10% of Alberta's emission reduction goal for 2035.

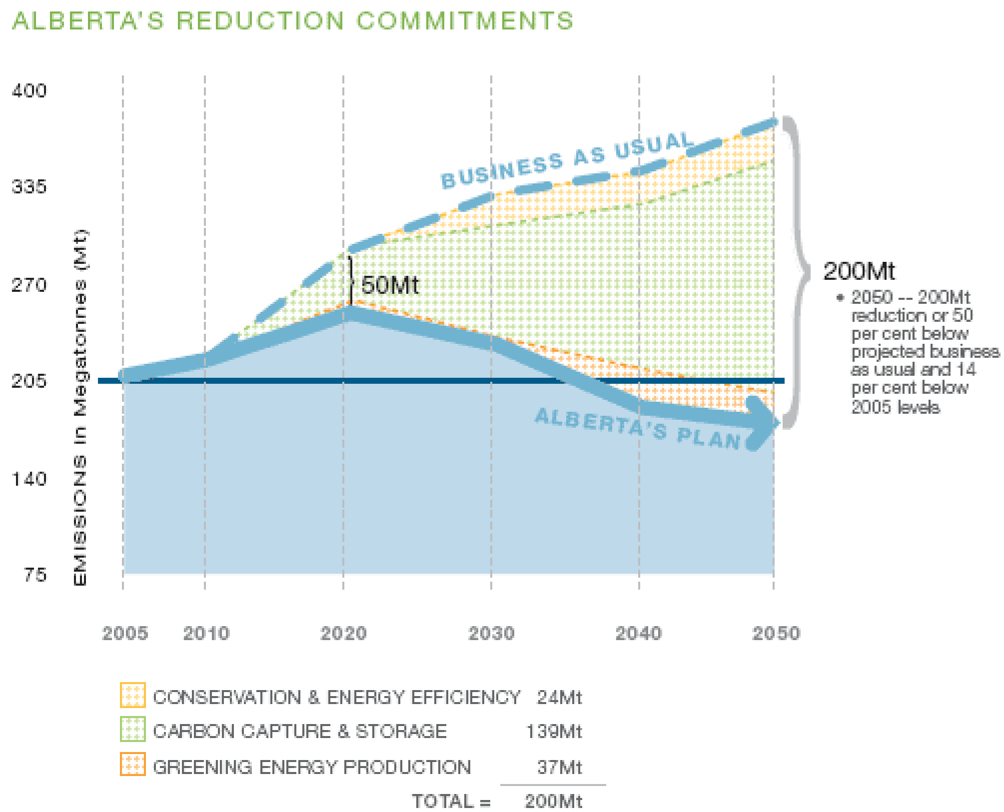


Figure 3. Alberta's Greenhouse Gas Emissions Reductions Commitments

In April 2008, the Alberta government appointed an expert panel to study the potential use of nuclear energy in Alberta. Its findings are expected to form the basis for future public debates and eventually a nuclear energy policy in Alberta. A supportive nuclear energy policy for oil sands applications is a vital component to a successful project and therefore engagement in these discussions are critical.

5 Public and Government Outreach Programs

5.1 Objectives

Outreach programs are needed in order to:

- support the development of constructive energy policy (supporting early development of nuclear regulatory capacity and skills and providing financial supports for first-of-a-kind costs and projects),
- support the development of practical regulatory policy (used as a basis for regulation and rulemaking),
- support the formal public consultation requirements mandated by the federal and provincial governments,
- develop broad public acceptance (supporting industrial user acceptance),
- eliminate misconceptions and incorrect interpretations of facts and data, and
- cultivate stakeholder support for early projects, providing time for accommodation of stakeholder interests and concerns and building familiarity.

5.2 Formal Public Consultation Requirements

One objective of an outreach program is to support the formal public consultation requirements that are mandated by the Canadian Environmental Assessment Act (CEAA) and by Canadian Nuclear Safety Commission (CNSC) regulations. Public consultation is required early on to identify public concerns with respect to the scope of the Environmental Assessment (EA) as well as during the conduct of the EA. Public consultation must include public notice, access to records, and public comment on the EA scoping documents, the EA comprehensive study, and panel review and mediation processes. Public hearings are also required as part of the EA process. Public comments are integrated into the scoping report, analysis and comprehensive study report. Later on, public hearings are also required by the CNSC as parts of the review of both the construction license and the operating license. These public consultation activities are required by law; an effective outreach program prepares for these formal interactions with a multitude of outreach initiatives that foster a more collaborative (rather than a confrontational) atmosphere during the formal interactions. Additionally, early interaction with stakeholders allows a more comfortable familiarization period without the formal pressure of regulatory deadlines.

5.3 Stakeholder Identification

An effective public and government outreach program must identify the stakeholders and determine the general existing attitudes and concerns of each stakeholder group. The use of nuclear energy in oil sands applications involves the following key stakeholders:

- federal Canadian energy and environmental planning and regulatory agencies (the CNSC, NRCan, Environment Canada in particular),
- provincial Albertan energy and environmental planning and regulatory agencies (Energy Alberta and Environment Alberta in particular),
- any additional federal, provincial, and local policymakers,

- relevant federal and provincial advisory committees (e.g., Alberta expert panel on nuclear energy),
- universities (e.g., University of Calgary and University of Alberta),
- industry and labor organizations (including organizations involved in both the oil sands and nuclear industries),
- special interest organizations (e.g., environmental, political, community, and other advocacy and activist groups),
- the general public,
- local community members (located near proposed projects), and
- First Nations.

The general existing attitudes and concerns of some of these stakeholder groups can be initially determined through public opinion surveys and introductory meetings. Government policy formation at federal and provincial levels is documented in policy documents and subject to open public review and discussion, so the views of many of the key stakeholders will be publicly known at an early stage of a potential project. Based on these initial baselines, the focus of an outreach program can be tuned to address the educational and collaborative needs of each stakeholder group.

