AREVA NP Inc.,

an AREVA and Siemens company

NGNP with Hydrogen Production Conceptual Design Studies Power Conversion System Study

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001	2/6/2009	Throughout document	Editorial changes made (spelling and punctuation).
		Figures 6-8, 6-10, and 6-13	Corrections made to heat balance numbers.
		Figures 3-14 and 3-20	Improved legibility of numbers and legends.
		Figure 3-21	Replaced entire drawing with relevant portions of drawing for improved legibility.

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1.0 INTRODUCTION

The Next Generation Nuclear Plant (NGNP) is capable of achieving very high operating temperatures. Taking full advantage of this will promote commercial viability of this design for process heat and high efficiency electricity production. The Power Conversion System (PCS) study assesses candidate cycles to connect to the primary loop. The study consists of four main parts. The first part of the study consists of recommending a configuration of the PCS to be coupled to the primary loop of the high temperature helium cooled gas reactor. The second part covers evaluating feasibility issues with the recommended cycle. An evaluation of the feasibility of an indirect combined cycle gas turbine configuration is undertaken in the third part of the PCS study. Finally, PCS configurations are identified for commercial applications including electrical power production and support of hydrogen production.

Abbreviations and definitions used throughout this document are defined in Table 1-1.

Table 1-1: Abbreviations and Definitions

Abbreviation	Definition
AOO	Anticipated Operational Occurrence
AVR	Arbeitsgemeinschaft Versuchsreaktor
BDBE	Beyond Design Basis Event
CCGT	Combined Cycle Gas Turbine
CHP	Combined Heat and Power
DBE	Design Basis Event
EAB	Exclusion Area Boundary
FSV	Fort Saint-Vrain
HTR	High Temperature Reactor
HTS	Heat Transport System
IHX	Intermediate Heat Exchanger
LBE	Licensing Basis Event
LOHS	Loss of Heat Sink
MCNP	Monte Carlo N Particle
MHTGR	Modular High Temperature Gas-Cooled Reactor
NGNP	Next Generation Nuclear Plant
NRC	Nuclear Regulatory Commission
PAG	Protective Action Guideline
PCRV	Pre-Stressed Concrete Reactor Vessel
PCS	Power Conversion System
PCU	Power Conversion Unit
PH	Process Heat
PRA	Probabilistic Risk Assessment

Abbreviation	Definition
PSID	Preliminary Safety Information Document
PWR	Pressurized Water Reactor
R&D	Research and Development
RCCS	Reactor Cavity Cooling System
RSS	Reserve Shutdown System
SCS	Shutdown Cooling System
SDHRS	Start-up and Decay Heat Removal System
SG	Steam Generator
SRDC	Safety-Related Design Condition
VHTR	Very High Temperature Reactor

2.0 RECOMMENDED CONFIGURATION FOR NGNP

2.1 Cycles Considered for High-Level Assessment

The first of the four parts of the PCS study covers the selection of a PCS configuration for further detailed evaluation in part two of the study. The discussion below details the PCS configuration selection process.

2.1.1 Updated List of Assessed Cycles

In 2007, a high-level assessment was made of several alternative PCS configurations (see Appendix B3 of [1]) Several criteria were used for comparing the cycles such as performance and cost among others. A new list of cycles was made for this high level evaluation which is partly based on the list of cycles from the 2007 study. Several of these cycles were eliminated and new cycles were added to the list for consideration. See Table 2-1 below. The cycles in the 2007 list in italics were eliminated and the new cycles to be considered are in bold. “Direct” refers to a cycle without an IHX, while “indirect” refers to one with an IHX.

Table 2-1: Cycles List

2007 Cycles	**2008 Cycles**
Direct Subcritical Steam	Direct Subcritical Steam
Direct Supercritical Steam	Direct Supercritical Steam
CCGT with He/N_2	CCGT with He/N_2
Indirect He Brayton	Indirect He Brayton
Direct He Brayton	**Indirect Subcritical Steam**
Supercritical CO_2	**Indirect Supercritical Steam**
Cascaded Supercritical CO_2	

The direct He Brayton cycle was no longer of interest to Idaho National Laboratory (INL) for consideration, therefore this study excluded it. The supercritical CO_2 cycles were eliminated due to technical risk from the immature turbomachinery technology, complexity, and project schedule risk.

2.1.2 Other Thermodynamic Cycles Not Assessed

Several other cycles were surveyed as candidates for the PCS, such as the Stirling and Stoddard cycles, but were eliminated because of lack of scalability to higher power levels or they were deemed impractical for use.

2.2 PCS Selection Methodology

The cycles from the new list above of “2008 Cycles” were assessed and ranked based on a Kepner-Tregoe type analysis with scoring of weighted criteria for each cycle. Each criterion, defined in the next section, was scored from 0 to 10 for each cycle, then appropriately weighted. A score of 0 would mean an unacceptable rating and a 10 would mean a score that is the best that could be reasonably expected. For example, a 0 rating for the performance criterion would mean that the particular cycle had a net plant efficiency in the upper 30% range, whereas a cycle with a net plant efficiency in the upper 40’s to 50% would be rated a 10. Although the scoring method is somewhat subjective, it nevertheless keeps the selection process as objective as possible as well as records the thought process for cycle scoring and ranking.

2.2.1 Scoring Criteria and Definitions

Ten criteria were selected and scored for each cycle. The list and definitions of each criterion are listed below:

<u>Performance (net plant generating efficiency)</u>
Thermal to electric power conversion efficiency and total available electricity after accounting for auxiliary loads (circulators, feedwater pumps, cooling water pumps, cooling tower fans, etc) and house loads.

<u>Cost (capital, operating, maintenance)</u>
Cost of Plant for NGNP including capital, operating, and maintenance expenses.

Technology Maturity
The ability to deploy the system within schedule and budget. Immature (underdeveloped) component or system technology is problematic and unpredictable, and requires investment of resources to bring to a state of commercial viability. Simple and well-developed systems and components lead to high system availability and are readily deployable.

Flexibility / Operability
The ability to shift the way the PCS is being used in order to serve the needs of a variety of process heat options

Use of Existing Technology
Impacts the deployment schedule and the development cost of the PCS.
This criterion is a measure of how many components are "off-the-shelf." Is the technology already available commercially? Will some measure of development be needed in order to meet the deployment deadline?

Deployment Schedule (ready by 2021)
Function of the development status of the technology as well as its level of complexity and materials of construction. This criterion addresses the question: Is the technology prohibitively time consuming for development, construction, and or deployment?

Reliability, Availability, Maintainability
Related to technology maturity. Unreliable or high maintenance component or system technology is problematic and unpredictable. Reliable and low maintenance systems and components yield high availability.

Design Safety
Related to the potential for the given PCS technology to contribute to or detract from off normal or accident condition probabilities and consequences such as loss of primary heat sink, overpower / overcooling accident, water ingress, or IHX over temperature to name a few.

Licensing
This criterion measures the given cycle's ability to be licensed by the NRC and also the amount of time and resources to get a license.

Scalability
This refers to the ability of the plant or fleet to be expanded in anticipation of future demand growth.

2.2.2 Criteria Scoring and Weighting

An interdisciplinary committee consisting of engineers with Licensing, Systems Engineering, component design, and overall HTR design and analysis experience provided input into the scoring process assigning raw scores between 0 and 10 for each of the ten criteria for all cycles, as well as assigning weighting factors to each criterion. The weighting factor was applied to each criterion's score then totaled to arrive at a final score for each cycle. Before scoring and results are shown and discussed, a description of the performance calculations of plant efficiency must be made.

2.3 Performance Calculations

In 2007, Rocketdyne had modeled the cycles listed in the Cycles Table above for the "2007 Cycles" (Reference 1). Their models had predicted steady-state thermodynamic cycle performance. Rocketdyne was going to provide the same support in this current study to revisit performance calculations for all cycles shown above in the

"2008 Cycles" list, but this was not possible contractually. From the above table of cycles, the only new cycles that need to be modeled are the two indirect steam cycles: subcritical and supercritical. To obtain the efficiencies of these two cycles, the results of the corresponding direct cycle heat balances were used (Reference 1). These results were modified by adding the additional loads from the secondary circulators. This allows a consistent comparison across all cycles using the same set of assumptions. The assumptions used in the above referenced 2007 study performed by Rocketdyne are listed below with one additional assumption for secondary circulator loads for the indirect steam cycles. Some loads were not taken into account, such as cooling tower fan loads and cooling water pump loads, but relative performance comparison is still valid. These additional loads are taken into account later in this report for detailed performance assessments.

2.3.1 Additional Assumptions Used for Cycle Performance

In order to maintain consistency, the following assumptions were applied as appropriate, to each of the cycle evaluations.

1. 565 MWt helium gas cooled reactor power.
2. 900°C reactor outlet temperature.
3. 500°C reactor inlet temperature.
4. 55 kPa pressure drop across the core.
5. 55 kPa pressure drop across IHX when used.
6. 5 MPa reactor inlet pressure – desired.
7. 1% reactor heat loss.
8. 98% generator efficiency.
9. 1% BOP loads.
10. Condenser pressure of 0.00475 MPa.
11. Total primary circulator power of 11 MWe (13.4 MWe for indirect Brayton cycle).
12. Secondary circulator power of 32 MWe (16 MWe per loop x two loops) was used for the indirect steam cycles (additional assumption not in PCDSR).
13. For the calculation of indirect steam cycle gross power, the same gross cycle efficiency was used from the corresponding direct steam cycle (subcritical/supercritical) from PCDSR.

The above cycles were all compared based on a 900°C reactor outlet temperature, which is somewhat unfair to the direct steam cycles to a certain degree, because the steam cycle gross efficiency is not sensitive to reactor outlet temperature (turbine inlet temperature is roughly constant). The direct steam cycle net efficiency, therefore suffers somewhat due to the somewhat higher primary circulator load. Using a lower total primary circulator load of 7 MWe (3.5 MWe x 2) vs.11 MWe (5.5 MWe x 2) would add approximately 0.5% additional net plant efficiency to the direct steam cycles if analyzed at a reactor outlet temperature of 750°C. For example, the subcritical direct steam cycle's net plant efficiency of 42.8% would increase to 43.3% if reactor power were increased from 565 MWt to 600 MWt and circulator power were decreased from 11 MWe to 7 MWe, using identical gross cycle efficiencies. For the direct supercritical cycle, making the same changes, the net plant efficiency would increase from 46.9% to 47.4%.

An investigation was desired of several alternative working fluids for the indirect Brayton and Combined Cycle Gas Turbine (CCGT) cycles: indirect Brayton with the mixture of helium plus either nitrogen or argon and indirect CCGT with pure helium and also with helium plus argon. The motivation for looking at these alternative fluids was either to avoid using nitrogen because of nitriding in the IHX or to use a working fluid mixture that has densities closer to air so more mature air-breathing turbomachinery can be used. This was not possible, again because of not having Rocketdyne available to perform these analyses with alternative working fluids.

Table 2-2: Net Plant Efficiencies

Cycles	Net Plant Efficiency (%)
Direct Subcritical Steam	42.8
Indirect Subcritical Steam	39.8
Direct Supercritical Steam	46.9
Indirect Supercritical Steam	44.1
Indirect CCGT with He/N_2	47.9
Indirect He Brayton	44.5

2.4 Results of Scoring

Table 2-3 below shows the raw scoring, criteria weighting factors, subtotals (raw score x weighting factor), and total scores for each cycle. As described above, cycles 6, 7a, and 7c were not analyzed for performance (no heat balances). The performance ranking of these cycles was made relative to the same cycles (with the original working fluid) that had been analyzed.

Table 2-3: Results of Scoring

Cycle#:		1		2		3		4		5		6		7a		7b		7c	
Direct / Indirect		"Direct" (No IHX)		"Direct" (No IHX)		Indirect (IHX and Intermed Loop)		Indirect (IHX and Intermed Loop)		Indirect (IHX)		Indirect (IHX)		Indirect (IHX)		Indirect (IHX)		Indirect (IHX)	
Cycle Name		Super-critical Steam		Sub-critical Steam		Super-critical Steam		Sub-critical Steam		Brayton		Brayton		Combined Cycle Gas Turbine		Combined Cycle Gas Turbine		Combined Cycle Gas Turbine	
PCS Working Fluid		Steam		Steam		Steam		Steam		Helium		He+ other (N2 or Ar)		Helium		Helium & Nitrogen		Helium & Argon	
Criterion	**Wt.**	**Criteria Rating (0 to 10): A rating of 0 is unacceptable, a rating of 10 is acceptable and the best you could hope for.**																	
		Raw Score	Raw Score x wt.	Raw Score	Raw Score x wt.	Raw Score	Raw Score x wt.	Raw Score	Raw Score x wt.	Raw Score	Raw Score x wt.	Raw Score	Raw Score x wt.	Raw Score	Raw Score x wt.	Raw Score	Raw Score x wt.	Raw Score	Raw Score x wt.
1. Performance	10%	8	0.80	6	0.60	7	0.70	5	0.50	7	0.70	6	0.60	8	0.80	9	0.90	8	0.80
2. Cost	10%	9	0.90	10	1.00	6	0.60	7	0.70	5	0.50	5	0.50	3	0.30	2	0.20	2	0.20
3. Technology Maturity	20%	9	1.80	10	2.00	5	1.00	6	1.20	2	0.40	2	0.40	2	0.40	3	0.60	3	0.60
4. Flexibility/ Operability	15%	7	1.05	7	1.05	8	1.20	8	1.20	3	0.45	2	0.30	10	1.50	9	1.35	9	1.35
5. Use of Existing Technology	5%	8	0.40	10	0.50	5	0.25	5	0.25	2	0.10	2	0.10	2	0.10	4	0.20	3	0.15
6. Deployment Schedule	5%	8	0.40	10	0.50	5	0.25	5	0.25	2	0.10	2	0.10	2	0.10	3	0.15	3	0.15
7. RAMI	15%	8	1.20	10	1.50	5	0.75	6	0.90	5	0.75	5	0.75	4	0.60	5	0.75	5	0.75
8. Design Safety	10%	7	0.70	7	0.70	6	0.60	6	0.60	6	0.60	6	0.60	6	0.60	6	0.60	6	0.60
9. Licensing	5%	6	0.30	6	0.30	6	0.30	6	0.30	6	0.30	6	0.30	6	0.30	6	0.30	6	0.30
10. Scalability	5%	10	0.50	10	0.50	10	0.50	10	0.50	9	0.45	9	0.45	9	0.45	9	0.45	9	0.45
Total	*100%*		**8.05**		**8.65**		**6.15**		**6.40**		**4.35**		**4.10**		**5.15**		**5.50**		**5.35**

The highest ranking cycle is cycle 2, the direct subcritical steam cycle. This is not surprising given its high ranking for cost, technology maturity, use of existing technology, deployment schedule, and reliability. This cycle got a relatively low score for performance (net efficiency) compared with the supercritical steam cycles and indirect Brayton and CCGT cycles. The direct supercritical steam cycle gets high marks for cost and technology maturity, but due to higher operating pressures, its cost would be more than the subcritical steam cycle, although performance is somewhat better. The indirect supercritical steam cycle has relatively high efficiency, but due to the IHX, its technology maturity, deployment schedule, use of existing technology, and cost ratings are low. The indirect subcritical steam cycle is similar to the indirect supercritical cycle except that its performance is somewhat lower, but its cost is lower due to lower operating pressures. The indirect He Brayton cycle has good performance, but it gets low marks for cost, technology maturity, flexibility, use of existing technology, deployment schedule, and reliability because of the use of an IHX and helium turbomachinery. The indirect He/N_2 Brayton cycle was not analyzed for performance, but would have roughly the same rankings as the indirect helium Brayton due to the IHX, even though air-breathing turbomachinery is used. All of the CCGT cycles get the highest marks for performance (only cycle 7b was modeled for performance) and flexibility, since there are a wide range of temperatures to get process heat (in both the Brayton loop and the steam loop). The CCGT cycles get low ratings for technology maturity, deployment schedule, and use of existing technology, mainly because of the IHX. The CCGT cycles get low cost ratings because there are a lot of components: an IHX as well as gas and steam turbomachinery.

Later in this report, detailed performance analyses are made with more refined assumptions concerning additional loads such as cooling tower fans and cooling water circulator loads.

2.5 Discussion of Reactor Operation at 750°C vs. 950°C (high temperature vs. very high temperature)

The NGNP is defined as a 600 MWt very high temperature reactor which will provide process heat at temperatures up to 950°C as well as demonstrate direct hydrogen production. Such high temperature process heat can be used in many domains. These markets are expected to continue to grow but there are numerous challenges associated with building both a reactor with such high temperature and a high-efficiency hydrogen production plant. The main issues are technology maturity (materials, hydrogen loop, IHX, etc), schedule and cost.

In order to provide higher design margins, address these challenges and ensure timely deployment of the NGNP, the following options are suggested:

1) Initially build a 750°C plant, then build a 950°C plant
2) Build an upgradeable 750°C to 950°C plant
3) Build a 950°C plant but initially run it at 750°C
4) Build a dual mode plant
   - Operate the PCS at 100% power and 750°C
   - Operate the PH loop at 10% power and 950°C

Materials reasonably expected to be used over these temperature ranges are shown in Table 2-4 below.

Table 2-4: Materials Candidates Expected to be used at High Temperature vs. Very High Temperature

Component	750°C	950°C
Vessels	SA508/533	9Cr-1 Mo
Core Barrel	800H	800H
Upper Core Restraints	800H/Composite	Composite
Hot Duct Liner	800H	Composite
Control Rods	800H/composite	Composite
IHX	800H	Inconel 617
SG	2 ¼ Cr – 800H	2 ¼ Cr-800H-Inconel 617

A discussion of each of the four options is provided below.

<u>Option 1: Build a 750°C plant and then build a 950°C plant</u>

This first option consists of initially building a 750°C plant as the technology associated with such core outlet temperature is already available. Therefore, the risk associated with building the initial plant is very low. The 750°C plant will provide valuable information on the use of “moderately high” temperature process heat and the operation of prismatic core reactors at such temperatures. Once it has been determined that sufficient data has been collected from the 750°C plant and technology for the higher temperature plant is available, a second plant operating at 950°C will be built.

This option, most likely, means that the schedule on the 950°C plant will be pushed back and cost more as it results in two plants being built.

It is important, however, to keep in mind that both plants can ultimately be used whereas the other options described below end up with only one very high temperature plant. In terms of cost, option 1 initially costs more than option 2 or 3 although it is still cheaper than two option 2 or 3 plants. In the long run, this could prove to be very profitable as the 750°C plant would provide pay back by being available for commercial operation in conjunction with the 950°C plant.

Three scenarios have been identified regarding process heat in the 750°C plant:

- No demonstration of high temperature process heat until the 950°C plant is built
- Demonstration of process heat at 750°C
- Demonstration of process heat at temperatures higher than 750°C by using supplemental electric heating

Although potentially more costly, option 1 is low-risk and includes commercialization of a 750°C plant ahead of schedule as well as a 950°C plant afterward. This should not necessarily be seen as a disadvantage considering that the technology to deliver very high temperature process heat to the market is not ready.

Option 2: Build a plant that can be upgraded from 750°C to 950°C

In this case, the recommendation is to build a 750°C plant that can be upgraded to 950°C. This scenario involves making sure that all parts, systems and components that will need to be changed are replaceable. This option reduces the risk (described in option 3) of using inadequate materials or components before R&D has been performed and data collected.

The plant still has to be licensed twice, first for 750°C operation and then updated for 950°C operation. Discussions with the regulator are expected to be facilitated by the fact that the plant is upgraded to match the results of R&D and data collection (versus showing that the current materials and systems are adequate for higher temperature operation or why they are not – as in option 3)

This option is viewed as initially more expensive than option 3. Nonetheless, it tremendously reduces the available room for error (which has potential to be costly) in terms of material/system selection for operation at very high temperature. Compared with option 1, option 2 is also initially more costly to achieve testing at 750°C, but ultimately could be quite a bit cheaper than building two plants. There is some risk that the upgradeable components in the 750°C plant would not be designed properly and make the switch-over to the 950°C plant challenging.

Option 3: Build a 950°C plant but initially run it at 750°C

This option entails building a plant that can withstand 950°C temperatures (piping, IHX, core, etc) as far as we currently know but initially operating it at 750°C. This option permits testing of the core, materials and systems at moderately high temperature (750°C). Additionally, R&D and data collection on higher temperatures (950°C) can be performed to ensure that the design and materials selected for use at 950°C are indeed appropriate. The plant is licensed for operation at 750°C and then, once ready to run at 950°C, the license is updated.

The main potential issues associated with this option are:

- If the plant is designed to operate at 950°C, how difficult will it be to run it at 750°C? Materials used to withstand very high temperature are not necessarily ideal for lower temperature environments. For instance, the steam generator contains a bi-metallic weld between the two tube materials. When operating at different temperatures, the boiling region will shift and can potentially damage or weaken the weld.

- The plant will be designed and built to operate at 950°C before all data collection and R&D are preformed. If the results of R&D show that the materials or core design used are inadequate, significant modifications may need to be performed.

- Having to update the license to operate at 950°C could prove challenging.

Option 3 presents some challenges in terms of licensing and operation at different temperatures. However, it provides a useful stepping stone at intermediate temperature to reach the 950°C goal and collect valuable data in the process. Similarly to option 2, initial 750^{o}C testing could reveal design flaws that preclude 950^{o}C testing or entail design modifications.

Option 4: Build a dual mode plant

As depicted below, option 4 involves building one plant with multiple operating modes as follows:

- PCS at 100% power and 750^{o}C or
- PCS at 90%, PH loop at 10%, with both at 750^{o}C or
- PH loop at 10% power and 950^{o}C

With this option, only the core and process heat loop are designed to handle 950^{o}C core outlet temperature. The rest of the plant only needs to withstand 750^{o}C core outlet temperature. The PCS is shutdown while the reactor runs at 950^{o}C. This makes the material/equipment selection for the PCS much easier while the 950^{o}C requirement is still fulfilled by operating the PH loop at 950^{o}C. Operating at lower power on a part-time basis allows for much higher margins than if operating at 950^{o}C at 100% power. Figure 2-1 illustrates the relationship between power, temperature and margin.

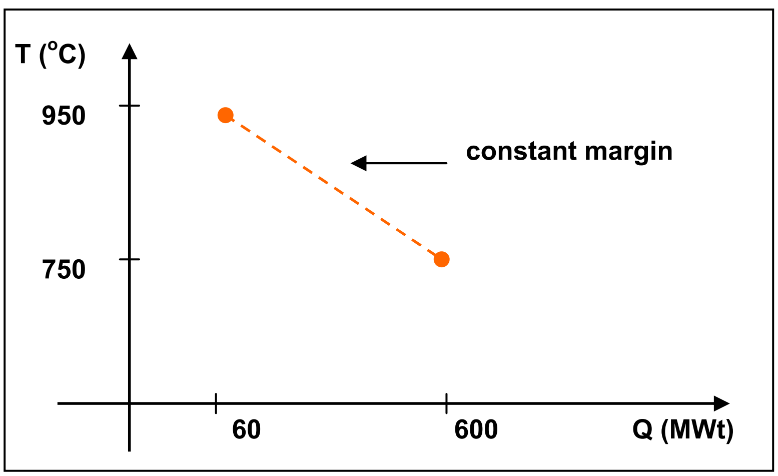


Figure 2-1: Temperature vs. Power for Constant Margin

Option 4 was analyzed and due to its unusual mode of operation, several new feasibility issues were identified and are discussed below.

Inlet and Peak Fuel Temperatures

Fuel temperatures need to be analyzed carefully. Peak fuel temperature depends on the power level and temperature difference across the core. Additionally, these temperatures need to ultimately satisfy a number of safety and structural margins. Temperatures also determine the types of materials available for use.

Scoping analyses of this condition were performed using existing AREVA models. With an outlet temperature of 750ºC at 600 MWt, the peak fuel temperature is expected to be about 1250 ºC, which provides significant margin compared to the past reference case. (The past reference case with T_{in}=500 ºC and T_{ou}t=900 ºC has a peak fuel temperature of approximately 1350 ºC.) Estimates based on the scoping calculation for 10% power operation with an inlet temperature of 350 ºC and an outlet temperature of 950 ºC give a local peak fuel temperature of 1366 ºC. This suggests that low power, high temperature operation is probably feasible, although more detailed analysis will be required to specify precise operating parameters.

Flow Distribution and Cooling Through the Core

Uniformity of the flow distribution is a potential concern. Due to the large flow rate at 100% power, uniformity is easily achieved (and will be addressed at the conceptual design stage). At 10% power, flow is drastically reduced and flow distribution could be problematic due to relatively higher buoyancy forces in the core vs. the relatively small core pressure drop. It is conceivable that at low flow rate, forced flow is not significant enough to overcome buoyancy due to the density differences in the hot and cold channels. Should that be the case, hot channels may have significantly reduced flow, and at the extreme cold helium would flow down through the coolant channels then flow up through the hot channels. These hot channels would see a hot inlet temperature and fuel temperatures would be very high near these “reverse flow” channels.

A preliminary qualitative assessment of the buoyancy force was performed at 100% power (with inlet temperature of 350^{o}C and outlet temperature of 750^{o}C) and at 10% power (with inlet temperature of 375^{o}C and outlet temperature of 950^{o}C). As expected at 100% power, the buoyancy forces only represents about 0.1% of the pressure drop across the core. At 10% power, the buoyancy forces are about 10% of the core pressure drop. Although the percentage significantly increases between full and part power operation, this preliminary calculation suggests that buoyancy forces are not dominant and that there is not a significant concern regarding potential stagnating or reverse flow channels in the core.

Further analysis will be necessary to confirm these results, analyze the consequences of low flow on core cooling, and determine if additional insulating blocks or increased flow may be necessary for core stability.

Neutronic Stability – Temperature Coefficient – Cycle Length – Rod Worth

At lower power and higher temperature, stability of the core is a concern that needs to be addressed. The reactor is designed to operate primarily at 750 ^{o}C and 100% power. The core needs to be analyzed to determine its behavior at lower flow and power. The temperature coefficient, cycle length, rod worths and xenon concentrations need to be studied to determine how much they are affected and ensure neutronic stability. If analysis determines that it is not the case, the core should be modified to meet this requirement.

Circulator

At full power, the main circulator is operating and helps circulate helium through the primary loop. When operating the process heat loop at 10% power, the main circulator is shutdown and the small circulator in the IHX loop is turned on.

At 10% reactor power, the small circulator is operating at its full speed and therefore designed to operate stably. Power requirement is actually reduced, because system ΔP is reduced. Circulator performance for this condition would be assessed in conceptual design, but it is not a significant concern.

If the PCS is shutdown, backflow needs to be prevented. Stopping the main circulator should take care of the issue as the circulator contains a flapper valve which will prevent backflow without the need for isolation valves. Additionally, because the reactor inlet pressure is higher than reactor outlet pressure, back flow consists of “cold” helium from the reactor inlet. Therefore, although it needs to be prevented, leakage would be minimal and originate from the reactor inlet.

IHX Loop

Because the IHX loop is designed for 950°C at 60 MWt, it is anticipated to have a shorter lifetime than the systems designed to operate at 750°C and 600 MWt.

Option 4 Conclusions

This initial evaluation shows that dual-mode operation seems feasible although a few issues still need to be addressed more in depth. Initial assessment of peak and inlet temperatures gives reasonable results. Additional work should be performed to determine the consequences of peak fuel temperature location within the channel as well as the implications of small coolant vs. fuel temperature difference. Natural convection, neutronic stability, circulator stability and IHX lifetime are topics that will need further analysis.

Conclusions

The options presented in this section provide prudent approaches to satisfying the very high temperature requirement of the NGNP project. Moreover, they permit testing and data collection at moderately high temperature in order to better prepare for operation at 950°C. And because the technology to deliver hydrogen and high temperature process heat to the market is quite a few years behind high temperature reactor technology, this gradual approach should not be perceived as a hindrance.

2.6 Considerations between Conventional and Indirect Steam Cycles

The “indirect” steam cycle separates the steam generator from the reactor using an Intermediate Heat Exchanger and a secondary gas loop. This is the configuration that was examined in detail previously in the AREVA IHX and Secondary Loop Alternatives Study Report (Reference 2). While the indirect configuration helps to separate the design issues of the primary circuit from those of the PCS, it also adds extra cost and technology development risk. One of the key arguments in the past for the indirect cycle has been to allow the development of the integrated

PCS system in an uncontaminated environment. However, the steam Rankine cycle PCS is based on mature technology which requires no development, and the steam generator requires only minimal confirmatory testing. As a result, this benefit of the indirect cycle is of negligible value for a steam cycle system. This suggests that the conventional or "direct" steam cycle system may be more attractive.

In comparing the direct and indirect steam cycle systems, several considerations must be taken into account including:

- Technology Risk
- Safety
- Schedule
- Cost
- Flexibility
- Contamination Control

Technology Risk

The indirect cycle concept has significantly greater technology risk than the conventional steam cycle. The conventional steam cycle technology has been demonstrated successfully in past HTRs. The indirect cycle concept requires significant technology development or demonstration for the IHX and also for secondary hot gas piping, etc. Some incremental circulator development might also be required.

For a lower reactor outlet temperature (e.g., 750-800°C), the IHX technology development would be significantly less challenging than for very high temperature applications, but it would still be required. More importantly, this development of a lower temperature IHX would be of limited long-term value, since it would not provide the key technology required for a future high temperature IHX such as would be required for long-term very high temperature process heat applications such as direct hydrogen production.

Even with a low reactor outlet temperature, the indirect cycle concept also poses a slightly more challenging environment for the reactor and primary circuit components. The reactor will have to operate about 50°C hotter than it would for the equivalent direct cycle system. This makes the core design more challenging, and it puts a greater burden on fuel performance and on moderate temperature reactor materials. In some cases, alternate materials could be required to maintain design margins.

Safety

For a direct steam cycle system, the main incremental safety impact is the potential for significant water ingress into the primary circuit due to steam generator leaks. This concern must be taken seriously, but it is manageable. It has been addressed successfully in all previous operating HTRs, and it is not expected to have a major impact on overall plant safety. This issue is discussed in detail in a later section of this report.

Loss of heat sink (LOHS) is the main incremental safety concern for the indirect cycle system. The heat capacity of the IHX is small, and significant overheating of the primary coolant cold leg can occur if cooling is disrupted on the secondary side of the IHX. This situation is manageable with protection system action. However, the consequences without protection are unacceptable. This issue is also discussed in detail later.

For the indirect steam cycle, the effect of water ingress from a steam generator leak in the secondary circuit would also have to be considered. The impact on system pressure and resulting IHX integrity would be significant concerns. This concern was not assessed during this study.

<u>Schedule</u>

The project schedule is impacted by technology development, design activities, and fabrication and construction. In each of these areas, the conventional direct steam cycle system has an advantage. The direct steam cycle has less major equipment to be designed, fabricated, and installed. Most importantly, the indirect cycle requires significantly more R&D due to the IHX and high temperature materials. This would delay deployment of the NGNP if the indirect cycle configuration were selected.

<u>Capital Cost</u>

The capital cost is affected significantly by this decision. The indirect cycle configuration requires all of the equipment of the conventional direct steam cycle system plus major additional equipment including the IHXs, IHX vessels and supports, secondary circulators, and the secondary coolant piping. Depending on the plant layout, large very high temperature isolation valves may also be required. The reactor building would also be impacted.

An indication of this cost difference is provided by comparing the cost estimate developed in the previous study (Reference 1) for the indirect steam cycle to the cost estimate for the direct steam cycle provided later in this report. The indirect cycle system is estimated to cost 15-20% more than the conventional system for the single module demonstration plant. This difference is approximate, since the previous indirect cycle system was for a higher reactor outlet temperature, although this is not considered a significant factor. A lower temperature indirect system could perhaps use less costly material in the IHX, but the size of the IHX would have to be larger because more heat transfer surface area would be required due to the smaller temperature difference from the primary to secondary side of the IHX.

The cost savings of the conventional cycle would be greater for a commercial NOAK plant, since the cost savings are in the individual module costs and common support facilities make up a smaller fraction of the total cost for a commercial plant.

<u>Operating Cost</u>

The plant operating cost comparison hinges on differences in plant performance (efficiency) and in O&M costs. The conventional steam system has an advantage in efficiency. The Rankine cycle is identical, but the indirect cycle has larger house loads since the circulator power would more than double (see assumptions 11 and 12 in section 2.3).

The O&M costs would be higher for the indirect cycle system. The indirect cycle system has twice the number of circulators to be maintained. In addition to steam generator maintenance, the indirect cycle also must include IHX maintenance and replacement. The IHX maintenance and replacement is expected to be more significant than steam generator maintenance. For very high temperature systems, frequent replacement of the IHX is required. An assessment of IHX replacement for moderate temperature concepts has not been performed. Nonetheless it will not be better than the steam generator which is expected to last for the plant lifetime.

For the indirect cycle system, steam generator maintenance would no longer involve potential radiation zones. However, this concern is not eliminated; it is only shifted to the IHX which would potentially contain significant radionuclide plateout.

Thus, the direct steam cycle has a significant advantage in terms of operating cost.

<u>Flexibility</u>

The HTR has the potential to serve a number of current and future process heat applications in addition to electricity generation. Since the interface requirements vary by application, an important consideration in selecting the PCS configuration for the NGNP is the flexibility of the system in being able to serve a wide range of applications. It is useful to consider the market in two broad segments, those requiring heat up to 550°C and those such as direct hydrogen production requiring heat at significantly higher temperatures.

Either steam cycle system would serve the moderate temperature process heat markets up to 550°C very well. The specific configuration would vary for each application, but high temperature steam provides an efficient cost effective energy transport medium for any configuration. For markets requiring intermediate temperature steam (e.g., 300°C), high pressure steam could be put through a backpressure turbine to extract useful energy and then lower pressure extraction steam would support the process heat requirement. For markets requiring direct contact of steam with process fluids, a steam-to-steam reboiler would be used to separate the steam generator (or extraction steam) from the process steam. (This is necessary to maintain the stringent feedwater quality required for the HTR steam generator. Use of returning condensate from residual process fluids as the primary feedwater stream would place unrealistic demands on the water cleanup system. Installation of a full capacity water cleanup system capable of meeting the feedwater quality requirements for the once-through steam generator is not practical. Use of a reboiler allows optimum feedwater conditions to be maintained in the steam generator inlet.)

On the other hand, neither of the steam systems is well suited to supporting very high temperature applications. These applications would require an IHX designed to operate in the range of 900°C. While the indirect steam cycle would include an IHX, it would be developed for a lower temperature in order to accelerate deployment and reduce technical and schedule risk. The very high temperature IHX would require different materials, greater thermo-mechanical optimization, possibly alternate corrosion control strategies, and possibly a fundamentally different configuration (e.g., compact vs. tubular). The steam cycle IHX would not demonstrate these technologies.

<u>Contamination Control</u>

While circulating radionuclide activities in high temperature reactors are relatively low, the control of radionuclide contamination must still be considered. Three main aspects must be addressed – (i) impact on plant operations and maintenance, (ii) impact on the surrounding population and environment, and (iii) for process heat applications, potential contamination of the process heat user's product. The first two are typical considerations for any nuclear power plant. The third is a significant new concern for the application of nuclear process heat.

The impact on plant O&M has already been touched on above. The conventional direct steam cycle is believed to have an advantage, because it has fewer major components. Of particular interest here, the impact of contamination on maintenance is not significantly different between the two concepts, because contamination is simply displaced from the steam generator to the IHX.

Similarly, as discussed above, the impact of radiological release on the surrounding public is not judged to be fundamentally different between the two concepts. Neither LOHS in the indirect cycle nor water ingress in the conventional steam cycle is expected to dominate the overall HTR risk profile (see section 3.2 on water ingress and 4.2 on LOHS and comparison of both events in section 5.0).

Since this report is focused on the PCS for electricity generation, the potential for product contamination has not been examined in detail. Nonetheless, this is a very important issue for future process heat applications. In comparing the conventional and indirect steam cycles, the impact of potential contamination pathways on the adaptability of each PCS configuration to process heat applications must be considered.

The primary coolant heat exchanger (either steam generator or IHX) is impervious to most radionuclides, the key exception being tritium. Therefore, contamination of the process streams via the heat transport pathway is not a significant issue during normal operation. Even in an upset condition, rapid detection of any steam generator leak and the higher water side pressure would prevent most contaminants from entering the process stream.

As noted, tritium is a key exception to this. Tritium diffuses through many materials and could potentially diffuse through the IHX and the steam generator even under normal operating conditions. Therefore, the potential for tritium contamination of process product must be considered.

For the conventional steam cycle, tritium can migrate through the steam generator wall from the primary coolant to the water/steam loop. For the indirect steam cycle, tritium can migrate through the IHX wall to the secondary coolant and then through the steam generator wall to the steam/water loop. The indirect cycle offers an additional barrier to tritium transport, but ultimately, tritium will still reach the steam/water loop. The indirect steam cycle does offer the possibility of a tritium removal system on the secondary loop. Such a system operating between the two barriers (IHX and steam generator) has the potential to reduce the tritium reaching the water/steam loop, although probably at significant cost. Without such a system, the benefit of the additional barrier is diminished.

Tritium reaching the water/steam loop will become bound in water molecules. This significantly limits its mobility, minimizing diffusion to any downstream process or heat transport loops. Thus tritium migration into actual process streams should be minimized by the reboiler required for feedwater quality considerations between the nuclear steam and the process steam supply.

Substantial work would be needed to fully resolve concerns about tritium product contamination. Numerous uncertainties exist for tritium production, tritium retention within the primary circuit, tritium diffusion through materials, tritium removal technologies, and allowable tritium concentrations in various product forms (Reference 3).

Nonetheless, it seems reasonable based on past HTR experience and current knowledge that for low temperature (e.g., 750°C) reactor operation, tritium concentrations in process feed steam downstream of the reboiler would be acceptable. This conclusion does not change fundamentally whether a conventional direct steam cycle or an indirect steam cycle configuration is used.

<u>Steam Cycle Comparison Result</u>

In many respects the conventional steam cycle and the indirect steam cycle are very similar. They are adaptable to the same commercial markets, and they provide similar though not identical performance. However, in some key areas, there are significant differences as discussed above. Table 2-5 summarizes this comparison.