5.4 Understanding Information Paths and Sources

Available information paths and sources also need to be considered when developing a public and government outreach program. Modern information technology provides mechanisms for information dissemination that are unprecedented in the history of the nuclear industry, creating major opportunities and risks for advanced nuclear energy technologies. Easier access to information by the public results in higher expectations that governments will respond to public opinion in setting policy and implementing regulations.

The public can currently get its information on new technologies and projects from a multitude of sources and spokespersons including:

- Industry representatives (e.g., trade organizations, company executives, and public relations staff),
- Government representatives (e.g., lawmakers, government departments, and regulatory agencies),
- Academics (e.g., professors and academic researchers),
- Industry analysts representing the financial community supported by technical consultants,
- Special interest groups (e.g., environmental groups and political action groups), and
- Community representatives (e.g., community leaders and peers).

Most of the interested public receives its information passively through the news media, public education, higher education, and entertainment media. Interested parties actively seeking information most likely find information though internet search engines. These sources have varying levels of credibility in the public view. The most trusted sources are likely to be knowledgeable individuals without direct business interests, such as academics and industry analysts. Academics are a particularly important information source to consider, as in addition to their public credibility, government stakeholders at both the federal and provincial levels typically rely upon their opinions to inform policy decisions.

An important element of public debate is effective reaction to and interaction with misinterpretation and misinformation. The media and political systems sometimes capitalize on the dramatization of risk and catastrophe, with perceived threats and public deception creating much more public attention than technical documentation that risks have been mitigated successfully. As a result, many of the available information exchange paths are prone to sensationalizing low probability risks and associated impacts, rather than focusing on the positive features of the technology. Counteracting this media bias is a challenge for any public outreach program that promotes technologies, such as nuclear energy, that are perceived to have low probability risks. Framing nuclear technology in a way as to make it attractive to the traditional media (e.g., newspapers, broadcast radio, and broadcast television) and ensuring that high-quality information from trusted sources will reach each stakeholder group through new media (e.g., internet and mobile media) information paths will make a public and government outreach program more successful.

5.5 Development of Informational Materials to Support Outreach

Informational material must be developed such that the format and content is understandable and relevant to each stakeholder group. Stakeholder opinion baselines are important inputs to this development process, allowing informational material to be tailored to the needs of each stakeholder group. Generally speaking, the informational material needs can be divided into three broad categories: (1) the general public, (2) government policymakers, (3) members of academia, and (4) the oil sands industry.

The general public needs information to be presented without technical jargon and with a great deal of context and background information. The context should enable the public to determine the effects of key issues on them at a personal level. Appropriate formats for the general public include fact sheets, brochures, presentations, and videos, which should be available in hard copy and on a publicly accessible website.

Members of government agencies and policymakers typically want information at a much greater level of detail as members of the general public. Appropriate formats for government policymakers include broad based studies of energy utilization and security, environmental compliance, economic development and growth, and quality of life, often relying on academic, industry, and think tank resources. Detailed studies and analyses may be commissioned from independent parties to provide robust support for high level policy decisions. The series of PTAC studies is an example of the participation of government agencies in developing independent analyses of nuclear technology options. Examples of other studies relevant to the use of nuclear energy in Alberta oil sands include:

- a 2007 MIT study: *Integration of Nuclear Energy with Oil Sands Projects for Reduced Greenhouse Gas Emissions and Natural Gas Consumption*
- a 2007 CERI study: *Canadian Oil Sands Supply Costs and Development Projects (2007-2027)*, and
- an ongoing AERI study in collaboration with the University of Calgary.

Academics need informational materials to include technical details such that they can independently analyze the issue and form their own conclusions. In some cases technical information can work its way into curricula and form the basis for graduate student initiatives and support. The technical details must be sufficient for them to answer the detailed questions that very close examination of an issue will warrant. Appropriate formats for academics include technical papers and related documents, white papers, preliminary economics, implementation planning, and other details regarding the technology and its application. Understanding of underlying scientific and engineering details is important to support recognition of technology merits and risks.

The oil sands industry, representing potential users of this technology, need information at a variety of levels of detail, from familiarization material to very detailed technical studies. Appropriate formats vary from formats similar to those appropriate for the general public for initial familiarization to detailed studies similar to those appropriate for policymakers and academics.

5.6 Engagement of Government Stakeholders

Engagement of policymakers and regulators by nuclear technology suppliers and potential private industry users is a vital part of an outreach program. The long lead times associated with policy development, regulation, and rulemaking suggest that early steps by oil sands companies in cooperation with nuclear technology suppliers can be important in initiating the chain of events needed to support the implementation of advanced nuclear technology. Efforts like the current PTAC study provide the opportunity for the oil sands industry to assemble information in a form that will be helpful as inputs to regional energy planning. Without stated industry interest, it is unlikely that policy makers will formalize interest in nuclear technology given the strong political ties to existing Alberta energy industries (i.e., the coal industry).

Policymakers, legislators, and regulators at the federal and provincial levels need to be engaged by nuclear project teams far in advance of formal license or permit submissions for first-of-a-kind projects such as nuclear oil sands applications. Many issues, including licensing reactor designs that differ from the CANDU® design, resolving liability issues with international participants, and permitting a nuclear plant collocated with an industrial facility, may need to be resolved through new legislation and regulations, which require additional time. In addition because oil sands production areas are largely owned by the public and administered through Alberta Energy, a new oil sands project will require interactions with Alberta Energy and Alberta Environment through leasing proposals and approvals, which are subject to public hearings and environmental approvals. Because licensing is typically on the critical path of the project schedule, engaging regulators early, as discussed in the nuclear licensing section of the current PTAC study, will be important.

Direct engagement of government stakeholders can include:

- meetings and presentations with officials and staff,
- submittal of written reports and white papers, and
- submittal of comments on proposed policy, regulations, rulemaking and legislation.

Indirect engagement of government stakeholders can include:

- publishing papers and presenting at conferences,
- meetings with advisors to government agencies,
- supporting and providing inputs to government sponsored studies, and
- providing information on websites and easily accessible venues to support requests for data and questions.

5.7 Engagement of the Public

The public is a diverse amalgam of stakeholders that is distinct from government and academic stakeholders but otherwise generally inclusive. Engagement of the public is another vital part of an outreach plan as the public has indirect roles in licensing, permitting, and financing nuclear projects, with public opinion ultimately driving government policy. The manner in which the public is engaged is critical. The public must be engaged in an early phase of the project in an open manner. By engaging the public at an earlier phase of a first-of-a-kind project than regulations require, a collaborative relationship, rather than an adversarial one, can be cultivated.

Universities can be a very important partner in public outreach as they are viewed by the public as experts that can independently assess complex technical and social problems and thus have high public credibility. The public credibility of universities can be leveraged by collaborating with them in organizing a series of public meetings in Alberta. These meetings would serve to involve the local community in deciding how to use their oil sands resource by educating them about the use of nuclear energy in oil sands applications and seeking their input. Education at not only university level but also the secondary and primary school levels is another important long term goal of a public outreach program, which universities can play a large role in implementing.

In addition to large open public meetings in Alberta, smaller meetings in settings such as chambers of commerce and Rotary Clubs can be effective as well, particularly because of the novelty of nuclear energy to the Albertan business community. Small meetings and early direct engagement with First Nations members is also vital given the proximity of oil sands sites and opportunities that nuclear energy applications will provide First Nation members.

The establishment of a speakers bureau, representing both nuclear technology suppliers and oil sands industry users, to participate in public outreach meetings and interact with the media and other public forums is an effective way to ensure that accurate, consistent and clear messages are delivered to the public. Members of the speakers bureau should receive training in speaking techniques and risk communication. Key public risk communication points include:

- acceptance and involvement of the public as a legitimate partner,
- avoidance of acronyms and jargon,
- consolidation and simplification of subject matter to give the general public a clear fundamental understanding of important issues, and
- preparation for discussions about controversial issues (e.g., public benefits, worst-case scenarios, nuclear waste, decommissioning, cost overruns, etc.).

5.8 Engagement of Industrial Users

Encouraging positive public opinion about emerging nuclear technology is very important to the potential industrial users. Corporate image, stockholder relations, branding, as well as interactions with the public in seeking approval for expansions may all be impacted by the success of public outreach initiatives.

Developing a general familiarization of nuclear technology and issues also becomes an early challenge for industrial users that are considering such projects. Initial reluctance to become exposed to negative public opinion on untested nuclear issues provides a “chicken-and-egg” problem for early projects. An industrial user has to decide whether to declare an early interest in possible nuclear projects as part of a public outreach effort in collaboration with nuclear technology suppliers or to wait and judge public reactions thorough a third-party vetting of issues before taking a proactive position. Familiarization with nuclear issues will take time and should include active participation with nuclear project developers as well as visits to existing nuclear facilities and technology centers to support the visualization of applications in Alberta.

The role of an industrial user in an emerging first-of-a-kind project needs to be carefully considered and presented to the public in a positive way. It is likely that new commercial frameworks will be developed where a nuclear facility is developed, licensed, financed, and implemented by a third party special purpose entity (which may include partial ownership/investment by the industrial user at some point in time). Presenting the role of the industrial user in considering and planning a nuclear application could involve the following sequence:

1. **Technology assessment**: information gathering and clearing potential fatal flaws (no commitment)
2. **Prefeasibility studies**: understanding application requirements, plant concepts, and economics (no commitment)
3. **Feasibility prelicensing effort**: allowing a project developer to prepare for licensing (limited commitment to consider a project at a specific site, allowing a project developer to prepare for licensing, with the commitment being tentative subject to successful resolution of technical, licensing, commercial, and public open issues)
4. **Nuclear licensing**: commitment to support site environmental background and impact studies (commitment to proceed with project subject to successful outcome and resolution of other issues)
5. **Preliminary design**: limited commitment to support application engineering to detail design and operational interfaces, major licensing/permitting efforts, and the development of the project commercial structure
6. **Commitment to implementation**: full commitment through host site agreement and power and steam sales agreements, with possible participation in financing and project company

Given that nuclear licensing represents the likely critical path, especially for first-of-a-kind projects, submittal of the first license application represents a key first step to enable an option to build a plant. However, a ten year lead time towards completion of a plant requires much earlier attention to the planning process than conventional facilities. Early nuclear license applications will have to be based on many provisional design and operational assumptions. Prudent planning by the industrial user may include the planning of a conventional energy facility in parallel with a possible nuclear installation by a third party and employing an option strategy that addresses shareholder concerns and public oversight. Such planning could involve establishing interchangeable projects that extend full commitments to implement a nuclear project until a decision is needed on the implementation of a conventional alternative project. This prudent sequential commitment to a project development sequence can be communicated positively to the public and shareholders as being responsive to government and public policy, sensitive to public concerns, and contingent upon the successful resolution of open nuclear issues.

5.9 Key Issues and Concerns

Key issues and concerns regarding nuclear energy in oil sands applications that need to be addressed as part of a government and public outreach program include:

- nuclear safety,
- avoidance of greenhouse gas emissions,
- depletion of natural gas resources,
- energy security,
- nuclear weapons proliferation and terrorism,
- nuclear waste and spent fuel management,
- local employment and economic development, and
- vulnerability to long term volatile energy prices.

Public acceptance of risks is influenced by psychological factors. Large research efforts have shown that the public views risks in terms of factors apart from quantitative risks (i.e., mortality and morbidity statistics). Analyzing these perceived risk factors helps to select topics that should be emphasized in communicating to the public about advanced nuclear energy technology, namely:

- the very low catastrophic potential, with new passive safety features further limiting the potential for worst case nuclear events to only low level contamination and with no need for large exclusion zones or evacuation plans,
- nuclear spent fuel and waste can be safely stored and managed,
- low level radiation is common and natural and does not have significant adverse effects on health, and
- the fundamental gap between nuclear energy and nuclear weapons and the use of nuclear plant designs that discourage diversion of nuclear materials for terrorism.