The key difference between the two cycles is the major advantage of the conventional steam cycle in terms of significantly reduced technical risk and capital cost. The conventional steam cycle also has slight advantages in terms of operating cost and project schedule. The indirect steam cycle could have a slight advantage in terms of tritium control for direct process heat applications, but this is negated by the use of a reboiler which is required anyway for feedwater quality control.

Therefore, AREVA recommends the conventional direct steam cycle. The direct cycle has substantial advantages over the indirect cycle and no significant disadvantages.

Table 2-5: Comparison of Conventional Steam Cycle and Indirect Steam Cycle

	Direct Steam	Neutral	Indirect Steam
Technology Risk	++		
Safety		x	
Schedule	+		
Capital Cost	++		
Operating Cost	+		
Flexibility		x	
Contamination Control			+

3.0 DETAILED ASSESSMENT OF THE RECOMMENDED CONFIGURATION (DIRECT SUBCRITICAL STEAM CYCLE)

The second part of the PCS study covers a detailed assessment of the recommended configuration which is the direct subcritical steam cycle based on the high level assessment from part 1 described above. A schematic of this cycle is shown below.

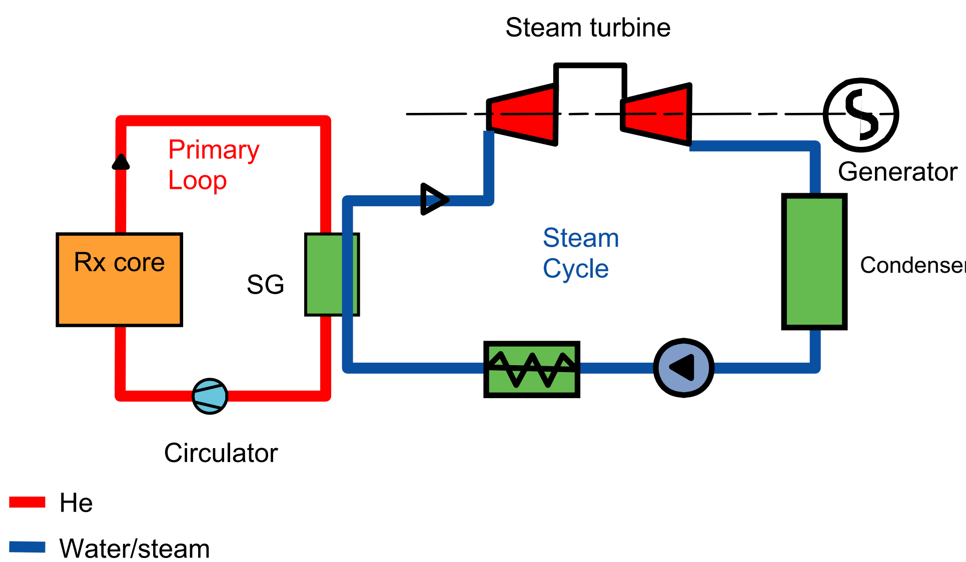


Figure 3-1: Direct Subcritical Steam Cycle

Detailed performance, safety, and cost analyses were conducted for this cycle which will be discussed below. Also covered are reliability and technology maturity.

3.1 Detailed Performance Analysis

Mitsubishi Heavy Industries (MHI) carried out a detailed performance assessment on the direct subcritical steam cycle for a 750 C outlet temperature. The assumptions used in performing the steady-state heat balance are as follows (from Reference 4):

- 600 MWt Reactor power
- 340 C/750 C reactor inlet/outlet temperatures
- Steam Water side inlet/outlet temperature 281 C/566 C
- Main steam pressure of 16.7 MPa
- He side pressure drop < 0.06 MPa
- House loads (total of 18.2 MWe):
  - Primary circulator power: 7 MWe (3.5 MWe x 2)
  - Feedwater pump: 4 MWe

- Condensate pump: 0.4 MWe
- Wet cooling Tower Fan: 1 MWe
- Circulating Water Pump: 2.8 MWe
- Miscellaneous loads: 3 MWe

- 2 Steam generators: heat duty 303 MWt each
  - (from 600 MWt – 1MWt Rx heat loss + 7 MWe circs. /2)
- One steam reheat cycle
- 0.0039 MPa condenser pressure

The gross cycle power is 284 MWe including turbine and generator losses.

Gross cycle efficiency = 284/(303x2)x100 = 46.9%

Net plant output = 284 – 18.2 = 265.8 MWe

Net plant efficiency = 265.8/600 = 44.3%.

A heat balance is shown below. Figure 3-2 shows the system configuration and Heat & Mass Balance of secondary system and Steam turbine system. The typical conventional steam turbine system and heat mass balance of 300MWe class are applied to this steam turbine system in order to eliminate development risk and to achieve reasonable high efficiency. Reheat adds approximately six percentage points to plant efficiency vs. no reheat (47% vs. 41% gross efficiency).

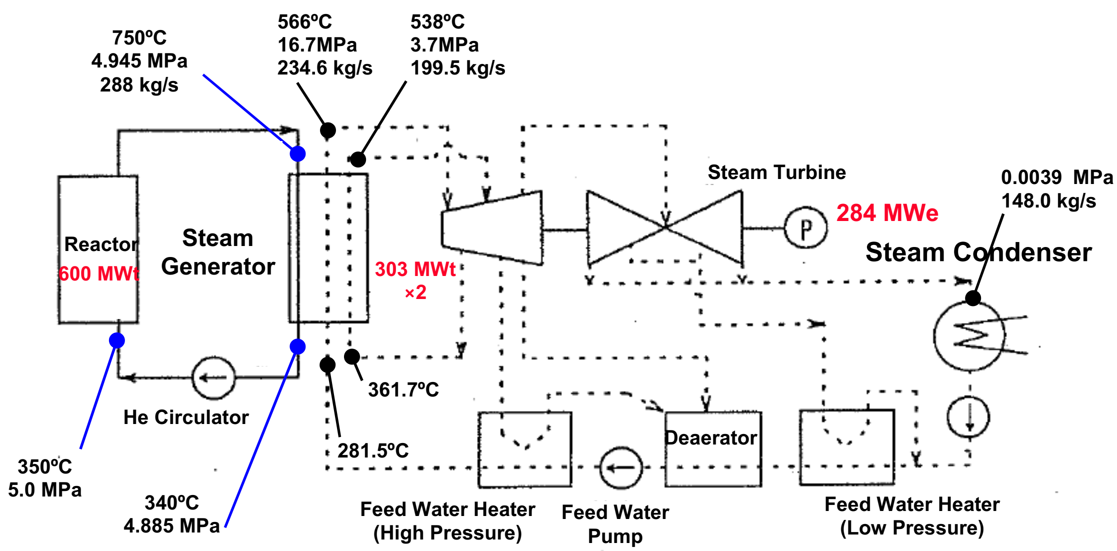


Figure 3-2: H & M Balance of Steam Turbine Cycle

3.2 Safety Assessment: Direct Subcritical Steam-Rankine Cycle

3.2.1 Introduction

All reactors are analyzed for a full spectrum of safety events. Some of the events are external to the plant, other internal. Internal events can initiate from the primary loop, secondary loop or a variety of other auxiliary loops. This assessment focuses on the direct subcritical steam-Rankine cycle power conversion system of a high temperature reactor (about 750°C) and the unique safety issues associated with it.

Water ingress is a safety concern that is mostly unique to this system. Although possible in other configurations such as a combined cycle gas turbine power conversion system, it is both less likely and more trivial as the secondary fluid is a helium/nitrogen mixture and the primary and secondary loops are connected through an intermediate heat exchanger. In the case of a steam cycle, a steam generator is introduced between the primary and secondary systems. A steam generator tube leak, if undetected, could yield to a water ingress event. This requires a detailed assessment of water ingress.

This assessment first defines the potential sources of water ingress in HTRs based on operating conditions and operational history. Then, the various water ingress accident categories are presented. After that, the main water ingress consequences are described: primary coolant pressure increase, reactivity and power effects, graphite oxidation, fuel hydrolysis, fission product mobilization, and investment risk. Next, the assessment focuses on the available mitigation options through detection, isolation and recovery systems as well as reactor and steam generator designs. Limited scoping calculations of the event, including a RELAP5-3D model and reactivity assessment, follow. This evaluation then presents a safety and risk evaluation of the event. Finally, additional recommended analysis and R&D are suggested in order to further minimize concerns of water ingress in a subcritical steam-Rankine power conversion system.

3.2.2 Potential for Water Ingress

All HTRs have a variety of water sources which depend on the type of power conversion system and the operating conditions. The direct subcritical steam-Rankine cycle, which is the focus of this report, is separated from the primary helium loop by a steam generator (see Figure 3-1). Since this configuration does not include an intermediate loop such as the helium-nitrogen loop of a CCGT cycle, steam generator failure could lead to water ingress into the primary system.

This is true both at power and during shutdown because of the high enthalpy of the system and the pressure conditions of an HTR. As portrayed in Figure 3-2, primary system pressure in a subcritical steam HTR is quite a bit lower than in a PWR primary cycle (5 MPa vs. 18 MPa), and the secondary system pressure is much higher than in a PWR (14 MPa vs. 6 MPa). Because primary pressure is lower than secondary pressure at power, a steam generator tube break during operation would cause secondary water to migrate to the primary helium loop.

During pressurized operation of the primary system, the secondary pressure in certain loops (e.g., Shutdown Cooling System water, circulator cooling, etc) is too low for ingress to occur [8]. Such loops can, however, become water ingress sources in the event of primary loop depressurization (shutdown, refueling). Nevertheless, these sources of water ingress are insignificant compared to the steam generator which represents a much larger source of water due to its large inventory.

Secondary fluid conditions are also a concern. During normal operation, ingress would result in steam in the primary system. If the plant is in cold shutdown mode, ingress would result in water in the primary system.

3.2.2.1 PWR Steam Generator Performance

Steam generator concerns are often associated with the fair operating experience of PWR steam generators. Tube plugging due to vibration, design, shell side corrosion and other material interactions is not uncommon in PWR steam generators.

PWR steam generators are, however, a poor comparison to HTR steam generators as they have different operating and design conditions. Water is the primary fluid in a PWR and the main cause of PWR steam generator problems. HTRs use helium, an inert gas. Also, in a PWR, the primary fluid flows through the SG tubes and the secondary fluid is on the shell side. In an HTR, the primary fluid instead flows on the shell side. This almost eliminates any of the shell-side corrosion concerns common to PWR SGs. Moreover, PWR steam generators are of the U-tube kind while the NGNP will use a helical coil once-through steam generator. The fluid going through the tubes of a helical coil SG flows at much higher velocities than the fluid going through a U-tube SG. This reduces the risk of water gathering at low points within the tubes.

3.2.2.2 Fossil Boiler Performance

Fossil boilers operate similarly to HTR steam generators. But again, the challenges encountered in fossil boilers do not apply to the HTR environment:

- Tube slagging is a common issue in fossil boilers which involves molten impurities from fossil fuel depositing on the tube surface. Some impurities have high emissivity and can create a hot spot on the tube leading to its failure. This would not happen in an HTR because helium being a chemically inert and neutronically transparent.
- Fossil boilers operate at firing temperatures much higher than high temperature reactor core outlet.

HTRs have a more benign environment than fossil plants.

3.2.2.3 Gas-Cooled Reactors Operating History

The operating history of existing gas-cooled reactor can provide valuable information on the level of concern that should be attributed to water ingress. Examples of existing gas-cooled reactors include Fort Saint-Vrain, Peach Bottom I, AVR, THTR, AGR and Magnox. Most of these reactors were built with a steam cycle, which provides an even better comparison in the context of this assessment. Gas-cooled reactors have had an excellent operating history with the exception of FSV and AVR.

3.2.2.3.1 Fort Saint-Vrain

The reactor at FSV is notorious for its inconsistent operating history and excessive downtime. FSV was designed with many advanced features such as a PCRV containing the entire primary coolant system, a hexagonal graphite-moderate core with TRISO fuel, a once-through steam generator producing 538^{o}C steam, as well as a steam turbine driven axial helium circulators [10]. It was helium-cooled, graphite-moderate, utilized a uranium-thorium fuel cycle and had a 330-MWe power rating. The power conversion system was a conventional steam cycle and the steam conditions were comparable to those of modern fossil plants [10]. FSV struggled throughout its 13 years of operation. Helium leaks, fuel handling issues, control rod drive degradation and scram failures were some of the issues the plant encountered [9]. Some of these issues were direct consequences of moisture intrusion problems. Moisture intrusion was a concern in terms of contamination in the fuel-moderator assemblies as water will react rapidly with the carbon contained in the assemblies. Moisture was also found to cause hydrolysis of the fuel and corrosion of the graphite core support post. Nonetheless, this issue proved not to be a safety concern. It was primarily a plant availability issue. Moisture removal was impeded due to the lack of a reactor drain. The moisture challenges FSV battled for year did not, however, originate from the steam generators. The water-lubricated bearings of the helium circulators were the source of the water ingress problems [10]. FSV was actually a valuable technology test-bed where performance of the steam generators (among other features) was successfully demonstrated [10]. Some early inconsequential leaks were detected and successfully repaired.

Circulator bearings in the NGNP will not be a water ingress concern since they will embody active magnetic bearings to prevent oil or water ingress into the core [2]. Furthermore, it will be designed with a drain at the bottom of the steam generator and reactor should moisture need to be removed.

3.2.2.3.2 Arbeitsgemeinschaft Versuchsreaktor (AVR)

The German AVR was a 17 MWe prototype pebble bed reactor built at Jülich Research Center to develop and test fuels and machinery. In 1978, shortly after the reactor was shutdown to repair a safety valve, coolant moisture increased as it had during prior shutdowns. Previously, these moisture values reached normal levels after a few days of restarting the reactor. This time, however, the moisture rose to values that made it necessary to dry the system before restart but the amount of water that had entered the system was too large to be cleaned out with the gas purification plant. It was found that a steam generator leak had occurred and grown to a leak area of 1 to 3 mm^2 [19]. Because the steam generator was located directly above the reactor vessel, the core and internals were found to be very wet. The reactor remained shutdown for 15 months to remove the water and repair the leak. Corrosion was not significant and no safety issues were identified but the extended shutdown was caused by the absence of a reactor vessel drain.

In the NGNP design, the reactor is located next to and slightly higher than the steam generators. Also, as previously mentioned, it will be designed with a reactor vessel drain to prevent moisture removal difficulties such as the ones encountered with the AVR.

3.2.2.3.3 Steam Generator Leak Study

Reference 16 includes a report entitled “Frequency and Distribution of Leakages in Steam Generators of Gas-Cooled Reactors” which contains valuable information from 13 HTRs studied over 1500 calendar years of SG operation (downtime and part-time load not included).

The majority of the plants referenced in Table 3-1 and all the reactors referenced in Table 3-2 are Magnox reactors. These reactors were built and operated in the UK as a fleet and most of them remained in operation for the length of their licensed lifetime. Magnox reactors use helical coil steam generators (see Figure 3-3) similar in concept to the ones proposed for use in the NGNP. Their power output is in the 200 MWe range with the exception of Wylfa where both units had an output just below 500 MWe. This also is similar to the anticipated 279 MWe power output of the NGNP [1].

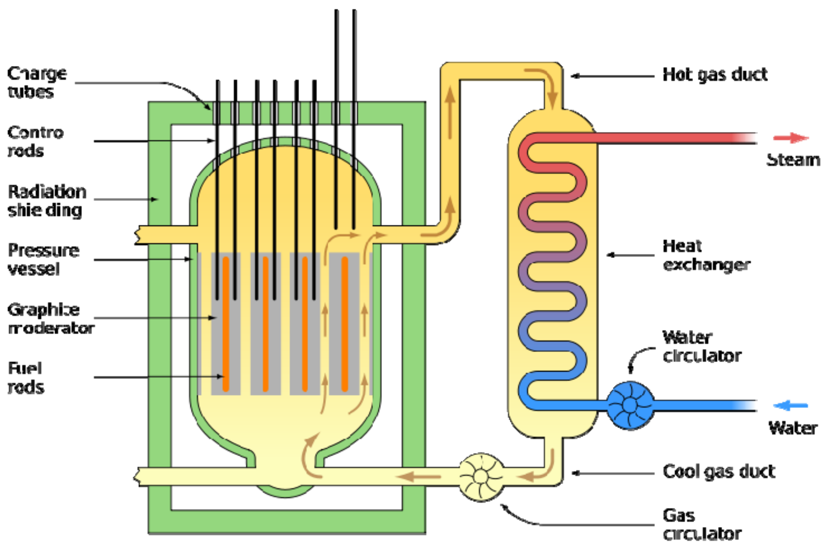
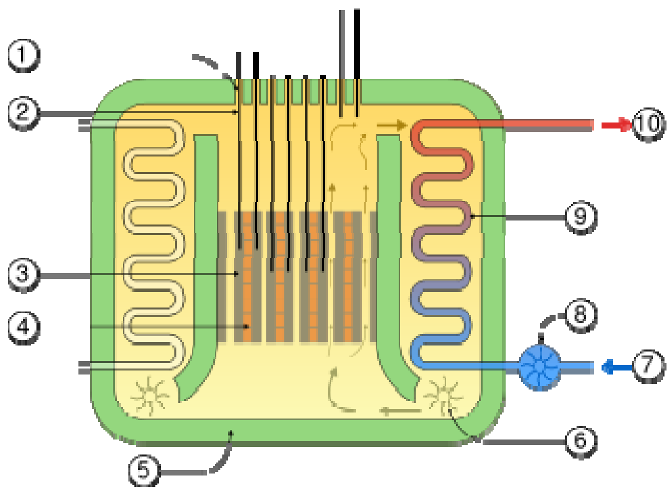


Figure 3-3: Magnox Reactor Configuration (www.wikipedia.org)

Table 3-1 also references an AGR reactor which, similarly to the Magnox, is part of a fleet of gas-cooled reactors with helical coil steam generators (Figure 3-4). On average, the AGRs have a power output in the vicinity of 600 MWe. Although quite a bit higher than the anticipated power output for the NGNP, the similarities in design and operating conditions make the AGR a good comparison to the NGNP.



1 – Charge Tubes
2 – Control Rods
3 – Graphite Moderator
4 – Fuel Assemblies
5 – Concrete Pressure Vessel and Radiation Shielding
6 – Gas Circulator
7 – Water
8 – Water Circulator
9 – Heat Exchanger
10 – Steam

Figure 3-4: AGR Configuration (www.wikipedia.org)

Reference 16 supports the claim that SG operation has excellent and improving history. The report shows that failure frequency is independent from temperature and pressure conditions or geometric size of the heating surface. Design, construction, fabrication, examination and operating conditions have the greatest influence on failure frequency. Although not practical to quantify, faulty design is the most common cause of failure and includes defects in design as well as systematic defects due to manufacture and deviation from design operating conditions. The data was summarized in Table 3-1 and the failure frequency per SG per year was plotted for each plant in Figure 3-5. Information on leak detection methods and plant-specific operational parameters that affected the postulated tube leaks are unavailable.

Table 3-1: Operating Experience of HTR Steam Generators up to 1979 (based on Reference 16)

	Online	Number of SGs	Years of Operation Until 1979	Years of SG Operation	Tube Failures	Failure Frequency per SG per Year	Comments
Berkeley*	1962	16	16.5	264	10	0.04	
Bradwell*	1962	12	16.5	198	112	0.57	Mainly weld defects leading to leakages in the high-pressure section during first few years of operation
Hunterston A*	1964	16	11 (until 1975)	176	75	0.43	Mostly leaks in low-pressure section in first few years of operation; One large leak in the high-pressure superheater region
Hinkley A*	1965	12	14	168	4	0.02	
Trawsfynydd*	1965	12	14	168	39	0.23	Most leaks in the high-pressure section and caused by poor water quality
Dungeness A*	1965	8	13.5	108	1	0.01	
Sizewell A*	1966	8	13	104	16	0.15	10 tube failures in 7th and 8th year (high-pressure section), 3 after 1975 (low-pressure section)
Peach Bottom 1	1966	2	7.5 (until 1973)	15	2	0.13	Small tolerable leaks on tube plate
Oldbury*	1967	8	11.5	92	6	0.07	
AVR	1969	1	10	10	1	0.10	
Wylfa*	1971	8	8.5	68	46	0.68	Unusual design modified for want of space; Leaks caused by corrosion, erosion, defects in design
Hinkley B**	1976	24	3	72	0	0.00	
FSV	1976	12	5 (until 1981)	60	1	0.02	
AVERAGE			11.1			0.19	

* Magnox Reactor

** AGR

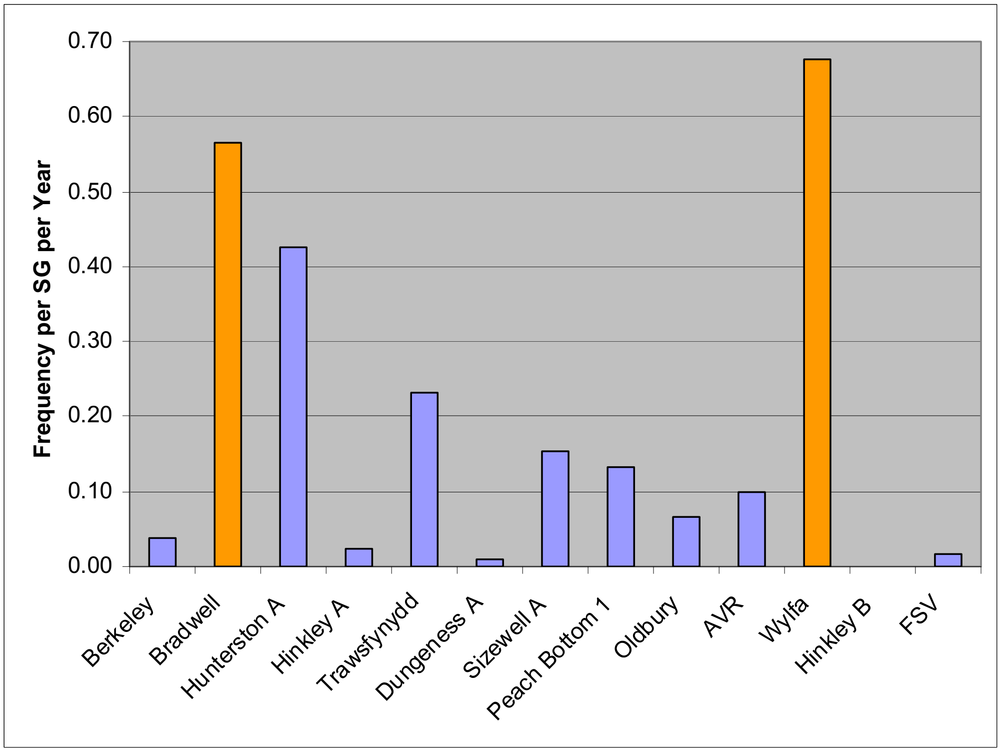


Figure 3-5: Steam Generator Failure Frequency per Steam Generator per Year for 13 Plants up to 1979 (based on Reference 16)

Several important results from the original paper should be pointed out:

- Only one steam generator leak was found to be in the cm^2 range.
- Simultaneous failure of several tubes or tube plate failures had not occurred by the time Reference 16 was written in the reactors specified.
- All leaks reported in the study fall into the small or moderate leak category (see section 3.2.3.1 for category descriptions).
- Most failures occurred in the first few years of operation and were caused by faulty design rather than wear.
- The failure distribution over the steam generator sections from 1975 to 1979 can be regarded as uniform.

Additionally, the above data is based mainly on AGR and Magnox reactors which use CO_2 as their primary fluid unlike the NGNP which is designed with a primary helium loop. Helium provides a much more benign environment than CO_2. Helium being an inert gas, issues such as corrosion are not expected at steam generator operating temperatures.

As illustrated in Figure 3-5, Wylfa exhibits a high failure frequency of steam generator leaks. It should be pointed out that its steam generators were of unusual design which was modified to deviate from the original concept for want of space. Reference 16 also indicates that the Bradwell steam generator leaks mainly resulted from systematic weld defects. Because of that, both Wylfa and Bradwell were discarded in the probability study performed in that reference. In Figure 3-6, Wylfa and Bradwell were removed as well. The new graph emphasizes even more the improving trend of steam generator performance.

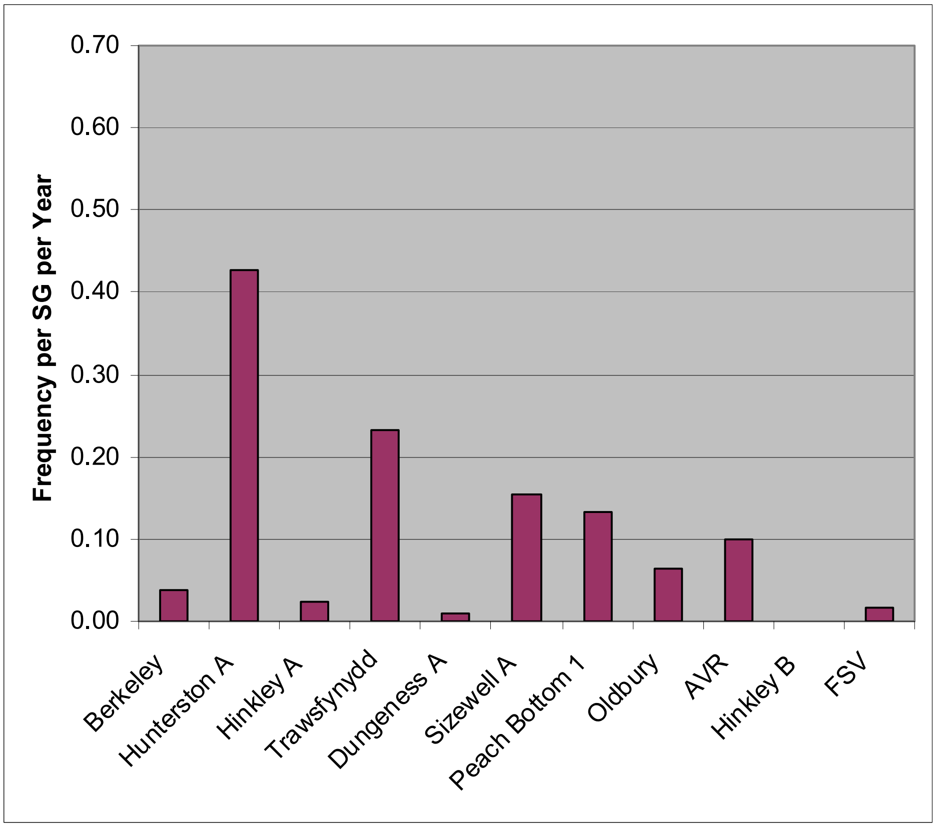


Figure 3-6: Steam Generator Failure Frequency per SG per Year up to 1979 (without Wylfa and Bradwell)

The previous table and figures clearly demonstrate that the later designs had less steam generator leaks than earlier designs. Moreover, most of the failures occurred in the first few years of operation [16]. Table 3-2 shows the number of failures for the individual years of operation over a period of 8 years for 8 Magnox stations with a total of 92 steam generators.

Table 3-2: Steam Generator Defects for 8 Magnox Stations over a Period of 8 Years

t (years)	Failures in the t-th Year	Cumulated Number of Defects	Defects per SG per Year
1	75	75	0.82
2	64	139	0.76
3	41	180	0.65
4	13	193	0.52
5	19	212	0.46
6	3	215	0.39
7	6	221	0.34
8	9	230	0.31

As can be seen in Table 3-2 and is illustrated in Figure 3-7, the number of defects per steam generator per year was reduced from 0.8 to 0.3 meaning that design defects led to damage especially during early operation [16].

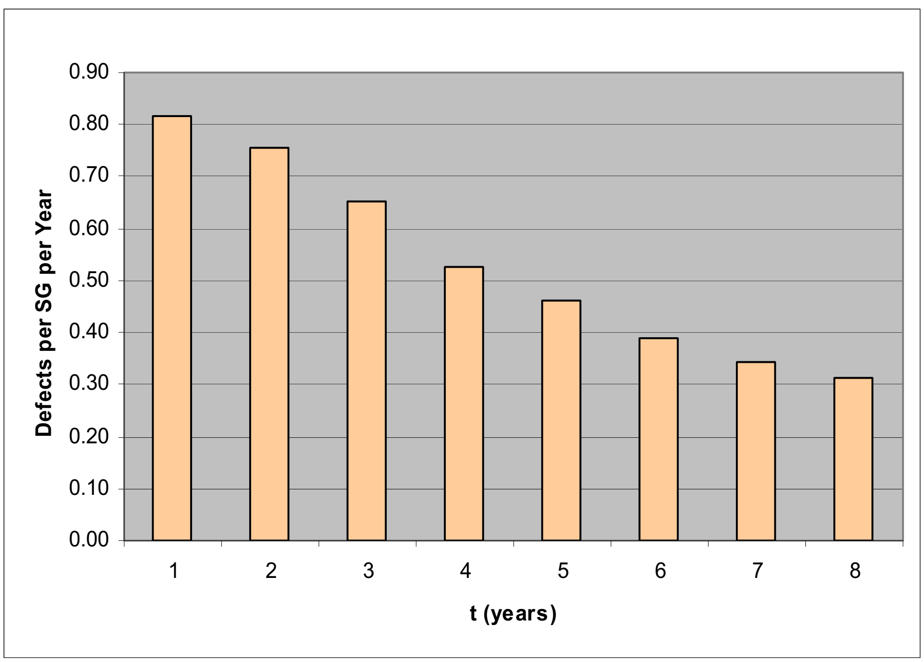


Figure 3-7: Defects per Steam Generator per Year for 8 Magnox Stations with a Total of 92 SGs over a Period of 8 Years

More up-to-date information would provide valuable input. It is nonetheless clear that the trend up to the early 80s was toward more and more reliable steam generators thanks to design improvements and lessons learned. The author of Reference 16 does claim that “the leakage frequencies will probably decrease if the latest data [from AGR steam generators] are included”. Further research is being conducted to trace newer steam generator operating history data.

3.2.3 Water Ingress Event Categories

Risk assessment can be classified in two different manners. It can either be based on the frequency of occurrence of the event or on the event type.

Assessing risk based on frequency of occurrence involves defining the event initiator probabilities and then sorting the events into groups defined by their characteristics (such as loss of pressure boundary, change in reactivity, and loss of heat removal capabilities) or their challenges to perform certain safety functions [5]. The grouping of events by type is based on the challenge of the event on fundamental safety functions or on dominant phenomena occurring during the course of the event. In this safety assessment the phenomena of interest is water ingress.

3.2.3.1 Event Type Category

The event of interest in this assessment is water ingress. And as detailed in section 3.2.2, the main potential source of water ingress from the PCS is through the steam generators. Moreover, the steam generators are the source of water ingress which differentiates the steam cycle from other power conversion systems. Reference 6 contains a PRA of the modular HTGR plant and includes information on the different types of steam generator leaks.

The frequency at which steam generator leaks of any size can occur is 0.1 per steam generator per year. Since the NGNP has a total of two steam generators, the frequency of occurrence is 0.2 per plant year or twice every 10 years.

3.2.3.1.1 Small Steam Generator Leaks

Since a leak with an ingress rate of 0.045 kg/s (0.1 lbm/s) is considered moderate, a small steam generator leak has an ingress rate less than 0.045 kg/s. It is characterized by a leak size ranging from crack or pinhole to roughly 5 mm^2 (0.008 in^2). The tubes remain intact. Because small steam generator leak events progress slowly, operator response time is fairly long and consequently successful intervention to prevent or mitigate offsite dose is highly probable.

As explained in section 3.2.4.2, because the ingress is gradual, any increase in reactivity will be compensated by the reactor control system, keeping the power constant.

This type of leak falls into the AOO category if detection and mitigation systems work properly, otherwise, it would be classified as a DBE.

3.2.3.1.2 Moderate Steam Generator Leaks

Moderate steam generator leaks are defined in the MHTGR PRA (Reference 6) as leaks with an ingress rate between 0.045 and 5.7 kg/s (12.5 lbm/s). An upper bound of 5.7 kg/s was selected because it corresponds to an offset steam generator tube rupture. The probability of a steam generator leak being larger is negligible. An average moderate steam generator leak has an ingress rate in the vicinity of 1.18 kg/s (2.6 lbm/s). Less than 30% of all moderate leaks have an ingress rate higher than this average value. They are typically associated with one steam generator tube failure and are ten times less likely than small steam generator leaks.

It is important to distinguish between small and moderate steam generator leaks as they are characterized by different occurrence rates and response times. As previously mentioned, small steam generator leaks are slow and therefore carry high probability of successful operator action. On the other hand, moderate leaks are much faster. This lowers the probability of successful operator action and increases the potential for larger releases [6]. Approximately 10% of all steam generator leaks have a rate of ingress higher than 0.045 kg/s (0.1 lbm/s). Consequently, only 10% are expected to fall into the moderate steam generator leaks category. Because the ingress rate is larger, a moderate steam generator leak has the potential to increase reactivity fast enough that the reactor control system is unable to compensate. Protective system action or the large negative temperature coefficient will terminate the power increase.

Similarly to small steam generator leak, moderate leaks are classified as AOO events if detection and mitigation systems function normally, or DBEs should the systems malfunction.

3.2.3.1.3 Large Steam Generator Leaks

A large steam generator leak is characterized by a water ingress rate larger than 5.7 kg/s due to multiple tube failures. Per Reference 6, the probability of such an event is negligible.

Because a large steam generator leak would occur very rapidly, graphite oxidation and fuel hydrolysis should be of minimal concern. System overpressurization would be the most concerning consequence of a large steam generator leak. Nonetheless, Reference 13 indicates that even in the worst case scenario (simultaneous rupture of all steam generator tubes), there is enough time for protective systems to be activated before the vessel pressure relief valve opens. Large steam generator leaks would most likely be classified as BDBEs. It is possible that moderately large steam generator leaks would fall in the DBE category. The case where all tubes rupture is a worst case scenario BDBE.

3.2.4 Consequences of Water Ingress

Most event sequences for small steam generator leaks result in no offsite dose. Typically, offsite dose occurs when the leak is coupled with failure of other protective functions [6]. However, water ingress could have other consequences such as graphite oxidation, fuel hydrolysis or pressure increase for example.

3.2.4.1 Water Ingress Effect on Primary Pressure

Due to the temperature and pressure conditions in the primary system, any water leaking into the primary system would quickly turn into steam unless the event occurs during depressurized shutdown [8]. Large quantities of vapor entering the primary system have a direct consequence on primary system pressure. Although unmitigated system pressure increase could lead to relief valve opening, steam ingress with normal system response is not enough to reach relief valve setpoint. Several pressure studies have been done and two are presented below.

3.2.4.1.1 HTR-MODUL of Side-by-Side Concept Study

Table 3-3 defines several types of steam generator leaks considered for the HTR-MODUL of side-by-side concept.

Table 3-3: Quantities of Water and Steam Entering the Primary in the Case of Steam Generator Leaks of Different Sizes and Positions with Different Plant Reactions [7]

Leak Size	Leak Position	SG-Dump	Quantities (kg)		
			Steam	Water	Total
2F	Super Heater	Yes	75	135	210
2F	Economizer	Yes	30	460	490
1F	Economizer	Yes	~10	450	460
1F	Super Heater	No	985	65	1050
1F	Economizer	No	235	3875	4110

Detection Time Inclusive Isolation: 12s

A leak at the bottom of the steam generator represents the largest water ingress as can be seen in the first two rows of Table 3-3. The values are based on a double-ended fracture (2F) of a steam generator tube, which corresponds to the size of a design basis accident steam generator leak. From a probabilistic risk assessment point of view, the dominant type of leak has a size less than $2cm^2$ (1F) because those leaks have a higher probability of occurrence [7].

Such a leak, associated with dumping of the steam generator after 12 seconds, produces approximately 460 kg of water ingress into the primary system. Due to the temperature and pressure conditions of the primary circuit, the water is quickly converted into steam increasing the pressure from 6 MPa to 6.23 MPa. This value is lower than the 6.9-MPa setpoint for the relief valve. However, should the gas purification plant fail, the increased temperature and gas production could cause the primary pressure to reach the relief valve setpoint [7].

Clearly, steam alone is not enough to reach the relief valve setpoint nor is steam generator isolation without dumping enough to cause the pressure to reach 6.9 MPa. Nonetheless, if the steam generator leak were to occur at the feedwater end (bottom) of the steam generator, the total inventory of the steam generator would enter the primary circuit. According to the last row of Table 3-3, this represents over 4000 kg of water.

For the HTR-MODUL concept from Reference 7, the total pressure rises to 6.5 MPa following a leak at the bottom of the steam generator. This pressure value remains well below the setpoint of the relief valve. If the ingress event is extended due to a smaller leak or a leak occurring at the top of the steam generator, the total pressure rises to 6.6 MPa, which is also well below the setpoint [7].

3.2.4.1.2 High Temperature Pebble Bed Reactor Study

Reference 13 also details the effects of pressure increase in the event of a water ingress accident. The analysis is based on the German PNP-500, a pebble bed reactor with primary pressures in the 4-MPa vicinity and secondary pressure at the steam generator outlet of 11.5 MPa. These values are slightly smaller but comparable to the NGNP pressure values of 5 MPa for the primary system and 16 MPa for the steam generator outlet on the secondary side.

Figure 3-8 and Figure 3-9 show the effect of steam ingress on primary pressure for ingress rates of 7 kg/s and 55 kg/s respectively. As described in section 3.2.3.1, both rates qualify as large steam generator leaks. 7 kg/s corresponds to the simultaneous rupture of two steam generator tubes and 55 kg/s corresponds to the hypothetical rupture of all steam generator tubes which is the worst case scenario. It should be noted that Reference 13 does not evaluate flammable gas concerns as it assumes that relief valves do not open. Flammable gas concerns will be further addressed at a later time.

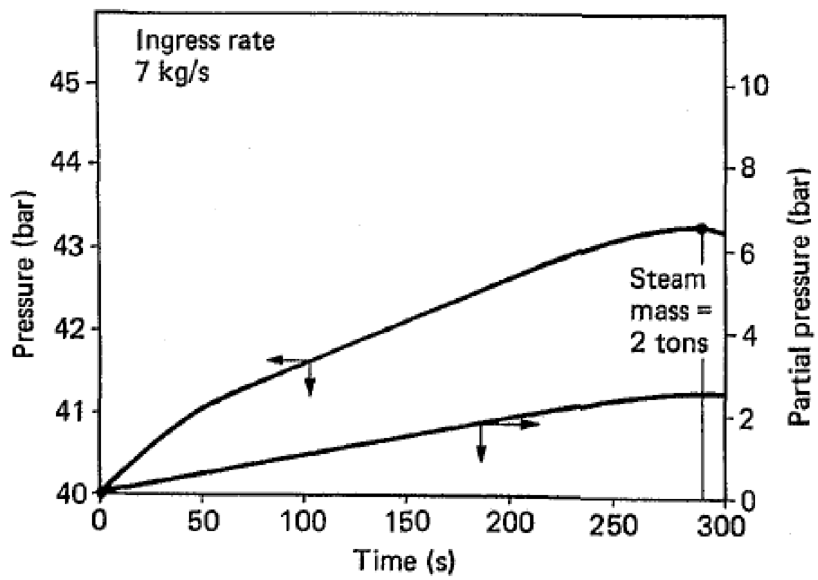


Figure 3-8: Pressure Transients in the Primary System during a Water Ingress Accident with Low Ingress Rate (7 kg/s) [13]

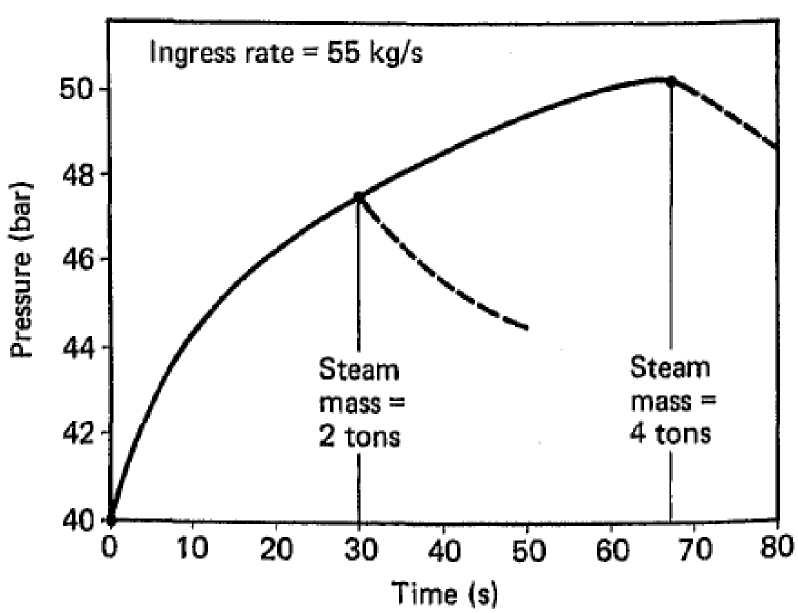


Figure 3-9: Pressure Transients in the Primary System during a Water Ingress Accident with High Ingress Rate (55 kg/s) [13]

Both Figure 3-8 and Figure 3-9 show the primary system pressure increasing after a water ingress event.

Figure 3-10 is a combination of Figure 3-8 and Figure 3-9 which provides better comparison of the pressure behavior for large and very large ingress rate.

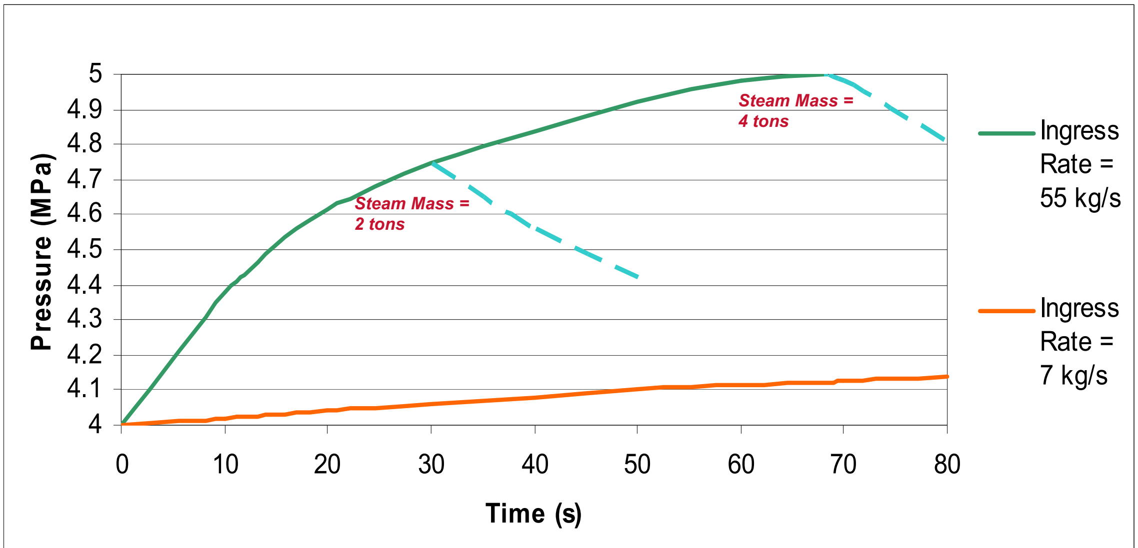


Figure 3-10: Pressure Transient in the Primary System during a Water Ingress Accident without Safety System Response (based on Figure 3-8 and Figure 3-9)

After the end of the ingress, the pressure decreases for about 10 seconds due to the decreasing gas temperature in the primary circuit. The drop is caused by the heat removal through the damaged steam generator which is kept effective by the blower. It is expected to be temporary until the blower stops or the steam generator is isolated. After that, the primary system condition will depend on how the plant protection system handles heat removal through the available auxiliary systems.

If the ingress rate is around 7 kg/s, the pressure reaches 4.3 MPa about 5 minutes after the accident. For this high temperature pebble bed reactor, the reactor vessel design pressure is 5.0 MPa which is well above the pressure reached. For a higher ingress rate, the pressure reaches 5.0 MPa after about 1 minute. Figure 3-9 does picture a worst case, highly improbable scenario. Nonetheless, 1 minute is sufficient for activation of automatic protective systems.

The dotted lines that are observed on the 55 kg/s ingress rate curves are, respectively, for a total steam mass of 2 tons or 4 tons. This means that if only 2 tons of water are available to enter the system, the pressure will drop after roughly 30 seconds. If 4 tons are available, the pressure drops after 70 seconds. This drop is due to the heat removal provided through the damaged steam generator. The pressure will drop until the steam generator is isolated or the blower is tripped. After that, the plant depends on plant protective systems.

Protective systems vary from one design to another. For the design referenced in Reference 13, some of the protective systems that would be notified of the steam ingress accident would be the pressure scram at 4.2 MPa (after about 5 seconds for a 55 kg/s rate) and the moisture surveillance system (after 10 seconds). This type of response is typical for a tube rupture at the steam end. Relief valves are also provided to cause a controlled blowdown keeping the system below design pressure.

3.2.4.2 Water Ingress Effect on Core Reactivity and Power

The consequences of water ingress on core reactivity and power partly depend on core conditions.

In any case, because the core is undermoderated, water or steam insertion in the core will increase reactivity. Gradual reactivity insertion can be compensated by reactor control system and keep the power steady that way. Should the reactivity increase be much larger, this could exceed the reactor control system’s ability to compensate for the reactivity insertion. In that case, power will go up until the negative temperature effect kicks in or protective system action is initiated.

Because the amount of hydrogen and oxygen is larger in the core, moderation and absorption go up as well as power. Increased moderation also means decreased reliance on reflectors which means less reliance on thermal neutrons and decreased control rod worth. Although this is undesirable, it is accounted for through design of shutdown margin and control rod worth.

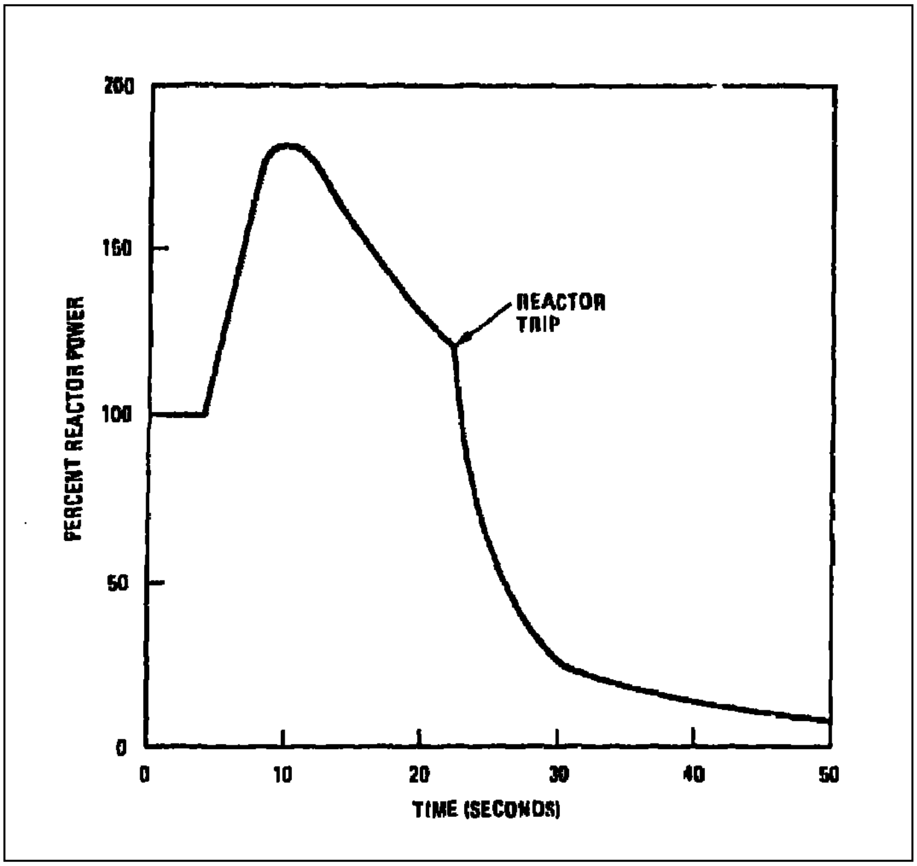


Figure 3-11: Reactivity Transient in the Standard MHTGR during Water Ingress [18]

Figure 3-11 illustrates the effect on reactivity for a water ingress of 27 kg/s initially. The ingress drops to 5.7 kg/s soon after onset. The graph exemplifies the counteraction of steam and temperature effects on reactivity. Reactivity increases due to the rate of reaction gain from steam being greater than the rate of reaction loss from core temperature increase (and vice-versa). Initially, the increase in moisture makes the reactivity go up. After 10 seconds, the neutron flux controller responds to the power increase by inserting multiple control rods to rematch power. Then around 20 seconds, high moisture is detected which causes an automatic reactor trip and all outer reflector control rods are dropped. In this study, although reactor trip on high power is ignored, no serious consequences on the core were observed or expected.

3.2.4.3 Oxidation of Graphite due to Water Ingress

Water or steam in the core also has the potential effect of removing carbon from core structures. Graphite oxidation and structural integrity are hence possible concerns. Oxidation of graphite reduces component strength and exposes fuel particle. But as explained in section 3.2.5.4, the quality of TRISO fuel particle coatings limits the release of radionuclide should ingress or oxidation occur. As seen in Figure 3-12, graphite is inherently porous and contains cleavage planes. If fission products are released, graphite will trap most within its structure.

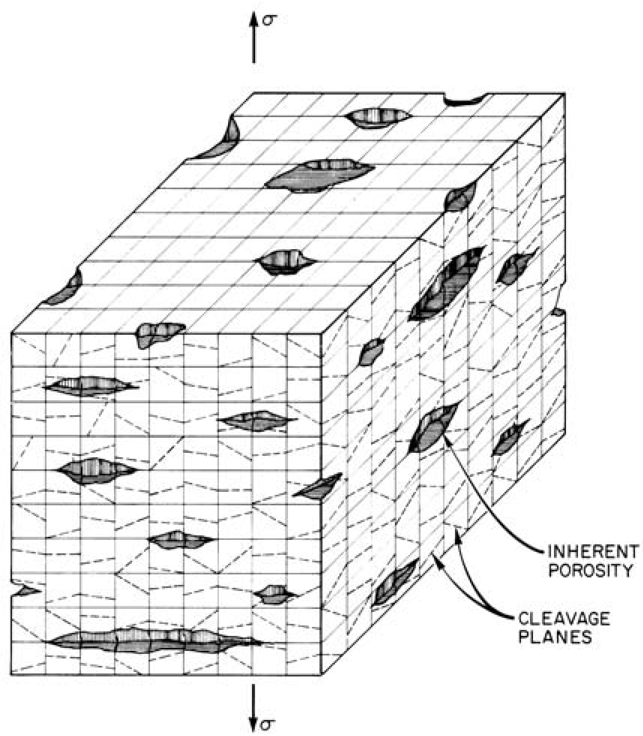


Figure 3-12: Graphite Microstructure as Represented in the Burchell Model [15]

Figure 3-13 illustrates the fraction of core graphite oxidized for two LBEs as a function of time. It also includes the very rare tubesheet failure event. The reference does not specify the type of graphite studied, however, the MHTGR Graphite Design Handbook [49] covers Nuclear Grade 2020 and Grade H-451 graphite. Oxidation characteristics of NGNP graphite are expected to be comparable or better than H-451. Detailed analyses will be performed when actual graphite data is available.

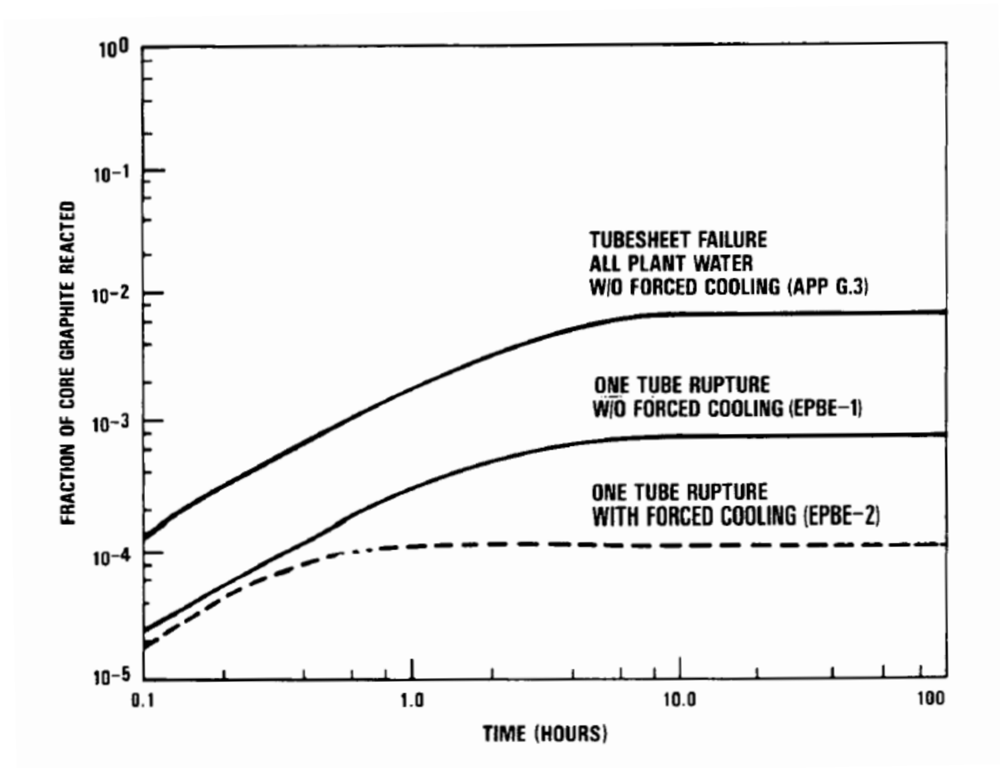


Figure 3-13: Fraction of Core Graphite Reacted during Water Ingress [12]

In all cases, with or without forced cooling, with one or more steam generator tube failure and even without moisture detection, Figure 3-13 shows that the impact on the core graphite is small. Moreover, the quality of the fuel particle coatings limits the radionuclide inventory available for release due to chemical attack to initially failed fuel particles [12].

The MHTGR PSID [18] also discusses the effects of a moderate steam generator leak on graphite. It shows that moisture in the primary can certainly lead to the chemical attack of graphite mainly in the bottom half and central part of the core. The PSID does confirm that there is, however, no significant localized oxidation damage and low overall graphite oxidation.

If adequate system response is available (DBE-6) or in the event of steam generator dump failure (DBE-9), low overall graphite oxidation occurs due to the decrease in graphite temperature after reactor trip. Limited leak rate and low normal operating temperature limit oxidation if the moisture monitors fail (DBE-8). Finally, should the SCS not be operational (DBE-7), the limited amount of moisture available to react with core graphite (due to lack of circulation) ensures low oxidation. In all four design basis events, the small amount of weight loss calculated was determined to have insignificant affect on the strength of the core support components. Oxidation was observed mainly on the surface of the core support blocks and posts. Taking into account safety margin, no significant loss of core support capability can occur as a result of steam attack during moisture ingress.

The combination of water and oxidized graphite could also yield to combustible gas production: $H_2O + C \rightarrow CO + H_2$. It should be noted, though, that this is not unique to high temperature reactors but will be assessed as a standard safety concern.

Clearly, the effects of ingress on graphite described above are theoretically possible; nevertheless, Figure 3-13 and reference 18 demonstrate that even a large amount of water or lack of adequate system response would affect graphite very little. Also, water or steam ingress effects on core structures, including graphite oxidation, will be accounted for in the design margins of the NGNP.

3.2.4.4 Fuel Hydrolysis due to Water Ingress

Previously damaged fuel is also susceptible to hydrolysis in the event of water ingress into the core. The extent of hydrolysis on initially failed fuel is determined by the duration of the leak and the amount of water entering the core [7]. Even for extended periods of time, water ingress has minimal effect on intact fuel. On the other hand, exposed kernels such as in previously damaged fuel are most affected by water ingress. The kernel can be oxidized by water in such a way that its structure is modified and most of its stored fission product inventory is released [20]. As shown in Figure 3-14, the kernel structure does change after oxidation causing a fast release of stored fission products. Once the process is over, the release rates slowly return to normal levels.

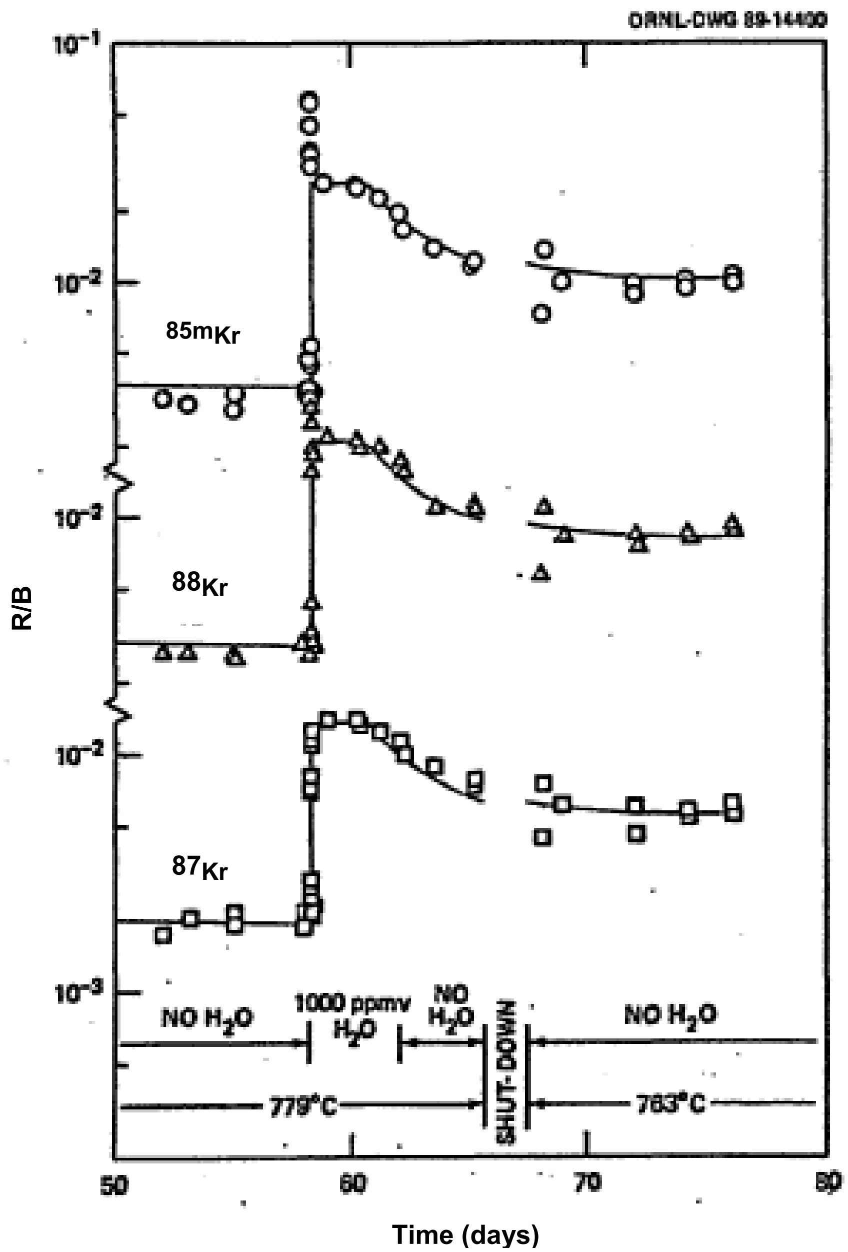


Figure 3-14: Fractional Release (R/B) of Exposed Kernel in the Presence of Water Vapor [20]

Fuel hydrolysis from water ingress not only affects previously damaged fuel but it also a temporary process. In the unlikely event that moisture ingress should occur, it is not expected to be a sustained incident (unlike the results shown in Figure 3-14 where the ingress occurs during several days). The numerous systems that will equip the NGNP, including monitoring of the circulating activity as an indicator of fuel performance, will provide fast and accurate moisture detection. Finally, improvements in fuel quality have reduced the fraction of initially failed fuel [6], reducing further the probability of occurrence of fuel hydrolysis.

3.2.4.5 Fission Product Mobilization due to Water Ingress

The MHTGR PRA [6] mentions that, following a steam generator leak, some liftoff material plateout on the primary circuit surface could be noticed. In fact, fission product plateout on the steam generator tubes does occur during normal operation due to the large temperature gradient from hot to cold end. If a steam generator tube leak or rupture occurs, it is plausible that the jet could wash deposited helium impurities into the primary system. Such an event would most likely be minimized by the fact that wash off would be localized and the liftoff material would be trapped in the water originating from the source of ingress.

Fission product mobilization is a speculative consequence of water ingress and should be researched and analyzed further.

3.2.4.6 Investment Risk Consequences

As detailed in the previous sections, moisture ingress could have certain consequences on the primary system such as pressure increase, reactivity and power increase, graphite oxidation, fuel hydrolysis and fission product mobilization. Although these consequences are not expected to generate safety concerns, investment risk consequences are conceivable.

The impact of moisture on metallic component, graphite and fuel for instance need to be assessed. Component and plant lifetime could possibly be shortened. However, design margins are in place specifically for this purpose.

Plant availability is another aspect of investment risk. Although plant and component lifetime will not be compromised by water ingress thanks to design margins, such an event would require shutdown to repair the leak, remove moisture and assess the incident. The availability impact of water ingress events is included in the overall plant availability assessment. Based on the expected frequency of steam generator leaks, the events and repair intervals are included in the steam generator unavailability allocations.

3.2.5 Mitigation of Water Ingress Event

The NGNP will be equipped with various safety features designed to prevent, detect and respond to a water or steam ingress event. This section describes the many detection, mitigation and recovery systems of typical steam cycle HTRs. It also describes the safety features embedded in the steam generator and reactor designs.

During depressurized conditions (such as shutdown or refueling), water ingress could result from in-vessel heat exchanger leakage. There are, as seen below, limitations on the transport of liquid water designed to minimize the amount of water reaching the core [11]. Water ingress during depressurized condition could only be an issue if the operators fail to monitor the moisture detectors properly as occurred on occasion at FSV [8] or AVR.

3.2.5.1 Detection Systems

Moisture monitors are installed in each loop to protect the reactor from water ingress. If high moisture is detected, the reactor will automatically trip followed by steam generator isolation and dump. If the moisture monitor detection system fails, other trip setpoints will cause a reactor trip [6]. A small steam generator leak would be detected by the moisture monitors before being detected by the pressure monitors.

The NGNP will also be equipped with **system pressure monitors** to detect unusual pressure levels in the primary and secondary loop. This feature will be especially useful for detection of large ingress incidents.

Because water and steam ingress events affect reactivity and reactor power (as discussed in section 3.2.4.2), the **reactor power levels** will also serve as a detection system.

3.2.5.2 Protective Actions

Steam generator isolation is designed to limit the possibility of water ingress into the primary system by closing a set of feedwater and steam outlet valves. The steam generator outlet can also be isolated by a check valve to prevent reverse flow [6].

After successful steam generator isolation, the dump valves are designed to open in order to transfer the steam generator inventory to the dump tank. The valves close just before the steam generator pressure reaches that of the primary coolant to prevent primary coolant depressurization. The **automatic steam generator dump system** limits the water inventory available to migrate to the primary system and accelerates the pressure balance between primary and secondary loops. Section 3.2.6.1 illustrates the efficacy of the dump system in limiting the ingress flow into the primary circuit.

Primary coolant circulator trip can also mitigate a water ingress event since it stops the supply of heat to the steam generator, therefore additional water vapor will stop being generated in the tube bundle. Primary circulator trip in addition to steam generator isolation helps isolate the damaged loop.

Reactor trip can also protect the reactor from water ingress as it causes reactor power to drop very quickly and subsequently shutdown. It is currently estimated for the MHTGR that if more than 800 kg of water enter the core, only inserting the outer control rods or RSS is enough to maintain cold shutdown conditions [6].

The **Pressure Relief System** provides overpressure protection to the primary coolant loop as required by ASME pressure relief code [1]. The vessel itself is designed to sustain high enough pressures and the relief valve train is sized for potentially high flow rates.

3.2.5.3 Recovery Systems

Steam Generator and Reactor Vessel Drains will be designed at all low points within the primary system. At restart, water should be drained from all low points in the primary and moisture detectors should be carefully monitored during restart to prevent vaporization of hide-out moisture in graphite from being removed through the helium purification system [8].

The Helium Purification System is a means of removing circulating impurities from the primary helium coolant and dry out moisture in the event of a moisture ingress incident.

3.2.5.4 Reactor and Steam Generator Design

The design of the components themselves and the materials used also serve to prevent and mitigate accidents.

TRISO fuel can withstand extremely high temperatures while still retaining radionuclides. TRISO fuel can be exposed to temperatures of 1600°C for several hours without suffering loss of particle coating integrity. This is significant as design basis event peak fuel temperatures do not exceed 1460°C [14].

The very large size of the reactor vessel, solid blocks of fuel and graphite moderator all give the system very **high heat capacity.** Graphite moderator more specifically can withstand even higher temperatures than the fuel without suffering any structural damage. Graphite also holds up certain fission products therefore decreasing the potential for release of radionuclides. The massive graphite structures in the reactor core have very high heat capacity providing very slow heat up even during extreme conditions. This also supplies operators with long response times [14].

Helium is the primary reactor coolant. Because it is chemically inert and neutronically transparent, it will not participate in any chemical or nuclear reaction or change phase in the reactor. Pump cavitation or reactivity changes are therefore not an issue in a helium environment. The use of this benign primary coolant minimizes the problems of corrosion seen in PWR steam generators and reduces buildup of radioactive by-products [14].

The NGNP is designed to have **negative temperature coefficient of reactivity**. In the event of core temperature increase, the change in temperature will tend to reduce reactor power as described in section 3.2.4.2 [14].

The **helical coil steam generator** has a robust design which has been proven to operate well in other gas-cooled reactors (see section 3.2.2). Moreover, the primary fluid flows on the shell side which almost eliminates any of the shell-side corrosion concerns common to PWR SGs. The fluid going through the tubes of a helical coil SG flows at high velocities reducing the risk of water gathering at low points within the tubes.

3.2.5.5 Mitigation of a Water Ingress Event during Shutdown Conditions

Water ingress taking place during a rapid depressurization accident at a specific break location requires core cooldown on RCCS while the SCS and PCU are being isolated. Each system should then be tested to determine the location of the leak and isolate the affected unit. Once isolation is reach, the intact units can resume cooldown [8].

In the event of water ingress during depressurized shutdown, water has the potential to gather and drain to primary system low points. Therefore, drains are required to help dry-out water droplets during restart and prevent core damage. Moreover, moisture can hide out in graphite and in-vessel insulation requiring heatup to remove the moisture. Moisture can only be removed from the coolant over time by the water-cooled chiller-dryer in the helium purification system [8].

3.2.6 Scoping Evaluation of Water Ingress Events

Very limited calculations were performed to evaluate the significance of steam generator leaks in the NGNP steam cycle configuration.

3.2.6.1 Water Ingress Assessment Using RELAP5-3D

An internal RELAP5-3D analysis was performed to evaluate the potential effects of water ingress caused by a steam generator tube rupture.

The steady state core inlet pressure was initialized at 5.5 MPa and the core inlet and outlet temperatures were respectively calculated to be 401^{o}C and 839^{o}C. Four parameters were chosen to examine the effects of water ingress on the direct subcritical steam cycle NGNP. These parameters are shown in Table 3-4. In addition, a calculation was performed at each rupture size, at each rupture location, with no trip activated. This final set of four calculations examined the response of the system if the leak were not detected.

Table 3-4: Parameters Studied for RELAP5-3D Model

Parameter	First Value	Second Value
Rupture size	4 mm^2	4 cm^2
Rupture location	Top of superheat section	Bottom of steam generator
Trip condition	7% overpressure	200 ppm H2O
water-steam dump system	Operational	Non-operational

The results of the parameter study on rupture size are shown in Figure 3-15, which illustrates the integral flow through the rupture for both the large and small rupture sizes when the break is at the top of the superheater and the secondary system is isolated on trip. For either rupture size the total flow through the rupture is similar, differing significantly only in response time. The trip on high moisture is so sensitive, even with a 5 second response delay, that the secondary system is isolated almost immediately. The system then comes to a pressure equilibrium between primary and secondary system, releasing a similar amount of steam.

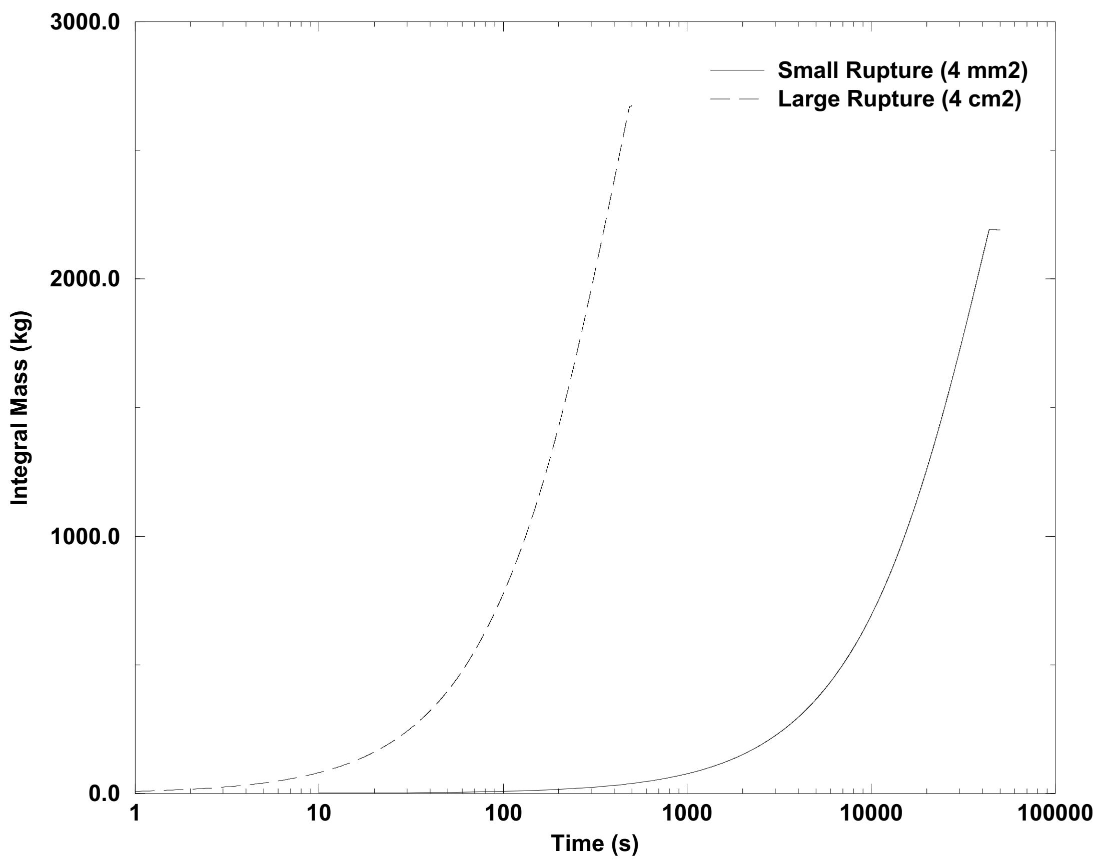


Figure 3-15: Effect of Rupture Size on Ingress Flow

The effects of the second parameter in the study, the location of the break, are shown in Figure 3-16. As shown in this figure, a rupture low in the secondary system injects water rather than steam and the initial mass flow is significantly higher than when the rupture injects primarily steam, as in the rupture at the top. It should be noted that, once again, the system detects the presence of moisture very rapidly, isolates the secondary loop, and the total mass of water injected is approximately 40% greater.

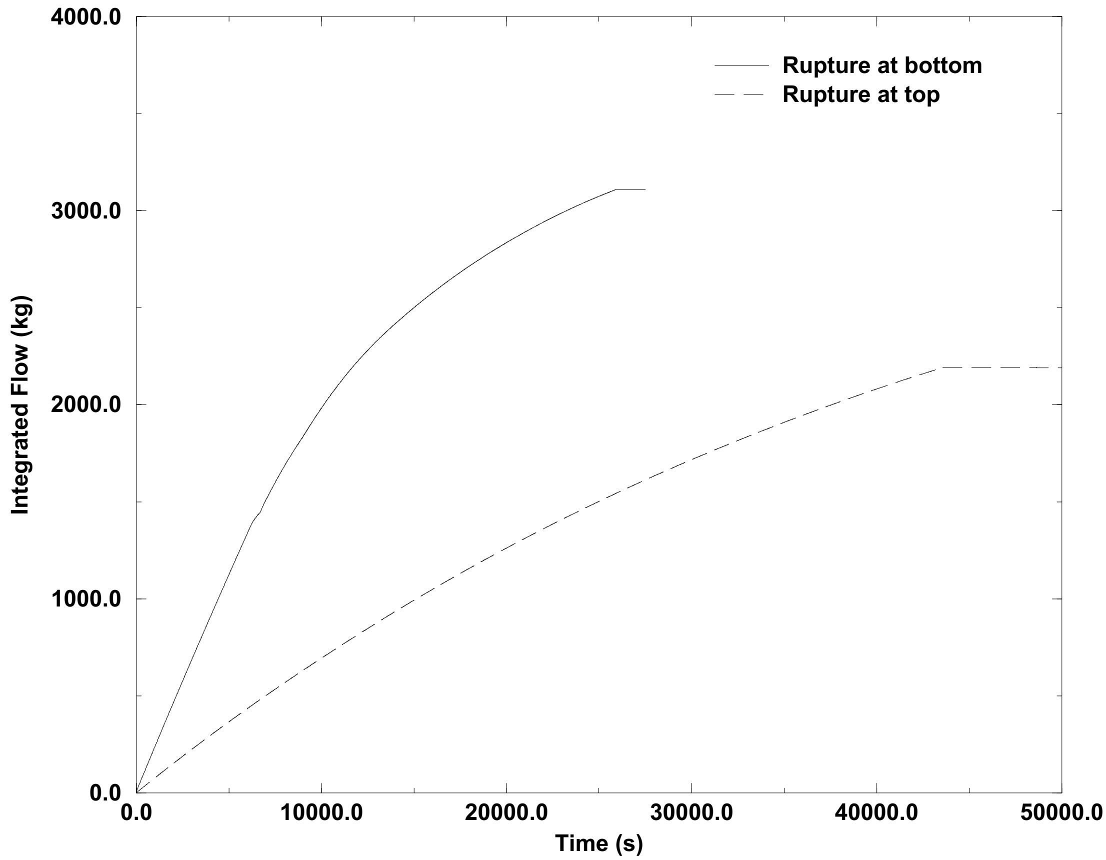


Figure 3-16: Effect of Rupture Location on Ingress Flow

The final parameter, the operation of the steam-water dump system, impacts the mass of water injected into the primary system more significantly than any other. The impact of this parameter is shown in Table 3-5, which summarizes the water ingress for each of the parameters studied. It could be expected that the dump system would have the most impact for the small rupture, when it has time to deplete the secondary inventory, and indeed, Table 3-5 shows that the mass of water injected into the primary is reduced by nearly an order of magnitude when the system is operational.

Table 3-5: Summary of RELAP5-3D Calculation Results

Size	Location	Trip Condition	Trip (s)	Mass H_2O in Primary (kg)	
				Dump open	Dump closed
Small	High	High Moisture	45.92	22.95	2190.64
		High Pressure	5249.6	415.17	2378.9
		Unprotected	30858.5	2435.8	
	Low	High Moisture	7.24	42.9	3110.4
		High Pressure	1893	837.3	3452.7
		Unprotected	8918.22	3724.4	
Large	High	Moisture	6.59	946.56	2673.4
		Pressure	80.54	1489.9	3080.6
		Unprotected	348.44	2780.32	
	Low	Moisture	7.24	1699.1	3110.4
		Pressure	27.3	2396.7	3912.85
		Unprotected	74.69	3166.65	

In summary, RELAP5-3D does a credible job in modeling the water ingress event in a high temperature gas-cooled reactor, and the mass of water is manageable particularly with the implementation of a steam-water dump system on the secondary system.