Emphasizing these points and highlighting the enhanced safety features of advanced nuclear energy technologies that both protect the public and that will dramatically help combat global warming and future shortages of premium fuels should provide a foundation for positive public opinion.

6 Conclusions and Recommendations

Successful commercialization of advanced nuclear energy technology requires not only technology development and first-of-a-kind nuclear licensing initiatives, but also public acceptance and the development of government policies that encourage and support new projects. An informed public acceptance of nuclear energy technologies and recognition of the next generation of improvements to its safety paradigm are important to support a publicly accessible licensing and permitting process and also to satisfy industry users that the majority of its customers will be supportive of its association with nuclear technology.

In order for the opportunities provided by advanced nuclear energy technology to be realized, various mechanisms of public and government outreach programs must be initiated. The manner in which the public perceives risks must be considered in developing a public outreach program. This program should engage the public openly at the very early stages of commercialization and project development and provide information from credible sources in accessible formats. The public will have its say in energy and environmental policymaking, especially as easier access to information about new energy and environmental technology becomes available through the internet and educational institutions. By ensuring that sound, factual information about nuclear power is made available to the public from trustworthy sources, advanced nuclear energy technology can improve its chances at achieving timely project implementation.

Based on this review of outreach requirements, the following recommendations are presented for PTAC consideration:

1. After completion of the current screening study of nuclear technology, PTAC should enter into collaborations with nuclear technology suppliers to support an appropriate sequence of outreach efforts with increasing industry visibility and participation. It is important for industrial users to participate in outreach initiatives in a positive fashion to encourage development of beneficial project options. Establishing collective goals and strategies through PTAC will allow major nuclear issues to be vetted with the public, while enabling reactions to be observed by individual industry participants.
2. A long term implementation strategy is necessary that extends well beyond the normal planning time frame for projects in the oil sands industry. Creating the option for a nuclear project in the oil sands business will require a sequence of very limited but growing commitments in support of project development, outreach, and licensing. Using an option strategy and seeking interchangeable nuclear and conventional options for implementation promotes the concept of undertaking a prudent effort to maintain off-ramps and explore opportunities to participate in and respond to emerging government policy and public opinion.
3. Cultivation of information centers, public meetings, a speaker's bureau, and other appropriate outreach initiatives can be established and developed with grants to universities in collaboration with nuclear technology suppliers. Reference information in various formats can be prepared to document application concepts, benefits, implementation strategies, and resolution of open issues that are important to the public as prerequisites for project implementation.

7 Glossary of Terms and Acronyms

ACR	Advanced CANDU® Reactor
AECL	Atomic Energy of Canada Limited
AERI	Alberta Energy Research Institute
Alberta Energy	Alberta Ministry of Energy
Alberta Environment	Alberta Ministry of the Environment
ALWR	Advanced Light Water Reactor
AOO	Anticipated Operational Occurrence
AUC	Alberta Utilities Commission
BDBA	Beyond Design Basis Accident
CANDU®	CANada Deuterium Uranium
CCS	Carbon Capture and Storage
CEAA	Canadian Environmental Assessment Act
CERI	Canadian Energy Research Institute
CNSC	Canadian Nuclear Safety Commission
CO_2	Carbon dioxide
COL	Construction and Operating License
DBA	Design Basis Accident
DC	Design Certification
EA	Environmental Assessment
Environment Canada	Federal Ministry of the Environment
ERCB	Alberta Energy Resources Conservation Board
ESP	Early Site Permit
HTGR	High Temperature Gas Reactor
IAEA	International Atomic Energy Agency
INPO	Institute of Nuclear Power Operations
IPCC	Intergovernmental Panel on Climate Change
LWR	Light Water Reactor
MIT	Massachusetts Institute of Technology
MMTCDE	Million metric tonnes of carbon dioxide equivalent
Mt	Megatonnes
MW_t	Megawatt-thermal
NEB	National Energy Board
NEI	Nuclear Energy Institute
NPP	Nuclear Power Plant
NRC	United States Nuclear Regulatory Commission
NRCan	Federal Ministry of Natural Resources
NSCA	Nuclear Safety and Control Act
PHWR	Pressurized Heavy Water Reactor
PPR	Pre-Project Design Review
PSA	Probabilistic Safety Assessment
PTAC	Petroleum Technology Alliance Canada
RD	Regulatory Document
WANO	World Association of Nuclear Operators

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Unique Nuclear Considerations

Building and operating a nuclear reactor as a power source involves some unique requirements and considerations. The purpose of this appendix is to ensure readers are familiar with those issues at a very basic level. Since basic nuclear plant design (see Section 3.1 for a discussion of the basics of how a nuclear reactor functions), construction (Section 4), and regulation (Section 6) are discussed in the body of the report, this appendix deals primarily with operating and end-of-life issues.

1. Nuclear Cogeneration Plant: Licensee/Operator/Owner/Host/User/Vendor

In a cogeneration type arrangement, an end-user of electrical power, steam, heat, hydrogen, etc. relies on a separate company "outside the fence" to provide these products "over the fence" for the end-users needs. The following terms apply:

- The vendor refers to the company that provides the equipment to build and prepare the cogeneration plant for operation.
- The user is the entity that guarantees the demand for the products to be used over a period of time. This legally guaranteed demand provides the assurance that there will be a market for the cogenerated product. In some cases, there may be multiple users and contracts for these products.
- The user may be referred to as host if the user also owns or leases the land upon which the cogeneration plant will be built.
- The owner of the cogeneration plant owns and has responsibility for creating and/or sustaining the plant, for contracting its output and accepting contractual responsibilities for production guarantees. The owner may be the same as the user, in whole or in part, if they are different entities.
- The operator operates the cogeneration plant in accordance with all the laws and regulations associated with the plant's productions. The operator is responsible to the owner for the proper and efficient operation of the plant and its performance in meeting all liabilities for production quality and quantity and safe and proper operation and maintenance. In some arrangements, the same company may both own and operate the cogeneration plant.
- The licensee is the organization that interacts with the CNSC, providing the assurances that CNSC requirements (technical, operational, and financial) will be met throughout the licensee application period and the period when the license is in effect. It is possible that the CNSC would accept a different organization as the licensee for site preparation than for HTR operation. (See CNSC Constraints on Ownership below.)