3.2.6.2 Reactivity Assessment

Because water vapor is a moderator material, a water ingress event has the potential to induce a positive reactivity insertion into the core. As the amount of water in the core increases, the effectiveness of negative reactivity introduction mechanisms is reduced. The effectiveness of the control banks to shut down the chain reaction in the core therefore must be evaluated. An assessment was performed to observe the reactivity impact introduced into the active core by incrementally injecting higher fractions of water vapor into the coolant system. Additionally, the impact on control rod worth was calculated with varying fractions of water vapor. At this point in the development of the NGNP design, the core configuration is not optimized. Further developments will include burnable poison and fuel enrichment zoning as well as other neutronically significant enhancements. In light of this, the results of this analysis should be used for making observations concerning system behavior, but are not necessarily appropriate for quantifying absolute results. A full core model of the NGNP was created for use in the Monte Carlo N Particle (MCNP) transport code, version 5. Because of the early development status of the NGNP core, a series of input assumptions and model simplifications were implemented.

In the first portion of this assessment, system reactivity with all rods withdrawn is analyzed. The base case is performed with no water vapor in the coolant system, and then subsequent cases are calculated with incrementally increased percentages of water vapor modeled in the coolant channels and plenums of the core. Key data points are detailed in Table 3-6.

Table 3-6: Water Ingress Reactivity Assessment Data

Water Density Fraction	% Water Vapor	% Liquid Water	Case ID	Normalized K-effective
0%	0%	0%	Base-Case	1.00000
1.75%	100%	0%	V100	1.01201
11.57%	90%	10%	W10	1.04443
100.00%	0%	100%	W100	0.86064

It should be noted that the cases designated with a "W" are modeled with a fraction of superheated water vapor (5 MPa and 550 °C) combined with a fraction of liquid water at saturated conditions (5 MPa and 264 °C). This condition reflects a more realistic scenario where the core and primary system have cooled somewhat in order to permit the formation of liquid water. The fuel cross sections were set at 1200 Kelvin and were not modified for any portion of this calculation. Figure 3-17 shows the reactivity curve as a function of percentage of full water density from the above data.

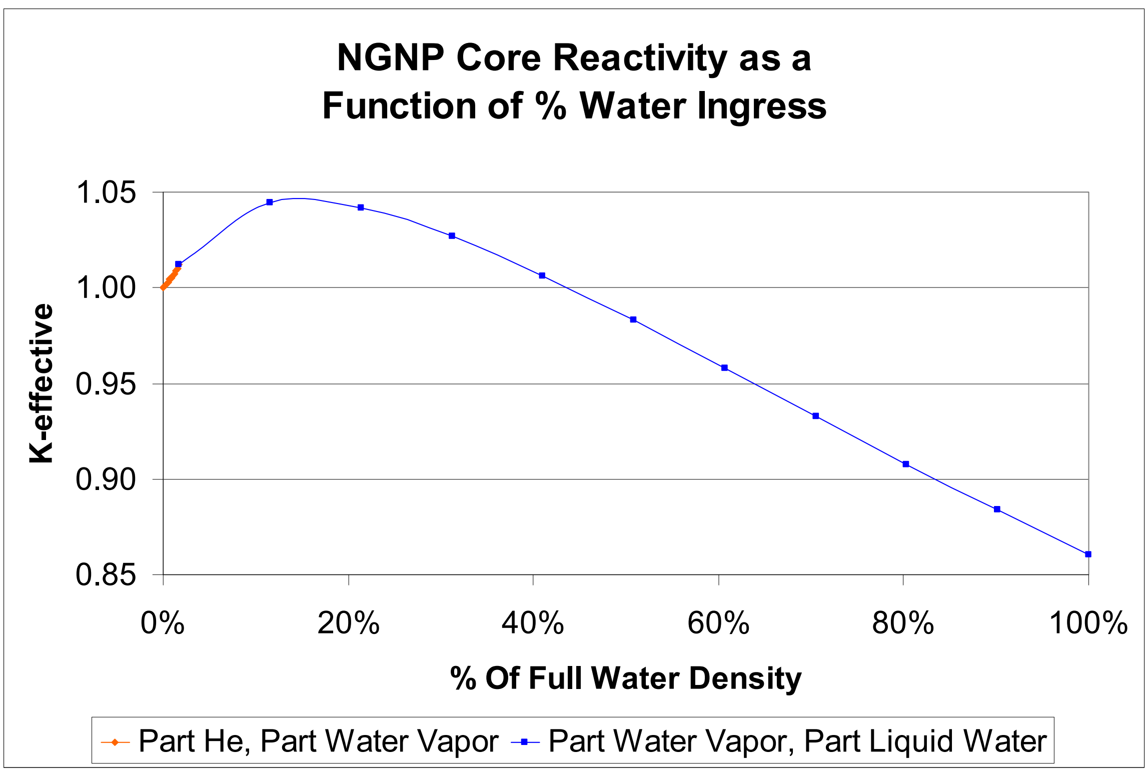


Figure 3-17: Plot of Water Ingress Reactivity Assessment Data

Of significance from the Table 3-6 data, is the fact that as the fraction of hydrogen atoms is increased in the critical primary system, the reactivity balance of the system shifts up to an absolute maximum value. After this point, additional hydrogen causes the core to become overmoderated and the reactivity balance shifts down. The maximum point of reactivity occurs when the coolant channels are uniformly filled with a mixture composed of 90% water vapor and 10% liquid water. This condition is calculated in case ID W10 which shows an addition of 4.43% reactivity from the base case due to the presence of the additional moderator material.

In the second part of this assessment, system reactivity is calculated with all rods inserted as well as with all rods withdrawn. The analysis is ran at first with no water vapor in the coolant system, and then repeated with incrementally increased percentages of water vapor modeled in the coolant channels and plenums of the core model. The rod bank worth is calculated using these two reactivity values in accordance with Equation 1.

Equation 1: Rod Worth Assessment in Units of Percent Milli-Rho

$$Rod\_Bank\_Worth(PCM) = \left[\frac{\left(K_{all-rods-out} - k_{all-rods-in}\right)}{\left(K_{all-rods-out} * k_{all-rods-in}\right)}\right] * 1000$$

In Equation 1, $K_{all\text{-}rods\text{-}out}$ is the K-effective of the model with all control rod banks withdrawn to a point above the top of the active fuel region, and $K_{all\text{-}rods\text{-}in}$ is the K-effective of the model with all control rod banks inserted to the bottom of the active fuel region. The rod banks which are to be withdrawn and inserted are the 36 operating control rods and the 12 startup control rods. The 18 reserve shutdown channels do not contain rod assemblies and remain unoccupied during power operations. The locations of the control and shutdown rods are detailed in Figure 3-18 below.

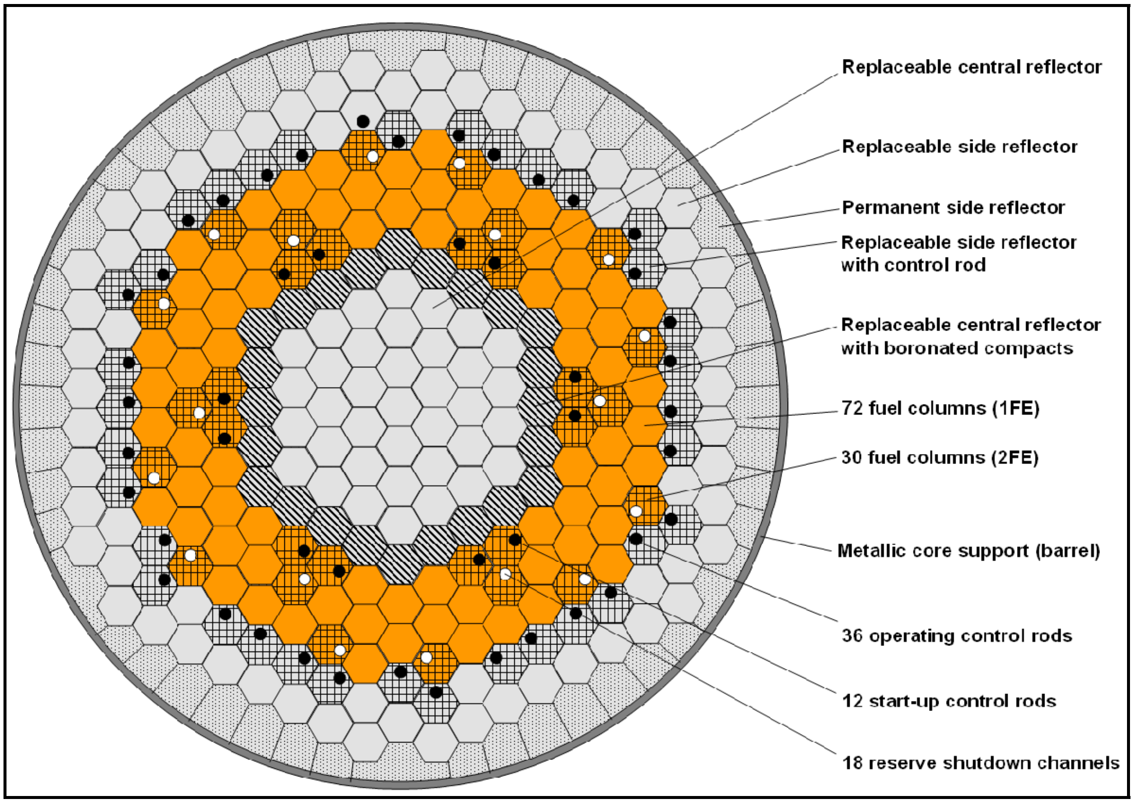


Figure 3-18: NGNP Core Map with Control Rod Bank Locations [1]

The results of the control rod bank worth calculation are detailed in Table 3-7 and illustrated in Figure 3-19 below.

Table 3-7: Water Ingress Rod Bank Worth Assessment Data

Coolant Condition	No H2O	100% Vapor	90% Vapor 10% Liquid	100% Liquid	PWR Example
All Rods Out K-effective	1.2082	1.2195	1.2502	1.0603	1.0271
All Rods In K-effective	0.9389	0.9582	1.0349	0.9984	0.9520
Rod Worth	**No H2O**	**100% Vapor**	**90% Vapor 10% Liquid**	**100% Liquid**	**PWR Example**
K(fin)-K(init) / K(fin)*K(init)	23.74	22.36	16.64	5.84	7.68
Percent Milli-rho	23736.44	22363.96	16635.77	5843.43	7681.48

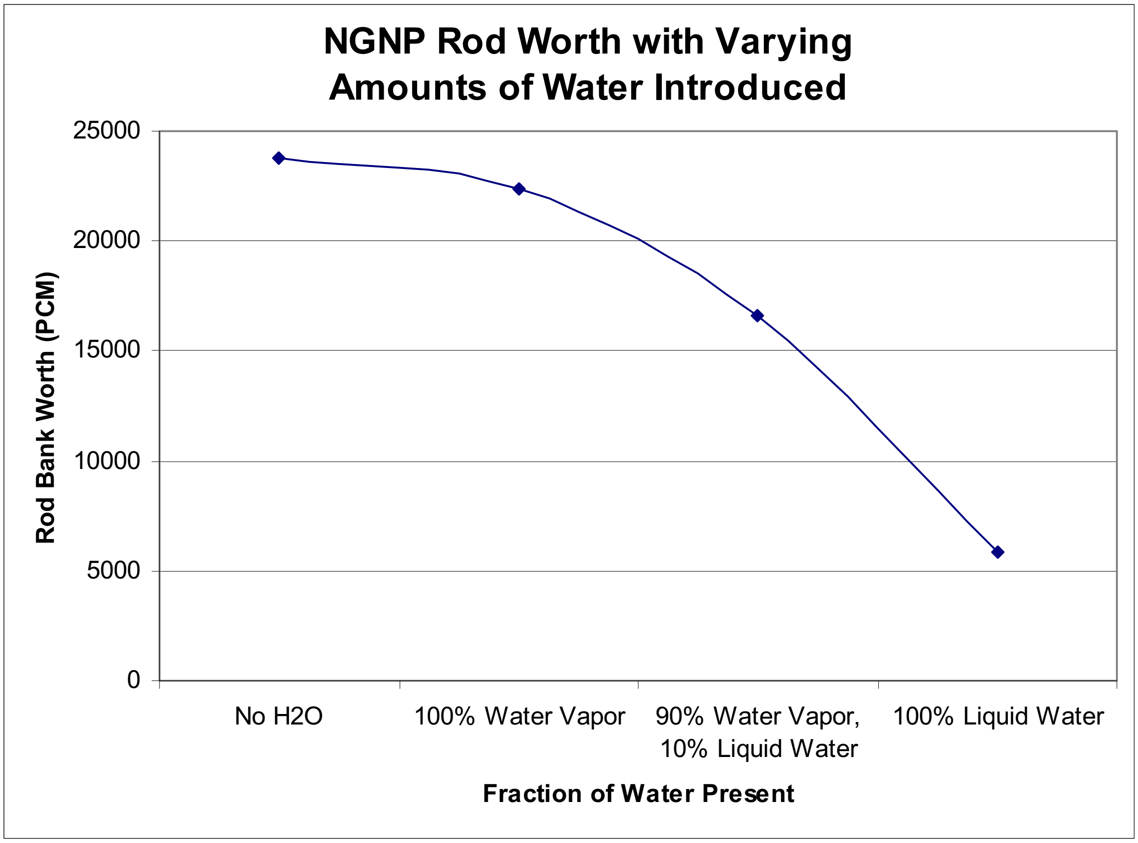


Figure 3-19: Plot of Water Ingress Rod Bank Worth Assessment Data

Of significance from the Table 3-7 data is the observed behavior of the rod bank worth as a function of fraction of water introduced. From a condition of zero water vapor to a condition of 100% water vapor, the control rod banks loose ~5 % of their design beginning of cycle worth. This suggests that as long as the primary system is hot enough to not allow water condensation to occur during a secondary to primary boundary leak, the control rod worth is not significantly affected. The introduction of liquid water decreases the calculated rod worth more significantly. Rod bank worth is reduced by a factor of 4 upon complete filling of the primary with saturated liquid water. With an optimized core and control bank design, sufficient hold down protection will be engineered into the NGNP core to protect against such accidents.

3.2.7 Water Ingress Impact on Safety and Risk

According to the PSID for the Standard MHTGR [18], most moisture inleakage DBEs result in no thyroid or whole body dose. The only case which yields minimal release is when SCS cooling is unavailable. It should be pointed out though that, even without SCS cooling, the releases are still equal or below the potential offsite doses for all primary coolant leak DBE (Table 3-8).

Table 3-8: Potential Offsite Doses from Various Design Basis Events Analyzed in Reference 18

DBE		Dose – 30 day EAB	
		Thyroid (rem)	Whole Body (rem)
Moisture Inleakage		No Release	No Release
Moisture Inleakage w/o SCS Cooling			
	Median Dose	0.00244	0.0000386
	95th Percentile Dose	0.0352	0.000466
Moisture Inleakage with Moisture Monitor Failure		No Release	No Release
Moisture Inleakage with Steam Generator Dump Failure		No Release	No Release
Primary Coolant Leak			
	Median Dose	0.0024	0.00034
	95th Percentile Dose	0.18	0.00410
Primary Coolant Leak w/o HTS and SCS Cooling			
	Median Dose	0.064	0.000185
	95th Percentile Dose	0.61	0.0015

The standard MHTGR PRA [17] obtained risk assessment results showing that it is capable of satisfying the very stringent PAG dose requirements. Accident type depends on “whether ingress has occurred (W) or not (D) and whether heat removal from the core is accomplished with forced circulation core cooling (F) or conduction and radiation (C)” [17]. Figure 3-20 shows that events of type DF dominate the whole body risk envelope and are the largest risk contributors. Events including ingress are more infrequent than dry events and should they occur, lower offsite dose is expected.

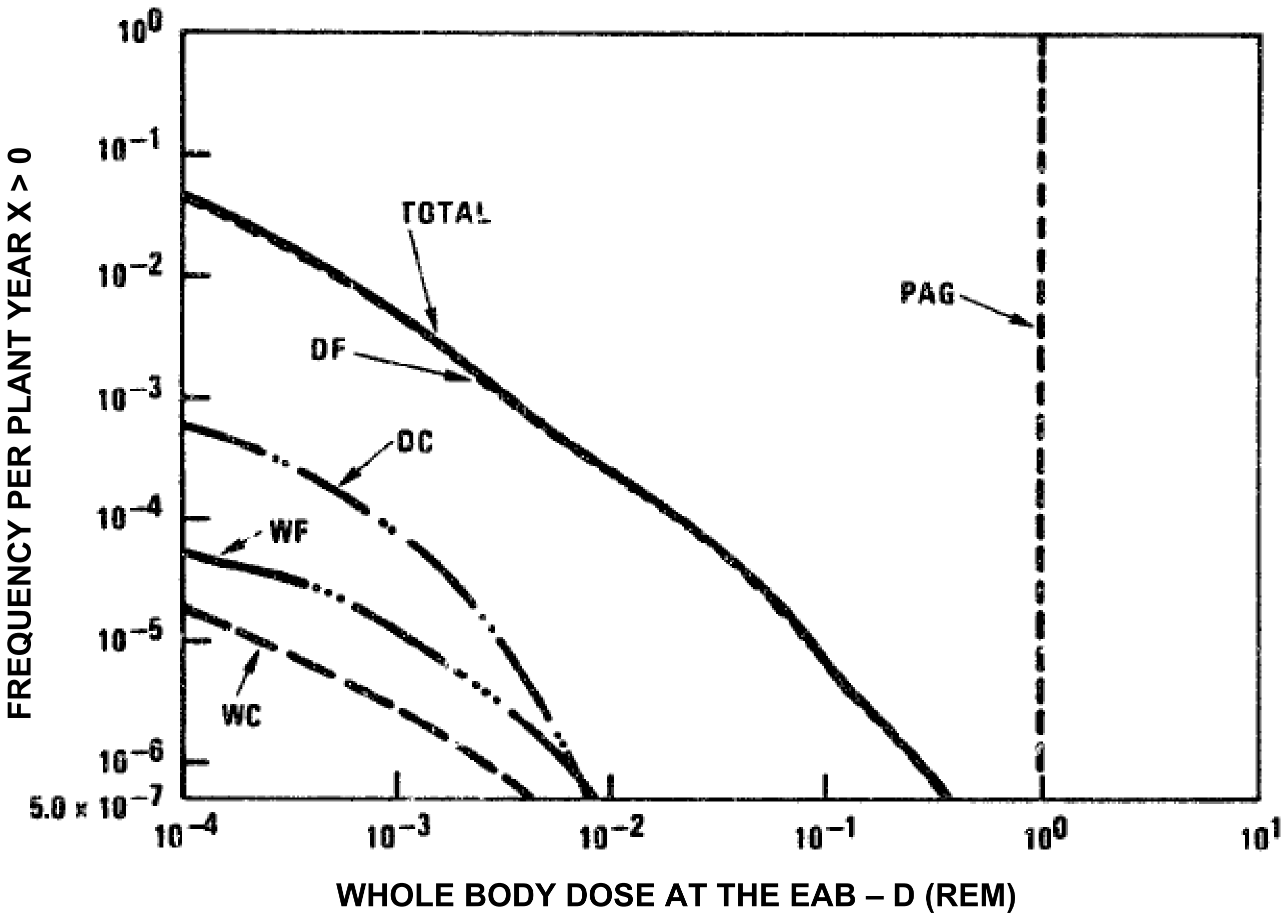


Figure 3-20: MHTGR Cumulative Frequency Whole Body Dose for All Release Categories [17]

The overall results of the standard MHTGR PRA [17] and the PSID [18] agree, however, the PSID is based on specific DBE or SRDC event sequences whereas the PRA analyzes discrete events with different sequences. The important results are that Table 3-8 shows that moisture release events either yield no release or the release is smaller or equal or that of a primary leak. Also, Figure 3-20 illustrates that the risk profile is dominated by dry events; therefore steam generator-type leaks have a small impact on the total cumulative risk.

The MHTGR PRA also contains a table (reproduced as Table 3-9) depicting the fact that for potential accidents involving offsite release, steam generator leaks are the accident family with the lowest mean risk. Primary coolant leaks, depressurized conduction cooldowns and earthquakes all have a higher mean risk.

Table 3-9: Mean Risk for MHTGR Accident Families Involving Offsite Release [Adapted from Reference 6]

Accident Family	Mean Risk	
	Acute Fatalities per Plant Year	Latent Fatalities per Plant Year
Primary Coolant Leaks	0	8×10^{-9}
Steam Generator Leaks	0	***4×10^{-11}***
Depressurized Conduction Cooldowns	0	2×10^{-9}
Earthquakes	0	3×10^{10}

Finally, water ingress does not adversely impact the fundamental safety characteristics of the plants. For instance, offsite consequences are still minimal as is reliance on operator actions. Ingress does not prevent passive decay heat removal and the temperature coefficient remains negative. Fission product retention in undamaged fuel is maintained also.

3.2.8 Suggested Analysis and R&D

As noted in section 3.2.2.3, research is being conducted to trace more up-to-date data on steam generator operating history on AGR and Magnox reactors. Information is available up to the early 1980s and clearly shows an improving operating history trend. Later data could either show that the trend is continuing to improve or point out areas of weaknesses in newer designs.

The input assumptions and simplifications incorporated into the MCNP model used in the reactivity assessment should be examined in greater detail to ensure that they are truly conservative assumptions. Once the assumptions are verified, further analysis should be performed to ensure enough negative reactivity is available to keep the core subcritical.

Detailed analysis based on the actual NGNP configuration and operating conditions will be required. The consequences of water ingress identified in this assessment will be evaluated. Since fission product mobilization is a speculative consequence of water ingress further research and analysis should be performed to determine whether or not it is a concern and if it is, what the actual consequences are and how to mitigate such an event. A plant availability study should be performed to determine the expected frequency and length of time of shutdowns due to water or steam ingress from steam generator leaks as this seems to be the most realistic concern and consequence of such an accident scenario.

Complete scoping analyses will be needed during Conceptual Design, and final analyses will be required for the Safety Analysis Report to be submitted to the NRC.

3.2.9 Conclusions

Even though the results of this assessment are only a starting point and will require additional work to be validated, past data analyzed in this study shows that water ingress must be considered in the development of an HTR using a direct steam PCS configuration.

This initial assessment shows that water ingress events are manageable and the safety consequences are acceptable. Moreover, the frequency of water ingress events in HTR steam generators is expected to be sufficiently low to not adversely impact plant availability. The NGNP will be equipped with multiple safety features for the prevention, detection and mitigation of such unlikely incidents. Moreover, the design of the reactor itself will provide inherent safety and time for response: passive heat removal, large heat capacities, design margins, etc. Should the reactor be operated at very high temperatures (such as 950°C), additional safety considerations would need to be addressed.

Plant availability also needs to be addressed as this seems to be the most realistic concern associated with water ingress events. However, risk analysis and profiles demonstrate that water ingress events do not dominate the risk profile and that they mean risk and frequency are lower than for other accident families.

These conclusions are supported by valuable gas-cooled reactor steam generator operating history which was studied. This data revealed an excellent operating history. The data was particularly valuable as the majority of the reactors studied used a direct steam cycle and helical coil steam generators.

Comprehensive safety analyses will have to be performed for the NGNP as part of the formal design process. The specific behavior for the system will depend on the detailed design selections made in the conceptual and preliminary phases. Prudent design can reasonably be expected to give system behavior consistent with past predicted data and will be determined by detailed safety analysis based on the actual NGNP configuration.

3.3 Operability and Control Strategies for the NGNP with a Direct Steam Cycle PCS

A brief review of the direct steam cycle operability was performed. Review of existing HTR plants demonstrates basic operational strategy and capability is well established for steam cycles. This includes both single loop and multiple loop configurations. Detailed evaluation requires design of plant controls. Operational sequences will be developed in conceptual design.

3.4 Cost Assessment of the Direct Steam Cycle

The cost of the NGNP Direct Cycle has been estimated based on the following assumptions: a two-loop configuration with a 600 MWt reactor and SA508/533 vessels (due to lower operating and accident temperatures). The characteristics of the 600 MWt reactor are well understood based on the ANTARES program. The use of a two loop system allows steam generator and main circulator sizes which are within the range examined in detail for past programs (e.g., MHTGR). The reactor inlet temperature of 350°C is fully compatible with SA-508, and accident temperatures are predicted to be within the anticipated ASME code limit for SA-508, so modified 9Cr-1Mo is not required for the direct steam cycle concept reactor vessel.

An NGNP indirect steam cycle (with IHX) cost estimate was made in April of 2008 (Reference 2). Modifications were made to this indirect cycle cost estimate based on the differences in nuclear island configuration (equipment changes and elimination), reactor building, and reduced R&D costs to arrive at the NGNP cost estimate for the direct steam cycle.

The major differences in the nuclear island configuration from the indirect cycle are the elimination of the two PCS IHXs along with the corresponding secondary circulators (two) and hot gas ducts (two). The small process heat loop does not change, of course (small IHX, circulator, hot gas duct). The reactor vessel material was changed to SA 508/533 from modified 9 Cr 1 Mo, because of the reduced operating temperatures to 750°C reactor outlet (down from 900°C for the indirect steam cycle).

The reactor building configuration (cross-section and height) assumed for cost estimation purposes for the direct steam cycle is as follows. Burns and Roe had several alternative building layouts from a previous study of reactor building alternatives. The cross-section used is alternative 8a from the drawing in Figure 3-21 with two steam generators replacing the two IHXs in the same location (SGs have a slightly smaller footprint). Since the steam generators sit lower than the IHXs relative to the reactor, an increased building height was estimated from scaling dimensions off of the same drawing to obtain a height of 54 m.

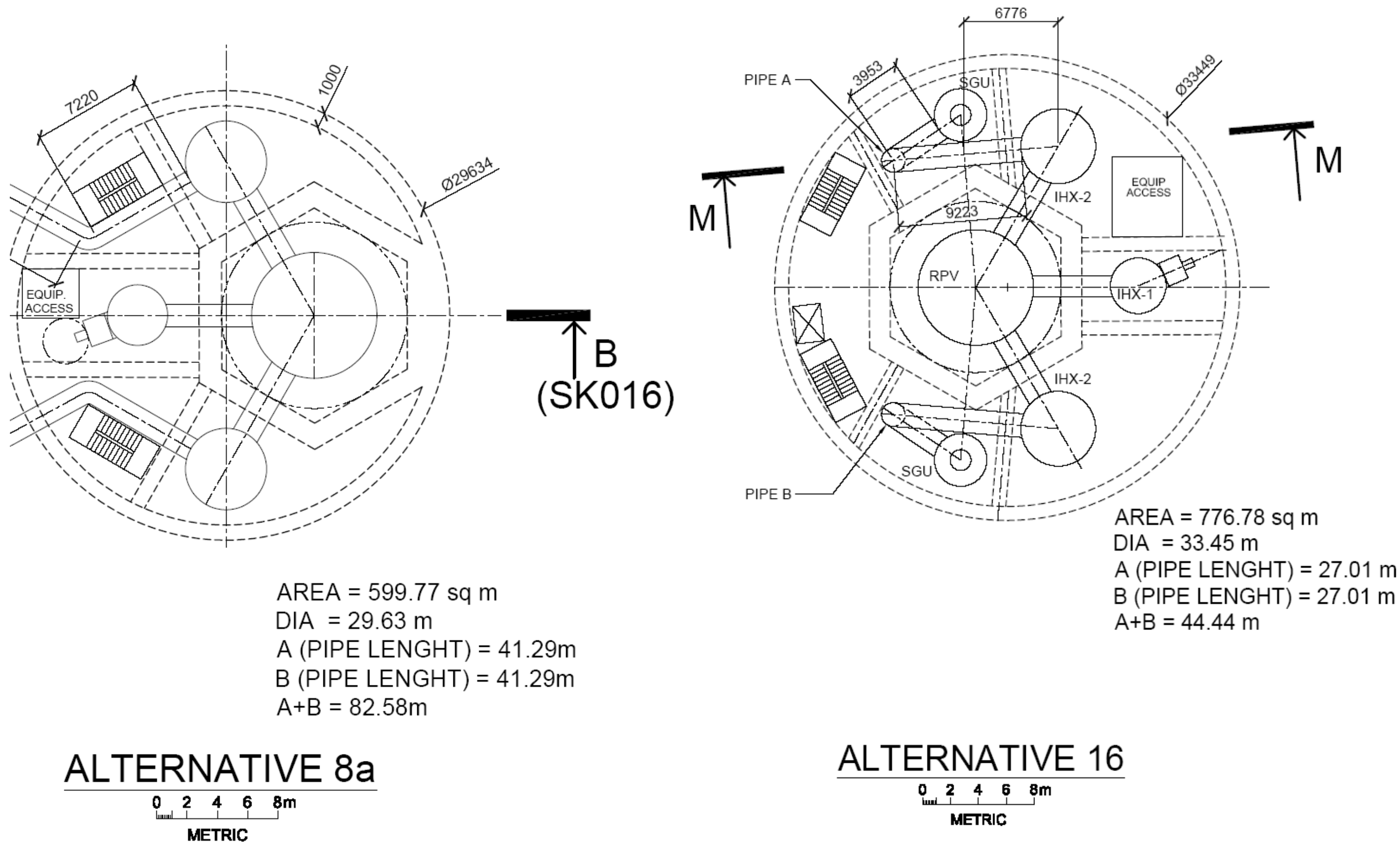


Figure 3-21: Reactor Building Layout Alternatives

Burns and Roe estimated the cost of this building (54m high x 29.63 m diameter) at $72.6 million vs. the indirect cycle reactor building, alternative 16 from the drawing in Figure 3-21, (47 m high x 33.45 m diameter) cost estimate of $67 million.

Nuclear island costs were estimated, based on previous indirect steam cycle estimates. Burns and Roe provided a complete NGNP cost reflecting all of the above described costs: nuclear island, reactor building, and an assumed 25% reduction in R&D costs from the indirect steam cycle due to lack of a high temperature IHX development program.

The total cost of the NGNP (without H_2 plant) is estimated at $3.765 billion in 2007 $$. This cost includes contingency of $446 million. Later in this report cost comparisons will be made with the direct steam, indirect steam, and combined cycle gas turbine plants. The table below shows a breakdown of some of the direct steam plant costs.

Table 3-10: Plant Costs

		NGNP direct steam cycle, $MIL	**% of Total**
C.2	**Design**	**1,022.05**	**30.8**
C.3	**Construction (w/o H_2 Plant)**	**1,627.32**	**49**
C.3.42	License and Permit to Operate	87.5	2.6
C.3.52.PM2	Project Management, Construction	54	1.6
C.3.52.BOP	Overall Site & BOP	521.2	15.7
C.3.52.NHP	Nuclear Heat Plant	679.6	20.5
C.3.52.PCP	Power Conversion Plant	249.9	7.5
C.3.52.H2P	Hydrogen Plant	-	-
C.3.62	Environment, Safety & Health	5.9	0.2
C.3.64	Security	14.9	0.4
C.3.66	Training	12.2	0.4
C.3.68	Waste Management	2.3	0.1
C.4	**Initial Ops & Inspection (w/o H_2 plant)**	**447.2**	**13.5**
C.6	**Post Ops & DD&D (w/o H_2 plant)**	**222.5**	**6.7**
C	**Total costs (w/o H_2 plant)**	**3319.07**	**100%**
	Contingency	446.3	
C	**Total costs (w/o H_2 plant) w/Contingency**	**3765.37**	

3.5 Assessment of Direct Steam Cycle Reliability and Technology Maturity

Reliability is a measure of the available up-time of a system or component. A good reliability is generally achieved by performing preventative maintenance in accordance with the manufacturer's recommendations on a mature product that has resolved the failure prone parts.

A direct (sub-critical) steam cycle has been applied in all previous nuclear gas reactors. The reliability information is gathered from the historic performance issues at related power plants.

The reliability of the direct (sub-critical) steam thermodynamic cycle is highly based on the reliability of the major equipment components of this system. Many of the major components in the PCS portion of this system are shown in Figure 3-22.

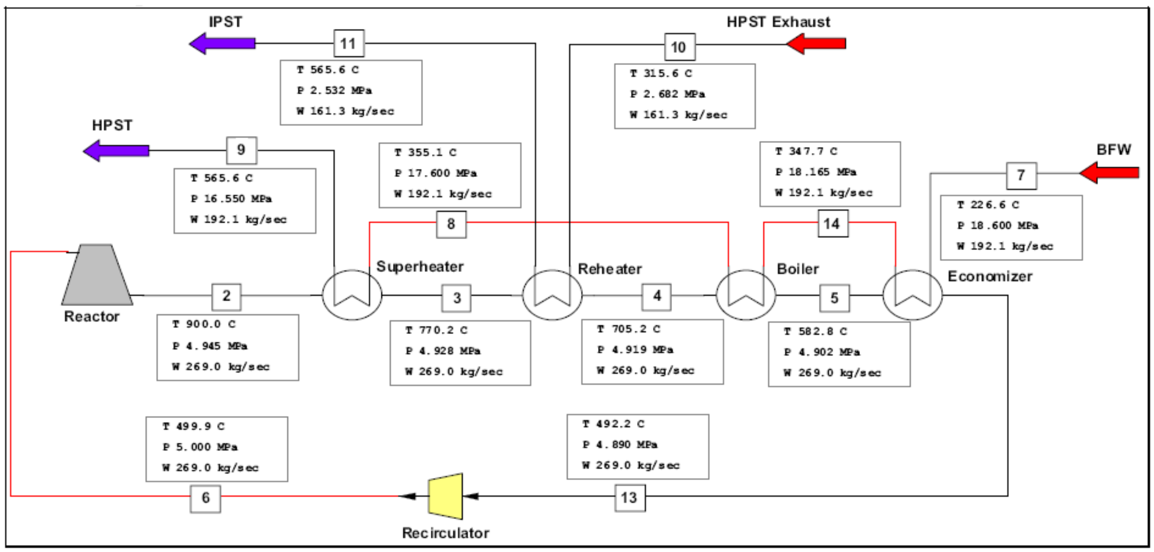


Figure 3-22: Schematic of Direct Steam Cycle

- High Temperature Steam Generator (HTSG)
  The reliability of a new design concept of an HTSG is unknown. However, a reliability trend can be paralleled to:
  - Prototype (historic) high temperature gas reactors
  - Traditional modern sub-critical steam generators (SG) used at commercial pressurized water reactors (PWRs) (for elevated pressures)
  - Heat Recovery Steam Generators (HRSG) used in fossil applications (for elevated temperatures)

<u>Historic Gas Reactors</u>

The key steam generator parameters that are considered are the operating temperature, absolute pressure, and pressure difference between the primary and secondary system boundaries.

Historically, there have been approximately thirteen gas reactors that have been constructed and operated with a steam generator, three of these reactors with helium as the primary coolant. A majority of the reactors are located in the United Kingdom (UK). The below table (Reference 21) summarizes the various gas reactor plants and the major operating conditions.

Station	Exchanged heat per SG	Inlet Gas Temp	Outlet Gas Temp	Coolant Pressure	HP - Steam		LP – Steam	
	MWe	°C	°C	MPa	°C	MPa	°C	MPa
Berkeley	73	168	345	0.9	322	2.2	322	0.5
Bradwell	89	175	390	1	372	5.4	372	1.5
Hunterston A	71	205	380	1	374	3.9	374	1
Hinkley A	162	190	378	1.4	363	4.8	349	1.4
Trawsfynydd	143	184	392	1.8	375	6.7	365	2.2
Dungeness A	210	220	410	2	393	9.8	395	4.1
Sizewell	237	220	410	1.9	391	4.8	390	1.9
Oldbury	223	235	412	2.5	400	9.7	393	4.9
Wylfa	469	230	414	2.8	396	4.8	--	--
Hinkley B	125	285	550	4.1	540	16	541	4.1
AVR Julich	45	275	950	1.1	505	7.3	--	--
Peach Bottom	115	340	730	2.4	540	10	--	--
Fort St. Vrain	70	400	770	4.9	538	17	538	4.8

Note: In the table above (and below), the yellow text on pink (white text on dark gray) represents those reactor sites that used Helium as the primary coolant. The black text on light gray represents those reactors that used Carbon Dioxide (CO_2) as the primary coolant.

The desired operating conditions of the proposed high temperature gas reactor (HTR) are listed below:

Station	Exchanged heat per SG	Inlet Gas Temp	Outlet Gas Temp	Coolant Pressure	HP - Steam		LP – Steam	
	MWt	°C	°C	MPa (bar)	°C	MPa (bar)	°C	MPa (bar)
AREVA HTR	565	500	900	5 (50)	565	16.5 (165)	565	2.5 (25)

The pressure difference between the primary and secondary boundaries is listed in the following table. The generalization can be made that as the outlet gas temperature rises, then the pressure difference also rises. The proposed AREVA high temperature gas reactor (HTR) has similar pressure differences as the British Energy - Hinkley B power plant and the Public Service Company of Colorado (PSC) – Fort Saint Vrain power plant of approximately 12 MPa (120 bar).

Station	Pressure Difference MPa	Pressure Difference Bar
Berkeley	1.3	13
Bradwell	4.4	44
Hunterston A	2.9	29
Hinkley A	3.4	34
Trawsfynydd	4.9	49
Dungeness A	7.8	78
Sizewell	2.9	29
Oldbury	7.2	72
Wylfa	2.0	20
Hinkley B	11.9	119
AVR Julich	6.2	62
Peach Bottom	7.6	76
Fort St. Vrain	12.1	121
AREVA HTR	11.5	115

The following table summarizes the reliability experience of numerous gas reactors.

Station	Number of Steam Generators	Years of Operation (until 1979)	Years of Steam Generator Operation	Tube Failures
Berkeley	16	16.5	264	10
Bradwell	12	16.5	198	112
Hunterston A	12	14	168	4
Hinkley A	12	14	168	39
Trawsfynydd	8	13.5	108	1
Dungeness A	8	13	104	16
Sizewell	8	11.8	92	6
Oldbury	8	8.5	68	46
Wylfa	16	11	176	75
Hinkley B	24	3	72	0
AVR Julich	1	10	10	1
Peach Bottom	2	7.5	15	2
Fort St. Vrain	12	5	60	1
Totals	139		1503	313

The large number of leakages in the Bradwell steam generators mainly resulted from systematic weld defects. The Wylfa steam generators had an unusual design which, moreover, was modified to deviate from the original concept for want of space. Difficulties with the steam generators have been encountered from the onset of operation.

Neglecting Bradwell and Wylfa leads to 126 failures in 1129 years of steam generator operation, resulting in an average number of 0.11 failures per steam generator per year (i.e. one failure per steam generator in about 9 years on average).

The heating tube failures are with one exception small leaks extending at most into the mm^2 range. Under the steam cycle conditions of a modern HTR concept, a leak cross-section of 1 mm^2 on the feedwater side would lead to a water ingress rate in the range of 0.1 kg/sec. The leakage rate under HTR steam conditions is in the range of 10 kg/sec for a 1 cm^2 on the feedwater side.

This failure estimate is the highest which includes small leaks. The likelihood for larger leaks is much more remote. Additionally, the likelihood of failure is the highest in the first few years and decreases during the life of the plant. Major damage such as a failure at the interface of a tube plate and connecting cylinder has not been experienced. For these reasons the failure estimate of 0.11 is quite infrequent, yet conservatively high that reasonably bounds the applicable data for the high temperature gas reactor.

Traditional Pressurized Water Reactor (PWR)

The NRC is very concerned about tube failure in modern traditional steam generators. Generally, modern steam generators suffer from the tube material and heat treatment of the Alloy 600 and Alloy 690 metals. (Reference 22)

Traditional steam generators operate at approximately 15 MPa @ 315°C on the primary (water) inlet and 6 MPa @ 290°C on the secondary (steam) exit.

The existing PWR steam generators give a good operating history for the maintenance requirements and higher pressure challenges.

The traditional steam generators used in pressurized water reactors (PWR) are considered highly reliable. However, the steam generators are also very burdensome with high maintenance. Extreme amounts of time, effort, and radiation dose are spent every year to maintain traditional steam generators. The critical failure mechanism of traditional steam generators is a tube failure. There have been very few failures that have affected tube integrity in the United States. (References 23 and 24)

The expected HTSG operating conditions for the proposed High Temperature Reactor (HTR) is 900°C @ 5 MPa on the primary (Helium) side and about 570°C @ 17 MPa on the secondary (steam) side.

The below table summarizes the typical temperature and pressure for the primary and secondary sides of each of the most relevant steam generators. Each type of steam generator has key features that can be paralleled to the intended HTR application. The pressure difference value gives a strong indication to the amount of stress applied to the boundary interface. The greater this value, then the more challenging (and robust) the final operating design must be.

	Primary Side		**Secondary Side**		
Configuration	**Max Temp**	**Max Pressure**	**Max Temp**	**Max Pressure**	**Pressure Difference**
AREVA HTR (Proposed Design)	1650°F	700 psi	1100°F	2400 psi	1700 psi
Ft. St. Vrain	1420°F	710 psi	1000°F	2450 psi	1740 psi
AVR (Experimental)	1740°F	160 psi	940°F	1060 psi	900 psi
CCGT - HRSG	1100°F	0 psi	700°F	600 psi	600 psi
Traditional PWR SG	600°F	2200 psi	550°F	900 psi	1300 psi

(Note: All values are approximate and are not for design purposes.)

The high pressure desired of the high temperature steam generator (HTSG) secondary pressure of 2400 psi (16.5 MPa) is most similar to the previously constructed gas reactors (Fort Saint Vrain and the German experimental prototype AVR). Additionally, similar high pressure and similar pressure differences have been repeatedly performed using traditional PWR steam generators.

The high temperature desired of the high temperature steam generator (HTSG) is most similar to the previously constructed gas reactors (Fort Saint Vrain and the German prototype AVR). Additionally, similar high temperatures used in a combined cycle fossil power plant heat recovery steam generators (HRSG) demonstrate the materials needed to operate at higher temperatures.

High temperature steam generators are a new design with no limited operating experience at the designed conditions. This new design will need to include all operating experience of similar steam applications. There is a chance that unknown future issues could arise that directly affects the reliability of the high temperature steam generators (i.e. high temperature material life & compatibility).

- Steam Turbine
  The steam turbines are very well understood equipment components. The cycle operating temperature and pressure easily align with existing and well manufactured steam turbines. The reliability is very high with known preventative maintenance activities.

- Condenser
  The condenser is a very well understood equipment component. The pumping of atmospheric water to condense the steam from the turbine has been done hundreds of times in nuclear applications. The reliability is very high with a known inspection and preventative maintenance activities.

- Pumps
  Pumping mechanisms for traditional water is very well understood in thousands of applications. The reliability is very high with known inspection and preventative maintenance activities.

- Extraction Steam to Feedwater Heaters
  The extracting of high temperature steam from the turbine to heat the returning feedwater is a standard common practice for all steam cycle applications. The reliability is very high with known inspection and preventative maintenance activities.

- Piping
  Pipe construction, erosion, and maintenance activities are well understood; although not always inspected. This has caused various problems in commercial operating combined cycle plants.

- Valves
  When valves are maintained under a good program, very minimal leakage can be achieved. However, the general practice of the 10CFR50 Appendix J program controls the regular leak testing requirements for water cooled reactors. A similar program for gas cooled reactors should be implemented; however, such a program is not currently required. Additionally, normal preventative maintenance keeps motor and air operators functioning properly for many years. Overall, valves are highly reliable key equipment components when properly maintained in both gas and water applications. The greatest unknown in reliability is the effects of high temperatures on isolation boundaries of certain materials.

In summary, a direct subcritical steam cycle is mature technology with high reliability. Several gas reactors connected to steam generators have been built and successfully run in commercial operations.

4.0 DETAILED ASSESSMENT OF THE CCGT

4.1 Performance Assessment

Mitsubishi Heavy Industries (MHI) carried out a detailed performance assessment on the combined cycle gas turbine configuration (CCGT) for a 900 C outlet temperature. The assumptions used in performing the steady-state heat balance are as follows (from reference 25):

- 565 MWt Reactor power
- 500 C/900 C reactor inlet/outlet temperatures
- IHX secondary side inlet/outlet temperature: 450 C/850 C
- IHX secondary side inlet pressure: 5 MPa
- HRSG inlet conditions (Feed Water): 157 C and 14.8 MPa
- HRSG outlet conditions (to HP turbine): 535 C and 11.8 MPa
- Condenser Pressure: 0.004 MPa
- House loads (total of 25.3 MWe):
  - Primary circulator power: 15 MWe (5 MWe x 3)
  - Feedwater pump: 3.6 MWe
  - Condensate pump: 0.3 MWe
  - Wet cooling Tower Fan: 0.9 MWe
  - Cooling Water Circ. Pump: 2.5 MWe
  - Miscellaneous loads: 3.0 MWe

- 3 IHXs: heat duty 193 MWt each
  - (from 565 MWt – 1MWt Rx heat loss + 15 MWe)
- One steam reheat cycle
- 0.004 MPa condenser pressure

The gross cycle power = 53 MWe (Brayton) + 226 MWe (Steam) = 279 MWe including turbine and generator losses.

Gross cycle efficiency = 279/(193x3)x100 = 48.2%

Net plant output = 279 – 25.3 = 253.7 MWe

Net plant efficiency = 253.7/565 = 44.9%.

A heat balance is shown below. Figure 4-1 below shows the system configuration and its heat and mass balance.

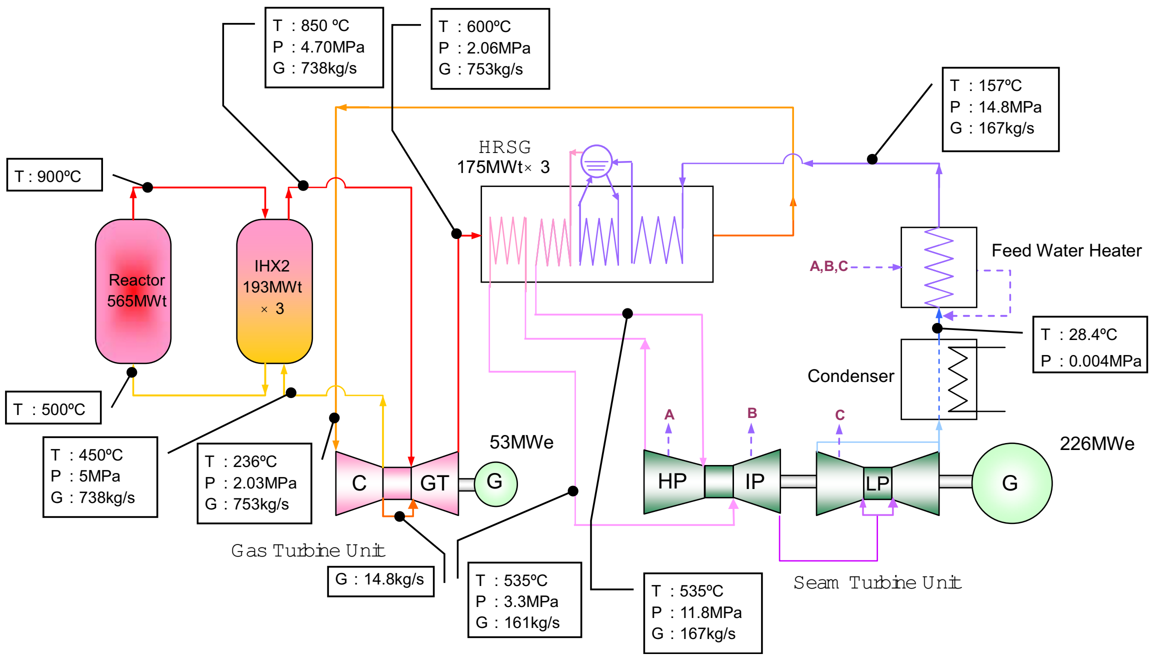


Figure 4-1: Heat and Mass Balance of the Indirect CCGT

4.2 Safety Assessment

4.2.1 Introduction

The CCGT cycle uses a helium-nitrogen mixture and is connected to the primary system through an IHX. Due to the small size of the IHX and absence of liquid secondary coolant, sudden loss of heat transfer could lead to a potentially serious loss of heat sink (LOHS) event. This is the primary safety concern associated specifically with the combined cycle gas turbine power conversion system.

This evaluation first details the factors that could initiate LOHS. It reviews the IHX and CCGT cycle designs, categorizes the event and explains why LOHS is not a significant concern with a steam cycle. The consequences of LOHS are presented through results obtained from previous AREVA analysis. Then, the evaluation gives an overview of the mitigation capability available, the main one being circulator trip. Detection systems, automatic trips, cooling systems and alternate sources of heat sink all help mitigate the consequences of the event and minimize investment risk but they cannot prevent loss of heat sink from occurring. Recommended analysis and conclusions follow.

4.2.2 Potential for LOHS Event

Any sudden loss of heat removal from the primary to the secondary system through the IHX can cause a LOHS event. Although faults in the IHX represent direct initiating events, secondary equipment failure, secondary system depressurization, gas turbine failure or spurious isolation valve actuation could all reduce secondary fluid flow and heat removal capabilities from the primary to secondary loop and lead to LOHS. As pointed out in

Reference 1, initiating events are mainly faults located on the secondary circuit but they could also originate from the tertiary circuit and indirectly affect heat transfer in the IHX.

4.2.2.1 IHX and CCGT Cycle Design

The CCGT cycle is a "variant of the mature, fossil-fuel fired, open cycle combined cycle plants" [1]. It is a closed cycle which uses a working fluid made up of 20% helium and 80% nitrogen [1]. Due to the fact that the secondary cycle contains a gas mixture, the primary and secondary loops are connected through an IHX (Figure 4-2).

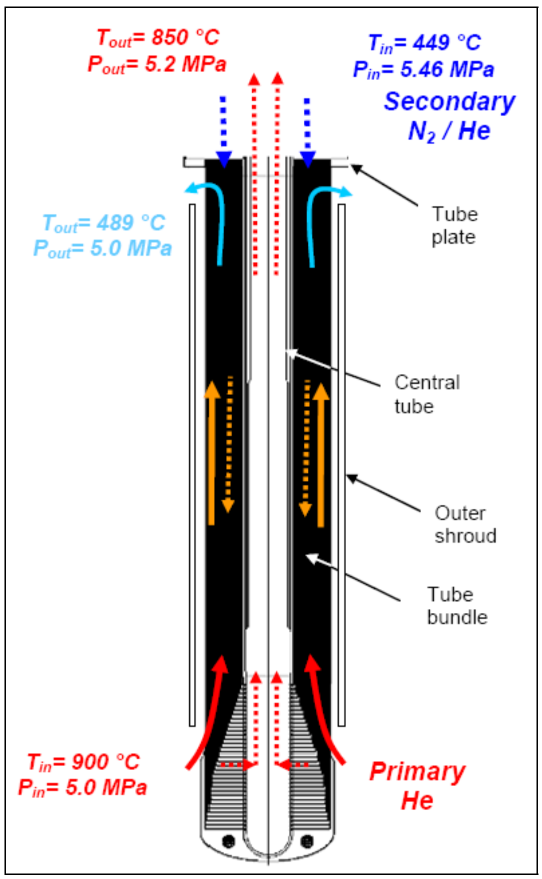


Figure 4-2: Tubular Intermediate Heat Exchanger [1]

There are various possible sources of loss of heat removal. They include:

- **Loss of secondary fluid** could occur in the event of a secondary pipe break or IHX leak
- **Loss of flow** could happen if the secondary circulator is tripped (in an indirect steam cycle concept) or in case of spurious secondary isolation valve closure. The latter is the worst case scenario for a loss of heat sink event as it would stop flow almost instantaneously.
- **Loss of load** could be caused by a turbine or compressor trip as well as any other failure in the gas turbine. This event will eventually turn into a complete loss of flow but is not expected to occur quite as fast as a loss of flow due to secondary circulator trip or spurious secondary isolation valve closure.

In the absence of heat transfer to the secondary circuit, the primary coolant temperature in the primary coolant cold leg between the IHX outlet and the reactor core inlet would quickly increase. If not quickly mitigated, this would have a significant effect on cold leg components, and it would raise the primary coolant pressure significantly.

4.2.2.2 Event Category

A LOHS event is considered an AOO [1] as long as all safety systems are functional. An AOO is an event deviating from normal operation that is expected to happen at most a few times during plant lifetime. Such events have a mean frequency of occurrence greater or equal to 10^{-2} per plant year [28].

4.2.2.3 Steam Cycle

A LOHS event could also happen in a steam cycle configuration through a loss of steam generator cooling due to loss of water/steam flow, spurious closure of secondary (water side) isolation valves, or steam/water leakage [1]. However, steam generators are much more resistant to LOHS due to the large liquid water inventory they carry. Long response times are available because of the large heat transfer mass contained in the steam generator.

4.2.3 Consequences of LOHS

In the event of a LOHS, the primary coolant would cease to transfer heat to the secondary cycle through the heat exchanger. Instead of being cooled through the IHX, 900^{o}C helium would be transported through the primary loop, therefore quickly raising primary coolant temperature and pressure. During normal operation, the reactor vessel inlet is in contact with 500^{o}C helium (Figure 4-3).

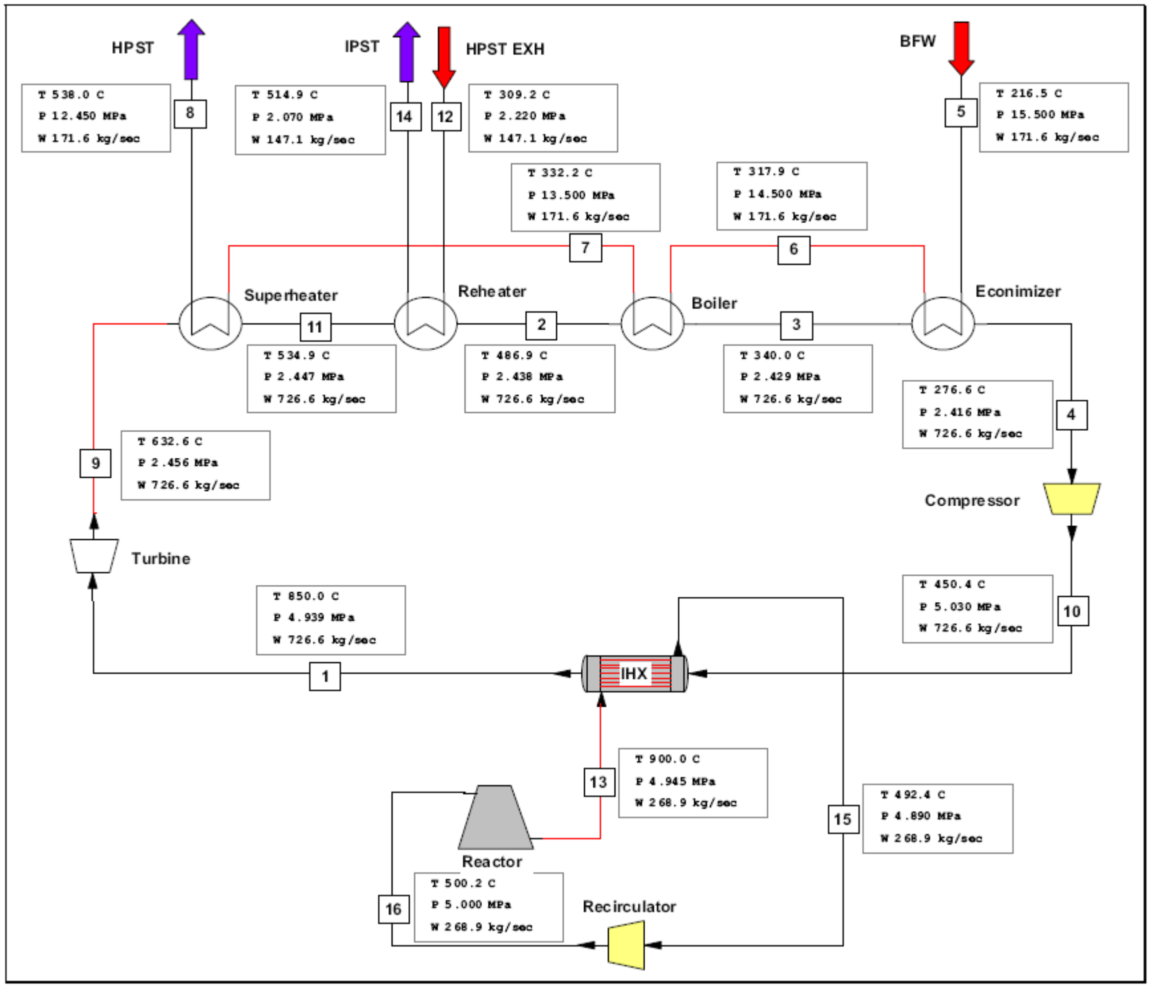


Figure 4-3: Combined Cycle Gas Turbine Cycle [1]

A VHTR transient calculation was performed previously within AREVA. It is a simple scoping calculation with conservative pressure and temperature responses. Part of the analysis addresses the issue of loss of load due to turbo machine trip. This is one of the less severe cases of LOHS as flow is not stopped instantly. Therefore, most LOHS events would be at least as severe as this loss of load event. The design inputs used are similar to the NGNP normal operating parameters and are compared in Table 4-1.

Table 4-1: Comparison of Design Input Parameters for the AREVA VHTR Analysis and the NGNP

Design Inputs	AREVA VHTR Model [29]	NGNP [1]
Rated thermal power (MW)	600	565
Reactor outlet temperature (^oC)	1000	900
Reactor inlet temperature (^oC)	490	500
Primary mass flowrate (kg/s)	226	272
Circulator outlet pressure (MPa)	5	5
IHX secondary inlet temp (^oC)	431	449.1
IHX secondary outlet temp (^oC)	950	850
IHX secondary pressure (MPa)	4.5	5.46

The AREVA VHTR model inputs are similar enough to the NGNP inputs for qualitative purposes. In each figure described below, grid disconnection occurs at t=0 and bypass is opened within 10 seconds of the loss of load event.

Core Temperature

Figure 4-4 illustrates the behavior of core inlet and outlet temperature in the event of a loss of load without reactor or circulator trip. Reactor outlet temperature first rises and then slowly decreases due to negative fuel reactivity which causes neutron power to decrease also. The loss of secondary flow causes the inlet temperature to rise to reactor outlet temperature within less than 120 seconds.

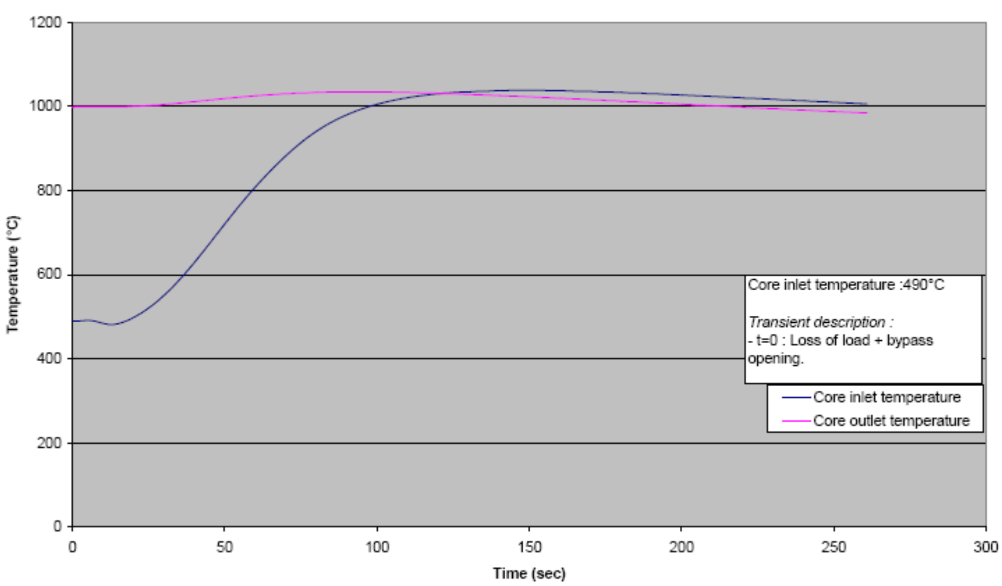


Figure 4-4: Core Temperature during Loss of Load without Reactor or Circulator Trip [29]

Figure 4-5 pictures the behavior of reactor core inlet and outlet temperature after a loss of load event with reactor trip only (circulator is not tripped). Because the reactor is tripped, core neutron power drops drastically within a few seconds causing the reactor outlet temperature to decrease more rapidly than in Figure 4-4. Consequently, the reactor inlet temperature peak is lower and decreases at a higher rate.

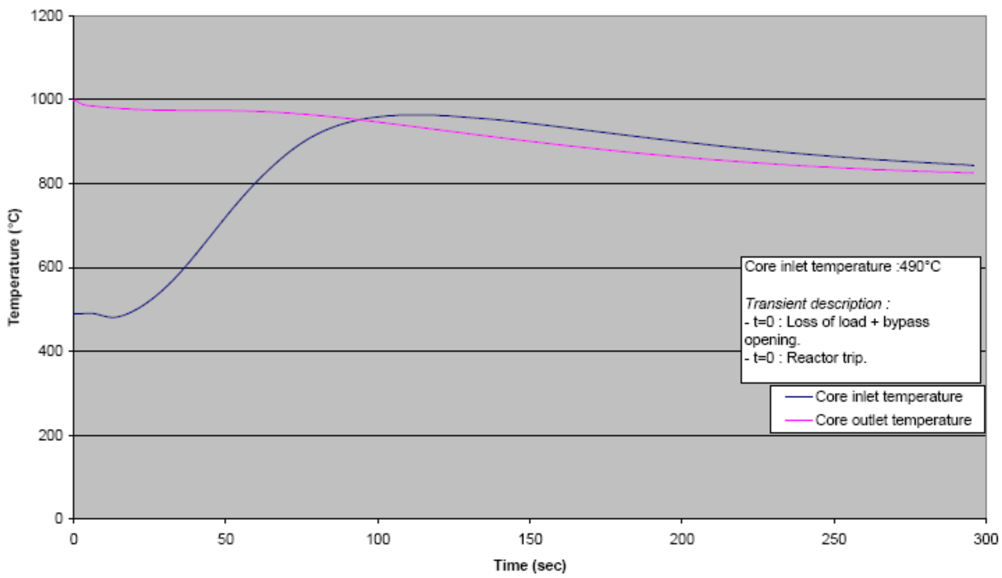


Figure 4-5: Core Temperature during Loss of Load with Reactor Trip and without Circulator Trip [29]

Finally, Figure 4-6 shows a loss of load event with reactor trip and circulator shutdown. Depending on the amount of time the circulator takes to shutdown, the core inlet temperature drops more or less rapidly. It is clear that circulator trip avoids the core temperature increase seen in Figure 4-4 and Figure 4-5.

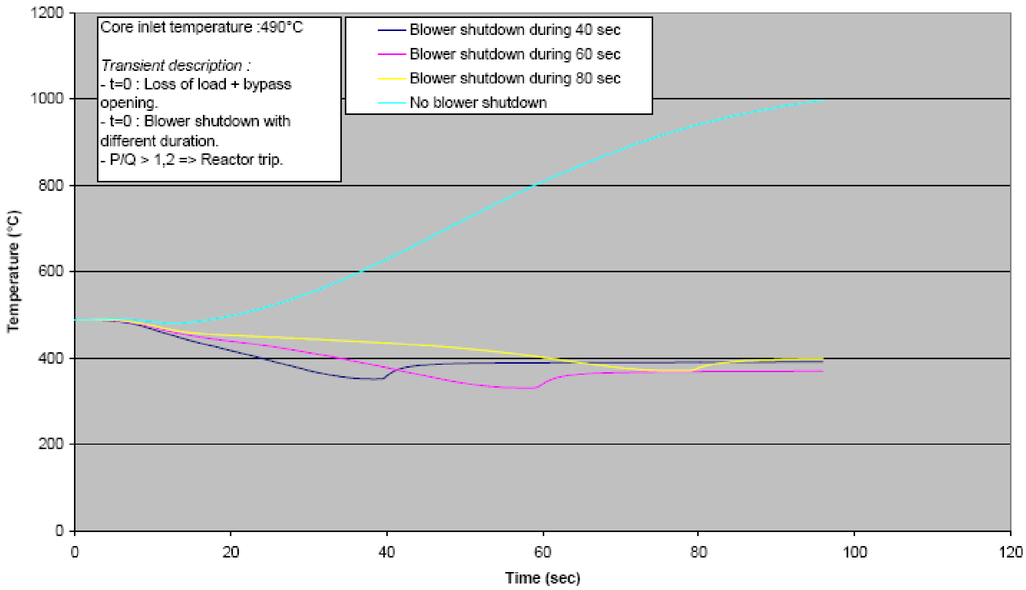


Figure 4-6: Core Inlet Temperature during Loss of Load with Reactor and Circulator Trip [29]

Core Pressure

Figure 4-7 shows the behavior of core pressure during loss of load with reactor trip.

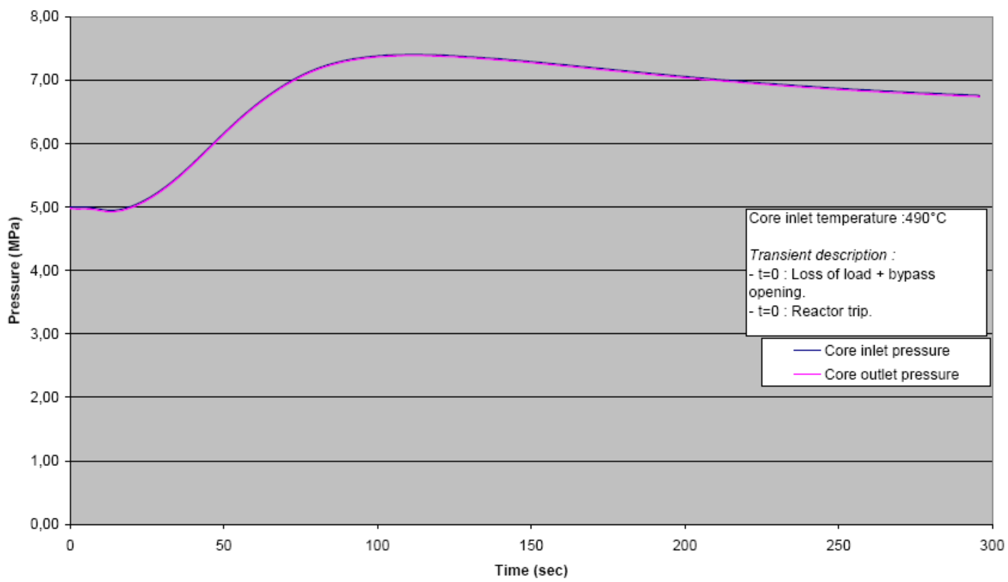


Figure 4-7: Core Pressure during Loss of Load with Reactor Trip and without Circulator Trip [29]

Core inlet and outlet pressure are identical. Pressure initially increases due to gas expansion from the temperature increase. Then, as power and temperature decrease, so does pressure.

The AREVA VHTR transient calculation shows that a loss of load event causes a large and somewhat rapid increase in core inlet temperature and core pressure if unmitigated. It also illustrates that reactor trip, which brings neutron power down very quickly, helps reduce the effects of the loss of load but only in a small way. Clearly, circulator trip has a much more significant effect on core temperature and should be relied upon in mitigating a LOHS event.

As seen above, worst case unmitigated scenario would suggest that the primary coolant temperature would eventually reach reactor core outlet temperature and be transferred to the reactor core inlet. This represents a very large temperature rise which would be coupled with a primary pressure increase due to gas expansion. The IHX would also be quickly exposed to high helium temperatures at its outlet [1]. The hot helium leaving the IHX and entering the reactor vessel could cause severe damage to the equipment and result in the unavailability of the SDHRS.

4.2.4 Mitigation/Safety Features against Loss of Heat Sink

The following provides additional information and details on available detection, prevention, and mitigation systems of high temperature reactors.

4.2.4.1 Detection Means

The NGNP will be equipped with system temperature and pressure monitors which will be appropriate for detection of loss of heat sink events.

4.2.4.2 Reactor and Circulator Trip

As illustrated in the AREVA VHTR transient calculation results in section 4.2.3, reactor trip offers a small amount of mitigation in the case of a loss of load. The rapid power drop provides for a slightly faster drop in temperature and pressure. It is clear, however, that tripping the circulator is the only way to prevent unacceptable core inlet temperature from increasing and challenging the primary coolant boundary.

The NGNP will be designed such that in an accident scenario, an abnormal increase in primary temperature or pressure causes a reactor trip and automatic trip of the primary circulators so as to prevent the hot helium from reaching the reactor inlet. The primary circulator trip will be highly reliable and diverse. It should operate within a short duration following LOHS. Electrical braking is also put in place to quickly stop primary loop circulation. The same results can be achieved by turning off the power to the primary circulator motors [1]. Although subject to natural coastdown characteristics, the circulators are equipped with highly reliable trip functions.

4.2.4.3 Cooling Systems and Alternate Sources of Heat Sink

High temperature reactors have numerous safety features designed to deal with heat generation and removal.

According to the preconceptual design studies performed in Reference 1, heat generation will be controlled by automatic control rods insertion as abnormal parameter value is detected. Should LOHS be combined with loss of electrical power, control rods drop by gravity in the core. Also, RSS insertion by operator action will be provided in case of control rod insertion failure.

Although circulator trip is the only way to effectively prevent severe consequences, the SCS will help minimize the consequences of LOHS after the circulators are stopped by gradually bringing the entire system to cold shutdown temperatures. In the event that the SCS is not available, residual heat would be transferred to the RCCS by conduction and radiation.

The NGNP core is designed such that even if the RCCS fails (a BDBE), the following systems still provide heat removal:

- Core – passive heat conduction
- Reactor Vessel – Thermal Radiation
- Silo Walls and Surrounding – Conduction

Acceptable fuel temperatures are maintained even for this extreme condition. This passive heat removal system is illustrated in Figure 4-8.

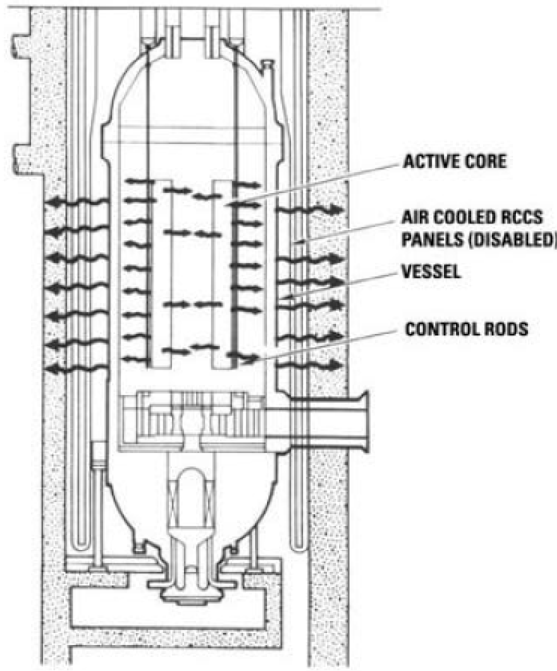


Figure 4-8: Passive Radiation and Conduction of Afterheat to Reactor Building [26]

Such passive heat removal systems are sufficient to keep peak core temperatures and system pressures below design limit and therefore prevent or mitigate damage to the core.

It should be noted that reactor design also plays an important role in mitigating LOHS as it does prevent the event from having a significant effect on the fuel. Additionally, keeping fuel temperatures below damage limit temperature is very important to preclude any significant particle coating failure, radionuclide release or investment risk consequences.

TRISO fuel can withstand extremely high temperatures while still retaining radionuclides. TRISO fuel can be exposed to temperatures of 1600°C for several hours without suffering loss of particle coating integrity. This is significant as design basis event peak fuel temperatures do not exceed 1460°C [14].

The NGNP is designed to have negative temperature coefficient of reactivity. In the event of core temperature increase, the change in temperature will tend to reduce reactor power which will in turn reduce the reactor outlet temperature [14].

The very large size of the reactor vessel, solid blocks of fuel and graphite moderator all give the system very high heat capacity**.** Graphite is used for the central, inner and outer reflectors (Figure 4-9).

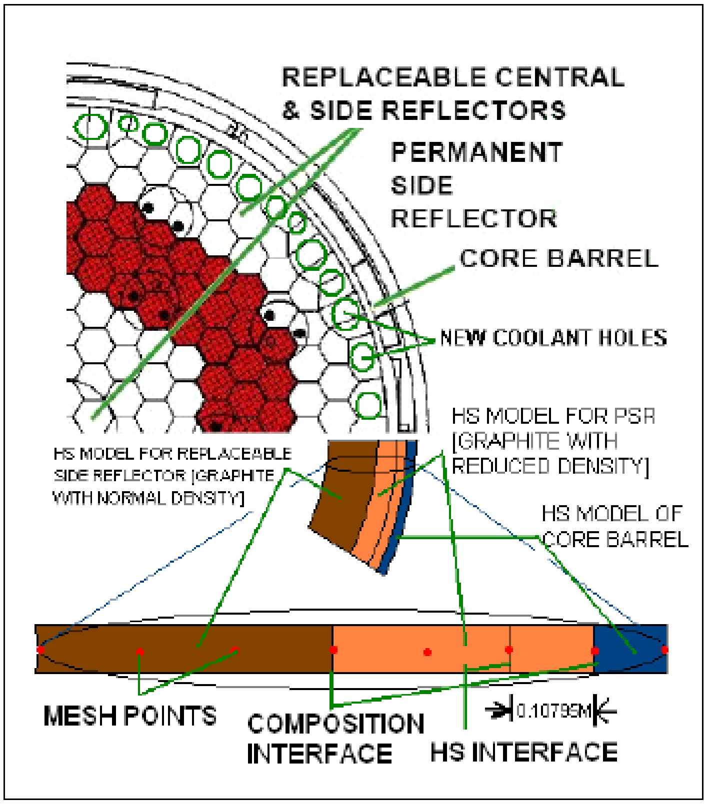


Figure 4-9: Graphite Reflectors [27]

Graphite moderator can withstand even higher temperatures than the fuel without suffering any structural damage. Graphite also holds up certain fission products therefore decreasing the potential for release of radionuclides. The massive graphite structures in the reactor core have very high heat capacity providing very slow heat up even during extreme conditions. This also supplies operators with long response times [14].

4.2.5 Recommended Analysis

Detailed analyses of all relevant LOHS scenarios will have to be performed using the NGNP configuration to confirm acceptable response. This includes studying the effects of circulator trip on power, pressure, temperature, and flow rate. Various types of events should be considered and compared such as loss of secondary fluid, loss of flow and loss of load. These analyses will have to be taken into account in the deterministic accident analysis and in the PRA.

4.2.6 Conclusion

This combined cycle gas turbine cycle safety evaluation explains that LOHS is an important additional potential safety concern for any indirect (secondary gas loop with IHX) PCS configuration. The consequences of a loss of heat sink on the primary system and the IHX could very serious in the absence of active and passive safety systems. However, mitigation is efficiently provided by promptly tripping the main circulator which can prevent the primary system from heating up and therefore preclude hot helium from entering the reactor inlet. Nonetheless, additional analysis should be performed in order to both better understand the consequences of LOHS on our specific system, and improve the safety systems available. More specifically, modeling of the NGNP to study temperature, pressure, power and flow rate transients would be very valuable. Research and analysis are also needed to develop an additional trip function for the main circulator as this system is crucial in preventing undesirable consequences on the system due to LOHS.