Cogeneration plants are typically built to provide products such as steam and electricity, with excess electricity sold to the electric power grid; but other examples exist such as hydrogen production where excess hydrogen is sold to local hydrogen pipelines. These plants have typically used fossil fuel combustion as the source of energy. The application of nuclear reactors as an energy source for these cogeneration plant concepts is new and evolving at this time but the basic business model for cogeneration should be applicable. The Next Generation Nuclear Plant Project (NGNP), sponsored by the US Department of Energy, is looking at the cogeneration model as a basis for initial application of high temperature gas reactors to supply process heat for industrial applications.

2. Oil Sands Plant - HTR Plant Battery Limits (BL) and Relationship

The relationship between the oil sands plant (OSP) (user) and the alternate energy source plant (HTR) (operator/licensee) involves both technical interdependencies and requirements and, potentially, mutual contractual obligations. This section will discuss technical interdependencies and interface agreements and arrangements that are needed for the smooth and safe operation of both the oil sands plant and the HTR plant.

The organizations must first reach agreement on the mutually required functional responsibilities to be contained within each set of battery limits (BL). Broadly speaking, the HTR will provide in-specification steam at specified flow rates, specified startup/shutdown/transient rates and specified level of continuous steam supply reliability. In return, the OSP will supply makeup and feed water within agreed upon specifications at specified flow rates, transient rates and reliability for continuity of flow. In addition, the HTR is responsible for providing an agreed upon amount of electric power for the OSP and the well heads with excess electrical production going back into the grid and with shortages being picked by demanding more from the grid. Finally, the OSP will provide distribution lines for natural gas for backup boilers located inside the HTR BL and will accept return lines of water waste (e.g., blowdowns) for recycle.

Agreements need to be reached on actions to be taken for off-normal conditions, including violation of water specification, planned and unexpected shutdowns or reductions in flow, communications required before changes in operations, etc. Agreements on procedures and communications for normal and casualty operations must be mutually agreed upon.

If feedwater and makeup water meet the agreed on specifications, and further water treatment is required for turbine electric or process steam, this process should be the responsibility Of the HTR. If feedwater or makeup water does not meet the agreed upon specifications, it is the responsibility of the OSP to provide additional controls to assure that acceptable quality water is going to the HTR.

These and other agreements need to be worked out in advance to assure readiness exists to meet typical and off-nominal conditions. Perhaps the most advantageous arrangement in light of the above considerations and others discussed elsewhere in this report would be for there to be a single owner for both the HTR and OSP and a subcontracted operator/licensee.

3. CNSC CONSTRAINTS ON OWNERSHIP

The CNSC imposes its nuclear safety and security requirements on licensees, who are authorized to prepare the site for, construct, operate, or decommission and abandon a nuclear facility. The NSCA states that "no licence may be issued unless, in the opinion of the Commission, the applicant is qualified to carry on the activity that the licence will authorize the licensee to carry on and will, in carrying on that activity, make adequate provision for the protection of the environment, the health and safety of persons and the maintenance of national security and measures required to implement international obligations to which Canada has agreed." A license may contain any term or condition that the CNSC considers necessary, including a condition that the applicant provide a financial guarantee in an acceptable form. Thus, the licensee must be accepted by CNSC as qualified and financially sound enough to perform the licensed activity.

The licensee need not be the owner of the land or even of the reactor itself. For example, Bruce Power Limited is the licensee and operator for the Bruce site reactors, which the company leased from owner Ontario Power Generation (OPG). In August 2006, the CNSC received an application from Bruce Power for a license to prepare a site for future construction and operation of a new nuclear power plant on the site located in Kincardine, Ontario. The company actually leases this site from OPG. The CNSC conditionally accepted Bruce Power's application based on Bruce Power submitting additional information regarding ownership of the land or authority from the owner of the site to carry on the activity to be licensed.

If the licensee for a nuclear reactor were to change due to sale of the company or transfer to another operating company, the CNSC would need to authorize the license transfer. Thus, CNSC would become involved in assessing the acceptability of the transfer before responsibility could be yielded by the original license holder.

4. NUCLEAR POWER PLANT LIABILITY

The applicable Canadian legislation is the Nuclear Liability Act (NLA). Strict liability or absolute liability used in Canada attributes all liability of a nuclear incident back to the operator regardless of the actual cause. The liability is limited in time and amount. Victims must make their claims for damages arising from a nuclear incident within a specified time frame. Furthermore, the operator is responsible for a specified limit of liability. The operator must purchase appropriate insurance coverage to cover this liability. When this limit is exhausted, it is presumed that supplementary compensation will be provided by the jurisdiction's government from public funds.

Under the NLA, an operator is, without proof of fault or negligence, absolutely and exclusively liable for nuclear damage arising from the nuclear installation it operates. The current limit that the large nuclear power operators must carry is $75 million Canadian. Although claims are to be filed within three years of having knowledge of injury or damage, there is an absolute 10-year period in which persons injured must file their claim.