4.3 Operability and Control Strategies for the NGNP with a CCGT PCS

It has been proposed that the NGNP enlist the use of a Combined Cycle Power Conversion system in parallel with a direct process heat supply loop. The combined cycle configuration places as the topping cycle, a high temperature, high efficiency closed Brayton cycle loop downstream of three intermediate heat exchangers. The Brayton cycle exhausts into a heat recovery steam generator which supports a bottoming Rankine steam cycle. This configuration allows flexibility of operations, very high efficiencies, and a diversity of process heat draw points to end users.

4.3.1 Issues

Key operational and control issues for the NGNP equipped in such a manner include the following:
The start up and shut down of the as proposed system is a first of a kind exercise in itself. The CCGT operating in parallel with a process heat loop is an as of yet untested configuration.

Electrical load control of balanced Rankine and Brayton driven generators has not yet been accomplished in a deployed system. Operations during load following operations and step increase or decrease in load will present unique challenges to the control system.

Related to electrical load control is Brayton turbine generator set speed control. Controlling the speed of the turbine during asynchronous generator operation and start up and shut down operations has been explored in the OBERHAUSSEN II test facility and other applications, but with mixed results. Variations in loop helium/nitrogen inventory, system temperature transients, various bypass flow operations and variation of load on the Heat Recovery Steam Generator (HRSG) will all need to be addressed by the turbine speed control system.

Although steam turbine generator set speed control is a well understood control matter, operations of a bottoming cycle with dependence on enthalpy input from the Brayton topping cycle will complicate this as well. Of concern is asynchronous generator operation and load following as mentioned earlier. Also, start up and shut down operations will require implementation of such mechanisms as variable feed water flow, variable HRSG load, and steam dumping operations.

It is also plausible to consider dumping electrical loads VIA an electricity consumption device as opposed to using enthalpy dumping for quick and large magnitude transients.

4.3.2 Options

Some available options considered for overcoming these challenges include the following:

For electrical load control, the balanced Rankine and Steam driven generators may be loaded in one of two manners. Either both generator loads can be varied in a parallel and proportional manner or one may be designated as the primary load varying generator with the second generator used for load reduction only after the primary has been completely unloaded.

For Brayton turbine generator set speed control, several variations of a bypass control system have been proposed, and one such configuration was tested in the OBERHAUSSEN II test facility. One option bypasses the turbine and the supply heat source and effectively short circuits the compressor. Another option simply bypasses the turbine and allows enthalpy to pass through to the HRSG uninterrupted. What ever method is chosen will have to be very responsive and sensitive to small changes in loop pressure. The OBERHAUSSEN II test facility experienced a speed control accident which destroyed a turbine set.

Steam turbine load and speed control during transients will be challenging in that the HRSG load may be impacted by upstream transients and steam dump operations. Ensuring that the steam turbine can maintain full load during transients will be an operational challenge.

Compensating for the NGNP core's relatively slow transient response time will also create challenges. The critical primary parameter of concern is that of the primary loop cold leg temperature. The allowable operating band is from 350 °C to 500 °C. With operations proposed near the upper end of this band, a load reduction in the PCS will challenge the ability of the core to drop in thermal power in a timely manner so as to not exceed this maximum allowable temperature. Steam dumping and electrical load shedding are proposed as mechanisms which can temporarily mitigate the thermal imbalance which will occur during such large magnitude transients.

Also of concern during such transients is the maximum allowable operating temperature of the IHX. During a load reduction transient, the primary hot leg temperature will increase. Left unmitigated, this could lead to overheating of the primary hot side of the IHX.

4.3.3 Proposed Solutions

The core control rod banks will need to be adjusted in such a manner as to maintain primary coolant average temperature during transient operations at power. The NGNP core will be designed with a negative power coefficient, but reactivity imbalances induced by load changes will be insufficient to move the core through these transients without potentially exceeding a critical control parameter. They shall also be rapidly inserted or a SCRAM initiated if a critical parameter trip set point is reached.

The primary PCS loops should be equipped with variable speed circulators. The blower speed will need to be varied in such a manner as to maintain core differential temperature within maximum control limits during transient operations at power. This control action is necessary to maintain the cold leg temperature below the maximum allowed temperature of 500 °C.

The primary loop pressure will need to be controlled in such a manner as to maintain core differential temperature and loop pressure within operating band limits during heat up and cool down operations and during transient operations at power. Primary pressure will also need to be controlled in such a manner as to maintain differential pressure across the IHX as low as possible while also ensuring that primary loop pressure remains below secondary loop pressure. Two methods available are total mass control (feed and bleed of inventory) and enclosed volume control (active accumulator).

Secondary loop pressure will need to be controlled in such a manner as to maintain maximum Brayton turbine work production. Primary loop pressure will be controlled as a dependant variable in relation to secondary loop pressure to maintain differential pressure across the IHX.

The IHX differential temperature control system shall adjust primary blower speed, Brayton turbine bypass flow, tertiary feed water flow, and steam dump operation so as to maintain IHX differential temperatures within the design operating band.

The process heat loop system should be equipped with a variable speed blower in the primary process heat supply loop in order to accommodate start up and warm up of the loop and to accommodate load transients in the process heat end use system.

The process heat loop should also be designed so as to be able to be idled or isolated during power operations to allow for protection of the primary cold leg in case of a load rejection incident.

The process heat loop secondary side should be equipped with a heat sink dump system in order to provide for warm up and load rejection incident capabilities.

The Brayton turbine shall be equipped with a bypass throttle control system. Several configuration options are available and one such configuration has been demonstrated in the OBERHAUSSEN II test facility (Reference 31). The proposed CCGT PCS should be equipped with a Brayton turbine bypass valve. This configuration provides for the ability to reduce work output of the Brayton turbine during a significant load reduction or rejection incident while maintaining enthalpy flow to the tertiary loop heat sink. Of paramount concern for this system is the need to reject loads quickly while maintaining the primary cold leg temperature below the maximum allowed temperature of 500 °C, and to protect the IHX assemblies from experiencing an over temperature condition. The Brayton turbine bypass throttle will need to be controlled in such a manner as to maintain Brayton turbine speed through any generator load transient, and through any secondary fluid pressure or mass flow transient.

The PCS tertiary loop should be equipped with a steam dump system. This system will be used to maintain primary loop cold leg temperature below the maximum critical temperature of 500 °C during secondary and or tertiary generator load reduction or rejection transients.

There exist many operational challenges associated with this PCS approach as this system has not been developed to a point where it may be commercially deployed. Past experience is minimal and not entirely applicable to the currently proposed CCGT system for the NGNP project. Development effort will need to be invested into the IHX, the Brayton turbine generator set and throttle control system, the primary and secondary pressure control systems, the tertiary loop steam dump control system, and the process heat loop system. Modifications will need to be made to a current production conventional CCGT steam supply system in order to adapt it to function appropriately with the nuclear heat source and closed loop Brayton top cycle. The control and operation of such a system will be complex and interact to a great degree with many control sub-systems throughout the primary, secondary, tertiary, and process heat loop systems as well as control of reactor core rod banks. Such a system has not yet been deployed, and no prototype development project pursued to date has investigated all of the many aspects of technology that this machine will require.

4.4 Cost Assessment of the CCGT

A detailed cost assessment of the CCGT was made previously. See chapter 16 of PCDSR (Reference 32). A summary of the costs is shown in the table below. The total NGNP cost is $3.8 billion ($4.25 billion with contingency).

Table 4-2: CCGT Plant Costs

		NGNP CCGT (PCDSR), $MIL	% of Total
C.2	**Design**	**1,139.60**	**30.2**
C.3	**Construction (w/o H_2 Plant)**	**1,966.00**	**52.1**
C.3.42	License and Permit to Operate	87.5	2.3
C.3.52.PM2	Project Management, Construction	54	1.4
C.3.52.BOP	Overall Site & BOP	540.9	14.3
C.3.52.NHP	Nuclear Heat Plant	895.9	23.7
C.3.52.PCP	Power Conversion Plant	352.6	9.3
C.3.52.H2P	Hydrogen Plant	-	-
C.3.62	Environment, Safety & Health	5.9	0.2
C.3.64	Security	14.9	0.4
C.3.66	Training	12.2	0.3
C.3.68	Waste Management	2.3	0.1
C.4	**Initial Ops & Inspection (w/o H_2 plant)**	**447.2**	**11.8**
C.6	**Post Ops & DD&D (w/o H_2 plant)**	**222.5**	**5.9**
C	**Total costs (w/o H_2 plant)**	**3775.20**	**100%**
	Contingency	470.4	
C	**Total costs (w/o H_2 plant) w/Contingency**	**4245.60**	

4.5 CCGT Reliability and Technology Maturity

A combined cycle process has only been applied in fossil power applications. There have been no nuclear power plants that utilize this process. All known reliability information is gathered from the historic performance issues at related commercial fossil power plants.

The reliability of the combined cycle gas turbine (CCGT) thermodynamic cycle is highly based on the reliability of the major equipment components of this system. Many of the major components in the power conversion system (PCS) portion of this system are shown in Figure 4-10.

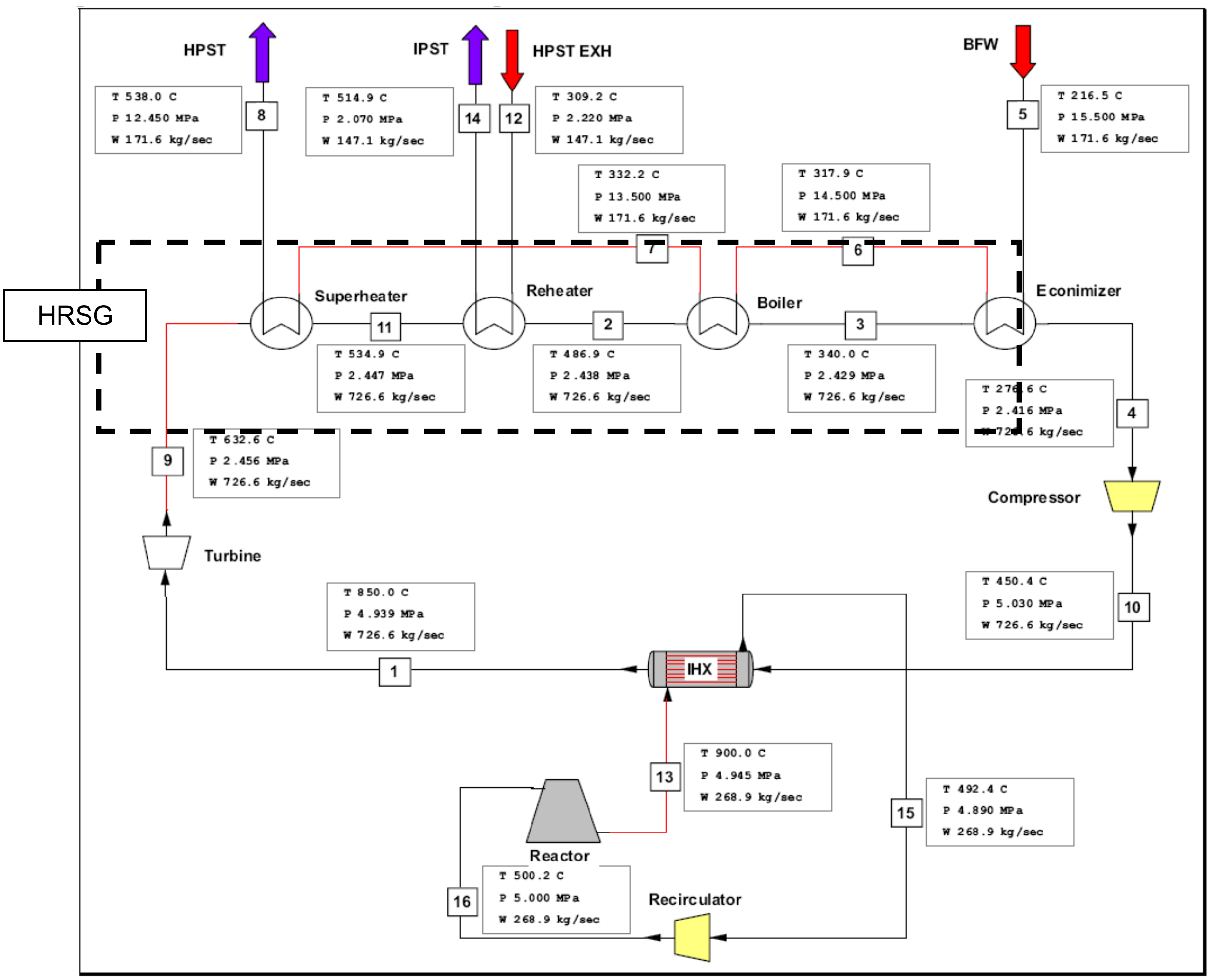


Figure 4-10: Schematic of CCGT

- Intermediate Heat Exchanger (IHX)
  The IHX unique heat exchanger has not been constructed. The impact of high temperature, high pressure, and flow effects are unknown on the performance reliability of this critical piece of equipment.

- Gas Turbine
  Large Helium turbines (50MW) have been successfully constructed (OBERHAUSEN 2). There is great difficulty scaling this gas turbine to much larger sizes. (Reference 35)

  The Oberhausen 2 gas turbine did have a blade failure within 2 years of operation which caused significant damage and down time (Reference 36). There is little additional information for the performance reliability for this critical piece of equipment at larger sizes.

  The variety of gas types significantly affects the cycle pressure ratio. However, the optimized cycle efficiencies of each cycle are almost the same. Helium turbocompressor has lower stage pressure ratio and more number of stages than those for nitrogen and air machines, while helium and nitrogen turbocompressors have shorter blade length than that for an air machine (reference 37).

- Heat Recovery Steam Generator (HRSG)
  The typical operating temperature of a fossil HRSG is up to 1100°F (590°C) exhaust gas temperature at nearly ambient pressure while heating steam (water) up to 700°F (370°C) at 600 psi (4.2 MPa).

  HRSG tube failures at fossil plants continue to be the leading cause of combined cycle plant unreliability. The modular designs of modern HRSGs do not lend themselves to easy access for repairs (Reference 33). There has not been a Combined Cycle Gas Turbine (CCGT) power conversion system (PCS) used at any previous gas reactors. The historic failures have all occurred at fossil power plants that have continued to use a CCGT process.

  The dominant damage mechanisms are most aggravated by cycling conditions (tube bowing, gas baffle damage, drain leaks and failures). The most significant damage that occurs in HRSGs is generally leaks and failures of pressure parts; specifically, tubes, headers and connecting pipes. Tube failures are well known as dominant contributors to plan unreliability. The most common tube damage mechanism is bowing which is attributable to a variety of sources including differential thermal stress, manufacturing variations in tube length, etc. (Reference 34).

  Flow accelerated corrosion (FAC) is a high-visibility issue which has been the cause of numerous fatalities at power plants over the years. Experience from previous HRSG designs that have operated for longer periods (50,000 – 100,000 hrs) indicates that will likely change despite the best efforts of plant staffs to maintain water chemistry within targets.

  Condensate formation during startup is a well-known problem and plants experiencing repeated tube failures, extreme tube bowing and or related problems. Some plants have installed thermocouples to determine whether steam binding is occurring in HP Economizers that are poorly vented.

  Problems with boiler and steam piping are often associated with the reheat piping; particularly where sprays have been designed with too short downstream straight pipe lengths (less than 10 pipe diameters). Incomplete atomization of the sprays impact downstream piping surfaces as liquid droplets where it causes significant thermal stresses.

  Water hammer is another phenomenon that has been observed at various combined cycle plants. Water hammer is a destructive transient that typically damages adjacent pipe supports and steam piping.

- Gas Compressor (He, He / N_2, He / Ar)
  This piece of critical equipment is closely related to the Gas Turbine listed above. This is commonly an integrated component on the same drive shaft to compress the gas to upon return to the high pressure intermediate heat exchanger (IHX).

- Steam Turbine
  The steam turbines are very well understood equipment components. The cycle operating temperature and pressure easily align with existing and well manufactured steam turbines. The reliability is very high with known preventative maintenance activities.

- Condenser
  The condenser is a very well understood equipment component. The pumping of atmospheric water to condense the steam from the turbine has been done hundreds of times in nuclear applications. The reliability is very high with a known inspection and preventative maintenance activities.

- Pumps
  Pumping mechanisms for traditional water is very well understood in thousands of applications. The reliability is very high with known inspection and preventative maintenance activities.

- Extraction Steam to Feedwater Heaters
  The extracting of high temperature steam from the turbine to heat the returning feedwater is a standard common practice for all steam cycle applications. The reliability is very high with known inspection and preventative maintenance activities.

- Piping
  Pipe construction, erosion, and maintenance activities are well understood; although not always inspected. This has caused various problems in commercial operating combined cycle plants.

- Valves
  When valves are maintained under a good program, very minimal leakage can be achieved. However, the general practice of the 10CFR50 Appendix J program controls the regular leak testing requirements for water cooled reactors. A similar program for gas cooled reactors should be implemented; however, such a program is not currently required.

  Additionally, normal preventative maintenance keeps motor and air operators functioning properly for many years. Overall, valves are highly reliable key equipment components when properly maintained in both gas and water applications. The greatest unknown in reliability is the effects of high temperatures on isolation boundaries of certain materials.

The key power producing equipment is frequently not fully maintained in a commercial fossil power plant. A leading contributor to this lack of rigor is the attitudes and expected culture of running the equipment to failure. A different proactive preventative maintenance program at a typical nuclear power plant can improve the equipment reliably.

As far as technology maturity, the CCGT configuration has mature elements: it uses air-breathing turbomachinery since the working fluid mixture of helium/nitrogen at a 20/80 weight percent, respectively, has the same density of air and the steam cycle is of course mature technology.

5.0 COMPARISON OF CONVENTIONAL STEAM CYCLE AND CCGT

The conventional steam cycle and CCGT configurations each have their advantages and shortcomings. The trade-offs of each system are as follows. The CCGT has higher gross efficiency (48.2% vs. 46.9%) and higher net efficiency (45.1% vs. 44.3%) than the conventional steam cycle, but at a higher cost. See Table 5-1 below for a comparison of NGNP costs for the conventional steam cycle and CCGT. A cost estimate for an indirect steam cycle was made recently. So, this cost estimate is included in the table below as well.

Table 5-1: NGNP Cost Comparison of Configurations

		NGNP direct steam cycle, $MIL	**NGNP CCGT (PCDSR), $MIL**	**NGNP Indirect Steam Cycle, $MIL**
C.2	**Design**	**1,022.05**	**1,139.60**	**1,139.60**
C.3	**Construction (w/o H_2 Plant)**	**1,627.32**	**1,966.00**	**1,954.60**
C.3.42	License and Permit to Operate	87.5	87.5	87.5
C.3.52.PM2	Project Management, Construction	54	54	54
C.3.52.BOP	Overall Site & BOP	521.2	540.9	515.6
C.3.52.NHP	Nuclear Heat Plant	679.6	895.9	1012.50
C.3.52.PCP	Power Conversion Plant	249.9	352.6	249.9
C.3.52.H2P	Hydrogen Plant	-	-	-
C.3.62	Environment, Safety & Health	5.9	5.9	5.9
C.3.64	Security	14.9	14.9	14.9
C.3.66	Training	12.2	12.2	12.2
C.3.68	Waste Management	2.3	2.3	2.3
C.4	**Initial Ops & Inspection (w/o H_2 plant)**	**447.2**	**447.2**	**447.2**
C.6	**Post Ops & DD&D (w/o H_2 plant)**	**222.5**	**222.5**	**222.5**
C	**Total costs (w/o H_2 plant)**	**3319.07**	**3775.20**	**3763.80**
	Contingency	446.3	470.4	469.5
C	**Total costs (w/o H_2 plant) w/Contingency**	**3765.37**	**4245.60**	**4233.30**

It is clear that the direct (conventional) steam cycle is the least expensive of the above three configurations for NGNP, by over $450 Million, mainly due to cost reductions in design (eliminate IHX R&D) and the nuclear heat plant (NHP). Table 5-2 shows a more detailed cost breakdown comparing the same three configurations. As illustrated in the table, the NHP cost is reduced mainly because of eliminated IHXs and associated equipment: secondary circulators and secondary hot gas ducts.

Table 5-2: Detailed NGNP Cost Comparison of Configurations

Configuration:	**NGNP PCDSR $MIL**	**NGNP indirect steam cycle $MIL**	**NGNP direct steam cycle $MIL**
Construction (w/o H_2 plant)	**1,966.00**	**1954.6**	**1627.3**
License & Permit to Operate	87.5	87.5	87.5
Project Management, Construction	54	54	54
Overall Site & BOP	**540.9**	**515.6**	**521.6**
Reactor Building	78.6	67.0	72.6
Power Conversion Building	20.9	13.9	13.9
Other buildings and systems	441.3	434.7	435.1
Nuclear Heat Plant	**895.9**	**1,012.50**	**679.60**
Reactor System	406.9	405.3	*388.1*
Reactor vessels, supports, and pressure relief	*Yes*	*Yes*	*Yes*
Cross vessels	*Yes*	*Yes*	*Yes*
Other reactor equipment	*Yes*	*Yes*	*Yes*
Electrical equipment	*Yes*	*Yes*	*Yes*
Miscellaneous equipment	*Yes*	*Yes*	*Yes*
Heat rejection system	*Yes*	*Yes*	*Yes*
Primary HTS Capital Costs	368.6	280.5	114.8
Primary coolant circulators	*3x 5 MWe+ 1x 1.5 MWe*	*2x 8 MWe+ 1x 1.5 MWe*	*2x 3.5 MWe+ 1x 1.3 MWe*
Primary hot gas ducts	*Yes*	*Yes*	*Yes*
IHXs	*3 tubular IHX+ 1 compact IHX*	*2 tubular IHX+ 1 compact IHX*	*1 compact IHX*
IHX vessels & supports	*3 tubular IHX vessels+ 1 compact IHX vessel*	*2 tubular IHX vessels+1 compact IHX vessel*	*1 compact IHX vessel*
Primary helium services system	*Yes*	*Yes*	*Yes*
Secondary HTS Capital Costs	120.5	326.7	176.7
Secondary coolant circulators	*None*	*2x 16 MWe*	*None*
Secondary hot gas ducts	*Yes (up to isolation valves)*	*Yes (up to SG)*	*Yes (on process heat side - up to isolation valves)*
Secondary hot gas isolation valves	*on PCS and H2 plant loops*	*on H2 plant loop only*	*on H2 plant loop only*
Secondary cold gas isolation valves	*on PCS and H2 plant loops*	*on H2 plant loop only*	*on H2 plant loop only*
Steam generators	*None*	*2x 306 MWt*	*2x 306 MWt*
Other SHTS equipment	*Yes*	*Yes*	*None*
Power Conversion Plant	**352.6**	**249.9**	**249.9**
Hydrogen Plant	-	-	-
Environment, Safety & Health	5.9	5.9	5.9
Security	14.9	14.9	14.9
Training	12.2	12.2	12.2
Waste Management	2.3	2.3	2.3

Other advantages of the conventional steam cycle over the CCGT are its simpler operability. For example, in the CCGT, control of IHX differential pressure from primary to secondary side is critical. The reliability and technical maturity of each configuration's steam cycle is high, but the CCGT's overall technical maturity and reliability rating drop due to the relatively new technology of the IHX.

Comparing the safety aspects of the direct steam cycle and CCGT - Water ingress must be considered in the development of an HTR using a direct steam PCS configuration. An initial assessment shows, however, that the event is expected to occur with manageable frequencies and the safety consequences acceptable as supported by the excellent operating history of gas-cooled reactor steam generators. Plant availability is the most realistic concern and will need to be studied in detail although risk analysis shows that water ingress events do not dominate the risk profile.

Loss of heat sink can potentially have much more serious consequences on the primary system and IHX in the absence of active and passive safety systems. However, mitigation can be efficiently provided and the event terminated by tripping the main circulator.

Going to a direct steam cycle from an indirect cycle eliminates a lot IHX-related R&D but adds some water ingress R&D. Water ingress and LOHS events can be mitigated and they will not be drivers for choice of PCS configuration.

6.0 PCS FOR COMMERCIAL APPLICATIONS

6.1 Introduction

The unique energy supplied by the high temperature reactor is available at temperatures and pressures only currently achieved by the combustion of hydrocarbons, which is an inefficient use of this valuable fuel that results in considerable pollution. If nuclear energy could replace a significant portion of industrial process heat requirements currently generated by combustion, the lifetime our petroleum reserves would increase dramatically, accompanied by an equally dramatic decrease in the emissions of the following toxins: sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), particulates, and volatile organic compounds (VOCs). In addition to displacing as much industrial combustion of fuel as possible, the process heat available from a high temperature reactor can be used to upgrade hydrocarbons so that the resulting fuel product releases fewer emissions when consumed by the end user, mainly the transportation industry.

The power conversion system is the link between the high temperature reactor and the consumer application, and ultimately dictates the overall efficiency and operability of the installation. For this reason, very careful consideration of the application's requirements and constraints on the incoming energy needs to be prioritized. The continuing analysis of this part of the system can ensure the successful integration of this technology into the marketplace.

6.2 Purpose

Pairing the vast energy available from high temperature reactors with the specific requirements of energy intensive industries is the key to commercial success of this new technology. Many industries have considerable investment in their current facilities, and shifting to a new technology requires a clear and feasible path forward. The power conversion system is the interface between the high temperature reactor and the industrial process, and this interface must be optimized to each commercial application. Identifying the key factors in configuring the

PCS to align with the customers' needs and existing constraints is another step along the clear and feasible path forward.

The energy demands of major industrial processes are of great interest to many, and the quantity of material available on this topic is vast. One of goals of this report is to make sense of this data and identify the most promising commercial applications that utilize the different facets of the HTR capabilities, including high quality steam production, efficient electricity production, and revolutionary very high temperature process heat to 900ºC. This report aims to target these applications and present a power conversion system uniquely tailored to each. The specific requirements and constraints for the selected applications are examined and provide the bases for the recommended configurations. The resulting material provides the HTR designers with a more complete picture of the topics that affect the requirements for the reactor, and the power conversion system in particular. Another important function this work needs to accomplish is to illustrate to potential industries just how adaptable and reliable this technology is. Finally, this report serves to illicit innovation and to add to the wide body of existing, future, and previously unidentified applications of nuclear process heat.

6.3 Methodology

The process to configure a power conversion cycle for an HTR for several commercial applications begins with a careful examination of energy use in general, both in the U.S. and world wide. Several sources were employed to this end, including the EIA, the IEA, and several industrial journals. After framing the main energy supply and demand structure, the next step was to gather more detailed information for the largest consumers of energy. Several key factors were investigated for all industries, such as total market size, the desired temperature range for the process heat, electricity demands, and the size of the installation. This information was compiled into an industry matrix, and from this matrix, the most important key factors were identified. Based on these factors, the industries were ranked, and the top three candidate applications were selected. For these applications, additional information was gathered concerning reliability requirements, and specific constraints related to each industry. With the application requirements identified, a PCS was configured to suit each of the three industries. Once configured, each PCS was analyzed to determine if it met the needs of the industries, for overall power, electricity, hydrogen production, water treatment, as well as for reliability and any of the industry specific constraints, factoring in considerations such as cost, efficiency, and technical readiness.

6.4 Key Assumptions

Several minor assumptions or simplifications were made regarding specific industry details that were used to calculate the amount of process heat and electricity required for various product streams. These assumptions are outlined in the associated spreadsheets.

No major assumptions were made in this section of the report.

6.5 Selecting Candidate Commercial Applications

6.5.1 Energy Supply

Table 6-1 shows U.S. and World reserves for oil, natural gas, and coal. Also included is the oil reserve life, which is the number of years it would take to consume the reserves at present production values.

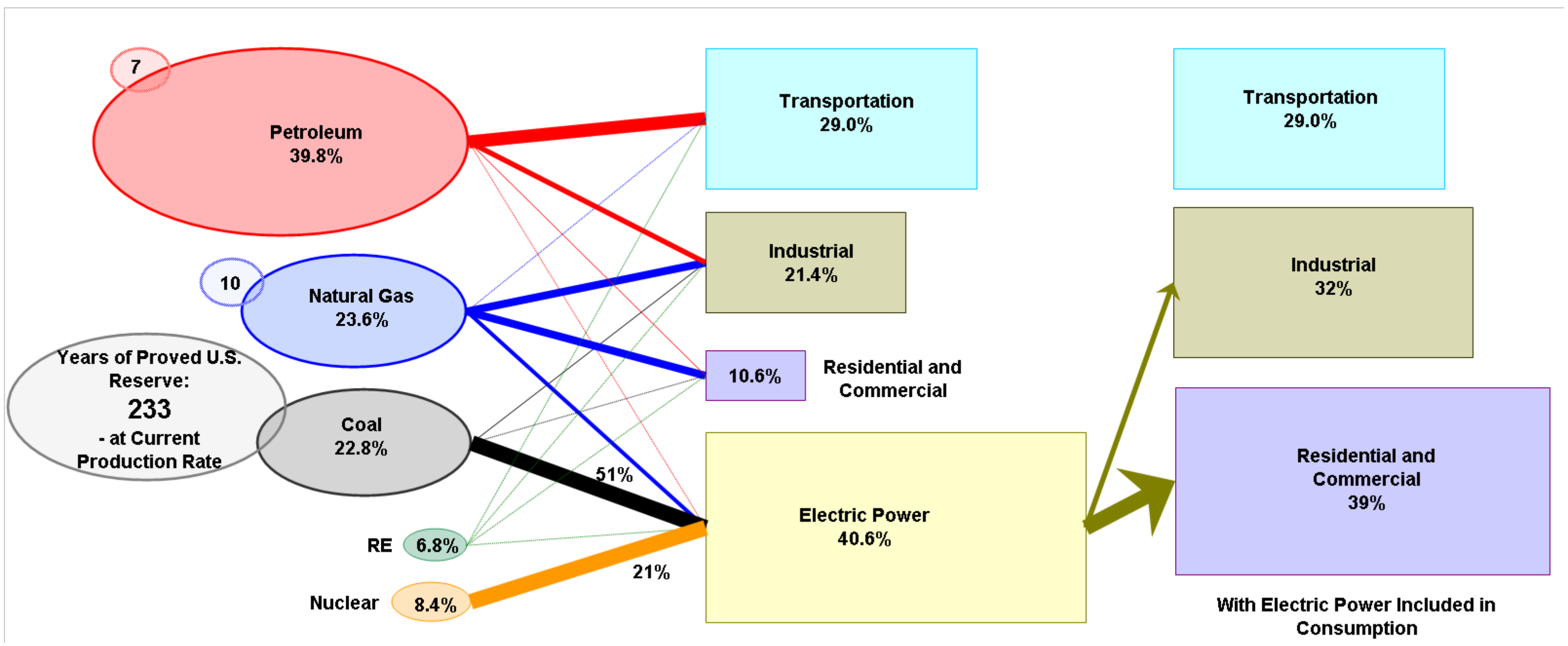
Table 6-1: U.S. and World Energy Reserves

	U.S.	% of US Reserves	World	% of World Reserves
Proved Oil Reserves [a] **(billion barrels)**	21.3	1.98%	1,240	20.17%
Oil Reserve Life [c] **(years)**	11	N/A	65	N/A
Proved Natural Gas Reserves [a] in trillion cubic feet **(equivalent billion barrels of oil)**	237.7 (45)	4.19%	6,300 (1,195)	19.43%
Proved Recoverable Coal Reserves [b] in million tonnes **(equivalent billion barrels of oil)**	246,643 (1,007)	93.82%	909,064 (3,714)	60.40%

Sources: [a] EIA 2007
[b] “BP Statistical review of world energy June 2007". British Petroleum (June 2007)
[c] Oil & Gas Journal, January, 2007
Note: The EIA publishes world energy data, but does not verify it.

6.5.2 Energy Consumption

The U.S. energy consumption by fuel is shown in Figure 6-1. It is worthy to note the disparity between the form in which energy is consumed and the form in which it is available in U.S. reserves (and world reserves shown in Table 6-1). Oil is the majority form of fuel the world consumes, but only 2% of the U.S. reserves are in the form of oil. Likewise, coal, which comprises over 90% of the U.S. reserves, only accounts for 8% of consumption.



7,644 Million Tonnes of Oil Equivalent (Mtoe) ~ 56 billion barrels

Figure 6-1: U.S. Energy Consumption by Fuel and by Sector

The next table shows the emissions associated with combustion for the refining industry. By replacing as much of the energy source for process heat, electricity, and hydrogen from combustion to HTR technology, the reduction in these emissions would be considerable.

Table 6-2: Estimated Combustion-Related Air Emissions for Petroleum Refining[a] —2002

CO2 1000 tons	SOx (million lb/year)	NOx (million lb/year)	CO (million lb/year)	Particulates (million lb/year)	VOCs (million lb/year)
278,059	5,457	2,187	129	1,563	16

[a] Includes generation of electricity

Table 6-3 presents the energy consumed as fuel by the top industries, and does not include feedstock.

Table 6-3: Fuel Consumption by Industry

Subsector and Industry	Trillion Btu	% of Total
Food	1,116	6.9%
Textile Mills	205	1.3%
Wood Products	375	2.3%
Paper	2,361	14.5%
Petroleum and Coal Products	3,202	19.7%
Chemicals	3,769	23.2%
Plastics and Rubber Products	348	2.1%
Nonmetallic Mineral Products	1,052	6.5%
Primary Metals	2,123	13.0%
Fabricated Metal Products	387	2.4%
Machinery	175	1.1%
Computer and Electronic Products	200	1.2%
Transportation Equipment	424	2.6%
Total	16,276	

Table 6-4 shows industrial fuel consumption for heat, power, and electricity that is either purchased or transferred from offsite. These values do not include onsite electricity generation, such as cogeneration and generation from noncombustible renewable resources. The important distinction shown in this table is which energy is up for grabs for energy merchants to compete for. The surprising fact is just how much energy is produced offsite, even for industries one might expect to generate the majority of their own power and steam, such as the chemical and paper industries. Even the petroleum and coal industries purchase 40% of their heat, power, and electricity.

Table 6-4: Offsite-Produced Fuel Consumption (Trillion Btu)

Subsector and Industry	Total	% of Offsite Fuel	Electricity	Natural Gas	Coal	Other
Food	1,079	97%	233	575	184	51
Beverage and Tobacco Products	104	100%	27	46	17	9
Textile Mills	206	100%	87	74	22	15
Textile Product Mills	60	100%	17	29	Q	0
Apparel	30	100%	12	16	0	0
Leather and Allied Products	7	100%	2	4	0	0
Wood Products	198	53%	74	57	1	50
Paper	1,413	60%	245	504	234	310
Printing and Related Support	98	100%	50	46	0	0
Petroleum and Coal Products	1,290	40%	141	878	13	222
Chemicals	3,154	84%	551	1,674	314	526
Plastics and Rubber Products	347	100%	182	128	Q	4
Nonmetallic Mineral Products	960	91%	141	421	309	51
Primary Metals	1,614	76%	500	669	47	379
Fabricated Metal Products	387	100%	161	209	1	2
Machinery	175	100%	84	82	1	4
Computer and Electronic Products	200	100%	131	65	*	2
Electrical Equip., Appliances, and Components	103	100%	47	53	*	1
Transportation Equipment	422	100%	173	203	8	27
Furniture and Related Products	55	87%	24	25	1	2
Miscellaneous	71	100%	35	32	0	2
Total	11,973		2,917	5,790	1,182	1,664

Table 6-5 shows the amount of energy consumed at a single location, which is an important factor in selecting suitable candidates for a high temperature reactor because it distinguishes between industries with large sites requiring a lot of energy in a single location from those industries that are comprised of many small sites, which may not require as much energy as the HTR provides.

These values are averaged over the number of sites for a given industry, so in some cases it can mask the potential of an industry that has a high number of small sites, but a few very large ones, such as the chemical industry. According to this table, the chemical industry would appear to be a marginal market for an HTR, but in fact, the very large plants are ideal candidates for an HTR. Nevertheless, this table is a starting point to get a feel for the sizes of sites for various industries. A particularly interesting item to note in this table is the how the use by site can be very high for certain subcategories for a given industry, for example, where it is shown that newsprint paper mills consume considerably more electricity than other types of paper mills, or that any chemical plant that produces nitrogenous fertilizers is probably a very good fit for HTR technology.

Another important factor shown in Table 6-5 is the relative breakdown of energy between electricity, steam, and process heat, considering that most of the natural gas is probably consumed in furnaces.

Table 6-5: Energy Consumed per Site

Subsector and Industry	Electricity per site (MW)	Natural Gas per site (MW)	Steam per site (MW)
Paper	0	5	35
Pulp Mills	0	30	W
Paper Mills, except Newsprint	9	25	31
Newsprint Mills	59	31	W
Paperboard Mills	0	33	45
Petroleum and Coal Products	2	21	88
Petroleum Refineries	20	141	109
Chemicals	2	11	20
Petrochemicals	0	218	W
Industrial Gases	0	12	W
Alkalies and Chlorine	46	112	47
Carbon Black	3	29	0
Cyclic Crudes and Intermediates	11	39	74
Ethyl Alcohol	3	21	15
Other Basic Organic Chemicals	0	40	34
Plastics Materials and Resins	0	18	24
Synthetic Rubber	2	9	44
Noncellulosic Organic Fibers	8	21	0
Nitrogenous Fertilizers	7	358	11
Phosphatic Fertilizers	8	48	W
Plastics and Rubber Products	1	1	19
Flat Glass	6	45	0
Glass Containers	7	28	0
Primary Metals	0	6	45
Iron and Steel Mills	8	30	61
Electrometallurgical Ferroalloy Products	27	16	W
Alumina and Aluminum	0	10	92
Primary Aluminum	0	15	W
Transportation Equipment	0	1	11
Light Trucks and Utility Vehicles	13	29	11

Note: W = Withheld by EIA to avoid disclosing data for individual establishments.

The last table presented in this section shows how various industries use energy as a feedstock to produce their final product. It is not very surprising to see that over 50% of the energy consumed by the petroleum industry is used as feedstock, given that the final product is itself fuel. What is surprising is that this number isn't higher, which highlights two points; first is that half of this valuable resource is being consumed by refining, and the second point, made even more evident by the following entry in the table, is that over half of the vast amount of energy consumed by the chemical industry is in the form of feedstock, which may be even more challenging to replace in the future than energy. 36% of total industrial energy use is for feedstock, which is an excellent reason to replace as much hydrocarbon combustion with alternative energy sources as early as possible, to ensure adequate supplies of durable goods for generations to come.