On October 26, 2007, the Minister of Natural Resources introduced Bill C-5, an Act respecting civil liability and compensation for damage in case of a nuclear incident, in the House of

Commons. This bill includes provisions to revise the amount of insurance required for nuclear operators and bring the requirements for nuclear operators more in line with international standards. The proposed legislation requires nuclear operators to have $650 million in insurance coverage instead of the $75 million currently required under the existing Act. The revisions also require the responsible minister to review the amount of liability coverage at regular intervals of no more than five years. The act was last debated in June 2008. Debate included discussion of whether the $650 million limit was sufficient.

The Canadian nuclear insurance pool, named Nuclear Insurance Association of Canada (NIAC) - is managed by CGI Insurance Business Services. Nineteen Canadian insurers and reinsurers are members of NIAC. NIAC provides 92% of the $75 million, third-party liability insurance limit the NLA requires. However, if the new limit of $650 million becomes effective, NIAC's percentage share will drop to 10% (foreign reserves, provided through the British and US nuclear pools, supplement the Canadian capacity, as required).

5. QUALITY ASSURANCE

High quality standards are required to reduce the likelihood of an initial failure in plant equipment. Specific quality standards are invoked for nuclear work, such as CAN3-Z299.1 through 4, Quality Assurance Program. In the US, the standards are implemented via documents such as the American Society of Mechanical Engineers Boiler and Pressure Vessel Code Section III. These requirements add to the cost of components, construction, and maintenance.

Nuclear vendors include the costs of meeting these quality requirements in their equipment prices. Some non-nuclear equipment can be accepted for nuclear use with an additional effort called “commercial grade dedication.” Care must be taken when arranging for companies to perform construction, modification, and maintenance to ensure that they can meet nuclear quality requirements and that their prices include the associated additional effort. Work performed by a company not familiar with nuclear requirements could lead to costly rework and delays.

6. PLANT STARTUP AND OPERATIONAL LIMITATIONS

A nuclear plant, like any large industrial plant, has technical limitations on how it can be operated. Certain criteria must be met for plant startup and operation. The origin of these requirements can be either engineering or regulatory (or both).

If safety limits on power, temperature, pressure, or other monitored parameters are exceeded, the reactor may be automatically or manually “scrammed,” inserting the control devices to stop the fission reaction. The condition would have to be identified and corrected before the reactor could be restarted. There are technical restrictions on heat-up rate due to stresses induced in components that can limit how fast the reactor is brought up to full power. Depending on the reactor design and where it is in its fuel cycle (how close to its next refueling), a reactor that is shut down from high power operation may not be physically capable of being taken critical until some time – up to a day – has passed (this is referred to as a xenon-precluded startup; xenon is a remnant of the fission process that adds negative reactivity that may prevent criticality until enough time has passed for it to decay). There are regulatory limitations on startup and continued plant operation based on availability of safety and emergency equipment, off-site power, sufficient operating staff, etc. An example is that a reactor might be required to shut down if a diesel generator installed to provide emergency power is not operable, even though there is no current need for emergency power.

7. Fitness For Duty

Due to the significance of operator responsibilities in regard to protecting health and safety, a Fitness for Duty program must be established that provides confirmation that any person seeking a certification, holding a certification or seeking renewal of a certification does not have a physical or a mental limitation that would make the person incapable of performing the duties of the applicable position.

8. Operator Qualification

The CNSC sets obligations of the licensee with respect to the certification of its workers, including programs and processes that the licensee must implement to train and examine persons seeking a certification or a renewal of certification; respective qualifications required of persons seeking a certification for those positions referred to in the license; and respective training and requalification tests that certified persons seeking a renewal of certification must have completed. The specific personnel for whom certification is required are: Senior health physicist; reactor operator; control room shift supervisor; and plant shift supervisor.

Training and certification requirements are specific to each position. As an example, the requirements for a Reactor Operator are discussed; note that this is not a complete list.

Education: The person must have a high school diploma obtained from a recognized educational institution that includes course credits in both science and mathematics.

Minimum Experience: The person must have a minimum of two years of plant experience at the Nuclear Power Plant (NPP) where certification is sought, or an acceptable alternative to this experience. Since the reactor for the thermal, in-situ recovery plant would be a First-of-a-Kind, the alternative criterion would apply for the initial cadre of operators. Acceptable alternatives are discussed but none are applicable to the particular situation faced by the owner of a First-of-a-Kind design.

Training: Each of the following categories of training require formal written evaluations that confirm and document that, at the completion of the training, the person has the required knowledge to perform the duties of a reactor operator.

- Initial General Training: Appropriate to the knowledge requirements of the position, covering science fundamentals relevant to the operation of the plant and principles of operation of the equipment.
- Radiation Protection Training: Radiation fundamentals, radiation hazards, radiation protection theory and practices, and radiation protection procedures used during normal, abnormal and emergency operation of the plant.
- Plant-specific Training:

1. Design and operation of plant systems;
2. Integrated operation of plant systems including, where applicable, interactions between the systems of a reactor unit and those of other reactor units;
3. Expected response of plant systems and units to accident conditions;
4. Technical bases for emergency operating procedures;
5. Diagnosis of equipment failures and assessment of abnormal plant conditions;
6. Phenomena that may significantly affect core reactivity and neutron flux shape;
7. Reactor fuelling, fuelling limitations, fuel handling and storage, and irradiated fuel cooling;
8. Configuration of systems and equipment isolation for maintenance activities;
9. Safety culture;
10. Principles of nuclear safety and their application;
11. The NPP license and documents referenced in the license;
12. Situations that may result in the violation of conditions in the plant license and Operating Policies and Principles;
13. Administrative procedures related to plant operation and maintenance; and
14. The responsibilities and authority of a reactor operator and of other plant personnel who interfaces with the reactor operator.

- Simulator-based Training: Completion of training on the full scope simulator (see next section) that covers operation and monitoring of plant systems under normal, abnormal and emergency conditions.
- On-the-job Training: This includes standard control room operating practices; operation and monitoring of systems from the main control room that cannot be performed on the simulator; operations and monitoring performed in the control equipment room; operation and monitoring of systems from the emergency control room; and authorization of maintenance and repair of plant systems.

Nuclear Power Plant Management Interview: The person must have completed an interview administered by plant management that confirms and documents the person's competence to perform the duties of a reactor operator.

Certification Examinations: These include a general examination, nuclear power plant specific examination, and simulator-based examination.

9. PLANT SIMULATOR

Training of operators of nuclear reactors is required to include practice operating the plant on a full scope simulator. The simulator shall be capable of simulating, realistically and in real time, all significant plant maneuvers and transients that may occur under normal and abnormal operating conditions, including: start-ups and shutdowns; upset and accident conditions; and all significant failures of systems and their equipment and the consequences of such failures. For conditions and failures that may vary in magnitude, such as pipe breaks, loss of inventory, loss of flow, loss of pressure, and loss of vacuum, the simulator shall have adjustable rates to simulate all possible degrees of severity of a condition or failure that impact on unit response or operator actions.

For the HTR for the thermal, in-situ recovery plant, development of a simulator will require finalization of the design including the details of the human-machine interface in the control room and development of accurate computer models that can predicts how the plant behaves under normal, abnormal, and accident conditions. This will require extensive development for a First-of-a-Kind design. The simulator must be complete and available for operator training sufficiently in advance of plant completion that sufficient number of operators can be trained and proficient when needed for the actual plant. This can result in the simulator being the critical path for new plant construction.

10. FUEL LOGISTICS

Nuclear reactor fuel has special storage and handling requirements both when it is new and used (“spent”). The requirements are implemented to ensure safety and security of the fuel

One safety consideration for both new and spent fuel is to ensure that the fuel cannot inadvertently undergo a self-sustaining nuclear reaction – go critical. This is accomplished by limitation on handling (e.g., number, placement) of fuel assemblies and by incorporating special features in nuclear fuel storage racks (e.g., fixed separation, installed neutron absorbing materials). For spent fuel, there are additional safety issues to ensure adequate cooling, shielding, and retention of radioactivity. Cooling is usually maintained by requiring the fuel to be held for a certain time in an appropriate environment (e.g., for 4S fuel two years in the Ex-Vessel Storage Tank) until the decay heat has dwindled sufficiently to allow long term storage in a sealed canister. The spent fuel is highly radioactive and cannot be handled without radiation shielding and use of remote devices. Retention of radioactivity is ensured by cooling and careful handling.

Security of new fuel is required to prevent theft. Although the fuel for all designs is low enriched (i.e., less than 20 percent U-235), prevention of theft is still required by use of physical security measures. The higher enrichment of the 4S and MHTGR fuel may be viewed as a greater security risk, but the CNSC requirements do not distinguish among the enrichment levels of the three designs. For spent fuel, security is maintained to prevent radiological sabotage with the intent to release radioactivity to the environment by damaging the fuel. Due to the high radiation levels and heavy shielding required to protect personnel, spent fuel is generally viewed as unattractive for theft.

11. RADIOACTIVITY

Radioactivity is everywhere in the world, and humans are routinely exposed to natural sources of radioactivity. Radioactivity refers to the particles which are emitted from nuclei as a result of nuclear instability. The energy or energetic particles given off by radioactive substances is radiation. There are many nuclear isotopes which are unstable and emit some kind of radiation; some exist naturally (e.g., , uranium-235, potassium-40) and some are man-made (e.g., sodium-24, cobalt-60). The most common types of radiation are called alpha, beta, and gamma radiation. Different isotopes release different types of radiation at different energies. Higher energy radiation is a greater potential health risk.

When radioactive isotopes give off radiation, they change identity or "decay." Radioactive decay rates are normally stated in terms of their half-lives (the time over which half the radioactivity decays), and the half-life of a given nuclear species is related to its radiation risk. An isotope with a short half-life will quickly disappear as a risk.

The fission process creates radioactivity in two ways:

1. The nuclei created when U-235 fissions are called "fission fragments" and are radioactive; they are the reason that spent reactor fuel is very highly radioactive.
2. Some of the neutrons released during fission do not causes other fissions but are instead absorbed by substances other than uranium. This can create radioactive isotopes in a process called activation. Sodium-24 is an example of a activation isotope.

The units for measuring the radioactivity of a substance is the Becquerel, which is equal to one nuclear decay per second. Since there are a very large number of nuclei in a small amount of material (more than a billion trillion in a gram of water), a radioactive material need not have a large number of Becquerel just to be detectable with a radiation counter and is not hazardous unless at a much higher level than the limit of detectability. The hazard presented by a radioactive substance depends on both the amount and type of radioactivity; it is addressed in the following paragraphs.

12. RADIATION MONITORING

Operating a nuclear reactor involves working with man-made radioactivity. Unintended spread of radioactive substances is called radioactive contamination. In addition to potentially exposing humans to radiation directly, contamination is a concern because it could be ingested/inhaled and remain in a person's body. The protection of plant workers, the public, and the environment requires limits on exposure to radiation and spread of contamination. To ensure these controls are effective, continuous monitoring and periodic sampling are required. Personnel at the plant must wear radiation monitoring devices called dosimeters. Air and water effluent must be checked for radioactivity; the HTR process steam flowing to the thermal, in-situ recovery plant would be checked to ensure no unacceptable radioactivity was present. Surveys are routinely taken in the plant to check for unexpected spread of contamination. Areas and items found to be radioactively contaminated are controlled and then either cleaned or disposed of in accordance with regulations.

13. RADIATION EXPOSURE

Everyone is exposed to radiation from natural sources in the environment. Canada and other countries have developed limits for human exposure to man-made (non-medical) radiation to reduce the risk of health effects to a negligible level. Canada follows the principle of ALARA – As Low As Reasonably Achievable – which has the objective of keeping radiation exposures very low. The units for measuring radiation are the Sievert and millSievert.