Table 6-6: Energy as a Feedstock

Subsector and Industry	Feedstock Trillion Btu	Total Energy Trillion Btu	% as Feedstock
Petroleum and Coal Products	3,689	6,799	54%
Chemicals	3,750	6,465	58%
Petrochemicals	939	889	106%
Industrial Gases	26	204	13%
Alkalies and Chlorine	W*	191	0%
Carbon Black	59	88	67%
Other Basic Inorganic Chemicals	27	218	12%
Cyclic Crudes and Intermediates	29	99	29%
Other Basic Organic Chemicals	937	1,833	51%
Plastics Materials and Resins	1,355	1,821	74%
Synthetic Rubber	6	57	11%
Nitrogenous Fertilizers	295	497	59%
Phosphatic Fertilizers	12	38	32%
Primary Metals	646	2,120	30%
Iron and Steel Mills	502	1,308	38%
Electrometallurgical Ferroalloy Products	3	27	11%
Alumina and Aluminum	122	473	26%
Primary Aluminum	117	325	36%
Nonferrous Metals, except Aluminum	7	101	7%
Iron Foundries	6	87	7%
Electrical Equip., Appliances, and Components	69	172	40%
Total	8,189	22,666	36%

Note: * Value was not reported for proprietary reasons

The final sector to be considered for an HTR is the transportation sector. There are multiple ways in which HTR technology can serve the transportation sector. One of these ways is to improve the efficiency of refining petroleum to provide a better conversion rate than 50%, and to generate cleaner burning fuel. A second way is to use the HTR to produce hydrogen efficiently. There are several technologies under development that use very high temperatures, in excess of 800ºC, to produce hydrogen at much greater efficiencies than is currently achievable on a commercial scale. These technologies include high temperature electrolysis (HTE), the sulfur-iodine (SI) process, and the hybrid sulfur (HyS) process.

6.5.3 Future Market Place

The following section identifies well known future markets, and discusses some potential new areas where considerable energy may be required in the future.

The EIA shows energy consumption for the U.S. to steadily increase out to 2030, with more pronounced increases in liquid fuels and electricity.

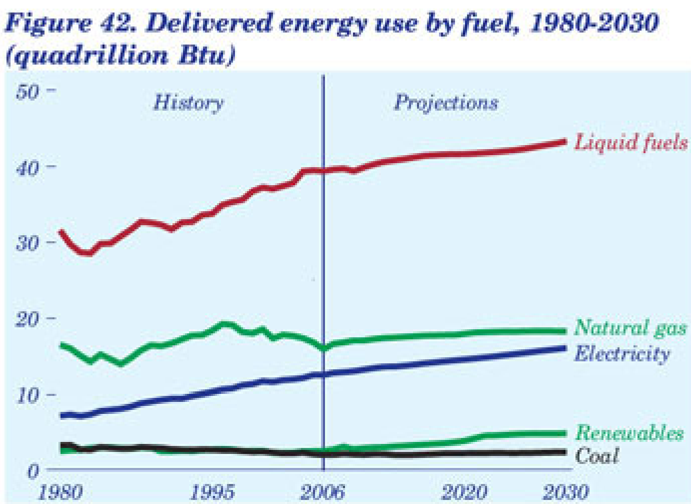


Figure 6-2: Energy Demand to 2030

Petroleum reserves are getting heavier and heavier. Lower quality crude will require more and more energy to obtain the desired end product. As air emission restrictions get tighter, additional treatment of the oil will require more hydrogen, which requires more energy.

Water treatment is not currently shown as an independent industry in the EIA's consumption tables, but with increasing populations, potential climate change, and residential and commercial development of extremely arid regions such as the American southwest and the Middle East, this will be an emerging energy intensive industry. Related topics include more sustainable food sources, and air quality.

The hydrogen economy is a tremendously large potential emerging market, and the HTR is ideally suited to meet the demands of this technology. Considerable work has already been done on this topic, so it will not be treated in this report as a stand alone industry, but will be included as a portion of the overall energy supplied to other industries.

Other emerging technologies that could alter the market place for high temperature process heat are manufacturing of new materials associated with computers and electronics. In addition, the potential is great for synthetic materials to replace existing materials requiring significant petroleum feedstocks, such as plastics.

Waste treatment using gasification or newer technologies to recapture the energy in discarded or recycled materials will grow. This market is similar, but differs from the biofuels market based on the types of materials being converted, particularly from the dismantling of obsolete technologies such as personal vehicles, computer components, and building materials from poor quality construction.

Other areas that could possibly use very high temperature process heat if the technology matures include mass transit, heating of commercial and residential buildings (from a novel concept study by the Germans of a heat transport mechanism using a set of chemicals that require incredible heat input to produce in isolation in one location, which then release that energy when recombined in a new location).

It should also be considered that once industry has access to a constant supply of steam it will soon identify and implement other technologies and upgrades which were previously unattractive due to high steam consumptions, such as using more catalysts which can easily be regenerated with an ample steam supply.

Eventually, all of the combustion of fossil fuels to provide process heat and electricity should be replaced to preserve fossil fuels for the applications where they are the only practical fuel form to use, such as for very high temperature heat (>1500C) and for feedstock.

6.5.4 In-Depth Market Analysis

Considerable work has been done to identify potential markets for a high temperature reactor, dating all the way back to the 1970s, and many of the principles have stayed the same. In addition, there are several current reports on this topic, most notably the MPR-3181 report, *Survey of HTGR Process Energy Applications*. From information gathered from these works, the industry energy data presented in the previous sections, and other data available in the open literature, an industry matrix was developed to capture the most promising commercial applications and identify which factors are most relevant to the configuration of a power conversion system. Once this material was collected in one place, the factors that are most important to the successful integration of an HTR became evident.

The following table shows the key components of the industry matrix.

Table 6-7: Industry Matrix

Industry	Total Energy Consumed per Year in GW (# of HTRs)	Projected Energy Consumption to 2030 (MWth / year)	# of HTRs per Site (500 MW)	An Prod Rate: -World - U.S. - per Site	Process	Temp	Steam MWt (250C< T<550C)	Hot Gas MWt (550C<T<950C)	Electricity MWe	Hydrogen
							Per Site			
Oil Recovery										
Oil Sands	12.7 GW 30 HTRs	50-80 GW 120-240 HTRs	4+	1.75 million bpd N/A 100K bpd	SAGD	250-350C @ 8-16 MPa	1800 MWt	N/A	100 MWe	6 kg H2/bbl 1200 MWe (LTE)
					Distillation	300-400C				
					Hydrocracking	500C +				
					Hydrotreating	400-500C				
					Coking	500C				
Oil Shale	N/A	100+ GW 100s to 1000s	4+	< 1M bbl total N/A 100K bpd	Wall Conduction	340-370	N/A	N/A	1200 MWe	> 10 kg/bbl 2000 MWe (LET)
					Pyrolysis	450-500	N/A	1500 MWt	N/A	> 10 kg/bbl 2000 MWe (LET)
Chemical Industry	216 GW	187 GW	4 to 10							
Ethylene	6.6 GW	+ 5% per year (no ref. but definately not from EIA, which says its flat).	4 to 8	93 Million tonnes 21 million tonnes 1 million tonnes	Thermal Cracking	760-870°C	5-7 tons of steam / 1 ton product	2040		Some H2 is produced.
Chlorine	6 GW		0.31	150,000 tonnes / year	Electrolysis (diaphram)				133	Produces 28 kg of H2 / tonne Cl
Petroleum Refining	227 GW	234 GW	2 to 5	200,000 bpd			913		187	3 kg H2/bbl increasing 10%/yr
Coal-To-Liquid	N/A	~ 240,000 up to 1.2 million bpd	4+	160,000 bpd 0 bpd 30,000 bpd	Direct				1314	4 kg H2 / bbl
					Indirect					
Hydrogen (HTE SI)										
Paper	158 GW	160 GW 100+ HTRs	2	52 Billion tonnes 1500 tonnes / day	Gasification	600C				N/A
Biomass	biofuel mandate under EISA2007 reaches 36 billion gallons in 2022									
Metal	84 GW	85.5 GW								
Pure Electricity	12 Quads	16 Quads								
Desalination / Purification	3.6 GW for 2005 supply	5.2 GW for 2050 supply								
Cement	14 GW	14 GW								
Glass	11 GW	11.3 GW								
Computers and Electronics	6.7 GW	7.1 GW								

Another important parameter that is captured is the Reliability Requirements for each application. What are the consequences of heat loss during some of these processes? Solidification inside the equipment, considering the capital cost of the equipment and the production loss given the very high throughput of some of these processes, could result in tremendous losses. The reliability requirement pairs well with modularity of the HTR technology, which can ensure backup heat with multiple reactors. This topic is discussed in more detail in later sections.

Other categories in the matrix include Earliest Deployment Date, Specific Constraints (ex: integration of the HTR into existing sites with limited space available or low levels of technology readiness for certain processes), and Safety (ex: for the Canadian Oil Sands application: steam is released directly into the ground, so contamination leaking into the steam would be immediately released, lots of heavy machinery moving around as new wells are brought online and surface mining is conducted, lots of personnel not familiar with radiation safety, and the sites are very remote, so backup security would have to come from a considerable distance).

This big picture matrix is intended to grow and stay up to date with changes in the market place and new technologies coming online. As items pertinent to one industry are unearthed, it may trigger ideas not yet identified in other industries. It will also accommodate design factors not necessarily specific to the PCS, such as External Hazards associated with each industry that could impact containment.

6.5.5 Ranking Criteria

The following key factors were identified as being the most significant for ranking the industries:

- Market Size
- Installation Size
- Temperatures and Pressures of Various Processes
- Future Demand
- Energy Mix (Steam, Electricity, other Process Heat)
- Earliest Deployable Date

The next set of factors which were important for considering the configuration of a PCS, but not necessarily key to identifying the best candidates for this analysis:

- Reliability Requirements
- Constraints
- Safety
- Process Information

Based on Energy Use and Market Size, the top three candidates are:

- Petroleum Refining (> 6 Quadrillion BTUs)
- Chemical Industry (> 6 Quadrillion BTUs)
- Oil Recovery (> 200 Trillion BTUs)

Based on Diverse Energy Requirements, the top three candidates are:

- Petroleum Refining (over 6 major processes at T > 250°C with need for electricity and hydrogen)

- Chemical Industry (over 20 processes at T > 250°C with need for electricity and hydrogen)
- Coal and Natural Gas Derivatives (over 5 processes at T > 250°C with high need for electricity and hydrogen)

And based on Future Demand, the top three candidates are:
- Oil Recovery
- Hydrogen Production
- Coal to Liquid

Ultimately, the following three industries were selected:
- Petroleum Refining: Existing Facility
- Chemical Industry: ethylene production by thermal cracking (760-870°C)
- Oil Recovery: Bitumen recovery by SAGD and upgrading (335-550°C)

For a large complex, like an existing petroleum refinery, a suitable implementation is a cogeneration power block configuration, where the HTRs and their associated PCS equipment are situated in a given area very near, but separate from the customer site. The required steam, electricity, and/or processes heat is transported to the site by insulated pipelines and transmission lines. This type of configuration is very adaptable to existing facilities and requires very little in the way of site integration, and can be used for any existing industrial site requiring steam, electricity, and/or process heat. To illustrate this type of configuration it is featured in the Petroleum Refining application.

For the Oil Recovery market, there is a very large shale reserve in the U.S. that is estimated to have over 1 trillion barrels. However, due to the technology readiness factor, bitumen was selected for this study because of its very early deployable date, which requires no new technology other than the HTR. Because these sites are built new as crude recovery levels demand, this application also has relatively few site integration issues as compared to existing plants.

For Hydrogen production and CTL, a lot of research and analysis has already gone into these particular processes, so the scope of their evaluation in this study will be restricted to identifying the specific factors that impact the PCS and providing discussion on how these factors might influence the configuration of the PCS.

6.6 Oil Sands

6.6.1 Industry Background

The Canadian oils sands cover 80,000 square kilometers and contain 1.7-2.5 trillion barrels of bitumen, which is a naturally occurring and highly viscous hydrocarbon mixture. Some of this resource can be obtained from surface mining, but the majority can only be accessed from underground, using in-situ methods. The bitumen is too thick to recover using conventional oil wells, and one of the most common extraction methods is steam assisted gravity drainage (SAGD), where steam is injected into the ground to heat the bitumen to allow it to flow. Once recovered, the bitumen is often upgraded on site. The upgrading process involves heating the bitumen to break down the large complex carbon chains and adding hydrogen to produce "synthetic crude" which is then sent on to refineries just like conventional crude oil.

Current sites are generally centered around a central processing facility (CPF) that generates steam which is piped up to 10 km to the injection wells, and the extracted bitumen/water mixture is returned to the CPF for separating and upgrading. The SAGD process generally uses between 2 to 4 barrels of steam to extract a single barrel of bitumen. Currently, this water is obtained from the nearby Athabasca River, and some is treated and recycled.

As production increases from the current rate of 1 million barrels per day to the projected 4-6 million barrels per day, the need for water treatment will become even more significant.

6.6.2 Central Processing Facility Implementation

The area serviceable by a CPF is restricted by the distance that steam can be transported while retaining the necessary heat. However, with high temperature and pressure steam available from an HTR, this radius could potentially be extended to 30 km, as shown in the next section. Additionally, the constraint on piping distances applies only to the steam, not the returning bitumen/water mixture, so it would be feasible to have a main CPF where the upgrading and water treatment is carried out for a much larger area. The bitumen could be piped from surrounding "satellite" recovery sites to the main CPF for upgrading, and the waste water could be treated and then piped back.

Each satellite site would only require the energy needed to produce the injection steam for its given radius, and the relatively small size and modular configuration of an HTR makes it an ideal candidate for distribution over a wide area of varying bitumen densities. Areas very rich in bitumen, capable of producing 100,000 or more bpd in less than a 10 km radius may require four or more HTRs, while less abundant sites only capable of 20,000 bpd can be serviced by a single HTR.

In addition to eliminating redundant equipment necessary for upgrading and water treatment, this kind of configuration also addresses reliability concerns. The reliability is very high for the upgrading processes, and loss of heat to the upgrading equipment would likely results in total equipment loss. The reliability for steam to the injection wells is not as high, and though not desirable, heat loss would only result in slower recovery.

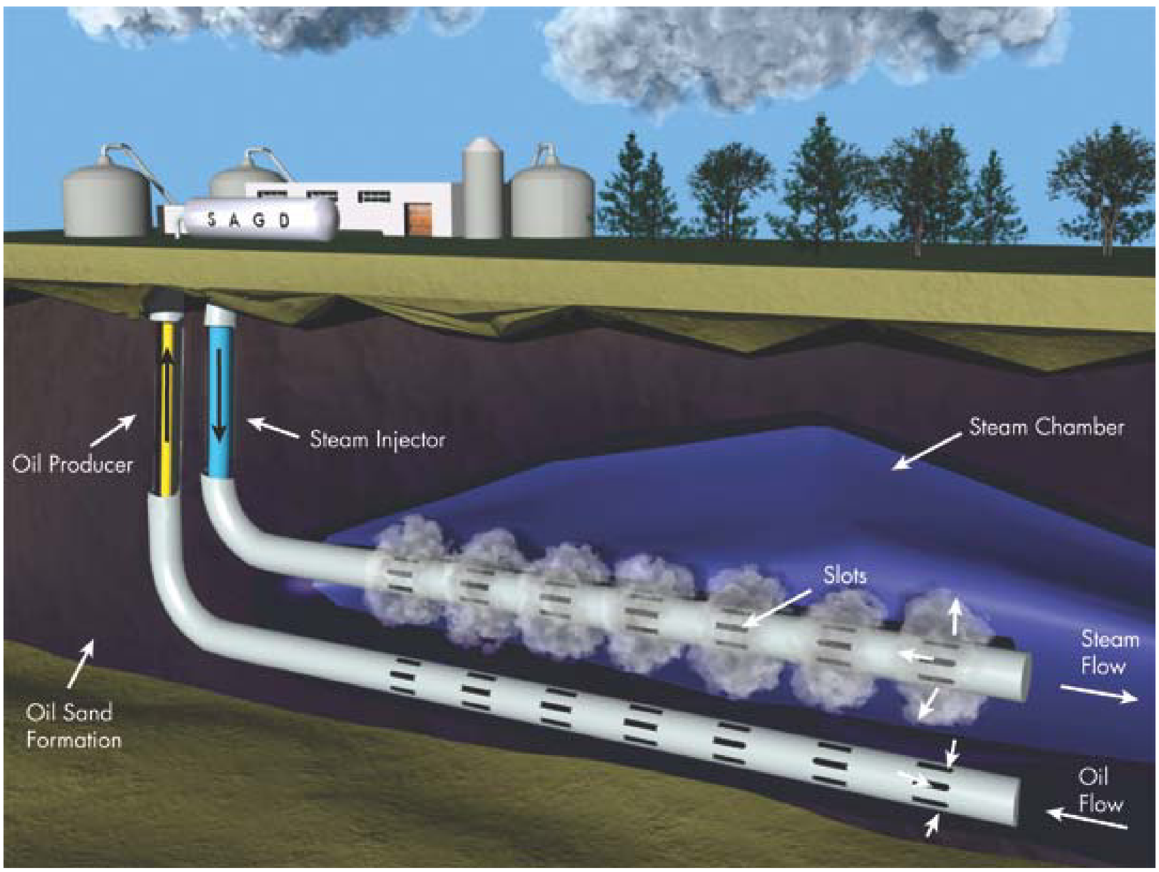
This study explores the implementation of HTR technology to a high density area with a main CPF capable of handling 100,000 bpd of recovery, upgrading and water treatment capacity. An additional analysis considers a satellite site with a 20,000 bpd recovery capacity.

6.6.2.1 Central Processing Facility Components

The central processing facility provides energy for the injection wells, the upgrading plant, the hydrogen plant, and the water treatment plant, in the form of steam and electricity. Each of these components is described in the following sections.

6.6.2.2 Injection Wells

A steam assisted gravity drainage (SAGD) well produces between 500 and 1000 barrels of bitumen per day, which would mean that a 100,000 bpd facility could have up to 200 wells operating at once. The wells are usually about 300 m deep, and extend out laterally up to 1200 m. The injection wells are shown in Figure 6-3 and Figure 6-4.



SOURCE: J&W COMMUNICATIONS, THE PEMBINA INSTITUTE.

Figure 6-3: Steam Assisted Gravity Drainage (SAGD) Well Pair

SOURCE: PETRO-CANADA

Figure 6-4: Injection well

A well pad occupies approximately 4 hectares (10 acres) and can contain as many as 17 wells, which are spaced as close as 10 meters apart. Steam is transported from the CPF to the well pads through an insulated 24-inch pressurized pipe. The recovered bitumen and water mixture is transported back to the central processing facility in a 30-inch pipe.

6.6.2.3 Long Distance Piping of HP Steam

This section evaluates the possibility of using a pipeline to supply superheated steam from the NGNP to injection wells located up to 30 km away. The evaluation models pressure loss and heat conduction with convective boundary conditions for an insulated pipeline carrying steam from the NGNP site to the delivery point. The pressure loss methods follow ORNL/TM 7983 while the heat conduction methods come from Glasstone (1955).

The total length of the steam pipe is divided into segments of 100 m as shown below:

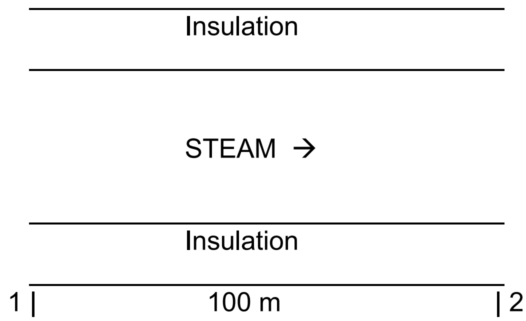


Figure 6-5: Insulated Steam Pipe – 100 m

Pressure losses due to friction and heat losses due to conduction, convection, and thermal radiation to the environment are calculated for each segment, starting with the segment closest to the source. Steam properties are calculated at point 2 for each segment and then used as the point 1 conditions for the next segment, and so on. The equation used to calculate the pressure loss is completely general and holds for both compressible and incompressible flow in pipes of constant cross section under the following conditions: (1) temperature can be determined at every point along the pipe and (2) $dp/dx = p_2 - p_1$ is negative for every segment along the pipe.
The equation for pressure loss (ORNL/TM 7983, p. 3) is:

$$p_1 - p_2 = 2 [G^2 / (2g_c)]\, v_1 (v_R - 1) + f [L / D] [G^2 / (2g_c)]\, v_1 \phi (v_R + 1)$$

where

p_1 and p_2 = pressure at locations 1 and 2
G = mass velocity = V/v = constant
g_c = conversion constant = 1 kg-m/N-s^2
v = specific volume of steam
$v_R = v_2 / v_1$
ϕ = averaging factor = 0.5
f = friction factor = 4(0.0027)(1+3.6/D) where D is in feet
L = pipe length
D = pipe inside diameter
V = velocity
T = temperature

Pipe elbows and fittings cause pressure drops that are usually estimated by using empirical correlations of test data. Since the number and nature of such fittings are not yet known for this pipeline, an approximation of their pressure losses is made by adding 25% to the actual pipe length.

For the heat loss part of the evaluation, the physical system consists of the insulated pipe with convection at the interior and exterior surfaces. The boundary conditions as the outer surface of the pipe determine the heat transfer coefficient, which follows the thermal circuit concept. These calculations use an insulation thickness of 10 cm and a pipe wall thickness of 4 cm. For the purpose of these calculations the metallic pipe wall can be ignored in the thermal circuit since its thermal conductivity is much larger than that of the insulation.

The equation for the temperature difference from the inner wall of the pipe to the outer wall (outer surface of the insulation on the outside of the pipe) is:

$$T_i - T_o = Q / (2 \pi r' U_{r'})$$

where

T_i = inner wall temperature
T_o = temperature at the outer surface of insulation on the outside of the pipe (0 °C assumed)
Q = heat loss (W per m horizontal length of pipe)
$U_{r'}$ = heat transfer coefficient (W m^{-2} °C^{-1})
r' = radius from the center of the pipe to the outer edge of the insulation

The following equation determines $U_{r'}$:

$$U_{r'} = 1 / [(r'/(h_s r) + (r'/k_i) \ln (r'/r) + 1/h_a] \text{ W m}^{-2} \,^{o}\text{C}^{-1}$$

where

h_s = heat transfer coefficient for steam (assumed 12,000 W m^{-2} °C^{-1})
r = inner radius of pipe
k_i = thermal conductivity of the insulation (assumed 0.1 W m^{-1} °C^{-1})
h_a = heat transfer coefficient for air (assumed 100 W m^{-2} °C^{-1})

The calculation ignores wind, temperature lapse rate, humidity, and other atmospheric effects on h_a since the value chosen should maximize convective heat loss under the most severe combinations of atmospheric effects.

Five cases are evaluated for the source conditions, pipeline diameters, and pipeline lengths shown in the following table:

Table 6-8: Pipeline Cases

Case	Pressure (MPa)	Mass Flowrate (kg/s)	Temperature (^oC)	Diameter (cm)	Length (km)
1	12	400	400	61	16
2	12	500	400	61	16
3	12	750	400	80	16
4	12	1000	400	97	16
5	14	400	400	61	30

The following figure shows the steam line pressure as a function of length along the line for Cases 1-4.

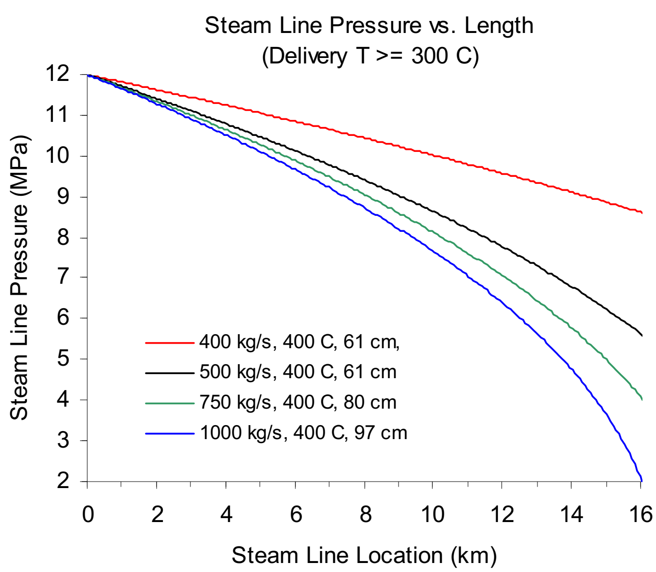


Figure 6-6: Steam Pressure Along Pipeline for Four Flowrates

The next figure shows the steam line pressure as a function of length for Case 5 with Case 4 also shown for comparison.

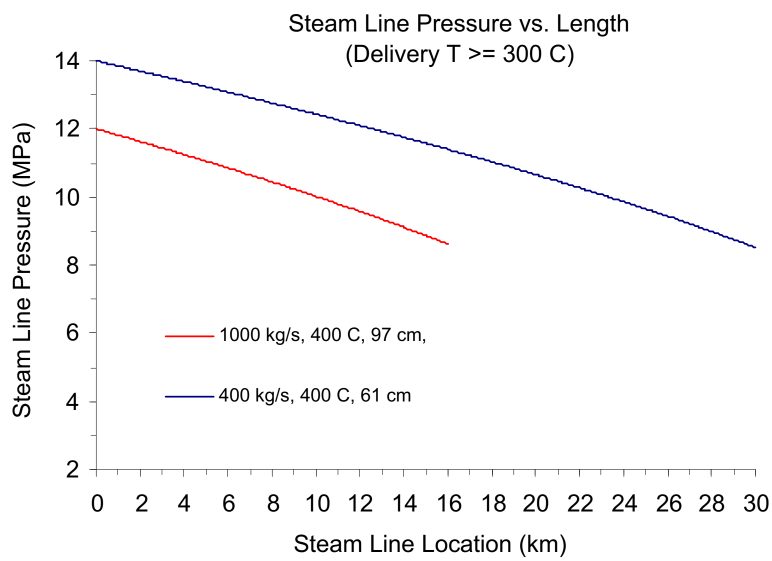


Figure 6-7: 12 MPa and 14 MPa Starting Pressures

The delivery point temperatures for each case are as follows: Case 1 (371 ^{o}C), Case 2 (375 ^{o}C), Case 3 (387 ^{o}C), Case 4 (392 ^{o}C), Case 5 (353 ^{o}C).

6.6.2.4 Upgrading Plant

The upgrading plant receives the water bitumen mixture and ultimately converts it into synthetic crude oil (syncrude). First, the water bitumen mixture is separated, and the water is transported to the water treatment plant, while the bitumen goes to a distillation column where it is mixed with steam and separated into its various components by their boiling points. The heavier fractions go to a hydrocracker, where they are heated to a very high temperature in the presence of excess hydrogen. The products from the hydrocracker go through another distillation process and the middle fractions from the both distillation columns are then hydrotreated to saturate the molecules with hydrogen remove impurities such as sulfur and nitrogen. The product from the hydrotreater and the lighter fractions from the various distillation processes are then blended and ready for shipment to a refinery.

All of these upgrading processes require energy, which is supplied by the HTR in the form of steam or electricity. High, medium and low pressure steam is used indirectly to heat product streams to temperatures as high as 400C. Steam is also fed into the distillation columns where it mixes with the product. The steam consumed in the product stream is later separated and sent to the water treatment plant.

6.6.2.5 Water Treatment Plant

There are various methods of treating produced waters, such as the traditional treatment of warm or hot lime softening, filtration, and weak acid cation exchange, but the method selected for this analysis is falling film evaporation, which produces a much higher-quality boiler feed water and minimizes the disposal of water and sludge. The produced waters from the various product streams are fed into the vertical shell and tube evaporator and pumped up to the top of the tubes, where if flows down in a film on the inside of the tubes, which are over 30 m long. Steam flows on the shell side, and as the produced waters are vaporized, the clean distillate is drawn out and the brine solution is concentrated, producing a very small (or sometimes non-existent in the case of ZLQ) liquid waste stream. The pressure inside the tubes is 2 kPa above atmospheric, and 30-35 kPa above atmospheric.

6.6.2.6 Process Requirements

To recover 100,000 bpd day of bitumen, 300,000 bpd of steam is required (volume refers to the liquid volume), which equates to a 550 kg/s steam flow rate. The steam conditions at the injection well vary depending on the geology of the area, and more fragile formations require lower pressure steam. In general, the desired conditions are pressures between 8 and 16 MPa and temperatures between 250 and 350C with a quality greater than 80%. Because the steam may need to travel up to 10 km in a pipeline, the goal for this analysis will be to produce superheated steam at 400C and 18 MPa. Superheated steam does not transfer as much heat as steam near saturation, so transporting superheated steam will result in smaller heat losses along the pipeline. The process heat requirement for these steam flow rates and conditions is 1800 MWt. The electricity requirements for recovery are 37.5 MWe, which are relatively small and are for pumping the bitumen / water mixtures from the wells back to the CPF.

The upgrading requirement for process heat for a 100,000 bpd facility is 1800 MWt and includes steam to heat various process streams and to interact with some of these streams. The overall requirement for upgrading though is dominated by the need for hydrogen, up to 6 kg per barrel of bitumen. Ideally, this requirement would be met with very efficient technology such as high temperature electrolysis, however, for this analysis that demonstrates an early deployable configuration, low temperature alkaline electrolysis was selected, which takes 45 MWe per tonne of hydrogen. The electricity required to produce hydrogen is 1,125 MWe and another 50 MWe is required for other upgrading processes. It is anticipated that later installations of HTRs at the Oil Sands will utilize the more efficient hydrogen producing technology, and when this technology comes online, it may be feasible to extend the main CPF upgrading capacity even further to upgrade the majority of the oil sands bitumen at a single location.

The water treatment requirements are for electricity to treat produced water using falling film evaporation, which is a process currently in-use in the Canadian Oils Sands and produces zero liquid discharge. The water treatment plant requires 70 kWh per 1000 gallons of water treated, which is equivalent to 32 MWe to treat the produced water resulting from the recovery and upgrading of 100,000 barrels of bitumen.

To meet the MWt and MWe requirements for recovery, upgrading, and water treatment for a 100,000 bpd central processing facility, 7 HTRs are needed.

6.6.2.7 Configuration

The following figure illustrates the power conversion system for the 100K bpd recovery, upgrading and water treatment central processing facility.

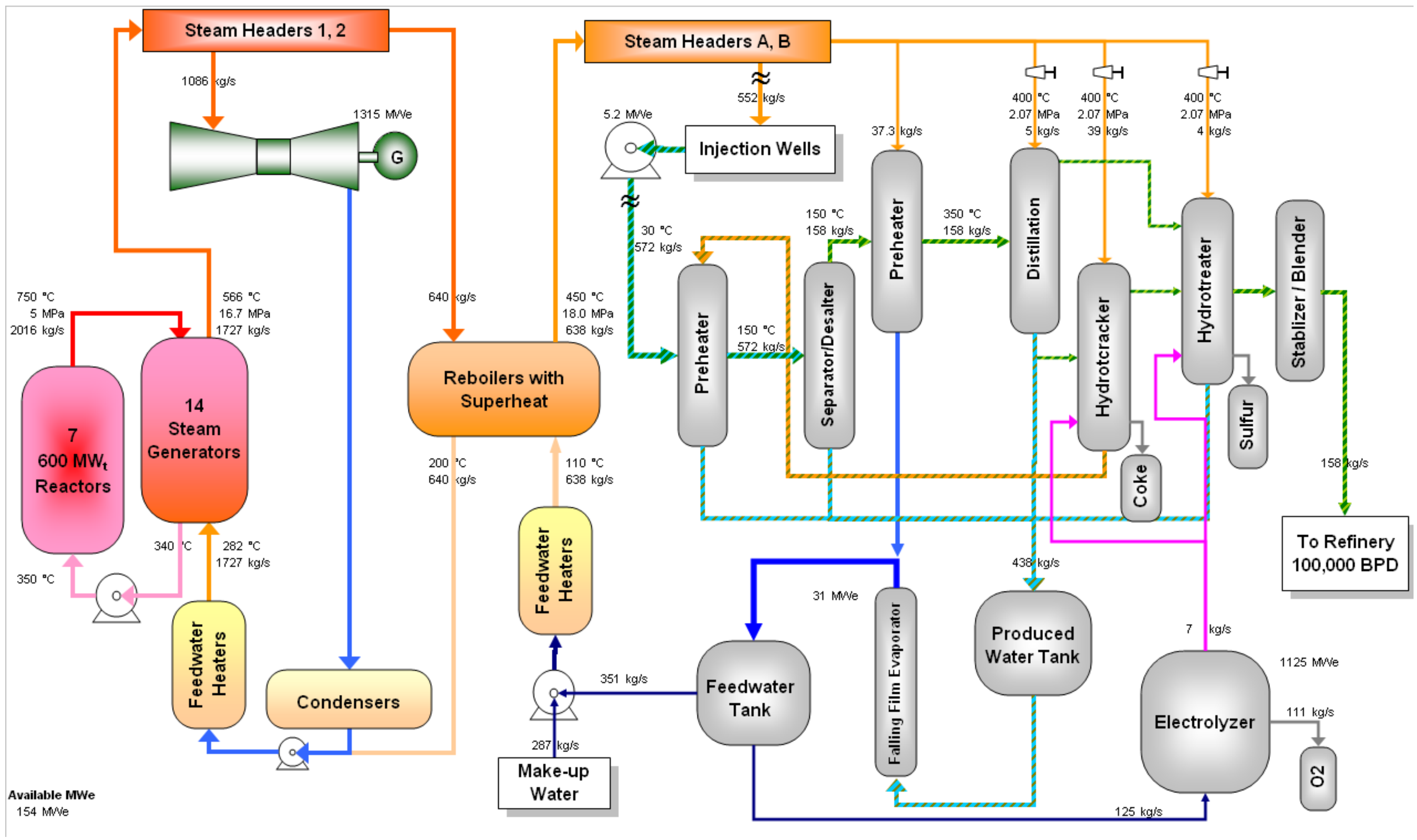


Figure 6-8: Oil Sands Power Conversion System

The two steam loops are shown in Figure 6-9. The first steam loop transfers heat from the primary steam generators to steam headers 1 and 2, which supply steam to a turbine and two reboilers. Low pressure steam supplies heat to the feedwater heaters. The first steam loop is a closed loop, and all of the condensate from the turbine and reboilers is returned to the main steam generator.

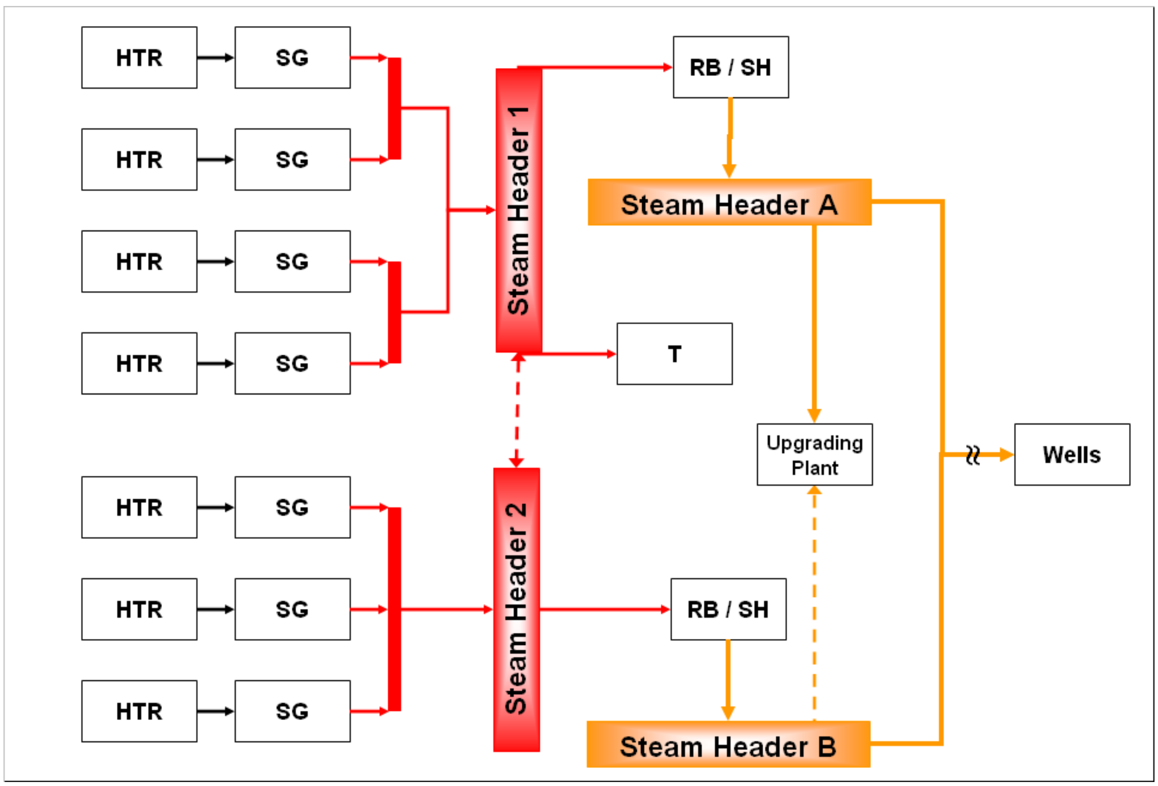


Figure 6-9: Oil Sands Steam Headers

The second steam loop provides high pressure steam for the injection wells and some upgrading processes. Process steam is controlled by throttle valves as needed for processes in the upgrading plant, hydrogen plant, and water treatment plant. The second steam loop is an open loop, and as much water as possible, from the various processes is sent to the water treatment plant and routed back to the reboilers, but some water is lost to the processes and a water make-up stream is necessary.