In Canada, the limit for radiation dose to the whole body is 1 milliSievert for a member of the general public. The doses received by members of the public from routine releases from nuclear generating stations are too low to measure directly. Therefore, to ensure that the public dose limit is not exceeded, CNSC licenses restrict the amount of radioactive materials that may be released in effluents from nuclear generating stations.

Workers at the reactor site receive more exposure because of their proximity to the reactor and because they work with radioactive materials. Protection of workers from radiation exposure is accomplished by a combination of minimizing spread of radioactivity, limiting the time the worker is exposed, increasing the distance from the radioactive material, and interposing shielding material between the worker and the radioactive source. Worker radiation exposure is monitored: the limit for nuclear energy workers is 50 mSv per year. If a worker's exposure approaches a control limit, that worker's assignments will be restricted.

14. RADIOACTIVE WASTE

High-level waste refers to the used nuclear fuel bundles discharged from reactors. Low-level waste includes radioactively contaminated clothing, rags, mops, tools, paper and other items, such as reactor components, from nuclear reactor sites and other nuclear facilities.

CNSC regulates the management of radioactive wastes to ensure that they will not pose undue risk to human health and the environment. In Canada, all radioactive wastes are placed in storage. Storage is a short-term management technique that requires human intervention for maintenance and security and allows for recovery of the waste. Radioactive waste is stored in above- or below-ground engineered structures. The management method used for a particular waste is dependent on the source and characteristics of the radioactive waste.

The used fuel from water-cooled power reactors is stored at the reactor sites in deep pools of water enclosed by thick concrete walls that are lined with stainless steel. The water cools the fuel and blocks its radiation. After five or six years of cooling, the waste can then either remain in water storage or be transferred to above-ground dry concrete canisters. For the HTR designs being considered, the short-term cooling would not be provided by storage in water pools, but the longer term storage would likely be similar canisters (except for PBMR where all fuel for 30+ years of operation is held in the spent fuel system tanks).

Most low-level waste is stored in protected above-ground (or just below-ground) engineered facilities. Such facilities include concrete trenches and "tile holes" which are concrete cylinders set vertically in the ground. However, certain types of radioactive wastes contain only small amounts of short-lived radioactive materials that decay quickly, in hours or days. After holding the waste until the radioactivity has decayed to CNSC authorized acceptable levels, it can be disposed by conventional means.

Each facility in Canada that stores radioactive waste or spent fuel has a monitoring program in place to ensure that radioactive discharges are, and continue to remain, within regulatory limits. Samples are obtained at regular intervals at various locations around the site, and the results are analyzed for trends. The monitoring programs ensure the detection of any radiation releases and steps can then be taken to control the releases. As a condition of the license, licensees must submit the results of their monitoring programs to CNSC at regular intervals.

15. SPENT FUEL DISPOSITION

Although the Canadian government will take eventual custody of spent fuel, there is no long-term disposition path yet available. Therefore, nuclear plant licensees are currently storing their spent fuel on their sites. This requires storage containers, associated facilities, and monitoring by the plant owner. Since the fuel designs of the three technologies under consideration are not of a type currently used in Canada, there could be additional costs to achieve CNSC acceptance of storage methods and for eventual transfer.

In 2002, the Canadian Parliament enacted the Nuclear Fuel Waste Act which required the nuclear industry to form a not-for-profit organization, the Nuclear Waste Management Organization (NWMO), which would develop options for a general approach for the long-term management of nuclear fuel waste. NWMO was to submit a recommendation to the federal Minister of Natural Resources by November 15, 2005. In the spring of 2005, the NWMO released the draft study entitled "Choosing a Way Forward" for public comment, in which it described four options and presented its preferred option for a general approach for the long-term management of nuclear fuel waste. After receipt of the study, a ministerial recommendation was be developed and presented to the Governor in Council. Under government oversight, the NWMO will implement the approved general approach, including starting the site selection process.

16. DECOMMISSIONING

The NSCA requires that applicants and licensees make adequate provisions for decommissioning. This includes development of acceptable decommissioning plans, credible estimates of the cost of implementing decommissioning plans, provisions to ensure the costs of decommissioning will be met, and eventual implementation and completion of decommissioning. Financial guarantees must be sufficient to cover the cost of decommissioning work resulting from licensed activities, must be at arm's length from the licensee, and must provide assurance that adequate funds will be available if a licensee is not available to fulfill the obligation. Examples of acceptable guarantees are: cash, irrevocable letters of credit, surety bonds, insurance, and expressed commitments from a government.

Decommissioning plans must specify the radiological standards considered acceptable for release of the site and any remaining facilities. Surveys are taken as part of the decommissioning process to confirm standards are met. A license to abandon is an indication that the facility is acceptable to move from a licensed to an unlicensed state. Before issuing a license to abandon, the CNSC must be satisfied that no undue risk would result; this does not mean that there is no detectable radioactivity resulting from facility operations. The requirements to be satisfied will depend on those applicable at the time that the license application is submitted.

17. Funding for Spent Fuel Disposition and Plant Decommissioning

A nuclear operator must set aside funds specifically for its nuclear waste management and decommissioning liabilities. The amounts required annually will depend on the anticipated liability, which are proportional to the amount of nuclear power generated. As an example, Ontario Power Generation (OPG), which is the largest nuclear operator with 12 CANDU reactors of which 10 are operating at a total power level of about 22,000 MWt, had required fuel disposition funding for 2007 of $454 million.

18. References

1. Canadian Nuclear Safety Commission website, http://www.cnsc-ccsn.gc.ca/eng/.

2. RD–204, "Certification of Persons Working at Nuclear Power Plants," February 2008.

3. "Status Report of the Commissioner of the Environment and Sustainable Development to the House of Commons," Office of the Auditor General of Canada, March 2008.

4. LEGISinfo, 39th Parliament - 2nd Session (Oct. 16, 2007-Sept. 7, 2008), Bill C-5.