6.6.2.8 Reliability

A 100,000 bpd facility requires 7 HTRs, half for upgrading, hydrogen production, and water treatment, and the other half for the injection wells within a 10-20 km. Each HTR has its own dedicated steam generator in the primary loop, and each steam generator feeds one of two primary steam headers; these are Steam Header 1 and Steam Header 2, shown in Figure 6-9. These headers provide what is referred to in this document as “first steam”, which means it is the first *steam* loop (the real primary loop being helium between the reactors and steam generators).

The solid lines represent the main piping scheme, and the dotted lines illustrate the backup piping, which provide options for ensuring that all critical systems receive the required heating or cooling during both normal operations and under any transient condition. The backup piping from the steam generators ensure that if one of the first steam headers is down for service or fails, the steam could be routed to the other first steam header and then back to the designated component. This piping scheme would allow for scheduled outages for up to two HTRs and still maintain heating and cooling if an additional two reactors tripped. If any of the components receiving steam from Steam Header 1 or 2 went off-line, either scheduled or not, that steam could be routed to the turbine. If the turbine went off-line, the steam consumption by all of the other components would be sufficient for cooling until the turbine could come back on-line.

The reboilers take heat from the first steam (Steam Headers 1 and 2) and generate steam for the second set of steam headers, Steam Header A and Steam Header B, as shown in Figure 6-9. The steam for Steam Header A and B is referred to as second steam because it is in second steam loop (actually in the tertiary loop with the primary loop being helium). Steam Headers A and B each provide high pressure steam for the injection wells and for various upgrading processes. Medium and low pressure steam can be obtained from the high temperature and pressure steam headers using throttle valves. As with the first steam loop, the main piping is shown in solid lines and the backup piping in dotted lines. The backup piping ensures that even during normal operations and transient conditions, sufficient steam will be supplied to the various processes. Of the processes consuming the second steam, only a fraction of the upgrading processes require a very high level of reliability, to ensure that the product does not solidify or coke in the various pieces of equipment. This reliability is met with two or more sources of steam, and backup piping to these key pieces of equipment.

6.6.3 Satellite Site Implementation

For smaller capacity satellite sites producing 20,000 bpd or less, the HTR only needs to provide steam for the injection wells, and therefore has a much simpler power conversion system, as shown in Figure 6-10. The HTR provides high temperature helium to a steam generator, which provides high temperature, high pressure steam to the reboiler to generate steam for the injection wells.

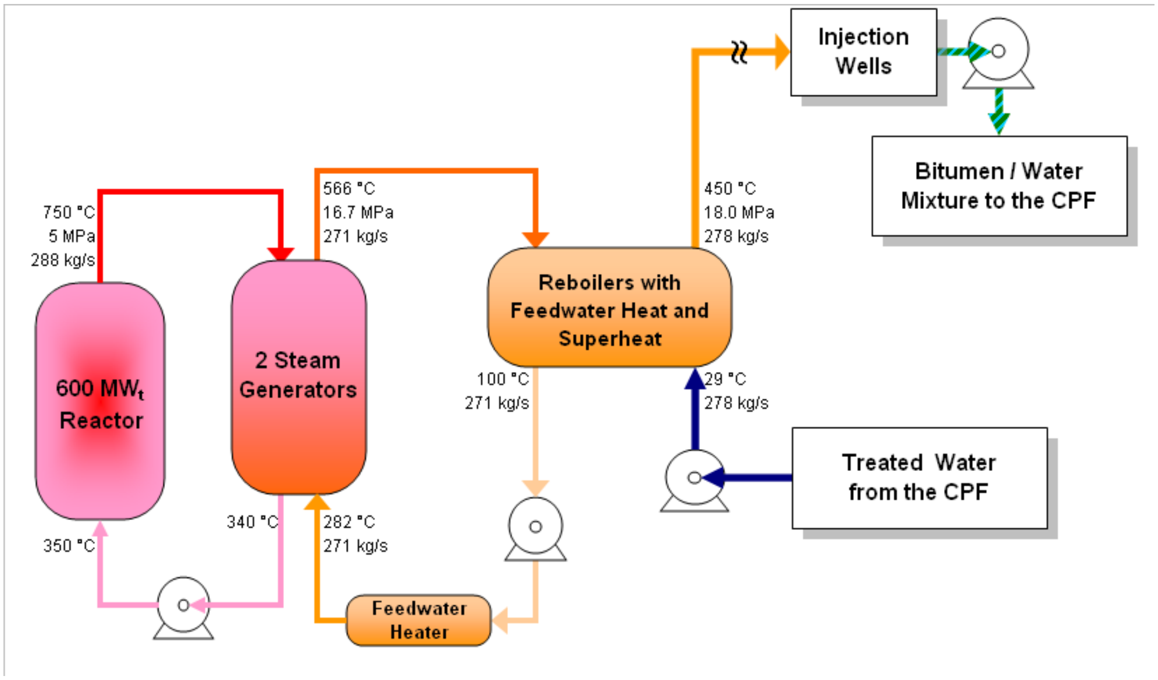


Figure 6-10: Satellite Site PCS

A satellite site does not have nearly the same requirement for reliability, and a single HTR could service a site, with the only consequence to heat loss being an interruption in the bitumen warming process. In most cases, this interruption would simply be tolerated because the consequences of a relatively short period without steam would not warrant the expense of supplying backup systems. If oil demand were particularly high, and such an interruption were not tolerable, this size site could use bitumen fired boilers during these intermittent periods when the HTR, steam generator, or reboiler are down for servicing or for some unscheduled event. Most sites are larger than 20,000 bpd, and these sites would have the redundancy of 2 or more HTRs, depending on the size, and these sites, like the CPF, could have redundant piping to ensure that process steam was always available.

The NGNP is ideally suited to provide the flexibility to placing a single 600 MW reactor in less bitumen-rich regions, where it would not be cost effective to locate larger reactors.

6.7 Combined Heat & Power Block: Petrochemical Plant

A CHP, or cogeneration implementation of HTR technology locates the HTRs and their associated PCS equipment in a given area which is near, but separate from the customer site. The required steam, electricity, and/or other processes heat is transported to the site by insulated pipelines and transmission lines. This type of configuration is very adaptable to existing facilities, requiring very little in the way of site integration, and can be used for any existing industrial site requiring steam, electricity, and/or process heat. To illustrate this type of configuration it is featured in the Petroleum Refining application.

6.7.1 Industry Background

As described in Section 5.2, the refining industry uses vast amounts of energy producing fuel and other products from crude oil. The following figure shows the main processes involved in refining.

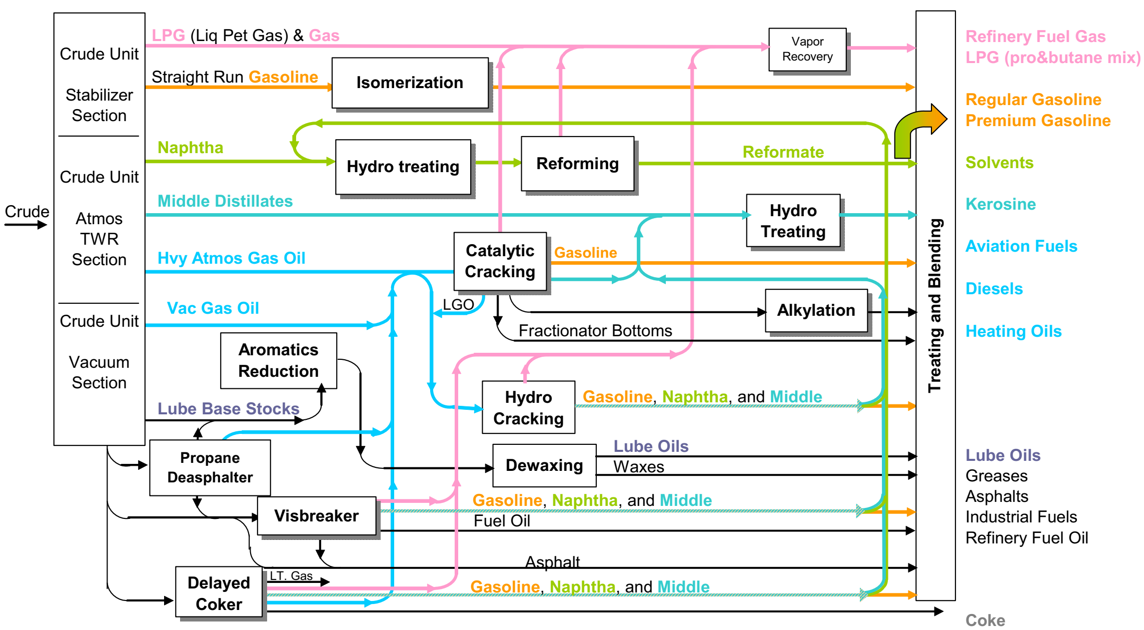


Figure 6-11: Refinery Process Flow Diagram

Crude oil is a complex mixture of hydrocarbons that also contains small quantities of nitrogen, sulfur, and very small quantities of metals like iron and nickel. Each barrel of crude is first fed into a distillation column, where steam is added to heat and separate the various components by their boiling point. The larger and more complex the hydrocarbon, the more processing and therefore energy is required.

The lighter fractions, those with lower boiling points, are drawn off the top and either recovered or sent on for additional light processing which rearranges molecules to increase the octane of the final product. The next lightest fractions from the column are hydrotreated to remove the sulfur and nitrogen by reacting them with hydrogen to form H_2S and NH_3. The sulfur and nitrogen are removed to provide a cleaner-end product fuel that will not emit the pollutants SO_2 or NO_2 when combusted, and also to prevent poisoning of the catalyst in the next processing step, which is reforming. Reforming uses a catalyst to rearrange the hydrocarbons from straight chains into more valuable rings, which increases the octane level.

The lightest of the heavier fractions from the column require significantly more energy to produce the final desired products. These fractions are sent to a catalytic cracker, where the stream is raised to a very high temperature, between 400-500ºC, and the large, complex, hydrocarbon molecules "crack" or break into smaller molecules. Then the stream follows a similar path to the lighter distillate fractions gets hydrotreated and reformed as needed. The next heaviest fractions go to a hydrocracker, where the molecules are cracked in the presence of hydrogen (additional energy input), and a catalyst, and then on to hydrotreating and reforming as needed.

The very heavy fractions are treated based on the desired end product, and may be subjected to various processes to obtain lubricants, asphalt, or coke.

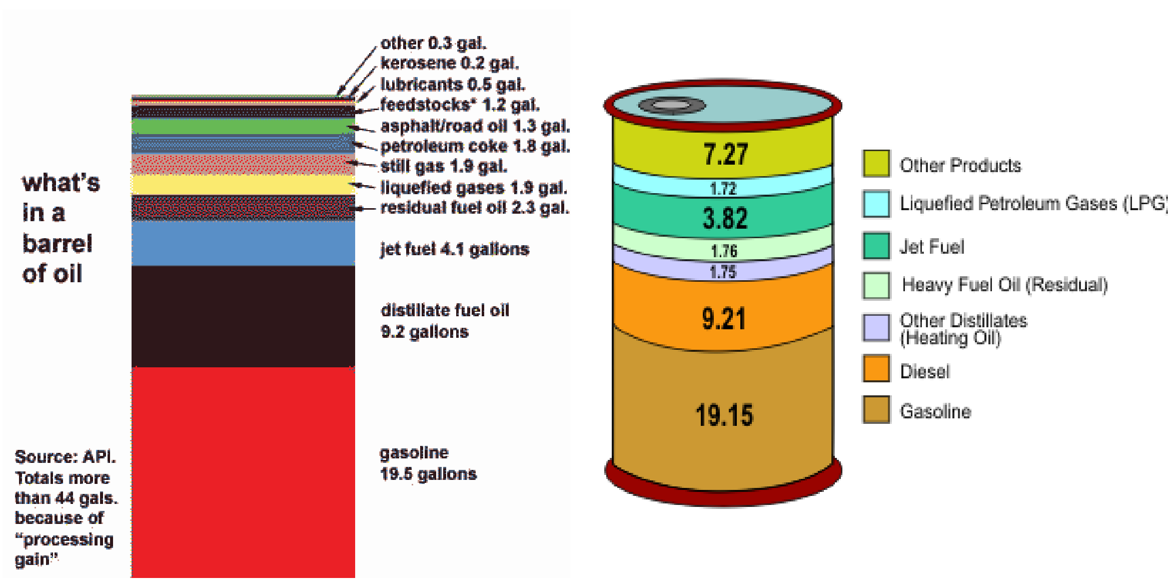


Figure 6-12: Variations in a Barrel of Oil

As shown in Figure 6-12, each refinery produces its own set of finished products and has its own way of doing things. In the first HTR implementation for refining, a more generic power block arrangement is explored. This configuration uses HTRs to generate a variety of process heat streams and electricity. This particular implementation is sized to meet the needs of an existing refinery with a 500,000 barrel per day capacity. This type of configuration could be used at many facilities requiring process steam and electricity. The second refinery implementation examines the use of very high temperature streams (500-850ºC) for specific processes that could be reconfigured to utilize HTR process heat instead of the combustion of fossil fuels.

6.7.2 Power Block Implementation

A series of high temperature reactors could be configured as a power block, where the HTR and its associated equipment are situated in one area, adjacent to the customer facility. The process heat and electricity from the HTR would be integrated into the existing facility by means of steam headers and power lines. This type of configuration could meet the needs of many existing facilities, whether it's an oil refinery, a chemical plant, or some other type of manufacturing. Though this type of configuration may not optimize the true potential of a high temperature reactor, the considerable benefit it provides is a relatively straightforward integration with an existing facility.

As was stated earlier, no two refineries are alike, so for the purposes of illustration, this section will look at a representative refinery, with process capacities that correspond to the U.S. national production capacities, that is scaled to a 500,000 barrel per day facility. The following table includes the main refining processes with their energy consumption on a per barrel basis.

Table 6-9: Energy Requirements for Refining Processes

Process	Process Temperature	Barrels / Day	Electricity (kWh / bbl)	Steam (lb / bbl)	Hydrogen (scf / bbl)
Atm Distillation	400ºC	500,000	0.9	10	0
Vac Distillation	400-500ºC	225,095	0.3	10	0
Reforming	500-550ºC	117,605	3	30	-1100 to -1700[a]
Hydrotreating	250-400ºC	431,943	3	8	800 to 1000
Catalytic Cracking	480->800 ºC	191,270	6	-30[b]	0
Alkylation	< 30ºC	37,678	4	25	0
Hydrocracking	290-400ºC	49,795	13	75	1500
Visabreaking	400-500ºC	552	.2	10	0
Delayed Coking	500ºC	70,692	30[c]	700[c]	0

Note: [a] Reforming produces hydrogen, so its hydrogen consumption number is negative.
[b] Catalytic Cracking produces steam, so its steam value is negative.
[c] These values are per tonne of coke produced.

The HTR can supply the needed electricity and steam described in Table 6-9. This steam is fed into the various processes along with the crude feed. For obvious reasons, this steam would not be returned to the steam generator. Some of this water is treated and recycled, but it would not be economically feasible to treat this water to steam generator standards. Therefore, this steam is provided in an open loop, and water returning from a treatment facility would be converted to steam in a reboiler, which does not have the same stringent requirements for water quality.

The HTR can also supply a good portion of the heating that is currently achieved by combustion of fuel in furnaces, thereby reducing the overall quantity of fuel consumed. To be consistent with the easy integration approach, the existing furnaces will still be a part of the process, but they will receive the feed already heated to maximum extent possible (up to 500ºC, or just shy of any coking or cracking reactions) by heat exchangers using HTR steam. At current refineries, attempts are made to keep the streams hot between processes, to reduce the amount of energy necessary to bring the stream back up to temperature. However, this is not always feasible, and there is always some amount of heat loss. This analysis will assume that the product stream leaving a given process will lose 50ºC before entering the next process, and the steam necessary to regain this loss will be included in the tally. An average heat capacity for all product streams was estimated at 0.7 Btu/lbºF or 2.9 kJ/kgK, which corresponds to a heating oil at ~ 300ºC. The steam used for heating product streams is used indirectly, in heat exchangers, and does not come into contact with the product stream, so it is returned to the steam generator.

The quantity of hydrogen required for a facility of this size is approximately 718 tonnes of hydrogen per day. This hydrogen is supplied by steam methane reforming (SMR), using refinery gas at a rate of 241 Btu/scf or 70 GBtu/day. About 115 MWt of the process heat for SMR can be supplied by the HTR. The electricity for this production can easily be provided by the HTR, and this quantity would require about 8 MWe. Ideally, the required hydrogen could be generated utilizing the available process heat from the HTR, however, this integration is not considered in this power block implementation, which is designed to be a stand alone configuration that could easily be sited adjacent to an existing refinery facility, without concern about the transport of really high temperature fluids over 800ºC.

The following table provides the energy requirements for each process, converted to consistent units.

Table 6-10: Refinery Power Block Requirements

Process	Product Flow Rate (kg/s)	Consumed Steam (kg/s)	Stream Temperature Change from – to (ºC)	Indirect Steam Process Heat MWt	Electricity MWe
Atm Distillation	789	26	30 - 400	847	42.73
Vac Distillation	355	12	350-450	103	3.3
Reforming	186	19	400-525	67	14.07
Hydrotreating	682	18	350-400	99	98.08
Catalytic Cracking	302	-30	350-500	131	29.19
Alkylation	59	5	N/A	N/A	18.81
Hydrocracking	79	20	350-400	11	23.65
Visabreaking	0.9	0	350-500	0	0
Coking	112	38	350-500	54	18.57
Total		107.8	N/A	1,426	248.4 [a]

Note: [a] The electricity for steam reforming hydrogen production, 8 MWe is included in this total.

Given the requirements stated in Table 6-10, an 85% capacity factor for the HTR also needs to be factored in with a 46% electricity generating efficiency, brining the total MWt to 2109, which requires 4 HTRs. To meet these requirements, the following configuration is proposed in Figure 6-13.

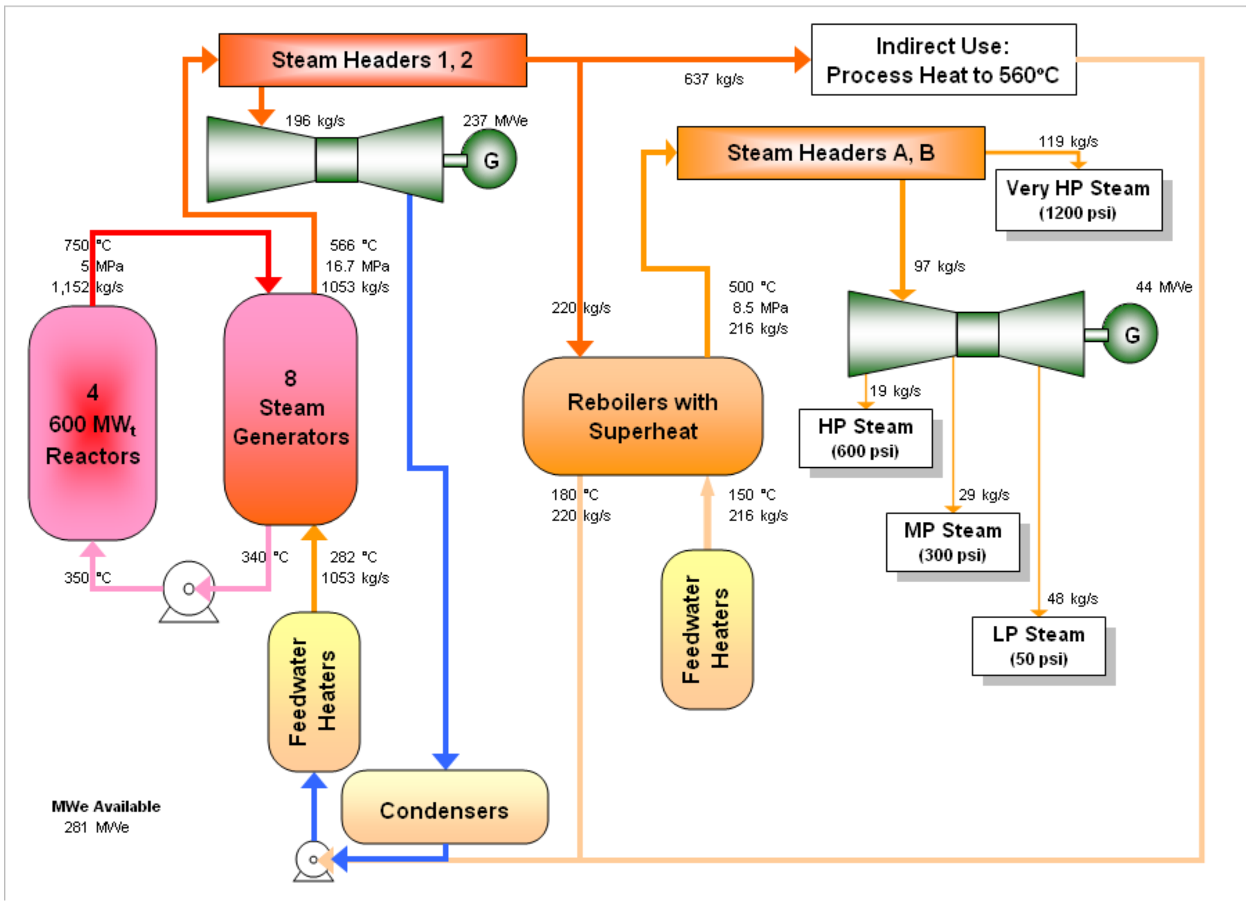


Figure 6-13: Power Block Conversion System

The very high temperature process heat, to heat streams to 500ºC, is part of the first steam loop, which is a closed loop, so all of this steam is used indirectly in heat exchangers, and all of the condensate is returned. The four steam pressures in the second steam loop are in an open loop, and some fraction may be returned as condensate, some fraction may become contaminated by various product streams and be treated in the water treatment plant before returning to the condenser, and some fraction is consumed entirely, and the balance is accounted for in the water make-up stream.

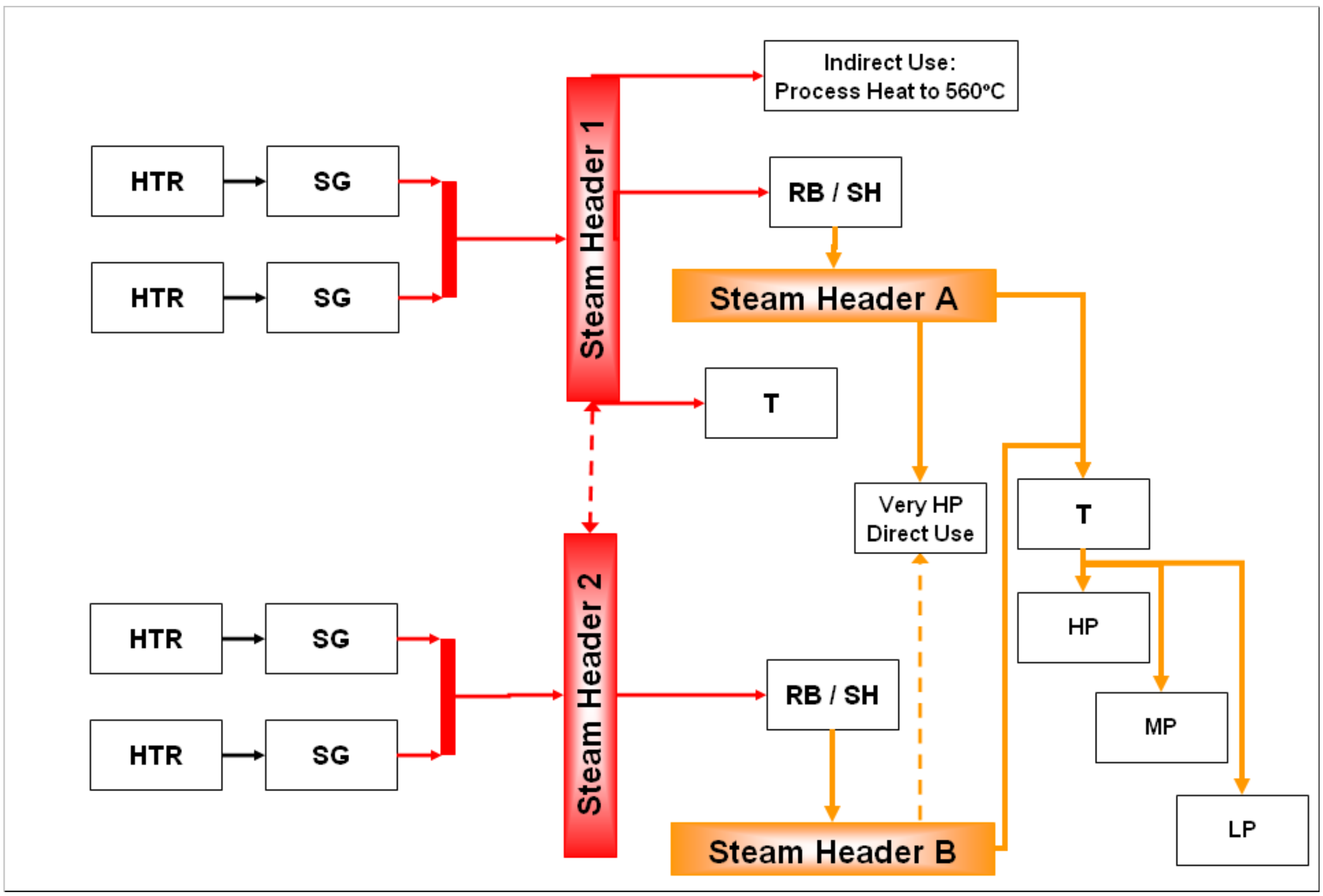


Figure 6-14: Power Block Steam Headers

6.7.2.1 Reliability

Employing 4 HTRs exactly meets the requirements of an existing refinery with a 500,000 bpd capacity. If a new power block were being designed for a new plant, an additional 2 reactors would be warranted to provide for a comfortable margin. But, given that this study is to look at integrating HTRs into an existing facility, it would be more economically feasible to stay with 4 reactors and supplement any additional energy needs with available refinery gas and/or coke in existing boilers and electricity purchases from the grid.

Like the oil sands configuration, there is redundancy in the power conversion systems as shown in Figure 6-14 However, to maintain the plant at full capacity during a scheduled outage or an unscheduled event, the existing fired boilers could be used. For scheduled outages of the HTR equipment, it would be prearranged for the appropriate number of fired boilers to be on-line and ready to supply steam. For unscheduled outages, it would not be necessary or cost effective to keep any fired boilers on-line and ready at all times because the remaining HTR equipment, combined with the option of purchasing electricity from the grid, would be sufficient to maintain critical processes until the fired boiler(s) came on-line.

6.8 Higher Temperature Process Heat

To realize the maximum potential of a high temperature reactor, most facilities would need to be redesigned from conception with all of the integration issues in mind. For some processes that require heat above a certain temperature, the heat source and the process equipment would need to be located as closely as possible, and the process equipment could be redesigned to take heat from a helium or other gas stream rather than from the combustion of hydrocarbons.

An ethylene cracking furnace is shown in Figure 6-15.

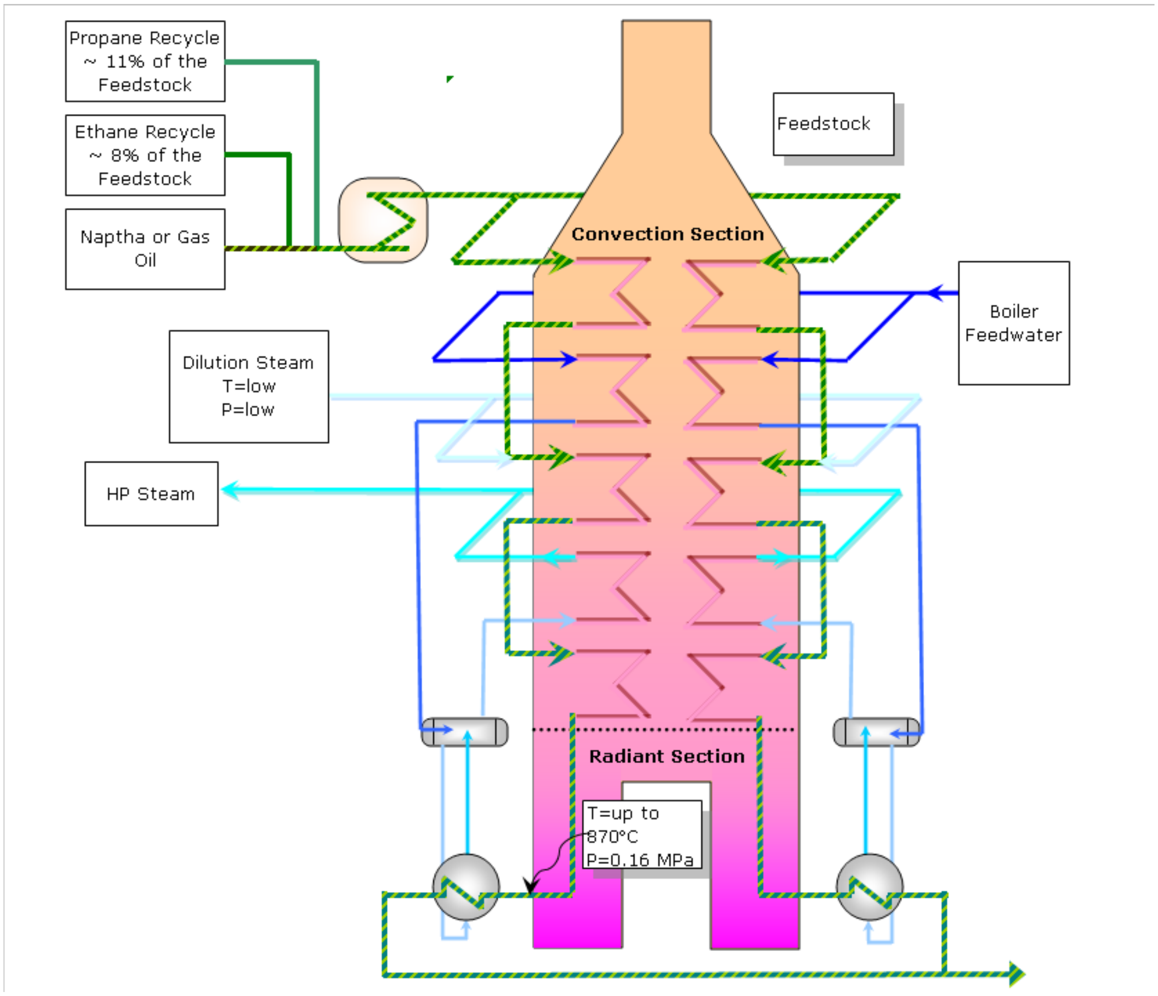


Figure 6-15: Ethylene Cracking Furnace

Direct implementation of the HTR to this high temperature application does not appear to be feasible given this design that requires a combustion heated radiant section. It is unlikely that if a very high temperature helium stream up to 900C were cycled through this existing equipment, that the equipment could be modified to provide the desired heat transfer. The cracking reactions are very sensitive to temperature, and these reactions are currently optimized for very short contact times. In addition, the helium would be under considerable pressure, up to 5 MPa, and this equipment would not be designed to contain such pressures on the shell side. Therefore, the entire ethylene equipment would have to be redesigned from conception. Given this revolutionary source of heat, this effort will likely have a very large return on the investment. Since the HTR technology can not be integrated to the process equipment as is, this section examines some of the issues related to ethylene production, and proposes some very unconventional ideas to be considered down the road.

Currently, cracking is limited by the heat transfer through the coils. If the hot He were introduced straight into a vessel with the ethylene feedstock, where the two fluids were actually in contact, the heat transfer would no longer be a limiting factor. The interface between the streams would have to be designed to provide a very high level of controlled so that exact temperatures and fractions of seconds of contact time could be optimized to produce ethylene, or any desired cracked product, with a high level of efficiency.

The subsequent separation of the He from the product stream would be similar to current methods used in conventional oil recovery, where He is extracted and separated for sale at high levels of purity. The direct contact of the product stream with the helium stream would also reduce the partial pressure of the hydrocarbons, thereby favoring the forward reaction. The ethylene/He contact heat exchanger would need to be designed with the following factors in mind:

1. How can the reaction time be limited to a very high degree of precision, in order to stop further undesired reactions and subsequent degradation of the product?
2. How can the interface of the two fluids be managed to maximize the desired reaction?
3. How can the interface of the two fluids be managed to achieve the highest level of conversion? What type of structures could be used to allow as much feedstock molecule-to-He molecule contact as possible? Nanotechnology?
4. How do we handle the tritium contamination issue? Could an intermediate liquid metal loop be used between the primary helium loop and the tertiary helium loop?

6.9 Results

The results of this analysis show considerable flexibility in PCS configurations for the commercial applications.

For the oil sands application, the steam that gets injected into the ground at the injection wells is in the tertiary loop, so the possibility of contamination is extremely low, with opportunities to identify any leak in the first two loops before any contamination could be released. The same is true for the steam that goes to the upgrading plant that is mixed with the product. The application requires a tremendous amount of energy, 7 reactors worth, so there is ample redundancy in the HTR structure so that no fired burners would be required for backup heating.

The satellite site, which can situate a single HTR in a fairly remote area to recover a relatively small amount of bitumen, is very cost effective because it does not require a turbine or any backup heating for critical processes and the scale of the reactor is very well suited to a region only capable of producing 10,000 bpd, where a larger reactor would be producing excess steam.

For the petrochemical power block application, the steam headers provide steam to the processes in a third open loop, which greatly reduces the chances for contamination, and as with the oil sands configuration, there would be opportunity for a leak to be detected in the first two loops before the steam in the third loop contacted the product stream. The number of reactors for this configuration is on the lower end, in order to minimize investment cost, and the trade-off, which is to use fired burners for backup heat, is a very small cost, considering the equipment is already available on-site, and the operating costs would be minimal because it would only need to operate during scheduled and unscheduled outages of the HTR equipment.

6.10 Conclusions/Recommendations

The conclusions of this analysis indicate that the HTR technology is very well suited to the Canadian Oil Sands application, and the modularity of the HTR design enables overall facility optimization to be carried out. A large central processing facility that contains all of the upgrading equipment, the water treatment plant, and they hydrogen plant, has a very high reliability requirement, and because all three plants are located at one main site, the number of HTRs required to supply the needed energy creates ample backup process heat and electricity, without the need for any gas fired burners to be purchased and kept on the ready.

The reboiler is a critical piece of equipment that allows for heat to be transferred from the closed and pristine secondary loop to the open tertiary loop that is made up of water that does not need to be treated to the exacting standards of a traditional steam generator. Therefore, the water in this loop can come into contact with the product streams, or be injected into the ground and returned via pipeline to the treatment plant, and then be recycled back through the boiler.

Another feature of the PCS that is very well suited to the oil sands application is the use of multi-extraction turbines, in both the secondary and tertiary loops. Steam can be extracted from these turbines at several different points, depending on the temperature and pressure required, and any unused steam remains in the turbine and generates electricity.

For the petrochemical power block application, the availability of both directly used steam from headers at 4 different pressures, and the availability of superheated steam provided in an indirect form for heat exchangers, allows for the elimination of a large portion of the hydrocarbon combustion that currently occurs in furnaces to heat product streams. Like the Oil Sands PCS, the petrochemical power block configuration utilizes a reboiler to allow for an open tertiary loop, and multi-extraction turbines, in both the secondary and tertiary loops allowing for steam at several temperatures and pressures, while any unused steam remains in the turbine and generates electricity. This configuration could be adapted to any existing industrial site to provide electricity and process heat, with minimal integration issues.

7.0 OVERALL CONCLUSIONS

AREVA recommends the direct subcritical steam cycle with initial operations at 750°C- 800°C. This choice has the main advantages over an indirect cycle of minimizing technology and capital cost risks that would be present in an indirect cycle mainly because of the IHX and its associated equipment and development costs. R&D still will be required for the direct steam cycle regarding water ingress, but IHX and some high temperature materials R&D will be eliminated. The direct steam cycle has a slight advantage regarding project schedule and operating cost. The indirect CCGT cycle would have lower reliability and technology maturity than the recommended cycle due to its IHX as well as gas turbomachinery along with having more components.

As far as differences in safety concerns, neither water ingress in a direct steam cycle nor LOHS in an indirect cycle would be a main driver for configuration selection. Both events could be mitigated for the corresponding cycle. Water ingress is mainly an availability issue, while LOHS consequences could be dramatic, but system protection/mitigation is relatively simple.

The potential for product contamination has not been addressed in detail since this report focuses on the PCS for electricity generation, but needs to be considered for future process heat applications. In comparing the direct and indirect cycles potential contamination pathways need to be accounted for when considering configurations for process heat applications. Contamination of process streams through the heat transport pathway is not significant since the heat exchanger in the primary loop (whether an IHX or steam generator) would stop most radionuclides except for tritium.

Tritium that reaches the water/steam loop will become bound in the water molecules, minimizing migration to process heat loops. A reboiler, required for feedwater quality issues, would also minimize tritium migration into the process heat loops. The indirect steam cycle could have a slight advantage regarding tritium control for direct process heat application due to its additional secondary loop, but advantage is minimized because this configuration needs a reboiler anyway for control of feedwater quality.

The recommended cycle would allow use of existing technology to demonstrate lower temperature operation and would address current market needs such as oil refining, petrochemical operations, and oil sands extraction, as well as high efficiency electricity generation. Initial low temperature demonstration would provide a less risky path and act as a stepping stone to higher temperature demonstration to address future market needs for high temperature process heat such as direct hydrogen production.

Key areas where further research or analysis in support of the conventional direct steam cycle is recommended include:

- Testing to provide required data to support water ingress safety analyses (graphite oxidation in steam environment, fuel hydrolysis, fission product washoff)
- Detailed analysis of water ingress scenarios including water transport, reactivity effect, and system pressure (part of normal safety analysis process)
- Inclusion of steam generator (including water ingress events) in plant availability allocation study
- Investigation of tritium migration and control in steam generator and secondary water loops
- Evaluation of reboiler configuration options including high pressure steam capability
- For NGNP configuration with dual mode option (750°C full power vs 950°C at low power) perform further detailed analysis to confirm capability (e.g., flow stability, neutronic stability, temperature distributions, etc.)

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